# Comparing Climate-Change Mitigating Potentials of Alternative Synthetic Liquid Fuel Technologies Using Biomass and Coal

Robert H. Williams

Eric D. Larson

Haiming Jin

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CONFERENCE PROCEEDINGS

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**Robert H. Williams[1], Eric D. Larson[1], Haiming Jin[2]**
[1]Princeton Environmental Institute, Princeton University
Guyot Hall, Washington Road, Princeton, NJ, 08544
[2]TX Energy, 1330 Post Oak Boulevard, Suite 1600, Houston, TX, 77056

## Abstract

The climate-change mitigation potentials of alternative options for making synthetic liquid fuel from coal and biomass without and with $CO_2$ capture and storage are explored. The emphasis is on making Fischer-Tropsch liquids, with comparisons to cellulosic ethanol. Particular attention is given to exploitation of the negative $CO_2$ emissions potential of $CO_2$ capture and storage for bioenergy systems. One Fischer-Tropsch option involves coprocessing biomass and coal. All liquid fuel production options involve production of electricity as a net coproduct. Both $CO_2$ aquifer storage and $CO_2$ enhanced oil recovery options are analyzed.

The metrics by which the alternatives are compared are: (*i*) the net greenhouse gas emission rate associated with liquid fuel production and use, (*ii*) the specific capital cost of liquid fuel production, (*iii*) the lifecycle cost calculated for a fixed capital charge rate, and (*iv*) the internal rate of return on equity as a function of both the crude oil price and the price of greenhouse gas emissions. In addition, for options that involve biomass, liquid fuel yields per tonne of biomass are compared. And for enhanced oil recovery applications of the captured $CO_2$, the relative profitability of using $CO_2$ from synfuel plants and integrated gasifier combined cycle power plants is explored.

## Introduction

Synthetic fuels derived from secure domestic resources have attracted wide interest recently in light of high oil prices and oil supply insecurity concerns. Here carbon management options are investigated for the production and use of synthetic liquid fuels derived from coal and biomass. The emphasis is on making synthetic diesel and gasoline via the Fischer-Tropsch (F-T) process. Commercially established F-T technology offers synfuels that are inherently cleaner than the diesel or gasoline fuels derived from crude oil that they would displace and with which they can be blended and thus introduced into transportation fuel markets with no change in infrastructure. Comparisons to cellulosic ethanol derived from biomass are made.

The attractions of coal are its abundant availability from secure sources and its low and stable prices. The major concerns about a large coal synfuels program are its potential adverse impacts on climate, and coal mining health and safety and environmental risks associated with expanded coal production.

The attractions of biomass are: (*i*) security of supply (as for coal), (*ii*) the potential for phasing out subsidies now paid to farmers for producing less food to the extent that they might otherwise earn a livelihood growing biomass for energy, (*iii*) its renewability as an energy resource, and, perhaps most importantly, (*iv*) its climate-change mitigation benefits. Because the $CO_2$ emitted from bioenergy combustion is of recent photosynthetic origin, there is no net buildup of atmospheric $CO_2$ if the biomass is produced on a sustainable basis. Moreover, by capturing and storing below ground some $CO_2$ from biomass during its conversion to fuel or electricity, biomass becomes a negative $CO_2$-emitting energy supply; such negative $CO_2$ emissions can be used to offset GHG emissions from difficult-to-decarbonize fossil energy supplies, such as liquid fuels used in transportation. The major concerns about biomass are the typical high cost of biomass compared to coal, and the land intensity of biomass production (reflecting the low efficiency of photosynthesis) and resulting competition with alternative land uses.

The assumed feedstocks for energy production are bituminous coal and switchgrass, a perennial grass native to the Great Plains of the USA that is a promising future bioenergy crop [1, 2].

The scale of switchgrass energy conversion for all the F-T options studied is ~ 4500 dry tonnes per day. This is larger than most prior analyses have considered, although biomass processing facilities this size and larger are operating commercially today (e.g., some Brazilian sugarcane mills). If switchgrass were to be produced as a dedicated energy crop, average transport distances would be relatively modest for delivering the feedstock to conversion facilities of this size. In earlier work it was shown that up to very large conversion plant sizes, the impact on overall economics of increasing average delivered feedstock costs with increasing plant sizes is more than offset by scale-economy gains in the capital cost of the larger conversion facilities [3].

The bulk of this paper summarizes and extends detailed analyses [4, 5, 6, 7] of mass/energy balances and economics for plants that co-produce Fischer-Tropsch (F-T) diesel and gasoline blendstocks plus electricity from coal and from biomass, with and without carbon capture and storage (CCS)—including analysis of plants that co-process coal and biomass with CCS to make F-T liquids. Stand-alone coal and biomass integrated gasification combined cycle (IGCC) power generation with and without CCS are also discussed, again based on previous work [4, 5, 8, 9]. Aquifer storage ($CO_2$-AqS) and enhanced oil recovery ($CO_2$-EOR) are analyzed as alternative $CO_2$ storage options.

The F-T plants are "polygeneration" units that use commercial "once-through" liquid-phase reactors with iron-based catalyst for synthesis of F-T fuels from syngas. The syngas unconverted in a single pass is used to make co-product electricity in a combined cycle power plant.

Six carbon management options for F-T systems are investigated—four of which are shown schematically in Figure 1. Three use only coal, two use only biomass, and one involves the co-processing of coal and biomass.

The three F-T production systems that use only coal are: one that vents the $CO_2$ coproduct (C-FT-V); one (Figure 1a, upper) that captures $CO_2$ and stores it underground (C-FT-C); and one that involves co-capture and underground co-storage of $CO_2$ and $H_2S$ (C-FT-CoC). In a fourth option (Figure 1a, lower), coal and biomass are co-processed with co-capture and under-ground co-storage of $CO_2$ and $H_2S$ (C/B-FT-CoC). For the co-processing option $H_2$ derived from biomass syngas supplements $H_2$–deficient coal syngas in making F-T liquids, exploiting the negative emissions potential of CCS for biomass; the biomass input is adjusted to reduce the net fuel-cycle-wide GHG emissions for synfuel production and use to near zero (Figure 2).

The two biomass F-T production systems are: one (Figure 1 b, upper) that vents the $CO_2$ coproduct (B-FT-V); and one (Figure 1b, lower) that captures $CO_2$ and stores it underground (B-FT-C).

