ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2012–0401; FRL–9816–3]

RIN 2060—AR21

Regulation of Fuels and Fuel Additives: RFS Pathways II and Technical Amendments to the RFS 2 Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of Proposed Rulemaking.

SUMMARY: In this Notice of Proposed Rulemaking, EPA is proposing amendments to three separate sets of regulations relating to fuels. First, EPA is proposing to amend certain of the renewable fuels standard (RFS2) program regulations. We believe these proposals will facilitate the introduction of new renewable fuels as well as improve implementation of the program. This proposal includes various changes related to biogas, including changes related to the revised compressed natural gas (CNG)/liquefied natural gas (LNG) pathway and amendments to various associated registration, recordkeeping, and reporting provisions. This proposed regulation includes the addition of new pathways for renewable diesel, renewable naphtha, and renewable electricity (used in electric vehicles) produced from landfill biogas. Adding these new pathways will enhance the ability of the biofuels industry to supply advanced biofuels, including cellulosic biofuels, which greatly reduce the greenhouse gas emissions (GHG) compared to the petroleum-based fuels they replace. It also addresses ''nameplate capacity'' issues for certain production facilities that do not claim exemption from the 20% greenhouse gas (GHG) reduction threshold. In this notice, EPA addresses issues related to crop residue and corn kernel fiber and proposes an approach to determining the volume of cellulosic RINs produced from various cellulosic feedstocks. We also include a lifecycle analysis of advanced butanol and discuss the potential to allow for commingling of compliant products at the retail facility level as long as the environmental performance of the fuels would not be detrimental. Several other amendments to the RFS2 program are included.

Second, EPA is also proposing various changes to the E15 misfueling mitigation regulations (E15 MMR). Among the E15 changes proposed are technical corrections and amendments to sections dealing with labeling, E15 surveys, product transfer documents, and prohibited acts. We also propose to amend the definitions in order to address a concern about the rounding of test results for ethanol content violations.

Lastly, EPA is proposing changes to the survey requirements associated with the ultra-low sulfur diesel (ULSD) program.

DATES: Comments must be received on or before July 15, 2013. We do not expect a request for a public hearing. However, if we receive a request for a public hearing by July 1, 2013 we will publish information related to the timing and location of the hearing and the timing of a new deadline for public comments.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2012–0401, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov,* Attention Air and Radiation Docket ID No. EPA–HQ–OAR–2012–0401.
- *Mail:* Air and Radiation Docket, Docket No. EPA–HQ–OAR–2012–0401, Environmental Protection Agency, Mail code: 6406J, 1200 Pennsylvania Ave. NW., Washington, DC 20460. Please include a total of two (2) copies.
- *Hand Delivery:* EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460, Attention Air and Radiation Docket, ID No. EPA–HQ–OAR–2012–0401. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2012–0401. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through www.regulations.gov or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information for which disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Joseph Sopata, Chemist, Office of Transportation and Air Quality, Mail Code: 6406J, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., 20460; telephone number: (202) 343–9034; fax number: (202) 343–2801; email address: *sopata.joe@epa.gov.*

SUPPLEMENTARY INFORMATION: This preamble follows the following outline:

I. Why is EPA taking this action?

EPA is taking this action to amend various provisions in its regulations pertaining to fuels and fuel additives. First, EPA is proposing to amend 40 CFR part 80, subpart M related to the renewable fuels standard (RFS2). The RFS2 program was required by the Energy Independence and Security Act of 2007 (EISA 2007), which amended the Clean Air Act (CAA). The final regulations for RFS2 were published in the **Federal Register** on March 26, 2010 (75 FR 14670). In this notice, references to the ''RFS2 final rule'' refer to the March 26, 2010 **Federal Register** notice unless otherwise noted. Second, EPA is proposing to amend provisions of 40 CFR part 80, subpart N, related to misfueling mitigation for 15 volume percent (%) ethanol blends (E15). The final regulations for E15 were published in the **Federal Register** on July 25, 2011 (76 FR 44422). Several items in this proposed action will assist regulated parties in complying with RFS2 and E15 requirements. This action is not expected to result in significant changes in regulatory burdens or costs associated with the RFS2 and E15 programs. Third, EPA is proposing a change to the ultra low sulfur diesel (ULSD) program of 40 CFR part 80, subpart I. Specifically, EPA is proposing an amendment to the survey provisions that would likely result in decreasing the number of samples that must be taken, and as such would be expected to result in a decrease in regulatory burdens or costs.

II. Does this action apply to me?

Entities potentially affected by this action include 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 Codes [a]	SIC Codes [b]	Examples of potentially regulated parties
Industry	324110	2911	Petroleum refiners, importers.
Industry	325193	2869	Ethyl alcohol manufacturers.
Industry	325199	2869	Other basic organic chemical manufacturers.
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.

[a] North American Industry Classification System (NAICS).
[b] 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 I, M and N 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.

III. What should I consider as I prepare my comments for EPA?

A. *Submitting CBI.* Do not submit this information to EPA through *www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

B. *Tips for Preparing Your Comments.* When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

C. *Docket Copying Costs.* You may be charged a reasonable fee for photocopying docket materials, as provided in 40 CFR part 2.

IV. Executive Summary

EPA is proposing amendments to three sets of regulations. First, EPA is proposing to amend certain of the renewable fuels standard (RFS2) program regulations at 40 CFR part 80, Subpart M. Section V of this preamble includes several proposed amendments to the RFS2 regulations of 40 CFR part 80. The final regulations for RFS2 were published in the **Federal Register** on March 25, 2010 (75 FR 14670). EPA has issued technical corrections in the past. We have identified several additional changes. Some of the proposed changes in this notice are of a substantive nature; others are more in the nature of technical corrections, including corrections of obvious omissions and errors in citation. Among the more substantive modifications are various proposed changes related to biogas, including changes related to the revised compressed natural gas (CNG)/liquefied natural gas (LNG) pathway and amendments to various associated registration, recordkeeping, and reporting provisions. These fuels have the potential to add notable volumes of advanced biofuel including cellulosic biofuel to the existing renewable fuel volumes already being produced. Many of these changes are being proposed in order to facilitate the introduction of new renewable fuels under the RFS2 program and have come at the suggestion of industry stakeholders.

This preamble includes the addition of new pathways for renewable diesel, and renewable naphtha, and renewable electricity (used in electric vehicles) produced from landfill biogas. It includes a proposal to address ''nameplate capacity'' issues for certain production facilities that do not claim exemption from the 20% greenhouse gas (GHG) reduction threshold. EPA proposes to address issues related to crop residue and corn kernel fiber. We propose an approach for approving the cellulosic volumes from cellulosic feedstocks. We include a lifecycle analysis of advanced butanol and discuss the potential to allow for commingling of compliant products at the retail facility level as long as the environmental performance of the fuels would not be detrimental when compared to existing practices. We specifically discuss this consideration for commingling in regards to the volatility associated with butanol gasoline and ethanol gasoline blends.

We state when and how EPA may cancel a company registration. Of a more minor scope, this preamble includes proposed amendments that would define terminology used for registration and reporting purposes and propose changes to registration and reporting requirements. This preamble also discusses some minor corrections, including adding language to registration, recordkeeping and reporting sections requiring English language translation of documents. We have also proposed to correct obvious omissions and errors in citation in the existing RFS2 regulation.

Second, EPA is also proposing various changes to the E15 misfueling mitigation regulations (E15 MMR) at 40 CFR part 80, subpart N. The final E15 MMR was published in the **Federal Register** on July 25, 2011 (76 FR 44406). Among the E15 changes proposed are technical corrections and amendments to sections dealing with labeling, E15 surveys, product transfer documents, and prohibited acts. We also propose to amend the definitions in order to address a concern about the rounding of Reid Vapor Pressure (RVP) test results, in response to a question raised by some industry stakeholders.

Third, in response to questions received from regulated parties, we propose to amend the ultra low sulfur diesel (ULSD) survey provisions in a manner that will likely reduce the number of samples required. This may mean a reduction in costs and burdens associated with compliance for regulated parties, with no expected degradation in the highly successful environmental performance of the program.

V. Renewable Fuel Standard (RFS2) Program Amendments

The RFS2 program was required by the Energy Independence and Security Act of 2007 (EISA 2007), which amended the Clean Air Act (CAA). The final regulations for RFS2 were published in the **Federal Register** on March 26, 2010 (75 FR 14670). The rule took effect on July 1, 2010. In this notice, we are proposing several new renewable fuel pathway options for advanced biofuels including new cellulosic biofuel pathways. This proposed regulation would also provide modifications and technical amendments to the existing RFS2 program.

A. Approving Cellulosic Volumes From Cellulosic Feedstocks

Since the inception of the RFS program, EPA has qualified several fuel pathways that are able to generate cellulosic biofuel RINs (D codes 3 and 7). *See* 40 CFR 80.1426. Each of the qualified cellulosic feedstocks listed in section 80.1426 contain other components such as starches, sugars, lipids, and proteins. To date, EPA has not provided detailed information on how other components should be treated. This has led to uncertainty amongst renewable fuel producers about whether their entire volume of fuel produced from a cellulosic feedstock would be eligible to generate cellulosic RINs. In this rulemaking, EPA proposes to allow 100% of the volume of renewable fuel produced from certain specified, currently approved cellulosic feedstocks to generate cellulosic (D–3 or D–7) RINs. We also take comment on two alternative approaches for how to treat non-cellulosic components of cellulosic feedstocks.

For purposes of the RFS program, cellulosic biofuel is defined as ''renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.'' This definition was added in Section 211(o)(1)(E) by the Energy Independence and Security Act (EISA) of 2007, where Congress specified four different categories of renewable fuel and their associated volume requirements. The threshold for reduction in greenhouse gases is set at a higher percentage for cellulosic biofuel than the reduction for the other categories of renewable fuels. While the volume requirements for cellulosic biofuel start at a relatively low volume, Congress specified large volume increases over time such that the main growth in the use of renewable fuels comes from cellulosic biofuels. This reflects a strong Congressional intention to promote the use of cellulosic biofuel and achieve the associated greenhouse gas emissions reductions.

However, no plant matter can ever consist entirely of cellulose, hemicellulose and lignin. Plants require proteins, DNA, carbohydrates and many other types of compounds in order to grow and function. Even feedstocks such as switchgrass, corn stover, and woody materials which are the most commonly cited ''cellulosic'' feedstocks, contain measurable proportions of other types of organic molecules. However, these ''cellulosic'' feedstocks contain much more cellulose, hemicellulose and lignin than do other types of biomass. As shown in Table V.A.–1, most ''cellulosic'' feedstocks consist of approximately 80–95% cellulose, hemicellulose, or lignin.[1] In contrast, corn kernels contain roughly 75% starch and less than 10% fiber (which includes the cellulosic components, as well as other materials),[2] and soybeans are roughly 60% oil and protein and only about 15% fiber.[3]

TABLE V.A.–1—AVERAGE CELLULOSIC COMPOSITION OF DIFFERENT TYPES OF FEEDSTOCKS[4]

Feedstock type	Average adjusted cellulosic composition (percent)
Crop Residue	90
Switchgrass	85
Miscanthus	85
Other Grasses	81
Wood and Branches	92

EPA is proposing to allow 100% of the volume of renewable fuel produced from specific cellulosic feedstock sources found in Table 1 of section 80.1426 to generate D–3 or D–7 RINs (depending on the type of finished fuel). However separated food waste, separated yard waste, and separated MSW would continue to be treated as before, as discussed below. There are three major justifications for this determination: (1) There can be significant variation in the amount of cellulosic content in any feedstock, which varies within a growing season, across samples, and across sites. Attempting to account for this variability would impose a significant administrative burden on producers and EPA; (2) The amount of the final fuel that is produced from the cellulosic portion of the feedstock is likely to be very high, particularly for fuels produced using a biochemical reaction; (3) EPA has already made previous determinations in which a single RIN value was assigned to the fuel produced since it came primarily from one source even though it was also produced from incidental amounts of other sources.

This determination is based on the view that the statutory requirement does not mandate that in all cases the renewable fuel must be produced solely from the cellulosic material in the renewable biomass. EPA considers the statutory definition of cellulosic biofuel to be flexible on this point. Given these factors cited above, the Agency believes this interpretation of ''derived from'' is consistent with the Congressional intent to require increased use of cellulosic biofuels while ensuring that the program can be implemented in a reasonable way. Details on the variability in feedstocks, characteristics of the final fuel, previous precedents, and alternative proposals are included in the following sections.

1. Variability in Cellulosic Content Estimates of Feedstocks

The cellulosic components of feedstock consist of the major structural components; cellulose; hemicellulose; and lignin. EPA has reviewed research characterizing the different components of feedstocks, mainly focused on how the materials could be broken down and converted into fuel. There has been work also in defining standardized procedures and test methods for analyzing the different components of biomass;[5] however, the studies considered all employ slightly different methods. For the purposes of this rule, EPA considered the amount of the feedstocks that is composed of cellulosic components i.e., how much comes from the cellulose, hemicellulose or lignin, as opposed to any other components of the feedstock. There is significant variation in the data reported on feedstock component compositions. The variation is due to a number of causes, such as measurement methods,[6 7] variety within a generic feedstock type, and storage time.[8]

Although there are many factors that contribute to the large variability in assessments of cellulosic content, all studies confirm that the feedstocks in Table 1 of section 80.1426 have an adjusted cellulosic content of at least 70%, with an average content of around 85% cellulosic.[9] A memorandum to the docket provides more information on cellulosic terminology, percent composition of various feedstocks, and the variability of different feedstock components.[10] From this data, EPA concludes that each of the qualified feedstocks listed in section 80.1426 are comprised predominantly of cellulose, hemicellulose and lignin.

[1] *See* Memorandum to Docket, ''Cellulosic Content of Various Feedstocks,'' Docket EPA–HQ–OAR–2012–0401.

[2] Peplinski et al. (1992) Physical, chemical and dry-mill properties of corn of varying density and breakage susceptibility. *Cereal Chemistry,* 69(4), 397–400.

[3] Illinois Soybean Association. Facts and Statistics for the Illinois Soybean Industry. *http://www.ilsoy.org/_data/mediaCenter/files/1290.pdf.*

[4] Values have been adjusted to account for the presence of inorganic ash, which will not produce fuel, as described in the Memorandum to the Docket, ''Cellulosic Content of Various Feedstocks,'' Docket EPA–HQ–OAR–2012–0401.

[5] *See, e.g.,* the Standard Biomass Analytical Procedures developed by the National Renewable Energy Laboratory, *http://www.nrel.gov/biomass/analytical_procedures.html.*

[6] Compositional Analysis of Lignocellulosic Feedstocks. 2. Method Uncertainties, David W. Templeton, Christopher J. Scarlata, Justin B. Sluiter, And Edward J. Wolfrum, J. Agric. Food Chem. 2010, 58, 9054–9062

[7] Relative standard deviations (RSD) of 5–8% are reported for cellulose, hemicelluloses and lignin with the other minor components showing 16–22% RSD.

[8] Composition of Herbaceous Biomass Feedstocks, DoKyoung Lee, Vance N. Owens, Arvid Boe, Peter Jeranyama, Plant Science Department, South Dakota State University, SGINC1–07, June 2007.

[9] EPA only considered the organic components of the materials when determining cellulosic content. Inorganic materials are not likely to end up in the final fuel product and would not contribute to the fuel heating content in the event that they remained in the final fuel. This methodology is consistent with how RINs are determined. In this section, EPA refers to this as ''adjusted cellulosic.'' Adjusted cellulosic content does not consider other material that is not converted into biofuel such as minerals or other components that would show up as part of the ash remaining after a thermo-chemical conversion process.

[10] *See* Memorandum to Docket, ''Cellulosic Content of Various Feedstocks,'' Docket EPA–HQ–OAR–2012–0401.

2. Characteristics of the Amount of the Final Fuel Derived From Cellulosic Materials

Process technology plays a key role in how much of the final fuel product is actually produced from cellulose, hemicellulose, or lignin. There are two basic processes for converting cellulosic feedstocks into fuel: thermo-chemical and biochemical. Thermo-chemical processes mainly consist of pyrolysis—in which cellulosic biomass is decomposed with temperature to bio-oils and could be further processed to produce a finished fuel—and gasification—in which cellulosic biomass is decomposed to synthesis gas (''syngas'') with further catalytic processing to produce a finished fuel product. The biochemical process requires the release of sugars from biomass and the use of microorganisms to convert sugars into fuels. Thermo-chemical processes can accept a more heterogeneous mix of feedstock and typically convert all of the organic components of the feedstock into finished fuel. The biochemical process generally accepts a more homogeneous mix of feedstocks and typically converts only the cellulosic and hemicellulosic components of the feedstock into the final fuel product. Therefore, regardless of the feedstock used, the final fuel produced from the biochemical process will typically only come from the cellulosic or hemicellulosic portions of feedstock, while the final fuel produced from the thermo-chemical process could come from cellulosic and non-cellulosic components.

For thermo-chemical production in which the non-cellulosic components of the feedstock can contribute to the volume of fuel produced in addition to the cellulosic components, the percent of fuel produced from the non-cellulosic portion can vary due to such factors as feedstock type and the time and location of feedstock harvest. Regardless, we believe that the majority of the fuel produced will be from the cellulosic components. As a practical matter, there is no simple test that can be used to measure the amount of fuel end product that originated from cellulosic materials. For fuel produced via the biochemical process, 100% of the fuel produced is directly the result of conversion of the cellulosic content.

In selecting a cellulosic process, whether based on biochemical or thermo-chemical design, the fuel producer is clearly demonstrating that its primary intent is to convert the cellulosic portions of the feedstock. Cellulosic fuel producers invest in expensive process technologies with the intent of converting the cellulosic components of a feedstock into fuel; conversion of the non-cellulosic components can be achieved much more easily with less of a capital investment. Furthermore, since the fuel produced will be primarily the result of the direct conversion of cellulosic content of the feedstock and considering the relatively small range of non-cellulosic portion of feedstock that could contribute to the volume of fuel produced, EPA believes it is reasonable to consider all the fuel produced when relying on cellulosic conversion processes to be cellulosic biofuel.

3. Previous Precedents

EPA has already considered instances where one RIN value was assigned to the fuel produced since it came primarily from one source even though it was also produced from some amount of other chemical compounds. In the March 2010 RFS rulemaking, EPA discussed two different situations for fuel produced from separated yard waste and food waste as the renewable biomass feedstock. The first involved food waste or yard waste that was kept separate, from generation, from municipal solid waste (MSW). EPA determined that both of these feedstocks could be considered renewable biomass. With respect to separated yard waste, EPA determined that the yard waste was expected to be composed almost entirely of woody material or leaves, and this would be deemed to be cellulosic material and would generate cellulosic biofuel RINs. Separated food waste, however, was likely to be composed of both cellulosic and non-cellulosic materials, and in certain cases would likely be composed primarily of non-cellulosic materials, such as sugars and starches from the food. EPA determined that separated food waste would be deemed to be non-cellulosic material, and would generate advanced biofuel RINs and not cellulosic RINs, unless the renewable fuel producer demonstrated the part of the food waste that was cellulosic. This portion would then generate cellulosic RINs.[11]

The second situation EPA previously addressed involved separated MSW. EPA determined that separated MSW that met certain regulatory requirements would qualify as a renewable biomass for purposes of producing renewable fuel. EPA recognized that the biogenic portion of this feedstock would be composed of a ''variety of materials, including yard waste (largely cellulosic) and food waste (largely starches and sugar), as well as incidental materials remaining after reasonably practicable separation efforts such as plastic and rubber of fossil origin.'' Testing could identify the portion of the fuel produced from biogenic materials, and these biogenic materials ''will likely be largely derived from cellulosic materials (yard waste, textiles, paper, and construction materials), and to a much smaller extent starch-based materials (food wastes).'' However, EPA was not aware of a test method to distinguish between renewable fuel produced from the cellulose and fuel produced from the starch and under those circumstances determined that it was appropriate to base the assignment of RINs on the ''predominant'' component of the biogenic material. EPA thus determined that all of the fuel generated from the biogenic portion of separated MSW would be considered cellulosic biofuel.[12]

Thus, EPA has interpreted the definition of cellulosic biofuel as including in some cases a renewable fuel that is produced from both the cellulosic and incremental amounts of non-cellulosic components of the feedstock. EPA has treated the resulting fuel as all derived from cellulosic material where the feedstock is composed almost entirely of woody materials and leaves, or where the predominant component of the feedstock is likely cellulosic. The fuel will be largely derived from this cellulosic material and to a much smaller extent from non-cellulosic materials. There currently is no ready test to identify the portion of fuel produced from non-cellulosic materials. EPA has not considered the fuel as cellulosic in cases where the feedstock was likely to be largely non-cellulosic materials. In all of these cases, EPA has recognized that the fuel would be produced from both the cellulosic and non-cellulosic materials in the feedstock, and has determined in some cases to consider the fuel entirely cellulosic biofuel based on the relative amounts of the cellulosic and non-cellulosic materials and, for fuel made from the biogenic portion of separated MSW, on the lack of availability of a test procedure to differentiate how much of the fuel came from the cellulosic materials.

These determinations have been based on the view that the statutory requirement that cellulosic biofuel be ''derived from cellulose, hemicellulose, or lignin'' does not mandate that in all cases the renewable fuel must be produced solely from the cellulosic material in the renewable biomass. EPA

[11] 75 FR 14670, 14706 (March 26, 2010).

[12] 75 FR at 14706.

considers the statutory definition of cellulosic biofuel to be ambiguous on this point, providing EPA the discretion to reasonably determine under what circumstances a fuel appropriately could be considered cellulosic biofuel when the fuel is produced from a feedstock that is a mixture of cellulosic and non-cellulosic materials. To date, EPA has specified certain circumstances where the entire fuel will be considered cellulosic biofuel. EPA has taken this action in cases where the cellulosic material is almost entirely woody materials or leaves, or the fuel is produced from materials that are predominantly composed of cellulosic materials and to a much smaller extent non-cellulosic materials, with no current test to identify the differing portions. There have been two elements present in these decisions. One involves a determination that the feedstock is composed almost entirely or largely of cellulosic materials. EPA has also considered whether or not there is a test method to identify the actual portion of the fuel produced from cellulosic materials. In this rulemaking EPA is proposing an approach that is consistent with and an outgrowth of the approach taken in the RFS2 rulemaking. EPA is proposing to approve certain fuels as cellulosic biofuel where the cellulosic components account for a predominant percentage of the biogenic material in the renewable biomass feedstock used to produce the fuel, even where the non-cellulosic components of the renewable biomass could be reasonably identified or estimated.[13]

EPA is proposing to classify all of the biofuel as cellulosic in the fuel pathways proposed today, where the cellulosic material makes up a predominant percentage of the organic material from which the fuel is produced. This approach will avoid the administrative and technical burden on producers and EPA of trying to determine the specific amounts of cellulosic and non-cellulosic materials in the specified high-cellulosic feedstock sources, removing potential difficult and potentially time-consuming and expensive impediment to expansion of the cellulosic biofuel industry. The growth in cellulosic biofuel volumes promoted by today's proposal is expected to result in greater reductions in GHGs, as all of the biofuel qualified as cellulosic would have to achieve the minimum 60% reduction in GHG emissions specified in the Act.

EPA's application of this approach to the specific fuel pathways and feedstocks discussed in this proposal is intended to ensure that cellulosic materials are the predominant portion of the biogenic materials used to produce cellulosic biofuel. This approach avoids administrative, technical and cost burdens on EPA and industry and promotes the volume and greenhouse gas objectives of Congress. EPA proposes that this is a reasonable interpretation of the definition of cellulosic biofuels, and invites comment on this approach.[14]

EPA is proposing that biofuel made from the following cellulosic feedstocks will be able to generate applicable cellulosic RINs for 100% of the volume produced: crop residue; slash; pre-commercial thinnings and tree residue; annual cover crops; switchgrass; miscanthus; and energy cane. EPA's prior treatment of separated yard waste, separated food waste, and separated MSW is discussed above and is not being changed. On January 5, 2012, EPA proposed to qualify napier grass and Arundo donax as new feedstocks that would be eligible to generate cellulosic RINs. If those pathways are approved before this rule is final, EPA is proposing to apply the approach discussed above to these feedstocks as well.[15] To the extent that additional cellulosic pathways are approved in the future, we would expect to apply this same methodology to those feedstocks as well, but will evaluate them on a case-by-case basis.

