Appendix A: Technical Projection Tables

Table A-1: Biomass Volume and Price Projections through 2030 (Minus Allocations for Losses, Chemicals, and Pellets) at an Estimated $84/Dry Ton Delivered Feedstock Cost[1] (2014$)

Feedstock Category	Feedstock Resource	Feedstock Available for Cellulosic Fuel Production (MM Dry Tons/Year)							
		SOT	Projection						
		2013	2014	2015	2016	2017	2018	2022	2030
Agricultural Residues	Corn Stover	70.7	83.2	106.7	131.8	138.1	150.7	154.1	172.5
	Wheat Straw	11.2	12.9	13.9	15.9	17.1	18.7	13.9	35.6
Energy Crops	Herbaceous Energy Crops	-	0.5	1.9	3.3	6.4	9.2	10.7	50.2
	Woody Energy Crops	-	-	-	-	-	0.2	5.0	22.9
Forest Residues	Pulpwood	0.8	1.2	1.6	2.1	2.7	3.3	1.7	31.4
	Logging Residues and Fuel Treatments	60.6	56.6	55.1	34.0	50.2	50.5	67.1	60.9
	Other Forestland Removals	0.6	0.8	0.4	0.6	1.3	1.2	0.9	2.9
	Urban and Mill Wood Wastes	32.3	31.3	31.0	27.0	29.9	29.7	31.0	33.8
Totals (MM Dry Tons/Year)		**176.1**	**186.5**	**210.6**	**214.7**	**245.7**	**263.4**	**284.5**	**410.2**

Note: Transport distance and other factors impact feedstock logistics cost, and therefore, the biomass volumes at $84/dry ton is an estimate (Idaho National Laboratory (2014), "Feedstock Supply System Design and Analysis," INL/EXT-14-33227).

[1] Volumes presented estimate quantities available at $84/dry ton delivered to the throat of a conversion reactor. This cost is calculated based on current and projected biomass availability at a given stumpage fee/grower payment, combined with logistics cost estimated for the various feedstocks. The estimated logistics costs are based on a 2017 design.

Table A-2: Unit Operation Cost Contribution Estimates (2014$) and Technical Projections for Algae Farm[2]

Processing Area Cost Contributions & Key Technical Parameters	Metric	2015 SOT [a]	2015 SOT (Fully Lined) [a]	2022 Projection
Biomass Selling Price	$/ton AFDW	$1227	$1641	$494
Production Cost	$/ton AFDW	$1069	$1483	$409
Harvest/Dewatering Cost	$/ton AFDW	$116	$116	$64
Other Cost (Facility Circulation, Storage)	$/ton AFDW	$42	$42	$21
Gross Biomass Production Yield	ton AFDW/acre-year	12.4	12.4	37.5
Total Farm Power Demand	KWh/ton AFDW	860	860	407
Production				
Total Cost Contribution	$/ton AFDW	$1069	$1483	$409
Capital Cost Contribution	$/ton AFDW	$629	$1015	$213
Operating Cost Contribution	$/ton AFDW	$440	$468	$196
Cultivation Productivity (Annual Average)	g/m^2/day AFDW	8.5	8.5	25
Max Seasonal Production Variability	max:min productivity	2.3:1	2.3:1	3:1
Lipid Content	dry wt% as FAME	27.4%	27.4%	27.4%
N Content	AFDW wt%	1.8%	1.8%	1.8%
CO_2 Utilization Efficiency	% utilized for biomass	90%	90%	90%
Gross CO_2 + Nutrient Cost Contributions[b]	$/ton AFDW	$124	$124	$120
Operating Days Per Year	days/year	330	330	330
Biomass Concentration at Harvest	g/L AFDW	0.27	0.27	0.5
Dewatering				
Total Cost Contribution	$/ton AFDW	$116	$116	$64
Capital Cost Contribution	$/ton AFDW	$93	$93	$52
Operating Cost Contribution	$/ton AFDW	$23	$23	$12
Gross Dewatering Efficiency [c]	%	87%	87%	87%
Net Dewatering Efficiency [c]	%	99%	99%	99%
Final Concentration of Dewatered Biomass	g/L AFDW	200	200	200
Dewatering CAPEX	$/MGD from cultivation	$18	$18	$6
Dewatering OPEX	$/MM gal from cultivation	$4	$4	$1
Balance of Plant				
Total Cost Contribution	$/ton AFDW	$42	$42	$21
Capital Cost Contribution	$/ton AFDW	$31	$31	$15
Operating Cost Contribution	$/ton AFDW	$11	$11	$6

[a] Base case assumes nth-plant facility utilizing low-cost unlined ponds; alternative SOT scenario considers fully lined ponds
[b] Included as part of “operating cost contribution”; gross cost does not account for CO_2/nutrient recycling from conversion
[c] “Gross” efficiency = product of individual operations’ dewatering efficiencies. “Net” efficiency = rate of algal biomass recovered in dewatered product to conversion relative to biomass produced from cultivation (including recycle of clarified effluent streams)

[2] R. Davis et al. (2015), *Process Design and Economics for the Production of Algal Biomass: Algal Biomass Production in Open Pond Systems and Processing Through Dewatering for Downstream Conversion*, National Renewable Energy Laboratory, NREL/TP-5100-64772, http://www.nrel.gov/docs/fy16osti/64772.pdf.

Table A-3: Unit Operation Cost Contribution Estimates (2014$) and Technical Projections for Combined Algae Processing

Processing Area Cost Contributions & Key Technical Parameters	Metric	2015 SOT	2015 SOT (Fully Lined)	2022 Projection (ALU design case) [a]	Revised 2022 Projection (2015 Farm Design) [b]
Fuel Selling Price	$/GGE fuel	$13.89	$17.69	$4.38	$5.90
Conversion Contribution	$/GGE	$2.64	$2.64	$1.32	$1.67
Diesel Production	mm GGE/year	3.3	3.3	45.4	13.0
Naphtha Production	mm GGE/year	1.1	1.1	0.9	0.3
Ethanol Production	mm GGE/year	2.4	2.4	16.1	8.6
Diesel Yield (AFDW algae basis)	GGE/U.S. ton algae	53	53	103	69
Naphtha Yield (AFDW algae basis)	GGE/U.S. ton algae	17	17	2	2
Ethanol Yield (AFDW algae basis)	GGE/U.S. ton algae	39	39	36	46
Total Fuel Yield from Algae Farm	GGE/acre-year	1,352	1,352	6,235	4,380
Natural Gas Usage (AFDW algae basis)	scf/U.S. ton algae	1,800 (3,642 including NG for off-site H_2)	1,800 (3,642 including NG for off-site H_2)	2,698 (4,337 including NG for off-site H_2)	1,396 (2,486 including NG for off-site H_2)
Feedstock					
Total Cost Contribution	$/GGE fuel	$11.25	$15.05	$3.06	$4.23
Feedstock Cost (AFDW algae basis)	$/U.S. ton algae	$1227	$1641	$433	$494
Feedstock Solids Content	wt% AFDW	20%	20%	20%	20%
Feedstock Lipid/Carb/Protein Content	dry wt%	27%/53% /13% [c]	27%/53% /13% [c]	41%:38%:9%	27%/53%/13%
Conversion					
Total Cost Contribution	$/GGE fuel	$1.95	$1.95	$1.14	$1.35
Capital Cost Contribution	$/GGE fuel	$1.08	$1.08	$0.66	$0.83
Operating Cost Contribution	$/GGE fuel	$0.87	$0.87	$0.48	$0.52
Pretreatment Solids Loading	wt% AFDW	20%	20%	20%	20%
Pretreatment Acid Loading	wt% of water feed	2%	2%	1%	1%
Pretreatment Fermentable Sugar Yield	%	74%	74%	90%	90%
Carbs to Degradation Products	%	1.5%	1.5%	0.3%	0.3%
Fermentation Batch Time	hr	<18	<18	72	72
Fermentation Total Solids Loading	wt%	20%	20%	20%	20%
Sugar Diversion to Organism Growth	%	6%	6%	4%	4%
Fermentable Sugar Utilization	%	98.5%	98.5%	95%	95%
Extraction Solvent Loading	g/g solvent/dry biomass	5.9	5.9	5.0	5.0
FAME Lipid Extraction Yield	%	87%	87%	95%	95%
Polar Lipid Impurity Partition to Extract	%	<11.5%	<11.5%	33%	33%
Lipid Hydrotreating to Finished Fuels					
Total Cost Contribution	$/GGE fuel	$0.81	$0.81	$0.30	$0.46
Capital Cost Contribution	$/GGE fuel	$0.51	$0.51	$0.21	$0.31
Operating Cost Contribution	$/GGE fuel	$0.30	$0.30	$0.09	$0.15
Hydrotreating Diesel Yield	wt% of oil feed	66%	66%	80%	80%
Hydrotreating Naphtha Yield	wt% of oil feed	22%	22%	2%	2%
Hydrotreating H_2 Consumption	wt% of oil feed	5%	5%	2%	2%

Processing Area Cost Contributions & Key Technical Parameters	Metric	2015 SOT	2015 SOT (Fully Lined)	2022 Projection (ALU design case) [a]	Revised 2022 Projection (2015 Farm Design) [b]
Anaerobic Digestion + Combined Heat & Power					
Total Cost Contribution	$/GGE fuel	($0.27)	($0.27)	($0.20)	($0.25)
Capital Cost Contribution	$/GGE fuel	$0.16	$0.16	$0.09	$0.12
Operating Cost Contribution	$/GGE fuel	$0.05	$0.05	$0.02	$0.03
AD N/P Nutrient Coproduct Credits	$/GGE fuel	($0.15)	($0.15)	($0.10)	($0.13)
AD CO_2 Coproduct Credit	$/GGE fuel	($0.26)	($0.26)	($0.15)	($0.20)
AD Power Coproduct Credit	$/GGE fuel	($0.06)	($0.06)	($0.05)	($0.06)
AD Digestate Fertilizer Credit	$/GGE fuel	($0.01)	($0.01)	($0.01)	($0.01)
Balance of Plant					
Total Cost Contribution	$/GGE fuel	$0.15	$0.15	$0.08	$0.11
Capital Cost Contribution	$/GGE fuel	$0.11	$0.11	$0.04	$0.07
Operating Cost Contribution	$/GGE fuel	$0.04	$0.04	$0.04	$0.04
Models: Case References		*HCSD + Store SOT*	*HCSD + Store SOT + Liners*	*HLSD + Store*	*HCSD + Store (Revised)*

[a] Original 2022 projection based on 2014 ALU design report [3] assumed targets for biomass cost, yield, and composition
[b] Revised 2022 projection based on running the ALU design model for biomass cost, yield, and composition details consistent with outputs from 2015 algal biomass design report[4]
[c] SOT case assumes algal biomass feedstock composition consistent with revised 2022 target case.

[3] R. Davis et al. (2014), *Process Design and Economics for the Conversion of Algal Biomass to Biofuels: Algal Biomass Fractionation to Lipid- and Carbohydrate-Derived Fuel Products*, National Renewable Energy Laboratory, NREL/TP-5100-62368, http://www.nrel.gov/docs/fy14osti/62368.pdf.
[4] R. Davis et al. (2015), *Process Design and Economics for the Production of Algal Biomass: Algal Biomass Production in Open Pond Systems and Processing Through Dewatering for Downstream Conversion*, National Renewable Energy Laboratory, NREL/TP-5100-64772, http://www.nrel.gov/docs/fy16osti/64772.pdf.

Table A-4: Unit Operation Cost Contribution Estimates (2014$) and Technical Projections for Whole Algae Hydrothermal Liquefaction and Upgrading to Diesel[5]

Processing Area Cost Contributions & Key Technical Parameters	Metric	2015 SOT[2] No Pond Liners	2015 SOT[2] Pond Liners	Original 2022 Projected[3]	Revised 2022 Projected[4]
Fuel Selling Price	$/GGE	$14.78	$18.60	$4.51	$4.72
Conversion Contribution	$/GGE	$3.45	$3.45	$1.19	$1.54
Production Diesel	mm gallons/year	5	5	54	23
Production Naphtha	mm gallons/year	2	2	11	5
Diesel Yield (AFDW Algae Basis)	gal/U.S. ton algae	77	77	122	122
Naphtha Yield (AFDW Algae Basis)	gal/U.S. ton algae	25	25	25	25
Natural Gas Usage-Drying (AFDW Algae Basis)	scf/U.S. ton algae	3,291	3,291	2,946	3,126
Feedstock					
Total Cost Contribution	$/gge fuel	$11.33	$15.15	$3.33	$3.18
Feedstock Type		Field Grown	Field Grown	14% ash; 20% total lipid	mid-lipid Scenedesmus
Feedstock Cost (AFDW Algae Basis)	$/U.S. ton algae	$1,227	$1,641	$433	$494
HTL Biocrude Production					
Total Cost Contribution	$/GGE fuel	$1.18	$1.18	$0.61	$0.49
Capital Cost Contribution	$/GGE fuel	$0.64	$0.64	$0.45	$0.00
Operating Cost Contribution	$/GGE fuel	$0.55	$0.55	$0.16	$0.49
Liquid Hourly Space Velocity (LHSV)	vol/h/vol	4.0	4.0	4.0	8.0
HTL Biocrude Yield (AFDW)	lb/lb algae	0.40	0.40	0.59	0.59
HTL Biocrude Hydrotreating to Finished Fuels					
Total Cost Contribution	$/GGE fuel	$0.44	$0.44	$0.35	$0.31
Capital Cost Contribution	$/GGE fuel	$0.24	$0.24	$0.13	$0.00
Operating Cost Contribution	$/GGE fuel	$0.21	$0.21	$0.22	$0.31
Mass Yield on Dry HTL Biocrude	lb/lb AHTL oil	0.86	0.86	0.83	0.83
HTL Aqueous Phase Treatment					
Total Cost Contribution	$/GGE fuel	$1.54	$1.54	$0.61	$0.57
Capital Cost Contribution	$/GGE fuel	$0.81	$0.81	$0.35	$0.00
Operating Cost Contribution	$/GGE fuel	$0.72	$0.72	$0.26	$0.57

