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GHG Intensity of Natural Gas Transport

Comparison of Additional Natural Gas Imports to Europe by Nord Stream 2 Pipeline and LNG Import Alternatives

Final Report

Title:	**GHG Intensity of Natural Gas Transport** Comparison of Additional Natural Gas Imports to Europe by Nord Stream 2 Pipeline and LNG Import Alternatives
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On behalf of thinkstep AG and its subsidiaries

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List of acronyms

Locations

AU	Australia
AU-NWS	Australia - North West Shelf
AU-QL	Australia - Queensland
DZ	Algeria
QA	Qatar
RU	Russia
US	United States of America

Substances

BOG	Boil-off Gas
CBM	Coalbed Methane
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
CO_2	Carbon Dioxide
HC	Hydro Carbons
HFO	Heavy Fuel Oil
H_2S	Hydrogen Sulphide
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDO	Marine Diesel Oil
N_2	Nitrogen
NGL	Natural Gas Liquids
N_2O	Nitrous Oxide (laughing gas)
NO_2	Nitrogen Dioxide
O_2	Oxygen

Technical units

bcm	Billion cubic metre (10^9)
°C	Degree Celsius
kg	Kilogramme
km	Kilometre
kWh	Kilo Watt hours
m^3	Cubic metre
MJ	Mega Joule
MT	Million tonnes (metric)
MTPA	Million tonnes per annum
MW	Mega Watt
Nm^3	Norm cubic metre (at 0°C)
ppmv	Parts per million volume
vol. %	Volume percentage
wt. %	Weight percentage
t	Tonne (metric)

Others

AP	Air Products and Chemicals, Inc.
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CF	Carbon Footprint
CP	ConocoPhillips
DFDE	Dual-fuel Diesel Electric LNG Vessel
EoL	End-of-Life
GCU	Gas Compressor Unit
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	Higher Heating Value
ISO	International Organisation for Standardization
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LHV	Lower Heating Value
NGO	Non-Governmental Organisation
NSP2	Nord Stream Pipeline 2

OC	Optimised Cascade
ORV	Open Rack Vaporiser
REC	Reduced Emission Completion
SCV	Submerged Combustion Vaporisers
SSD	Slow Speed Diesel
TFDE	Tri-fuel Diesel Electric LNG Vessel
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LCA glossary

Life cycle

A view of a product system as "consecutive and interlinked stages … from raw material acquisition or generation from natural resources to final disposal" (ISO 14040:2006, section 3.1). This includes all material and energy inputs as well as emissions to air, land and water.

Life Cycle Assessment (LCA)

"Compilation and evaluation of the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle" (ISO 14040:2006, section 3.2)

Life Cycle Inventory (LCI)

"Phase of life cycle assessment involving the compilation and quantification of inputs and outputs for a product throughout its life cycle" (ISO 14040:2006, section 3.3)

Life Cycle Impact Assessment (LCIA)

"Phase of life cycle assessment aimed at understanding and evaluating the magnitude and significance of the potential environmental impacts for a product system throughout the life cycle of the product" (ISO 14040:2006, section 3.4)

Life cycle interpretation

"Phase of life cycle assessment in which the findings of either the inventory analysis or the impact assessment, or both, are evaluated in relation to the defined goal and scope in order to reach conclusions and recommendations" (ISO 14040:2006, section 3.5)

Functional unit

"Quantified performance of a product system for use as a reference unit" (ISO 14040:2006, section 3.20)

Allocation

"Partitioning the input or output flows of a process or a product system between the product system under study and one or more other product systems" (ISO 14040:2006, section 3.17)

Critical Review

"Process intended to ensure consistency between a life cycle assessment and the principles and requirements of the International Standards on life cycle assessment" (ISO 14044:2006, section 3.45).

Executive summary

The European Union is projected to face a substantial natural gas supply shortage in the next 30 years. This is a result of decreasing domestic natural gas supply combined with steadily increasing demand. Bridging this gap will require additional imports from abroad. This study compares two major supply options. One option is the transport of Russian natural gas via pipeline, specifically the proposed Nord Stream 2 pipeline (NSP2), a twin system to the existing Nord Stream pipeline. NSP2 would have an annual capacity of 55 billion m^3 (bcm) of natural gas transported from Northern Russia to Central Europe. The other option is the shipping of liquefied natural gas (LNG) from existing and emerging producer countries around the world, namely the United States, Qatar, Australia and Algeria.

In addition to market mechanisms – which play a major role in the selection of natural gas supply options for the European market – political deliberations increasingly incorporate environmental aspects like climate change, in this case, the greenhouse gas (GHG) emissions associated with the supply of natural gas. Thus, the two options for additional gas supply to Europe are examined and compared on the basis of their respective potential GHG emissions, commonly called carbon footprint.

Study approach

The study was conducted to provide high-quality, reliable and up-to-date GHG intensity data for the defined natural gas supply routes to Europe, based on a life cycle approach and in accordance with ISO 14040/14044. This is done by performing a carbon footprint comparison of the system supplying Russian gas to Europe via the Nord Stream pipeline and the system alternatives delivering LNG from overseas. The life cycle assessment (LCA) explores the environmental impacts of each stage of natural gas supply along the value chain – from gas extraction to processing and transport to the European natural gas grid. The study results are also intended to inform responses to any external stakeholder inquiries.

Study boundary

The life cycle assessment divides the natural gas supply alternatives into two product systems:

Product system A

- Natural gas import from Russia via Nord Stream 2 pipeline (NSP2)

Product system B

- LNG imports from the United States
- LNG imports from Qatar
- LNG imports from Australia, i.e., North West Shelf (NWS) and Queensland (QL)
- LNG imports from Algeria

The selection of the LNG producer countries as potential suppliers of the additional natural gas imports needed to compensate for decreasing domestic production is based on the following considerations:

- The United States is considered a major alternative source of additional LNG due to its forecasted LNG capacity expansion.
- Qatar is currently the world's biggest global LNG exporter and is expected to remain an important source in the future.
- Australia typically exports LNG to Asia but sizable investments in new capacity make it a potential future supplier to Europe as well.
- The proximity of Algeria to the European market supports its role as an important LNG supplier, also in the future.

The two systems' value chains of natural gas along their respective life cycle stages are shown in Figures A and B. Within the defined product system A, natural gas is produced in Northern Russia and transported via on- and offshore pipeline to the European market.

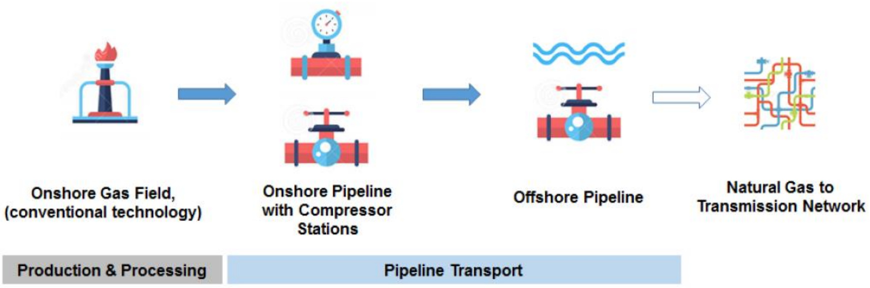


Figure A Flow chart of product system A; Pipeline imports from Russia (schematic)

Within the defined product system B, natural gas is produced in the United States, Qatar, Australia (NWS and QL) or Algeria and transported to port via pipeline and shipped to the EU via LNG vessels.

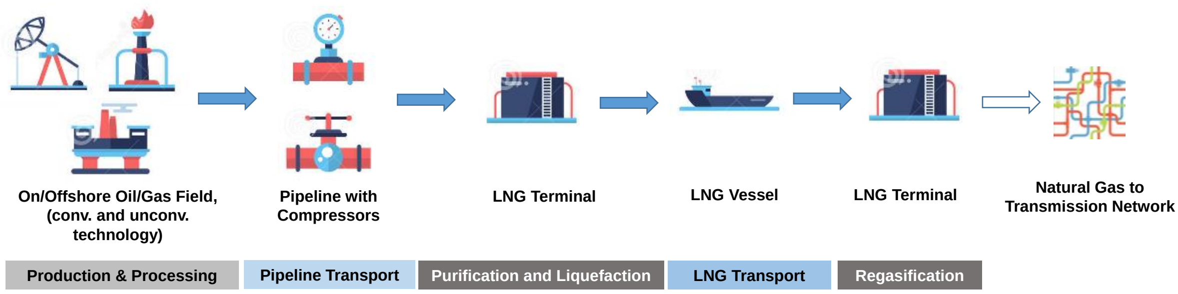


Figure B Flow chart of product system B, LNG imports from USA, Qatar, Australia and Algeria (schematic)

Analysis

To enable a balanced analysis and interpretation of the LCA results, a base case is established for both the gas import via the Russian Nord Stream 2 pipeline and the LNG import alternatives. Then, additional scenarios are defined to examine the effects of conceivable future technical developments.

For the base cases, parameters and data are set and applied according to the defined technical, geographical and sectorial situations of each respective product system. The base cases represent the current technologies and market realities as well as facilities already under construction and LNG market forecasts published. The additional scenarios are intended to show the effect of variations from the base cases based on conceivable, hypothetical changes. For instance, one additional Russian scenario applies production and processing data from an average Russian gas field and one additional US scenario represents a different LNG export terminal with a transport distance to Europe that is shorter than that of the base case. All additional scenarios for product system A are designed to explore the effect of *less* favorable settings compared with the base case, while all additional scenarios for product system B are designed to reflect *more* favorable settings compared with the base case.

In the carbon footprint comparison between the Nord Stream corridor and the supply via LNG, the Nord Stream 2 pipeline shows clear advantages. As is shown in Figures C, Russian natural gas transported to Europe via pipeline is preferable from a carbon-footprint perspective. In the base case, LNG import GHG results are 2.4 – 4.6 times higher than GHG results for the pipeline import from Russia via NSP2.

The carbon footprint of the different supply routes is broken down into the different stages of the value chain. Key drivers for GHG emissions of LNG imports are the liquefaction of the gas as well as its upstream production and processing (Algeria, Australia-QL, US) and downstream transport to Europe (all except Algeria). GHG emissions for the pipeline import from Russia are dominated by the long-distance pipeline operations necessary to transport the gas to its destination.

Figure C shows the GHG results for the Russian pipeline imports as well as all LNG supply options.

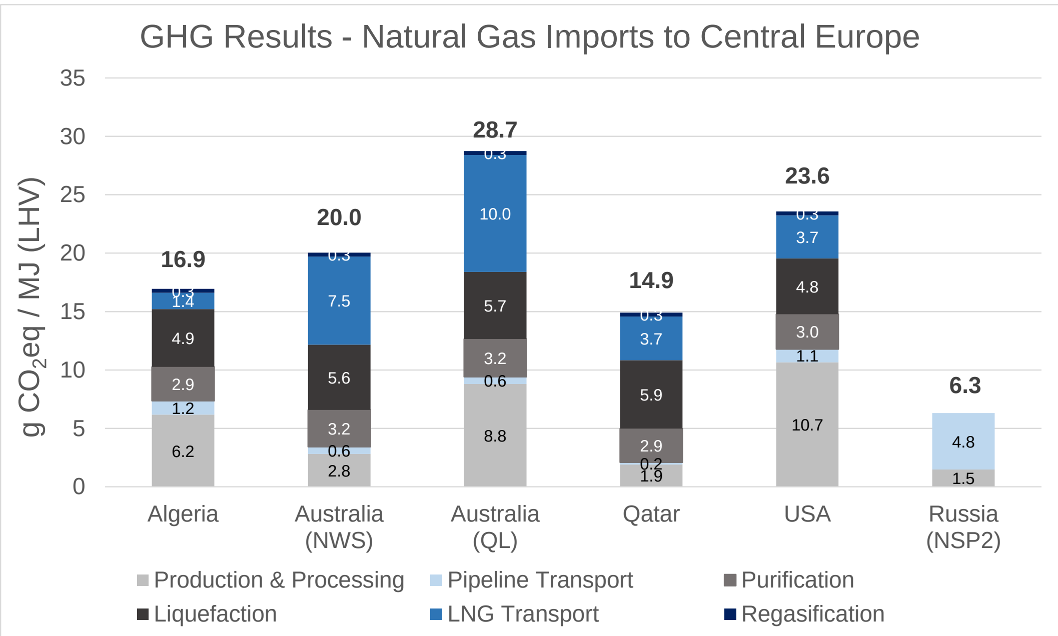


Figure C **Carbon footprint of product system A and B [g CO_2eq/MJ] – base case**

Results

The main findings of this study are:

- Natural gas imports to Europe via the Nord Stream 2 pipeline show a preferable environmental profile from a climate change perspective when compared with LNG import alternatives (as displayed in Figure C; base case). The also performed scenario analysis shows that even optimistic scenarios for the LNG import routes result in higher GHG emissions than pessimistic scenarios for Russian natural gas import via pipeline.
- The NSP2 base case shows absolute GHG savings of 17.1 – 44.6 million tonnes of CO_2eq per year in comparison to the best and worst performing base cases for LNG import (best: Qatar, worst: Australia-QL). This is based on 55 billion m^3 (bcm) of gas transported per year.
- Key GHG emission contributors to LNG import are production and processing, liquefaction and transport, while GHG emissions from the pipeline import from Russia are dominated by pipeline operations.
- The calculated GHG results of this study were correlated and compared with third-party studies and found to be within the range of corresponding literature values. Average literature values differ by -10 % for the United States, +15 % for Qatar, +15 % for Australia-QL, +140 % for Algeria and +15 % for Russia compared with the GHG results of the base cases in this study. The high Algerian literature value originates from methane emissions in production and processing as well as inefficiencies in old LNG plants. Differences between this study's GHG results and those of comparative studies may also be a reflection of different reference years applied.

1. Introduction

1.1. Natural gas and liquefied natural gas (LNG)

Natural gas and liquefied natural gas (LNG) are the subjects of this report. Therefore, these two terms are introduced in the first place.

Natural gas

History:

The use of natural gas dates back to 500 BC (before Christ), as the Chinese are believed to have used natural gas for salt water desalination. In the seventeenth century natural gas seepages were discovered in the United States and the first gas well is believed to have been ploughed in 1821.

Resource:

Conventional natural gas is commonly found in underground sandstone and limestone formations, whereas unconventional gas refers to coal bed methane, shale gas, gas hydrates and tight sand gas.

Definition and Composition:

A gaseous hydrocarbon fuel obtained from underground sources. Natural gas remains in the gaseous state under the temperature and pressure conditions in service.

In general, the term natural gas applies to a mixture of combustible hydrocarbon gases that are produced from either natural gas wells or oil wells as associated gas. When being produced from a reservoir, conventional or unconventional, natural gas consists of its main component methane (CH_4), but also of ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), carbon dioxide (CO_2), hydrogen sulphide (H_2S), water vapour (H_2O), and other compounds. When natural gas contains heavier hydrocarbons like butane, propane, and ethane – so called natural gas liquids (NGLs) – it is referred to as `wet gas´; if the share of methane is significant (>80 %) it is called `dry gas´.

Characteristics:

- Colourless, odourless, tasteless, shapeless and lighter than air. At atmospheric pressure, it is gaseous at any temperature above -160 ºC.
- High ignition temperature and narrow flammability range, making it an inherently safe fossil fuel compared with other fuel sources.
- Condenses to Liquefied Natural Gas (LNG) when cooled to a temperature of approximately -162 °C at atmospheric pressure.
- Commercialised natural gas is practically sulphur free and produces – if combusted – virtually no sulphur dioxide (SO_2) and emits lower levels of nitrogen oxides (NO_X) and CO_2 than other fossil fuels.

Applications:

- Gas district cooling
- Power sector
- Cooking
- Fuel for industrial and residential use
- Transportation

- LNG
- Heating
- Feedstock in petrochemical industry

The terminology around natural gas and its constituents is presented in Figure 1-1.

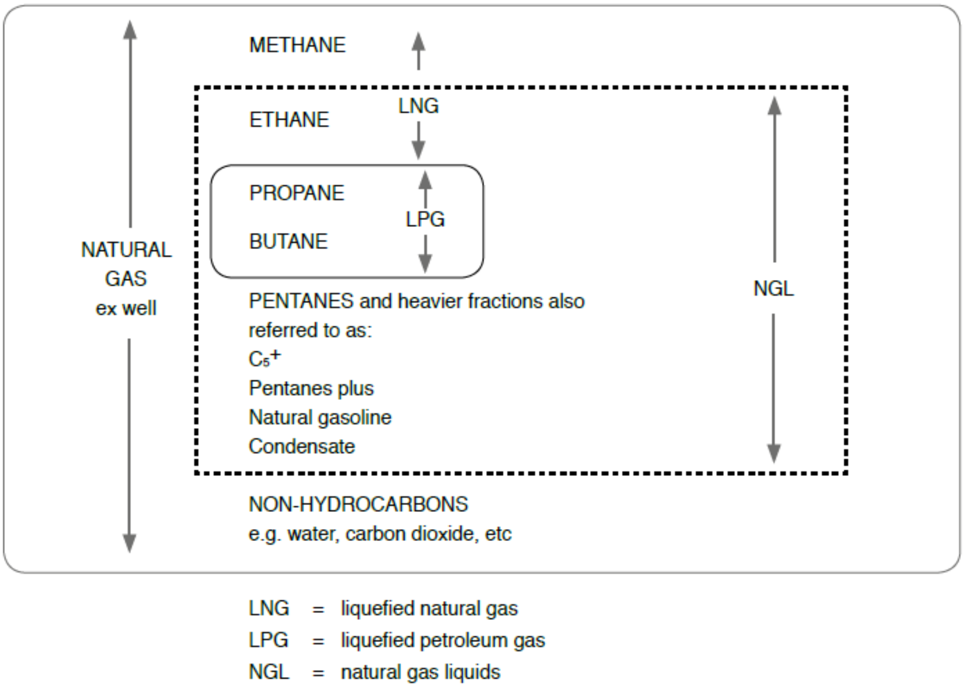


Figure 1-1: Terminology and constituents of natural gas (IGU, 2012)

Liquefied Natural Gas (LNG)

History:

Natural gas liquefaction dates back to the 19th century when British chemist and physicist Michael Faraday experimented with liquefying different types of gases, including natural gas. The first LNG plant was built in West Virginia in 1912 and began operation in 1917. In January 1959, the world's first LNG tanker, The Methane Pioneer, carried an LNG cargo from Lake Charles, Louisiana, to Canvey Island, United Kingdom.

Definition:

Natural gas which, after purification, is liquefied for storage and transportation purpose. At atmospheric pressure, LNG remains in a liquid state at a temperature below -160 ºC.

Composition:

Primarily methane (CH_4) but also contains other components like ethane (C_2H_6), butane (C_4H_{10}) up to hexane (C_6H_{14}) as well as nitrogen (N). Impurities may include carbon dioxide (CO_2), sulphur (S), carbonyl sulphide, mercaptans and mercury. Since natural gas is purified before it is liquefied to LNG, LNG typically contains fewer impurities than gaseous natural gas.

Characteristics

- Volume is typically around 600 times smaller in a liquid state based on composition, pressure and temperature.

- With its clean burning properties, it produces less air pollutants and can be more efficient compared with traditional fuels, e.g., oil, diesel, wood, coal and other organic matter.
- LNG is an option when pipeline gas is not possible or economically viable due to distance, environment (deep sea, natural reserve, mountains) or political reasons.

The forecast for the coming 25 years regarding the global trade volume of natural gas shows that, overall, the market will grow by about 70 % for the global long-distance natural gas trade. The identified major exporting countries for additional LNG in the future are Australia and the USA – see Figure 1-2.

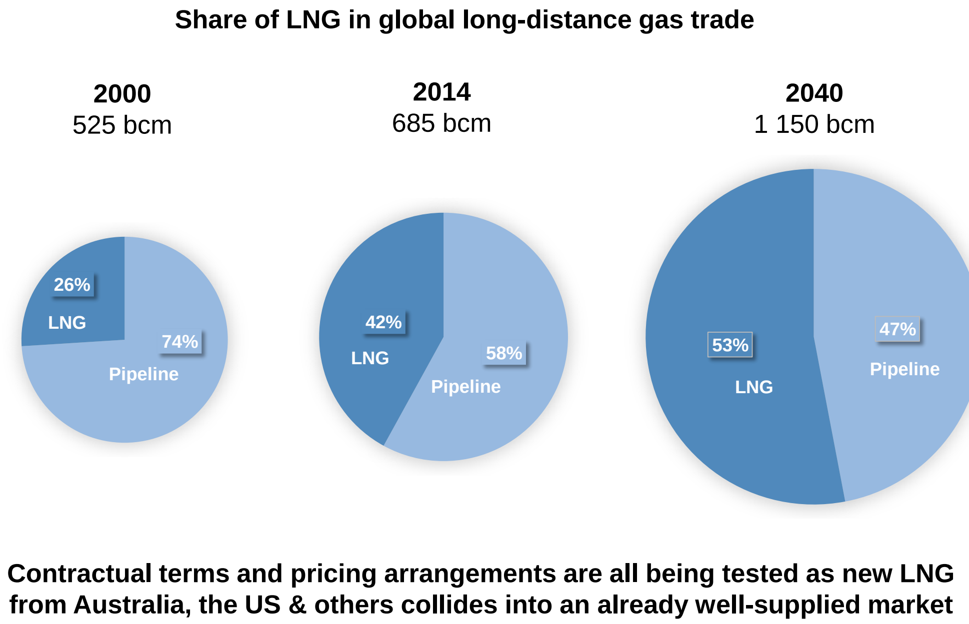


Figure 1-2: Expected future development of natural gas trade (IEA, 2016)

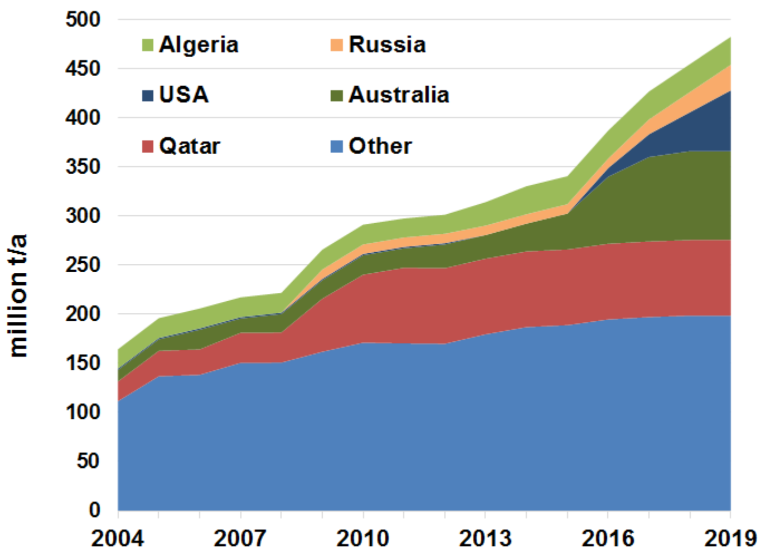


Figure 1-3: Current LNG capacity including plants under construction (GIIGNL, 2004-2016)

That is underpinned by Figure 1-3 which shows current LNG capacities including LNG plants under construction. For most countries, capacities change minimally whereas US and Australian capacities will increase significantly.

Natural gas is the fastest growing primary energy source in the world. Natural gas is widely available, and it is the cleanest burning hydrocarbon-based fuel. CO_2 emissions of natural gas are lower than all other petroleum-derived fuels, which makes it favourable also in terms of greenhouse effect. And one of the major topics in societal and political discussions today is climate change. As said, natural gas is a relatively "clean" petroleum-based fuel regarding the greenhouse effect at combustion – but how about the greenhouse gas (GHG) impacts of making natural gas available? And what environmental effects are associated with the different means of producing, processing and transporting natural gas from the location of resource to where it is consumed?

According to the US Department of Energy (DOE, 2015), about 13 % (by volume) of natural gas is consumed (CH_4 emissions and mainly natural gas used as fuel) in the natural gas system before it is delivered to consumers (considering production, processing, transmission, storage and distribution of natural gas – with production and processing responsible for about 70 %). This value by volume is not taking into account the higher effect of methane emissions to the atmosphere on the greenhouse gas effect compared with CO_2. As CH_4 and CO_2 are identified in the study of DOE as the main associated GHG emissions in the natural gas supply chain and CO_2 is the major GHG emission during combustion of natural gas, the share of the "indirect" emissions in the natural gas system (from the perspective of the natural gas consumer) to the greenhouse gas effect is even higher than 13 %. This exemplary and simplified relation between "direct" and "indirect" GHG emissions in application of natural gas shows that the "indirect" GHG emissions are relevant to consider in the natural gas system. In absolute numbers, the combustion of natural gas causes GHG emissions (so, "direct" GHG emissions) of approx. 55.1 g CO_2 equivalents per MJ (LHV). This study is providing absolute GHG emissions numbers for different natural gas supply chain options (so, the "indirect" GHG emissions).

The relation between energetic and feedstock use concerning various application cases of natural gas is as follows: the non-energy consumption of natural gas accounts for only 4 % of the gross inland consumption of natural gas in Europe (EU 28) in 2014 (Eurostat, 2014). So, the vast majority of 96 % of natural gas in Europe is applied in energy transformation applications (mainly thermal power stations), consumed to a lesser extent in the energy branch itself and the greater part is used for final energy consumption in the industry (e.g. iron and steel, chemical) as well as in residential, commercial and public services. Thus, the focus of natural gas use lays clearly on its role as energy supplier.

1.2. Introduction to the study

The European Union will face a substantial natural gas supply gap in the coming 30 years, partly triggered by decreasing domestic natural gas production over the last ten years and ongoing (European Commission, 2016 and Eurostat, 2016). Consequently, additional natural gas has to be imported to Europe to satisfy the demand of natural gas on the European energy market. The reference scenario 2016 of the European Commission (European Commission, 2016) which analyses the trends to 2050 regarding energy, transport and GHG emissions in Europe determines substantial amounts of incremental net imports of natural gas up to 2050 – see Figure 1-4.

Several options could be considered to close that gap. One option is the Nord Stream 2 pipeline (NSP2) from Russia as a twin pipeline system to the existing Nord Stream pipeline. NSP2 will have a yearly capacity of additional 55 billion m^3 (bcm) natural gas transported from Northern Russia to Central Europe. By definition of the study (supply of additional natural gas to Europe), other already existing natural gas pipeline routes are not considered within this study.

An alternative option to pipeline natural gas is to contract the LNG (Liquefied Natural Gas) imports from various producing countries around the world into Europe using both already existing and emerging resources. USA and Qatar are expected to be the most relevant suppliers to Europe for additional LNG supply in the near future. In addition, Australia, due to its relevance of current and future LNG export capacity, and Algeria, due to its close geographical proximity to Europe, are analysed in this study.

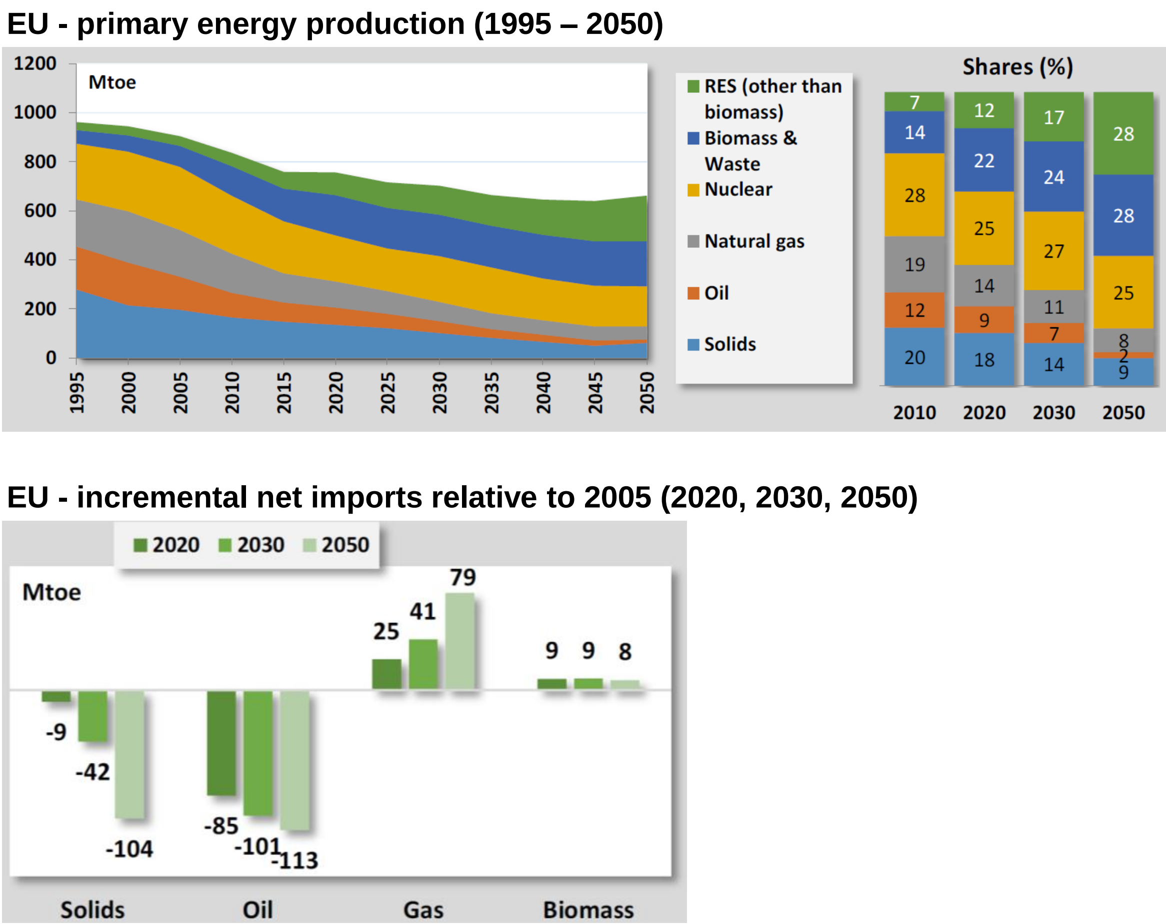


Figure 1-4: Primary energy production in Europe (past, present and forecast) and projected incremental net energy imports into Europe (European Commission, 2016)

Besides market mechanisms – which play a major role in the European domestic market in the selection of natural gas supply options – political deliberations increasingly consider environmental aspects like GHG emissions from the supply of natural gas. Thus, the two main options for additional gas supply to Europe – pipeline gas from Russia and LNG imports from select countries – are investigated and compared with focus on the potential emission of greenhouse gases (GHG).

Nord Stream 2 commissioned *thinkstep* for this study, "GHG intensity of Natural Gas Transport," with the intention to advance an open and transparent dialogue with external stakeholders regarding the climate impact from the proposed Nord Stream 2 pipeline.

The value chain of natural gas is shown in Figure 1-5 with its different constituents and related applications. The blue coloured area highlights the technical focus area of this study – namely production of natural gas, processing to a marketable condition, and transport to market. The LNG technology for transporting natural gas overseas is considered as well as the option of transporting natural gas via pipeline.

The direct link to specific applications is outside of the scope of this study. The target market of the natural gas investigated in this study is considered to be North-West and Central Europe.

