Docket Optical System - Comments on AB 2007 reports

From: "Tam Hunt"
To: "'McKinley Addy'" ,
Date: 6/8/2007 4:45 PM
Subject: Comments on AB 2007 reports
Attachments:

Mr. Addy,

Please find attached our 2nd set of comments on the AB 1007 alt. fuels plan. Also find attached a report from Carnegie Mellon University re the lifecycle emissions of domestic natural gas, LNG, and synfuels. This report was peer-reviewed and accepted for publication in Environmental Science & Technology, with publication forthcoming.

Sincerely,

Tam Hunt
Energy Program Director / Attorney
Community Environmental Council

Community Environmental Council

June 8, 2007

California Energy Commission
Docket Office
Attn: Docket 06-AFP-1, "Alternative Fuels Transportation Plan"
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Dear Mr. Addy,

We previously submitted comments on the draft TIAX reports on March 24, 2007. We re-submit these comments below because we do not know if our previous comments were considered in TIAX's revisions between March and the present due to the fact that the updated reports have not been posted. The presentations at CEC's May 31st workshop suggest that TIAX has not fully considered our previous comments relating to the increased greenhouse gas emissions from LNG. To the contrary, presentations from TIAX and CEC appear to reflect backsliding on this key issue in that they further downplay the difference between natural gas, CNG and LNG – conflating these energy sources and treating them all as though the more favorable emissions aspects of domestic natural gas apply also to CNG and LNG.

However, lifecycle greenhouse gas emissions from domestic natural gas, CNG and LNG can be widely divergent. Recent peer-reviewed reports, most notably a recently published report from a team at Carnegie Mellon University, found that <u>GHGs from LNG can be as high as coal</u>, when both are measured on a lifecycle emissions basis. (See attached a draft of the CMU report).

Accordingly, with natural gas forming the primary energy source for many different energy pathways in California – e.g., electricity, heating, cooling and cooking, transportation through CNG and LNG, and transportation and/or power production from hydrogen with natural gas as the feedstock – it is <u>absolutely imperative</u> that the final AB 1007 reports fully reflect the impact on California's greenhouse gas emissions by relying on LNG as a source of natural gas in the future. With Sempra's Baja LNG import terminal set to come online next year, and eventually supplying up to 20% of California's total natural gas demand, the increased GHGs resulting from LNG imports may well <u>by itself</u> torpedo California's efforts to reduce GHGs from its transportation sector.

With the draft TIAX report making basic mistakes like projecting Chile as a source of LNG for California (Chile plans to import LNG, not export it), it is clear that much work remains to be done on the TIAX reports.

Our March 24, 2007, comments on the TIAX reports follow:

We read with great interest the draft consultant report from TIAX, LLC, pursuant to AB 1007. With our organization's efforts focused on weaning our region from fossil fuels in about two decades (www.fossilfreeby33.org), AB 1007 is clearly a step in the right direction for us and for California.

In these comments, we focus on one technology area: natural gas and LNG. While the draft report does a great job of distinguishing between corn and cellulosic feedstocks for ethanol, and hydrogen from fossil fuels versus hydrogen from renewable electricity – and the lifecycle impacts of these differences – it doesn't do as good a job of distinguishing between natural gas, compressed natural gas (CNG) and liquefied natural gas (LNG). <u>This distinction is as important, or potentially more important, than the distinction between different types of ethanol and hydrogen.</u>

This is the case because, as the draft report makes clear in some places (if one delves deep) CNG and LNG produce high emissions levels, whereas domestically produced natural gas produces much fewer emissions – when compared to coal or petroleum. In other words, <u>CNG and LNG do not share the same environmental benefits that domestic natural gas enjoys</u>.

This distinction is at times spelled out in the draft report. However, it should be made clear whenever natural gas, CNG or LNG are mentioned, that there is a large difference between these fuel types, in terms of both criteria pollutants and greenhouse gases when each fuel type is assessed on a lifecycle basis. These categories should not be lumped together, as they often are in the draft.

This distinction is even more important when we consider that the draft report discussions of electric vehicles (using electricity from predominantly natural gas) and hydrogen vehicles (using hydrogen from natural gas) rest on the assumption that the natural gas used for these purposes is domestically produced natural gas. When we factor in the "high GHG pathway" for LNG for natural gas-fired electricity and steam reformed natural gas to produce hydrogen, it should be clear that the actual greenhouse gas emissions from these technologies will be far higher when LNG supplies the natural gas.

