Determining Carbon Intensity Values for Fuels Derived from Crude Oil

Interim Crude Oil Screening Process

Background: On April 23, 2009, the California Air Resources Board (ARB/Board) approved the Low Carbon Fuel Standard (LCFS) regulation. At that hearing, the Board also adopted Resolution 09-31, which includes a number of provisions related to ongoing work on the LCFS. Two provisions relate to the preparation of guidelines to assist regulated parties in determining carbon intensity values for new or modified fuel pathways.

The Board-approved resolutions read:

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with interested stakeholders to prepare guidelines to assist regulated parties in determining the data, documentation, and other information needed to support the expeditious development of carbon intensity values for new or modified pathways…"

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with interested stakeholders to develop an informal screening process for assessing the carbon intensity of new or modified fuel pathways."

In March 2010, ARB staff convened an informal workgroup comprised of industry, government, environmental, and academic representatives to assist in developing a screening process for determining the carbon intensity of crude oil sources under the LCFS. The workgroup met a total of five times and a smaller subgroup formed to discuss details of the screening process met weekly over a period of six weeks.

Workgroup Objective: Develop a recommendation for a screening process to be used to determine the appropriate carbon intensity to be assigned to fuels derived from crude oil sources which are not "included in the 2006 California baseline crude oil mix."

Definitions

- "included in the 2006 California baseline crude mix" means the crude oil constituted at least 2.0 percent of the 2006 California baseline crude mix, by volume, as shown by California Energy Commission records for 2006.
- "high carbon intensity crude oil" (HCICO) means any crude oil that has a total production and transport carbon intensity value greater than 15.00 gCO_2e/MJ.

Regulation requirements

Section 95486(b)(2)(A) of the LCFS regulation specifies the requirements for using the Lookup Table to determine carbon intensity values for CARBOB, gasoline, and diesel fuel. This section requires a regulated party to use the average carbon intensity value shown in the Lookup Table if the fuel is derived from crude oil that is either:

1. "included in the 2006 California baseline crude mix" (hereafter referred to as a baseline crude oil source) or
2. not a HCICO.

For non-baseline crude oil sources determined to be HCICO, the regulated party must either use:

1. the carbon intensity shown in the Lookup Table corresponding to the HCICO's pathway or
2. the carbon intensity determined via Method 2B if there is no carbon intensity shown in the Lookup Table corresponding to the HCICO's pathway.

The regulation does not specify how ARB or the regulated party is to determine whether a non-baseline crude oil is HCICO. It also does not specify what carbon intensity value should be used for fuels derived from this crude until such a determination is made. Working with the crude oil screening workgroup, ARB has developed the following interim process for determining which non-baseline crude oil sources are HCICO and assigning an appropriate carbon intensity value to the fuels derived from these HCICO sources.

Proposal for an Interim Crude Oil Screening Process
The process consists of several steps to be used to "screen out" non-HCICO sources. The process starts with two simple identifiers to be used to separate out a substantial fraction of the non-HCICO sources. Subsequent steps become increasingly more rigorous culminating in a thorough life cycle assessment to identify any remaining non-HCICO sources.

Step 1: Non-HCICO Identifiers

1. Crude oil produced using recovery techniques other than thermal enhanced oil recovery (steam/hot water injection or in-situ combustion) or crude bitumen mining.
2. Crude oil produced from a country with an average flaring rate of less than 10 scm/bbl as determined using the most recent NOAA/NGDC gas flaring rate data together with annual oil production data.

The identifiers will be applied to crudes that are not part of the 2006 California baseline crude mix. Crude oil for which both 1 and 2 are applicable will be considered non-HCICO. This finding will be made public by adding this crude source to the ARB-maintained list of non-HCICOs. Fuels derived from this crude oil will be assigned the average carbon intensity value for CARBOB or diesel from the lookup table.

If a marketing crude name consists of a blend of crudes produced using different production methods, each production method must meet the requirements of the Identifiers for the marketing crude name to be classified as non-HCICO. If one or more production methods do not meet the requirements of Identifiers above, only that portion of the marketing crude blend produced using production methods that do meet the requirements will be classified as non-HCICO.

