Techno-Economic Systems Analysis of Jet Fuel and Electricity Co-Production from Biomass and Coal with CO_2 Capture: an Ohio River Valley (USA) Case Study

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System and Integration Aspects of Biomass-Based Gasification Joint Workshop between IEA Bioenergy Task 33 and IEA Industrial Energy-Related Technologies and Systems
19-20 November 2013, Gothenburg, Sweden

Financial support for the research described here was provided by the U.S. Department of Energy's National Energy Technology Laboratory, the Edgerton Foundation, and Princeton University's Carbon Mitigation Initiative.

Abstract

Globally, air transportation consumes more than 100 million tons of jet fuels annually, and the IEA expects greenhouse gas emissions from air travel to increase from about 14% of global transportation emissions in 2005 to 20% by 2050 as a result of a projected 4-fold growth in air travel. In the U.S. the use of petroleum-derived jet fuel is projected to increase by 14% over the next 25 years, even as projected total petroleum-derived transportation fuel use in the U.S. falls about 5%.

There are few potential low-carbon alternative fuels with the energy density and other features needed for jet aircraft. One option is co-processing of biomass and coal via gasification and Fischer-Tropsch (FT) synthesis with capture and storage of byproduct CO2. We assess the technical, economic, and environmental viability of such plants in the next 5 to 10 years in the United States' Ohio River Valley (ORV) using bituminous coal and corn stover biomass from the region. The impact of co-producing electricity is also examined, since new sources of electricity supply will be needed in the ORV as coal plant retirements accelerate due to new air pollution regulations. Siting co-processing plants at retired coal power plant sites will offer benefits with respect to permitting and public acceptance. Captured CO2 is assumed to be sold into enhanced oil recovery (EOR) markets via anticipated pipeline systems connecting the ORV to oil fields in the Gulf Coast and/or the Permian Basin.

Detailed steady-state performance simulations are developed for plants that gasify coal and biomass in separate oxygen-blown reactors and convert the resulting syngas via FT synthesis and syncrude refining into synthetic jet fuel plus gasoline. Unconverted syngas and off-gases from synthesis and refining are used to fire a gas turbine combined cycle, which additionally uses heat recovered from the synthesis reactor and elsewhere to augment steam production for a bottoming steam cycle. CO2 is captured upstream of FT synthesis, compressed to 150 bar, and sold for EOR use, as a result of which the CO2 is permanently stored underground.

Two plant configurations are analyzed, each designed for a production capacity of about 10,000 bbls/day of synthetic jet fuel and 3,000 bbls/day of coproduct synthetic gasoline. One plant (designated "HF" for High Fuel) exports 174 MW of electricity coproduct and the other ("CP" for Coproduction) exports more than double this amount, 393 MW. The biomass input capacity is 730 dry metric t/day, representing 5 to 7% of total feedstock input (HHV basis). Steady-state Aspen Plus process simulations provide a basis for greenhouse gas emission estimates and equipment sizing for purposes of capital cost estimation.

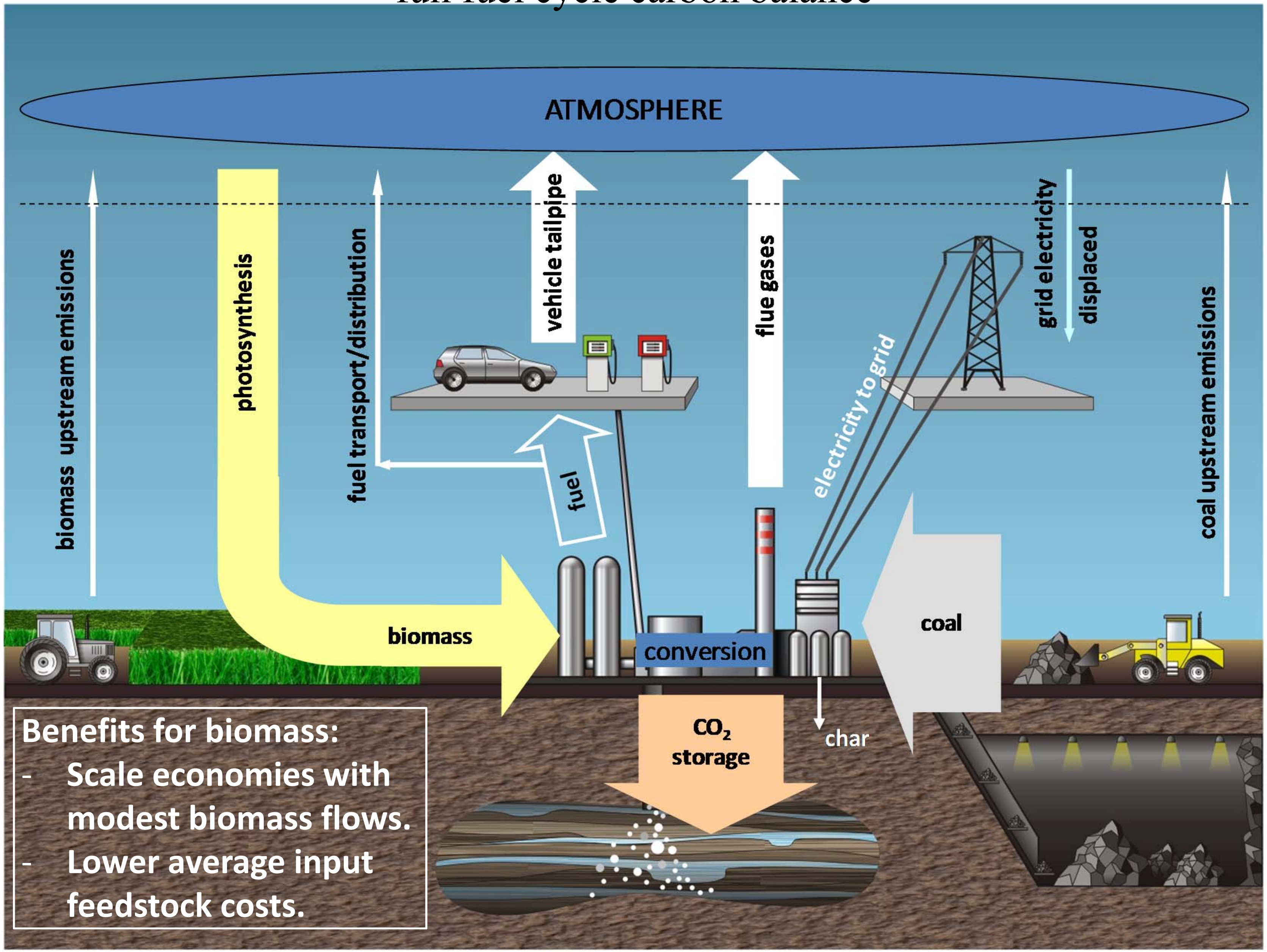
Estimated installed plant capital costs (in 2012$ for an "Nth plant") are $2.3 billion for HF and $2.7 billion for CP. The internal rates of return on equity (IRRE) depend sensitively on the assumed crude oil price. For projected coal purchase and grid-sale electricity prices in the ORV the real IRRE ranges from 8.6% percent per year for either plant at $100/bbl to 14-15% per year at $125/bbl.

