Western States Petroleum Association

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Catherine H. Reheis-Boyd
President

October 1, 2012

Clerk of the Board
Air Resources Board
1001 I St.
Sacramento, CA 95814
Via e-mail to http://www.arb.ca.gov/lispub/comm/bclist.php

Dear Clerk of the Board:

Re. **WSPA Comments on Second 15 -Day Modified LCFS Regulation Order**

The Western States Petroleum Association (WSPA) submits below, comments on ARB's third 15-day package of modifications to the LCFS regulation that were made available for public review on September 17. WSPA is a non-profit trade organization representing twenty-seven companies that explore for, produce, refine, distribute and market petroleum, petroleum products, natural gas and other energy supplies in California and five other western states.

In addition to these comments, we have also included in Appendix A a copy of our comment letter submitted to ARB on the July 27th Workshop relative to the crude oil OPGEE model since we note in the 15 day package that almost none of our comments were incorporated from our letter, and want to ensure it is in the legal record. An additional comment regarding a crude oil production flaring reference is included at the beginning of the Appendix as well.

WSPA continues to be very concerned about the feasibility and timing of ARB's LCFS program, as well as the economic impact of the program on the petroleum industry and the entire state as an economic entity. The current fuels policies will have significant unintended consequences on California's refiners, and consequently their employees, consumers and the state. We would like to be very clear that the fact WSPA continues to work with ARB on correcting/modifying technical issues associated with the ever-evolving LCFS program, in no way is meant to indicate that our trade association's members endorse the current program.

WSPA's comments are as follows:

Page 6 - Section 95480.3(b). Carbon intensity is not the only parameter that needs to be defined by opt-in parties. Paragraph (3) correctly specifies the appropriate EER for that option, but paragraphs (1) and (2) should also state that the EER appropriate to the chosen CI must be used.

Page 19 - Section 95482. Average Carbon Intensity Requirements for Gasoline and Diesel, and
Page 62 Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline

- In updating the LCFS baseline for gasoline to 2010, staff only completed one portion of the revisions – the updated baseline to reflect changes in the estimates for the CI of CARBOB based on new information on crude oil - but staff failed to update the CI of ethanol based on new information. Because the CARBOB 2010 baseline value was updated, the ethanol value should be as well.

  ARB is continuing to use an ethanol CI value of 95.66 as documented in the following document Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG) http://www.arb.ca.gov/regact/2011/lcfs2011/carfg.pdf which is part of the 15-day package. This value is the same as what was used for the 2006 baseline and included a disproportionate amount of ethanol assumed to be from California with a lower CI. ARB assumed ethanol consisted of "80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG". According to the CEC's IEPR document "California ethanol facilities contributed less than 4 percent of the state's needs in 2010" (IEPR page 183). The lower, inaccurate CI value used by CARB impacts the CaRFG 2010 baseline value used in setting the annual compliance targets in Section 95482(b).

  In addition, the CI values for Midwestern corn ethanol should have been updated based on data presented to CARB since the original rulemaking: specifically, many of the large number of "new" pathways approved by CARB via Method 2A actually reflect existing industry practices employed in 2010 that were not represented in the original calculations.

  This exercise should be simple since the LCFS was in effect for reporting in 2010 and therefore, ARB can calculate the average ethanol CI for 2010. Once this calculation is made, the CaRFG baseline value and compliance target table should be updated accordingly. ("Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG)" and Section 95482(b) page 19).

Section 95486. Determination of Carbon Intensity Values

- Page 58 - (a)(5)(B) - The default CI for biodiesel was deleted in the text but a replacement value was not substituted.
- Page 68 - Table 7 is missing biodiesel CI values from the guidance that was issued in July.
- Page 71 – Table 8 – Carbon Intensity Lookup Table for Crude Oil Production and Transport.
  - The crude CI values for 2010 are not the same as the crude CIs issued for review in July. Can ARB explain these differences?
  - Table 8 (cont.) - The volumes used to assess the baseline crude average are not shown in Table 8. Are they the same as was issued in the July data? In the future, will the volumes be disclosed annually when the crude CI is estimated?

