Heating Oil: Transitioning to Bioblends 2023 - 2050

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Executive Summary

This report was produced by IHS Markit for the National Oilheat Research Alliance (NORA) and its members. NORA commissioned IHS Markit to perform the work to answer some key questions about the future of heating oil and transitioning to Bioheat™ fuel.

- Will there be enough biodiesel and feedstock for a transition to 100 percent biodiesel blend in heating oil (B100 Bioheat™) by 2050? What will be the major feedstocks?
- Can Bioheat™ compete with electricity in the residential/commercial heating market on a CO_2 emissions basis?
- What types of investment will be needed to deliver higher biodiesel blends?
- Can a liquid heating oil reach net zero emissions by 2050?

IHS Markit's analysis covers the biodiesel/Bioheat™ supply chain from field to end users to answer these and other questions for the New England (PADD 1a) and Mid-Atlantic (PADD 1b) heating markets. In general, the analysis answers many of the questions asked by NORA in the affirmative. The key conclusions and observations include:

- **Policy:** decarbonization is a major global policy force in the energy markets in both stationary and transportation uses. For Bioheat™, a policy framework will be needed to provide the demand certainty necessary to support the investments in infrastructure and technology for market development.
- Policies are being implemented across North America that will increase the demand for renewable diesel and biodiesel for engines, which may affect overall demand for these resources. A policy framework that includes Bioheat™ could provide the proper signals to the market to supply both on-road and heating markets.
- **Biodiesel supply in 2023, 2030 and 2050:**
- Biodiesel blends of 20 percent (B20) in 2023 can be achieved, using the existing supply chain and infrastructure with nominal modifications. Supply could be physically available to meet B20 demand. However, trade flows may also affect the overall volume of biofuels available to the heating oil market and the necessary 800 million gallons of biodiesel:

    1. B20 heating oil in 2023 may require imports.

        - Argentina supplied large amounts of biodiesel in 2016 to the US east coast until tariffs were imposed. While Argentine supply may not be necessary to meet B20 in 2023, resumption of imports will provide significant additional supplies. Imports from the EU, or other South American sources could also increase to meet B20 in 2023

    2. Rather than exporting 300 million gallons of soybean oil (SBO), the US can process much of this into soy-oil methyl ester (SME) in its biodiesel plants with available capacity

  - B50 in 2030 is also possible, if additional supplies from both domestic and foreign sources are obtained. The EU may be a source of significant supply by 2030 due to falling diesel fuel demand — a trend which also results in a decline in biodiesel demand. US farmland is being taken out of production as productivity increases faster than demand. This analysis assumes that soybean acreage returns to the 2017 level, which was the record high year, and remains at that level. This analysis also assumes that oil yields from soybeans will rise throughout the study period. Both developments may require market signals.

  - B100 by 2050 could also be supplied if US agriculture can continue to increase oil yields from soybeans. This analysis assumes yields can increase from the current 19.4 percent (by weight) to 25 percent by 2050. Additional feedstock supply from crops such as canola and inedible distiller corn oil (DCO or ICO) are also likely.

- **Linkage to agriculture:** As biodiesel blends in heating oil increase, the heating oil industry will become increasingly linked to agriculture. As heating oil moves toward B100, the heating oil supply chain will change from well-to-home to field-to-home. With agricultural productivity projected to increase faster than demand for food and animal feed, agriculture will require 'new' markets for oil to maintain production of protein and other coproducts for the food supply. Both industries will take on each other's weather risks; heating oil will be exposed to the agriculture summer growing season weather risks, and agriculture to winter weather risks.

- **Net zero by 2050:** Heating oil could reach net zero by 2050. However, reaching this goal will likely require carbon sequestration. Agriculture may be the pathway to net zero through soil carbon sequestration (SCS) in farming practices. The potential to store carbon in soils is significant, but many questions remain. However, programs and policies that pay farmers to increase the carbon content of their soils are emerging.

- **Distribution infrastructure:** Investments will be needed due to the higher cloud point that Bioheat™ blends possess as they move beyond B20, which are:

  1. Infrastructure, such as heated pipes, trucks, tanks and railcar reheating.

  2. Increased capacity to receive larger supplies by rail and marine.

  3. Enhanced blending capacity and associated systems for blends above B20.

The heating oil industry as expressed in the Providence Resolution aims to achieve net zero emissions by 2050 with intermediate targets of 15 percent by 2023 and 40 percent by 2030. IHS Markit is using the following biodiesel blend rates in heating oil as proxies for the goals laid out in the Providence Resolution:

- B20 by 2023 -- 2025

- B50 by 2030

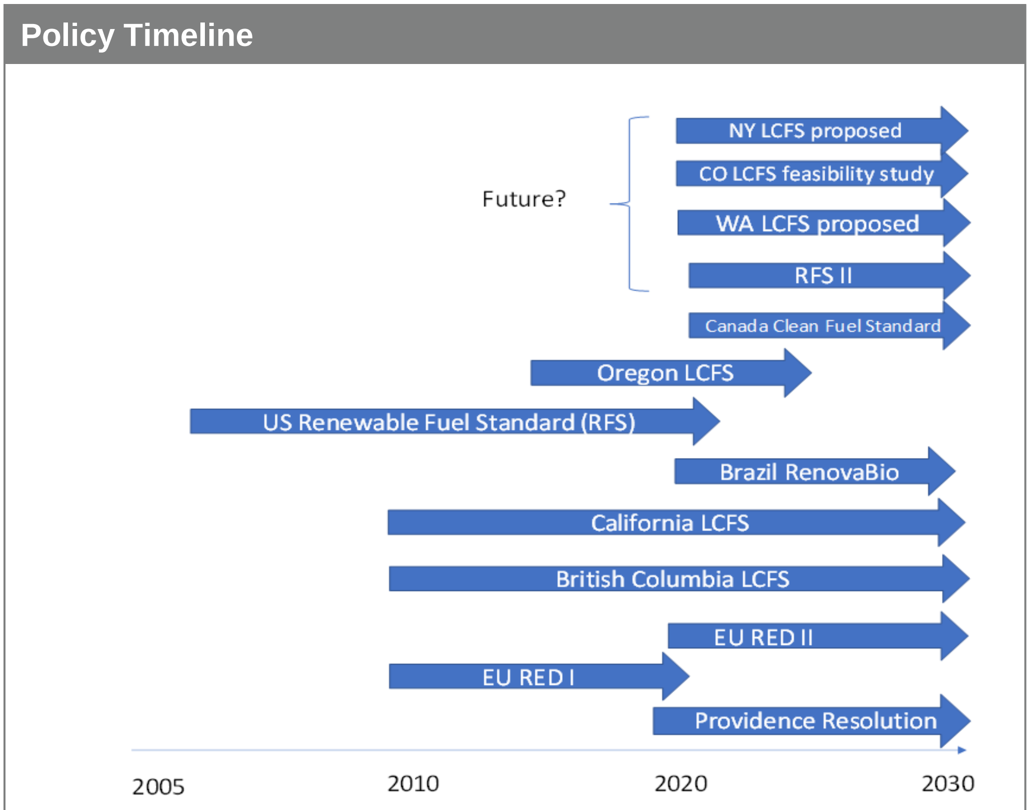
- B100 and net zero emissions by 2050

These goals could be met with an enabling policy framework in place that provides the proper signals to stakeholders to make the investments necessary from field to end user.

Policy review and future framework

Decarbonization is one of the major driving forces in energy markets. Many countries and policy jurisdictions have or will soon implement policies to reduce greenhouse gas (GHG) emissions. Many of these policies are targeted toward transportation fuels. These policies have taken various forms depending on the prevailing view at the time and the particular characteristics of the policy jurisdiction.

Figure 1



Source: IHS Markit

Below is a description of the major policies that are either in effect or scheduled to be enacted over the next few years.

Renewable Fuel Standard (RFS)

In the US, the regulatory framework is based on the Renewable Fuel Standard (RFS) that was introduced in the Energy Policy Act of 2005. The RFS sets mandatory blend levels for renewable fuels. It currently requires 36 billion gallons by 2022, an increase from 9 billion gallons in 2008. It also established greenhouse gas reduction thresholds and a methodology for calculating lifecycle GHG emissions. The program established definitions and separate requirements for renewable fuels, including conventional biofuels, advanced biofuels (including biomass-based diesel), and cellulosic biofuels according to their GHG reduction profiles. Partially renewable heating oil is listed as an approved pathway alongside other renewable fuels, such as ethanol, biodiesel and renewable diesel. (EPA, Renewable Fuel Standard Program, Approved Pathways, 2020). The Environmental Protection Agency (EPA) proposes volume requirements for renewable fuels by the summer and announces a final rule by November 30 to set the

RFS for each ensuing year. The EPA's final 2020 RFS mandate calls for a slight (+0.9 percent) increase in overall biofuel volumes compared to 19.92 billion gallons in 2019. The EPA has the authority to waive the RFS requirements if there is inadequate domestic supply to meet them which has been done nearly every year for cellulosic biofuels.

Under the RFS, all refiners and importers are obligated parties and must demonstrate that they have blended an amount of renewable fuel equal to or exceeding a predetermined percentage of their total fuel volume that year. Alternatively, the refiner/importer can meet this requirement by purchasing Renewable Identification Number (RIN) credits from others that actually do the blending. RINs from the prior year can also be used to meet 20 percent of requirements for the current year. Each gallon of biodiesel produced is equivalent to 1.5 RINs. Each gallon of renewable diesel produced can be equivalent to 1.5 RINs, 1.6 RINs, or 1.7 RINs, depending on energy content.

The RFS is the major reason biodiesel has reached its current level of use in the US. Obligated parties have specific blending targets. In addition, biodiesel has been used to meet the advanced biofuels Renewable Volume Obligation (RVO) and generate RINs. This is important as ethanol reached the blend wall several years ago.

RINs are attached to each eligible gallon of biofuel that is made and transferred to obligated parties when the fuel is purchased or can be separated. In other words, RINs can remain with the physical product or be separated and sold into the paper market. The market price of RINs is self-adjusting so that supply tends to meet demand and provides incentives for the biofuel industry to expand when warranted.

Low Carbon Fuel Standard (LCFS)

The Low Carbon Fuel Standard (LCFS) requires obligated parties to calculate the amount of credits and deficits generated for an LCFS fuel and report compliance on a quarterly basis. The fuels affected by this policy are currently transportation fuels. Fuels that have a carbon intensity (CI) above the target generate deficits whereas fuels with CI's below the target generate credits. The LCFS credit can be traded or borrowed. As such, all refiners, blenders, producers, or importers of transportation fuels in California are required to purchase LCFS credits, if necessary, to comply with the law. The amount of low carbon fuels or LCFS credits needed for compliance is determined by the CI target for fuels which is set by the policy each year.

First enacted in British Columbia and subsequently by California and Oregon, the LCFS may become the policy of choice by other jurisdictions to lower the CI of fuels. Brazil has begun implementing their RenovaBio program this year, and the liquid fuels portion of Canada's Clean Fuel Standard is scheduled to be implemented in 2022. Washington state has made a number of attempts at implementing an LCFS and as of the fall of 2019, Colorado was undertaking a feasibility study. Combined, the LCFS programs have resulted in increased consumption of renewable fuels. California alone has been drawing increasing domestic as well as international supply of biodiesel and renewable diesel. The CA LCFS has been the major driving force behind the development of renewable diesel fuel in the US. Obligated parties in CA use renewable diesel to meet their overall requirement to lower fuel CI. Under the LCFS, the lower the CI of the biofuel, the higher the value of the LCFS credit. Renewable diesel uses the same feedstocks as biodiesel, but unlike biodiesel, renewable diesel can be blended into diesel fuel at any level; e.g., there are no quantity limits. The LCFS in CA has caused nearly all of the low CI feedstocks, such as used cooking oil (UCO), inedible distiller corn oil (DCO), and fats and tallow, to move from biodiesel to renewable diesel fuel production for CA. This trend has left the biodiesel producers to process more higher CI SBO or canola.

This may be beneficial for the heating oil market since these feedstocks provide the best cold-flow operability for biodiesel and Bioheat™.

California's LCFS was approved in April 2010. Beginning January 1, 2011, a regulated party must meet the average CI requirements as well as reduction targets. The LCFS calls for a 10 percent reduction in the CI of fuel sold in the state by 2020 (versus the 2010 baseline) based on full fuel-cycle carbon emissions. Most types of ethanol, when blended at a 10 percent level, are insufficient to meet the gasoline CI target. As a result, biodiesel and renewable diesel are "over-blended" to offset the limits in gasoline and to achieve compliance.

