

# GASIFICATION-BASED BIOREFINING AT KRAFT PULP AND PAPER MILLS IN THE UNITED STATES

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### ABSTRACT

Commercialization of black liquor and biomass gasification technologies is anticipated in the 2010-2015 timeframe, and synthesis gas from gasifiers can be converted into liquid fuels using catalytic synthesis technologies that are already commercially established today in the gas-to-liquids or coal-to-liquids industries. This paper describes key results from a major assessment of the prospective energy, environmental, and financial performance of commercial gasification-based biorefineries integrated with kraft pulp and paper mills. Seven detailed biorefinery designs were developed for a reference mill in the Southeastern U.S., together with the associated mass/energy balances, air emissions estimates, and capital investment requirements. The biorefineries provide chemical recovery services and co-produce process steam for the mill, some electricity, and one of three liquid fuels: a Fischer-Tropsch synthetic crude oil (which would be refined to vehicle fuels at existing petroleum refineries), dimethyl ether (a diesel engine fuel or propane substitute), or an ethanol-rich mixed-alcohol product.

Compared to installing new Tomlinson power/recovery systems, biorefineries would require more capital investment and greater purchases of woody residues for energy use. However, because biorefineries would be more efficient, have lower air emissions, and produce a more diverse product slate, for nearly all cases examined, the internal rate of return (IRR) on the incremental capital investment lies between 14% and 18%, assuming a \$50/bbl world oil price. The IRRs would more than double if plausible federal and state financial incentives are captured. Industry-wide adoption of such biorefining in the United States would provide significant energy and environmental benefits to the country.

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### INTRODUCTION

This paper summarizes results from a recently-completed two-year effort to assess prospective technical viability, commercial viability, and environmental and energy impacts locally and nationally of gasification-based biorefineries making liquid fuels from black liquor and woody biomass residues at kraft pulp and paper mills [1]. The study builds on an earlier study examining the potential for black liquor gasification combined cycle (BLGCC) electricity generation at kraft pulp and paper mills in the United States [2]. The same reference mill – an integrated pulp and paper mill in the Southeast – was used as the basis for analysis in both studies.

The biorefinery analysis assumed that gasification technologies will reach commercial readiness in the 2010 to 2015 timeframe and that the risks involved with installing such gasification systems in the post-2010 time frame will be comparable to those of installing a new Tomlinson-based power/recovery system. The implicit assumption is that in the years between the present and the post-2010 time period, research, development, and demonstration will bring gasification technologies to the point where their commercial reliability approaches that of Tomlinson technology. The equipment for downstream processing of the synthesis gas (syngas) from the gasifiers, including for sulfur capture and for catalytic synthesis of liquids, is already commercial in all but one of the process designs examined in this study.

Using potential domestic market size and potential for enhancing domestic energy security as screening criteria, our biorefinery analysis identified three liquid products for detailed analysis: Fischer-Tropsch liquids (FTL, a mixture of primarily straight-chain hydrocarbons – olefins and paraffins – that resembles a semi-refined crude oil), dimethyl ether (DME, a propane substitute or diesel-engine fuel), and mixed-alcohols (MA, a mixture of ethanol and higher alcohols that is a potential gasoline substitute). Detailed process designs and simulations were pursued for alternative configurations for the manufacture of these products assuming projected commercial (N<sup>th</sup> plant) performance. Environmental impacts were estimated by quantifying emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, particulate matter, and total reduced sulfur. A detailed internal rate of return analysis was carried out for each process design. The mill-level energy and environmental performance results were used as a basis for estimating potential national energy/environment impacts under alternative assumptions about the rate at which existing Tomlinson systems would be retired and replaced with biorefineries. Not all results from the study are presented here. For full results, see [1].

### STUDY ASSUMPTIONS

#### Characteristics of reference pulp/paper mill

The reference mill is an integrated kraft pulp and paper mill producing uncoated freesheet paper from a 65/35 mix of hardwood and softwood. Consistent with the forward-looking nature of this study and the continual improvements in process energy efficiency historically achieved by U.S. pulp and paper makers, the process steam demands at the mill are taken to be about 10% below current U.S. "best-practice" levels. The

Table 1. Reference mill characteristics.

POWER/RECOVERY SYSTEM →		Tomlinson	Gasification
PULPING CHEMISTRY →		Conventional	Polysulfide
Product Flow (paper)	Machine-dry metric tons / day	1,725	
Unbleached Pulp Rate	Bone dry short tons / day	1,580	
Hardwood/Softwood Mix	% HW, % SW	65% HW, 35% SW	
Digester Yield	% for softwood	45.50%	48.75%
	% for hardwood	46.50%	49.75%
Wood To Digester		3,434	3,208
Hog Fuel	Bone dry short tons / day	340	317
Total pulpwood logs		3,774	3,525
Black Liquor Concentration	% solids	80%	80%
BL Solids Flow Rate	lb BLS / day	6,000,000	5,419,646
	kg BLS / day	2,721,555	2,458,311
BL Energy Content	MJ / kg of BLS, LHV (HHV)	12.46 (13.89)	12.31 (13.87)
	Btu / lb of BLS, LHV (HHV)	5,359 (5,974)	5,295 (5,966)
	MW, LHV (HHV)	392.6 (437.6)	350.7 (394.7)
BL Solids Composition mass%	C	33.46%	32.97%
	H	3.75%	3.70%
	O	37.35%	36.88%
	S	4.10%	4.27%
	Na	19.27%	20.03%
	K	1.86%	1.93%
	Ash/chlorides	0.21%	0.22%
Hog Fuel Energy Content (50% moisture content)	MJ / kg of hog fuel, LHV (HHV)	8.14 (10.0)	8.14 (10.0)
	Btu / lb of hog fuel, LHV (HHV)	3,501 (4,300)	3,501 (4,300)
	MWth, LHV (HHV)	57.8 (71.3)	54.1 (66.6)
Mill O <sub>2</sub> use (for delignification)	kg / metric t pulp	23	23
Mill Steam Use, 55 psig Steam (including evaporators, but excl. power/recovery area)	kg / kg of paper	3.384	3.207
	MWth	142.8	135.3
	MJ / mt of paper	7,149	6,774
Mill Steam Use, 175 psig Steam (including evaporators, but excl. power/recovery area)	kg / kg of paper	1.760	1.648
	MWth	69.3	64.8
	MJ / mt of paper	3,469	3,247
Total Mill Steam Use	MWth	212.1	200.1
Mill Electricity Use (excl power/recovery)	kWh / mt of paper	1,407	1,407
	MWe	100.1	100.1

nominal scale of the reference mill is 6 million lbs/day (2,721 metric tonnes/day) of dry black liquor solids (BLS).

Key reference mill parameter assumptions are shown in Table 1 for both conventional kraft pulping and polysulfide pulping. The latter pulping chemistry is enabled by the use of black liquor gasification in the recovery area, and we assume this chemistry is implemented in our biorefineries. Compared to conventional kraft pulping, polysulfide pulping raises the digester yield [3], enabling a reduction in wood feed to the mill compared to conventional pulping (for the same level of paper production<sup>2</sup>). The higher digester yield also reduces the amount of black liquor solids sent to the recovery area.

### Black liquor gasification

A number of concepts for black liquor gasification have been proposed in the past [4]. Our study utilizes the pressurized, oxygen-blown, high-temperature design being developed by Chemrec [5,6]. The Chemrec design is characterized by the majority of the inorganic material in the BLS leaving the reactor as a smelt due to the high reactor temperature (950-1000°C). In the late 1990s, the Weyerhaeuser company installed the world's first commercial Chemrec gasifier, an atmospheric-pressure, air-blown unit designed to process 365 t/d BLS at a mill in North Carolina to

<sup>2</sup> The implicit assumption here is that the mill is already operating at capacity (outside of the power/recovery area) when using conventional pulping, so that an increase in digester yield can be accommodated only by decreasing wood input, not by increasing pulp production.

augment the chemical recovery capacity of the existing Tomlinson boiler. A pilot plant pressurized Chemrec gasifier (30 bar pressure and capacity to process up to 20 tpd BLS with oxygen firing) has been operating under a test program at a pulp mill in Piteå, Sweden since mid-2006. This unit will provide data for scale-up [7] to full-scale Tomlinson boiler replacement applications.

