

Economic Analysis of Renewable Fuels for Marine Propulsion

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Executive Summary

The current global marine fuel consumption is estimated to be around 330 million tonnes annually, and the demand is expected to be doubled by 2030 due to increased global trade. Over 90% of the world's shipped goods travel by marine cargo vessels—one of the largest contributors to emissions of SO_x, NO_x, and PM. To meet the growing demand and the upcoming more stringent air emission regulations, now is the time to explore alternative fuels to penetrate the marine fuel markets. Biofuels can undoubtedly play an essential role in the future marine fuel that is more renewable, and lower sulfur and emissions. Both techno-economic analysis (TEA) and life cycle analysis (LCA) are effective tools to assess the economic and environmental feasibility of various biofuel pathways, in terms of their market competitiveness and environmental benefits concerning energy savings and air emissions reductions.

To support this effort, the National Renewable Energy Laboratory (NREL) is performing TEA of two pathways for the production of marine fuel. This study evaluates the economic potential of producing renewable fuels for marine propulsion. The selected fuel production pathways for the techno-economic analysis are:

Pathway 1: Syngas conversion via Fischer-Tropsch synthesis with a range of feedstock scenarios, including biomass only (BTL), natural gas only (GTL), biomass and coal co-feed (CBTL), and biomass and natural gas co-feed (GBTL).

Pathway 2: Conversion of extracted oils to marine fuels via hydrotreating. The feedstock options are yellow grease only (YG) and yellow grease and heavy oil co-feed (YG+HO).

This report presents a preliminary comparative TEA analysis of these conversion pathways. The summary of TEA results is presented in Figure ES1. It is important to note that the modeled costs are based on a set of nth plant financing and operating assumptions used for the U.S.

Department of Energy’s Bioenergy Technologies Office’s (or BETO’s) conversion pathway techno-economic analyses (see Table 1). Based on these assumptions, the modeled target MFSPs for the developing pathways decrease in the following order: \$3.79/GGE (CBTL) > \$3.50/GGE (YG) > \$2.99/GGE (BTL) > \$2.95/GGE (YG+HO) > \$2.37/GGE (GBTL) > \$1.95/GGE (GTL). Relative to the other pathways studied, Pathway GTL has the lowest MFSP due to a combination of favorable yields and lower operating costs. Pathway CBTL has the highest MFSP, attributing largely to the higher capital expenditure associated with the air separation unit and the high-temperature slagging gasifier as well as hydrogen cost. Pathways GBTL and YG+HO exhibit relatively favorable MFSPs. Cofeeding biomass with the fossil feedstock (NG or HO) is an effective synergistic approach to improve liquid fuel yields while simultaneously lowering greenhouse gas (GHG) emissions. Future studies will include sensitivity studies, which are necessary to understand better the uncertainty associated with the MFSP and the impact of major technical parameters and assumptions on the results. Nevertheless, the current TEA evaluations will provide an important baseline analysis for the bio-economy and marine fuel industry.

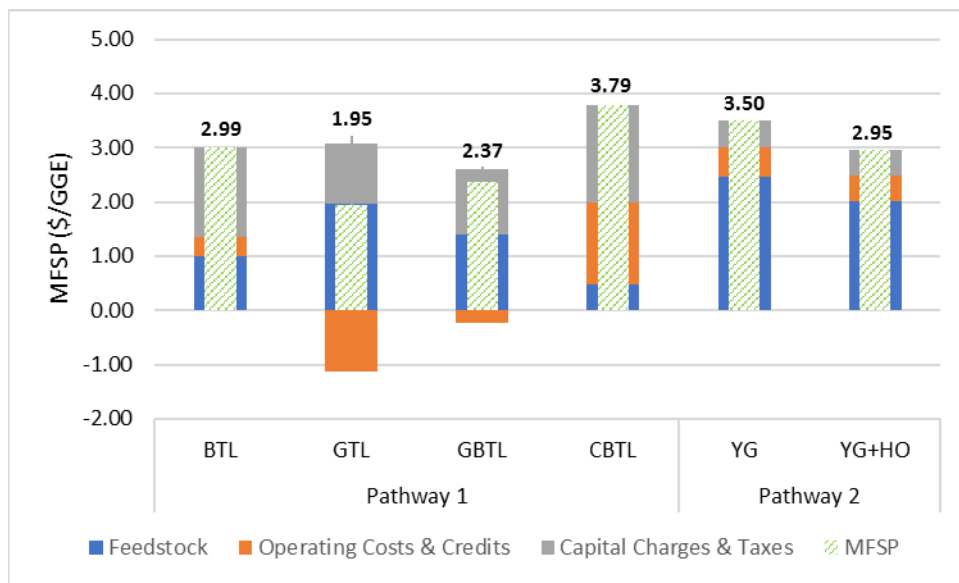


Figure ES1. TEA Result Summary.

