California Environmental Protection Agency

**Air Resources Board**

# Staff Report: Initial Statement of Reasons for Proposed Rulemaking

# Amendments to the Low Carbon Fuel Standard Regulation Carbon Intensity Lookup Tables

Date of Release: **January 6, 2011**
Scheduled for Consideration: **February 24, 2011**

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State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Source Division

**Staff Report: Initial Statement of Reasons for Proposed Rulemaking**

**Public Hearing to Consider:**

# Amendments to the Low Carbon Fuel Standard Regulation Carbon Intensity Lookup Tables

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Location:

California Air Resources Board
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Sacramento, California 95814

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## Executive Summary

On April 23, 2009, the Air Resources Board (ARB or Board) approved the Low Carbon Fuel Standard (LCFS) for adoption. The regulation became effective on January 12, 2010; additional provisions became effective on April 15, 2010. The LCFS is designed to reduce the carbon intensity of the transportation fuels used in California by 10 percent by 2020. Further, to allow for a smooth transition, the LCFS requires gradual reductions in carbon intensity of transportation fuels in the early years of the program with increasingly more stringent standards to meet the 10 percent requirement in 2020.

As discussed in this staff report, the development and submittal of pathways and their associated carbon intensities for transportation fuels is an integral part of the LCFS regulation. In fact, the proposed action to add pathways and carbon intensities is a clear indication that the LCFS regulation is doing what it was intended to do—facilitate the production of fuels with lower lifecycle greenhouse gas (GHG) emissions.

As background, the carbon intensity of transportation fuels is the currency of the LCFS; lower carbon intensity fuels have lower lifecycle GHG emissions. Specifically, carbon intensity is a full lifecycle measure of the greenhouse gas emissions associated with the production, transport, storage, and use of a fuel. To facilitate comparison across fuels, carbon intensity is expressed in terms of grams of $CO_2$ equivalent per megajoule of fuel energy (g $CO_2$e/MJ). The term “$CO_2$ equivalent” refers to the fact that $CO_2$ is the baseline against which the atmospheric warming potential of all other greenhouse gases (GHGs) is measured. Providers of transportation fuels (referred to as regulated parties) must demonstrate that the mix of fuels they supply meets the LCFS carbon intensity standards for each annual compliance period.

The LCFS provides regulated parties with multiple compliance options. Because the regulation is performance-based, it allows fuel providers the flexibility to meet the annual carbon intensity compliance limit with any combination of approved fuels. They may supply a mix of fuels that are both above and below the limit, but that, collectively, would yield a carbon intensity that is at or below the annual limit. They may also choose to provide fuels that are all below the annual limit. Another option is to purchase credits generated by other fuel providers to offset any accumulated deficits from their own production. Credits are earned when aggregate fuel carbon intensities fall below the annual regulatory limit. Regulated parties who earn credits may sell them to other regulated parties, or bank them for future sale or use. As all of these compliance strategies indicate fuel carbon intensity is the currency on which the LCFS operates; therefore, the development of lower-carbon-intensity fuels for use by regulated parties is essential to the success of the LCFS.

As new lower-carbon-intensity fuels are developed and approved, they are added to the LCFS Lookup Table for use by regulated parties under the LCFS. All fuels approved for use in California under the LCFS are listed in the Lookup Table. The LCFS regulation allows the Executive Officer to approve new carbon intensities for fuel pathways after a complete rulemaking process, including a 45-day public comment period and a public hearing.

Fuel Pathways

Fuel pathways describe the production process and transport of transportation fuels and are used use to determine the appropriate carbon intensity for a given fuel. New pathways can be added to the LCFS Lookup Table in two ways: fuel providers may apply to ARB for new pathways under the regulatory “Method 2” process, and staff may develop new pathways internally. Pathways falling into each of these two categories are proposed under this rulemaking.

The Method 2 application process consists of two variants known as Methods 2A and 2B. Method 2A is reserved for applicants whose proposed pathways consist of modified versions of existing pathways. Method 2B, on the other hand, is reserved for entirely new fuels or production processes.

On November 18, 2010, the Board adopted Resolution 10-49, which provided staff with direction for the ongoing implementation of the LCFS. Among other things, this Resolution established a policy of allowing the use of draft carbon intensity values and directed staff to develop guidelines to clarify the use of such draft carbon intensity values. Accordingly, guidance clarifying this policy was issued in December 2010 in the form of LCFS Regulatory Advisory 10-04 (advisory). Under that advisory, Method 2A and 2B applicants will be allowed to use the draft carbon intensity values for which they are seeking approval as soon as staff has evaluated those values, found them to be correct and properly documented, and posted them to the LCFS web site. Further, the advisory allows the use of draft carbon intensity values for a maximum of six months following the effective date of the formal regulatory action. That is, even if a posted draft value is modified or ultimately disapproved during the rulemaking, the applicant would be allowed to use the original draft value for up to six months from the effective date of either the draft value’s disapproval or the final modified value’s adoption.

Soon after draft carbon intensity values are approved by staff and posted to the LCFS web site, staff prepares a Staff Report which provides detailed background information on those values. The public release of that Report initiates a 45-day comment period which culminates in a hearing before either the Board or the Executive officer (in the case of the carbon intensities covered by this Staff Report, the comment period will culminate with an Executive Officer hearing). Based on the public comments received, the proposed values will either be approved as submitted, revised and approved, or disapproved. Following Executive Officer approval and subsequent approval by the Office of Administrative Law, the pathways proposed in this staff report will be added to the LCFS Lookup Table.

## Carbon Intensities

A fuel's carbon intensity is comprised of two primary components: "direct" and "indirect" emissions. As the name implies, direct emissions are those that are directly connected with the production and use of a fuel, such as the growing and harvesting of the feedstock, the transport of the feedstock to the biorefinery, the emissions from the biorefinery, the transport of the fuel from the biorefinery, and vehicle tailpipe emissions. Indirect emissions are generated by secondary processes (usually economic) set in motion by a fuel production process. For example, the diversion of food, feed, and fiber crop acreage to the production of biofuels creates the need to replace a portion of the lost food, feed, and fiber crop acreage. Some of that acreage is replaced by the conversion of non-agricultural land to agriculture uses. This conversion releases significant GHGs into the atmosphere. Not all fuels are known to generate indirect emissions.

Board Resolution 09-31 specifies that proposed changes to existing Board-approved indirect carbon intensities can only be considered by the Board itself. This provision leaves the staff and the Executive officer with the discretion to decide whether proposed new indirect values should be heard by the Board or the Executive Officer.

## Staff's Proposed Modifications to the Lookup Table

Staff is seeking Executive Officer approval of a total of 28 new Method 2A, 2B, and ARB-developed pathways. Tables ES-1 and ES-2, below, are expanded and revised LCFS Lookup Tables containing these proposed new pathways. The existing pathways from the original LCFS Lookup Table are shown in a normal font while the proposed new pathways (along with other proposed changes to the tables) are underlined. Table ES-1 contains pathway information for gasoline and gasoline substitutes while Table ES-2 contains the same information for diesel and diesel substitutes.

The three new staff-developed pathways in Table ES-1 and ES-2 are biodiesel from used cooking oil (with and without cooking), and corn oil biodiesel. The new Method 2 pathways shown in Table ES-1 include corn ethanol and sugarcane ethanol processed in the Caribbean under the provisions of the Caribbean Basin Initiative.[1] The specific proposed changes to the Lookup Tables are the following:

- The identification codes associated with all pathways, approved and proposed, are shown in a new "Pathway Identifier" column. These identifiers were developed for use in the fuel carbon intensity reporting process, but would, upon Executive Officer approval of the revised Lookup Table appearing in Appendix A, be associated with these pathways across the entire LCFS program.
- The process fuel used in two approved pathways (ETHC001 and ETHC008) has been specified in the "Pathway Description" column

[1] The U.S. Caribbean Basin Initiative (CBI) exempts 19 countries in the Caribbean and Central America from the ethanol import tariffs that apply to all other foreign producers of ethanol. CBI countries generally buy hydrous sugarcane ethanol from Brazil, dehydrate it, and export the anhydrous product to the U.S.

- Eight new Midwest corn ethanol pathways proposed by Archer Daniels Midland Corporation are included (pathways ETHC014 through ETHC021). These pathways describe a new very efficient plant using varying combinations of natural gas, coal, and biomass for process fuel.
- 11 new Midwest corn ethanol pathways proposed by POET LLC are included (Pathways ETHC025 through ETHC035). Five pairs of these pathways differ only in the type of distillers' grains with soluables (DGS, a co-product used as livestock feed) produced. Most pathways use a lower-energy raw starch hydrolysis process for initial cooking. All pathways use natural gas for process power, but some also use biogas. Some use combined heat and power while others use corn fractionation.
- Three new pathways for hydrous Brazilian sugarcane ethanol dehydrated in the Caribbean basin under the terms of the Carribean Basin Initiative are included (Pathways ETHS004 through ETHS006) (see footnote 2).
- Three new pathways for modern natural-gas-powered Midwestern dry mill corn ethanol plants are included. Green Plains Holdings, Lakota Division (ETHC024), Green Plains Central City LLC (ETHC023), and Louis Dreyfus Commodities (ETHC022) each submitted one of these pathways.
- Three internal, staff-developed pathways are included:
    - Two Midwestern used cooking oil biodiesel pathways. One is for a higher-energy rendering process requiring "cooking" (BIOD004), and the other for a lower-energy "non-cooking" rendering process (BIOD005).
    - One Midwestern corn oil biodiesel pathway in which corn oil is extracted from DGS near the end of the corn ethanol production process (BIOD007)

**Table ES-1: Proposed Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline**

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values ($gCO_2e/MJ$) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| Gasoline | CBOB001 | CARBOB - based on the average crude oil delivered to California refineries and average California refinery efficiencies | 95.86 | 0 | 95.86 |
| Ethanol from Corn | ETHC001 | Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS; NG | 69.40 | 30 | 99.40 |
| | ETHC002 | California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG | 65.66 | 30 | 95.66 |
| | ETHC003 | California; Dry Mill; Wet DGS; NG | 50.70 | 30 | 80.70 |
| | ETHC004 | Midwest; Dry Mill; Dry DGS, NG | 68.40 | 30 | 98.40 |
| | ETHC005 | Midwest; Wet Mill, 60% NG, 40% coal | 75.10 | 30 | 105.10 |