Considering these plants as electricity providers, the crude oil price at which electricity could be provided at the same levelized generating cost as a new baseload natural gas gas combined cycle (NGCC) is $113/bbl for CP and $109/bbl for HF. (The IRRE values at these breakeven oil prices is 11-12 percent per year.) For perspective, the levelized crude oil price over the 20-year economic lives of such plants (assuming startup in 2021) is $124/bbl according to the Reference Scenario of the USDOE/EIA Annual Energy Outlook 2013. CP and HF plants would have ultra-low minimum dispatch costs and so would be able to defend high design capacity factors (90%). The dispatch costs for CP and HF power plants would be less than for NGCC plants for crude oil prices as low as $40 a barrel.

A key assumption underlying the above results is the absence of a carbon mitigation policy that would effectively price GHG emissions. If such a policy were in place, CP and HF plants would probably be designed with more CO2 capture and larger biomass input fractions, and economic performance may improve substantially.

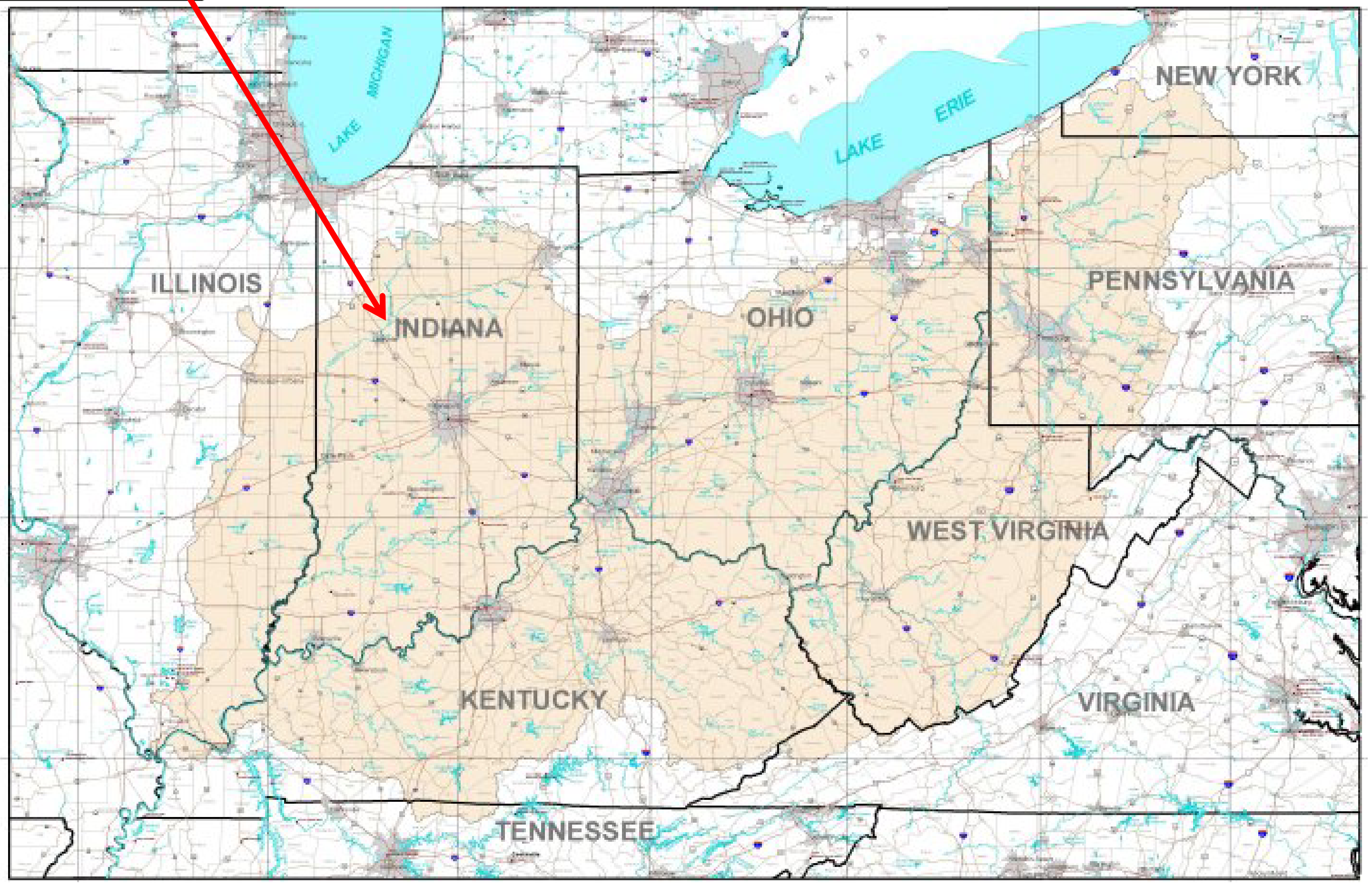
Co-Processing Biomass and Coal with CCS

full fuel cycle carbon balance



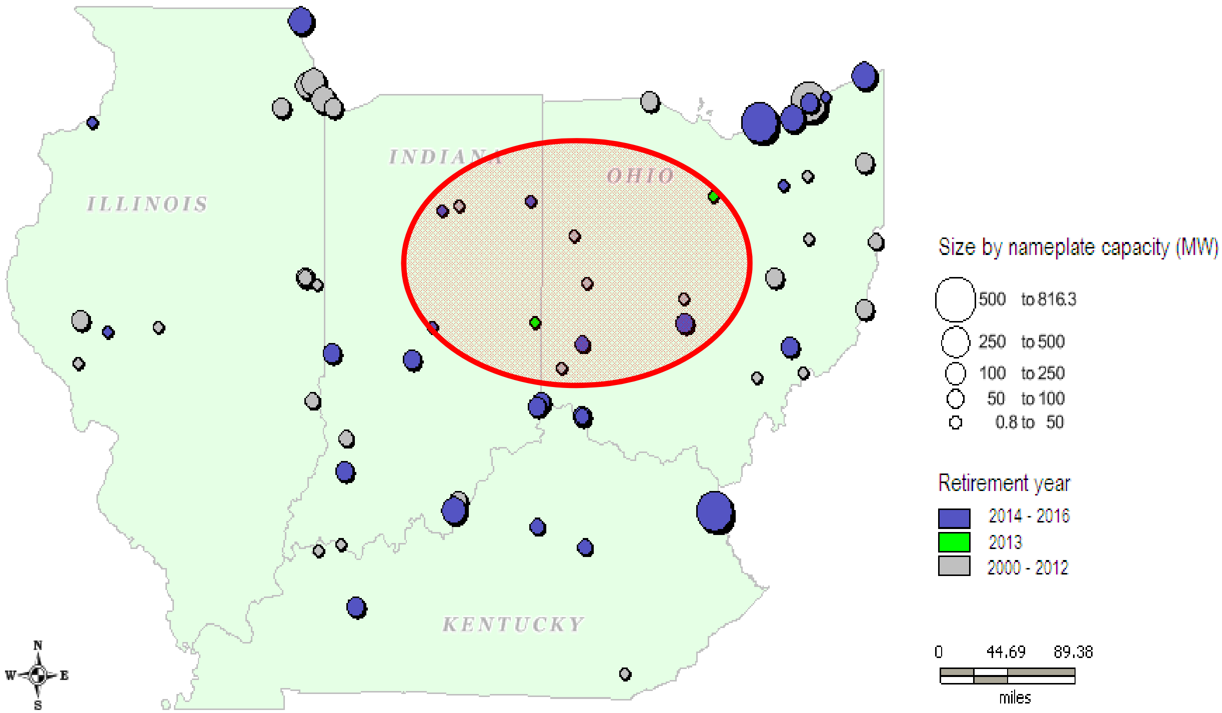
The Ohio River Valley (ORV)

- Major coal producing region.
- Major coal power producing region
- Rich agricultural producer.



Context

- Aging coal power plant industry in the ORV is facing stricter environmental regulations and low natural gas prices. Many power plants closing or already closed. As an alternative, gasification-based liquid fuel production from coal could enhance U.S. energy security, but carbon footprint would be increased.