1. Introduction

The current marine fuels are mostly heavy fuel oils (HFO). The annual global marine fuel consumption is projected to be around 330 million metric tons (87 billion gallons) annually, which is higher than the world yearly jet fuel consumption of 220 metric million tons (1.4 billion barrels). Currently, approximately 90% of the world's marine fuels are used by cargo ships—over 90% of world's shipped goods travel by marine cargo vessels—while the remaining 10% is consumed by passenger vessels, fishing boats, tug boats, navy ships, and other miscellaneous vessels. Additionally, the overall demand for marine fuels is expected to double by 2030 due to the increase in global trade [1,2]. The engines used to power these vessels range from large two-stroke diesel engines (for inland and coastal transport) to the even larger crosshead engines (fueled with high sulfur bunker C heavy fuel oil) used to power large marine cargo vessels.

The marine industry is facing several challenges related to emission regulations. Marine fuel is actually one of the most significant contributors to air emissions of SO_x, NO_x, and PM. In the United States, the California Air Resources Board (CARB) and other state agencies have established regulations limiting the sulfur content of fuel used in coastal regions (known as emission control areas or ECAs) to 0.1%. The reduced sulfur content has required ship operators to shift their engines from lower cost bunker C heavy fuel oil to much costlier distillate fuels, such as diesel. Additionally, ship operators now power their vessels at slow speed conditions which promote the formation of sulfuric acid in the combustion chamber. This combination (reduced emission targets and slow speed conditions) are moving the marine industry to aggressively seek alternatives with lowered sulfur content and carbon content [3]. Beyond 2025, IMO has established a framework for reducing CO₂ emissions per tonne mile by 30%.

Bio-derived fuels offer potential synergistic benefits when blended with petroleum fuels by reducing sulfur content, improving overall lubricity and providing potentially lower ash and

emission profiles. However, there remains a lot of uncertainty and need for further evaluation of blending biofuels, such as the potential need to remove water (as these fuels can be hydrophilic due to oxygen content) or any residual solids.

This study evaluates the economic potential of producing renewable fuels for marine propulsion. The selected fuel production pathways for the techno-economic analysis are:

Pathway 1: Gasification and Fischer-Tropsch for a range of feedstocks including biomass, natural gas, biomass and coal, and biomass and natural gas.

Pathway 2: Conversion of extracted oils (yellow grease for this study) to marine fuels via hydrotreating with and without co-feeding of fossil feedstock (heavy oil).

2. Techno-economic Analysis Methodology and Assumption

The TEA reported here uses n^{th} -plant economic assumptions. The important aspect associated with n^{th} -plant economics is that a successful industry has been established with many operating plants using similar process technologies. The TEA model encompasses a process model and an economic model. For a given set of conversion parameters, the process model solves mass and energy balances for each unit operation. This data is used to size and cost process equipment and compute raw material and other operating costs.

Once the capital and operating costs are determined, a discounted cash flow rate of return (DCFRROR) calculation was performed to determine the minimum fuel selling price (MFSP) that meets the economic parameter using the general methodology [4] and the financial parameters summarized in Table 1. The MFSP value represents the minimum selling price of fuels assuming a 30-year plant life and 40% equity financing with 10% internal rate of return and the remaining 60% debt financed at 8% interest. The unit for the MFSP is dollars per gasoline gallon equivalent or \$/GGE. GGE is determined using the following equation:

$$GGE = \frac{LHV \text{ of Fuel}}{LHV \text{ of Gasoline Blendstock}}$$

LHV is lower heating value. The LHV of gasoline blendstock (116,090 BTU/gal) is obtained from GREET [5].

For Pathway 1, four feedstock scenarios are considered: 1) biomass-to-liquid (BTL) with 100% biomass, 2) gas-to-liquid (GTL) with 100% natural gas, 3) coal and biomass co-feed (CBTL), and 4) natural gas and biomass co-feed (GBTL). For CBTL and GBTL, the ratio for each of the two co-feeding feedstocks is 1-to-1 by weight. The feedstock specifications for biomass and coal are shown in Table 2.

For pathway 2, two feedstock scenarios are considered: 1) yellow grease (100%), and 2) yellow grease and heavy fuel oil co-feed (50/50 by weight). The feedstock costs are summarized in Table 3. For Pathway 1, the plant scale of hydrocarbon fuels production is set at 50 MM GGE per annum. Additionally, the liquid hydrocarbon products are separated into naphtha-, jet-, and marine/diesel-range blendstocks.

3. Pathway 1: Gasification and Fisher-Tropsch Synthesis

3.1 Process Description and Assumption

The simplified block flow diagram for Pathway 1 is shown in Figure 1. The processing steps of the thermochemical conversion pathway include the conversion of feedstocks to synthesis gas via gasification, gas cleanup via reforming of tars and other hydrocarbons, syngas conditioning (compression and acid gas removal), Fisher-Tropsch synthesis (FT), hydrotreating, and product separation.

