DOMESTIC ENERGY PARKS – FILLING THE TRANSPORTATION VOID

Final Report

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ACKNOWLEDGMENTS

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DOMESTIC ENERGY PARKS – FILLING THE TRANSPORTATION VOID

EXECUTIVE SUMMARY

The findings of this study show that coproduction of liquid transportation fuels, heat, and electric power in plants that integrate biomass and coal gasification into existing pulp and paper mills can contribute significantly in moving the nation closer to energy independence. Transportation fuels and electric power can be produced at prices that are competitive with current markets. Fuels produced from biomass are essentially carbon neutral in the environment, and the processes used for gasifying coal and converting syngas to liquid fuels and power offer opportunities for strict control of carbon emissions and priority pollutants. Carbon capture and coprocessing with biomass can appreciably reduce the carbon intensity of the overall process in the interest of using the nation's abundant coal resources to reduce dependency on imported oil.

Study Approach

The driving forces that governed this study were the need to produce alternative transportation fuels from domestic resources at or below market prices and the growing recognition that high levels of carbon management will be required in the future. The objective is to develop energy parks that process biomass and coal to produce transportation fuels, chemicals, and electricity under policies that place strict controls on carbon emissions. This study evaluates the integration of synfuels and power production from biomass and coal in four pulp and paper mills in different regions of the country (South, Northeast, Midwest, and West) to reflect differences in local markets, including coal and electricity prices, environmental regulations, water use restrictions, and demand for various products. The mills selected have access to coal resources, potential sites for CO_2 sequestration, and marketing infrastructure (e.g., oil refineries). The engineering design and financial analysis performed for each of the four mills was based on the conceptual flow diagram shown in Figure ES-1 (Figure 5 in text). Summary data for the existing mills and the integrated plants along with financial results for the most promising case studies are given in Table ES-1.

Major Findings

The results of this study support the following findings:

- The pulp and paper industry provides an ideal platform for economically viable synfuel production from coal and biomass. The industry has the existing infrastructure for harvesting and transporting biomass at low cost, and the steam and electric power required on-site can be provided by biomass–coal integrated plants.

- Utilizing coal along with biomass allows the construction of large plants that offer economy of scale for producing profitable amounts of fuel, chemicals, and power for sale off-site, which typically would not be possible using only the biomass available within an economic transport radius of the plant.
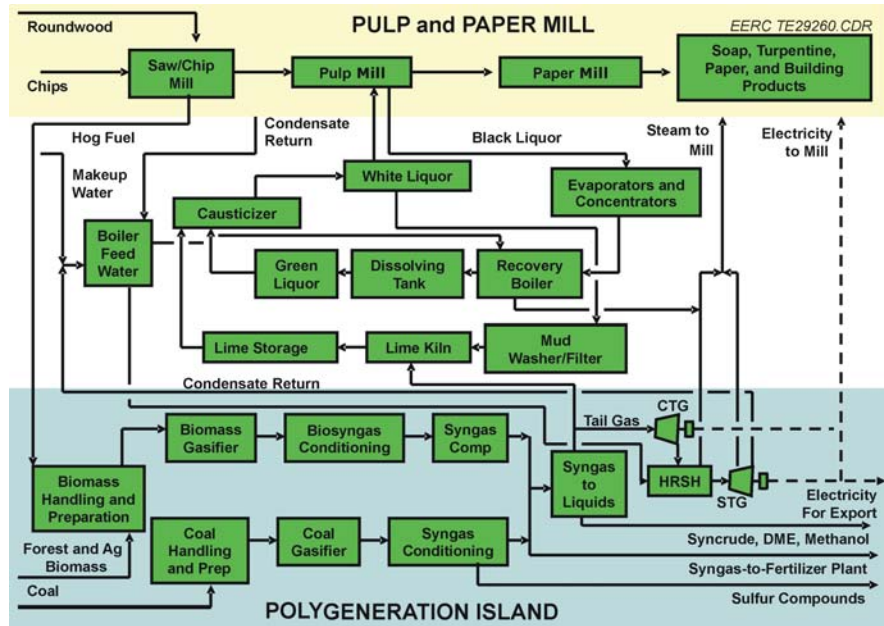
Figure ES-1. Typical block diagram for a polygeneration plant at or adjacent to a pulp and paper mill.

- High thermal efficiencies can be achieved in converting carbon feedstocks to syncrude for production of transportation fuels, ranging from 63% to 72% for biomass and from 46% to 65% for biomass and coal.

- Capital costs for plants producing between 14 and 17 thousand barrels of syncrude per day from coal and biomass (Mills 1–3 in Table ES-1) range from $1.6 billion to $1.8 billion for the most promising cases studied, and the first-year selling prices are in the range of $46 to $57/bbl ($7.61 to $9.42/MMBtu).

- For dimethyl ether (DME), the second product studied, capital costs are marginally higher but product prices from the coprocessing of coal and biomass are lower, in the range of $5.00 to $7.13/MMBtu.

- Processing biomass only in Mill 4 resulted in the lowest cost overall for syncrude at $43/bbl or $7.11/MMBtu, indicating that low-cost biomass fed at high rates can be as economically viable as coprocessing with coal.

- Carbon in captured CO_2 ranged from 41% to 45% of the carbon in the coal and biomass for production of syncrude, and 45% to 52% for production of DME. Taking credit for biomass neutrality at a high biomass feed rate would increase the effective level of carbon control to about 75%. Carbon capture, along with use of biomass, offsets the carbon intensity of liquid fuels produced from coal.

- The advanced synfuel technologies required for coproduction of liquid fuels, chemicals, and electric power from coal and biomass are commercially available and are suitable for integration with pulp and paper plants.

Synfuels Products

The products selected for study were syncrude produced by Fischer–Tropsch (FT) technology for subsequent conversion to diesel fuel and gasoline and DME for use as a fuel additive. These products satisfy the strategic need for alternative transportation fuel derived from domestic resources, and they can be produced using commercially available technologies. The primary FT product is a sulfur-free crude oil containing straight-chain olefins and paraffins without any aromatics and producing no heavy bottoms in refining. FT products can be refined far more easily than heavy crude oil, providing a price premium estimated to be as high as $10 a barrel. Refined FT diesel is a premium fuel having lower sulfur content and a higher cetane number than diesel produced from petroleum. DME is a gas at ambient temperature which liquefies under slight pressure and can be handled and transported like liquefied petroleum gas (LPG), for which it is a suitable substitute. DME also has a high cetane number and can be blended with diesel fuel. DME blends can achieve the same efficiency as straight diesel fuel in suitably adapted diesel engines. A number of other fuels and chemicals were considered in the early stage of this study, including methanol, hydrogen, and ammonia fertilizer. All of these products can be produced from syngas by commercial technologies similar to those evaluated in this study. The choice of product will be determined by the market in a particular region of the country and by the project owners, which may include stakeholders such as rural electric cooperatives.

Integration of Commercial Technologies

Alternative technologies were evaluated to determine their commercial readiness and their suitability for integration into a pulp and paper mill. Suitable commercial technologies were found to be available for all of the required unit processes. These included technologies for biomass and coal gasification, syngas cleanup, shift conversion to adjust the H_2/CO ratio, and conversion of syngas to FT syncrude or DME. The general arrangement of these technologies is shown in Figure ES-1.

Kraft mills are chemical plants that convert wood to pulp and paper products and require large amounts of steam, electric power, and recycled chemicals for internal use. About 5 tons of steam is needed for each ton of product, plus additional steam for generating the electricity sold off-site. This makes a kraft mill an ideal heat sink for cogeneration of steam and electricity and heat recovery from synfuel processes. The integrated plant is synergistically suited for using waste wood and black liquor for synfuel production and to recover heat needed in the kraft process. Because of technical similarities between the chemical processes, operators of kraft mills already have the knowledge and skill required to run the integrated plant.

The technology offered by ThermoChem Recovery International Inc. (TRI) is the only biomass gasification process that has been successfully operated on a commercial scale in North America. This technology utilizes a bubbling fluidized-bed steam reformer operating at

atmospheric pressure. Heat is introduced by proprietary pulsed heater tubes immersed in the bed. Both wood waste and black liquor feeds can be processed. The sodium in black liquor is recovered as solid sodium carbonate, and sulfur is reduced to hydrogen sulfide in the raw syngas.

Coal gasification offers high efficiency, low emissions, and opportunities for cost-effective CO_2 separation. It is the key technology for using coal to reduce dependency on foreign energy sources. The ConocoPhillips gasifier selected for this study is a two-staged, entrained-flow, slurry-fed gasifier which meets the downstream process requirement for syngas with a high H_2/CO ratio and essentially no methane or other hydrocarbon products. Because slurry is fed in two stages, the design is more adaptable to processing high-moisture coals than other slurry-fed gasifiers. The design has been tested on Appalachian and Illinois bituminous coals, Wyoming subbituminous coal, and Texas lignite. The gasifier has operated successfully on Illinois Basin bituminous coal and petroleum coke in a 262-MW integrated gasification combined cycle (IGCC) Clean Coal demonstration project at Wabash River Plant since 1995.

Separate syngas cleanup systems were selected for the biomass and coal gasifiers because of differences in operating pressures and temperatures and the different sulfur contents in coal and biomass. Syngas from the biomass gasifier passes through a series of cyclones to remove particulates and unburned carbon and is then cooled in a heat recovery steam generator to remove condensable hydrocarbons. The coal gas requires more elaborate cleanup, including initial cooling in a fire-tube heat recovery boiler, particulate removal in a cyclone and dry char filter, scrubbing to remove water-soluble impurities, hydrolysis to convert COS to H_2S and CO_2, and, finally, removal of acid gases (H_2S and CO_2) using methyl diethanol amine (MDEA). The stripped carbon dioxide is combined with CO_2 from FT or DME plant tail gas and compressed storage. A sulfur-polishing step reduces the H_2S content of the syngas to less than 0.03 ppmv as required to prevent poisoning of the downstream catalysts.

To produce liquid fuels from coal, it is necessary to increase the atomic hydrogen to carbon ratio (H/C) of the syngas to a suitable level. As points of reference, the H/C ratio of bituminous coal is about 0.8, the typical ratio for crude oil is 1.3 to 1.9, and the ratio for gasoline and diesel fuel is about 2. The H/C ratio of the syngas is adjusted using a catalyst to promote the water–gas shift reaction, $CO + H_2O \rightarrow H_2 + CO_2$.

FT synthesis is a well-established commercial technology used by Sasol in South Africa to convert 51 million tons of coal annually to synthetic fuel and chemicals; it was previously used in the 1930s in Germany, Japan, and Manchuria; and most recently it has been used by Shell in gas-to-liquid plants built in Malaysia and Qatar in the 1990s and early 2000s. FT processes operate in different temperature regimes to produce either predominantly gasoline at high temperature or high-quality diesel at lower temperature. Sasol, Shell, BP, Rentech, Sasol Chevron, and others supply proprietary FT technology using either cobalt- or iron-based catalyst. Different fixed-bed, fluidized-bed, and slurry-phase reactors are offered depending on temperature and the desired product slate. The heavier FT liquids are separated from the entrained catalyst by filtration, cooled, and mixed with the lighter hydrocarbons. The low-octane naphtha fraction, which requires further upgrading for use as a gasoline-blending component, can also be used as an excellent feedstock for an ethylene cracker. Unconverted syngas and light hydrocarbons are compressed and sent to combustion turbines for power generation.

DME synthesis processes are offered by a number of well-known technology licensors including Air Products and Chemicals, Chevron, NKK Itochu, Mitsubishi, Haldor Topsoe, and others. Commercial plants are operating or are under design and construction in China, Iran, Japan, Qatar, and Russia. The synthesis of DME generally takes place in two steps involving methanol synthesis followed by dehydration of the methanol. It can also be synthesized directly from carbon monoxide and hydrogen. The synthesis pathway chosen depends on the syngas composition and the catalyst used. DME is separated from by-products by distillation, and the methanol is recycled. The carbon dioxide produced is further separated, compressed, and sent to storage.

Financial Analysis

The prices shown in Table ES-1 are based on the first-year selling price (tariff) that would meet obligations for that year and provided a 15% internal rate of return on equity with an annual price escalation of no more than 5% per year. The first-year price is the financial metric that can most suitably be compared to current market prices. The economic assumptions used were a 20-year plant life, a debt/equity ratio of 35/65, 9% interest on debt, 39% income tax, and 20-year straight-line depreciation. The first-year product prices shown here were calculated for a reference coal price of $25/ton with a heating value of 10,900 Btu/lb. Other financial metrics included in the report are the escalated price in Year 20 and a levelized cost presented for comparison with other studies that use that metric.

Prices for syncrude in Table ES-1 fall in the range of $43 to $57 per barrel, fully competitive with current crude prices without counting a premium for the high quality of the FT product. Estimated prices for DME in the range of $129 to $320 per ton are all below the early 2006 contract price of $520 per ton in the international market and 2005 average refinery gate price of $412 per ton in the United States for LPG. Estimated prices for electricity in the range of $38 to $57/MWh with CO_2 capture are almost competitive with existing wholesale power rates in the four regions of this study and are well below the projected cost of new coal-based generation that includes carbon capture. In this study, carbon capture increased capital cost by about 33%, reduced net electricity generation by about 17%, and increased the price of electricity by 27% to 34%. The cost of captured CO_2 is in the range of $15 to $17/ton, which may allow profitable sale for tertiary oil recovery in some locations. Regional variations in the price of coal between $0.79 and $1.15/MMBtu in relation to reference coal at $25/ton or $1.15/MM Btu resulted in price reductions ranging from essentially none up to 10% for syncrude, 31% for DME, and 13% for electricity, with the greatest reductions in the South and Northeast.

Table ES-1. Summary of Plant Data and Financial Results

	Mill No. 1	Mill No. 2	Mill No. 3	Mill No. 4
Current Characteristics of the Mills Studied				
Location	South	Northeast	West	Midwest
Feed Materials	Wood chips	Wood chips and round wood	Wood chips and recycled paper	Wood chips and round wood
tons/day	1616	2072	1989	2860
Pulp and Paper Products				
tons/day	811	1184	1548	1124
Fuel Source	Natural gas	Coal and wood waste	Natural gas	Natural gas and wood waste
Steam Generated				
lb/hr	654,305	746,200	832,760	1,407,298
tons/day	7852	8954	9993	16,888
Electricity, average MW				
Generation	30	50	73	85
Imported	5	9		
Exported			23	14
Selected Results for the Integrated Synfuels/Cogeneration Plant for the Most Promising Cases[1]				
Feed Materials				
Biomass, tons/day	1386	1886	6708	4170
Coal, tons/day[2]	10,807	10,807	10,807	none
Carbon in Captured CO_2, % of C in Feed Normalized to Account for 100% of C	45.6%	45.4%	44.1%	
Product, Syncrude Case[3]				
Syncrude, bbl/day	13,868	14,202	16,803	3747
tons/day[4]	2117	2168	2566	572
Exported Electricity, MW	542	459	346	14
Product, DME Case				
DME, tons/day	5290	4006	4503	845
Exported Electricity, MW	567	642	260	14

Continued…

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Table ES-1. Summary of Plant Data and Financial Results (continued)

Capital Cost, $million				
Syncrude Product	$1618	$1606	$1778	$279
DME Product	$1894	$1635	$2010	$369
First-Year Selling Prices[5]				
Syncrude, $/bbl:$/MM Btu[4]	$57:$9.42	$46:$7.61	$51:$8.43	$43:$7.11
DME, $/ton:$/MM Btu	$177:$6.86	$129:$5.00	$184:$7.13	$320:$12.40
Electricity, $/MWh with CO_2 capture	$38	$42	$57	$41
Cost of CO_2 Captured, $/MWh[6]	$8	$9	$13	$9
Cost of CO_2 Captured, $/ton[6]	$17	$16	$16	$15

[1] The cases summarized for Mills 1–4 are FT-1-2A, FT-2-2A, FT-3-1A, and B-FT-4, respectively, for syncrude production and DME-1-2A, DME-2-2A, DME-3-1A, and B-DME-4 for DME production.

[2] The price of reference coal was set at $25/ton, equivalent to $1.15/MMBtu at 10,900 Btu/lb. The price of biomass was $11.80/ton, equivalent to $0.67/MMBtu at 8858 Btu/lb. Differences in regional coal prices between $0.79 and $1.15/MMBtu had only modest effect on product prices (not shown here).

[3] Syncrude produced by FT synthesis.

[4] Conversion from bbl/day to tons/day and from $/ton to $/MMBtu are based on the density and heating value of light crude at an American Petroleum Institute (API) gravity of 30.

[5] Based on the first-year selling price (tariff) that met obligations for that year and provided a 15% internal rate of return on equity with an annual price escalation of no more than 5% per year. Other economic assumptions were a 20-year plant life, a debt/equity ratio of 35/65, 8% interest on debt, 39% income tax, and 20-year straight-line depreciation. The first-year product prices shown here were calculated for coal prices at $25/ton with a heating value of 10,900 Btu/lb.

[6] Costs for CO_2 capture are for cases in Table 35 that are based on average tariffs over 20 years not the same as those used to compute the first year price of electricity.

Applying the Findings of This Study

This study identified authenticated opportunities in the pulp and paper industry where biomass is being economically harvested and transported to plant locations having access to coal. The strategic importance of integrating coal and biomass to coproduce alternative transportation fuels and electric power is derived from the economy of scale provided by coal utilization and the ability of biomass and carbon capture technologies to offset the high carbon intensity of coal derived fuels. Prices for the fuel and power produced were shown to be competitive in current markets. Commercialization of these opportunities will be advanced by national policies requiring controls on carbon emissions. The stakeholders having a direct interest are in the mining, agriculture, forestry, refinery, and power industries—including rural electric cooperatives.

DOMESTIC ENERGY PARKS – FILLING THE TRANSPORTATION VOID

INTRODUCTION

This study explores the potential for domestic energy resources to mitigate the high prices, volatility, and security concerns associated with current oil and natural gas markets. It assesses the technical and economic potential of domestically produced coal and biomass resources to serve as feedstock for energy parks that would generate a number of useful products for the nation's liquid fuels, steam, electricity, chemical, and fertilizer markets. The study focuses on existing infrastructure and institutions such as the pulp and paper industry and regional energy cooperatives and presents a description of the technologies required for converting the above-mentioned domestic resources to useful products, followed by an examination of their economics and product markets in different regions of the country. Carbon management is an explicit consideration of this study.

This study was cofunded by the National Commission for Energy Policy (NCEP) and the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). It was carried out by 3E Consulting, LLC, under a subcontract with the University of North Dakota Energy & Environmental Research Center (EERC) and with guidance from a Review Committee. The members of the Review Committee were selected by NCEP because of their extensive experience in gasification technology, coal- and biomass-to-liquid technologies, environmental issues, and understanding of regional market forces and issues (see Figure 1).

Study Scope and Objective

The objective of this study is to evaluate the potential for pulp and paper mills to be an anchor for developing energy parks for production of liquid and gaseous fuels, chemicals, and/or electricity from biomass and coal in a carbon-managed environment. The goal is to improve the economic viability of producing domestic hydrocarbon-based energy and chemical products (including fertilizer) while enhancing pulp and paper mills' economic and environmental performance by developing a new energy and chemical delivery system model for the mills and their surrounding communities. The product mix and quantities are dictated by product cost and local market forces, with no intention of reducing pulp and paper production from its current levels. The study considers four typical pulp and paper mills in four different regions of the country to reflect differences in local markets, such as coal and electricity prices, environmental regulation, water use restrictions, product mix, etc. It evaluates the potential financial viability and economics of collocating biomass- and coal-based polygeneration plants at these mills assuming a rural electric cooperative-owned project structure.

The study began by identifying and characterizing the operating kraft mills in different regions of the United States and selecting representative candidate mills for analysis.

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Figure 1. Project organizational structure.

Next, publicly available data (steam, hot water, and electric demand; steam pressure; fuel-mix use; and access to biomass and coal resources and potential CO_2 sequestration sites) for each candidate mill were reviewed to select four mills: one in each pulp- and paper-producing region (South, Northeast, Midwest, and West) of the country. The collected data on selected mills were then used to simulate current energy consumption of the mill and ensure that future polygeneration simulated models meet the current energy demand and steam conditions required by the mills. The energy and material balances, at different biomass and coal feed rates, were used to develop equipment sizes and estimate capital and operating costs for assessing the economic and environmental impact of various cases at each mill. At the outset of the study, it was determined that the study should focus on production of Fischer–Tropsch (FT) fuels and dimethyl ether (DME) as a fuel additive because of the commercial availability of those technologies, increasing demand for transportation fuel in the United States, and national energy security issues.

U.S. Pulp and Paper Industry

The United States is one of the world's largest paper consumers and enjoys significant fiber resources. However, since the late 1990s, the competitive status of the U.S. pulp and paper industry has been eroding, and the industry's financial performance has not met investor expectations.[1] Aging assets, high energy consumption costs, capital-rationing strategies, and international competition are some of the reasons for the erosion of U.S. pulp and paper competitiveness. For the U.S. pulp and paper industry to flourish, an essential ingredient is for it

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[1] McNutt, J.; *State of the North American Pulp & Paper Industry – An Update & Outlook – Industry Competitiveness & Transformation to Survive & Dominate;* TAPPI EPE Conference, Atlanta, GA, Nov 6, 2006.

to transform itself into a proactive, sustainable biomass industry that not only produces its traditional pulp and paper products but also produces other products, such as transportation fuel, electricity, and intermediate hydrocarbon products for production chemicals and fertilizers. In those geographic areas where appropriate and where there are adequate coal supplies, teaming with coal producers and suppliers may offer greater business opportunities by coprocessing biomass and coal to produce a wide range of liquid fuels, chemicals, hydrogen, electricity, and heat.

The pulp and paper industry in the United States, unlike in other countries, relies on privately owned forest land for most of its raw material. The industry is accustomed to sustainable use of privately owned forest land, harvesting and transporting the timber it grows, and processing it into raw material for the production of pulp and paper. Although the industry uses a substantial amount of fossil energy, it is also the largest producer and user of biomass energy. Renewable resources used in this industry for energy production are hog fuel (woody residues including bark and wood waste) and black liquor, a pulping waste product. According to the American Forest and Pulp Association, biomass energy accounted for about 1.3 quads (10^{15} Btu) used by the industry in 2004.[2] This is exclusive of a substantial amount of biomass residue that is left behind in the forest after the harvesting of trees for pulpwood. DOE and the U.S. Department of Agriculture (USDA) estimate that the United States has the potential to produce over 1.3 billion dry tons per year of biomass—"enough to produce biofuels to meet more than one-third of current demand for transportation fuel.[3]" That is about 16 quads Btu per year, or 2752 million barrels of oil. This is, however, much greater than the Energy Information Agency (EIA) projection of 5.04 quads of biomass production by 2025 which, at 60% conversion efficiency, would only supply about 6% of 49 quads liquid fuel consumption in 2025.

Most pulp and paper mills in the United States, in particular chemical mills, also produce steam, electric power, and chemicals for their internal use; some mills also export electricity. Most mills also rely on fossil fuels—natural gas, oil, or coal—to meet some of their steam and electric power demand. A mill's demand for steam makes it an ideal heat sink for cogeneration of steam and electric power; adding to that the mill's need for transportation fuel (for transporting its raw and final products) and chemicals (e.g., sulfur for chemical cooking) makes chemical mills an ideal site for polygeneration of steam, electricity, liquid fuel, and chemicals.

Today, about 160 pulp and paper mills operate in the United States.[4] They include 105 kraft, six sulfite, 23 semichemical, and 27 mechanical mills. A typical kraft mill produces about 1000 tons a day of pulp and 700,000 lb/hr of steam, exports about 35 MW$_e$, and has a chemical recovery plant. Figure 2 shows the distribution of kraft mills in the United States by region. Figure 3 shows the approximate locations of the kraft mills.

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[2] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006, p. 1.

[3] Perland, R.D. et al. *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: Technical Feasibility of Billion-Ton Annual Supply;* Oak Ridge National Laboratory, April 2005.

[4] 2005 Lockwood-Post Directory of Pulp and Paper Mills.
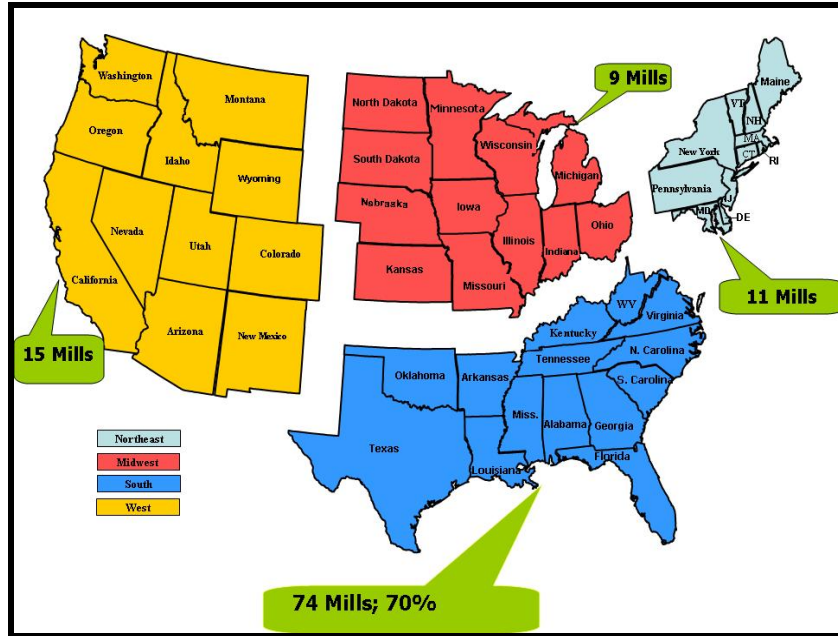
Figure 2. Operating kraft mill distribution.
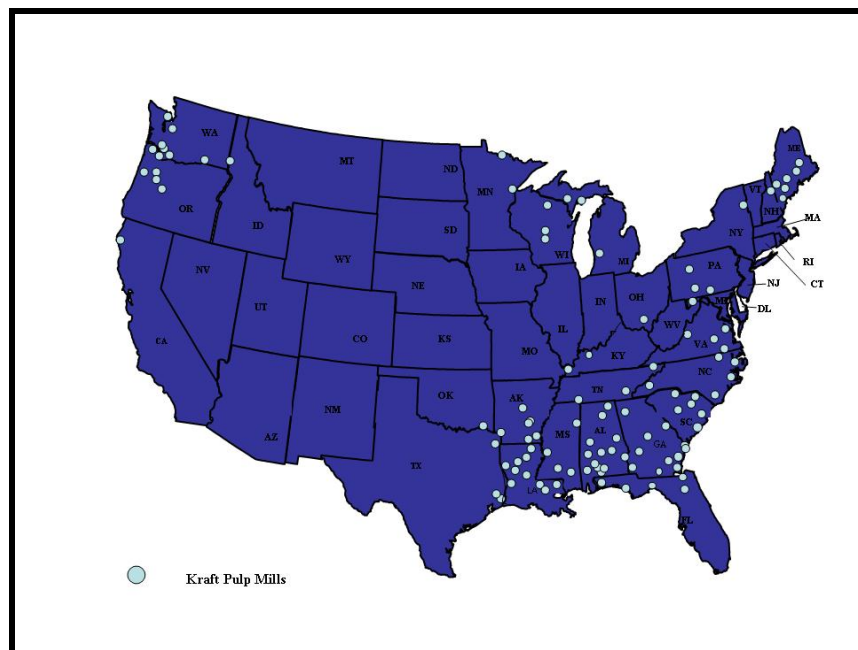
Figure 3. Operating kraft mill locations.

Table 1 lists the major characteristics of U.S. kraft mills. These characteristics can be summarized as follows:

- Almost 70% of the mills located in the South (a high percentage of privately owned forest land also is located in the South[5]).

- Most mills in the South rely on natural gas for power generation to some extent; a few mills rely 100% on natural gas.

- The fuel of choice in the Northeast is oil and in the Midwest is coal.

- Western mills rely on natural gas and oil as their primary fuel.

- About 17% of the mills in the South generate more than 2000 MWh/d of electricity for their internal consumption.

- Most mills purchase some electricity to meet their needs.

In the 1990s, most mills, particularly in the South, began increasing their reliance on natural gas because of its low cost and environmental benefits (the U.S. pulp and paper industry consumes about 504 trillion Btu per year, 9% of the nation's total natural gas consumption, and is the fifth largest consumer of natural gas after the chemical [28%], petroleum [15%], primary metals [12%], and food [10%] industries[6]). Some mills also reduced their electricity production because of the availability of low-cost electric supply. Natural gas and electricity prices have increased since 2000, requiring mills to reevaluate their energy supply and resources. Increased reliance on imported fuel (natural gas, oil, and refined hydrocarbon products), high fuel prices, the energy intensity of pulp and paper mills, the lack of reliable and secure imported fuel sources, access to biomass resources, and advances in biomass conversion technologies have created an impetus for some mill owners and/or operators to move toward collocating biorefineries or polygeneration plants at or adjacent to their mills. However, the size and the economic benefits of these biorefineries or polygeneration plants are limited by the availability of the maximum amount of biomass resources that can be economically transported to the mills. The economics of liquid production facilities also favor large-scale plants. This study evaluates the potential economic benefit of larger polygeneration plants located adjacent to pulp and paper mills by coprocessing or refining biomass and coal.

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[5] U.S. Department of Agriculture. http://ncrs.fs.fed.us/4801/regional-programs/tpo/.
[6] U.S. Department of Energy/Energy Information Agency 2002 data.

