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December 3, 2020

VIA E-MAIL
Angelika.Stewart@dec.ny.gov

Angelika Stewart
New York State Department of
Environmental Conservation
Division of Environmental Permits, Region 4
1130 North Westcott Road
Schenectady, NY 12306-2014

RE: Request for Additional Information Related to the 2019 Climate Leadership and Community Protection Act
Global Companies, Albany Terminal
Air Title V Permit Application
DEC #4-0101-00112/00029
City of Albany, Albany County

Dear Ms. Stewart:

Global Companies LLC (Global or Applicant) is submitting this letter in response to DEC's September 11, 2020 Request for Additional Information concerning Global's application to renew and modify its existing Title V air permit for the Albany Terminal (hereinafter "Secord RFAI"). This letter focuses solely on the section of the request entitled "Greenhouse Gas Emission Reduction Consistency Analysis." In the request, DEC asks Global to expand upon its analysis of the consistency of the proposed modification as it relates to the goals of the 2019 Climate Leadership and Community Protection Act (CLCPA), as set forth in Global's July 7, 2020 response to DEC's first Request for Additional Information, dated May 19, 2020 (hereinafter "First RFAI"). The remainder of the response to DEC's Second RFAI will be addressed in a separate submission.

In brief, Global has proposed the following modifications to its Albany Terminal as set forth in its Title V permit renewal/modification application: (1) reduce allowable crude oil throughput from 1,850 to 450 million gallons (a 1,400 million gallon reduction, or about 75%) while reducing overall product throughput at the Terminal by 950 million gallons (a 27% reduction); (2) install exempt natural gas-fired boilers/heaters to enable the Terminal to manage biodiesel; (3) accept stricter emission limits on several of the Terminal's existing air pollution controls and install a new vacuum assist system ("vac assist") to reduce, if not eliminate, fugitive emissions at the railcar loading rack; (4) reconfigure the Terminal's existing throughput caps to enable the Terminal to better respond to market demand; and (5) add loading arms at the truck and railcar loading racks to reduce unnecessary truck idling and railcar movement, respectively (collectively, the "Project").

The First RFAI asked Global to assess the consistency of the Project with the CLCPA, which is codified primarily at New York Environmental Conservation Law (ECL) Article 75. In response, Global focused its analysis on the biodiesel handling and storage aspect of the Project because the boilers/heaters required to manage biodiesel are the only significant source of greenhouse gas (GHG) emissions associated with the Project. The First RFAI response described the biodiesel component of the Project in greater detail; summarized the federal and state programs intended to encourage the use of biodiesel, a low-carbon fuel; described the GHG emissions associated with the biodiesel component of the Project; and explained that the biodiesel component of the Project facilitates the management of biodiesel and is therefore consistent with the goals of the CLCPA.

In the Second RFAI, DEC has expanded on its request for information relevant to the consistency analysis. Global submits this second response, as it did the first response, without the benefit of final CLCPA regulations or Department-wide guidance on implementation of the CLCPA prior to the adoption of regulations. Key information sought by the Second RFAI is discussed below. The expanded analysis shows that the changes Global is proposing support the State of New York's GHG reduction goals. Global's proposed Project aligns with the State's objectives in the following ways:

- Global will voluntarily reduce its total product throughput cap by 27% and reduce its crude oil throughput cap by 75%, which is consistent with the State's goal of reducing reliance on fossil fuel and decreasing GHG emissions.
- Global will enhance its ability to manage biodiesel, a fuel that is key to the transition away from fossil fuel and reduces overall GHG emissions.

In order to manage biodiesel, Global will need to install natural gas-fired boilers and heaters to heat biodiesel so it will flow in colder weather. No other products, including crude oil, will be heated. The biodiesel component of the Project (which includes the boilers/heaters required to manage the biodiesel) will result in a significant reduction in overall GHG emissions based on the lifecycle GHG emission reductions associated with the substitution of biodiesel for petroleum diesel and is consistent with the CLCPA goal of reducing GHG emissions 40% below 1990 levels by 2030. The more biodiesel the Terminal handles, the greater the benefits of the Project from a climate change perspective.

Allowable GHG Emissions Before and After the Project (Excluding New Boilers/Heaters Required to Manage Biodiesel)

As set forth in greater detail in Global's First RFAI response, the Albany Terminal essentially functions as a fuel warehouse. Fuel is purchased from one location, stored at the Terminal and then shipped in bulk to entities who may either use it themselves or sell it to a third-party consumer. In the case of heating oil, the fuel may be burned by a residential, commercial or industrial source in the state or eventually consumed out of state. Likewise, gasoline shipped from the Terminal may eventually be sold and consumed either in state or out of state. The Global Terminal functions as a conduit for product, providing a link between the producer and the end-user. In this way, the Terminal is no different from a traditional wholesale distribution center, which collects products from various producers and then ships them to other wholesalers and/or retailers.

In determining the carbon dioxide equivalent (CO_2e) emissions from the Project, the Second RFAI asks Global to consider the impacts of the 27% reduction in overall allowable throughput at the Terminal from 3.329 million gallons to 2.379 million gallons as well as the impact of the Project's reduction in crude oil throughput from 1,850 million gallons to 450 million gallons. In essence, DEC is asking Global to quantify the potential GHG emissions associated with the storage and distribution of product throughput at the Terminal before and after the requested Title V permit modification is approved. These emissions include GHG emissions associated with day-to-day operation of the Terminal, in particular, carbon dioxide (CO_2) emissions associated with existing on-site fuel handling operations, etc.

The CLCPA regulates six pollutants as GHGs: CO_2, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons, and sulfur hexafluoride and assigns each GHG a CO_2 equivalent. The Terminal does not emit perfluorocarbons, hydrofluorocarbons, and sulfur hexafluoride. Accordingly, these GHGs are not addressed in the analysis.

As discussed in greater detail below, total GHG emissions from the Terminal are relatively low. These emissions originate almost exclusively from two sources—operation of the Terminal vapor combustion units (VCUs), which are used to control emissions of volatile organic compounds such as benzene associated with the Terminal's loading activities and—to a much lesser extent—miscellaneous small combustion equipment (e.g., office, garage and other similar boilers). The estimated emissions relating to the Project are set forth below.[1] All emissions are measured in tons per year (tpy). Information about how the emissions below were calculated can be found in Attachment A, which includes the Potential to Emit (PTE) for the Terminal's combustion sources.