Table 1. Summary of nth-Plant Assumptions for Techno-Economic Analysis [6]

Description of Assumption	Assumed Value
Cost year	2016 US dollars
IRR on equity	10%
Plant financing by equity/debt	40%/60% of total capital investment
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 purchase cost)
Depreciation schedule	7-year MACRS schedule ^a
Construction period (spending schedule)	3 years (8% Y1, 60% Y2, 32% Y3)
Plant salvage value	No value
Startup time	6 months
Revenue and costs during startup	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream percentage after startup	90% (7,884 operating hours per year)

^aCapital depreciation is computed according to the United States Internal Revenue Service modified accelerated cost recovery system (MACRS). Because the plant described here is not a net exporter of electricity, the steam plant and power generation equipment are not depreciated over a 20-year recovery period, according to the Internal Revenue Service. The whole plant capital is depreciated over a 7-year recovery period.

Table 2. Woody Biomass Feedstock Specifications

Feedstock	Woody Biomass	Bituminous Coal
Component	Weight % (Dry Basis)	
Carbon	49.81	74.55
Hydrogen	5.91	4.96
Nitrogen	0.17	1.59
Sulfur	0.09	2.44
Oxygen	41.02	6.84
Ash	3.00	9.66
Heating Value	HHV	8,449
(Btu/lb)	LHV	7,856
		13,326
		12,812

HHV: Higher Heating Value LHV: Lower Heating Value

Table 3. Feedstock Cost Assumption

Feedstock	Cost (2016\$)	Unit	Source
Woody biomass	60.58	\$/dry ton	[6]
Bituminous coal	29.52	\$/ton	[7]
Natural gas	0.13	\$/lb	[8]
Yellow grease	0.28	\$/lb	[9]
Heavy oil	0.26	\$/lb	[10]

Again, for Pathway 1, four feedstock scenarios are considered: 1) biomass-to-liquid (BTL) with 100% biomass, 2) gas-to-liquid (GTL) with 100% natural gas, 3) coal and biomass co-feed (CBTL), and 4) natural gas and biomass co-feed (GBTL). Detailed process description for BTL, GTL, and GBTL can be found in Zhang et al. [11]. For GTL, feedstock preprocessing and gasification steps are not required. Nature gas is directly sent to a reformer—a circulating, fluidized solid catalyst system, with reforming and regeneration operations in separate beds [12].

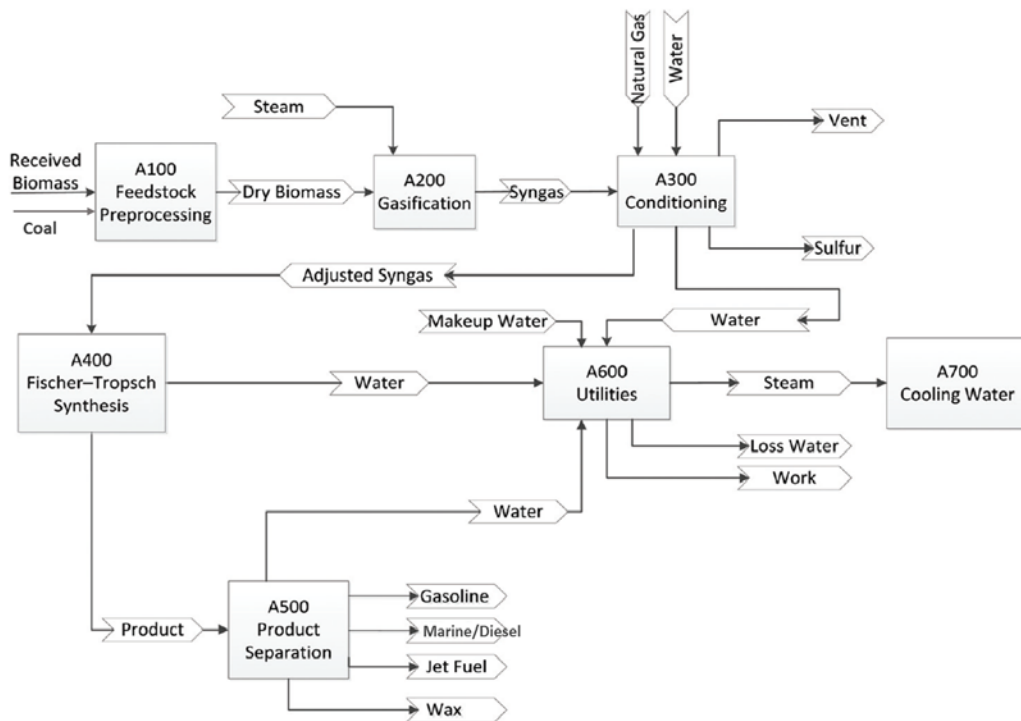


Figure 1. Process flow diagram for the BTG, GTL, CBTL, or GBTL process.

