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EUROPEAN COMMISSION
DG ENER

STUDY ON ACTUAL GHG DATA FOR DIESEL, PETROL, KEROSENE AND NATURAL GAS

INTERIM REPORT

WORK ORDER: ENER/C2/2013-643

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ABBREVIATIONS

ACG	Azeri–Chirag–Gunashli
AFRA	Average Freight Rate Assessment
AGR	Acid Gas Removal
AIS	Automatic Identification System
APEX	Analysis of Petroleum Exports
APG	Associated Petroleum Gas
API	American Petroleum Institute
BAT	Best Available Techniques
BCF	Billion Cubic Feet
BPS	Baltic Pipeline System
BTC	Baku-Tbilisi-Ceyhan
CARB	California Air Resources Board
CDU TEK	Central Dispatching Department of Fuel Energy Complex
CDP	Carbon Disclosure Project
CHP	Combined Heat and Power
CI	Carbon Intensity
CIF	Cargo Insurance Freight
CNG	Compressed Natural Gas
CNPC	China National Petroleum Corporation
CPC	Caspian Pipeline Consortium
DEA	Danish Energy Agency
DECC	Department of Energy and Climate Change
DEFRA	Department of Environment, Food and Rural Affairs
DG ENER	Directortate General for Energy
DUC	Danish Underground Consortium
DWT	Dead Weight Tonnage
EBRD	European Bank for Recontstruction and Development
EC	European Commission
EEA	European Environment Agency
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
ETS	European Trading Scheme

EU	European Union
EW	Environmental Web
FCC	Fuel Catalytic Cracking
FOB	Free on Board
FOR	Flaring to Oil Ratio
FQD	Fuel Quality Directive
FSU	Former Soviet Union
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas
GOR	Gas-to-oil ratio
GWP	Global Warming Potential
HCICO	High Carbon Intensity Crude Oil
ICCT	International Council on Clean Transportation
ICE	Inter Continental Exchange
IEA	International Energy Agency
IFP	Institut Français du Pétrole
ILUC	Indirect Land Use Change
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
ISO	International Organization for Standardization
JEC	JRC - EUCar and CONCAWE
JRC	Joint Research Centre
LCA	Lifecycle Assessment
LCFS	Low Carbon Fuel Standard
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
MCON	Marketable Crude Oil Name
MENA	Middle East and North Africa
mmcm	million cubic meters
MS	Member State
MTA	Million Tonne per Annum
NCS	Norwegian Continental Shelf
NETL	National Energy Technology Laboratory
NG	Natural Gas
NNPC	National Nigeria Petroleum Company
NOAA	National Oceanic and Atmospheric Administration

NPD	Norwegian Petroleum Directorate
NWE	NorthWest Europe
OGJ	Oil and Gas Journal
OGP	International Association of Oil & Gas Producers
OPGEE	Oil Production Greenhouse gas Emissions Estimator
OSPAR	Oslo and Paris Convention
PDVSA	Petroleos de Venezuela
RED	Renewable Energy Directive
SCO	Synthetic Crude Oil
SOC	(Iraq's state-owned) South Oil Company
SOR	Steam-to-Oil Ratio
TEOR	Thermally Enhanced Oil Recovery
toe	tonne of oil equivalent
ToR	Terms of Reference
TSP	Technical Service Provider
UAE	United Arab Emirates
UGTS	United Gas Transmission System
ULCC	Ultra Large Crude Carrier
ULSD	Ultra Low Sulphur Diesel
UNFCCC	United Nations Framework Convention on Climate Change
VFF	Venting, Flaring and Fugitive
VLCC	Very Large Crude Carrier
VOR	Venting to Oil Ratio
WOR	Water to Oil Ratio
WSPA	Western State Petroleum Association
WTI	West Texas Intermediate
WTO	World Trade Organization
WTT	Well-to-Tank
WTW	Well-to-Wheel
WWF	World Wildlife Fund

SUMMARY

This project, “Study on actual GHG data for diesel, petrol, kerosene and natural gas”, is implemented by EXERGIA S.A. (Leader), in collaboration with E3M-Lab (Economics Energy Environment Modelling Laboratory) of the National Technical University of Athens and COWI A/S. This Report is submitted at the end of the 6th month that is end of October, whereas the total project duration is 15 months.

The project implementation is organized in six discrete Tasks (a to f) with the addition of the project management Task 0. Two of the Tasks, namely **Task a: Literature survey** and **Task b: Data acquisition,** have been completed and two of the Tasks, namely **Task c: Models to estimate max and min GHG emissions** and **Task d: Emissions due to accidents and other operational failures** are in good progress according to the project schedule. The remaining two Tasks, namely **Task e: Other issues related to sustainability** and **Task f: Emissions projections up to 2030** have been initially considered. In general the proposed schedule of project activities has been followed and till the time of Interim Report there is no indication that amendments are necessary.

The major effort of the Consultant has been addressed to the activities of data acquisition and especially in collecting lifecycle Actual GHG emissions data**,** both for oil and natural gas, in accordance to the main objective of the project mandate. Thus, all open sources of relevant information have been investigated, mainly availed by national, international organizations and oil and gas associations. Furthermore, all major oil and natural gas companies have been contacted related to oil and gas streams directed to the EU and requested specific and disaggregated data per process. The results were satisfactory in countries where organized GHG emissions are registered and relevant reporting procedure are in place (e.g. Norway, UK, Netherlands, Denmark, etc.). On the other hand, aggregated actual data were also identified in the UNFCCC reports of Annex I countries and in specific reports of companies operating the oil and gas fields. The response of the oil and gas companies contacted for provision of GHG disaggregated data was very poor till now. For the cases where actual could not be found, we intend to assess GHG emissions by using two models, namely OPGEE for oil and GHGenius for natural gas. Consequently, the necessary input data for these models were gathered. Especially, regarding the estimation of the downstream oil sector GHG emissions we updated the PRIMES-Refinery model with recent information about the EU refining capacity and developments.

Resonable assumptions were made in order to structure the estimations of GHG emissions in comprehensive and realistic pathways for the EU, we proceeded to reasonable assumptions. The Marketable Crude Oil Name (MCON) system was used as the basis for oil sector pathways definition and the Gas Stream concept for natural gas sector respectively. In addition, focus was given on the most significant flows of oil and gas imported in the EU, leaving aside the small and insignificant fuel flows.

Therefore, around 100 pathways of oil products (petrol, diesel, kerosene) GHG emissions estimations were considered and respectively around 40 pathways for natural gas products (CNG, LNG) supplying transportation. For all these pathways the lifecycle GHG estimation will be carried out either as an elaboration of actual data, or as a model output or as a combination of both approaches.

1 REVIEW AND PROGRESS OF STUDY TASKS

1.1 INTRODUCTION

In order to reach the targets set by the Renewable Energy and Fuel Quality Directives, a certain percentage of fuels used in the transport sector nowadays have to be replaced by biofuels. Sustainability issues arising from the enhanced use of biofuels and the Greenhouse Gas (GHG) emissions from their whole lifecycle have been discussed extensively; however, there is no detailed information about the **actual lifecycle GHG emissions** of fossil fuels consumed in the transport sector.

In many cases, lifecycle GHG emissions of biofuels are compared to the respective average emissions of oil products used as fuels in transport. In order to provide a fair and clear picture of fossil fuel GHG emissions directed to transport, more detailed data, especially throughout Europe, are needed. Therefore, the overall aim of this project is to provide lifecycle GHG emissions based on the actual data as possible. The considerable information uncertainty endorsed to collection and elaboration of these data might be tackled with estimations on the range of the GHG emission quantities in the form of minimum and maximum values.

Therefore, the lifecycle Carbon Intensity (CI) of petrol, diesel, kerosene and natural gas will be assessed in a “well-to-tank” approach. In general, “well-to-tank” emissions refer to those ones associated with fuel pathways from extraction up to fuelling the tanks of land, sea and air transportation means. A chain of significant production stages of oil and gas, like exploration, exploitation, upgrading, transportation, transmission, refining, distribution, etc. are considered; thus excluding the final stage of combustion in the transportation means’ engines.

The study results will be based on data acquisition from reliable and official sources and on output from consistent and widely acceptable GHG emissions and energy models.

The project has been assigned through the REQUEST NO: ENER/C2/2013-643 and will be implemented by **EXERGIA S.A**. (leader), in collaboration with **E3M-Lab** (Economics Energy Environment Modelling Laboratory) of the National Technical University of Athens and **COWI A/S**. These three organisations are core members of the consortium led by COWI Belgium, which participates in the Framework Service Contract SRD MOVE/ENER/SRD.1/2012-409-LOT3-COWI. The group of organizations accumulates important experience in energy and GHG modelling relative to energy policy decision making, collection and elaboration of data and analysing sustainability issues.

Lastly, readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the European Commission.

1.2 LEGAL CONTEXT

The EU policy on GHG emissions of oil products is implemented under the context of two Directives:

- **(RED) Renewable Energy Directive** (2009/28/EC) and
- **(FQD) Fuel Quality Directive** (2009/30/EC)

In the framework of mandatory national overall targets and measures for the use of energy from renewable sources provided by the RED, the overall target set for the EU is at least a 20 % share of energy from renewable sources in the Community's gross final consumption of energy in 2020. According to Article 3/4 of the RED, each Member State shall ensure that the share of energy from renewable sources in all **forms of transport in 2020 is at least 10 % of the final consumption** of energy in transport in that Member State. The blending of biofuels is one of the methods available for Member States to meet this target, and is expected to be the main contributor. Also in Article 17/2 it is provided that under sustainability criteria biofuels under consideration should reduce GHG emissions by at least 35% compared to substituted gasoline or diesel. Thus volumetric targets are set, but also some sort of mandatory CI performance is imposed, which is implemented in the broader area of conventional fuel substitution. The latter GHG emissions percentage increases to 50%-60% by January 1, 2017 according to set provisions.

On the other hand, the FQD, Article 7a mandates that Member States shall require suppliers to reduce as gradually as possible life cycle greenhouse gas emissions per unit of energy from fuel and energy supplied by **actually up to 6 %** by 31 December 2020; thus setting this way a Low Carbon Fuel Standard (LCFS). As in the RED, the greenhouse gas emission saving from the use of biofuels taken into account shall be at least 35 %. Furthermore, with effect from 1 January 2011, suppliers shall report annually, to the authority designated by the Member State, on the greenhouse gas intensity of fuel and energy supplied within each Member State by providing, as a minimum, the following information:

- the total volume of each type of fuel or energy supplied, indicating where purchased and its origin; and
- lifecycle greenhouse gas emissions per unit of energy.

An accurate accounting of the lifecycle GHG emissions of fossil fuel extraction based on actual data is important for the implementation of both Directives, due to the required fulfilment of the volumetric target. Especially in the case of the FQD the accounting is requested also as a necessary tool to assess and verify GHG emissions. A differentiated accounting of GHG emissions of various oil and gas streams contributes in demonstrating cases of low and high carbon fuels, but also in considering measures for reductions in the carbon intensity at the stages of extraction, transportation and refining, in principle. The comparison with alternative or renewables based fuels (biofuels, electricity, CNG, LNG, etc.), mentioned in both Directives, becomes substantial and realistic in the case of differentiated accounting. Therefore a combination of policies could be undertaken towards fulfilling the set targets for the transportation fuels.

1.3 OVERVIEW OF STUDY TASKS

Figure 1.1 depicts the main Tasks of the project and the main data flows and information linked with the project tasks. In the following Sections a brief description of these Tasks is presented.

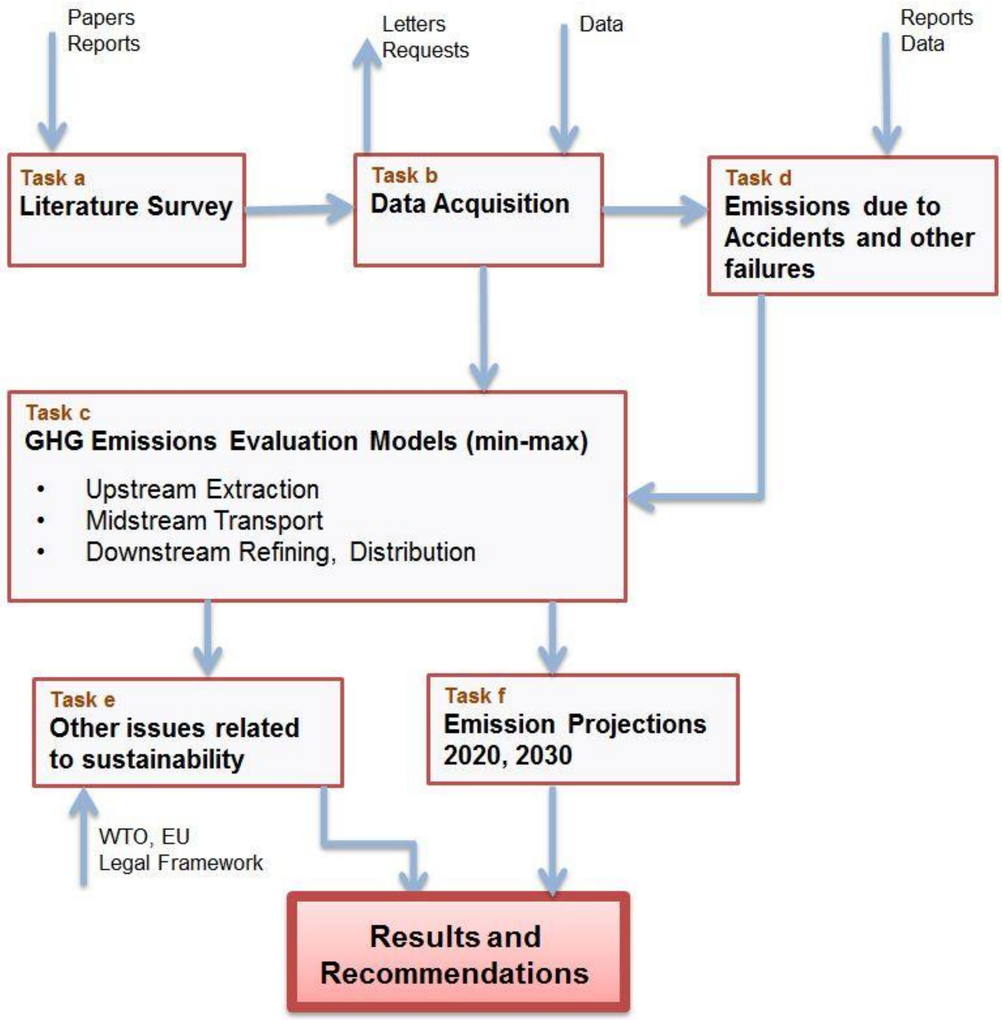


Figure 1.1: Diagram with project Tasks and flows of information inputs

1.3.1 Task a: Literature survey

The starting point of the literature survey is the in-depth analysis of EU legislation related to GHG emissions of transport fuels and its targets, as well as the Member States' laws that comply with these targets. More specifically, the Directives that are being used as reference, i.e. the Renewable Energy Directive (RED), along with the

National Renewable Energy Action Plans submitted by the Member States and the Fuel Quality Directive (FQD) are analysed thoroughly, in order to understand the requirements of EU policies and their implementation within the legislation of each Member State. Moreover, all relevant EC Communications and Initiatives will be reviewed, in order to further comprehend the principles and recommendations of EU GHG emissions policy.

The literature survey covers also a broad range of subjects related to GHG emissions of lifecycle of diesel, petrol, kerosene and natural gas and will break these down by type. The subjects that are covered will include e.g. GHG emissions calculation methods, fuel extraction, fuel transport, fuel refinement, etc. Additionally, the literature survey includes a broad range of information resources that are also broken down by type, e.g. private companies reports, international organisations reviews, scientific papers, etc.

The literature survey focuses on the **most up-to-date data and knowledge on the subject of GHG emissions** and is based on two methods: extensive online literature search, as well as identifying valuable items based on discussion and communication with stakeholders. The consultant sets the criteria, in communication with the Contracting Authority, that allow sorting out the various reading materials, in order to create a literature database.

The main output of this Task is a comprehensive categorised literature database based on the assessment of available documentation.

1.3.2 Task b: Data acquisition

It is stressed that the outcome of the assignment is largely dependent on the development of a detailed and robust database. In principle, **the Consultant bases the analysis on actual data** provided mainly by public organizations, oil companies and oil companies' associations. However, acknowledging the fact that oil companies have been reluctant to disclose data in the past, information from other sources are used for the development of the database that will be the basis for the assessment of the GHG emissions (to be carried out during Tasks c and f).

This project mandate suggests a two-step approach regarding data collection that involves data acquisition from private companies and data acquisition from other open access sources, including international organisations. Necessary information refers to all sectors of the oil and gas fuels value chain (upstream, midstream, downstream), i.e. data pertaining to the crude oil extraction, tanker transportation, gas production and transmission, LNG and CNG transformation, energy consumption in refineries, venting/flaring emissions, data regarding unconventional oil and gas production and transportation, etc.

The main output of this Task is the database on direct GHG emissions from the lifecycle of diesel, petrol, kerosene and natural gas concentrating on the year 2012 that will be the main input to the following modelling Tasks.

1.3.3 Task c: Models to estimate max and min GHG emissions

The focus of this study is the assessment of the well-to-tank (WTT) GHG emissions of petroleum fuels and natural gas. **Actual data of GHG emissions are considered in priority, however in cases of lack of proper data the use of specialized models**, namely OPGEE for oil and GHGenius for gas, are used to estimate the necessary GHG emissions. These models are modified to adapt to the EU reality in terms of gas and oil imports and transmission, processing up to distribution to tanks of final consumers. Differentiated oil pathways based on Marketable Crude Oil Names (MCONs) are used for oil types reaching the EU refineries. Respectively the main gas streams of gas are used to represent the gas pathways from the main gas producing fields up to their entry to the transmission systems of the EU countries and their transfer to distribution to final consumers in the form of CNG or LNG.

The GHG emissions associated with petroleum fuels and natural gas are estimated based on the data collected during the course of Task b; in principal this study intends to make use of actual data obtained from private companies and other sources, as specified by the requirements of Task b. In case disclosure of actual data by companies is not feasible, other sources will be used; the latter will be determined during the development of the database that will be undertaken in Task b. The already existing OPGEE and GHGenius databases serve as guidance to determine information requirements and as checks to verify the quality and accuracy of the new data to be collected.

The present study additionally takes into account oil from unconventional sources. Emissions due to bituminous sand, shale oil and gas extraction and upgrading are estimated separately. The estimation will take into account emissions due to energy consumption and venting/flaring emissions within the unconventional oil and gas extraction and upgrading stages.

The midstream GHG emissions pertain to emissions resulting from the feedstock transportation from the extraction source to the refinery gate. Emissions mainly occur due to the energy consumption during the transport of petroleum and its products and gas. In addition to seaborne transportation, land transportation (most commonly via pipelines) is included. For natural gas transportation the present study will use the currently available PRIMES gas supply model and database, which is very detailed and has sufficient resolution, including all current and future gas pipelines (Eurasian and North Africa coverage) as well as details on the global trade, liquefaction and gasification of LNG.