With gasification (unlike in a Tomlinson boiler), there is a natural partitioning of sulfur (mainly as hydrogen sulfide, H<sub>2</sub>S) to the gas phase and sodium to the condensed phase. This split represents an important potential benefit to a pulp mill, since it can facilitate alternative pulping chemistries that can lead to increased pulp yields per unit of wood consumed [8]. With the high-temperature gasifier design adopted here, slightly more than half of the sulfur goes to the gas phase. To take advantage of the natural separation of sulfur (S) and sodium (Na), it is necessary to recover H<sub>2</sub>S from the gas in a form suitable for preparing modified pulping liquors. H<sub>2</sub>S must also be removed from the syngas so that downstream fuel-synthesis catalysts are not poisoned. Capture of acid gases like H<sub>2</sub>S is routinely practiced in other industries (e.g., petroleum refining) using patented physical or chemical absorption processes such as Selexol<sup>®</sup> or Rectisol<sup>®</sup>. A negative consequence of the S/Na split in a gasifier is a higher causticizing load, i.e., larger required lime kiln capacity and lime kiln fuel consumption per unit of BLS processed compared to processing in a Tomlinson boiler [2].

### Biomass gasification

Our biorefinery designs explore the potential impacts of supplementing to a substantial degree the relatively modest quantities of woody residues that are used for energy at typical pulp mills today. To maximize the effectiveness of woody residue use, most of our biorefinery designs incorporate gasification (rather than combustion) of the biomass. We have chosen to use a pressurized, oxygen/steam-blown circulating fluidized-bed design based on the gasifier developed at the Gas Technology Institute (GTI). For synthesis of fuels, a pressurized syngas undiluted by nitrogen is preferred for feeding to the synthesis reactor, since synthesis conversion rates generally increase with pressure and decrease with increasing fraction of inert components in the syngas. Also, reactor size and cost increase with inert content.

Development and pilot-plant demonstration efforts with pressurized oxygen/steam-blown fluidized bed gasification date to the early-1980s in Sweden [9,10] and the mid-1980s in the USA [11,12]. Most such efforts were curtailed when world oil prices fell in the late 1980s. There has been some recent re-assessment of pressurized oxygen-blown gasification in the USA [13], and a major Finnish technology development effort for production of FT fuels from woody biomass is focusing on pressurized oxygen-blown fluidized bed gasification, including plans for a demonstration of the

**Table 2. Summary of technologies included in our biorefinery designs indicating commercial status of each technology.**

		Status*	FTa	FTb	FTc	DMEa	DMEb	DMEc	MA
Black Liquor Gasification	High-temp gasifier	pilot	♦	♦	♦	♦	♦	♦	♦
	Quench	pilot	♦	♦	♦	♦	♦	♦	♦
	O <sub>2</sub> feed	com	♦	♦	♦	♦	♦	♦	♦
Woody Biomass Conversion	Fluid-bed gasifier	pilot	♦	♦	♦		♦	♦	♦
	Syngas cooler	pilot	♦	♦	♦	♦	♦	♦	♦
	Hot gas filter	pilot	♦	♦	♦		♦	♦	♦
	Quench cleanup	com			♦				♦
	O <sub>2</sub> feed Boiler	com	♦	♦	♦	♦	♦	♦	♦
H <sub>2</sub> S Capture and Recovery	Rectisol®	com	♦	♦	♦	♦	♦	♦	
	Selexol®	com							♦
	Claus/SCOT	com	♦	♦	♦	♦	♦	♦	♦
Fuel Synthesis	Slurry bed reactor	com	♦	♦	♦	♦	♦	♦	
	Fixed-bed reactor	lab							♦
	Syngas recycle	com				♦	♦	♦	♦
Power Island	Gas turbine	com	♦	♦	♦		♦	♦	♦
	Back pressure ST	com	♦	♦	♦	♦	♦	♦	♦
	Condensing ST	com	♦	♦	♦				♦

\* com = commercial; pilot = demonstrated at pilot scale; lab = demonstrated in laboratory.

technology before 2010 at a scale of 100 to 200 dry tonnes per day of biomass feed [14].

### BIOREFINERY DESIGNS

We developed seven biorefinery designs: three variants for DME production, three variants for FTL production, and one design for MA production.

The process designs all include five basic equipment “islands”: (i) black liquor gasification, (ii) biomass gasification (or, in one case, a hog fuel boiler island), (iii) syngas heat recovery and syngas clean-up, (iv) fuel synthesis, and (v) power. The gasification island includes a cryogenic air separation unit (ASU) for the production of oxygen. The syngas clean-up island is centered around Rectisol® technology, except for the MA case in which Selexol® technology is adopted because of less stringent downstream sulphur concentration requirements. For the fuel synthesis island, where clean syngas is converted into a liquid fuel by reaction over a catalyst promoting the desired synthesis reactions, we consider a slurry-phase reactor for FTL and DME and a fixed-bed reactor for MA. For the power island, in one case a boiler + back-pressure steam turbine cycle is adopted. In the other six cases, a gas turbine/steam turbine combined cycle is used. The gas turbine in most cases is the medium-scale, heavy-duty 6FA offered by General Electric. In one case, we consider the larger 7FA.

Table 2 summarizes the technology incorporated into each of our seven biorefinery designs. The column labeled “status” indicates the proximity to commercial offering for each technology. The majority of components are already in wide commercial use (in non-biorefinery applications). All but one of the technologies not in the commercial category fall into the category of technologies that have been or are currently being demonstrated at pilot scale, such that relatively near term (2010-2015 time frame) commercial deployment of biorefineries is

feasible. Only one technology (mixed-alcohols synthesis) is at a relatively under-developed stage today.

Table 3 summarizes key characteristics for each of our biorefinery designs, with comparisons to the Tomlinson and BLGCC designs developed earlier [2]. The black liquor flow is the same in all cases, except for the Tomlinson case where more black liquor is available due to lower pulp yield. The amount of woody biomass input as energy (including hog fuel and purchased residues) is set by the constraint that the biorefinery provide all of the pulp/paper mill’s process steam demand. Table 3 shows the net increase in total wood (pulpwood and purchased residues) that must be handled in the wood yard at the pulp/paper mill compared to the Tomlinson case. There is some reduction in pulpwood input to the mill (compared with the Tomlinson case due to higher-yield pulping process), but this reduction is more than compensated by the additional purchased residues that are needed.

In our DMEa design, the black liquor gasifier, supplied with oxygen from an ASU, provides the syngas for DME synthesis. Syngas that is unconverted in passing through the synthesis reactor is separated from product DME and 97% is recycled to synthesis to increase DME production. The 3% purge stream prevents excessive buildup of inert gases in the recycle loop. The purge gas is burned with wood residues in the power island boiler. Heat recovered from the black liquor and syngas processing areas is integrated into the boiler to increase steam production and minimize the amount of woody residues needed. The steam is expanded through a back-pressure turbine to generate some electricity. After meeting the parasitic electricity demands of the biorefinery, the net power output is nearly zero and essentially all the electricity required by the mill is purchased from the grid.

One approach to increasing net electricity production is to increase the use of wood residues and/or increase the efficiency of electricity generation. Biorefinery DMEb adopts both of these approaches. In this design (Figure 1), the black liquor and synthesis gas processing areas are unchanged from DMEa, and DME production is identical to that in DMEa. However, woody biomass is gasified and used to fuel a gas turbine-steam turbine combined cycle (GTCC). Because the GTCC is characterized by a higher electricity to steam

**Table 3. Summary of key design parameter values for biorefinery simulations and, for comparison, BLGCC and Tomlinson cases.**

	BLS Metric t/d (MW <sub>LHV</sub> )	Biomass used for energy		Net incremental biomass to mill, metric dry t/d (%) <sup>a</sup>	Gas turbine <sup>b</sup>	Syngas from wood gasifier goes to	Synthesis loop design
		Dry metric t/d	MW <sub>th</sub> LHV				
<b>Biorefineries</b>							
DMEa	2,458 (351)	700	132	186 (5.4%)	no GT	no wood gasif.	97% recyc.
DMEb	2,458 (351)	1,326	250	813 (24%)	6FA	gas turbine	97% recyc.
DMEc	2,458 (351)	678	128	165 (4.8%)	6FA	gas turbine	one pass
FTa	2,458 (351)	829	156	316 (9.2%)	6FA	gas turbine	one pass
FTb	2,458 (351)	2,246	423	1,733 (51%)	7FA	gas turbine	one pass
FTc	2,458 (351)	2,704	505	2,191 (64%)	6FA	synthesis	one pass
MA	2,458 (351)	760	143	247 (7.2%)	6FA	synthesis	76% recyc.
<b>From 2003 BLGCC study [2]</b>							
Tomlinson	2,722 (393)	308	58	0 (0)	no GT	no wood gasif.	no synth.
BLGCC	2,458 (351)	432	81	-82 (-2.4%)	6FA	no wood gasif.	no synth.