For BTL and GBTL cases, biomass feedstock is preprocessed, dried from the moisture level of 30% to 10%, and sent to an entrained flow gasifier operating at 1633°F and 33 psia to make raw syngas (such as CO, H₂, CO₂, and CH₄), tars, and solid char. Cyclones at the exit of the gasifier separate the char and olivine (heat carrier) from the syngas. The solids flow to the char combustor where the char is burned in air in a fluidized bed, resulting in olivine temperatures higher than 1800°F [13]. The hot olivine and residual ash are carried out of the combustor by the combustion gases and separated using a pair of cyclones.

For the CBTL case, the coal feed is mixed with water before merging with biomass. Instead of undergoing indirect gasification to make raw syngas, the confluent of biomass and coal are fed to a high-temperature entrained flow slagging gasifier (i.e., direct gasification) with conditions similar to the Shell gasifier [14]. Since oxygen with high purity is required for the high-temperature gasification, an air separation unit (ASU), not shown in Figure 1, is used to produce nearly pure oxygen from the air. The biomass-coal direct gasification is modeled using Gibbs free energy minimization method. The oxygen flow rate to the gasifier is controlled using the desired gasifier temperature (at 2470°F which is similar to the literature [14]). Both ASU and high-temperature gasification are modeled using conditions specified in [15]. It is noteworthy that as opposed to the low-temperature indirect gasification, high-temperature gasification does not favor the formation of methane and tars, and thus the raw syngas cleanup step with a reformer may be optional. The downstream processes (after gasification) are the same for all cases.

Fisher-Tropsch (FT) synthesis is considered a relatively mature conversion technology which involves the catalytic conversion of synthesis gas into a mixture of reaction products which could

be refined to synthetic fuels, lubricants, and petrochemicals. One of the important advantages that the FT process offers is its capability of producing liquid hydrocarbon fuels from synthesis gas, which are nearly free from sulfur and relatively low in aromatic content. An important aspect of this process is the adjustment of the H₂ to CO ratio which is usually determined by the upstream gasification and reforming technologies and operating conditions. The FT reactions involve catalytic CO polymerization and hydrogenation, where the chain growth and termination of the reaction products can be described by a carbon number distribution.

The FT reactor products are condensed and separated through typical hydrocarbon separation process in a multi-cut distillation column to recover the primary products (naphtha, jet, and diesel fractions) as individual streams. Each of the primary hydrocarbon cuts is further processed to yield finished fuel blendstocks for gasoline, jet fuel, and marine/diesel. Wax produced from the synthesis reactor is sold as a co-product. However, for bunker fuels, the wax produced from the synthesis reactor can be included in the blendstock and not sent to a wax hydrocracker for upgrading. The jet and marine/diesel fractions undergo mild hydrotreating to remove any remaining heteroatom contaminants (sulfur, nitrogen, and oxygen) and improve properties for blending.

3.2 Performance and Economic Results

The capital costs are presented in Table 4. The capital costs for each plant area are based on data from various sources including NREL design reports and publications [4,11,16]. The purchased costs for the equipment and installation factors are used to determine the installed equipment cost. The indirect costs (non-manufacturing fixed-capital investment costs) are estimated using factors based on the total direct cost (TDC). The factors used in this study are adopted from Tan et al. [4] as percentages of total purchased equipment costs (TPEC), TDC, and

fixed capital investment (FCI), which is equal to the sum of TDC and total indirect costs. With the calculated total installed cost (TIC) and assumptions for indirect costs and working capital, the FCI and total capital investment (TCI) can be determined. The TCI for the four feedstock scenarios increases in the order: GTL (422 MM) < GBTL (455 MM) < BTL (633 MM) < CBTL (717 MM). CBTL exhibits the highest TCI and is mainly attributed to the requirement of ASU and more expensive of high-temperature slagging gasifier. BTL and GBTL do not need an ASU to produce pure oxygen for the less expensive low temperature entrained flow gasifier.