The present study estimates GHG emissions of petroleum fuels during the upstream and midstream sectors at world level, i.e. feedstock originating from all continents will be taken into account. However, only the EU refinery system will be taken into consideration in regard to the processing of the fossil fuels at downstream operations. In order to associate emission factors to the concrete refinery output products (diesel, petrol, kerosene) in a more adequate manner, the study uses a methodology, which allows calculation of both average emission and marginal emission factors. This method includes allocation of emissions to individual products based on marginal emission content.

The output of Task c is the minimum and maximum GHG emission factors associated with the WTT supply chain of diesel, petrol, kerosene and natural gas for the year 2012.

1.3.4 Task d: Emissions due to accidents and other operational failures

The objective of this Task is to evaluate the importance of the various sources of indirect GHG emissions identified within the existing literature and data resources. The indirect emission sources have to be considered in addition to the direct emissions related to upstream, midstream and downstream processes. The most significant sources of indirect GHG emissions of fossil fuels include (among others):

- Emissions from **accidents outside of normal operation conditions:** These include the emissions from the accident itself, the emergency response and clean-up or remediation efforts.
- Emissions from **induced land development:** The Induced Land Development is the land use change that is caused by fossil fuel extraction in an indirect way, i.e. the construction of access roads for oil and gas extraction etc. This type of indirect emissions is in correspondence with GHG emissions produced by the Indirect Land Use Change (ILUC), which is an important emissions source for biofuels.
- Emissions caused by **military involvement:** These include the military activities and reconstruction efforts to protect and stabilise the supply of oil to global markets, i.e. from military vehicles, military infrastructure etc.

The main output of this Task will be the data on indirect GHG emissions from the lifecycle of diesel, petrol, kerosene and natural gas that will be considered in addition to the direct emissions for the completion of the picture of 2012.

1.3.5 Task e: Other issues related to sustainability

Depending on the emission levels found for various fossil fuels, the EU is likely to be faced with a variety of policy options. Indeed, the EU could decide to impose a cap on the emissions of fossil fuels, which could in turn result in certain trade restrictions that may be incompatible with international trade law. Furthermore, depending on the values found, the EU could decide to revise the greenhouse-gas-emission saving values, targets and other conditions, which are set in the Renewable Energy Directive (2009/28/EC) and the Fuel Quality Directive (2009/30/EC). Therefore the objective of Task e is to study the above two significant effects.

In light of the above, a Task exploring the various policy options as well as potential trade law concerns appears pertinent. Therefore, the current Task includes a **legal and policy exercise** addressing these issues.

The analysis and results of Task e will provide the EU with the necessary background allowing it to continue framing a robust and sustainable policy, while avoiding exposure to potential WTO litigation.

1.3.6 Task f: Emissions projections up to 2030

The study will address the objective of Task f using the **official projections provided by E3M-Lab to the European Commission in 2013 using the PRIMES** large scale energy model. Projections of demand and supply of oil fuels and natural gas will be used for a Reference and a Decarbonisation scenario as quantified using the PRIMES energy system model for the European Commission in 2013. Refineries inputs and outputs are also explicitly projected by the PRIMES model. PRIMES also provides projections regarding net imports of refinery feedstock, ready-to-use refinery products and natural gas. The coverage is by EU Member States.

The projected net imports of refinery feedstock and ready-to-use petroleum products by PRIMES will be analysed based on country of origin and type, in order to obtain detailed commercial flows. The analysis for projection years will be based on assumptions relevant to current trends and to future production/import projections. These assumptions will be harmonized to latest IEA World Outlook projection of global oil/gas trade flows and regional production. For all projection years, average/marginal emissions of the fuel WTT supply chain will be calculated. Emissions will be allocated to each fuel based on the marginal emission content of fuels. Similarly to Task c, the output of the analysis will be a range of GHG emissions resulting from the WTT supply chain.

The output of Task f will be the minimum and maximum GHG emission factors for projection years until 2030 (with emphasis up to 2020) associated with the WTT supply chain. Similarly to the Task c output, results will be presented in a tabular format for each fuel.

1.4 Contribution of The Present Study to Oil and Gas GHG Emissions Assessment

This project contributes to the scientific area of lifecycle GHG emissions assessment of oil and gas directed to transport sector by combining methods and approaches, which build on the existing experience and the available information by public institutions and private companies. Certainly there is a number of important studies carried out in both sides of Atlantic, which provide key background information for the current study as they provide recent data and/or approaches. A brief presentation of these studies in the following Sections provide an overview of their scope and main characteristics and indicates the differences compared to our project analysis and scope.

The main characteristics of this study could be considered as follows:

- **Emphasis and priority is placed on the collection and use of actual data.** This approach is interpreted in two ways: either effort to use directly available

GHG data coming from reliable sources or in case the analysis of the collected data is not sufficient for direct use, utilization of actual data on verification exercises concerning data produced from models or other analyses of relevant studies.

- **The WTT approach includes full and thorough analyses of upstream, midstream and downstream stages for the EU case.** Therefore our approach is absolutely related to the most significant pathways or streams of oil and gas fuels addressed to the EU transportation sector, thus covering mostly the presentation of the current situation (2012), but also carrying out the necessary extrapolation up to 2030 by using the most well-known model (PRIMES) for the EU energy economic policy assessments.
- **Linkage of upstream and midstream stages through the MCON concept.** The utilization of the concept of MCON aims at correlating the physical properties characterizing crude oil as it is extracted from the oil field and those of the crude oil blended during or before the refining process. Furthermore, the concept of MCON practically facilitates the connection of the refinery input (which has a marketable name) with the primary source of crude oil (at the oil field).
- **Use of min/max methodology.** The study aims at developing an integrated, consistent and detailed methodology to evaluate the actual range of emissions in the form of minimum, weighted average and maximum values that relate to the whole lifecycle of diesel, petrol, kerosene and natural gas. The presentation of final GHG emissions per MCON or final fuel in a range incorporates the inherent uncertainties around GHG emission estimation and allows policymakers to better evaluate the emissions of each primary source or final fuel as these are illustrated in a more objective manner.
- **Incorporates indirect emissions and unconventional crude oil and natural gas cases.** We do not ignore the contribution of indirect GHG emissions, although they are considered of small scale in comparison to the direct emissions. Furthermore, we consider potential and characteristic pathways of unconventional oil and gas that might play significant role in the supply of EU in the forthcoming years.
- **Place particular emphasis on significant oil and gas streams for EU supply.** Especially, we consider that the size and the significance of the Russian oil and gas directed to the EU requires proportional effort for the analysis, given that the provision of information is poor at institutional and energy company level. For example we try to cope with difficulties on the disaggregation to specific types of crude oil, where several types of MCONs might be depending on the mode of transport, port and transport costs. In general although we pace a step forward on this analysis the lack of proper data remains a restrictive factor.
- **Detailed assessment of crude oil emissions using the OPGEE model.** In the absence of direct GHG emissions data by oil companies, the Consultant has used the OPGEE model for the assessment of GHG emissions for the upstream and midstream life cycle stages. OPGEE is a complex engineering model that requires a large amount of data as inputs. The collection of such data has been a rather time consuming Task, since it requires research in a large amount of sources. The effort and the resources that have been committed by the Consultant for the collection of OPGEE inputs have been based on the parametric analysis of inputs. For the missing inputs smart default values are

used by the model. Our effort is to minimize the use of the default values and thus to optimize the accuracy of the estimated GHG emissions.

- **Assessment of emissions of oil refined products imported in EU.** Besides crude oil imports, EU is increasingly importing refined oil products primarily from Russia and United States of America. This fact is usually being overlooked in relevant studies. In the context of this study the emissions of refined products imported from the United States and Russia will be assessed as these constitute significant part of EU final fuel supply.

1.4.1 JEC Report: Well-To-Tank (WTT) emissions

The present version of this report (version 4) has been published by the JEC Consortium in July 2013 (JRC - EU Commission's Joint Research Centre, EUCAR - the European Council for Automotive R&D and CONCAWE - the oil companies' European association for environment, health and safety in refining and distribution) and replaces the previous version (version 3c).

The current version of the study addresses the processes of producing, transporting, manufacturing and distributing a number of fuels suitable for **road transport powertrains**. Oil products and gas in the form of CNG are included also. It covers all steps from extracting, capturing or growing the primary energy carrier to refuelling the vehicles with the final fuel.

In this study, all fuels and primary energy sources (crude oil, coal, natural gas, shale gas, LPG, biomass, nuclear energy, wind energy and electricity) that appear relevant within the analysed timeframe, which broadly speaking is the next decade, i.e. around 2020-2025, have been considered and it has been attempted to answer the following questions:

- What are the alternative uses for a given resource and how can it best be used?
- What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?

The primary target of the study has been to establish the energy and greenhouse gas (GHG) balance for the different routes. The methodology used is based on the description of individual processes, which are discreet steps in a total pathway, and thereby easily allows the inclusion of additional combinations, that will be regarded as relevant in the future. The study is forward-looking and considers state-of-the-art technology to assess and project future choices.

The average WTT GHG emissions for crude oil based fuels for Europe has been estimated at slightly above 15 grCO_2/MJ of final fuel. The processes that have been analysed are production and conditioning at extraction source, transportation to the market, conditioning and distribution and transformation near the market for all types of fuels. The study concludes that crude oil refining is the most energy-consuming step followed by crude production.

For Compressed Natural Gas (CNG) the GHG balance is estimated at approximately

13 g CO_2/MJ of final fuel for EU mix supply. CNG from imported natural gas on an average distance of 7,000 km (typically Russia) is estimated at above 22 grCO_2/MJ final fuel, while CNG from imported NG from an average distance of 4,000 km (typically Middle East, Caspian Sea) is estimated at approximately 16 grCO_2/MJ. Emissions for CNG coming from LNG stations vary from approximately 17 grCO_2/MJ to 22 grCO_2/MJ (depending mainly on the vaporisation and liquefaction process).

Version 4.0 of the JEC WTT report is a comprehensive analysis of primary fuels pathways and GHG balances. Even though, the high level methodology is analysed sufficiently, the GHG emissions results are mostly aggregated and only in some cases uncertainty is estimated (gas). Furthermore, emphasis is placed on detailed analysis of alternative or unconventional fuels, whereas gas and oil products for transport are rather treated in a way not relevant to their significance for the EU energy balance.

1.4.2 NETL Report: An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions

The National Energy Technology Laboratory (NETL) has analysed the full lifecycle GHG emissions of transportation fuels derived from **US crude oil and crude oil imported to the US** from the most significant exporting countries. The study analyses the impact of crude oil from a WTT perspective for the following lifecycle stages:

- Raw Material Acquisition (Associated Natural Gas Flaring and Venting, Bitumen Extraction and Upgrading);
- Emissions by Feedstock Source;
- Raw Material Transport;
- Liquid Fuels Production (refining of crude oils of different quality).

This analysis reveals that producing diesel fuel from imported crude oil results in WTT GHG emissions that are, on average, 59% higher than diesel from domestic crude oil (22.6 versus 14.2 grCO_2eq/MJ). The study concludes that imported crude oils are on average heavier and contain higher levels of sulphur, and the controls on venting and flaring during crude oil production are not as good as in US operations. The study also shows that Venezuela bitumen, Canada oil sands, and Nigerian crudes stand out as having high GHG emissions compared to other sources.

The NETL clearly outlines the scope of the analysis and the system boundary for the LCA. It takes into consideration the most important emission sources and excludes from the analysis construction-related emissions and any emissions from land use change. The analysis conforms to the International Standards Organization (ISO) 14040 and 14044 lifecycle assessment standards. Lastly, the analysis has been conducted on a country basis, rather than crude oil type or oil field basis, which provides a more generic assessment of crude oil type’s carbon intensity.

1.4.3 ICCT Study: Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels Consumed in the European Union

The main goal of this study prepared by the International Council for Clean Transportation (ICCT) in collaboration with Energy Redefined (ER), Stanford University and Defense Terre, is to define the **Carbon Intensity (CI) for crude oils entering the European Union** up to the refinery gate. The analysis is based on the list of crude oil imports published by DG ENER for 2010. Emphasis is given on the use of publicly available data and publicly available LCA GHG assessment models.

The report begins with a thorough analysis of existing legislation and a presentation of the sources of European crude oils. Then, it presents and compares productively the results of several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions. Onwards, it provides information on OPGEE, a spreadsheet model for lifecycle analysis of crude oil extraction and transportation, developed by Stanford University and provides an estimate using that model of the carbon intensity of crude oil supplied to the European Union. The objective is to calculate the carbon intensity (CI) for the most important types of crude oil entering the EU.

The analysis has been done on an oil-field basis by collecting key data for each one of these. Each aggregated type of crude, as given in the DG ENER list, was further correlated to oil fields contributing to each given type of crude oil entering the EU. In total, 265 oil fields worldwide covering 93% of European oil consumption were considered. Available data to be used as inputs in OPGEE were thoroughly analyzed and commented within the report.

The study concludes that the biggest challenge in calculating the CI of crude oil pathways is the collection of robust data. Given the available data, the volume weighted average upstream emissions of crude oil arriving to European refineries were estimated using OPGEE at 10 grCO_2eq/MJ, which is lower than the CI of crude oil consumed in California, but slightly higher than the estimations of previous studies.

This study includes one of the most comprehensive estimations for carbon intensity of crude oil entering Europe and one of the few conducting a detailed analysis on an oil field basis. However, it does not provide the percentage in which the oil fields participate into the aggregated types of crude, thus being unclear on the method used for the final calculation of carbon intensities of the aggregates.

1.4.4 ICF Study: Independent Assessment of the European Commission's Fuel Quality Directive's "Conventional" Default Value

This report has been prepared by ICF International in 2013 and analyzes the lifecycle GHG emissions for diesel and petrol with a two-fold objective: (a) to analyze the methodology that has been used in the last JEC reports (version v3c and version 4.0) to determine the default conventional crude oil, gasoline and diesel carbon intensity values; and (b) building on that knowledge, to develop a more accurate carbon intensity range for gasoline and diesel from conventional crude oils, using the OPGEE model.

The study elaborates a lifecycle analysis from “well-to-tank” (WTT) perspective taking into consideration the most important emissions sources during crude oil extraction and production, venting, flaring, and fugitives, crude oil transport and refining. It gives specific emphasis on data quality and availability since these are two of the most important factors in LCA estimations. The study also points out the lack of reliable reported data for crude oils outside Canada and the USA. In order to mitigate this, ICF uses literature data that by definition introduce some bias in the analyses.

The study estimated as the most likely range of crude oil GHG intensity from production processes using the OPGEE model at 2.0–5.9 grCO_2eq/MJ and from VFF (Venting, Flaring, Fugitive) releases at 3.8–11.0 grCO_2eq/MJ.

The ICF study builds on existing LCA methodologies and conducts a comprehensive literature review of existing studies. Unlike other studies which mainly analyze GHG emissions on a regional or country basis, ICF uses the concept of MCON introduced by California Air Resources Board (CARB), while the analysis of GHG emission intensity per MCON is done via representative oil fields. Nonetheless, the coverage of specific crude oils imported in Europe is limited. Furthermore, the number of representative oil fields analyzed in order to assess carbon intensity of specific crude oil types remains limited. Furthermore, there is no analysis for specific MCONs that constitute significant part of European crude oil imports, such as Urals crude oil. Lastly, the rationale and methodology for the choice of the specific dataset of MCONs and oil fields remains unclear.

1.4.5 Jacobs Consultancy Report: EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context

Jacobs Consultancy in collaboration with Life Cycle Associates was assigned in 2011-2012 by the Alberta Petroleum Marketing Commission, to carry out a study concerning the lifecycle GHG emissions for crude oil pathways to Europe.

The goal of this Study was twofold: (i) to evaluate the lifecycle GHG emissions for potential crude oil pathways to Europe for producing gasoline and diesel from representative heavy crude oils from Alberta, Canada and (ii) to evaluate the lifecycle GHG emissions of representative crude oils refined in representative refineries. This approach should help achieve a better understanding of the variability in GHG emissions for different pathways for producing gasoline and diesel for the EU market.

The intent of this work was to better understand the carbon intensity of pathways for gasoline and diesel from particular individual crude oils. The approach of representative pathways went beyond calculating **carbon intensities from average crude oils in an average European refinery**, as such an approach would entail the risk of losing the information that defines the range of carbon intensities for gasoline and diesel from different crude oils produced in different regions and refined in different refineries.

Thus, the authors chose to rather select representative crude oils ranging from light to heavy from the major supply regions for the purpose of their study. Therefore their study does not cover all crude oils imported in Europe, but only the ones treated in three representative refineries, namely:

- FCC-Coking refinery – situated in Germany;
- FCC-Visbreaking refinery – situated in France;
- Hydrocracking-Visbreaking refinery – situated in Italy.

The results were compared to the GHG emissions from a US and a Russian refinery exporting refined products to Europe, in order to point out that the location of the refinery affects the lifecycle emissions.

The study concludes that Well to Tank (WTT) carbon intensities vary widely, depending on how the crude is produced, the amount of gas flaring, the amount of fugitive emissions released during production, and the emissions from oil refining, Also, the limited availability of robust data is discussed, as well as the uncertainty in the calculation due to this unavailability, especially in the production processes. The study provides also a valuable assessment of the emissions of the refining sector depending on the physical properties (API and sulphur content) of crude oil, the refinery configuration the exact input blend of the refinery and the refinery final product (diesel kerosene, petrol, etc.).

The average carbon intensity of diesel fuel produced from representative crude oils refined in representative European refineries has been found to be in the order of 15 grCO_2eq/MJ and around 18 grCO_2eq/MJ respectively for the produced petrol.

1.4.6 ICF Study: Desk Study on Indirect GHG Emissions from Fossil Fuels

The study was assigned by DG CLIMA to ICF international and was carried out in 2013. The overall objective is to provide an overview that enables the European Commission to evaluate the indirect GHG emissions from fossil transport fuel pathways.

Direct emissions are defined as the ones emitted from the processes of production, transport and combustion of the fuel along its lifecycle, whereas the indirect emissions are those that are influenced or induced by economic, geopolitical or behavioral factors, but which are not directly related to extraction, processing, distribution or final combustion of the fuels.

The study identifies and evaluates six possible sources of indirect GHG emissions from fossil fuels:

- Induced land development;

- Military involvement;
- Accidents;
- Marginal effect;
- Price effects;
- Export of co-products.

The study has been based on a thorough literature review in the field of indirect emissions. Where possible, estimates on the emissions are provided. The report concludes that there is no common characterization of direct and indirect sources of GHG emissions between relevant stakeholders and those comprehensive methodologies to calculate indirect emissions are still to be developed. Among the above listed sources of emissions, only the emissions due to accidents are considered as negligible, whereas the market mediated effects (i.e. prices effects and export of co-products to other markets) appear to be the most important source, representing 2.2% – 4.5% of the whole WTW GHG emissions.

