# California Natural Gas Vehicle Coalition

October 31, 2008



California Energy Commission
Dockets Office, MS-4
Re: Docket No. 08-ALT-1
1516 Ninth Street
Sacramento, CA 95814-5512

RE: AB 118 Program, Docket No. 08-ALT-1

On behalf of the California Natural Gas Vehicle Coalition, enclosed are four documents from the Coalition and two of our member organizations, Clean Energy Fuels and Sempra Energy. The fifth document, submitted to the ARB by TIAX, was prepared at the request of Clean Energy. It analyzes the ARB's comparison of greenhouse gas emissions from natural gas and diesel vehicles. All of these documents have been submitted to the docket electronically.

These documents were originally submitted to the Air Resources Board as comments on the proposed Low Carbon Fuel Standard, but they also are relevant to the CEC's development of its AB 118 Investment Plan.

Sincerely,

PETE PRICE
Price Consulting
1029 K Street, Suite 24
Sacramento, CA 95814

Enclosures

California
Natural Gas Vehicle
Coalition

September 30, 2008

Mr. Floyd Vergara, Esq., P.E.
Manager, Industrial Section
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: GHG Emissions Analysis -- Natural Gas vs. Diesel

Dear Mr. Vergara:

The California Natural Gas Vehicle Coalition (CNGVC) appreciates the opportunity to comment on the ARB's preliminary analysis of the GHG emissions for CNG and LNG compared to existing California diesel and LCFS diesel. It is encouraging to see that even in its draft form; this analysis corroborates our confidence in natural gas as a clean transportation fuel:

- Compared to existing diesel, all five CNG pathways and two out of three LNG pathways have lower GHG emissions when used in light-duty vehicles, with reductions as great as 29+%. In the heavy-duty sector, four out of five CNG pathways and two out of three LNG pathways have lower GHG emissions.

- Even when compared with a projected LCFS diesel with 10% GHG emission reduction, three out of five CNG pathways for light-duty vehicles, and the same two LNG pathways, maintain lower emissions. For heavy-duty vehicles, only one of the five CNG pathways moves to a net increase in emissions.

The analysis does, however, raise a number of concerns which, if addressed, will give the ARB a much more credible basis upon which to determine the value of CNG and LNG as low-GHG transportation fuels. We believe that analysis will show even greater opportunities for CNG and LNG to reduce GHG emissions from the transportation sector.

**Analysis uses unrealistic natural gas pathways.**

1) None of the LNG pathways identified in the analysis (Canadian gas piped to California and liquefied; LNG shipped to Baja and piped to California; LNG shipped to southern California) are currently used to supply LNG to California. Even if LNG eventually is imported to the west coast, which is speculative and far from certain, we do not believe it will be used as a transportation fuel.

2) The CNG-Gulf (LNG shipped to gulf coast port, gasified and piped to California) and CNG-Canada (natural gas piped from Canada to California) pathways also do not reflect current or anticipated practice. California does not pull gas from Canada or the Gulf, and given the growing economic supplies of natural gas throughout much of the United States it is unlikely we will do so in the time frame of the analysis.

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**Analysis ignores likely and promising natural gas pathways.**

1) CNG-Rocky Mountains: Unlike the pathways cited above, CNG from the Rocky Mountains is currently being piped to California, where it is liquefied for the LNG market. Clean Energy, a member of the CNGVC, operates a plant in Boron, CA that receives pipeline gas for LNG production. Another plant in Arizona receives piped gas from west Texas for conversion to LNG.

2) Biomethane: The capture and conversion of methane from landfills, dairies, and wastewater treatment plants present a much more likely scenario for future growth in natural gas transportation fuels, and the GHG emission analysis on this pathway will be outstanding regardless of the source of the gas. There is a significant opportunity to process biomethane and use it in on-site vehicles or add it to the state's natural gas pipeline grid. Even biomethane produced at a significant distance would yield very good emission results and could be transported to California via pipeline. For example, Clean Energy recently purchased a landfill in Dallas, TX for the express purpose of producing up 20,000 GGE/day of pipeline-grade biomethane.

As the ARB knows, a well-to-wheels pathway analysis of biomethane has been conducted for the ARB and CEC by TIAX. The TIAX document has not been made available, despite repeated requests by members of the Coalition at various LCFS meetings. It is important that the results of this analysis be released to the public and be incorporated into the LCFS consideration of natural gas as a transportation fuel.

**LCFS diesel pathway is speculative and vague.**

The analysis uses a "generalized diesel pathway," but provides no details on the sources of the petroleum used to produce the diesel fuel. For example, are the values assigned to various segments of a well-to-wheels analysis of diesel fuel based on the sources of current petroleum supplies? Does the diesel pathway account for anticipated changes in supply sources in the future?

The values for LCFS diesel are simply a straight-line 10% reduction in carbon intensity from current California diesel. Does this mean the ARB has analyzed the likely production of LCFS fuel and concluded there will be no changes in any of the segments for LCFS diesel compared to California diesel?

The ARB appears to favor a compliance path for LCFS diesel that will allow refiners to make only minimal reductions in carbon intensity for most of the period leading up to the 2020 deadline. We believe this approach is a recipe for failure and makes the 10% carbon intensity reduction in LCFS diesel all the more speculative. The fact is that various CNG and LNG pathways show significant GHG emission reductions compared to California diesel, and even ultra-low GHG emission biomethane is currently being produced and is expected to grow substantially by 2020. Conversely, no LCFS diesel exists or is expected to exist, even in the best of worlds, before 2018. Whether it is available in 2020 remains more a hope than an expectation.

In summary, the CNGVC urges the ARB to delete specific pathways that are not relevant to California's transportation fuels market and to add biomethane and other relevant pathways to the

analysis. Given the ready availability of natural gas in various pathways that results in significant GHG emission reductions, and the unavailability and speculative nature of LCFS diesel, we also urge the ARB to recognize and account for these reliability factors in the final draft of the analysis. Finally, we hope the ARB will make it clear that this "preliminary analysis" is a draft document that will be posted for full public comment before a final document is released.

Thank you for your consideration of our views. Please do not hesitate to contact me at (916) 448-1015 or pete@pricecon.com if you wish to discuss this matter further.

Sincerely,

Pete Price
Governmental Affairs Representative

cc: Mr. William Zobel, President, CNGVC

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Todd R. Campbell, MEM, MPP
Director of Public Policy

Clean Energy

September 29, 2008

Mr. Floyd Vergara, Esq., P.E.
Manager, Industrial Section
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Clean Energy's Comments on CARB's Draft Comparison of Greenhouse Gas Emissions from Natural Gas and Diesel Vehicles.

Dear Mr. Vergara:

Thank you for allowing the public to comment on the California Air Resources Board's (CARB) draft comparison of greenhouse gas emissions from natural gas and diesel vehicles (noted as "Comparison Document" herein).

Clean Energy has several comments and serious concerns pertaining to this document, including a complaint on process. This document appears to have been created August 10, 2008, distributed to a limited set of stakeholders on September 9, 2008 and does not appear to have been made publicly available. The document was not provided to Clean Energy despite the fact that we have previously submitted comments to CARB's Low Carbon Fuel Working Group. Clean Energy received no notification that this document was open for public comment from CARB. Further, as of September 19, this document could not be located on CARB's website nor is it marked "draft". Clean Energy only became aware of this draft document comparing natural gas vehicles to diesel vehicles from our colleagues in the industry. This lack of public process is both discouraging and troubling and we hope that future opportunities to comment on CARB's low carbon fuel evaluation efforts will be more open and transparent in the future. Finally, this document should be marked "draft" as it contains numerous assumptions that are subject to change and omissions that we believe must be corrected in order to achieve CARB's goals and the development of low carbon fuels. We view the current version of this document to be fatally flawed and it must be corrected before it is finalized or it may seriously impair the development of and utilization of viable low carbon fuels in the State of California.