EPA requests comments on this proposed approach to allow 100% of the volume of renewable fuel produced from the specified cellulosic feedstock sources found in Table 1 of section 80.1426 to generate cellulosic RINs. We also take comment on the cellulosic content values presented for different feedstocks. In addition, we request comments about any analytical methods that may exist to determine what percent of a finished biofuel product may have derived from cellulosic versus non-cellulosic components, and what the costs may be associated with these test methods. We also request comment on the alternative approaches outlined below.

4. Alternative Approaches

EPA seeks comment on two alternative approaches to assigning cellulosic RINs to fuels produced from the cellulosic feedstocks discussed above. Separate from the specific pathways addressed in this proposal, EPA also seeks comment on potential approaches for assigning cellulosic RINs for anticipated future pathways for renewable fuels produced from feedstocks that contain lower cellulosic content than those discussed in this rulemaking.

Cellulosic Content Threshold Approach

An alternative approach for handling the variability in cellulosic content would be for EPA to set a minimum threshold of cellulosic content in the feedstock. Fuels produced from feedstocks with a cellulosic content above this minimum threshold would be eligible to generate cellulosic RINs for 100% of their volume. Thresholds under consideration would range from 70% to 99.9%. A higher percentage would place more emphasis on the feedstock content having a higher actual cellulosic component, whereas the lower percentages would place more emphasis on promoting the volume of fuels that could be categorized as cellulosic biofuel. EPA invites comment on this approach, and also invites comment on the most appropriate value to use as the threshold. Furthermore, EPA invites comment on whether individual producers should be responsible for submitting data that their feedstock meets this threshold, or whether EPA should determine whether feedstocks meet this threshold based on existing published data.

Since biochemical processes generally only convert the cellulosic, hemicellulosic, or lignin components of the feedstock to fuel, EPA believes under this alternative approach, it may still be appropriate to allow fuel producers using biochemical processes to generate RINs for 100% of the fuel produced from cellulosic feedstocks. EPA requests comments on our assumption that biochemical processes will be specific for the cellulosic components, and we also request comment on whether to allow 100% of the fuel produced via biochemical processes to generate cellulosic RINs.

Specified Percentage Approach

As noted above, examining the range of feedstock data compiled by EPA, it appears that 85% would be a reasonable approximation for the average adjusted

[13] By predominant, EPA means the very high percentages for adjusted cellulosic content discussed in section V.A.1. above for the feedstocks at issue in this proposal.

[14] *See Bot* v. *IRS,* 353 F.3d 595 (8th Cir. 2003), *Wuebker* v. *IRS,* 205 F.2d 897 (6th Cir. 2000), *Milligan* v. *IRS,* 38 F.3d 1094 (9th Cir. 1994). *See also Hecla Mining Company* v. *US,* 909 F.2d 1371 (10th Cir. 1990) (DOE's interpretation of the term ''derived from'' in the Uranium Mill Tailings Radiation Control Act of 1978 accepted as a reasonable interpretation under *Chevron*).

[15] In addition, in section B of this proposal, EPA is also proposing to include corn fiber, CNG, LNG, electricity, and renewable diesel and naphtha from landfill biogas as cellulosic pathways for the reasons discussed therein.

cellulosic content across a range of assessments of the specific feedstocks that are qualified to produce cellulosic fuel. Under this approach, fuels produced from the cellulosic feedstocks discussed above would be eligible to generate cellulosic RINs for 85% of their volume, and the remaining 15% would be eligible to generate advanced RINs. The specified percentage approach would reduce administrative burden but also incentivize renewable fuel production. For this approach, EPA would effectively be treating 85% of the fuel produced from all of these feedstock sources as being derived from cellulosic material. However, EPA would consider allowing a larger percentage of the fuel to qualify for cellulosic RINs if the producer could submit data that demonstrates a consistently higher cellulosic content in their feedstock. Under this approach, producers could submit a written plan for approval under the registration procedures in 40 CFR 80.1416(b)(vii). The plan would need to detail the cellulosic content of the feedstock, the method used for quantifying the cellulosic and non-cellulosic contents, and the production process used.

Since biochemical processes generally only convert the cellulose, hemicellulose, or lignin components of the feedstock to fuel, EPA believes under this alternative approach it would be appropriate to allow fuel producers using biochemical processes to generate RINs for 100% of the fuel produced from cellulosic feedstocks. EPA requests comments on our assumption that biochemical processes will be specific for the cellulosic components, and we also request comment on whether to allow 100% of the fuel produced via biochemical processes to generate cellulosic RINs.

Request for Comment on Potential Approaches for Fuels Produced From Feedstocks With Lower Cellulosic Content

Finally, EPA anticipates that in the future, we may address biofuels that are produced from feedstocks that contain lower cellulosic content than those discussed in this rulemaking. Accordingly, we request comment on how EPA should assign RINs to the fuels produced from feedstocks with lower cellulosic content than those presented in this rulemaking but for which some of the fuel is produced from the cellulosic components. One possible example would be a feedstock that contained in the range of 40–60% cellulose, hemicellulose and lignin, where the fuel was produced using thermochemical methods such that the same percentage of the fuel may come from cellulosic materials. EPA invites comments about what approaches could be taken for assigning cellulosic RINs to the biofuel. For example, would one or more of the approaches outlined above be appropriate for assigning RINs to this fuel? Are there variations on these approaches that EPA should consider? EPA also invites comments on how to assign cellulosic RINs where processes other than thermochemical methods are used.

B. Lifecycle Greenhouse Gas Emissions Analysis for Renewable Electricity, Renewable Diesel and Naphtha Produced from Landfill Biogas

EPA has received several facility-specific petitions under § 80.1416 to allow renewable electricity, renewable diesel and naphtha produced from landfill biogas to qualify as renewable fuels under the RFS program. Since these new pathways could be more broadly applicable, EPA is proposing to add these pathways to Table 1 to § 80.1426 through this rulemaking process. Based on questions from companies, EPA is also modifying the existing biogas pathway to specify that compressed natural gas (CNG) or liquefied natural gas (LNG) is the fuel and biogas is the feedstock. For this proposal, EPA considered both the cellulosic origin of landfill biogas and the lifecycle GHG impacts of three types of fuel produced from landfill-derived biogas. In the final RFS2 rule, EPA established biogas as a fuel type when derived from landfills, sewage waste treatment plants, and manure digesters. This biogas was classified as an advanced biofuel eligible to generate D-Code 5 RINs. EPA also established cellulosic diesel and cellulosic naphtha as cellulosic biofuels eligible to generate D-Code 7 and 3 RINs, respectively. The eligible feedstocks for these biofuels include cellulosic components of separated municipal solid waste but did not include biogas from landfills.

Based in part on additional information received through the petition process for EPA approval of renewable electricity and renewable diesel and naphtha produced from landfill biogas, EPA has evaluated these pathways and is proposing to include renewable electricity produced from landfill biogas feedstock in Table 1 to § 80.1426 as a cellulosic fuel type. It is important to note that RINs may only be generated for electricity from biogas that can be tracked to use in the transportation sector, such as by an electric vehicle. We are also proposing to add renewable diesel produced from landfill biogas via the Fischer-Tropsch process as an approved advanced and/or biomass-based diesel biofuel and naphtha produced from landfill biogas via the Fischer-Tropsch process as an approved advanced biofuel. If the Fischer-Tropsch facilities produce at least 20% of their electricity demand at the facility from certain allowed sources, we are proposing that the renewable diesel and naphtha produced would further qualify as cellulosic biofuels. We are also proposing to amend the existing biogas pathway to list renewable CNG/LNG as the fuel types instead of biogas since the biogas is converted into CNG or LNG before being used as a transportation fuel, as discussed below. Renewable CNG/LNG produced from biogas from waste treatment plants and waste digesters is still classified as an advanced biofuel. However, renewable CNG/LNG produced from biogas from landfills now qualifies as a cellulosic pathway. The changes to the renewable CNG/LNG pathway are described in section C.1. ‘‘Changes Applicable to the Revised CNG/LNG pathway from Biogas’’ below.

1. Feedstock Production

When waste materials are buried in a landfill, decomposition of the organic materials consumes all of the oxygen present within roughly one year, leaving the bulk of the material to undergo slower, anaerobic decomposition. This process produces large amounts of methane for several decades, as well as other products, with the gases released as ‘‘biogas.’’ Biogas from landfills typically contains approximately 50% methane and 50% carbon dioxide, with small or trace amounts of other gases. Methane is a potent greenhouse gas (GHG), with a global warming potential of 21 times that of carbon dioxide, and landfills are the third-largest anthropogenic source of methane to the atmosphere in the United States.[16]

The methane present in biogas is also a potential energy source that may be purified and compressed to be used directly in CNG or LNG vehicles, combusted to produce electricity or converted to renewable diesel and naphtha via the Fischer-Tropsch process. The March 2010 RFS final rule concluded that municipal solid waste has no agricultural or land use change GHG emissions associated with its production. Furthermore, the feedstock for these fuels is landfill biogas, which already appears in Table 1 of

[16] U.S. Environmental Protection Agency. 2013. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011, Chapter 8: Waste. EPA 430–R–13– 001, *available at http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf.*

§ 80.1426(f) of the RFS2 regulations and has already been evaluated as part of the RFS2 final rule lifecycle GHG determinations. Therefore no new renewable feedstock production modeling was required, no GHG emissions were attributed to feedstock production for any of these renewable fuel pathways, and EPA focused our analysis on the new fuel production processes.

2. Determination of the Cellulosic Composition of Landfill Biogas

In order for fuels produced from landfill biogas as a feedstock to qualify to generate D-Code 3 or 7 (cellulosic) RINs, the renewable fuel must be derived from cellulosic materials and must meet a 60% GHG emissions reduction threshold, as described in the following sections. In this section, we discuss our determination that biogas derived from landfills is derived from cellulose, hemicellulose or lignin.

CAA 211(o) specifies ''separated yard waste or food waste'' as a type of renewable biomass, and in the March 2010 RFS final rule, EPA stated:

> As a result of the intermixing of wastes, the fact that biogas is formed only from the biogenic portion of landfill material, and the fact that landfill material is as a practical matter inaccessible for further separation, EPA believes that no further practical separation is possible for landfill material and biogas should be considered as produced from separated yard and food waste for purposes of EISA.

The March 2010 RFS final rule stated that all landfill-derived biogas was therefore eligible to generate RINs.

An in-depth study of methane production from different chemical components of municipal solid waste found that roughly 90% of the methane generated in landfills derived was from cellulose and hemicellulose.[17] Accordingly, EPA is proposing to classify renewable fuels produced from landfill biogas as derived from cellulose, hemicellulose or lignin. This determination is discussed in more detail in a memo to the docket.[18] Consistent with the discussion in the section above, ''Approving Cellulosic Volumes from Cellulosic Feedstock,'' we are classifying all of the biofuel volume produced from landfill biogas as cellulosic in origin. Therefore the entire volume of renewable fuels using landfill biogas as a feedstock will be eligible to generate cellulosic RINs (D-Codes 3 and 7) if the fuel also meets the required 60% GHG emissions reductions. EPA invites comment and data on the cellulosic component of biogas.

3. Fuel Production—General Considerations

Landfills currently treat their methane in one of several ways. Municipal solid waste (MSW) landfills designed to collect at least 2.5 million megagrams (Mg) and 2.5 million cubic meters of waste and emitting at least 50 Mg of non-methane organic compounds per year are required by EPA regulations to capture and control their biogas.[19] These large, regulated landfills represent a small percentage of all landfills by number but are responsible for the majority of biogas emissions from landfills. To comply with the regulations, these landfills must at a minimum combust their biogas in a flare, converting the methane to carbon dioxide, a less potent GHG. They may also use it to generate electricity from combustion of the methane, in which case, the electricity produced may displace electricity from other sources (such as gas-fired power plants) once it enters the grid. If displacing other sources of electricity that on average have greater GHG emissions, landfills that generate electricity may reduce GHG emissions and are using the ''best practices'' in the industry.[20] Many smaller, unregulated landfills do not collect their biogas, and this methane is ''vented'' to the atmosphere. In 2010, 29% of the methane generated at landfills was flared and 29% of the methane was used to generate electricity.[21] Accounting for the 25% average collection efficiency of biogas collection systems,[22] we estimate that approximately 38% of the methane generated is derived from landfills that flare their gas and another 38% is derived from landfills with gas-to-electricity projects. By mass balance, this suggests that 24% of the landfill methane generated is from landfills that vent their methane.

In our lifecycle GHG analysis of these biofuels we need to consider what would have happened to the landfill gas if it was not used to produce transportation fuels. This is the baseline for comparison to calculate the GHG impacts of the fuels in question. Once we have chosen a baseline for comparison, we propose to treat biogas from all landfills the same regardless of how the biogas is processed at that landfill. This approach is consistent with how we have treated the implementation of advanced technologies for all biofuels producers.

For the landfill gas-to-electricity pathway we use landfills that flare their biogas as the baseline GHG emissions with which we compare scenarios involving production of electricity from the landfill biogas. We chose this baseline because these landfills are the ones most likely to convert to gas-to-energy projects, since they already have gas collections systems in place. They are also the ones most likely to be the alternative to gas to energy projects since these projects will likely go into larger landfills that are required by regulation to collect and treat the biogas. We expect that small, unregulated landfills would be unlikely to generate enough biogas to justify collecting it for conversion to renewable fuels. Furthermore, we expect that the capital costs for such small landfills would preclude them from making such changes. However, if such small landfills were to capture and use their biogas in transportation fuels, this would result in significantly greater reductions in GHG emissions at each landfill than assumed for landfills already capturing biogas because of the decrease in methane release, so that biofuels produced from such facilities would easily meet the required emissions reduction thresholds. Since landfills that currently have gas-to-energy projects in place at one point either replaced flaring with a gas-to-energy project or installed a gas-to-energy project as an alternative to the minimal compliance route of flaring, we are proposing to treat the emissions from these landfills compared to the same flaring baseline. We show lifecycle results calculated using alternative baselines and discuss our choice of baseline in more depth in a memo to the

[17] Barlaz, M.A., R.K. Ham, and D.M. Schaefer. 1989. Mass-balance analysis of anaerobically decomposed refuse. Journal of Environmental Engineering, 15(6) 1088–1102.

[18] ''Support for Cellulosic Determination for Landfill Biogas and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Landfill Biogas,'' which has been placed in docket EPA–HQ–2012–0401.

[19] Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, 61 FR 9905, 9944 (March 12, 1996).

[20] Some facilities also use the biogas directly in boilers and other applications or purify the biogas to create CNG or LNG or inject it directly into natural gas pipelines.

[21] Environmental Protection Agency. 2012. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2010, Annex 3: Methodological Descriptions for Additional Source or Sink Categories. *http://epa.gov/climatechange/emissions/usinventoryreport.html.* As of December 2012, landfills produced 1913 MW of electricity based on figures from LMOP. This electricity would be almost entirely sold for use on the grid. From *http://www.epa.gov/lmop/projects-candidates/index.html.*

[22] Environmental Protection Agency, Landfill Methane Outreach Program. 2010. LFG Energy Project Development Handbook: Chapter 2. Landfill Gas Modeling. *http://epa.gov/lmop/publications-tools/handbook.html.*

docket.[23] We invite comment on our baseline assumptions for the electricity pathway. If commenters believe a different baseline is appropriate, EPA specifically invites the submission of data supporting this alternative baseline.

For gas to liquids projects we also use landfills that flare their biogas as the baseline GHG emissions with which we compare scenarios involving production of gas to liquids, for the same reasons outlined above. We further consider that landfills that have already invested the capital to generate electricity are unlikely to stop doing so in order to generate liquid fuels from the biogas, which would require considerable additional capital investments. These facilities are therefore an unlikely baseline for the pathways generating renewable diesel and naphtha. We invite comment on our baseline assumptions for the liquids pathway and whether a different baseline would be more appropriate. If commenters believe a different baseline is appropriate, EPA specifically invites the submission of data supporting this alternative baseline.

4. Fuel Production for Renewable Electricity

Landfills can generate electricity by combustion of the methane in their biogas. Generating electricity at landfills requires collection of the biogas (using wells, piping and blowers), purification and compression of the biogas and electricity generation. Most landfills use internal combustion engines to generate the electricity, but a significant proportion also use gas or steam turbines or combined cycle systems. Once generated, the electricity enters the electrical grid.

In determining the lifecycle GHG analysis of renewable electricity, we examined two main factors. The first involved determining by how much emissions at the landfill (from flaring) would change upon installation of a gas-to-energy project. For this calculation, we used emission factors from the GREET model.[24] The second involved calculation of the decrease in GHG emissions caused by powering the gas blowers already in use with biogas-derived electricity rather than grid electricity upon installation of a gas-to-energy project. This calculation used data from the EPA Landfill Methane Outreach Project (LMOP).[25] For each factor, we needed to first calculate how much electricity could be generated and delivered to the consumer. We used values from LMOP as estimates of the relative shares of different types of engines or turbines, the electricity generation efficiency, parasitic losses, energy use in collecting and preparing the biogas, and a value from the U.S. Energy Information Agency to estimate distribution losses. Values used are shown in Table V.B.–1, and the assumptions and calculations are discussed in more detail in a memo to the docket.[26]

TABLE V.B.–1—CALCULATION OF THE NET AMOUNT OF ELECTRICITY DELIVERED TO THE CONSUMER PRODUCED FROM A GIVEN AMOUNT OF LANDFILL BIOGAS [27]

	Value	Units
Electricity generation efficiency	11700	Btu/kWh.
Gross electricity production	0.292	mmBtu/mmBtu biogas.
Electricity produced after parasitic losses	0.267	mmBtu/mmBtu biogas.
Energy used for blowers	0.014	mmBtu/mmBtu biogas.
Distribution losses	0.017	mmBtu/mmBtu biogas.
Net electricity delivered to consumer	0.236	mmBtu/mmBtu biogas.

We used the value for the net city yield from biogas to calculate how GHG emissions from the landfill itself would change upon conversion from flaring to a gas-to-energy project. We first calculated emissions per mmBtu electricity (Table V.B.–2). However, the drivetrains of electric vehicles are roughly three times as efficient as those of conventional gasoline-powered vehicles, meaning that any given EV would be able to travel about three times as far per Btu of input. To account for this difference, we also calculated emissions per mmBtu fuel equivalent. It would take roughly three times the amount of energy from liquid fuel to drive a conventional vehicle a given distance compared to an EV powered by electricity, so the emissions per mmBtu fuel equivalent are approximately one third as large as the emissions per mmBtu electricity. EPA invites comments on the assumptions regarding electricity equivalence.[28]

[23] ‘‘Support for Cellulosic Determination for Landfill Biogas and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Landfill Biogas,’’ which has been placed in docket EPA–HQ–2012–0401.

[24] Argonne National Laboratory (2011) Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET), Version 1 2011, *http://greet.es.anl.gov/*.

[25] EPA LMOP Data.

[26] ‘‘Support for Cellulosic Determination for Landfill Biogas and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Landfill Biogas,’’ which has been placed in docket EPA–HQ–2012–0401.

[27] All values are derived from information provided by the EPA Landfill Methane Outreach Program except the distribution loss number, which is from the U.S. Energy Information Agency. Parasitic losses were calculated by apportioning the gross electricity generation to different types of generators and using parasitic loss values for that particular type of generator.

[28] Note that in order to determine the number of RINs generated from a given amount of renewable electricity, section 80.1415(b)(6) of the regulations states that 22.6 kW-hr of electricity shall represent one gallon of renewable fuel with an equivalence value of 1.0.

TABLE V.B.–2—FUEL GHG EMISSIONS FOR THE RENEWABLE ELECTRICITY PATHWAY, CALCULATED PER MMBTU ELECTRICITY AND PER MMBTU FUEL EQUIVALENT COMPARED TO THE 2005 GASOLINE BASELINE

Lifecycle stage	GHG emissions			
	Renewable electricity		2005 Gasoline baseline	U.S. Average grid electricity
	kg CO_2-eq/ mmBtu electricity	kg CO_2-eq/ mmBtu fuel equivalent	kg CO_2-eq/ mmBtu fuel	kg CO_2-eq/ mmBtu electricity
On-site emissions	25	8		
Upstream (electricity production for blowers)	−13	−4		
Total Emissions:	12	4	98	220
% Change from Gasoline Baseline	−87%	−96%		
% Change from Grid Electricity	−94%	N/A		

On-site emissions of facilities that generate electricity would be slightly higher than emissions from facilities that flare because reciprocating engines, which are the dominant technology used to generate electricity from biogas, are less efficient at destroying methane than flares. Facilities that originally flared their biogas are assumed to have been purchasing electricity from the grid to power the blowers needed to collect the biogas. Upon conversion to gas-to-energy projects, the facilities would now generate that electricity themselves and thus no longer need to purchase this electricity from the grid. The calculations above include a credit in GHG emissions for the avoided purchase of grid electricity (Table V.B.–2). Unlike traditional transportation fuels, there are no GHG emissions involved in transportation or distribution of renewable electricity (distribution losses are accounted for above), nor are there any tailpipe emissions from the direct use of the fuel. Therefore, the only emissions considered are those from production of the fuel, as outlined in Table V.B.–2. The total GHG emissions for conversion from flaring to a gas-to-energy project are 12 kg CO_2-eq/mmBtu electricity, or 4 kg CO_2-eq/mmBtu fuel equivalent. Compared with the gasoline baseline GHG emissions of 98 kg CO_2-eq/mmBtu, these projects would be accompanied by an 87% reduction in GHG emissions when normalized per mmBtu electricity. Accounting for the improved efficiency of EV drivetrains increases the GHG emissions reductions to 96%. Renewable electricity therefore meets the statutory baseline of 60% reductions in GHG emissions relative to the gasoline baseline and qualifies as a cellulosic biofuel. EPA invites comments on the assumptions and calculations of GHG emissions related to renewable electricity from landfill gas.

5. Fuel Production, Transport and Tailpipe Emissions for Renewable Diesel and Naphtha

Renewable diesel and naphtha can be made from landfill biogas by a combination of methane reforming and the Fischer-Tropsch gas-to-liquids (GTL) process. For methane reforming, the biogas must first be purified and then be reformed to create synthesis gas, known as ''syngas,'' which is composed of a mixture of carbon monoxide and hydrogen gas. This process may occur via either steam methane reforming or autothermal reforming. The syngas is next purified and then sent to a Fischer-Tropsch (F–T) system in which the carbon monoxide and hydrogen are combined in the presence of a catalyst to form a range of hydrocarbons. This reaction produces relatively short-chain (naphtha), medium-length (diesel) and long-chain (wax) hydrocarbons. The wax can subsequently be upgraded by hydroprocessing to form naphtha and diesel fuels. The different products are then separated by simple distillation. Heat generated by the reaction can be used to preheat gases in the system and to generate electricity for use in the system or for export. Unconverted syngas from the F–T process and fuel gas from hydroprocessing can also be combusted to generate electricity. GTL plants may have substantially different lifecycle GHG impacts depending on whether they upgrade their waxes and whether they generate electricity as a side product of the reaction. Electricity generation can add to the capital costs of a facility but also greatly reduces the lifecycle GHG emissions of a plant.

In determining the lifecycle GHG impacts of GTL fuels, we considered two main factors: on-site emissions at the landfill and upstream emissions from electricity production to power the plant. Additionally, a facility that produced wax was assigned a co-product credit for the wax generated. We did the calculations assuming the facility did not generate any electricity and then calculated what fraction of their electricity demands they would need to generate internally to meet the 60% emissions reduction threshold to qualify for cellulosic RINs.