Similarly, when CNG is created from LNG, the emissions concerns become even more pronounced because of the additional energy required to compress natural gas from LNG. The full pathway for this fuel source is: discovery and extraction, liquefaction, transportation, re-gasification, transportation, compression, transportation, use in vehicles. It should be clear that this process takes far more energy than simply compressing domestic natural gas and, therefore, there are substantially higher greenhouse gas emissions from this process.

Last, in discussions with TIAX staff, we learned that the GREET model used by TIAX omits certain key energy requirements for LNG, such as onshore re-gasification energy requirements. With any LNG import terminal in California likely to require additional natural gas for re-gasification (instead of seawater re-gas facilities because of concerns about sea life entrainment), this will substantially add to the emissions profile of LNG in California.

If all this was just theoretical, we wouldn't be writing this letter. However, with LNG projected to supply 20 to 30 percent of California's natural gas over the next decade or so, this high GHG pathway will very likely take the state of California backwards in meeting its AB 32 goal – not forwards as LNG proponents would advocate.

In other words, if LNG does become a large supplier of natural gas to California, much, if not all, of the greenhouse gas emissions reductions in the electricity and natural gas sector may be mooted by LNG imports.

Sincerely,

Tam Hunt
Energy Program Director

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Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

1. Introduction

Natural gas currently provides 24% of the energy used by U.S. homes (1). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than \$3/thousand cubic feet (Mcf) (2)) spurred a surge in construction of natural gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural gas-fired capacity more than tripled, from 60 to 208 GW (3). Adding to this economic incentive was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around \$4/Mcf) through 2020 (4), lower capital costs, shorter construction times, and generally lower air emissions for natural gas-fired plants (5) compared to coal-fired facilities. However, instead of remaining near projected levels, the average well head price of natural gas peaked at \$10.97/Mcf in October 2005 (6). This price increase made natural gas uneconomical as a feedstock, so most natural gas-fired plants are operating below capacity (7). Despite these trends, natural gas consumption is expected to increase by 20% in 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the U.S. and pipeline imports from Canada and Mexico are expected to remain fairly constant (8). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projection by EIA estimate that LNG imports will increase 16% of the total U.S. natural gas supply by 2030 (8). Alternatively, researchers at the Harvard John F. Kennedy School of Government call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy would allow the U.S. to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (7), equivalent to 5% of expected 2030 demand.

The natural gas supply chain is the second largest source of greenhouse gas emissions in the U.S., generating around 132 million tons of CO_2 equivalents annually (1). Significant emissions of criteria air pollutants might also come from the upstream from combustion life cycle stages of the fuel. Several studies have performed emission inventories for much of the natural gas life cycle (from production to distribution). These analyses are limited to the domestic natural gas supply chain. Emissions from the emerging LNG life cycle stages or from the production of SNG have not been included. If larger percentages of the U.S. supply of natural gas will come from these alternative sources of natural gas, then LNG/SNG supply chain emissions become an important part of understanding overall natural gas life cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas life cycle air emissions including the emissions from LNG and SNG processing and delivery. Direct emissions from the processes during the life cycle will be considered, as well as emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life Cycles

2.1. The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. natural gas transmission system consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to the distribution system at the city gate. Pressure in the pipes is maintained by compressor stations that are generally fueled with a small amount of the pipeline gas. Natural gas is stored in underground facilities e.g. reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. The final step before the end users involves local distribution companies that transport natural gas to local delivery points via low-pressure, small-diameter pipelines that use small compressors to maintain the required pressure.

2.2. The LNG Life Cycle

The use of liquefied natural gas (LNG) adds three additional life cycle stages to the natural gas life cycle. Natural gas is produced and processed to remove contaminants as before, then liquefied. In the liquefaction process, natural gas is cooled and pressurized, reducing its volume by 610 fold (9). Liquefaction plants are generally located in coastal areas of LNG exporting countries. Dedicated LNG tankers transport LNG to the U.S. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. Regasification facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. At this point the regasfied LNG enter the U.S. transmission and distribution system.

2.3. The Coal Life Cycle

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion. U.S. coal is produced from surface mines (67%), or underground mines (33%%) (1). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (10). More than 90% of the coal used in the U.S. is used by the electric power sector (8).