The following are comments that we urge CARB staff to consider when they modify and update this comparison document:

First, it is very hard for anyone to adequately review, verify or question several values presented within the Comparison Document as pathways, methods and assumptions are not sourced, explained, or described. Here are a few examples:


- What assumptions and values were used to determine each pathway (LNG, CNG, CARB Diesel, and Low Carbon Diesel Pathway) presented in the Comparison Document?

    - The pathways that CARB published in April had detailed documentation on the assumptions used in the calculations. None of the assumptions are noted in the recent report. As noted in the current document, CARB has made many changes to previous assumptions but the changes are not noted.

    - Table 3 represents the first time that the industry has seen a pathway for LNG and the assumptions are not obvious. Liquefaction has two different carbon intensity values depending upon whether the LNG is liquefied off-shore or in Southern California. One needs to see the underlying assumptions before the industry can evaluate the results and their significance. We note that all of the LNG utilized in transportation in Southern California has historically been, and will for the foreseeable future continue to be, North American in origin. Utilizing foreign LNG sources to conduct this analysis is potentially very misleading.

- What assumptions and values are used in the "generalized diesel pathway" and how does this pathway vary from other diesel pathways that CARB has considered or developed?

    - In the ULSD pathway published by CARB in April, diesel had overall Wells-To-Wheels ("WTW") Greenhouse Gas ("GHG") emissions of 99.4 gmCO2e/MJ – now CARB is reporting a range of 95.9 – 96.8. What changed regarding diesel? In the April pathway, vehicle CH4 and NO2 emissions from combustion were noted as 5.2 gmCO2/MJ -- - whereas the current report says these are now zero. Please explain the basis for changing these numbers.

- Has CARB performed a "generalized CNG pathway" or a "generalized LNG pathway"? We note that there have been increases in the WTW pathway emissions for CNG – but these haven't been explained. CARB needs to publish a formal LNG pathway to reflect the same detail as was published in the April pathway reports.

    - Instead of publishing separate pathways for each fuel – then doing separate reports on the impact of vehicles, CARB has chosen to combine pathways with vehicle emissions as though they are absolute. TIAX in their AB1007 report for the California Energy Commission (CEC) made a similar mistake in combining the pathways with end-use emissions. The results are not reflective of reality or supported by facts. In the final TIAX report, the end-use emissions were reflective of the potential ratio of off-shore LNG to North American natural gas in California. CARB should use this same approach. If there was a demand for imported LNG in California – one would certainly not bring LNG into Gulf ports then

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try to cram it into a nearly full pipeline to California. ***If LNG is ever brought into California and put in the pipeline system – the GHG emissions will only be impacted by the ratio of North American gas to LNG gas – and not the full penalty subscribed to the entire pathway analysis. Moreover, it is extremely unlikely that any imported LNG will be used in transportation in California at any point in the foreseeable future given current market realities – a critical fact that is glaringly absent from the Comparison Document analysis.***

- Westport Innovations and Clean Energy commissioned TIAX earlier this year to do a Wells-To-Wheels assessment of LNG produced at Clean Energy's Boron plant and used in the Westport/Kenworth trucks at the Ports of Long Beach and Los Angeles. That assessment which modeled the performance of the Boron liquefaction plant and in-use emission of trucks showed that LNG reduced GHG emissions by 20% as compared to diesel trucks. The current CARB document we are reviewing says those GHG emission reductions would only be about 6% (using pathway #7 in the report). We respectfully believe that CARB's numbers are wrong –and in order to understand the discrepancy we must be provided the assumptions that were made by CARB in conducting their assessment.

- Why did CARB fail to consider a pathway that reflects the use of biomethane from landfills, dairy farms, or sanitation facilities? The NGV industry has been asking for this pathway assessment since the beginning of the year. We understand the study was completed by TIAX for the CEC (and CARB) in April, and still the report has not been released. Use of renewable natural gas as a transportation fuel would certainly have the impact of further reducing GHG emissions for NGVs. At Clean Energy we have recently invested in a landfill gas production facility that is currently producing substantial volumes of pipeline quality biomethane and has the potential of fueling thousands of vehicles, including heavy duty vehicles, daily with 100% renewable biomethane that reduces carbon emissions by 100% or more. This is not ten years away, or even two years away – it is happening today. Surely this is worth examination in the CARB report.

- What does "low carbon diesel" or "LCFS diesel" actually refer to in the Comparison Document? Does LCFS diesel fuel actually exist and, if so, why would the Petroleum Industry advocate for a delayed linear compliance pathway that only begins to achieve the 10% carbon reduction in years 2018-2020? If LCFS diesel does not currently exist, what is the purpose of this comparison? Further, why is biomethane, a fuel that does exist, not analyzed in the Comparison Document? Are there any scientific studies that demonstrate the carbon reduction that can be achieved through "low carbon diesel" – or does the analysis simply assume that a "low carbon diesel" will actually be produced and commercially available? It seems potentially very misleading to present data on a fuel that is not currently produced or commercially available in any quantities at present, particularly when the industry responsible for producing such a fuel has indicated that their ability

to achieve a 10% carbon reduction in diesel is at least 10 years away. As you are all too aware, California cannot wait that long for such minimal results in carbon reduction.

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Second, we are also very concerned that none of the three LNG pathways represent how LNG will arrive at an LNG fueling pump in California. California does not import any LNG from overseas to meet its current natural gas demand nor will imported LNG be used to power LNG vehicles in the State of California. In fact, the only natural gas that is imported from overseas is limited to the Eastern seaboard where access to domestic natural gas supplies is constrained in certain areas. All other LNG terminals for the country are either mothballed or currently applying to become export terminals as the price of natural gas on the world market is significantly higher than what natural gas sells for here in the United States. This is largely due to the abundance of North American natural gas, complimented by recent findings of additional natural gas shale throughout the country. Advancements in technology now allow American gas producers, like Chesapeake and XTO, to capture this new natural gas resource, resulting in practically a doubling of natural gas supply.

Specifically, Clean Energy California, which is located in Boron, California, will pull its natural gas from the Colorado Rocky Mountains. Spectrum Energy Services, located in Ehrenberg, Arizona, will pull its natural gas from the Permian Basin in West Texas. Neither of these LNG producing facilities that intend to fuel California-based vehicles will draw their gas from any potential LNG import facilities nor could they as there are no pipelines that directly connect to LNG import terminals. Both terminals, however, could draw upon Clean Energy's recently acquired Dallas Clean Energy Landfill that has the capability of producing 20,000 gasoline gallon equivalents per day of pipeline quality biomethane. We therefore urge CARB to remove all three LNG pathways, as they are irrelevant and will never be utilized, and replace them with LNG producing pathways that actually reflect the reality of the marketplace. Further, we also request that CARB perform additional pathways that reflect biomethane benefits for both CNG and LNG pathways. Anything short of this would damage the LNG Fueling Industry, mislead the public as to the true benefits of LNG-powered vehicles, and quite possibly seriously and adversely impact CARB's own goal to reduce the carbon intensity in vehicle fuels.

Third, Clean Energy urges CARB to remove the two CNG pathways that draw on Canada and the Gulf from the Comparison Document as they do not reflect reality. California does not currently draw natural gas from Canada or the Gulf. According to a June 2008 study by Navigant Consulting, North American has at least a 120-year supply of natural gas – contradicting the notion that America is running out. And as the technology comes on line to develop large reserves that five years ago weren't possible to develop, that supply is growing. "The assessments and estimates on natural gas supply are very impressive and have, frankly, caught industry forecasters off guard," shared Rick Smead, one of the study's co-authors and overall project manager for Navigant Consulting. The study found that while all three unconventional gas sources have increased production over the past decade, natural gas production from shale formations is growing exponentially, increasing from less than a billion cubic feet a day in 1998, to about 5 billion cubic feet a day now. That's a compound annual rate of growth of over 20%, which is over 600% for the time period. There are at least 22 shale basins located onshore in more than 20 states in the U.S. including Texas, Oklahoma, Arkansas, Louisiana, West Virginia, Wyoming, Colorado, New Mexico, West Virginia, Pennsylvania, New York and Michigan. In conclusion,

American producers can clearly supply enough natural gas to meet today's uses and become an economical source of transportation fuel in the form of CNG or greater supplies of electricity for plug-in hybrids for generations to come.