Current Potential Emissions (based on allowable throughput):
CO_2: 18,338.9 tpy
Methane: 0.34 tpy
Nitrous Oxide: 0.35 tpy
Total CO_2e: 18,450.5 tpy

Future Potential Emissions (based on proposed allowable throughput excluding new boilers and heaters):
CO_2: 16,656.7 tpy
Methane: 0.32 tpy
Nitrous Oxide: 0.30 tpy
Total CO_2e: 16,755.7 tpy

[1] These numbers do not include emissions from the existing small boilers/furnaces used primarily to heat various parts of the Terminal (e.g., office, garage, water treatment building). The activities associated with this equipment—which have the potential to emit approximately 544.41 tons per year of CO_2e—will not change in any way as a result of the Project and so should not be considered in assessing the consistency of the Project with the CLCPA.

As set forth above and in Attachment A, the reduction in allowable Terminal throughput and other "non-boiler/heater" components of the Project reduce GHG emissions by approximately 1,694.8 tpy.[2]

GHG Emissions Associated with New Boilers/Heaters Required to Manage Biodiesel

The production and use of biofuel is encouraged by both federal and state programs, in large part because of its climate change benefits. As discussed in the response to the First RFAI, fuel producers and importers are regulated under EPA's Renewable Fuel Standards (RFS) program, which requires them to include increasing amounts of comparatively climate-friendly fuels, such as biodiesel, in transportation and other fuels, including home heating oil. In deciding whether a particular fuel qualifies as renewable fuel, advanced biofuel, biomass-based diesel, or cellulosic biofuel under the RFS program, EPA must conduct an analysis of the lifecycle GHG emissions associated with the fuel to determine whether the fuel meets the threshold in the statute for the fuel type. To qualify as biomass-based diesel under the RFS program, the producer/importer must show that the particular type of diesel fuel has lifecycle GHG emissions that are at least 50% lower than comparable petroleum diesel and meets other criteria spelled out in the RFS regulations. To qualify generally as "renewable fuel," the fuel must have lifecycle GHG emissions that are at least 20% less than the baseline fuel it replaces and meet other criteria spelled out in the regulations. See 40 CFR § 80.1401 for the relevant definitions. See the First RFAI response for additional information about the RFS program as it relates to the Global Project.

New York State and New York City have adopted laws requiring the inclusion of biodiesel in home heating oil in the downstate area. Other nearby states, including Massachusetts and Rhode Island, also have adopted laws encouraging the use of biodiesel. Global has played a key role in the distribution of biodiesel in the Northeast for many years. As the focus of many states shifts to increasing the use of biodiesel, Global has expanded the availability of biodiesel within its terminal network and continues to look for additional opportunities to facilitate greater use of biodiesel consistent with the various statutory mandates. Global is currently working with the United States Department of Agriculture under the Higher Blends Infrastructure Incentive Program (HBIIP). The HBIIP is designed to expand the sale and use of ethanol and biodiesel fuels by providing financial incentives to fuel suppliers to purchase equipment and make other changes designed to facilitate the management of renewable fuels. Global's current plan is to install biodiesel infrastructure not only at the Albany Terminal, but at several other terminals within New York and the Northeast states to increase the availability of biodiesel.

Heating oil will remain a key component of the energy landscape in the Northeast for the foreseeable future. According to the U.S. Energy Information Administration, in 2018

[2] The Second RFAI requests that Global use the emission factors in 40 CFR Part 98 to calculate GHG emissions from the Project. However, petroleum terminals are not among sources covered by EPA's GHG reporting program. Moreover, as set forth below, the key issue for purposes of assessing the GHG impact of the Project are the GHG benefits of biodiesel relative to the "costs" (i.e., GHG emissions) associated with operating the boiler/heaters needed to manage the biodiesel on-site. For purposes of that analysis, Global has relied on emission factors established under the Renewable Fuel Standards program, which more accurately reflect the relative merits of petroleum versus bio-based fuels on a lifecycle basis.

approximately 5.5 million households in the United States used heating oil as their main heating source, about 82% of which are located in the Northeast. Not surprisingly, New York is ranked first among the Northeastern states in residential heating oil consumption.[3] Accordingly, it is crucial to find ways to "decarbonize" heating oil until the homes that rely on it for heat can transition to another heating source. Biodiesel is a pathway to lowering the carbon footprint of heating oil and achieving the short-term goals of the CLCPA. To manage biodiesel in the cold climate of the Northeast, the fuel must be stored and heated.

In the Second RFAI, DEC asked for additional information about the GHG emission impacts of managing biodiesel at the Terminal. In particular, DEC asked about the status of the biodiesel managed by Global under the RFS program (in particular, whether Global's biodiesel meets the 50% threshold for biomass-based diesel), Global currently stores and distributes biodiesel blends within its terminal network which only contain biodiesel that qualifies as "biomass-based diesel" under the RFS program.[4] This biodiesel emits a *minimum* of 50% less lifecycle GHGs than the petroleum diesel it replaces. In fact, certain biodiesel fuels that qualify as biomass-based diesel achieve lifecycle GHG emission reductions relative to petroleum diesel that exceed the 50% reduction threshold. To be conservative for purposes of the CLCPA analysis, however, Global has assumed that the biodiesel it will manage using the boilers/heaters meets the less stringent 20% threshold for renewable fuels.

A review of the lifecycle GHG emissions associated with petroleum versus biodiesel shows that the comparatively modest potential GHG emissions associated with operating the natural gas-fired boilers/heaters needed to manage the biodiesel will be more than offset by the GHG benefits of switching from petroleum to biomass-based diesel even if it is assumed that the biofuel meets only the 20% lifecycle reduction threshold for renewable fuel.