- CO_2 capture during coal conversion would reduce carbon footprint to about the level of petroleum-derived fuels.
- Co-processing biomass with coal and capturing CO_2 can reduce the carbon footprint further.
- Co-producing electricity with liquids can help replace existing coal power and may improve the economics of low-carbon power.



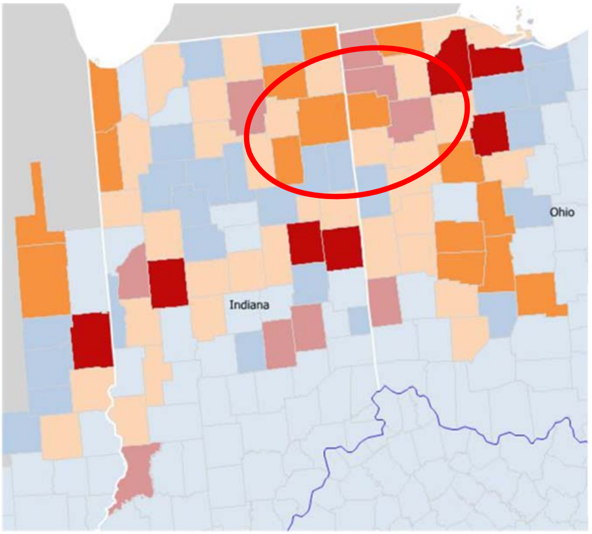
Retired, or soon-to-be retired, coal plants in the ORV

Objective and Methodology

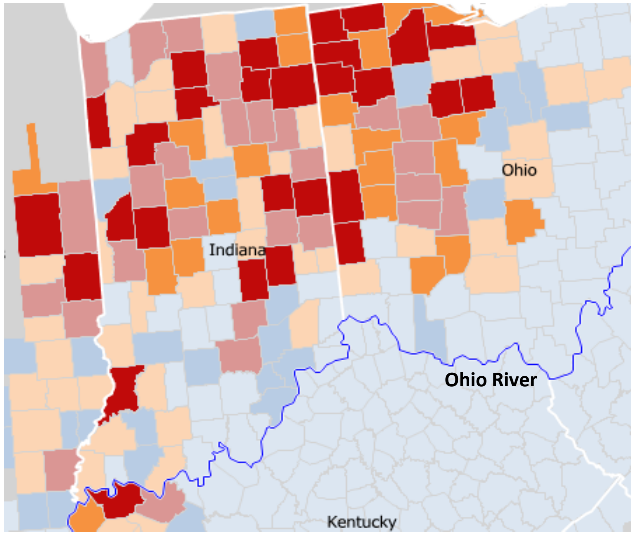
- *Objective*:
  - Assess technical, economic, and environmental viability of producing jet fuel in the ORV from Illinois #6 coal plus corn stover biomass.
- *Methodology*:
  - Biomass resource assessment based on USDOE "Billion ton study update"
  - Plant design and steady-state performance simulations (using Aspen Plus) as basis for N^{th} plant capital and operating cost estimates.*
  - Simulation outputs provide basis for N^{th} plant capital cost estimates building on Princeton unit capital cost database (which draws heavily on NETL cost studies and industry expertise).*
  - Integrated economic analysis* includes biomass logistics and CO_2 sale for use (and permanent underground storage) via enhanced oil recovery (EOR) in the U.S. Gulf Coast or Permian Basin.

* For additional background on underlying methodologies and assumptions, see Liu, G., E.D. Larson, R.H. Williams, T.G. Kreutz, X. Guo. (2011), "Making Fischer−Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis," *Energy & Fuels* **25**(1): 415-437, 2011.