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| | ETHC006 | Midwest; Wet Mill, 100% NG | 64.52 | 30 | 94.52 |
| | ETHC007 | Midwest; Wet Mill, 100% coal | 90.99 | 30 | 120.99 |
| | ETHC008 | Midwest; Dry Mill; Wet, DGS; NG | 60.10 | 30 | 90.10 |
| | ETHC009 | California; Dry Mill; Dry DGS, NG | 58.90 | 30 | 88.90 |
| | ETHC010 | Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass | 63.60 | 30 | 93.60 |
| | ETHC011 | Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass | 56.80 | 30 | 86.80 |
| | ETHC012 | California; Dry Mill; Dry DGS; 80% NG; 20% Biomass | 54.20 | 30 | 84.20 |
| | ETHC013 | California; Dry Mill; Wet DGS; 80% NG; 20% Biomass | 47.44 | 30 | 77.44 |
| | ETHC014 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Coal use not to exceed 63% of fuel use (by energy); Coal carbon content not to exceed 48% | 61.00 | 30 | 91.00 |
| | ETHC015 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 5% of the fuel use (by energy); Coal use not to exceed 58% of fuel use (by energy); Coal carbon content not to exceed 48% | 59.09 | 30 | 89.09 |
| | ETHC016 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 10% of the fuel use (by energy); Coal use not to exceed 52% of fuel use (by energy); Coal carbon content not to exceed 48% | 57.17 | 30 | 87.17 |
| | ETHC017 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 15% of the fuel use (by energy); Coal use not to exceed 46% of fuel use (by energy); Coal carbon content not to exceed 48% | 55.25 | 30 | 85.25 |
| | ETHC018 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Coal use not to exceed 68% of fuel use (by energy); Coal carbon content not to exceed 48% | 60.11 | 30 | 90.11 |

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| | ETHC019 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 5% of the fuel use (by energy); Coal use not to exceed 62% of fuel use (by energy); Coal carbon content not to exceed 48% | 58.16 | 30 | 88.16 |
| | ETHC020 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 10% of the fuel use (by energy); Coal use not to exceed 56% of fuel use (by energy); Coal carbon content not to exceed 48%. | 56.22 | 30 | 86.22 |
| | ETHC021 | 2B Application*: Midwest; Dry Mill; Plant energy use not to exceed a value the applicant classifies as confidential; No grid electricity use; Biomass must be at least 15% of the fuel use (by energy); Coal use not to exceed 50% of fuel use (by energy); Coal carbon content not to exceed 48% | 54.27 | 30 | 84.27 |
| | ETHC022 | 2A Application*: Midwest; Dry Mill; 15% Dry DGS, 85% Partially Dry DGS; NG; Plant energy use not to exceed a value the applicant classifies as confidential | 57.16 | 30 | 87.16 |
| | ETHC023 | 2A Application*: Midwest; Dry Mill; Partially Dry DGS; NG; Plant energy use not to exceed a value the applicant classifies as confidential | 54.29 | 30 | 84.29 |
| | ETHC024 | 2A Application*: Midwest; Dry Mill; 75% Dry DGS, 25% Wet DGS; NG; Plant energy use not to exceed a value the applicant classifies as confidential | 61.60 | 30 | 91.60 |
| | ETHC025 | 2A Application*: Dry Mill; Dry DGS; Raw starch hydrolysis; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 62.40 | 30 | 92.40 |
| | ETHC026 | 2A Application*: Dry Mill; Dry DGS; Raw starch hydrolysis/ combined heat and power; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 58.50 | 30 | 88.50 |

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| | ETHC027 | 2A Application*: Dry Mill; Dry DGS; Raw starch hydrolysis/biomass & landfill gas fuels; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 58.50 | 30 | 88.50 |
| | ETHC028 | 2A Application*: Dry Mill; Dry DGS; Raw starch hydrolysis/corn fractionation; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 61.70 | 30 | 91.70 |
| | ETHC029 | 2A Application*: Dry Mill; Dry DGS; Conventional cook/combined heat and power; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 60.50 | 30 | 90.50 |
| | ETHC030 | 2A Application*: Dry Mill; Dry DGS; Raw starch hydrolysis/biogas process fuel; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 44.70 | 30 | 74.70 |
| | ETHC031 | 2A Application*: Dry Mill; Wet DGS; Raw starch hydrolysis; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 53.70 | 30 | 83.70 |
| | ETHC032 | 2A Application* : Dry Mill; Wet DGS; Raw starch hydrolysis/ combined heat and power; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 49.80 | 30 | 79.80 |
| | ETHC0033 | 2A Application*: Dry Mill; Wet DGS; Raw starch hydrolysis/corn fractionation; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 50.70 | 30 | 80.70 |
| | ETHC034 | 2A Application*: Dry Mill; Wet DGS; Conventional cook/combined heat and power; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 50.50 | 30 | 80.50 |

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| | ETHC035 | 2A Application*: Dry Mill; Wet DGS; Raw starch hydrolysis/biogas process fuel; Amount and type of fuel use, and amount of grid electricity use not to exceed a value the applicant classifies as confidential | 43.20 | 30 | 73.20 |
| Ethanol from Sugarcane | ETHS001 | Brazilian sugarcane using average production processes | 27.40 | 46 | 73.40 |
| | ETHS002 | Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit | 12.40 | 46 | 58.40 |
| | ETHS003 | Brazilian sugarcane with average production process and electricity co-product credit | 20.40 | 46 | 66.40 |
| | ETHS004 | 2B Application*: Brazilian sugarcane processed in the CBI with average production process; Thermal process power supplied with NG | 32.94 | 46 | 78.94 |
| | ETHS005 | 2B Application*: Brazilian sugarcane processed in the CBI with average production process, mechanized harvesting and electricity co-product credit; Thermal process power supplied with NG | 17.94 | 46 | 63.94 |
| | ETHS006 | 2B Application*: Brazilian sugarcane processed in the CBI with average production process and electricity co-product credit; Thermal process power supplied with NG | 25.94 | 46 | 71.94 |
| Compressed Natural Gas | CNG001 | California NG via pipeline; compressed in CA | 67.70 | 0 | 67.70 |
| | CNG002 | North American NG delivered via pipeline; compressed in CA | 68.00 | 0 | 68.00 |
| | CNG003 | Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA | 11.26 | 0 | 11.26 |
| | CNG004 | Dairy Digester Biogas to CNG | 13.45 | 0 | 13.45 |
| Liquefied Natural Gas | LNG001 | North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency | 83.13 | 0 | 83.13 |
| | LNG002 | North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency | 72.38 | 0 | 72.38 |
| | LNG003 | Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency | 93.37 | 0 | 93.37 |

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| | LNG004 | Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency | 82.62 | 0 | 82.62 |
| | LNG005 | Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA | 77.50 | 0 | 77.50 |
| | LNG006 | Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency | 26.31 | 0 | 26.31 |
| | LNG007 | Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency | 15.56 | 0 | 15.56 |
| | LNG008 | Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency | 28.53 | 0 | 28.53 |
| | LNG009 | Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency | 17.78 | 0 | 17.78 |
| Electricity | ELC001 | California average electricity mix | 124.10 | 0 | 124.10 |
| | ELC002 | California marginal electricity mix of natural gas and renewable energy sources | 104.71 | 0 | 104.71 |
| Hydrogen | HYGN001 | Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps) | 142.20 | 0 | 142.20 |
| | HYGN002 | Liquid H2 from central reforming of NG | 133.00 | 0 | 133.00 |
| | HYGN003 | Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps) | 98.80 | 0 | 98.80 |
| | HYGN004 | Compressed H2 from on-site reforming of NG | 98.30 | 0 | 98.30 |
| | HYGN005 | Compressed H2 from on-site reforming with renewable feedstocks | 76.10 | 0 | 76.10 |

* Specific conditions apply

## Table ES-2: Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel.

| Fuel | Pathway Identifier | Pathway Description | Carbon Intensity Values ($gCO_2e/MJ$) Direct Emissions | Land Use or Other Indirect Effect | Total |
|---|---|---|---|---|---|
| Diesel | ULSD001 | ULSD - based on the average crude oil delivered to California refineries and average California refinery efficiencies | 94.71 | 0 | 94.71 |
| Biodiesel | BIOD002 | Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is required | 15.84 | 0 | 15.84 |
| | BIOD003 | Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is not required | 11.76 | 0 | 11.76 |
| | BIOD001 | Conversion of Midwest soybeans to biodiesel (fatty acid methyl esters - FAME) | 21.25 | 62 | 83.25 |
| | BIOD004 | Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is required. Fuel produced in the Midwest | 18.44 | 0 | 18.44 |
| | BIOD005 | Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is not required. Fuel produced in the Midwest | 13.53 | 0 | 13.53 |
| | BIOD007 | Conversion of corn oil, extracted from distillers grains prior to the drying process, to biodiesel | 5.90 | 0 | 5.90 |
| | RNWD002 | Conversion of tallow to renewable diesel using higher energy use for rendering | 39.33 | 0 | 39.33 |
| Renewable Diesel | RNWD003 | Conversion of tallow to renewable diesel using lower energy use for rendering | 19.65 | 0 | 19.65 |
| | RNWD001 | Conversion of Midwest soybeans to renewable diesel | 20.16 | 62 | 82.16 |
| | CNG001 | California NG via pipeline; compressed in CA | 67.70 | 0 | 67.70 |
| Compressed Natural Gas | CNG002 | North American NG delivered via pipeline; compressed in CA | 68.00 | 0 | 68.00 |
| | CNG003 | Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA | 11.26 | 0 | 11.26 |
| | CNG004 | Dairy Digester Biogas to CNG | 13.45 | 0 | 13.45 |
| | LNG001 | North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency | 83.13 | 0 | 83.13 |

| Fuel | <u>Pathway Identifier</u> | Pathway Description | Carbon Intensity Values (gCO2e/MJ) | | |
|---|---|---|---|---|---|
| | | | Direct Emissions | Land Use or Other Indirect Effect | Total |
| Liquefied Natural Gas | <u>LNG002</u> | North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency | 72.38 | 0 | 72.38 |
| | <u>LNG003</u> | Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency | 93.37 | 0 | 93.37 |
| | <u>LNG004</u> | Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency | 82.62 | 0 | 82.62 |
| | <u>LNG005</u> | Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA | 77.50 | 0 | 77.50 |
| | <u>LNG006</u> | Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency | 26.31 | 0 | 26.31 |
| | <u>LNG007</u> | Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency | 15.56 | 0 | 15.56 |
| | <u>LNG008</u> | Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency | 28.53 | 0 | 28.53 |
| | <u>LNG009</u> | Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency | 17.78 | 0 | 17.78 |
| | <u>ELC001</u> | California average electricity mix | 124.10 | 0 | 124.10 |
| Electricity | <u>ELC002</u> | California marginal electricity mix of natural gas and renewable energy sources | 104.71 | 0 | 104. 71 |
| | <u>HYGN001</u> | Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps) | 142.20 | 0 | 142.20 |
| Hydrogen | <u>HYGN002</u> | Liquid H2 from central reforming of NG | 133.00 | 0 | 133.00 |
| | <u>HYGN003</u> | Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps) | 98.80 | 0 | 98.80 |
| | <u>HYGN004</u> | Compressed H2 from on-site reforming of NG | 98.30 | 0 | 98.30 |
| | <u>HYGN005</u> | Compressed H2 from on-site reforming with renewable feedstocks | 76.10 | 0 | 76.10 |