Table 1. U.S. Kraft Mill Characteristics

U.S. Regions	South	West	Midwest	Northeast
Number of Mills	74	15	9	11
Mill Characteristics	Number of Mills			
Recovery Boiler Capacity, TSPD				
Less than 1000	5	2	5	5
1000–2000	25	7	5	6
2000–3000	26	5	0	0
3000–4000	14	0	0	0
Greater than 4000	4	1	0	0
Steam Generation Capacity, lb/hr				
Less than 1,000,000	32	9	5	4
1,000,000–2,000,000	16	4	3	1
Greater than 2,000,000	1			
Unknown Capacity	25	2	2	6
Self-Generation Capacity, MWh/d				
Less than 1000	19	4	6	5
1000 – 2000	28	3	2	2
2000 – 3000	10			
Greater than 3000	1			
Unknown Capacity	16	7	1	3
Purchased Electricity, MWh/d				
Less than 100	8	1	1	3
100–500	30	3	1	2
500–1000	14	3	4	2
1000– 2000	5	2		
Greater than 2000	3			
Unknown	10	5	2	3
Power Sale, MWh/d				
Up to 550	4		1	1
Mills with CTG				
CTG Capacity, MWe	25–80	40–60		Less than 10
Number of Mills	5	2		1
Boiler Fuel Mix				
Natural Gas (NG)	2			
NG and Bark/Waste (B/W)	10	4		1
NG, B/W, and Oil	15	3		
NG, B/W, and Coal	3		3	
NG, B/W, Oil, and Coal	7		3	
NG and Oil	1	3		
Oil and B/W	3			5
Oil, B/W, and Coal	7			1
Coal and B/W	3			
Coal and Oil			1	
Unknown	23	6	2	4

KRAFT PULP AND PAPER MILLS WITH INTEGRATED BIOMASS–COAL GASIFICATION, BIOLIQUID FUEL, AND POWER GENERATION SYSTEMS

Figure 4 presents a simplified block diagram for a typical kraft mill. It consists of three different process operation areas: pulp- and paper-processing operation, including receiving and processing of round woods and chips; black liquor processing for recovery of chemicals and energy; and power island or plant. As such, a pulp and paper mill is a pulp and paper, chemical, and energy production or a polygeneration facility.

At a typical kraft mill, logs are debarked and chipped. Bark and waste wood (known as hog fuel) is used as boiler fuel. The clean chips are sent to the pulp mill where a cooking chemical, a solution of sodium sulfite (Na_2S) and sodium hydroxide (NaOH), known as white liquor, is used in the digester to separate cellulose from lignin and hemicellulose material in the wood chips. Cellulose is then recovered in a subsequent washing step. The separated cellulose is processed into pulp and/or paper products depending on the mill type. The spent liquor, containing lignin, hemicellulose, and pulping chemicals, is known as black liquor. It contains about 50% of the energy content of wood sent to the digester and a significant amount of sulfur and sodium. To make effective use of this energy and to recover the valuable chemicals, the black liquor solids are concentrated in an evaporator, and solids containing not more than 25% moisture are burned in a recovery boiler. The organic content of the black liquor is burned to produce steam, the inorganic compounds leave the boiler as molten smelt containing Na_2S and Na_2CO_3. The smelt is dissolved in water to produce green liquor. Lime (CaO) is added to the green liquor in the causticizer to convert Na_2CO_3 to NaOH for reuse in the pulp mill. The lime
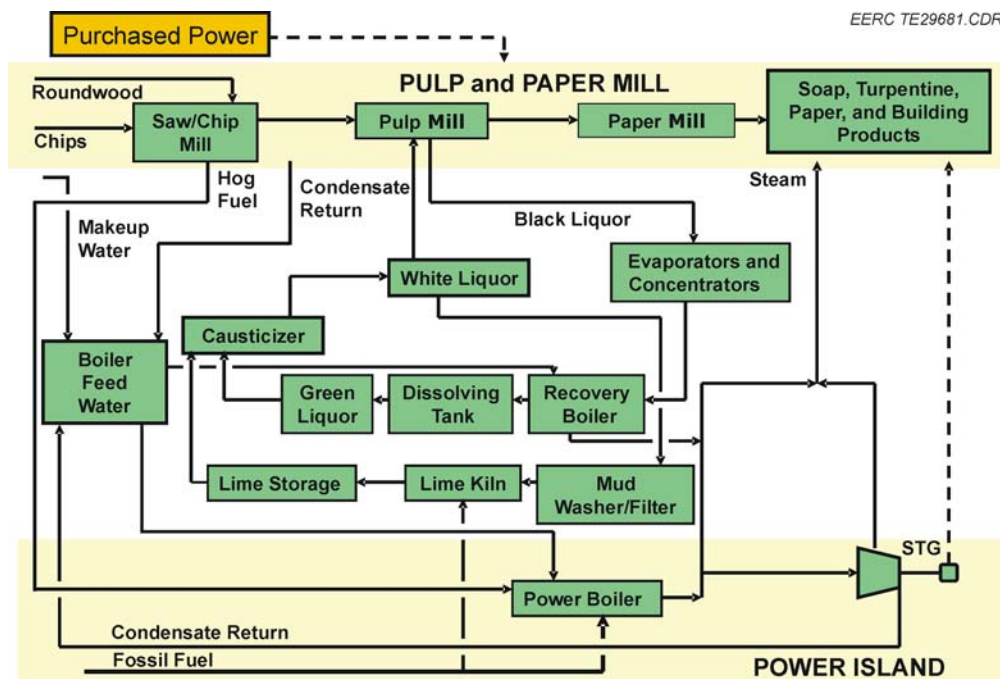
Figure 4. Typical kraft mill block diagram.

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that is converted to $CaCO_3$ in the causticizer is separated and converted back to lime by heating in a kiln. The recovery boiler is the most expensive piece of equipment in a mill[7] and is subject to occasional explosions because of the adverse reaction of molten slag and water. Recovery boilers are expected to be replaced with more advanced gasification technology in the future because of more stringent environmental regulations and safety hazards associated with recovery boilers.

The pulping process is energy-intensive, and power boilers are used to generate steam for the mill's use. Some mills also generate electricity using a steam turbine. A few mills also generate electricity using combustion turbines and hydropower.

Figure 5 shows the replacement of the mill's power plant with a new polygeneration island based on biomass and coal. The island consists of a biomass and coal gasifier with their associated gas-cleaning trains and a syngas-to-liquid plant. The tail gas from the syngas-to-liquid plant is used in a combined-cycle plant to generate electricity. The proposed configuration does not include replacing the recovery boiler with a black liquor gasifier. Addition of a black liquor gasifier could further improve the energy efficiency of the integrated plant, but it could also necessitate changes to the cooking chemistry [8] if a low-temperature steam reformer is used or to the kiln if a high-temperature partial oxidation-type gasifier is used.[9] The reported changes in the cooking chemistry can also increase pulp production.[10] For the purposes of this study, a decision was made not to consider replacing the recovery boiler in order to minimize changes to current mill operation. Furthermore, based on a preliminary analysis, a decision was made not to consider cogasification of biomass and coal in a single gasifier. Cogasification of up to 30% biomass with coal is reported to be practical in large-scale commercial gasifiers.[11] However, a preliminary energy and material balance analysis showed a lower CO_2 generation for the multiple-gasifier configuration. The lower CO_2 generation not only reduces the plant's overall CO_2 emissions but could also reduce costs associated with CO_2 separation, pressurization, transportation, and storage. This advantage appears to decrease as the amount of biomass is increased. The lower CO_2 generation with separate gasifiers is also reported in an unpublished study that is currently being carried out by others.[12] Figure 6 exemplifies how CO_2 generation changes as a function of biomass-to-coal ratio for a single partial oxidation gasifier and a multigasifier configuration using a partial oxidation gasifier for coal and an indirectly heated steam reformer for gasifying biomass. The lower CO_2 generation of the multigasifier configuration can be attributed to:

- The lower-temperature requirement for biomass gasification and, therefore, lower demand for combustion of biomass to generate the heat required for the endothermic gasification reactions.

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[7] Biermann, C.J. *Essentials of Pulping and Paper Making;* Academic Press, 1993, p. 110.
[8] Discussions with TRI representatives at TAPPI EPE Conference, Atlanta, GA, Nov 2006; and Biomass Thermochemical Workshop, Washington DC, Jan 2007.
[9] Larson, E.D.; Consonni, S.; Katofsky, R.E. *A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry;* Final Report; Oct 2003.
[10] Ibid.
[11] Hofmester, J.D. Key Note Session, Gasification Technologies Conference,   Washington, DC, Oct 2006.
[12] Private correspondence with Dr. D. Cicero, Dec 2006.
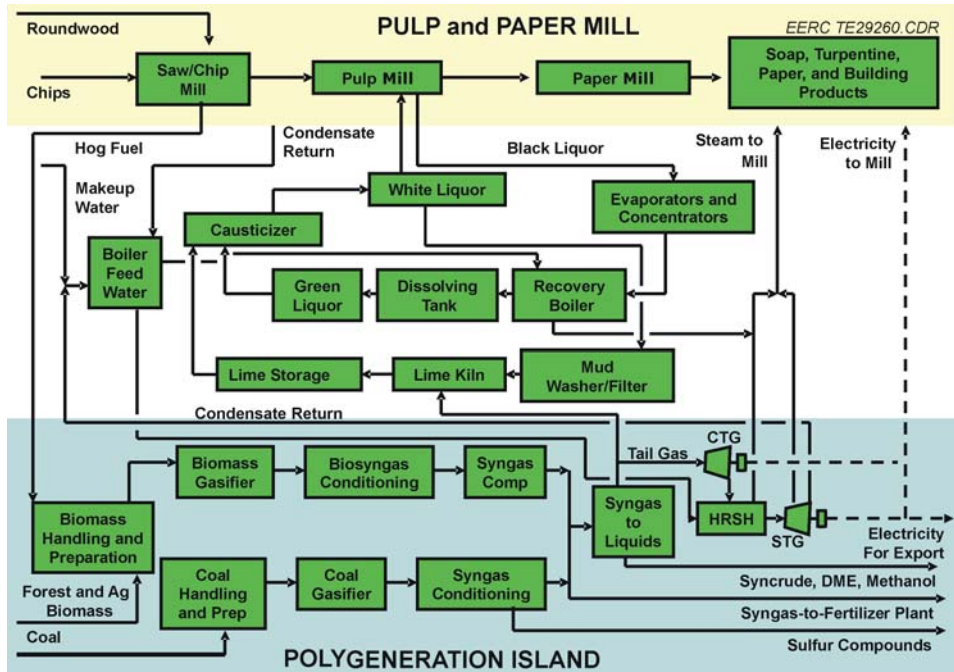
Figure 5. Typical block diagram for a polygeneration plant at or adjacent to a pulp and paper mill.
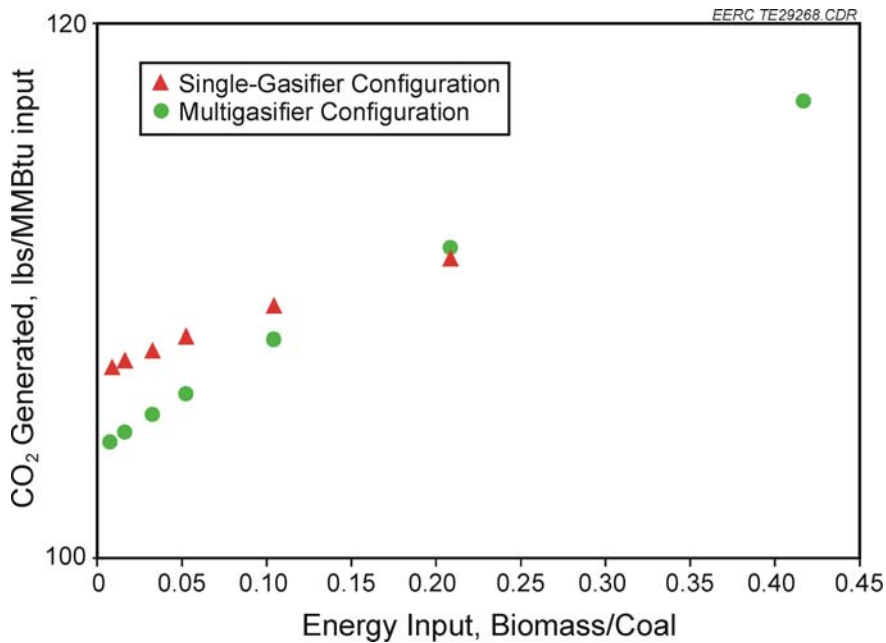
Figure 6. CO_2 generation from cogasification of biomass and coal in single- and multigasifier configuration systems. At an energy input of about 0.25, biomass input is about 30%; therefore, cogasification of biomass and coal in a single gasifier is not analyzed beyond that point.

- The higher hydrogen content of biomass gasification product gas, particularly in the case of indirectly heated gasifiers. The higher hydrogen content minimizes the requirement for the water–gas shift reaction ($CO + H_2O \rightarrow H_2 + CO_2$) that is needed for adjusting H_2-to-CO ratios dictated by the syngas-to-liquid conversion process and thus reducing the amount of CO_2 produced.

In interpreting the information presented in Figure 6, attention must be drawn to the fact that biomass is carbon neutral and, even though this figure shows that CO_2 generation increases with increasing biomass input, the net CO_2 emission from biomass is zero. Furthermore, it should be noted that the overall emissions are reduced because of the higher hydrogen content of biomass syngas. Another important point is that using separate gasifiers could result in lower CO_2 emission than cogasifying coal and biomass in a single gasifier.

Biomass Gasification Technology

Over 15 different technologies have been under development for biomass gasification since the early 1980s in the United States and Europe.[13,14,15] The level of effort and availability of government and private sector funding for these development efforts have conversely followed oil prices. The initial technology development and commercialization were curtailed when oil prices fell in the late 1980s. With a growing interest in the global-warming issue and reduction of CO_2 in the atmosphere, the desire to use hydrogen as an energy carrier and biorefineries for production of liquid fuel, and concerns about higher oil prices, there has been a renewed interest in commercialization of biomass technologies. To date, however, only one large-scale biomass gasification technology has been successfully commercialized in North America.[16] In early 2007, Norampac, a Canadian pulp and paper producer, announced that a 200-ton-per-day dry black liquor (50% solids) gasification technology that was licensed and designed by ThermoChem Recovery International Inc. (TRI) reached 18,000 hours of commercial operation (see Figure 7). A high-temperature partial oxidation system was installed at Weyerhaeuser's New Bern Mill in the mid-1990s before TRI technology was fully developed. However, it appears that because of long-term start-up difficulties and other commercial and business concerns, no new biomass gasifier of this type has been ordered or built commercially since the New Bern Plant was built. In this study, TRI's technology is used for biomass gasification facility specifications and costs.

TRI's technology utilizes a bubbling fluidized-bed steam reformer to gasify biomass and/or black liquor. The endothermic heat needed for the gasification reactions is provided by utilizing proprietary pulsed heater modules (see Figure 8). The pulse combustor fuel is internally supplied from a portion of the product gas generated in the process.

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[13] Rezaiyan, J.; Cheremisinoff, N. *Gasification Technologies – A Primer for Engineers and Scientists;* CRC Press, Taylor & Francis Group, 2005; Table 2.5.

[14] Bridgwater, A.V.; Kuester, J.L. *Research in Thermochemical Biomass Conversion;* Elsevier Applied Science, 1988.

[15] Klass, D.L. *Biomass for Renewable Energy, Fuels, and Chemicals;* Academic Press, 1988.

[16] Norampac and TRI Announce Full Operation of World's First Commerical Black Liquor Gasification Project. Market Wire, Jan 26, 2007.

Figure 7. TRI's first commercial plant, Norampac Mill.
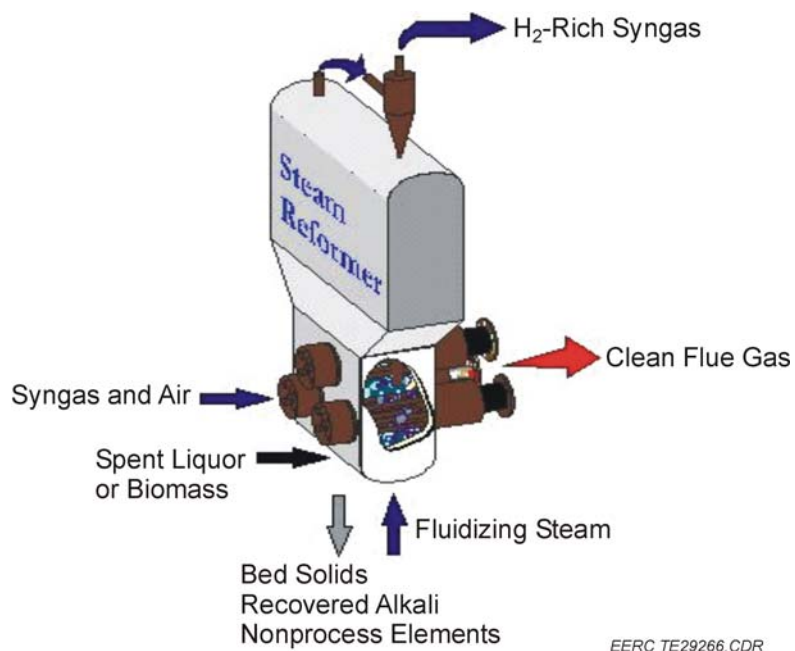
Figure 8. PulseEnhanced™ steam reformer (adapted from www.tri-inc.net/tritech.htm).

The steam reformer contains a bed of solids (sodium carbonate is used as bed material when technology is applied to black liquor recovery and inert material when biomass is used) into which hundreds of pulsed heater tubes are immersed. The reformer operates at about atmospheric pressure and is fluidized with steam. Feedstock is injected directly into the bed, then withdrawn as solids. In the case of black liquor recovery, the sodium in the spent liquor reports to the bed and is withdrawn as solid sodium carbonate pellets, and most of the sulfur in the spent liquor is reduced to hydrogen sulfide and leaves the reformer mixed with raw syngas.

The raw syngas is processed through gas coolers and gas cleanup systems to cool the gas and remove particulates, tars, and other contaminants. The clean syngas is then used to produce biofuel and chemicals and or power. A portion of the cleaned syngas or the tail gas from the syngas-to-liquid processes is sent to the pulse combustor and combusted to provide the required heat input to the gasifier.

Table 2 shows the composition of biomass feed assumed in this study. It is a typical analysis of woody biomass that is anticipated to be available at most mills. Appendix A provides ultimate and proximate analysis for various types of biomass.

Coal Gasification Technology

Coal gasification is not new. The first commercial coal gasifier was built in London in 1812, producing syngas for street lighting, cooking, and home heating. In the 1930s, about 1100 gasifiers consuming more than 12 million tons of coal a year were operating in the United States. Soon thereafter, with the discovery of low-priced oil resources at home and abroad, the coal gasification industry was displaced by the petroleum-refining industry.

The interest in coal gasification technology was renewed after the oil price increases of the 1970s and 1980s. The first modern and large coal gasification plant built in the United States was the 100-MW$_e$ Cool Water project. It was built and operated in the mid-1980s until natural gas prices collapsed and natural gas combined cycle (NGCC) became the technology of choice for thermal power generation in the United States and many other parts of the world. The Cool

Table 2. Biomass Analysis (dry)[17,18]

Components	wt%
C	51.8
H	6.3
O	41.3
N	0.1
S	0.4
Ash	1.02
HHV, Btu/lb	8858

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[17] Klass, D.L. *Biomass for Renewable Energy, Fuel, and Chemicals;* Academic Press, 1998; Tables 3.3, 3.5, and 9.13.
[18] www.woodgas.com/proximate.htm.

Water project was also the first fully integrated gasification combined cycle (IGCC) plant built in the United States. This plant utilized a gasification technology developed by Texaco, which is now owned by GE.

Today, over 100 solid fuel gasifiers (mostly supplied by Texaco) are operating worldwide producing syngas for a variety of applications: methanol, hydrogen, fertilizer, chemicals, and electric power production. Most of these plants use coal as their feedstock and are located in China.[19] Table 3 shows gasification plants currently operating in the United States. Two coal gasification plants, the 350-MW$_e$ Elcogas Plant in Spain and the 250-MW$_e$ Buggenum Plant in the Netherlands, have also been in commercial operation since the mid-1990s. Both plants utilize gasifier technology offered by Shell and, like the Dakota, Wabash River, and Tampa Electric Plants in the United States, were partially financed in collaboration with public sector energy programs to demonstrate the viability of the gasification technology in IGCC configuration.

Interest in coal gasification systems has increased in recent years because 1) the technology has matured, 2) technology suppliers are willing to support project financing and provide wraparound technology warrantees, and 3) in IGCC configuration, coal gasification offers high efficiency, low emissions, and opportunities for cost-effective CO_2 separation. Furthermore, gasification offers the opportunity for coproduction of hydrogen, synthetic natural gas (SNG), and liquid fuels from coal (polygeneration), reducing dependency on foreign energy sources.

Since 2000, over 35 new gasification projects have been announced and are at various stages of planning, design, and/or construction in the United States. Most announced projects (about 32) are to produce syngas for IGCC power generation.[20] These projects range from 200 to

Table 3. Operating Gasification Plants in the United States

Plant Name	Location	Technology Supplier	Capacity, MWt of syngas	First Year of Operation	Feedstock	Products
Eastman Chemical	Tennessee	GE		1983	Coal	Chemicals
Dakota	North Dakota	Lurgi	1900	1984	Lignite	SNG
Motiva	Louisiana	GE	257	1984	Oil residue	Hydrogen
Wabash River	Indiana	ConocoPhillips	591	1995	Coal, coke	IGCC, repowering
Tampa Electric	Florida	GE	451	1996	Coal, coke	IGCC
Exxon	Texas	GE	347	2000	Pitch	Syngas
Farmland	Kansas	GE	293	2000	Coke	Hydrogen
Motiva	Delaware	GE	520	2001	Coke	Cogeneration

[19] www.netl.doe.gov/technologies/coalpower/gasification/database/GASIF2004.xls.
[20] *Tracking New Coal-Fired Power Plants;* NETL, Jan 2007.

1100 MW$_e$ in size. A number of projects in Pennsylvania, Wyoming, North Dakota, and Illinois have been also announced for production of liquid fuels and electric power. In addition, new gasification projects for power and or liquid fuel projects have been announced in Australia and China.

Gasification Processes

The characteristics of the major gasifiers are summarized in Table 4 by type and technology suppliers. Coal gasification processes can be grouped into three different types: fixed bed, fluidized bed, or entrained flow, depending on the gasifier design. They are further divided into dry or slurry feed, depending on the coal feed system used, and dry-ash or slagging, depending on the gasifier temperature and the ash discharge mode. The primary group of reactions taking place in a gasifier includes pyrolysis, combustion, and steam gasification. The resulting gases interact to a certain degree with each other and carbon, forming a series of secondary reactions. The product gas leaving an oxygen-blown gasifier includes mainly CO, CO_2, H_2, and CH_4. The product gas from air-blown gasifiers also includes nitrogen. Depending on the gasifier design, the coproducts may include tar, oil, phenol, char, hydrogen sulfide, carbonyl sulfide, ammonia, and hydrogen cyanide. Depending on the final uses of the syngas and for the protection of environment and or equipment and catalysts downstream of the gasifier, these coproducts must be removed from the syngas product. For carbon management purposes and in anticipation of future CO_2 regulations, new plants are expected to be CO_2 capture-ready.

Table 4. Characteristics of Major Gasifier Types [21]

Gasifier Type	Fixed-Bed Dry Ash	Fixed-Bed Slagging	Fluidized-Bed	Transport Reactor	Entrained Slurry-Fed	Entrained Dry Feed
Technology Supplier	Lurgi	BGL	U-Gas, KRW, and HTW	KBR	GE and E-Gas	Shell, Prenflow, and Future Energy
Ash Discharge	Dry ash	Slag	Dry ash or agglomerated	Dry ash	Slag	Slag
Coal Feed Size	2 × ¼ in.	2 × ¼ in. with some fines	−¼ in.	−1/16 in.	−100 mesh	−100 mesh
Coal Moisture Tolerance, %	35	28	10–25	25 or higher		Dried to 5–10
Gasifier Pressure, psig	450	450	450	450	500–1000	450
Exit Gas Temperature, °F	500–1200	300–1200	1500–1900	1500–1900	1900–2500	2500–3000
Issues	Tars and oils in raw gas		Carbon conversion		Gas cooling load	

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[21] Adapted from Sondreal, E.A., et al. A Review of Gasification Technology for Coproduction of Power, Synfuels, and Hydrogen from Low-Rank Coals. In *Proceedings of the Symposium on Western Fuels,* Denver, CO, Oct 24, 2006.

Dry feed systems can meet the pressure requirements of current generation gas turbines of nominally 450 psi. Slurry feed systems are better suited for higher pressures that may be required for some chemical processes.

The selection of an optimum design depends on the effect of coal properties on the operation of the gasifier and the desired gas exit conditions in relation to downstream process conditions. The temperature, pressure, and composition of the gas leaving the gasifier should match as closely as possible the requirements of the gas-cleaning and separation processes which are dictated by the end-use application to minimize costs and efficiency penalties associated with gas cooling, compression, and downstream processing of the cleaned syngas.

In this study, a ConocoPhillips gasifier is used. It is a two-staged, entrained-flow, slurry-fed gasifier. About 75% of coal slurry reacts with a concurrent flow of oxygen at peak temperatures of up to 3000°F in the first stage to produce syngas and molten slag. The remaining 25% of the coal slurry is injected into the second stage of the gasifier where the latent heat of the gas from the first stage is used to gasify additional coal and reduce the gas exit temperature to about 1900°F. Unreacted char is separated from the product gas and recycled to achieve greater than 99% carbon conversion, and hot product gas is quenched in a syngas-cooling system. The design has been tested on Appalachian and Illinois bituminous coals, Wyoming subbituminous coal, and Texas lignite.[22] The gasifier has operated successfully on Illinois Basin bituminous coal and petroleum coke in a 262-MW IGCC clean coal demonstration project at the SG Solutions Wabash River Plant since 1995.

The advantage of this and other entrained, slagging gasifiers for production of hydrogen or synthetic liquids is that they produce a syngas that has a relatively high H_2/CO ratio and essentially no methane or other hydrocarbon products.[23]

Table 5 shows the analysis of the reference coal, Illinois No. 6, assumed for this study. Figure 9 shows a typical block diagram of the proposed biomass–coal-to-liquid or polygeneration plant.

Syngas Cleanup

Because of the differences in the operating pressures and temperature of the biomass and coal gasifiers and because of the different level of sulfur content in biomass and coal, two separate syngas cleanup systems are used. The clean biomass syngas is then pressurized and mixed with clean coal syngas prior to entering the syngas-to-liquid plant. Use of separate gasifier trains could also reduce CO_2 reduction without imposing a 30% maximum limit on biomass feed which is the maximum amount that could be cogasified with coal in a single gasifier.

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[22] Ibid.

[23] Rezaiyan, J.; Cheremisinoff, N. *Gasification Technologies – A Primer for Engineers and Scientists;* CRC Press, Taylor & Francis Group, 2005; Table 2.5.

Table 5. Coal Analysis, dry[24]

Components	wt%
C	70.02
H	4.99
O	8.27
N	1.30
S	2.58
Ash	12.70
HHV, Btu/lb	12,749
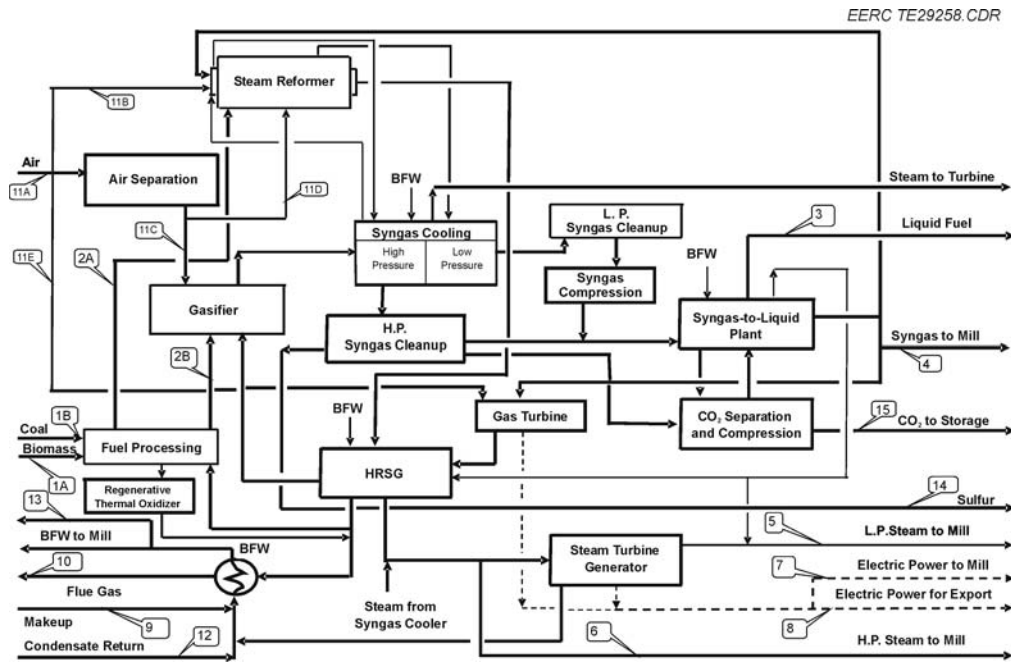
Figure 9. Typical biomass–coal syngas-to-liquid system block diagram.

Evaluating the impact of a single- versus a multitrain gasifier system on the products' costs was not within the scope of this study and was not considered.

Biomass Syngas Cleanup

Figure 10 shows a biomass syngas cleanup flow diagram. The syngas leaving the biomass gasifier is directed to a series of cyclones to remove any particulate and unburned carbon. The underflow from the primary cyclone is recycled back to the gasifier to improve carbon conversion efficiency while the underflow from the final cyclone is discharged through a lock hopper system to an ash cooler and ash collection system. The final cyclone overflow is then

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[24] *Gasification Plant Cost and Performance Optimization – Task 1 Topical Report IGCC Plant Cost Optimization;* NETL. May 2002; Table 1, Subtask 1.5, Appendix F.

16
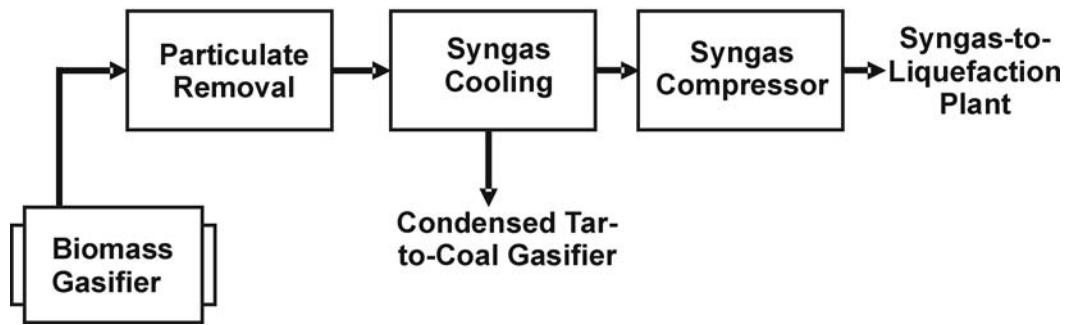
Figure 10. Biomass syngas cleanup block diagram.

cooled in a steam heat recovery generator to remove any condensable hydrocarbon (C^{6+}) formed during the pyrolysis process in the gasifier. The cooled, condensed wastewater stream containing tars is sent to a decanter–separator to separate tars from condensed water. The tars are sent to the coal gasifier where it is gasified at high temperature and pressure with coal. The water is sent to a wastewater treatment facility. The clean syngas is compressed, mixed with the clean syngas from the coal gasifier, and sent to the syngas-to-liquid plant.