The study is an important source for analyzing and estimating indirect emissions and also provides the basis for defining the boundaries between direct and indirect GHG emissions sources in the current project.

1.4.7 NETL: Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

The main objective of the study is to present the methodology used by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy to analyze and create an inventory of GHG emissions related to natural gas lifecycle, including extraction, transport and use of gas in the U.S. The inventory focuses on the “cradle-to-gate” value chain, i.e. the lifecycle up to the power station gate, therefore it is considered as an upstream inventory in principle. The study utilizes data from 2009.

The report analyzes the upstream emissions of natural gas compared to those of coal and concludes that despite the fact that natural gas combustion emits less greenhouse gases than coal combustion, nevertheless the GHG emissions related to its production and transport to the U.S. power plants are higher than those of coal. This conclusion is probably related to the sources of natural gas consumed within the U.S. which are, at their majority unconventional (56% unconventional sources of natural gas according to the present report).

The overall emissions of the U.S. natural gas lifecycle including combustion are lower than those of coal. However, the extraction and delivery of the gas has a large climate impact 32 % of U.S. methane emissions and 3 percent of U.S. greenhouse gases. The vast majority of the GHG emissions in extracted natural gas - 70 % of the total cradle-to-gate emissions can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations.

1.4.8 OGP Report: Environmental Performance Indicators - 2012 Data

The International Association of Oil & Gas Producers (OGP) has been collecting environmental data from its member companies for the last 14 years on an annual basis. These data are divided into the following categories, which follow the guidelines provided within the "Oil and gas industry guidance on voluntary sustainability reporting" by IPIECA/API/OGP:

- Gaseous emissions;
- Energy consumption;
- Flaring;
- Aqueous discharges;
- Non-aqueous drilling fluids retained on cuttings discharged to sea;
- Spills of oil and chemicals.

This report summarises the above listed environmental information on activities related to exploration and production (upstream) carried out by OGP member companies in 2012. Data coverage is relatively low - 32% of 2012 world production - while regional coverage varies from 96% in Europe to 8% in Former Soviet Union. Overall, data from 43 OGP member companies, representing upstream activities in 78 countries, are presented in the report.

The results provided within this report are aggregated following confidential information provided by member companies to OGP and no specific data by company or by field are given.

1.4.9 Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries

The study was carried out in 2010-2011 by Adam R. Brandt from Stanford University. The issues the report focused on were the following:

a) to provide an overview and description of oil sands extraction, upgrading, Synthetic Crude Oil (SCO) and bitumen, non-combustion process emissions and land use change associated emissions;

b) to compare a variety of recent estimates of GHG emissions from oil sands and to outline the reasons for variations between the estimates in surface mining, in situ production, upgrading, refining and VFF;

c) to outline low, high and "most likely" estimates of GHG emissions from oil sands, given results from previously produced estimates, and compare these emissions to those of conventional EU refinery feedstock.

The author used EU-specific emission factors for transport and refining of fuels. The study concludes that, while oil sands based crude oil is endorsed with higher emissions than conventional crude oil, the production-weighted emission profiles are significantly different and therefore, the regulatory frameworks should address this discrepancy with pathway-specific emissions factors that distinguish between oil sands and conventional oil processes.

Closing, the author suggests the need for additional research of the uncertainties in modelling GHG emissions from the Canadian oil sands. The most important uncertainties mentioned are treatment of cogenerated electric power, treatment of refining and the interaction of markets with LCA results.

1.5 Progress Achieved Till October 2014

The time schedule of the project Tasks as they have been set in the proposal is presented in Figure 1.2. The time schedules of the Tasks are drawn with blue colour, whereas the progress of Tasks is drawn with brown colour. In principle, project execution until the delivery of this Report is focused on 4 Tasks, namely Tasks a, b, c and d (and 0). The work in Task f has also been initiated, but it is not reported in detail in this Interim Report.

Tasks/Months (after signature)	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Task 0 Project Management															
Task a															
Task b															
Task c															
Task d															
Task e															
Task f															
Meetings and deliverables															
Kick-off meeting	X														
Draft Interim report						X									
Interim Steering group meeting							X								
Interim report								X							
Draft final report												X			

Tasks/Months (after signature)	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Final Steering group meeting													X		
Final report															X

Scheduled Tasks Executed Tasks

Figure 1.2: Time schedule of project Tasks as in the proposal

The work in ***Task a: Literature survey*** has been carried out in time; thus the database development and its enrichment with the main reports have been carried out. However, the addition of necessary literature will continue until the end of the project as far as new literature is produced and becomes available. It should be considered that this Task has been completed.

The work in ***Task b: Data acquisition*** has lasted more time than expected, but it may be stated that the main bulk of required information has been collected and it is available to feed the models (Task c). The reason of longer time requirement could be attributed to the difficulty to collect actual data, which might be either used directly or will be the main input in the models for GHG estimations. It is worth mentioning that great effort was dedicated to receive data from the involved private companies, however the results were very poor till now. We continue to be in communication with some of the organizations which might provide with actual data and hope this effort will be fruitful at the end. Nevertheless, although the largest part of information has been collected, we consider that improvements, additions and further elaborations of collected information might be needed until the end of the GHG modelling Task c and even until the end of the project. We may consider that this Task has been finished, given the expressed need for necessary small amendments as far as the modelling Task c develops.

The work in ***Task c: Models to estimate max and min GHG emissions*** has started on time and is well developed. The two models under consideration, namely OPGEE for oil and GHGenius for natural gas, have been thoroughly assessed and have been modified to adapt to the specific needs of this project. More specifically, the significance of the inserted parameters has been evaluated and the research of data collection has been directed to ensure the proper calculation and assessment of these parameters. Task c is carried out in parallel to Task b and this link and close coordination is prerequisite in order to produce reliable and consistent results. Initial and testing runs of both models have been already carried out and some initial outputs are included in this report and willll be further developed to be presented in the scheduled workshop. This Task is expected to produce final results by the end of February 2014, as it was scheduled in the proposal.

The work in ***Task d: Emissions due to accidents and other operational failures*** has started according to the schedule and is well developed as it is reported in the relevant Chapter of this report. The approach and definition of the indirect emission cases have been decided and analysed, the relevant literature and data collection have been carried out and preliminary results have been assessed for further verification and comparison. It is estimated that this Task will be finished by the end of November as it was initially scheduled.

As already mentioned ***Task f*: *Emissions projections up to 2030*** has been initiated a little earlier than scheduled in the proposal because the use of certain modules of PRIMES (refining) are under development to incorporate the recent changes in the sector and data of the gas module will be used to better detail gas transmission and distribution activities within the EU countries.

Finally ***Task e: Other issues related to sustainability*** has not been elaborated till now.

With regard to the other deliverables of the project, it is worth mentioning that the schedule and the scope have been followed:

- The kick-off meeting has been organized at the beginning of June, when all the Tasks and the Consultant's approach have been discussed with the EC desk officer.
- An additional half-day workshop has been organized in the premises of DG ENER with main objective to coordinate efforts of the Consultant to receive useful information from the EC services.
- An interim workshop for presentation of the work carried out to experts from main counterparts was organized on November 28 in Brussels at the premises of DG ENER.

1.5.1 Key dates of project evolution

Until the time of submission of the Interim Report, that is end of October, the proposed schedule of project Tasks has been followed. Our estimation is that we will continue keeping the schedule until the end of the project. The key dates and next steps onwards are expected to be:

- November 28, 2014, presentation of project progress in interim workshop organized in DG ENER.
- End of November 2014, finalization of Task d on indirect emmissions.
- End of February 2015, completion of main OPGEE and GHGenius model runs (Task c).
- End of April 2015, completion of runs of PRIMES model on 2020-2030 projections (Task f).
- End of June 2015, completion of sustainability analyses (Task e).
- End of July 2015, submission of the Final Report.

2 TASK A: LITERATURE SURVEY

The literature survey was the initiating Task of the project and focused on identifying and reviewing up-to-date documents publicized worldwide regarding life-cycle GHG gas emissions of transport fuels.

The literature survey considered a number of subjects, including:

- Important legal documents in the framework of the present project regarding the Renewable Energy Directive (RED), which sets a target of 10% renewables in the transport sector, the Fuel Quality Directive (FQD), which sets a target of 6% reduction of GHG emissions from road transport, as well as relevant EC Communications and initiatives which set the basis of the EU GHG emissions policy.
- A broad range of subjects related to lifecycle GHG emissions of diesel oil, petrol, kerosene and natural gas. The subjects included regard GHG emissions calculation methods, fuel extraction, fuel transport, fuel refinement, etc.
- Broad range of information resources broken down by type, including private companies reports, international organisations reviews, scientific papers, etc.

The literature survey focused on the most up-to-date data and knowledge on the subject of life-cycle GHG emissions and was based on two methods: extensive on-line literature search, as well as the identification of important relevant information sources through communication with stakeholders i.e. oil and natural gas companies and international organizations. The Consultant set the criteria which allowed the classification of the various documents and the establishment of a tailor made literature electronic database.

2.1 SURVEY APPROACH

A large number of documents could be in principle considered in the literature survey related to oil and gas and the respective transportation fuels. It was considered however that a more efficient and targeted approach would be required focusing on documentation whose content is closely related to the subjects addressed by the current study and considering as well their reliability and their significance on the project topics for the potential future reader or researcher. The survey work focused on collection of literature selected in accordance with criteria relating to the content and the type of these documents.

Documents focusing on the following content topics were surveyed:

- **GHG emissions (direct/indirect) for oil and natural gas**: The exact distinction between direct and indirect emissions is related to the choice of the system boundaries. In general, direct emissions are related to the processes of production, transport and combustion of the fuel along its life-cycle, while indirect emissions are related to economic, geopolitical or behavioural factors not directly related to the aforementioned processes.

- **Policies related to transportation fuels and GHG emissions**: Documents referring to policy and strategy aspects of GHG emissions and emission reduction options.
- **Modelling and methodological aspects of Life-cycle Analysis (LCA) of GHG emissions**: Such documents include information regarding models used widely for the estimation of GHG emissions such as OPGEE, GHGenius and GREET or other aspects related to modelling specific aspects of the fuel life cycle.
- **Conventional and unconventional oil and natural gas pathways, processes and technologies**: These type of documents describe engineering and technological aspects of oil and natural gas production and extraction that will help the reader understand sources of various types of emissions.

Furthermore, literature of the following types was surveyed:

- **Reports and studies**: This is the main type of literature source utilized for the elaboration of the project Tasks. It includes studies from international organizations, national authorities, research institutes, consulting firms and oil and gas companies, which provide comprehensive and up-to-date analyses of life cycle GHG emissions of transportation fuels.
- **Books**: Textbooks as literature sources providing fundamental technical background for oil and gas exploration, production and transportation.
- **Research papers**: Refers to papers published by universities and research institutes and provide a valuable input for the project, particularly when related to fundamental concepts for the assessment of carbon intensity of fossil fuels.
- **User manuals**: Refers to the supporting documentation for the use of life-cycle emission's assessment and macroeconomic models (OPGEE, GHGenius, GREET, PRIMES etc.) and are particularly useful for introducing these models to the reader and for analysing methodological aspects of GHG emission's assessment.
- **Datasheets**: Refers to data sets published by international organizations or private entities (such as oil and gas companies) that provide input regarding crude oil specifications, crude oil and natural gas production, transport and refining data, overall emissions from their activities.
- **Presentations**: Refers to presentations given by individual experts or organizations which are a useful literature source, despite the fact that they may not provide an in-depth analysis on specific issues. However, they can provide a comprehensive overview of extensive studies and a compact summary of key issues and results.
- **Legislation**: It refers to documents such as relevant European Directives, Regulations and Communications.

The literature survey was carried out during the first months of the project period resulting the selection of a large number of documents on the basis of content as mentioned above. It is planned that more literature will be added until the end of the project, as the project team will be collecting and registering additional documents in the course of carrying out the other project Tasks.

In order to store the identified literature and to provide access to all project partners and EC officials, an online literature database was created. The database will remain active and will be updated throughout the duration of the project so as to include all the necessary documentation that was utilized for the needs of the forthcoming Tasks of the study. Currently the literature database includes references to more than 60 documents.

An updated list of the literature stored in the database, including all information attached to each document is presented in Annex 8.3.

2.2 PRESENTATION OF LITERATURE DATABASE

The literature database is a tool developed for the needs of the project in order to store and classify the documentation surveyed and provide a common document repository accessible by all project partners and EU officials. It is a user-friendly web-based platform designed specifically for use in the course of this project, providing reference and information on the collected documents.

The database is available on-line at the web address http://ghg-oilgas-literature.eu.

Documents are added to the database along with certain "data fields" providing specific additional information on each document. These fields can be used for sorting and classifying the database documents according to a predefined order depending on the content, thus facilitating the user in selecting specific document references for review.

For each document in the database, the following information is provided

- **Literature fields** (Publisher, Author(s), date of publication);
- **Document type** (Report, Research paper, Legislation, Datasheet, etc);
- **Content (**Policy, Modelling, etc);
- **Lifecycle stage** (the specific stage of the lifecycle of transport fuels the document refers to - if applicable);
- **Geographical coverage** (the geographic areas the document provides information on);
- **Referenced model (**the GHG emissions model the document refers to (if applicable);
- **Key points** i.e. a short review of the information provided within the document and its relevance for the study;
- **Web link** i.e. the internet location where the document can be found (if applicable).

A snapshot of the literature database in presented in the following Figure 2.1 while Annex 8.3 presents the complete list of documents and related information which is currently stored in the literature database and the generic database.

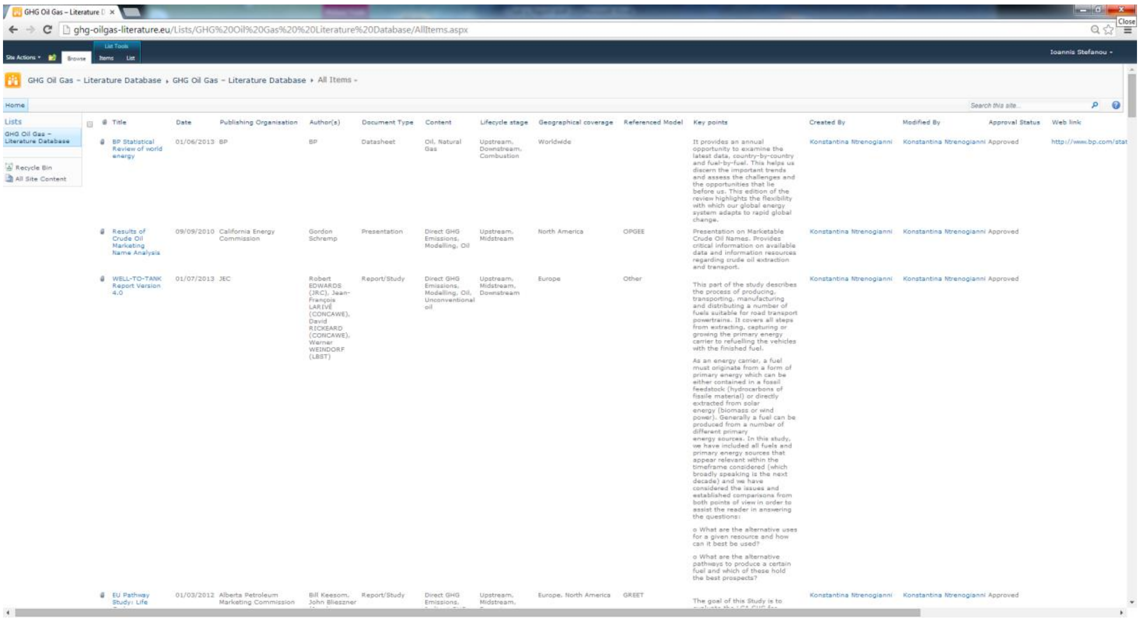


Figure 2.1: Snapshot of the literature database.

The Consultant has added a section under the name “generic literature database” which includes documents of general interest i.e. handbooks, glossaries, general environmental reports for GHG emissions and other relevant studies. These literature sources are not vital for the elaboration of the study but include useful background information for the potential reader.

3 TASK B: DATA ACQUISITION

3.1 EU OIL AND GAS SUPPLY

3.1.1 EU crude oil supply

Europe is largely dependent on Former Soviet Union for its primary energy supply in crude oil - approximately 40% - as it can be obtained by Figure 3.1. Europe produces approximately 20% of its domestic consumption, while another 20% is approximately being supplied from countries of the Middle East.

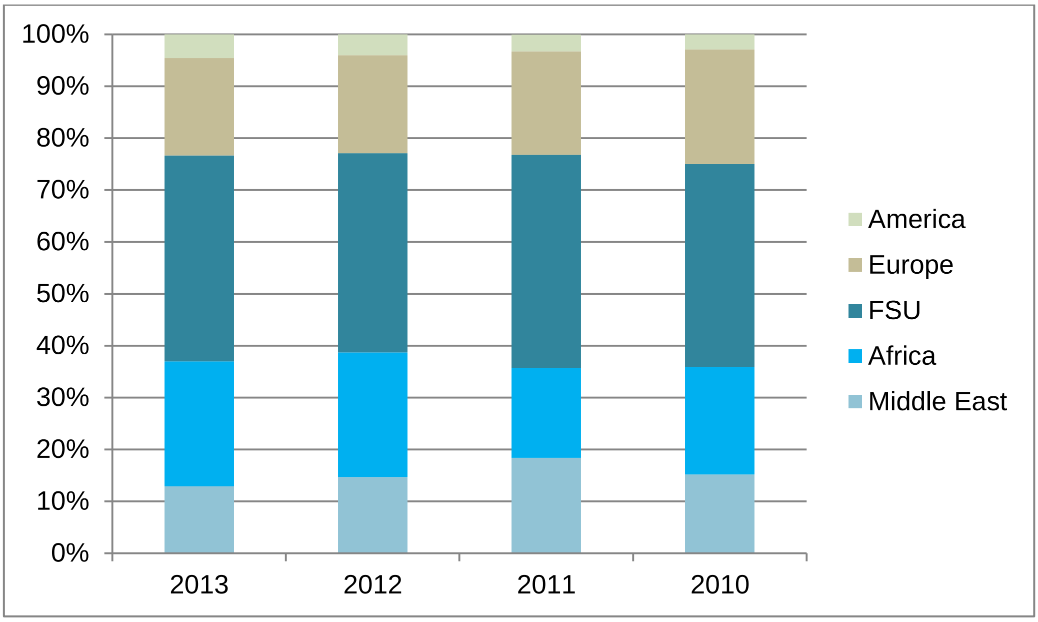


Figure 3.1: EU crude oil supply 2010 - 2014 (source: DG ENER)

Figure 3.2. illustrates the EU 28 crude oil supply by country of origin for 2012. Currently, Russia is steadily the largest exporter of oil to Europe, exporting crude oil to Europe from the areas of Urals-Volga, Western Siberia and Timan-Pechora under several marketable names (Urals, Western Siberia and Russian Export Blend, also known as REBCO). The second largest supplier of crude oil to Europe is Norway with approximately 11% of total imports. Europe is also supplied significant quantities of Arabian light and heavy crudes, as well as light and medium crude oils from Nigeria. Apart from the Russian crude oil, Europe is supplied large quantities of crude oil from other FSU countries, primarily Azerbaijan (Azeri light and Azeri BTC) and Kazakhstan (Tengiz and CPC blend).