To determine the lifecycle GHG emissions, we used confidential business information (CBI) data provided in a petition submitted to EPA. This process did not involve upgrading of wax to liquid fuels. For this scenario, we used the supplied information about inputs of biogas, outputs of fuel and co-product and electrical demand for the lifecycle analysis. We first determined how many GHG emissions would be avoided on-site at the landfill by changing from the baseline scenario of flaring to collecting the biogas for conversion to liquid fuels. This calculation was similar to that described above for renewable electricity and relied on values from GREET [29] for the emissions factor for flaring. To calculate the emissions from electricity required by the process, we used the emissions factors for average U.S. electrical production used in the RFS2 final rule.

To assign a co-product credit to the fuels, we assumed that the wax produced during the Fischer-Tropsch process would enter a market in which it would displace wax derived from petroleum. To determine the effects of such a displacement on GHG emissions, we used data from a model by the Department of Energy's National Energy Technology Laboratory (NETL) [30] for the yields and GHG emissions attributable to wax production from petroleum

[29] Argonne National Laboratory, ''Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET),'' Version 1 2011, *http://greet.es.anl.gov/.*

[30] Department of Energy: National Energy Technology Laboratory. (2009) NETL: Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis—2005 Baseline Model. *www.netl.doe.gov/energy-analyses.*

feedstock. These values only include production emissions and do not include any emissions from combustion of the wax in, for example, candles because we do not have information about what fraction of wax is combusted. If combustion emissions were included, the co-product credit would be even larger. The global wax market is growing, with demand expected to outpace supply in the next few years.[31] As such, it is unlikely that F–T waxes would in reality displace petroleum-derived waxes. Instead, waxes from both sources are likely to be used in parallel to fulfill demand, and such waxes would replace any substitutes that might be used to fill the gap between supply and demand. The nature of these alternatives is presently unknown to EPA, as are their lifecycle GHG emissions. As an alternative to assigning a displacement credit, we could allocate emissions to the waxes along with the renewable diesel and naphtha products. In this case, the co-product credit disappears but total fuel production emissions decrease to 30 kg CO_2-eq/mm Btu, leading to overall GHG emissions reductions of 68%. Our use of the displacement approach is conservative compared to the allocation approach, which would have resulted in a larger credit for the wax co-product. We welcome comment regarding what kinds of materials these new waxes might replace, as well as how to best account for them in our lifecycle GHG analysis.

The results of this analysis are shown on the ''Fuel Production'' line of Table V.B.–3, and the assumptions and calculations are discussed in more detail in a memo to the docket.[32] Emissions from electricity production used to power the F–T plant is the greatest contributor to the overall fuel production emissions. In addition to emissions from fuel production, there were minor GHG emissions attributable to fuel transport and tailpipe emissions of non-CO_2 GHGs (Table V.B.–3). Overall, renewable diesel and naphtha produced from landfill biogas via this process showed 52% and 51% reductions in GHG emissions, respectively, relative to the diesel or gasoline baseline (Table V.B.–3). These fuels would therefore qualify as advanced biofuels but not qualify as cellulosic biofuels. However, if the facility produced roughly 15% of its process electricity internally, using either waste heat from the reaction or combustion of unreacted chemicals, emissions from purchased electricity would drop enough to reach the 60% GHG reduction threshold, qualifying these fuels as cellulosic. Because emissions from production of these biofuels (without internal production of electricity) fall so close to the 50% threshold to qualify as advanced biofuels, the assumptions used to make the calculations are especially important and could potentially change the classification of these fuels. Accordingly, we request comments about the assumptions and values used in the calculations, which are detailed in a memo to the docket.[33] In particular, we request comment about the estimate for the on-site GHG emissions at the Fischer-Tropsch facility. Data regarding fugitive emissions from Fischer-Tropsch facilities using methane as a feedstock appear to be limited, however, the GREET model assumed a loss factor of 1.0000 for the production of F–T diesel, indicating their estimate that no methane is lost during this process. Several studies mentioned emissions from the steam methane reforming of natural gas to produce hydrogen, and we assumed emissions would be similar from a Fischer-Tropsch facility using steam methane reforming. Two of these studies [34] [35] found or estimated that losses of methane from such facilities were negligible, agreeing with the GREET estimate. Accordingly, we assumed no emissions of methane from F–T facilities. However, another study [36] estimated losses of 0.125% of the natural gas processed. Using this last value, the GHG emissions reductions for renewable diesel and naphtha would decrease to 49% for both fuels, meaning that the biofuels would no longer qualify as advanced fuels. We request comments and information about our estimates of fugitive emissions from Fischer-Tropsch facilities.

TABLE V.B.–3—TOTAL GHG EMISSIONS FOR RENEWABLE DIESEL AND NAPHTHA PRODUCED FROM LANDFILL BIOGAS AND COMPARED TO THE APPROPRIATE PETROLEUM BASELINE

Lifecycle stage	GHG emissions (kg CO_2-eq/mmBtu)			
	Biofuels		Petroleum baselines	
	Renewable diesel	Naphtha	2005 diesel baseline	2005 gasoline baseline
Fuel Production	44	44	18	19
Fuel Transport	1	2	*	*
Tailpipe Emissions	1	2	79	79
Total Emissions	47	48	97	98
% Change from Petroleum Baseline	−52%	−51%		

* Emissions included in fuel production stage.

For this lifecycle analysis, we have only examined a facility that does not upgrade its wax and therefore produces wax as a co-product. It is likely that other facilities may produce F–T renewable diesel and naphtha by a

[31] Kline Group (2011) Global Wax Industry 2010: Market Analysis and Opportunities. *http://www.klinegroup.com/reports/brochures/y635a/brochure.pdf.*

[32] ''Support for Cellulosic Determination for Landfill Biogas and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Landfill Biogas,'' which has been placed in docket EPA–HQ–2012–0401.

[33] ''Support for Cellulosic Determination for Landfill Biogas and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Landfill Biogas,'' which has been placed in docket EPA–HQ–2012–0401.

[34] Skone, T.J. and Gerdes, K. (2008) NETL: Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. *http://www.netl.doe.gov/energy-analyses/pubs/NETL%20LCA%20Petroleum-Based%20Fuels%20Nov%202008.pdf.*

[35] Spath, P.M. and Mann, M.K. (2001) Lifecycle Assessment of Hydrogen Production via Natural Gas Steam Reforming. NREL Technical Report NREL/TP–570–27637, *http://www.nrel.gov/docs/fy01osti/27637.pdf.*

[36] Contadini, J.F., Diniz, C.V., Sperling, D., and Moore, R.M. (2000) Hydrogen production plants: emissions and thermal efficiency analysis. *ITS-Davis. Presented at the Second International Symposium on Technological and Environmental Topics in Transports,* October 26–27, 2000. Milan, Italy. Publication No. UCD–ITS–RR–00–16.

process that does involve upgrading waxes to increase the yield of the liquid fuels. Accordingly, we used assessments from other analyses of theoretical F–T [37] or steam methane reforming [38] plants using wax upgrading to estimate the lifecycle GHG emissions from such products. Based on this analysis (not shown), these facilities should theoretically have GHG emissions that are as low as or lower than those calculated above. For this reason, we believe that the lifecycle analysis shown above is a reasonable, if slightly conservative,[39] representation of expected landfill biogas-to-liquids projects. We accordingly classify all renewable diesel and naphtha produced via the F–T process from landfill biogas as advanced biofuel.

The lifecycle analysis for these fuels considered that the renewable diesel product produced from the Fischer-Tropsch process would be used as conventional diesel fuel. EPA does not have sufficient information to evaluate the lifecycle greenhouse gas emissions for jet fuel or heating oil produced from landfill biogas using the Fischer-Tropsch process. Because the lifecycle analysis results for this process fell so close to the threshold for advanced biofuels, in this pathway, we are proposing to only allow renewable diesel for use as conventional diesel fuel to qualify under the RFS program. We invite comments and supporting data about whether we should also allow jet fuel and heating oil produced from landfill biogas to qualify.

Our lifecycle analysis showed that if the evaluated facility meets approximately 15% of its electricity demand with internally produced electricity from eligible sources, it will meet the 60% threshold to qualify as cellulosic. Because other facilities are likely to be somewhat different, and because this analysis relies on a number of assumptions, we are using a slightly more conservative threshold of 20% of electrical generation. Accordingly, we are proposing that if a biogas-to-liquids facility produces at least 20 percent of its process electricity internally as discussed above, these biofuels will qualify as cellulosic. These requirements are discussed in greater length in Section C.4. ''*Changes Applicable to Process Electricity Production Requirement for the Biogas-Derived Cellulosic Diesel and Naphtha Pathways'' below.* Facilities that can supply data that demonstrate they meet the 60% GHG emissions reduction threshold without production of 20% electricity are welcome to petition the EPA individually under section 80.1416.

EPA invites comment and data on the GHG emissions associated with landfill biogas renewable fuel pathways. We also welcome comment on the methodology and assumptions underlying this analysis. We do not at this point have sufficient information to evaluate the lifecycle greenhouse gas emissions for production of renewable electricity or renewable diesel and naphtha from biogas from waste treatment plants or waste digesters. Accordingly, we invite comments providing information about these potential pathways.

C. Proposed Regulatory Amendments Related to Biogas

1. Changes Applicable to the Revised CNG/LNG Pathway From Biogas

In the existing RFS2 regulations, an approved fuel pathway in Table 1 to section 80.1426(f)(1) allows biogas from landfill gas, manure digesters or sewage treatment plants to qualify as an advanced biofuel and generate a D code of 5 for the biofuel produced under the RFS2 program. Since the promulgation of the final rule, we have received many requests about what fuel qualifies under this pathway, including: (1) The renewable fuel type that is qualified under the term ''biogas,'' (2) what are the eligible sources of biogas, (3) what company along the production chain of biogas from generation to end user is considered the producer that qualifies to register under this pathway and generate RINs, and (4) what are the contract requirements to track the biogas from generation to end use.

In response, EPA is proposing in this rulemaking to amend the existing biogas pathway in Table 1 to section 80.1426(f) by changing the renewable fuel type in the pathway from ''biogas'' to ''renewable compressed natural gas (renewable CNG) and renewable liquefied natural gas (renewable LNG)'' and to replace the feedstock type of ''landfills, manure digesters or sewage waste treatment plants'' with ''biogas from landfills, waste treatment plants or waste digesters.'' We are also proposing to revise the definition of biogas and add definitions for CNG and LNG to section 1401 to provide additional clarity. In addition, we are proposing to revise and add new contracting, registration, reporting and recordkeeping requirements along the production chain. Furthermore, we are specifying which company along the production chain is considered the ''producer'' and eligible to generate RINs under the RFS2 program. These proposed compliance requirements are applicable to this revised CNG/LNG pathway, and all the newly proposed pathways for renewable fuels produced from landfill gas in this rulemaking. The details of the proposed new requirements for contract, registration, reporting and recordkeeping are discussed below in the section titled ''Changes Applicable to All Biogas-Related Pathways for RIN Generation.''

The existing biogas pathway in Table 1 to section 80.1426(f) refers to ''biogas'' as the renewable fuel type and ''landfills, manure digesters and sewage waste treatment plants'' as the feedstock. Companies have raised questions whether the term ''biogas'' in this pathway could refer to the unprocessed or raw gas from the landfills, manure digesters or sewage treatment plants, or processed ''biogas'' that has been upgraded and could be used directly for transportation fuel or as an ingredient in the production of transportation fuel or as an energy source used in the production of transportation fuel, or other fuel types that can be produced from the raw biogas either through a physical or chemical process (such as CNG, LNG, renewable electricity, renewable diesel or naphtha). The companies further inquire if the various forms of biogas discussed above could qualify under this pathway, and therefore be eligible for RIN generation under the RFS2 program.

We agree that the term ''biogas'' in this pathway is used broadly in the industry to refer to various raw and processed forms of the biogas from various sources. However, under the existing requirements in sections 80.1426(f)(10) and (11), only biogas that is used for transportation fuel can qualify as renewable fuel for RIN generation under the RFS2 program. We believe the stipulations in sections 80.1426(f)(10) and (11) are clear that biogas used for non-transportation fuel purposes, such as an energy source for providing process heat would not qualify under this biogas pathway for RIN generation. Similarly, raw biogas would also not qualify under this pathway since unprocessed biogas cannot be used as transportation fuel. With regard to the fuel types that can be

[37] Swanson, R.M., Satrio, J.A., Brown, R.C., Platon, A., and Hsu, D.D. (2010) Techno-Economic Analysis of Biofuels Production Based on Gasification. NREL Technical Report NREL/TP–6A20–46587, *http://www.nrel.gov/docs/fy11osti/46587.pdf.*

[38] Skone, T.J. and Gerdes, K. (2008) NETL: Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. *http://www.netl.doe.gov/energy-analyses/pubs/NETL%20LCA%20Petroleum-Based%20Fuels%20Nov%202008.pdf.*

[39] Emissions estimates are conservatively high.

produced from the raw biogas such as CNG, LNG, renewable electricity, renewable diesel, or naphtha, the pathway determinations for the final rule did not account for all factors relevant for the additional fuel types such as renewable electricity, renewable diesel or naphtha produced from the raw biogas through a chemical process. Therefore, renewable electricity, renewable diesel and naphtha produced from biogas do not qualify under the existing pathway.[40] For CNG and LNG, we concluded that these types of fuels were close enough to the physical molecules of biogas since these fuels only go through a physical process in which the biogas is compressed or liquefied, and that because CNG and LNG can be used directly for transportation purposes, thus meeting the provisions in sections 80.1426(f)(10) and (11), we concluded that CNG and LNG could qualify under the existing pathway. For the reasons discussed above, we are proposing to amend the existing biogas pathway to clearly state that only CNG and LNG produced from biogas from landfills, waste treatment plants and waste digesters, and used as transportation fuel, qualify as a cellulosic or advanced biofuel for RIN generation under the RFS2 program.

The current regulations provide a pathway for biogas produced from a bio-digester which uses manure. We are also proposing to expand the type of materials that may be used to produce CNG/LNG in a digester to include animal wastes, biogenic waste oils/fats/greases, separated food and yard wastes, and crop residues. These feedstock sources are already eligible in the existing rules pathways and therefore should reasonably be added to the bio-digester pathway. We are doing so in response to a petition request to generate RINs from biogas which is produced from bio-feedstock sources in addition to the already allowed manure, either individually or in combination with manure in a bio-digester. As with other LCA pathways using these materials, EPA is proposing to assume these waste materials do not have emissions associated with feedstock production, and therefore qualify as cellulosic or advanced renewable fuels when used to produce CNG/LNG.

To provide improvement for this revised pathway, we are proposing to revise the definition of biogas and add new definitions for renewable CNG and renewable LNG to section 80.1401 to read as follows:

We are proposing Biogas would mean a mixture of hydrocarbons that is a gas at 60 degrees Fahrenheit and 1 atmosphere of pressure that is produced through the conversion of organic matter. We are also proposing that Biogas would include landfill gas, gas from waste digesters, and gas from waste treatment plants. Waste digesters would include digesters processing animal wastes, biogenic waste oils/fats/greases, separated food and yard wastes, and crop residues. Waste treatment plants would include wastewater treatment plants and publicly owned treatment works.

We are proposing that Renewable compressed natural gas (''renewable CNG'') would mean biogas that is processed to the standards of pipeline natural gas as defined in 40 CFR 72.2 and that is compressed to pressures up to 3600 psi. We are also proposing that only renewable CNG that qualifies as renewable fuel and is used for transportation fuel can generate RINs.

We are proposing that Renewable liquefied natural gas (''renewable LNG'') would mean biogas that is processed to the standards of pipeline natural gas as defined in 40 CFR 72.2 and that goes through the process of liquefaction in which the biogas is cooled below its boiling point and weighs less than half the weight of water so it will float if spilled on water. We are also proposing that only renewable LNG that qualifies as renewable fuel and is used for transportation fuel can generate RINs.

2. New Registration (Contract Requirements) for Renewable Electricity and Fuels Produced From Biogas That Qualify as Renewable Fuel and That Are Registered for RIN Generation

The regulations as currently written allow a producer of biogas or renewable electricity[41] that qualifies as renewable fuel and has an approved fuel pathway in Table 1 of section 1426(f)(1) to register and generate RINs for the volume it produces under the RFS2 program. We modified the existing regulations to state that biogas is the feedstock used to produce renewable fuel, as described above. The revised regulations in sections 1426(f)(10) and (11) detail the requirements for distribution and tracking for renewable electricity and biogas used to produce fuel that qualifies as renewable fuel that can either be distributed in a dedicated pipeline or transmission line or distributed in a shared pipeline or power grid system. The purpose of these requirements is to provide EPA assurance and verification that once the biogas or renewable electricity is put into a dedicated or shared distribution system that in fact an equivalent volume of biogas or renewable electricity will be used for transportation fuel, and for no other purposes. The requirements are also meant to address concerns of double counting of the biogas or renewable electricity, especially in situations that the biogas or renewable electricity is placed in or loaded onto shared distribution systems that contain gas or electricity from non-renewable biomass sources. EPA intended to require producers to submit the information and contract requirements in sections 1426(f)(10) and (11) as part of the registration requirements for renewable electricity and renewable fuels produced from biogas that are used for transportation[42] fuel, but had not done so in the prior rulemakings. Therefore, as a natural outgrowth of the regulations for implementation and compliance purposes, we are proposing in this rulemaking to incorporate the requirements in sections 1426(f)(10) and (11) as part of registration requirements for producers of renewable electricity and renewable fuels produced from biogas that qualify as renewable fuel under the regulations under section 1450(b)(1)(iv)(C).

Section 1426(f)(11)(ii) of the regulations requires that, in order for renewable fuel made from biogas withdrawn from a commercial distribution system for use as a transportation fuel to generate RINs, the biogas introduced into the system must have been added to a common carrier pipeline. We propose to add a similar provision to section 1426(f)(11)(i) for renewable electricity, requiring a company to load the renewable electricity to a power grid shared by the second company that withdraws the electricity, such that the two companies must be physically connected to the same grid or located within the same area.

EPA is requesting comments about whether the other existing requirements in sections 1426(f)(10) and (11) for renewable electricity and renewable fuels from biogas used for transportation

[40] For this rulemaking, we conducted lifecycle analysis for renewable electricity, renewable diesel, naphtha produced from landfill gas, and are proposing new fuel pathways to Table 1 to Section 80.1426 for these fuel types. Please see section titled, ''Lifecycle Greenhouse Gas Emissions Analysis for Renewable Electricity, Renewable Diesel and Naphtha Produced from Landfill Biogas'' for the lifecycle analysis discussion in this rulemaking.

[41] EPA notes that currently, producers of renewable electricity that may qualify as a renewable fuel cannot register and generate RINs because there is no approved pathway in Table 1 for renewable electricity from any approved feedstock. But in the event that an approved pathway for renewable electricity is added to Table 1, EPA notes there are existing requirements such as tracking and distribution requirements recordkeeping and reporting that are applicable for the registration of renewable electricity for RIN generation.

[42] Distribution and registration requirements for biogas used as process heat, and not for RIN generation as renewable fuel is detailed in Section 1426(f)(12) and 1450(b)(1)(iv), respectively.

fuel are sufficient to provide assurance and verification for the following situations. First, do the proposed requirements provide assurance and verification that the same amount of biogas or renewable electricity is in fact delivered to the renewable fuel producer or end user who will actually use the biogas or renewable electricity for transportation purposes? If the proposed requirements are not sufficient, what alternative requirements should be considered? Second, are the proposed requirements sufficient to ensure that double counting does not occur, e.g., to ensure that the biogas or renewable electricity once it is loaded into a shared pipeline or power grid is not sold to multiple clients or for purposes other than for transportation purposes? Similarly, if the proposed requirements are not sufficient, what alternative requirements could be considered to ensure double counting does not occur?

3. Changes Applicable to All Biogas Related Pathways for RIN Generation

As discussed above, we have had many inquiries related to the ''biogas'' pathway, specifically regarding contract requirements for tracking the biogas through the distribution system and regarding what company along the production chain is considered the ''producer'' and eligible to generate RINs under the RFS2 program. In this rulemaking, we are proposing to revise and add new requirements for contracts to track the biogas as it moves into and out of the distribution system, as well as provisions on registration, reporting and recordkeeping. These proposed amended requirements are applicable to all pathways related to biogas that are eligible for RIN generation that are existing or proposed in this rulemaking.

In response to the question of what company is considered the producer of renewable fuel and eligible to generate RINs under the RFS program, we propose to clarify who is the ''producer'' for renewable CNG/LNG and renewable electricity. We propose that the ''producer'' of renewable CNG/LNG is the company that compresses or liquefies the gas and distributes the CNG/LNG for transportation fuel, and for renewable electricity, the ''producer'' is the company that distributes the electricity for use as transportation fuel. There are two registration situations that this clarification will address: (1) The owner/operator of a landfill collects biogas and processes it to a qualifying renewable CNG/LNG/electricity for transportation use and distributes on site and (2) the owner/operator of a landfill collects biogas and it is processed into a qualifying renewable CNG/LNG/electricity for transportation use by a contracted third party and distributed by this third party. The party that converts the biogas to renewable CNG/LNG/electricity and distributes for use as a transportation fuel is responsible for RIN generation. Under the first scenario, the registration package, including the engineering review, would cover the biogas source (landfill, waste digester, etc.) as well as the distribution that is occurring on site. Under the the second scenario, the registration package, including engineering review, would cover the biogas source (landfill, waste digester, etc.) the pipeline (common carrier or dedicated) and each distribution facility. By requiring the party that is responsible for conversion and distribution to register as the RIN generator, we can prevent RINs from being generated for a batch or renewable CNG/LNG/electricity prior to use as a qualifying transportation fuel. For any of the fuels, the company designated as the ''producer'' will be required to register under the RFS2 program. We seek comment on our proposed definition of producer regarding renewable CNG/LNG and renewable electricity.

We acknowledge that the process train from raw biogas to the final transportation fuel is complex, and may include many companies and processing steps from the point when the raw biogas is withdrawn from its source (such as landfills, waste digesters, waste treatment plants), processed and converted into biofuel and distributed to consumers. Alternatively, the fuel may be cleaned at a biogas facility to pipeline quality specifications for distribution, and then withdrawn from the commercial pipeline to be processed further at another production facility into renewable CNG/LNG or renewable electricity. Due to the complexity of the many entities potentially involved in this process train, we are proposing that the company deemed as the ''producer'' under the qualifications described above also be responsible for providing all the required information and supporting documentation in their registration, reporting and recordkeeping to track and verify the information from point of extraction of the raw biogas from its original source, and all the processing steps and distribution in between, to the last step where the actual fuel is used for transportation purposes. In the engineering review report required for registration, the producer must include documentation that the professional engineer performed site visits at each production facility, including the biogas facility and the facility that produces the final fuel (if these are not the same facility). The producer must also review and verify all related supporting documents such as design documents, calculations, regulatory permits, and contracts between facilities that track the raw biogas from the point of withdrawal from its source, the various injection/withdraw points into the distribution pipeline, the various production facilities, and the final step for use as transportation fuel. We believe these requirements will ensure that producers will perform due diligence that the fuel for which they generate RINs under the RFS2 program are in compliance with all the regulatory requirements for renewable fuel. The proposed registration, reporting and recordkeeping requirements are in sections 80.1426(f), 80.1450, 80.1451 and 80.1454 in this rulemaking. Additional changes regarding the contract requirements for distribution of the biogas in shared commercial pipelines are discussed below, and can be located in sections 80.1426(f)(10), (11), and (13).

4. Changes Applicable To Process Electricity Production Requirement for the Biogas-Derived Cellulosic Diesel and Naphtha Pathways

In this proposed rulemaking, EPA conducted greenhouse gas (GHG) lifecycle analysis for various renewable fuels produced from landfill gas as new or revised advanced and cellulosic biofuel pathways that will be added to Table 1 to section 80.1426(f).[43] For some of these pathways, we are proposing to add various registration, recordkeeping and reporting requirements to the regulations to ensure that the facilities using these pathways meet the parameters stipulated in the lifecycle analysis. The additional registration, recordkeeping and reporting requirements are discussed in detail below.

