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Clerk of the Board
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RE: Low Carbon Fuel Standard; Notice of Public Availability of Modified Text and Additional Documents issued July 19, 2009; Pathway for Liquefied Natural Gas (LNG) from North American and Remote Natural Gas Sources; Version 1.0 – July 20, 2009 ("LNG Pathway Document")

Sempra Energy appreciates this opportunity to offer comments in response to the notice of modified text of the Low Carbon Fuel Standard (LCFS) regulation issued July 20, 2009, and to identify revisions we believe should be made to the proposed pathways for LNG from North American and Remote Natural Gas Sources. Calculations and data included in the LNG Pathway Document provide the basis for certain values related to natural gas fuels that are contained in the Look-up Table (Table 6) of the revised regulation. Comments were solicited in the Notice concerning the LNG Pathway Document and other of additional supporting documents listed at page 5 of the Notice. The attached comments by Sempra Energy address the following areas:

<u>North American Sources (Attachment A)</u>

- Energy intensity and pipeline leak rate for pipeline transportation of natural gas to LNG plants in California
- Natural gas recovery efficiency
- Natural gas processing efficiency
- Vented CO2
- LNG truck transport distance

<u>Remote Sources (Attachment B)</u>

- Remote natural gas processing
- LNG ocean tanker transport distance
- LNG truck transport distance and natural gas pipeline distance from Baja to California
- Natural gas recovery efficiency and methane leakage rate

Sempra Energy is concerned that some values contained in the pathway document are cited as CA-GREET default and may not be adequately supported by information or data. We believe these "default values" should be subject to the same level of review as the proposals for replacement values. In at least some cases, there is sufficient publicly available information to warrant replacement. This will lead to more accurate emissions intensity values in the regulation Look-up Table. The majority of the comments related to North American Sources apply equally to the North American CNG pathway (Version 2.1 – February 28, 2009). Therefore, any revisions to the CA-GREET Model should be applied to both pathways to maintain consistency. Further, a value should be developed for a Remote LNG to CNG pathway and added to the Look-up Table, since this is a scenario that will likely occur.

These comments are based upon readily obtainable public information, and citations are offered to support every revision that is suggested herein. Sempra Energy is also available to answer any questions and/or to provide additional explanations and support for the revisions suggested in these comments.

Yours sincerely,

c: Mr. Dean Simeroth
Mr. Anil Prabhu
Mr. Floyd Vergara

Attachment A

Pathway for Liquefied Natural Gas (LNG) from North American and Remote Natural Gas Sources

Version 1.0 – July 20, 2009

Sempra Energy Comments – North American Natural Gas Sources

Appendix A1 (Scenario 1)

Section 3. Natural Gas Transportation and Distribution

3.1 Energy Use for NG Transport to LNG Plants in California

The pathway document utilizes values for energy intensity (405 Btu/ton-mile) and pipeline leak rate (0.08%) that are substantially understated and not supported by publically available information. Both of these values require revision to rectify errors made in their derivation(NA NG to CNG Pathway, Page 30)

Information is publicly available from the EIA and EPA that can be utilized to calculate the average fuel consumption rate and methane emissions rate for gas transportation in the US. Additional information from interstate gas pipelines must be used to adjust the average US rates to the specific situation described in the pathway document.

The energy intensity value utilized for the pipeline transportation equates to a fuel consumption rate of less than 1% for the 750-mile pipeline. This is far lower than the existing interstate pipelines serving Southern California. This understated value was primarily the result of assuming the pipeline required only a single compressor station. A review of actual operating pipelines would show a 750-mile pipeline requires multiple gas compressor stations for proper operation. Based on the published tariff data the 750-mile pipeline would have a fuel consumption rate of 3.0%. The energy intensity value used for pipeline transportation should be increased to 1654 Btu/ton-mile to be more reflective of actual pipelines.