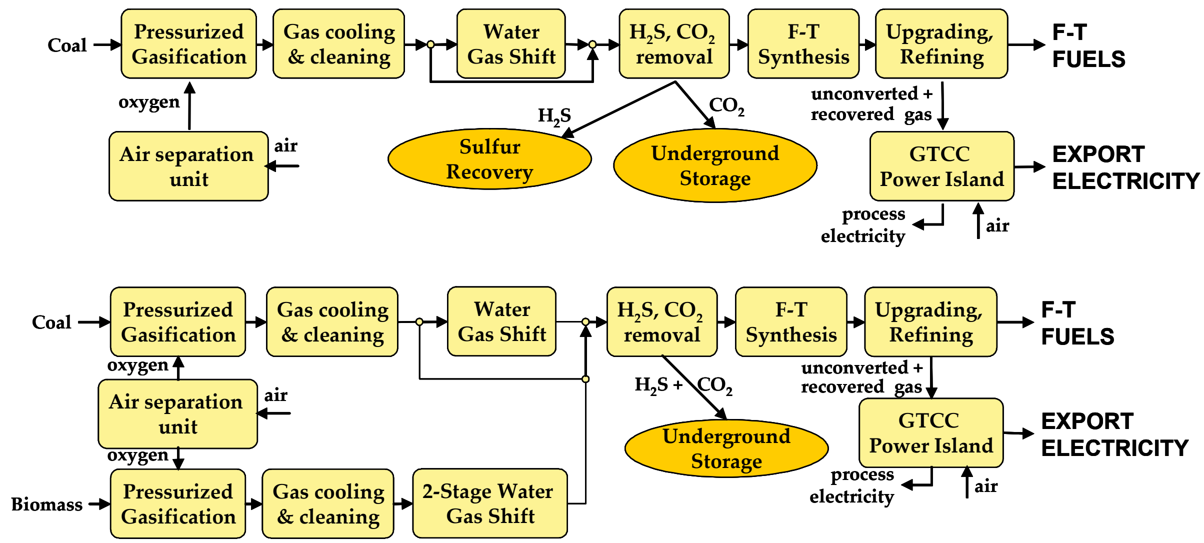



**Figure 1a: Process configurations for C-FT-C (upper) and C/B-FT-CoC (lower) systems.**

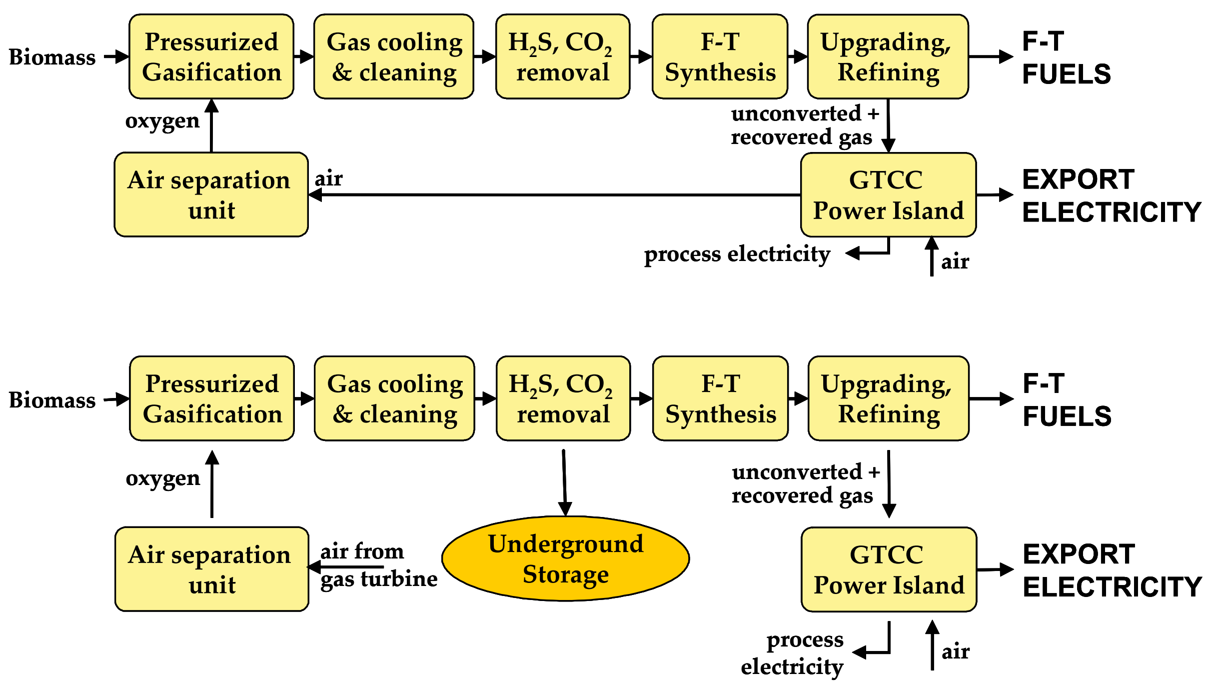
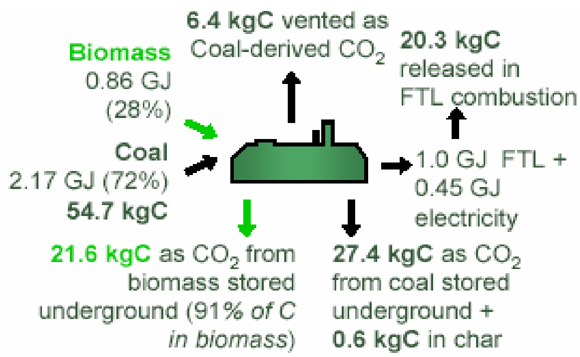



**Figure 1b: Process configurations for B-FT-V (upper) and B-FT-C (lower) systems.**

Energy and carbon balances, as well as fuel cycle-wide GHG emission rates, are estimated. In addition, for options that involve biomass, liquid fuel yields per tonne of biomass are compared. The economic analyses include estimates of capital costs, levelized production costs, and internal rates of return on equity as functions of carbon and oil prices. For $CO_2$–EOR applications of the captured $CO_2$, the relative profitability of using $CO_2$ from synfuel plants and integrated gasifier combined cycle power plants with CCS for both coal (C-IGCC-C) and biomass (B-IGCC-C) is explored. The analysis includes comparisons to cellulosic ethanol production based on studies of cellulosic ethanol carried out at the National Renewable Energy Laboratory; two cases were considered: one based on vintage 2000 technology [10] and one based on advanced technology [11].




| Mine-to-wheels GHG emissions, $kgC_{equiv}$/GJ FTL | |
|---|---|
| Coal-derived $CO_2$ emissions from plant | + 6.4 |
| Bio-$CO_2$ storage credit | - 21.6 |
| $CO_2$ emissions from burning FTL | + 20.3 |
| Upstream GHG emissions from coal | +2.2 |
| Upstream GHG emissions from biomass | + 1.8 |
| GHG emissions allocated to electricity | - 3.6 |
| **Net GHG emissions allocated to FTL** | **5.5** |

**Figure 2: Carbon/energy balances for the C/B-FT-CoC system.**

**Methodology**

The F-T liquids plant modeling used: (*i*) AspenPlus chemical process simulation software to estimate detailed mass and energy balances and (*ii*) AspenPinch software for system heat integration. A GE pressurized, $O_2$–blown, entrained flow, quench gasifier (commercially available) was modeled for coal. In all cases involving biomass (including C/B-FT-CoC), modeling of biomass gasification was for a pressurized, $O_2$–blown, fluidized bed gasifier based on GTI technology (not yet commercial). In the C/B-FT-CoC system there is a sharing of other process equipment between coal and biomass (Figure 1a, lower). The biomass systems include a separate vessel following the gasifier for complete tar cracking. Both coal and biomass systems involve gas cleanup to specifications for downstream synthesis or gas turbine combustion.