In September 2018, California Air Resources Board (CARB) approved changes to the LCFS. It now requires a 20 percent reduction in CI by 2030 (vs. 2010 baseline). Alternative jet fuel has been added as an opt-in for credit generating fuels and there are incentives for the sale of electric and hydrogen vehicles.

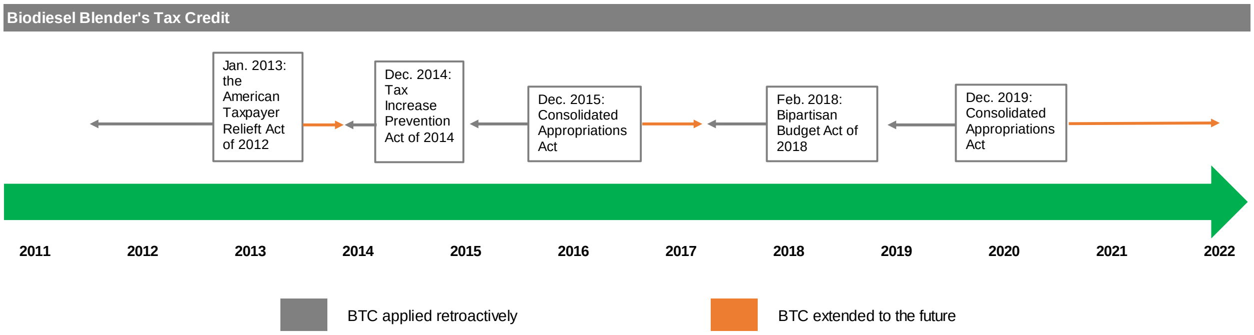
Oregon's program is similar to the LCFS and is called the Clean Fuels Program. The program requires a 10 percent reduction in average CI from 2015 levels by 2025. As of January 1, 2019, alternative jet fuel and renewable propane can generate credits in the program. On March 2020, Governor Kate Brown issued an Executive Order instructing relevant government entities to amend the Clean Fuels Program to reduce the CI of fuels by 20 percent by 2030 and 25 percent by 2035 (vs. 2015 baseline). (OGSO, 2020).

Biodiesel Blenders Tax Credit (BTC)

The Biodiesel Blenders Tax Credit (BTC) was part of the American JOBS Creation Act of 2004 (P.L. 108-357), which has been amended over time. The biodiesel tax incentive allows biodiesel prices to be more competitive with petroleum diesel. In simple terms, companies that blend biodiesel or renewable diesel into their diesel mix receive a dollar per gallon credit. However, the BTC has been allowed to expire repeatedly over time. Since 2011, Congress has extended or retroactively reinstated the BTC five times (Hanson, 2020). As a result, it has not been a consistent and reliable source of support for the biofuels industry. However, the most recent renewal in 2019 is for five years, including two that are retroactive.

Figure 2

Biodiesel Blender's Tax Credit



Source: IHS Markit, EIA

State-level biodiesel volume requirements

State policies and volume requirements continue to play a significant role in driving the biodiesel market. Several northeastern states have adopted legislation mandating biodiesel usage in home heating oil.

- New York State

  - July 1, 2018: 5 percent blend required for Nassau, Suffolk and Westchester counties

- New York City
  - October 1, 2017: 5 percent blend
  - October 1, 2025: 10 percent blend
  - October 1, 2030: 15 percent blend
  - October 1, 2034: 20 percent blend

- Rhode Island
  - July 1, 2014: 2 percent blend
  - July 1, 2015: 3 percent blend
  - July 1, 2016: 4 percent blend
  - July 1, 2017: 5 percent blend

Several states across the United States require the use of biodiesel in transportation fuel as well. Some states require state-owned vehicles, school districts, and the like to use biodiesel blended fuels, but the requirement does not extend to the general public.

Table 1

Key biodiesel requirements and incentives in transportation fuel

State	Requirements/Incentives
Minnesota	April through September: at least 20% Remainder of the year: at least 5% From April 1 to April 14, diesel fuel sold in the state can be a lower blend than 20%, but not less than 10%
Oregon	All diesel fuel sold in the state must be blended with at least 5% biodiesel
Pennsylvania	All diesel fuel sold must contain at least 2% biodiesel (B2) one year after in-state production of biodiesel reaches 40 million gallons. The required biodiesel blend level will continue to increase according to the following schedule: • 5% biodiesel (B5) one year after in-state production of biodiesel reaches and sustains 100 million gallons for three months; • 10% biodiesel (B10) one year after in-state production of biodiesel reaches and sustains 200 million gallons for three months; and • 20% biodiesel (B20) one year after in-state production of biodiesel reaches and sustains 400 million gallons for three months.
Washington	At least 2% of all diesel fuel sold must be biodiesel or renewable diesel. This requirement will increase to 5% 180 days after the Washington State Department of Agriculture (WSDA) determines that in-state feedstocks and oil-seed crushing capacity can meet a 3% requirement.
Illinois	Proceeeds from the sale of biodiesel blends between 11% and 99% are exempt from sales and use taxes until December 31, 2023.
Iowa	Iowa has a state income tax credit of $0.035 and $0.055 per gallon of biodiesel sold for blends containing a minimum of 5% and 11%, respectively. The tax credit expires December 31, 2024.
Texas	The biodiesel or ethanol portion of blended fuel is exempt from the diesel fuel tax, which is currently $0.20.

Source: IHS Markit, U.S. Department of Energy

The Renewable Portfolio Standard (RPS)

The Renewable Portfolio Standard (RPS) is a common US state policy mechanism that requires utilities and competitive energy suppliers to produce or procure targeted levels of electric generating supply from qualifying renewable sources (calculated as a percent of the retail sales of the load they serve, sometimes inclusive of losses). The definition of qualifying renewable sources varies by state. Several states have incorporated renewable heat into RPS schemes. Most RPS policies are mandatory and backed by state legislation.

Most RPS policies have multiple tiers (also sometimes referred to as classes) of obligation beyond a solar carve-out that are designed to promote the growth or sustainability of specific technology or fuel categories, such as existing hydroelectric or biomass power generation.

Renewable Energy Certificate (REC) is a policy-based instrument representing the environmental (or "green") attributes associated with qualifying renewable supply resources. The number of RECs created for each megawatt-hour of renewable energy is often 1:1, unless "multipliers" are in effect. RPS compliance is typically achieved by surrendering a sufficient number of RECs, or solar RECS (SRECs) in the case of solar carve-outs. Most policies allow for the trading of RECs (separate from the associated energy), giving rise to a spot market for the compliance instruments.

Table 2

RPS targets in the Northeast and Mid-Atlantic
(terminal year)

	Tier 1 RPS target		Solar carve-out target or other incentive	
Connecticut	40%	2030	350 MW	2021
Massachusetts	35%	2030	3,200 MW	2022
Maine	50%	2030		
New Hampshire	15%	2025	7%	2025
Rhode Island	39%	2035		
Vermont	75%	2032	10%	2032
Delaware	25%	2026	3.5%	2026
Maryland	50%	2030	14.5%	2030
New Jersey	50%	2030	5.1%	2021
Pennsylvania	8%	2021	0.5%	2020
New York	50%	2030		

Notes: **Connecticut** does not have a solar carve-out. However, its Residential Solar Investment Program (RSIP) target amounts to specified demand for solar by 2021. Connecticut also has a commercial solar incentive program (Zero Emission Renewable Energy Credit) that provides competitively solicited long-term REC contracts.
Massachusett's RPS has no terminal year; the target increases to 35% by 2030, after which it increases 1% per year. The solar target is a sum of SREC I, SREC II, and the entirety of the SMART program targets.
Maine's RPS establishes escalating annual targets for Class I renewables through 2030 and also includes a goal of 100% renewables by 2050. Maine Class I qualifying resources include biomass and (more recently) some existing hydro resources. Maine relies most heavily on this broader renewable resource pool for its Class I RPS compliance needs, and the associated RECs are limited in their use in other New England Class I markets.
Vermont's tier 1 RPS includes existing large hydro, a large portion of which is imported. Vermont relies most heavily on this broader renewable resource pool for its Class I RPS compliance needs, and the associated RECs are limited in their use in other New England Class I markets.
New Jersey's solar carve-out peaks in 2021 and declines thereafter as the state plans to phase in new solar policies.

Source: IHS Markit

The Alternative Energy Portfolio Standard (APS)

Massachusetts has a complementary program to the RPS called the Alternative Energy Portfolio Standard (APS). The APS requires a certain percentage of the state's electric load to be met by eligible technologies, such as Combined Heat and Power (CHP), flywheel storage, and efficient steam technologies. Eligible facilities can generate Alternative Energy Certificates (AECs) (Mass.gov, Program Summaries, 2020). The target for 2020 is five percent and after this year, the standard is set to increase by 0.25 percent per year. (Mass.gov, Alternative Energy Portfolio Standard, 2019).

The APS allows up to 20 percent of annual compliance obligation to be met using liquid biofuels (Mass.gov, Qualifying Eligible Liquid Biofuel in the APS, 2019). At least 10 percent biofuels derived from organic waste feedstocks, namely used cooking oil, must be used as the blendstock. The Massachusetts Department of Energy Resources (DOER) is set to review the APS this year and may adjust the minimum standard and rates of increase (Mass.gov, Alternative Energy Portfolio Standard, 2019).

Transportation and Climate Initiative (TCI)

Formed in 2010, the Transportation and Climate Initiative (TCI) is a regional effort consisting of 12 Northeast and Mid-Atlantic states and District of Columbia that "seeks to improve transportation, develop the clean energy economy and reduce carbon emissions from the transportation sector" (TCI, 2010). The states involved are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. Similar to the Regional Greenhouse Gas Initiative (RGGI), the TCI is modeled on the concept of "cap and invest." The program would set a binding GHG emissions cap on certain sectors of the economy and reinvest the proceeds from the auction of emissions allowances into initiatives that help further the overall aims of the TCI (Drew Veysey, 2018). A final Memorandum of Understanding is expected to be published in the fall of 2020, and the TCI could become operational by 2022. It is estimated that achieving a 20 to 25 percent reduction in emissions by 2032 would add between 5 and 17 cents per gallon of fuel, respectively. Governor Chris Sununu of New Hampshire has opposed TCI based on expected costs to consumers. The future of TCI and the cohesion of its members are uncertain, especially in light of COVID-19 related developments.

New York may see a move towards an LCFS separate from the TCI. The state passed the Climate Leadership and Community Protection Act last year, which requires New York to achieve a net zero electricity system by 2040 and reduce GHG emissions by 85 percent below 1990 levels by 2050. In February 2019, a bill was introduced in the New York General Assembly calling for the establishment of an LCFS with a target of 20 percent reduction in CI by 2030. In January 2020, the Clean Fuels NY Coalition, which is led by the New York League of Conservation Voters and counts biofuel producers and industry groups as members, addressed a letter to Governor Cuomo urging the adoption of an LCFS in the state (Coalition, 2020).

Canada's Clean Fuel Standard (CFS)

In 2017, Canada announced plans to enact the Clean Fuel Standard (CFS). The CFS is just one component of the Pan-Canadian Framework on Clean Growth and Climate Change to reduce Canada's GHG emissions to 30 percent below 2005 levels by 2030. The CFS is targeted to contribute 30 million tonnes of annual greenhouse gas emissions reductions by 2030 vs. 2005 levels. The CFS is proposed to apply to all solid, liquid, and gaseous fuels used for transportation, industry, homes, and buildings. It will ultimately incorporate the volumetric requirement (5 percent low CI fuel in gasoline; 2 percent in diesel and heating distillate fuel) of the renewable fuel regulations.

CFS will reduce the CI of Canada's liquid fossil fuels by 10 gCO_2e/MJ by 2030. Reductions would start at 3.6 gCO_2e/MJ and would increase by 0.8 gCO_2e/MJ annually (3.6 in 2022, 4.4 in 2023 and so on until reaching 10 in 2030). Reductions for the years after 2030 would be held at 10 gCO_2e/MJ, subject to review and future amendments (Canada, 2019). Implementation of the liquid portion of the CFS has been deferred to 2022 to ensure adequate analysis and consultation. Gaseous and solid fuel regulations (which will tentatively be produced and published in 2021) would come into force in January 2023. Moreover, the Canadian government is reviewing the annual targets in light of the COVID-19 outbreak.

Canada has been a supplier of biodiesel to the US, largely into PADD 1. Last year, Canadian producers supplied 78 million gallons. The implementation of the CFS may lead to lower imports or stop Canadian imports altogether as obligated parties in Canada blend to meet the policy in Canada.

British Columbia enacted an LCFS in 2008 which requires a 10 percent reduction in the CI of its fuel mix by 2020 (vs. a 2010 baseline). British Columbia has announced intentions to extend the LCFS to 2030 and issue further CI reduction targets, but nothing has been enacted to date.