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- Crudes for all countries other than the United States have CI values listed in the regulations via this table, the significance of which is that changes to those values require a rulemaking. Despite the diversity of crudes produced in California, this state is represented by an average rather than values for the individual crude. This constitutes unequal treatment for California crudes vs. non-California crudes.

- (b)(2) – A general comment that WSPA continues to make and is effectively ignored by staff, is that if the California Average goes <u>down below the baseline,</u> there should be an allowance for incremental credits if ARB wants to stay consistent with it's GHG reduction goals.

- Page 73-74 – (b)(2)(A)(1) – Deficit Calculation for CARBOB or Diesel Fuel
The paragraph which starts on page 73 and continues on to page 74 which defines"$CI^{XD}_{20XXCrudeAvg}$" includes the following sentence:

"$CI^{XD}_{20XXCrudeAvg}$ will be calculated using data for crude oil supplied to California refineries during the calendar year 2012."

We understand this <u>data</u> will include market crude oil names, volumes of these market crudes oils, and the carbon intensity of the individual market crude oils defined in Table 8 of this 15 day package. However we do <u>not</u> see the following in this package:

1. A specific regulatory process for ARB to add any new <u>individual</u> crude to the Crude CI lookup table (which is necessary when a crude not supplied to any California refiners in baseline year 2010 is subsequently supplied to one or more California refiners in 2012 or later years).
2. A specific regulatory process to revise the CI for a crude already in Lookup Table 8, because:
   a. the OPGEE CI model input data for that crude has changed since 2010 due to changes in production of that crude after 2010, or
   b. the OPGEE CI model input data for that 2010 crude has been found to be incorrect based on the availability of new/additional information on 2010 production of that crude, or
   c. the OPGEE model itself is changed/revised due to new information.

   Changes in categories (b) and/or (c) would be expected to impact the original 2010 baseline industry average CI and not just the industry average actual years of the program.

ARB needs to address these issues in rulemaking now, otherwise modifications to Table 8 (other than the posting of individual year average crude carbon intensities from "fixed" individual crude carbon intensities), will require additional formal rulemaking which could delay the publication of the individual year average crude CI's, potentially into the year in which obligated parties must know and account for the generation of any potential incremental deficits.

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- Pages 74 – 84 - Innovative Crude Production Technologies
  WSPA has arrived at a consensus position that we do NOT support the inclusion of the concept of incremental credits for innovative crude oil technology within the LCFS program because there does not appear to be a way to implement such a program without double counting of credits while correctly calculating the California Average. WSPA supports voluntary advances in crude oil recovery technologies that reduce CO2 emissions. We believe those benefits should be captured but do not believe a "unique" or "stand-alone" or "one-off" type methodology as proposed is the proper means to capture the benefit. WSPA therefore does not support the inclusion of sections in the regulation that provide details of this approach, and request that this concept be removed.

  If, however, ARB decides to not agree to our request, we have several suggestions for revisions to this innovative crude credits area of the regulation. They are:
    - Innovative methods should not be restricted to crude oil production using CCS or solar steam generation (as stated on page 75) but these can be used as examples of methods,
    - There should be absolutely no double crediting or counting, and,
    - The California Average needs to be calculated correctly.

  Additional detailed comments are as follows:

- Page 74 - It is not clear how the benefits from innovative crude production methods will not be "credited" twice. Section 95486(b)(2)(A)(1) states the average "...will be calculated using data for crude oil supplied to California refineries during the most recent three calendar years.". If a crude is produced using the methods listed, it will be part of the overall crude mix supplied to the refineries; there is no exclusion for crudes produced by "innovative methods". Section 95486(b)(2)(A)(4) page 75 then contains requirements for capturing an additional credit from the use innovative crude production methods. This results in "double-counting" of credits.

- Page 75 - 95486(b)(2)(A)(4)- Innovative Crude Technologies
    - Staff has inappropriately and without explanation reduced the CI reduction threshold by 80% from 5.00 g/MJ to 1.00 g/MJ. This is inconsistent with the treatment for any other fuel under the Method 2A provisions, which require a minimum reduction of 5.00 g/MJ. This inequitable treatment of different fuels must not be permitted under the LCFS.