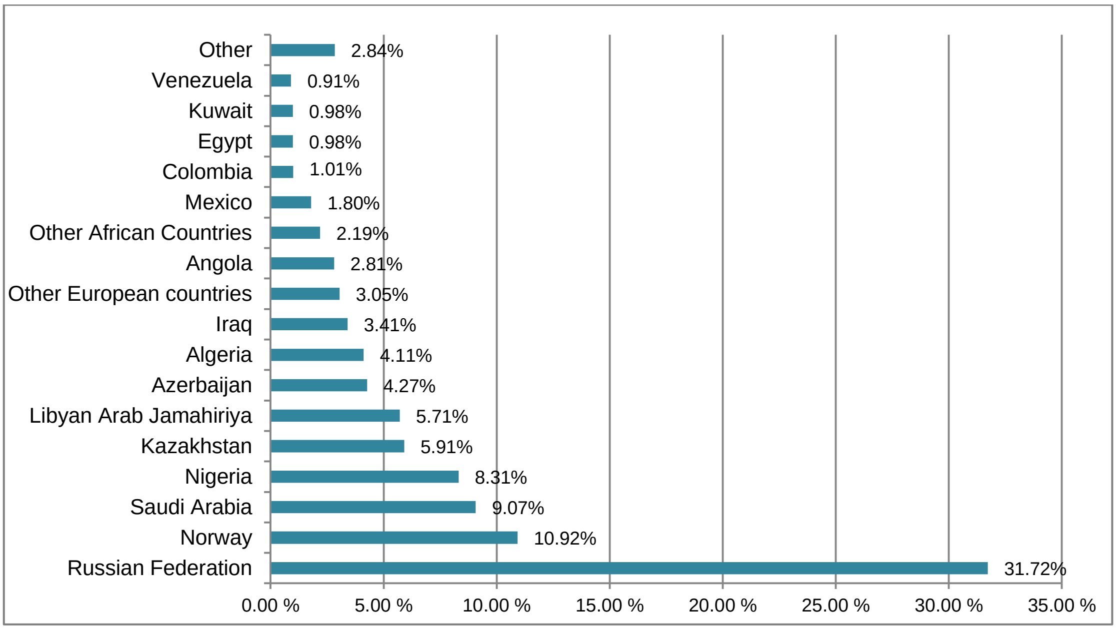


Figure 3.2: EU crude oil by country in 2012 (source: DG ENER)

The largest part of Russian oil towards Europe is exported through the Transneft pipeline system. The Transneft pipeline system spans over 31,000 miles in total and reaches to the ports of Novorossiysk and Primorsk from which major crude oil exports take place.. The Druzhba pipeline system trasnports the largest part of Russian oil to Europe. Figure 3.3 provides the Russian crude oil exports of the years 2010 and 2011 via various modes of transport.

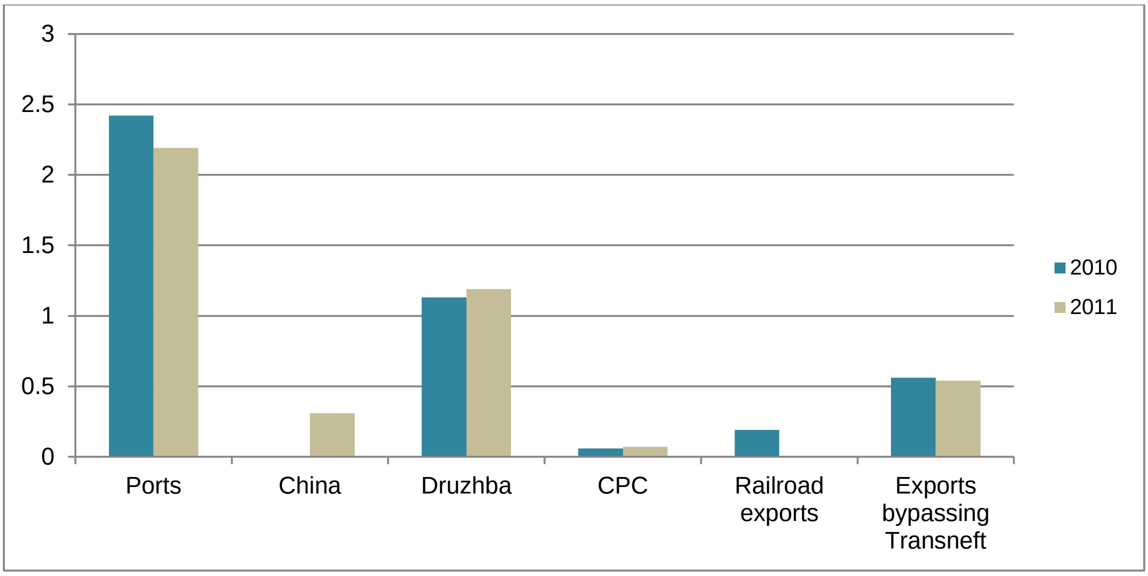


Figure 3.3: Russian crude oil exports in million b/d (source: CDU-TEK)

From the crude oil transported via the Druzhba pipeline Germany imports the largest fragment with 0.45 million b/d and Poland comes next with 0.4 million b/d in the first quarter of 2011, as it is shown in Figure 3.4. Hungary, Slovakia, Czech Republic receive a smaller fragment of crude via the pipeline at the order of magnitude of 0.1 million b/d.

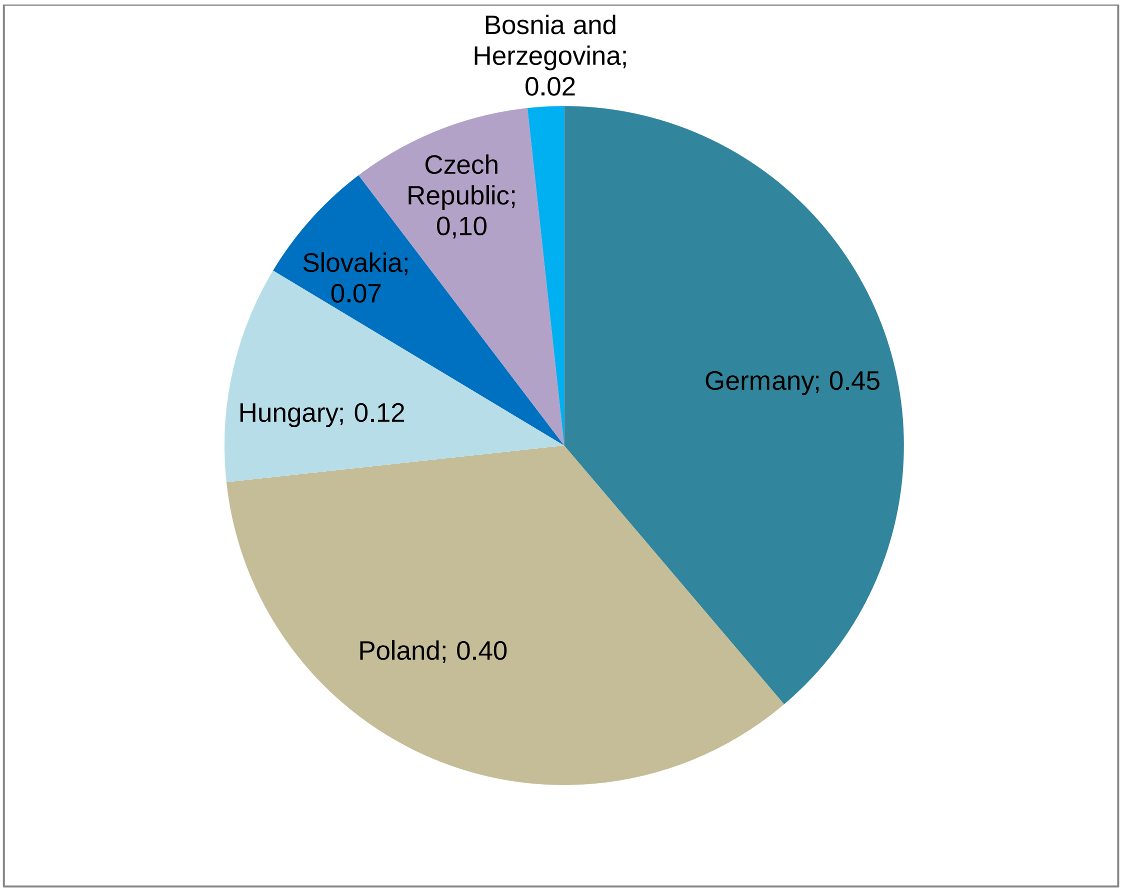


Figure 3.4: Transneft's Druzhba deliveries plan for 1st Quarter of 2011 in million b/d excluding transit (source: Transneft)

3.1.2 Supply of refined products from third countries

Besides crude oil imports, Europe is increasingly importing refined oil products primarily from Russia and United States of America, as it can be seen in Table 3.1:

Source and Year	Daily imports (1.000 barrels)	Annual imports (1.000 barrels)
Imports from FSU 2013	559	204,035
Imports from FSU 2014 (until May 22)	629	229,585
Imports from US 2013	321	117,165
Imports from US 2014 (until May 22)	304	110,960
Total FSU+US imports 2013	880	321,200
Total FSU+US imports 2014 (projection)	933	340,545

Table 3.1: Imports of refined products by FSU and USA (source: Bloomberg)

The increase of refining output and quality of refined products in Russia over the last years has been the result of recent regulatory reforms. Russia has adopted the European fuel quality standards, both for imported and domestically manufactured ones, for road transport vehicles. As of January 2013, Russia switched to Euro-3 standards, which caps sulphur content at 350 ppm (diesel oil) and 150 ppm (petrol) sulphur required. Euro-4 fuel standard will be implemented beginning 1 January 2015 (with max 50 ppm sulphur required), while Euro 5 fuel (with max 10 ppm sulphur required beginning) as of 1 January 2016. These regulations have led Russian oil companies to make investments in order to upgrade their refineries so as to produce cleaner products, primarily Ultra Low Sulphur Diesel (ULSD). This has resulted into an increased share of Russian refiners in the EU market at the expense of their European competitors. Figure 3.5 illustrates that the ULSD is the major refined oil export product to OECD EU and that the OGJ forecast anticipates increase for OECD EU diesel imports; thus it can be considered that domestic EU diesel production is anticipated to decline until 2020, with this gap between production and demand to be covered by diesel imports from USA and FSU.

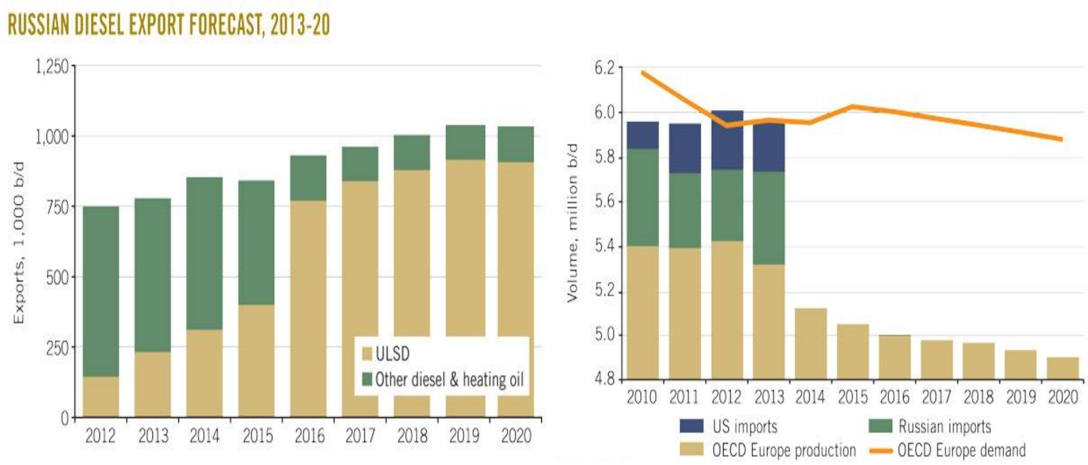


Figure 3.5: Russian diesel export forecast 2014 – 2020 and OECD Europe diesel supply forecast 2014-2020 (source: OGJ, based on ESAI Energy study)

The increased diesel production to Europe will be supported by expansions of the Sever pipeline. More specifically, the operator of the pipeline, Transneft, has planned two expansion projects of the pipeline. With a nominal capacity of 170,000 b/d to facilitate ULSD exports from the Baltic Sea, the pipeline already operates above the nominal capacity. In late 2013, the average diesel exports were 200,000 b/d, which rose to a record of 235,000 b/d in January 2014. This implies that approximately half of the refined products imported from Russia are transported to Europe via the Sever pipeline.

United States exported 13.37 million tons (about 273,000 b/d) to Europe, or 42% of the 32.2 million tons (about 658,000 b/d) that was imported into the region in 2013 (Eurostat). The Netherlands with 576,000 tons of all ULSD imported into Europe is the major importer, followed by France with 310,000 tons, the country with Europe's biggest diesel deficit.

3.1.3 EU natural gas supply

Unlike oil supply in the EU, which is almost exclusively dependent on imports from third countries, natural gas supply is ensured by domestic production combined with imports by non EU countries. In 2012, 66% of total natural gas demand in the EU was met by imported gas, up from 45% in 1990. This growing dependence is caused in a large extent by two factors: increasing demand for natural gas, as the cleanest and most versatile fossil fuel, and decreasing domestic production for domestic use within the EU. The large gas fields, which produce at relatively low cost, are becoming depleted, while smaller and offshore gas fields are more expensive to exploit.

Dependence on natural gas imports varies widely among individual EU Member States. Imports to the United Kingdom and Romania are relatively low, while Denmark and the Netherlands are net exporters. On the other hand, six countries (Finland, Latvia, Lithuania, Estonia, Slovakia and Bulgaria) are fully dependent on imports from Russia.

The most important suppliers of the EU natural gas market are Russia (23.24% of total EU supply), Norway (21.45% of total EU supply - pipeline and LNG combined), the Netherlands (17.55% of total EU supply), the UK (8.46% of total EU supply) and Algeria (9.14% of total EU supply – pipeline and LNG combined). These five countries provided almost 80% of the EU gas supply in 2012.

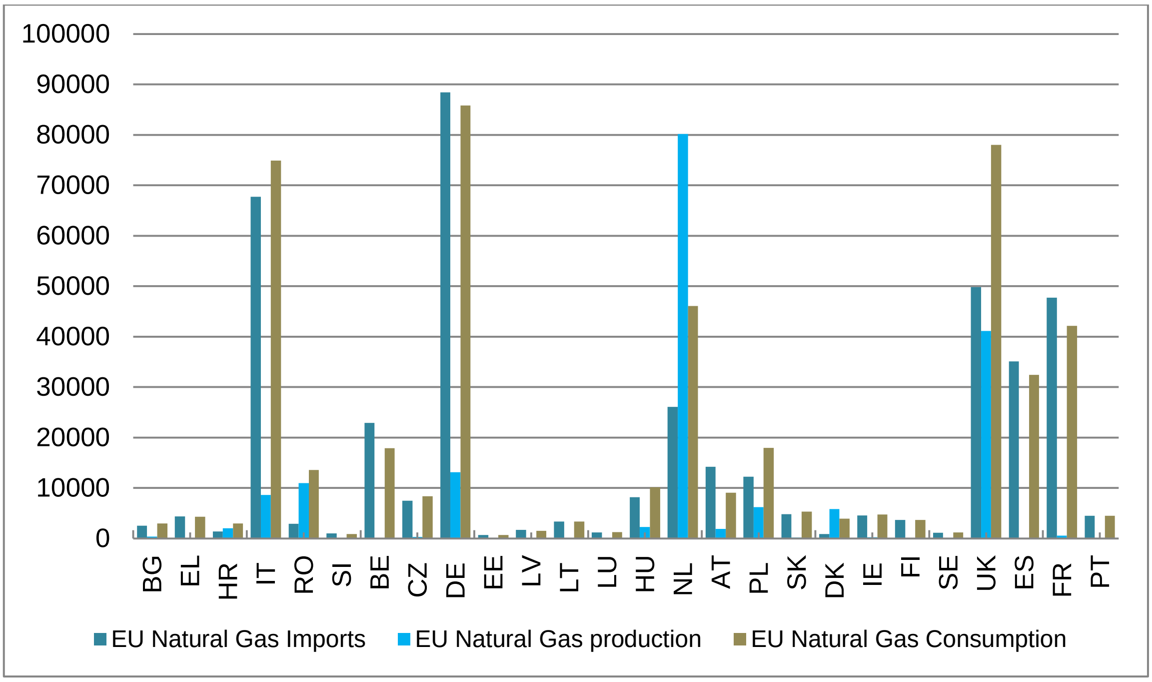


Figure 3.6: EU Natural Gas Imports, Production and Consumption in million cubic meters for 2012.

As shown in the graph in Figure 3.6 the most important producers of natural gas in the EU are the Netherlands, the UK and Germany. Italy, Romania, Poland and Hungary consume almost the entire quantities of natural gas produced within their territory. The

Netherlands, on the other hand, is a major exporter of natural gas, not only to the EU, but also to third countries.