(a) This is the net additional biomass that must be handled in the woodyard at the mill. It is the sum of pulpwood logs and purchased wood residues less the pulpwood-log flow in the reference (Tomlinson) case.

(b) The rated output in simple-cycle mode when operating on natural gas is 75MW for the 6FA and 170MW for the 7FA.

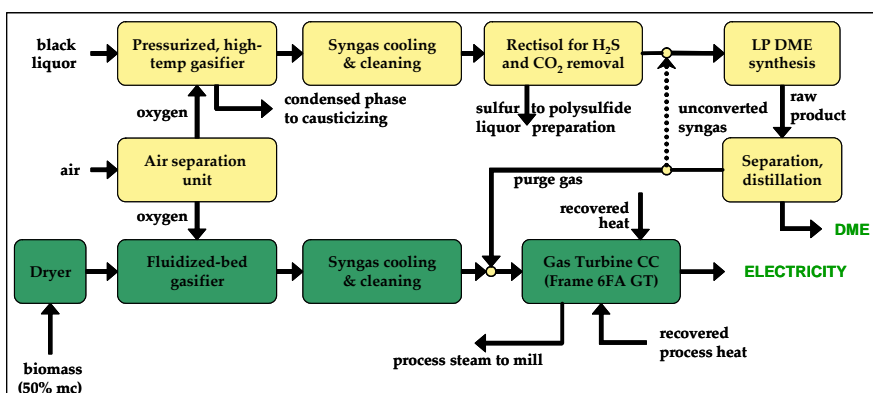


Figure 1. Schematic of DME biorefineries representing DMEb and DMEc designs – the flow represented by the dashed line is absent in the case of DMEc. The DMEa design replaces the shaded modules of the DMEb configuration with a boiler steam turbine system.

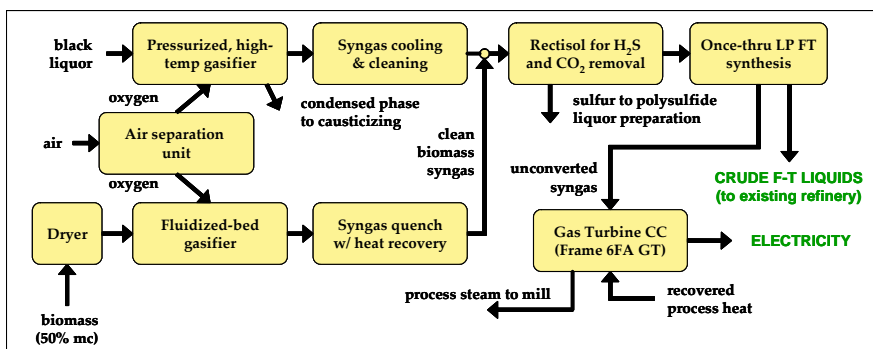


Figure 2. Schematic of biorefinery FTc. Unlike the three DME designs and the two other FT designs, in this case gasified woody biomass is mixed with gasified black liquor flowing to the synthesis island, and only unconverted syngas is used as fuel in the gas turbine island.

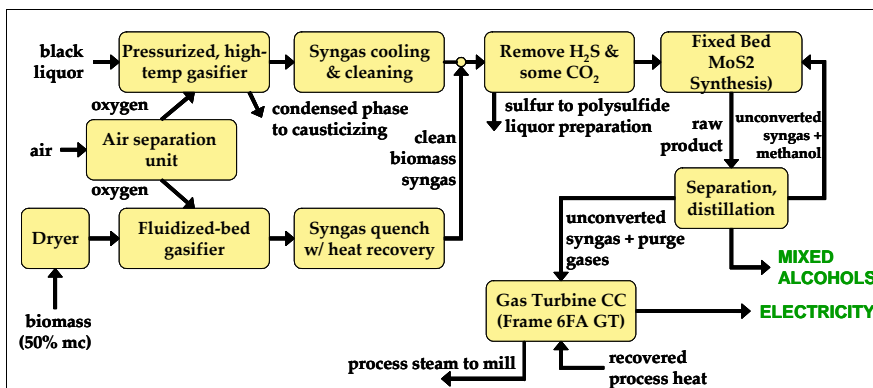


Figure 3. Schematic of biorefinery MA. The design is similar to FTc in that syngas from both the black liquor gasifier and the biomass gasifier are processed through the synthesis reactor. MA differs from FTc in that a significant fraction of the unconverted synthesis gas is recycled for further conversion, as indicated by the more darkly-shaded blocks.

production ratio than the boiler/steam turbine system in DMEa, more biomass must be used in the DMEb design than in the DMEa design to deliver the same amount of process steam, but electricity production with DMEb is considerably greater than with DMEa.

Another approach to increasing electricity production involving woody biomass consumption not much greater than DMEa, is to use a lower level of syngas recycle to the synthesis reactor, such that more unconverted gas is available

for power generation. In DMEc (Figure 1), syngas recycle loop is eliminated, and the syngas passes only once through the reactor, leading to much lower DME production than in DMEb but requiring relatively little purchased biomass. The design is otherwise very similar to DMEb.

For our FT biorefinery designs, we considered only single-pass synthesis due to the much higher single-pass conversion of syngas that can be achieved with FT synthesis compared to DME synthesis. Our FTa configuration is conceptually identical to the DMEc design described in Figure 1. The FTb configuration substitutes the 6FA gas turbine with a 7FA unit, but is otherwise identical to FTa. The larger fuel requirement of the 7FA necessitates a larger input of woody biomass. The FTc design involves passing all syngas (from both black liquor and biomass gasification) through the FT synthesis reactor and using only unconverted syngas to fuel the (6FA) gas turbine (Figure 2). This design involves the largest amount of woody biomass use among the seven designs investigated.

For the production of mixed-alcohols (Figure 3) we adopt a design similar to FTc in that syngas from black liquor and woody residue gasification are combined for processing through the synthesis reactor. In the MA design, however, because the single-pass syngas conversion is much lower than for synthesis of FTL we recycle 76% of the unconverted syngas. The unrecycled portion of the syngas fuels the GTCC island.

## PERFORMANCE SIMULATION

The detailed equipment configurations and operating parameter values for our biorefineries were selected with the objective of maximizing energy efficiency within practical thermodynamic and capital cost constraints, so as to optimize overall financial performance. Our final process designs were arrived at only after reviewing detailed mass/energy balance simulation results from initial designs with engineers at Nexant, the A&E firm that subsequently developed “N<sup>th</sup> plant” capital cost estimates, and revising the initial designs accordingly to improve performance and/or reduce capital costs and parasitic power consumption. Our energy and mass balance calculations were done using the computer code (“GS”) used in our prior BLGCC work [2]. Additionally, we used Aspen Plus software for calculations for the sulfur removal and fuel synthesis islands, including kinetic models for synthesis that were developed as part of this work. As an illustrative example of our calculations, Figure 4 shows the detailed plant scheme and simulated mass/energy balances of one of the biorefinery designs (FTc).