For the proposed fuel pathways for cellulosic diesel and cellulosic naphtha produced from landfill gas, we are proposing to require the renewable fuel production facility to produce a minimum of 20 percent of the process electricity used at the facility on a calendar year basis, from raw landfill gas, waste heat from the production process, unconverted syngas from the

[43] Refer to preamble discussion for these various biogas pathways in section titled, ''Lifecycle Greenhouse Gas Emissions Analysis for Renewable Electricity, Renewable Diesel and Naphtha Produced from Landfill Biogas.''

F–T process, fuel gas from the hydroprocessing or combined heat and power (CHP) units that use non-fossil fuel based gas or other renewable sources. We propose that if less than 20 percent (on an annual average basis) of process energy comes from one of these alternative sources, then no cellulosic RINs can be generated for that year.

For the renewable fuel production facility applying to use the proposed fuel pathway with the requirement to internally produce at least 20 percent of the total amount of process electricity used at its facility, we are proposing the facility submit to EPA the information described below to demonstrate compliance with this requirement. For registration purposes, we are proposing that producers submit the following additional information in the process fuel supply plan that is currently required as part of the registration process (estimated summaries are to be reported on an annual/calendar year basis):

—Estimated amount of total electricity used at the facility
—Estimated amount of total electricity purchased for the facility
—Estimated amount of total renewable electricity produced on-site, including the source of the energy and the equipment and/or process used to generate the renewable electricity
—Calculation that verifies the facility meets the specified 20 percent minimum electricity production requirement based on the reported total amount of electricity used at the facility, total amount of electricity purchased, and total amount of renewable electricity produced

For reporting purposes, we are proposing for producers to submit the following additional information as part of their existing quarterly and annual reporting obligations (reported amounts should be provided as monthly summaries on an annual/calendar year basis, and must be obtained from a utility meter that is continuously measured):

—Actual total amount of electricity used at the facility
—Actual total amount of electricity purchased for the facility
—Actual amount of total renewable electricity produced on-site, including source of energy and the equipment or process used to generate the renewable electricity
—Calculation that verifies the facility meets the specified 20 percent minimum electricity production requirement based on the reported total amount of electricity used at the facility, total amount of fossil-fuel based electricity purchased, and total amount of renewable electricity produced

For recordkeeping purposes, we are proposing that producers retain the additional information, calculations and supporting documents required for registration and reporting as discussed above. The regulatory requirements for registration, reporting and recordkeeping as discussed in this proposed rulemaking can be located in the following applicable regulatory sections 80.1450, 80.1451 and 80.1454, respectively.

D. Amendment to the Definition of "Crop Residue" and Definition of a Pathway for Corn Kernel Fiber

We propose to amend the definition of "crop residue" so that this category includes only feedstock sources that are determined by EPA would not result in a significant increase in direct or indirect GHG emissions. "Crop residue" is the biomass left over from the harvesting or processing of planted crops from existing agricultural land and any biomass removed from existing agricultural land that facilitates crop management (including biomass removed from such lands in relation to invasive species control or fire management), whether or not the biomass includes any portion of a crop or crop plant. Biomass is considered crop residue only if the use of that biomass for the production of renewable fuel has no significant impact on demand for the feedstock crop, products produced from that feedstock crop, and all substitutes for the crop and its products including the residue, nor any other impact that would result in a significant increase in direct or indirect GHG emissions.

EPA is amending the definition of "crop residue" to confirm the meaning of the term "left over" in the text of this definition. The phrase "left over" in our original definition of "crop residue" is meant to indicate that the use of a residue as a biofuel feedstock should not increase demand for the crop it is derived from, should not induce further crop production, and should not result in additional direct or indirect GHG emissions. The residue must come from crop production or processing for some other primary purpose (e.g., refined sugar, corn starch ethanol), such that the crop residue is not the reason the crop was planted. The residue must also come from existing agricultural land, the exact definition of which is laid out in our current regulations that define "renewable biomass".[44] Further, the residue should generally not have a significant market in its own right, to the extent that removing it from that market to produce biofuels instead will result in increased GHG emissions. EPA is seeking comments on this revision to the crop residue definition. EPA invites all comments regarding this revision, but specifically invites comments regarding the potential for the revision to create a significant shift in direct or indirect GHG emissions and what ought to constitute a "significant" increase or decrease in GHG emissions in the context of this definition.

EPA has previously identified several potential feedstocks that we believe meet the criteria of crop residue. Table IV.D.–1 lists feedstocks which may fit the definition of crop residue. Most of these feedstocks were discussed in the final RFS2 rulemaking. For example, EPA analyzed the agricultural sector GHG emissions of using corn stover for biofuels in the final RFS2, and found that fuel produced from this feedstock met the 60% GHG reduction threshold for cellulosic biofuels. Since the direct and indirect impacts of citrus residue, rice straw, and wheat straw removal were expected to be similar to corn stover, EPA also applied the land use change impacts associated with corn stover to citrus residue, rice straw, and wheat straw. Based on that analysis, EPA found that fuels produced from citrus residues, rice straw, and wheat straw also met the 60% reduction threshold. EPA further determined that fuels produced from materials left over after the processing of a crop into a useable resource had land use impacts sufficiently similar to agricultural residues to also meet the 60% threshold. EPA specifically cited bagasse left over from sugarcane processing as an example of this type of residue. EPA is seeking comment on whether the feedstocks on this list should be considered crop residues, if these feedstocks would have similar direct and indirect impacts as corn stover, and whether additional feedstocks should also be included in this list.

TABLE IV.D.–1—FEEDSTOCKS THAT MAY QUALIFY AS CROP RESIDUE

Feedstock	D Code
Sugarcane Bagasse.	D–3 Cellulosic biofuel.
Corn Kernel Fiber (excluding the corn starch component).	D–3 Cellulosic biofuel.

[44] *See* specifically § 80.1401 Definitions.

TABLE IV.D.–1—FEEDSTOCKS THAT MAY QUALIFY AS CROP RESIDUE—Continued

Feedstock	D Code
Corn Stover	D–3 Cellulosic biofuel.
Citrus Residue	D–3 Cellulosic biofuel.
Rice Straw	D–3 Cellulosic biofuel.
Wheat Straw	D–3 Cellulosic biofuel.

While EPA believes that, under current conditions, generation of RINs for batches of renewable fuel produced from the feedstocks listed in Table IV.D.–1 above would not result in a significant increase in direct or indirect GHG emissions, we also acknowledge the potential for this assessment to change in the future based on unforeseeable factors. For example, some new use for one of these products could be developed which would change our assessment that the feedstock has no significant market in its own right. Further, it is possible that, at some point in the future, large enough quantities of renewable fuel could be produced from one of these fuels to create demand pull for the feedstock, potentially altering the behavior of producers of the residue and leading to significant increases in direct or indirect GHG emissions. To our knowledge, this is not currently the case for any of the feedstocks listed above. However, EPA will continue to monitor RIN generation from fuel produced using each of these feedstocks and the general use of these feedstocks in the marketplace. We further reserve the right to revisit the status of any feedstock that we have determined qualifies under the crop residue pathway. Should any feedstock qualifying as a crop residue be used to generate significant quantities of ethanol in the future, or should a significant market emerge for the product such that there is demand pull for it in excess of the demand pull for the planted crop from which it is a derived byproduct, we will revisit whether that feedstock should remain under the crop residue pathway or be subjected to further scrutiny. EPA is seeking comment on this approach and on the potential for significant demand pull to emerge for the feedstocks we are proposing to consider as crop residues.

We also propose that this definition of ''crop residue'' includes corn kernel fiber. Corn kernel fiber is not specifically mentioned as a type of crop residue under the Renewable Fuel Standard (RFS2) regulations. Per the RFS2 definition of ''crop residue'', EPA must evaluate whether corn kernel fiber is ''left over from the harvesting or processing of planted crops'' and that it has no ''impact that would result in a significant increase in direct or indirect GHG emissions'' for this feedstock to qualify as a residue.

One additional consideration in the classification of corn kernel as a crop residue is the fact that some amount of corn starch might still adhere to the corn kernel after separation. The percentage of contamination will vary, but as much as 20% of the final fuel could be derived from corn starch. By definition, corn starch ethanol can only qualify as a renewable fuel, not as an advanced fuel. However, our current regulations state that ''producers and importers may disregard any incidental, de minimis feedstock contaminants that are impractical to remove and are related to customary feedstock production and transport''.[45] Therefore, EPA is seeking comment on whether the definition of crop residue should be amended to explicitly exclude the corn starch component.

EPA also invites comment on how RINs should be allocated for ethanol derived from corn fiber. EPA has existing regulations that define procedures for generating RINs from batches of fuel that contain multiple feedstocks, including feedstocks that generate RINs of different D codes.[46] We believe that these regulations provide sufficient guidance to producers and importers regarding how to assign RINs to batches of renewable fuel that can be described by two or more pathways (e.g., corn starch ethanol and corn kernel fiber ethanol). However, we invite comment on the sufficiency of these regulations with regards to the assignment of RINs to coprocessed batches of corn starch ethanol and corn kernel fiber ethanol, including whether producers have the technological capability to adequately demonstrate volume produced under each pathway.

To determine whether the use of corn kernel fiber to produce ethanol would lead to increased direct or indirect GHG emissions, EPA conducted a detailed assessment of the two major potential sources of emissions from this feedstock, namely effects on feed markets and effects on demand for corn. The proposed method of acquiring corn kernel fiber is to extract it from matter that is otherwise converted to dried distillers grains (DDG) during the dry mill corn ethanol process. Consequently, this analysis relied significantly on the assessment of corn starch ethanol-derived DDG that was conducted for the RFS2 final rule, adjusting the analysis to account for the extraction of fiber from this product. The analysis also drew substantially on the available scientific literature on low fiber DDG (LF–DDG), as well as the expertise of the U.S. Department of Agriculture. Potential producers also submitted important data to EPA that helped determine whether producing cellulosic ethanol from corn kernel fiber would result in a significant increase in GHG emissions. This included a full nutritional analysis of LF–DDG for swine, poultry, and cattle.

EPA found that extracting the fiber from corn matter used to produce standard DDG would not have a significant effect on feed markets. Processors who extract the fiber from corn produce a feed product known as LF–DDG, as opposed to standard DDG which retains the fiber. The scientific literature on LF–DDG animal nutrition has found that this product has at least equal, and perhaps even slightly superior, nutritional value for swine and poultry compared to standard DDG.[47] This means that, even though the physical volume of the DDG produced by ethanol plants using corn kernel fiber extraction technology will be somewhat smaller, its nutritional content for swine and poultry will be equivalent to or greater than their output without fiber extraction.

Conversely, LF–DDF is an inferior feed for cattle compared to standard DDG, since ruminants benefit from ingesting corn fiber in DDG.[48] Therefore, EPA expects swine and poultry producers to absorb the supply of LF–DDG, while the cattle and dairy industry will continue to consume standard DDG. With this dynamic in place, fiber extraction from DDG should not significantly affect feed markets, since there will be no reduction in the overall supply of DDG in terms of nutritional content nor will there be any impact on aggregate demand for other animal feed sources.

If enough corn ethanol producers adopt fiber extraction technology, LF–DDG could saturate swine and poultry demand and spill over into dairy and cattle feed markets. If a situation arises where LF–DDG begin to replace standard DDG in cattle markets, this could lead to an increase in feed

[45] *See* specifically § 80.1426(f)(1).

[46] *See* specifically § 80.1426(f)(3).

[47] *See, e.g.,* Kim, E.J., C.M. Parsons, R. Srinivasan, and V. Singh. 2010. *Nutritional composition, nitrogen-corrected true metabolizable energy, and amino acid digestibilities of new corn distillers dried grains with solubles produced by new fractionation processes. Poultry Science* 89, p. 44, available on the docket for this rulemaking. *See also* additional studies cited within Kim et al 2010.

[48] *See* Shurson, G.C. 2006. *The Value of High-Protein Distillers Coproducts in Swine Feeds. Distillers Grains Quarterly,* First Quarter, p. 22, available on the docket for this rulemaking.

demand, most likely in the form of increased demand for fiber supplements in dairy and cattle feed. This could cause an increase in GHG emissions. If swine and poultry demand for LF–DDG becomes saturated, demand for standard DDG in the cattle and dairy industries should create sufficient market incentives for the remaining corn starch ethanol producers to decide against adopting corn fiber ethanol production. EPA believes this will prevent a situation where there is insufficient supply of standard DDG in the cattle and dairy industries. However, as noted above, EPA reserves the right to reexamine corn kernel fiber as a feedstock in the future.

EPA's analysis indicates that producing cellulosic ethanol from corn kernel fiber is unlikely to increase overall demand for corn. In order to meet the definition of a crop residue, the source of corn kernel fiber must be a crop processing facility (e.g., a corn starch ethanol plant). A corn kernel fiber ethanol producer cannot purchase whole corn specifically for the generation of corn fiber ethanol and still qualify their feedstock as crop residue. EPA is seeking comment on this analysis.

Based on our assessment, EPA proposes that corn kernel fiber would meet the definition of a crop residue, and qualify for Cellulosic Ethanol and Advanced Biofuel (D-codes 3 & 5, respectively) RINs under the RFS2. EPA is seeking comment on whether corn kernel fiber should be considered a crop residue.

E. Consideration of Advanced Butanol Pathway

1. Proposed New Pathway

EPA is proposing to add a new pathway to Table 1 to section 80.1426 that allows butanol made from corn starch using a combination of advanced technologies to meet the 50% GHG emissions reduction needed to qualify as an advanced renewable fuel. This pathway applies to dry mill fermentation facilities that use natural gas and biogas from an on-site thin stillage anaerobic digester for process energy with combined heat and power (CHP) producing excess electricity of at least 40% of the purchased natural gas energy of the facility (the proposed ''advanced butanol pathway'').

GEVO Incorporated submitted a petition requesting authorization to generate D-code 5 RINs for fuel produced through the GEVO butanol pathway. A petition is required because the proposed process utilizes a high yield butanol fermentation process that is different from those analyzed as part of the RFS2 corn ethanol pathways, and does not use the approved advanced technologies shown in Table 2 to section 80.1426 of the RFS2 regulations.

EPA's evaluation of the lifecycle GHG emissions of the advanced butanol pathway under this petition request is consistent with EISA's applicable requirements, including the definition of lifecycle GHG emissions and threshold evaluation requirements. It was based on information regarding GEVO's production process that was submitted under a claim of Confidential Business Information (CBI) by GEVO on April 11, 2011. The information provided included the mass and energy balances necessary for EPA to evaluate the lifecycle GHG emissions of the advanced butanol pathway.

The lifecycle GHG emissions of fuel produced pursuant to the advanced butanol pathway were determined as follows:

Feedstock production—The advanced butanol pathway uses corn starch as a feedstock. Corn starch is one of the feedstocks already listed in Table 1 to section 80.1426 of the RFS2 regulations. Since corn starch has already been evaluated as part of the RFS2 final rule, no new feedstock production modeling was required.

The FASOM and FAPRI models were used to analyze the GHG impacts of the feedstock production portion of the fuel's lifecycle. The same FASOM and FAPRI results representing the emissions from an increase in corn production that were generated as part of the RFS2 final rule analysis of the existing corn butanol pathways were used in this analysis of the advanced butanol pathway. These results represent agriculture/feedstock production emissions for a certain quantity of corn produced. For the RFS2 analysis, this was roughly 960 million bushels of corn used to produce 2.6 billion gallons of fuel. We have calculated GHG emissions from feedstock production for that amount of corn. EPA does not believe the advanced butanol process for converting corn into butanol will materially affect the total amount of corn used for biofuels and modeled as part of the RFS2 final rule. Based on information provided by industry, the technologies to produce corn butanol are primarily being targeted at retrofitting existing corn ethanol facilities, where the infrastructure to produce renewable fuels already exists and the capital expenditures would be relatively small. Therefore, the existing agricultural sector modeling analyses for corn as a feedstock remain valid for use in estimating the lifecycle impact of renewable fuel produced using the advanced butanol pathway. The Agency is seeking comment on whether there is any research to suggest that converting corn into an advanced butanol pathway would materially affect the total amount of corn used.

GEVO provided, as part of the information claimed CBI, their process yield in terms of gallons of fuel produced per bushel of corn. Based on the data, GEVO's process yield is slightly more efficient than the pathways modeled as part of the RFS2 rulemaking. Therefore, compared to the corn butanol pathways already analyzed, the GEVO process results in 0.93% more Btus of fuel produced for the same amount of corn feedstock.

Fuel production—The fuel production method included in this advanced butanol pathway involves the production of butanol from corn starch in a dry mill. The amount and type of energy used in this analysis is different than production methods that were analyzed under the final rule. While there were slight differences in the total amount of natural gas and electricity used in this analysis, the main difference was the use of biogas and production of excess electricity. To analyze the GHG impacts of the advanced butanol pathway, EPA utilized the same approach that was used to determine the impacts of processes in the RFS2 corn butanol pathways.

The amount and type of energy used was taken from GEVO's mass balance & energy balance submitted to EPA. GEVO submitted energy data on natural gas and biogas (in Btus) and electricity (in kWhs) inputs, as well as gallons of fuel produced. Biogas and natural gas are used in combination, while the RFS2 corn butanol analyses only considered natural gas or biogas used independently, not in combination.

The emissions from the use of energy 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 RFS2 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.

One area where EPA is soliciting comments is on the most appropriate energy content assumption to use for butanol (lower heating value). As part of this analysis, EPA used the GREET value for the energy content of butanol, which is 99,837 Btus per gallon.[49] Differences in the measurement of the energy content of butanol can occur for a number of reasons including variations amongst isomers (t-butanol, n-butanol, isobutanol, and sec-butanol), and differences in testing methodologies. EPA is seeking comment on whether there are any reasons why EPA should change its assumptions and use a different energy content of butanol.

The RFS2 corn butanol pathways included an estimate for DDGs co-product production which we similarly applied to the advanced butanol production process. Since DDGs impact the agricultural markets, production of DDGs was already included as part of the FASOM and FAPRI modeling already described in the feedstock production section, above. Thus no additional co-product credits for the DDGs are applied for the fuel production stage of the analysis.

The advanced butanol production process analyzed here also results in excess electricity production. As per the pathway description the process produces excess electricity of at least 40% of the purchased natural gas energy of the facility. The onsite emissions of the electricity production are accounted for in the facility natural gas and biogas use. The co-product credit of the excess electricity is accounted for by assuming the electricity offsets average grid electricity production and results in associated emission reductions.

The estimated production emissions from the advanced butanol process are shown below in Table V.F.–1.

TABLE V.F.–1—FUEL PRODUCTION EMISSIONS FOR THE ADVANCED BUTANOL PROCESS

Fuel production source	GEVO isobutanol (g CO_2-eq./mmBtu)
On-Site Emissions	15,273
Upstream (natural gas and electricity production)	2,424
Emissions Credit from Offset Electricity	−17,448
Total Fuel Production Emissions	249

Fuel and feedstock distribution—We used the same feedstock distribution emissions assumption considered for corn butanol under the RFS2 final rule for the advanced butanol pathway corn feedstock. The fuel type, butanol, and hence the fuel distribution for butanol, was already considered as part of the RFS2 final rule. Therefore, the existing feedstock and fuel distribution lifecycle GHG impacts for corn butanol were applied to the advanced butanol pathway analysis.

Use of the fuel—The advanced butanol pathway produces a fuel that was analyzed as part of the RFS2 final rule. Thus, the fuel combustion emissions calculated as part of the RFS2 final rule for butanol were applied to our analysis of the advanced butanol pathway.

The advanced butanol fuel was then compared to baseline petroleum gasoline, using the same value for baseline gasoline as in the RFS2 final rule analysis. The results of the analysis indicate that the advance butanol pathway would result in a GHG emissions reduction of 51.3% compared to the gasoline fuel it would replace.

Based on our LCA, we are proposing to add a new pathway to Table 1 to section 80.1426 that includes butanol from corn starch using the butanol process described here as an advanced biofuel (D–5 RINs). EPA invites comments on the assumptions used in this analysis.

Table V.F.–2 below breaks down by stage the lifecycle GHG emissions for the RFS2 corn butanol pathway, the advanced butanol pathway and the 2005 gasoline baseline. This table demonstrates the contribution of each stage in the fuel pathway and its relative significance in terms of GHG emissions.

TABLE V.F.–2—LIFECYCLE GHG EMISSIONS FOR THE ADVANCED BUTANOL PATHWAY, 2022

[Kg CO2-eq./mmBtu]

Fuel type	RFS2 corn ethanol, natural gas fired dry mill 63% dry DDGS	GEVO butanol	RFS2 2005 gasoline baseline
Net Domestic Agriculture (w/o land use change)	4	4	
Net International Agriculture (w/o land use change)	12	12	
Domestic Land Use Change	−4	−4	
International Land Use Change, Mean (*Low/High*)	32 (*21/46*)	*31*	
Fuel Production	28	0	19
Fuel and Feedstock Transport	4	4	*
Tailpipe Emissions	1	1	79
Total Emissions, Mean	77 (66/91)	48	98
% Reduction	−21%	−51%	

* Emissions included in fuel production stage.

Table V.F.–3 lists the proposed D-Codes by fuel type (butanol), considering the feedstock (corn starch) and different production process requirements.

[49] The GREET value is based on: Guibet, J.-C., 1997, Carburants et Moteurs: Technologies, Energie, Environnement, Publication de l'Institut Français du Pétrole, ISBN 2–7108–0704–1.

TABLE V.F.–3—PROPOSED D CODES FOR BUTANOL

Fuel type	Feedstock	Production process requirements	D-Code
Butanol	Corn starch	Fermentation; dry mill using natural gas, biomass, or biogas for process energy	6
Butanol	Corn starch	Fermentation; dry mill using natural gas and biogas from on-site thin stillage anaerobic digester for process energy w/CHP producing excess electricity of at least 40% of the purchased natural gas energy used by the facility.	5

2. Butanol, Biobutanol, and Volatility Considerations

Butanol is a flammable colorless liquid that is used as a fuel and as an industrial solvent. Butanol is composed of the chemical elements hydrogen, oxygen, and carbon. It can be made from petroleum or renewable biomass, such as corn, grasses, agricultural waste and other renewable sources. It can be used in internal combustion engines as an additive to gasoline and is currently registered under the Fuel and Fuel Additives Registration System (FFARS) for use at up to 12 volume percent. A higher blend level would require a new FFARS registration that would include meeting Tier 1 and Tier 2 health effects testing requirements. Biobutanol is the common name for butanol made from renewable sources.

There has been an increased interest in the use of biobutanol as a direct result of the requirements for increased use of renewable fuel volumes, adopted in EISA 2007. These provisions require an increase in the use of renewable fuels, with 36 billion gallons of renewable fuel to be used in the U.S. by 2022. Parties required to meet these standards are interested in cost effective and practical ways to satisfy the standards and meet the performance needs of the vehicles and engines. Biobutanol is one attractive option because of its higher energy density, lower blending vapor pressure, and lower heat of vaporization in comparison to ethanol, as well as the fact that it can be distributed as a gasoline blend throughout the fungible gasoline distribution system.

The Clean Air Act (section 211(h)(4)) requires EPA to adopt regulations limiting the volatility of gasoline during the summer months, when ozone is of most concern, including a one pound per square inch (psi) Reid Vapor Pressure (RVP) increase in the volatility limit for blends of gasoline containing 9–10% ethanol (E10). This allowance for a 1 psi increase in allowable volatility is commonly called the 1 psi waiver.

EPA's regulations at 40 CFR 80.27 adopt RVP standards that apply to the gasoline at all points in the distribution system, including the retail outlet. Under the provisions for the 1 psi waiver, blends of gasoline that contain from 9 volume percent to 10 volume percent ethanol are allowed to have volatility 1 psi higher than otherwise would be allowed (40 CFR 80.27(d)(2)). The chemical characteristics of ethanol are such that blends of gasoline with less than 9 volume percent to 10 volume percent ethanol would still have a significant increase in volatility. Thus the restriction on the 1 psi waiver to blends that have 9 volume percent to 10 volume percent ethanol has the effect of prohibiting the blending of E10 with other gasoline/renewable fuel blends at any point in the gasoline distribution system (wholesale or retail) in conventional gasoline areas during the summer control season. Blends of E10 gasoline and gasoline that is not E10 would have less than 9 volume percent or greater than 10 volume percent ethanol, would have a resulting increase in volatility compared to E0, but would not have the 1 psi waiver to allow for such an increase. This increase would lead to an RVP above the allowable limit, unless a sub-RVP gasoline blendstock was used. The practical effect is a prohibition on commingling of E10 and gasoline blends other than E10.