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Fourth, Clean Energy is aware that CARB has performed WTW analysis for biomethane as early as April of this year with TIAX. Clean Energy is very curious as to why this analysis has yet to become public or incorporated into the Low Carbon Fuel Standard (LCFS) analysis. It would seem only fair to include this analysis, particularly for CNG and LNG applications, as the natural gas fueling industry will and already has acquired facilities for this exact purpose. Why has CARB performed WTW analysis for all other renewable biofuels other than what is perhaps the best biofuel in terms of GHG emissions reductions for motor vehicles: biomethane? We find that odd, irresponsible, and an action that could damage the CNG and LNG fueling industry. Clean Energy urges CARB to complete its natural gas v. diesel vehicle comparison with the inclusion of biomethane pathways for all CNG and LNG pathways. As the abundant natural gas supplies being developed in North America continue to bring down prices for natural gas, it is critical to demonstrate the GHG reduction value of utilizing biomethane as a transportation fuel in order to sustain investment in biomethane projects.

For the purpose of the LCFS it is important that CARB publish separate comprehensive fuel pathway reports for fuels and not try to combine the pathways with in-use emission modeling. The mix of fuel in the market (e.g. percent off-shore LNG to North American natural gas) can then be calculated in exactly the same way that CARB calculated the carbon content of RFG by using a ratio of 10% ethanol to 90% CARBOB. Had CARB used this approach in their current assessment of CNG and LNG, it would not have erroneously concluded that the carbon-intensity of imported LNG prevents NGVs from obtaining the LCFS, as natural gas imported from overseas will not constitute any of the LNG or CNG used for transportation in the State of California.

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Once the pathways are properly documented, CARB should publish guidelines on how to properly use the data to address a mix of CNG and LNG fuels that can consist of North American natural gas and renewable natural gas. Then conducting the in-use emissions modeling will give the correct assessment of natural gas as a transportation fuel.

In conclusion, the Comparison Document requires substantial disclosure for evaluation purposes, correction in accuracy for its proposed pathways, and inclusion of critical values that demonstrate CNG and LNG fuel pathways fairly and accurately. If done correctly, Clean Energy believes both CNG and LNG can demonstrate clear reductions of greenhouse gas emissions when compared to CARB diesel and forecasted fuels that are not currently in the marketplace like LCFS diesel. Failure to revise the Comparison Document as proposed will undeniably harm the public and the natural gas fueling industry as well as misrepresent the true benefits of utilizing domestic natural gas as a vehicle fuel to the public and both current and future customers. Understating the GHG reduction benefits of utilizing natural gas as a transportation fuel will result in continuing dependence on petroleum fuels and seriously impair California's ambitious goals with respect to GHG reductions and the expansion of alternative fuels. Quite frankly, we believe that utilizing domestic natural gas and biomethane in transportation is the single best way to achieve substantial GHG reductions in the transportation section utilizing available technology and resources and that a thorough and complete study based on actual market realities will support this conclusion. CARB's apparent failure to utilize appropriate inputs for LNG sourcing, disregard of biomethane production, and inclusion of a hypothetical petroleum based fuel (Low Carbon Diesel) that could be a decade from commercial production and achieves only a 10% carbon reduction constitutes a total abdication of CARB's responsibility to the citizens of the State of California. Liquified biomethane can be utilized today (not in a decade) to fuel heavy duty vehicles while reducing GHG emissions by 100% or more, not 10%. We can't afford to wait 10 years to achieve 10% reductions in GHG, particularly when the technology is currently available to do so much more.

We request that CARB (1) disclose the values and assumptions used to justify each pathway analysis it provides in the Comparison Document, (2) re-draft the pathways to reflect real conditions of the market for CNG and LNG (in particular the source of CNG and LNG used in transportation), (3) include biomethane pathways (which serve as natural gas' renewable pathway) in its Comparison Document analysis and (4) schedule a face-to-face meeting to discuss these items in full. Finally, we also question the inclusion of LCFS diesel in the Comparison Document as the regulation doesn't call for such a comparison, nor is it clear if such a fuel will ever exist in the marketplace. We look forward to your response.

Sincerely,

Todd R. Campbell
Director of Public Policy

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October 6, 2008

Mr. Dean C. Simeroth
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Stationary Source Division
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Sacramento, CA 95812

Re: Meeting on CARB's Comparison Document of Natural Gas vs. Diesel (August 10, 2008)

Dear Mr. Simeroth:

Clean Energy would like to thank you and your staff for your collective time spent with us to discuss the draft Comparison Document, dated August 10, 2008, estimating the lifecycle greenhouse gas emissions of natural gas and diesel as a transportation fuel. During this meeting, Clean Energy staff and our consultants gained a better understanding of CARB's approach in drafting this preliminary document and we have collectively identified areas within the analysis where we can help CARB staff refine its analysis to better reflect our industry's current and future operations.

You have asked us to identify pathways that would best reflect the operations of both compressed natural gas (CNG) and liquefied natural gas (LNG) vehicle fueling for the natural gas vehicle industry. Based on our knowledge and experience in the industry, we recommend that CARB incorporate the following CNG pathways for the final document:

(1) CNG (using Canada as a source);
(2) CNG (using the Rocky Mountains as a source)
(3) CNG (using the Permian Basin/San Juan as a source)
(4) CNG (using California landfill gas)
(5) CNG (using out-of-state landfill gas)
(6) CNG (using remote LNG shipped to Baja, re-gasified, pipelined to CA, then compressed).


We also recommend that CARB incorporate six LNG pathways to be analyzed for the final document:

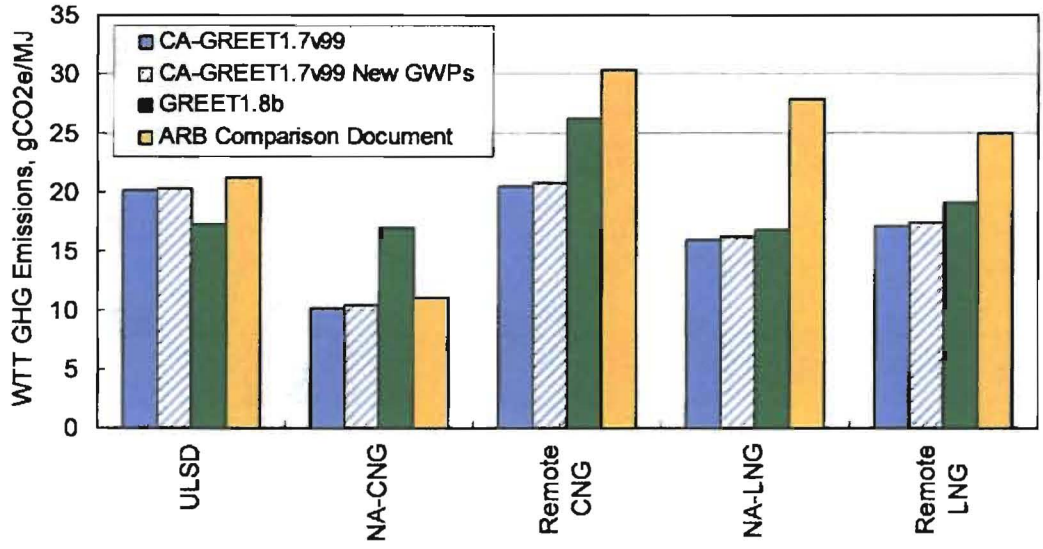
(1) LNG (using Canada as a source);
(2) LNG (using the Rocky Mountains as a source);
(3) LNG (using the Permian Basin/San Juan as a source);
(4) LNG (using California landfill gas)
(5) LNG (using out-of-state landfill gas); and,
(6) LNG (using remote LNG shipped to Baja as a source and trucked to the station).