[5] Jones et al. (2014), *Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading*, Pacific Northwest National Laboratory, PNNL- 23227, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Metric	2015 SOT[2] No Pond Liners	2015 SOT[2] Pond Liners	Original 2022 Projected[3]	Revised 2022 Projected[4]
Balance of Plant					
Total Cost Contribution	$/GGE fuel	$0.29	$0.29	($0.38)	$0.17
Capital Cost Contribution	$/GGE fuel	$0.25	$0.25	$0.17	$0.00
Operating Cost Contribution	$/GGE fuel	$0.23	$0.23	$0.04	$0.22
Credits	$/GGE fuel	($0.20)	($0.20)	($0.58)	($0.05)
Models: Case References		T-021716-15SOT-14$-NL	T-021716-15SOT-14$-WL	030114P-14$	N-120815-22P-14$

[1] The table may contain very small (≤ $0.01) rounding errors due to the difference between the way that rounded values.
Microsoft Excel™ displays and calculates

[2] New Basis: 188 tpd AFDW algae @ $1222/ton; naphtha valued at production cost

[3] Original Basis: 1340 tpd AFDW algae @ $430/ton; naphtha values at $3.25/gal (Jones 2014a)

[4] New Basis: 568 tpd AFDW algae @ 491/ton; naphtha valued at production cost

Table A-5: Unit Operation Cost Contribution Estimates (2014$) and Technical Projections for Fast Pyrolysis Conversion to Gasoline and Diesel Baseline Process Concept[6]

(Process Concept: Woody Feedstock, Fast Pyrolysis, Bio-Oil Upgrading, Fuel Finishing)*

Processing Area Cost Contributions & Key Technical Parameters	Metric	2009 SOT†	2010 SOT	2011 SOT	2012 SOT	2013 SOT	2014 SOT	2015 SOT	2016 Projection*	2017 Projection*
Conversion Contribution	$/gal gasoline blendstock	$12.71	$9.45	$7.50	$6.36	$4.62	$4.12	$3.73	$2.99	$2.49
	$/gal diesel blendstock	$13.36	$9.93	$7.88	$6.68	$5.14	$4.58	$4.16	$3.32	$2.76
Conversion Contribution, Combined Blendstocks	$/GGE	$12.33	$9.17	$7.27	$6.17	$4.71	$4.19	$3.80	$3.05	$2.53
Performance Goal	$/GGE	-	-	-	-	-	-	-	-	$3
Combined Fuel Selling Price	$/GGE	$13.78	$10.57	$8.50	$7.25	$5.95	$5.42	$4.92	$4.10	$3.50
Production Gasoline Blendstock	mm gallons/year	30	30	30	30	29	29	29	29	29
Production Diesel Blendstock	mm gallons/year	23	23	23	23	32	32	32	32	32
Yield Combined Blendstocks	GGE/dry U.S. ton	78	78	78	78	87	87	87	87	87
Yield Combined Blendstocks	mmBTU/dry U.S. ton	9	9	9	9	10	10	10	10	10
Natural Gas Usage	scf/dry U.S. ton	1,115	1,115	1,115	1,115	1,685	1,742	1,774	1,685	1,685
Feedstock										
Total Cost Contribution	$/GGE fuel	$1.45	$1.40	$1.23	$1.08	$1.24	$1.23	$1.12	$1.05	$0.97
Capital Cost Contribution	$/GGE fuel	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE fuel	$1.45	$1.40	$1.23	$1.08	$1.24	$1.23	$1.12	$1.05	$0.97
Feedstock Cost	$/dry U.S. ton	$112.86	$108.68	$95.60	$84.14	$107.80	$107.09	$97.34	$91.54	$84.45
Fast Pyrolysis										
Total Cost Contribution	$/GGE fuel	$1.00	$0.97	$0.95	$0.93	$0.81	$0.81	$0.80	$0.79	$0.78
Capital Cost Contribution	$/GGE fuel	$0.85	$0.82	$0.80	$0.78	$0.69	$0.68	$0.68	$0.67	$0.67
Operating Cost Contribution	$/GGE fuel	$0.15	$0.15	$0.15	$0.15	$0.12	$0.12	$0.12	$0.12	$0.11
Pyrolysis Oil Yield (dry)	lb organics/lb dry wood	0.60	0.60	0.60	0.60	0.62	0.62	0.62	0.62	0.62

[6] S. Jones et al. (2013), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-Oil Pathway*, Pacific Northwest National Laboratory, PNNL-23053, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Metric	2009 SOT†	2010 SOT	2011 SOT	2012 SOT	2013 SOT	2014 SOT	2015 SOT	2016 Projection*	2017 Projection*
Upgrading to Stable Oil via Multi-Step Hydrodeoxygenation/Hydrocracking										
Total Cost Contribution	$/GGE fuel	$10.32	$7.21	$5.36	$4.27	$2.95	$2.45	$2.07	$1.34	$0.96
Capital Cost Contribution	$/GGE fuel	$0.72	$0.69	$0.68	$0.67	$0.60	$0.63	$0.49	$0.46	$0.43
Operating Cost Contribution	$/GGE fuel	$9.59	$6.52	$4.68	$3.60	$2.34	$1.82	$1.57	$0.88	$0.53
Annual Upgrading Catalyst Cost, mm$/year	Annual cost is a function of WHSV,[2] number of reactors, catalyst replacement rate, and $/lb	525	352	249	188	133	100	82	41	19
Upgraded Oil Carbon Efficiency on Pyrolysis Oil	wt%	65%	65%	65%	65%	68%	68%	68%	68%	68%
Fuel Finishing to Gasoline and Diesel via Hydrocracking and Distillation										
Total Cost Contribution	$/GGE fuel	$0.25	$0.25	$0.24	$0.24	$0.25	$0.24	$0.24	$0.25	$0.14
Capital Cost Contribution	$/GGE fuel	$0.16	$0.16	$0.15	$0.15	$0.17	$0.16	$0.16	$0.16	$0.07
Operating Cost Contribution	$/GGE fuel	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.07
Balance of Plant										
Total Cost Contribution	$/GGE fuel	$0.75	$0.74	$0.73	$0.72	$0.70	$0.70	$0.69	$0.67	$0.64
Capital Cost Contribution	$/GGE fuel	$0.38	$0.36	$0.35	$0.35	$0.31	$0.31	$0.31	$0.31	$0.30
Operating Cost Contribution	$/GGE fuel	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.37	$0.34
Models: Case References		2009 SOT 090913	2010 SOT 090913	2012 SOT 090913	2012 SOT 090913	2013 SOT 122013	2014 SOT 123014	2015 P 123013	2016 P 121913	2017 P 093013

*Pyrolysis conversion performance tests conducted through 2017 are based on dried, debarked pine that has been ground to a 2-mm particle size. As explained in Section 2.1.1.5, research funded by FSL aims to develop a blend that will support comparable conversion performance as a pure pine feedstock.
† SOT: State of Technology

1. Note: The table may contain very small (< $0.01) rounding errors due to the difference between the way that Microsoft Excel™ displays and calculates rounded values.
2. WHSV=weight hourly space velocity: weight of oil feed per hour per weight of catalyst.

Note that while the blend is under development, research will continue to expand the specification accepted by the pyrolysis process, making it more robust. Relying solely on pine as a feedstock will not only limit the amount of material available for fuel production via pyrolysis, but will also influence the delivered cost of feedstock to the throat of the conversion process (Figure A-1).

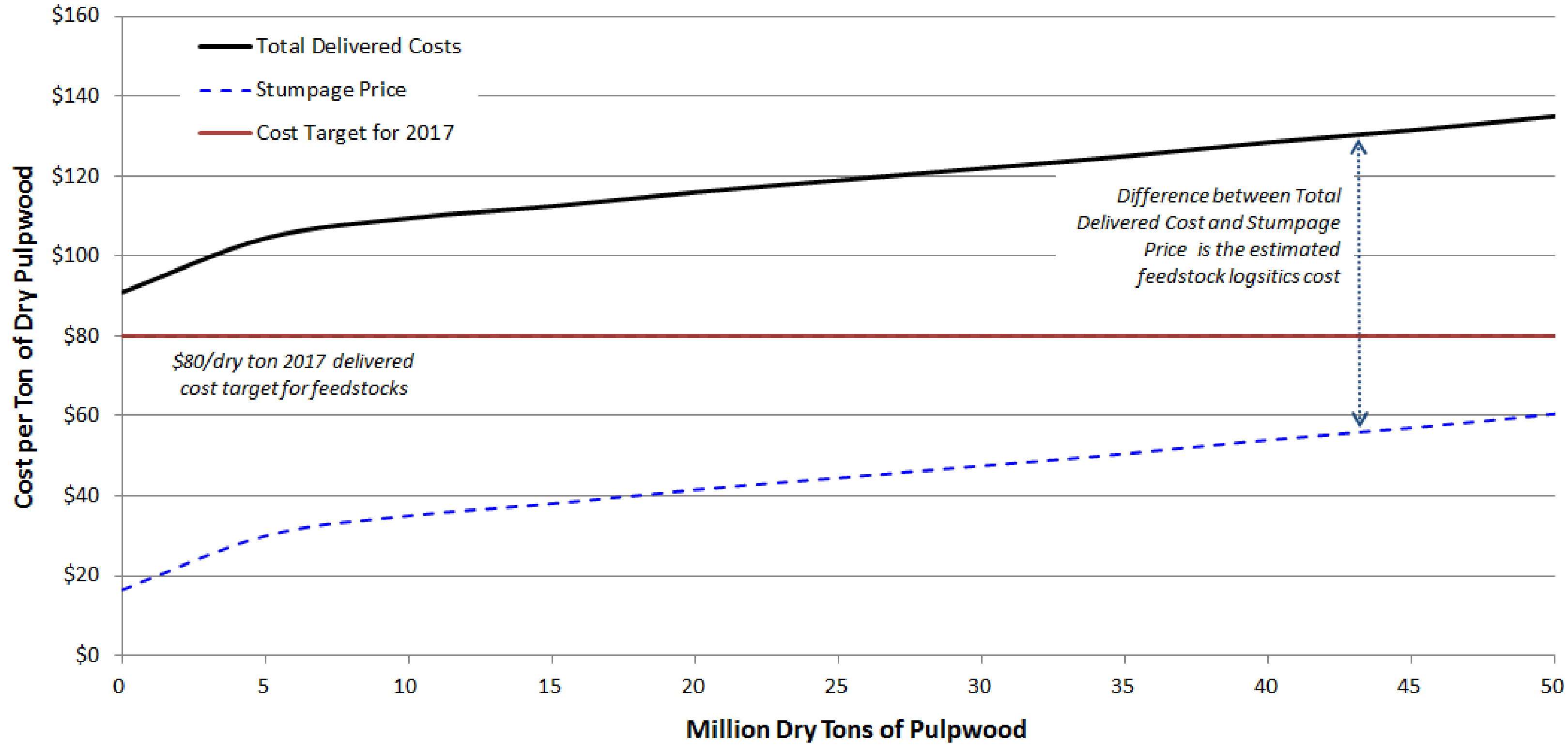

Figure A-1: Estimated total delivered cost of debarked, dried, ground pulpwood, delivered to the throat of the reactor and meeting the conversion specifications for pyrolysis. Pulpwood prices are based on values presented in the 2011 *U.S. Billion-Ton Update* for the year 2017

As demonstrated in Figure A-1, pulpwood resources are available for conversion in 2017; however, they are more expensive and available in lower volumes than the woody blend scenario presented in Table 2-4. The volumes presented in Figure A-1 are consistent with and are generated from the same data as those presented in Table A-1. However, the volumes presented in Table A-1 were constrained to those available at a low-enough stumpage price such that the total delivered cost target of $80/dry ton could be met.

Table A-6: Processing Area Cost Contribution (2014$) and Key Technical Parameters for In Situ Catalytic Pyrolysis Vapors to Gasoline and Diesel Baseline Process Concept7

(Process Concept: Hydrocarbon Fuel Production via In Situ Upgrading of Fast Pyrolysis Vapors)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection	2019 Projection	2020 Projection	2021 Projection	2022 Projection (Design Case)
		Pulp-wood	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend
Projected Minimum Fuel Selling Price▲	$/GGE*	$6.32	$5.80	$5.26	$4.57	$4.37	$4.16	$3.95	$3.75	$3.54
Conversion Contribution	$/GGE*	$3.97	$3.77	$3.49	$3.11	$2.97	$2.83	$2.69	$2.55	$2.40
Total Project Investment per Annual GGE	$/GGE/ year	$16.07	$15.20	$14.02	$12.44	$11.85	$11.26	$10.67	$10.08	$9.50
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	46	49	52	59	62	65	68	72	75
Diesel Product Proportion (GGE** basis)	% of fuel product	17%	17%	17%	17%	19%	21%	23%	25%	27%
Feedstock										
Total Cost Contribution	$/GGE	$2.35	$2.02	$1.77	$1.46	$1.40	$1.33	$1.27	$1.20	$1.14
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE	$2.35	$2.02	$1.77	$1.46	$1.39	$1.33	$1.26	$1.20	$1.14
Feedstock Cost	$/dry U.S. ton	$107.09	$97.34	$91.54	$84.45	$84.45	$84.45	$84.45	$84.45	$84.45
Feedstock Moisture at Plant Gate	wt% H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%

