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Comparative analysis of efficiency, environmental impact, and process economics for mature biomass refining scenarios

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Abstract: Fourteen mature technology biomass refining scenarios – involving both biological and thermochemical processing with production of fuels, power, and/or animal feed protein – are compared with respect to process efficiency, environmental impact – including petroleum use, greenhouse gas (GHG) emissions, and water use–and economic profitability. The emissions analysis does not account for carbon sinks (e.g., soil carbon sequestration) or sources (e.g., forest conversion) resulting from land-use considerations. Sensitivity of the scenarios to fuel and electricity price, feedstock cost, and capital structure is also evaluated. The thermochemical scenario producing only power achieves a process efficiency of 49% (energy out as power as a percentage of feedstock energy in), 1359 kg CO_2 equivalent avoided GHG emissions per Mg feedstock (current power mix basis) and a cost of $0.0575/kWh ($16/GJ), at a scale of 4535 dry Mg feedstock/day, 12% internal rate of return, 35% debt fraction, and 7% loan rate. Thermochemical scenarios producing fuels and power realize efficiencies between 55 and 64%, avoided GHG emissions between 1000 and 1179 kg/dry Mg, and costs between $0.36 and $0.57 per liter gasoline equivalent ($1.37 – $2.16 per gallon) at the same scale and financial structure. Scenarios involving biological production of ethanol with thermochemical production of fuels and/or power result in efficiencies ranging from 61 to 80%, avoided GHG emissions from 965 to 1,258 kg/dry Mg, and costs from $0.25 to $0.33 per liter gasoline equivalent ($0.96 to

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$1.24/gallon). Most of the biofuel scenarios offer comparable, if not lower, costs and much reduced GHG emissions (>90%) compared to petroleum-derived fuels. Scenarios producing biofuels result in GHG displacements that are comparable to those dedicated to power production (e.g., >825 kg CO_2 equivalent/dry Mg biomass), especially when a future power mix less dependent upon fossil fuel is assumed. Scenarios integrating biological and thermochemical processing enable waste heat from the thermochemical process to power the biological process, resulting in higher overall process efficiencies than would otherwise be realized – efficiencies on par with petroleum-based fuels in several cases.

Keywords: biomass; biorefinery; efficiency; economics; environment; energy; biofuels

Introduction

The Role of Biomass in America's Energy Future (RBAEF) project was initiated to identify and evaluate paths by which biomass can make a large contribution to energy services. In the present study, we compare a variety of biomass conversion technologies – including both biological and thermochemical processing – and multiple biorefining configurations producing fuels, power, and/or animal feed protein. The work builds directly upon other papers appearing in this issue[1–7] and focuses on mature technology, an emphasis that is supported by the realization that answers to many important public policy questions – including evaluating the long-term potential of energy supply based on biomass-based technologies, the appropriate level of support these technologies merit, and reconciling land-use concerns – depends more on future achievable performance than on today's performance. Although there is inherent uncertainty in projecting future technology, there are also several factors that make such projections more robust than they might at first appear. The economics of both existing mature energy production technologies (e.g., oil refining) and projected mature biomass refining (herein) are dominated by the cost of feedstock, not the cost of processing. As a result, cost estimates for mature process technology can be substantially different from what is actually achieved, while overall production costs and conclusions about cost competiveness will not be affected significantly. Similarly, the process yields and efficiencies projected in this study – which determine quantities such as greenhouse gas (GHG) emission reductions – do not, in general, exhibit a large sensitivity to assumed performance parameters. In a scenario producing ethanol, Fischer-Tropsch F-T fuels and power, for example, a lower-than-assumed ethanol yield would be compensated for by higher yields of F-T fuels and/or power, resulting in relatively similar overall efficiency and fossil fuel displacement.

Technical and economic studies comparing processes involving biological and/or thermochemical biomass conversion exist in the literature. So and Brown,[8] for example, compared fast pyrolysis, simultaneous saccharification and fermentation (SSF), and acid hydrolysis, all producing ethanol. They concluded that the three processes have comparable capital, operating, and ethanol production costs, and recommended further research on the pyrolysis process to verify its feasibility. Wright and Brown[9] evaluated processes producing corn ethanol (dry grind process), cellulosic ethanol (enzymatic hydrolysis), methanol (gasification and synthesis), hydrogen (gasification), and F-T fuels (gasification and synthesis), assuming first-generation technology for the cellulosic biomass processes. The authors concluded that biological and thermochemical processing had comparable capital costs ($3.60–$5.70 per annual gallon gasoline equivalent) and operating costs ($1.05–$1.80 per gallon gasoline equivalent), and that both platforms could compete with corn ethanol when corn was priced at more than $3/bushel. Piccolo and Bezzo[10] compared ethanol produced biologically via separate hydrolysis and fermentation with that produced thermochemically through gasification and synthesis, concluding that the gasification process would require substantial technological improvements before it could be cost competitive with biological processing.

The RBAEF analysis, to our knowledge, is the first to compare the technologies in their mature context – i.e., a state of advancement such that additional R&D effort would

Table 1. RBAEF biorefinery scenarios.

Scenario
1. Ethanol + Rankine power
2. Ethanol + gas turbine with combined cycle (GTCC) power
3. Ethanol + F-T fuels + GTCC power
4. Ethanol + F-T fuels (w/once-through syngas) + CH_4
5. Ethanol + F-T fuels (w/recycle syngas) + CH_4
6. Ethanol + H_2
7. Ethanol + protein + Rankine power
8. Ethanol + protein + GTCC power
9. Ethanol + protein + F-T fuels
10. F-T fuels + GTCC power
11. Dimethyl ether + GTCC power
12. H_2 + GTCC power
13. Rankine power
14. GTCC power

offer only incremental improvement in cost reduction or benefit realization. As described in Lynd *et al.*,[1] the issue's introductory paper, performance parameters were selected consistent with the above operational definition according to a knowledgeable optimist's most likely estimate. This is neither the optimist's best-case estimate, nor the average, most likely estimate of experts spanning the optimist–pessimist spectrum. Estimates were made by members of the project team with some consultation with experts not part of the project, but without a systematic survey of such experts. Fourteen mature technology scenarios – briefly summarized below and listed in Table 1 – have been evaluated in this issue and are compared here with respect to process efficiency, environmental impact, and economic profitability.

1. Ethanol + Rankine power

As in all scenarios producing ethanol in this study, feedstock carbohydrate (cellulose and hemicellulose) is converted biologically in a configuration featuring ammonia fiber expansion (AFEX) pre-treatment and consolidated bioprocessing (CBP), with 95% hydrolysis yield and 95% fermentation yield for all sugars. The fermentation effluent (5% mass ethanol) is purified via energy-efficient distillation that incorporates an internal heat pump with optimal sidestream return (IHOSR) and molecular sieve adsorption. Distillation bottoms solids and liquids are separated with the liquid stream being fed to waste-water treatment that consists of anaerobic digestion – which produces methane-rich biogas that's captured – followed by treatment in an aerated lagoon and a clarification step, with 95% of treated water being returned to the process. Lignin-rich residues and methane-rich biogas from the biological conversion process are used to generate electricity in a conventional Rankine cycle having an efficiency of 33%. Details of this model are provided by Laser *et al.*[5] in this issue.

2. Ethanol + gas turbine combined cycle (GTCC) power

Ethanol is produced via the biological conversion process described above with lignin-rich residues being gasified in a pressurized, oxygen-blown gasifier, combined with biogas, and used to generate power at 49% efficiency in a gas turbine combined cycle (GTCC). Details of this model are provided by Laser *et al.*[5] in this issue.

3. Ethanol + F-T fuels + GTCC power

Ethanol is produced via the biological conversion process described above with lignin-rich residues being gasified in a pressurized, oxygen-blown gasifier – and biogas being partially oxidized in a separate unit – to produce synthesis gas used to produce F-T fuels in a single-pass configuration achieving 80% CO conversion. Unconverted syngas is used to generate electricity in a GTCC system. Details of this model are provided by Laser *et al.*[7] in this issue.

4. Ethanol + F-T fuels (w/once-through syngas) + CH_4

Ethanol is produced via the biological conversion process described above with lignin-rich residues being gasified in a pressurized, oxygen-blown gasifier – and biogas being partially oxidized in a separate unit – to produce synthesis gas used to produce F-T fuels in a single-pass configuration achieving 80% CO conversion. Biogas from the bioconversion process is separated into a methane-rich stream and sold as a natural gas (NG) coproduct instead of being converted to F-T liquids. Details of this model are provided by Laser *et al.*[7] in this issue.

5. Ethanol + F-T fuels (w/recycle syngas) + CH_4

Ethanol is produced via the biological conversion process described above with lignin-rich residues being gasified in a pressurized, oxygen-blown gasifier – and biogas being partially oxidized in a separate unit – to produce synthesis gas used to produce F-T fuels. Unconverted syngas is recycled back to the F-T synthesis block with unconverted light-end gases being combined with biogas methane to form a NG coproduct. Details of this model are provided by Laser *et al.*[7] in this issue.

6. Ethanol + H_2

Ethanol is produced via the biological conversion process described above with lignin-rich residues being gasified in a pressurized oxygen-blown gasifier – and biogas being partially oxidized in a separate unit – to produce synthesis gas from which hydrogen is separated via pressure swing adsorption (PSA). Details of this model are provided by Laser *et al.*[7] in this issue.

7. Ethanol + protein + Rankine power

Ethanol is produced via biological conversion similar to the process described above, but including aqueous protein extraction that occurs in two stages – one before AFEX pre-treatment, and one after achieving 84% total extraction. Lignin-rich residues and methane-rich biogas from the biological conversion process are used to generate electricity in a conventional Rankine cycle. Details of this model are provided by Laser *et al.*[7] in this issue.

8. Ethanol + protein + GTCC power

Ethanol and protein are coproduced via biological conversion as described above. Lignin-rich residues are gasified in a pressurized, oxygen-blown gasifier, combined with biogas, and used to generate power in a GTCC system. Details of this model are provided by Laser *et al.*[7] in this issue.

9. Ethanol + protein + F-T fuels

Ethanol and protein are coproduced via biological conversion as described above. Lignin-rich residues are gasified in a pressurized, oxygen-blown gasifier – and biogas is partially oxidized in a separate unit – to produce synthesis gas used to produce F-T fuels in a single-pass configuration. Unconverted syngas is used to generate electricity in a GTCC system. Details of this model are provided by Laser *et al.*[7] in this issue.