European Union Renewable Energy Directive (RED)

Renewable Energy Directive (RED) came into force in 2009. RED is a set of binding legislation that aims to ensure that the European Union meets its climate and energy targets from renewable sources, including wind, solar, geothermal, hydropower, biomass and biofuels by 2020. The three targets, known as the "20-20-20" are:

- 20 percent reduction in EU GHG emissions from 1990 levels
- 20 percent of the European Union's energy to come from renewable resources.
- 20 percent improvement in the European Union's energy efficiency

The 20 percent target is an overall EU target, where member states are then assigned national targets depending on their capabilities. In addition, all member states were obliged to achieve a minimum target of 10 percent for the use of renewable fuels in the transport sector (by energy content) by 2020.

To promote investments in advanced biofuel production, which has limited impact on indirect land use change (ILUC) but requires high capital costs, RED allowed the biofuels produced from nonfood feedstock to count twice ("double counting") toward the 10 percent renewable energy target.

In September 2015, the EU approved Directive 2015/1513, which amended RED to address ILUC emissions. The Directive capped the contribution of food-based biofuels to RED from 10 percent renewable energy to 7 percent by 2020. It also introduced a flexible nonbinding national target for non-food based (advanced) biofuels at 0.5 percent of transportation fuel by 2020.

RED requires that the minimum GHG emission savings from the use of biofuels to be 35 percent in comparison with the use of fossil fuels. Starting January 1, 2018, GHG emission savings from the use of biofuels produced in old production units must be at least 50 percent while the threshold for biofuel installations commissioned after October 5, 2015 is 60 percent. In addition, biofuels must not be made from land with high biodiversity, such as primary forests, protected lands, wetlands, and other areas supporting high natural biodiversity.

On November 30, 2016, the European Commission published a formal proposal to revise the RED, which expires at the end of 2020. The new directive, RED II, will replace RED and will come into effect on January 1, 2021. RED II has an overall target of 32 percent renewable fuels and a binding target of at least 14 percent renewable fuels in transport by 2030. Within the 14 percent target, the target for advanced biofuels is 0.2 percent in 2022 and 3.5 percent in 2030. Additionally, palm oil would be phased out by the same time frame.

While biofuels produced from advanced feedstocks listed in Annex IX parts A and B continue to benefit from double counting, biofuels produced from UCO and animal fat face a soft cap of 1.7 percent. In 2018, biofuel blending using feedstocks listed in Annex IX (most of which was UCO and animal fat) was around 1.2 percent of transport energy. Some individual countries, such as Portugal, are already at or beyond the target. Given the amount of UCO and animal fat-based renewable diesel and jet production capacity in the pipeline around the world, the soft cap could be reached relatively quickly. The text of RED II does not specify any procedure or criteria to obtain a modification to the 1.7 percent soft cap, but IHS Markit expects individual Member States to seek modifications. Given the soft cap, the UCO and animal fat-based biofuel plant projects, and impacts of COVID-19, the availability of those feedstocks could face significant limitations in the future.

Energy Supply

Overview

Heating oil has three major competitors: natural gas, propane and electricity. Fuels like heating oil, can be modified to reduce the carbon intensity of the fuel. Additionally, each fuel can improve the heating technology to reduce carbon emissions from a home. IHS Markit did not evaluate technologies and potential improvements to technologies for home heating in this study.

Electricity

US lower-48 net on-grid electricity demand is projected to grow by roughly 0.6 percent per year in 2020-50. Energy savings attributable to continued investment in energy efficiency and behind-the-meter (BTM) solar reduce the growth rate by 50 percent over this period, from 1.3 percent to 0.6 percent per year (Giuffre, 2019). Demand growth will continue to be uneven across North America due to varying economic and demographic trends as well as energy policy. Growth will be slowest in regions like New England (average 0.26 percent per year between 2020 and 50) and New York (0.15 percent), where demographic trends including slower household formation converge with energy policy that supports a greater investment in energy efficiency and BTM solar.

Across New England and the Mid-Atlantic states, the power generation mix will see wind and solar gain shares with the gains being more modest in the latter region. Spurred by state level policies, offshore wind is projected to grow dramatically in New England and New York. Over the next three decades, IHS Markit expects nearly 20 GW of offshore wind to be developed in the Northeast. This growth will reshape power market fundamentals in the region. By the early 2030s, wind will become the second-leading source of generation in both New England and New York. By the early 2040s, it will assume the top spot from natural gas. Offshore wind will also put downward pressure on energy market prices – particularly in winter periods when output is the strongest. In late November 2019, New Jersey Governor Phil Murphy signed an executive order increasing the state's goal for offshore wind from 3.5 GW by 2030 to 7.5 GW by 2035. The state has already contracted with Ørsted for the development of a 1.1 GW offshore wind project planned for completion in 2024. How these large-scale state-contracted resources will be allowed to participate in the capacity market without suppressing capacity prices is an open question, and further reforms may be required in the future. Nuclear plants will see more retirements in the forecast period, except for a couple in New Jersey (Hope Creek and Salem) that IHS Markit assumes will continue to receive state financial support.

Retail electricity prices in the Northeast are among the highest in the country. Residential retail electricity prices across New England averaged 20.5 cents per kWh in 2018. Weighted average residential retail price for customers across the PJM footprint, which serves most of the Mid-Atlantic states, was equal to the US weighted average residential price of 12.9 cents per kWh (in the year to date through November 2018 period).

Natural Gas

US lower-48 total natural gas demand is expected to grow from 94 Bcf/d in 2019 to 140 Bcf/d by 2050, owing primarily to LNG feed gas and US pipeline exports to Mexico. The rise in power sector gas demand is attributable to coal and nuclear plant retirements and modest electric load growth. IHS Markit projects more than 90 GW of new gas-fired capacity to be installed during 2022-30. Of that amount, 59 GW is expected to enter service in the PJM Interconnection. However, these additions will be outpaced by the adoption of increased battery storage as well as wind and solar capacity. As a result, the power sector's dependence on gas' share of total demand is anticipated to drop from 33 percent in 2019 to 29 percent in 2050.

The New York/New Jersey and New England power sector should mirror the trend nationwide of greater renewables penetration and stronger hydroelectricity imports. The larger share of renewables partly reflects decarbonization initiatives, including a direct procurement approach to decarbonize the power fleet. As a result, the power sector gas demand in 2050 is expected to be down by 1 Bcf/d from the anticipated 2020 level. Northeast residential and commercial gas demand is also expected to decline by 0.1 Bcf/d during 2020-50 because of higher-efficiency applications and demand response management.

The carbon intensity of natural gas can be reduced with the use of renewable natural gas which is produced from landfills or biomass digesters. Renewable natural gas is being developed in California and Oregon under their low carbon fuels standards. However, the major use for renewable natural gas to date has been as compressed natural gas in transportation to take advantage of the low carbon fuels standard credits. Renewable natural gas is a limited resource and can be high cost. As other policy jurisdictions adopt policies that enable the use of renewable natural gas, the competition for supply will increase. In addition, given the relative size of the renewable natural gas resource base compared to total natural gas demand, its impact on overall natural gas carbon intensity will be limited. It is likely that renewable natural gas will be used in specific applications where significant value can be generated.

Propane

The US has become the world's largest producer and exporter of propane due to the production of oil and gas from shale. As a result, propane prices have become delinked from oil prices over the last few years. This has allowed propane to make some inroads against heating oil. It is unlikely the carbon intensity of propane can be reduced significantly. Although it is theoretically possible to reduce the CI of propane, such improvements are limited by the low availability of lower CI alternatives. One such alternative would be renewable LPG. The only supply of renewable LPG is currently produced as a by-product of renewable diesel fuel production — a process that has not gained traction in the Northeast. Another alternative would be to use bio-DME as a propane blending component. At this time, the only bio-DME produced is in California in very small quantities and used as a diesel substitute for transportation. Given the scarcity of these alternatives, it is thus unlikely that the CI of propane can be substantially lowered over time. As a result, on a CO_2 emissions basis, propane in the home heat market could mature and, possibly, decline if policy requires lower emissions.

Biofuels Feedstocks

In the US, the primary feedstocks for biodiesel and renewable diesel production are UCO, DCO, animal fats, SBO and canola oil. All of these feedstocks are potentially available for biodiesel and renewable diesel production for heating oil blending. However, in today's market with current policies the low CI feedstocks (UCO, animal fats and DCO) are primarily moving to the US West Coast for the LCFS market. Unlike vegetable oils, the CI for these feedstocks is low because they do not carry an ILUC penalty in their CI scores.

This analysis focused on soybean oil due to:

- The potential for future supply growth in the US and globally at a rate faster than non-fuels demand
- The agricultural industry's extensive knowledge, experience and infrastructure
- The potential for reductions in the CI

Lower CI feedstocks

- Used cooking oil (UCO): UCO or yellow grease is collected mainly from restaurants, food processing and institutions. Growth in UCO supply is a function of increased collection, income and population growth. The US has a relatively high rate of UCO collection. The majority of UCO collection is used for biodiesel and renewable diesel.
- Animal fats: Animal fats are by-products of meat production. Growth in supply is a function of the growth in meat demand for domestic and export use which is driven by growth in income and population as well as consumer tastes and preferences. Animal fats are also used in other applications; their use is also shifting to biofuels.
- Distiller corn oil (DCO): DCO is an inedible oil produced in corn ethanol plants. DCO supply is likely to increase as much as 40 percent in the medium term as ethanol plants increase the rate of oil extraction. Over the long-term, DCO supply growth will be a function of the growth in ethanol domestic and export demand. However, with ethanol use in gasoline generally limited to 10% and gasoline demand mature and likely to fall, the potential for DCO supply growth is limited.

Growth in low CI biodiesel and renewable diesel feedstocks are limited. They could contribute to biofuels supply for heating oil blending. However, due to their low CI, they will likely continue to be favored in CA and other LCFS markets. It is important to note that while the current CI of these feedstocks are low compared to vegetable oils (soy and canola), there is limited potential to reduce the CIs of these feedstocks.

To attract fuels produced from these feedstocks into the heating oil market, a policy framework that supports an obligation or incentive for these fuels at least equivalent to their value in LCFS markets will likely be needed.

Higher CI feedstocks

Higher CI feedstocks for biodiesel and renewable diesel fuel production are vegetable oils or oil seed crops, primarily soybean oil with some supply from canola oil. These feedstocks are the largest source of supply for biodiesel production in the US. The production and yields of these oilseeds have consistently increased over the last several decades. They also have significant potential for:

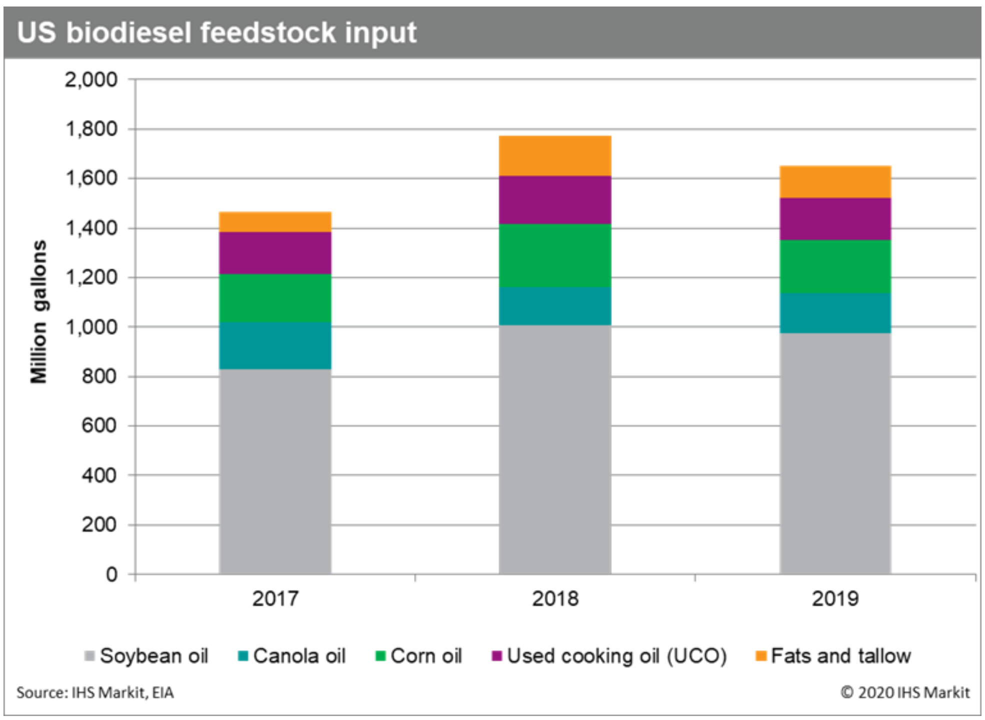
- Continued yield increases
- For soybeans, increased oil yield per pound of seed
- CI reduction from technology and agricultural practices

Energy crops

Another potential source of future biooil feedstocks for biodiesel and renewable diesel production could be energy crops such as carinata, camelina, penny cress and others. These crops can be planted as winter cover crops or second crops in compatible growing areas. These crops would have a relatively low CI since they would not have ILUC penalties.