The pathway document utilizes a fugitive methane emissions rate of 0.08% based on information from an AB 1007 analysis. That analysis incorrectly applied the methane leakage rate for the California utility pipeline system alone to represent the entire 750-mile pipeline. Based on publically available data, a more appropriate rate for the pipeline would be 0.53%, which is very similar to the original CA-GREET default value 0.56% before modification.

The following provides additional information regarding the derivation of appropriate values for energy intensity and fugitive methane emissions rate.

Information from the Kern River, Transwestern, and El Paso pipeline tariffs was evaluated to determine appropriate fuel consumption rates for natural gas transportation. [1,2,3]

Pipeline	2007 Volume, MMcfd[7]	Usage Rate	Distance, Miles	Usage Rate per 100 Miles
El Paso	1673	2.56%	450	0.57%
Transwestern	825	2.90%	450	0.64%
Kern River	1629	1.67%	600	0.28%

Weighted Average				0.47%

The tariff information generated a weighted average gas usage rate of 0.47% per 100 miles for natural gas transportation. Because this total usage rate addresses both natural gas consumed as fuel and fugitive methane emissions, the rate must be allocated between the two categories. Data from the EIA for 2006 was utilized to calculate the average fuel gas consumption rate for the US associated with natural gas transportation by pipeline.

2006 Gas Volume Data – EIA Natural Gas Annual 2007 – Table 1[4]
Pipeline & Distribution Fuel – 584,213 MMscf
Total Natural Gas Delivered to Consumers - 19,958,451 MMscf

The fuel gas consumption rate should be calculated by dividing pipeline and distribution fuel by the total natural gas delivered to consumers. Using the EIA 2006 actual gas volume data described above, the fuel gas consumption rate is 2.93% (584213 ÷ 19958451) for 2006.

The average fugitive methane emission rate for the US associated with natural gas transportation by pipeline should be calculated using the following EPA actual data for natural gas transmission in 2006:

2006 Fugitive Methane Data – Table 3-35, Page 3-45[5]
Transmission & Storage Fugitive Methane – 1,817 Gigagrams or 1,817,000 tonnes

In order to use this fugitive emissions data for transmission in the GREET model, it has to be converted to a gas volume equivalent. This conversion is calculated below:

Methane density - 23.654 Scf/lb or 0.05215 MMscf/tonne
1,817,000 tonnes * 0.05215 MMscf/tonne = 94,757 MMscf

The actual transmission fugitive emission rate should be calculated on the basis of the total fugitive emissions above (94,757 MMscf), by dividing these total fugitive emissions by the same total volume of natural gas delivered to consumers that has been used to calculate the transmission fuel gas consumption rate above. On this basis, the actual fugitive methane emission rate for natural gas transmission is 0.48% (94757 ÷ 19958451) for 2006

Now the US average rates derived above for fuel consumption and fugitive methane emissions can be utilized to allocate the gas usage rate between the two categories. The transmission fuel consumption is calculated by multiplying the total usage rate for gas transportation by the US average fuel consumption rate divided by the total of the US fuel consumption rate and US fugitive methane emission rate. The transmission fugitive methane rate is calculated in a similar manner. These calculations are set forth below:

Transmission fuel consumption - 0.47% * 2.93%/(2.93% + 0.48%) = 0.40% per 100 miles
Transmission fugitive methane - 0.47% * 0.48%/(2.93% + 0.48%) = 0.07% per 100 miles

The transmission fuel consumption rate must be converted to an energy intensity value for input in the GREET Model based on the parameters from the model set forth below. This should be done by multiplying the fuel consumption rate by the grams per ton by the natural gas lower heating value, divided by the product of natural gas density and 100 miles. This calculation is set forth below:

Natural Gas Lower Heating Value (LHV) – 930 Btu/Scf
Natural Gas Density – 20.40 grams/Scf
Fuel Consumption – 0.40% per 100 miles
907,200 grams per ton
0.40% * 907200 * 930 ÷ (20.40 * 100) = 1654 Btu/ton-mile

The pipeline leak rate calculated above of 0.07% per 100 miles is utilized to calculate the appropriate value for the gas transmission pipeline to the liquefaction plant in California. The fugitive methane leak rate for the 750-mile pipeline should be 0.53% (0.07 * 7.5).

