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Fuels and electricity from biomass with CO_2 capture and storage

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Abstract

Mass/energy balances and financial analysis are presented for (1) plants co-producing Fischer-Tropsch diesel and gasoline blendstocks plus electricity from biomass and (2) biomass integrated gasification combined cycle power plants. Plant designs with and without carbon capture and storage are analyzed. The feedstock is switchgrass. For plants with CO_2 capture, we assume that the CO_2 is stored in deep saline aquifers or used for enhanced oil recovery.

Keywords: biomass, gasification, Fischer-Tropsch, IGCC, CO_2

Introduction

Sustainably produced biomass is an essentially carbon-neutral energy source since the CO_2 emitted from its use as energy is of recent photosynthetic origin. By capturing and storing below ground some carbon from biomass during its conversion to fuel or electricity, this biomass becomes a negative CO_2-emitting energy supply. This paper summarizes and extends detailed analyses [1,2] of mass/energy balances and economics for plants that co-produce Fischer-Tropsch (FT) diesel and gasoline blendstocks plus electricity from biomass, with and without carbon capture and storage (CCS). Stand-alone biomass integrated gasification combined cycle (IGCC) power generation with and without CCS is similarly analyzed. For plants with CCS, overall economics are explored assuming the CO_2 is stored in deep saline aquifers or used for enhanced oil recovery (EOR). The feedstock is switchgrass, a perennial grass native to the Great Plains of the USA that is a promising future bioenergy crop [3,4].

Methodology

We use Aspen Plus software to help design the FT and IGCC plants and calculate mass/energy balances. Some equipment components in our plants are not commercially available today but can be expected to be so in the 2010-2015 timeframe. To help understand the potential for these biomass conversion systems in this timeframe and beyond, our process simulations assume that key achievable technology advances are, in fact, realized. These include feeding of switchgrass to a pressurized fluidized-bed gasifier, reliable high-efficiency oxygen-blown fluidized-bed gasification, complete tar cracking in a separate vessel following gasification, and gas cleanup to specifications for downstream synthesis or gas turbine combustion.

We consider a switchgrass feed rate of 5,669 tonnes per day (20% moisture as received), or 4535 dry tonnes per day. This scale of bioenergy conversion 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). When switchgrass is produced as an agricultural crop, average transport distances will be relatively modest for delivering feedstock to conversion facilities of the size we consider here. In earlier work we have 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 [5].

All plants include chopping of the switchgrass, followed by oxygen-blown fluidized-bed gasification, gas cooling and gas cleanup. In our IGCC design with CCS (IGCC-C), CO_2 is removed with Rectisol technology following water gas shift (WGS), after which the remaining hydrogen-rich syngas is burned in a gas turbine combined cycle. With CO_2 venting (IGCC-V), no

WGS or Rectisol is required. Gas turbine operating parameters (in both IGCC designs and also in our FT designs) are modeled on those of GE's 7FB turbine. Captured CO_2 at IGCC-C and FT-C plants is dried and compressed to 150 bar, transported 100 km, and injected 2 km below ground for aquifer storage or used for EOR.

In our FT designs (Figure 1), the clean syngas leaving the gas cleanup area contains (dry volume basis) 23% CO, 40% H_2, 31% CO_2, 5% CH_4, and trace other components. CO_2 is removed using a Rectisol system together with the approximately 500 ppmv of H_2S in the gas. H_2S is removed to protect the downstream synthesis catalyst. CO_2 is removed to reduce synthesis reactor size/cost and to improve modestly the synthesis rate. A commercially-available liquid-phase synthesis reactor with iron-based catalyst (to avoid the need for an upstream WGS reactor) is used in a "once-through" configuration, whereby syngas unconverted in one pass is burned in a gas turbine combined cycle to make electricity to meet process needs and for export to the grid. Their high single-pass conversion rates make liquid-phase reactors especially attractive from a cost perspective for co-production process designs [6]. The raw mix of FT synthesis products is sent to an integrated refinery area to produce gasoline and diesel blendstocks in a mass ratio of 62:38. Light (C_1-C_4) gases from refining are burned with the unconverted syngas in the gas turbine.

