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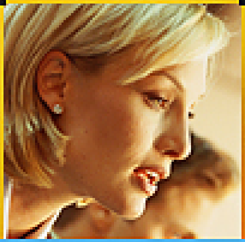


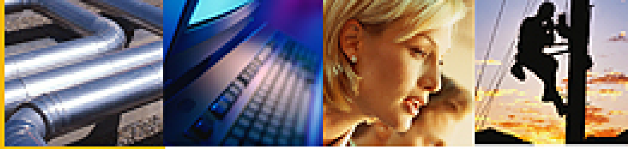
CALIFORNIA ENERGY COMMISSION
2009 Integrated Energy Policy Report


Comments by Sempra LNG
Joint IEPR and Electricity & Natural Gas Committee Worshop
May 14, 2009

DOCKET
09-IEP-1J
DATE May 14 2009
RECD. June 05 2009

Bill Tobin
Manager, Regulatory Affairs
Sempra Global Regulatory Affairs
June 5, 2009

Infrastructure Expansions Created Insurance for California's Natural Gas Consumers

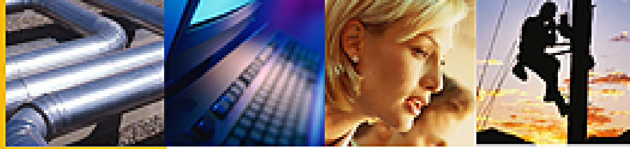


- CEC's Natural Gas Infrastructure Draft Staff Report points out:
  - During and after the [energy crisis of 2000-2001], California bought an insurance policy in the form of increased interstate pipeline delivery capacity, utilities improved their receiving ability, and the utility and independent storage owners enhanced their storage operations to meet future high-demand day conditions. The result has given California utilities the flexibility to choose supply sources in their day-to-day operations, forcing the production areas to compete for a share of the state's natural gas market.
- We agree that insurance in the form of increased deliverable capacity is necessary to protect against potential shortages and that recent infrastructure additions have created this benefit.

LNG Will Benefit California

- The CEC Draft Staff Paper asks, "What role would LNG from Costa Azul . . . Play in California's future natural gas supply mix?" (p.24.)
  - Costa Azul could play a significant role in addressing the Staff's period of greater concern, "Long-Term High Winter Demand," a period lasting for up to 150 days (p. 13).

LNG Access Creates an Additional Form of Insurance for California



- The Draft Staff Report discusses a hypothetical commodity shortage resulting from increases in East of California demand and concludes:
  - “In this scenario the flowing supply from pipelines and production would be available, but gas in storage would be used to meet the long-term demand. Under these conditions supply would be limited to 9,330 MMcf/d
  - “Without changes in infrastructure, only two options could raise the level of natural gas supply. First, a lower demand in the Pacific Northwest would allow more gas to flow to Malin, Oregon. Second, part, or all, of the Mojave Pipeline supply would be delivered to the Kern River/Mojave pipeline system rather than to Ehrenberg, via El Paso’s Line 1903. Together these two options could add up to 650 MMcf/d to the pipeline and production summary in Table 2.” (Draft Staff Report, at pp. 10-11.)
  - A principle area of concern is “Long-Term High Winter Demand” (when “High-demand levels occur for an extended period, which could include all of the five winter months . . . . As in the 2000-2001 energy crisis, pipeline flows would be at or near maximum, and there would be few options for manipulating storage operations.”) (p. 13)
- Staff’s “two options” do not recognize the potential availability of LNG shipments to Costa Azul.
  - Even if West Coast prices are not adequate to support regular LNG deliveries under normal market conditions, sustained scarcity-driven prices would attract LNG shipments.
  - LNG shipments would move California from the end of the pipe to the beginning of the pipe.

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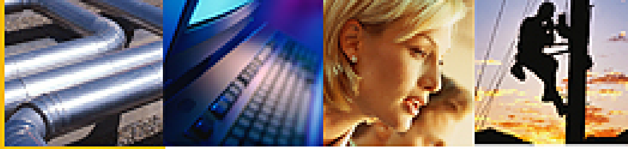
Costa Azul Provides Free Insurance for California



- The potential availability of LNG provided by Costa Azul provides insurance for California
  - Price
  - Reliability
- The infrastructure investments that have created this insurance policy were made by SLNG, and not by California’s natural gas utilities or their ratepayers
  - SLNG funded Otay Mesa Receipt point construction
  - The Costa Azul facility was funded and constructed by SLNG, at no cost to California or California’s natural gas consumers
- Sempra LNG funded infrastructure improvements improve system reliability for SoCalGas, SDG&E and El Paso Natural Gas at Erhenberg, Blythe and Otay Mesa.
  - Sempra LNG expanded receipt point capacity at Otay Mesa allowing for up to 700 MMCFd as a bidirectional flow, even though only 400 MMCFd of this capacity is firm.
    - Under Long-Term High Winter Demand conditions, it is likely that more than the 400 MMCFd of firm capacity would be available
  - The expanded North Baja and Baja Norte Pipelines and the ability for them to reverse flow and move LNG north, provides supply for California and East of California through the Otay Mesa receipt point and the reverse flow on North Baja Pipeline to both Blythe and Erhenberg,

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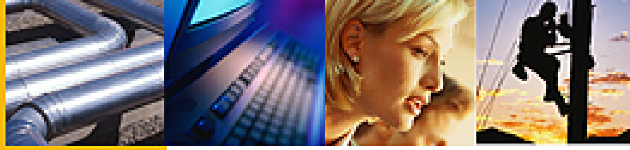
LNG Access Will Ensure Adequate Natural Gas Supplies; Are Available to Promote GHG Reductions and Will Not Lead to Higher GHG Emissions



- Natural Gas is the lowest emitting fossil fuel.
- Natural gas generation facilities will be necessary to ensure reliability with increasing reliance on intermittent renewable resources.
- GHG Emissions from LNG are about the same as for natural gas produced in the U.S.
  - Average life cycle emissions for domestically-produced natural gas: 145.78 lbs/MMbtu
  - Average life cycle emissions for LNG consumed in the U.S.: 145.92 lbs/MMbtu
  - See, “Greenhouse Gas Life Cycle Emission Study: Fuel Life Cycle of U.S. Natural Gas Supplies and International LNG,” prepared by Advanced Resources International and ICF International, November 10, 2008
- GHG emissions generating electricity with coal are three times higher than generating electricity with LNG
  - Coal: 2731 lbs CO2e/MWh
  - LNG: 1045 lbs CO2e/MWh
  - See, “Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios,” PACE, February 3, 2009

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PACE

4401 Fair Lakes Court
Fairfax, VA 22033-3848 USA
Phone: 1.703.818.9100
Fax: 1.703.818.9108

Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results

Prepared for:

Center for Liquefied Natural Gas (CLNG)

Date

February 3, 2009

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PACE OVERVIEW

The Center for Liquefied Natural Gas (CLNG) retained Pace to perform an independent assessment of the greenhouse gas emissions resulting from the life cycle process of generation using LNG fuel supply and competing coal fired generation options. This document presents the results of this independent assessment and the major assumptions underlying this analysis.

Pace is an independent energy and carbon consulting and management firm with clients and engagements across the globe in over 40 countries and six continents. Headquartered outside Washington, D.C. with offices in Houston, New York, Columbia, San Diego, Sacramento, London and Moscow, Pace provides expertise in the following areas: energy asset and infrastructure development and management, risk management, global energy market forecasting and transaction due diligence, M&A and asset disposition, carbon & environmental market advisory and management and related technical services. Since 1979, Pace has provided innovative services to support the execution of a full spectrum of business strategies and complex energy transactions. Throughout our history, Pace has developed integrated solutions that address both environmental and economic considerations by applying creativity, deep subject matter knowledge and integrity to every engagement.

Pace is well qualified to perform this life cycle greenhouse gas emissions analysis due to its depth and breadth of experience across the energy sector including fuel supply, energy technology and engineering, carbon management and power generation. Pace assists clients through all stages of energy production from fuel supply at the wellhead through consumption at the burner tip. Notably, Pace is or has been engaged in permitting, financing, and / or development efforts for more than five LNG facilities in the U.S. alone. In addition, Pace has a dedicated Carbon Management practice comprised of top professionals experienced in the formation of carbon markets, global regulatory drivers and the cutting edge standards and practices for quantifying GHG footprints and lifecycle carbon intensity. Pace's carbon services are highly regarded in the industry and Pace is actively deploying cutting edge carbon management practices and management systems to prepare companies for future carbon constraints. Pace has provided comparative greenhouse gas life cycle emission assessments on behalf of proposed LNG terminals and other generation options.

INTRODUCTION & KEY FINDINGS

The Center for Liquefied Natural Gas (CLNG) commissioned a multi-scenario life cycle assessment (LCA) of carbon (or greenhouse gas – GHG) emissions attributable to several domestic generation options including natural gas-fired power generation supplied by imported liquefied natural gas (LNG) and conventional and advanced coal generation alternatives. The following four technology cases are included in the multi-scenario carbon LCA prepared for CLNG:

1. U.S. notional LNG supply and transportation system and end-use combustion using a modern natural gas fired combined cycle (NGCC) power plant;

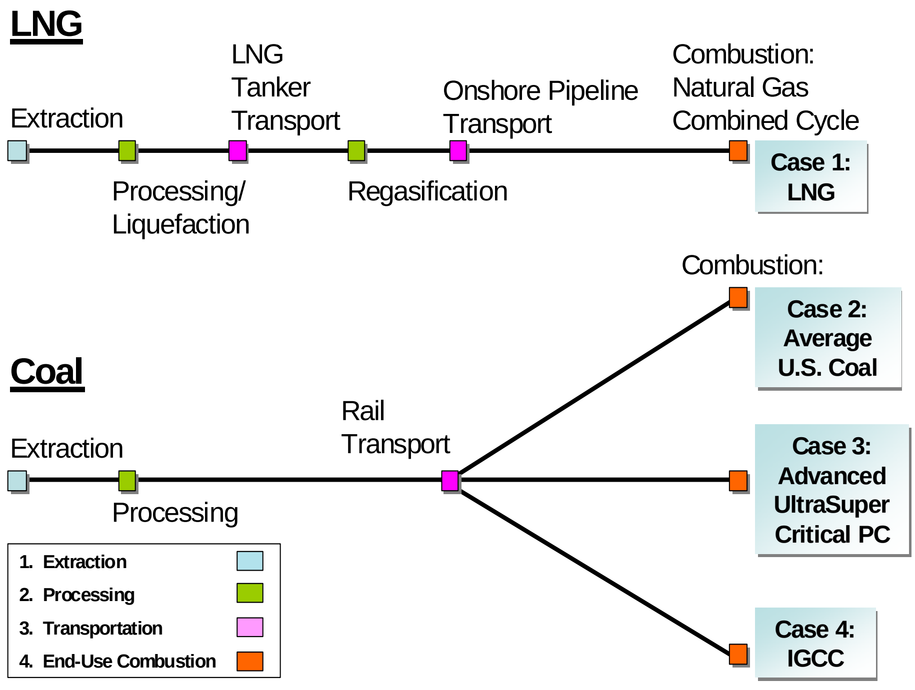
2. Coal supply, transportation, and end use combustion representative of the current U.S. coal technology mix;

3. Representative U.S. coal supply and transportation and end-use combustion using advanced ultra supercritical coal fired (SCPC) power plant (that is characterized by high efficiency);

4. Representative U.S. coal supply and transportation and end-use combustion using integrated gasification combined cycle (IGCC) coal fired power plant.

Pace calculated the aggregate life cycle carbon emissions for all scenarios. All assumptions, calculations and interpretation of the results of the LCA will be presented in this report. Exhibit 1 presents the generation scenarios assessed.

Exhibit 1: LCA Scenario Diagrams



Source: Pace

The intent of this analysis was to provide a transparent, consistent, and equitable "apples to apples" comparison of the GHG emissions attributable to generation in the U.S. based on assumptions that reflect the typical, average, or most common practices, processes, equipment, and geographical considerations associated with the selected scenarios.[1] The LCA quantifies the amount of three of the six main Kyoto GHGs (carbon dioxide – CO_2, methane – CH_4 and nitrous oxide – N_2O) emissions associated with electric energy consumption, fuel combustion and fugitive losses (including CO_2 and CH_4). The other three main Kyoto GHGs (sulfur hexafluoride – SF_6, hydrofluorocarbons - HFCs, and perfluorocarbons - PFCs) were excluded from the analysis as emissions of these GHGs were estimated to be negligible in the processes considered.

DEFINITION OF BOUNDARY CONDITIONS

This LCA quantified and compared all applicable GHG emissions associated with the life cycle of power produced with imported LNG and coal using a variety of different combustion technologies. The analysis was carried out under the following assumptions:

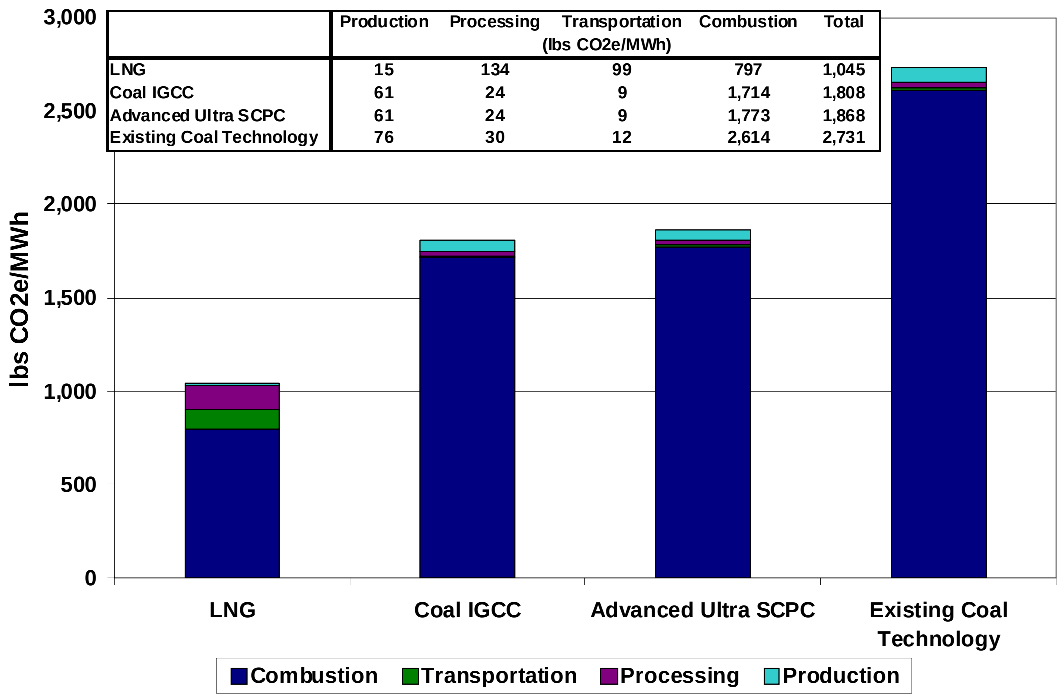
[1] While the results of the analyses are reported in a single value for each scenario, it should be noted that this report will not be representative of any facility specific supply chains and that significant variation exists within actual supply chains. This analysis was constrained by the relative accuracy of publicly available data sources for characterizing the notional U.S. generation supply chain. These sources of uncertainty and variation make it impractical to draw strong conclusions from small differences in life-cycle emissions. Instead, the reported results are intended to demonstrate the relative GHG impact of various fuel alternatives and technology options.

- Production, processing, and transportation of fuels representative of current U.S. energy production streams.
- With the exception of the current coal technology scenario, combustion technologies represent advanced and efficient generation options expected for new builds.
- The LCA examined the entire life cycle of the fuels including extraction (of fuel from already developed wells and mines), processing, transportation, and combustion.
- The LCA boundary included only process and operation-related emissions and did not include emissions from the construction or decommissioning of infrastructure, such as construction of power plants, trains, ships, etc.
- The LCA only included emissions from the operation of infrastructure directly attributable to the fuel combusted in the end-use power plant. Results are presented in terms of pounds of carbon dioxide equivalents per megawatt hour of generation (lbCO2e/MWh).

SUMMARY OF RESULTS

Exhibit 2 presents total GHG emissions for each stage of the life cycle for all scenarios. For all of the coal cases, production and combustion emissions were greater than the LNG case. However, the processing and transportation segment emissions were greater in the LNG case. Existing coal technologies emitted more GHG emissions than advanced coal technologies --- IGCC and advanced ultra SCPC.

Exhibit 2: Summary of LCA Results



	Production	Processing	Transportation	Combustion	Total
			(lbs CO2e/MWh)		
LNG	15	134	99	797	1,045
Coal IGCC	61	24	9	1,714	1,808
Advanced Ultra SCPC	61	24	9	1,773	1,868
Existing Coal Technology	76	30	12	2,614	2,731

Source: Pace

LCA ASSUMPTIONS

Data and assumptions for this analysis were obtained from publicly available sources. Estimations and judgments, where needed, were made by industry experts from Pace and CLNG membership base. A complete list of references follows this document.

LNG COMBUSTION USING MODERN NGCC POWER PLANT

Production (Offshore, Includes Field Processing)

The production segment assumed offshore production as well as field processing. Pace's LNG production assumptions were primarily based on *Tamura et. al* which surveyed gas fields in LNG exporting countries: Indonesia, Malaysia, Brunei, Australia, and Alaska. A dry gas proportion of product mix of 0.89 based on data from the API Compendium was assumed.

Emissions in this segment included:

- CO_2 from natural gas combustion in gas turbines driving compressors for extraction;
- CO_2 from purge gas burned and discharged in the flare stack;
- Vented CH_4 produced during dehydration; and
- Fugitive CH_4 from compressors were deemed insignificant and were not quantified.

Pace referred to Climate Mitigation Services (CMS) and Tamura et al. in determining fuel consumption (through combustion) rates in offshore production. Pace found Tamura's emissions rate of 2.13 lbs CO2e/MMBtu produced to be consistent with other industry estimates and consequently adopted it for this analysis. Pace further proportionately adjusted the fuel consumption estimate of CMS to reflect Tamura's emissions rate.

Segment CO2e Emissions	1.889	lbs CO2e/MMBtu Produced
	12.69	lbs CO2e/MWh
	15.13	Adj. lbs CO2e/MWh

Processing / Liquefaction Plant

Emissions and fuel consumption rates for processing and liquefaction segments from several sources were reviewed for this LCA. Actual emissions and fuel consumption rates will vary depending on a number of factors including technology vintage, local environmental conditions, feed gas composition, and facility capacity and utilization. For this analysis, data from the Tamura study was selected, which was based on a survey of several international LNG suppliers. The results from the Tamura study were found to be consistent with figures from several facilities cited in the Pluto study. The data takes into account CO_2 emissions from fuel consumption, flare combustion, vented CH_4, and release of raw CO_2 gas. Pace assumed 8.8% of liquefied volume is combusted during this phase based on data from Tamura. It should be noted that other studies, including studies of Atlantic LNG Train 4, calculated a higher combustion percentage values. Pace found that using an 11.57% value consistent with other studies, would change the total LCA emissions by a negligible amount (less than 0.4%). Therefore, Pace used the Tamura combustion percentage to maintain a consistency of sources throughout the segment.

Segment CO2e Emissions	16.167	lbs CO2e/MMBtu Liquefied
	108.62	lbs CO2e/MWh
	127.79	Adj. lbs CO2e/MWh

Transportation via LNG Tanker

Several studies were evaluated to determine the emissions during the transportation segment. The LCA used the following assumptions and calculations:

- Tanker size of 138,000 cubic meters;
- Roundtrip transport distance to the U.S. (weighted average) of 7,369 nautical miles;
- Average tanker speed rated at 19.5 knots;
- Transport emission rate of 2,670 lbs CO2e/nm;
- Cargo combustion rate of 19.87 MMBtu/nm; and
- Natural gas fuel consumption at 5% of delivered volume.

Segment CO2e Emissions	6.409	lbs CO2e/MMBtu Delivered LNG
	43.07	lbs CO2e/MWh
	46.57	Adj. lbs CO2e/MWh

Regasification Facility

Data available for GHG emissions from the regasification segment of the LNG lifecycle vary greatly. Some studies suggest that the cryogenic energy of LNG can be used to create power, provide air separation services, and to conduct other useful services that can potentially offset the net emissions of the LNG lifecycle. However, this LCA used conservative data to estimate emissions during this segment. The Yang and Huang study suggested that this segment consumes 1.5% of natural gas send-out. The LCA assumed emissions of 0.85 pounds of CO2e based on the Tamura study and then assumed that the regasification facilities necessitate the use of one crew (security) boat operating during the entire docking and unloading process along with two tug boats.

Tug:

Segment CO2e Emissions	0.155	lbs CO2e/MMBtu Delivered LNG
	1.04	lbs CO2e/MWh
	1.07	Adj. lbs CO2e/MWh

Plant:

Segment CO2e Emissions	0.850	lbs CO2e/MMBtu Sent Out
	5.71	lbs CO2e/MWh
	5.89	Adj. lbs CO2e/MWh

Pipeline to Power Plant

Emissions from pipeline transport are very segment specific, varying with pipeline infrastructure, compression energy source, and segment distance. In order to most accurately define the related emissions for an average U.S. pipeline haul, the LCA assumed pipeline fuel consumption and both combustion and non-combustion CO2e emissions based on EIA natural gas consumption data and data from the U.S. GHG Inventory released by EPA in 2008. This data yielded an average retention rate of 1.7% (per unit volume). This fell within the range of retention rates for major U.S. interstate pipeline tariffs, which Pace found to be between 0.5% and 4%. For LNG, this U.S. average rate may be considered conservative for terminals located within close proximity to the point of natural gas delivery.

Segment CO2e Emissions	7.496	lbs CO2e/MMBtu
	50.37	lbs CO2e/MWh
	51.12	Adj. lbs CO2e/MWh

Power Plant

For this analysis, the LCA used assumptions from the U.S. Department of Energy's National Energy Technology Laboratory (NETL)'s Exhibit ES-2, Case 13.[2] The study assumes that:

- The NGCC plant has a capacity of 560 MW;
- The heat rate is 6,719 Btu/kWh; and
- The CO2e emissions factor is 797 lbs CO2e/MWh.

Segment CO2e Emissions	Plant Emissions Factor	797	lbs CO2e/MWh

Total CO2e Emissions	Total lbs CO2e/MWh	1,045	lbs CO2e/MWh

U.S. COAL PRE-COMBUSTION LIFE CYCLE

MINING

Pace used published data to estimate the emissions attributable to coal production and transported an "average" distance to a coal-fired generation unit in the U.S. The details underlying the U.S. based coal generation scenarios in the LCA are as follows:

- EIA data indicates about 69% of coal produced in the U.S. is produced through surface mining and 31% is produced through underground mining.[3] Pace used these statistics to produce a weighted average estimate of emissions from mining coal in the U.S.

- To estimate emissions from underground and surface mining, Pace uses assumptions from a study prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE).

[2] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007
[3] EIA Production Data, 2007

- Pace estimated fugitive methane emissions from coal mining using EIA coal production data and data from the U.S. GHG Inventory data released by the EPA in 2008. Captured methane is not included as a (fugitive) emission.

- Pace used emissions factors published by The Climate Registry to estimate emissions from diesel combustion in locomotive transportation and mining equipment.

- Pace used EPA eGrid national average emissions factors for estimating a weighted average of GHG emissions generated by the existing U.S. coal fleet. Pace used global warming potentials for methane and nitrous oxide from IPCC's Second Assessment report where applicable.