Table 4. Summary of Capital Cost for Pathway 1

in MM\$	BTL	GTL	GBTL	CBTL
Feedstock Handling*	1.67	--	1.18	2.90
Air Separation Unit	--	--	--	36.84
Gasification	51.59	--	25.59	94.66
Syngas Cleanup & Conditioning	109.52	55.19	53.83	88.75
Fisher-Tropsch synthesis	159.14	147.72	145.36	143.06
Product Separation	5.34	5.56	4.50	4.55
Steam System & Power Generation	31.96	30.53	27.86	39.32
Cooling Tower & Others	5.21	2.68	3.42	3.67
Total Installed Equipment Cost (TIC)	362.75	241.68	260.57	410.86
Total Direct Costs (TDC)	375.77	250.02	269.74	425.58
Total Indirect Costs	225.46	150.01	161.84	255.35
Fixed Capital Investment (FCI)	601.24	400.03	431.59	680.92
Land Purchase Costs	1.85	1.85	1.85	1.85
Working Capital	30.06	20.00	21.58	34.05
Total Capital Investment (TCI)	633.15	421.88	455.01	716.82

*Feedstock Handling not included in this calculation

The annual operating costs are presented in Table 5. Operating costs, including labor costs, materials, and feedstock costs, utility costs, and disposal costs, were evaluated for the 50 MM GGE per year facility. Variable operating costs, including the annualized costs for catalysts, olivine, and disposal are determined based on raw materials, waste-handling charges, and by-product credits incurred only during the process operation. Fixed operating costs are generally

incurred in full whether or not the plant is producing at full capacity. These costs include labor and various overhead items. Many of the assumptions on fixed operating costs follow NREL’s earlier reports [6,8]. General overhead equals 90% of total salaries, maintenance equals 3% of FCI, and insurance and taxes equal 0.7% FCI. As shown in Table 5, the fixed operating costs range from \$20.75MM (GTL) to \$31.14MM (CBTL) per year. Similarly, the total operating costs vary from \$42.14MM (GTL) to \$99.31MM (CBTL) per year.

Table 5. Annual Operating Costs for Pathway 1

MM\$/yr	BTL	GTL	GBTL	CBTL
Biomass Feedstock	49.94	--	13.5	16.24
Natural Gas	--	98.37	57.02	--
Coal	--	--	--	7.16
Catalysts	7.53	5.03	4.63	6.96
Olivine	0.63	--	0.17	--
Makeup Hydrogen	--	--	--	44.79
Other Raw Materials	2.11	0.87	1.04	12.96
Waste Disposal	1.66	0.01	0.42	1.71
Electricity	--	--	0.44	--
Co-product credits	-22.48	-82.89	-40.13	-21.65
Total Variable Operating Cost	39.39	21.39	37.09	68.17
Fixed Operating Costs	28.19	20.75	21.91	31.14
Total Operating Costs	67.58	42.14	59.00	99.31

Note: \$/GGE can be obtained by dividing the values by 50 MM

The corresponding material and energy flows are summarized in Table 6. The material and energy flows in the conversion step capture the impacts of input raw materials, and outputs, such as emissions, wastes, and coproducts as predicted by the process models. Hence, Table 6 is also the foreground data describes the conversion process and represents the conversion stage life cycle inventory for a life cycle assessment study.

Table 6. Material and energy flows (gate-to-gate) for Pathway 1

Scenarios	BTL		GTL		GBTL		CBTL	
	lb/hr	MMBtu/hr (LHV)	lb/hr	MMBtu/hr (LHV)	lb/hr	MMBtu/hr (LHV)	lb/hr	MMBtu/hr (LHV)
Products								
Marine/Diesel	8020	151.40	7755	146.40	7729	145.90	7884	148.83
Jet	17395	329.47	16851	319.18	16806	318.31	16632	315.02
Naphtha	14506	255.37	15340	270.66	15413	272.02	15431	272.39
Co-products								
Wax	5144.4	96.85	4975.3	93.66	4959.1	93.36	4956.4	93.31
Excess electricity	1.10 kWh/hr		78.15 kWh/hr		-573.38 kWh/hr		-49.89 kWh/hr	
Material Input								
Feedstock - Woody Residue (dry)	209104		0		56523		68019	
Magnesium Oxide (MgO)	26		0		7		8	
Fresh Olivine Makeup	594		0		161		0	
Natural Gas for Gasifier	0		0.00		0.00		0	
Tar Reformer Catalyst	26		16		13		28	
Zinc Oxide (ZnO) Catalyst	6.7		6.3		5.3		3.7	
FT Synthesis Catalyst (Co based)	4.9		2.8		3.2		2.6	
Hydrotreating Catalyst (sulfided CoMo or NiMo)	6.3		5.9		6.1		5.1	
LO-CAT Chemicals	144		0		39		1405	
Natural Gas for Reformer	0.00		97516		56523		0.00	
Amine Make-Up	0.03		11.91		12.72		102.63	
Boiler Feed Water Makeup	41927		46884		867		18275	
Boiler Chemicals	0.8		0.8		0.2		5.3	
Cooling Tower Chems	4.8		3.1		2.7		3.1	
Cooling Tower Makeup	424135		261794		227143		708187	
No. 2 Diesel Fuel	69		69		69		69	
Make-Up Hydrogen	-		-		-		9063	
Coal (dry)	-		-		-		71220	
Waste Streams								
Sand and Ash Purge	7595		0		2053		8046	
Spent Catalyst Disposal	43		31		28		39	
Wastewater	48759		1659		1398		35566	
Air Emissions								
Water (H2O)	130140		123246		97191		54742.67	
Nitrogen Dioxide (NO2)	123		0.00		39.57		0	
Sulfur Dioxide (SO2)	70		0.00		17.38		0	
Carbon monoxide (CO)	0.00		0.00		0.00		0.00	
Methane (CH4)	0.00		0.00		0.00		0.00	
Carbon Dioxide (CO2) - fossil	0.00		132719		50888		89805	
Carbon Dioxide (CO2) - biogenic	245842		0.00		72391		67029	

