p.m. on the Thursday before Memorial Day (observed), and, if necessary due to inclement weather, from 2 p.m. through 7 p.m. on the Thursday following Memorial Day (observed).

Dated: February 21, 2013.

Kevin C. Kiefer,

Captain, U.S. Coast Guard, Captain of the Port Baltimore.

[FR Doc. 2013–05076 Filed 3–4–13; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2011–0542; FRL–9686–3]

RIN 2060–AR07

Regulation of Fuels and Fuel Additives: Identification of Additional Qualifying Renewable Fuel Pathways Under the Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is issuing a final rule identifying additional fuel pathways that EPA has determined meet the biomass-based diesel, advanced biofuel or cellulosic biofuel lifecycle greenhouse gas (GHG) reduction requirements specified in Clean Air Act section 211(o), the Renewable Fuel Standard (RFS) Program, as amended by the Energy Independence and Security Act of 2007 (EISA). This final rule describes EPA's evaluation of biofuels produced from camelina (*Camelina sativa*) oil and energy cane; it also includes an evaluation of renewable gasoline and renewable gasoline blendstocks, and clarifies our definition of renewable diesel. The inclusion of these pathways creates additional opportunity and flexibility for regulated parties to comply with the advanced and cellulosic requirements of EISA and provides the certainty necessary for investments to bring these biofuels into commercial production from these new feedstocks.

We are not finalizing at this time determinations on biofuels produced from giant reed (*Arundo donax*) or napier grass (*Pennisetum purpureum*) or biodiesel produced from esterification. We continue to consider the issues concerning these proposals, and will make a final decision on them at a later time.

DATES: This rule is effective on May 6, 2013.

FOR FURTHER INFORMATION CONTACT: Vincent Camobreco, Office of Transportation and Air Quality (MC6401A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–9043; fax number: (202) 564–1686; email address: *camobreco.vincent@epa.gov*.

SUPPLEMENTARY INFORMATION:

Does this action apply to me?

Entities potentially affected by this action are those involved with the production, distribution, and sale of transportation fuels, including gasoline and diesel fuel or renewable fuels such as ethanol and biodiesel. Regulated categories and entities affected by this action include:

Category	NAICS [1] Codes	SIC [2] Codes	Examples of potentially regulated entities
Industry	324110	2911	Petroleum Refineries.
Industry	325193	2869	Ethyl alcohol manufacturing.
Industry	325199	2869	Other basic organic chemical manufacturing.
Industry	424690	5169	Chemical and allied products merchant wholesalers.
Industry	424710	5171	Petroleum bulk stations and terminals.
Industry	424720	5172	Petroleum and petroleum products merchant wholesalers.
Industry	454319	5989	Other fuel dealers.

[1] North American Industry Classification System (NAICS).
[2] Standard Industrial Classification (SIC) system code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could be potentially regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria of Part 80, subparts D, E and F of title 40 of the Code of Federal Regulations. If you have any question regarding applicability of this action to a particular entity, consult the person in the preceding **FOR FURTHER INFORMATION CONTACT** section above.

Outline of This Preamble

I. Executive Summary

A. Purpose of This Regulatory Action

In this rulemaking, EPA is taking final action to identify additional fuel pathways that we have determined meet the greenhouse gas (GHG) reduction requirements under the Renewable Fuel Standard (RFS) program. This final rule describes EPA's evaluation of biofuels produced from camelina (*Camelina sativa*) oil, which qualify as biomass-based diesel or advanced biofuel, as well as biofuels from energy cane which qualify as cellulosic biofuel. This final rule also qualifies renewable gasoline and renewable gasoline blendstock made from certain qualifying feedstocks as cellulosic biofuel. Finally, this rule clarifies the definition of renewable diesel to explicitly include jet fuel.

EPA is taking this action as a result of changes to the RFS program in Clean Air Act (''CAA'') Section 211(o) required by the Energy Independence and Security Act of 2007 (''EISA''). This rulemaking modifies the RFS regulations published at 40 CFR § 80.1400 *et seq.* The RFS program regulations specify the types of renewable fuels eligible to participate in the RFS program and the procedures by which renewable fuel producers and importers may generate Renewable Identification Numbers (''RINs'') for the qualifying renewable fuels they produce through approved fuel pathways. See 75 FR 14670 (March 26, 2010); 75 FR 26026 (May 10, 2010); 75 FR 37733 (June 30, 2010); 75 FR 59622 (September 28, 2010); 75 FR 76790 (December 9, 2010); 75 FR 79964 (December 21, 2010); 77 FR 1320 (January 9, 2012); and 77 FR 74592 (December 17, 2012).

By qualifying these new fuel pathways, this rule provides opportunities to increase the volume of advanced, low-GHG renewable fuels—such as cellulosic biofuels—under the RFS program. EPA's comprehensive analyses show significant lifecycle GHG emission reductions from these fuel types, as compared to the baseline gasoline or diesel fuel that they replace.

B. Summary of the Major Provisions of the Regulatory Action In Question

This final rule describes EPA's evaluation of:

Camelina (*Camelina sativa*) oil *(*new feedstock)

- Biodiesel, and renewable diesel, (including jet fuel, and heating oil)—*qualifying to generate biomass-based diesel and advanced biofuel RINs*
- Naphtha and liquefied petroleum gas (LPG)—*qualifying to generate advanced biofuel RINs*

Energy cane cellulosic biomass (new feedstock)

- Ethanol, renewable diesel (including renewable jet fuel and heating oil), and renewable gasoline blendstock—*qualifying to generate cellulosic biofuel RINs*

Renewable gasoline and renewable gasoline blendstock (new fuel types)

- Produced from crop residue, slash, pre-commercial thinnings, tree residue, annual cover crops, and cellulosic components of separated yard waste, separated food waste, and separated municipal solid waste (MSW)
- Using the following processes—all utilizing natural gas, biogas, and/or biomass as the only process energy sources—*qualifying to generate cellulosic biofuel RINs:*
  - ○ Thermochemical pyrolysis
  - ○ Thermochemical gasification
  - ○ Biochemical direct fermentation
  - ○ Biochemical fermentation with catalytic upgrading
  - ○ Any other process that uses biogas and/or biomass as the only process energy sources

This final rule adds these pathways to Table 1 to § 80.1426. This final rule allows producers or importers of fuel produced under these pathways to generate RINs in accordance with the RFS regulations, providing that the fuel meets other definitional criteria for renewable fuel. The inclusion of these pathways creates additional opportunity and flexibility for regulated parties to comply with the requirements of EISA. Substantial investment has been made to commercialize these new feedstocks, and the cellulosic biofuel industry in the United States continues to make significant advances in its progress towards large scale commercial production. Approval of these new feedstocks will help further the Congressional intent to expand the volumes of cellulosic and advanced biofuels.

We are also finalizing two changes to Table 1 to 80.1426 that were proposed on July 1, 2011(76 FR 38844). The first change adds ID letters to pathways to facilitate references to specific pathways. The second change adds ''rapeseed'' to the existing pathway for renewable fuel made from canola oil.

II. Identification of Additional Qualifying Renewable Fuel Pathways Under the Renewable Fuel Standard (RFS) Program

This rule was originally published in the **Federal Register** at 77 FR 462, January 5, 2012 as a direct final rule, with a parallel publication of a proposed rule. A limited number of relevant adverse comments were received, and EPA published a withdrawal notice of the direct final rule on March 5, 2012 (77 FR 13009). A second comment period was not issued, since the simultaneous publication of the proposed rule provided an adequate notice and comment process. EPA is finalizing several of the proposed actions in this final rule, but continues to consider determinations on biofuels produced from giant reed (*Arundo donax*) or napier grass (*Pennisetum purpureum*) or biodiesel produced from esterification. EPA will make a final decision on theses elements of the proposal at a later time.

In this action, EPA is issuing a final rule to identify in the RFS regulations additional renewable fuel production pathways that we have determined meet the greenhouse gas (GHG) reduction requirements of the RFS program. There are three critical components of a renewable fuel pathway: (1) Fuel type, (2) feedstock, and (3) production process. Each specific combination of the three components, or fuel pathway, is assigned a D code which is used to designate the type of biofuel and its compliance category under the RFS program. This final rule describes EPA's lifecycle GHG evaluation of camelina oil and energy cane.

Determining whether a fuel pathway satisfies the CAA's lifecycle GHG reduction thresholds for renewable fuels requires a comprehensive evaluation of the lifecycle GHG emissions of the renewable fuel as compared to the lifecycle GHG emissions of the baseline gasoline or diesel fuel that it replaces. As mandated by CAA section 211(o), the GHG emissions assessments must evaluate the aggregate quantity of GHG emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes) related to the full fuel lifecycle, including all stages of fuel and feedstock production, distribution, and use by the ultimate consumer.

In examining the full lifecycle GHG impacts of renewable fuels for the RFS program, EPA considers the following:

- Feedstock production—based on agricultural sector models that include direct and indirect impacts of feedstock production.
- Fuel production—including process energy requirements, impacts of any raw materials used in the process, and benefits from co-products produced.
- Fuel and feedstock distribution—including impacts of transporting feedstock from production to use, and transport of the final fuel to the consumer.
- Use of the fuel—including combustion emissions from use of the fuel in a vehicle.

Many of the pathways evaluated in this rulemaking rely on a comparison to the lifecycle GHG analysis work that was done as part of the Renewable Fuel

Standard Program Final Rule, published March 26, 2010 (75 FR 14670) (March 2010 RFS). The evaluations here rely on comparisons to the existing analyses presented in the March 2010 final rule. EPA plans to periodically review and revise the methodology and assumptions associated with calculating the GHG emissions from all renewable fuel pathways.

A. Analysis of Lifecycle Greenhouse Gas Emissions for Biodiesel, Renewable Diesel, Jet Fuel, Heating Oil, Naphtha, and Liquefied Petroleum Gas (LPG) Produced From Camelina Oil

The following sections describe EPA's evaluation of camelina (*Camelina sativa*) as a biofuel feedstock under the RFS program. As discussed previously, this analysis relies on a comparison to the lifecycle GHG analysis work that was done as part of the Renewable Fuel Standard Program (RFS) Final Rule, published March 26, 2010 for soybean oil biofuels.

1. Feedstock Production

Camelina sativa (camelina) is an oilseed crop within the flowering plant family Brassicaceae that is native to Northern Europe and Central Asia. Camelina's suitability to northern climates and low moisture requirements allows it to be grown in areas that are unsuitable for other major oilseed crops such as soybeans, sunflower, and canola/rapeseed. Camelina also requires the use of little to no tillage.[1] Compared to many other oilseeds, camelina has a relatively short growing season (less than 100 days), and can be grown either as a spring annual or in the winter in milder climates.[2 3] Camelina can also be used to break the continuous planting cycle of certain grains, effectively reducing the disease, insect, and weed pressure in fields planted with such grains (like wheat) in the following year.[4]

Although camelina has been cultivated in Europe in the past for use as food, medicine, and as a source for lamp oil, commercial production using modern agricultural techniques has been limited.[5] In addition to being used as a renewable fuel feedstock, small quantities of camelina (less than 5% of total U.S. camelina production) are currently used as a dietary supplement and in the cosmetics industry. Approximately 95% of current US production of camelina has been used for testing purposes to evaluate its use as a feedstock to produce primarily jet fuel.[6] The FDA has not approved camelina for food uses, although it has approved the inclusion of certain quantities of camelina meal in commercial feed.[7]

In response to the proposed rule, EPA received comments highlighting the concern that by approving certain new feedstock types under the RFS program, EPA would be encouraging their introduction or expanded planting without considering their potential impact as invasive species.[8] The degree of concern expressed by the commenters depended somewhat on the feedstock. As pointed out by the commenters, camelina and energy cane are not ''native species,'' defined as ''a species that, other than as a result of an introduction, historically occurred or currently occurs in that ecosystem.'' The commenters asserted that there is a ''potential risk posed by the non-native species camelina and energy cane.'' In contrast, comments stated that giant reed (*Arundo donax*) or napier grass (*Pennisetum purpureum*) have been identified as invasive species in certain parts of the country. These commenters asserted that the Arundo donax and napier grass pose a ''clear risk of invasion.'' Commenters stated that EPA should not approve the proposed feedstocks until EPA has conducted an invasive species analysis, as required under Executive Order (EO) 13112.[9]

The information before us does not raise significant concerns about the threat of invasiveness and related GHG emissions for camelina. For example, camelina is not listed on the Federal Noxious Weed List,[10] nor is it listed on any state invasive species or noxious weed list. We believe that the production of camelina is unlikely to spread beyond the intended borders in which it is grown, which is consistent with the assumption in EPA's lifecycle analysis that significant expenditures of energy or other sources of GHGs will not be required to remediate the spread of this feedstock from the specific locations where it is grown as a renewable fuel feedstock for the RFS program. Therefore, we are finalizing the camelina pathway in this rule based on our lifecycle analysis discussed below.[11]

Camelina is currently being grown on approximately 50,000 acres of land in the U.S., primarily in Montana, eastern Washington, and the Dakotas.[12] USDA does not systematically collect camelina production information; therefore data on historical acreage is limited. However, available information indicates that camelina has been grown on trial plots in 12 U.S. states.[13]

In response to the proposed rule, two commenters were supportive of the use of renewable feedstocks such as camelina oil to produce biofuels for aviation. One commenter noted that aviation is unique in its complete dependency upon liquid fuel—today and into the foreseeable future. Another commenter noted that development of additional feedstocks and production pathways should increase supply and ultimately move us closer to the day when renewable jet fuels are price-competitive with legacy fossil fuels and help cut our dependence on foreign oil. EPA also received comment regarding a concern that EPA did not adequately establish that camelina would only be grown on fallow land and therefore would not have a land use impact and that EPA overestimated the likely yields in growing camelina and therefore underestimated the land requirements.

In terms of the comment on camelina not being grown on fallow land, for the purposes of analyzing the lifecycle GHG emissions of camelina, EPA has considered the likely production pattern for camelina grown for biofuel production. Given the information currently available, camelina is

[1] Putnam, D.H., J.T. Budin, L.A. Field, and W.M. Breene. 1993. Camelina: A promising low-input oilseed. p. 314–322. In: J. Janick and J.E. Simon (eds.), New crops. Wiley, New York.

[2] Moser, B.R., Vaughn, S.F. 2010. Evaluation of Alkyl Esters from Camelina Sativa Oil as Biodiesel and as Blend Components in Ultra Low Sulfur Diesel Fuel. Bioresource Technology. 101:646–653.

[3] McVay, K.A., and P.F. Lamb. 2008. Camelina production in Montana. MSU Ext. MT200701AG (revised). *http://msuextension.org/publications/AgandNaturalResources/MT200701AG.pdf.*

[4] Putnam *et al.,* 1993.

[5] Lafferty, Ryan M., Charlie Rife and Gus Foster. 2009. Spring camelina production guide for the Central High Plains. Blue Sun Biodiesel special publication. Blue Sun Agriculture Research & Development, Golden, CO. *http://www.gobluesun.com/upload/Spring%20Camelina%20Production%20Guide%202009.pdf.*

[6] Telephone conversation with Scott Johnson, Sustainable Oils, January 11, 2011.

[7] See *http://agr.mt.gov/camelina/FDAletter11-09.pdf.*

[8] Comment submitted by Jonathan Lewis, Senior Counsel, Climate Policy, Clean Air Task Force *et al.,* dated February 6, 2012. Document ID # EPA–HQ–OAR–2011–0542–0118.

[9] *http://www.gpo.gov/fdsys/pkg/FR-1999-02-08/pdf/99-3184.pdf.*

[10] However, this list is not exhaustive and is generally limited to species that are not currently in the U.S. or are incipient to the U.S. See *http://plants.usda.gov/java/noxious?rptType=Federal&statefips=&sort=sc.* Accessed on March 28, 2012.

[11] EPA continues to evaluate Arundo donax and napier grass as feedstock for a renewable fuel pathway, and will make a final decision on these pathways at a later time.

[12] McCormick, Margaret. ''Oral Comments of Targeted Growth, Incorporated'' Submitted to the EPA on June 9, 2009.