Underground Mining

For the underground mining component of the analysis, Pace used assumptions from EERE's hypothetical Eastern Underground Coal Mine.[4] This study assumed:

- A room and pillar coal mine operating over a 20-year lifetime with a 20 million-ton output at the end of its life;
- Mine runs 301 days per year with two 9 hour shifts per day, giving it a daily production rate of 3,322 tons per day;
- Deposit characteristics are a bedded deposit with an average dip of 18 degrees;
- Average maximum horizontal is 2,900 feet and a minimum of 20 feet;
- Average maximum vertical is 5.9 feet with a vertical distance to the surface of 1000 feet.

Electrical equipment at this hypothetical site includes:

- 11 main fans;
- 25 LHDs;
- 13 drills;
- Two boon jumbos;
- Two continuous mining machines;
- One crusher;
- One conveyor;
- Two water pumps;
- One diamond drill.

Diesel equipment at this hypothetical includes:

- 31 service trucks;
- Six ANFO loaders;
- One roof bolter.

Segment CO2e Emissions (Underground)	206.6	lbs CO2e/Ton

[4] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002

Surface Mining

For the surface mining component of the analysis, Pace used assumptions from EERE's hypothetical Western Surface Mine. [5] This study assumed:

- Coal mine operation over a 20-year lifetime with a 200 million-ton output at the end of its life;
- Mine runs 360 days per year with two shifts per day of 10 hours which gives it a daily production rate of 27,778 tons per day and a daily waste production of 138,890 tons per day;
- Distance the ore must travel is 1,000 feet at a gradient of 8 percent and the distance the waste must travel is 70 feet with a gradient of 8 percent.

Electrical equipment at this hypothetical site included:

- Four cable shovels;
- Two rotary drills.

Diesel equipment at this hypothetical included:

- 11 rear dump trucks;
- Seven bulldozers;
- 20 pick-up trucks;
- One water tanker;
- Two pumps;
- Two service trucks;
- Two bulk trucks;
- One grader.

Segment CO2e Emissions (Surface)	106.3	lbs CO2e/Ton

Segment CO2e Emissions (Weighted Ave.)	137.2	lbs CO2e/Ton
	7.0	lbs CO2e/MMBtu
	75.9	lbs CO2e/MWh

COAL PREPARATION

For the coal preparation component of the analysis, Pace used assumptions for the beneficiation process from EERE's hypothetical Eastern Mine.[6] Over 98% of the energy in this case is used by the electric grinding mill. Other sources of emissions are an electric centrifuge, floatation machine, screens, and a magnetic separator.

Fugitive methane emissions associated with coal preparation were estimated by Pace using EPA's 2008 GHG Inventory data and data from EIA on US coal production.

[5] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002
[6] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002

Segment CO2e Emissions	54.1	lbs CO2e/Ton
	2.8	lbs CO2e/MMBtu
	29.9	lbs CO2e/MWh

RAIL TRANSPORTATION

For the transportation component of this analysis, Pace estimated that:

- The average rail trip for a roundtrip delivery of coal is 1,480 miles;
- The average delivery is 12,200 tons of coal per trip;
- The average consumption of diesel fuel during delivery by the trail is 0.13 gallons per mile;
- The rail train has 100 cars and 2 locomotives.

Segment CO2e Emissions	21.0	lbs CO2e/Ton
	1.1	lbs CO2e/MMBtu
	11.6	lbs CO2e/MWh

COAL POWER GENERATION TECHNOLOGIES

AVERAGE U.S. COAL-FIRED POWER PLANT

For this analysis, Pace preliminarily estimated that:

- The average capacity of existing coal plants currently operating in the U.S. is 455 MW;
- The weighted average heat rate is 10,824 Btu/kWh;
- The weighted average CO_2e emissions factor is 2,614 lbs CO2e/MWh.

Segment CO2e Emissions	2,614	lbs CO2e/MWh

Total CO2e Emissions	2,731.4	lbs CO2e/MWh

ADVANCED ULTRA SUPERCRITICAL COAL FIRED POWER PLANT

For this analysis, Pace used assumptions from the U.S. Department of Energy's National Energy Technology Laboratory (NETL)'s Exhibit ES-2, Case 11.[7] The study assumed that:

- The advanced ultra supercritical coal fired plant has a capacity of 550 MW;
- The heat rate is 8,721 Btu/kWh;
- The CO_2e emissions factor is 1,773 lbs CO_2e/MWh.

Segment CO2e Emissions	1,773	lbs CO2e/MWh

Total CO2e Emissions	1,867.6	lbs CO2e/MWh

[7] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) COAL FIRED POWER PLANT

For this analysis, Pace used assumptions from NETL's Exhibit ES-2, Cases 1, 3, and 5, averaged.[8] The study assumed that:

- The IGCC plant has a capacity of 633 MW;
- The heat rate is 8,636 Btu/kWh;
- The CO2e emissions factor is 1,714 lbs CO2e/MWh.

Segment CO2e Emissions	1,714	lbs CO2e/MWh

Total CO2e Emissions	1,808	lbs CO2e/MWh

[8] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007

RESULTS AND INTERPRETATION

BASE CASE RESULTS

Exhibit 3 presents a summary of the base case LCA by process for each scenario.

Exhibit 3: Results of Base Case LCA by Process

Scenario	Production	Processing	Transportation	Combustion	Total
(lbs CO2e/MWh)					
LNG	15	134	99	797	1,045
Current U.S. Coal Technology Mix	76	30	12	2,614	2,731
Advanced Ultra Supercritical	61	24	9	1,773	1,868
IGCC	61	24	9	1,714	1,808

Source: Pace

INTERPRETATION OF LCA BASE CASE RESULTS

To date the U.S. has declined to implement regulated carbon constraints. Federal climate change bills have been proposed sporadically in the U.S. Congress since the late 1990's and have gained little traction until very recently. Over the past year or so, pressures for the U.S. to take mandatory action to address climate change have been mounting. With federal GHG regulation on the horizon, it is important to consider the full realm of carbon implications from large scale generation options in planning energy developments to support a low carbon economy.

Benefits of LNG Supply in the U.S.

- The increases in current domestic natural gas reserves are dependent upon greater exploitation of unconventional reservoirs and difficult to drill areas. These types of domestic sources of natural gas need to be supported by sources of natural gas from other locations, especially under a carbon constrained economy where natural gas is the low carbon alternative to oil and coal. The natural gas reserve to production ratio in North America is around 10, while that of other prominent producing regions is much greater, with the Middle East at 246, South and Central America at 51, Africa at 88, and Europe (including Russia) at 60. LNG can supply the need while still emitting fewer GHGs compared to other fossil fuel alternatives
- Increasing the supply of natural gas through LNG is expected to place downward pressure on prices in the longer term. Much of the incremental production in North American basins is from unconventional sources such as shale formations, tight sands, and coal bed methane. These resources are generally more costly and energy intensive to develop due the need for advanced drilling techniques, such as horizontal drilling, and are also often characterized by smaller concentrations and steeper decline rates. Over the long-term, delivered LNG prices are expected to fall below the costs of incremental North American production, thereby moderating long-term natural gas prices.

- Significant investment in LNG in recent years contributes to increased supply and capacity as larger ships are used to haul LNG, the pipeline infrastructure is updated and expanded, and new technologies are developed that are potentially more efficient, cost-effective, and cleaner (emit fewer emissions).
- The significant number of geological structures in the US that are conducive to storage of natural gas will allow the U.S. to attract volumes of LNG during periods of oversupply to ensure reliable supply and mitigate commodity price volatility.

Comparison of Existing Coal Technology to Advanced Coal Technologies

Existing coal technologies emit approximately 50% more emissions than advanced coal technologies, IGCC and advanced ultra SCPC, through the combustion stage in the life cycle only, assuming all other life cycle stages are held constant. Due to environmental concerns, permitting and siting of new traditional coal-fired power plants has become increasingly difficult and IGCC and advanced ultra SCPC plants are not yet currently commercially viable in the U.S. Thus, in the near term, and considering the current situation of carbon regulatory uncertainty, it is not clear how much new coal capacity will be permitted, placing incremental supply pressures on gas – sourced either of domestically or internationally.

Comparison of LNG to Existing Coal Technology

The base case LCA results highlight some important differences between LNG and existing coal technologies, including:

- The overall difference between LNG and existing coal technology emissions was found to be 1,687 lbs CO_2e/MWh; or existing coal produces 161% greater emissions on a life cycle basis than that of LNG.
- The analysis indicated that the cleanest coal scenario (IGCC) releases 73% more emissions from a life cycle perspective than LNG.
- The LNG scenario emissions from processing and transportation segments were found to be greater than coal cases, largely due to the incremental processing steps (liquefaction and regasification) required for LNG and the resulting fugitive methane emissions' greater GHG potency (21 times that of carbon dioxide).

APPENDIX A: CONVERSION FACTORS AND EMISSION FACTORS

Description	Value	Unit	Source
kWh to Btu	3,412	Btu / kWh	TCR
kg to lb	2.205	lb / kg	TCR
g to kg	0.001	kg / g	TCR
barrel to gallon	42	gallons / barrel	TCR
short ton to lb	2,000	lb / short ton	TCR
MMBtu/Btu	1,000,000	Btu / MMBtu	TCR
MWh to KWh	1,000	kWh / MWh	TCR
g-C equiv/MJ to lbs CO2e/MMBtu	8.528	MMBtu –g-C / MJ-lb	Unit Analysis
Days to Hours	24	hour / day	
Years to Days	365	day / year	
Tonne LNG to MMBtu	51.1	MMBtu / Tonne LNG	Pace
Emissions Factors			
US Grid Electric Emissions Factor	1,369	lbs CO2e / MWh	EPA EGRID
Diesel Emissions Factors	73.15	kg CO2 / MMBtu	TCR
Diesel Emissions Factors	3	g CH4 / MMBtu	TCR
Diesel Emissions Factors	0.6	g N2O / MMBtu	TCR
Diesel Heat Content	5.825	MMBtu / barrel	TCR
Global Warming Potentials			
CO2	1	lbs CO2e / lb CO2	1995 IPCC SAR / TCR
CH4	21	lbs CO2e / lb CH4	1995 IPCC SAR / TCR
N2O	310	lbs CO2e / lb N2O	1995 IPCC SAR / TCR

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The Drewry Annual LNG Shipping Market Review and Forecast 2007/07. Gardiner, Nigel; July 2007.	LNG Case ▪ Tanker transportation
Energy Information Administration (EIA). 2008. Natural Gas Annual 2006. Table 1: Summary Statistics for Natural Gas in the United States, 2002-2006. January. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html	LNG Case ▪ Pipeline fuel consumption ▪ Emissions from pipeline transmission Coal Cases ▪ Methane fugitive emissions associated with mining and coal preparation ▪ Production volume for US mining
Heede, Richard. 2006. Climate Mitigation Services (CMS). LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California. May. http://www.edcnet.org/ProgramsPages/LNGrptplusMay06.pdf	LNG Case ▪ Production ▪ Subsea Pipeline ▪ Tanker transportation
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Platts Coal Outlook	Coal Cases ▪ Energy content of coal
Pluto LNG Project, Draft Public Environmental Report/Public Environmental Review, Chapter 5, Table 5-2, 5-3 & 5-4	LNG Case ▪ General cross reference

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The Climate Registry. 2008. General Reporting Protocol. May. http://www.theclimateregistry.org/downloads/GRP.pdf	All Cases ▪ Standard emissions and conversion factors
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U.S. Environmental Protection Agency (EPA). 2008. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. EPA 430-R-08-005. April 15. http://www.epa.gov/climatechange/emissions/downloads/08_CR.pdf	LNG Case ▪ Emissions from pipeline transmission Coal Cases ▪ Methane fugitive emissions associated with mining and coal preparation
Yang, C.C. and Zupeng Huang. 2004. Lower Emission LNG Vaporization. *LNG Journal* Nov/Dec. http://www.fwc.com/publications/tech_papers/files/Lower%20Emission%20LNG%20Vap.pdf	LNG Case ▪ Natural gas consumption at a regasification facility

GREENHOUSE GAS
LIFE-CYCLE EMISSIONS STUDY:
Fuel Life-Cycle of
U.S. Natural Gas Supplies and International LNG

Prepared for:
Sempra LNG

Prepared by:
Advanced Resources International, Inc.
and
ICF International

November 10, 2008

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LIST OF EXHIBITS

EXECUTIVE SUMMARY

The purpose of this study was to compare the greenhouse gas (GHG) emissions intensity (defined in terms of fuel life-cycle carbon dioxide-equivalent (CO_2e) emissions per million British thermal units (MMBtu) of natural gas) for the two major natural gas supply chains in the United States -- natural gas produced in the United States and liquefied natural gas (LNG) imported into the United States. This is intended to include the entire supply chain analysis of CO_2e emissions associated with natural gas delivered to California and other regions of the U.S.

The comparison considered the GHG emissions associated with carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). GHG emissions were estimated under current (defined for purposes of this study as 2006) and forecast (defined for purposes of this study as 2020) conditions, based on existing and expected future supplies and infrastructure.

In all cases, for the national level comparison, the primary specification parameter is pounds of CO_2e per MMBtu of natural gas consumed .

In interpreting the results of this analysis, two important caveats must be kept in mind:

- The analyses assume that there are no major changes to policies affecting GHG emissions controls, at either the state or federal level. In particular, it assumes that no emission trading systems or carbon taxes are established in the U.S. or in specific countries supplying natural gas for LNG to the U.S. market.
- The analyses assume that new facilities/supplies for the 2020 case utilize state-of-the-art technology to minimize GHG emissions.

The overall approach for estimating GHG emissions from the supply chain for the U.S. was derived in part from publicly available domestic greenhouse gas estimates, models, and analytical procedures developed in part by ICF International to support EPA in their GHG emission inventory work for the U.S. petroleum and natural gas sectors and for the American Petroleum Institute.

All GHG emissions associated with the natural gas supply chain, from the wellhead to the burner tip, were estimated so that intensity of each supply chain component could be compared directly. The overall U.S. comparison was determined using total natural gas delivered to end users as a common denominator across all sectors, for both U.S. natural gas supply and imported LNG.

The total GHG emissions intensity for U.S. natural gas supply was estimated to be 145.78 lb CO_2e/MMBtu of natural gas in 2006, while imported LNG was estimated to have an intensity of 145.92 lb CO_2e/MMBtu. Consequently, on average for the U.S., the overall emissions intensity for the U.S. gas supply chain and imported LNG serving U.S. markets are quite comparable.

Exhibit 1 displays the supply chain emissions intensity for the 2006 U.S. supply scenario, and Exhibit 2 displays the comparable graph for LNG supplies serving U.S. markets in 2006.

Natural gas consumed by end-users has an emissions intensity of 117.06 lb CO_2e/MMBtu, or over three-fourths of the total supply chain emissions. The other supply chain emissions are due to natural gas fugitives, venting, and combustion for energy to move the gas through the chain.

Similarly, the GHG emissions intensity for U.S. natural gas supply was estimated to be 140.61 lb CO_2e/MMBtu in 2020, compared to an estimated emissions intensity for imported LNG of 147.25 lb CO_2e/MMBtu. Exhibit 3 displays the supply chain emissions intensity for the 2020 U.S. scenario, and Exhibit 4 displays the comparable graph for LNG supplies in 2020.

Exhibit 1: 2006 GHG Emissions Intensity from U.S. Natural Gas Supply

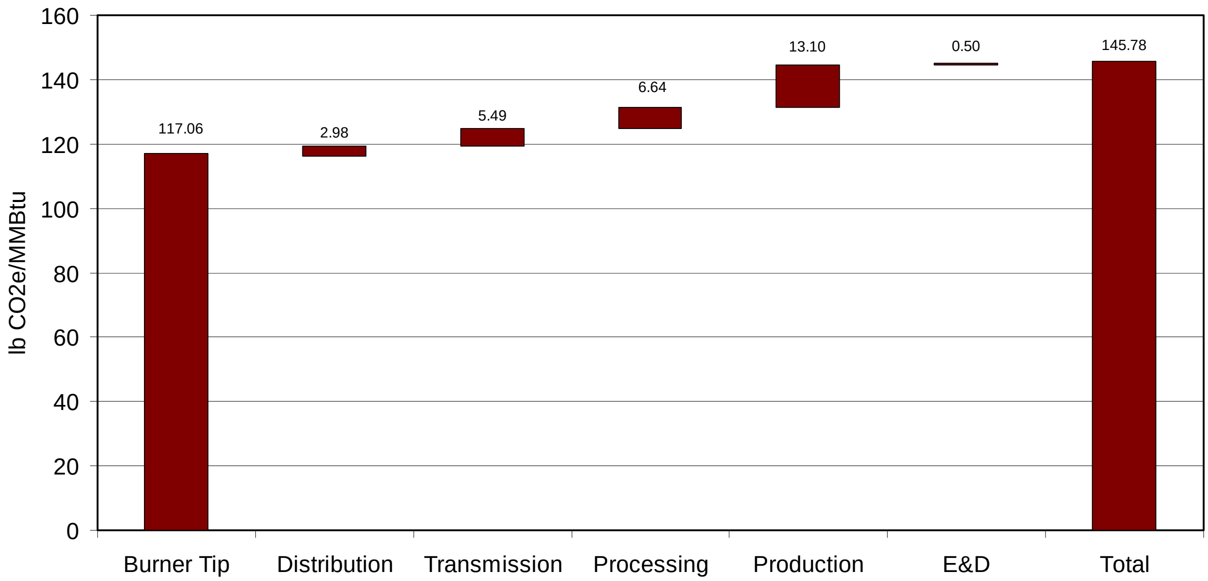


Exhibit 2: 2006 GHG Emissions Intensity from LNG Supply Serving U.S. Market

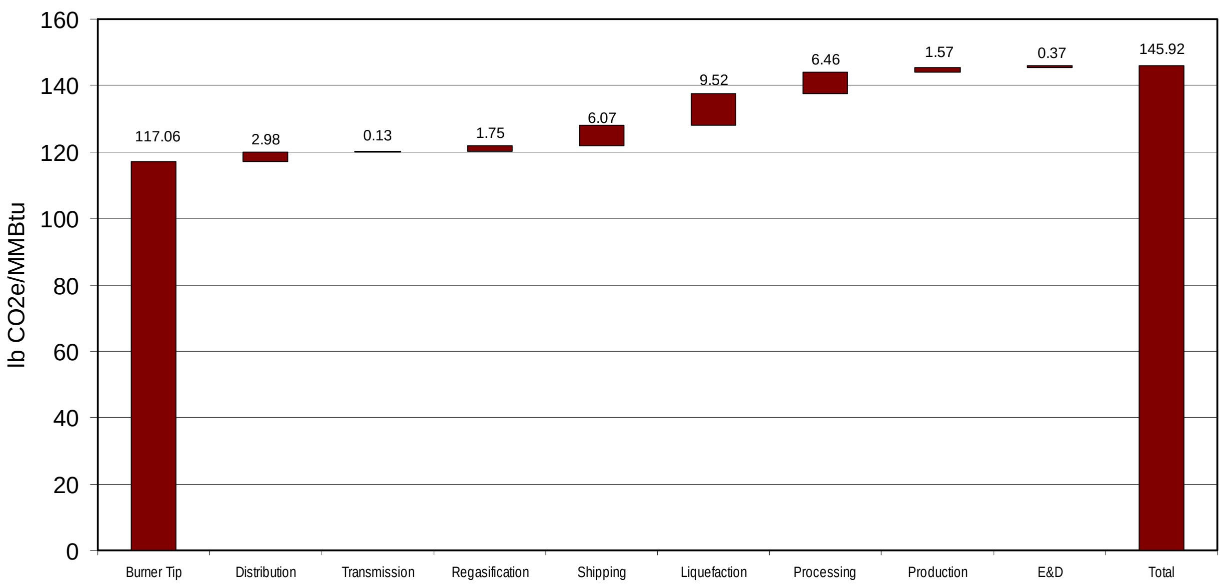


Exhibit 3: 2020 GHG Emissions Intensity from U.S. Natural Gas Supply

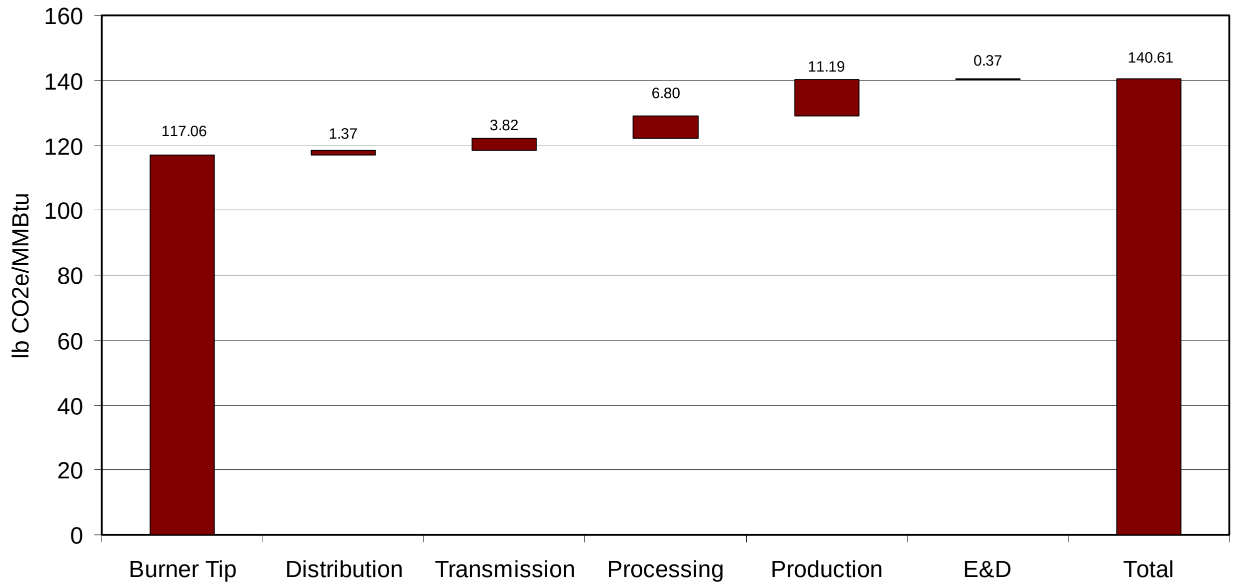
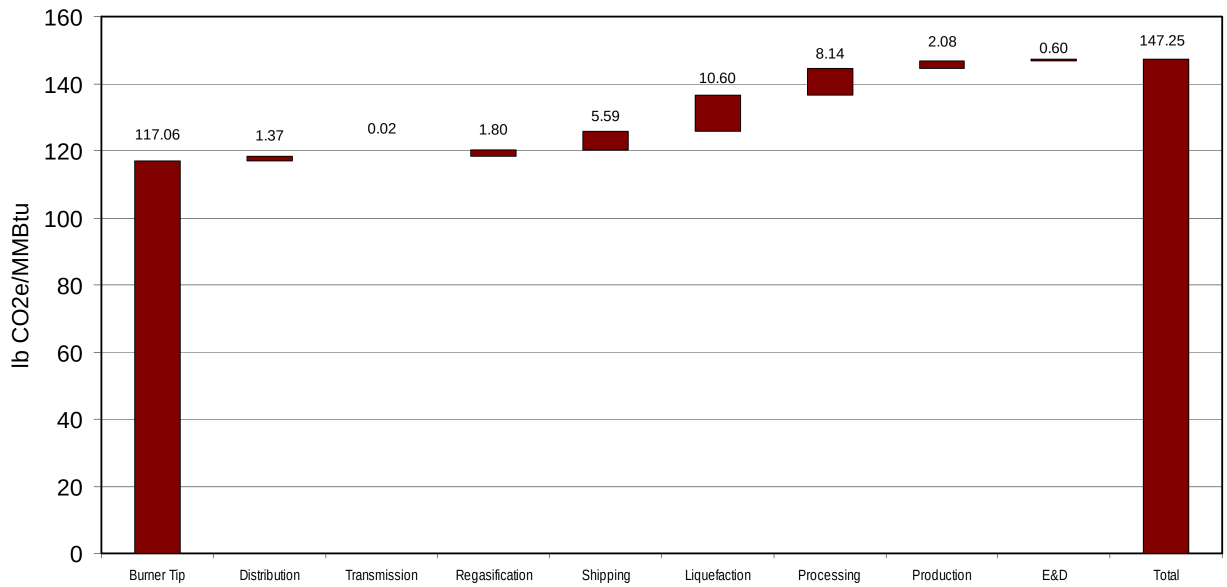


Exhibit 4: 2020 GHG Emissions Intensity from LNG Supply Serving U.S. Market



The conclusion to be drawn from comparisons between 2006 and 2020 for both supply sources is that improvements in efficiencies in limiting emissions in some sectors over time, on average, offset emissions from supplies from higher emission sources that will need to be tapped in the future.