Because of the $H_2$ deficiency in the syngas exiting the coal gasifier ($H_2$:CO = 0.62), a high temperature water-gas-shift (WGS) reactor is employed upstream of synthesis to boost $H_2$:CO. (Some syngas bypasses the WGS reactor—see Figure 1a.) For C-FT-V, syngas from the gasifier is shifted to the extent that $H_2$:CO = 2.25 for syngas entering the synthesis reactor—the value that maximizes conversion to liquid fuel. The system design for the coal and coal/biomass CCS cases is such that for the syngas entering the synthesis reactor $H_2$:CO = 2.75—a value at which essentially all carbon (except in $CH_4$) entering the synthesis reactor leaves as F-T products, and syngas conversion to liquids is only slightly below the maximum value. For B-FT-V and B-FT-C, no WGS reactor is used because the syngas exiting the gasifier has $H_2$:CO = 1.74, which is sufficiently high for subsequent F-T synthesis. Even without WGS, about half of the biomass carbon in the biomass-derived syngas is available for capture as $CO_2$ upstream of synthesis. For C/B-FT-CoC, both high- and low-temperature WGS reactors are employed, to fully shift the biomass syngas to a mixture of mainly $H_2$ and $CO_2$.

Upstream of synthesis $CO_2$ and $H_2S$ are captured using Rectisol technology. Even though the sulfur content of biomass is extremely low and is thus of no environmental concern if it is oxidized and vented as $SO_2$, the $H_2S$ concentration is sufficiently high (500 ppmv) that most of it must be removed even in the biomass cases to protect the synthesis catalyst. For C-FT-V and C-

FT-C the $H_2S$ and $CO_2$ are recovered in separate columns. The $H_2S$ recovered from Rectisol is reduced to elemental sulfur in a Claus plant, and tail gases are cleaned up in a SCOT plant. The $CO_2$ is dried and compressed to 150 bar and transported 100 km to a site for storage in a saline aquifer 2 km underground or in conjunction with $CO_2$-EOR. For C-FT-CoC, the $H_2S$ and $CO_2$ are recovered in the same column, and no Claus or SCOT plant is needed; in this case the $CO_2$ + $H_2S$ are dried and compressed to 150 bar and transported 100 km to a storage site. Also for B-FT-V and B-FT-C the $H_2$ S and $CO_2$ are recovered in the same column, and no Claus or SCOT plant is needed. For B-FT-V, the recovered $CO_2$ and $H_2S$ are sent to the gas turbine combustor where the $H_2S$ is oxidized to $SO_2$ and vented. For B-FT-C, the $H_2S$ and $CO_2$ are dried and compressed for pipeline transport to the storage site.

The products of F-T synthesis (light gases, naphtha, middle distillates, and waxes) are sent to an integrated refinery area, the final liquid products from which are gasoline and diesel blendstocks; the light ($C_1$-$C_4$) gaseous byproducts of refining plus the unconverted syngas exiting the synthesis reactor are burned for power generation in a combined cycle plant.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. It is assumed that the coal has the properties of a coal from Yanzhou, Shandong Province, China: 7.1% moisture, a LHV and carbon content of 23.5 GJ/tonne and 25.2 kgC/GJ, respectively (wet basis), and ash and sulfur contents of 20.2% and 4.0%, respectively (dry basis). It is assumed that the switchgrass properties are: 20% moisture, a LHV and carbon content of 13.5 GJ/tonne and 27.8 kgC/GJ, respectively (wet basis), and ash and sulfur contents of 5.7% and 0.1%, respectively (dry basis). All costs are in 2003$.

In systems producing both F-T liquids and electricity, allocation of GHG emissions[1] and costs between the products is arbitrary. For the present analysis it is assumed that the GHG emission rate allocated to electricity ($gC_{equiv}$/kWh) is that for a stand-alone coal IGCC plant with $CO_2$ vented (C-IGCC-V) in the C-FT-V case and for a coal IGCC plant with $CO_2$ captured (C-IGCC-C) in all capture cases. In estimating F-T liquids production costs at a given monetary value for GHG emissions, it is assumed that the value of the co-product electricity (in $/kWh) equals the generation cost for the least-costly stand-alone C-IGCC power plant for that monetary value of GHG emissions.

For simulated energy and mass balances, installed capital costs were estimated for the six F-T plant configurations, assuming commercially-ready components for coal and future mature N$^{th}$ plant technology components for biomass. Capital costs were developed by sub-unit in each major plant area using a database developed by building on prior work [9, 12, 13], literature studies, and discussions with industry experts.

Energy production cost estimates for F-T polygeneration and IGCC plants were made assuming an 80% capacity factor, financing with 55% debt (4.4%/y real cost) and 45% equity, a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate,

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[1] The GHG emissions include $CO_2$ emissions from the plant and ultimate combustion of the F-T liquids and the $CO_2$-equivalent GHG emissions upstream of the conversion plant. From the GREET model of the Argonne National Laboratory these are estimated as 1.00 $kgC_{equiv}$ and 2.06 $kgC_{equiv}$ per GJ for coal and switchgrass, respectively.

and an owner's cost of 5.5% of the total installed capital cost. Base Case financing involves a 14.0% real internal rate of return on equity (ROE), so that the discount rate (real weighted after-tax cost of capital) is 7.8%/year, and the levelized annual capital charge rate is 15.0%/year. It is assumed that plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction is 12.3% of the overnight construction cost. It is assumed that prices of coal and biomass (20% moisture content) are $\$1.35/GJ_{HHV}$ and $\$3.0/GJ_{HHV}$ (which is likely to be typical for many residue and dedicated energy crop applications). Energy production cost estimates include valuation of greenhouse gas (GHG) emissions assuming alternative monetary values of \$0 and \$100 per tonne of carbon equivalent ($tC_{equiv}$); the latter value was chosen because it is approximately the minimum carbon price needed to motivate CCS for coal power generation in the absence of $CO_2$–EOR opportunities.

For the cellulosic ethanol plants modeled in NREL studies[2], all the economic assumptions are the same except for three: a higher capacity factor (90% -- reasonable in light of the low operating temperatures of these plants); a two year construction time (in light of the smaller plant sizes), so that interest during construction is reduced to 3.9%; slightly lower biomass prices—again to take into account the prospective lower biomass transport costs for these smaller plants: $\$2.79/GJ_{HHV}$ for vintage 2000 technology and a 1118 dry tonnes per day processing rate and $\$2.86/GJ_{HHV}$ for advanced technology and a 2000 dry tonnes per day processing rate.

Costs for $CO_2$ transport and for aquifer storage are based on a model developed by Ogden [14], assuming that the maximum $CO_2$ injection rate per well for the AqS-$CO_2$ storage cases is 1000 t/day, a typical value for mid-continental aquifers.

Breakeven crude oil prices are estimated assuming that the F-T gasoline and diesel products (38% and 62% of liquids output, respectively) compete with gasoline and low-sulfur diesel derived from crude oil; the refining cost increment for this mix is \$10.4 per barrel. The refining cost increment is \$11.6 per barrel for gasoline, against which ethanol must compete.

For the $CO_2$-EOR cases, it is assumed that the captured $CO_2$ is transported 100 km and sold for EOR at a price in \$ per $10^3$ scf (1 tonne = 19 x $10^3$ scf) equal to 3% of the oil price in \$/barrel—a "rule of thumb" for Permian Basin $CO_2$-EOR (Vello Kuuskraa, Advanced Resources International, private communication, December 2005).

With Base Case financing, the economic analysis identifies the crude oil price at which F-T liquids are competitive with gasoline and diesel. Electricity costs for coal and biomass IGCC power with $CO_2$–EOR are also estimated with Base Case financing. The economic analysis is extended beyond Base Case financing to estimate the real internal rate of return on equity as a function of oil price—assuming all financial parameters other than the ROE are the same as with Base Case financing.