Clean Energy believes that the first five CNG and LNG pathways recommended above are the most reflective of the natural gas vehicle industry today and will continue to be well into the future. We continue to submit that Option 6 (Baja) for LNG is an unlikely LNG pathway for vehicle refueling as the country is flush with natural gas (new natural gas shale discoveries in North America are projected to extend proven natural gas reserves from 83 to 120 years, increased renewable portfolios should displace natural gas use in power generation, and the rise of biomethane use provides additional resources) and existing LNG production facilities for vehicles are not physically connected to the Baja terminal's pipelines. That said, we have included it based on CARB staff's desire to be thorough in its analysis and to cover the unexpected. We strongly recommend that CARB alter the mechanics of Option 6 in that we believe any LNG fuel purchased by Clean Energy from the Baja import terminal would be trucked directly to fueling stations, not gasified into existing pipelines and then re-liquefied at a California-based LNG production facility. Such an operational practice would be pre-empted by economics and presumably an increasingly tightened low carbon fuel standard by CARB over time.

Clean Energy would like to reiterate the critical importance of displaying the recommended pathways in the final document over the pathways drafted in the current CARB document. For example, the current document contains pathways that are not reflective of how the LNG industry currently operates or plans to produce vehicle fuel. While we appreciate CARB's efforts to provide a model that will allow each fuel provider to calculate the carbon intensity of its product using its own special circumstances, maintaining three LNG pathways that will never be implemented in a finalized CARB document could harm the LNG refueling industry irreparably and mislead potential customers, adversely impacting the state's low carbon fuel goals.

During our meeting, we also questioned the comparison of a low carbon diesel fuel that achieved a ten percent reduction in carbon. We have confirmed with CARB staff that this was a hypothetical analysis and that no such fuel existed in the market place to date. When asked why this comparison was performed for natural gas and not for any other fuel under consideration, CARB staff explained that it was done for internal purposes only but would likely not be in the final version of the Comparison Document. We, therefore, would ask that hypothetical fuels not be included in the final version of the analysis as such a comparison could harm or unfairly stunt the growth opportunities of a vital and existing low carbon fuel, such as domestic or renewable LNG.

Clean Energy is also concerned that the values presented in the ARB Comparison document are significantly different than the values resulting from the AB1007 analysis and from the ULSD and CNG pathway documents posted on the LCFS website. We understand that the first CA-GREET model posted on the LCFS website is based on GREET1.7 while the soon to be released ARB version of the CA-GREET model is based on GREET1.8b. However, the only change for natural gas fuels in the new version of the GREET model is the global warming potential (GWP) factors for CH4 and N2O. Figure 1 below compares the WTT values produced by CA-GREET1.7 v99 with the old and new GWP values. The updated GWP factors minimally impact the results for NG fuels.




Also shown in the figure are the values generated by GREET1.8b with all Argonne National Lab default values, including the U.S. average electricity mix. The ULSD values are markedly lower because of the increased refining efficiency values. The CNG values are higher than the CA-GREET values, mainly because of the higher pipeline leak rate assumption. The LNG values are higher than the CA-GREET values largely due to poorer boil-off recovery efficiencies.

Finally, the values presented in the ARB Comparison document are shown. The ULSD and NA-NG CNG values are higher than those in the pathway documents posted on the LCFS website. The remote CNG values and the LNG values are substantially higher than the CA-GREET and GREET1.8b values. To better understand the underlying assumptions in the ARB analysis, Clean Energy requests that ARB provide the version of GREET utilized to generate the results presented in the Comparison document. If this level of transparency is not feasible, at a minimum we request the following:

- Electricity Mix for each case
- ULSD Case
    - Crude recovery efficiency
    - Crude transport modes and miles for each mode
    - ULSD refining efficiency
    - Refining non-combustion emissions
    - ULSD transport modes and miles for each mode
- For all NG Fuels:
    - NG Recovery efficiency
    - Vented methane in recovery %
    - Processing efficiency
    - Vented methane in processing %
    - Non-combustion emission in processing step
- CNG from California NG
    - Pipeline transport distance
    - Pipeline leak rate %/mile
- CNG Remote Baja Case
    - Pipeline transport distance to liquefaction
    - Pipeline leak rate %/mile
    - Liquefaction efficiency
    - Storage losses
    - Storage days
    - Boil-off recovery efficiency
    - LNG transport modes and distances
    - Boil-off assumptions during transport
    - Boil-off assumptions during terminal storage
    - Regasification efficiency
    - Pipeline transport distance and leakrate
    - Compression efficiency
- LNG Canada NG Case
    - Pipeline transport distance
    - Pipeline leak rate %
    - Liquefaction efficiency
    - Boil-off assumptions at the liquefaction plant
    - Heavy duty truck transport distance and boil-off assumptions
    - Station storage boil-off assumptions (days, loss rate, recovery)
- LNG Remote LA Case
    - Pipeline transport distance to liquefaction
    - Pipeline leak rate %
    - Liquefaction efficiency
    - Boil-off assumptions at liquefaction plant
    - LNG transport modes and distances
    - Boil-off assumptions during transport
    - Boil-off assumptions during storage at terminal
    - Distribution distances and boil-off assumptions

Finally, you mentioned during the meeting that CARB is currently engaged in internal discussions regarding which entities that are involved in the LNG and CNG vehicle fuel production cycle should be the "regulated entity" responsible for compliance with the LCFS. You indicated that CARB was currently contemplating regulation of the

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entity that holds title to the natural gas at the border of the State of California. We strongly believe this is the wrong approach, and that in order to effectively regulate and incentivize participants in the LNG and CNG vehicle fuel market the regulated entity for purposes of LCFS compliance must be the CNG or LNG fuel provider. Gas marketing firms and utilities that purchase gas at the California border are commodities businesses (not fuel businesses) that sell that gas downstream to a multitude of customers for a wide variety of end uses. Vehicle fuel providers like Clean Energy currently constitute a tiny fraction of the utility and/or gas marketing firms' natural gas customers, and the commodity supplier has no visibility or control over the fuel creation and sales process. In order for natural gas to be used as a low-carbon fuel alternative, it must be either compressed or liquefied and trucked to the end customer. It is the fuel providers that compress, liquefy ***and sell natural gas as a vehicle fuel*** that should be regulated under the LCFS.[1] It is the fuel providers, like Clean Energy, that make the decisions regarding gas sourcing and CNG and LNG production methods that are critical to determining the carbon intensity of the fuel production process. The fuel providers, like Clean Energy, enter into long-term natural gas vehicle fuel supply agreements with fuel consumers and make the capital investments necessary to build natural gas fueling infrastructure. Ultimately, it is the fuel providers that must be the regulated entity under the LCFS. Attempting to regulate the commodity provider that holds title to the gas at the border would presumably require highly inefficient and complicated supervision by the commodity provider of a certain portion of their downstream customers that compress or liquefy natural gas for use as a vehicle fuel. This presents numerous significant practical and logistical problems that may prove highly detrimental to the natural gas fueling industry as a whole and result in an ineffective regulation. We would welcome the opportunity to speak in greater detail with CARB regarding the "regulated entity" decision. We believe that it is a critical decision that must be made correctly if the LCFS is going to effectively regulate and incentivize the low carbon natural gas fueling industry.

Again, Clean Energy would like to thank you and your staff for your time and consideration of our comments, input and analysis. We hope that you will continue to view us as a resource and ally in developing and implementing the state's Low Carbon Fuel standard.

Most sincerely,

Todd R. Campbell
Director of Public Policy

Cc: Floyd V. Vergara, Esq., P.E.
Linda Lee, P.E.

[1] Properly defining the "fuel provider" under the LCFS will be of critical importance. For CNG, we would propose that the fuel provider be defined as the owner of the compression infrastructure utilized to compress the gas for use as a vehicle fuel. For LNG, we would propose the fuel provider be defined as the entity supplying the LNG to the end-user for use as a vehicle fuel.

Bernie Orozco
Director
State Governmental Affairs

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September 30, 2008

Mr. Floyd Vergara, Esq., P.E.
Manager, Industrial Section
California Air Resources Board
1001 I Street
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.

