PNNL-29882

Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels: 2019 State of Technology

April 2020

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Summary

Data from Pacific Northwest National Laboratory's conversion hydrothermal liquefaction (HTL) program for wet waste was used to update the pathway techno-economic analysis (TEA) for the fiscal year 2019 State of Technology (2019 SOT). An overview of the current process model is given in Section 1. The experimental data used to inform the updated SOT is presented in Section 2. Section 3 gives modeled costs for the SOT and Section 4 discusses future work needed to drive progress toward the goal case.

Figure S.1 shows the modeled minimum fuel selling price (MFSP) for the 2019 SOT, along with the 2018 SOT and the 2022 projected (goal) cases for comparison. These costs are for an HTL plant scale of 110 dry ton/day sludge feed and an upgrading plant scale of 38 million gallons/year biocrude feed, commensurate with the design case. All costs are in 2016 dollars. Corresponding costs and technical parameters are given in Section 3 and Appendix B. Options with and without ammonia stripping treatment of the HTL aqueous recycle stream are included in the analysis to account for wastewater treatment plants that could handle the stream untreated.

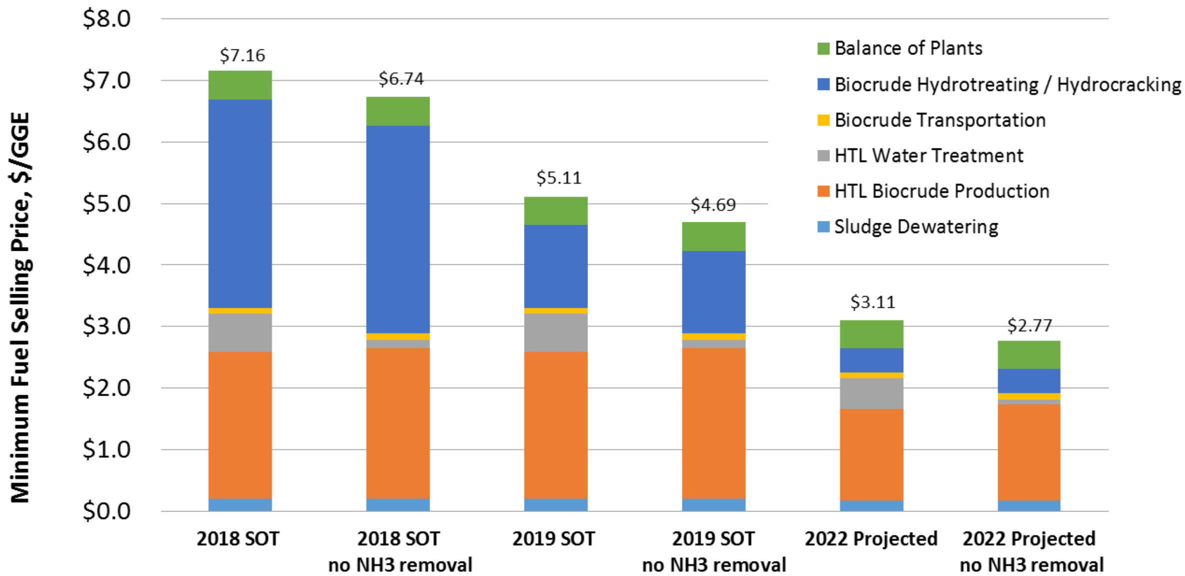

Figure S.1. Wet waste HTL and biocrude upgrading pathway cost allocations.

As shown in Figure ES.1, the reduction in modeled MFSP from the 2018 SOT to the 2019 SOT is specifically due to improved hydrotreating performance. The research increased time-on-stream (used as the catalyst lifetime in the TEA)from 300 hours to 553 hours, guard bed weight hourly space velocity (WHSV) from 0.46 hr^{-1} to 0.67 hr^{-1}, and hydrotreater WHSV from 0.29 hr^{-1} to 0.39 hr^{-1}, resulting in a MFSP reduction of $1.79/GGE (gasoline-gallon equivalent). Additionally, NiMo catalyst was used in place of CoMo catalyst in the main hydrotreater bed without sacrificing performance. The change to NiMo, a less expensive catalyst than CoMo, saves an additional $0.26/GGE, resulting in a total MFSP that is $2.05/GGE lower than the 2018 SOT.

Additional waste feedstocks beyond sludge were tested in fiscal year 2019 (FY19) year, including a sludge/FOG (fats, oils, and grease) blend and a swine manure from concentrated feeding operations. These runs were successful (no plugging or shut-downs) and showed significantly higher biocrude yields than sludge-only results. For example, a 80/20 sludge/FOG mixture resulted in a 35% higher yield than pure sludge, indicating at least a one-to-one relationship between FOG and biocrude product (on a dry, ash-free basis). The FOG feed was decanted scum from primary wastewater treatment, a very non-homogeneous mixture of brown grease and bits of trash, leaves, twigs, and other floating debris. Proximate analysis revealed that the scum contained only about 50% fatty acid. Upgrading of the biocrude from the sludge/FOG feed resulted in increased diesel-range content in the hydrotreated product relative to the sludge-only case, likely due to the predominance of C16-C18 fatty acids in FOG. These results are not yet integrated directly into the SOT price, but are included as a sensitivity in Figure S.2 to illustrate the potential impact of blending of FOG and sludge on biocrude yield and MFSP. Relative to the 2019 SOT, the addition of 20% FOG can reduce MFSP by about 65 cents/GGE. Demonstration of additional wastes and waste blends expands our understanding of the potential waste resource base and fuel production potential beyond sludge feedstock.

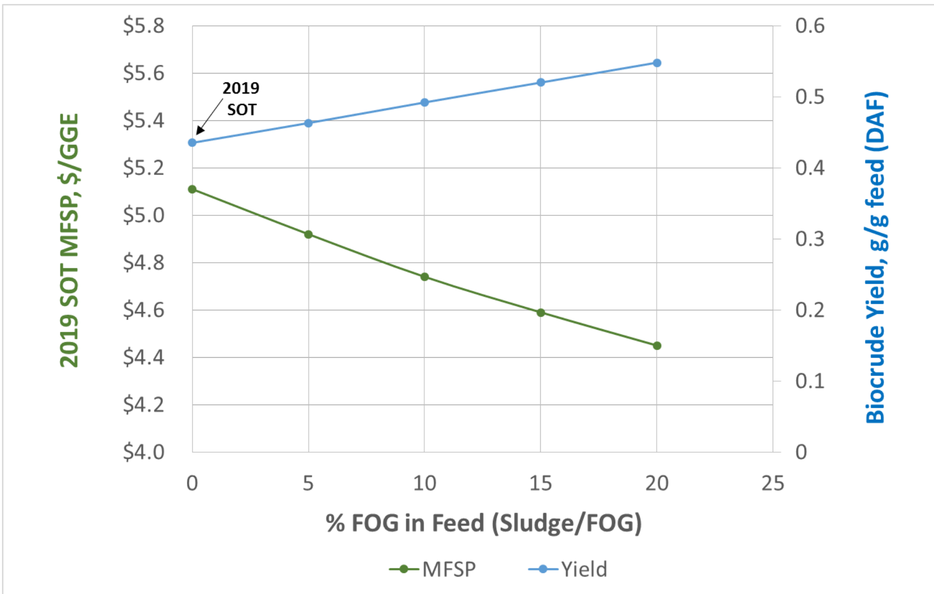

Figure S.2. Impact of blending FOG (scum) into sludge feedstock on 2019 SOT biocrude yield and MFSP.

Future research planned to drive the SOT toward the 2022 projected goal includes the following focus areas:

<u>FY 2020:</u>

- **Improve HTL Operations:** Increasing HTL feed solids content reduces capital and operating costs associated with processing extra feed water and can also improve yields through better oil/water separation. A goal of 25% feed solids was established in the design case and is estimated to reduce cost by 24 cents/GGE. Testing of 25% solids will be performed to demonstrate this level of solids can be pumped for sludge and other relevant waste feedstocks.
- **Faster Hydrotreating Throughput:** Further improvements in hydrotreating performance are critical to reducing costs. Biocrude hydrotreating will be performed at an increased WHSV of 0.5 hr^{-1}, which is expected to reduce MFSP by approximately 21 cents/GGE from the 2019 SOT. Further improvements through the use of alternative guard bed designs will also be investigated.
- **Optimize HTL Heat Integration:** The sludge heaters constitute approximately 50% of the total HTL capital cost. Engineering design analysis initiated in FY19 will be completed to optimize the modeled heating and pumping design and configuration. A reduction of 25% in heater capital is expected to reduce MFSP by 26 cents/GGE.

- **Optimize Ammonia Stripping:** Preliminary FY19 HTL aqueous phase titration and ammonia stripping results indicate lime consumption may be significantly lower than originally anticipated, and that ammonia removal is limited to due to the presence of organics. Further work will be performed to validate titration results and air stripping performance.

FY 2021:

- **Optimize Hydrotreater Guard Bed:** Continued improvements will be made in biocrude upgrading plant performance through incorporation of strategies for such as new configurations and reduced catalyst cost for the guard bed.
- **Use Variety of Price Advantaged Wastes:** The uniqueness of this pathway warrants a new approach that includes identifying regional hot spots of wet waste generation and strategies for enabling blending scenarios that can maximize waste resource utilization and fuel production at a feasible price point. Utilizing the Pacific Northwest National Laboratory / National Renewable Energy Laboratory Waste-to-Energy team’s body of work, including planned FY20 geospatial and siting work to generate plant scales and gate feedstock costs, the SOT will be transitioned to regional wet waste blend scenarios.

FY 2022:

- **Hydrotreating Operation and Catalyst Maintenance:** Catalytic upgrading of wet-waste derived HTL biocrude will be performed with improved scalable reactor design, higher activity catalyst, and biocrude pretreatment to achieve a main hydrotreater bed WHSV of 0.75 $kg/kg/hr^{-1}$ and an extended time-on-stream of 1000 hours that can be extrapolated to a 1-2 year lifetime.