It is also important to note that while the emissions intensity of the U.S. sources of gas and LNG serving U.S. markets are comparable, substantial regional differences can exist for both sources. These differences are illustrated throughout this report for each step in the supply chain, for each of the regions considered in this assessment. Regional intensities, it should be noted, are based on regional and supply chain-specific throughput, and not always final consumption. Therefore, regional intensities cannot simply be added together to develop a regional supply chain intensity.

Finally, it is important to note that this report does not reflect recent revised forecasts that project decreased U.S. and worldwide natural gas consumption compared to earlier forecasts, recent increases in U.S. gas production from unconventional sources, and the anticipated continued growth in production from these unconventional sources.

Conclusions

Overall, the GHG emissions intensity of LNG imported to the U.S. relative to U.S. supply-sourced gas is not significantly different. LNG has considerably lower emissions for development and production, due to the much higher productivity of the resources serving LNG export terminals. Far fewer wells are associated with producing the same volume of gas for LNG relative to U.S. natural gas supplies. Thus, other than the ultimate consumption of the gas itself, the largest sources of emissions are the production and gas processing stages. For LNG, the largest emissions are associated with the processing and liquefaction, shipping, and gasification. A major factor influencing the level of these emissions is the extent to which CO_2 that would otherwise be vented during processing is/will be sequestered, and the distances over which the LNG would need to be shipped.

The most significant factor, by far, contributing to GHG emissions from the natural gas sector, regardless of the source of the gas, is the volume of natural gas consumed. Even dramatic changes in other factors do not make a major contribution to the overall GHG "footprint" of the natural gas industry. Overall, GHG emissions overall are much larger for U.S. sources supply relative to LNG because the volume consumed it much larger. However, the emissions intensity is the same regardless of source.

While the average emissions intensity of LNG or U.S.-sourced natural gas supplies is not materially different, there is considerable variability among the regional sources of gas supplies. This is true for different supply regions in the U.S. and for the different countries serving current and potential future demand for LNG in the United States. Since the global flow and regional consumption of natural gas are based on market conditions, and because greenhouse gas emissions are global in scope, this report focuses on average emissions for both domestically produced natural gas and international LNG likely to be consumed in the United States. When characterizing the emissions intensity of natural gas supply from a specific source -- either from domestic sources or foreign sources serving the international LNG market -- the unique characteristics and variability of specific supply sources (domestic or international) are considered.

OVERVIEW OF INPUT DATA, METHODOLOGY AND ASSUMPTIONS

Background and Introduction

The purpose of this study was to compare the greenhouse gas (GHG) emissions intensity (defined in terms of fuel life-cycle carbon dioxide-equivalent (CO_2e) emissions per million British thermal units (MMBtu) of natural gas) for the two major natural gas supply chains in the United States -- natural gas produced domestically and liquefied natural gas (LNG) imported into the United States. This was intended to include the entire supply chain analysis of CO_2e emissions associated with natural gas delivered to consumers. The analysis considers all GHG emissions associated with fuel consumption, flaring/venting, and fugitive methane emissions, and considers them through each step in the natural gas supply chain:

- Exploration and development
- Production
- Gas processing
- Liquefaction (LNG only)[*]
- Shipping (LNG only)
- Regasification (LNG only)
- Transmission
- Distribution
- Combustion/consumption.

The comparison excludes consideration of the emissions associated with both construction and decommissioning of the facilities associated with each supply source, for example:

- For LNG, this excludes emissions associated with the construction and/or decommissioning of the liquefaction and gasification facilities, transport ships, etc.
- For traditional gas development and production, it excludes emissions associated with construction/decommissioning of drilling rigs, compressors, gas processing facilities, etc.
- For both, it excludes CO_2e emissions associated with construction and/or decommissioning of pipelines, distribution systems, power plants, etc.

The comparison considered the GHG emissions associated with carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). GHG emissions estimates are provided under current (defined for purposes of this study as 2006) and forecast (defined for purposes of this study as 2020) conditions, based on existing and expected future supplies and infrastructure. In all cases, the primary specification parameter is pounds (lbs) of CO_2e per MMBtu of natural gas. For the overall national comparison, GHG emissions intensities associated with each stage of the natural gas supply chain were determined using total natural gas delivered to end users as a common denominator across all sectors, for both U.S. natural gas supply and imported LNG. For the regional comparisons, on the other hand, the emissions intensities were based on the natural gas volumes associated with operations at each stage of the supply chain. For example:

- The emissions intensities for exploration, development, and production are associated with the gas volumes produced.

[*] In the case of LNG, gas processing and liquefaction are part of a single process chain.

- The emissions intensities for gas processing, liquefaction, shipping, and regasification are associated with the gas volume throughput for these processes.
- The emissions intensities for gas transmission, distribution, and consumption are associated with the ultimate natural gas volumes delivered and consumed.

In interpreting the results of this analysis, two important caveats must be kept in mind:

- The analysis assumes that there are no major changes to policies affecting GHG emissions controls, at either the state or federal level; in particular, it assumes that no emission trading systems or carbon taxes are established in the U.S. or in specific regions supplying natural gas for LNG to the U.S. market.
- The analysis assumes that new facilities/supplies built after 2006 for the 2020 case utilize state-of-the-art technology to minimize GHG emissions.

The analysis of the life cycle GHG emissions intensity of natural gas produced in U.S. versus LNG imported into the U.S. was performed jointly by Advanced Resources (ARI) and ICF International (ICF). ARI worked primarily to develop activity data to characterize the two scenarios, while ICF provided emissions factor data and modeled each supply chain.

The overall approach for estimating GHG emissions from the supply chain for the U.S. was derived from ICF's proprietary set of data, models, and analytical procedures, for the most part developed to support EPA in its GHG emission inventory work for the U.S. petroleum and natural gas sectors.[1] For the LNG supply chain, new data, assumptions and analytical procedures were developed specifically for this study.

In general, GHG emissions were estimated for each sector at the lowest level of aggregation, i.e. at an individual source level. For example, emissions were estimated from individual sources like compressors, engines, wellheads, etc. There are a few exceptions to this, such as:

- Offshore platform emissions, which are estimated on a per platform basis
- Emissions from fuel combustion in production and processing, which are estimated at a national level.

The individual sources of GHG emissions are classified into three broad categories:

- <u>Vented emissions</u> from designed/intentional equipment or process vents
- <u>Fugitive emissions</u> are unintentional equipment leaks
- <u>Combustion emissions</u> are those associated with the fuel combustion.

The emissions from each source were estimated as a product of individual emission factors and activity factors:

- <u>Emission factor</u> is defined as the emissions rate per equipment or activity.
- <u>Activity factor</u> is defined as an equipment count or frequency of an activity.

The emissions from natural gas production and processing were primarily estimated using emission factors and activity factors from:

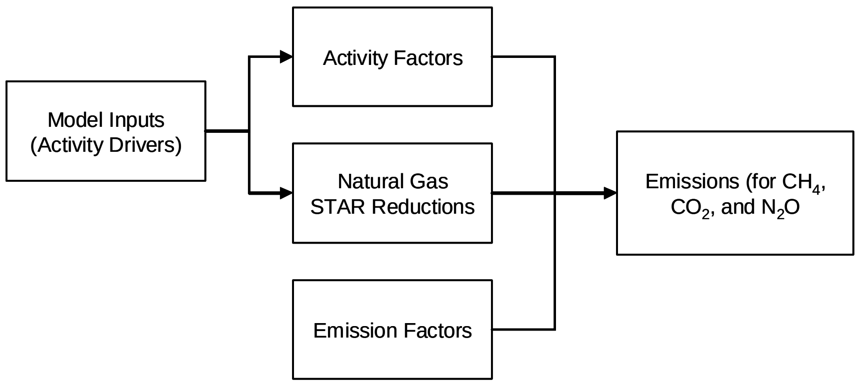
- API's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (API 2004)

[1] http://www.epa.gov/climatechange/emissions/usinventoryreport.html

- U.S. Environmental Protection Agency (EPA) Study – *Methane Emissions from the Natural Gas Industry* (EPA/GRI 1996)
- EPA study *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA/ICF 1999).

A schematic of the emissions estimation process is provided in Exhibit 5.

Exhibit 5: Process for Estimating GHG Emissions



The two years of interest for this study are 2006 and 2020, while the measurements made in the various EPA studies are from different historical years. The activity factors (and total emissions) needed to be adjusted to provide for updated emission estimates. Activity factor drivers were used to proportion activity factors in the reference study base year and then were used for each year of interest (either 2006 or 2020) in the same proportion, using the following formula:

$$\text{Analysis Year Activity Factor} = \frac{\text{(RSBY Activity Factor * Analysis Year Activity Factor Driver)}}{\text{RSBY Activity Factor Driver}}$$

Where RSBY = Reference Study Base Year

Methodology Description – U.S. Natural Gas

The U.S. natural gas supply chain consists of six sectors: exploration and development, production, gas processing, transmission, distribution, and consumption. The current state of the U.S. natural gas industry is well defined in data from the U.S. Energy Information Administration (EIA). Greenhouse gas emissions from the natural gas industry are also estimated in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*,[2] so the estimate of emissions intensity for U.S. natural gas supply in 2006 should accurately reflect the current state of the industry.

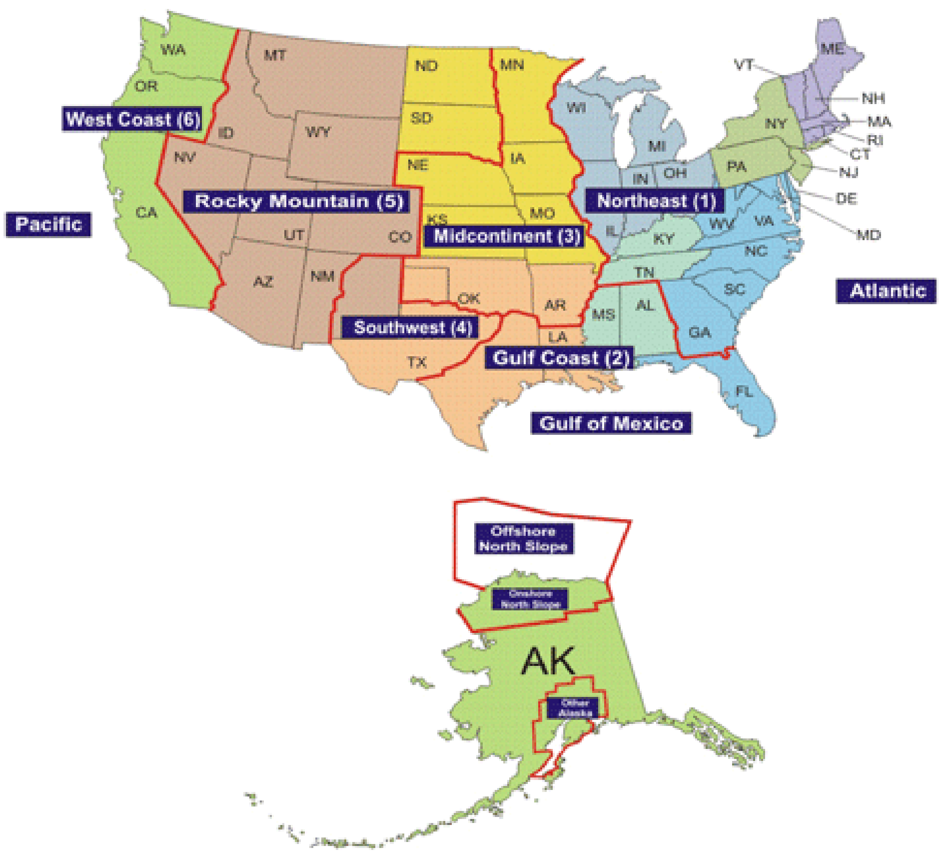
Projections to 2020 are subject to many factors, including changing natural gas prices and GHG emission legislation, which are outside the scope of this study. The emissions intensity estimates for 2020 are built primarily off of the EIA's Annual Energy Outlook (AEO) for 2007.[3] Some adjustments to the emissions profile of the U.S, gas industry have been made to characterize changing technology in 2020. The EPA Natural Gas STAR Program[4] tracks emission reductions from Partner companies in the U.S. natural gas industry; data from this program was used to project reductions to non-Partner companies and implementing best available technology industry-wide by 2020. The Natural Gas STAR Program reports reductions

[2] http://www.epa.gov/climatechange/emissions/usinventoryreport.html
[3] http://www.eia.doe.gov/oiaf/archive/aeo07/index.html
[4] http://www.epa.gov/gasstar/

for four sectors: Production, Processing, Transmission, and Distribution. No other sectors have reductions accounted for (i.e., E&D, Liquefaction, Shipping, Regasification, and Consumption).

For purposes of this study, forecasts for U.S. upstream activities (exploration and development, production and processing) were based on ICF's Hydrocarbon Supply Model (HSM). For both current (2006) and forecast (2020) activity, supply-related emissions are developed by AEO supply region and resource type: conventional gas (associated and non-associated) and unconventional gas (tight gas, gas shales, coalbed methane). Estimates were developed by play and basin, and then were aggregated to the AEO supply region, as represented in EIA's Annual Energy Outlook (AEO). AEO supply regions are illustrated in Exhibit 6.

Exhibit 6: EIA AEO Supply Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Exploration and Development

The two major GHG emissions sources associated with natural gas exploration and development include diesel combustion from drilling rigs, which is a function of the depth of the wells drilled, and natural gas venting and flaring during gas well drilling and completion operations, which is a function of the number and type of completion practices used.

Data factoring into emissions included, by AEO supply region and resource type:

- Number of oil and gas wells drilled
- Type of well (oil with associated gas or non-associated gas)
- Well depth
- Drilling time, in days per representative well
- Number of completions per well drilled
- Fraction of gas wells requiring hydraulic fracturing to stimulate production.

U.S. natural gas well drilling in 2006 and 2020 was estimated using the ICF Hydrocarbon Supply Model (HSM). In 2006, over 35,000 exploratory and developmental wells were estimated to be drilled in the United States; this number was projected to decrease to a little over 20,000 wells in 2020. The breakdown in well drilling by AEO supply region is summarized below:

Estimated wells drilled		2006	2020
Northeast		14,191	5,975
Midcontinent		6,383	4,381
Rocky Mountain		6,530	4,678
Southwest		3,123	1,904
West Cost		130	206
Gulf Coast		5,243	3,254
	TOTAL	**35,600**	**20,399**

For purposes of this analysis, it was assumed that well drilling rates averaged 200 feet per day,[5] and that diesel fuel consumption in well drilling was 1.5 gallons per foot drilled.[6] The average depth of a typical or average well by AEO supply region was assumed to be as follows, based on data in the HSM:

Supply Region	Average Well Depth (feet)
Northeast	4,500
Midcontinent	6,500
Rocky Mountain	3,500
Southwest	8,500
West Coast	6,500
Gulf Coast	10,500

Natural Gas Production

Natural gas is produced from associated gas wells that produce both oil and gas, non-associated gas wells that produce gas only, and unconventional wells such as coal-bed methane wells. GHG emissions from natural gas production are a function of the amount of gas produced, the type of wells producing the gas, and the age and upkeep of producing wells. Specifically, the data factoring in GHG emissions estimation include the following:

- Natural gas production volumes
- Number of producing wells

[5] Gaddy, Dean E., "Coiled-tubing drilling technologies target niche markets," *Oil and Gas Journal*, January 10, 2000
[6] www.arb.ca.gov/ei/areasrc/ccosmeth/att_l_fuel_combustion_for_petroleum_production.doc

- Average gas/condensate production per well
- Average CO_2 content of produced gas
- Average wellhead pressure, methane, and water content of gas
- Portion of wells requiring workovers.

For purposes of this analysis, all of these parameters were based on data from the HSM.

Emissions from most sources in the natural gas production sector were estimated based on the EPA-derived emission factors.[7] The number of these sources was estimated by adjusting the original factors in the EPA studies to 2006 and 2020 conditions based on the number of production wells in each AEO supply region for each of the years (2006 and 2020), as forecast by the HSM, and summarized in Exhibit 7:

The primary GHG emission sources in the production sector are as follows:

- Field separation equipment (heaters, separators, dehydrators, meters/piping)
- Gathering compressors
- Operations equipment (pneumatics, chemical injection pumps, Kimray pumps, dehydrator vents)
- Condensate tanks
- Combustion exhausts (engines, lease fuel, flares)
- Well workovers and cleanups
- Blowdowns
- Upsets (pressure relief, mishaps).

The number of these emission sources in 2006 and 2020 were estimated as a function of the number of producing wells in each of those years.

CO_2 emissions from lease fuel consumption associated with operating field equipment such as pumps, compressors, heaters, etc. are calculated for the production sector. Additional CO_2 emissions associated with fugitive leaks and venting of natural gas have also been calculated using the average regional CO_2 content in produced natural gas.

Natural Gas Processing

After the gas is produced from the well, it is generally delivered to a gas processing facility, where the gas is processed to meet gas pipeline specifications. The configuration of each gas processing plant was estimated from details in the Annual Worldwide Processing Survey from the *Oil and Gas Journal*.[8]

Data factoring into GHG emissions from gas processing are the number of number of processing plants, by type and the gas throughput of plants, again by type for each region. The major factors contributing to GHG emissions are the energy requirements for processing (which is function of gas composition), and the CO_2 vented from processing (which is a function of the CO_2 content of produced gas).

[7] U.S. Environmental Protection Agency, *Methane Emissions from the Natural Gas Industry* (EPA/GRI) 1996

[8] See, for example, Warren True, "SPECIAL REPORT: Mideast leads global growth; shift from US, Canada holds," *Oil and Gas Journal*, March 18, 2008

Exhibit 7: Estimated Number of Production Wells, by Region and Resource Type, in 2006 and 2020

Emission Sources (Producing Wells)	2006	2020
Northeast Region		
Associated Gas Wells	47,034	54,744
Non-associated Gas Wells	164,319	114,734
Unconventional Gas Wells	0	48,398
	211,353	217,876
Midcontinent Region		
Associated Gas Wells	65,903	84,722
Non-associated Gas Wells	67,188	86,795
Unconventional Gas Wells	6,726	32,810
	139,816	204,327
Rocky Mountain Region		
Associated Gas Wells	13,579	19,206
Non-associated Gas Wells	53,419	46,212
Unconventional Gas Wells	22,195	81,495
	89,193	146,914
Southwest Region		
Associated Gas Wells	55,301	44,012
Non-associated Gas Wells	29,640	26,462
Unconventional Gas Wells	6,519	25,531
	91,460	96,006
West Cost Region		
Associated Gas Wells	22,189	32,965
Non-associated Gas Wells	1,503	3,819
Unconventional Gas Wells	0	1,817
	23,692	38,602
Gulf Coast Region		
Associated Gas Wells	27,319	51,159
Non-associated Gas Wells	60,715	57,025
Unconventional Gas Wells	0	31,801
	88,034	139,985
TOTAL US		
Associated Gas Wells	**231,325**	**286,809**
Non-associated Gas Wells	**376,784**	**335,048**
Unconventional Gas Wells	**35,440**	**221,852**
	643,549	**843,709**

Both direct (combustion, fugitive and vented/flared) and indirect (imported electrical power) emissions are estimated for each U.S. processing plant. The carbon-dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions for the natural gas processing sector were estimated using the ICF Gas Processing GHG Model for the base year 2006, and projected forward to 2020. The model calculates source-specific CO_2, CH_4, and N_2O emissions from individual gas processing facilities in the United States. These data were developed based on initial work for the Gas Research Institute (GRI).[9]

The average CO_2 content assumed for each AEO supply region, for both conventional and unconventional gas production, for each resource type, is shown in Exhibit 8, for 2006 and 2020. As shown, in most regions, based the mix of supply sources in the two years, the overall CO_2 content of produced gas in the region, on average, often does not change much.

Exhibit 8: Average CO_2 Content (weighted by production), by Region and Resource Type, in 2006 and 2020

	2006 Gas Composition		2020 Gas Composition	
Region	**Well Type**	**CO_2 Content in Produced Gas**	**Well Type**	**CO_2 Content in Produced Gas**
Northeast	Conventional	0.9%	Conventional	0.9%
	Unconventional	7.4%	Unconventional	7.4%
	All	1.2%	All	2.9%
Gulf Coast	Conventional	2.2%	Conventional	2.2%
	Unconventional	0.2%	Unconventional	2.0%
	All	2.1%	All	2.1%
Southwest	Conventional	3.8%	Conventional	3.8%
	Unconventional	4.0%	Unconventional	4.0%
	All	3.8%	All	3.9%
Midcontinent	Conventional	0.8%	Conventional	0.8%
	Unconventional	0.3%	Unconventional	1.0%
	All	0.7%	All	0.8%
Rocky Mountains	Conventional	8.0%	Conventional	8.0%
	Unconventional	2.0%	Unconventional	4.0%
	All	6.1%	All	5.4%
West Coast	Conventional	0.2%	Conventional	0.2%
	Unconventional	0.0%	Unconventional	0.0%
	All	0.1%	All	0.1%

However, there can still be considerable variability within supply regions and between basins, as well as considerable variability even within the same basin. Based on the GRI database referenced above,[10] Exhibit 9 gives some examples of the variability in CO_2 content that exists within supply regions and within basins.