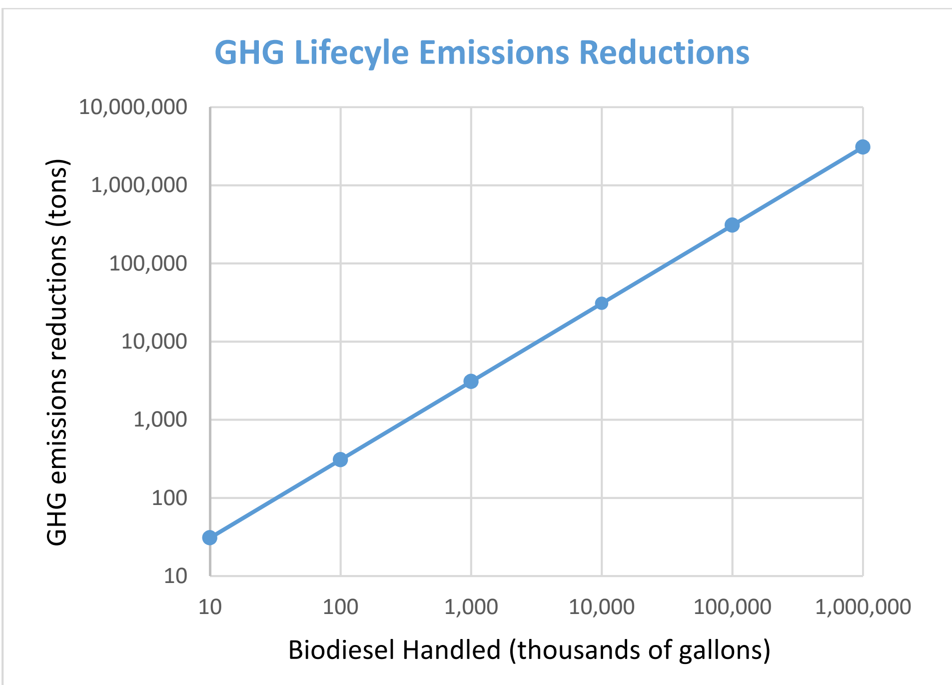
Per the Second RFAI, the CLCPA requires DEC—in considering Global's application to significantly reduce product throughput and install boilers/heaters to manage biodiesel—to confirm whether its decision on the application will be inconsistent with or interfere with the attainment of the Act's statewide GHG emission reduction limits. These limits—which were recently proposed by DEC—quantify the CLCPA's goal of reducing GHG emissions 40% below 1990 levels by 2030. To answer this inquiry, Global compared the GHG benefits associated with swapping biodiesel for petroleum diesel (i.e., distillate) with the additional GHG emissions associated with the combustion of the natural gas used to fuel the boilers/heaters needed to manage the biodiesel at the Terminal. As previously noted, although Global currently handles only biodiesel that meets the 50% minimum threshold for biomass-based diesel, Global conducted its analysis using the 20% threshold for renewable fuels. In other words, Global calculated the GHG emission benefits associated with biodiesel assuming a 20% reduction from the lifecycle GHG emissions of distillate fuel. The emission factor for the lifecycle GHG emissions of distillate was

[3] https://www.eia.gov/energyexplained/heating-oil/use-of-heating-oil.php.

[4] In particular, Global either buys biodiesel with biomass-based diesel renewable identification numbers (RINs) already attached or acquires biomass-based diesel RINs in the marketplace after the biodiesel has been purchased. In either case, the biodiesel acquired by Global is backed by RINs that satisfy the requirements for biomass-based diesel under the RFS program.

taken from the EPA summary of the lifecycle GHG analyses that EPA undertook for the RFS program. On a per gallon basis, each gallon of biodiesel loaded emits approximately 6 lbs. of lifecycle CO_2e emissions less than petroleum distillate assuming the biodiesel is regulated only as renewable fuel (i.e., is subject to the 20% threshold under the RFS program). Obviously, the GHG benefit is much greater for biodiesel that is classified as biomass-based diesel and subject to the 50% reduction threshold. Relevant calculations are included as Attachment B. The example provided in Attachment B shows that Global would need to replace approximately 12,742,280 gallons of diesel with biodiesel to achieve emission reductions of CO_2e equivalent to a 40% reduction from pre-Project baseline emissions. Attachment B also clearly shows that the potential GHG emissions associated with operating the boilers/heaters at full capacity are more than outweighed by the GHG benefits of burning biodiesel rather than petroleum diesel.

The graph below illustrates the relationship between GHG emissions from the boilers/ heaters needed to manage biodiesel at the Terminal and the GHG benefits associated with biodiesel versus petroleum diesel. A value was created by dividing the 27,784 tons of GHG emissions from the boilers/heaters by the maximum volume of biodiesel product that can be managed at the Terminal (about 300 million gallons). The boiler/heater GHG emissions were then deducted from the lifecycle GHG emission reductions to obtain an estimate of the per gallon GHG benefits of biodiesel relative to petroleum diesel taking the boiler/heater emissions into account. The results were then plotted for different levels of biodiesel product.



The information provided clearly shows that the Project will have a significant climate change benefit since it will enable the Terminal to manage fuel with much lower lifecycle CO_2e emissions and that these benefits more than outweigh the additional emissions associated with operating the boilers/heaters needed to manage those fuels.

It is worth noting that requiring Global to conduct a CLCPA analysis effectively penalizes the company for seeking approval of all components of the current Project as one Title V permit modification. Because the boilers/heaters associated with the biodiesel component of the Project are exempt from permitting under Title V, Global could have installed them without seeking DEC approval, and without triggering review under the CLCPA. Because Global is presenting the entire Project to DEC as a single "package," it is compelled to conduct a CLCPA analysis that may not otherwise have been required owing to the GHG emission reductions associated with the remainder of the Project.

Emissions Associated with Extraction/Transmission of Electricity and Fuels Imported Into State

The Second RFAI states that "The Department must consider GHGs emissions produced within the state from the project and GHGs emissions resulting from the project that are produced outside of the state that are associated with the generation of electricity imported into the state or the extraction and transmission of fossil fuels imported into the state." The statement presumably originates from the CLCPA, which defines "statewide greenhouse gas emissions" as "the total annual emissions of greenhouse gases produced within the state from anthropogenic sources and greenhouse gases produced outside of the state that are associated with the generation of electricity imported into the state and the extraction and transmission of fossil fuels imported into the state. . . . " ECL § 75-0101.13. DEC's decision to include the reference to imports in the Second RFAI suggests that they want Global to quantify out-of-state emissions associated with "imported" electricity and fuels relating to the Project in its CLCPA consistency analysis. Assuming this interpretation of the Second RFAI is correct, this request raises several concerns. First, while the statute speaks generally about the need for the *state* to consider GHG emissions associated with "imports," it does not clearly specify how *sources* are expected to address those emissions. Second, the request could be interpreted as requiring Global to quantify emissions associated with the extraction and transmission of all fuels it "imports" into the State not just those Global consumes, which raises significant concerns.