[13] See *https://www.camelinacompany.com/Marketing/PressRelease.aspx?Id=25.*

expected to be primarily planted in the U.S. as a rotation crop on acres that would otherwise remain fallow.[14] Because camelina has not yet been established as a commercial crop with significant monetary value, farmers are unlikely to dedicate acres for camelina production that could otherwise be used to produce other cash crops. Since camelina would therefore not be expected to displace another crop but rather maximize the value of the land through planting camelina in rotation, EPA does not believe new acres would need to be brought into agricultural use to increase camelina production. In addition, camelina currently has only limited high-value niche markets for uses other than renewable fuels. Unlike commercial crops that are tracked by USDA, camelina does not have a well-established, internationally traded market that would be significantly affected by an increase in the use of camelina to produce biofuels. For these reasons, which are described in more detail below, EPA has determined that production of camelina-based biofuels is not expected to result in significant GHG emissions related to direct land use change since it is expected to be grown on fallow land. Furthermore, due to the limited non-biofuel uses for camelina, production of camelina-based biofuels is not expected to have a significant impact on other agricultural crop production or commodity markets (either camelina or other crop markets) and consequently would not result in significant GHG emissions related to indirect land use change. To the extent camelina-based biofuel production decreases the demand for alternative biofuels, some with higher GHG emissions, this biofuel could have some beneficial GHG impact. However, it is uncertain which mix of biofuel sources the market will demand so this potential GHG impact cannot be quantified.

Commenters stated that EPA failed to justify why camelina would be grown on fallow land and thus result in no land use change. In the proposed rule, EPA provided a detailed description of the economics indicating why producers are most likely to grow camelina on land that would otherwise remain fallow. This analysis formed the basis for why it was reasonable and logical for camelina to be grown on acres that would otherwise remain fallow. Comments also indicated that EPA's economic basis for assuming camelina would most likely be grown on fallow land was inadequate, especially if production of camelina was scaled up. However, the comment did not indicate any specific point of error in our economically based analysis. As we described in the proposed rule and discuss below, camelina is currently not a commercially raised crop in the United States, therefore the returns on camelina are expected to be low compared to wheat and other crops with established, commercially traded markets.[15] Therefore, EPA expects that initial production of camelina for biofuel production will be on land with the lowest opportunity cost. Based on this logic, EPA believes camelina will be grown as a rotation crop, as discussed below, on dryland wheat acres replacing a period that the land would otherwise be left fallow.

In the semi-arid regions of the Northern Great Plains, dryland wheat farmers currently leave acres fallow once every three to four years to allow additional moisture and nutrients to accumulate (see Figure 1). Recent research indicates that introducing cool season oilseed crops such as camelina can provide benefits by reducing soil erosion, increasing soil organic matter, and disrupting pest cycles. Although long-term data on the effects of replacing wheat/fallow growing patterns with wheat/oilseed rotations is limited, there is some data that growing oilseeds in drier semi-arid regions year after year can lead to reduced wheat yields.[16] However, the diversification and intensification of wheat-fallow cropping systems can improve the long term economic productivity of wheat acres by increasing soil nitrogen and soil organic carbon pools.[17] In addition, selective breeding is expected to reduce the potential negative impacts on wheat yields.[18] Additional research in this area is needed and if significant negative impacts on crop rotations are determined from camelina grown on fallow acres EPA would take that into account in future analysis.

[14] Fallow land here refers to cropland that is periodically not cultivated.

[15] See Shonnard, D. R., Williams, L., & Kalnes, T. N. 2010. Camelina-Derived Jet Fuel and Diesel: Sustainable Advanced Biodiesel. Environmental Progress & Sustainable Energy, 382–392.

[16] Personal communication with Andrew Lenssen, Department of Agronomy, Iowa State University, April 17, 2012. See also *http://www.ars.usda.gov/is/pr/2010/100413.htm.*

[17] See Sainju, U.M., T. Caesar-Tonthat, A.W. Lenssen, R.G. Evans, and R. Kohlberg. 2007. Long-term tillage and cropping sequence effects on dryland residue and soil carbon fractions. Soil Science Society of America Journal 71: 1730–1739.

[18] See Shonnard *et al.,* 2010; Lafferty *et al.,* 2009.

Figure 1: Examples of Traditional Wheat and Camelina/Wheat Rotations

Example 1: Traditional Winter Wheat/Spring Wheat/Fallow Rotation

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Year 0										Winter Wheat Planting		
Year 1								Winter Wheat Harvest				
Year 2				Spring Wheat Planting				Spring Wheat Harvest				
Year 3										Winter Wheat Planting		

Example 2: Winter Wheat/Camelina/Spring Wheat Rotation

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Year 0										Winter Wheat Planting		
Year 1								Winter Wheat Harvest				
Year 2				Camelina Planting				Camelina Harvest				
Year 3				Spring Wheat Planting				Spring Wheat Harvest		Winter Wheat Planting		

Shaded cells indicate fallow months

Hatched line cells indicate growing months

As pointed out by commenters, in the future camelina production could expand beyond what is currently assumed in this analysis. However, camelina would most likely not be able to compete with other uses of land until it becomes a commercial crop with a well-established market value. EPA once again reiterates that we will continue to monitor the growing patterns associated with camelina to determine whether actual production is consistent with the assumptions used in this analysis. Monitoring will be done by tracking the amount of RIN generating camelina fuel produced through the EPA Moderated Transaction System (EMTS). We can compare the amount of RIN generating fuel against expected volumes from fallow acres in conjunction with USDA. Consistent with EPA's approach to all RFS feedstock pathway analyses, we will periodically reevaluate whether our assessment of GHG impacts will need to be updated in the future based on the potential for significant changes in our analyses.

a. Land Availability

USDA estimates that there are approximately 60 million acres of wheat in the U.S.[19] USDA and wheat state cooperative extension reports through 2008 indicate that 83% of US wheat production is under non-irrigated, dryland conditions. Of the approximately 50 million non-irrigated acres, at least 45% are estimated to follow a wheat/fallow rotation. Thus, approximately 22 million acres are potentially suitable for camelina production. However, according to industry projections, only about 9 million of these wheat/fallow acres have the appropriate climate, soil profile, and market access for camelina production.[20] Therefore, our analysis uses the estimate that only 9 million wheat/fallow acres are available for camelina production.

One commenter stated that EPA assumed more than 8 million acres would be used to produce camelina, even though a recent paper stated that only 5 million acres would have the potential to grow camelina in a sustainable manner in a way that would not impact the food supply. This commenter misinterpreted EPA's assumptions. EPA's assessment is based on a three year rotation cycle in which only one third of the 9 million available acres would be fallow in any given year. In other words, EPA assumed only 3 million acres would be planted with camelina in any given year. This number is less than the 5 million acres the Shonnard et. al. paper states would be available annually for camelina planting.

b. Projected Volumes

Based on these projections of land availability, EPA estimates that at current yields (approximately 800 pounds per acre), approximately 100 million gallons (MG) of camelina-based renewable fuels could be produced with camelina grown in rotation with existing crop acres without having direct land use change impacts. Also, since camelina will likely be grown on fallow land and thus not displace any other crop and since camelina currently does not have other significant markets, expanding production and use of camelina for biofuel purposes is not likely to have other agricultural market impacts and therefore, would not result in any significant indirect land use impacts.[21] Yields of camelina are expected to approach the yields of similar oilseed crops over the next few years, as experience with growing camelina improves cultivation practices and the application of existing technologies are more widely adopted.[22] Yields of 1650 pounds per acre have been achieved on test plots, and are in line with expected yields of other oilseeds such as canola/rapeseed. Assuming average US yields of 1650 pounds per acre,[23] approximately 200 MG of camelina-based renewable fuels could be produced on existing wheat/fallow acres. Finally, if investment in new seed technology allows yields to increase to levels assumed by Shonnard et al (3000 pounds per acre), approximately 400 MG of camelina-based renewable fuels could be produced on existing acres.[24] Depending on future crop yields, we project that roughly 100 MG to 400 MG of camelina-based biofuels could be produced on currently fallow land with no impacts on land use.[25]

We also received comments that we overestimated long term camelina yields. The commentors stated that reaching yields of 3000 pounds per acre may be attainable, but previous trials do not suggest that yields could reach this level in ten years. As a point of clarification, we did not assume that yields would need to be 3000 pounds per acre for biodiesel produced from camelina oil to qualify as an advanced biofuel. In the analysis presented below, EPA assumed yields of camelina would be 1650 pounds per acre. Since the use of camelina as a biofuel feedstock in the U.S. is in its infancy, it is reasonable to consider how yields will change over time. Furthermore, jet fuel contracts and the BCAP programs play a very important part in determining the amount of camelina planted, and therefore interest in increasing yields. As the commenter noted, this yield assumption is within the range of potential yields of 330–2400 pounds per acre found in the current literature.

c. Indirect Impacts

Although wheat can in some cases be grown in rotation with other crops such as lentils, flax, peas, garbanzo, and millet, cost and benefit analysis indicate that camelina is most likely to be planted on soil with lower moisture and nutrients where other rotation crops are not viable.[26] Because expected returns on camelina are relatively uncertain, farmers are not expected to grow camelina on land that would otherwise be used to grow cash crops with well established prices and markets. Instead, farmers are most likely to grow camelina on land that would otherwise be left fallow for a season. The opportunity cost of growing camelina on this type of land is much lower. As previously discussed, this type of land represents the 9 million acres currently being targeted for camelina production. Current returns on camelina are relatively low ($13.24 per acre), given average yields of approximately 800 pounds per acre and the current contract price of $0.145 per pound.[27] See Table 1. For comparison purposes, the USDA projections for wheat returns are between $133–$159 per acre between 2010 and 2020.[28] Over time, advancements in seed technology, improvements in planting and harvesting techniques, and higher input usage could significantly increase future camelina yields and returns.

[19] 2009 USDA Baseline. See *http://www.ers.usda.gov/publications/oce091/*.

[20] Johnson, S. and McCormick, M., Camelina: an Annual Cover Crop Under 40 CFR Part 80 Subpart M, Memorandum, dated November 5, 2010.

[21] Wheeler, P. and Guillen-Portal F. 2007. Camelina Production in Montana: A survey study sponsored by Targeted Growth, Inc. and Barkley Ag. Enterprises, LLP.

[22] See Hunter, J and G. Roth. 2010. Camelina Production and Potential in Pennsylvania, Penn State University Agronomy Facts 72. See *http://pubs.cas.psu.edu/freepubs/pdfs/uc212.pdf*.

[23] Ehrensing, D.T. and S.O. Guy. 2008. Oilseed Crops—Camelina. Oregon State Univ. Ext. Serv. EM8953–E. See *http://extension.oregonstate.edu/catalog/pdf/em/em8953-e.pdf*; McVay & Lamb, 2008.

[24] See Shonnard *et al.,* 2010.

[25] This assumes no significant adverse climate impacts on world agricultural yields over the analytical timeframe.

[26] See Lafferty et al, 2009; Shonnard et al, 2010; Sustainable Oils Memo dated November 5, 2010.

[27] Wheeler & Guillen-Portal, 2007.

[28] See *http://www.ers.usda.gov/media/273343/oce121_2_.pdf*.

TABLE 1—CAMELINA COSTS AND RETURNS

Inputs	Rates	2010 Camelina [29]	2022 Camelina [30]	2030 Camelina [31]
Herbicides:				
Glysophate (Fall)	16 oz. ($0.39/oz)	$7.00	$7.00	$7.00
Glysophate (Spring)	16 oz. ($0.39/oz)	$7.00	$7.00	$7.00
Post	12 oz ($0.67/oz)	$8.00	$8.00	$8.00
Seed:				
Camelina seed	$1.44/lb	$5.76 (4 lbs/acre)	$7.20 (5 lbs/acre)	$7.20 (5 lbs/acre)
Fertilizer:				
Nitrogen Fertilizer	$1/pd	$25.00 (25 lb/acre)	$40.00 (40 lb/acre)	$75 (75 lbs/acre)
Phosphate Fertilizer	$1/pd	$15.00 (15 lb/acre)	$15.00 (15 lb/acre)	$15 (15 lb/acre)
Sub-Total		$67.76	$84.20	$119.20
Logistics:				
Planting Trip		$10.00	$10.00	$10.00
Harvest & Hauling		$25.00	$25.00	$25.00
Total Cost		$102.76	$119.20	$154.20
Yields	lb/acre	800	1650	3000
Price	$/lb	$0.145	$0.120	$0.090
Total Revenue at avg prod/pricing		$116.00	$198	$270
Returns		$13.24	$78.80	$115.80

While replacing the fallow period in a wheat rotation is expected to be the primary means by which the majority of all domestic camelina is commercially harvested in the short- to medium-term, in the long term camelina may expand to other regions and growing methods.[32] For example, if camelina production expanded beyond the 9 million acres assumed available from wheat fallow land, it could impact other crops. However, as discussed above this is not likely to happen in the near term due to uncertainties in camelina financial returns. Camelina production could also occur in areas where wheat is not commonly grown. For example, testing of camelina production has occurred in Florida in rotation with kanaf, peanuts, cotton, and corn. However, only 200 acres of camelina were harvested in 2010 in Florida. While Florida acres of camelina are expected to be higher in 2011, very little research has been done on growing camelina in Florida. For example, little is known about potential seedling disease in Florida or how camelina may be affected differently than in colder climates.[33] Therefore, camelina grown outside of a wheat fallow situation was not considered as part of this analysis.

The determination in this final rule is based on our projection that camelina is likely to be produced on what would otherwise be fallow land. However, the rule applies to all camelina regardless of where it is grown. EPA does not expect that significant camelina would be grown on non-fallow land, and small quantities that may be grown elsewhere and used for biofuel production will not significantly impact our analysis.

Furthermore, although we expect most camelina used as a feedstock for renewable fuel production that would qualify in the RFS program would be grown in the U.S., today's rule would apply to qualifying renewable fuel made from camelina grown in any country. For the same reasons that pertain to U.S. production of camelina, we expect that camelina grown in other countries would also be produced on land that would otherwise be fallow and would therefore have no significant land use change impacts. The renewable biomass provisions under the Energy Independence and Security Act would prohibit direct land conversion into new agricultural land for camelina production for biofuel internationally. Additionally, any camelina production on existing cropland internationally would not be expected to have land use impacts beyond what was considered for international soybean production (soybean oil is the expected major feedstock source for US biodiesel fuel production and thus the feedstock of reference for the camelina evaluation). Because of these factors along with the small amounts of fuel potentially coming from other countries, we believe that incorporating fuels produced in other countries will not impact our threshold analysis for camelina-based biofuels.

d. Crop Inputs

For comparison purposes, Table 2 shows the inputs required for camelina production compared to the FASOM agricultural input assumptions for soybeans. Since yields and input assumptions vary by region, a range of values for soybean production are shown in Table 2. The camelina input values in Table 2 represent average values, camelina input values will also vary by region, however, less data is available comparing actual practices by region due to limited camelina production. More information on camelina inputs is available in materials provided in the docket.

[29] See Sustainable Oils Memo dated November 5, 2010.

[30] Based on yields technically feasible. See McVey and Lamb, 2008; Ehrenson & Guy, 2008.

[31] Adapted from Shonnard et al, 2010.

[32] See Sustainable Oils Memo dated November 5, 2010 for a map of the regions of the country where camelina is likely to be grown in wheat fallow conditions.

[33] Wright & Marois, 2011.

TABLE 2—INPUTS FOR CAMELINA AND SOYBEAN PRODUCTION

	Camelina		Soybeans (varies by region)	
	Inputs (per acre)	Emissions (per mmBtu fuel)	Inputs (per acre)	Emissions (per mmBtu fuel)
N_2O	N/A	22 kg CO_2-eq	N/A	9–12 kg CO_2-eq.
Nitrogen Fertilizer	40 lbs	7 kg CO_2-eq	3.5–8.2 lbs	1–3 kg CO_2-eq.
Phosphorous Fertilizer	15 lbs	1 kg CO_2-eq	5.4–21.4 lbs	0–2 kg CO_2-eq.
Potassium Fertilizer	10 lbs	0 kg CO_2-eq	3.1–24.3 lbs	0–2 kg CO_2-eq.
Herbicide	2.75 lbs	3 kg CO_2-eq	0.0–1.3 lbs	0–2 kg CO_2-eq.
Pesticide	0 lbs	0 kg CO_2-eq	0.1–0.8 lbs	0–2 kg CO_2-eq.
Diesel	3.5 gal	5 kg CO_2-eq	3.8–8.9 gal	7–20 kg CO_2-eq.
Gasoline	0 gal	0 kg CO_2-eq	1.6–3.0 gal	3–5 kg CO_2-eq.
Total		39 kg CO_2-eq		21–47 kg CO_2-eq.