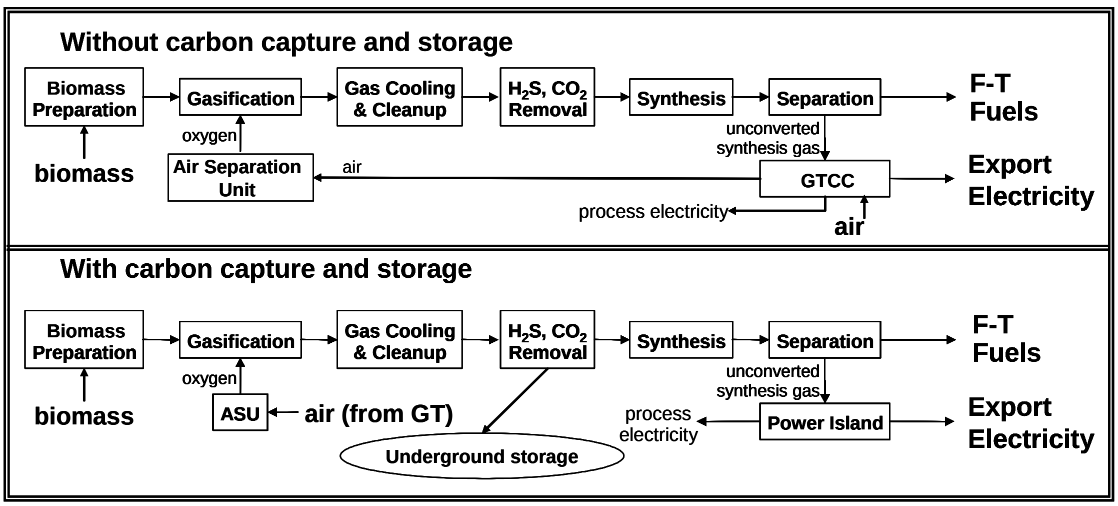

Figure 1. Simplified process configurations for co-production of FT fuels and electricity.

We estimate installed capital costs assuming commercially-mature Nth plants based on our process simulations. Costs are developed by sub-unit in major plant areas using a cost database developed from our own prior work, from literature studies, and from discussions with industry experts. The level of detail in our process simulations and accompanying cost estimates, including multiple trains for some components, yields an estimated uncertainty of ±30% in our capital costs.

The relatively large scale of our plant designs enables equipment scale economies to be captured, but also requires switchgrass supply from energy plantations for manageable feedstock costs and logistics. From plantations in the United States, switchgrass can be delivered for an average price of $\$3/GJ_{HHV}$ [3], the biomass price we assume in our analysis.

The values for other input parameters and the overall framework for our financial analysis parallel those described in a companion paper [7]. Key assumptions include 80% plant capacity factor, 55/45 debt/equity financing, 4.4%/yr real cost of debt, 30-year (20-year) plant (tax) life, 38.2% corporate income tax rate, property tax and insurance of 2% of installed cost per year, and a four-year plant construction time. Our Base Case financing assumes a real rate of return on equity (ROE) of 14%/yr, giving a real weighted after-tax cost of capital (discount rate) of 7.8%/yr and a levelized annual capital charge rate of 15%.

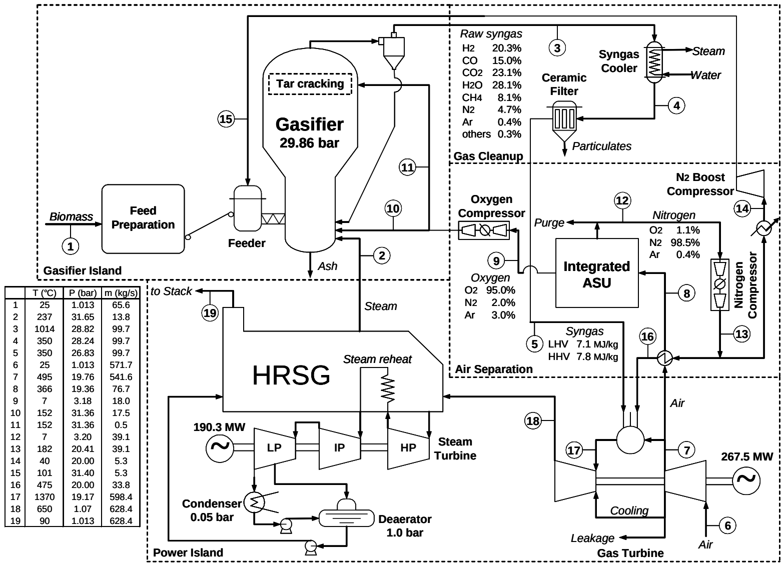

Figure 2. Mass/energy balance for stand-alone electricity generation with CO_2 venting (IGCC-V).