The proposed Method 2A and 2B pathways appearing in Tables ES-1 and ES-2 represent only the pathway applications that staff received in time to include in the February 24, 2011 Executive Officer Hearing. Staff is currently evaluating the following additional applications:

Plans for Additional Pathways

- Six corn ethanol applications representing 16 pathways;
- Two applications for a total of five pathways using corn or sorghum, corn and sorghum, and a mix of corn, sorghum, and wheat slurry as ethanol feedstocks;
- One application covering three pathways for Brazilian sugarcane ethanol dehydrated in the Caribbean Basin under the terms of the Caribbean Basin Initiative (see footnote 1 on page ES-2);
- Four Brazilian sugarcane ethanol pathway applications for one pathway each;
- One application for a single beverage-waste-to-ethanol pathway;
- One application for a single ethanol pathway using molasses from the Indonesian sugar industry as a feedstock; and
- One application for a single liquefied natural gas pathway.

In addition, staff is developing the following three internal priority pathways. Analysis of the direct effects of these pathways was completed and the results posted along with the other Method 2A, 2B, and staff-developed pathways discussed in this staff report. The pathways listed below, however, require additional analysis before they can be considered for final approval, and will therefore be considered at a future hearing.

- Two Midwest dry mill natural-gas-powered sorghum ethanol pathways: one for dry distillers' grains with solubles, and the other for wet distiller's grains with soluble; and
- Conversion of North American canola oil, extracted in Canada from Canadian-grown canola, to biodiesel.

When staff completes its analysis of the Method 2A and 2b applications listed above, they will be posted for an initial informal comment period and then scheduled for formal rulemaking. The internally developed sorghum and canola pathways listed above have already been posted for informal comment. As staff completes its analysis of those pathways, therefore, they can proceed directly to the formal rulemaking process. In keeping with the provisions of Board Resolution 10-49 and Regulatory Advisory 10-04, the applicants will be able to begin using the carbon intensities in their applications when those applications are posted for comment. As each pathway is approved at a public hearing, it is added to the Lookup Table.

Biorefineries with fuel pathways and carbon intensities matching those already present in the approved Lookup Tables may register those pathways under the LCFS

Biorefinery Registration program.  Registration provides biorefineries and fuel providers with two main benefits:

- When they purchase fuel produced at registered biorefineries, regulated parties can identify fuel vendors who have provided evidence of a physical pathway of their fuels to California, as required by the LCFS regulation.  Furthermore, the carbon intensities of fuels from registered biorefineries are included in a drop-down menu in the electronic LCFS Reporting Tool.[2]
- The carbon intensities of registered biorefineries are available to regulated parties on the biorefinery registration web site.  This information greatly facilitates the process of shopping for fuels at desired carbon intensities

Excluding facilities that have applied for new pathways under the Method 2A/2B process, the production capacity of the ethanol facilities currently registered under the LCFS Biorefinery Registration program totals more than 6.3 billion gallons per year (BGY).  The combined ethanol production capacity of the 22 domestic Method 2A and 2B pathways shown in Table ES-1 is nearly 1.6 BGY[3].  Overall, therefore, about 7.9 BGY of the nation's ethanol production capacity is accounted for under the LCFS.  This represents approximately 55 percent of the nation's total ethanol production capacity.[4] This percentage will increase as additional ethanol pathways are approved.

Although fuel providers report their production capacities when they register or apply for new pathways, neither the registration nor the pathway application process in any way obligates providers to sell fuel into the California market.  Both processes simply provide fuel suppliers with the ability to obtain a carbon intensity value for their fuel and market the fuel in the State under the LCFS program.  While some suppliers will sell all of the fuel they produce on the California market, others will sell a proportion of their production, and still others may not sell any fuel to California.

A number of factors affect a provider's sales decisions:  relative prices across different markets, the availability of long-term contracts, transportation costs, etc.  Due to this complexity and uncertainty, the proportion of LCFS-approved ethanol that will actually be sold in the State is not known. Given, however, that 7.9 BGY ethanol are approved for sale in a State that actually consumed 1.5 BGY in 2010 (Shremp, January 3, 2011), staff anticipates that there is more than enough supply to meet California's needs in 2011 and beyond.  As Brazilian sugarcane ethanol producers begin providing fuel to California, either directly, or via the Caribbean Basin, in-State supplies of low-carbon ethanol will increase even further.

[2] The regulated party remains responsible for verifying the accuracy of the carbon intensity values provided by the registered fuel providers.

[3] Because this discussion concerns U.S. production capacity, it excludes the 100 MGY capacity of the Trinidad Bulk Traders LTD (TBTL) dehydration plant.  The TBTL plant, which dehydrates Brazilian sugarcane ethanol, is located in the Caribbean Basin.

[4] According to Ethanol Producers Magazine (http://www.ethanolproducer.com/plant-list.jsp), The production capacity of the U.S. as of December 13, 2010 was 14.3 BGY.

Although no biodiesel or renewable diesel producers have applied for Method 2A or 2B pathways, 13 have registered under the Biorefinery Registration process. Together, these facilities have the capacity to produce more than 250 million gallons per year (MGY) of fuel. This is well in excess of the approximately 15.7 MGY of biodiesel California consumed in 2010 (Shremp, January 3, 2011). Nationwide, 110 facilities with a combined capacity of more than 1.9 BGY are in operation (Biodiesel Magazine, December 19, 2010). Thus, about 13 percent of the national capacity is registered as LCFS capacity. Staff expects that proportion to grow as producers begin using the ARB internal priority pathways included in this staff report

Recommendation

We recommend that the Executive Officer approve the additions to the lookup tables described in this Staff Report.

## I. Introduction

On April 23, 2009, the Board approved the LCFS for adoption. This approval was embodied in Resolution 09-31, which provided staff with detailed guidance on implementing the rule once it became effective. Resolution 09-31 also approved a Lookup Table containing 62 fuel pathways, and directed staff to develop additional fuel pathways, as needed, and to assist fuel providers to develop their own LCFS fuel pathways.

In this rulemaking, staff is proposing to add 28 new fuel pathways to the Lookup Table. The proposed Regulation Order is presented in Appendix A. These pathways will be considered at an Executive Officer hearing scheduled for February 24, 2011. Consistent with the provisions of a second LCFS-related Board Resolution (10-49, approved on November 18, 2010), the carbon intensities associated with the proposed new pathways are currently available to fuel providers to use in meeting their LCFS reporting requirements. Resolution 10-49 established a policy of allowing the use of draft carbon intensity values and directed staff to develop guidelines to clarify the use of such draft carbon intensity values. Accordingly, guidance clarifying this policy was issued in December 2010 in the form of LCFS Regulatory Advisory 10-04 (advisory). Under that advisory, Method 2A and 2B applicants will be allowed to use the draft carbon intensity values for which they are seeking approval as soon as staff has evaluated those values, found them to be correct and properly documented, and posted them to the LCFS web site. Further, the advisory allows the use of draft carbon intensity values for a maximum of six months following the effective date of the formal regulatory action. That is, even if a posted draft value is modified or ultimately disapproved during the rulemaking, the applicant would be allowed to use the original draft value for up to six months from the effective date of either the draft value's disapproval or the final modified value's adoption.

The 28 proposed pathways scheduled to be heard on February 24, 2011 were posted to the LCFS web site on December 14, 2010.

## II. Overview of the Pathway Development Process

The LCFS regulates fuel "carbon intensity." Carbon intensity (CI) is a greenhouse gas emissions measure that includes, but is not limited to, vehicle tailpipe emissions. A CI is the sum of all GHGs emitted during the production, transport, storage, dispensing, and use of a fuel—during, in other words, the full fuel lifecycle. Fuels vary in terms of where in their life cycles they emit most of their GHGs. Although all vehicles powered by internal combustion engines generate tailpipe GHG emissions, biofuel and petroleum tailpipe emissions are accounted for differently within the lifecycle GHG accounting framework. The $CO_2$ emitted during biofuel combustion is assumed to simply replace the atmospheric $CO_2$ originally fixed by the feedstock crops. Most of the tailpipe GHG emissions from petroleum fuels, on the other hand, are generated from compounds that were sequestered in geologic formations prior to being recovered and refined into transportation fuel. Unlike biofuel $CO_2$ emissions, therefore, these emissions are included in the carbon intensities of petroleum fuels.

Unlike petroleum fuels, most of the GHG emissions associated with biofuels occur during the fuel production process. In the case of biofuels produced from feedstocks that displace food crops, indirect land use change emissions are included in the total fuel carbon intensity value. The diversion of food, feed, and fiber crop acreage to the production of biofuels creates the need to replace a portion of the lost food, feed, and fiber crop acreage. Some of that acreage is replaced by the conversion of non-agricultural land to agriculture uses. This conversion releases significant GHGs into the atmosphere.