Coal Syngas Cleanup

Figure 11 shows the flow diagram for the coal–gas cleanup train. The gas and entrained particulate matter exiting the gasifier are cooled in a fire-tube heat recovery boiler and directed into a cyclone/dry char filter system for particulate removal. The cooled syngas is then scrubbed of water-soluble impurities in a wet scrubber and sent to a carbonyl sulfide hydrolysis unit where COS is hydrolyzed to hydrogen sulfide and CO_2. The resulting gases are then cooled in a low-temperature heat recovery unit prior to being sent to an acid gas removal unit for bulk removal of hydrogen sulfide and carbon dioxide using methyl diethanol amine (MDEA). The sour water leaving the cooler contains condensed water, ammonia, and some carbon dioxide and hydrogen sulfide in aqueous solution which is treated in a sour water treatment unit.

The concentrated H_2S stream is sent to a Claus unit for recovery of elemental sulfur. A portion of the sulfur in the sulfur-rich offgas from the MDEA plant can be recycled to the mill for pulping chemical makeup. The stripped carbon dioxide is then combined with stripped CO_2 from FT liquid or DME plant tail gas and directed to a CO_2 compressor for compression and storage. The synthesis gas exiting the acid gas removal unit still contains about 1–2 ppmv H_2S which is poisonous to most catalysts for syngas-to-liquid conversion. To remove this residual H_2S, a sulfur-polishing reactor is used. The product gas leaving the sulfur-polishing reactor contains less than 0.03 ppmv.

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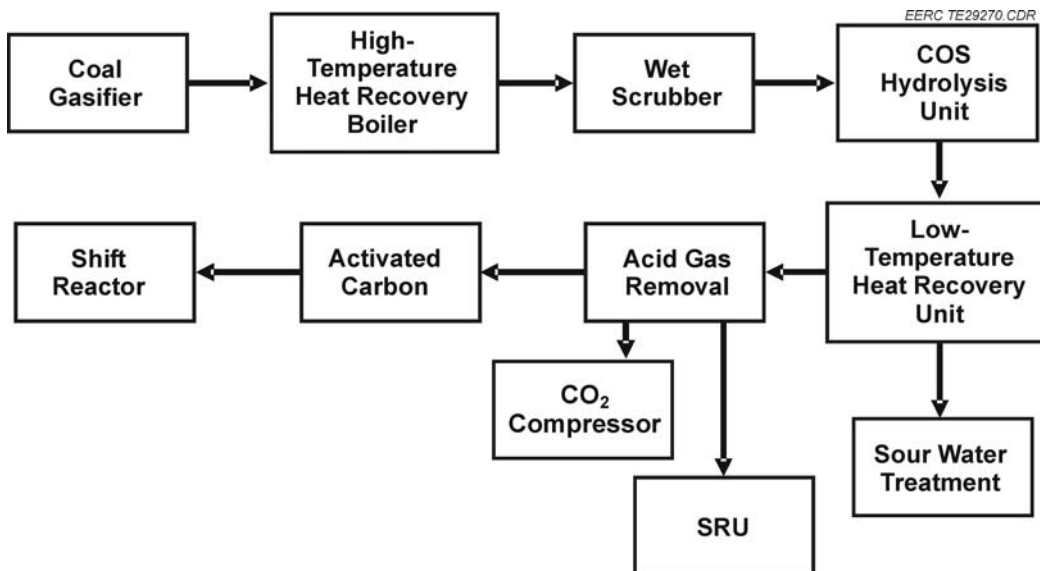
Figure 11. Coal syngas cleanup flow diagram.

Syngas to Liquids

A variety of chemicals and liquids can be produced from syngas. They include FT liquids (gasoline and diesel), DME, methanol, hydrogen, and ammonia. Other products can be produced from further processing of methanol. This study focuses on synthesis products that can replace transportation fuel without significant changes to current infrastructure, including vehicle engines. These synthesis products include FT liquids, methanol, and DME. Ethanol and mixed alcohol were excluded from this analysis because a demonstrated commercial technology is not available for their production from synthesis gas.[25,26]

The use of methanol as a blending fuel was practiced in California and New York in the late 1980s and early 1990s. By 1996, approximately 13,000 flexible-fuel vehicles (FFVs), along with about 500 buses (including school buses) and trucks, were running on methanol in California.[27,28] However, the use of methanol as a transportation fuel was discontinued in the United States by the mid-1990s because of:

- Introduction of cleaner gasoline which eliminated the environmental benefits of methanol as a transportation fuel.

[25] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006.

[26] Ekbom, T.; Lindblom, M.; Berglin, N.; Ahlvik, P. *Technical and Commercial Feasibility Study of Black Liquor Gasification with Methanol/DME Production as Motor Fuels for Automotive Uses-BLGMF;* Alterner II; Dec 2003.

[27] www.energy.ca.gov/afvs/vehicle_fact_sheets/methanol.html.

[28] www.eri.ucr.edu/ISAFXVCD/ISAFXVAF/MTFLBLF.pdf.

- Price competition for methanol as a chemical feedstock.

- Discontinuation and/or lack of auto industry and government support.

- Requirement for engine modifications.

- Separation of methanol from gasoline at the presence of water.

- Methanol's lower energy density than gasoline (lower miles per gallon).

- Engine start-up difficulties at low temperatures.

Furthermore, methanol has a tendency to form formaldehyde during combustion. Formaldehyde is toxic and, possibly, carcinogenic. It can be removed by catalytic conversion, but it adds to automobile cost and is a perceived environmental and health risk. For this and other reasons listed above, methanol was not considered for evaluation in this study.

Shift Reaction

The major challenge in producing liquid fuel from coal is to increase the hydrogen-to-carbon molecular ratio (H/C) of the syngas to an optimum level. As a point of reference, the H/C ratio for gasoline and diesel is about 2, the ratio for typical crude oil is 1.3–1.9, and for typical bituminous coal, 0.8. FT technology and other indirect coal liquefaction technologies such as LPMEOH™ and LPDME™ processes (Air Products) for production of methanol and dimethyl ether rely on first gasifying the coal to produce syngas. The H/C ratio is then adjusted, as needed, using the water–gas shift reaction (shown below).

$$CO + H_2O \rightarrow H_2 + CO_2$$
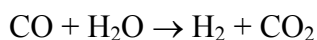
The CO and H_2 molecules are then catalytically combined to produce synthetic fuel containing primarily diesel or gasoline by FT processes or oxygenated fuel using processes such as LPMEOH™ or LPDME™. The CO_2 produced by the shift reaction and any CO_2 generated in the syngas-to-liquid process can be separated from the product stream, combined with CO_2 from the gasification process, and pressurized and sent to the storage tank for sequestration, enhanced oil recovery, or other uses.

There are two types of catalyst materials for CO shift conversion:

- Iron and chromium oxide-based catalysts – these catalysts are not sulfur resistant, requiring very clean syngas and inlet temperatures of 570°–650°F.

- Cobalt and molybdenum oxide-based catalyst – these are sulfur resistant, requiring lower shift reactor inlet syngas temperatures (535°–570°F) than iron and chromium catalysts, and they are more expensive.

One advantage of cogasification of biomass and coal, in particular when an indirectly heated biomass gasifier is used, is the high concentration of hydrogen in the syngas, resulting in lower CO shift requirements. This can reduce operating costs by reducing demand shift reaction catalyst, increase liquid production rate, and reduce conversion of CO to CO_2.

FT Liquids

FT technology is not new; it is a well-established commercial technology. Sasol in South Africa has extensive construction and operating experience with FT technology and annually converts about 51 million tons of coal into about 1.58 billion gallons of synthetic fuels and 528 million gallons of chemicals.[29]

In the mid- to late 1930s, nine plants were built in Germany, two in Japan, and one in Manchuria.[30] The transportation fuel comprised 72% of the total liquid production. The remainder (28%) included alcohols, aldehydes, soft waxes, and heavy oil. These plants operated at low-to-medium pressure and low temperature and utilized fixed-bed reactors using cobalt catalysts. Similar reactor designs, using advanced fixed-bed reactors and cobalt catalysts, are used by Shell at new commercial gas-to-liquid plants built in Malaysia and Qatar in the 1990s and early 2000s.

The FT process operates in two temperature regimes: high and low. The high-temperature (570°–625°F) processes convert CO and H_2 to a liquid fuel consisting predominantly of gasoline and light olefins (ethylene, propylene, pentene, etc.). The liquid fuel is further processed to separate gasoline and olefins. Olefins are sold to the polymer industry or are converted to diesel fuel. The high-temperature reaction can be represented as:

$$nCO + 2nH_2 \rightarrow nH_2O + CnH_{2n}$$
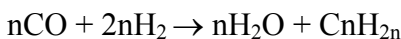
where n represents the number of CO molecules.

The low-temperature (390°–445°F) FT processes convert CO and H_2 to a liquid fuel that can easily be converted to a predominantly high-quality diesel. The low-temperature reaction can be shown as:

$$nCO + (2n +1)H_2 \rightarrow nH_2O + C_nH_{2n}+2$$
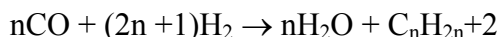
Both the low- and high-temperature processes are exothermic, and heat must be removed from the reactor vessel to maintain the desired reactor temperature. Sasol, Shell, BP, Rentech, Sasol Chevron, and others supply proprietary FT technology; most use a slurry-phase reactor with a cobalt- or iron-based catalyst. Shell and BP use a fixed reactor. Sasol uses iron-based catalysts and now offers fluidized-bed reactors for high-temperature and slurry-phase reactors instead of the original circulating and fixed-bed reactors, respectively, for high- and low-temperature processes. Typically, Sasol high-temperature reactors are 26–36 feet in diameter and

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[29] Greetsema, A. Synthesis Gas to Fuels and Chemicals. Fifth China–Japan Symposium on Coal and C1 Chemistry, Hungshan, China, 1996.

[30] Steynberg, A.P.; Dry, M.E. *Fischer–Tropsch Technology;* Elsevier, 2004; p 28.

about 125 feet high and produce up to 20,000 barrels a day per reactor. The low-temperature reactors are typically about 16.5 feet in diameter and 72 feet high and produce about 2500 barrels per day of FT liquids. Roughly 75% of a barrel of high-temperature FT liquid can easily be converted to transportation fuel (diesel, gasoline, jet fuel), which is about the same as can be produced from a barrel of Venezuelan crude by "deep" refining. Without deep refining, only 15%–25% of a barrel of Venezuelan crude can be converted to diesel fuel. In contrast, low-temperature FT liquid is about 75% diesel. The avoidance cost of "deep" refining allows FT liquids to demand a premium price. This premium price was estimated to be as high as $10 a barrel of equivalent crude oil prices (a 50% premium) in 2003, depending on the refinery configuration and relative demand for refined products.[31] It should also be noted that the premium price for light crude and/or FT liquids is expected to increase as demand for the refined products increases in countries with economies in transition, such as China and India. Furthermore, light crude is not as readily available as it was a decade ago, and there are few refineries in the United States that are designed to process heavy crude oils and even fewer that are designed to process heavy crude oils such as those being imported from Venezuela.

Figure 12 presents a typical flowsheet for the FT process used in this study. This study assumes cleaned, sulfur-free syngas is fed to the slurry-bed FT reactor which converts syngas to hydrocarbons over an iron-based catalyst.[32] The heat of reaction is removed by the generation of inside steam tubes that are placed within the slurry bed. The lighter hydrocarbon products and unconverted syngas leave the reactor as vapors and are cooled to recover the condensed hydrocarbons as liquids. The unconverted syngas and noncondensable light hydrocarbons (primarily C1 through C3s) are compressed and sent to the combustion turbines for power generation. The heavier products are removed from the reactor as liquids, separated from the entrained catalyst by filtration, cooled, and mixed with the lighter hydrocarbons. This material needs to be further processed in a light refining process to produce transportation fuels. The FT liquid fuel precursors essentially are a bottomless, sulfur-free crude oil. Basically they are straight-chain olefins and paraffins without any aromatics. The diesel fraction has a very high cetane number (>70) and is a premium diesel fuel blending component. The naphtha fraction is a low-octane material that requires further upgrading for use as a gasoline-blending component. However, it is an excellent feedstock for an ethylene cracker.

DME

DME is a liquefied petroleum gas (LPG)-like synthetic product. It is colorless at ambient temperature and pressure, has a slight ethereal odor, liquefies under slight pressure, and has a high cetane number. It can be transported like LPG. It is relatively inert, noncorrosive, noncarcinogenic, almost nontoxic, and does not form peroxides by prolonged exposure to air.[33] DME is suitable as a LPG substitute and as a diesel blending fuel. Diesel engines adapted for DME can achieve the same efficiency as diesel fuel.

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[31] Williams, R.; Larson, E. A Comparison of Direct and Indirect Liquefaction Technologies for Making Fluid Fuels from Coal. *Energy for Sustainable Development* **Dec 2003,** *VII* (4).

[32] NETL. *Gasification Plant Cost and Performance Optimization.* May 2002; Vol. 1, 2, and 3.

[33] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006, p. 9.
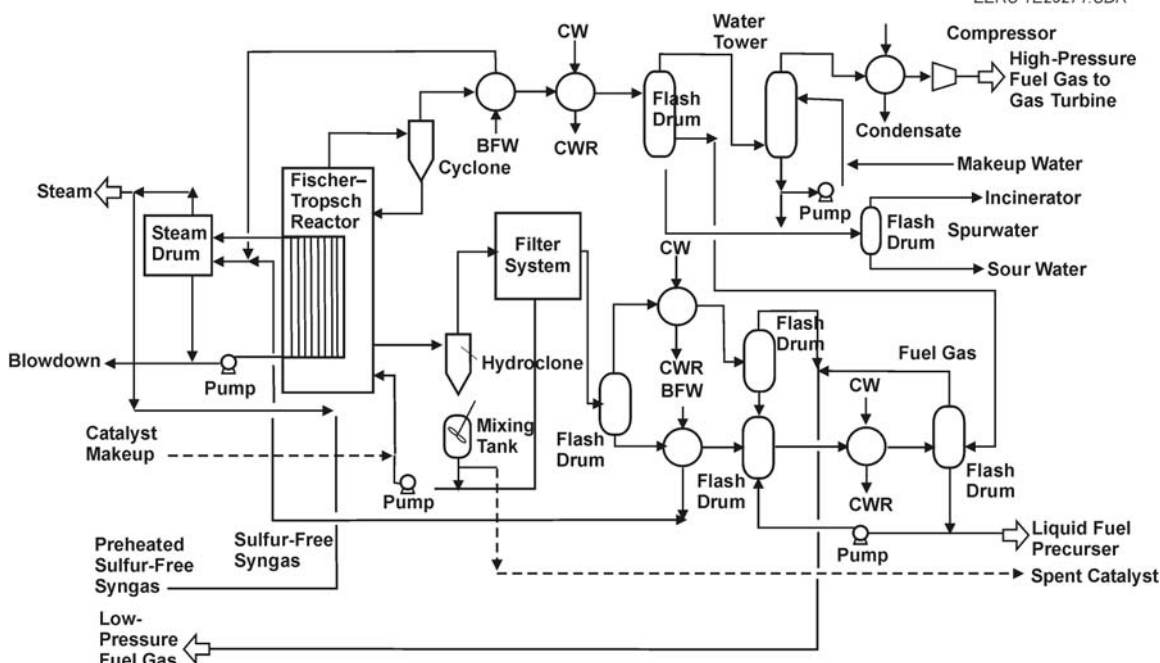
Figure 12. FT process flow diagram.

As diesel fuel replacement, DME has the potential of reducing emissions and meeting the new diesel emission standards. Particulate formation is largely avoided with DME in comparison to hydrocarbon fuels. Since DME is essentially sulfur-free, the aftertreatment catalytic devices for emission control are more effective and more easily facilitated. Use of DME as a fuel or fuel additive, however, requires certain modifications to the automobile fuel delivery and injection system. DME attacks most elastomers and rubber material; therefore, proper seals have to be developed, and the long-term durability of the high-pressure fuel tank and injection system has to be demonstrated before DME is introduced to the market as a diesel fuel additive. New injection systems are being developed for buses and heavy-duty trucks, and the test results to date are promising.[34] Volvo and Nissan have designed a special fuel pump and sealing materials for use with DME-injected engines.[35] The Swedish Energy Agency is supporting Volvo's effort to develop a new DME engine for heavy-duty vehicles by 2010 and has awarded Volvo $8.5 million for this effort. DME engines have been tested in Europe, Japan, and China and are being introduced in the United States by Nissan for pilot trials.

A number of well-known technology licensors include Air Products and Chemicals, Chevron, NKK Itochu, Mitsubishi, Haldor Topsoe, and others.[36,37,38,39] Commercial plants are

[34] www.volvo.com/NR/rdonlyres/15685CDA-8F2E-4E8A-827D-180ECC427A85/0/DME_204.pdf.

[35] www.enzenglobal.com/whitepapers/DME_nextgenfuel.pdf.

[36] Ohno, Y. *A New DME Production Technology and Operation Results;* NKK Corporation, Japan.

[37] www.enzenglobal.com/whitepapers/DME_nextgenfuel.pdf.

[38] www.ripi.ir/EN/congress10/large%20scale.pdf.

[39] Ekbom, T.; Lindblom, M.; Berglin, N.; Ahlvik, P. *Technical and Commercial Feasibility Study of Black Liquor Gasification with Methanol/DME Production as Motor Fuels for Automotive Uses-BLGMF;* Alterner II; Dec 2003.

operating or are at various stages of planning, design, and construction in China, Iran, Japan, Qatar, and Russia.[40]

Current annual DME production is about 147,000 tons in China. The production capacity in China can increase to 24.5 million tons (from coal) by 2020.[41] China has begun construction of a 3.6-million-ton-per-year plant with a total project cost of $2.6 billion and is developing a 245,000-ton-per-year plant which is being supported by International Finance Corporation (IFC). A plant with a capacity of 800,000 tons a year of DME is under construction in Iran.[42] Thus by the end of this decade, DME production capacity globally may reach between 3.8 and 6.8 million tons a year, which would represent a 25- to 45-fold increase compared to the beginning of this decade.[43] Most of the DME produced today is used as an LPG substitute for domestic (household) fuel. Some of the new DME capacity in China is, however, targeted for transportation use (in buses).[44]

The synthesis of DME generally takes place in two steps: methanol synthesis reactions (Reactions 1 and 2) and dehydration reactions (Reaction 3). It can also be synthesized by reacting carbon monoxide and hydrogen (Reactions 4 and 5) directly.

$$CO + 2H_2 \rightarrow CH_3OH \qquad [1]$$
$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \qquad [2]$$
$$2CH_3OH \rightarrow CH_3OCH_3 + H_2O \qquad [3]$$
$$3CO + 3H_2 \rightarrow CH_3OCH_3 + CO_2 \qquad [4]$$
$$2CO + 4H_2 \rightarrow CH_3OCH_3 + H_2O \qquad [5]$$
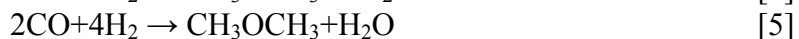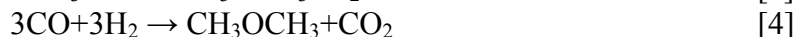
The synthesis reactions are dependent on the reactor design, the catalyst used, and the syngas composition.

Figure 13 shows the block diagram for the proposed DME production facility.

The clean, cooled syngas from coal and biomass gasifiers is directed to a DME synthesis reactor (depending on the catalyst used and the reactor design, the syngas may have to be reacted with steam in a shift reactor to adjust the H_2/CO ratio). The synthesis gas is first converted to methanol, and then methanol is dehydrated to produce DME. The by-products—CO_2, methanol, and water—are separated from the product DME in distillation columns; methanol is recycled to the DME synthesis reactor to be converted into DME. Carbon dioxide is directed to a CO_2 separation and compression plant, compressed, and sent to a storage tank.

[40] www.enzenglobal.com/whitepapers/DME_nextgenfuel.pdf.

[41] Ibid.

[42] Bakhtiari, H.R. Research Institute for Petroleum Industry (research arm of the Iranian Ministry of Petroleum).

[43] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006, p. 9.

[44] Garimella, S. *DME-Nextgen Fuel;* www.enzenglobal.com, Enzen Global.
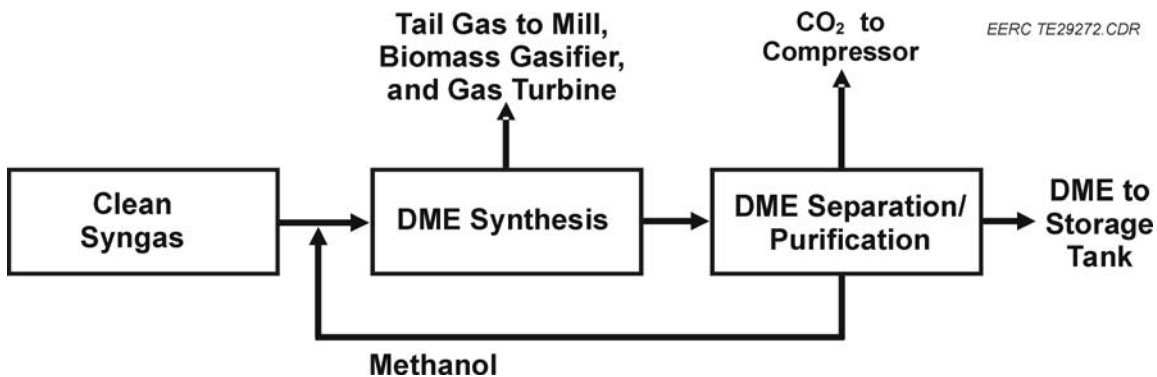
Figure 13. DME synthesis block diagram.

REFERENCE MILLS

As noted earlier, about 160 pulp and paper mills are operating in the United States. They include 105 kraft, six sulfite, 23 semichemical, and 27 mechanical mills. A typical kraft mill produces about 1000 tons a day of pulp and 700,000 lb/hr of steam, exports about 35 MW$_e$, and has a chemical recovery plant. The mills in the South tend to be larger than the mills in other parts of the country and rely on natural gas as their primary source of fossil energy.

This study focuses on four mills located in the South, Northeast, Midwest, and West of the United States. They were selected because they represent typical kraft mills in their region and because sufficient data were available to the study team on 1) their current biomass, fossil fuel, electricity, steam, and hot-water consumption; 2) black liquor, steam, and electricity consumption; and or 3) recovery boiler, power boiler, steam turbine, and/or gas turbine capacities. Access to these data was critical to the development of energy and material balances for each reference mill and the execution of the economic analysis required for this study. Other considerations included ease of access to coal resources (see Figure 14) and availability of potential sites for CO_2 sequestration. One mill provided detailed information on its energy use and equipment. Using the available data, a spreadsheet model was developed to simulate the energy (heat and electricity) requirement, hog fuel availability, recovery boiler steam capacity, and power generation capacity at each mill. This information was then used as input for developing integrated polygeneration facility energy and material balances (see the upcoming section on "Mass and Energy Balances"). To maintain the confidentially of the data used, reference mills are referred to as Mill Nos. 1, 2, 3, and 4.

Mill No. 1

Mill No. 1 is located in the South. Figure 15 presents the current energy production infrastructure at the mill. It has a recovery boiler with a design capacity of 750 tpd of black liquor solids (BLS), consumes about 590,000 tons/year of wood chips, and produces about 296,000 tons/year of paper and paperboard products. This mill does not produce any hog fuel and relies on natural gas to generate 375,000 lb/hr of steam in its power boilers and meet the

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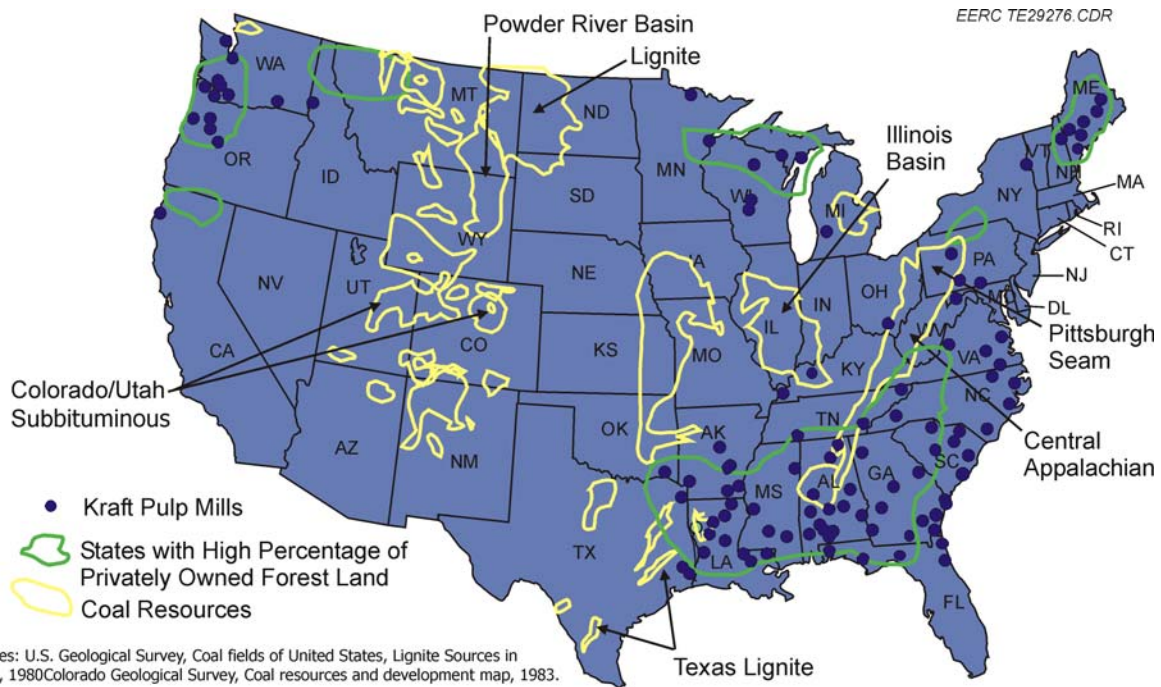
Figure 14. Proximity of biomass and coal resources to kraft mills.

energy demand of its kiln. It has the capacity to generate up to 730 MWh/d of electricity and purchases 120 MWh/d or more of electricity depending on the electricity prices. This mill has easy access to biomass and coal resources. Because of the low electricity prices in this region, many of the mills have reduced their electricity production and are currently operating their power plants based on their steam needs and meet their electric power needs by purchased electricity. For the purpose of the analysis, natural gas purchases and electricity production were reduced based on the mill steam demand.

Mill No. 2

Mill No. 2 is located in the Northeast. Figure 16 presents the current energy use and equipment at this mill. The design capacity of the recovery boiler is 2550 tpd of BLS. The mill consumes about 464,100 tons/year of round wood (logs) and 292,000 tons/year of wood chips and produces about 432,000 tons/year of paper and paperboard products. The mill's hog fuel is assumed to be 12% of round wood consumption. The mill currently sells hog fuel to an adjacent charcoal-producing facility and uses mostly coal to generate steam for the mill use and power generation. It has 65 MW$_e$ of steam turbine capacity, can generate up to 1200 MWh/d, and purchases 210 MWh/d or more of electricity. It has easy access to biomass and coal resources.
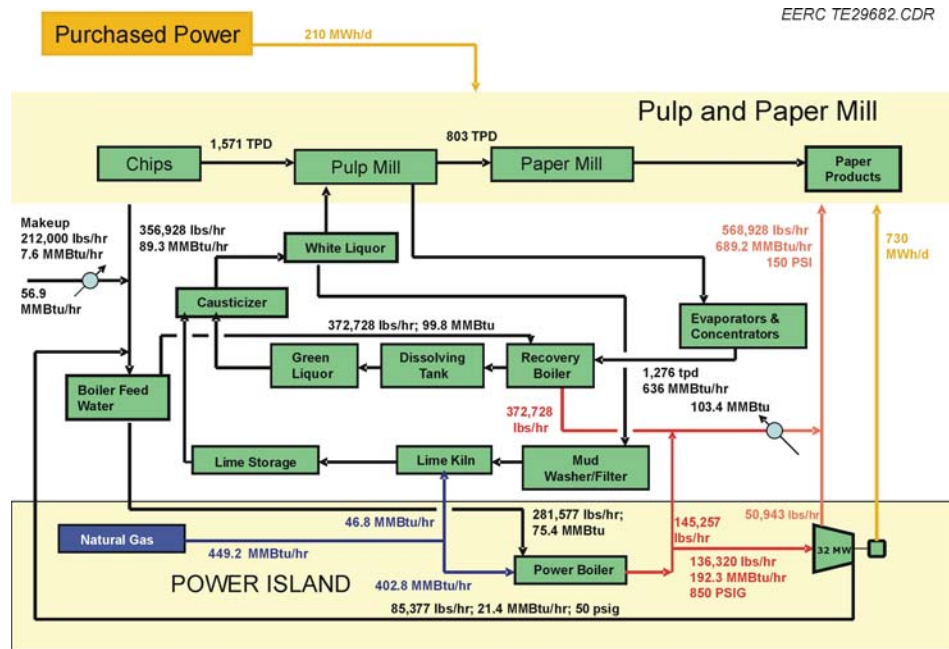
Figure 15. Mill No. 1 configuration and energy supply and demand.

Mill No. 3

Mill No. 3 is located in the western region of the country. It operates one of the most efficient combined heat and power plants in the industry. It converts about 300,000 tons of recycled paper and 426,000 tons of wood chips a year to pulp and paper products and thus does not produce any hog fuel on-site. It operates a gas turbine with a capacity of 47 MW$_e$, a 26-MW$_e$ steam turbine generator, and a heat recovery steam generator (HRSG) that produces about 294,984 lb an hour of steam. The recovery boiler produces 537,776 lb an hour of steam. The mill exports 552 MWh a day of electricity and consumes about 1200 MWh. Figure 17 shows the mill's steam, hot water, and electric power consumption.