References


(1) http://www.rrc.state.tx.us/divisions/og/statistics/fielddata/barnettshale.pdf
(2) http://www.qatargas.com/Projects.aspx?id=78
(3) http://www.createacceptance.net/fileadmin/create-acceptance/user/docs/CASE_24.pdf
(4) Pluto LNG Project, Draft Public Environmental Report/Public Environmental Review, Chapter 5, Table 5-2, 5-3 & 5-4
(5) 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
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(10) http://www.kernrivergas.com/InternetPortal/FrontDesktop.aspx?
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(12) http://passportebb.elpaso.com/ebbEPG/ebbmain.asp?sPipelineCode=EPNG
(13) Environmental Protection Agency 2008 Inventory of Greenhouse Gas Emissions and Sinks

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**Memorandum**

**Date:** September 28, 2008
**To:** Todd Campbell and Mike Eaves, Clean Energy Fuels
**Cc:** Michael Jackson, Michael Chan, Jeff Rosenfeld

**From:** Jennifer Pont
**Loc:** Cupertino Office
**Phone:** 408.517.1573

**Subject:** Review of ARB's "Comparison of Greenhouse Gas Emissions from Natural Gas and Diesel Vehicles"

Recently, ARB distributed a document[1] comparing Well to Wheel (WTW) GHG emissions from NG vehicles to diesel vehicles (both current and "LCFS compliant"). ARB used the CA-GREET model to estimate WTT GHG emissions for eight natural gas pathways (5 CNG and 3 LNG) and diesel.

At present, there are several versions of CA-GREET. CA-GREET1.7v98 is currently posted on the ARB LCFS website and was utilized in development of the State Alternative Transportation Fuels Plan. Under funding from the Energy Commission, TIAX recently added two new pathways: landfill gas to CNG and landfill gas to LNG. We also provided, at ARB's request, a detailed documentation of the LFG to CNG pathway for posting on the LCFS website. The version of the model with the LFG pathways is CA-GREET1.7v99; it has not yet been posted to the ARB or CEC websites. This version of the model includes three feedstocks (North American NG, Remote NG, and Landfill Gas) and two fuels (CNG, LNG) for a total of six NG pathways.

Argonne National Laboratory (ANL) has recently released a new version of GREET (GREET1.8b) which is essentially the same as version 1.7 for the natural gas based fuels, but has not been tailored to California conditions. ARB is working on modifications to GREET1.8b to reflect California conditions, and it appears this was used to generate this natural gas document out for limited comment. ARB now refers to this model as CA-GREET1.8b, but it has not been posted to the ARB website for review.

This memo compares the GHG emissions estimated with CA-GREET1.7 v99 to the emission estimates presented in the ARB Comparison document. Underlying assumptions for the CA-GREET1.7 v99 results are also provided.

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[1] "Comparison of Greenhouse Gas Emissions From Natural Gas and Diesel Vehicles", Simeroth, CARB, September 9, 2008.

## Well To Tank Emission Estimates

Table 1 presents the WTT emission estimates from the CA-GREET1.7 v99 model. Note that the values shown for cases D3 and C1 match the values in the detailed pathway descriptions on the ARB LCFS website. The underlying assumptions for each pathway are listed in Tables 2-6.

**Table 1. Breakdown of WTT GHG Emissions Estimates from CA-GREET1.7 v99**

| Pathway # | D3 | C1 | C2 | C4 | L1 | L3 | L4 |
|---|---|---|---|---|---|---|---|
| Fuel | ULSD | CNG | CNG | CNG | LNG | LNG | LNG |
| Feedstock | CA Avg Crude | NA-NG | Remote NG | Landfill Gas | NA-NG | Remote NG | Landfill Gas |
| Recovery | 6.60 | 3.30 | 3.42 | 0.49 | 3.33 | 3.41 | 0.50 |
| Transport to Processing | 2.20 | | | 0.00 | | | 0.00 |
| Processing/Refining | 11.00 | 3.59 | 3.75 | 15.03 | 3.62 | 3.74 | 20.50 |
| Pipeline Transport | | 1.16 | 0.06 | 0.06 | 1.23 | 0.06 | |
| Compression/Liquefaction | | 2.10 | 7.08 | 2.10 | 6.85 | 7.04 | |
| LNG Transport | | | 1.29 | | 0.31 | 2.34 | 0.03 |
| LNG Storage | | | 0.24 | | 0.53 | 0.53 | 0.03 |
| LNG Regasification | | | 0.89 | | | | |
| Pipeline Transport | | | 0.24 | | | | |
| Compression/Liquefaction | | | 3.42 | | | | |
| Final Transport | 0.30 | | | | | | |
| Flaring Credit | | | | -64.38 | | | -75.67 |
| | | | | | | | |
| WTT Total | 20.10 | 10.15 | 20.40 | -46.69 | 15.87 | 17.11 | -54.62 |

NA-NG refers to North American Natural Gas

Remote NG refers to NG from overseas, shipped to the LNG facility in Baja California, Mexico.

**Table 2. Main Assumptions for ULSD Pathway**

| Parameter | | Units | Value |
|---|---|---|---|
| Electricity Mix | California Average | | |
| Recovery | Efficiency | % | 93.9% |
| | Vented Methane | g/mmBtu | 2.3 |
| Crude Transport | Ocean Tanker | miles | 3,550 |
| | Tanker payload | tons | 250,000 |
| | Tanker fuel consumption | Btu/hp-hr | 4620 |
| | Tanker speed | mph | 19 |
| | Pipeline | miles | 266 |
| | Vented Methane | g/mmBtu | 69.5 |
| Refining | Efficiency | % | 86.70% |
| | Non-combustion CO2 | g/mmBtu | 1117 |
| Transport | Pipeline | miles | 40 |
| | HD Truck | miles | 50 |
| | Terminal/station VOC losses | g/mmBtu | 3.57 |

**Table 3. Main Assumptions for CNG From North American Natural Gas**

| Parameter | | Units | Value |
|---|---|---|---|
| Electricity Mix | California Marginal | | |
| Recovery | Efficiency | % | 97.2% |
| | Methane vented | % | 0.35% |
| Processing | Efficiency | % | 97.20% |
| | Methane vented | % | 0.15% |
| | Non-combustion CO2 | g/mmBtu | 1,237 |
| Pipeline Transport | Pipeline distance | miles | 1000 |
| | Leak rate | %/mile | 0.08% / 600 miles |
| Compression | Efficiency | % | 98% |

**Table 4. Main Assumptions for CNG From Remote Natural Gas**

| Parameter | | Units | Value |
|---|---|---|---|
| Electricity Mix | Overseas Mix | | |
| Recovery | Efficiency | % | 97.2% |
| | Methane vented | % | 0.35% |
| Processing | Efficiency | % | 97.20% |
| | Methane vented | % | 0.15% |
| | Non-combustion CO2 | g/mmBtu | 1,237 |
| Pipeline Transport | Pipeline distance | miles | 50 |
| | Leak rate | %/mile | 0.08% / 600 miles |
| Liquefaction | Efficiency | % | 91% |
| | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 80% |
| LNG Transport | Ocean Tanker Distance | miles | 7200 |
| | Fuel Type | | NG/Residual Oil |
| | Tanker payload | tons | 65,000 |
| | Tanker fuel consumption | Btu/hp-hr | 4620 |
| | Tanker speed | mph | 19 |
| | Boil-off recovery | % | 100% |
| LNG Storage | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 90% |
| Regasification | Efficiency | % | 99.40% |
| | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 80% |
| Pipeline Transport | Pipeline distance | miles | 200 |
| | Leak rate | %/mile | 0.08% / 600 miles |
| Compression | Efficiency | % | 98% |