Under the current regulations, EPA applies the RVP standard to the commingled mixture as a whole, not to the components of the commingled mixture. Once the ethanol and non-ethanol blends are mixed, the commingled mixture is treated as the gasoline that is tested and compared to the RVP standard. A single RVP value is determined by testing the volatility of the commingled mixture, and this is compared to the standard. If the mixture has from 9 volume percent to 10 volume percent ethanol, then the 1 psi waiver applies to the mixture. If the mixture has a different percentage of ethanol, whether lower or higher, then the 1 psi waiver does not apply to the mixture.

This avoids a situation where there is an overall increase in volatility because of the commingling of E10 and gasoline that is not E10. As discussed below, the chemical characteristics of ethanol and the nonlinear nature of the volatility increase associated with varying volumes of ethanol, mean that mixing E10 gasoline with gasoline that is not E10 typically results in a net overall increase in emissions—the mixture has a higher volatility and emissions than the separate gasolines had on average before they were mixed.

Several parties have identified this as an obstacle that currently inhibits the opportunity for biobutanol to enter the commercial market. The primary issue is application of the RVP regulations at the final point of fuel dispensing, when the biobutanol (Bu) and the ethanol blends would be mixed, that is in a storage tank at the retail station. When a butanol product that complies with the RVP standards prior to commingling (e.g., a complying Bu12 blend) is commingled with a compliant E10 in underground storage tanks at fuel dispensing facilities, the resulting mix generally would exceed the applicable RVP standard as EPA's RVP regulations currently apply the standard. Certain fuels, including renewable biofuels such as butanol, however, do not have a net negative impact on RVP when blended with E10 at wholesale or retail. That is, the RVP and related emissions of the commingled blend of butanol and ethanol is no higher than the average RVP if the fuels had never been commingled. Thus, in these kinds of circumstances it may be appropriate to adopt a modified approach to applying the RVP standard to permit the commingling of complying E10 blends with complying butanol blends at wholesale and retail, as there is no overall degradation of RVP and the air quality impacts compared to what would occur if they were not blended.

Today, the agency is providing some additional background on this issue and requesting information for use in deciding whether EPA can and should modify its RVP regulations as discussed below. Specifically, we are inviting comment on the ability of regulated parties to comply with the existing regulations by segregating biobutanol blends from ethanol blends and whether there is a need to change the regulations. We are also seeking comment on an alternative approach to applying the RVP standards to a commingled mixture of E10 with biobutanol or other approved gasoline additives, where the additives have characteristics such that there is no net adverse emissions effect from the commingling. We are inviting comments as to whether the RVP standards can and should be applied such that the commingled mixture of E10 and specified blends of gasoline additives such as biobutanol is treated as complying with the RVP standard as long as the components of that mixture complied with the RVP standard prior to the commingling. This approach would provide a limited modification to how the RVP standards are applied, and the modification would apply for only certain fuel mixtures—those where the overall or net volatility of the commingled mixture is no higher than the weighted average of the original blends themselves, such that there is no adverse impact on emissions from the mixing compared to what would have occurred without such mixing. In order to assist parties in preparing comments, EPA is providing some additional background regarding the RVP program in the following paragraphs.

Background and History of Volatility Regulations

Reid Vapor Pressure (RVP) is the most common measure of gasoline volatility under ambient conditions. In 1989, EPA began reducing gasoline volatility by limiting its RVP (54 FR 11868, March 22, 1989) (40 CFR 80.27). Due to the presence of gasoline in certain markets mixed with about 10 volume percent ethanol (known as gasohol at the time), and because blending an alcohol into gasoline increases the volatility of the final product, EPA provided an additional 1 psi allowance for such blends. In the absence of the 1 psi allowance, a special blend stock would have been required for such blends to comply with the RVP standards and such sub-RVP blendstocks did not exist at the time. EPA imposed the RVP standards at all points in the gasoline distribution system, i.e., anywhere gasoline is sold, supplied, offered for sale or supply or transported, including service stations, refinery shipping, tanks, importer shipping tanks, pipeline and bulk terminals and plants. (40 CFR 80.28) (1989). In 1990, the agency promulgated additional regulations that further lowered the RVP standards. (55 FR 23658, June 11, 1990). EPA continued to provide both the 1.0 psi allowance to fuel blends containing about 10 volume percent ethanol, (40 CFR 80.27) (1990), and the requirement that RVP standards applied at all points in the distribution system.

Congress largely codified the approach taken in EPA's RVP regulations by adding a new section 211(h) in the 1990 CAA amendments. Section 211(h)(1) requires EPA to set the maximum RVP standard during the high ozone season as 9.0 psi. EPA was to ''promulgate regulations making it unlawful for any person during the high ozone season to sell, offer for sale, dispense, supply, offer for supply, transport, or introduce into commerce gasoline with a Reid Vapor Pressure in excess of 9.0 pounds per square inch (psi).'' Lower RVP standards could be set for ozone nonattainment areas. *See* Clean Air Act section 211(h)(1). Section 211(h)(2) addresses the RVP standard that apply in attainment areas, and sets the standard at 9.0 psi for attainment areas with authority for EPA to set a more stringent RVP level under certain circumstances. In section 211(h)(2), Congress allowed a 1-psi waiver for E10 gasoline, stating: ''For fuel blends containing gasoline and 10 percent denatured anhydrous ethanol, the Reid vapor pressure limitation under this subsection shall be one pound per square inch (psi) greater than the applicable Reid vapor pressure limitations established under paragraph (1).'' Additionally, Congress enacted a conditional defense against liability for violations of the RVP level allowed under the 1 psi waiver by stating that ''[p]rovided; however, that a distributor, blender, marketer, reseller, carrier, retailer, or wholesale purchaser-consumer shall be deemed to be in full compliance with the provisions of this subsection and the regulations promulgated there under if it can demonstrate that—(A) the gasoline portion of the blend complies with the Reid vapor pressure limitations promulgated pursuant to this subsection; (B) the ethanol portion of the blend does not exceed its waiver condition under subsection (f)(4) of this section; and (C) no additional alcohol or other additive has been added to increase the Reid Vapor Pressure of the ethanol portion of this blend.'' Section 211(h)(4).

In a 1991 rulemaking, EPA modified the RVP regulations to conform to the 1990 amendments (56 FR 64704, December 12, 1991). These regulations addressed the RVP standards in attainment areas, required the use of denatured anhydrous ethanol as a specific condition for the 1-psi waiver for fuel blends containing gasoline and from 9 volume percent to 10 volume percent ethanol, and included a new defense against liability for violations of the RVP standards for such fuel blends. We made no changes to the requirement that the RVP standards applied at all points in the distribution system.

What modification is EPA considering to the application of the RVP standards to certain fuel blends?

Gasoline and ethanol are mixed or blended after the refining process. The practice of blending ethanol with gasoline increases the RVP of the resulting blend by approximately 1.0 psi. It is a non-linear relationship, most of the volatility increase occurs after just a few percent of ethanol have been added, with the volatility increasing more slowly as the gasoline ethanol blend increases to 10 volume percent. Above 10 volume percent the volatility generally does not increase any more, and at even higher levels of ethanol the volatility starts to decrease again. As explained above, section 211(h)(4) provides a 1-psi waiver for fuel blends containing gasoline from 9 volume percent to 10 volume percent ethanol. The absence of such a waiver would have required the creation of a production and distribution network for sub-9.0 psi RVP gasoline, to offset the increase in volatility associated with blending ethanol into the gasoline. At the time the costs of producing and distributing an additional grade of this type of fuel, especially in consideration of the low volumes of fuel being blended with ethanol at the time, would have likely been prohibitive and resulted in the termination of the availability of ethanol in the marketplace. Thus, the 1-psi waiver facilitated the participation of ethanol in the transportation fuel industry while also limiting gasoline volatility resulting from ethanol blending.

But the RVP levels of gasoline actually used by consumers are dependent on the mixture of alcohol blends and gasoline that are commingling in either vehicle or storage tanks. Depending on the mixture, the resulting RVP level could be significantly higher than the average volatility of the fuels prior to the commingling. This is because the volatility increase when ethanol is added to gasoline is non-linear, with a large increase with the first few percent and then slowly tapering off as the concentration increases (see Illustration V.F.–4). In other words, mixing E10 and EO gasoline results in a net increase in the volatility of the gasoline mixture, compared to the average volatility that would occur absent such mixing. For example, 2000 gallons of 10 psi E10 added to a service station tank with 8000 gallons of 9.0 psi E0 would result in 10,000 gallons of fuel with a volatility of approximately 10 psi. However if the fuels had not been mixed, the average volatility of the 10000 gallons would have been 9.2 psi. The emissions associated with the commingled mixture (10000 gallons at 10 psi) would be significantly higher than the emissions associated with the two separate blends of 2000 gallons at 10 psi and 8000 gallons at 9 psi. The commingling thus results in an adverse environmental impact compared to what would occur absent the commingling. EPA's current RVP regulations address this adverse emissions impact by applying the RVP standard to the commingled mixture as a single fuel. In this case the commingled mixture has an RVP of 10 psi. The 1 psi waiver does not apply as the mixture is now 2% ethanol, not from 9 volume percent to 10 volume percent ethanol. The commingled mixture thus would not comply with the 9.0 psi RVP standard, effectively prohibiting such commingling.

As discussed earlier, the EPAct 2005 and EISA2007 mandated increased volumes of renewable fuel for use in gasoline. This has resulted in the increased use of ethanol. E10 is now present in nearly all gasoline sold in the country. Recently, EPA granted a waiver from the substantially similar requirements under section 211(f)(4) for the use of E15 blends in MY2001 and newer light-duty vehicles (*See* 75 FR 68094, November 4, 2010 and 76 FR 4662, January 26, 2011). EPA interpreted section 211(h) as not extending the 1 psi waiver to such blends with ethanol levels above 10%. Several companies are also developing and planning on introducing biobutanol into commerce. The characteristics of butanol are such that it could be beneficial with respect to volatility and vehicle evaporative emission performance. For example, 2000 gallons of 10 psi E10 added to a service station tank with 8000 gallons of 9.0 psi Bu12 would result in 10000 gallons of fuel with an RVP of 9.2 psi. The RVP of the commingled blend would be the same as the average of the separate blends if they had never been commingled. There is no adverse emissions impact from the commingling of the E10 and Bu12 blends. However the 1-psi waiver would not be applicable because the resulting blend no longer contains from 9 volume percent to 10 volume percent ethanol. The RVP level for the resulting blend would also be higher than the maximum RVP standard of 9.0 psi, making the commingled blend noncomplying with the RVP standard. However the available data indicates that commingling of biobutanol blends with ethanol blends would not result in any net increase in gasoline volatility. This is because biobutanol blends and gasoline containing from 9 volume percent to 10 volume percent ethanol blend linearly from a volatility perspective, resulting in no net increase in volatility compared to what would occur without the blending. This means that there would be no net degradation in environmental performance, as indicated in Illustration V.F.–4, below.

We are inviting comment on an alternative approach to applying the RVP standard to the gasoline that results from commingling of E10 and certain other products like biobutanol. We are inviting comment as to whether the RVP standards could be applied to the commingled blend such that the commingled blend would be considered in compliance as long as the separate components of the commingled product were in compliance with the RVP standards prior to commingling. In effect the RVP standard would be applied to the commingled mixture by treating it as if it still contained two separate products, with each product required to comply with the RVP standard separately. This approach would be somewhat artificial but would allow for the commingling of specified blends of fuels, such as biobutanol, with E10 where the resulting commingled mixture does not result in a net increase in average RVP and associated emissions. This would provide more flexibility in achieving the RFS standards while avoiding adverse environmental impacts. This approach would provide a limited modification to the RVP provisions for only certain fuel blends. EPA invites comment on whether it would have the authority under § 211(h) to adopt such an approach, and if so whether it would be appropriate to do so and under what conditions.

Specifically, we would consider imposing the following conditions on such fuel blends:

(1) Each separate component must individually meet the applicable RVP standards (e.g., 10 psi for E10 and 9 psi for other blends).

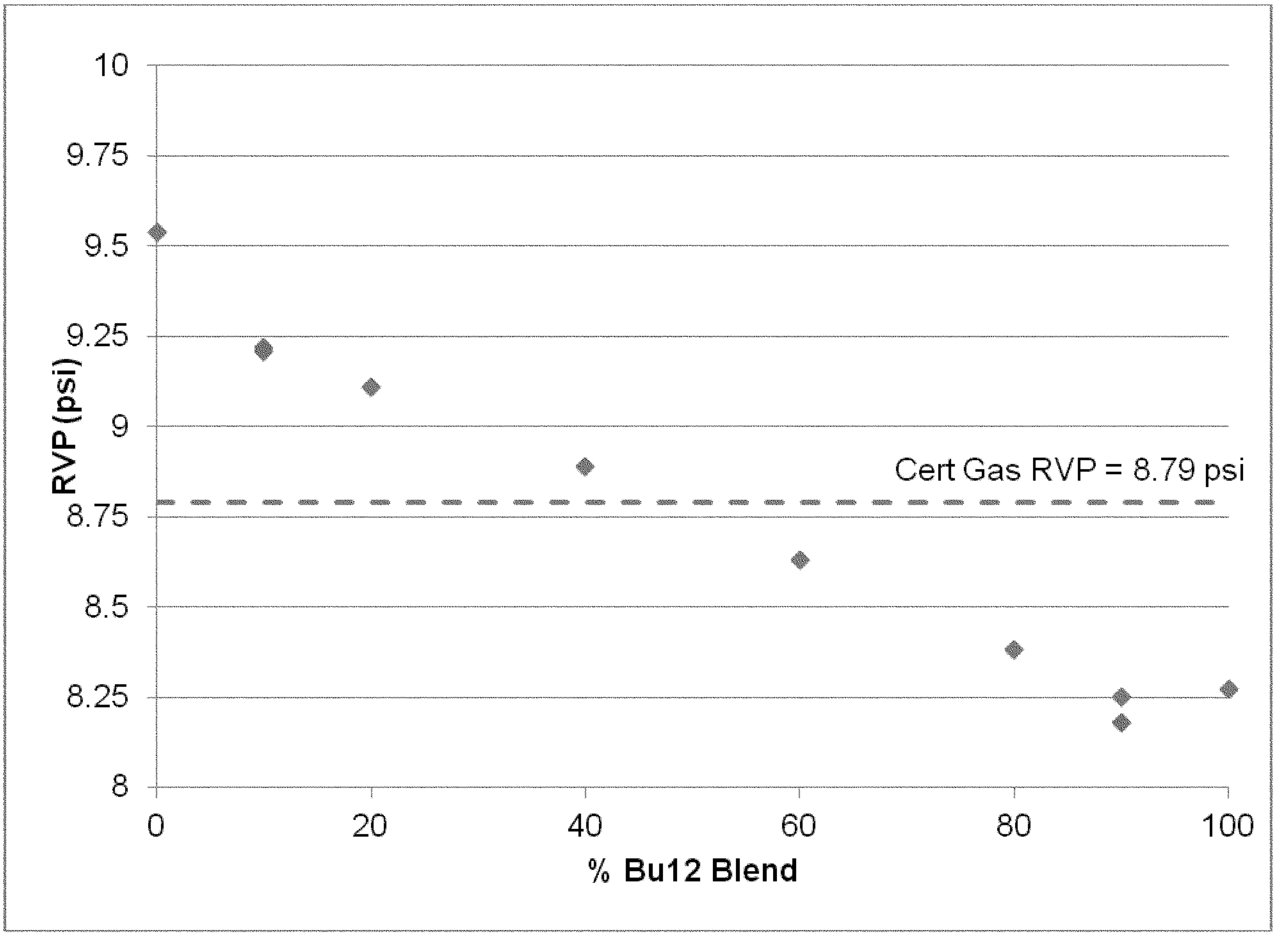
(2) The resulting commingled mixture would have to have an RVP that is no higher than the weighted average of the products or components considered separately. This could occur with blends that blend linearly with respect to RVP (e.g., butanol).

(3) The burden would be on the retailer to show that these conditions had been satisfied. If a commingled product had volatility above the allowable standard, and did not have from 9 volume percent to 10 volume percent ethanol, then the fuel would be considered noncomplying unless the regulated party demonstrated that it met the limited conditions discussed here. The retailer would have to demonstrate that the conditions were met for application of this modified method of determining compliance. This would call for at least retaining records of the products received (with all required regulatory statements and indications required) and volumes of the products received in order to demonstrate a calculation to verify compliance with the RVP standard.

(4) In situations where the RVP of retail tank samples exceed 9.0/7.8 psi, for defense purposes the retailer would need to test the sample for the concentration of ethanol, butanol, and any other applicable oxygenate in addition to the RVP level in order to allow for the calculation in (3). The resulting blend ratio would need to meet or demonstrate better performance reductions of such ratio on a linear scale as established through regulation.

Under this approach, we believe there would be no adverse environmental effects because such mixtures would result in no net increase in volatility. We also believe this would enable us to give effect to the RFS provisions that call for increased use of renewable fuels, and also be consistent with our rational for the treatment of gasohol at the time we promulgated the RVP standards.

Illustration V.F.-4 – Linear Plot for Commingled E10 and Bu12 Retail Fuel Blending
Source: EPA



F. Amendments to Various RFS2 Compliance Related Provisions

We are proposing a number of changes to the RFS2 regulations.

1. Proposed Changes to Definitions

''Responsible Corporate Officer''

The existing RFS2 regulations at sections 80.1416, 80.1451 and 80.1454, and EPA guidance and instructions regarding registration and reporting, frequently refer to the responsibilities of the ''owner or a responsible corporate officer.'' However, the term ''responsible corporate officer'' is not currently defined in the RFS2 regulations. We propose that, for purposes of the RFS2 program, a ''responsible corporate officer'' (RCO) means a corporate officer who has the authority and is assigned responsibility to provide information to EPA on behalf of a company. A company may name only one RCO, and the RCO may not delegate his/her responsibility to any other person. However, the RCO may delegate the ability to submit information to EPA to one or more employees of the company or to one or more agents. The RCO remains responsible for the information submitted to EPA by any employee or agent. Adding a definition of RCO will codify existing practices and will assist regulated parties in understanding roles under the RFS2 regulation.

''Small Refinery''

Section 211(o)(9)(A) of the Clean Air Act provides an exemption from RFS requirements through 2010 for ''small refineries,'' defined as refineries having an average aggregate daily crude oil throughput for a calendar year that does not exceed 75,000 barrels. It also provides for possible extensions of this exemption, through individual petitions to EPA. CAA 211(o)(9)(B). In EPA's March 26, 2010 regulations implementing the EISA amendments we specified in the regulatory definition of ''small refinery'' that the 75,000 bpd threshold determination should be calculated based on information from calendar year 2006. At the beginning of the program, having a single year in which to make this determination, simplified the calculations, and helped to ensure that all refineries were treated similarly. However, we no longer believe that it is appropriate that refineries satisfying the 75,000 bpd threshold in 2006 should be eligible for extensions to their small refinery RFS exemption if they no longer meet the 75,000 bpd threshold. Allowing such facilities to qualify for an exemption extension, while not allowing similarly sized facilities that have not grown since 2006 to qualify for an exemption, does not appear fair, nor does it further the objectives of the statute to target relief to only truly small facilities. Therefore, we propose modifying the definition of small refinery so that the crude throughput threshold of 75,000 bpd must apply in 2006 and in all subsequent years. We also propose specifying in section 80.1441(e)(2)(iii) that in order to qualify for an extension of its small refinery exemption, a refinery must meet the definition of ''small refinery'' in section 80.1401 for all full calendar years between 2006 and the date of submission of the petition for an extension of the exemption.

We proposed that that these changes would not affect any existing exemption extensions under CAA 211(o)(9)(B); rather, they would apply at such time as any approved exemption extension expires and the refinery at issue seeks a further exemption extension. No further extension would be permitted unless the revised crude oil throughput specifications were satisfied.

2. Provisions for Small Blenders of Renewable Fuels

The RFS2 regulations at section 80.1440 allow renewable fuel blenders who handle and blend less than 125,000 gallons of renewable fuel per year, and who are not obligated parties or exporters, to delegate their RIN-related responsibilities to the party directly upstream from them who supplied the renewable fuel for blending. EPA has received feedback from several parties to the effect that the 125,000 threshold is too low, and is a lower threshold than what industry considers ''small.'' EPA seeks input on what a more appropriate gallon threshold should be. EPA seeks comment on the regulated community's experience with the existing gallon threshold associated with the provisions. EPA may adjust the gallon threshold in the final rule based on further consideration of this issue and evaluation of comments received.

3. Proposed Changes to Section 80.1450—Registration Requirements

We propose to add a new paragraph (h) to section 80.1450 that will describe the circumstances under which EPA may cancel a company registration. EPA proposes to initiate a process to cancel a company registration if the company has reported no activity in the EPA Moderated Transaction System (EMTS) under section 80.1452 for one year. EPA also proposes to initiate a process to cancel a company registration if a party fails to comply with any registration requirement of section 80.1450, if the party fails to submit any required compliance report under section 80.1451, if the party fails to meet the requirements related to the EPA Moderated Transaction System (EMTS) under section 80.1452, or if the party fails to meet the requirements related to attest engagements under section 80.1454. If any required report, including the attest engagement, is thirty (30) or more days overdue, EPA would provide written notice to the owner or responsible corporate officer (RCO) that it intends to cancel the company's registration and would allow the company fourteen (14) days from the date of the letter's issuance to respond. If there is no satisfactory response received, then EPA would cancel the registration. Re-registration would be possible following the standard registration procedures.

4. Proposed Changes to Section 80.1452—EPA Moderated Transaction System (EMTS) Requirements—Alternative Reporting Method for Sell and Buy Transactions for Assigned RINs

Reporting and product transfer document (PTD) requirements, found in sections 80.1452 and 80.1453, respectively, currently state that the reportable event for a RIN purchase or sale occurs on the date of transfer. Sellers must report the sale of RINs within five (5) business days of the reportable event via the EPA Moderated Transaction System (EMTS). Buyers must report the purchase of RINs within ten (10) business days of the reportable event via EMTS. The date of transfer is the date on which title of RINs is transferred from the seller to the buyer. Some buyers and sellers of assigned RINs have expressed concerns with these requirements stating they have difficulty determining the date of transfer since title of the renewable fuel is not transferred until the fuel physically reaches the buyer. Some transactions, for example those by rail or barge, may take several weeks, and their current accounting systems do not include a means for capturing the buyer's receipt date.

EPA understands this concern, but also recognizes that some regulated parties have modified their accounting systems to address the current reporting and PTD requirements in RFS2. We also believe that for parties separating, retiring, and selling or buying separated RINs, the current reporting and PTD requirements are effective and should remain unchanged. Therefore, at this time EPA is not proposing to replace existing requirements, but is instead proposing an additional, alternative method for reporting sell and buy transactions involving assigned RINs only.

The proposed alternative method for sell and buy transactions of assigned RINs would redefine the reportable event for both the seller and the buyer, introduce a unique identifier that the seller must provide to the buyer, and require the buyer to report the date of transfer. Buyers and sellers would need to agree on which method they would be using to report transfers of assigned RINs; either the current method or the alternative method. EPA believes that this alternative would provide the regulated community with the flexibility to address their reporting concerns and also provide EPA with the data necessary to effectively administer and enforce transactions of assigned RINs. EPA welcomes comment on this proposed alternative method for reporting assigned RIN buy and sell transactions.