These crops were not considered in this analysis but do have potential to contribute to future biofuels feedstock supply without competing for land with current crop production.

Figure 3



The crushing of oil seeds produces two products: oil and meal. In the case of soybeans, the meal is the main product which goes to animal feeds, and oil is generally considered a by-product. Soybeans are about 20 percent oil and 80 percent meal, and canola are about 40 percent oil and 60 percent meal. If agriculture produces more oil for use in biodiesel, it is likely that the amount of meal production will also increase. The relationship of value of oils in seeds to protein will be affected by both the value of renewable fuels and demand for protein for consumption. This will be important in the characteristics of soybeans, but may also impact other oil crops such as canola and corn.

Soybean meal demand is expected to grow about 0.5 percent per year in the US to 2050. There are a number of seeds that are available that could result in a higher oil yields per bean. In addition, there are other sources of meal for animal feed. As a result, the oil/meal markets will balance, but will require price changes in between oil and meal for soybean processors.

In 2019, 2.66 billion gallons of biodiesel and renewable diesel were used in the US on-road fuels market, or about 6 percent bio-content. As noted previously, nearly all of the renewable diesel goes to CA, and CA blended about 6 percent biodiesel and 16 percent renewable diesel last year. (CARB, 2019) Outside of CA, biodiesel blends have been on the order of 4 percent of the on-road diesel market or 1.7 billion gallons. (EPA, 2019).

IHS Markit's view is for the demand for SBO to meet food, exports and a relatively flat biodiesel demand in 2020 of 3.2 billion gallons and an increase to 3.7 billion gallons in 2050. This outlook is based on the following assumptions:

- Crop yield: soybean yields in bushels/acre increase by 0.8 percent per year.
- Acres harvested: fall by 0.6 percent/year as the yield increase more than offsets the demand increases for soybeans.
- Oil yield per bushel of soybeans remains unchanged over the period.

However, SBO production could increase over the next 30 years:

- Acres harvested: soybean acres could be higher with higher prices and the meal market increases to take up increased supply. IHS Markit expects total acres planted in the US to decline over the next 30 years due to productivity growth outpacing demand growth. This analysis assumes soybean acres harvested return to the record high level reached in 2017
- Oil yield: the oil content of soybeans can increase by changing the variety of soybean planted. However, the price of SBO has to be high enough for a long enough period to encourage farmers to plant higher oil yielding varieties. In this analysis, oil yield is expected to increase from 19.4 percent to 25 percent by 2050. The USDA and others have indicated the soybean genome can support yields of 27.9 percent and even higher

In IHS Markit's alternative case SBO production could increase by as much as 2.3 billion gallons by 2050 compared to 3.7 billion gallons production in 2019. All of this increase could be used for renewable diesel, renewable jet fuel, and biodiesel production.

Although higher blend rates of biodiesel are associated with lower CO_2 emissions, they also result in higher pour and cloud point of the blended fuel, increasing the likelihood of gelling and residual deposits during winter transit if the fuels are not handled correctly. At higher blend rates, strategies to respond to the high cloud point of some biodiesels may be necessary.

Biofuels Supply

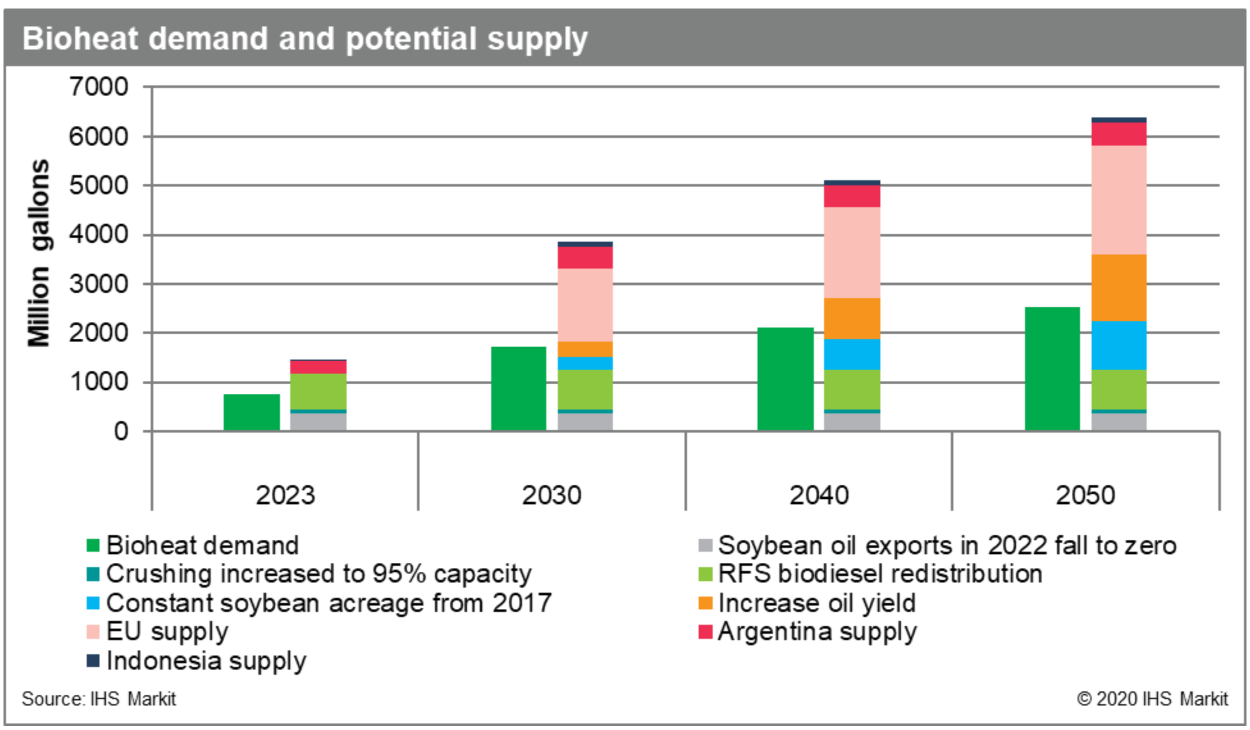
Decarbonization has become a major driving force in the energy industry worldwide. As a result, enabling policies are causing major changes in the supply chains for renewable low carbon energy. The industries supporting renewable low carbon energy have responded to policy and delivered large amounts of energy over relatively short periods of time. For example:

- Renewable diesel volumes being delivered to California has increased from over 1.8 million gallons in 2011 to 617.9 million gallons in 2019 according to data from the California Air Resources Board. This combined with the 6 percent biodiesel in California translates into renewable diesel and biodiesel providing over 22 percent of the diesel volumes in California, which displaces over 830 million gallons of petroleum diesel.
- According to EIA data, ethanol blend rates increased nearly ten-fold from around 1.3 percent in 2000 to 10.3 percent in 2010, which was due in large part to the ban on MTBE in the US. Since then, blend rates have gradually risen to around 11.4 percent in 2019. In volume terms, fuel ethanol consumption has increased from 1.65 billion gallons to 14.5 billion gallons between 2000 and 2019.

The supply of biodiesel could outpace the demand for Bioheat™ through 2050. However, a number of factors can impact this view both positively and negatively. These include:

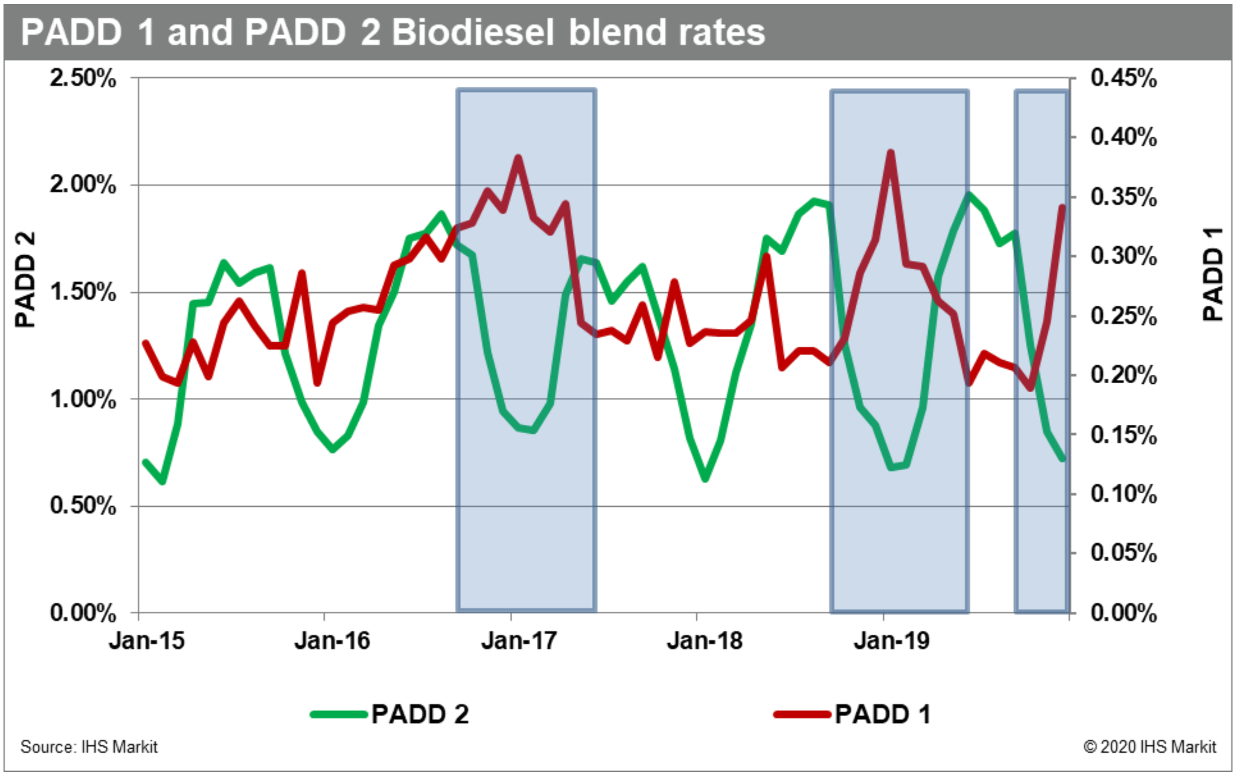
- Import policies
- Renewable and biodiesel related policies in other jurisdictions
- Agricultural productivity per acre

Figure 4



The demand for biodiesel between PADD 1 and PADD 2 is somewhat complementary. As a result, an increase in the on-road use of biodiesel may not reduce the capacity to produce biodiesel for Bioheat™. Utilization rates for US biodiesel plants are the highest from the 2nd quarter through the 4th quarter of the year. The higher rates of utilization are due to higher transportation and agricultural demand for the fuel during the summer and fall seasons. During the 4th quarter, demand for on-road use declines due to the cold flow properties of biodiesel.

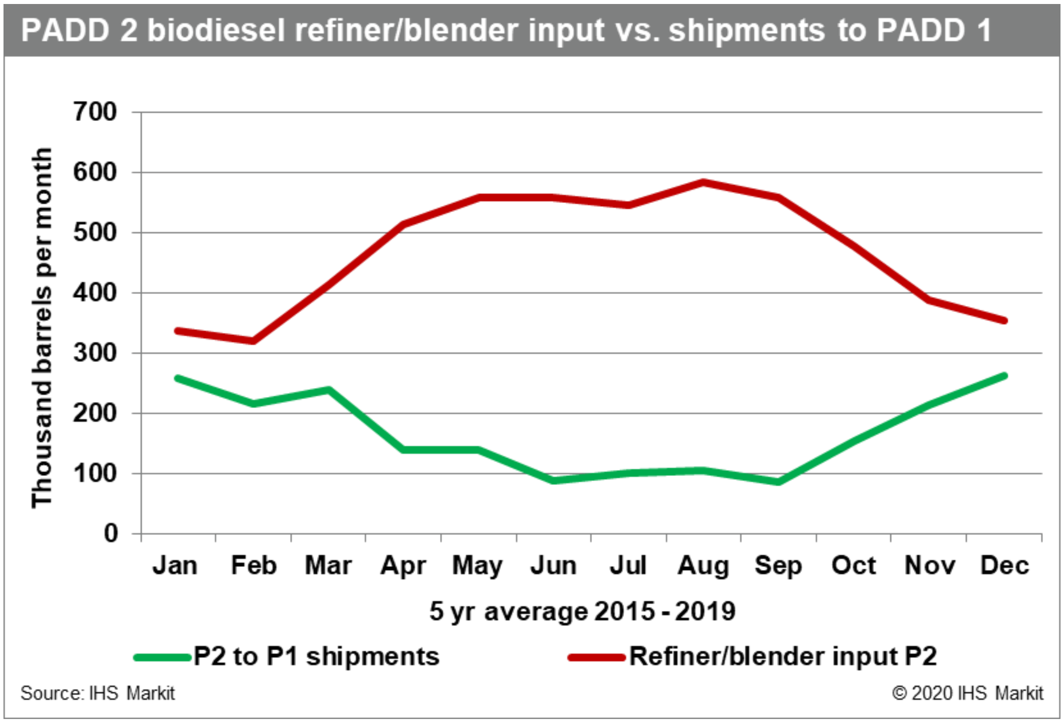
Figure 5



Biodiesel demand in PADD 2 is also counter-seasonal to biodiesel shipments from PADD 2 to PADD 1. These counter-seasonal trends indicate that an increase in biodiesel blending in PADD 2 may increase biodiesel availability in PADD 1 if new capacity is added. Therefore, policy actions that incentivize higher biodiesel blending outside of PADD 1 could increase the production capacity of biodiesel available for heating oil markets.

