What is the Future of Liquid Hydrocarbon Fuels and Feedstocks?

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Crude oils can be replaced with hydrocarbon liquids made from cellulosic biomass with massive external inputs of hydrogen and heat. Here, it's discussed how this can be done on a large-scale basis.

The chemical engineering discipline first arose from the need to refine crude oil. These refined oil products, especially liquid hydrocarbon fuels, enabled the development of the modern world — including urbanization, global transportation networks, and new materials — resulting in an unprecedented level of prosperity.

Liquid hydrocarbon fuels (*e.g.,* gasoline, diesel, and jet fuel) and feedstocks are remarkable for three main reasons:

- they can serve as high-density energy sources and feedstocks for the chemical industry
- they are inexpensive to store
- they can be transported long distances at relatively low costs.

Consequently, in the U.S., almost half of all energy used by the final customer comes from liquid hydrocarbons. While these hydrocarbons are primarily made from crude oil, they can also be produced from coal, natural gas, biomass, and carbon dioxide.

Given concerns about increasing carbon dioxide (CO_2) levels in the atmosphere, it is critically important to know whether all crude oil can be replaced with liquid hydrocarbons made from non-fossil feedstocks at competitive prices.

We describe herein the potential of replacing all crude oil products, such as gasoline, diesel, jet fuel, and chemical feedstocks, with hydrocarbons made from cellulosic biomass. Cellulosic biomass — *e.g.,* corn stover, trees, kelp, and other renewable organic materials — is the most abundant form of biomass on earth. If liquid hydrocarbon fuels are made from plant biomass that removes CO_2 from the atmosphere or CO_2 that comes from the atmosphere, then the process becomes net zero, and concerns about increasing CO_2 levels are eliminated. Burning these fuels emits the same amount of CO_2 that was taken up by the plants during their growth cycle.

We acknowledge the interest in other potential low-carbon fuels, such as ammonia and hydrogen. These may fill some niche markets. However, the existing fuel storage, distribution, and use systems are designed for liquid and gaseous hydrocarbon fuels. Assuming it can even be done at the required scale, replacing these systems to accommodate ammonia, hydrogen, or electricity will take decades, cost trillions of dollars, and emit large amounts of CO_2 during the replacement process.

If we wish to move quickly to a lower-carbon future, it seems much more feasible to replace petroleum liquid hydrocarbon fuels with the same fuels derived from plant biomass. Thus, we believe that the viability of replacing liquid hydrocarbons depends on finding alternatives for all three functions provided by these petroleum hydrocarbon fuels, namely: a source of energy, ease of storage, and ease of transport.

Demand for liquid hydrocarbon fuels

Over the last two decades, the U.S. has consumed 18–20 million barrels of crude oil per day. In many applications, the product contains carbon; thus, the feedstock must contain carbon. There is no substitutability. Certain applications, like aircraft and over-the-road long-haul trucks, face maximum weight limits. While it is possible to substitute feedstocks, it is expensive because every kilogram of fuel onboard results in a kilogram less of cargo capacity. Alternatively, applications such as light-duty vehicles do not have such hard constraints.

Assuming large-scale deployment of hybrid electric vehicles, the U.S. long-term liquid hydrocarbon fuel demand will ultimately be 10–16 million barrels of hydrocarbon liquids per day *(1)*. The largest uncertainty, however, is how liquid hydrocarbons will be used to partly replace hourly to seasonal energy storage currently provided by coal piles, oil tanks, and underground natural gas storage facilities. Current reductions in fossil fuel-based energy demand are primarily due to improvements in energy efficiency and the use of hybrid electric cars, in which a small battery can increase fuel mileage by 30%.

Comparing energy storage by liquid hydrocarbon fuels and their alternatives

A crucial function of fossil fuels is low-cost energy storage, which is required to meet the variable demands for energy *(2)*. Energy needs, primarily for heating, are higher in winter. For example, the peak monthly demand for natural gas in winter is about twice the peak electricity demand *(3)*, while the peak hourly demands in winter are even greater. At any given time, the U.S. stores about 6 weeks' worth of energy in the forms of oil, coal, and natural gas. This includes a 90-day supply of oil in the strategic oil reserve, which is stored at very low costs. The total stored energy required for the U.S. economy to function is about 3 million gigawatt hours (GWh).