2.4. The Life Cycle of SNG

The life cycle of SNG is a combination of some stages from the coal life cycle and some stages of the natural gas life cycle. Coal is mined, processed, and transported to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H), is produced and converted, via methanation reactor, to methane and water. The SNG is then sent to the natural gas transmission, storage and distribution system.

3. Methods for Calculating Life Cycle Air Emissions

3.1. Life Cycle Air Emissions from Natural Gas produced in North America

In 2003, the total supply of natural gas available in the U.S. was over 27 trillion cubic feet (tcf). Of this supply, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (11). According to the Environmental Protection Agency (EPA), 1.42% of the natural gas produced is lost in the production, processing, transmissions, storage and distribution of natural gas (12). Total methane emissions were calculated using this percentage of natural gas lost. It was assumed that natural gas has an average heat content of 1,030 Btu/ft^3 (11), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lbs/ ft^3 (12).

In 1993 the EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the supplemental information, was combined with the data described above in order to develop a range of methane emissions factors for the North American natural gas life cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life cycle stages and from electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, transmission, storage, and distribution of natural gas. In 2003, approximately 1,900 billion cubic feet of natural gas were consumed during these stages of the natural gas life cycle (11). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 14.47 Tg C/QBtu and an oxidation fraction of 0.995 (1). According to Transportation Energy Data Book, 3 billion kWh were used by natural gas pipeline transport in 2003 (13). The average GHG emission factor from the generation of this electricity is 1,392 lbs CO_2 Equiv/MWh (14). These emissions were added to methane emissions to obtain the total GHG emission factors for North American natural gas

SO_x and NO_x emissions from the natural gas upstream from electricity generation stages of the life cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the supplemental information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (15). A range of emissions from the combustion of the natural gas used during the upstream stages of the life cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (15). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lbs SO_x /MWh and 2.96 lbs NO_x/MWh (14).

In addition to emission from the energy used during the life cycle of natural gas, SO_x emissions are produced in the processing stage of the life cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas in order to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas were developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (15). In order to use the AP 42 emission factors for sulfur recovery, we found that in 2003 1,945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas (11,16). This data was also used to calculate an average natural gas H_2S mole percentage of 0.0226, which was then used with the data given in the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from LNG Life Cycle

In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (11). In 2003, 75% of the LNG imported to the U.S. came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (11). According to EIA, the LNG tanker fleet capacity will reach 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (17). There are currently 5 LNG terminals in operation in the U.S., with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (18).

It is assumed that natural gas produced in other countries and imported to the U.S. in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the life cycle as as does North American natural gas. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies and assumed to be operated similar to those in the U.S. This is likely a conservative assumption and the LNG life cycle emissions may be higher than those estimated here.

Additional emission factors were developed for the liquefaction, transport, and regasification life cycle stages of LNG. Tamura et.al. have reported emission factors for the liquefaction stage in the range of 11 to 31 lbs CO_2 equivalents per million Btu (MMBtu) (19). The sources of these emissions are outlined in the supplemental information.

Emissions from tanker transport of LNG were then calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_{x=1}^{n}\left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

where *EF* is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed (20,21);
n is the number of countries exporting LNG to the U.S.;
2 is the number of trips each tanker does for every load (one bringing the LNG and one traveling back empty);
LNG_x is the amount of natural gas brought from each country in cubic feet;
TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG);
D_x is the distance from each country to U.S. LNG facilities;
TS is the tanker speed of 14 Knots;
FC is a fuel consumption of 41 tons of fuel per day; and
24 is hours per day (20).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA (22), and the 2003 U.S. imports are shown in the supplemental materials. These two terminals were chosen because they are two of the largest terminals in the U.S. and they represent longest and shortest tanker travel distances for which route information is available. This permits a best-worst estimate for shipment.

Regasification emissions were reported by Tamura et.al. to be 0.85 lb CO_2 equiv./MMBtu (19). Ruether et.al. report an emission factor of 3.75 lb CO_2 equiv./MMBtu for this stage of the LNG life cycle by assuming that 3% of the gas is used to run the regasification equipment (23). The emission reported by Tamura et.al. differs because they assume only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the U.S. in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, transmission, and distribution stages of the life cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (15). It is assumed that 8.8% of natural gas is used in the liquefaction plant (19) and 3% is used in the regasification plants (23).

Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated based on fuel use, as done for the carbon emissions from the tanker life cycle stage (above). The conventional design of LNG tankers uses steam turbines that run on bunker fuel oil as well as on fuel boil-off (LNG that evaporates from the tank and is captured for use as fuel). The emission factors for this engine type used in Equation 1 are 54 kg SO_x/ton of fuel used (20,21) and 6.98 kg NO_x/ton fuel used (20).

3.3. Air Emissions from the Coal Life Cycle

Greenhouse gas emissions from the mining life cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 68 Tg CO_2 equivalents, of which 57 Tg CO_2 equivalents came from underground mines and 11 Tg CO_2 equivalents came from surface mines (1). Carbon dioxide is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S Census Bureau provides fuel consumption data for mines in 1997 (24). These data are available in the supplemental information. Fuel consumption data were converted to greenhouse gas emission using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (1) (see supplemental information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lbs CO_2 equiv (14). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (25). In order to use this tool, economic values for coal transportation were needed. In 1997, the year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (10). For a million tons of coal, EIO-LCA estimates that 31,500 metric tons of CO_2 equivalents are emitted from rail transportation, 1,800 metric tons of CO_2 equivalents from water transportation, and 2,400 metric tons of CO_2 equivalents from truck transportation (25). These emissions were then converted to an emission factor by using a weighted average U.S. coal heat content of 10,520 Btu/lb (26) and the coal production data for 1997 (see supplemental information).

The energy consumption data used to develop carbon emissions from the mining life cycle stage was used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (15,27). In addition, the average emission factors from electricity generation in 1997 (3.92 lbs NO_x/MWh and 7.86 lbs SO_x/MWh (14)) were used.

SO_x and NO_x emissions for coal transportation were again calculated using the EIO-LCA tool (25). EIO-LCA estimates that a million tons of coal transported via rail emits 15.4 metric tons of SO_x and 289 metric tons of NO_x. A million tons of coal transported via water would emit 21 metric tons of SO_x, and 111 metric tons of NO_x. Finally, a million tons of coal transported via truck would emit 2.08 metric tons of SO_x, and 49.3 metric tons of NO_x (25). This data was added to emissions from mines to find the total SO_x and NO_x emission factors for the coal life cycle upstream of combustion for electricity generation.

3.4. Air Emissions from the SNG Life Cycle

Performance characteristics for two SNG plants are given in the supplemental information. These plants have a high heating value efficiency between 57% and 60% Using these efficiencies, emissions from coal mining, processing and transportation previously obtained were converted to lbs of CO_2 equiv./MMBtu of SNG. The data was also used to calculate the emissions at the gasification/methanation plant using a coal carbon content of 26 Tg/MMBtu and a calculated SNG storage fraction of 37% (1), Finally, the emissions from transmission, storage, distribution and combustion of SNG are the same as for all other natural gas.

In order to develop the SO_x and NO_x emissions from the life cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG. In addition, the emissions from natural gas transmissions, storage and distribution were assumed to represent emissions from these life cycle stages of SNG. The emissions from the gasification/methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (28) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lbs/MMBtu coal (0.026 to 0.17 lbs/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lbs/MMBtu coal (0.0228 lbs/MMBtu of coal if there is carbon capture). These were converted to lbs/MMBtu of SNG using the same efficiencies previously described.

4. Results

4.1. Life Cycle Air Emission Factors for Natural Gas/LNG, coal, and SNG.

Table 1 summarizes GHG emission factors for all fuels. Emission factors are the average emission rate relative to units of fuel produced (or electricity generated). These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life cycle stage can be seen in the Supplemental Information. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification/methanation. CCS is a process by which carbon emissions are separated from other combustion products, and injected into underground geologic formations such as saline formations and depleted oil/gas fields. When CCS sequestration is preformed at the gasification/methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the gasification/methanation plant (29). It is also important to note that the emission factors shown in Table 1 (and the emission factors given in Table 2) are not comparable to each other, since one btu of coal does not generate the same amount of electricity as one btu of natural gas or SNG. These emission factors will later be transformed to comparable units, namely lbs/MWh of electricity produced.

Table 1: Life Cycle GHG Emission Factors (all units are in lbs/MMBtu of Fuel Produced)

Life Cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	22.1	23.8	35.8	65.8	10	16.5	249	291	54.8	70.3
Combustion	120	120	120	120	205	205	120	120	12	12
Total	142	144	156	186	215	222	369	411	66.8	82.3

SO_x and NO_x emission factors for the upstream of combustion for electricity generation stages of the fuel life cycles can be seen in Table 2. SO_x and NO_x emissions from the combustion of fuels at power plant are very dependent on specific plant characteristic, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life cycle (lbs/MMBtu) by simply using the efficiency of the power plants. For this reason, SO_x and NO_x emission from the combustion of the fuels will be discussed in Section 5, and are not included below.