**Table 5. Main Assumptions for LNG From North American Natural Gas**

| Parameter | | Units | Value |
|---|---|---|---|
| Electricity Mix | California Marginal | | |
| Recovery | Efficiency | % | 97.2% |
| | Methane vented | % | 0.35% |
| Processing | Efficiency | % | 97.20% |
| | Methane vented | % | 0.15% |
| | Non-combustion CO2 | g/mmBtu | 1,237 |
| Pipeline Transport | Pipeline distance | miles | 1000 |
| | Leak rate | %/mile | 0.08% / 600 miles |
| Liquefaction | Efficiency | % | 91% |
| | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 80% |
| LNG Distribution | Heavy Duty Truck Distance | Miles | 50 |
| | Payload | tons | 15 |
| | Fuel Economy | mpg | 5 |
| | Fuel Type | | Natural Gas |
| | Boil-off | g/mmBtu | 0 |
| LNG Storage | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 90% |

**Table 6. Main Assumptions for LNG From Remote Natural Gas**

| Parameter | | Units | Value |
|---|---|---|---|
| Electricity Mix | Overseas Mix | | |
| Recovery | Efficiency | % | 97.2% |
| | Methane vented | % | 0.35% |
| Processing | Efficiency | % | 97.20% |
| | Methane vented | % | 0.15% |
| | Non-combustion CO2 | g/mmBtu | 1,237 |
| Pipeline Transport | Pipeline distance | miles | 50 |
| | Leak rate | %/mile | 0.08% / 600 miles |
| Liquefaction | Efficiency | % | 91% |
| | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 5 days |
| | Boil-off recovery | % | 80% |
| LNG Transport | Ocean Tanker Distance | miles | 7200 |
| | Fuel Type | | NG / Residual Oil |
| | Tanker payload | tons | 65,000 |
| | Tanker fuel consumption | Btu/hp-hr | 4620 |
| | Tanker speed | mph | 19 |
| | Boil-off recovery | % | 100% |
| Terminal Storage | Storage Losses | %/day | 0.10% |
| | Storage Days at Terminal | days | 5 days |
| | Boil-off recovery | % | 90% |
| LNG Distribution | Heavy Duty Truck Distance | Miles | 170 |
| | Payload | tons | 15 |
| | Fuel Economy | mpg | 5 |
| | Fuel Type | | Natural Gas |
| Station Storage | Storage Losses | %/day | 0.10% |
| | Storage Days | days | 3 days |
| | Boil-off recovery | % | 80% |

The WTT values for these five pathways are compared to the values in the ARB Comparison Document in Figures 1-5. There are significant differences for several of the pathways. Because the underlying assumptions for the ARB cases are not provided in the Comparison document, the causes for the differences can not yet be identified. However, it is likely that assumptions regarding pipeline leakage and boil-off recovery are not consistent. Additionally, the global warming potential (GWP) factors have been slightly increased in GREET1.8b.