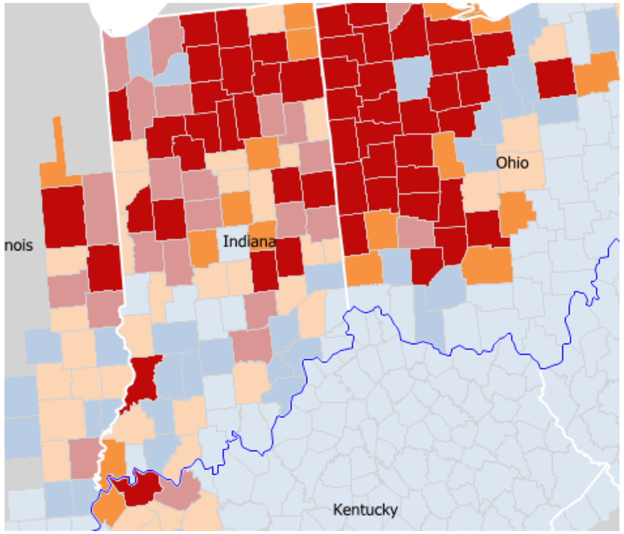
Projected (2020) county-level corn stover availability in the ORV north of the Ohio River ("Billion Ton Study")*



~4.4 million tonnes (dry) per year available baled at farm gate for \$40/dt.

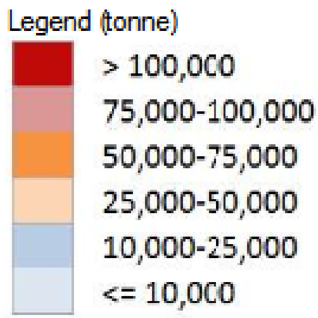


~10 million tonnes (dry) per year available baled at farm gate for \$51/dt.



~15 million tonnes (dry) per year available baled at farm gate for \$61.2/dt.

- Case study plant will use 0.2 million dt/yr.
- Truck transport to plant gate adds \$11/dry t, for total cost of bales (with 20% moisture content) delivered to plant gate of \$51/dry t (\$2.9/GJ_{HHV}).
- Projected coal and natural gas prices in the region (2021-2040) are \$2.84/GJ_{HHV} and \$5.71/GJ_{HHV}, respectively.**



* *Billion Ton Study Update:* https://bioenergykdf.net/content/billiontonupdate.

** Levelized values for the RFCW region (which includes the ORV) based on Reference Case projections of the Energy Information Administration, *Annual Energy Outlook 2013.*

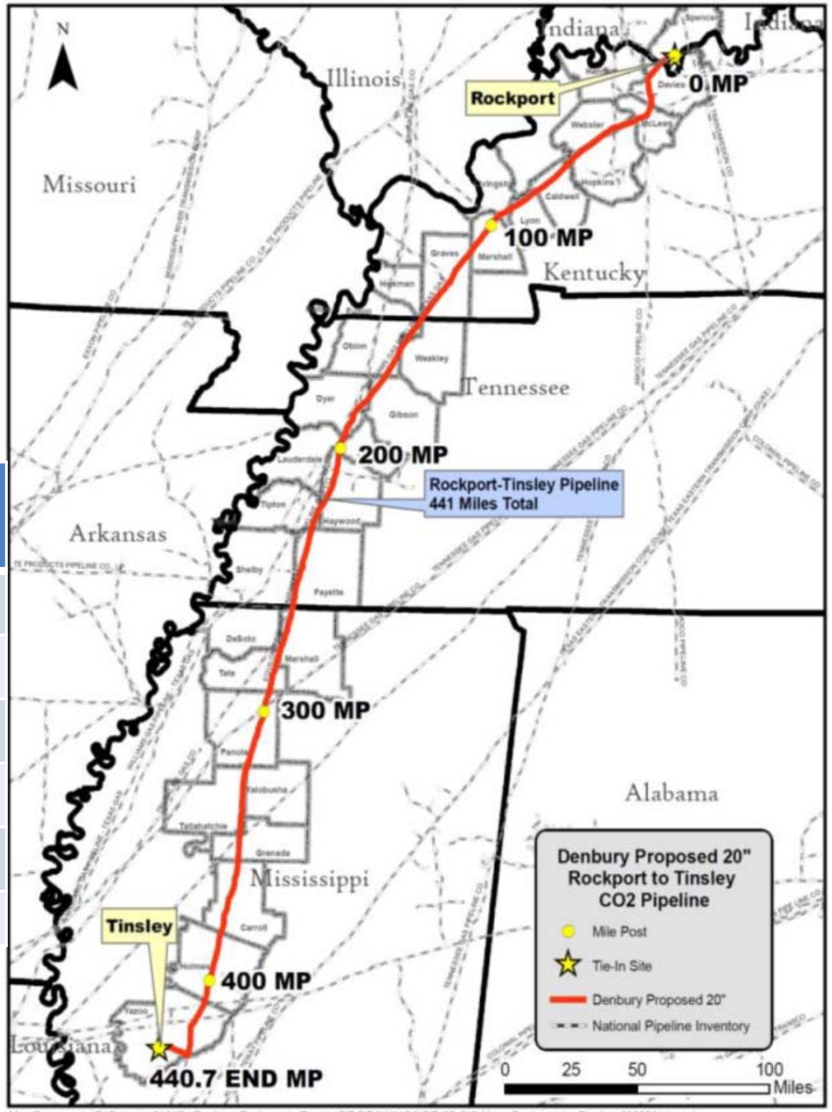
CO_2 EOR

- CO_2 EOR provides ~6% of U.S. domestic oil production today (0.28 million bbls/day).
  - Up to 3.6 million bbls/day might be produced by 2035, if there is a sufficient supply of CO_2.[1,2]
  - This implies large CO_2 storage potential (> 400 million tCO_2 per year).
  - A CO_2 pipeline from ORV to EOR sites in Mississippi has been proposed.
  - Transport cost from ORV to EOR site is estimated at about $20/$tCO_2$:

Estimated cost to transport CO_2 from the ORV to Mississippi EOR site[2]	Length (miles)	Cost ($/$tCO_2$)
Pipeline from plant to collector line [x]	100	3.8
Collector line to main trunk line [y]	300	4.6
Main trunk line [y]	441	6.7
Main trunk line to EOR site [x]	159	6.1
Totals	**1000**	**21.2**

