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ENERGY

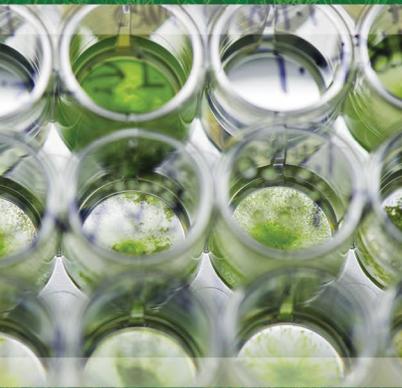
Office of
**ENERGY EFFICIENCY &
RENEWABLE ENERGY**



BIOENERGY TECHNOLOGIES OFFICE

R&D State of Technology

2020



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Acronyms and Abbreviations

ABY1	Algal Biofuel Yield Funding Opportunity	GGE	gasoline gallon equivalent
AD	anaerobic digestion	GHG	greenhouse gas
AFDW	ash-free dry weight	GREET	Greenhouse gases, Regulated Emissions, and Energy use in Technologies
AHTL	algal hydrothermal liquefaction		
ANL	Argonne National Laboratory	H ₂ O	water
APL	alkaline pretreated liquor	HDO	hydrodeoxygenation
ATP ³	Algae Testbed Public-Private Partnership	HHV	higher heating value
BCD	base-catalyzed depolymerization	HTL	hydrothermal liquefaction
BDO	butanediol	IDL	indirect liquefaction
BEA	beta-zeolite	kWh	kilowatt hour
BETO	Bioenergy Technologies Office	LA	lactic acid
Biochem	biochemical processes or pathways	LHV	lower heating value
Btu	British thermal unit	MBSP	minimum biomass selling price
CA	carboxylic acids	MFSP	minimum fuel selling price
CAP	combined algae processing	MJ	megajoule
CFP	catalytic fast pyrolysis	MM	million
ChemCatBio	Chemical Catalysis for Bioenergy Consortium	NG	natural gas
CHN	carbon-hydrogen-nitrogen	NH ₃	ammonia
CHP	combined heat and power	NO _x	oxides of nitrogen
CO ₂	carbon dioxide	psia	pounds per square inch absolute
CSTR	continuous stirred-tank reactor	PU	polyurethane
DME	dimethyl ether	R&D	research and development
DMR	deacetylation and mechanical refining	scf	standard cubic feet
EVAP	evaporation	SCSA	supply chain sustainability analysis
FA	Florida algae	SEQHTL	sequential hydrothermal liquefaction
FAME	fatty acid methyl ester	SOT	state of technology
FCIC	Feedstock-Conversion Interface Consortium	TEA	techno-economic analysis
FT	Feedstock Technologies	WHSV	weight hourly space velocity
FY	fiscal year	wt	weight
		WRRF	water resource recovery facility

Bioenergy Technologies Office State of Technology—2020 Research and Development Status

The U.S. Department of Energy's Bioenergy Technologies Office (BETO) funds research and development (R&D) on technologies necessary for the deployment and production of cost-competitive bioenergy, primarily biofuels. Results of experimental efforts are periodically compiled and compared with benchmark technology designs to assess overall progress. This report provides a status of those R&D efforts at the end of 2020.

This report first describes the approach for assessing progress, followed by specific technology pathway configurations within which progress is charted. Each pathway configuration is described separately and the state of technology progress is presented for the combined pathway, as well as for pathway components. Detailed component descriptions reference technology barriers and challenges that are detailed in the appendix.

BETO develops and maintains example conceptual design cases with analysis for feedstock production, feedstocks logistics, and conversion to a specific fuel and, where economical, coproduct(s) and biopower. Design cases provide engineering-based goal-year (2022 or 2030) projections and R&D technical targets based on techno-economic analysis (TEA) across the supply chain accompanied by a whole supply chain sustainability analysis (SCSA) of that configuration. Design cases provide the benchmark against which the current state of technology (SOT) for BETO fuel production pathways is assessed to understand the technology breakthroughs needed to reach ultimate design-case-based technical targets. Interim projections between the latest SOT results and goal-year projections anchor interim R&D technical targets.

Each design case is based on specific design reports for feedstock technologies and conversion components of the pathway. These design reports include sensitivity analyses that highlight factors having the greatest impact on cost of production and those most able to be addressed through R&D investments. SOT progress is monitored annually based on actual experimental results, translated to relevant metrics, and presented for each illustrative pathway. Periodically, BETO adjusts R&D priorities based on technology development progress, which may also result in refinements to design cases.

Techno-economic analyses calculate mature modeled minimum fuel selling price (MFSP) for a set of technical design parameters and R&D technical targets for key operations using standard financial assumptions¹ to calculate goal-year and interim price projections, as well as annual SOT progress. “Mature” means that capital and operating costs are assumed to be for an “nth-plant,” where several plants have been built and are operating successfully at design capacities, so additional costs for risk financing, longer startups, underperformance, overengineering, and other costs associated with first-of-a-kind or early-implementation plants are not included.

Design cases for technology pathways are process-specific and include specific feedstock requirements with corresponding costs for feedstock supply, logistics, and conversion. These process-specific designs are configured to reach a net present value of zero at a target rate of return (i.e., operating costs and return on capital investment are met). As such, the calculated mature modeled MFSP assumes a minimum acceptable rate of return on investment has been reached. MFSP is comparable to the wholesale rack price of current fuel products with downstream costs, subsidies, and tax incentives excluded. All dollar projections are presented in 2016 dollars and on a gasoline gallon equivalent (GGE) lower heating value (LHV) basis.

The example pathway configurations shown in Figure 1 are currently used to assess progress toward achieving BETO cost and sustainability goals²:

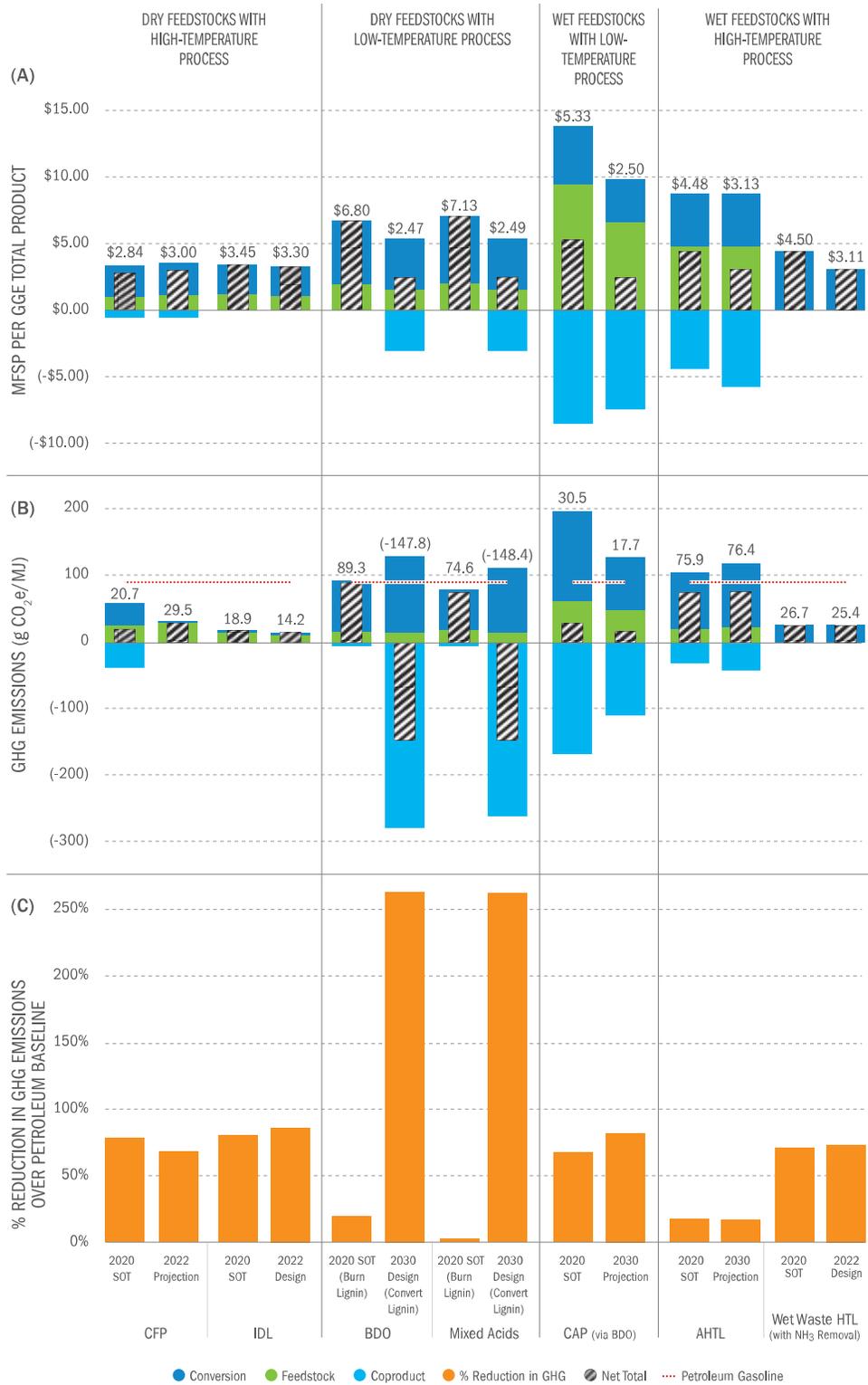
By 2022, verify integrated systems research for hydrocarbon biofuel technologies that achieve a mature modeled MFSP of \$3/GGE with a minimum 60% reduction in emissions relative to currently predominant fuels.

By 2030, verify integrated systems research for hydrocarbon biofuel technologies that achieve a mature modeled MFSP of \$2.5/GGE with a minimum 60% reduction in emissions relative to currently predominant fuels.

Although multiple pathways are shown in the same figure, each pathway is at a different level of technological maturity as well as degree of optimization for both cost reduction and sustainability, so the absolute MFSP values and greenhouse gas (GHG) reductions should not be directly compared.

¹ These financial assumptions are standardized across BETO design cases.

² Potential goals to be included in U.S. Department of Energy, *Bioenergy Technologies Office 2022 Multi-Year Plan* (forthcoming).



Figures 1A–C: 2020 state of technology and goal-year MFSP and GHG emissions projections for illustrative pathways used to assess technology progress

In addition to TEAs that annually translate technical progress into cost impact, pathway SCSAs monitor progress against environmental and other sustainability metrics. SCSAs are used to monitor progress against BETO goals of developing pathways with increased net energy efficiency and improved environmental performance. Life cycle GHG emissions of design and SOT cases are evaluated using the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model.³ Figure 1B and 1C compares the GHG reduction potential of each of the target pathways in their design case target year. Because the design case process designs are currently optimized to hit cost targets, some pathways do not currently represent an improvement in GHG emissions over incumbent petroleum pathways. Additional research in the coming years may focus on alternate designs to maximize sustainability benefits, including GHG emissions reduction.

Pathway-specific SCSA results do not address all aspects of environmental sustainability, but are critical to understanding the key drivers of energy use, GHG and oxides of nitrogen (NO_x) emissions, and water consumption, and how these attributes change in relation to process design changes and cost improvements. Oftentimes, changes to the overall process to reduce MFSP including changes in feedstock composition, and/or the addition of different strategies to produce coproducts will cause fluctuations in the sustainability metrics between years rather than a linear improvement.

The metrics measured in the SCSAs also vary based on the final slate of products. Since 2017, several BETO pathways have integrated coproducts to varying degrees to increase overall yields and supplement MFSPs. As indicated in Fig. 1A, coproducts may also contribute to GHG reduction potential. There are multiple methodologies for accounting for coproducts in the SCSA. The GHG values shown in Fig. 1B are based on the displacement method, which attributes all the supply chain emissions burdens to the fuel product, but also attributes all avoidance of emissions that otherwise would have taken place with the incumbent technology to produce the coproduct—or coproduct displacement credit—to the fuel product. Starting in 2020, BETO began considering alternative methods of evaluating coproduct contribution to SCSA metrics. These methods and analysis results are described in more detail starting in the Dry Feedstocks Converted via Low Temperature and Upgrading section.

These illustrative technology pathways are periodically assessed for economic viability and, when appropriate, replaced with more robust pathway designs. Technology pathway designs may be selected as candidates for process integration and possibly for experimental verification at

³ For more information, see <http://greet.es.anl.gov/>.

engineering and/or pilot scale after component technologies are deemed sufficiently developed. The technology pathways are not meant to serve as a business model, but are used to guide and focus R&D on the largest cost and sustainability barriers, as well as inform stakeholders and researchers of quantitative progress on specific pathway elements. As noted in Figure 1, these example technology pathways are organized by the primary category of feedstock used by R&D efforts—dry or wet—and by the type of conversion process employed, either high or low temperature. This state of technology report is organized in the same manner as the seven pathways in Figure 1—i.e., design cases using:

1. Dry feedstocks converted via high temperature and upgrading.
 - a. Direct liquefaction and upgrading (catalytic fast pyrolysis [CFP]).
 - b. Indirect liquefaction (IDL) and upgrading.
2. Dry feedstocks converted via low temperature and upgrading.
 - a. Biochemical conversion via 2,3-butanediol (BDO) intermediate.
 - b. Biochemical conversion via mixed-acids intermediate.
3. Wet feedstocks converted via low temperature and upgrading.
 - a. Combined algae processing (CAP) via 2,3-BDO or carboxylic acid intermediate.
4. Wet feedstocks converted via high temperature and upgrading.
 - a. Algal hydrothermal liquefaction (AHTL).
 - b. Wet waste hydrothermal liquefaction.

Dry feedstocks can economically meet a conversion specification of 50 weight (wt) % or less moisture content (e.g., herbaceous, woody, or municipal solid waste feedstocks). Wet feedstocks can be accepted into a conversion process at higher than 50 wt % moisture content (e.g., algal and wet waste/biosolids feedstocks).⁴ BETO is also developing TEAs and life cycle analyses for conversion of gaseous feedstocks—i.e., those that enter the conversion process as a gas stream (e.g., waste carbon dioxide [CO₂], waste flue gas, and biogas).

In addition to production of hydrocarbon fuels, most of these pathways are based on design cases that include coproducts with various market sizes and price ranges. Table 1 presents recent market information on potential coproducts.

⁴ The distinction of “dry” versus “wet” feedstock is used to roughly classify broad types of preprocessed feedstocks based on conversion process specifications. While a particular type of raw biomass may be harvested at greater than the 50 wt % basis, the biomass will be processed into a feedstock that can meet lower moisture specifications.

Table 1: Potential Coproducts with Historical Market Information⁵

Product	World Production (million metric tons/year)	U.S. Price Range 2011–2018 (\$/metric ton)	Projected Growth Rate	Major Uses	Potential Conversion Pathways
Methyl Ethyl Ketone	~1.5	1,400–2,600	~1.9%	Adhesives, paints, coatings, inks, dewaxing	CFP, Biochem*
1,4-Butanediol	~3.8	1,650–3,700	~3.4%	Tetrahydrofuran, specialty chemicals	Biochem, CAP
Adipic Acid	~4.6	1,100–1,700	~3.0%	Nylon-6,6, polyurethanes, plasticizers	Biochem, CAP
Acetone	~8.3	650–1,300	~2.7%	Solvent, methyl methacrylate, bisphenol A	CFP
Phenol	~13	960–1,700	~2.8%	Bisphenol A, resin	CFP
1,3-Butadiene	~16	750–2,900	~3.6%	Synthetic rubber	Biochem
Lactic Acid	0.5	1,400–2,200	~5.6%	Acidulant, flavor enhancer, shelf-life extender, polylactic acid	AHTL
Polyurethane	14	4,000–4,900	~3.5%	Flexible foam (cushioning), rigid foams	CAP, AHTL

*Biochemical processes or pathways

⁵ IHS Markit. *Chemical Economics Reports*. Accessed September 2021.

Technology Pathways Using Dry Feedstocks

BETO tracks progress for technologies used in pathways using dry feedstocks. Dry feedstocks are defined as those that can economically meet a conversion specification of 50% or less moisture content after preprocessing raw biomass into conversion-ready feedstocks. Dry feedstocks are categorized as woody (e.g., logging residues, forest thinnings, and purpose-grown woody energy crops such as pine, eucalyptus, poplar, and willow), herbaceous (e.g., agricultural crop residues, primarily corn stover, and dedicated energy crops such as switchgrass, biomass sorghum, miscanthus, and energy cane), or dry waste (the organic fraction of sorted municipal solid waste).

For dry feedstocks, the Feedstock Technologies (FT) R&D program focuses on delivering feedstocks that meet the required conversion specifications at a nearer-term targeted feedstock cost of \$86 or less per dry ton to a biorefinery throat. FT cost targets include grower payment and logistics costs. Grower payment is based on supply curves from the *2016 Billion-Ton Report*⁶ and represents the cost of production, compensation for soil nutrient removal, and grower profit. Logistics costs include harvest and collection, storage, transportation, and preprocessing (primarily reduction of organic species and drying) from the point of harvest or collection to the conversion reactor throat in-feed. Longer term, FT focuses on delivering conversion-ready, industrially relevant, and economically advantaged feedstocks and waste streams at a targeted per-dry-ton feedstock cost of \$71 or less. Individual technology configurations discuss design-case-specific feedstock specifications and assumptions.

Dry Feedstocks Converted via High Temperature and Upgrading

Direct Liquefaction Design Case

Research on dry feedstocks converted via the direct liquefaction and upgrading pathway helps BETO understand challenges related to coupling high-temperature deconstruction processes with downstream upgrading, including catalyst contamination and deactivation, separation of desired intermediates, and various opportunities for deoxygenation and finishing. The design case configuration used to assess progress for technologies relevant to this pathway is the CFP with *ex situ* vapor-phase upgrading and subsequent additional upgrading into hydrocarbon fuel

⁶ U.S. Department of Energy. *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks*. Oak Ridge, TN: Oak Ridge National Laboratory, ORNL/TM-2016/160, 2016. https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

blendstocks, as illustrated in Figure 2.⁷ Figure 3 outlines the modeled cost projections of the CFP design case with SOT contributions from feedstocks and conversion from 2014 to 2020 and interim projections up to the goal year of 2022.⁸

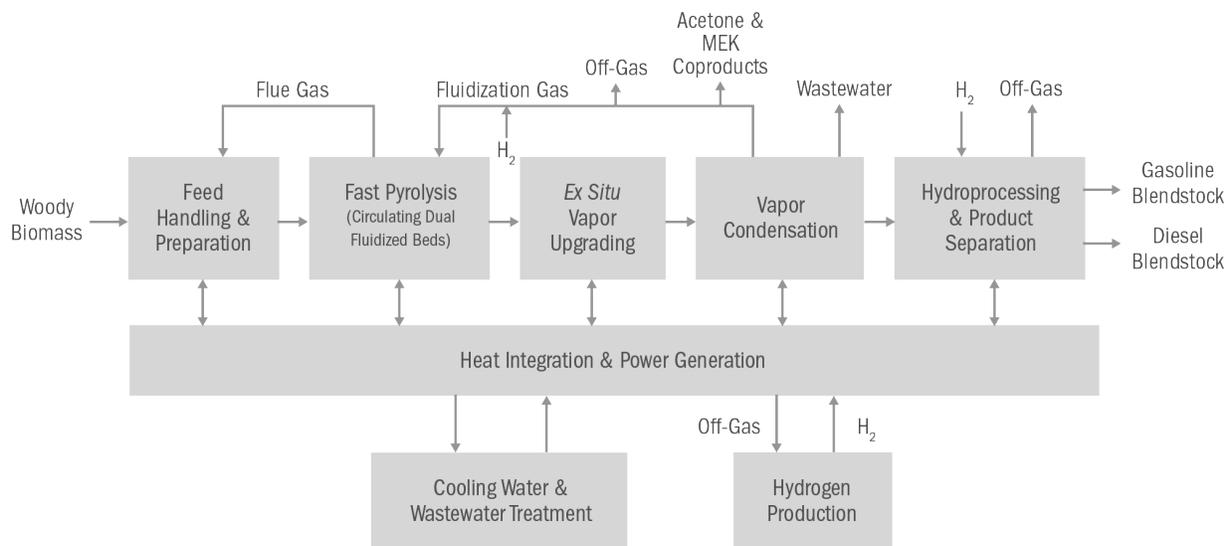


Figure 2: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel via direct liquefaction

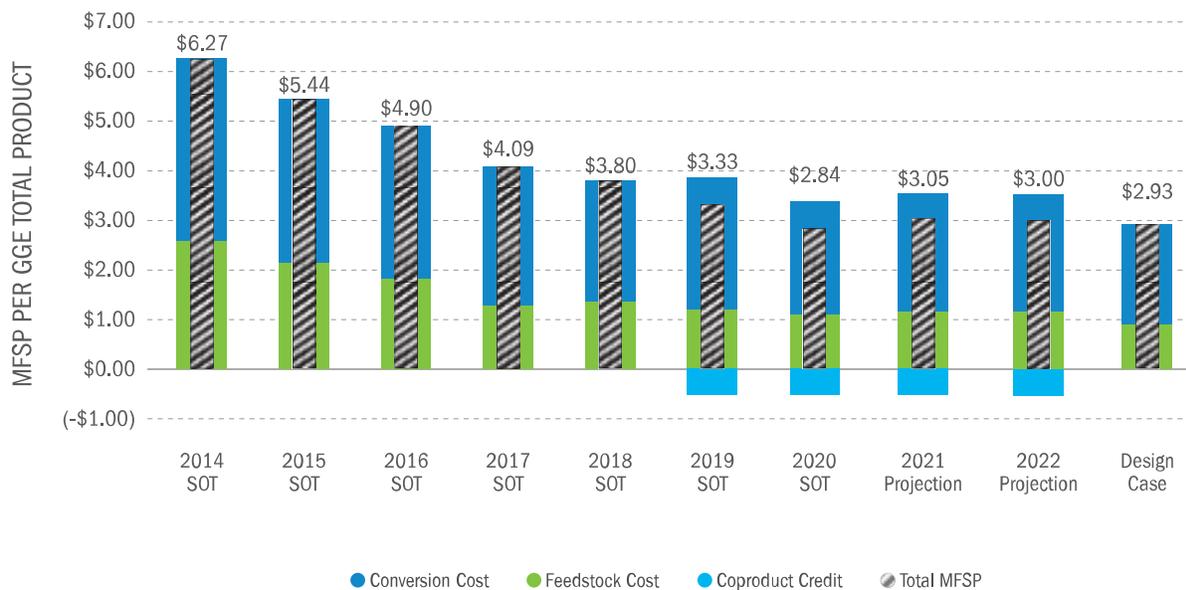


Figure 3: Cost projections with feedstock and conversion breakouts for the CFP design case

⁷ A. Dutta, A. H. Sahir, E. Tan, D. Humbird, L. J. Snowden-Swan, P. A. Meyer, J. Ross, D. Sexton, R. Yap, and J. Lukas. *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*. Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, NREL/TP-5100-62455; PNNL-23823, 2015. <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

⁸ A. Dutta, C. Mukarakate, K. Lisa, H. Wang, M. Talmadge, D. Santosa, K. Harris, F. Baddour, D. Hartley, H. Cai, L. Ou, J. Schaidle, and M. Griffin. *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2020 State of Technology*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-80291, 2021. <https://www.nrel.gov/docs/fy21osti/80291.pdf>.

Feedstocks

Feedstock composition is a key factor in conversion process performance. MFSP projections for the CFP design assume that low concentrations of inorganic species (i.e., ash) and high-quality feedstock can be provided at compositional specifications summarized in Table 2 and at the targeted feedstock cost.⁹

Table 2: Feedstock Composition and Processing Assumptions for the CFP 2020 SOT Case

Component	Composition (dry wt %)
Carbon	50.51
Hydrogen	5.99
Nitrogen	0.17
Sulfur	0.03
Oxygen	41.55
Inorganic species ^a	≤1.75
Heating value (Btu ^b /lb)	8,601 HHV ^c
	7,996 LHV
Moisture (bulk wt %)	10.0
Particle size (inches)	≤0.08

^a Specs for inorganic species such as alkali and alkaline earth metals (1,300 parts per million) are included in the 2022 projection, not in the SOT cases.

^b British thermal units

^c Higher heating value

equipment performance are also under investigation so as to develop and define the critical feedstock specifications. Other R&D strategies include understanding how blending and formulation can utilize low-quality and low-cost biomass such as logging residues and other waste streams, and developing preprocessing technologies capable of reducing the physical and chemical variability of raw biomass for more reliable, predictable, and efficient performance in conversion processes.

FT R&D efforts focus on understanding the inherent and introduced variability in feedstock and the fundamental drivers of feedstock quality and flowability, while developing and improving preprocessing operations such as air classification, advanced fractionation, mechanical and chemical preprocessing, material handling and conveyance, and densification, to transform low-cost, more abundant woody biomass and logging residues into feedstocks that meet or exceed conversion quality specifications and flowability that can currently only be met with less available, more expensive clean pine feedstocks. In addition to the chemical composition described in Table 2, physical properties (e.g., particle size distribution, aspect ratio, microstructure, and surface characteristics) that impact flowability, convertibility, and

⁹ D. S. Hartley, D. N. Thompson, and H. Cai. *Woody Feedstocks 2020 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-59976, 2021. <https://doi.org/10.2172/1782211>.

Figure 4 and Table 3 show the projected reduction in the delivered feedstock cost from 2013 through 2022 for woody biomass provided as input to the CFP process.^{10,11,12} The 2015 and 2016 SOTs reflect feedstock blends that combine multiple types of biomass to deliver a feedstock that conforms to CFP conversion specifications and cost targets. The 2017 and 2018 SOTs, which were based on clean pine feedstock that is not projected to be available in adequate quantities or at a price point required to meet the annual supply requirement for a biorefinery¹³ using a single clean pine feedstock, resulted in 2017 and 2018 SOT costs of \$87.82/dry ton, exceeding the \$86/dry ton threshold.^{14,15} In comparison, the 2019 SOT achieved a lower cost of \$70.15/dry ton by focusing on the blend of clean pine and pine logging residue, which assumed that the pine logging residues brought to the landing are part of the primary harvest operation with all cost attributed to the main product; the application of fieldside preprocessing operations resulted in the further decrease of transportation cost.¹⁶ The 2020 SOT focused on the same blend but further optimized process configuration to dry the materials after size reduction via rotary shearing. In comparison to the conventional process of drying chips prior to size reduction, such advancement resulted in a reduction of energy consumption by 47% and a lower feedstock cost of \$67.03/dry ton.¹⁷ It should be noted that the 2019 and 2020 SOTs cost are below the 2020 projection cost due to the higher inorganic species content of 1.75% vs. 1.0% used in the 2020 assumption. The process of removing inorganic species content to meet the feedstock quality specification adds cost to the preprocessing step.

The 2021 and 2022 projections are based on a blend of clean pine and pine logging residues as one possible option, and assume technology advancements in mechanical deconstruction, advanced fractionation, and other preprocessing technologies to improve the quality of pine logging residues to formulate a blend that meets or exceeds quality conversion specifications

¹⁰ P. Jernigan, T. Gallagher, D. Mitchell, M. Smidt, and L. Teeter. "High tonnage harvesting and skidding for loblolly pine energy plantations." *Forest Products Journal* 66, nos. 3–4 (2016): 185–191. <https://doi.org/10.13073/FPJ-D-14-00055>.

¹¹ P. Jernigan, T. Gallagher, J. Aulakh, R. Tufts, and T. McDonald. "Implementing Residue Chippers on Harvesting Operations in the Southeastern US for Biomass Recovery." *International Journal of Forest Engineering* 24, no. 2 (2013): 129–136. <https://doi.org/10.1080/14942119.2013.798130>.

¹² M. H. Eisenbies, T. A. Volk, J. Posselius, C. Foster, S. Shi, and S. Karapetyan. "Evaluation of a Single-pass, Cut and Chip Harvest System on Commercial-scale, Short-rotation Shrub Willow Biomass Crops." *Bioenergy Research* 7, no. 4 (2014): 1506–1518. <https://doi.org/10.1007/s12155-014-9482-0>.

¹³ The 2017 SOT assumes an annual supply of 800,000 dry tons and the 2018 and 2019 SOTs assume an annual supply of 725,000 dry tons with 90% on-stream time using locations tied to high availability of resources.

¹⁴ D. S. Harthartley, D. N. Thompson, H. Hu, and H. Cai. *Woody Feedstock 2017 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-17-43459, 2017. This reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

¹⁵ D. S. Hartley, D. N. Thompson, H. Hu, and H. Cai. *Woody Feedstock 2018 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-18-51655, 2018. https://inldigitalibrary.inl.gov/sites/sti/sti/Sort_7464.pdf.

¹⁶ D. S. Hartley, D. N. Thompson, and H. Cai. *Woody Feedstocks 2019 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57181, 2020. https://inldigitalibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.

¹⁷ Hartley et al. 2021, <https://doi.org/10.2172/1782211>.

(based on clean pine) at a delivered feedstock cost of less than \$70.31/dry ton. The final selection of feedstock for the 2022 verification will be determined through continuing R&D with feedstock critical quality attributes (e.g., elemental contents, inorganic species, particle size distribution, aspect ratio, microstructure) and critical process parameters to be defined through the Feedstock-Conversion Interface Consortium (FCIC). Out-year cost projections will be updated going forward as new research is completed.

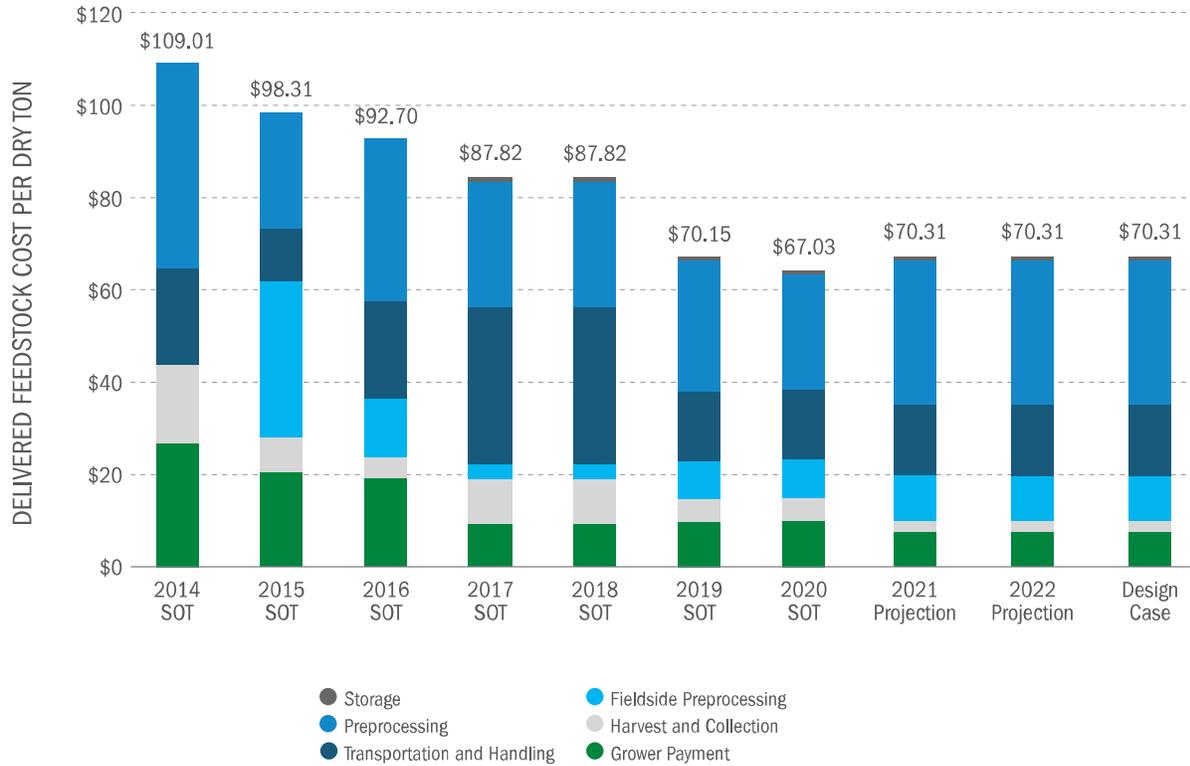


Figure 4: Dry feedstock cost delivered to the reactor throat, modeled for the CFP design case

Table 3: Dry Feedstock Costs Delivered to Reactor Throat for the CFP Design Case

Cost per Dry Ton	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT ^a	2021–2022 Projection ^a	Design Case
Feedstock Type	Clean Pine ^b	Blend ^c	Blend ^d	Clean Pine ^b	Clean Pine ^b	Blend ^e	Blend ^e	Blend ^f	Blend ^f
Grower Payment	\$26.71	\$20.49	\$19.30	\$9.48	\$9.48	\$9.74	\$9.74	\$7.64	\$7.64
Harvest and Collection	\$17.11	\$7.68	\$4.37	\$9.87	\$9.87	\$4.94	\$4.94	\$2.47	\$2.47
Fieldside Preprocessing	\$0.00	\$33.84	\$12.81	\$2.82	\$2.82	\$8.41	\$8.41	\$9.81	\$9.81
Transportation and Handling	\$20.71	\$11.19	\$21.25	\$34.18	\$34.18	\$14.87	\$14.87	\$15.41	\$15.41
Preprocessing	\$44.48	\$25.11	\$34.97	\$27.14	\$27.14	\$28.55	\$25.43	\$31.12	\$31.12
Storage	\$0.00	\$0.00	\$0.00	\$0.86	\$0.86	\$0.68	\$0.68	\$0.58	\$0.58
Preprocessing Construction	-	-	-	\$3.47	\$3.47	\$2.96	\$2.96	\$3.28	\$3.28
Delivered Feedstock Price	\$109.01	\$98.31	\$92.70	\$87.82	\$87.82	\$70.15	\$67.03	\$70.31	\$70.31

^a The 2021 and 2022 projections are assumed to be the same as the design case cost. The delivered feedstock cost in the 2019 and 2020 SOT cases is lower than the 2021–2022 projections and design cases because the projections have a feedstock quality requirement of <1.0% ash content, compared with 1.75% ash content in the 2019 and 2020 SOTs. The process of removing inorganic content to meet the feedstock quality specification adds to the preprocessing costs.

^b Clean, debarked pine chips.

^c The overall blend composition (after preprocessing) was targeted to match the elemental analysis of clean pine. Modeled costs shown reflect the use of 45% clean pine chips (pulp wood), 35% pine logging residues, and 20% construction and demolition waste with subsequent preprocessing to meet the clean pine elemental analysis specified in the 2015 CFP design report.¹⁸ The 2015 SOT conversion experiments were conducted using clean pine.

^d The overall blend composition (after preprocessing) was targeted to match the elemental analysis of clean pine. Modeled costs shown reflect the use of 30% clean pine chips (pulp wood), 60% air-classified pine logging residue, and 10% hybrid poplar with subsequent preprocessing to meet the clean pine elemental analysis specified in the 2015 CFP design report. The 2016 SOT conversion experiments were conducted using clean pine.

^e 50% clean pine chips (pulp wood), 50% pine logging residues.

^f 25% clean pine chips (pulp wood) and 75% air-classified and preprocessed pine logging residues. This is a potential feedstock option for 2022 verification and final selection will be determined through continuing R&D.

¹⁸ Dutta et al. 2015, <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

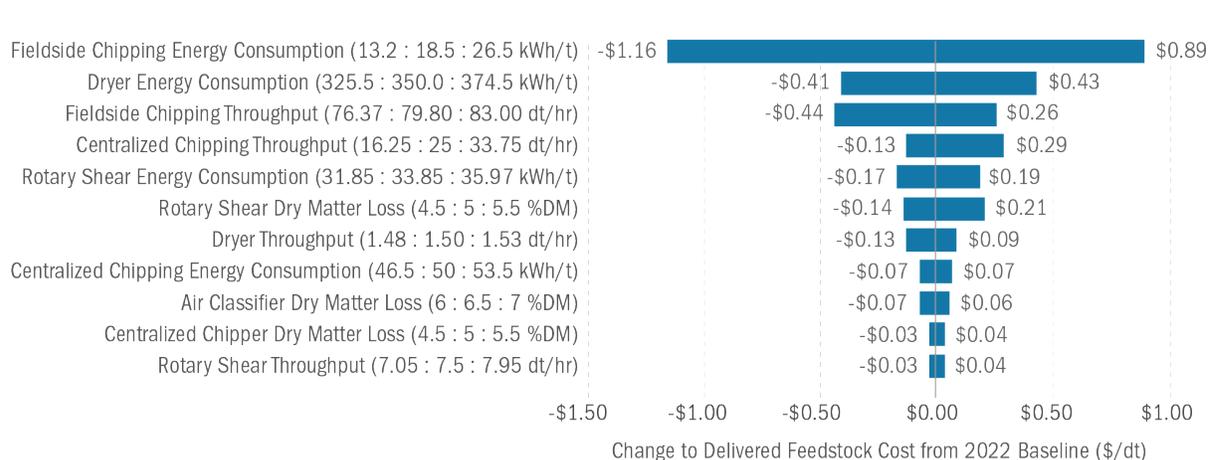


Figure 5: Sensitivity analysis of the delivered feedstock cost in the CFP design case

Figure 5 shows the impact on total delivered cost of varying energy consumption and throughput of key feedstock preprocessing operations, based on actual process experience and from literature.^{19,20,21,22} The 2022 cost of the blended feedstock is most sensitive to the energy consumption of the fieldside chipper, followed by the dryer energy consumption and the fieldside and centralized chipping throughput.

The inherent and introduced variability in feedstocks and their physical, chemical, and mechanical properties can have significant impacts on the equipment operations and downstream conversion performance (for reference, see the appendix, barriers Ft-E and Ft-J). The FCIC's objective is to quantify, understand, and manage feedstock variability from field to conversion. The FCIC focuses on developing first-principles-based knowledge and tools to understand the interactions between feedstock quality properties, preprocessing equipment performance (e.g., energy consumption, throughput, and wear), and conversion performance and yield. FCIC also focuses on identifying underlying factors, critical quality attributes, and critical process parameters to enable development of technologies that can reduce the delivered feedstock cost and provide well-defined, homogeneous, and quality-controlled feedstock for efficient conversion performance with 90% on-stream time and design-rated throughput.

¹⁹ Hartley et al. 2021, <https://doi.org/10.2172/1782211>.

²⁰ Jernigan et al. 2013, <https://doi.org/10.1080/14942119.2013.798130>.

²¹ R. Spinelli, E. Cavallo, A. Facello, N. Magagnotti, C. Nati, and G. Paletto. "Performance and energy efficiency of alternative comminution principles: chipping versus grinding." *Scandinavian Journal of Forest Research* 27, no. 4 (2012): 393–400. <https://doi.org/10.1080/02827581.2011.644577>.

²² J. S. Tumuluru. "Specific energy consumption and quality of wood pellets produced using high-moisture lodgepole pine grind in a flat die pellet mill." *Chemical Engineering Research and Design* 110 (2016): 82–97. <https://doi.org/10.1016/j.cherd.2016.04.007>.

Conversion

In the CFP design case, on-spec dry feedstocks are fed into a non-catalytic fast pyrolysis reactor and the resulting vapors are catalytically upgraded in a fixed-bed reactor through deoxygenation, hydrogenation, and the coupling of smaller molecules. The resulting vapors are condensed and separated into component streams, with the majority of the non-condensable gases recycled to the fast pyrolysis reactor for fluidization and the remaining gases used for hydrogen production. Light oxygenated coproducts, acetone, and methyl ethyl ketone are also recovered from the gases. The resulting pyrolysis oil is subsequently hydrotreated for deoxygenation and saturation of a portion of the products to reduce aromatic content to produce a gasoline- or diesel-range blendstock and the aqueous liquid fraction that is sent to wastewater treatment. CFP oil from this process may also be coprocessed in a petroleum refinery.

BETO currently works to decrease overall modeled conversion costs for the direct liquefaction of dry feedstocks pathway by addressing a number of research barriers, including improving overall yield, increasing catalyst lifetime, and decreasing process severity (for reference, see the appendix, barriers Ct-E, Ct-F, Ct-G, and Ct-N). Figure 6 shows the impact that improvements in each of these areas may have on the 2022 projected MFSP for the CFP design.

Figure 6 shows that increasing overall carbon efficiency is key to achieving future cost and performance goals. Research in this area focuses on improving catalyst and reactor performance to provide cheaper catalysts that have a longer lifetime and that can generate targeted products in high yields. Higher yields have the added benefit of potentially reducing heat recovery and electricity generation expenses. This work is supported through the Chemical Catalysis for Bioenergy Consortium (ChemCatBio) and the Consortium for Computational Physics and Chemistry. Additional benefits from coproduct recovery and refinery coprocessing of the CFP oil are further discussed in the fiscal year (FY) 2020 SOT report.²³

²³ Dutta et al. 2021, <https://www.nrel.gov/docs/fy21osti/80291.pdf>.

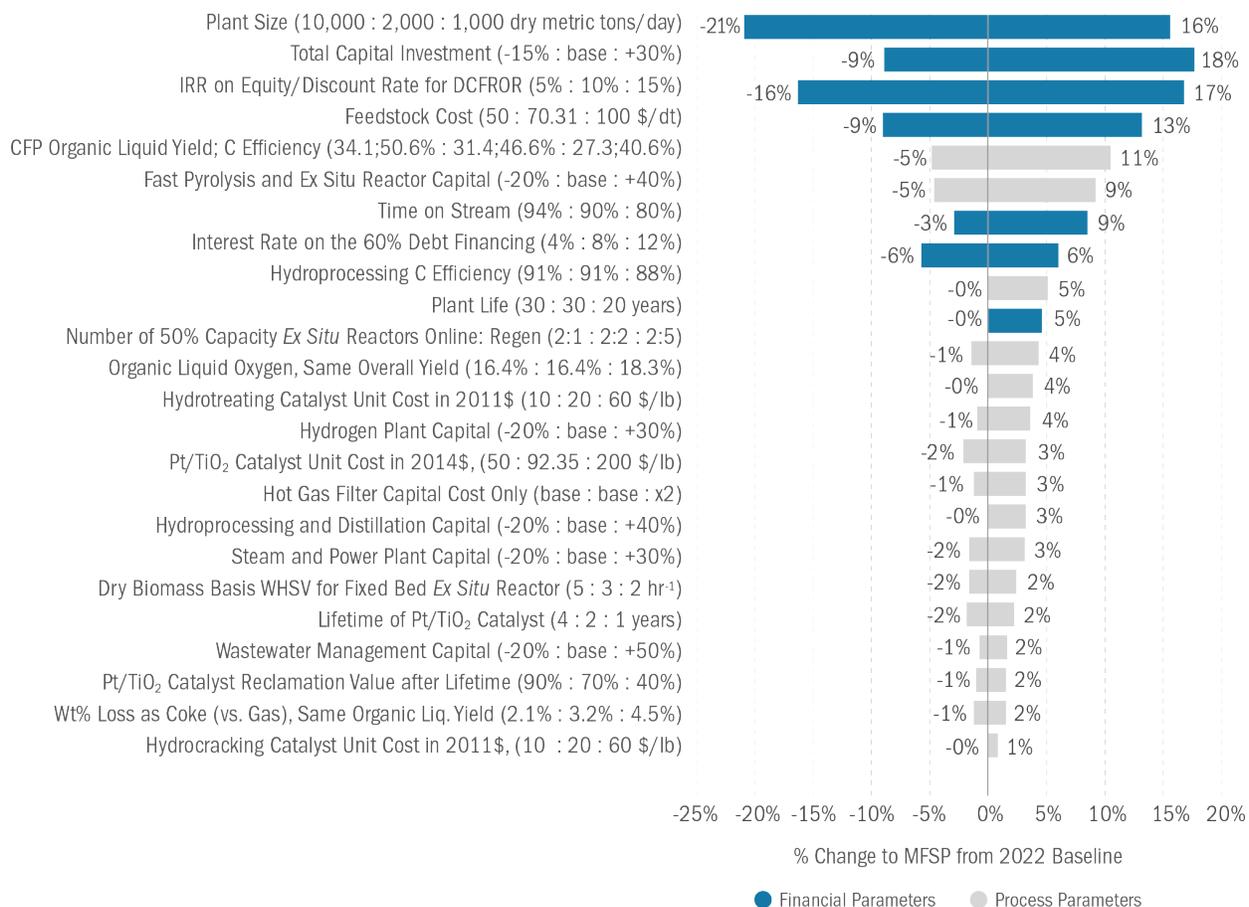


Figure 6: Factors influencing conversion costs relative to the CFP design case 2022 projection²⁴

In addition to improving overall yields, BETO also invests in other methods for reducing costs from the vapor upgrading step, including improving online time for reactors, increasing space velocity, designing catalysts with reduced precious metal content, and more efficient catalyst regeneration. The current SOT model assumes that half of the fixed-bed upgrading reactors would need to be dedicated to catalyst regeneration at any one time; a significant decrease in redundancy has been achieved since 2017 with catalyst development, allowing increased experimental on-stream times before requiring regeneration. Further increases in on-stream times are being pursued to increase cycle times during future commercial operations. Experimental work in this area also currently utilizes a platinum or titanium dioxide catalyst, but research on the viability of using either lower platinum loadings or alternate catalysts with no noble metals (such as molybdenum carbide) is ongoing. Use of lower-cost materials depends on a number of factors, including performance and regenerability.

²⁴ Baseline may not reflect exact 2022 design case values; ranges chosen based on potential representative values for each parameter.

Costs for the FY 2019 SOT decreased compared with FY 2017 and FY 2018 based on experimentally showing shorter regeneration times while using a catalyst with lower platinum loading. Upstream deoxygenation during the catalytic upgrading process can be beneficial because downstream hydroprocessing steps require relatively higher hydrogen purity (and significantly higher hydrogen partial pressures) compared to vapor-phase upgrading. Achieving future cost goals may be accomplished by further increasing carbon efficiency by lowering conversion to light gases and enabling the use of lower-cost and lower-quality feedstocks.

In FY 2019, enhanced analytical capabilities allowed for near 100% mass and carbon balance closures for the CFP process, which revealed that about 10% of the biomass carbon was being converted to light oxygenates.²⁵ Hydrotreating these compounds yields light hydrocarbon gases instead of liquid-range fuels, which results in a lower carbon efficiency to liquid fuel blendstocks than previously assumed and leads to an increase in the MFSP compared to previous projections. As a result, new process steps were added in FY 2019 to recover the light oxygenates and separate them for the recovery of chemical products (such as acetone and methyl ethyl ketone) and/or additional upgrading to fuels and coproducts.

For the 2019 SOT, only acetone was recovered and sold as an additional coproduct from the light oxygenate stream. In FY 2020, additional experiments demonstrated a near-100% recovery of acetone and 2-butanone from the light oxygenate stream. A new model was also developed that demonstrates the viability of separation and purification of these compounds. Based on these results, the 2020 SOT includes the recovery and sale of both acetone and 2-butanone in the overall MFSP. Additional modeling and experimentation in this area may take place in the future if resources allow.

In 2020, BETO continued evaluating coprocessing CFP oil in petroleum refineries as a means to avoid the high capital costs associated with upgrading pyrolysis oils. This work analyzed potential impacts to a traditional refinery due to the highly oxygenated nature of CFP oils and investigated the potential for meeting other targets including cost and GHG reduction metrics. Additional experiments performed in 2020 involved co-hydrotreating bio-oil from a CFP process with straight-run diesel. These experiments produced liquid fuel blendstocks with no detectable oxygen content at greater than 95% carbon efficiency. Additional research on the impact of this mixed stream on catalysts and reactors will take place in the future if resources are available.