10. F-T fuels + GTCC power

Switchgrass feedstock is gasified in a pressurized, oxygen-blown gasifier, producing synthesis gas used to produce F-T fuels in a single-pass configuration. Unconverted syngas is converted to electricity in a GTCC system. Details of this model are provided by Larson *et al.*[4] in this issue.

11. DME + GTCC power

Switchgrass feedstock is gasified in a pressurized, oxygen-blown gasifier, producing synthesis gas used to produce dimethyl ether (DME) in a single-pass configuration. Unconverted syngas is converted to electricity in a GTCC system. Details of this model are provided by Larson *et al.*[4] in this issue.

12. H_2 + GTCC power

Switchgrass feedstock is gasified in a pressurized, oxygen-blown gasifier, producing synthesis gas from which hydrogen is separated via pressure swing adsorption. Unconverted syngas is converted to electricity in a GTCC system. Details of this model are provided by Larson *et al.*[4] in this issue.

13. Rankine power

Switchgrass feedstock is used to generate electricity in a conventional Rankine cycle having an efficiency of 33%. Details of this model are provided by Jin *et al.*[3] in this issue.

14. GTCC power

Switchgrass feedstock is gasified in a pressurized oxygen-blown gasifier and used to generate power at 49% efficiency in a GTCC system. Details of this model are provided by Jin *et al.*[3] in this issue.

Each scenario assumes a scale of 4535 dry Mg feedstock/day, the use of switchgrass having a delivered cost of $49/Mg, a capital structure of 35% debt financing, electricity price of $0.05/kWh, internal rate of return of 12% and a

2006 cost year.* As part of the comparison, sensitivity of the scenarios to several variables – including fuel and electricity price, feedstock cost, and capital structure – was also evaluated.

As noted in Lynd *et al*.,[1] this issue's introductory paper, different technologies differ substantially with respect to their current state of development, and may also differ in the extent to which features of mature technology can be anticipated. While comparisons are presented in this paper on a side-by-side basis, we recognize uncertainties inherent in comparing performance and cost projection for different mature technologies. For thermochemical processing, cost and performance for most of the unit operations (e.g., gasification, power generation via GTCC, fuel synthesis) are largely based on existing commercial or demonstration plants, though some key projected improvements, such as integrated tar cracking and gas clean-up, have yet to be realized at scale. Fermentative production of ethanol is the basis for production of over 38 billion liters (10 billion gallons) annually, but a key aspect of the mature biological processing scenarios, CBP, is still under development. Detailed understanding and well-developed predictive capability support the feasibility of organism development for CBP.[5] A substantial effort to standardize costs and accounting assumptions was made in an effort to make results for the various technologies as comparable as possible, as described in Lynd *et al*.[1] In particular, the same designs, performance assumptions and costs were assumed for stand-alone power generation, power generation from residues in cellulosic ethanol production, and power cogeneration in conjunction with production of thermochemical fuels. For all scenarios examined in this study, the largest capital cost – ranging from 70% to 100% – is for operations necessary for power and steam generation, including feed preparation, gasification, syngas cooling and clean-up, air separation, and the power island. Cost estimates for unit operations directly involved in biological fuel production and production of thermochemical fuels were developed separately. This introduces an element of uncertainty in making cross-technology cost comparisons. Separately developed cost estimates are, however, difficult to avoid and may well reflect reality in light of the rather different equipment involved: largely high-pressure and gas-phase for thermochemical fuel synthesis, largely low-pressure and aqueous-phase for biological fermentation.

Process efficiency

The mature technology designs make extensive use of 'waste' heat that would otherwise be lost to the environment. Although waste-heat utilization involves added capital cost and can be difficult to accomplish at large scales, the payoff is significantly higher process efficiencies, resulting in lower operating costs. Overall process efficiency – defined as energy produced as fuel, power, and/or feed† divided by the lower heating value of the feedstock – for the evaluated scenarios is presented in Fig. 1. The dedicated biomass power scenarios are least efficient (33% for Rankine; 49% for GTCC), followed by those producing thermochemical fuels and electricity (55% for DME/GTCC, 58% for F-T/GTCC, and 64% for H_2/GTCC). Scenarios involving ethanol production via biological conversion are the most efficient; especially those coproducing thermochemical fuels, which achieve efficiencies from 70% to 80%. The corresponding fossil fuel displacement ratios (i.e., renewable energy produced divided by fossil energy input for a given fuel) for these scenarios – assuming that 7% of the feedstock energy value is required as fossil fuel input as presented in the paper by Sokhansanj *et al*.[2] for mature technology at a switchgrass yield of 20 Mg/ha – is between 10.0 and 11.4. As a basis of comparison, the efficiency for petroleum refining is typically 70% for fuels production and 85% for all products;‡ for corn ethanol via dry milling, it's about 45%.[11] Fossil fuel displacement ratios for gasoline and corn ethanol are 0.80 and 1.4, respectively.[11] The high efficiency of configurations that integrate biological and thermochemical processing as arises because waste heat from the thermochemical portion of the plant that would otherwise

* The purchased equipment cost year is indexed to the analysis cost year, 2006, using the Chemical Engineering Plant Cost Index. Costs for chemicals are indexed to the analysis cost year using the Industrial Chemicals Producer Price Index published by the US Department of Labor Bureau of Labor Statistics.

† The energy content of the feed protein (21.4 MJ/kg lower heating value) is used in the efficiency calculation.

‡ Based on refinery outputs from EIA (www.eia.doe.gov) and external inputs/efficiencies from GREET.39.

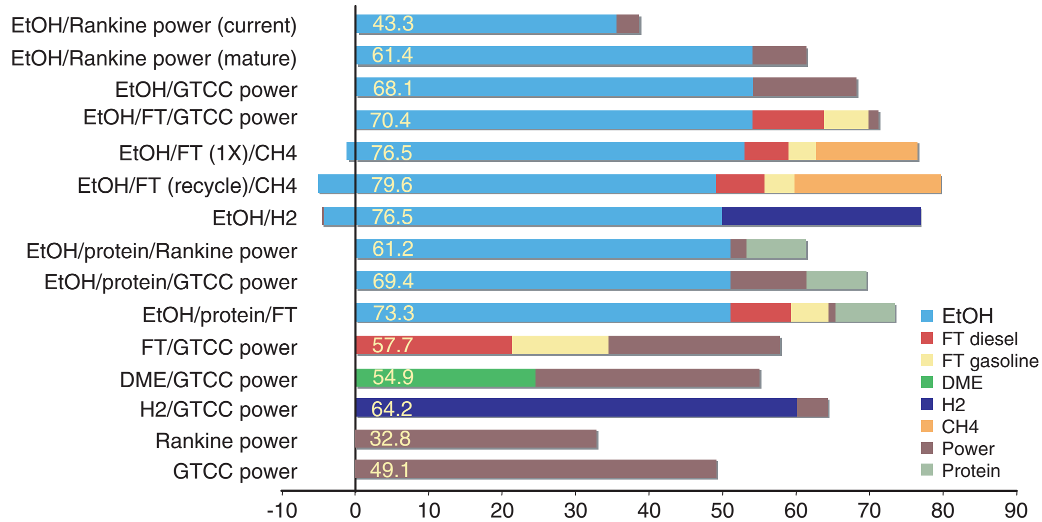

Figure 1. Processing efficiencies for biorefinery scenarios (energy out as percent of feedstock lower heating value).

be lost is used to meet much of the energy required by the biological process.

Environmental and energy impact

Metrics used here to evaluate environmental impact of the various biorefinery configurations include GHG displacement, petroleum displacement, carbon dioxide emissions, petroleum use, and water use. GHG displacement for a given scenario is dependent upon the amount of biofuel, electricity, and/or protein produced, and the GHGs resulting from the equivalent status quo (i.e., petroleum fuels, current power mix, and soybean animal feed protein). For biofuels, GHG displacement is a function of GHGs resulting from petroleum fuels, the biofuel-to-petroleum fuel displacement ratio, and the biofuel yield. Similarly, for power, it depends on GHGs resulting from the current power mix, the biorefinery power yield, and the power transmission efficiency. For protein it depends on the GHGs resulting from current animal feed protein production and the biorefinery protein yield. Petroleum displacement is also a function of the amount of biofuel, electricity, and/or protein made and the oil required in the equivalent status quo. Both GHG and petroleum displacement must also account for the GHGs emitted and petroleum used in biomass feedstock production.

Equations 1 and 2 are used to estimate greenhouse gas displacement and petroleum displacement, respectively:

$$D_{GHG} = \left(\left[GHG_{oil} * \frac{1}{EQ} * Y_{biofuel} \right] + \left[GHG_{power} * Y_{power} * \eta_t \right] \right) * \tag{1}$$

$$D_{oil} = \left(\left[P_{oil} * \frac{1}{EQ} * Y_{biofuel} \right] + \left[P_{power} * Y_{power} * \eta_t \right] \right) * L \tag{2}$$

where:

D_{GHG} = greenhouse gas displacement (kg CO_2 equivalent/dry Mg biomass)

D_{oil} = petroleum displacement (GJ petroleum/dry Mg biomass)

EQ = biofuel:petroleum fuel displacement ratio (GJ biofuel/GJ petroleum fuel)

LHV = biomass lower heating value (GJ biomass/dry Mg biomass)

GHG_{oil} = GHGs (CO_2 equivalent) resulting from petroleum fuel on a well-to-wheel basis (kg GHG/GJ petroleum fuel)

GHG_{power} = GHGs (CO_2 equivalent) resulting from power on a fuel extraction-to-end use basis (kg GHG/GJ power)
$GHG_{protein}$ = GHGs (CO_2 equivalent) resulting from animal feed protein on full life cycle basis (kg GHG/kg protein)
$GHG_{biomass}$ = GHGs (CO_2 equivalent) resulting from biomass production, including farming, harvesting, and transportation to biorefinery (kg GHG/dry Mg biomass)
P_{oil} = petroleum used to produce petroleum fuel (GJ petroleum/GJ petroleum fuel)
P_{power} = petroleum used to produce power (GJ petroleum/GJ power)
$P_{protein}$ = petroleum used to produce animal feed protein (GJ petroleum/kg protein)
$P_{biomass}$ = petroleum used to produce biomass (GJ petroleum/dry Mg biomass)
$Y_{biofuel}$ = biofuel yield (GJ biofuel/GJ biomass)
Y_{power} = power yield (GJ power/GJ biomass)
$Y_{protein}$ = protein yield (kg protein/dry Mg biomass)
η_t = power transmission efficiency

The first term in each equation calculates displacement resulting from biofuels production in the biorefinery; the second, displacement from power production; and the third from protein coproduction (if applicable). The final term accounts for GHG emissions and petroleum used during production of the biomass feedstock, and therefore has a negative sign.