Acronyms and Abbreviations

AD	anaerobic digestion
AFDW	ash-free dry weight
CCCSD	Central Contra Costa Sanitary District
CSTR	continuous stirred-tank reactor
DAF	dry, ash-free
FOG	fats, oils, and grease
FY	fiscal year
GGE	gasoline-gallon equivalent
GHG	greenhouse gas
GLWA	Great Lakes Water Authority
HTL	hydrothermal liquefaction
ICP	inductively coupled plasma
MBSP	minimum biocrude selling price
MFSP	minimum fuel selling price
PFR	plug-flow reactor
PNNL	Pacific Northwest National Laboratory
SOT	state of technology
TEA	techno-economic analysis
TOS	time-on-stream
WHSV	weight hourly space velocity
WWTP	wastewater treatment plant

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1.0 Introduction

Each year, the U.S. Department of Energy Bioenergy Technologies Office assesses progress in their research and development efforts toward sustainable production of renewable fuels (DOE 2016). Technical and cost targets were previously established for the wet waste hydrothermal liquefaction (HTL) and biocrude upgrading pathway and summarized in a design report (Snowden-Swan et al. 2017).

The present report summarizes the research and associated techno-economic analysis (TEA) in support of the 2019 state of technology (SOT) assessment for this pathway. Methods and economic assumptions for the n^{th} plant analysis used for the TEA are consistent with the design report (Snowden-Swan et al. 2017), with the exception of updates in the modeled cost year (2016) and income tax rate (21%). Appendix D provides the full list of financial and economic assumptions used in the analysis.

2.0 Conversion Model Overview

Figure 1 shows the overall block flow diagram for the conversion of wastewater treatment plant (WWTP) sludge via HTL and biocrude upgrading. There has been no change in the process model configuration or product yields from the 2018 SOT assessment (see Appendix B); only the cost model has been changed to reflect improvements in hydrotreating catalyst performance and reactor throughput (weight hourly space velocity, or WHSV). The blue dashed boxes highlight the conversion processes that are the focus of research and analysis supporting development of this pathway. The modeled scales for the WWTP/HTL plant and the biocrude upgrading plant are 110 dry ton/day sludge and 38 million gal/yr biocrude feed, respectively, and are consistent with the design case (Snowden-Swan et al. 2017).

The HTL plant is assumed to be co-located with the WWTP to avoid the cost of transporting sludge. While collection of sludge from nearby WWTP facilities is possible and could conceivably benefit economics by increasing HTL plant scale, this scenario is not considered here. In addition, regional collection of other wet or dry wastes could be feasible at a low enough cost to support larger scale facilities. Future resource analysis work is needed to elucidate the tradeoffs between wet waste collection and plant scale. Biocrude from the HTL plant is shipped by tanker truck to a larger scale upgrading plant where it is combined with biocrude from multiple WWTP/HTL plants for catalytic hydroprocessing and product fractionation into naphtha and diesel fuel blendstocks. Co-processing at a petroleum refinery is also feasible.

The aqueous phase wastewater from HTL is pretreated prior to recycling back to the WWTP treatment train to reduce the ammonia load to the WWTP. However, there is significant uncertainty around whether or not a WWTP would require ammonia removal prior to recycling the HTL aqueous phase back to its treatment train, depending primarily on local regulations and the plant's existing capacity to remove nitrogen. For this reason, direct recycle without ammonia removal is also considered to represent WWTPs where treatment would not be necessary.

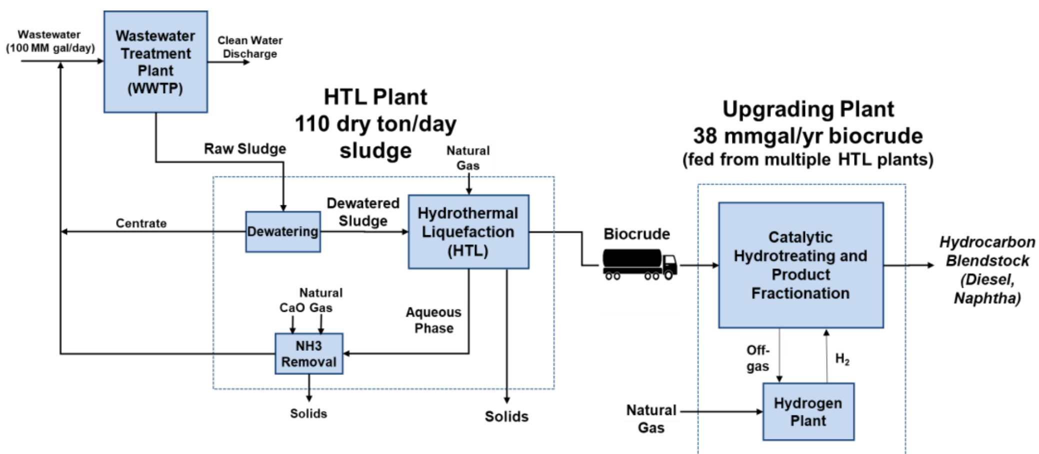

Figure 1. Sludge HTL and biocrude upgrading block diagram for the 2019 SOT.

As part of the pathway analysis, additional wet waste feedstocks are being evaluated to expand the potential resource base for HTL conversion, boost fuel production, and ultimately increase opportunity for the circular bioeconomy. This includes fats, oils, and greases (FOG), manure, and food wastes. A head-to-head comparison of sludge with a 20% FOG in sludge mixture was tested in FY19 as part of this effort.

To provide a consistent feedstock comparison to the goal case, the testing results for this blend have not yet been incorporated into the modeled cost. Sensitivity analysis was conducted, however, to provide insight into the cost impact of introducing FOG into the feedstock for this pathway, presented in Section 3. Future analysis of wet waste blends appropriate to “hot spot” regions (e.g., metropolitan, agricultural) and the associated cost of collection and blending is needed for the techno-economic analysis to provide realistic estimates for the full scale potential of fuel production from this pathway.

3.0 Experimental Results

Primary experimental results used in the SOT analysis include 1) wet waste compositional analysis; 2) wet waste HTL processing; and, 3) hydrotreating of resulting biocrudes. The experimental data and discussion of their use in the analysis are presented in the following sections.

3.1 Wet Waste Feedstock Composition

Feedstocks tested include Central Contra Costa Sanitary District (CCCSD) sludge (50/50 primary/secondary), a mixture of 80% CCCSD sludge and 20% scum (the FOG that is generated in primary wastewater treatment), and swine manure. Table 1 shows ultimate and proximate analysis for these feedstocks. Analysis for the City of Detroit Great Lakes Water Authority (GLWA) sludge, on which the design case (Snowden-Swan 2017) and SOT are based, is also listed for comparison. Analysis for the pure FOG (scum) used in the sludge/FOG run is also listed. Major compositional differences between the sludge/FOG blend and the sludge-only feedstocks include a higher carbon content and lower nitrogen content due to the low concentration of protein in the FOG.

Note that the modeled 2019 SOT feedstock composition remains unchanged to maintain consistency with the design case at this time. However, testing of FOG/sludge provides critical information to begin to predict the impact of incorporation of scum and other regional FOG resources for regional blending scenarios and ultimately increasing fuel production potential from all wet waste resources.

Table 1. Ultimate and proximate analysis (wt%) of wet waste samples tested.

	WW06 50/50 Sludge GLWA (Dry)	WW06 50/50 Sludge GLWA (DAF)	WW09 50/50 Sludge CCCSD (Dry)	WW09 50/50 Sludge CCCSD (DAF)	WW10 CCCSD Sludge/FOG (80/20) (Dry)	WW10 CCCSD Sludge/FOG (80/20) (DAF)	WW15 Swine Manure (Dry)	WW15 Swine Manure (DAF)	2019 SOT and 2022 Models (Dry)	2019 SOT and 2022 Models (DAF)
C	41.1	52.0	43.3	51.1	49.5	58.5	47.6	53.7	46.8	52.1
H	5.8	7.3	6.3	7.4	6.9	8.2	6.3	7.1	6.5	7.2
O	26.1	33.0	30.2	35.6	24.6	29.0	30.9	34.8	29.7	33.1
N	5.0	6.3	4.5	5.3	3.1	3.7	3.4	3.8	5.7	6.3
S	1.0	1.3	0.6	0.5	0.5	0.6	0.6	0.6	1.2	1.3
Ash	26.1		16.7(a)		17.2		12.5		15.0	
P	1.9		2.5		2.2		1.4		1.9	
Carb	16.7	22.8	37.2	46.1	45.2	55.2		50.1		Not modeled
Fat	22.6	30.8	6.5	8.0	15.0	18.3		24.7		Not modeled
Protein	34.1	46.4	36.7	45.4	21.6	26.4		25.2		Not modeled
FAME	11.9	16.2	13.7	17.0	26.5	32.3		16.6		Not modeled
Ash	26.6		19.2		18.1					

(a) CCCSD currently treats their wastewater with lime to help incineration process. Ash content without lime is estimated at 14%.
DAF = dry, ash-free

3.2 Wet Waste Hydrothermal Liquefaction

Figure 2 shows a schematic of the sludge HTL experimental bench-scale system at Pacific Northwest National Laboratory (PNNL). The capacities of the system's stirred vessel reactor and plug-flow reactor (PFR) are 600 mL and 550 mL, respectively. Engineering-scale HTL testing has also been conducted with similar sludge at a space velocity of 4, in a pure PFR (no stirred vessel reactor), but at lower solids content.

