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Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States

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Disclaimer

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Acronyms and Abbreviations

AR4	Fourth Assessment Report (IPCC)
AR5	Fifth Assessment Report (IPCC)
AU	Australia
Btu	British thermal unit
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DZ	Algeria
ECF	Energy conversion facility
EIA	Energy Information Administration
EU	End use
GHG	Greenhouse gas
GWP	Global warming potential
HRSG	Heat recovery steam generator
I-6	Illinois No. 6
IPCC	Intergovernmental Panel on Climate Change
JP	Japan
kg	Kilogram
km	Kilometer
lb	Pound
LCA	Life cycle analysis
LNG	Liquefied natural gas
mi	Mile
MWe	Megawatt electric
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NL	Netherlands
Nmi	Nautical mile
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NSPS	New Source Performance Standards
PRB	Powder River Basin
PT	Product Transport
RMA	Raw material acquisition
RMT	Raw material transport
RU	Russia
SF_6	Sulfur hexafluoride
scf	Standard cubic foot
SCPC	Supercritical pulverized coal
U.S.	United States

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1 Introduction

This analysis calculates the life cycle greenhouse gas (GHG) emissions for regional coal and imported natural gas power in Europe and Asia. The primary research questions are as follows:

- How does exported liquefied natural gas (LNG) from the U.S. compare with regional coal (or other LNG sources) for electric power generation in Europe and Asia, from a life cycle greenhouse gas (GHG) perspective?
- How do those results compare with natural gas sourced from Russia and delivered to the same European and Asian markets via pipeline?

The National Energy Technology Laboratory (NETL) exercised its life cycle analysis (LCA) model to represent unconventional natural gas production and transport to a New Orleans liquefaction facility, liquefaction, and then transport to an import terminal in Rotterdam, Netherlands to represent a European market and to Shanghai, China to represent Asian Markets. LNG from Oran, Algeria was modeled to represent an alternative regional LNG European market supply source with a destination of Rotterdam and LNG from Darwin, Australia was modeled to represent an alternative regional LNG Asian market supply source with a destination of Osaka, Japan. Conventional natural gas extracted from the Yamal region of Siberia in Russia was modeled as the regional pipeline gas alternative for both the European and Asian markets. Regional coal production and consumption (i.e., Germany and China) were also modeled. Scenario specific variability was modeled by adjusting methane leakage for natural gas production, coal type (bituminous and sub-bituminous), transport distance (ocean tanker for LNG and rail for coal), and power plant efficiency.

This analysis is based on data that were originally developed to represent U.S. energy systems. In general, the NETL natural gas and coal LCA models were adapted for this study. U.S. natural gas production and average U.S. coal production were modeled as representative of foreign natural gas and coal production. No ocean transport of coal was included to represent the most conservative coal profile (regionally sourced or imported). The specific LNG export/import locations used in this study were chosen to represent an estimate for a region (e.g. New Orleans as U.S. Gulf Coast). Specific locations were required to allow for the estimation of LNG transport distances and do not imply the likelihood that LNG export or import will occur from that exact location. The same assumptions hold true for the Russian natural gas cases.

2 LCA Approach

This is a cradle-to-grave LCA that begins with extraction of natural gas or coal and ends with electricity delivered to the consumer. NETL uses five life cycle (LC) stages, beginning with the acquisition of raw materials and ending with energy consumption. These five life cycle stages are listed below:

- **LC Stage #1:** Raw Material Acquisition (RMA) includes extraction of a natural resource and any necessary processing steps that prepare it for transport. The raw materials of this analysis are natural gas and coal.
- **LC Stage #2:** Raw Material Transport (RMT) includes the transport of a raw material between the extraction site and power plant. Natural gas is transported by pipeline and ocean tanker for the LNG cases and pipeline only for the Russian natural gas cases; coal is transported by rail.
- **LC Stage #3:** Energy Conversion Facility (ECF) includes the operation of a power plant that converts fuel to energy. The power plants of this analysis convert natural gas or coal to

electricity. The handling and disposal of coal waste products are outside of the boundary of this analysis and are assumed to have minimal GHG emissions relative to the other processes considered in this analysis.

- **LC Stage #4:** Product Transport (PT) moves the product from the ECF to the consumer. In this analysis, electricity is transported over a national electricity grid.
- **LC Stage #5:** End Use (EU) represents the final consumption of a product. In this analysis, no burdens are associated with the consumption of electricity.

Four scenarios are modeled in this analysis for two different geographies (Europe and Asia)[1]:

- **Scenario 1:** Natural gas is extracted in the U.S. from the Marcellus Shale, transported by pipeline to an LNG facility where it is compressed and loaded onto an LNG tanker, transported to an LNG port in the receiving country (Rotterdam for the European case and Shanghai for the Asian case) where it is re-gasified, and then transported to a natural gas power plant. It was assumed that the power plant is located near the LNG import site.
- **Scenario 2:** This is the same as Scenario 1, except that the natural gas comes from a regional source relative to the destination. In the European case, the source is Algeria, and in the Asian case, the source is Australia. It was assumed that the regional gas is produced using conventional extraction methods. The LNG tanker transport distance is adjusted accordingly.
- **Scenario 3:** Natural gas is produced in the Siberian region of Russia utilizing conventional extraction methods and is transported by pipeline to a power plant in Europe or Asia.
- **Scenario 4:** Coal is extracted in the region of study (Europe or Asia) and transported by rail to a domestic coal-fired power plant in China or Germany. This analysis models both surface sub-bituminous and underground bituminous coals based on U.S. extraction data.

In all four scenarios, electricity is distributed using existing transmission infrastructure. The functional unit, which serves as a basis for comparison, is 1 MWh of electricity delivered to a consumer. The results of this analysis include only GHG emissions. GHGs in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2013 Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) (IPCC, 2013). The default GWP used is the 100-year time frame but, in some cases, results for the 20-year time frame are presented as well. **Table 2-1** shows the GWPs used for the GHGs inventoried in this study. The Appendix also provides results on the basis of the GWPs developed in the Fourth Assessment Report (AR4) in the Appendix (Forster, et al., 2007). Note that the AR5 GWP value used for fossil methane emissions was 30. There are no biogenic methane releases in the natural gas or coal models. The AR5 GWP for biogenic methane is 28.

[1] The goal of this analysis is to model plausible (medium and long distance) export scenarios while also considering regional fuel alternatives. The purpose of the medium and long distance scenarios is to establish low and high bounds for likely results.

Table 2-1: IPCC AR4 and AR5 Global Warming Potentials (Forster, et al., 2007 and IPCC, 2013)

GHG	AR5 (IPCC 2013)		AR4 (IPCC 2007)	
	20-year	100-year (Default)	20-year	100-year
CO_2	1	1	1	1
CH_4	85	30	72	25
N_2O	264	265	289	298
SF_6	17,500	23,500	16,300	22,800

3 Natural Gas Modeling Approach

NETL's natural gas model uses a comprehensive set of parameters within a flexible network of unit processes, allowing the modeling of different types of natural gas sources. Key variables include lifetime well production rates, emission factors for episodic emissions (e.g. completions and workovers), flaring rates at extraction and processing, workover and liquid unloading frequency, and pipeline distance. The model currently has scenarios for natural gas from the following seven sources: conventional onshore, associated, conventional offshore, tight gas, Barnett Shale, Marcellus Shale, and coal bed methane. For additional details on the natural gas model, refer to the NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation (NETL, 2014). For Scenario 1 of this analysis, all natural gas is modeled as unconventional gas from the Marcellus Shale. For the purposes of this analysis, Marcellus Shale gas was utilized as a proxy for new unconventional natural gas production. The life cycle GHG emissions for the extraction of natural gas from Barnett Shale, Marcellus Shale, and tight gas as modeled in the NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation differed by less than 2 percent (NETL, 2014). For Scenarios 2 and 3, the extraction process is modeled after conventional onshore natural gas production in the U.S. This includes both the regional LNG supply options (Algeria for Europe and Australia for Asia) and extraction in Siberia for pipeline transport to the demand centers.

In all three natural gas scenarios, the extracted and processed natural gas is transported via pipeline, either to an LNG terminal (Scenarios 1 and 2) or directly to a power plant (Scenario 3). The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. For Scenarios 1 and 2, the pipeline distance from natural gas extraction site to the LNG terminal is 971 km. This is the average distance of natural gas pipeline transmission in the U.S. (NETL, 2014). This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. Note, the same pipeline distance is utilized for both the U.S. and regional LNG scenarios. This simplification was utilized to focus on the differences in life cycle GHG emissions from transport of the LNG.

NETL's model also includes an option for the LNG supply chain. After extraction and processing, natural gas is transported by pipeline to a liquefaction facility. The LNG is then loaded onto an ocean tanker, transported to an LNG terminal with regasification operations, and then fed to a pipeline that transports it to a power plant. The data for the LNG supply chain accounts for the construction and operation of LNG infrastructure. For this analysis, it was assumed that the natural gas power plant in each of the import destinations is existing and located close to the LNG port, so no additional pipeline transport of natural gas is modeled in the destination country.

For the U.S. (New Orleans) to Shanghai, China route, it was assumed that the Panama Canal is a viable option for LNG tankers. This assumption is tested in the uncertainty analysis section of this study. All other routes (New Orleans to Rotterdam, Netherlands; Oran, Algeria to Rotterdam, Netherlands; and Darwin, Australia to Osaka, Japan) do not require the use of a canal. The distances used for LNG transport are available in **Table 5-1**.