Mill No. 4

Figure 18 shows the mill's steam, hot water, and electric power consumption. This mill is located in the midwestern region of the country. It converts about 839,700 tons of round wood and 204,000 tons of wood chips a year to pulp and paper products. It produces about 23,990 lb of hog fuel on-site which is assumed to be burnt in the power boilers. It has the capacity to generate 750,000 lb an hour of steam (in addition to the steam produced by the recovery boiler) and generate 2031 WMh a day operating a 61-MW$_e$ steam turbine generator and a small hydro power plant. The recovery boiler is estimated to produce 657,298 lb an hour of steam. The mill exports 340 MWh a day and consumes 1591 MWh a day of electricity.
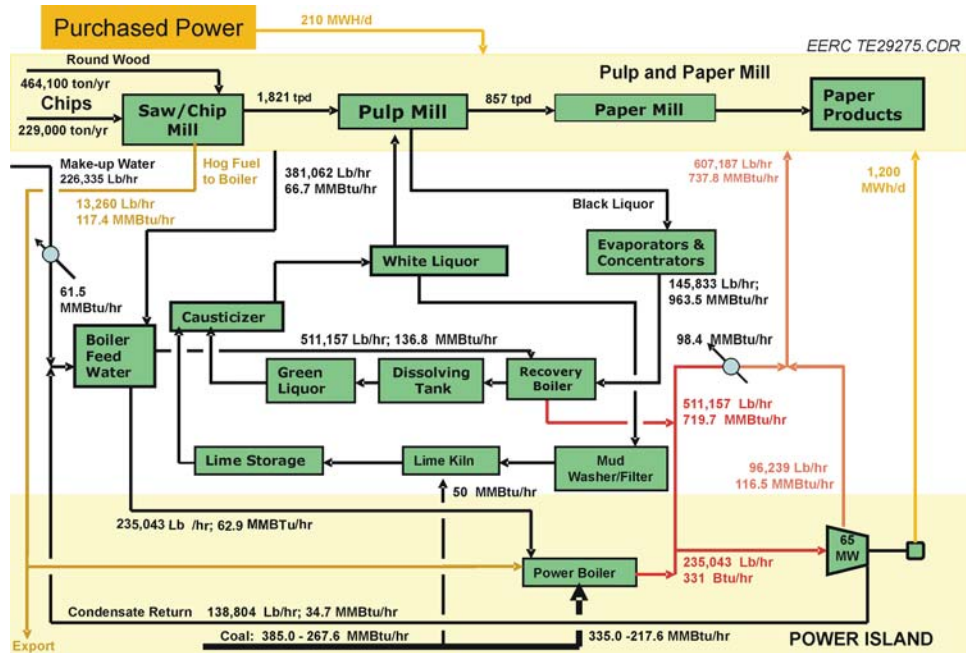
Figure 16. Mill No. 2 configuration and energy supply and demand.
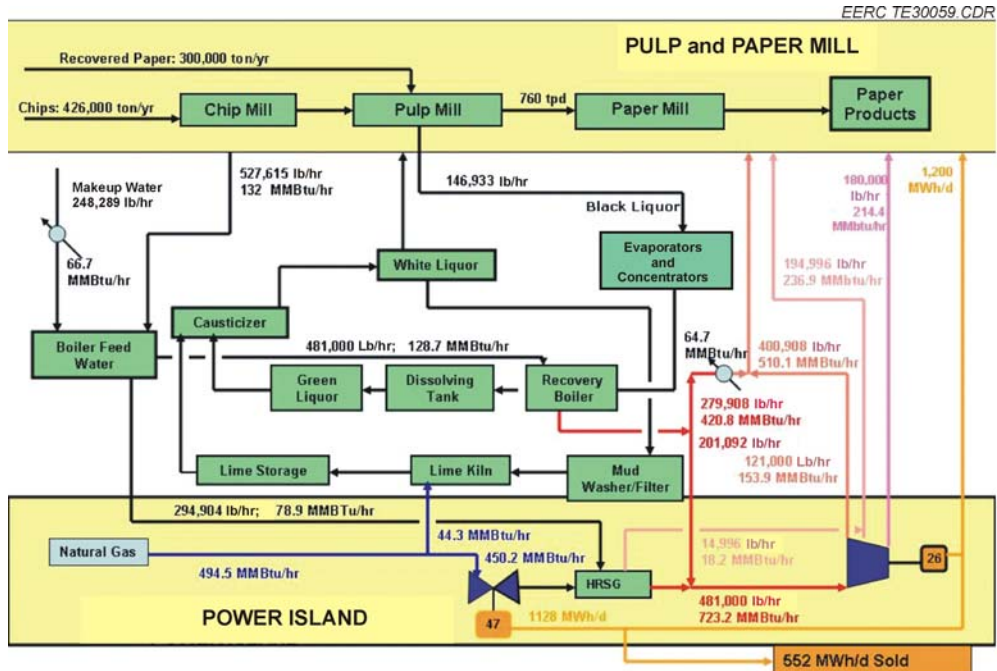
Figure 17. Mill No. 3 configuration and energy supply and demand.
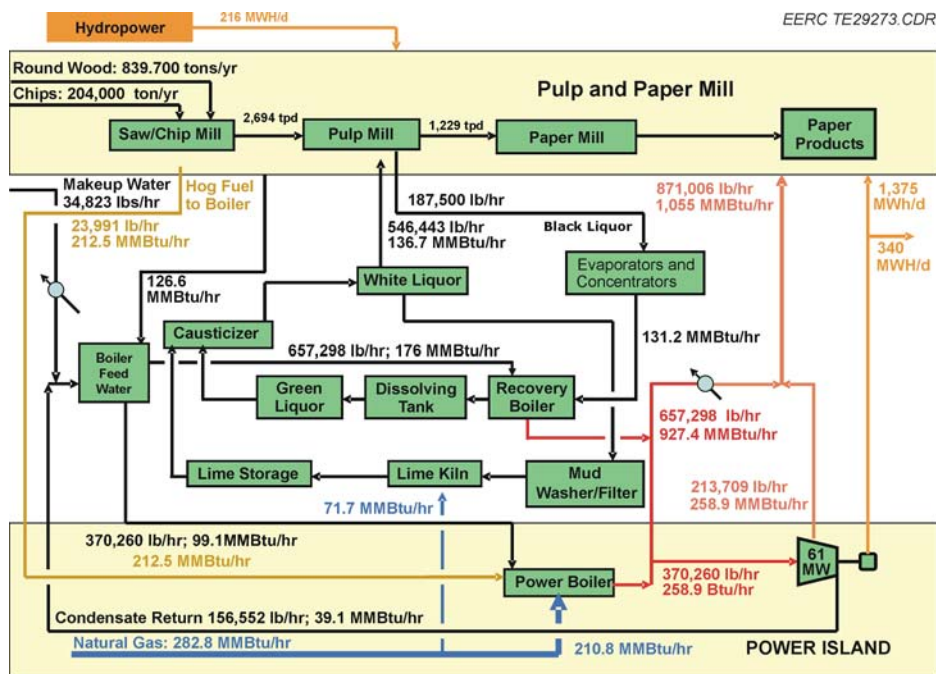
Figure 18. Mill No. 4 configuration and energy supply and demand.

Integrated System Design and Performance Modeling and Results

Integration of biomass and coal gasification, syngas to liquids, and electric power and heat generation for development of a polygeneration plant is attracting increasing attention worldwide. The uncertainties with future production levels of oil, increasing demand for oil worldwide, awareness of the impact of greenhouse gases on the world economy, and concerns about energy security at home and in other oil-importing countries are all driving policy makers to focus on increasing the use of indigenous resources such as coal and biomass. Advances in clean coal technologies have made it possible to gasify coal and capture environmentally undesirable by-products such as CO_2, sulfur compounds, nitrogen compounds, mercury, and particulate. Many of the technologies developed for coal gas (a synthetic gas) cleaning can be applied to biomass gas (another synthetic gas) cleaning if needed. The economy of scale for cleaning, and converting syngas to liquid products, however, favors large reactors and plants: FT reactors with capacities of 10,000 to 20,000 bbl a day and plant capacities of over 30,000 bbl a day. For example the Secunda Plant in South Africa has eight reactors and a total capacity of 124,000 bbl a day: four reactors with a capacity of 20,000 bbl a day each and four with 11,000 bbl a day. The capacity of the gas-to-liquid project in Qatar is 34,000 bbl a day.

Developing large-scale biomass refineries economically and widespread may not be possible considering limitations on supply and economic transportation of biomass beyond 50 to 80 miles. Integrating biomass and coal gasification into a single, fully integrated carbon-to-liquid facility can help to increase biomass utilization and production of liquid fuels from a carbon-neutral feedstock. Furthermore, assuming that biomass to liquids, or biorefineries, can be

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economical as stand-alone facilities, the current potential of all biomass resources is about 3.3 quads and can increase to 4.3 quads in the future.[45] That is about 10% of the total U.S. liquid fuel and petroleum consumption in 2004. By 2025, the U.S. total sustainable biomass energy resource (wood waste, forest thinning, logging residue, mill residue, urban waste, crop residue, crop processing residue, and potential future biomass crop) is estimated to be between 14 to 21 quads,[46] provided that production and use of energy crops become a reality. The Energy Information Administration (EIA) projects the U.S. biomass resource production and consumption to be 5.04 and 3.91 quads, respectively, in 2025.[47] EIA-projected U.S. liquid fuel consumption for 2025 is 49.05 quads. Limited supply of biomass dictates the use of our other indigenous and plentiful resource, coal, to meet our energy needs and maintain our high standard of living, continued economic growth, and energy and economic independence. This can be done by maximizing the use of biomass resources and applying advanced technologies in an environmentally responsible manner.

Collocating carbon-to-liquid facilities and pulp and paper mills can also provide a number of advantages:

- Mill demand for steam and hot water provides a heat sink: increasing energy efficiency of carbon to liquid or polygeneration facilities per barrel of liquid or MW of electricity produced and reducing emissions and carbon input requirements.

- Sulfur in the fuel (e.g., coal and black liquor) can be captured and partially recycled to the mills for use in digesters; any excess sulfur or sulfur products can be sold, improving the plant economics.

- Mills have access to biomass resources and have infrastructure in place for efficient and cost-effective harvesting, transporting, and processing of biomass.

- Carbon-to-liquid or cogeneration facilities can be reliable and secure suppliers of fuel, gas and liquid, and electricity to the mills.

- Mill supplier and customer transportation needs could be met by liquid fuel produced domestically and at the mill site.

- Large polygeneration facilities create new jobs, attract a skilled workforce, and improve local economy and growth.

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[45] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006, p. 1.
[46] Ibid.
[47] www.eia.doe.gov/oiaf/aeo/excel/yearbyyear.xls.

APPROACH AND ASSUMPTIONS

As noted earlier, this study assessed the technical and economic potential of a polygeneration facility producing liquid fuels (FT liquids and DME), electricity, and heat from biomass and coal. The polygeneration facility is assumed to be located adjacent to a pulp and paper mill, fully integrated with the mill's operation and meeting the mill's electric and heat demand. To integrate mill operation with a polygeneration facility, a number of resources were used to develop the mill's energy (electrical and heat) demand and energy and material balances for the polygeneration facility. The approach taken to select the reference mills and develop energy and material balances for them was described earlier (see "U.S. Pulp and Paper Industry" and "Reference Mills" sections). That information was then used as input to the energy and material balances developed for the integrated polygeneration facility concept.

A study by NETL[48] formed the basis for developing energy and material balances for coal gasification and coal gas-cleaning sections of the plants. This and a number of other sources[49,50] were used as the primary sources for developing energy and material balances for the FT plants (other sources consulted are listed at the end of the report under the heading "Additional References"). The energy and material balances for the DME plants were based on a recent study sponsored by DOE and the American Forest and Paper Association.[51] The energy and material balances for the biomass gasification plants are based on the energy and material balances provided by TRI for a typical plant. Using data from the above sources and energy and material balances developed earlier, a spreadsheet model was developed for each reference mill. Nine scenarios—assuming various combinations of high, intermediate, and low coal and biomass feed rates—were developed. Additional cases were also developed assuming that the mills' energy needs are met by a biorefinery: a polygeneration facility that excludes the use of coal.

Table 6 shows coal and biomass feed rates for the polygeneration plant scenarios at each reference mill. The high coal feed rate was selected based on the NETL study. This study indicated that the optimum plant size for a coal-to-liquids plant would require 900,585 lb an hour of coal having a moisture content of 14.5% and a heating value of 12,749 Btu for a pound of dry coal (see Table 5 for coal analysis). The NETL coal-to-liquid case was optimized based on the economics of the plant, assuming 12% return on investment, 8% and 10% interest, 80% debt, and a repayment term of 15 years.

The intermediate and low coal feed rates were selected arbitrarily to be 50% and 25% of the high coal feed. The high biomass coal feed rate was developed based on the maximum biomass feed rate required for a biorefinery meeting all of the mill's electric power and heat

[48] National Energy Technology Laboratory. *Gasification Plant Cost and Performance Optimization;* May 2002, Vols. 1, 2, and 3.

[49] Steynberg, A.P.; Dry, M.E. *Fischer–Tropsch Technology;* Elsevier, 2004.

[50] Gray, D.; Salerno, S.; Tomlinson, G. *A Techno-Economic Analysis of Wyoming-Located Coal-to-Liquids (CTL) Plant;* NETL, April 2006.

[51] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006.

Table 6. Coal and Biomass Feed Rates

Mill No.:	1	2	3	4
High Coal Feed Rate, lb/hr		← 900,585 →		
Intermediate Coal Feed Rate, lb/hr		← 450,929 →		
Low Coal Feed Rate, lb/hr		← 225,146 →		
High (or base case) Biomass Feed Rate, lb/hr	231,000	314,300	559,000	347,500
Intermediate Biomass Feed Rate, lb/hr	115,500	157,150	279,500	173,750
Low Biomass Feed Rate, lb/hr	17,852	41,386	55,318	47,980

demand. The intermediate biomass feed rate was assumed to be 50% of the high feed rate. The amount of waste generated from debarking of logs and producing wood chips for pulping ranges from 10% to 20% of the tree stem[52] and is typically 10% to 14% of the tree stem.[53] Thus the low feed rate was calculated assuming that 12% of all round wood processed on-site or off-site to produce chips for the mill would be available as hog fuel to the mill. Relative to coal feed rates, low-biomass-feed-rate scenarios had very little impact on production rates of electricity or liquid fuels and were eliminated from further analysis. Detailed energy and material balances were performed for nine (9) cases at each mill at three (3) coal feed rates and three (3) biomass feed rates for production of FT liquids, electricity, and steam.

Initial analyses focused on polygeneration plants based on FT liquids. Upon completion of economic analyses for these plants, the most promising cases were selected for comparative analyses of FT liquids and DME production. The results of these analyses are presented in the following sections.

Mass and Energy Balances

FT Liquid Cases

Energy and material balances for polygeneration cases considered for FT liquid production at Mill Nos. 1, 2, 3, and 4 are summarized in Tables 7 through 10. The following designation is used to identify each case and mill:

B-X: Current mill status
B-FT-X: Biomass refinery case
FT-X-YZ: Biomass – coal cases

Where B = base case
FT = FT liquid case
X = Mill No. 1, 2, 3, or 4
Y = 1 = high biomass feed rate
Y = 2 = intermediate biomass feed rate (50% of high feed rate)

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[52] Biermann, C.J.; *Essentials of Pulping and Paper Making;* Academic Press; San Diego, Ca; 1993; p. 13.
[53] Private conversation, Dan Burciaga, TRI.

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Z = A = high coal feed rate
Z = B = intermediate coal feed rate (50% of high feed rate)
Z = C = low coal feed rate (25% of high feed rate)

For example, FT-1-2B designates a case for producing FT liquids at the Mill No. 1 site using intermediate biomass and coal feed rates.

A more detailed energy and material balance, including block flow diagrams for each case, is presented in Appendix B. It should be noted that no attempt was made to optimize the mill's or polygeneration plant's operation; such an optimization would have required detailed knowledge of the mill's operation and significantly more resources and was not within the scope of this study. However, when sufficient steam or electricity could not be provided to the mill using the FT plant tail gas alone, a portion of the clean syngas was diverted and mixed with the tail gas and fired in the gas turbine combustor of the combined-cycle plant to generate sufficient electricity and or steam for the plant.

In addition to meeting the steam, hot water, and/or electric power demand of the mills, syngas is exported to the mills to meet the energy demand of the kilns. Any excess electric power is exported for sale. All of the liquid fuel and sulfur produced is also assumed to be available for sale. The auxiliary power requirement for the gasification and FT or DME plant is assumed to be 10% of the total electric power generated.

The useful energy output (electricity, steam, liquid fuel, syngas to kiln) to energy input (coal, biomass, recycle condensate) is defined as the polygeneration plant efficiency. It ranges from 63% to 72% for biomass-only cases and from 46% to 65% for biomass and coal cogasification cases. Cases with intermediate biomass and low coal feed rates (case numbers ending with 2C) generally exhibit a higher efficiency. This is not unexpected as these cases more closely match the mill's baseline cases that are designed to meet the mill's base load heat demand. An exception is Mill No. 4. The mill efficiency decreases as coal feed rate is reduced. It is postulated that a combination of a number of factors are contributing to the lower efficiency for Mill No. 4:

- Relatively high condensate return – i.e., high volume of low-quality steam demand but relatively low heat utilization.

- High syngas demand for kiln – i.e., lower liquid production.

- Inaccuracy in assumed tail gas composition. The tail gas composition and heating value change with changes in biomass-to-coal ratio; however, the model assumes a fixed composition for the tail gas.

DME Cases

Based on the results of the economic and financial analysis for the production of FT liquids at different biomass-to-coal feed ratios at each mill, the most economically viable cases were selected for further analysis, including analysis and evaluation of producing DME instead of FT

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liquids. The Financial Analysis section presents the financial analysis results for the FT liquids and DME production at different coal, liquid fuel, and electricity prices. This section presents the energy and material balances for selected DME production cases for each mill. A similar case designation as in the FT cases is used to identify DME cases; the only exception is that the FT is replaced by DME designating DME production rather than FT liquids.

Tables 11 through 14 compare the production rates of liquid fuel and electricity and plant efficiency for the selected FT liquid and DME production cases.

At the same biomass and/or coal feed rates, the production rate of DME compared to FT significantly increases at each mill. However, the overall plant efficiency is not generally increasing at the same rate as DME production. Other than lower heating value of DME compared to FT liquids (9718 Btu/lb for DME vs. 20,030 Btu/lb of FT liquids) a number of factors or their combinations could be contributing to this outcome:

- The impact of varying biomass-to-coal ratios on the resulting syngas composition, particularly the concentration of inert gases (e.g., CH_4, C_2H_6, C_3H_8) in the biomass syngas. These gases are not converted to FT liquids, but CH_4 is converted to CH_4OH and then to DME.

- Differing quantity and quality, including heating value of the tail gas from FT and DME plants, resulting in different electrical power output.

- Inaccuracy in assumed composition of the product and/or recycle gas to FT and DME plants. It should be noted that this study used results from other studies for coal-to-liquid and biomass-to-liquid processes. Therefore, production rates and tail gas compositions are not based on equilibrium data or actual biomass–coal-to-liquid processes but are best estimates.

A comparison of biomass-only cases in Mills 2 and 4 indicates that increased DME production relative to FT production is inversely proportional to electric power production. However, when coal and biomass are used, both DME and electricity production increase at these and other mills compared to FT liquid production cases. The rate of power generation increases slightly while DME mass production rates more than double. The highest-efficiency improvements because of DME production compared to FT liquid production are observed in Mill No. 1 at 512 MMBtu/hr of biomass and 9816 MMBtu/hr of coal. At a biomass feed rate of 1842 MMBtu/hr and no coal feed, higher plant efficiency is observed for the FT liquid production case in Mill No. 4. At Mill No. 2, for biomass-only cases (1392 MMBtu per hour of biomass feed), similar efficiencies are estimated for FT liquid and DME production.

Table 7. Mill No. 1 Energy and Material Balance Summary, Southern Region

Case No.		B-1	B-FT-1	FT-1-1A	FT-1-1B	FT-1-1C	FT-1-2A	FT-1-2B	FT-1-2C
Description	Biomass Feed Rate	High		High			50% of High		
	Coal Feed Rate	Zero		High	50% of High	25% of High	High	50% of High	25% of High
	Liquid Product	None	FT	FT			FT		
Purchased Fuel:									
Natural Gas, MMBtu/hr		393.8	0	0	0	0	0	0	0
Coal, MMBtu/hr		0	0	9816	4908	2454	9816	4908	2454
Biomass, MMBtu/hr		0	1023	1023	1023	1023	512	512	512
Electric Power, MWh/d		511	511	0	0	0	0	0	0
Import from Mill:									
Condensate Return, MMBtu/hr		89.3	89.3	89.3	89.3	89.3	89.3	89.3	89.3
Exports to Mill:									
H.P. (850 psig) Steam, lb/hr		145,257	145,257	145,257	145,257	145,257	145,257	145,257	145,257
H.P. (850 psig) Steam, MMBtu/hr		205	205	205	205	205	205	205	205
L.P. (150 psig) Steam, lb/hr		50,943	50,943	50,943	50,943	50,943	50,943	50,943	50,943
L.P. (150 psig) Steam, MMBtu/hr		61.7	61.7	61.7	61.7	61.7	61.7	61.7	61.7
Hot Water, MMBtu/hr		0	0	0	0	0	0	0	0
Syngas, MMBtu/hr		0	47	47	47	47	47	47	47
Electric Power, MWh/d		429	429	940	940	940	940	940	940
Sulfur, tons/d		0	0	0	0	0	0	0	0
Export for Sale:									
Electric Power, MWh/d		0	0	12,098	4848	4516	13,012	4875	4503
FT Liquids, bbl/d		0	1850	14,793	8322	5086	13,868	7397	4161
Sulfur, tons/d		0	0	239	122	64	237	120	61
Useful Energy/Energy Input, %[1]		59	63	50	49	61	52	50	65

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 8. Mill No. 2 Energy and Material Balance Summary, Northeast Region

Case No.		B-2	B-FT-2	FT-2-1A	FT-2-1B	FT-2-1C	FT-2-2A	FT-2-2B	FT-2-2C
Description	Biomass Feed	High		High			50% of High		
	Coal Feed	Zero		High	50% of High	25% of High	High	50% of High	25% of High
	Liquid Product	None	FT	FT			FT		
Purchased Fuel:									
Natural Gas, MMBtu/hr		0	0	0	0	0	0	0	0
Coal, MMBtu/hr		385	0	9816	4908	2454	9816	4908	2454
Biomass, MMBtu/hr		0	1392	1392	1392	1392	696	696	696
Electric Power, MWh/d		210	0	0	0	0	0	0	0
Import from Mill:									
Condensate Return, MMBtu/hr		66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7
Exports to Mill:									
L.P. (150 psig) Steam, lb/hr		96,239	96,239	96,239	96,239	96,239	96,239	96,239	96,239
L.P. (150 psig) Steam, MMBtu/hr		116.9	116.6	116.6	116.6	116.6	116.6	116.6	116.6
Hot Water, MMBtu/hr		0	0	0	0	0	0	0	0
Syngas, MMBtu/hr		0	51	51	51	51	51	51	51
Electric Power, MWh/d		1200	1410	1410	1410	1410	1410	1410	1410
Sulfur, tons/d		0	0	0	0	0	0	0	0
Export for Sale:									
Electric Power, MWh/d		0	201	10,987	4003	3209	11,011	3694	3204
FT Liquids, bbl/d		0	2517	15,460	8989	5753	14,202	7730	4494
Sulfur, tons/d		0	0	241	124	66	238	121	62
Hog Fuel, MMBtu/hr		117.4	0	0	0		0		
Useful Energy/Energy Input, %[1]		60	63	48	46	53	48	46	56

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 9. Mill No. 3 Energy and Material Balance Summary, Western Regions

Case No.		B-3	B-FT-3	FT-3-1A	FT-3-1B	FT-3-1C	FT-3-2A	FT-3-2B	FT-3-2C
Description	Biomass Feed	High		High			50% of High		
	Coal Feed	Zero		High	50% of High	25% of High	High	50% of High	25% of High
	Liquid Product	None	FT	FT			FT		
Purchased Fuel:									
Natural Gas, MMBtu/hr		494.5	0	0					
Coal, MMBtu/hr		0	0	9816	4908	2454	9816	4908	2454
Biomass, MMBtu/hr		0	2135	2135	2135	2135	1067	1067	1067
Electric Power, MWh/d		0	0	0					
Import from Mill:									
Condensate Return, MMBtu/hr		132	132	132	132	132	132	132	132
H.P. (1248 psig) steam, lb/hr		201,092	201,092	201,092	201,092	201,092	201,092	201,092	201,092
H.P. (1248 psig) steam, MMBtu/hr		302	302	302	302	302	302	302	302
Exports to Mill:									
I.P. (450 psig) steam, lb/hr		121,000	121,000	121,000	121,000	121,000	121,000	121,000	121,000
I.P. (450 psig) steam, MMBtu/hr		154	154	154	154	154	154	154	154
L.P. (160 psig) Steam, lb/hr		194,996	194,996	194,996	194,996	194,996	194,996	194,996	194,996
L.P. (160 psig) Steam, MMBtu/hr		236.9	236.9	236.9	236.9	236.9	236.9	236.9	236.9
L.P. (65 psig) Steam, lb/hr		180,000.0	180,000.0	180,000.0	180,000.0	180,000.0	180,000.0	180,000.0	180,000.0
L.P. (65 psig) Steam, MMBtu/hr		214	214	214	214	214	214	214	214
Hot Water, MMBtu/hr		0	0	0	0	0	0	0	0
Syngas, MMBtu/hr		0	44	44	44	44	44	44	44
Electric Power, MWh/d		1200	1200	1200	1200	1200	1200	1200	1200
Sulfur, tons/d									
Export for Sale:									
Electric Power, MWh/d		552	−1	8310	3885	1450	9233	4025	1414
FT Liquids, bbl/d		0	3860	16,803	10,332	7,096	14,873	8402	5166
Sulfur, tons/d		0	0	245	128	70	240	123	64
Useful Energy/Energy Input, %[1]		92	66	47	49	52	48	51	55

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 10. Mill No. 4 Energy and Material Balance Summary, Midwest Region

Case No.		B-4	B-FT-4	FT-4-1A	FT-4-1B	FT-4-1C	FT-4-2A	FT-4-2B	FT-4-2C
Description	Biomass Feed Rate	High		High			50% High		
	Coal Feed Rate	Zero		High	50% High	25% High	High	50% High	25% High
	Liquid Product	None	FT	FT			FT		
Purchased Fuel:									
Natural Gas, MMBtu/hr		282.8	0	0	0	0	0	0	0
Coal, MMBtu/hr		0	0	9816	4908	2454	9816	4908	2454
Biomass, MMBtu/hr		0	1842	1842	1842	1842	867	867	867
Electric Power, MWh/d		0	0	0	0	0	0	0	0
Import from Mill:									
Condensate Return, MMBtu/hr		136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7
Hog Fuel, MMBtu/hr		212.5	0	0	0	0	0	0	0
Exports to Mill:									
L.P. (150 psig) Steam, lb/hr		213,709	213,709	213,709	213,709	213,709	213,709	213,709	213,709
L.P. (150 psig) Steam, MMBtu/hr		258.9	258.9	258.9	258.9	258.9	258.9	258.9	258.9
Hot Water, MMBtu/hr		0	0	0	0	0	0	0	0
Syngas, MMBtu/hr		0	71.7	72	72	72	72	72	72
Hydropower, MWh/d		216	216	216	216	216	216	216	216
Electric Power, MWh/d		1375	1375	1375	1375	1375	1375	1375	1375
Sulfur, tons/d		0	0	0	0	0	0	0	0
Export for Sale:									
Electric Power, MWh/d		340	340	10,424	2138	417	10,467	2499	64
FT Liquids, bbl/d		0	3747	16,273	9802	5253	14,608	8137	4411
Sulfur, tons/d		0	0	244	127	68	239	122	63
Useful Energy/Energy Input, %[1]		80	72	48	44	40	49	46	44

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 11. DME and FT Liquid Production Case Comparison – Mill No. 1

Case No.		DME-1-2A	FT-1-2A
Description	Biomass Feed	50% of High	
	Coal Feed	High	
	Liquid Product	DME	FT
Purchased Fuel:			
Coal, MMBtu/hr		9816	
Biomass, MMBtu/hr		512	
Electric Power, MWh/d		0	
Import from Mill:			
Condensate Return, MMBtu/hr		89.3	
Exports to Mill:			
H.P. (850 psig) steam, lb/hr		145,257	
H.P. (850 psig) steam, MMBtu/hr		205	
L.P. (150 psig) Steam, lb/hr		50,943	
L.P. (150 psig) Steam, MMBtu/hr		62	
Syngas, MMBtu/hr		47	
Electric Power, MWh/d		940	
Sulfur, tpd		0	
Export for Sale:			
Electric Power, MWh/d		13,615	13,012
Liquid Product, tpd		5290	1872
Sulfur, tpd		237	
Useful Energy/Energy Input, %[1]		64	52

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 12. DME and FT Liquid Production Case Comparisons – Mill No. 2

Case No.		B-DME-2	B-FT-2	DME-2-1A	FT-2-1A	DME-2-2A	FT-2-2A
Description	Biomass Feed	High				50% of High	
	Coal Feed	Zero		High			
	Liquid Product	DME	FT	DME	FT	DME	FT
Purchased Fuel:							
Coal, MMBtu/hr		0		9816			
Biomass, MMBtu/hr		1392				696	
Import from Mill:							
Condensate Return, MMBtu/hr		66.7					
Exports to Mill:							
L.P. (150 psig) Steam, lb/hr		96,239					
L.P. (150 psig) Steam, MMBtu/hr		116.6					
Hot Water, MMBtu/hr		0					
Syngas, MMBtu/hr		51					
Electric Power, MWh/d		1410					
Sulfur, tpd		0					
Export for Sale:							
Electric Power, MWh/d		0	201	15,201	10,987	15,408	11,011
Liquid Product, tpd		760	340	4246	2087	4006	1917
Sulfur, tpd		0		241		238	
Useful Energy/Energy Input, %[1]		64	63	52	48	54	48

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 13. DME and FT Liquid Production Case Comparisons – Mill No. 3

Case No.		DME-3-1A	FT-3-1A	DME-3-1B	FT-3-1B
Description	Biomass Feed	High			
	Coal Feed	High		50% of High	
	Liquid Products	DME	FT	DME	FT
Purchased Fuel:					
Coal, MMBtu/hr		9816		4908	
Biomass, MMBtu/hr		2135			
Import from Mill:					
Condensate Return, MMBtu/hr		132			
H.P. (1248 psig) steam, lb/hr		201,092			
H.P. (1248 psig) steam, MMBtu/hr		302			
Exports to Mill:					
I.P. (450 psig) steam, lb/hr		121,000			
I.P. (450 psig) steam, MMBtu/hr		145			
L.P. (160 psig) Steam, lb/hr		194,996			
L.P. (160 psig) Steam, MMBtu/hr		237			
L.P. (65 psig) Steam, lb/hr		180,000			
L.P. (65 psig) Steam, MMBtu/hr		214			
Hot Water, MMBtu/hr		0			
Syngas, MMBtu/hr		44			
Electric Power, MWh/d		1200			
Export for Sale:					
Electric Power, MWh/d		6235	8310	5407	3885
Liquid Product, tpd		4503	2268	2620	1395
Sulfur, tpd		245	245	128	128
Useful Energy/Energy Input, %[1]		43	47	50	49

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Table 14. DME and FT Liquid Production Case Comparisons – Mill No. 4

		B-DME-4	B-FT-4
Case No.		B-DME-4	B-FT-4
Description	Biomass Feed	High	
	Coal Feed	Zero	
	Liquid Product	DME	FT
Purchased Fuel:			
Coal, MMBtu/hr		0	
Biomass, MMBtu/hr		1842	
Import from Mill:			
Condensate Return, MMBtu/hr		137	
Exports to Mill:			
L.P. (150 psig) Steam, lb/hr		213,709	
L.P. (150 psig) Steam, MMBtu/hr		259	
Hot Water, MMBtu/hr		0	
Syngas, MMBtu/hr		72	
Hydro Power, MWh/d		216	
Electric Power, MWh/d		1375	
Sulfur, Tons/d		0	
Export for Sale:			
Electric Power, MWh/d		14	340
Liquid Product, tpd		845	506
Sulfur, tpd		0	0
Useful Energy/Energy Input, %[1]		61	72

[1] Energy output from liquefaction and power plants divided by energy input to liquefaction and power plants.