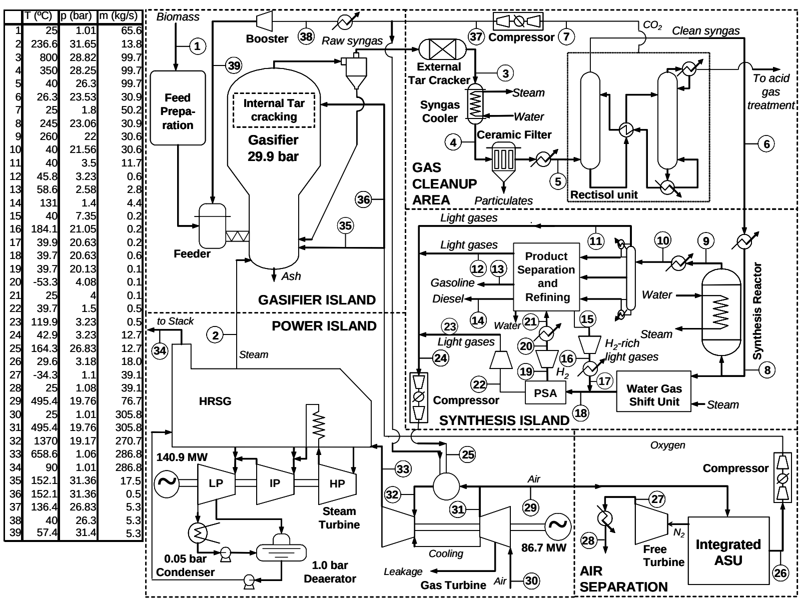

Figure 3. Mass/energy balance for co-producing FT fuels and electricity with CO_2 venting (FT-V).

Costs for CO_2 transport and for aquifer storage are based on the model of Ogden [8], assuming a maximum CO_2 injection rate per well of 1000 t/day, a typical value for mid-continental aquifers. For EOR applications we assume that CO_2 is sold (after 100 km transport) for a price in $ per thousand standard cubic feet (1 tonne = 19,000 scf) equal to 3% of the oil price in $/barrel [7]. We assume that the amount of CO_2 injected to produce an incremental barrel of crude averages 0.21 tonnes [7].

Financial results are given for two monetary values of GHG emissions: $0/tC and $100/tC. Carbon emitted at the plant and during later combustion of the FT fuels is excluded from our GHG accounting, since it is of recent photosynthetic origin. However, we include upstream GHG emissions that arise during production and transport of switchgrass (2.06 kg of carbon equivalent per GJ_{LHV}, based on the Argonne National Laboratory's GREET model). For accounting purposes, when fuels and electricity are co-produced, we allocate carbon emissions to electricity (in gC_{equiv}/kWh) equal to those for biomass IGCC plants and the rest to fuels. Carbon stored in an aquifer or an oil well is counted as negative emissions.

Co-product electricity from the FT plants is sold at a price equal to the cost of generating electricity using the least-costly stand-alone coal-IGCC system, assuming the long-run marginal cost for this technology will set the market price for electricity in the USA. For a GHG value of $0/tC ($100/tC), this is 4.75 ¢/kWh (6.94 ¢/kWh) [7].

Breakeven crude oil prices are estimated assuming that the FT fuels compete with gasoline and low-sulfur diesel derived from crude oil. For a 62:38 diesel:gasoline mix, we estimate the refining margin on crude oil to be $10.4/barrel.