For Scenario 3, the pipeline distance was calculated based on the great circle distance between the Yamal district of Siberia, Russia to a power plant located in Rotterdam, Netherlands or Shanghai, China. Yamal was chosen as the extraction site because that region accounted for 82.6 percent of Russian natural gas production in 2012 (EIA, 2013). The great circle distance is the shortest possible distance between two points on a sphere and was therefore used to represent the shortest possible pipeline distance between the extraction source and the power plant. An additional 1,000 km of pipeline transport were added to the great circle distance to specify the expected pipeline transport distance. Given the extensive pipeline networks in Europe and Asia, determining an actual distance was not possible, nor was it required for this level of analysis. This assumption is tested in the uncertainty analysis section of this study. The distances used for pipeline transport of Russian gas are available in **Table 5-2**.

The efficiency of the destination power plant is an important parameter required for determining the life cycle emissions for natural gas power. Average baseload natural gas-fired power plants in the U.S. have a net efficiency of 46.4 percent (NETL, 2014). This analysis utilized the range of efficiencies that are consistent with the NETL modeling of natural gas power in the U.S. (NETL, 2014). This analysis assumed the same range of power plant efficiencies in the destination countries as was used for the U.S. model. The efficiency range is designed to be representative of fleet baseload power plants.

The transmission of electricity from the power plant to consumer incurs a 7 percent loss of electricity. The consumption of electricity does not have any energy or material flows. A comprehensive list of the modeling parameters and values for the natural gas scenarios are provided in **Table 5-1** and **Table 5-2**.

4 Coal Modeling Approach

This analysis utilizes NETL's existing LCA model for the extraction and transport of sub-bituminous and bituminous coal in the U.S. for foreign extraction in Germany and China. Foreign coal production was modeled as having emissions characteristics equivalent to average U.S. coal production.

Raw material extraction for coal incorporates extraction profiles for coal derived from the Powder River Basin (PRB), where sub-bituminous, low-rank coal is extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 (I-6) coal seam, where bituminous coal is extracted via underground longwall and continuous mining. In general, PRB represents coal from surface mining sources, and I-6 coal represents coal from underground sources. The regionally extracted coal is transported to the power plant by rail in both the European and Asian cases. The expected rail distance for both locations is 725 miles.

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009). For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on the NETL Quality Guidelines for Energy Systems Studies, this analysis uses a factor of 8 scf/ton for coal bed methane emissions for surface mining of PRB coal and a heating value of 8,564 Btu/lb (NETL, 2010a; 2012).

I-6 coal is part of the Herrin Coal seam, and is a bituminous coal that is found in seams in the southern and eastern regions of Illinois and surrounding areas that typically range from about 2 to 15 feet in thickness. I-6 coal is commonly extracted via underground mining techniques, including continuous and longwall mining. I-6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. During the acquisition of I-6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Based on the NETL Quality Guidelines for Energy Systems Studies, this analysis uses a factor of 360 scf/ton for coal bed methane emissions for underground mining of I-6 coal and a heating value of 11,666 Btu/lb (NETL, 2010b; 2012).

The heating value of coal and the heat rate of the power plant were used to determine the feed rate of coal to the power plant. Average baseload coal-fired power plants in the U.S. have a net efficiency of 33.0 percent (NETL, 2014). For consistency, this analysis utilized the range of efficiencies that were previously used for the modeling of coal power in the U.S. (NETL, 2014). This analysis assumed the same range of power plant efficiencies for Europe and Asia as the U.S. model. The efficiency range is designed to be representative of fleet baseload power plants.

Electricity transmission and consumption is modeled using the same data used by the natural gas power scenario. The transmission of electricity from the power plant to consumer incurs a 7 percent loss of electricity. The consumption of electricity does not have any energy or material flows. A comprehensive list of the modeling parameters and values for the coal scenarios are provided in **Table 5-3**.

5 Key Modeling Parameters

The LCA results are sensitive to changes in natural gas and coal and extraction characteristics, transport distances, and power plant performance. The key parameters for the natural gas scenarios are shown in **Table 5-1** (LNG) and **Table 5-2** (Russian natural gas), and the key parameters for the coal scenario are shown in **Table 5-3**. The range of natural gas methane leakage rates is calculated as a function of more specific parameters used in that model, such as the flaring rate, well completion, and well workover factors. The range in leakage rate is a function of the uncertainty of the underlying parameters. These parameter values and ranges are detailed in **Tables 5-4, 5-5,** and **5-6**, as well as the the NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation (NETL, 2014).

The methane leakage for the Russian natural gas cases is higher than the leakage for LNG because of the difference in the pipeline distance. There are also slight differences in methane leakage from extraction between the difference gas types, but the majority of the difference is driven by pipeline losses. A methane leakage breakeven analysis is conducted in **Section 6** of this document. That analysis determines the breakeven leakage at which the life cycle GHG emissions for natural gas power would equal those for the coal reference case. NETL's upstream results are consistent with other life cycle studies on natural gas. For a more detailed review of the status of current natural gas research, related uncertainties, and a comparison of the NETL life cycle GHG results with those from literature, see **Section 6** of the NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation (NETL, 2014).

Table 5-1: Key Modeling Parameters for Natural Gas Extraction, Export, and Power Generation – LNG Cases

LC Stage	Model Parameter		Low	Expected	High
LC Stage #1 (RMA) and #2 (RMT)	Methane Leakage (cradle-to-liquefaction)	Marcellus Shale Gas	1.2%	1.4%	1.6%
		Conventional Onshore Gas	1.1%	1.3%	1.6%
	Gas Type		Marcellus Shale – U.S. Gas Conventional Onshore – Regional Gas		
	Pipeline Distance (Extraction to LNG Facility) (km)		777	971	1,166
	Transport Distances (Nautical mi)	New Orleans to Rotterdam, Netherlands	4,301	4,801	5,301
		Oran, Algeria to Rotterdam, Netherlands	1,082	1,582	2,082
		New Orleans to Shanghai, China	9,497	9,997	14,844
		Darwin, Australia to Osaka, Japan	2,385	2,885	3,385
LC Stage #3 (ECF)	Power Plant Net Efficiency		41.2%	46.4%	49.2%
LC Stage #4 (PT)	Electricity Transmission and Distribution Loss		7%		

Table 5-2: Key Modeling Parameters for Natural Gas Extraction, Export, and Power Generation – Russian Cases

LC Stage	Model Parameter		Low	Expected	High
LC Stage #1 (RMA) and #2 (RMT)	Methane Leakage[1] (cradle-to-delivered)	Yamal, Russia to Rotterdam, Netherlands	2.8%	3.4%	4.1%
		Yamal, Russia to Shanghai, China	3.7%	4.3%	5.0%
	Gas Type		Conventional Onshore		
	Pipeline Distance (km)	Yamal, Russia to Rotterdam, Netherlands	3,792	4,792	5,792
		Yamal, Russia to Shanghai, China	5,447	6,447	7,447
LC Stage #3 (ECF)	Power Plant Net Efficiency		41.2%	46.4%	49.2%
LC Stage #4 (PT)	Electricity Transmission and Distribution Loss		7%		

Table 5-3: Key Modeling Parameters for Coal Extraction and Power Generation

LC Stage	Model Parameter	Low	Expected	High
LC Stage #1 (RMA)	Coal Mine Methane (scf/ton)	8	8	360
	Coal Type	PRB	PRB	I-6
LC Stage #2 (RMT)	Rail Transport Distance (miles)	225	725	1,225
LC Stage #3 (ECF)	Power Plant Net Efficiency	28.3%	33.0%	36.7%
LC Stage #4 (PT)	Electricity Transmission and Distribution Loss	7%		

[1] U.S. conventional onshore extraction is used as a proxy for Russian natural gas extraction in the model for this analysis. The differences in the calculated leakage rates for Russian natural gas (as compared to the U.S. leakage rates in Table 5-1) are driven only by the longer pipeline transmission distance for the extracted gas. As the pipeline distance increases, the total methane leakage from pipeline transmission increases and so does the amount of natural gas that is extracted to meet the same demand for delivered natural gas.

Table 5-4 summarizes the key extraction parameters for each extraction type. The average production rate of each well is used to apportion episodic emissions per unit of gas produced. Episodic emissions occur as one-time impulses or, in some cases, as periodic well maintenance activities. Examples of episodic emissions include the volume of natural gas vented during well completions and workovers (which are higher for unconventional wells than for conventional wells) and liquid unloading (a practice assumed to be unique to onshore conventional wells). Flaring rate is a modeling parameter because the global warming potential of vented natural gas, which is composed mostly of methane, can be reduced if it is flared to CO_2. Emissions from valves and other sources are key sources of emissions that occur during steady-state extraction operations. **Table 5-4** also shows uncertainty bounds when such data are available. The two uncertainties that the model accounts for during natural gas extraction are well production rates and flaring rates.