Section 1. Natural Gas Recovery

1.1 Energy Use for Natural Gas Recovery
The pathway includes a recovery efficiency of 97.2% for NA natural gas based on the GREET default value. (Page 40). This value should be revised to reflect more current information.

All natural gas consumed (fuel, vented or flared) during the production operations would be included in the determination of recovery efficiency (total gas consumption). Dividing total natural gas consumed by the total produced gas volume gives the fuel consumption percentage. Because it is the most recent actual data available, the following data from the EIA for 2006 should be utilized to calculate the average fuel gas consumption rate for the US associated with natural gas production:

2006 Gas Volume Data – EIA Natural Gas Annual 2007 – Table 1[4]
Vented & Flared - 129,469 MMscf
Lease Fuel - 782,992 MMscf
Total Dry Production - 18,503,605 MMscf

The fuel gas consumption rate should be calculated by dividing the total of the lease fuel and vented & flared volume by total dry production. Therefore the fuel gas consumption rate is (129469 + 782992) ÷ 18503605 or 4.93% for 2006. The natural gas efficiency value can then be calculated by subtracting the fuel gas consumption rate from 100% as follows:

100% - 4.93% = 95.07%

The NA natural gas recovery efficiency in the pathway document and GREET Model should be revised to incorporate this 95.07% value.

Section 2. Natural Gas Processing

2.1 Energy Use for Natural Gas Processing

The pathway document includes a processing efficiency of 97.2% for NA natural gas based on the GREET default value (Page 40). . This value should be revised to reflect more current information from EIA for 2006 regarding the average fuel gas consumption rate for the US associated with natural gas production:

2006 Gas Volume Data – EIA Natural Gas Annual 2007 – Table 1[4]
Plant Fuel – 358,985 MMscf
Total Dry Production - 18,503,605 MMscf

The fuel gas consumption rate should then be calculated by dividing plant fuel by total dry production. Using the forgoing more recent data, the fuel gas consumption rate is 1.94% (358985 ÷ 18503605) for 2006. Using this fuel gas consumption rate, North American gas processing efficiency can be calculated by deducting this consumption rate from 100% as follows:

100% - 1.94% = 98.06%

The NA natural gas processing efficiency in the pathway document and GREET Model should be revised to incorporate the 98.06% value reflected in more recent data.

2.2 GHG Emissions from Natural Gas Processing

The pathway document includes an emissions rate of 1,237 gram CO2/MMBtu for vented CO2 associated with NA natural gas based on the GREET default value(NA NG to CNG, Page 27). This value should be revised to reflect more current information.

Any CO2 removed from natural gas and vented during the production or processing operations should be included in the determination of the vented CO2 rate. An accurate vented CO2 rate can be calculated by dividing total vented CO2 weight by the net energy content of natural gas produced. Produced gas volumes can then be converted to energy content using the average lower heating value. Source data for vented CO2 should be based on the Environmental Protection Agency's 2008 Inventory of Greenhouse Gas Emissions and Sinks and EIA data should be used as the basis for total dry production. The EPA and EIA data for 2006 necessary to calculate an accurate average vented CO2 rate for the US is set forth below:

2006 Vented CO2 – Table 3-37, Page 3-45[6]
Field Production - 7,203 Gigagrams (10^9 grams)
Processing – 21,204 Gigagrams (10^9 grams)

2006 Gas Volume Data – EIA Natural Gas Annual 2007 – Table 1[4]
Dry Production - 18,503,605 MMscf

On the basis of the forgoing, as well as the Lower Heating Value (LHV) of 930 Btu/Scf (930 MMBtu/MMscf) from the GREET Model, the vented CO2 rate for North American natural gas processing should be calculated as follows:

$(7203 + 21204) * 10^9 \div (18503605 * 930) = 1{,}653$ gram CO2 per MMBtu

The vented CO2 rate for NA natural gas processing in the pathway document and GREET Model should be revised to incorporate the 1653-gram CO2/MMBtu value reflected above.