[x] 4.5 million tCO_2/year. [y] 22.7 million tCO_2/year

- CO_2 selling price at the plant gate is estimated to be[3] ($/t) = {0.444 x ($/bbl crude oil price) – Trpt Cost}



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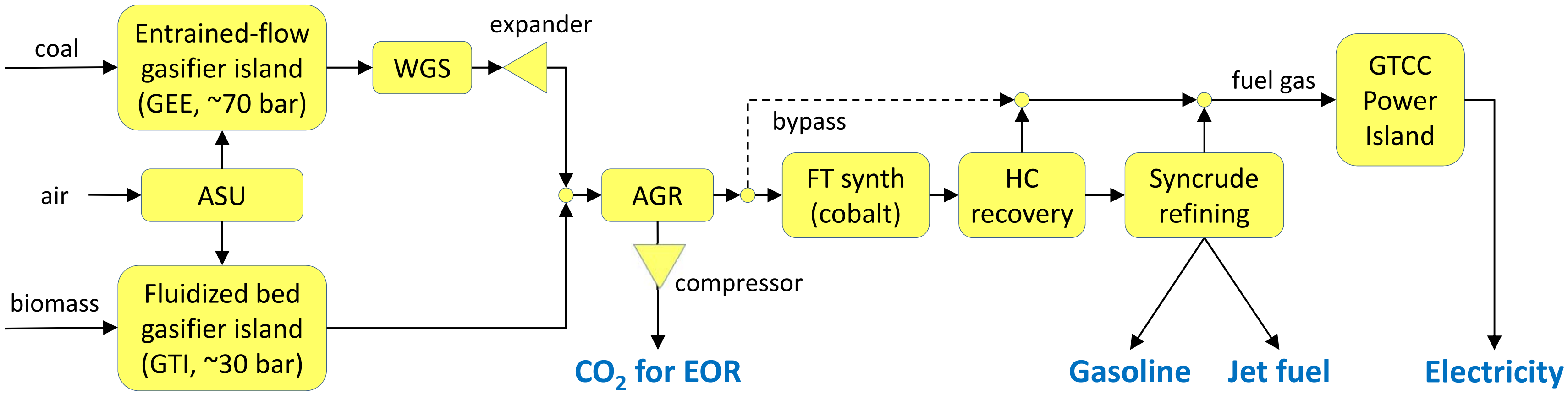
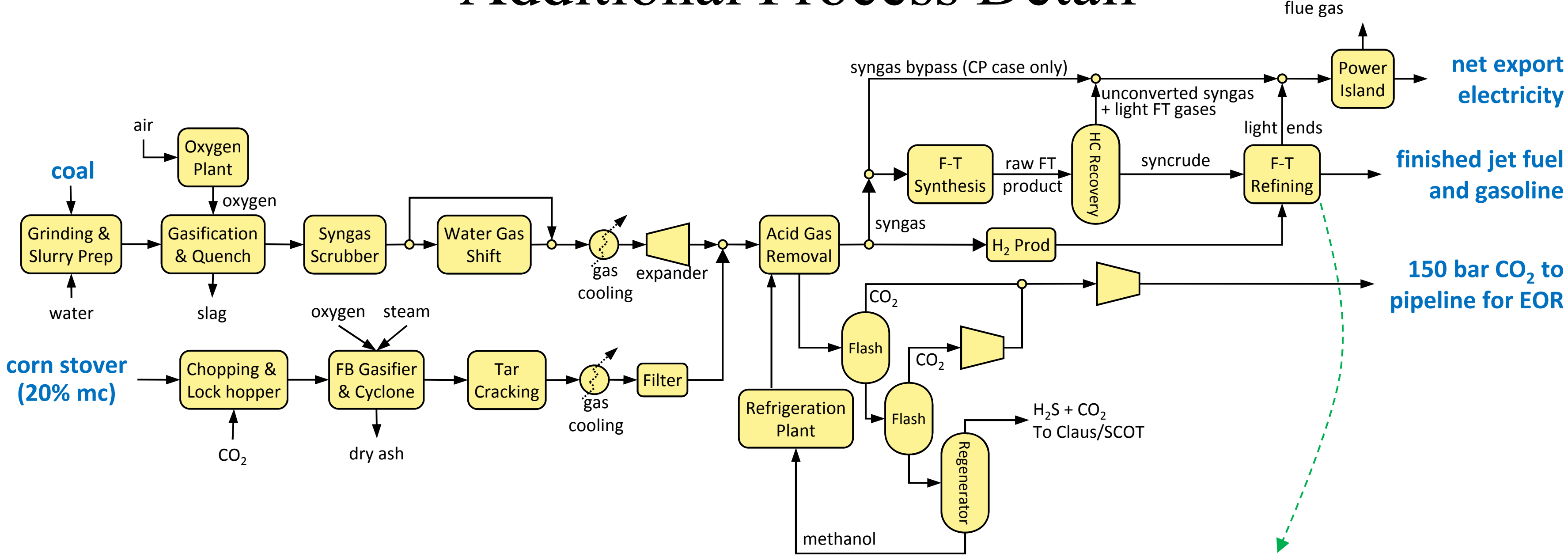
1. National Energy Technology Laboratory. "Improving Domestic Energy Security and Lowering CO2 Emissions with 'Next Generation' CO2-Enhanced Oil Recovery (CO2-EOR)," DOE/NETL-2011/1504 Activity 04001.420.02.03, June, 2011.
2. National Coal Council, "Harnessing Coal's Carbon Content to Advance the Economy, Environment, and Energy Security," June, 2012.
3. S. Wehner, "U.S. CO2 and CO2 EOR Developments," 9th CO2 EOR & Carbon Management Workshop, Houston, 5-6 December 2011.