    - Also in this section, detailed calculation methodologies have been added that serve only to replicate calculations that go into the calculation of the California Average crude CI value described elsewhere in the regulations. The California Average calculations are the proper mechanism for inclusion of crude CI changes. The result of this section is a double-counting of crude oil carbon intensity impacts and the awarding of LCFS credits for which there are no actual GHG reductions. This entire section should have been removed, or at the very least had some means inserted that would prevent such improper awarding of credits.

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- Obligated parties (refiners) should not be in the position of having credits cancelled if ARB finds out an innovative reduction technology never works as designed or loses its efficacy over time.

- Page 84 - (b)(2)(A)(4)(d)(v)(I) – Crude Oil Producer Recordkeeping

  With regard to the record keeping requirements for a crude oil producer to submit an application in order for refiners to receive credits for purchasing crudes produced using innovative crude production methods, the following requirement should be partially deleted as follows:

  "The annual volume of crude oil produced using the approved innovative crude oil production method ~~and the annual volume of crude subsequently sold in California under the approved innovative crude oil production method~~"

  It is infeasible to impose the 2nd portion of this requirement on the crude oil producer submitting the application for the innovative crude oil production method, because the crude oil may be sold multiple times, so the crude oil producer may not know how much of this particular crude was actually delivered to refiners in California. Further, it is unnecessary for the crude oil producer to obtain and maintain a record on the volume of this innovative production method crude oil delivered to California, because ARB staff will already have this data via the quarterly reports from California refiners (which contain the market crude oil names and volumes supplied to their California refineries).

- Page 93 - 95486 (f)(3)(A)(1)- Application of ASTM standards

  The revised provision no longer requires that a fuel be compliant with applicable ASTM standards, but instead references that the fuel could alternately be compliant with "…generally recognized consensus standards." WSPA recommends that the alternative to ASTM compliance be re-phrased as follows: "…generally recognized consensus standards from an ANSI recognized standards development organization". Adding this phrase would cover the SAE International standards likely referenced for alternative fuels.

If you have any comments or questions, please feel free to give me a call at this office or contact my staff, Gina Grey at (480) 595-7121 for assistance.

Sincerely,

c.c. R. Corey – ARB
C. Marvin - ARB
M. Waugh – ARB
F. Vergara - ARB

Appendix A - WSPA's Comment Letter on July OPGEE Crude Oil Workshop

As a supplemental comment to the previously submitted comment letter shown below, WSPA wants to alert ARB to a reference regarding flare combustion efficiency. We are unsure if ARB is aware of this report, but there is a literature review completed by the International Flaring Consortium (IFC), CanmetENERGY, entitled "Emissions from Elevated Flares – A Survey of the Literature – April 2010" (If you have problems accessing the reference please let us know).

The review covers several published studies regarding flaring efficiency. These studies (references compiled in section 6.0 of the report) coupled with the Shell Nigerian flare study referenced in the previous WSPA comment letter below, support a flare combustion efficiency in excess of the 95% that ARB has elected to use in the OPGEE model. These studies support a value of at least 98%. ARB appears to have selected 95% as a conservative value based on just one study in contrast to an efficiency supported by numerous studies demonstrating combustion efficiencies in the range of 98 to 99%. If ARB is going to continue using 95% combustion efficiency as a default, WSPA requests that ARB provide an explanation of what field-specific information could be provided to substantiate a higher combustion efficiency.

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President

July 27, 2012

Mr. John Courtis
Manager, Alternative Fuels Section
California Air Resources Board
P.O. Box 2815
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Via e-mail to jcourtis@arb.ca.gov

Re: **WSPA Comments on July 12 Workshop on the Oil Production GHG Emissions Estimator**

Dear Mr. Courtis,

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This letter is in response to the California Air Resources Board's (ARB's) July 12th public workshop on the OPGEE estimator tool. The Western States Petroleum Association (WSPA) has provided below a number of preliminary comments in anticipation of the next 15 day package, but direct ARB to our April 30, 2012 letter that contains many similar comments in more detail.

WSPA is a non-profit trade association representing twenty-seven companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas and other energy supplies in California and five other western states.