Table 2: Upstream SO_x and NO_x Emission Factors (all units are in lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.037	0.154	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.024	0.835	0.030	0.535	0.090	0.234	0.104	0.253

4.2. Comparing Fuel Life Cycle Emissions for Fuels Used at Currently Operating Power Plants.

Emission factors for the fuel life cycles have been calculated as pounds of pollutants per MMBtu of fuel produced. Since coal and natural gas power plants have different efficiencies, one MMBtu of coal does not generate the same amount of electricity as one MMBtu of natural gas/LNG/SNG. For this reason, emission factors must be converted to units of pounds of pollutant per MWh of electricity generated. This conversion is done using the heat rates of natural gas and coal power plants. According to DOE, currently operating power plants have heat rates ranging from 9,300 Btu/kWh to 11,500 Btu/KWh, while currently operating natural gas power plants have heat rates ranging from 5,900 Btu/kWh to 12,300 Btu/kWh (30) (shown in Figure 8 of the supplemental information). The life cycle GHG emissions factors of natural gas, LNG, coal and SNG described in Section 4.1 were converted to a lower and upper bound emission factor from coal and natural gas power plants using these heat rate ranges. Figure 1 shows the final bounds for the emission factors for each fuel. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the U.S.: 1,390 lbs CO_2 Equiv/MWh (14). Note that the upstream emissions used for SNG assume no CCS is done at the gasification/methanation plant. A scenario where CCS is performed at these plants will be discussed in the following section.

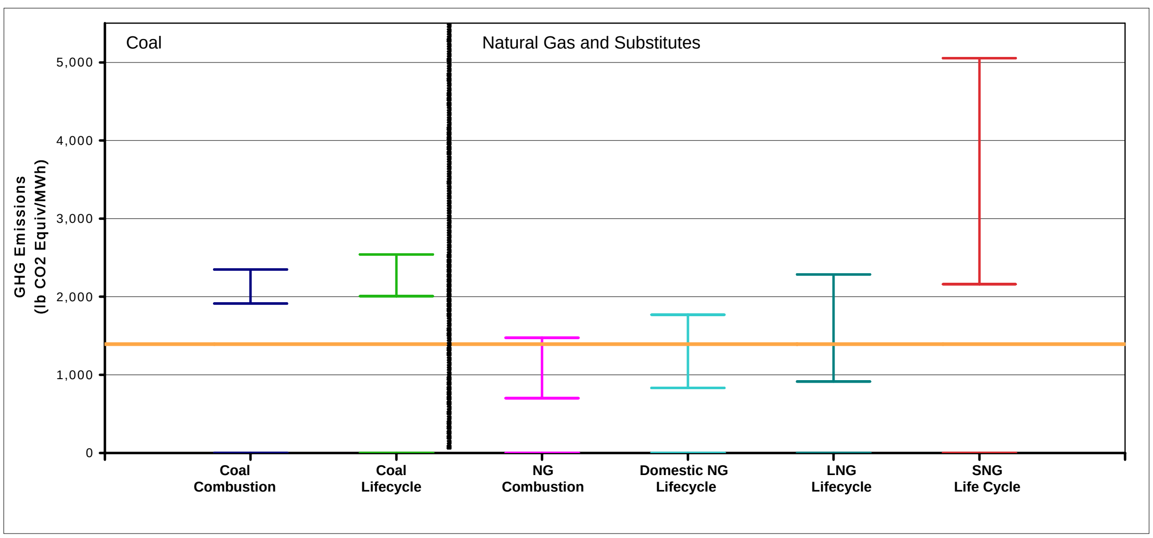

Figure 1: Fuel Combustion and Life Cycle GHG Emissions for Current Power Plants

It can be seen that combustion emissions from coal power plants are higher than combustion emissions from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2,100 lbs CO_2 Equivalents/MWh, while the midpoint for natural gas combustions is approximately 1,100 lbs CO_2 Equivalent/MWh. This reflects the known environmental advantages of natural gas combustion over coal combustion. Figure 1 also shows that the life cycle of electricity generated with coal is dominated by combustion emissions and adding the upstream life cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life cycle emission factors being 2,250 lbs CO_2