However, counter-seasonality also indicates that as the blending of bio-heat increases in PADD 1, the heating oil market in PADD 1 will increasingly be exposed to the risks associated with agriculture, such as weather, and could be sensitive to any disruptions affecting domestic biodiesel production.

Figure 6



B20 in 2023

Will there be enough biodiesel to meet a B20 blend with SME in 2023? In IHS Markit's view, there could be enough supply available to meet B20 demand in 2023. There are several potential sources of incremental biodiesel supply that could be used to supply the estimated 809 million gallons (NORA, 2019) needed for B20 in PADDs 1a and 1b. IHS Markit estimates as much as 1.9 billion gallons of potential supply. These sources include:

- Imports
- US SBO production and exports redirected to produce biodiesel
- Supply redistribution

Imports

Imports into PADD 1a and 1b have occurred as market demand requires, primarily from Canada, Europe, and South America. As demand increases for heating oil blending, the market will react by supplying more imports if the domestic biodiesel industry has not developed sufficient production and logistics capacity. Ample supply of biodiesel exists around the globe to satisfy any additional needs which may arise beyond the capabilities of the domestic industry.

US SBO production and exports

With the right price signals, there can be flexibility in SBO supply to the US market for SME production. The US is an exporter of whole beans, meal and oil. US exports include:

- Soybeans: over 45 percent of soybean production as whole beans.

- Meal: over 5 percent of soybean production as meal.
- Oil: nearly 1 percent of soybean production as oil.

However, SBO production is currently limited by crushing capacity. IHS Markit estimates that an increase in the crushing utilization rate from the current 93 percent to a likely maximum of 95 percent, based on existing crushing capacity, would only produce an additional 74 million gallons of SBO. In 2019, US biodiesel plants ran at an average utilization rate of about 68 percent, which leaves a substantial amount of capacity, or about 680 million gallons, theoretically available. This leaves approximately 606 million gallons of spare biodiesel capacity.

Supply redistribution

In 2019, biodiesel demand in the US was just over 1.811 billion gallons. IHS Markit estimates about 1.038 billion gallons were used in states with biodiesel volume requirements or LCFS programs. The remaining volume of about 773 million gallons are used by obligated parties to meet the RFS and blended where it is the most economical. Some of this volume could be redistributed to the heating oil market. Since biodiesel is being used in other areas to meet RFS requirements, some of this volume could be moved into Bioheat™ with obligated parties continuing to be in compliance.

B50 in 2030

Will there be enough biodiesel supply to meet a B50 Bioheat™ in 2030? An increase to B50 by 2030 from B20 in 2023 will require about 900 million more gallons of biodiesel (an increase of 1.7 billion gallons from the 2019 level). IHS Markit estimates the supply of SME could increase by 2.5 billion gallons. However, the supply and demand for biodiesel and renewable diesel and jet fuel feedstocks are also likely to change over the next decade.

As decarbonization of fuels continue, it is likely there will be more policies that will provide incentives to increase the use of biodiesel and renewable diesel and jet fuel. For example, Canada is scheduled to begin its Clean Fuels Standard in 2022, and several other states are considering LCFS.

To date, most renewable diesel (which uses the same feedstocks as biodiesel) demand has been met with lower carbon intensity ‘waste oils’ such as used cooking oil, fats and tallow, and distiller corn oil. These feedstocks are growing in demand worldwide as they are favored due to their low CI. Supply in the US and Canada are likely to be highly utilized for renewable diesel production for jurisdictions with LCFS policies (CA, OR, BC, Canada in 2022, and other states over the next few years). It is likely there will also be SBO moving into renewable diesel production as LCFS policies continue to be implemented. With enough lead time (3 – 4 years) the SBO supply chain could deliver more SBO from field to furnace.

An increase in SBO supply could come from two major sources:

- Higher oil yield per pound of soybeans.
- Soybean acres harvested continues at the record high level of 2017 rather than declining over time.

If 2.5 billion gallons is potentially available for Bioheat™ and B50 requires 1.7 billion gallons, that leaves about 0.8 billion gallons for other market uses of biodiesel. Feedstocks that could become available include conventional oils such as canola. Other sources that are not currently produced in large amounts include energy crops, biomass gasification to diesel, pyrolysis oils, and other technologies that have not yet been commercialized or, possibly, not developed. These could be higher cost and require a greater level of incentives than currently provided.

B100 in 2050

Will there be enough biodiesel to meet a B100 Bioheat™ in 2050? In IHS Markit's view, there could be enough available to meet B100 if there are supporting policy frameworks in place for biodiesel production. Without policy support, supply will not develop unless there are sustained high oil prices and investors are convinced petroleum prices will remain high enough to make biodiesel economical through 2050. Historic experience has shown petroleum prices are a major risk factor from an economic perspective as much as from a policy perspective.

The development of policy framework with tradable credits across jurisdictions or states may make compliance more efficient and benefit Bioheat™. Obligated parties could blend biodiesel in excess of policy requirements and use the 'surplus' credits generated to comply with other fuels-related carbon reduction obligations. As a result, both renewable and biodiesel demand will increase as suppliers reduce the carbon intensity of fuels. Consequently, the demand for feedstocks will also increase.

Past experience with both agriculture and fuels markets has shown that if there is a market and producers can profitably supply the market, there will be no shortage as long as there is enough lead time for the supply chain to respond.

IHS Markit estimates that biodiesel demand in the northeast will be on the order of 2.5 billion gallons to meet B100 in 2050. This level of demand could be met with:

- Imports could add as much as 2 billion gallons by 2030 and continue through 2050.
- Maintaining soybean area planted at the 2017 high level could add as much as 1 billion gallons.
- Increasing the SBO yield from 19.4 percent to 25 percent could increase supply by 1.4 billion gallons.
- Redistribution of biofuels supply from blending to meet RFS, excluding states with volume requirements, could move 1.2 billion gallons from on-road to Bioheat™ by 2022 and continued to 2050.

Additional biodiesel and renewable diesel supply could be developed over the next 30 years with supportive policies. In IHS Markit's view, as renewable and biodiesel blends increase, the liquid fuels market and agriculture become increasingly interdependent. Historically, very little investment has been made in higher oil yielding varieties of crops. As decarbonization policies drive demand for low carbon fuels, this could change. The agricultural industry may begin to make investments to develop and produce higher oil-yielding varieties, provided there is sufficient price incentive. B100 could therefore be achieved earlier than 2050 and allow the potential supply of SME to be higher than the demand from home heat even by 2030. However, achieving B100 at any time in the future will require additional investment across the supply chain in agriculture, soybean processing capacity, biodiesel production, infrastructure and compatible systems at the customer level. In order for these investments to occur, a policy driven framework that sends the proper price signals to the market needs to be in place.

Other sources of feedstocks that are not yet commercial or developed could enter the market over time without competing for land resources with vegetable oils.

Can net zero heating oil be achieved by 2050?

IHS Markit estimates the CI of SME could be reduced over time from about 70.23 lbs.CO_2/MMBtu to about 22.59 lbs.CO_2/MMBtu. This corresponds to a CI change from around 34% of conventional heating oil to approximately 11%. To achieve this level of reduction:

- All energy inputs in the production, processing and transportation of SME moves to renewable fuels and biodiesel.
- The indirect land use change (ILUC) included in the current CI is reduced to zero.
- Green methanol is used in biodiesel production rather than methanol from natural gas.

If the transition to 22.59 lbs. CO_2/MMBtu of SME can be made, CO_2 emissions from heating oil can be substantially reduced. SME emissions could be reduced even further to the point of negative emissions through the development of soil carbon sequestration (SCS). There is significant interest and investment in SCS today. It is viewed as a low-cost way of reducing carbon emissions. Companies are emerging that are offering to pay farmers to capture carbon in the soil. With these incentives, farmers are essentially creating a new crop – carbon – and will have incentive to increase SCS.

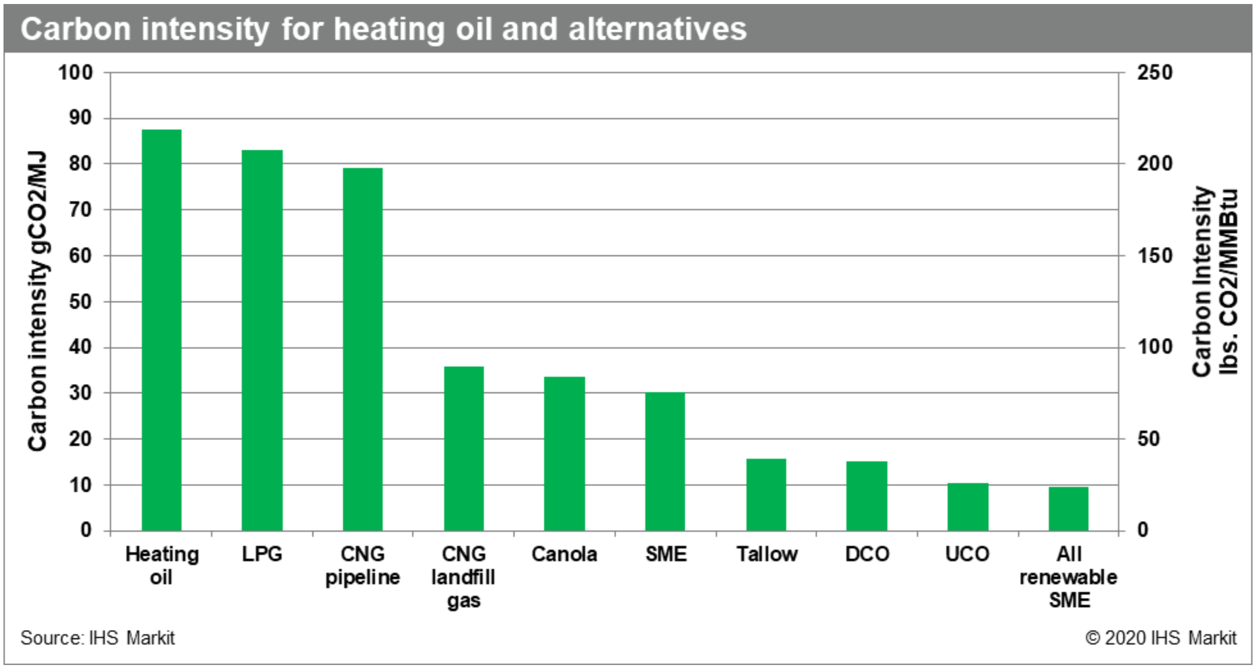
SCS could result in negative emissions SME. However, there are several uncertainties that remain to be addressed.

- How much carbon can be sequestered and over what period of time?
- Is the carbon sequestered in soils permanent?
- How will agriculture change in terms of crop rotations and production of key crops?
- Who will get the credit for carbon emissions reductions? Will it be the firms buying the sequestered carbon from farmers and selling it as offsets to stationary emissions? Or, will it be biofuels where the farmer is paid for the sequestered carbon through a higher price for the crop reflecting the lower CI?

Carbon Intensity and CO_2 Emissions

Based on the GREET model developed by Argonne National Laboratory, alternatives to petroleum-based fuels have, on average, carbon intensities (CIs) that are less than half of that for their petroleum counterparts. Figure 7 below shows the average CIs for petroleum-based and alternative fuel options that are available for heating.