Results and conclusions

Figures 2 and 3 give mass/energy balances for the IGCC-V and FT-V designs. Table 1 gives capital cost estimates (including equipment, installation, balance of plant, and all indirect costs) for IGCC-

V, IGCC-C, FT-V, and FT-C plants. The installed cost (overnight construction) for the IGCC-V plant is \$968/kW$_e$, which is consistent with an installed cost of \$1200/kW$_e$ for a coal-IGCC plant of similar scale with GE quench-gasifier and 7FB gas turbine, as discussed by Larson [1].

Table 1. Installed capital cost estimates (million \$2003). Capacity of each plant is 4535 dry metric tonnes per day of switchgrass input.

	IGCC-V	IGCC-C	FT-V	FT-C
Biomass preparation & handling	46.6	46.6	46.6	46.6
Gasifier and ash cyclone	34.5	34.5	34.5	34.5
Syngas cooler	65.4	51.4	51.6	51.6
Gas cleaning	24.2	26.9	26.8	26.8
Two-stage water gas shift		29.5		
Rectisol plant		47.3	44.0	41.4
CO_2 compressor		11.1	7.60	7.68
Supercritical CO_2 compressor		7.5	--	5.04
FT synthesis reactor			38.77	43.99
FT Upgrading area				
Hydrocarbon recovery plant			7.42	7.43
H_2 recovery			3.49	3.49
Wax hydrocracking			34.65	34.65
Distillate hydro treatment			5.63	5.63
Naphtha hydro treating			3.37	3.37
Naphtha reforming			21.09	21.09
C_5/C_6 Isomerization unit			3.65	3.65
CO shift reactor plant			1.86	1.87
Fuel gas compressor			3.87	3.88
Air separation unit (ASU)	25.7	25.9	25.75	25.75
O_2 compressor	4.6	4.6	4.68	4.68
N_2 expander			1.23	--
N_2 compressor	5.5	5.6	--	6.34
Gas Turbine	71.4	66.1	30.65	33.96
HRSG + heat exchangers	77.2	80.6	84.77	86.02
Steam cycle (ST + condenser)	72.4	65.5	59.17	57.62
Overnight installed capital cost	428	503	541	557

For an FT plant (Table 2), one-quarter of the biomass carbon leaves the plant in FT fuel. For the FT-C case 50% of the biomass carbon is captured for aquifer storage or EOR use. For the FT-V and FT-C cases, the fuel-cycle GHG emissions per GJ of FT fuel are 12% and 8%, respectively, of the emissions of the crude-oil-derived hydrocarbon fuels displaced. The CO_2 captured during FT production and used for EOR results in 3.5 barrels of incremental crude oil production per barrel (gasoline-equivalent) of FT fuel produced.

Table 2 shows a breakdown of FT production cost with <u>Base Case</u> financing. With CO_2 vented, the net total production cost corresponds to a breakeven crude oil price of \$73/bbl (\$40/bbl) for a carbon value of \$0/tC (\$100/tC). With CO_2 captured for aquifer storage, these values are \$86/bbl (\$33/bbl). Selling CO_2 for EOR dramatically reduces the breakeven oil price – to \$57/bbl (with \$0/tC) and \$21/bbl (with \$100/tC).

Table 3 gives results for the IGCC energy/carbon balances and economics with <u>Base Case</u> financing. Fuel cycle GHG emissions per kWh for an IGCC-V plant are 7% of the emissions for a coal IGCC-V plant, and net emissions for an IGCC-C plant (with stored CO_2 being negative emissions) are strongly negative. These negative emissions can be used to offset emissions from difficult-to-decarbonize CO_2 sources such as fossil fuels used in transportation. The net electricity production cost is 5.3 to 5.4 ¢/kWh with CO_2 venting. With CO_2 sold for EOR, the net production cost for an IGCC-C plant falls below 5 ¢/kWh.

We extended the economic analysis beyond the <u>Base Case</u> financing to estimate the ROE as a function of oil price for all IGCC and FT plants—assuming all financial parameters other than ROE remain as for <u>Base Case</u> financing.

For a zero carbon price (Figure 3, left), the IGCC-V offers the most favorable ROE up to an oil price of about \$40/bbl. At higher oil prices FT-C and IGCC-C plants offer ROEs that exceed that for IGCC-V when the captured CO_2 is used for EOR. The other options – IGCC-C and FT-C (with aquifer storage) and FT-V – provide lower or negative ROE over the range of oil prices shown.