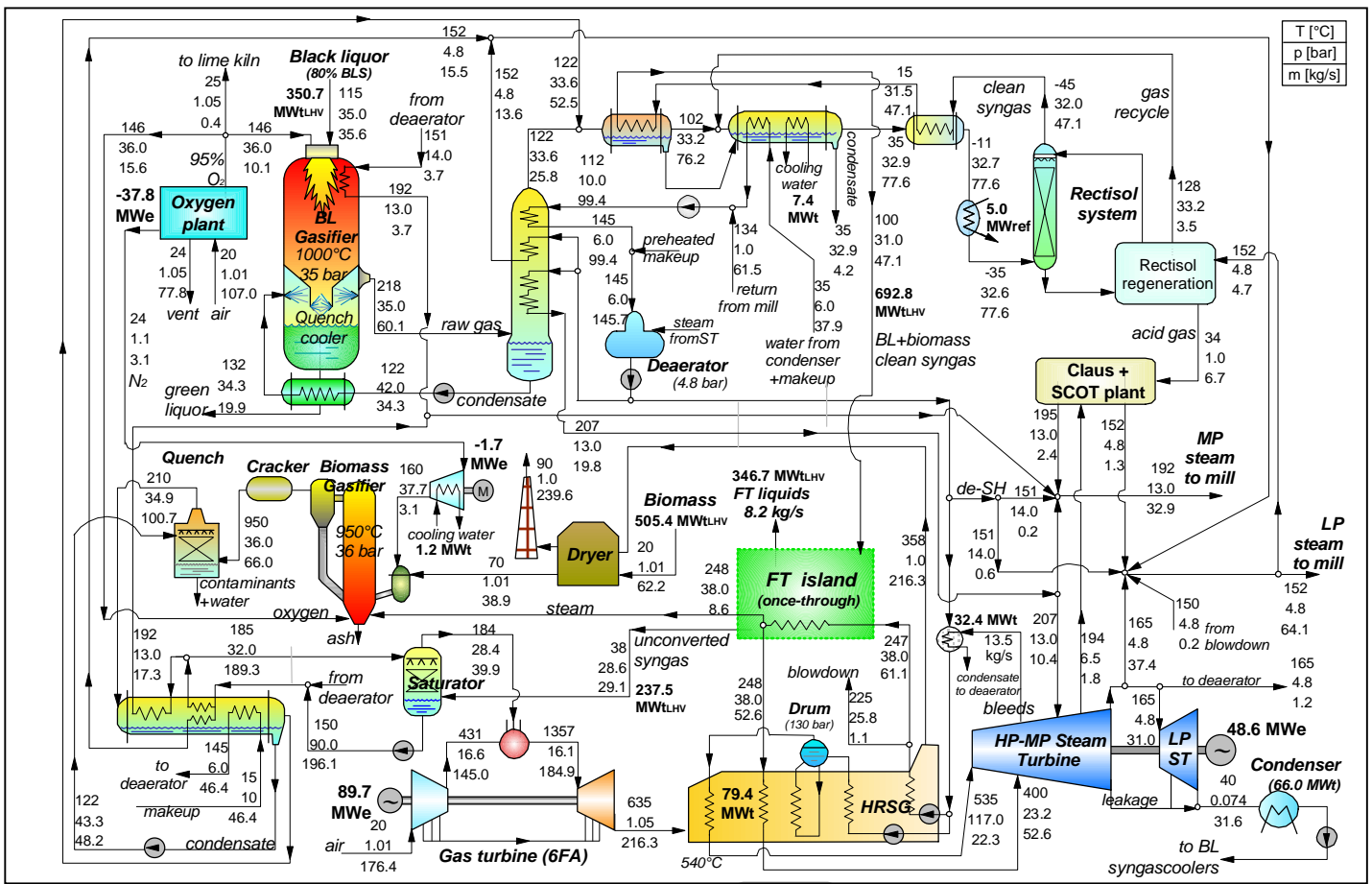


Figure 4. Plant configuration and mass/energy balances for FTc case. For clarity, details of the FT island balances are not shown.

Table 4 summarizes all of our performance results and compares them to our prior BLGCC and Tomlinson results. (Table 5 gives HHV and LHV for the various feedstocks and fuels in our analysis.) Figure 5 graphically summarizes the biorefinery and Tomlinson energy balances, showing energy inputs and outputs. The ratio between the height of the “out” bar and that of the “in” bar is the overall energy efficiency according to the First Law of Thermodynamics. It is an indication of the overall energy performance, but a more nuanced efficiency analysis [1] gives a more accurate comparison of performances due to different thermodynamic values associated with the different plant outputs (fuel, electricity, heat, and chemical services).

Several comparisons are informative:

- The ratio of useful energy outputs to total energy inputs (second row from bottom in Table 4) is higher for the biorefineries than for the BLGCC case and substantially higher than for the Tomlinson case. This reflects the more effective use of biomass with gasification-based conversion and with producing a more diverse product slate.
- All the biorefineries require more fuel inputs than the Tomlinson. How well are these added inputs being used? The “effectiveness of purchased energy use”,<sup>3</sup> (last row of

Table 4) exceeds 100%, or nearly so, in six of the eight cases indicating the very effective use of additional energy inputs.

- A comparison between the BLGCC and DMEa cases is of interest because the former exports electricity only and the latter exports liquid fuels only, while both utilize a black liquor gasifier and both meet the pulp/paper mill’s steam needs using hog fuel boilers. The DMEa case shows a higher useful energy output ratio, although this does not necessarily translate to better financial performance since considerable purchases of electricity by the pulp/paper mill will be required with the DMEa system.
- DMEc and FTa have nearly identical equipment configurations. FTa produces about 50% more liquid fuel (in terms of lower heating value, LHV) due to the higher one-pass syngas conversion efficiency of FT synthesis. However, purchased biomass use is higher in the FTa case because more of the fuel for the gas turbine must be provided from gasified biomass.
- The FTc and MA designs both utilize a feed of combined syngas from black liquor and from biomass gasification to the synthesis reactor. Because of the low MA synthesis rates, the purchased biomass that must be used to ensure sufficient fuel gas for the gas turbine is much more modest than in the FTc case. This is true even though the FTc case uses a once-through synthesis design and the MA case uses recycle, because the overall conversion of syngas to liquids

<sup>3</sup> We use “effectiveness”, rather than efficiency, since efficiency > 100% is not possible. Values of effectiveness > 100% are possible because the denominator includes only purchased biomass (not black liquor and hog fuel).

**Table 4. Biorefinery performance estimates, with comparisons to Tomlinson and BLGCC. Units are megawatts unless otherwise indicated. Fuel values are given on a lower heating value basis.**

	Power Only		Biorefineries						
	Tomlin.	BLGCC	DMEa	DMEb	DMEc	FTa	FTb	FTc	MA
<b>FUEL INPUTS</b>									
Black liquor	392.6	350.7	350.7	350.7	350.7	350.7	350.7	350.7	350.7
Hog fuel	57.8	54.1	54.1	54.1	54.1	54.1	54.1	54.1	54.1
<i>Total mill by-product fuels</i>	<i>450.4</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>	<i>404.8</i>
Purchased wood residues	0	27.1	77.4	195.5	73.4	101.6	368.5	451.3	89.2
Natural gas to duct burner	--	12.9	--	--	--	--	--	--	--
Lime kiln #6 fuel oil	31.1	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
<i>Total purchased fuels</i>	<i>31.1</i>	<i>75.9</i>	<i>113.3</i>	<i>231.4</i>	<i>109.3</i>	<i>137.5</i>	<i>404.4</i>	<i>487.2</i>	<i>125.1</i>
<b>Total fuel inputs</b>	<b>481.5</b>	<b>480.7</b>	<b>518.1</b>	<b>636.2</b>	<b>514.1</b>	<b>542.3</b>	<b>809.2</b>	<b>892.0</b>	<b>529.9</b>
<b>STEAM TO MILL</b>									
LP (55 psig) steam to process	142.8	135.3	135.3	135.3	135.3	135.3	135.3	135.3	135.3
MP (175 psig) steam to process	69.3	64.9	64.9	64.9	64.9	64.9	64.9	64.9	64.9
<b>Total process steam production</b>	<b>212.1</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>	<b>200.2</b>
<b>LIQUID FUEL PRODUCTION</b>	--	--	<b>168.0</b>	<b>168.0</b>	<b>74.2</b>	<b>111.6</b>	<b>111.6</b>	<b>342.7</b>	<b>59.6</b>
Barrels per day petroleum equiv. <sup>a</sup>	--	--	2362	2362	1043	1549	1549	4757	948
<b>ELECTRICITY BALANCE</b>									
Gas turbine gross output	--	87.0	--	89.5	82.9	83.9	186.5	89.7	89.7
Steam turbine gross output	72.0	48.2	32.9	42.0	38.7	34.0	87.9	48.6	40.8
Syngas expander output	--	--	2.58	5.01	1.96	1.65	4.26	--	2.99
<i>Total gross production</i>	<i>72.0</i>	<i>135.1</i>	<i>35.5</i>	<i>136.5</i>	<i>123.6</i>	<i>119.5</i>	<i>278.7</i>	<i>138.3</i>	<i>133.5</i>
Air separation unit power use	--	14.9	15.8	27.0	21.5	22.8	35.7	38.4	22.1
Syngas compressor power use	--	--	1.95	1.95	2.17	--	--	--	7.37
Gas compressors (mainly recycle)	--	--	7.26	7.26	--	--	--	--	1.77
Steam cycle auxiliaries	6.7	1.2	1.38	2.30	1.52	1.31	3.76	5.40	2.75
Black liquor gasification island aux.	--	2.7	2.67	2.67	2.67	2.67	2.67	2.67	2.67
Biomass gasification island aux.	--	--	--	3.37	1.74	2.11	5.66	6.75	1.95
Biomass boiler auxiliaries	1.00	1.2	1.75	--	--	--	--	--	--
Acid gas removal & S recovery aux.	--	1.1	0.97	0.97	0.96	0.96	0.96	2.59	1.81
Refrigeration for AGR	--	--	2.15	2.15	2.07	2.01	2.01	5.11	1.21
Synthesis island auxiliaries	--	--	1.00	1.00	0.40	--	--	--	--
<i>Total recovery area use</i>	<i>7.7</i>	<i>21.1</i>	<i>34.9</i>	<i>48.7</i>	<i>33.0</i>	<i>31.8</i>	<i>49.8</i>	<i>60.9</i>	<i>41.6</i>
<b>Net Electricity Production</b>	<b>64.3</b>	<b>114.1</b>	<b>0.56</b>	<b>87.8</b>	<b>90.5</b>	<b>87.7</b>	<b>228.9</b>	<b>77.3</b>	<b>91.9</b>
Power in excess of Tomlinson	--	50.4	-63.2	24.1	26.8	24.0	165.2	13.6	28.2
Process use (excl. recovery area)	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1
Mill electricity purchases	35.8	-15.2	99.6	12.3	9.58	12.4	-128.8	22.8	8.21
<b>Energy Ratios</b>									
Useful outputs/total inputs <sup>b</sup>	0.574	0.654	0.712	0.717	0.710	0.737	0.668	0.695	0.664
Effectiveness of purchased fuel use <sup>c</sup>	--	1.11	1.27	0.956	1.28	1.27	0.740	0.780	0.928