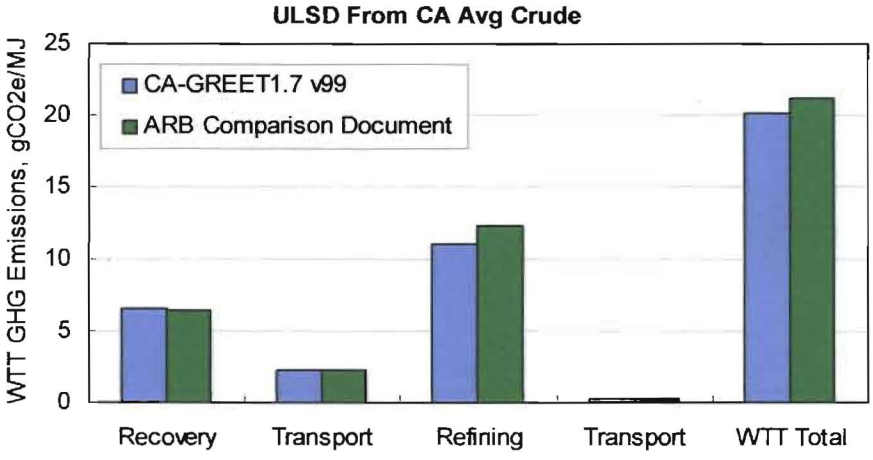


**Figure 1. Comparison of WTT GHG Emissions for CA Avg ULSD**

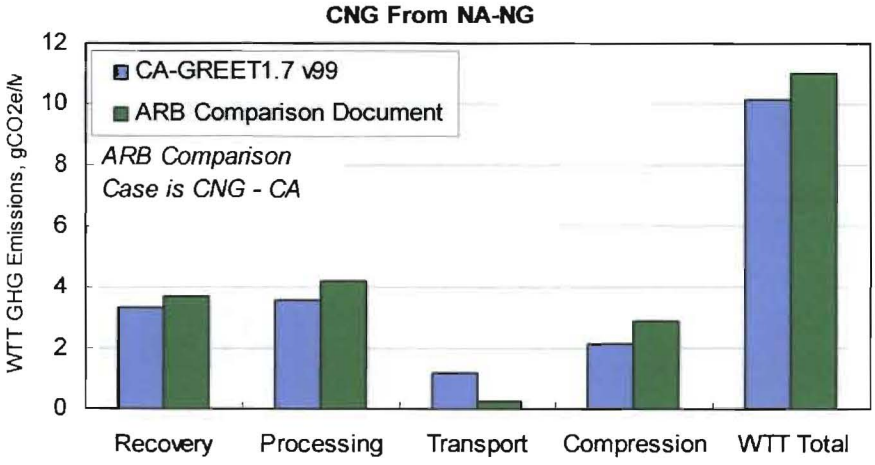


**Figure 2. Comparison of WTT GHG Emissions for CNG From NA-NG**

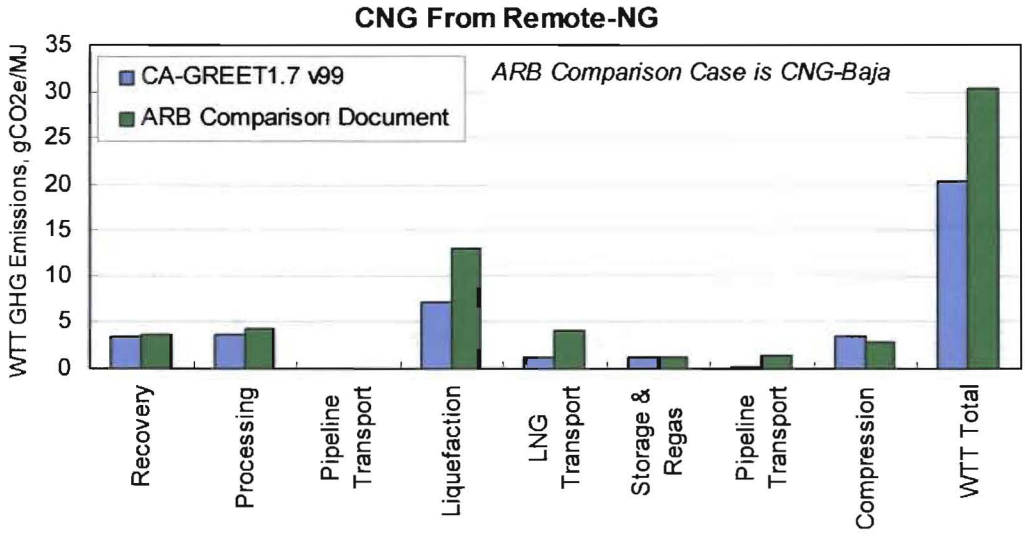


**Figure 3. Comparison of WTT GHG Emissions for CNG From Remote NG**

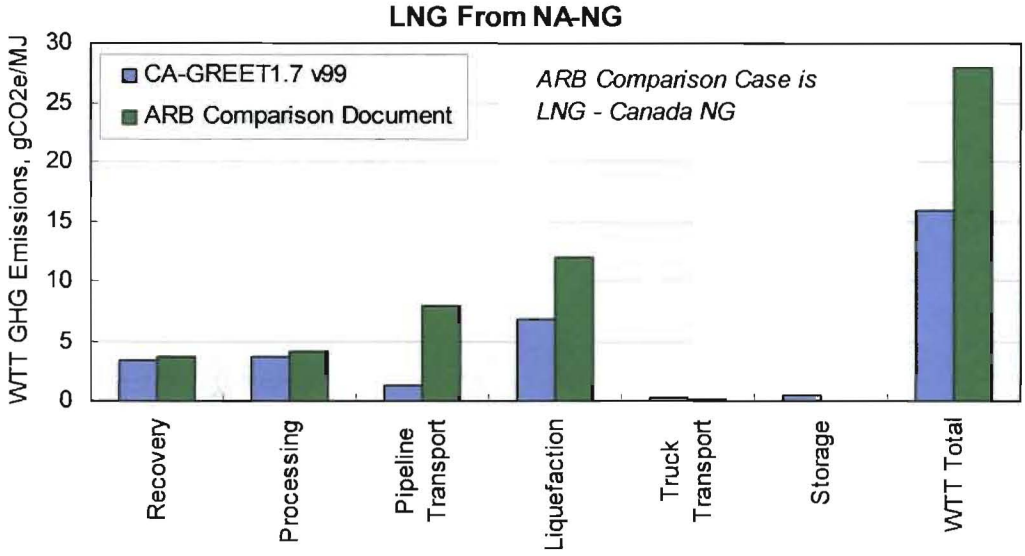


**Figure 4. Comparison of WTT GHG Emissions for LNG From NA-NG**

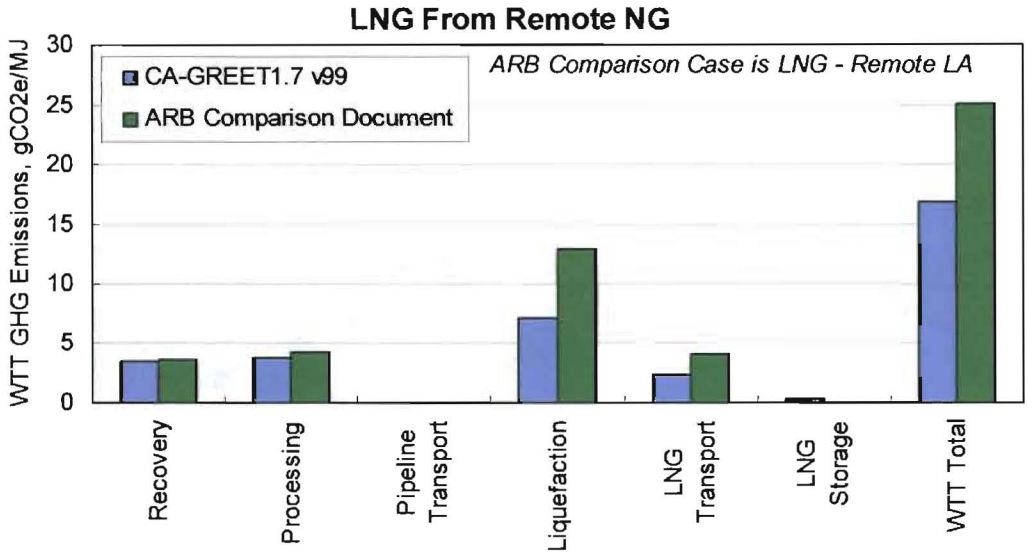


**Figure 5. Comparison of WTT GHG Emissions for LNG From Remote NG**

## Tank-To-Wheel Emission Estimates

The TTW estimates include CO2 from combustion of the carbon in the fuel and the vehicle N2O and CH4 emissions. Since the completion of the AB1007 analysis, ARB has revisited vehicle fuel economy values, and the California Climate Action Registry (CCAR) has updated the vehicle emission factors for CH4 and N2O in the general reporting protocol. The CH4 and N2O emission factors are provided on a g/mi basis for diesel and LNG/CNG light duty and heavy duty vehicles. The citation in the CCAR protocol is the California Greenhouse Gas Inventory: 1990-1999. This report has a substantial discussion of CH4 and N2O emission factors for gasoline and diesel vehicles, but no reference to NG vehicle emissions was found.

At any rate, Table 7 provides TTW emissions utilizing CCAR emission factors for N2O and CH4 along with fuel economies from the ARB Comparison document. These TTW emission estimates are compared to those from the ARB Comparison Document in Figure 7. The main differences are that the TIAX values include vehicle CH4 and N2O values, and the GWP factors are consistent with GREET1.7 rather than GREET1.8b.

**Table 7. Tank-To-Wheel GHG Emissions**

| | | ULSD | CNG | CNG | CNG | LNG | LNG | LNG |
|---|---|---|---|---|---|---|---|---|
| | | CA Avg Crude | NA-NG | Remote NG | Landfill Gas | NA-NG | Remote NG | Landfill Gas |
| Fuel C Content | wt % | 86.50% | 72.40% | 72.40% | 72.40% | 75% | 75% | 75% |
| Density | g/gal or g/scf | 3,142 | 20.4 | 20.4 | 20.4 | 1,621 | 1,621 | 1,621 |
| LHV | Btu/gal or /scf | 127,464 | 930 | 930 | 930 | 74,720 | 74,720 | 74,720 |
| Vehicle CO2 | g CO2/MJ | 74.11 | 55.20 | 55.20 | 55.20 | 56.55 | 56.55 | 56.55 |
| | | | | | | | | |
| LDV CH4 | g/mi | 0.01 | 0.04 | 0.04 | 0.04 | | | |
| LDV N2O | g/mi | 0.02 | 0.04 | 0.04 | 0.04 | | | |
| HDV CH4 | g/mi | 0.06 | 3.48 | 3.48 | 3.48 | 3.48 | 3.48 | 3.48 |
| HDV N2O | g/mi | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| | | | | | | | | |
| LDV Fuel Economy | MJ/mi | 5.38 | 5.49 | 5.49 | 5.49 | 5.49 | 5.49 | 5.49 |
| HDV Fuel Economy | MJ/mi | 25.25 | 26.86 | 26.86 | 26.86 | 26.86 | 26.86 | 26.86 |
| | | | | | | | | |
| LDV TTW CO2 | gCO2e/mi | 398.7 | 303.0 | 303.0 | 303.0 | | | |
| LDV TTW CH4 | gCO2e/mi | 0.2 | 0.9 | 0.9 | 0.9 | | | |
| LDV TTW N2O | gCO2e/mi | 5.9 | 11.8 | 11.8 | 11.8 | | | |
| LDV TTW Total | gCO2e/mi | 404.8 | 315.8 | 315.8 | 315.8 | | | |
| LDV TTW Total | gCO2e/MJ | 75.2 | 57.5 | 57.5 | 57.5 | | | |
| | | | | | | | | |
| HDV TTW CO2 | gCO2e/mi | 1,871 | 1,483 | 1,483 | 1,483 | 1,519 | 1,519 | 1,519 |
| HDV TTW CH4 | gCO2e/mi | 1 | 80 | 80 | 80 | 80 | 80 | 80 |
| HDV TTW N2O | gCO2e/mi | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| HDV TTW Total | gCO2e/mi | 1,887 | 1,577 | 1,577 | 1,577 | 1,614 | 1,614 | 1,614 |
| HDV TTW Total | gCO2e/MJ | 74.7 | 58.7 | 58.7 | 58.7 | 60.1 | 60.1 | 60.1 |
| CH4 and N2O Emissions from California Climate Action Registry General Reporting Protocol, March 2008. | | | | | | | | |
| Vehicle Fuel Economy from ARB's Comparison Document | | | | | | | | |

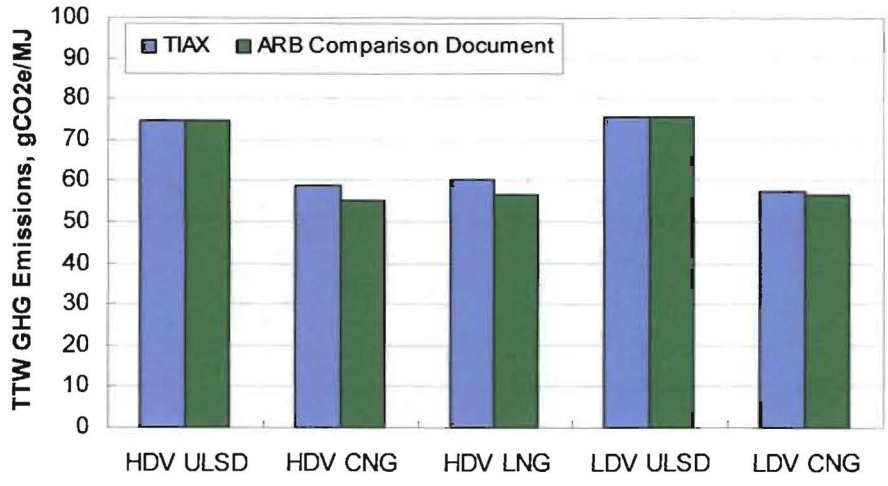


**Figure 6. Comparison of TTW emissions.**

## Well-to-Wheel Results

Combining the GREET1.7 v99 WTT estimates with the TIAX TTW estimates above results in the WTW values shown in Table 8 and Figures 7 and 8. As indicated NG light duty vehicles result in a 17% to 88% reduction relative to diesel; heavy duty NG vehicles yield from 11% to 94% percent reduction.