Plant Design Overview

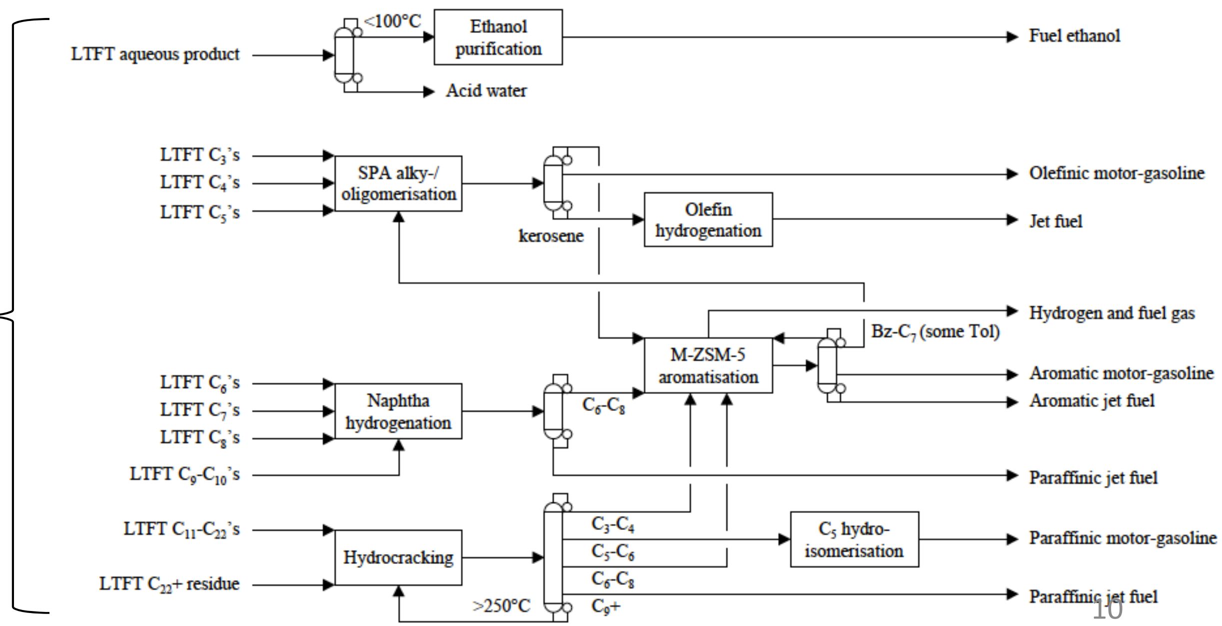


- Pressurized entrained flow slurry gasifier (GE Energy radiant quench) using Illinois #6 coal.
- Pressurized fluidized bed gasifier (GTI design) using corn stover biomass.
- Water gas shift as needed to achieve $H_2/CO = 2$ entering FT synthesis.
- Rectisol AGR for H_2S and CO_2 removal. Onsite CO_2 pressurization for pipeline transport.
- Cobalt FT synthesis (SMDS process). Refine onsite to jet fuel + finished gasoline.
- F-Class gas turbine combined cycle for on-site electricity supply and some export.
- Pinch-based process heat integration.
- Two Process Configurations
  - High Fuel (HF) produces primarily jet fuel and gasoline + small electricity byproduct
  - Coproduction (CP) produces liquid fuels plus a substantial electricity co-product.
- Plant scale determined by
  - Design liquid output capacity about 13,000 barrels per day
  - Corn stover input of 200,000 dry metric tons/yr (single gasifier < 750 t/d capacity).

Additional Process Detail



Integrated syncrude refinery designed to maximize jet fuel and also produce finished gasoline*



* Design based on A. de Klerk. (2008). "Fischer-Tropsch Refining," PhD dissertation, University of Pretoria, South Africa.

Steady-state mass/energy balance simulation results

	HF	CP
Input Feedstocks		
Coal input, AR metric t/day	5,832	7,843
Coal input, MW (HHV)	1,830	2,461
Biomass input, AR metric t/day	730	730
Biomass input rate, MW (HHV)	135	135
Liquid fuel production		
Jet fuel, barrels per day petroleum-jet equivalent	9,864	9,859
Jet fuel, MW, LHV	622	622
Gasoline, barrels per day	2,975	2,974
Gasoline, MW, LHV (HHV)	173	173
Total liquids, bbl/day	12,840	12,833
Electricity balance, MW		
Gas turbine output	102	263
Steam turbine output	186	294
Process gas expanders output	16	22
On-site consumption	-130	- 185
Net electricity to grid	174	393
Energy Ratios		
Electricity fraction of outputs (LHV)	18%	33%
Plant energy efficiency (LHV)	52%	48%

System Carbon Balances

	HF	CP
C input as coal, kgC/second	43.0	57.9
C input as biomass, kgC/second	3.37	3.37
Total feedstock C input, kgC/second	46.4	61.2
% of feedstock C as EOR-CO2	45.8%	45.9%
% of feedstock C in char	3.9%	3.9%
% of feedstock C vented to atmosphere	16.2%	24.3%
% of feedstock C in jet fuel	26.6%	20.2%
% of feedstock C in gasoline	7.4%	5.6%
Upstream CO2eq emissions (kgCeq/second)	1.62	3.26
Pounds of CO_2 vented at the plant per gross MWh of electricity produced	719	749
GHGI	0.83	0.77

$$\mathbf{GHGI} \equiv \frac{\textbf{Lifecycle emissions for the system}}{\textbf{Lifecycle emission for } \boldsymbol{reference\ system}}$$