WSPA has not altered our core position that there should not be ANY crude differentiation treatment within the LCFS, and we want to be clear that providing comments on the workshop in no way should be perceived as a shift in our position on this baseline position.

Overall, WSPA wants any model associated with the LCFS to be consistent and workable. Our conclusion is we consider the use of the OPGEE model for regulatory purposes inappropriate due primarily to data integrity problems which was identified over the past several years as a core, fundamental problem. This is why WSPA did not support the development of a complex differentiation approach.

WSPA has requested a meeting with ARB within the next two weeks to discuss our comments as well as to address some outstanding implementation issues such as:

- ARB needs to finalize requirements for crude reporting and credit impacts for 2011.
- ARB needs to provide guidance on what, if anything, the oil industry should be doing for crude reporting and credit impacts for 2012.
- WSPA believes, due to the lack of detailed field data, that ARB will only be requiring crude MCON identities and volumes for 2013 reporting. We request confirmation of this level of obligation. We note that ARB didn't have more detailed data than this when developing the baseline.
- We understand ARB will be the only entity running OPGEE within the context of the LCFS, and ARB will be the official custodian for compliance reasons. Please confirm this understanding.
- We need further details about how a refiner would use the available crude CIs. We need the full list of global crude CIs to purchase crudes intelligently and evaluate (as best we can under the average rule) the impact on our businesses before we purchase crude oil. We reiterate the difficulty ARB's crude oil treatment places on companies that do not have access to detailed crude oil data, nor do they have knowledge about other companies crude purchases in order to be able to assess where the average value may end up every year.
- We need more clarity about the workshop references to continuous updates of crude CIs on baseline/annual updates. How and when will ARB notify our industry of MCON revisions or module changes, and what will be the process to update the crude CIs and targets? This will impose additional challenges since a refiner has to plan crude oil selections in a climate of changing CI values.

Our first set of comments are general, and the second are more specific/technical.

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General Comments

False sense of accuracy: OPGEE was created to be a very detailed tool that requires a great many field-specific inputs that are generally unavailable in the public realm. The tool also over-simplifies very complex oil field production processes. As a tool for specific fields that are well-characterized and where field-specific information can be used in lieu of defaults, it may have some utility. However, to estimate average CI values for all crudes run in California refineries, it gives a false sense of accuracy. The output from the model is only as good as the input, and its flexibility to accommodate specific production field details.

Understanding crude data reporting and data availability: There needs to be further discussion about what the regulated parties (i.e. oil companies) are able to provide or acquire in terms of data. Regulated parties are the entities under the jurisdiction of the LCFS, however crude producers are under no obligation to provide competitive, proprietary data. Also, crude is traded on the open market and regulated parties will likely process economic crudes, not just equity production. Many oil companies do not or no longer produce any crude and therefore are concerned that they are placed at a disadvantage in comparison with those companies which may be able to make informed crude selection decisions.

Technical Validation: WSPA strongly recommends additional time be provided for technical validation or peer review in addition what has already been done; and more documentation of the model furnished to make additional review time productive. It is difficult to track formulas from sheet to sheet to figure out what the model is doing. If the outputs from the OPGEE tool are adopted without adequate time to error check, it is highly likely that many errors will be discovered throughout the course of the next few years. ARB needs to outline a process for how these future discoveries will be handled, including possible changes to the baseline and yearly targets for each major change. WSPA also requests ARB/Stanford provide an estimate of the tool's uncertainty.

Yearly Variation: WSPA requests 2009/2010 results from OPGEE to see yearly variations prior to implementation of the tool.

Co-product credits: The OPGEE model used the substitution method instead of the allocation method where associated gas and liquids co-produced with crudes are assumed to replace NG, NGLs and other products in the existing market. The GHG credits given for these co-products were borrowed from the NG pathway in the GREET model. There are several issues with this approach, since the GHG emissions in the GREET NG pathway were calculated based on the allocation method. Certain pathways under CA LCFS also use the allocation method for crediting certain types of co-products. In addition, substitution only works if the co-product production volume is relatively small compared to the whole market. In some production fields, however, both gas and NGLs are in relatively large quantities and could potentially cause market saturation, where the use of the substitution method would become questionable. As mentioned during the workshop, WSPA suggests the OPGEE model be run with both the substitution and the allocation methods and see if there is a material difference in the results.