[7] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, and J. Lukas (2015), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels - Thermochemical Research Pathways With In Situ and Ex Situ Upgrading of Fast Pyrolysis Vapors*, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, NREL/TP-5100-62455, PNNL-23823, http://www.nrel.gov/docs/fy15osti/62455.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection		2018 Projection	2019 Projection	2020 Projection	2021 Projection	2022 Projection (Design Case)
Feed Moisture Content to Pyrolyzer	wt% H_2O	10%	10%	10%	10%		10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	BTU/lb	8,000	8,000	8,000	8,000		8,000	8,000	8,000	8,000	8,000
Pyrolysis and Vapor Upgrading											
Total Cost Contribution	$/GGE	$2.52	$2.36	$2.16	$1.86		$1.75	$1.64	$1.53	$1.41	$1.30
Capital Cost Contribution	$/GGE	$0.74	$0.70	$0.64	$0.57		$0.54	$0.51	$0.48	$0.46	$0.43
Operating Cost Contribution	$/GGE	$1.78	$1.66	$1.51	$1.29		$1.21	$1.13	$1.04	$0.96	$0.87
Gas Phase	wt% of dry biomass	31%	30%	29%	27%		26%	25%	24%	24%	23%
Aqueous Phase	wt% of dry biomass	26%	26%	26%	27%		27%	28%	28%	28%	29%
Carbon Loss	% of C in biomass	3.2%	3.1%	2.6%	2.4%		2.3%	2.3%	2.2%	2.2%	2.1%
Organic Phase	wt% of dry biomass	19.5%	20.6%	21.6%	24.0%		24.9%	25.7%	26.6%	27.5%	28.3%
H/C Molar Ratio	ratio	1.1	1.1	1.2	1.2		1.3	1.3	1.4	1.4	1.5
Oxygen	wt% of organic phase	15.6%	15.5%	14.4%	14.0%		13.3%	12.6%	11.9%	11.2%	10.5%
Carbon Efficiency	% of C in biomass	29%	31%	33%	37%		38%	40%	41%	43%	44%
Solid Losses (Char + Coke)	wt% of dry biomass	24%	24%	23%	23%		22%	22%	21%	21%	20%
Char	wt% of dry biomass	12%	12%	12%	12%		12%	12%	12%	12%	12%
Coke	wt% of dry biomass	12.0%	11.6%	11.2%	10.6%		10.1%	9.6%	9.1%	8.6%	8.1%
Pyrolysis Vapor Quench											
Total Cost Contribution	$/GGE	$0.29	$0.27	$0.25	$0.22		$0.21	$0.20	$0.19	$0.18	$0.17
Capital Cost Contribution	$/GGE	$0.18	$0.17	$0.15	$0.13		$0.13	$0.12	$0.11	$0.11	$0.10
Operating Cost Contribution	$/GGE	$0.12	$0.11	$0.10	$0.08		$0.08	$0.08	$0.07	$0.07	$0.07

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection	2019 Projection	2020 Projection	2021 Projection	2022 Projection (Design Case)
Hydroprocessing and Separation										
Total Cost Contribution	$/GGE	$0.36	$0.35	$0.33	$0.32	$0.31	$0.31	$0.30	$0.29	$0.28
Capital Cost Contribution	$/GGE	$0.20	$0.20	$0.19	$0.18	$0.17	$0.17	$0.17	$0.16	$0.16
Operating Cost Contribution	$/GGE	$0.16	$0.16	$0.15	$0.14	$0.14	$0.13	$0.13	$0.13	$0.12
Carbon Efficiency of Organic Liquid Feed to Fuels	%	88%	88%	89%	89%	90%	90%	90%	91%	91%
Hydrotreating Pressure	psia	2,000	2,000	2,000	2,000	1960	1920	1880	1840	1,800
Oxygen Content in Cumulative Fuel Product	wt%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.5%	0.5%
Hydrogen Production										
Total Cost Contribution	$/GGE	$0.63	$0.61	$0.58	$0.56	$0.55	$0.53	$0.52	$0.51	$0.49
Capital Cost Contribution	$/GGE	$0.42	$0.41	$0.39	$0.37	$0.36	$0.35	$0.35	$0.34	$0.33
Operating Cost Contribution	$/GGE	$0.21	$0.20	$0.19	$0.19	$0.18	$0.18	$0.17	$0.17	$0.17
Additional Natural Gas**	% of biomass LHV	0.3%	0.0%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%
Balance of Plant										
Total Cost Contribution	$/GGE	$0.17	$0.18	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16
Capital Cost Contribution	$/GGE	$0.81	$0.75	$0.68	$0.57	$0.53	$0.49	$0.45	$0.41	$0.37
Operating Cost Contribution	$/GGE	($0.65)	($0.58)	($0.51)	($0.41)	($0.37)	($0.33)	($0.29)	($0.25)	($0.21)
Electricity Production from Steam Turbine (credit included in operating cost above)	$/GGE**	($0.98)	($0.89)	($0.79)	($0.64)	($0.59)	($0.53)	($0.48)	($0.42)	($0.36)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection	2019 Projection	2020 Projection	2021 Projection	2022 Projection (Design Case)
Sustainability and Process Efficiency Metrics										
Fuel Yield by Weight of Biomass	% w/w of dry biomass	15.0%	15.8%	17.0%	19.0%	19.9%	20.9%	21.9%	22.8%	23.8%
Carbon Efficiency to Fuels	% C in feedstock	25.8%	27.3%	29.2%	32.6%	34.1%	35.7%	37.3%	38.8%	40.4%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	25.8%	27.3%	29.2%	32.6%	34.1%	35.7%	37.3%	38.8%	40.4%
Overall Energy Efficiency to Fuels	% LHV of feedstock + NG	33.2%	35.3%	37.9%	42.4%	44.8%	47.2%	49.6%	52.0%	54.3%
Electricity Production	kWh/GGE	18.5	16.8	14.9	12.2	11.1	10.1	9.1	8.1	7.0
Electricity Consumption (entire process)	kWh/GGE	11.7	10.9	10.0	8.7	8.2	7.7	7.2	6.8	6.3
Water Consumption	gal H_2O/GGE	1.3	1.2	1.1	0.9	0.9	0.9	0.8	0.8	0.8
Fossil GHG Emissions (with electricity credit)	g CO_2e/MJ fuel	(32.8)	(28.6)	(23.8)	(16.1)	(13.4)	(10.7)	(8.0)	(5.3)	(2.6)
Fossil Energy Consumption (with electricity credit)	MJ fossil energy/MJ fuel	(0.4)	(0.3)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	0.0
TEA Reference File		PyVPU-v218g IS - 2014 (2014$)-v03.xlsm	PyVPU-v218g IS - 2015 (2014$)-v03.xlsm	PyVPU-v218g IS - 2016 (2014$)-v03.xlsm	PyVPU-v218g IS - 2017 (2014$)-v03.xlsm					PyVPU-v218 IS - 2022 (2014$)-v03.xlsm

▲Conceptual design result with margin of error +/- 30%

† SOT: State of Technology

* Gallon Gasoline Equivalent (GGE) on a Lower Heating Value (LHV) basis

** A negligible stream was maintained in the model to allow natural gas use if necessary.

Table A-7: Processing Area Cost Contribution (2014$) and Key Technical Parameters for Ex Situ Pyrolysis Vapors Baseline Process Concept8

(Process Concept: Hydrocarbon Fuel Production via Ex Situ Upgrading of Fast Pyrolysis Vapors)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT●	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
		Pulpwood	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend
Projected Minimum Fuel Selling Price▲	$/GGE*	$6.61	$5.76	$5.34	$4.67	$4.41	$4.15	$3.89	$3.63	$3.38
Conversion Contribution	$/GGE*	$4.03	$3.62	$3.47	$3.13	$2.96	$2.79	$2.62	$2.45	$2.29
Total Project Investment per Annual GGE	$/GGE /year	$19.67	$17.49	$16.51	$14.55	$13.60	$12.66	$11.72	$10.78	$9.83
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	42	46	50	56	60	64	69	73	78
Diesel Product Proportion (GGE* basis)	% of fuel product	15%	15%	14%	14%	22%	30%	38%	47%	55%
Feedstock										
Total Cost Contribution	$/GGE	$2.58	$2.14	$1.87	$1.54	$1.45	$1.36	$1.27	$1.18	$1.09
Capital Cost Contribution	$/GGE	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE	$2.57	$2.13	$1.86	$1.53	$1.45	$1.36	$1.27	$1.18	$1.09
Feedstock Cost	$/dry U.S. ton	$107.09	$97.34	$91.54	$84.45	$84.45	$84.45	$84.45	$84.45	$84.45
Feedstock Moisture at Plant Gate	wt% H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feed Moisture Content to Pyrolyzer	wt% H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	BTU/lb	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000

[8] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, and J. Lukas (2015), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels - Thermochemical Research Pathways With In Situ and Ex Situ Upgrading of Fast Pyrolysis Vapors*, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, NREL/TP-5100-62455, PNNL-23823, http://www.nrel.gov/docs/fy15osti/62455.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Pyrolysis and Vapor Upgrading										
Total Cost Contribution	$/GGE	$2.48	$2.16	$2.09	$1.86	$1.75	$1.63	$1.52	$1.41	$1.29
Capital Cost Contribution	$/GGE	$1.08	$0.94	$0.91	$0.81	$0.76	$0.71	$0.67	$0.62	$0.57
Operating Cost Contribution	$/GGE	$1.40	$1.23	$1.18	$1.05	$0.98	$0.92	$0.85	$0.79	$0.73
Gas Phase	wt% of dry biomass	35%	34%	32%	30%	29%	27%	26%	24%	23%
Aqueous Phase	wt% of dry biomass	25%	25%	25%	26%	27%	27%	28%	29%	30%
Carbon Loss	% of C in biomass	2.9%	2.9%	2.4%	2.3%	2.1%	1.9%	1.7%	1.5%	1.3%
Organic Phase	wt% of dry biomass	17.5%	18.6%	20.2%	22.0%	23.0%	24.1%	25.1%	26.2%	27.2%
H/C Molar Ratio	ratio	1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.6
Oxygen	wt% of organic phase	15.0%	13.3%	14.0%	12.5%	11.3%	10.1%	8.8%	7.6%	6.4%
Carbon Efficiency	% of C in biomass	27%	29%	31%	34%	36%	38%	40%	42%	44%
Solid Losses (Char + Coke)	wt% of dry biomass	23%	21%	23%	22%	22%	21%	21%	20%	20%
Char	wt% of dry biomass	12%	11%	12%	12%	12%	12%	12%	12%	12%
Coke	wt% of dry biomass	11.0%	9.5%	10.5%	10.2%	9.8%	9.3%	8.9%	8.4%	8.0%
Pyrolysis Vapor Quench										
Total Cost Contribution	$/GGE	$0.38	$0.36	$0.31	$0.27	$0.25	$0.23	$0.22	$0.20	$0.18
Capital Cost Contribution	$/GGE	$0.23	$0.21	$0.19	$0.16	$0.15	$0.14	$0.13	$0.12	$0.11
Operating Cost Contribution	$/GGE	$0.15	$0.14	$0.12	$0.11	$0.10	$0.09	$0.09	$0.08	$0.07
Hydroprocessing and Separation										
Total Cost Contribution	$/GGE	$0.35	$0.33	$0.33	$0.30	$0.29	$0.28	$0.27	$0.25	$0.24
Capital Cost Contribution	$/GGE	$0.20	$0.18	$0.19	$0.17	$0.16	$0.16	$0.15	$0.14	$0.14
Operating Cost Contribution	$/GGE	$0.15	$0.14	$0.14	$0.13	$0.13	$0.12	$0.12	$0.11	$0.11

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Carbon Efficiency of Organic Liquid Feed to Fuels ‡	%	88%	90%	89%	90%	91%	92%	93%	93%	94%
Hydrotreating Pressure	Psia	2,000	2,000	2,000	2,000	1900	1800	1700	1600	1,500
Oxygen Content in Cumulative Fuel Product	wt%	0.8%	0.8%	0.8%	0.7%	0.6%	0.6%	0.5%	0.4%	0.4%
Hydrogen Production										
Total Cost Contribution	$/GGE	$0.67	$0.61	$0.62	$0.57	$0.55	$0.53	$0.50	$0.48	$0.45
Capital Cost Contribution	$/GGE	$0.44	$0.41	$0.41	$0.38	$0.36	$0.35	$0.33	$0.31	$0.30
Operating Cost Contribution	$/GGE	$0.23	$0.21	$0.20	$0.19	$0.19	$0.18	$0.17	$0.16	$0.15
Additional Natural Gas**	% of biomass LHV	0.3%	0.1%	0.1%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
Balance of Plant										
Total Cost Contribution	$/GGE	$0.16	$0.17	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12
Capital Cost Contribution	$/GGE	$0.91	$0.80	$0.70	$0.58	$0.53	$0.48	$0.42	$0.37	$0.31
Operating Cost Contribution	$/GGE	($0.76)	($0.64)	($0.58)	($0.46)	($0.41)	($0.36)	($0.30)	($0.25)	($0.19)
Electricity Production from Steam Turbine (credit included in operating cost above)	$/GGE**	($1.12)	($0.96)	($0.85)	($0.69)	($0.62)	($0.54)	($0.47)	($0.39)	($0.32)
Sustainability and Process Efficiency Metrics										
Fuel Yield by Weight of Biomass	% w/w of dry biomass	13.7%	15.0%	16.1%	17.9%	19.2%	20.6%	21.9%	23.2%	24.6%
Carbon Efficiency to Fuels	% C in feedstock	23.5%	25.9%	27.6%	30.6%	32.8%	34.9%	37.1%	39.3%	41.5%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	23.5%	25.9%	27.6%	30.6%	32.8%	34.9%	37.1%	39.3%	41.5%

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Overall Energy Efficiency to Fuels	% LHV of feedstock + NG	30.4%	33.4%	36.0%	40.2%	43.5%	46.8%	50.0%	53.3%	56.6%
Electricity Production	kWh/ GGE	21.0	18.0	16.0	13.1	11.7	10.3	8.9	7.6	6.2
Electricity Consumption (entire process)	kWh/ GGE	12.7	11.0	10.4	9.1	8.4	7.8	7.1	6.4	5.7
Water Consumption	gal H_2O/ GGE	1.4	1.4	1.2	1.1	1.0	0.9	0.8	0.8	0.7
Fossil GHG Emissions (with electricity credit)	g CO_2e/MJ fuel	(41.5)	(35.5)	(27.9)	(19.3)	(15.7)	(12.0)	(8.4)	(4.8)	(1.2)
Fossil Energy Consumption (with electricity credit)	MJ fossil energy/MJ fuel	(0.5)	(0.4)	(0.3)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	0.0
TEA Reference File		PyVPU-v218g ES - 2014 (2014$)-v03.xlsm	PyVPU-v218g ES - 2015 SOT (2014$)-r35.xlsm	PyVPU-v218g ES - 2016 (2014$)-v03.xlsm	PyVPU-v218g ES - 2017 (2014$)-v03.xlsm	Interpolated Values from 2017 and 2022 Target Cases.				PyVPU-v218g ES - 2022 (2014$)-v03.xlsm

▲Conceptual design result with margin of error +/- 30%

† SOT: State of Technology
* Note: The projections for 2018–2021 are based solely on an interpolated linear reduction in costs between 2017 and 2022.

* Gallon Gasoline Equivalent (GGE) on a Lower Heating Value (LHV) basis

** A negligible stream was maintained in the model to allow natural gas use if necessary.
‡ Interpolated value is based on Figure 8 in http://www.nrel.gov/docs/fy15osti/62455.pdf.
● Experiments for the FY 2015 SOT were completed using pulpwood with only minor variations from the woody feedstock specifications in the SOT model.