For a carbon price of \$100/tC (Figure 3, right), the IGCC-V offers a high ROE (25%/y), exceeding the 20%/y ROE of the IGCC-C with aquifer storage. However, at oil prices above \$19/bbl, the ROE for the IGCC-V is exceeded by that for the IGCC-C when the CO_2 is sold for EOR. The ROE in the latter case reaches 30%/y with $40/bbl oil and 34%/y with $60/bbl oil. When CO_2 from the FT-C plant is sold for EOR, the ROE reaches 25%/y when oil is $50/bbl.

In summary, large-scale conversion of biomass to power or fuels can provide very attractive financial returns when carbon emissions are valued at $100/tC; at this carbon value, the incremental cost of CO_2 capture and storage is less than the negative emissions benefit. The best returns arise when CO_2 is captured and sold for enhanced oil recovery.

Table 2. F-T liquids from biomass with CO_2 vented and stored via aquifer or EOR (Base Case financing)

	FT-V		FT-C			
CO_2 storage mode	none		aquifer		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			
F-T Liquids Production Cost, $/$GJ_{LHV}$ (2003 $)						
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
Net FT production cost $/$GJ_{LHV}$	15.40	11.90	17.86	10.67	12.54	8.40
F-T liquids product cost, $/liter gasoline equivalent	0.484	0.374	0.562	0.335	0.394	0.264
Breakeven crude oil price, $/barrel	72.6	39.7	85.9	33.1	57.2	20.9

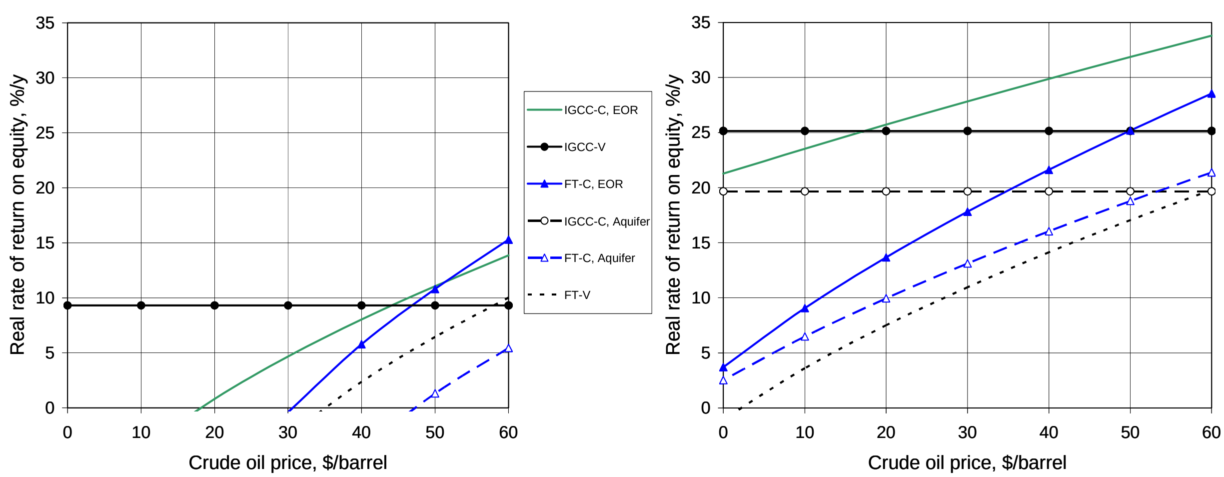

Figure 3. Return on equity as a function of crude oil price with carbon value of $0/tC (left) and $100/tC (right).

Table 3. Performances and costs for biomass IGCC power plants (base case financing).

	B-IGCC-V		B-IGCC-C			
CO_2 storage mode	none		Aquifer		EOR	
Price of GHG emissions, $/tC$_{equiv}$	0	100	0	100	0	100
Installed capacity, MW$_e$	442		351.6			
CO_2 storage rate, tCO_2/hour			294			
CO_2 emission rate from plant, tCO_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			
Generation Cost, ¢/kWh (2003$)						
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
Net total production cost, ¢/kWh	5.28	5.43	7.96	5.87	4.91	4.55

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