²⁵ A. Dutta, K. Iisa, M. Talmadge, C. Mukarakate, M. Griffin, E. C. D. Tan, N. Wilson, et al. *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2019 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76269, 2020. <https://www.nrel.gov/docs/fy20osti/76269.pdf>.

BETO also considered a number of other factors that may contribute to meeting longer-term cost targets. The Bioprocessing Separations Consortium has considered how catalytic hot gas filtration can enable additional chemistry to improve product quality and yield of desirable liquid-range molecules in the product stream via removal of contaminants and reactions that are synergistic with the *ex situ* upgrading; this can prolong catalyst on-stream time and increase the lifetime of the *ex situ* reactor catalyst.

Based on research performed in 2020, this pathway has shown the potential to meet BETO cost goals. Future research will primarily focus on a demonstration of CFP technology at scale, and BETO will work with the National Renewable Energy Laboratory to publish a closeout report documenting research progress on this pathway in FY 2022. If additional funds become available in this area and there is significant interest from industrial stakeholders, BETO may allocate them to some of the remaining research questions presented above.

Table 5 presents the process efficiency metrics for the CFP design. Table 6 includes the detailed cost and technical projections for the CFP design.



Figure 7: Cost projections for the conversion portion of the CFP design case

Table 4: Cost Projections for the CFP Design Case

Conversion Cost Breakdown (\$/GGE)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Pyrolysis and Vapor Upgrading	\$2.34	\$2.03	\$1.84	\$1.46	\$1.10	\$1.14	\$1.13	\$1.13	\$1.12	\$0.91
Vapor Quench, Coproduct Recovery + Contingency	\$0.35	\$0.33	\$0.28	\$0.20	\$0.22	\$0.34	\$0.45	\$0.40	\$0.40	\$0.18
Hydroprocessing and Separation/Refinery Coprocessing	\$0.33	\$0.31	\$0.34	\$0.35	\$0.38	\$0.30	\$0.23	\$0.21	\$0.21	\$0.33
Hydrogen Production	\$0.61	\$0.56	\$0.60	\$0.62	\$0.51	\$0.61	\$0.44	\$0.44	\$0.44	\$0.44
Balance of Plant	\$0.04	\$0.07	\$0.03	\$0.20	\$0.23	\$0.27	\$0.09	\$0.20	\$0.19	\$0.16
Coproduct Credit	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.52)	(\$0.55)	(\$0.52)	(\$0.53)	\$0.00
Net Conversion Contribution to MFSP	\$3.66	\$3.30	\$3.08	\$2.82	\$2.44	\$2.14	\$1.74	\$1.87	\$1.83	\$2.02

Table 5: Process Efficiency Metrics for the CFP Design Case

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT*	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Fuel and Coproducts Yield by Weight of Biomass	% w/w of dry biomass	13.7%	15.0%	16.5%	22.2%	20.9%	22.5%	23.0%	22.7%	22.8%	24.8%
Carbon Efficiency of Biomass to Fuels and Coproducts	% C in feedstock	23.5%	25.9%	28.3%	38.1%	35.9%	37.2%	38.0%	37.2%	37.3%	42.3%
Overall Carbon Efficiency to Liquid Hydrocarbon Fuels	% C in feedstock	23.5%	25.9%	28.3%	38.1%	35.9%	33.0%	33.7%	33.0%	33.0%	42.3%
Overall Energy Efficiency to Liquid Hydrocarbon Fuels	% LHV of feedstock	30.5%	33.4%	37.1%	50.3%	47.2%	43.6%	45.1%	43.6%	43.6%	56.1%
Electricity Production	kWh/GGE	21.0	18.0	14.7	8.0	8.7	7.8	10.6	10.8	10.7	6.3
Electricity Consumption (Entire Process)	kWh/GGE	12.7	11.0	9.6	6.4	7.5	7.4	5.9	7.1	7.0	5.9

*Note: For the 2017 SOT, the unquantified portion of CFP yields were prorated to solids, liquids, and gases using measured yields.

Table 6: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via Catalytic Fast Pyrolysis With Further Hydroprocessing of CFP Oil

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Process Concept: Hydrocarbon Fuel Production via <i>Ex Situ</i> Upgrading of Fast Pyrolysis Vapors		Clean Pine	Clean Pine	Clean Pine	Clean Pine	Clean Pine	50% Residues/ 50% Pine ^b	50% Residues/ 50% Pine ^b	75% Residues/ 25% Pine	75% Residues/ 25% Pine	75% Residues/ 25% Pine
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Projected MFSP	\$/GGE	\$6.27	\$5.44	\$4.90	\$4.09	\$3.80	\$3.33	\$2.83	\$3.05	\$3.00	\$2.93
Conversion Contribution	\$/GGE	\$3.66	\$3.30	\$3.08	\$2.82	\$2.44	\$2.14	\$1.74	\$1.87	\$1.83	\$2.02
Total Project Investment per Annual GGE	\$/GGE-yr	\$18.50	\$16.46	\$14.94	\$12.17	\$12.47	\$13.53	\$11.62	\$12.19	\$12.07	\$10.22
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	2,000
Total Gasoline Equivalent Yield	GGE/dry ton	42	46	51	69	65	59	61	60	61	77
Diesel-Range Product Proportion (GGE Basis)	% of fuel product	15%	15%	15%	52%	52%	48%	50%	48%	48%	52%
Feedstock											
Total Cost Contribution ^c	\$/GGE	\$2.60	\$2.14	\$1.82	\$1.27	\$1.36	\$1.18	\$1.10	\$1.18	\$1.17	\$0.91
Capital Cost Contribution ^c	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Operating Cost Contribution ^c	\$/GGE	\$2.60	\$2.14	\$1.81	\$1.27	\$1.35	\$1.18	\$1.09	\$1.18	\$1.16	\$0.91
Feedstock Cost ^d	\$/dry ton	\$109.01	\$98.31	\$92.70	\$87.82	\$87.82	\$70.15	\$67.03	\$70.31	\$70.31	\$70.31
Feedstock Moisture at Plant Gate	wt % water (H ₂ O)	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feed Moisture Content to Pyrolyzer	wt % H ₂ O	10%	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	7,900	7,900	8,000	8,000	8,000
Pyrolysis and Vapor Upgrading											
Total Cost Contribution ^c	\$/GGE	\$2.60	\$2.14	\$1.82	\$1.27	\$1.36	\$1.18	\$1.07	\$1.18	\$1.17	\$0.91
Capital Cost Contribution ^c	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.58	\$0.00	\$0.00	\$0.51

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Operating Cost Contribution ^c	\$/GGE	\$2.60	\$2.14	\$1.81	\$1.27	\$1.35	\$1.18	\$0.49	\$1.18	\$1.16	\$0.40
Ex Situ Reactor Configuration	reactor type	fluidized bed	fluidized bed	fluidized bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed
Ratio of Online: Regenerating Fixed-Bed Reactors	ratio	N/A	N/A	N/A	2:5	2:3	2:2	2:2	2:2	2:2	2:2
Gas Phase	wt % of dry biomass	35%	36%	34%	31%	35%	38%	42%	38%	38%	31%
Aqueous Phase	wt % of dry biomass	25%	25%	24%	27%	22%	24%	20%	24%	24%	23%
Carbon Loss	% of C in biomass	2.9%	2.9%	3.4%	2.9%	5.0%	4.4%	1.8%	4.4%	4.4%	3.0%
Organic Phase	wt % of dry biomass	17.5%	18.6%	21.8%	28.3%	27.9%	23.2%	24.0%	23.4%	23.4%	31.4%
H/C Molar Ratio	ratio	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.2	1.2	1.2
Oxygen	wt % of organic phase	15.0%	13.3%	16.8%	16.5%	18.6%	15.1%	16.6%	15.1%	15.1%	16.4%
Carbon Efficiency	% of C in biomass	27%	29%	33%	42%	40%	35%	36%	35%	35%	47%
Solid Losses (Char + Coke)	wt % of dry biomass	23%	21%	20%	14%	15%	14%	13%	14%	14%	15%
Char	wt % of dry biomass	12.0%	11.0%	12.0%	10.4%	11.7%	11.6%	11.1%	11.7%	11.7%	11.7%
Coke	wt % of dry biomass	11.0%	9.5%	8.3%	3.3%	3.7%	2.3%	1.7%	2.3%	2.3%	3.2%
Vapor Quench, Coproduct Recovery + Contingency											
Total Cost Contribution	\$/GGE	\$0.35	\$0.33	\$0.28	\$0.20	\$0.22	\$0.34	\$0.45	\$0.40	\$0.40	\$0.18
Capital Cost Contribution	\$/GGE	\$0.20	\$0.19	\$0.16	\$0.12	\$0.13	\$0.22	\$0.28	\$0.24	\$0.24	\$0.10
Operating Cost Contribution	\$/GGE	\$0.15	\$0.14	\$0.12	\$0.08	\$0.09	\$0.12	\$0.18	\$0.16	\$0.16	\$0.08

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Hydroprocessing & Separation/Refinery Coprocessing											
Total Cost Contribution	\$/GGE	\$0.33	\$0.31	\$0.34	\$0.35	\$0.38	\$0.30	\$0.23	\$0.21	\$0.21	\$0.33
Capital Cost Contribution	\$/GGE	\$0.17	\$0.16	\$0.18	\$0.19	\$0.20	\$0.16	\$0.00	\$0.00	\$0.00	\$0.17
Operating Cost Contribution	\$/GGE	\$0.15	\$0.14	\$0.16	\$0.16	\$0.18	\$0.14	\$0.23	\$0.21	\$0.21	\$0.15
Carbon Efficiency of Organic Liquid Feed to Fuels	%	88.4%	89.5%	87.2%	91.0%	89.0%	93.5%	94.5%	93.5%	93.5%	91.0%
Hydrotreating Pressure	psia	2,000	2,000	2,000	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Oxygen Content in Cumulative Fuel Product	wt %	0.8%	0.8%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.6%
Hydrogen Production											
Total Cost Contribution	\$/GGE	\$0.61	\$0.56	\$0.60	\$0.62	\$0.51	\$0.61	\$0.44	\$0.44	\$0.44	\$0.44
Capital Cost Contribution	\$/GGE	\$0.39	\$0.36	\$0.38	\$0.41	\$0.33	\$0.39	\$0.28	\$0.28	\$0.28	\$0.28
Operating Cost Contribution	\$/GGE	\$0.22	\$0.20	\$0.22	\$0.21	\$0.18	\$0.22	\$0.16	\$0.16	\$0.16	\$0.16
Additional Natural Gas at the Biorefinery ^e	% of biomass LHV	0.3%	0.1%	0.2%	0.1%	0.3%	0.1%	0.1%	0.6%	0.6%	0.2%
Coproducts											
Total Cost Contribution	\$/GGE	-	-	-	-	-	(\$0.52)	(\$0.55)	(\$0.52)	(\$0.53)	-
Capital Cost Contribution ^f	\$/GGE	-	-	-	-	-	-	-	-	-	-
Operating Cost Contribution ^f	\$/GGE	-	-	-	-	-	-	-	-	-	-
Coproduct Credit	\$/GGE	-	-	-	-	-	(\$0.52)	(\$0.55)	(\$0.52)	(\$0.53)	-
Balance of Plant											
Total Cost Contribution	\$/GGE	\$0.04	\$0.07	\$0.03	\$0.20	\$0.23	\$0.27	\$0.09	\$0.20	\$0.19	\$0.16
Capital Cost Contribution	\$/GGE	\$0.80	\$0.71	\$0.56	\$0.43	\$0.46	\$0.45	\$0.46	\$0.52	\$0.51	\$0.33
Operating Cost Contribution ^f	\$/GGE	(\$0.76)	(\$0.64)	(\$0.54)	(\$0.23)	(\$0.23)	(\$0.18)	(\$0.37)	(\$0.32)	(\$0.32)	(\$0.17)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection	Design Case
Electricity Production from Steam Turbine (Credit Included in Operational Cost Above)	\$/GGE	(\$1.12)	(\$0.96)	(\$0.78)	(\$0.42)	(\$0.45)	(\$0.40)	(\$0.57)	(\$0.57)	(\$0.57)	(\$0.34)

^a For the 2017 SOT, the unquantified portion of CFP yields were prorated to solids, liquids, and gases using measured yields.

^b Modeled ash is 1.75% for 2019 and 2020, and less than 1% for all other years.

^c An additional biomass heater is included as a small additional in-plant cost, as shown in the 2015 process design report: <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

^d Small adjustments made to previously published feedstock cost estimates for 2014–2016.

^e Natural gas stream was negligible in most of the biorefinery models. This was included to maintain model flexibility to allow natural gas use as an option.

^f Capital and operating costs for coproduct recovery in the 2019–2022 models are included in the “Vapor Quench, Coproduct Recovery + Contingency” section.

Integration and Scale-Up

Once the technical targets are reached through R&D, unit operations or process steps developed at lab-scale R&D will require integration at engineering scale, along with testing to ensure technical targets can be reached when run as an integrated process. Key integration challenges for dry feedstocks converted via the direct liquefaction and upgrading pathway may include:

- Reliable and robust operations of feed handling systems, including feeding woody biomass into a pressurized conversion reactor (for reference, see the appendix, barrier SDI-A).
- Addressing the buildup of impurities in process recycle systems and their impact on catalyst performance and regeneration requirements for converting pyrolysis vapor to hydrocarbon fuels (for reference, see the appendix, barrier SDI-F).
- The influence of inorganic species present in feedstocks on conversion efficiency to desired products (for reference, see the appendix, barrier SDI-F).
- Developing efficient product separation and purification schemes.
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier SDI-D).
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feedstock (for reference, see the appendix, barrier SDI-H).
- Lack of a commercially availability filter technology to be used between the pyrolysis reactor and the fixed-bed reactor.

To further decrease modeled fuel costs, BETO researches opportunities for coprocessing catalytic fast pyrolysis oils with petroleum-derived vacuum gas oil through fluid catalytic cracking. Coprocessing the pyrolysis oil in the refinery is expected to reduce capital and operating costs for upgrading to stable oil, fuel finishing to gasoline and diesel, and balance of plant. To be accepted for coprocessing, petroleum refiners need to understand how bio-oil or bio-intermediates will perform when integrated into existing operations (for reference, see the appendix, barriers SDI-C and SDI-G). Integrated system research includes understanding how the characteristics and components of bio-oil and bio-oil intermediates differ from those found in petroleum feedstocks, developing equipment operating conditions for blending bio-intermediates with petroleum feedstocks to meet existing product specifications, and extending

current refinery practices and procedures to include characteristics of biomass and bio-intermediates.

Supply Chain Sustainability Analysis

Table 7 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions of renewable gasoline and diesel production from CFP for the 2015–2020 SOTs and the 2022 projection and design case.²⁶ The CFP design consumes little net fossil energy after accounting for fossil energy displacement credits from coproduced electricity. The net energy balance of renewable gasoline and renewable diesel from the CFP design is about 0.52 MJ/MJ net fossil energy from using biofuels to displace in the 2022 projection case. Utilizing a larger portion of energy-intensive air-classified logging residues as part of the feedstock blend in the 2022 projection case leads to trade-offs of lower fuel yields, lower costs, and reduced net energy balance, as shown in Tables 4 and 7. As mentioned earlier, the original design case had a higher fuel yield due to the assumed carbon balance.

²⁶ H. Cai, L. Ou, M. Wang, R. Davis, A. Dutta, K. Harris, M. R. Wiatrowski, et al. *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2020 State-of-Technology Cases*. Lemont, IL: Argonne National Laboratory. ANL/ESD-21/1, 2021. <https://doi.org/10.2172/1807565>.

Table 7: Supply Chain Sustainability Metrics for the CFP Design Case

	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2022 Projection	Design Case	Petroleum Gasoline
Biofuel Yield									
MMBtu/dry	5.3	5.9	8.0	8.3	6.9	7.3	7.0	9.0	
Fossil Energy Consumption^a									
MJ/MJ	0.4 (-97%)	0.11 (-91%)	0.19 (-85%)	0.33 (-74%)	0.19 (-85%)	0.31 (-75%)	0.48 (-61%)	0.42 (-66%)	1.23
Net Energy Balance^b									
MJ/MJ	0.6	0.89	0.81	0.67	0.81	0.69	0.52	0.58	
GHG Emissions									
g CO ₂ e/MJ	6.0 (-94%)	11.4 (-88%)	17.7 (-81%)	26.4 (-72%)	16.2(-83%)	21 (-78%)	32 (-66%)	29.5 (-69%)	93
g CO ₂ e/GGE	738	1,402	2,171	3,234	1,985	2,538	3,916	3,619	11,360
Water Consumption									
gal/MJ	0.006	0.013	0.025	0.030	0.029	-0.015	-0.016	0.030	0.027
gal/GGE	0.8	1.6	3.0	3.7	3.6	-1.8	-2.0	3.7	3.2
Total NO_x Emissions									
g NO _x /MJ	0.11	0.10	0.07	0.13	0.33	0.27	0.34	0.16	0.052
g NO _x /GGE	13.1	11.7	8.7	15.6	40.6	32.5	41.8	19.2	6.3
Urban NO_x Emissions^c									
g NO _x /MJ	0.018	0.019	0.021	0.021	0.020	0.018	0.019	0.020	0.023
g NO _x /GGE	2.3	2.4	2.5	2.5	2.4	2.21	2.3	2.5	2.8

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT, 2022 projection, and petroleum reference emissions and water consumption values are based on GREET2020 model. The design case and prior year SOTs are based on GREET2019 model.

^a Includes both renewable gasoline and renewable diesel.

^b This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^c Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

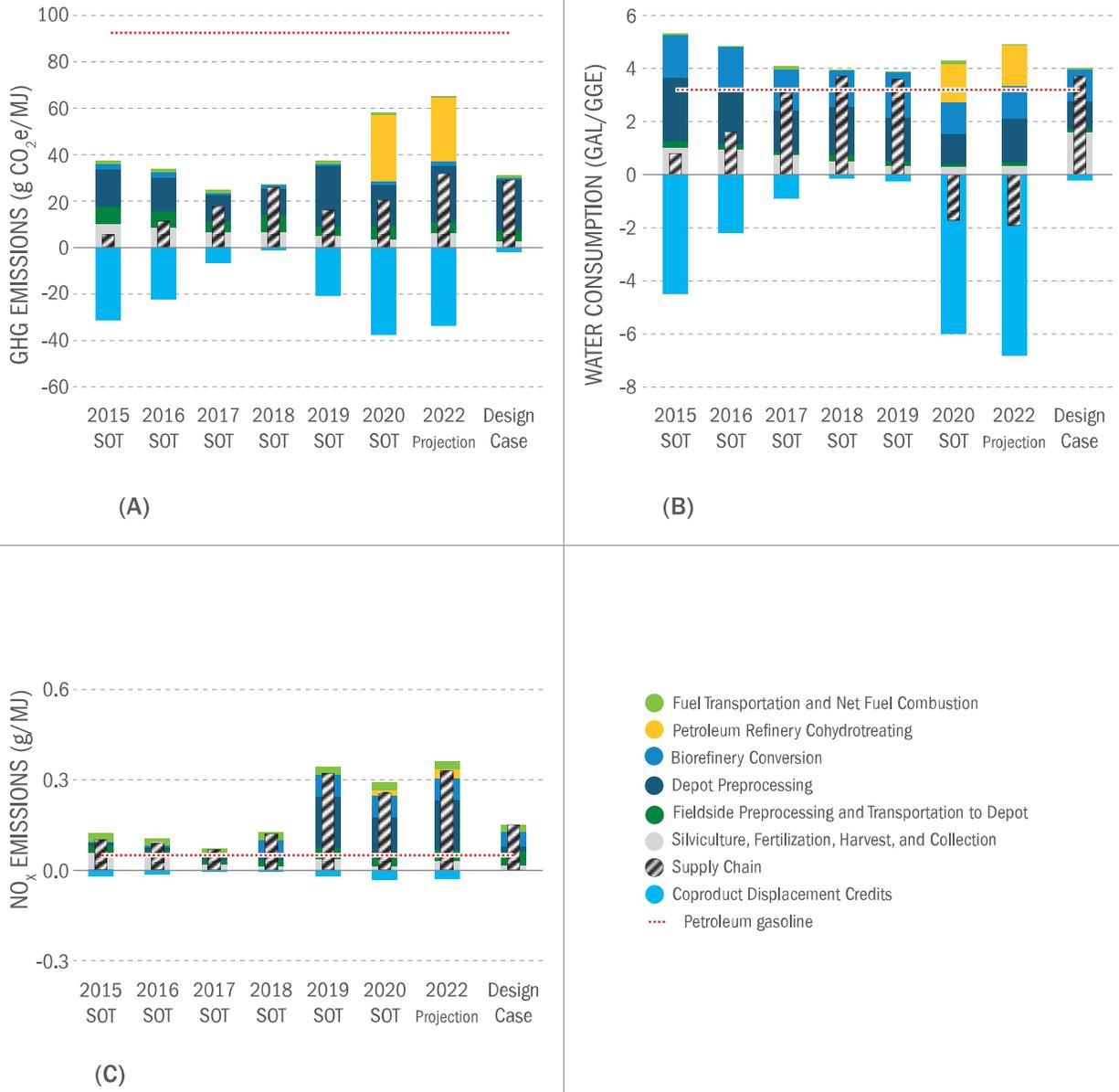
^d Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 8A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO₂e/MJ, compared to a life cycle carbon intensity for petroleum gasoline of 93 g CO₂e/MJ. The introduction of refinery coprocessing in the 2020 SOT and 2022 projection cases reduces biorefinery GHG emissions, but this is more than offset by emissions from the petroleum refinery. Table 7 shows that a total GHG reduction of 66% compared to petroleum gasoline can be achieved by 2022 through improvement in biofuel yields and by reducing energy consumption during conversion.

The GHG emissions increase from the 2020 SOT case to the 2022 projection case is due to switching to 75% air-classified and preprocessed pine logging residues in the 2022 design case. 2019 and 2020 SOT data assume a feedstock of 50% clean pine and 50% logging residues. The 2022 projection assumes a feedstock of 25% clean pine and 75% logging residues. These feedstock changes impact many of the SCSA metrics compared to 2018 and earlier. Preprocessing air-classified and leached pine logging residues is much more energy-intensive, and thus more emission-intensive, than preprocessing clean pine used in the 2018 and earlier SOT cases. Starting with the 2019 SOT, improvements in the carbon balance resulted in the addition of acetone and methyl ethyl ketone coproducts. The coproducts result in displacement credits, which more than offset increased GHG emissions associated with more energy-intensive feedstock preprocessing. The net GHG emissions increase from the 2015 SOT to the 2018 SOT is due to the reduction in coproduced electricity generation (and the corresponding reduction in coproduct displacement credits).

Figure 8B shows that water consumption decreases from 3.6 gal/GGE in the 2019 SOT case to -1.8 gal/GGE in the 2020 SOT case. This large decrease is due to a greater yield and different mix of coproducts when compared to previous years, especially the addition of 2-butanone, which is water-intensive to produce through traditional methods. The direct water consumption excluding coproduct effects still declines from 1.7 gal/GGE in 2019 to 1.1 gal/GGE in 2020. Reducing the total supply chain water consumption to -2.0 gal/GGE in the 2022 projection case can be achieved through less water consumption associated with energy consumption at feedstock depot preprocessing, less direct process water consumption in the CFP conversion processes (e.g., through water-free air-cooling technologies), and higher biofuel yields.

Figure 8C shows that total supply chain NO_x emissions remain high in the 2020 SOT and 2022 projection cases relative to petroleum-derived fuels due to more energy-intensive feedstock depot preprocessing that is also more NO_x emission-intensive, as well as the addition of co-hydrotreating. This presents a trade-off between cost and environmental performance of this pathway.



Figures 8A–8C: Supply chain for the CFP design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Indirect Liquefaction Design Case

Research on dry feedstocks converted via the IDL and upgrading to hydrocarbon fuels pathway helps BETO address multiple challenges in upgrading biomass-derived syngas and other shorter carbon chain intermediates. Progress for technologies relevant to this pathway is assessed using the woody biomass converted via gasification with catalytic upgrading of cleaned syngas to high-octane gasoline.²⁷ This is illustrated in Figure 9. Figure 10 shows the modeled costs of this configuration, with feedstocks and conversion contributions specified.²⁸

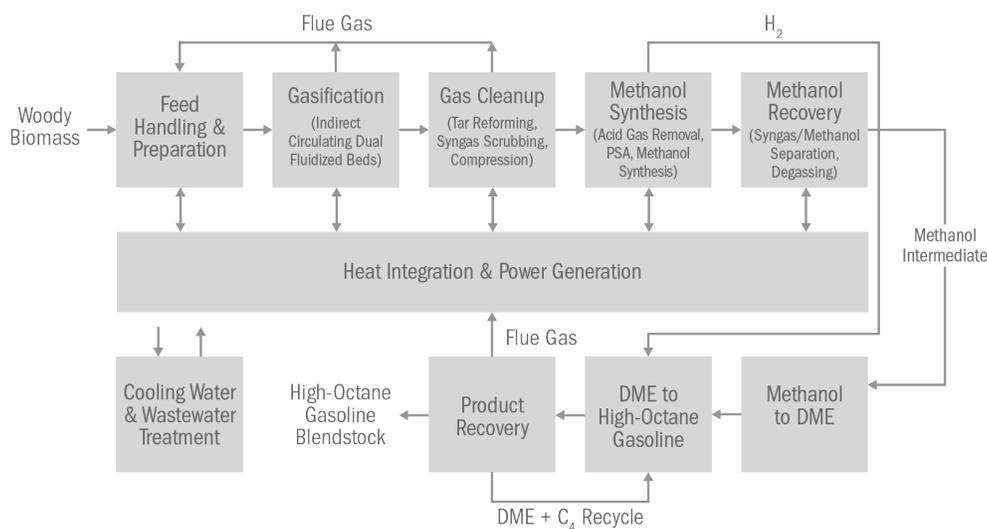


Figure 9: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel via indirect liquefaction

²⁷ E. C. D. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Bidy, D. Humbird, et al. *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons via Indirect Liquefaction: Thermochemical Research Pathway to High-Octane Gasoline Blendstock Through Methanol/Dimethyl Ether Intermediates*. Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, NREL/TP-5100-62402; PNNL-23822, 2015. <https://www.nrel.gov/docs/fy15osti/62402.pdf>.

²⁸ K. Harris, D. Ruddy, C. Nash, A. Dutta, D. Dupuis, E. Tan, D. Hartley, and H. Cai. *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2020 State of Technology*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-79986, 2021. <https://www.nrel.gov/docs/fy21osti/79986.pdf>.

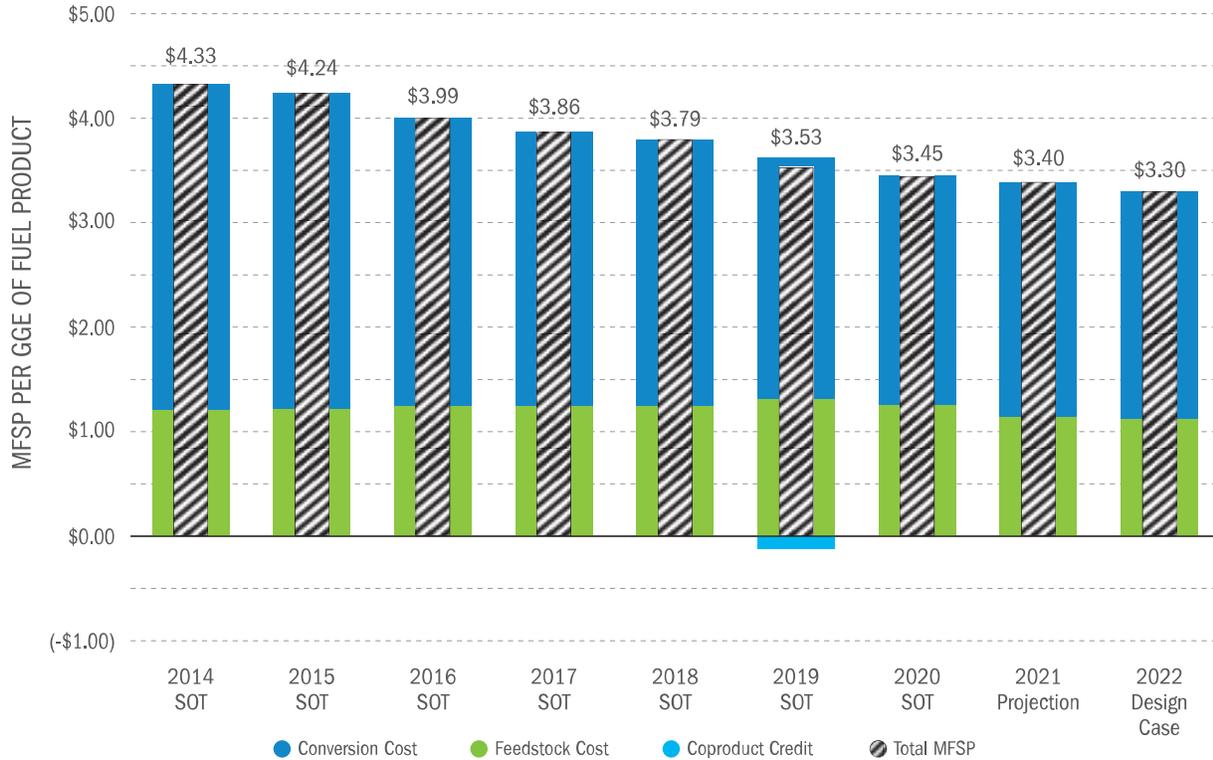


Figure 10: Feedstock and conversion cost contributions for the IDL design case

Feedstocks

As shown in Table 8, the IDL pathway has less stringent feedstock quality and physical composition requirements than the direct liquefaction pathway. The feedstock design for the IDL pathway utilizes a conventional system that delivers un-processed wood chips from logging residue directly to the biorefinery. The ability to accommodate feedstocks derived from lower-quality biomass along with less required preprocessing result in lower overall delivered feedstock costs for the IDL pathway.

Table 8: Delivered Feedstock Composition Specifications for the IDL Design Case

Component	Composition (dry wt %)
Carbon	49.81
Hydrogen	5.91
Nitrogen	0.17
Sulfur	0.09
Oxygen	41.02
Inorganic Species	≤3.00
Heating Value (Btu/lb)	8,449 HHV 7,856 LHV
Moisture (bulk wt %)	10.0
Particle Size	≤2-inch chips

Figure 11 and Table 9 show the projected feedstock costs delivered to the reactor throat for this design.^{29,30} The 2018 woody SOT and 2021–2022 cases project a modeled delivered feedstock cost of \$60.54/dry ton. The cost of logging residue delivered to the reactor throat in the 2018 SOT increased by \$3.26/dry ton over the 2017 SOT due to projected reductions in material availability, necessitating greater travel distances and higher transportation costs.^{31,32,33,34} The 2019 and 2020 SOTs update the 2018 SOT to utilize a blend of 50% pine logging residues and 50% clean pine, delivering 725,000 dry tons, with the location

(Southeast region) tied to the high availability of resources. The cost of the delivered feedstock for IDL increased by \$2.69/dry ton from the 2018 Woody SOT for IDL due to the incorporation of clean pine, which was partially offset by shrinking of the required draw radius. Logistics costs include harvest, collection, storage, transportation, and preprocessing costs from the point of harvest to the conversion reactor throat in-feed. The introduction of clean pine in the blend reduced the ash content to 1.75%, to the benefit of conversion performance and yield.

The IDL design case currently includes the minimum process steps required to deliver feedstock that meets conversion quality specifications. However, these specifications are limited to chemical compositions in Table 8, and feedstock quality parameters may change as they are informed by future research to consider downstream impacts (e.g., feeding disruption, equipment wear, and pollution emissions) that can be caused by the large particle size, aspect ratio, microstructure, surface characteristics, and relatively high levels of inorganic species for the feedstock composition shown in Table 8. The critical feedstock quality

²⁹ Hartley et al. 2021, <https://doi.org/10.2172/1782211>.

³⁰ Hartley et al. 2020, https://inldigitalibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.

³¹ U.S. Department of Energy. 2016 *Billion-Ton Report*.

³² A. Dutta, K. Iisa, C. Mukarakate, M. Griffin, E. C. D. Tan, J. Schaidle, D. Humbird, et al. *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2018 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71954, 2018. www.nrel.gov/docs/fy19osti/71954.pdf.

³³ Hartley et al. 2018, https://inldigitalibrary.inl.gov/sites/sti/sti/Sort_7464.pdf.

³⁴ Hartley et al. 2017. This reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

attributes of pine logging residues combined with clean pine and their impacts on the performance of unit operations and conversion yields need to be investigated and understood through the FCIC. The FCIC, as well as other FT fundamental R&D, will quantify trade-offs between cost and yield improvement.

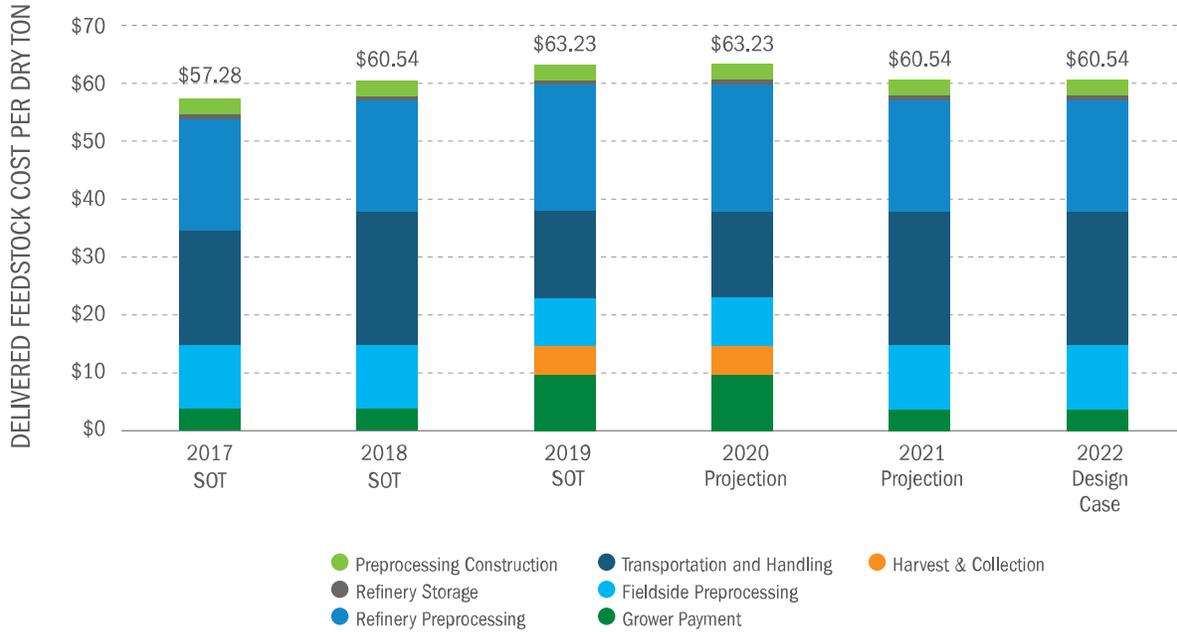


Figure 11: Cost contributions of on-spec feedstock delivered to the reactor throat for the IDL design case

Table 9: Cost Contributions of On-Spec Feedstock Delivered to Reactor Throat for the IDL Design Case

Cost per Dry Ton	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	2022 Projection
Feedstock Type	Logging Residues	Logging Residues	Blends*	Blends*	Logging Residues	Logging Residues
Grower Payment	\$3.75	\$3.75	\$9.74	\$9.74	\$3.75	\$3.75
Harvest and Collection	\$0.00	\$0.00	\$4.94	\$4.94	\$0.00	\$0.00
Fieldside Preprocessing	\$11.08	\$11.08	\$8.41	\$8.41	\$11.08	\$11.08
Transportation and Handling	\$19.67	\$22.93	\$14.87	\$14.87	\$22.93	\$22.93
Refinery Preprocessing	\$19.38	\$19.38	\$21.87	\$21.87	\$19.38	\$19.38
Refinery Storage	\$0.67	\$0.67	\$0.67	\$0.67	\$0.67	\$0.67
Preprocessing Construction	\$2.73	\$2.73	\$2.73	\$2.73	\$2.73	\$2.73
Total Feedstock Production Cost	\$57.28	\$60.54	\$63.23	\$63.23	\$60.54	\$60.54

*50% clean pine chips (pulp wood), 50% pine logging residues.

Figure 12 shows the impact of varying key operational parameters on feedstock cost for the IDL design case. Because feedstock specifications for this design are based on logging residues and require minimal processing, relatively few model parameters impact the final delivered cost. The final parameters, which were chosen for their variability or their potential to cause variability in the preprocessing operations, were chipper throughput and energy consumption and dryer throughput and energy consumption. Ranges were based on literature and observed process variation and compared with the 2022 design targets.^{35,36,37} The less stringent feedstock specifications for this pathway can significantly impact equipment energy consumption and throughput. Figure 12 shows that the delivered feedstock cost is most sensitive to chipper energy consumption, followed by chipper throughput. Chipper energy consumption is impacted by the variability in processing low-quality, low-cost logging residues. Throughput impacts are determined by distributing the capital equipment costs over the amount of material that is processed. When throughput decreases, the cost per unit increases; when throughput increases, costs decrease.

³⁵ C. W. Cao, D. Y. Yang, and Q. Liu. "Research on Modeling and Simulation of Mixed Flow Grain Dryer." *Drying Technology* 25, no. 4 (2007): 681–687. <https://doi.org/10.1080/07373930701290951>.

³⁶ Spinelli et al. 2012, <https://doi.org/10.1080/02827581.2011.644577>.

³⁷ J. Thompson and W. Sprinkle. "Production, Cost and Chip Characteristics of In-Woods Microchipping," presented at the Council on Forest Engineering Annual Meeting, Missoula, Montana, July 7–10, 2013. https://www.srs.fs.usda.gov/pubs/ja/2013/ja_2013_thompson_001.pdf.



Figure 12: Impacts on cost of feedstock unit operations for the IDL design case 2022 projection

Logging residues and clean pine utilize conventional feedstock supply systems that are limited in their ability to adjust the quality of the material (for reference, see the appendix, barrier Ft-I). Reducing energy consumption and improving equipment throughput will require shifting to advanced feedstock supply systems with more active quality management and controls and additional preprocessing operations.

Conversion

In this design, woody biomass is converted to synthesis gas (i.e., syngas) via gasification, followed by gas cleanup, compression, and catalytic conversion of syngas to a methanol intermediate. The methanol intermediate is then dehydrated to dimethyl ether (DME) and catalytically converted via homologation reactions to high-octane gasoline hydrocarbon fuel blendstocks. The resulting blendstock is high in branched paraffin content, similar to alkylates from petroleum refineries, and has a highly desirable octane number. This design case leverages technologies demonstrated in 2012 for the production of mixed alcohols from biomass^{38,39}; however, the high-octane gasoline case uses much lower-severity fuel synthesis operating conditions, making it more economically competitive.

Similar to the direct liquefaction and upgrading pathway, many of BETO's efforts to reduce modeled fuel costs during upgrading focus on improving overall yield, increasing catalyst lifetime, and increasing process intensity (for reference, see the appendix, barriers Ct-E, Ct-F, Ct-G, and Ct-N). Figure 13 shows how these areas have a potentially high impact on the conversion contribution to the final modeled cost of fuel with this design.

Research for this pathway focuses on increasing the selectivity of C₅₊ products during upgrading with metal-modified beta-zeolite (BEA) catalysts.

³⁸ R. L. Bain, K. A. Magrini-Bair, J. E. Hensley, W. S. Jablonski, K. M. Smith, K R. Gaston, and M. M. Yung. "Pilot Scale Production of Mixed Alcohols from Wood." *Industrial & Engineering Chemistry Research* 53, no. 6 (2014): 2204–2218. <https://doi.org/10.1021/ie403631h>.

³⁹ A. Dutta, J. Hensley, R. Bain, K. Magrini, E. C. D. Tan, G. Apane, D. Barton, et al. "Technoeconomic Analysis for the Production of Mixed Alcohols via Indirect Gasification of Biomass Based on Demonstration Experiments." *Industrial & Engineering Chemistry Research* 53, no. 30 (2014): 12149–12159. <https://doi.org/10.1021/ie402045q>.

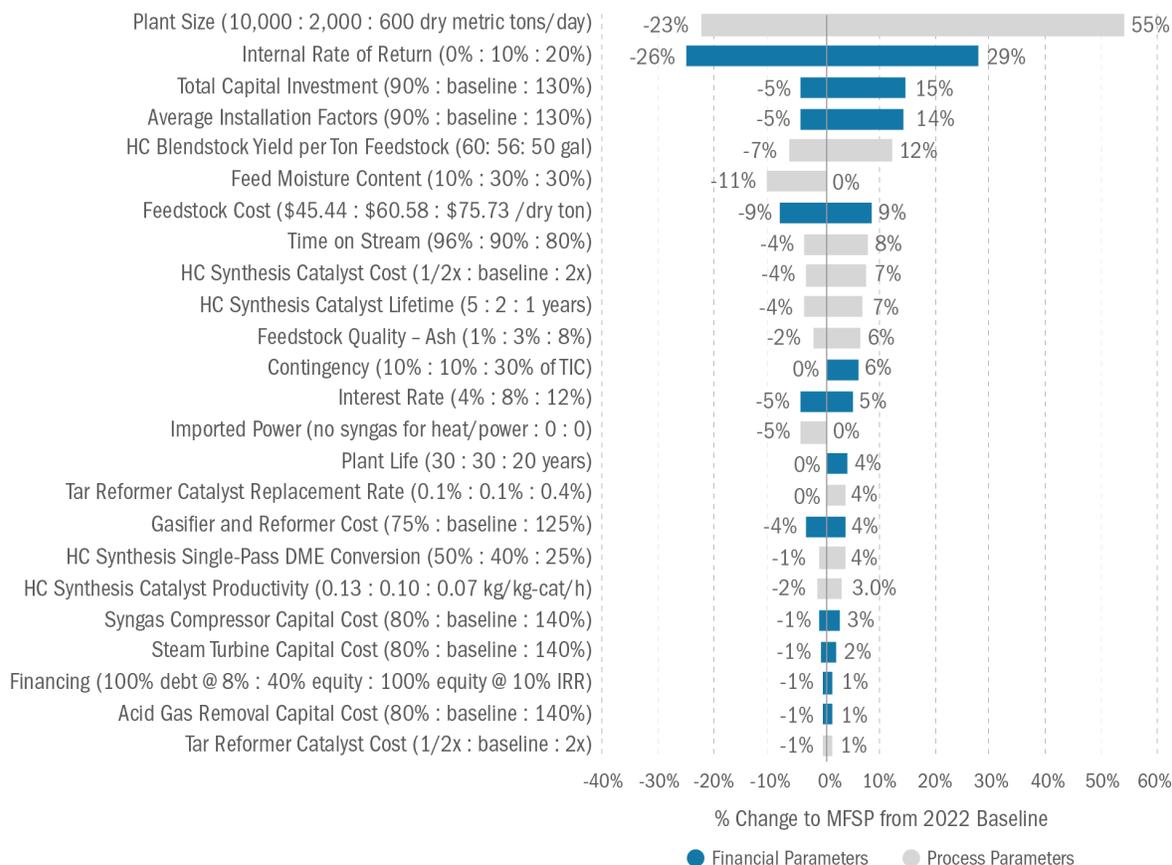


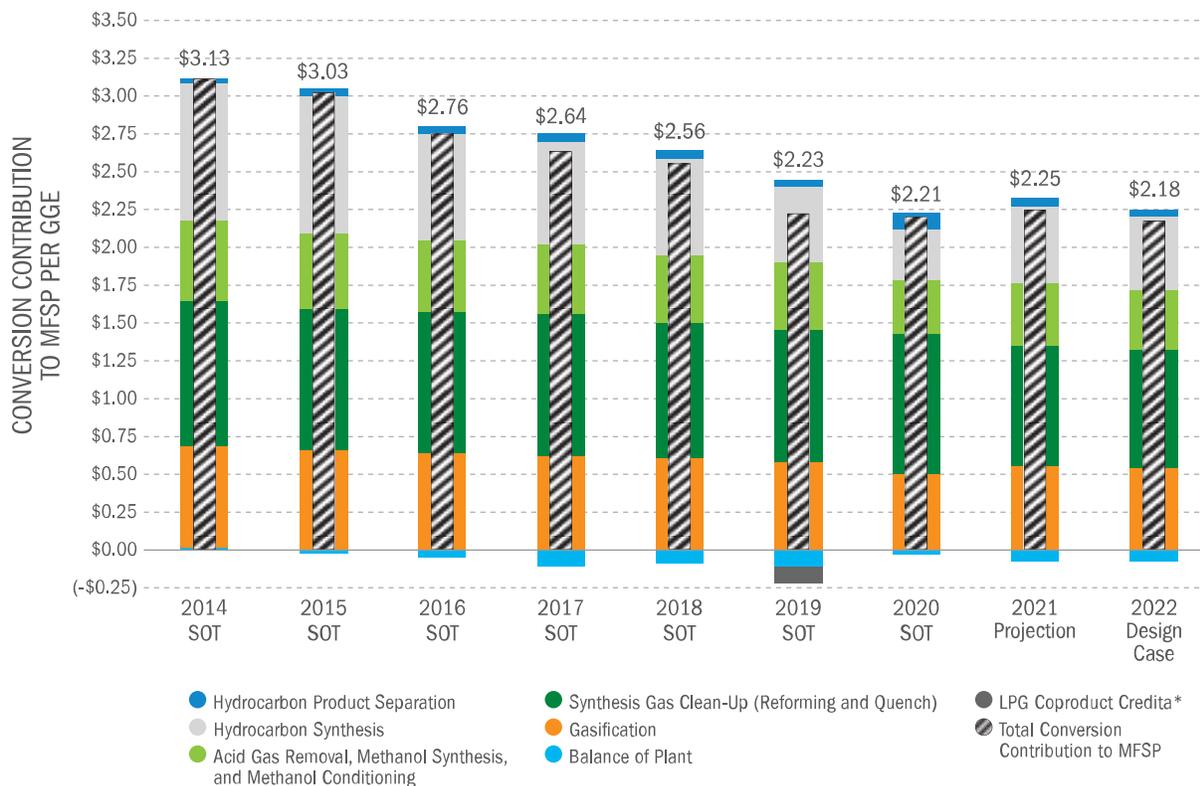
Figure 13: Key conversion factors impacting MFSP for the IDL design case

BETO currently supports work on computationally guided catalyst development with controlled ratios of ionic to metallic active sites to address this barrier through ChemCatBio and the Consortium for Computational Physics and Chemistry. ChemCatBio researchers also work to increase overall catalyst lifetime while maintaining higher selectivity. Recent SOT improvements shown in Figure 14 and Table 10 were achieved by increasing the single-pass DME conversion (from 19% in 2016 to 44% in 2019), and nearly doubling the hydrocarbon productivity over a Cu/BEA catalyst by operating at higher temperature and pressure.^{40,41,42}

⁴⁰ Harris et al. 2021, <https://www.nrel.gov/docs/fy21osti/79986.pdf>.

⁴¹ E. C. D. Tan, D. Ruddy, C. Nash, D. Dupuis, K. Harris, A. Dutta, D. Hartley, and H. Cai. *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2019 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76619, 2020. <https://www.nrel.gov/docs/fy20osti/76619.pdf>.

⁴² E. C. D. Tan, D. Ruddy, C. Nash, D. Dupuis, A. Dutta, D. Hartley, and H. Cai. *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2018 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71957, 2018. <https://www.nrel.gov/docs/fy19osti/71957.pdf>.