Field-to-wheels carbon dioxide emissions account for emissions from biomass production; biofuels production; biofuel transportation, storage, and distribution; and vehicle operation and are calculated using the following equations:

$$E_{FTW} = E_{biomass} + E_{process} + E_{TSD} + E_{vehicle} - U_{biomass} \quad (3)$$

$$E_{biomass} = C_{biomass}\left(\frac{1}{Y_{fuel}}\right)\left(\frac{1}{VE}\right) \quad (4)$$

$$E_{process} = \left[\left(C_{process} - C_{credit}\right)\left(\frac{1}{F}\right)\right]\left(LHV_{gasoline}\right)\left(\frac{1}{VE}\right) \quad (5)$$

$$E_{TSD} = C_{TSD}\left(\frac{1}{Y_{fuel}}\right)\left(\frac{1}{VE}\right) \quad (6)$$

$$E_{vehicle} = \left(C_{combust}\right)\left(LHV_{gasoline}\right)\left(\frac{1}{VE}\right) \quad (7)$$

$$U_{biomass} = E_{process} + E_{vehicle} \quad (8)$$

where:
E_{FTW} = field-to-wheel emissions for biofuel production (g CO_2/km)
$E_{biomass}$ = emissions from biomass production (g CO_2/km)
$E_{process}$ = emissions from biofuel production process (g CO_2/km)
E_{TSD} = emissions from biofuel transportation, storage, and distribution (g CO_2/km)
$E_{vehicle}$ = emissions from vehicle operation using biofuels (g CO_2/km)
$U_{biomass}$ = carbon uptake resulting from biomass growth (g CO_2/km)
$C_{biomass}$ = emissions resulting from biomass production (g CO_2/dry Mg biomass)
Y_{fuel} = biofuel yield (liters gasoline equivalent/dry Mg biomass)
VE = vehicle efficiency (km/L)
$C_{process}$ = emissions from biofuel process (g CO_2/hr)
C_{credit} = coproduct emissions credit (g CO_2/hr)
F = biofuel production rate (GJ/hr)
$LHV_{gasoline}$ = lower heating value of gasoline (GJ/L)
C_{TSD} = emissions from transportation, storage, and distribution of biofuel (g CO_2/GJ fuel)
$C_{combust}$ = emissions from biofuel combustion in vehicle (g CO_2/GJ fuel)

Here, it is assumed that CO_2 released during fuel production and vehicle operation – which involves only biomass and no fossil fuel in these scenarios – exactly matches that assimilated by the feedstock biomass during growth (i.e., Eqn 8). Field-to-wheel emissions are therefore primarily dependent upon feedstock production; fuel yield; fuel transportation, storage, and distribution; and vehicle efficiency. We have not accounted for carbon sinks (e.g., soil carbon sequestration) or sources (e.g., forest conversion) resulting from land use changes such as those analyzed by Searchinger *et al*.[12] and Fargione *et al*.[13] We do recognize the importance of such considerations, though they are beyond the scope of this study for which the focus is biomass processing. Wu *et al*.[14] conducted a more detailed fuel lifecycle assessment for a subset of the scenarios presented in this study (Table 1, Scenarios 1, 2, 3, 7, 10, and 11). Their analysis, which assumes that 39% of the switchgrass feedstock is grown on cropland, does account for soil carbon sequestration benefits resulting from converting this land from conventional row crops to switchgrass.

Petroleum use for the mature biorefining scenarios – which is limited to biomass production and fuel transportation, storage, and distribution, as no petroleum is used in the biorefinery – is calculated using Eqn 9:

$$OIL = \left(O_{biomass} + O_{TSD}\right)\left(\frac{1}{Y_{fuel}}\right)\left(\frac{1}{VE}\right) \tag{9}$$

where:

OIL = petroleum requirement for biofuel production (GJ/km)

$O_{biomass}$ = petroleum required for biomass production (GJ/dry Mg biomass)

O_{TSD} = petroleum required for biofuel transportation, storage, and distribution (GJ/dry Mg biomass)

Values for and sources of the parameters used in the above calculations are listed in Table 2. Figures 2 and 3 present results for GHG and petroleum displacement, respectively. Scenarios producing biofuels result in GHG displacements that are comparable to those dedicated to power production (e.g., > 825 kg CO_2 equivalent/dry Mg biomass), especially when a future power mix less dependent upon fossil fuel is assumed. This runs counter to the conventional notion that potential GHG emissions reductions are higher for biomass power production than for biofuels production,[15,16] since it is typically assumed that biopower would replace coal power. While GHG emissions per unit delivered energy are indeed much greater for electricity than for fuels with the current power mix (coal 50.5%, nuclear 20.4%, natural gas 18.0%, hydro 6.8%, oil 2.3%, other renewables 2.1% (www.eia.doe.gov)) – 183 vs. 95 kg CO_2 equivalent/GJ (Table 2) – the potentially high biofuel yields calculated in many of the mature technology scenarios compared to the mature power-only scenarios lead to comparable GHG emissions displacement potential when a future power mix is assumed. As the electricity system becomes decarbonized to a greater extent in the future,[17] the GHG benefit of biomass used for fuel production will increase relative to the benefit of using biomass for power generation.

When considering petroleum displacement, it's important to note that only about 2% of the current US power mix is derived directly from oil (www.eia.doe.gov), and little petroleum is used in the production of power from other sources (Table 2). In fact, petroleum displacement for dedicated electricity production from biomass is zero or negative – i.e., more petroleum is required to produce the biomass than is displaced by the power produced from the biomass – for the scenarios evaluated here. Fuels produced using biological conversion also displace more petroleum than do fuels produced solely from thermochemical processing, as biological conversion scenarios have higher fuel yields (recall Fig. 1).

Figure 4 presents results for CO_2 emissions and petroleum use as a percent change relative to a conventional gasoline base case. Scenarios involving biological ethanol all result in CO_2 emissions that are about 90% lower than the gasoline base case and petroleum use that is more than 92% lower. If soil carbon sequestration is accounted for – using the same value as assumed by Wu *et al*.[14] (53,471 g CO_2/dry Mg biomass) – then CO_2 emissions for the bioethanol scenarios become at least 96% lower than the base case. The thermochemical fuels scenarios result in 78%, 84%, and 91% CO_2 reduction and 84%, 89%, and 94% petroleum use reduction for DME, F-T fuels, and H_2, respectively. When soil carbon sequestration is accounted for, CO_2 emissions become 91%, 94%, and 96% lower than the base case for DME, F-T fuels, and H_2, respectively. These results correspond reasonably well to Wu *et al*.,[14] who found that GHG emissions are reduced by 82% to 87% (E85 basis) and petroleum use by more than 90% relative to the base case.

Figures 5(a) and 5(b) illustrate the overall water flows through the integrated bioprocessing/thermochemical and standalone thermochemical configurations, respectively. Water balance and make-up requirement results for each

Table 2. Parameter values and sources for GHG and petroleum displacement and emissions calculations.

Parameter (units)	Value	Sources
EQ (GJ biofuel/GJ petroleum fuel)	1.08 (ethanol)[a] 1.00 (TC fuels)b	Kenney T, 2004, personal communication
LHV (GJ biomass/dry Mg biomass)	17.17 (all except protein)[c] 16.95 (protein scenarios)[d]	Ref. 5 Ref. 7
GHG_{oil} (kg GHG/GJ petroleum fuel)	94.66 (reformulated gasoline) 94.53 (low sulfur diesel)	Ref. 39
GHG_{power} (kg GHG/GJ power)	183 (current power mix)[e] 96 (future power mix)[f]	www.eia.doe.gov; Ref. 39 Refs 38, 39
$GHG_{protein}$ (kg GHG/kg protein)	1.51 (soy protein)	Ref. 39
$GHG_{biomass}$ (kg GHG/dry Mg biomass)	96.2 (switchgrass)	Ref. 39
P_{oil} (GJ petroleum/GJ petroleum fuel)	1.20 (reformulated gasoline) 1.09 (low sulfur diesel)	Ref. 39
P_{power} (GJ petroleum/GJ power)	0.10 (current power mix)[e] 0.02 (future power mix)[f]	www.eia.doe.gov; Ref. 39 Refs 38, 39
$P_{protein}$ (GJ petroleum/kg protein)	0.01 (soy protein)	Ref. 39
$P_{biomass}$ (GJ petroleum/dry Mg biomass)	0.74 (switchgrass)	Ref. 39
$Y_{biofuel}$ (GJ biofuel/GJ biomass)	0.25 – 0.85 (scenario dependent)	This study
Y_{power} (GJ power/GJ biomass)	–0.05–0.49 (scenario dependent)	This study
$Y_{protein}$ (kg protein/dry Mg biomass)	0.09	Ref. 7
η_t	0.92	Ref. 39
$C_{biomass}$ (g CO2/dry Mg biomass)	86.3 (switchgrass)	Ref. 39
Y_{fuel} [L gasoline equivalent/Mg]	130–435 (scenario dependent) (31.2–104.1 gal GEq/dry ton)	This study
VE (km/L)	8.33 (gasoline ICE) (19.6 miles/gallon)	Ref. 39
$C_{process}$ (Mg CO_2/hr)	165–397 (scenario dependent)	This study
C_{credit} (Mg CO_2/hr)	0–95 (scenario dependent)	This study
F (GJ/hr)	788–2,632 (scenario dependent)	This study
$LHV_{gasoline}$ (GJ/L)	0.0320	Ref. 39
$C_{combust}$ (g CO_2/GJ fuel)	0 (H_2) – 75,726 (gasoline)	Ref. 39

[a] Accounts for efficiency benefit that can be realized by designing and tuning an engine to run specifically on ethanol.

[b] Thermochemical fuels assumed to have same engine efficiency as petroleum diesel compression ignition engine.

[c] Represents late-season switchgrass that is higher in lignin and lower in protein content.

[d] Represents early-season switchgrass that is higher in protein and lower in lignin content.