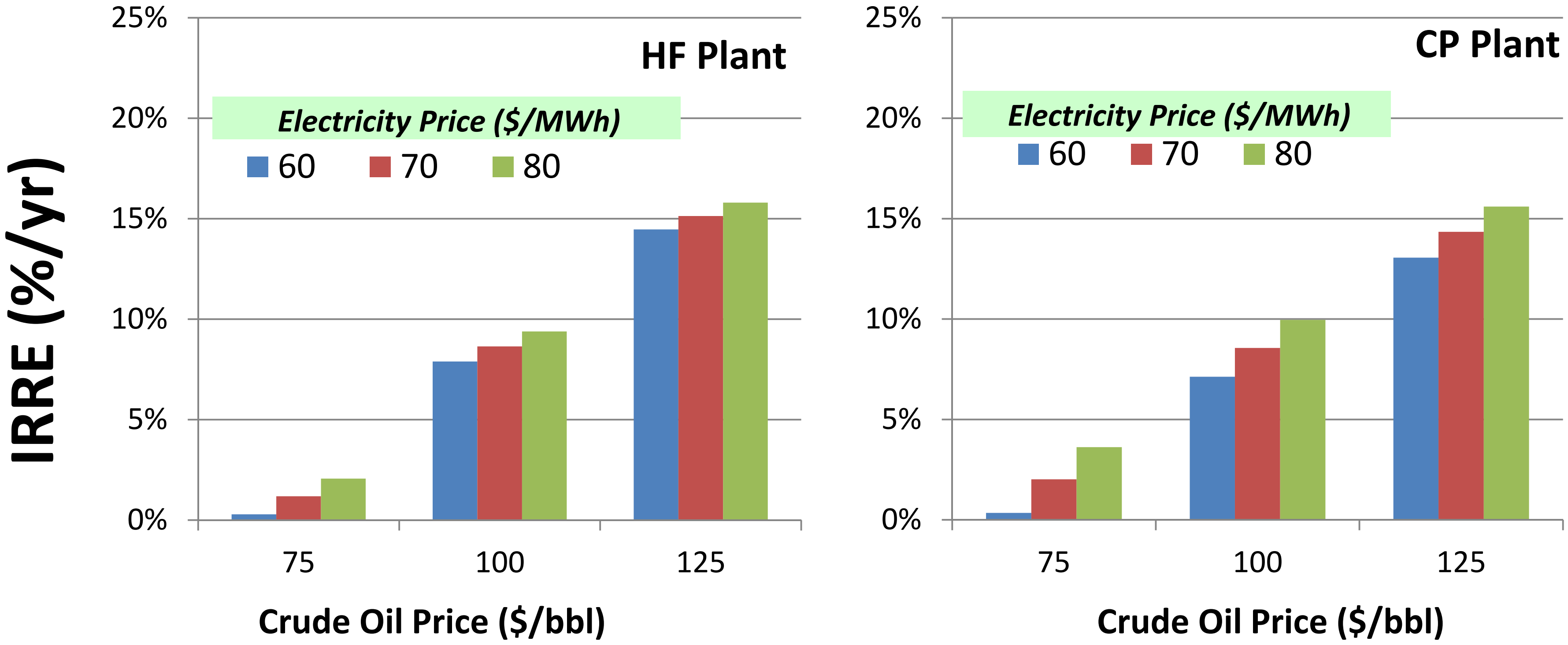
Reference system = System that makes the same amount of liquid fuels from petroleum plus the same amount of electricity from a supercritical pulverized coal plant with CO_2 venting.

Installed Capital Cost Estimates

Million 2012 US$	HF	CP
Air separation unit	256.6	295.8
N_2 compressor	6.0	14.5
Biomass preparation	11.9	11.8
Biomass gasifier and auxiliaries	87.3	87.3
Biomass tar/methane reforming	9.2	9.2
Coal handling and slurry preparation	152.9	199.3
Coal gasifier island (including spare gasifier)	427.6	526.8
Water gas shift	9.5	12.3
Syngas expanders	18.2	22.2
Rectisol system	171.2	246.2
Claus/SCOT	46.6	66.6
CO_2 compression	26.0	31.3
F-T synthesis	313.5	314.0
F-T refinery	423.9	420.1
Gas turbine and auxiliaries	50.6	102.5
HRSG	197.2	283.4
Steam cycle	67.4	91.8
Total Plant Cost	**2,276**	**2,735**
Interest during construction	163.0	195.9
Total Plant Investment (10^6 2012 US$)	**2,439**	**2,931**

Internal rates of return on equity

(with zero GHG emissions price)



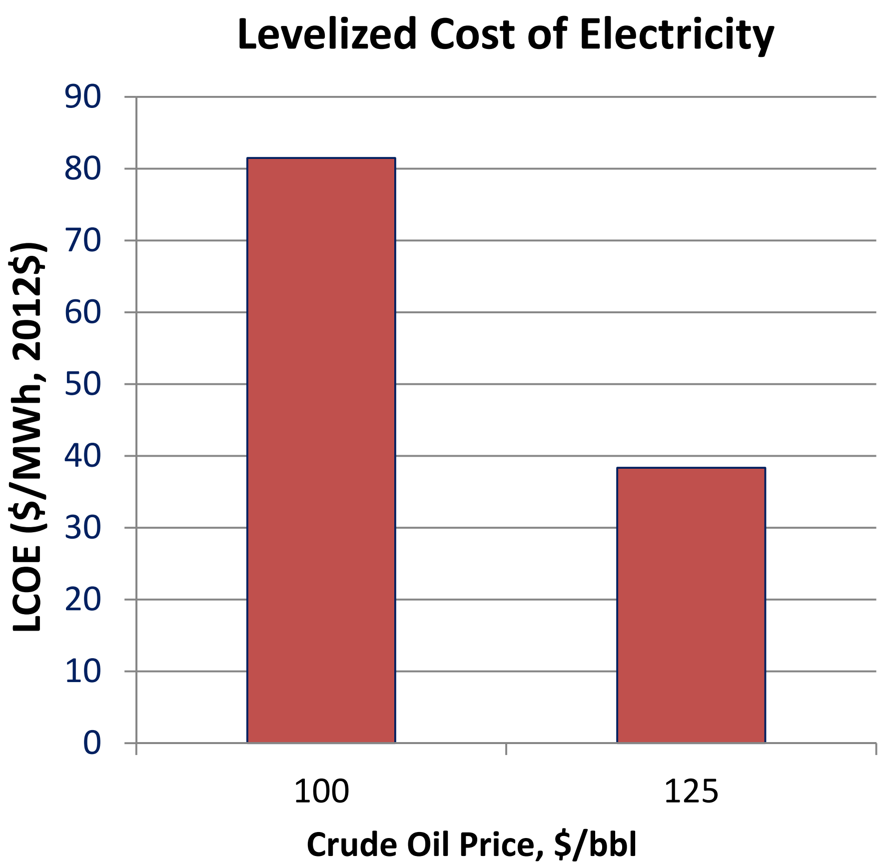
- HF and CP returns are similar.
- IRRE is sensitive to assumed oil price.
- Electricity price more important for CP.