- (a) Barrels (bbl) per day of equivalent petroleum-derived fuel potentially displaced by the biorefinery fuel. The potentially-displaced fuels are: diesel (6.15 GJ/bbl, LHV) for DME, crude oil (6.22 GJ/bbl, LHV) for FTL, and gasoline (5.43 GJ/bbl, LHV) for MA.
- (b) This is the sum of process steam, net electricity, and liquid fuel outputs divided by the sum of all fuel inputs.
- (c) This is the sum of net electricity and liquid fuel production for the gasification-based facility minus this quantity for the Tomlinson facility divided by the difference in total purchased fuel between the gasification and Tomlinson facilities.

(in LHV terms) is much higher for once-through FTL (49%) than for recycle MA (17%).

- The MA and DMEb systems are similar insofar as they both utilize a recycle synthesis loop and the same gas turbine. The higher overall conversion of syngas to liquids in the DMEb case means that a larger amount of biomass must be purchased since there is less unconverted syngas available to fuel the gas turbine.

**Liquid fuel produced per ton of biomass input**

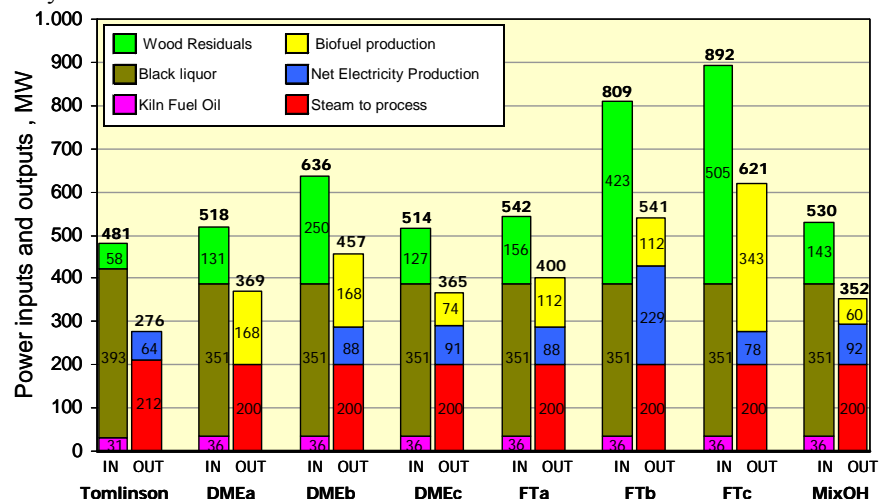
A commonly cited metric for liquid biofuels production is the liquid yield per unit of biomass input, typically expressed in terms of gallons per dry ton. Figure 6 shows biofuel yields expressed in terms of gallons of gasoline energy equivalent per metric tonne of dry biomass feedstock (lower x-axis) and also in terms of gallons of ethanol energy equivalent per dry metric tonne of biomass (upper x-axis). Included in this figure are results from several studies in addition to ours

[15, 16, 17, 18, 19, 20]. All of the designs included in Figure 6 generate one or more co-products with the biofuel. Appropriate adjustments to the amount of biomass charged against liquid fuel production have been made to account for co-products.

All results above the horizontal dashed line in Figure 6 are for plant designs that include some level of electricity co-production. To obtain a measure of the effective liquid fuel yield per ton of biomass for these cases, we have charged a portion of the input biomass to the electricity co-product. We have assumed that the amount of biomass charged to electricity is the amount that would be required to generate the same amount of electricity at a stand-alone biomass power plant having a lower-heating value generating efficiency of 49.5% [21].

For the pulp mill biorefinery cases (below the dashed line in Figure 6), it is appropriate to make some additional adjustments to the biomass charged against liquid fuel production since these biorefineries serve to provide, in addition to liquid fuel, not only some electricity but also process steam to the pulp/paper mill and chemical recovery services. Accordingly, for the process designs below the dashed line, we charge against liquid fuels production only the purchased woody biomass residues.

Black liquor and residues generated on site (hog fuel) are charged against the pulp mill’s steam, power, and chemical



**Figure 5. Energy balance (lower heating value basis) of biorefinery and Tomlinson systems.**

**Table 5. Lower and higher heating values for biorefinery feedstocks and various liquid fuels.**

	LHV	HHV
Black liquor dry solids <sup>a</sup>	12.3 MJ/kg	13.9 MJ/kg
Woody residues (50% moisture)	8.1 MJ/kg	10.0 MJ/kg
Fischer-Tropsch synthetic crude	31.2 MJ/liter	33.5 MJ/liter
Dimethyl ether	19.2 MJ/liter	21.1 MJ/liter
Mixed alcohols	28.2 MJ/liter	31.0 MJ/liter
Ethanol	21.3 MJ/liter	23.6 MJ/liter
Petroleum gasoline	32.4 MJ/liter	34.5 MJ/liter
Petroleum diesel	34.5 MJ/liter	36.3 MJ/liter
Petroleum low-sulfur diesel	36.1 MJ/liter	38.6 MJ/liter

(a) See Table 1.

recovery needs, since this is how these inputs are used with Tomlinson systems at pulp mills today to provide all process steam, chemical recovery services, and some electricity.

Additionally, several of the pulpmill biorefineries generate more electricity than the Tomlinson systems they would replace. In these cases, some of the purchased residues are charged to the added electricity production. In several other cases, the pulp mill biorefinery produces less electricity than the Tomlinson systems they would replace. In these cases, some additional biomass purchases would be required to reach the same level of electricity production as with the Tomlinson. In these cases, this added biomass requirement is charged against liquid fuels production.