Section 5. LNG Transport, Distribution and Storage

5.2 LNG Truck Transport Energy Consumption

The pathway document includes a distance of 50 miles for the LNG truck transport from the liquefaction plant in California to the LNG station. Existing plants that liquefy pipeline gas are located near the California border or outside Los Angeles. A value of 100 to 150 miles would be more appropriate for the typical distance for trucked LNG.

References

[1]Kern River Pipeline - http://www.kernrivergas.com/InternetPortal/FrontDesktop.aspx?

[2]Transwestern Pipeline - https://twtransfer.energytransfer.com/index.jsp?companyName=TW&pg=IP&frames=none

[3]El Paso Pipeline - http://passportebb.elpaso.com/ebbEPG/ebbmain.asp?sPipelineCode=EPNG

[4]Energy Information Administration / Natural Gas Annual 2007, Table 1. Summary Statistics for Natural Gas in the United States, 2003-2007; http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html

[5]Environmental Protection Agency 2008 Inventory of Greenhouse Gas Emissions and Sinks, 2006 Fugitive Methane - Table 3-35, Page 3-45

[6]Environmental Protection Agency 2008 Inventory of Greenhouse Gas Emissions and Sinks, 2006 Vented CO2 - Table 3-37, Page 3-45

Attachment B

Pathway for Liquefied Natural Gas (LNG) from North American and Remote Natural Gas Sources

Version 1.0 – July 20, 2009

Sempra Energy Comments – Remote Natural Gas Sources

Appendix A2 (Scenario 2) & Appendix A3 (Scenario 3)

<u>Section 1. Remote Natural Gas Recovery, Processing and Transport to LNG Plant</u>

1.1 <u>Remote Natural Gas Recovery and Processing</u>

<u>Natural Gas Processing</u>

The two scenarios for imported LNG both include separate GHG emissions associated with natural gas processing (Table A, Page 5). Information provided in a document entitled "Liquefied Natural Gas: Understanding the Basic Facts" from the Department of Energy (1) clearly demonstrates there is no separate Natural Gas Processing segment associated with the delivery of imported LNG. In particular, Figure 10 on Page 11 shows how all the gas treating and processing components are included at the LNG liquefaction plant. Including separate natural gas processing emissions results in a double counting of combustion and fugitive methane emissions. In addition, the Tamura et al report (2) and EIS studies for Pluto (3), Gorgon (4) and Snohvit (5) further support that natural gas processing activities occur at the LNG liquefaction plant.

CO2 contained within the produced natural gas is actually removed and vented (or sequestered) at the LNG liquefaction plant as shown by the information sources cited above

Based on the above, the energy use and all associated emissions (other than vented CO2) should be revised to zero for the natural gas processing associated with imported LNG.(Pages 21 & 35).

<u>Section 3. LNG Transport to California, Distribution, Re-Gasification, Transport and Storage Within California</u>

<u>3.1 LNG Transportation via Ocean Tanker</u>

Table 3.01 includes a distance of 8,769 miles between the LNG source in Southeast Asia and the LNG terminal in Baja Mexico. Southeast Asia is more representative of an LNG market than a supply region and is a further distance from Baja Mexico than likely LNG supply sources. The two primary sources of LNG for the Baja Mexico LNG terminal are Tangguh, Indonesia and Sakhalin, Russia. The average shipping distance to Baja Mexico for these two supply sources is 5,773 nautical miles. This is a more appropriate value to utilize in the pathway calculation.

The shipping distances were estimated using an online shipping calculator tool (6) and the following port locations:

Tangguh – Sorong, Indonesia

Sakhalin – Vladivostok, Russia

Baja – Ensenada, México

3.2 LNG Transportation and Storage from Baja, to California (Scenario 3)

The pathway document includes a distance of 250 miles the LNG truck transport from Baja, Mexico to California (Page 41) The actual distance from the Baja, Mexico LNG terminal to primary California markets is much shorter with 150 miles being a more appropriate average value for calculating emissions.