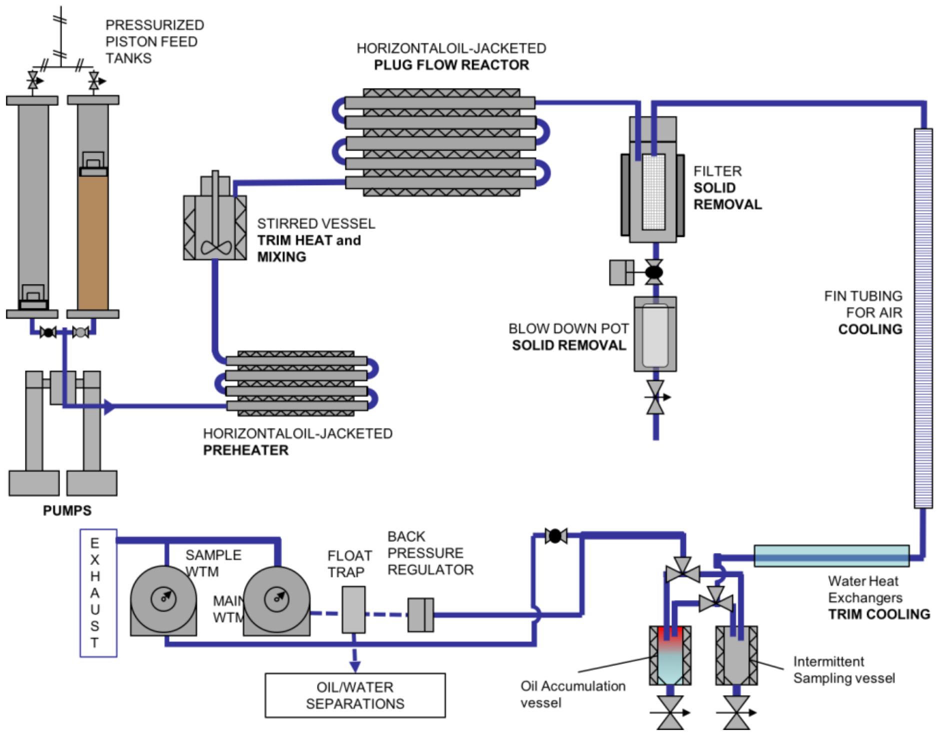

Figure 2. PNNL continuous flow laboratory HTL reactor system.

Experimental HTL testing conditions and results are given in Table 2, along with the parameters used for the modeled SOT and projected cases. Note that the 2019 SOT HTL model, feedstock and biocrude yields have not changed from the 2018 SOT assumptions (see Appendix B). Testing results show that biocrude yield for the CCCSD sludge/FOG feed (WW10) is 35% higher than the pure CCCSD sludge (WW09). This roughly translates to an estimated one-to-one ratio of FOG to the boost in biocrude. Sludge/FOG biocrude also has a 4% lower density than the pure sludge biocrude. This is not surprising because FOG is high in free fatty acids, which have lower density than cyclics and aromatics produced from carbohydrates and proteins in sludge. Its lower density is likely facilitating better separation from the aqueous phase, hence improving biocrude yield. The difference in biocrude yield between the two pure sludge runs may be caused in part by processing at different feed solids contents (20% for WW06 and 17% for WW09), which affects oil/water separation efficiency. Other possible factors are differences in fat content, pH, and the presence of different WWTP treatment chemicals (e.g., lime for CCCSD sludge and iron chloride for GLWA sludge).

Swine manure testing (WW15) showed a high biocrude yield of 49% versus 44% and 37% for the two 50/50 sludge samples tested (WW06 and WW09). Again, part of this effect may be the result of higher feed solids and fat content in the manure feedstock compared to the sludge feeds.

Table 2. Wet waste HTL testing results and model assumptions.

Operating Conditions and Results	50/50 Sludge (GLWA) WW06	50/50 Sludge (CCCSD) WW09	80/20 Sludge/FOG (CCCSD) WW10	Swine Manure WW15	2019 SOT Model	2022 Projected Model
Temperature, °F (°C)	656 (347)	655 (346)	653 (345)	653 (345)	656 (347)	656 (347)
Pressure, psia (MPa)	2979 (20.5)	2845 (19.6)	2895 (20.0)	2840 (19.6)	2979 (20.5)	2979 (20.5)
Feed solids, wt%						
Ash included	20%	17.4%	16.8%	24.9%	20%	25%
Ash-free basis	15%	14.5%	13.9%	21.8%	17%	21%
Liquid hourly space velocity, vol./h per vol. reactor	3.6[(d)]	3.6[(d)]	3.7[(d)]	3.5[(d)]	3.6	6
Equivalent residence time, min.	17	17	16	17	17	10
Product yields[(a)] (dry, ash-free sludge), wt%						
Oil (biocrude)	44%	37%	50%	49%	44%	48%
Aqueous	31%	34%	26%	21%	29%	25%
Gas	16%	23%	19%	25%	16%	16%
Solids	9%	5%	5%	5%	12%	11%
Carbon yields						
Oil (biocrude)	58%	52%	60%	59%	72%	72%
Aqueous	24%	29%	26%	22%	18%	18%
Gas	8%	12%	9%	13%	9%	16%
Solids	10%	6%	5%	7%	1%	1%
HTL dry biocrude analysis, wt%						
C	78.5%	77.6%	77.9%	71.3%	78.3%	78.3%
H	10.7%	9.9%	10.9%	10.0%	10.8%	10.8%
O	4.7%	6.8%	7.2%	13.4%	4.8%	4.8%
N	4.8%	5.2%	3.6%	4.3%	4.9%	4.9%
S	1.2%	0.4%	0.3%	0.6%	1.2%	1.2%
P	0.0%	0.0%	0.0%	0.0%	Not modeled[(b)]	Not modeled[(b)]
Ash	0.06%	0.07%	0.05%	0.28%	0.0%	0.0%
HTL dry biocrude H:C ratio	1.6	1.5	1.7	1.7	1.6	1.6
HTL biocrude dry higher heating value, Btu/lb (MJ/kg)	16,900 (39.5)[(c)]	16,400 (38.0) [(c)]	16,900 (39.3) [(c)]	15,200 (35.3)[(c)]	17,100 (39.7)	17,100 (39.7)
HTL biocrude moisture, wt%	4.4%	4.0%	3.2%	5.0%	4.0%	4.0%
HTL biocrude wet density @25°C (g/ml)	0.98	0.99	0.95	0.96	0.98	0.98
Aqueous phase chemical oxygen demand (mg/L)	61,300	75,200	77,800	95,400	62,700	61,100

(a) Recovered after separations.
(b) Phosphorus partitioning is not directly modeled in Aspen because of the small quantity, most of which reports to the solid phase.
(c) Calculated using Boie’s equation (Boie 1953).
(d) The experimental system includes a continuous stirred-tank reactor (CSTR) followed by a PFR. The CSTR helps prevent overheating of the feed.

3.3 HTL Aqueous Phase Ammonia Treatment

A lab-scale ammonia stripping and scrubbing system (Figure 3) was built and scoping studies were performed to help define process condition ranges for future ammonia stripping testing on HTL aqueous phase. Scoping studies were performed at pH 9-11, 45-50°C, and 80-120 L/h air flow rate through the system.

Figure 4 shows the pH titration curve generated for the HTL aqueous phase from the 80/20 sludge/FOG run (WW10). Approximately 0.4 mol OH- per liter of aqueous phase is indicated to reach a pH of 11, where the NH_3/NH_4+ equilibrium is shifted to the gas phase. This is considerably lower than that assumed in the HTL model (0.75 mol OH-/L aqueous) and therefore may result in cost savings from reduced lime consumption. Lime is a very greenhouse gas (GHG)-intensive chemical and therefore reducing lime rates could also help reduce GHG emissions for the pathway, as shown in the 2018 SOT supply chain sustainability analysis (Cai et al. 2018). Preliminary air stripping results showed ammonia removal levels of 11-52% at pH 9-11. Additional testing is needed to optimize system performance and validate these results.

Figure 3. Ammonia stripping and scrubbing apparatus for HTL aqueous phase.

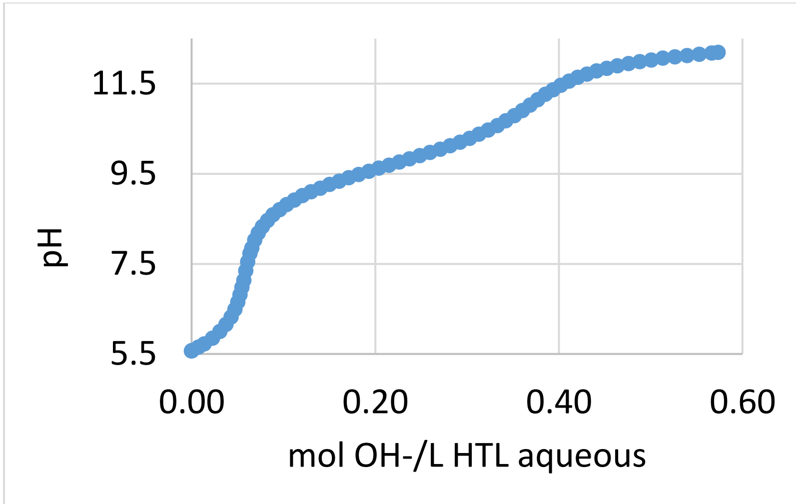

Figure 4. Titration curve for aqueous phase from HTL of 80/20 sludge/FOG (WW10).

3.4 HTL Biocrude Catalytic Hydrotreating

Biocrudes from the CCCSD sludge (WW09) and sludge/FOG blends (WW10) were hydrotreated in a fixed catalyst bed at 400°C and 1500 psi. The experimental system and detailed reactor packing configuration is shown in Figure 5. The guard bed packing was gradated to improve the distribution of impurity (e.g., Fe) throughout the reactor bed by decreasing the catalyst particle size down the length of the reactor. This design is the gradated approach used by commercial-scale hydrotreaters. The guard bed section was filled with $CoMo/Al_2O_3$ and the main hydrotreating bed was filled with $NiMo/Al_2O_3$. This differs from the 2018 SOT, where CoMo was used for both the guard bed and the main bed (see Appendix B). NiMo was tested to investigate the feasibility of a less expensive catalyst than CoMo. Further, the NiMo catalysts tend to have improved hydrodenitrogenation activity.

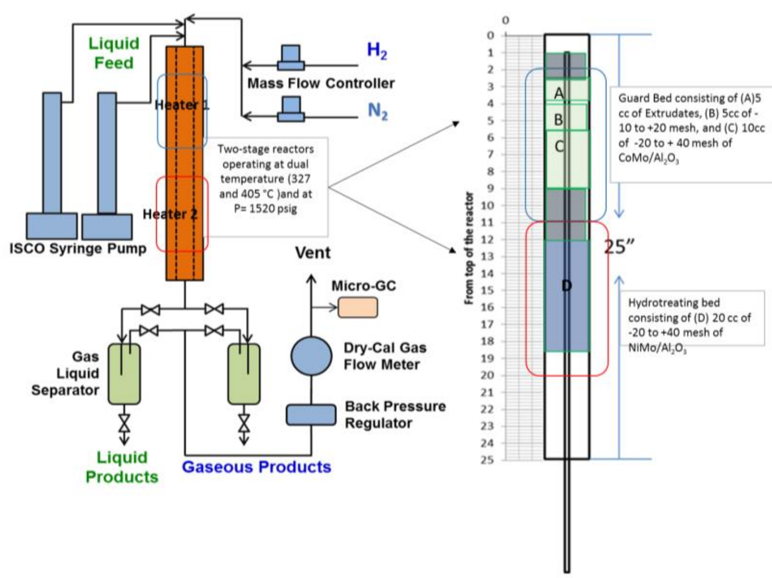

Figure 5. Schematic of laboratory biocrude hydrotreating system and reactor bed packing.