Carbon Management

Tables 15–18 show the results of carbon balances for the power and fuel islands, including carbon in captured CO_2 gas, for each case at each mill. The upper part of the tables shows the estimated amount of carbon in various feed and output streams as predicted by the energy and material balance model. The carbon capture increases with increasing coal feed rate ranging from 42% to 51% of the carbon in the total plant feed for FT production cases, 46% to 51% for Mill No. 1, 45% to 50% for Mill No. 2, 42% to 50% for Mill No. 3, and 43% to 50% for Mill No. 4 (see "Carbon in Captured CO_2, %" row under "Model Results"). The captured carbon for DME production cases ranges from 48% to 54% and is consistently 1 to 3 percentage points higher than carbon capture of the corresponding FT liquid production cases.

Because the energy and material balance model used in this study is not based on equilibrium data but is rather based on overall energy and material balances for biomass- and coal-to-liquid processes, it was considered prudent (or conservative) to normalize (or

proportionally adjust) the carbon content of each stream (shown in the upper section of Tables 15 through 18) for each case using the same percentage carbon loss as the biomass-only cases (B-FT-X), the highest carbon loss for FT liquid production case for each mill. The normalized values are shown in the lower section of Tables 15 through 18. The normalized carbon in the captured CO_2 gas stream is lower than the reported model results, ranging from 41% to 45% of the carbon content of the total plant feed for FT production cases.

Production of DME results is a few percentage points higher in carbon capture than FT production. It should, however, be noted that this study does not take into account any impact that FT liquid or DME final uses, energy densities, or combustion efficiencies may have on CO_2 generation, capture, or emissions.

Table 15. Mill No. 1 Carbon Balance

Case No.	B-FT-2	FT-1-1A	FT-1-1B	FT-1-1C	FT-1-2A	FT-1-2B	FT-1-2C	DME-1-1A	DME-1-2A
Model Results:									
Carbon in Coal Feed, tph	0	270	135	67	270	135	67	270	270
Carbon in Biomass Feed, tph	30	30	30	30	15	15	15	30	15
Total Carbon in Feed, tph	30	299	164	97	284	150	82	299	284
Carbon in Liquid Fuel, tph	9	74	42	26	70	37	21	60	57
Carbon in Tail Gas, tph	17	72	38	21	69	36	19	50	45
Carbon in Captured CO_2, tph	0	149	79	45	144	75	40	150	145
Carbon in Captured CO_2, %	0.00	49.86	48.32	45.95	50.75	49.86	48.32	50.24	51.13
Carbon Loss, tph	3	4	5	6	1	2	3	39	36
Carbon Loss, %	10.62%	1.43%	3.10%	5.68%	0.46%	1.43%	3.10%	12.92%	12.76%
Normalized Values:		295	159	91	283	147	80	261	248
Carbon in Liquid Fuel, tph		67	39	24	62	34	19	62	59
Carbon in Tail Gas, tph		65	35	20	62	32	18	51	46
Carbon in CO_2 Captured Gas, tph		135	73	42	130	68	37	154	149
Net Carbon Loss, tph		32	17	10	30	16	9	32	30
Carbon in Liquid Fuel, %		22.50	23.43	24.93	21.97	22.50	23.43	20.64	20.71
Carbon in Tail Gas, %		21.67	21.38	20.91	21.83	21.67	21.38	17.18	16.29
Carbon in Captured CO_2, %	0.00	45.21	44.57	43.54	45.57	45.21	44.57	51.56	52.38
Carbon Loss, %		10.62	10.62	10.62	10.62	10.62	10.62	10.62	10.62
Total Carbon Output, %		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 16. Mill No. 2 Carbon Balance

	B-FT-2	FT-2-1A	FT-2-1B	FT-2-1C	FT-2-2A	FT-2-2B	FT-2-2C	B-DME-2	DME-2-1A	DME-2-2A
Model Results:										
Carbon in Coal Feed, tph	0	270	135	67	270	135	67	0	270	270
Carbon in Biomass Feed, tph	40	40	40	40	20	20	20	40	40	20
Total Carbon in Feed, tph	40	310	175	108	290	155	88	40	310	290
Carbon in Liquid Fuel, tph	13	78	45	29	71	39	23	1	46	44
Carbon in Tail Gas, tph	23	73	40	23	70	37	20	35	98	92
Carbon in Captured CO_2, tph	0	153	83	48	146	76	41	0	161	154
Carbon in Captured CO_2, %	0.00	49	47	45	50	49	47	0	52	53
Carbon Loss, tph	4	6	7	8	2	3	4	4	4	0
Carbon Loss, %	10.62%	2.07%	4.13%	7.10%	0.82%	2.07%	4.13%	10.62%	1.44%	−0.04%
Normalized Values:										
Carbon in Liquid Fuel, tph		71	42	28	64	35	21	1	42	39
Carbon in Tail Gas, tph		67	37	22	63	33	19	35	89	82
Carbon in CO_2 Captured Gas, tph		139	77	46	132	70	39	0	146	138
Net Carbon Loss, tph		33	19	11	31	16	9	4	33	31
Carbon in Liquid Fuel, %		22.85	24.02	25.79	22.17	22.85	24.02	2.87	13.51	13.43
Carbon in Tail Gas, %		21.56	21.19	20.64	21.77	21.56	21.19	86.51	28.62	28.32
Carbon in CO_2 Captured Gas, %		44.97	44.17	42.95	45.44	44.97	44.17	0.00	47.25	47.64
Carbon Loss, %		10.62	10.62	10.62	10.62	10.62	10.62	10.62	10.62	10.62
Total Carbon Output, %		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 17. Mill No. 3 Carbon Balance

	B-3-2	FT-3-1A	FT-3-1B	FT-3-1C	FT-3-2A	FT-3-2B	FT-3-2C	B-DME-3	DME-3-1A	DME-3-1B
Model Results:										
Carbon in Coal Feed, tph	0	270	135	67	270	135	67	0	270	135
Carbon in Biomass Feed, tph	62	62	62	62	31	31	31	62	62	62
Total Carbon in Feed, tph	62	332	197	129	300	166	98	62	331	197
Carbon in Liquid Fuel, tph	19	84	52	36	75	42	26	1	49	28
Carbon in Tail Gas, tph	36	77	43	27	72	38	22	47	104	61
Carbon in Captured CO_2, tph	0	160	90	55	150	80	45	0	169	95
Carbon in Captured CO_2, %	0.00	48.11	45.77	42.66	49.79	48.20	45.77	0.00	50.97	48.41
Net Carbon Loss, tph	7	11	12	12	5	5	6	14	9	12
Net Carbon Loss, %	11.53%	3.42%	5.86%	9.24%	1.51%	3.23%	5.86%	22.29%	2.82%	5.95%
Normalized Values:										
Carbon in Liquid Fuel, tph		77	49	35	67	39	24	1	45	27
Carbon in Tail Gas, tph		70	41	26	64	35	20	54	95	58
Carbon in CO_2 Captured Gas, tph		146	85	54	134	73	42	0	154	90
Net Carbon Loss, tph		38	23	15	35	19	11	7	38	23
Carbon in Liquid Fuel, %		23.26	24.79	26.87	22.31	23.26	24.79	2.39	13.44	13.63
Carbon in Tail Gas, %		21.14	20.66	20.01	21.43	21.14	20.66	86.07	28.62	29.31
Carbon in Captured CO_2, %		44.07	43.02	41.58	44.72	44.07	43.02	0.00	46.40	45.53
Carbon Loss, %		11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53
Total Carbon Output, %		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 18. Mill No. 4 Carbon Balance

	B-FT-4	FT-4-1A	FT-4-1B	FT-4-1C	FT-4-2A	FT-4-2B	FT-4-2C	B-DME-4
Model Results:								
Carbon in Coal Feed, tph	0	270	135	67	270	135	67	0
Carbon in Biomass Feed, tph	54	54	54	54	27	25	25	54
Total Carbon in Feed, tph	54	323	189	121	296	160	93	54
Carbon in Liquid Fuel, tph	17	82	49	26	73	41	22	1
Carbon in Tail Gas, tph	29	75	42	21	71	38	19	47
Carbon in Captured CO_2, tph	0	157	87	52	148	78	44	0
Carbon in Captured CO_2, %		48.53	46.23	43.15	50.03	49.08	47.13	0.00
Carbon Loss, tph	8	10	10	22	4	3	8	6
Carbon Loss, %	14.86%	2.95%	5.50%	17.98%	1.24%	1.85%	8.29%	11.53%
Normalized Values**:**								
Carbon in Liquid Fuel, tph		72	44	27	63	35	21	1
Carbon in Tail Gas, tph		66	38	22	61	33	18	45
Carbon in CO_2 Captured Gas, tph		138	79	54	128	68	40	0
Net Carbon Loss, tph		48	28	18	44	24	14	8
Carbon in Liquid Fuel, %		22.15	23.49	22.57	21.33	22.15	22.21	1.37
Carbon in Tail Gas, %		20.42	20.00	17.78	20.67	20.42	19.17	83.77
Carbon in Captured CO_2, %		42.57	41.65	44.79	43.14	42.57	43.75	0.00
Carbon Loss, %		14.86	14.86	14.86	14.86	14.86	14.86	14.86
Total Carbon Output, %		100.00	100.00	100.00	100.00	100.00	100.00	100.00

CAPITAL AND OPERATING COST ESTIMATES

Approach and Assumptions

Capital and operating cost estimates were developed for biomass-only and high biomass and coal feed rate cases at each mill using an in-house cost database that includes both published and unpublished data. Equipment cost factors were then used to estimate equipment costs for other scenarios at each mill. The in-house cost database includes equipment, installation, and other capital cost data for IGCC, coal-to-liquid, hydrogen production, biomass gasification, and biorefinery projects since the mid-1990s.[54,55,56,57,58,59,60,61,62,63,64,65,66,67,68,69,70,71,72] It is used to establish cost factors for various equipment based on capacity and most recent costs and provides a source for assessing reasonableness of the estimated equipment costs. It uses Chemical Engineering's CE Plant Cost Index (CEPCI) to adjust equipment costs to 2006 costs.

[54] Gray, D.; Salerno, S.; Tomlinson, G. *A Techno-Economic Analysis of a Wyoming-Located Coal-to-Liquids (CTL) Plant;* NETL, April 2005.

[55] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006.

[56] Bechtel, Global Energy, and Nexant. *Gasification Plant Cost and Performance Optimization;* Final Report; NETL Contract No. DE-AC26-99FT40342, 2003.

[57] Gray, D.; Salerno, S.; Tomlinson, G.; Marano, J.J. *Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite;* NETL, Dec 2004.

[58] Williams, R. *IGCC: Next Step on the Path to Gasification-Based Energy from Coal;* Princeton University, June 2004.

[59] Stone & Webster, Inc. *Confidential Report*; 2002.

[60] Parsons, E.L.; Shelton, W.W.; Lyons, J.L. *Advanced Fossil Power Systems Comparison Study*; Final Report; NETL, Dec 2002.

[61] National Energy Technology Laboratory. *Hydrogen Production Facilities Plant Performance and Cost Comparison;* Final Report; March 2002.

[62] Larson, E.D.; Consonni, S.; Katofsky, R.E. *A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry;* Final Report; Princeton University, Oct 2003.

[63] National Energy Technology Laboratory. *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project;* Final Technical Report; Aug 2002.

[64] Spath, P.L.; Mann, M.K. *Biomass Power and Conventional Fossil Systems with and Without CO_2 Sequestration – Comparing Energy Balance, Greenhouse Gas Emissions, and Economics;* NREL, Jan 2004.

[65] National Energy Technology Laboratory. *Wabash River Coal Gasification Repowering Project;* Final Technical Report; Aug 2000.

[66] National Energy Technology Laboratory. *Shell Gasifier IGCC Base Cases;* PED-IGCC-98-002, June 2000.

[67] National Energy Technology Laboratory. *Texaco Gasifier IGCC Base Cases;* PED-IGCC-98-001, June 2000.

[68] National Energy Technology Laboratory. *Transport Gasifier IGCC Base Cases*; PED-IGCC-98-006, June 2000.

[69] National Energy Technology Laboratory. *British Gas/Lurgi Gasifier IGCC Base Cases;* PED-IGCC-98-004, June 2000.

[70] National Energy Technology Laboratory. *Destec Gasifier IGCC Base Cases;* PED-IGCC-98-003, June 2000.

[71] National Energy Technology Laboratory. *Gasification Plant Cost and Performance Optimization;* Contract No. DE-AC26-99FT40342. September 2003; Vols. 1 and 2.

[72] Spath, P.; Arden, A.; Eggeman, T.; Ringel, M.; Wallace, B.; Jechura, J. *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly Heated Gasifier;* NREL, May 2005.

EPC Costs

Tables 19 through 22 show the engineering, procurement, and construction (EPC) cost for each case considered at Mill Nos. 1, 2, 3, and 4. The EPC cost is exclusive of interest costs during the construction period but includes total installed equipment cost, home office costs (project management, permitting, and detailed engineering) at 8.5%, process contingency at 10%, project contingency at 5%, and licensing fees at 5% of installed equipment costs. Installed equipment costs include solids (biomass and coal) handling including biomass dryer and thermal oxidizer, air separation unit cost (for coal and biomass cases – it is assumed that for biomass-only cases, an air separation unit will be leased), reformer island, coal gasification island, CO_2 separation and compression equipment, FT liquids or DME plant, power island, and balance-of-plant equipment. It should be noted that the thermal oxidizer for the biomass dryer exhaust gas handling is more expensive than the biomass steam reformer and may not be required; however, to be conservative, the cost of the thermal oxidizer is included in the installed equipment cost.

FINANCIAL ANALYSIS

Approach and Assumptions

A financial model was developed to estimate levelized costs as well as tariff for electricity or liquid fuel produced based on capital and operating costs of each case.

One way to perform comparisons among different cases is to use the levelized cost method; another is to estimate the actual year-by-year tariff. The levelized cost is the average cost of a unit of product (electricity or liquid fuel) over the life of a plant, taking into account all capital expenses, operating expenses (including interest payment, return on equity), fuel costs, and any revenue generated from the sale of any other product or by-products: all at present value or worth. The impact of taxes can be taken into account by adjusting the interest on debt for taxes. For example, if the interest on debt is 9% and taxes are levied at 39%, the effective interest on debt after adjustment for taxes is about 5.49% ([1 − 0.39] × 9% = 5.49). The levelized cost method can be used to rank alternative technologies or options but does not provide sufficient information to assess the financial viability of a project or compare the cost of the production of a product (electricity and/or liquid fuel) to its market value. Levelized costs are presented in this report for the purpose of comparison with other studies that use the levelized cost method.

Tariff is the price that a plant owner must charge for a product in order to recover all of its operating costs and meet its financial obligations to local and federal governments, lenders, and equity share holders. It is not an average cost of the product over the life of the plant but an average product cost over a shorter period (i.e., day, week, month, or year). In this study, tariffs are estimated annually; the tariff changes from year to year as the principal amount of the loan, the amount of interest payments, and the owner's tax obligations change. Over the life of the plant, the tariff can increase or decrease steadily or stepwise or remain constant depending on how fast an owner wishes to or can recover its equity. Thus a range of tariffs can be calculated

Table 19. Mill No. 1 Installed Equipment Costs,[1] 2006 $1000

Case No.	B-FT-1	FT-1-1A	FT-1-1B	FT-1-1C	FT-1-2A	FT-1-2B	FT-1-2C	DME-1-1A	DME-1-2A
Solid Handling	$54,396	$87,198	$79,213	$73,171	$67,094	$59,109	$53,067	$87,198	$67,094
Air Separation Unit	$0	$133,551	$86,879	$57,589	$132,145	$85,102	$55,362	$133,551	$132,145
Reformer Island	$35,559	$29,803	$29,803	$29,803	$20,583	$20,583	$20,583	$29,803	$20,583
Coal Gasification Island	$0	$433,229	$274,181	$188,457	$433,229	$274,181	$188,457	$433,229	$433,229
CO_2 Separation and Compression	$0	$62,244	$46,087	$35,942	$61,248	$44,726	$33,129	$179,349	$61,248
Liquefaction Island	$4996	$68,204	$50,885	$39,600	$65,998	$47,921	$35,752	$223,332	$216,870
Power Island	$16,088	$138,603	$75,636	$68,408	$142,230	$74,458	$51,392	$159,889	$150,834
Balance of Plant	$10,921	$93,710	$63,207	$48,483	$90,730	$59,607	$43,052	$122,577	$106,414
Total Installed Cost	$121,960	$1,046,542	$705,891	$541,453	$1,013,257	$665,687	$480,794	$1,368,929	$1,188,417
Home Office (project management, detail engineering) @ 8.5%	$10,367	$88,956	$60,001	$46,024	$86,127	$56,583	$40,867	$116,359	$101,015
Process Contingency @ 10%	$12,196	$104,654	$70,589	$54,145	$101,326	$66,569	$48,079	$136,893	$118,842
Project Contingency @ 5%	$6098	$52,327	$35,295	$27,073	$50,663	$33,284	$24,040	$68,446	$59,421
Licensing Fees @ 5%	$6098	$52,327	$35,295	$27,073	$50,663	$33,284	$24,040	$68,446	$59,421
Total EPC Cost	$156,718	$1,344,806	$907,070	$695,768	$1,302,036	$855,408	$617,820	$1,759,073	$1,527,116

[1] EPC costs are exclusive of interest during construction.

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Table 20. Mill No. 2 Installed Equipment Costs, 2006 $1000

Case No.	B-FT-2	FT-2-1A	FT-2-1B	FT-2-1C	FT-2-2A	FT-2-2B	FT-2-2C	B-DME-2	DME-2-1A	DME-2-2A
Solid Handling	$66,773	$99,575	$91,590	$85,549	$67,094	$59,109	$53,067	$66,773	$99,575	$67,094
Air Separation Unit	$0	$134,560	$88,148	$59,168	$132,653	$85,745	$83,306	$0	$134,560	$132,653
Reformer Island	$43,438	$36,407	$36,407	$36,407	$21,876	$21,876	$21,876	$43,438	$36,407	$21,876
Coal Gasification Island	$0	$433,229	$274,181	$173,523	$433,229	$274,181	$173,523	$0	$433,229	$433,229
CO_2 Separation and Compression	$0	$62,910	$47,043	$36,279	$61,600	$45,222	$33,816	$0	$64,607	$63,262
Liquefaction Island	$6104	$69,754	$52,923	$42,166	$66,802	$49,010	$37,184	$7281	$54,698	$52,665
Power Island	$27,925	$131,847	$71,403	$68,358	$132,329	$75,431	$68,321	$15,945	$160,024	$161,587
Balance of Plant	$14,186	$95,230	$65,077	$49,317	$90,047	$60,049	$46,331	$13,123	$96,687	$91,697
Total Installed Cost	$158,426	$1,063,512	$726,771	$550,766	$1,005,629	$670,622	$517,424	$146,561	$1,079,787	$1,024,063
Home Office (project management, detail engineering) @ 8.5%	$13,466	$90,399	$61,776	$46,815	$85,478	$57,003	$43,981	$12,458	$91,782	$87,045
Process Contingency @ 10%	$15,843	$106,351	$72,677	$55,077	$100,563	$67,062	$51,742	$14,656	$107,979	$102,406
Project Contingency @ 5%	$7921	$53,176	$36,339	$27,538	$50,281	$33,531	$25,871	$7328	$53,989	$51,203
Licensing Fees @ 5%	$,921	$53,176	$36,339	$27,538	$50,281	$33,531	$25,871	$7328	$53,989	$51,203
Total EPC Cost	$203,577	$1,366,613	$933,901	$707,734	$1,292,233	$861,749	$664,890	$188,330	$1,387,526	$1,315,920

Table 21. Mill No. 3 Installed Equipment Costs, 2006 $1000

Case No.	B-FT-3A	FT-3-1A	FT-3-1B	FT-3-1C	FT-3-2A	FT-3-2B	FT-3-2C	B-DME-3A	DME-3-1A	DME-3-1B
Solid Handling	$88,768	$121,571	$113,586	$107,544	$88,755	$80,769	$74,728	$88,768	$121,571	$113,586
Air Separation Unit	$0	$136,579	$86,879	$62,279	$133,673	$87,032	$57,780	$0	$136,579	$86,879
Reformer Island	$57,356	$48,072	$48,072	$48,072	$33,201	$33,201	$33,201	$57,356	$48,072	$48,072
Coal Gasification Island	$0	$433,229	$274,181	$183,579	$433,229	$274,181	$183,579	$0	$433,229	$274,181
CO_2 Separation and Compression	$0	$64,275	$48,904	$38,719	$61,248	$46,203	$35,154	$0	$66,009	$50,223
Liquefaction Island	$8059	$72,777	$56,812	$46,920	$68,392	$51,134	$39,917	$91,214	$190,447	$144,550
Power Island	$34,008	$136,457	$82,417	$45,211	$143,754	$83,399	$45,849	$32,364	$151,122	$93,348
Balance of Plant	$18,508	$99,623	$69,911	$52,354	$94,636	$64,509	$46,244	$26,525	$112,809	$79,745
Total Installed Cost	$206,700	$1,112,582	$780,762	$584,678	$1,056,888	$720,427	$516,452	$296,227	$1,259,838	$890,583
Home Office (project management, detail engineering) @ 8.5%	$17,569	$94,570	$66,365	$49,698	$89,835	$61,236	$43,898	$25,179	$107,086	$75,700
Process Contingency @ 10%	$20,670	$111,258	$78,076	$58,468	$105,689	$72,043	$51,645	$29,623	$125,984	$89,058
Project Contingency @ 5%	$10,335	$55,629	$39,038	$29,234	$52,844	$36,021	$25,823	$14,811	$62,992	$44,529
Licensing Fees @ 5%	$10,335	$55,629	$39,038	$29,234	$52,844	$36,021	$25,823	$14,811	$62,992	$44,529
Total EPC Cost	$265,609	$1,429,668	$1,003,279	$751,312	$1,358,101	$925,749	$663,641	$380,652	$1,618,892	$1,144,400

Table 22 . Mill No. 4 Installed Equipment Costs, 2006 $1000

Case No.	B-FT-4A	FT-4-1A	FT-4-1B	FT-4-1C	FT-4-2A	FT-4-2B	FT-4-2C	B-DME-4	DME-4-1A
Solid Handling	$80,451	$113,253	$105,268	$99,227	$83,513	$75,528	$69,487	$80,451	$113,253
Air Separation Unit	$0	$135,784	$89,682	$61,061	$133,271	$86,525	$57,148	$0	$135,784
Reformer Island	$52,104	$43,670	$43,670	$43,670	$30,161	$30,161	$30,161	$52,104	$43,670
Coal Gasification Island	$0	$433,229	$274,181	$183,579	$433,229	$274,181	$183,579	$0	$433,229
CO_2 Separation and Compression	$0	$63,740	$48,179	$37,772	$62,027	$45,819	$34,630	$0	$65,460
Liquefaction Island	$7321	$71,598	$55,308	$40,257	$67,769	$50,306	$36,830	$65,828	$192,441
Power Island	$30,967	$106,055	$64,351	$42,762	$137,499	$77,992	$38,347	$28,836	$165,229
Balance of Plant	$16,802	$95,136	$66,940	$49,993	$93,182	$62,994	$44,275	$22,347	$113,009
Total Installed Cost	$187,645	$1,062,465	$747,578	$558,321	$1,040,650	$703,504	$494,457	$249,565	$1,262,075
Home Office (project management, detail engineering) @ 8.5%	$15,950	$90,310	$63,544	$47,457	$88,455	$59,798	$42,029	$21,213	$107,276
Process Contingency @ 10%	$18,765	$106,247	$74,758	$55,832	$104,065	$70,350	$49,446	$24,957	$126,208
Project Contingency @ 5%	$9382	$53,123	$37,379	$27,916	$52,033	$35,175	$24,723	$12,478	$63,104
Licensing Fees @ 5%	$9382	$53,123	$37,379	$27,916	$52,033	$35,175	$24,723	$12,478	$63,104
Total EPC Cost	$241,124	$1,365,268	$960,638	$717,442	$1,337,236	$904,003	$635,377	$320,692	$1,621,767

that meets all of the owner's obligations mentioned above. For the purpose of this study, the tariff for each year was estimated using the following constraints:

- A first-year tariff, as a minimum, must generate sufficient revenue to meet all of the owner's obligations for that year.

- Annual tariff increases or decreases were limited to a maximum of 5%.

- If the required 15% rate of return on equity could not be obtained at a minimum first-year tariff with a 5% annual escalation, then the first-year tariff was increased to a value that, with a 5% annual tariff escalation, a 15% return on equity could be obtained.

- Generally, either the liquid fuel prices or the electricity prices were kept constant over the life of the plant (in a few cases, both electricity and liquid fuel prices were escalated to project a more realistic scenario; these cases are specified within the report).

Capital and Operating Costs

The capital cost includes EPC, interest during construction, finance charges, insurance, working capital, start-up, and project development costs. Table 23 lists capital cost components and assumptions made for estimating those costs. These assumptions are based on past experience with large-scale power projects.[73]

Operating costs or revenues are estimated based on the results of energy and material balances and biomass, coal, sulfur, and electricity or liquid fuel (FT or DME) prices. Operation and maintenance (O&M) costs are estimated at 4% of EPC costs.[74] The O&M cost does not include the cost of transporting and sequestering captured CO_2. The cost of transport and storage in deep saline aquifers in North America is estimated to be \$12 to \$15 per ton of CO_2.[75]

Initially, a coal price of \$25 per ton and regional wholesale electricity prices were used to estimate levelized costs and tariff for FT liquid products. A FT liquid price of \$52/bbl was used for estimating plant electricity levelized cost and tariff based on FT liquid production rates. This information was then used to select cases with the lowest electricity or FT liquid tariff for developing energy and material balances, capital and operating costs, and financial modeling for DME cases.

Finally, coal prices and quantities were adjusted to reflect available coal prices and heating values at each region where the mills are located and to assess the impact of regional coal prices on electricity and liquid fuel tariff. The differences in coal composition can impact the gasifier

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[73] Rezaiyan, A.J; McVeigh, J.; Menendez, J. *Assessing the Economic Potential of IGCC Innovation with Liquid Sparing;* Princeton Energy Resources International; Rockville, MD; June 2005.

[74] Rezaiyan, A.J; McVeigh, J.; Menendez, J. *Assessing the Economic Potential of IGCC Innovation with Liquid Sparing;* Princeton Energy Resources International; Rockville, MD; June 2005.

[75] Dooley, J.J.; Dahowski, R.T.; Davidson, C.L.; Wise, M.A.; Gupta, N.; Kim, S.H.; Malone, E.L. *Carbon Dioxide Capture and Geological Storage;* Technical Report from Global Energy Technology Strategy Program; 2006. p. 36.

Table 23. Capital Cost Components

Capital Cost Components	Assumptions
EPC Cost	See EPC Costs section
Interest During Construction	Construction period: 2 years for biomass only and 4 years for biomass and coal cases. Interest on debt: 9%
	Term: 20 years
Commitment Fee	0.75% of outstanding balance
Financing Costs	Legal/out-of-pocket costs: $1,000,000
	Facility fee: 1% of debt
	Retainer fee: 0.4% of debt
Insurance, Start-Up, and Working Capital Costs	Owner's engineer: $2,000,000 per project
	Insurance: 2% of EPC cost
	Initial working capital: 25% of first-year expenses
	Start-up costs: 3% of EPC cost
Project Development Costs	2.5% of EPC, financing, insurance, start-up, and working capital costs

performance and syngas composition. However, a review of a study prepared for Southern States Energy Board (SSEB) indicates that the difference in capital costs for the same size coal-to-liquid plants using bituminous and subbituminous coal is less than 7%, while the difference in the operating costs, excluding coal costs, is less than 2%, with the subbituminous plant having lower capital and operating costs.[76]

A DME price of $224 per ton was assumed for estimating levelized electricity costs and tariff for DME production cases. DME is not produced widely on a commercial basis; therefore, DME prices cannot be established readily. However, DME can be blended with LPG and used in combustion equipment designed for LPG without any equipment modification. Therefore, LPG price is used as a substitute price for DME price in this study. Using LPG prices as a substitute price for DME is somewhat conservative. As noted earlier, DME could also be used as a blending stock for diesel fuel; however, diesel fuel prices are about $1/million Btu higher than LPG prices. Sulfur and syngas prices of $40 per ton and $3.5 per MMBtu were assumed for all cases independent of the mill location. No value was assigned to steam or hot water export to or import from the mills. This will result in a conservative economic assessment, as the amount of steam imported to the mill is greater than the amount of hot water or steam exported from a mill, except for Mill No. 3, which exports steam from its recovery boiler operations to the polygeneration plant. This impact is expected to be greater on the biomass-only case compared to other cases evaluated for this mill.