The discussion of the need to account for electricity and fuel "imports" appears in just two sections of the CLCPA—the definition of "statewide greenhouse gas emissions" quoted above and the discussion of the Statewide Greenhouse Gas Emission Report in ECL § 75-0105.3. Nowhere in the CLCPA does the law specifically require *sources* to supply that information, let alone make them responsible for considering those emissions in assessing the consistency of projects with the CLCPA. Likewise, the recent rulemaking proposing GHG emission limits under the CLCPA addresses only GHG emissions from "imported" electricity and fuels statewide. The rulemaking does not discuss how such emissions are to be addressed with respect to individual facilities/projects. Absent clear regulatory direction, Global should not be required to take emissions associated with these imports into account in assessing the consistency of the Project with the CLCPA. To the extent in-state sources are expected to quantify GHG emissions associated with "imports," the obligation should fall on the electricity/natural gas supplier not the consumer.

The challenge with making sources responsible for quantifying GHG emissions associated with imports is most obvious in the case of imported electricity. An electricity purchaser, such as Global, has no way to determine whether the electricity it uses was generated in-state or imported from out-of-state. Absent such information, electricity purchasers, such as Global, cannot be responsible for considering imported electricity as part of their project-specific CLCPA consistency analyses.

Although the issues relating to natural gas are slightly different, the conclusion is the same. In the case of natural gas, the product is combusted by the consumer. As a result, the consumer—in this case, Global—can reasonably be expected to account for its own direct emissions in assessing its activities under the CLCPA. However, while the consumer can control its own, direct GHG emissions (by operating less, installing more fuel efficient equipment, etc.), it has no control over emissions associated with its extraction and transmission. Accordingly, it should not be accountable for those emissions for purposes of assessing the consistency of a project with the CLCPA.

Another concern with the Second RFAI is that the mention of imported electricity and fuel arguably could be interpreted as requiring Global to quantify the extraction and transmission emissions associated with all the fuel it "imports" into New York State for management at the Terminal not just the fuel it actually combusts on-site. However, DEC's recent rulemaking clarifies that the requirement in ECL § 75-0101 to include emissions associated with the extraction and transmission of fuels imported into the State is limited to fuels consumed in the State. In August, DEC proposed regulations setting statewide GHG emission limits for 2030 and 2050 as required by the Act. The limits include both GHGs produced outside the state that are associated with the generation of electricity imported into the state and those associated with the extraction and transmission of fossil fuels imported into the state. The Regulatory Impact Statement (RIS) accompanying the rulemaking makes clear that the requirement to quantify the GHG emissions associated with fuel imports is limited to fuels imported *and consumed* in the State. For example, the RIS specifies that statewide GHG emissions include "certain sources that are located outside of the state that are associated with *in-state energy consumption*" (emphasis added). Likewise, the discussion of lifecycle or out-of-state emissions refers to "upstream emissions associated with *in-state energy demand and consumption*" (emphasis added). Global does not consume the fuel it imports nor can it say for certain where the fuels it manages are finally consumed (i.e., whether they are consumed in-state or out-of-state). In light of these considerations, Global should not be required to quantify emissions associated with the fuel it "imports" into the State.

Overall Project GHG Consistency Analysis

The Project is consistent with the goals of the CLCPA.

- The Project will reduce allowable crude oil throughput at the Terminal by 1,400 million gallons (75%). This change is consistent with the CLCPA goal of reducing reliance on fossil fuels.
- The Project will reduce overall allowable throughput at the Terminal by 950 million gallons (27%). This change is consistent with the CLCPA goal of reducing reliance on fossil fuels.
- The 950 million gallon reduction in overall Terminal throughput reduces allowable emissions associated with the actual on-site management of product at the Terminal, in particular, the emissions associated with the operation of the VCUs used to limit emissions of benzene and other volatile organic compounds at the Terminal.

- The change in the Terminal's throughput caps will improve operational flexibility as well as Global's ability to respond quickly to changes in the fuel market, many of which will be driven by efforts to implement the CLCPA and handle low-carbon fuels. The CLCPA can be expected to change the mix of fuels available in the marketplace. For example, the goal of reducing GHG emissions may lead to a switch from petroleum to biodiesel. The change in the throughput caps will facilitate achievement of that goal.
- The emission increases from the Project are due *solely* to operation of the boilers/heaters needed to manage biodiesel. As set forth above, the climate benefits associated with managing biodiesel more than outweigh the costs in terms of emissions from the natural gas-fired boilers/heaters needed to manage the biodiesel, even under the conservative assumption that the biodiesel only meets the standard for renewable fuel not the stricter standard for biomass-based diesel. The emission reductions associated with the management of biodiesel are consistent with the CLCPA goal of reducing GHG emissions 40% below 1990 levels by 2030.

Options for Further Reducing GHG Emissions

The Second RFAI asks Global to "discuss whether and in what manner new GHG emissions from the project or any other GHG emissions associated with current operations at the Albany Terminal can be further reduced, such as the use of alternate fuels, electricity, etc. If there are no technologically and economically feasible methods of further reducing GHG emissions, please confirm the same and provide an explanation."

Options for reducing GHG emissions from the Project are limited.

- As noted above, the only increase in GHG emissions associated with the Project is due to the boilers/heaters required to manage biodiesel. These boilers are proposed to be fired using natural gas. Global has investigated the option of installing electric heating in place of the planned natural gas-fired boilers and has determined that electrically heating the tanks is infeasible because electrical heaters cannot supply the energy necessary to adequately heat the product in tanks of the size and diameter of those at the Terminal.
- The vast majority of the GHG emissions relating to current Terminal operations are linked to operation of the VCUs. The VCUs reduce emissions of VOCs, such as benzene, from the Terminal and ensure that the marine loading operations comply with Coast Guard requirements relating to explosion prevention.
- The changes intended to improve operational flexibility (in particular, the replacement of product/loading rack-specific caps with facility-wide caps) do not require Global to purchase new equipment or modify existing equipment. Accordingly, this aspect of the Project provides limited opportunities for Global to implement alternatives to reduce GHG emissions.

DEC has also asked whether "GHG emissions associated with current operations at the Albany Terminal can be further reduced." The Title V permit review process for a modification is limited to an assessment of the emissions implications of the Project. DEC does not require the Applicant to review facility operations that are unaffected by the proposed changes.

The enactment of the CLCPA does not change the scope of the Title V decision-making process. Although the CLCPA may require assessments of GHG emissions from the facility as a whole after implementing regulations are promulgated, no such obligation exists now. CLCPA § 7.2 addressing permits and approvals requires agencies in considering and issuing permits to "consider whether such *decisions* are inconsistent with or will interfere with the attainment of the statewide greenhouse gas emission limits" (emphasis added). The *decision* in this case, is whether to grant Global's Title V permit modification request. Accordingly, the focus must be on those aspects of the modification that have the potential to negatively impact GHG emissions. Global should not now be required to assess GHG reduction options for the entire facility simply because it is seeking permission to make physical changes to small portions of its relatively small Terminal.[5]

Moreover, as noted above, the vast majority of emissions from the Terminal are linked to the operation of the VCUs and proposed boilers/heaters. The remaining combustion equipment at the Terminal is small and emits very little GHGs. As a result, the remaining equipment does not offer opportunities for significant GHG emission reductions.