NG = natural gas; Psia = pounds per square inch absolute.

Table A-8: Processing Area Cost Contribution (2014$) and Key Technical Parameters for Indirect Gasification and Methanol Intermediate Conversion to High-Octane Fuels[9]

(Process Concept: Gasification, Syngas Clean-Up, Methanol/Dimethyl Ether [DME] Synthesis & Conversion to Hydrocarbons)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT	2016 Projection§	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
		Pulp-wood	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**
C_5+ Minimum Fuel Selling Price (per Actual Product Volume) ▲	$/gallon	$5.57	$5.11	$3.95	$3.63	$3.57	$3.50	$3.44	$3.37	$3.57
Mixed C_4 Minimum Fuel Selling Price (per Actual Product Volume) ▲	$/gallon	$3.69	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Fuel Selling Price (per Gallon of Gasoline Equivalent) ▲	$/GGE	$5.60	$5.20	$4.13	$3.80	$3.73	$3.67	$3.60	$3.54	$3.47
Conversion Contribution (per Gallon of Gasoline Equivalent) ▲	$/GGE	$3.49	$3.49	$2.57	$2.41	$2.34	$2.28	$2.22	$2.16	$2.10
Total Capital Investment per Annual Gallon	$	$14.34	$14.42	$8.83	$8.36	$8.33	$8.30	$8.28	$8.25	$8.23
Plant Capacity (Dry Feedstock Basis)	tonnes/dry	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
High-Octane Gasoline Blendstock (C_5+) Yield	gallons/dry ton	39.7	39.9	61.8	64.2	64.4	64.5	64.6	64.8	64.9
Mixed C_4 Co-Product Yield	gallons/dry ton	17.9	17.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feedstock										
Total Cost Contribution	$/GGE	$2.10	$1.88	$1.56	$1.39	$1.39	$1.38	$1.38	$1.38	$1.37
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE	$2.10	$1.88	$1.56	$1.39	$1.38	$1.38	$1.38	$1.38	$1.37

[9] E. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Biddy, D. Humbird, L. Snowden-Swan, J. Ross, D. Sexton, J. Lukas (2015), *Process Design for the Conversion of Lignocellulosic Biomass to High Octane Gasoline - Thermochemical Research Pathway With Indirect Gasification and Methanol Intermediate*, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, NREL/TP-5100-62402, PNNL-23822, http://www.nrel.gov/docs/fy15osti/62402.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Feedstock Cost	$/dry U.S. ton	$107.09	$97.34	$91.54	$84.45	$84.45	$84.45	$84.45	$84.45	$84.45
Feedstock Moisture at Plant Gate	wt% H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
In-Plant Handling and Drying / Preheating	$/dry U.S. ton	$0.55	$0.54	$0.73	$0.73	$0.73	$0.72	$0.72	$0.72	$0.72
Cost Contribution	$/gallon	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Feed Moisture Content to Gasifier	wt% H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	BTU/lb	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Gasification										
Total Cost Contribution	$/GGE	$0.71	$0.68	$0.57	$0.54	$0.53	$0.53	$0.52	$0.51	$0.50
Capital Cost Contribution	$/GGE	$0.48	$0.45	$0.36	$0.35	$0.34	$0.33	$0.32	$0.31	$0.31
Operating Cost Contribution	$/GGE	$0.23	$0.23	$0.20	$0.20	$0.20	$0.20	$0.19	$0.19	$0.19
Raw Dry Syngas Yield	lb/lb dry feed	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Raw Syngas Methane (Dry Basis)	mole %	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%
Gasifier Efficiency (LHV)	% LHV	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%
Synthesis Gas Clean-Up (Reforming and Quench)										
Total Cost Contribution	$/GGE	$1.08	$1.03	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84
Capital Cost Contribution	$/GGE	$0.59	$0.55	$0.44	$0.42	$0.42	$0.42	$0.42	$0.43	$0.43
Operating Cost Contribution	$/GGE	$0.48	$0.48	$0.41	$0.42	$0.42	$0.42	$0.41	$0.41	$0.41
Tar Reformer (TR) Exit CH_4 (Dry Basis)	mole %	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
TR CH_4 Conversion	%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
TR Benzene Conversion	%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
TR Tars Conversion	%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%
Catalyst Replacement	% of inventory /day	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Acid Gas Removal, Methanol Synthesis, and Methanol Conditioning										
Total Cost Contribution	$/GGE	$0.60	$0.56	$0.44	$0.43	$0.42	$0.41	$0.41	$0.40	$0.39
Capital Cost Contribution	$/GGE	$0.41	$0.38	$0.29	$0.28	$0.27	$0.27	$0.26	$0.25	$0.25
Operating Cost Contribution	$/GGE	$0.19	$0.18	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.14
Methanol Synthesis Reactor Pressure	psia	730	730	730	730	730	730	730	730	730

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Methanol Productivity	kg / kg-cat / hour	3.4	3.7	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Methanol Intermediate Yield	gallons/ dry ton	156	156	145	145	144	144	143	143	142
Hydrocarbon Synthesis										
Total Cost Contribution	$/GGE	$1.02	$1.01	$0.68	$0.57	$0.53	$0.50	$0.46	$0.42	$0.38
Capital Cost Contribution	$/GGE	$0.66	$0.64	$0.46	$0.41	$0.37	$0.34	$0.30	$0.27	$0.24
Operating Cost Contribution	$/GGE	$0.37	$0.36	$0.22	$0.17	$0.16	$0.16	$0.15	$0.15	$0.14
Methanol to DME Reactor Pressure	Psia	145	145	145	145	145	145	145	145	145
Hydrocarbon Synthesis Reactor Pressure	Psia	129	129	129	129	129	129	129	129	129
Hydrocarbon Synthesis Catalyst	-	Commercially available beta-zeolite		NREL modified beta-zeolite with copper (Cu) and gallium (Ga) as active metals for activity and performance improvement						
Hydrogen Addition to Hydrocarbon Synthesis	-	No H_2 Addition	Supplemental H_2 added to hydrocarbon synthesis reactor inlet to improve selectivity to branched paraffins relative to aromatics							
Utilization of C_4 Reactor Products	-	Co-Product	Co-Product	Recycle	Recycle	Recycle	Recycle	Recycle	Recycle	Recycle
Single-Pass DME Conversion	%	15%	15%	20%	30%	32%	34%	36%	38%	40%
Overall DME Conversion	%	81%	85%	84%	88%	89%	90%	91%	92%	93%
Hydrocarbon Synthesis Catalyst Productivity	kg / kg-cat / hour	0.02	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10
Carbon Selectivity to C_5+ Product	% C in reactor feed	46.2%	48.3%	86.1%	89.9%	90.5%	91.2%	91.8%	92.4%	93.1%
Carbon Selectivity to Total Aromatics (Including Hexamethylbenzene)	% C in reactor feed	25.0%	20.0%	8.0%	4.0%	3.3%	2.6%	1.9%	1.2%	0.5%
Carbon Selectivity to Coke and Pre-Cursors (Hexamethylbenzene Proxy)	% C in reactor feed	10.0%	9.3%	4.0%	2.0%	1.7%	1.4%	1.1%	0.8%	0.5%
Dimerization of C_4-C_8 Olefins to Jet / Kerosene-Range Hydrocarbons	-	Not consi-dered	Production of jet / kerosene range hydrocarbons will be considered as sensitivity case or modified design case starting in FY 2015							
Hydrocarbon Product Separation										
Total Cost Contribution	$/GGE	$0.05	$0.05	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Capital Cost Contribution	$/GGE	$0.04	$0.04	$0.04	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Operating Cost Contribution	$/GGE	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT	2016 Projection	2017 Projection		2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Balance of Plant											
Total Cost Contribution	$/GGE	$0.04	($0.01)	($0.01)	($0.01)		($0.02)	($0.03)	($0.04)	($0.05)	($0.06)
Capital Cost Contribution	$/GGE	$0.48	$0.44	$0.35	$0.33		$0.32	$0.31	$0.30	$0.29	$0.27
Operating Cost Contribution	$/GGE	($0.44)	($0.45)	($0.35)	($0.33)		($0.33)	($0.33)	($0.33)	($0.33)	($0.33)
Sustainability and Process Efficiency Metrics											
Carbon Efficiency to C_5+ Product	% C in feedstock	20.7%	20.8%	29.9%	31.0%		31.0%	31.0%	31.1%	31.1%	31.2%
Carbon Efficiency to Mixed C_4 Co-Product	% C in feedstock	7.5%	7.4%	0.0%	0.0%		0.0%	0.0%	0.0%	0.0%	0.0%
Overall Carbon Efficiency to Hydrocarbon Products	% C in feedstock	28.2%	28.3%	29.9%	31.0%		31.0%	31.0%	31.1%	31.1%	31.2%
Overall Energy Efficiency to Hydrocarbon Products	% LHV of feedstock	37.3%	37.4%	43.1%	44.6%		44.7%	44.8%	44.9%	45.0%	45.0%
Electricity Production	kWh/gall on C_5+	11.4	8.8	6.7	6.4		6.3	6.3	6.3	6.2	6.2
Electricity Consumption	kWh/gall on C_5+	11.4	8.8	6.7	6.4		6.3	6.3	6.3	6.2	6.2
Water Consumption	gal H_2O/gal C_5+	12.4	7.4	5.8	5.2		4.5	3.8	3.1	2.4	1.7
Fossil GHG Emissions	g CO_2e / MJ Fuel	1.64	1.65	0.81	0.96		0.88	0.81	0.74	0.67	0.60
Fossil Energy Consumption	MJ fossil energy/MJ fuel	0.023	0.022	0.011	0.013		0.011	0.010	0.009	0.007	0.006
TEA Reference File		2014 SOT Rev4a.xlsm	2015 SOT Rev5 Comm-HBEA.xlsm	2016 Target Rev4a.xlsm	2017 Target Rev4a.xlsm		Interpolated values based on 2017 and 2022 target cases.	H09G1e Rev4-Final1a Final5a.xlsm			

▲ Conceptual design result with margin of error +/- 30%

† SOT: State of Technology
§ Note: The 2016 projection is based on technology progression via advances in new catalytic tools from previously reported, commercially available materials utilized prior to 2016. These novel materials have shown improved performance over the current catalysts and are reflected in future projections.
● NREL will complete FY2015 SOT scenario for production of jet / kerosene range hydrocarbons in December 2015 and incorporate results into subsequent MYPP updates.
○ FY2015 SOT values for fossil GHG emissions and energy consumption are negative due to electricity export from higher hexamethylbenzene (HMB) production relative to target. Higher overall selectivity to gasoline-range products relative to target

LHV = lower heating value.

Table A-9: Unit Operation Cost Contribution Estimates (2014\$) and Technical Projections for Low-Temperature Deconstruction and Fermentation Process Concept[10] [11]

(Process Concept: Dilute Acid Pretreatment, Enzymatic Hydrolysis, Biological Upgrading, Succinic Acid/Adipic Acid Co-Product)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT†	2016 Projection	2017 Projection		2022 Projectio n
Process Concept: Hydrocarbon Fuel Production via Biological Upgrading of Sugars	**-**	**Stover**	**Stover**	**Blend**	**Blend**		**Blend**
Projected Minimum Fuel Selling Price	\$/GGE	\$17.16	\$12.11	\$9.47	\$5.81		\$3.14
Conversion Contribution[1]	\$/GGE	\$13.36	\$9.32	\$7.28	\$4.07		\$1.73
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000		2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	15.6	17.4	19.1	20.7		44.0
Succinic Acid Yield	lb/dry ton biomass	256	323	336	351		0
Feedstock							
Total Cost Contribution	\$/GGE	\$3.80	\$2.79	\$2.19	\$1.74		\$1.41
Capital Cost Contribution	\$/GGE	NA	NA	NA	NA		NA
Operating Cost Contribution	\$/GGE	\$3.80	\$2.79	\$2.19	\$1.74		\$1.41
Feedstock Cost[2]	\$/dry U.S. ton	\$137	\$120	\$100	\$84		\$84
Feedstock Moisture at Plant Gate	wt% H_2O	20%	20%	20%	20%		20%
Pretreatment							
Total Cost Contribution	\$/GGE	\$2.33	\$2.06	\$1.87	\$1.73		\$1.05
Capital Cost Contribution	\$/GGE	\$1.22	\$1.10	\$1.00	\$0.92		\$0.55
Operating Cost Contribution	\$/GGE	\$1.11	\$0.96	\$0.87	\$0.81		\$0.49
Solids Loading	wt%	30%	30%	30%	30%		30%
Xylan to Xylose (including conversion in C5 train)	%	73%	76%	78%	78%		>73%

[10] Davis et al. (2013), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Biological Conversion of Sugars to Hydrocarbons*, National Renewable Energy Laboratory, NREL/TP-510060223, http://www.nrel.gov/docs/fy14osti/60223.pdf.
[11] Davis, R et al., Update to NREL/TP-510060223, *Manuscript in Preparation*.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT†	2016 Projection	2017 Projection		2022 Projection
Hydrolysate Solid-Liquid Separation	-	Yes	Yes	Yes	Yes		No
Xylose Sugar Loss (into C6 stream after acid PT separation)	%	5.0%	4.0%	2.5%	1.0%		NA
Enzymatic Hydrolysis, Conditioning, Bioconversion							
Total Cost Contribution	$/GGE	$5.14	$4.43	$3.96	$3.40		$0.95
Capital Cost Contribution	$/GGE	$3.34	$2.92	$2.62	$2.26		$0.46
Operating Cost Contribution	$/GGE	$1.80	$1.51	$1.34	$1.13		$0.49
Total Solids Loading to Hydrolysis	wt%	15%	15%	17.5%	17.5%		20%
Enzymatic Hydrolysis Time	days	3.5	5.0	3.5	3.5		3.5
Hydrolysis Glucan to Glucose	%	77%	86%	85%	90%		90%
Hydrolysis Residual Xylan to Xylose	%	30%	93%	93%	93%		>30%
Glucose Sugar Loss (into solid lignin stream after EH separation)	%	5%	5%	5%	5%		1%
Bioconversion Volumetric Productivity	(g/L/hour)	0.29	0.34	0.35	0.40		1.30
Lipid Content	wt%	57%	60%	65%	70%		NA
Glucose to Product [total glucose utilization] [3]	%	73% [100%]	75% [100%]	78% [100%]	82% [100%]		87% [95%]
Xylose to Product [total xylose utilization] [3]	%	71% [98%]	44% [59%]	77% [98%]	80% [98%]		82% [86%]
C6 Train Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.24 (0.24)	0.25 (0.24)	0.26 (0.26)	0.27 (0.27)		0.34 (0.28)
Intermediate Product Recovery	%	90%	90%	90%	90%		97%
Carbon Yield to RDB from Biomass	%	8.9%	9.9%	10.9%	11.8%		25.6%
Cellulase Enzyme Production							
Total Cost Contribution	$/GGE	$1.56	$1.21	$0.96	$0.88		$0.41
Capital Cost Contribution	$/GGE	$0.32	$0.25	$0.23	$0.21		$0.10
Operating Cost Contribution	$/GGE	$1.23	$0.96	$0.73	$0.67		$0.31
Enzyme Loading	mg/g cellulose	14	12	10	10		10
Product Recovery + Upgrading							
Total Cost Contribution	$/GGE	$1.77	$1.76	$1.72	$1.58		$0.34
Capital Cost Contribution	$/GGE	$1.03	$0.99	$0.99	$0.92		$0.21
Operating Cost Contribution	$/GGE	$0.74	$0.76	$0.72	$0.67		$0.13
Natural Gas Usage[4]	scf/GGE fuel blendstock	11	10	10	10		18