Figure 7



There is potential for the carbon intensities of some alternative fuels, such as those produced from vegetable oil feedstocks, to further decrease as farming and logistical practices in the agriculture industry moves to reduce its carbon footprint. For instance, the CI for SME and other vegetable oils has the potential to decrease by approximately 66 percent over time with renewable energy substitutes across the supply chain and SCS. Reductions could, in the long run, make vegetable oil-based biodiesel more attractive than the current lower CI waste fats/grease biodiesel for decarbonization.

The carbon intensity estimates for SME varies from as low as 10 (potential estimated by IHS Markit) to 30 (today's average) using the GREET model. The overwhelming share of SME CI comes from the agricultural production and oil extraction of soybeans (39 percent), followed by biodiesel production (27 percent) and indirect land use change (ILUC) (26 percent). These emissions can and are being reduced slowly. For example, soybean yield increases could reduce CI by less than 0.1 percent per year.

Figure 8

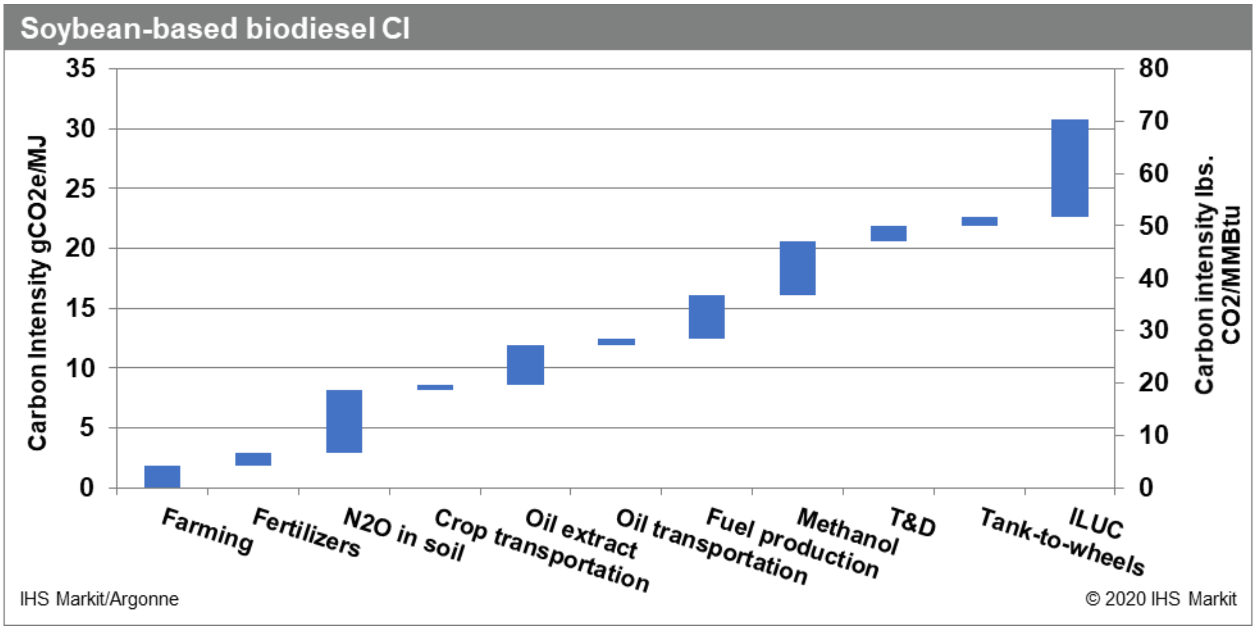
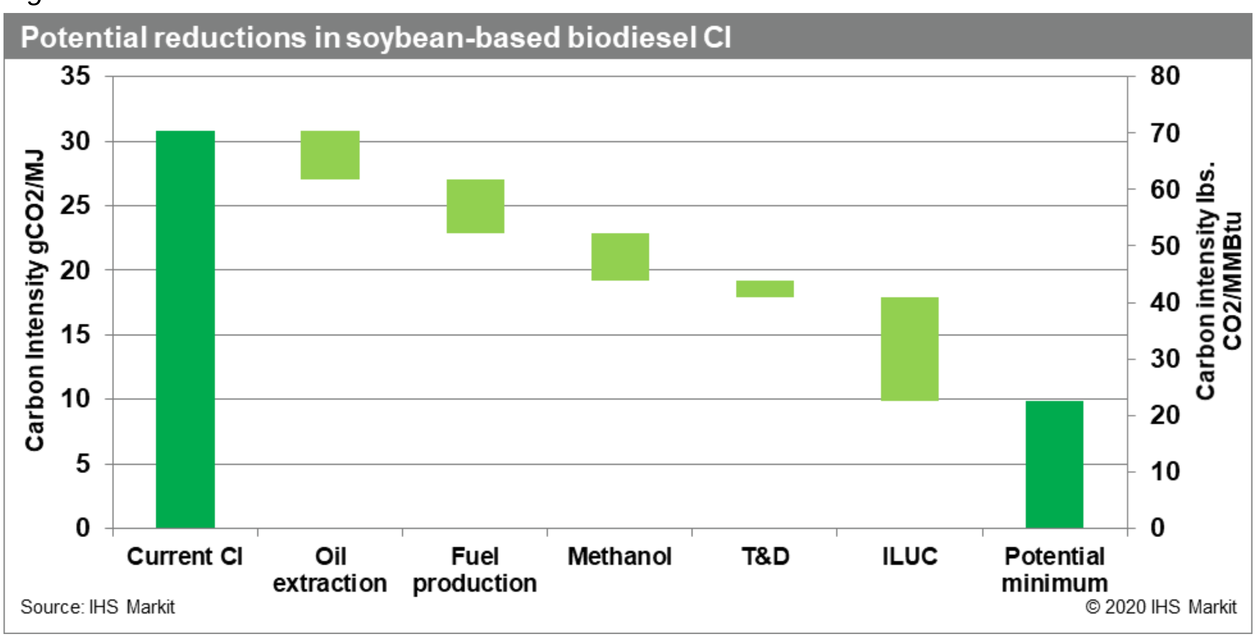


Figure 9 below shows the reductions in soy-based biodiesel CI that could potentially take place after implementing the renewable substitutes and SCS mentioned previously. In order for any of these reductions in the SME CI to occur, price signals have to be put in place by policy. Most critically, farmers will need to see higher prices for high oil yielding soybeans compared to relatively low oil yield varieties. Soybean processors and biodiesel plants will need to see policy and price signals to shift from fossil fuels to renewable energy such as biomass, renewable natural gas, solar and wind.

Figure 9



Given SME's potential CI reductions, it may be possible to reduce the future CI of heating oil from 81.7 to 26.3 lbs. CO_2/MMBtu with 100 percent SME blend rates, with both figures adjusted for a process efficiency of 86%. For instance, biodiesel could be used to reduce the transportation and distribution (T&D) carbon intensity to deliver harvested soybeans to the biodiesel plant, and renewable methanol can be used for the fuel production process. Much of the remaining CI value originate at the farm — coming from energy, fertilizers and soil N_2O emissions. Research is still underway to reduce these emissions. The CI can be reduced further and possible to negative levels if soil carbon sequestration is scored as an offset indirect land use change. There are ongoing efforts and research to increase soil carbon levels through farming practices and technology. In addition, yield increases can also reduce ILUC.

B100 compared to other home heat fuels

In general, the CO_2 emissions from today's home energy supply will decrease over time due to two major factors:

- Efficiency: most home heat appliances are expected to become more efficient over time
- Fuel carbon intensity: the CI of some home energy supplies can be reduced over time through fuel decarbonization

Despite having some of the lowest fuel costs (based on 2019 actual residential prices), petroleum-based fuels have the highest CIs, resulting in the highest CO_2 emissions per unit cost (above 5 lbs. CO_2 per unit cost of fuel). SME represents a lower cost and lower CO_2 option for heating compared to all petroleum fuels, having a CO_2 emissions per unit cost that could be outperformed only by highly efficient, electric heating options running predominantly on renewable electricity.

Moving toward 100 percent biofuels in heating oil will reduce its CO_2 emissions/MMBtu (carbon intensity) relative to other home heat fuels. Figures 10 through 12 show the cost comparison for various heating fuels in New England, New York and PJM Mid-Atlantic for both 2020 and 2050. These power markets were chosen due to this report's focus on the Northeast heating oil market. The heating fuels are evaluated based on the efficiency of their use, costs, and carbon emissions. These metrics are then combined to provide a higher level, holistic metric of emissions per unit cost, and finally compared to competing alternatives running on grid average electricity. In 2020, SME with a boiler configuration is among the options with the lowest carbon intensities at and emissions per unit cost, at 3.38 lbs. CO_2 per dollar.

In figures 10 through 12, bars and left-hand axis indicate carbon intensities of the fuels respectively, while markers and right-hand axis indicate the CO_2 emissions associated with the use of the fuel per unit cost. The data is sorted in ascending order with the overall lowest carbon intensity and lowest emissions per unit cost fuel in 2050 listed on the left. All carbon intensities and emissions per unit cost shown are adjusted for efficiency. For example, in Figure 10, the B100 heat pump carbon intensity in 2020 (green bar) and 2050 (gray bar) are 48.4 lbs. CO_2/MMBtu and 15.6 lbs. CO_2/MMBtu, respectively. And, the CO_2 emissions per unit cost in 2020 (green triangle) and 2050 (gray triangle) are 2.01 lbs. CO_2/\$ and 0.65 lbs. CO_2/\$, respectively.