[9] Gas Research Institute, Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases, Second Edition GRI-01/0136 (2001)
[10] Gas Research Institute, Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases, Second Edition GRI-01/0136 (2001)

Exhibit 9: Ranges of CO_2 Content for Selected Regions by Basin and Resource Type

Region	Basin Name	Formation	No. of Reservoirs	Avg. CO2 Content (%)	Min. CO2 Content (%)	Max. CO2 Content (%)	Ann Production (Bcf)	Undiscovered Conventional Resources (Bcf)	Undiscovered Unconventional Resources (Bcf)	Resource Type
GULF COAST	WARRIOR BASIN	CARTER	107	0.97	0	20.7	4.62	1,513	0	
	WARRIOR BASIN	OTHER	71	0.17	0.1	0.4	6.372	359	0	
	MID-GULF COAST BASIN	VALLEY	12	7.29	4.6	8.85	3.411	79	0	
	MID-GULF COAST BASIN	HOSSTON	51	4.64	1.5	6.83	27.792	1,140	0	
	MID-GULF COAST BASIN	SPORT	12	4.47	4.1	4.65	2.642	128	0	
	MID-GULF COAST BASIN	T	10	12.26	6.1	42.35	23.767	5,132	0	
	MID-GULF COAST BASIN	OTHER	140	1	0.1	4.2	9.87	1,008	0	
	MID-GULF COAST BASIN	PALUXY	25	2.31	1.6	2.8	6.624	146	0	
	MID-GULF COAST BASIN	RODESSA	24	2.82	2.5	4	8.524	134	0	
	MID-GULF COAST BASIN	SLIGO	23	3.54	2.4	4.34	2.866	62	0	
	MID-GULF COAST BASIN	OSA	41	3.63	0.9	5.1	2.747	23	0	
	MID-GULF COAST BASIN	WASHITA	14	2.2	2.2	2.2	5.034	43	0	
	EAST TEXAS BASIN	BOSSIER	45	2.38	2	2.4	25.733	118	73	Tight
	EAST TEXAS BASIN	VALLEY	208	2.19	0.8	3.1	464.39	796	37,561	Tight
	EAST TEXAS BASIN	PETTIT	188	1.02	0.5	2	35.573	254	0	
	EAST TEXAS BASIN	RODESSA	192	1.35	0	2.4	13.699	191	0	
	EAST TEXAS BASIN	E	83	1.91	0.5	2.4	7.273	254	0	
	LOUISIANA GULF COAST	CHALK	10	3.87	3.87	3.87	1.36	0	0	
	LOUISIANA GULF COAST	OSA	25	6.91	4.72	7.35	106.015	1,881	908	CoProd
	TEXAS GULF COAST	CHALK	45	4.73	4.7	5.2	220.351	352	1,015	Tight
	TEXAS GULF COAST	G	507	0.34	0	3.3	412.989	4,069	4,758	Tight
	TEXAS GULF COAST	WILCOX	1,358	3.28	0.14	17.9	991.211	14,017	15,671	Tight
	TEXAS GULF COAST	YEGUA	940	1	0.1	3	118.177	2,249	9,417	CoProd
NORTHEAST	MICHIGAN BASIN	SHALE	5	10.17	0	37	192.159	0	16,880	Shale
	MICHIGAN BASIN	OTHER	36	0.52	0	4.05	2.482	308	0	
	CENTRAL APPALACHIA			2.09						
	NORTHERN APPALACHIA			8.84						
	NORTHERN APPALACHIA			2.44						
MIDCONTINENT	ARKLA BASIN	VALLEY	110	2.32	1.6	6.4	48.381	1,904	4,171	Tight
	ARKLA BASIN	OTHER	352	2.3	1.35	3.3	71.241	7,336	273	Tight
	ARKLA BASIN	PEAK	112	1.35	0.7	5.8	182.175	1,993	1,393	Tight
	ARKOMA BASIN	E	4	2	1.7	2	5.42	555	0	
	ARKOMA BASIN	ATOKA	151	1.55	0	4.5	267.952	1,089	2,758	Tight
	ARKOMA BASIN	OTHER	652	0.93	0	4.8	121.381	418	0	
	ANADARKO BASIN	CHESTER	243	0.48	0.1	14.6	54.526	2,826	0	
	ANADARKO BASIN	DOUGLAS	72	3.58	0.05	10.9	24.294	989	0	
	ANADARKO BASIN	HUNTON	128	3.33	0	8.37	50.289	332	212	Tight
	ANADARKO BASIN	MORROW	877	1	0	5.1	374.949	20,271	178	Tight
	ANADARKO BASIN	OTHER	2,221	0.69	0	2.9	297.555	11,235	0	
	ANADARKO BASIN	RED FORK	135	1.24	0.1	2.3	144.312	5,199	4,726	Tight
	ANADARKO BASIN	SKINNER	63	1.09	0.1	3.5	29.951	471	0	
	ANADARKO BASIN	VIOLA	44	2.27	0.2	2.65	3.315	115	0	

Exhibit 9: Ranges of CO_2 Content for Selected Regions by Basin and Resource Type (continued)

Region	Basin Name	Formation	No. of Reservoirs	Avg. CO2 Content (%)	Min. CO2 Content (%)	Max. CO2 Content (%)	Ann Production (Bcf)	Undiscovered Conventional Resources (Bcf)	Undiscovered Unconventional Resources (Bcf)	Resource Type
ROCKY MTNS	POWDER RIVER BASIN	UNION	2	0.47	0.47	0.47	58.178	0	10,036	Coal
	POWDER RIVER BASIN	MUDDY	37	1.89	0.4	2.2	8.886	511	0	
	POWDER RIVER BASIN	OTHER	78	0.91	0.1	14.3	1.038	748	0	
	WIND RIVER BASIN	CODY	11	2.92	1.5	3	4.511	599	0	
	WIND RIVER BASIN	UNION	25	2.04	0.3	4.85	48.759	393	8,280	Tight
	WIND RIVER BASIN	DE	10	3.96	1.3	5.1	4.842	735	4,541	Tight
	WIND RIVER BASIN	OTHER	58	3.31	0.1	3.95	9.267	59	540	Coal
	GREEN RIVER BASIN	DAKOTA	68	0.76	0	3.2	34.209	2,175	1,143	Tight
	GREEN RIVER BASIN	UNION	24	0.66	0.1	2.55	4.952	165	7,526	Tight
	GREEN RIVER BASIN	FRONTIER	113	0.69	0.1	4.15	168.205	2,786	7,342	Tight
	GREEN RIVER BASIN	LEWIS	65	0.66	0	2	29.332	459	205	Tight
	GREEN RIVER BASIN	DE	127	2.42	0.1	5.7	131.949	12,368	117,288	Tight
	GREEN RIVER BASIN	DE	6	0.04	0.04	0.04	0.07	0	4,660	Coal
	GREEN RIVER BASIN	NUGGET	15	2.39	1.4	2.95	8.994	377	0	
	GREEN RIVER BASIN	OTHER	162	0.38	0.1	0.7	19.168	122	0	
	DENVER BASIN	D SAND	129	1.25	0.9	2.15	0.805	54	0	
	DENVER BASIN	DAKOTA	5	2.3	2.3	2.3	1.352	7	106	Tight
	DENVER BASIN	J SAND	180	2.46	0.3	2.7	27.293	435	2,426	Tight
	UINTA BASIN	DE	6	4.29	3.05	5.53	52.331	0	3,810	Coal
	UINTA BASIN	OTHER	53	0.9	0.04	1.7	3.411	197	0	
	PICEANCE BASIN	DAKOTA	47	4.11	0.1	27.9	6.54	69	1,062	Tight
	PICEANCE BASIN	DE	43	2.9	0.8	18.3	50.768	1,583	43,843	Tight
	PICEANCE BASIN	DE	13	14.8	14.8	14.8	2.058	0	11,550	Coal
	PICEANCE BASIN	OTHER	74	0.54	0.3	37.5	4.709	60	0	
	PICEANCE BASIN	WASATCH	13	1.48	0	3.2	6.498	61	821	Tight
SOUTHWEST	SAN JUAN BASIN	DAKOTA	11	0.96	0.4	4.8	123.001	259	6,352	Tight
	SAN JUAN BASIN	D	31	1.13	0.09	4.83	1.877	7	319	Tight
	SAN JUAN BASIN	D COAL	4	5.72	3.61	7.79	970.512	0	7,690	Coal
	SAN JUAN BASIN	OTHER	56	1.4	1.4	1.4	10.352	361	0	
	SAN JUAN BASIN	CLIFFS	28	0.83	0.05	2.07	80.817	130	3,947	Tight
	PERMIAN BASIN	ATOKA	246	0.5	0	3.3	36.479	1,560	1,099	Tight
	PERMIAN BASIN	RGER	150	18.06	0.1	47.7	220.086	3,846	0	
	PERMIAN BASIN	AN	81	4.98	0.1	21.3	12.637	656	0	
	PERMIAN BASIN	OTHER	836	0.28	0	7.2	81.168	2,297	0	
	PERMIAN BASIN	STRAWN	334	1.85	0.1	4.9	90.31	376	1,099	Tight
	PERMIAN BASIN	P	287	0.65	0	6.8	66.747	2,255	1,254	Tight
WEST COAST	SAN JOAQUIN BASIN	OTHER	40	0.1	0.1	0.1	6.814	823	0	
	SAN JOAQUIN BASIN	STEVENS	10	4.3	4.3	4.3	0.759	13	0	

Natural Gas Transmission

Emissions from the transport of natural gas in North America occur chiefly from compressor exhaust at compressor stations located along a natural gas pipeline. To calculate emissions, the amount of fuel used by the compressor was needed. The amount of fuel was calculated from the horsepower and efficiency of the compressor. Centrifugal compressor horsepower was obtained from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2005*, while the value for compressor efficiency was obtained from the *Standard Handbook of Petroleum and Natural Gas Engineering.* Emissions factors from the *API Compendium* were then applied to the calculated fuel use, thus determining emissions from transmission compressors.

Specifically, the data factoring into GHG emissions included the following activity factors:

- Gas consumption associated with transmission
- Transmission pipelines' length
- Representative length that produced gas travels in transmission lines
- Number of LNG storage facilities w/liquefaction (not import terminals)
- Total LNG storage facility (w/liquefaction) capacity
- Number of LNG storage facilities w/o liquefaction (not import terminals)
- Total LNG storage facility (w/o liquefaction) capacity
- Required electricity for transmission/storage

These data were aggregated by AEO demand region, which correspond to U.S. Bureau of the Census regions. These AEO demand regions are illustrated in Exhibit 10.

The key activity factor drivers are summarized in Exhibit 11, by AEO demand region, for 2006 and 2020.

Exhibit 10: EIA AEO Demand Regions

Division 1
New England
Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic
New Jersey
New York
Pennsylvania

Division 3
East North Central
Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central
Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic
Delaware
District of Columbia
Floprida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central
Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central
Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific
Alaska
California
Hawaii
Oregon
Washington

Exhibit 11: Estimates of Key Activity Factors for Natural Gas Transmission, by Region, in 2006 and 2020

		NATIONAL TOTAL	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
2006											
Gas Consumption: Residential	Quads	**4.48**	0.18	0.79	1.26	0.39	0.41	0.17	0.28	0.33	0.66
Transmission Pipelines Length	miles	**290,680**									
Average length that N. A. produced gas travels in transmission line	miles		850	950	800	1400	450	200	200	200	1100
No. of LNG storage facilities w/liquefaction (not import terminals)		**57**	20	23	8	6	7	4	0	0	3
Total LNG storage facility (w/liquefaction) capacity	Bcf	**49**	17	20	7	5	6	3	0	0	3
No. of LNG storage facilities w/o liquefaction (not import terminals)		**39**	12	18	5	4	5	3	0	0	2
Total LNG storage facility (w/o liquefaction) capacity	Bcf	**33**	10	15	4	3	4	3	0	0	2
2020											
Gas Consumption: Residential	Quads	**5.27**	0.21	0.88	1.44	0.47	0.52	0.20	0.34	0.43	0.79
Transmission Pipelines Length	miles	**342,399**									
Average length that N. A. produced gas travels in transmission line	miles		850	950	800	1,400	450	200	200	200	1,100
No. of LNG storage facilities w/liquefaction (not import terminals)		**67**	24	25	9	7	9	5	0	0	4
Total LNG storage facility (w/liquefaction) capacity	Bcf	**57**	21	22	8	6	8	4	0	0	3
No. of LNG storage facilities w/o liquefaction (not import terminals)		**46**	14	20	6	5	6	4	0	0	2
Total LNG storage facility (w/o liquefaction) capacity	Bcf	**39**	12	17	5	4	5	3	0	0	2

Natural Gas Distribution

Natural gas distribution uses essentially no energy to move gas, as the operating pressures are low, and high pressure gas received from transmission pipelines can flow through the system with no additional compression. Therefore, nearly all emissions from this sector are fugitive emissions, which are a function of the types of pipes and services deployed. Specifically, data factoring into GHG emissions from the distribution sector include the following (by AEO demand region):

- Type of distribution mains - cast iron, unprotected steel, protected steel, plastic
- Type of services - unprotected steel, protected steel, plastic, copper.

These data are summarized in Exhibit 12.

Imported LNG and U.S. natural gas supply have identical emissions profiles in the distribution sector.

End Use Consumption

Emissions from consumption of natural gas by end users were estimated by assuming the complete combustion of all natural gas delivered. Consumption was disaggregated nationally by residential, commercial, industrial, transportation, and electric generation consumers, as reported in the 2007 EIA AEO. Small amounts of unburned hydrocarbons may be vented from combustion devices that are not 100% efficient, but the portion of unburned methane would have an insignificant impact on overall emissions from end use consumption. This breakdown of end use consumption by AEO demand region and sector is provided in Exhibit 13.

Again, imported LNG and U.S. natural gas supply have identical emissions profiles in the end use consumption sector.

Exhibit 12: Estimates of Key Activity Factors for Natural Gas Distribution, by Region, in 2006 and 2020

2006		TOTAL	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	California Only
Consumption: Residential	Quads	**4.48**	0.18	0.79	1.26	0.39	0.41	0.17	0.28	0.33	0.66	0.52
Consumption: Commercial	Quads	**2.92**	0.12	0.57	0.65	0.26	0.34	0.13	0.30	0.22	0.33	0.24
Consumption: Industrial	Quads	**6.76**	0.08	0.35	1.15	0.44	0.55	0.47	2.41	0.31	0.99	0.80
Dist. Mains - Cast Iron	miles	**37,371**	1,484	6,627	10,517	3,248	3,382	1,417	2,376	2,791	5,530	4,317
Dist. Mains - Unprotected steel	miles	**69,291**	2,800	13,609	15,398	6,204	8,036	3,042	7,077	5,254	7,872	6,145
Dist. Mains - Protected steel	miles	**461,459**	5,655	24,016	78,770	30,204	37,661	31,929	164,336	20,973	67,915	53,016
Dist. Mains - Plastic	miles	**525,788**	20,875	93,232	147,972	45,695	47,581	19,932	33,436	39,265	77,801	60,733
Services - Unprotected steel		**5,308,375**	210,757	941,276	1,493,928	461,336	480,378	201,237	337,566	396,418	785,479	613,163
Services Protected steel		**15,833,423**	639,736	3,109,800	3,518,550	1,417,686	1,836,270	695,011	1,617,117	1,200,479	1,798,772	1,404,163
Services - Plastic		**36,152,277**	443,051	1,881,500	6,171,081	2,366,316	2,950,454	2,501,429	12,874,612	1,643,118	5,320,718	4,153,475
Services - Copper		**1,212,260**	48,130	214,957	341,165	105,354	109,703	45,956	77,089	90,529	179,378	140,026
2020												
Consumption: Residential	Quads	**5.27**	0.21	0.88	1.44	0.47	0.52	0.20	0.34	0.43	0.79	0.62
Consumption: Commercial	Quads	**3.75**	0.15	0.67	0.81	0.34	0.52	0.18	0.39	0.29	0.39	0.28
Consumption: Industrial	Quads	**8.02**	0.12	0.38	1.41	0.65	0.53	0.47	3.13	0.35	0.97	0.78
Dist. Mains - Cast Iron	miles	**37,371**	1,514	6,230	10,173	3,297	3,692	1,435	2,390	3,035	5,605	4,363
Dist. Mains - Unprotected steel	miles	**69,291**	2,814	12,390	14,942	6,246	9,669	3,313	7,247	5,383	7,287	5,672
Dist. Mains - Protected steel	miles	**572,919**	8,917	26,910	101,027	46,196	38,041	33,661	223,790	25,187	69,190	53,856
Dist. Mains - Plastic	miles	**637,248**	25,820	106,234	173,461	56,219	62,958	24,469	40,760	51,750	95,577	74,396
Services - Unprotected steel		**5,308,375**	215,082	884,947	1,444,956	468,314	524,452	203,829	339,538	431,084	796,173	619,730
Services Protected steel		**15,833,423**	642,948	2,831,222	3,414,338	1,427,242	2,209,435	757,111	1,655,918	1,230,153	1,665,056	1,296,055
Services - Plastic		**47,827,785**	744,397	2,246,465	8,433,804	3,856,500	3,175,731	2,810,060	18,682,190	2,102,602	5,776,036	4,495,981
Services - Copper		**1,459,297**	59,127	243,276	397,225	128,742	144,174	56,033	93,341	118,507	218,872	170,367

Exhibit 13: Estimates of Key Activity Factors for Natural Gas Consumption, by Region, in 2006 and 2020

Gas Consumption in Sector, in Quads

2006	TOTAL	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	California only
National	21.78	0.79	2.20	3.68	1.26	2.19	1.02	5.73	1.75	3.16	2.50
Residential	4.48	0.18	0.79	1.26	0.39	0.41	0.17	0.28	0.33	0.66	0.52
Commercial	2.92	0.12	0.57	0.65	0.26	0.34	0.13	0.30	0.22	0.33	0.24
Industrial	6.76	0.08	0.35	1.15	0.44	0.55	0.47	2.41	0.31	0.99	0.80
Elec. Generarion	5.88	0.40	0.43	0.54	0.05	0.81	0.17	2.07	0.54	0.87	0.71
Lease & Plant Fuel	1.12	0.00	0.01	0.01	0.03	0.02	0.03	0.53	0.22	0.27	0.21
Pipeline Fuel	0.58	0.01	0.04	0.06	0.08	0.05	0.06	0.13	0.12	0.03	0.02
Transportation	0.04	0.00	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.01
2020											
National	26.30	1.07	2.59	4.34	1.67	2.74	1.43	6.93	2.05	3.48	2.75
Residential	5.27	0.21	0.88	1.44	0.47	0.52	0.20	0.34	0.43	0.79	0.62
Commercial	3.75	0.15	0.67	0.81	0.34	0.52	0.18	0.39	0.29	0.39	0.28
Industrial	8.02	0.12	0.38	1.41	0.65	0.53	0.47	3.13	0.35	0.97	0.78
Elec. Generarion	7.19	0.56	0.60	0.59	0.08	1.05	0.48	2.38	0.62	0.82	0.67
Lease & Plant Fuel	1.21	0.00	0.01	0.01	0.03	0.02	0.03	0.51	0.23	0.37	0.30
Pipeline Fuel	0.76	0.01	0.05	0.07	0.10	0.08	0.06	0.17	0.12	0.12	0.09
Transportation	0.09	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01

Methodology Description – Liquefied Natural Gas

Imported LNG shares the same six supply chain steps as for U.S. natural gas supply; and includes three additional steps: liquefaction and loading, shipping, and regasification and storage. However, it is important to note that in the case of LNG, gas processing and liquefaction are generally consolidated as part of liquefaction facility operations. For purposes of this analysis, emissions from small, land-based peak shaving LNG facilities were not considered. In addition, it was assumed that LNG from Alaska would continue to serve Japanese, rather than U.S., markets.

The United States currently has only five active LNG import terminals along the East and Gulf coasts. Countries importing LNG to the U.S. in 2006 were Algeria, Egypt, Nigeria, and Trinidad & Tobago. The EIA tracks LNG imports delivered to these terminals, but does not report data on the activities upstream of the import terminals in the countries of origin. Downstream of the import terminals, LNG is regasified and enters the U.S. transmission and distribution systems as any other source of supply of natural gas. Natural gas losses through fugitives, venting, and consumption upstream of the LNG import terminal were estimated to back calculate the amount of natural gas that must be produced in each foreign country to satisfy market requirements for LNG.

Actual data on LNG imports and the sources of those LNG supplies were used to develop the supply and emissions characterization for 2006. This information is provided below:

Existing LNG Terminals	**Capacity (Bcf/d)**	**Capacity (Bcf/year)**	**2006 Imports (Bcf/year)**	**2006 Capacity Utilization**	**2006 Imports (Bcf/day)**
Everett, MA	1.035	378	176	47%	0.48
Cove Pt., MD	1.000	365	117	32%	0.32
Elba Island, GA	1.200	438	147	34%	0.40
Lake Charles, LA	2.100	767	144	19%	0.39
Gulf Gateway, LA	0.500	183	0.453	0%	0.00
	5.835	**2,130**	**584**	**27%**	**1.60**

Source: FERC (Capacity), EIA (Imports)

The data on sources or countries of origin of LNG imports for 2006 were based on data acquired by the U.S. Department of Energy[11] and reported by EIA.[12] Data on capacity were obtained from Federal Energy Regulatory Commission (FERC).[13] The sources and volumes of LNG supplying these terminals in 2004, 2005, and 2006 are summarized in Exhibit 14:

[11] http://www.fe.doe.gov/programs/gasregulation/analyses/Analyses.html
[12] http://tonto.eia.doe.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm
[13] http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf

Exhibit 14: Sources and Volumes of LNG Supplying U.S. LNG terminals in 2004, 2005, and 2006

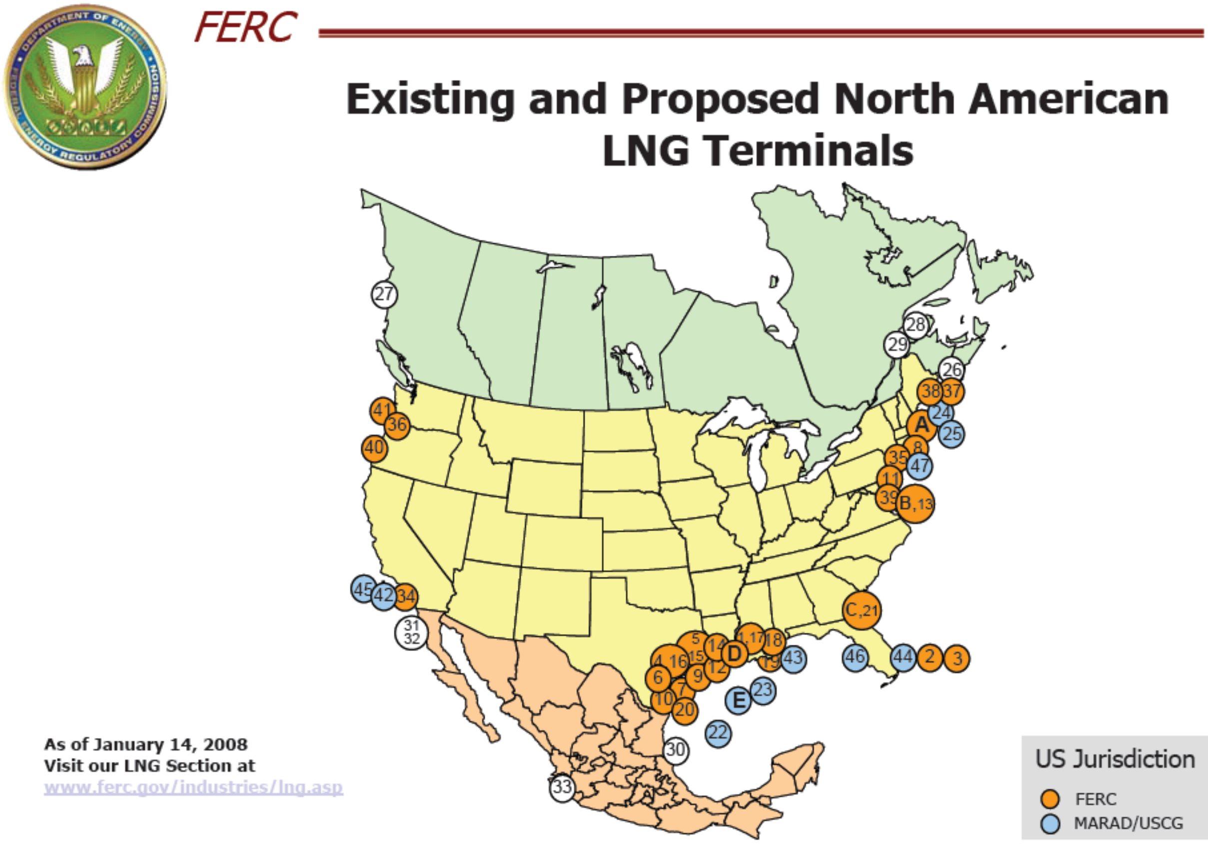
(All volumes in MMcf/year)

	2004	2005	2006	% of U.S Total in 2006
U.S. Total	**652,015**	**631,260**	**583,537**	
From Algeria	**120,343**	**97,157**	**17,449**	3%
Cove Point, MD	33,554	35,222	17,449	3%
Lake Charles, LA	86,789	61,935	0	
From Australia	**14,990**			0%
Lake Charles, LA	14,990	0	0	
From Egypt	_	**72,540**	**119,528**	20%
Cove Point, MD	0	22,591	14,575	2%
Elba Island, GA	0	24,891	42,411	7%
Lake Charles, LA	0	25,058	62,542	11%
From Malaysia	**19,999**	**8,719**		0%
Gulf Gateway, LA	0	2,624	0	
Lake Charles, LA	19,999	6,095	0	
From Nigeria	**11,818**	**8,149**	**57,292**	10%
Cove Point, MD	2,986	0	0	
Elba Island, GA	0	2,895	0	
Gulf Gateway, LA	0	2,574	0	
Lake Charles, LA	8,831	2,681	57,292	10%
From Oman	**9,412**	**2,464**		0%
Lake Charles, LA	9,412	2,464	0	
From Qatar	**11,854**	**2,986**		0%
Lake Charles, LA	11,854	2,986	0	
From Trinidad/Tobago	**462,100**	**439,246**	**389,268**	67%
Cove Point, MD	172,753	163,876	84,590	14%
Elba Island, GA	105,203	104,276	104,356	18%
Everett, MA	173,780	168,542	176,097	30%
Gulf Gateway, LA		0	453	0%
Lake Charles, LA	10,364	2,552	23,773	4%
From Other Countries	**1,500**			0%
Lake Charles, LA	1,500	0	0	0%

As demand for LNG increases, additional import terminals will likely be constructed along the U.S. coasts. The FERC tracks existing and proposed LNG terminals; there are currently 21 new LNG terminals approved by FERC and many more terminals are proposed.[14] Exhibit 15 shows the locations of proposed LNG import terminals in North America. Not all of these terminals will be built.