For comparison, a typical gasoline station stores 1–2 GWh of energy in the form of gasoline and diesel. If we were to replace the energy stored by a gasoline station with the same amount of energy stored in batteries, it would cost about half a billion dollars. If we were to replace a million GWh of storage with batteries, the investment would cost several hundred trillion dollars. Clearly, the costs of energy storage in batteries are too large for batteries to meet anything but a small fraction of our energy storage needs. While we store electricity in water at higher elevations behind hydroelectric dams, the quantities are small and relatively invariable when compared to U.S. needs.

Therefore, the goal of electrifying the economy depends on some future hoped-for low-cost electricity storage breakthrough. If that breakthrough does not occur, low-carbon liquid hydrocarbon fuels will become a frontline requirement to meet energy storage needs and partly replace the energy storage functions of coal and natural gas.

Comparing energy transport via liquid hydrocarbon fuels and their alternatives

Another crucial feature of liquid fuels is their ability to transport energy long distances at low costs. Much of the U.S. uses liquid hydrocarbons for home heating and other purposes because the delivered cost of energy (production and transportation) is less than that of other energy sources. This includes local transport by truck and long-distance transport via pipeline. The remarkably low cost of moving energy long distances in the form of liquid hydrocarbons is summarized in Table 1, where it is compared with the high cost of transporting electricity long distances *(4)*.

The numbers displayed in Table 1 assume each transport system operates at 100% capacity factor. If that is not the case, the costs are much higher. For example, if a long-distance power line is used to transmit solar electricity, the actual transport costs will be four times larger because solar power systems typically operate at 25% of installed capacity.

The structure of the electricity grid is driven by the combination of energy storage costs and energy transport costs. Fossil fuels are transported by ship, rail, truck, and pipeline to locations near the consumer, where they are stored to address the customer's hourly to seasonal needs. The local power station then converts these fossil fuels into electricity as needed. The grid is primarily used to connect groups of power stations so that if one station goes down, electricity can be delivered by nearby power stations. Changing the electricity grid to move large quantities of energy long distances becomes very expensive to meet peak electricity demand loads.

Making liquid hydrocarbons from alternative feedstocks to replace all crude oil is clearly a massive challenge. However, given the realistic alternatives and considering the remarkable properties of liquid hydrocarbons, it may be the lowest-cost option.

Table 1. The cost of transporting different energy sources varies. These values have been standardized to assume 100% capacity factors *(4)*.

	Electricity	Liquid Pipeline			Gas Pipeline	
Energy Carrier	High Voltage DC	Crude Oil	Methanol	Ethanol	Natural Gas	Hydrogen
Delivered Power (MWe, MWLHV)	2,656	91,941	37,435	50,116	17,391	8,360
Power Loss in %	12.9	0.78	2.02	1.51	2.67	1.94
Amortized Cost ($/MWh/1,000 mi)	41.5	0.77	2.2	1.7	3.7	5.0

Table 2. Non-fossil feedstocks for producing liquid hydrocarbons can be categorized into three main classes. Each has different advantages and limitations.

Feedstock	Resource Base	Notes
Plant Products: Oils (Soybeans), Sugars (Sugar Cane), and Starches (Corn)	Limited with potential conflicts with food production	Minimum processing to produce liquid hydrocarbons
Cellulosic Biomass (Non-Food Plant Matter)	Replaces crude oil if external H_2 is used for conversion processes	Requires ~2 hydrogens per carbon atom
Carbon Dioxide	Limited supplies of low-cost non-fossil CO_2	Requires ~6 hydrogens per carbon atom

Non-fossil liquid hydrocarbon fuel production

Three major classes of non-fossil carbon feedstocks can be converted into liquid hydrocarbon fuels: plant products, carbon dioxide, and cellulosic biomass (Table 2). There are also hundreds of combinations of processes that convert these feedstocks into liquid hydrocarbons.

Plant products. Today, most biofuels are produced from starches (corn), vegetable oils (*e.g.,* soybeans), and sugar (sugar cane) because there are minimal transport and storage issues, and the conversion technologies are well-established. However, the resource base is limited, there are potential conflicts with food production, and the feedstocks are relatively expensive.

Carbon dioxide. Using CO_2 as a feedstock to produce liquid hydrocarbons will likely be substantially more expensive than producing hydrocarbons from cellulosic biomass. First, this process requires six hydrogens to convert one CO_2 molecule into a hydrocarbon — four to remove the oxygen as water and two to attach to the carbon. Second, there are an increasing number of government incentives to remove CO_2 from the atmosphere and sequester it underground, setting a minimum price for CO_2. Third, there are limited sources of low-cost, essentially pure CO_2 (*e.g.,* CO_2 from ethanol plants). Other CO_2 sources, such as incinerators and most industrial processes, provide dilute CO_2; thus, it costs money to concentrate the CO_2 into a feedstock.