Table 3 gives the reactor conditions and product results from the CCCSD sludge (WW09) and CCCSD sludge/FOG blend (WW10), along with results from the previous run with GLWA sludge (Snowden-Swan et al. 2017) and the 2019 SOT and the 2022 goal case models. The sludge/FOG biocrude (WW10) was fed for 419 hours, at which time the reactor was put into warm standby due to inclement winter weather. After light resulfidation of the catalyst, the reactor was restarted and run with the remainder of WW10 feed and then the WW09 feed. The catalyst activity following shutdown improved slightly, indicating the ability to restore activity with light catalyst sulfiding. Figure 6 shows the hydrotreated product density as a function of time-on-stream (TOS). The run was ended at 553 hours TOS, when the feed was exhausted.

As shown in Table 3 and Figure 6, the FOG/sludge blend hydrotreated product (WW10) has a lower density than the sludge-only hydrotreated products (WW09 and WW06), aligning with the difference in the respective biocrude feeds. The increase in density seen after 419 hours (Figure 6) is due to the change from the FOG-sludge blend to the sludge-only feedstock after the standby period. Improvements incorporated into the 2019 SOT are increased catalyst life (corresponding to the demonstrated TOS), increased WHSV, and a change from CoMo to NiMo for the main hydrotreater bed. A transition has also been made from a reporting basis of liquid hourly space velocity to WHSV as it can be scaled more directly from bench and engineering scale to commercial scale.

Table 3. Wet waste biocrude hydrotreating experimental results and model assumptions.

Component	WW06 (GLWA sludge) (HT-62005-60)	WW09 (CCCSD sludge) HT-62006-86	WW10 (CCCSD sludge/FOG) HT-62006-86	2019 SOT Model	2022 Projected Model
Temperature, °F (°C)	752 (400)	752 (400)	752 (400)	752 (400)	752 (400)
Pressure, psia	1540	1535	1535	1540	1515
Guard bed catalyst sulfided?	CoMo/alumina Yes	CoMo/alumina Yes		CoMo/alumina Purchased presulfided	CoMo/alumina Purchased presulfided
Main bed catalyst sulfided?	CoMo/alumina Yes	NiMo/alumina Yes		NiMo/alumina Purchased presulfided	CoMo/alumina Purchased presulfided
Guard bed WHSV, wt./hr per wt. catalyst	0.46	0.68	0.65	0.67	1.3
Main bed WHSV, wt./hr per wt. catalyst	0.29	0.39	0.38	0.39	0.75
HTL biocrude feed rate, ml/h	5.6	7.3		Commercial scale	Commercial scale
Time-on-stream (catalyst life)	302 hours	552 hours		552 hours	2 years
Chemical H_2 consumption, wt/wt HTL biocrude (wet)	0.046	0.058	0.051	0.046	0.044
Product yields[(a)], lb/lb dry biocrude (vol/vol wet biocrude)					
Hydrotreated oil	0.82 (0.99)	0.84	0.82	0.82 (0.97)	0.84 (0.97)
Aqueous phase	0.14 (0.13)	0.13	0.17	0.14	0.13 (0.19)
Gas	0.08	0.08	0.06	0.10	0.07
Product oil, wt%					
C	85.6	85.0	84.8	85.3	85.3
H	14.6	14.3	15.1	14.1	14.1
O	1.0	<0.5	<0.5	0.6	0.6
N	<0.05	0.73	0.07	0.04	0.04
S	7-10 ppm	0.03	0.14	0.0	0.0
Aqueous carbon, wt%	0.10	Not measured	Not measured	0.6	0.2
Gas analysis, volume%					
CO_2, CO	0	5	4	0	0
CH_4	51	9	33	39	33
C_2+	49	86	63	35	38
NH_3	Not measured	Not measured	Not measured	23	26
NH_4HS	Not measured	Not measured	Not measured	3	3
Total acid number, feed (product)	59 (<0.01)	Not measured	Not measured	Not calculated	Not calculated
Viscosity@40°C, cSt, feed (product)	400 (2.7)	Not measured	166 (3.7)	Not calculated	Not calculated
Density@40°C, g/ml, feed (product)	0.98 (0.79)	0.99 (0.81)	0.95 (0.79)	0.98 (0.79)	0.98 (0.79)

(a) Yield after phase separation.

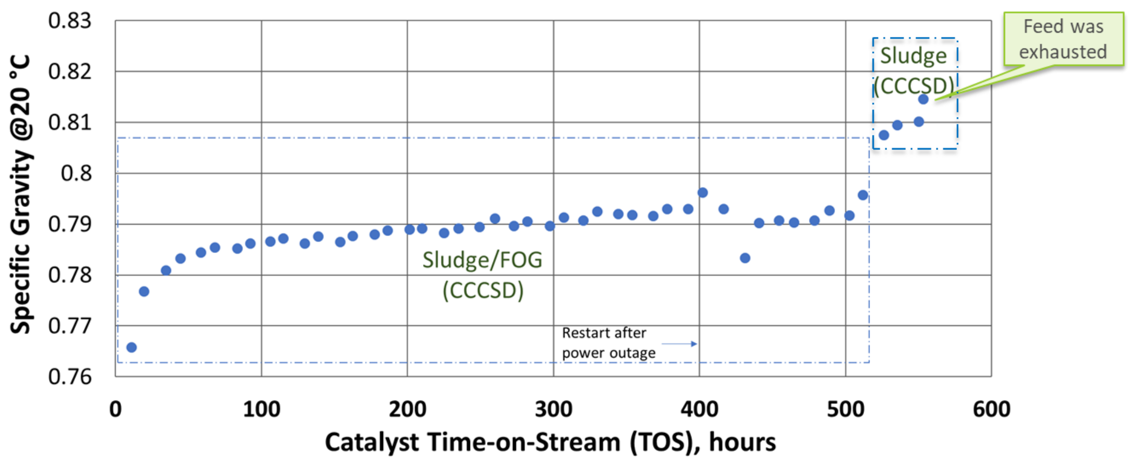

Figure 6. Density of upgraded biocrude from an 80/20 sludge/FOG blend (WW-10) and sludge only (WW-09) as a function of TOS.

Figure 7 shows boiling point curves from simulated distillation (ASTM Method D2887) of the hydrotreated product from sludge and sludge/FOG blend biocrudes. Curves from the previous GLWA sludge run (WW06) and the modeled product (matched to WW06 data) are also shown for comparison. Table 4 gives the approximate fuel cuts from each of the products based on the simulated distillation results. The addition of FOG increases the diesel-range cut contained in the hydrotreated product, due to FOG being rich in fatty acids with diesel-range carbon numbers (C16-C18). The conversion of fatty acids into n-alkanes during hydrotreating is expected to increase the cetane number.

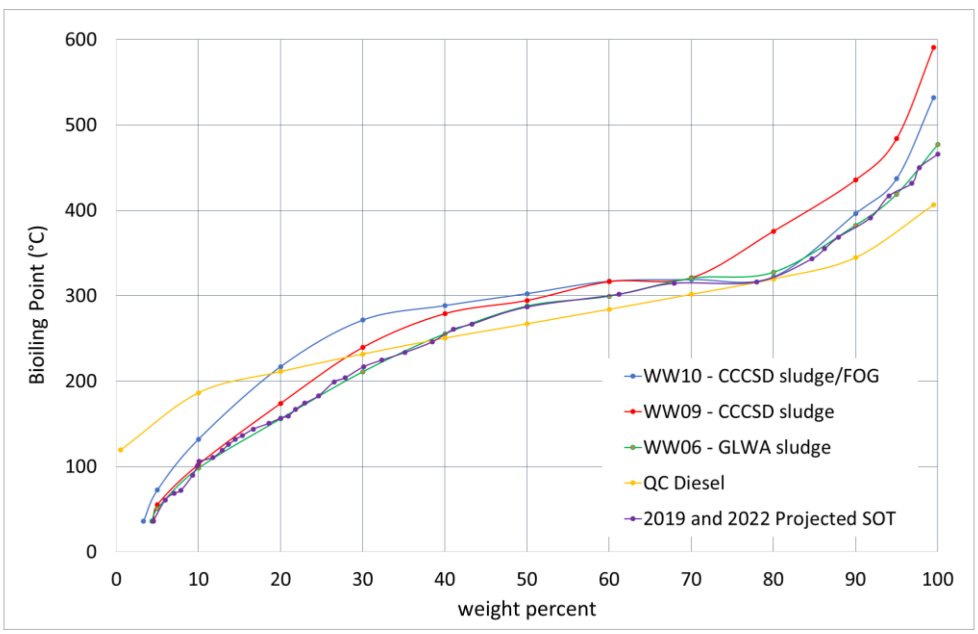

Figure 7. Boiling point distribution (ASTM D2887) for hydrotreated product from sludge and sludge/FOG biocrudes and process model.

Table 4. Fuel cuts in hydrotreated biocrude product.

Boiling Point according to ASTM D2887, °C	WW06 (GLWA sludge) (HT-62005-60)	WW09 (CCCSD sludge) HT-62006-86	WW10 (CCCSD sludge/FOG) HT-62006-86
IBP-184 (gasoline), wt%	24.7%	20.4%	14.7%
184-390 (diesel), wt%	66.8%	64.5%	75.5%
>390 (heavies), wt%	8.5%	15.1%	9.9%
153-256 (jet), wt%	21.8%	17.7%	15.0%

After the hydrotreating test, the reactor was disassembled and inductively coupled plasma (ICP) analysis was conducted on the contents of the reactor. Results for silicon (Si) and iron (Fe) are given in Figure 8 and show that the inorganic deposition is spread across the length of the bed (Na, Ca, and K results are given in Appendix A). Silicon deposition at the bed entrance (before the catalyst) is consistent with previous testing that showed silica precipitation upon heating the biocrude and filtration in the top of the catalyst bed (Figure 8, left). At commercial scale, a filter between the feed pre-heater and hydrotreating reactor is a good candidate solution for silica removal since silica is removed via a non-catalytic mechanism.