Equivalent/MWh. For power plants that run on natural gas, the emissions from the upstream stages of the life cycle of the natural gas are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life cycle emission factors for domestic natural gas is 1,300 lbs CO_2 Equivalent/MWh; for LNG and SNG it is 1,600 lbs CO_2 Equivalent/MWh and 3,600 lbs CO_2 Equivalent/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life cycle emissions of natural gas produced in North America: The upper bound life cycle emission factor for LNG is 2,300 lbs CO_2 Equivalent/MWh, while the lower bound life cycle emission factor for coal is 1,900 lbs CO_2 Equivalent/MWh.

In order to compare the emissions of SO_x and NO_x from all life cycles, the upstream emission factors developed and the heat rates previously mentioned are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EPA's EGRID program (31). Table 3 show life cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the U.S is also presented in this table (14).

Table 3: SO_x and NO_x Combustion and Life Cycle Emission Factors for Current Power Plants.

Fuel/Pollutant		SO_x (lbs/MWh)		NO_x (lbs/MWh)	
		Min	Max	Min	Max
Current Electricity Mix		6.04		2.96	
Coal	Combustion	1.54	25.47	2.56	9.08
	Life Cycle	1.60	25.80	2.83	9.69
Natural Gas	Combustion	0.00	1.13	0.12	5.20
	Life Cycle	0.04	1.49	0.17	9.40
LNG	Life Cycle	0.22	3.01	0.26	15.46
SNG	Life Cycle	0.30	3.88	0.65	8.08

It can be seen that coal has significantly larger SO_x emission than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG and even SNG make a significant contribution to the total life cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come form the liquefaction plant; finally for SNG most upstream NO_x emissions come from the gasification/methanation plant.

4.3. Comparing Fuel Life Cycle Emissions for Fuels Used with Advanced Technologies

According to the U.S. DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (8). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC) and natural gas combine cycle (NGCC) power plants could be installed. IGCC plants have higher capital costs than PC power plants ($1,380/kW vs. $1,260/kW). NGCC plants have lower capital costs ($560/kW) than both designs for coal power plants, but their cost of operation is more dependant on volatile fuel prices (29). PC, IGCC and NGCC plants are generally more efficient (average heat rates are 8,700 Btu/kWh, 9,100 Btu/kWh and 6,800 Btu/kWh, for PC, IGCC and NGCC power plants, respectively (29)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (5,29). Having CCS at PC, IGCC and NGCC plants decreases the efficiency of the plants to average heat rates of 11,400 Btu/kWh, 10,500 Btu/kWh and 8,000 Btu/kWh respectively (29). It would also increase the capital cost of PC, IGCC and NGCC plants to $2,210/kW $1,880/kW and $1190/kW, respectively (29).

Using the heat rates for advanced technologies and the GHG emission factors developed, Figure 2 was developed. This figure represents total life cycle emissions for electricity generated with each fuel. In the case of SNG, CCS is performed at the gasification/methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the U.S.: 1,390 lbs CO_2 Equiv/MWh (14). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants is used (these is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that life cycle emission of electricity generated with the fuels but without CCS would decrease slightly compared to emissions from current power plants. This emission reduction is caused by efficiency gains. If CCS is used, there would be a significant reduction in emissions. In addition the midpoint between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life cycle emission factors when CCS is used.