* A small amount of LPG (primarily C4's) coproduct was included in the FY19 SOT model to maintain C4 recycle assumptions in the range of C4 recycle tested experimentally

Figure 14: Conversion cost contributions for the IDL design case

Table 10: Conversion Cost Contributions for the Hydrocarbons via the IDL Design Case

Conversion Cost Breakdown (\$/GGE)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
Gasification	\$0.69	\$0.67	\$0.65	\$0.62	\$0.61	\$0.58	\$0.50	\$0.56	\$0.54
Synthesis Gas Cleanup (Reforming and Quench)	\$0.96	\$0.93	\$0.94	\$0.94	\$0.89	\$0.88	\$0.93	\$0.80	\$0.78
Acid Gas Removal, Methanol Synthesis, and Methanol Conditioning	\$0.52	\$0.50	\$0.47	\$0.47	\$0.45	\$0.45	\$0.36	\$0.41	\$0.40
Hydrocarbon Synthesis	\$0.91	\$0.91	\$0.70	\$0.67	\$0.64	\$0.49	\$0.34	\$0.51	\$0.48
Hydrocarbon Product Separation	\$0.04	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.11	\$0.05	\$0.05
Balance of Plant	\$0.01	(\$0.02)	(\$0.05)	(\$0.11)	(\$0.09)	(\$0.09)	(\$0.03)	(\$0.08)	(\$0.07)
Liquefied Petroleum Gas Coproduct Credit*	-	-	-	-	-	(\$0.11)	-	-	-
Conversion Contribution to MFSP	\$3.13	\$3.03	\$2.76	\$2.64	\$2.56	\$2.23	\$2.21	\$2.25	\$2.18

*A small amount of liquefied petroleum gas (primarily C4s) coproduct was included in the FY 2019 SOT model to maintain C4 recycle assumptions in the range of C4 recycle tested experimentally.

Researchers have identified that understanding and controlling C₄ alkane dehydrogenation and alkene alkylation to maximize C₅₊ product selectivity remains the critical research challenge,

and accordingly, can significantly boost yields and reduce overall cost. The 2019 SOT focused on improvements in the recycling of C₄ hydrocarbons back to the DME-to-hydrocarbon reactor. The current process relies on a multistep conversion of methanol to DME before upgrading to target fuels. Additional reductions in the MFSP in 2020 resulted from continued improvement to this recycle process, as well as improvements to the catalyst used for DME upgrading. Moving forward, the research team will focus on additional improvements in DME upgrading, including increasing single-pass conversion yields and selectivity for C₅₊ products, which have higher octane values and result in higher-value finished fuel.

Research on this pathway also considers the impact of using lower-cost feedstocks on catalyst performance and the potential for utilization of waste streams such as CO₂ for coproduct production (for reference, see the appendix, barriers Ct-A, Ct-J, and Ct-K). The FCIC researches how feedstock quality impacts catalyst performance. If value-added coproducts are required to meet future cost targets, evaluating where in the process coproduct production can be introduced (either through new process steps or valorizing waste streams) will be critical. Research in this area is currently too preliminary to project 2030 modeled costs.

Table 11 presents the process efficiency metrics for the IDL design, and Table 12 includes the detailed cost and technical projections for the IDL design.

Table 11: Process Efficiency Metrics for the IDL Design Case

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
Carbon Efficiency to C ₅₊ Product	% C in feedstock	19.3%	19.4%	25.2%	24.3%	25.5%	24.8%	26.1%	27.4%	27.9%
Carbon Efficiency to Mixed C ₄ Coproduct	% C in feedstock	7.0%	6.9%	0.0%	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%
Overall Carbon Efficiency to Hydrocarbon Products	% C in feedstock	26.3%	26.3%	25.2%	24.3%	25.5%	27.1%	26.1%	27.4%	27.9%
Overall Energy Efficiency to Hydrocarbon Products	% LHV of feedstock	37.7%	37.7%	36.6%	35.1%	36.6%	39.6%	37.6%	39.6%	40.4%
Electricity Production	kWh/gal C ₅₊	11.7	11.8	7.9	8.4	8.1	7.6	12.2	7.2	7.0
Electricity Consumption	kWh/gal C ₅₊	11.7	11.8	7.9	8.5	8.1	7.6	12.2	7.2	7.0

Table 12: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via Indirect Gasification and Methanol/DME Intermediates to High-Octane Gasoline

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
Process Concept: Gasification Syngas Cleanup, Methanol/DME Synthesis, and Conversion to Hydrocarbons		Logging Residues	50/50 Blend Logging Residues + Clean Pine	50/50 Blend Logging Residues + Clean Pine	Logging Residues	Logging Residues				
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016
C ₅₊ MFSP (per Actual Product Volume)	\$/gal	\$4.31	\$4.17	\$3.85	\$3.67	\$3.66	\$3.35	\$3.22	\$3.30	\$3.22
Mixed C ₄ MFSP (per Actual Product Volume) ^a	\$/gal	\$3.98	\$3.91	N/A	N/A	N/A	\$1.02	N/A	N/A	N/A
MFSP (per GGE)^a	\$/GGE	\$4.33	\$4.24	\$3.99	\$3.86	\$3.79	\$3.53	\$3.45	\$3.40	\$3.30
Conversion Contribution (per GGE) ^a	\$/GGE	\$3.13	\$3.03	\$2.76	\$2.64	\$2.56	\$2.23	\$2.21	\$2.25	\$2.18
Total Capital Investment per Annual Gallon	\$	\$15.80	\$15.94	\$11.01	\$11.54	\$11.07	\$11.07	\$10.94	\$10.03	\$9.79

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
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
High-Octane Gasoline Blendstock (C ₅₊) Yield	gal/dry ton	36.2	36.4	51.4	50.0	51.4	51.6	55.1	55.1	56.0
Mixed C ₄ Coproduct Yield	gal/dry ton	16.3	16.2	0.0	0.0	0.0	5.6	0.0	0.0	0.0
Feedstock^b										
Total Cost Contribution	\$/GGE	\$1.20	\$1.21	\$1.24	\$1.22	\$1.23	\$1.31	\$1.24	\$1.14	\$1.12
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	\$1.20	\$1.21	\$1.24	\$1.22	\$1.23	\$1.30	\$1.24	\$1.14	\$1.12
Feedstock Cost	\$/dry ton	\$60.58	\$60.58	\$60.58	\$57.28	\$60.54	\$63.23	\$63.23	\$60.54	\$60.54
Ash Content	wt % ash	3.00%	3.00%	3.00%	3.00%	3.00%	1.75%	1.75%	3.00%	3.00%
Feedstock Moisture at Plant Gate	wt % H ₂ O	30%	30%	30%	30%	30%	30%	30%	30%	30%
In-Plant Handling and Drying/Preheating	\$/dry ton	\$0.72	\$0.70	\$0.70	\$0.69	\$0.69	\$0.69	\$0.57	\$0.69	\$0.69
Cost Contribution	\$/gal	\$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 ₂ O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	Btu/lb	7,856	7,856	7,856	7,856	7,856	7,933	7,930	7,856	7,856
Gasification										
Total Cost Contribution	\$/GGE	\$0.69	\$0.67	\$0.65	\$0.62	\$0.61	\$0.58	\$0.50	\$0.56	\$0.54
Capital Cost Contribution	\$/GGE	\$0.43	\$0.41	\$0.38	\$0.35	\$0.34	\$0.33	\$0.28	\$0.31	\$0.30
Operating Cost Contribution	\$/GGE	\$0.26	\$0.26	\$0.27	\$0.28	\$0.26	\$0.25	\$0.23	\$0.25	\$0.24

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
Raw Dry Syngas Yield	lb/lb dry feed	0.76	0.76	0.76	0.76	0.76	0.77	0.83	0.76	0.76
Raw Syngas Methane (Dry Basis)	mol %	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	8.6%	15.4%	15.4%
Gasifier Efficiency (LHV)	% LHV	71.9%	71.9%	71.9%	71.9%	71.9%	72.3%	78.0%	71.9%	71.9%
Synthesis Gas Cleanup (Reforming and Quench)										
Total Cost Contribution	\$/GGE	\$0.96	\$0.93	\$0.94	\$0.94	\$0.89	\$0.88	\$0.93	\$0.80	\$0.78
Capital Cost Contribution	\$/GGE	\$0.51	\$0.49	\$0.46	\$0.43	\$0.41	\$0.39	\$0.40	\$0.37	\$0.36
Operating Cost Contribution	\$/GGE	\$0.45	\$0.45	\$0.48	\$0.51	\$0.48	\$0.49	\$0.53	\$0.44	\$0.42
Tar Reformer Exit CH ₄ (Dry Basis)	mol %	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.3%	1.7%	1.7%
Tar Reformer CH ₄ Conversion	%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
Tar Reformer Benzene Conversion	%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
Tar Reformer 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	\$0.52	\$0.50	\$0.47	\$0.47	\$0.45	\$0.45	\$0.36	\$0.41	\$0.40
Capital Cost Contribution	\$/GGE	\$0.35	\$0.33	\$0.30	\$0.28	\$0.28	\$0.27	\$0.20	\$0.25	\$0.24
Operating Cost Contribution	\$/GGE	\$0.17	\$0.17	\$0.17	\$0.19	\$0.18	\$0.18	\$0.15	\$0.16	\$0.16
Methanol Synthesis Reactor Pressure	psia	730	730	730	730	730	730	730	730	730

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case	
Methanol Productivity	kg/kg-cat/h	0.7	0.7	0.8	0.8	0.8	0.7	0.8	0.7	0.7	
Methanol Intermediate Yield	gal/dry ton	143	142	138	144	141	137	150	136	134	
Hydrocarbon Synthesis											
Total Cost Contribution	\$/GGE	\$0.91	\$0.91	\$0.70	\$0.67	\$0.64	\$0.49	\$0.34	\$0.51	\$0.48	
Capital Cost Contribution	\$/GGE	\$0.56	\$0.56	\$0.46	\$0.44	\$0.42	\$0.34	\$0.11	\$0.34	\$0.32	
Operating Cost Contribution	\$/GGE	\$0.35	\$0.35	\$0.24	\$0.23	\$0.22	\$0.16	\$0.23	\$0.17	\$0.16	
Methanol to DME Reactor Pressure	psia	145	145	145	145	145	145	169	145	145	
Hydrocarbon Synthesis Reactor Pressure	psia	129	129	129	129	129	129	205	129	129	
Hydrocarbon Synthesis Catalyst		commercial BEA				National Renewable Energy Laboratory-modified BEA with Cu as active metal 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 Outlet via Recycle		0%	0%	100%	100%	100%	90%	97%	recycle	100%	
Single-Pass DME Conversion	%	15.0%	15.0%	19.2%	27.6%	38.9%	44.7%	43.4%	39.7%	40.0%	
Overall DME Conversion	%	83%	85%	83%	88%	92%	88%	96%	90%	90%	
Hydrocarbon Synthesis Catalyst Productivity	kg/kg-cat/h	0.02	0.03	0.04	0.09	0.07	0.07	0.07	0.09	0.10	
Carbon Selectivity to C ₅₊ Product	% C in reactor feed	46.2%	48.3%	81.8%	74.8%	72.3%	73.6%	72.1%	83.4%	86.7%	

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2021 Projection	Design Case
Carbon Selectivity to Total Aromatics (Including Hexamethylbenzene)	% C in reactor feed	25.0%	20.0%	4.0%	4.0%	8.0%	5.8%	3.3%	2.4%	0.5%
Carbon Selectivity to Coke and Precursors (Hexamethylbenzene Proxy)	% C in reactor feed	10.0%	9.3%	4.0%	4.0%	4.0%	2.9%	1.6%	1.4%	0.5%
Hydrocarbon Product Separation										
Total Cost Contribution	\$/GGE	\$0.04	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.11	\$0.05	\$0.05
Capital Cost Contribution	\$/GGE	\$0.03	\$0.03	\$0.04	\$0.04	\$0.04	\$0.03	\$0.06	\$0.03	\$0.03
Operating Cost Contribution	\$/GGE	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.05	\$0.01	\$0.01
Liquefied Petroleum Gas Coproduct Credit										
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.11)	\$0.00	\$0.00	\$0.00
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	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.11)	\$0.00	\$0.00	\$0.00
Balance of Plant										
Total Cost Contribution	\$/GGE	\$0.01	(\$0.02)	(\$0.05)	(\$0.11)	(\$0.09)	(\$0.11)	(\$0.03)	(\$0.08)	(\$0.07)
Capital Cost Contribution	\$/GGE	\$0.42	\$0.40	\$0.36	\$0.34	\$0.33	\$0.29	\$0.31	\$0.29	\$0.28
Operating Cost Contribution	\$/GGE	(\$0.41)	(\$0.42)	(\$0.42)	(\$0.45)	(\$0.42)	(\$0.41)	(\$0.33)	(\$0.37)	(\$0.36)

Integration and Scale-Up

Unit operations and processes proven at small-scale laboratory conditions would need to be scaled up and assembled together in an integrated setup or pilot-scale facility to verify process performance. For this pathway, key integration challenges may include:

- Reliable and robust operations of feed handling systems, including feeding woody biomass into gasification reactors (for reference, see the appendix, barriers SDI-A and SDI-D).
- Addressing buildup of impurities in process recycle systems and its impact on catalyst performance and regeneration requirements for the conversion of syngas to high-octane gasoline blendstock (for reference, see the appendix, barrier SDI-F).
- The influence of inorganic species present in the feed on conversion efficiency to desired products (for reference, see the appendix, barrier SDI-F).
- Developing efficient product separation and purification schemes of syngas and high-octane gasoline.
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier SDI-D).
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feed (for reference, see the appendix, barrier SDI-H).
- Addressing impurities in the gases before the compressing stage and their effect on the compressors.

Supply Chain Sustainability Analysis

Table 13 summarizes the supply chain sustainability metrics evaluated for the 2016–2020 SOT cases, as well as for the 2022 design case for the IDL design.^{43,44} The SCSA for the 2019 and 2020 SOTs assumes a combination of pine logging residues and clean pine chips. The SCSA for prior year SOTs and the design case assume pine logging residues only. The logging residues and clean pine do not require air classification or preprocessing in any of the SOT feedstock cases.

⁴³ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

⁴⁴ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, L. Tao, et al. *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases*. Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020. https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 13: Supply Chain Sustainability Metrics for the IDL Design Case

	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 SOT	Design Case	Petroleum Gasoline
Biofuel Yield							
MMBtu/dry ton	5.8	5.5	5.8	6.3	6.1	6.3	
Fossil Energy Consumption^a							
MJ/MJ	0.20 (-84%)	0.20 (-84%)	0.19 (-85%)	0.20 (-84%)	0.21 (-83%)	0.17 (-86%)	1.23
Net Energy Balance^b							
MJ/MJ	0.80	0.80	0.81	0.80	0.79	0.83	
GHG Emissions							
g CO ₂ e/MJ	16 (-83%)	17 (-82%)	16 (-83%)	21 (-78%)	19 (-80%)	14 (-85%)	93
g CO ₂ e/GGE	2,020	2,065	1,993	2,530	2,309	1,735	11,357
Water Consumption							
gal/MJ	0.04	0.04	0.04	0.04	0.04	0.03	0.03
gal/GGE	4.4	4.7	4.5	4.5	4.7	3.8	3.2
Total NO_x Emissions							
g NO _x /MJ	0.25	0.26	0.25	0.18	0.22	0.23	0.052
g NO _x /GGE	30.5	32.0	30.6	22.3	26.7	28.2	6.3
Urban NO_x Emissions^c							
g NO _x /MJ	0.020	0.020	0.020	0.021	0.019	0.020	0.023
g NO _x /GGE	2.4	2.4	2.4	2.5	2.3	2.4	2.8

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT and petroleum reference emissions and water consumption values are based on the GREET2020 model. Design case and prior year SOTs are based on the GREET2019 model.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

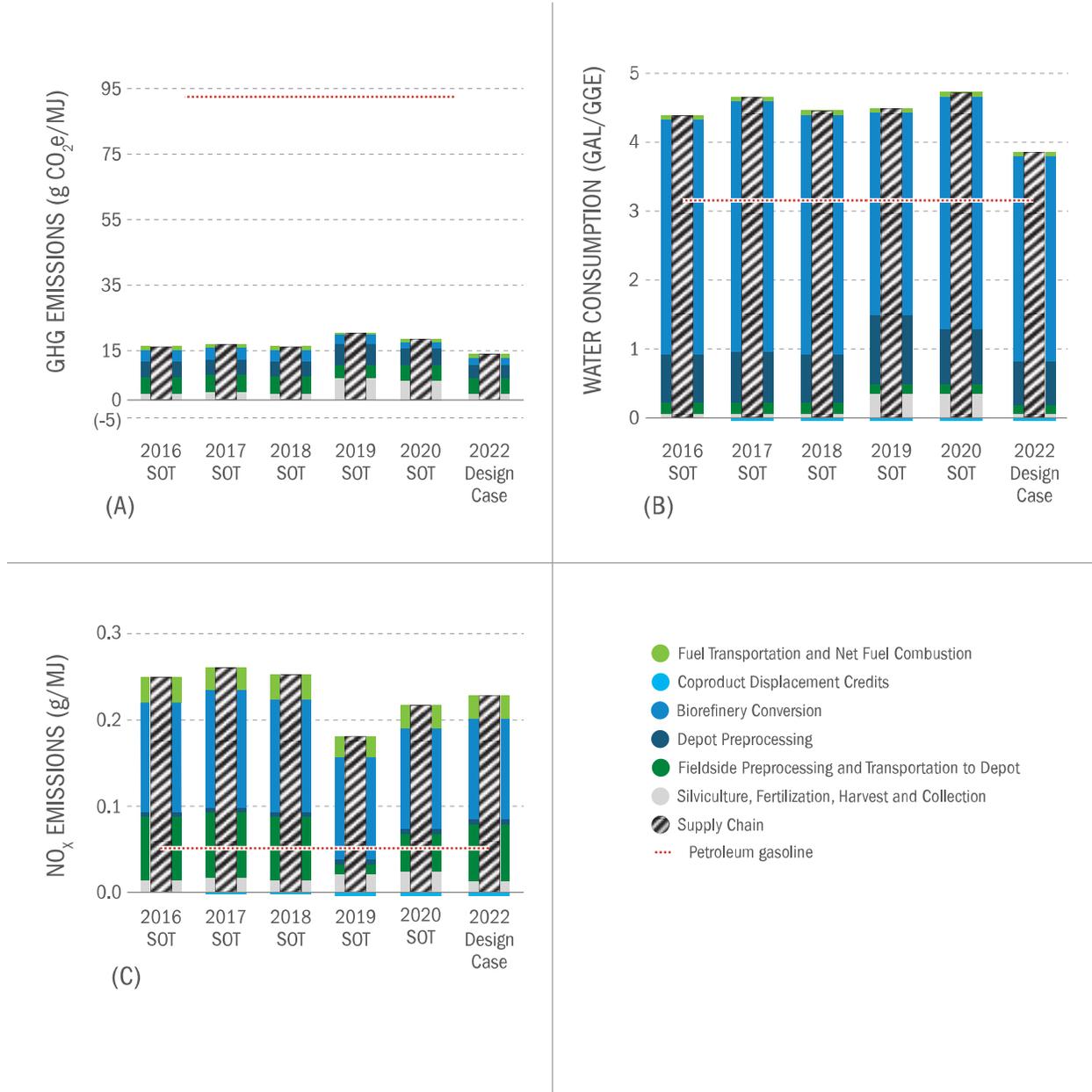
^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 15A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO₂e/MJ. The GHG reductions of the SOT and design cases are relative to a life cycle carbon intensity of 93 g CO₂e/MJ for petroleum-derived gasoline. Figure 15A shows that a total GHG reduction of 85% compared to petroleum gasoline can be achieved by 2022 through reducing energy consumption in feedstock logistics, especially at the fieldside preprocessing step, and improvement in biofuel yield.

Figure 15B shows that reducing water consumption from about 4.4 gal/GGE in the 2016 SOT case to about 3.8 gal/GGE in the 2022 design case projection can be achieved through using low-water-intensity feedstock (such as logging residues), switching from water-cooling technologies to novel air-cooling technologies in the conversion process, and improving biofuel yield.

Figure 15C shows that NO_x emissions exceed those of petroleum gasoline for all the SOT results and 2022 design case projections. The greatest opportunities for NO_x emission reduction are in NO_x emissions control of combusting intermediate bio-char and fuel gas inside of the biorefinery for process heat.



Figures 15A–15C: Supply chain for the IDL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions⁴⁵

⁴⁵ 2019 and 2020 SOT data assume a feedstock of 50% clean pine and 50% logging residues, whereas all other years (including the 2022 projection) assume a feedstock of 100% logging residue. This impacts many of the SCSA metrics. Results from 2019 and 2020 will be incorporated into future projections in outyear analyses. Additional details are available in the SOT reports referenced earlier.

Dry Feedstocks Converted via Low Temperature and Upgrading

Research into the pathway for dry feedstocks converted via low temperature and upgrading helps BETO identify key challenges and informs R&D priorities associated with areas including deconstruction of lignocellulosic biomass, hybrid conversion approaches (a combination of biochemical and catalytic), separation of desired intermediates, and upgrading of lignin. The design case configurations used to assess progress of technologies used in this pathway include low-temperature deconstruction of biomass into sugars and lignin, followed by fermentation of sugars to either a 2,3-BDO or mixed-acid intermediate followed by catalytic conversion of the resulting intermediate streams into fuels and coproducts, as illustrated in Figure 16A and 16B, respectively.⁴⁶ The TEAs for these two design case variations for this pathway are described separately and the SCSA results for the two designs are presented together.

Feedstocks

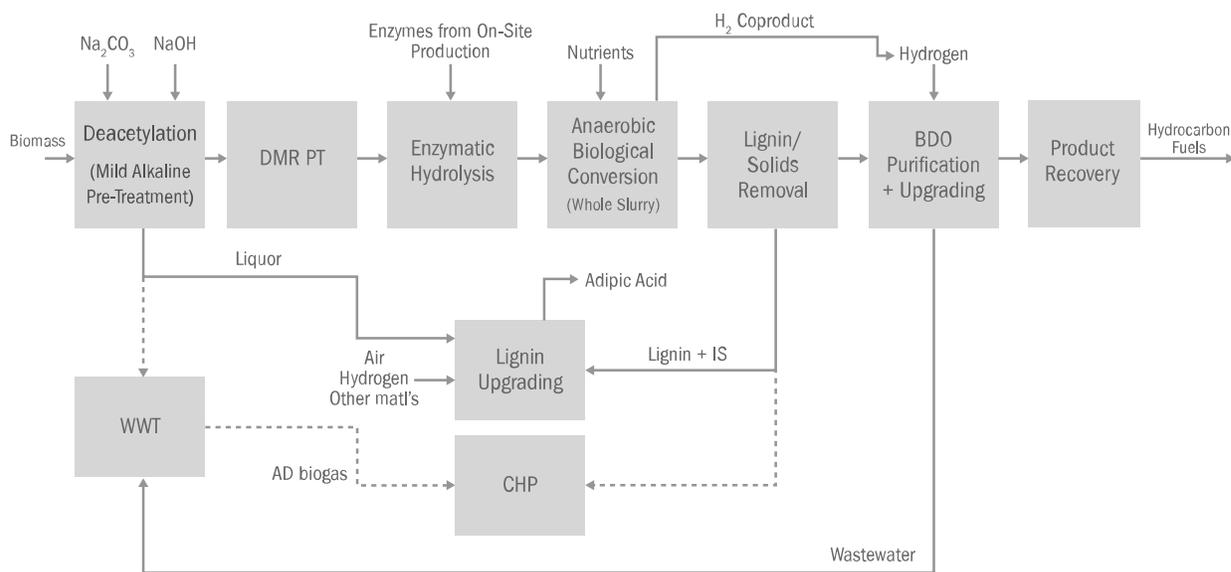
Table 14: Feedstock Composition Specifications for Low-Temperature Pathway Design Cases

Component	Composition (dry wt %)
Glucan	35.1
Xylan	19.5
Lignin	15.8
Inorganic Species	4.9
Acetate	1.8
Protein	3.1
Extractives	14.7
Arabinan	2.4
Galactan	1.4
Mannan	0.6
Sucrose	0.8
Total Structural Carbohydrate	59.0
Total Structure Carbohydrate Plus Sucrose	59.8
Moisture (bulk wt %)	20.0

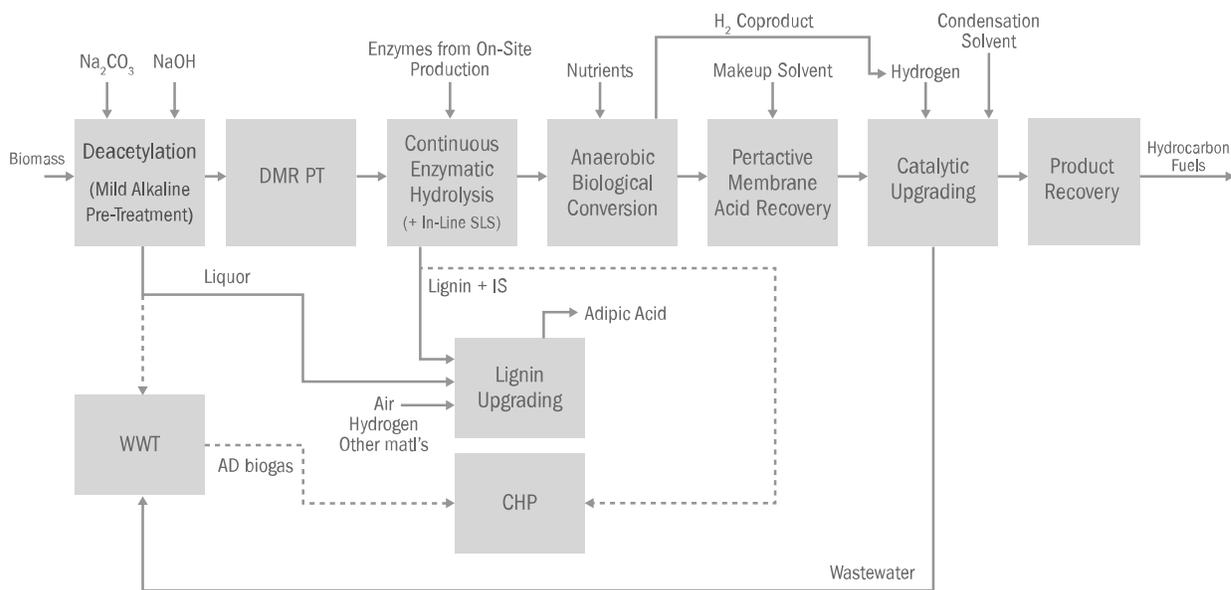
The composition (including chemical, mechanical, and physical properties) of feedstocks being fed into the conversion processes is a key determinant of their convertibility into biofuels. MFSP projections for both low-temperature designs assume the compositional specifications shown in Table 14 can be met at the given delivered feedstock cost goal.⁴⁷ Other physiochemical and biological properties and their impact on flowability, convertibility, and equipment performance are under investigation and will be implemented into feedstock specifications as new research is completed.

⁴⁶ R. Davis, N. Grundl, L. Tao, M. J. Bidy, E. C. D. Tan, G. T. Beckham, D. Humbird, D. N. Thompson, and M. S. Roni. *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Coproducts: 2018 Biochemical Design Case Update*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71949, 2018. <https://www.nrel.gov/docs/fy19osti/71949.pdf>.

⁴⁷ Davis et al. 2018, <https://www.nrel.gov/docs/fy19osti/71949.pdf>.



(A)



(B)

Figures 16A–16B: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel and products via low-temperature deconstruction and upgrading design cases. Figure 16A shows design via BDO intermediate and Figure 16B shows design via mixed-acid intermediate.

The low-temperature pathway design case specifications assume use of herbaceous feedstocks (corn stover or a blend). Herbaceous biomass can be costly to handle, transport,

and convey because of its low bulk density, high inorganic species content, fibrous nature, and relatively high and inconsistent moisture. It is subject to dry matter loss and degraded quality during biomass storage (for reference, see the appendix, barriers Ft-E, Ft-F, Ft-G, and Ft-J). FT R&D focuses on understanding inherent and introduced variability in feedstocks and interactions between feedstock quality and conversion performance, and on developing preprocessing technologies that can preserve and improve the physical, chemical, and mechanical properties of harvested biomass. FT R&D also explores how developing active feedstock quality post-harvest management (such as storage) and other preprocessing technologies (such as mechanical deconstruction, advanced fractionation, blending and formulation, and densification) could enable lignocellulosic biomass as well as low-cost and low-quality economically advantaged feedstock (such as municipal solid wastes) to be effectively fractionated and processed to meet conversion process in-feed specifications at cost targets.

The modeled delivered costs of on-spec herbaceous feedstocks for the low-temperature designs are shown in Figure 17 and Table 15. The delivered cost of \$83.90/dry ton achieved by the 2017 SOT⁴⁸ exceeded the target set forth in the 2016 *Multi-Year Program Plan*⁴⁹ of \$85.04/dry ton (2016\$, originally \$84/ton in 2014\$). The 2019 herbaceous SOT feedstock cost,⁵⁰ based on equipment and processes available now or in the near term, is \$81.37/dry ton and represents a \$2.30/dry ton decrease from 2018.⁵¹ The decreases in SOT costs are due to the incorporation of several technology changes in feedstock preprocessing, opportunities stemming from the integrated landscape management strategy, and reduced biomass access cost due to increased grower participation—while maintaining or improving grower profitability. All designs assume 90% time-on-stream performance of the feedstock preprocessing depots. The 2020 SOT⁵² incorporates an actively managed storage system comprising a combination of best management practices and “farm-scale technologies” such as enhanced in-storage drying, as well as reduced biological degradation and dry matter loss, to achieve storage stability objectives for early-harvested wet bales and decrease the transportation cost. These technological advancements result in a modeled delivered feedstock cost of \$80.10/dry ton, which is a \$1.27/dry ton decrease from

⁴⁸ M. Roni, D. N. Thompson, H. Hu, D. Hartley, Q. Nguyen, and H. Cai. *Herbaceous Feedstock 2017 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, 2017. Reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

⁴⁹ U.S. Department of Energy. *Bioenergy Technologies Office 2016 Multi-Year Program Plan*. Washington, DC: U.S. Department of Energy, DOE/EE-1385, 2016. https://www.energy.gov/sites/prod/files/2016/07/f33/mypp_march2016.pdf.

⁵⁰ M. Roni, Y. Lin, M. Griffel, D. Hartley, and D. N. Thompson. *Herbaceous Feedstock 2019 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57182-Revision-0, 2020. https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_21886.pdf.

⁵¹ M. Roni, D. S. Hartley, M. Griffel, H. Hu, Y. Lin, Q. Nguyen, H. Cai, and D. N. Thompson. *Herbaceous Feedstock 2018 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-18-51654-Revision-0, 2020. https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_7462.pdf.

⁵² Y. Lin, M. S. Roni, D. N. Thompson, D. S. Hartley, M. Griffel, and H. Cai. *Herbaceous Feedstock 2020 State of Technology Report*. Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-59958-Rev.1, 2020. https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_41817.pdf.

the 2019 SOT.

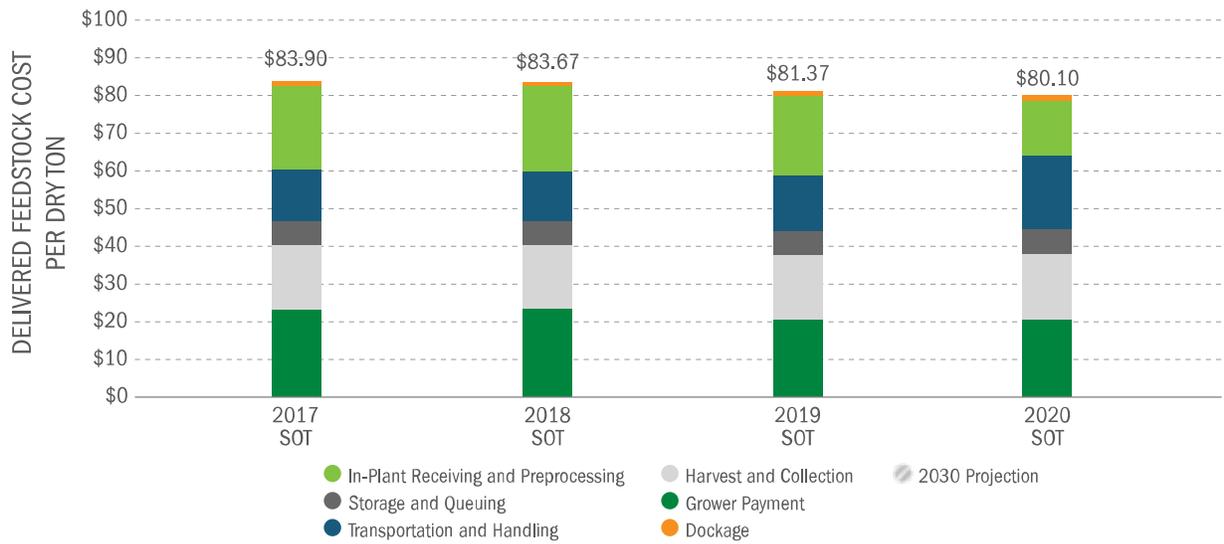


Figure 17: Cost contributions from herbaceous feedstock delivered to reactor throat for low-temperature design cases

Table 15: Cost Contributions From Herbaceous Feedstock Delivered to Reactor Throat for Low-Temperature Design Cases

Cost per Dry Ton	2017 SOT	2018 SOT	2019 SOT	2020 SOT
Feedstock Type	Blend ^a	Blend ^b	Blend ^c	Blend ^d
Grower Payment	\$23.24	\$23.54	\$20.56	\$20.62
Harvest and Collection	\$16.91	\$16.68	\$17.14	\$17.33
Storage and Queuing	\$6.54	\$6.45	\$6.49	\$6.72
In-Plant Receiving and Preprocessing ^e	\$22.52	\$22.49	\$20.84	\$14.61
Transportation and Handling	\$13.43	\$13.23	\$14.76	\$19.43
Dockage ^f	\$1.27	\$1.27	\$1.58	\$1.39
Delivered Feedstock Price	\$83.90	\$83.67	\$81.37	\$80.10

^a 2017 blend consists of 12.15% three-pass corn stover, 75.72% two-pass stover, 8.23% switchgrass, and 3.91% grass clippings.

^b 2018 blend consists of 12.74% three-pass corn stover, 73.22% two-pass stover, 9.83% switchgrass, and 4.21% grass clippings.

^c 2019 blend consists of 33.33% three-pass corn stover and 66.67% two-pass stover.

^d 2020 blend consists of 29.63% three-pass corn stover and 70.37% two-pass stover.

^e Includes depot deconstruction cost, bale processor, hammer mill, densifier, conveyors, blending equipment, dust collection equipment, bulk storage, and other miscellaneous equipment such as destringers, moisture meters, bale rejecters, and electromagnets used in preprocessing.

^f Dockage represents a cost adder over the baseline design needed to mitigate the impact of off-spec ash, moisture, and/or carbohydrate in the supplied biomass.

In order to meet the 2030 technical targets and modeled MFSP projection for the conversion process, current analysis suggests that feedstock would need to be delivered at a cost of \$71.26/dry ton. To achieve this feedstock cost target, FT will continue to pursue improvements including:

- Incorporation of additional integrated land management strategies to reduce grower payments and increase biomass supply.
- Optimized selection of biomass resource locations, low-cost renewable carbon sources, and depot sizes for least-cost blending.
- Incorporating variable two-pass harvesting and collection methods to meet chemical composition specifications.

- Reduced material degradation and dry matter losses, and improved feedstock quality from actively managed storage and handling system.
- The use of preprocessing, mechanical deconstruction, and advanced fractionation equipment for improved uniformity of biomass flow, critical quality attributes for conversion, and value-added coproducts.
- Improved size reduction, fractionation, and conditioning performance to achieve high-quality feedstock fractions and formats.
- Improved high-moisture densification throughput and reduced energy consumption.
- Improved transportation and handling costs through blending, formulation, drying, and densification.

Figure 18 shows the impact of varying key operational parameters on delivered feedstock cost for the low-temperature design, based on actual process experience and from literature. Baling rate, interest rate, bale density, storage dry matter loss, bale processor throughput, and hammer mill energy consumption and throughput had the greatest impact. Costs are impacted by equipment performance (such as throughput and energy consumption) that is heavily impacted by the feedstock's physical, chemical, and mechanical properties (for reference, see the appendix, barriers Ft-E and Ft-J). Dry matter loss due to insufficient moisture management also impacts costs. The FCIC conducts research to develop a fundamental understanding of interactions between feedstock quality properties and preprocessing equipment performance (e.g., flowability, energy consumption, throughput, material loss, and wear) to identify underlying factors, critical quality attributes, and critical process parameters that can support developing technologies that improve feedstock quality, reduce delivered feedstock cost, and improve feedstock preprocessing efficiency. The FCIC and FT R&D also examines the gap between n^{th} -plant design case assumptions and actual first-of-a-kind plant experience. These findings will shape future design case assumptions and inform future R&D needs.

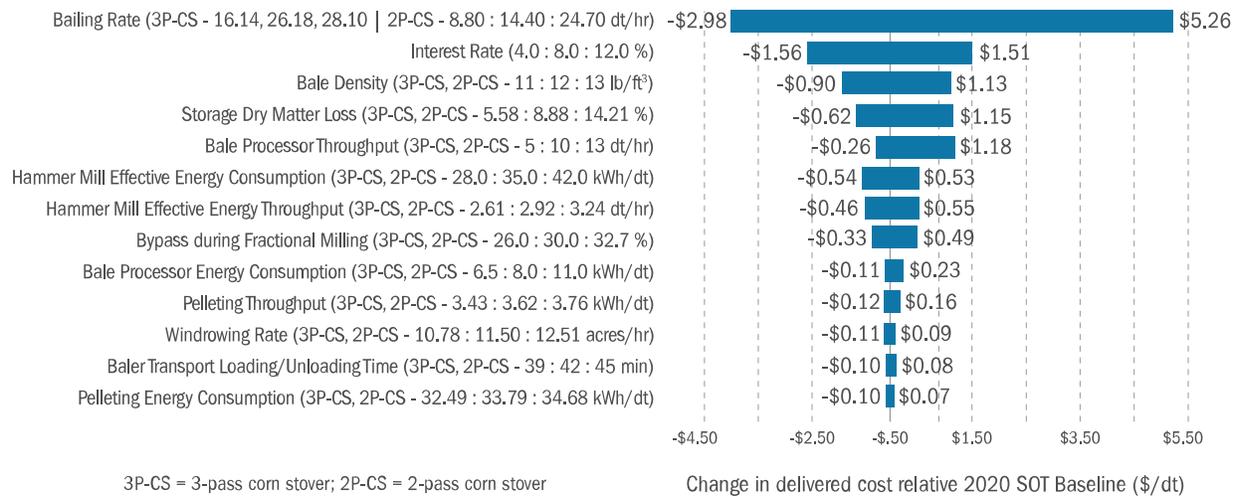


Figure 18: Key operational factors impacting costs in the herbaceous feedstock SOT design

Biochemical Conversion via 2,3-BDO Intermediate Design Case

Figure 19 shows the modeled SOT and projected future production costs for the 2,3-BDO intermediate design case broken down by feedstock and conversion contributions.^{53,54}

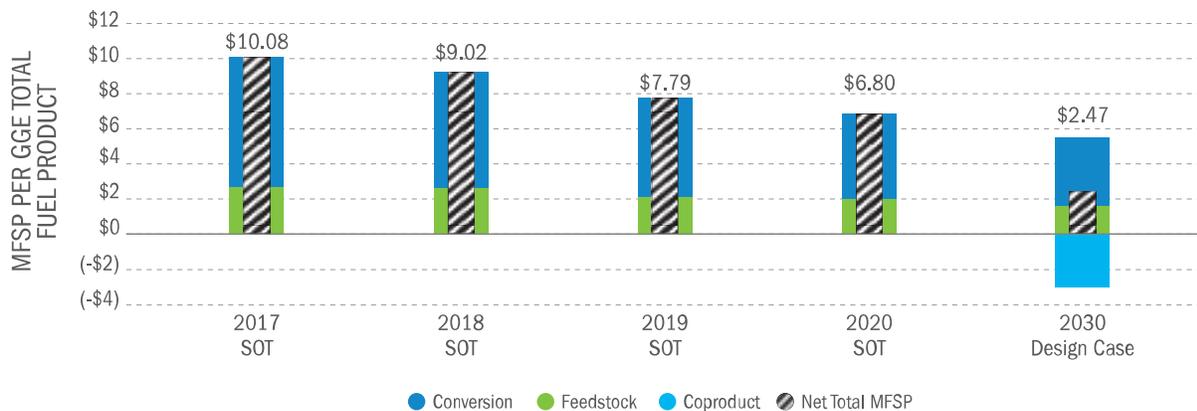


Figure 19: Cost contribution of feedstocks and conversion for the hydrocarbon biofuels 2,3-BDO intermediate design case

⁵³ R. Davis, A. Bartling, and L. Tao. *Biochemical Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Products: 2020 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-79930, 2021. <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

⁵⁴ R. Davis, A. Bartling, and L. Tao. *Biochemical Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Products: 2019 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76567, 2020. <https://www.nrel.gov/docs/fy20osti/76567.pdf>.

Conversion

This conversion process design case is based on deacetylation and mechanical refining (DMR) pretreatment of corn stover, followed by hydrolysis with cellulase and hemicellulase enzymes.

The resulting whole-slurry hydrolysate including solids is routed to fermentation with an engineered *Zymomonas mobilis* organism to produce 2,3-BDO.

The aqueous 2,3-BDO product is clarified and then undergoes a series of catalytic upgrading steps—dehydration, oligomerization, and hydroprocessing—to produce finished hydrocarbon fuels.

The lignin streams from the pretreatment and post-fermentation solids removal steps are commingled and undergo a separate upgrading process, starting with deconstruction to monomers and followed by upgrading to coproducts (adipic acid in this case). The revenue from this coproduct stream helps offset biorefinery costs of producing the hydrocarbon biofuel and reduces net MFSP.

Figure 20 illustrates that several of the largest sensitivity impacts to fuel selling price pertain to lignin deconstruction and upgrading (i.e., metabolically accessible lignin and the productivity of muconic acid, an intermediate). Based on experiments completed in 2019, and as shown in Figure 21, the current state of technology for lignin upgrading actually results in an increase in the net MFSP compared to SOT designs wherein lignin is sent to a boiler and combusted for heat and power. Research performed in 2020 drove down the MFSP in the lignin upgrading scenario, but the total cost remains higher than combusting the lignin.

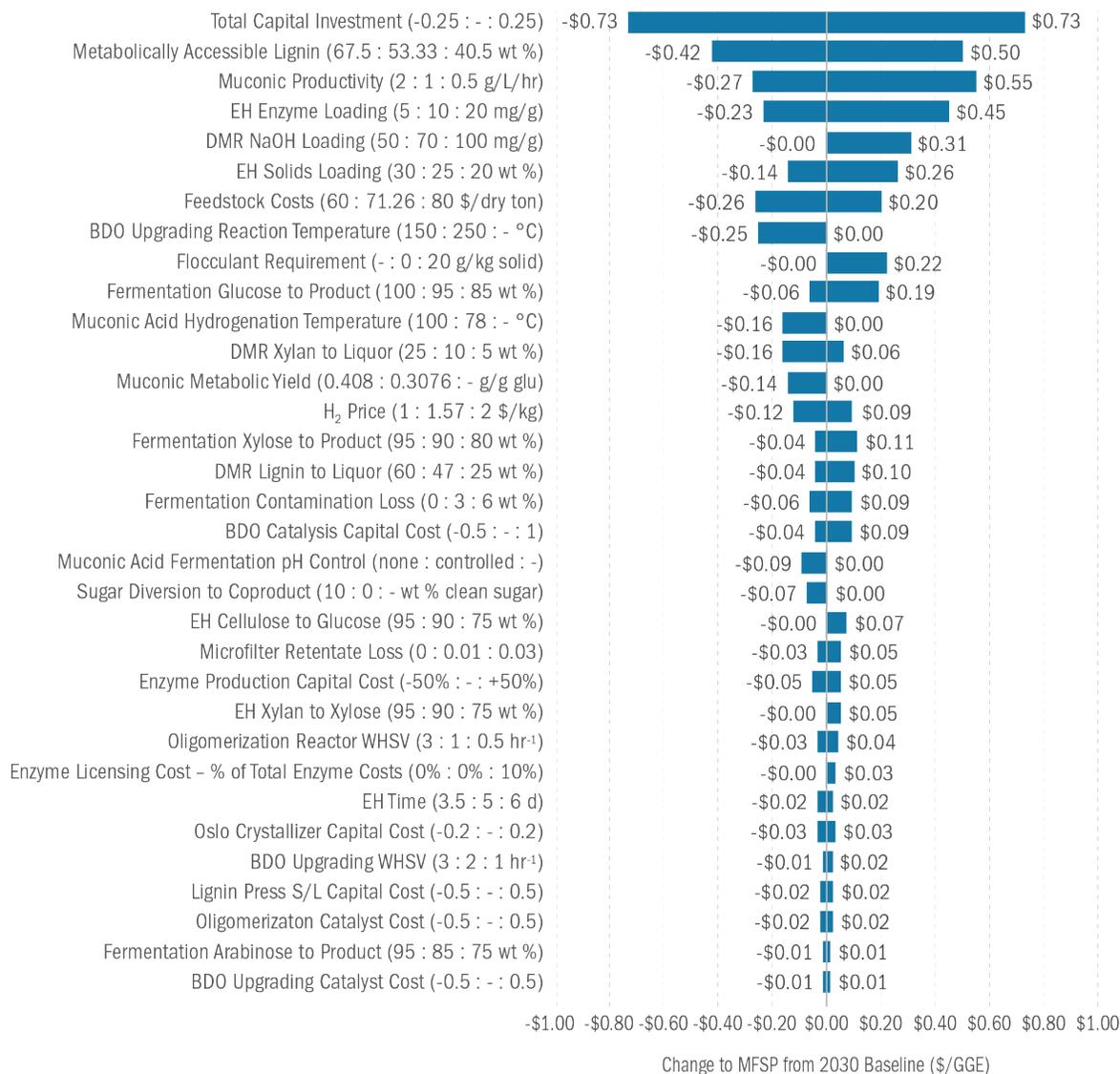


Figure 20: Major cost factors in the production of hydrocarbon biofuels via the 2,3-BDO intermediate design case Future improvements to lignin deconstruction and upgrading are expected to achieve higher yields, and as technical performance improves, the revenue from coproducts is projected to lower MFSP (for reference, see the appendix, barriers Ct-C, Ct-F, and Ct-J). Figure 21 shows that meeting 2030 technical targets for lignin conversion to a coproduct alone can result in more than \$2.5/GGE net decrease in MFSP. Multiple deconstruction chemistries are being explored, including heterogeneous catalysis, solvent-based hydrolysis, and enzymatic treatments, all of which target specific linkages between lignin monomers to convert lignin macromolecules into smaller molecular weight species. For each of these deconstruction processes, ChemCatBio R&D is focused on developing low-cost, robust catalysts to perform these oxidative and reductive chemistries. Additional R&D strategies to achieve ultimate goals for lignin

deconstruction and upgrading include the use of solvents to drive toward higher levels of metabolically accessible lignin and, by extension, coproducts.

Conversion yields for each conversion step are also critical to achieving technical and economic feasibility. For the carbohydrate fractions, bioprocess development is critical to achieving high yields, rates of product formation, and product titers. Researchers employ genetic engineering to maximize the production of 2,3-BDO from carbohydrates, including:

1. Knocking out competing metabolic pathways.
2. Heterologous expression of more active enzymes, and adaptation to higher concentrations of the resulting products.
3. Leveraging high-throughput genetic transformation techniques and genetic tools developed under the Agile BioFoundry (for reference, see the appendix, barriers Ct-D and Ct-L).