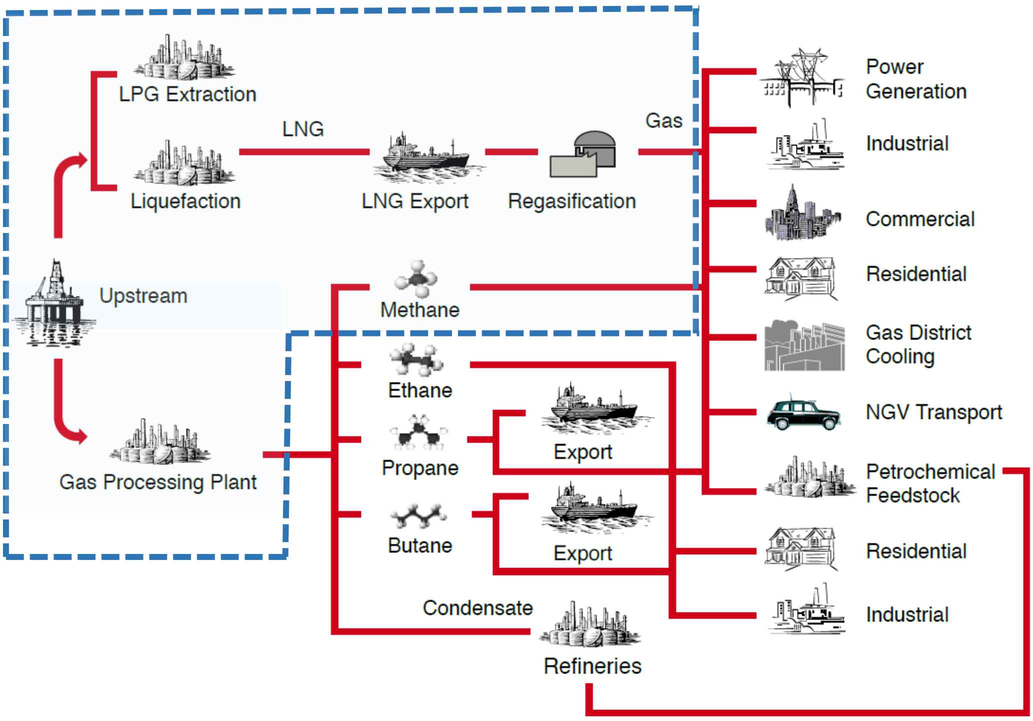


Figure 1-5: Value chain of natural gas with technical focus area of the study highlighted in blue (IGU, 2012)

Several studies have been conducted in recent years investigating environmental aspects of the natural gas supply chain, partly including defined application cases of natural gas, e.g., JEC (JEC, 2014), Zukunft Erdgas e.V. (DBI, 2016b), CIRAIG (CIRAIG, 2016), Exergia (Exergia_et_al, 2015) and others. The goal and scope of those studies may vary and may be different from that of this study. However, the outcome of the study on hand is put into context of the outcome of further studies under consideration of different boundary conditions.

2. Goal of the study

The study considers potential future development, namely the forecasted additional demand for natural gas imports to the European market. Based on the projected supply gap, Europe has to identify additional delivery channels. The study investigates two possible routes for additional imported natural gas – Russian natural gas via Nord Stream 2 pipeline and LNG import from select producer countries.

To be able to assess the environmental impact with focus on climate change of the two selected technical options to supply natural gas to Europe, a greenhouse gas (GHG) intensity – also called carbon footprint (CF) – study is conducted.

The two options for importing additional natural gas are:

- Natural gas import from Russia via Nord Stream 2 pipeline
- LNG imports from
    - USA (US),
    - Qatar (QA),
    - Australia (AU),
    - Algeria (DZ).

Existing options to supply natural gas via other pipeline routes than Nord Stream 2 to Europe are not considered in this study as explained in section 1.2.

The goal of the study is to provide high-quality, reliable and up-to-date GHG intensity data with a life cycle scope for the defined natural gas supply routes into Europe. This is done by performing a carbon footprint comparison between the defined supply alternatives.

The reason for carrying out the study is the anticipated supply gap of natural gas in Europe within the coming 30 years as analysed in the reference scenario 2016 of the European Commission (European Commission, 2016).

The intended application of the study outcome is mainly to enrich the open and transparent communication with external stakeholders of the projected Nord Stream 2 pipeline. The results are also expected to provide sound data basis for responses to any other external inquiries. The intended audience of the study is the administration responsible for the permitting process of NSP2 as well as policy and decision makers and NGOs.

The results of the study are intended to support comparative assertions intended to be disclosed to public. The study is conducted according to the requirements of ISO 14040/14044 (ISO, 2006). According to these standards, a critical review process done by a critical review panel is required for the study.

3. Scope of the study

The following sections describe the scope of the project to achieve the stated goals. This includes, but is not limited to, the identification of specific product systems to be assessed, the product function(s), functional unit and reference flows, the system boundary, allocation procedures, and cut-off criteria of the study.

3.1. Product systems

The study covers two product systems. One of the product systems includes several sub-systems.

Product System A Supply of natural gas via NSP2 from Russia to Europe

Product System B Supply of natural gas via LNG imports to Europe

- Import from USA – LNG supply: country average
- Import from Qatar – LNG supply: country average
- Import from Australia
  - LNG supply: North West Shelf (NWS)
  - LNG supply: Queensland (QL)
- Import from Algeria – LNG supply: country average

The selection of the producing countries of LNG imported to Europe is made for the following reasons and considering the premise of the study, which is that additional imports will be needed to compensate for decreasing domestic production to supply sufficient natural gas in Europe in the near future (within the next 30 years):

- USA is seen as the major alternative market for additional LNG supply to the EU due to its geographical location and the availability of additional capacity (see forecasted significant expansion of tight and shale gas production (EIA, 2016),
- Qatar is the biggest LNG exporter globally today and is seen as one of the most important exporting markets also in the future,
- Australia delivers LNG mainly to Asia today but has invested significantly in increasing LNG capacity, which is why Australia is seen as a potentially relevant LNG supplier for Europe in the future,
- Algeria specifically and Africa in general are relevant markets for LNG imported to Europe today, also due to the short distance, and are deemed as such in the near future.

The geographical differentiation of LNG production in Australia only is made for the following reasons: USA is a “fluid market” (a large interconnected natural gas transmission network) as it is not possible to determine the geographical origin of the natural gas. One major natural gas field exists in Qatar, the offshore North field. For Algeria, country average data for LNG production is available. However, it is possible to differentiate the LNG production in Australia in the production area of North West Shelf as representative for the conventional LNG route and the LNG production in Queensland as representative for the un-conventional LNG route (coal bed methane).

Defined routes for maritime LNG transportation via vessels from all producing countries to Europe are considered as base case as described in section 3.3. That means specifically that Australian imports and imports from Qatar are transported through the Suez Canal.

The defined product systems correspond to and serve the following described product function and are related to the functional unit determined in the following.

3.2. Product function and functional unit

The product function is the supply of energy to the European natural gas grid at the external border of Europe. Thereby, the lower heating value (LHV) of natural gas is taken into account. The time period of this function is set to 30 years as this timeframe is reported in literature (e.g., Skone, 2013) as the minimum life time for LNG plants. Similarly, LNG tankers as well as natural gas pipelines are expected to operate for a period of at least 30 years. The study draws a conceptual zero line for all infrastructure considered, as facilities and capital equipment in product system B have been in operations for many years. Hence, the absolute lifetime is taken into account for comparison of the product systems.

Natural gas and liquefied natural gas (LNG) are deemed to have the equivalent function. The composition of both natural gas product types might differ slightly as by nature the composition of natural gases from different locations around the globe differ slighty. But this variation does not have any relevant effect on the equivalence in product function.

The functional unit is defined as 1 MJ of energy in the European natural gas grid at the external border of Europe. The results are also presented for 1 kWh of natural gas in Annex A.

The technical characteristics of the respective natural gas from the different sources is taken into consideration. The various reference flows related to the defined functional unit are:

- 1 MJ (LHV) natural gas via NSP2 from Russia to Europe
- 1 MJ (LHV) natural gas via LNG imports from USA to Europe
- 1 MJ (LHV) natural gas via LNG imports from Qatar to Europe
- 1 MJ (LHV) natural gas via LNG imports from Australia - NWS to Europe
- 1 MJ (LHV) natural gas via LNG imports from Australia - QL to Europe
- 1 MJ (LHV) natural gas via LNG imports from Algeria to Europe.

The infrastructure which serves the product function is part of the system wherever relevant for the comparison of both product systems. This study considers as infrastructure mainly the material consumption of facilities, in exceptional cases also the process of construction.

The coupling to the functional unit of the environmental burdens related to the infrastructure is achieved by a method comparable to a “linear depreciation” based on the defined time period of 30 years. The linear depreciation assumes that the deterioration and wear out of the infrastructure is constant over a defined time period. This assumption is deemed appropriate for the purpose of the study.

No infrastructure in the system has a lifetime less than 30 years. For infrastructure with a lifetime exceeding this period, the respective proportional share is considered in relation to the amount of total energy processed in the infrastructure over the time period of 30 years.

3.3. System boundaries

The system boundaries for both product systems include the extraction of natural gas from natural resources, starting with exploration, up to the entry point of imported natural gas into the European natural gas grid. The entry points for the different product systems are (see also Figure 3-1):

- Greifswald, Germany for
    - Supply of natural gas via NSP2 from Russia to Europe
- Rotterdam (“Gate terminal”), the Netherlands for
    - Supply of natural gas via LNG imports to Europe
        - Import from USA
        - Import from Qatar
        - Import from Australia
            - Source of LNG: North West Shelf (NWS)
            - Source of LNG: Queensland (QL)
        - Import from Algeria.

The alternative LNG terminal for Rotterdam is Zeebrugge in Belgium regarding provided services and the maximum vessel size required for this study (Q-Flex vessels for example from Qatar). The terminal in Rotterdam began operating in 2011 whereas Zeebrugge began in 1987, so the technical parameters of Rotterdam are preferable compared with Zeebrugge and, therefore, helped select Rotterdam as the base case.

Supporting the definition of the system boundaries, the core market for natural gas in Europe is North West & Central Europe. According to Eurostat 2015, the largest inland consumers of natural gas in Europe are Germany, UK, Italy, France and the Netherlands – with North West & Central Europe (Belgium, Denmark, Germany, France, the Netherlands, Austria, and UK) representing in sum about 70 % of total consumed natural gas in Europe (Eurostat, 2015).

Both entry points of the selected product systems (incl. the sub-systems), Greifswald and Rotterdam, are part of this region.

The countries in the region North West & Central Europe can be seen as a “natural-gas pool” since they are very well interconnected with respect to the natural gas grid, including the United Kingdom. The transmission and distribution of natural gas to gas pools or gas hubs in, for example, South or Eastern Europe and final consumers anywhere in Europe is excluded, because:

- Firstly, there is no relevant difference expected in the comparison of the two product systems (supply of natural gas via NSP2 from Russia to Europe and supply of natural gas via LNG imports to Europe) even though different entry points to the European natural gas grid are applied, and
- Secondly, the determination of the various destination points linked to the different application cases of natural gas would have to be based on assumptions including weak or soft parameters like methane emissions due to transmission and distribution which would increase the uncertainty and reduce the robustness of the overall results.

Portugal and Spain as closer entry points for LNG imported from all selected producing countries are not considered because the Iberian Peninsula is an isolated market regarding natural gas. There are very limited interconnections between the Iberian Peninsula and France. Therefore, no impact is assumed from LNG imported to Spain and Portugal on the EU core market.

Other Mediterranean states with existing LNG import terminals – namely Greece, Italy and France – like the Iberian Peninsula have limited interconnections to the considered core market of natural gas consumption in Europe. The LNG terminals of these states are in addition outdated as the maximum vessel size that can be operated is below the size of vessels used for LNG imports, especially from Qatar and Australia (King&Spalding, 2015).

In principle, the basic requirements for the selection of the LNG entry point to Europe is the technical feasibility to operate the respective LNG vessels importing LNG from the defined producing countries and the connection to the natural gas transmission grid of North West & Central Europe. The energy required for natural gas transmission and distribution to consumers in North West & Central Europe whether entering the grid in Greifswald or Rotterdam is comparable as similar technical equipment is installed.

Figure 3-1 gives an overview of the geographical situation of the entry points of imported natural gas into Europe with the comparison of the locations of both selected entry points.

LNG import terminals in Europe
with entry point in Rotterdam (compared to Greifswald)

NSP2 with entry point in Greifswald
(compared to Rotterdam)

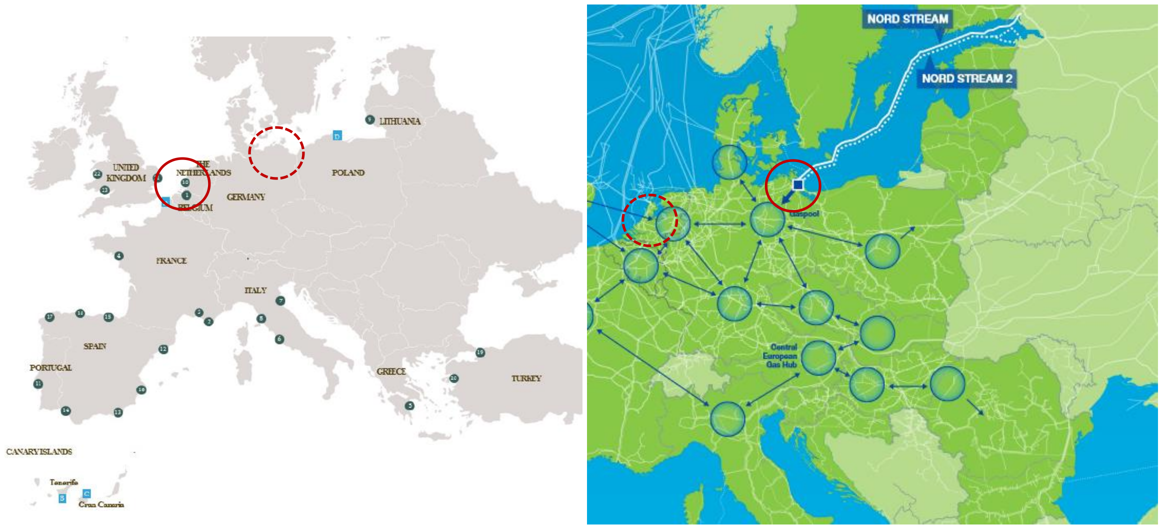


Figure 3-1: System boundary – entry points of imports to Europe, LNG vs. NSP2 (King&Spalding, 2015) (Nord Stream 2, 2016)

However, to check the influence of the transport distances, a scenario analysis is conducted (please see Annex B). The analysis checks the effect on the overall GHG results assuming an entry point in Europe (with LNG import terminals available already or in the near future) as close as possible to Algeria, Australia, Qatar and the USA.

The following graph shows the maritime and land routes of the imported natural gas including the transport distances. Sabine Pass (USA) is defined as base case for the American LNG export terminal, with Cove Point serving as an additional scenario (see section 5.4, referring to USA "improved" scenario 1).

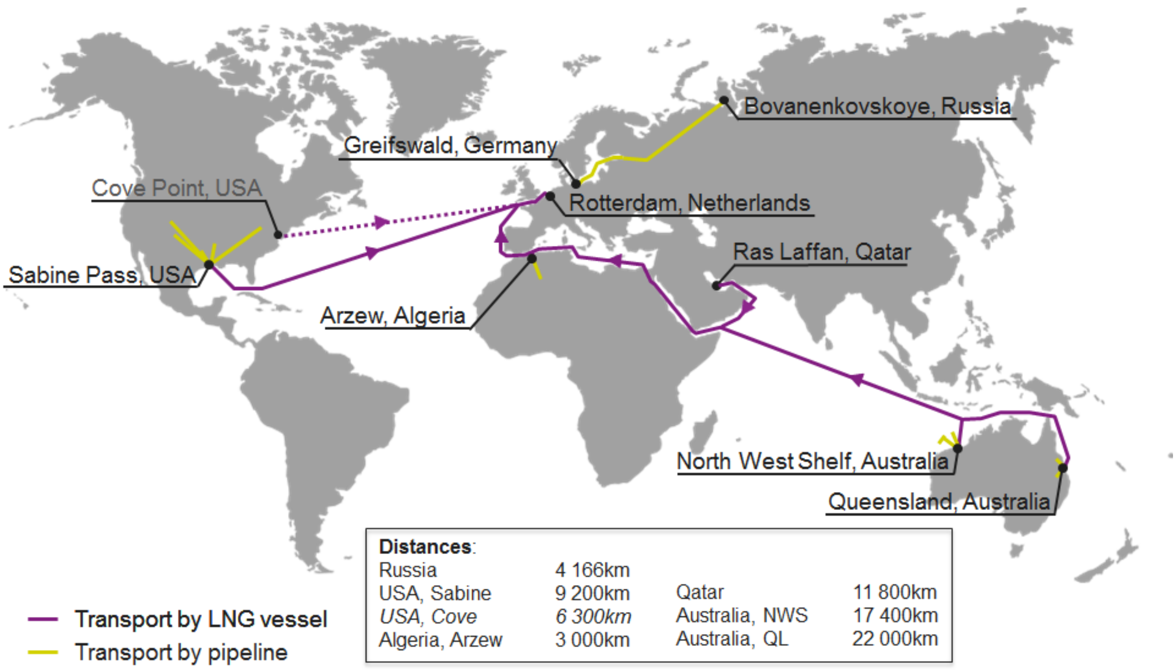


Figure 3-2: System boundaries – considered natural gas import pathways to Europe (thinkstep, 2017a)

The visualisation of the system boundaries for the study regarding the included and excluded process steps in the natural gas supply chain is shown in Figure 3-3. This graph is complemented by Table 3-4 which gives an overview of included and excluded elements and activities.

The End-of-Life (EoL) phase in the context of the study, taking into account the product systems and function as well as the functional unit, is the scrapping of the infrastructure – pipeline, LNG vessels, compressors, various plants in the LNG supply chain, platforms, etc. The infrastructure consists largely of metals (mainly – regarding the applied quantities – steel of different grades). Metals are generally recyclable and/or re-usable as long as the metals are recovered. The recycling and re-use of metals typically leads to environmental benefits in LCA studies as the usability of waste in one product system is considered as valuable secondary material in another product system, due to substitution of primary material. The influencing parameters are recovery rates, metal types, recyclability and market for secondary metals which results in the total amount of available metals for secondary use.

For the base case of the study, the EoL is not considered because it is difficult to predict actual recovery and recycling of the relevant infrastructure. However, exploring the sensitivity of this life cycle phase on the overall carbon footprint results, a scenario is calculated which takes into account the scrapping of all relevant infrastructure (e.g., neglecting the platforms since they are equally used in both product systems, so not relevant for the comparison) and the related environmental benefits (please see Annex B).

Maintenance efforts for infrastructure are excluded from the system boundaries of the study as these efforts are deemed to be irrelevant concerning the GHG impact compared with the provision and use of infrastructure.

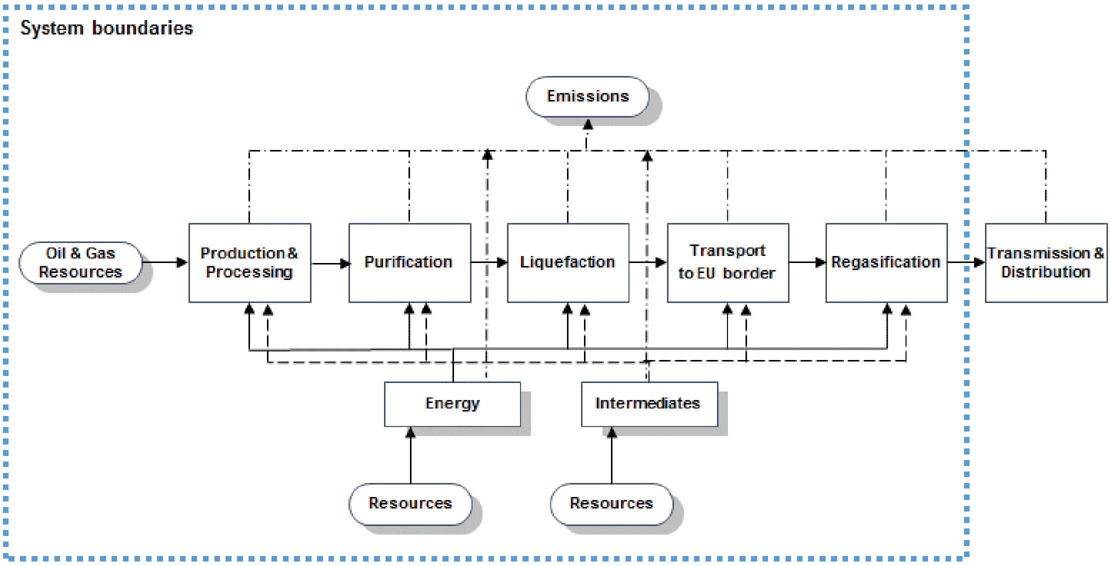
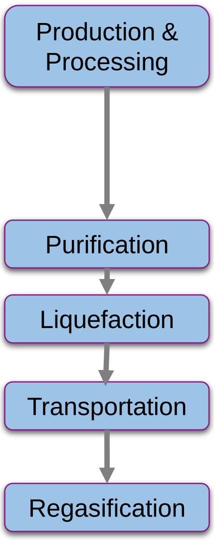


Figure 3-3: System boundary – supply chain of natural gas (LNG route), included and excluded process steps (thinkstep, 2017b)

Table 3-4: System boundary – included and excluded elements or activities

Included	Excluded
✓ Production and processing (CO_2 removal, water removal, H_2S removal) including well drilling	× Seismic exploration and exploratory drilling
✓ Transport pipeline	× Overhead of production plants, e.g., personnel lodging and transport, employee commuting, administration
✓ Purification	× Maintenance efforts for infrastructure relevant for comparison (e.g. pipeline, LNG tankers, liquefaction plants)
✓ Liquefaction	× Potential environmental benefits and burdens of infrastructure End-of-Life (EoL)
✓ LNG transport	
✓ Regasification	
✓ Energy supply: gas turbine, gas engine, diesel generators, grid electricity	
✓ Methane emissions (vented, pneumatic device, and fugitive emissions as well as other unburnt emissions)	
✓ Infrastructure relevant for comparison (e.g. pipeline, LNG tankers, liquefaction plants)	
✓ Consideration of co-products (crude oil, NGLs)	
✓ Production of materials and intermediates used at each facility	

Figure 3-5 describes the different process steps of the natural gas supply chain under consideration, while Figure 3-6 summarises the system boundary definition for each product system.



Description

• Well drilling, well completion, well workovers, well testing, well abandonments
• Production of natural gas from underground formation
• Different production technologies for:
  • conventional gas (associated gas, non-associated gas)
  • unconventional gas (shale gas, tight gas, coalbed methane)
  • onshore and offshore gas fields
• Processing to pipeline quality natural gas (e.g. NGL recovery, removal of acid gas, sulphur recovery, water, mercury, nitrogen)

Purification to Liquefaction quality natural gas (e.g. LPG removal)
Liquefaction of natural gas to LNG (considering plant technology, efficiencies, ambient temperature)

Transport from producing country to Europe (defined EU entry point)
  • NG: compression and transport of natural gas by pipeline
  • LNG: transport by LNG vessel (incl. loading, laden journey, unloading, ballast journey)

Regasification of LNG to NG

Figure 3-5: Description of process steps within the supply chain of natural gas (LNG route) (thinkstep, 2017b)

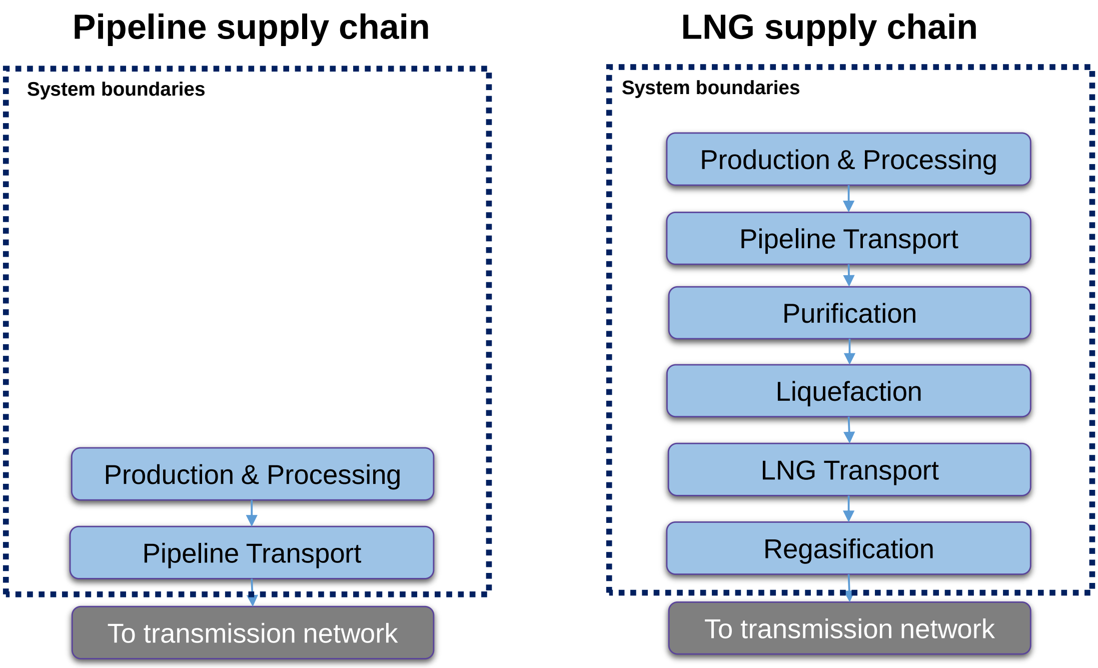


Figure 3-6: System boundary – comparison of both product systems (thinkstep, 2017b)

3.3.1. Time coverage

As described in section 3.2, the time period of the defined product function is set to 30 years in accordance with the premise of the study. For infrastructure with a lifetime longer than 30 years, the respective proportional impact will be taken into account in the total GHG intensity result.

The technical lifetime of the Nord Stream 2 pipeline from Russia amounts to 50 years. The life time of LNG vessels and LNG plants (purification / liquefaction / regasification) assumed to be around 30 to 35 years.

The reference period for the Russian pipeline data is 2015. That year is the reference year of the primary data collection. The reference period for the data related to LNG imports is 2012 to 2015.

3.3.2. Technology coverage

The technology covered in the study is described in detail in section 4.4 for the product system A (pipeline gas from Russia to Europe) and in section 4.5 for the product system B (LNG imports to Europe). For the overview on all technologies considered, please see the table below.

Table 3-7: Overview on technologies covered in the study

Technology	Specification	Description
Natural gas production and processing	Onshore	conventional production and processing (gas wells, oil wells)
	Onshore	unconventional production and processing (coalbed methane, shale gas)
	Offshore	conventional production and processing (gas wells, oil wells)
Natural gas pipeline	Onshore	incl. infrastructure (construction and materials)
	Offshore	incl. infrastructure (construction and materials)
Compressor station for natural gas pipeline (GCU)	Natural gas engine	incl. infrastructure (materials)
	Natural gas turbine	incl. infrastructure (materials)
LNG plant - purification	Acid gas removal	(infrastructure included in liquefaction)
	Gas dehydration	(infrastructure included in liquefaction)
	Mercury removal	(infrastructure included in liquefaction)
	NGL recovery	(infrastructure included in liquefaction)
LNG plant - liquefaction	AP-C3MR	incl. infrastructure (materials)
	AP-C3MR/Split MR	incl. infrastructure (materials)
	AP-X	incl. infrastructure (materials)
	CP – Optimised Cascade	incl. infrastructure (materials)
LNG plant - regasification	Open rack vaporisers	incl. infrastructure (materials)
	Ambient air vaporisers	incl. infrastructure (materials)
LNG transport with vessels	Steam turbine	incl. infrastructure (materials)
	DFDE	incl. infrastructure (materials)
	TFDE	incl. infrastructure (materials)
	SSD	incl. infrastructure (materials)

3.3.3. Geographical coverage

The geographical coverage comprises firstly the natural gas consuming area North West & Central Europe as the core market of natural gas demand in Europe. Secondly, it contains the selected natural gas producing countries or regions – Northern Russia, USA, Qatar, Australia (North West Shelf and Queensland) and Algeria, including the shortest possible maritime roundtrips of the LNG transports from the respective export LNG terminals in the producing countries (excluding Russia, connection via pipeline only) to the entry point of imported natural gas in Rotterdam.

3.4. Allocation

Multi-output allocation generally follows the requirements of ISO 14044, section 4.3.4.2. The main occurring products and co-products in the given product system listed in the following:

- Products and by-products of “crude oil and natural gas production”:
  - crude oil
  - natural gas
  - natural gas liquids (NGL → ethane, propane, butane, pentanes)
- Products and by-products of “natural gas purification” (LNG technology route):
  - natural gas
  - liquefied petroleum gas (LPG → propane, butane)

The allocation is done respectively on the basis of the energy content as it is common practice in modelling oil and gas supply chains. The same allocation procedures are applied for extraction processes in all considered systems.

Allocation of background data (electricity and materials) taken from the GaBi 2016 databases is documented online at → http://www.gabi-software.com/support/gabi/gabi-database-2016-lci-documentation/. (thinkstep, 2016) For example, the products and by-products of “combined heat and power (CHP, co-gens) units” – thermal energy and electricity – are allocated based on exergy.

3.5. Cut-off criteria

No cut-off criteria are defined for this study. The system boundary was defined based on the relevance to the goal of the study. For the processes within the system boundary, all available energy, material and activity data have been included in the model. In cases where no matching life cycle inventories are available to represent a flow, proxy data have been applied based on conservative assumptions regarding environmental impacts. The choice of proxy data is documented. The influence of these proxy data on the results of the assessment is discussed in sections 6.2 and 6.4.

3.6. Selection of global warming potential (GWP) as impact category

The energy sector and the sectors interlinked with the application of namely natural gas, e.g., mobility and construction, are currently driven by policy makers, NGOs and the public towards carbon reduction to mitigate the effects and consequences of climate change as much as possible.

Therefore, this study is not a full LCA, which would include a selection of result indicators within environmental impact categories at the midpoint level with respect to different environmental compartments (like air, water and soil). Instead, the study focuses exclusively on the effect that is called climate change and is caused by a number of substances emitted into the air (atmosphere), e.g., CO_2, CH_4 and N_2O. This is done by way of the global warming potential (GWP) displayed by the amount of emitted CO_2-equivalents which is also labelled as greenhouse gas (GHG) intensity or Product Carbon Footprint (PCF).

The dominating contributors to GWP in the natural gas system are carbon dioxide and methane – to a significantly lesser extent also nitrous oxide. Numerous trace emissions are contributing to the overall GHG result as well but with a factor related to mass of at least 100 000 000 times less than CO_2 and CH_4. Even though the characterisation factors of those trace emissions are 10 000 or 25 000 times higher (means significantly higher effect to the greenhouse effect) then those of CO_2 and CH_4, they have no relevant effect on the GHG result. The origins of the trace emissions are diverse. They are a part of the analysed foreground as well as background system of the study, for example due to the use of LCA datasets representing country-specific electricity grid mixes, or materials like steel and concrete.

The global warming potential impact category is assessed based on the IPCC characterisation factors taken from the 4th Assessment Report (IPCC, 2007) for a 100 year timeframe (GWP100). The most current factors from the 5th Assessment Report (IPCC, 2013) for a 100 year timeframe (GWP100) are used in a scenario calculation to check the sensitivity of the different factors on the overall results (please see Annex B).

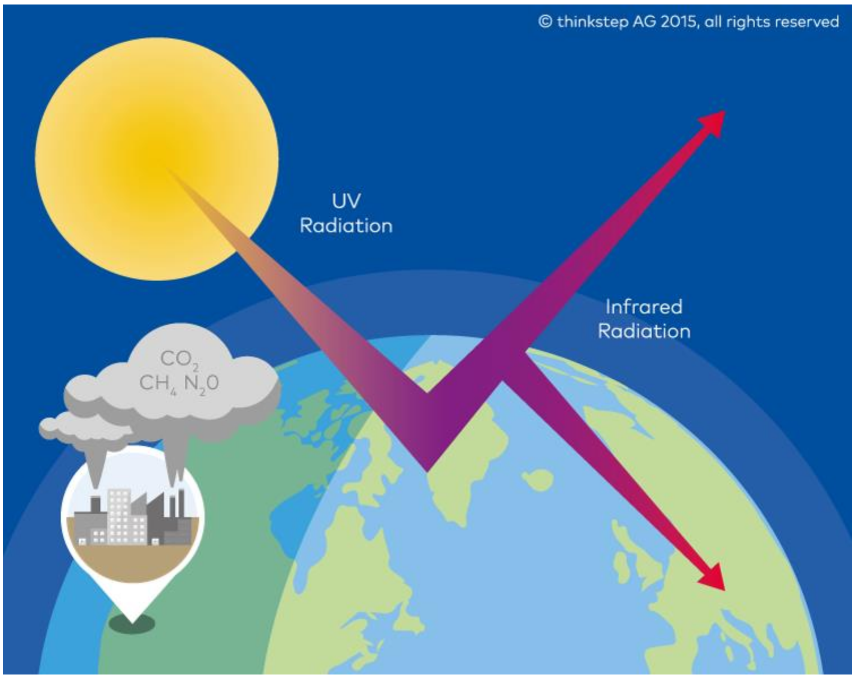


Figure 3-8: Global Warming Potential (thinkstep, 2017a)

It shall be noted that the above impact category represents impact *potentials*, i.e., they are approximations of environmental impacts that could occur if the emissions would (a) actually follow the underlying impact pathway and (b) meet certain conditions in the receiving environment while doing so. In addition, the inventory only captures that fraction of the total environmental load that corresponds to the functional unit (relative approach). GHG results are therefore relative expressions only and do not predict actual impacts, the exceeding of thresholds, safety margins, or risks.