3.3 Pipeline Transport to California under Scenario 2

The pathway document includes a distance of 250 miles for transporting natural gas by pipeline from Baja, Mexico to California. (Page 28). The actual distance from the Baja, Mexico LNG terminal to primary California markets is much shorter with 150 miles being a more appropriate average value for calculating emissions.

Section 1. Remote Natural Gas Recovery, Processing and Transport to LNG Plant

1.1 Remote Natural Gas Recovery and Processing

Natural Gas Recovery

The pathway document utilizes values for natural gas recovery efficiency (97.2%) and natural gas leak rate (0.35%) based on the CA-GREET default values (Page 40). The derivation of these default values is not adequately supported and should be replaced by values developed based on publicly available information. Past studies and recent project environmental reports provide sufficient information to support more appropriate values. Based on this information we would recommend values of 99% for the natural gas recovery efficiency and 0% for the natural gas leak rate, as further explained below.

The following provides additional information regarding the derivation of replacement values recovery efficiency and leakage rate associated with natural gas recovery.

Natural Gas Recovery Efficiency

Tamura Study

A study conducted by Tamura et al (2) included GHG emissions data from a survey of five LNG supply projects. The following represents the average emission rate from gas combustion for the production segment. The average includes data from the four countries (Indonesia, Malaysia, Brunei & Australia) with data available.

Table 1 – Page 307

CO_2 from fuel consumption – 0.15 gram-carbon/MJ
CO_2 from flare combustion – 0.04 gram-carbon/MJ
Total CO_2 from combustion – 0.19 gram-carbon/MJ

gram-CO_2/gram-carbon = 44.01/12.0107 = 3.6642
Average LNG – 50.71 gram-CO_2/MJ (Appendix A composition)

Equivalent fuel consumption = (0.19 * 3.6642)/50.71 = 0.0137 = 1.37%

Therefore average fuel usage rate for gas production associated with LNG projects in Tamura et al study was 1.37%

Pluto PER
The Draft Public Environmental Report/Public Environmental Review for the Pluto LNG Project (3) included the following emissions estimate for the offshore production facilities related to combustion.

Table 5-3, Page 63 (Post Offshore Compression)
Power Generation – 21700 tonnes CO2e
Flaring & Venting – 2400 tonnes CO2e
Transport – 3200 tonnes CO2e
Compression – 265600 tonnes CO2e
Fire Water – 20 tonnes CO2e
Total Combustion Emissions – 292920 tonnes CO2e

Project LNG output rate is 11.8 million tonnes per year during the Post Offshore Compression phase (Chapter 4, Page 25)
Therefore the project emission rate is 0.0248 tonne CO2 per tonne LNG (292920/11800000) or 0.0248 lb CO2 per lb LNG

Average LNG – 2.758 lb CO2/lb LNG

Equivalent fuel consumption = 0.0248/2.758 = 0.0090 = 0.90%

Therefore the projected fuel usage rate for the Pluto project gas production segment is 0.90%

Gorgon EIS
Gorgon LNG Project Draft Environmental Impact Statement/Environmental Review and Management Plan for the Gorgon LNG Project (4) states on Page 616 that subsea developments such as Gorgon & Snohvit have essentially no greenhouse gas emissions associated with the Production segment.

Typical LNG projects require significantly fewer wells in a smaller area than US production. Information for RasGas 3 & 4 LNG projects (5) states only 33 wells, 3 platforms and two pipelines are required to deliver 2.8 Bcfd of feed gas for the Qatargas 3 and Qatargas 4 LNG projects. This indicates an average well production rate of 84 MMcfd. Barnett Shale data (6) shows an average well rate of only ~ 0.4 MMcfd with production spread over nineteen counties.

The Snohvit LNG project in Norway utilizes subsea wells and does not require any surface production facility (5)

The above information supports an average fuel consumption rate for the production segment of 1.0%. Therefore the natural gas recovery efficiency value for imported LNG would be 99% (100% - 1%).