[14] http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf

Exhibit 15: Existing and Proposed North American LNG Import Terminals



New sources of LNG supplies will also come online as LNG export terminals are constructed worldwide in areas of abundant gas supply to serve increasing worldwide requirements for LNG, including increasing requirements in the U.S.

For purposes of this analysis, the characterization of future supplies of LNG delivered to the U.S. was developed by ARI. Estimates for total LNG imported into the U.S. in 2020 were based on the AEO 2007 forecasts. Estimates for future increases of U.S. LNG import capacity were developed, which included both expansions of existing facilities and the building of new facilities on the East Coast, Gulf Coast, and West Coast. Expansions of existing facilities were based on literature reports[15] and numerous company press releases.

EIA's 2007 Annual Energy Outlook forecasts that 3.69 trillion cubic feet (Tcf) of natural gas will be imported into the U.S. in 2020.[16] Consistent with this forecast, this analysis assumed the following:

- Expansions of each of the existing LNG import terminals on the Gulf Coast, along with three new facilities constructed on the Gulf by 2020

[15] U.S. Department of Energy, Office of Fossil Energy, *Liquefied Natural Gas: Understanding the Basic Facts*, DOE/FE-0489, August 2005 (http://www.fe.doe.gov/programs/oilgas/publications/lng/LNG_primerupd.pdf)

[16] The more recent AEO (2008) now forecasts that LNG imports into the U.S. in 2020 will be 2.37 Tcf, a 36% drop in LNG imports compared to the forecast for 2020 in the 2007 AEO.

- Expansions of existing LNG import terminals on the East Coast, along with one new East Coast facility
- One new West Coast facility, probably built in Mexico in Baja California.

The assumed capacity expansions for existing facilities, sizes for new facilities, and their assumed capacity utilizations in 2020 are summarized in Exhibit 16.

Exhibit 16: Assumed Capacity Expansions for Existing LNG Import Facilities, Sizes for New Facilities, and Assumed Capacity Utilization in 2020

Existing LNG Terminals	**2006 Capacity (Bcf/d)**	**Assumed Capacity Expansion (Bcf/d)**	**2020 Capacity (Bcf/year)**	**Est. 2020 Imports (Bcf/year)**	**Est. 2020 Imports (Bcf/day)**	**2020 Capacity Utilization**
Everett, MA	1.035	0.000	378	268	0.73	71%
Cove Pt., MD	1.000	0.800	657	493	1.35	75%
Elba Island, GA	1.200	0.900	767	575	1.58	75%
Lake Charles, LA	2.100	0.000	767	575	1.58	75%
Gulf Gateway, LA	0.500	0.000	183	137	0.38	75%
	5.835	**1.700**	**2,750**	**2,048**	**5.61**	
Representative New LNG Terminals	**2006 Capacity (Bcf/d)**	**Assumed Capacity Expansion (Bcf/d)**	**Capacity (Bcf/year)**	**Est. 2020 Imports (Bcf/year)**	**Est. 2020 Imports (Bcf/day)**	**2020 Capacity Utilization**
Other Gulf		4.000	1,460	1,095	3.00	75%
Baja California, Mex.		1.500	548	411	1.13	75%
East Coast		0.500	183	137	0.38	75%
		6.000	**2,190**	**1,643**	**4.50**	
Total Capacity/Imports	**5.835**	**7.700**	**4,940**	**3,690**	**10.11**	
LNG imports forecast for 2020 in 2007 AEO				**3,690**	**10.11**	

Again, these assumptions for new facilities were based on selected proposed LNG terminals that have received FERC approval.

To provide the gas supplies to meet these LNG import requirements in 2020, the following was assumed:

- The sources of gas to East Coast (3 existing plus 1 new facility) would be Trinidad & Tobago, Egypt, Nigeria, Algeria, Norway, and Qatar
- The sources of gas to the Gulf Coast (2 existing plus 4 new facilities) would be Nigeria, Egypt, Algeria, Trinidad & Tobago, and Norway
- The sources of gas to the Baja California facility would be Russia, Indonesia/Papua New Guinea, and Australia.

The primary factors leading to these assumptions for future supply sources of LNG to the U.S. include the establishment of existing, long-term relationships, the relative cost of supply (primarily related to transportation distance), and the anticipated ownership of both liquefaction facilities and receiving terminals.[17,18,19]

[17] http://intelligencepress.com/features/lng/terminals/lng_terminals.html

The breakdown of 2020 LNG imports by country of origin for the East Coast, Gulf Coast, and West Coast facilities is summarized in Exhibit 17, along with the estimated transport distance from the country of origin to the respective delivery locations.[20,21]

Exhibit 17: LNG Imports and Estimated Transport Distance by Country of Origin in 2020

	T & T	Nigeria	Egypt	Algeria	Russia	Australia	Indonesia	Qatar	Norway
Volumes of LNG (Bcf/year) to Various Regions - 2020									
Gulf Coast	361	335	351	361					396
East Coast	368	354	157					515	79
West Coast					205	123	82		
TOTAL	**730**	**689**	**509**	**361**	**205**	**123**	**82**	**515**	**475**
2006 Exports	584	628	528	844		702	1,074	1,110	0
2006 Capacity	735	863	594	1,104		562	1,400	941	200
Planned Exp					466	920	341		339
Other Expansions	919	1,079	743	1,380		702	500	1,176	250
TOTAL	**919**	**1,079**	**743**	**1,380**	**466**	**1,622**	**841**	**1,176**	**589**
Distances between Various Regions (miles)									
Gulf Coast	2,200	6,100	6,500	4,700					5,000
East Coast	2,000	5,000	5,000					8,000	3,800
West Coast					4,000	7,500	7,000		

Exploration and Development

The activity factors and emission factors affecting emissions from exploration and production activities serving LNG exports are the same as those for U.S. natural gas supply, and the drivers establishing the activity factors are also essentially the same. U.S. natural gas is produced through a mix of associated, non-associated, and unconventional oil and gas wells; the average natural gas production rate from individual wells in the U.S. is only around 30 million cubic feet per year. In contrast, natural gas wells from countries exporting LNG can have production rates of nearly 20 million cubic feet per well per day. The larger number of wells needed to produce the same amount of gas in the U.S. requires more equipment, more activity factors, and consequently more fugitive and venting emissions, than that associated with producing gas to serve as the supply for LNG exports.

In the process of assessing LNG imports, the emissions intensity associated with only wells drilled (oil and gas) for the purposes of producing gas to meet the demand requirements of the United States were counted in the supply chain emissions. Well drilling activities associated with LNG export terminals anticipated to meet U.S. demand were estimated to be 144 wells in 2006 and 820 wells in 2020.

The number of wells required in each source country was estimated by dividing the anticipated supply volume from that country by the expected average production per well from the source fields. Estimates of typical production per well, along with the average depth per well, were developed primarily from country statistics, where reported, and from a variety of Environmental Impact Statements (EISs) and supporting documentation prepared for the proposed export

[18] Energy Information Administration, "U.S. LNG Markets and Uses, June 2004 Update,", June 2004
[19] http://www.energy.ca.gov/lng/documents/2005-08_EXISTING_LNG_EXPORT_WORLDWIDE.PDF
[20] True, Warren R., "LNG questions loom amid wave of project completions," *Oil and Gas Journal*, January 7, 2008
[21] Energy Information Administration, "The Global Liquefied Natural Gas Market: Status and Outlook," DOE/EIA-0637, December 2003 (http://www.eia.doe.gov/oiaf/analysispaper/global/index.html)

terminals. A complete listing of all of the EISs and supporting documentation used this analysis is provided in Appendix A.

The key activity factors affecting emissions from exploration and development activities to serve U.S. LNG requirements for 2006 and 2020 are summarized in Exhibit 18, by source of supply.

Exhibit 18: Key Activity Factors Affecting Emissions from Exploration and Development Activities to Serve U.S. LNG Requirements for 2006 and 2020

2006

		T&T	Nigeria	Egypt	Algeria
Required Supply	Bcf	436	67	139	20
	MMcf/d	1,200	186	386	55
Rep. Well Depth	feet	10,000	10,000	10,500	15,000
No. of wells drilled		72	22	46	4
Drilling Time	Days/well	50	50	53	75
No. of Completions		61	19	39	3

2020

		T&T	Nigeria	Egypt	Algeria	PNG	Russia	Australia	Qatar	Norway
Required Supply	Bcf	826	811	603	422	98	232	148	633	540
	MMcf/d	2,248	2,214	1,647	1,148	269	634	406	1,734	1,479
Rep. Well Depth	feet	10,000	10,000	10,500	15,000	12,000	15,000	13,500	10,000	10,000
No. of wells drilled		133	261	194	54	18	33	14	39	75
Drilling Time	Days/well	50	50	53	75	60	75	68	50	50
No. of Completions		113	222	165	46	14	26	11	35	60

Representative emission factors for exploration and production for Trinidad and Tobago, which served as a major source of LNG imports to the U.S. in 2006, and is anticipated to also play a major role in 2020, are summarized in Exhibit 19.

Natural Gas Production

Again, because of the much larger number of wells needed to produce the same amount of gas in the U.S. compared to that required to produce the same amount of LNG, U.S. production will have considerably greater fugitive and venting emissions from production operations.

Again, estimates of production per well, the relative supplies coming from associated gas (with condensate) and non-associated gas wells, the distances from the producing fields to the export terminals, and average gas composition, were based primarily on estimates reported in the variety of EISs and supporting documentation described above and referenced in Appendix A.

The key activity factors affecting emissions from production activities to serve U.S. LNG requirements for 2006 and 2020 are summarized in Exhibit 20, by source of supply.

Representative emission factors for fugitive emissions for Trinidad and Tobago in the production sector for 2020 are summarized in Exhibit 21.

Exhibit 19: Representative Emission Factors for Exploration and Development for Trinidad and Tobago for 2006 and 2020

Trinidad & Tobago

Carbon Dioxide Emissions

Emission Sources	CO_2 Emissions Factor		Activity Factor		CO_2 Emissions (Mg)
Drilling and Well Completion					
Completion Venting and Flaring	192,469	scf/comp	90.05	completions/year	899.32
Well Drilling Venting	106.72	scf/well	132.94	wells	0.7362
Well Drilling Combustion	152.79	tonnes/well	132.94	wells	20,312

Methane Emissions

Emission Sources	CH_4 Emissions Factor		Activity Factor		CH_4 Emissions (Mg)
Drilling and Well Completion					
Completion Venting and Flaring	4,993,593	scf/comp	90.05	completions/year	8,660
Well Drilling Venting	2,769	scf/well	132.94	wells	7.09

Exhibit 20: Representative Activity Factors for Fugitive Emissions for Trinidad and Tobago in the Production Sector for 2006 and 2020

2006

		T&T	Nigeria	Egypt	Algeria
Gas Production	Tcf	0.436	0.067	0.139	0.020
Assoc. Gas Wells		23	22	39	3
Non-ass. Gas Wells		38	0	0	0
Avg. Gas Prod/Well	MMcfd	20	8	10	18
Condensate Prod.	MMbbl	6.94	5.5	9.45	2.0
WH Pressure	psig	250	250	250	250
Wells workovers		12	4	8	1
Dist. To export facility	miles	125	50		
CH4 content	vol %	85	88	92	90
CO2 content	vol %	0.8	0.8	2.0	2.0

2020

		T&T	Nigeria	Egypt	Algeria	PNG	Russia	Australia	Qatar	Norway
Gas Production	Tcf	0.826	0.811	0.603	0.422	0.098	0.232	0.148	0.633	0.540
Assoc. Gas Wells		23	148	39	30	14	0	0	0	0
Non-ass. Gas Wells		90	74	126	16	0	26	11	35	60
Avg. Gas Prod/Well	MMcfd	20	10	10	25	19	24	37	50	25
Condensate Prod.	MMbbl	12.99	65.1	40.27	41.3	2.6	0.02	0.00	438	8.97
WH Pressure	psig	250	250	250	250	250	250	250	250	250
Wells workovers		23	44	33	9	3	5	2	7	12
Dist. To export facility	miles	150	100			184	75	50		89
CH4 content	vol %	85	88	88	88	88	95	80	90	85
CO2 content	vol %	0.8	0.8	2.0	2.0	5.0	0.3	7.0	2.0	8.0

BASIS FOR DETERMINING CO2 CONTENT OF GAS SOURCES FOR LNG EXPORTS

		CO_2 content (mol %)	Source
Algeria		2.00%	
	mulitple reservoirs range	1-10%	http://www.opec.org/home/Press%20Room/EU-OPEC%20presentations/HaddadjiSonatrach%20Algeria.pdf
Egypt		2.00%	
Nigeria		1.80%	
	Nigeria LNG	1.80%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
Trinidad		0.80%	
	Atlantic LNG	0.80%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
Indonesia/ PNG		5.00%	
	Tangguh	10.00%	http://www.bp.com/sectiongenericarticle.do?categoryId=9004748&contentId=7008786
	PNG	0.41%	Esso Highlands Limited on behalf of the Govt. of PNG, *Papua New Guinea: PNG Gas Project,* Summary Environmetnal Assessment, Prj. No. 39584, May 2006,Table 4
Russia		3.00%	
		0.30%	Shakhalin Energy Investment Company, Environmental Impact Assessment, p. 2-7
Australia		7.00%	
	Darwin	6.00%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
		6.11%	Darwin LNG Plant Program Environmental Review, Table 2.3
	NW Shelf	2.50%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
	Gorgon	14.00%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
		14-15%	Gorgon, Draft Environmental Impact Statement/Environmental Review and Management Plan, Table 6-1
	Pluto	2.00%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
		2.00%	Pluto LNG Development, Draft Public Environmental Report/Public Environmental Review, Table 4-2
Qatar/Oman		2.00%	
	Qatargas	2.10%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
	RasGas	2.10%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
	Oman LNG	1.00%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
Norway		8.00%	
	Snohvit	8.00%	Woodside, *Pluto LNG Project, Greenhouse Gas Abatement Program*, DRIMS-#3586918, Sept. 2007, Table 4.1
		5-8%	http://www.hydrocarbons-technology.com/projects/snohvit/

Exhibit 21: Selected Key Emission Factors for Fugitive Emissions for Trinidad and Tobago in the Production Sector

Emission Sources	Units	CO_2 Emission Factor	CH_4 Emission Factor
Gas Wells			
Associated Gas Wells	scfd/well	0.000	0.000
Non-associated Gas Wells	scfd/well	0.925	39.311
Unconventional Gas Wells	scfd/well	0.180	0.000
Field Separation Equipment			
Heaters	scfd/heater	1.465	62.256
Separators	scfd/sep	3.097	131.617
Dehydrators	scfd/dehy	2.313	98.299
Meters/Piping	scfd/meter	1.343	57.067
Gathering Compressors			
Small Reciprocating Comp.	scfd/comp	6.796	4,610.202
Large Reciprocating Comp.	scfd/comp	385.914	16,401.332
Large Reciprocating Stations	scfd/station	209.304	8,895.418
Pipeline Leaks	scfd/mile	1.349	57.334
Normal Operations			
Pneumatic Device Vents	scfd/device	8.756	372.145
Chemical Injection Pumps	scfd/pump	6.294	267.513
Kimray Pumps	scf/MMscf	25.178	1,070.051
Dehydrator Vents	scf/MMscf	6.995	297.284
Condensate Tank Vents			
Tanks w/o Control Devices	scf/bbl	3.528	21.870
Tanks w/ Control Devices	scf/bbl	0.706	4.374
Well Workovers			
Conventional Gas	scfy/w.o.	62.284	2,647.081
Blowdowns			
Vessel BD	scfy/vessel	1.980	84.137
Pipeline BD	scfy/mile	7.843	333.312
Compressor BD	scfy/comp	95.787	4,070.939
Compressor Starts	scfy/comp	214.289	9,107.297
Upsets			
Pressure Relief Valves	PRV	0.863	36.675
Mishaps	miles	16.980	721.637

Natural Gas Processing

Again, data factoring into GHG emissions from gas processing associated with LNG is equivalent to that for U.S. natural gas supply, which is primarily a function of gas throughput. The major factors contributing to GHG emissions are the energy requirements for processing (which is a function of gas composition), and the CO_2 vented from processing (which is a function of the CO_2 content of produced gas). The average CO_2 content of gas produced in each country of origin exporting LNG to the U.S. was shown in Exhibit 20, along with the references from which those values were derived.

Gas processing emissions in LNG exporting countries was estimated from the proprietary ICF Gas Processing GHG Model. U.S. plants of similar size and configuration necessary to handle gas produced in foreign countries were selected to model the processing emissions associated with exported LNG. This structure was utilized since it was that already established for developing emissions from natural gas processing from U.S. source gas. This was done for modeling convenience, and does not necessarily reflect the process train for LNG. Natural gas processing for LNG generally occurs at the LNG liquefaction plant and is integrated into that process; i.e., it is generally not a stand-alone operation.

The representative gas processing facilities assumed to estimate the GHG emissions were required to include Acid Gas Removal (AGR) units for the removal of CO_2 and hydrogen sulfide (H_2S) where and in the amounts present, along with dehydrators with molecular sieves for the extraction of water from the natural gas feed, as these impurities will cause difficulties in gas liquefaction downstream of the gas processing plant. The representative gas processing facilities also required fractionation for the removal of heavy hydrocarbons when the throughput was associated gas (which included condensate production), whereas, no fractionation was assumed to be required for non-associated gas throughput. Gas throughput and CO_2 content of the gas were adjusted in the representative facility to match the production characteristics of the producing country.

The one factor that may be somewhat different for imported LNG relative to U.S. natural gas supply (except for selected fields in certain areas of the country, like West Texas and Wyoming) is that several large LNG projects overseas currently plan to permanently sequester the CO_2 separated in nearby geologic formations. Such plants include Gorgon (Australia), In Salah (Algeria), Tangguh (Papua/New Guinea), Snohvit (Norway), and possibly others.

The assumed gas throughput of the plants anticipated to serve U.S. LNG requirements for 2006 and 2020 are summarized below, by source of supply.

2006

		T&T	Nigeria	Egypt	Algeria
Gas throughput	MMcfd	1,163	179	371	53

2020

		T&T	Nigeria	Egypt	Algeria	PNG	Russia	Australia	Qatar	Norway
Gas throughput	MMcfd	2,185	2,143	1,591	1,116	260	629	392	1,617	1,447

Natural Gas Liquefaction and Loading

The volume of natural gas consumed by the liquefaction process was estimated by conducting an energy and material balance around the LNG liquefaction plant and loading activities. Specifications from the Pluto LNG and Darwin LNG projects in Australia, as well as the ConocoPhillips Optimized Cascade process, were utilized to construct a generic LNG liquefaction plant and loading model.[22]

The fuel required for the loading activities is dependent on the natural gas consumed by the electric power generators and boil off compressors. The natural gas fired generators are used to run the loading pump used to deliver LNG from the storage tanks to the LNG carriers, as well as satisfy the base electricity needs of the liquefaction plant. The loading pump horsepower was calculated by assuming the LNG shipping carrier specifications and the loading pipe parameters. These generators have a higher fuel requirement during loading operations, however, they are assumed to be functional throughout the year.

The LNG liquefaction and storage plant was assumed to have boil-off compressors sized to meet the daily boil-off rate, and included the assumption of an additional compressor to handle gas from the ship vapor return lines during loading activities. The amount of natural gas required to fuel the boil-off compressor is based on the horsepower requirement of the compressor, and is assumed to operate throughout the year. The ship vapor recovery compressor is assumed to have a similar horsepower requirement as the boil-off, operating only during loading.

Total natural gas consumption as fuel for liquefaction and loading was estimated to be around 8% of the amount of gas liquefied and delivered to the U.S.

The key activity factors affecting emissions from liquefaction facilities for 2006 and 2020 are summarized in Exhibit 22, by source of supply.

Exhibit 22: Key Activity Factors for Gas Liquefaction by Source Country for 2006 and 2020

2006

		T&T	Nigeria	Egypt	Algeria
Amount LNG Delivered to US	MMcf	389,269	57,292	119,528	17,449
Storage cap alloc to U.S.	m^3	360,826	25,011	73,490	4,348
Allocation factor		69%	10%	24%	2%

2020

		T&T	Nigeria	Egypt	Algeria	PNG	Russia	Australia	Qatar	Norway
Amount LNG Delivered to US	MMcf gas	752,734	741,491	551,368	384,547	90,037	212,418	135,865	580,525	495,392
Storage cap alloc to U.S.	m^3	540,319	271,844	152,512	108,676	14,640	91,166	26,804	167,839	252,322
Allocation factor		82%	69%	74%	28%	4%	46%	8%	49%	84%

[22] ConocoPhillips. "ConocoPhillips Optimized Cascade Process." March. 2006. http://lnglicensing.conocophillips.com/lng_tech_licensing/cascade_process/index.htm
ConocoPhillips. "Darwin LNG – Environment." March 2006. www.darwinlng.com/Environment/Index.htm
GE. "GE Aero Energy." January 2008. www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm2500plus.pdf
Pluto LNG. "Emissions, Discharges, and Wastes." http://standupfortheburrup.de/downloads/05emissionsdischargesandwaste.pdf

LNG Shipping

LNG is transported in specialized cryogenic tankers that keep the LNG insulated to minimize boil-off during the voyage. LNG tankers can be fueled in a number of ways: boil-off fired steam plants, dual-fired boil-off gas and diesel, and diesel only with boil-off gas re-liquefaction. For this analysis, all LNG shipping was assumed to use a dual-fired engine that consumes boil-off gas for 80% to 90% of its fuel requirements, with the remainder supplemented by diesel. In 2006, the average tanker volume shipped was assumed to be 80,000 m^3. This assumed tanker size was estimated by dividing the volume of LNG imported into the U.S. by the number of import shipments reported. Newly constructed tankers were assumed to increase the average fleet size to 154,000 m^3 in 2020.[23]

Voyage duration was estimated using a service speed of 19.5 knots to cover the approximate distance between the port of origin and destination terminal. LNG losses along the voyage were estimated assuming a 0.15% of cargo capacity per day boil-off rate for the laden voyage.[24] The LNG tanker was assumed to keep a small heel of LNG in its tanks to maintain cryogenic temperatures on the unladen voyage. This heel was estimated to be 200% of the boil-off fuel required for the laden voyage.