Cellulosic biomass. Lignocellulosic biomass (wood, straw, crop residues, grasses, kelp, etc.) is the most abundant form of biomass on earth and has long been used as an energy source. About 100 billion tons of biomass, containing roughly 50% carbon on a mass basis, are created by photosynthesis each year *(5)*. If there was a demand for additional biomass, much more cellulosic biomass could be readily and sustainably produced *(6, 7)*.

There are two strategies to convert cellulosic biomass ($CH_{1.44}O_{0.66}$) into liquid hydrocarbon fuels ($(CH_2)_xH_2$). The traditional biofuel production reaction is:

Biomass + Oxygen → Hydrocarbon Fuels + Carbon Dioxide

The biomass serves four functions in this process:

- a source of carbon for the hydrocarbon product
- a source of carbon to remove the oxygen from the biomass as CO_2
- a source of hydrogen
- an energy source for the conversion process.

The second strategy is to use massive quantities of external hydrogen and nuclear heat to convert the biomass into hydrocarbon fuels, chemical feedstocks, and water:

Biomass + Hydrogen + External Heat →
Hydrocarbon Fuels + Water

where hydrogen removes the oxygen in biomass as water and further reduces the carbon to provide a hydrocarbon fuel. Cellulosic biomass contains approximately one oxygen atom for every carbon atom.

In traditional biofuel production, the cost of biofuels is driven by the cost of biomass. Alternatively, with external heat and hydrogen, the quantity of biomass needed per unit of final product is cut in half. Therefore, the land requirement to grow the feedstock is reduced by a factor of two.

If external hydrogen is used to convert cellulosic biomass into hydrocarbon liquids, hydrogen becomes the largest cost in producing a barrel of hydrocarbon liquids. Therefore, the cost of the cellulosic biomass feedstock per barrel of product decreases because less biomass is required to produce a barrel of liquid hydrocarbons. Because hydrogen is the most costly feedstock in this production process, greater prices can be paid to farmers for their biomass than would be possible if biomass were the major feedstock cost component. Paying higher prices to farmers can be beneficial because it greatly increases the availability of cellulosic biomass feedstocks and increases prosperity in rural areas.

Increasing cellulosic biomass feedstocks by hundreds of millions of tons per year can be achieved through multiple routes *(6)*. For example, double cropping — which involves producing a high-value grain or oilseed crop such as corn or soybeans and a lower-value grass or forage crop — is not widely practiced in the U.S. because there are no markets for the second crop. However, a recent assessment *(7)* indicates that there is sufficient cellulosic biomass to replace all crude oil in the U.S., provided we use external heat and hydrogen at the biorefinery for the conversion processes.

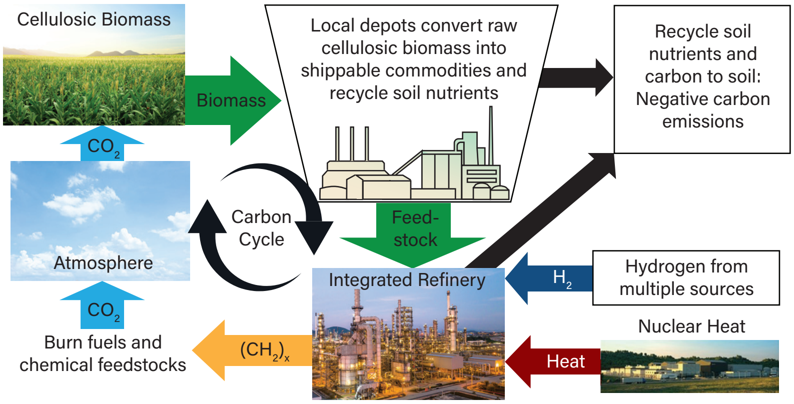
System structure for hydrocarbon fuels based on cellulosic biomass

The system structure *(5–8)* of a hydrocarbon future based on cellulosic biomass is shown in Figure 1. The structure relies on the capabilities of large integrated biorefineries (essentially modified crude oil refineries) and the logistics of moving biomass.

Under this approach, very large biorefineries are required to achieve the cost advantages offered by economies of scale. These refineries would likely be modified integrated oil refineries with throughputs equivalent to 250,000 bbl of crude oil per day. Thus far, three factors have driven oil refineries to such large sizes. First, large sizes offer significant economies of scale. Second, large refineries mix different crude oils to produce a feed that matches their operational capabilities, resulting in lower feedstock costs. Last, large refineries can produce different products throughout the year to match changing product demand. These same factors apply to hydrocarbon biorefineries.