**Table 8. TIAX Estimates of WTW GHG Emissions**

| | Units | ULSD CA Avg Crude | CNG NA-NG | CNG Remote NG | CNG Landfill Gas | LNG NA-NG | LNG Remote NG | LNG Landfill Gas |
|---|---|---|---|---|---|---|---|---|
| WTT | gCO2e/MJ | 20.10 | 10.15 | 20.40 | -46.69 | 15.87 | 17.11 | -54.62 |
| LDV F.E. | MJ/mi | 5.38 | 5.49 | 5.49 | 5.49 | | | |
| HDV F.E. | MJ/mi | 25.25 | 26.86 | 26.86 | 26.86 | 26.86 | 26.86 | 26.86 |
| Light Duty | | | | | | | | |
| WTT | gCO2e/mi | 108 | 56 | 112 | -256 | | | |
| TTW | gCO2e/mi | 405 | 316 | 316 | 316 | | | |
| WTW | gCO2e/mi | 513 | 371 | 428 | 59 | | | |
| % change | | | -28% | -17% | -88% | | | |
| Heavy Duty | | | | | | | | |
| WTT | gCO2e/mi | 508 | 273 | 548 | -1,254 | 426 | 460 | -1,467 |
| TTW | gCO2e/mi | 1,887 | 1,577 | 1,577 | 1,577 | 1,614 | 1,614 | 1,614 |
| WTW | gCO2e/mi | 2,395 | 1,850 | 2,125 | 323 | 2,040 | 2,074 | 147 |
| % change | | | -23% | -11% | -86% | -15% | -13% | -94% |

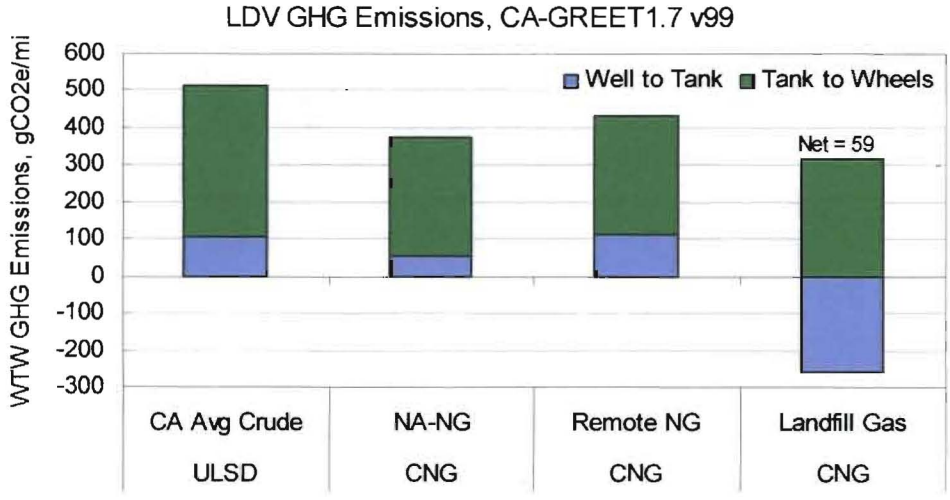


**Figure 7. Light Duty WTW GHG Emissions**

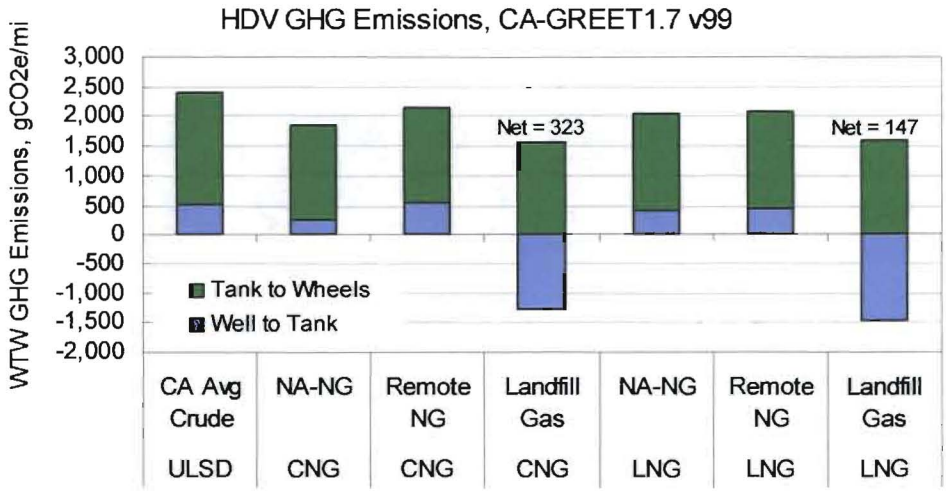


**Figure 8. Heavy Duty WTW GHG Emissions**

Finally, Figure 9 provides a comparison of the TIAX estimated WTW emissions and the ARB Comparison Document estimates. Except for the CNG from NA-NG, the ARB estimates are much less favorable than the TIAX estimates based on GREET1.7 v99. For the CNG from NA-NG case, ARB's California NG case is utilized. The ARB estimate is more favorable, likely because of the reduced pipeline transport distances (the TIAX estimate assumes 1000 miles of pipeline travel). For the LNG case from NA-NG, the ARB case utilizing NG from Canada is utilized. For the CNG case from remote NG, the ARB case assuming LNG imported to Baja is utilized. For the LNG case from remote NG, the ARB case assuming receipt in Los Angeles and direct distribution from the shipping terminal is utilized.

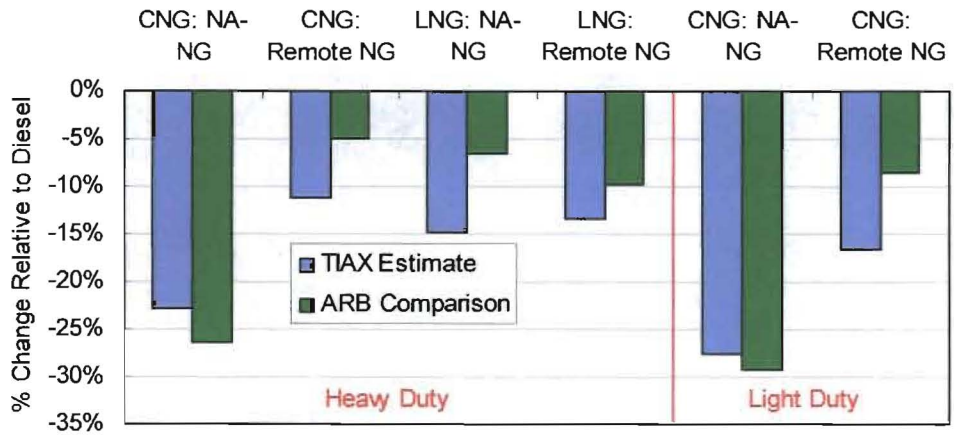


**Figure 9. TIAX WTW Estimates and the ARB Comparison Document Estimates**