Technical comments/questions

1. We request that ARB release a completed model for each crude that leads to the indicated carbon intensity. There is a summary table of final crude CI's, and a summary of crude OPGEE inputs, however, in some cases the tool does not return the same CI when the listed inputs are entered by inexperienced users. It is extremely difficult to evaluate the effectiveness of the tool when it is not known which of the other inputs or defaults have been changed.

2. Although the tool allows many features to be turned on or off (such as steam or water flood, downhole pump), there are many components that need that option as well. Some examples include the Amine Treater, Glycol Dehydrator, and the Demethanizer. Some production methods do not have these processes and therefore should not have those GHG emissions attributed to them.

3. The calculations for horsepower to pump fluids into the well appear to only take the pump discharge pressure into account. It is important to consider the pump suction pressure as well, as there are cases of recovered water being sent to a pump at pressure after high pressure separation.

4. The flaring rates obtained from NOAA are not to be considered accurate on an absolute scale, and are not suitable for regulatory purposes. It is not uncommon for NOAA rates to be off by several hundred percent from reliably measured flaring rates. In the event that flaring rates are also reported to a government agency, those reported numbers should be used in place of the NOAA figures.

5. The general assumption that flare combustion efficiency is 95% appears far too conservative, particularly for the larger flares that the NOAA satellites detect. An assumption of 98% flare efficiency would appear more appropriate. For example, there is a Shell Nigerian flaring study that supports 98%.

6. There are a number of crude oil extraction parameters (for example, emissions from drilling, gas compositions, gas-to-oil-ratio, water-to-oil ratio, etc.) which are based on correlations for Canada and/or California, even though California gets most of their imported crude from Alaska, the Middle East, and Central/South America. These correlations may not be applicable to these other locations.

7. In the drilling energy plot (Fig 3.1), why is the energy intensity of drilling in 2005 generally higher than the previous years? We would expect energy consumption to trend down over time, other things being equal.

8. Regarding LUC, the only reference used is Sonia Yeh. Given the debate around this topic, other viewpoints should also be sought out and considered. What, if any, other models/papers for land use change were considered and why were they rejected?

9. Concerning LUC:
   a. What time horizon is used? Is it 100 years- like EPA for LUC?
   b. Is ultimate restoration of the land at the end of the field life taken into account?

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10. For Production and Extraction, there seems to be no transmission losses between the prime mover and the pump. These may be small, but should be included.

11. Some of the efficiency defaults (pump, compressor) in Table 3.4 are below the literature range. These should be "typical" (median) values from within that range, not "conservative" values below that range.

12. To calculate default field age, a discovery to production time lag of 3 years is assumed. At a minimum we believe there should be a range of values which might be dependent on other values and be molded into smart defaults, or that there be the flexibility to enter specific data. Generally, the concept of field age is flawed. A field does not simply appear as fully drilled out in a specific year. Development of a field can continue for decades with infill wells drilled on periodic timeframes. Dependent on management of the field – water flood; gas pressure maintenance, etc. Age is not relevant to the energy load of production.

13. The default well productivity excludes low productivity US wells. More than half of California's crude comes from California and Alaska. We believe the low productivity wells should be included.

14. When calculating default GOR, API for the pool is calculated by averaging high and low API's. ARB should really average SG, and recalculate API from the average.

15. When dealing with natural gas byproducts of crude production, how is energy input partitioned between crude and NG, especially if NG is sold or used to generate electricity (in a CoGen plant) which is sold back to the grid? If on-site gas displaces gas which would otherwise have been purchased, is there an offset used? (See comment above under General Comments)

16. How are upstream emissions for electricity, diesel, gasoline, fuel oil, natural gas, etc. calculated? There should be local input to account for electricity mix or fuel production where it is actually supplied and used.

17. Three diluents for Dilbit are available. What are the CIs?

18. Diluent from NGL is counted as external NG. What was the CI of the NGL?

19. Natural gas composition for steam generation for TEOR is fixed, when in fact it will vary with location and source. Local inputs should be allowed.