Table 24 summarizes biomass, coal, electricity, FT liquid, and DME prices assumed in various model calculations in this study. Table 25 summarizes the economic assumptions used.

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[76] www.americanenergysecurity.org/AES%20Appendices.pdf – Appendix D.

Table 24. Assumed Feed and Product Prices for Estimating Levelized Costs and Tariff

Region	South	Northeast	West	Midwest
Mill No.	1	2	3	4
Biomass, $/ton	11.80			
Coal, $/ton				
Reference Coal	25.00	25.00	25.00	25.00
Delivered Coal at the Mill Location[1]	17.00	25.00	19.60	19.73
Coal Heating Value, Btu/lb				
Reference Coal	10,900	10,900	10,900	10,900
Delivered Coal at the Mill Location	10,700	12,500	8500	10,300
Syngas, $/MMBtu	3.50			
Sulfur, $/ton	40			
	For Estimating Liquid Products Levelized Costs and Tariff			
Average Wholesale Electricity Price, $/MWh[2]	30	45	48	44.80
	For Estimating Electricity Levelized Costs and Tariffs			
FT liquids, $/bbl[3]	52			
DME, $/ton[4]	520			

[1] Coal prices are estimated based on the coal selling price at nearby coal-producing regions plus delivery costs. Mill No. 2 is adjacent to a coal mine; therefore, no delivery cost is included in the delivered coal price for this mill. Average prices of delivered coal to utilities where the mills are located were $25.56/ton for Mill No.1, $21.33/ton for Mill No. 3, and $19.73/ton for Mill No. 4 in 2005.[77] The average price of coal in the open market where Mill No. 2 is located was $28.55/ton in the same year.[78]

[2] Mill No. 1 has a long-term power purchase agreement at $30/MWh; wholesale prices for other regions are based on a 2005 EIA report.[79]

[3] FT liquids are expected to compete with light crude oil.

[4] Assumes LPG price as a substitute price for DME.[80,81]

Table 25. Summarizes the Economic Assumptions Used in Estimating Levelized Costs and Tariff

Economic Indicators	Assumed Values
Interest on Debt, %	9
Loan Term, year	20
Debt, % total capital	35
Equity, % total capital	65
Plant Life, years	20
Depreciation, year/method	20/straight line
Income tax, %	39
Inflation	None
Internal Rate of Return (equity), %	15

[77] www.eia.doe.gov/cneaf/coal/page/acr/table34.html.

[78] www.eia.doe.gov/cneaf/coal/page/acr/table31.html.

[79] www.eia.doe.gov/cneaf/electricity/wholesale/wholesalet2.xls. Table 2. Average Wholesale Price by NERC region, 2001–2005.

[80] www.doe.gov.ph/press/2006-04-01-lpg%20prices.htm – DOE Media Release April 1, 2006.

[81] Larson, E.D.; Consonni, S.; Katofsky, R.E.; Campbell, M.; Pisa, K.; Frederick, W.J. *A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry*; Vol. 1, Final Report for U.S. Department of Energy Contract DE-FC26-04NT42260; Princeton University; Princeton, NJ, Dec 2006, Table 1.

Reference Coal Prices and Regional Electricity Cost Impact

Tables 26 through 29 present the results of the financial analysis for Mill Nos. 1, 2, 3, and 4 at an assumed coal price of $25 a ton. Electricity levelized costs and tariff (presented in the upper section of the tables) are estimated assuming a FT liquid price of $52/ton. The lower section of the tables shows FT liquid levelized costs and tariff assuming regional wholesale electricity prices: $30/MWh for Mill No. 1, $45/MWh for Mill No. 2, $48/MWh for Mill No. 3, and $44.80 MWh for Mill No. 4.

The general findings can be summarized as follows:

- Coal–biomass polygeneration plants are more economical than biomass only plants (see Mill No. 1 in the South, Mill No. 2 in the Northeast, and Mill No. 3 in the West) unless biomass feed rates are about 5000 tpd or greater.

- Biomass polygeneration is more economical than biomass–coal polygeneration plants at Mill No. 4 in the Midwest. This indicates that biomass refineries can be economically more viable than coal–biomass refineries at biomass feed rates of 1842 MMBtu/hr (4990 tpd) or greater depending on the thermal demand of the mill.

Case FT-1-2A with a coal feed rate of 9816 MMBtu/hr, a biomass feed rate of 512 MMBtu/hr, and a capital cost of about $1.6 billion is the most economical case for Mill No. 1; it has the lowest levelized costs and tariff compare to other cases.

At a constant (no escalation) FT liquid price of $52/bbl over 20 years, electricity tariff ranges from a low of about $38/MWh in the first year of operation to a high of $96/MWh in the 20th year, with an average tariff of $63/MWh. At a constant electricity price of $30/MWh over 20 years, the required tariff for FT liquid ranges from $57/bbl for the first year (2011) to $126/bbl for the 20th year, with an average FT liquid tariff of $87/bbl. However, as both electricity and liquid fuel prices are expected to increase simultaneously, the 20-year tariff for electricity and FT liquids would be lower. Assuming a first-year electricity tariff of $30/MWh, FT liquid of about $52/bbl, and an electricity and FT liquid escalation of 4%, the estimated 20th-year electricity tariff will be $63/MWh (compared to $96/MWh), and the FT liquid tariff will be $110/bbl (compared to $126/bbl).

Table 27 shows that at a FT liquid price of $52/bbl, the electricity tariff for Case B-FT-2, Case FT-2-1A, and Case FT-2-2A at Mill No. 2 located in the northeast region of the country are about the same, with Case FT-2-1A having a slightly lower tariff. However, at an electricity price of $45/MWh, the required FT liquid tariff for Case B-FT-2 is much higher than the required average tariff of $73 to $75 per barrel for Case FT-2-1A and FT-2-2A, making Case B-FT-2 economically less attractive than the other two cases. ***This analysis indicates that even at a biomass feed rate of about 1400 MMBtu/hr (3772 tpd), biomass refineries may not be able to compete with large-scale coal or coal–biomass refineries.***

Table 26. Mill No. 1 (southern region) Estimated Electricity and Liquid Fuel Levelized Cost and Tariff

Case Description	Biomass Feed	High				@ 50% of High		
	Coal Feed	Zero	High Coal	@50% of High	@25% of High	High Coal	@50% High Coal	@25% High Coal
	Liquid Product	FT						
	Case No.	B-FT-1	FT-1-1A	FT-1-1B	FT-1-1C	FT-1-2A	FT-1-2B	FT-1-2C
Capital Cost, MM$		$343	$1672	$1126	$862	$1618	$1062	$766
After-Tax Investment Charges		0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity Levelized Cost and Tariff at FT Liquid Price of $52/bbl								
Capital Cost, $/kW		$19,190	$3077	$4669	$3794	$2784	$4381	$3377
After-Tax Annual Levelized Capital Cost, $/MWh		$269	$43	$65	$53	$39	$61	$47
Fuel Cost, $/MWh		$87	$26	$33	$21	$23	$30	$18
Revenue (from sale of liquid fuel and/or sulfur), $/MWh		($233)	($60)	($76)	($50)	($53)	($68)	($41)
O&M Costs		$50	$14	$22	$18	$13	$20	$16
Levelized Cost of Electricity, $/MWh		$173	$24	$44	$42	$23	$44	$40
First-Year Tariff, $/MWh		$304	$41	$69	$61	$38	$67	$56
20th-Year Tariff, $/MWh		$258	$104	$174	$154	$96	$168	$142
Average Tariff, $/MWh		$280	$68	$114	$101	$63	$110	$93
Liquid Product Levelized Cost and Tariff at Electricity Price of $30/MWh								
Capital Cost, $1000/tpd		$32,961	$20,090	$24,055	$30,145	$20,744	$25,515	$32,719
After-Tax Annual Levelized Capital Cost, $/ton		$462	$282	$337	$423	$291	$358	$459
Fuel Cost, $/ton of liquid product		$131	$152	$149	$146	$153	$152	$149
Revenue (from sale of electricity and sulfur), $/ton of liquid product		($7)	($203)	($162)	($248)	($231)	($183)	($302)
O&M Costs, $/ton of liquid product		$86	$93	$111	$139	$96	$118	$151
Levelized FT Liquid Cost, $/ton		$673	$323	$435	$460	$309	$444	$458
Tariff – First Year, $/ton		$906	$435	$570	$627	$424	$586	$639
20th year, $/ton		$827	$925	$1137	$1361	$935	$1195	$1447
Average, $/ton		$866	$651	$823	$950	$648	$856	$991
Levelized FT Liquid Cost, $/bbl		$91	$44	$59	$62	$42	$60	$62
Tariff – First Year, $/bbl		$122	$59	$77	$85	$57	$79	$86
20th Year, $/bbl		$112	$125	$153	$184	$126	$161	$195
Average Tariff, $/bbl		$117	$88	$111	$128	$87	$116	$134

Table 27. Mill No. 2 (northeastern region) Estimated Electricity and Liquid Fuel Levelized Cost and Tariff

Case Description	Biomass Feed	High				@50% of High		
	Coal Feed	Zero	High	@50% of High	@25% of High	High	@50% of High	@25% of High
	Liquid Product	FT						
	Case No.	B-FT-2	FT-2-1A	FT-2-1B	FT-2-1C	FT-2-2A	FT-2-2B	FT-2-2C
Capital Cost, MM$		$236	$1697	$1160	$878	$1606	$1070	$824
After-Tax Investment Charges		0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Electricity Levelized Cost and Tariff at FT Liquid Price of $52/bbl						
Capital Cost, $/kW		$3512	$3285	$5142	$4562	$3104	$5030	$4285
After-Tax Annual Levelized Capital Cost, $/MWh		$49	$46	$72	$64	$44	$71	$60
Fuel Cost, $/MWh		$31	$26	$38	$28	$27	$35	$22
Revenue (from sale of liquid fuel and/or sulfur), $/MWh		($84)	($66)	($88)	($66)	($61)	($81)	($52)
O&M Costs		$17	$15	$24	$21	$14	$23	$20
Levelized Cost of Electricity, $/MWh		$14	$21	$45	$46	$24	$48	$50
First-Year Tariff, $/MWh		$42	$41	$74	$70	$42	$75	$71
20th-Year Tariff, $/MWh		$105	$103	$186	$177	$105	$189	$180
Average Tariff, $/MWh		$69	$68	$122	$116	$69	$124	$117
		Liquid Product Levelized Cost and Tariff at Electricity Wholesale Price of $45/MWh						
Capital Cost, $1000/tpd		$16,648	$19,540	$22,936	$27,128	$20,111	$24,602	$32,587
After-Tax Annual Levelized Capital Cost, $/ton		$234	$274	$322	$381	$282	$345	$457
Fuel Cost, $/ton of liquid product		$131	$151	$148	$144	$153	$151	$148
Revenue (from sale of electricity and sulfur), $/ton of liquid product		($226)	($274)	($208)	($276)	($299)	($229)	($353)
O&M Costs, $/ton of liquid product		$82	$90	$106	$125	$93	$114	$151
Levelized FT Liquid Cost, $/ton		$221	$241	$367	$374	$229	$381	$403
Tariff – First Year, $/ton		$525	$349	$495	$524	$340	$517	$583
20th year, $/ton		$1043	$843	$1051	$1198	$851	$1119	$1400
Average, $/ton		$756	$562	$740	$818	$559	$782	$936
Levelized FT Liquid Cost, $/bbl		$30	$33	$50	$50	$31	$51	$54
Tariff – First Year, $/bbl		$71	$45	$67	$71	$46	$70	$79
20th Year, $/bbl		$141	$110	$142	$162	$115	$151	$189
Average Tariff, $/bbl		$102	$73	$100	$110	$75	$106	$126

Table 28. Mill No. 3 (western region) Estimated Electricity and Liquid Fuel Levelized Cost and Tariff

Case Description		High				@ 50% of High		
	Biomass Feed	High				@ 50% of High		
	Coal Feed	Zero	High Coal	@50% High	@25% High	High	@50% High	@25% High
	Liquid Product	FT						
Case No.		B-FT-3	FT-3-1A	FT-3-1B	FT-1-1C	FT-3-2A	FT-1-2B	FT-1-2C
Capital Cost, MM$		$307	$1778	$1246	$933	$1688	$1149	$823
Electricity Levelized Cost and Tariff at FT Liquid Price of $52/bbl								
Capital Cost, MM$		$6154	$4488	$5882	$8450	$3883	$5278	$3563
After-Tax Investment Charges		0.11	0.11	0.11	0.11	0.11	0.11	0.11
		$86	$63	$83	$119	$54	$74	$50
Capital Cost, $/kW		$65	$40	$45	$58	$33	$37	$21
After-Tax Annual Levelized Capital Cost, $/MWh		($171)	($93)	($174)	($142)	($75)	($85)	($50)
Fuel Cost, $/MWh		$30	$21	$27	$39	$18	$24	$16
Revenue (from sale of liquid fuel and/or Sulfur), $/MWh		$11	$31	($18)	$74	$30	$50	$38
O&M Costs		$62	$57	$31	$121	$52	$78	$56
Levelized Cost of Electricity, $/MWh		$157	$144	$79	$305	$131	$197	$142
First-Year Tariff, $/MWh		$103	$94	$52	$199	$86	$129	$93
20th-Year Tariff, $/MWh		Liquid Product Levelized Cost and Tariff at Wholesale Electricity Price of $48/MWh						
Average Tariff, $/MWh		$14,159	$18,813	$21,446	$23,373	$20,178	$25,515	$28,328
		$199	$264	$301	$328	$283	$341	$397
Capital Cost, $1000/tpd		$131	$149	$146	$141	$152	$149	$146
After-Tax Annual Levelized Capital Cost, $/ton		($118)	($227)	($181)	($140)	($256)	($229)	($189)
Fuel Cost, $/ton of liquid product		$70	$87	$99	$108	$93	$112	$131
Revenue (from sale of electricity and sulfur), $/ton of liquid product		$282	$273	$364	$438	$272	$374	$485
O&M Costs, $/ton of liquid product		$470	$377	$483	$568	$384	$509	$642
Levelized FT Liquid Cost, $/ton		$912	$844	$999	$1118	$883	$1100	$1323
Tariff – First Year, $/ton		$668	$581	$712	$814	$601	$769	$944
20th year, $/ton		$38	$37	$49	$59	$37	$50	$65
Average, $/ton		$63	$51	$65	$77	$52	$69	$87
Levelized FT Liquid Cost, $/bbl		$123	$114	$135	$151	$119	$149	$179
Tariff – First Year, $/bbl		$90	$78	$96	$110	$81	$104	$127

Table 29. Mill No. 4 (midwestern region) Estimated Electricity and Liquid Fuel Levelized Cost and Tariff

Case Description	Biomass Feed	High				@ 50% of High		
	Coal Feed	Zero	High Coal	@50% of High	@25% of High	High Coal	@50% of High	@25% of High
	Liquid Product	FT						
	Case No.	B-FT-4	FT-4-1A	FT-4-1B	FT-4-1C	FT-4-2A	FT-4-2B	FT-4-2C
		Electricity Levelized Cost and Tariff at FT Liquid Price of $52/bbl						
Capital Cost, MM$		$279	$1699	$1193	$891	$1662	$1122	$788
After-Tax Investment Charges		0.11	0.11	0.11	0.11	0.11	0.11	0.11
		$3906	$3455	$8153	$11,931	$3369	$6951	$13,146
Capital Cost, $/kW		$55	$48	$114	$167	$47	$98	$184
After-Tax Annual Levelized Capital Cost, $/MWh		$39	$32	$63	$80	$29	$48	$77
Fuel Cost, $/MWh		($105)	($73)	($148)	($157)	($65)	($112)	($165)
Revenue (from sale of liquid fuel and/or Sulfur), $/MWh		$19	$16	$38	$55	$16	$32	$61
O&M Costs		$9	$23	$66	$145	$26	$66	$156
Levelized Cost of Electricity, $/MWh		$41	$43	$112	$201	$45	$103	$221
First-Year Tariff, $/MWh		$103	$109	$284	$508	$114	$260	$552
20th-Year Tariff, $/MWh		$67	$72	$186	$333	$75	$170	$363
Average Tariff, $/MWh		Liquid Product Levelized Cost and Tariff at Wholesale Electricity Price of $44.80/MWh						
		$14,902	$18,557	$21,646	$30,149	$20,229	$24,515	$31,769
Capital Cost, $1000/tpd		$209	$260	$304	$423	$284	$344	$446
After-Tax Annual Levelized Capital Cost, $/ton		$131	$150	$147	$178	$152	$150	$163
Fuel Cost, $/ton of liquid product		($184)	($248)	($127)	($125)	($277)	($168)	($123)
Revenue (from sale of electricity and sulfur), $/ton of liquid product		$74	$85	$100	$139	$93	$113	$147
O&M Costs, $/ton of liquid product		$229	$248	$423	$615	$252	$439	$633
Levelized FT Liquid Cost, $/ton		$316	$351	$545	$782	$365	$575	$809
Tariff – First Year, $/ton		$797	$810	$1048	$1498	$870	$1163	$1555
20th year, $/ton		$522	$551	$771	$1103	$583	$837	$1144
Average, $/ton		$31	$33	$57	$83	$34	$59	$85
Levelized FT Liquid Cost, $/bbl		$43	$47	$74	$106	$49	$78	$109
Tariff – First Year, $/bbl		$108	$109	$141	$202	$117	$157	$210
20th Year, $/bbl		$70	$74	$104	$149	$79	$113	$154

Table 28 shows the result of financial analysis for Mill No. 3 located in the western part of the country. Case FT-3-1B at a capital cost of about $1.2 billion, a biomass feed rate of 2135 MMBtu/hr, and a coal feed rate of 4908 MMBtu/hr results in the lowest electricity tariff—$31/MWh to $79/MWh over 20 years—at a constant FT liquid price of $52/bbl. At a wholesale electricity price of $48/MWh, the lowest FT liquid tariff ($51/bbl to $114/bbl over 20 years) is estimated for Case FT-3-1A with a total capital cost of about $1.8 billion, a coal feed rate of 9816 MMBtu/hr, and the same biomass feed rate as in Case FT-3-1B. This indicates that the optimum plant size at this location would have a coal feed rate capacity of between 4908 MMBtu/hr (5408 tpd) and 9816 MMBtu/hr (10,807 tpd) and a biomass feed rate of 2135 MMBtu/hr (5784 tpd). *Table 28 also shows that a coal–biomass refinery is more economical than a biomass-only refinery at this location and under the assumed operating conditions and coal and electricity costs.*

Table 29 presents the financial analysis for Mill No. 4 located in the Midwest. It indicates that Case B-FT-4, a biomass refinery, has the lowest tariff. *That is indicative that biomass (only) refineries can be economically more viable than biomass–coal refineries at biomass feed rates of 1842 MMBtu/hr (4990 tpd) or greater depending on the thermal demand of the mill.* This raises the question of why similar results are not observed for Mill No. 3. A review of energy and material balances for Case B-FT-3 (see Table 9) and B-FT-4 (Table 10) shows that Case B-FT-3 is less efficient than Case B-FT-4. Mill No. 3 exports a large quantity of high-pressure steam from its recovery boiler to the polygeneration (biorefinery) plant for power production, minimizing the heat load of the mill and lowering net energy export from the polygeneration plant to the mill and the overall efficiency of the polygeneration plant. Replacing the recovery boiler with a spent liquor gasifier and incorporating it into the polygeneration plant could improve the overall efficiency and, potentially, the economics of Case B-FT-3.

FT Liquid Tariff vs. DME Tariff

Tables 30 and 31 compare the electricity and liquid fuel levelized costs and tariff for selected FT and DME production cases in Mill Nos. 1, 2, 3, and 4. These cases were selected because they are the most economically viable cases based on the analysis presented in the Reference Coal Prices and Regional Electricity Cost Impact section at the mills' assumed operating conditions and economic parameters. *The results show that at a current price of $520/ton of DME, production of DME is financially more viable than production of FT liquids at $52/bbl.*

At DME prices of $520/ton, even at zero electricity prices, the rate of return on equity exceeds the required return of 15%. DME prices of $462/ton or lower will achieve 15% return at zero electricity wholesale prices (see Table 30) in all cases evaluated. Case B-DME-2, a biomass-only refinery case at Mill No. 2 located in the Northeast, is the most financially viable case for DME production, followed by Case DME-1-2A, DME-2-1A and 2A, DME-3-1A, B-DME-4, and DME-3-1B.

Table 31 shows levelized cost and tariff for DME and FT liquid, in dollar per ton and million Btu bases, at fixed regional electricity prices. At the assumed regional electricity prices and within the constraints (15% return, minimum first-year tariff, etc.) imposed on the financial analysis, some of the FT cases (FT-2-1A, FT-3-1B, and B-FT-4) are financially more viable than their

corresponding FT production cases (i.e., have a lower tariff). However, comparison of the first-year tariffs with a current assumed FT liquid price of $52/bbl and DME price of $520/ton indicates that while FT liquid tariff for these cases is within −17% to +25% of the assumed FT market value of $52/bbl, the DME tariff is −66% to −39% of its assumed market value of $520/ton. *The wide margin between DME market price and tariff allows a greater chance for capital recovery in earlier operating years, increasing return on equity and minimizing financial risks*.

Table 30. Comparison of FT Liquid and DME Plant Electricity Levelized Costs and Tariff [1,2]

Case Description	Biomass Feed, MMBtu/hr	512	512	1392	1392	1392	1392	696	696
	Coal Feed, MMbtu/hr	9816	9816	0	0	9816	9816	9816	9816
		FT	DME	FT	DME	FT	DME	FT	DME
	Liquid Product Price	$52/bbl	$310/t	$52/bbl	$274/t	$52/bbl	$318/t	$52/bbl	$318/t
Rate of Return (on equity), %		15							
Case No.		FT-1-2A	DME-1-2A	B-FT-2	B-DME-2	FT-2-1A	DME-2-1A	FT-2-2A	DME-2-2A
Capital Cost, $MM		$1618	$1894	$236	$219	$1697	$1725	$1606	$1636
Capital Cost, $/kW		$2784	$3123	$3512	$3721	$3285	$2492	$3104	$2334
Inv. Charge After Taxes		0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Levelized Capital After Tax, $/MWh		$39	$44	$49	$52	$46	$35	$44	$33
Fuel Cost, $/MWh		$23	$22	$31	$36	$29	$22	$27	$20
Revenue (from sale of liquid fuel and sulfur), $/MWh		($53)	($133)	($84)	($124)	($66)	($73)	($61)	($85)
O&M Costs		$13	$14	$17	$18	$15	$11	$14	$11
Levelized Cost of Electricity, $/MWh		$23	($33)	$14	($44)	$21	($25)	$24	($24)
First-Year Tariff, $/MWh		$38	$0	$42	$0	$41	$0	$42	$0
20th-Year Tariff, $/MWh		$96	$0	$105	$0	$103	$0	$105	$0
Average Tariff, $/MWh		$63	$0	$69	$0	$68	$0	$69	$0

[1] Coal prices of $25/ton.
[2] Rate of return on equity at DME price of $524/ton and zero electricity prices: 27% for Case DME-1-2A, 38% for Case B-DME-2, 28% for Case DME-2-1A, 28% for Case DME-2-2A, 22% for Case DME-3-1A, 18% for Case DME-3-1B, and 24% for Case B-DME-4.

Continued…

Table 30. Comparison of FT Liquid and DME Plant Electric Levelized Costs and Tariff [1, 2] (continued)

Case Description		2135	2135	2135	2135	1842	1842
	Biomass Feed, MMBtu/hr	2135	2135	2135	2135	1842	1842
	Coal Feed, MMBtu/hr	9816	9816	4908	4908	0	0
		FT	DME	FT	DME	FT	DME
	Liquid Product Price	$52/bbl	$392/t	$52/bbl	$462/t	$52/bbl	$397/t
Rate of Return (on equity), %		15					
Case No.		FT-3-1A	DME-3-1A	FT-3-1B	DME-3-1B	B-FT-4	B-DME-4
Capital Cost, $MM		$1778	$2010	$1246	$1419	$279	$369
Capital Cost, $/kW		$4488	$12,644	$5882	$5155	$3906	$6368
Inv. Charge After Taxes		0.11	0.11	0.11	0.11	0.11	0.11
Levelized Capital After Tax, $/MWh		$63	$177	$83	$72	$55	$89
Fuel Cost, $/MWh		$40	$101	$45	$35	$39	$48
Revenue (from sale of liquid fuel and sulfur), $/MWh		($93)	($466)	($174)	($185)	($105)	($246)
O&M Costs		$21	$58	$27	$24	$19	$32
Levelized Cost of Electricity, $/MWh		$31	($130)	($18)	($53)	$9	($77)
First-Year Tariff, $/MWh		$57	$0	$31	$0	$41	$0
20th-Year Tariff, $/MWh		$144	$0	$79	$0	$103	$0
Average Tariff, $/MWh		$94	$0	$52	$0	$67	$0

[1] Coal prices of $25/ton.

[2] Rate of return on equity at DME price of $524/ton and zero electricity prices: 27% for Case DME-1-2A, 38% for Case B-DME-2, 28% for Case DME-2-1A, 28% for Case DME-2-2A, 22% for Case DME-3-1A, 18% for Case DME-3-1B, and 24% for Case B-DME-4.

Table 31. Comparison of FT Liquids and DME Levelized Costs and Tariff[1,2]

Biomass Feed, MMBtu/hr	512	512	1392	1392	1392	1392	696	696
Coal Feed, MMBtu/hr	9816	9816	0	0	9816	9816	9816	9816
Liquid Product	FT	DME	FT	DME	FT	DME	FT	DME
Rate of Return (on equity), %	15							
Case No.	FT-1-2A	DME-1-2A	B-FT-2	B-DME-2	FT-2-1A	DME-2-1A[2]	FT-2-2A	DME-2-2A
Capital Cost, $MM	$1618	$1894	$236	$219	$1699	$1725	$1606	$1635
Capital Cost, $1000/TPD	$20,744	$8592	$16,648	$6903	$19,540	$9749	$20,111	$9800
Inv. Charge After Taxes	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Levelized Capital After Tax, $/ton	$291	$121	$234	$97	$274	$137	$282	$137
Fuel Cost, $/ton of liquid product	$153	$54	$131	$59	$151	$74	$153	$73
Revenue (from sale of electricity and sulfur), $/ton of liquid product	($231)	($85)	($226)	($89)	($274)	($135)	($299)	($192)
O&M Costs, $/ton of liquid product	$96	$40	$82	$34	$90	$45	$93	$45
Levelized Liquid Fuel Cost, $/ton	$309	$129	$221	$100	$241	$121	$229	$63
First-Year Tariff, $/ton	$424	$177	$525	$222	$349	$176	$340	$129
20th-Year Tariff, $/ton	$935	$387	$1043	$437	$843	$417	$851	$327
Average Tariff, $/ton	$648	$269	$756	$318	$562	$280	$559	$214
Levelized Liquid Fuel Cost, $/MMBtu	7.71	6.65	5.52	5.16	6.01	6.23	5.71	3.25
First-Year Tariff, $/MMBtu	10.58	9.10	13.10	11.40	8.71	9.06	8.49	6.66
20th-Year Tariff, $/MMBtu	23.33	19.89	26.03	22.48	21.05	21.44	21.25	16.82
Average Tariff, $/MMBtu	16.17	13.84	18.87	16.35	14.03	14.41	13.96	11.01

[1] Assumes regional electricity prices (see Table 24) and coal prices of $25/ton.
[2] Although FT liquid Cases FT-2-1A, FT-3-1B, and B-FT-4 are lower than the tariff for their corresponding DME production cases, DME production cases have a much greater margin compared to DME market value of $524/ton and, therefore, a lower risk. The differences in tariff are (with exception of the biomass-only case of Mill No. 4) with the error margin of the study.

Continued…

Table 31. Comparison of FT Liquids and DME Levelized Costs and Tariff [1,2] (continued)

	FT-3-1A	DME-3-1A	FT-3-1B	DME-3-1B	B-FT-4	B-DME-4
Biomass Feed, MMBtu/hr	2135	2135	2135	2135	1842	1842
Coal Feed, MMbtu/hr	9816	9816	4908	4908	0	0
Liquid Product	FT	DME	FT	DME	FT	DME
Rate of Return (on equity), %	15					
Case No.	FT-3-1A	DME-3-1A	FT-3-1B	DME-3-1B	B-FT-4	B-DME-4
Capital Cost, $MM	$1778	$2010	$1246	$1419	$279	$369
Cap Cost, $1000/TPD	$18,813	$10,713	$21,446	$13,001	$14,902	$10,469
Inv. Charge After Taxes	0.11	0.11	0.11	0.11	0.11	0.11
Levelized Cap After Tax, $/Ton	$264	$150	$301	$182	$209	$147
Fuel Cost, $/ton of liquid product	$149	$75	$146	$78	$131	$70
Revenue (from sale of electricity and sulfur), $/ton of liquid product	($227)	($150)	($181)	($124)	($184)	($26)
O&M Costs, $/ton of liquid product	$87	$49	$99	$60	$74	$52
Levelized Liquid Fuel Cost, $/ton	$273	$125	$364	$196	$229	$243
First Year Tariff, $/ton	$377	$184	$483	$268	$316	$320
20th Year Tariff, $/ton	$844	$455	$999	$586	$797	$644
Average Tariff, $/ton	$581	$300	$712	$407	$522	$464
Levelized Liquid Fuel Cost, $/MMBtu	6.82	6.41	9.09	10.07	5.73	12.49
First Year Tariff, $/MMBtu	9.41	9.47	12.06	13.79	7.89	16.44
20th Year Tariff, $/MMBtu	21.06	23.41	24.94	30.13	19.90	33.15
Average Tariff, $/MMBtu	14.50	15.45	17.77	20.96	13.03	23.87

[1] Assumes regional electricity prices (see Table 24) and coal prices of $25/ton.

[2] Although FT liquid Cases FT-2-1A, FT-3-1B, and B-FT-4 are lower than the tariff for their corresponding DME production cases, DME production cases have a much greater margin compared to the DME market value of $524/ton and, therefore, a lower risk.