Regarding crop inputs per acre, it should be noted that camelina has a higher percentage of oil per pound of seed than soybeans. Soybeans are approximately 18% oil, therefore crushing one pound of soybeans yields 0.18 pounds of oil. In comparison, camelina is approximately 36% oil, therefore crushing one pound of camelina yields 0.36 pounds of oil. The difference in oil yield is taken into account when calculating the emissions per mmBTU included in Table 2. As shown in Table 2, GHG emissions from feedstock production for camelina and soybeans are relatively similar when factoring in variations in oil yields per acre and fertilizer, herbicide, pesticide, and petroleum use.

In summary, EPA concludes that the agricultural inputs for growing camelina are similar to those for growing soy beans, direct land use change impacts are expected to be negligible due to planting on land that would be otherwise fallow, and the limited production and use of camelina indicates no expected impacts on other crops and therefore no indirect land use impacts.

e. Crushing and Oil Extraction

We also looked at the seed crushing and oil extraction process and compared the lifecycle GHG emissions from this stage for soybean oil and camelina oil. As discussed above, camelina seeds produce more oil per pound than soybeans. As a result, the lifecycle GHG emissions associated with crushing and oil extraction are lower for camelina than soybeans, per pound of vegetable oil produced. Table 3 summarizes data on inputs, outputs and estimated lifecycle GHG emissions from crushing and oil extraction. The data on soybean crushing comes from the March 2010 RFS final rule, based on a process model developed by USDA–ARS.[34] The data on camelina crushing is from Shonnard *et al.* (2010).

TABLE 3—COMPARISON OF CAMELINA AND SOYBEAN CRUSHING AND OIL EXTRACTION

Item	Soybeans	Camelina	Units
Material Inputs:			
Beans or Seeds	5.38	2.90	Lbs.
Energy Inputs:			
Electricity	374	47	Btu.
Natural Gas & Steam	1,912	780	Btu.
Outputs:			
Refined vegetable oil	1.00	1.00	Lbs.
Meal	4.08	1.85	Lbs.
GHG Emissions	213	64	gCO2e/lb refined oil.

2. Feedstock Distribution, Fuel Distribution, and Fuel Use

For this analysis, EPA projects that the feedstock distribution emissions will be the same for camelina and soybean oil. To the extent that camelina contains more oil per pound of seed, as discussed above, the energy needed to move the camelina would be lower than soybeans per gallon of fuel produced. To the extent that camelina is grown on more disperse fallow land than soybean and would need to be transported further, the energy needed to move the camelina could be higher than soybean. We believe the assumption to use the same distribution impacts for camelina as soybean is a reasonable estimate of the GHG emissions from camelina feedstock distribution. In addition, the final fuel produced from camelina is also expected to be similar in composition to the comparable fuel produced from soybeans, therefore we are assuming GHG emissions from the distribution and use of fuels made from camelina will be the same as emissions of fuel produced from soybeans.

3. Fuel Production

There are two main fuel production processes used to convert camelina oil into fuel. The trans-esterification process produces biodiesel and a glycerin co-product. The hydrotreating process can be configured to produce renewable diesel either primarily as diesel fuel (including heating oil) or primarily as jet fuel. Possible additional products from hydrotreating include naphtha LPG, and propane. Both processes and the fuels produced are described in the following sections. Both processes use camelina oil as a feedstock and camelina crushing is also included in the analysis.

[34] A. Pradhan, D.S. Shrestha, A. McAloon, W. Yee, M. Haas, J.A. Duffield, H. Shapouri, September 2009, ''Energy Life-Cycle Assessment of Soybean Biodiesel'', United States Department of Agriculture, Office of the Chief Economist, Office of Energy Policy and New Uses, Agricultural Economic Report Number 845.

a. Biodiesel

For this analysis, we assumed the same biodiesel production facility designs and conversion efficiencies as modeled for biodiesel produced from soybean oil and canola/rapeseed oil. Camelina oil biodiesel is produced using the same methods as soybean oil biodiesel, therefore plant designs are assumed to not significantly differ between fuels made from these feedstocks. As was the case for soybean oil biodiesel, we have not projected in our assessment of camelina oil biodiesel any significant improvements in plant technology. Unanticipated energy saving improvements would further improve GHG performance of the fuel pathway.

The glycerin produced from camelina biodiesel production is chemically equivalent to the glycerin produced from the existing biodiesel pathways (*e.g.,* based on soy oil) that were analyzed as part of the March 2010 RFS final rule. Therefore the same co-product credit would apply to glycerin from camelina biodiesel as glycerin produced in the biodiesel pathways modeled for the March 2010 RFS final rule. The assumption is that the GHG reductions associated with the replacement of residual oil with glycerin on an energy equivalent basis represents an appropriate midrange co-product credit of biodiesel produced glycerin.

As part of our RFS2 proposal, we assumed the glycerin would have no value and would effectively receive no co-product credits in the soy biodiesel pathway. We received numerous comments, however, asserting that the glycerin would have a beneficial use and should generate co-product benefits. Therefore, the biodiesel glycerin co-product determination made as part of the March 2010 RFS final rule took into consideration the possible range of co-product credit results. The actual co-product benefit will be based on what products are replaced by the glycerin and what new uses develop for the co-product glycerin. The total amount of glycerin produced from the biodiesel industry will actually be used across a number of different markets with different GHG impacts. This could include for example, replacing petroleum glycerin, replacing fuel products (residual oil, diesel fuel, natural gas, etc.), or being used in new products that don't have a direct replacement, but may nevertheless have indirect effects on the extent to which existing competing products are used. The more immediate GHG reduction credits from glycerin co-product use could range from fairly high reduction credits if petroleum glycerin is replaced to lower reduction credits if it is used in new markets that have no direct replacement product, and therefore no replaced emissions.

EPA does not have sufficient information (and received no relevant comments as part of the March 2010 RFS rule) on which to allocate glycerin use across the range of likely uses. Therefore, EPA believes that the approach used in the RFS of picking a surrogate use for modeling purposes in the mid-range of likely glycerin uses, and the GHG emissions results tied to such use, is reasonable. The replacement of an energy equivalent amount of residual oil is a simplifying assumption determined by EPA to reflect the mid-range of possible glycerin uses in terms of GHG credits. EPA believes that it is appropriately representative of GHG reduction credit across the possible range without necessarily biasing the results toward high or low GHG impact. Given the fundamental difficulty of predicting possible glycerin uses and impacts of those uses many years into the future under evolving market conditions, EPA believes it is reasonable to use the more simplified approach to calculating co-product GHG benefits associated with glycerin production at this time. EPA will continue to evaluate the co-product credit associated with glycerine production in future rulemakings.

Given the fact that GHG emissions from camelina-based biodiesel would be similar to the GHG emissions from soybean-based biodiesel at all stages of the lifecycle but would not result in land use changes as was the case for soy oil used as a feedstock, we believe biodiesel from camelina oil will also meet the 50% GHG emissions reduction threshold to qualify as a biomass based diesel and an advanced fuel. Therefore, EPA is including biodiesel produced from camelina oil under the same pathways for which biodiesel made from soybean oil qualifies under the March 2010 RFS final rule.

b. Renewable Diesel (Including Jet Fuel and Heating Oil), Naphtha, and LPG

The same feedstocks currently used for biodiesel production can also be used in a hydrotreating process to produce a slate of products, including diesel fuel, heating oil (defined as No. 1 or No. 2 diesel), jet fuel, naphtha, LPG, and propane. Since the term renewable diesel is defined to include the products diesel fuel, jet fuel and heating oil, the following discussion uses the term renewable diesel to also include diesel fuel, jet fuel and heating oil. The yield of renewable diesel is relatively insensitive to feedstock source.[35] While any propane produced as part of the hydrotreating process will most likely be combusted within the facility for process energy, the other co-products that can be produced (*i.e.,* renewable diesel, naphtha, LPG) are higher value products that could be used as transportation fuels or, in the case of naphtha, a blendstock for production of transportation fuel. The hydrotreating process maximized for producing a diesel fuel replacement as the primary fuel product requires more overall material and energy inputs than transesterification to produce biodiesel, but it also results in a greater amount of other valuable co-products as listed above. The hydrotreating process can also be maximized for jet fuel production which requires even more process energy than the process optimized for producing a diesel fuel replacement, and produces a greater amount of co-products per barrel of feedstock, especially naphtha.

Producers of renewable diesel from camelina have expressed interest in generating RINs under the RFS program for the slate of products resulting from the hydrotreating process. Our lifecycle analysis accounts for the various uses of the co-products. There are two main approaches to accounting for the co-products produced, the allocation approach, and the displacement approach. In the allocation approach all the emissions from the hydrotreating process are allocated across all the different co-products. There are a number of ways to do this but since the main use of the co-products would be to generate RINs as a fuel product we allocate based on the energy content of the co-products produced. In this case, emissions from the process would be allocated equally to all the Btus produced. Therefore, on a per Btu basis all co-products would have the same emissions. The displacement approach would attribute all of the emissions of the hydrotreating process to one main product and then account for the emission reductions from the other co-products displacing alternative product production. For example, if the hydrotreating process is configured to maximize diesel fuel replacement production, all of the emissions from the process would be attributed to diesel fuel, but we would then assume the other co-products were displacing

[35] Kalnes, T., N., McCall, M., M., Shonnard, D., R., 2010. Renewable Diesel and Jet-Fuel Production from Fats and Oils. Thermochemical Conversion of Biomass to Liquid Fuels and Chemicals, Chapter 18, p. 475.

alternative products, for example, naphtha would displace gasoline, LPG would displace natural gas, etc. This assumes the other alternative products are not produced or used, so we would subtract the emissions of gasoline production and use, natural gas production and use, etc. This would show up as a GHG emission credit associated with the production of diesel fuel replacement.

To account for the case where RINs are generated for the jet fuel, naphtha and LPG in addition to the diesel replacement fuel produced, we would not give the diesel replacement fuel a displacement credit for these co-products. Instead, the lifecycle GHG emissions from the fuel production processes would be allocated to each of the RIN-generating products on an energy content basis. This has the effect of tending to increase the fuel production lifecycle GHG emissions associated with the diesel replacement fuel because there are less co-product displacement credits to assign than would be the case if RINs were not generated for the co-products.[36] On the other hand, the upstream lifecycle GHG emissions associated with producing and transporting the plant oil feedstocks will be distributed over a larger group of RIN-generating products. Assuming each product (except propane) produced via the camelina oil hydrotreating process will generate RINs results in higher lifecycle GHG emissions for diesel fuel replacement as compared to the case where the co-products are not used to generate RINs. This general principle is also true when the hydrotreating process is maximized for jet fuel production. As a result, the worst GHG performance (*i.e.,* greatest lifecycle GHG emissions) for diesel replacement fuel and jet fuel produced from camelina oil via hydrotreating will occur when all of the co-products are RIN-generating (we assume propane will be used for process energy). Thus, if these fuels meet the 50% GHG reduction threshold for biomass based diesel or advanced biofuel when co-products are RIN-generating, they will also do so in the case when RINs are not generated for co-products.

We have evaluated information about the lifecycle GHG emissions associated with the hydrotreating process which can be maximized for jet fuel or diesel replacement fuel production. Our evaluation considers information published in peer-reviewed journal articles and publicly available literature (Kalnes et al., 2010, Pearlson, M., N., 2011,[37] Stratton *et al.,* 2010, Huo *et al.,* 2008 [38]). Our analysis of GHG emissions from the hydrotreating process is based on the mass and energy balance data in Pearlson (2011) which analyzes a hydrotreating process maximized for diesel replacement fuel production and a hydrotreating process maximized for jet fuel production.[39] This data is summarized in Table 4.

TABLE 4—HYDROTREATING PROCESSES TO CONVERT CAMELINA OIL INTO DIESEL REPLACEMENT FUEL AND JET FUEL[40]

	Maximized for diesel fuel production	Maximized for jet fuel production	Units (per gallon of fuel produced)
Inputs:			
Refined camelina oil	9.56	12.84	Lbs.
Hydrogen	0.04	0.08	Lbs.
Electricity	652	865	Btu.
Natural Gas	23,247	38,519	Btu.
Outputs:			
Diesel Fuel	123,136	55,845	Btu.
Jet fuel	23,197	118,669	Btu.
Naphtha	3,306	17,042	Btu.
LPG	3,084	15,528	Btu.
Propane	7,454	9,881	Btu.

Table 5 compares lifecycle GHG emissions from oil extraction and fuel production for soybean oil biodiesel and for camelina-based diesel and jet fuel. The lifecycle GHG estimates for camelina oil diesel and jet fuel are based on the input/output data summarized in Table 3 (for oil extraction) and Table 4 (for fuel production). We assume that the propane co-product does not generate RINs; instead, it is used for process energy displacing natural gas. We also assume that the naphtha is used as blendstock for production of transportation fuel to generate RINs. In this case we assume that RINs are generated for the use of LPG in a way that meets the EISA definition of transportation fuel, for example it could be used in a nonroad vehicle. The lifecycle GHG results in Table 5 represent the worst case scenario (*i.e.,* highest GHG emissions) because all of the eligible co-products are used to generate RINs. This is because, as discussed above, lifecycle GHG emissions per Btu of diesel or jet fuel would be lower if the naphtha or LPG is not used to generate RINs and is instead used for process energy displacing fossil fuel such as natural gas. Supporting information for the values in Table 5, including key assumptions and data, is provided through the docket.[41] The key assumptions and data discussed in the docket include the emissions factors for natural gas, hydrogen and grid average electricity, and the energy allocation and displacement credits given to co-products. These data and assumptions are based on the approach taken in the March 2010 RFS rule, as explained further below.

[36] For a similar discussion see page 46 of Stratton, R.W., Wong, H.M., Hileman, J.I. 2010. Lifecycle Greenhouse Gas Emissions from Alternative Jet Fuels. PARTNER Project 28 report. Version 1.1. PARTNER–COE–2010–001. June 2010, *http://web.mit.edu/aeroastro/partner/reports/proj28/partner-proj28-2010-001.pdf.*

[37] Pearlson, M., N. 2011. A Techno-Economic and Environmental Assessment of Hydroprocessed Renewable Distillate Fuels.

[38] Huo, H., Wang., M., Bloyd, C., Putsche, V., 2008. Life-Cycle Assessment of Energy and Greenhouse Gas Effects of Soybean-Derived Biodiesel and Renewable Fuels. Argonne National Laboratory. Energy Systems Division. ANL/ESD/08–2. March 12, 2008.

[39] We have also considered data submitted by companies involved in the hydrotreating industry which is claimed as confidential business information (CBI). The conclusions using the CBI data are consistent with the analysis presented here.

[40] Based on Pearlson (2011), Table 3.1 and Table 3.2.

[41] See for example the spreadsheet with lifecycle GHG emissions calculations titled ''Final Camelina Calculations for Docket'' with document number EPA–HQ–OAR–2011–0542–0046.