**Findings**
Tables 1-6 summarize the characteristics of each set of options analyzed.

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[2] The NREL studies were carried out for corn stover as feedstock. It is assumed that the energy balances and capital and operating and maintenance costs would not change in shifting to switchgrass as feedstock.

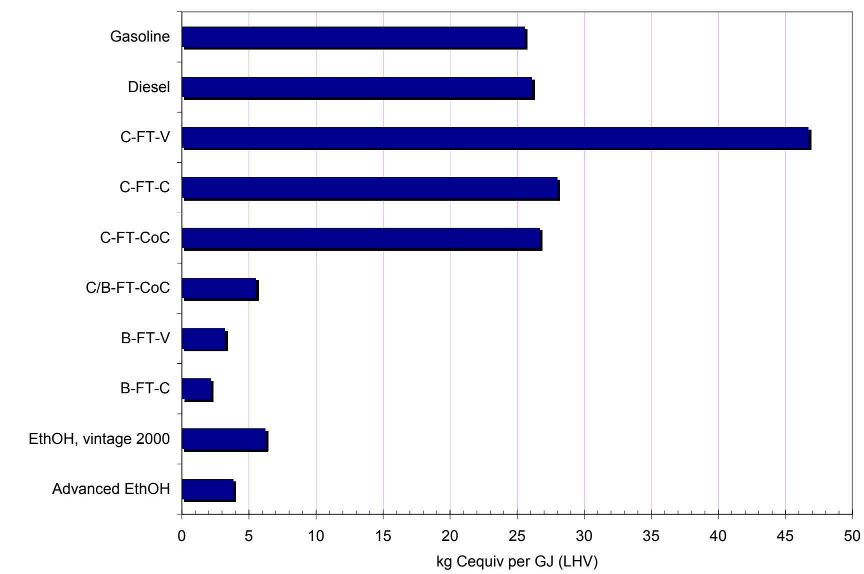


**Figure 3: Greenhouse gas emission rates for liquid fuel production and use.**

Figure 3 presents, from these tables, the greenhouse gas emission rates associated with synfuel production and use for the alternative synfuel options along with the emission rates for the crude oil-derived gasoline and diesel that would be displaced. For C-FT-V the GHG emission rate is 1.8 times that for crude-derived hydrocarbon (HC) fuels displaced, so that this option is very unattractive from a climate change mitigation perspective. Deploying the C–FT-C option instead would make it possible to reduce the GHG emission rate to about the level for crude oil-derived HC fuels. In contrast, for the various options using biomass, including C/B-FT-CoC, the emission rates are 0.2 times the emission rates for the crude oil derived hydrocarbon fuels displaced or less.

Figure 4 shows for the alternative biomass options the net liquid fuel yield.[3] Notably, the liquid fuel yield is ~ 2X as large or more for the C/B-FT-CoC option as for the others, because in this instance biomass is used only to the extent of offsetting the coal-derived $CO_2$ emissions associated with ultimately burning the synfuel (Figure 2); in this case only ~ 0.9 GJ of biomass is needed to produce 1.0 GJ of liquid fuel characterized by a low net GHG emission rate. Thus the C/B-FT-CoC option makes it feasible to get much more low GHG-emitting liquid fuel from scarce biomass resources than with conventional biofuel technologies.

Figure 5, displaying the specific capital requirement for liquid fuel production[4], shows that, with the exception of vintage 2000 ethanol technology, the specific capital requirements are comparable for the alternative options. Thus capital intensity is not likely to be a significant

[3] In constructing this index the amount of biomass allocated to liquid fuel is the total biomass input less the biomass that would have been used to produce the electricity co-product, had the latter been produced in a stand-alone B-IGCC plant—assuming a B-IGCC-C plant for B-FT-C and a B-IGCC-V plant for the other cases except C/B-FT-CoC, in which case the total biomass input is used, because all the electricity co-product is generated by coal.

[4] The specific capital requirement for liquid fuel production is defined as the ratio: (total capital required – capital required for the electricity coproduct)/(liquid fuel output capacity). The capital required for the electricity coproduct = (electric output capacity, in kW)*(specific capital cost, in $/kW, for the appropriate equivalent stand-alone power plant). For C-FT-V the appropriate stand-alone power plant is taken to be C-IGCC-V (Table 5). For C-FT-C, C-FT-CoC, and C/B-FT-CoC it is C-IGCC-C (Table 5). For B-FT-V and ethanol it is B-IGCC-V (Table 6). For B-FT-C it is B-IGCC-C (Table 6).

deciding factor in technology choice—except to the extent that it might be considered important that this common capital intensity can be realized at a much smaller scale in the advanced cellulosic ethanol case.

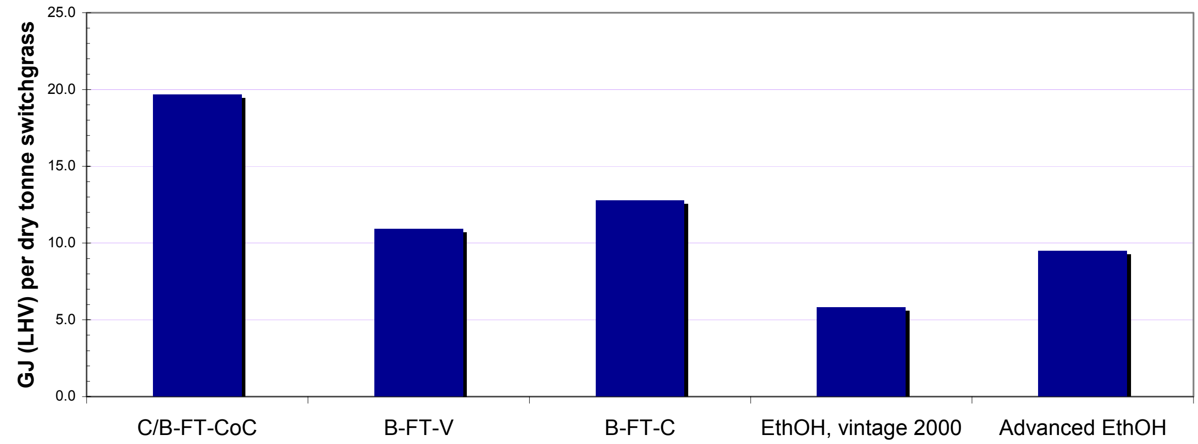


**Figure 4: Net liquid fuel yield per tonne of dry biomass.**

Tables 1-6 and Figures 6-9 summarize the overall economics.[5] One might consider the economics "attractive" if the real internal rate of return on equity is ~ 14%/y (the cost of equity capital assumed for the levelized cost analysis in Tables 1-6) or more.