Biomass logistics: The need for biomass processing depots

Because of its low density, unprocessed biomass can only be shipped 50–80 km economically. Therefore, it is traditionally assumed that biorefineries are limited to feed rates of less than about 3,000 tons per day. A biorefinery with the throughput of a 250,000 bbl per day oil refinery will need cellulosic biomass feed input rates approaching 60,000 tons per day, which is a 20-fold increase in feedstock. As a result, intermediate biomass processing depots are required to convert raw biomass into energy-dense commodities that can be economically shipped to the refinery *(9).*



▲ **Figure 1.** Designing a system for converting cellulosic liquid hydrocarbons into biofuels is a crucial step toward replacing all crude feedstocks in the U.S. The system structure depends on the capacity of large integrated biorefineries and their ability to support economies of scale, in addition to an efficient and inexpensive system for transporting large amounts of biomass.

One such system for biorefineries integrated with oil refineries is already being built. Ethanol produced from corn starch at depots is beginning to be sent to large oil refineries, where the Guerbet reaction is used to polymerize it into sustainable aviation fuels. It is unclear at this time whether the alternative processes to convert cellulosic feedstocks to ethanol will become commercial. Table 3 lists currently available major depot processing options for the conversion of cellulosic feedstocks into economically transportable commodities to large biorefineries. Cellulosic biomass is a much more abundant feedstock than corn — a starch. The preferred options for specific situations depend on the feedstock and refinery capabilities.

Growing food or biomass extracts nutrients from the soil. For biofuel production, only hydrogen and carbon are of value; potassium, phosphorus, and other plant nutrients are unwanted in the biofuel and in the chemical processes. Some depot options (*e.g.,* pyrolysis and anaerobic digestion) create a refractory carbon char as a byproduct that enables easy local recycling of nutrients back to the soil. Adding carbon to the soil improves its mechanical and biological properties and helps ensure long-term soil productivity while also sequestering CO_2 from the atmosphere in stable carbon compounds. These carbon inputs to soils ensure the entire system is strongly carbon-negative.

Coproduction of cellulosic biomass and food/animal feed will likely be mutually beneficial. For example, average corn yields over the last century have increased from

Table 3. Major depot processing options for biofuels and their characteristics are listed below. Different feedstock and refinery capabilities will influence which option is optimal.

Processing Option	Characteristics	Status
Pelletization	Compress to increase density	Commercial
Anaerobic Digestion	Convert biomass to methane, CO_2, and solid digestate	Commercial for some types of biomass
Fast Pyrolysis	Fast heating to produce pyrolysis oil (up to 70%) and char	Early commercial plants
Direct Hydrogenation	Produces liquid, char, and water, and is dependent on H_2 supply	Pilot plant
Pulp and Paper	Convert mill wastes to hydrocarbons	Pilot plant
Guerbet Reaction	Polymerizes ethanol from corn starch into sustainable aviation fuels	Early commercial plants

20 to 180 bushels per acre *(10).* Corn stover yields have increased proportionally. Record corn yields on small plots of land exceed 600 bushels per acre, but the economic tradeoffs (fertilizer, seeds, land preparation, etc.) favor lower yields. If farmers are paid for corn stover in addition to the corn, the economics will favor higher yields of both corn and corn stover. Therefore, paying for cellulosic biomass production may result in increased production of edible sugars, starches, and oils.

Hydrogen and heat supply to the biorefinery

Hydrogen is used in the production of liquid fossil hydrocarbon fuels to remove sulfur and to produce gasoline, diesel, and jet fuel. Hydrogen is also used to remove oxygen. Since cellulosic biomass has approximately one oxygen atom per carbon atom, massive quantities of hydrogen are required to remove that oxygen *(7).* Since desulfurization also removes oxygen from crude oil, much of the technology used for the desulfurization of crude oil can be directly applied to deoxygenating biomass.

In the U.S., the current low-cost source of hydrogen is the conversion of natural gas to hydrogen and CO_2. The costs are estimated to be between $1.1–1.6 per kg hydrogen at the factory gate *(11, 12)* with sequestering the carbon dioxide underground — a factor of two to three less than other hydrogen production routes, such as electrolysis. The costs of hydrogen from other routes are decreasing but not yet competitive in the U.S. Recent studies *(13)* show that the greenhouse gas footprint of properly designed systems, starting with natural gas, can approach that of green hydrogen from other sources.