GHG Mitigation Measures

For the reasons set forth above, the Project is consistent with the GHG emission limits set forth in the CLCPA. Accordingly, no mitigation measures are necessary.

De Minimis Nature of GHG Emissions Associated with the Proposed Project

In the Second RFAI, DEC declares that "neither the Climate Act nor any state regulatory authority presently identifies any specific thresholds for new or modified sources of GHG emissions for the applicability of the Climate Act's statewide GHG emissions limits." While this statement is technically correct, ECL § 75-0103.14(c) specifically authorizes the New York State Climate Action Council to "[t]ake into account the relative contribution of each source or source category to statewide greenhouse gas emissions, and the potential for adverse effects on small businesses, and recommend a de minimis threshold of greenhouse gas emissions below which emission reduction requirements will not apply." This provision reflects a recognition by the Legislature that not all GHG emitting sources should be treated equally and that the Legislature expects the Council to take the quantity of GHG emissions into account when deciding how to treat particular sources or source categories under the CLCPA. Those same considerations should govern DEC's review of individual projects pending full implementation of the CLCPA.

As reported in Global's response to the First RFAI, Global estimates actual emissions from the boilers/heaters needed to manage biodiesel at only 6,950 tons or 6,305 metric tons. By way of

[5] In theory, Global's request to reduce its throughput and reconfigure its throughput caps implicates the entire Terminal in the proposed Title V permit modification. However, it makes no sense to require Global to evaluate alternatives for reducing GHG emissions associated with its entire operation simply because it is proposing a change (a significant reduction in total allowable throughput) that provides a climate change benefit and does not require any changes to existing equipment or the purchase of new equipment.

comparison, the Astoria Generating Station in Queens reported 726,414 CO_2e metric tons of GHG emissions in 2018 under EPA's GHG reporting program (40 CFR Part 98). As this comparison shows, the Global Albany Terminal is a comparatively small source of GHG emissions. In determining what type of submission is required to demonstrate consistency with the CLCPA, DEC must consider the relative contribution of the source to the State's GHG emissions.

Conclusion

From a GHG perspective, the Project is comprised of two basic components: the installation of natural gas-fired boilers/heaters to enable the Terminal to manage biodiesel and the remainder of the Project, which includes reductions in crude oil and total product throughput, installation of a new vac assist system to control fugitive emissions from the railcar loading rack, reconfiguration of the Terminal product caps, and installation of additional loading positions. The 75% reduction in allowable crude oil throughput and 27% reduction in allowable total product throughput is consistent with the basic goal of minimizing fossil fuel use in the State. Moreover, as discussed above, the "non-biodiesel" components of the Project reduce possible GHG emissions associated with Terminal operations by reducing allowable product throughput. Although the boilers/heaters needed to manage biodiesel will emit GHGs, these emissions are more than outweighed by the lifecycle GHG benefits associated with biodiesel as compared to the petroleum diesel it replaces. Overall, the Project is consistent with the CLCPA goal of reducing GHG emissions 40% below 1990 levels by 2030.

Global hopes that this submission satisfies the Department's concerns regarding the consistency of its throughput reduction/biomass-based diesel Project with the goals of the CLCPA. If questions or concerns remain, Global would welcome the opportunity to discuss its approach to CLCPA consistency with Department staff in the hopes of resolving any outstanding issues and avoiding the need for multiple future submissions.

Many thanks for your attention to this matter. I look forward to hearing from you.

Very truly yours,

Tom Keefe
Vice President Environmental, Health & Safety

Attachments

ATTACHMENT A
Potential to Emit for Combustion Sources

Fuel Combustion Emissions

Existing Exempt Combustion Sources:

Unit ID	Product	Source	Gal/yr (Liquid)	SCF/yr (Gas)	Liters/year (Gas)	MMBTU/yr
NA	Distillate	Furnace	590			–
NA	Natural Gas	Boiler (water bldg)	–			54
NA	Natural Gas	Boiler (garage)	–			22
NA	Natural Gas	Boiler (office)	–			163
NA	Natural Gas	Furnace	–			120

Proposed Exempt Combustion Sources:

Unit ID	Product	Source	Gal/yr (Liquid)	SCF/yr (Gas)	Liters/year (Gas)	MMBTU/yr
NA	Natural Gas	Heater (line trace)	–			35,040
NA	Natural Gas	Boiler (line trace)	–			35,040
NA	Natural Gas	Boiler (tanks)	–			52,560
NA	Natural Gas	Boiler (lube bldg)	–			86,724
NA	Natural Gas	Boiler (lube bldg)	–			86,724
NA	Natural Gas	Boiler (lube bldg)	–			86,724
NA	Natural Gas	Boiler (lube bldg)	–			86,724

Existing Non-Exempt Combustion Sources:

VCUML/VCUM2/VCURR*	Natural Gas	VCU	–			150,000

*Includes natural gas used as assist gas for both marine VCUs (VCUML and VCUM2) and the rail VCU (VCURR)

Distillate Combustion Emissions:

	Combustion Emissions								
Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG**
Emission Factor - lb/1000 gal*	2.00	0.21	20.00	0.20	5.00	0.22	0.26	2.2E+04	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	1.18	0.13	11.80	0.12	2.95	0.13	0.15	13157.00	13,205.90
tons/yr	0.00	0.00	0.01	0.00	0.00	0.00	0.00	6.58	6.60

* Emission factors used to estimate emissions are from AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I. SOx, Nox, CO, and PM Emission Factors are from Table 1.3-1. VOC and CH4 Emission Factors are from Table 1.3-3. CO2 Emission Factor is from Table 1.3-12. N2O Emission Factor is from Table 1.3-8.