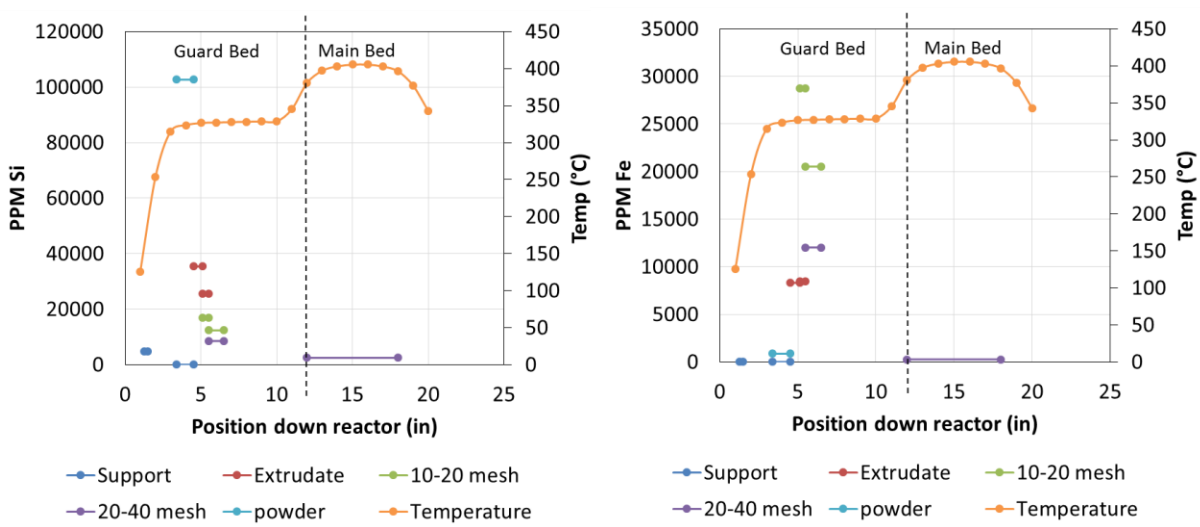

Figure 8. Post-processing hydrotreater catalyst ICP results for Si (left) and Fe (right).

4.0 2019 SOT Modeled Costs

Table 5 lists the major economic results for the HTL plant for the 2019 SOT. Costs for the 2018 SOT and 2022 projected (goal) case are also given for comparison. All costs are in 2016 dollars. Improvements in the SOT are exclusively from the upgrading research progress and therefore costs for the HTL plant did not change between the 2018 and 2019 SOTs. Table 6 lists major economic results for the biocrude upgrading plant. The fuel blendstock minimum fuel selling price (MFSP) for the upgrading plant includes $0.10/GGE (gasoline-gallon equivalent) for transporting the biocrude to the upgrading facility. Note that economics are dependent on plant scale, which is at 110 ton/day sludge feed and 38 mmgal/yr biocrude feed, for the HTL and upgrading plant, respectively. The 2022 projected costs in Table 5 and Table 6 differ slightly from the costs presented in the original design case (Snowden-Swan 2017) due to updates made in the modeled year and income tax rate (see Appendix D).

Figure 9 shows the breakdown of modeled MFSP by process area for the combined wet waste HTL and biocrude upgrading process pathway. Results for the separate HTL plant are given in Appendix B. The 2019 SOT MFSP is $5.11/GGE and $4.69/GGE for the cases with and without ammonia removal from the HTL aqueous phase, respectively. The cost reduction compared to the 2018 SOT is due to improved hydrotreating performance as described in Section 3.4. Relative to the 2018 SOT, demonstrated catalyst TOS (the assumed catalyst life) increased from 300 hours to 553 hours, guard bed WHSV increased from 0.46 hr^{-1} to 0.67 hr^{-1}, and hydrotreater WHSV increased from 0.29 hr^{-1} to 0.39 hr^{1}, resulting in an MFSP reduction of $1.79/GGE. Additionally, the hydrotreater bed was changed from CoMo to NiMo catalyst with no observed changes in product quality. Because NiMo is a lower cost catalyst than CoMo, the modeled MFSP is reduced further by $0.26/GGE, resulting in an overall decrease of $2.05/GGE. The complete list of processing area costs and key technical parameters and targets for the SOT and projected cases are given in Appendix B.

Table 5. Economic results for 110 dry ton/day sludge HTL plant (with NH_3 removal).

	2018 and 2019 SOTs	2022 Projected
Capital Costs, $ million		
Installed costs		
Sludge feedstock dewatering	1.3	1.3
HTL biocrude production	19.5	12.3
HTL aqueous phase recycle treatment	2.8	2.3
Balance of plant	0.6	0.6
Total installed capital cost	24.2	16.5
Indirect costs	17.1	11.7
Fixed capital investment	45.7	31.3
Total capital investment (TCI)	48.1	32.9
Operating Costs, $ million/yr		
Variable operating cost		
Avoided sludge disposal cost	0	0
Natural gas	0.4	0.4
Chemicals	0.7	0.7
Electricity	0.6	0.4
Fixed costs	3.2	2.7
Capital depreciation	1.5	1.0
Average income tax	0.5	0.3
Average return on investment	4.3	3.0
MBSP, $/gal biocrude	3.27	2.27
MBSP, $/GGE biocrude	3.04	2.11

Table 6. Economics for 115,000 gal/day biocrude upgrading plant (using HTL costs with NH_3 removal).

	2018 SOT	2019 SOT	2022 Projected
Capital Costs, $ million			
Installed costs			
Hydrotreating	46.7	41.9	31.6
Hydrocracking	6.1	6.1	6.2
Hydrogen plant	26.3	26.3	25.6
Steam cycle	1.7	1.7	1.5
Balance of plant	6.2	6.2	6.1
Total installed capital cost	87.0	82.2	71.0
Indirect costs	60.9	57.5	49.6
Fixed capital investment	162.5	153.4	132.3
Total capital investment (TCI)	173.7	164.0	141.5
Operating Costs, $ million/yr			
Biocrude feedstock (including transport)	127.6	127.6	89.6
Natural gas	1.4	1.4	1.7
Catalyst	105.9	31.9	0.5
Wastewater disposal	0.1	0.1	0.1
Electricity and water makeup	0.9	0.9	0.9
Fixed costs	10.2	9.9	9.1
Capital depreciation	5.4	5.1	4.4
Average income Tax	1.9	1.6	1.4
Average return on investment	17.7	15.0	12.4
MFSP, $/GGE fuel blendstock	7.16	5.11	3.11
MFSP, $/GGE (upgrading conversion cost only)	3.79	1.74	0.79
MFSP, $/gal diesel	7.67	5.48	3.33
MFSP, $/gal naphtha	7.07	5.05	3.06

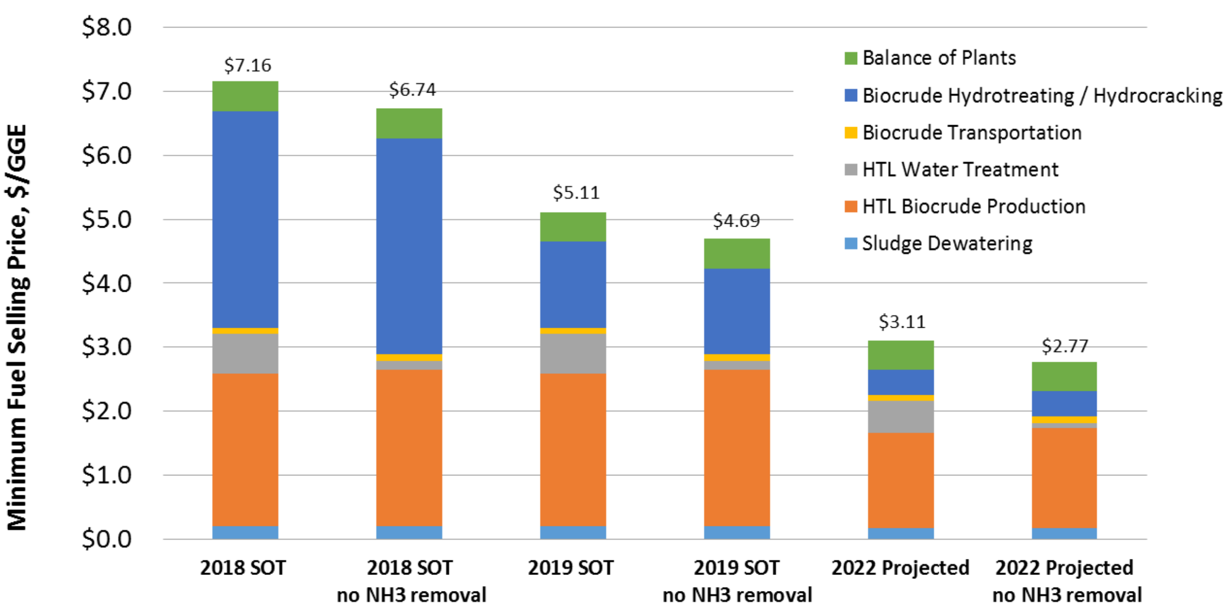

Figure 9. Combined HTL and biocrude upgrading process cost allocations.

This year's testing has also shown that HTL can process a range of wet wastes, including but not limited to wastewater sludge, blends of sludge and FOG, and swine manure. Blending of FOG with sludge was shown to have a positive yield effect (Section 3.2) and therefore can improve economics.

To maintain consistent feedstock composition with the design case, the blend results are not used in the 2019 SOT reported model and costs, but rather are shown as a sensitivity in Figure 10 to show the effect of collecting and blending regional FOG and sludge feedstock resources. The one-to-one FOG-to-biocrude result from testing was applied to the 2019 SOT model (baseline biocrude yield 44%) to predict the potential yield and cost impact from blending FOG with sludge at 0-20% FOG. These results suggest that incorporating 20% FOG into sludge increases biocrude yield from 44% to 55% and reduces MFSP from \$5.11/GGE to \$4.45/GGE.