[e] Calculated assuming current (2003) power mix in the USA: coal (50.46%); oil (2.27%); natural gas (17.96%); hydropower (6.81%); nuclear (20.43%); other renewable (2.07%); (www.eia.doe.gov); Emissions per fuel type for current power mix (kg GHG/GJ power): coal (296); oil (252); natural gas (155);[39] Petroleum per fuel type for current power mix (GJ petroleum/GJ power): coal (0.0466); oil (3.1621); natural gas (0.0088).[39]

[f] Calculated assuming a future power mix (2020) in the USA: coal (33.23%); oil (0.30%); natural gas (21.95%); hydropower (10.06%); nuclear (19.51%); other renewable (14.94%);[38] Emissions per fuel type for future power mix (kg GHG/GJ power): coal (208); oil (232); natural gas (116);[39] Petroleum per fuel type for future power mix (GJ petroleum/GJ power): coal (0.0329); oil (2.9092); natural gas (0.0066).[39]

Power Mix (%)	Current	A Future
Coal	50.46	33.23
Oil	2.27	0.30
Natural Gas	17.96	21.95
Hydropower	6.81	10.06
Nuclear	20.43	19.51
Renewables	2.07	14.94

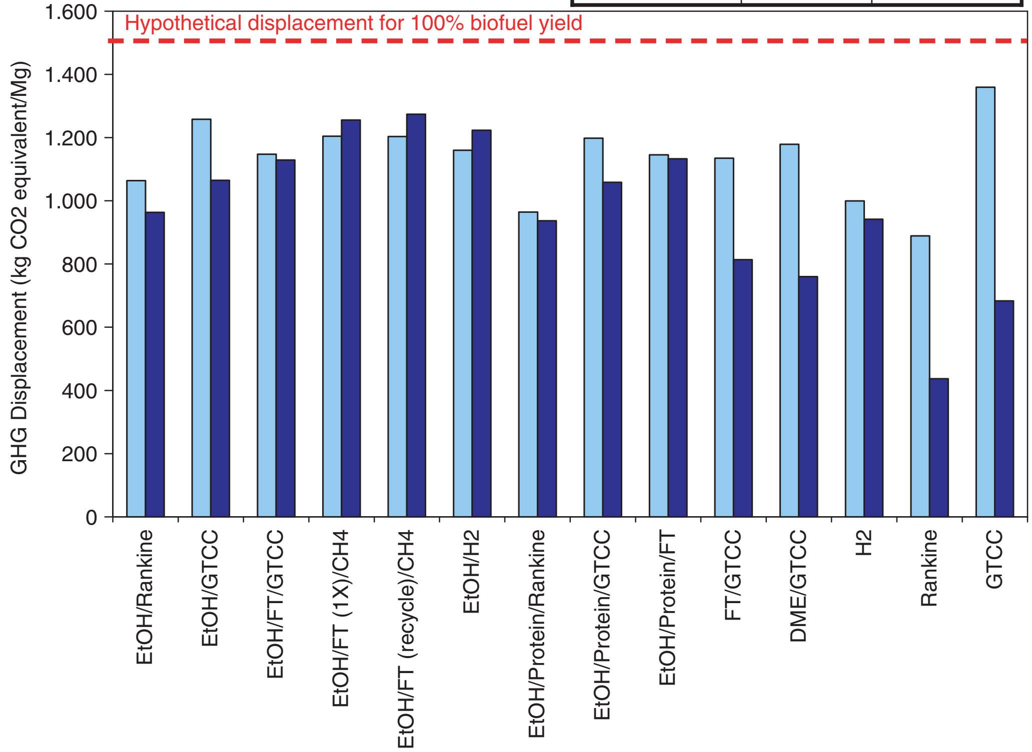

Figure 2. Greenhouse gas displacement for mature biorefinery scenarios (kg GHG/dry Mg feedstock). Current power mix: coal 50.5%, nuclear 20.4%, natural gas 18.0%, hydro 6.8%, oil 2.3%, other renewables 2.1% (www.eia.doe.gov). Future power mix: coal 33.2%, natural gas 22.0%, nuclear 19.5%, other renewables 14.9%, hydro 10.1%, oil 0.3%.[39]

scenario are listed in Tables 3(a) and 3(b). In the integrated scenarios without protein coproduction, the total make-up water requirement – to account for cooling tower evaporation and windage losses, water in vapor streams vented to atmosphere, and water consumed in hydrolysis reactions – ranges from 5.8 to 6.5 liter per liter gasoline equivalent, denoted L GEq throughout the rest of the paper. Make-up water for only the biological processing portion of the plant producing ethanol is about 4.0 L/L GEq. As a point of reference, this value compares favorably to corn ethanol production which requires, on average, about 6.1 L/L GEq (4 L/L ethanol),[18] or about 6.6 L/L GEq when water needed for process power is included (0.17 kWh/L ethanol[19]).[§] Estimates of water use for petroleum fuels vary significantly, from as low as 1–2.5 L water/L GEq[20] to several-fold higher – 10–40 L/L GEq, for example.[21] Conventional thermoelectric power requires about 15.8 L/L GEq (1.8 L/kWh). [22] We note that comparisons between configurations in this study are on common basis; the same cannot necessarily be said of comparisons between this study and others.

[§] Estimate is as follows: 0.17 kW/L ethanol*1.89 L water/kW ≈ 0.33 L water/L ethanol ≈ 0.5 L water/L gasoline equivalent. Corn ethanol power requirement from Wallace et al.19; water for thermoelectric power production from Torcellini[22].

Power Mix (%)	Current	A Future
Coal	50.46	33.23
Oil	2.27	0.30
Natural Gas	17.96	21.95
Hydropower	6.81	10.06
Nuclear	20.43	19.51
Renewables	2.07	14.94

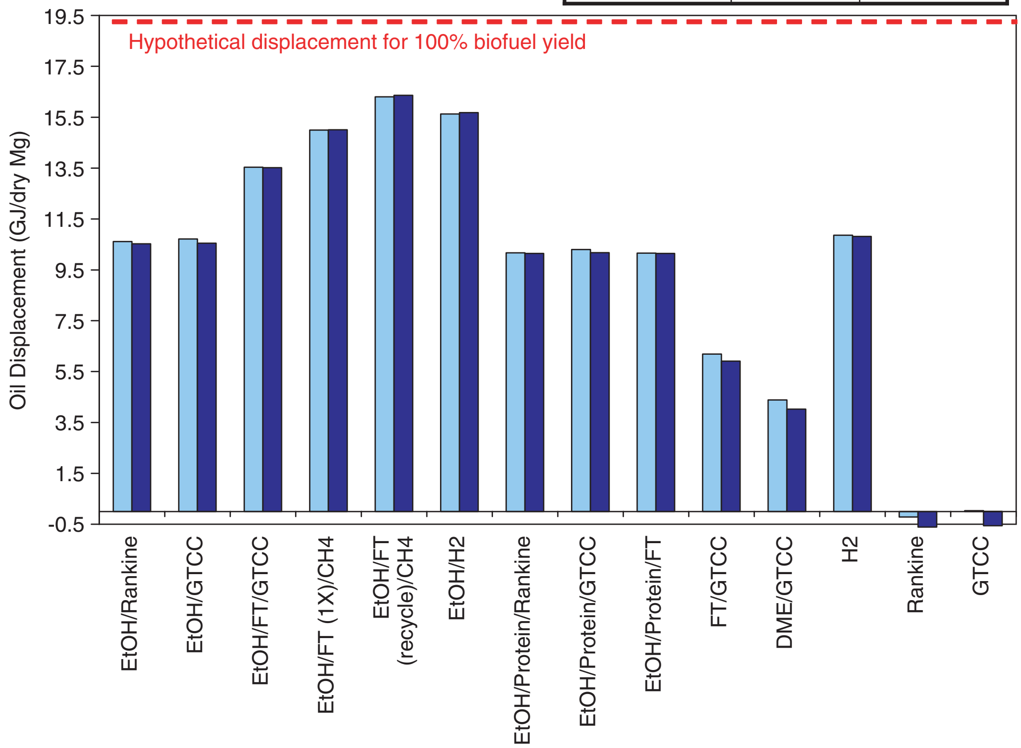

Figure 3. Petroleum displacement for mature biorefinery scenarios (GJ petroleum/dry Mg feedstock). Current power mix: coal 50.5%, nuclear 20.4%, natural gas 18.0%, hydro 6.8%, oil 2.3%, other renewables 2.1% (www.eia.doe.gov). Future power mix: coal 33.2%, natural gas 22.0%, nuclear 19.5%, other renewables 14.9%, hydro 10.1%, oil 0.3%.[38]

Integrated biorefineries coproducing animal feed protein, which involves an aqueous extraction process, use more water, ranging from 9.6 to 10.5 L/L GEq. The water consumed during protein coproduction in these cases—as moisture in the product and vapor vented from scrubbers—is about 11.0 L/kg protein, which is on par with that for soy meal production (12.5 L water/kg soy protein; calculated from[23]). Water use in the protein coproduction scenarios can likely be reduced—by recovering scrubber vapor losses or reducing process cooling load, for example. Such optimization was not undertaken in the work reported here.

The standalone thermochemical fuels and/or power scenarios required still more process water, ranging from 12.6 L/L GEq for the H2/GTCC power scenario, to 16.7 L/L for Rankine power. Unlike the cases involving biological processing, no special effort was made to reduce water consumption in the thermochemical processing designs; opportunities for doing so undoubtedly exist – for example, adding onsite water treatment so that process blowdown can be recycled, which would reduce the make-up water requirement by about 10%.