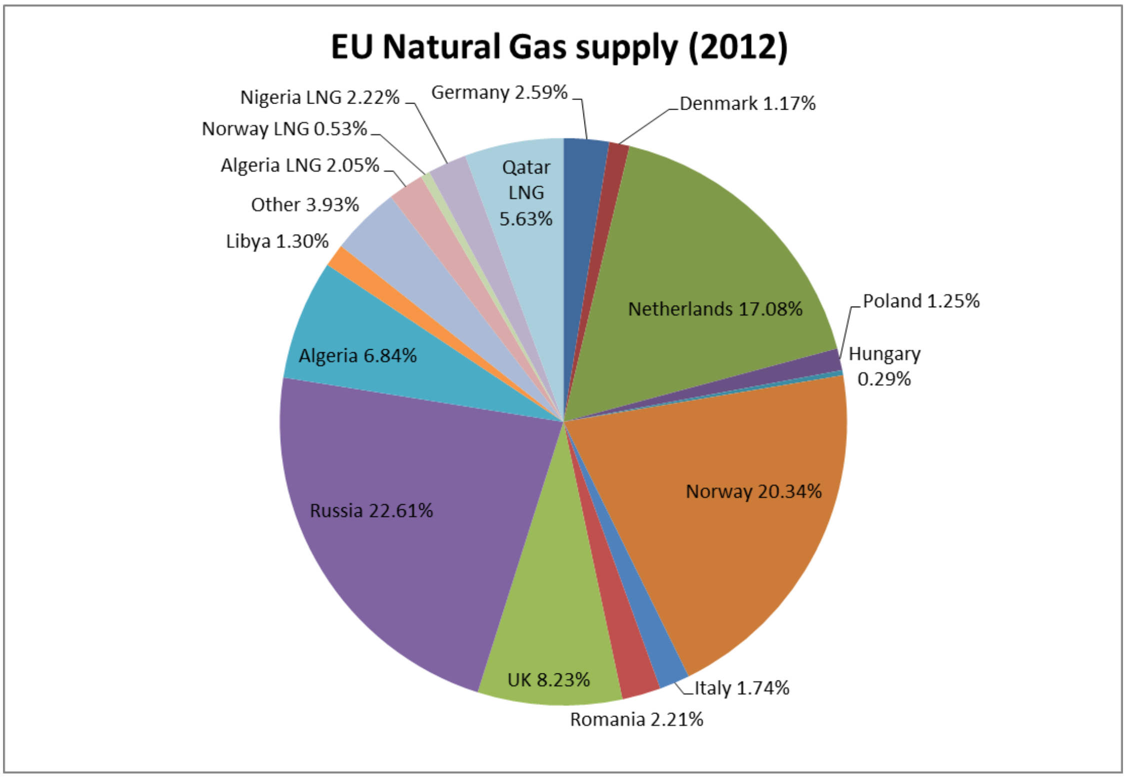


Figure 3.7: EU natural gas supply by country of origin, 2012 (source: IEA)

Figure 3.7 illustrates the countries supplying natural gas to EU and the corresponding share for 2012.

Gas is imported into Europe by two ways: through pipeline in gaseous form or alternatively by LNG supply chain, where it is liquefied in the country of origin, transported in marine vessels and finally regassified at the entry points in Europe.

There are two major LNG suppliers to Europe, although smaller quantities may arrive from other countries i.e. Algeria and Qatar. Algeria is also connected to the European gas transmission system by pipeline through Spain and Italy. The EU countries receiving the largest quantities of LNG are Spain, France, Italy and Germany. Overall, the share of LNG in the European gas market is presented in Table 3.2.

EU NG supply mode	Quantity (million cubic meters - mmcm)	Percentage
Pipeline	**430,682**	**89.3%**
LNG	**516,49**	**10.7%**

Table 3.2: EU natural gas supply share by mode of transport

The physical flows of natural gas within EU (blue lines) and the major importing pipelines transporting gas to EU (red lines) are illustrated in the IEA map of **Figure** 3.8:

Figure 3.8: Gas trade flows in Europe (source: IEA)

3.2 General Methodological Considerations for GHG Life Cycle Emission Assessment

3.2.1 Fuels examined

The overall aim of the assignment is to provide the actual, as possible, GHG emissions of petrol, diesel, kerosene and natural gas through a lifecycle “well-to-tank” approach. In this context, the Consultant assesses the upstream, midstream and downstream emissions for existing pathways of crude oil and natural gas. Furthermore, the Consultant develops a specific methodology for the assessment of LCA emissions for a basket of the most significant grades of unconventional crude oil and natural gas that will be imported and/or produced in Europe in the forthcoming years.

3.2.2 Categorization of data collection

Generally a GHG emissions inventory of actual data is comprised of calculated and estimated emissions from individual emission sources that are aggregated to produce the inventory. Emissions information is typically obtained either through direct on-site measurement of emissions, or the combination of an emission factor and some measure of the activity that results in the emission which is referred to as the activity factor. Emission factors describe the emission rate associated with a given emission source, which may be either based on site-specific measurements or published data. Activity factors are generally a measured quantity, such as a count of equipment or amount of fuel consumed.

According to ISO14041, data quality requirements should be specified. The requirements should concern time, geographical and technical coverage of the data. To meet those requirements, one may collect adequate data in several ways. Especially in this project the collected data have been classified according to the source of origin that implies also the level of reliability. A three stage hierarchy of data collection with highest priority of course placed on the Actual Data has been considered, as it is the mandate of this project:

- **Actual Data** gathered from existing data bases of renown national and international organizations as well from certified data availed by oil and gas companies. These data are in principle based on direct measurements, mass balances, validated emission factors and relevant engineering calculations which have been verified.
- **Modelling data**, calculated from runs of the three models used in this project, namely OPGEE, GHGenius and PRIMES. These data are actually covering the cases where actual data are not available or there is lack of them. In order to run these models a large number of input data are required and have been collected. These latter data are in principle actual data.

- **Literature data**, coming from other studies in GHG emissions for which the Consultant has no access on the detailed way these estimations have been carried out. This latter stage will be used only in cases where the previous two stages fail to provide reliable results and hopefully its contribution in the project output will be negligible.

Therefore the Consultant has collected actual emission data both for oil and natural gas in priority i.e. data verified through measurements and calculations as those are provided by energy companies or authorities related to GHG emissions. In order to do so, the Consultant has investigated all open sources of relevant information, mainly availed by national, international organizations and oil and gas associations. Furthermore, all major oil and natural gas companies related to oil and gas streams directed to the EU have been contacted and requested specific and disaggregated data per process. Another source of actual data have been reports published by oil and natural gas companies, which typically include aggregated data, with limited usefulness for our analyses and comparative purposes.

The procedure and the priorities in GHG data collection that has been explained above is presented in Figure 3.9:

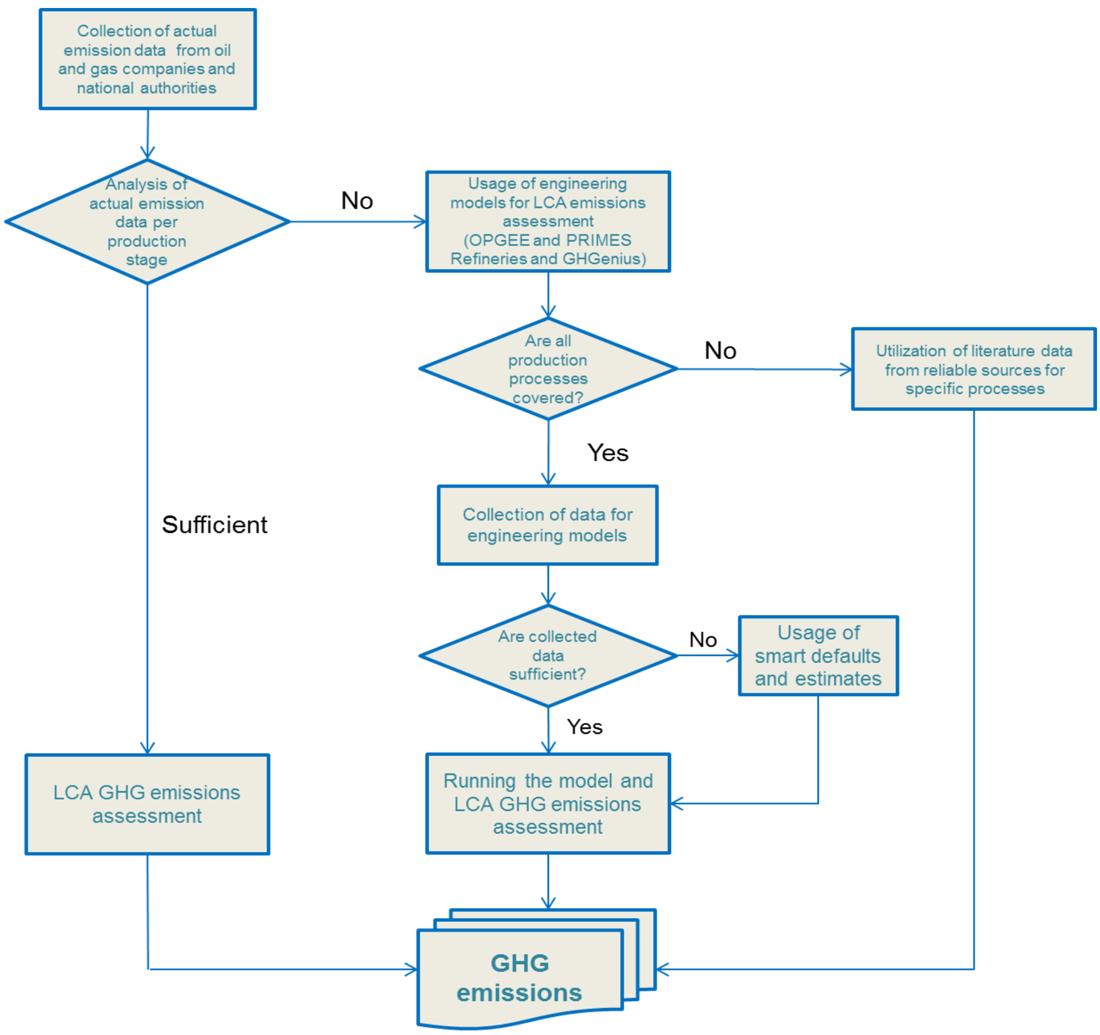


Figure 3.9: Overview of the strategy for the assessment of GHG emissions for crude oil and natural gas

3.2.3 Geographical coverage

The study examines the GHG emissions of petrol, diesel oil, kerosene and natural gas in the form of CNG or small scale LNG used in the transportation sector of EU 28 countries. It must be noted that at the time the ToR was written Croatia was not a full MS. Thus, the country coverage has been extended to include Croatia also.

3.2.4 Choice of baseline year

The baseline year for the assessment of carbon intensity has been chosen to be 2012, primarily because there is a large availability of data for this year regarding all lifecycle stages of the oil value chain, namely upstream, midstream and downstream.

3.2.5 System boundaries

In general, “well-to-tank” emissions refer to those associated with exploration, production, fuel recovery, upgrading, pipeline and maritime transportation, refining, LNG transformation, gas transmission and storage, CNG compression and distribution to final consumers, thus excluding the emissions resulting from the final combustion in the transportation means’ engines.

3.2.6 Global Warming Potential (GWP) used

The latest versions of OPGEE (1.1c) and GHGenius (4.03a) use the GWP of 2007, as most of the recent LCA studies. Therefore, it has been considered as preferable option to utilize the GWP 2007 instead of the 2013 GWP in order to ensure consistency of figures and allow comparisons between various studies.

3.2.7 Utilization of Minimum/Maximum approach

The study aims to develop an integrated, consistent and detailed methodology to evaluate the actual range of emissions in the form of minimum, weighted average and maximum values that relate to the whole lifecycle of diesel oil, petrol, kerosene and natural gas. Unlike other relevant studies, which provide one single value regarding GHG emissions per field or fuel type, the present study through the utilization of a minimum/maximum approach allows various uncertainties to be better expressed and consequently policymakers to better understand the range of GHG emissions of each oil and gas stream and final fuel, as these are evaluated in a more realistic and objective manner.

The potential range in the value of GHG emissions of each oil and gas pathway can be influenced by the following parameters, as also by other ones:

A. Upstream

- Different fields constituting the source of each pathway (MCON or Gas stream).
- Variable quantities of oil or gas production for a specific field.
- Differences in oil field characteristics (particularly API gravity and depth), as also in the natural gas characteristics contributing to a pathway of oil or gas.

B. Midstream

- Mode of transport for a specific oil or gas pathway (marine/pipeline).
- Different final destinations of crude oil or gas per mode of transport.
- Uncertainties related to the exact properties of a crude pipeline blend.

C. Downstream

- Exact constitution of a crude oil blend for the refining process.
- Estimations of emissions for the oil and gas distribution systems within a country.
- Estimations of crude yields on specific products during the refining process.

3.3 Methodological Approach for Oil

3.3.1 Introduction

The methodology for the assessment of GHG emissions of crude oil has been adapted to the three main stages of oil handling chain: upstream, midstream and downstream. Figure 3.10 illustrates the main stages of crude oil handling chain and indicates at high level the general pathways followed in the assessment of each oil grade. In the following sections more detailed presentations of these pathways will be explained. It is worth considering that 35 crude oil pathways in the upstream and midstream stages will be considered covering approximately 88% of the crude oil imports in the EU in 2012. Finally 105 streams (35 for each one of diesel oil, petrol, kerosene) of oil products are considered in the downstream stage up to the tank of transport means.

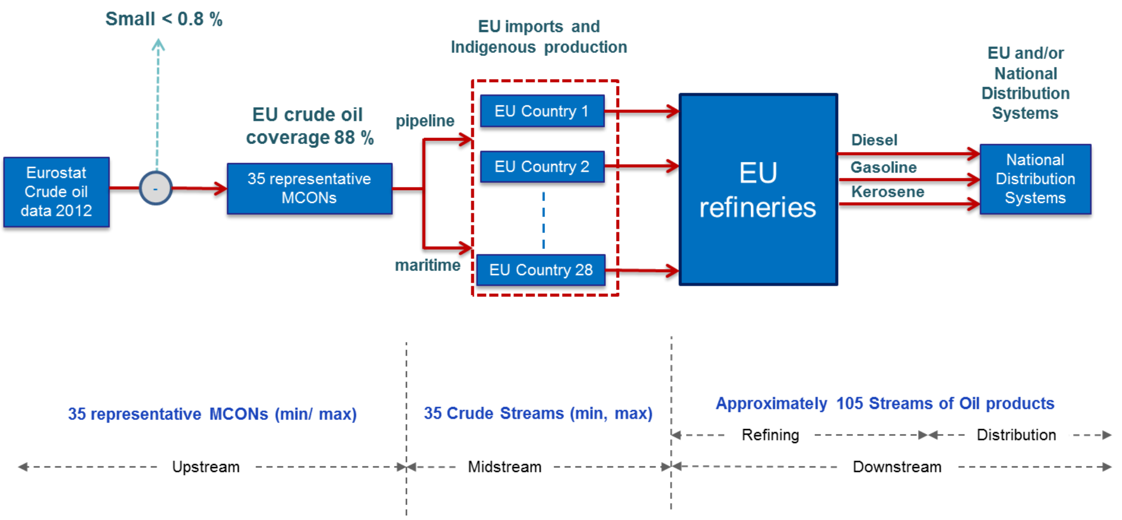
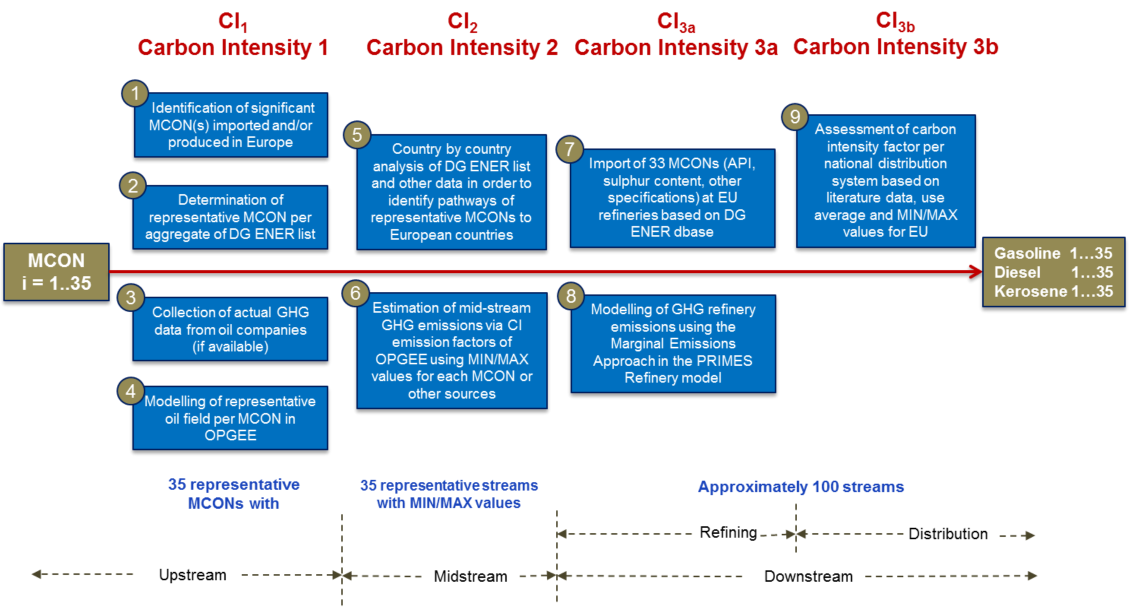


Figure 3.10: Physical flow of crude oil illustrating the basic stages that are examined by the study

The nine methodological steps for the calculation of the Carbon Intensities (CI) or GHG emissions in the three stages for each oil pathway are illustrated in Figure 3.11. Essentially four components of CI are distinguished in each oil pathway and the relevant calculation or data collection effort will be directed accordingly. In the following Sections of this Chapter each stage and the relevant approach of the Consultant is thoroughly analyzed.



$$CI_{j,tot} = CI_{j,1} + CI_{j,2} + CI_{j,3a} + CI_{j,3b} \quad j=1,\dots 105$$

Figure 3.11: Main steps for the assessment of GHG emissions of gasoline, diesel and kerosene

Oil trading fundamentals

Oil is a very particular commodity since it is simultaneously a financial asset, but also has a physical dimension. Therefore, the pricing of crude oil in the financial markets is inevitably related to its physical characteristics, production techniques, transportation and storage patterns. The complexity in the pricing of crude oil is related to the various types of internationally traded crude oil with different qualities and characteristics which have a bearing on refining yields. Therefore, different crude oils have different prices.

The adoption of the market-related pricing system by many oil exporters in 1986-1988 constituted a shift from a system in which prices were first administered by the large multinational oil companies in the 1950s and 1960s and then by OPEC for the period 1973-1988 to a market base system. In the current system, the prices of these crudes are usually set at a discount or a premium to a benchmark price of a crude oil according to their quality and their relative supply and demand balance. The main benchmarks currently used are: **Brent, West Texas Intermediate (WTI) and Dubai-Oman**.

Other reference benchmark is the OPEC reference basket, which is the weighted average of the following blends of oil:

- Saharan Blend (Algeria)
- Ecuador
- Iran Heavy (Islamic Republic of Iran)
- Basra Light (Iraq)
- Kuwait Export (Kuwait)
- Es Sider (Libya)
- Bonny Light (Nigeria)
- Qatar Marine (Qatar)
- Arab Light (Saudi Arabia)
- Murban (UAE)
- BCF 17 (Venezuela)
- Girassol (Angola)

Other significant reference crude oils include Tapis crude oil, which is traded in Singapore, Urals oil used in Russia and Mexico's Isthmus. Figure 3.12 presents the extent of oil benchmarks used worldwide.