The lifecycle carbon intensity of transportation fuels is estimated under the LCFS using the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model (Systems Assessment Section, September 2008). CA-GREET contains the energy, emissions, and transportation data, as well as the formulas and coefficients, needed to calculate the lifecycle emissions of most fuels. When additional information is needed for a new fuel pathway, the model can be expanded to include the required information.

CA-GREET calculates only what is known as "direct" GHG emissions. Some fuels also produce what are known as "indirect" emissions. Indirect emissions are generated by secondary processes (usually economic) set in motion by a fuel production process. Biofuels that displace food crops, for example, create land use change emissions as new land is converted to agricultural uses to replace the cropland that has been dedicated to the cultivation of feedstocks. Not all fuels are known to generate indirect emissions. This Initial Statement of Reasons considers direct GHG emissions only. Board Resolution 09-31 specifies that proposed changes to existing Board-approved indirect carbon intensities can only be considered by the Board itself. This provision leaves the staff and the Executive officer with the discretion to decide whether proposed new indirect values should be heard by the Board or by the Executive Officer.

### *A. Methods 2A, and 2B Pathway Applications*

The LCFS established two mechanisms by which fuel providers can determine the CIs of the transportation fuels they provide to the California market. The first, Method 1, allows fuel providers to select appropriate carbon intensity values from the Lookup Table found in §95486(b)(1) of the LCFS Regulation. The second, Method 2, allows any entity to apply for Board or Executive Officer approval of additional fuel pathways. Pathways approved under the Method 2 process are added to the Lookup Table, and become available to all fuel providers. In keeping with the provisions of Resolution 10-49, the use of a new pathway or sub-pathway may begin as soon as staff has approved the pathway application and posted it to the LCFS web site for comment.

Method 2 is further subdivided into two similar but distinct sub-processes. Method 2A is reserved for applicants whose proposed pathways consist of modified versions of existing pathways. A Method 2A sub-pathway consists of a new or improved fuel production, transport, storage, and/or dispensing process which significantly reduces the lifecycle carbon intensity of an existing reference pathway. Method 2B, on the other hand, is reserved for entirely new fuels or fuel production pathways.

The procedures that Method 2A/2B applicants must follow are described in a guidance document that ARB staff prepared (ARB, August 2, 2010). Those guidelines urge potential applicants to begin by consulting with ARB LCFS staff. Depending upon the complexity of the proposed new pathway—as well as staff's prior experience with similar pathways—the consultation phase can be brief or lengthy. Once staff is acquainted with the general outlines of the proposed pathway and the applicant is clear on how to proceed, the applicant can optionally submit a draft application for staff comment. Once that draft packet has been revised to reflect staff comments, the applicant submits a final version for formal review. Once in receipt of a final application packet, staff has 30 calendar days to determine whether it is complete enough to continue through the review process. At a minimum, packets must contain the following:

1. A completed Method 2A/2B application form[5];
2. Two versions of a technical report describing the pathway, the analysis done, and the proposed final pathway carbon intensities:
    a. A full version containing confidential business information (if any), and
    b. A non-confidential version, suitable for public posting;
3. Natural gas, electricity, and coal utility invoices for 1 to 2 years;
4. Fuel production volumes for the period covered by the energy invoices (see previous item);
5. Trucking/transport invoices (if non-default transportation values are claimed);
6. A full CA-GREET spreadsheet along with a listing of all cells that have been modified (the GREET input parameter name, the cell reference, and the value entered must be specified);
7. A list of combustion-powered equipment;
8. One or more process flow diagrams, as appropriate; and
9. All current air pollution control permits.

The guidance document for Method 2A/2B applicants (California Air Resources Board, August 2, 2010) presents a general timeline for the evaluation of Method 2A and 2B applications. That timeline, which is shown schematically in Figure 1, was not always observed with the first group of applications—those covered by this Staff Report. In some cases, evaluations were expedited in order to assure that the applicants would be ready to supply fuel to California by January 1, 2011. Staff determined that a single comment period—the upcoming 45-day rulemaking comment period—would be sufficient for these pathway applications. This is especially true, given that that all pathway applications have been posted since December 14, 2010. In other cases, applicants required significant levels of assistance from staff as they prepared their applications. Because the application process was new and unfamiliar, and because examples of successful application packets did not yet exist, staff determined that providing extensive assistance to early applicants was warranted.

[5] A link to the form resides in the first bullet under "Low Carbon Fuel Standard" on this web page: http://www.arb.ca.gov/fuels/guidancedocs.htm

As future pathway applications are evaluated, staff will continue to exercise due diligence in deciding how best to apply the general timeline shown in Figure 1 to specific applications.  While some applications may require more evaluation and development time and more public comment, others are likely to be relatively routine, requiring less evaluation time.

As directed in Resolution 09-31, staff will be working during 2011 to convert the pathway approval process from a regulatory procedure to a certification process.  As staff gains experience assisting applicants, evaluating applications, responding to comments, and holding hearings, it will be applying that experience the development of a pathway certification process proposal.  The goal will be to systematize and standardize the application evaluation and approval process.  The result will be a proposal describing a streamlined, efficient, and clearly defined process.  As this process is developed, it may be necessary to continue the current process of reviewing carbon intensity values associated with indirect effects.  This process reserves consideration of changes to existing, approved indirect effect values for the Board.  The Executive Officer and staff determine on a case-by-case basis how best to seek approval for indirect effect values that have not received previous Board approval. Once a pathway certification proposal has been drafted, staff will seek Board approval to formally integrate that process into the LCFS regulation.  If the Board approves a certification program, a regulatory change will not be necessary in order to add new pathways to the Lookup Table in the future.

The Executive Officer and staff determine on a case-by-case basis how best to seek approval for new indirect effect values

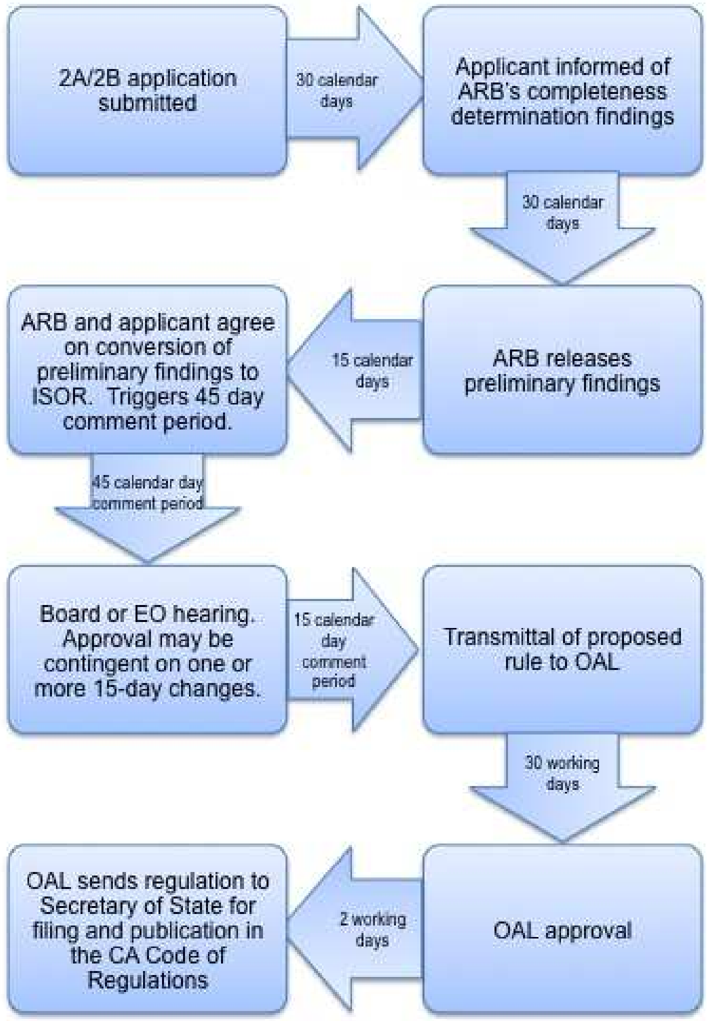


Figure 1: The Method 2A/2B Evaluation and Approval Process

Because most applications contain at least some confidential business information, applicants are asked to submit two versions of their application packets—a full version that contains all necessary confidential business information and a redacted version. The latter is posted, along with the Staff Report, for public comment. A public comment period of at least 45 days is required under the California Administrative Procedures Act (Government Code section 11340 *et seq*.). Once the comment period has concluded, the proposal is heard before either the Board or the Executive Officer. If approved, the rulemaking package is sent to the Office of Administrative Law (OAL). If OAL approves, the new package is sent to the Secretary of State for filing, and the new pathway becomes part of the regulation (and available to LCFS regulated parties).[6]

[6] Board Resolution 10-49 established a policy of allowing the use of draft carbon intensity values and directed staff to develop guidelines to clarify the use of such draft carbon intensity values. Accordingly, guidance clarifying this policy was issued in December 2010 in the form of LCFS Regulatory Advisory 10 04 (advisory). Under that advisory, Method 2A and 2B applicants will be allowed to use the

### B. 2A/2B Applications and the Application Evaluation Process

The Method 2A/2B application process was designed to provide staff with enough information—including supporting documentation—to enable staff to reach a finding the applicant will be able to reliably produce transportation fuel at the proposed CI on an ongoing basis. Applicants are encouraged to describe a fuel pathway and CI that would be verified by production audits performed at random times throughout the year. To that end, staff requires applicants to submit separate documents that must fully corroborate each other: air pollution control permits and comprehensive combustion-powered equipment lists; energy consumption calculations and utility invoices covering at least one, but preferably two, years; and a detailed technical narrative describing the pathway and all CI calculations. Staff cross-checks these items for consistency. Applications containing inconsistencies across (or within) these documents cannot be approved until the sources of inconsistency are identified and rectified.

As the review proceeds, staff continues to evaluate the ability of the applicant to operate at the proposed carbon intensity level on an ongoing basis. If, for example, the application were based on an anomalous period of operation, staff would not accept the proposed carbon intensity. Examples of such atypical episodes might include periods in which fuel-grade biomass is in unusually abundant supply, and periods just prior to the closure of a nearby cattle feedlot.[7]

External consistency is also an important consideration in the application evaluation process. Descriptions of production processes, claimed energy consumption values, greenhouse gas emission rates, and measures employed to reduce energy consumption and emissions are compared to standard external reference cases as a consistency check. Any parameters that deviate significantly from known reference cases result in follow-up requests to the applicant. When these deviations are explained and documented to the satisfaction of staff, the evaluation process can resume.