** GHG Emission calculated by using the CO2 Equivalency Factor for CO2 (1), CH4 (25), and N2O (298)

Example calculation (using SOx):
= gal/yr / 1000 gal * Emission Factor
= 590 gal/yr / 1000 gal * 52.54 lb/1000 gal (SOx)
= 31.00 lb/yr

Natural Gas Combustion Emissions (from existing sources)*:

	Combustion Emissions								
Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG***
Emission Factor - lb / MM BTU**	0.0075	0.00059	0.098	0.0054	0.082	0.002	0.002	117.647	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	1,120.32	88.45	14,741.08	810.76	12,382.51	339.04	324.30	17,689,294.12	17,794,412.75
tons/yr	0.56	0.04	7.37	0.41	6.19	0.17	0.16	8,844.65	8,897.21

*Total emissions from natural gas combustion from existing sources include emissions from the combustion of natural gas in furnaces and boilers and emissions from the combustion of natural gas used as assist gas in the VCUs.

** Emission factors used to estimate emissions are from AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I, Tables 1.4-1, 1.4-2, and 1.4-3, except for GHG.

*** GHG Emission calculated by using the CO2 Equivalency Factor for CO2 (1), CH4 (25), and N2O (298)

Total Natural Gas Used 150,359 MMBTU/yr

Example Calculation (using SOx):
= Total Natural Gas Used * Emission Factor
= Total Natural Gas Used (150,359) MMBTU/yr * 0.00059 lb / MM BTU
= 117.86 lb/yr

Natural Gas Combustion Emissions (from proposed sources)*:

	Combustion Emissions								
Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG***
Emission Factor - lb / MM BTU**	0.0075	0.00059	0.098	0.0054	0.082	0.002	0.002	117.647	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	3,498.50	276.20	46,032.94	2,531.81	38,667.67	1,058.76	1,012.72	55,239,529.41	55,567,790.32
tons/yr	1.75	0.14	23.02	1.27	19.33	0.53	0.51	27,619.76	27,783.90

*Total emissions from natural gas combustion from proposed sources include emissions from the combustion of natural gas in proposed boilers.

** Emission factors used to estimate emissions are from AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I, Tables 1.4-1, 1.4-2, and 1.4-3, except for GHG.

*** GHG Emission calculated by using the CO2 Equivalency Factor for CO2 (1), CH4 (25), and N2O (298)

Total Natural Gas Used 469536.00 MMBTU/yr

Example Calculation (using SOx):
= Total Natural Gas Used * Emission Factor
= Total Natural Gas Used (469,536) MMBTU/yr * 0.00059 lb / MM BTU
= 276.2 lb/yr

VCU Vapor Combustion Emissions
(Emissions from Combustion of Petroleum Product Loaded)

Petroleum Vapor Combusted (lbs):

6,216,821 Total
3,510,000 at VCUML (gasoline and ethanol loading) (See Marine Loading - Refined Product Calculations.)
809,804 at VCUM2 (crude loading) (See Marine Loading - Crude Oil Calculations.)
1,897,017 at VCURR (gasoline loading) (See Rail Loading - Refined Product Calculations.)

Conversion from Petroleum Vapor Combusted in lbs to MMSCF (as Natural Gas Equivalent):

MMSCF (as Natural Gas) = Petroleum Vapor Combusted (lbs) * (21,000 BTUs / lb gasoline (high avg. for C4-C8 gases)(/ (1000 BTU/SCF) / (1,000,000)
MMSCF (as Natural Gas) combusted at VCUML = 74
MMSCF (as Natural Gas) combusted at VCUM2 = 17
MMSCF (as Natural Gas) combusted at VCURR = 40

Marine VCU Emissions from Gasoline & Ethanol Loading (Emission Unit VCUML):

	Combustion Emissions									
Pollutant	PM	PM10	SOx	NOx	VOC*	CH4	N2O	CO	CO2	GHG
Emission Factor - lbs / MM SCF**	7.60	7.60	197.47	150.00	NA	2.30	2.20	84.00	120,000.00	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	560.20	560.20	14,555.66	11,056.50	NA	169.53	162.16	6,191.64	8,845,200.00	8,897,762.60
tons/yr	0.28	0.28	7.28	5.53	NA	0.08	0.08	3.10	4,422.60	4,448.88

Marine VCU Emissions from Crude Oil Loading (Emission Unit VCUM2):

	Combustion Emissions									
Pollutant	PM	PM10	SOx	NOx	VOC*	CH4	N2O	CO	CO2	GHG
Emission Factor - lbs / MM SCF**	7.60	7.60	197.47	150.00	NA	2.30	2.20	84.00	120,000.00	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	129.24	129.24	3,358.19	2,550.88	NA	39.11	37.41	1,428.49	2,040,706.95	2,052,833.85
tons/yr	0.06	0.06	1.68	1.28	NA	0.02	0.02	0.71	1,020.35	1,026.42

Rail VCU Emissions from Gasoline & Ethanol Loading (Emission Unit VCURR):

	Combustion Emissions									
Pollutant	PM	PM10	SOx	NOx	VOC*	CH4	N2O	CO	CO2	GHG
Emission Factor - lbs / MM SCF**	7.60	7.60	197.47	150.00	NA	2.30	2.20	84.00	120,000.00	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	302.76	302.76	7,866.76	5,975.60	NA	91.63	87.64	3,346.34	4,780,482.47	4,808,890.49
tons/yr	0.15	0.15	3.93	2.99	NA	0.05	0.04	1.67	2,390.24	2,404.45

* These emissions are from gasoline and crude oil vapor combustion and pilot light gas. Gasoline and crude oil VOCs are already accounted for in the VCU emissions (i.e. 2 mg/l loaded or 98% efficiency).
** PM Emission Factor is from AP-42 (Table 1.4-2), as it is higher than the Emission Factor from the VCU manufacturer of zero (0). SOx Emission Factor is calculated as described below. NOx Emission Factor is from VCU manufacturer, as it is higher than the AP-42 Emission factor of 140 lbs/MMSCF (Table 1.4-1). CO Emission Factors is identical from VCU manufacturer and AP-42 (Table 1.4-1). CO2 Emission Factor is from AP-42 (Table 1.402). GHG Emission calculated by using the CO2 Equivalency Factor for CO2 (1), CH4 (25) and N2O (298)

Example calculation of SOx Emission Factor:

SOx Emission Factor = y_{H2S} * (1/C) * M_{SO2} * MW_{SO2} (Equation from EPA Emission Inventory Improvement Program (EIIP) Document Volume 3, Ch.10: Preferred & Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production & Procesing Operations, Sept. 1999, Pg 10.2-16.)