Table 5-4: Parameters for Natural Gas Extraction

Property (Units)		Onshore Conventional	Marcellus Shale
Natural Gas Source			
Average Production Rate (Mcf/day)	L	46	201
	E	66	297
	H	86	450
Expected EUR (Bcf)		0.72	3.25
Natural Gas Extraction			
Flaring Rate of Vented NG (%)		51% (41 - 61%)	15% (12 - 18%)
Well Completion (Mcf natural gas/episode)		37	9,000
Well Workover (Mcf natural gas/episode)		2.44	9,000
Lifetime Well Workovers (Episodes/well)		1.1	0.3
Liquids Unloading (Mcf/episode)		3.57	N/A
Lifetime Liquid Unloadings (Episodes/well)		930	N/A
Valve Emissions, Fugitive (lb. CH_4/Mcf)		0.11	
Other Sources, Point Source (lb. CH_4/Mcf)		0.003	
Other Sources, Fugitive (lb. CH_4/Mcf)		0.043	

Table 5-5 shows the modeling parameters for natural gas processing. It accounts for the removal efficiencies and emissions from acid gas removal and dehydration, emissions from valves and other processing infrastructure, and the type of compressors used at processing facilities. All natural gas processing plants are assumed to have the same performance characteristics, regardless of natural gas source. The one exception is compressor profiles; most onshore processing plants use gas-powered reciprocating compressors, all offshore processing plants use gas-powered centrifugal compressors, and processing plants in the Barnett Shale region uses a combination of gas-powered reciprocating and electrically-powered centrifugal compressors.

Table 5-5: Parameters for Natural Gas Processing

Property (Units)	Onshore Conventional	Marcellus Shale
Acid Gas Removal (Amine Absorber and Regenerator)		
Flaring Rate of Vented NG (%)	100%	
CH_4 Absorbed (lb. CH_4/Mcf)	0.04	
CO_2 Absorbed (lb. CO_2/Mcf)	0.56	
H_2S Absorbed (lb. H_2S/Mcf)	0.21	
NMVOC Absorbed (lb. NMVOC/Mcf)	6.59	
Dehydration (Glycol Dehydrator and Regenerator)		
Flaring Rate of Vented NG (%)	100%	
Water Removed (lb. H_2O/Mcf)	0.045	
CH_4 Emission Rate (lb. CH_4/Mcf)	0.0003	
Valves & Other Sources of Emissions		
Flaring Rate (%)	100%	
Valve Emissions, Fugitive (lb. CH_4/Mcf)	0.0003	
Other Sources, Point Source (lb. CH_4/Mcf)	0.02	
Other Sources, Fugitive (lb. CH_4/Mcf)	0.03	
Natural Gas Compressor Profile at Processing Plant		
Gas-powered Reciprocating (%)	100%	100%
Gas-powered Centrifugal (%)	0%	0%
Electrically-powered Centrifugal (%)	0%	0%

Table 5-6 shows the modeling parameters for natural gas transmission by pipeline. An average transmission distance of 971 km (604 miles) with an uncertainty of +/- 20 percent is used for all natural gas types. The mix of compressor technologies used for natural gas transmission is also parameterized.

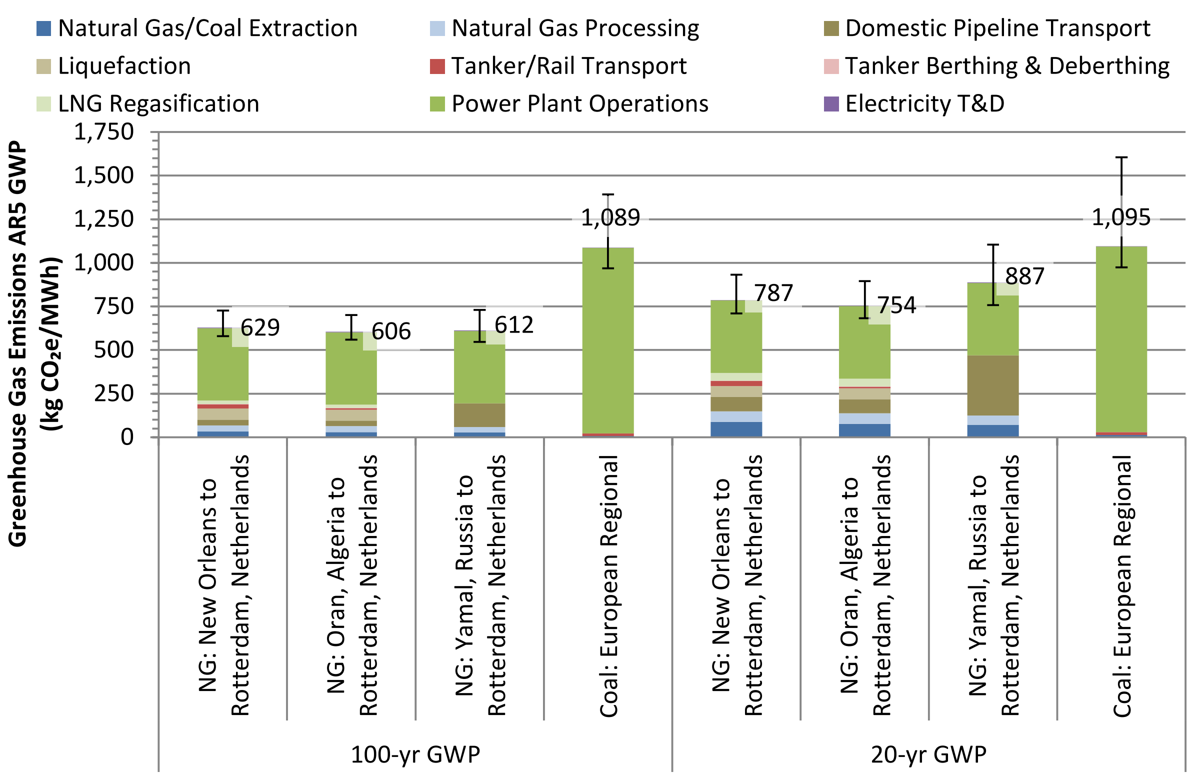
Table 5-6: Parameters for Natural Gas Transmission by Pipeline

Property (Units)	Value (Uncertainty)
Pipeline Transport Distance (km)	971 (777 – 1,166)
Distance Between Compressors (km)	121
Compressor, Gas-powered Reciprocating (%)	78%
Compressor, Gas-powered Centrifugal (%)	19%
Compressor, Electrical, Centrifugal (%)	3%

6 Results

The LCA results for natural gas and coal power generation in Europe and Asia are shown in **Figure 6-1** and **Figure 6-2**, respectively. The results in both figures are shown on both 100-year and 20-year GWP time frames, which is especially important due to the uncaptured venting and fugitive emissions of methane in natural gas systems. Detailed results for all of the scenarios in these figures are provided in the Appendix for both AR4 and AR5 GWPs. It is important to note that the results from this analysis bracket the range of variability based on the cumulative change to the key parameters. **Figure 6-1** and **Figure 6-2** report an expected value for each of the scenarios. These values should not be interpreted as the most likely values due to the wide range of scenario variability and uncertainty in the underlying modeled data. Rather, the expected values allow for the evaluation of the contribution of each of the major processes to the total life cycle emissions (e.g. extraction, transport, combustion). The results should be interpreted as general guidance to provide perspective on trends only and not as prescriptive, scenario-specific results.

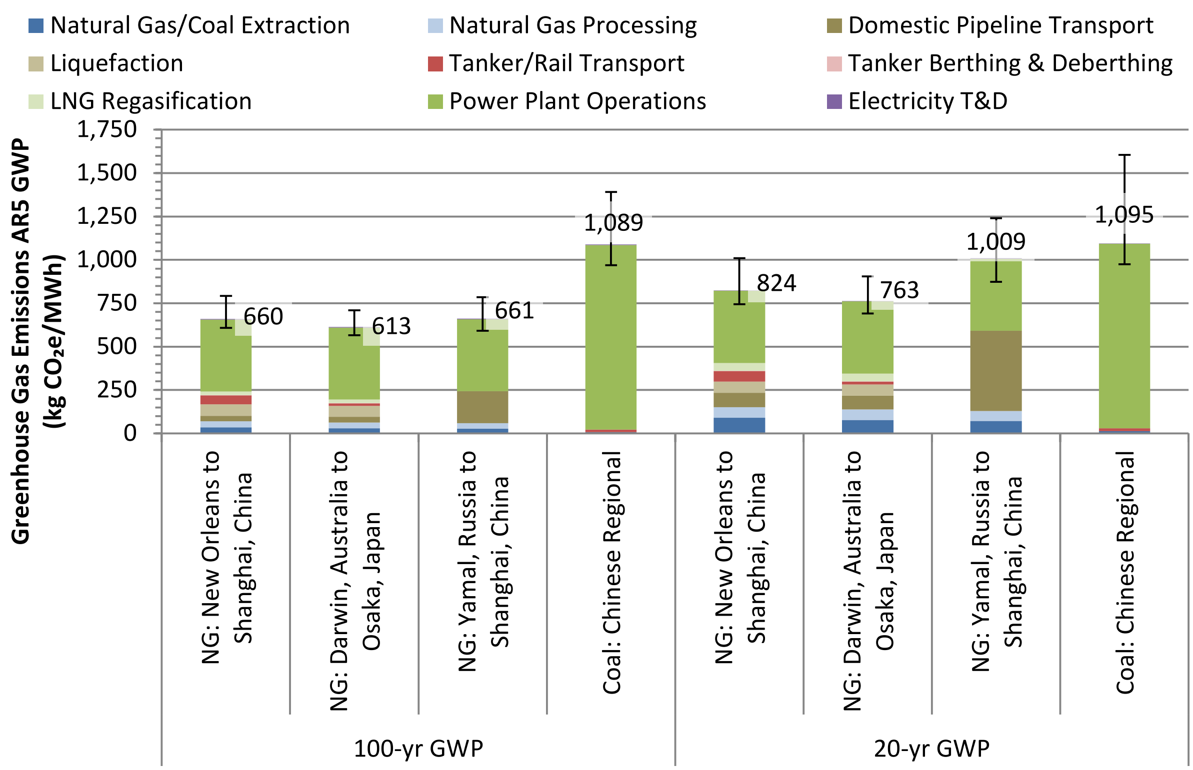
Figure 6-1: Life Cycle GHG Emissions for Natural Gas and Coal Power in Europe