20. What is the 0.5gCO2/MJ "fudge" factor supposed to represent? Why did ARB choose that value since it seems large?

21. The value denominated in **gCO2e/<u>bbl</u>** in cell Bitumen Extraction & Upgrading!M164 is transferred to User Inputs & Results'!G188 as **gCO2e/<u>MJ</u>**. The default sheet is preloaded with a value which suggests that the cell in Extraction & Upgrading is labeled with the wrong units and should be gCO2e/MJ.

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22. With regard to flaring emissions, the model contains a cell ('user inputs & results'J99) that allows the user to input their own flaring values. However, the cell is not accessed in any calculation.

23. With regard to venting emissions, if the user input cell is set to zero, emissions are still generated due to "default leaks". What is the basis for these "default leaks"?

24. In the bitumen module, the upstream emissions of natural gas liquids (NGL's) are assumed to be the same as natural gas. However, NGL's do not undergo the same treatment as natural gas (e.g. there is no point in removing sulfur from a diluent that is going to be added to bitumen) and the transport distances for NGL's are much smaller than those for natural gas (most Canadian gas is transported from Alberta to Ontario, whereas NGL's are mostly produced and consumed within Alberta).

25. Section 3.8 of the User Manual clearly states that "…Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE" (page 73). However at the same time, the input assumptions and data sheet ARB used for the Albian Heavy Synthetic (AHS) identifies the crude as a "…partially upgraded dil-synbit..." Given this conflict between what OPGEE can model and ARB's description of AHS as a "partially upgraded dil-synbit" how can ARB use OPGEE for crudes identified as "dil-synbits"?

<u>2010 Baseline</u>

A few specific examples of concerns we have regarding the inputs used by ARB to develop the 2010 baseline CI values dated July 10, 2012, are summarized below:

1. There is a differing quality of data used for the 2010 baseline – field specific for California from DOGGR reports and simplified MCON estimates for imported crude. The data should be consistent and based on MCONs. Field data will not be uniformly available - even in California. WSPA requests MCONs for California crude production to facilitate MCON reporting and to understand ARB's knowledge of the complex California crude delivery systems. Most of the OPGEE model processes and defaults are based on California production and the request for tests is so a field-to-MCON evaluation can be completed.

2. The vast majority of crudes assessed by ARB staff use many model defaults; however, the available defaults cannot be applied blindly. As an example, Arab Light, which makes up 8% of the 2010 baseline crude volume, is assigned a water-oil ratio of 17.8 which was derived from the "smart default" curve based on field age. This "smart default" was used despite data available to staff that indicates that the water-oil ratio is actually much lower. The chart reproduced below was taken from a presentation by Jacobs Engineering to the Crude Oil Screening Workgroup obtained from ARB's own web site:

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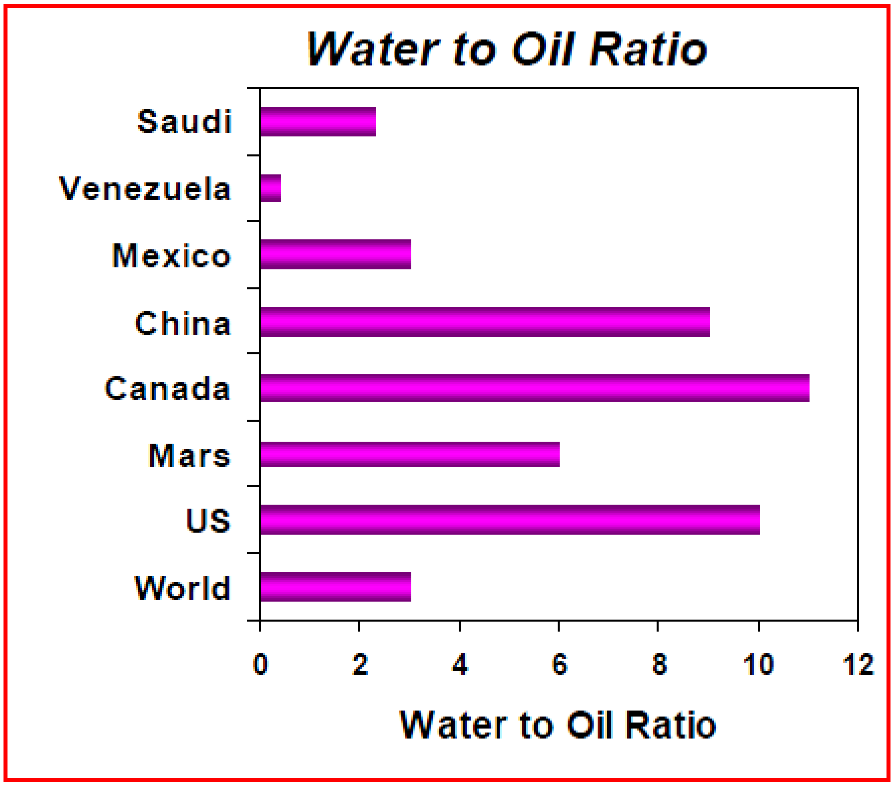