The total FOG (in the form of scum) generated at a WWTP is actually less than 1% of the sludge generated; however, the total quantity of under-utilized FOG in the U.S. is about one quarter that of sludge (DOE 2017), so a 20% FOG/sludge blend is not an unreasonable assumption if regional collection of FOG were considered. Trap grease from restaurants and food processing operations (aka brown grease), one readily available form of FOG waste, is already being collected at several WWTPs for co-processing in anaerobic digestion (AD) units (City of Riverside 2015; Water Environment Federation 2017). Trap grease concentrations above 30% (w/w) volatile solids in the digester have been shown to inhibit the microbial AD community (Davidsson et al. 2008), so HTL may provide a flexible alternative to AD in some cases.

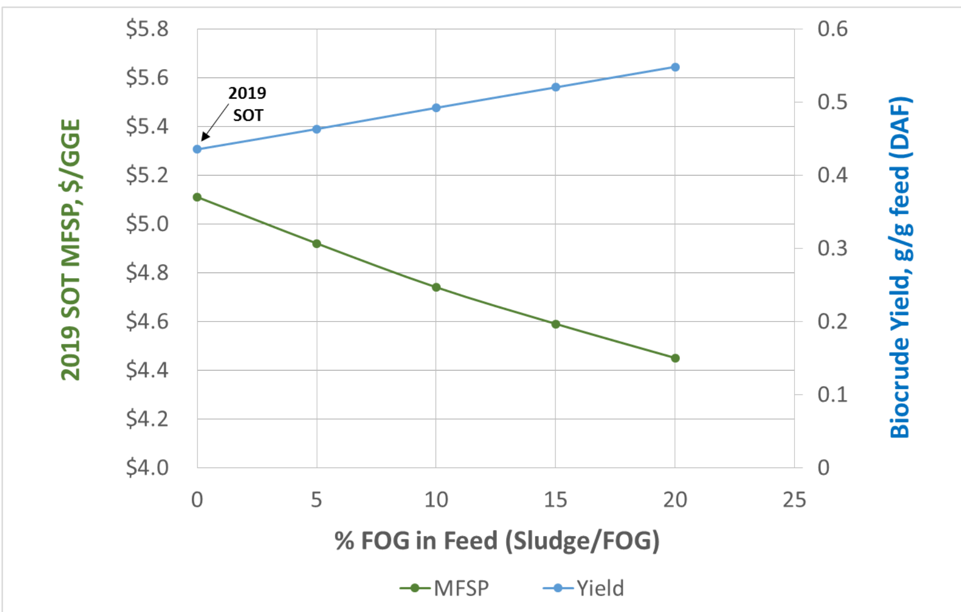

Figure 10. Impact of blending sludge and FOG on 2019 SOT biocrude yield and cost.

5.0 Future Work and Progression to 2022 Projected Case

Substantial progress was made in reducing the modeled cost for the 2019 SOT by $2.05/GGE fuel blendstock from the 2018 SOT. Future research to drive down costs toward the 2022 target will focus on the following areas.

HTL: Increasing the solids content in the feed slurry reduces capital and operating costs associated with processing extra feed water and can also improve yields through better oil/water phase separation. Increasing feed solids from 20% to 25% is predicted to lower MFSP by approximately 24 cents/GGE. Testing in FY19 with a 25% solids swine manure was successful; however, additional testing is needed to provide additional evidence that this level of solids is consistently pumpable in scaled-up systems for sludge and other pertinent wet waste feedstocks. Pumping of thick slurries is also expected to be less challenging at commercial scale than at bench scale with specialized slurry pump technologies and larger line sizes (Berglin et al. 2012).

A higher overall heat transfer coefficient (100 Btu/hr/ft^2/°F) for the sludge heaters was assumed in the goal case design relative to the SOT. After gaining more data and conducting an in-depth engineering design analysis, we now know this is not theoretically possible with the given heat exchanger design. We are currently investigating alternative designs/configurations that may potentially reduce exchanger cost. Preliminary results indicate that material costs for the exchangers can be substantially reduced by using an intermediate heat transfer fluid on the shell side, thus reducing shell pressure and thickness. A staged heating/pumping scheme may further reduce exchanger material costs. Completion and review of the design analysis is needed so that improved design configuration and costs can be incorporated into the SOT. In addition, sludge rheology data is needed to understand the sludge viscosity behavior at process conditions and provide an accurate design and costing of the exchanger system. Reducing the capital cost of the heat exchangers by 25% could reduce MFSP by about 26 cents/GGE.

Upgrading: Further advancements in hydrotreating performance are critical to drive the SOT toward the 2022 target, with increased catalyst life and reactor throughput key aspects of this strategy. Figure 11 shows the impact of varying hydrotreater WHSV and catalyst lifetime on MFSP . At higher catalyst lifetimes of 1 and 2 years (typical for commercial-scale processes), there are diminishing returns from increasing WHSV because catalyst operating cost is reduced to a minor portion of the MFSP. There is also a technical limit to how high WHSV can be increased without sacrificing extent of hydrotreating (i.e., product quality). In FY20, a WHSV of 0.5 hr^{-1} will be tested, which is estimated to reduce the SOT cost by about 21 cents/GGE.

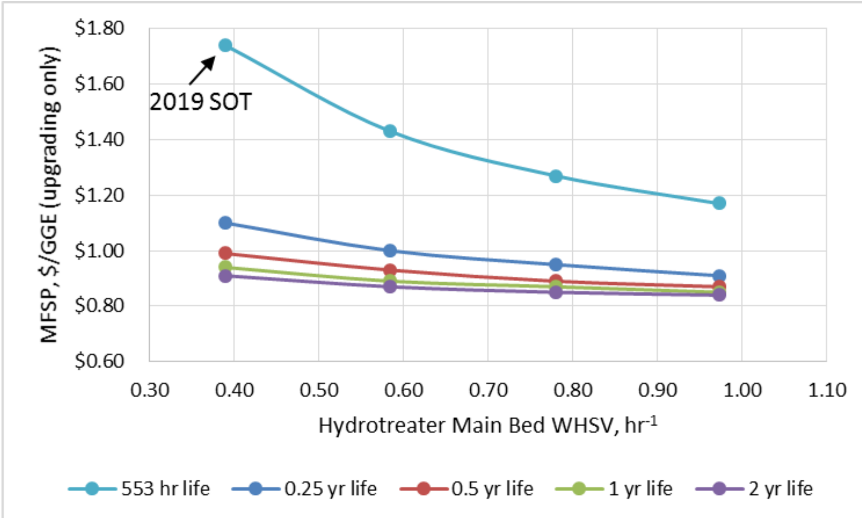

Figure 11. Catalyst life and WHSV impact on upgrading cost.

Additional strategies being considered include the use of an alternative bed type and reduced cost catalyst for the guard bed. Previous work has shown that as Fe deposits on the catalyst (as high as 20+% Fe), the catalyst remains active for hydrodemetalization. We expect to explore Fe catalysts for the guard bed. Based on prior work on upgrading of fast pyrolysis bio-oil, it may also be possible to recycle the heavies back to the hydrotreater, eliminating the need for a hydrocracker. Removing the hydrocracker is estimated to reduce the SOT MFSP by about 4 cents/GGE. PNNL is currently working with the Separations Consortium to determine ways to remove the organic nitrogen from HTL biocrude, which is necessary to facilitate recycling of the heavier-than-diesel fraction around the hydrotreater. Removal of nitrogen from the biocrude may also improve refinery co-processing opportunities. Co-processing at a petroleum refinery is estimated to reduce the SOT MFSP by about 53 cents/GGE. In support of this effort, the Strategies for Co-processing in Refineries program at the National Renewable Energy Laboratory and PNNL is currently investigating co-processing with vacuum gas oil.

Aqueous Phase Treatment: Preliminary work in FY19 on titration of the aqueous phase indicates that about 60% less lime is needed than is modeled in the SOT. If validated, this result is estimated to reduce the SOT MFSP by approximately 6 cents/GGE. Preliminary stripping tests showed 52% ammonia removal from the HTL aqueous phase. This is less than expected, and is possibly due to the high level of organics in the stream. Further testing is needed to validate the titration results and in particular the ammonia stripping performance results. Recovery of nitrogen co-product from the aqueous phase is desirable but may be economically challenging, as the extra processing needed to produce an on-spec, marketable fertilizer product may outweigh the potential return. Alternatives to ammonia stripping are also being considered and baseline testing is planned for several off-the-shelf options.

Transition to Waste Blend Scenarios: The wet waste HTL pathway is unique relative to other biofuel pathways in that it is based on feedstocks that are already being generated in large quantities today (DOE 2017). These feedstock resources are distributed, and as such, the feed composition and cost, and plant scale and economics, will vary greatly depending on the region of interest. For these reasons, a new paradigm is needed for the SOT that identifies realistic regional scenarios that can capture as much of the existing waste pool as possible while enabling a $3/GGE MFSP.

A blending study performed in FY19 that identified 213 service areas (100-mile collection radius), or "hot spots," of wet waste generation in the U.S. indicated that much of the wet waste in the country is generated within 25 miles of a WWTP (Seiple 2019). This is encouraging as it suggests that regional collection at economically feasible scales may be plausible for a significant portion of the wet waste resource. Analysis of regional blending scenarios in the SOT will require information on waste feedstock composition and plant gate cost (including transportation), production scale, HTL performance, and hydrotreating performance of the hot spot blends. In addition, siting analysis is needed for centralized biocrude upgrading and/or co-processing at existing petroleum refineries. Other logistical aspects of collection, such as how to transport waste with minimal biological degradation and odor, are additional challenges. Building on previous waste resource analyses (Seiple et al. 2017; Milbrandt et al. 2018; Skaggs et al. 2018; Badgett et al. 2019), geospatial and siting analysis will be conducted in FY20 to estimate TEA inputs for regional blending scenarios. This information, along with blend testing and predictive modeling results from the experimental and techno-economic analysis teams, will be used to transition the SOT to several regional waste blend scenarios in FY21-FY22.