We propose that sellers of assigned RINs under the alternative method be required to do the following:

• Within five (5) business days of shipping renewable fuel with assigned RINs, report a sell transaction, using the alternative method, via EMTS;

• Include in the EMTS sell transaction report other required information per section 80.1452; and

• Provide a PTD to the assigned RIN buyer with a unique identifier, also reported via EMTS, in addition to the information in section 80.1453. The date of transfer is not required for the alternative method.

We propose that buyers of assigned RINs under the alternative method be required to do the following:

• Within five (5) business days of receiving a shipment of renewable fuel with assigned RINs, report a buy transaction, indicating use of the alternative method, via EMTS;

• Include in the EMTS buy transaction report other required information per section 80.1452;

• Include in the EMTS buy transaction report the unique identifier provided by the seller; and

• Include in the EMTS buy transaction report the date the renewable fuel was received, i.e. the date of transfer.

If this proposed alternative method is finalized, the EMTS would be modified to accept such transactions. EPA would provide additional instruction and guidance at the time of the new EMTS version release. EPA invites comment on all aspects of this proposal.

5. Proposed Changes to Section 80.1463—Confirm That Each Day an Invalid RIN Remains in the Marketplace Is a Separate Day of Violation

Preventing the generation and use of invalid RINs and encouraging rapid retirement and replacement of invalid RINs is crucial to the integrity of the RFS2 program. The RFS regulations include various provisions related to prohibited acts and liability for violations. Section 80.1460(a) sets forth the prohibited acts for the renewable fuels program. Section 80.1460(b)(2) prohibits parties from creating or transferring invalid RINs. Section 80.1461(a) states that the person who violates a prohibited act is liable for the violation of that prohibition. Section 80.1461(b) provides the liability provisions for failure to meet other provisions of the regulations. The penalty provisions of the regulations at section 80.1463(a) state that any person who is liable for a violation under section 80.1461 is subject to a civil penalty as specified in sections 205 and 211(d) of the Clean Air Act (CAA), for every day of each such violation and the amount of economic benefit or savings resulting from each violation. Section 80.1463(c) provides that ''any person . . . is liable for a separate day of violation for each day such a requirement remains unfulfilled.''

EPA interprets these statutory and regulatory penalty provisions to give the Agency the authority to seek penalties against parties generating, transferring or causing another person to generate or transfer invalid RINs for each day subsequent to the party's action that an invalid RIN is available for sale or use by a party subject to an obligation under the RFS2 program to acquire and retire RINs. For example, for a RIN generator, this time period typically runs from the date of invalid RIN generation until either corrective action is taken by the RIN generator to remove the invalid RIN from the marketplace or a party uses the RIN to satisfy an RVO or other requirement to retire RINs (such as would apply under today's proposal to exporters of renewable fuel or parties using fuel produced as renewable fuel for a use other than as transportation fuel, heating oil or jet fuel). This is consistent with the CAA approach of assessing penalties for every day of a violation, consistent with EPA's historic approach under the fuels regulations (*See* Section 80.615), and will encourage renewable fuel producers that generate invalid RINs to promptly take corrective action.

We are proposing to amend section 80.1463 to more explicitly incorporate EPA's interpretation of these penalty provisions into the regulations. The amendments would state that any person liable for a violation of section 80.1460(b) for creating or transferring an invalid RIN, or for causing another person to create or transfer and invalid RIN, is subject to a separate day of violation for each day that the invalid RIN remains available for use for compliance purposes, and EPA has the authority to seek the maximum statutory penalty for each day of violation. EPA will apply the statutory factors in sections 211(c) and 205(b) of the CAA to evaluate the appropriate penalties for each violation on a case by case basis.

6. Proposed Changes to Section 80.1466—Require Foreign Ethanol Producers, Importers and Foreign Renewable Fuel Producers That Sell to Importers To Be Subject to U.S. Jurisdiction and Post a Bond

The current regulations include requirements that foreign renewable fuel producers that generate RINs agree to be subject to a number of additional requirements at section § 80.1466, including, but not limited to, designation, foreign producer certification, product transfer document, load port independent testing and producer identification, submission to U.S. jurisdiction and posting of a bond. We are proposing to require the same requirements for foreign renewable fuel producers, and foreign ethanol producers that produce biofuel for which importers ultimately generate RINs, and for importers of renewable fuel.

In order to evaluate whether a fuel qualifies as RIN generating renewable fuel (including determining the proper renewable fuel category and RIN type for the imported fuel), EPA must be able to evaluate the feedstocks and processes used to produce the renewable components of the fuel. This is a particular challenge for fuel produced at foreign facilities; unlike our other fuels programs, EPA cannot determine whether a particular shipment of renewable fuel is eligible to generate RINs under the RFS program by testing the fuel itself. Furthermore, significant opportunity for fraud and non-compliance with the regulations exists where EPA is not able to ensure that RINs entering the U.S. are valid, and where enforcement of the regulations may be hampered due to a facility's foreign location. We believe that the same safeguards that apply to foreign RIN generating renewable fuel producers should apply to other foreign producers whose product is used by importers to generate RINs, and to those importers themselves. Accordingly, we propose that foreign renewable fuel producers and foreign ethanol producers who do not themselves generate RINs for their product, and importers of renewable fuel, be required to comply with the safeguards of section 80.1466. Given the challenges associated with EPA's ability to determine whether a fuel qualifies as RIN generating renewable fuel, and the potential for fraud, we believe these additional safeguards are necessary for all foreign produced renewable fuel, regardless of who generates the RINs. However, we seek comment on the reasonability of expanding these additional requirements onto foreign renewable fuel producers, and foreign ethanol producers that produce biofuel for which importers ultimately generate RINs, and for importers of renewable fuel. We further propose to amend section 80.1426(a)(4) to prohibit importers from generating RINs for renewable fuel imported from a foreign renewable fuel producer or foreign ethanol producer, unless and until the foreign renewable fuel producer or foreign ethanol producer has satisfied all requirements of section 80.1466.

7. Proposed Changes to Section 80.1466(h)—Calculation of Bond Amount for Foreign Renewable Fuel Producers, Foreign Ethanol Producers and Importers

EPA proposes two changes to section 80.1466 regarding calculation of bonds. EPA proposes to amend the procedures for calculating the bond amount for foreign renewable fuel producers, foreign ethanol producers and importers to require that the bond amount be the larger of: (1) One cent times the largest volume of renewable fuel produced by the foreign producer and exported to the United States, in gallons, during a single calendar year among the five preceding calendar years, or the largest volume of renewable fuel that the foreign producers expects to export to the Unites States during any calendar year identified in the Production Outlook Report required by section 80.1449, or (2) the sum of the following calculation for each RIN type: 0.25 times the largest volume of renewable fuel produced by the foreign producer and exported to the United States, in gallons, during a single calendar year among the five preceding calendar years, or the largest volume of renewable fuel that the foreign producers expects to export to the Unites States during any calendar year identified in the Production Outlook Report required by section 80.1449, times a ''RIN multiplier D code'' established by EPA in the regulations.

The proposed ''RIN multiplier D codes'' vary from $.02 for D code 6 to $1.30 for D code 4. When the original renewable fuels standard regulations (RFS1) were written, an RFS1 RIN was worth pennies. With the implementation of RFS2, the price of some RINs has increased significantly, in part because of the demand for certain categories of fuel such as biomass-based diesel. In order to keep up with these market conditions, the bond amount needs to be increased; a penny per gallon of fuel may no longer be a fair valuation of a foreign renewable fuel producer's potential penalty for RFS violations. Bonds are used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart. Therefore, we propose to amend section 80.1466(h)(1) to include the calculation described above, that reflects current market valuation for different types of RINs. We seek comment on whether the proposed bond calculation procedures are appropriate, and in particular whether they are sufficiently large to cover potential liability.

EPA also proposes to amend paragraph (h) of section 80.1466 to be consistent with paragraph (j)(4), which prohibits generating RINs in excess of the number for which the bond requirements have been satisfied. Paragraph (h) regulates the size of the bond a foreign renewable fuel producer must post in order to generate RINs. This formula takes into account the volume of renewable fuel a foreign renewable fuel producer has exported or intends to export to the United States. Section 80.1466(h) states, in part: ''If the volume of renewable fuel exported to the United States increases above the largest volume identified in the Production Outlook Report during any calendar year, the foreign producer shall increase the bond to cover the shortfall within 90 days.'' This conflicts with the stricter language in paragraph (j)(4) of the same section, which prohibits a foreign producer of renewable fuel from generating RINs in excess of the number for which the bond requirements of section 80.1466 have been satisfied. EPA interprets the stricter provision at section 80.1466(j)(4) to be controlling, and we propose to change the language in section 80.1466(h) accordingly.

8. Proposed Changes to Facility's Baseline Volume To Allow ''Nameplate Capacity'' for Facilities Not Claiming Exemption From the 20% GHG Reduction Threshold

As a requirement of registration under the RFS2 program, each renewable fuel producer and foreign ethanol producer must establish and provide documents to support its facility's baseline volume as defined in section 80.1401. This is either the permitted capacity or, if permitted capacity cannot be determined, the actual peak capacity of a specific renewable fuel production facility on a calendar year basis. After the promulgation of the March 26, 2010 RFS2 rule, we have received many requests from companies to allow them to use their nameplate or ''design'' capacity to establish their facility's baseline volume due to either the facility being exempt from obtaining a permit, and thus not able to determine their permitted capacity, or the facility not starting operations, or not being operational for a full calendar year to produce actual production records to establish actual peak capacities. Because the regulations currently only allow a facility's baseline volume to be established by a limit stated in a permit or actual production records for at least one calendar year, facilities that had neither a permit or sufficient production records had difficulty registering under the RFS2 program. To allow facilities that fall under this predication to register under the RFS2 program, we are proposing in this rulemaking to allow a facility to use its ''nameplate capacity'' to establish its facility's baseline volume for the purposes of registration, only if (1) the facility does not have a permit or there is no limit stated in the permit to establish their permitted capacity, and (2) has not started operations or does not have at least one calendar year of production records, and (3) does not claim exemption from the 20 percent GHG threshold under § 80.1403. Due to the complexity of the exemption provision provided under § 80.1403, and the added flexibility that facilities claiming this exemption are allotted under the program, we are not proposing to extend this option to facilities claiming an exemption under § 80.1403. Additionally, by this stage in the RFS2 program, the facilities that would qualify for registration under § 80.1403 would be very few, if any. This proposal would revise the definition of baseline volume to include ''nameplate capacity,'' add a new definition for ''nameplate capacity'' to § 80.1401, and include conforming amendments to the registration requirements of § 80.1450.

G. Minor Corrections to RFS2 Provisions

We are proposing a number of corrections to address minor definitional issues that have been identified as we have been implementing the RFS2 program.

Renewable Biomass

We propose to amend the definition of ''renewable biomass'' in section 80.1401 to make clear that biomass obtained in the vicinity of buildings means biomass obtained within 200 feet of the buildings. The preamble for the March 26, 2010 RFS2 final rule cites the distance of 200 feet (*see* 75 FR 14696), but EPA did not include a reference to this value in the regulations. We believe doing so would provide additional clarity to the regulations.

English Language Translations

We propose to add a new paragraph (i) to section 80.1450 to state that any registration materials submitted to EPA must be in English or accompanied by an English language translation. Similarly, we propose to add a new paragraph (h) to section 80.1451 that will state that any reports submitted to EPA must be in English or accompanied by an English language translation and add a new paragraph (q) to section 80.1454 that will state that any records submitted to EPA must be in English or accompanied by an English language translation. The translation and all other associated documents must be maintained by the submitting company for a period of five (5) years, which is already the established time period for keeping records under the existing RFS2 program.

Correction of Typographical Errors

We propose to correct various typographical errors in section 80.1466. Specifically, we propose to amend paragraph (o) to correct a typographical error in the last sentence of the affirmation statement, by changing the citation from § 80.1465 to § 80.1466. We also propose to amend paragraph (d)(3)(ii) to correct a typographical error. The current regulation cites section 80.65(e)(2)(iii), which does not exist. The correct citation is to section 80.65(f)(2)(iii).

VI. Amendments to the E15 Misfueling Mitigation Rule

We propose the following minor corrections and other changes to the E15 misfueling mitigation rule (E15 MMR) found at 40 CFR Part 80, subpart N.

A. Proposed Changes to Section 80.1501—Label

We propose to correct several minor errors in the description of the E15 label required by the E15 MMR at section 80.1501, including corrections in the dimensions of the label and ensuring that the word ''ATTENTION'' is capitalized. The Agency intended the label required by the regulations to look identical to that pictured in the **Federal Register** notice for the final E15 MMR (*see* 76 FR 44406, 44418, July 25, 2011).

B. Proposed Changes to Section 80.1502—E15 Survey

We are proposing two changes to the survey requirements found at section 80.1502. First, we propose to clarify that E15 surveys need to sample for Reid vapor pressure (RVP) only during the high ozone season as defined in section 80.27(a)(2)(ii) or during any time RVP standards apply in any state implementation plan approved or promulgated under the Clean Air Act. EPA did not intend to require RVP sampling and testing during the rest of the year, when RVP standards do not apply.

Second, we propose to change when the results of surveys that detect potential noncompliance must be reported to the Agency. As originally drafted, the regulations require the independent survey association conducting a survey to notify EPA of potentially noncompliant samples within 24 hours of the laboratory receiving this sample (*see* 76 FR at 44423, July 25, 2011). EPA has since learned that more time may be needed for reporting of noncompliant samples since it may take several days for analysis of the sample to be completed. We are therefore requiring that noncompliant samples be reported to EPA within 24 hours of being analyzed.

C. Proposed Changes to Section 80.1503—Product Transfer Documents

EPA is proposing certain minor changes to the product transfer document (PTD) requirements found at section 80.1503. Specifically, we are proposing to allow the use of product codes for conventional blendstock/gasoline upstream of an ethanol blending facility, since historically, the codes have been allowed to be used for conventional blendstock/gasoline upstream of an ethanol blending facility in other fuels programs. This was an omission from the original regulation.

We are also seeking comment on potential ways of streamlining the PTD language required at section 80.1503.

D. Proposed Changes to Section 80.1504—Prohibited Acts

EPA is slightly rewording section 80.1504(g) to state that blending E10 that has taken advantage of the statutory 1.0 psi RVP waiver during the summertime RVP control period with a gasoline-ethanol fuel that cannot take advantage of the 1.0 psi RVP waiver (i.e., a fuel that contains more than 10.0 volume percent ethanol (e.g., E15) or less than 9 volume percent ethanol) would be a violation of the E15 MMR. As originally written, the language does not clearly describe the prohibited activity (*see* 76 FR 44435, 44436, Jult 25, 2011).

E. Proposed Changes to Section 80.1500—Definitions

On August 17, 2011, the National Petroleum Refiners Association, now called American Fuel and Petrochemical Manufacturers (AFPM), filed a petition for reconsideration with the Agency under CAA section 307(d)(7)(B) asking EPA to reconsider certain portions of the E15 MMR. A copy of the petition has been placed in the docket. The petition fundamentally focuses on one issue—AFPM expressed concern that the Agency had defined E10 and E15 in the E15 MMR in a way that would change how ethanol concentrations are determined for regulatory purposes. Today we grant AFPM's request for reconsideration of this issue as explained in their August 17, 2011 petition. As explained below, while EPA did not intend the definitions of E10 and E15 in the E15 MMR to have this effect, we are proposing changes to the regulations to avoid this perceived impact.

On April 6, 1979, fuel containing 90% unleaded gasoline and 10% ethyl alcohol received a waiver under section 211(f)(4) by operation of law (see 44 FR 20777, April 6, 1979). Later, EPA issued an interpretative ruling that stated the April 6, 1979 waiver covered gasoline-ethanol blends that contained *up to* 10 vol% ethanol content (see 47 FR 14596, April 5, 1982). Finally, in the context of regulations limiting the Reid vapor pressure (RVP) of gasoline, EPA has defined E10 as gasoline containing between 9 and 10 volume percent ethanol. Under the RVP regulations and the Clean Air Act, the RVP of E10 is allowed to be 1 pound per square inch (psi) higher than it is for gasoline or gasoline-ethanol blends containing less than 9 and more than 10 vol% ethanol (often referred to as the ''1.0 psi waiver'').

In the E15 MMR, EPA defined E10 as gasoline containing at least 9.0 and no more than 10.0 vol% ethanol and defined E15 as a gasoline-ethanol blend containing greater than 10.0 and no more than 15.0 vol% ethanol. EPA included those definitions in the E15 MMR so that fuels blended to contain more than 10.0 vol% ethanol were subject to the misfueling mitigation requirements for E15. After publication of the E15 MMR, stakeholders including AFPM expressed concern that by defining E10 as E10.0, the Agency may have effectively made the ethanol concentration limits specified in the E10 and the E15 waiver decisions and the RVP regulations more stringent, which in turn would impact whether a party must comply with the E15 MMR requirements and whether a fuel qualifies for the RVP 1.0 psi waiver.

In its petition, AFPM noted that under existing EPA regulations at 40 CFR 80.9, the results of compliance testing for the ethanol concentration in gasoline are ''rounded down'' when the results indicate that gasoline-ethanol fuel may contain slightly more than 10 vol% ethanol. AFPM further stated that in view of this rounding procedure, fuel that compliance testing indicates has an ethanol concentration of between 10.0 and 10.4 should be considered E10. AFPM argued that the E15 MMR definition of E10 as containing no more than 10.0 vol% ethanol constituted a ''substantive change'' to the proposed E15 MMR that would also alter the implementation of other EPA fuels regulations without a required rulemaking.

As part of the E15 MMR proposed rule, we identified prospective responsible parties for each misfueling mitigation measure, including requirements related to labeling E15 fuel dispensers, compliance surveys, and product transfer documents. We received a number of comments from many affected stakeholders, including AFPM, that asked us to clarify which party or parties would be responsible for each misfueling mitigation measure and when each party or parties would be subject to those requirements. In the final E15 MMR, we added the significant digit to the definitions of E10 and E15 in order to provide a delineation between E10 and E15 and consequently the parties subject to one or more of the E15 misfueling mitigation measures.

AFPM argued in their petition that by defining E10 as containing no more than 10.0 vol% ethanol, EPA effectively made a substantive change to the way test results used for determining compliance with fuel requirements are rounded. For example, for a gasoline-ethanol blend to be considered E10, it could no longer contain up to 10.4 vol% ethanol; it could only contain up to 10.04 vol% ethanol. AFPM asserted that there is a tolerance for blending ethanol that allows blends containing up to 10.4 vol% ethanol to be considered E10. While we do not agree that there is a blending tolerance for ethanol, we agree that test results are rounded utilizing the procedures identified in section 80.9 when compared to applicable standards, in this case the ethanol concentrations specified in the E10 and the E15 waivers.

The Agency specifically addressed the issue of blending tolerances versus testing tolerances for gasoline-ethanol blends in the RFS2 NPRM.[50] At the time, some stakeholders had suggested that the implementation of a blending tolerance for the ethanol content of gasoline could be allowed to help obligated parties satisfy RFS requirements without the need for a CAA section 211(f)(4) waiver. In response, we argued that although the test methods used to measure ethanol concentration (ASTM D 5599 and ASTM D 4815) include some variability, ethanol is different than other fuel properties and components that are controlled in other fuel programs.[51] Fuel properties such as RVP, and components such as sulfur and benzene, are natural characteristics of gasoline as a result of the chemical nature of crude oil and the refining process. Their levels or concentrations in gasoline are unknown until measured and are dependent upon the accuracy of the test method. In contrast, ethanol is intentionally added in known amounts using equipment designed to ensure a specific concentration within a very narrow range. Parties that blend ethanol into gasoline normally have precise control over the final concentration. Therefore, a blending tolerance for ethanol would not be appropriate. During the comment period for the RFS2 NPRM, EPA received a number of comments from stakeholders that argued that the volume percentage of ethanol in gasoline is readily determined using very accurate volumetric ratio blending facilities now in place at most blending terminals; therefore, the Agency should not allow a blending tolerance. In the final RFS rule, we did not include a blending tolerance for ethanol blends.[52]

We continue to believe that blending tolerances for ethanol are not appropriate, and the definitions of E10 and E15 in the E15 MMR are consistent with this view. The E10 waiver is for gasoline containing ''up to'' 10 vol% ethanol, not for gasoline containing ''up to'' 10.4 vol% ethanol, and the E15 partial waivers are for fuel designed to contain ''greater than 10 vol% ethanol and not more than 15 vol% ethanol.'' In the case of both waivers, the ''10'' and the ''15'' are exact numbers, not approximations, and they express how much ethanol can be lawfully added to fuel. Testing by the Department of Energy utilized in making the E15 partial waiver decisions was blended as precisely as possible to contain the relevant percentage of ethanol, not that percentage plus ''0.49.'' Testing for registration of E10 and E15 fuel and fuel additives under 40 CFR part 79 was also done with fuels blended as precisely as possible to contain the relevant percentage of ethanol. Similarly, EPA regulations provide that only fuel with an ethanol concentration of between 9 and 10 vol%, not more or less, may lawfully use the statutory 1.0 psi RVP waiver.

At the same time, we did not intend to change the definition of E10 in a way that impacts the rounding of test results for ethanol concentrations.[53] If a manufacturer blends in a way designed to result in a gasoline-ethanol fuel containing no more than 10.0 vol% ethanol, but compliance testing indicates a concentration of 10.4 vol%, we will still round down the test result in accordance with procedures in section 80.9. The purpose of the E15 MMR definitions state that if a manufacturer blends ethanol into gasoline in a way *designed* to *result* in a gasoline-ethanol fuel containing greater than 10.0 vol% and no more than 15.0 vol% ethanol, it will be subject to applicable E15 MMR requirements. For example, bills of lading for an E10 fuel manufacturer that indicates the manufacturer has purchased and blended more ethanol than 10.0 vol% ethanol may indicate that a fuel does not meet the definition of E10 for E15 MMR purposes.

AFPM also argued that the E15 MMR definitions of E10 would alter the implementation of other EPA fuels regulations without a required rulemaking, specifically the application of the 1.0 psi RVP waiver to E10. Since the Agency intended the E15 MMR definition of E10 to only apply for purposes of determining the applicability of E15 MMR requirements, the Agency does not believe these definitions affect the implementation and enforcement of others fuels programs, including the applicability of the 1.0 psi RVP waiver. The introductory language to the definitions at 40 CFR part 80, subpart N clearly states that definitions in section 80.1500 are ''[f]or purposes of this subpart only.''

In order to clarify that these definitions only apply in the context of the E15 MMR, EPA is proposing to add a new section 80.1509, which contains language that clearly states that when ethanol concentrations are measured for compliance testing purposes for 40 CFR, Part 80, Subpart N, the applicable ethanol concentration value will be rounded using the rounding procedures at section 80.9. EPA is also proposing new prohibited acts language in section 80.1504 that should make it clear that only those parties that (1) produce gasoline, blendstocks for oxygenate blending (BOBs), or ethanol designed to be used in the manufacture of E15 as currently defined (i.e., E15.0); (2) that manufacture E15 to be introduced into commerce; or (3) that dispense E15 from a retail outlet. The Agency specifically seeks comments on this proposed language.

VII. Proposed Amendments to the ULSD Diesel Sulfur Survey

EPA is requesting comment concerning whether to amend a provision of the ultra-low sulfur diesel (ULSD) rule. The ULSD rule includes a provision that deems branded refiners liable for violations of the ULSD sulfur standard that are found at retail outlets displaying the refiner's brand (40 CFR 80.612). The regulations include defense provisions. One element of a branded refiner's defense to such violations is that it must have a periodic sampling and testing program at the retail level (40 CFR 80.613(b) and (d)). The regulations also set forth an alternative sampling and testing defense element provision for branded refiners.

This alternative defense element provision (40 CFR 80.613(e)) allows a branded refiner to meet the company-specific downstream periodic sampling and testing element of its defense by participating in funding a survey consortium that samples diesel fuel at retail outlets nationwide. This sampling and testing of fuel to determine compliance with the ULSD sulfur standard is carried out by an independent survey association. EPA reviews and approves the annual survey plan submitted by the survey association. The number of samples that are taken each year is determined by a statistical formula that is based in part on the previous year's compliance rate. In addition, the regulations set a floor and a ceiling for the number of samples that must be taken in an annual survey cycle regardless of the sample number that would be calculated using the regulatory formula. Therefore, the number of samples required to be taken can potentially be less than the formula would require, or it can be more.