$y_{H2S,\ crude\ oil}$ = 0.001 (mole fraction of H2S in inlet gas (lb mole H2S/ lb mole) based on 10 ppm H2S liquid concentration)
C = 379.00 (molar volume of ideal gas at 60F and 1atm (scf/lb-mole))
M = 0.99 (molar conversion ratio from H2S to SO2 (lb-mole SO2/lb-mole H2S) (From VCU Manufacturer))
MW = 64.066 (molecular weight of SO2 (lb SO2/lb-mole SO2))

$EF_{SOX,crude\ oil}$ = 197.47 lb/ MMSCF

Total of Combustion Sources

Pollutant	PM	PM10	SOx	NOx	VOC	CH4	N2O	CO	CO2	GHG
lb/yr	5,612.21	992.20	26,145.38	80,368.81	3,342.69	1,698.20	1,624.40	62,019.60	88,608,369.95	89,134,895.90
tons/yr	2.81	0.50	13.07	40.18	1.67	0.85	0.81	31.01	44,304.18	44,567.45

Emergency Generators (Exempt)

Emergency Generator Sources:

Fuel Type	Source	Gal/hr (Liquid)	SCF/hr (Gas)	Gal/hr (Gas)	MMBTU/hr*
Propane	QT100 Generator	13.9			1.26
Propane	QT100 Generator	13.9			1.26
Natural Gas	20kw NG Generator		1,020		1.02
Diesel	500kw	26.1			
Diesel	350kw	18.5			
Diesel	350kw	18.5			

*Generac Spec Sheet states, "For BTU content multiply gal/hr x 90950 (LP) or ft3/hr x 1000 (NG)."

Distillate Fired Engine Emissions:

	Pollutant								
Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG**
Factor - lb/1000 gal*	2.00	0.21	20.00	0.20	5.00	0.22	0.26	2.2E+04	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	63.10	6.72	631.00	6.31	157.75	6.81	8.20	703,565.00	706,179.86
tons/yr	0.03	0.00	0.32	0.00	0.08	0.00	0.00	351.78	353.09

* Emission factors used to estimate emissions are from AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I. SOx, Nox, CO, and PM Emission Factors are from Table 1.3-1. VOC Emission Factor is from Table 1.3-3. CO2 Emission Factor is from Table 1.3-12.
** GHG Emission calculated by using the CO2 Equivalency Factors for CH4 (25), N2O (298) and CO2 (1).

Example calculation:
= gal/yr / 1000 gal * emission factor

Natural Gas & Propane Fired Engine Emissions:

	lbs Pollutant / MM BTU								
Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG**
Factor* - lb/MMBtu	0.0099	0.0006	2.270	0.0296	3.720	0.230	0.2	110.0	(CH4*25)+(N2O*298)+(CO2*1)
lb/yr	17.58	1.04	4,027.45	52.52	6,600.04	408.07	408.07	195,162.55	326,968.24
tons/yr	0.01	0.00	2.01	0.03	3.30	0.20	0.20	97.58	163.48

* Emission factors used to estimate emissions are from AP-42 Table 3.2-3. No emission factor was available for N2O so the CH4 emission factor was used.
** GHG Emission calculated by using the CO2 Equivalency Factors for CH4 (25), N2O (298) and CO2 (1).

Example Calculation of Natural Gas Usage
= Natural Gas Used 1,774 MMBTU/yr Assumes 500 hours/yr
= Natural Gas Used * Emission factor

Total of Generator Sources

Pollutant	PM	SOx	NOx	VOC	CO	CH4	N2O	CO2	GHG
lb/yr	80.68	7.76	4,658.45	58.83	6,757.79	414.88	416.27	898,727.55	1,033,148.10
tons/yr	0.04	0.00	2.33	0.03	3.38	0.21	0.21	449.36	516.57

EMISSIONS FROM MARINE LOADING OF REFINED PRODUCT (AS GASOLINE):

ALTERNATIVE OPERATING SCENARIO (OS#1) - MARINE LOADING AT 2 MG/L WITH VAC ASSIST

Throughput: 369 Mmgal

For combustion emissions assumed 900 Mmgal of throughput
Loading rack emissions (pounds) for combustion calcs: 3,510,000

Control Device Emission Rate: 2 mg/L equal to: 0.0167 lbs/1000 gallons

Loading into an Uncleaned Barge:

Emission Factor* (lb/1000 gal)	Throughput (Mmgal)	Loading Rack Emissions (lb/yr)	0% Remaining after 100% goes to VCU	100% to VCU	2 mg/L from VCU	Total Emissions (lbs)	Total Emissions (tons)
3.9000	369	1,439,100	0	1,439,100	6,159	6,159	3.08

* Emission Factor from Table 5.2-2 in AP-42 for an Uncleaned Barge previously loaded with a Volatile Liquid

Max Emissions Per Hour:

25,000 barrels / hr
1,050,000 gal / hr

Emission Factor* (lb/1000 gal)	Throughput (Mmgal)	Loading Rack Emissions (lb/hr)	0% Remaining after 100% goes to VCU	100% to VCU	2 mg/L from VCU	Total Emissions (lbs/hr)	Total Emissions (tons/hr)
3.9000	1.05	4095	0	4095	18	18	0.01

Throughput of gasoline at marine for emissions estimates is developed based on maximizing the project emission potential for PSD analysis.

NOTE: Loading emission calculations were performed in accordance with guidance in AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I.

EMISSIONS FROM MARINE LOADING OF CRUDE OIL:
ALTERNATIVE OPERATING SCENARIO (CRD#1) - MARINE LOADING AT 2 MG/L WITH VAC ASSIST

Throughput: 450 Mmgal

Control Device Emission Rate: 2 mg/L equal to: 0.0167 lbs/1000 gallons

Loading into an Uncleaned Barge:

Emission Factor* (lb/1000 gal)	Throughput (Mmgal)	Loading Rack Emissions (lb/yr)	0% Remaining after 100% goes to VCU	100% to VCU	2 mg/L from VCU	Total Emissions (lbs)	Total Emissions (tons)
1.7996	450	809,804	0	809,804	7,511	7,511	3.76

* Emission Factor calculated below, per AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I, Section 5.2, Equation 2.

Max Emissions Per Hour:

25,000 barrels / hr
1,050,000 gal / hr

Emission Factor CL (lb/1000 gal)	Throughput (Mmgal)	Loading Rack Emissions (lb/hr)	0% Remaining after 100% goes to VCU	100% to VCU	2 mg/L from VCU	Total Emissions (lbs/hr)	Total Emissions (tons/hr)
1.7996	1.05	1890	0	1890	18	18	0.01

Emission Factor Calculation from AP-42:

CL	=	Ca	+	Cg
1.7996		0.86		0.94

where:

CL = Total loading loss, lb/1,000 gal of crude oil loaded.
Ca = Arrival emission factor (from Table 5.2-3), contributed by vapors in the empty tank compartment before loading, lb/1,000 gal of crude oil loaded.
Cg = Calculated emission factor (from Equation 3), contributed by evaporation during loading, lb/1,000 gal loaded.