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT†	2016 Projection	2017 Projection		2022 Projection
C5 Coproduct Processing Train							
Total Cost Contribution	$/GGE	($1.37)	($3.92)	($4.68)	($6.20)		$0.00
Capital Cost Contribution	$/GGE	$4.32	$4.52	$4.21	$3.50		$0.00
Operating Cost Contribution	$/GGE	($5.70)	($8.44)	($8.89)	($9.69)		$0.00
Bioconversion Volumetric Productivity	g/L/hour	0.3	1.45	1.5	2		NA
C5 Train Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.63 (0.59)	0.80 (0.62)	0.785 (0.63)	0.795 (0.74)		NA
Carbon Yield to Succinic Acid from Biomass	%	11.6%	14.6%	15.2%	15.9%		NA
Lignin Utilization							
Total Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		($1.88)
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		$0.31
Operating Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		($2.19)
Balance of Plant							
Total Cost Contribution	$/GGE	$3.93	$3.79	$3.46	$2.68		$0.86
Capital Cost Contribution	$/GGE	$4.58	$4.11	$3.70	$3.10		$1.04
Operating Cost Contribution	$/GGE	($0.65)	($0.32)	($0.24)	($0.42)		($0.18)
Sustainability and Process Efficiency Metrics [5]							
Fuel Yield by Weight of Biomass	% w/w of dry biomass	4.8%	5.4%	5.9%	6.4%		13.6%
Carbon Efficiency to Fuels	% C in feedstock	8.9%	9.9%	10.9%	11.8%		25.6%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	8.8%	9.8%	10.8%	11.7%		25.6%
Net Electricity Import (Entire Process)	kWh/GGE	14.4	16.5	15.6	6.4		0.29
Water Consumption	gal H_2O/GGE	44	36	31	28		12.3
Fossil GHG Emissions	g CO_2e/MJ fuel	247.7	261.9	244.7	184.7		24.4
Fossil GHG Emissions Credits	g CO_2e/MJ fuel	-326.5	-367.4	-348.2	-336.3		-325
Net Fossil GHG Emissions	g CO_2e/MJ fuel	-78.7	-105.4	-103.6	-151.6		-301
Fossil Energy Consumption	MJ fossil energy/MJ fuel	2.9	3.1	2.9	2.2		0.40
Fossil Energy Consumption Credits	MJ fossil energy/MJ fuel	-4.1	-4.7	-4.4	-4.3		-1.70

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 SOT†	2016 Projection	2017 Projection		2022 Projection
Net Fossil Energy Consumption	MJ fossil energy/MJ fuel	-1.2	-1.6	-1.6	-2.1		-1.30

[1] Cost breakdowns to feedstock vs. conversion cost contributions are re-allocated in new target case according to carbon efficiency to renewable diesel blendstock (RDB) fuel vs. succinic acid (feedstock contribution reflects cost allocated to "C6 train" for RDB production).
[2] Feedstock costs shown here based on a 5% "ash equivalent" basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash "dockage" costs for each year.
[3] First number represents sugar conversion to desired product (free fatty acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).

[4] Represents natural gas (NG) demand implicit in H_2 usage delivered from off-site steam methane reformer

[5] Succinic acid life-cycle inventory based on maleic anhydride proxy.

† SOT: State of Technology

scf = standard cubic feet.

Table A-10: Unit Operation Cost Contribution Estimates (2014$) and Technical Projections for Low Temperature Deconstruction and Catalytic Sugar Upgrading Process Concept[12]

(Process Concept: Dilute Acid Pretreatment, Enzymatic Hydrolysis, Chemocatalytic Upgrading to Hydrocarbons)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection		2022 Projection
Process Concept: Hydrocarbon Fuel Production via Catalytic Upgrading of Sugars		**Stover**	**Stover**	**Blend**	**Blend**		**Blend**
Projected Minimum Fuel Selling Price	$/GGE	$7.59	$6.11	$5.02	$4.20		$3.16
Conversion Contribution	$/GGE	$4.87	$4.07	$3.53	$3.12		$2.08
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000		2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	50	59	68	78		76
Feedstock							
Total Cost Contribution	$/GGE	$2.72	$2.03	$1.48	$1.08		$1.08
Capital Cost Contribution	$/GGE	NA	NA	NA	NA		NA
Operating Cost Contribution	$/GGE	$2.72	$2.03	$1.48	$1.08		$1.08
Feedstock Cost[1]	$/dry U.S. ton	$137	$120	$100	$84		$84
Feedstock Moisture at Plant Gate	wt% H_2O	20%	20%	20%	20%		20%
Pretreatment							
Total Cost Contribution	$/GGE	$0.72	$0.61	$0.53	$0.45		$0.49
Capital Cost Contribution	$/GGE	$0.38	$0.33	$0.28	$0.25		$0.23
Operating Cost Contribution	$/GGE	$0.34	$0.28	$0.25	$0.21		$0.26
Solids Loading	wt%	30%	30%	30%	30%		30%
Xylan to Xylose Conversion (overall)[2]	%	81%	84%	87%	90%		90%

[12] R. Davis, L. Tao, C. Scarlata, and E.C.D. Tan et al. (2015), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Catalytic Conversion of Sugars to Hydrocarbons*, National Renewable Energy Laboratory, NREL/TP-5100-62498, http://www.nrel.gov/docs/fy15osti/62498.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
Enzymatic Hydrolysis and Conditioning						
Total Cost Contribution	$/GGE	$0.72	$0.60	$0.52	$0.46	$0.41
Capital Cost Contribution	$/GGE	$0.50	$0.41	$0.36	$0.31	$0.27
Operating Cost Contribution	$/GGE	$0.22	$0.19	$0.17	$0.15	$0.14
Solids Loading	wt%	20%	20%	20%	20%	20%
Enzymatic Hydrolysis Time	days	3.5	3.5	3.5	3.5	3.5
Glucan to Glucose Conversion[2]	%	77%	85%	85%	90%	90%
Sugar Loss in S/L Separation	%	5%	4%	2.5%	1%	1%
Microfiltration Soluble Retention Loss	%	10%	10%	10%	10%	10%
Cellulase Enzyme Production						
Total Cost Contribution	$/GGE	$0.46	$0.34	$0.26	$0.22	$0.22
Capital Cost Contribution	$/GGE	$0.10	$0.07	$0.06	$0.06	$0.05
Operating Cost Contribution	$/GGE	$0.36	$0.26	$0.19	$0.17	$0.17
Enzyme Loading	mg/g cellulose	14	12	10	10	10
Conversion and Upgrading						
Total Cost Contribution	$/GGE	$2.18	$1.87	$1.65	$1.50	$1.44
Capital Cost Contribution	$/GGE	$0.54	$0.47	$0.42	$0.37	$0.32
Operating Cost Contribution	$/GGE	$1.64	$1.39	$1.23	$1.13	$1.12
Hydrogen Feed Molar Ratio (H2 : total APR feed)	-	9.8	9.8	9.8	9.8	9.8
Total Hydrogen Consumption (wt% vs APR feed)	%	4.6%	5.3%	5.9%	6.5%	6.5%
Hydrogenation WHSV	h^{-1}	0.7	0.85	1.0	1.2	1.2
APR WHSV	h^{-1}	0.7	0.8	0.9	1.0	1.0
Condensation WHSV	h^{-1}	0.7	0.85	1.0	1.2	1.2
Hydrogenation catalyst lifetime	years	0.5	0.6	0.8	1.0	1.0
APR catalyst lifetime	years	1.0	1.3	1.6	2.0	2.0
Condensation catalyst lifetime	years	1.0	1.3	1.6	2.0	2.0
Natural Gas Usage[3]	scf/GGE fuel blendstock	102	100	99	97	97
Overall C Yield to Fuels vs APR Feed Components	%	64%	70%	78%	86%	86%
Overall C Yield to Fuels vs Biomass C [vs Total C] [4]	%	29% [25%]	34% [28%]	39% [32%]	45% [36%]	44% [35%]

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection		2022 Projection
Lignin Utilization							
Total Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		($0.82)
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		$0.15
Operating Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00		($0.97)
Balance of Plant							
Total Cost Contribution	$/GGE	$0.79	$0.67	$0.57	$0.49		$0.34
Capital Cost Contribution	$/GGE	$1.06	$0.87	$0.73	$0.61		$0.46
Operating Cost Contribution	$/GGE	($0.27)	($0.20)	($0.16)	($0.12)		($0.12)
Sustainability and Process Efficiency Metrics							
Fuel Yield by Weight of Biomass	% w/w of dry biomass	16%	18%	21%	24%		24%
Carbon Efficiency to Fuels	% C in feedstock	29%	34%	39%	45%		41%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	25%	28%	32%	36%		35%
Net Electricity Export (Entire Process)	kWh/GGE	4.7	3.5	2.5	1.5		0.63
Water Consumption	gal H_2O/GGE	12.0	9.4	7.6	5.8		5.31
Fossil GHG Emissions	g CO_2e / MJ fuel	64.8	61.4	58.9	57.3		64.5
Fossil GHG Emissions Credits	g CO_2e / MJ fuel	(25.0)	(18.6)	(13.1)	(8.3)		(134)
Net Fossil GHG Emissions	g CO_2e / MJ fuel	39.8	42.7	45.8	49.1		(69.4)
Fossil Energy Consumption	MJ fossil energy / MJ fuel	1.0	1.0	0.9	0.9		1.0
Fossil Energy Consumption Credits	MJ fossil energy / MJ fuel	(0.3)	(0.2)	(0.1)	(0.1)		-0.7
Net Fossil Energy Consumption	MJ fossil energy / MJ fuel	0.7	0.8	0.8	0.8		0.3

[1] Feedstock costs shown here based on a 5% “ash equivalent” basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash “dockage” costs for each year.

[2] For this pathway, values represent glucan/xylan conversion to both monomeric and oligomeric sugars given flexibility in downstream conversion step.

[3] Values represent natural gas (NG) demand implicit in H_2 usage delivered from off-site steam methane reformer (SMR).

[4] “Total carbon” includes external natural gas carbon implicit in SMR-derived H_2 (0.44 mol C in natural gas/mol H_2 product).

† SOT: State of Technology

Appendix B: Calculation Methodology for Cost Goals

The two primary goals of this appendix are as follows:

1. Summarize the bases for the Bioenergy Technologies Office's performance goal
2. Explain the general methodology used to develop the cost goals and projections and adjust them to different year dollars.

Table B-1 describes the primary documents—including the Multi-Year Program Plan (MYPP)—that cover the evolution of technology design and cost projections for specific conversion concepts. Additional details for the technical performance targets and cost goals can be found in Appendix A.

Table B-1: Primary Source Documents for Office Cost Goals

Document	Design and Cost Information: Bases and Differences
2009 MYPP	• Introduction of first projection of woody feedstock costs. • Thermochemical conversion model included based on first design report for pyrolysis, pyrolysis-oil upgrading and stabilization, and fuel synthesis to gasoline/diesel blendstock. • All costs in 2007 dollars using actual economic indices up to 2007.
2010 MYPP	• Thermochemical conversion models updated based on first detailed design report for pyrolysis to hydrocarbon biofuels.[1]
2011 MYPP	• Thermochemical conversion models, including preliminary technical projections, provide further detail for pyrolysis to hydrocarbon fuels.
2012 MYPP	• The Office's 2017 performance goals are based on the EIA reference case projections for the wholesale price of gasoline, diesel, and jet fuel.[2] • All costs in 2011 dollars using updated cost indices. • Algae cost goals added for the Algae Lipid Upgrading pathway based on 2012 technical report.[3]
2014 MYPP	• Thermochemical conversion cost goals revised based on updated design report for fast pyrolysis and upgrading to hydrocarbon biofuels.[4] • Biochemical conversion interim cost goal based on first detailed design report for biological conversion of sugars to hydrocarbon biofuels.[5] • Feedstocks cost goals were revised to $80/DM ton, including both grower payment and logistics, based on updated cost projections that incorporate the need for higher volumes and the need to address feedstock quality. Grower payments were based on resource assessment analyses, rather than a fixed cost as in 2011.

[1] S.B. Jones, C. Valkenburg, C.W. Walton, et al. (2009), "Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case," Pacific Northwest National Laboratory, PNNL-18284, http://www.pnl.gov/main/publications/external/technical_reports/pnnl-18284.pdf.

[2] U.S. Department of Energy (2012), *Annual Energy Outlook 2012: Table 131*, Washington: Government Printing Office, http://www.eia.gov/oiaf/aeo/supplement/suptab_131.xlsx.

[3] R. Davis et al. (2013), "Renewable Diesel from Algal Lipids: An Integrated Baseline for Cost, Emissions, and Resource Potential from a Harmonized Model," Argonne National Laboratory, ANL/ESD/12-4, http://greet.es.anl.gov/publication-algae-harmonization-2012.