6.0 References

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Appendix A – Post-Processing Hydrotreater Catalyst Inductively Coupled Plasma Results

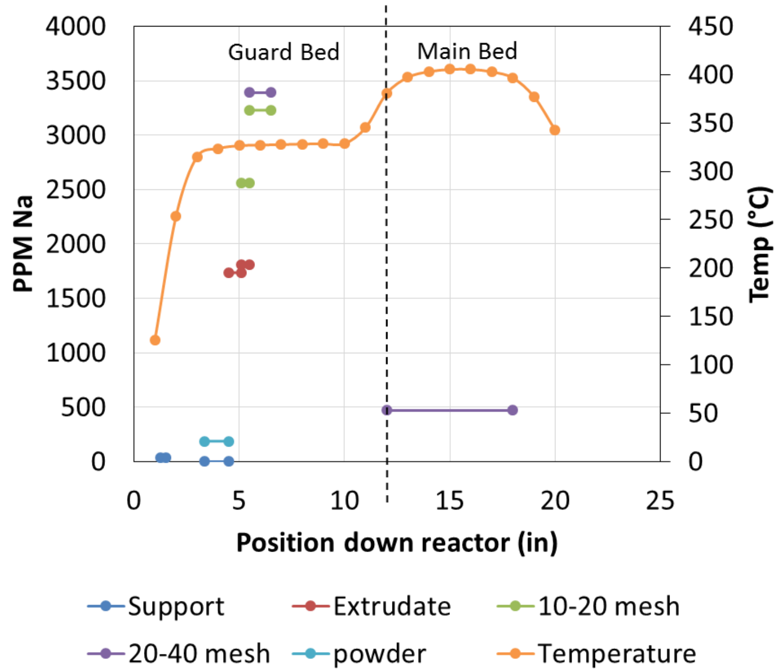

Figure A.1. Post-processing hydrotreater catalyst inductively coupled plasma results for sodium.

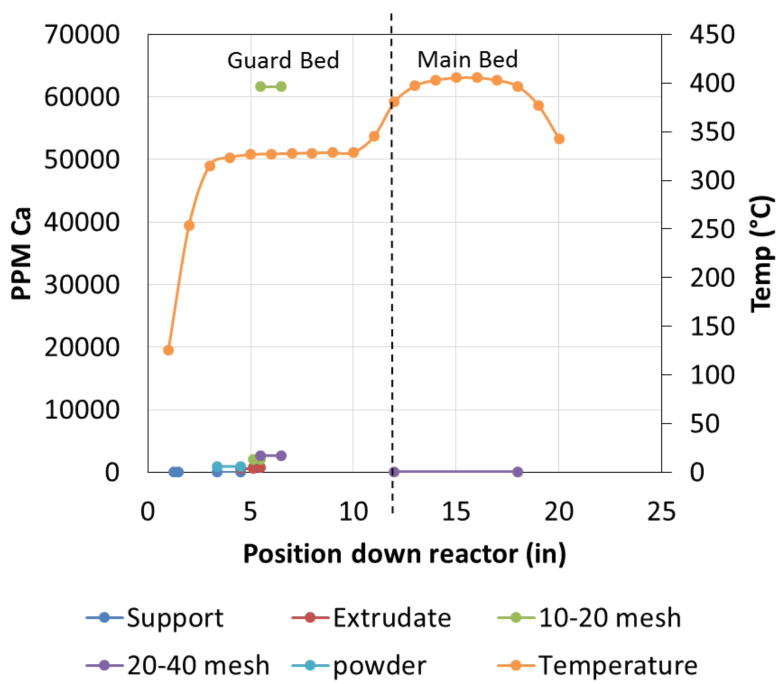

Figure A.2. Post-processing hydrotreater catalyst inductively coupled plasma results for calcium.

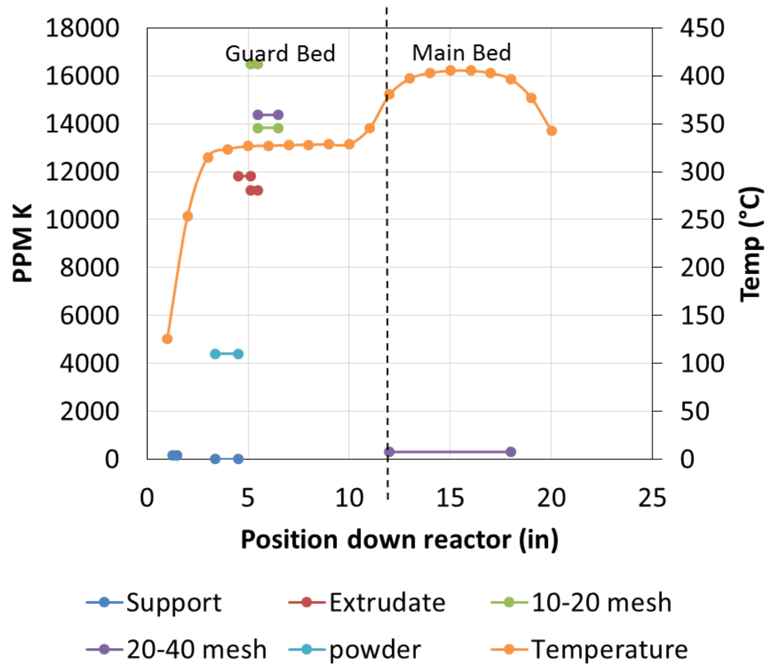

Figure A.3. Post-processing hydrotreater catalyst inductively coupled plasma results for potassium.

Appendix B – Technical Tables and Separate HTL Plant Economics

Table B.1 gives the processing area costs and key technical parameters for the individual HTL plant. Figure B.1 provides a graphical comparison of the processing costs for the SOTs and projected cases.

Table B.1. Processing area cost contributions and key technical parameters for the SOT and projected cases for the combined wet waste HTL and upgrading pathway.

Processing Area Cost Contributions & Key Technical Parameters	Metric	2018 SOT with NH3 removal	2018 SOT no NH3 removal	2019 SOT with NH3 removal	2019 SOT no NH3 removal	2022 Projected with NH3 removal	2022 Projected no NH3 removal
Fuel selling price	$/GGE	$7.16	$6.74	$5.11	$4.69	$3.11	$2.77
Conversion Contribution	$/GGE	$7.06	$6.64	$5.01	$4.59	$3.01	$2.67
Performance Goal	$/GGE					$3	$3
Production Diesel	mm gallons/yr	27	27	27	27	28	28
Production Naphtha	mm gallons/yr	9	9	9	9	9	9
Diesel Yield (AFDW sludge basis)	gal/US ton sludge	79	79	79	79	89	89
Naphtha Yield (AFDW sludge basis)	gal/us ton sludge	27	27	27	27	30	30
Natural Gas Usage (AFDW sludge basis)	scf/US ton sludge	4,951	3,898	4,951	3,898	4,914	3,861
Feedstock							
Total Cost Contribution	$/GGE fuel	$0	$0	$0	$0	$0	$0
Feedstock Cost (dry sludge basis)	$/US ton sludge	$0	$0	$0	$0	$0	$0
Sludge Dewatering							
Total Cost Contribution	$/GGE fuel	$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	$0.09	$0.09
Operating Cost Contribution	$/GGE fuel	$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	$1.49	$1.55
Capital Cost Contribution	$/GGE fuel	$1.46	$1.46	$1.46	$1.46	$0.83	$0.83
Operating Cost Contribution	$/GGE fuel	$0.94	$0.99	$0.94	$0.99	$0.66	$0.72
HTL Biocrude Yield (dry)	lb/lb sludge	0.44	0.44	0.44	0.44	0.48	0.48
Liquid Hourly Space Velocity (LHSV)	vol/h/vol	3.6	3.6	3.6	3.6	6.0	6.0
Preheaters Capital Cost (installed)	$MM	12	12	12	12	6	6
HTL Water Recycle Treatment							
Total Cost Contribution	$/GGE fuel	$0.61	$0.13	$0.61	$0.13	$0.49	$0.09
Capital Cost Contribution	$/GGE fuel	$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	$0.33	$0.09
Balance of Plant - HTL							
Total Cost Contribution	$/GGE fuel	$0.06	$0.07	$0.06	$0.07	$0.07	$0.07
Capital Cost Contribution	$/GGE fuel	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Operating Cost Contribution	$/GGE fuel	$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
Biocrude Upgrading to Finished Fuels							
Total Cost Contribution	$/GGE fuel	$3.38	$3.38	$1.34	$1.34	$0.40	$0.40
Capital Cost Contribution	$/GGE fuel	$0.40	$0.40	$0.34	$0.34	$0.25	$0.25
Operating Cost Contribution	$/GGE fuel	$2.97	$2.97	$1.01	$1.01	$0.15	$0.15

Processing Area Cost Contributions & Key Technical Parameters	Metric	2018 SOT with NH3 removal	2018 SOT no NH3 removal	2019 SOT with NH3 removal	2019 SOT no NH3 removal	2022 Projected with NH3 removal	2022 Projected no NH3 removal
Hydrotreating Mass Yield on dry Biocrude	lb/lb biocrude	0.82	0.82	0.82	0.82	0.84	0.84
Guard Bed Weight Hourly Space Velocity (WHSV)	wt/h/wt	0.46	0.46	0.67	0.67	1.30	1.30
Guard Bed Catalyst Lifetime	years	0.03	0.03	0.06	0.06	1	1
Hydrotreater Weight Hourly Space Velocity (WHSV)	wt/h/wt	0.29	0.29	0.39	0.39	0.75	0.75
Hydrotreater Catalyst Lifetime	years	0.03	0.03	0.06	0.06	2	2
Balance of Plant - Upgrading							
Total Cost Contribution	$/GGE fuel	$0.42	$0.42	$0.40	$0.40	$0.39	$0.39
Capital Cost Contribution	$/GGE fuel	$0.26	$0.26	$0.24	$0.24	$0.22	$0.22
Operating Cost Contribution	$/GGE fuel	$0.16	$0.16	$0.16	$0.16	$0.17	$0.17
Models: Case References		Sludge HTL 2018 SOT final.bkp; Sludge HTL Biocrude Upgrading 2018 SOT.bkp				Sludge HTL Goal Case 8-17-2017 FINAL 110 TPD 1.bkp; WW-06 Bio-Oil Upgrading 10X 110 TPD.bkp	

Table B.2. Processing area cost contributions and key technical parameters for the SOT and projected cases for the separate wet waste HTL plant.