Consider first the situation when the GHG emissions price is $0/tC$_{equiv}$. Figure 6 shows that C-FT-V and advanced ethanol become attractive at oil prices of $50 and $60 a barrel, respectively, while all the other options are unattractive when there are no $CO_2$-EOR opportunities. Notably, the profitability of advanced ethanol falls off steeply at lower oil prices. But, with the exception of B-IGCC-C, options that can use captured $CO_2$ for EOR would be more profitable than any of the $CO_2$ vent options (Figure 7); the C/B-FT-CoC and C-FT-C options are the most profitable $CO_2$-EOR options for oil prices above $50 a barrel, while the C-IGCC-C option

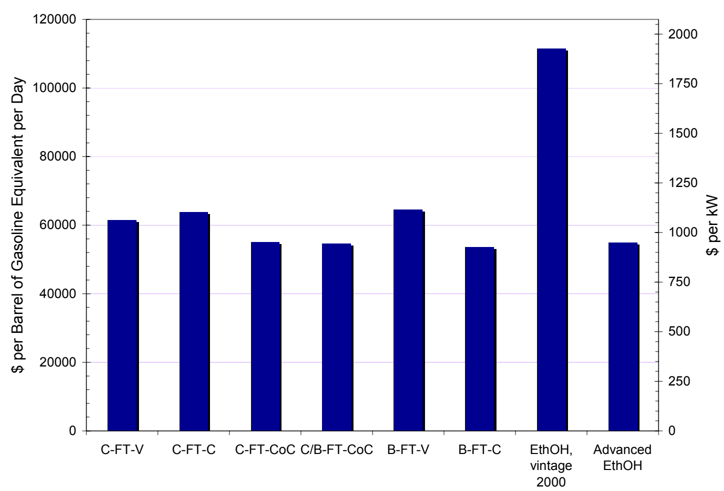


**Figure 5: Specific capital requirement for liquid fuel production.**

[5] Cellulosic ethanol based on vintage 2000 technology is not shown in any of the figures because for all oil prices the real internal rate of return on equity is negative.

is more profitable at lower oil prices. The C/B-FT-CoC option stands out as the most promising option for using biomass-derived $CO_2$ for EOR at \$0/tC$_{equiv}$.

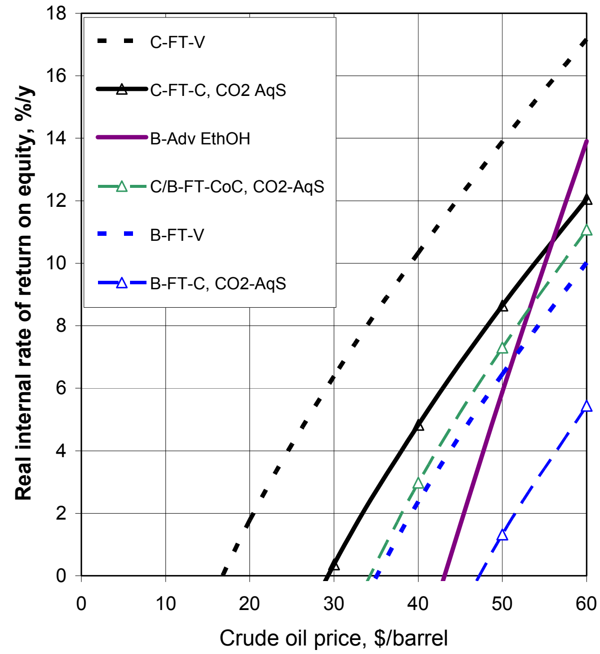


**Figure 6: Profitability of alternative synfuel options without $CO_2$–EOR @ \$0/tC.**

Consider next the situation when the GHG emissions price is \$100/tC$_{equiv}$. Figure 8 shows that, in the absence of $CO_2$-EOR opportunities, all the options using biomass are very attractive at oil prices above \$35-\$45 a barrel and are much more profitable than the coal F-T options. Notably again, the profitability of advanced ethanol falls off steeply at oil prices below \$45 a barrel. Where the captured $CO_2$ can be used for EOR, the profitability is much higher than for any of the $CO_2$ vent options (Figure 9).

The strong negative GHG emission rate (-209.5 gC$_{equiv}$ per kWh) associated with the B-IGCC-C option (Table 6) and the electricity coproduct of the B-FT-C option (Table 3) can be used to offset GHG emissions from difficult-to-decarbonize energy carriers such as crude oil-derived hydrocarbon fuels used in transportation. This opportunity can be seized at a GHG emissions price of \$100/tC$_{equiv}$ in the B-FT-C case but not until the GHG emissions price reaches ~ \$150/tC$_{equiv}$ in the B-IGCC-C $CO_2$–AqS case, because until the GHG emissions price reaches that level a B-IGCC-V plant would be more profitable than a B-IGCC-C $CO_2$-AqS plant (Table 6). Moreover, unless motivated by public policy that promotes low GHG-emitting synfuel production or unless there are EOR opportunities to exploit, the bioenergy investor will gravitate to B-IGCC-V technologies, which are the most profitable (~ 25%/y real internal rate of return on equity) of all the non-EOR bioenergy options at a GHG emissions price of \$100/tC$_{equiv}$.

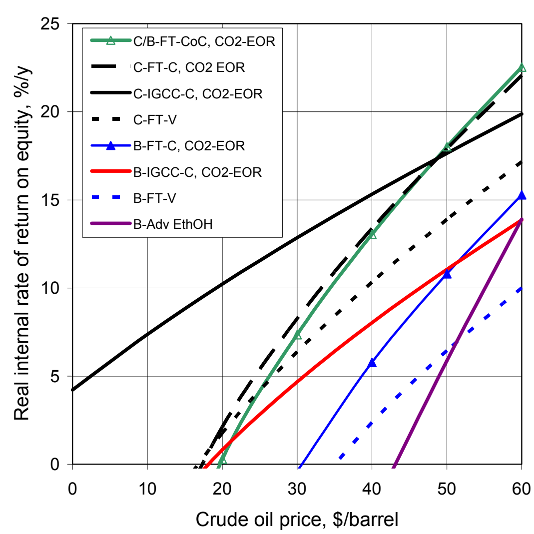


**Figure 7: Profitability of alternative energy options with $CO_2$-EOR @ \$0/tC.**

This analysis shows that projects coupling gasification energy and $CO_2$-EOR could help establish CCS technologies in the market even at a GHG emission price of \$0/tC$_{equiv}$. Recent studies [15] estimated for 10 US basins/regions the economic (technical) $CO_2$-EOR potential based on state-of-the-art technology to be 47 (89) billion barrels. The economic potential could support 4.3 million barrels/day of crude oil production for 30 years (a typical lifetime for a gasification energy plant that might provide the needed $CO_2$). At the average $CO_2$ purchase rate of 0.21 t $CO_2$/barrel estimated in these studies, the required $CO_2$ could in principle be provided by ~ 60 C-FT-C or C/B-FT-CoC plants (Table 1), ~ 230 B-FT-C plants (Table 4), or ~ 125 C-IGCC-C (Table 5) or B-IGCC-C (Table 6) plants. Although coupling gasification energy and $CO_2$–EOR projects will not always be feasible, this "niche activity" would nevertheless be large enough to gain extensive early experience and technology cost buydown (learning by doing) for both gasification energy and CCS technologies.