Compliance with the ULSD sulfur content standard has been extremely high; less than 1% of the samples have been in violation in recent years. The

[50] *See* 74 FR 25018 (May 26, 2009).

[51] *See* 74 FR 25018 (May 26, 2009).

[52] *See* 75 FR 14762–14764 (March 26, 2010).

[53] For an explanation of the rounding procedures outlined in § 80.9 and the rationale the Agency used to adopt those procedures, *see* 71 FR 16496 (April 3, 2006).

minimum number of samples currently required to be taken annually is set by the regulation at 5,250 regardless of this high compliance rate. Due to the high compliance rate, use of the statistical formula would result in a sampling rate of several hundred samples for each of the past several years, instead of 5,250 samples. The cost difference between taking several hundred samples versus taking over 5,000 samples is significant. For these reasons we believe the continued high compliance rate, and the substantial discrepancy between the sampling rate calculated by the formula and the minimum sampling rate, argue for lowering the minimum sampling rate. However, we believe there is a point where the number of samples per year would be so few that the survey would be meaningless relative to robust sampling and testing programs conducted by each refiner individually. Balancing these concerns, we believe minimum sampling rate of about 1,800 samples is appropriate. We are requesting comment on reducing the minimum number of samples to some rate below 2,000 samples.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel legal or policy issues. 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

The information collection requirements in this notice of proposed rulemaking have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA related to this proposal has been assigned EPA ICR number 2469.01. A supporting statement for the proposed ICR has been placed in the docket. The proposed information collection is described in the following paragraphs.

This action contains recordkeeping and reporting that may affect the following parties under the RFS2 regulation: RIN generators (producers, importers), obligated parties (refiners), exporters, and parties who own or transact RINs. We estimate that 670 parties may be subject to the proposed information collection. We estimate an annual recordkeeping and reporting burden of 3.1 hours per respondent. This action contains recordkeeping and reporting that may affect the following parties under the E15 regulation: gasoline refiners, gasoline and ethanol importers, gasoline and ethanol blenders (including terminals and carriers). We estimate that 2,000 respondents may be subject to the proposed information collection. We estimate an annual recordkeeping and reporting burden of 1.3 hours per respondent. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review the instructions; develop, acquire, install, and utilize technology and systems for the purpose of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transit or otherwise disclose the information. Burden is as defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, EPA has established a public docket for this proposed rule, which includes the ICR described above, under Docket ID number EPA–HQ–OAR–2012–0401. Submit any comments related to the ICR to EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 14, 2013, a comment to OMB is best assured of having its full effect if OMB receives it by July 15, 2013.

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 action will not have a significant economic impact on a substantial number of small entities. The amendments to the RFS2 provisions in this direct final rule will not impose any requirements on small entities that were not already considered under the final RFS2 regulations, as it makes relatively minor corrections and modifications to those regulations. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

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 RFS2 and diesel 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 RFS2 and diesel regulations. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

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

This proposed 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 and diesel regulations, and does not impose any enforceable duties on communities of Indian tribal governments. Thus, Executive Order 13175 does not apply to this action. EPA specifically solicits additional comment on this proposed action from tribal officials.

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 action amends existing regulations related to renewable fuel, E15, and ultra-lower sulfur diesel. We have concluded that this rule is not likely to have any adverse energy effects. In fact, we expect this proposed rule may result in positive effects, because many of the changes we are proposing will facilitate the introduction of new renewable fuels under the RFS2 program and have come at the suggestion of industry stakeholders.

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. EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

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 proposed 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 technical amendments do not relax the control measures on sources regulated by the RFS regulations and therefore will not cause emissions increases from these sources.

K. Clean Air Act Section 307(d)

This rule is subject to Section 307(d) of the CAA. Section 307(d)(7)(B) provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to the EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

List of Subjects in 40 CFR Part 80

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

Dated: May 20, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend 40 CFR chapter I as set forth below:

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, 7542, 7545 and 7601(a).

■ 2. Section 80.613 is amended by revising paragraph (e)(4)(v)(A) definition ''n'' as follows:

§ 80.613 What defenses apply to persons deemed liable for a violation of a prohibited act under this subpart?

* * * * *

(e) * * *

(4) * * *

(v) * * *

(A) * * *

Where:

n= minimum number of samples in a year-long survey series. However, in no case shall *n* be larger than 9,600 nor smaller than 1,800.

* * * * *

■ 3. Section 80.1401 is amended by adding the definitions of ''Nameplate capacity'', ''Renewable compressed natural gas'', ''Renewable fuel producer'', ''Renewable liquefied natural gas'', ''Responsible corporate officer'', in alphabetical order and revising the definitions of ''Biogas'', ''Crop residue'', ''Naphtha'', ''Renewable biomass'', and ''Small refinery'' in to read as follows:

§ 80.1401 Definitions.

* * * * *

Biogas means a mixture of hydrocarbons that is a gas at 60 degrees Fahrenheit and 1 atmosphere of pressure that is produced through the conversion of organic matter. Biogas includes landfill gas, gas from waste digesters, and gas from waste treatment plants. Waste digesters include digesters processing animal wastes, biogenic waste oils/fats/greases, separated food and yard wastes, and crop residues, and waste treatment plants include wastewater treatment plants and publicly owned treatment works.

* * * * *

Crop residue is the biomass left over from the harvesting or processing of planted crops from existing agricultural land and any biomass removed from existing agricultural land that facilitates crop management (including biomass removed from such lands in relation to invasive species control or fire management), whether or not the biomass includes any portion of a crop or crop plant. Biomass is considered crop residue only if the use of that biomass for the production of renewable fuel has no significant impact on demand for the feedstock crop, products produced from that feedstock crop, and all substitutes for the crop and its products, nor any other impact that would result in a significant increase in direct or indirect GHG emissions.

* * * * *

Nameplate capacity means the peak design capacity of a facility for the purposes of registration of a facility under § 80.1450(b)(1)(V)(E).

Naphtha means a blendstock or fuel blending component falling within the boiling range of gasoline which is composed of only hydrocarbons, is commonly or commercially known as naphtha and is used to produce gasoline through blending.

* * * * *

Renewable biomass means each of the following (including any incidental, de minimis contaminants that are impractical to remove and are related to customary feedstock production and transport):

(1) Planted crops and crop residue harvested from existing agricultural land cleared or cultivated prior to December 19, 2007 and that was nonforested and either actively managed or fallow on December 19, 2007.

(2) Planted trees and tree residue from a tree plantation located on non-federal land (including land belonging to an Indian tribe or an Indian individual that is held in trust by the U.S. or subject to a restriction against alienation imposed by the U.S.) that was cleared at any time prior to December 19, 2007 and actively managed on December 19, 2007.

(3) Animal waste material and animal byproducts.

(4) Slash and pre-commercial thinnings from non-federal forestland (including forestland belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States) that is not ecologically sensitive forestland.

(5) Biomass (organic matter that is available on a renewable or recurring basis) obtained from the immediate vicinity (i.e., obtained within 200 feet) of buildings and other areas regularly occupied by people, or of public infrastructure, in an area at risk of wildfire.

(6) Algae.

(7) Separated yard waste or food waste, including recycled cooking and trap grease, and materials described in § 80.1426(f)(5)(i).

Renewable compressed natural gas means biogas as defined in this section, that is processed to the standards of pipeline natural gas as defined in 40 CFR 72.2 and that is compressed to pressures up to 3600 psi. Only renewable CNG that qualifies as renewable fuel and is used for transportation purposes can generate RINs.

* * * * *

Renewable fuel producer means a person who operates or directly supervises the operation of a facility where renewable fuel is produced.

* * * * *

Renewable liquefied natural gas means biogas as defined in this section, that is processed to the standards of pipeline natural gas as defined in 40 CFR 72.2 and that goes through the process of liquefaction in which the biogas is cooled below its boiling point and weighs less than half the weight of water so it will float if spilled on water. Only renewable LNG that qualifies as renewable fuel and is used for transportation fuel can generate RINs.

Responsible Corporate Officer, or *RCO,* for this subpart only, means a corporate officer who has the authority and is assigned responsibility to provide information to EPA on behalf of a company. A company may name only one Responsible Corporate Officer. A Responsible Corporate Officer may not delegate his or her responsibility to any other person. The Responsible Corporate Officer may delegate the ability to submit information to EPA, but the Responsible Corporate Officer remains responsible for the actions of such employees or agents.

* * * * *

Small Refinery, for this subpart only, means a refinery for which the average aggregate daily crude oil throughput for calendar year 2006 and subsequent years (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

■ 4. Section 80.1415 is amended by revising paragraphs (b)(5) and (c)(1) to read as follows:

§ 80.1415 How are equivalence values assigned to renewable fuel?

(b) * * *

(5) 77,000 Btu (lower heating value) of compressed natural gas (CNG) or liquefied natural gas (LNG) shall represent one gallon of renewable fuel with an equivalence value of 1.0.

(c) * * *

(1) The equivalence value for renewable fuels described in paragraph (b)(7) of this section shall be calculated using the following formula:

$$EV = (R/0.972) * (EC/77{,}000)$$

Where:

EV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.
R = Renewable content of the renewable fuel. Except as provided in § 80.1426(f)(4)(iii), this is a measure of the portion of a renewable fuel that came from renewable biomass, expressed as a fraction, on an energy basis.
EC = Energy content of the renewable fuel, in Btu per gallon (lower heating value).

■ 5. Section 80.1426 is amended by:
■ a. Revising Table 1 of paragraph (f)(1) by:
■ 1. Revising the entry for ''Q''; and
■ 2. Adding new entries for T through AA to the end of the table;
■ b. Revising paragraphs (f)(10) and f(11); and
■ c. Adding paragraph (f)(14).

The revisions and additions 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
*	*	*	*	*
Q	Renewable Compressed Natural Gas, Renewable Liquefied Natural Gas.	Biogas from waste treatment plants and waste digesters.	Any	5
*	*	*	*	*
T	Butanol	Corn starch	Fermentation; dry mill using natural gas and biogas from on-site thin stillage anaerobic digester for process energy w/CHP producing excess electricity of at least 40% of the purchased natural gas energy used by the facility.	5
U	Renewable Compressed Natural Gas, Renewable Liquefied Natural Gas.	Biogas from Landfills	Any	3
V	Renewable Electricity	Biogas from landfills	Any	3
W	Cellulosic Naphtha	Biogas from landfills	Fischer-Tropsch process; Facilities must produce at least 20% of their electricity usage at the facility.	3
X	Cellulosic Diesel for use as conventional diesel fuel.	Biogas from landfills	Fischer-Tropsch process; Facilities must produce at least 20% of their electricity usage at the facility.	7
Y	Naphtha	Biogas from landfills	Fischer-Tropsch process	5
Z	Renewable Diesel for use as conventional diesel fuel.	Biogas from landfills	Fischer-Tropsch process; Excluding processes that co-process renewable biomass and petroleum.	4
AA	Renewable Diesel for use as conventional diesel fuel.	Biogas from landfills	Fischer-Tropsch process; Includes only processes that co-process renewable biomass and petroleum.	5

* * * * *

(10)(i) For purposes of this section, renewable electricity that is not introduced into a distribution system with electricity derived from non-renewable feedstocks is considered renewable fuel and the producer may generate RINs if all of the following apply:

(A) The electricity is produced from renewable biomass and qualifies for a D code in Table 1 to this section or has received approval for use of a D code by the Administrator;

(B) The fuel producer has entered into a written contract for the sale of a specific quantity of renewable electricity as transportation fuel; and

(C) The renewable electricity is used as a transportation fuel.

(ii) For purposes of this section, fuels produced from biogas that is not introduced into a distribution system with gas derived from non-renewable feedstocks is considered renewable fuel and the producer may generate RINs if all of the following apply:

(A) The fuel is produced from renewable biomass and qualifies for a D code in Table 1 to this section or has received approval for use of a D code by the Administrator;

(B) The fuel producer has entered into a written contract for the sale of a specific quantity of biogas to be used as a feedstock for transportation fuel; and

(C) The fuel produced from the biogas is used as a transportation fuel.

(iii) A producer of renewable electricity that is generated by co-firing a combination of renewable biomass and fossil fuel may generate RINs only for the portion attributable to the renewable biomass, using the procedure described in paragraph (f)(4) of this section.

(11)(i) For purposes of this section, renewable electricity that is introduced into a commercial distribution system (transmission grid) may be considered renewable fuel and the producer may generate RINs if:

(A) The electricity is produced from renewable biomass and qualifies for a D code in Table 1 of this section or has received approval for use of a D code by the Administrator;

(B) The fuel producer has entered into a written contract for the sale of a specific quantity of electricity derived from renewable biomass sources with a party that uses electricity taken from a commercial distribution system for use as a transportation fuel, and such electricity has been introduced into that commercial distribution system (transmission grid);

(C) The quantity of renewable electricity for which RINs were generated was sold for use as transportation fuel and for no other purposes; and

(D) The renewable electricity was loaded onto and withdrawn from a physically connected transmission grid as defined by the North American Electrical Reliability Corporation (NERC) regions.

(ii) For purposes of this section, fuel produced from biogas that is introduced into a commercial distribution system may be considered renewable fuel and the producer may generate RINs if:

(A) The fuel is produced from renewable biomass and qualifies for a D code in Table 1 of this section or has received approval for use of a D code by the Administrator;

(B) The fuel producer has entered into a written contract for the sale of a specific quantity of fuel derived from renewable biomass sources with a party that uses fuel taken from a commercial distribution system for transportation fuel, and such fuel has been introduced into that commercial distribution system (e.g., pipeline);

(C) The quantity of fuel produced from the biogas for which RINs were generated was sold for use as transportation fuel and for no other purposes;

(D) The biogas was injected into and withdrawn from a physically connected carrier pipeline;

(E) The gas that is ultimately withdrawn from that pipeline for use in a transportation fuel is withdrawn in a manner and at a time consistent with the transport of gas between the injection and withdrawal points; and

(F) The volume and heat content of biogas injected into the pipeline and the volume of gas withdrawn to make a transportation fuel are measured by continuous metering.

(iii) The fuel sold for use in transportation fuel is considered produced from renewable biomass only to the extent that:

(A) The amount of fuel sold for use as transportation fuel matches the amount of fuel derived from renewable biomass that the producer contracted to have placed into the commercial distribution system; and

(B) No other party relied upon the contracted volume of biogas or renewable electricity for the creation of RINs.

(iv) For renewable electricity that is generated by co-firing a combination of renewable biomass and fossil fuel, the producer may generate RINs only for the portion attributable to the renewable biomass, using the procedure described in paragraph (f)(4) of this section.

* * * * *

(14) For purposes of verification, in order for facilities to meet the renewable electricity production requirement for the biogas-derived cellulosic diesel and cellulosic naphtha pathways, all conditions below apply.

(i) The quantity of process electricity produced on-site must be measured by continuous metering.

(ii) The electricity must be used to provide power to process units or process equipment at the facility.

(iii) The electrical energy must derive from raw landfill gas, waste heat from the production process, unconverted syngas from the F–T process, fuel gas from the hydroprocessing or combined heat and power (CHP) units that use non-fossil fuel based gas or other renewable sources.

■ 6. Section 80.1427 is amended by:

■ a. Revising paragraphs (a)(1), (a)(1)(i) definition ''$RVO_{CB,i}$'', (a)(1)(ii) definition ''$RVO_{BBD,i}$'', (a)(1)(iii) definition ''$RVO_{AB,i}$'', (a)(1)(iv) definition ''$RVO_{RF,i}$, (a)(5) introductory text, and (a)(6); and

■ b. Adding paragraph (a)(1)(v), (a)(1)(vi), (a)(1)(vii), (a)(1)(viii),

The additions and revisions read as follows:

§ 80.1427 How are RINs used to demonstrate compliance?

(a) *Renewable Volume Obligations and Exporter Renewable Volume Obligations.* (1) Except as specified in paragraph (b) of this section or § 80.1456, each party that is an obligated party under § 80 1406 and is obligated to meet the Renewable Volume Obligations under § 80.1407, or is an exporter of renewable fuel that is obligated to meet the Exporter Renewable Volume Obligations under § 80.1430, must demonstrate pursuant to § 80.1451(a)(1) that it is retiring for compliance purposes a sufficient number of RINs to satisfy the following equations.

(i) * * *

$RVO_{CB,i}$ = The renewable Volume Obligation for cellulosic biofuel for the obligated party for calendar year i, in gallons, pursuant to § 80.1407.

(ii) * * *

$RVO_{BBD,i}$ = The renewable Volume Obligation for biomass-based diesel for the obligated party for calendar year i, in gallons, pursuant to § 80.1407.

(iii) * * *

$RVO_{AB,i}$ = The renewable Volume Obligation for advanced biofuel for the obligated party for calendar year i, in gallons, pursuant to 80.1407.

(iv) * * *

$RVO_{RF,i}$ = The renewable Volume Obligation for renewable fuel for the obligated party for calendar year i, in gallons, pursuant to 80.1407.

(v) *Cellulosic biofuel—Exporter.*

$$(\Sigma RINNUM)_{CB,i} + (\Sigma RINNUM)_{CB,i-1} = ERVO_{CB,i}$$

Where:

$(\Sigma RINNUM)_{CB,i}$= Sum of all owned gallon-RINs that are valid for use in complying with the cellulosic biofuel ERVO, were generated in year i, and are being applied towards the $ERVO_{CB,i}$, in gallons.

(ΣRINNUM)CB,i-1= Sum of all owned gallon-RINs that are valid under subparagraph (6) of this paragraph for use in complying with the cellulosic biofuel ERVO, were generated in year i-1, and are being applied towards the $ERVO_{CB,i}$, in gallons.

$ERVO_{CB,\ k}$= The Exporter Renewable Volume Obligation for cellulosic biofuel for the renewable fuel exporter for an export of renewable fuel k, in gallons, pursuant to § 80.1430.

(vi) *Biomass-based diesel—Exporter.*

$$(\Sigma RINNUM)_{BBD,i} + (\Sigma RINNUM)BBD,i\text{-}1= ERVO_{BBD,i}$$

Where:

$(\Sigma RINNUM)_{BBD,i}$= Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel ERVO, were generated in year i, and are being applied towards the $ERVO_{BBD,i}$, in gallons.

(ΣRINNUM)BBD,i-1= Sum of all owned gallon-RINs that are valid under subparagraph (6) of this paragraph for use in complying with the biomass-based diesel ERVO, were generated in year i-1, and are being applied towards the $ERVO_{BBD,i}$, in gallons.

$ERVO_{BBD,i}$= The Exporter Renewable Volume Obligation for biomass-based diesel for the renewable fuel exporter for an export of renewable fuel I after 2010, in gallons, pursuant to § 80.1430.

(vii) *Advanced biofuel—Exporter.*

$$(\Sigma RINNUM)_{AB,i} + (\Sigma RINNUM)AB,i\text{-}1= ERVO_{AB,i}$$

Where:

$(\Sigma RINNUM)_{AB,i}$= Sum of all owned gallon-RINs that are valid for use in complying with the advanced biofuel ERVO, were generated in year i, and are being applied towards the $ERVO_{AB,i}$, in gallons.

(ΣRINNUM)AB,i-1= Sum of all owned gallon-RINs that are valid under subparagraph (6) of this paragraph for use in complying with the advanced biofuel ERVO, were generated in year i-1, and are being applied towards the $ERVO_{AB,i}$, in gallons.

$ERVO_{AB,i}$= The Exporter Renewable Volume Obligation for advanced biofuel for the renewable fuel exporter for an export of renewable fuel i, in gallons, pursuant to § 80.1430.

(viii) *Renewable fuel—Exporter.*

$$(\Sigma RINNUM)_{RF,i} + (\Sigma RINNUM)RF,i\text{-}1= ERVO_{RF,i}$$

Where:

$(\Sigma RINNUM)_{RF,i}$= Sum of all owned gallon-RINs that are valid for use in complying with the renewable fuel (D code 6) E $ERVO_{RF,i}$, in gallons.

(ΣRINNUM)RF,i-1= Sum of all owned gallon-RINs that are valid under subparagraph (6) of this paragraph for use in complying with the renewable fuel (D code 6) ERVO, were generated in year i-

1, and are being applied towards the $ERVO_{RF,i}$, in gallons.

$ERVO_{RF,i}$= The exporter Renewable Volume Obligation for renewable fuel for the renewable fuel exporter for an export of renewable fuel i, in gallons, pursuant to § 80.1430.

* * * * *

(5) The value of (ΣRINNUM)i-1 may not exceed values determined by the following inequalities as provided in paragraph (a)(7)(iii) of this section and 80.1442(d), for obligated parties only.

* * * * *

(6) Except as provided in paragraph (a)(7) of this section:

(i) For obligated parties, RINs may only be used to demonstrate compliance with the RVOs for the calendar year in which they were generated or the following calendar year.

(ii) [Reserved.]

(iii) For Renewable Fuel Exporters, RINs generated in calendar year i, must be used to demonstrate compliance with the ERVOs from renewable fuel export(s) in calendar year i, except as provided in paragraph (a)(6)(iv) of this section.

(iv) For Renewable Fuel Exporters, RINs generated in calendar year i-1, may only be used to demonstrate compliance with the ERVOs from renewable fuel exports in January of calendar year i.

* * * * *

■ 7. Section 80.1441 is amended by adding paragraph (e)(2)(iii) to read as follows:

§ 80.1441 Small refinery exemption.

* * * * *

(e) * * *

(2) * * *

(iii) In order to qualify for an extension of its small refinery exemption, a refinery must meet the definition of ''small refinery'' in § 80.1401 for all full calendar years between 2006 and the date of submission of the petition for an extension.

* * * * *

■ 8. Section 80.1450 is amended by:

■ a. Adding paragraph (b)(1)(iv)(C);

■ b. Revising paragraphs (b)(1)(v)(C), (b)(1)(v)(D); and adding (b)(1)(v)(E); and

■ c. Adding paragraphs (h) and (i).

The additions and revisions read as follows:

§ 80.1450 What are the registration requirements under the RFS program?

* * * * *

(b) * * *

(1) * * *

(iv) * * *

(C) To demonstrate compliance with the renewable electricity production requirement for the biogas-derived cellulosic diesel and cellulosic naphtha pathways, provide all the following information:

(*1*) The energy source, equipment and/or process used to generate the electricity. Permitted sources are raw landfill gas, waste heat from the production process, unconverted syngas from the Fischer-Tropsch process, fuel gas from the hydroprocessing, or combined heat-and-power (CHP) units that use non-fossil fuel based gas or other renewable sources.

(2) Estimates of the total amount of electricity to be used, the total amount of grid electricity to be purchased, the total amount of renewable electricity to be produced, and a calculation of the percent of total process electricity use to be produced from allowed sources at the facility.

(v) * * *

(C)(*1*) For all facilities, copies of documents demonstrating each facility's actual peak capacity as defined in § 80.1401 if the maximum rated annual volume output of renewable fuel is not specified in the air permits specified in paragraphs (b)(1)(v)(A) and (b)(1)(v)(B) of this section, as appropriate.

(2) For facilities claiming the exemption described in § 80.1403 (c) or (d) which are exempt from air permit requirements and for which insufficient production records exist to establish actual peak capacity, copies of document demonstrating the facility's nameplate capacity, as defined in § 80.1401.

(D) For all facilities producing renewable electricity or fuel from biogas that qualifies as renewable fuel, submit all relevant information in § 80.1426(f)(10) or (11), and copies of all contracts that the track the biogas or renewable electricity from its original source, to the producer that processes it into renewable fuel, and finally to the end user that will actually use the renewable electricity or the renewable fuel derived from biogas for transportation purposes.

(1) Specific quantity and the heat content, percent efficiency of transfer, if applicable, and any conversion factors of the biogas or renewable biomass.

