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October 30, 2008

Mr. Floyd Vergara, Esq., P.E.
Manager, Industrial Section
California Air Resources Board
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RE: LOW CARBON FUELS STANDARD (LCFS) REGULATION: NGV FUEL PATHS

Dear Mr. Vergara:

This responds to the Air Resources Board's (CARB) preliminary analysis of greenhouse gas (GHG) emissions for compressed natural gas (CNG) and liquefied natural gas (LNG), dated September 9, 2008. Sempra filed extensive comments (attached) on September 30 that identified how the carbon intensity levels are overstated resulting in values which are not representative of typical levels. Subsequent to the previous comments, CARB provided access to Version 1.8b of the California GREET Model.

Attached are specific comments related to Sempra's review of the model. It should be noted the emissions shown by CARB for the Liquefaction and Shipping segments of the LNG fuel pathway are almost twice the levels generated from the GREET Model.

As can be seen from the revised values, natural gas delivered as CNG transportation fuel has similar lifecycle GHG emissions for both North American produced natural gas and imported LNG, and are substantially less than diesel. LNG trucked from Baja would also have a similar lifecycle GHG emission level.

Yours sincerely,

Bernie Orozco

c: Dean Simeroth, Chief, Criteria Pollutants Branch

COMMENTS
Sempra Energy, October 30, 2008
Inputs, Values and Assumption
GREET Modeling

The following comments are provided primarily to address values and calculations included in the California GREET Model 1.8b for LNG and CNG fuel.

LNG Properties

Most of the values shown on the "Fuel_Spec" worksheet for LNG should be adjusted to reflect non-North American supplies. This may require two sets of values with one representing imported LNG and the other used for North American sourced LNG. Shown below are revised average values based on the LNG composition data shown in Appendix A.

Parameter	Cell	GREET Value	Revised Values Calculated from LNG Composition Data
Lower Heating Value, Btu/gallon	C26	74,720	80,968
Higher Heating Value, Btu/gallon	D26	84,820	89,647
Density, gram/gallon	E26	1621	1724
Carbon Ratio	F26	75.0%	75.3%

The net result of these changes will reduce the CO2 emissions from combustion of non-North American LNG supply to 55.7 gram CO2/MJ for the suggested values from a current value of 56.6 gram CO2/MJ.

Natural Gas Recovery & Natural Gas Processing – Non-North American

The California GREET Model includes the same default efficiency factors (97.2% for each) for both North American and non-North American gas production. Most natural gas recovery activities and all gas processing associated with LNG feed gas occur at the liquefaction plant. LNG supply fields typically have substantially fewer production wells with significantly higher production rates than producing fields in the United States. For example it requires thousands of wells in the Barnett

Shale (East Newark Field) (1) to produce the same volume of gas as a dozen wells in Qatar (2). In addition the Barnett Shale wells are spread over nineteen counties (1) and require an extensive network of gathering lines with associated production facilities. The Qatar wells are drilled from central platforms and delivered to the liquefaction plant through a subsea pipeline (2). The recent Snohvit LNG project in Norway utilizes subsea wells and does not require any surface production facility (3).

Information from the Pluto Environmental Impact Statement shows a fuel rate of 0.90% associated with gas production (4). An older study by Tamura et al for LNG projects shows an average fuel rate of 1.47% for gas production (5).

The California GREET Model includes default values of 0.35% (Cell I108, "NG" Worksheet) and 0.15% (Cell J108, "NG" Worksheet) for fugitive methane emissions from natural gas recovery and gas processing activities associated with non-North American gas production. These may be appropriate values for North American gas supply but fugitive methane emissions for non-North American gas supply would be negligible due to the minimum wells and production facilities required. The fugitive emission rate for the production segment of the Pluto LNG project was less than 0.001%. The Gorgon LNG project documents stated the upstream emissions are small and included in the liquefaction plant (6).

Based on the above, the efficiency factor for non-North American natural gas recovery should be revised to 99.0% and the value for non-North American natural gas processing should be set to 100.0%. The fugitive methane emissions for both segments should be zero with only methane from combustion being included.