In petroleum refining, corn dry milling, and conventional power generation, cooling water comprises the largest fraction of make-up process water demand – an estimated 50%, 70%, and 100%, respectively.[22, 24, 25] The same is true of the biomass refining designs developed in this study for

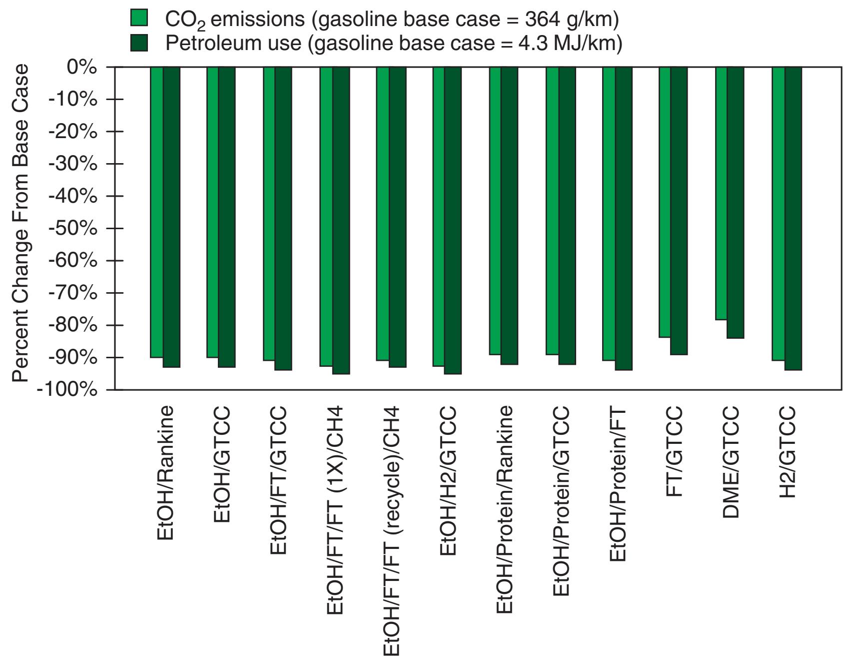

Figure 4. Field-to-wheel CO_2 emissions and petroleum use for mature biorefinery scenarios relative to a conventional gasoline base case. Vehicle efficiency is 8.33 km/L (19.6 miles/gallon); base case emissions are 349 g CO_2/km; base case petroleum use is 4.31 MJ/km.[39]

which cooling water accounted for 79–94% of the make-up demand. Evaporative cooling via cooling water towers is currently used in oil refineries, corn dry mills, and power plants,[22, 24, 25] and is used in the biorefinery designs evaluated here. Alternatives, such as air cooling, are currently being developed and incorporated into industrial processes as a means to reduce water consumption.[26]

Process water demand, however, is a small fraction of water demand in the field. In corn ethanol production, for example, processing requires about 4 liters of water per liter ethanol produced, while corn production requires 313 L water/kg corn (2100 gallons water/bushel), or about 780 L water/L ethanol.[27] More recent analysis by Wu and Wang[28] evaluates water demand for corn production on a regional basis, with results ranging from 7.1 L water/L ethanol (Ohio, Indiana, Illinois, Iowa, Missouri – 52% of US ethanol production) to 13.9 L/L (Michigan, Wisonsin, Minnesota – 14% of US ethanol production) to 320.6 L/L (North Dakota, South Dakota, Nebraska, Kansas – 30% of US ethanol production). The focus of their study is on water actually consumed by the corn plant during growth as opposed to total water applied to the field (Wu M, 2008, personal communication), suggesting that water demand for corn is perhaps less intensive than commonly assumed. Herbaceous perennial energy crops, such as switchgrass, will likely require less water than corn. McLaughlin *et al.*[29] estimate that switchgrass production requires about three times less water than corn on the basis of biomass for biofuel production (i.e., grain only for corn). Even so, water requirements for feedstock production would still be several-fold greater than that for ethanol production.

Process economics

The profitability of the biorefining scenarios is assessed here via discounted cash flow analysis using the same parameter values presented in Laser *et al.*,[5] Table 15. Capital costs are also compared. Finally, sensitivity of the process economics to fuel price, electricity price, feedstock cost, and capital structure is evaluated.

Figures 6(a) and 6(b) present internal rate of return as a function of fuel price for the mature technology biorefinery scenarios at a plant scale of 4535 dry Mgs/day and electricity price of $0.05/kWh – the approximate average US industrial price over the last 10 years (www.eia.doe.gov). The figures

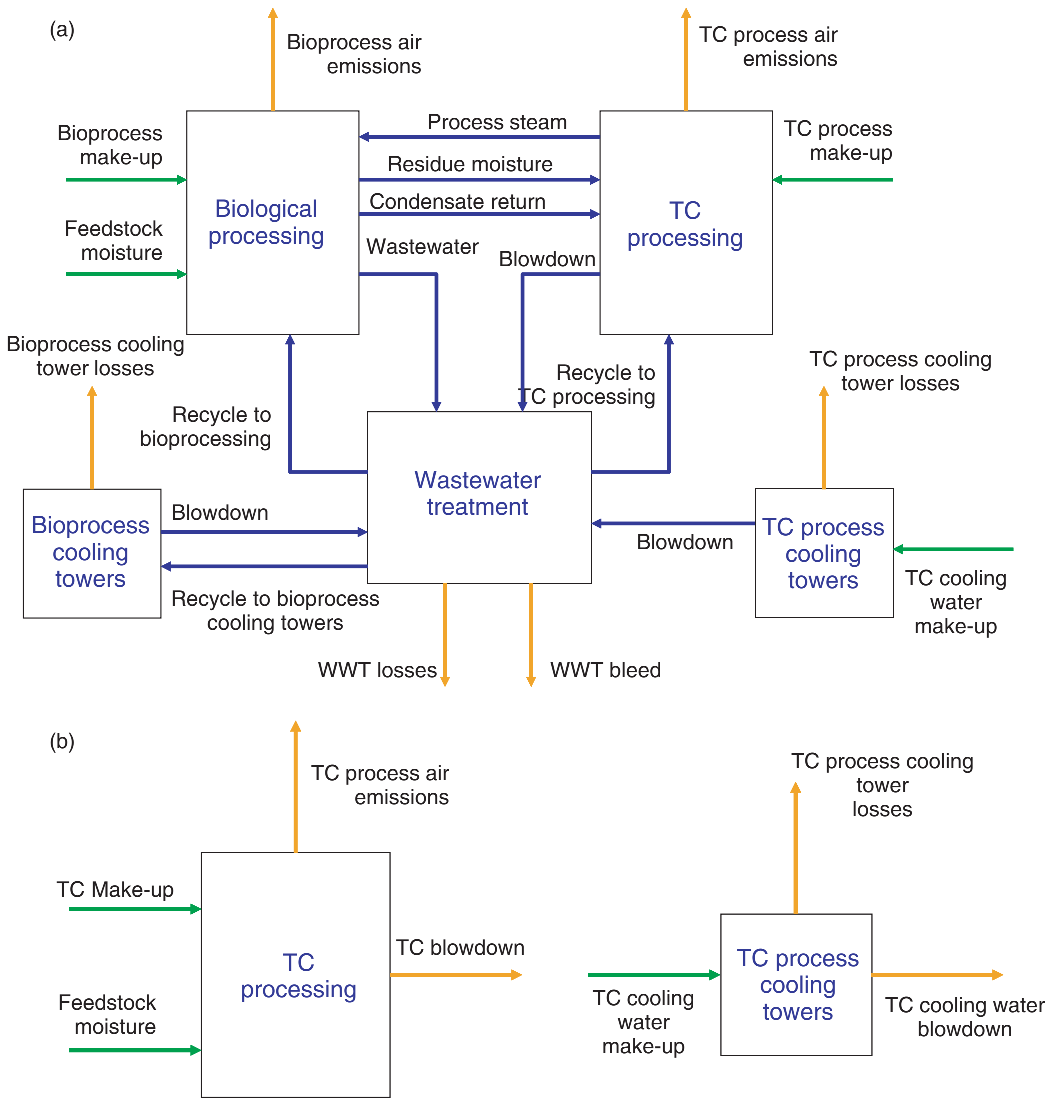

Figure 5(a). Overall water flows through biorefinery scenarios with integrated biological and thermochemical processing. (b). Overall water flows through biorefinery scenarios with stand-alone thermochemical processing.

also indicate the annual averages for US crude and gasoline wholesale prices from 2002 to 2006 (annual averages for Cushing, OK, West Texas Intermediate crude spot price FOB). As would be expected, the internal rate of return (IRR) for the dedicated power scenarios remains constant as a function of fuel price, with the Rankine and GTCC scenarios realizing 4.3 and 8.4 %, respectively, while IRR increases with fuel price for the fuels scenarios. The dedicated thermochemical scenarios producing F-T fuels/GTCC power and DME/GTCC power achieve greater than 10% IRR at a fuel prices of \$0.46 and \$0.49/L GEq (\$1.76 and \$1.85/gallon), respectively. At \$0.79/L GEq (\$3.00/gallon), the IRR rises to 17% for DME and 19% for F-T fuels. The H2/GTCC power scenario is considerably more profitable, achieving 10% IRR at fuel prices above \$0.34/L GEq (\$1.27/gallon) and about 35% at \$0.79/L GEq (\$3.00/gallon). It must be stressed, however, that hydrogen as a large-scale transportation fuel would require huge investments in distribution and end-use infrastructures – costs that are not included in these results. Post-production costs for hydrogen would be significantly larger than for the other fuels evaluated here. According to Wang *et al.*,[30] for example, it would cost about \$1.4 million to convert a current filling station to dispense 189,270 L GEq per month (50,000 gallons/month). They estimate the filling

Table 3a. Overall process water balance and make-up water requirements for integrated biorefinery scenarios.

	Scenario									Petroleum	Corn	Thermo
Stream	1	2	3	4	5	6	7	8	9	Fuels	Ethanol	Power
In (kg/hr)												
Bioprocess make-up	217,656	217,862	217,862	217,862	217,862	217,862	380,713	380,713	380,713			
Feedstock moisture	47,421	47,421	47,421	47,421	47,421	47,421	47,241	47,241	47,241			
TC cooling water make-up	139,189	198,841	198,841	198,841	198,841	198,841	139,189	198,841	198,841			
TC make-up	31,807	26,416	39,640	31,804	64,898	36,449	30,479	25,056	36,791			
Combustion release	55,808	55,808	27,238	41,063	7,652	7,652	55,808	55,808	26,550			
TOTAL	491,881	546,348	531,002	536,990	536,674	508,225	653,429	707,658	690,136			
Out (kg/hr)												
Bioprocess emissions	1,635	1,635	1,635	1,635	1,635	1,635	23,569	23,569	23,569			
TC emissions	81,714	81,714	66,369	72,357	72,040	43,591	83,891	83,891	66,369			
WWT bleed	65,975	66,007	66,007	66,007	66,007	66,007	62,290	62,290	62,290			
WWT losses	1,041	1,047	1,047	1,047	1,047	1,047	991	991	991			
Bio cooling tower losses	200,290	200,480	200,480	200,480	200,480	200,480	343,473	343,473	343,473			
TC cooling water losses	126,535	180,764	180,764	180,764	180,765	180,764	126,535	180,764	180,764			
Hydrolysis consumption	14,690	14,700	14,700	14,700	14,700	14,700	12,680	12,680	12,680			
TOTAL	491,881	546,348	531,002	536,990	536,674	508,225	653,429	707,658	690,136			
Make-up (L/L gasoline equivalent)												
Bioprocess	3.98	3.98	3.98	3.98	3.98	3.98	7.52	7.52	7.52			
TC process	22.94	20.14	13.78	10.15	10.21	10.37	83.32	27.98	22.23			
TOTAL	6.25	6.43	6.46	5.79	5.98	5.85	10.45	9.95	9.62	1.75[a]	7.19[b]	15.84[c]
Cooling water (% of total)	84%	86%	84%	85%	79%	84%	85%	87%	85%			

[a] Source: Ref. 20.
[b] Source: Ref. 18.
[c] Source: Ref. 22.