In general, the results from **Figure 6-1** and **Figure 6-2** indicate that for most scenarios in both the European and Asian regions, the generation of power from imported natural gas has lower life cycle GHG emissions than power generation from regional coal. On the basis of a 20-year GWP, there is some overlap in the uncertainty bars for the Russian natural gas and regional coal cases for both Europe and Asia. Additionally, there is a small overlap between the uncertainty bars for the U.S. LNG to Shanghai case and regional coal case on a 20-year GWP basis. It is important to note that this overlap is based on an assumption of high methane leakage (1.6%) and low power plant efficiency (41.2%) for U.S. LNG and low methane content (8 scf/ton) and high power plant efficiency (36.7%) for regional coal. Given the uncertainty in the underlying model data, it is not clear if there are any significant differences between the corresponding European and Asian cases other than the LNG transport distance from the U.S. and the pipeline distance from Russia. Differences between the U.S LNG, regional LNG, and Russian natural gas options are also indeterminate on a 100-year GWP basis due to the underlying uncertainty in the modeling data, therefore no significant increase or decrease in net climate impact is anticipated from any of these scenarios. It is important to note that the European and Asian coal scenarios are identical because the same parameter ranges are used for both.

Both figures show that the majority of GHG emissions come from combustion at the power plant; however, the contributions from the upstream acquisition of the two fuels are very different. For the natural gas scenarios, 31 to 37 percent of the life cycle emissions are from the natural gas supply chain, compared to 1.3 percent for coal on a 100-year basis. On a 20-year basis, the upstream share for the natural gas scenarios increases to 45 to 59 percent, compared to 1.4 percent for coal, due to high global warming potential associated with methane. The results show that the LNG and Russian natural gas cases produce essentially the same amount of GHG emissions on a 100-year basis. The emissions from the steps involved in LNG (liquefaction, tanker transport, and regasification) are approximately equal to the pipeline transport emissions for the Russian natural gas cases. However, when comparing the scenarios on a 20-year basis, the difference between the LNG and Russian natural gas cases is more significant. This is driven by the pipeline contribution to the Russian natural gas GHG results. The majority of pipeline emissions are methane, which has a much higher GWP on a 20-year basis. The natural gas power results are based on U.S natural gas production in 2010. The results do not include the anticipated 30 percent reduction in upstream life cycle greenhouse gas emissions for new marginal unconventional wells in compliance with EPA's 2012 New Source Performance Standards (NSPS) for the oil and gas sector. On a complete life cycle basis through power production the net reduction would be approximately 3.4 percent for the U.S. LNG scenarios and 7.4 percent for the Russian natural gas scenarios. This is based on the assumption that the Russian natural gas industry would implement the same changes as prescribed for the U.S.

Figure 6-2: Life Cycle GHG Emissions for Natural Gas and Coal Power in Asia



Compared to domestically produced and combusted gas, there is a significant increase in the life cycle GHG emissions that are attributed to the LNG supply chain, specifically from liquefaction, tanker transport, and regasification processes. **Figure 6-3** shows the speciated GHGs from the key processes in the natural gas power production life cycle for the U.S. LNG to Rotterdam scenario on a 100-yr GWP basis. The liquefaction, ocean transport, and regasification of natural gas are energy intensive activities with significant GHG emissions, accounting for 17.5 percent of the cradle-to-grave emissions in this scenario. For comparison, the natural gas extraction, processing, and transport activities in the exporting country (either U.S. or regional) account for 16.0 percent of the cradle-to-grave emissions. In this study, Marcellus Shale natural gas is used as an example, but the same patterns would be shown for other types of natural gas. As shown by **Figure 6-3**, methane emissions account for 13.8 percent of the total life cycle GHG emissions, while CO_2 accounts for 85.5 percent. The total emissions from the plant stack account for 65.9 percent of the total life cycle GHG emissions.

For comparison, a speciated GHG drilldown is also shown for the Russian natural gas to Rotterdam scenario in **Figure 6-4** on a 100-yr GWP basis. In that scenario, methane emissions account for 24.6 percent of the total life cycle GHG emissions, while CO_2 accounts for 74.8 percent. In the Russian scenario, 67.7 percent of the total life cycle GHG emissions are direct emissions from the power plant stack. The increased percentage of methane emissions is the result of larger methane leakage due to the longer pipeline distance. As previously mentioned, the emissions from the steps involved in LNG (liquefaction, tanker transport, and regasification) are approximately equal to the pipeline transport emissions for the Russian natural gas cases.

Figure 6-5 shows a speciated GHG drilldown for the coal power production case on a 100-yr GWP basis. Methane emissions, primarily from releases during coal mining, account for 0.4 percent of the total life cycle GHG emissions, compared to 98.8 percent for CO_2. The contribution of methane to the total life cycle GHG emissions for the coal scenario is significantly less than for the natural gas scenarios. For the coal power plant, 97.7 percent of the total GHG emissions come directly from power plant stack emissions. As shown by the figures, the upstream extraction, processing, and transport emissions are much more significant for the natural gas supply chain than for coal.

Figure 6-3: Speciated Life Cycle GHG Emissions of Natural Gas Power – U.S. LNG to Rotterdam Scenario

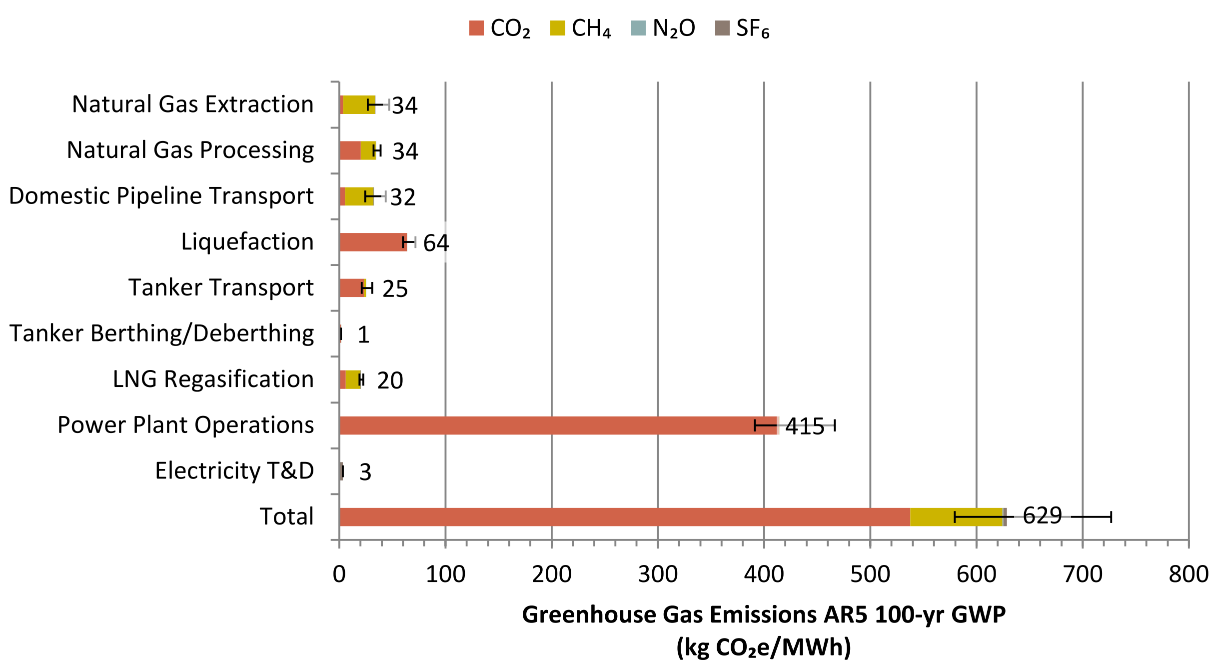


Figure 6-4: Speciated Life Cycle GHG Emissions of Natural Gas Power – Russian NG to Rotterdam Scenario