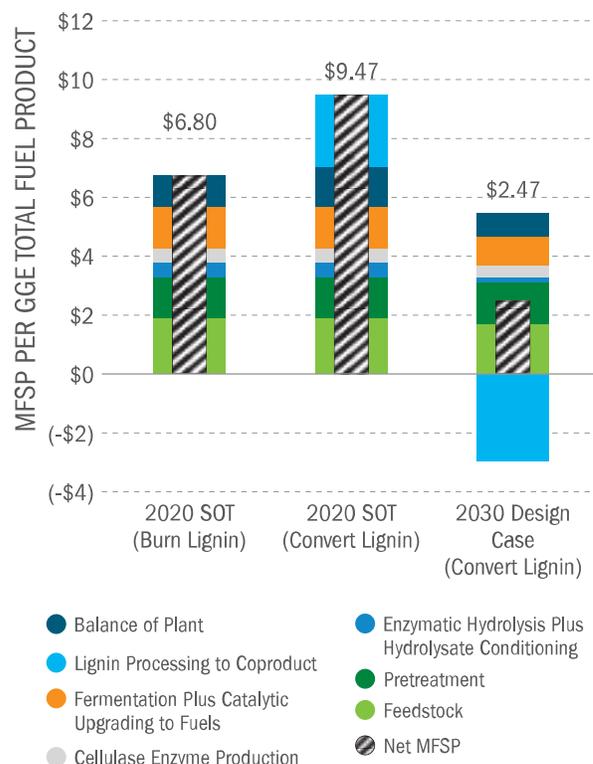


Figure 21: Modeled hydrocarbon biofuels production costs via the 2,3-BDO intermediate design case comparing SOT lignin conversion to coproduct versus burning

Figure 22 and Table 16 show significant decreases in modeled costs from knocking out competing metabolic pathways and increasing the titer of the 2,3-BDO, as well as moving toward fermentation on whole-slurry hydrolysate rather than clarified sugars. These organism improvements have cascading economic impacts: increasing overall fuel yields, reducing the capital intensity of the process, and reducing the need for 2,3-BDO concentration prior to catalytic upgrading.

The 2020 SOT update focused on a two-stage deacetylation process, which reduced overall sodium hydroxide loading and increased sugar yields from the enzymatic hydrolysis step. This improvement was responsible for the primary MFSP savings seen in 2020 for both the BDO and acids intermediate pathways, and translated to improved sustainability metrics as well (see Figure 27A).

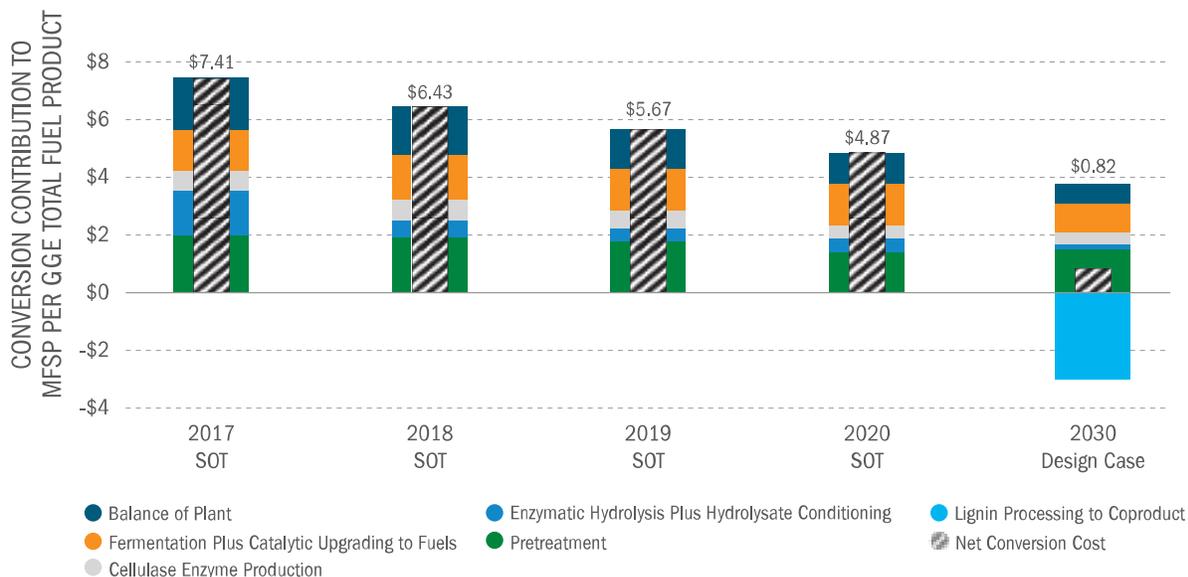


Figure 22: Conversion cost contributions for hydrocarbon biofuels via the 2,3-BDO intermediate design case

Table 16: Conversion Cost Contributions for Hydrocarbon Biofuels via the 2,3-BDO Intermediate Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2030 Projection (Design Case)
Pretreatment	\$1.97	\$1.89	\$1.73	\$1.36	\$1.48
Enzymatic Hydrolysis + Hydrolysate	\$1.53	\$0.58	\$0.47	\$0.52	\$0.15
Cellulase Enzyme Production	\$0.72	\$0.70	\$0.59	\$0.45	\$0.44
Fermentation + Catalytic Upgrading to Fuels	\$1.39	\$1.57	\$1.45	\$1.41	\$0.97
Lignin Processing to Coproduct	\$0.00	\$0.00	\$0.00	\$0.00	(\$3.00)
Balance of Plant	\$1.80	\$1.70	\$1.43	\$1.12	\$0.79
Net Conversion Contribution to MFSP	\$7.41	\$6.43	\$5.67	\$4.87	\$0.82

Other key areas for reducing MFSP include lowering reaction temperatures, reducing hydrogen requirements, and decreasing catalyst costs through improved catalyst lifetimes or novel chemistries (for reference, see the appendix, barriers Ct-E, Ct-F, and Ct-G). ChemCatBio activities focus on developing catalysts that can tolerate streams with >85% water (removing the need for intermediary evaporation steps) and developing oligomerization reactors that selectively produce jet- and diesel-range molecules.

Additional longer-term R&D activities include:

- Preprocessing and pretreatment improvements identified in the FCIC (for reference, see the appendix, barrier Ct-B).
- Developing next-generation enzyme formulations and enzymatic hydrolysis processes (for reference, see the appendix, barrier Ct-B).
- Developing strategies to recapture and valorize waste streams, such as CO₂ and biogas (for reference, see the appendix, barrier Ct-H).
- Identifying and developing processes to produce novel coproducts from lignin or other streams, such as carbon fibers from lignin and coproducts from sugars (for reference, see the appendix, barriers Ct-J and Ct-K). The 2030 projection in Figure 22 and Table 16 illustrates the potential effect of such future technology development on MFSP.

Table 17 presents the process efficiency metrics for the 2,3-BDO intermediate design case; Table 18 shows the detailed breakout of unit operation cost estimates and technical projections for this design.

Table 17: Process Efficiency Metrics for the 2,3-BDO Intermediate Design Case

Sustainability and Process Efficiency Metrics	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin*	2019 SOT Burn Lignin	2019 SOT Convert Lignin*	2020 SOT Burn Lignin	2020 SOT Convert Lignin*	2030 Projection Convert Lignin (Design Case)
Fuel Yield by Weight of Biomass	% w/w of dry biomass	9.6%	9.9%	9.9%	11.7%	11.7%	12.6%	12.7%	13.2%
Carbon Efficiency to Fuels	% C in feedstock	18.2%	18.7%	18.7%	22.1%	22.1%	23.8%	23.9%	25.0%
Carbon Efficiency to Lignin Coproduct	% C in feedstock	N/A	N/A	2.3%	N/A	2.3%	N/A	2.2%	14.8%
Net Electricity Import (Entire Process)	kWh/GGE	12.3	5.1	14	5.7	12.5	4.9	11.4	10.5
Purchased Natural Gas Import (Entire Process)	Btu/GGE (LHV)	0	0	75,284	0	69,928	0	60,607	14,596

*FY 2018–FY 2020 lignin conversion SOT cases based on actual black liquor/base-catalyzed depolymerization (BCD) hydrolysate experiments. Higher productivities have been observed based on model lignin monomers.⁵⁵

Table 18: Unit Operation Cost Estimates and Technical Projections for Conversion of Dry Herbaceous Feedstocks to Hydrocarbon Fuels via the 2,3-BDO Intermediate Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin-Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016
Projected MFSP	\$/GGE	\$10.08	\$9.02	\$12.81	\$7.79	\$10.80	\$6.80	\$9.47	\$2.47
Feedstock Contribution	\$/GGE	\$2.67	\$2.59	\$2.59	\$2.11	\$2.11	\$1.93	\$1.93	\$1.65
Conversion Contribution	\$/GGE	\$7.41	\$6.43	\$10.22	\$5.67	\$8.69	\$4.87	\$7.55	\$0.82
Total Gasoline Equivalent Yield	GGE/dry ton	31.4	32.3	32.3	38.5	38.5	41.3	41.6	43.2

⁵⁵ Davis et al. 2021, <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin-Design Case)
Adipic Acid Coproduct Yield	lb/dry ton biomass	0	0	40	0	42	0	39	266
Feedstock									
Total Cost Contribution	\$/GGE	\$2.67	\$2.59	\$2.59	\$2.12	\$2.11	\$1.93	\$1.93	\$1.65
Capital Cost Contribution	\$/GGE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Operating Cost Contribution	\$/GGE	\$2.67	\$2.59	\$2.59	\$2.12	\$2.11	\$1.93	\$1.93	\$1.65
Feedstock Cost ^b	\$/dry ton	\$83.90	\$83.67	\$83.67	\$81.37	\$81.37	\$80.10	\$80.10	\$71.26
Pretreatment									
Total Cost Contribution	\$/GGE	\$1.97	\$1.89	\$1.91	\$1.73	\$1.74	\$1.36	\$1.37	\$1.48
Capital Cost Contribution	\$/GGE	\$0.47	\$0.45	\$0.46	\$0.38	\$0.40	\$0.41	\$0.42	\$0.38
Operating Cost Contribution	\$/GGE	\$1.50	\$1.45	\$1.44	\$1.35	\$1.34	\$0.96	\$0.95	\$1.10
Method	-	DMR	DMR	DMR	DMR	DMR	DMR	DMR	DMR
Solids Loading	wt %	20%	20%	20%	20%	20%	20%	20%	30%
Temperature	°C	92	92	92	90	90	90	90	92
Reactor Mode	batch versus counter-current	batch	batch	batch	batch	batch	batch	batch	counter-current
Total Caustic (NaOH) [Na ₂ CO ₃] Loading	mg/g dry biomass	70	70	70	80	80	24 [80]	24 [80]	70
Net Solubilized Lignin to Liquor	%	47%	47%	47%	50%	50%	20%	20%	47%
Net Solubilized Glucan to Liquor	%	2%	2%	2%	2%	2%	3%	3%	2%
Net Solubilized Xylan to Liquor	%	17%	17%	17%	16%	16%	12%	12%	10%
Net Solubilized Arabinan to Liquor	%	46%	46%	46%	46%	46%	48%	48%	30%
Enzymatic Hydrolysis									

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin-Design Case)
Total Cost Contribution	\$/GGE	\$1.53	\$0.58	\$0.58	\$0.47	\$0.47	\$0.52	\$0.52	\$0.15
Capital Cost Contribution	\$/GGE	\$0.78	\$0.19	\$0.19	\$0.17	\$0.18	\$0.21	\$0.21	\$0.12
Operating Cost Contribution	\$/GGE	\$0.75	\$0.39	\$0.39	\$0.30	\$0.29	\$0.31	\$0.31	\$0.03
Hydrolysis Configuration	batch versus continuous	batch	batch	batch	batch	batch	batch	batch	batch
Total Solids Loading to Hydrolysis	wt %	20%	20%	20%	20%	20%	20%	20%	25%
Enzymatic Hydrolysis Batch Time	days	5	5	5	5	5	7	7	5
Hydrolysis Glucan to Glucose	%	78%	78%	78%	84%	84%	88%	88%	90%
Hydrolysis Xylan to Xylose	%	85%	85%	85%	82%	82%	93%	93%	90%
Sugar Loss (into Solid Stream after Enzymatic Hydrolysis Separation)	%	5%	N/A (whole)	N/A (whole slurry)	N/A (whole)	N/A (whole slurry)	N/A (whole slurry)	N/A (whole slurry)	N/A (whole slurry)
Cellulase Enzyme Production									
Total Cost Contribution	\$/GGE	\$0.72	\$0.70	\$0.70	\$0.59	\$0.59	\$0.45	\$0.46	\$0.44
Capital Cost Contribution	\$/GGE	\$0.14	\$0.13	\$0.14	\$0.11	\$0.12	\$0.09	\$0.09	\$0.09
Operating Cost Contribution	\$/GGE	\$0.58	\$0.57	\$0.57	\$0.48	\$0.47	\$0.36	\$0.36	\$0.35
Enzyme Loading	mg/g cellulose	12	12	12	12	12	10	10	10
Fermentation, Catalytic Conversion, and Upgrading to Fuels									
Total Cost Contribution	\$/GGE	\$1.39	\$1.57	\$1.62	\$1.45	\$1.47	\$1.42	\$1.42	\$0.97
Capital Cost Contribution	\$/GGE	\$0.52	\$0.67	\$0.69	\$0.59	\$0.61	\$0.56	\$0.58	\$0.48
Operating Cost Contribution	\$/GGE	\$0.87	\$0.90	\$0.93	\$0.86	\$0.86	\$0.85	\$0.84	\$0.49
Bioconversion Volumetric Productivity	g/L/hour	1.7	1.1	1.1	1.4	1.4	1.4	1.4	2.6

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin-Design Case)
Glucose to Product [Total Glucose Utilization] ^c	%	86% [100%]	95% [100%]	95% [100%]	96% [100%]	96% [100%]	96% [100%]	96% [100%]	95% [98%]
Xylose to Product [Total Xylose Utilization] ^c	%	89%	90%	90% [92%]	89%	89% [92%]	89% [92%]	89%	90% [92%]
Arabinose to Product [Total Arabinose Utilization] ^c	%	0% [0%]	0% [0%]	0% [0%]	0% [0%]	0% [0%]	0% [0%]	0% [0%]	85% [89%]
Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.44 (0.42)	0.48 (0.46)	0.48 (0.46)	0.49 (0.46)	0.49 (0.46)	0.47 (0.45)	0.47 (0.45)	0.47 (0.45)
Fermentation Intermediate Product Recovery	wt %	99.70%	96.80%	96.80%	97.65%	97.65%	97.70%	97.70%	96.40%
Aqueous BDO Upgrading: Weight Hourly Space Velocity (WHSV)	hr ⁻¹	1	1	1	1	1	1	1	2
Aqueous BDO Upgrading: Per-Pass Conversion	wt % to desired products	89%	90%	90%	100%	100%	100%	100%	100%
Oligomerization: WHSV	hr ⁻¹	1	1	1	1	1	1	1	1
Oligomerization: Per-Pass Conversion	wt % to desired	100%	100%	100%	100%	100%	100%	100%	100%
Hydrotreating: WHSV	hr ⁻¹	5	5	5	5	5	5	5	5
Hydrotreating: Per-Pass Conversion	wt % to desired	100%	100%	100%	100%	100%	100%	100%	100%
Lignin Processing to Coproduct									
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$3.46	\$0.00	\$2.92	\$0.00	\$2.40	(\$3.00)
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$2.86	\$0.00	\$2.39	\$0.00	\$2.13	\$1.01
Operating Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.60	\$0.00	\$0.53	\$0.00	\$0.28	(\$4.01)
Solid Deconstruction to Soluble Lignin	wt % BCD lignin feed	-	-	85% ^e	-	85% ^e	-	85% ^e	53%
Convertible Components in Soluble Lignin	wt % of total soluble lignin (APL + BCD)	-	-	16%	-	16%	-	16%	98%

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin-Design Case)
Muconic Acid Process Yield from Lignin	g/g soluble lignin	-	-	0.15	-	0.16	-	0.16	1.59
Muconic Acid Metabolic Yield from Lignin	g/g lignin consumed	-	-	0.93	-	0.93	-	0.93	0.93
Overall Carbon Upgrading Efficiency to Coproduct ^d	mol%	-	-	3.80%	-	3.80%	-	4.00%	27.80%
Muconic Acid Productivity	g/L/h	-	-	0.06	-	0.06	-	0.06	1
Adipic Acid Production	MMlb/yr	-	-	29	-	30	-	29	193
Balance of Plant									
Total Cost Contribution	\$/GGE	\$1.80	\$1.70	\$1.95	\$1.43	\$1.50	\$1.12	\$1.38	\$0.79
Capital Cost Contribution	\$/GGE	\$1.32	\$1.51	\$1.35	\$1.25	\$1.11	\$1.07	\$1.00	\$0.80
Operating Cost Contribution	\$/GGE	\$0.48	\$0.19	\$0.60	\$0.18	\$0.39	\$0.05	\$0.38	(\$0.01)

^a FY 2018–FY 2020 lignin conversion SOT cases based on actual black liquor/BCD hydrolysate experiments. Higher productivities have been observed based on model lignin monomers.⁵⁶

^b Feedstock costs shown here based on a 5% “ash equivalent” and 20% “moisture equivalent” basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash and moisture “dockage” costs for each year.

^c First number represents sugar conversion to desired product (BDO/acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).

^d Includes fermentation of all convertible components, product recovery (crystallization) efficiencies, and hydrogenation yields to adipic acid (overall convertible C to adipic acid).

^e SOT assumes only post-enzymatic hydrolysis lignin solids are routed through BCD; target cases route both lignin solids and DMR liquor through BCD.

“Solubilized” lignin remains low in convertible components for SOT cases relative to future targets, translating to lower overall carbon efficiency to adipic acid coproduct.

⁵⁶ Davis et al. 2021, <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

Biochemical Conversion via Mixed-Acids Intermediate Design Case

This design provides a second option for assessing the progress of technologies used in the dry feedstock conversion via the low-temperature and upgrading pathway. Research into this pathway helps identify challenges in biomass deconstruction, hybrid biochemical and catalytic conversion approaches, innovative separations of desired intermediates, and lignin upgrading.

Figure 23 shows the SOT and projected future production costs for the mixed-acids design broken into feedstock and conversion contributions.^{57,58}

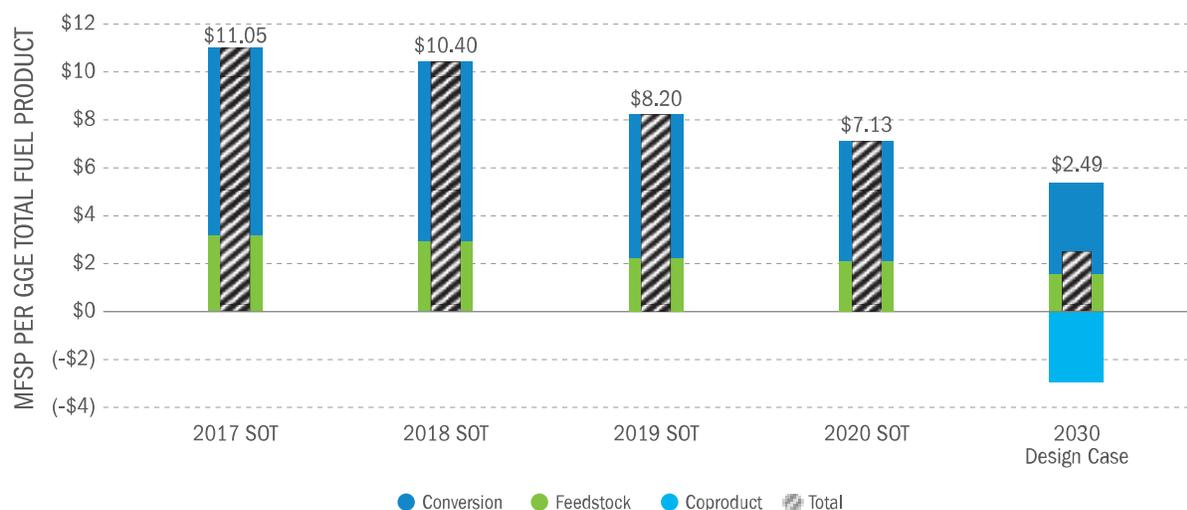


Figure 23: Cost contribution of feedstocks and conversion for hydrocarbon biofuels via the mixed-acid design

Conversion

This conversion design case uses DMR pretreatment of corn stover, followed by treatment with cellulase and hemicellulose enzymes in a novel continuous enzymatic hydrolysis process with integrated solids removal. The sugar stream is concentrated for fermentation with an engineered *Clostridium* organism to produce acetic acid and butyric acids. These mixed-acids intermediates are recovered continuously from the fermentation broth via a membrane and extraction system prior to further purification. The resulting acids are catalytically upgraded, undergoing ketonization, condensation, and hydrodeoxygenation to produce jet- and diesel-range hydrocarbon fuels. Lignin streams from pretreatment and continuous enzymatic

⁵⁷ Davis et al. 2021, <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

⁵⁸ Davis et al. 2020, <https://www.nrel.gov/docs/fy20osti/76567.pdf>.

hydrolysis filtration are commingled and upgraded to an adipic acid coproduct, whose revenue reduces net MFSP.

Figure 24 shows that many of the key cost drivers for this design are very similar to those in the 2,3-BDO intermediate design case, which illustrates how technological improvements for either of these designs would likely translate into cost improvements for a larger number of processes beyond these two configurations.

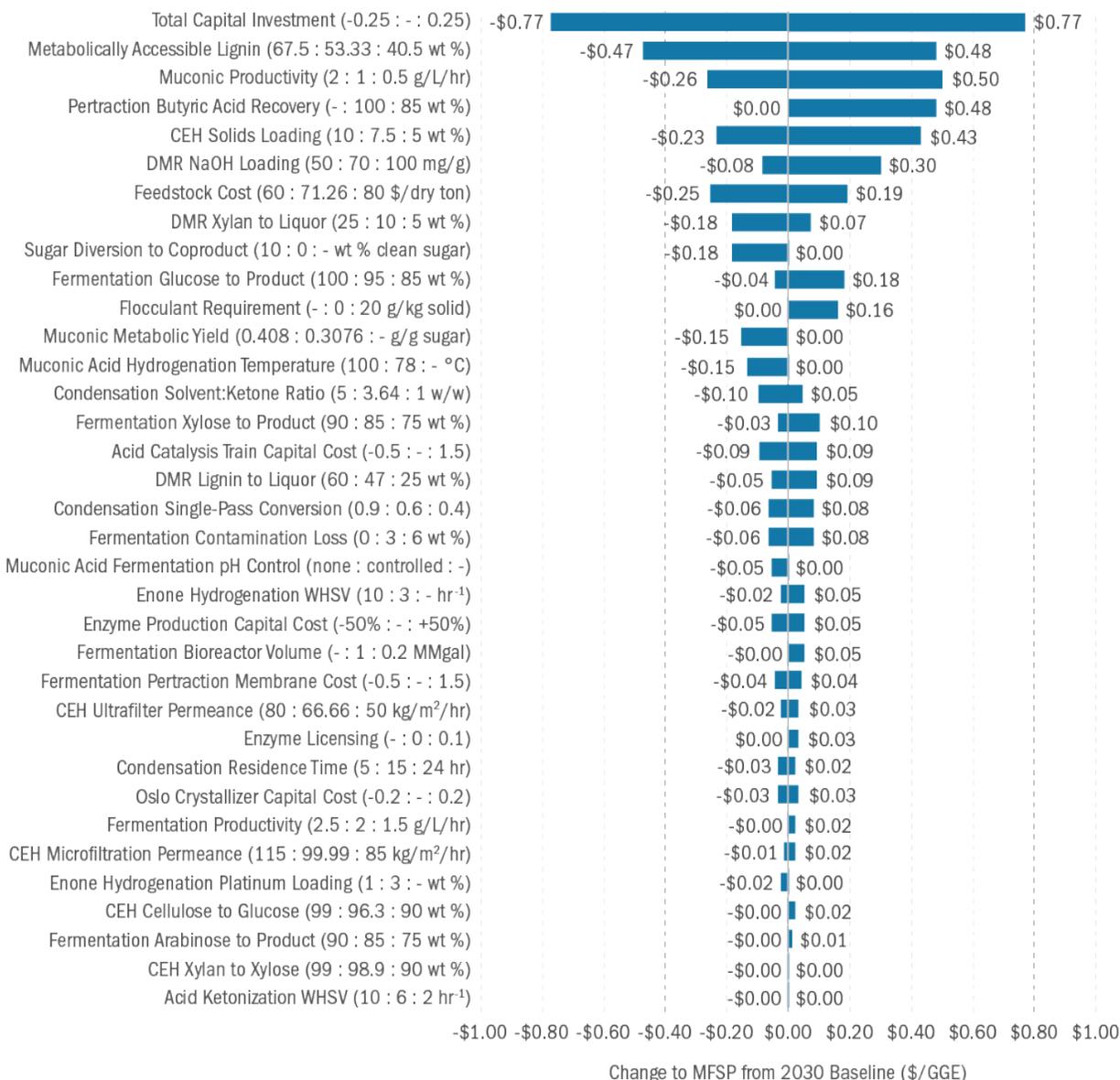


Figure 24: Major cost factors in the production of hydrocarbon biofuels via the mixed-acid intermediate design case

This design helps BETO identify a number of additional key areas for achieving future cost goals. For example, the fermentation to produce the mixed-acids intermediate is very closely integrated with acids recovery. Work within the Bioprocessing Separations Consortium has indicated that butyric acid more readily separates in the extractive separation process and that product yields are significantly higher when performed at a low pH (pH 5 and lower). To this end, BETO is prioritizing innovative approaches to simultaneously improve separation efficiency of the acids during fermentation, genetically engineer the organism to function effectively under acidic conditions, and prioritize producing butyric acid. This continuous extraction approach also requires a novel fermentation configuration, improvements in long-term organism viability, and development of ways to avoid extraction membrane fouling to meet future year cost targets (for reference, see the appendix, barriers Ct-D and Ct-O).

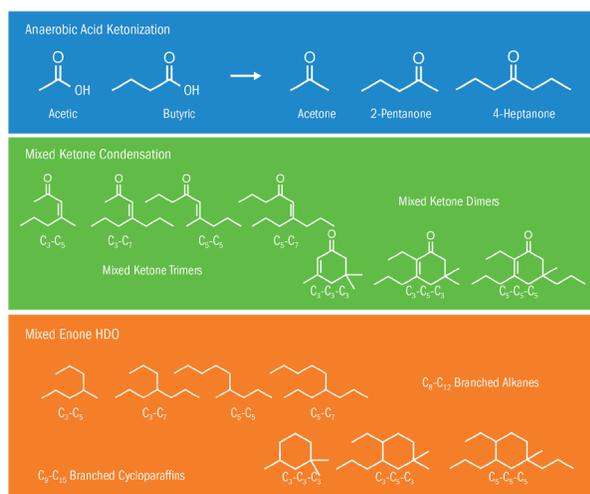


Figure 25: Mixed-acid catalytic upgrading reactions

Sensitivity analysis also identifies that following carboxylic acids purification, subsequent catalytic steps are key cost contributors. While the top-level barriers are similar to those discussed in the 2,3-BDO intermediate design case (for reference, see the appendix, barriers Ct-E, Ct-F, and Ct-G), in this design they are applied to significantly different chemical upgrading steps. In the catalytic first step, these acids can be coupled via ketonization. This step shows a further advantage of butyric acid, as each ketonization step results in the loss of a CO₂ equivalent, giving butyric acid

higher carbon efficiency compared to butyric/acetic or acetic/acetic acid coupling. ChemCatBio is developing catalysts capable of high yields irrespective of the acids ratios produced in the fermentation processes. After ketonization, efforts focus on decreasing the process capital intensity by combining the dehydration and reduction reactions in a single reactor. Like the ketonization catalytic steps, significant improvements can be achieved by developing catalysts that react the same regardless of the ketones supplied to the reactor (Figure 25).

Figure 26 and Table 19 show the cost contribution of conversion unit operations for this design case. Many additional early-stage research areas are part of BETO's broader strategy to reach future cost and performance goals, but are not reflected in the current modeled costs for this design.

Improvements to the MFSP for the mixed-acids case in 2020 primarily result from the changes to the deacetylation step described in the BDO section.

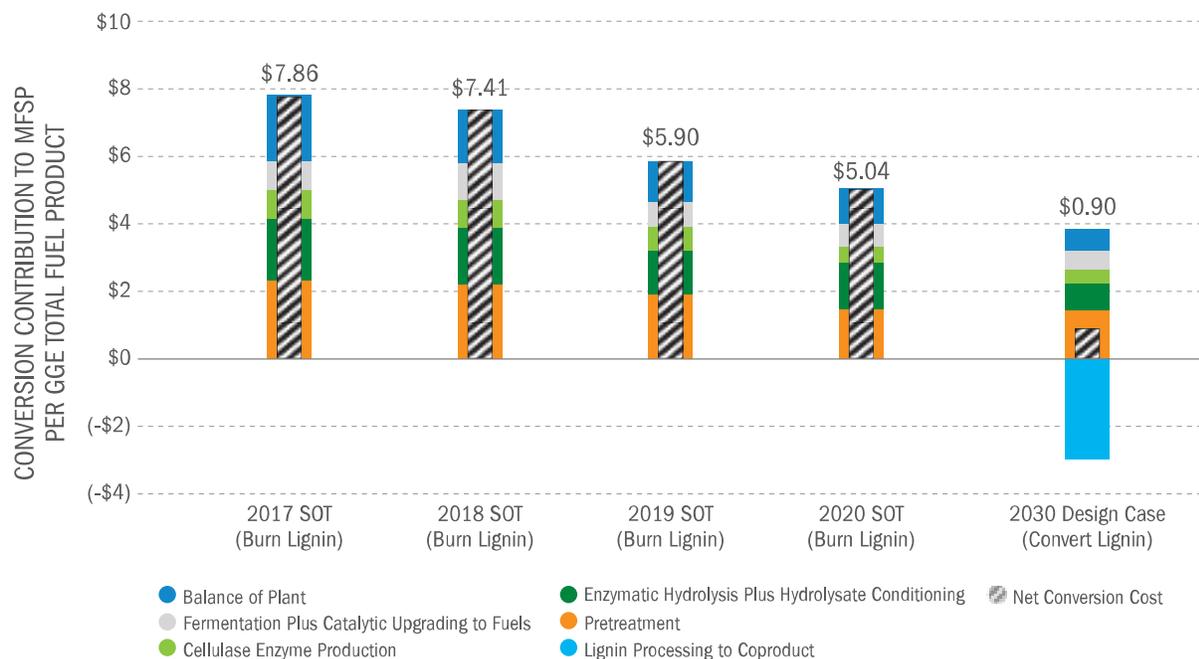


Figure 26: Conversion cost contributions for producing hydrocarbon biofuels via the mixed-acid intermediate design case

Table 19: Conversion Cost Contributions for Producing Hydrocarbon Biofuels via the Mixed-Acid Intermediate Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT (Burn Lignin)	2018 SOT (Burn Lignin)	2019 SOT (Burn Lignin)	2020 SOT (Burn Lignin)	2030 Projection (Convert Lignin-Design Case)
Pretreatment	\$2.34	\$2.19	\$1.89	\$1.47	\$1.42
Enzymatic Hydrolysis + Hydrolysate	\$1.82	\$1.69	\$1.34	\$1.35	\$0.81
Cellulase Enzyme Production	\$0.86	\$0.81	\$0.64	\$0.49	\$0.43
Fermentation + Catalytic Upgrading to Fuels	\$0.85	\$1.09	\$0.73	\$0.71	\$0.56
Lignin Processing to Coproduct	\$0.00	\$0.00	\$0.00	\$0.00	(\$2.97)
Balance of Plant	\$1.99	\$1.63	\$1.30	\$1.03	\$0.65
Net Conversion Contribution to MFSP	\$7.86	\$7.41	\$5.90	\$5.04	\$0.90

Table 20 presents the process efficiency metrics for the mixed-acids intermediate design case; Table 21 shows technical targets and a detailed breakdown of costs for this pathway.

Table 20: Process Efficiency Metrics for the Mixed-Acids Intermediate Design Case

Sustainability and Process Metrics	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Fuel Yield by Weight of Biomass	% w/w of dry biomass	8.1%	8.6%	8.6%	10.8%	10.8%	11.8%	11.8%	13.8%
Carbon Efficiency to Fuels	% C in feedstock	15.5%	16.3%	16.3%	20.6%	20.6%	22.5%	22.4%	26.2%
Carbon Efficiency to Lignin Coproduct	% C in feedstock	NA	NA	2.3%	NA	2.3%	NA	2.2%	14.4%
Net Electricity Import (Entire Process)	kWh/GGE	5.8	1.3	21.5	2.8	17.4	2.2	15.5	10.7
Purchased Natural Gas Import (Entire Process)	Btu/GGE (LHV)	0	15,790	15,790	11,803	11,803	11,064	11,035	9,055

^a FY 2018–FY 2020 lignin conversion SOT cases based on actual black liquor/BCD hydrolysate experiments. Higher productivities have been observed based on model lignin monomers.⁵⁹

Table 21: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via the Mixed-Acid Intermediate Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016
Projected MFSP	\$/GGE	\$11.05	\$10.40	\$14.66	\$8.20	\$11.47	\$7.13	\$10.02	\$2.49
Feedstock Contribution	\$/GGE	\$3.19	\$2.99	\$2.99	\$2.30	\$2.30	\$2.08	\$2.09	\$1.59

⁵⁹ Davis et al. 2021, <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Conversion Contribution	\$/GGE	\$7.86	\$7.41	\$11.67	\$5.90	\$9.17	\$5.04	\$7.93	\$0.90
Total Gasoline Equivalent Yield	GGE/dry ton	26.3	28	28	35.3	35.3	38.5	38.4	44.8
Adipic Acid Coproduct Yield	lb/dry ton biomass	0	0	41	0	42	0	40	259
Feedstock									
Total Cost Contribution	\$/GGE	\$3.19	\$2.99	\$2.99	\$2.30	\$2.30	\$2.08	\$2.09	\$1.59
Capital Cost Contribution	\$/GGE	NA	NA	NA	NA	NA	NA	NA	NA
Operating Cost Contribution	\$/GGE	\$3.19	\$2.99	\$2.99	\$2.30	\$2.30	\$2.08	\$2.09	\$1.59
Feedstock Cost ^b	\$/dry ton	\$83.90	\$83.67	\$83.67	\$81.37	\$81.37	\$80.10	\$80.10	\$71.26
Pretreatment									
Total Cost Contribution	\$/GGE	\$2.34	\$2.19	\$2.21	\$1.89	\$1.90	\$1.47	\$1.48	\$1.42
Capital Cost Contribution	\$/GGE	\$0.55	\$0.52	\$0.54	\$0.42	\$0.43	\$0.44	\$0.45	\$0.37
Operating Cost Contribution	\$/GGE	\$1.79	\$1.67	\$1.67	\$1.47	\$1.47	\$1.03	\$1.03	\$1.05
Method	-	DMR	DMR	DMR	DMR	DMR	DMR	DMR	DMR
Solids Loading	wt %	20%	20%	20%	20%	20%	20%	20%	30%
Temperature	°C	92	92	92	90	90	90	90	92
Reactor Mode	batch versus counter-current	batch	batch	batch	batch	batch	batch	batch	counter-current
Total Caustic (NaOH) [Na ₂ CO ₃]	mg/g dry biomass	70	70	70	80	80	24 [80]	24 [80]	70
Net Solubilized Lignin to Liquor	%	47%	47%	47%	50%	50%	20%	20%	47%
Net Solubilized Glucan to Liquor	%	2%	2%	2%	2%	2%	3%	3%	2%
Net Solubilized Xylan to Liquor	%	17%	17%	17%	16%	16%	12%	12%	10%

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Net Solubilized Arabinan to	%	46%	46%	46%	46%	46%	48%	48%	30%
Enzymatic Hydrolysis									
Total Cost Contribution	\$/GGE	\$1.82	\$1.69	\$1.73	\$1.34	\$1.37	\$1.35	\$1.38	\$0.81
Capital Cost Contribution	\$/GGE	\$0.92	\$0.86	\$0.90	\$0.69	\$0.72	\$0.70	\$0.73	\$0.47
Operating Cost Contribution	\$/GGE	\$0.90	\$0.83	\$0.83	\$0.65	\$0.65	\$0.65	\$0.65	\$0.34
Hydrolysis Configuration	batch versus continuous	batch	batch	batch	batch	batch	batch	batch	continuous
Total Solids Loading to	wt %	20%	20%	20%	20%	20%	20%	20%	7.60%
Enzymatic Hydrolysis Batch Time	days	5	5	5	5	5	7	7	continuous
Hydrolysis Glucan to Glucose	%	78%	78%	78%	84%	84%	88%	88%	96%
Hydrolysis Xylan to Xylose	%	85%	85%	85%	82%	82%	93%	93%	99%
Sugar Loss (into Solid Stream after Enzymatic Hydrolysis)	%	5%	5%	5%	5%	5%	5%	5%	1%
Cellulase Enzyme Production									
Total Cost Contribution	\$/GGE	\$0.86	\$0.81	\$0.81	\$0.64	\$0.64	\$0.49	\$0.49	\$0.43
Capital Cost Contribution	\$/GGE	\$0.17	\$0.16	\$0.16	\$0.12	\$0.13	\$0.10	\$0.10	\$0.09
Operating Cost Contribution	\$/GGE	\$0.70	\$0.65	\$0.65	\$0.52	\$0.52	\$0.39	\$0.39	\$0.34
Enzyme Loading	mg/g cellulose	12	12	12	12	12	10	10	10
Fermentation, Catalytic Conversion, and Upgrading to Fuels									
Total Cost Contribution	\$/GGE	\$0.85	\$1.09	\$1.12	\$0.73	\$0.75	\$0.71	\$0.73	\$0.56

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Capital Cost Contribution	\$/GGE	\$0.51	\$0.63	\$0.66	\$0.43	\$0.44	\$0.42	\$0.43	\$0.33
Operating Cost Contribution	\$/GGE	\$0.34	\$0.46	\$0.46	\$0.31	\$0.30	\$0.30	\$0.30	\$0.23
Bioconversion Volumetric Productivity	g/L/hour	1.1	0.3	0.3	0.6	0.6	0.6	0.6	2
Glucose to Product [Total	%	86% [100%]	90% [95%]	90% [95%]	95% [98%]	95% [98%]	95% [98%]	95% [98%]	95% [100%]
Xylose to Product [Total Xylose	%	82% [100%]	77% [90%]	77% [90%]	95% [98%]	95% [98%]	95% [98%]	95% [98%]	85% [100%]
Arabinose to Product [Total	%	82% [100%]	32% [38%]	32% [38%]	20% [29%]	20% [29%]	20% [29%]	20% [29%]	85% [87%]
Bioconversion Metabolic Yield	g/g sugars	0.44 (0.44)	0.45 (0.41)	0.45 (0.41)	0.46 (0.44)	0.46 (0.44)	0.45 (0.44)	0.45 (0.44)	0.45 (0.43)
Fermentation Intermediate Product Recovery	wt %	60% (C ₂), 95% (C ₄)	60% (C ₂), 95% (C ₄)	60% (C ₂), 95% (C ₄)	76% (C ₂), 98% (C ₄)	76% (C ₂), 98% (C ₄)	76% (C ₂), 98% (C ₄)	76% (C ₂), 98% (C ₄)	100% (C ₄)
Ketonization: WHSV	hr ⁻¹	6	4	4	4	4	4	4	6
Ketonization: Per-Pass	wt % to desired	100%	100%	100%	100%	100%	100%	100%	100%
Condensation: WHSV	hr ⁻¹	0.5	10-hr residence	15-hr batch					
Condensation: Overall	wt % to desired	81%	92%	92%	92%	92%	92%	92%	60% pp
Hydrotreating: WHSV	hr ⁻¹	3	4.7	4.7	4.7	4.7	4.7	4.7	3
Hydrotreating: Per-Pass	wt % to desired	100%	100%	100%	100%	100%	100%	100%	100%
Lignin Processing to Coproduct									
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$4.05	\$0.00	\$3.26	\$0.00	\$2.71	(\$2.97)
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$3.30	\$0.00	\$2.61	\$0.00	\$2.34	\$0.96
Operating Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.75	\$0.00	\$0.65	\$0.00	\$0.37	(\$3.93)

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT Burn Lignin	2018 SOT Burn Lignin	2018 SOT Convert Lignin ^a	2019 SOT Burn Lignin	2019 SOT Convert Lignin ^a	2020 SOT Burn Lignin	2020 SOT Convert Lignin ^a	2030 Projection (Convert Lignin–Design Case)
Solid Deconstruction to Soluble	wt % BCD lignin	-	-	85% ^e	-	85% ^e	-	85% ^e	53%
Convertible Components in Soluble Lignin	wt % of total soluble lignin (APL +BCD)	-	-	16%	-	16%	-	16%	98%
Muconic Acid Process Yield from Lignin	g/g soluble lignin	-	-	0.15	-	0.16	-	0.16	1.59
Muconic Acid Metabolic Yield	g/g lignin consumed	-	-	0.93	-	0.93	-	0.93	0.93
Overall Carbon Upgrading Efficiency to Coproduct ^d	mol%	-	-	4.00%	-	4.00%	-	4.00%	30.10%
Muconic Acid Productivity	g/L/h	-	-	0.06	-	0.06	-	0.06	1
Adipic Acid Production	MMlb/yr	-	-	30	-	31	-	29	187
Balance of Plant									
Total Cost Contribution	\$/GGE	\$1.99	\$1.63	\$1.75	\$1.30	\$1.25	\$1.02	\$1.15	\$0.65
Capital Cost Contribution	\$/GGE	\$1.64	\$1.81	\$1.41	\$1.36	\$1.07	\$1.20	\$0.96	\$0.79
Operating Cost Contribution	\$/GGE	\$0.36	(\$0.18)	\$0.34	(\$0.07)	\$0.18	(\$0.18)	\$0.19	(\$0.14)

^a FY 2018–FY 2020 lignin conversion SOT cases based on actual black liquor/BCD hydrolysate experiments. Higher productivities have been observed based on model lignin monomers.⁶⁰

^b Feedstock costs shown here based on a 5% “ash equivalent” and 20% “moisture equivalent” basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash and moisture “dockage” costs for each year.

⁶⁰ Davis et al. 2021, <https://www.nrel.gov/docs/fy21osti/79930.pdf>.

- ° First number represents sugar conversion to desired product (BDO/acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).
- ° Includes fermentation of all convertible components, product recovery (crystallization) efficiencies, and hydrogenation yields to adipic acid (overall convertible C to adipic acid).
- ° SOT assumes only post-enzymatic hydrolysis lignin solids are routed through BCD; target case routes both lignin solids and DMR liquor through BCD. “Solubilized” lignin remains low in convertible components for SOT cases relative to future targets, translating to lower overall carbon efficiency to adipic acid coproduct.

Integration and Scale-Up

Unit operations and process steps developed at lab-scale R&D for both the BDO and mixed-acid designs must be integrated and tested to verify that technical targets can be achieved when run as an integrated process. Examples of key integration challenges for these pathways include:

- Reliable and robust operations of feed handling systems, including feeding herbaceous feedstocks into the pretreatment reactor (for reference, see the appendix, barrier SDI-A).
- Optimizing the DMR process to reduce refining operation energy requirements.
- Devising control strategies to improve operability and process flexibility (for reference, see the appendix, barrier SDI-A).
- The influence of inorganic species present in the feedstock on conversion efficiency to desired products (for reference, see the appendix, barrier SDI-F).
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier SDI-D).
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feed (for reference, see the appendix, barrier SDI-H).

Integration challenges unique to the BDO pathway include:

- Developing efficient product separation and purification schemes for separating solids and optimal separation of desired intermediates and products.
- Addressing the buildup of impurities in process recycle systems and its impact on catalyst performance and regeneration requirements for the conversion of 2,3-BDO to hydrocarbon fuels (for reference, see the appendix, barrier SDI-F).

Integration challenges unique to the mixed-acids pathway include:

- Developing efficient product separation and purification schemes for the separation of lignin and cellulosic sugars from the hydrolysate, and optimal continuous separation of desired intermediates and products to improve quality.
- Addressing buildup of impurities in process recycle systems and their impact on catalyst performance and regeneration requirements for the conversion of carboxylic acid mixtures to hydrocarbon fuels (for reference, see the appendix, barrier SDI-F).

Supply Chain Sustainability Analysis

The SCSA results include both BDO and mixed-acid intermediate pathway designs. Both designs coproduce a significant amount of adipic acid and recover sodium sulfate salt from wastewater

treatment that could displace products produced from conventional methods. The feedstock blends used in the SCSA are the same as those listed in the footnotes to Table 15.

Table 22 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions of the renewable hydrocarbon fuels from these low-temperature conversion designs. Coproducts in Table 22 and Figure 27 are accounted for using the displacement method.⁶¹ Under this method, all the chemical use and associated emissions are attributed to the hydrocarbon fuels. Meanwhile, the renewable diesel fuel gets all the credits from the adipic acid coproduct displacing conventional fossil-based adipic acid. In addition, bio-based adipic acid generates GHG emission credits by sequestering biogenic carbon given that its carbon is derived from herbaceous biomass.

Figure 27A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO_{2e}/MJ, of fuel produced compared to a life cycle carbon intensity of 91 g CO_{2e}/MJ for petroleum diesel. Adipic acid production has a significant impact on GHG emissions in the 2030 target case because of a significant increase in adipic acid yield, generating -261 to -279 g CO_{2e}/MJ GHG emission credits from both displacing conventional adipic acid (-222 to -238 g CO_{2e}/MJ) and biogenic carbon sequestration (-39 to -41 g CO_{2e}/MJ). As a result, supply chain GHG emission intensities of renewable diesel are -148 g CO_{2e}/MJ in both the acids and BDO intermediate pathways.

Figure 27B shows that both acids and BDO cases have higher water consumption relative to that of petroleum diesel, owing to significant embedded water consumption associated with the process chemical use, as well as to the process makeup water requirement during the biochemical conversion. Water consumption is reduced in the 2030 design case for both the acids and BDO intermediates scenarios due to improved biofuel and coproduct yields and process energy and chemical consumption reductions.

Figure 27C shows that total NO_x emissions could be lower than those of petroleum diesel in the 2030 design case when the significant coproducts displacement credits are included. Significantly higher coproduct yields contribute to a large reduction in total NO_x emissions in the 2030 design case for both the acids and BDO intermediates scenarios, compared to the SOT case.