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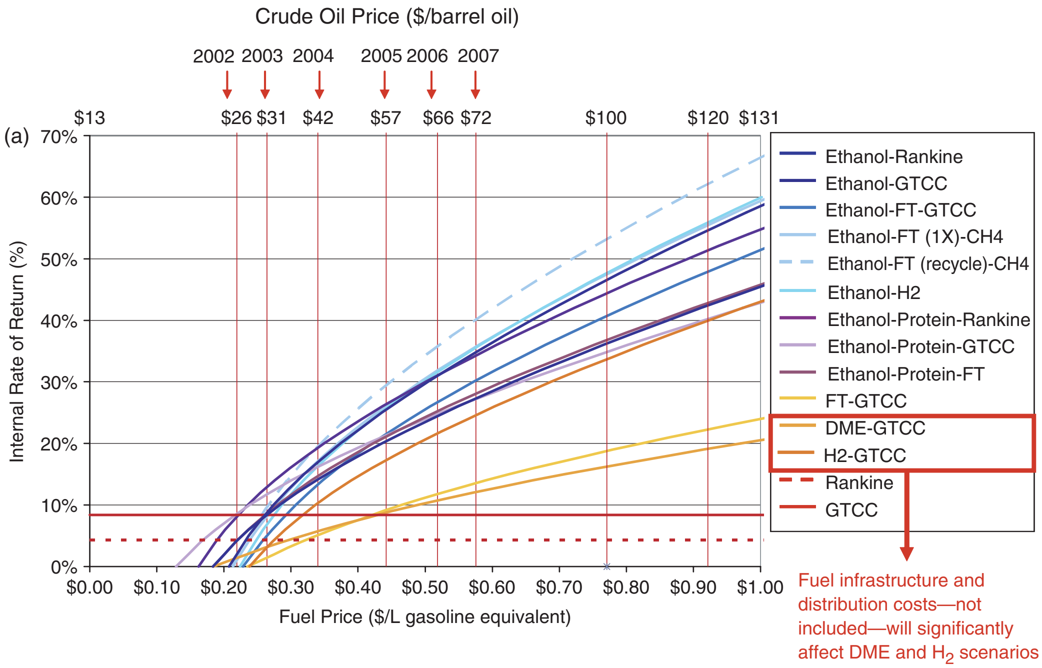
Table 3b. Overall process water balance and make-up water requirements for dedicated thermochemical fuels and power scenarios.

	Scenario					Petroleum	Corn	Thermo
Stream	10	11	12	13	14	Fuels	Ethanol	Power
In (kg/hr)								
TC make-up	110,455	58,150	91,126	48,965	48,965			
Feedstock moisture	47,421	47,421	47,421	47,421	47,421			
TC cooling water make-up	720,201	720,201	720,201	504,141	720,201			
Combustion release	98,656	83,520	83,160	106,034	106,034			
TOTAL	976,733	909,292	941,908	706,561	922,621			
Out (kg/hr)								
TC emissions	240,385	172,944	205,560	186,273	186,273			
TC blowdown	16,147	16,147	16,147	16,147	16,147			
TC cooling water losses	654,729	654,729	654,729	458,310	654,729			
TC cooling water blowdown	65,473	65,473	65,473	45,831	65,473			
TOTAL	976,733	909,292	941,908	706,561	922,621			
Make-up (L/L gasoline equiv.)	14.23	14.13	12.55	16.68	15.24	1.75[a]	7.19[b]	15.84[c]
Cooling water (% of total)	87%	93%	89%	91%	94%			

[a] Source: Ref. 20.
[b] Source: Ref. 18.
[c] Source: Ref. 22.



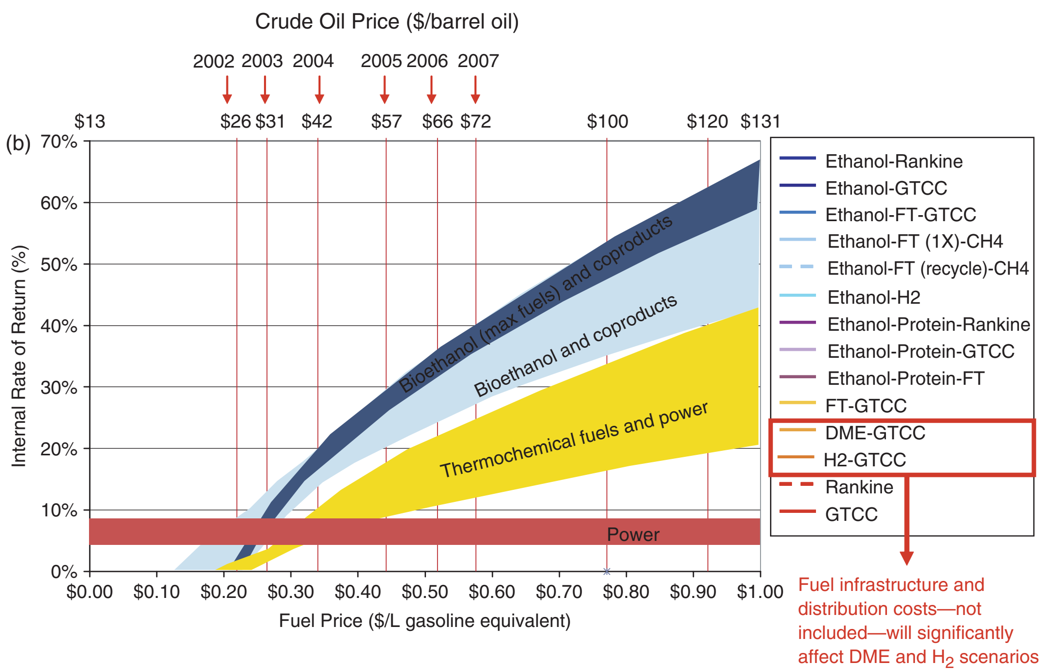


Figure 6(a). Internal rate of return as a function of fuel price for mature technology biorefinery scenarios. Plant scale = 4535 dry Mg feedstock/day; electricity price = $0.05/kWh (fuel scenarios); feedstock cost = $49/dry Mg; protein coproduct price = $0.44/kg; debt/equity ratio = 35/65; loan rate = 7.0%. Crude oil price reference corresponds to annual averages for Cushing, OK West Texas Intermediate Spot Price FOB (www.eia.doe.gov). Gasoline price reference corresponds to annual US wholesale averages (www.eia.doe.gov). (b). Internal rate of return as a function of fuel price for categories of mature technology biorefinery scenarios. Plant scale = 4535 dry Mg feedstock/day; electricity price = $0.05/kWh (fuel scenarios); feedstock cost = $49/dry Mg; protein coproduct price = $0.44/kg; debt/equity ratio = 35/65; loan rate = 7.0%. Crude oil price reference corresponds to annual averages for Cushing, OK West Texas Intermediate Spot Price FOB (www.eia.doe.gov). Gasoline price reference corresponds to annual US wholesale averages (www.eia.doe.gov).

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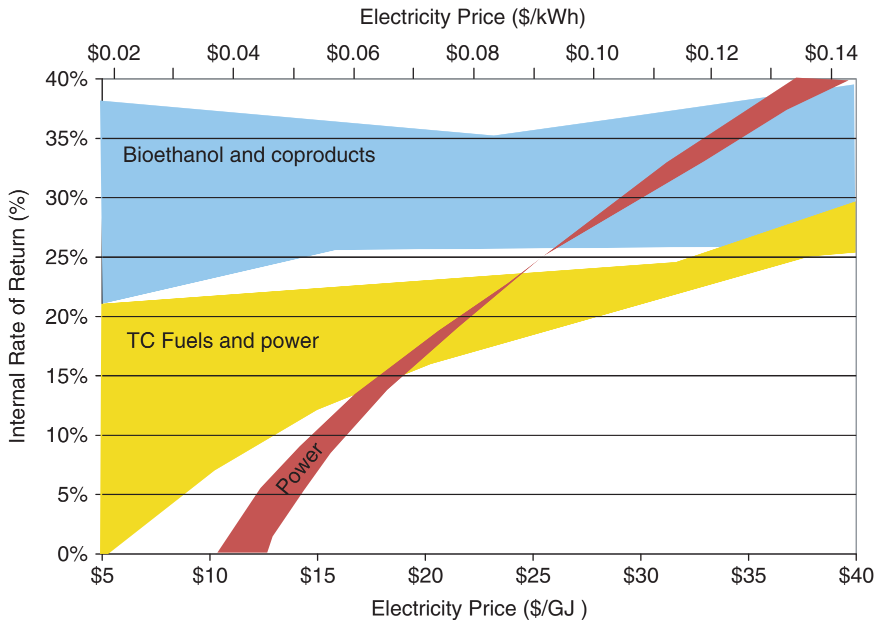

Figure 7. Internal rate of return as a function of electricity price for categories of mature technology biorefinery scenarios. Plant scale = 4535 dry Mg feedstock/day; fuel price = $0.53/L GEq ($2.00/gallon); feedstock cost = $49/dry Mg; protein coproduct price = $0.44/kg; debt/equity ratio = 35/65; loan rate = 7.0%.

station conversion cost for ethanol and DME at $200,000, and minimal costs for F-T diesel. James and Perez [31] estimate infrastructure (terminal construction and dispensing) and distributions costs for hydrogen produced via switchgrass gasification at about $0.40/L GEq ($1.50/gallon), which would roughly double the costs presented here.