TABLE 5—FUEL PRODUCTION LIFECYCLE GHG EMISSIONS

[kgCO2e/mmBtu] [42]

Feedstock	Production process	RIN-Generating products	Other co-products	Oil extraction	Processing	Total
Soybean Oil	Trans-Esterification	Biodiesel	Glycerin	14	(1)	13
Camelina Oil	Trans-Esterification	Biodiesel	Glycerin	4	(1)	3
Camelina Oil	Hydrotreating Maximized for Diesel.	Diesel Jet Fuel. Naphtha. LPG.	Propane	4	8	12
Camelina Oil	Hydrotreating Maximized for Jet Fuel.	Diesel Fuel Jet Fuel. Naphtha. LPG.	Propane	4	11	14

As discussed above, for a process that produces more than one RIN-generating output (*e.g.,* the hydrotreating process summarized in Table 5 which produces diesel replacement fuel, jet fuel, and naphtha) we allocate lifecycle GHG emissions to the RIN generating products on an energy equivalent basis. We then normalize the allocated lifecycle GHG emissions per mmBtu of each fuel product. Therefore, each RIN-generating product from the same process will be assigned equal lifecycle GHG emissions per mmBtu from fuel processing. For example, based on the lifecycle GHG estimates in Table 5 for the hydrotreating process maximized to produce jet fuel, the jet fuel and the naphtha both have lifecycle GHG emissions of 14 kgCO2e/mmBtu. For the same reasons, the lifecycle GHG emissions from the jet fuel and naphtha will stay equivalent if we consider upstream GHG emissions, such as emissions associated with camelina cultivation and harvesting. Lifecycle GHG emissions from fuel distribution and use could be somewhat different for the jet fuel and naphtha, but since these stages produce a relatively small share of the emissions related to the full fuel lifecycle, the overall difference will be quite small.

Given that GHG emissions from camelina oil would be similar to the GHG emissions from soybean oil at all stages of the lifecycle but would not result in land use change emissions (soy oil feedstock did have a significant land use change impact but still met a 50% GHG reduction threshold), and considering differences in process emissions between soybean biodiesel and camelina-based renewable diesel, we conclude that renewable diesel from camelina oil will also meet the 50% GHG emissions reduction threshold to qualify as biomass based diesel and advanced fuel. Although some of the potential configurations result in fuel production GHG emissions that are higher than fuel production GHG emissions for soybean oil biodiesel, land use change emissions account for approximately 80% of the soybean oil to biodiesel lifecycle GHGs. Since camelina is assumed not to have land use change emissions, our analysis shows that camelina renewable diesel will qualify for advanced renewable fuel and biomass-based diesel RINs even for the cases with the highest lifecycle GHGs (*e.g.,* when all of the co-products are used to generate RINs.) Because the lifecycle GHG emissions for RIN-generating co-products are very similar, we can also conclude renewable gasoline blendstock and LPG produced from camelina oil will also meet the 50% GHG emissions reduction threshold. If the facility does not actually generate RINs for one or more of these co-products, we estimate that the lifecycle GHG emissions related to the RIN-generating products would be lower, thus renewable diesel (which includes diesel fuel, jet fuel, and heating oil) from camelina would still meet the 50% emission reduction threshold.

4. Summary

Current information suggests that camelina will be produced on land that would otherwise remain fallow. Therefore, increased production of camelina-based renewable fuel is not expected to result in significant land use change emissions; however, the agency will continue to monitor volumes through EMTS to verify this assumption. For the purposes of this analysis, EPA is projecting there will be no land use emissions associated with camelina production for use as a renewable fuel feedstock.

However, while production of camelina on acres that would otherwise remain fallow is expected to be the primary means by which the majority of all camelina is commercially harvested in the short- to medium- term, in the long term camelina may expand to other growing methods and lands if demand increases substantially beyond what EPA is currently predicting. While the impacts are uncertain, there are some indications demand could increase significantly. For example, camelina is included under USDA's Biomass Crop Assistance Program (BCAP) and there is growing support for the use of camelina oil in producing drop-in alternative aviation fuels. EPA plans to monitor, through EMTS and in collaboration with USDA, the expansion of camelina production to verify whether camelina is primarily grown on existing acres once camelina is produced at larger-scale volumes. Similarly, we will consider market impacts if alternative uses for camelina expand significantly beyond what was described in the above analysis. Just as EPA plans to periodically review and revise the methodology and assumptions associated with calculating the GHG emissions from all renewable fuel feedstocks, EPA expects to review and revise as necessary the analysis of camelina in the future.

Taking into account the assumption of no land use change emissions when camelina is used to produce renewable fuel, and considering that other sources of GHG emissions related to camelina biodiesel or renewable diesel production have comparable GHG emissions to biodiesel from soybean oil, we have determined that camelina-based biodiesel and renewable diesel should be treated in the same manner as soy-based biodiesel and renewable diesel in qualifying as biomass-based diesel and advanced biofuel for purposes of RIN generation, since the GHG emission performance of the

[42] Lifecycle GHG emissions are normalized per mmBtu of RIN-generating fuel produced. Totals may not be the sum of the rows due to rounding error. Parentheses indicate negative numbers. Process emissions for biodiesel production are negative because they include the glycerin offset credit.

camelina-based fuels will be at least as good and in some respects better than that modeled for fuels made from soybean oil. EPA found as part of the Renewable Fuel Standard final rulemaking that soybean biodiesel resulted in a 57% reduction in GHG emissions compared to the baseline petroleum diesel fuel. Furthermore, approximately 80% of the lifecycle impacts from soybean biodiesel were from land use change emissions which are assumed to be not significant for the camelina pathway considered. Thus, EPA is including camelina oil as a potential feedstock under the same biodiesel and renewable diesel (which includes diesel fuel, jet fuel, and heating oil) pathways for which soybean oil currently qualifies. We are also including a pathway for naphtha and LPG produced from camelina oil through hydrotreating. This is based on the fact that our analysis shows that even when all of the co-products are used to generate RINs the lifecycle GHG emissions for RIN-generating co-products including diesel replacement fuel, jet fuel, naphtha and LPG produced from camelina oil will all meet the 50% GHG emissions reduction threshold.

We are also clarifying that two existing pathways for RIN generation in the RFS regulations that list ''renewable diesel'' as a fuel product produced through a hydrotreating process include jet fuel. This applies to two pathways in Table 1 to § 80.1426 of the RFS regulations which both list renewable diesel made from soy bean oil, oil from annual covercrops, algal oil, biogenic waste oils/fats/greases, or non-food grade corn oil using hydrotreating as a process. If parties produce jet fuel from the hydrotreating process and co-process renewable biomass and petroleum they can generate advanced biofuel RINs (D code 5) for the jet fuel produced. If they do not co-process renewable biomass and petroleum they can generate biomass-based diesel RINs (D code 4) for the jet fuel produced.

§ 80.1401 of the RFS regulations currently defines non-ester renewable diesel as a fuel that is not a mono-alkyl ester and which can be used in an engine designed to operate on conventional diesel fuel or be heating oil or jet fuel. The reference to jet fuel in this definition was added by direct final rule dated May 10, 2010. Table 1 to § 80.1426 identifies approved fuel pathways by fuel type, feedstock source and fuel production processes. The table, which was largely adopted as part of the March 26, 2010 RFS final rule, identifies jet fuel and renewable diesel as separate fuel types. Accordingly, in light of the revised definition of renewable diesel enacted after the RFS2 rule, there is ambiguity regarding the extent to which references in Table 1 to ''renewable diesel'' include jet fuel.

The original lifecycle analysis for the renewable diesel from hydrotreating pathways listed in Table 1 to § 80.1426 was not based on producing jet fuel but rather other transportation diesel fuel products, namely a diesel fuel replacement. As discussed above, the hydrotreating process can produce a mix of products including jet fuel, diesel, naphtha, LPG and propane. Also, as discussed, there are differences in the process configured for maximum jet fuel production vs. the process maximized for diesel fuel production and the lifecycle results vary depending on what approach is used to consider co-products (*i.e.,* the allocation or displacement approach).

In cases where there are no pathways for generating RINs for the co-products from the hydrotreating process it would be appropriate to use the displacement method for capturing the credits of co-products produced. This is the case for most of the original feedstocks included in Table 1 to § 80.1426.[43] As was discussed previously, if the displacement approach is used when jet fuel is the primary product produced it results in lower emissions than the production maximized for diesel fuel production. Therefore, since the hydrotreating process maximized for diesel fuel meets the 50% lifecycle GHG threshold for the feedstocks in question, the process maximized for jet fuel would also qualify.

Thus, we are interpreting the references to ''renewable diesel'' in Table 1 to include jet fuel, consistent with our regulatory definition of ''non-ester renewable diesel,'' since doing so clarifies the existing regulations while ensuring that Table 1 to § 80.1426 appropriately identifies fuel pathways that meet the GHG reduction thresholds associated with each pathway.

We note that although the definition of renewable diesel includes jet fuel and heating oil, we have also listed in Table 1 of section 80.1426 of the RFS regulations jet fuel and heating oil as specific co-products in addition to listing renewable diesel to assure clarity. This clarification also pertains to all the feedstocks already included in Table 1 for renewable diesel.

[43] The exception is renewable gasoline blendstock produced from waste categories, but these would pass the lifecycle thresholds regardless of the allocation approach used given their low feedstock GHG impacts.

B. Lifecycle Greenhouse Gas Emissions Analysis for Ethanol, Diesel, Jet Fuel, Heating Oil, and Naphtha Produced From Energy Cane

For this rulemaking, EPA considered the lifecycle GHG impacts of a new type of high-yielding perennial grass similar in cellulosic composition to switchgrass and comparable in status as an emerging energy crop. The grass considered in this rulemaking is energy cane, which is defined as a complex hybrid in the Saccharum genus that has been bred to maximize cellulosic rather than sugar content.

As discussed above, in response to the proposed rule, EPA received comments highlighting the concern that by approving certain new feedstock types under the RFS program, EPA would be encouraging their introduction or expanded planting without considering their potential impact as invasive species.[44]

As described in the previous section on camelina, the information before us does not raise significant concerns about the threat of invasiveness and related GHG emissions for energy cane. Energy cane is generally a hybrid of *Saccharum officinarum* and *Saccharum spontaneum*, though other species such as *Saccharum barberi* and *Saccharum sinense* have been used in the development of new cultivars.[45] Given the fact that *S. spontaneum* is listed on the Federal Noxious Weed List, this rulemaking does not allow for the inclusion of *S. spontaneum* in the definition of energy cane. However, hybrids derived from *S. spontaneum* that have been developed and publicly released by USDA are included in this definition of the energy cane feedstock. USDA's Agricultural Research Service has developed strains of energy cane that strive to maximize fiber content and minimize invasive traits. Therefore, we believe that the production of cultivars of energy cane that were developed by USDA are unlikely to spread beyond the intended borders in which it is grown, which is consistent with the assumption in EPA's lifecycle analysis that significant expenditures of energy or other sources of GHGs will not be required to remediate the spread of this feedstock from the specific locations where it is grown as a renewable fuel

[44] Comment submitted by Jonathan Lewis, Senior Counsel, Climate Policy, Clean Air Task Force *et al.,* dated February 6, 2012. Document ID # EPA–HQ–OAR–2011–0542–0118.

[45] See *https://www.crops.org/publications/jpr/abstracts/2/3/211?access=0&view=pdf* and *http://www.cpact.embrapa.br/eventos/2010/simposio_agroenergia/palestras/10_terca/Tarde/USA/4%20%20%208-10-2010%20Cold%20Tolerance.pdf.*

feedstock for the RFS program. Therefore, we are finalizing the energy cane pathway in this rule based on our lifecycle analysis discussed below.

In the proposed and final RFS rule, EPA analyzed the lifecycle GHG impacts of producing and using cellulosic ethanol and cellulosic Fischer-Tropsch diesel from switchgrass. The midpoint of the range of switchgrass results showed a 110% GHG reduction (range of 102%–117%) for cellulosic ethanol (biochemical process), a 72% (range of −64% to −79%) reduction for cellulosic ethanol (thermochemical process), and a 71% (range of −62% to −77%) reduction for cellulosic diesel (F–T process) compared to the petroleum baseline. In the RFS final rule, we indicated that some feedstock sources can be determined to be similar enough to those modeled that the modeled results could reasonably be extended to these similar feedstock types. For instance, information on miscanthus indicated that this perennial grass will yield more feedstock per acre than the modeled switchgrass feedstock without additional inputs with GHG implications (such as fertilizer). Therefore in the final rule EPA concluded that since biofuel made from the cellulosic biomass in switchgrass was found to satisfy the 60% GHG reduction threshold for cellulosic biofuel, biofuel produced from the cellulosic biomass in miscanthus would also comply. In the final rule we included cellulosic biomass from switchgrass and miscanthus as eligible feedstocks for the cellulosic biofuel pathways included in Table 1 to § 80.1426.

We did not include other perennial grasses such as energy cane as feedstocks for the cellulosic biofuel pathways in Table 1 at that time, since we did not have sufficient time to adequately consider them. Based in part on additional information received through the petition process for EPA approval of the energy cane pathway, EPA has evaluated energy cane and is now including it as a feedstock in Table 1 to § 80.1426 as approved pathways for cellulosic biofuel pathways.

As described in detail in the following sections of this preamble, because of the similarity of energy cane to switchgrass and miscanthus, and because crop production input emissions (*e.g.,* diesel and pesticide emissions) are generally a small fraction of the overall lifecycle GHG emissions (representing approximately 1% of total emissions for switchgrass), EPA believes that new agricultural sector modeling is not needed to analyze energy cane. We have instead relied upon the switchgrass analysis to assess the relative GHG impacts of biofuel produced from energy cane. As with the switchgrass analysis, we have attributed all land use impacts and resource inputs from use of these feedstocks to the portion of the fuel produced that is derived from the cellulosic components of the feedstocks. Based on this analysis and currently available information, we conclude that biofuel (ethanol, cellulosic diesel, jet fuel, heating oil and naphtha) produced from the cellulosic biomass of energy cane has similar lifecycle GHG impacts to switchgrass biofuel and meets the 60% GHG reduction threshold required for cellulosic biofuel.

1. Feedstock Production and Distribution

For the purposes of this rulemaking, energy cane refers to varieties of perennial grasses in the *Saccharum* genus which are intentionally bred for high cellulosic biomass productivity but have characteristically low sugar content making them less suitable as a primary source of sugar as compared to other varieties of grasses commonly known as ''sugarcane'' in the Saccharum genus. Energy cane varieties developed to date have low tolerance for cold temperatures but grow well in warm, humid climates. Energy cane originated from efforts to improve disease resistance and hardiness of commercial sugarcane by crossbreeding commercial and wild sugarcane strains. Certain higher fiber, lower sugar varieties that resulted were not suitable for commercial sugar production, and are now being developed as a high-biomass energy crop. There is currently no commercial production of energy cane. Current plantings are mainly limited to research field trials and small demonstrations for bioenergy purposes. However, based in part on discussions with industry, EPA anticipates continued development of energy cane particularly in the south-central and southeastern United States due to its high yields in these regions.

a. Crop Yields

For the purposes of analyzing the GHG emissions from energy cane production, EPA examined crop yields and production inputs in relation to switchgrass to assess the relative GHG impacts. Current national yields for switchgrass are approximately 4.5 to 5 dry tons per acre. Average energy cane yields exceed switchgrass yields in both unfertilized and fertilized trails conducted in the southern United States. Unfertilized yields are around 7.3 dry tons per acre while fertilized trials show energy cane yields range from approximately 11 to 20 dry tons per acre.[46 47] Until recently there have been few efforts to improve energy cane yields, but several energy cane development programs are now underway to further increase its biomass productivity. In general, energy cane will have higher yields than switchgrass, so from a crop yield perspective, the switchgrass analysis would be a conservative estimate when comparing against the energy cane pathway.

Furthermore, EPA's analysis of switchgrass for the RFS rulemaking assumed a 2% annual increase in yield that would result in an average national yield of 6.6 dry tons per acre in 2022. EPA anticipates a similar yield improvement for energy cane due to their similarity as perennial grasses and their comparable status as energy crops in their early stages of development. Given this, our analysis assumes an average energy cane yield of 19 dry tons per acre in the southern United States by 2022.[48] The ethanol yield for all of the grasses is approximately the same so the higher crop yields for energy cane result directly in greater ethanol production compared to switchgrass per acre of production.