Optional elements of the ISO 14040/44 standard include normalsation, grouping and weighting factors. Normalisation was not applied. Weighting and grouping were not included because just one impact category is selected for result generation.

3.7. Interpretation to be used

The results of the LCA are interpreted according to the goal and scope. The interpretation addresses the following topics:

- Identification of significant findings, such as the main process step(s), material(s), and/or emission(s) contributing to the overall results.
- Evaluation of completeness, sensitivity, and consistency to justify the exclusion of data or life cycle phases from the system boundaries as well as the use of proxy data.
- Conclusions, limitations and recommendations.

3.8. Data quality requirements

The data used to create the inventory model shall be as precise, complete, consistent, and representative as possible with regards to the goal and scope of the study under given time and budget.

- Measured primary data are considered to be of the highest precision, followed by calculated data, literature data, and estimated data.
- Completeness is judged based on the completeness of the inputs and outputs per unit process and the completeness of the unit processes themselves. The goal is to capture all relevant data in this regard.
- Consistency refers to modelling choices and data sources. The goal is to ensure that differences in results reflect actual differences between product systems and are not due to inconsistencies in modelling choices, data sources, emission factors, or other artefacts.
- Reproducibility expresses the degree to which third parties would be able to reproduce the results of the study based on the information contained in this report. The goal is to provide enough transparency with this report so that third parties are able to approximate the reported results.
- Representativeness expresses the degree to which the data matches the geographical, temporal, and technological requirements defined in the study's goal and scope. The goal is to use the most representative specific resp. industry-average data. Whenever such data were not available (e.g. no industry-average data available for a certain country), best-available proxy data were employed because they are seen as representative and/or the impact on the overall GHG results are anyway negligible.

For this study, three distinct data sources are used: industry data (partly confidential), *thinkstep* engineering know-how and publically available data (e.g. from literature studies). An evaluation of the data quality with regard to the above described requirements in context of the applied data sources is provided in section 6.4 of this report.

3.9. Type and format of the report

In accordance with the ISO requirements (ISO14040/44, 2006) this document aims to report the results and conclusions of the GHG intensity completely, accurately and without bias to the intended audience. The results, data, methods, assumptions and limitations are presented in a transparent manner and in sufficient detail to convey the complexities, limitations, and trade-offs inherent in the LCA to the reader. This allows the results to be interpreted and used in a manner consistent with the goals of the study.

The final report of the study "GHG Intensity of Natural Gas Transport" will be made publically available after the completion of the critical review process.

3.10. Software and database

The GHG intensity model is created using *thinkstep's* GaBi software system for life cycle engineering – GaBi ts. The associated LCI databases (GaBi databases 2016) provides the life cycle inventory data for the raw and process materials obtained from the system.

3.11. Critical review

The results of the study are intended to support comparative assertions intended to be disclosed to the public. Therefore, according to ISO 14040/14044, a critical review process done by a critical review panel is required for the study.

The critical review report can be found in Annex C. Members of the critical review panel are:

Table 3-9: Members of the critical review panel

Reviewer	Organisation, Location	Role
Dr. Ivo Mersiowsky	DEKRA Assurance Services GmbH, Stuttgart	Chair of Review Panel
Matthias Fischer	Fraunhofer Institute for Building Physics, Stuttgart – Fraunhofer-Gesellschaft e.V.	Co-Reviewer
Michael Ritthoff	Wuppertal Institute for Climate, Environment and Energy gGmbH, Wuppertal	Co-Reviewer

4. Life cycle inventory analysis

4.1. Number format

For the number format in this report, a decimal point is applied. Example: 1 234.56

4.2. Product characteristics

Natural gas is a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane and pentane. The composition of natural gas can vary, so below is a table outlining the typical composition of natural gas before it is refined.

Table 4-1: Natural gas composition, typical ranges for high-calorific gases [vol. %], before processing (NGSA, 2016)

CH_4	C_2H_6 / C_3H_8 / C_4H_{10}	O_2	CO_2	N_2	H_2S/others
70-90	0-20	0-0.2	0-8	0-5	0-5

Natural gas is considered *dry* when it is almost pure methane (after processing), having had most of the other commonly associated hydrocarbons (natural gas liquids [NGL]) removed. When other hydrocarbons are present, the natural gas is termed *wet*.

The following table indicates the CO_2 content of the different natural gas resources applied in the GHG models. The higher the CO_2 content, the higher the related CO_2 emissions in production and processing. However, compared with the CO_2 emissions related to energy provision in production and processing, the CO_2 emissions related to the CO_2 content in wet natural gas are of low relevance.

Table 4-2: CO_2 content of considered natural gas resources [wt. %], before processing (thinkstep, 2016)

AU-NWS	AU-QL	DZ	QA	US (conv.)	US (shale)	RU
5	3	5	5	5	7	2.1

4.3. Data collection procedure

The data applied in the study for product system A related to the production and processing as well as the pipeline operations are publically available data from the Ministry of Energy in Russia. The data was compiled by the institute of DBI Gas- und Umwelttechnik GmbH together with Gazprom and was also used in the DBI study “Critical Evaluation of Default Values for the GHG Emissions of the Natural Gas Supply Chain” (DBI, 2016b). The data were provided by Gazprom.

Additional data for the infrastructure of the pipeline and the compressor stations were collected from Gazprom and Nord Stream 2 AG. Data were collected using customised data collection templates, which were sent out by email to the respective data providers.

All data applied was cross-checked for completeness and plausibility using mass balance, stoichiometry, as well as internal and external benchmarking. If gaps, outliers, or other inconsistencies occurred, *thinkstep* engaged with the data provider to resolve any open issues.

Data collected for product system A comprises:

- Production and processing of natural gas in Russia – related to a new natural gas field (comparable to the Bovanenkovo gas field of the Yamal project)
- Pipeline transport operations from Russia to Europe – related to onshore and offshore Nord Stream 2 pipeline
- Pipeline construction and infrastructure – related to onshore and offshore Nord Stream 2 pipeline
- Compressor stations infrastructure – related to onshore Nord Stream 2 pipeline.

For the LNG import supply chains in product system B consolidated and consistent information are used. These information are taken from literature (API, 2015), (Alabdulkarem_et_al, 2011), (Brimm_et_al, 2013), (ESI-Services, 2012), (GIIGNL, 2004-2016), (IGU, International Gas Union - 2016 World LNG Report, 2016), (IMO, 2014), (Lowell_et_al, 2013), (PACE, 2015), (Petal_et_al, 2013), (NETL, 2010), (NETL, 2013), (NETL, 2013), (Spilsbury_et_al, 2006), (Thompson_et_al, 2004), (White, 2012)), the GaBi databases 2016 as well as from confidential industry data and *thinkstep* engineering know-how.

The following sections 4.4 and 4.5 describe the technical settings for the base cases of both product systems under consideration – the natural gas import to Europe from Russia via NSP2 and from LNG import alternatives.

4.4. Product system A – supply of natural gas via NSP2 to EU

4.4.1. Overview on product system A

Within the defined product system A, natural gas is produced in Northern Russia and transported via on- and offshore pipeline to the EU market. The following sub section with tables and figures provides an overview of the technical aspects of this product system.

The considered source is a new natural gas field in Northern Russia comparable to the Bovanenkovo gas field of the Yamal project.

Table 4-3: Overview on Product System A

Production and Processing		
RU	(new) natural gas field in Northern Russia	onshore conventional technology
Pipeline Transport		
RU	onshore pipeline	2 940 km
RU	onshore compressor stations	18 stations
RU	offshore pipeline	1 226 km
RU	offshore compressor stations	1 station (however, located at shore)

The flow chart of product system A is shown in the following figure. The feeding of natural gas into the transmission network (white arrow) is outside of the scope of the study.

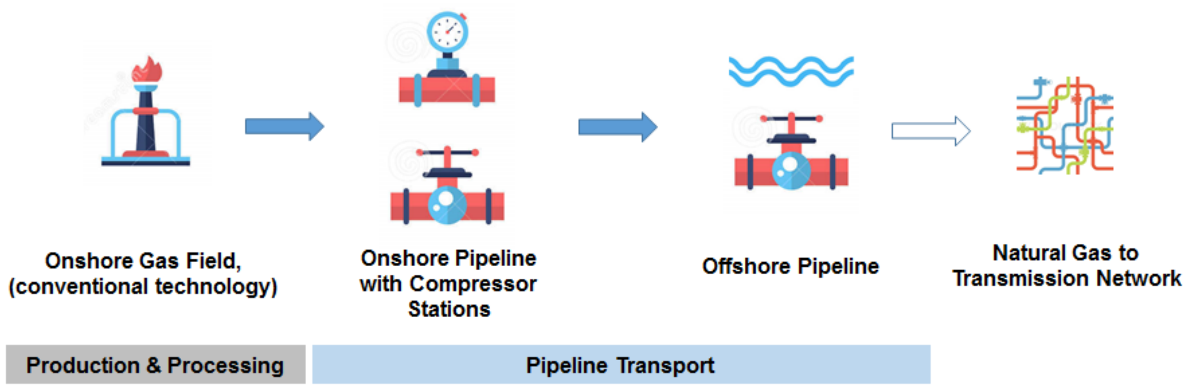


Figure 4-4: Flow chart of product system A (thinkstep, 2017b)

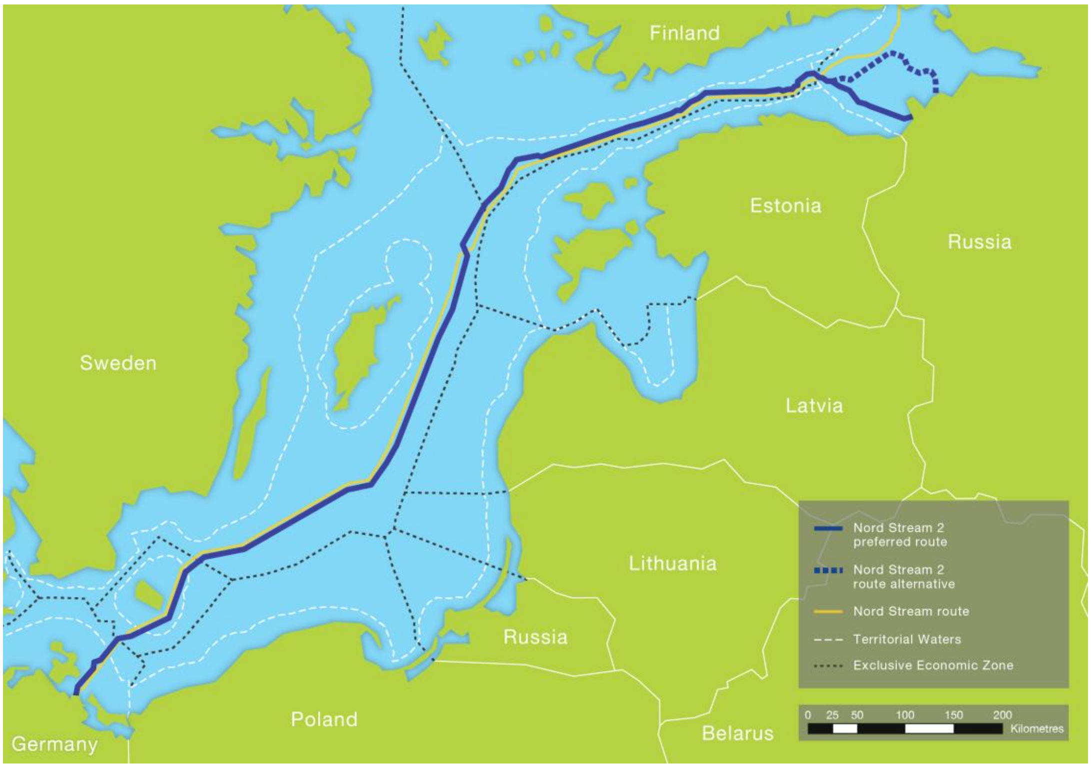


Figure 4-5: Route of offshore pipeline from Russia to Europe (Greifswald, Germany) (Nord Stream 2, 2016)

Figures 4-5 through 4-7 give an impression of the geographical and technical set-up of NSP2.

Figure 4-6: Example for a compressor station (Baidaratskaya compressor station) (Gazprom, 2016)

Figure 4-7: Construction of a onshore pipeline (Gazprom, 2016)

4.4.2. Production and processing

Table 4-8 shows the unit process data for production and processing excluding drilling operations. These data are based on primary data collection procedures as described in section 4.3.

Table 4-8: Unit process data for production and processing in Russian gas field – per MJ natural gas at processing output

Production & Processing	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Electricity from grid mix	3.0E-4	MJ/MJ	measured	RU: Electricity grid mix 1kV-60kV	ts
Electricity from gas turbine	4.8E-3	MJ/MJ	measured	GLO: Natural Gas CHP	ts
OUTPUT					
CO_2 emissions – direct	2.5E-3	g/MJ	measured		
CH_4 emissions – direct	1.7E-3	g/MJ	measured		

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Direct CO_2 and CH_4 emissions are from vented, pneumatic device, and fugitive emissions as well as other unburnt emissions.

The relevance of direct unit process GHG emissions (direct CO_2 and CH_4): the generation of the required electrical energy in the process above causes about 0.81 g of CO_2 emissions per MJ produced and processed natural gas.

Technical data for production and processing in the new Russian gas field are shown below.

Table 4-9: Technical data for production and processing in (new) Russian gas field

Technical parameter	Value
Electrical efficiency of natural gas turbine	35 %
CH_4 content of processed natural gas	89.1 wt. %
CO_2 content of processed natural gas	2.1 wt. %

<u>Well drilling and well installation at the (new) Russian gas field</u>

Comparing the 60 countries modelled in the GaBi databases (thinkstep, 2016), the GHG emissions from production and processing (incl. drilling operations and well installations efforts) are typically between 1.5 to 10 g CO_2eq/MJ, with an average of 4.4 g CO_2eq/MJ. Note: the average value is not weighted by production. The purpose of presenting these numbers is to give an idea of the order of magnitude of the production and processing step.

The drilling operation and well installation efforts are typically in the range of 5 to 10 % of the production and processing GHG emissions, in some cases below 3 % and in some cases up to 15 % and even higher. The drilling operation and well installation efforts depend mainly on the amount of drilled meters in the well (which varies significantly depending on the depth of the respective natural gas resources), the drilling activity in the analysed year and the estimated ultimate natural gas recovery rate of the assets in a country, since the associated GHG emissions are related to 1 MJ produced natural gas over the whole period.

As the compilation of primary data was focussing on the main production and processing operations on the new Russian gas field and the pipeline transport via Nord Stream 2, the efforts related to well drilling activities are estimated based on existing data as described above. As well drilling has in rare cases a contribution of about 15 to 20 % to the GHG intensities of production and processing of natural gas (in most cases substantially lower shares) and the new Russian gas field analysed in the base case of this study is operating on best-practice technology level, an addition of 50 % on the GHG results of production and processing is taken into account for product system A. This is a conservative or “worst-case” approach, as the contributions of drilling operations and well installation efforts typically are significantly lower as outlined above.

<u>Description of conventional technologies – production and processing of natural gas</u>

The following description fits product system A (natural gas from Russia to Europe) as well as all LNG import countries that apply conventional technology in product system B (Australia-NWS, Qatar and Algeria).

Raw natural gas comes from three types of wells: oil wells, gas wells and condensate wells. Natural gas that comes from oil wells is typically termed “associated gas.” This gas can exist separate from oil in the formation (free gas) or dissolved in crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is called “non-associated gas.” Gas wells typically produce raw natural gas by itself, while condensate wells produce natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapour, hydrogen sulphide (H_2S), carbon dioxide, helium, nitrogen and other compounds.

Natural gas processing consists of separating the various hydrocarbons and fluids from the pure natural gas (i.e., methane), to produce what is known as *pipeline quality* dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that, before natural gas can be transported, it must be treated. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'.

In fact, associated hydrocarbons, known as 'natural gas liquids' (NGLs) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants and as sources of energy.

While some of the required processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of kilometres of pipes, interconnecting the processing plant to upwards of 100 wells in the area.

4.4.3. Pipeline transport

Table 4-10 shows the unit process data for pipeline transport. These data are based on primary data collection procedures as described in section 4.3.

Table 4-10: Unit process data for pipeline transport in Russia – per transported MJ natural gas

Production & Processing	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Electricity from gas engine	1.3E-3	MJ/MJ	calculated	GLO: Natural Gas Engine	ts
Electricity from gas turbine	0.022	MJ/MJ	calculated	GLO: Natural Gas CHP	ts
OUTPUT					
CO_2 emissions – direct	7.9E-4	g/MJ	calculated		
CH_4 emissions – direct	0.034	g/MJ	calculated		

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Direct CO_2 and CH_4 emissions are from vented, pneumatic device, and fugitive emissions as well as other unburnt emissions.

Technical data for the natural gas pipeline transport via the new Nord Stream 2 pipeline and its infrastructure (both the pipeline itself and the compressor stations) are shown below.

Table 4-11: Technical data for pipeline transport in Russia via Nord Stream 2

Technical parameter	Value
Gas losses	0.001677 J/J
Energy consumption	1.59E-5 J/(J*km)
Pipeline distance	4 166 km
Natural gas capacity (yearly)	55 billion m^3 / year

Table 4-12: Technical data for onshore pipeline in Russia (NSP2)

Technical parameter	Value
Number of parallel pipelines	2 (twin pipeline)
Length of each line pipe	12.2 m
Average weight of each line pipe	13.2 t (per 12.2 m)
Steel grade	SAWL 485 equiv. to L485MB equiv. to X70
Anti-corrosion thickness	3 mm
3-layer anti-corrosion coating	based on Polyethylene
Constant inside diameter	1 356 mm
Constant outside diameter	1 420 mm
Lifetime	50 years

Table 4-13: Infrastructure: construction material used per km onshore pipeline in Russia

Onshore pipeline	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Excavated material	195 350	t/km	calculated	GLO: Excavator	ts
Polyethylene	13	t/km	calculated	EU-27: Polyethylene foil (PE-HD) (without additives)	ts
Steel pipe	2 191	t/km	calculated	GLO: Steel UO pipe *in combination with* GLO: Value of scrap	worldsteel worldsteel

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-14: Estimated transport distances for materials of onshore pipeline to construction site

Transport mode	Value	Unit	DSI*	GaBi dataset	Dataset provider
valid for all materials					
Train transport	2 000	km	estimated	GLO: Rail transport cargo – average	ts
Truck transport	200	km	estimated	GLO: Truck-trailer ts, payload 27t	ts

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-15: Technical data for gas compressor units (GCU) in Russia

Technical parameter	Value
Electrical Efficiency of natural gas turbine (GCU)	35 %
Electrical Efficiency of natural gas engine (GCU)	38 %
Share of gas turbine	95 %
Share of gas engines	5 %
Installed capacity at GCUs	65 – 352 MW
Share of GCUs – less than 100 MW	55 %
Share of GCUs – between 100 and 225 MW	40 %
Share of GCUs – more than 225 MW	5 %

Technical parameter	Value
Inlet pressure	65 – 75 bar
Outlet pressure	98 bar
Outlet pressure before offshore pipe	220 bar
Lifetime	50 years

Table 4-16: Infrastructure: construction material used for one average compressor station

Construction of GCU	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Section steel	12 100	t	estimated	GLO: Steel sections *in combination with* GLO: Value of scrap	worldsteel worldsteel
Concrete	172 000	t	estimated	EU 27: Concrete C35/45	ts
Rebar steel	8 500	t	estimated	EU 27: Reinforced steel *in combination with* GLO: Value of scrap	ts worldsteel

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-17: Technical data for offshore pipeline in Baltic Sea

Technical parameter	Value
Number of parallel pipelines	2 (twin pipeline)
Length of each line pipe	12.2 m
Average weight of each line pipe	24 t (per 12.2 m)
Steel thickness	26.8 – 41 mm
Steel grade	SAWL 485 equiv. to L485MB equiv. to X70
Anti-corrosion thickness	4.2 mm
3-layer anti-corrosion coating	based on Polyethylene
Concrete thickness	60 – 110 mm
Concrete density	3 040 kg/m^3 (incl. 70 % of iron ore supplement)
Constant inside diameter	1 153 mm
Lifetime	50 years

Table 4-18: Infrastructure: construction material used per km offshore pipeline in Baltic Sea

Offshore pipeline	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Cement	307	t/km	calculated	DE: Cement (CEM I 52.5) Portland cement	ts
Gravel	205	t/km	calculated	DE: Gravel (Granulation 2/32)	ts
Polyethylene	15	t/km	calculated	EU-27: Polyethylene foil (PE-HD) (without additives)	ts
Iron ore	1 433	t/km	calculated	DE: Iron ore mix	ts

Offshore pipeline	Value	Unit	DSI*	GaBi dataset	Dataset provider
Steel pipe	1 871	t/km	calculated	GLO: Steel UO pipe *in combination with* GLO: Value of scrap	worldsteel worldsteel

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-19: Estimated transport distances for materials of offshore pipeline to construction site

Transport mode	Value	Unit	DSI*	GaBi dataset	Dataset provider
valid for all materials					
Train transport	800	km	estimated	GLO: Rail transport cargo – average	ts
Ship transport	1 200	km	estimated	GLO: Bulk commodity carrier	ts

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Further aspects of pipeline transport in product system A

- Efforts of pipeline construction are included as far as information and data are available
- Included are:
    - Transportation of materials from various manufacturers (e.g., steel pipes) to construction site of pipeline and
    - Earth movement during construction of onshore pipeline
- The pipeline exit pressure in Greifswald is approx. 100 bar. The pressure level at LNG terminals is usually 60-80 bar.
- End-of-Life of pipeline is considered with a simplified approach as a scenario of the overall results (see Annex B). Simplifications are:
    - Recovery rates of 100 % (material losses for disassembly, sorting etc. not considered)
    - Metal scrap: fully recovered and recycled
    - Other material: landfilled
- Time scope of the study is set to 30 years. However, the designed lifetime of the pipeline is 50 years.

4.5. Product system B – supply of natural gas via LNG imports to EU

4.5.1. Overview on product system B

Within the defined product system B, natural gas is produced in Algeria, Australia (NWS and QL), Qatar and the USA and transported via pipeline and LNG vessels to the EU market. The following sub section with tables and figures provides an overview of the technical aspects of this product system.

Table 4-20: Overview on Product System B

Well drilling, Production and Processing		
AU - NWS	natural gas production in North West Shelf	offshore conventional technology
AU - QL	natural gas production in Queensland	onshore unconventional technology
DZ	natural gas production in Hassi R´Mel	onshore conventional technology
QA	natural gas production in the North field	offshore conventional technology
US	natural gas production in USA	offshore conv. technology, onshore conv. and unconv. technology
Pipeline Transport		
AU - NWS	offshore pipeline incl. compressors	to the LNG terminal in Karratha
AU - QL	onshore pipeline incl. compressors	to the LNG terminal in Curtis Island
DZ	onshore pipeline incl. compressors	to the LNG terminal in Arzew
QA	offshore pipeline incl. compressors	to a LNG terminal in Ras Laffan
US	onshore pipeline incl. compressors	to the LNG terminal in Sabine Pass
Purification		
AU, DZ, QA, US	process step 1: acid gas removal	CO_2 and H_2S removal with amine treater and sulphur recovery unit
AU, DZ, QA, US	process step 2: gas dehydration	done with molecular sieve unit
AU, DZ, QA, US	process step 3: mercury removal	done with molecular sieve unit
AU, DZ, QA, US	process step 4: NGL recovery	done with turbo expander and direct refrigeration
Liquefaction		
QA, AU, DZ	type of technology A: AP-C3MR	technology developed in 1970, most commonly used globally, size of plants: 2 to 8.2 MTPA, most plants between 2.5 and 3.5 MTPA
QA, DZ	type of technology B: AP-C3MR/Split MR	further development of C3MR, size of plants: 3.6 to 5 MTPA
QA	type of technology C: AP- X	further development of C3MR, size of plants: 7.8 MTPA (used only in Qatar so far)

Liquefaction		
AU, US	type of technology D: CP - Optimised Cascade	technology developed in 1969, most commonly used in USA and AUS, size of plants: 1.5 to 5.3 MTPA, most plants between 3.3 and 4.3 MTPA
LNG transport with LNG vessels		
AU, DZ, US	propulsion type A: steam turbine	Fuels: BOG and HFO, size of vessels: 65 000 to 175 000 m³
AU, US	propulsion type B: TFDE	Fuels: BOG, HFO and MDO, size of vessels: 145 000 to 175 000 m³
QA	propulsion type C: SSD	Fuels: HFO, size of vessels: 210 000 to 266 000 m³
DZ	propulsion type D: DFDE	Fuels: BOG and MDO, size of vessels: 80 000 to 177 000 m³
Regasification		
AU, DZ, QA, US	type of technology A: open rack vaporisers (ORV)	liquid to gaseous: heat is taken from mostly seawater
AU, DZ, QA, US	type of technology B: submerges combustion vaporisers (SCV)	liquid to gaseous: heat is taken from natural gas or waste heat

The flow chart of product system B is shown in the following figure. The feeding of natural gas into the transmission network (white arrow) is outside the scope of the study.

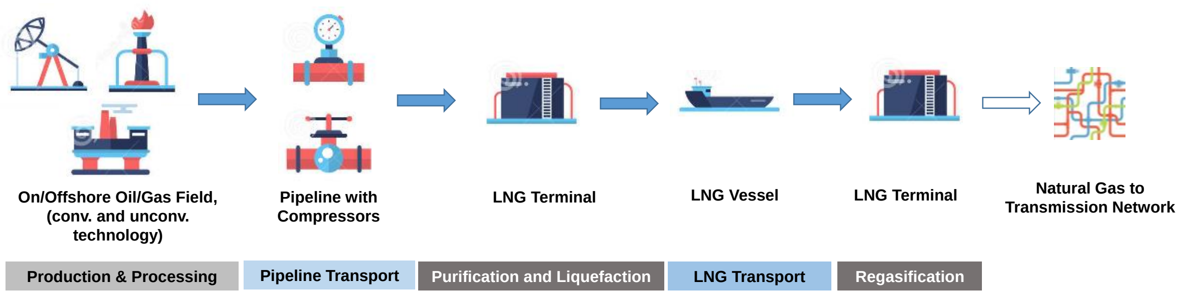


Figure 4-21: Flow chart of product system B (thinkstep, 2017b)

Figure 4-22 shows the share of global LNG exports by country, in recent years up until 2015. The countries considered in this study are highlighted (Russia is not relevant concerning LNG exports in the context of the study but pipeline gas exports).

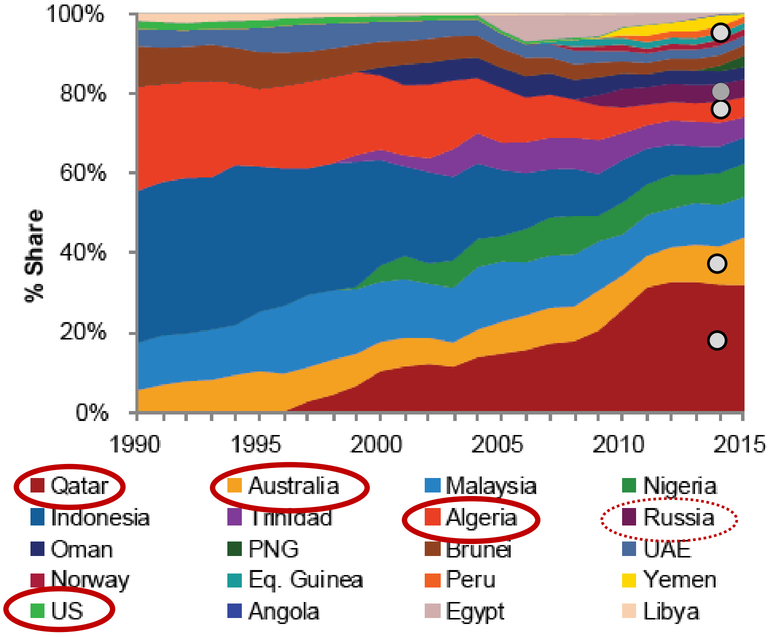


Figure 4-22: Share of global LNG exports by country, 1990 to 2015 (IGU, 2016)

Figure 4-23: Example for a LNG import terminal (Regasification in Rotterdam, Netherlands) (King&Spalding, 2015)

Figures 4-23 through 4-25 provide an impression of the technical set-up of the LNG supply chain.

Figure 4-24: Example for a small-scale LNG plant (Liquefaction in Australia, under 1 MPTA) (IGU, 2016)

Figure 4-24 shows an example of a “small-scale” LNG plant in Australia (small-scale means less than 1 MPTA). However, the LNG plant capacities investigated in this report are bigger – see Table 4-20.

Figure 4-25: Example for a LNG vessel (King&Spalding, 2015)

4.5.2. Production and processing

For the general description of the conventional technologies used for production and processing of natural gas, see section 4.4.2. For product system B, both conventional and unconventional natural gas is produced and hence related technologies are used. The general description of unconventional technologies is provided in the following.

Description of unconventional technologies – production and processing of natural gas

The unconventional oil and gas resources include:

- Extra heavy oil (oil with high viscosity),
- Oil sand (sand containing bitumen),
- Oil shale (sedimentary rock containing kerogen),
- Tight gas (natural gas with low permeability),
- Coalbed methane (CBM, natural gas associated with coal),
- Shale gas (natural gas associated with shale oil), and
- Natural gas hydrates (structures of water ice trapping natural gas).

Development and production of unconventional oil and natural gas resources requires processes and technologies that differ considerably from those used for conventional resources in terms of energy input, cost and environmental impact. Shale gas, tight gas and CBM extraction technologies include hydraulic fracturing and horizontal wells to allow the fluids to flow more easily through a well.

Shale gas and CBM production and processing are described in detail below, as they are investigated as part of the AU-QL and the US LNG import route to Europe.

Shale Gas / Tight gas – Natural gas with low permeability does not flow easily. Low-permeability natural gas is called *tight gas* when it is contained in oil rock and shale gas when it is in shale rock. This resource cannot be developed profitably by vertical wells because of low flow rates. Production of tight and shale gas require hydraulic fracturing or horizontal wells. Hydraulic fracturing consists of pumping a fluid into wells to increase pressure and produce fractures in the formation rock. In order to keep the fracture open after the injection stops, sand with high permeability is added to the fracture. Horizontal well techniques provide greater surface area in contact with the deposit compared with vertical wells and enable more effective gas transfer and recovery of the gas in place.

Coalbed Methane (CBM) – In coal deposits, significant amounts of methane-rich gas are generated and stored within the coal structure. The gas is normally released during mining but more recent practices aim to capture and extract the gas not only for safety and environmental reasons, but also for economic exploitation. However, CBM is typically methane gas trapped within coal deposits that are not profitable for extraction because of high depth or poor coal quality. Coal beds have low permeability that decreases with increasing depth. Therefore, hydraulic fracturing and/ or horizontal wells are needed to ease the flow of fluid through a well. Because of the pressure, water permeates into coal and traps the gas. It is then extracted again, thus, reducing the pressure and enabling methane to flow out of the coal through the well. In the first phase, a large amount of contaminated water is produced, which is usually re-injected in the formations.

Production and Processing in Algeria

Technical data for natural gas production and processing based on 100 % conventional resources from onshore gas field in Hassi R´Mel are shown below. CH_4 emissions are from vented, pneumatic device, and fugitive emissions as well as other unburnt emissions.