Cg Formula Inputs:

Vapor Pressure	12.5	(from Global data)
Molecular Weight	50	(from AP-42)
Vapor Growth Factor	1.02	(from AP-42)
Temperature *R	507.37	(from AP-42)

The calculated crude emission factor is lower than the gasoline emission factor of 3.9 lb/1000 gallons.

CRUDE ALTERNATIVE SCENARIOS (CRD#2 AND CRD#3) ASSUME SAME RATIOS AS GASOLINE SCENARIOS TO BE CONSERVATIVE.

NOTE: Loading emission calculations were performed in accordance with guidance in AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I.

RAIL LOADING OF REFINED PRODUCT - 2 MG/L WITH VAC ASSIST

Gasoline Throughput at the Rail (MM gal) **300.0**

VCU Emission Rating (mg/liter) **2**

(VCU Emission Rating is guaranteed by the manufacturer of the VCU and verified with a Performance Stack Test every 5 years.)

Tank-Truck Loss Factor (mg/liter) **0***

(EPA Approved Factor. Submerged Loading emission factor of 980 mg/L (AP-42, Compilation of Air Pollutant Emission Factors, 5th Ed., Vol. I, Table 5.2-5), multiplied by the leakage rate of 0.8% (AP-42, Compilation of Air Pollutant Emission Factors, 5th Ed., Vol. I))

Controlled gasoline Loading Losses (lb/yr) **5,007**

		Loading Losses 2mg/l		Tank-truck loss 8 mg/l		Total	
	Vapor Fraction	Lbs/Year	Tons/Yr.	Lbs/Year	Tons/Yr.	Lbs/Year	Tons/Yr.
Total VOC	100.00%	5,007	2.503	-	-	5,007	2.503
Benzene	0.41%	20	0.010	0	-	20	0.010
Ethylbenzene	0.14%	7	0.003	0	-	7	0.003
Hexane (-n)	3.96%	198	0.099	0	-	198	0.099
Iso-octane	0.63%	31	0.016	0	-	31	0.016
Toluene	0.87%	43	0.022	0	-	43	0.022
Xylene (-m)	0.67%	34	0.017	0	-	34	0.017
Naphthalene	0.05%	3	0.001	0	-	3	0.001
Methanol	1.18%	59	0.030	0	-	59	0.030
Total HAP Species*	7.90%	396	0.198	-	-	396	0.198
Non Hap VOC	92.10%	4,611	2.306	-	-	4,611	2.306
Total VOC		5,007	2.503	-	-	5,007	2.503
Total HAP		396	0.198	-	-	396	0.198
Largest Single HAP							
Hexane (-n)		198	0.099	-	-	198	0.099

* Tank-truck Loss Factor is 0 mg/L as a result of a Vacuum Assist System installed at the Truck Loading Rack.

Sample Calculations

Volume Of Gasoline Loaded (gallons)*3.785 litres/gallon*Overall Emission Rate (mg/liter)*2.2046 lbs/Kg*1 Kg / 1,000,000 mg = Emissions (lbs)

300,000,000 gal * 3.785 L/gal * (2 mg/L) * 2.2046 lbs/Kg * 1 Kg / 1,000,000 mg = Emissions (lbs)

Emissions (lbs) = 5006.6 lbs

Emission Factor (AP-42 equation 5.2-4 (1)), S = 0.6, MW = 66, VP = 6.6, T = 55deg Emission Factor = 6.32339 lb/1000 gal Emissions =(Emission Factor * Throughput * 1000)= 1,897,016.85 lb

Refined product is calculated as gasoline but includes all refined products 948.51 tons

NOTE: Loading emission calculations were performed in accordance with guidance in AP-42, Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I.

ATTACHMENT B
GHG Lifecycle Emission Reductions

ATTACHMENT B

Maximum potential biodiesel thruput at full boiler capacity
840,000 gal/day
306,600,000 gal/yr.

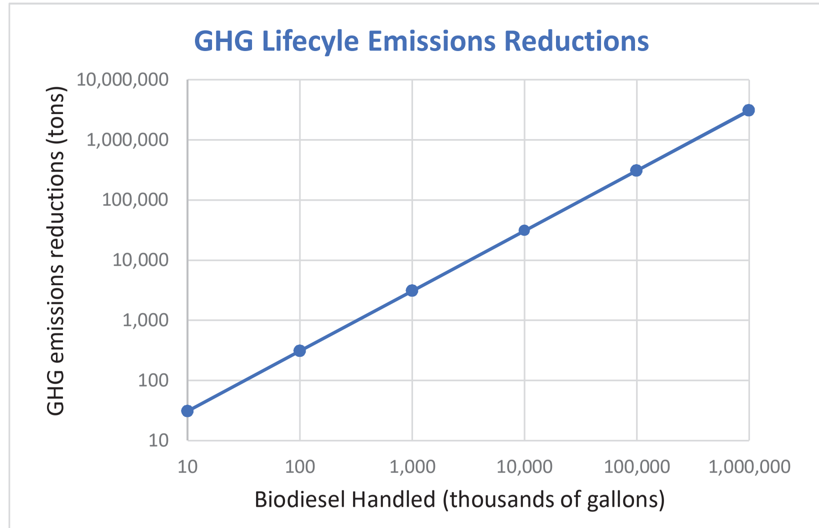
Boiler GHG potential to emit
27,784 tons CO2e
55,568,000 lbs. CO2e

Boiler GHG per gallon of biodiesel handled
0.181 lbCO2e/gal

Lifecycle emission factors

Diesel	29.876	lbCO2e / gal
Biodiesel	23.901	lbCO2e / gal
Lifecycle benefit	5.975	lbCO2e / gal

Per gallon benefit including boiler emissions
5.794 lbCO2e / gal



Gallons of Biodiesel Handled	Boiler GHG Emissions (tons)	Diesel GHG Emissions (tons)	Biodiesel GHG Emissions (20% reduction) (tons)	Overall GHG Reduction (Tons)
10,000	0.9	149	120	31
100,000	9.1	1,494	1,195	308
1,000,000	91	14,938	11,950	3,078
10,000,000	906	149,380	119,504	30,782
100,000,000	9,062	1,493,800	1,195,040	307,822
1,000,000,000	90,620	14,938,000	11,950,400	3,078,220