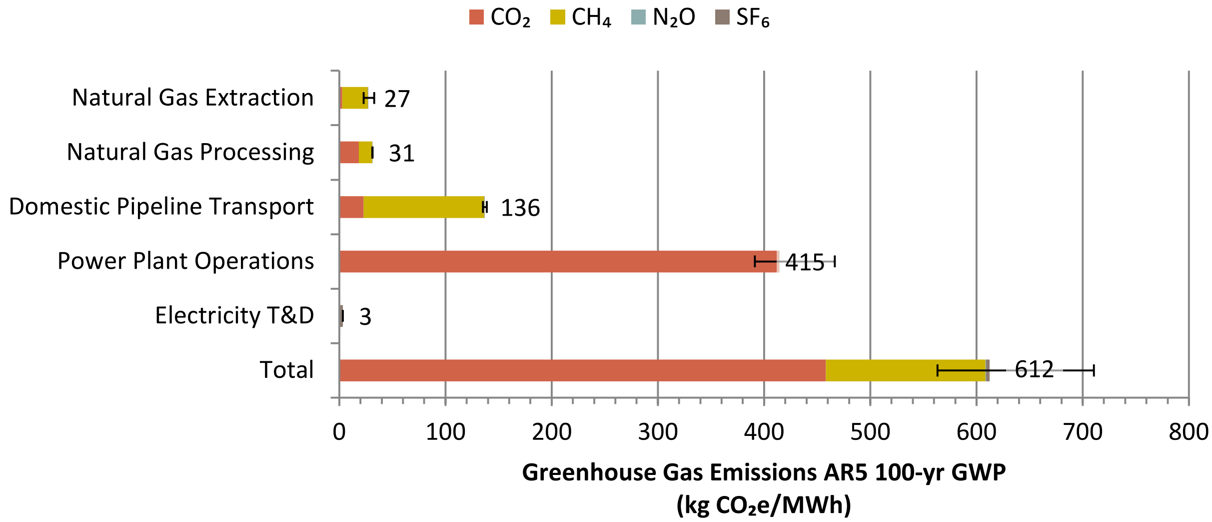


Figure 6-5: Speciated Life Cycle GHG Emissions of Coal Power

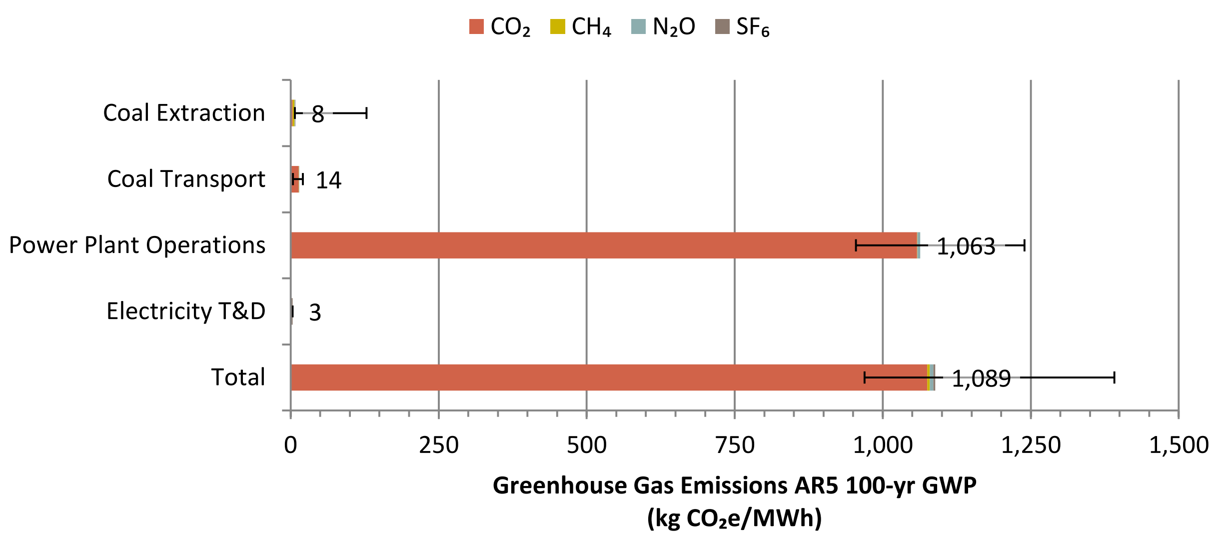


Figure 6-6 and **Figure 6-7** utilize the uncertainty bands shown in **Figure 6-1** and **Figure 6-2** to compare the range of LC GHG emissions for the gas and coal scenarios in Europe and Asia on 100 and 20-year bases. On a 100-year basis, natural gas power is 25 to 61 percent less than coal for Europe and 18 to 59 percent less than coal for Asia. The small difference in the ranges for Europe and Asia is driven by the longer transport distances for natural gas to Asia (both LNG from the U.S. and pipeline from Russia). On a 20-year basis, there is still potential for natural gas to have lower GHG emissions than coal (up to 57 percent less); however, the high end of the Russian gas results overlap with the low range of the coal results for both Europe and Asia and the high end of the U.S LNG results overlap with the coal results for Asia. As noted, the 20-year GWP emissions for the Russian natural gas scenarios are driven by the methane emissions from pipeline transport. The estimated pipeline distances for Russian natural gas transport are roughly four to eight times longer than for the LNG cases.