The most profitable scenarios all involve biological processing of the feedstock carbohydrate fraction, achieving 10% IRR at fuel prices ranging from $0.24 to $0.31/L GEq ($0.89 to $1.16/gallon) depending on the scenario, and rising to 36%–54% at $0.79/L GEq ($3.00/gallon). At fuel prices of $0.26/L GEq ($1.00/gallon) – or about $30/barrel oil – the dedicated thermochemical fuels scenarios have IRRs less than 5%, while the two biological scenarios involving protein coproduction and power remain profitable with the ethanol-protein-GTCC-power scenario achieving about 12%, and the ethanol-protein-Rankine power realizing 14%. At the historical low soy meal protein price from 1980 to 2006 – about $0.31/kg, as noted in Laser *et al.*[5] – the fuel price for the ethanol-protein-Rankine configuration is $0.19/L, equal to the break-even price (i.e., the point at which the price is equal to that for the same configuration without protein coproduction). At the historical high ($0.62/kg), the fuel price is $0.14/L. Scenarios that maximize fuel production become the most profitable above fuel prices of $0.40/L GEq ($1.50/gallon; ~$50/barrel), with IRRs greater than 25%.

Figure 7 presents IRR as a function of wholesale electricity price for the three main categories of scenarios: bioethanol + coproducts, dedicated thermochemical fuels, and dedicated power. The group involving bioethanol + coproducts is more profitable than the thermochemical fuels scenarios over the range of power prices shown ($0.02–$0.14/kWh). The dedicated power scenarios become competitive with those producing bioethanol when the price of electricity rises to between $0.09 and $0.14/kWh – considerably higher than the $0.05/kWh inflation-corrected industrial average seen over the past 10 years in the USA (www.eia.doe.gov).

Levelized costs at 12% IRR are listed in Table 4. Scenarios involving bioethanol range from $0.25/L GEq ($0.96/gallon; ethanol + protein + Rankine power) to $0.33/L GEq ($1.24/gallon; ethanol + F-T + GTCC). Thermochemical fuels scenarios range from $0.36/L GEq ($1.37/gallon; H_2 + GTCC) to $0.57/L GEq ($2.16/gallon; DME + GTCC), though as noted above, these costs will likely be much higher when downstream infrastructure and distribution costs are

Table 4. Levelized costs for mature biorefinery scenarios.[a]

Scenario	Feedstock ($/L GEq)	Capital Charge ($/L GEq)	O&M[b] ($/L GEq)	Coproduct Credit ($/L GEq)	Total Cost ($/L GEq)
1. Ethanol + Rankine	$0.17	$0.12	$0.06	($0.06)	$0.29
2. Ethanol + GTCC	$0.17	$0.20	$0.06	($0.12)	$0.31
3. Ethanol + F-T + GTCC	$0.17	$0.20	$0.06	($0.11)	$0.33
4. Ethanol + F-T (1X) + CH_4	$0.17	$0.18	$0.06	($0.12)	$0.29
5. Ethanol + F-T (recycle) + CH_4	$0.17	$0.17	$0.06	($0.12)	$0.28
6. Ethanol + H_2	$0.17	$0.19	$0.06	($0.11)	$0.30
7. Ethanol + protein + Rankine	$0.18	$0.15	$0.06	($0.14)	$0.25
8. Ethanol + protein + GTCC	$0.18	$0.23	$0.07	($0.21)	$0.27
9. Ethanol + protein + F-T	$0.18	$0.25	$0.07	($0.20)	$0.30
10. F-T + GTCC	$0.27	$0.46	$0.10	($0.30)	$0.52
11. DME + GTCC	$0.38	$0.61	$0.13	($0.55)	$0.57
12. H2 + GTCC	$0.16	$0.20	$0.04	($0.03)	$0.36
13. Rankine	$0.28	$0.23	$0.05	-	$0.56
14. GTCC	$0.19	$0.27	$0.05	-	$0.51

[a]Plant scale = 4535 Mg feedstock/day; electricity price = $0.05/kWh (fuel scenarios); feedstock cost = $49/Mg; protein coproduct price = $0.44/kg; debt/equity ratio = 35/65; loan rate = 7.0%; IRR = 12%.
[b]Operating and maintenance.

included. Rankine power costs $0.55/L GEq ($0.062/kWh); GTCC power costs $0.51/L GEq ($0.058/kWh).

Capital and operating costs for the biorefinery scenarios are listed in Table 5, assuming a plant scale of 4535 dry Mgs/day and capital costs presented in the paper by Laser *et al.*[5] Table 15. The nine bioethanol scenarios have total capital investment per annual unit energy values less than $1.12/annual L GEq ($4.25/annual gallon), with the ethanol-Rankine-power scenario the lowest at $0.69/L GEq ($2.60/gallon). Among the dedicated thermochemical processes, only the H_2/GTCC scenario is below $1.12/annual L GEq; the F-T fuels and DME scenarios both have capital costs greater than $1.32/annual L GEq ($5/annual gallon). The above values assume a one-to-one energy equivalence for ethanol relative to gasoline. If one accounts for potential efficiency gains resulting from engines tuned specifically to operate using ethanol with its high octane number – estimated as 8% for hybrid electric internal combustion engines (Kenney T, 2004, personal communication) – then per-gallon capital costs decrease according to the fraction ethanol produced in the overall biorefinery output. In comparison, energy efficiency benefits on the order of 15% to 25% can be realized for diesel fuels relative to gasoline.[32]

Sensitivity to feedstock cost is shown in Fig. 8 for the three main categories of mature biorefinery configurations: bioethanol + coproducts, dedicated thermochemical fuels, and dedicated power production. The bioethanol scenarios result in the lowest minimum selling price over the feedstock cost range evaluated ($0–$100/dry Mg), and remain competitive with petroleum over this range. When the feedstock cost is $110/dry Mg, for example, these scenarios are comparable to gasoline priced between $0.42 and $0.52/L ($1.58 and $1.98/gallon). By comparison, TC fuels are competitive with gasoline priced between $0.56 and $1.05/L ($2.12 and $3.99/gallon); and power, between $0.75 and $0.91/L ($2.83 and $3.45/gallon). Among the TC configurations, the H_2-GTCC-power scenario is the most economic, comparable to gasoline at about $0.56/L ($2.12/gallon) when feedstock costs $110/dry Mg. As noted above, though, this does not include the substantial cost of hydrogen infrastructure and distribution.

The sensitivity of minimum selling price to the fraction of equity versus debt investment is shown in Fig. 9. The capital charge rates corresponding to total debt and total equity financing are about 0.1 and 0.2, respectively. The

Table 5. Capital and operating cost comparison of biorefinery scenarios.

Scenario	Total Capital Investment			Operating Cost
	($MM)	($/annual GJ)	($/annual L GEq)	($/L GEq)
1. Ethanol + Rankine power	$359.1	$21.45	$0.69	$0.73
2. Ethanol + GTCC power	$532.6	$28.70	$0.92	$0.69
3. Ethanol + F-T fuels + GTCC power	$569.8	$29.38	$0.94	$0.66
4. Ethanol + F-T fuels (w/once-through syngas) + CH_4	$521.2	$24.99	$0.80	$0.63
5. Ethanol + F-T fuels (w/recycle syngas) + CH_4	$477.9	$22.03	$0.71	$0.65
6. Ethanol + H_2	$525.7	$25.22	$0.81	$0.67
7. Ethanol + protein + Rankine power	$401.5	$24.53	$0.79	$0.88
8. Ethanol + protein + GTCC power	$593.5	$31.98	$1.02	$0.80
9. Ethanol + protein + F-T fuels	$674.9	$34.70	$1.11	$0.77
10. F-T fuels + GTCC power	$666.7	$42.44	$1.36	$1.40
11. Dimethyl ether + GTCC power	$617.6	$41.64	$1.33	$1.92
12. H2 + GTCC power	$488.3	$28.03	$0.90	$0.75
13. Rankine power	$294.2	$32.96	$1.06	$1.23
14. GTCC power	$527.5	$38.83	$1.24	$0.91

[a]Includes feedstock, other raw materials, waste disposal, labor, overhead, maintenance, insurance and taxes. Fuel equivalent includes both fuel and electricity.

price difference between these extremes is about 30% for the power scenarios, 31% for the bioethanol scenarios, and 57% for TC fuels. The general trend is that the impact of financing structure increases with increasing capital cost. Even with total equity financing, though, the bioethanol scenarios remain competitive with gasoline priced at $0.29–$0.36/L ($1.08–$1.35/gallon) – prices not seen since 2004 (www.eia.doe.gov).

Given the uncertainty in estimating production costs – especially for conversion technologies yet to be commercialized – it's useful to consider the sensitivity of minimum selling price as a function of such costs (Fig. 10). While minimum fuel price is obviously sensitive to processing costs, integrated scenarios involving biological processing remain very competitive with gasoline at about $0.66/L ($2.50/gallon) even when processing costs are double that assumed in this study. Scenarios maximizing fuel production (e.g., ethanol + F-T liquids with recycle + CH_4) are competitive at about $0.52/L ($1.95/gallon) when processing costs are doubled. Maximum fuels scenarios remain competitive at petroleum priced at $120/barrel even when processing costs are increased by a factor of 3.75.

Summary, conclusions, and recommendations

Fourteen cellulosic biorefinery process designs producing fuels, power, and/or animal feed – described in this issue's papers – have been compared with respect to process efficiency, aspects of environmental impact, and profitability. The designs, which include biological or thermochemical processing, or both, are assumed to have a level of technological maturity comparable to today's petroleum refineries – ie., as state of advancement such that additional R&D effort would offer only incremental improvement in cost reduction or benefit realization. Overall, mature cellulosic biomass refining – especially configurations that integrate biological and thermochemical processing – has the potential to realize efficiencies on par with petroleum-based fuels; avoid substantial GHG emissions and displace large amounts of petroleum; require modest volumes of process water; and achieve production costs competitive with gasoline at oil prices at about $30/barrel.