The Method 2A and 2B pathways included in this rulemaking are described in Section III.

### C. Internal Priority Pathways

Included in the current rulemaking are three general (non-producer-specific) fuel pathways developed by ARB Staff. In Resolution 09-31, the Board directed staff to

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draft carbon intensity values for which they are seeking approval as soon as staff has evaluated those values, found them to be correct and properly documented, and posted them to the LCFS web site. Further, the advisory allows the use of draft carbon intensity values for a maximum of six months following the effective date of the formal regulatory action. That is, even if a posted draft value is modified or ultimately disapproved during the rulemaking, the applicant would be allowed to use the original draft value for up to six months from the effective date of either the draft value's disapproval or the final modified value's adoption.

[7] Ethanol plants produce a co-product known as distillers' grains with solubles (DGS), which is used for livestock feed. When livestock feeding operations are sufficiently close to ethanol plants, the DGS the plant produces do not need to be dried (or fully dried) prior to delivery. Not fully drying DGS significantly reduces energy consumption and GHG emissions.

work with fuel providers and other interested parties to identify additional fuel pathways for internal staff development (State of California, Air Resources Board, April 23, 2009). In deciding which pathways to develop internally, staff gives priority to fuels that are most likely to be available in significant quantities during the first few years of the LCFS implementation. This preference is irrespective of whether the fuels would be produced outside California or within; The goal is to develop the pathways to encourage such fuels to be delivered or otherwise made available in California. Fuels that may not be available in significant quantities early on, but which could contribute to overall fuel carbon intensity reductions over the longer term (e.g., very low-carbon fuels) are also given priority. Another category of candidate fuels are those that are likely to provided by producers that generally lack the resources to develop Method 2A or 2B applications. Across all small-scale producers of such fuels, however, a significant quantity of lower-carbon fuel could be made available to the California market.

The internal priority pathways included in this rulemaking are also described in Section III.

## III. Summary of Proposed Amendments to the Low Carbon Fuel Standard

This Staff Report proposes to amend the LCFS Lookup Table by adding to it a total of 28 new fuel pathways. The proposed amendments, including the amendments to the Lookup Table is presented in Appendix A. The preceding section of this report describes the two available methods for developing new fuel pathways: the Method 2A/2B process whereby fuel providers can apply for new pathways, and the internal process whereby ARB staff undertake pathway development. To date, staff has received a total of 21 Method 2A and 2B applications. Of those, nine were received in time to be included in this rulemaking. These nine applications contain a total of 25 individual fuel pathways. Because fuel production processes vary in response to a variety of factors, many applications request more than one pathway. Many ethanol production facilities, for example, are capable of producing a livestock feed co-product (distillers grains with solubles, or DGS) at varying dryness levels. Due to the energy consumed in the drying process, a separate pathway is usually needed for each discrete dryness level.

Also included in this Staff Report are four internal staff-developed pathway documents containing six individual pathways. All pathways in both groups are briefly summarized in Table 1, and more fully described in subsequent sections of this report. Full information on all pathways is available on the LCFS web site at http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm.

**Table 1**
**Summary: Method 2A/2B Applications and Internal Priority Pathways**

| Applicant | Fuel/Feedstock | Number of Pathways | Lookup Table Pathway IDs | Description |
|---|---|---|---|---|
| Archer Daniels Midland Company | Ethanol from Corn | 8 | ETHC014-ETHC021 | Midwestern dry mill production using different combinations of plant energy use values and process fuel mixes. |
| Louis Dreyfus Commodities | Ethanol from Corn | 1 | ETHC022 | Midwestern dry mill production with a combination of dry and partially dry DGS[1] co-product. Process fuel used is natural gas (NG). |
| Green Plains Central City LLC | Ethanol from Corn | 1 | ETHC023 | Midwestern dry mill production with a partially dry DGS co-product. Process fuel used is NG. |
| Green Plains Holdings II LLC | Ethanol from Corn | 1 | ETHC024 | Midwestern dry mill production with a combination of dry and wet DGS co-product. Process fuel used is NG. |
| POET | Ethanol from Corn | 11 | ETHC025-ETHC035 | Six distinct Midwestern dry mill pathways. Five of the six pathways produce both dry and wet DGS co-product; one produces only dry DGS. Pathways vary in their use of raw starch hydrolysis, fractionation, CHP[2], and process fuel. |
| Trinidad Bulk Traders LTD | Ethanol from Sugarcane | 3 | ETHS004-ETHS006 | Hydrous Brazilian sugarcane ethanol dehydrated in Trinidad and shipped to California (under the Caribbean Basin Initiative). Process fuel used is NG. The three CIs represent the three existing Brazilian sugarcane ethanol pathways plus the CI increment from the Caribbean dehydration process. |
| Internal Priority Pathway | Biodiesel from Used Cooking Oil | 2 | BIOD004, BIOD005 | Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME); with and without cooking. Fuel produced in the Midwest. |
| Internal Priority Pathway | Biodiesel from Corn Oil | 1 | BIOD007 | Corn oil is extracted during the production of corn ethanol. Oil is extracted from distillers grains prior to the drying process. Extracted oil is converted to biodiesel using the FAME[3] process. |

[1] Distillers grains with solubles—a livestock feed
[2] Combined heat and power
[3] Fatty Acid Methyl Ester conversion process

The proposed Method 2A and 2B pathways appearing in Table 1 represent only the pathway applications that staff received in time to include in the February 24, 2011, Executive Officer Hearing. Staff is currently evaluating the following additional Method 2 applications:

- Six corn ethanol applications representing 16 pathways;

- Two applications for a total of five pathways using corn or sorghum, corn and sorghum, and a mix of corn, sorghum, and wheat slurry as ethanol feedstocks;
- One application covering three pathways for Brazilian sugarcane ethanol dehydrated in the Caribbean Basin under the terms of the Caribbean Basin Initiative (see footnote 1 on page ES-2);
- Four Brazilian sugarcane ethanol pathway applications for one pathway each;
- One application for a single beverage-waste-to-ethanol pathway;
- One application for a single ethanol pathway using molasses from the Indonesian sugar industry as a feedstock; and
- One application for a single liquefied natural gas pathway.

In addition, staff is developing the following three internal priority pathways. Analysis of the direct effects of these pathways was completed and the results posted along with the other Method 2A, 2B, and staff-developed pathways discussed in this staff report. The pathways listed below, however, require additional analysis before they can be considered for final approval:

- Two Midwest dry mill natural-gas-powered sorghum ethanol pathways: one for dry distillers' grains with solubles, and the other for wet distiller's grains with soluble; and
- Conversion of North American canola oil, extracted in Canada from Canadian-grown canola, to biodiesel.

When staff completes its analysis of the Method 2A and 2b applications listed above, they will be posted for an initial informal comment period and then scheduled for formal rulemaking. The internally developed sorghum and canola pathways listed above have already been posted for informal comment. As staff completes its analysis of those pathways, therefore, they can proceed directly to the formal rulemaking process. In keeping with the provisions of Board Resolution 10-49 and Regulatory Advisory 10-04, the applicants will be able to begin using the carbon intensities in their applications when those applications are posted for comment. As each pathway is approved at a public hearing, it is added to the Lookup Table..

The combined ethanol production capacity of the 25 Method 2A and 2B pathways appearing in this Staff report is almost 1.7 billion gallons per year (BGY). Of that volume, almost 1.6 BGY consists of domestic production and the remainder is from a Caribbean Basin facility that dehydrates hydrous sugarcane ethanol from Brazil. In combination with the production capacity registered under the LCFS Biorefinery Registration program,[8] almost 8 BGY of ethanol has received LCFS approval. Considering only the 7.9 BGY of domestically produced ethanol that has received LCFS approval, approximately 55 percent of the total U.S. production capacity is LCFS-approved.[9] This percentage will increase as additional ethanol pathways are approved.

[8] The purpose and structure of the Biorefinery Registration Program is discussed in the Executive Summary, above.
[9] According to Ethanol Producers Magazine (http://www.ethanolproducer.com/plant-list.jsp), The production capacity of the U.S. as of December 13, 2010 was 14272.0 MGY

Although fuel providers report their production capacities when they register or apply for new pathways, neither the registration nor the pathway application process in any way obligates providers to sell fuel into the California market. Both processes simply provide fuel suppliers with the ability to sell fuel in the State. While some suppliers will sell all of the fuel they produce on the California market, others will sell a proportion of their production, and still others may not sell any fuel.

A number of factors affect a provider's sales decisions: relative prices across different markets, the availability of long-term contracts, transportation costs, etc. Due to this complexity and uncertainty, the proportion of LCFS-approved ethanol that will actually be sold in the State is not known. Given, however, that 7.9 BGY ethanol are approved for sale in a State that actually consumed 1.5 BGY in 2010 (Shremp, January 3, 2011), staff anticipates that there is more than enough supply to meet California's needs in 2011 and beyond. As Brazilian sugarcane ethanol producers begin providing fuel to California, either directly, or via the Caribbean Basin, in-State supplies of low-carbon ethanol will increase even further.

Although no biodiesel or renewable diesel producers have applied for Method 2A or 2B pathways, 13 have registered under the Biorefinery Registration process. Together, these facilities have the capacity to produce more than 250 million gallons per year (MGY) of fuel. This is well in excess of the approximately 15.7 MGY of biodiesel California consumed in 2010 (Shremp, January 3, 2011). Nationwide, 110 facilities with a combined capacity of more than 1.9 BGY are in operation (Biodiesel Magazine, December 19, 2010). Thus, about 13 percent of the national capacity is registered as LCFS capacity. Staff expects that proportion to grow as producers begin using the ARB internal priority pathways included in this staff report

## *A. Detailed Summaries of Proposed Method 2A and 2B Fuel Pathways*

### 1. Archer Daniels Midland

<u>Plant Summary</u>

The ADM Columbus dry corn mill ethanol plant is located in Columbus, Nebraska. The plant is permitted to produce more than 800,000 gallons per day of denatured ethanol. The plant has the capability of producing both dry and wet DGS. Design for the facility is based on an annual average moisture content of about 27 percent. The plant uses electricity produced at an adjacent combined-heat-and-power plant, and consequently uses no grid electricity during normal operations. This reduces the total energy use at the plant. The use of a dryer heat recovery system and Mechanical Vapor Recompression (MVR) evaporator further reduces energy use at the plant.