Figure 6-6: 100-yr GWP comparison of Coal and NG Power in Europe and Asia

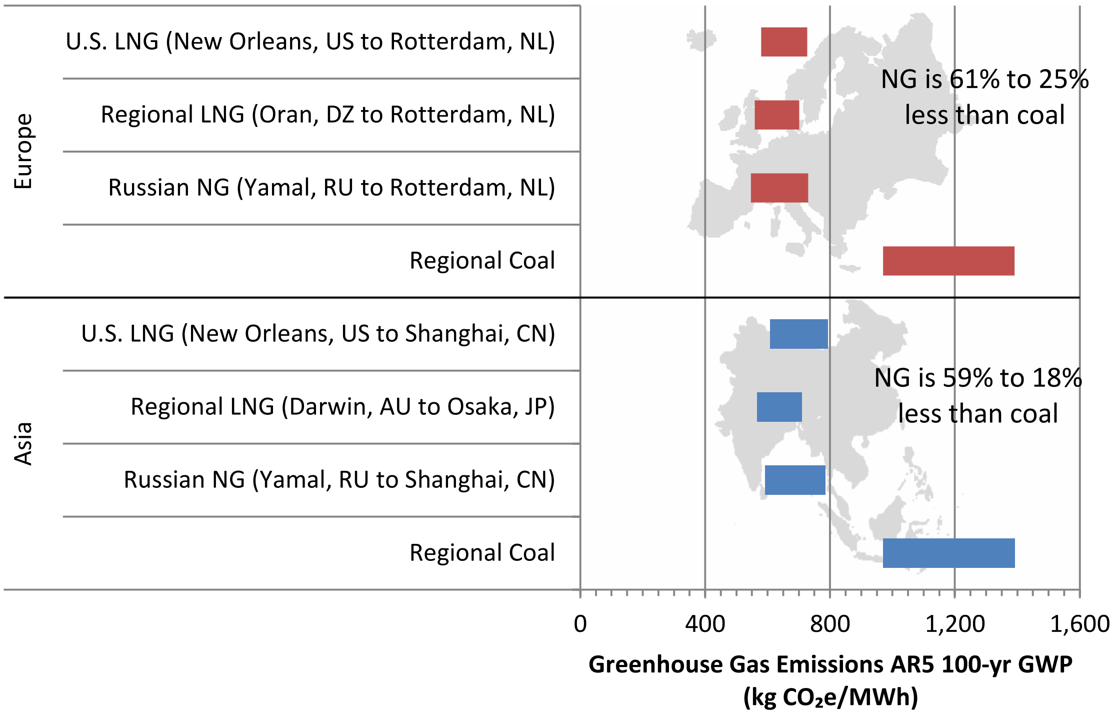


Figure 6-7: 20-yr GWP comparison of Coal and NG Power in Europe and Asia

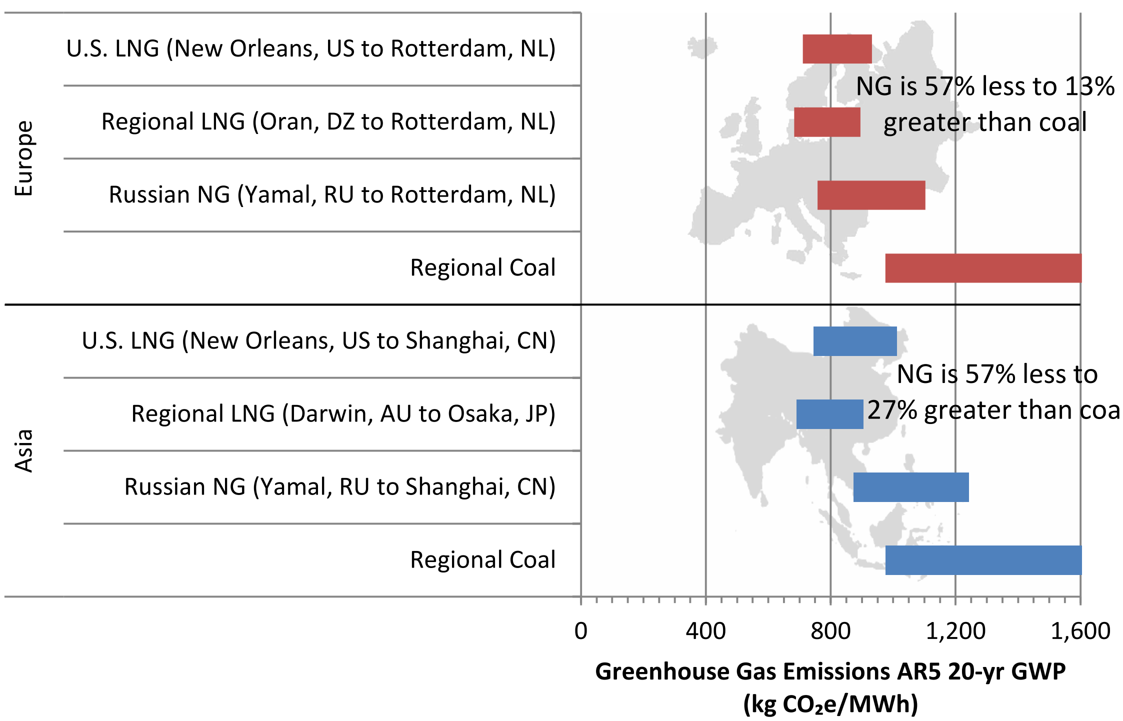


Figure 6-8 and **Figure 6-9** depict the life cycle GHG emissions for the U.S. LNG and Russian natural gas scenarios as a function of the methane leakage that occurs during extraction, processing, and transport on a 100-year and 20-year basis, respectively. Both figures also include a reference line for the coal power scenario. The diamond-shaped data points represent the modeled leakage for each scenario and the circular data points represent the breakeven leakage at which the life cycle GHG emissions for natural gas power would equal those for the coal reference case. These results are based on the most conservative breakeven point which occurs between the high natural gas cases (i.e. lowest power plant efficiency, longest transport distance, and highest methane leakage) with the low coal case (i.e. highest power plant efficiency and shortest transport distance). All of the breakeven results are compiled in **Table 6-1**.

Methane leakage (cradle-to-delivered) from natural gas production would have to increase by a factor of 2.8 before the high estimate for U.S. LNG exports would overlap the low estimate for regional coal production and consumption for power production for the U.S. to Shanghai scenario on a 100-year GWP basis. The leakage could increase by a factor of 3.6 for the European case, slightly higher due to the shorter transport distance between the U.S. and Rotterdam. The breakeven methane leakage for the Asian scenario is 4.6 percent and 5.8 percent for the European scenario.

For the Russian natural gas to Shanghai scenario, methane leakage (cradle-to-delivered) from natural gas production would have to increase 1.7 times before the high estimate for natural gas would overlap the low estimate for regional coal production and consumption for power production on a 100-year GWP basis. The leakage could increase by a factor of 2.2 for the European case, slightly higher due to the shorter pipeline distance. The breakeven methane leakage for the Asian scenario is 8.8 percent and 8.9 percent for the European scenario.

Figure 6-9 presents the same scenarios on a 20-year GWP basis. The high modeled leakage rate for the U.S. LNG scenarios (1.6 percent) is still less than the breakeven percentage for the European scenario (1.9 percent), but slightly higher than the breakeven for the Asian scenario (1.4 percent). The current leakage rates for the Russian natural gas scenarios are higher than the breakeven percentages for the corresponding scenarios on a 20-year basis. This corresponds to the results shown in **Figure 6-7**, which shows that there is some overlap in the uncertainty bands for the Russian natural gas scenarios and the reference coal scenario on a 20-year GWP basis. As previously noted, the calculated breakeven points are the most conservative, so these results do not indicate that natural gas has a higher GHG than coal on a 20-year basis in all cases.

Table 6-1: Coal and Natural Gas Breakeven for U.S. LNG and Russian NG Scenarios

Scenario	Modeled Leakage	Breakeven Leakage		X Times Higher Than Modeled Leakage	
		100-yr GWP	20-yr GWP	100-yr GWP	20-yr GWP
U.S. LNG to Rotterdam	1.6%	5.8%	1.9%	3.6	1.2
U.S. LNG to Shanghai	1.6%	4.6%	1.4%	2.8	0.9
Russia NG to Rotterdam	4.1%	8.9%	3.2%	2.2	0.8
Russia NG to Shanghai	5.0%	8.8%	3.1%	1.7	0.6

Figure 6-8: Coal and Natural Gas Breakeven for U.S. LNG and Russian NG Scenarios (100-year GWP)

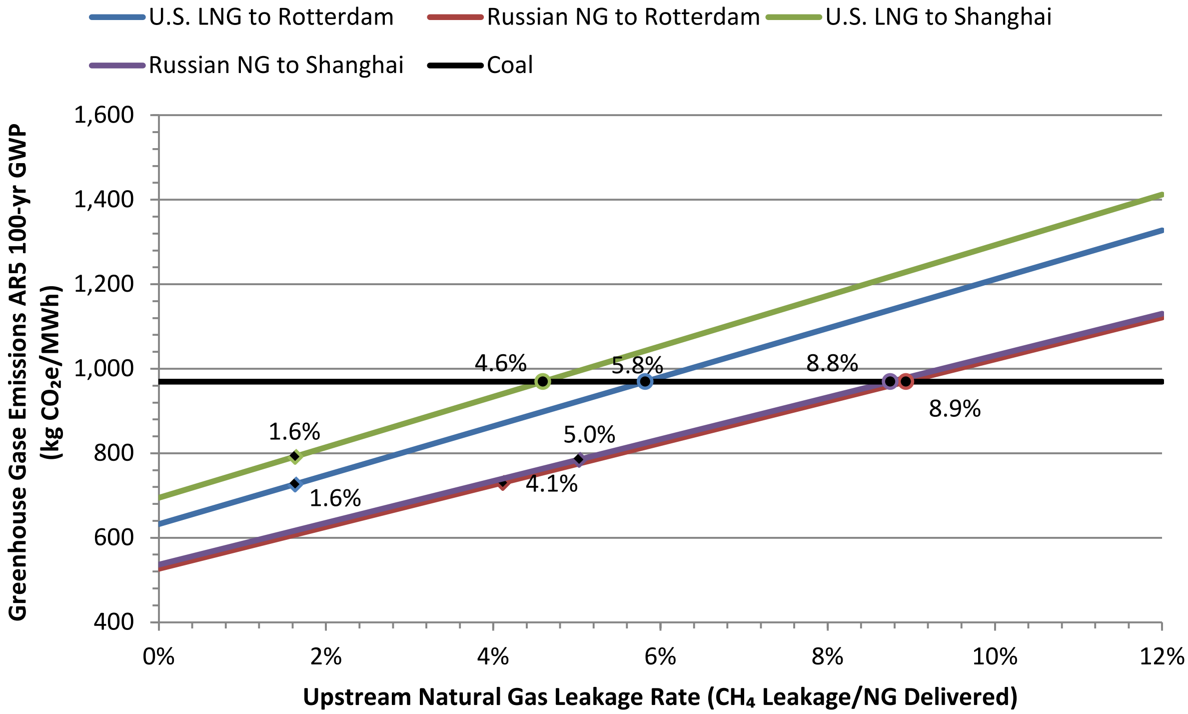


Figure 6-9: Coal and Natural Gas Breakeven for U.S. LNG and Russian NG Scenarios (20-year GWP)

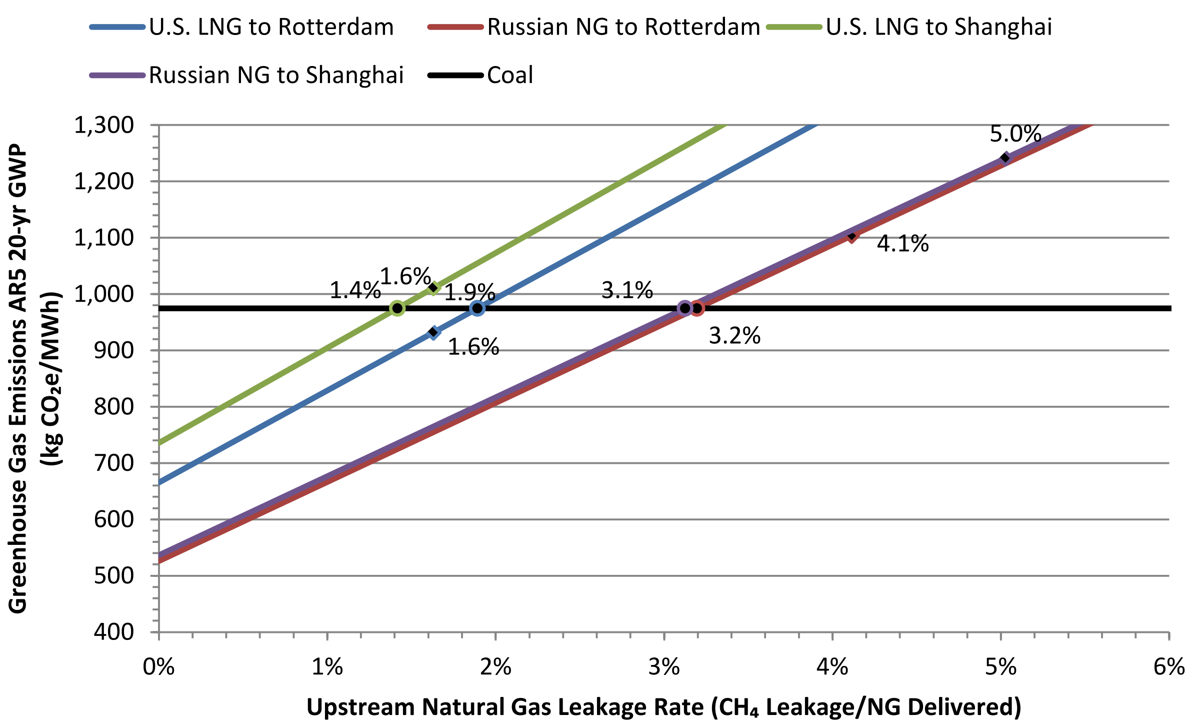


Figure 6-10 through **Figure 6-16** are uncertainty tornado diagrams for each of the 100-year GWP scenarios from **Figure 6-1** and **Figure 6-2**. The parameter ranges for these figures are based on the values in **Table 5-1**, **Table 5-2** and **Table 5-3**. These figures show the uncertainty in the total life cycle results based on changes to only a single parameter or variable.