Based on these yield assumptions, in areas with suitable growing conditions, energy cane would require approximately 26% to 47% of the land area required by switchgrass to produce the same amount of biomass due to higher yields. Even without yield growth assumptions, the currently higher crop yield rates means the land use required for energy cane would be lower than for switchgrass. Therefore less crop area would be converted and displaced resulting in smaller land-use change GHG impacts than that assumed for switchgrass to produce the same amount of fuel. Furthermore, we believe energy cane will have a similar impact on international markets as assumed for switchgrass. Like switchgrass, energy cane is not expected to be traded internationally and its impacts on other crops are expected to be limited.

b. Land Use

In EPA's March 2010 RFS analysis, switchgrass plantings displaced primarily soybeans and wheat, and to a lesser extent hay, rice, sorghum, and cotton. Energy cane, with production focused in the southern United States, is

[46] See Bischoff, K.P., Gravois, K.A., Reagan, T.E., Hoy, J.W., Kimbeng, C.A., LaBorde, C.M., Hawkins, G.L. *Plant Regis.* 2008, 2, 211–217.

[47] See Hale, A.L. *Sugar Bulletin,* 2010, 88, 28–29.

[48] These yields assume no significant adverse climate impacts on world agricultural yields over the analytical timeframe.

likely to be grown on land once used for pasture, rice, commercial sod, cotton or alfalfa, which would likely have less of an international indirect impact than switchgrass because some of those commodities are not as widely traded as soybeans or wheat. Given that energy cane will likely displace the least productive land first, EPA concludes that the land use GHG impact for energy cane per gallon should be no greater and likely less than estimated for switchgrass.

Considering the total land potentially impacted by all the new feedstocks included in this rulemaking would not impact these conclusions (including the camelina discussed in the previous section and energy cane considered here). As discussed previously, the camelina is expected to be grown on fallow land in the Northwest, while energy cane is expected to be grown mainly in the south on existing cropland or pastureland. In the switchgrass ethanol scenario done for the Renewable Fuel Standard final rulemaking, total cropland acres increases by 4.2 million acres, including an increase of 12.5 million acres of switchgrass, a decrease of 4.3 million acres of soybeans, a 1.4 million acre decrease of wheat acres, a decrease of 1 million acres of hay, as well as decreases in a variety of other crops. Given the higher yields of the energy cane considered here compared to switchgrass, there would be ample land available for production without having any adverse impacts beyond what was considered for switchgrass production. This analysis took into account the economic conditions such as input costs and commodity prices when evaluating the GHG and land use change impacts of switchgrass.

One commenter stated that by assuming no land use change for energy cane and other feedstocks, the Agency may have underestimated the increase in GHG emissions that could result from breaking new land. According to the commenter, EPA assumed that these feedstocks will be grown on the least productive land without citing any specific models or studies.

The commenter appears to have misinterpreted EPA's analysis. EPA did not assume these crops would be grown on fallow acres, nor did EPA assume that switchgrass would only be produced on the least productive lands. EPA assumed these crops would be grown on acres similar to switchgrass, and therefore applied the land use change impacts of switchgrass analyzed in the final RFS rule. In the final RFS, EPA provided detailed information on the types of crops (*e.g.,* wheat) that would be displaced by dedicated switchgrass. This analysis took into account the economic conditions such as input costs and commodity prices when evaluating the GHG and land use change impacts of switchgrass.[49]

[49] See Final Regulatory Impact Analysis Chapter 2, February 2010.

c. Crop Inputs and Feedstock Transport

EPA also assessed the GHG impacts associated with planting, harvesting, and transporting energy cane in comparison to switchgrass. Table 6 shows the assumed 2022 commercial-scale production inputs for switchgrass (used in the RFS rulemaking analysis), average energy cane production inputs (USDA projections and industry data) and the associated GHG emissions.

Available data gathered by EPA suggest that energy cane requires on average less nitrogen, phosphorous, potassium, and pesticide than switchgrass per dry ton of biomass, but more herbicide, lime, diesel, and electricity per unit of biomass.

This assessment assumes production of energy cane uses electricity for irrigation given that growers will likely irrigate when possible to improve yields. Irrigation rates will vary depending on the timing and amount of rainfall, but for the purpose of estimating GHG impacts of electricity use for irrigation, we assumed a rate similar to what we assumed for other irrigated crops in the Southwest, South Central, and Southeast as shown in Table 6.

Applying the GHG emission factors used in the March 2010 RFS final rule, energy cane production results in slightly higher GHG emissions relative to switchgrass production (an increase of approximately 4 kg CO_2eq/mmbtu).

Table 6: Production Inputs and GHG Emissions for Switchgrass and Energy Cane (Biochemical Ethanol), 2022

	Emission Factors		Switchgrass Inputs (per dry ton of biomass)		Switchgrass Emissions (per mmBtu fuel)		Energy Cane Inputs (per dry ton of biomass)		Energy Cane Emissions (per mmBtu fuel)	
Nitrogen Fertilizer	3,29	$kgCO_2e$/ton of nitrogen	15.2	lbs	3.6	$kgCO_2e$	8.4	lbs	2	$kgCO_2e$
N_2O	N/A		N/A		7.6	$kgCO_2e$	N/A		5.9	$kgCO_2e$
Phosphorus Fertilizer	1,12	$kgCO_2e$ /ton of phosphate	6.1	lbs	0.5	$kgCO_2e$	3.2	lbs	0.3	$kgCO_2e$
Potassium Fertilizer	743	$kgCO_2e$ /ton of potassium	6.1	lbs	0.3	$kgCO_2e$	4.2	lbs	0.2	$kgCO_2e$
Herbicide	23,45	$kgCO_2e$ /tons of herbicide	0.002	lbs	0.003	$kgCO_2e$	1.0	lbs	1.8	$kgCO_2e$
Insecticide (average across regions)	27,22	$kgCO_2e$ /tons of pesticide	0.025	lbs	0.04	$kgCO_2e$	0	lbs	0	$kgCO_2e$
Lime	408	$kgCO_2e$ /ton of lime	0	lbs	0	$kgCO_2e$	104.7	lbs	3.1	$kgCO_2e$
Diesel	97	$kgCO_2e$ /mmBtu diesel	0.4	gal	0.8	$kgCO_2e$	1.3	gal	2.4	$kgCO_2e$
Electricity (irrigation)	220	$kgCO_2e$ /mmBtu	0	kWh	0	$kgCO_2e$	14.7	kWh	1.6	$kgCO_2e$
Total Emissions					13	$kgCO_2e$ / mmBtu			17	$kgCO_2e$ / mmBtu

Assumes 2022 switchgrass yield of 6.59 dry tons/acre and 92.3 gal ethanol/dry ton and 2022 energy cane yield of 19.1 dry tons/acre and 92 gal ethanol/dry ton.

More detail on calculations and assumptions is included in materials to the docket.

GHG emissions associated with distributing energy cane are expected to be similar to EPA's estimates for switchgrass feedstock because they are all herbaceous agricultural crops requiring similar transport, loading, unloading, and storage regimes. Our analysis therefore assumes the same GHG impact for feedstock distribution as we assumed for switchgrass, although distributing energy cane could be less GHG intensive because higher yields could translate to shorter overall hauling distances to storage or biofuel production facilities per gallon or Btu of final fuel produced.

2. Fuel Production, Distribution, and Use

Energy cane is suitable for the same conversion processes as other cellulosic feedstocks, such as switchgrass and corn stover. Currently available information on energy cane composition shows that hemicellulose, cellulose, and lignin content are comparable to other crops that qualify under the RFS regulations as feedstocks for the production of cellulosic biofuels. Based on this similar composition as well as conversion yield data provided by industry, we applied the same production processes that were modeled for switchgrass in the final RFS rule (biochemical ethanol, thermochemical ethanol, and Fischer-Tropsch (F–T) diesel [50]) to energy cane. We assumed the GHG emissions associated with producing biofuels from energy cane are similar to what we estimated for switchgrass and other cellulosic feedstocks. EPA also assumes that the distribution and use of biofuel made from energy cane will not differ significantly from similar biofuel produced from other cellulosic sources. As was done for the switchgrass case, this analysis assumes energy grasses grown in the United States for production purposes. If crops were grown internationally, used for biofuel production, and the fuel was shipped to the U.S., shipping the finished fuel to the U.S. could increase transport emissions. However, based on analysis of the increased transport emissions associated with sugarcane ethanol distribution to the U.S. considered for the 2010 final rule, this would at most add 1–2% to the overall lifecycle GHG impacts of the energy grasses.

3. Summary

Based on our comparison to switchgrass, EPA believes that cellulosic biofuel produced from the cellulose, hemicellulose and lignin portions of energy cane has similar or better lifecycle GHG impacts than biofuel produced from the cellulosic biomass from switchgrass. Our analysis suggests that energy cane has GHG impacts associated with growing and harvesting the feedstock that are similar to switchgrass. Emissions from growing and harvesting energy cane are approximately 4 kg CO_2eq/mmBtu higher than switchgrass. These are small changes in the overall lifecycle, representing at most a 6% change in the energy grass lifecycle impacts in comparison to the petroleum fuel baseline. Furthermore, energy cane is expected to have similar or lower GHG emissions than switchgrass associated with other components of the biofuel lifecycle.

Under a hypothetical worst case, if the calculated increases in growing and harvesting the new feedstocks are incorporated into the lifecycle GHG emissions calculated for switchgrass, and other lifecycle components are projected as having similar GHG impacts to switchgrass (including land use change associated with switchgrass production), the overall lifecycle GHG reductions for biofuel produced from energy cane still meet the 60% reduction threshold for cellulosic biofuel. We believe these are conservative estimates, as use of energy cane as a feedstock is expected to have smaller land-use GHG impacts than switchgrass, due to higher yields. The docket for this rule provides additional detail on the analysis of energy cane as a biofuel feedstock.

Although this analysis assumes energy cane biofuels produced for sale and use in the United States will most likely come from domestically produced feedstock, we also intend for the approved pathways to cover energy cane from other countries. We do not expect incidental amounts of biofuels from feedstocks produced in other nations to impact our assessment that the average GHG emissions reductions will meet the threshold for qualifying as a cellulosic biofuel pathway. Moreover, those countries most likely to be exporting energy cane or biofuels produced from energy cane are likely to be major producers which typically use similar cultivars and farming techniques. Therefore, GHG emissions from producing biofuels with energy cane grown in other countries should be similar to the GHG emissions we estimated for U.S. energy cane, though they could be slightly higher or lower. For example, the renewable biomass provisions under the Energy Independence and Security Act as outlined in the March 2010 RFS final rule regulations, would preclude use of a crop as a feedstock for renewable fuel if it was gown on land that was a direct conversion of previously unfarmed land in other countries into cropland for energy grass-based renewable fuel production. Furthermore, any energy grass production on existing cropland internationally would not be expected to have land use impacts beyond what was considered for switchgrass production. Even if there were unexpected larger differences, EPA believes the small amounts of feedstock or fuel potentially coming from other countries will not impact our threshold analysis.

Based on our assessment of switchgrass in the March 2010 RFS final rule and this comparison of GHG emissions from switchgrass and energy cane, we do not expect variations to be large enough to bring the overall GHG impact of fuel made from energy cane to come close to the 60% threshold for cellulosic biofuel. Therefore, EPA is including cellulosic biofuel produced from the cellulose, hemicelluloses and lignin portions of energy cane under the same pathways for which cellulosic biomass from switchgrass qualifies under the RFS final rule.

C. Lifecycle Greenhouse Gas Emissions Analysis for Certain Renewable Gasoline and Renewable Gasoline Blendstocks Pathways

In this rule, EPA is also adding pathways to Table 1 to § 80.1426 for the production of renewable gasoline and renewable gasoline blendstock using specified feedstocks, fuel production processes, and process energy sources. The feedstocks we considered are generally considered waste feedstocks such as crop residues or cellulosic components of separated yard waste. These feedstocks have been identified by the industry as the most likely feedstocks for use in making renewable gasoline or renewable gasoline blendstock in the near term due to their availability and low cost. Additionally, these feedstocks have already been analyzed by EPA as part of the RFS rulemaking for the production of other fuel types. Consequently, no new modeling is required and we rely on earlier assessments of feedstock production and distribution for assessing the likely lifecycle impact on renewable gasoline and renewable gasoline blendstock. We have also relied on the petroleum gasoline baseline assessment from the March 2010 RFS rule for estimating the fuel distribution and use GHG emissions impacts for renewable gasoline and renewable gasoline blendstock. Consequently, the only new analysis required is of the technologies for turning the feedstock into renewable gasoline and renewable gasoline blendstock.

[50] The F–T diesel process modeled applies to cellulosic diesel, jet fuel, heating oil, and naphtha.

1. Feedstock Production and Distribution

EPA has evaluated renewable gasoline and renewable gasoline blendstock pathways that utilize cellulosic feedstocks currently included in Table 1 to § 80.1426 of the regulations. The following feedstocks were evaluated:

- Cellulosic biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual cover crops;
- Cellulosic components of separated yard waste;
- Cellulosic components of separated food waste; and
- Cellulosic components of separated MSW

The FASOM and FAPRI models were used to analyze the GHG impacts of the feedstock production portion of a fuel's lifecycle. In the March 2010 RFS rulemaking, FASOM and FAPRI modeling was performed to analyze the emissions impact of using corn stover as a biofuel feedstock and this modeling was extended to some additional feedstock sources considered similar to corn stover. This approach was used for crop residues, slash, pre-commercial thinnings, tree residue and cellulosic components of separated yard, food, and MSW. These feedstocks are all excess materials and thus, like corn stover, were determined to have little or no land use change GHG impacts. Their GHG emission impacts are mainly associated with collection, transport, and processing into biofuel. See the RFS rulemaking preamble for further discussion. We used the results of the corn stover modeling in this analysis to estimate the upper bound of agricultural sector impacts from the production of the various cellulosic feedstocks noted above.

The agriculture sector modeling results for corn stover represents all of the direct and significant indirect emissions in the agriculture sector (feedstock production emissions) for a certain quantity of corn stover produced. For the March 2010 RFS rulemaking, this was roughly 62 million dry tons of corn stover to produce 5.7 billion gallons of ethanol assuming biochemical fermentation to ethanol processing. We have calculated GHG emissions from feedstock production for that amount of corn stover. The GHG emissions were then divided by the total heating value of the fuel to get feedstock production emissions per mmBtu of fuel. In addition to the biochemical ethanol process, a similar analysis was completed for thermochemical ethanol and F–T diesel pathways as part of the RFS rulemaking.

In this rulemaking we are analyzing renewable gasoline and renewable gasoline blendstock produced from corn stover (and, by extension, other waste feedstocks). The number of gallons of fuel produced from a ton of corn stover (modeled process yields) is specific to the process used to produce renewable fuel. EPA has adjusted the results of the earlier corn stover modeling to reflect the different process yields and heating value of renewable gasoline or renewable gasoline blendstock product. The results of this calculation are shown below in Table 7.

We based our process yields and heating values for renewable gasoline and renewable gasoline blendstock on several process technologies representative of technologies anticipated to be used in producing these fuels. As discussed later in this section, there are four main types of fuel production technologies available for producing renewable gasoline. These four processes can be characterized as (1) thermochemical gasification, (2) catalytic pyrolysis and upgrading to renewable gasoline or renewable gasoline blendstock (''catalytic pyrolysis and upgrading''), (3) biochemical fermentation with upgrading to renewable gasoline or renewable gasoline blendstock via carboxylic acid (''fermentation and upgrading''), and (4) direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock (''direct fermentation''). The thermochemical gasification process was modeled as part of the March 2010 RFS final rule, included as producing naptha via the F–T process. Our analysis of the catalytic pyrolysis process was based on the modeling work completed by the National Renewable Energy Laboratory (NREL) for this rule for a process to make renewable gasoline blendstock.[51] The fermentation and upgrading process was modeled based on confidential business information (CBI) from industry for a unique process which uses biochemical conversion of cellulose to renewable gasoline via a carboxylic acid route. In addition, we have qualitatively assessed the direct fermentation to renewable gasoline process based on similarities to the biochemical ethanol process already analyzed as part of the March 2010 RFS rulemaking. The fuel production section below provides further discussion on extending the GHG emissions results of the biochemical ethanol fermentation process to a biochemical renewable gasoline or renewable gasoline blendstock fermentation process. In some cases, the available data sources included process yields for renewable gasoline or renewable gasoline blendstock produced from wood chips rather than corn stover which was specifically modeled as a feedstock in the RFS final rule. We believe that the process yields are not significantly impacted by the source of cellulosic material whether the cellulosic material comes from residue such as corn stover or wood material such as from tree residues. We made the simplifying assumption that one dry ton of wood feedstock produces the same volume of renewable gasoline or renewable gasoline blendstock as one dry ton of corn stover. We believe this is reasonable considering that the RFS rulemaking analyses for biochemical ethanol and thermochemical F–T diesel processes showed limited variation in process yields between different feedstocks for a given process technology.[52] In addition, since the renewable gasoline and renewable gasoline blendstock pathways include feedstocks that were already considered as part of the RFS2 final rule, the existing feedstock lifecycle GHG impacts for distribution of corn stover were also applied to this analysis.[53]

Feedstock production emissions are shown in Table 7 below for corn stover. Corn stover feedstock production emissions are mainly a result of corn stover removal increasing the profitability of corn production (resulting in shifts in cropland and thus slight emission impacts) and also the need for additional fertilizer inputs to replace the nutrients lost when corn stover is removed. However, corn stover removal also has an emissions benefit as it encourages the use of no-till farming which results in the lowering of domestic land use change emissions. This change to no-till farming results in a negative value for domestic land use change emission impacts (see also Table 13 below). For other waste feedstocks (*e.g.,* tree residues and cellulosic components of separate yard, food, and MSW), the feedstock production emissions are even lower than the values shown for corn stover since the

[51] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

[52] Aden, Andy. Feedstock Considerations and Impacts on Biorefining. National Renewable Energy Laboratory (NREL). December 2009. The report indicates that woody biomass feedstocks generally have higher yields than crop residues or herbaceous grasses (~6% higher yields). However the same lower yield was assumed for all as a conservatively low estimate.