<u>Natural Gas Transportation from Producing Field to LNG Liquefaction Plant – Non-North American</u>

The California GREET Model includes a default distance of 50 miles (Cell C94, "Inputs" Worksheet) for the natural gas pipeline from the producing field to the liquefaction plant for non-North American gas supply. For fugitive methane emissions the California GREET Model includes a value of 0.45% (0.0027 + 0.0018) hard coded in formulas for both LNG as transport fuel (Cell P108, "NG" Worksheet) and as intermediate fuel (Cell O108, "NG" Worksheet). As previously discussed, the information from several recent projects indicates the emissions from the pipeline are already included in either the gas production or liquefaction segment. The Tamura study also did not identify any separate greenhouse gas emissions associated with transportation of feedgas to the liquefaction plant (5). This is similar to the fact the emissions from gathering pipelines and compression for North American production is included in the gas recovery segment. In summary, no separate emissions should be included in the GREET Model for this segment as they have already been addressed in other segments.

<u>LNG Liquefaction Plant – Non-North American</u>

The California GREET Model includes fugitive methane emissions at the liquefaction plant associated with LNG storage. Default values include five days of storage with a daily boil-off rate of 0.1% and an 80% recovery (Cells C180 & C188, "Inputs" Worksheet). This results in a net fugitive methane emission rate of 0.1%. A review of available information indicates this significantly overstates the fugitive methane rate. The following table lists three planned liquefaction plants and their projected emission rates (4) (6) (7):

LNG Plant	Total Methane Rate, % of LNG Output	Total Methane Rate, lb CO2e/MMBtu Output
Pluto	0.0004%	0.002
Darwin	0.0678%	0.604
Gorgon	0.0005%	0.004

These three projects are representative of the new liquefaction plants that will be the primary sources of LNG to the North America West Coast. In addition the IPCC Guidelines include a value of 0.05% for methane emissions associated with an LNG plant (8). Given the de minimus nature of these emissions, the rate should be revised in GREET to reflect a zero value by increasing the recovery rate to 100% (Cell C188, "Inputs" Worksheet).

<u>LNG Transportation from Plant to US Terminal (LNG Shipping)</u>

The California GREET Model includes fugitive methane (boil-off gas) emissions for the LNG shipping segment associated with non-North America supply. Default values for the LNG shipping include a daily boil-off rate of 0.1% with 80% recovery (Cells D180 & D188, "Inputs" Worksheet). Because boil-off gas is utilized by the ship as fuel, the recovery percentage should be increased to 100% (Cell D188, "Inputs" Worksheet) with no net methane emissions (9).

<u>LNG US Terminal Storage (Receiving Terminal)</u>

Non-North America LNG would be imported into a receiving terminal for distribution. The California GREET Model includes fugitive methane emissions for the bulk storage at the receiving terminal. Default values included in the model for this activity include a daily boil-off rate of 0.1% for a period of five days with a recovery rate of 80% (Cells E180 & E188, "Inputs" Worksheet). Any boil-off gas will be either utilized as fuel in the terminal or delivered to the outlet gas pipeline (10) (11). Therefore the recovery rate should be increased to 100% (Cell E188, "Inputs" Worksheet).

<u>LNG Transportation from US Terminal</u>

The California GREET Model includes emissions for barge (50%) and rail (50%) transportation of LNG from the US terminal to the bulk storage terminal. The default value for the distance for non-North America supply is 520 miles for barging and 800 miles for rail transport. These assumptions are excessive as the majority of any imported LNG would be trucked short distances to local markets. For example the approximate distance from the Costa Azul Terminal in Baja to the Los Angeles area is ~ 150 miles.

<u>Natural Gas Pipeline</u>

The California GREET Model includes the following energy intensity values and weighting values for pipeline transportation of natural gas.