Impact of Regional Coal Prices on FT and DME Electricity and Liquid Product Tariff

Tables 32 through 35 compare tariffs at a reference coal price of $25 per ton (10,900 Btu/lb) at each mill, with tariff at prices of higher- and lower-rank bituminous and/or Powder River Basin (PRB) coal that might be available in the regions where these mills are located. In general, changes in the coal prices (in $/MMBtu) have a greater impact on DME production cases than FT liquid production cases. *The greatest tariff changes are observed for Mill No. 1 in the South followed by Mill No. 2 in the Northeast.*

At the regional coal price of $17/ton (10,700 Btu/lb), the DME price had to be reduced by 6% in order to maintain a 15% return on equity and zero electricity tariff at Mill No. 1. At the regional electricity price of $45/MWh and coal price of $17/ton, the DME tariff was reduced by 3.9% to 8.3%, while the FT tariff was reduced by 4.5% to 10.1%, relative to the reference coal price of $25/ton.

For Mill No. 2, in the Northeast, higher-heating-value coals are available at the same price as the reference coal; therefore, coal prices are lower on a $/MMBtu basis. DME prices are reduced by 2.5% because of the lower regional coal price of $1/MMBtu compared to the reference coal price of $1.15/MMBtu. At the coal price of $1/MMBtu and the regional electricity price of $45/MWh, the DME tariff on a $/MMBtu basis was reduced 5% to 30% compared to the FT liquid tariff reduction of 3.5% to 4.0%.

Regional coal prices in the West and Midwest do not have significant impacts on DME or FT liquid production tariffs relative to the reference coal price.

It should be noted that coal prices used in this evaluation are based on recent coal prices, which are at historically high levels.

Impact of CO_2 Capture on Electricity Tariff

Table 36 compares capital costs, net electricity generation, and electricity tariff for selected FT liquid production cases with CO_2 and without CO_2 capture at each mill. It should be noted that capital costs for CO_2 capture are exclusive of transportation and final sequestration costs but include costs associated with CO_2 separation, compression, and on-site storage in a day tank. CO_2 compression is energy-intensive and reduces the plant's net electricity generation by about 17%.[82] The capital costs associated with CO_2 separation and compression are estimated to increase capital costs by about 33% (see Tables 20 through 23). *Increases in the capital cost and reductions in the net power generation increases electricity tariff by 27% to 34%. The cost for capturing CO_2 is estimated to be $15 to $17 per ton of CO_2.*

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[82] www.iec.tu-freiberg.de/conference/conf07/pdf/9.2.pdf

Table 32. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 1

Case Description	Region	South				% Reduction	
	Coal Price, $/ton	17.00	17.00	25.00	25.00		
	Coal Heating Value, Btu/lb	10,700	10,700	10,900	10,900		
	Biomass Feed, MMBtu/hr	512	512	512	512		
	Coal Feed, MMBtu/hr	9816	9816	9816	9816		
	Liquid Product	FT	DME	FT	DME	FT	DME
	Case No.	FT-1-2A	DME-1-2A	FT-1-2A	DME-1-2A	FT-1-2A	DME-1-2A
Electricity Tariff							
Liquid Product Price		$52/bbl	$291/ton	$52/bbl	$310/ton	0	6
First-Year Tariff, $/MWh		33	0	38	0	13	--
20th-Year Tariff, $/MWh		85	0	96	0	11	--
Average Tariff, $/MWh		56	0	63	0	11	--
Liquid Product Tariff[1]							
First-Year Tariff, $/MMBtu		9.51	8.34	10.58	9.10	10.1	8.3
20th-Year Tariff, $/MMBtu		22.27	19.10	23.33	19.89	4.5	3.9
Average Tariff, $/MMBtu		15.04	13.02	16.17	13.84	6.9	5.9

[1] Assumes wholesale electricity price of $30/MWh.

Table 33. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 2

Case Description	Region	Northeast								% Reduction	
	Coal Price, $/ton	0	0	% Reduction		$25.00	$25.00	$25.00	$25.00		
	Coal Heating Value, Btu/lb	0	0			12,500	12,500	10,900	10,900		
	Biomass Feed, MMBtu/hr	1392	1392			1392	1392	1392	1392		
	Coal Feed, MMBtu/hr	Zero	Zero			9816	9816	9816	9816		
	Liquid Product	FT	DME	FT	DME	FT	DME	FT	DME	FT	DME
	Case No.	B-FT-2	B-DME-2	B-FT-2	B-DME-2	FT-2-1A	DME-2-1A	FT-2-1A	DME-2-1A	FT-2-1A	DME-2-1A
Electricity Tariff											
Liquid Product Prices		$52/bbl	$274/ton	No impact from changes in coal prices		$52/bbl	$310/ton	$52/bbl	$318/ton	0	2.5
First-Year Tariff, $/MWh		42	0			41	0	41	0	Nil	--
20th-Year Tariff, $/MWh		105	0			103	0	103	0	Nil	--
Average Tariff, $/MWh		69	0			67	0	68	0	Nil	--
Liquid Product Tariff[1]											
First-Year Tariff, $/MMBtu		13.10	11.40	No impact from changes in coal prices		8.36	6.29	8.71	9.06	4.0	30.6
20th-Year Tariff, $/MMBtu		26.03	22.48			20.27	15.90	21.05	21.44	3.7	25.8
Average Tariff, $/MMBtu		18.87	16.35			13.49	10.40	14.03	14.41	3.8	27.8

[1] Assumes wholesale electricity price of $45/MWh.

Continued…

Table 33. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 2 (continued)

Case Description	Region	Northeast					
	Coal Price, $/ton	$25.00	$25.00	$25.00	$25.00	% Reduction	
	Coal Heating Value, Btu/lb	12,500	12,500	10,900	10,900		
	Biomass Feed, MMBtu/hr	696	696	696	696		
	Coal Feed, MMBtu/hr	9816	9816	9816	9816		
	Liquid Product	FT	DME	FT	DME	FT	DME
Case No.		FT-2-2A	DME-2-2A	FT-2-2A	DME-2-2A	FT-2-2A	DME-2-2A
Electricity Tariff							
Liquid Product Price		$52/bbl	$310/ton	$52/bbl	$318/ton	0	2.5
First-Year Tariff, $/MWh		39	0	42	0	7	–-
20th-Year Tariff, $/MWh		99	0	105	0	6	–-
Average Tariff, $/MWh		65	0	69	0	6	–-
Liquid Product Tariff[1]							
First-Year Tariff, $/MMBtu		8.11	6.29	8.49	6.66	4.5	5.5
20th-Year Tariff, $/MMBtu		20.50	15.90	21.25	16.82	3.5	5.4
Average Tariff, $/MMBtu		13.41	10.40	13.96	11.01	3.9	5.5

[1] Assumes wholesale electricity price of $45.00/MWh.

Table 34. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 3

Case Description	Region	West					
	Coal Price, $/ton	19.60	19.60	25.00	25.00	% Reduction	
	Coal Heating Value, Btu/lb	8500	8500	10,900	10,900		
	Biomass Feed, MMBtu/hr	2135	2135	2135	2135		
	Coal Feed, MMBtu/hr	9816	9816	9816	9816		
	Liquid Product	FT	DME	FT	DME	FT	DME
Case No.		**FT-3-1A**	**DME-3-1A**	**FT-3-1A**	**DME-3-1A**	**FT-3-1A**	**DME-3-1A**
Electricity Tariff							
Liquid Product Price		$52/bbl	$392/ton	$52/bbl	$392/ton	0	0
First-Year Tariff, $/MWh		57	0	57	0	Nil	–-
20th-Year Tariff, $/MWh		144	0	144	0	Nil	–-
Average Tariff, $/MWh		94	0	94	0	Nil	–-
Liquid Product Tariff[1]							
First-Year Tariff, $/MMBtu		9.44	9.49	9.41	9.47	Nil	Nil
20th-Year Tariff, $/MMBtu		21.00	23.46	21.06	23.41	Nil	Nil
Average Tariff, $/MMBtu		14.49	15.49	14.50	15.45	Nil	Nil

[1] Assumes wholesale electricity price of $48.00/MWh.

Continued…

Table 34. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 3 (continued)

	Region	West					
Case Description	Coal Price, $/ton	19.60	19.60	25.00	25.00	% Reduction	
	Coal Heating Value, Btu/lb	8500	8500	10,900	10,900		
	Biomass Feed, MMBtu/hr	2135	2135	2135	2135		
	Coal Feed, MMBtu/hr	4908	4908	4908	4908		
	Liquid Product	FT	DME	FT	DME	FT	DME
Case No.		FT-3-1B	DME-3-1B	FT-3-1B	DME-3-1B	FT-3-1B	DME-3-1B
Electricity Tariff[1]							
Liquid Product Price		$52/bbl	$462/ton	$52/bbl	$462/ton	0	0
First-Year Tariff, $/MWh		31	0	31	0	Nil	---
20th-Year Tariff, $/MWh		79	0	79	0	Nil	---
Average Tariff, $/MWh		52	0	52	0	Nil	---
Liquid Product Tariff[1]							
First-Year Tariff, $/MMBtu		12.07	13.79	12.06	13.79	Nil	Nil
20th-Year Tariff, $/MMBtu		24.97	30.13	24.94	30.13	Nil	Nil
Average Tariff, $/MMBtu		17.78	20.96	17.77	20.96	Nil	Nil

[1] Assumes wholesale electricity price of $48.00/MWh.

Table 35. Impact of Regional Coal Prices on FT and DME Plant Tariff – Mill No. 4

	Region	Midwest									
Case Description	Coal Price, $/Ton	0	0	% Reduction		19.73	19.73	25.00	25.00	% Reduction	
	Coal Heating Value, Btu/Lb	0	0			10,300	10,300	10,900	10,900		
	Biomass Feed, MMBtu/hr	1842	1842			1842	1842	1842	1842		
	Coal Feed, MMBtu/hr	Zero	Zero			9816	9816	9816	9816		
	Liquid Product	FT	DME	FT	DME	FT	DME	FT	DME	FT	DME
Case No.		B-FT-4	B-DME-4	B-FT-4	B-DME-4	FT-4-1A	DME-4-1A	FT-4-1A	DME-4-1A	FT-4-1A	DME-4-1A
Electricity Tariff											
Liquid Product Price		$52/bbl	$325/ton	No impact from changes in coal prices		$52/bbl	$388/ton	$52/bbl	$399/ton	0	2.7
First-Year Tariff, $/MWh		41	45			40	0	43	0	7	---
20th-Year Tariff, $/MWh		103	45			102	0	109	0	6	---
Average Tariff, $/MWh		67	45			67	0	72	0	7	---
Liquid Product Tariff[1,2]											
First-Year Tariff, $/MMBtu		7.89	14.49	No impact from changes in coal prices		8.24	8.67	8.69	9.09	5.1	4.6
20th-Year Tariff, $/MMBtu		19.90	32.33			19.79	21.92	20.15	22.96	1.7	4.5
Average Tariff, $/MMBtu		13.03	22.94			13.22	14.34	13.68	15.02	3.3	4.5

[1] Assumes wholesale electric price of $44.80/MWh.
[2] Biomass-only cases are more economic for Mill No.4; Case FT-4-1A and DME-4-1A are included to show the impact of regional coal prices.

Table 36. Impact of CO_2 Capture on Electricity Tariff

Case No.	FT-1-2A	FT-1-2A	FT-2-2A	FT-2-2A	FT-3-1A	FT-3-1A	FT-4-1A	FT-4-1A
CO_2 Capture	Yes	No	Yes	No	Yes	No	Yes	No
Capital Cost, MM$	1618	1215	1606	1205	1778	1340	1699	1275
Coal Price, $/ton	17.00	17.00	25.00	25.00	19.60	19.60	19.73	19.73
FT Liquid Price, $/bbl	52.00	52.00	52.00	52.00	52.00	52.00	52.00	52.00
FT Liquid Production, bbl/d	13,868	13,868	14,202	14,202	16,803	16,803	16,273	16,273
Net Electric Power, MW	581	680	518	606	396	463	492	575
First-Year Tariff, $/MWh	38	25	42	30	57	44	41.	31
20th-Year Tariff, $/MWh	85	65	99	76	144	111	102	77
Average Tariff, $/MWh	56	42	65	50	94	72	67	50
CO_2 Captured, tph[1]	477	0	484	0	535	0	506	0
CO_2 Captured, ton/MWh	0.82	0	0.93	0	1.35	0	1.03	0
Tariff Increase, $/ton of CO_2 Captured	17	0	16	0	16	0	15	0

[1] Estimated based on data from Tables 15–18.

SUMMARY AND CONCLUSIONS

A number of different products can be produced in a biomass- or biomass and coal-to-liquid facility. These facilities are generally referred to as a biorefinery, a polygeneration plant, or a carbon-to-liquid plant. This study focuses on the synthesis products that can replace transportation fuel without significant changes to current infrastructure, including the pulp and paper mills or the vehicle's engines. FT liquids with a minor refining can produce gasoline and/or diesel that can be used in existing engines without any engine modification. FT diesel is found to be superior to petroleum diesel, having a lower sulfur and higher cetane number. FT technology is a well-established commercial technology. Sasol in South Africa has extensive construction and operating experience with FT technology. Others, including Shell, BP, Rentech, Chevron, and Syntroleum, supply proprietary high- or low-temperature FT technology using slurry, fluidized-bed, or fixed reactors with iron or cobalt catalysts. Typical Sasol high-temperature reactors are 26–36 feet in diameter and 125 feet high and produce up to 20,000 barrels a day per reactor. The low-temperature reactors are typically about 16.5 feet in diameter and 72 feet high and produce about 2500 barrels a day of FT liquids.

Another synthetic liquid product that, in recent years, has been attracting market attention and share is DME. This technology is being licensed by Air Products and Chemicals, Chevron, NKK Itochu, Mitsubishi, Haldor Topsoe, and others. Commercial plants are operating or are at various stages of planning, design, and construction in China, Iran, Japan, Qatar, and Russia. Current production capacity in China is about 147,000 tons and is expected to increase to 24.5 million tons by 2020; most of the new capacity will use coal gas. DME is currently used as a substitute for LPG and is expected to become a diesel additive in the next 5 to 10 years when the necessary on-board vehicle storage and handling of the fuel and engine modifications are demonstrated.

Because carbon-to-liquid plants and/or polygeneration plants must take advantage of economies of scale to be economically viable, and because it is generally perceived that sufficient biomass is not available within 50 to 80 miles of a large-scale plant, this study assesses the potential for biomass and coal cogasification and conversion of the resulting syngas to liquid fuels and electricity. The sulfur from coal is also recovered for sale.

Furthermore, this study assumes that polygeneration plants are collocated with existing pulp and paper mills. Thus the mill's demand for steam and hot water provides a heat sink, increasing the energy efficiency of polygeneration plants per barrel of liquid or megawatt of electricity produced and reducing emissions and carbon input requirements.

Four mills in four regions of the United States—South, Northeast, West, and Midwest—were selected for analysis. Detailed descriptions of these mills and the rationale for their selections are provided in the Reference Mills section of this report. Biomass-only and biomass and coal-based FT liquid and DME production plant scenarios were developed, meeting the electrical and heat demand of the mills; excess power and all the liquid and sulfur products were exported for sale. Energy and material balances indicate the following:

- Biomass-only cases are more energy efficient than biomass and coal cogasification cases for FT liquid production. The efficiency of polygeneration plants producing FT liquid ranges from 63% to 72% for biomass-only cases and 46% to 65% for biomass and coal cases. The biomass-only cases are more efficient because they are sized based on the mills' demands for heat and electricity and because they do not include CO_2 separation and compression.

- Biomass-only cases are more efficient than biomass and coal cogasification cases for DME production. The efficiency of polygeneration plants producing DME ranges from 61% to 64% for select biomass-only cases and 43% to 54% for select biomass and coal cases. The biomass-only cases are more efficient because they are sized based on the mills' demands for heat and electricity and because they do not include CO_2 separation and compression.

- Carbon in captured CO_2 gas ranges from 41% to 45% of the carbon in the coal–biomass feed for FT production cases and 45% to 52% for DME production cases. The percentage of carbon capture increases with the increased coal feed rate.

Financial analysis concludes that, in general:

- Production of DME is more economical than production of FT liquids.

- Regional coal prices relative to the reference coal price of $25/ton ($1.15/MMBtu) generally have a greater impact on tariff for DME production cases than FT production cases. The greatest tariff reductions are observed for Mill No. 1 in South followed by Mill No. 2 in the Northeast because of the lower regional coal prices relative to the reference coal price.

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- Coal–biomass polygeneration plants are more economical than biomass-only cases at Mill No. 1 in the South, Mill No. 2 in the Northeast, and Mill No. 3 in the West. Biomass polygeneration is more economical than biomass–coal polygeneration plants at Mill No. 4 in the Midwest, indicating that biomass-only plants can be more economical than biomass–coal plants at biomass feed rates of about 5000 tpd and higher and depending on the thermal demand of the mill.

- CO_2 capture increases capital costs by about 33%, reduces net electricity generation by about 17%, and increases electricity tariff by 27% to 34%.

- Cost of capturing CO_2 is estimated to be $15 to $17 per ton of captured CO_2.

The results of mill-specific financial analyses are as follows:

- In the South, at a coal price of $25/ton ($1.15/MMBtu), a biomass price of $11.80/ton, an electricity wholesale price of $30/MWh, and a 15% rate of return on equity, a polygeneration plant with a coal feed rate of 9816 MMBtu/hr, a biomass feed rate of 512 MMBtu, and a capital cost of $1.6 billion is the most economic case (Case FT-1-2A) at the mill's assumed operating conditions and financial parameters (see the Financial Analysis section).

  - At a constant FT liquid price of $52/bbl and a coal price of $25/ton, the projected electricity tariff for Case FT-1-2A ranges from $38/MWh to $96/MWh over 20 years of operation.

  - At a constant wholesale electricity price of $30/MWh, the FT liquid tariff ranges from $57/bbl ($424/ton or $10.58/MMBtu) to $126/bbl ($935/ton or $23.33/MMBtu).

  - Applying a regional coal price of $17/ton ($0.79/MMBtu) reduces the first-year electricity tariff (at constant FT liquid price of $52/bbl) by $5/MWh from $38/MWh to $33/MWh and the 20th-year tariff by $11/MWh from $96/MWh to $88/MWh. The higher 20th-year tariff is because of the constraint (i.e., minimum first-year tariff and 15% return on equity) imposed on the tariff calculations. Allowing the first-year tariff to increase would reduce the 20th-year tariff and/or increase the return on equity.

  - Applying a regional coal price of $17/ton reduces the FT liquid tariff (at a constant electricity price of $30/MWh) from $10.58/MMBtu to $9.51/MMBtu for the first year and from $23.33/MMBtu to $22.27/MMBtu for the 20th year of the operation.

  - Assuming a 4% escalation for electricity and FT liquid prices and assuming a first-year electricity tariff of $30/MWh and a FT liquid of $52/bbl, the 20th-year projected tariff for electricity is about $63/MWh and for FT liquid about $109/bbl.

- At a constant electricity price of $30/MWh and a coal price of $25/ton, the DME tariff ranges from $9.10/MMBtu ($177/ton) to $19.89/MMBtu ($387/ton) and at regional coal prices of $17/ton, from $8.34/MMBtu to $19.10/MMBtu over 20 years of operation. The current market price of DME is estimated to be $524/ton.

- To obtain 15% return on equity, the DME tariff is estimated to be $310/ton at a coal price of $25/ton and $291/ton at a coal price of $17/ton, both at zero-dollar-per-MWh electricity prices.

- In the Northeast, at a coal price of $25/ton ($1/MMBtu), a biomass price of $11.80/MMBtu, an electricity wholesale price of $45/MWh, and a 15% rate of return on equity, a polygeneration plant with a coal feed rate of 9816 MMBtu/hr, a biomass feed rate of 696 MMBtu/hr, and a capital cost of $1.6 billion is the most economical case (Case FT-2-2A) at the assumed mill's operating conditions and financial parameters. Case FT-2-1A with a biomass feed rate of 1392 MMBtu/hr and a capital cost of $1.7 billion is a close-second option.

  - At a constant FT liquid price of $52/bbl and a coal price of $1.15/ton, the projected electricity tariff for Case FT-2-2A ranges from $42/MWh to $105/MWh over 20 years of operation. The electricity wholesale price in this region is currently estimated to be $45/MWh, which indicates some flexibility on electricity and FT liquid-pricing strategy, the potential for capital recovery in a shorter time period than the assumed 20 years, and/or lower electricity price increases over the plant life.

  - At a constant wholesale electricity price of $45/MWh, the FT liquid tariff ranges from $46/bbl ($340/ton or $8.49/MMBtu) to $115/bbl ($851/ton or $21.25/MMBtu) over 20 years of operation.

  - Applying a regional coal price of $1/MMBtu reduces the first-year electricity tariff (at a constant FT liquid price of $52/bbl) by $3/MWh, from $42/MWh to $39/MWh, and the 20th-year tariff by $6/MWh from $105/MWh to $99/MWh.

  - Applying a regional coal price of $1/MMBtu reduces the FT liquid tariff (at a constant electricity price of $45/MWh) from $8.49/MMBtu to $8.11/MMBtu for the first year. The 20th-year tariff is reduced from $21.25/MMBtu to $20.50/MMBtu.

  - At a constant electricity cost of $45/MWh and a coal price of $1.15/MMBtu, the DME tariff ranges from $6.66/MMBtu ($129/ton) to $16.82/MMBtu ($327/ton) and at a regional coal price of $1/MMBtu, from $6.29/MMBtu to $15.90/MMBtu over 20 years of operation. The current market price of DME is estimated to be $524/ton.

  - To obtain a 15% return on equity, the DME tariff is estimated to be $318/ton at a coal price of $1.15/MMBtu and at $310/ton at a coal price of $1/MMBtu, both at zero dollars per MWh electricity prices.

- In the West, at a coal price of $25/ton ($1/MMBtu), a biomass price of $11.80/ton, an electricity wholesale price of $48/MWh, and a 15% rate of return on equity, a polygeneration plant with a biomass feed rate of 2135 MMBtu/hr, a coal feed rate of between 9816 MMBtu/hr and 4908 MMBtu/hr, and a capital cost of $1.2 to 1.8 billion appears to be the most economical case (a scenario that was not modeled but falls between Case FT-3-1A and FT-3-2A).

  – Regional coal prices have little or no impact on tariffs.

  – At a constant FT liquid price of $52/bbl, the electricity tariff ranges from $31/MWh to $57/MWh for the first year and $79/MWh to $144/MWh for the 20th year of operation. The wholesale price for electricity in this region is currently estimated to be $48/MWh.

  – At a constant wholesale electricity price of $48/MWh, the FT liquid tariff ranges from $51/bbl ($377/ton or $9.41/MMBtu) to $65/bbl ($483/ton or $12.07/MMBtu) for the first year of operation and from $21.00/MMBtu to $24.94/MMBtu for the 20th year of operation.

  – At a constant electricity cost of $48/MWh and a coal price of $1.15/MMBtu, the DME tariff ranges from $9.47/MMBtu ($184/ton) to $13.79/MMBtu ($268/ton) for the first year and from $23.41/MMBtu ($455/ton) to $30.13/MMBtu ($586/ton) for the 20th year of operation. The current market price of DME is estimated to be $524/ton.

  – To obtain 15% return on equity, the DME tariff is estimated to be $463/ton at a coal price of $1.15/MMBtu and at zero dollars per MWh electricity prices.

- In the Midwest, a biomass refinery case with a biomass feed rate of 1842 MMBtu/hr (4999 tpd) is economically more viable than the biomass–coal biorefinery cases. The capital cost for the FT production case is $279 million and for the DME production case, $369 million. DME production is more economical than FT production in this case.

  – At a constant FT liquid price of $52/bbl, the electricity tariff in Case B-FT-4 ranges from $41/MWh to $103/MWh over 20 years of operation. The wholesale price for electricity in this region is currently estimated to be $44.80/MWh. At a DME constant price of $397/ton, the electricity tariff is zero dollars per MWh and, at $325/ton, the electricity tariff remains constant at $44.80/MWh over 20 years of operation.

  – At a constant wholesale electricity price of $44.8/MWh, the FT liquid tariff ranges from $31/bbl ($316/ton or $7.89/MMBtu) to $108/bbl ($797/ton or $19.90/MMBtu) over 20 years of plant operation.

- At a constant electricity cost of \$44.8/MWh, the DME tariff ranges from \$15.49/MMBtu (\$301/ton) to \$32.33/MMBtu (\$628/ton) over 20 years of the operation. The current market price of DME is estimated to be \$524/ton.

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APPENDIX A

APPENDIX A

ULTIMATE AND PROXIMATE ANALYSIS OF BIOMASS

Name	Fixed Carbon, %	Volatiles, %	Ash, %	C, %	H, %	O, %	N, %	S, %	HHV, kJ/g
				WOOD					
Beech	–	–	0.65	51.64	6.26	41.45	0	0	20.38
Black Locust	18.26	80.94	0.8	50.73	5.71	41.93	0.57	0.01	19.71
Douglas Fir	17.7	81.5	0.8	52.3	6.3	40.5	0.1	0	21.05
Hickory	–	–	0.73	47.67	6.49	43.11	0	0	20.17
Maple	–	–	1.35	50.64	6.02	41.74	0.25	0	19.96
Ponderosa Pine	17.17	82.54	0.29	49.25	5.99	44.36	0.06	0.03	20.02
Poplar	–	–	0.65	51.64	6.26	41.45	0	0	20.75
Red Alder	12.5	87.1	0.4	49.55	6.06	43.78	0.13	0.07	19.3
Redwood	16.1	83.5	0.4	53.5	5.9	40.3	0.1	0	21.03
Western Hemlock	15.2	84.8	2.2	50.4	5.8	41.1	0.1	0.1	20.05
Yellow Pine	–	–	1.31	52.6	7	40.1	0	0	22.3
White Fir	16.58	83.17	0.25	49	5.98	44.75	0.05	0.01	19.95
White Oak	17.2	81.28	1.52	49.48	5.38	43.13	0.35	0.01	19.42
Madrone	12	87.8	0.2	48.94	6.03	44.75	0.05	0.02	19.51
Mango Wood	11.36	85.64	2.98	46.24	6.08	44.42	0.28		19.17

Name	Fixed Carbon, %	Volatiles, %	Ash, %	C, %	H, %	O, %	N, %	S, %	HHV, kJ/g
BARK									
Douglas Fir Bark	25.8	73	1.2	56.2	5.9	36.7	0	0	22.1
Loblolly Pine Bark	33.9	54.7	0.4	56.3	5.6	37.7	0	0	21.78
ENERGY CROPS									
Eucalyptus Camaldulensis	17.82	81.42	0.76	49	5.87	43.97	0.3	0.01	19.42
Casuarina	19.58	78.58	1.83	48.5	6.04	43.32	0.31	0	18.77
Poplar	16.35	82.32	1.33	48.45	5.85	43.69	0.47	0.01	19.38
Sudan Grass	18.6	72.75	8.65	44.58	5.35	39.18	1.21	0.01	17.39
PROCESSED BIOMASS									
Plywood	15.77	82.14	2.09	48.13	5.87	42.46	1.45	0	18.96
AGRICULTURAL									
Peach Pits	19.85	79.12	1.03	53	5.9	39.14	0.32	0.05	20.82
Walnut Shells	21.16	78.28	0.56	49.98	5.71	43.35	0.21	0.01	20.18
Almond Prunings	21.54	76.83	1.63	51.3	5.29	40.9	0.66	0.01	20.01
Black Walnut Prunings	18.56	80.69	0.78	49.8	5.82	43.25	0.22	0.01	19.83

Name	Fixed Carbon, %	Volatiles, %	Ash, %	C, %	H, %	O, %	N, %	S, %	HHV, kJ/g
Corncobs	18.54	80.1	1.36	46.58	5.87	45.46	0.47	0.01	18.77
Wheat Straw	19.8	71.3	8.9	43.2	5	39.4	0.61	0.11	17.51
Cotton Stalk	22.43	70.89	6.68	43.64	5.81	43.87	0	0	18.26
Corn Stover	19.25	75.17	5.58	43.65	5.56	43.31	0.61	0.01	17.65
Sugarcane Bagasse	14.95	73.78	11.27	44.8	5.35	39.55	0.38	0.01	17.33
Rice Hulls	15.8	63.6	20.6	38.3	4.36	35.45	0.83	0.06	14.89
Pine needles	26.12	72.38	1.5	48.21	6.57	43.72			20.12

Source: www.woodgas.com/proximate.htm.