[53] Results for feedstock distribution are aggregated along with fuel distribution and are reported in a later section, see conclusion section.

use of such feedstocks does not require land use changes or additional agricultural inputs. Therefore, we conclude that if the use of corn stover as a feedstock in the production of renewable gasoline and renewable gasoline blendstock yields lifecycle GHG emissions results for the resulting fuel that qualify it as cellulosic biofuel (*i.e.,* it has at least a 60% lifecycle GHG reduction as compared to conventional fuel), then the use of other waste feedstocks with little or no land use change emissions will also result in renewable gasoline or renewable gasoline blendstock that qualifies as cellulosic biofuel.

One commenter stated that the Agency assumed that using the corn stover for biofuels production would result in additional no-till farming without any evidence that the stover would actually be removed from no-tilled acres. This commenter feels that with recent increased profitability from corn production, farmers may actually increase tillage to reap high corn prices. This commenter urged the EPA to consider changes to soil carbon from the removal of corn stover as they may have an impact on the GHG score of this new biofuel pathway. This commenter further urged the Agency to not simply assume that additional no-till practices will be adopted with residue extraction.

The analysis the EPA conducted to evaluate the GHG impacts associated with corn stover removal as part of the March 2010 RFS final rule did not assume that the corn stover had to be removed from no-till corn production. The models used to evaluate the impacts of stover removal included the option for farmers to switch to no-till practices and therefore have the option for more stover removal. As the demand for stover increased in the case where stover is used for biofuel production, the relative costs associated with no-till factored in the impact of lost corn yield as well as higher yield for corn stover. The model optimized the rate of returns for the farmers such that no-till practices were applied until the increased returns for greater stover removal on no-till acres were balanced by lost profits from lower corn yields. Therefore, the comment that we assumed stover had to come from no-till acres or that the economics would drive more intensive tillage practices is not accurate, as described in more detail in the March 2010 RFS final rule.

Furthermore, there is an annual soil carbon penalty applied to crops with residue removal in our models. Thus, as one shifts from conventional corn to residue corn, an annual soil carbon penalty factor is applied. If residue removal is combined with switching to conservation tillage or no-till, then the net soil C effect would be the sum of the till change effect and the ''crop change'' effect.

For the March 2010 RFS rulemaking, EPA conducted an in-depth literature review of corn stover removal practices and consulted with numerous experts in the field. In the FRM, EPA recognized that sustainable stover removal practices vary significantly based on local differences in soil and erosion conditions, soil type, landscape (slope), tillage practices, crop rotation managements, and the use of cover crops. EPA, in consultation with USDA, based its impacts on corn stover from reduced till and no till acres based on agronomical practices, nutrient requirements, and erosion considerations. EPA does not believe that the commentor has provided new information that would substantially change our analysis of the GHG emissions associated with corn stover. However, EPA will continue to monitor actual practices and based on new data will consider reviewing and revising the methodology and assumptions associated with calculating the GHG emissions from all renewable fuel feedstocks.

TABLE 7—FEEDSTOCK PRODUCTION EMISSIONS FOR RENEWABLE GASOLINE AND RENEWABLE GASOLINE BLENDSTOCK PATHWAYS USING CORN STOVER

Feedstock production emission sources	Catalytic pyrolysis and upgrading to renewable gasoline and renewable gasoline blendstock (g CO_2-eq./mmBtu)	Biochemical fermentation and upgrading to renewable gasoline and renewable gasoline blendstock via carboxylic acid (g CO_2-eq./mmBtu)	Direct biochemical fermentation process to renewable gasoline and renewable gasoline blendstock (g CO_2-eq./mmBtu)
Domestic Livestock	7,648	6,770	~ 9,086
Domestic Farm Inputs and Fertilizer N_2O	1,397	1,237	~ 1,660
Domestic Rice Methane	366	324	~ 434
Domestic Land Use Change	−9,124	−8,076	~ −10,820
International Livestock	0	0	0
International Farm Inputs and Fertilizer N_2O	0	0	0
International Rice Methane	0	0	0
International Land Use Change	0	0	0
Total Feedstock Production Emissions:	287	254	~ 361
Assumed yield (gal/ton of biomass)	64.5	75	92.3

The results in Table 7 differ for the different pathways considered because of the different amounts of corn stover used to produce the same amount of fuel in each case. Table 7 only considers the feedstock production impacts associated with the renewable gasoline or renewable gasoline blendstocks pathways, other aspects of the lifecycle are discussed in the following sections.

2. Fuel Distribution

A petroleum gasoline baseline was developed as part of the RFS final rule which included estimates for fuel distribution emissions. Since renewable gasoline and renewable gasoline blendstocks when blended into gasoline are similar to petroleum gasoline, it is reasonable to assume similar fuel distribution emissions. Therefore, the existing fuel distribution lifecycle GHG impacts of the petroleum gasoline baseline from the RFS final rule were applied to this analysis.

3. Use of the Fuel

A petroleum gasoline baseline was developed as part of the RFS final rule which estimated the tailpipe emissions from fuel combustion. Since renewable gasoline and renewable gasoline blendstock are similar to petroleum gasoline in energy and hydrocarbon content, the non-CO_2 combustion emissions calculated as part of the RFS final rule for petroleum gasoline were applied to our analysis of the renewable gasoline and renewable gasoline blendstock pathways. Only non-CO_2 emissions were included since carbon fluxes from land use change are accounted for as part of the biomass feedstock production.

4. Fuel Production

In the March 2010 RFS rulemaking, EPA analyzed several of the main cellulosic biofuel pathways: a biochemical fermentation process to ethanol and two thermochemical gasification processes, one producing mixed alcohols (primarily ethanol) and the other one producing mixed hydrocarbons (primarily diesel fuel). These pathways all exceeded the 60% lifecycle GHG threshold requirements for cellulosic biofuel using the specified feedstocks. Refer to the preamble and regulatory impact analysis (RIA) from the final rule for more details. From these analyses, it was determined that ethanol and diesel fuel produced from the specified cellulosic feedstocks and processes would be eligible for cellulosic and advanced biofuel RINs.

The thermochemical gasification process to diesel fuel (via F–T synthesis) also produces a smaller portion of renewable gasoline blendstock. In the final rule, naphtha produced with specified cellulosic feedstocks by a F–T process was included as exceeding the 60% lifecycle GHG threshold, with an applicable D–Code of 3, in Table 1 to § 80.1426. In this rule, we are changing the reference to F–T as the process technology to the more correct reference as gasification technology since F–T reactions are only part of the process technology.

Since the final March 2010 RFS rule was released, EPA has received several petitions and inquiries that suggest that renewable gasoline or renewable gasoline blendstock produced using processes other than the F–T process could also qualify for a similar D–Code of 3.[54] For the reasons described below, we have decided to authorize the generation of RINs with a D code of 3 for renewable gasoline and renewable gasoline blendstock produced using specified cellulosic feedstocks for the processes considered here.

Several routes have been identified as available for the production of renewable gasoline and renewable gasoline blendstock from renewable biomass. These include catalytic pyrolysis and upgrading to renewable gasoline or renewable gasoline blendstock (''catalytic pyrolysis and upgrading''), biochemical fermentation with upgrading to renewable gasoline or renewable gasoline blendstock via carboxylic acid (''fermentation and upgrading''), and direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock (''direct fermentation'') and other thermo-catalytic hydrodeoxygenation routes with upgrading such as aqueous phase processing.[55] [56]

Similar to how we analyzed several of the main routes for cellulosic ethanol and cellulosic diesel for the final March 2010 RFS rule, we have chosen to analyze the main renewable gasoline and renewable gasoline blendstock pathways in order to estimate the potential GHG reduction profile for renewable gasoline and renewable gasoline blendstock across a range of other production technologies for which we are confident will have at least as great of GHG emission reductions as those specifically analyzed.

a. Catalytic Pyrolysis With Upgrading to Renewable Gasoline and Renewable Gasoline Blendstock

The first production process we investigated for this rule is a catalytic fast pyrolysis route to bio-oils with upgrading to a renewable gasoline or a renewable gasoline blendstock. We utilized process modeling results from the National Renewable Energy Laboratory (NREL). Information provided by industry and claimed as CBI are based on similar processing methods and suggest similar results than those reported by NREL. Details on the NREL modeling are described further in a technical report available through the docket.[57] Catalytic pyrolysis involves the rapid heating of biomass to about 500°C at slightly above atmospheric pressure. The rapid heating thermally decomposes biomass, converting it into pyrolysis vapor, which is condensed into a liquid bio-oil. The liquid bio-oil can then be upgraded using conventional hydroprocessing technology and further separated into renewable gasoline, renewable gasoline blendstock and renewable diesel streams (cellulosic diesel from catalytic pyrolysis is already included as an acceptable pathway in the RFS program). Some industry sources also expect to produce smaller fractions of heating oil in addition to gasoline and diesel blendstocks. Excess electricity from the process is also accounted for in our modeling as a co-product credit in which any excess displaces U.S. average grid electricity. Excess electricity is generated from the use of co-product coke/char and product gases and is available because internal electricity demands are fully met. The estimated energy inputs and electricity credits shown in Table 8, below, utilize the data provided by the NREL process modeling. However, industry sources also identified potential areas for improvements in energy use, such as the use of biogas fired dryers instead of natural gas fired dryers for drying incoming wet feedstocks and increased turbine efficiencies for electricity production which may result in lower energy consumption than estimated by NREL and thus improve GHG performance compared to our estimates here.

TABLE 8—2022 ENERGY USE AT CELLULOSIC BIOFUEL FACILITIES

[Btu/gal]

Technology	Biomass use	Natural gas use	Purchased electricity	Sold electricity
Catalytic Pyrolysis to Renewable Gasoline or Renewable Gasoline Blendstock	136,000	51,000	0	−2,000

[54] See *http://www.epa.gov/otaq/fuels/renewablefuels/compliancehelp/rfs2-lca-pathways.htm* for list of petitions received by EPA.

[55] Regalbuto, John. ''An NSF perspective on next generation hydrocarbon biorefineries,'' Computers and Chemical Engineering 34 (2010) 1393–1396. February 2010.

[56] Serrano-Ruiz, J., Dumesic, James. ''Catalytic routes for the conversion of biomass into liquid hydrocarbon transportation fuels,'' Energy Environmental Science (2011) 4, 83–99.

[57] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

The emissions from energy inputs were calculated by multiplying the amount of energy by emission factors for fuel production and combustion, based on the same method and factors used in the March 2010 RFS final rulemaking. The emission factors for the different fuel types are from GREET and were based on assumed carbon contents of the different process fuels. The emissions from producing electricity in the U.S. were also taken from GREET and represent average U.S. grid electricity production emissions.

The major factors influencing the emissions from the fuel production stage of the catalytic pyrolysis pathway are the use of natural gas (mainly due to hydrogen production for hydroprocessing) and the co-products available for additional heat and power generation.[58] See Table 9 for a summary of emissions from fuel production.

TABLE 9—FUEL PRODUCTION EMISSIONS FOR CATALYTIC PYROLYSIS AND UPGRADING TO RENEWABLE GASOLINE OR RENEWABLE GASOLINE BLENDSTOCK USING CORN STOVER

Lifecycle stage	Catalytic pyrolysis to renewable gasoline or renewable gasoline blendstock (g CO_2-eq./mmBtu)
On-Site & Upstream Emissions (Natural Gas & Biomass*)	31,000
Electricity Co-Product Credit	−3,000
Total Fuel Production Emissions:	28,000

* Only non-CO_2 combustion emissions from biomass

b. Catalytic Upgrading of Biochemically Derived Intermediates to Renewable Gasoline and Renewable Gasoline Blendstock

The second production process we investigated is a biochemical fermentation process to intermediate, such as carboxylic acids with catalytic upgrading to renewable gasoline or renewable gasoline blendstock. This process involves the fermentation of biomass using microorganisms that produce a variety of carboxylic acids. If the feedstock has high lignin content, then the biomass is pretreated to enhance digestibility. The acids are then neutralized to carboxylate salts and further converted to ketones and alcohols for refining into gasoline, diesel, and jet fuel.

The process requires the use of natural gas and hydrogen inputs.[59] No purchased electricity is required as lignin is projected to be used to meet all facility demands as well as provide excess electricity to the grid. EPA used the estimated energy and material inputs along with emission factors to estimate the GHG emissions from this process. The energy inputs and electricity credits are shown in Table 10, below. These inputs are based on Confidential Business Information (CBI), rounded to the nearest 1000 units, provided by industry as part of the petition process for new fuel pathways.

TABLE 10—2022 ENERGY USE AT CELLULOSIC FACILITY

[Btu/gal]

Technology	Biomass use	Natural gas use	Purchased electricity	Sold electricity
Biochemical Fermentation to Renewable Gasoline or Renewable Gasoline Blendstock via Carboxylic Acid	49,000	59,000	0	−2,000

The process also uses a small amount of buffer material as neutralizer which was not included in the GHG lifecycle results due to its likely negligible emissions impact. The GHG emissions estimates from the fuel production stage are seen in Table 11.

TABLE 11—FUEL PRODUCTION EMISSIONS FOR BIOCHEMICAL FERMENTATION TO RENEWABLE GASOLINE OR RENEWABLE GASOLINE BLENDSTOCK VIA CARBOXYLIC ACID USING CORN STOVER

Lifecycle stage	GHG Emissions (g CO_2-eq./mmBtu)
On-Site & Upstream Emissions (Natural Gas & Biomass*)	33,000
Electricity Co-Product Credit	−3,000
Total Fuel Production Emissions:	30,000

* Only non-CO_2 combustion emissions from biomass

[58] A steam methane reformer (SMR) is used to produce the hydrogen necessary for hydroprocessing. In the U.S. over 95% of hydrogen is currently produced via steam reforming (DOE, 2002 ''A National Vision of America's Transition to a Hydrogen Economy to 2030 and Beyond''). Other alternatives are available, such as renewable or nuclear resources used to extract hydrogen from water or the use of biomass to produces hydrogen. These alternative methods, however, are currently not as efficient or cost effective as the use of fossil fuels and therefore we conservatively estimate emissions from hydrogen production using the more commonly used SMR technology.