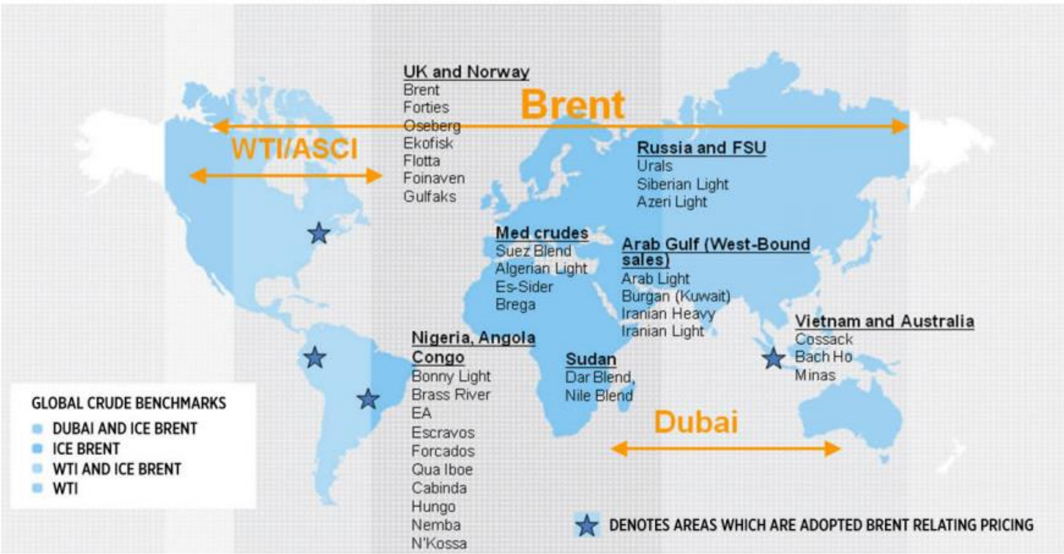


Figure 3.12: Crude oil benchmarks used worldwide (source: ICE)

The names of the above mentioned crude oils indicate their origin but also and most particularly their commercial recognition in the oil markets. These names are used in the marketing of crude oils and are generally understood as Marketable Crude Oil Names (MCONs).

Marketable Crude Oil Name

One of the novelties of the study is the utilization of the concept of Marketable Crude Oil Name (MCON) in order to correlate the physical properties characterizing crude oil as it is extracted from the oil field and those of the crude oil blended during or before the refining process. Furthermore, the concept of MCON facilitates practically the connection of the refinery input (which has a marketable name) with the primary source of crude oil (at the oil field).

More specifically, the concept of MCON has been introduced by the California Air Resources Board (CARB) in order to match the marketable crude oil names to their respective field sources. The ultimate purpose of this classification is to systematize the various types of crude oils in order to identify High-Carbon Intensity Crude Oils (HCICOs) at a second stage and implement regulatory barriers on polluting crudes imported in the State of California. The initial crude oils of the list have been provided to the Air Resources Board by the Western State Petroleum Association (WSPA) and augmented with other proprietary information resources:

- International Crude Oil Handbook (ICOM)
- Energy Information Administration list of crude oil names (EIA-856)
- Journal of Commerce – Petroleum Import Exports Reporting System
- Crude Information Management System from PetroTech Intel

For the crude oils selected in the CARB list a sequential procedure to assign “pass” or “fail” according to LCA GHG emissions is implemented based on:

- Flaring intensity
- Thermally enhanced oil recovery (TEOR)
- Mining extraction of bitumen
- Use of upgrading facilities to produce synthetic crude oils

Currently, CARB has identified over 250 MCONs globally, while the list is often reviewed. MCON characteristics are constantly changing due to large number of oil fields, oil fields relative contribution in the MCON, depletion of oil fields, and emergence of new exploration and development effort. Figure 3.13 below illustrates the most important crudes.

In the Proposal for a Council Directive (COM(6.10.2014) 617 final) on laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC, a number of 618 **Feedstock Trade Names** are specified and included in the proposed methodology for calculating the greenhouse gas intensity of conventional fuels directed to transport sector. Nevertheless the need for using Feedstock Trade Names for crude oils is the same as in CARB with MCONs, i.e. to adopt a more precise crude oil naming that is widely recognized in the market and easier to link to GHG emissions.

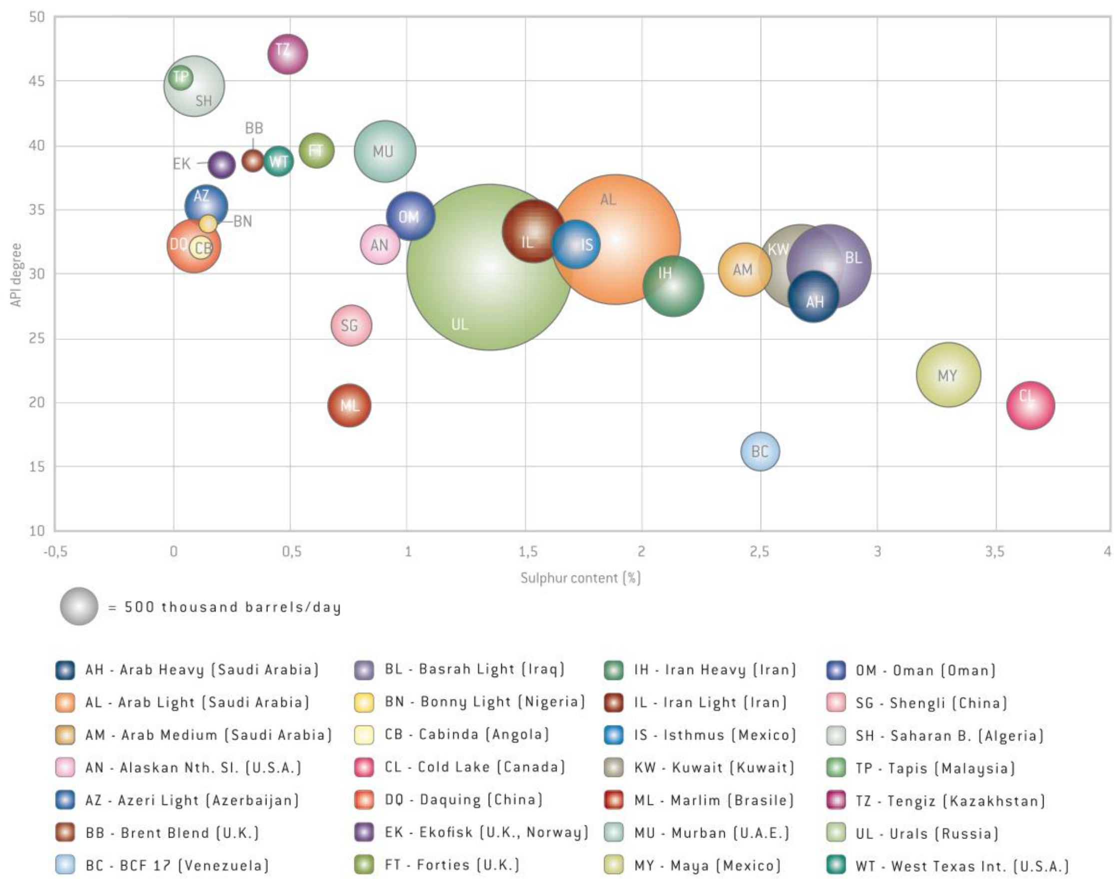


Figure 3.13: Quantities produced globally and properties of main crudes (source: ENI 2012)

3.3.2 Upstream

Step 1: Identification of key MCONs for Europe

The starting point of this study step is the list published by DG ENER regarding imports and deliveries of crude oil for 2012, which is illustrated in Table 3.3 as this has been considered the most reliable source of the crude oils imported in Europe.

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
Middle East	Abu Dhabi	Upper Zakum	617	71,007	115,08	0.02 %
	Iran	Other Iran Crude	3,429	382,270	111,50	0.09 %
		Iranian Heavy	33,221	3,746,230	112,77	0.82 %
		Iranian Light	13,665	1,508,091	110,36	0.34 %
	Iraq	Basrah Light	79,604	8,401,086	105,54	1.98 %
		Kirkuk	61,288	6,717,371	109,60	1.52 %
		Other Iraq Crude	10,909	1,121,944	102,84	0.27 %
	Kuwait	Kuwait Blend	33,600	3,636,667	108,23	0.83 %

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
	Oman	Oman	621	69,620	112,14	0.02 %
	Other Middle East Countries	Other Middle East Crude	433	55,264	127,58	0.01 %
	Saudi Arabia	Arab Light	282,801	31,412,348	111,08	7.02 %
		Arab Medium	17,468	1,917,619	109,78	0.43 %
		Arab Heavy	38,376	4,092,054	106,63	0.95 %
		Berri (Extra Light)	15,672	1,728,847	110,31	0.39 %
Middle East			**591,703**	**64,860,417**	**109,62**	**14.68 %**
Africa	Algeria	Saharan Blend	106,964	11,814,595	110,45	2.65 %
		Other Algeria Crude	8,301	934,748	112,61	0.21 %
	Angola	Cabinda	1,992	240,228	120,60	0.05 %
		Other Angola Crude	65,971	7,407,561	112,28	1.64 %
	Cameroon	Cameroon Crude	12,561	1,405,290	111,88	0.31 %
	Congo	Congo Crude	16,594	1,858,782	112,02	0.41 %
	Congo (DR)	Congo (DR) Crude	5,811	637,775	109,75	0.14 %
	Egypt	Heavy	8,832	946,578	107,17	0.22 %
		Medium/Light (30-40o)	18,595	2,075,434	111,61	0.46 %
	Gabon	Other Gabon Crude	6,612	728,845	110,23	0.16 %
	Libyan Arab Jamahiriya	Medium (30-40o)	175,327	19,828,547	113,09	4.35 %
		Heavy	16,405	1,819,254	110,90	0.41 %
		Light (>40o)	124,749	13,936,209	111,71	3.10 %
	Nigeria	Medium	91,210	10,524,436	115,39	2.26 %
		Light (33-45o)	206,569	23,681,373	114,64	5.13 %
		Condensate (>45o)	14,383	1,599,594	111,21	0.36 %
	Other African Countries	Other Africa Crude	77,954	8,858,861	113,64	1.93 %
	Tunisia	Tunisia Crude	9,571	1,064,795	111,25	0.24 %
Africa			**968,402**	**109,362,907**	**112,93**	**24.03 %**
Australia	Papua New Guinea	Papua New Guinea Crude	1,622	177,421	109,38	0.04 %
Australia			**1,622**	**177,421**	**109,38**	**0.04 %**
FSU	Azerbaijan	Azerbaijan Crude	132,683	15,433,873	116,32	3.29 %
	Kazakhstan	Kazakhstan Crude	204,049	22,932,053	112,39	5.06 %
	Other FSU countries	Other FSU Crude	22,030	2,618,938	118,88	0.55 %

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
	Russian Federation	Other Russian Fed. Crude	540,118	59,653,602	110,45	13.40 %
		Urals	647,728	71,665,578	110,64	16.07 %
FSU			**1,546,607**	**172,304,045**	**111,41**	**38.38 %**
Europe	Denmark	Denmark Crude	42,716	4,871,698	114,05	1.06 %
	Norway	Statfjord	42,622	4,837,953	113,51	1.06 %
		Ekofisk	69,118	7,759,280	112,26	1.71 %
		Other Norway Crude	225,439	25,590,415	113,51	5.59 %
		Oseberg	39,138	4,493,530	114,81	0.97 %
		Gullfaks	34,095	3,906,708	114,58	0.85 %
	Other European countries	Other Europe Crude	104,909	11,463,813	109,27	2.60 %
	United Kingdom	Flotta	14,075	1,620,525	115,13	0.35 %
		Forties	38,083	4,274,373	112,24	0.94 %
		Brent Blend	56,028	6,359,949	113,51	1.39 %
		Other UK Crude	93,937	10,659,678	113,48	2.33 %
Europe			**760,159**	**85,837,922**	**112,92**	**18.86 %**
America	Brazil	Brazil Crude	26,412	2,920,991	110,60	0.66 %
	Canada	Light Sweet (>30o API)	3,634	407,144	112,03	0.09 %
	Colombia	Other Colombia Crude	30,410	3,152,847	103,68	0.75 %
	Mexico	Olmeca	331	36,790	111,15	0.01 %
		Isthmus	12,393	1,374,428	110,90	0.31 %
		Maya	50,426	5,193,475	102,99	1.25 %
	Other L. America countries	Other Latin America Crude	1,485	167,421	112,74	0.04 %
	United States	Other US Crude	60	4,851	80,75	0.00 %
	Venezuela	Medium (22-30o)	2,785	298,050	107,01	0.07 %
		Heavy (17-22o)	3,716	410,023	110,34	0.09 %
		Light (>30o)	4,933	540,946	109,67	0.12 %
		Extra Heavy	25,055	2,556,660	102,04	0.62 %
America			**161,640**	**17,063,627**	**105,57**	**4.01 %**
	World	Other crudes	75	8,456	112,17	0.00 %
World			**4,030,208**	**449,614,795**	**111,56**	**100. %**

Table 3.3: European imports and deliveries of crude oil for 2012 (source: European Commission, DG ENER)

Step 2: Representative MCONs and oil fields

One significant methodogical pitfall of the DG ENER list – relevant to the study - is that the used term "type of crude" oil does not necessarily correspond to specific MCONs as expected. Instead, crudes are presented in an aggregated form that does not allow for the precise identification of MCONs imported in Europe. For example, the "Nigerian Light" crude oil corresponds to several MCONs. Furthermore, the list uses also aggregate figures such as "Other Norwegian Crude" which again corresponds to several marketable names (MCONs). Therefore, the Consultant has determined to use the concept of **representative MCON** so that one or two representative MCONs are used for each "type of crude oil". The choice of representative MCONs has been based on the following principles:

- **Largest quantities of related MCONs imported and/or produced in Europe.** Representative MCONs have been chosen on the basis of quantities of crude oil imported and/or produced in Europe in order to maximize the coverage the DG ENER aggregates. Thus, MCONs with the higher quantities of imports or production (for European crudes) have been chosen as representative. However, in the case of certain countries (i.e. Nigeria, Angola, Libya) it has been difficult to exactly identify the quantities imported in Europe from all MCONs and therefore determined the one with the largest imports. In these cases, it has been assumed that the MCON that corresponds to the fields with the largest production is representative of the DG ENER aggregate.
- **Maximum geographical coverage of the exporting country.** Another significant consideration for the choice of representative MCONs has been the maximization of the geographic coverage of the exporting country. This is necessary because our background analysis using the OPGEE and work previously done has shown that crudes extracted within a specific vicinity exhibit similar upstream emissions. This has been anticipated because the reservoirs of fields that are located closely most likely have the same geological characteristics.
- **Significance of MCON in EU crude supply over the years.** The supply of Europe and Member States in specific MCONs does not exhibit significant variations over time. However, the choice of a specific baseline year for the study might not capture significant crude oil sources. For instance, Iranian crude is significant for EU crude oil supply (4.00 % of EU imports in 2011 and 2.47% in 2012 %,), but no quantities were imported in 2013 for political reasons. However, it is anticipated that in the close future Europe will start importing again Iranian. Similarly the Venezuelan extra heavy crude oil (Boscan), in 2012 constituted 0.62% of EU supply and is anticipated according to our market prospects that it play a constantly increasing role in Europe's crude oil supply. Therefore, it has been determined to include of the scope the analysis these two crudes.

In order to take account only MCONs that constitute significant fragment of EU supply, the Consultant has removed aggregates comprising less than 0.8% of EU imports with the exception of Venezuela bitumen. Additionally, the aggregates "other Europe crude" and "other UK crude" have been removed. With the removal of these aggregates the EU import coverage reaches the satisfactory level of 87.84%.

Following the choice of representative MCON, an intensive analysis of the oil fields comprising each MCON has followed. The extent to which an oil field is representative of an MCON (and by extension affects its physical characteristics) is highly volatile as this depends on the number of fields feeding an MCON and spans over time. For instance, the Stratfjord blend is fed by the oil fields of Statfjord, Snorre, Sygna, Satellites Statfjord North and East, which demands for manageable effort regarding data collection. However, for crude aggregates such as Brent there are over 70 fields feeding the MCON. Furthermore, the analysis of work previously done and primarily the analysis of upstream emissions conducted by ICCT using the OPGEE model has shown oil fields with small geographical proximity have similar upstream emissions. Thus, it has been considered that the choice of the fields with the highest production is representative for each MCON. The revised DG ENER list with representative fields and MCONs is illustrated in Table 3.1. This list is considered for the analyses carried out onwards in this study.

Region	Country of Origin	Type of crude oil	Share	Representative MCON	Representative Oil field Name
Middle East	Iran	Iranian Heavy	0.82 %	Iranian Heavy	Gachsaran
	Iraq	Basrah Light	1.98 %	Basrah Light	Rumaila (South)
					West Qurna
		Kirkuk	1.52 %	Kirkuk	Kirkuk
	Kuwait	Kuwait Blend	0.83 %	Kuwait Blend	Burgan
	Saudi Arabia	Arab Light	7.02 %	Arab Light	Gwahar
					Kurais
		Arab Heavy	0.95 %	Arab Heavy	Manifa
Africa	Algeria	Saharan Blend	2.65%	Saharan Blend	Hassi Messaoud
	Angola	Other Angola Crude	1.64%	Dalia	Block 17/Dalia
				Girassol	Girassol
				Greater Plutonio	Greater Plutonio
	Libyan Arab Jamahiriya	Medium (30-40o)	4.35%	Es Sider	Es Sider
		Light (>40o)	3.10%	El Sharara	El Sharara
	Nigeria	Medium	2.26%	Bonga	Bonga
				Forcados	Forcados Yokri
		Light	5.13%	Bonny light	Agbada
					Caw Thorne Channel
				Escravos	Escravos Beach
FSU	Azerbaijan	Azerbaijan Crude	3.29 %	Azeri light	Azeri-Chirag-Gunashli (ACG)
				Azeri BTC	Azeri-Chirag-Gunashli (ACG)
	Kazakhstan	Kazakhstan Crude	5.06 %	CPC Blend	Tengiz
				Tengiz	Tengiz
	Russian Federation	Other Russian Fed. Crude	13.40 %	Western Siberia Light	Tevlinsko-Russkinskoye
					Uryevskoye
					Samotlor
					Vat-Yeganskoye
					Povkhovskoye
				Druzhba	
		Urals	16.07 %	Urals	Romashkino
					Unvinskoye

Region	Country of Origin	Type of crude oil	Share	Representative MCON	Representative Oil field Name
					Pamyatno-Sasovskoye
Europe	Denmark	Denmark Crude	1.06 %	DUC	Halfdan
	Norway	Statfjord	1.06 %	Statfjord	Statfjord
		Ekofisk	1.71 %	Ekofisk	Ekofisk
		Other Norway Crude	5.59%	Troll	Troll B/C
				Asgard Blend	Tyrihans
		Oseberg	0.97%	Oseberg	Oseberg
		Gullfaks	0.85 %	Gullfaks blend	Gullfaks
	UK	Forties	0.94 %	Forties	Buzzard
		Brent Blend	1.39 %	Brent Blend	Ninian
		Other UK Crude	2.33 %	Captain	Captain
America	Mexico	Maya	1.25 %	Maya	Cantarell
	Venezuela	Extra Heavy	0.62 %	Boscan	Boscan
Total EU import coverage:			**87. 84%**		

Table 3.4: List of representative MCONs and oil fields

One significant methodological difficulty for the disaggregation is that for a specific type of crude oil, there might be several types of MCONs or grades depending on the mode of transport (e.g. pipeline or maritime), exporting port, etc. This difficulty is mostly related to Russian crudes and the case of Urals crude oil is illustrated in Table 3.5. The presented grades of Urals are mostly imported in Europe via several ports and the Druzhba pipeline.