(2) Specific quantity and the heat content and percent efficiency of transfer, if applicable, and any conversion factors for the renewable fuel derived from biogas or renewable electricity.

(E) Such other records as may be requested by the Administrator.

* * * * *

(h) *Cancellation of Company Registration.* (1) EPA may cancel a company's registration, using the process in paragraph (h)(2) of this section, if any of the following circumstances exist:

(i) The company has reported no activity in EMTS for one calendar year (January 1 through December 31) or has failed to meet any EMTS requirement under § 80.1452;

(ii) The company has failed to comply with the registration requirements of this section;

(iii) The company has failed to submit any required report within thirty (30) days of the required submission date under § 80.1451; or

(iv) The attest engagement required under § 80.1454 has not been received within thirty (30) days of the required submission date.

(2) EPA will use the following process whenever it decides to cancel the registration of a company:

(i) EPA will notify the company's owner or Responsible Corporate Officer (RCO), in writing, that it intends to cancel the company's registration, and identifying the reasons for that proposed action. The company will have fourteen (14) calendar days from the date of the notification to correct the deficiencies identified or explain why there is no need for corrective action.

(ii) If the basis for EPA's notice of intent to cancel registration is the absence of EMTS activity for one calendar year, a stated intent to engage in activity reported through EMTS within the next calendar year will be sufficient to avoid cancellation of registration.

(iii) If the company does not respond, does not correct identified deficiencies, or does not explain why such correction is not necessary within the time allotted for response, EPA may cancel the company's registration within further notice to the party.

(3) Impact of registration cancellation.

(i) A company whose registration is cancelled shall still be liable for violation of any requirements of this subpart.

(ii) A company whose registration is cancelled will not be listed on any public list of actively registered companies that is maintained by EPA.

(iii) If the company whose registration is cancelled is a renewable fuel producer or foreign ethanol producer, it will not be listed on any public list of registered producers maintained by EPA.

(iv) A company whose registration is cancelled will not have access to any of the electronic reporting systems associated with the renewable fuel standard program, including the EPA Moderated Transaction System (EMTS).

(v) A company whose registration is canceled must submit any corrections of deficiencies to EPA on forms, and following policies, established by EPA.

(vi) If a company whose registration has been canceled wishes to re-register, they may initiate that process by submitting a new registration, consistent with paragraphs (a)–(c) of this section.

(vii) *English language registrations.* Any document submitted to EPA under § 80.1450 must be submitted in English, or shall include an English translation.

■ 9. Section 80.1451 is amended by revising paragraphs (a)(1)(vi) and (b)(1)(ii)(Q), and by adding paragraph (h) to read as follows:

§ 80.1451 What are the reporting requirements under the RFS program?

(a) * * *

(1) * * *

(vi) The RVOs for obligated parties, as defined in § 80.1427(a) and for exporters of renewable fuel, as defined in § 80.1427(a) and 80.1430(b), for the reporting year.

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(Q) Producers or importers of renewable fuel produced at facilities that use biogas for process heat as described in § 80.1426(f)(12), shall report the total energy supplied to the renewable fuel facility, in MMBtu based on metering of gas volume. Producers or importers of renewable fuel produced at facilities that meet the renewable electricity production requirement for the biogas-derived cellulosic diesel and cellulosic naphtha pathways as described in § 80.1426(f)(13), shall report the total renewable electricity produced by the renewable facility, in kilowatt-hour (kWh) or megawatt-hour (MWh), the total amount of electricity used, the total amount of grid electricity purchased, and a calculation verifying the percent of total process electricity from allowed sources produced on-site.

* * * * *

(h) *English language reports.* Any document submitted to EPA under § 80.1451 must be submitted in English, or shall include an English translation.

■ 10. Amend Section 80.1452 to revise paragraph (c) introductory text and add paragraphs (e) and (f) to read as follows:

§ 80.1452 What are the requirements related to the EPA Moderated Transaction System (EMTS)?

* * * * *

(c) Starting July 1, 2010, each time any party sells, separates, or retires RINs generated on or after July 1, 2010, all of the following information must be submitted to EPA via the submitting party's EMTS account within five (5) business days of the reportable event, except as provided in § 80.1430(f). Starting July 1, 2010, each time any party purchases RINs generated on or after July 1, 2010, all the following information must be submitted to EPA via the submitting party's EMTS account within ten (10) business days of the reportable event. The reportable event for a RIN separation occurs on the date of separation as described in § 80.1429. The reportable event for a RIN retirement occurs on the date of retirement as described in this subpart.

* * * * *

(e) [Reserved.]

(f) [Reserved.]

■ 11. Amend Section 80.1454 by

■ a. Adding paragraph (a)(7);

■ b. Revising paragraph (b)(4)(i);

■ c. Adding paragraph (b)(7);

■ d. Revising paragraph (f)(3)(i) and adding paragraph (f)(5); and

■ e. Revising paragraph (k)(1); and

■ f. Adding paragraph (q).

The additions and revisions read as follows:

§ 80.1454 What are the recordkeeping requirements under the RFS program?

* * * * *

(a) * * *

(7) Records related to any volume of renewable fuel that was disqualified by the party pursuant to § 80.1433:

(b) * * *

(4) * * *

(i) A list of the RINs owned, purchased, sold, separated, retired, or reinstated.

* * * * *

(7) Records related to any volume of renewable fuel where RINs were not generated by the renewable fuel producer or importer pursuant to § 80.1426(c):

* * * * *

(f) * * *

(3) * * *

(i) A list of the RINs owned, purchased, sold, separated, retired, or reinstated.

* * * * *

(5) Records related to any volume of renewable fuel that was disqualified by the party pursuant to § 80.1433.

* * * * *

(k)(1) Biogas and electricity in pathways involving feedstocks other than grain sorghum. A renewable fuel producer that generates RINs for renewable CNG/LNG or renewable electricity produced from renewable biomass for fuels that are used for transportation pursuant to § 80.1426(f)(10) and (11), or that uses process heat from biogas to generate RINs for renewable fuel pursuant to § 80.1426(f)(12) or that meets the renewable electricity production requirement for the biogas-derived cellulosic diesel and cellulosic naphtha pathways pursuant to § 80.1426(f)(13) shall keep all of the following additional records:

(i) Documents demonstrating the kilowatt-hours (kWh) of allowable electricity relied upon under § 80.1426(f)(13) that was generated at the facility, if applicable.

(ii) The energy source, equipment and/or process used to generate the electricity relied upon under § 80.1426(f)(13), if applicable. Permitted sources are raw landfill gas, waste heat from the production process, unconverted syngas from the Fischer-Tropsch process, fuel gas from the hydroprocessing, or combined heat-and-power (CHP) units that use non-fossil fuel based gas or other renewable sources.

(iii) Contracts and documents memorializing the sale of renewable CNG/LNG or renewable electricity for use as transportation fuel relied upon in § 80.1426(f)(10), § 80.1426(f)(11), or for use of biogas for use as process heat to make renewable fuel as relied upon in § 80.1426(f)(12) and the transfer of title of the biogas or renewable electricity and all associated environmental attributes from the point of generation to the facility which sells or uses the fuel for transportation purposes.

(iv) Documents demonstrating the volume and energy content of biogas, or kilowatts of renewable electricity, relied upon under § 80.1426(f)(10) that was delivered to the facility which sells or uses the fuel for transportation purposes.

(v) Documents demonstrating the volume and energy content of biogas, or kilowatts of renewable electricity, relied upon under § 80.1426(f)(11), or biogas relied upon under § 80.1426(f)(12) that was placed into the common carrier pipeline (for biogas) or transmission line shared power grid (for renewable electricity).

(vi) Documents demonstrating the volume and energy content of biogas relied upon under § 80.1426(f)(12) at the point of distribution.

(vii) Affidavits from the biogas or renewable electricity producer and all parties that held title to the biogas or renewable electricity confirming that title and environmental attributes of the biogas or renewable electricity relied upon under § 80.1426(f)(10) and (11) were used for transportation purposes only, and that the environmental attributes of the biogas or process electricity relied upon under § 80.1426(f)(12) or § 80.1426(f)(13) were used for process heat or electricity at the renewable fuel producer's facility, and for no other purpose. The renewable fuel producer shall create and/or obtain these affidavits at least once per calendar quarter.

(viii) The biogas or renewable electricity producer's Compliance Certification required under Title V of the Clean Air Act.

(ix) Documents demonstrating the total amount of grid electricity purchased and calculations showing the percent of total electricity usage provided by allowable electricity production at the facility, if applicable.

(x) Such other records as may be requested by the Administrator.

* * * * *

(q) *English language records.* Any document requested by the Administrator under this section must be submitted in English, or shall include an English translation.

■ 12. Section 80.1463 is amended by adding paragraph (d) to read as follows:

§ 80.1463 What penalties apply under the RFS program?

* * * * *

(d) Any person violating § 80.1460(b)(1)–(4) or (6) engages in a separate violation for each day that an invalid RIN remains available for use in RFS compliance, and each such daily violation is punishable by the maximum daily penalty allowed under the Clean Air Act.

■ 13. Section 80.1466 is amended by revising the section heading and paragraphs (a), (d)(1), (d)(1)(vi), (d)(3)(ii), (e)(1)(i), (f) introductory text, (h), (h)(1), and (o)(2) and adding paragraph (p) as follows:

§ 80.1466 What are the additional requirements under this subpart for RIN-generating foreign producers, non RIN-generating foreign producers, foreign ethanol producers and importers of renewable fuels?

(a) *Foreign producer of renewable fuel.* For purposes of this subpart, a foreign producer of renewable fuel is a person located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'') that has been registered with EPA as a renewable fuel producer or foreign ethanol producer, regardless of whether the foreign renewable fuel producer generates RINs or an importer of renewable fuel generates RINs for the fuel. Hereinafter referred to as a ''foreign producer'' under this section.

(d) * * * (1) On each occasion that RFS–FRRF is loaded onto a vessel for transport to the United States the foreign producer shall have an independent third party do all the following:

* * * * *

(vi) Review original documents that reflect movement and storage of the RFS–FRRF from the foreign producer to the load port, and from this review determine all the following:

* * * * *

(3) * * *

(ii) Be independent under the criteria specified in § 80.65(f)(2)(iii); and

* * * * *

(e) * * * (1)(i) Any foreign producer and any United States importer of RFS–FRRF shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of renewable fuel, standardized per § 80.1426(f)(8), except as specified in paragraph (e)(1)(ii) of this section.

* * * * *

(f) *Foreign producer commitments.* Any foreign producer shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved as a foreign producer under this subpart.

* * * * *

(h) *Bond posting.* Any foreign producer shall meet the requirements of this paragraph (h) as a condition to approval as a foreign producer under this subpart and on a continuing basis if the foreign producer exceeds projections used in calculated the bond.

(1) The foreign producer shall post a bond of the amount calculated using one of the two following equations whichever equation results in a higher bond value:

$$Bond = G * \$0.01$$

Or

$$Bond = .25 * \Sigma(M_i * RIN_i)$$

Where:

Bond = amount of the bond in U.S. dollars.

G = the greater of: the largest volume of renewable fuel produced by the foreign producer and exported to the United States, in gallons, during a single calendar year among the five preceding calendar years, or the largest volume of renewable fuel that the foreign producer expects to export to the Unites States during any calendar year identified in the Production Outlook Report required by § 80.1449. If the volume of renewable fuel anticipated to be exported to the United States during any calendar year increases above the value used in calculating the existing bond amount, the foreign producer shall increase the bond by using the higher anticipated export volume for the calendar year to calculate a higher bond amount and purchasing the higher bond prior to the generation of RINs to reflect the increase in export volume. M_i = RIN multiplier for specified D code, i, in U.S. dollars, as follows:

The RIN multiplier for a D3 RIN is $0.78
The RIN multiplier for a D4 RIN is $1.30
The RIN multiplier for a D5 RIN is $0.80
The RIN multiplier for a D6 RIN is $0.02
The RIN multiplier for a D7 RIN is $0.78

RIN_i = the greater of: (i) the largest quantity of RINs for a specified D code, i, produced by the foreign producer and exported to the United States, in gallons, during a single calendar year among the five preceding calendar years, or (ii) the largest quantity of RINs that the foreign producer expects to export to the United States during any calendar year identified in the Production Outlook Report required by § 80.1449. If the volume of renewable fuel anticipated to be exported to the United States during any calendar year increases above the value used in calculating the existing bond amount, the foreign producer shall increase the bond by using the higher anticipated export volume for the calendar year to calculate a higher bond amount and purchasing the higher bond prior to the generation of RINs to reflect the increased export volume.

* * * * *

(o)

(2) Signed by the president or owner of the foreign producer company, or by that person's immediate designee, and shall contain the following declaration: ''I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [INSERT NAME OF FOREIGN PRODUCER] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart M, including 40 CFR 80.1466 apply to [INSERT NAME OF FOREIGN PRODUCER]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of

up to $10,000 U.S., and/or imprisonment for up to five years.''

(p) *Foreign Produced Renewable Fuel and Foreign Produced Ethanol for Which RINs Have Been or Will Be Generated by the Importer*

(1) For non-RIN generating foreign producers and foreign ethanol producers already registered pursuant to section § 80.1450, all of the requirements in paragraphs (a) through (o) of this section must be satisfied no later than January 1, 2013.

(2) For RIN generating foreign producers and foreign ethanol producers already registered pursuant to section § 80.1450 and 80.1466, paragraph (h) of this section must be satisfied no later than January 1, 2013 if the required amount in paragraph (h) of this section exceeds the original amount of the bond posted when the producer was originally approved under 80.1466.

■ 14. Section 80.1500 is amended by revising the definitions of E10, E15, and EX to read as follows:

§ 80.1500 Definitions.

* * * * *

E10 means a gasoline-ethanol blend that contains at least 9 and no more than 10 volume percent ethanol.

E15 means a gasoline-ethanol blend that contains greater than 10 volume percent ethanol and not more than 15 volume percent ethanol.

EX means a gasoline–ethanol blend that contains less than 9 volume percent ethanol where X equals the maximum volume percent ethanol in the gasoline-ethanol blend.

* * * * *

■ 15. Section 80.1501 is amended by revising the section 80.1501 heading paragraphs (a) introductory text, (b)(3)(i) and (iv), and (b)(4)(ii) to read as follows:

§ 80.1501 What are the labeling requirements that apply to retailers and wholesale purchaser-consumers of gasoline-ethanol blends that contain greater than 10 volume percent ethanol and not more than 15 volume percent ethanol?

(a) Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing E15 shall affix the following conspicuous and legible label to the fuel dispenser:

* * * * *

(b) * * *

(3) * * *

(i) The word ''ATTENTION'' shall be capitalized in 20-point, orange, Helvetica Neue LT 77 Bold Condensed font, and shall be placed in the top 1.25 inches of the label as further described in (b)(4)(iii) below.

* * * * *

(iv) The words ''Use only in'' shall be in 20-point, left-justified, black, Helvetica Bold font in the bottom 1.875 inches of the label.

(4) * * *

* * * * *

(ii) The background of the bottom 1.875 inches of the label shall be orange.

* * * * *

■ 16. Section 80.1502 is amended by revising paragraphs (b)(3)(iii)(A), (b)(3)(iv), (b)(4)(iv)(B), (b)(4)(v)(A), (c)(4), and (c)(6) to read as follows:

§ 80.1502 What are the survey requirements related to gasoline-ethanol blends?

* * * * *

(b) * * *

(3) * * *

(iii) * * *

(A) Samples collected at retail outlets shall be shipped the same day the samples are collected via ground service to the laboratory and analyzed for oxygenate content. Samples collected at a dispenser labeled E15 in any manner, or at a tank serving such a dispenser, shall also be analyzed for RVP during the high ozone season defined in § 80.27(a)(2)(ii) or any SIP approved or promulgated under §§ 110 or 172 of the Clean Air Act. Such analysis shall be completed within 10 days after receipt of the sample in the laboratory. Nothing in this section shall be interpreted to require RVP testing of a sample from any dispenser or tank serving it unless the dispenser is labeled E15 in any manner.

* * * * *

(iv) In the case of any test that yields a result that does not match the label affixed to the product (e.g., a sample greater than 15 volume percent ethanol dispensed from a fuel dispenser labeled as ''E15'' or a sample containing greater than 10 volume percent ethanol and not more than 15 volume percent ethanol dispensed from a fuel dispenser not labeled as ''E15''), or the RVP standard of § 80.27(a)(2), the independent survey association shall, within 24 hours after the laboratory has completed analysis of the sample, send notification of the test result as follows:

* * * * *

(4) * * *

(iv) * * *

(B) In the case of any retail outlet from which a sample of gasoline was collected during a survey and determined to have an ethanol content that does not match the fuel dispenser label (e.g. a sample greater than 15 volume percent ethanol dispensed from a fuel dispenser labeled as ''E15'' or a sample with greater than 10 volume percent ethanol and not more than 15 volume percent ethanol dispensed from a fuel dispenser not labeled as ''E15'') or determined to have a dispenser containing fuel whose RVP does not comply with § 80.27(a)(2), that retail outlet shall be included in the subsequent survey.

* * * * *

(v) * * *

(A) The minimum number of samples to be included in the survey plan for each calendar year shall be calculated as follows:

$$n = \left\{ \left[\left(Z_\alpha + Z_\beta \right) \right]^2 / \left(4 * [arc\sin(\sqrt{\phi_1}) - arc\sin(\sqrt{\phi_0})]^2 \right) \right\} * St_n * F_a * F_b * Su_n$$

Where:

n = minimum number of samples in a year-long survey series. However, in no case shall n be smaller than 7,500.

$Z\alpha$ = upper percentile point from the normal distribution to achieve a one-tailed 95% confidence level (5% α-level). Thus, $Z\alpha$ equals 1.645.

$Z\beta$ = upper percentile point to achieve 95% power. Thus, $Z\beta$ equals 1.645.

ϕ_1 = the maximum proportion of non-compliant stations for a region to be deemed compliant. In this test, the parameter needs to be 5% or greater, i.e., 5% or more of the stations, within a stratum such that the region is considered non-compliant. For this survey, ϕ_1 will be 5%.

ϕ_o= the underlying proportion of non-compliant stations in a sample. For the first survey plan, ϕ_o will be 2.3%. For subsequent survey plans, ϕ_o will be the average of the proportion of stations found to be non-compliant over the previous four surveys.

St_n = number of sampling strata. For purposes of this survey program, St_n equals 3.

F_a = adjustment factor for the number of extra samples required to compensate for collected samples that cannot be included in the survey, based on the number of additional samples required during the previous four surveys. However, in no case shall the value of F_a be smaller than 1.1.

F_b = adjustment factor for the number of samples required to resample each retail outlet with test results exceeding the labeled amount (e.g. a sample greater than 15 volume percent ethanol dispensed from a fuel dispenser labeled as ''E15'', a sample with greater than 10 volume percent ethanol and not more than 15 volume percent ethanol dispensed from a fuel dispenser not labeled as ''E15''), or a sample dispensed from a fuel dispenser labeled as ''E15'' with greater than the applicable seasonal and geographic RVP pursuant to § 80.27, based on the rate of resampling required during the previous four surveys. However, in no case shall the value of F_b be smaller than 1.1.

Su_n = number of surveys per year. For purposes of this survey program, Su_n equals 4.

* * * * *

(c) * * *

(4) The survey program plan must be sent to the following address: Director, Compliance Division, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Mail Code 6506J, Washington, DC 20460.

* * * * *

(6) The approving official for a survey plan under this section is the Director of the Compliance Division, Office of Transportation and Air Quality.

* * * * *

■ 17. Section 80.1503 is amended by revising paragraphs (a)(1)(vi)(B)(3), (a)(1)(vi)(C)(2), adding paragraph (a)(1)(vi)(C)(3), and revising paragraphs (b)(1)(vi)(B) through (D).

The revisions and additions read as follows:

§ 80.1503 What are the product transfer document requirements for gasoline-ethanol blends, gasolines, and conventional blendstocks for oxygenate blending subject to this subpart?

(a) * * *

(1) * * *

(vi) * * *

(B) * * *

(*3*) ''The use of this blendstock/gasoline to manufacture a gasoline-ethanol blend containing anything other than between 9 and 10 volume percent ethanol may cause a summertime RVP violation.''

(C) * * *

(2) The requirements in paragraph (a)(1) do not apply to reformulated gasoline blendstock for oxygenate blending, as defined in § 80.2(kk), which is subject to the product transfer document requirements of § 80.69 and § 80.77.

(3) Except for transfers to truck carriers, retailers, or wholesale purchaser-consumers, product codes may be used to convey the information required under paragraph (a)(1) of this section if such codes are clearly understood by each transferee.

(b) * * *

(1) * * *

(vi) * * *

(B) For gasoline containing less than 9 volume percent ethanol, the following statement: ''EX—Contains up to X% ethanol. The RVP does not exceed [fill in appropriate value] psi.'' The term X refers to the maximum volume percent ethanol present in the gasoline.

(C) For gasoline containing between 9 and 10 volume percent ethanol (E10), the following statement: ''E10: Contains between 9 and 10 vol % ethanol. The RVP does not exceed [fill in appropriate value] psi. The 1 psi RVP waiver applies to this gasoline. Do not mix with gasoline containing anything other than between 9 and 10 vol % ethanol.''

(D) For gasoline containing greater than 10 volume percent and not more than 15 volume percent ethanol (E15), the following statement: ''E15: Contains up to 15 vol % ethanol. The RVP does not exceed [fill in appropriate value] psi;'' or

* * * * *

■ 18. Section 80.1504 is amended by revising paragraphs (a)(1), (a)(3), (e), and (g) to read as follows:

§ 80.1504 What acts are prohibited under this subpart?

* * * * *

(a)(1) Sell, introduce, cause or permit the sale or introduction of gasoline containing greater than 10 volume percent ethanol (i.e., greater than E10) into any model year 2000 or older light-duty gasoline motor vehicle, any heavy-duty gasoline motor vehicle or engine, any highway or off-highway motorcycle, or any gasoline-powered nonroad engines, vehicles or equipment.

* * * * *

(3) Notwithstanding paragraphs (a)(1) and (a)(2) of this section, no person shall be prohibited from manufacturing, selling, introducing, or causing or allowing the sale or introduction of gasoline containing greater than 10 volume percent ethanol into any flex-fuel vehicle.

* * * * *

(e)(1) Improperly blend, or cause the improper blending of, ethanol into conventional blendstock for oxygenate blending, gasoline or gasoline already containing ethanol, in a manner inconsistent with the information on the product transfer document under § 80.1503(a)(1)(vi) or § 80.1503(b)(1)(vi);

(2) No person shall produce E10 by blending ethanol and gasoline in a manner designed to produce a fuel that contains less than 9.0 or more than 10.0 volume percent ethanol.

(3) No person shall produce E15 by blending ethanol and gasoline in a manner designed to produce a fuel that contains less than 10.0 volume percent ethanol or more than 15.0 volume percent ethanol.

(4) No person shall produce EX by blending ethanol and gasoline in a manner designed to produce a fuel that contains less than 9.0 volume percent ethanol.

* * * * *

(g) For gasoline during the regulatory control periods, combine any gasoline-ethanol blend that qualifies for the 1 psi allowance under the special regulatory treatment as provided by § 80.27(d) applicable to 9–10 volume percent gasoline-ethanol blends with any gasoline containing less than 9 volume percent ethanol or more than 10 volume percent ethanol up to a maximum of 15 volume percent ethanol.

* * * * *

■ 19. Section 80.1508 is amended by revising paragraph (b) as follows:

§ 80.1508 What evidence may be used to determine compliance with the requirements of this subpart and liability for violations of this subpart?

* * * * *

(b) Determinations of compliance with the requirements of this subpart and determinations of liability for any violation of this subpart may be based on information obtained from any source or location. Such information may include, but is not limited to, business records and commercial documents.

■ 20. Section 80.1509 is added to read as follows:

§ 80.1509 Rounding a test result for purposes of this Subpart.

The provisions of Section 80.9 apply for purposes of determining the ethanol content of a gasoline-ethanol blend under this subpart.

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