⁶¹ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 22: Supply Chain Sustainability Metrics for Renewable Diesel via the Low-Temperature Pathway by Displacement Method

	2018 SOT				2019 SOT				2020 SOT				2030 Design Case		Petroleum Diesel
	Via Acids (Burn Lignin)	Via Acids (Convert Lignin)	Via BDO (Burn Lignin)	Via BDO (Convert Lignin)	Via Acids (Burn Lignin)	Via Acids (Convert Lignin)	Via BDO (Burn Lignin)	Via BDO (Convert Lignin)	Via Acids (Burn Lignin)	Via Acids (Convert Lignin)	Via BDO (Burn Lignin)	Via BDO (Convert Lignin)	Via Acids (Convert Lignin)	Via BDO (Convert Lignin)	
Biofuel Yield															
MMBtu/dry ton	3.2	3.2	3.8	3.8	4.1	4.1	4.4	4.5	4.5	4.5	4.8	4.8	5.2	5.0	
Fossil Energy Consumption^a															
MJ/MJ	1.41	2.15	1.54	2.51	1.25	1.74	1.46	2.14	0.8	1.2	0.9	1.0	-1.3	-1.5	1.2
Net Energy Balance^b															
MJ/MJ	-0.41	-1.15	-0.54	-1.51	-0.25	-0.74	-0.46	-1.14	0.2	-0.2	0.1	0.0	2.3	2.5	
GHG Emissions															
g CO ₂ e/MJ	103	143	111	158	91	112	104	132	75 (-18%)	97 (7%)	89 (-2%)	119 (30%)	-148 (-263%)	-148 (-262%)	91
g CO ₂ e/GGE	12,612	17,538	13,657	19,358	11,088	13,663	12,777	16,151	9,136	11,917	10,941	14,521	-18,174	-18,101	11,157
Water Consumption															
gal/MJ	0.6	0.6	0.3	0.4	0.5	0.5	0.3	0.3	0.4	0.4	0.2	0.3	0.4	0.3	0.02
gal/GGE	69	76	43	49	56	60	38	42	45.6	48.6	28.4	31.7	38.4	29.3	2.7
Total NO_x Emissions															
g NO _x /MJ	0.22	0.10	0.12	0.12	0.19	0.09	0.18	0.10	0.13	0.03	0.12	0.05	-0.65	-0.70	0.06
g NO _x /GGE	27.0	12.5	24.4	15.0	23.0	10.5	22.0	12.7	15.3	4.0	14.8	6.4	-80.0	-86.0	7.0
Urban NO_x Emissions^c															
g NO _x /MJ	0.035	0.049	0.036	0.045	0.034	0.044	0.035	0.041	0.03	0.04	0.03	0.04	0.02	0.02	0.03

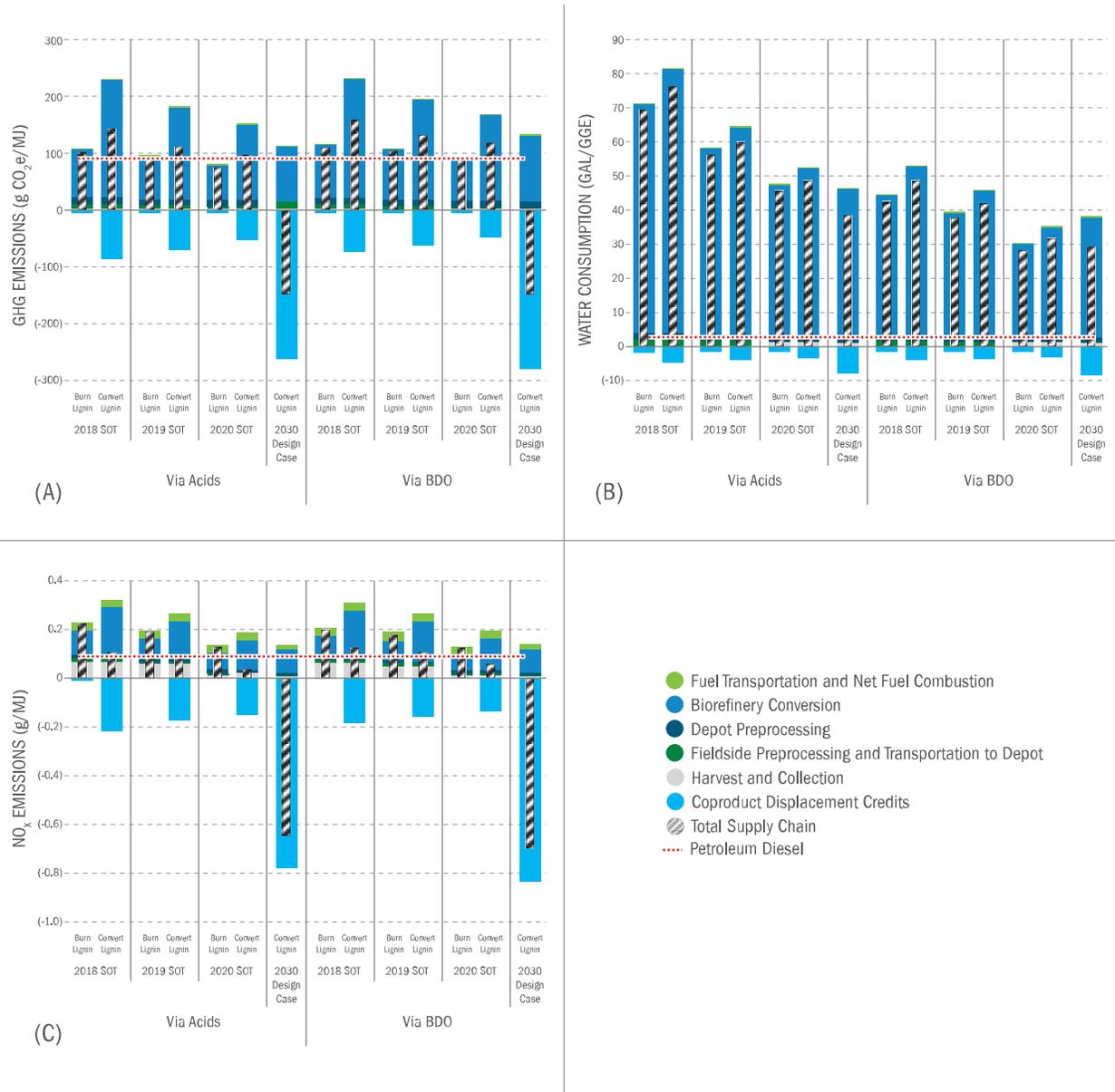
g NO _x /GGE	4.2	6.0	4.4	5.5	4.2	5.4	4.3	5.1	3.8	4.9	4.0	4.6	2.8	2.8	3.5
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Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT, 2030 design cases, and petroleum reference emissions and water consumption values are based on the GREET2020 model. Prior year SOTs are based on the GREET2019 model.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.



Figures 27A–27C: Supply chain for renewable diesel via low-temperature design cases for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions⁶²

Alternative SCSA Methodologies

A key issue in dealing with coproducts from these designs is how to capture their environmental impacts, especially under the current, fuel-focused GHG regulations. In Table 22 and Figure 27, coproducts are accounted for using a displacement method that attributes all the supply chain

⁶² Negative GHG emissions in the 2030 designs are mainly attributed to using the displacement method for accounting for coproducts. GHG emission reduction results estimated with the displacement method should be interpreted with caution. More information is available in the full text of this report, and this analysis will be subject to additional review moving forward as the effects of coproducts on SCSA metrics are better understood.

emission burdens to the fuel product, but also attributes all avoidance of emissions that otherwise would have taken place with the incumbent technology to produce the coproduct—or coproduct displacement credit—to the fuel product. As seen for the 2030 design, this creates large negative emissions values for pathways utilizing coproducts, which may overestimate the actual benefits that these pathways would provide.

Beginning with the 2020 SCSA, coproducts are also accounted for using a method that uses the masses and market values of the finished products as the allocation basis at the conversion process level. This process-level allocation method generates product-specific results for biofuel and non-fuel coproducts, respectively. As a result, this method results in only minor emissions savings for the fuel product compared to the petroleum incumbent, and represents a large departure from the values obtained through the displacement method. After internal discussions during 2020 between BETO and Argonne National Laboratory (ANL), it was determined that both methods have pros and cons, and there are not currently enough data available from actual biorefinery facilities to conclusively suggest that one method should be used over the other.

As a result of these internal discussions, ANL added a third method. This method is a system-level expansion of the process-level allocation method. This method assesses the total emissions from producing both the biofuel and non-fuel bio-based coproducts, as well as the total emission reduction from both the biofuel and coproducts, displacing their respective incumbent counterparts. BETO and ANL believe this biorefinery-level method provides a more complete picture of biorefinery emission performance and may more accurately reflect the actual impact of coproducts on biorefinery systems. BETO and ANL will continue to discuss how to accurately reflect the SCSA impact of coproducts. For transparency, ANL has published all three methods for each pathway that contains a significant portion of the carbon going toward coproducts. More information on these methods and results can be found in ANL's 2020 SCSA publication.⁶³

Table 23 presents biorefinery-level fossil energy consumption and GHG emission results based on a 2,000-dry-metric-ton/day facility operating at 90% process uptime. The results are presented independently for both renewable diesel and adipic acid product, then summed to provide overall biorefinery performance. These results demonstrate the potential of a 2,000-dry-metric-ton/day biochemical-based biorefinery to provide nearly one million metric tons/year of GHG reduction in the 2030 design case.

⁶³ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 23: Biorefinery-Level Emissions and Consumption Reductions Summary for Biochemical Pathways Using Mass-Based Allocation

		2020 SOT				2030 Design	
		Burn Lignin		Lignin Upgrading		Lignin Upgrading	
		Via Acids	Via BDO	Via Acids	Via BDO	Via Acids	Via BDO
Plant Capacity							
Biomass Processed	dry metric ton/yr	657,000	657,000	657,000	657,000	657,000	657,000
Renewable Diesel Production	MMBtu/yr	3,232,585	3,484,949	3,226,642	3,496,967	3,771,200	3,633,868
Adipic Acid Production	metric ton/yr	-	-	13,194	12,937	84,911	87,449
Fossil Energy Consumption Reductions^a							
By Renewable Diesel Production ^b	MMBtu/yr	-1,269,572	-992,461	313,265	-137,369	-1,872,456	-1,959,167
By Adipic Acid Production ^b	MMBtu/yr	-	-	-338,993	-518,460	-7,724,814	-7,742,671
Total Reduction	MMBtu/yr	-1,269,572	-992,461	-25,728	-655,828	-9,597,271	-9,701,838
GHG Emission Reductions^a							
By Renewable Diesel Production ^b	metric ton CO ₂ e/yr	-56,286	-6,497	75,799	161,975	-130,507	-108,203
By Adipic Acid Production ^b	metric ton CO ₂ e/yr	-	-	-54,673	-60,640	-822,260	-807,584
Total Reduction	metric ton CO₂e/yr	-56,286	-6,497	21,126	101,335	-952,767	-915,787

^a Negative values indicate reductions while positive values indicate increases.

^b The contributions of renewable diesel and adipic acid production are based on mass-based process allocation.

Table 24 provides a comparison of the displacement and biorefinery-level emission methods. As discussed earlier, the displacement method attributes all emission impacts to the biofuel product. As a result, when significant coproduct GHG benefits are estimated, as is the case in the 2030 design, the result is a large -262% to -263% (via BDO and acids, respectively) reduction in GHG emissions relative to petroleum diesel. When emission impacts are allocated at the process level and combined at the biorefinery level, the net combined reduction for the 2030 design is estimated at -74% to -77% (via BDO and acids, respectively) relative to petroleum-based products. As indicated in Table 23, 88% of the GHG emission reduction benefit in the 2030 design results from production of bio-based adipic acid relative to fossil-based.

Table 24: Comparison of Biorefinery-Level and Displacement SCSA Methods for Biochemical Pathways Based on Percent Reduction (Increase) over Petroleum-Derived Products

Method Used	2020 SOT				2030 Design	
	Burn Lignin		Lignin Upgrading		Lignin Upgrading	
	Via Acids	Via BDO	Via Acids	Via BDO	Via Acids	Via BDO
Fossil Energy Consumption Reductions^a						
Displacement ^b	-33%	-24%	-1%	-16%	-212%	-222%
Biorefinery Level	-33%	-24%	0%	-11%	-64%	-64%
GHG Emission Reductions^a						
Displacement ^b	-18%	-2%	7%	30%	-263%	-262%
Biorefinery Level	-18%	-2%	5%	22%	-77%	-74%

^a Negative values indicate reductions while positive values indicate increases.

^b The displacement method may lead to distorted results if the amount of coproduct is significant.

Technology Pathways Using Wet Feedstocks

BETO tracks progress for technologies used in two pathways using wet feedstocks: (1) conversion via low-temperature process and upgrading and (2) conversion via high-temperature process and upgrading. Wet feedstocks, which include algal feedstocks and wet waste/biosolids, are suitable for conversion processes that can accept feedstocks (biomass that has undergone preprocessing) with higher than 50 wt % moisture content. As illustrated in Figure 28, pathways using algal feedstocks require significant improvements in feedstock production costs in contrast to wet wastes, where no feedstock cost reductions are needed to reach ultimate MFSP projections. This reflects the well-developed infrastructure for wet wastes produced by municipal wastewater treatment facilities. An alternative strategy to mitigate the risks of high algal feedstock costs relies on valuable coproduct generation. This approach has been used in past CAP pathway SOTs and is investigated for the first time in the AHTL pathway through the addition in 2020 of a sequential hydrothermal liquefaction (SEQHTL) 2020 SOT and accompanying projections. SEQHTL includes a preprocessing step that releases fermentable sugars to an aqueous phase while sending remaining oils and solids on to traditional hydrothermal liquefaction (HTL).

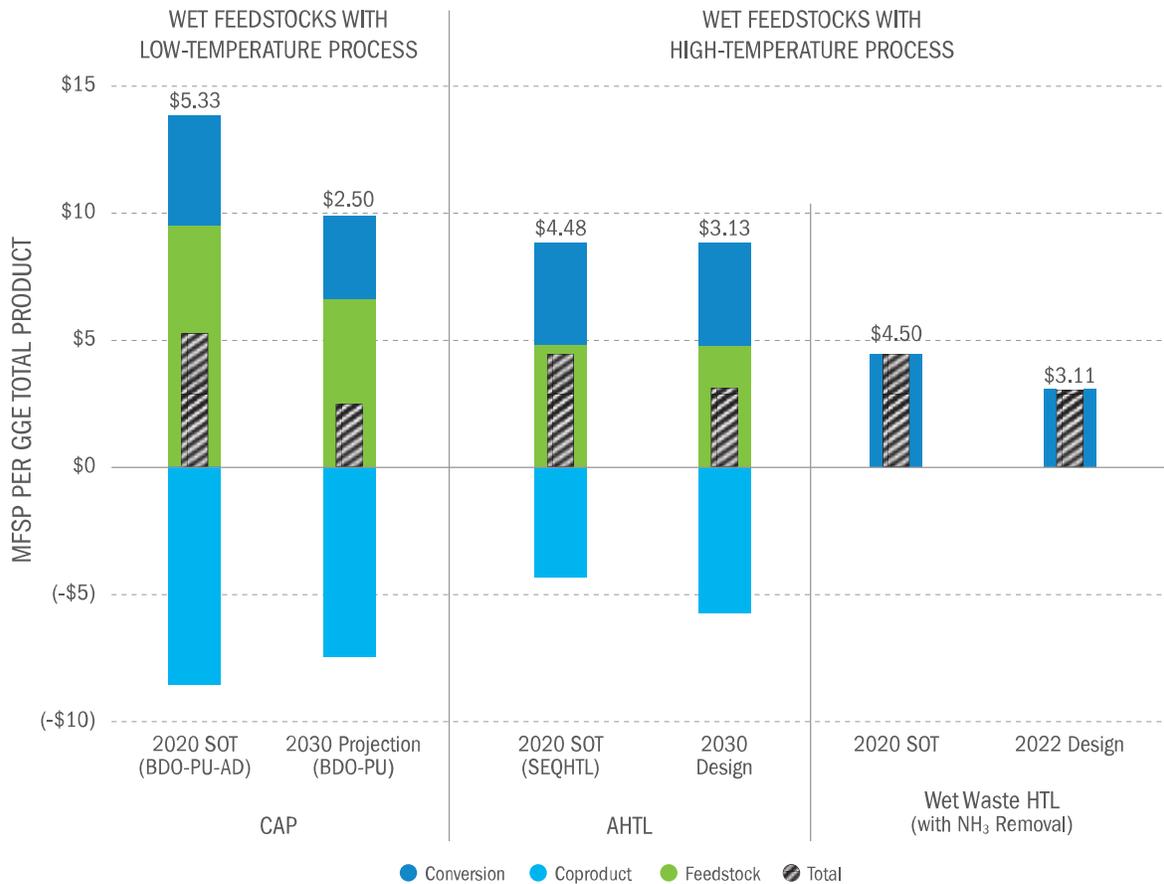


Figure 28: Cost breakdown for technology pathways using wet feedstocks

Algae Production

Both high- and low-temperature pathways using algal feedstock use the same biomass production configuration: the algae farm design.⁶⁴ This configuration identifies improvements needed for the cultivation and harvesting/dewatering (for reference, see the appendix, barrier Aft-D) of algal biomass grown photosynthetically in open, well-mixed, CO₂-enriched, low-cost ponds to reach cost goals expressed as minimum biomass selling prices (MBSPs).⁶⁵ Figure 29 and Table 25 show the progression of MBSP SOTs from 2015 to present (currently: 2020), as well as future projections for 2025 and 2030 that assume that R&D improvements toward design targets

⁶⁴ R. Davis, J. Markham, C. Kinchin, N. Grundl, E. C. D. Tan, and D. Humbird. *Process Design and Economics for the Production of Algal Biomass: Algal Biomass Production in Open Pond Systems and Processing Through Dewatering for Downstream Conversion*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-64772, 2016. <http://www.nrel.gov/docs/fy16osti/64772.pdf>.

⁶⁵ MBSP is the minimum selling price needed to produce algae at a specified return on investment such that the net present value of the production facility equals zero.

and underlying productivities shown in Table 26 have been achieved in a timely manner.⁶⁶ Progress in reducing MBSP from 2015 to present is attributable to increased annual average productivity realized in the respective cultivation campaigns. The FY 2020 SOT achieved an annual average productivity of >18 g/m²/day, more than double the initial 2015 value. While annual average productivity is a reliable, high-level metric, seasonal variations on productivity related to winter/spring/summer/fall climate progression strongly impact the amount of algae harvested in a given time, which has significant impacts on unit operations downstream of the cultivation ponds in terms of sizing and operability. Increases in productivity are attributable to the use of faster growing and more robust strains, novel management of the cultivation, and application of crop protection techniques, as described in the 2020 algae farm SOT technical report.⁶⁷

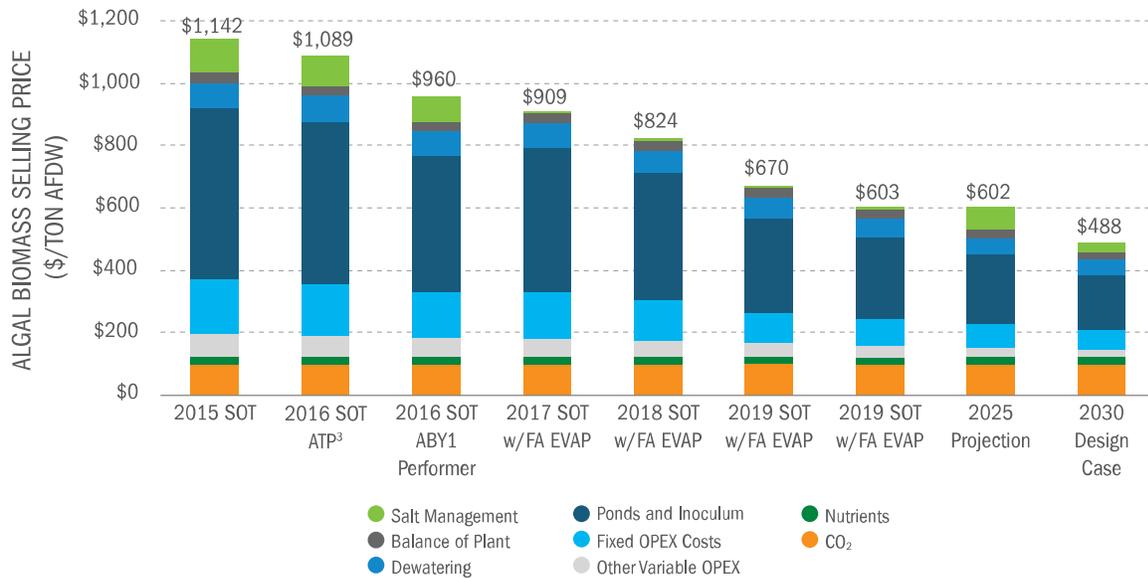


Figure 29: Cost contribution for algal biomass selling price by process area, assuming unlined ponds (pond liners increase costs; see Figure 30)⁶⁸

⁶⁶ The algae farm design assumes process integration with the conversion facility but models a stand-alone MBSP. The MBSP SOT is based on cultivation data furnished by the Algae Testbed Public-Private Partnership (ATP³), projects awarded under the Algal Biofuel Yield Funding Opportunity (ABY1), and the national laboratory consortium Development of Integrated Screening, Cultivar Optimization, and Verification Research (DISCOVER). All use comparable methodologies to those originally established by the ATP³ consortium. BETO requires in-house experimental data for critical variables in the design pathways to ensure results are publicly available, non-proprietary, and high quality, representing all seasons of the year in outdoor trials.

⁶⁷ R. Davis and B. Klein. *Algal Biomass Production via Open Pond Algae Farm Cultivation: 2020 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-79931, 2021. <https://www.nrel.gov/docs/fy21osti/79931.pdf>.

⁶⁸ The FY 2017–FY 2020 SOT bars are based on productivities demonstrated at the Arizona State University site using the Florida algae (FA) evaporation (EVAP) scenario to maintain continuity with the 2015 and 2016 SOT data that was collected from a Florida field site. The FY 2017–FY 2020 SOT cases also apply different assumptions for optimizing blowdown salt management costs, with future updates to apply salt management consistently for future projection cases as well. The biomass selling price is reported on an ash-free dry weight (AFDW) basis.

Table 25: Cost Contribution for Algal Biomass Selling Price by Process Area

\$/ton AFDW	2015 SOT	2016 SOT - ATP ³	2016 SOT - ABY1 Performer	2017 SOT w/FA EVAP	2018 SOT w/FA EVAP	2019 SOT w/FA EVAP	2020 SOT w/FA EVAP	2025 Projection	2030 Design
CO ₂	\$100	\$100	\$100	\$99	\$99	\$99	\$99	\$98	\$98
Nutrients	\$24	\$24	\$24	\$24	\$24	\$24	\$24	\$23	\$23
Other Variable Operating Expenses	\$71	\$68	\$59	\$58	\$53	\$42	\$39	\$31	\$25
Fixed Operating Expense Costs	\$177	\$167	\$144	\$149	\$132	\$101	\$88	\$77	\$63
Ponds + Inoculum	\$548	\$515	\$437	\$463	\$408	\$302	\$261	\$226	\$179
Dewatering	\$82	\$86	\$84	\$77	\$69	\$66	\$60	\$49	\$46
Balance of Plant	\$35	\$31	\$29	\$33	\$30	\$31	\$28	\$29	\$23
Salt Management	\$105	\$98	\$83	\$5	\$9	\$6	\$5	\$70	\$31
Total Algae Biomass Selling Price*	\$1,142	\$1,089	\$960	\$909	\$824	\$670	\$603	\$602	\$488

*Note: Total selling price may differ from column totals by \$1 due to the way the values were rounded.

Table 26: Unit Operation Cost Contribution Estimates and Technical Projections for Algae Farm

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT - ATP ^{3a}	2016 SOT - ABY1 ^a	2017 SOT ^{a,b} w/FA EVAP	2018 SOT ^{a,b} w/ FA EVAP	2019 SOT ^{a,b} w/ FA EVAP	2020 SOT ^{a,b} w/ FA EVAP	2025 Projection	2030 Design
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016
Minimum Biomass Selling Price	\$/ton AFDW	\$1,142	\$1,089	\$960	\$909	\$824	\$670	\$603	\$602	\$488
Production Cost	\$/ton AFDW	\$999	\$947	\$824	\$775	\$704	\$556	\$500	\$509	\$400
Harvest/Dewatering Cost	\$/ton AFDW	\$105	\$110	\$107	\$97	\$87	\$82	\$75	\$62	\$63
Other Cost (Facility Circulation,	\$/ton AFDW	\$38	\$32	\$28	\$36	\$33	\$32	\$28	\$32	\$25
Net Biomass Production Yield	ton AFDW/acre-yr	12.4	13.2	15.6	15	17	23.1	26.7	29.9	37.2
Total Farm Power Demand	kWh/ton AFDW	860	831	739	717	647	529	486	395	334

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT - ATP ^{3a}	2016 SOT - ABY1 ^a	2017 SOT ^{a,b} w/FA EVAP	2018 SOT ^{a,b} w/ FA EVAP	2019 SOT ^{a,b} w/ FA EVAP	2020 SOT ^{a,b} w/ FA EVAP	2025 Projection	2030 Design
Production										
Total Cost Contribution	\$/ton AFDW	\$999	\$947	\$824	\$775	\$704	\$556	\$500	\$509	\$400
Capital Cost Contribution	\$/ton AFDW	\$556	\$524	\$446	\$470	\$415	\$310	\$270	\$234	\$210
Operating Cost Contribution	\$/ton AFDW	\$443	\$424	\$379	\$305	\$289	\$245	\$230	\$275	\$190
Cultivation Productivity (Annual Average)	g/m ² /day AFDW	8.5	9.1	10.7	10.3	11.7	15.9	18.4	20	25
Seasonal Productivity	winter - spring - summer - fall (g/m ² /day)	5.0 - 11.4 - 10.9 - 6.8	5.0 - 11.1 - 13.3 - 7.0	4.8 - 13.0 - 17.5 - 7.8	5.5 - 13.2 - 14.1 - 8.5	7.7 - 15.2 - 15.4 - 8.5	6.5 - 18.7 - 27.1 - 11.4	8.3 - 18.5 - 31.6 - 15.0	10.0 - 24.0 - 27.7 - 18.4	11.7 - 28.5 - 35.0 - 24.9
Lipid Content ^c	dry wt % as fatty acid methyl ester (FAME)	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
N Content ^c	wt % AFDW	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
CO ₂ Utilization Efficiency ^d	% utilized for biomass	90%	90%	90%	90%	90%	90%	90%	90%	90%
Gross CO ₂ + Nutrient Cost Contributions ^e	\$/ton AFDW	\$124	\$124	\$124	\$124	\$124	\$124	\$122	\$121	\$121
Operating Days per Year	days/yr	330	330	330	330	330	330	330	330	330
Biomass Concentration at Harvest	g/L AFDW	0.27	0.26	~0.5	0.43	0.51	0.49	0.46	0.5	0.5
Dewatering										
Total Cost Contribution	\$/ton AFDW	\$105	\$110	\$107	\$97	\$87	\$82	\$75	\$62	\$63
Capital Cost Contribution	\$/ton AFDW	\$82	\$86	\$84	\$77	\$69	\$66	\$60	\$49	\$51
Operating Cost Contribution	\$/ton AFDW	\$23	\$24	\$23	\$20	\$18	\$17	\$15	\$13	\$12
Gross Dewatering Efficiency ^f	%	87%	87%	87%	87%	87%	87%	87%	87%	87%

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT – ATP ^{3a}	2016 SOT – ABY1 ^a	2017 SOT ^{a,b} w/FA EVAP	2018 SOT ^{a,b} w/ FA EVAP	2019 SOT ^{a,b} w/ FA EVAP	2020 SOT ^{a,b} w/ FA EVAP	2025 Projection	2030 Design
Net Dewatering Efficiency ^f	%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Final Concentration of Dewatered Biomass	g/L AFDW	200	200	200	200	200	200	200	200	200
Dewatering Capital Expenditures ^g	\$(MMgal/day) from cultivation	\$119,600	\$105,500	\$89,400	\$102,300	\$104,200	\$91,300	\$93,600	\$100,200	\$91,300
Balance of Plant										
Total Cost Contribution	\$/ton AFDW	\$38	\$32	\$28	\$36	\$33	\$32	\$28	\$32	\$25
Capital Cost Contribution	\$/ton AFDW	\$28	\$22	\$20	\$26	\$23	\$22	\$20	\$21	\$17
Operating Cost Contribution	\$/ton AFDW	\$10	\$10	\$8	\$10	\$10	\$9	\$9	\$11	\$8

^a Base case assumes nth-plant facility utilizing low-cost unlined ponds; alternative SOT scenarios were also considered with fully lined ponds.

^b FY 2017–FY 2020 SOT columns shown here reflect Florida algae evaporation scenario, based on productivities demonstrated at the Arizona State University site.

^c SOT cases assume algal biomass composition consistent with 2025–2030 targets.

^d Fraction of CO₂ delivered to ponds that is utilized for biomass (currently assumed constant for all SOT cases relative to future 2030 targets).

^e Included as part of “operating cost contribution”; gross cost does not account for CO₂/nutrient recycling from conversion (recycling credits are taken downstream in conversion models).

^f 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). SOTs assume same values as 2025–2030 targets.

^g Total installed dewatering cost based on peak season flow from cultivation.

As shown in Figure 30, algal productivity is a key factor in reducing the cost of algal biomass minimum selling prices (for reference, see the appendix, barriers Aft-A and Aft-C). Feedstock composition is another key determinant of whether algal feedstocks can be cost-effectively converted into biofuels and bioproducts (for reference, see the appendix, barriers Aft-E and Aft-G). The projections for both the low- and high-temperature pathway designs using algal feedstocks assume that certain compositional specifications can be met at the target MBSP. The impact of those specifications on MBSP has not yet been modeled. To meet conversion specifications, alternative cultivation system configurations and operational practices may be needed that could add costs not reflected in the current algae farm design. Differences between actual algae composition (experimental data from harvested algae) used for SOT reporting and design case-specific composition requirements are discussed in each pathway section.

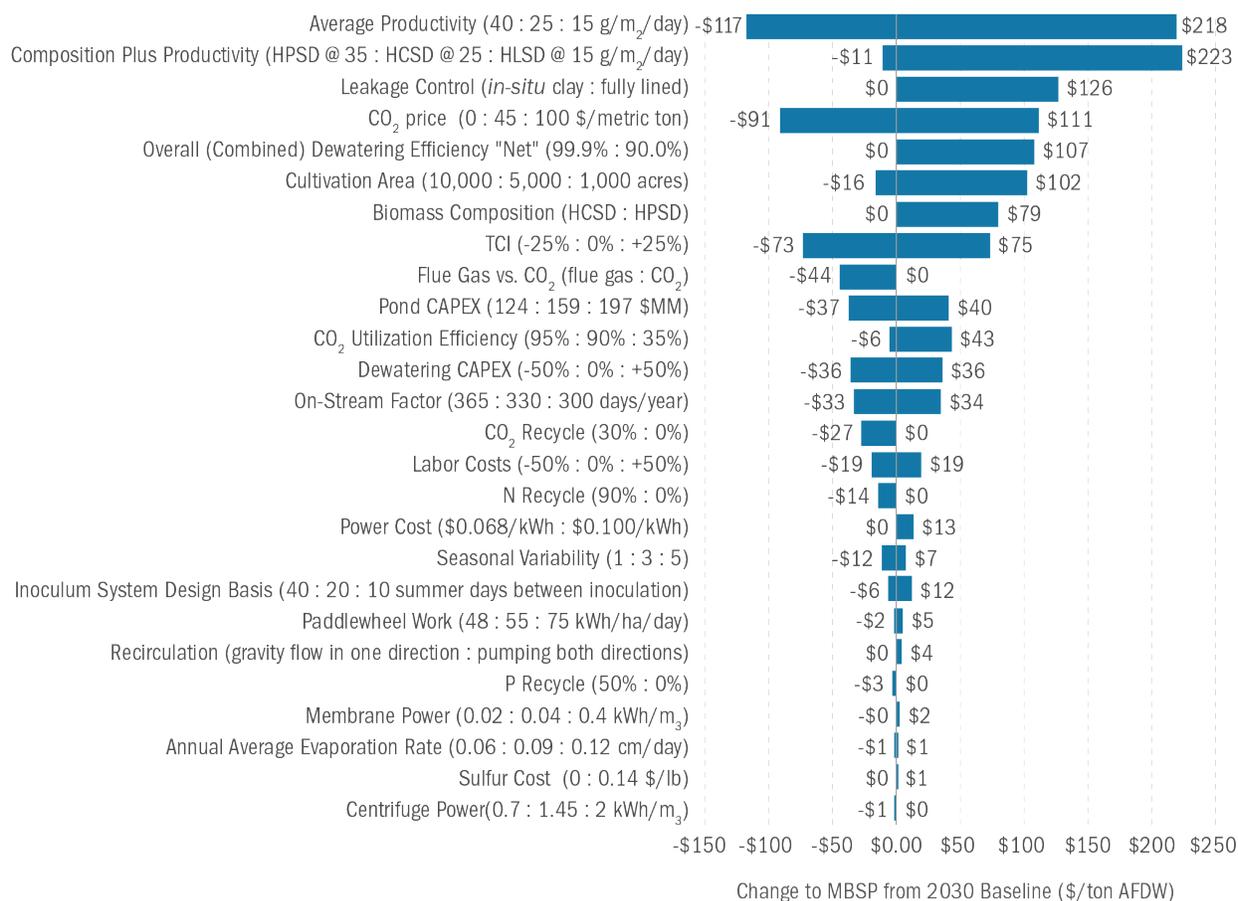


Figure 30: Key factors influencing algae production costs relative to the algae farm 2030 design baseline

Wet Feedstocks Converted via Low Temperature and Upgrading

Combined Algae Processing Design Case

The configuration used to assess progress of technologies relevant to low temperature and upgrading of wet feedstocks to fuel blendstocks and products is based on the CAP design case along with subsequent process design modifications.^{69,70,71} The 2014 CAP process design uses low-temperature deconstruction of algal feedstocks with dilute acid under low pressure to release fermentable sugars. This is followed by fermentation of the solubilized sugars and wet extraction and upgrading of lipids, as well as processing the fermentation and extraction stillage into fuels and products. This process concept is illustrated in Figure 31. Current SOT process designs convert carbohydrates to either mixed-acids (i.e., carboxylic acids [CA]) or 2,3-BDO intermediates to produce renewable diesel and coproduct electricity. Following extraction, lipids are converted to renewable diesel and polyurethane (PU) coproducts.

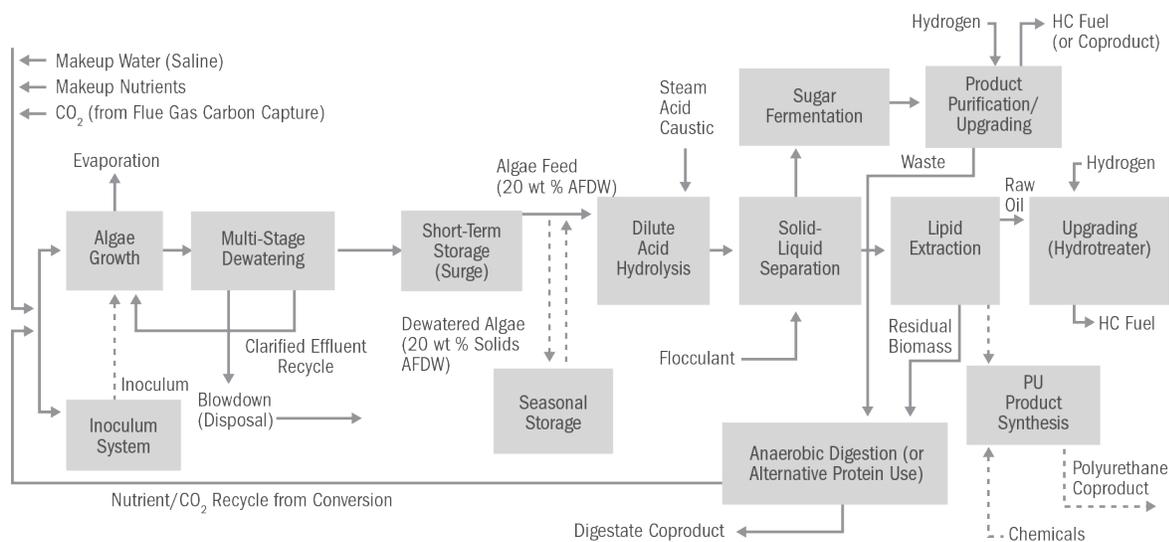


Figure 31: Process flow diagram for conversion of algal feedstocks to hydrocarbon fuels and coproducts via low-temperature deconstruction with upgrading

⁶⁹ R. Davis, C. Kinchin, J. Markham, E. C. D. Tan, L. M. L. Laurens, D. Sexton, D. Knorr, P. Schoen, and J. Lukas, *Process Design and Economics for the Conversion of Algal Biomass to Biofuels: Algal Biomass Fractionation to Lipid- and Carbohydrate-Derived Fuel Products*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-62368, 2014. <http://www.nrel.gov/docs/fy14osti/62368.pdf>.

⁷⁰ R. E. Davis, J. N. Markham, C. M. Kinchin, C. Canter, J. Han, Q. Li, A. Coleman, S. Jones, M. Wigmosta, and Y. Zhu. *2017 Algae Harmonization Study: Evaluating the Potential for Future Algal Biofuel Costs, Sustainability, and Resource Assessment from Harmonized Modeling*. Lemont, IL: Argonne National Laboratory; Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, ANL-18/12; NREL/TP-5100-70715; PNNL-27547, 2018. <https://www.nrel.gov/docs/fy18osti/70715.pdf>.

⁷¹ R. Davis, M. Wiatrowski, C. Kinchin, and D. Humbird. *Conceptual Basis and Techno-Economic Modeling for Integrated Algal Biorefinery Conversion of Microalgae to Fuels and Products. 2019 NREL TEA Update: Highlighting Paths to Future Cost Goals via a New Pathway for Combined Algal Processing*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-75168, 2020. <https://www.nrel.gov/docs/fy20osti/75168.pdf>

The net benefit of all the improvements considered in the FY 2020 SOT is substantial, resulting in more than a 45% decrease in MFSP compared to FY 2019 SOT results. Figure 32 shows how the CAP SOT estimates and projections combine algae MBSP from the algae farm design with conversion cost projections to derive MFSP. Notably, starting with the 2020 SOT, experimental results have enabled proof-of-concept modeling of the PU coproduct synthesis.⁷² The updated CAP configuration and process parameters, combined with updated FY 2020 SOT biomass costs (MBSPs) and associated yields from the front-end algae farm model, translate to an estimated FY 2020 SOT minimum fuel selling price of \$4.94/GGE and \$5.33/GGE (CA and BDO, respectively). Diversion of feedstock to the PU operation raises the feedstock cost contribution to the MFSP due to lower yield of biofuel products. This increase is more than offset by the resulting coproduct credits.

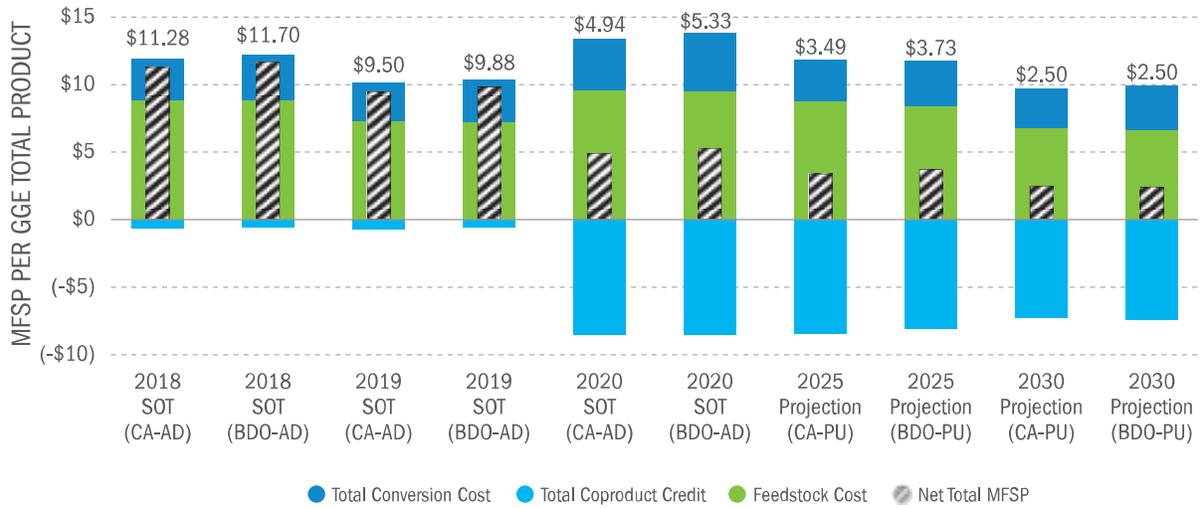


Figure 32: Cost breakdown of algae converted via the low-temperature and upgrading pathway

While feedstock cost is the largest driver of MFSP, the main cost drivers in the CAP conversion processes are conversion efficiencies and yield. BETO is researching various fuel/product combinations to optimize the MFSP. The original CAP design report included ethanol as a representative fermentative product from algal sugars as a proof of concept for efficient utilization of algal sugars into an energy product. This concept was first experimentally shown using algal sugars fermented to ethanol, lipids extracted and hydrotreated to hydrocarbon fuels, and protein stillage sent to anaerobic digestion (AD) with biogas recovery. This design was projected to be able to reach only \$5/GGE MFSP, suggesting a need to incorporate higher-value fuels and products to reach BETO performance goals.

⁷² M. Wiatrowski and R. Davis. *Algal Biomass Conversion to Fuels via Combined Algae Processing (CAP): 2020 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-79935, 2021. <https://www.nrel.gov/docs/fy21osti/79935.pdf>.

The ultimate use of algal sugars is a key research area for lowering MFSP. The CAP pathway leverages sugar conversion technologies previously described in the section on dry feedstocks converted via low temperature and upgrading using the design cases for 2,3-BDO and mixed-acids intermediates. These intermediates will need to be catalytically upgraded to hydrocarbons suitable as fuels and/or fuel blendstocks. Figure 33 and Table 27 show the conversion cost projections for the CAP design. The 2018 and 2019 SOTs are based on experimental yields using algal feedstocks in these two design cases. The SOT and projection cases all assume that the protein fraction is sent to AD for conversion to biogas used for combined heat and power (CHP) production. A small coproduct credit results from sale of the AD biosolids for use as fertilizer. The 2020 SOT retains the experimental yields from 2019 CA and BDO SOTs and adds in experimental data on polyol and polyurethane yields. Polyurethane synthesis was chosen as an example coproduct based on an optimization of factors related to market size, value, and domestic manufacturing. The largest cost driver of the PU synthesis is the purchase of the isocyanate reagent because the polyol derived from the algae feedstock must be blended roughly 1:1 with the isocyanate reagent to form a polyurethane. The resulting polyurethane is more valuable than the component reagents. The finished polyurethane is assigned a fixed coproduct credit of \$2.04/lb (2016-dollars), representing a recent 5-year average price for commodity flexible PU foam, per BETO's TEA methodology. The projection cases do not model further improvement in the PU synthesis operation. Future SOTs may consider alternative PU formulations, such as non-isocyanate PUs, or isocyanates derived internally from the algae feedstock instead of the current purchase arrangement. Fully renewable PUs may have a different value proposition as well—these are areas of ongoing R&D.

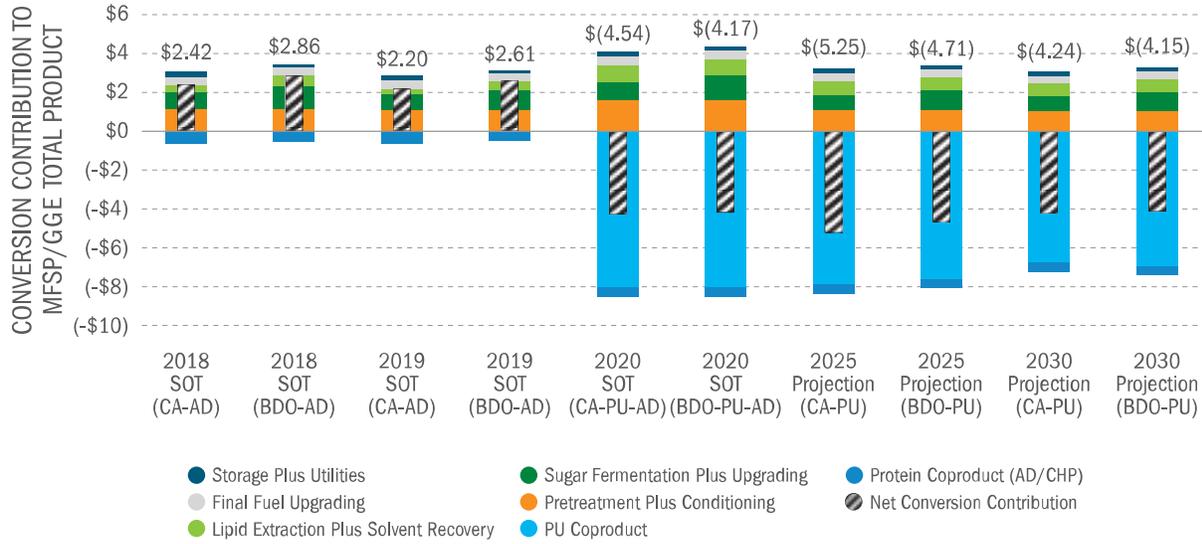


Figure 33: Cost projections for the conversion portion of the CAP design case

Table 27: Cost Projections and Coproduct Credits for the Conversion Portion of the CAP Design Case

Conversion Cost Breakdown (\$/GGE)	2018 SOT (CA-AD)	2018 SOT (BDO-AD)	2019 SOT (CA-AD)	2019 SOT (BDO-AD)	2020 SOT (CA-PU-AD)	2020 SOT (BDO-PU-AD)	2025 Projection (CA-PU)	2025 Projection (BDO-PU)	2030 Projection (CA-PU)	2030 Projection (BDO-PU)
Pretreatment and Conditioning	\$1.13	\$1.15	\$1.09	\$1.10	\$1.59	\$1.58	\$1.10	-	\$1.05	\$1.02
Sugar Fermentation and Upgrading	\$0.86	\$1.16	\$0.77	\$0.99	\$0.94	\$1.27	\$0.75	\$1.01	\$0.71	\$0.98
Lipid Extraction and Solvent Recovery	\$0.32	\$0.56	\$0.29	\$0.50	\$0.87	\$0.87	\$0.73	\$0.70	\$0.69	\$0.67
Final Fuel Upgrading	\$0.47	\$0.41	\$0.45	\$0.38	\$0.43	\$0.43	\$0.40	\$0.39	\$0.40	\$0.39
Storage and Utilities	\$0.28	\$0.14	\$0.27	\$0.13	\$0.18	\$0.20	\$0.20	\$0.21	\$0.187	\$0.20
Net Conversion and Coproduct Contribution to MFSP	\$2.42	\$2.86	\$2.20	\$2.61	\$(4.54)	\$(4.17)	\$(5.25)	\$(5.76)	\$(4.23)	\$(4.15)
PU Coproduct	-	-	-	-	\$(8.04)	\$(8.07)	\$(7.90)	\$(7.64)	\$(6.77)	\$(7.00)
Protein Coproduct (sent to AD with CHP)	\$(0.63)	\$(0.55)	\$(0.67)	\$(0.48)	\$(0.51)	\$(0.45)	\$(0.53)	\$(0.42)	\$(0.51)	\$(0.41)
Total Coproduct Credit	\$(0.63)	\$(0.55)	\$(0.67)	\$(0.48)	\$(8.55)	\$(8.52)	\$(8.43)	\$(8.06)	\$(7.28)	\$(7.41)

For consistency, biomass with elemental and component composition consistent with a *Scenedesmus* strain of algae shown as the design basis in Table 28 is used in all CAP process conversion research and SOT assessments (though this does not necessarily require that the

demonstrated strain actually be *Scenedesmus*). Table 28 also shows the algal feedstock compositions as measured from 2020 SOT cultivation trials, for comparison with the design basis algal feedstock.^{73,74} Aligning the SOT productivities with the design case basis compositions is an area of ongoing R&D.