The process designs feature an annual production capacity of 50 MM GGE of liquid hydrocarbon fuels and 90% on-stream time (7,884 annual operating hours). The capacity is attained by adjusting the feedstock flowrates. The product distributions and MFSP results for each scenario are summarized in Table 7. The liquid fuel products include naphtha-, jet-, and marine/diesel-range hydrocarbons. All fuel products are reported in GGE. The product distribution is similar for all scenarios, roughly 20% for marine/diesel, 37% for jet, and 43% for naphtha. Note that the current FT process is modeled based on the Anderson-Schulz-Flory (ASF) value of 0.84 and with assumed targeted syngas H₂/CO ratio of 2.1, which gives the maximum yield of the reaction product slate, in terms of GGE [17]. Varying the ASF value will have a direct effect on the product distribution, which in turn will also have a direct impact on the MFSP. Additionally, as the marine fuels typically are distillate and residual bunker fuel, the FT crude hydrocarbon separation process can be easily tailored to meet the desired properties for blending. Moreover, marine biofuels do not need intensive refining and the production cost attributed to the separation process can be relatively lower.

MFSPs are obtained by performing the discounted cash flow analysis—via iterating the selling cost of fuel until the net present value of the project is zero. This analysis requires that the discount rate, depreciation method, income tax rates, plant life, and construction start-up duration be specified. The fuel products (naphtha, jet, and marine/diesel blendstocks) are combined and referred to as a single-fuel product for simplicity. All MFSP calculations are performed and reported on a combined product basis. The cost contributions to the MFSP are divided into (i) capital charges and taxes, (ii) operating costs and co-product credits, and (iii) feedstock costs

(biomass, natural gas, and coal). The MFSP for the evaluated scenarios increases in the order: \$1.95/GGE (GTL) < \$2.37/GGE (GBTL) < \$2.99/GGE (BTL) < \$3.79/GGE (CBTL).

Table 7. Techno-economic Analysis Summary for Pathway 1

	Unit	BTL	GTL	GBTL	CBTL
MFSP	\$/GGE	2.99	1.95	2.37	3.79
<i>Contributions:</i>					
Biomass Feedstock	\$/GGE	1.00	--	0.27	0.32
Natural Gas	\$/GGE	--	1.97	1.14	--
Coal	\$/GGE	--	--	--	0.14
Operating Costs & Credits	\$/GGE	0.35	-1.13	-0.23	1.52
Capital Charges & Taxes	\$/GGE	1.64	1.11	1.19	1.80
Fuel Production					
Marine/Diesel	MM GGE/yr	10.28	9.94	9.91	10.11
Jet	MM GGE/yr	17.34	18.38	18.47	18.50
Naphtha	MM GGE/yr	22.37	21.68	21.62	21.39
Total		50.00	50.00	50.00	50.00

4. Pathway 2: Conversion of Extracted Oils (Yellow Grease) to Hydrocarbon Fuels via Hydrotreating

4.1 Process Description and Assumption

A representative process flow diagram for the conversion of yellow grease to fuels via hydrogenation is shown in Figure 2. Detailed process description can be found in Tao et al. [9]. Briefly, bio-oil (yellow grease) is sent to the hydroprocessing facility (first block in Figure 2), fundamentally with three reaction steps—hydrogenation, propane cleave, and decarboxylation—according to patents by UOP and Syntroleum. The reactions take place at 400 °C and 9.2 megapascals using the Pd/ γ -Al₂O₃ catalyst, resulting in the overall conversion of 91.9%.

The second hydrotreating step includes hydrocracking and hydroisomerization reactions, which are operated at a temperature of 355 °C, the pressure of 600 psig, a liquid hourly space

velocity of $1(\text{h}^{-1})$, and an H_2 /feed ratio of 50 standard cubic feet/gal using Pt/HZSM-22/ $\gamma\text{-Al}_2\text{O}_3$ catalyst.

The hydroisomerization and hydrocracking processes are followed by a fractionation process to separate the mixtures to paraffinic kerosene, paraffinic marine/diesel, naphtha, and light gases. The hydrocracking reactions are exothermic and result in the production of lighter liquids and gas products.