The adjusted liquid fuel yields are higher or substantially higher for all

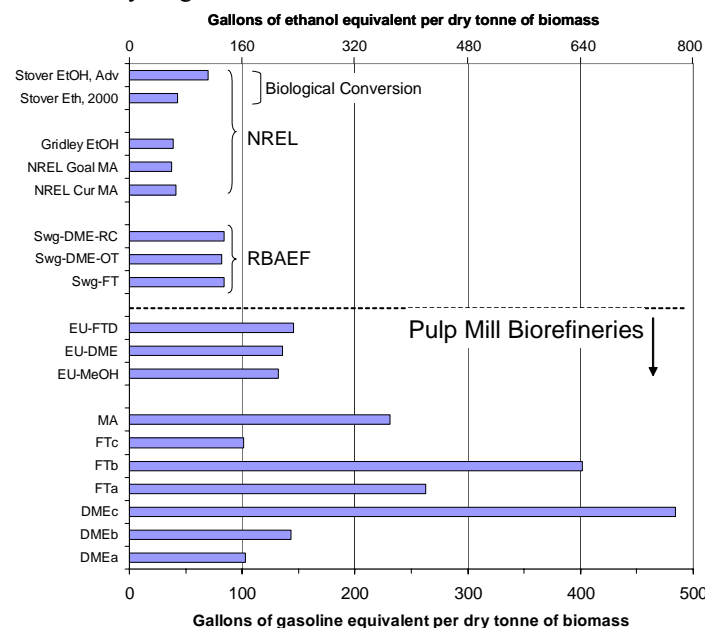
pulp mill biorefineries than for “stand-alone” biorefineries that co-produce liquid fuels and electricity.<sup>4</sup> The high values arise primarily because of the credits allocated for the services the biorefineries provide in addition to delivery of liquids. In effect, the biomass resource is utilized more efficiently by integrating the biorefinery with a pulp mill than by using biomass in a stand-alone biorefinery.

### FINANCIAL ANALYSIS

To assess prospective economics, biorefinery capital costs were estimated as a basis for calculating effective biofuel production costs and detailed cash flow/internal rates of return on investments made to replace with a biorefinery an existing Tomlinson system that had reached the end of its working life. The capital cost considered in all cases is the incremental capital investment required for the biorefinery over a new Tomlinson system.

**Table 6. Estimated overnight installed capital costs (thousand 2005\$) and non-fuel operating and maintenance costs (thousand 2005\$ per year). Installed capital costs include engineering, equipment, installation, owner’s costs (including initial catalyst), contingencies, and spare parts.**

THOUSAND 2005\$	Power/Steam		Biorefinery -- Power/Steam/Liquid Fuel						
	Tomlin.	BLGCC	DMEa	DMEb	DMEc	FTa	FTb	FTc	MA
Recovery boiler	125,018	0	0	0	0	0	0	0	0
Steam system modifications	11,136	0	3,000	0	0	0	0	0	0
Air separation unit (ASU)	0	42,628	43,053	61,561	52,933	55,001	72,762	77,823	54,080
ASU increment for O <sub>2</sub> delig.	0	1,118	1,061	879	954	933	805	776	948
BL gasifier & green liquor filter	0	63,720	63,720	63,720	63,720	63,720	63,720	63,720	63,720
Nitrogen compressor	0	0	0	1,188	810	1,071	1,757	2,013	5,181
Acid gas removal & sulfur recov.	0	19,003	37,732	37,732	27,321	27,321	27,321	42,164	24,529
Synthesis island	0	0	49,344	49,344	16,287	22,019	22,019	38,767	83,548
Combined cycle power island	0	89,243	0	105,303	100,091	90,018	171,895	104,300	90,348
Wood yard expansion	0	0	867	2,697	789	1,303	4,832	5,788	1,077
Biomass dryer, including RTO	0	0	0	50,295	32,523	37,286	72,507	45,558	31,383
Biomass gasifier & tar cracker	0	0	0	28,354	18,320	20,867	41,365	47,063	22,949
Biomass syngas cooler & filter	0	0	0	8,484	4,998	5,666	11,372	0	0
Biomass syngas cooler & wash	0	0	0	0	0	0	0	34,425	16,092
Biomass syngas expander	0	0	0	3,778	2,661	2,670	9,410	0	0
Hog fuel boiler	0	0	50,736	0	0	0	0	0	0
Other	0	2,359	2,359	2,359	2,359	2,359	2,359	2,359	2,359
<b>Overnight Installed Capital Cost</b>	<b>136,154</b>	<b>218,072</b>	<b>251,873</b>	<b>415,695</b>	<b>323,766</b>	<b>330,234</b>	<b>502,125</b>	<b>464,755</b>	<b>396,215</b>
<b>Annual non-fuel O&amp;M cost</b>	<b>5,446</b>	<b>8,723</b>	<b>10,075</b>	<b>16,628</b>	<b>12,951</b>	<b>13,209</b>	<b>20,085</b>	<b>18,590</b>	<b>15,849</b>



**Figure 6. Comparison of adjusted liquid fuel yields.**

### Capital cost estimates

Capital cost estimates consistent with previous estimates for Tomlinson and BLGCC systems [2] were developed for each biorefinery design by engineers at Nexant, LLC. Based on the detailed mass/energy balances described earlier, Nexant was asked to provide estimates with  $\pm 30\%$  uncertainty and to assume “N<sup>th</sup> plant” levels of technology maturity and operational reliability. The resulting capital and non-fuel operating and maintenance costs are given in Table 6.

### Effective capital intensities and production costs

It is of interest to compare the capital investment charged to liquid fuels production capacity for our biorefineries with the investments needed to produce liquid fuels through other routes. The capital charged to liquid fuels for our biorefineries is the extra investment required relative to an investment for a

<sup>4</sup> Note that in several cases the adjusted yield corresponds to an energy conversion of the biomass that is greater than 100%. [A liquid yield of 126 gallons of gasoline equivalent per dry metric tonne of biomass, or 202 gallons of ethanol per dry metric tonne of biomass, corresponds to an actual energy conversion of 100% on a LHV basis]. Of course, the “adjusted yield” is not a measure of actual energy conversion.

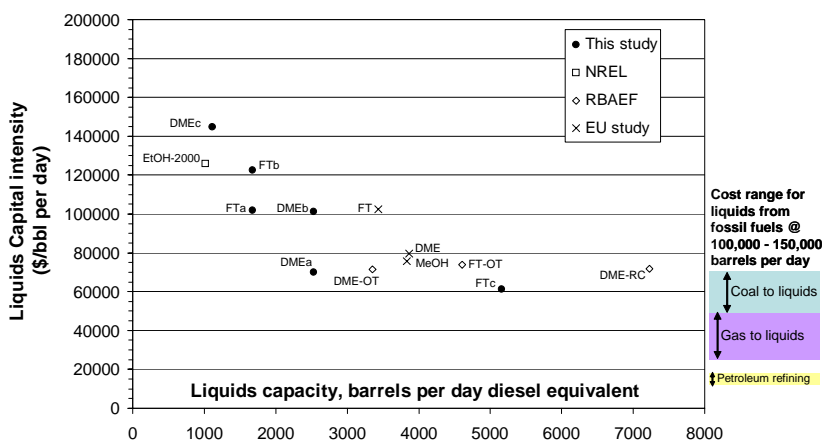


Figure 7. Effective capital investment intensity (2005\$ per barrel diesel-equivalent per day) for liquid fuels production as a function of production capacity.

Table 7. Effective leveled cost of liquid fuels production at pulp mill biorefineries.

	FTa	FTb	FTc	DMEa	DMEb	DMEc	MA
\$ per GJ (LHV)							
Capital	7.38	8.87	4.55	5.18	7.40	10.46	18.76
Working capital	0.26	0.31	0.16	0.18	0.26	0.37	0.66
Taxes	0.72	0.47	1.87	1.85	1.32	0.39	0.82
O&M	2.06	2.49	1.24	1.42	2.05	2.94	5.26
Biomass	1.73	2.08	1.06	1.21	1.73	2.45	4.40
<b>Total</b>	<b>12.16</b>	<b>14.23</b>	<b>8.88</b>	<b>9.83</b>	<b>12.76</b>	<b>16.60</b>	<b>29.90</b>
\$/bbl crude oil equivalent			\$/gallon diesel equivalent			\$/gal gasoline equiv.	
Capital	42.4	51.0	26.1	0.71	1.01	1.43	1.51
Working capital	1.5	1.8	0.9	0.02	0.04	0.05	0.05
Taxes	4.1	2.7	10.8	0.25	0.17	0.05	0.07
O&M	11.9	14.3	7.1	0.19	0.28	0.40	0.42
Biomass	9.9	12.0	6.1	0.16	0.23	0.33	0.35
<b>Total</b>	<b>69.8</b>	<b>81.7</b>	<b>51.0</b>	<b>1.33</b>	<b>1.73</b>	<b>2.26</b>	<b>2.40</b>

new Tomlinson system. The biorefinery provides the same process steam and chemical recovery services to the mill as a Tomlinson system, and provides less or more electricity as a Tomlinson (depending on the specific biorefinery design). If the biorefinery delivers more electricity to a mill than would a Tomlinson system, a credit against the capital charged to liquid fuels is appropriate. If the biorefinery delivers less electricity to the mill than would a Tomlinson, then an additional charge against liquid fuels production is appropriate. We credit (or charge) the biorefinery for the difference in electricity delivered to the mill at a rate of \$968/kW<sub>e</sub>, the estimated overnight investment cost that would be required to generate this electricity in a separate stand-alone biomass-gasifier/combined cycle facility, once this technology reaches commercial maturity [21].