The 2025 and 2030 MFSP projections are based on continued progress toward technical targets as a result of BETO R&D for these conversion pathways. This will be enabled by R&D that results in increased lipid yields in algal biomass and the development of processes to convert algal lipids to high-value coproducts (e.g., PU). Figure 34 shows the key factors impacting cost relative to the 2030 design case for the CAP design. Table 30 details the technical targets and related cost projections for the CAP design cases.

⁷³ Wiatrowski and Davis 2021, <https://www.nrel.gov/docs/fy21osti/79935.pdf>.

⁷⁴ E. Knoshaug, L. M. L. Laurens, C. Kinchin, and R. Davis. *Use of Cultivation Data from the Algae Testbed Public Private Partnership as Utilized in NREL's Algae State of Technology Assessments*. Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-67289, 2016. <http://www.nrel.gov/docs/fy17osti/67289.pdf>.

Table 28: CAP Design Case Algal Biomass Compositions Compared to Measured Values From 2020 SOT Cultivation Trials

Elemental (AFDW) ^{a,b}	Design Case Basis	Fall <i>Scenedesmus</i> / <i>Monoraphidium</i> ^c	Winter <i>Monoraphidium</i>	Spring <i>Monoraphidium</i> / <i>Scenedesmus</i> ^d	Summer <i>Picochlorum</i>
Carbon	54	53.2 (52.5)	53.1	52.2 (53.2)	52.3
Hydrogen	8.2	7.8 (7.9)	7.9	7.7 (7.8)	7.5
Oxygen	35.5	27.4 (27.9)	27.8	27.6 (27.4)	27.8
Nitrogen	1.8	10.2 (10.3)	9.8	11.1 (10.2)	10.9
Sulfur	0.2	0.2 (0.2)	0.2	0.2 (0.2)	0.2
Phosphorus	0.22	1.2 (1.2)	1.2	1.2 (1.2)	1.2
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Component (dry wt) ^b					
Ash	2.4	6.4 (9.9)	6.5	9.2 (6.4)	18.2
Protein	13.2	45.5 (44.3)	43.9	48.0 (45.5)	42.7
FAME Lipids ^e	26.0	8.6 (9.0)	9.8	9.0 (8.6)	9.1
Glycerol ^e	3.0	1.0 (1.0)	1.1	1.0 (1.0)	1
Non-Fuel Polar Lipid Impurities	1.0	5.2 (5.4)	5.9	5.4 (5.2)	5.5
Sterols ^f	1.8	0.5 (0.5)	0.5	0.5 (0.5)	0.5
Fermentable Carbohydrates ^g	47.8	11.3 (11.5)	10.2	9.1 (11.3)	4.3
Other Carbohydrates (Galactose)	3.2	2.3 (2.3)	2	1.8 (2.3)	0.9
Cell Mass	1.6	19.2 (16.0)	20.1	15.9 (19.2)	17.8
Total	100.00%	100.00%	100.00%	100.00%	100.00%

^a Carbon-hydrogen-nitrogen (CHN) composition is reported as measured CHN data corrected for ash content of the biomass. Oxygen was calculated as the difference from mass balance after estimating sulfur and phosphorus (as 0.2% and 1.2%, respectively) and adjusted to 100%.

^b SOT biomass compositions are less detailed than the high-carbohydrate *Scenedesmus* design basis; CHN and composition data for *Scenedesmus* and *Monoraphidium* cases are based on measured averaged data for harvested production samples and are considered primarily representative for nutrient-replete growth conditions. Composition data are currently broken down to ash, protein, lipids as FAME (in this case triglyceride lipids measured as FAME, with an added estimate of 10% glycerol relative to measured FAME, and an assumed polar lipid headgroup fraction that increased the FAME content by at least 60%), and total carbohydrate content (reported here as 80% fermentable from the measured sum of monosaccharides detected, 20% non-fermentable, and an additional 10% assumed unhydrolyzable or recalcitrant). A remaining component called “cell mass” accounts for between 5% and 18% of the biomass and reflects unidentified components that are not measured but are needed to account for the mass balance.

^c Fall: first value: *Monoraphidium* 26BAM (October–November); value in parentheses: *Scenedesmus* UTEX393 (September). Fall data for 26BAM were not available; values above reflect 26BAM data during spring cultivation.

^d Spring: *Scenedesmus* UTEX393 (April–May); value in parentheses: *Monoraphidium* 26BAM (March).

^e Lipids originally characterized as triglycerides (1:1 FAME equivalent); adjusted here to free fatty acids plus glycerol (as ~11% of the measured FAME content, and reflective of actual components in pretreated hydrolysate for *Scenedesmus* biomass).

^f Sterols originally included in “polar lipid impurity” fraction in prior models. Value currently estimated for high-carbohydrate *Scenedesmus*, based on a representative earlier-harvest biomass sample. For SOT biomass, sterol concentration is estimated at a flat 0.5% of the biomass, consistent with earlier observations at the National Renewable Energy Laboratory.

^g “Fermentable carbohydrates” typically consist of 75% glucose and 25% mannose for all species analyzed in FY 2019.

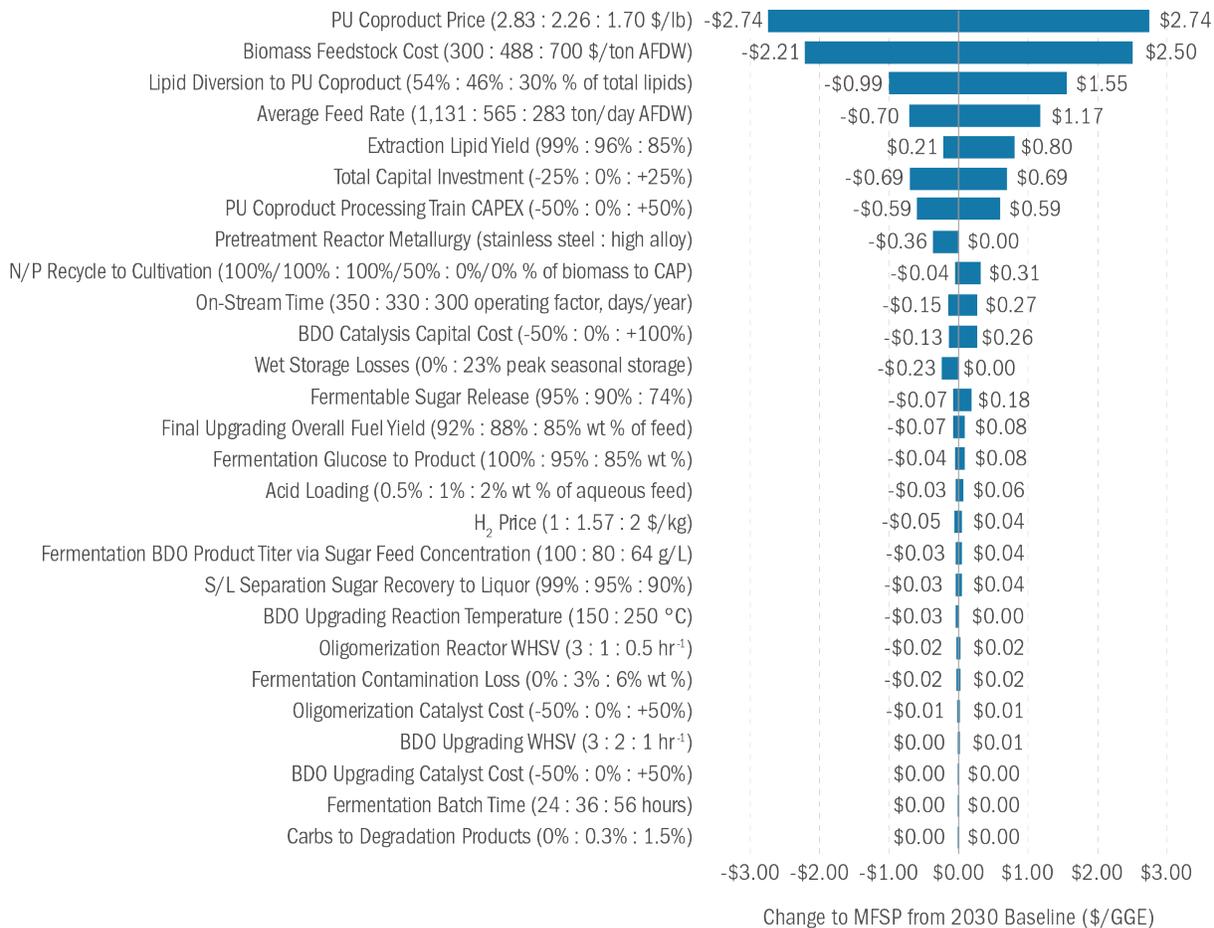


Figure 34: Factors influencing MFSP for the CAP design case (BDO fuel train pathway example)

Table 29: Process Efficiency Metrics for CAP SOTs and Projections

Sustainability and Process Efficiency Metrics	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Fuel Yield by Weight of Biomass (AFDW)	% w/w of biomass	38.4%	27.2%	28.0%	26.4%	19.4%	19.3%	21.0%	21.7%	22.1%	22.3%
Fuel Yield by Weight of Biomass (dry biomass)	% w/w of dry biomass	27.7%	26.6%	27.3%	25.8%	18.9%	18.8%	20.5%	21.2%	21.5%	21.8%
Carbon Efficiency to Fuels	% of algal carbon	46.1%	44.3%	46.3%	43.7%	31.1%	30.8%	32.8%	33.8%	34.5%	34.7%
Carbon Efficiency to Coproducts	% of algal carbon	0.0%	0.0%	0.0%	0.0%	20.6%	20.6%	20.5%	20.5%	18.6%	19.4%
Electricity Export	kWh/GGE	3.3	0.0	3.6	0.5	5.0	6.0	6.4	6.6	6.2	6.5
Natural Gas Import	Btu/GGE (LHV)	33,861	15, 102	34,443	15,547	98,283	163,783	102,484	149,477	97,244	145,032

^a 2018–2020 SOT cases based on FA evaporation scenario for biomass feed cost.

^b 2025–2030 columns represent example scenarios that may demonstrate achievement of BETO’s cost goals (\$2.5/GGE); CA = carboxylic acids (upgraded to hydrocarbon fuels); BDO = 2,3-butanediol (upgraded to hydrocarbon fuels); AD = anaerobic digestion; PU = polyurethanes.

Table 30: Unit Operation Cost Contribution Estimates and Technical Projections for Combined Algae Processing Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE fuel	\$11.28	\$11.70	\$9.50	\$9.88	\$4.94	\$5.33	\$3.49	\$3.72	\$2.50	\$2.50
Net Conversion Contribution	\$/GGE	\$2.42	\$2.86	\$2.20	\$2.61	(\$4.54)	(\$4.17)	(\$5.25)	(\$4.72)	(\$4.24)	(\$4.15)
Diesel Production	MMGGE/yr	4.6	5.6	6.2	7.4	6.1	5.5	8.9	8.2	9.4	8.5
Naphtha Production	MMGGE/yr	3.2	2.3	4.3	3.1	2.4	3.0	3.5	4.7	3.7	4.8
Diesel Yield (AFDW Algae Basis)	GGE/ton	54	65	54	64	45	41	49	45	52	47

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Naphtha Yield (AFDW Algae Basis)	GGE/ton	38	27	37	27	18	22	19	26	20	26
Total Fuel Yield from Algae Farm	GGE/acre/yr	1,573	1,577	2,105	2,114	1,685	1,682	2,494	2,587	2,619	2,658
Natural Gas (NG) Usage (AFDW Algae Basis)	scf/ton algae	2,611 (4,307 including NG for off-site H ₂)	1,168 (2,764 including NG for off-site H ₂)	2,620 (4,292 including NG for off-site H ₂)	1,187 (2,747 including NG for off-site H ₂)	6,147 (7,231 including NG for off-site H ₂)	10,227 (12,050 including NG for off-site H ₂)	6,947 (8,121 including NG for off-site H ₂)	10,501 (12,646 including NG for off-site H ₂)	6,918 (8,167 including NG for off-site H ₂)	10,470 (12,658 including NG for off-site H ₂)
Carbon from Biomass in Fuels	%	46.1	44.3	46.3	43.7	31.1	30.8	32.8	33.8	34.5	34.7
Carbon from Biomass in Other Products ^c	%	NA	NA	NA	NA	20.6	20.6	20.5	20.5	18.6	19.4
Feedstock											
Total Cost Contribution	\$/GGE fuel	\$8.86	\$8.84	\$7.30	\$7.27	\$9.49	\$9.50	\$8.75	\$8.44	\$6.74	\$6.66
Feedstock Cost (AFDW Algae Basis)	\$/ton algae	\$824	\$824	\$670	\$670	\$603	\$603	\$602	\$602	\$488	\$488
Feedstock Solids Content	wt % AFDW	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Feedstock Lipid/Carb/Protein Content ^d	dry wt %	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%
Pretreatment											
Total Cost Contribution	\$/GGE fuel	\$1.13	\$1.15	\$1.09	\$1.10	\$1.59	\$1.58	\$1.10	\$1.06	\$1.05	\$1.03
Capital Cost Contribution	\$/GGE fuel	\$0.58	\$0.58	\$0.56	\$0.56	\$0.79	\$0.79	\$0.65	\$0.62	\$0.61	\$0.61
Operating Cost Contribution	\$/GGE fuel	\$0.55	\$0.57	\$0.53	\$0.54	\$0.80	\$0.79	\$0.45	\$0.43	\$0.43	\$0.42
Pretreatment Solids Loading	wt % AFDW	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Pretreatment Acid Loading	wt % of water feed	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Fermentable Sugar Yield	%	74%	74%	74%	74%	83%	83%	90%	90%	90%	90%

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Carbs to Degradation Products	%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	0.30%	0.30%	0.30%	0.30%
Sugar Fermentation/Upgrading											
Total Cost Contribution	\$/GGE fuel	\$0.86	\$1.16	\$0.77	\$0.99	\$0.94	\$1.27	\$0.75	\$1.02	\$0.71	\$0.99
Capital Cost Contribution	\$/GGE fuel	\$0.40	\$0.60	\$0.35	\$0.53	\$0.46	\$0.63	\$0.35	\$0.47	\$0.34	\$0.46
Operating Cost Contribution	\$/GGE fuel	\$0.46	\$0.56	\$0.42	\$0.46	\$0.48	\$0.65	\$0.39	\$0.55	\$0.37	\$0.53
Fermentation Productivity	g/L/h	0.3	56-hr batch time	0.3	56-hr batch time	0.3	56-hr batch time	2	36-hr batch time	2	36-hr batch time
Fermentation Glucose to Product	%	92%	74%	92%	74%	92%	74%	95%	95%	95%	95%
Fermentation Mannose to Product	%	92%	55%	92%	55%	92%	57%	95%	95%	95%	95%
Fermentation Process Yield	g product/g sugars ^e	0.48 (CA)	0.34 (BDO)	0.48 (CA)	0.34 (BDO)	0.48 (CA)	0.34 (BDO)	0.50 (CA)	0.48 (BDO)	0.50 (CA)	0.48 (BDO)
Catalytic Upgrading Yield to Hydrodeoxygenation (HDO) Feed ^f	wt % of recovered fermentation product	53%	60%	53%	60%	53%	63%	53%	63%	53%	63%
Catalytic Upgrading Carbon Yield to HDO Feed ^f	C yield from recovered fermentation product	57%	56%	57%	56%	83%	98%	83%	98%	83%	98%
Lipid Recovery and Processing											
Total Cost Contribution	\$/GGE fuel	\$0.32	\$0.56	\$0.29	\$0.50	(\$7.16)	(\$7.20)	(\$7.17)	(\$6.93)	(\$6.08)	(\$6.31)
Capital Cost Contribution	\$/GGE fuel	\$0.19	\$0.32	\$0.17	\$0.29	\$2.52	\$2.51	\$2.11	\$2.03	\$1.90	\$1.92
Operating Cost Contribution	\$/GGE fuel	\$0.13	\$0.24	\$0.12	\$0.21	\$4.54	\$4.53	\$4.12	\$3.96	\$3.60	\$3.67
Lipid Coproduct Credits ^g	\$/GGE fuel	NA	NA	NA	NA	(\$14.22)	(\$14.24)	(\$13.39)	(\$12.91)	(\$11.58)	(\$11.89)

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Extraction Configuration		2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR
Extraction Solvent Loading	nonpolar: ethanol: dry biomass (wt basis)	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1
FAME Lipid Extraction Yield	%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Polar Lipid Impurity Partition to Extract	%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%
Fractional Diversion of FAME Lipids to PU Coproduct Train	% ^h	NA	NA	NA	NA	50%	50%	50%	50%	45%	47%
Polyol Yield (Precursor to PU)	g polyol/g algae AFDW	NA	NA	NA	NA	0.16	0.16	0.16	0.16	0.15	0.16
PU Coproduct Yield	g PU/g algae AFDW	NA	NA	NA	NA	0.22	0.22	0.22	0.22	0.21	0.22
Final Fuel Upgrading											
Total Cost Contribution	\$/GGE fuel	\$0.47	\$0.41	\$0.45	\$0.38	\$0.43	\$0.43	\$0.40	\$0.39	\$0.40	\$0.39
Capital Cost Contribution	\$/GGE fuel	\$0.15	\$0.16	\$0.13	\$0.14	\$0.14	\$0.15	\$0.13	\$0.13	\$0.12	\$0.13
Operating Cost Contribution	\$/GGE fuel	\$0.32	\$0.25	\$0.32	\$0.24	\$0.29	\$0.28	\$0.28	\$0.26	\$0.28	\$0.26
Hydrotreating Diesel Yield	wt % of HDO feed ⁱ	51.9%	60.6%	51.9%	60.5%	64.4%	56.6%	64.5%	55.8%	64.3%	56.0%
Hydrotreating Naphtha Yield	wt % of HDO feed ⁱ	35.9%	25.3%	35.9%	25.4%	25.3%	30.5%	25.6%	31.6%	25.3%	31.2%
Hydrotreating H ₂ Consumption	wt % of HDO feed ⁱ	3.2%	3.0%	3.2%	2.9%	2.6%	2.2%	2.6%	2.2%	2.6%	2.2%
Protein/Residual Processing											
Total Cost Contribution	\$/GGE fuel	(\$0.80)	(\$0.76)	(\$0.83)	(\$0.68)	(\$1.24)	(\$1.56)	(\$1.28)	(\$1.49)	(\$1.23)	(\$1.45)

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA-AD) ^a	2018 SOT (BDO-AD) ^a	2019 SOT (CA-AD) ^a	2019 SOT (BDO-AD) ^a	2020 SOT (CA-AD) ^a	2020 SOT (BDO-AD) ^a	2025 Projection (CA-PU-AD) ^b	2025 Projection (BDO-PU-AD) ^b	2030 Projection (CA-PU-AD) ^b	2030 Projection (BDO-PU-AD) ^b
Capital Cost Contribution	\$/GGE fuel	\$0.12	\$0.09	\$0.11	\$0.08	\$0.15	\$0.13	\$0.13	\$0.10	\$0.13	\$0.10
Operating Cost Contribution		\$0.07	\$0.07	\$0.06	\$0.05	\$0.09	\$0.08	\$0.07	\$0.06	\$0.07	\$0.05
Coproduct Credits ^l	\$/GGE fuel	(\$0.99)	(\$0.92)	(\$1.00)	(\$0.82)	(\$1.47)	(\$1.76)	(\$1.49)	(\$1.64)	(\$1.42)	(\$1.60)
Biogas Yield	L CH ₄ /g TS	0.26	0.25	0.26	0.25	0.23	0.22	0.26	0.25	0.26	0.25
Balance of Plant											
Total Cost Contribution	\$/GGE fuel	\$0.44	\$0.35	\$0.42	\$0.33	\$0.90	\$1.31	\$0.95	\$1.23	\$0.91	\$1.20
Capital Cost Contribution	\$/GGE fuel	\$0.20	\$0.18	\$0.19	\$0.17	\$0.30	\$0.36	\$0.31	\$0.35	\$0.30	\$0.34
Operating Cost Contribution	\$/GGE fuel	\$0.24	\$0.17	\$0.23	\$0.16	\$0.60	\$0.94	\$0.64	\$0.88	\$0.61	\$0.86

^a 2019 and 2020 SOT cases based on Florida algae evaporation scenario for biomass feed cost.

^b 2025–2030 columns represent example scenarios that may demonstrate achievement of BETO’s cost goals (\$2.5/GGE). CA = carboxylic acids (upgraded to hydrocarbon fuels); BDO = 2,3-butanediol (upgraded to hydrocarbon fuels); AD = anaerobic digestion; PU = polyurethanes.

^c “Other products” = algal carbon yields to PU coproducts, as applicable.

^d SOT cases assume algal biomass feedstock composition consistent with 2025–2030 targets.

^e Includes glycerol conversion.

^f Represents overall catalytic upgrading yield of fermentation intermediate (after recovery) through feed to final fuel finishing (hydrotreating) step.

^g Lipid coproduct for 2020–2030 = lipid-derived polyurethanes.

^h Model assumes FAME lipids are present as 50% triglycerides and 50% free fatty acids. Triglycerides are used for PU coproduction, whereas free fatty acids are used as fuel precursors.

ⁱ Includes final fuel upgrading step for hydrotreating of lipids combined with CA- or BDO-derived intermediates (values based on combined feed).

^j Includes coproduct credits for N/P nutrient recycling, CO₂ recycling, CHP generation, and AD digestate fertilizer (minimal credit).

Integration and Scale-Up

Once the technical targets are reached through R&D, process steps developed at the R&D scale must be integrated at engineering scale and tested to ensure technical targets can be achieved when run as an integrated process (for reference, see the appendix, barrier Aft-H). Key integration challenges for CAP include:

- Integration of process steps to ensure robust pretreatment operations and efficient release of algal sugars for further processing (for reference, see the appendix, barriers Aft-I and SDI-A).
- Integration of fermentation and catalytic upgrading.
- Improving lipid extraction and solvent recovery.
- Addressing buildup of impurities in process recycle systems and its impact on catalyst performance for the conversion of 2,3-BDO and mixed-acids intermediates to hydrocarbon fuels (for reference, see the appendix, barriers Aft-J, SDI-A, and SDI-F).
- Optimizing nutrient recycle processes to improve and achieve cost targets.
- Optimizing use of protein to maximize values.
- Developing efficient product separation and purification schemes.
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier SDI-D).
- Demonstration of ability to produce value-added coproducts at scale in integrated process.
- Identifying efficient valorization methodologies of streams post fermentation and product conversion steps.

Supply Chain Sustainability Analysis

The two alternative CAP design case pathways (through 2,3-BDO or mixed-acids intermediates) both produce a diesel-range blendstock, as well as polyurethane and electricity as coproducts. The SCSAs for all SOTs and for the 2025 and 2030 projections assume algae biomass cultivation with Florida evaporation rates and unlined ponds using saline algae strains for both the 2,3-BDO and mixed-acids designs.

Table 31 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions from the CAP design

cases using the displacement method.⁷⁵ The SCSA results consider the impact of all finished products from the CAP designs. These results include a displacement credit for recycled nutrients such as ammonia (NH₃) and diammonium phosphate from anaerobic digester effluent that reduces the nutrient requirement for algae cultivation. Notably, beginning with the 2020 SOT, experimental results have enabled the modeling of PU synthesis and incorporation of associated coproduct displacement and biogenic carbon sequestration credits into the SCSA results.

Table 31: Supply Chain Sustainability Metrics for CAP Design Cases by Displacement Method

	Scenario 1: Via Acids					Scenario 2: Via 2,3-BDO					Petroleum Diesel
	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	
Biofuel Yield											
MMBtu/dry	10.8	10.6	7.3	7.9	8.3	10.6	10.6	7.3	8.2	8.4	
Fossil Energy Consumption^a											
MJ/MJ	1.08	1.03	0.7	0.6	0.6	1.00	0.99	1.1	1.0	0.9	1.2
Net Energy Balance^b											
MJ/MJ	-0.08	-0.03	0.3	0.4	0.4	0.00	0.01	-0.1	0.0	0.1	
GHG Emissions											
g CO ₂ e/MJ	80 (-14%)	75 (-20%)	7 (-92%)	3 (-97%)	9 (-90%)	75 (-20%)	71 (-25%)	31 (-67%)	24 (-74%)	25 (-72%)	91
g CO ₂ e/GGE	9,859	9,185	861	381	1,099	9,201	8,664	3,737	2,947	3,118	11,157
Water Consumption											
gal/MJ	0.28	0.27	0.30	0.27	0.34	0.21	0.19	0.22	0.25	0.24	0.02
gal/GGE	34.4	33.5	36.9	39.0	37.0	25.2	23.4	27.6	30.1	29.0	2.7
Total NO_x Emissions											
g NO _x /MJ	0.12	0.12	0.08	0.05	0.05	0.10	0.10	0.09	0.06	0.06	0.06
g NO _x /GGE	14.4	14.1	9.3	6.0	6.3	11.8	11.7	10.9	7.2	7.2	7.0
Urban NO_x Emissions^c											
g NO _x /MJ	0.03	0.03	0.03	0.02	0.02	0.03	0.03	0.03	0.02	0.02	0.03
g NO _x /GGE	4.0	3.8	3.7	2.6	2.6	4.1	4.0	3.8	2.5	2.5	3.3

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT, projection cases, and petroleum reference emissions and water consumption values are based on the GREET2020 model. Prior year SOTs are based on the GREET2019 model.

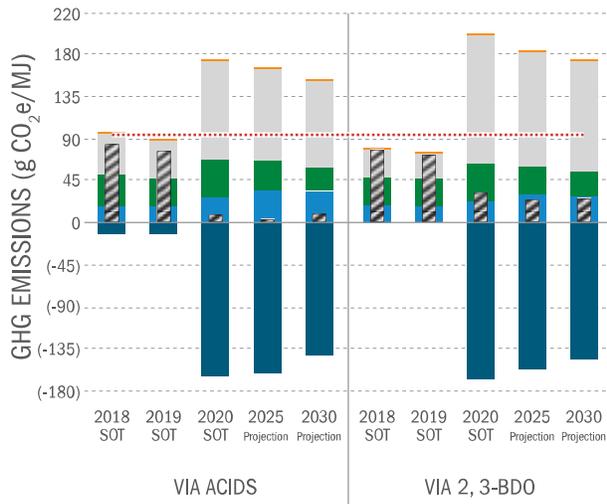
⁷⁵ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

- ^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.
- ^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.
- ^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

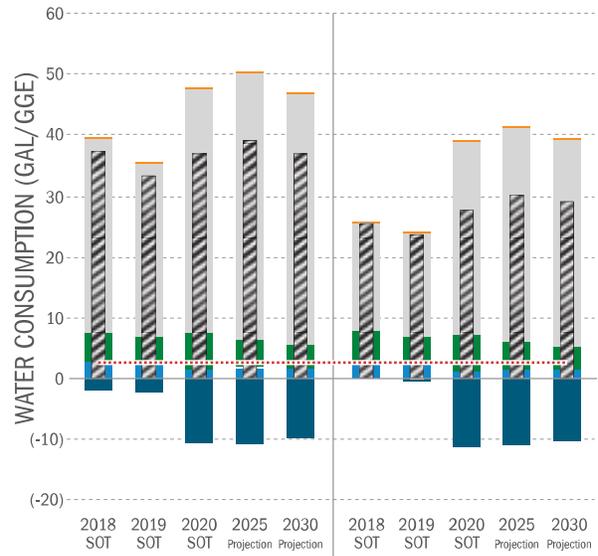
Figure 35A shows the supply chain GHG emissions for the 2018, 2019, and 2020 SOTs, and 2025 and 2030 projections for the 2,3-BDO and mixed-acids intermediate design cases. These compare to life cycle GHG emissions for petroleum-derived diesel of 91 g CO_{2e}/MJ. The major emission sources for the SOTs and 2025 and 2030 projections include manufacturing chemicals and catalysts used in the CAP conversion processes, as well as energy consumption for CO₂ capture and transportation to the algae farm, as well as for algae growth and dewatering. Starting with the 2020 SOT, the coproduction of PU has a significant impact on the GHG emissions for the 2020 SOT and projection cases. The PU coproduct generates significant credits for displacing petroleum-derived PU and for biogenic carbon sequestration. As a result, renewable diesel produced from CAP has low supply chain GHG emissions: 9 g CO_{2e}/MJ for the acids pathway and 25 g CO_{2e}/MJ for the BDO pathway for the 2030 projection cases. This corresponds to a 90% and 72% reduction, respectively, relative to petroleum-derived diesel.

Figure 35B shows significantly higher water consumption for the 2018, 2019, and 2020 SOTs, and the 2025 and 2030 projections relative to petroleum-derived diesel. This is due to the significant embedded water consumption associated with process chemical and catalyst use, as well as for process makeup water required by the CAP designs. Another major driver of water consumption is electricity generation and algae dewatering. Saline water evaporation in the pond or lost in blowdown during cultivation of saline algae strains does not contribute to water consumption because the SCSA only considers freshwater consumption in this analysis.

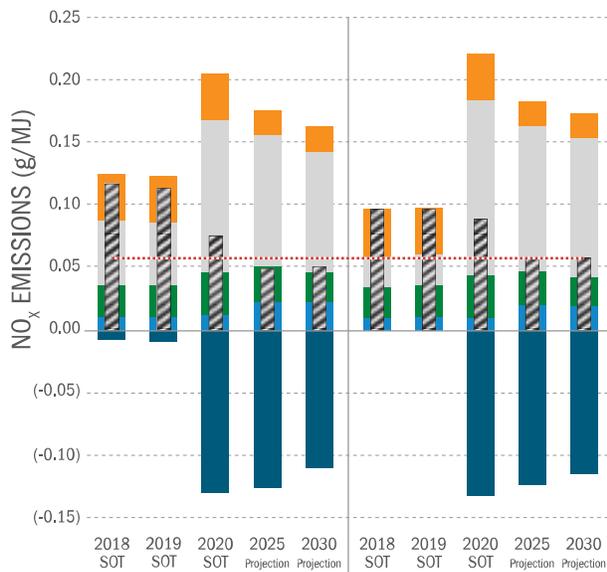
Figure 35C shows that total NO_x emissions are higher for the 2018, 2019, and 2020 SOT cases compared to petroleum-derived diesel. This is primarily due to embedded emissions from manufacturing the process chemicals and catalysts required for the CAP design case. The 2025 and 2030 projections for the CAP design cases see NO_x emissions on par with petroleum-derived diesel due to improved conversion efficiencies and significant NO_x emission displacement credits from coproduced PU.



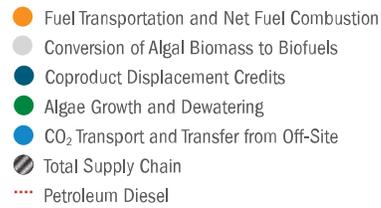
(A)



(B)



(C)



Figures 35A–35C: Supply chain for the CAP design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Alternative SCSA Methodologies

A key issue in dealing with coproducts from CAP designs is how to capture their environmental impacts, especially under the current, fuel-focused GHG regulations. In Table 31 and Figure 35, coproducts are accounted for using a displacement method that attributes all the supply chain

emission burdens to the fuel product, but also attributes all avoidance of emissions that otherwise would have taken place with the incumbent technology to produce the coproduct—or coproduct displacement credit—to the fuel product. As seen for the 2020 SOT as well as 2025 and 2030 projections, this creates significant coproduct displacement credits, which may overestimate the actual benefits that these pathways would provide.

As discussed in the Dry Feedstocks Converted via Low Temperature and Upgrading section of this report, beginning with the 2020 SCSA, BETO and ANL began evaluating other methods of accounting for coproduct credits. These included process-level allocation and biorefinery-level methods in addition to the displacement method. For this 2020 SOT update, BETO and ANL believe the biorefinery-level method may more accurately reflect the actual impact of coproducts on biorefinery systems. BETO and ANL will continue to discuss how to accurately reflect the SCSA impact of coproducts. For transparency, ANL has published SCSA results for all three methods in their 2020 SCSA publication.⁷⁶

Table 32 presents biorefinery-level fossil energy consumption and GHG emission results for CAP 2020 SOT and 2025 and 2030 projection cases. The biorefinery-level results are based on a 5,000-acre algae farm with year-over-year improvements in cultivation productivity (Table 26). Based on 330 biorefinery operating days per year, this results in 365 dry metric tons per day of algae processed in the 2020 SOT case and 500 dry metric tons per day in the 2025 and 2030 projections. For the 2025 and 2030 projection cases, the total biorefinery GHG reduction is greater than 100,000 metric tons per year. For the 2030 projection, biofuel and coproduct production contribute roughly equally to overall biorefinery GHG emissions reduction. When comparing biorefinery-level SCSA results with the dry feedstock-based biochemical cases, it's important to note the biorefinery scale for the CAP cases is about one-fourth of the 2,000-dry-metric-ton/day scale used in the biochemical conversion cases.

⁷⁶ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 32: Biorefinery-Level Emissions and Consumption Reductions Summary for CAP Pathway Using Mass-Based Allocation

		2020 SOT		2025 Projection		2030 Projection	
		Via Acids	Via BDO	Via Acids	Via BDO	Via Acids	Via BDO
Plant Capacity							
Algae Processed (AFDW basis)	dry metric ton/yr	121,273	121,273	165,715	165,715	165,715	165,715
Renewable Diesel Production	GGE/yr	6,044,150	5,444,239	8,925,516	8,220,525	9,393,709	8,499,103
Renewable Naphtha Production	GGE/yr	2,372,341	2,958,883	3,539,805	4,698,770	3,689,775	4,777,037
Total Biofuel Production	GGE/yr	8,416,491	8,403,122	12,465,321	12,919,295	13,083,484	13,276,140
Polyurethane Production	metric ton/yr	27,181	27,181	37,913	37,887	34,412	35,841
Fossil Energy Consumption Reductions^a							
By Biofuel Production ^b	MMBtu/yr	-417,115	-107,242	-716,106	-285,112	-784,183	-339,769
By Polyurethane Production ^b	MMBtu/yr	-97,617	56,019	-193,088	-69,637	-155,498	-63,918
Total Reduction	MMBtu/y	-514,733	-51,223	-909,194	-354,749	-939,681	-403,687
GHG Emission Reductions^a							
By Biofuel Production ^b	metric ton CO ₂ e/yr	-33,862	-18,295	-57,307	-35,688	-62,767	-40,015
By Polyurethane Production ^b	metric ton CO ₂ e/yr	-52,790	-44,055	-77,019	-70,376	-68,824	-66,715
Total Reduction	metric ton CO₂e/yr	-86,653	-62,350	-134,326	-106,064	-131,591	-106,731

^a Negative values indicate reductions while positive values indicate increases.

^b The contributions of renewable diesel and adipic acid production are based on mass-based process allocation.

Table 33 provides a comparison of the displacement and biorefinery-level SCSA methods for CAP. As discussed earlier, the displacement method attributes all emission impacts to the biofuel product. As a result, the displacement method indicates nearly double the GHG reduction benefits compared with the biorefinery-level method. For the 2030 projection via BDO intermediate, the displacement methods gives a 72% reduction in GHG emissions compared with 38% for the biorefinery-level method. It's important to note that historically, CAP pathway design and research has focused

primarily on optimizing cost reduction. Going forward, BETO will factor GHG reduction and other emission impacts into CAP designs and research focus.

Table 33: Comparison of Biorefinery-Level and Displacement SCSA Methods for CAP Pathway Based on Percent Reduction (Increase) over Petroleum-Derived Products

Method Used	2020 SOT		2025 Projection		2030 Projection	
	Via Acids	Via BDO	Via Acids	Via BDO	Via Acids	Via BDO
Fossil Energy Consumption Reductions^a						
Displacement ^b	-44%	-4%	-52%	-20%	-52%	-22%
Biorefinery Level	-20%	-2%	-24%	-9%	-26%	-11%
GHG Emission Reductions^a						
Displacement ^b	-92%	-67%	-97%	-74%	-90%	-72%
Biorefinery Level	-45%	-32%	-48%	-37%	-48%	-38%

^a For fossil energy consumption reductions and GHG emission reductions, negative values indicate reductions while positive values indicate increases.

^b The displacement method may lead to distorted results if the amount of coproduct is significant.

Wet Feedstocks Converted via High Temperature and Upgrading

BETO R&D includes two configurations for assessing the progress of technologies used in converting wet feedstocks via the high-temperature and upgrading pathways. Both designs use HTL conversion processes—one with an algal feedstock and the second using wet waste from wastewater treatment facilities. Each of these designs is described separately.

Algal Hydrothermal Liquefaction Design Case

For the FY 2017–FY 2019 SOTs, the process configuration was based on the original 2014 AHTL design case for a single-stage HTL and biocrude upgrading process co-located with an algae farm.⁷⁷ In this design, illustrated in Figure 36A, a biomass slurry is pumped to a single-stage HTL reactor, where hot, pressurized water converts the slurry to four phases: a thermally stable biocrude intermediate, an aqueous phase containing organic species, and solid and gaseous streams. These four streams are separated and the biocrude intermediate is hydrotreated to form diesel and some naphtha-range fuels. Process off-gas may be used to generate hydrogen, heat, and/or power. The aqueous phase contains significant levels of nitrogen and organic carbon that must be recovered for their value as nutrients and/or coproducts. The original AHTL design used catalytic hydrothermal gasification to recover and recycle nutrients (nitrogen and organic carbon). Subsequent research has identified nutrient recycling methods as the most cost-effective alternative. By recycling treated water containing dissolved CO₂ and NH₃, flue gas containing CO₂, and phosphorus recovered from treated HTL solids, nutrients are recovered and fed back to the algae ponds. This design also co-locates a hydrogen generation plant for biocrude hydrotreating with the algae ponds and HTL conversion. Process heat is partially recovered by steam generation and used for electricity generation.

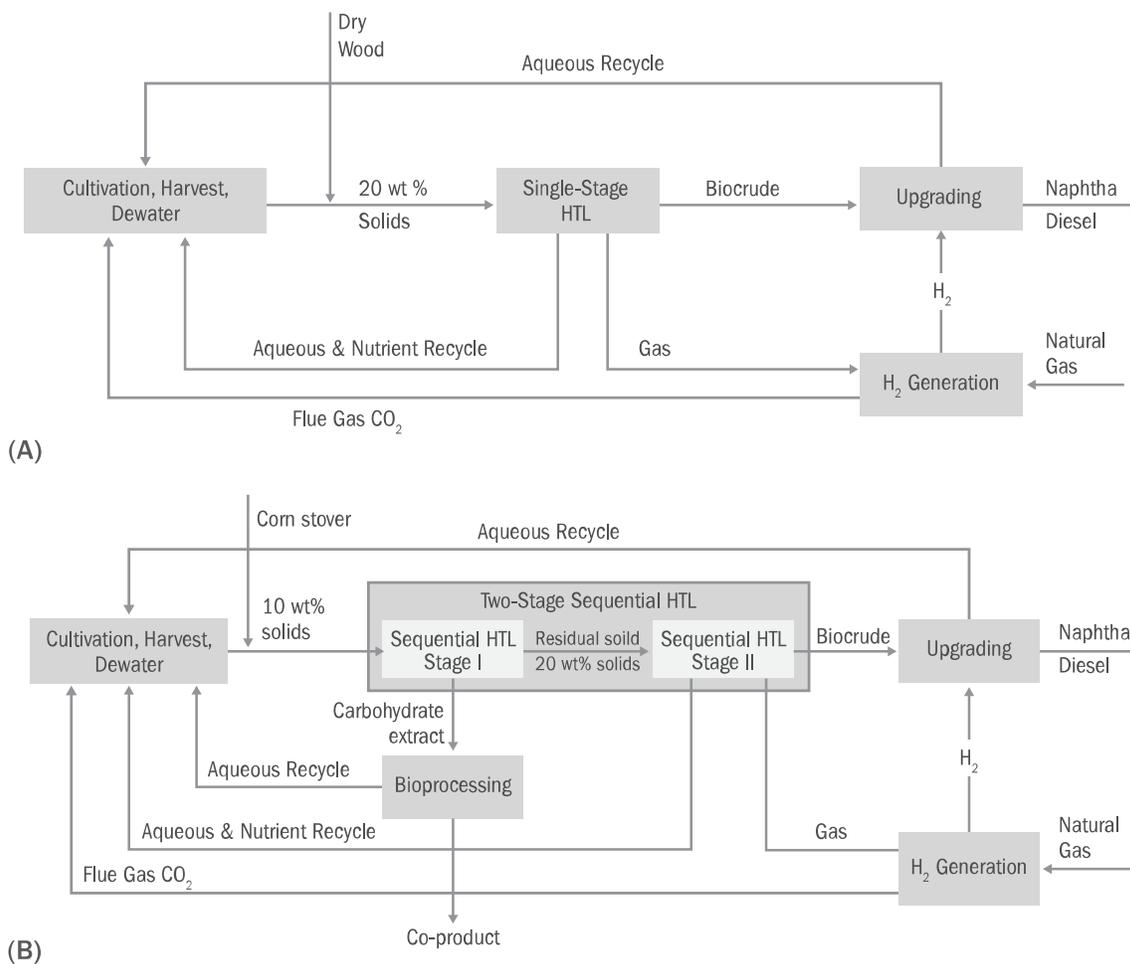
In the 2014 AHTL design, algae from summer peak production is assumed to be dried and stored for use in the lower-productivity seasons in order to provide a consistent conversion plant capacity throughout the year. Further cost reductions from the original AHTL design basis were achieved for the FY 2017–2019 SOTs by addressing seasonal variability through setting the plant scale equal to the summer algae productivity rate (see Table 26) and coprocessing algae with dry biomass (e.g., wood) supplement during non-summer seasons with low algal productivity. This eliminated drying a

⁷⁷ S. Jones, R. Davis, Y. Zhu, C. Kinchin, D. Anderson, R. Hallen, D. Elliott, et al. *Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading*. Richland, WA: Pacific Northwest National Laboratory, PNNL-23227, 2014. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf.

portion of peak season algae for later use, thus reducing capital costs for dryers and operating costs for natural gas.

For the FY 2020 SOT,⁷⁸ a two-stage SEQHTL algae conversion configuration was developed to enable generation of valuable coproduct and the associated economic benefit. In this design, illustrated in Figure 36B, algae only (in the summer season) or algae/corn stover blended feedstock (in non-summer seasons) is first processed in stage I using milder conditions than typical HTL to release the majority of carbohydrates from the biomass. Corn stover was selected as the non-algae feedstock supplement instead of wood, which was used in previous year SOTs, because corn stover demonstrated higher levels of carbohydrate extraction than wood in the prescreening tests. The carbohydrates from SEQHTL stage I are separated from the residual solid and sent to a bioprocessing section for coproduct generation via fermentation. Lactic acid is assumed to be the coproduct based on current bioprocessing testing results. Residual solid from stage I is further converted to biocrude in the SEQHTL stage II and subsequently hydrotreated to final fuel products, similar to the single-stage HTL case.

⁷⁸ Y. Zhu, S. B. Jones, A. J. Schmidt, H. M. Job, J. M. Billing, J. R. Collett, et al. *Microalgae Conversion to Biofuels and Biochemical via Sequential Hydrothermal Liquefaction (SEQHTL) and Bioprocessing: 2020 State of Technology*. Richland, WA: Pacific Northwest National Laboratory, PNNL-30124, 2021. <https://www.osti.gov/servlets/purl/1784347>.



Figures 36A–36B: Process flow diagram for the conversion of algal feedstocks to hydrocarbon fuels and coproduct via high-temperature deconstruction with upgrading via (A) single-stage and (B) sequential HTL

Figure 37 shows the SOT MFSP, projections assuming R&D improvements in coproduct yield (see Table 38), and algae pond productivities, scales, and costs for the 2025 and 2030 cases. Note that the MFSP for the 2025 projected case is higher than the 2020 SOT. This is due in part to the fact that the algae pond 2025 case has lower summer productivity than the 2020 SOT (27.7 g/m²/d for the 2025 case and 31.6 g/m²/d for the 2020 SOT). The summer productivity rate sets the HTL plant scale, so lower summer productivity means smaller scale, which increases capital and conversion costs. Also, the 2025 algae pond case has a smaller gap between the summer and other seasonal productivities than the 2020 SOT. Therefore, less corn stover is needed in the non-summer seasons for the 2025 case, which results in a higher annual average algae/corn stover blend ratio and feedstock cost (see Table 38). Also included for reference in Figure 37 is the MFSP for the original 2014 design case based on the single-stage HTL configuration.

It is evident from Figure 37 that costs for the AHTL pathway are dominated by algae feedstock production costs, and even with coproduct credits from the SEQHTL configuration and projected improvements in the process and algae productivity, the projected 2030 case does not meet the $\leq \$2.5/\text{GGE}$ target. For this reason, a pivot to low-cost algal feedstocks will be made in FY 2021 and moving forward. These may include algae used for water cleanup or remediation (e.g., turf scrubber), nuisance algae blooms, or macroalgae. Development of a new design case that addresses ways to reduce the feedstock production cost, brings value through coproducts, and can enable the 2030 target is being considered.

The algal biomass compositions for the SOTs and projections are shown in Table 34, and the elemental compositions of woody biomass (forestry residue), corn stover, and annual average blends of these feedstocks with algae assumed for the 2019 and 2020 SOTs are given in Table 35. The 2017 and 2018 SOTs assumed the same algae and wood feedstock with different blending ratios on an annual average basis, which depend on the algae seasonal production rates of each year.

Figure 38 and Table 36 show the conversion cost contributions to MFSP for algae-based biofuel produced via the AHTL pathway based on the technical parameters shown in Table 38. While the addition of the SEQHTL configuration bioprocessing section for the 2020 SOT increases the overall plant capital cost, coproduct credits significantly reduce the overall conversion cost contribution to the MFSP. Improved carbohydrate yields assumed for the 2025 and 2030 cases further reduce conversion costs.

Figure 39 shows that the main drivers influencing MFSP in the 2020 SOT case are algae feedstock cost, HTL plant scale, HTL biocrude yield, and coproduct price and yield. Although the AHTL process design is less sensitive to biomass composition than the CAP design, biomass composition still affects the MFSP (for reference, see the appendix, barriers Aft-E and Aft-G).