The cost of carbon capture and sequestration (CCS) when producing hydrogen from natural gas is low because the process chemistry of autothermal reforming of natural gas produces a nearly pure waste stream of CO_2. In contrast, CO_2 capture from fossil power plants is expensive because the CO_2 concentration in the stack gas is ~10%. Additionally, carbon sequestration on a large scale is cheap. Four chemical processes produce nearly pure CO_2 as a waste: removal of CO_2 from raw natural gas, autothermal conversion of natural gas to hydrogen, fermentation to produce ethanol, and anaerobic digestion. As a consequence, nearly all existing and announced projects for CCS involve these processes — not fossil-fuel power plants.

Today, refineries consume about 10% of the oil going into the refinery in operation *(14),* which, in the U.S., is about a million GWh of heat per year. In a low-carbon world, nuclear energy is the low-cost option for base-load heat. Dow Chemical recently announced an agreement with X-energy to build four high-temperature nuclear reactors to provide process heat for its Seadrift chemical site in Texas. This will replace the use of natural gas. In China, one large chemical plant is building two pressurized water reactors (PWRs) and one high-temperature reactor to provide process heat in the form of steam to reduce coal consumption *(15).* The Chinese PWRs are identical to those built to produce electricity. The same reactor systems can provide steam to oil or biorefineries.

Although we know of no master plan to build large nuclear-powered cellulosic-to-hydrocarbon liquid production systems, we are seeing evolution in this direction. Oil refineries are being modified to accept various bio-liquid feedstocks. The Neste refinery in Finland is the first large refinery to announce plans to fully convert to biomass feedstocks by the mid-2030s. DG Fuels has announced a plan to build a $5 billion cellulosic biomass-to-jet fuel plant in Minnesota *(16).* In this facility, massive external hydrogen inputs will be used to convert over 90% of the carbon in the incoming biomass to hydrocarbon fuels in a similar process as previously described.

Biomass processing depots employing different technologies are beginning to ship bio-crude to refineries. ExxonMobil and other energy companies are starting the process of building massive hydrogen production plants from natural gas with sequestration of the byproduct CO_2. These new hydrogen production facilities will initially replace

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existing natural gas-to-hydrogen plants that release byproduct CO_2 into the atmosphere. Most of this hydrogen will be used to produce ammonia and chemicals and to refine crude oil.

Closing thoughts

As outlined earlier, we are in a period of massive experimentation. Many processes are being developed or modified for hydrocarbon biofuel production; however, it will take time before industries determine the most favorable processes. Cellulosic hydrocarbon biofuels are estimated to cost $70–90 per bbl of oil equivalent, with hydrogen being the largest component, assuming a delivered price at the refinery gate of $2.00 per kg hydrogen. An important challenge to consider is that oil prices are volatile, with average yearly prices in the last decade varying from $37.22 to $102.58 per bbl. This makes investments in any replacement technology risky. Perhaps the greatest challenge, however, is the current belief that cellulosic hydrocarbon liquids cannot significantly replace petroleum-derived liquids.

This belief should be reexamined in light of the facts outlined in this article. No technological breakthroughs are needed to implement the biomass-to-hydrocarbon fuels approach. Implementation of the cellulosic biomass-to-hydrocarbon biofuels system is primarily a function of logistics and system integration, something that the existing agricultural and petroleum industries excel at.

There have been continued attempts to legislate solutions that provide low-carbon replacements for hydrocarbon liquids. These have failed. Unfortunately, the reality is that the energy transition is not proceeding as hoped. None of the currently legislated solutions can provide the three critical functions of liquid hydrocarbon fuels: dense, stable energy sources; inexpensive energy storage; and inexpensive energy transport.

We acknowledge that there are major challenges associated with changing feedstocks for liquid hydrocarbon production. However, these challenges seem small compared to those involved in inventing, developing, commercializing, and globally deploying multiple new technologies to replace these three unique functions of liquid hydrocarbon fuels.

Lastly, the proposed system has many potential environmental and economic benefits, particularly in the agricultural sector, both globally and in the U.S. For example, a market for sequestering carbon in soils would benefit soil fertility and increase farmer revenues while reducing atmospheric carbon levels. Nutrient recycling from depots to soil would further improve farm income by reducing fertilizer costs and would reduce nutrient loadings in waterways and groundwater. Furthermore, such a strategy would globally diversify liquid hydrocarbon production, thus reducing resource conflicts and economically helping poorer nations with significant land resources.

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