Table 4-26: Technical parameter on natural gas production from conventional resources in Algeria (thinkstep, 2016)

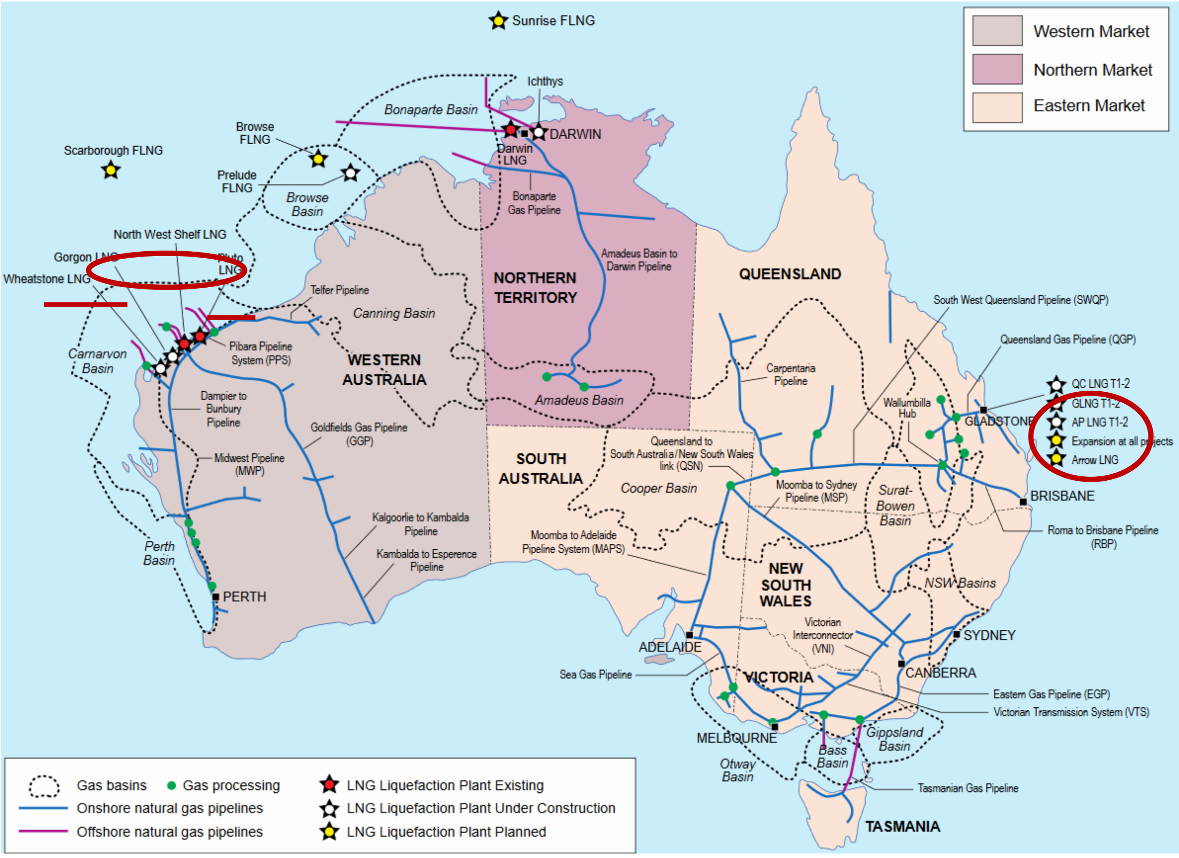
Technical parameter	Value
Flared natural gas	0.024 MJ/MJ
Fugitive/vented/unburnt natural gas	0.0063 MJ/MJ
Share of natural gas produced from wells using primary recovery	50 %
Share of natural gas produced from wells using secondary recovery	50 %

Production and Processing in Australia

- Current situation
    - about 90 % of natural gas is produced from conventional resources
    - about 10 % of natural gas is produced from unconventional resources (coalbed methane)
- Study considers potential future development
- Australia will increase the LNG capacity considerably in the near future (see Figure 4-27)
- Increase will be pushed on the one hand by CBM resources in Queensland (see Figure 4-30)
- Increase will be pushed on the other hand by conventional offshore resources in North West Australia
- Hence, the assumptions made for the Australian base cases in this study represent near-future development:
    - 100 % conventional technology in NWS (offshore)
    - 100 % unconventional technology with CBM in QL (onshore)

The LNG projects in Queensland are (see Figure 4-27):

- APLNG – Australia Pacific LNG, operating in Queensland (mainly in Curtis Island and Gladstone)
- GLNG – Gladstone LNG, operating in Queensland
- QCLNG – Queensland Curtis LNG, operating in Queensland



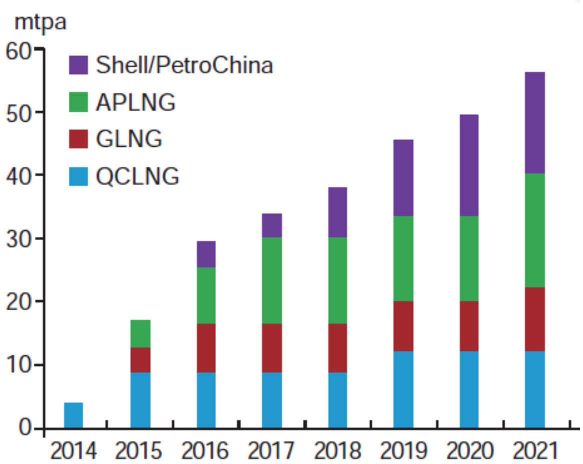


Figure 4-27: Australia – existing and projected LNG projects (2014-2021) (JOGMEC, 2014) (Oxford, 2014)

North West Shelf

Technical data for the natural gas production and processing based on 100 % conventional resources from the offshore gas field are shown below. CH_4 emissions are from vented, pneumatic device, and fugitive emissions as well as other unburnt emissions.

Table 4-28: Technical parameter on natural gas production from conventional resources in AU-NWS (thinkstep, 2016)

Technical parameter	Value
Flared natural gas	0.0033 MJ/MJ
Fugitive/vented/unburnt natural gas	0.0011 MJ/MJ
Share of natural gas produced from wells using primary recovery	50 %
Share of natural gas produced from wells using secondary recovery	50 %

Queensland

Technical data for natural gas production and processing based on 100 % unconventional resources from the onshore gas field – sourced from coalbed methane (sub-bituminous coal) – are shown below (Table 4-30).

The expected CBM production until 2020 is displayed in figure 4-29. In the paragraph following, the situation regarding CH_4 emissions at the wells is discussed.

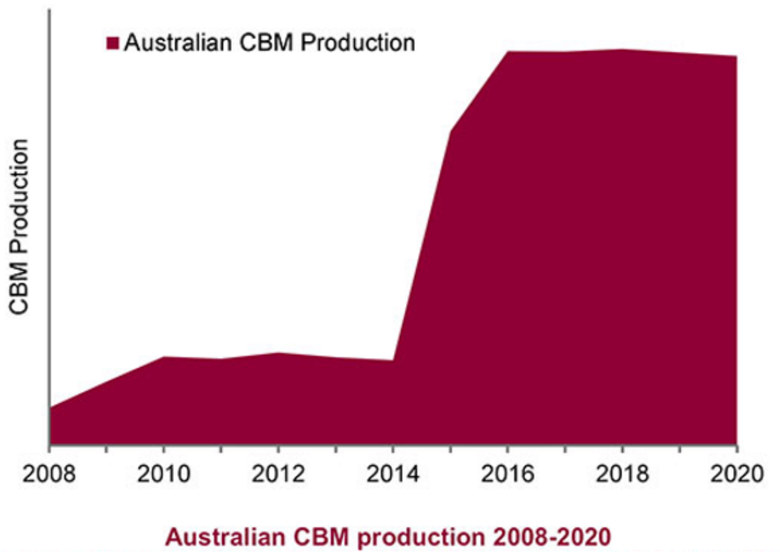


Figure 4-29: Australia – CBM production forecast until 2020 (Douglas-Westwood, 2015)

CH_4 emissions at production of natural gas from unconventional resources in Australia-Queensland:

- Gas wells in tight formations (e.g., coal beds and shale) require hydraulic fracturing to produce gas
- During completion of the well, flow back of fracturing liquids and proppant (often sand) is necessary to clean out the well bore and formation prior to production
- A standard practice is for operators to produce flow back to an open pit or tank to collect sand, cuttings, and fluids for disposal
- This practice leads to venting or flaring of the natural gas resulting in possible high CH_4 emissions
- The use of Reduced Emission Completions (RECs) recovers natural gas and condensate produced during flow back following hydraulic fracture. The REC equipment captures produced natural gas during clean-up with a sand trap and a three-phase separator. A dehydrator removes water from the produced natural gas.

- The benefit is reduced methane and other air emissions during completions and workovers
- Data situation about CH_4 fugitives → high uncertainty in data, wide range of estimated CH_4 emissions in different studies
- approach in this study: conservative assumption regarding comparison of pipeline natural gas and LNG, so comparably low CH_4 emissions applied
- Assumption in the study: 40 % of well pads using RECs

Table 4-30: Technical parameter on natural gas production from CBM resource (sub-bituminous coal) in Australia (thinkstep, 2017b)

Technical parameter	Value
Flared natural gas	0.0053 MJ/MJ
Fugitive/vented/unburnt natural gas	0.0025 MJ/MJ
Share of wells with REC installation	40 %

Production and Processing in Qatar

Technical data for the natural gas production and processing based on 100 % conventional resources from the offshore gas field called “North Field” are shown below.

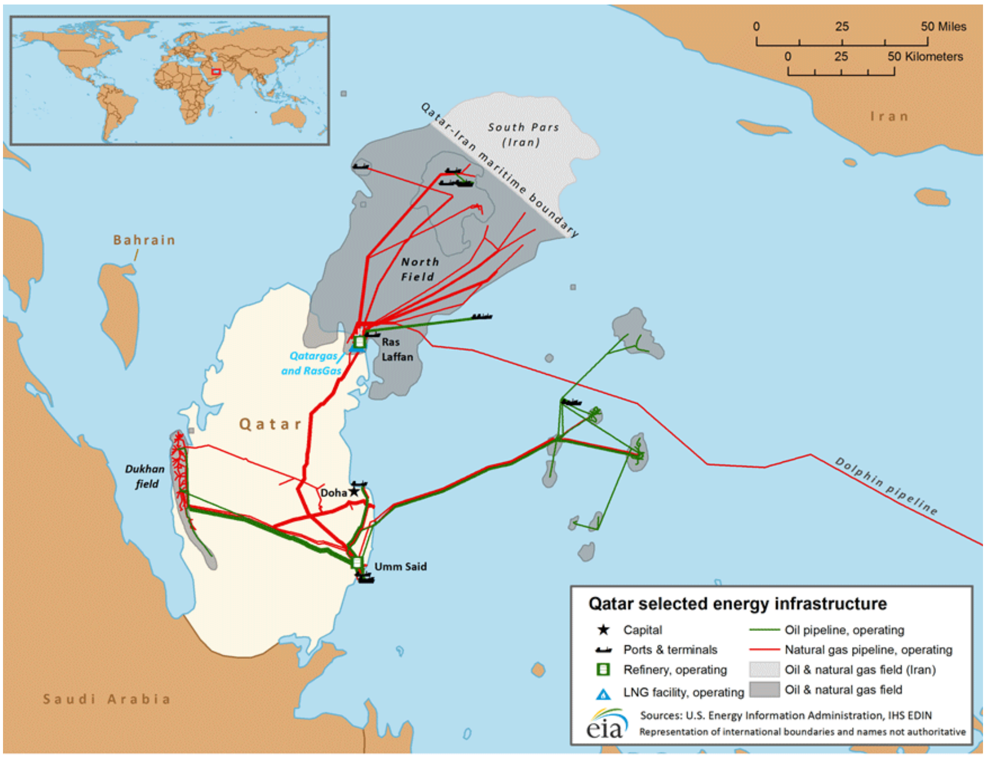


Figure 4-31: Qatar – natural gas field (“North Field”) and LNG plant in Ras Laffan (EIA, 2016)

Table 4-32: Technical parameter on natural gas production from conventional resources in Qatar (thinkstep, 2016)

Technical parameter	Value
Flared natural gas	0.00295 MJ/MJ
Fugitive/vented/unburnt natural gas	0.00062 MJ/MJ

Technical parameter	Value
Share of natural gas produced from wells using primary recovery	50 %
Share of natural gas produced from wells using secondary recovery	50 %

Production and Processing in USA

- Current situation
    - about 35 % of natural gas is produced from conventional resources
    - about 65 % of natural gas is produced from unconventional resources (mainly shale gas, also tight gas)
- Study considers potential future development
- Especially in the USA, it is expected that natural gas production increases significantly in the near future
- Most of the additional natural gas is produced from unconventional resources (mainly shale gas)
- Thus, a mix of 85 % unconventional technology (shale gas, onshore) and 15 % conventional technology (mainly onshore but also offshore) is defined as base case for this study – according the US EIA (see Figure 4-35)

Technical data for the natural gas production and processing based on unconventional and conventional resources in the US are shown below.

Table 4-33: Technical parameter on natural gas production from shale gas resource in USA (thinkstep, 2017b)

Technical parameter	Value
Flared natural gas	0.0234 MJ/MJ
Fugitive/vented/unburnt natural gas	0.0102 MJ/MJ
Share of wells with REC installation	40 %

Table 4-34: Technical parameter on natural gas production from conventional resources in USA (thinkstep, 2016)

Technical parameter	Value
Flared natural gas	0.0066 MJ/MJ
Fugitive/vented/unburnt natural gas	0.0012 MJ/MJ
Share of natural gas produced from wells using primary recovery	43.3 %
Share of natural gas produced from wells using secondary recovery	43.3 %
Share of natural gas produced from wells using steam injection	5.6 %
Share of natural gas produced from wells using natural gas injection	1.6 %
Share of natural gas produced from wells using N_2 injection	0.4 %
Share of natural gas produced from wells using CO_2 injection	5.8 %

The differences in flared and fugitive/vented/unburnt natural gas from conventional and unconventional resources in the US (see Tables 4-33 and 4-34) are based on flow back following hydraulic fracturing within the unconventional production technologies.

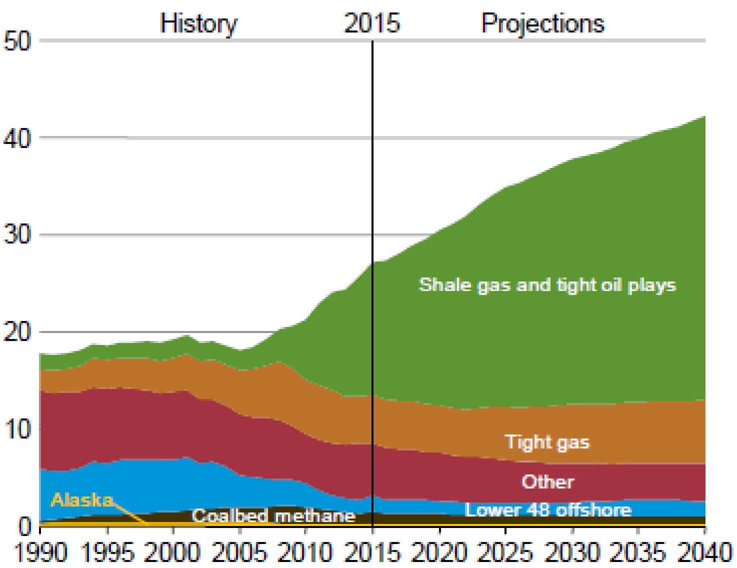


Figure 4-35: USA – dry natural gas production by source – projections until 2040 (EIA, 2016)

CH_4 emissions at production of natural gas from unconventional resources in the US:

- Gas wells in tight formations (e.g., coal beds and shale) require hydraulic fracturing to produce gas
- During completion of the well, flow back of fracturing liquids and proppant (often sand) is necessary to clean out the well bore and formation prior to production
- A standard practice is for operators to produce flow back to an open pit or tank to collect sand, cuttings, and fluids for disposal
- This practice leads to venting or flaring of the natural gas resulting in possible high CH_4 emissions
- The use of Reduced Emission Completions (RECs) recovers natural gas and condensate produced during flow back following hydraulic fracture. The REC equipment captures produced natural gas during clean-up with a sand trap and a three-phase separator. A dehydrator removes water from the produced natural gas.
- The benefit is reduced methane and other air emissions during completions and workovers
- Current situation: 10-15 % of well pads in the USA using RECs. Expectation for the future: due to environmental regulations, the use of RECs will increase significantly
- Data situation about CH_4 fugitives → high uncertainty in data, wide range of estimated CH_4 emissions in different studies
- approach in this study: conservative assumption regarding comparison of pipeline natural gas and LNG, so comparably low fugitive emissions applied
- Assumption in the study: 40 % of well pads using RECs

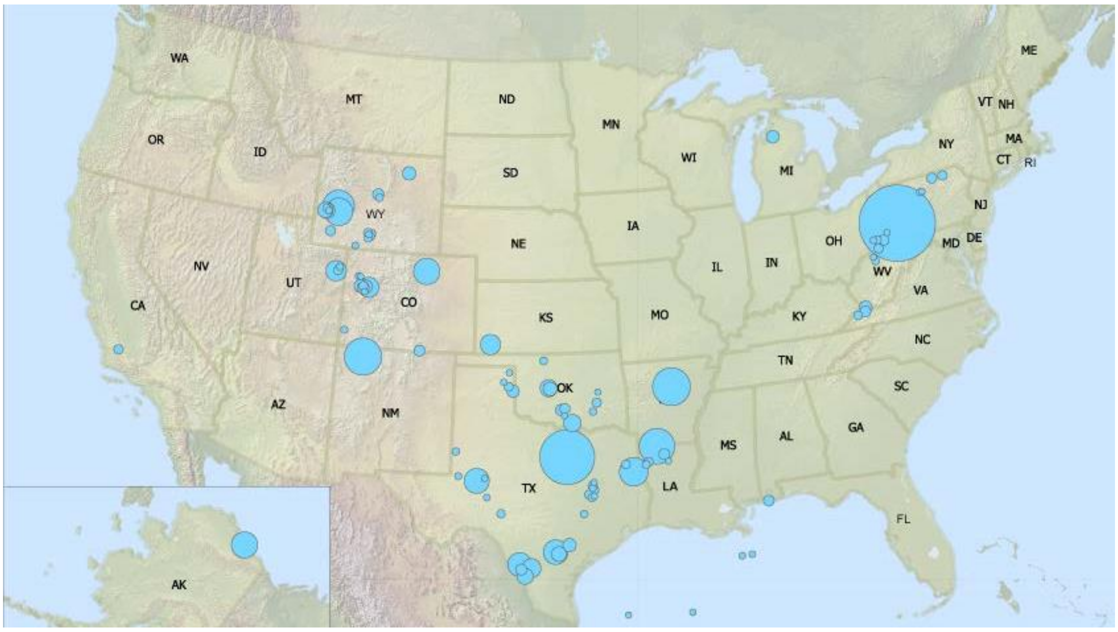


Figure 4-36: USA – major natural gas fields, mainly shale gas (EIA, 2015)

Figure 4-36 shows the top natural gas fields in the USA. Most gas fields are shale gas resources. The gas fields are widely spread over the country.

4.5.3. Pipeline transport

An overview of technical pipeline data for natural gas transport in the respective countries from well to LNG terminal, is given below (Russian NSP2 data is shown for comparison).

Table 4-37: Pipeline data

Country	Distance [km]	Energy demand [J/(J*km)]	Gas losses [J/(J*km)] referred to total distance
Australia-NWS	250	2.01E-05	9.0E-07
Australia-QL	250	2.01E-05	9.0E-07
Algeria	550	2.01E-05	12.0E-07
Qatar	80	2.04E-05	12.0E-07
USA	500	2.03E-05	15.0E-07
for comparison:			
Russia (NSP2)	*4 166*	*1.59E-05*	*4.1E-07*

- Gas losses in the pipeline transported in the USA and Australia might be lower in the future as new pipelines are added for emerging gas fields.
- So, low gas losses comparable to the Russian value of NSP2 are considered in a scenario calculation for all selected LNG producing countries (see section 5.4)
- Relatively short transport distance of 500 km for pipeline transport in the USA:
  - Some shale gas resources are located far from Sabine Pass (US LNG export terminal in Gulf of Mexico) – see Figure 4-36
  - Therefore, a weighted average is applied for different transport distances, taking into account higher weighting factors for wells closer to Sabine Pass and lower weighting factors for wells farther away, to capture the lower probability of natural gas being transported longer distances.

Technical data for the compressor stations used for the natural gas pipeline transport are given below. Data on infrastructure of pipelines and compressor stations are based on the same data applied for the Russian pipeline – see relevant tables in section 4.4.3.

Table 4-38: Technical data for an average compressor station (GCU)

Technical parameter	Value
Efficiency of the compressor	80 %
Electrical efficiency	31 %
Efficiency of the electric motors	96 %
Share of gas turbines	95 %
Share of gas engines	5 %
Average distance between two GCUs	150 km
Outlet pressure	max. 80 bar

4.5.4. Purification (part of liquefaction)

The purification is based on the following average technical parameters. Note that the purification step follows the natural gas processing step, in which the natural gas is already treated to a certain extent, e.g., the CO_2 content is reduced from its natural concentration down to 1.5 %.

Table 4-39: Technical data of the purification step

Technical parameter	Value
CO_2 content in natural gas (feed into gas treatment)	1.5 %
CO_2 content in natural gas (after gas treatment)	50 ppmv
H_2S content in natural gas (feed into gas treatment)	0.0034 wt.%
H_2S content in natural gas (after gas treatment)	4 ppmv
Sulphur recovery rate	99.9 %
Mercury content in natural gas (feed into gas treatment)	5.5 µg/kg
Mercury content in natural gas (after gas treatment)	0.01 µg/Nm³
Water content in natural gas (feed into gas treatment)	8 000 – 10 000 ppmv
Water content in natural gas (after gas treatment)	0.1 ppmv
Share of C3 separated	66 %
Share of C4 separated	80 %
Share of C5 separated	91.7 %
Electrical efficiency of gas CHP	35 %
Total efficiency of gas CHP	90 %
Share of carbon capture and storage (CCS)	0 %
CH_4 emissions	0.0021 MJ/MJ
Lifetime of molecular sieve	4 years

The process steps of purification and liquefaction are combined in the same LNG plant, so information and data on infrastructure of that plant is given in section 4.5.5.

As outlined in section 3.4, allocation is applied for by-products in the purification step. The related allocation factors are displayed in the following table. The majority of environmental burdens are allocated to natural gas.

Table 4-40: Allocation factors for purification step based on energy content (based on mass for comparison)

Energy carrier	Allocation factor (energy)	*Allocation factor (mass)*
Natural gas (after treatment)	96.23 %	*95.95 %*
Propane (C3)	1.76 %	*1.87 %*
Butane (C4)	1.37 %	*1.48 %*
Pentane (C5)	0.64 %	*0.70 %*

4.5.5. Liquefaction

This section describes the different liquefaction technologies used globally and specifically in the countries under consideration of the study.

AP-C3MR

- The abbreviation AP-C3MR stands for: "Air Products and Chemicals" (AP) – "Propane" (=C3), "Mixed Refrigerant" (MR)
- AP-C3MR has two different refrigerant cycles
- The first cycle uses propane (C3) as a refrigerant and pre-cools the natural gas and the second refrigeration cycle.
- The second cycle uses a mixed refrigerant (MR) composed of nitrogen, methane, ethane and propane.

Table 4-41: Technical data of the liquefaction technology AP-C3MR

Technical parameter	Value
Specific compression power	30 MW per MTPA
Size of plants	2 to 8.2 MTPA
Typical size of plant	between 2.5 and 3.5 MTPA
C3 (propane) cycle	
Four-stage centrifugal compressor, efficiency	83 %
Gas turbine, power output	44 MW
Helper motor	8 MW
MR (mixed refrigerant) cycle	
Axial compressor, efficiency	86 %
Gas turbine, power output	91 MW
Helper motor	8 MW

AP-C3MR/Split MR

- AP-C3MR/Split MR technology is similar to AP-C3MR liquefaction technology, as the refrigerant cycles are the same.
- Nevertheless, it is considered an independent technology, because its efficiency is slightly higher.

- This is caused by the difference in distribution of the compressors on the turbines, so that the power demand is split more evenly.

Table 4-42: Technical data of the liquefaction technology AP-C3MR/Split MR

Technical parameter	Value
Specific compression power	30 MW per MTPA
Size of plants	3.6 to 5 MTPA
C3 (propane) cycle	
Four-stage centrifugal compressor, efficiency	83 %
Gas turbine, power output	91 MW
Helper motor	12 MW
MR (mixed refrigerant) cycle	
Axial compressor, efficiency	86 %
Gas turbine, power output	91 MW
Helper motor	12 MW

AP- X

- AP-X technology is also based on the AP-C3MR technology, but it uses three instead of two refrigerant cycles.
- The first refrigerant cycle pre-cools with propane (C3) the incoming natural gas stream and the other two refrigerant cycles.
- The second cycle uses mixed refrigerant (MR) composed of methane and ethane. However, this cycle does not reach the same temperatures as the MR cycle in the AP-C3MR technology.
- The third and final refrigerant uses nitrogen as a refrigerant, sub-cooling the natural gas stream to its final temperature.

Table 4-43: Technical data of the liquefaction technology AP-X

Technical parameter	Value
Specific compression power	30 MW per MTPA
Size of plants	7.8 MTPA (used only in Qatar so far)
C3 (propane) cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output	132 MW
Helper motor	15 MW
MR (mixed refrigerant) cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output	132 MW
Helper motor	15 MW
Nitrogen cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output	132 MW
Helper motor	15 MW

CP – Optimised Cascade

- This technology uses three different refrigerant cycles.
- The first cycle uses propane as a refrigerant to pre-cool the natural gas stream and the other two refrigerants.
- The second cycle uses ethane as a refrigerant and cools the natural gas stream and the final refrigerant further down.
- And the third cycle uses methane as a refrigerant and sub-cools the natural gas stream to round about -162 °C.

Table 4-44: Technical data of the liquefaction technology CP Optimised Cascade

Technical parameter	Value
Specific compression power	36 MW per MTPA
Size of plants	1.5 to 5.3 MTPA
Typical size of plant	between 3.3 and 4.3 MTPA
C3 (propane) cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output (50 % applied)	32 MW
C2 (ethane) cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output	32 MW
C (methane) cycle	
centrifugal compressor, efficiency	83 %
Gas turbine, power output	32 MW

Further technical data on liquefaction

Boil-Off Gas (BOG) use:

- Boil-Off Rate (BOR) is estimated to represent 3 % of the produced LNG.
- This BOG is sent to the gas turbines as fuel.
- An estimated 1 % of the BOG is released into the atmosphere as methane emissions.

Table 4-45: Technical data to Boil-Off Gas at liquefaction process, storage, loading / unloading

Technical parameter	Value
Boil-Off Rate (BOR), **liquefaction process**	3 % per produced LNG
BOG, used as fuel for gas turbines	99 % of BOR
BOG, CH_4 emissions	1 % of BOR
Boil-Off Rate (BOR), **storage**	0.15 % per day
Average storage duration	5 days
BOG, used as fuel	97.5 % of BOR
share of CH_4 emissions	1 % of BOG which is used as fuel
BOG, flared	2.5 % of BOR
Boil-Off Rate (BOR), **loading / unloading**	0.13 % per moved LNG
BOG, used as fuel	95 % of BOR

Technical parameter	Value
share of CH_4 emissions	1 % of BOG which is used as fuel
BOG, flared	5 %

Infrastructure of liquefaction plant (incl. purification)

Table 4-46: Infrastructure: construction material used for a liquefaction plant

Liquefaction plant	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Concrete	182 600	m^3	calculated	EU-27: Concrete C35/45 (Ready-mix concrete)	ts
Structural steel	9 300	t	calculated	GLO: Steel sections *in combination with* GLO: Value of scrap	worldsteel worldsteel
Steel pipe	28 000	t	calculated	GLO: Steel welded pipe *in combination with* GLO: Value of scrap	worldsteel worldsteel
Others	32 000	t	calculated	GLO: Steel sections *in combination with* GLO: Value of scrap	worldsteel worldsteel

* DSI – Data Source Indicator → measured / calculated / estimated / literature

- Lifetime of liquefaction plants: 30 years.

Country-specific liquefaction parameters

The following table shows the technical parameter settings for the four countries considered as LNG import alternatives to Europe in the GHG model concerning liquefaction technology.

Table 4-47: Technical data of Liquefaction in the considered countries applied in the GHG model

Country	LNG terminal	Technology	Share [%]	Efficiency [%]	Ambient Temp. [°C]
Algeria	Arzew	AP-C3MR/Split MR	36.4	37	20
		AP-C3MR	63.6	37	
AU-NWS	Karratha	CP Opti. Cascade	55.6	39	22
		AP-C3MR	44.4	39	
AU-QL	Curtis Island	CP Opti. Cascade	55.6	39	22
		AP-C3MR	44.4	39	
Qatar	Ras Laffan	AP-X	60.8	31.8	27
		AP-C3MR/Split MR	18.3	39	
		AP-C3MR	20.9	33.9	

Country	LNG terminal	Technology	Share [%]	Efficiency [%]	Ambient Temp. [°C]
USA	Sabine Pass	CP Opti. Cascade	100	39	15

- The ambient temperatures shown in the above table represent the yearly average temperature respectively.
- Concerning the technology mix: comparing the four major types of liquefaction technologies with respect to GHG intensity, all technology types range within ±5 % (assuming the same technical efficiencies and the same ambient temperature levels) of each other (small variances).
- Relevant parameters for liquefaction technology
    - If efficiency is doubled (+100 %), GHG intensity decreases by 81 %
    - If the yearly average ambient temperature is +5 °C, GHG intensity increases by 8 %.
- Thus, the mix of the applied technologies per country is not as relevant for the GHG result as the improvement in efficiency and the yearly average ambient temperature, the latter of which is not technically open to influence as it depends on the location of the LNG plant.

<u>Future development - liquefaction plants worldwide</u>

Development specifically in Algeria

- First liquefaction plants built in the 1970s and 1980s.
- These older plants are being modernised or replaced by new plants – this started in 2013, and first new plants have been producing LNG since 2015.
- Further refurbishment is planned in coming years.
- This technical refurbishment is already reflected in the liquefaction parameters of the Algerian GHG model, i.e. high efficiency plants (new plants) are considered.

Development specifically in USA

- Liquefaction capacity will be expanded in Sabine Pass in the next 3 years by 18 MTPA.
- Cove Point LNG on the east coast is considered a possible alternative for LNG exports to Europe (start of a new plant operation with 5.25 MTPA is planned for 2017).

General development, (see Figure 4-48):

- High increase of liquefaction capacities especially in Australia und USA.
- Constant high capacity in Qatar, slightly decreasing capacity in Algeria.

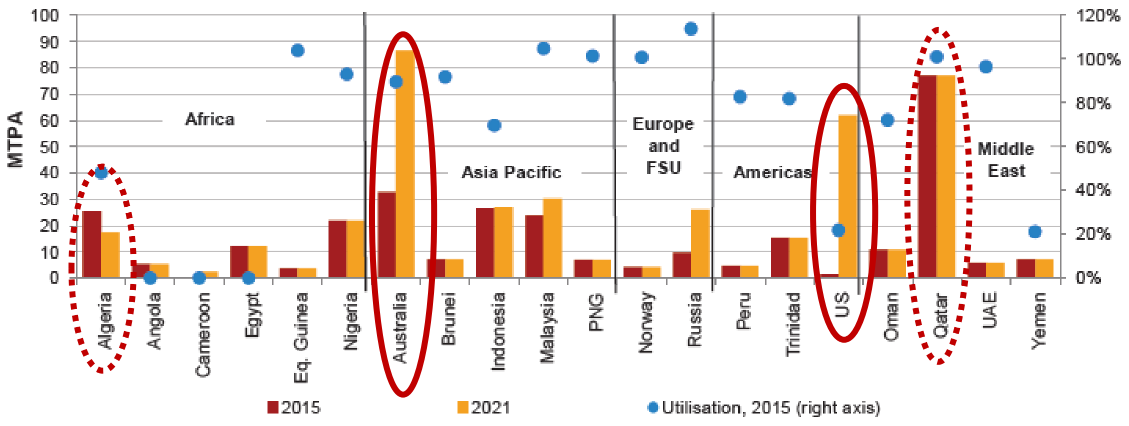


Figure 4-48: Nominal Liquefaction capacity by country in 2015 and 2021 (IGU, 2016)

The current and future representativeness regarding the technology mix used in the present study is illustrated in Figure 4-49.

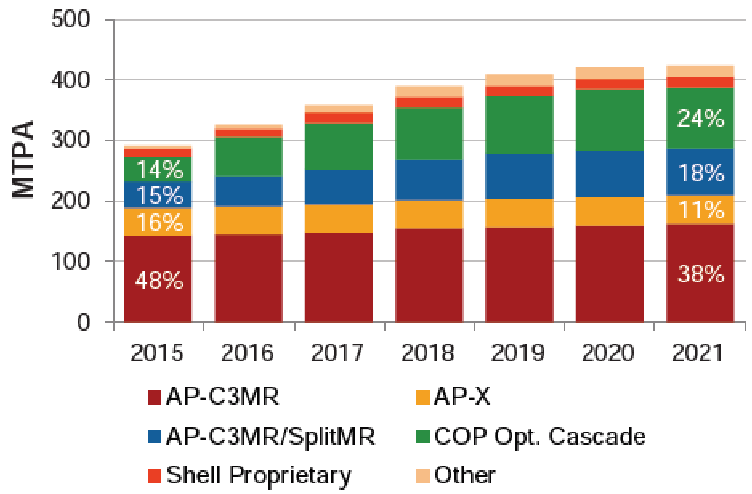


Figure 4-49: Liquefaction capacity by type of process, 2015 – 2021 (IGU, 2016)

- The four liquefaction technologies considered in this study represent more than 95 % of technologies applied globally in 2015.
- Expected future development: increasing capacity overall, major current technologies remain most important technologies.
- Shares of the four main technologies might change to a certain extent in the future → increasing share of CP – optimised cascade.
- Type of natural gas resource (conventional or unconventional) has no expected effect on choice of liquefaction technology.
- Data up to 2021 as shown in Figure 4-49 are based on liquefaction plants under construction of projected plants.