The key activity factors affecting emissions from LNG shipping are shown, by source of supply and destination, for 2006 in Exhibit 23, and for 2020 in Exhibit 24.

Exhibit 23: Key Activity Factors for LNG Shipping, by Source Country and Delivery Point, for 2006

	Volume Imported (MMcf)	Average size of ship (m3)	Distance between ports (miles)
Algeria			
Cove Point, MD	17,449	80,000	3,300
Egypt			
Cove Point, MD	14,575	80,000	5,000
Elba Island, GA	42,411	80,000	5,000
Lake Charles, LA	62,542	80,000	6,500
Nigeria			
Lake Charles, LA	57,292	80,000	6,100
Trinidad & Tobago			
Cove Point, MD	84,590	80,000	2,000
Elba Island, GA	104,356	80,000	2,000
Everett, MA	176,097	80,000	2,000
Gulf Gateway, LA	453	80,000	2,200
Lake Charles, LA	23,773	80,000	2,200

[23] U.S. Department of Energy, Office of Fossil Energy, *Liquefied Natural Gas: Understanding the Basic Facts*, DOE/FE-0489, August 2005 (http://www.fe.doe.gov/programs/oilgas/publications/lng/LNG_primerupd.pdf)
[24] http://www.shell.com/static/shipping-en/downloads/lngbrochure.pdf

Exhibit 24: Key Activity Factors for LNG Shipping, by Source Country and Delivery Point, for 2020

	Volume Imported (MMcf)	Average size of ship (m3)	Distance between ports (miles)
Algeria			
New Gulf	361,000	154,000	4,700
Egypt			
Cove Point, MD	147,000	154,000	5,000
Lake Charles, LA	214,000	154,000	6,500
Gulf Gateway, LA	137,000	154,000	6,500
New East Coast	10,000	154,000	5,000
Nigeria			
Cove Point, MD	147,000	154,000	5,000
Elba Island, GA	207,000	154,000	4,500
New Gulf	335,000	154,000	6,100
Trinidad & Tobago			
Elba Island, GA	368,000	154,000	2,000
Lake Charles, LA	361,000	150,000	2,200
Indonesia/Papua New Guinea			
Baja California	82,000	154,000	7,000
Russia			
Baja California	205,000	154,000	4,000
Australia			
Baja California	123,000	154,000	7,500
Middle East/Qatar			
Everett, MA	268,000	154,000	8,000
Cove Point, MD	199,000	154,000	9,700
New East Coast	48,000	154,000	9,700
Norway			
New East Coast	79,000	154,000	4,000
New Gulf	396,000	154,000	5,000

LNG Storage and Regasification

LNG delivered to the U.S. is stored as LNG at the import terminals, and is then pumped up to pipeline pressure and vaporized for injection into the U.S. transmission system. Storage tanks are equipped with boil-off gas compression, all vaporization was assumed to use submerged combustion vaporizers (SCV). Vaporization of LNG requires around 1.5% of the gas send-out as fuel for the SCV. *However, it should be noted that the LNG industry is making considerable advancements in the area of revaporization, that, when implemented, will result in substantial reductions in fossil fuel consumption and GHG emissions. For example, the use of seawater and open rack vaporizers (ORVs) uses renewable resources and no fossil fuels, resulting in no* CO_2 *(and* NO_x*) emissions.*[25]

[25] http://fwc.com/publications/tech_papers/files/Lower%20Emission%20LNG%20Vap.pdf

The key activity factors affecting emissions from LNG storage and regasification are shown below, by receiving coast, for 2006 and 2020.

		West Coast		Gulf Coast		East Coast	
		2006	2020	2006	2020	2006	2020
No. of terminals			1	2	6	3	4
Volume imported into region	MMcf		410,000	144,000	1,804,000	439,476	1,473,000
Number of unloadings			120	81	521	234	431
Storage capacity	m^3		303,000	425,000	1,232,000	354,233	632,850
Gas used for regasification	MMcf		6,080	2,136	26,751	6,516	21,542

Natural Gas Transmission

LNG imports enter the domestic transmission system and have been assumed to travel only a short distance to the nearest market of sufficient size to consume the total imports to a particular region. Because LNG imports make up a small portion of the overall transmission system throughput and travel much shorter distances in the pipeline as compared to U.S. natural gas supplies, transmission sector emissions intensity for imported LNG is relatively small. Emissions were allocated to LNG imports using an estimate of emission intensity per mile that the gas travels. Applying this intensity factor to the distances traveled by imported LNG yielded the portion of total transmission emissions associated with LNG, the remainder was allocated to U.S. natural gas supplies.

OVERVIEW OF SECTOR-SPECIFIC RESULTS

Exploration and Development

As described above, in 2006, it was estimated that over 35,000 exploratory and developmental wells were drilled in the United States; this number is projected to decrease to about 20,000 wells drilled in 2020.

For LNG, only wells drilled for the purposes of producing gas to meet the demand requirements of the United States are accounted for in the supply chain emissions estimates. Well drilling activities to meet U.S. demand were estimated to be only 144 wells in 2006 and 820 wells in 2020.

For either U.S. natural gas supply or for LNG, emissions from exploration and development are small and account for less than 1% of supply chain emissions. Overall, total emissions from exploration and development from U.S. supply sources were 4.4 million tonnes of CO_2e in 2006, declining to 3.5 million tonnes of CO_2e in 2020. In comparison, total emissions from exploration and development of the various sources of supply of LNG to serve U.S. markets were only 100,000 tonnes of CO_2e in 2006, growing to over 980,000 tonnes of CO_2e by 2020.

Emissions from exploration and development are characterized in Exhibit 25 for U.S. natural gas supplies in each of the AEO supply regions, for the three main sources of emissions. As shown, the vast majority (over 99%) of the emissions are associated with energy consumption during drilling operations, in most cases diesel fuel. Consequently, the regions with the highest drilling levels (in both 2006 and 2020) are the regions with the greatest GHG emissions. Overall, emissions decline between 2006 and 2020 almost directly proportional to the decline in well drilling assumed in the HSM. Methane emissions from natural gas venting and flaring during gas well completion operations increases somewhat, due to the increased number of wells targeted at unconventional gas, relative to conventional gas well completions, in most regions.

Emissions from exploration and development associated with LNG supplies serving the U.S. market are characterized in Exhibit 26. Similar to U.S. natural gas, nearly all of the emissions are associated with energy consumption during drilling operations. CO_2 and methane emissions increase significantly between 2006 and 2020, due to the increased drilling levels that must be pursued to supply the growing U.S. requirements for LNG.

The total emissions associated with exploration and development for LNG is still only 6% of those from U.S. operations, even in 2020.

Overall the emissions intensity for exploration and development associated U.S.-sources natural gas supplies was 0.50 lb CO_2e/MMBtu in 2006 and 0.37 lb CO_2e/MMBtu in 2020, though it can range considerably by AEO supply region, as shown in Exhibit 27. The emission intensity is greatest in the areas with the lowest productivity wells, such as the Northeast and Mid-continent. For exploration and production associated with LNG, the overall emissions intensity was 0.37 lb CO_2e/MMBtu in 2006 and 0.60 lb CO_2e/MMBtu in 2020. The emissions intensity by supply region in 2020 for LNG is shown in Exhibit 28.

Exhibit 25: Comparison of GHG Emissions for Exploration and Development for U.S. Natural Gas for 2006 and 2020
(Not Accounting for Natural Gas Star Program Reductions)

Emission Sources	CO_2 Emissions (Mg)		CH_4 Emissions (Mg)	
	2006	**2020**	**2006**	**2020**
Northeast Region				
Drilling and Well Completion				
Completion Venting and Flaring	914	2,217	22,903	22,738
Well Drilling Venting	30	31	757	319
Well Drilling Combustion	975,671	410,829		
Midcontinent Region				
Drilling and Well Completion				
Completion Venting and Flaring	254	466	9,925	16,060
Well Drilling Venting	8	7	328	225
Well Drilling Combustion	633,930	435,085		
Rocky Mountain Region				
Drilling and Well Completion				
Completion Venting and Flaring	2,014	3,043	9,706	16,393
Well Drilling Venting	67	43	321	230
Well Drilling Combustion	349,199	250,148		
Southwest Region				
Drilling and Well Completion				
Completion Venting and Flaring	620	907	4,729	6,800
Well Drilling Venting	20	13	156	95
Well Drilling Combustion	405,545	247,331		
West Cost Region				
Drilling and Well Completion				
Completion Venting and Flaring	1	3	224	841
Well Drilling Venting	0	0	7	12
Well Drilling Combustion	12,891	20,504		
Gulf Coast Region				
Drilling and Well Completion				
Completion Venting and Flaring	618	923	8,739	12,784
Well Drilling Venting	20	13	289	179
Well Drilling Combustion	841,181	521,964		
	3,222,983	**1,893,527**	**58,084**	**76,676**

Exhibit 26: Comparison of GHG Emissions for Exploration and Development for LNG Supplies Serving U.S. Markets for 2006 and 2020
(Not Accounting for Natural Gas Star Program Reductions)

	CO_2 Emissions (Mg)#		CH_4 Emissions (Mg)	
Region/Emission Source	**2006**	**2020**	**2006**	**2020**
Trinidad & Tobago				
Completion Venting and Flaring	379.99	899.32	3,659.30	8,660.48
Well Drilling Venting	0.40	0.74	3.83	7.09
Well Drilling Combustion	10,964.62	20,311.51		
Nigeria				
Completion Venting and Flaring	0.00	185.66	0.00	6,870.13
Well Drilling Venting	0.03	0.36	1.15	13.42
Well Drilling Combustion	3,415.21	39,904.03		
Egypt				
Completion Venting and Flaring	0.00	2,893.33	0.00	11,160.52
Well Drilling Venting	0.58	2.47	2.25	9.53
Well Drilling Combustion	7,360.68	31,141.32		
Algeria				
Completion Venting and Flaring	0.00	183.80	0.00	1,411.39
Well Drilling Venting	0.02	0.35	0.18	2.71
Well Drilling Combustion	808.87	12,402.61		
Indonesia/Papua New Guinea				
Completion Venting and Flaring		0.00		0.00
Well Drilling Venting		0.11		0.88
Well Drilling Combustion		3,208.50		
Russia				
Completion Venting and Flaring		305.55		2,346.30
Well Drilling Venting		0.21		1.63
Well Drilling Combustion		7,448.30		
Australia				
Completion Venting and Flaring		129.27		992.67
Well Drilling Venting		0.09		0.69
Well Drilling Combustion		2,836.08		
Middle East/Qatar				
Completion Venting and Flaring		411.32		3,158.49
Well Drilling Venting		0.25		1.95
Well Drilling Combustion		5,941.67		
Norway				
Completion Venting and Flaring		705.11		5,414.55
Well Drilling Venting		0.49		3.75
Well Drilling Combustion		11,458.93		
TOTAL EMISSIONS	**22,930.40**	**140,371.39**	**3,666.70**	**40,056.17**

Mg = megagram = 1,000 kg = 1 metric tonne

Exhibit 27: Exploration and Development
Emissions Intensity by AEO Supply Region for 2006 and 2020

	Exploration and Development	
Total Emissions (1,000 lbs CO_2e)	**2006**	**2020**
Northeast	3,248,396	1,978,082
Midcontinent	1,872,804	1,714,173
Rocky Mountain	1,238,637	1,327,865
Southwest	1,121,637	866,509
West Coast	39,150	84,703
Gulf Coast	2,273,791	1,752,944
Offshore	n.e.	n.e.
Natural Gas Supply (Quads)		
Northeast Region	0.86	1.12
Midcontinent Region	2.30	3.24
Rocky Mountain Region	4.34	3.74
Southwest Region	1.84	3.40
West Cost Region (inc AK)	0.71	2.34
Gulf Coast Region	9.22	9.10
Offshore	n.e.	n.e.
Emissions Intensity (lb. CO_2e/MMBtu)		
Northeast Region	3.79	1.77
Midcontinent Region	0.81	0.53
Rocky Mountain Region	0.29	0.36
Southwest Region	0.61	0.25
West Cost Region	0.05	0.04
Gulf Coast Region	0.25	0.19
Offshore	n.e.	n.e.

Exhibit 28: Exploration and Development
Emissions Intensity for LNG, by Source Country, for 2006 and 2020

Total Emissions (1000 lbs CO_2e)	Exploration and Development	
	2006	2020
Trinidad & Tobago	194,600	448,039
Nigeria	7,582	407,065
Egypt	16,332	592,170
Algeria	1,791	93,216
Indonesia/Papua N. Guinea		7,114
Russia		125,795
Australia		52,526
Qatar		160,323
Norway		277,665

Natural Gas Supply (Quads)	2006	2020
Trinidad & Tobago	0.44	0.84
Nigeria	0.07	0.82
Egypt	0.14	0.61
Algeria	0.02	0.43
Indonesia/Papua N. Guinea		0.10
Russia		0.24
Australia		0.15
Qatar		0.64
Norway		0.55

Emissions Intensity (lb. CO_2e/MMBtu)

	2006	2020
Trinidad & Tobago	0.44	0.53
Nigeria	0.11	0.49
Egypt	0.12	0.97
Algeria	0.09	0.22
Indonesia/Papua N. Guinea		0.07
Russia		0.54
Australia		0.35
Qatar		0.25
Norway		0.51

Natural Gas Production

U.S. natural gas is produced through a mix of associated, non-associated, and unconventional wells. Proportionally, on a per-unit-of-production basis, emissions are much higher for U.S. gas production than for that associated with gas production serving LNG exports. This is because the average production rate from individual wells in the U.S. is only around 30 million cubic feet per year, whereas wells from countries exporting LNG can have natural gas production rates of nearly 20 million cubic feet per well per day. The larger number of wells needed to produce the same amount of gas in the U.S. requires more equipment, and consequently, results in more fugitive and vented emissions.

Overall, total emissions from natural gas production from U.S. supply sources were 116 million tonnes of CO_2e in 2006, decreasing to 105 million tonnes of CO_2e in 2020. In comparison, total emissions from natural gas production from the various sources of supply of LNG to serve U.S. markets were only about 420,000 tonnes of CO_2e in 2006, growing to over 3.4 million tonnes of CO_2e by 2020.

In 2006, GHG emissions intensity from U.S. production was 13.10 lb CO_2e/MMBtu as compared to 1.57 lb CO_2e/MMBtu for countries exporting LNG. In 2020, GHG emissions intensity from U.S. production decreases to 11.19 lb CO_2e/MMBtu, while increasing to 2.08 lb CO_2e/MMBtu for countries exporting LNG to the U.S. However, the emissions and emissions intensity can range considerably by supply region. Total U.S. emissions by AEO supply region are shown in Exhibit 29 for 2006, and Exhibit 30 for 2020, *not accounting for emissions reductions attributable to the Natural Gas Star Program*. Overall emission intensity is shown by AEO supply region for U.S. gas supply sources for both 2006 and 2020 in Exhibit 31 and for the source countries for LNG (for both 2006 and 2020) in Exhibit 32, this time adjusting to take into account for emissions reductions attributable to the Natural Gas Star Program.

The uniquely high emissions level and emissions intensity for Qatar is the result of the very high condensate production associated with natural gas production in this country. The model used for this analysis assumed condensate was stored in tanks without vapor recovery or other emissions controls. While this was assumed in all countries and regions of the U.S., the implications of this for Qatar, given its high ratio of condensate to gas, was most pronounced. Given this high level of condensate production, vapor recovery or other emissions controls would most likely be implemented in this case, resulting in emission rates of approximately one-fifth of that assumed in this analysis.

Moreover, it is important to note that the emissions intensity of U.S. offshore production, again given the much higher productivity per well characteristic of offshore production, is much less intensive that onshore production, and in fact approaches the intensity of the sources of supply for LNG.

Exhibit 29: Emissions from Production Operations by AEO Supply Region – 2006
(Not Accounting for Natural Gas Star Program Reductions)

Emission Sources	CO_2 Emissions (Mg)	CH_4 Emissions (Mg)	N_2O Emissions (Mg)
Northeast Region	1,572,247	847,450	36
Midcontinent Region	1,544,828	1,062,868	34
Rocky Mountain Region	7,021,187	1,252,766	125
Southwest Region	5,164,753	574,899	119
West Cost Region	632,403	87,640	16
Gulf Coast Region Onshore	11,032,555	806,692	229
Purchased Electricity	16,317,494	135	
Offshore	3,035,939	227,774	
	46,321,406	**4,860,224**	**559**

Exhibit 30: Emissions from Production Operations by AEO Supply Region – 2020
(Not Accounting for Natural Gas Star Program Reductions)

Emission Sources	CO_2 Emissions (Mg)	CH_4 Emissions (Mg)	N_2O Emissions (Mg)
Northeast Region	2,215,590	1,044,129	50
Midcontinent Region	2,036,861	1,783,394	45
Rocky Mountain Region	6,792,467	2,218,582	115
Southwest Region	6,488,166	879,461	152
West Cost Region	747,939	312,823	19
Gulf Coast Region Onshore	12,545,320	1,274,922	266
Purchased Electricity	15,934,637	132	
Offshore	2,955,576	213,424	
	49,716,556	**7,726,868**	**648**

Exhibit 31: Natural Gas Production
Emissions Intensity by AEO Supply Region for 2006 and 2020
(Including Natural Gas Star Program Reductions)

Total Emissions (1,000 lbs CO_2e)

	2006	2020
Northeast	35,101,370	25,163,970
Midcontinent	42,919,609	38,406,488
Rocky Mountain	63,999,846	58,893,138
Southwest	34,403,659	33,295,210
West Coast	4,845,579	7,761,123
Gulf Coast	74,170,117	68,102,362

Natural Gas Supply (Quads)

	2006	2020
Northeast	0.86	1.12
Midcontinent	2.30	3.24
Rocky Mountain	4.34	3.74
Southwest	1.84	3.40
West Coast	0.71	2.34
Gulf Coast	9.22	9.10
Offshore		

Emissions Intensity (lb. CO_2e/MMBtu)

	2006	2020
Northeast	40.97	22.50
Midcontinent	18.64	11.87
Rocky Mountain	14.75	15.75
Southwest	18.69	9.79
West Coast	6.78	3.31
Gulf Coast	8.04	7.49

Exhibit 32: Natural Gas Production
Emissions Intensity for LNG, by Source Country, for 2006 and 2020
(Including Natural Gas Star Program Reductions)

Total Emissions (1,000 lbs CO_2e)

	2006	2020
Trinidad & Tobago	486,289	718,473
Nigeria	135,420	1,073,276
Egypt	258,246	740,925
Algeria	46,419	603,453
Indonesia/Papua N. Guinea		96,375
Russia		178,016
Australia		110,817
Qatar		3,546,024
Norway		476,898

Natural Gas Supply (Quads)

	2006	2020
Trinidad & Tobago	0.44	0.84
Nigeria	0.07	0.82
Egypt	0.14	0.61
Algeria	0.02	0.43
Indonesia/Papua N. Guinea		0.10
Russia		0.24
Australia		0.15
Qatar		0.64
Norway		0.55

Emissions Intensity (lb. CO_2e/MMBtu)

	2006	2020
Trinidad & Tobago	1.10	0.86
Nigeria	1.99	1.30
Egypt	1.83	1.21
Algeria	2.28	1.41
Indonesia/Papua N. Guinea		0.97
Russia		0.76
Australia		0.74
Qatar		5.52
Norway		0.87

Natural Gas Processing

Overall, total emissions from natural gas processing from U.S. supply sources were 59 million tonnes of CO_2e in 2006, increasing to 64 million tonnes of CO_2e in 2020. In comparison, total emissions from natural gas processing associated with the sources of supply for LNG to serve U.S. markets were only 1.7 million tonnes of CO_2e in 2006, growing to over 13 million tonnes of CO_2e by 2020.

Emissions intensity from gas processing was 6.64 lb CO_2e /MMBtu for U.S. natural gas supply and 6.46 lb CO_2e /MMBtu for imported LNG in 2006. Gas processing emissions intensity is projected to increase slightly to 6.80 lb CO_2e /MMBtu for U.S. natural gas supply, while increasing to 8.14 lb CO_2e/MMBtu for imported LNG in 2020.

The decrease in emissions intensity for U.S.-sourced supplies is due primarily to slight changes in the relative mix of regional production, the changing sources of that production (conventional vs. unconventional sources of natural gas) and the CO_2 content of production from those sources. For LNG, the increase in emissions intensity for gas processing is due to the need to bring on new sources of gas to serve U.S. LNG markets that tend to have a lower quality and higher CO_2 content. Only a relatively small portion of the CO_2 produced from planned projects is currently planned to be sequestered. If more of the CO_2 produced from these LNG operations is sequestered, beyond that currently planned, then the emissions intensity associated with these sources would decline proportionally.

For U.S. supplies, natural gas processing facilities were grouped into the NEMS supply region. Detailed emissions from these regions are shown in Exhibit 33 for 2006 and Exhibit 34 for 2020. A few items are important to note in understanding these results. First, West Coast emissions are dominated by Alaska operations. Virtually all of the associated gas produced on the North Slope is processed, the gas liquids blended into the crude stream to the Alaska pipeline, and what methane is not consumed as fuel for electricity generation, heating, engines and processing is re-injected into the oil reservoirs. With regard to the CO_2 emissions intensity in the Rocky Mountain region, the ICF gas processing model includes consideration of some CO_2 capture and injection for EOR operations in the Rockies, which reduced the CO_2 that would otherwise be emitted to the atmosphere. Emissions from Gulf Coast processing facilities also consider gas produced from offshore facilities in the Gulf of Mexico that is brought on shore to be processed.

Based on that, given the assumed throughput for gas processing in each of the NEMS supply regions contributing to U.S. supplies, the relative emissions intensity for the various regions, and the basis for that emissions intensity, is summarized in Exhibit 35 for 2006 and Exhibit 36 for 2020.

Emissions from gas processing for supplies destined to serve U.S. LNG requirements were disaggregated by country of origin. These are shown in Exhibit 37 for 2006 and Exhibit 38 for 2020. Based on that, given the assumed contribution for each of the countries providing LNG to U.S. markets, the relative emissions intensity for the various LNG source countries, and the basis for that emissions intensity, is summarized in Exhibit 39 for 2006 and Exhibit 40 for 2020.

As discussed above, a number of large LNG projects overseas plan to permanently sequester the CO_2 separated in nearby geologic formations. Such plants include Gorgon (Australia), Tangguh (Papua/New Guinea), Snohvit (Norway) and possibly others. Specifically, proposed sequestration rates planned for Gorgon, Snohvit, and Tangguh (assuming a comparable rate) are sufficient to sequester all of the vented CO_2 emissions from their respective source countries that are allocated to U.S. markets, amounting to over 900,000 tonnes per year, as shown in the table below.