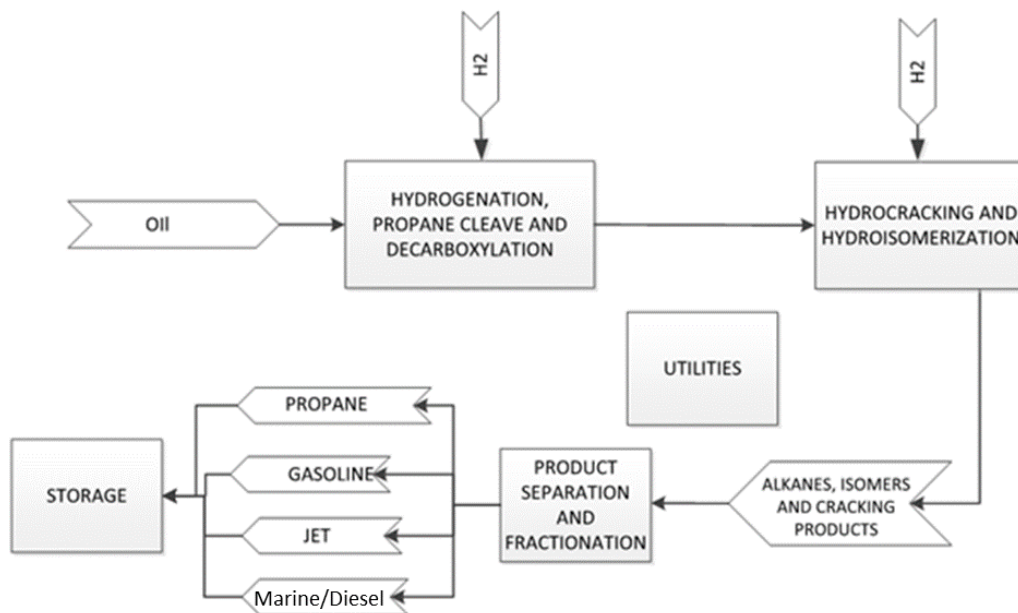


Figure 2. Schematic process flow diagram.

4.2 Performance and Economic Results

The capital costs are presented in Table 8. The capital costs for each plant area are based on data from the recent study by Tao et al. [9]. Fuel upgrading area, which includes hydrogenation, propane cleave, and decarboxylation, as well as hydrocracking and hydroisomerization, exhibits the highest capital expenditure for both scenarios for Pathway 2. The total installed costs for the

case with yellow grease only and the case with yellow grease and heavy oil co-feed are similar, at \$130.73MM and 134.15MM, respectively.

Table 8. Summary of Capital Cost for Pathway 2

in MM\$	Yellow Grease Only	Yellow Grease and Heavy Oil Co-feed
Fuel Upgrading	118.20	120.40
Product Separation	3.96	4.14
Storage	6.24	7.27
Utilities	2.33	2.33
Total Installed Equipment Cost (TIC)	130.73	134.15
Total Direct Costs (TDC)	152.11	155.94
Total Indirect Costs	91.27	93.57
Fixed Capital Investment (FCI)	243.38	249.51
Land Purchase Costs	1.85	1.85
Working Capital	12.17	12.48
Total Capital Investment	257.40	263.83

The annual operating costs for Pathway 2 are presented in Table 9. The total annual operating costs for the case with yellow grease only and the case with yellow grease and heavy oil co-feed are \$197.07MM and 171.95MM, respectively. The feedstock costs represent the largest contribution (~82%) to the operating costs. The lower operating cost for the heavy oil co-feed case is largely attributed to the lower heavy oil cost (\$0.56/kg vs. \$0.61/kg for the yellow grease) and the lower hydrogen cost.

The corresponding material and energy flows are summarized in Table 10. The material and energy flows in the conversion step capture the impacts of input raw materials, and outputs, such as emissions, wastes, and coproducts as predicted by the process models. Hence, Table 10 is also the foreground data describes the conversion process and represents the conversion stage life cycle inventory for a life cycle assessment study.

Table 9. Annual Operating Costs for Pathway 2

MM\$/yr	Yellow Grease Only	Yellow Grease and Heavy Oil Co-feed
Yellow Grease	161.78	73.12
Heavy Oil	--	67.14
Hydrogenation catalyst	7.76	7.72
Isomerization/cracking catalyst	1.51	1.62
Hydrogen	9.04	6.31
Waste Disposal	1.98	0.89
Other Chemicals	5.75	5.79
Co-Product Credit	-0.74	-0.74
Total Variable Operating Cost	187.08	161.85
Fixed Operating Costs	9.99	10.10
Total Operating Costs	197.07	171.95