APPENDIX B

CASE B-FT-1
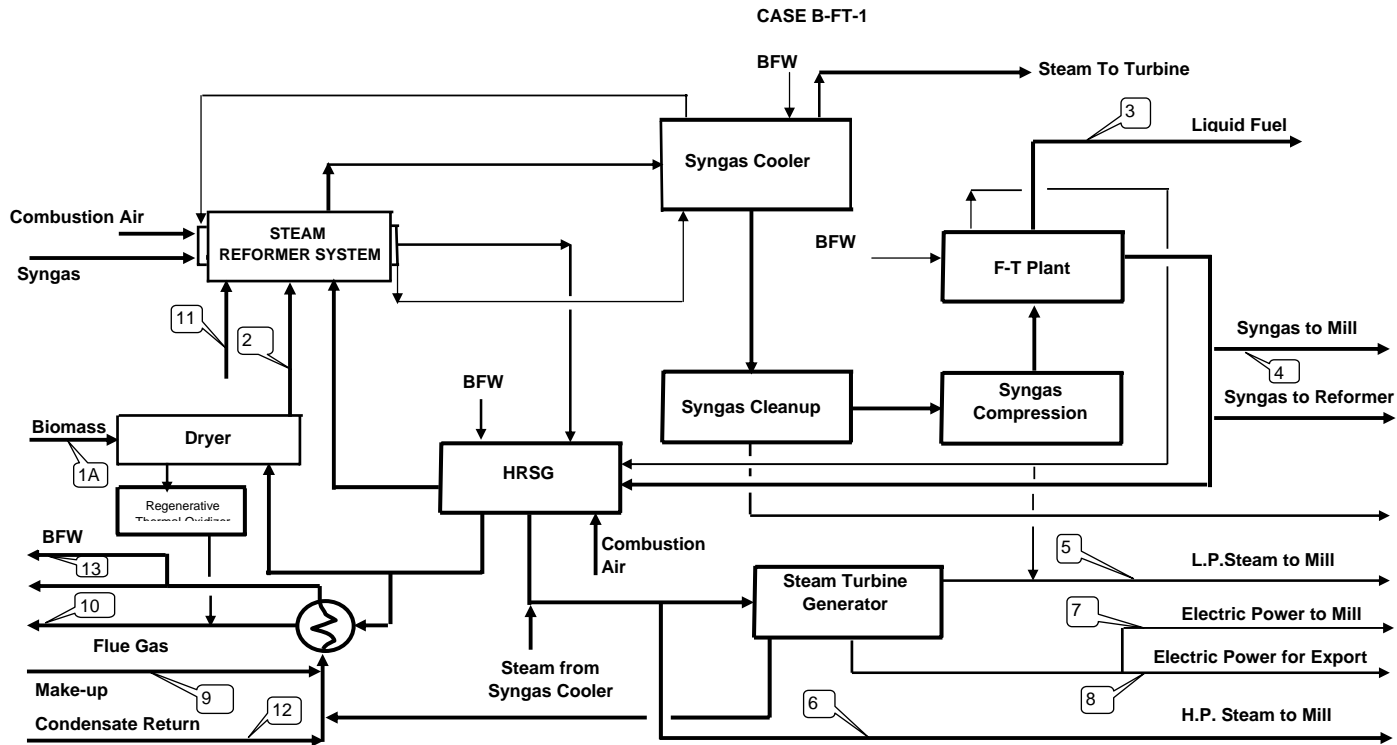
No.	1A	2	3	4	5	6	7	8	9	10	11	12	13
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW
Temp, F	70	135	100	180	366	825			70	285		281	350
Pres, Psig			5	10	150	850			60			50	210
Flow, Lbs/hr	231,000	128,333	20,814	16,450	50,943	145,257				332,227	25,212	356,928	372,728
HHV, MMBtu/hr	1,023	1,023	417	47	60	204							
Entholpy, MMBtu/hr		5	1	0.7					0	18	0.9	89	100
Total Energy, MMBtu/hr	1,023	1,028	418	47	60	204	61	-73	0	18	0.9	89	100
MWH/D	--	--		--			429	(511)					

Case FT-1-1A

No.	1A	1B	3	4	5	6	7	8	9	10	1A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	231,000	900,585	166,422	2,845	50,943	145,257				9,217,394	12,325,547	792,769	356,928	372,728	19,953	1,094,073
HHV, MMBtu/hr	1,023	9,816	3,279	47	60	204										
Entholpy, MMBtu/hr				0.1					0	462			89	103		
Total Energy, MMBtu/hr	1,023	9,816	3,279	47	60	204	134	1,720	0	462		30	89	103		
MWH/D	--	--			--		940	12,098								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

Case FT-1-1B

No.	1A	1B	3	4	5	6	7	8	9	10	1A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	231,000	450,292	93,618	2,835	50,943	145,257				4,769,341	6,274,391	409,184	356,928	372,728	10,201	582,594
HHV, MMBtu/hr	1,023	4,908	1,844	47	60	204										
Entholpy, MMBtu/hr				1.6					0	239			89	103		
Total Energy, MMBtu/hr	1,023	4,908	1,844	48	60	204	134	689	0	239			30	89	103	
MWH/D	--	--			--		940	4,848								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-1-1C

Diagram labels:
- Steam Reformer
- Air Separation — Air (11A)
- Syngas Coolers (High Pressure / Low Pressure) — BFW
- L. P. Syngas Cleanup
- Syngas Compression — BFW
- F-T Plant — Liquid Fuel (3), Syngas to Mill (4)
- Gasifier
- H.P. Syngas Cleanup
- CO2 Separation and Compression — CO2 to Storage (15)
- Boiler — BFW
- Fuel Processing — Coal, Biomass (1B, 1A)
- Regenerative Thermal Oxidizer
- Steam Turbine Generator
- BFW to Mill
- Flue Gas (10)
- Make-up (9), Condensate Return (12)
- Steam from Syngas Coolers
- Steam To Turbine
- Sulfur (14)
- L.P. Steam to Mill (5)
- Electric Power to Mill (7)
- Electric Power for Export
- H.P. Steam to Mill (6, 8)
- Stream labels: 11B, 11C, 11D, 11E, 2A, 2B

No.	1A	1B	3	4	5	6	7	8	9	10	1A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	231,000	225,146	57,216	2,819	50,943	145,257				1,359,939	2,050,330	217,392	356,928	372,728	5,324	326,855
HHV, MMBtu/hr	1,023	2,454	1,127	47	60	204										
Enthalpy, MMBtu/hr				0.9					0	68			89	103		
Total Energy, MMBtu/hr	1,023	2,454	1,127	48	60	204	134	642	0	68			30	89	103	
MWH/D	--	--			--		940	4,516								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

CASE FT-1-2A

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	115,500	900,585	156,015	2,851	50,943	145,257				9,180,459	12,170,116	779,970	356,928	372,728	19,729	1,058,515
HHV, MMBtu/hr	512	9,816	3,074	47	60	204										
Entholpy, MMBtu/hr				0.1					0	460			89	103		
Total Energy, MMBtu/hr	512	9,816	3,074	47	60	204	134	1,850	0	460		30	89	103		
MWH/D	--	--			--		940	13,012								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

Case FT-1-2B

Diagram labels: Steam Reformer; Air Separation; Air; Syngas Coolers (High Pressure / Low Pressure); BFW; L. P. Syngas Cleanup; Steam To Turbine; Liquid Fuel; Gasifier; Syngas Compression; BFW; F-T Plant; Syngas to Mill; H.P. Syngas Cleanup; Coal; Biomass; Fuel Processing; BFW; Gas Turbine; CO2 Separation and Compression; CO2 to Storage; Regenerative Thermal Oxidizer; HRSG; Sulfur; BFW to Mill; BFW; Steam Turbine Generator; L.P.Steam to Mill; Electric Power to Mill; Electric Power for Export; Flue Gas; Make-up; Steam from Syngas Coolers; Condensate Return; H.P. Steam to Mill

Stream numbers: 11B, 11A, 11C, 11D, 11E, 2A, 2B, 1B, 1A, 13, 3, 15, 14, 5, 7, 10, 9, 12, 6, 8, 4

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	115,500	450,292	83,211	2,845	50,943	145,257				4,565,335	6,122,318	396,385	356,928	372,728	9,977	547,036
HHV, MMBtu/hr	512	4,908	1,639	47	60	204										
Entholpy, MMBtu/hr				0.1					0	229			89	103		
Total Energy, MMBtu/hr	512	4,908	1,639	47	60	204	134	693	0	229		30	89	103		
MWH/D	--	--		--			940	4,875								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

Case FT-1-2C

Diagram labels: Steam Reformer; Air Separation; Air; Steam Reformer; BFW; Steam To Turbine; L. P. Syngas Cleanup; Liquid Fuel; Syngas Coolers (High Pressure / Low Pressure); Syngas Compression; BFW; F-T Plant; Syngas to Mill; Gasifier; H.P. Syngas Cleanup; Gas Turbine; CO2 Separation and Compression; CO2 to Storage; Coal; Biomass; Fuel Processing; BFW; HRSG; Regenerative Thermal Oxidizer; Sulfur; BFW to Mill; BFW; Steam Turbine Generator; L.P.Steam to Mill; Electric Power to Mill; Electric Power for Export; Flue Gas; Steam from Syngas Coolers; Make-up; Condensate Return; H.P. Steam to Mill

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	115,500	225,146	46,809	2,835	50,943	145,257				1,260,988	2,016,400	204,593	356,928	372,728	5,100	291,297
HHV, MMBtu/hr	512	2,454	922	47	60	204										
Entholpy, MMBtu/hr				0.1					0	63			89	103		
Total Energy, MMBtu/hr	512	2,454	922	47	60	204	134	640	0	63		30	89	103		
MWH/D	--	--			--		940	4,503								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

CASE DME-1-2A

No.	1A	1B	3	4	5	6	7	8	9	10	1A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	115,500	900,585	440,806	2,845	50,943	145,257				10,194,630	13,424,500	779,970	356,928	372,728	19,729	1,066,317
HHV, MMBtu/hr	512	9,816	4,284	47	60	204										
Entholpy, MMBtu/hr				0.1					0	511			89	103		
Total Energy, MMBtu/hr	512	9,816	4,284	47	60	204	134	1,936	0	511		30	89	103		
MWH/D	--	--			--		940	13,615								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas				Includes Mill Losses	Includes N2 Recycle		95% O2				

Case B-FT-2

Diagram labels: BFW, Steam To Turbine, Liquid (3), Syngas Cooler, Combustion Air (14), STEAM REFORMER SYSTEM, Syngas, BFW, DME Plant, B (11), 2, BFW, Syngas to Mill, Syngas Cleanup, Syngas Compression, Syngas to Reformer (4), Biomass, Dryer (1A), BFW to, HRSG, B (14), Sulfur, RTO, 13, Combustion Air, L.P.Steam to Mill (5), 10, Steam Turbine Generator, Electric Power to Mill (7), Flue Gas, Electric Power for Export, Make-up (9), 12, Steam from Syngas Cooler, 6, 8, H.P. Steam to Mill, Condensate Return

No.	1A	2	3	4	5	6	7	8	9	10	11	12	13	14	14
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW	Sulfur	Combustion Air
Temp, F	70	135	100	180	365	825			70	285		281	298		
Pres, Psig			5	10	150	850			60			50	65		
Flow, Lbs/hr	314,300	174,611	28,320	17,650	96,239	0			523,635	468,218	34,831	381,062	511,157	154	331,343
HHV, MMBtu/hr	1,392	1,392	576	50	117	0									
Entholpy, MMBtu/hr		7		0.5					20	25	0.9	95	137		
Total Energy, MMBtu/hr	1,392	1,399	576	51	117	0	201	29	0	25	0.9	95	137		
MWH/D	--	--	--				1410	201							
Notes	50% Moisture	10% Moisture	FT Liquids												

B-9

Case FT-2-1A

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	314,300	900,585	173,928	6,243	96,239	0				9,468,384	12,068,039	802,001	356,928	372,728	20,115	1,119,717
HHV, MMBtu/hr	1,392	9,816	3,427	50	114	0										
Entholpy, MMBtu/hr				0.2					0	475			89	103		
Total Energy, MMBtu/hr	1,392	9,816	3,427	50	114	0	201	1,562	0	475			30	89	103	
MWH/D	--	--		--			1410	10,987								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas						Includes N2 Recycle		95% O2				

Case FT-2-1B

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	314,300	450,292	101,124	6,137	96,239	0				4,846,537	6,170,614	418,416	356,928	372,728	10,362	608,239
HHV, MMBtu/hr	1,392	4,908	1,992	50	114	0										
Entholpy, MMBtu/hr				0.2						243			89	103		
Total Energy, MMBtu/hr	1,392	4,908	1,992	50	114	0	201	569		243			30	89	103	
MWH/D	--	--			--		1410	4,003								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas						Includes N2 Recycle		95% O2				

Case FT-2-1C

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.	70	10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	314,300	225,146	64,722	6,042	96,239	0				1,426,431	2,137,033	226,624	356,928	372,728	5,486	352,499
HHV, MMBtu/hr	1,392	2,454	1,275	50	114	0										
Entholpy, MMBtu/hr				0.2					0	72			89	103		
Total Energy, MMBtu/hr	1,392	2,454	1,275	50	114	0	201	456	0	72		30	89	103		
MWH/D	--	--			--		1410	3,209								
Notes	50% Moisture	14.5% Moisture	F-T Tail Gas							Includes N2 Recycle		95% O2				

Case FT-2-2A

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	157,150	900,585	159,768	6,243	96,239	0				9,303,924	11,866,150	784,585	356,928	372,728	19,810	1,071,337
HHV, MMBtu/hr	696	9,816	3,148	50	114	0										
Entholpy, MMBtu/hr				0.2					0	467			89	103		
Total Energy, MMBtu/hr	696	9,816	3,148	50	114	0	201	1,566	0	467		30	89	103		
MWH/D	--	--		--			1410	11,011								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas						Includes N2 Recycle		95% O2				

Case FT-2-2B

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	157,150	450,292	86,964	6,137	96,239	0				4,687,808	5,975,158	401,000	356,928	372,728	10,057	559,859
HHV, MMBtu/hr	1,392	4,908	1,742	50	114	0				235						
Entholpy, MMBtu/hr				0.2									89	103		
Total Energy, MMBtu/hr	1,392	4,908	1,742	50	114	0	201	525		235			30	89	103	
MWH/D	--	--			--			1410	3,694							
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-2-2C

No.	1A	1B	3	4	5	6	7	8	9	10	11A	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	157,150	225,146	50,562	6,137	96,239	0				1,293,885	2,681,263	383,586	356,928	372,728	5,181	304,119
HHV, MMBtu/hr	696	2,454	1,013	50	114	0										
Entholpy, MMBtu/hr				0.2					0	65			89	103		
Total Energy, MMBtu/hr	696	2,454	1,013	50	114	0	201	456	0	65		30	89	103		
MWH/D	--	--			--		1410	3,204								
Notes	50% Moisture	14.5% Moisture	F-T Tail Gas							Includes N2 Recycle		95% O2				

B-15

Case B-DME-2

No.	1A	2	3	4	5	6	7	8	9	10	11	12	13	14	14
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW	Sulfur	Combustion Air
Temp, F	70	135	100	180	365	825			70	285		281	298		
Pres, Psig			5	10	150	850			60			50	65		
Flow, Lbs/hr	314,300	174,611	63,337	17,650	96,239	0			523,635	360,817	34,831	381,062	511,157	154	255,338
HHV, MMBtu/hr	1,392	1,392	207	50	117	0									
Entholpy, MMBtu/hr		7	616	0.5					20	19	0.9	95	137		
Total Energy, MMBtu/hr	1,392	1,399	822	51	117	0	201	0	0	19	0.9	95	137		
MWH/D	--	--		--			1410	0							
Notes	50% Moisture	10% Moisture	DME	Tail Gas + Syngas											

Case DME-2-1A

Process flow diagram showing: Air → Air Separation; Steam Reformer; Gasifier; Syngas Coolers (High Pressure / Low Pressure); L.P. Syngas Cleanup; Syngas Compression; H.P. Syngas Cleanup; DME Plant; Gas Turbine; CO2 Separation and Compression; HRSG; Fuel Processing; Regenerative Thermal Oxidizer; Steam Turbine Generator. Streams: Coal (1B), Biomass (1A), BFW to Mill, Flue Gas (10), Make-up (9), Condensate Return (12), Steam from Syngas Coolers, Steam To Turbine, Liquid Fuel (3), Syngas to Mill (4), CO2 to Storage (15), Sulfur (14), L.P. Steam to Mill (5), Electric Power to Mill (7), Electric Power for Export (8), H.P. Steam to Mill (6).

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	314,300	900,585	353,837	3,154	96,239	0				13,154,760	15,530,343	802,001	356,928	372,728	20,115	1,184,094
HHV, MMBtu/hr	1,392	9,816	3,439	50	114	0										
Entholpy, MMBtu/hr				0.1					0	660			89	103		
Total Energy, MMBtu/hr	1,392	9,816	3,439	50	114	0	201	2,162	0	660		30	89	103		
MWH/D	--	--			--		1410	15,201								
Notes	50% Moisture	14.5% Moisture		Tail Gas						Includes N2 Recycle		95% O2				

Case DME-2-2A

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P. Steam to Mill	H.P. Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	366	825			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150	850			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	157,150	900,585	333,809	3,170	96,239	0				13,148,320	15,479,342	784,585	356,928	372,728	19,810	1,132,933
HHV, MMBtu/hr	696	9,816	3,244	50	114	0										
Entholpy, MMBtu/hr				0.1					0	660			89	103		
Total Energy, MMBtu/hr	696	9,816	3,244	50	114	0	201	2,191	0	660		30	89	103		
MWH/D	--	--			--		1410	15,408								
Notes	50% Moisture	14.5% Moisture		Tail Gas						Includes N2 Recycle		95% O2				

Case B-FT-3
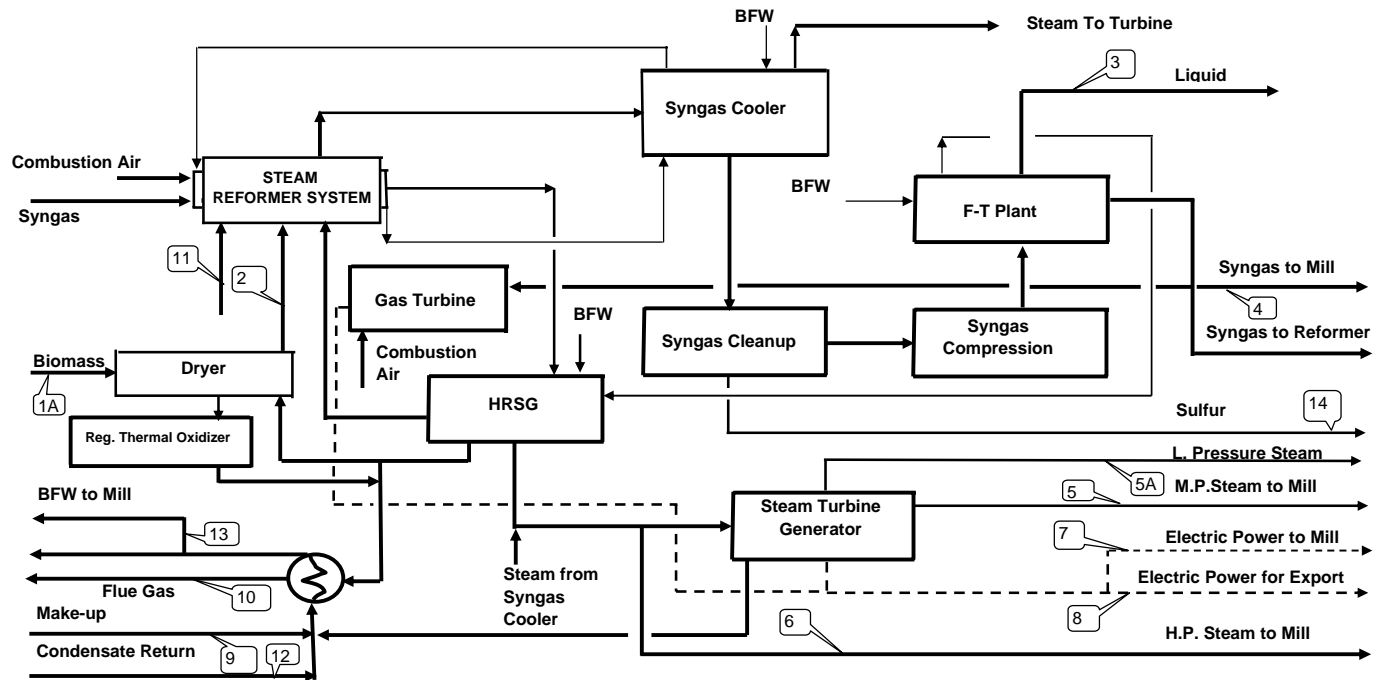
No.	1A	2	3	4	5A	5	6	7	8	9	10	11	12	13	14
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	M.P. Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW	Sulfur
Temp, F	70	135	100	180	320	385	546		70	285	260	281	280		
Pres, Psig			5	10	65	160	450		60		Atm	50	50		
Flow, Lbs/hr	482,000	267,778	43,430	15,500	180,000	194,996	121,000				1,678,598	53,415	527,615	481,000	239
HHV, MMBtu/hr	2,142	2,142	883	44							80	0	132	129	
Entholpy, MMBtu/hr				0.5	214	237	154								
Total Energy, MMBtu/hr	2,142	2,142	883	45	214	237	154	171	0		80	0	132	129	
MWH/D	--	--		--				1,200	-1						
Notes	50% Moisture	10% Moisture													

B-19

Case FT-3-1A

Steam Reformer

Air → Air Separation

11B, 11A, 11D, 11C, 11E, 2A

Gasifier

2B

Coal, Biomass → Fuel Processing

1B, 1A, 13

Regenerative Thermal Oxidizer

BFW to Mill
Flue Gas
Make-up
Condensate Return

10, 9, 12

BFW

Syngas Coolers — High Pressure | Low Pressure

H.P. Syngas Cleanup

BFW

HRSG

Steam from Syngas Coolers

L. P. Syngas Cleanup

Syngas Compression

Gas Turbine

Steam Turbine Generator

BFW

F-T Plant

CO2 Separation and Compression

Steam To Turbine
Liquid Fuel — 3
Syngas to Mill — 4
CO2 to Storage — 15
Sulfur — 14
L.P.Steam to Mill — 5
Electric Power to Mill — 7
Electric Power for Export
H.P. Steam to Mill — 6, 8

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	482,000	900,585	189,038	5,428	180,000	194996	121,000				9,650,553	12,289,414	820,585	356,928	372,728	20,440	1,171,345
HHV, MMBtu/hr	2,135	9,816	3,786	44	214	237	154										
Entholpy, MMBtu/hr				0.2						0	484			89	103		
Total Energy, MMBtu/hr	2,135	9,816	3,786	44	214	237	154	171	1,281	0	484		30	89	103		
MWH/D	--	--			--			1200	9,009								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

Case FT-3-1B

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	482,000	450,292	116,234	5,357	180,000	194,996	121,000				5,020,073	6,399,596	437,000	356,928	372,728	10,688	659,867
HHV, MMBtu/hr	2,135	4,908	2,328	44	214	237	154				252						
Entholpy, MMBtu/hr				0.2						0				89	103		
Total Energy, MMBtu/hr	2,135	4,908	2,328	44	214	237	154	171	552	0	252		30	89	103		
MWH/D	--	--			--			1200	3,885								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

Case FT-3-1C

Diagram labels: Steam Reformer; Air Separation; Air (11A); 11B; 11C; 11D; 11E; 2A; Gasifier; 2B; Syngas Coolers (High Pressure / Low Pressure); BFW; L. P. Syngas Cleanup; Syngas Compression; F-T Plant; 3 Liquid Fuel; Steam To Turbine; H.P. Syngas Cleanup; CO2 Separation and Compression; 4 Syngas to Mill; 15 CO2 to Storage; Coal (1B); Biomass (1A); Fuel Processing; BFW; Gas Turbine; HRSG; Regenerative Thermal Oxidizer; 13 BFW to Mill; 10 Flue Gas; Steam from Syngas Coolers; Steam Turbine Generator; 14 Sulfur; 5 L.P.Steam to Mill; 7 Electric Power to Mill; Electric Power for Export; 6 H.P. Steam to Mill; 8; Make-up (9); Condensate Return (12)

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.	10	65	450			60	Atm.	Atm.	40/610	50	210			2,000
Flow, Lbs/hr	482,000	225,146	79,832	5,256	180,000	121,000				2,688,963	3,438,754	245,208	356,928	372,728	5,811	404,127
HHV, MMBtu/hr	2,135	2,454	1,599	44	214	154										
Entholpy, MMBtu/hr				0.2					0	135			89	103		
Total Energy, MMBtu/hr	2,135	2,454	1,599	44	214	154	171	206	0	135			30	89	103	
MWH/D	--	--		--			1200	1,450								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas						Includes N2 Recycle		95% O2				

B-22

Case FT-3-2A

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	241,000	900,585	167,323	5,472	180,000	194996	121,000				9,403,275	11,984,731	793,878	356,928	372,728	19,972	1,097,151
HHV, MMBtu/hr	1,067	9,816	3,351	44	214	237	154										
Entholpy, MMBtu/hr				0.2						0	472			89	103		
Total Energy, MMBtu/hr	1,067	9,816	3,351	44	214	237	154	171	1,313	0	472		30	89	103		
MWH/D	--	--			--			1200	9,233								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

Case FT-3-2B

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	241,000	450,292	94,519	5,428	180,000	194,996	121,000				4,784,442	6,106,588	410,293	356,928	372,728	10,220	585,673
HHV, MMBtu/hr	1,067	4,908	1,893	44	214	237	154										
Entholpy, MMBtu/hr				0.2						0	240			89	103		
Total Energy, MMBtu/hr	1,067	4,908	1,893	44	214	237	154	171	572	0	240		30	89	103		
MWH/D	--	--		--				1200	4,025								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

Case FT-3-2C

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	241,000	225,146	58,117	5,256	180,000	121,000				2,469,237	3,162,581	218,501	356,928	372,728	5,344	329,933
HHV, MMBtu/hr	1,067	2,454	1,164	44	214	154				124						
Entholpy, MMBtu/hr				0.2					0				89	103		
Total Energy, MMBtu/hr	1,067	2,454	1,164	44	214	154	171	201	0	124			30	89	103	
MWH/D	--	--		--			1200	1,414								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas						Includes N2 Recycle		95% O2				

Case DME-3-1A

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	482,000	900,585	375,209	2,736	180,000	194996	121,000				13,158,550	15,581,882	820,585	356,928	372,728	20,440	1,238,689
HHV, MMBtu/hr	2,135	9,816	3,646	44	214	237	154										
Entholpy, MMBtu/hr				0.1						0	660			89	103		
Total Energy, MMBtu/hr	2,135	9,816	3,646	44	214	237	154	171	1,794	0	660		30	89	103		
MWH/D	--	--			--			1200	12,615								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

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Case DME-3-1B

No.	1A	1B	3	4	5	5A	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	M.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	320	385	546			70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	65	160	450			60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	482,000	450,292	218,318	2,736	180,000	194996	121,000				6,517,680	7,802,331	437,000	356,928	372,728	10,688	697,803
HHV, MMBtu/hr	2,135	4,908	2,122	44	214	237	154										
Entholpy, MMBtu/hr				0.1						0	327			89	103		
Total Energy, MMBtu/hr	2,135	4,908	2,122	44	214	237	154	171	769	0	327		30	89	103		
MWH/D	--	--			--			1200	5,407								
Notes	50% Moisture	14.5% Moisture		F-T Tail Gas							Includes N2 Recycle		95% O2				

Case B-FT-4

No.	1A	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW	Sulfur	Combustion Air
Temp, F	70	135	100	180	365	825			70	285		281	298		
Pres, Psig			5	10	150	850			60			50	65		
Flow, Lbs/hr	415,800	217,622	37,465	25,000	213,708	0				613,780	122,661	546,443	657,298	204	434,353
HHV, MMBtu/hr	1,842	1,842	762	71	259	0									
Entholpy, MMBtu/hr		9		0.8					0	33	0.9	137	176		
Total Energy, MMBtu/hr	1,842	1,851	762	72	259	0	196	48	0	33	0.9	137	176		
MWH/D	--	--	--				1375	340							

Case FT-4-1A

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	415,800	900,585	183,073	8,774	213,709	0				9,533,454	12,527,474	813,249	546,433	657,298	20,312	1,150,965
HHV, MMBtu/hr	1,842	9,816	3,667	72	259	0										
Entholpy, MMBtu/hr				0.0					0	478			137	176		
Total Energy, MMBtu/hr	1,842	9,816	3,667	72	259	0	196	1,482	0	478			137	176		
MWH/D	--	--			--		1,375	10,424								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT- 4 - 1B

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	415,800	450,292	110,269	8,669	213,709	0				3,162,933	4,620,220	429,664	546,433	657,298	10,559	639,486
HHV, MMBtu/hr	1,842	4,908	2,209	71	259	0				159						
Entholpy, MMBtu/hr				0.2					0				137	176		
Total Energy, MMBtu/hr	1,842	4,908	2,209	71	259	0	196	304	0	159			137	176		
MWH/D	--	--			--		1,375	2,138								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-4-1C

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	415,800	225,146	59,094	7,926	213,709	0				1,530,433	2,411,089	237,872	546,433	657,298	5,683	383,638
HHV, MMBtu/hr	1,842	2,454	1,184	71	259	0										
Entholpy, MMBtu/hr			0.2						0	77			137	176		
Total Energy, MMBtu/hr	1,842	2,454	1,184	71	259	0	196	59	0	77			137	176		
MWH/D	--	--			--		1,375	417								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-4-2A

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	207,900	900,585	164,341	8,837	213,709	0				9,318,489	12,252,596	790,209	546,433	657,298	19908	1,086,961
HHV, MMBtu/hr	921	9,816	3,292	72	259	0										
Entholpy, MMBtu/hr				0.0					0	467			137	176		
Total Energy, MMBtu/hr	921	9,816	3,292	72	259	0	196	1,488	0	467			137	176		
MWH/D	--	--			--		1,375	10,467								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-4-2B

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	207,900	450,292	91,537	8,774	213,709	0				2,986,112	4,762,427	406,624	546,433	657,298	10,156	575,482
HHV, MMBtu/hr	921	4,908	1,812	71	259	0				150						
Entholpy, MMBtu/hr				0.2					0				137	176		
Total Energy, MMBtu/hr	921	4,908	1,812	71	259	0	196	355	0	150			137	176		
MWH/D	--	--			--		1,375	2,499								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

Case FT-4-2C

Process flow diagram for Case FT-4-2C showing Steam Reformer, Air Separation, Syngas Coolers (High Pressure / Low Pressure), L.P. Syngas Cleanup, Syngas Compression, F-T Plant, Gasifier, H.P. Syngas Cleanup, Gas Turbine, CO2 Separation and Compression, Fuel Processing, Reg. Thermal Oxidizer, HRSG, Steam Turbine Generator with labeled streams.

No.	1A	1B	3	4	5	6	7	8	9	10	11	11C & 11D	12	13	14	15
Description	Biomass	Coal	Liquid Products	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Air	Oxygen	Condensate Return	BFW	Sulfur	CO2
Temp, F	70	70	70	100	365				70	260	60	240	281	350		
Pres, Psig	Atm.	Atm.		10	150				60	Atm.	Atm.	40/610	50	210		2,000
Flow, Lbs/hr	207,900	225,146	49,621	8,377	213,709	0				1,406,033	2,229,015	214,832	546,433	657,298	5,280	319,698
HHV, MMBtu/hr	921	2,454	994	71	259	0										
Entholpy, MMBtu/hr				0.2					0	71			137	176		
Total Energy, MMBtu/hr	921	2,454	994	71	259	0	196	9	0	71			137	176		
MWH/D	--	--			--		1,375	64								
Notes	50% Moisture	14.5% Moisture			F-T Tail Gas					Includes N2 Recycle		95% O2				

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Case B-DME-4

No.	1A	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Description	Biomass	Dried Biomass	Liquid Fuel	Syngas to Mill	L.P.Steam to Mill	H.P.Steam to Mill	Power Export to Mill	Power Export for Sale	Make-up Water	Flue Gas	Oxygen	Condensate Return	BFW	Sulfur	Combustion Air
Temp, F	70	135	100	180	365	825			70	285		281	298		
Pres, Psig			5	10	150	850			60			50	65		
Flow, Lbs/hr	415,800	217,622	70,412	25,000	213,708	0				525,910	46,079	546,443	657,298	204	372,169
HHV, MMBtu/hr	1,842	1,842	684	71	259	0									
Entholpy, MMBtu/hr		9		0.8					0	28	0.9	137	176		
Total Energy, MMBtu/hr	1,842	1,851	684	72	259	0	196	2	0	28	0.9	137	176		
MWH/D	--	--		--			1375	14							