The Jacobs data indicates that the water-oil ratio is about 2 for Saudi Arabian crudes. Staff's use of the "smart default" value rather than the Jacobs data, combined with the very high well flow rates (5700 barrels per day per well versus a model default of 188 barrels per day per well) for Saudi Arabian production, results in the model estimating an unreasonable CI value (> 200 gCO2e/MJ) when all of the other field-specific inputs and defaults are utilized. Rather than questioning the "smart default", staff appears to have arbitrarily chosen to increase the assumed well diameter for Arab Light and Arab Extra light to 7.5 inches, which is 3 inches larger than the upper range from the literature reported in the OPGEE documentation. The resulting CI value for Arab Light is 12.5 g/MJ. However, if staff had utilized the Jacobs-based water-oil ratio of 2, then the extraordinary well diameter assumption would not have been necessary and the OPGEE prediction for the CI of Arab Light would have been 7.1 g/MJ - which is still high compared to other estimates, but more reasonable than 12.5 g/MJ.

Given the significant historical consumption of Arab Light by California refiners, WSPA has grave concerns about ARB staff's application of OPGEE to the calculation of the 2010 baseline and the California average. We are also concerned that if the estimate for such a high profile crude could be so far off, the estimates for other crudes that we have not had time to examine may contain similar errors.

3. Basrah Light, which makes up 8% of the 2010 California baseline crude volume, is also assumed to come from wells with a high flow rate (1500 barrels per day per well with a water-oil ratio of 14.4, again based on the "smart default" curve as a function of field age). In that case, ARB has

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assumed a well diameter of 4 inches. What was the basis of the well diameter estimate? Given that there is a significant difference between the water-oil ratio assumed for Saudi Arabian production from the "smart default" versus available data, we are concerned about the validity of the use of the "smart default" for Basrah Light. Has ARB attempted to validate this estimate with other sources of data?

4. Another parameter that was modified for cases in which wells have a high flow rate is the Productivity Index, which has a baseline value of 3.0. Arab Light and Arab Extra Light are assumed to have a Productivity Index of 75, and Basrah Light is assumed to have a Productivity Index of 15. What is the basis of these estimates?

5. The water-oil ratio has a significant impact on the model results, but the data used to derive the "smart default" values as a function of field age are highly variable and exhibit extreme scatter (see Figure 3.11 in the OPGEE documentation). How confident is ARB that these "smart defaults" are accurately estimating the water-oil ratio for specific fields, particularly in Saudi Arabia and Iraq? Also, the field age appears to be based on the oldest well ever drilled in a given field (e.g., for Arab Light, the assumed age is 56 years). Given the long development timelines and massive size of the fields in some of these locations (e.g., Ghawar in the case of Arab Light), a field age would be much more reasonably based on an average age of the wells as they were brought on stream. As discussed earlier, Arab Light is an example of an unreasonable "field" age being used to calculate an unreasonable (and data-contrary) "smart default" for the water-oil ratio that produces a CI estimate that is out of line with all other work.

WSPA would appreciate an opportunity to discuss these comments in more detail, and ask ARB staff to please coordinate with my staff, Gina Grey at (480) 595-7121 to arrange a follow up meeting.

Sincerely,

Catherine H. Reheis-Boyd

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