ADM has specified two plant energy values for which it is seeking a sub-pathway approval. One plant energy value represents the baseline energy use of the plant, the other value is lower and is intended to represent the energy use of the plant when additional heat recovery and energy savings are achieved in the future due to a more optimized mode of operation. The fuels used at the plant are various combinations of coal, natural gas, and biomass (waste seed and other agricultural waste).

ADM has specified two sets of four different combinations of coal, natural gas, and biomass fuel use. One of the sets of four combinations would be used with the baseline plant energy value, while the other set of four combinations would be used with the expected energy value for the plant when it is operating in the optimized mode. Thus, ADM is requesting ARB approval for eight sub-pathways, each with a different combination of plant energy values and fuel mix. The eight sub-pathways are as follows.

For the baseline plant energy use value, the four combinations are:

1) 37 percent natural gas, 63 percent coal, 0 percent biomass;
2) 37 percent natural gas, 58 percent coal, 5 percent biomass,
3) 38 percent natural gas, 52 percent coal, 10 percent biomass;
4) 39 percent natural gas, 46 percent coal, 15 percent biomass.

For the optimized plant energy mode, the four fuel combinations are:

1) 32 percent natural gas, 68 percent coal, 0 percent biomass:
2) 33 percent natural gas, 62 percent coal, 5 percent biomass;
3) 34 percent natural gas, 56 percent coal, 10 percent biomass;
4) 35 percent natural gas, 50 percent coal, 15 percent biomass.

<u>Carbon Intensity of Ethanol Produced</u>

Table 2 summarizes the carbon intensities, as calculated by ADM, of the eight sub-pathways of the application. Also shown in the table are the conditions under which the carbon intensity values would be applicable for ethanol sold under the LCFS.

**Table 2**
**ADM Pathway Summary and "Not-To-Exceed" Conditions**

| Sub-pathway (% biomass[2]) | Carbon Intensity ($gCO_2e/MJ$) | Conditions for Applicability of Carbon Intensity Value[1] |
|---|---|---|
| *Baseline Plant Energy* | | |
| 0 | 91.00 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Coal use not to exceed 63% of fuel use (by energy); 4) Coal carbon content not to exceed 48%. |
| 5 | 89.09 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 5% of the fuel use (by energy); 4) Coal use not to exceed 58% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |
| 10 | 87.17 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 10% of the fuel use (by energy); 4) Coal use not to exceed 52% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |
| 15 | 85.25 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 15% of the fuel use (by energy); 4) Coal use not to exceed 46% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |
| *Optimized Plant Energy* | | |
| 0 | 90.11 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Coal use not to exceed 68% of fuel use (by energy); 4) Coal carbon content not to exceed 48%. |
| 5 | 88.16 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 5% of the fuel use (by energy); 4) Coal use not to exceed 62% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |
| 10 | 86.22 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 10% of the fuel use (by energy); 4) Coal use not to exceed 56% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |
| 5 | 84.27 | 1) Plant energy use not to exceed a value the applicant classifies as confidential; 2) No grid electricity use; 3) Biomass[2] must be at least 15% of the fuel use (by energy); 4) Coal use not to exceed 50% of fuel use (by energy); 5) Coal carbon content not to exceed 48%. |

[1]Compliance with the "not-to-exceed" values will be based on monthly, quarterly, or annual average values, as determined by operational conditions. Calculation of the average values can exclude periods of abnormal operations, such as planned maintenance or force majeure events, and the facility may use grid electricity during such periods.

[2]Biomass fuels consist of waste seed and other agricultural waste.

The ADM Columbus Plant achieves lower carbon intensity values relative to the reference pathway through three principal means. First, through the use of dryer heat-recovery and mechanical vapor-recompression evaporation, plant energy values are reduced by about 20 percent for the current plant energy value and by about 24 percent for the optimized plant energy value. Second, the use of cogeneration eliminates the need for grid power during normal operations. Electrical energy is supplied by the cogeneration facility. Third, the use of biomass reduces carbon intensities by about 2 $gCO_2e/MJ$ for each five percent increment of biomass co-fired in the cogeneration plant. The amount of coal currently used in the plant ranges from about 46 percent to 63 percent. If all else is equal, moving from 46 percent to 63 percent coal when the only other process fuel is natural gas would raise carbon intensities by about 10 $gCO_2e/MJ$. But in the case of the Columbus plant, this carbon intensity increase is offset by the use of low-carbon-content coal. The carbon content of the coal used in the plant is about 48 percent compared to about 64 percent for the reference corn ethanol pathway.

Staff Analysis and Recommendation

The staff has reviewed the ADM application; the following are the results of the staff's review:

- Staff has replicated, using the CA-GREET spreadsheet, the carbon intensity values calculated by ADM for each of the eight sub-pathways;
- ADM has provided documentation for the plant's energy use and ethanol production;
- Staff agrees that the energy value in the application accurately represent the plant's energy value;
- The staff agrees that the electricity use value in the application accurately represents the plant's electricity use value; and
- Future electrical energy and total energy use for the plant will have to be periodically reported to the ARB in order to verify that the electrical and total energy values for the plant in the application are correct.

On the basis of these findings, and subject to the conditions in Table 2, the staff recommends that ADM's application for eight Method 2B corn ethanol sub-pathways be approved.

More information on the ADM application, including the ARB staff summary and other supporting documentation can be viewed at
http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/adm-col-rpt-ncbi-121410.pdf

2. Elkhorn Valley Ethanol LLC, c/o Louis Dreyfus Corporation

Plant Summary

Louis Dreyfus Corporation operates a gas-fired, dry mill corn ethanol plant in Norfolk, Nebraska. Louis Dreyfus has submitted an LCFS Method 2A application for the Norfolk plant. The ethanol production capacity of the plant is 53 million gallons per year. About 85 percent of the distillers' grains with solubles produced at the Norfolk are partially-dried modified distillers' grains with solubles (MDGS) with a typical moisture content of about 55 percent, by weight. The remaining distillers' grains with solubles co-product is dried to a nominal 10 percent moisture and sold as dried distillers grains with solubles (DDGS). The Norfolk plant uses grid electricity and natural gas for its process fuel.

Carbon Intensity of Ethanol Produced

Although the Louis Dreyfus plant produces DGS at two distinct moisture levels, it is applying for a single carbon intensity. The DDGS and MDGS are produced simultaneously; there is no practical way to collect data on the emissions associated with 100 percent MDGS and 100 percent DDGS operation. In addition, the proportion of DDGS produced is small compared to the proportion of MDGS. The single carbon intensity of the Norfolk plant, as calculated by Louis Dreyfus, is 87.16 $gCO_2e/MJ$ of ethanol produced. The reference carbon intensity from the LCFS Lookup Table is 98.4 $gCO_2e/MJ$. Because the proposed CI is five or more $gCO_2e/MJ$ below the reference pathway CI, the proposed pathway meets the LCFS substantiality requirement.

The Louis Dreyfus Norfolk plant achieves a lower carbon intensity value relative to the reference pathway through two principal means. First, the plant incorporates modern plant design developed by ICM, which results in less energy use in the plant. Energy use at the Norfolk plant is below the 36,000 BTU per gallon energy use value that forms the basis of the carbon intensity for the reference dry DGS pathway. Second, electricity use at the Norfolk plant is below the 1.08 kw-hr per gallon that is assumed for the reference pathway.[10]

Staff Analysis and Recommendation

Staff has reviewed the Louis Dreyfus application for the Norfolk plant and has replicated, using the CA-GREET spreadsheet, the carbon intensity value calculated by Louis Dreyfus. Louis Dreyfus has provided documentation for the plant's energy use and ethanol production. Staff agrees that the energy value in the application accurately represents the plant's energy value. Staff agrees that the electricity use value in the application accurately represents the plant's electricity use value. Staff agrees that the carbon intensity value calculated by Louis Dreyfus can be met on ongoing bases. Consequently, staff agrees that the carbon intensity value of 87.16 $gCO_2e/MJ$ accurately represents the carbon intensity value of the Norfolk plant. Therefore, staff recommends that Louis Dreyfus Commodities' application for a Method 2A corn ethanol sub-pathway be approved.

More information on the Louis Dreyfus application, including the ARB staff summary and other supporting documentation can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/ld-nor-rpt-ncbi-121410.pdf

[10] Actual plant energy use values are classified as confidential business information and not reported herein.

3. Green Plains Central City LLC

Plant Summary

The Green Plains Central City (Green Plains) corn ethanol plant is located in Central City, Nebraska.  Green Plains has submitted an LCFS Method 2A application for the Central City plant.  The Central City plant began operation on May 6, 2004, with a capacity of 48 million gallons per year (MGY) of denatured ethanol.  In November 2006, the capacity of the facility was expanded to 100 MGY.  The plant is a dry mill, ICM-designed, natural gas-fired plant producing modified distillers grains with solubles (MDGS) with an average moisture content of about 50 to 55 percent.

Carbon Intensity of Ethanol Produced

The carbon intensity of the Green Plains plant, as calculated by Green Plains, is 84.29 $gCO_2e/MJ$ of ethanol produced.  The reference carbon intensity from the LCFS Lookup Table is 98.4 $gCO_2e/MJ$ for gas-fired plants producing dry distillers' grains with solubles.  This reference value also applies to plants producing MDGS.  Because the proposed CI is five or more $gCO_2e/MJ$ below the reference pathway CI, the proposed pathway meets the LCFS substantiality requirement.

The Green Plains plant achieves a lower carbon intensity value relative to the reference pathway through two principal means.  First, the plant incorporates modern plant design developed by ICM that results in less energy use in the plant.  Energy use at the Central City plant is below the 36,000 BTU per gallon energy use value that forms the basis of the carbon intensity for the reference dry DGS pathway.  Second, electricity use at the Central City plant is below the 1.08 kw hr per gallon that is assumed for the reference pathway.[11]

Staff Analysis and Recommendation

Staff has reviewed the Green Plains application and has replicated, using the CA-GREET spreadsheet, the carbon intensity value calculated by Green Plains.  Green Plains has provided documentation of the plant's energy use and ethanol production. Staff agrees

- That the energy value in the application accurately represents the plant's energy value;
- That the electricity use value in the application accurately represents the plant's electricity value;
- That the carbon intensity value calculated by Green Plains can be met on an ongoing basis; and
- That the carbon intensity value of 84.29 $gCO_2e/MJ$ accurately represents the carbon intensity value of the Green Plains plant.