As expected, the power plant efficiency contributes a significant fraction of the uncertainty for the natural gas and coal scenarios. These figures generally indicate that the transport of LNG contributes very little uncertainty to the overall result, except in the New Orleans to Shanghai LNG case. The base case assumption for that scenario is that the LNG tanker travels to Shanghai via the Panama Canal. In the event that this is not possible due to ship dimensions, the transport distance increases by approximately 50 percent. The emissions associated with the extraction and processing of natural gas do contribute considerably to the uncertainty of the overall emissions. For more details on the factors the drive the uncertainty of upstream natural gas extraction, refer to the NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation (NETL, 2014). For the Russian natural gas cases shown in **Figure 6-14** and **Figure 6-15**, uncertainty in the pipeline transport distance results is a large driver in the overall uncertainty of the life cycle result. As previously noted, the exact distance the natural gas travels from the extraction point in Yamal to the destination power plant is unknown, so a wide range spanning 2,000 km from low to high was used to represent all potential scenarios. It should be noted that the type of coal used at the power plant does account for some uncertainty in the model. The high case utilizes I-6 coal, which has higher acquisition emissions due to higher methane emissions at the coal mine.

Figure 6-10: Uncertainty Tornado LNG – New Orleans to Rotterdam, Netherlands

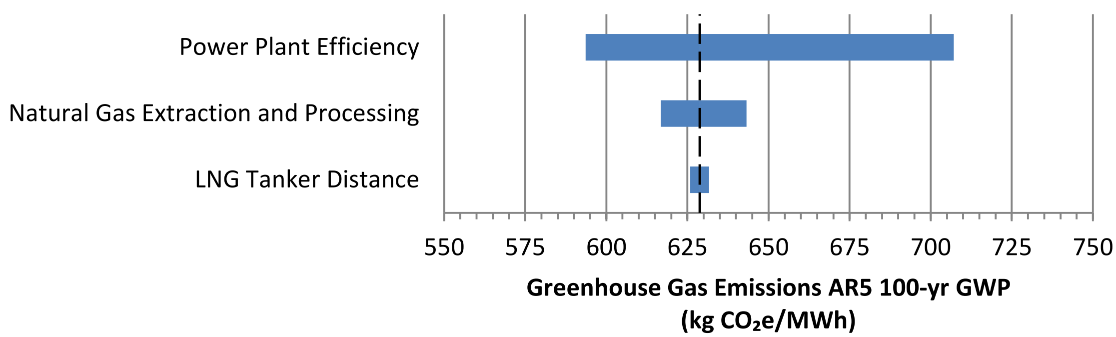


Figure 6-11: Uncertainty Tornado LNG – Oran, Algeria to Rotterdam, Netherlands

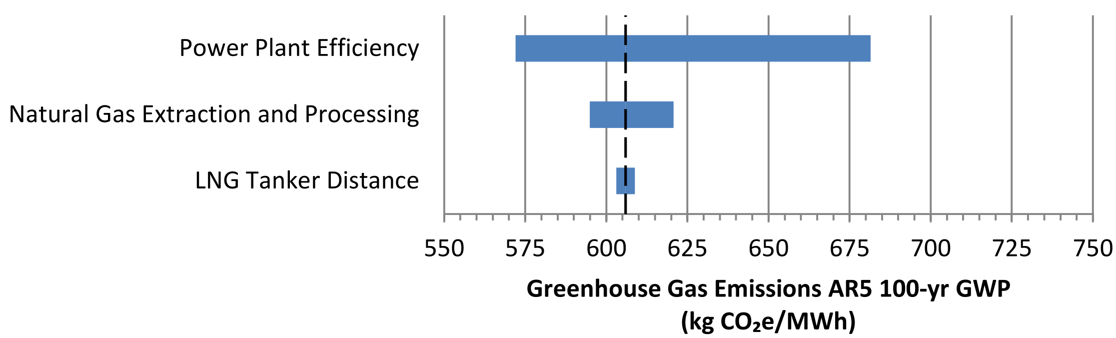


Figure 6-12: Uncertainty Tornado LNG – New Orleans to Shanghai, China

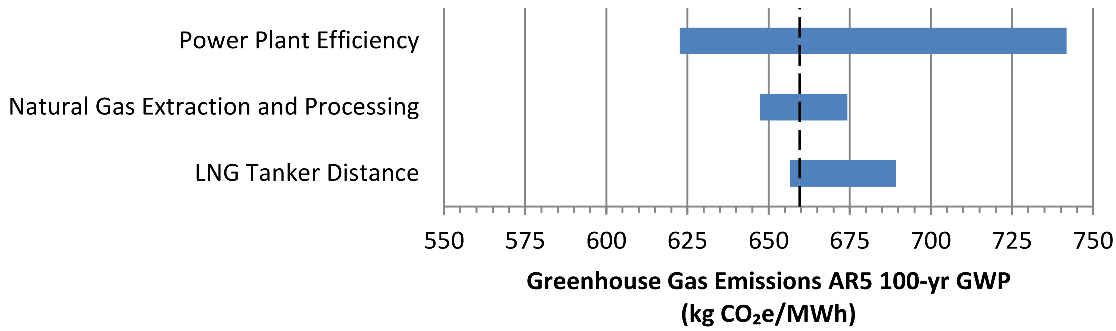


Figure 6-13: Uncertainty Tornado LNG – Darwin, Australia to Osaka, Japan

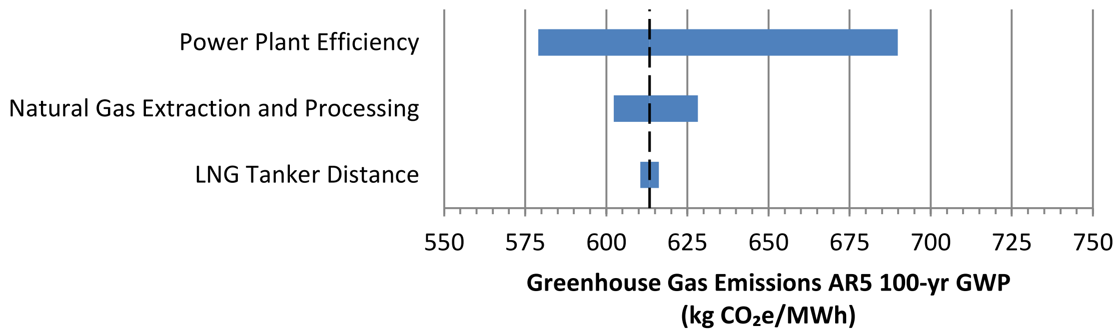


Figure 6-14: Uncertainty Tornado Russian NG – Yamal, Russia to Rotterdam, Netherlands