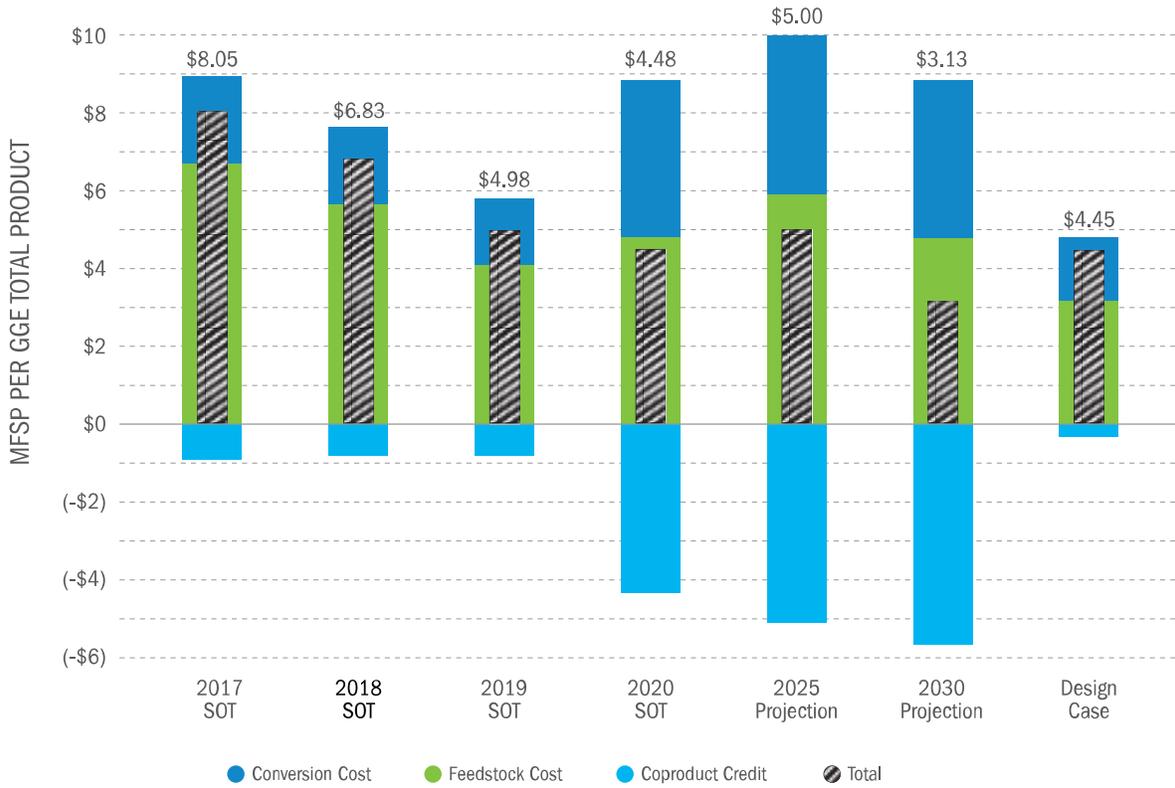


Figure 37: Cost contribution of feedstock and conversion for the algae converted via high-temperature and upgrading pathway⁷⁹

⁷⁹ The 2015 design included wastewater treatment for the 2025 projection. The 2017 SOT showed that wastewater treatment was not necessary, resulting in a reduction in 2018–2019 SOT costs. An update to the 2025 design is forthcoming in FY 2021.

Table 34: Algae Feedstock Composition for 2015–2020 SOTs and AHTL Projection Cases

Composition	2015–2016 SOTs	2017–2019 SOTs	2020 SOT, 2025, and 2030 Projections	Design Case
Elemental (wt % AFDW)				
Carbon	49.5	53.8	53.5	59.4
Hydrogen	6.8	7.5	7.1	8.6
Oxygen	35.3	30.8	28.6	25.1
Nitrogen	6.4	7.2	8.4	5.5
Sulfur	2.1	0.6	2.4	0.7
Total	100	100	100	100
Component (dry wt %)				
Ash	23.4	13.9	10.5	13
Phosphorus (in	0.5	0.3	1.1	0.7
Carbohydrates	28.1	23.7	17.7	19.1
Protein	28.1	38.6	65.3	31.3
Lipids	11.8	23.7	6.6	20.8
Other ^a	6.7	--	--	14.5
Total	98	100	100	99

*For 2017–2020 SOTs and projections, content data for “other” are unavailable and not listed in the table.

Table 35: Elemental Compositions of Algal and Non-Algal Biomass Feedstocks for AHTL 2019–2020 SOT and Projection Cases*

2017 to 2019 SOT Feedstock	Algae	Woody Biomass (Logging Residue)
Elemental (wt % AFDW)		
Carbon	53.8	50.0
Hydrogen	7.5	6.2
Oxygen	30.8	43.6
Nitrogen	7.2	0.2
Sulfur	0.6	0
Total	100	100
Inorganic Species (wt % Dry Basis)		
Phosphorus (in Ash)	0.3	0
2020 SOT Feedstock	Algae	Corn Stover
Elements (wt % AFDW)		
Carbon	53.5	49.1
Hydrogen	7.1	6.0
Oxygen	28.6	44.2
Nitrogen	8.4	0.7
Sulfur	2.4	0
Total	100	100
Inorganic Species (wt % Dry Basis)		
Phosphorus (in Ash)	1.1	0

*Algae, wood, and corn stover compositions data are from algae HTL testing conducted by Pacific Northwest National Laboratory. Non-algal biomass feedstock is added in non-summer seasons until the total feedstock flow rate matches the summer algae flow rate, thus maintaining stable conversion capacity.

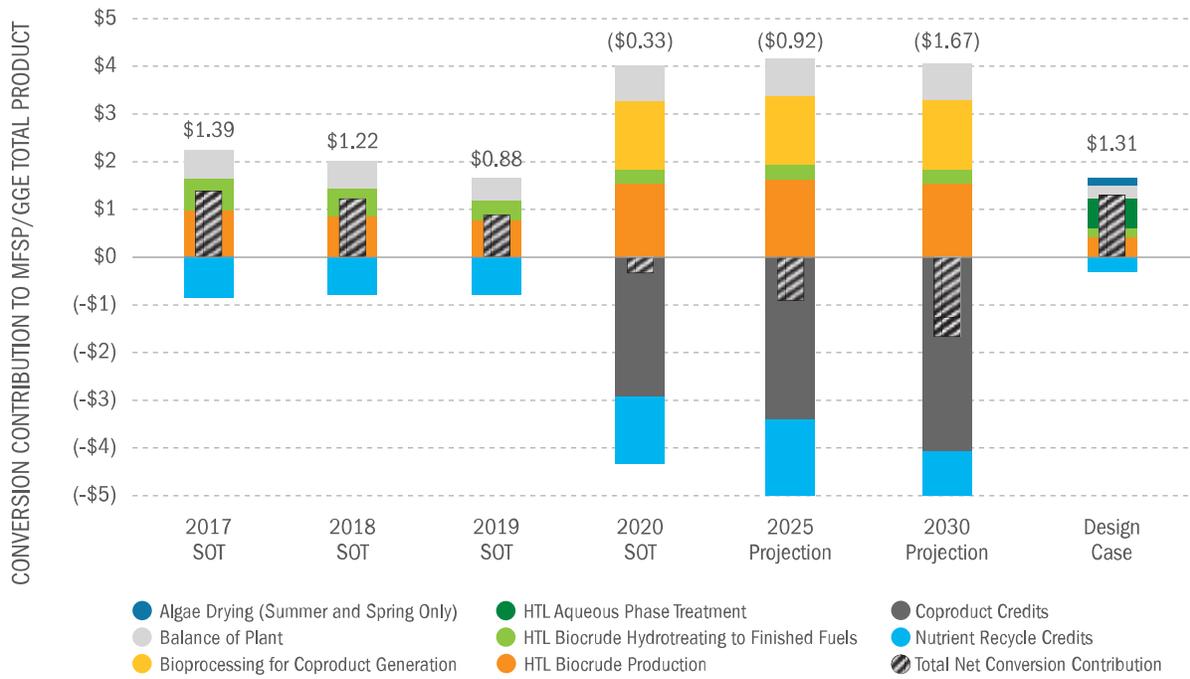


Figure 38: Conversion cost contributions for AHTL conversion and biocrude upgrading pathway

Table 36: Cost Contribution by Conversion Process Areas for the AHTL Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	Design Case
Algae Drying (summer and spring only)*	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.12
HTL Biocrude Production	\$0.95	\$0.84	\$0.75	\$1.54	\$1.62	\$1.53	\$0.43
HTL Biocrude Hydrotreating to Finished Fuels	\$0.69	\$0.59	\$0.42	\$0.30	\$0.32	\$0.30	\$0.22
HTL Aqueous Phase Treatment	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.61
Bioprocessing for Coproduct Production	\$0.00	\$0.00	\$0.00	\$1.43	\$1.43	\$1.45	\$0.00
Balance of Plant	\$0.61	\$0.57	\$0.49	\$0.74	\$0.79	\$0.76	\$0.25
Coproduct Credits	\$0.00	\$0.00	\$0.00	(\$2.92)	(\$3.41)	(\$4.08)	\$0.00
Nutrient Recycle Credits	(\$0.86)	(\$0.78)	(\$0.78)	(\$1.43)	(\$1.67)	(\$1.62)	(\$0.32)
Net Conversion Contribution to MFSP	\$1.39	\$1.22	\$0.88	(\$0.33)	(\$0.92)	(\$1.67)	\$1.31

*Note: The 2017, 2018, and 2019 SOT investigated blending woody biomass with the algae slurry to offset diminished algae biomass production during winter months; thus, the cost of drying and storage is \$0.00 in these SOTs.

Table 37: Process Efficiency Metrics for AHTL SOT and Projections

Sustainability and Process Efficiency Metrics	Units	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection
Fuel Yield by Weight of Biomass*	% w/w of dry biomass	0.30	0.32	0.30	0.22	0.22	0.22
Carbon Efficiency to Fuels	% C in feedstock	54%	58%	53%	41%	39%	39%
Carbon Efficiency to Coproduct	% C in feedstock	0%	0%	0%	10%	11%	13%
Net Electricity Import (Entire Process)	kWh/GGE	0.76	0.70	0.76	3.44	3.47	3.48
Purchased Natural Gas Import (Entire Process)	Btu/GGE (LHV)	38,491	36,285	39,105	92,233	98,018	105,922

*Note: The biomass or feedstock for FY 2017 to 2018 SOT cases is algae with wood supplement in non-summer seasons; the biomass or feedstock for FY 2020 SOT and 2025/2030 projected cases is algae with corn stover supplement in non-summer seasons; the biomass in the table represents all biomass used in the system, not algae only.

Table 38: Unit Operation Cost Contribution Estimates and Technical Projections for Algae Hydrothermal Liquefaction and Upgrading to Naphtha and Diesel*

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	Design Case
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE	\$8.05	\$6.83	\$4.98	\$4.48	\$5.00	\$3.13	\$4.45
Conversion Contribution	\$/GGE	\$1.39	\$1.22	\$0.88	(\$0.33)	(\$0.92)	(\$1.67)	\$1.31
Production Diesel	MMGGE/yr	7.1	8.9	14	11.8	10.3	12.9	24
Production Naphtha	MMGGE/yr	3.6	4.0	6.6	6.3	5.47	6.9	4.7
Diesel Yield (AFDW Feedstock Basis)	GGE/ton feedstock	69	79	70	51	49.7	50	130
Naphtha Yield (AFDW Feedstock Basis)	GGE/ton feedstock	35	36	33	27	26.5	27	25
Diesel Yield (Areal Basis)	GGE/acre/yr	1,416	1,771	2,746	2,365	2,053	2,583	4,851
Naphtha Yield (Areal Basis)	GGE/acre/yr	724	800	1,310	1,261	1,095	1,377	948
Coproduct Yield (AFDW Feedstock Basis)	lb/lb feedstock	0	0	0	0.12	0.13	0.16	N/A
Natural Gas Usage-Drying (AFDW Feedstock Basis)	scf/ton feedstock	0	0	0	0	0	0	1,798
Natural Gas Usage-H ₂ Gen (AFDW Feedstock Basis)	scf/ton feedstock	4,078	4,228	4,085	7,387	7,591	8,220	1,473
Carbon Efficiency, C in Fuel/C in Feedstock	%	54%	58%	53%	41%	39%	39%	70%
Carbon Efficiency, C in Coproducts/C in Feedstock	%	0%	0%	0%	10%	11%	13%	N/A
Feedstock								
Total Cost Contribution	\$/GGE fuel	\$6.66	\$5.61	\$4.10	\$4.81	\$5.91	\$4.80	\$3.14
Feedstock Type		algae/ wood blend	algae/ wood blend	algae/ wood blend	algae/corn stover blend	algae/corn stover blend	algae/corn stover blend	mid-lipid <i>Scenedesmus</i>
Feedstock Cost (AFDW Basis)	\$/ton feedstock	\$694	\$643	\$421	\$379	\$450	\$366	\$488
Algae Drying (summer and spring only)								
Total Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.12
Capital Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.05
Operating Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.06

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	Design Case
HTL Biocrude Production								
Total Cost Contribution	\$/GGE fuel	\$0.95	\$0.84	\$0.75	\$1.54	\$1.62	\$1.53	\$0.43
Capital Cost Contribution	\$/GGE fuel	\$0.56	\$0.50	\$0.47	\$0.56	\$0.58	\$0.55	\$0.29
Operating Cost Contribution	\$/GGE fuel	\$0.39	\$0.34	\$0.28	\$0.98	\$1.03	\$0.99	\$0.14
Liquid Hourly Space Velocity	vol/h/vol	4.0	4.0	4.0	stage I: 4; stage II: 3.5	stage I: 4; stage II: 3.5	stage I: 4; stage II: 3.5	8.0
HTL Carbohydrate Extraction	%, extracted/ carbohydrate in feedstock	0%	0%	0%	58%	66%	65%	N/A
HTL Biocrude Yield (AFDW)	lb/lb feedstock	0.41	0.45	0.41	0.30	0.29	0.29	0.59
HTL Biocrude Hydrotreating to Finished Fuels								
Total Cost Contribution	\$/GGE fuel	\$0.69	\$0.59	\$0.42	\$0.30	\$0.32	\$0.30	\$0.22
Capital Cost Contribution	\$/GGE fuel	\$0.30	\$0.27	\$0.23	\$0.17	\$0.18	\$0.17	\$0.12
Operating Cost Contribution	\$/GGE fuel	\$0.39	\$0.32	\$0.19	\$0.13	\$0.14	\$0.13	\$0.09
Mass Yield on Dry HTL Biocrude	lb/lb biocrude	0.81	0.82	0.81	0.83	0.83	0.83	0.83
HTL Aqueous Phase Treatment								
Total Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.61
Capital Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.35
Operating Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.26
Bioprocessing for Coproduct Generation								
Total Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$1.43	\$1.43	\$1.45	\$0.00
Capital Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.64	\$0.59	\$0.57	\$0.00
Operating Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.79	\$0.84	\$0.88	\$0.00
Fermentation Productivity	g/L-hr	0	0	0	0.46	1.00	1.00	N/A
Fermentation Process Yield	g product/g extracted carbohydrates	0.00	0.00	0.00	0.37	0.46	0.56	N/A

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2025 Projection	2030 Projection	Design Case
Balance of Plant								
Total Cost Contribution	\$/GGE fuel	\$0.61	\$0.57	\$0.49	\$0.74	\$0.79	\$0.76	\$0.25
Capital Cost Contribution	\$/GGE fuel	\$0.29	\$0.28	\$0.23	\$0.41	\$0.44	\$0.41	\$0.15
Operating Cost Contribution	\$/GGE fuel	\$0.31	\$0.29	\$0.26	\$0.34	\$0.35	\$0.35	\$0.10
Coproduct Credits	\$/GGE fuel	\$0.00	\$0.00	\$0.00	(\$2.92)	(\$3.41)	(\$4.08)	\$0.00
Nutrient Recycle Credits	\$/GGE fuel	(\$0.86)	(\$0.78)	(\$0.78)	(\$1.43)	(\$1.67)	(\$1.62)	(\$0.32)

*Note: The table may contain small (<\$0.01) errors due to the difference between the way that values were rounded.

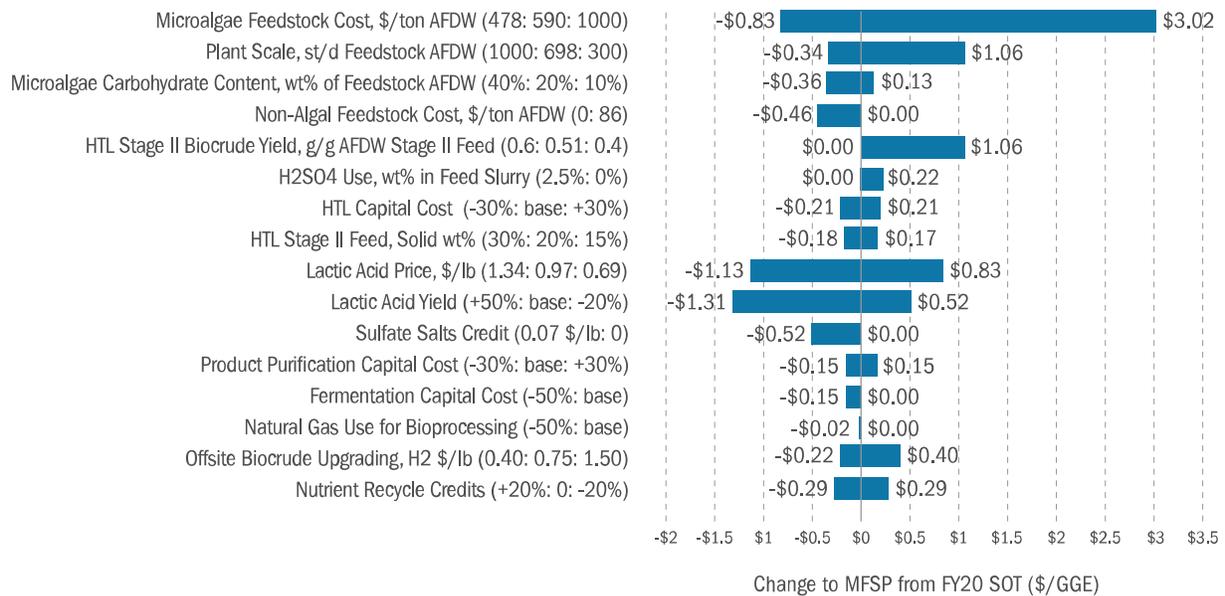


Figure 39: Key factors influencing AHTL MFSP compared with the 2020 SOT baseline

Integration and Scale-Up

Process steps and unit operations developed for the AHTL pathway at the R&D scale will need to be integrated and tested to ensure technical targets can be reached when run as an integrated process. Key integration challenges include:

- Robust operations for handling solid algal and terrestrial biomass streams during coprocessing operations, including reliably feeding materials into pressurized HTL reactors (for reference, see the appendix, barriers SDI-B and SDI-F).
- Achieving efficient separation of process streams from the HTL reactor, involving carbohydrate (for SEQHTL), solid, liquid, and gas phases (for reference, see the appendix, barrier SDI-D).
- Improving the conversion of HTL biocrude phase into hydrocarbon fuels using hydrotreating operations (for reference, see the appendix, barrier SDI-G).
- Developing an efficient bioconversion process for carbohydrate or other biochemical extract from algae pretreatment (for reference, see the appendix, barrier SDI-F).
- Developing efficient product separation and purification schemes for coproducts generation.
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barriers SDI-A and SDI-D).

- Addressing abrasion and corrosion of plant equipment due to ash and other inorganic species present in the algal and terrestrial feedstocks (for reference, see the appendix, barrier SDI-H).
- Developing nutrient recycling methods to improve algal productivity and profitability (for reference, see the appendix, barriers Aft-J and SDI-F).

Supply Chain Sustainability Analysis

Beginning with the 2020 SOT, the algae HTL pathway started using the SEQHTL process design, which included the production of a lactic acid coproduct. The 2020 SOT and projections also include blending of corn stover (instead of logging residues used previously) with saline algae as a feedstock blend. All SOTs and the 2030 projection SCSA results for the algae HTL pathway assume algae cultivation with Florida evaporation rates in unlined ponds using saline algae strains.

Table 39 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions from the algae HTL design cases using the displacement method.⁸⁰ The SCSA results for the 2020 SOT and 2030 projection consider the impact of all finished products from the SEQHTL designs. Notably, beginning with the 2020 SOT, this includes modeling of lactic acid (LA) synthesis and incorporation of associated coproduct credits for displacing conventional corn-based LA into the SCSA results.

⁸⁰ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 39: Supply Chain Sustainability Analysis for the AHTL SOT and Projections (Displacement Method)

	2017 SOT	2018 SOT	2019 SOT	2020 SOT	2030 Projection	Petroleum Diesel
Biofuel Yield						
MMBtu/dry ton	12.1	13.3	11.9	9.1	8.9	
Fossil Energy Consumption^a						
MJ/MJ	0.70 (-42%)	0.61 (-49%)	0.61 (-49%)	1.0 (-20%)	1.0 (-20%)	1.2
Net Energy Balance^b						
MJ/MJ	0.30	0.39	0.39	0	0	
GHG Emissions						
g CO ₂ e/MJ	59 (-38%)	49 (-48%)	45 (-52%)	76 (-17%)	76 (-16%)	91
g CO ₂ e/GGE	7,185	5,946	5,500	9,300	9,360	11,157
Water Consumption						
gal/MJ	0.06	0.06	0.05	-0.06	-0.12	0.02
gal/GGE	7.8	6.8	5.8	-7.5	-15.1	2.7
Total NO_x Emissions						
g NO _x /MJ	0.12	0.09	0.09	0.08	0.06	0.06
g NO _x /GGE	14.8	10.7	10.1	10.2	7.5	7.0
Urban NO_x Emissions^c						
g NO _x /MJ	0.025	0.025	0.025	0.03	0.02	0.03
g NO _x /GGE	3.04	3.03	3.03	3.8	2.6	3.3

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT, 2030 projection, and petroleum reference emissions and water consumption values are based on the GREET2020 model. Prior year SOTs are based on the GREET2019 model.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

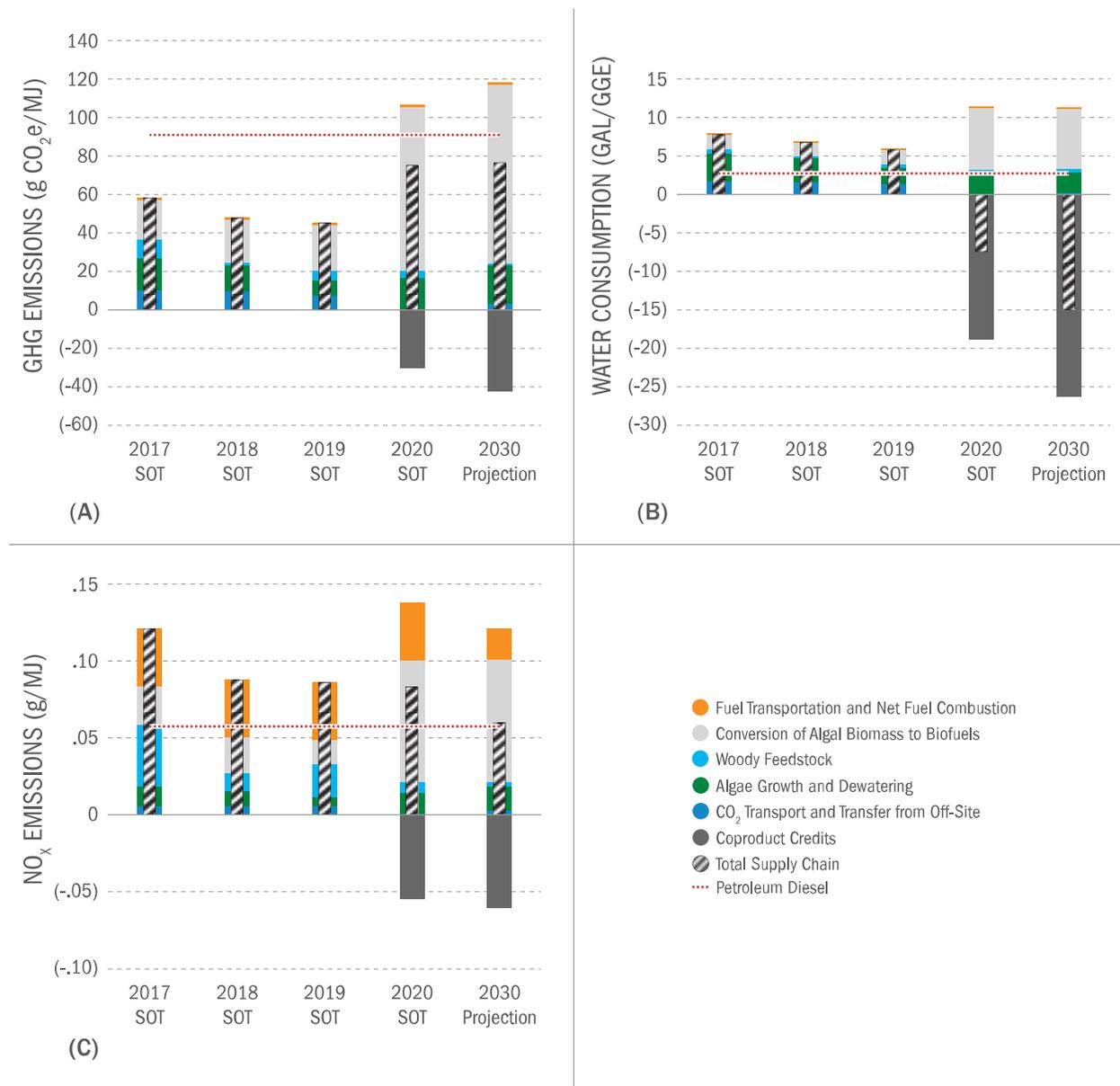
^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

Figure 40A shows the 2017 through 2020 SOT and 2030 projection results for supply chain GHG emissions and their key contributing supply chain processes compared with a life cycle carbon intensity of 91 g CO₂e/MJ for petroleum-derived diesel. The change to the SEQHTL process design in the 2020 SOT and 2030 project cases is driven by potential for process cost reductions through

incorporation of coproduct credits discussed earlier. As indicated by the data in Table 39 and Figure 40A, these process changes result in increased GHG emissions compared with prior year SOTs. Although the LA coproduct generates -30 to -42 g CO₂e/MJ credits for displacing corn-based LA in the 2020 SOT and 2030 projection cases, this is more than offset by the increased emissions for algae production and conversion processes. The 2020 SOT and 2030 projection result in 17% and 16% reductions in GHG emissions, respectively, compared to petroleum-derived diesel. Natural gas consumption for on-site hydrogen production via steam methane reforming, and energy consumption for CO₂ capture and transportation to the algae farm and for algae growth and dewatering are the major emission sources. Reduced energy consumption for algae dewatering and increased biofuel yield are the key factors driving improvements in GHG emissions from the 2017 to the 2019 SOT cases. The addition of co-fed corn stover only has a small impact on emissions in the 2020 SOT and 2030 projection cases.

Figure 40B shows renewable diesel produced by the SEQHTL process used in the 2020 SOT and 2030 projection has the potential to significantly reduce water consumption relative to petroleum-derived diesel. This is due to the large displacement credit associated with coproduct LA relative to corn-based LA. The embedded water consumption associated with energy consumption for algae dewatering and for CO₂ capture and transportation to the algae farm are the major contributors to supply chain water consumption in all SOT and projection cases.

Figure 40C shows that total NO_x emissions remain higher than petroleum diesel in the 2020 SOT case. Projected process improvements result in NO_x emissions comparable to petroleum diesel in the 2030 projection. Improvements in NO_x emissions for the 2020 SOT and 2030 projection cases result largely from displacement credits for the LA coproduct, which offset NO_x emission increases in algae production and conversion compared to prior year SOTs. The 2030 SEQHTL design may result in benefits in urban NO_x emission reductions, as shown in Table 39.



Figures 40A–40C: Supply chain for the AHTL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Alternative SCSA Methodologies

Similar to the biochemical and CAP conversion pathways, a key issue in dealing with coproducts from the AHTL designs is how to capture their environmental impacts, especially under the current, fuel-focused GHG regulations. In Table 39 and Figure 40, coproducts are accounted for using a displacement method that attributes all the supply chain emission burdens to the fuel product, but also attributes all avoidance of emissions that otherwise would have taken place with the incumbent technology to produce the coproduct—or coproduct displacement credit—to the fuel product. As seen for the 2020 SOT and 2030 projections in Figure 40, this creates significant

coproduct displacement credits, which may overestimate the actual benefits that these pathways would provide.

As discussed in the Dry Feedstocks Converted via Low Temperature and Upgrading section of this report, beginning with the 2020 SCSA, BETO and ANL began evaluating other methods of accounting for coproduct credits. These included process-level allocation and biorefinery-level methods. For this 2020 SOT update, BETO and ANL believe the biorefinery-level method may more accurately reflect the actual impact of coproducts on biorefinery systems. BETO and ANL will continue to discuss how to accurately reflect the SCSA impact of coproducts. For transparency, ANL has published all three methods in their 2020 SCSA publication.⁸¹

Table 40 presents the biorefinery-level results for the 2020 SOT and 2030 projection cases for AHTL pathway using the SEQHTL process based on a 5,000-acre algae farm with year-over-year improvements in cultivation productivity (Table 26). Based on 330 biorefinery operating days per year, this results in 633 and 713 dry metric tons/day of biomass (algae + corn stover) processed in the 2020 SOT and 2030 projection cases, respectively. When comparing with the biochemical cases, it's important to note the biorefinery scale for AHTL cases is about one-third of the 2,000-dry-metric-tons/day scale used in those cases.

⁸¹ Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 40: Biorefinery-Level Emissions and Consumption Reductions Summary for AHTL Pathways Using Mass-Based Allocation

		2020 SOT	2030 Projection
Plant Capacity			
Algae Processed (AFDW basis)	dry metric ton/yr	121,273	168,332
Corn Stover Processed (AFDW basis)	dry metric ton/yr	87,629	67,123
Total Biomass Processed	dry metric ton/yr	208,902	235,455
Renewable Diesel Production	GGE/yr	11,823,331	12,913,131
Renewable Naphtha Production	GGE/yr	6,304,769	6,885,903
Total Biofuel Production	GGE/yr	18,128,101	19,799,034
Lactic Acid Production	metric ton/yr	24,813	37,943
Fossil Energy Consumption Reductions^a			
By Biofuel Production ^b	MMBtu/yr	-1,064,666	-1,275,513
By Lactic Acid Production ^b	MMBtu/yr	541,451	706,167
Total Reduction	MMBtu/yr	-523,215	-569,346
GHG Emission Reductions^a			
By Biofuel Production ^b	metric ton CO ₂ e/yr	-81,287	-96,551
By Lactic Acid Production ^b	metric ton CO ₂ e/yr	46,720	59,577
Total Reduction	metric ton CO₂e/yr	-34,568	-36,973

^a Negative values indicate reductions while positive values indicate increases.

^b The contributions of biofuel and lactic acid production are based on mass-based, process-level allocation.

As indicated by the results in Table 40, an AHTL biorefinery at this scale results in about 35,000 metric tons per year of GHG reduction compared with incumbent petroleum diesel and corn-based LA production. Unlike the biochemical and CAP cases, in the algae SEQHTL cases all emission reduction benefits derive from biofuel production. The LA coproduct actually increases biorefinery-level emissions due to its higher carbon intensity relative to corn-based LA. This largely offsets the benefits of biofuels production and results in 11% net GHG reduction for the 2030 projection compared to petroleum diesel and corn-based LA (Table 41). By comparison, the displacement method indicates 16% GHG benefit compared to incumbent renewable diesel and LA products. It's important to note that historically, AHTL pathway design and research has focused primarily on optimizing cost reduction. Going forward, BETO plans to use SCSA in conjunction with TEA to focus its research and development activities in this pathway.

Table 41: Comparison of Biorefinery-Level and Displacement SCSA Methods for AHTL Pathways Based on Percent Reduction (Increase) over Petroleum-Derived Products

Method Used	2020 SOT	2030 Projection
Fossil Energy Consumption Reductions^a		
Displacement ^b	-20%	-20%
Biorefinery Level	-15%	-14%
GHG Emission Reductions^a		
Displacement ^b	-17%	-16%
Biorefinery Level	-13%	-11%

^a For fossil energy consumption reductions and GHG emission reductions, negative values indicate reductions while positive values indicate increases.

^b The displacement method may lead to distorted results if the amount of coproduct is significant.

Wet Waste Hydrothermal Liquefaction Design Case

Hydrothermal liquefaction of wet waste sludges (also called biosolids) produced by wastewater treatment facilities represents a second design used to assess technology development progress in the wet waste converted via the high-temperature and upgrading pathway. Research into this design helps identify key challenges and informs R&D priorities associated with conversion processes designed for distributed wet waste feedstocks and separations, as well as hydroprocessing of biocrude.

This pathway uses primary and secondary sludge from municipal water resource recovery facilities (WRRFs). These facilities currently incur sludge disposal costs, including drying, dewatering, and costs for transportation to composting or landfilling; treatment for land application; or incineration. In addition, tipping fees are frequently levied on these wastes by landfills and composting facilities. These sludge disposal costs, which can be as high as \$800/dry ton,⁸² are expected to increase as states and local governments implement organics diversion regulations that often include municipal sludges. Note that the modeled MFSP for the SOT does not include the avoided disposal savings at this time.

In water treatment, raw wastewater is first screened to remove large debris and then treated to separate solids through physical settling, often aided by chemical flocculants. This primary sludge constitutes about 50%–60% of the total solids. Solids concentrations of the wastewater are then reduced to 4%–6% and sent to secondary (aerobic) treatment, where a combination of aeration and exposure to microbes converts the remaining organic species, as well as nitrogen and phosphorus, into microbial biomass. After settling, this solids fraction is referred to as secondary sludge. In wastewater treatment operations where anaerobic digestion is employed as a means of managing primary and secondary sludge volumes, approximately 50% of the carbon in that stream is converted to biogas. This remaining sludge requires further thermal or pressure treatment in order to conform to U.S. Environmental Protection Agency biosolids disposal regulations.⁸³ Typically, the remaining, unconverted sludge is transported to landfills for disposal, further treated for land application, incinerated, or sent for composting, posing significant transportation costs.

As a resource, sludge is highly correlated with population areas—meaning that the proximity to fuel markets is high. This means that the most economically advantageous deployments of this technology would be located at or near the largest wastewater and sanitation facilities. While there

⁸² Badgett, A., E. Newes, and A. Milbrandt. “Economic analysis of wet waste-to-energy resources in the United States.” *Energy* 176 (2019) 224–234. <https://doi.org/10.1016/j.energy.2019.03.188>.

⁸³ U.S. Environmental Protection Agency. “Biosolids Laws and Regulations.” Accessed February 2019. <https://www.epa.gov/biosolids/biosolids-laws-and-regulations>.

may be opportunities to source sludge from multiple facilities, the transportation costs of aggregating sludge, which commonly comprises about 95% water, could make it cost-prohibitive. Unlike algae, where farms can potentially be upscaled, this creates challenges for economies of scale, requiring technologies that are down-scalable with a resulting energy-dense biocrude transported for centralized upgrading.

The conceptual design for utilizing wastewater sludges is represented in Figure 42.⁸⁴ Primary and secondary sludge from a wastewater treatment facility is mixed and sent to an on-site HTL reactor. Hydrothermal liquefaction operates quite similar to the AHTL design described previously. In the HTL reactor, hot, pressurized water converts this slurry to four phases: a thermally stable biocrude intermediate, an aqueous phase containing organic species, and solid and gaseous streams. The biocrude fraction is transported to a centralized unit, where it is hydrotreated to produce hydrocarbon fuel blendstocks. Ammonia is removed from the aqueous stream via an NH₃ stripping process to render the aqueous phase suitable for wastewater treatment. Note that NH₃ stripping will not be required for all WRRFs depending on their unique process limitations and discharge permit limits. The composition of primary and secondary sludge, illustrated in Table 42, resembles algae due to the high water content and elevated levels of nitrogen and sulfur.

Collection practices and infrastructure for wastewater sludges are well developed in the wastewater treatment industry. The primary wet waste feedstock-related barrier is the cost of transportation, and by extension, dewatering costs. This is addressed in the design case by directly processing wet wastes at the wastewater treatment site, then transporting the resulting biocrude for centralized upgrading. Because this approach avoids sludge transportation and disposal costs, the current design and SOTs do not include feedstock production costs (Figure 41).⁸⁵ The analysis also does not include disposal costs that would be potentially avoided (i.e., feedstock credit) that are currently incurred at a WRRF. Additional technical challenges may be

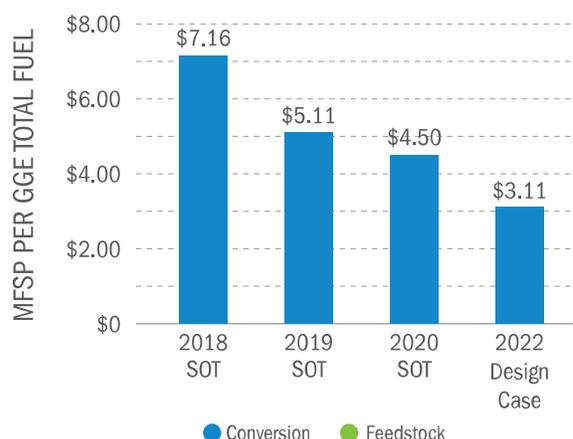


Figure 41: Cost breakdown showing no feedstock cost or credit for wet waste converted via the high-temperature and upgrading pathway (with NH₃ removal from HTL water)

⁸⁴ L. J. Snowden-Swan, R. T. Hallen, Y. Zhu, T. R. Hart, M. D. Bearden, J. Liu, T. E. Seiple, et al. *Conceptual Biorefinery Design and Research Targeted for 2022: Hydrothermal Liquefaction Processing of Wet Waste to Fuels*. Richland, WA: Pacific Northwest National Laboratory, PNNL-27186, 2017. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-27186.pdf.

⁸⁵ L. J. Snowden-Swan, J. M. Billing, M. R. Thorson, A. J. Schmidt, Y. Jiang, D. M. Santosa, et al. *Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels: 2020 State of Technology*. Richland, WA: Pacific Northwest National Laboratory, PNNL-30982, 2021. <https://www.osti.gov/servlets/purl/1771363>.

identified for using existing wastewater treatment collection practices and infrastructure. These challenges could require the development of technologies for wet waste feedstock.

The HTL plant in the design case is scaled to process 110 dry tons/day of municipal sludge at 25% solids. This plant scale was selected as the approximate minimum size that is economically viable for a zero-cost sludge feedstock and corresponds to a WRRF that processes about 110 million gallons per day of incoming wastewater. Smaller plants may be viable if avoided sludge disposal costs are considered. BETO is exploring ways to increase the available resources and take advantage of economies of scale through blending with other urban and suburban wastes (e.g., food waste and yard waste). The centralized upgrading plant in the design is sized to process the output of 10 HTL plants processing 110 dry tons/day, which corresponds to about 115,000 gal/day of biocrude. This corresponds to production of 2,700 barrels per stream day or 39 million GGE/year of fuel blendstocks.

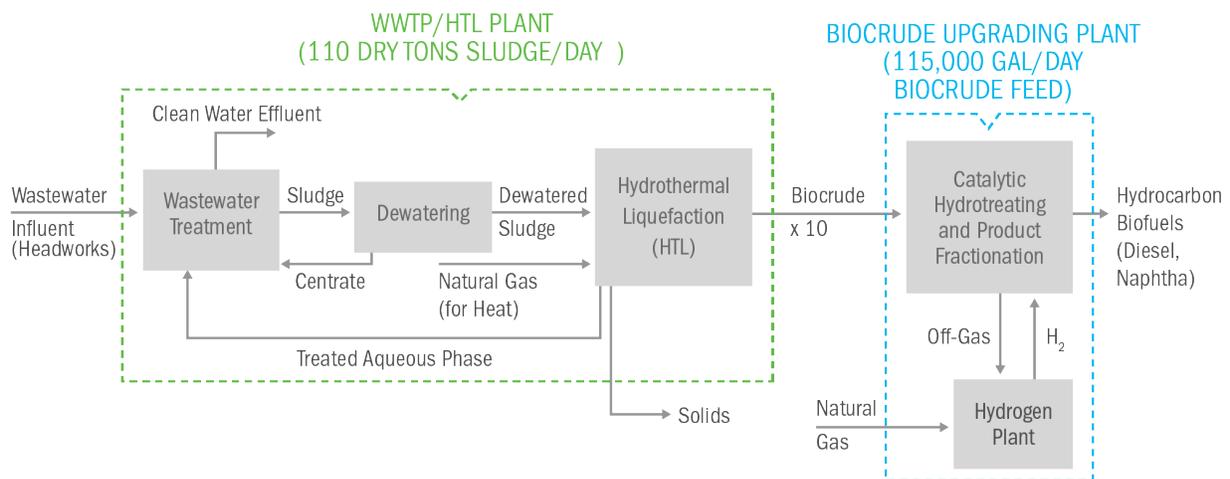


Figure 42: Process flow diagram for the conversion of wet waste feedstocks to hydrocarbon fuels via high-temperature deconstruction with upgrading

Table 42: Composition of Various Sludges (Elemental Content Shown on a Dry Weight Basis)^{86,87}

Feedstock	Weight %						Moisture Content (%)	Volatile Matter (%)	HHV (MJ/kg)
	C	H	N	O	S	Ash			
Primary Sludge	47.8	6.50	3.64	33.6	0.48	7.5	95.5	82.2	20.7
Secondary Sludge	43.6	6.55	7.90	29.0	0.72	16.2	96.1	76.3	19.6
Post-Digester Sludge	38.7	5.68	4.48	27.9	1.63	28.1	~72	N/A	16.8

⁸⁶ P. A. Marrone. *Genifuel Hydrothermal Processing Bench-Scale Technology Evaluation Report*. Alexandria, VA: Water Environment and Reuse Foundation; London: IWA Publishing, 2016. <https://doi.org/10.2166/9781780408408>.

⁸⁷ P. A. Marrone, D. C. Elliott, J. M. Billing, R. T. Hallen, T. R. Hart, P. Kadota, J. C. Moeller, M. A. Randel, and A. J. Schmidt. "Bench-Scale Evaluation of Hydrothermal Processing Technology for Conversion of Wastewater Solids to Fuels." *Water Environment Research* (April 2018): 329–342. <https://doi.org/10.2175/106143017X15131012152861>.

Table 43 shows the variation in feedstock composition from three different locations. For the SOTs from 2018 to 2020 and the 2022 design case, sludge from the city of Detroit/Great Lakes Water Authority was used to develop the HTL experimental data and process models, with the exception of ash content, which was decreased from 26% to 15%. A lower ash content is chosen based on two reasons: (1) process knowledge from Detroit/Great Lakes Water Authority indicates that their ash content is likely on the high end of the potential range due to aging infrastructure and addition of FeCl_3 that is used for phosphorus removal in primary treatment; and (2) the goal case assumes that future renovations in aging collection systems and outdated processes will enable a reduced sludge ash content over time.

Figure 43 shows that biocrude yield from the hydrothermal liquefaction reactor is a significant contributor to the modeled MFSP for this process. BETO R&D focuses on improving the yield in several ways, such as incorporating other feedstocks (e.g., brown grease or food waste) frequently disposed at wastewater treatment facilities. These waste fractions also constitute disposal liabilities, as they require landfilling or incineration, and would be available at zero or negative costs. Further, researchers are working on optimizing the temperature and pressure conditions of the HTL reactor to convert additional organic species into biocrude (for reference, see the appendix, barrier Ct-I). Higher-temperature operation converts additional organics into biocrude, but can produce contaminants such as nitrogen and sulfur that result in increased hydrotreating severity.

Another significant opportunity to reduce costs is nitrogen management. At present, the aqueous stream in some cases cannot be directly recycled back to wastewater treatment because the nitrogen and/or carbon species in these streams can exceed effluent limits or cause operational upsets in the aerobic treatment process.

Table 43: Ultimate Analysis of 50/50 (wt) Primary/Secondary Wastewater Sludge Samples

50/50 Primary/Secondary Sludge Mixture Characteristics	Detroit/Great Lakes Water Authority ⁸⁸	Metro Vancouver ^{89,90}	Central Contra Costa Sanitation District ⁹¹	2018–2020 SOTs and 2022 Design Case	2018–2020 SOTs and 2022 Design Case
Component	wt % dry basis	wt % dry basis	wt % dry basis	wt % dry basis	wt % dry, ash-free basis
Carbon	41.1	45.7	43.3	46.8	52.1
Hydrogen	5.8	6.5	6.3	6.5	7.2
Oxygen	26.1	31.3	30.2	29.7	33.1
Nitrogen	5	5.8	4.5	5.7	6.3
Sulfur	1	0.6	0.6	1.2	1.3
Ash	26.1	11.9	16.7	15	-
Phosphorus	1.9	2	2.5	1.9	-

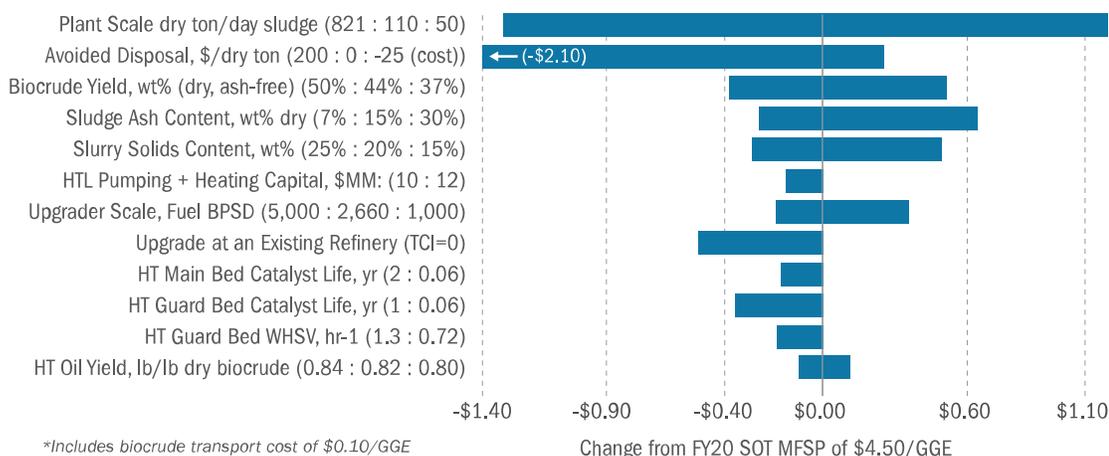


Figure 43: Key factors impacting production costs for the wet waste HTL design case

Figure 44 and Table 44 show the projected cost reductions for the conversion portion of the wet waste HTL pathway between the 2018 SOT and the 2022 projected MFSP, both with and without NH₃ removal for the HTL aqueous-phase recycle stream. Table 45 presents the corresponding process efficiency metrics for the SOT and design cases. Table 46 shows the unit operation, capital cost contributions, and technical targets for the SOT and design cases. Figure 44 shows the MFSP

⁸⁸ Snowden-Swan et al. 2017, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-27186.pdf.

⁸⁹ Marrone 2016, <https://doi.org/10.2166/9781780408408>.

⁹⁰ Marrone et al. 2018, <https://doi.org/10.2175/106143017X15131012152861>.

⁹¹ L. J. Snowden-Swan, J. M. Billing, M. R. Thorson, A. J. Schmidt, D. M. Santosa, S. B. Jones, and R.T. Hallen. *Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels: 2019 State of Technology*. Richland, WA: Pacific Northwest National Laboratory, PNNL-29882, 2020. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29882.pdf.

for removing NH₃ versus managing through existing wastewater treatment infrastructure. R&D improvements in this area can also reduce the modeled MFSP by reducing the amount of pH adjustment and associated lime consumption/disposal.

Research in 2020 focused on improvements to the configuration for sludge pumping and heating. Heat exchangers, which are used to pump sludge into the HTL reactor, account for a large percentage of the total capital cost for the HTL plant. The 2020 design changes allow for an approach to the heating and pumping process that is more scalable and accounts for the majority of cost savings relative to 2019. Additional cost reduction came from improvements in the HTL catalyst performance.

Additional R&D areas include increasing the solids loading to the HTL unit (for reference, see the appendix, barrier Ct-B), improving biocrude yields for sludge and through regional blending of sludge with other wet wastes, improving the hydrotreater catalyst performance, including lifetime and yield (for reference, see the appendix, barriers Ct-E and Ct-F), improving solid/liquid and liquid/liquid separations, and developing efficient processing schemes for treatment of the aqueous and solid phase with nutrient, energy, coproduct and/or water recovery. Several of these research areas are in preliminary stages and do not yet contribute to modeled costs. They are part of broader BETO strategies for assessing options for reaching future cost and performance goals. In the future, more rigorous projections will be developed to establish key technical targets and research objectives toward achieving 2025 and 2030 cost goals.