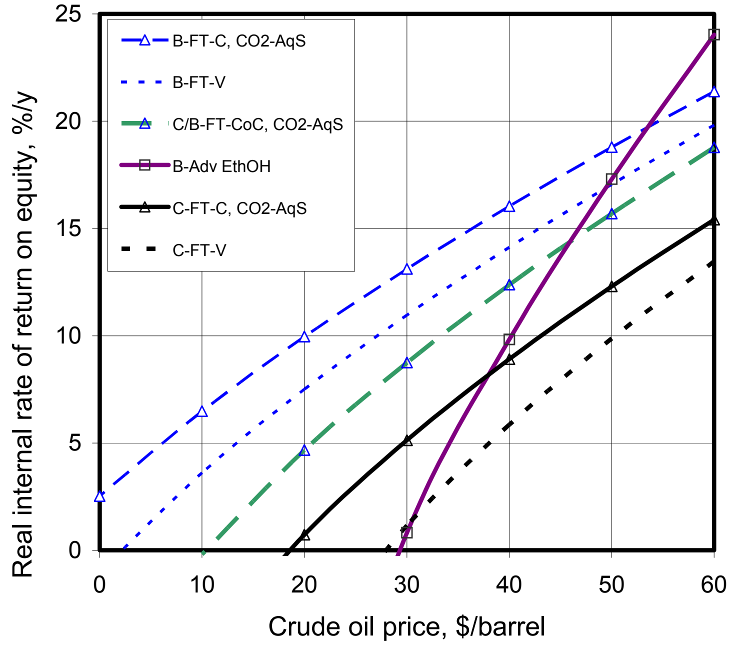


**Figure 8: Profitability of alternative synfuel options without $CO_2$–EOR @ \$100/t**

## Conclusions

Making F-T liquids from coal could help mitigate oil supply security concerns and would be profitable at sustained high oil prices. But without CCS, this option would lead to a large increase in GHG emissions relative to hydrocarbon fuels derived from crude oil. With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, to near zero, via co-processing biomass and coal with CCS so as to exploit the negative emissions of storing photosynthetic $CO_2$.

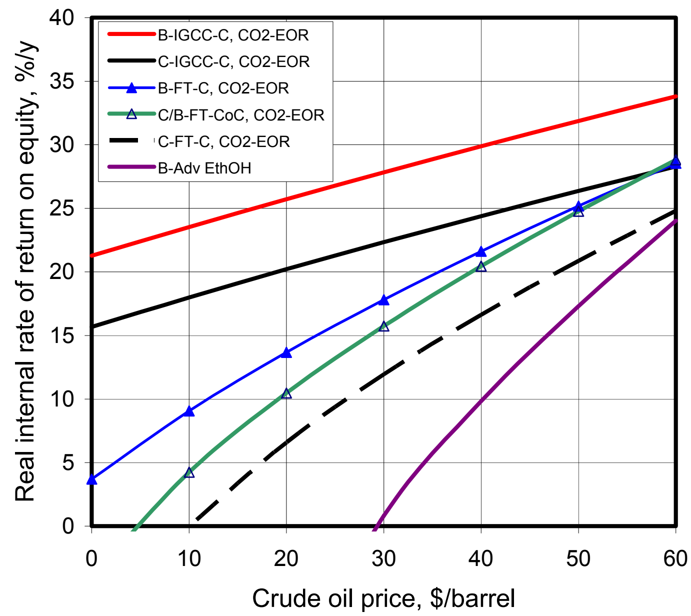


**Figure 9: Profitability of alternative energy options with $CO_2$-EOR @ \$100/tC**

The various biomass options offer near zero GHG emissions in the manufacture of liquid fuels but the economic prospects are poor except at oil prices generally higher than those considered in this paper when the price of GHG emissions is \$0/$tC_{equiv}$…with one exception. When the captured $CO_2$ can be used for EOR, the C/B-FT-CoC option would be very profitable for oil prices above \$45 a barrel.

When GHG emissions are valued at $100/$tC_{equiv}$, all the biofuel options (except cellulosic ethanol vintage 2000 technology) are very attractive for oil prices above $35 to $45 a barrel. However, the thermochemical options (B-FT-V, B-FT-C, and C/B-FT-C) are more profitable over a wider range of oil prices than advanced cellulosic ethanol, for which profitability declines steeply with falling oil prices.

The C/B-FT-CoC stands out as an attractive option for expanding the role of biomass in providing low GHG-emitting liquid fuels, because ~ ½ as much biomass is needed to make a unit of liquid fuel as with conventional biofuels such as cellulosic ethanol.

More generally, the negative emissions potential of any bioenergy option that involves storage of photosynthetic $CO_2$ provides a major opportunity to offset emissions from otherwise difficult-to-decarbonize fossil fuels.

And $CO_2$–EOR offers a major opportunity for launching gasification energy and CCS technologies in the market even before a market price is established for GHG emissions.

## Acknowledgments

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| Table 1: F-T liquids production from coal or coal + biomass with $CO_2$ vented or aquifer storage of $_{CO2}$ (Base Case financing) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Conversion Option** | **C-FT-V** | | **C-FT-C** | | **C-FT-CoC** | | **C/B-FT-CoC** | |
| Carbon flows (power balances) | | | | | | | | |
| Coal input, kgC/s (MW) | 74.2 (2946) | | 77.7 (3085) | | 77.7 (3085) | | 56.4 (2241) | |
| Switchgrass input, kgC/s (MW) | | | | | | | 24.7 (886.8) | |
| F-T liquids output, kgC/s (MW) [bbls/day gasoline equivalent] | 21.1 (1035) [17,890] | | 21.0 (1032) [17,840] | | 21.0 (1033) [17,860] | | 20.9 (1032) [17,840] | |
| Electric power output, MW | 461.3 | | 429.9 | | 428.3 | | 459.5 | |
| Unconverted coal char, kgC/s | 0.74 | | 0.78 | | 0.78 | | 0.56 | |
| Coal $CO_2$ emissions from plant, kgC/s | 52.5 | | 8.27 | | 6.94 | | 6.64 | |
| Coal $CO_2$ captured & stored, kgC/s [$CO_2$ capture rate for coal ($CCR_C$), t $CO_2$ /$GJ_{FTL}$] | | | 47.6 [0.169] | | 49.0 [0.174] | | 28.3 [0.101] | |
| Switchgrass $CO_2$ captured and stored, kgC/s [$CO_2$ capture rate for switchgrass ($CCR_S$), t $CO_2$/$GJ_{FTL}$] | | | | | | | 22.3 [0.0791] | |
| Fuel cycle GHG emissions, $kgC_{equiv}/GJ_{LHV}$ F-T liquids (relative to crude oil-derived hydrocarbon fuels) | 46.73 (1.80) | | 27.98 (1.08) | | 26.68 (1.03) | | 5.53 (0.21) | |
| Fuel cycle GHG emission rate, $gC_{equiv}$/kWh electricity | 219.4 | | 28.8 | | 28.8 | | 28.8 | |
| Price of GHG emissions, $/$tC_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 100 |
| Electricity co-product value, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 |
| Overnight construction cost, $$10^6$ | 1647 | | 1797 | | 1639 | | 1678 | |
| Specific overnight construction cost allocated to liquid fuel production, $ per barrel per day of gasoline equivalent ($ per kW) | 61,454 (1062) | | 63,840 (1104) | | 55,067 (952) | | 53,648 (927) | |
| $CO_2$ transport/storage cost, $/t $CO_2$ | | | 6.59 | | 6.47 | | 6.50 | |
| Interest during construction, % of overnight construction cost (years of construction) | 12.3 (4) | | 12.3 (4) | | 12.3 (4) | | 12.3 (4) | |
| Plant capacity factor, percent | 80 | | 80 | | 80 | | 80 | |
| **Levelized production cost, $/$GJ_{LHV}$** | | | | | | | | |
| Capital | 10.63 | | 11.63 | | 10.60 | | 10.87 | |
| Operation and maintenance | 2.52 | | 2.76 | | 2.52 | | 2.58 | |
| Coal input | 4.01 | | 4.21 | | 4.20 | | 3.06 | |
| Switchgrass input | | | | | | | 2.86 | |
| Electricity co-product credit | -5.88 | -8.59 | -5.49 | -8.03 | -5.47 | -7.99 | -5.87 | -8.58 |
| $CO_2$ transport/storage cost | | | 1.11 | | 1.12 | | 1.17 | |
| GHG emissions cost | - | 7.38 | - | 3.14 | - | 3.00 | - | 3.07 |
| Credit for bio-$CO_2$ storage | | | | | | | | -2.16 |
| Total | 11.28 | 15.96 | 14.22 | 14.82 | 12.97 | 13.46 | 14.65 | 12.85 |
| F-T liquids prod cost, $/gallon gasoline equivalent (ge) | 1.34 | 1.90 | 1.69 | 1.76 | 1.54 | 1.59 | 1.74 | 1.53 |
| Breakeven crude oil price, $/barrel | 50.4 | 61.7 | 66.2 | 55.6 | 59.6 | 47.8 | 68.6 | 45.0 |