	Proposed Injection Rate for CO_2 Sequestration (tonnes/yr)	(Mg/year)	Vented CO_2 emissions allocated to U.S. market (Mg/year)
Gorgon (Australia)	1,000,000	1,000,000	365,514
Tangguh (Papua New Guinea)	1,000,000	1,000,000	42,724
Snohvit (Norway)	700,000	700,000	495,517
			903,755

This could result in a reduction in the CO_2 emissions associated with gas processing for LNG exports, corresponding to a reduction in emissions intensity for LNG serving U.S. markets. These reductions are incorporated into the emissions estimates shown in Exhibit 38. If more of the CO_2 otherwise vented from processing gas serving LNG exports is sequestered, this impact could be greater. (The same also applies to the CO_2 otherwise vented as part of gas processing of U.S.-sourced natural gas.)

Exhibit 33: Emissions from Natural Gas Processing of U.S. Supplies, by Region for 2006
(Not Accounting for Natural Gas Star Program Reductions)

CO_2 Emission Sources	CO_2 Emissions (Mg)					
Normal Fugitives	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Plants - Before CO_2 removal	155	289	351	320	109	519
Plants - After CO_2 removal	37	69	84	77	26	125
Recip. Comp. - Before CO_2 removal	1,138	2,087	2,588	2,057	3,861	6,598
Recip. Comp. After CO_2 removal	274	502	623	495	929	1,587
Cent. Comp. - Before CO_2 removal	333	662	786	660	1,402	2,328
Cent. Comp. - After CO_2 removal	80	159	189	159	337	560
Vented						
AGR Vents	398,010	1,101,323	267,617	1,743,951	332,512	3,399,169
Kimray Pumps	14	56	52	67	9	132
Dehydrator Vents	162	320	294	373	57	825
Pneumatic Devices	17	33	39	36	12	58
Combusted	238,327	2,901,053	4,139,745	4,105,403	2,865,187	7,749,253
Routine Maintenance						
Blowdowns/Venting	386	718	872	795	270	1,289
Indirect Electricity Emissions	1,637,251	3,232,273	2,178,476	4,048,208	285,726	5,933,601

Methane Emission Sources	CH_4 Emissions (Mg)					
Normal Fugitives	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Plants	2,779	5,169	6,280	5,725	1,945	9,282
Reciprocating Compressors	20,366	37,354	46,324	36,812	69,097	118,097
Centrifugal Compressors	5,965	11,842	14,062	11,816	25,086	41,669
Vented						
AGR Vents	941	1,625	2,609	2,694	812	3,592
Kimray Pumps	145	567	523	676	95	1,333
Dehydrator Vents	1,644	3,243	2,973	3,783	582	8,357
Pneumatic Devices	159	295	358	327	111	530
Combusted	1,441	17,537	25,025	24,817	17,320	46,844
Routine Maintenance						
Blowdowns/Venting	3,910	7,272	8,836	8,054	2,737	13,059
Indirect Electricity Emissions	14	27	18	34	2	49

N_2O Emission Sources	N_2O Emissions (Mg)					
	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Combusted	6	75	107	106	74	200

Exhibit 34: Emissions from Natural Gas Processing of U.S. Supplies, by Region for 2020
(Not Accounting for Natural Gas Star Program Reductions)

CO_2 Emission Sources	CO_2 Emissions (Mg)					
Normal Fugitives	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Plants - Before CO_2 removal	181	338	410	374	127	606
Plants - After CO_2 removal	46	86	105	95	32	155
Recip. Comp. - Before CO_2 removal	1,224	2,261	2,794	2,234	4,273	7,267
Recip. Comp. After CO_2 removal	312	576	712	570	1,089	1,853
Cent. Comp. - Before CO_2 removal	363	733	858	727	1,526	2,545
Cent. Comp. - After CO_2 removal	92	187	219	185	389	649
Vented						
AGR Vents	270,228	797,059	739,201	2,291,963	304,342	5,274,304
Kimray Pumps	17	56	57	70	11	150
Dehydrator Vents	188	347	309	397	51	964
Pneumatic Devices	20	38	46	42	15	68
Combusted	276,371	3,364,149	4,800,573	4,760,750	3,322,557	8,986,269
Routine Maintenance						
Blowdowns/Venting	451	839	1,019	929	316	1,507
Indirect Electricity Emissions	2,028,167	4,004,022	2,699,069	5,014,772	353,947	7,336,273

Methane Emission Sources	CH_4 Emissions (Mg)					
Normal Fugitives	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Plants	3,442	6,403	7,780	7,091	2,410	11,498
Reciprocating Compressors	23,210	42,888	53,004	42,386	81,059	137,857
Centrifugal Compressors	6,882	13,914	16,273	13,785	28,943	48,269
Vented						
AGR Vents	1,155	2,266	3,122	3,207	1,026	4,405
Kimray Pumps	180	597	613	755	117	1,615
Dehydrator Vents	2,014	3,727	3,317	4,258	550	10,353
Pneumatic Devices	197	365	444	405	138	656
Combusted	1,671	20,336	29,019	28,779	20,085	54,322
Routine Maintenance						
Blowdowns/Venting	4,843	9,009	10,946	9,977	3,390	16,177
Indirect Electricity Emissions	17	33	22	42	3	61

N_2O Emission Sources	N_2O Emissions (Mg)					
	Northeast	Midcontinent	Rocky Mountain	Southwest	West Coast	Gulf Coast
Combusted	7	87	124	123	86	232

Exhibit 35: Emissions Intensity for U.S. Natural Gas Processing by NEMS Supply Region, for 2006

	(All emissions in Mg unless otherwise indicated)					
	Northeast	**Midcontinent**	**Rocky Mountain**	**Southwest**	**West Coast**	**Gulf Coast**
Fugitives (w/o Gas Star Reductions)						
CO2	400,608	1,106,217	273,495	1,748,989	339,524	3,413,190
CH4	35,907	67,367	81,966	69,887	100,466	195,918
Combustion						
CO2	1,875,578	6,133,326	6,318,221	8,153,611	3,150,913	13,682,854
CH4	1,454	17,564	25,043	24,851	17,322	46,893
N20	6	75	107	106	74	200
CO2e Total	2,864,749	8,614,196	8,530,139	11,373,593	5,567,082	20,966,813
Fugitives (w/ Gas Star)	956,720	2,088,767	1,652,820	2,665,193	2,029,420	6,237,051
Combustion	1,908,029	6,525,429	6,877,319	8,708,400	3,537,661	14,729,762
Fugitives	33%	24%	19%	23%	36%	30%
Combustion	67%	76%	81%	77%	64%	70%
Total Emissions (lb CO2e)	6,315,585,311	18,990,732,696	18,805,420,175	25,074,057,747	12,273,107,463	46,223,132,659
Gas Throughput (MMBtu)	928,336,255	1,883,124,425	2,204,933,829	1,845,224,833	3,758,691,160	6,304,954,721
Emissions Intensity (lb CO2e/MMBtu)	**6.80**	**10.08**	**8.53**	**13.59**	**3.27**	**7.33**

Exhibit 36: Emissions Intensity for U.S. Natural Gas Processing by NEMS Supply Region, for 2020 (Mg)

	(All emissions in Mg unless otherwise indicated)					
	Northeast	**Midcontinent**	**Rocky Mountain**	**Southwest**	**West Coast**	**Gulf Coast**
Fugitives (w/o Gas Star Reductions)						
CO2	273,122	802,520	745,730	2,297,586	312,171	5,290,067
CH4	41,922	79,169	95,499	81,864	117,634	230,830
Combustion						
CO2	2,304,538	7,368,171	7,499,643	9,775,522	3,676,504	16,322,542
CH4	1,687	20,369	29,042	28,820	20,088	54,383
N20	7	87	124	123	86	232
CO2e Total	2,820,068	8,844,148	9,287,808	12,083,006	5,277,736	21,736,467
Fugitives (w/ Gas Star)	477,876	1,021,239	1,139,788	1,664,078	1,152,743	4,199,819
Combustion	2,342,192	7,822,910	8,148,020	10,418,928	4,124,993	17,536,648
Fugitives	17%	12%	12%	14%	22%	19%
Combustion	83%	88%	88%	86%	78%	81%
Total Emissions (lb CO2e)	6,217,080,708	19,497,681,592	20,475,768,160	26,638,019,693	11,635,220,494	47,919,900,011
Gas Throughput (MMBtu)	1,149,989,003	2,332,745,670	2,731,391,391	2,285,797,041	4,656,129,150	7,810,347,330
Emissions Intensity (lb CO2e/MMBtu)	**5.41**	**8.36**	**7.50**	**11.65**	**2.50**	**6.14**

Exhibit 37: Emissions from Natural Gas Processing for U.S. LNG Markets, by Country of Origin, 2006
(Not Accounting for Natural Gas Star Program Reductions)

Carbon Dioxide Emission Sources	CO_2 Emissions (Mg)			
Normal Fugitives	Algeria	Egypt	Nigeria	Trinidad
Plants - Before CO_2 removal	1.95	1.95	1.75	0.78
Plants - After CO_2 removal	0.75	0.75	0.75	0.75
Reciprocating Compressors - Before CO_2 removal	12.22	85.04	36.93	106.22
Reciprocating Compressors - After CO_2 removal	4.69	32.60	15.73	101.81
Centrifugal Compressors - Before CO_2 removal	4.66	32.43	14.08	40.50
Centrifugal Compressors - After CO_2 removal	1.79	12.43	6.00	38.82
Vented				
AGR Vents	10,082.40	70,324.56	27,061.91	176,273.25
Kimray Pumps	0.00	0.00	0.00	0.00
Dehydrator Vents	5.63	39.30	17.01	49.26
Pneumatic Devices	0.22	0.22	0.20	0.09
Combusted	26,038.65	175,045.01	87,989.26	523,932.63
Routine Maintenance				
Blowdowns/Venting	4.84	4.84	4.36	1.94
Indirect Electricity Emissions	2,427.55	62,257.15	3,885.66	128,460.54

Methane Emission Sources	CH_4 Emissions (Mg)			
Normal Fugitives	Algeria	Egypt	Nigeria	Trinidad
Plants	55.58	55.58	55.58	55.58
Reciprocating Compressors	348.71	2,425.91	1,170.55	7,575.24
Centrifugal Compressors	132.97	925.01	446.34	2,888.47
Vented				
AGR Vents	42.76	42.76	42.76	42.76
Kimray Pumps	0.00	0.00	0.00	0.00
Dehydrator Vents	90.97	634.55	305.23	1,988.17
Pneumatic Devices	3.17	3.17	3.17	3.17
Combusted	157.40	1,058.15	531.89	3,167.17
Routine Maintenance				
Blowdowns/Venting	78.20	78.20	78.20	78.20
Indirect Electricity Emissions	0.02	0.52	0.03	1.07

Nitrous Oxide Emission Sources	N_2O Emissions (Mg)			
	Algeria	Egypt	Nigeria	Trinidad
Combusted	0.67	4.53	2.28	12.79

Exhibit 38: Emissions from Natural Gas Processing for U.S. LNG Markets, by Country of Origin, 2020
(Not Accounting for Natural Gas Star Program Reductions)

Carbon Dioxide Emission Sources — CO_2 Emissions (Mg)

Normal Fugitives	Algeria	Egypt	Nigeria	Trinidad	Indonesia/ Papua New Guinea	Russia	Australia	Middle East/ Qatar	Norway
Plants - Before CO2 removal	4.83	9.65	8.69	3.86	6.03	0.36	8.45	7.24	28.96
Plants - After CO2 removal	1.85	3.70	3.70	3.70	0.93	0.93	0.93	2.78	2.78
Reciprocating Compressors - Before CO2 removal	247.00	353.22	427.32	193.54	142.38	20.60	300.54	358.17	1,267.40
Reciprocating Compressors - After CO2 removal	94.70	135.43	182.04	185.51	21.84	52.65	32.92	137.33	121.48
Centrifugal Compressors - Before CO2 removal	91.69	131.12	158.63	71.85	53.00	7.67	111.87	132.96	471.78
Centrifugal Compressors - After CO2 removal	35.16	50.27	67.58	68.87	8.13	19.60	12.26	50.98	45.22
Vented									
AGR Vents	211,276.45	301,245.68	324,769.11	331,016.58	196,750.75	35,732.86	445,001.83	306,260.66	1,918,884.00
Kimray Pumps	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dehydrator Vents	118.07	168.35	204.18	92.49	68.72	9.98	145.07	171.15	612.78
Pneumatic Devices	0.54	1.07	0.97	0.43	0.67	0.04	0.94	0.81	3.22
Combusted	597,147.06	895,205.44	1,155,125.18	1,173,626.82	120,696.73	274,593.92	181,724.30	870,593.13	655,890.04
Routine Maintenance									
Blowdowns/Venting	12.00	24.00	21.60	9.60	15.00	0.90	21.00	18.00	71.99
Indirect Electricity Emissions	318,204.93	159,097.07	159,101.73	159,102.08	77,115.14	317,273.05	317,265.05	159,101.83	317,268.11
CO2 Emissions Sequestered	0	0	0	0	**42,724**	0	**365,514**	0	**495,517**

Methane Emission Sources — CH_4 Emissions (Mg)

Normal Fugitives	Algeria	Egypt	Nigeria	Trinidad	Indonesia/ Papua New Guinea	Russia	Australia	Middle East/ Qatar	Norway
Plants	137.70	275.39	275.39	275.39	68.85	68.85	68.85	206.55	206.55
Reciprocating Compressors	7,046.23	10,076.31	13,544.54	13,802.49	1,624.70	3,916.97	2,449.54	10,217.53	9,038.73
Centrifugal Compressors	2,615.71	3,740.54	5,028.03	5,123.78	604.78	1,458.06	911.82	3,792.97	3,364.58
Vented									
AGR Vents	85.53	171.05	171.05	171.05	42.76	42.76	42.76	128.29	128.29
Kimray Pumps	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dehydrator Vents	1,906.38	2,718.18	3,663.05	3,733.51	443.83	1,074.74	669.22	2,763.43	2,473.48
Pneumatic Devices	7.86	15.72	15.72	15.72	3.93	3.93	3.93	11.79	11.79
Combusted	3,609.75	5,411.51	6,982.72	7,094.57	729.61	1,659.92	1,098.52	5,262.73	3,964.85
Routine Maintenance									
Blowdowns/Venting	193.73	387.46	387.46	387.46	96.87	96.87	96.87	290.60	290.60
Indirect Electricity Emissions	2.64	5.28	5.28	5.28	0.64	2.63	2.63	3.96	7.90

Nitrous Oxide Emission Sources — N_2O Emissions (Mg)

	Algeria	Egypt	Nigeria	Trinidad	Indonesia/ Papua New Guinea	Russia	Australia	Middle East/ Qatar	Norway
Combusted	15.45	23.16	29.88	30.36	3.12	7.10	4.70	22.52	16.97

Exhibit 39: Emissions Intensity for U.S. Natural Gas Processing by LNG Source Country, for 2006

	(All emissions in Mg unless otherwise indicated)			
	Algeria	**Egypt**	**Nigeria**	**Trinidad**
Fugitives (w/o Gas Star Reductions)				
CO2	10,119	70,534	27,159	176,613
CH4	752	4,165	2,102	12,632
Combustion				
CO2	28,466	237,302	91,875	652,393
CH4	157	1,059	532	3,168
N20	1	5	2	13
CO2e Total	53,457	391,855	162,826	1,089,018
Fugitives (w/ Gas Star)	21,476	130,917	59,075	366,127
Combustion	31,981	260,938	103,751	722,891
Fugitives	40%	33%	36%	34%
Combustion	60%	67%	64%	66%
Total Emissions (lb CO2e)	117,849,452	863,876,802	358,963,377	2,400,832,780
Gas Throughput (MMBtu)	20,151,268	140,371,186	67,565,841	439,705,984
Emissions Intensity (lb CO2e/MMBtu)	**5.85**	**6.15**	**5.31**	**5.46**

Exhibit 40: Emissions Intensity for U.S. Natural Gas Processing by LNG Source Country, for 2020

(All emissions in Mg unless otherwise indicated)

	Algeria	Egypt	Nigeria	Trinidad	Indonesia/ Papua New Guinea	Russia	Australia	Middle East/ Qatar	Norway
Fugitives (w/o Gas Star Reductions)									
CO2	211,882	302,123	325,844	331,646	154,343	35,846	80,122	307,140	1,425,993
CH4	11,993	17,385	23,085	23,509	2,886	6,662	4,243	17,411	15,514
Combustion									
CO2	915,352	1,054,303	1,314,227	1,332,729	197,812	591,867	498,989	1,029,695	973,158
CH4	3,612	5,417	6,988	7,100	730	1,663	1,101	5,267	3,973
N20	15	23	30	30	3	7	5	23	17
CO2e Total	1,188,121	1,451,646	1,806,073	1,833,166	303,163	701,794	593,678	1,425,998	1,787,586
Fugitives (w/ Gas Star)	192,120	276,412	335,834	341,928	89,048	72,811	70,107	278,721	725,740
Combustion	996,001	1,175,234	1,470,239	1,491,238	214,115	628,983	523,571	1,147,277	1,061,846
Fugitives	16%	19%	19%	19%	29%	10%	12%	20%	41%
Combustion	84%	81%	81%	81%	71%	90%	88%	80%	59%
Total Emissions (lb CO2e)	2,619,314,662	3,200,277,674	3,981,641,944	4,041,371,288	668,348,974	1,547,164,766	1,308,814,425	3,143,734,695	3,940,886,628
Gas Throughput (MMBtu)	425,105,967	607,417,311	817,387,875	833,114,413	98,967,636	233,667,768	149,463,092	627,932,599	544,707,921
Emissions Intensity (lb CO2e/MMBtu)	**6.16**	**5.27**	**4.87**	**4.85**	**6.75**	**6.62**	**8.76**	**5.01**	**7.23**

Natural Gas Liquefaction and Loading

Total GHG emissions from the natural gas liquefaction and loading was slightly over 2.5 million tonnes CO_2e in 2006, but is forecast to grow to almost 17.5 million tonnes in 2020 due to the increased requirements for LNG in the U.S. In this analysis, these emissions are exclusively due to fuel consumption. Total natural gas consumption as fuel for liquefaction and loading was estimated to be around 8% of the amount of gas liquefied and delivered to the U.S. Overall, this represents an emissions intensity of 9.52 lb CO_2e/MMBtu for imported LNG in 2006 and 10.60 lb CO_2e /MMBtu in 2020. Emissions for both 2006 and 2020 are summarized by country of origin in Exhibit 41.

Exhibit 41: Natural Gas Liquefaction
Emissions Intensity for LNG, by Source Country, for 2006 and 2020

2006

LNG Country of Origin	Fuel Consumed for Refrigeration (MMcf/yr)	Fuel Consumed for Electricity Generation (MMcf/yr)	Fuel Consumed for Boil-off Gas Compressor (MMcf/yr)	CO_2 Emissions (tonnes)	CH_4 Emissions (tonnes)	N_2O Emissions (tonnes)	CO_2e Emissions (tonnes)	Natural Gas Delivered to US (BBtu)	Emissions Intensity (lb CO_2e/MMBtu)
Algeria	1,393	53	2	76,180	16	2	78,747	19,722	8.80
Egypt	9,713	65	31	529,821	25	27	533,674	137,559	10.45
Nigeria	4,672	58	10	254,611	26	6	257,890	66,168	11.09
Trinidad & Tobago	30,595	94	178	1,671,434	42	55	1,679,390	431,002	3.64

2020

LNG Country of Origin	Fuel Consumed for Refrigeration (MMcf/yr)	Fuel Consumed for Electricity Generation (MMcf/yr)	Fuel Consumed for Boil-off Gas Compressor (MMcf/yr)	CO_2 Emissions (tonnes)	CH_4 Emissions (tonnes)	N_2O Emissions (tonnes)	CO_2e Emissions (tonnes)	Natural Gas Delivered to US (BBtu)	Emissions Intensity (lb CO_2e/MMBtu)
Algeria	30,869	415	48	1,688,671	124	43	1,704,692	413,270	9.09
Egypt	44,716	469	70	2,439,109	179	63	2,462,250	589,255	9.21
Nigeria	59,833	531	133	3,260,591	240	84	3,291,525	794,085	9.14
Trinidad & Tobago	58,851	537	266	3,215,119	236	82	3,245,621	809,361	8.84
Indonesia/PNG	7,370	319	6	414,735	30	11	418,670	96,194	9.60
Russia	16,983	361	38	936,831	69	24	945,719	227,505	9.16
Australia	11,166	335	11	620,438	46	16	626,325	145,262	9.51
Middle East/Qatar	46,997	476	78	2,562,827	188	66	2,587,141	610,414	9.34
Norway	39,324	454	115	2,150,102	158	55	2,170,501	529,749	9.03

LNG Shipping

Overall, total GHG emissions from the LNG shipping was slightly over 1.6 million tonnes CO_2e in 2006, but is forecast to grow to over 9.2 million tonnes in 2020 due to the increased requirements for LNG in the U.S, and the longer distances LNG supplies serving this increased demand will need to travel.

Emissions intensity for LNG shipping was estimated as 6.07 lb CO_2e/MMBtu in 2006 and 5.59 lb CO_2e/MMBtu in 2020 as efficiencies improve, primarily by the use of much larger tankers, reducing the number of trips required to serve the same amount of LNG demand.

Total emissions from LNG shipping by country of origin are summarized in Exhibit 42 for 2006, and in Exhibit 43 for 2020.