[59] Hydrogen emissions are modeled as natural gas and electricity demands.

c. Biological Conversion to Renewable Gasoline and Renewable Gasoline Blendstock

The third production process we investigated involves the use of microorganisms to biologically convert sugars hydrolyzed from cellulose directly into hydrocarbons which could be either a complete fuel as renewable gasoline or a renewable gasoline blendstock. The process is similar to the biochemical fermentation to ethanol pathway modeled for the final rule with the major difference being the end fuel product, hydrocarbons instead of ethanol. Researchers believe that this new technology could achieve improvements over classical fermentation approaches because hydrocarbons generally separate spontaneously from the aqueous phase, thereby avoiding poisoning of microbes by the accumulated products and facilitating separation/collection of hydrocarbons from the reaction medium. In other words, some energy savings may result because fewer separation unit operations could be required for separating the final product from other reactants and there may be better conversion yields as the fermentation microorganisms are not poisoned when interacting with accumulated products. We also expect that the lignin/byproduct portions of the biomass from the fermentation to hydrocarbon process could be converted into heat and electricity for internal demands or for export, similar to the biochemical fermentation to ethanol pathway.

Therefore, we can conservatively extend our final March 2010 RFS rule biochemical fermentation to ethanol process results to a similar (but likely slightly improved) process that instead produces hydrocarbons. Since the final rule cellulosic ethanol GHG results were well above the 60% GHG reduction threshold for cellulosic biofuels, if actual emissions from other necessary changes to the direct biochemical fermentation to hydrocarbons process represent some small increment in GHG emissions, the pathway would still likely meet the threshold. Table 12 is our qualitative assessment of the potential emissions reductions from a process using biochemical fermentation to cellulosic hydrocarbons assuming similarities to the biochemical fermentation to cellulosic ethanol route from the final rule.

TABLE 12—FUEL PRODUCTION EMISSIONS FOR MARCH 2010 RFS CELLULOSIC BIOCHEMICAL ETHANOL COMPARED TO DIRECT BIOCHEMICAL FERMENTATION TO RENEWABLE GASOLINE OR RENEWABLE GASOLINE BLENDSTOCK USING CORN STOVER

Lifecycle stage	Cellulosic biochemical ethanol emissions (g CO_2-eq./mmBtu)	Direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock emissions (g CO_2-eq./mmBtu)
On-Site Emissions & Upstream (biomass)	3,000	< or = 3,000
Electricity Co-Product Credit	−35,000	= −35,000
Total Fuel Production Emissions[60]:	−33,000	< or = −33,000

Table 13 below breaks down by stage the lifecycle GHG emissionsfor the renewable gasoline and renewable gasoline blendstock pathways using corn stover and the 2005 petroleum baseline. The table demonstrates the contribution of each stage in the fuel pathway and its relative significance in terms of GHG emissions. These results are also presented in graphical form in a supplemental memorandum to the docket.[61] As noted above, these analyses assume natural gas as the process energy when needed; using biogas as process energy would result in an even better lifecycle GHG impact.

TABLE 13—LIFECYCLE GHG EMISSIONS FOR RENEWABLE GASOLINE AND RENEWABLE GASOLINE BLENDSTOCK PATHWAYS USING CORN STOVER, 2022

[kg CO_2-eq./mmBtu]

Fuel type	Catalytic pyrolysis and upgrade to renewable gasoline and renewable gasoline blendstock	Biochemical fermentation to renewable gasoline and renewable gasoline blendstock via carboxylic acid	Direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock	2005 gasoline baseline
Net Domestic Agriculture (w/o land use change)	9	8	~ 11	
Net International Agriculture (w/o land use change)				
Domestic Land Use Change	−9	−8	~ −11	
International Land Use Change				
Fuel Production	28	30	< or = −33	19
Fuel and Feedstock Transport	2	2	~ 2	*
Tailpipe Emissions	2	2	~ 1	79
Total Emissions	32	34	< or = −29	98

[60] Numbers do not add up due to rounding.

[61] Memorandum to the Air and Radiation Docket EPA–HQ–OAR–2011–0542 ''Supplemental Information for Renewable Gasoline and Renewable Gasoline Blendstock Pathways Under the Renewable Fuel Standard (RFS2) Program''.

TABLE 13—LIFECYCLE GHG EMISSIONS FOR RENEWABLE GASOLINE AND RENEWABLE GASOLINE BLENDSTOCK PATHWAYS USING CORN STOVER, 2022—Continued

[kg CO_2-eq./mmBtu]

Fuel type	Catalytic pyrolysis and upgrade to renewable gasoline and renewable gasoline blendstock	Biochemical fermentation to renewable gasoline and renewable gasoline blendstock via carboxylic acid	Direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock	2005 gasoline baseline
% Change from Baseline	−67%	−65%	−129%	

* Emissions included in fuel production stage.

d. Extension of Modeling Results to Other Production Processes Producing Renewable Gasoline or Renewable Gasoline Blendstock

In the March 2010 RFS rulemaking, we modeled the GHG emissions results from the biochemical fermentation process to ethanol, thermochemical gasification processes to mixed alcohols (primarily ethanol) and mixed hydrocarbons (primarily diesel fuel). We extended these modeled process results to apply when the biofuel was produced from ''any'' process. We determined that since we modeled multiple cellulosic biofuel processes and all were shown to exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel using the specified feedstocks its was reasonable to extend to other processes (*e.g.* additional thermo-catalytic hydrodeoxygenation routes with upgrading similar to pyrolysis and aqueous phase processing) that might develop as these would likely represent improvements over existing processes as the industry works to improve the economics of cellulosic biofuel production by, for example, reducing energy consumption and improving process yields. Similarly, this rule assesses multiple processes for the production of renewable gasoline and renewable gasoline blendstocks and all were shown to exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel using specified feedstocks.

As was the case in our earlier rulemaking, a couple reasons in particular support extending our modeling results to other production process producing renewable gasoline or renewable gasoline blendstock from cellulosic feedstock. Under this rule we analyzed the core technologies most likely available through 2022 for production of renewable gasoline and renewable gasoline blendstock routes from cellulosic feedstock as shown in literature.[62] [63] The two primary routes for renewable gasoline and renewable gasoline blendstock production from cellulosic feedstock can be classified as either thermochemical or biological. Each of these two major categories has two subcategories. The processes under the thermochemical category include:

• Pyrolysis and Upgrading—in which cellulosic biomass is decomposed with temperature to bio-oils and requires further catalytic processing to produce a finished fuel

• Gasification—in which cellulosic biomass is decomposed to syngas with further catalytic processing of methanol to gasoline or through Fischer-Tropsch (F–T) synthesis to gasoline

The processes under the biochemical category include:

• Biological conversion to hydrocarbons—requires the release of sugars from biomass and microorganisms to biologically convert sugars straight into hydrocarbons instead of alcohols

• Catalytic upgrading of biochemically produced intermediates—requires the release of sugars from biomass and aqueous- or liquid-phase processing of sugars or biochemically produced intermediate products into hydrocarbons using solid catalysts,

As part of the modeling effort here, as well as for the March 2010 RFS final rule, we have considered the lifecycle GHG impacts of the four possible production technologies mentioned above. The pyrolysis and upgrading, direct biological conversion, and catalytic upgrading of biochemically produced intermediates are considered in this rule and the gasification route was already included in the March 2010 final rule. In all cases, the processes that we have considered meet the 60% lifecycle GHG reduction required for cellulosic biofuels. Furthermore, we believe that the results from our modeling would cover all the likely variations within these potential routes for producing renewable gasoline and renewable gasoline blendstock which also use natural gas, biogas or biomass[64] for process energy and that all such production variations would also meet the 60% lifecycle threshold.[65]

The main reason for this is that we believe that our energy input assumptions are reasonable at this time but probably in some cases are conservatively high for commercial scale cellulosic facilities. The cellulosic industry is in its early stages of development and many of the estimates of process technology GHG impacts is based on pre-commercial scale assessments and demonstration programs. Commercial scale cellulosic facilities will continue to make efficiency improvements over time to maximize their fuel products/co-products and minimize wastes. For cellulosic facilities, such improvements include increasing conversion yields and fully utilizing the biomass input for valuable products.

An example of increasing the amount of biomass utilized is the combustion of undigested or unconverted biomass for heat and power. The three routes that we analyzed for the production of renewable gasoline and renewable gasoline blendstock in today's rule assume an electricity production credit from the economically-driven use of lignin or waste byproducts; we also ran

[62] Regalbuto, John. ''An NSF perspective on next generation hydrocarbon biorefineries,'' Computers and Chemical Engineering 34 (2010) 1393–1396. February 2010.

[63] Serrano-Ruiz, J., Dumesic, James. ''Catalytic routes for the conversion of biomass into liquid hydrocarbon transportation fuels,'' Energy Environmental Science (2011) 4, 83–99.

[64] Our lifecycle analysis assumes that producers would use the same type of biomass as both the feedstock and the process energy.

[65] One commenter wanted clarification of the term ''process energy'' as it applies to the production of renewable gasoline. The EPA did not intend for the term, ''process energy'', to include other energy sources, such as electricity to provide power for ancillary processes, such as lights, small pumps, computers, and other small support equipment.

a sensitivity case where no electricity credit was given. We found that all of the routes analyzed would still pass the GHG threshold without an electricity credit, providing confidence that over the range of technology options, these process technologies will surely allow the cellulosic biofuel produced to exceed the threshold for cellulosic biofuel GHG performance. Without excess electricity production the catalytic pyrolysis pathway results in a 65% lifecycle GHG reduction, the biochemical fermentation via carboxylic acid pathway results in a 62% lifecycle GHG reduction, and the direct biochemical fermentation pathway results in a 93% reduction in lifecycle GHG emissions compared to the petroleum fuel baseline.

Additionally, while the final results reported in this rule include an electricity credit, this electricity credit is based on current technology for generating electricity; it is possible that over the next decade as cellulosic biofuel production matures, the efficiency with which electricity is generated at these facilities will also improve. Such efficiency improvements will tend to improve the GHG performance for cellulosic biofuel technologies in general including those used to produce renewable gasoline.

Furthermore, industry has identified other areas for energy improvements which our current pathway analyses do not include. Therefore, the results we have come up with for the individual pathway types represent conservative estimates and any variations in the pathways considered are likely to result in greater GHG reductions than what is considered here. For example, the variation of the catalytic pyrolysis route considered here resulted in a 67% reduction in lifecycle GHG emissions compared to the petroleum baseline. However, as was mentioned this was based on data from our NREL modeling and industry CBI data indicated more efficient energy performance which, if realized, would improve GHG performance. Another area for improvement in this pathway could be the use of anaerobic digestion to treat organics in waste water. If the anaerobic digestion is on-site, then enough biogas could potentially be produced to replace all of the fossil natural gas used as fuel and about half the natural gas fed for hydrogen production.[66] Thus, fossil natural gas consumption could be further minimized under certain scenarios. We believe that as commercial scale cellulosic facilities develop, more of these improvements will be made to maximize the use of all the biomass and waste byproducts available to bring the facility closer to energy self-sufficiency. These improvements could help to increase the economic profitability for cellulosic facilities where fossil energy inputs become costly to purchase. Therefore we can extend the modeling results for our pyrolysis route to all variations of this production technology which use natural gas, biogas or biomass for production energy for producing renewable gasoline or renewable gasoline blendstock.

The F–T gasification technology route considered as part of the March 2010 RFS final rule resulted in an approximately 91% reduction in lifecycle GHG emissions compared to the petroleum baseline. This could be considered a conservatively high estimate as the process did not assume any excess electricity production, which as mentioned above could lead to additional GHG reductions. The F–T process involves gasifying biomass into syngas (mix of H_2 and CO) and then converting the syngas through a catalytic process into a hydrocarbon mix that is further refined into finished product. The F–T process considered was based on producing both gasoline and diesel fuel so that it was not optimized for renewable gasoline production. A process for producing primarily renewable gasoline rather than diesel from a gasification route should not result in a significantly worse GHG impacts compared to the mixed fuel process analyzed. Furthermore, as the lifecycle GHG reduction from the F–T process considered was around 91%, there is considerable room for variations in this route to still meet the 60% lifecycle GHG reduction threshold for cellulosic fuels. Therefore, in addition to the F–T process originally analyzed for producing naphtha, we can extend the results based on the above analyses to include all variations of the gasification route which use natural gas, biogas or biomass for production energy for producing renewable gasoline or renewable gasoline blendstock. These variations include for example different catalysts and different refining processes to produce different mixes of final fuel product. While the current Table 1 entry in the regulations does not specify process energy sources, we are adding these specific eligible energy sources since we have not analyzed other energy sources (*e.g.,* coal) as also allowing the pathway to meet the GHG performance threshold.

There is an even wider gap between the results modeled for the direct fermentation route and the cellulosic lifecycle GHG threshold. The variation we considered for the direct fermentation process resulted in an approximately 129% reduction in lifecycle GHG emissions compared to the petroleum baseline. This process did consider production of electricity as part of the process but as mentioned even if this was not the case the pathway would still easily fall below the 60% lifecycle threshold for cellulosic biofuels. If actual emissions from other necessary changes to the direct biochemical fermentation to hydrocarbons process represent some small increment in GHG emissions, the pathway would still likely meet the threshold. Therefore, we can extend the results to all variations of the direct biochemical route for renewable gasoline or renewable gasoline blendstock production which use natural gas, biogas or biomass for production energy.

The biochemical with catalytic upgrading route that we evaluated resulted in a 65% reduction in GHG emissions compared to the petroleum baseline. However, this can be considered a conservatively high estimate. For instance, the biochemical fermentation to gasoline via carboxylic acid route considered did not include the potential for generating steam from the combustion of undigested biomass and then using this steam for process energy. If this had been included, natural gas consumption could potentially be decreased which would lower the potential GHG emissions estimated from the process. Therefore, the scenario analyzed could be considered conservative in estimating actual natural gas usage. As was the case with the pyrolysis route considered, we believe that as commercial scale cellulosic facilities develop, improvements will be made to maximize the use of all the biomass and waste byproducts available to bring the facility closer to energy self-sufficiency. These improvements help to increase the economic profitability for cellulosic facilities where fossil energy inputs become costly to purchase. The processes we analyzed for this rulemaking utilized a mix of natural gas and biomass for process energy, with biogas replacing natural gas providing improved GHG performance. We have not analyzed other fuel types (*e.g.,* coal) and are therefore not approving processes that utilized other fuel sources at this point. Therefore, we are

[66] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

extending our results to include all variations of the biochemical with catalytic upgrading process utilizing natural gas, biogas or biomass for process energy.

While actual cellulosic facilities may show some modifications to the process scenarios we have already analyzed, our results give a good indication of the range of emissions we could expect from processes producing renewable gasoline and renewable gasoline blendstock from cellulosic feedstock, all of which meet the 60% cellulosic biofuel threshold (assuming they are utilizing natural gas, biogas or biomass for process energy). Technology changes in the future are likely to increase efficiency to maximize profits, while also lowering lifecycle GHG emissions. Therefore, we have concluded that since all of the renewable gasoline or renewable gasoline blendstock fuel processing methods we have analyzed exceed the 60% threshold using specific cellulosic feedstock types, we can conclude that processes producing renewable gasoline or renewable gasoline blendstock that fit within the categories of process analyzed here and are produced from the same feedstock types and using natural gas, biogas or biomass for process energy use will also meet the 60% GHG reduction threshold. In addition, while other technologies may develop, we expect that they will only become commercially competitive if they have better yields (more gallons per ton of feedstock) or lower production costs due to lower energy consumption. Both of these factors would suggest better GHG performance. This would certainly be the case if such processes also relied upon using biogas and/or biomass as the primary energy source. Therefore based on our review of the existing primary cellulosic biofuel production processes, likely GHG emission improvements for existing or new technologies, and consideration of the positive GHG emissions benefits associated with using biogas and/or biomass for process energy, we are approving for cellulosic RIN generation any process for renewable gasoline and renewable gasoline blendstock production using specified cellulosic biomass feedstocks as long as the process utilizes biogas and/or biomass for all process energy.