Table 10. Material and energy flows (gate-to-gate) for Pathway 2

Products	Yellow Grease Only		Yellow Grease and Heavy Oil Co-feed	
	kg/hr	MMBtu/hr	kg/hr	MMBtu/hr
Marine/Diesel	223	8.9	4912	204.0
Jet	17302	727.5	12676	532.3
Gasoline	6066	229.4	7355	285.3
Co-product	kg/hr	MMBtu/hr	kg/hr	MMBtu/hr
Propane	1047	82.9	1210	90.2
Resource Consumption	kg/hr		kg/hr	
Feedstock (Yellow Grease)	33633		15083	
Heavy Oil (co-feed)	-		15082.50	
Nitrogen	0.00		0.00	
Hydrotreating catalyst	3.51		3.49	
Isomerization/Hydrocracking catalyst	0.57		0.62	
Hydrogen	711		141	
Natural Gas	83.0 MMBtu/hr		356.2 MMBtu/hr	
Cooling Water	234099		93	
Electricity	3440 kWh/hr		233801 kWh/hr	
Waste Streams	kg/hr		2758.572	
Disposal of oil impurities	-		-	
Disposal of FFA impurities	5983		2683	

FFA: Free fatty acids

The process designs for the two feed scenarios feature an annual production capacity of 65.58 (yellow grease only) and 69.39 MM GGE (yellow grease co-feed with heavy oil) of hydrocarbon liquid fuels and 90% on-stream time (7,884 annual operating hours). The product distributions and MFSP results for each scenario are summarized in Table 11. The liquid fuel

products include naphtha-, jet-, and marine/diesel-range hydrocarbons. All fuel products are reported in GGE. The product distribution for the yellow grease only scenario is roughly 1% for marine/diesel, 75% for jet, and 24% for naphtha. The product distribution for the case with heavy oil co-feed is roughly 20% for marine/diesel, 52% for jet, and 28% for naphtha. It is noteworthy that the hydrocarbon product distribution, including increasing the marine/diesel slate, can be manipulated at the product separation and fractionation step. The current process is modeled with the focus on producing jet fuel that meets the jet fuel specifications (e.g., high flash point and good cold flow properties) and these are accomplished with the hydrocracking and isomerization steps. The current processes can be further optimized for marine fuel-range hydrocarbon production. Additionally, co-feeding yellow grease with heavy oil provides another process parameter for achieving the targeted product distribution, which can be tailored by varying the ratio of the two co-feeding feedstocks.

The MFSPs for the two feed scenarios are determined to be \$3.50/GGE for the case with yellow grease only and \$2.95/GGE for the case with heavy oil co-feed.

Table 11. Techno-economic Analysis Summary for Pathway 2

	Unit	Yellow Grease Only	Yellow Grease and Heavy Oil Co-feed
MFSP	\$/GGE	3.50	2.95
<i>Contributions:</i>			
Yellow Grease	\$/GGE	2.47	1.05
Heavy Oil	\$/GGE	--	0.97
Operating Costs & Credits	\$/GGE	0.54	0.46
Capital Charges & Taxes	\$/GGE	0.49	0.47
Fuel Production			
Marine/Diesel	MM GGE/yr	0.59	13.86
Jet	MM GGE/yr	49.41	36.15
Naphtha	MM GGE/yr	15.58	19.38
Total		65.58	69.39

5. Summary

This study performs a high-level comparative TEA analysis of two conversion pathways. Pathway 1 is the syngas conversion via Fischer-Tropsch synthesis of a range of feedstocks, including biomass only (BTL), natural gas only (GTL), biomass and coal co-feed (CBTL), and biomass and natural gas co-feed (GBTL). Pathway 2 is the conversion of extracted oils to marine fuels via hydrotreating, with two feedstock options: yellow grease only (YG) and yellow grease and heavy oil co-feed (YG+HO). The modeled target MFSPs for the developing pathways decrease in the following order: \$3.79/GGE (CBTL) > \$3.50/GGE (YG) > \$2.99/GGE (BTL) > \$2.95/GGE (YG+HO) > \$2.37/GGE (GBTL) > \$1.95/GGE (GTL). Relative to the other pathways studied, Pathway GTL has the lowest MFSP due to a combination of favorable yields and lower operating costs. Pathway CBTL has the highest MFSP, attributing to the higher capital expenditure associated with the air separation unit and the high-temperature slagging gasifier as well as hydrogen cost. Pathways GBTL and YG+HO exhibit relatively favorable MFSPs. Cofeeding biomass with the fossil feedstock (NG or HO) is an effective synergistic approach to improve liquid fuel yields while simultaneously lowering greenhouse gas (GHG) emissions. Future studies can include sensitivity studies, which are necessary to understand better the uncertainty associated with the MFSP and the impact of major technical parameters and assumptions on the results. Nevertheless, the current TEA evaluations will provide an important baseline analysis for the bio-economy and marine fuel industry.

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