Capital charged to biofuels from our analysis and those from some other studies are shown in Figure 7. The full scale range shown for biofuels is tiny compared to typical scales for fossil fuel conversion (see reference points on the right side of the figure). Nevertheless, the biorefinery investment costs are in the same range as investment costs for coal-to-liquids facilities with installed capacities 20 to 50 times as large. This highlights the benefit (capital cost credits) provided by integrating the biorefinery with the pulp and paper mill.

The capital investments in Figure 7 and the biomass charged against liquid fuel (Figure 6) can be used to calculate

effective biofuel production costs, which we have done (Table 7) using the same discounted cash flow methodology and assumptions as used by analysts at the National Renewable Energy Laboratory for estimates of bio-ethanol production by fermentation routes.<sup>5</sup> The lowest effective costs for FT and DME, which, it should be noted, can be achieved with technology that could be deployed at commercial-scale in the 2010-2015 time frame, are at approximately the same level as projected costs (after some R&D breakthroughs) for ethanol made by advanced enzymatic hydrolysis of lignocellulose at a stand-alone biorefinery [17].

### Internal rate of return analysis

Our detailed rate of return analysis accounts for all major changes to mill operations that would result from investing in an integrated biorefinery instead of a new Tomlinson system, including reduced wood costs due to higher digester yield with polysulfide pulping, increased use of #6 fuel oil in the lime kiln, the purchase of wood residues, the sale of electricity and biofuels, and other factors. Avoided costs (e.g., avoided grid power purchases) are also included. Financial parameter assumptions are in Table 8.

Because of uncertainties about future energy prices, we consider two scenarios to bracket the possibilities. We based our scenarios on the U.S. DOE's *Reference* and *High* price projections [22], referring to these as our Reference Energy Prices (REP) and Tight Supplies Energy Prices (TSEP) scenarios.<sup>6</sup> We utilized year-by-year values for oil and other energy prices over the 25 years spanned in each of these two scenarios. Table 9 summarizes our price

Table 8. Key input assumptions for the financial analysis.

Financial Parameters	
Inflation Rate	2.14%
Debt/Equity	50%/50%
Interest Rate on Debt	8%
Return on Equity (hurdle rate)	15%
Income Tax Rate; Property tax & insurance	40%; 2%
Economic Life (years)	25
Depreciation Method	20-year MACRS
Construction time (months)	24 (Tomlinson) 30 (gasification)
P&P Industry/Mill Assumptions	
O&M cost inflator (% per year, current \$)	2.67%
Annual Operating Hours	8,330
Start-up (% of full output), Year 1; Year 2-25	80%; 100%

<sup>5</sup> NREL's parameter assumptions include 100% equity investment, 10% discount rate, 5% working capital, 39% taxes, MACRS depreciation schedule, 20-year life, and a 6 month start-up time, during which revenues are 50% of normal, variable costs are 75% of normal, and fixed costs are 100% of normal. Additionally, we assume an annual operating and maintenance cost of 4% of the capital investment.

<sup>6</sup> Our price scenarios are not identical to the DOE forecasts, but our plant gate prices are based on the DOE projections. Also, we have extrapolated a few years beyond the DOE horizon of 2030 in order to do a 25-year cash flow.



**Table 9. Levelized costs (2005\$) for energy commodities (plant gate, no incentives).**

Energy Commodity	Reference Energy Prices (REP) Scenario	Tight Supplies Energy Price (TSEP) Scenario
World crude oil price	\$50/bbl	\$78/bbl
Electricity – avoided purchases	\$53.3/MWh	\$56.2/MWh
Electricity – sales to grid	\$48.2/MWh	\$51.8/MWh
Natural gas purchases	\$5.82/MCF	\$7.00/MCF
Residual fuel oil purchases	\$1.00/gallon	\$1.62/gallon
DME sales as motor diesel substitute	\$0.72/gallon	\$1.10/gallon
DME sales as LPG substitute	\$0.66/gallon	\$0.99/gallon
FT crude sales as petroleum crude substitute	\$0.96/gallon	\$1.54/gallon
FT crude sales as petroleum crude substitute <sup>b</sup>	\$40.3/barrel	\$64.7/barrel
Mixed alcohol sales	\$1.43/gallon	\$1.77/gallon
Ethanol sales	\$1.09/gallon	\$1.35/gallon
Methanol sales	\$0.54/gallon	\$0.67/gallon
Propanol sales (representing higher alcohols)	\$3.64/gallon	\$3.90/gallon
Purchased wood (higher heating value basis)	\$1.53/MMBtu	\$1.53/MMBtu

assumptions, giving levelized values over the projection period. Our two scenarios can be characterized in short-hand by the levelized world crude oil price calculated from our year-by-year oil price assumptions. In the REP scenario, this levelized price is \$50 per barrel (2005 \$). In the TSEP scenario, it is \$78 per barrel. The latter represents an extrapolation of mid-2006 oil prices.

Biorefineries may be able to capture monetary value from environmental and renewable energy attributes, e.g., a premium for renewable electricity sales. Existing and potential federal and state incentives (biofuels excise tax credits, tax exemptions and production tax credits) may also be available. The impacts of such incentives were considered in sensitivity analyses.

Figure 8 gives IRR and NPV results under the REP scenario. With no incentives (left bar in each set of two bars), the IRR for most configurations exceeds the 15% hurdle rate. The largest systems in terms of feedstock input (FTb and FTc) demonstrate the most attractive biorefinery economics, but do not quite reach the level for the BLGCC. The weakest financial performance is for the MA configuration.<sup>7</sup>

When a bundle of plausible incentives is considered including an excise tax credit (equivalent, on an energy basis, to the one currently available for ethanol), an investment tax credit for gasification investments (mandated by EPA 2005), a 10-year production tax credit for renewable electricity of \$9 per MWh, and a renewable energy credit (REC) of \$20/MWh, the financial performance is overwhelmingly attractive for all cases, with most IRRs between 30% and 35%.

In the TSEP scenario (not shown), the IRRs, even without incentives, exceed the hurdle rate by a wide margin in all cases except MA. They also surpass the BLGCC option by several points, since the BLGCC option is largely unaffected by changes in petroleum prices.

## INDUSTRY IMPACTS

The technical potential of the U.S. kraft pulp and paper industry for liquid biofuels production, if the entire industry were to adopt a biorefining configuration like the FTc case

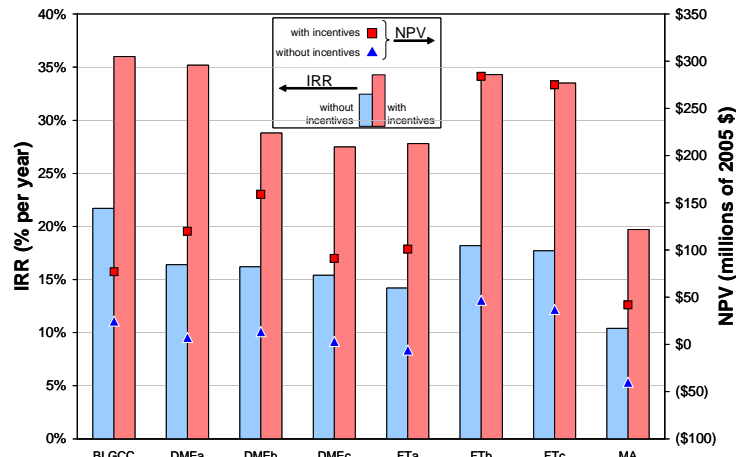
<sup>7</sup> Separating the mixed alcohols and selling the components as chemicals (rather than selling the mixture as fuel) would provide higher returns despite the low product yield because of the high unit values of chemical alcohols [1]. Chemicals markets are much smaller than fuel markets, however, so production from pulpmill biorefineries would quickly saturate the markets.

(for which liquids production is highest among all cases examined), is in excess of 9 billion gallons per year of FT synthetic crude oil. On an energy equivalent basis, this corresponds to about 14 billion gallons per year of ethanol. For comparison, the corn-ethanol industry in the U.S. produced 4.9 billion gallons in 2006.