Exhibit 42: Emissions from LNG Shipping in 2006

Origin	Destination	Trip Duration	One-way Boil-off (m^3 LNG)	LNG heel left (m^3 LNG)	Amount Unloaded (m^3 LNG)	Total Volume Delivered (MMcf gas)	# of Trips	Emissions (tonnes CO_2)	Country Specific Emissions Intensity (lbs CO_2e/MMBtu)
Algeria	Cove Point, MD	147 hr	735	1,471	77,794	17,449	10	52,178	6.30
Egypt	Cove Point, MD	223 hr	1,114	2,228	76,658	14,575	8	63,246	
Egypt	Elba Island, GA	223 hr	1,114	2,228	76,658	42,411	23	181,834	
Egypt	Lake Charles, LA	290 hr	1,448	2,897	75,655	62,542	35	359,714	10.45
Nigeria	Lake Charles, LA	272 hr	1,359	2,718	75,922	57,292	32	308,643	11.09
Trinidad & Tobago	Cove Point, MD	89 hr	446	891	78,663	84,590	45	142,305	
Trinidad & Tobago	Elba Island, GA	89 hr	446	891	78,663	104,356	55	173,928	
Trinidad & Tobago	Everett, MA	89 hr	446	891	78,663	176,097	93	294,096	
Trinidad & Tobago	Gulf Gateway, LA	98 hr	490	980	78,529	453	1	3,479	
Trinidad & Tobago	Lake Charles, LA	98 hr	490	980	78,529	23,773	13	45,221	3.64

Exhibit 43: Emissions from LNG Shipping in 2020

Origin	Destination	Trip Duration	Ship Size (m3 LNG)	One-way Boil-off (m3 LNG)	LNG heel left (m3 LNG)	Amount Unloaded (m3 LNG)	Total Volume Delivered (MMcf gas)	# of Trips	Emissions (tonnes CO2)	Country Specific Emissions Intensity (lbs CO_2e/MMBtu)
Algeria	New Gulf	209 hr	150,000	1,964	3,927	144,109	361,000	104	801,694	4.63
Egypt	Cove Point, MD	223 hr	150,000	2,089	4,178	143,733	147,000	43	352,627	
Egypt	Lake Charles, LA	290 hr	150,000	2,716	5,431	141,853	214,000	63	671,632	
Egypt	Gulf Gateway, LA	290 hr	150,000	2,716	5,431	141,853	137,000	40	426,433	
Egypt	New East Coast	223 hr	150,000	2,089	4,178	143,733	10,000	3	24,602	5.99
Nigeria	Cove Point, MD	223 hr	150,000	2,089	4,178	143,733	147,000	43	352,627	
Nigeria	Elba Island, GA	201 hr	150,000	1,880	3,760	144,360	207,000	60	442,834	
Nigeria	New Gulf	272 hr	150,000	2,548	5,097	142,355	335,000	98	980,468	5.34
Trinidad & Tobago	Elba Island, GA	89 hr	150,000	836	1,671	147,493	368,000	104	341,146	
Trinidad & Tobago	Lake Charles, LA	98 hr	150,000	919	1,838	147,243	361,000	102	368,045	2.09
Indonesia/Papua New Guinea	Baja California	312 hr	150,000	2,924	5,849	141,227	82,000	24	275,541	6.87
Russia	Baja California	178 hr	150,000	1,671	3,342	144,987	205,000	59	387,070	4.07
Australia	Baja California	334 hr	150,000	3,133	6,267	140,600	123,000	37	455,135	7.51
Middle East/Qatar	Everett, MA	357 hr	150,000	3,342	6,684	139,973	268,000	80	1,049,682	
Middle East/Qatar	Cove Point, MD	432 hr	150,000	4,052	8,105	137,843	199,000	60	954,554	
Middle East/Qatar	New East Coast	432 hr	150,000	4,052	8,105	137,843	48,000	15	238,639	8.80
Norway	New East Coast	178 hr	150,000	1,671	3,342	144,987	79,000	23	150,892	
Norway	New Gulf	223 hr	150,000	2,089	4,178	143,733	396,000	114	934,873	4.89

LNG Storage and Regasification

GHG emission from the LNG storage and regasification was almost 470,000 tonnes CO_2e in 2006, but is forecast to grow to almost 3 million tonnes by 2020 due to the increased requirements for LNG in the U.S. Emissions intensity for regasification operations is estimated to be 1.75 lb CO_2e/MMBtu, growing slightly to 1.80 lb CO_2e/MMBtu in 2020.

Total emissions from LNG storage and regasification by U.S. destination are summarized in Exhibit 44 for 2006 and in Exhibit 45 for 2020.

Exhibit 44: Emissions from LNG Storage and Regasification in 2006

Region	Fuel for Vaporization (MMcf/year)	CO_2 Emissions (tonnes)	CH_4 Emissions (tonnes)	N_2O Emissions (tonnes)	CO_2e Emissions (tonnes)	LNG Imports (MMcf)	Emissions Intensity (lbs CO_2e/MMBtu)
East Coast	6,516.81	351,233	7	7	353,392	439,478	1.75
Gulf Coast	2,136.20	115,134	2	2	115,841	144,060	1.75
West Coast	0.00	0	0	0	0	0	

Exhibit 45: Emissions from LNG Storage and Regasification in 2020

Region	Fuel for Vaporization (MMcf/year)	CO_2 Emissions (tonnes)	CH4 Emissions (tonnes)	N_2O Emissions (tonnes)	CO_2e Emissions (tonnes)	LNG Imports (MMcf)	Emissions Intensity (lbs CO_2e/MMBtu)
East Coast	21,842.41	1,177,229	23	22	1,184,465	1,473,000	1.75
Gulf Coast	26,750.65	1,441,766	28	27	1,450,628	1,804,000	1.75
West Coast	6,079.69	327,674	6	6	329,688	410,000	1.75

Natural Gas Transmission

As described above, LNG imports were assumed to enter the domestic transmission system and travel only a short distance to the nearest market of sufficient size to consume the total imports to a particular region. Because LNG imports make up a small portion of the overall transmission system throughput and travel much shorter distances compared to U.S. natural gas supplies, transmission sector emissions for imported LNG are relatively small, as are the corresponding emissions intensity.

Overall, total GHG emission from natural gas transmission in the U.S. was nearly 49 million tonnes in 2006, decreasing to 36 million tonnes in 2020 due to increased efforts at reducing emissions in the transmission sector. The vast majority of emissions in this sector are due to U.S.-sourced supplies in both 2006 and 2020. The incremental LNG-related emissions intensity for imported LNG in 2006 was 0.13 lb CO_2e/MMBtu, while the emissions intensity for the transmission system for U.S natural gas supply was 5.49 lb CO_2e/MMBtu. In 2020, the incremental emissions intensity for imported LNG was estimated to be 0.02 lb CO_2e/MMBtu, while that for the U.S. transmission associated with U.S. natural gas supply was estimated to be 3.82 lb CO_2e/MMBtu.

It should be noted that transmission emissions were estimated taking into consideration pipeline fuel use for both LNG and U.S. sources gas supplies. LNG emissions are estimated by applying a factor for emissions intensity per mile of pipeline, and the estimated the distance between the LNG regasification terminal and the nearest major market demand center in the appropriate in each region. Thus, the LNG sourced supply was assumed to travel a short distance within the transmission system, and therefore emissions are relatively small. These emissions are subtracted out of the total U.S. transmission system, and factor only into the transmission-related intensity for LNG sourced supply. The emissions associated with U.S. sourced supply are estimated by deducting the LNG emissions from the U.S. transmission system total, and then intensity is calculated using the total end user consumption of U.S. sourced supply only.

The breakdown of emissions by AEO demand region for both CO_2 and methane is show in Exhibit 46 for the U.S. natural gas supply scenario, with the emissions intensity defined in terms of gas throughput through the natural gas transmission system.

Exhibit 46: Transmission Sector Emissions by AEO Demand Region for 2006 and 2020

AEO Demand Region	CO_2(Mg)	CH_4 (Mg) -- w/ Natural Gas STAR Adj.	CO_2e (Mg)	Gas Throughput (Quads)	Intensity (lb CO_2e/MMBtu)	CO_2(Mg)	CH_4 (Mg) -- w/ Natural Gas STAR Adj.	CO_2e (Mg)	Gas Throughput (Quads)	Intensity (lb CO_2e/MMBtu)
New England	430,614	70,291	1,906,721	0.56	7.43	575,930	43,659	1,492,774	0.65	5.05
Middle Atlantic	1,279,817	239,494	6,309,200	2.56	5.42	1,494,756	132,265	4,272,325	2.56	3.68
East North Central	2,123,719	379,194	10,086,788	4.57	4.87	2,490,303	220,457	7,119,903	4.87	3.23
West North Central	718,615	135,163	3,557,047	1.63	4.80	938,040	86,079	2,745,705	1.93	3.14
South Atlantic	1,170,769	161,463	4,561,487	1.93	5.20	1,470,257	98,382	3,536,270	2.10	3.73
East South Central	542,620	89,443	2,420,930	1.14	4.67	748,581	50,762	1,814,588	1.14	3.53
West South Central	2,862,680	322,153	9,627,898	4.46	4.76	3,465,535	201,739	7,702,059	5.14	3.31
Mountain	941,056	109,536	3,241,313	1.29	5.54	1,109,818	66,559	2,507,559	1.43	3.88
Pacific	1,715,180	240,710	6,770,081	2.97	5.03	1,903,498	131,069	4,655,937	2.87	3.59

	CH_4 (Mg) -- No Natural Gas Star Adj.	CH_4 (Mg) -- No Natural Gas Star Adj.
	92,691	115,145
	315,817	348,831
	500,036	581,425
	178,237	227,022
	212,918	259,468
	117,947	133,878
	424,817	532,060
	144,443	175,540
	317,419	345,675
Natural Gas STAR Reductions	24.2%	62.1%

Natural Gas Distribution

Overall, total GHG emission from the distribution sector was 27 million tonnes in 2006, declining to 15 million tonnes in 2020 due to the replacement of older less efficient distribution piping, mains, and services with lower emissions technology over time. In 2006, emissions intensity was estimated as 2.98 lb CO_2e/MMBtu for U.S. natural gas supply and imported LNG. In 2020, emissions intensity for imported LNG and U.S. natural gas supply was 1.37 lb CO_2e/MMBtu.

Emissions for the distribution sector are the same for both the U.S. natural gas supply and LNG scenarios. The breakdown of emissions by AEO demand region for both CO_2 and methane is shown in Exhibit 47.

Exhibit 47: Distribution Sector Emissions by AEO Demand Region for 2006 and 2020

	2006					2020				
NEMS Demand Region	Gas Throughput (Quads)	CO_2 (Mg)	CH_4 (Mg) w/o Natural Gas STAR Reductions	CH_4 (Mg) w/ Natural Gas STAR Reductions	Emissions Intensity (2020) (lb CO_2e/MMBtu)	Gas Throughput (Quads)	CO_2 (Mg)	CH_4 (Mg) w/o Natural Gas STAR Reductions	CH_4 (Mg) w/ Natural Gas STAR Reductions	Emissions Intensity (2020) (lb CO_2e/MMBtu)
New England	0.48	1,500	51,933	50,449	4.91	0.52	1,694	58,661	28,493	2.52
Middle Atlantic	2.18	6,789	235,068	228,351	4.85	1.96	7,017	242,946	118,003	2.79
East North Central	4.09	10,348	358,245	348,009	3.95	4.33	11,144	385,838	187,407	2.01
West North Central	1.54	3,331	115,326	112,031	3.37	1.86	3,762	130,236	63,258	1.58
South Atlantic	1.91	3,617	125,180	121,603	2.96	1.91	4,407	152,558	74,100	1.80
East South Central	1.22	1,525	52,784	51,276	1.95	1.21	1,720	59,515	28,907	1.11
West South Central	5.29	2,985	103,166	100,218	0.88	6.56	3,407	117,715	57,176	0.40
Mountain	1.18	2,844	98,473	95,660	3.75	1.23	3,391	117,415	57,030	2.16
Pacific	2.87	5,484	189,824	184,401	2.98	2.67	6,093	210,923	102,448	1.78
Natural Gas STAR Reductions			**2.9%**					**51.4%**		

End Use Consumption

Overall, total GHG emission from end use consumption was 1.04 billion tonnes in 2006, growing to 1.10 billion tonnes in 2020 due to increased consumption of natural gas. The breakdown of end use consumption emissions by AEO demand region is shown in Exhibits 48 and 49 for 2006 and 2020, respectively. The emissions intensity of end use consumption is 117.06 lb CO_2/MMBtu for both imported LNG and U.S. natural gas supply and makes up over three-fourths of total well-to-burner tip emissions. Emissions for the end use consumption sector are the same for both the U.S. natural gas supply and LNG scenarios.

Exhibit 48: Consumption Emissions by AEO Demand Region for 2006 (tonnes CO_2e)

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	TOTAL
Residental	9,437,887	42,151,106	66,899,328	20,659,006	21,511,721	9,011,542	15,116,504	17,751,910	35,174,387	237,713,390
Commercial	6,270,956	30,483,527	34,490,258	13,896,735	17,999,869	6,812,781	15,851,641	11,767,579	17,632,295	155,205,642
Industrial	4,396,990	18,672,643	61,243,898	23,484,123	29,281,303	24,825,027	127,772,014	16,306,858	52,804,610	358,787,466
Electric Power Generation	21,202,881	22,692,591	28,669,330	2,746,491	43,069,974	8,831,733	110,070,487	28,896,656	46,229,882	312,410,024
Transportation	142,435	318,668	339,540	167,095	407,612	147,685	250,419	165,536	350,248	2,289,237

Exhibit 49: Consumption Emissions by AEO Demand Region for 2020 (tonnes CO_2e)

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	TOTAL
Residental	11,345,211	46,679,477	76,219,032	24,702,768	27,663,991	10,751,627	17,910,068	22,738,949	41,996,824	280,007,947
Commercial	8,086,770	35,610,097	42,944,323	17,951,343	27,789,480	9,522,677	20,827,549	15,472,420	20,942,483	199,147,143
Industrial	6,626,197	19,996,754	75,072,932	34,328,368	28,268,554	25,013,554	166,298,235	18,716,169	51,414,988	425,735,751
Electric Power Generation	29,704,961	31,945,805	31,250,415	4,412,241	56,014,420	25,538,310	126,376,234	32,964,145	43,703,114	381,909,645
Transportation	374,513	598,808	611,696	396,351	834,548	372,871	566,694	456,497	729,573	4,941,550

EMISSIONS INTENSITY OF NATURAL GAS SUPPLIES FROM CANADA

In this study, the GHG emissions intensity associated with natural gas supplies from Canada, delivered across the border to serve the U.S. market, was not specifically assessed. The primary reason was that ICF's proprietary set of data, models, and analytical procedures, for the most part developed to support EPA in their GHG emission inventory work for the U.S. petroleum and natural gas sector[26] did not have the capability of performing a comparable assessment for the Canadian supply chain.

Moreover, to our knowledge, the only comparable supply chain assessment performed on the Canadian natural gas supply chain was performed based on estimates of industry emissions in 1995.[27] The results of this study are summarized in Exhibit 50. As shown, this shows overall emissions intensity of the Canadian natural gas supply chain (production, transmission, and storage) of 13.71 lb CO_2e/MMBtu.

Some insight can also be gained from the Canadian national inventory of GHG emissions.[28] This report does look specifically at the emissions characteristics of natural gas exports (the vast majority of which are imports to the U.S.) A review of the results of this inventory, summarized in Exhibit 51, shows that the overall natural gas supply sector can be characterized by an overall emissions intensity of 16.66 to 16.98 lb CO_2e/MMBtu over the 2003 to 2006 time period.

Again, the emissions intensity of the Canadian gas supply system appears to be lower than that in the U.S., though it is difficult to ascertain whether either of these comparisons are truly "apples-to-apples."

When considering the relative role of Canadian natural gas in the overall emissions profile of the U.S. natural gas market, it is also important to realize that most forecasts call for a significant reduction in natural gas imports of Canadian gas into the U.S. between now and 2020. For example, the Canadian National Energy Board (NEB), in its most recent Reference Case outlook for Canada natural gas, forecasts that Canadian exports to the U.S. will drop from 7.3 Bcf per day in 2005 to 2.5 Bcf per day by 2020, a two-thirds reduction.[29] Under some scenarios considered by the NEB, Canada could become a net importer of gas by 2020. These results are summarized in Exhibit 52.

Similarly, EIA's 2007 AEO forecasts U.S. imports from Canada to decline from 8.24 Bcf per day in 2005 to 4.53 Bcf per day by 2020, a 45% decrease. (In the more recent 2008 AEO, imports from Canada are forecast to fall even further, to 3.24 Bcf per day, a 61% decline relative to the 2008 AEO estimate for Canadian imports in 2005.) These results are summarized in Exhibit 53.

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[26] http://www.epa.gov/climatechange/emissions/usinventoryreport.html

[27] Whittaker, S.M., G. McGuire, T, Irwin, and K. Humphreys, "A life cycle analysis of the Canadian natural gas system," Gasunie Engineering and Technology, paper presented at the 39th Annual Conference of Metallurgists of CIM, Ottawa, ON (Canada), August 8, 2000 (http://gasunie.eldoc.ub.rug.nl/root/2000/2042764/)

[28] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada (1990-2005)*, April 2007 (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)

[29] National Energy Board of Canada, *Canada's Energy Future: Reference Case and Scenarios to 2030*, An Energy Market Assessment, November 2007 (http://www.neb.gc.ca/clf-nsi/rthnb/nwsrls/2007/nwsrls38-eng.html)

Exhibit 50: Life Cycle Emissions Analysis of the Canadian Natural Gas System (1995)

	Emissions (kilotonnes)		
	CO_2	CH_4	Total
Upstream	25,500	735	26,235
Transmission	5,295	280	5,575
Storage	62	6	68
Supply Total	**30,857**	**1,021**	**31,878**
Distribution	81	58	139
End Use	119,515	3	119,518
TOTAL	**150,453**	**1,082**	**151,535**

	Emissions (tonnes/million m^3)		
	CO_2	CH_4	Total
Upstream	146.70	4.12	150.82
Transmission	31.90	1.69	33.59
Storage	1.00	0.10	1.10
Supply Total	**179.60**	**5.91**	**185.51**
Distribution	1.30	0.90	2.20
End Use	1851.20	0.05	1851.25
TOTAL	**2032.10**	**6.86**	**2038.96**

	Emissions (lb. CO_2e/MMBtu)		
	CO_2	CH_4	Total
Upstream	10.84	0.30	11.14
Transmission	2.36	0.12	2.48
Storage	0.07	0.01	0.08
Supply Total	**13.27**	**0.44**	**13.71**
Distribution	0.10	0.07	0.16
End Use	136.78	0.00	136.79
TOTAL	**150.15**	**0.51**	**150.66**

Exhibit 51: Canadian Natural Gas Production, Export, and GHG Emission Trends in the Canadian National Inventory Report (1990-2005)

	1990	1995	2000	2003	2004	2005
Production						
PJ	4,184	6,129	7,060	7,064	7,096	7,250
Quads	3,975	5,823	6,707	6,711	6,741	6,888
Imports						
PJ	24	26	62	370	415	375
Quads	23	25	59	352	394	356
Exports						
PJ	1,537	3,011	3,846	3,876	4,022	4,066
Quads	1,460	2,860	3,654	3,682	3,821	3,863
Consumption						
PJ	2,671	3,144	3,276	3,557	3,489	3,558
Quads	2,537	2,987	3,112	3,379	3,315	3,380
Emissions Associated with Gross Exports						
Mt CO_2e	13.9	26.5	33.1	33.4	34.6	34.9
Mt CO_2e/Quad	9,520	9,264	9,059	9,071	9,055	9,035
lb. CO_2e/MMBtu	20.99	20.42	19.97	20.00	19.96	19.92
Emissions Associated with Net Exports						
Mt CO_2e	12.7	25.1	31.1	25.6	25.9	27.0
Mt CO_2e/Quad	8,836	8,851	8,651	7,686	7,558	7,700
lb. CO_2e/MMBtu	**19.48**	**19.51**	**19.07**	**16.94**	**16.66**	**16.98**

Exhibit 52: Canadian Natural Gas Production and Export Forecasts of the Canadian National Energy Board

	2000	2005	2010	2015	2020
Fortified Islands			478	528	567
Triple E			470	351	199
Continuing Trends				434	387
Reference Case	484	485	450	434	

Canadian Natural Gas Export Outlook (million cubic meters per day)

	2000	2005	2010	2015	2020
Fortified Islands			243	275	307
Triple E			237	111	-42
Continuing Trends				154	87
Reference Case	268	258	197	154	

Canadian Natural Gas Production Outlook (billion cubic feet per day)

	2000	2005	2010	2015	2020
Fortified Islands			13.55	14.97	16.07
Triple E			13.32	9.95	5.64
Continuing Trends				12.30	10.97
Reference Case	13.72	13.75	12.76	12.30	

Canadian Natural Gas Export Outlook (billion cubic feet per day)

	2000	2005	2010	2015	2020
Fortified Islands			6.89	7.79	8.70
Triple E			6.72	3.15	-1.19
Continuing Trends				4.37	2.47
Reference Case	7.60	7.31	5.58	4.37	

Exhibit 53: U.S. Natural Gas Supply and Import Forecasts by the Energy Information Administration
(AEO 2007 vs. AEO 2008)
(Trillion cubic feet)

AEO 2007

	2005	2010	2015	2020
U.S. Dry Gas Production	18.23	19.35	19.60	20.79
Net Imports	3.57	4.55	5.62	5.35
Canadian Imports	3.01	2.74	2.63	1.65
Canadian Imports (Bcf/day)	***8.24***	***7.50***	***7.21***	***4.53***
LNG Imports	0.57	1.81	2.99	3.69
LNG Imports (Bcf/day)	***1.55***	***4.97***	***8.19***	***10.11***

AEO 2008

	2005	2010	2015	2020
U.S. Dry Gas Production	18.07	19.29	19.52	19.67
Net Imports	3.61	3.85	4.03	3.55
Canadian Imports	3.05	2.64	1.91	1.18
Canadian Imports (Bcf/day)	***8.35***	***7.24***	***5.24***	***3.24***
LNG Imports	0.57	1.20	2.12	2.37
LNG Imports (Bcf/day)	***1.55***	***3.29***	***5.80***	***6.50***

APPENDIX A

Environmental Impact Statements and Supporting Documentation used in this Analysis

Darwin LNG Project (Liquefaction)

Environmental Management Plan for 3.24 MMTPA LNG Plant (Built)
Table 5-3 on Page 5-10 of the following document:
http://www.darwinlng.com/NR/rdonlyres/29AF4F2F-5F81-4AB7-A10F-E7668F462826/0/DLNGHSEPLN001_s05_r1.pdf

Original Public Environmental Report for 10 MMTPA LNG Plant (Not Built)
Table 2.4.1 on Page 2-23 of the following document:
http://www.darwinlng.com/NR/rdonlyres/58532319-5951-480A-AAD1-732999333024/0/PER_Section_2.pdf
Table 4.4 on Page 4-8 of the following document:
http://www.darwinlng.com/NR/rdonlyres/FDFA46BA-9116-4E96-ADF3-F7F2E4ED77E7/0/PER_Section_4.pdf

General Environmental Information:
http://www.darwinlng.com/Environment/Index.htm

Gorgon LNG Project (Liquefaction)

Draft Environmental Impact Statement/Environmental Review and Management Plan
Chapter 1, Page 11, Table 1-2
Chapter 6, Page 96, Table 6-1
Chapter 13 (especially Table 13-6)
http://www.gorgon.com.au/03moe_eis.html#frames(content=03moe_eis_body.html)
http://www.gorgon.com.au/03-man_environment/EIS/gorgon_ch01_LR.pdf
http://www.gorgon.com.au/03-man_environment/EIS/gorgon_ch06_LR.pdf
http://www.gorgon.com.au/03-man_environment/EIS/gorgon_ch13_LR.pdf

Final Environmental Impact Statement/Environmental Review and Management Plan
http://www.gorgon.com.au/03moe_finaleis.html#frames(content=03moe_finaleis_body.html)

Snohvit LNG Project (Liquefaction)

The following two documents are in Norwegian but may be of some use. See Table 5-8 on Page 88 of the 2nd document.
http://www.snohvit.com/STATOILCOM/snohvit/svg02699.nsf/Attachments/Utslippssoknad.pdf/$FILE/Utslippssoknad.pdf
http://www.snohvit.com/STATOILCOM/snohvit/svg02699.nsf/Attachments/konsekvensutredning.pdf/$FILE/konsekvensutredning.pdf

Environmental and Technology Webpage
http://www.snohvit.com/STATOILCOM/snohvit/svg02699.nsf?OpenDatabase&lang=en

Pluto LNG Project (Liquefaction)

Draft Public Environmental Report/Public Environmental Review, Chapter 5 (Attached)
Table 5-2, 5-3 & 5-4
Chapters 1 and 4 also attached for generally background

Tangguh LNG Project (Liquefaction

BP statement regarding CO_2 content:
http://www.bp.com/sectiongenericarticle.do?categoryId=9004748&contentId=7008786

Summary Environmental Impact Statement (limited information)
http://www.adb.org/Documents/Environment/Ino/ino-tangguh-lng-project.pdf

Life cycle CO_2 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

Article contains some information but must be purchased at the following website:

http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V1T-423480C-6&_user=10&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=b92483f5a07fa8c315db500191722226

Canaport LNG Terminal

Environmental Impact Statement, Chapter 5
http://www.ceaa-acee.gc.ca/010/0003/0012/5a_e.pdf