Failure to meet either Identifier 1 or 2 will result in the crude source being considered potential-HCICO, therefore subjected to a more refined assessment to determine HCICO status as described starting in Step 2. Potential-HCICO sources will be assigned a default carbon intensity value for crude oil production and transport of 20 g/MJ. This default value was determined by ARB staff using existing literature assessments for potential-HCICO sources (see attachment).

ARB realizes that in some circumstances other production methods and/or production characteristics may result in a crude oil that is designated as non-HCICO while having a carbon intensity that approaches or exceeds 15 g/MJ. ARB will continue to analyze and research these and may revise the identifiers in the future based on the results of this analysis and research. Should a revision of the non-HCICO identifiers result in a reclassification of the crude, the regulated party using this crude shall use the new carbon intensity of the crude oil from the date the reclassification of the crude becomes final by ARB. The reclassification value should not be applied to the crude retroactively.

Step 2: Consideration of additional information

If an applicant believes a mistake was made during the application of Step 1 identifiers, the applicant would be permitted to produce data, relative to the above identifiers, to indicate special circumstances for that crude that might result in passage of the test(s) that was(were) failed. If the consideration of additional information results in a finding that the crude is a non-HCICO, this finding will be made public by adding this crude to the ARB-maintained list of non-HCICOs. The applicant will be allowed to retroactively substitute the average carbon intensity value for the default value.

Step 3: Simple Assessment of Crude CI

ARB realizes that some clearly non-HCICO sources may be classified as possible HCICO in Steps1 and 2 (e.g. crude oil produced by primary recovery with flaring near but in excess of 10 scm/bbl). For these situations, an applicant may submit evidence to ARB showing that the crude source is clearly non-HCICO. ARB will evaluate the adequacy of the evidence provided and make a determination. If the consideration of additional information results in a finding that the crude is a non-HCICO, this finding will be made public by adding this crude to the ARB-maintained list of non-HCICOs. The applicant will be allowed to retroactively substitute the average carbon intensity value for the default value.

Step 4: Rigorous Assessment of Crude CI

For crudes deemed to be possible HCICOs after Step 3, an applicant may perform a life cycle assessment, similar to the level of rigor required for a Method 2 application, to determine the production and transportation CI for that crude oil. This assessment may include control measures, such as carbon capture and sequestration or other methods, which reduce the crude oil's production and transport carbon intensity value. The data for the assessment may be provided on a confidential basis in order to protect proprietary information. ARB staff will evaluate the adequacy of the analysis and accuracy of the CI determined. If the CI is determined to be less than or equal to 15.00 gCO_2e/MJ, that crude will be designated as a non-HCICO and added to the ARB-maintained list of non-HCICOs. The applicant will be allowed to retroactively substitute the average carbon intensity value for the default value.

Attachment: Rationale for Interim Default Carbon Intensity of 20 g/MJ

Setting the interim default carbon intensity value for crude recovery and transport of potential-HCICO sources at 20 g/MJ is based on the following rationale:

- In the year 2009, the only non-baseline sources of CA crude oil produced using TEOR or mining recovery appear to be from Canada and Venezuela.
- Table 1 shows some literature and model default values for in situ TEOR with upgrading, in situ TEOR without upgrading, and bitumen mining with upgrading. These values are for Canadian oil sands production. The in situ thermal recovery values assume a steam-to-oil ratio of 3 to 3.4. In 2009, slightly more than half of oil sands production was mined and upgraded with the remainder being in situ production. Approximately 10 percent of in situ production was upgraded. Applying these rough percentages to the default values shown in Table 1 results in an average CI value of 19 g/MJ for Canadian oil sands production and transport. NETL reports similar average carbon intensity for Canadian oil sands of 21 g/MJ. In a study performed for the European Union, Brandt estimated a "most likely" value of 25 g/MJ assuming 55 percent mining with upgrading and 45 percent in situ with upgrading.
- Venezuelan extra-heavy oil is primarily produced using in situ thermal recovery with upgrading. The steam-to-oil ratio for thermal recovery in Venezuela is lower than that for Canada because of higher reservoir temperatures and lower viscosity oil. NETL has estimated an average carbon intensity of 19 g/MJ for production and transport of upgraded Venezuelan bitumen.
- The carbon intensity for production with excessive flaring will vary with flaring rate. An approximate conversion is that flaring at 10 scm/bbl contributes about 5 g/MJ to the CI value. A much-studied crude source with excessive flaring is Nigeria with estimated CI values of 18.5 g/MJ (Jacobs), 17.6 g/MJ (TIAX), and 25.3 g/MJ (NETL). Nigeria currently has an average flaring rate of 20 scm/bbl. One crude source (listed by WSPA companies as being considered for California) has a country-average flaring rate significantly greater than Nigeria. All other sources which are likely to fail the flaring screen (i.e. greater than 10 scm/bbl) have country-average flaring rates less than 25 scm/bbl.

Based on the above discussion, an interim default carbon intensity value of 20 g/MJ appears reasonable and appropriate.

Table 1: Some Literature CI Values for Crude Produced using TEOR and Mining

Source	In situ TEOR[1] with upgrading to SCO (gCO2e/MJ)	In situ TEOR[1] w/o upgrading to SCO (gCO2e/MJ)	Bitumen mining[2] with upgrading to SCO (gCO2e/MJ)
GHGenius	28.6	13.3	19.7
GREET[4]	18.7	13.6	15.4
Jacobs report[5]	~26	~16	~17
TIAX report	26.7	16.6	12.8
Default value[3,6]	**25 + 1 = 26**	**15 + 1 = 16**	**16 + 4 + 1 = 21**

Notes:

1. In situ TEOR
    a. GHGenius: SAGD with steam-to-oil ratio (SOR) of 3.2
    b. Jacobs: SAGD with SOR of 3.0
    c. TIAX:
        i. With upgrading: SAGD with SOR of 3,
        ii. w/o upgrading: CSS with SOR of 3.4
    d. GREET: Process method and SOR unknown.
2. Mining carbon intensity values obtained from the literature do not include land use change/tailings pond emissions.
3. Default values include emissions associated with transport of crude oil to the refinery. These are dependent on location but typically are about 1 g/MJ. Bitumen mining value also includes 4 g/MJ to account for land use change/tailings pond emissions. Yeh et al. ES&T have estimated these emissions at approximately 4 g/MJ (range 0.8 to 10.2 g/MJ).
4. GREET values were taken from Table 6-3 in the TIAX report. The value for in situ recovery without upgrading does not appear to include venting or flaring emissions.
5. Jacobs values from Table 8-7 in Jacobs report. These values do not appear to include venting and flaring emissions. Also, there is some uncertainty about allocation of upstream natural gas emissions between recovery and refining in the Jacobs values. Values in Table 1 (above) include upstream natural gas emissions estimates of 2 g/MJ for in situ recovery with upgrading, 1.5 g/MJ for in situ recovery without upgrading, and 1 g/MJ for mining recovery.
6. NETL reports single values for production and transport of Canadian oil sands (21.3 g/MJ) and Venezuelan upgraded extra-heavy oil (18.7 g/MJ).

<u>References:</u>

1. GHGenius values are from personal communication with Don O'Connor dated September 27, 2010.
2. NETL, 2009, An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions (Appendix A), DOE/NETL-2009/1362.
3. Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.
4. TIAX, 2009, Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions, prepared for Alberta Energy Research Institute.
5. Sonia Yeh, Sarah M. Jordaan, Adam R. Brandt, Merritt R. Turetsky, Sabrina Spatari, David W. Keith, Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands, *Environ. Sci. Technol.*, 2010, *44* (22), pp 8766–8772.
6. Brandt, Adam R., 2011, Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries, Department of Energy Resources Engineering, Stanford University.