[4] S. Jones et al. (2013), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-Oil Pathway," Pacific Northwest National Laboratory, PNNL-23053, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

[5] R. Davis et al. (2013) "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Biological Conversion of Sugars to Hydrocarbons," National Renewable Energy Laboratory, NREL/TP-5100-60223, http://www.nrel.gov/docs/fy14osti/60223.pdf.

Document	Design and Cost Information: Bases and Differences
	• Algae design reports for the Lipid Extraction and Upgrading[6] and Hydrothermal Liquefaction[7] pathways were added and updated to reflect changes from the harmonized baseline.
2015 MYPP	• Combined Conversion R&D section cost goals for combined supported by additional design cases for *Ex Situ* and *In Situ* Upgrading of Fast Pyrolysis Vapors,[8] Low-Temperature Deconstruction and Catalytic Sugar Upgrading,[9] and Hydrocarbons via Indirect Liquefaction[10] pathways. • Fast Pyrolysis and Low-Temperature Deconstruction and Fermentation pathways updated. • 2014 woody feedstock costs updated from projection to actual modeled cost. • Herbcaceous feedstock costs added to support biochemical conversion cost tables.
2016 MYPP	• All costs in 2014 dollars using updated cost indices. • Algae production design report added.[11]

Office's Performance Goal: Calculation Methodology

The Office's performance goals are based on commercial viability, specifically the Energy Information Administration's (EIA's) oil price outlook for future motor gasoline, diesel, and jet wholesale prices. The underlying assumptions include the following:

- Refinery gate production cost of gasoline can be compared to the biorefinery production cost of biomass-based renewable gasoline and ethanol (adjusted for Btu content). Similarly, refinery gate production cost of diesel and jet fuel can be compared to the biorefinery production cost of biomass-based renewable diesel and jet fuel.
- Downstream distribution costs are excluded as are subsidies and tax incentives.

The historical crude oil prices and EIA projections are presented in Figure B-1.

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[6] R. Davis, C. Kinchin, J. Markham, E. Tan, et al. (2014), *Process Design and Economics for the Conversion of Algal Biomass to Biofuels: Algal Biomass Fractionation to Lipid- and Carbohydrate-Derived Fuel Products*, National Renewable Energy Laboratory, NREL/TP-5100-62368, http://www.nrel.gov/docs/fy15osti/62368.pdf.

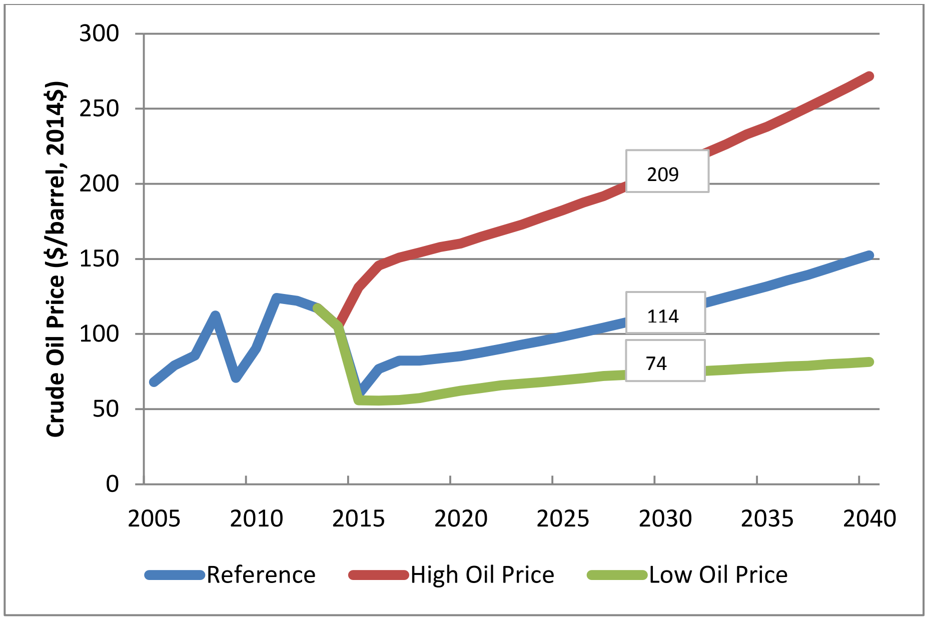
[7] S. Jones, et al. (2014), "Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading," Pacific Northwest National Laboratory, PNNL-23227, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf.

[8] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, J. Lukas (2015), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels - Thermochemical Research Pathways With In Situ and Ex Situ Upgrading of Fast Pyrolysis Vapors*, National Renewable Energy Laboratory, NREL/TP-5100-62455, Pacific Northwest National Laboratory, PNNL-23823.

[9] R. Davis et al. *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Catalytic Conversion of Sugars to Hydrocarbons*," National Renewable Energy Laboratory, NREL/TP-5100-62498, http://www.nrel.gov/docs/fy15osti/62498.pdf.

[10] E. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Biddy, D. Humbird, L. Snowden-Swan, J. Ross, D. Sexton, and J. Lukas (2015), *Process Design for the Conversion of Lignocellulosic Biomass to High Octane Gasoline - Thermochemical Research Pathway With Indirect Gasification and Methanol Intermediate*, National Renewable Energy Laboratory, NREL/TP-5100-62402, Pacific Northwest National Laboratory, PNNL-23822, http://www.nrel.gov/docs/fy15osti/62402.pdf.

[11] R. Davis et al. (2015), *Process Design and Economics for the Production of Algal Biomass: Algal Biomass Production in Open Pond Systems and Processing Through Dewatering for Downstream Conversion*, National Renewable Energy Laboratory, NREL/TP-5100-64772, http://www.nrel.gov/docs/fy16osti/64772.pdf.



Source: History: U.S. Energy Information Administration, "Petroleum & Other Liquids, Europe Bent Spot Price FOB," http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D.
Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE. D021915A.

Figure B-1: EIA projections for crude oil prices[12]

The crude oil, gasoline, diesel, and jet prices for EIA's reference and high oil cases are summarized in Table B-2.

Table B-2: EIA Oil Price Forecasts[14]

	Wholesale Prices in 2014$[15]	2017	2020	2022	2030	2035	2040
Reference Case							
	Crude oil ($/barrel)	82	85	90	114	132	152
	Diesel ($/gallon)	2.26	2.39	2.54	3.14	3.61	4.15
	Jet ($/gallon)	2.16	2.26	2.38	3.02	3.49	4.04
	Gasoline ($/gallon)	2.30	2.35	2.44	2.87	3.24	3.65
High Oil Price Case							
	Crude oil ($/barrel)	151	160	169	209	238	272
	Diesel ($/gallon)	4.00	4.32	4.55	5.66	6.39	7.24
	Jet ($/gallon)	3.77	4.12	4.35	5.48	6.2	7.02
	Gasoline ($/gallon)	3.67	3.88	4.06	4.85	5.5	6.24

[12] U.S. Energy Information Administration (2015), *Annual Energy Outlook 2015 with Projections to 2040*, http://www.eia.gov/forecasts/aeo/section_prices.cfm.
[13] Note: Fuel prices are reported in 2013$ in the *Annual Energy Outlook 2015*. They have been adjusted from 2013$ to 2014$ by using the gross domestic product implicit price deflators (1.110 for 2010; 1.133 for 2011) obtained from the U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Product Accounts: Table 1.1.9," http://www.bea.gov/iTable/index_nipa.cfm.
[14] U.S. Energy Information Administration (2015), *Annual Energy Outlook 2015 with Projections to 2040*, http://www.eia.gov/forecasts/aeo/section_prices.cfm.
[15] Note: Fuel prices are reported in 2013$ in the *Annual Energy Outlook 2015*. They have been adjusted from 2013$ to 2014$ by using the gross domestic product implicit price deflators (1.07 for 2013; 1.09 for 2014) obtained from the U.S. Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts: Table 1.1.9*, http://www.bea.gov/iTable/index_nipa.cfm.

Table B-2 shows that the Office performance goal of producing biofuels at around $3/gallon by 2017 is between the EIA reference case and high oil case projections for diesel, jet, and gasoline prices.

Cost Goals and Projections
Specific cost goals and projections are based on published design cases and state of technology (SOT) reports as defined below.

Design Case: A design case is a techno-economic analysis that outlines a target case and preliminary identification of data gaps and research and development (R&D) needs and is used by the Office as a basis for setting technical targets and cost of production goals.

- Design cases and related goals and targets serve four purposes:
    1. Provide goals and targets against which technology progress is assessed
    2. Provide goals and targets against which processes are validated at increasing scale and integration
    3. Identify optimal R&D areas for prioritizing funding and focus
    4. Provide justification for budget requests.
- A design case is documented in a peer-reviewed design report that represents a particular example of a technology pathway and which encompasses a set of technologies across the entire biomass-to-bioenergy supply chain—from feedstock input through product production (i.e., total feedstock cost: harvest, collection, storage, grower payment, handling, size reduction, moisture control, and total conversion costs).
- Design case technical targets and cost goals must be adequately detailed to fully integrate across all supply chain elements in order to credibly represent a total finished product cost (excluding distribution, taxes, and tax credits).
- A design case is based on (1) best available information at date of the associated design reports and (2) current projections of nth plant capital and operating costs. Depending on the maturity of technology development of a particular technology pathway, design cases can range from high-level conceptual, literature-based process flows with material balances for earlier-stage technologies, to more fully detailed and specified processes with material and energy balances and capital and operating estimates based on actual, experimental data. In more mature forms, design cases are based on design reports that include detailed, peer-reviewed process simulation based on ASPEN, Chemcad, or other process models.
- As technology development progresses, design cases generally become more detailed and are reconfigured, which results in changes to technical targets and cost goals to reflect advances in the R&D knowledge base.
- Over the time span from initial to final design case for a given technology pathway, the range of uncertainty around the associated technical targets and cost estimates is expected to decrease.

State of Technology: An SOT assessment is a periodic (usually annual) assessment of the status of technology development for a biomass to biofuels/products pathway. An SOT assesses progress within and across relevant technology areas based on actual experimental results relative to technical targets and cost goals from design cases and includes technical, economic, and environmental criteria as available.

Table B-3 shows the cost breakdown of the projected cost goals for the fast pyrolysis pathway as a result of updating the dollar year, initially from 2007 to 2011 and now to 2014 and adjusting other key assumptions, as shown in Table B-4. It also shows the changes resulting from updates to the fast pyrolysis design reports.[16] The cost components are based on the first two major elements of the biomass-to-biofuels supply chain (delivered cost of feedstock production and feedstock conversion) and their associated sub-elements.

The costs for feedstock production are based on simulated feedstock supply curves developed and published in the *U.S. Billion-Ton Update*.[17] This analysis projects feedstock production scenarios based on a series of factors that impact feedstock production decisions. The supply curves project the amount of feedstock produced at various market prices for each of several feedstock categories identified in Table A-1. The grower payment in Tables A-4 through A-9 reflects the component of the total feedstock cost paid to the producer. This grower payment corresponds to the estimated average price required to procure total volumes available using U.S. Billion-Ton data (e.g., Figure 2-9).

The projected production cost goals represent mature technology processing costs, which means that the capital and operating costs are assumed to be for an "nth plant," where several plants have been built and are operating successfully, no longer requiring increased costs for risk financing, longer startups, under-performance, and other costs associated with pioneer plants.

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[16] Jones et al. (2013), *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels Fast Pyrolysis and Hydrotreating Bio-Oil Pathway*, Pacific Northwest National Laboratory, PNNL-23053, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

[17] U.S. Department of Energy (2011), *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, R.D. Perlack and B.J. Stokes (Leads), ORNL/TM-2011/224, Oak Ridge National Laboratory, Oak Ridge, TN, https://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf.

Table B-3: Change Over Time in 2017 Production Cost Targets for Wood/Pyrolysis to Hydrocarbon Fuel

Supply Chain Areas	Units	2009 Wood/ Pyrolysis to Hydrocarbon Fuel Design Report	2012 MYPP 2017 Goals/Targets	2014 MYPP 2017 Goals/Targets	2016 MYPP
Year $	Year	2007	2011	2011	2014
Feedstock Production					
Grower Payment	$/DT	$22.60	$26.25	$21.90	$23.12
Feedstock Logistics					
Harvest and Collection	$/DT	$18.75	$19.53	$10.47	$11.05
Landing Preprocessing	$/DT	$11.42	$11.73	$10.24	$10.81
Transportation and Handling	$/DT	$8.95	$6.37	$7.52	$7.94
Plant Receiving and In-Feed Preprocessing	$/DT	$17.65	$16.88	$29.87	$31.53
Logistics Subtotal	**$/DT**	**$56.77**	**$54.50**	**$58.10**	**$61.33**
Feedstock Total	**$/DT**	**$79.37**	**$80.75**	**$80.00**	**$84.45**
Fuel Yield	(gal gasoline + diesel)/DT	106	106	84 (87 DT/GGE)	87 GGE/DT
		$/gal total fuel	**$/gal total fuel**	**GGE**	**GGE**
Feedstock Production					
Grower Payment	-	$0.21	$0.25	$0.25	$0.26
Feedstock Logistics					
Harvest and Collection	-	$0.18	$0.18	$0.12	$0.13
Landing Preprocessing	-	$0.11	$0.11	$0.12	$0.13
Transportation and Handling	-	$0.08	$0.06	$0.09	$0.10
Plant Receiving and In-Feed Preprocessing	-	$0.17	$0.16	$0.34	$0.36
Logistics Subtotal	-	$0.54	$0.51	$0.67	$0.70
Feedstock Total	**-**	**$0.75**	**$0.76**	**$0.92**	**$0.97/GGE**
Biomass Conversion					
Fast Pyrolysis*	-	$0.34	$0.39	$0.76	$0.78
Upgrading to Stable Oil	-	$0.47	$0.55	$0.95	$0.96
Fuel Finishing to Gasoline and Diesel	-	$0.11	$0.13	$0.14	$0.14
Balance of Plant	-	$0.65	$0.75	$0.63	$0.64
Conversion Total	**-**	**$1.57**	**$1.83**	**$2.47**	**$2.52**
Fuel Production Total	-	***$2.32***	***$2.83***	***$3.39***	***$3.50***

* Fast pyrolysis costs in 2009 Design Report and 2012 MYPP cost targets include feedstock drying and sizing. 2014 MYPP and 2016 MYPP cost targets assume feedstock costs to the reactor throat.

Table B-4 outlines changes in the analysis assumptions for the fast pyrolysis pathway, as well as other conversion design reports.