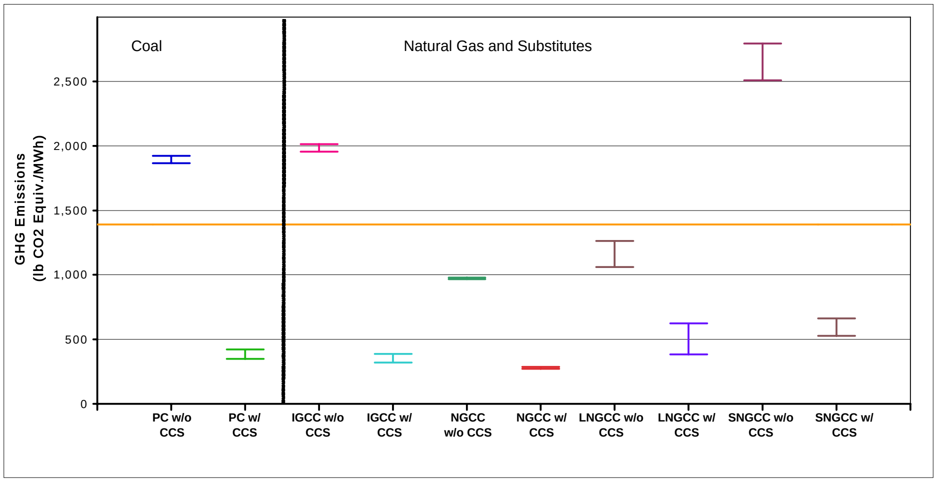

Figure 2: Fuel GHG Life Cycle Emissions Using Advanced Technologies

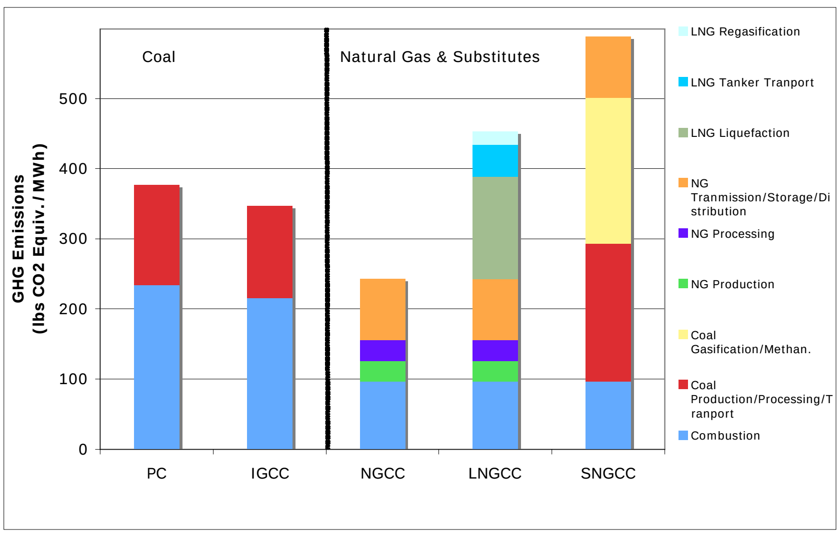

Figure 3: Midpoint Life Cycle GHG Emissions Using Advanced Technologies with CCS

Table 4 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (28) for PC and IGCC plants and by Rubin et.al for NGCC plants (29) These reported combustion emissions can be seen in the Supplemental Information.

Table 4: SO_x and NO_x Life Cycle Emission Factors for Advanced Technologies.

Fuel/Pollutant		SO_x (lbs/MWh)		NO_x (lbs/MWh)	
		Min	Max	Min	Max
Current Electricity Mix		6.04		2.96	
Coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.68
	IGCC w/ CCS	0.32	1.83	0.51	0.76
Natural Gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.41	5.92
	NGCC w/ CCS	0.30	1.23	0.48	6.94
SNG	NGCC w/o CCS	0.35	2.15	0.85	1.84
	NGCC w/ CCS	0.45	2.80	1.11	2.31

As can be seen from the table, if advanced technologies are used there could be a significant reduction of NO_x, and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulphurization. The removed sulfur compounds are then solidified and disposed off. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some SO_x emissions.

For NO_x, only LNG has higher life cycle emissions than what is generated at current power plants. These LNG life cycle emission factors would still be lower than life cycle emission factors of electricity generated using LNG in current power plants, however the emissions from liquefaction and regasification plants are so significant, that they still have a considerable impact.

5. Discussion

Natural gas is an important energy source for the residential, commercial and industrial sectors. In the 1990's, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial and industrial consumers between 2000 and 2005 total 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the less than $4.5 /Mcf average projected in earlier reports before the natural gas fired plant construction boom (4).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyze the effects of the additional air emissions from the LNG/SNG life cycle on the overall emissions from electricity generation in the U.S. We found that with current electricity generation technologies, natural gas life cycle GHG emissions are generally lower than coal life cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life cycle GHG emission than coal, domestic natural gas or LNG. It is important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have very similar life cycle NO_x emissions to coal.

In the future, as newer generation technologies and CCS are installed, the overall life cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG or SNG could be similar. Most important is that all fuels with advance combustion technologies and CCS have lower life cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life cycle emissions, but all fuels have lower life cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life cycle emissions and would be the only fuel that could have higher emission than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to revaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected.

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