Figure 10

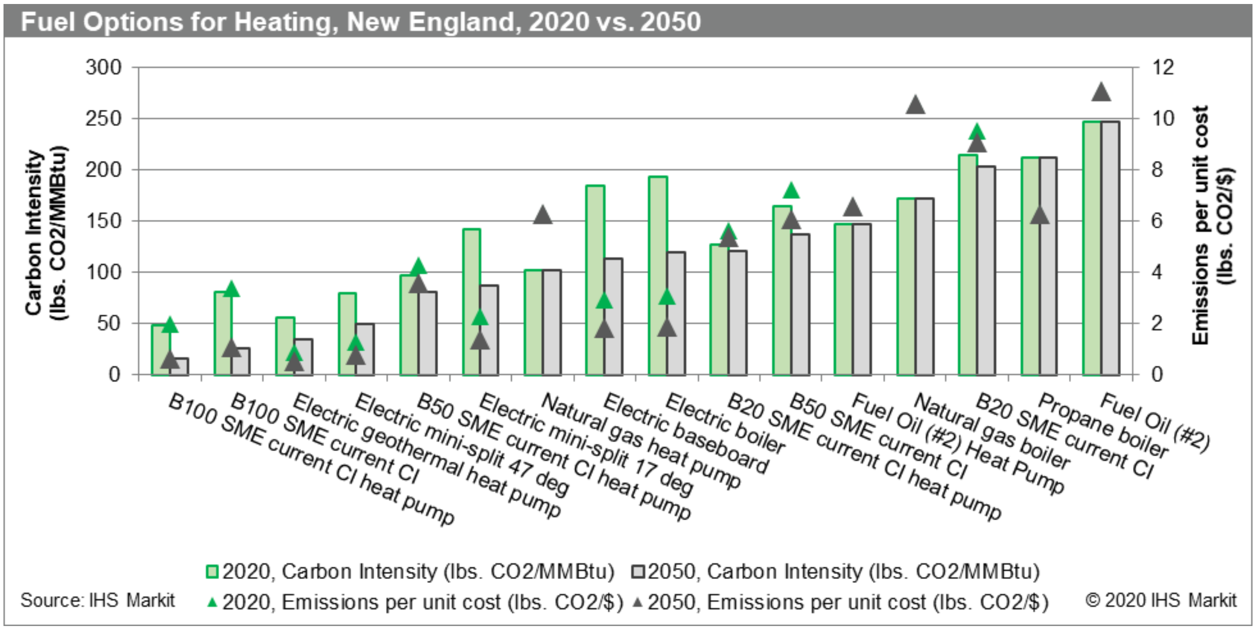


Figure 11

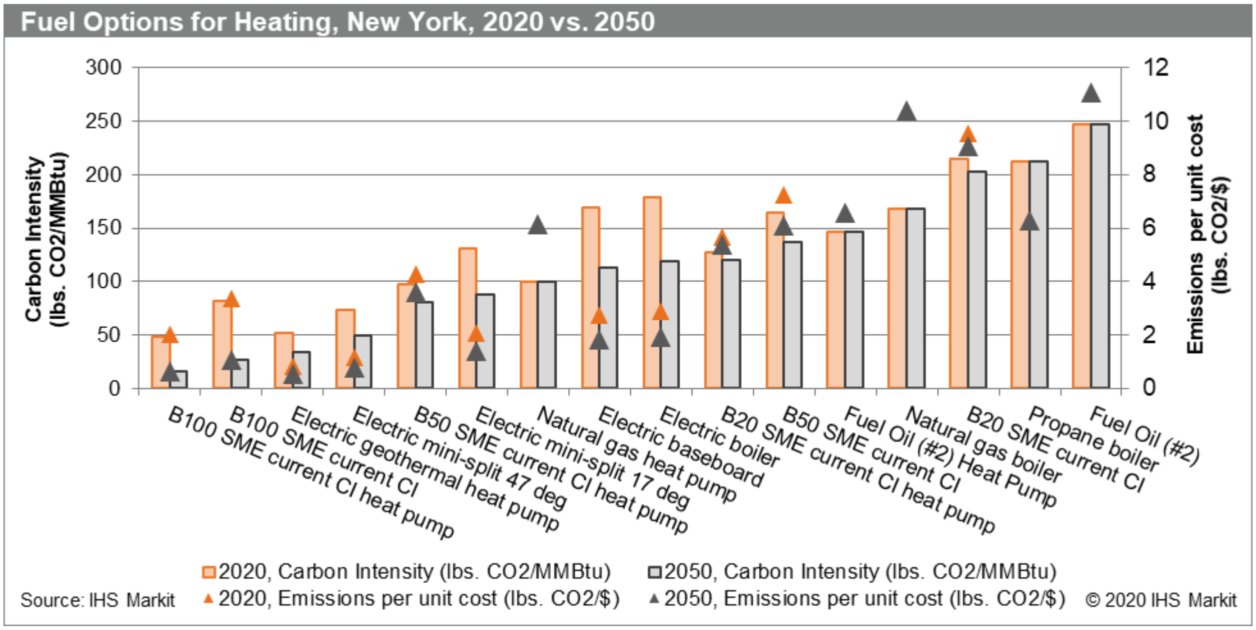
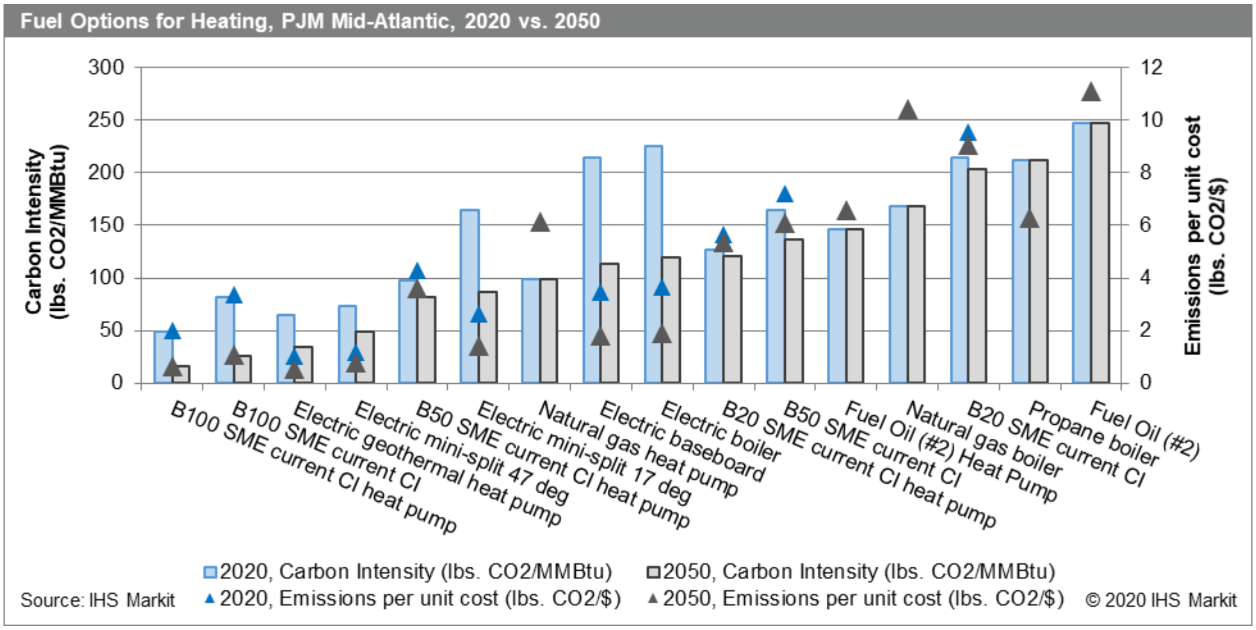


Figure 12



Provided that the carbon emissions for SME production are reduced successfully by 2050, the emissions per unit cost for SME in boilers could fall from 3.38 lbs. CO_2 per dollar in 2020 to 1.09 lbs. The use of low CI SME in an oil-fired heat pump would decrease the emissions per unit cost even further, pushing it down to 0.65 lbs. CO_2 per dollar, and allows low CI SME to outperform the 47-deg mini-split. Across all three Northeastern regions considered in the analysis, B100 SME is the fuel option with the lowest carbon intensity in 2050 and is among the options for lowest emissions per unit cost in both 2020 and 2050.

Figure 13 and Figure 14 on the next pages show electric mini-split emissions calculated using the IHS Markit base case average of the power grid and the fossil portion of the grid. The figures also show the marginal source of power for New England and PJM, respectively, which is assumed to be natural gas. Biodiesel blended heating oil is shown with two levels of CI:

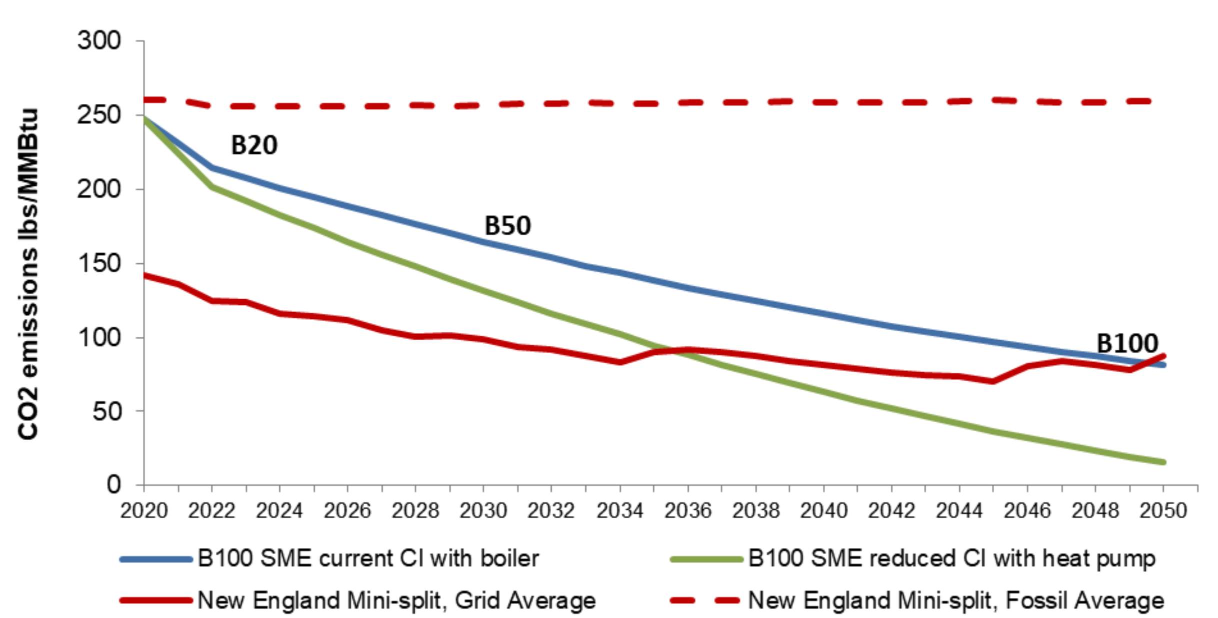
- The current CI of SME using a boiler
- The estimated level from the displacement of all fossil fuel in the supply chain using an oil-fired heat pump. The move to the lower CI SME is assumed to be ratable over the period.

If the CI of SME decreases as previously discussed, a B50 blend will outperform a mini-split system in CO_2 emissions in the PJM Mid-Atlantic, and B70 is sufficient in the New England for the average power grid emissions. For both New England and PJM, B20 has lower carbon intensity than the current fossil power generation capacity.

If, on the other hand, the CI of SME does not decrease from today's level, a B50 blend could approach the carbon intensity of mini-split electric heating in PJM Mid-Atlantic and outperform it at blends greater than B80. Due to the New England electric grid's minimal dependence on coal, biodiesel at current CI levels must be blended at close to 100 percent to be on par with a mini-split system in 2050. At this level, consumers would be carbon indifferent from an emissions perspective.

Figure 13

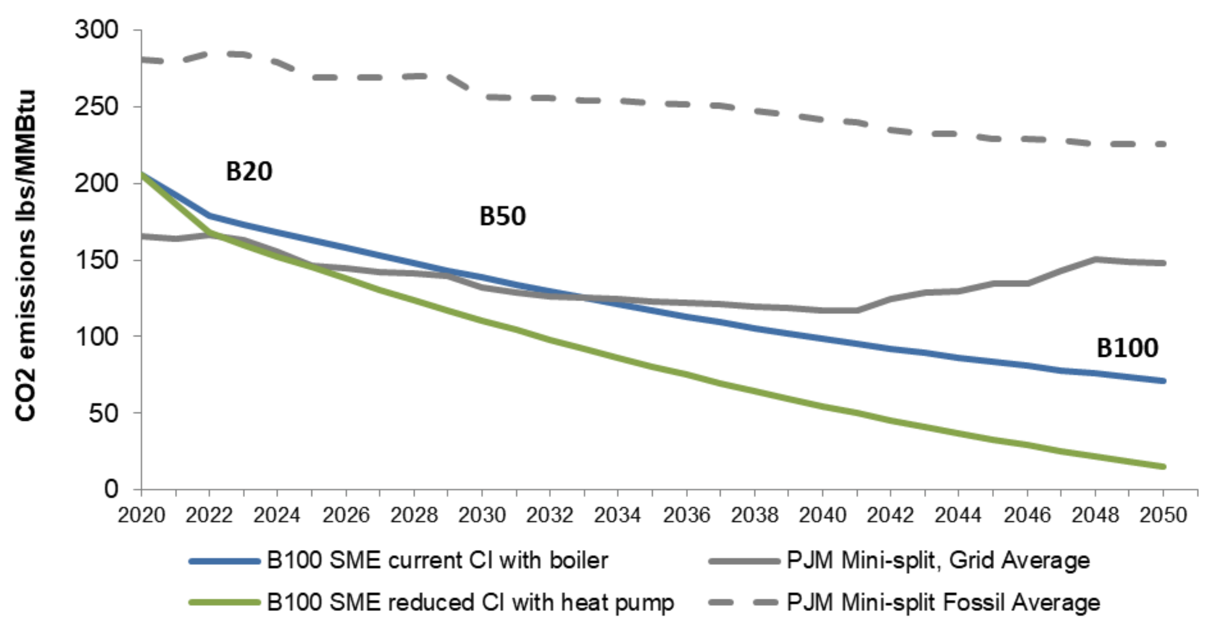
Carbon intensity comparison, SME versus New England electric grid



Source: IHS Markit

Figure 14

Carbon intensity comparison, SME versus PJM electric grid



Source: IHS Markit

Cost of various heating technologies

IHS Markit examined various studies that analyzed the costs of installing a range of heating oil technologies. These studies show that fully converting an existing home to a heat pump system incurs a substantial cost. On the other hand, moving from heating oil to a higher blend of heating oil and biodiesel has the advantage of requiring little to no additional cost to the end user. For instance, a study conducted by Diversified Energy Specialists (DES) that looked at air-source heat pump installation costs in Massachusetts between 2014 and 2019 estimated that on average, the total conversion cost was around $20,428 for an average conditioned space of 1,502 sq. ft. (Specialists, 2019). On the basis of original heating technology, the cost of converting to heat pumps ranges from $16,600 for wood stoves to $21,500 for natural gas. These figures assume that this conversion results in heat pump systems meeting sufficient heat load requirements for existing residences as opposed to the use of heat pumps as a supplemental heat source. However, the study found that most heat pumps installations that occurred during the five-year period did not provide sufficient heat for the entire home.

A NYSERDA study included capital costs per installation for 2018 for cold climate central air-source heat pumps, ductless mini-splits and ground-source heat pumps in different parts of New York State. For single-family residences in the Hudson Valley/Upstate/Western region, installing air-source heat pumps in existing homes cost an estimated $12,368 versus $17,522 in new homes (NYSERDA, 2019). The costs are $20,614 and $28,035, respectively, for small multi-family residences. Notably, the study assumes that air-source heat pumps installed in existing homes would not meet peak heating load whereas those installed in new homes would.