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tonnes)
Urals NWE	30.83	1.44	7.2161	CIF Northwest Europe	Loading 10-25 days ahead	
Urals Med 80,000t	30.84	1.29	7.2165	CIF Augusta, Italy	Loading 10-25 days ahead	80,000
Urals Med 140,000t	30.84	1.29	7.2165	CIF Augusta, Italy	Loading 10-25 days ahead	140,000
Urals fob Primorsk	30.83	1.44	7.2161	FOB Primorsk, Baltic	-	100,000
Urals fob Ust-Luga			7.2156	FOB Ust-Luga, Baltic	-	
Urals fob Novorossiysk 80,000t	30.84	1.29	7.2165	FOB Novorossiysk, Black Sea	-	80,000
Urals fob	30.84	1.29	7.2165	FOB	-	140,000

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tonnes)
Novorossiysk 140,000t				Novorossiysk, Black Sea		
Urals cif Black Sea 80,000t	30.84	1.29	7.2165	CIF Black Sea	-	80,000

Table 3.5: Different grades for Urals crude oil (source: Argus Media)

Similarly, there are several grades (usually referred as price assessments in crude oil pricing) for deliveries of Russian Urals crude to refineries in eastern inland Europe via the Druzhba (Friendship) pipeline, which have the same physical properties of oil and thus the same emissions related to upstream activities, but different emissions related to crude oil transport. Table 3.6 presents the reality with the Druzhba pipeline delivering the same MCON to different destinations in EU.

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tonnes)
Druzhba Czech Republic	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Czech delivery)	Delivered during the previous month	10,000t tranche
Druzhba Slovakia	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Slovak delivery)	Delivered during the previous month	10,000t tranche
Druzhba Hungary	30.82	1.60	7.2156	fit Fenyeslitke, Hungary (for Hungarian delivery)	Delivered during the previous month	10,000t tranche
Druzhba Poland	30.82	1.60	7.2156	fit Adamowo, Poland (for Polish delivery)	Delivered during the previous month	10,000t tranche
Druzhba Germany	30.82	1.60	7.2156	fit Adamowo, Poland (for German delivery)	Delivered during the previous month	10,000t tranche
Druzhba Czech Republic	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Czech delivery)	Delivered during the previous month	10,000t tranche

Table 3.6: Price assessments for crude oil transported via the Druzhba pipeline (source: Argus Media)

Reliability of the choice of representative MCONs and oil fields

It must be noted that for few specific cases there is a small possibility that a chosen representative MCON or oil field might not arrive at Europe, particularly for MCONs presented in an aggregated way (e.g. Nigerian crudes). However, this is strongly mitigated by the fact that the likelihood that the specific MCONs (e.g. Bonny light) arriving at Europe is increased as these are the most important crudes in terms of quantities for the specific category (e.g. Nigerian Light). Furthermore, a background consistency check has been made with several sources (Platts, Argus, Lloyd's, Bloomberg) so as to ensure that the specific MCON actually arrives at Europe.

Similarly, the rationale for the choice of a representative oil field based on production volumes entails a small risk that oil from the specific fields might not arrive at Europe. For Russian and FSU crudes, this risk is very limited as most of these crudes (and respectively oil fields) enter the same pipeline system that supplies Europe directly or via maritime. The possibility that an oil field is not fully representative is increased in the case where a large number of oil fields comprise an MCON (e.g. Brent, Forties, Bonny light). In this case, even though the field might not supply crude oil to Europe the reliable assumption that the field has similar characteristics to its neighboring fields and therefore emissions has been made. This assumption has been validated by background analysis of neighbouring fields in OPGEE which produce results in the same range of values.

The sites of all fields and the exporting ports of the MCONs considered in this study are presented in Figure 3.14.

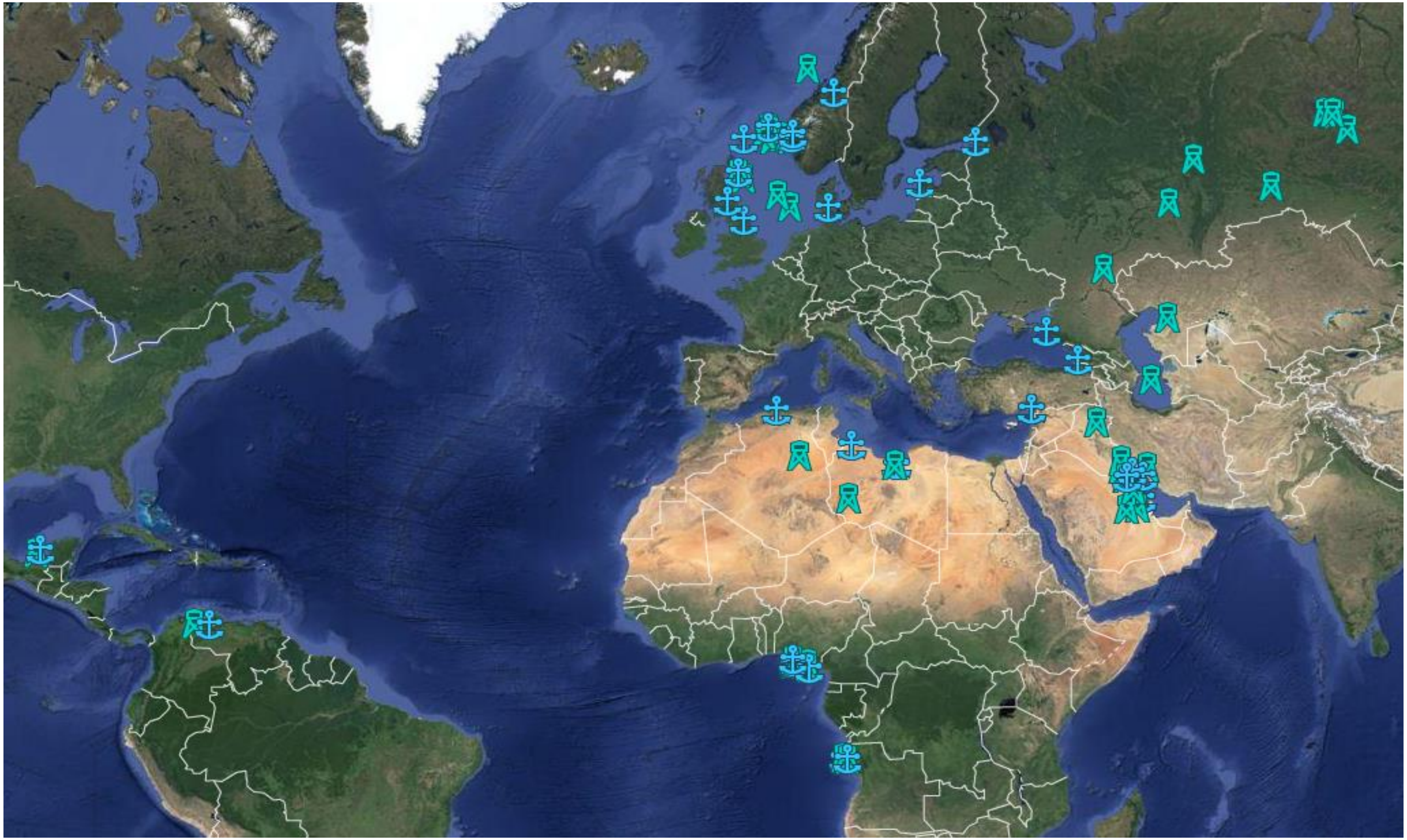


Figure 3.14: Map of representative oil fields and their terminals

Step 3: Collection of actual data from oil companies and national authorities

Following the finalization of representative MCONs and oil fields, the Consultant started the procedure for collecting actual data of MCONs and their representative oil fields. The main sources of these data are either the oil companies that are operators of the specific oil fields or the national authorities responsible for oil activities in each country. The list of the targeted field and MCON operators for the representative MCONs considered in this study as well as the other involved companies are presented in Table 3.7

Representative MCON	Operator	Other companies
Iranian Heavy	National Iranian Oil Company	-
Basrah Light	BP	China National Petroleum Corporation (CNPC) Iraq's state-owned South Oil Company (SOC)
	Iraq National Oil Company	Exxon Mobil, Royal Dutch Shell, Lukoil, Statoil
Kirkuk	North Oil Company	London-based BP, Iraq Petroleum Company, Iraq's National Oil Company
Kuwait Blend	Kuwait Oil Company	-
Arab Light	Saudi Aramco	-
Arab Heavy	Saudi Aramco	-
Saharan Blend	Sonatrach	-
Dalia	Total	Total is operator with 40% interest. Esso Exploration Angola holds 20%, BP holds 16.67%, Statoil holds 23.33%.
Girassol	Total	Esso Exploration Angola (20% interest), BP (16.7%), Statoil (13.3%) and Norsk Hydro (10%).
Greater Plutonio	BP	Sonangol Sinopec International, a joint venture between the Chinese and the Angolan state oil companies,
Es Sider	NOC / ConocoPhilips / Marathon / Hess	-
El Sharara	Repsol, Akakus	Total / OMV / Statoil
Bonga	Shell Nigeria	Royal Dutch Shell, ExxonMobil, Total S.A., Eni
Forcados	Shell Nigeria	-
Bonny light	Chevron	Shell
Escravos	Chevron ELF	-
Azeri light	BP	Chevron with 11.3%; SOCAR with 11.6%; INPEX with 11%; Statoil with 8.6%; ExxonMobil with 8%; TPAO with 6.8%; Itochu with 4.3%; and Hess with 2.7%

Representative MCON	Operator	Other companies
Azeri BTC	AIOC BP	Shareholders of the Azeri-Chirag-Gunashli offshore field include BP with 34.1367% of stakes, ChevronTexaco - 10.2814%,SOCAR - 10%, INPEX - 10%, Statoil - 8.5633%, ExxonMobil - 8.006%, TPAO - 6.75%, Devon Energy - 5.6262%, Itochu - 3.9205% and Hess - 2.7213%. Russia's Lukoil oil company pulled out of the project in 2003 selling all of its interest to INPEX.
Tengiz	Tengizchevroil	Chevron Corporation (50%), ExxonMobil (25%), KazMunayGas (20%)
CPC blend	Tengizchevroil	Chevron Corporation (50%), ExxonMobil (25%), KazMunayGas (20%)
Druzhba	Lukoil	-
	Lukoil	-
Siberia Light	Lukoil	-
	Lukoil	-
Urals	Lukoil	-
	Lukoil	
DUC	Maersk Oil	Gas A/S, Royal Dutch Shell, Chevron Corporation
Statfjord	Statoil	
Ekofisk	ConocoPhillips Skandinavia AS	Petoro, Statoil, Eni, ConocoPhillips, Total S.A.
Troll	Statoil	Petoro (56%), Royal Dutch Shell (8.1%), ConocoPhillips (1.62%) and Total S.A. (3.69%)
Asgard Blend	Statoil	Petoro (35.69%), Eni Norge (14.82%), Total E&P Norge (7.68%) and ExxonMobil (7.24%)
Oseberg	Statoil	ConocoPhillips Skandinavia AS 6.17 %, ExxonMobil Exploration & Production Norway AS 28.22 %, Petoro AS 28.94 %, Statoil Petroleum AS 36.66 %
Gullfaks blend	Statoil	Norsk Hydro the former Saga Petroleum
Forties	NEXEN PETROLEUM U.K. LIMITED	Suncor Energy - 30%, BG Group - 22%, Edinburgh Oil & Gas - 5%
Brent Blend	Canadian Natural Resources Limited (UK)	Eni 13%
Captain	Chevron	Texaco North Sea UK Company (85%) and the Korea Captain Company Limited (15%)
Maya	Pemex	-
Boscan	Empresa Mixta Petroboscan	Petroleos de Venezuela (PDVSA) and Chevron

Table 3.7: Representative MCONs and their operators

Step 4: Modelling of upstream emissions in OPGEE model

The literature review and the direct contacts with oil companies till present have made explicit that oil companies are cautious regarding the emission figures they publish, which are presented in generic and aggregated manner. Furthermore, data collected by national authorities or environmental organizations are typically on a country level which is insufficient for the analyses and comparisons of this study.

In order to mitigate the difficulty to obtain actual GHG emissions data on a field or MCON level the OPGEE model might be used for the estimation of GHG emissions of several MCONs. Therefore, the effort of the project team focused in gathering necessary data which are input for OPGEE. The main sources of these were official reports and publications from international organizations and oil companies involved in oil exploitation.

The rationale and the structure of the OPGEE model concentrates on simulating the upstream and midstream processes per oil field; details about the model are presented in the next Sections of this report.

3.3.3 Midstream

Step 5: Assessment of crude oil pathways to Europe

The purpose of this step is to estimate the GHG emissions related to the transport of crude oil to Europe. The Consultant has initially located the loading terminals for each MCON as they are presented in Table 3.8. These terminals are used for the calculation of distances towards the main EU unloading ports. The relevant estimation of distances and GHG emissions will be presented in the next Sections.

Type of crude oil	Representative MCON	Representative Oil field Name	Terminal Name
Iranian Heavy	Iranian Heavy	Gachsaran	Kharg Island
Basrah Light	Basrah Light	Rumaila (South)	Al Basrah Oil Terminal
		West Qurna	Al Basrah Oil Terminal
Kirkuk	Kirkuk	Kirkuk	Ceyhan
Kuwait Blend	Kuwait Blend	Burgan	Mina al Ahmadi
Arab Light	Arab Light	Gwahar	Ras Tanura
		Kurais	Ras Tanura
Arab Heavy	Arab Heavy	Manifa	Ras Tanura
Saharan Blend	Saharan Blend	Hassi Messaoud	Arzew
Other Angola Crude	Dalia	Block 17/Dalia	Dalia FPSO
	Girassol	Girassol	Girassol FPSO
	Greater Plutonio	Greater Plutonio	Greater Plutonio FPSO
Medium (30-40o)	Es Sider	Es Sider	Es Sider

Type of crude oil	Representative MCON	Representative Oil field Name	Terminal Name
Light (>40o)	El Sharara	El Sharara	Zawiya
Medium	Bonga	Bonga	Bonga FPSO
	Forcados	Forcados Yokri	Forcados Terminal
Light	Bonny light	Agbada	Bonny Terminal
		Caw Thorne Channel	Bonny Terminal
	Escravos	Escravos Beach	Escravos Terminal
Azerbaijan Crude	Azeri light	Azeri-Chirag-Gunashli (ACG)	Supsa
	Azeri BTC	Azeri-Chirag-Gunashli (ACG)	Ceyhan
Kazakhstan Crude	CPC Blend	Tengiz	Ceyhan
	Tengiz	Tengiz	Novorossiysk
Other Russian Fed. Crude	Western Siberia (light)	Tevlinsko-Russkinskoye	Novorossiysk, Primorsk
		Uryevskoye	Novorossiysk, Primorsk
		Samotlor	Novorossiysk, Primorsk
		Vat-Yeganskoye	Novorossiysk, Primorsk
		Povkhovskoye	Novorossiysk, Primorsk
Urals	Urals	Romashkino	Novorossiysk, Primorsk
		Unvinskoye	Novorossiysk, Primorsk
		Pamyatno-Sasovskoye	Novorossiysk, Primorsk
Denmark Crude	DUC	Halfdan	Fredericia
Statfjord	Statfjord	Statfjord	Statford
Ekofisk	Ekofisk	Ekofisk	Teeside
Other Norway Crude	Troll	Troll B/C	Mongstad
	Asgard Blend	Tyrihans	Asgard FPSO
Oseberg	Oseberg	Oseberg	Sture
Gullfaks	Gullfaks blend	Gullfaks	Mongstad
Forties	Forties	Buzzard	Hound Point
Brent Blend	Brent Blend	Ninian	Sullom Voe
Other UK Crude	Captain	Captain	Captain FPSO
Maya	Maya	Cantarell	Caya Arcas
Extra Heavy	Boscan	Boscan	Bajo Grande

Table 3.8: Most significant oil terminals supplying crude oil to Europe

Maritime transport

Europe is supplied with crude oil either via maritime transport from major ports that are interconnected with oil pipelines or directly from oil terminals. More specifically, significant part of Russian oil arrives in Europe via Primorsk which is Russia's largest oil terminal, with a loading capacity of 1.5 million b/d. It is located near St. Petersburg and is a two-berth harbor that can accommodate ships with maximum length of 307 meters. Novorossiysk is Russia's main oil terminal at the Black Sea coast. Its load capacity is 950,000 b/d, and it can load tankers up to 150,000 deadweight tonnes (dwt). Tuapse is located on the northeastern shore of the Black Sea, southeast of Novorossiysk. Two of the six berths load crude oil. The port mainly exports Siberian Light. Its loading capacity is about 350,000 b/d. In addition, the terminal has more than 580.000 barrels of oil and oil products storage capacity. The port can accommodate tankers with up to 80,000 dwt. Yuzhny terminal is located in Ukraine, near Odessa, although it mainly exports Russian and Kazakh crude oil via the Black Sea. This port's load capacity is 315,000 b/d, and it can accommodate vessels up to 70,000 dwt. Additionally, other significant Russian oil ports are at Ventspills, Ust Luga and Gdansk in Poland; all of them are exporting Urals oil.

In terms of quantities imported, the largest Russian oil terminal is Primorsk which in 2011 exported over 1.3 million b/d. Novorossiysk is the largest Russian oil terminal in the Black sea, through which Russia exported approximately 0.9 million b/d in 2011, as it can be obtained from Figure 3.15.

From these ports crude oil arrives at Europe via various categories of tankers the categories of which are illustrated in Table 3.9 and will be used in the calculation of GHG emissions of oil maritime transport.