[11] Actual plant energy use values are classified as confidential business information and not reported herein

Therefore, staff recommends that Green Plains' application for a Method 2A corn ethanol pathway be approved.

More information on the Green Plains Central City LLC application, including the ARB staff summary and other supporting documentation can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/gp-cct-rpt-ncbi-121410.pdf

4. Green Plains Holdings LLC, Lakota, Iowa

Plant Summary

The Green Plains Holdings, Lakota Plant Division operates a gas-fired, dry mill corn ethanol facility in Lakota, Iowa. Green Plains has submitted an LCFS Method 2A application for the Lakota plant. The ethanol production capacity of the Lakota plant is 100 million gallons per year. The plant is ICM-designed producing about 25 percent wet distillers' grains with solubles (WDGS) and about 75 percent dry distillers' grains with solubles (DDGS).

Carbon Intensity of Ethanol Produced

Although the Lakota plant produces DGS at two distinct moisture levels, it is applying for a single carbon intensity. The DDGS and WDGS are produced simultaneously; there is no practical way to collect data on the emissions associated with 100 percent WDGS and 100 percent DDGS operation. The carbon intensity of the Lakota plant, as calculated by Green Plains Holdings, is 91.6 $gCO_2e/MJ$ of ethanol produced. The reference carbon intensity from the LCFS Lookup Table is 98.4 $gCO_2e$ per MJ for DDGS. Because the proposed CI is five or more g $CO_2e/MJ$ below the reference pathway CI, the proposed pathway meets the LCFS substantiality requirement.

The Green Plains plant achieves a lower carbon intensity value relative to the reference pathway through three principal means. First, the plant incorporates modern plant design developed by ICM, which results in less energy use in the plant. Energy use at the Lakota plant is below the 36,000 BTU per gallon energy use value that forms the basis of the carbon intensity for the reference dry DGS pathway. Second, electricity use at the Lakota plant is below the 1.08 kw-hr per gallon that is assumed for the reference pathway.[12] Third, due to the proximity of the corn farms to the Lakota plant, corn transportation distances are less. The average transportation distance from the cornfield to the corn stacks is only two miles, compared to a distance of 10 miles in the reference pathway. The distance from the corn stacks to the ethanol plant is only 17 miles, compared to 40 miles in the reference pathway.

[12] Actual plant energy use values are classified as confidential business information and not reported herein

Staff Analysis and Recommendation

Staff has reviewed the Green Plains Holdings application for the Lakota plant and has replicated, using the CA-GREET spreadsheet, the carbon intensity value calculated by Green Plains Holdings. Green Plains Holdings has provided documentation for the plant's energy use and ethanol production. Staff agrees

- That the energy value in the application accurately represents the plant's energy value;
- That the electricity use value in the application accurately represents the plant's electricity value;
- That the carbon intensity value calculated by Green Plains can be met on an ongoing basis; and
- That the carbon intensity value of 91.6 $gCO_2e/MJ$ accurately represents the carbon intensity value of the Green Plains plant.

Therefore, the staff recommends that Green Plains' application for a Method 2A corn ethanol pathway be approved.

More information on the Green Plains Holdings LLC application, including the ARB staff summary and other supporting documentation can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/gp-lak-sum-ncbi-121410.pdf

5. POET LLC

Plant Summary

The POET, LLC application contains six distinct dry-mill production processes. With one exception, each of the six processes produces both wet and dry DGS co-products at separate times. However, currently over 97 percent of the DGS produced by the POET facilities is dry. Therefore, the application is for 11 differently defined corn ethanol sub-pathways. The six distinct production processes represent multiple POET facilities. Five of the six POET production processes use a Raw Starch Hydrolysis (RSH) process instead of the conventional dry grind process, which is the basis for the reference pathway carbon intensity values in the LCFS. The RSH process is a cold cook process in which the cooking occurs at lower temperatures than the cooking process used in the conventional process. The RSH process eliminates the liquefaction and saccharification steps. The total energy use is generally lower in the RSH process than the conventional process. A brief summary of the six production processes are as follows: 1) RSH process with natural gas process fuel; 2) RSH process with natural gas process fuel and the use of combined heat and power; 3) RSH process with natural gas, landfill gas, and biomass[13] as process fuel; 4) RSH process with corn fractionation and natural gas process fuel; 5) conventional cook process with natural gas process fuel and the use of combined heat and power; and 6) RSH process with biogas process fuel.

[13] Biomass fuel consists of waste wood, field waste and thin stillage.

The carbon intensities for the LCFS reference pathways are 98.4 $gCO_2e$ for sub-pathways using processes 1), 2), 4), and 5) and producing 100 percent dry DGS, and 90.2 $gCO_2e$/MJ for these processes producing 100 percent wet DGS. The reference carbon intensities are 93.6 $gCO_2e$/MJ for sub-pathways using processes 3) and 6) and producing 100 percent dry DGS, and 86.8 $gCO_2e$/MJ for the sub-pathway using process 6) and producing 100 percent wet DGS. The application contains no sub-pathway using process 3) and producing 100 percent wet DGS. On the basis of the carbon intensity values calculated by POET for each of the sub-pathways, the LCFS substantiality requirement is met.

Carbon Intensity of Ethanol Produced

The POET production processes achieve lower carbon intensity values relative to the reference pathway carbon intensity values through three principal means. First, the use of RSH process requires less process heat. Nine of the 11 sub-pathways use the RSH process. Second, four of the 11 sub-pathways use combined heat and power, which reduces the need for grid power and reduces total plant energy. Third, four of the 11 sub-pathways use either biogas, landfill gas, or waste wood as fuels for process heat, which reduces fossil fuel consumption.

Table 3 summarizes the carbon intensities, as calculated by POET, of the 11 sub-pathways in the application. The carbon intensity values in the table include a 30-gram-per-mega-joule component for the emissions from indirect land use change. Conditions on amount and type of fuel used and grid electricity uses apply to each of POET's sub-pathways. These conditions are not shown because the values in the conditions are considered confidential business information. The carbon intensity values and conditions for each sub-pathway would apply to each POET plant that is represented by the sub-pathway.

**Table 3**
**POET Pathway Carbon Intensities**

| Sub-Pathway number | Sub-Pathway Description | Carbon Intensity ($gCO_2e$/MJ) | |
|---|---|---|---|
| | | 100% Dry DGS | 100% Wet DGS |
| 1 | Raw Starch Hydrolysis | 92.4 | 83.7 |
| 2 | Raw Starch Hydrolysis/Combined Heat and Power | 88.5 | 79.8 |
| 3 | Raw Starch Hydrolysis/Biomass & Landfill Gas Fuels | 88.5 | none |
| 4 | Raw Starch Hydrolysis/Corn Fractionation | 91.7 | 80.7 |
| 5 | Conventional Cook/Combined Heat and Power | 90.5 | 80.5 |
| 6 | Raw Starch Hydrolysis/Biogas Process Fuel | 74.7 | 73.2 |

Staff Analysis and Recommendation

Staff has reviewed the POET application. Staff's findings are as follows:

- Staff has replicated, using the CA-GREET spreadsheet, the carbon intensity values calculated by POET for each of the eleven sub-pathways;
- POET has provided documentation for its plants' energy use and ethanol production levels;
- Staff agrees that the energy values in the application accurately represent the POET plants' energy values appearing in the application;
- Staff agrees that the grid electricity use values in the application accurately represents the POET plants' grid electricity use values claimed in the application; and
- Future grid electrical energy and total energy use for the plants, using these pathways will have to be reported to the ARB in order to verify that the grid electrical and total energy values for the POET plants in the application continue to be met.

On the basis of these findings, staff recommends that POET's application for eleven Method 2A corn ethanol sub-pathways be approved.

More information on the POET application, including the ARB staff summary and other supporting documentation can be viewed at
http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/poet-rpt-ncbi-121410.pdf

6. Trinidad Bulk Traders Limited

Plant Summary

Trinidad Bulk Traders Ltd. (TBTL) operates an ethanol dehydration plant in the city of Point Fortin, Trinidad and Tobago. Point Fortin is located in the southwest portion of the island of Trinidad. TBTL imports Brazilian hydrous sugarcane ethanol (95 percent ethanol) for dehydration at its Point Fortin plant. Dehydration is accomplished using molecular sieves. The finished product (99.5 percent ethanol) is shipped to the United States. Oceangoing tankers transport hydrous ethanol from Brazil to the TBTL plant and anhydrous product from that plant to the U.S. TBTL uses electricity and natural gas for its process power. The plant's natural gas supply is from wells within (and owned by) the country of Trinidad and Tobago. That same natural gas is used to generate most of the electricity used by the plant.

Trinidad and Tobago exports anhydrous sugarcane ethanol to the U.S. under the Caribbean Basin Initiative (CBI), an economic incentive program in which Caribbean Basin countries are permitted to export ethanol to the US. duty-free. CBI countries are collectively allowed to export a volume of ethanol equal to seven percent of the American consumption for the prior year. Ethanol imported directly to the U.S. from Brazil is subject to import duties.

Carbon Intensity of Ethanol Produced

The total carbon intensity of the ethanol produced by TBTL consists of the carbon intensity associated with the Brazilian sugarcane ethanol that is dehydrated in the TBTL plant, plus the carbon intensity of the dehydration process itself. The TBTL carbon intensity increment also includes a small transportation component reflecting the shipping distance differential between the existing Brazilian pathways and the proposed CBI pathway. The LCFS lookup table currently contains three Brazilian sugarcane ethanol pathways. The proposed TBTL pathway adds 5.54 $gCO_2e/MJ$ to these pathways, resulting in the final carbon intensities shown in Table 4.