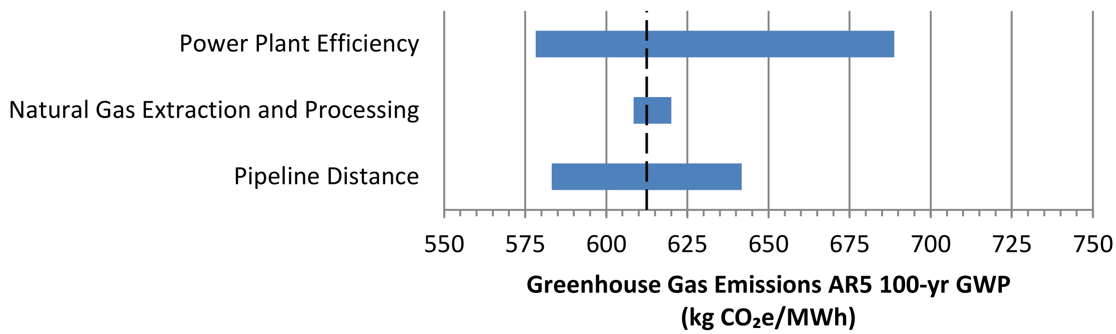


Figure 6-15: Uncertainty Tornado Russian NG – Yamal, Russia to Shanghai, China

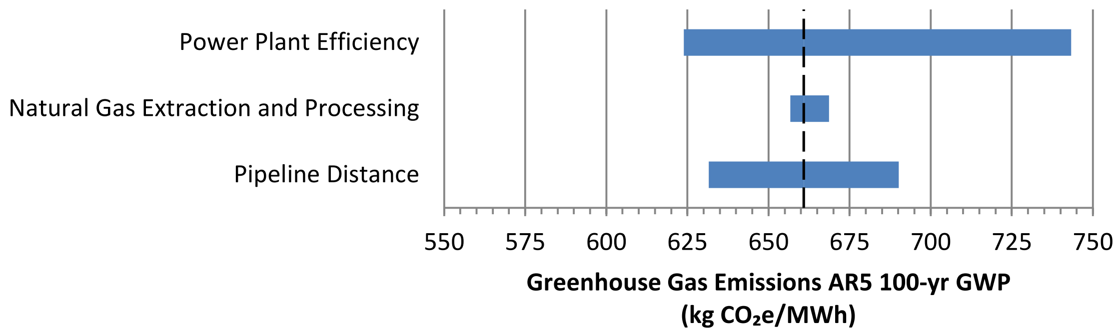
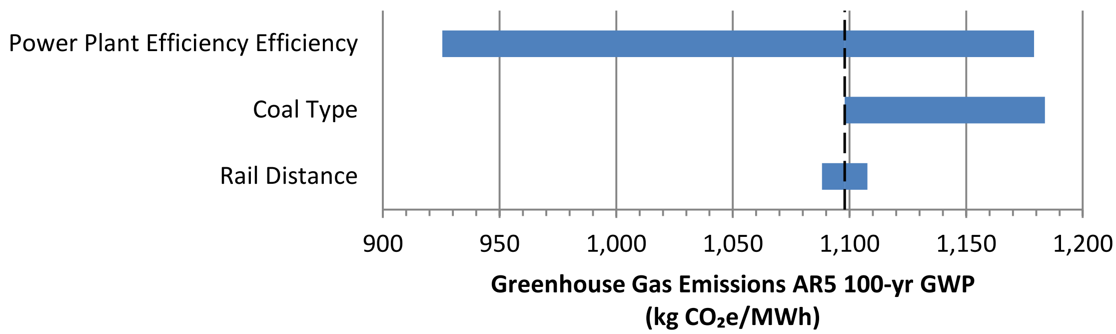


Figure 6-16: Uncertainty Tornado Coal – Europe and Asia Regional Production



7 Summary and Study Limitations

This analysis has determined that the use of U.S. LNG exports for power production in European and Asian markets will not increase GHG emissions, on a life cycle perspective, when compared to regional coal extraction and consumption for power production. Given the uncertainty in the underlying model data, it is not clear if there are any significant differences between the corresponding European and Asian cases other than the LNG transport distance from the U.S. and the pipeline distance from Russia. Differences between the U.S LNG, regional LNG, and Russian natural gas options are also indeterminate due to the underlying uncertainty in the modeling data, therefore no significant increase or decrease in net climate impact is anticipated from any of these scenarios. It is important to note that the European and Asian coal scenarios are identical because the same parameter ranges are used for both.

A limitation of this study is that the NETL natural gas life cycle analysis model and NETL coal life cycle analysis model are U.S.-based models that were adapted for foreign natural gas and coal production as well as power generation. The specific LNG export/import locations used in this study were chosen to represent an estimate for a region (e.g. New Orleans as U.S. Gulf Coast). Specific locations were required to allow for the estimation of LNG transport distances and do not imply the likelihood that LNG export or import will occur from that exact location. The same assumptions hold true for the Russian natural gas cases. Another limitation is that the efficiencies and other end uses for regional fuel alternatives are not considered.

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Appendix A – Life Cycle Results in IPCC AR4 and AR5 GWPs

Table A-1: Life Cycle GHG Emissions for Natural Gas and Coal Power in Europe IPCC AR-4 GWP (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal
Natural Gas/Coal Extraction	29.0	24.9	22.8	7.8	75.8	65.8	60.3	13.6
Natural Gas Processing	32.1	31.8	29.1	N/A	54.3	53.7	49.2	N/A
Domestic Pipeline Transport	27.8	27.5	117.5	N/A	69.8	69.1	295.1	N/A
Liquefaction	63.6	62.9	N/A	N/A	63.6	62.9	N/A	N/A
Tanker/Rail Transport	24.7	8.0	N/A	14.4	27.6	9.0	N/A	15.3
Tanker Berthing & Deberthing	1.5	1.5	N/A	N/A	1.6	1.6	N/A	N/A
LNG Regasification	17.7	17.7	N/A	N/A	39.3	39.3	N/A	N/A
Power Plant Operations	414.7	414.7	414.7	1,063.0	415.2	415.2	415.2	1,063.7
Electricity T&D	3.3	3.3	3.3	3.4	2.3	2.3	2.3	2.5
Total	614.3	592.3	587.4	1,088.6	749.4	719.0	822.1	1,095.1
Low	567.5	547.6	527.4	969.4	679.2	652.9	707.9	974.6
High	708.0	683.6	696.4	1,391.4	883.0	849.2	1,015.0	1,604.2

Table A-2: Life Cycle GHG Emissions for Natural Gas and Coal Power in Asia IPCC AR-4 GWP (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Shanghai, China	Darwin, Australia to Osaka, Japan	Yamal, Russia to Shanghai, China	Chinese Regional Coal	New Orleans to Shanghai, China	Darwin, Australia to Osaka, Japan	Yamal, Russia to Shanghai, China	Chinese Regional Coal
Natural Gas/Coal Extraction	29.5	25.0	23.3	7.8	77.1	66.1	61.7	13.6
Natural Gas Processing	32.7	31.9	29.8	N/A	55.2	53.9	50.3	N/A
Domestic Pipeline Transport	28.3	27.7	158.1	N/A	71.0	69.4	396.9	N/A
Liquefaction	64.7	63.2	N/A	N/A	64.7	63.2	N/A	N/A
Tanker/Rail Transport	52.3	14.7	N/A	14.4	58.4	16.5	N/A	15.3
Tanker Berthing & Deberthing	1.5	1.5	N/A	N/A	1.6	1.6	N/A	N/A
LNG Regasification	17.7	17.7	N/A	N/A	39.3	39.3	N/A	N/A
Power Plant Operations	414.7	414.7	414.7	1,063.0	415.2	415.2	415.2	1,063.7
Electricity T&D	3.3	3.3	3.3	3.4	2.3	2.3	2.3	2.5
Total	644.6	599.6	629.1	1,088.6	784.8	727.5	926.5	1,095.1
Low	595.8	554.5	566.8	969.4	712.1	660.8	806.2	974.6
High	772.2	691.9	743.5	1,391.4	958.7	858.9	1,133.0	1,604.2

Table A-3: Life Cycle GHG Emissions for Natural Gas and Coal Power in Europe IPCC AR-5 GWP (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal
Natural Gas/Coal Extraction	33.9	29.3	26.8	7.8	88.7	77.2	70.6	13.6
Natural Gas Processing	34.5	34.1	31.2	N/A	60.4	59.7	54.7	N/A
Domestic Pipeline Transport	32.3	32.0	136.4	N/A	81.4	80.6	344.2	N/A
Liquefaction	63.6	62.9	N/A	N/A	63.6	62.9	N/A	N/A
Tanker/Rail Transport	25.0	8.1	N/A	14.4	28.4	9.2	N/A	15.3
Tanker Berthing & Deberthing	1.5	1.5	N/A	N/A	1.6	1.6	N/A	N/A
LNG Regasification	20.0	20.0	N/A	N/A	45.3	45.3	N/A	N/A
Power Plant Operations	414.7	414.7	414.7	1,063.0	415.3	415.3	415.3	1,063.7
Electricity T&D	3.4	3.4	3.4	3.4	2.5	2.5	2.5	2.5
Total	628.8	605.9	612.5	1,088.6	787.2	754.4	887.4	1,095.1
Low	579.5	559.0	546.8	969.4	710.5	682.4	758.2	974.6
High	726.7	701.4	730.4	1,391.4	931.8	895.3	1,103.5	1,604.2

Table A-4: Life Cycle GHG Emissions for Natural Gas and Coal Power in Asia IPCC AR-5 GWP (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Shanghai, China	Darwin, Australia to Osaka, Japan	Yamal, Russia to Shanghai, China	Chinese Regional Coal	New Orleans to Shanghai, China	Darwin, Australia to Osaka, Japan	Yamal, Russia to Shanghai, China	Chinese Regional Coal
Natural Gas/Coal Extraction	34.5	29.4	27.4	7.8	90.2	77.5	72.3	13.6
Natural Gas Processing	35.1	34.3	32.0	N/A	61.4	60.0	56.0	N/A
Domestic Pipeline Transport	32.9	32.1	183.5	N/A	82.9	80.9	463.0	N/A
Liquefaction	64.7	63.2	N/A	N/A	64.7	63.2	N/A	N/A
Tanker/Rail Transport	52.9	14.9	N/A	14.4	60.1	16.9	N/A	15.3
Tanker Berthing & Deberthing	1.5	1.5	N/A	N/A	1.6	1.6	N/A	N/A
LNG Regasification	20.0	20.0	N/A	N/A	45.3	45.3	N/A	N/A
Power Plant Operations	414.7	414.7	414.7	1,063.0	415.3	415.3	415.3	1,063.7
Electricity T&D	3.4	3.4	3.4	3.4	2.5	2.5	2.5	2.5
Total	659.6	613.4	660.9	1,088.6	824.0	763.2	1,009.1	1,095.1
Low	608.3	565.9	592.4	969.4	744.6	690.6	872.8	974.6
High	792.1	709.8	785.1	1,391.4	1,010.7	905.5	1,241.1	1,604.2

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