5. Summary

Three renewable gasoline and renewable gasoline blendstock pathways were compared to baseline petroleum gasoline, using the same value for baseline gasoline as in the March 2010 RFS final rule analysis. The results of the analysis indicate that the renewable gasoline and renewable gasoline blendstock pathways result in a GHG emissions reduction of 65–129% or better compared to the gasoline fuel it would replace using corn stover as a feedstock. The renewable gasoline and renewable gasoline blendstock pathways which use corn stover as a feedstock all exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel, these pathways capture the likely current technologies, and future technology improvements are likely to increase efficiency and lower GHG emissions. Therefore we have determined that all processes producing renewable gasoline or renewable gasoline blendstock from corn stover can qualify if they fall in the following process characterizations:

- Catalytic pyrolysis and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources
- Gasification and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources
- Thermo-catalytic hydrodeoxygenation processes such as aqueous phase processing with upgrading sufficiently similar to pyrolysis and gasification
- Direct fermentation utilizing natural gas, biogas, and/or biomass as the only process energy sources
- Fermentation and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources
- Any process utilizing biogas and/or biomass as the only process energy sources.

As was the case for extending corn stover results to other feedstocks in the March 2010 RFS final rule, these results are also reasonably extended to feedstocks with similar or lower GHG emissions profiles, including the following feedstocks:

- Cellulosic biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual cover crops;
- Cellulosic components of separated yard waste;
- Cellulosic components of separated food waste; and
- Cellulosic components of separated MSW

For more information on the reasoning for extension to these other feedstocks refer to the feedstock production and distribution section or the March 2010 RFS rulemaking (75 FR 14670).

Based on these results, today's rule includes pathways for the generation of cellulosic biofuel RINs for renewable gasoline or renewable gasoline blendstock produced by catalytic pyrolysis and upgrading, gasification and upgrading, other similar thermo-catalytic hydrodeoxygenation routes with upgrading, direct fermentation, fermentation and upgrading, all utilizing natural gas, biogas, and/or biomass as the only process energy sources or any process utilizing biogas and/or biomass as the only energy sources, and using corn stover as a feedstock or the feedstocks noted above. In order to qualify for RIN generation, the fuel must meet the other definitional criteria for renewable fuel (*e.g.,* produced from renewable biomass, and used to reduce or replace petroleum-based transportation fuel, heating oil or jet fuel) specified in the Clean Air Act and the RFS regulations.

A manufacturer of a renewable motor vehicle gasoline (including parties using a renewable blendstock obtained from another party), must satisfy EPA motor vehicle registration requirements in 40 CFR part 79 for the fuel to be used as a transportation fuel. Per 40 CFR 79.56(e)(3)(i), a renewable motor vehicle gasoline would be in the Non-Baseline Gasoline category or the Atypical Gasoline category (depending on its properties) since it is not derived only from conventional petroleum, heavy oil deposits, coal, tar sands and/or oil sands (40 CFR 79.56(e)(3)(i)(5)). In either case, the Tier 1 requirements at 40 CFR 79.52 (emissions characterization) and the Tier 2 requirements at 40 CFR 79.53 (animal exposure) are conditions for registration unless the manufacturer qualifies for a small business provision at 40 CFR 79.58(d). For a non-baseline gasoline, a manufacturer under $50 million in annual revenue is exempt from Tier 1 and Tier 2. For an atypical gasoline there is no exemption from Tier 1, but a manufacturer under $10 million in annual revenue is exempt from Tier 2.

Registration for a motor vehicle gasoline at 40 CFR 79 is via EPA Form 3520–12, Fuel Manufacturer Notification for Motor Vehicle Fuel, available at: *http://www.epa.gov/otaq/regs/fuels/ffarsfrms.htm.*

D. Esterification Production Process Inclusion for Specified Feedstocks Producing Biodiesel

The Agency is not taking final action at this time on its proposed inclusion of the process ''esterification'' as an approved biodiesel production process in Table 1 to § 40 CFR 80.1426. See 77 FR 465. We continue to evaluate the issue and anticipate issuing a final determination as part of a subsequent rulemaking.

III. Additional Changes to Listing of Available Pathways in Table 1 of 80.1426

We are also finalizing two changes to Table 1 to 80.1426 that were proposed on July 1, 2011(76 FR 38844). The first change adds ID letters to pathways to facilitate references to specific pathways. The second change adds ''rapeseed'' to the existing pathway for renewable fuel made from canola oil.

On September 28, 2010, EPA published a ''Supplemental Determination for Renewable Fuels Produced Under the Final RFS2 Program from Canola Oil'' (75 FR 59622). In the July 1, 2011 NPRM (76 FR 38844) we proposed to clarify two aspects of the supplemental determination. First we proposed to amend the regulatory language in Table 1 to § 80.1426 to clarify that the currently-approved pathway for canola also applies more generally to rapeseed. While ''canola'' was specifically described as the feedstock evaluated in the supplemental determination, we had not intended the supplemental determination to cover just those varieties or sources of rapeseed that are identified as canola, but to all rapeseed. As described in the July 1, 2011 NPRM, we currently interpret the reference to ''canola'' in Table 1 to § 80.1426 to include any rapeseed. To eliminate ambiguity caused by the current language, however, we proposed to replace the term ''canola'' in that table with the term ''canola/rapeseed''. Canola is a type of rapeseed. While the term ''canola'' is often used in the American continent and in Australia, the term ''rapeseed'' is often used in Europe and other countries to describe the same crop. We received no adverse comments on our proposal, and are finalizing it as proposed. This change will enhance the clarity of the regulations regarding the feedstocks that qualify under the approved canola biodiesel pathway.

Second, we wish to clarify that although the GHG emissions of producing fuels from canola feedstock grown in the U.S. and Canada was specifically modeled as the most likely source of canola (or rapeseed) oil used for biodiesel produced for sale and use in the U.S., we also intended that the approved pathway cover canola/rapeseed oil from other countries, and we interpret our regulations in that manner. We expect the vast majority of biodiesel used in the U.S. and produced from canola/rapeseed oil will come from U.S. and Canadian crops. Incidental amounts from crops produced in other nations will not impact our average GHG emissions for two reasons. First, our analyses considered world-wide impacts and thus considered canola/rapeseed crop production in other countries. Second, other countries most likely to be exporting canola/rapeseed or biodiesel product from canola/rapeseed are likely to be major producers which typically use similar cultivars and farming techniques. Therefore, GHG emissions from producing biodiesel with canola/rapeseed grown in other countries should be very similar to the GHG emissions we modeled for Canadian and U.S. canola, though they could be slightly (and insignificantly) higher or lower. At any rate, even if there were unexpected larger differences, EPA believes the small amounts of feedstock or fuel potentially coming from other countries will not impact our threshold analysis. Therefore, EPA interprets the approved canola pathway as covering canola/rapeseed regardless of country of origin.

We are also correcting an inadvertent omission to the proposal which incorrectly did not include a pathway for producing naphtha from switchgrass and miscanthus; this pathway was included in the original March 2010 RFS final rule. This pathway also incorporates the additional energy grass feedstock sources being added today, namely energy cane.

IV. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action.'' Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The corrections, clarifications, and modifications to the final March 2010 RFS regulations contained in this rule are within the scope of the information collection requirements submitted to the Office of Management and Budget (OMB) for the final March 2010 RFS regulations.

OMB has approved the information collection requirements contained in the existing regulations at 40 CFR part 80, subpart M under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060– 0637 and 2060–0640. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this action on small entities, I certify that this rule will not have a significant economic impact on a substantial number of small entities. This rule will not impose any new requirements on small entities. The relatively minor corrections and modifications this rule makes to the final March 2010 RFS regulations do not impact small entities.

D. Unfunded Mandates Reform Act

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. We have determined that this action will not result in expenditures of $100 million or more for the above parties and thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. It only applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers and makes relatively minor corrections and modifications to the RFS regulations.

E. Executive Order 13132 (Federalism)

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This action only applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers and makes relatively minor corrections and modifications to the RFS regulations. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175 (Consultation and Coordination With Indian Tribal Governments)

This rule does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers. This action makes relatively minor corrections and modifications to the RFS regulations, and does not impose any enforceable duties on communities of Indian tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This rulemaking does not change any programmatic structural component of the RFS regulatory requirements. This rulemaking does not add any new requirements for obligated parties under the program or mandate the use of any of the new pathways contained in the rule. This rulemaking only makes a determination to qualify new fuel pathways under the RFS regulations, creating further opportunity and flexibility for compliance with the Energy Independence and Security Act of 2007 (EISA) mandates.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. These amendments would not relax the control measures on sources regulated by the RFS regulations and therefore would not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

V. Statutory Provisions and Legal Authority

Statutory authority for the rule finalized today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for today's rule comes from Section 301(a) of the Clean Air Act, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Administrative practice and procedure, Agriculture, Air pollution control, Confidential business information, Diesel Fuel, Energy, Forest and Forest Products, Fuel additives, Gasoline, Imports, Labeling, Motor vehicle pollution, Penalties, Petroleum, Reporting and recordkeeping requirements.

Dated: February 22, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons set forth in the preamble, 40 CFR part 80 is amended as follows:

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

■ 1. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7521(1), 7545 and 7601(a).

■ 2. Section 80.1401 is amended by adding definitions of ''Energy cane,'' ''Renewable gasoline'' and ''Renewable gasoline blendstock'' in alphabetical order to read as follows:

§ 80.1401 Definitions.

* * * * *

Energy cane means a complex hybrid in the Saccharum genus that has been bred to maximize cellulosic rather than sugar content. For the purposes of this section, energy cane excludes the species *Saccharum spontaneum*, but includes hybrids derived from *S.*

spontaneum that have been developed and publicly released by USDA.

* * * * *

Renewable gasoline means renewable fuel made from renewable biomass that is composed of only hydrocarbons and which meets the definition of gasoline in § 80.2(c).

Renewable gasoline blendstock means a blendstock made from renewable biomass that is composed of only hydrocarbons and which meets the definition of gasoline blendstock in § 80.2(s).

* * * * *

■ 3. Section 80.1426 is amended by revising Table 1 in paragraph (f)(1) to read as follows:

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

* * * * *

(f) * * *

(1) * * *

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS

	Fuel type	Feedstock	Production process requirements	D–Code
A	Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least two advanced technologies from Table 2 to this section.	6
B	Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least one of the advanced technologies from Table 2 to this section plus drying no more than 65% of the distillers grains with solubles it markets annually.	6
C	Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and drying no more than 50% of the distillers grains with solubles it markets annually.	6
D	Ethanol	Corn starch	Wet mill process using biomass or biogas for process energy.	6
E	Ethanol	Starches from crop residue and annual covercrops.	Fermentation using natural gas, biomass, or biogas for process energy.	6
F	Biodiesel, renewable diesel, jet fuel and heating oil.	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil *Camelina sativa* oil.	One of the following: Trans-Esterification Hydrotreating Excluding processes that co-process renewable biomass and petroleum.	4
G	Biodiesel, heating oil.	Canola/Rapeseed oil	Trans-Esterification using natural gas or biomass for process energy.	4
H	Biodiesel, renewable diesel, jet fuel and heating oil.	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil *Camelina sativa* oil.	One of the following: Trans-Esterification Hydrotreating Includes only processes that co-process renewable biomass and petroleum.	5
I	Naphtha, LPG	*Camelina sativa* oil	Hydrotreating	5
J	Ethanol	Sugarcane	Fermentation	5
K	Ethanol	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual covercrops, switchgrass, miscanthus, and energy cane; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Any	3
L	Cellulosic diesel, jet fuel and heating oil.	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual covercrops, switchgrass, miscanthus, and energy cane; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Any	7
M	Renewable gasoline and renewable gasoline blendstock.	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings, tree residue, annual cover crops; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Catalytic Pyrolysis and Upgrading, Gasification and Upgrading, Thermo-Catalytic Hydrodeoxygenation and Upgrading, Direct Biological Conversion, Biological Conversion and Upgrading, all utilizing natural gas, biogas, and/or biomass as the only process energy sources Any process utilizing biogas and/or biomass as the only process energy sources.	3
N	Naphtha	Cellulosic biomass from switchgrass, miscanthus, and energy cane.	Gasification and upgrading	3
O	Butanol	Corn starch	Fermentation; dry mill using natural gas, biomass, or biogas for process energy.	6

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS—Continued

	Fuel type	Feedstock	Production process requirements	D–Code
P	Ethanol, renewable diesel, jet fuel, heating oil, and naphtha.	The non-cellulosic portions of separated food waste.	Any	5
Q	Biogas	Landfills, sewage waste treatment plants, manure digesters.	Any	5
R	Ethanol	Grain Sorghum	Dry mill process using biogas from landfills, waste treatment plants, and/or waste digesters, and/or natural gas, for process energy.	6
S	Ethanol	Grain Sorghum	Dry mill process, using only biogas from landfills, waste treatment plants, and/or waste digesters for process energy and for on-site production of all electricity used at the site other than up to 0.15 kWh of electricity from the grid per gallon of ethanol produced, calculated on a per batch basis.	5

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[FR Doc. 2013–04929 Filed 3–4–13; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

49 CFR Part 219

[Docket No. FRA–2010–0155]

RIN 2130–AC24

Control of Alcohol and Drug Use: Addition of Post-Accident Toxicological Testing for Non-Controlled Substances

AGENCY: Federal Railroad Administration (FRA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: In 1985, FRA implemented a post-accident toxicological testing (post-accident testing) program to test railroad employees who had been involved in serious train accidents for alcohol and certain controlled substances (marijuana, cocaine, phencyclidine (PCP), and selected opiates, amphetamines, barbiturates, and benzodiazepines). This final rule adds certain non-controlled substances with potentially impairing side effects to its standard post-accident testing panel. The non-controlled substances include tramadol and sedating antihistamines. This final rule makes clear that FRA intends to keep the post-accident test results for these non-controlled substances confidential while it continues to obtain and analyze data on the extent to which prescription and over-the-counter (OTC) drug use by railroad employees potentially affects rail safety.

DATES: This rule is effective on May 6, 2013. Petitions for reconsideration must be received on or before May 6, 2013. Petitions for reconsideration will be posted in the docket for this proceeding. Comments on any submitted petition for reconsideration must be received on or before June 18, 2013.

ADDRESSES: Petitions for reconsideration or comments on such petitions: Any petitions and any comments to petitions related to Docket No. FRA–2010–0155, may be submitted by any of the following methods:

- *Online:* Comments should be filed at the Federal eRulemaking Portal, *http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Management Facility, U.S. DOT, 1200 New Jersey Avenue SE., W12–140, Washington, DC 20590.
- *Hand Delivery:* Room W12–140 on the Ground level of the West Building, 1200 New Jersey Avenue SE., Washington, DC between 9 a.m. and 5 p.m. Monday through Friday, except federal holidays.

Instructions: All submissions must include the agency name and docket number or Regulatory Identification Number (RIN) for this rulemaking. All petitions and comments received will be posted without change to *http://www.regulations.gov*; this includes any personal information. Please see the Privacy Act heading in the ''Supplementary Information'' section of this document for Privacy Act information related to any submitted petitions or materials.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov* at any time or to Room W12–140 on the Ground level of the West Building, 1200 New Jersey Avenue SE, Washington, DC between 9 a.m. and 5 p.m. Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Patricia V. Sun, Trial Attorney, Office of Chief Counsel, Mail Stop 10, FRA, 1200 New Jersey Avenue SE. Washington, DC 20590 (telephone 202–493–6060), *patricia.sun@dot.gov.*

SUPPLEMENTARY INFORMATION:

The NPRM

In 1985, to further its accident investigation program, FRA began conducting alcohol and drug tests on railroad employees who had been involved in serious train accidents that met its specified criteria for post-accident testing (*see* 49 CFR 219.201). Since the program's inception, FRA has routinely conducted post-accident tests for alcohol and for certain drugs classified by the Drug Enforcement Administration (DEA) as controlled substances because of their potential for abuse or addiction. *See* the Controlled Substances Act (CSA), Title II of the Comprehensive Drug Abuse Prevention Substances Act of 1970 (CSA, 21 U.S.C. 801 et seq.). As noted in the NPRM, FRA has historically conducted post-accident tests for alcohol and marijuana, cocaine, phencyclidine (PCP), and certain opiates, amphetamines, barbiturates, and benzodiazepines. The purpose of these tests is to determine if alcohol misuse or drug abuse played a role in the occurrence or severity of an accident.

On May 17, 2012, FRA proposed to add routine post-accident tests for certain non-controlled substances with potentially impairing side effects (77 FR 29307). As discussed in the NPRM, studies have shown a significant increase in the daily use of prescription drugs, OTC drugs, vitamins, and herbal