To achieve the performance targets and cost levels described in this study, several areas must undergo additional R&D and commercial-scale demonstra-

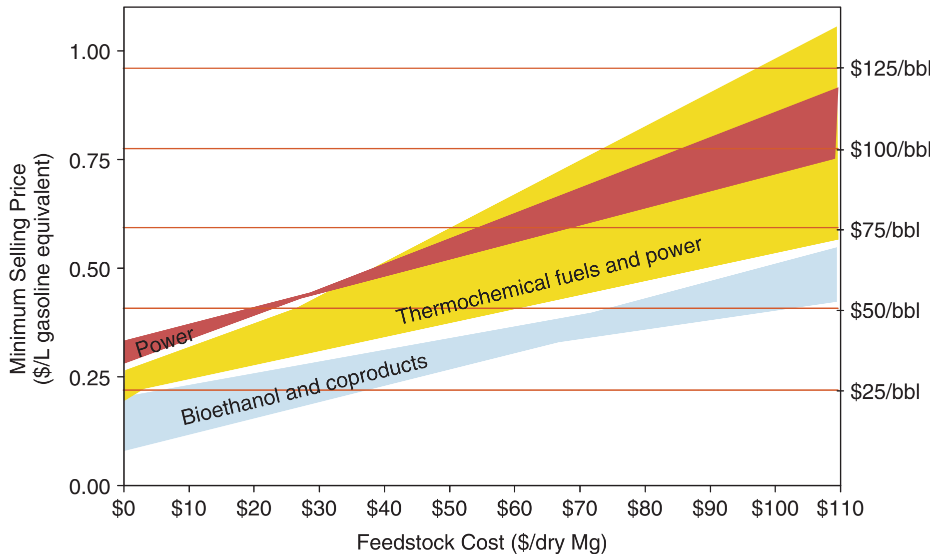

Figure 8. Minimum energy selling price as a function of feedstock cost for categories of mature biorefinery scenarios. Electricity price = $0.05/kWh (fuel scenarios); protein coproduct price = $0.44/kg; debt/equity ratio = 35/65; loan rate = 7.0%; IRR = 12%.

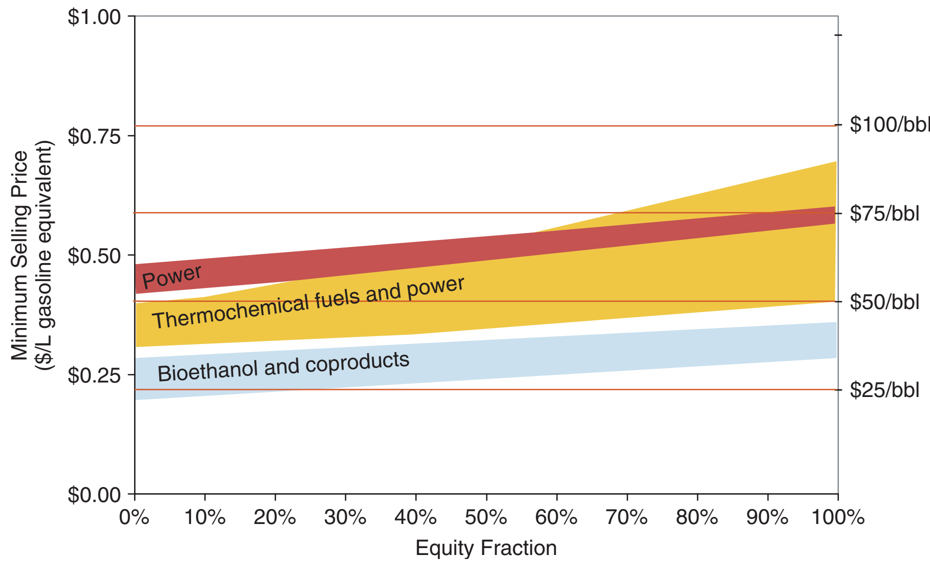

Figure 9. Minimum energy selling price as a function of the fraction of total project investment financed by equity for categories of mature biorefinery scenarios. Electricity price = $0.05/kWh (fuel scenarios); protein coproduct price = $0.44/kg; loan rate = 7.0%; IRR = 12%; feedstock cost = $49/dry Mg.

tion. For biological processing, the two most important breakthroughs that must be realized are overcoming the recalcitrance of cellulosic biomass (i.e., effective pre-treatment) and the development of CBP, in which enzyme production, hydrolysis, and fermentation occur in a single unit operation. Increasing fermentation yield and product titer is also important, though these developments will have less of an impact on cost than pre-treatment and CBP.[33] For thermochemical processing, key areas that must be commercially demonstrated include reliable feeding of low bulk-density biomass into a pressurized gasifier without excessive feeding energy requirements, reliable operation of oxygen-blown fluidized-bed gasification, complete cracking of tars by primary and/or secondary treatments, and tight

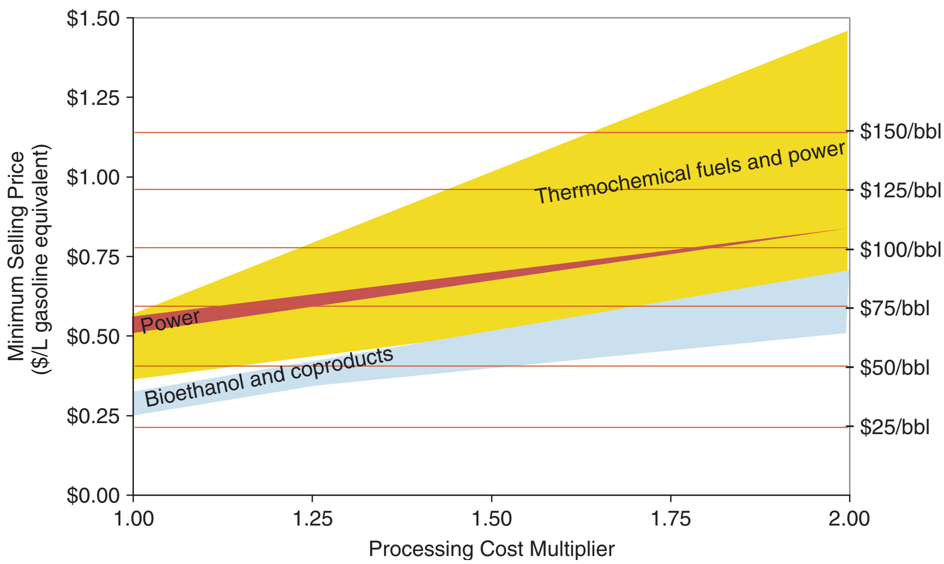

Figure 10. Minimum fuel selling price as a function of processing cost multiplier relative to reference case capital and operating costs presented in Table 5. Electricity price = $0.05/kWh; protein coproduct price = $0.44/kg; loan rate = 7.0%; IRR = 12%; feedstock cost = $49/dry Mg.

process heat integration and control for maximum recovery and use of process waste heat.

Though scenarios involving ethanol production via biological processing appear most promising, this is not to say that thermochemical processing is therefore unimportant and not worth pursuing. Quite the contrary, as the best performing scenarios involve both biological and thermochemical processing such that the carbohydrate fraction is converted biologically, and the lignin-rich residue converted thermochemically. This integrated configuration enables waste heat from the thermochemical process to power the biological process, resulting in higher overall process efficiencies than would otherwise be realized. Standalone thermochemical processing should also not be dismissed. Although the focus of this study has been on conversion of large-scale cellulosic energy crops, such as switchgrass, thermochemical processing holds a unique advantage in handling carbonaceous feedstocks that cannot be easily converted biologically. Examples include low-carbohydrate materials, such as sewage or slaughterhouse waste, mixed materials like municipal garbage, and exceptionally recalcitrant feedstocks such as certain softwoods.

Given the apparent advantages of integrating biological and thermochemical processing, we recommend that key aspects of such integration – waste-heat recovery and exchange; residue storage and handling; and scale compatibility between the two technologies, for example – become the subject of R&D in anticipation of a future point at which more complex processing facilities become viable. Animal feed protein coproduction is another area ripe for R&D given the economic potential indicated in this study (protein coproduction scenarios were among the most profitable over a wide range of fuel and feed prices) and the potential to produce food and fuel from the same acreage as discussed in Dale *et al*.[6] In addition to developing cost-effective extraction processes, further analysis should be done to examine supply-chain logistics of producing protein-rich feedstocks such as the cost and environmental impact of multiple-harvest schemes and storage of protein-rich feedstocks. The impact of seasonal protein coproduction on overall biorefinery economics, which goes hand-in-hand with assessment of the storability of protein-rich feedstocks, should also be evaluated. A comparison of technical feasibility, cost, and environmental impact of protein recovery in the field (e.g., leaf separation) versus in the procession facility is also important.

We also recommend that R&D continue in the area of reducing process-water requirements. The integrated biorefinery scenarios evaluated here – with onsite waste-water treatment and extensive recycle – have been designed with an eye toward reducing make-up water. Scenarios involving protein coproduction and standalone thermochemical processing, however, were not optimized with respect to water demand. In all scenarios, significant amounts are lost through evaporation in cooling towers. Reducing these losses through innovations, such as forced-air cooling and the HiCycler process – a sidestream hardness and silica removal process that reduces blowdown by 95% (http://www.chemico.com/HiCycler.htm) – would greatly improve the process-water balance. Development and evaluation of process designs incorporating such innovations would be a useful contribution. We also recommend that water pinch analysis be performed on these designs to elucidate further opportunities for more efficient water use. Water pinch analysis has been used predominantly in the food processing industry to great effect, with some reports of make-up water reductions of up to 50%.[34] While reducing process-water demand is an important goal, we note that when the entire lifecycle is considered for corn ethanol, significantly more water is consumed in the field during the growth of the corn than in the dry mill – between 75 and 895 L water/kg corn (500–6000 gallon water/bushel) depending on geographic location, or about 175–2140 L water/L ethanol.[27] (Again, more recent analysis by Wu and Wang[28] suggests that actual consumed water is much lower – 7.1 to 320.6 L water/L ethanol.) This is also likely to be the case for cellulosic biofuels. Research is underway, however, to identify and develop cellulosic energy crops that require less water than corn while achieving comparable if not greater biomass yields.[35–37] Such efforts, if successful, will profoundly contribute to the sustainability of biofuels.

Though the RBAEF project has examined many potential biorefinery scenarios, the effort has by no means been exhaustive; the project's encouraging results suggest analysis of additional technologies and process configurations, such as pyrolysis, liquefaction, syngas fermentation, and concentrated acid hydrolysis may also be fruitful and informative. In addition, a more extensive field-to-wheels lifecycle assessment that incorporates the RBAEF process design results – including a comparison of alternative feedstocks – would be useful, as would an evaluation of chemicals coproduction. Also, we recommend a more comprehensive analysis of the effect on carbon emissions of land conversion to biofuels than currently available in the literature. Finally, having sketched a picture of mature biomass refining – one having potential to contribute significantly to demand for energy services in the USA – it would be of great value to assess possible transition pathways to help streamline progress toward this promising and sustainable future.

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