Processing Area Cost Contributions & Key Technical Parameters	Metric	2018 SOT with NH3 removal	2018 SOT no NH3 removal	2019 SOT with NH3 removal	2019 SOT no NH3 removal	2022 Projected with NH3 removal	2022 Projected no NH3 removal
HTL Biocrude selling price	$/GGE	$3.04	$2.65	$3.04	$2.65	$2.11	$1.79
Conversion Contribution, Biocrude	$/GGE	$3.04	$2.65	$3.04	$2.65	$2.11	$1.79
Production Biocrude	mm GGE/yr	4	4	4	4	4	4
Production Biocrude	mm gallons/yr	3	3	3	3	4	4
Biocrude Yield (AFDW sludge basis)	gal/US ton sludge	111	111	111	111	123	123
Natural Gas Usage (AFDW sludge basis)	scf/US ton sludge	3,760	2,707	3,760	2,707	3,303	2,250
Feedstock							
Total Cost Contribution	$/GGE fuel	$0	$0	$0	$0	$0	$0
Feedstock Cost (AFDW sludge basis)	$/US ton sludge	$0	$0	$0	$0	$0	$0
Sludge Dewatering							
Total Cost Contribution	$/GGE biocrude	$0.18	$0.18	$0.18	$0.18	$0.17	$0.17
Capital Cost Contribution	$/GGE biocrude	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08
Operating Cost Contribution	$/GGE biocrude	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08
Sludge HTL							
Total Cost Contribution	$/GGE biocrude	$2.23	$2.28	$2.23	$2.28	$1.41	$1.47
Capital Cost Contribution	$/GGE biocrude	$1.36	$1.36	$1.36	$1.36	$0.79	$0.79
Operating Cost Contribution	$/GGE biocrude	$0.87	$0.92	$0.87	$0.92	$0.62	$0.68
HTL Biocrude Yield (dry)	lb /lb sludge	0.44	0.44	0.44	0.44	0.48	0.48
Liquid Hourly Space Velocity (LHSV)	vol/h/vol	3.6	3.6	3.6	3.6	6.0	6.0
Preheaters Capital Cost (installed)	$MM	12	12	12	12	6	6
HTL Water Recycle Treatment							
Total Cost Contribution	$/GGE biocrude	$0.57	$0.12	$0.57	$0.12	$0.46	$0.08
Capital Cost Contribution	$/gge biocrude	$0.19	$0.00	$0.19	$0.00	$0.15	$0.00
Operating Cost Contribution	$/GGE biocrude	$0.37	$0.12	$0.37	$0.12	$0.32	$0.08
Balance of Plant							
Total Cost Contribution	$/GGE biocrude	$0.06	$0.06	$0.06	$0.06	$0.06	$0.07
Capital Cost Contribution	$/GGE biocrude	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Operating Cost Contribution	$/GGE biocrude	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03
Models: Case References		Sludge HTL 2018 SOT final.bkp;				Sludge HTL Goal Case 8-17-2017 FINAL 110 TPD 1.bkp;	

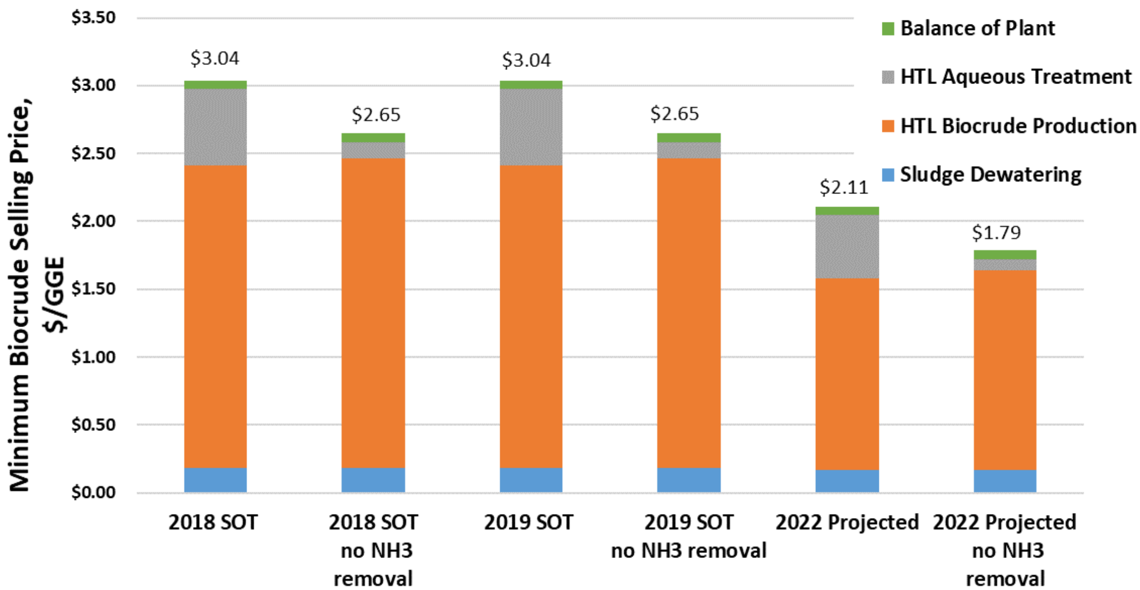

Figure B.1. Hydrothermal liquefaction biocrude cost allocations.

Appendix C – Life Cycle Inventory for Supply Chain Sustainability Analysis

Table C.1 and Table C.2 list the life cycle inventory for the hydrothermal liquefaction (HTL) and upgrading plants, respectively, that are provided to Argonne National Laboratory for Supply Chain Sustainability Analysis.

Table C.1. Hydrothermal liquefaction plant parameters for greenhouse gas and water analysis.

HTL Plant	2018 SOT with NH_3 Removal	2018 SOT without NH_3 Removal	2019 SOT with NH_3 Removal	2019 SOT without NH_3 Removal	2022 Projected with NH_3 Removal	2022 Projected without NH_3 Removal
Sludge Properties						
Solids content, %	20	20	20	20	25	25
Ash content (dry basis), %	15.02	15.02	15.02	15.02	15.02	15.02
Biocrude Properties						
Moisture content, %	4	4	4	4	4	4
Density, lb/gal	8.15	8.15	8.15	8.15	8.15	8.15
Lower heating value, Btu/gal	124,943	124,943	124,943	124,943	124,990	124,990
Inputs						
Sludge, lb/hr (dry basis)	9,167	9,167	9,167	9,167	9,167	9,167
Natural gas, lb/hr	625	450	625	450	549	374
Electricity, kW (HTL process)	297	264	297	264	181	148
Electricity, kW (at WWTP for chemical oxygen demand)	849	849	849	849	637	637
Dewatering polymer, lb/hr	24	24	24	24	24	24
Quicklime (CaO), lb/hr	994	0	994	0	994	0
Cooling water makeup, lb/hr	190	190	190	190	210	210
Outputs						
Biocrude, lb/hr	3,533	3,533	3,533	3,533	3,896	3,896
Aqueous phase, lb/hr	34,694	34,694	34,694	34,694	26,023	26,023
Wet solids,[(a)] lb/hr	5,681	5,681	5,681	5,681	5,522	5,522
Solids from HTL aqueous treatment	2,091	0	2,091	0	2,091	0

(a) 59% and 60% moisture for SOT and projected case, respectively.
SOT = state of technology
WWTP = wastewater treatment plant

Table C.2. Upgrading plant parameters for greenhouse gas and water analysis.

Upgrading Plant	2018 SOT	2019 SOT	2022 Projected
Fuel Product Properties			
Diesel density, lb/gal	6.66	6.66	6.66
Diesel lower heating value, Btu/gal	124,394	124,394	124,410
Naphtha density, lb/gal	6.13	6.13	6.12
Naphtha lower heating value, Btu/gal	114,650	114,650	114,478
Inputs			
Biocrude, lb/hr	38,961	38,961	38,961
Natural gas, lb/hr	2,182	2,182	2,678
Electricity, kW	1,673	1,673	1,637
Cooling tower chemical, lb/hr	0.4	0.4	0.4
Boiler chemical, lb/hr	0.3	0.3	0.3
Hydrotreating catalyst, lb/hr	811	317	3.0
Hydrocracking catalyst, lb/hr	0.3	0.3	0.3
Hydrogen plant catalyst, lb/hr	0.4	0.4	0.4
Cooling water makeup, lb/hr	25,069	25,069	23,485
Boiler feedwater makeup, lb/hr	11,022	11,022	10,479
Outputs			
Diesel, lb/hr	22,577	22,577	23,206
Naphtha, lb/hr	7,124	7,124	7,140
Wastewater, lb/hr	22,773	22,773	21,503

Appendix D – Cost Factors and Financial Assumptions

Table D.1. Cost factors for direct and indirect project costs.

Direct Costs	
Item	% of Total Installed Cost (TIC)
Buildings	4.0%
Site development	10.0%
Additional piping	4.5%
Total Direct Costs (TDC)	18.5%
Indirect Costs	
Item	% of TDC
Prorated expenses	10%
Home office & construction fees	20%
Field expenses	10%
Project contingency	10%
Startup and permits	10%
Total Indirect Costs	60%
Working Capital	5% of FCI
Land	HTL: 6 acres @ $15,000/acre Upgrading: 6% of Total Purchased Equipment Cost

Table D.2. Financial assumptions for the economic analysis.

Assumption Description	Assumed Value
Internal rate of return (IRR)	10%
Plant financing debt/equity	60% / 40% of total capital investment (TCI)
Plant life	30 years
Income tax rate	21%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land)
Depreciation schedule	7-years MACRS[(a)] schedule
Construction period	3 years (8% 1st yr, 60% 2nd yr, 32% 3rd yr)
Plant salvage value	No value
Start-up time	6 months
Revenue and costs during start-up	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream factor	90% (7,920 operating hours per year)

(a) Modified accelerated cost recovery system

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