4.5.6. LNG transport

The major propulsion types for LNG vessels considered in this study are

- Steam turbine,
- Tri-fuel diesel electric (TFDE),
- Slow speed diesel (SSD) and
- Dual-fuel Diesel Electric (DFDE).

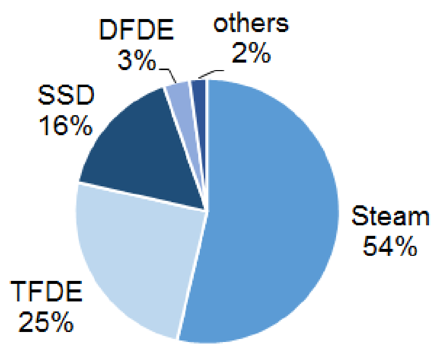


Figure 4-50: Global market share of propulsion types of LNG tanker (related to vessel capacities), own calculations, based on (GIIGNL, 2004-2016)

The most common LNG vessel sizes combined with the respective propulsion type considered in the study are

- Vessels with 50 000 to 80 000 m^3 for short-distance LNG trade (steam, DFDE)
- Vessels with 140 000 to 180 000 m^3 for long-distance LNG trade (steam, TFDE)
- Q-Flex vessels with 210 000 to 216 000 m^3 for trips from Qatar to Europe (SSD)

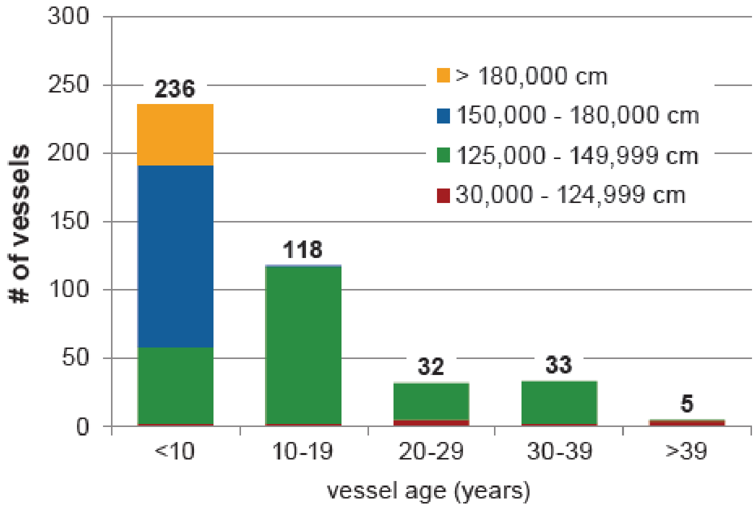


Figure 4-51: Active global LNG fleet by capacity and age, end 2015 (IGU, 2016)

- End of 2015 → global LNG fleet of about 430 vessels.
- Loading capacity: Majority (approx. 85 %) between 125 000 and 180 000 m^3.
- Small-size vessels (<125 000 m^3) are rarely in operation, while the number of operating big-size vessels (>180 000 m^3) is increasing.
- Age: Majority (55 %) less than 10 years old.
- General relation between size of vessels and energy efficiency: the specific energy consumption per transported MJ*km decreases as the vessel size increases.

Propulsion type A: steam turbine

- The steam turbine, which drives the propeller, is driven by heated seawater. Heavy Fuel Oil (HFO) and BOG from the LNG tanks fuel the steam boiler.

Table 4-52: Technical data for LNG vessel, type: steam turbine

Technical parameter	Value
Size of vessels	65 000 to 175 000 m^3
Fuels	BOG and HFO
Speed (< 90k m^3) laden journey	16 knot
Speed (< 90k m^3) ballast journey	16 knot
Speed (> 90k m^3) laden journey	19.5 knot
Speed (> 90k m^3) ballast journey	19.0 knot
Energy supply by BOG, laden journey	90 %
Energy supply by BOG, ballast journey	90 %
Energy supply by HFO, laden journey	10 %

Technical parameter	Value
Energy supply by HFO, ballast journey	10 %
Rate for fugitive emissions from tank to engine	0.1 %
Time for cargo operations (in-port, loading and unloading tanks of vessel)	2 days
Fuel consumption during in-port time (> 90k m³)	33 t HFO per day
Fuel consumption during in-port time (< 90k m³)	24 t HFO per day

Propulsion type B: TFDE

- TFDE is able to run on three fuels, BOG, HFO and MDO.
- Consequently, there are three different combustion engines used on each vessel, one for each fuel type, enabling the fuels to be used most efficiently.
- TFDE uses electric instead of mechanical propulsion, same as the steam engine.

Table 4-53: Technical data for LNG vessel, type: TFDE

Technical parameter	Value
Size of vessels	145 000 to 175 000 m³
Fuels	BOG, HFO, MDO
Speed, laden journey	18.5 knot
Speed, ballast journey	20.5 knot
Energy supply by BOG, laden journey	95 %
Energy supply by BOG, ballast journey	95 %
Energy supply by HFO, laden journey	2.5 %
Energy supply by HFO, ballast journey	2.5 %
Energy supply by MDO, laden journey	2.5 %
Energy supply by MDO, ballast journey	2.5 %
Rate of fugitive emissions from tank to engine	0.1 %
Time for cargo operations (in-port, loading and unloading tanks of vessel)	2 days
Fuel consumption during in-port time	33 t HFO per day

Propulsion type C: SSD

- This type of propulsion is different from the previous types, as it does not use BOG as fuel.
- It uses a slow speed diesel (SSD) engine fuelled by HFO for propulsion and BOG re-liquefied by a compressor, which requires additional energy.
- Q-Flex: 210 000 – 216 000 m³
- Q-Max: up to 266 000 m³
- In this study, Q-Flex vessels from Qatar to Europe are considered.

Table 4-54: Technical data for LNG vessel, type: SSD

Technical parameter	Value
Size of vessels	210 000 to 266 000 m^3
Fuels	HFO
Speed, laden journey	19.5 knot
Speed, ballast journey	20.5 knot
Rate of fugitive emissions from tank to engine	0.2 %
Time for cargo operations (in-port, loading and unloading tanks of vessel)	3.5 days
Fuel consumption during in-port time	33 t HFO per day

Propulsion type D: DFDE

- DFDE is able to use two fuels, BOG and Marine Diesel Oil (MDO).
- Consequently, there are two different combustion engines used on each vessel, one for each fuel type, enabling the fuels to be used most efficiently.
- DFDE uses electric propulsion.

Table 4-55: Technical data for LNG vessel, type: DFDE

Technical parameter	Value
Size of vessels	80 000 to 177 000 m^3
Speed (< 90k m^3) laden journey	18.5 knot
Speed (< 90k m^3) ballast journey	20 knot
Speed (> 90k m^3) laden journey	18.5 knot
Speed (> 90k m^3) ballast journey	20 knot
BOR, laden journey	0.1 %
BOR, ballast journey	0.1 %
Energy supply by BOG, laden journey	95 %
Energy supply by BOG, ballast journey	95 %
Energy supply by MDO, laden journey	5 %
Energy supply by MDO, ballast journey	5 %
Rate of fugitive emissions tank to engine	0.1 %
Time for cargo operations (in-port, loading and unloading tanks of vessel)	2.5 days
Fuel consumption during in-port time (> 90k m^3)	33 t HFO per day
Fuel consumption during in-port time (< 90k m^3)	24 t HFO per day

Further information about LNG transport with vessels

- The only purpose of an LNG tanker is to transport liquefied natural gas. That means that the tanks are empty on the return trip, apart from a little heel to keep the tanks cold (2 % of capacity) and fuel for the return trip.
- **All vessels**, incl. the biggest SSD tankers, **take the respective defined routes** for maritime LNG transportation to Europe. That means, specifically, that Australian imports and imports from Qatar are transported through the Suez Canal.

- Vessels with the propulsion types TFDE and DFDE have significantly **higher (up to 20 times) CH_4 emission factors** compared with vessels with propulsion types steam and SSD due to a higher CH_4 slip in the engines.
- The **utilisation rate** of the LNG fleets depends on short-term / long-term trade contracts, distances of the journey as well as utilisation rates of the liquefaction plants.
  - Utilisation rate of 100 % means: there are not idling times of the vessels, no delay during sailing or non-operative in-port time.
  - For Algeria, Australia, Qatar and USA, **a utilisation rate of 100 % is assumed** as best case assumption for LNG system**.**
- The **share of time** the vessels spend both **sailing and in-port** depends on the speed of the vessel, the trip distance and the time required for loading and unloading the tanks.
- This share slightly influences the extent to which infrastructure contributes to the overall environmental impact of the LNG transports and the energy demand (and related emissions) due to the time at the port, which adds to the energy needed for the trip.
- Hence, this **shipping share** is a factor – as described above – which describes the rate at which a defined vessel (e.g., speed, capacity) is at sea during a defined journey (e.g., distance) with a defined in-port time per one roundtrip.
- **One roundtrip** for LNG vessels is defined as follows:
  - Loading the tanks in-port (LNG export terminal),
  - Shipping from LNG export to LNG import terminal,
  - Unloading the tanks in-port (LNG import terminal),
  - Return to LNG export terminal.
- E.g., shipping share of 50 % means that the in-port time and the time at sea are equal for a vessel related to one roundtrip.

The **infrastructure** of vessels is defined for the purpose of this study within three groups with different vessel sizes. The following tables give an overview of the construction material used respectively.

Table 4-56: Infrastructure: construction material used for a LNG vessel with less than 80 000 m^3

LNG vessel, <80k m^3	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Steel plate	16 200	t	calculated	GLO: Steel plate *in combination with* GLO: Value of scrap	worldsteel worldsteel
Aluminium sheet	2 300	t	calculated	EU-27: Aluminium sheet (2010) *in combination with* EU-27: Aluminium ingot mix (2010)	EAA EAA
Stainless steel 304	450	t	calculated	RER: Stainless steel Quarto plate (304) *in combination with* GLO: Value of stainless steel scrap (304)	Eurofer Eurofer

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-57: **Infrastructure: construction material used for a LNG vessel with 140 000 to 170 000 m³**

LNG vessel, 140-170k m³	Value Unit	DSI*	GaBi dataset	Dataset provider
INPUT				
Steel plate	22 700 t	calculated	GLO: Steel plate *in combination with* GLO: Value of scrap	worldsteel worldsteel
Aluminium sheet	3 200 t	calculated	EU-27: Aluminium sheet (2010) *in combination with* EU-27: Aluminium ingot mix (2010)	EAA EAA
Stainless steel 304	640 t	calculated	RER: Stainless steel Quarto plate (304) *in combination with* GLO: Value of stainless steel scrap (304)	Eurofer Eurofer

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Table 4-58: **Infrastructure: construction material used for a LNG vessel with more than 210 000 m³**

LNG vessel, >210k m³	Value Unit	DSI*	GaBi dataset	Dataset provider
INPUT				
Steel plate	27 200 t	calculated	GLO: Steel plate *in combination with* GLO: Value of scrap	worldsteel worldsteel
Aluminium sheet	3 800 t	calculated	EU-27: Aluminium sheet (2010) *in combination with* EU-27: Aluminium ingot mix (2010)	EAA EAA
Stainless steel 304	760 t	calculated	RER: Stainless steel Quarto plate (304) *in combination with* GLO: Value of stainless steel scrap (304)	Eurofer Eurofer

* DSI – Data Source Indicator → measured / calculated / estimated / literature

Country-specific LNG vessel parameters

The following table shows the technical parameter settings for the four countries considered as LNG import alternatives to Europe in the GHG model concerning the LNG transport.

Table 4-59: **Technical data for LNG vessel fleets in the considered countries applied in the GHG model**

Country	Start and end point	Distance [km]	Vessel type	Average size [m³]	Share [%]	Shipping share [%]
Algeria	Arzew	3 000	Steam turbine	140 000	50	79.2
	Rotterdam		Small steam turbine	65 000	25	
			Small DFDE	81 000	25	

Country	Start and end point	Distance [km]	Vessel type	Average size [m^3]	Share [%]	Shipping share [%]
AU-NWS	Karratha	17 400	Steam turbine	160 000	67	95.3
	Rotterdam		TFDE	140 000	33	
AU-QL	Curtis Island	22 000	Steam turbine	160 000	67	96.2
	Rotterdam		TFDE	140 000	33	
Qatar	Ras Laffan	11 800	SSD (Q-Flex)	216 000	100	88.3
	Rotterdam					
USA	Sabine Pass	9 200	Steam turbine	160 000	67	91.4
	Rotterdam		TFDE	140 000	33	

4.5.7. Regasification

- After transporting LNG to the consumer country, the state of aggregation of the natural gas is changed from liquid to gaseous by adding heat in the regasification plant.
- The heat is either provided by the environment or produced at the plant. Heat from the environment is usually taken from seawater (open rack vaporisers, ORV) and only sometimes taken from the air (ambient air vaporisers).
- ORV is most common, representing 70 % of the market (Petal et al, 2013)
  - ORV: a stream of water is pumped along a heat exchanger whereby the LNG is regasified on the other side of the heat exchanger. Such regasification plants have low energy consumption, as only drive pumps for the water are needed.
- Technology alternative: submerged combustion vaporisers (SCV)
  - SCV is more energy intensive than ORV, as not only energy for the pumps is required but around 1.5 % of natural gas input is required to heat up the LNG. The natural gas is burned and the hot exhaust gases are dispensed into a container filled with water. Thereby the water is heated up directly.
- BOG use (and related BORs) for storage and loading / unloading as described in the liquefaction section is as well applied prior to regasification step.

Table 4-60: Infrastructure: construction material used for a regasification plant

Regasification plant	Value	Unit	DSI*	GaBi dataset	Dataset provider
INPUT					
Concrete	66 700	m^3	calculated	EU-27: Concrete C35/45 (Ready-mix concrete)	ts
Structural steel	12 200	t	calculated	GLO: Steel sections *in combination with* GLO: Value of scrap	worldsteel worldsteel
Reinforced steel	8 600	t	calculated	EU-27: Reinforced steel (wire) *in combination with* GLO: Value of scrap	ts worldsteel

* DSI – Data Source Indicator → measured / calculated / estimated / literature

- Lifetime of regasification plants: 30 years.

4.6. Background data

4.6.1. Fuels and electricity

National averages for fuel inputs and electricity grid mixes were obtained from the GaBi databases 2016. Table 4-61 shows the LCI datasets used in modelling the product systems. Electricity consumption was modelled using country-specific grid mixes that account for imports from neighbouring countries.

Documentation for all GaBi datasets can be found at http://gabi-software.com/support/gabi/gabi-database-2016-lci-documentation/. (thinkstep, 2016)

Table 4-61: Key energy datasets used in inventory analysis

Energy	Location	Dataset	Dataset Provider	Reference Year	Proxy
Electricity	DZ	DZ: Electricity grid mix	ts	2012	No
Electricity	DZ	DZ: Electricity grid mix 1kV-60kV	ts	2012	No
Electricity	RU	RU: Electricity grid mix 1kV-60kV	ts	2012	No
Electricity	AU	AU: Electricity grid mix	ts	2012	No
Electricity	AU	AU: Electricity grid mix 1kV-60kV	ts	2012	No
Electricity	QA	QA: Electricity grid mix	ts	2012	No
Electricity	QA	QA: Electricity grid mix 1kV-60kV	ts	2012	No
Electricity	US	US: Electricity grid mix	ts	2012	No
Electricity	US	US: Electricity grid mix 1kV-60kV (Texas)	ts	2012	No
Diesel	AU	AU: Diesel at refinery	ts	2012	No
Diesel	DZ, AU, QA	EU-27: Diesel mix at refinery	ts	2012	No
Diesel	US	US: Diesel mix at refinery	ts	2012	No
Heavy fuel oil	RU	EU-27: Heavy fuel oil at refinery (1.0wt.% S)	ts	2012	No
Heavy fuel oil	DZ, AU, QA, US	EU-27: Heavy fuel oil at refinery (2.5wt.% S)	ts	2012	No
Marine diesel oil	DZ, AU, QA, US	EU-27: Light fuel oil at refinery	ts	2012	No

4.6.2. Raw materials and processes

Data for raw materials, intermediate products and unit processes were obtained from the GaBi database 2016. Table 4-62 shows the LCI datasets used in modelling the product systems.

Documentation for all GaBi datasets can be found at http://gabi-software.com/support/gabi/gabi-database-2016-lci-documentation/. (thinkstep, 2016)

Table 4-62: Key material and process datasets used in inventory analysis

Material/ process	Location	Dataset	Dataset Provider	Reference Year	Proxy
Aluminium silicate	DZ, AU, QA, US	DE: Aluminium silicate (zeolite type A)	ts	2015	No
Aluminium ingot	AL, AU, QA, US	EU-27: Aluminium ingot mix (2010)	EAA	2010	No
Aluminium sheet	AL, AU, QA, US	EU-27: Aluminium sheet (2010)	EAA	2010	No
Barium sulphate	DZ, AU, QA, US	GLO: Barium sulphate (BaSO4) (energy model)	ts	2015	No
Bentonite	DZ, AU, QA, US	GLO: Bentonite	ts	2015	No
Cement	DZ, AU, QA, US	DE: Cement (CEM I 42.5) (EN15804 A1-A3)	ts	2015	No
Cement	RU	DE: Cement (CEM I 52.5) Portland cement grinding	ts	2015	No
Concrete	DZ, AU, QA, US, RU	EU-27: Concrete C35/45 (Ready-mix concrete) (EN15804 A1-A3)	ts	2015	No
Diesel generator	DZ, AU, QA, US	GLO: Diesel generator	ts	2015	No
Epoxy Resin	DZ, AU, QA, US, RU	DE: Epoxy Resin (EP) Mix	ts	2015	No
Gas turbine	DZ, AU, QA, US	GLO: Gas turbine	ts	2015	No
Gravel	RU	DE: Gravel (Granulation 2/32)	ts	2015	No
Inert rock	DZ, AU, QA, US	GLO: Inert rock	ts	2015	No
Iron ore	RU	DE: Iron ore-mix	ts	2015	No
Lubricants	DZ, AU, QA, US	EU-27: Lubricants at refinery	ts	2015	No
Lubricants	US	US: Lubricants at refinery	ts	2015	No
Normal Mortar	DZ, AU, QA, US, RU	EU-27: Normal mortar (A1-A3)	ts	2015	No
PE-HD	DZ, AU, QA, US RU	EU-27: Polyethylene foil (PE-HD) (without additives)	ts	2015	No
Reinforced steel	DZ, AU, QA, US, RU	EU-27: Reinforced steel (wire) (EN15804 A1-A3)	ts	2015	No
Steel sections	DZ, AU, QA, US, RU	GLO: Steel sections	worldsteel	2007	No

Material/ process	Location	Dataset	Dataset Provider	Reference Year	Proxy
Steel sheet	DZ, AU, QA, US, RU	DE: Steel sheet HDG	ts	2015	No
Steel plate	DZ, AU, QA, US, RU	GLO: Steel plate	worldsteel	2007	No
Steel turning	DZ, AU, QA, US	DE: Steel turning (adjustable)	ts	2015	No
Steel UO pipe	DZ, AU, QA, US, RU	GLO: Steel UO pipe	worldsteel	2007	No
Steel welded pipe	DZ, AU, QA, US, RU	GLO: Steel welded pipe	worldsteel	2007	No
Steel scrap	DZ, AU, QA, US, RU	GLO: Value of scrap	worldsteel	2007	No

4.6.3. Transportation

Average transportation distances and modes of transport are included for the transport of raw materials, operating materials and auxiliary materials to production and assembly facilities.

The GaBi database 2016 was used to model transportation. Transportation was modelled using the GaBi global transportation datasets. Fuels were modelled using the geographically appropriate datasets. (thinkstep, 2016)

Table 4-63: Transportation and road fuel datasets

Mode / fuels	Geographic Reference	Dataset	Dataset Provider	Reference Year	Proxy
Bulk commodity carrier	RU	GLO: Bulk commodity carrier	ts	2015	No
Excavator	DZ, AU, QA, US, RU	GLO: Excavator	ts	2015	No
Rail transport	DZ, AU, QA, US, RU	GLO: Rail transport cargo - average	ts	2015	No
Truck trailer	DZ, AU, QA, US, RU	GLO: Truck-trailer	ts	2015	No

4.7. Life cycle inventory analysis results

ISO 14044 defines the Life Cycle Inventory (LCI) analysis result as the “outcome of a life cycle inventory analysis that catalogues the flows crossing the system boundary (“elementary flows”) and provides the starting point for life cycle impact assessment”. As the complete inventory comprises hundreds of flows, the below table only displays a selection of flows based on their relevance to the subsequent impact assessment in order to provide a transparent link between the inventory and impact assessment results.

Table 4-64 shows the LCI of the study as base case results in g per MJ (LHV). The elementary flows are displayed as outputs of the LCA model which have an impact on Global Warming Potential (GWP).

Table 4-64: Life cycle inventory analysis results

GHG emission	Russia [g/MJ]	Algeria [g/MJ]	Austr-NWS [g/MJ]	Austr-QL [g/MJ]	Qatar [g/MJ]	USA [g/MJ]
Inorganic emissions						
Carbon dioxide	5.31	11.73	17.13	24.41	12.93	16.33
Nitrous oxide	1.00E-04	2.58E-04	4.89E-04	6.26E-04	3.52E-04	4.25E-04
others	*< 1E-12*	*< 1E-12*	*< 1E-12*	*< 1E-12*	*< 1E-12*	*< 1E-12*
Organic emissions						
Methane	0.038	0.206	0.111	0.165	0.075	0.285
others	*< 1E-08*	*< 1E-08*	*< 1E-08*	*< 1E-08*	*< 1E-08*	*< 1E-08*

The emission group "others" subsumes all trace emissions as described in section 3.6 with no relevant effect on the overall GHG results. The origin of those trace emissions is diverse. For instance, they are a part of the background system of the study, for example through the use of LCA datasets representing country-specific electricity grid mixes, or materials like steel, plastics and concrete.

In Annex B, the characterisation factors are listed which transform the LCI results into the subsequent Life cycle inventory results (see section 5). Also a more detailed table on LCI results is shown in Annex B.

5. Life cycle impact assessment results

This section contains the results for the impact category GWP as defined in section 3.6. It shall be reiterated at this point that the reported impact category represent an impact potential, i.e., it is an approximation of an environmental impact that could occur if the emissions would (a) follow the underlying impact pathway and (b) meet certain conditions in the receiving environment while doing so. In addition, the inventory only captures that fraction of the total environmental load that corresponds to the chosen functional unit (relative approach).

The LCIA result is therefore relative expressions only and does not predict actual impacts, the exceeding of thresholds, safety margins, or risks. See Annex A for the list of GWP characterisation factors (IPCC, 2007) applied for the calculation of the following LCIA results.

5.1. Overall GHG results

The following graph shows the overall GHG result for the base case of the comparison between:

- Product system A – natural gas import from Russia to Europe via NSP2 – and
- Product system B with its sub systems – natural gas imports to Europe from Algeria, Australia, Qatar and USA
    - For Australian imports, two cases are defined: natural gas from North West Shelf and natural gas from Queensland.

The unit of the results is gram CO_2-equivalents (g CO_2eq) per MJ delivered natural gas as low heating value (LHV), at European transmission network entry point.

Product system A results are broken down into two process steps:

- Production and processing (incl. well drilling) and
- Pipeline transport.

Product system B results are broken down into six process steps:

- Production and processing (incl. well drilling),
- Pipeline transport,
- Purification,
- Liquefaction,
- LNG transport and
- Regasification.

The following paragraph lists the key findings.

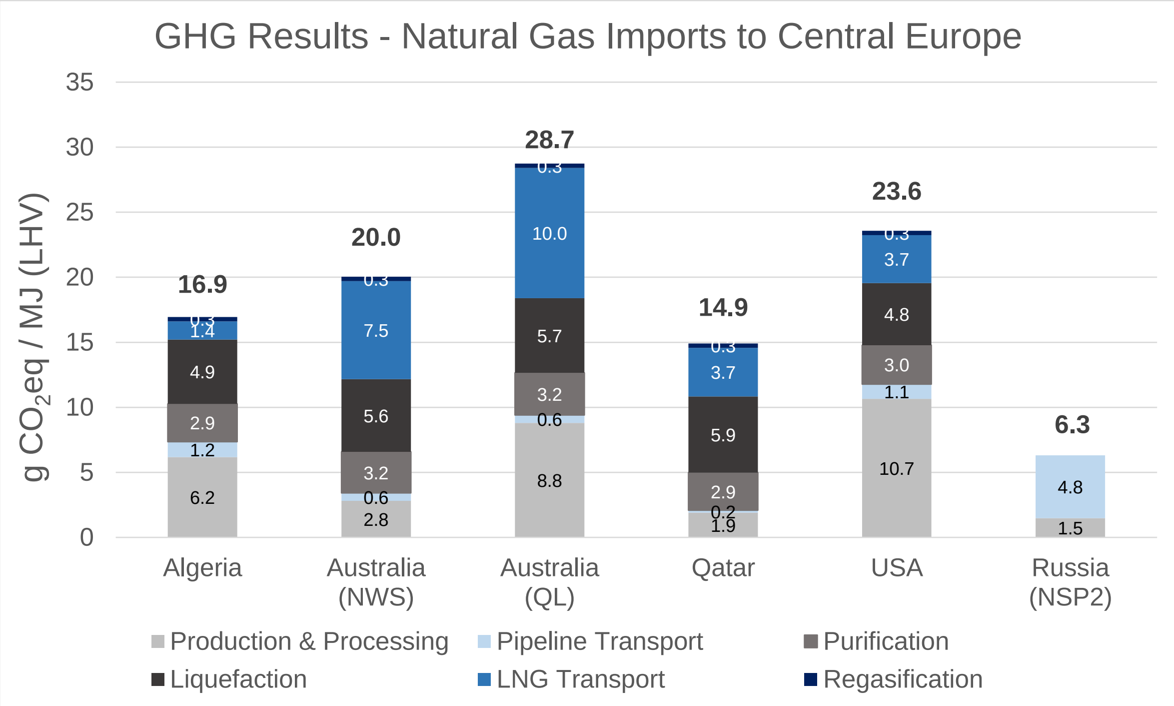


Figure 5-1: Overall GWP result for the base case

Key Findings:

- Natural gas import from Russia via NSP2 generates less GHG emissions (6.3 g CO_2eq/MJ) than any of the LNG import routes considered (14.9 – 28.7 g CO_2eq/MJ).
  - The LNG import routes generate ~2.4 to 4.6 times higher GHG emissions than natural gas imported from Russia via NSP2.
- The most relevant contributors to overall GHG intensity are:
  - Product system A: pipeline transport
  - Product system B: LNG transport, liquefaction and production and processing (particularly for unconventional natural gas production)
- The least relevant contributors to overall GHG intensity are:
  - Product system A: production and processing
  - Product system B: pipeline transport and regasification
- Conventional technologies for producing natural gas (Australia-NWS, Algeria, Qatar, and Russia) generate significantly lower GHG results than unconventional technologies (Australia-QL, USA).
- Conventional production and processing in Russia shows significantly lower GHG intensity than most other natural gas productions since a new gas field is considered.
- The natural gas from shale gas production in the USA generates by far the highest GHG emissions compared with all other production sites – approx. 20 % higher GHG intensity than the other unconventional natural gas source, CBM in Australia-QL.
- Algeria has the highest GHG footprint in conventional production and processing compared with the other conventional gas fields – more than 2 times higher than Australia-NWS.
- The purification step is almost equally GHG intensive for all LNG import routes.
- The liquefaction GHG footprint varies by ±10 % with the highest GHG result for Qatar from partly lower efficiencies in older plants and the highest yearly average ambient temperature (27 °C). Low GHG results for new plants in Algeria and USA due to relatively high efficiencies.

- The contribution of LNG transport to product system B's total GHG footprint closely correlates with transportation distance. However, vessel type (steam, DFDE, TFDE, SSD) and size (60 000 m^3 - 216 000 m^3) also impact GHG results. For instance, GHG-efficient transport from Qatar to Europe is possible with high-capacity vessels (e.g., Q-Flex, 216 000 m^3).
- Since, per the goal and scope of the study, all LNG is imported to Rotterdam, GHG intensity from regasification is identical for all LNG routes.

The findings presented in Figure 5-1 are supported by Figure 5-2. That diagram shows the exact same results as the previous graph, but the overall results per supply chain are subdivided by the three main contributors to the GHG result: CO_2, CH_4 and N_2O.

For all LNG import routes, on average: Inorganic emissions to air dominate GHG intensity. CO_2 accounts for approx. 99.1 % and N_2O for approx. 0.8 % of inorganic emissions to air. Other inorganic emissions contribute approx. 0.1 % (not displayed separately). CH_4 accounts for approx. 99.9 % of organic emissions to air. Other organic emissions are contributing about 0.1 %, so they are not displayed separately).

For pipeline import via NSP2: Inorganic emissions to air dominate GHG intensity. CO_2 accounts for approx. 99.4 % and N_2O for approx. 0.5 % of inorganic emissions to air. CH_4 accounts for approx. 99.9 % of organic emissions to air.

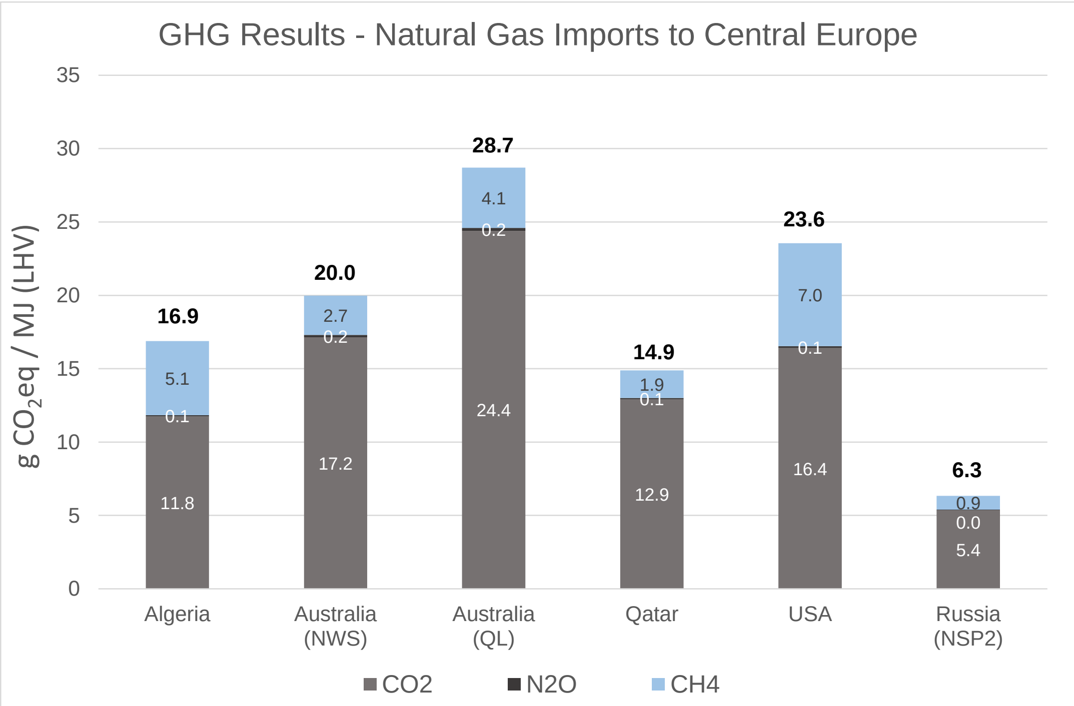


Figure 5-2: Breakdown of overall results, main contributors to GWP – CO_2, CH_4 and N_2O (base case)

CH_4 emissions are from vented, pneumatic device, and fugitive emissions as well as other unburnt emissions. The share of CH_4 emissions to the overall GHG result is highest for the USA, where CH_4 is responsible for ~30 % (7 g CO_2eq/MJ) of the GHG emissions. Significant CH_4 emissions come from the production and processing of natural gas from shale gas (64 % share of total CH_4 emissions, of which 85 % results from vented CH_4), from pipeline transport (15 % share of total CH_4) and from the purification step (14 % share of total CH_4).