**Table 4**
**TBTL CIs as Increments to Brazilian Sugarcane CIs**

| Brazilian Pathway Description | Direct Brazilian CI | Brazilian Land Use Change CI | Total Brazilian CI | TBTL Increment[1] | Total TBTL CI |
|---|---|---|---|---|---|
| Brazilian sugarcane using average production processes | 27.4 | 46 | 73.4 | 5.54 | 78.94 |
| Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit | 12.4 | 46 | 58.4 | 5.54 | 63.94 |
| Brazilian sugarcane with average production process and electricity co-product credit | 20.4 | 46 | 66.4 | 5.54 | 71.94 |

More information on the TBTL application, including the ARB staff summary and other supporting documentation can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/tbtl-rpt-ncbi-121410.pdf

## *B. Detailed Summaries of Proposed Internal Priority Fuel Pathways*

### 1. Corn Oil Biodiesel—Corn Ethanol Oil Extraction

ARB staff has estimated the carbon intensity for the production of biodiesel fuel using corn oil extracted at dry mill corn ethanol plants producing dry distillers' grains with solubles (DDGS). The estimated carbon intensity for this pathway is 5.9 gCO2e/MJ of biodiesel produced. This value does not include any emissions due to indirect land use changes (ILUC). ARB staff's estimate for the emissions associated with corn oil extraction at corn ethanol production facilities is based on information provided by Greenshift Corporation, a company that has commercialized corn oil extraction processes. It is the ARB staff's understanding that a number of companies have developed, or are developing, processes for the extraction of corn oil from distillers' grains with solubles (DGS) at corn ethanol production facilities. There is much more publicly available information on the Greenshift processes, and it is for this reason that ARB staff used the Greenshift information as the basis for its analysis. If information from other corn extraction processes is published, ARB staff will incorporate this into its analysis.

The Greenshift corn oil extraction processes (two Greenshift processes are discussed below) extract corn oil from the thin stillage produced at corn ethanol plants following fermentation and distillation. The Greenshift processes use a combination of washing and centrifuging to extract 60 to 75 percent of the corn oil contained in the stillage. This translates to about 6.5 gallons of corn oil per 100 gallons of ethanol produced at corn ethanol plants. The extracted corn oil is sent to biodiesel production plants where the corn oil is converted to fatty acid methyl esters (FAME) biodiesel using a transesterification process, as is done to produce biodiesel from soy oil.

Corn oil extraction facilities using the Greenshift process can be added to pre-existing corn ethanol plants with little modification to the plant and no effect on the ethanol production. ARB staff believes that as corn oil-based biodiesel becomes a more attractive option for compliance with the Low Carbon Fuel Standard (LCFS), corn oil extraction facilities will be added in this manner to pre-existing corn ethanol plants. ARB staff believes that corn ethanol will always be the primary fuel produced with corn oil being secondary.

The extraction of corn oil using the Greenshift process requires additional thermal energy that is used to heat the stillage and additional electricity requirements to run the motors on the pumps and centrifuges. However, there are energy savings that exceed the additional thermal and electricity requirements. These savings occur because the removal of the corn oil reduces the mass of the stillage that needs to be dried while also increasing the heat transfer characteristics of the stillage that is dried. Using the Greenshift information, ARB staff has estimated that the installation of corn oil extraction at pre-existing ethanol plants reduces the energy use at the plant by about nine percent.

ARB staff has assumed that the carbon intensity values for corn oil biodiesel pathway components other than the corn oil extraction (production of biodiesel from corn oil, corn oil transportation, biodiesel transportation, etc.) are the same as those in the other published ARB pathways. For example, the carbon intensity for transesterification of the corn oil is the same as the transesterification carbon intensity calculated in the ARB's pathway for the conversion of soy beans to FAME biodiesel. Because two fuel products (ethanol and corn oil) are produced at corn ethanol plants, the allocation of some of the emissions associated with the corn production and transportation can be complicated. Various schemes for allocating these emissions have been suggested. ARB staff chose, for the reasons discussed below, to allocate all of the emissions associated with corn production and transportation to the carbon intensity of corn ethanol, and none of the emissions to corn oil. The rationale for this decision lies in the incremental and secondary nature of the corn oil production. Because corn oil production facilities will be added to pre-existing corn ethanol plants, ARB staff believes that the carbon intensity of corn oil should be calculated as an incremental, carbon intensity including only the additional energy requirements and savings that occur as a result of adding the corn oil extraction facility. For the same reason, ARB staff believes that any and all emissions associated with indirect land use changes should all be allocated to corn ethanol. Staff recommends that the Executive Officer approve this pathway.

More information on the proposed Corn Oil Biodiesel pathway can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/121410lcfs-cornoil-bd.pdf

2. Used Cooking Oil Biodiesel

The Midwestern used cooking oil (UCO) biodiesel pathway described in this analysis yields a higher carbon intensity (CI) than the approved "Detailed California-Modified GREET Pathway for Biodiesel Produced in California from Used Cooking Oil." Except for the final distribution and use of the fuel, all of the production steps for the Midwestern product occur in the Midwest. The carbon intensity difference between the Midwestern and California fuels is due to: (1) differences in the feedstocks used to generate electricity in the two regions, and (2) the distances the finished biodiesel must be transported for final use.

The differences between the electrical generation fuel mixes used in the current and approved UCO pathway analyses are shown in Table 7.

**Table 7**
**Electrical Generation Fuel Mix Differences Between the California and Midwestern UCO Biodiesel Pathways**

| | Natural Gas | Coal | Biomass | Other (Solar Wind, Hydroelectric,etc.) |
|---|---|---|---|---|
| Midwest | 33.5% | 51.6% | 5.8% | 9.1% |
| California | 78.7% | 0% | 0% | 21.3% |

The differences in the biodiesel transport distances are as follows:

- Approved California pathway: 50 miles to bulk terminals and 90 miles to distribution points, all by heavy-duty diesel truck;
- New Midwestern pathway: 1,400 miles by rail to California and 90 miles to distribution points by heavy-duty diesel truck.

Tables 8 through 10 summarize the CI differences between the new Midwestern pathway and the already approved UCO pathways

**Table 8**
**Carbon Intensity Comparison—Biodiesel produced in the Midwest (New Pathway) versus BD produced in California (Existing Approved Pathway) (Cooking Required)**

| | **New Midwest Pathway Emissions ($gCO_2e/MJ$)** | **Existing CA Pathway Emissions ($gCO_2e/MJ$)** |
|---|---|---|
| Rendering of UCO | **5.71** | **4.73** |
| UCO Transport (after rendering) | 0.31 | 0.31 |
| Biodiesel Production | **6.07** | **5.56** |
| Biodiesel Transport | **1.87** | **0.76** |
| **Total (Well To Tank)** | **13.96** | **11.36** |
| **Total (Tank To Wheel)** | 4.48 | 4.48 |
| **Total (Well To Wheel)** | **18.44** | **15.84** |

For the scenario in which no cooking is required, the only difference in carbon intensities results from UCO rendering emissions (Table 9).

**Table 9**
**Comparison of Rendering Carbon Intensities (Cooking versus Non-cooking)**

| | **New Midwest Pathway Emissions ($gCO_2e/MJ$))** | **Existing CA Pathway Emissions ($gCO_2e/MJ$** |
|---|---|---|
| UCO Rendering (Cooking) | 5.71 | 4.73 |
| UCO Rendering (No cooking) | 0.80 | 0.65 |

**Table 10**
**Comparison of Carbon Intensities of Biodiesel produced in the Midwest versus Biodiesel produced in California (No Cooking Required)**

| | New Midwest Pathway Emissions ($gCO_2e/MJ$) | Existing CA Pathway Emissions ($gCO_2e/MJ$ |
|---|---|---|
| **Rendering of UCO** | **0.80** | **0.65** |
| Total (Well To Tank) | 9.05 | 7.28 |
| Total (Tank To Wheel) | 4.48 | 4.48 |
| **Total (Well To Wheel)** | **13.53** | **11.76** |

Staff recommends that the Executive Officer approve this fuel pathway.

More information on the proposed UCO biodiesel pathways can be viewed at http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/121410lcfs-uco-bd.pdf

## IV. Environmental Impacts of Proposed Amendments

The rulemaking described in this Staff Report was undertaken in response to implementation activities described in the LCFS Regulation (2009) and in Resolution 09-31 (State of California, Air Resources Board, April 23, 2009). The LCFS established the Method 2A and 2B processes. These processes allow fuel providers to apply to the ARB for the addition of new fuel pathways to the LCFS Lookup Tables. Resolution 09-31 directed staff to "work with biofuel producers and other interested stakeholders to identify specialized fuel pathways . . . that the Board staff will develop and propose for incorporation into the Carbon Intensity Lookup Table."

The regulatory changes described in this Staff Report were undertaken in direct response to these regulatory provisions and Board directives. They contain no elements that in any way modify, supersede, or extend the analytical boundaries of those provisions and directives. As such, the implementation of these regulatory changes occurs entirely within the context established by the Staff Report prepared in support of the LCFS (Air Resources Board, March 5, 2009). Hence, the environmental impacts attributed to the original LCFS Regulation order apply equally to the rulemaking proposed in this Staff Report. No actions which would go beyond those described in that prior analysis would be undertaken as a result of the current proposed rulemaking. Further, after consideration of the technologies involved in the staff-initiated pathways and pathways submitted by the applicants, staff is not aware of any pollutants that would be emitted or released under these pathways in such a way as to be substantially different in nature or magnitude from the emissions that were characterized and evaluated in the original 2009 rulemaking. Therefore, for the above reasons, staff believes that no significant adverse environmental impacts beyond those described in that original analysis would occur as a result of this rulemaking.

## V. Economic Impacts of Proposed Amendments

As described in Section IV, above, the current rulemaking was undertaken in response to implementation activities described in the LCFS Regulation (2009) and in Resolution 09-31 (State of California, Air Resources Board, April 23, 2009). As such, the implementation of these regulatory changes occurs entirely within the context established by the Staff Report prepared in support of the LCFS (Air Resources Board, March 5, 2009). Hence, the economic impacts attributed to the original LCFS Regulation order apply equally to the rulemaking proposed in this Staff Report. No actions which would modify, supersede, or extend the analytical boundaries described in that prior analysis would be undertaken as a result of the current proposed rulemaking. No economic impacts beyond those described in that analysis would therefore occur as a result of this rulemaking.

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