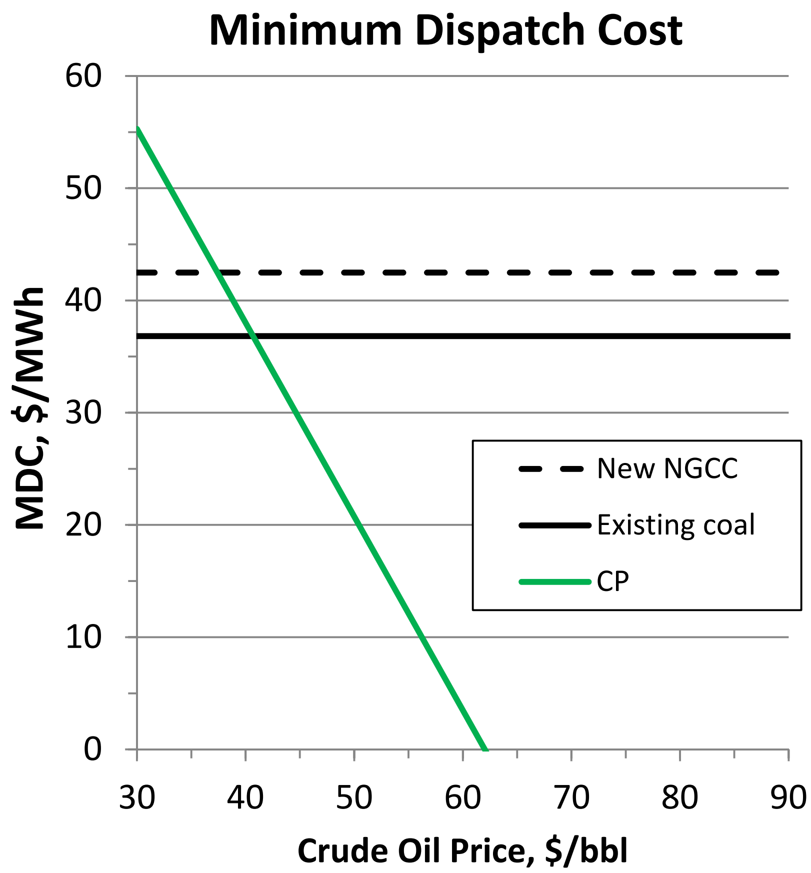
<u>Assumptions</u>
CO_2 sale price ($/tCO2) = 0.444*(crude oil price, $/bbl) – 20.
Liquids sold at refinery-gate price of equivalent petroleum-derived fuels
Annual capital charge rate = 15.6% | Debt:equity ratio = 55:45
Plant capacity factor = 90%
Coal price = 2.84 $/$GJ_{HHV}$ | Biomass price = 2.9 $/$GJ_{HHV}$

- Oil price > $100/bbl needed for acceptable return.
- USDOE/EIA *Annual Energy Outlook 2013* (Reference Scenario) projects levelized (2021-2040) crude oil price of $124/bbl (2012$) and price paid to electricity generators in ORV of ~$70/MWh.

Economics of CP as an electricity plant

- CP plant produces electricity at power plant scales (~400 MW)
- Competitive LCOE with projected world oil price of $124/bbl.
- CP very competitive in dispatch competition for oil price > $40/bbl.





Assumed natural gas price is 5.71 $/$GJ_{HHV}$

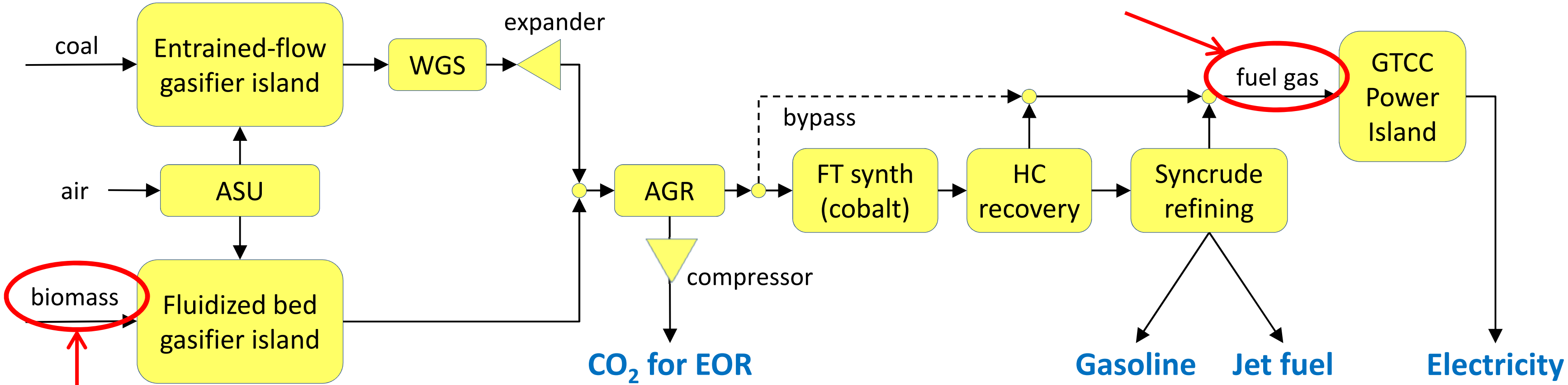
Impact of GHG emission price on IRRE

	HF		CP	
Oil price >>>	**$100/bbl**	**$125/bbl**	**$100/bbl**	**$125/bbl**
GHG Emissions Price ($/metric tCO2eq)	**Internal Rate of Return on Equity**			
0	8.6%	15.1%	8.6%	14.3%
50	9.0%	15.4%	8.5%	14.3%
100	9.3%	15.7%	8.5%	14.3%

GHG emission price has little impact because plants are not designed for a carbon-constrained world.

Design Modifications for a Carbon-Constrained World

Install (ATR + WGS + AGR) system to capture CO2 from fuel gas sent to the power island.



Increase biomass input fraction.

Conclusions and Future Work

- The plant designs investigated co-produce jet fuel, gasoline and electricity and achieve reductions in lifecycle GHG emissions of 10-20% relative to using traditional fossil fuel systems.
- Crude oil prices projected for the next couple of decades ($125/bbl) provides good internal rate of return on equity.
- The large electricity output of the CP design makes it appropriate to consider it economics from the perspective of a power generator.
  – With the oil price at $125/bbl, the LCOE for the CP design of < $40/MWh would be competitive with new natural gas plants in the ORV, and it's low minimum dispatch cost would help ensure high capacity factor operation.
- The economics for these plants in the presence of a GHG emissions price would not improve much from those presented here, but the plants would likely be designed quite differently if there were a price on emissions, and this would have a substantial impact on economics. Design modifications might include:
  – Larger fraction of input carbon captured rather than vented.
  – Larger biomass input fraction.