For Algeria, the breakdown of significant CH_4 contributors is the following: from production and processing of natural gas with conventional technologies (57 % results from CH_4 emissions), from the purification step (20 % share of total CH_4) and from pipeline transport (9 % share of total CH_4 emissions).

For Australia's Queensland (QL), the breakdown of significant CH_4 contributors is twofold: from production and processing of natural gas with unconventional technologies (38 % results from CH_4 emissions) and from the purification step (29 % share of total CH_4 emissions). In addition, LNG transport contributes as follows: 11 % share of total CH_4 due to CH_4 slip in TFDE engines – this CH_4 slip accounts to 74 % to the total GHG emissions related to LNG transport from Queensland to Europe.

The other two LNG supply chains (Australia-NWS and Qatar) have similar shares as the rotes described above. They also show considerably lower CH_4 emissions (1.9 resp. 2.7 g CO_2eq/MJ).

Comparing all imports, the Russian import via NSP2 shows the lowest CH_4 emission values, in absolute and relative numbers (0.9 g CO_2eq/MJ and a 14 % share of total GHG burden). This suggests that CH_4 emissions are controlled effectively in the production and processing of Russian natural gas and throughout the pipeline transport.

CO_2 emissions mainly come from combustibles, and very small amounts is vented CO_2 from processing and purification of natural gas (CO_2 removal).

Further analysis of product system A – natural gas import from Russia to Europe via NSP2

For the construction of the pipeline as well as for the construction of the compressor stations, a high amount of materials is consumed and effort is undertaken to set up the facilities. The amount of steel required to build up the complete length of the onshore and offshore pipeline as well as the compressor stations amounts to about 9.3 million tonnes. This represents the steel production volume of an average blast furnace over the course of almost four years. The manufacturing of the steel pipes is via primary steel route (blast furnace route) and the environmental burden of used steel scrap is considered.

However, the pipeline's infrastructure (building materials and construction) contributes less than 5 % to the total GHG result for product system A. The natural gas pipeline-transport operations over 30 years with an annual capacity of 55 billion m^3 (bcm) far dominates, as shown in the below figure.

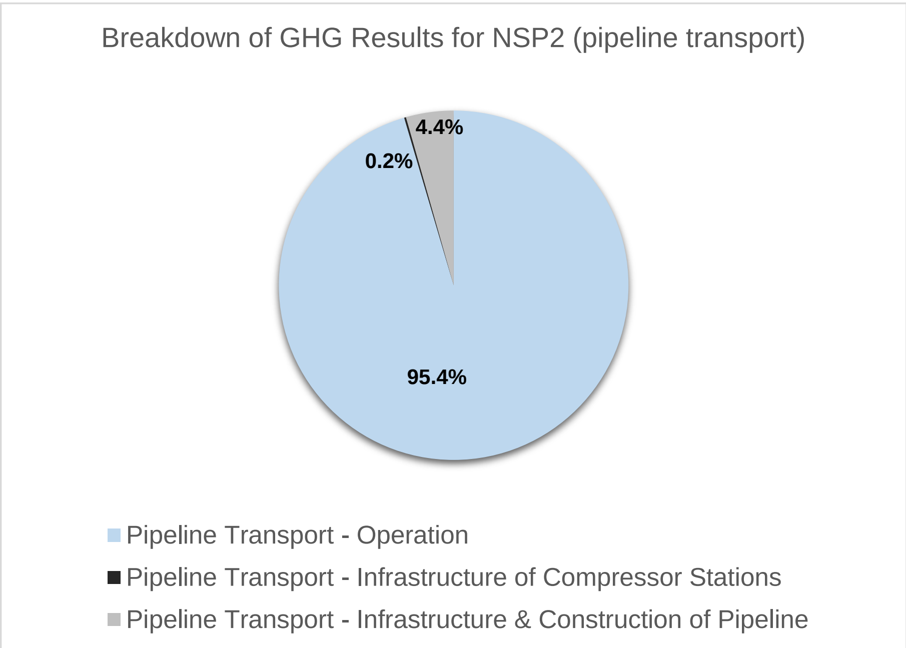


Figure 5-3: NSP2 Russia to Europe – breakdown of GHG results for pipeline transport

Further analysis of product system B – natural gas imports from DZ, AU, QA and US to Europe

The manufacturing of the facilities and vessels associated with the LNG supply chain requires a variety materials and energy, however considering the lifetime considered in the study, this infrastructure has a minor share of the overall GHG results and the related process steps, e.g., LNG transport.

- For the liquefaction plants, infrastructure accounts for less than 0.1 % to the overall GHG results of all LNG import routes and less than 1 % of the intensity of the liquefaction operations themselves.
- The share of infrastructure in the LNG vessels accounts for less than 1 % to the overall GHG results of all LNG import routes and less than 3 % of the GHG intensity of the LNG transport operations itself.

5.2. Comparison of results with literature data

5.2.1. Considered studies

The main studies considered for comparison are:

- JEC (“JEC - Joint Research Centre-EUCAR-CONCAWE collaboration, Well-to-Tank Report” Version 4.a, April 2014) (JEC, 2014),
- DBI Gas- und Umwelttechnik (“Critical Evaluation of Default Values for the GHG Emissions of the Natural Gas Supply Chain”, Final Report 2016, commissioned by Zukunft Erdgas e.V.) (DBI, 2016b)
- CIRAIG (“GHG emissions related to the life cycle of natural gas and coal in different geographical contexts”, Final Report 2016, commissioned by TOTAL) (CIRAIG, 2016)
- Delphi Group (“LNG Emissions Benchmarking”, 2013, prepared for BC Climate Action Secretariat) (Delphi, 2013)
- PACE (“LNG and Coal Life Cycle Assessment of Greenhouse Gas Emissions, 2015, prepared for Centre for Liquefied Natural Gas) (PACE, 2015)
- Exergia (“Study on actual GHG data for diesel, petrol, kerosene and natural gas”, Final report, 2015, commissioned by the EC) (Exergia_et_al, 2015)
- NETL (“Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States” 2014, prepared by Skone, T.J.) (NETL, 2014))

5.2.2. Comparison for natural gas import via pipeline

The recently published (December 2016) **DBI study** considers three different corridors for pipeline gas from Russia to Europe. The Northern corridor is directly comparable to the Nord Stream 2 pipeline with regard to route and length. The GHG results are shown in the following figure, in g CO_2eq per GJ.

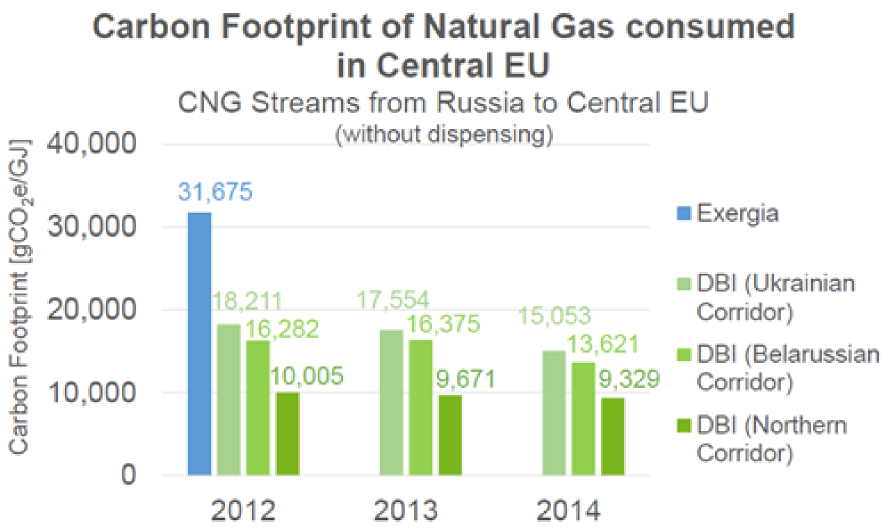


Figure 5-4: Results for pipeline gas from Russia to Europe – DBI study (DBI, 2016a)

The resulting value of 9 329 g CO_2eq per GJ (2014) includes the transmission, storage and distribution within Central EU. The GHG value for this is approx. 1 810 g CO_2eq per GJ (see page 50 final report (DBI, 2016b)). This GHG result was calculated by the institute of DBI using the GHGenius version 4.03, developed and licensed by (S&T)² Consultants.

As energy (natural gas) is needed to transmit, store and distribute natural gas within central Europe, and as these operations are also associated with methane emissions (loss of gas), some additional natural gas has to be produced in Russia and transported from Russia to Europe to enable this transmission, storage and distribution operation in Europe.

In summary, as this study focuses on the analysis from the gas well to the EU entry point, no transmission, storage and distributions needs to be considered. Subtracting the transmission, storage and distribution GHG value from the total value (9.33 – 1.81 g CO_2eq per MJ) would not be correct because of a scaling effect. The effect is that less gas needs to be produced and transported which would be needed for the transmission, storage and distribution. The scaling effect amounts to a range of 0.3 – 0.5 g CO_2eq per MJ. Hence, the value correct to reflect the EU entry point is: 7.1 g CO_2eq per MJ for 2014 (→ 9.33 – 1.81 – 0.4 = 7.1 g CO_2eq/MJ).

The GHG emission calculated for natural gas imports from Russia via NSP2, is 6.3 g CO_2eq per MJ based on data from 2015 including the estimated well drilling contribution of 0.5 g CO_2eq per MJ. However, drilling operations are not considered in the DBI study. When the 2014 input parameters used in the DBI study are entered into the GaBi model that results in 5.9 g CO_2eq per MJ (excl. well drilling operations).

The difference of 1.2 g CO_2eq per MJ (7.1 g CO_2eq per MJ for 2014 in DBI study vs. 5.9 g CO_2eq per MJ resulting out of GaBi based on the same values of 2014 as used in DBI study) may be caused by the use of different models and different background datasets (GHGenius vs. GaBi). Since the production and processing GHG results derived from the GaBi model and the DBI study are very similar (besides the additional drilling effort modelled in GaBi), the main differences may be traced back to the pipeline transport. However, the calculations and equations in the GaBi model are deemed to be correct.

The **CIRAIG study**, "GHG emissions related to the life cycle of natural gas and coal in different geographical contexts", Final Report 2016, commissioned by TOTAL (CIRAIG, 2016), considers Russian pipeline gas in a scenario, see the results below. The underlying data is not provided completely in the study, so the length of the pipeline is unclear. The following information is given along with the resulting value of 23.7 g CO_2eq/MJ: only onshore and no offshore pipeline; underlying database is ecoinvent 2.2 and the authors state that the results might be based on data taking low-efficient compressors and a high amount of fugitives into account without quantifying the technical parameters more in detail.

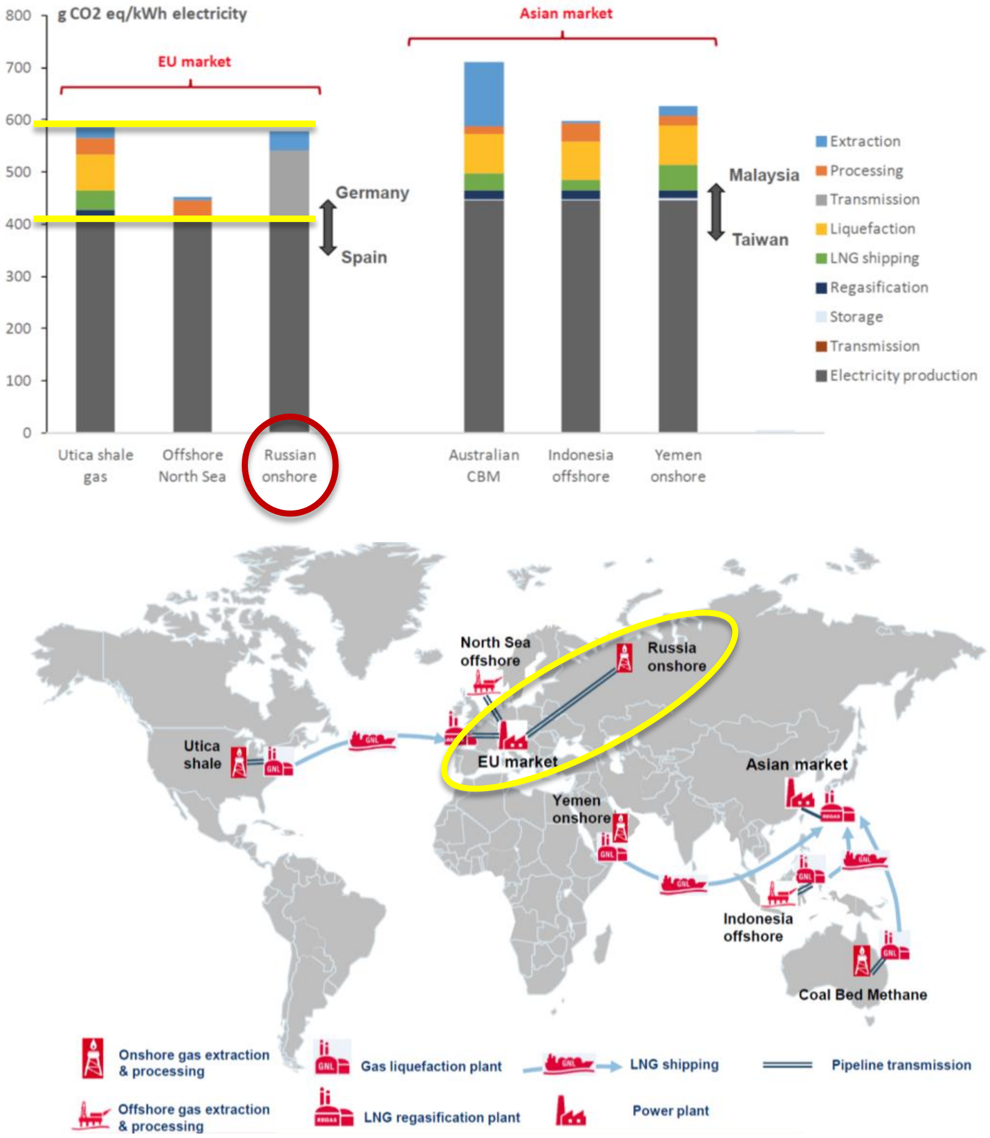


Figure 5-5: Results for pipeline gas from Russia to Europe – CIRAIG study (CIRAIG, 2016)

5.2.3. Comparison for natural gas import via LNG routes

The LNG routes are investigated in several recent studies. The studies using different units for displaying the GHG results. In the following overview, all results are converted in the unit used in this study: g CO_2eq per MJ.

The below figure is structured firstly by the four selected LNG import routes (DZ, AU, QA and US). For each of those routes, one or more studies are compared with the results of the present study. The comparability of the different values is partly limited as the boundary conditions are not the same.

For example:

- CIRAIG, transport distances
  - for Australia 7 300 km (compared with 22 000 km);
  - for USA 9 097 km (compared with 9 200 km)
- NETL, transport distances
  - USA to Trinidad and Tobago 2 956 km (low)
  - USA to Trinidad and Tobago 18 544 km (high)
- Pace Global, transport distances
  - USA (Houston) 9 526 km (low, US-Germany)
  - USA (Houston) 18 635 km (high, US-China)
- Pace Global, different conventional/unconventional natural gas mix
  - 16.0 g CO_2eq/MJ (low)
  - 24.5 g CO_2eq/MJ (high)

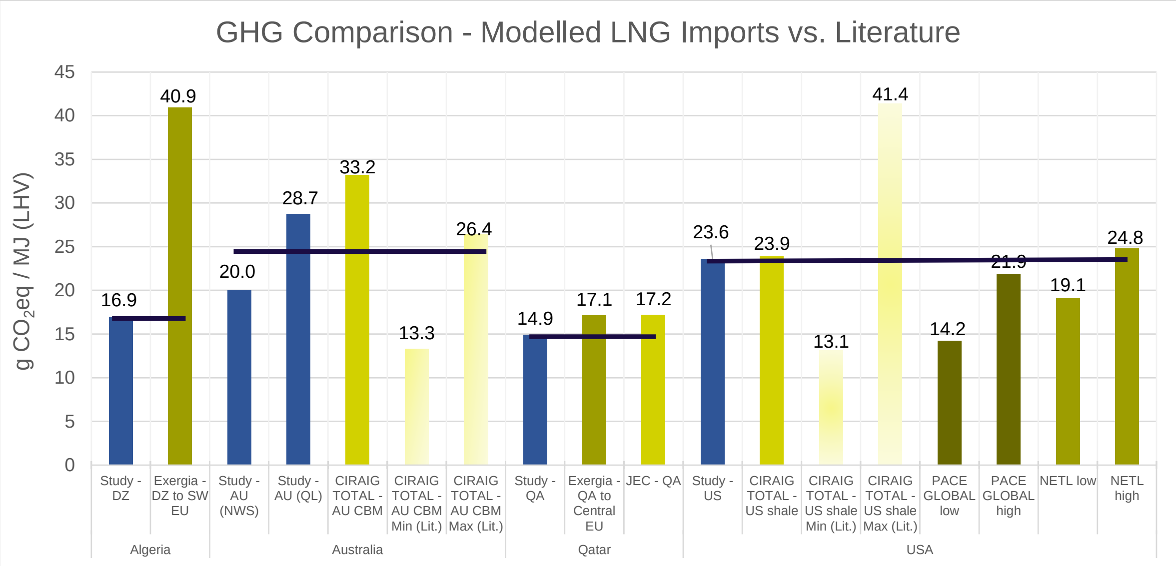


Figure 5-6: LNG route (product system B), comparison of study results with literature data – (CIRAIG, 2016), (Exergia, 2015), (PACE, 2015), (Skone, 2014) adapted sources

The high **Algerian** result presented in the Exergia study originates from methane emissions in production and processing and inefficient old LNG plants. 95 % of the resulting GHG emissions occur in the process chain up to liquefaction. The LNG transport results are in the same range as this study. Note that the reference year in the Exergia study is 2012. Since 2013, new LNG plants have been built and first new facilities came online in 2015, while old LNG plants have been closed. This trend may continue in the next 2-3 years. In line with the perspective of this study, new LNG plants are assumed to deliver LNG to Europe.

The **Australian** values from CIRAIG are different in one further aspect beyond the considered transport distance: CIRAIG estimates very high fugitive emissions at production and processing due to CBM resources. Almost half of the GHG results is driven by the production of natural gas (excl. processing) which balances out the significantly lower GHG emissions from shorter LNG transport distance.

The **Qatari** result in the present study is slightly lower compared with Exergia and JEC.

The set-up of the **US** system is similar in the present study and the CIRAIG study. Overall GHG results of both studies for US LNG, based on shale gas, imported to Europe differ by less than 2 %. However, the contributors are different: CIRAIG numbers result show lower contribution of production and processing together with pipeline transport (approx. 40 % less compared with this study) but higher share of liquefaction through regasification (approx. 40 % more compared with this study).

The CIRAIG values are taken from the ecoinvent database 2.2, and the reference period for those data documented in that report is 1990 to 2000 for the LNG import data (e.g., production and processing, liquefaction, LNG transport). Hence, the data foundation of the CIRAIG study seems to be not up-to-date or may be obsolete.

Focussing on **LNG liquefaction**, the graph below shows a comparison of the liquefaction step of this study (incl. purification) to values from other studies.

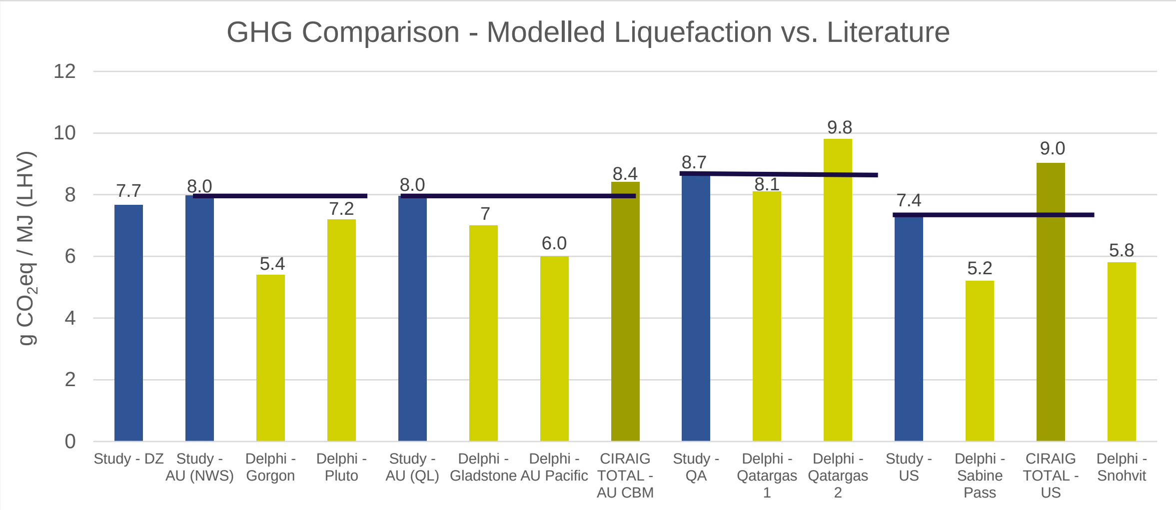


Figure 5-7: LNG route (product system B) with focus on purification and liquefaction, comparison of study results with literature data (Delphi, 2013), (CIRAIG, 2016) adapted sources

For Australian LNG plants, the GHG results of this study are higher compared with the values taken from the Delphi study. Also for further countries – with the exception of one Qatari plant – Delphi values are below the values of this study. In comparison, the CIRAIG study indicates higher results compared with the present study.

The intention of the Delphi study is to perform a GHG benchmark considering mainly best practice liquefaction technology amongst facilities under construction or proposed facilities (at the time of the study, 2014). Therefore, technical design values for energy consumptions to calculate GHG values were taken into account as well as the incorporation of Carbon Capture and Storage (CCS). So, this is the reason for the comparably low GHG results of the Delphi study.

Overall, the above comparison indicates that the values calculated in this study are comparable to data derived from literature sources or that deviations can be explained.

5.3. Sensitivity analysis

The sensitivity analysis considers the influence of the variation of single parameters in certain ranges on the GHG results. These parameter variations outline a simplification of the actual technical context. The sensitivity analysis is not comparable to a thermodynamic simulation allowing to express and analyse complex technical, physical or chemical dependencies of various parameters.

Sensitivity analysis for Nord Stream 2 pipeline transport

- **Influence of pipeline length** – methane emissions are proportionate to pipeline length, i.e., same CH_4 emission rate per km (short pipeline, lower overall fugitive emissions; longer pipeline, higher overall methane emissions).
- Relation is almost linear:
    - Double the pipeline length (+ 50 %), overall GHG results increase by 42.5 %
    - Half the pipeline length (- 50 %), overall GHG results decrease by 42.3 %.

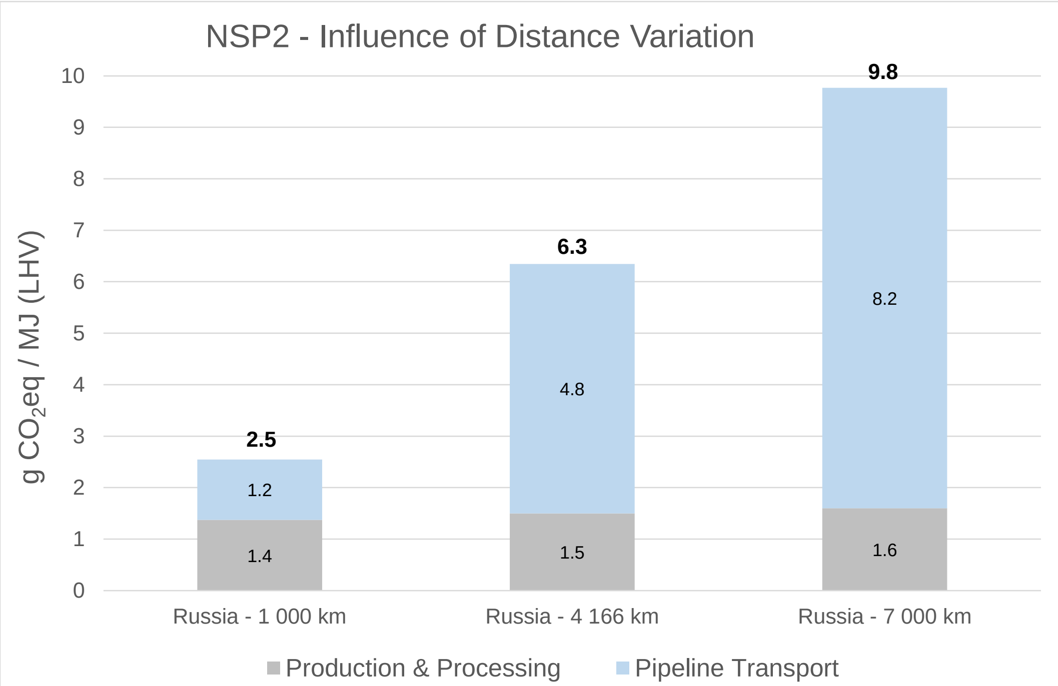


Figure 5-8: Sensitivity analysis on pipeline length (fugitives adapted accordingly)

Further sensitivity analyses for NSP2:

- **Pipeline transport – fugitives**
    - Varied isolated, i.e., independent from pipeline length
    - Effect: medium impact on overall GHG results of pipeline: 7 % per 50 % parameter variation.
- **Pipeline transport – energy consumption**
    - Varied isolated, i.e., independent from pipeline length
    - Effect: ***very high impact*** on overall GHG results of pipeline: 32 % per 50 % parameter variation.
- **Pipeline transport – annual pipeline capacity**
    - Maximum pipeline capacity applied in base case, reduced utilisation of pipeline capacity enhances the influence of the infrastructure overall.

- Effect: low impact on overall GHG results of pipeline: 3 % per 50 % parameter variation.

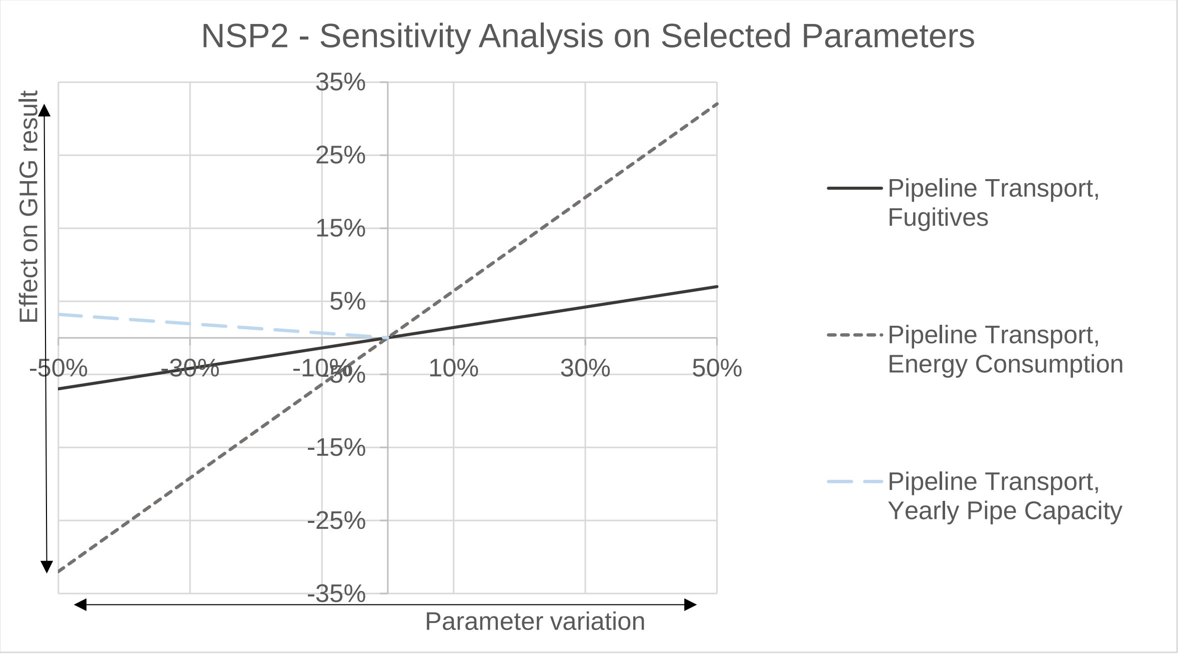


Figure 5-9: Sensitivity analysis on various further NSP2 parameters

Sensitivity checks for LNG import routes

USA

- **Production and processing – REC share**
  - Effect: medium impact on overall GHG results of LNG import alternative: 9 % per 50 % parameter variation.
- **Pipeline transport – length of pipeline**
  - Effect: medium impact on overall GHG results of LNG import alternative: 7 % per 50 % parameter variation.
- **LNG transport – utilisation rate**
  - Effect: low impact on overall GHG results of LNG import alternative: 3.5 % per 50 % parameter variation.
- **Liquefaction – efficiency**
  - Non-linear relation between parameter variation and GHG results – significant effect for decreasing efficiencies, moderate effect for increasing efficiencies.
  - Effect for decreasing efficiencies: ***very high impact*** on overall GHG results of LNG import alternative, +21 % per -50 % parameter variation.
  - Effect for increasing efficiencies: medium impact on overall GHG results of LNG import alternative, -7 % per +50 % parameter variation.

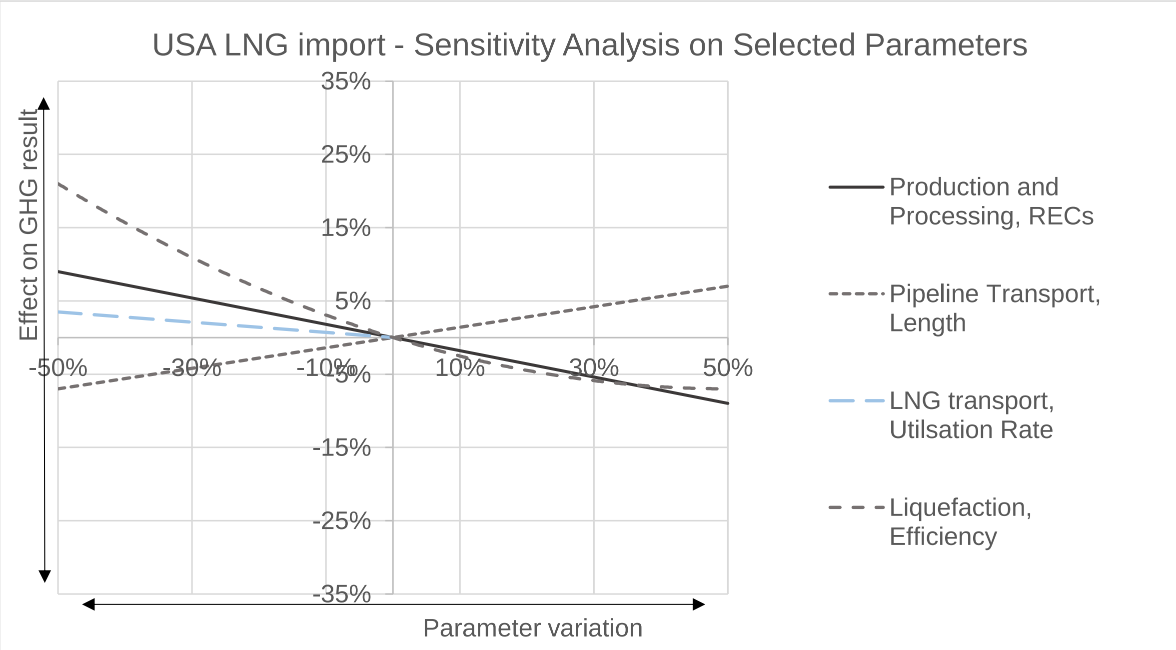


Figure 5-10: Sensitivity checks on various parameters from the US LNG import model

Australia - Queensland

- **Production and processing – REC share**
  - Effect: low impact on overall GHG results of LNG import alternative: 2 % per 50 % parameter variation.
- **Pipeline transport – length of pipeline**
  - Effect: low impact on overall GHG results of LNG import alternative: 1 % per 50 % parameter variation.
- **LNG transport – utilisation rate**
  - Effect: medium impact on overall GHG results of LNG import alternative: 7 % per 50 % parameter variation.
- **Liquefaction – efficiency**
  - Non-linear relation between parameter variation and GHG results – significant effect for decreasing efficiencies, moderate effect for increasing efficiencies.
  - Effect for decreasing efficiencies: ***very high impact*** on overall GHG results of LNG import alternative, +19 % per -50 % parameter variation.
  - Effect for increasing efficiencies: medium impact on overall GHG results of LNG import alternative, -6 % per +50 % parameter variation.