| **Table 2: Economics of making F-T liquids from coal or coal + biomass if $CO_2$ is used for EOR** (Base Case financing) | | | | | | |
|---|---|---|---|---|---|---|
| **Conversion Option** | **C-FT-C** | | **C-FT-CoC** | | **C/B-FT-CoC** | |
| $CO_2$ available for EOR, t $CO_2$/hour | 628.4 | | 646.0 | | 667.5 | |
| Barrels of crude EOR/barrel of F-T liquids (ge) | 4.00 | | 4.11 | | 4.25 | |
| Price of GHG emissions, \$/tC$_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Electricity co-product value, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 |
| Price at which $CO_2$ is sold for EOR, \$/t $CO_2$ | 23.6 | 19.6 | 20.9 | 16.5 | 23.9 | 15.2 |
| $CO_2$ transport cost (100 km), \$/t $CO_2$ | 2.94 | | 2.89 | | 2.84 | |
| Interest during construction, % of overnight construction cost (years of construction) | 12.3 (4) | | 12.3 (4) | | 12.3 (4) | |
| Plant capacity factor, percent | 80 | | 80 | | 80 | |
| **Levelized production cost, \$/GJ$_{LHV}$** | | | | | | |
| Capital | 11.63 | | 10.60 | | 10.87 | |
| Operation and maintenance | 2.76 | | 2.52 | | 2.58 | |
| Coal input | 4.21 | | 4.20 | | 3.06 | |
| Biomass input | | | | | 2.86 | |
| Electricity co-product credit | -5.49 | -8.03 | -5.47 | -7.99 | -5.87 | -8.58 |
| $CO_2$ transport cost | 0.50 | | 0.50 | | 0.51 | |
| GHG emissions cost | - | 3.14 | - | 2.92 | - | 3.07 |
| Credit for EOR | - 3.99 | - 3.31 | - 3.63 | - 2.86 | - 4.30 | - 2.73 |
| Credit for bio-$CO_2$ storage | | | | | | -2.16 |
| Total | 9.61 | 10.89 | 8.73 | 9.89 | 9.70 | 9.46 |
| F-T liquids production cost, \$/gallon, ge | 1.14 | 1.30 | 1.04 | 1.18 | 1.15 | 1.13 |
| Breakeven crude oil price, \$/barrel | 41.4 | 34.4 | 36.6 | 28.9 | 41.9 | 26.7 |

| **Table 3: F-T liquids from biomass with $CO_2$ vented or stored in an aquifer or $CO_2$ used for EOR** (Base Case financing) | | | | | | |
|---|---|---|---|---|---|---|
| | **B-FT-V** | | **B-FT-C** | | | |
| $CO_2$ storage mode | None | | $CO_2$-AqS | | $CO_2$-EOR | |
| Price of GHG emissions, $/tC_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Electricity co-product value, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 |
| $CO_2$ selling price, \$/t $CO_2$ (= 0.57 x the crude oil price in \$/bbl) | | | | | 32.6 | 11.9 |
| Switchgrass input, kgC/s ($MW_{LHV}$) | 24.7 (893) | | 24.7(893) | | | |
| F-T liquids out, kgC/s ($MW_{LHV}$) [bbl/day gasoline equivalent] | 6.2 (305) [5272] | | 6.2 (306) [5285] | | | |
| Electric power output, MW | 207 | | 191 | | | |
| $CO_2$ emissions from plant, kgC/s | 18.5 | | 6.2 | | | |
| $CO_2$ captured & stored, kgC/s [t $CO_2$ /$GJ_{FTL}$] | | | 12.3 [0.147] | | | |
| Fuel cycle net GHG emissions, $gC_{equiv}$/kWh electricity | 15.0 | | - 209.5 | | | |
| Fuel cycle GHG emissions, $kgC_{equiv}/GJ_{LHV}$ FT (relative to emissions for crude oil-derived fuels) | 3.21 (0.12) | | 2.15 (0.08) | | | |
| Incremental crude oil via $CO_2$-EOR, barrels per barrel of F-T liquids (gasoline equivalent) | | | | | 3.48 | |
| $CO_2$ transport cost, \$/t $CO_2$ | | | 5.94 | | | |
| $CO_2$ storage cost, \$/t $CO_2$ | | | 3.53 | | 0 | |
| Overnight construction cost, $\$10^6$ | 541 | | 557 | | | |
| Specific overnight construction cost allocated to liquid fuel production, \$ per barrel per day of gasoline equivalent (\$ per kW) | 64,596 (1117) | | 53,646 (927) | | | |
| Interest during construction, % of overnight construction cost (years of construction) | 12.3 (4) | | 12.3 (4) | | | |
| Plant capacity factor, percent | 80 | | 80 | | | |
| **Levelized production cost, $/GJ_{LHV}$** | | | | | | |
| Capital | 11.85 | | 12.17 | | | |
| Operation and maintenance | 2.81 | | 2.89 | | | |
| Switchgrass input | 9.67 | | 9.64 | | | |
| Electricity co-product credit | -8.93 | -13.04 | -8.23 | -12.01 | -8.23 | -12.01 |
| $CO_2$ transport cost | | | 0.87 | | | |
| $CO_2$ storage cost | | | 0.52 | | 0 | |
| GHG emissions cost | 0 | 0.60 | 0 | 0.60 | 0 | 0.60 |
| Credit for $CO_2$ sold for EOR | | | | | -4.80 | -1.75 |
| Credit for bio-$CO_2$ storage | | | 0 | - 4.02 | 0 | -4.02 |
| Total | 15.40 | 11.90 | 17.86 | 10.67 | 12.54 | 8.40 |
| F-T liquids product cost, \$/gallon gasoline equivalent | 1.83 | 1.42 | 2.13 | 1.27 | 1.49 | 1.00 |
| Breakeven crude oil price, \$/barrel | 72.6 | 39.7 | 85.9 | 33.1 | 57.2 | 20.9 |