Driver	Energy Intensity (Btu/ton-mile)	Share of Power Source for Compressor Stations
Turbine	405	55%
NG Engine (Current)	405	36%
NG Engine (Future)	405	9%

The resulting weighted value is 405 Btu/ton-mile. This would equate to a fuel consumption rate of only 0.83% for a 750 mile pipeline which is the value in the model for the distance between gas processing plant and CNG refueling station. In contrast the 2006 average US fuel consumption for gas transportation and distribution was 2.93% (13). Information from the Kern, Transwestern and El Paso pipelines indicate gas usage rates of 0.30 – 0.64% per 100 miles with an average value of 0.51% per 100 miles (14) (15) (16). Because this represents both gas used as fuel and fugitive emissions the value needs to be allocated between these two categories for proper assessment of greenhouse gas emissions.

Information from the EPA's greenhouse gas emission inventory was utilized to calculate a US average fugitive methane rate of 0.48% for gas transportation & storage (17). Using these US average rates would allocate the 0.51% to a fuel consumption rate of 0.438% [0.51% * 2.93%/(2.93% + 0.48%)] and a fugitive methane rate of 0.072% [0.51% * 0.48%/(2.93% + 0.48%)] per 100 miles of gas pipeline. The fuel consumption rate would be equivalent to a weighted average energy intensity of 1813 Btu/ton-mile.

Most imported LNG is in close proximity to gas markets and requires very little transmission over the pipeline network. In the California GREET Model the default distance from the LNG Terminal to CNG refueling stations for non-North America supply is 500 miles (Cell F469, "T&D_Flowcharts" Worksheet). As previously discussed this value should be reduced to 150 miles to reflect the distance from the Costa Azul Terminal to the Los Angeles region.

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(17) Environmental Protection Agency 2008 Inventory of Greenhouse Gas Emissions and Sinks

Appendix A

LNG Composition Information

	Tangguh	Malaysia	Bontang	NW Shelf	RasGas	Qatar	Oman	Peru	Darwin
Data Source	(A)	(B)	(C)	(A)	(D)	(D)	(D)	(B)	(E)
Methane	96.30%	91.23%	91.18%	89.30%	90.32%	89.72%	88.46%	89.05%	87.30%
Ethane	2.60%	4.30%	5.51%	7.10%	6.16%	6.65%	7.04%	10.56%	10.34%
Propane	0.50%	2.95%	2.41%	2.50%	2.21%	2.28%	2.72%	0.02%	1.97%
iButane	0.00%	0.00%	0.00%	0.00%	0.40%	0.42%	0.79%	0.00%	0.16%
nButane	0.20%	1.40%	0.88%	1.00%	0.61%	0.66%	0.78%	0.00%	0.13%
iPentane	0.00%	0.01%	0.00%	0.00%	0.01%	0.02%	0.04%	0.00%	0.00%
nPentane	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.03%
Hexane+	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nitrogen	0.40%	0.12%	0.02%	0.10%	0.29%	0.23%	0.15%	0.37%	0.06%

(A) Gas Technology Institute "Natural Gas in California: Environmental Impacts and Device Performance" (October 2006)

(B) "Comments of Peru LNG S.R.L. for Consideration in the Natural Gas Quality Standards Workshop on February 17-18, 2005" (R.04-01-025) dated February 9, 2005

(C) ILEX Energy Consulting "Importing Gas into the UK – Gas Quality Issues" (November 2003)

(D) Department of Energy LNG composition database

(E) Darwin LNG Plant Public Environmental Report (March 2002)

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September 30, 2008

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Sacramento, CA 95814

RE: LOW CARBON FUELS STANDARD (LCFS) REGULATION: PRELIMINARY ANALYSIS OF GREENHOUSE GAS EMISSIONS FOR CNG AND LNG COMPARED TO EXISTING CALIFORNIA DIESEL AND LCFS DIESEL

Dear Mr. Vergara:

Sempra Energy has reviewed your preliminary analysis of the GHG emissions for CNG and LNG as compared to existing California diesel and LCFS diesel. Our comments in response to that analysis are attached.

We appreciate the opportunity to provide input on this important matter. Should you have any questions, please feel free to contact me or John Fooks at (619) 696-3006.