Table B-4: 2012 Changes to Conversion Cost Assumptions

	Prior Values	2012 Updated Values
% Equity / % Debt Financing	100%	40% / 60%
Loan Terms (% Rate, Term)	N/A	8%, 10 years
Discount Factor	10%	10%
Year-Dollars	2007 dollars	2011 dollars
Depreciation Method, Time	MACRS 7 years general plant 20 years steam/boiler	MACRS 7 years general plant 20 years steam/boiler (if exporting electricity)
Cash Flow / Plant Life	20 years	30 years
Income Tax	39%	35%
Online Time	90%	90%
Indirect Costs (Contingency, Fees, etc.)	51% of total installed costs	60% of total direct costs*
Lang Factor	3.7	4.7 (fast pyrolysis case)

* Total direct costs include installed costs plus other direct costs (buildings, additional piping, and site development).

General Cost Estimation Methodology

The Office uses consistent, rigorous engineering approaches for developing detailed process designs, simulation models, and cost estimates, which in turn are used to estimate the minimum selling price for a particular biofuel using a standard discounted cash-flow rate of return calculation. The feedstock logistics element uses economic approaches to costing developed by the American Society of Agricultural and Biological Engineers. Details of the approaches and results of the technical and financial analyses are thoroughly documented in the Office's conceptual design reports[18] and are not included here. Instead, a high-level general description of how costs are developed and escalated to different year dollars is provided below.

Cost estimate development is slightly different between the feedstock logistics and biomass conversion elements, but generally both elements include capital costs, costs for chemicals and other material, and labor costs. The indices for plant capital chemicals and materials have increased significantly since 2003, while the labor index has shown a consistent and steady rise of about 2.5% per year.

[18] S.B. Jones, C. Valkenburg, and C.W. Walton et al. (2009), *Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case*, Pacific Northwest National Laboratory, PNNL-1828, http://www.pnl.gov/main/publications/external/technical_reports/pnnl-18284.pdf.

The total project investment (based on total equipment cost), as well as variable and fixed operating costs, are developed first using the best available cost information. Cost information typically comes from a range of years, requiring all cost components to be adjusted to a common year. For the case shown in Appendix B, each cost component was adjusted based on the ratio of the 2011 index to the actual index for the particular cost component. The delivered feedstock cost was treated as an operating cost for the biomass conversion facility. With these costs, a discounted cash-flow analysis of the conversion facility was carried out to determine the selling price of fuel when the net present value of the project is zero.

Design reports added in the 2015 MYPP update have utilized updated published index values, which are summarized in each respective design report. This minor inconsistency across design cases will be resolved in future MYPP updates.

Total Project Investment Estimates and Cost Escalation

The Office design reports include detailed equipment lists with sizes and costs, as well as details on how the purchase costs of all equipment were determined. For the feedstock logistics element, some of the equipment, such as harvesters and trucks, do not require additional installation cost; however, other logistics equipment and the majority of the conversion facility equipment will be installed.

For the types of conceptual designs the Office carries out, a "factored" approach is used. Once the installed equipment cost has been determined from the purchased cost and the installation factor, it can be indexed to the project year being considered. The purchase cost of each piece of equipment has a year associated with it. The purchased cost year will be indexed to the year of interest using the Chemical Engineering Plant Cost Index.

Figure B-2 and Table B-5 show the historical values of the index. Notice that the index was relatively flat between 2000 and 2002 with less than a 0.4% increase, while there was a jump of nearly 18% between 2002 and 2005 and an additional increase of nearly 23% between 2005 and 2008. Changes in the plant cost indices can drive dramatic increases in equipment costs, which directly impact the total project capital investment.

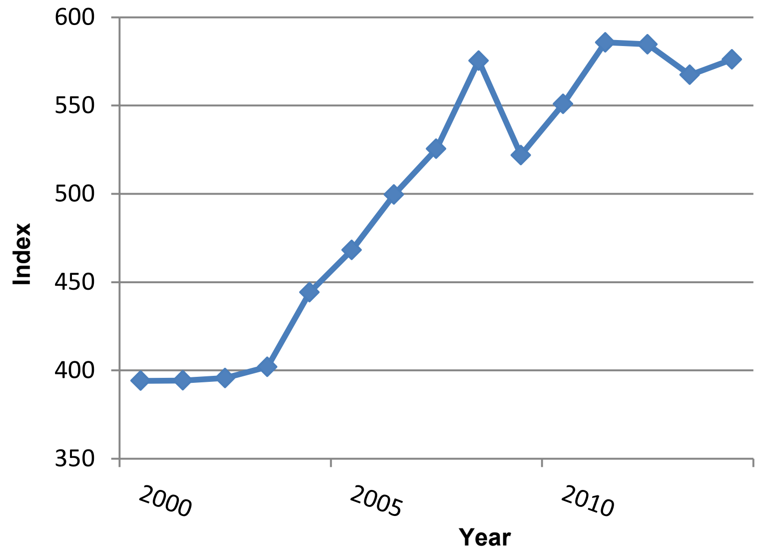

Figure B-2: Chemical Engineering Plant Cost Index (see Table B-5 for values)

Table B-5: Annual Values for the Plant Cost Index

Source	Year	Chemical Engineering Annual Index
(1)	2000	394.1
(2)	2001	394.3
(2)	2002	395.6
(3)	2003	402.0
(3)	2004	444.2
(3)	2005	468.2
(4)	2006	499.6
(4)	2007	525.4
(4)	2008	575.4
(4)	2009	521.9
(4)	2010	550.8
(4)	2011	585.7
(4)	2012	584.6
(4)	2013	567.3
(4)	2014	576.1
Sources (http://www.che.com/ei):		
(1) *Chemical Engineering Magazine*, April 2002		
(2) *Chemical Engineering Magazine*, December 2003		
(3) *Chemical Engineering Magazine*, May 2005		
(4) *Chemical Engineering Magazine*, July 2015		

Any extrapolation of this data is extremely difficult. Trends prior to 2003 were nearly linear, followed by significant increases until an economic downturn in 2009. The index increased from 2009 until 2011 when it regained 2008 levels and, since then, the trend has been fairly flat.

For equipment cost items in which actual cost records do not exist, a representative cost index is used. For example, the U.S. Department of Agriculture (USDA) publishes Prices Paid by Farmers indexes that are updated monthly. These indexes represent the average costs of inputs purchased by farmers and ranchers to produce agricultural commodities and a relative measure of historical costs. For machinery list prices, the Machinery Index was used. The Repairs Index was used for machinery repair and maintenance costs. These USDA indices were used for all machinery used in the feedstock supply system analysis, including harvest and collection machinery (combines, balers, tractors, etc.), loaders and transportation-related vehicles, grinders, and storage-related equipment and structures.

Operating Cost Estimates and Cost Escalation

For the different design cases, variable operating costs—which include fuel inputs, raw materials, waste handling charges, and byproduct credits—are incurred when the process is operating and are a function of the process throughput rate. All raw material quantities used and wastes produced are determined as part of the detailed material and energy balances calculated for all the process steps. As with capital equipment, the costs for chemicals and materials are associated with a particular year. The U.S. Producer Price Index from SRI Consulting was used as the index for all chemicals and materials and can be seen in Figure B-3 and Table B-6.

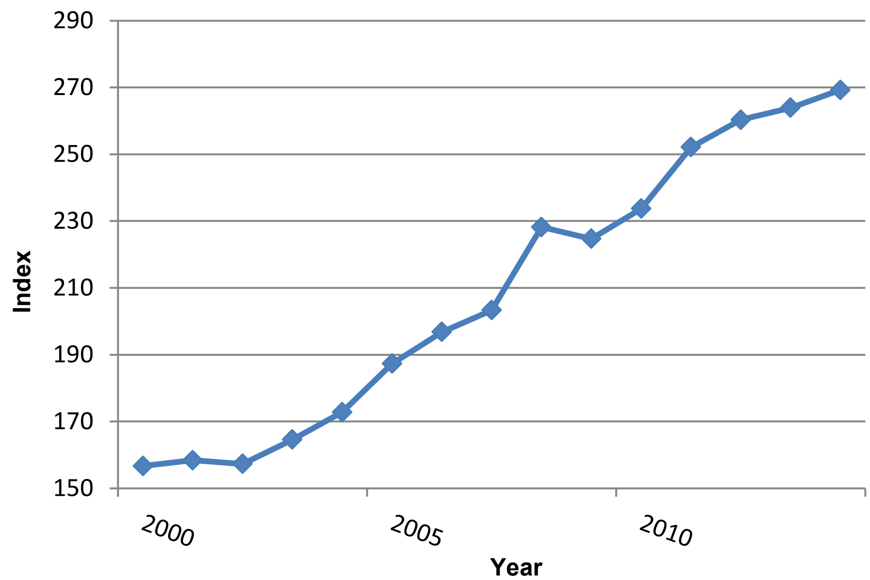

Figure B-3: U.S. Producer Price Index for chemicals and allied products (see Table B-6 for values)

Table B-6: Annual Values for U.S. Producer Price Index—Total, Chemicals and Allied Products

Year	U.S. Producer Price Index
2000	156.7
2001	158.4
2002	157.3
2003	164.6
2004	172.8
2005	187.3
2006	196.8
2007	203.3
2008	228.2
2009	224.7
2010	233.7
2011	252.1
2012	260.3
2013	263.9
2014	269.2

Source: Handbook, Economic Environment of the Chemical Industry 2011, http://chemical.ihs.com/CEH/Private/EECI/EECI.pdf.

Some types of labor—especially related to feedstock production and logistics—are variable costs, while labor associated with the conversion facility are considered fixed operating costs.

Fixed operating costs are generally incurred fully, whether or not operations are running at full capacity. Various overhead items are considered fixed costs in addition to some types of labor. General overhead is often a factor applied to the total salaries and covers items such as safety, general engineering, general plant maintenance, payroll overhead (including benefits), plant security, janitorial and similar services, phone, light, heat, and plant communications. Annual maintenance materials are generally estimated as a small percentage (e.g., 2%) of the total installed equipment cost. Insurance and taxes are generally estimated as a small percentage (e.g., 1.5%) of the total installed cost. The index to adjust labor costs is taken from the Bureau of Labor Statistics and is shown in Figure B-4 and Table B-7.

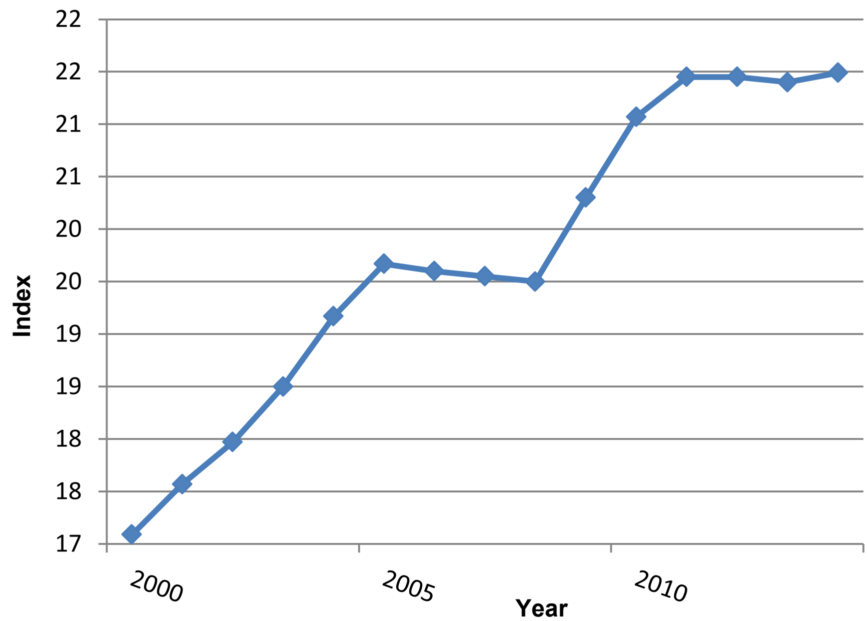

Figure B-4: Actual labor cost index—earnings of chemical production workers (see Table B-7 for values)

Table B-7: Annual Values for Labor Cost Index

Year	Labor Cost Index
2000	17.09
2001	17.57
2002	17.97
2003	18.50
2004	19.17
2005	19.67
2006	19.60
2007	19.55
2008	19.50
2009	20.30
2010	21.07
2011	21.45
2012	21.45
2013	21.40
2014	21.49
Source: Bureau of Labor Statistics, Series ID: CEU3232500008, Chemicals Average Hourly Earnings of Production Workers, http://data.bls.gov/cgi-bin/srgate.	

Discounted Cash-Flow Analysis and the Selling Price of Biofuels

Once the two major cost areas—total project investment and operating costs—have been determined, a discounted cash-flow analysis can be used to determine the minimum selling price per gallon of biofuel produced. The discounted cash-flow analysis program iterates on the selling price of the biofuel until the net present value of the project is zero. This analysis requires that the discount rate, depreciation method, income tax rates, plant life, and construction startup duration be specified. The Office has developed a standard set of assumptions for use in the discounted cash-flow analysis.

Appendix C: 2012 Cellulosic Ethanol Success

The Bioenergy Technologies Office has supported research, development, and demonstration for the production of cellulosic ethanol, focusing on three key areas: feedstock logistics, biochemical conversion, and thermochemical conversion. In September 2012, after 10 years of dedicated research and development (R&D) at the lab/bench and pilot[1] scales, the Office's research, development, and demonstration (RD&D) activities resulted in a four-fold reduction in cost and ultimately demonstrated two biofuels pathways that can produce cellulosic ethanol at a modeled nth plant cost of approximately $2.65 per gallon. This equates to a 77% reduction in the minimum ethanol selling price (MESP) from an estimated $10.92 (2014$U.S.) in 2001.

This achievement marks a critical milestone for the industry that was accomplished with strong bipartisan federal support across two presidential administrations. This milestone was achieved through U.S. Department of Energy (DOE) support of R&D at DOE national laboratories, academic institutions, and industry. RD&D was specifically focused on improving the efficiency and economics around biomass harvesting and feedstock supply system logistics, developing techno-economically viable process steps for both biochemical and thermochemical conversion processes, and through process integration. Reduced costs, technology improvements, and progress in scale-up and integration of processes represent major successes in cost-competitive cellulosic ethanol production. With conservative economic assumptions and proven process parameters, the technologies demonstrated at pilot scale[1] are modeled to produce cellulosic ethanol at commercial-scale costs that are competitive with gasoline production at $110/barrel of crude oil.