| **Table 4: Performance and cost of cellulosic EthOH production from switchgrass** (Base Case financing) | | | | |
|---|---|---|---|---|
| Technology status | Current (2000) | | Advanced | |
| Value of GHG emissions, $\$/tC_{equiv}$ | 0 | 100 | 0 | 100 |
| Value of co-product electricity, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 |
| Liquid fuel output capacity, barrels per day of gasoline equivalent (MW LHV) | 1148 (66.4) | | 3158 (183) | |
| Liquid fuel yield per dt of switchgrass allocated to making liquid fuel, GJ LHV | 5.13 | | 7.89 | |
| Electric output capacity, $MW_e$ | 8.3 | | 24.8 | |
| Electricity coproduction rate, $kWh/GJ_{LHV}$ of EthOH | 34.7 | | 37.8 | |
| Biomass processing rate, dry tonnes/day | 1118.6 | | 2000 | |
| Net GHG emissions allocated to liquid fuel, $kgC_{equiv}/GJ_{LHV}$ | 6.23 | | 3.83 | |
| Biomass price, $\$/GJ_{HHV}$ | 2.79 | | 2.86 | |
| Overnight construction cost for plant, $\$10^6$ | 136.1 | | 197.4 | |
| Specific overnight construction cost allocated to liquid fuel production, $ per barrel per day ($ per kW) | 111,500 (1927) | | 54,890 (949) | |
| Interest during construction, % of overnight construction cost (years of construction) | 3.9 (2) | | 3.9 (2) | |
| Plant capacity factor, percent | 90 | | 90 | |
| **Levelized production cost, $\$/GJ_{LHV}$** | | | | |
| Capital | 11.06 | | 5.86 | |
| Operation and maintenance | 7.04 | | 3.78 | |
| Switchgrass | 9.77 | | 6.51 | |
| Coal | - | | - | |
| Electricity coproduct credit | -1.65 | - 2.41 | - 1.79 | - 2.62 |
| GHG emissions | 0 | 0.68 | 0 | 0.44 |
| Total | 26.22 | 26.14 | 14.36 | 13.97 |
| Total production cost, $ per gallon of gasoline equivalent | 3.12 | 3.11 | 1.71 | 1.66 |
| Total production cost relative to cost of gasoline from $50/barrel crude | 2.13 | 1.76 | 1.17 | 0.94 |

| **Table 5: Performances and costs for coal IGCC power plants**[a] (Base Case financing) | | | | | | |
|---|---|---|---|---|---|---|
| **Conversion Option** | **C-IGCC-V** | | **C-IGCC-C** | | | |
| Storage mode | | | $CO_2$-AqS | | $CO_2$-EOR | |
| Price of GHG emissions, $/tC$_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Installed capacity, $MW_e$ | 390.1 | | 361.9 | | | |
| $CO_2$ storage rate, t $CO_2$/hour | | | 297.3 | | | |
| $CO_2$-EOR supported, barrels/day of incremental crude oil produced | | | | | 27,200 | |
| $CO_2$ emission rate from plant, t $CO_2$/hour | 301.5 | | 25.2 | | | |
| Fuel cycle GHG emission rate, gC$_{equiv}$/kWh | 219.4 | | 28.8 | | | |
| Efficiency at design point, LHV | 42.95 | | 36.79 | | | |
| $CO_2$ transport cost, $/t $CO_2$ | | | 4.33 | | | |
| $CO_2$ storage cost, $/t $CO_2$ | | | 3.84 | | - | |
| Price at which $CO_2$ is sold for EOR, $/t $CO_2$—assumed to be the same as for the C-FT-C option in Table 2 (assumed crude oil price, $/barrel) | | | | | 23.6 (41.4) | 19.6 (34.4) |
| Overnight construction cost (OCC), $/kW$_e$ | 1187 | | 1531 | | | |
| Interest during construction, % of overnight construction cost (years of construction) | 12.3 (4) | | 12.3 (4) | | | |
| Plant capacity factor, percent | 80 | | 80 | | | |
| **Levelized production cost, ¢/kWh** | | | | | | |
| Capital | 2.85 | | 3.68 | | | |
| Operation and maintenance | 0.68 | | 0.87 | | | |
| Fuel | 1.22 | | 1.42 | | | |
| $CO_2$ transport | | | 0.36 | | | |
| $CO_2$ storage | | | 0.31 | | - | |
| Credit for EOR | | | | | - 1.94 | - 1.61 |
| GHG emissions | 0 | 2.19 | 0 | 0.29 | 0 | 0.29 |
| Total | 4.75 | 6.94 | 6.64 | 6.93 | 4.39 | 5.01 |

[a] Based on [8, 9] except that (as for the F-T polygeneration analysis) the coal is assumed to have a heating value of 23.5 GJ$_{LHV}$/tonne and a C content of 25.2 kgC/GJ$_{LHV}$.

| **Table 6: Performances and costs for biomass IGCC power plants** (Base Case financing) | | | | | | |
|---|---|---|---|---|---|---|
| | **B-IGCC-V** | | **B-IGCC-C** | | | |
| $CO_2$ storage mode | None | | $CO_2$-AqS | | $CO_2$-EOR | |
| Price of GHG emissions, $/tC_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Installed capacity, $MW_e$ | 442 | | 351.6 | | | |
| $CO_2$ storage rate, t $CO_2$/hour | | | 294 | | | |
| $CO_2$ emission rate from plant, t $CO_2$/hour | 325.6 | | 31.6 | | | |
| Fuel cycle net GHG emissions, $gC_{equiv}/kWh$ | 15.0 | | - 209.5 | | | |
| Efficiency at design point, LHV | 0.494 | | 0.394 | | | |
| $CO_2$ transport cost, $/t $CO_2$ | | | 4.36 | | | |
| $CO_2$ storage cost, $/t $CO_2$ | | | 3.87 | | 0 | |
| Price $CO_2$ sold for EOR, $/t $CO_2$ –assume same as price in FT-C option in Table 2 (assumed crude oil price, $/barrel—breakeven price for FT-C) | | | | | 32.6 (57.2) | 11.9 (20.9) |
| $CO_2$-EOR supported, barrels/day of incremental crude oil produced | | | | | 26,700 | |
| Overnight construction cost (OCC), $/kW_e$ | 968 | | 1431 | | | |
| Interest during construction, % of overnight construction cost (years of construction) | 12.3 (4) | | 12.3 (4) | | | |
| Plant capacity factor, percent | 80 | | 80 | | | |
| **Levelized production cost, ¢/kWh** | | | | | | |
| Capital | 2.33 | | 3.44 | | | |
| Operation and maintenance | 0.55 | | 0.81 | | | |
| Fuel | 2.40 | | 3.02 | | | |
| $CO_2$ transport | | | 0.36 | | | |
| $CO_2$ storage | | | 0.32 | | 0 | |
| Credit for bio-$CO_2$ storage | | | 0 | -2.28 | 0 | -2.28 |
| Credit for $CO_2$ sold for EOR | | | | | -2.73 | -1.00 |
| GHG emissions | 0 | 0.15 | 0 | 0.19 | 0 | 0.19 |
| Total | 5.28 | 5.43 | 7.96 | 5.87 | 4.91 | 4.55 |
| Real internal rate of return on equity if B-IGCC power is sold at a price equal to the levelized production cost for the least costly C-IGCC option, %/year | 9.31 | 25.1 | neg | 19.7 | 13.1 | 25.9 |
| Carbon price required to realize same real internal rate of return for B-IGCC-C with $CO_2$–AqS and B-IGCC-V, $/tC (real internal rate of return at that carbon price, %/y) | 152 (26.6) | | | | | |