Yours sincerely,

Bernie Orozco

c: Dean Simeroth, Chief, Criteria Pollutants Branch

Sempra Energy Comments
Air Resources Board Comparison of Greenhouse Gas Emissions from Natural Gas and Diesel Vehicles
September 30, 2008

I. Introduction

Sempra Energy ("Sempra") appreciates the opportunity to provide comments on staff's recommended comparison of greenhouse gas (GHG) emissions from natural gas and diesel vehicles dated, September 9, 2008. We fully support CARB's efforts to develop a market based program to implement the Low Carbon Fuel Standard (LCFS). If properly developed and implemented, this market can deliver cost-effective measures for meeting the transportation sector's carbon reduction goals. In developing this new market, we encourage staff to construct a program which creates real competition by avoiding unnecessary rules and definitions to maximize available supply alternatives and leveling the playing field between alternative fuels and traditional petroleum based fuels. This can best be done by implementing policies which create market signals that incorporate the value of GHG emission reductions and the value of fuel diversity. Such policies will promote the introduction of readily available alternative fuels, and encourage the rapid development and deployment of the next generation technology.

CARB should recognize that natural gas streams cannot be separated in the local distribution company systems that serve California's natural gas needs. Sempra Energy also believes it is critical that comparisons such as those that have been offered by staff, reflect accurate data and an accurate analysis of that data; through these comments, Sempra Energy clarifies several areas in which staff's analysis falls short of these goals and should be revised. Success means moving California's transportation sector further and faster towards petroleum independence, lower carbon emissions and increased use of alternative fuels failure would result from the adoption of unnecessarily complex standards that fail to reflect accurate analysis of the natural gas sector and, as such stifle alternate fuel use in the transportation sector that would otherwise occur. .

II. The LCFS Must Be Implemented in a Simple, Straight-forward, and Achievable Manner

The number of NG pathways must be kept to a minimum, and retail quantification must be made relatively simple at the outset of the LCFS program. The fact that natural gas streams cannot be separated in the local distribution company systems that serve California's natural gas needs should result in a single upstream pathway for each utility (allowing for differences in compression/liquefaction at the fuel distribution site). Simplifying the number of NG pathways in this manner will simplify the quantification, recordkeeping and reporting. Such simplification will be necessary to staff, retailers, and system operators to focus on the development of a well functioning market. As the program moves ahead, CARB may, as staff has suggested, allow NG retailers and system operators to propose alternative and potentially more complex pathways and means of quantification to the extent operationally feasible. However, attempting to track every molecule throughout the system would not be physically possible and, as a result, would result in regulatory paralysis and unnecessary delays. Our companies are committed to helping CARB find the right balance between the almost infinite complexities of gas supply and system-wide quantification and identification of NG pathways that make sense and could result in feasible implementation of the LCFS as it pertains to natural gas use as a transportation fuel.

Unfortunately, we find staff's conclusions are based on assumptions that do not properly represent the NG sector. Through these comments, Sempra offers changes that would render this analysis far more representative of the NG sector. Failure to incorporate these very specific recommendations - which cover gas production, processing, transportation and delivery - unnecessarily elevate the Carbon Intensity (CI) of several proposed NG pathways and would eliminate or unnecessarily hinder alternate fuel use opportunities that should be pursued. With the adoption of the recommendations set forth herein staff will find many CNG and LNG pathways are relatively close in CI independent of where the gas is produced, how it was processed and from where it was delivered. This, in turn, eliminates any temptation to treat different streams of natural gas in the LDC or interstate transmission system differently for purposes of the LCFS, which, in any event, would not be feasible. As well, we question the value and probability of some of the NG pathways identified. While conceivable, the "CNG-Gulf" and "LNG-Baja" pathways as described in the document are highly unlikely and should be tabled for the time being. Instead, we recommend staff analyze carefully and incorporate the recommendations made by Sempra and look for ways to minimize the number of NG pathways, along with associated recordkeeping and reporting requirements.