The cost of installing a mini-split is around $5,497 in single family homes and $10,994 in small multi-family homes in the Hudson Valley/Upstate/Western region. The study assumes that mini-splits fulfill only part of the heating needs of a home and are used as a supplemental heat source. Therefore, homes that opt for installing mini-splits are likely to be reliant on existing heating system as a backup heat source which will continue to require use and maintenance to maintain reliability.

Switching from heating oil to another heating/fuel system, such as electric whole house air-source heat pumps, can carry a significant upfront cost to the consumer. For example, in a roughly 1,500 square foot home, installing a complete whole house system could cost on the order of $20,000.

From the perspective of the overall value proposition, the continued use of heating oil with higher biodiesel blends can reduce CO_2 emissions at lower costs per pound of carbon emitted and a lower upfront cost to the consumer.

Table 3

Costs of installing air-source heat pumps

	Cost	Time period	Back-up heating source needed?	Geography	Study
Average total conversion cost in existing residences	$20,428	2014-2019	No	Massachusetts	DES
Average capital cost of installation in existing single family	$12,368	2018	Yes	Hudson Valley/Upstate/Western part of New York state	NYSERDA
Average capital cost of installation in existing small multi- family residences	$20,614	2018	Yes	Hudson Valley/Upstate/Western part of New York state	NYSERDA
Average capital cost of installation in new single family residences	$17,522	2018	No	Hudson Valley/Upstate/Western part of New York state	NYSERDA
Average capital cost of installation in new small multi- family residences	$28,035	2018	No	Hudson Valley/Upstate/Western part of New York state	NYSERDA
Average cost per heat pump	$7,860	2014-2019	Yes	Massachusetts	DES

Infrastructure

IHS Markit's assessment, which is based, in part, on interviews with industry stakeholders is that B20 can be made available across New England and the Mid-Atlantic markets within 18 to 24 months with existing infrastructure, confirming the industry's goal of B20 by 2023. B20 can be supplied by:

- Moving biodiesel to distribution terminals from inland intermodal locations and from marine terminals with the capability of receiving heated barges of B100 and heated storage.
- B20 can be blended and stored in terminals without heated tanks. In some terminals that have the capability to receive rail cars and reheat biodiesel, B100 can be stored in heated storage or blend with ULSD and store as B20 in non-heated tanks.
    - B100 can be trucked from these locations to other terminals without heated storage and blended with ULSD and stored as B20. Tank mixers and/or insulated lines may be needed at some locations during very cold weather.

At locations with existing heated storage and a compatible blending systems, blends higher than B20 are currently being made available.

- Heated storage tanks will be required at more terminals to store either B100 or B20+ blends. Depending on the location and situation, new tanks may be required, or existing tanks can be converted.
- Rail car reheat capability at more terminals to receive larger amounts of biodiesel and reduce trucking of biodiesel between terminals.
- Some marine terminals may need to add the capability to receive heated barges and store biodiesel in heated tanks as the percent blended increases.
- A B20 blend can be managed with the existing equipment in the supply and distribution facilities for heating oil and petroleum products. Most cold climate wholesale facilities have invested in heated storage and handling capabilities for their B100 storage and rack operations. As demand grows for higher blend levels above B20, these facilities may not need significant further investment. There are a number of facilities that have not yet made investments to handle B100.

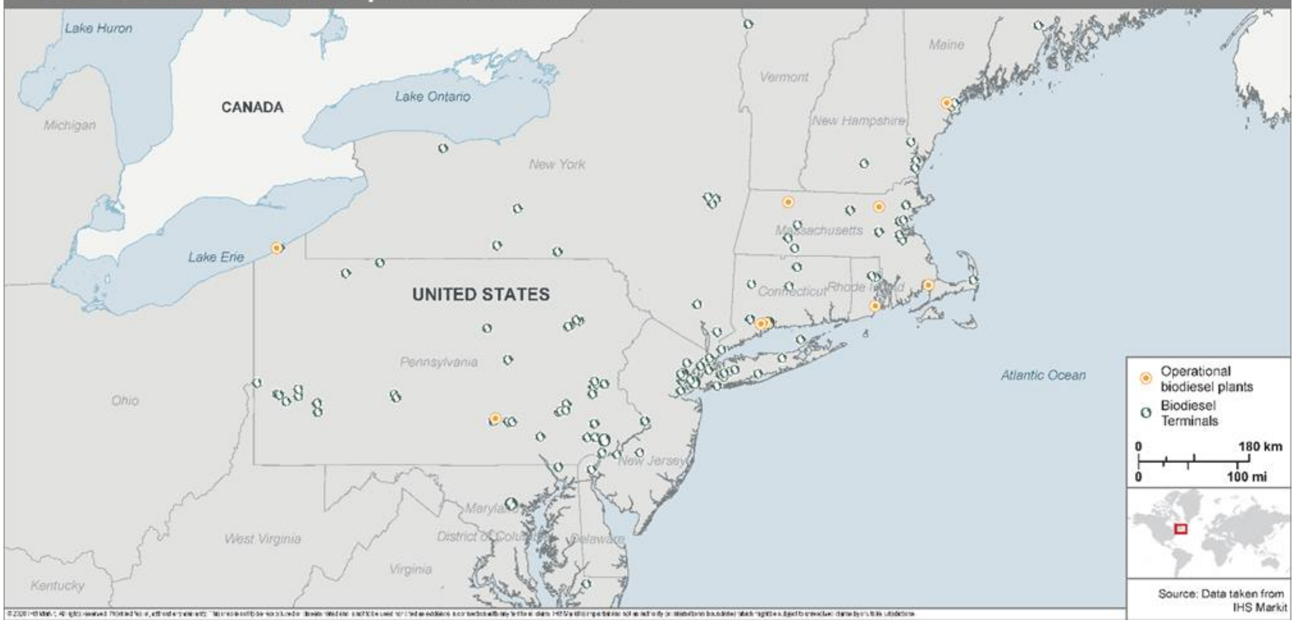
Demand uncertainty has been a major disincentive for biodiesel related investment and stymied further development of terminal and rail infrastructure that are capable of handling higher blends. The uncertainty has been the result of:

- Low and/or volatile oil prices
- Differing market drivers in the biofuels feedstocks and crude oil markets
- Policy unreliability – the intermittency of the BTC
- Internal subsidization of biodiesel which led to the unfair trade practice case with Argentina.

Based on the historic markets and experience in other markets/jurisdictions (CA LCFS, US ethanol), it is likely that stable policy framework, potentially including incentives, will be necessary to have biodiesel blends move to the levels desired by the industry and to satisfy the needs of the state's low carbon policies. If a stable policy framework is established with clear decarbonization or volume goals, logistics infrastructure and production capacity will be built. The cost of the added infrastructure will be part of the cost of supply and covered by the price of the product supplied to the end user.

Figure 15

PADD 1A and 1B biodiesel plants and terminals



There are nine biodiesel plants currently in operation and about 150 terminals capable of storing biodiesel blends across PADD 1a and 1b. The biodiesel plants amount to roughly 153 million gallons of production capacity and where known, the predominant feedstock is UCO. However, a shift to SBO is occurring in the region as a result of rising demand for UCO in renewable diesel to meet the CA LCFS. A predictable increase in SME demand, based on policy or some other enforceable framework, would reduce the risk for stakeholders to invest in capacity that would be able to grow with demand.

Due to the large difference in the size of the heating oil demand compared to gasoline, the infrastructure requirements for meeting B20 are only a fraction of the infrastructure required to supply 10 percent ethanol (E10) to the gasoline market in the New England and mid-Atlantic markets. The highest demand month for heating oil blended at B20 requires about one fifth of the volume of ethanol needed to meet E10. At B50, the biodiesel requirement is about half the amount of ethanol needed for E10.

Adding a product such as biodiesel in high volumes to heating oil would not be unprecedented. High blends of ethanol and the resulting distribution and storage system have been accommodated seamlessly throughout the country. From a transportation and storage capacity perspective, the logistics system went from supplying New England with almost no ethanol in 2003 to over 650 million gallons in 2010. In 2010, all ethanol supply was by rail from the US Midwest.

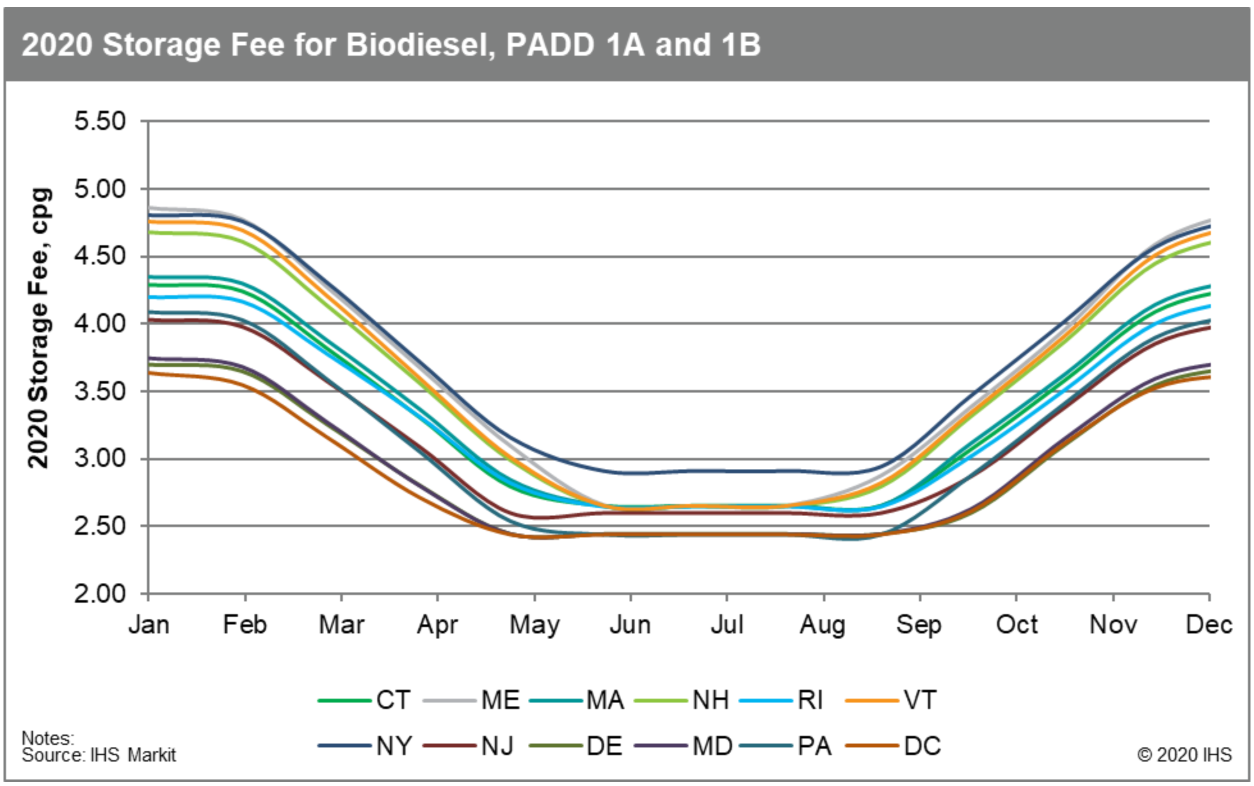
Nearly all of the ethanol supplied to New England and the mid-Atlantic markets is by rail from the Midcontinent which is also the likely major source of biodiesel. Ethanol is supplied to all distribution terminals that supply gasoline to the wholesale market.

The cost of fuel storage in the US East Coast is above the US average by approximately 18 percent (RCCI, 2020), and these higher costs apply to both storage and heating. A higher cloud point and cold filter plugging point of the fuel necessitates the use of heating during the colder months of the year, resulting in biodiesel storage costs being higher than that of other products (gasoline, jet fuel, and diesel).

The operating cost of biodiesel storage is higher than that for light petroleum products during the winter months. This heightened cost from heating can increase the cost of storage in some of the northernmost PADD 1a states. Figure 8 below shows the change in heated storages costs for PADD 1a and PADD 1b over an annual seasonal cycle. The cost of heating in the US East Coast is approximately $0.02/bbl/ºF/month (IHSM, 2019).

During the summer months between May and September, the storage cost of biodiesel falls to parity with the light petroleum products, at approximately $1.10/bbl/month. During the winter months between December and February, at below 30˚F, heating increases storage costs by $0.80/bbl/month to $1.00/bbl/month, leading the storage cost of biodiesel in PADD 1 states with the lowest average winter temperatures to spike to $2.00/bbl/month. Heated storage will thus increase the operating costs of terminals when more biodiesel or higher biodiesel blends are stored.

Figure 16



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