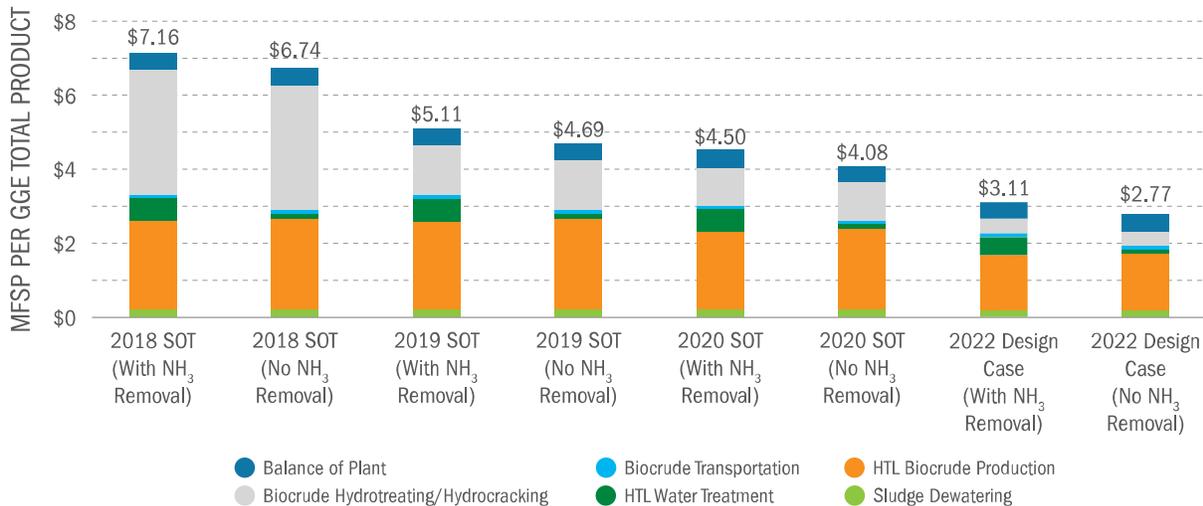


Figure 44: Cost projections for the wet waste HTL design case

Table 44: Cost Projections for the Wet Waste HTL Design Case

Conversion Cost Breakdown (\$/GGE)	2018 SOT		2019 SOT		2020 SOT		2022 Projection	
	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal
Sludge Dewatering	\$0.20	\$0.20	\$0.20	\$0.20	\$0.20	\$0.20	\$0.18	\$0.18
HTL Biocrude Production	\$2.40	\$2.45	\$2.40	\$2.45	\$2.12	\$2.18	\$1.49	\$1.55
HTL Water Treatment	\$0.61	\$0.13	\$0.61	\$0.13	\$0.62	\$0.13	\$0.49	\$0.09
Biocrude Transportation	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10
Biocrude Hydrotreating/Hydrocracking	\$3.38	\$3.38	\$1.34	\$1.34	\$1.00	\$1.00	\$0.40	\$0.40
Balance of Plants	\$0.48	\$0.48	\$0.46	\$0.46	\$0.46	\$0.47	\$0.45	\$0.46
MFSP	\$7.16	\$6.74	\$5.11	\$4.69	\$4.50	\$4.08	\$3.11	\$2.77

Table 45: Process Efficiency Metrics for Wet Waste HTL SOT and Design Cases

Sustainability and Process Efficiency Metrics	Units	2018 SOT		2019 SOT		2020 SOT		2022 Projection	
		w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal
Fuel Yield by Weight of Biomass (AFDW)	% w/w of biomass	34.60%	34.60%	34.60%	34.60%	34.60%	34.60%	38.90%	38.90%
Fuel Yield by Weight of Biomass (dry biomass)	% w/w of dry biomass	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	33.10%	33.10%
Carbon Efficiency to Fuels	% of waste carbon	56.90%	56.90%	56.90%	56.90%	56.80%	56.80%	64.10%	64.10%
Electricity Import*	kWh/GGE	2.7	2.7	2.7	2.7	2.8	2.7	2.0	2.0
Electricity Import (excluding extra power for COD processing at WRRF)	kWh/GGE	0.62	0.55	0.62	0.55	0.69	0.62	0.37	0.30
Natural Gas Import	MJ/GGE (LHV)	38	30	38	30	29	21	34	26
Natural Gas Import	Btu/GGE (LHV)	35,752	28,332	35,752	28,332	27,060	19,640	31,840	24,578

*The analysis includes an estimate of extra power that may be required at the WRRF to treat the aqueous-phase chemical oxygen demand (COD) recycled to the WRRF.

Table 46: Unit Operation Cost Estimates and Technical Projections for the Wet Waste HTL Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT		2019 SOT		2020 SOT		2022 Projection	
		w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE	\$7.16	\$6.74	\$5.11	\$4.69	\$4.50	\$4.08	\$3.11	\$2.77
Conversion Contribution	\$/GGE	\$7.06	\$6.64	\$5.01	\$4.59	\$4.40	\$3.98	\$3.01	\$2.67
Performance Goal	\$/GGE	NA	NA	NA	NA	NA	NA	\$3	\$3
Production Diesel	MMgal/yr	27	27	27	27	27	27	28	28
Production Naphtha	MMgal/yr	9	9	9	9	9	9	9	9
Diesel Yield (AFDW Sludge Basis)	gal/ton sludge	79	79	79	79	79	79	89	89
Naphtha Yield (AFDW Sludge Basis)	gal/ton sludge	27	27	27	27	27	27	30	30
Natural Gas Usage (AFDW Sludge Basis)	scf/ton sludge	4,951	3,898	4,951	3,898	3,717	2,664	4,914	3,861
Feedstock									
Total Cost Contribution	\$/GGE fuel	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Feedstock Cost (Dry Sludge Basis)	\$/ton sludge	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Sludge Dewatering									
Total Cost Contribution	\$/GGE fuel	\$0.20	\$0.20	\$0.20	\$0.20	\$0.20	\$0.20	\$0.18	\$0.18
Capital Cost Contribution	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.09	\$0.09
Operating Cost Contribution	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.09	\$0.09
Sludge HTL									
Total Cost Contribution	\$/GGE fuel	\$2.40	\$2.45	\$2.40	\$2.45	\$2.12	\$2.18	\$1.49	\$1.55
Capital Cost Contribution	\$/GGE fuel	\$1.46	\$1.46	\$1.46	\$1.46	\$1.27	\$1.27	\$0.83	\$0.83
Operating Cost Contribution	\$/GGE fuel	\$0.94	\$0.99	\$0.94	\$0.99	\$0.84	\$0.91	\$0.66	\$0.72
HTL Biocrude Yield (Dry)	lb/lb sludge	0.44	0.44	0.44	0.44	0.44	0.44	0.48	0.48
Liquid Hourly Space Velocity	vol/h/vol	3.6	3.6	3.6	3.6	4.0	4.0	6.0	6.0
Preheaters Capital Cost (Installed)	\$MM	12	12	12	12	9	9	6	6

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT		2019 SOT		2020 SOT		2022 Projection	
		w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal	w/ NH ₃ Removal	w/out NH ₃ Removal
HTL Water Recycle Treatment									
Total Cost Contribution	\$/GGE fuel	\$0.61	\$0.13	\$0.61	\$0.13	\$0.62	\$0.13	\$0.49	\$0.09
Capital Cost Contribution	\$/GGE fuel	\$0.21	\$0.00	\$0.21	\$0.00	\$0.21	\$0.00	\$0.16	\$0.00
Operating Cost Contribution	\$/GGE fuel	\$0.40	\$0.13	\$0.40	\$0.13	\$0.41	\$0.13	\$0.33	\$0.09
Balance of Plant HTL									
Total Cost Contribution	\$/GGE fuel	\$0.06	\$0.07	\$0.06	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07
Capital Cost Contribution	\$/GGE fuel	\$0.04	\$0.04	\$0.04	\$0.04	\$0.05	\$0.05	\$0.04	\$0.04
Operating Cost Contribution	\$/GGE fuel	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.03	\$0.03
Biocrude Transport	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10
Biocrude Upgrading to Finished Fuels									
Total Cost Contribution	\$/GGE fuel	\$3.38	\$3.38	\$1.34	\$1.34	\$1.00	\$1.00	\$0.40	\$0.40
Capital Cost Contribution	\$/GGE fuel	\$0.40	\$0.40	\$0.34	\$0.34	\$0.30	\$0.30	\$0.25	\$0.25
Operating Cost Contribution	\$/GGE fuel	\$2.97	\$2.97	\$1.01	\$1.01	\$0.70	\$0.70	\$0.15	\$0.15
Hydrotreating Mass Yield on Dry Biocrude	lb/lb biocrude	0.82	0.82	0.82	0.82	0.82	0.82	0.84	0.84
Guard Bed WHSV	wt/h/wt	0.46	0.46	0.67	0.67	0.72	0.72	1.30	1.30
Guard Bed Catalyst Lifetime	years	0.03	0.03	0.06	0.06	0.06	0.06	1	1
Hydrotreater WHSV	wt/h/wt	0.29	0.29	0.39	0.39	1.02	1.02	0.75	0.75
Hydrotreater Catalyst Lifetime	years	0.03	0.03	0.06	0.06	0.06	0.06	2	2
Balance of Plant Upgrading									
Total Cost Contribution	\$/GGE fuel	\$0.42	\$0.42	\$0.40	\$0.40	\$0.40	\$0.40	\$0.39	\$0.39
Capital Cost Contribution	\$/GGE fuel	\$0.26	\$0.26	\$0.24	\$0.24	\$0.24	\$0.24	\$0.22	\$0.22
Operating Cost Contribution	\$/GGE fuel	\$0.16	\$0.16	\$0.16	\$0.16	\$0.16	\$0.16	\$0.17	\$0.17

Integration and Scale-Up

Due to challenging economies of scale, biocrude from multiple HTL units is expected to be transported to a centralized hydrotreating facility. Unit operations and processes proven at small-scale laboratory conditions would need to be scaled up and assembled together in an integrated setup or pilot-scale facility to verify process performance (for reference, see the appendix, barriers SDI-A and SDI-D). Understanding integration and scale-up is essential to characterize the interactions between unit operations and generate predictive engineering models to guide process optimization and scale-up strategies. Even with combining biocrude from multiple locations, hydrotreating and hydrocracking represent the second largest contribution to MFSP, contributing \$1.00/GGE.

Key integration challenges include:

- Achieving efficient separation of process streams from the HTL reactor involving solid, liquid, and gas phases (for reference, see the appendix, barrier SDI-F).
- Demonstrating long-duration operations free of heat exchanger or reactor plugging.
- Understanding the impact of aqueous-phase recycling and developing efficient methods for mitigating any impact while optimizing recovery of nutrient, energy, coproduct, and water.
- Improving the conversion of HTL biocrude into hydrocarbon fuels using hydrotreating operations (for reference, see the appendix, barrier SDI-G).
- Understanding rheological and heat transfer performance with organic waste slurries including pumpability, heat exchanger design, and materials compatibility.
- Identifying efficient separations methods for inorganic species such as calcium, iron, silicon, nickel, and sulfur. This could include the use of a combination of desalting and washing operations and guard beds (slurry, ebullated, or fixed bed) as management approaches.

Significant improvements are needed in areas including the catalysts used in hydroprocessing (specifically on catalyst lifetime), increasing the liquid hourly space velocities, and managing key ash species such as calcium, iron, and silicon through the use of reactor guard beds. As observed in Figure 44 and shown in Table 46, a large portion of the reduction between the FY 2018 and FY 2019 SOTs was a result of the increased catalyst lifetime. Ongoing work within ChemCatBio will continue to inform future strategies for managing these species and other constituents that cause catalyst performance loss and issues with regenerability.

Although further experimental validation (ASTM International testing) would be necessary to verify the performance of this as a finished fuel (for reference, see the appendix, barrier SDI-B), on a

compositional basis, the resulting hydrotreated oil exhibits low oxygen, nitrogen, and sulfur levels, as well as boiling point distributions with high degrees of overlap with quality control diesel. Additionally, these biocrudes could be coprocessed with petroleum-derived straight-run diesel in a hydrotreater or with vacuum gas oil in fluid catalytic cracking units (for reference, see the appendix, barrier SDI-G), similar to the dry feedstocks converted via the direct liquefaction pathway. This would help reduce the capital expenses of the process.

Supply Chain Sustainability Analysis

The SCSA for the wet waste HTL pathway includes scenarios with and without NH₃ removal from the HTL aqueous phase. Table 47 summarizes SCSA results.⁹² These results show a small amount of fossil energy use for both the SOT cases and 2022 projections, primarily associated with using natural gas and electricity during the HTL and upgrading processes. The net energy balance for the 2022 wet waste HTL design case is 0.52 MJ/MJ with NH₃ removal and 0.63 MJ/MJ without NH₃ removal.

Figure 45A shows that the supply chain GHG emissions for the wet waste HTL design case for the 2018, 2019, and 2020 SOTs and the 2022 design case are lower than for petroleum-derived diesel, especially without NH₃ removal. Higher GHG emission reduction without NH₃ removal is achieved by avoiding quicklime use and a reduction in the natural gas and electricity required for the removal process. The 2022 design case shows reduced GHG emissions from improved conversion efficiency and reduced energy requirement. In all scenarios, the major contributor to supply chain GHG emissions are from HTL biocrude production. The 2022 case relative to the SOT cases for HTL biocrude production shows significant improvement in energy efficiency and GHG emissions. The 2022 case without NH₃ removal also improves water consumption and fossil fuel consumption compared to petroleum-derived diesel.

⁹² Cai et al. 2021, <https://doi.org/10.2172/1807565>.

Table 47: Supply Chain Sustainability Metrics for Renewable Diesel via Wet Waste Sludge HTL

	Scenario 1: With NH ₃ Removal				Scenario 2: No NH ₃ Removal				Petroleum Diesel
	2018 SOT	2019 SOT	2020 SOT	2022 Projection (Design Case)	2018 SOT	2019 SOT	2020 SOT	2022 Projection (Design Case)	
Biofuel Yield									
MMBtu/dry ton	11.0	11.0	11.0	12.4	11.0	11.0	11.0	12.4	-
Fossil Energy Consumption^a									
MJ/MJ	0.66 (-45%)	0.58 (-52%)	0.44 (-63%)	0.48 (-60%)	0.54 (-56%)	0.46 (-62%)	0.36 (-70%)	0.37 (-69%)	1.2
Net Energy Balance^b									
MJ/MJ	0.34	0.42	0.56	0.52	0.46	0.54	0.64	0.63	-
GHG Emissions									
g CO _{2e} /MJ	54 (-42%)	49 (-48%)	43 (-53%)	40 (-58%)	38 (-60%)	32 (-66%)	27 (-71%)	25 (-73%)	91
g CO _{2e} /GGE	6,587	5,946	5,239	4,862	4,616	3,977	3,270	3,122	11,157
Water Consumption									
gal/MJ	0.044	0.037	0.034	0.029	0.033	0.026	0.024	0.019	0.026
gal/GGE	5.4	4.5	4.4	3.5	4.0	3.1	3.1	2.3	2.7
Total NO_x Emissions									
g NO _x /MJ	0.08	0.07	0.065	0.06	0.07	0.06	0.056	0.05	0.06
g NO _x /GGE	9.7	8.7	7.9	7.7	8.6	7.6	6.8	6.7	7.0
Urban NO_x Emissions^c									
g NO _x /MJ	0.028	0.028	0.037	0.027	0.028	0.027	0.027	0.026	0.030
g NO _x /GGE	3.4	3.4	4.6	3.3	3.4	3.3	3.3	3.2	3.3

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values. 2020 SOT and petroleum reference emissions and water consumption values are based on the GREET2020 model. Design case and prior year SOTs are based on the GREET2019 model.

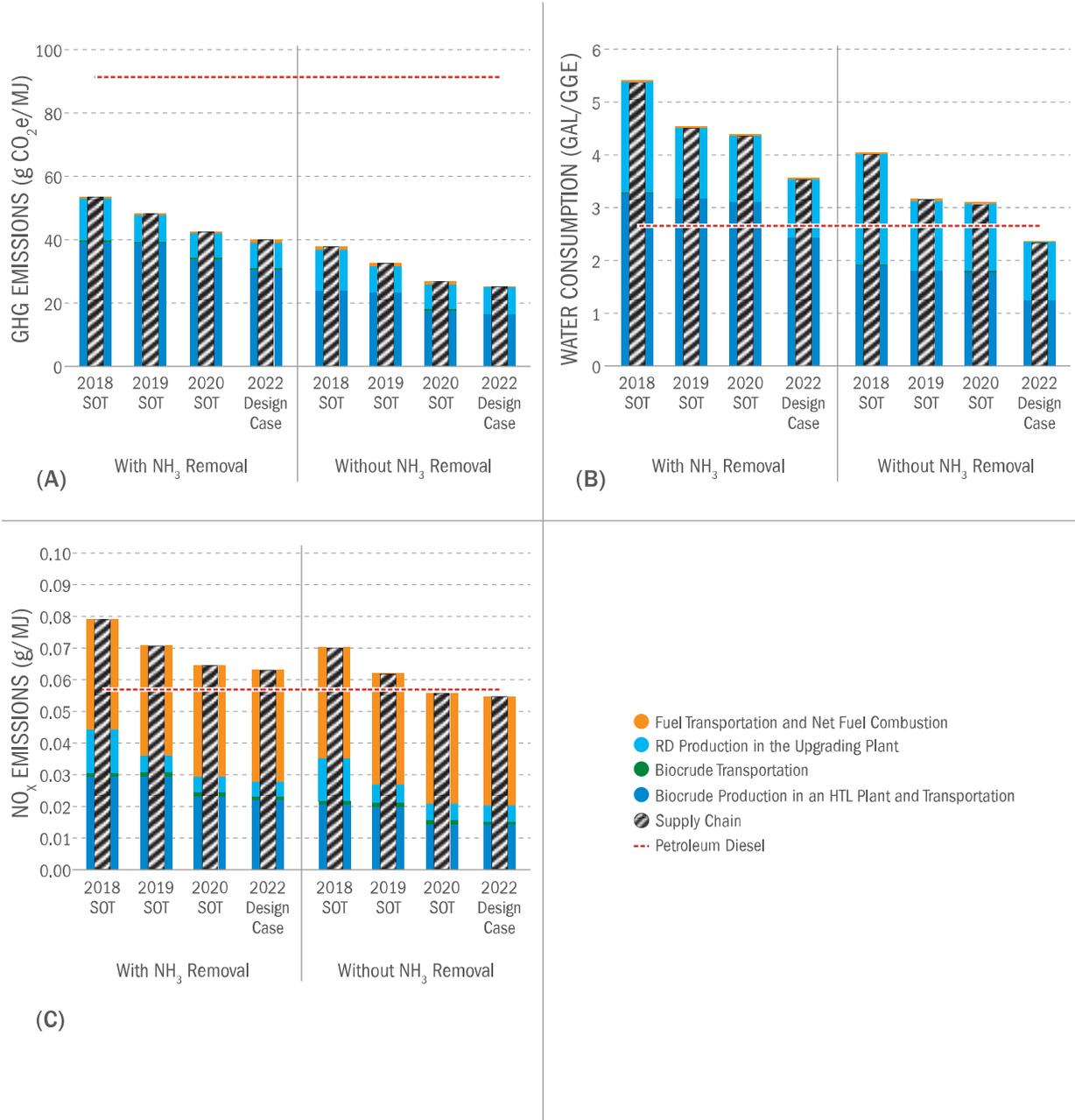
^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 45B shows the supply chain water consumption for the production of renewable diesel via the wet waste HTL design case. For both the SOT and design cases, supply chain water consumption of renewable diesel is higher than that of petroleum-derived diesel (see Table 47). The major contributor is water used in the production of chemicals such as quicklime and the dewatering polymer used in the biocrude production. However, without NH_3 stripping, water use during HTL biocrude production diminishes significantly, as no quicklime or polymers are needed. As a result, water consumption is reduced to 2 gal/GGE in the 2022 case, which is slightly lower than that of petroleum-derived diesel. More importantly, HTL of municipal waste sludges could enable lower costs of clean drinking water by reducing biosolids disposal costs.

Figure 45C shows that the total supply chain NO_x emissions in the 2022 design cases are below the petroleum diesel baseline and slightly reduced relative to the 2018, 2019, and 2020 SOT cases due to reduced chemical and energy inputs during production of biocrude. The main contributor of NO_x emissions in both the SOT and 2022 designs is fuel combustion, and the second largest contributor is NO_x emissions released during biocrude production.



Figures 45A–C: Supply chain for the west waste HTL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Appendix: Technology Barriers and Challenges

Bioenergy Technologies Office R&D is focused on addressing key technology barriers and challenges across the supply chain—from feedstocks to conversion—and across the technology development life cycle from early-stage to later-stage R&D, as well as cross-cutting considerations.⁹³ This appendix lists the key barriers and challenges referenced throughout this document by barrier code, the leading characters for each barrier. These barriers are categorized by the BETO program structure. The barriers below have been updated to reflect BETO barriers that were in place at the time the 2020 SOT R&D work was underway.

Overall Barriers and Challenges

Ot-B. Availability of Quality Feedstock: There are a variety of technical, operational, and economic uncertainties in the availability of consistent and affordable quality feedstock supplies. Mobilizing large volumes of untapped resources will require establishing advanced supply chains to improve quality. This may require significant changes to existing agricultural and forestry practices, as well as deploying new supply chains for other renewable carbon streams. Costs associated with grower inputs, establishing new supply chain infrastructure, and preprocessing to improve feedstock quality constrain the overall cost reduction potential for biomass. To meet quality requirements of conversion facilities, feedstock supply and logistics R&D will need to improve feedstock quality from harvest and collection through delivery while also meeting conversion performance and cost goals.

Ot-B. Cost of Production: Significant R&D is required to develop highly efficient and robust feedstock handling, preprocessing, and conversion processes to compete with conventional petroleum fuels. The distributed nature of biomass and waste streams requires greater conversion efficiency at smaller scales compared to petroleum refineries. This drives research in process integration, systems efficiencies, and advanced, robust separations and molecular efficiency to convert current waste streams (an expense) into desirable products (a revenue). This includes developing innovative ways to derive higher values from all primary and secondary product streams (such as lignin and carbon dioxide). As with petroleum refineries, product slates will need to include bioproducts to spread the costs of production across biofuels and higher-valued bioproducts and optimize the use of all feedstocks to be competitive in commodity markets.

⁹³ U.S. Department of Energy. *Bioenergy Technologies Office – FY19 Multi-Year Plan: Technical Barriers and Challenges*. Washington, D.C.: U.S. Department of Energy, 2019. <https://eere-exchange.energy.gov/Default.aspx?foald=c8d40744-1eeb-4bc9-b3af-feb2fefc3251>. (Click on the FY19 BETO Barriers link, under Documents, on the EERE Funding Opportunity Exchange page.)

Ot-C. Risk of Financing Large-Scale Biorefineries: Obtaining traditional financing is a challenge for new innovative bioenergy technologies, and most pioneer commercial-scale facilities require equity financing of \$200 million or more. Biorefineries face significant first-of-a-kind risks in deploying technology. For investors to gain confidence in a technology, processes must function efficiently and reliably with the full variability of feedstocks for significant lengths of time to reduce uncertainty around processing capability and verify that different newly developed technologies can be integrated successfully into a complete, reliable system. Investors also need assurance that operational performance can be scaled up and transferred from smaller to larger scales. That requires a greater number of more cost-effective experiments be run on smaller-scale, integrated processes.

Feedstock Technologies R&D Barriers and Challenges

Ft-A. Feedstock Availability and Cost: Conversion technologies face a variety of technical, operational, and economic uncertainties. High-quality, affordable feedstock supplies are not consistently available, and supply and logistics systems can be unreliable due to a lack of fundamental understanding of properties and unique material handling challenges of many renewable carbon sources. Complete data on volumes, compositional variability, and characteristics by geographic location are needed to design and develop economical processes to deliver conversion-ready feedstocks.

Ft-B. Production: The production systems and performance of energy crop species are not well-characterized. The range of production-scale yields of energy crops across genetics, environments, and agronomic practices is not fundamentally understood and requires comprehensive characterization and reliable data from real-world production operations. Scientific information is lacking on new varieties/cultivars of energy crops to inform the degree to which they show performance improvements relative to better characterized predecessor varieties, how well adapted they are across regions, whether they may be more cost-effective to produce, and whether they can be shown to be more sustainable relative to a control variety and/or traditional cropping/pasture systems.

Ft-C. Feedstock Genetics and Variety Improvement: The productivity and robustness of bioenergy crops is not optimized for bioenergy applications, and could be significantly increased by traditional breeding and selection and/or modern genetic engineering technologies. Reduced production uncertainty associated with more stress-tolerant varieties is needed to encourage farmers, biorefineries, and financial institutions to seriously consider energy crops.

Ft-D. Sustainable Harvesting: Current crop harvesting machinery is unable to selectively harvest or collect preferred components of renewable carbon sources to meet the capacity, efficiency, quality, or delivered requirements of biorefineries. Harvest, collection, sorting, and transport systems and equipment are not optimized for bioenergy applications. Logistics costs need to be reduced while improving biomass quality and processing efficiency.

Ft-E. Feedstock Quality: Monitoring and Impact on Preprocessing and Conversion Performance: The physical, chemical, microbiological, and post-harvest physiological variations in renewable carbon sources can be significant. For bioenergy crops, variability can arise from differences in genetics, relative crop maturity, agronomic practices and harvest methods employed, soil type, geographical location, and climatic patterns and events. Available data and information are extremely limited to identify the key physical (e.g., particle size, shape, pore volume, surface area, bulk density, and thermal conductivity), mechanical (e.g., compressibility, yield stress, shear, cohesion, friction, and rheological behavior), and chemical (e.g., moisture, ash content/speciation, carbohydrate, lignin content/speciation, extractives, and problematic contaminants) quality characteristics of feedstocks, and to understand the magnitude of their impacts on feeding, preprocessing, and conversion performance (e.g., throughput, yield, and equipment failure). Methods and instrumentation are also lacking for quickly, accurately, and economically measuring these quality-related properties. Analytical and processing standards, understanding of causal relationships and mechanisms at the molecular level, and quality specifications for bioenergy feedstocks are not well developed and may vary from one conversion process to another.

Ft-F. Biomass Storage Systems: Current storage systems (especially for wet, herbaceous materials and wastes) often result in degraded quality between the time of harvest or collection and use. This leads to storage-related physical and chemical degradation, poor feeding and handling performance, and periodic shutdown related to mill and conveyor plugging. The effect of different storage methods, and specifically moisture management, is not adequately defined to enable design of cost-effective systems that preserve quality and increase the stability of downstream operations.

Ft-G. Biomass Physical State Alteration: The initial sizing and grinding, cell wall structure, and particle characteristics of biomass affect conversion efficiencies and yields of all downstream conversion operations. To design technologies and equipment to economically process renewable carbon feedstocks to conversion specifications, information is needed on how the specific differences in the physical and mechanical properties of each feedstock at the nanoscale and microscale impact feed handling as well as conversion cost and yields.

Ft-H. Material Handling and Transportation: Raw herbaceous biomass and other renewable carbon sources have very low bulk and energy density, making transport costly. Conventional handling systems cannot cost-effectively deliver high volumes and are not optimized for bioenergy processes.

Ft-I. Feedstock Supply System Integration and Infrastructure: Conventional supply systems used to harvest, collect, store, preprocess, handle, and transport biomass are not designed to satisfy the large-scale needs of a nationwide system of integrated biorefineries. The infrastructure for feedstock logistics has not been defined for the potential variety of locations, climates, feedstocks, storage methods, and processing alternatives that will need to be implemented on a national scale.

Ft-J. Operational Reliability: Recent evidence indicates that biorefinery development and operation have suffered from failing to account for the complexity and variability of lignocellulosic biomass, inconsistent feeding and handling, inadequate equipment design, and flawed integration. To reach cost-effective operation, biorefineries need to operate at a design capacity of at least 90% on-stream reliability. Fundamental R&D is needed to identify the key feedstock quality and operation factors affecting operational reliability, develop technologies to address contributing factors, and develop process or operational strategies for mitigation.

Advanced Algal Systems R&D Barriers and Challenges

Aft-A. Biomass Availability and Cost: The lack of sufficient data on potential price, location, seasonality, environmental sustainability, quality, and quantity of available algal biomass feedstock creates uncertainty. Established biomass production history is required to understand feedstock supply risks. Reliable, consistent, and sustainable biomass supply is needed to reduce financial, technical, and operational risk to downstream processes.

Aft-B. Sustainable Algae Production: The productivity, energy use, and environmental effects of algae production and harvest systems have not been comprehensively addressed. New production technologies for algae cultivation are needed to lower the resource intensity of algae production.

Aft-C. Biomass Genetics and Development: The productivity and robustness of algae strains against such factors as temperature, seasonality, predation, and competition could be improved by selection, screening, breeding, mixing cultures, and/or genetic engineering. These approaches require extensive ecological, genetic, and biochemical information. In addition, any genetically modified organisms deployed commercially will also require regulatory approval by the appropriate federal, state, and local government agencies.

Aft-D. Sustainable Harvesting: Harvesting and dewatering technologies can be costly and energy- and resource-intensive. Algae biomass harvesting technology must be scalable with low energy

intensity and high reliability. After removal of algae biomass, recycle of harvest water and media can be important.

Aft-E. Algal Biomass Characterization, Quality, and Monitoring: Physical, chemical, biological, and post-harvest physiological variations in algae affect the efficiency of downstream conversion processes. The fundamental components (lipids, carbohydrates, and proteins) of algal biomass vary greatly within strains, among strains, and in comparison to plants. A better understanding of the effects of the high variability in feedstock characteristics on biorefinery operations and performance is needed. Standard procedures to reliably and reproducibly quantify biomass components from algae and to close mass balances are necessary.

Aft-F. Algae Storage Systems: Characterization and analysis of different algae storage methods and strategies are needed to define storage requirements for seasonal variances or design flexibility. These storage methods should preserve harvested algal biomass or biofuel intermediates to maintain product yield over time. Energy use and environmental implications of storage methods must also be understood.

Aft-G. Algal Feedstock Material Properties: Data on algal feedstock quality and physical property characteristics in relation to conversion process performance characteristics are limited. Methods and instruments for measuring physical, chemical, and biomechanical properties of biomass are needed.

Aft-H. Integration: Integration of co-located inoculation, cultivation, primary harvest, concentration, and preprocessing systems is challenging and requires interdisciplinary expertise. In addition, the potential for co-location with other related bioenergy technologies to improve balance-of-plant costs and logistics may be important.

Aft-I. Algal Feedstock On-Farm Preprocessing: After cultivation and harvesting, algal biomass may require processing or fractionation into lipids, bio-oils, carbohydrates, and/or proteins before these individual components can be converted into the desired fuel and/or products. Integration of preprocessing with algae cultivation poses challenges in operations, as well as energy efficiency and capital costs.

Aft-J. Resource Recapture and Recycle: Residual materials remaining after preprocessing and/or residual processing may contain valuable nitrogen, phosphorus, carbon, or micronutrients, all of which can displace a portion of fresh fertilizer inputs in upstream cultivation. The recapture of these resources from harvest and logistics process waste streams may pose separation challenges, and the recovered materials may not be in biologically available chemical forms. In closed-loop systems, inhibitory compounds may also accumulate.

Conversion R&D Barriers and Challenges

Ct-A. Defining Metrics Around Feedstock Quality: Discrete and quantifiable metrics relating feedstock quality characteristics (e.g., ash content, ash speciation, particle size distribution, particle shape distribution, surface roughness, concentration of contaminant species, and organic impurities) and their impact on conversion performance (e.g., yield, catalyst deactivation, and organism toxicity) is necessary. At a minimum, the upper and lower bounds of feedstock quality characteristics that can result in economically viable convertibility need to be identified. End-to-end system throughput analysis is needed to quantify trade-offs between cheaper, lower-quality feedstocks (including blends) and biofuel and coproduct yields, maintenance cycles, and costs.

Ct-B. Efficient Preprocessing and Pretreatment: Trade-off analysis is necessary to optimize pretreatment and preprocessing steps with further downstream processes. This relates to barrier Ct-A, with respect to identifying unit operations that can mitigate against particular contaminant species or lower-quality feedstocks, as additional unit operations increase the overall energy intensity, capital expenditure, and costs of biomass processes. If/when pretreatment and preprocessing strategies are not available, it may be necessary to further develop more robust downstream processes. Particle and reaction modeling, experimental evaluation, and concurrent development of subsequent conversion processes is needed to assess key parameters including sugar yields, lignin convertibility, pretreatment reactor uptime, and heat and mass transfer properties.

Ct-C. Process Development for Conversion of Lignin: Converting lignin into value-added products has been a widespread challenge associated with the development of lignocellulosic biofuels. Despite constituting between 15% and 40% of biomass by weight, lignin is generally burned in biorefineries for relatively low-value heat and power. The structural complexity of the lignin polymer makes it difficult to extract greater value from lignin. Recent advances in molecular understanding of this complex polymer point to the potential for lignin to play an increasingly important role in the development of biofuel and value-added bioproducts. In addition to fully deconstructing lignin into low-molecular-weight compounds, strategies for the synthesis of high-performance products that maintain some structural properties of native lignin (e.g., carbon fibers, resins, and foams) afford additional avenues for deriving value from lignin.

Ct-D. Advanced Bioprocess Development: Increasing titer, rates, and yields of bioproducts through metabolic engineering and fermentation processing improvements is correlated with lowering the costs of fuels and chemicals produced from biomass. In addition, continuous or semicontinuous bioprocessing strategies can reduce the needed capital and operating costs through increased productivity and reduced organism propagation costs compared to traditional batch fermentation.

Unique challenges exist to develop robust organisms or biocatalysts, along with advanced bioreactors, that can achieve long efficacy times. Real-time measurement and adaptive control strategies that are tailored to the particular organism, catalyst, and/or product are also necessary.

Ct-E. Improving Catalyst Lifetime: There is a need both for catalysts that are more tolerant of lower-quality feedstocks and for pretreatment and separation processes that eliminate contaminant species from intermediate solutions. Developing these processes should be coupled with efforts to obtain a better understanding of the causes of catalyst poisoning and deactivation, specifically in bio-based processes, to more efficiently target contaminants. In addition to developing more robust catalysts and processes, there is a need to decrease the energy intensity and material demand required for catalyst regeneration.

Ct-F. Increasing the Yield From Catalytic Processes: There is also a need to identify catalysts and process conditions that increase overall yield. This can be accomplished by direct improvements to catalyst performance that minimize the loss of carbon and by process improvements that decrease the formation of undesirable intermediates. A better understanding of catalytic active sites and reaction mechanisms across both low- and high-temperature processes can be obtained through advanced characterization techniques. Advanced reactor modeling and developing bio-oil characterization techniques can help identify reaction conditions that impact the ratio of different intermediates in high-temperature processes that typically produce a wide range of intermediates. Challenges associated with hydrogen sourcing, cost, and utilization also must be addressed to enable the development of more efficient, highly active, selective, and durable catalysts. Current methods for generating hydrogen are not cost-efficient at the scale envisioned for most biorefineries, and a reliance on externally produced hydrogen contributes to operating costs.

Ct-G. Decreasing the Time and Cost to Develop Novel, Industrially Relevant Catalysts: Emerging technologies and processes may require the design and synthesis of novel catalysts. Existing catalysts may also contain materials that become cost-prohibitive when used at larger scales. Researchers need to be able to respond to these needs and identify and synthesize novel catalysts that meet cost and performance targets on an industrially relevant time scale. Understanding the trade-offs between catalyst material and catalyst performance requires detailed information on material costs, as well as robust computational models that can predict reaction mechanisms and catalyst and reactor performance under different operating conditions.

Ct-H. Gas Fermentation Development: There are unique challenges that must be overcome for gaseous feedstocks to be processed viably. Gas fermentations inherently require continuous modes of operation, as gas storage/recycle loops are largely infeasible (due to costs of compression and

capital equipment sizing). Gas streams from biomass can be challenging to transition from gas to liquid, so novel reactors and/or process configurations to maximize the single-pass conversion of these feedstocks are needed.

Ct-I. Development of Processes Capable of Processing High-Moisture Feedstocks in Addition to Conventional Anaerobic Digestion: Anaerobic digestion is a widely practiced method for waste management and biogas production from high-moisture feedstocks (e.g., sludge from wastewater treatment plants, manure, food waste, and other fractions of municipal solid waste). High-temperature processes, such as gasification or pyrolysis, are inherently inefficient, as a high amount of energy is expended in heating or drying. Additionally, anaerobic digestion requires significant feedstock volumes to offset the high capital costs. Furthermore, anaerobic digestion typically only converts 50% of the organic matter, which results in a significant disposal problem for waste producers. Developing systems with lower capital costs that can convert higher fractions of the waste and that can produce liquid fuels and bioproducts present unique opportunities. A number of unique challenges exist to developing these processes, including identifying individual organisms or consortia of organisms that can produce high quantities of product (e.g., organic acids), developing methods for continuous separations of these products, and testing and developing stable systems (>2,000 hours).

Ct-J. Identification and Evaluation of Potential Bioproducts: To more efficiently realize the full value of biomass feedstocks, conversion processes need to integrate bioproduct production with that of drop-in fuels. Experimental methods and computational analysis to link intermediates from specific processes with potential products (both drop-in replacements and novel molecules that utilize the unique characteristics of biomass feedstocks) need to be developed. Once potential structures are identified, novel molecules will also require high-throughput screening tools to characterize and optimize them for properties that are advantageous to the molecules already used in industrial processes. Metrics and protocols for high-throughput screening will need to be standardized. Additional analysis of molecules and their properties, including machine learning, will be required to develop a larger database of predictive structure-function relationships that will reduce development time. Experimental methods for comparing both drop-in replacements and novel products with existing products to assess purity and performance will need to be developed.

Ct-K. Developing Methods for Bioproduct Production: Bioproducts will be introduced into existing markets that typically have high requirements for purity. Additional separation steps or other unit operations may need to be added to existing processes to ensure that bioproducts are recovered with industrially relevant specs. Additionally, properties present in molecules that are tested at the lab and bench scale must be understood fundamentally to enable a transfer to larger scales.

Because production processes for many bio-based molecules cannot be scaled rapidly, this increases the risk associated with testing bio-based replacements in formulas.

Ct-L. Decreasing Development Time for Industrially Relevant Microorganisms: There are few public case studies of the overall cost to bring a bio-derived chemical to market outside of biological pharmaceuticals, where the cost is upwards of \$1 billion. For renewable chemicals, development of bio-based 1,3-propanediol by Dupont/Tate & Lyle and the development of NatureWorks' lactic acid process suggests that \$100–\$200 million and 10–15 years of development time are a reasonable baseline for the current state of the art. Although individual companies have made some progress on reducing this time and cost, they often rely on proprietary methods that are specific to individual organisms and product targets, limiting broad applicability. To decrease this time and cost for the bioeconomy as a whole, new publicly available biomanufacturing techniques are needed, as well as new microbial host organisms with improved industrial properties. Central to this challenge is the development of new microbiology techniques in conjunction with databases and machine-learning methods to enable better, more automated design of bioprocesses with predictable performance and scaling, as well as significantly increased conversion efficiency. To be truly industrially useful, these efforts must be integrated into a methodology that enables faster and more efficient development cycles.

Ct-M. Current Reactors Not Designed to Handle Harsh Conditions Inherent to Converting Biomass Feedstock: Current reactors must be improved to cost-effectively deliver an environment in which catalysts and organisms can be most efficient, including the ability to withstand highly corrosive bio-oil and cost-effectively handle harsh pretreatment conditions for low-temperature deconstruction. This involves developing reactors with cost-effective materials that are optimized for process conditions. In addition, it is currently difficult to precisely control many biological and other processes. New techniques, instruments, and methods are needed to maximize process operation efficiency.

Ct-N. Multiscale Computational Framework toward Accelerating Technology Development: Predictive models need to be integrated with experimental data and verified at multiple scales to accelerate technology development. Models must be developed for translating material behavior and performance from atomic scales to industrially relevant reactor scales and developing methods to reduce technology uncertainty and time requirements for the scale-up of advanced conversion technologies.

Ct-O. Selective Separations of Organic Species: Separation of organic species in biomass processes for upgrading to final fuel and bioproduct molecules has high energy requirements. Desirable

compounds are often closely related structurally to undesired intermediates. These separations require a more thorough compilation of physical properties for complex mixtures of process intermediates, as well as better modeling methods to improve predictions of acid-water interactions. Low-cost purification technologies need to be developed to remove other organic contaminants and provide concentrated, clean intermediates from which biofuels and bio-based chemicals can be manufactured.

Ct-P. Selective Separations of Inorganic Contaminants: Inorganic species found in feedstocks or in intermediate streams can be incompatible with conversion processes, as they can result in issues such as catalyst poisoning and side reactions. Additionally, their presence in product streams can lead to off-specification products that are unacceptable for fuels or bioproducts. Effective mitigation strategies, such as treatments that can be applied for their selective removal, are needed. Absent these mitigation strategies, these feedstocks may be limited to conversion processes that are insensitive to these feedstock compositions.

Systems Development and Integration R&D Barriers and Challenges

SDI-A. Process Integration: The concept of an integrated biorefinery encompasses a wide range of process steps and technical issues. These include collecting, storing, transporting, and processing diverse feedstocks and moving feedstocks through multiple complex conversion subsystems to produce fuel and/or product outputs. The technical performance and operational behavior of unit operations during individual component verification could be significantly different when the same set of individual unit operations are assembled together to form an integrated system. Researching that systems perform as designed when integrated is a challenging and time-consuming process. Understanding process integration is essential to: (1) characterize the interactions between unit operations, (2) identify the impacts of inhibitors and contaminants on processing systems, (3) generate predictive engineering models to guide process optimization and scale-up efforts and develop process control methodologies, and (4) devise equipment design parameters and operational considerations to improve reliability of operations and increase on-stream performance of equipment.

SDI-B. Feedstock Supply Chain Infrastructure: The supply chain infrastructure capable of handling large volumes of highly variable feedstocks is limited. Variable composition, geographical diversity, and diverse physical properties (such as particle size, bulk density, moisture content, and inorganic species present) impact supply chain costs. Feedstock infrastructure, such as handling and storage facilities, must also meet existing construction, safety, and fire codes, which, in most cases, were not developed for large-scale lignocellulosic biomass operations.

SDI-C. Codes, Standards, and Approval for Use: New biofuels and biofuel blends are not available in sufficient volumes required to perform product certification prescreening requirements. Biofuels and biofuel blends must comply with federal, state, and regional regulations before being approved and certified for end use. Codes and standards are adopted by federal, state, and regional jurisdictions to ensure product safety and reliability and reduce liability.

SDI-D. Technology Uncertainty of Integration and Scaling: Unit operations proven at small scale under laboratory conditions need to be scaled up and assembled together in an integrated setup or pilot-scale facility to verify process performance. Determining scaling factors for industry best practice of stepwise scaling needs to be based on credible data from operations at the appropriate level of process integration and scale. This enables subsequent robust, full integration and development of equipment specifications for commercial application.

SDI-F. First-of-a-Kind Technology Development: Studies have shown that the number and complexity of new process steps implemented in first-of-a-kind technology projects are a strong predictor of the challenges to be encountered with reliable performance and operations. Understanding relationships between and within unit operations is useful to inform R&D gaps and for further technology development. Heat and mass balances, along with other implications, including characterization of bioprocessing streams, are not likely to be well understood in new technologies. Additional challenges can be attributed to handling of non-pristine solids; buildup of impurities in process recycle streams; degradation of chemical or catalyst performance; inorganic species in the process streams, char, and slag buildup; and abrasion, fouling, and corrosion of plant equipment. Furthermore, reliable databases providing interactions of various feedstocks with processing equipment, efficient handling of feedstocks, and predictive methods for feedstock properties are not readily available.

SDI-G. Coprocessing with Petroleum Refineries: Bio-oil and bio-intermediates are composed of components and mixtures different than those found in petroleum refineries, and knowledge on the influence of bio-intermediates blending with petroleum processing is still in the developmental stage. Material characteristics such as physiochemical properties, reactivities, and compatibilities of bio-intermediates with petroleum derivatives need to be well understood. To be accepted for coprocessing, petroleum refineries need to understand how a bio-oil or bio-intermediates will perform when integrated into existing operations. The results will be useful to address the GHG effects of coprocessed fuel products.

SDI-H. Materials Compatibility and Equipment Design and Optimization: Current equipment may not be designed to handle the harsh conditions inherent to biofuels production; for example, they may

be incompatible with the highly corrosive and erosive nature of feedstocks, biomass, and bio-intermediates. Methods are needed to identify appropriate construction materials and establish process optimization conditions to co-develop equipment. In addition, procedures employed from current refinery practices must be extended to include characteristics of biomass and bio-intermediates.

Analysis and Sustainability Barriers and Challenges

At-A. Analysis to Inform Strategic Direction: Analysis is needed to better understand factors influencing the growth and development of the bioenergy and bioproducts industries, identify the most impactful R&D strategies, define BETO goals, and inform BETO strategic direction.

At-B. Analytical Tools and Capabilities for System-Level Analysis: High-quality analytical tools and models are needed to better understand bioenergy supply chain systems, linkages, and dependencies. Models need to be developed and refined to reflect new knowledge, scientific breakthroughs, and enable informed decision-making. Improvements in model components and linkages are necessary to improve utility, consistency, and reliability.

At-C. Data Availability across the Supply Chain: Understanding the biomass-to-bioenergy supply chain and its economic, environmental, and other impacts requires complete and comparable data. Filling data gaps and improving data accessibility would improve efforts to understand all relevant dimensions of bioenergy and bioproducts production and use and inform model development.

At-D. Identifying New Market Opportunities for Bioenergy and Bioproducts: Biofuels and bioproducts can potentially offer performance advantages relative to other technology options, and they can also provide unique solutions in certain sectors that have limited energy alternatives, such as aviation and marine. Ongoing, forward-looking analyses are needed to identify these opportunities so that R&D priorities can be adjusted appropriately.

At-E. Quantification of Economic, Environmental, and Other Benefits and Costs: When the economic, environmental, and other benefits of bioenergy and bioproducts are uncertain or not quantified, it is difficult to define their value proposition and to make comparisons among energy alternatives. This makes bioenergy technologies less likely to be adopted by the private sector. It is necessary to quantify both the costs and benefits so that synergies can be enhanced, trade-offs can be minimized, and R&D can be directed toward more sustainable outcomes. Furthermore, analyses must use transparent and defensible assumptions to be properly interpreted and to drive toward agreement across the stakeholder community.

At-F. Science-Based Methods for Improving Sustainability: Once the costs and benefits of a given bioenergy or bioproduct system are evaluated, solutions must be developed that improve system performance and economic and environmental outcomes. Furthermore, as bioenergy and bioproduct production from cellulosic, algal, and waste feedstocks is relatively new, few “best practices” are defined for all components of the supply chain. This requires research and development of science-based tools and improved practices in a variety of contexts to accelerate learning and continuous improvement across the emerging bioeconomy.

At-G. Stakeholder Acceptance and Involvement: The successful transfer of bioenergy technologies to the private sector will require significant involvement from landowners, technology developers, local communities, environmental organizations, regulatory bodies, and the broader public. Improved mechanisms are needed to better inform and involve these stakeholders in developing context-specific goals that consider local opportunities and constraints.

At-H. Consensus, Data, and Proactive Strategies for Improving Land-Use Management: The limitations of existing data sources to capture the dynamic state of land use and management, as well as an incomplete understanding of the drivers of land-use and land-management changes, have undermined efforts to assess the environmental effects of bioenergy production and consumption. Science-based, multi-stakeholder strategies are needed to integrate bioenergy with agricultural and forestry systems in a way that reduces wastes, maintains crop yields, enhances resiliency, and supports multiple ecosystem services without increasing pressure on native habitats and wildlife.

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