Natural Gas Recovery Methane Leakage Rate

The Tamura study (2) included production fugitive methane emission survey data for four countries (Indonesia, Malaysia, Brunei & Australia). The average emission rate is as follows:

Table 1 – Page 307
CH_4 from vent – 0.06 gram-carbon/MJ

gram-CO_2/gram-carbon = 44.01/12.0107 = 3.6642
gram-CO_2/MJ = 2.326 lb CO_2/MMBtu

CH_4 from vent – 0.06 * 3.6642 * 2.326 = 0.51 lb CO_2e/MMBtu

Methane emissions are equivalent to 879 lb CO_2e/MMBtu

Equivalent fugitive methane rate = 0.51/879 = 0.06%

Therefore average fugitive methane rate for gas production associated with LNG projects in Tamura et al study was 0.06%.

Pluto PER
The Draft Public Environmental Report/Public Environmental Review for the Pluto LNG Project (3) included the following fugitive methane emissions estimate for the offshore production facilities.

Table 5-3, Page 63 (Post Offshore Compression)
Power Generation – 2300 tonnes CO_2e

Project LNG output rate is 11.8 million tonnes per year during the Post Offshore Compression phase (Chapter 4, Page 25)

Therefore, the project emission rate is 0.00019 tonne CO_2e per tonne LNG (2300/11800000) or 0.00019 lb CO_2e per lb LNG

Based on a methane intensity factor of 21 the fugitive methane rate would be 0.00019/21 or 0.0009%.

Therefore the projected fugitive methane rate for the Pluto project gas production segment is 0.0009%.

Gorgon EIS
Gorgon LNG Project Draft Environmental Impact Statement/Environmental Review and Management Plan for the Gorgon LNG Project (4) states on Page 616 that subsea developments such as Gorgon & Snohvit have essentially no greenhouse gas emissions associated with the Production segment.

Typical LNG projects require significantly fewer wells in a smaller area than US production. Information for RasGas 3 & 4 LNG projects (7) states only 33 wells, 3 platforms and two pipelines are required to deliver 2.8 Bcfd of feed gas for the Qatargas 3 and Qatargas 4 LNG projects. These type developments should have very low fugitive methane emission rates due to the low number of producing wells and associated equipment. In contrast, Barnett Shale data (8) shows an average well rate of only ~ 0.4 MMcfd with production spread over nineteen counties.

Based on the above information the fugitive methane emissions rate for the production segment of LNG projects should be negligible and set to 0.03%.

References:

(1) Liquefied Natural Gas: Understanding the Basic Facts, US Dept of Energy; http://fossil.energy.gov/programs/oilgas/publications/lng/LNG_primerupd.pdf

(2) Life cycle CO2 analysis of LNG and city gas; Itaru Tamura, Toshihide Tanaka, Toshimasa Kagajo, Shigeru Kuwabara, Tomoyuki Yoshioka, Takahiro Nagata, Kazuhiro Kurahashi, Hisashi Ishitani. Applied Energy 68 (2001) 301±31

(3) Pluto LNG Project, Draft Public Environmental Report/Public Environmental Review, Chapter 5, Table 5-2, 5-3 & 5-4

(4) Gorgon LNG Project, Draft Environmental Impact Statement/Environmental Review and Management Plan; http://www.gorgon.com.au/03moe_eis.html#frames(content=03moe_eis_body.html)

(5) Snohvit LNG Environmental Impact Assessment - http://www.snohvit.com/STATOILCOM/snohvit/svg02699.nsf?opendatabase&lang=en&artid=91351D138007671AC1256C45003EF89D

(6) Eship – “Sea Distances – Voyage Calculator”; http://www.e-ships.net/dist.htm

(7) Number of Qatar wells and platforms for two projects - http://www.qatargas.com/Projects.aspx?id=132&tmp=76

(8) Barnett Shale Statistics - http://www.rrc.state.tx.us/divisions/og/statistics/fielddata/barnettshale.pdf