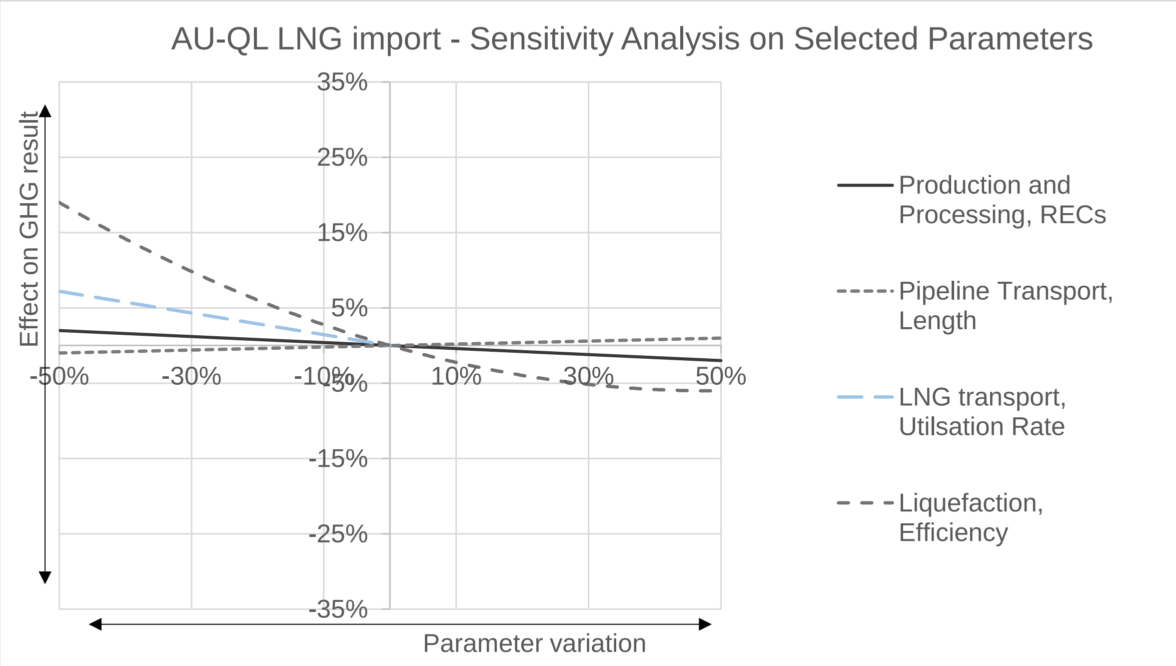


Figure 5-11: Sensitivity checks on various parameters from the AU-QL LNG import model

Australia – North West Shelf

- **Production and processing – share of fugitives**
  - Effect: low impact on overall GHG results of LNG import alternative: 1 % per 50 % parameter variation.
- **Pipeline transport – length of pipeline**
  - Effect: low impact on overall GHG results of LNG import alternative: 1 % per 50 % parameter variation.
- **LNG transport – utilisation rate**
  - Effect: medium impact on overall GHG results of LNG import alternative: 8 % per 50 % parameter variation.
- **Liquefaction – efficiency**
  - Non-linear relation between parameter variation and GHG results – significant effect for decreasing efficiencies, moderate effect for increasing efficiencies.
  - Effect for decreasing efficiencies: ***very high impact*** on overall GHG results of LNG import alternative, +24 % per -50 % parameter variation.
  - Effect for increasing efficiencies: medium impact on overall GHG results of LNG import alternative, -8 % per +50 % parameter variation.

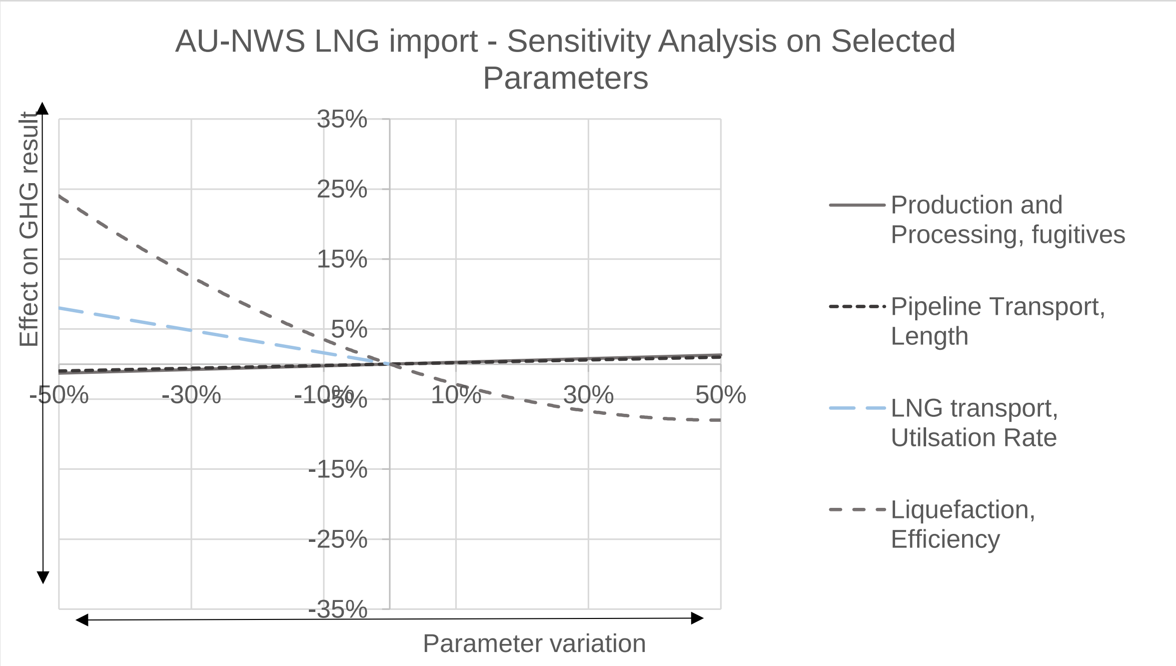


Figure 5-12: Sensitivity checks on various parameters from the AU-NWS LNG import model

Qatar

- **Production and processing – share of fugitives**
  - Effect: low impact on overall GHG results of LNG import alternative: 1.5 % per 50 % parameter variation.
- **Pipeline transport – length of pipeline**
  - Effect: low impact on overall GHG results of LNG import alternative: 0.7 % per 50 % parameter variation.
- **LNG transport – utilisation rate**
  - Effect: medium impact on overall GHG results of LNG import alternative: 5.5 % per 50 % parameter variation.
- **Liquefaction – efficiency**
  - Non-linear relation between parameter variation and GHG results – significant effect for decreasing efficiencies, moderate effect for increasing efficiencies.
  - Effect for decreasing efficiencies: ***very high impact*** on overall GHG results of LNG import alternative, +34 % per -50 % parameter variation.
  - Effect for increasing efficiencies: **high impact** on overall GHG results of LNG import alternative, -12 % per +50 % parameter variation.

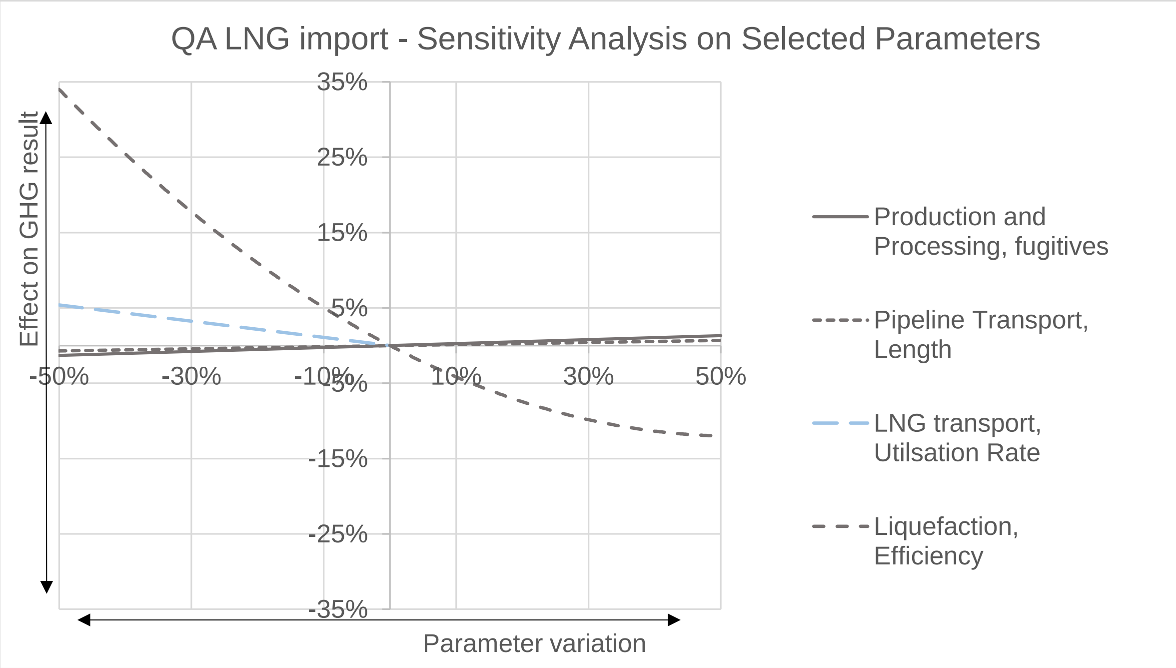


Figure 5-13: Sensitivity checks on various parameters from the QA LNG import model

Algeria

- **Production and processing – share of fugitives**
  - Effect: medium impact on overall GHG results of LNG import alternative: 9 % per 50 % parameter variatio
- **Pipeline transport – length of pipeline**
  - Effect: low impact on overall GHG results of LNG import alternative: 4 % per 50 % parameter variation.
- **LNG transport – utilisation rate**
  - Effect: low impact on overall GHG results of LNG import alternative: 3 % per 50 % parameter variation.
- **Liquefaction – efficiency**
  - Non-linear relation between parameter variation and GHG results – significant effect for decreasing efficiencies, moderate effect for increasing efficiencies.
  - Effect for decreasing efficiencies: ***very high impact*** on overall GHG results of LNG import alternative, +26 % per -50 % parameter variation.
  - Effect for increasing efficiencies: medium impact on overall GHG results of LNG import alternative, -9 % per +50 % parameter variation.

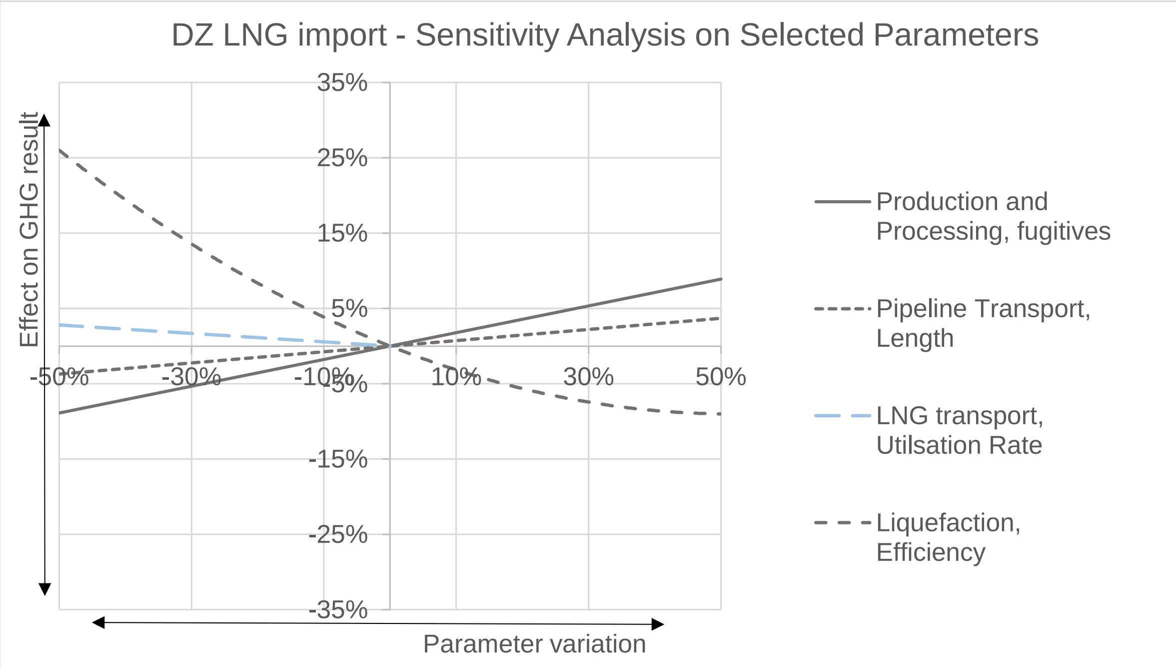


Figure 5-14: Sensitivity checks on various parameters from the DZ LNG import model

5.4. Scenario analysis

In the base case of the study, for both systems A and B, the parameters and data are set and applied according to the defined technical, geographical and sectoral situations respectively. This includes current technologies and market realities as well as facilities under construction and LNG market forecasts for the USA and Australia. The appraisal of the future development is based partly on current state, partly on planned additional capacities and partly on forecasts.

However, different scenarios than those informing the base case are conceivable. The premise of the defined additional scenarios is as follows:

- Explore parameter changes which lead to an improvement of the results for the LNG import alternatives, looking specifically at future technical or organisational improvement potentials.
- At the same time, explore parameter changes for the Russian import to Europe via pipeline, looking specifically at existing gas fields and pipelines from Russia to Europe.

The sensitivity analysis helps to inform the selection of parameters for the scenarios in this analysis. That leads to a set of parameters that is adapted for all countries almost similarly (see Table 5-16).

The “improved” scenarios for Algeria, Australia, Qatar and USA as well as the “adverse” scenarios for Russia are generated based on the premise above, as described in the Table 5-15. The scenarios USA “improved” 1 to 3 and Russia “adverse” 1 to 2 are of theoretical nature in the context of the defined study scope to explore and test the possible range of GHG results.

Table 5-15: Definition of scenarios – both “improved” and “adverse”

Scenario	Description
Algeria “improved”	Optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology, best practice re CH_4 slip for TFDE engines at LNG transport
Australia-QL “improved”	Optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology, best practice re CH_4 slip for TFDE engines at LNG transport, shortest imaginable pipeline distances from gas field to LNG terminal, CCS applied (projected facilities)
Australia-NWS “improved”	Optimum leakage management for pipeline transport from gas field to LNG terminal, best practice re CH_4 slip for TFDE engines at LNG transport, shortest imaginable pipeline distances from gas field to LNG terminal
Qatar “improved”	Optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology
USA “improved” 1	LNG export terminal changed from Sabine Pass to Cove Point (Gulf of Mexico to East coast, closer to Europe), optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology, LNG transport with highly efficient Q-flex vessels

Scenario	Description
USA "improved" 2	Take current production mix of natural gas (conventional/ unconventional) in the US into account (less unconventional more conventional technology), optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology, best practice re CH_4 slip for TFDE engines at LNG transport, shortest imaginable pipeline distances from gas field to LNG terminal
USA "improved" 3	Take 100 % conventional technology into account, optimum leakage management for pipeline transport from gas field to LNG terminal, highly-efficient liquefaction technology, best practice re CH_4 slip for TFDE engines at LNG transport, shortest imaginable pipeline distances from gas field to LNG terminal
Russia "adverse" 1	Take energy consumption and losses for pipeline transport operations of the Ukrainian corridor from DBI study ("worst" pipeline option from Russia to Europe in the DBI study due to age and length)
Russia "adverse" 2	Scenario 1 and additionally production and processing data from average Russian gas field (versus to new Russian gas field)

The table below gives an overview of the settings of the adapted parameters.

Table 5-16: Parameters for scenario analysis – both "improved" and "adverse"

Parameter	Scenarios "improved" and "adverse"	*Scenarios base case*
Algeria "improved"		
Pipeline transport, gas losses	**0.004 %**	*0.012 %*
Liquefaction, efficiency	**39 %**	*37 %*
LNG transport, CH_4 slip for TFDE engines	**0.0028 MJ/MJ**	*0.056 MJ/MJ*
Australia-QL "improved"		
Pipeline transport, distance	**100 km**	*250 km*
Pipeline transport, gas losses	**0.004 %**	*0.009* **%**
Purification, incl. Carbon Capture Storage	**100 % CCS, gas feed with 2 % CO_2 content**	*0* **%** *CCS, gas feed with 1.5* **%** *CO_2 content*
LNG transport, CH_4 slip for TFDE engines	**0.0028 MJ/MJ**	*0.056 MJ/MJ*
Australia-NWS "improved"		
Pipeline transport, distance	**100 km**	*250 km*
Pipeline transport, gas losses	**0.004 %**	*0.009* **%**
LNG transport, CH_4 slip for TFDE engines	**0.0028 MJ/MJ**	*0.056 MJ/MJ*
Qatar "improved"		
Pipeline transport, gas losses	**0.004 %**	*0.012* **%**
Liquefaction, efficiency	**39 %**	*34* **%** *and 32* **%**

Parameter	**Scenarios “improved” and “adverse”**	*Scenarios base case*
USA “improved” 1 (Cove Point)		
Pipeline transport, distance	**150 km**	*500 km*
Pipeline transport, gas losses	**0.004 %**	*0.015* **%**
Liquefaction, efficiency	**40 %**	*39* **%**
Liquefaction, average outside temp.	**8 °C**	*15 °C*
LNG transport, type of vessels	**SSD, Q-Flex**	*Steam, TFDE*
LNG transport, distance	**6 300 km**	*9 200 km*
USA “improved” 2		
Production and Processing	**Unconv. 65 %**	*Unconv. 85* **%**
	Conv. 35 %	*Conv. 15* **%**
Pipeline transport, distance	**300 km**	*500 km*
Pipeline transport, gas losses	**0.004 %**	*0.015* **%**
Liquefaction, efficiency	**40 %**	*39* **%**
LNG transport, CH_4 slip for TFDE engines	**0.0028 MJ/MJ**	*0.056 MJ/MJ*
USA “improved” 3		
Production and Processing	**Unconv. 0 %**	*Unconv. 85* **%**
	Conv. 100 %	*Conv. 15* **%**
Pipeline transport, distance	**300 km**	*500 km*
Pipeline transport, gas losses	**0.004 %**	*0.015* **%**
LNG transport, CH_4 slip for TFDE engines	**0.0028 MJ/MJ**	*0.056 MJ/MJ*
Liquefaction, efficiency	**40 %**	*39* **%**
Russia “adverse” 1		
Pipeline transport, energy	**2.72 $E10^{-5}$ J/(J*km)**	*1.59 $E10^{-5}$ J/(J*km)*
Pipeline transport, gas losses	**5.94 $E10^{-7}$ J/(J*km)**	*4.05 $E10^{-7}$ J/(J*km)*
Russia “adverse” 2		
Pipeline transport, energy	**2.72 $E10^{-5}$ J/(J*km)**	*1.59 $E10^{-5}$ J/(J*km)*
Pipeline transport, gas losses	**5.94 $E10^{-7}$ J/(J*km)**	*4.05 $E10^{-7}$ J/(J*km)*
Production and Processing	**average Russian gas field, average technology applied**	*new Russian gas field (comparable to Bovanenkovo), top technology applied*

The results of the scenario analysis are presented in the below table.

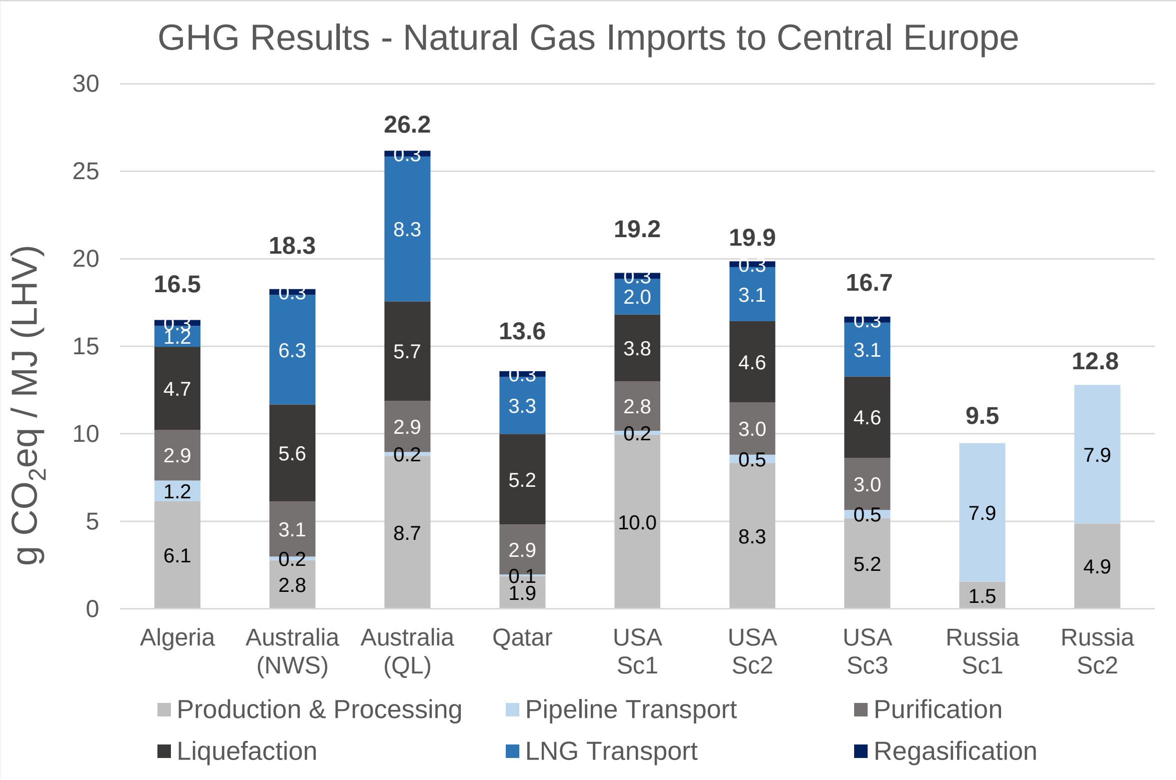


Figure 5-17: Overall GHG results for the different scenarios

The key findings of the scenario analysis are:

Key Findings

- GHG results of LNG imports improve by ~2.5 % and ~29 %.
- GHG results of pipeline import change unfavourably by ~50 % and ~103 %.
- Best LNG import alternative still higher in GHG results than worst-case Russian pipeline import scenario.

The GHG results of the pipeline route continue to outperform those of all LNG import alternatives considered, even:

- **when LNG imports are optimised with scenarios representing technical improvements and theoretical scenarios so these become more favourable, and**
- **Russian pipeline imports are adjusted with theoretical scenarios so these become less favourable.**

Additional scenario analyses are done on the following aspects:

- IPCC 2007 vs. IPCC 2013
- Consideration of End-of-Life (EoL)
- Shorter LNG transport routes due to different entry points to Europe

The results of these analyses are presented in Annex B.

5.5. Uncertainty analysis

Uncertainty analyses test the combined effect of parameter uncertainties on the final results as some of the effects seen in sensitivity or scenario analyses may cancel each other out or reinforce each other.

Uncertainty analysis is performed using Monte Carlo simulation which draws random numbers from defined uncertainty intervals to calculate a multitude of possible results. The less these results vary, the lower is the overall parameter uncertainty of the GHG model.

In the following table, uncertainty intervals are defined for relevant parameters, which are independent from each other, in the GHG model for Russian natural gas import to Europe via NSP2 – called variance 1 and variance 2. 10 000 simulations are run and every simulation is generating a GHG result for the product system based on a random combination of parameter values.

Table 5-18: Uncertainty analysis, Monte Carlo simulation for Russian natural gas via NSP2 to EU – defined variances

Process step	Parameter	Base case	Variance 1	Variance 2
Production and processing	Electricity consumption, from grid mix	0.30 kJ/MJ	-30 %	+30 %
Production and processing	Electricity consumption, from gas turbine	4.76 kJ/MJ	-30 %	+30 %
Production and processing	CH_4 emissions	8.1885E-5 J/J	-60 %	+60 %
Production and processing	CO_2 emissions (excl. CO_2 from fugitive emissions and combustion emissions)	0.00011 %	-30 %	+30 %
Pipeline transport	CH_4 emissions	0.001677 J/J	-60 %	+60 %
Pipeline transport	Energy consumption	1.59E-5 J/(J*km)	-30 %	+30 %

The intervals per parameter are defined with the following premises:

- ±30 % variation for parameter related to energy consumption and CO_2 emissions
- ±60 % variation for parameter related to CH_4 emissions due to higher uncertainty

The results for the Monte Carlo simulation are shown in Table 5-19. The simulations show that the results based on the GHG model with the parameter settings for Russian natural gas imports are stable and robust. The standard deviation of 21.2 % is low. This low standard deviation is visible in Figure 5-20 as the results create a high Gaussian bell curve. The higher the bell curve is, the more stable the results are.

Table 5-19: Uncertainty analysis, Monte Carlo simulation for Russian natural gas via NSP2 to EU – results

Parameter	Value
Base case, GHG result	6.3 g CO_2eq/MJ
Monte Carlo simulation	
Median, GHG result	6.4 g CO_2eq/MJ
Standard deviation	21.2 %
10 % Percentile, GHG result	4.7 g CO_2eq/MJ
25 % Percentile, GHG result	5.4 g CO_2eq/MJ
75 % Percentile, GHG result	7.3 g CO_2eq/MJ
90 % Percentile, GHG result	8.1 g CO_2eq/MJ

The median result of the Monte Carlo analysis (arithmetic average result) correspond to the determined base case result of the study. So, the stability of the base case is confirmed by this analysis. The percentile values show the distribution of the simulation results: for instance, 90 % of all simulation results are below 8.1 g CO_2eq/MJ and 10 % of all simulation results are below 4.7 g CO_2eq/MJ.

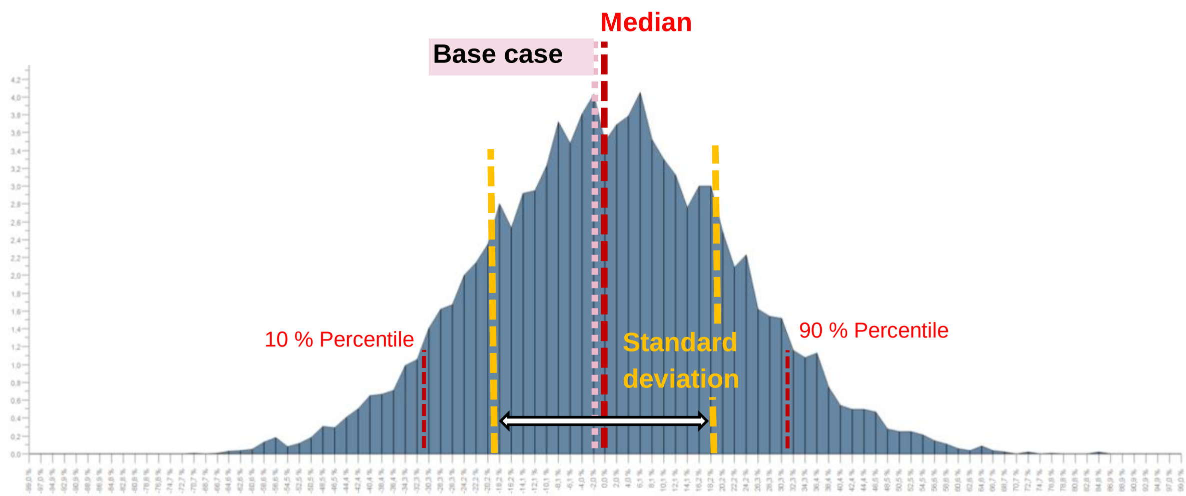


Figure 5-20: Uncertainty analysis, Monte Carlo simulation for Russian natural gas via NSP2 to EU – distribution of results

6. Interpretation

6.1. Identification of relevant findings

The overall GHG result of the different natural gas import options are displayed in Figure 6-1 (duplicate of Table 5.1)

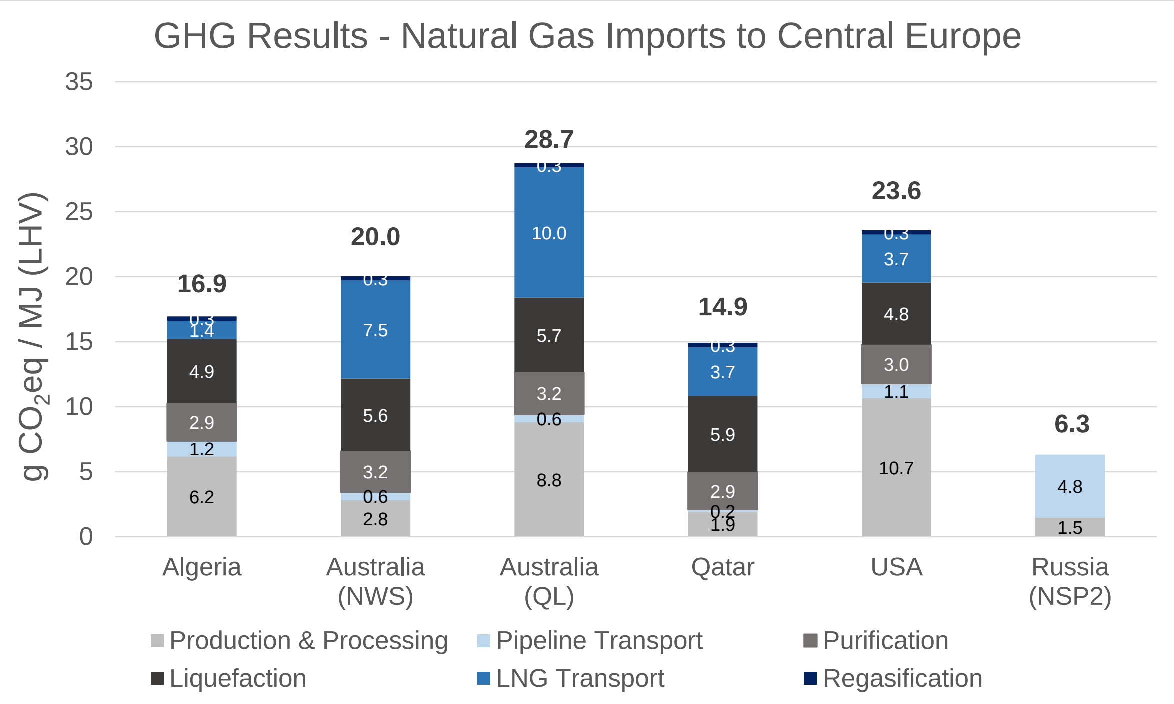


Figure 6-1: Overall GWP result for the base case

In the following, the relevant findings are listed:

- The different LNG import routes are associated with significantly higher GHG results compared with the natural gas import from Russia to Europe via Nord Stream Pipeline 2 (NSP2).
- The NSP2 supply chain shows very low GHG intensity at the new Russian gas field, attributed to low energy consumption and low fugitive emissions in production and processing.
- Therefore, the main driver of product system A GHG intensity is the pipeline transport with a distance of 4 166 km; however, pipeline transport represents high energy efficiency and low rates of methane emissions.
- LNG import GHG results are 2.4 to 4.6 times higher than the pipeline import from Russia via NSP2.
- Main GHG contributors to the LNG routes are production and processing, LNG transport and liquefaction (incl. purification); results also depend to country specific boundaries, like natural gas field characteristic (defining energy demand for production), ambient temperature (defining energy for liquefaction) and methane emissions, as well as technology in use in operations (e.g. efficiency).

- In all cases, CO_2 is the main source of GHG intensity, but CH_4 contributes to overall GHG results (up to 30 %).
- The range of total GHG results related to product system A, including the scenario calculations, is 6.3 to 12.8 g CO_2eq/MJ.
- The range of total GHG results related to product system B, including all scenario calculations, is 13.3 to 28.7 g CO_2eq/MJ.

Comparison of GHG results based on product system level including scenarios

The comparison of single natural gas supplies, e.g. natural gas from Russia via NSP2 versus LNG from Australia-NWS is not meaningful as the provision of natural gas to a region like Europe is always a mix of different supply options. The LNG import alternatives into Europe can be rather seen as "pool". So, Figure 6-2 offers a graphical way of comparing the product system A with product system B results respectively including the "adverse" scenarios for A (see arrow from left to right for Russian import in figure below) and the "improved" scenarios for B (see arrow from right to left for LNG import in figure below).