Many industry partners are also demonstrating their proprietary technology pathways to produce biofuel at pilot, demonstration, and commercial scales. Some of these technologies are similar to those demonstrated in the recent R&D accomplishment, while others demonstrate or commercialize newly developed technologies for cellulosic ethanol production.

Feedstock Logistics

Improvements in biomass harvesting and feedstock supply system logistics are crucial to meeting modeled 2,200 U.S. tons (2,000 tonne) per day refinery input/uptake/requirement for commercial-scale production costs of cellulosic ethanol. For 2012, research focused on corn stover as a model agricultural residue feedstock and purpose-grown trees as a model woody feedstock for biochemical and gasification routes, respectively.

Key advances in sustainable harvesting and collection include using the Residue Removal Tool[2] for accurate area assessments, improved storage strategies for preservation of biomass quantity and quality, and more energy- and cost-efficient mechanisms for preprocessing of biomass appropriate for introduction into the conversion processing system. Additional improvements included increased harvest efficiency, which contributes to higher sustainable yields, and improved biomass quality through ash content reduction. Higher bale density and reduced losses during handling and storage further contributed to meeting cost targets by lowering the cost of

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[1] Pilot throughput is defined as ½ to ≥ 1 dry ton per day.

[2] D. Muth and K.M. Bryden (2012), "An Integrated Model for Assessment of Sustainable Agricultural Residue Removal Limits for Bioenergy Systems," *Environmental Modelling and Software* 39(1).

transporting feedstocks. Other contributions to cost reduction include lower-cost storage methods, reduced uncertainty associated with storage losses through meeting a 59% carbohydrate preservation target, and direct improvements in grinder efficiency and capacity. These feedstock advancements, paired with increases in conversion yield/efficiency, resulted in a reducing production costs in 2012 by $0.48 and $0.58 per gallon for biochemical and thermochemical cellulosic ethanol, respectively.

Biochemical Conversion

Biochemical conversion route costs were significantly impacted through an approximate 90% reduction in enzyme cost (enabled by development of new enzymes and enzyme cocktails) and the engineering of microorganisms that can more effectively utilize multiple sugars produced from hydrolyzed plant cell wall cellulose and hemicellulose (i.e., glucose, xylose, and arabinose). A biochemical conversion pilot plant demonstrated a fully integrated suite of technologies capable of producing cellulosic ethanol from corn stover at a cost of $2.65 per gallon ethanol ($3.95 gasoline gallon equivalent [GGE]) when modeled at commercial scale.

Biochemical conversion of biomass to cellulosic ethanol can involve many steps, including pretreatment, conditioning, and enzymatic hydrolysis, followed by fermentation. Key breakthroughs in these process steps included the development of more efficient pretreatment processes, resulting in increased sugar yields; improved enzyme production method and enzymes that reduced enzyme loading and associated enzyme costs; and more robust fermentation organisms that were able to utilize sugars in the presence of biomass-derived inhibitors, ultimately achieving significantly higher ethanol yields. The deconstruction strategy, tested at bench and pilot scales, resulted in greater than 80% conversion of the xylan to desired xylose monomer in whole slurry mode while simultaneously lowering acid usage from 3.0% to 0.3%. An improved neutralization step reduced conditioning-related sugar losses from 13% to undetectable amounts. Increased enzyme efficiency resulted in reduced enzyme loading and cellulose-to-glucose yields of nearly 80%, contributing to an overall reduction in enzyme costs by 20-fold. Improvements in fermentation and microbial strain development resulted in the industrially relevant strains capable of converting cellulosic sugars at total conversion yields greater than 95% and tolerant of ethanol titers of approximately 72 gram/liter.

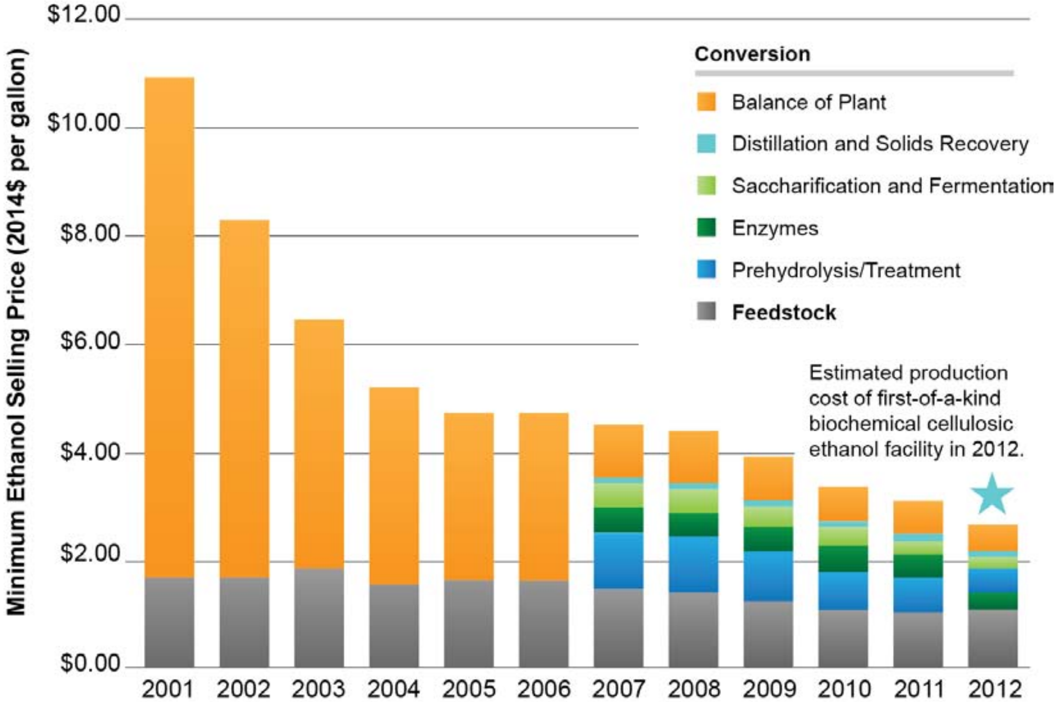

Figure C-1: Biochemical R&D impact on MESP from corn stover

Figure C-1 illustrates the R&D impact on MESP of corn stover to ethanol via biochemical conversion, from 2001 to 2012. The dotted line denotes success at varying scales: bench scale prior to 2007 and pilot and modeled nth plant scale thereafter, until 2012. The star represents the published production cost[3] expected at one of the first cellulosic ethanol facilities to come online.

Thermochemical Conversion

The thermochemical conversion process used for cellulosic ethanol production included a gasifier, syngas clean-up, and catalytic fuel synthesis reactors. Significant process engineering improvements were achieved within the gasifier and fuel synthesis steps, and technical improvements were achieved in the syngas cleanup and catalytic fuels synthesis steps.

After developing, improving, and down-selecting a variety of technologies for each process step, the Office demonstrated a configuration capable of producing cellulosic ethanol from a woody feedstock at a cost of $2.45 per gallon ethanol ($3.66 GGE) when modeled at commercial scale (using the pilot plant at its thermochemical users facility). The Office's notable technical breakthroughs included the optimization of its indirectly heated fluidized bed gasifier; the development of tar- and methane-reforming catalysts that increased methane conversion to syngas from 20% to more than 80%; and development of catalysts and operational strategies for the conversion of syngas to mixed alcohols production. These key improvements resulted in an increase in ethanol yield from 62 gallons to greater than 84 gallons per ton of biomass. Figure C-2 illustrates the R&D successes contributing to the decrease in MESP for a gasification process between 2007 and 2012.

[3] Chris Standlee (2014), "Advanced Ethanol: Coming Online," National Ethanol Conference, February 18, 2014, Orlando, Florida.

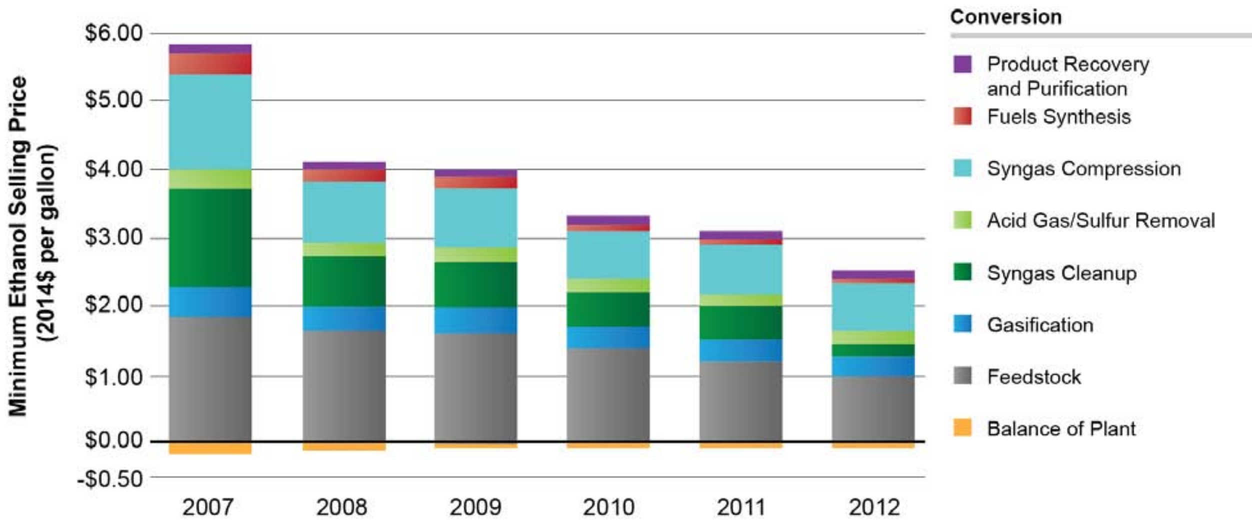

Figure C-2: Thermochemical R&D impact on MESP from woody feedstock

Figure C-2 illustrates the R&D impact on MESP of woody feedstocks to ethanol via thermochemical conversion, from 2007 to 2012.

Leveraging Success

More than 10 years of dedicated RD&D enabled the breakthroughs necessary for the production of cost-competitive cellulosic ethanol. Meeting cost-competitive production targets is important because cellulosic ethanol represents a very significant life-cycle reduction in greenhouse gas emissions compared to petroleum gasoline (roughly 80% and roughly 90% for fermentation and gasification pathways, respectively).[4] This does not suggest that these processes cannot be further improved. Updated design cases have shown that the escalation of costs to 2014 U.S. dollar bases increased the MESP and helps to identify further process efficiencies that could be addressed through additional R&D.

These R&D achievements demonstrated in 2012 and afterward for cellulosic ethanol production provide the groundwork for the development and optimization of biomass conversion technologies and techniques capable of producing hydrocarbon liquids that are virtually indistinguishable from gasoline, diesel, jet fuel, and other petroleum products, and that are fully compatible with existing fuel handling and distribution infrastructures. These breakthroughs will be repurposed and leveraged to accelerate the commercialization of new, renewable fuels and chemicals from biomass.

[4] J.B. Dunn, M. Johnson, M. Wang (2013), "Supply Chain Sustainability Analysis of SOT Pathways," BETO Quarterly Meeting, January 17, 2013, Washington, D.C.

Appendix D: Matrix of Revisions

Section Name	Specific Reference	Revision	Version Change was Implemented
July 2014			
All Sections	Throughout	Major and minor updates to all sections	July 2014
Feedstock Supply and Logistics R&D	Section 2.1	Terrestrial Feedstocks and Algal Feedstocks separated into two sub-sections	July 2014
Thermochemical Conversion R&D	Section 2.2.2	Oils and Gaseous Intermediate Sections combined into Thermochemical Conversion R&D	July 2014
Demonstration and Deployment	Section 2.3	Combined Integrated Biorefinery and Distribution Infrastructure and End Use sections and redrafted/refocused D&D section	July 2014
November 2014			
Terrestrial Feedstock Supply & Logistics R&D	Section 2.1.1 and Appendix B	Updates to reflect volume revisions associated with goals and changes in blending strategies. Added feedstock logistics costs table to Appendix B	November 2014
Algal Feedstocks	Section 2.1.2	Inclusion of Algal Lipid Upgrading and Algal Hydrothermal Liquefaction design cases	November 2014
Thermochemical Conversion R&D	Section 2.2.2 and Appendix B	Added 2013 Sustainability metrics and feedstock costs to out-year projections	November 2014
March 2015			
Introduction to Research, Development, and Demonstration	Section 2	Inclusion of Wet Waste to Energy Feedstocks and change to Demonstration and Market Transformation	March 2015
Feedstocks Supply and Logistics	Section 2.1	Define Wet Waste to Energy Feedstocks	March 2015
Terrestrial Feedstocks Supply and Logistics	Section 2.1.1	Added herbaceous feedstocks cost tables	March 2015

Section Name	Specific Reference	Revision	Version Change was Implemented
Algal Feedstocks	Section 2.1.2	Minor clarifications	March 2015
Conversion R&D	Section 2.2	Integration of themo- and bio-chemical activities, strategic refocus on technology building blocks, additional technology pathways for hydrocarbon-based fuels, and addition of co-products to enable cost competitive biofuels	March 2015
Demonstration and Market Transformation	Section 2.3	Renamed	March 2015
Sustainability	Section 2.4	Milestone modifications	March 2015
Appendices	-	Former Appendix A removed and subsequent appendices renamed	March 2015
Technical Projection Tables	Appendix A	Tables added for new conversion pathways	March 2015
March 2016			
Entire Document	-	Updated to 2014 dollars and minor updates throughout; milestone additions throughout Section Two	March 2016
Office Vision and Mission	Section 1.2	Revised wording of vision statement and mission statement	March 2016
Algal Supply Systems	Section 2.1.2 and Appendix A	Renamed section and included Algae Farm Design Case	March 2016
Demonstration and Market Transformation	Section 2.3	Revised milestones and impact analysis	March 2016
Crosscutting	Section 2.4	Added crosscutting description; restructured Sustainability, Strategic Analysis, and Strategic Communications as sub-sections of Section 2.4	March 2016
Strategic Communications	Section 2.4.3	Revisions throughout; added a key milestones and activities chart and a table of key stakeholders	March 2016
Office Portfolio Management	Section 3	Revisions throughout	March 2016