Of course, 100% of U.S. kraft pulp mills are unlikely to adopt biorefining, even in the long term. To estimate more realistic potential industry-wide environmental and energy impacts, we developed three biorefinery market penetration scenarios. The *Low* scenario was characterized by a 30-year period to reach market saturation (defined as 90% of technical potential). In the *Base* scenario, market saturation was reached in 20 years, and in the *Aggressive* scenario, 10 years. The large investments supporting the current rapid expansion in building of corn-ethanol plants in the U.S. suggests that capital availability alone is not a constraint on building pulp mill biorefineries, even at the *Aggressive* rate [1].

Figure 9 illustrates the potential CO<sub>2</sub> emissions benefits for the United States under the *Aggressive* biorefinery market penetration scenario. CO<sub>2</sub> benefits arise primarily because products of the biorefineries have low net lifecycle CO<sub>2</sub> emissions, and they displace fossil fuel derived electricity and petroleum transportation fuels with high lifecycle CO<sub>2</sub> emissions. Relative to continued use of Tomlinson technology, reductions in net CO<sub>2</sub> emissions could reach as much as 100 million metric tons per year nationally. This is equivalent to about 5% of the transportation sector CO<sub>2</sub> emissions in the U.S. in 2004. The main driver affecting the amount of the CO<sub>2</sub> benefit is the amount of purchased woody biomass utilized. By comparing results in Figure 9 for FTb and FTc, which use similar quantities of purchased biomass but have quite different outputs of electricity relative to fuel, one may note that displacement of grid electricity (generated with a fuel mix representing the average generating mix in the U.S.) results in greater CO<sub>2</sub> reductions per unit of biomass consumed than petroleum fuel displacement.

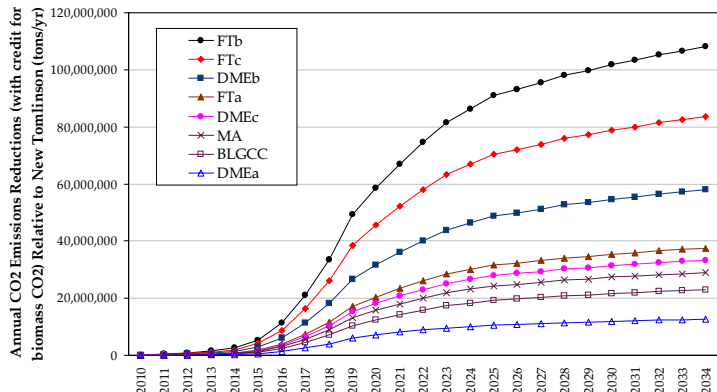
Figure 10 shows cumulative fossil fuel savings for each of the three market penetration scenarios over the first 25 years following initial deployment of biorefineries. Net fossil fuel savings relative to continued use of Tomlinson systems range from 1 to 5.5 quads (1.1 to 5.8 EJ) in the *Low* scenario and 3



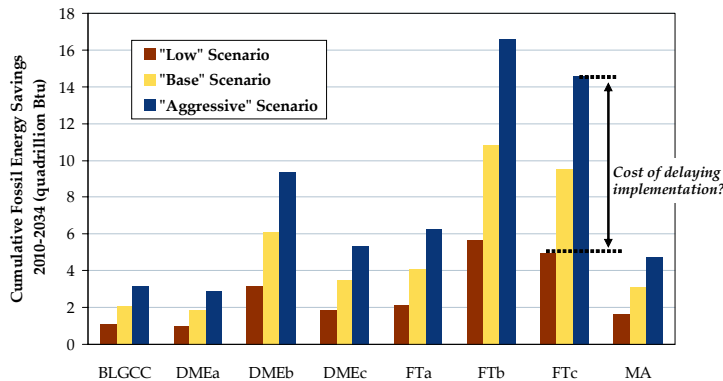
**Figure 8. Internal rates of return and net present values for all cases under the Reference Energy Price Scenario, with and without incentives included.**

to 17 quads (3.2 to 17.9 EJ) in the *Aggressive* scenario. The difference between the *Low* and *Aggressive* scenarios can be viewed as a proxy for the “lost” fossil fuel savings opportunity if implementation of pulp mill biorefineries is delayed or, alternatively, as the national payoff on government support for more aggressive commercial deployment.

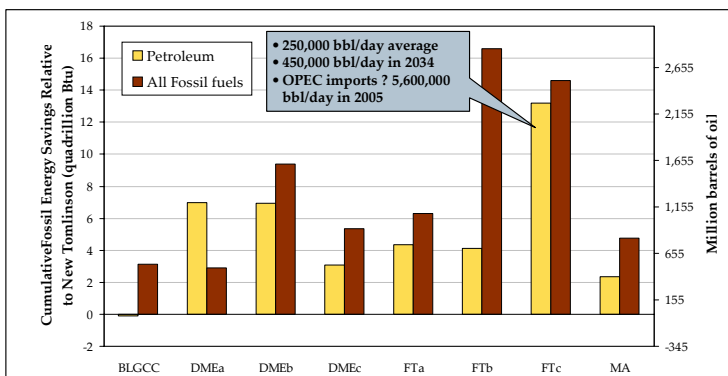
Figure 11 (for the *Aggressive* scenario) shows that



**Figure 9. Net annual CO<sub>2</sub> emissions reductions for the United States with biorefining relative to continued use of Tomlinson systems under the *Aggressive* biorefinery market penetration scenario. CO<sub>2</sub> emissions from carbon that originated in biomass and black liquor are not included in this CO<sub>2</sub> accounting, since this CO<sub>2</sub> is of recent photosynthetic origin, and replacement biomass growth will absorb an equivalent amount of CO<sub>2</sub> from the atmosphere. (Units here are short tons: 1 short ton = 0.907 metric tonne.)**



**Figure 10. Cumulative (25-year) net fossil fuel savings for the United States with biorefining relative to continued use of Tomlinson systems under different biorefinery market penetration scenarios. (One quadrillion Btu = 10<sup>15</sup> Btu = 1.055 EJ = 1.055 x 10<sup>18</sup> J.)**



**Figure 11. Cumulative (25-year) net fossil fuel and petroleum savings for the U.S. with biorefining relative to continued use of Tomlinson systems under the *Aggressive* market penetration scenario. (One quadrillion Btu = 10<sup>15</sup> Btu = 1.055 EJ = 1.055 x 10<sup>18</sup> J.)**

petroleum savings would represent a significant portion of the total fossil fuel savings. Cumulative petroleum displacement could exceed 2.2 billion barrels of oil over a 25-year period. By the end of this period, the corresponding annual petroleum savings (assuming the FTc configuration) would be approximately 165 million barrels per year, or 0.45 million barrels per day. This is equivalent to nearly 10% of the 2005 level of oil imports to the United States from OPEC countries.

## CONCLUSIONS

Gasification-based pulp mill biorefinery technologies, once fully commercialized, offer the potential for attractive investment returns and a revitalization of the pulp and paper industry. They also offer the potential for important contributions toward petroleum savings, emissions reductions, improved energy security, and rural economic development in the U.S. – contributions that could be two to three times larger than those from the existing corn-ethanol industry.

These potential private and public benefits arise, fundamentally, because of the integration of biorefining with pulp and paper production, such that the biorefinery is providing chemical recovery services, process steam, and process electricity in addition to exporting liquid fuel and perhaps some electricity. Integration can effectively enable more efficient use of biomass resources for liquid biofuel production compared to non-integrated biofuel production. Integration also can effectively reduce the capital investment required per unit of biofuel production to levels comparable to investments needed for coal-to-liquids facilities that are more than an order of magnitude larger than prospective pulp mill biorefineries. Finally, integration can effectively reduce the cost of producing a variety of gasification-based biofuels to ~\$1 per gallon of ethanol equivalent (~\$1.50/gallon gasoline equivalent).

All of the component technologies needed for gasification-based biofuels production at a pulp/paper mill biorefinery are either already commercially used (in non-biorefinery applications) or are undergoing pilot-scale demonstration, such that with some modest additional targeted research and development work and effective multi-industry/government partnerships to manage overall risk, commercial-scale facilities could begin to be built in the 2010-2015 timeframe. The one caveat to this conclusion is that development and demonstration at significant scale of synthesis catalysts for mixed-alcohols production that perform better than the one we modeled are needed to gain confidence that mixed-alcohols could be produced competitively as a fuel.

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