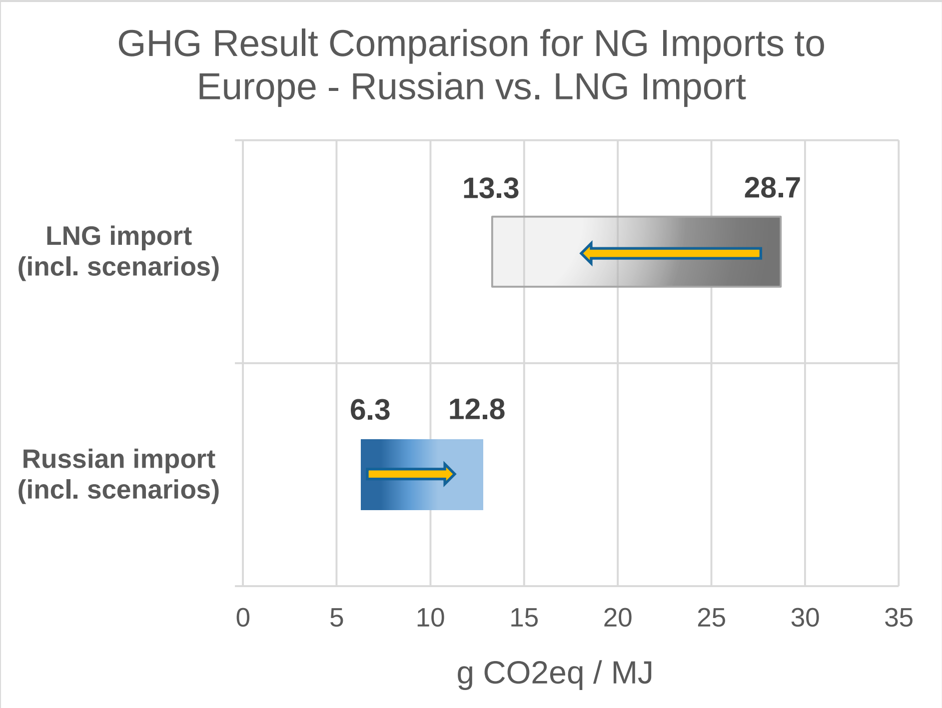


Figure 6-2: GHG result comparison – Russian import (product system A) vs. LNG import routes (product system B), including scenarios ("improved" scenarios for LNG, "adverse" scenarios for NSP2)

The Nord Stream 2 pipeline has an annual capacity of 55 billion m^3 (bcm) of natural gas. With an average energy value of 36.1 MJ/m^3 for natural gas the absolute GHG difference per year comes to between **17.1 and 44.6 million tonnes of CO_2eq** for the difference between the NSP2 base case and the best and worst base cases of the LNG import alternatives (best: Qatar, worst: Australia-Queensland).

6.2. Assumptions and limitations

The assumptions made and limitations identified are compiled in the following:

- Natural gas and liquefied natural gas (LNG) have an equivalent function.
- Europe has to import additional natural gas to fulfil the energy demand in the next 30 years.
- The study assumes future developments in the global and European LNG market, i.e., incremental supply of LNG imports from USA and Australia to Europe based on decreasing European domestic natural gas production.
- Primary data are used for the natural gas from Russia to Central Europe via the Nord Stream Corridor. However, literature data as well as data from the GaBi databases 2016 are used for the LNG import supply chains. While the primary data are referring to 2015, the literature data covers a reference time period of 2012-2015 with the exception of background data for steel and aluminium (steel → worldsteel data based on 2007, aluminium → European Aluminium Association data based on 2010).
- For the base cases of the study, the current technical situation is considered as well as facilities under construction and LNG market forecasts for USA and Australia. Some technical and LNG-market-related settings are assumed, e.g.,
    - New liquefaction plants with higher efficiencies are coming online in Algeria in the next 1-3 years
    - Additional natural gas production in the US for LNG export is sourced mainly from shale gas resources
    - Australian LNG capacities for exports will increase significantly
    - Australian natural gas in Queensland is mainly based on coalbed methane resources
    - The share of applied REC technology at wells tapping unconventional resources (40 %)
    - Amount of boil-off gas used as well as methane emissions due to boil-off gas (BOG) use at liquefaction plants
    - The minimum life time of LNG plants based on literature data (30 years)
    - The utilisation rate for all selected LNG import alternatives to Europe (100 %).
- The scenarios in section 5.4 look at potential future technical development, e.g.,
    - Optimum leakage management for pipeline transport from gas field to LNG terminal
    - Highly-efficient liquefaction technology
    - Best practice re CH_4 slip for TFDE engines at LNG transport
    - CCS applied in Australia-Queensland (projected facilities).
- Some proxy data have been used in the study, but only wherever country- or region-specific data sets were not available. However, no relevant energy carrier is modelled with a proxy dataset. The limitation due to the choice of proxy datasets is, therefore, considered very low.
- End-of-Life (EoL) of the life cycle of both product systems analysed (i.e., the recycling of metal scrap and landfilling of other materials) is not taken into account in the base case of the study. The scenario analysis shows that EoL is of no relevance to the overall GHG results (see Annex B).
- The goal and scope of the study is limited to the analysis of the GHG result. No further environmental aspects are taken into consideration.
- Transmission of natural gas to further distribution and applications in Central Europe is not considered. As the entry points to Europe for both product systems are not exactly the same, that might cause slight deviations in downstream analyses.

6.3. Results of comparison with literature data as well as sensitivity, scenario, and uncertainty analysis

6.3.1. Comparison of GHG results with Literature data

The GHG results are compared with literature data. The three main literature sources used are

- DBI Gas- und Umwelttechnik ("Critical Evaluation of Default Values for the GHG Emissions of the Natural Gas Supply Chain", Final Report 2016, commissioned by Zukunft Erdgas e.V.)
- CIRAIG ("GHG emissions related to the life cycle of natural gas and coal in different geographical contexts", Final Report 2016, commissioned by TOTAL)
- PACE ("LNG and Coal Life Cycle Assessment of Greenhouse Gas Emissions, 2015, Prepared for Centre for Liquefied Natural Gas)

The comparison with the DBI study is performed in detail and the GHG results show comparable results, apart from a 0.8 g CO_2eq per MJ difference that might be caused by the use of different models and different background datasets. However, the calculations and equations in the GaBi model are deemed to be correct.

In summary, the calculated GHG results of this study are in the range of corresponding literature values. Differences can be explained, e.g., the significantly lower GHG values for the investigated Nord Stream 2 pipeline, based on low energy intensive primary data compared with the literature values.

6.3.2. Sensitivity analysis

Sensitivity analyses are performed to test the sensitivity of the GHG results towards changes in parameter values that are relevant for the overall GHG result, based on assumptions or otherwise uncertain.

- The analyses showed for product system A, "supply of natural gas via NSP2 from Russia to EU," that the overall GHG result reacts sensitively to a change in the specific energy consumption at the pipeline operations.
- The analyses also show for product system B, "supply of natural gas via LNG import alternatives to EU," that the liquefaction efficiency has a significant impact on the overall GHG results, especially with a decreasing efficiency.
  - For the US, also the length of the considered pipeline and the share of gas fields with RECs (Reduced Emission Completion) cause significant changes in the overall GHG result.
  - For LNG from Australia and Qatar, the utilisation rate of the LNG vessels is important as well.
  - The variation of the methane emissions is relevant on the Algerian gas field besides liquefaction efficiency.

6.3.3. Scenario analysis

Multiple scenario analyses are performed. The premise of the defined main scenarios is the following:

- Explore those parameter settings which favourably impact the results for LNG imports ("improved" scenarios) and, at the same time, explore those parameter settings which unfavourably impact the results for Russian pipeline import ("adverse" scenarios).

In short, the key settings and key findings are:

- Scenario analysis was performed to compare results between different sets of assumptions or modelling choices.
- The results of the scenario analysis show that the relevant findings of the study's base case are not overturned but that those findings and conclusions are confirmed.
- The gap between both product systems is reduced due to the scenario settings but Russian natural gas imports still perform better than the LNG import alternatives – which means that none of the GHG model and parameter adaptations lead to a GHG results for LNG import alternatives that would be better than for Russian imports via NSP2 specifically, and for Russian imports in general.

In addition, further scenarios on EoL relevance, IPCC factor choice (2007 vs. 2013) and LNG entry point to Europe are analysed (see Annex B) to quantify their influence on overall GHG results. Here, the key findings are:

- EoL is not relevant to the overall GHG results.
- The choice of characterisation factors of IPCC is of minor relevance to the GHG results.
- The choice of the entry point to the European market is relevant for the GHG results for most LNG import routes (independent from the choice of LNG export terminal, e.g., Sabine Pass or Cove Point in the USA). But none of the changes in LNG transport distance lead to a GHG result close to that for the Russian imports via the NSP2.

6.3.4. Uncertainty analysis

Uncertainty analysis is performed to test the robustness of the results towards the combined parameter uncertainty. The product system A, Russian natural gas import to Europe, is tested with 10 000 Monte Carlo simulations for a set of six parameters with defined intervals. The overall GHG result is deemed to be robust based on the simulation results with a low standard variation of 21 % and with a median result of the Monte Carlo analysis corresponding with the base case result.

6.4. Data quality assessment

Inventory data quality (see data source indicator) is judged by its precision (measured, calculated or estimated), completeness (e.g., unreported emissions), consistency (degree of uniformity of the methodology applied) and representativeness (geographical, temporal, and technological).

To cover these requirements and to ensure reliable results, first-hand industry data in combination with consistent background LCA information from the GaBi 2016 database were used. The LCI datasets from the GaBi database 2016 are widely distributed and used with the GaBi ts software. The datasets have been used in LCA models worldwide in industrial and scientific applications in internal as well as in many critically reviewed and published studies. In the process of providing these datasets they are cross-checked with other databases and values from industry and science.

6.4.1. Precision and completeness

- ✓ **Precision:** As the majority of the relevant foreground data are measured data or calculated based on primary information sources of the owner of the technology, precision is considered to be high for the Nord Stream 2 Pipeline. For the LNG import supply chains consolidated and consistent information are used. These information are taken from literature and the GaBi databases 2016. So, for these data the precision can be seen as appropriate according to the goal and scope of the study. Seasonal variations/variations across different manufacturers were balanced out by using yearly averages/weighted averages. All background data are sourced from GaBi databases with the documented precision.

- ✓ **Completeness:** Each foreground process was checked for mass and energy balance and completeness of the emission inventory related to GHG. No data were knowingly omitted. Completeness of foreground unit process data is considered to be high. All background data are sourced from GaBi databases with the documented completeness.

6.4.2. Consistency and reproducibility

- ✓ **Consistency:** To ensure data consistency, all primary data were collected with the same level of detail, while all background data were sourced from the GaBi databases.
- ✓ **Reproducibility:** Reproducibility is supported as much as possible through the disclosure of input-output data, dataset choices, assumptions and modelling approaches in this report. Based on this information, any third party should be able to approximate the results of this study using the same data and modelling approaches.

6.4.3. Representativeness

- ✓ **Temporal:** All primary data were collected for the year 2015. All secondary data come from the GaBi 2016 databases and are representative of the years 2012-2015 with the exception of background data for steel and aluminium (steel → worldsteel data based on 2007, aluminium → European Aluminium Association data based on 2010). As the study intended to compare the product systems for the reference year 2015, temporal representativeness is considered to be high.
- ✓ **Geographical:** All primary and secondary data were collected specifically to the countries or regions under study. Where country-specific or region-specific data were unavailable, proxy data were used. Geographical representativeness is considered to be high.
- ✓ **Technological:** All primary and secondary data were modelled to be specific to the technologies or technology mixes under study. Where technology-specific data were unavailable, proxy data were used. Some technical parameters and assumptions for the Australian coal bed methane production is based on US shale gas information. Technological representativeness is considered to be high.

6.5. Model completeness and consistency

6.5.1. Completeness

All relevant process steps for each product system were considered and modelled to represent each specific situation. The process chain is considered sufficiently complete and detailed with regards to the goal and scope of this study.

6.5.2. Consistency

All assumptions, methods and data are consistent with each other and with the study's goal and scope. Differences in background data quality were minimised by exclusively using LCI data from the GaBi database 2016. System boundaries, allocation rules, and impact assessment methods have been applied consistently throughout the study.

6.6. Conclusions, limitations, and recommendations

This study was performed in the context of a potential future demand for additional natural gas imports to the European market and explores several possible supply options, i.e.

- Natural gas import from Russia via Nord Stream 2 pipeline
- LNG import from USA
- LNG import from Qatar
- LNG import from Australia
- LNG import from Algeria.

The reason for carrying out the study is the anticipated supply gap of natural gas in Europe within the coming 30 years as analysed in the reference scenario 2016 of the European Commission.

The goal of the study is to provide high-quality, reliable and up-to-date GHG intensity data with a life cycle scope for the defined natural gas supply routes into Europe. This is done by performing a carbon footprint comparison between the defined supply alternatives.

The intended application of the study outcome is mainly to inform the dialogue between the NSP2 project team and its external stakeholders. The results are also positioned to provide a scientifically sound basis for any future third-party inquiries.

6.6.1. Conclusions

The main conclusions of this study are as follows:

Goal and Scope

- Comprehensive LCA models are set up to quantify the GHG performance of the different import options. All GHG emissions are displayed in g CO_2-equivalents per MJ (lower heating value (LHV)) of natural gas supplied to the entry point of imported natural gas into the European natural gas grid.
- The goals of the study – provision of high-quality and up-to-date GHG intensity data with a life cycle focus on the defined natural gas supply routes into Europe and comparison of those import supply chains to Europe – are accomplished.
- The defined scope of the study is considered to be appropriate to draw conclusions upon thorough examination of various scenarios, sensitivities and uncertainties of the data and parameters applied.

Result

- Natural gas imports to Europe via the Nord Stream 2 pipeline show environmental benefits with focus on climate change perspective compared with LNG import alternatives.
- The calculated GHG results of this study are in the range of corresponding literature values. Respective differences are explained.

Interpretation

- The robustness of the underlying GHG model in the GaBi software system as well as the GHG results was substantiated by conducting intensive sensitivity, scenario and uncertainty analyses.
- None of the scenarios examined lead to a GHG profile of LNG import alternatives preferable to the Russian import via NSP2 specifically or any of the additional Russian pipeline import scenarios in general.

6.6.2. Limitations

The limitations can be summarized as follows:

- Focus on GHG intensity only; other environmental aspects, like acidification or summer smog, are not considered.
- No primary data collection from industry for the LNG supply chains, but compilation of most recent and relevant publically available data.

6.6.3. Recommendations

The recommendations are as follows:

- Enhance the scope of the study with respect to a broader analysis of various environmental aspects (full LCA).
- By conducting a full LCA, the commissioner will be enabled to differentiate the conclusions from the comparison of both product systems in additional detail. Furthermore, this would provide a broader data basis for communication to external stakeholders.
- Improve the data symmetry by applying underlying data bases for both product systems with primary data based on industry sources, ideally verified by third-party organisations.
- Use the knowledge gained and the sound data bases created to enhance the scope regarding defined application cases of natural gas, e.g., to compare provision of energy by natural gas power plants with renewable energy sources (e.g., wind power, photovoltaic).

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Annex A: Additional result analysis

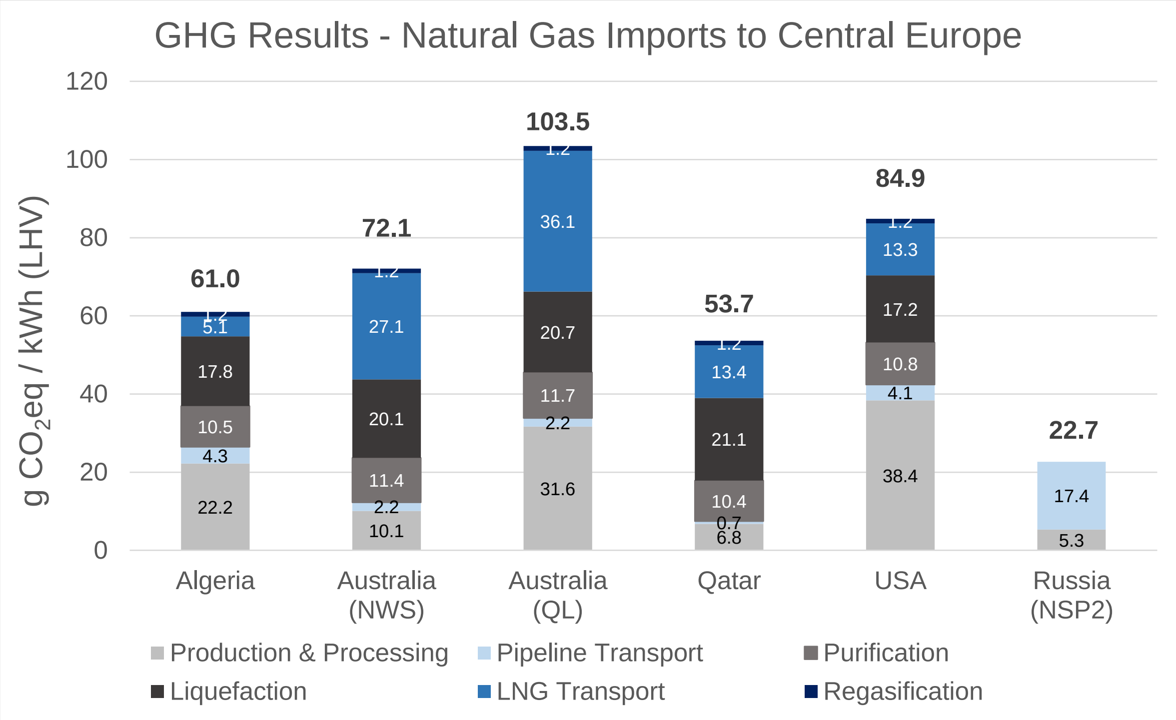
Life cycle inventory analysis results

GHG emission	Russia [g/MJ]	Algeria [g/MJ]	Austr-NWS [g/MJ]	Austr-QL [g/MJ]	Qatar [g/MJ]	USA [g/MJ]
Inorganic emissions						
Carbon dioxide	5.31	11.73	17.13	24.41	12.93	16.33
Nitrous oxide	1.00E-04	2.58E-04	4.89E-04	6.26E-04	3.52E-04	4.25E-04
Sulphur hexafluoride	3.56E-12	1.84E-12	2.67E-12	3.16E-12	1.47E-12	2.92E-12
Organic emissions						
Methane	0.038	0.206	0.111	0.165	0.075	0.285
Tetrafluoro-methane	2.28E-08	7.21E-08	2.24E-07	2.81E-07	1.29E-07	1.30E-07
R116 (Hexafluoro-ethane)	2.53E-09	8.66E-09	2.72E-08	3.41E-08	1.57E-08	1.57E-08
R114 (Dichloro-tetrafluoro-ethane)	9.64E-11	3.17E-10	1.17E-09	1.48E-09	6.91E-10	8.23E-10
R23 (Trifluoro-methane)	9.37E11	4.67E-11	6.10E-11	2.41E-10	7.57E-11	3.46E-10

GWP (Global Warming Potential) 100 years – characterisation factors (factors listed for substances displayed in Table above)

GHG emission	IPCC 2007, AR4	IPCC 2013, AR5
Inorganic emissions		
Carbon dioxide	1	1
Nitrous oxide	298	265
Sulphur hexafluoride	22 800	23 500
Organic emissions		
Methane	25	28
Tetrafluoromethane	7 390	6 630
R116 (Hexafluoroethane)	12 200	11 100
R114 (Dichlorotetrafluoroethane)	10 000	8 590
R23 (Trifluoromethane)	14 800	12 400

Base case results per kWh (LHV)



The basic GHG results in the study are calculated based on the factors of IPCC 2007. The GHG results of a scenario applying IPCC 2013 factors are presented in Annex B.

Annex B: Additional scenario analysis

IPCC 2007 vs. IPCC 2013

The global warming potential impact category is assessed based on the IPCC characterisation factors taken from the 4th Assessment Report (IPCC, 2007) for a 100 year timeframe (GWP100). Therefore, the most current factors from the 5th Assessment Report (IPCC, 2013) for a 100 year timeframe (GWP100) are used in an additional scenario calculation to check the sensitivity of the different factors on the overall results.

The important difference in the context of this study between the characterisation factors is that the factor for CH_4 is 25 in IPCC 2007 and 28 in IPCC 2013 as applied in the CO_2-equivalent calculations. N_2O is 298 in IPCC 2007 and 265 in IPCC 2013 also as applied in the CO_2-equivalent calculations.

IPCC scenario analysis – IPCC 2013 vs IPCC 2007 (base case: IPCC 2007)

Country	Result with IPCC 2013	*Result with IPCC 2007*	Unit
Algeria	**17.5**	*16.9*	g CO_2eq / MJ
Australia-NWS	**20.3**	*20.0*	g CO_2eq / MJ
Australia-QL	**29.2**	*28.7*	g CO_2eq / MJ
Qatar	**15.1**	*14.9*	g CO_2eq / MJ
USA	**24.4**	*23.6*	g CO_2eq / MJ
Russia	**6.4**	*6.3*	g CO_2eq / MJ

The outcome of this IPCC 2013 vs. 2007 analysis is that they are no significant differences in the overall GHG results. The overall GHG results increase compared with the base case by min. 1.3 % (Qatar) to max. 3.4 % (USA).

Consideration of End-of-Life (EoL)

In this scenario, the influence of EoL benefits is taken into consideration for all infrastructure processes.

- Metal scrap: fully recovered and recycled
- Other material: landfilled
- EoL of pipelines, plants and vessels → effect on results mainly due to environmental benefits for recovered and recycled metal scrap (principle of substituting primary material with secondary material)
- Recovery rate is for reasons of simplification set to 100 %, i.e., no loss of materials due to disassembling, separating, sorting etc.

End-of-Life (EoL) scenario– GaBi datasets applied for scenario analysis

Material	GaBi dataset	Data provider
Steel plate, metal scrap	DE: Recycling potential steel sheet	ts
Steel sections, metal scrap	DE: Recycling potential steel sheet	ts
Reinforced steel, metal scrap	DE: Recycling potential steel sheet	ts
Steel UO pipe, metal scrap	DE: Recycling potential - Steel pipe	ts
Aluminium sheet, metal scrap	DE: Recycling potential aluminium sheet	ts
Stainless steel plate, metal scrap	DE: Recycling potential stainless steel sheet	ts
Concrete, construction waste	EU-27: Inert matter (Unspecific construction waste) on landfill	ts
Cement, construction waste	EU-27: Inert matter (Unspecific construction waste) on landfill	ts

The following table shows the GHG results of this scenario analysis.

EoL scenario – EoL included and excluded (base case: EoL excluded)

Country	Result incl. EoL	*Result excl. EoL*	Unit
Algeria	**16.8**	*16.9*	g CO_2eq / MJ
AU-NWS	**19.9**	*20.0*	g CO_2eq / MJ
AU-QL	**28.6**	*28.7*	g CO_2eq / MJ
Qatar	**14.8**	*14.9*	g CO_2eq / MJ
USA	**23.5**	*23.6*	g CO_2eq / MJ
Russia	**6.2**	*6.3*	g CO_2eq / MJ

The outcome of this scenario analysis is that the effect of EoL on the overall GHG results is negligible.

Shorter LNG transport routes due to different entry points to Europe

The effect on the overall GHG results from selecting Rotterdam as the entry point for all LNG import routes to Europe is examined in this scenario analysis. Different entry point countries are chosen which leads to shorter transport distances for the LNG vessels. In all chosen alternative countries, appropriate LNG import terminals are existing or planned.

Scenario with alternative LNG terminals, entry points to Europe

LNG producing Country	Entry point, scenario	*Entry point, base case*	Distance, scenario [km]	*Distance, base case [km]*	Result, scenario [g CO_2eq/MJ]	*Result, base case [g CO_2eq/MJ]*
AU-QL	**Greece**	*Rotterdam*	**16 900**	*22 000*	**25.5**	*28.7*
AU-NWS	**Greece**	*Rotterdam*	**12 300**	*17 400*	**17.2**	*20.0*
Qatar	**Greece**	*Rotterdam*	**6 700**	*11 800*	**13.3**	*14.9*
Algeria	**Italy**	*Rotterdam*	**1 300**	*3 000*	**16.0**	*16.9*
USA	**Portugal**	*Rotterdam*	**8 300**	*9 200*	**23.1**	*23.6*

Key findings:

- The effect on overall GHG results ranges between a minimal 2 % reduction (USA – from 10 % distance reduction) to a max. GHG reduction of 14 % (AU-NWS – from 29 % distance reduction).
- Algeria has the highest reduction in distance with 57 %, resulting in a 5 % reduction in GHG.
- Qatar has the second highest reduction in distance with 43 %, resulting in an 11 % reduction in GHG.

There are some significant reductions in the overall GHG results due to the selection of alternative entry points to the European gas market. However, none of the changes in LNG transport distance lead to a GHG result close to the Russian imports via the NSP2 pipeline (6.3 g CO_2eq per MJ).

Annex C: Critical review report

GHG Intensity

of Natural Gas Transport

Comparison of Additional Natural Gas Imports to Europe
by Nord Stream 2 Pipeline and LNG Import Alternatives
— Critical Review Panel Report

Commissioned by
Nord Stream 2 AG

Review Panel chaired by
DEKRA Assurance Services GmbH
Sustainability & Regulatory Compliance
March 2017

REVIEW STATEMENT

Based upon predictions of a gap in natural gas supply in Europe, the study "GHG Intensity of Natural Gas Transport: Comparison of Additional Natural Gas Imports to Europe by Nord Stream 2 Pipeline and LNG Import Alternatives" uses Life Cycle Assessment (LCA) methodology to examine the greenhouse gas (GHG) impacts of alternative import options via pipeline and liquefied natural gas (LNG) shipping.

In a comparative assertion, the import of natural gas to Europe via the Nord Stream 2 pipeline from Russia is thus demonstrated to have a potentially lower climate impact compared with LNG import alternatives from USA, Qatar, Australia and Algeria.

The critical review panel confirms that the LCA study meets the ISO 14040/44 standards in terms of methodological compliance and formal requirements. Further, the critical review confirms that data sources and life cycle models appear sufficiently consistent and robust to support this interpretation. Assumptions, calculations, and results are transparently and appropriately presented to inform decision makers and stakeholders, such as political or governmental bodies and NGOs involved in the permitting process.

Stuttgart, 17 March 2017

Dr.-Ing. Ivo Mersiowsky
on behalf of
DEKRA Assurance
Services GmbH
Chair of review panel

Matthias Fischer
Fraunhofer Institute
for Building Physics
Co-reviewer

Michael Ritthoff
Wuppertal Institute
for Climate, Environment
and Energy gGmbH
Co-reviewer

CRITICAL REVIEW REPORT

Introduction

Where Life Cycle Assessment (LCA) studies are conducted to derive comparative assertions to be disclosed to the public, the ISO 14040/44 standards require that a critical review is conducted by a panel of independent external experts.

The objectives of this critical review were to –

- Ascertain whether the LCA study meets the ISO 14040/44 standards in terms of methodological compliance and formal requirements;
- Conduct a review of the subject matter, providing an appraisal of data sources, life cycle models, assumptions, calculations, and results in terms of transparency and appropriateness.

The critical review consisted of an analysis of the report with regard to methodological and technical aspects. The panel held two online meetings to assess the study. Further, one face-to-face meeting took place between commissioner, practitioner, and review panel to discuss the questions and comments of the reviewers.

Review Panel

The review panel consisted of the following members:

Dr.-Ing. Ivo Mersiowsky	DEKRA Assurance Services GmbH, Stuttgart	Chair of review panel
Matthias Fischer	Fraunhofer Institute for Building Physics, Stuttgart – part of Fraunhofer-Gesellschaft e.V.	Co-reviewer
Michael Ritthoff	Wuppertal Institute for Climate, Environment and Energy gGmbH	Co-reviewer

Goal & Scope

The review panel confirms that the goal and scope of the study follows from the European Reference Scenario “EU Energy, Transport and GHG emissions – Trends to 2050” which projects a gap in European natural gas supply. Both the prospective volume and the supply options selected for comparison, natural gas via pipeline and liquefied natural gas (LNG) shipping, are derived from this scenario. It is essential to consider the results and interpretation in the light of this goal and scope.

More specifically, the study aims at providing reliable and up-to-date greenhouse gas (GHG) impact data for these supply options informing decision makers and stakeholders, such as political or governmental bodies and NGOs. The review panel considers the comprehensible and balanced presentation of the subject matter to be crucial. While governmental organisations and NGOs involved in the permitting process of a prospective pipeline should find the report informative, the wider public cannot reasonably be included in the target audience of such a comprehensive technical report.

The two product systems – pipeline and shipping – are set out clearly and well-illustrated to allow even a non-expert audience a good grasp of the fundamental options under comparison. The processes included in each option as well as the time coverage, technological coverage, and geographical coverage are clarified. The methodology of the calculation – reference to a functional unit measured as lower heating value, allocation by energy content, no cut-offs, and conservative use of proxy data especially in the background system – is presented in sufficient detail.

Life Cycle Inventory

The review panel discussed the data collection procedure which is underpinned by the practitioner’s philosophy: to render a consistent dataset and model, *thinkstep* draws on three distinct data sources: industry data, literature references, and engineering know-how to ensure internal consistency (for instance, through element, mass, and energy balances as well as cross-referencing among comparable processes). A downside of this procedure is that referencing is often not straightforward. For this reason, the study presents all relevant technical parameters and input/output relationships in a transparent manner to achieve reproducibility. Sensitive parameters, such as flaring, fugitive emissions, and process efficiencies were subject to particular scrutiny in the course of this review.

The proxy data used in the background system (generic fuels, materials, and transportation processes) were exclusively sourced from the *GaBi* database. This ensures consistency, while primary sources are dataset providers such as industry associations (e.g. *Worldsteel*), and also *thinkstep* itself with the above blended approach.

Calculations in the *GaBi* LCA software render a complete life cycle inventory (LCI) of all substance and energy flows. A reduced selection of relevant GHG entries is reported to provide a transparent link between the inventory and impact assessment results. The review panel confirms that the entire LCI was included in the subsequent characterisation step.

Life Cycle Impact Assessment

The study restricts the impact assessment to the GHG emissions (carbon footprint). While entries with less than 0.1% contribution to the climate impact indicator were dropped for readability reasons, all GHG were assessed as per IPCC characterisation factors from the 4th Assessment Report (2007) for a 100 year timeframe.

The study commendably compares its findings with a number of literature sources, in particular other industry and academic studies on similar subject matter. Differences appear minor and are plausibly explained.

A sensitivity analysis was performed to assess the influence of key parameters, identifying pipeline length as the main driver, with energy consumption of pipeline transport and fugitive emissions being additional important influences. In addition, a number of scenarios were analysed varying settings and parameters both for the pipeline and for the LNG import solutions. The review panel confirms that the best LNG import alternative showed still higher GHG impacts than the worst-case scenario for the pipeline.

The review panel extensively discussed the uncertainty analysis which laudably was conducted by means of a sophisticated Monte Carlo analysis. The issue remains that statistical distributions for most parameters, in particular technical parameters or losses, are virtually unknown. Assuming normal distributions in an error margin of 30% or even 60% above and below the base case value seems a defensible approach to assess the impact of such “fuzzy values” on final results. The resulting spread is characterised by 10% and 90% percentiles and confirms that the base case assessment renders robust and qualitatively distinct results.

Interpretation & Conclusions

Consistent with the goal and scope, the report avoids comparisons of the different LNG origins and rather focuses on the difference between natural gas via pipeline and LNG shipping. As a consequence, the pipeline base case is compared with the range of alternative LNG supply routes to North/Western Europe. The review panel holds this solution to be informative for decision makers.

Consequently, the pipeline is conclusively shown to be a dominant solution. The import of natural gas to Europe via the Nord Stream 2 pipeline is thus demonstrated to have a potentially lower climate impact compared with LNG import alternatives.

The study mentions the relevant assumptions and limitations. Particularly, these concern the technological developments during the time period of the next 30 years: both the increased importance of unconventional natural gas sources and the increased efficiency of gas processing technologies introduce an element of uncertainty, balanced by the mid-term perspective of such investments. In view of the analysis conducted, the data and model appear sufficiently consistent and robust to support the interpretation.