III. Errors in Staff's Analysis Must be Corrected

The Air Resources Board's preliminary analysis of GHG emissions for CNG and LNG overstates many of the carbon intensities levels, resulting in values which are not representative of typical levels. We believe the corrected lifecycle analysis will demonstrate how a common GHG intensity value is appropriate for all natural gas supply. The following identifies areas of primary concern regarding this analysis.

A. Production & Processing

The total of the values shown for production and processing are consistent with the average intensities calculated for domestic gas production from publically available data. The values are not, however, representative of emission rates for LNG sourced natural gas. Most natural gas recovery activities and all gas processing associated with LNG feed gas occur at the liquefaction plant. LNG supply fields typically have substantially fewer production wells with significantly higher production rates than producing fields in the United States. For example it requires thousands of wells in the Barnett Shale (East Newark Field) to produce the same volume of gas as a dozen wells in Qatar. In addition the Barnett Shale wells are spread over nineteen counties and require an extensive network of gathering lines with associated production facilities. The Qatar wells are drilled from central platforms and delivered to the liquefaction plant through a subsea pipeline (1)(2). The recent Snohvit LNG project in Norway utilizes subsea wells and does not require any surface production facility (3). Available public information supports a GHG emission rate of 0.56 gCO_2e/MJ in lieu of 3.7 gCO_2e/MJ for the production segment for imported LNG (4)(5).

The emissions associated with the processing segment for imported LNG will be included in the liquefaction segment as these activities are fully integrated.

B. LNG Liquefaction Plant

The preliminary document included a GHG emission rate of 13 gCO_2e/MJ associated with the liquefaction segment. A review of publically available information for various LNG plants indicates a value of 7.32 gCO_2e/MJ would be more appropriate for this segment (4)(6)(7).

C. LNG Shipping

A typical gas boil-off rates and voyage times for LNG ships are 0.15% per day and 32 day roundtrip. The ships utilize all the boil-off gas as fuel for propulsion and utilities (8). This fuel consumption translates to an emission rate of 2.67 gCO_2e/MJ which is less than the 4 gCO_2e/MJ shown in the document.

D. LNG Regasification

LNG receiving terminals have fuel consumption rates ranging from 0.6% for open-rack vaporizers to 1.4% for submerged combustion vaporizers. Using an average fuel rate of 1.0% would generate an emission rate of 0.56 gCO_2e/MJ for the regasification segment compared to the 1.16 gCO_2e/MJ value shown in the document**.**

E. Natural Gas Transport (Transmission)

The document included five different paths for delivering natural gas to California for use as CNG fuel. The emission rates associated with the transport segment for most of these paths were overstated. The calculated values in the following table are based on fuel and fugitive emissions rates more fully described in Sempra's June 9, 2008 document (9)(10)(11)(12)(13). The Baja LNG terminal is located approximately the same distance from California markets as California based gas production sources.

Natural Gas Source	Transmission Distance (miles)	Carbon Intensity (gCO_2e/MJ)
NG Produced in California	75	0.38
NG Delivered from Baja Terminal	75	0.38
NG Produced in Midwest	800	4.32
NG Produced in Canada	1200	6.47
NG Delivered from Gulf Terminal	1200	6.47

F. Summary of Proposed Revision Impacts on Emission Estimates

Implementing the suggested revisions described in these comments would result in the following total upstream emissions rates compared to the preliminary values:

CNG Pathway	Original Upstream (gCO2e/MJ)	Revised Upstream (gCO2e/MJ)
NG Produced in California	11.02	11.18
NG Produced in Midwest	17.07	15.12
NG Produced in Canada	18.70	17.27
NG Delivered from Baja Terminal	30.35	14.39

As can be seen from the revised values, natural gas delivered as CNG transportation fuel has similar lifecycle greenhouse gas emissions for both North American produced natural gas and imported LNG and are substantially less than diesel. LNG trucked from Baja would also have a similar lifecycle GHG emission level (11.09 gCO_2e/MJ). And given the similarities of the values from all the sources would suggest a single value for each utility or a single value for the State for GHG emissions upstream from the fuel delivery site based on a weighted average of the sources in the utility's or State's portfolio.

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