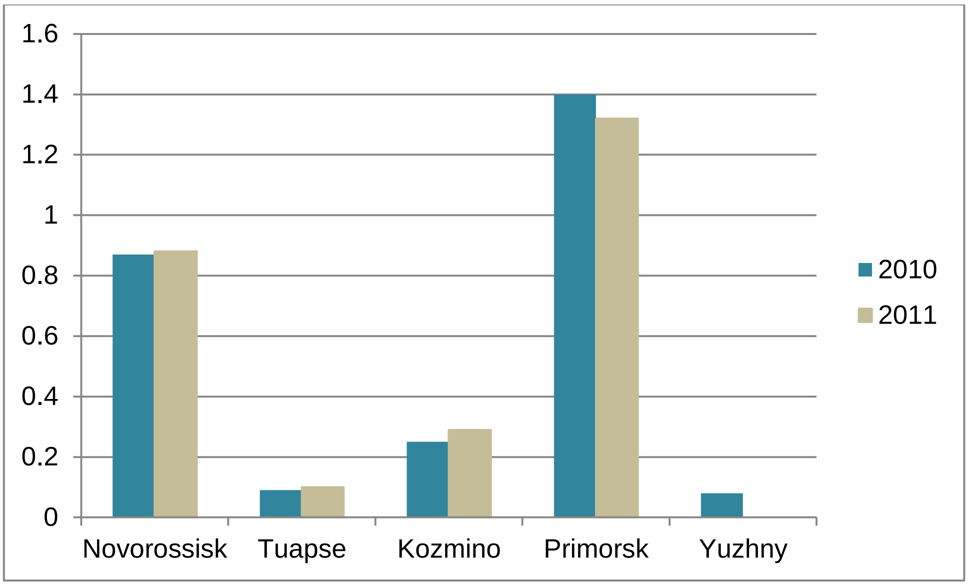


Figure 3.15: Exports in million b/d including transit through Russian ports Quarter 1 of 2010 to Quarter 1 of 2011 (source: CDU)

Name	DWT Range (tonnes)	Description
Aframax	80,000 - 119,000	This is the largest crude oil tanker size in the AFRA (Average Freight Rate Assessment) tanker rate system.
Suezmax	120,000 - 150,000	This is the maximum size crude oil ship that can pass through the Suez Canal in Egypt.
VLCC	150,000 - 319,999	These are very large crude oil carriers that transport crude oil from the Gulf, West Africa, the North Sea and Prudhoe Bay to destinations in the United States, Mediterranean Europe and Asia. Although VLCCs are otherwise too large, it is possible to ballast these vessels through the Suez Canal.
ULCC	320,000 - 999,999	These are the largest man-made vessels that move. Currently, the largest ULCC is 564,939 dwt. These ships sail the longest routes, typically from the Gulf to Europe, the United States and Asia. They are so large that they require custom-built terminals for loading and unloading.

Table 3.9: Crude oil tanker categories (source: Lloyds)

Figure 3.16 illustrates the major ports that have facilities for unloading of crude oil in Europe. These ports are the recipients of crude oil transported from the exporting ports of the representative MCONs which have been presented above.

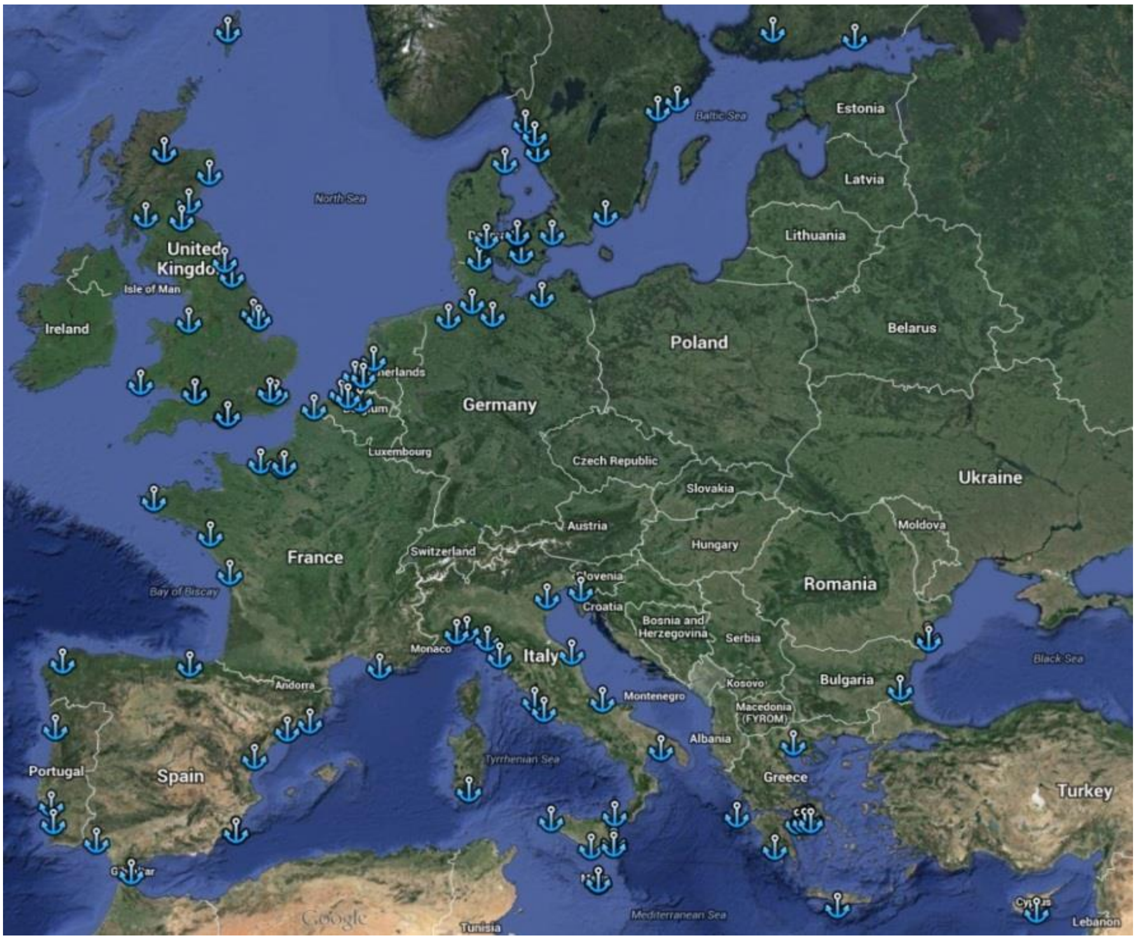


Figure 3.16: Map of major ports importing crude oil in Europe

Pipeline transport

The largest part of the Russian oil is supplied to Europe via the **Druzhba pipeline** system, which remains the largest oil pipeline in the world. The vast majority of the oil refined in Poland, Slovakia, Hungary, Eastern part of Germany and Czech Republic is supplied via the Druzhba pipeline. Table 3.10 presents the main destinations of the Druzhba pipeline and the capacity of refineries which are supplied by the pipeline.

The **Baltic Pipeline System (BPS)** is a Russian oil transport system operated by the oil pipeline company Transneft. The BPS transports oil from the Timan Pechora region, Western Siberia and Urals-Volga regions to Primorsk oil terminal. Main sections of the BPS I are the Yaroslavl Kirishi pipeline and Kirishi-Primorsk pipeline. The capacity of the BPS I is 76.5 million tons of oil per year. The Baltic Pipeline System II is the second route of the Baltic Pipeline System. The BPS-II was completed in 2011 and became operational in 2012. The pipeline runs from Unecha to the port of Ust Luga (west of St. Petersburg and passes through Smolensk. It has a total length of 1,170 km and a capacity of 50 million tons per year. The main routes are presented in Figure 3.17.

Country	Location	Capacity (MTA)
Lithuania	Mazeikiai	9.4
Poland	Gdansk	10.5
	Plock	17.8
Germany	Leuna	11.2
	Schwedt	12.0
Czech Republic	Litvinov	5.1
	Kralupy	3.1
	Padubice	1.0
Slovakia	Bratislava	5.7
Hungary	Szazhalombatta	7.9
TOTAL		83.7

Table 3.10: EU refining locations and capacities linked to Druzhba pipeline

Figure 3.17: The Baltic Pipeline System. Gas pipelines are shown in red colour, oil pipelines in green and the dashed line shows the planned pipelines. (source: EIA)

The **Caspian Pipeline Consortium (CPC)** oil pipeline, was commissioned in 2001 and runs from Kazakhstan's Tengiz oil field to the Russian port of Novorossiysk at the Black Sea. The consortium transported an average of 684,000 b/d of crude oil in 2011, including 608,000 b/d from Kazakhstan and 76,000 b/d from Russia. In addition, approximately 53,000 b/d of Tengiz crude was discharged at Atyrau, Kazakhstan, for loading onto rail cars. In 2011, CPC partners began the expansion of the pipeline capacity to 1.4 million b/d. The project will be implemented in three phases, with capacity increasing until 2016. The expansion is expected to provide additional transportation capacity to accommodate increased production from Tengizchevroil.

The **Baku-Novorossiysk pipeline** is 830 miles long and has a capacity of 100,000 bbl/d. The pipeline runs from the Sangachal Terminal to Novorossiysk, Russia on the Black Sea. SOCAR operates the Azeri section, and Transneft operates the Russian section. An ongoing dispute between SOCAR and Transneft concerning transportation tariffs occasionally complicates the pipeline's operation. There are proposals to increase the pipeline capacity to between 180,000 and 300,000 bbl/d, a key transportation addition as production grows in the ACG oil field and throughput from Kazakhstan increases in the future. In 2010, Baku-Novorossiysk transported approximately 45,500 b/d.

Since the collapse of the Soviet Union, European countries have begun investing in alternative export routes. The **Baku-Tbilisi-Ceyhan** (BTC) pipeline is a 1-million b/d line in Azerbaijan, which came online in 2006. Kazakhstan has a contract with Azerbaijan and the BTC Pipeline Company to ship up to 500,000 b/d of oil via the BTC pipeline. Kazakh oil supplies were loaded into the BTC for re-export for the first time in October 2008. Oil supplies are delivered by tanker across the Caspian to Baku. The BTC pipeline system runs 1,110 miles from the ACG field in the Caspian Sea, via Georgia, to the Mediterranean port of Ceyhan, Turkey. From there the oil is shipped by tanker mainly to European markets.

Kazakhstan's other major oil export pipeline, **Uzen-Atyrau-Samara**, is a northbound link to Russia's Transneft distribution system, which provides Kazakhstan with a connection to world markets via the Black Sea. The line was upgraded in 2009 by the addition of pumping and heating stations and currently has a capacity of approximately 600,000 b/d. Before the completion of the CPC pipeline, Kazakhstan exported almost all of its oil through this system.

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
Arab Light	Gwahar		MIN	Ghawar oil field - Ras Tanura - Agioi Theodoroi	93	4,375	100,000
			CENTRAL	Ghawar oil field - Ras Tanura - Le Havre	93	7,171	200,000
			MAX	Ghawar oil field - Ras Tanura - Rotterdam	93	7,456	100,000
Bonny light	Agbada		MIN	Agbada oil field - Bonny terminal - Huelva	42	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal -	42	5,704	135,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Trieste			
			MAX	Agbada oil field - Bonny terminal - Gothenburg	42	6,311	135,000
Bonny light	Caw Thorne Channel		MIN	Caw Thorne Channel oil field - Bonny terminal - Huelva	17	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5,704	13,500
			MAX	Caw Thorne Channel oil field - Bonny terminal - Gothenburg	17	6,311	135,000
Siberia Light	Samotlor	Novorossisk	MIN	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,880	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,881	1,850	135,000
			MAX	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,880	4,999	135,000
		Primorsk	MIN	Samotlor - Perm - Primorsk - Gdansk	1,862	699	100,000
			CENTRAL	Samotlor - Perm - Primorsk - Rotterdam	1,862	1,495	100,000
			MAX	Samotlor - Perm - Primorsk - Megara oil terminal	1,862	5,495	100,000
		Germany		Samotlor - Surgut - Perm - Plock - Leuna	2,912	0	-
		Poland		Samotlor - Surgut - Perm - Plock	2,528	0	-
		Czech Republic		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha -	2,751	0	-

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov			
		Slovakia		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2,983	0	-
		Hungary		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,692	0	-
Urals	Romashkino	Novorossisk	MIN	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,036	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,036	1,850	135,000
			MAX	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,036	4,999	135,000
		Primorsk	MIN	Romashkino - Perm - Primorsk - Gdansk	1,838	699	100,000
			CENTRAL	Samotlor - Perm - Primorsk - Rotterdam	1,838	1,495	100,000
			MAX	Romashkino - Perm - Primorsk - Megara oil terminal	1,838	5,495	100,000
		Germany		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock - Schwedt - Leuna	1,888	0	-
		Poland		Romashkino - Almayetsk - Syzran - Unecha -	1,504	0	-

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Mozyr - Plock			
		Czech Republic		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	1,727	0	-
		Slovakia		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	1,960	0	-
		Hungary		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,040	0	-
Troll	Troll B/C	Troll B/C	MIN	Troll - Mongstad - Gothenburg port - Gotheburg refinery	86	439	80,000
			CENTRAL	Troll - Mongstad - Gothenburg port - Wilhelshaven	86	583	80,000
			MAX	Troll - Mongstad - Trieste port - Trieste refinery	86	4,055	80,000

Table 3.12 presents the main oil pipelines supplying crude oil to Europe as well the capacities of the pipelines and the estimated distances to the main destinations. Also Figure 3.19 presents in a regional map the main routes of Russian oil pipelines supplying oil to Europe.

Due to the above presentation of the Russian oil pathways it is evident that there is high complexity in defining the MCONs and their precise oil field components. Figure 3.18 presents the approach of the Consultant in representing the midstream pathways and the relevant Russian MCONs, especially those directed to EU destinations. Therefore oil transported by Druzhba constitutes one MCON which differentiates in the GHG emissions according to the country of delivery due to different distances and a min-max calculation will be used. On the other hand we consider two Urals MCONs due to the two pathways used to export it by maritime (Primorsk, Novorossiysk) and one Siberian Light MCON export through Novorossiysk.

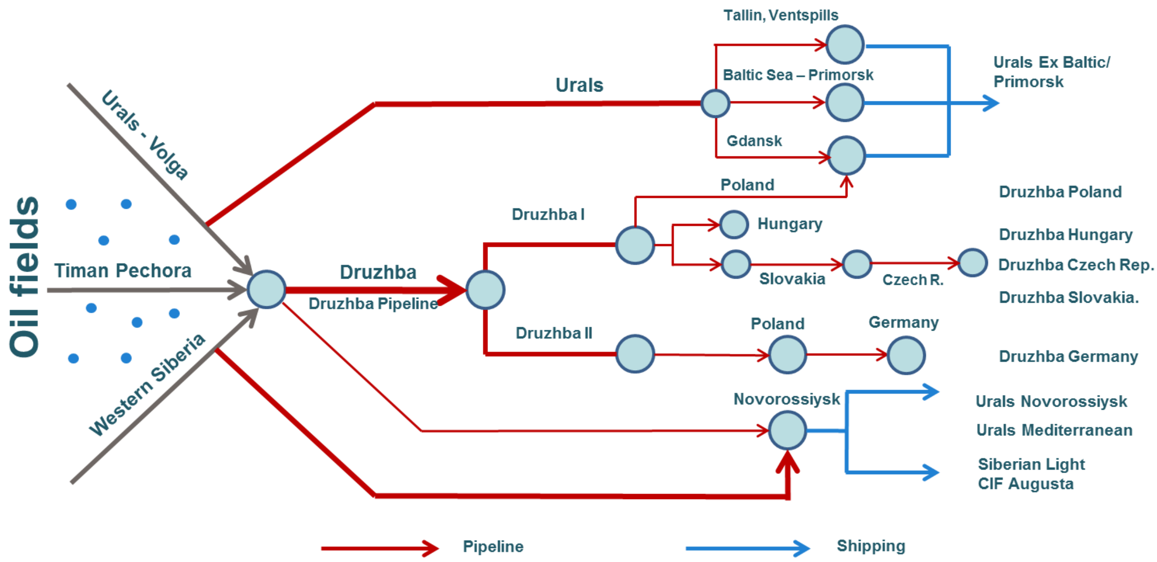


Figure 3.18: Russian crude oil analysis from oil field to MCON

Pipeline	Route	Length (miles)	Capacity (million bbl/d)	Details
Druzhba	Northern Route: Belarus, Poland Germany; Southern Route: Belarus, Ukraine, Slovakia, Czech Republic, Hungary	2,400	2	
Baltic Pipeline System I	Timan Pechora to Primorsk Terminal	730	1.5	
Baltic Pipeline System 2	Unecha to Ust-Luga Terminal	620	1	
North-West Pipeline System	Polotsk to Butinge and Ventspils	500	0.3	Branches off of Druzhba near Russia-Belarus border and transports Russian oil via Belarus to Latvia and Lithuania
Caspian Pipeline Consortium (CPC)	Tengiz (Kazakhstan) to Russian Black Sea port of Novorossiysk	940	0,7	Planned expansion to 1.4 million b/d by 2016
Baku-Tbilisi-Ceyhan	Connects ACG, Shah Deniz, Tengiz		1,000,000 bbl/d	Kazakhstan-Azerbaijan-Georgia-Turkey

Pipeline	Route	Length (miles)	Capacity (million bbl/d)	Details
(BTC)				
Baku-Novorossiysk Pipeline	Sangachal Terminal (Azerbaijan) to Russian Black Sea port of Novorossiysk	830	0.1	Planned expansion to 0.3 million b/d
Source: Transneft, IHS, PFC Energy, Petroleum Economist				

Table 3.11: Russian and Caspian pipeline supplying Europe (source: EIA)

Rail export routes

Rail exports comprise a very small portion of Russian oil exports. Rail transport generally used as an alternative to Transneft's pipeline network, although rail transport is generally more expensive than pipeline transportation. It is referred that Russia exports crude oil and petroleum products by rail to Estonia and Latvia. These quantities are small and will be ignored in this study.

Figure 3.19: **Map with main routes of Russian pipelines supplying crude oil to Europe**

Step 6: Estimation of midstream GHG emissions

The Consultant has approached the transportation of crudes (MCONs) by ships at the refinery gate by correlating discharges of crude oil cargoes at ports (which is an information relatively available) with neighbouring refineries. It has been taken into account that most EU refineries either own an oil terminal or are built close to ports. Similarly, most refineries in Central Europe are built alongside major crude oil pipelines. The precise blend input of refineries - either via marine transport or pipeline - is unfortunately not available as it is of high commercial value for refineries and has therefore been impossible to find this information in a consistent and reliable manner. One possible source of this information could be maritime databases using vessel tracking via the automatic Identification System (AIS) that most ships have installed over the last decade.

Maritime transport

A database that contains such information and reviewed by the Consultant is APEX (Analysis of Petroleum Exports) providing details of laden tanker movements for vessels greater than 10,000 DWT engaged in world-wide crude oil trades and laden tanker movements for vessels greater than 60,000 DWT in world-wide oil product trades as well as current tanker activities for specific size ranges.

The APEX database is a product of Lloyd's List Intelligence that draws on the extensive movements database of its parent company Informa Group. The database is compiled from movements observed by over 1,500 Lloyd's Agents worldwide, supplemented with data from the network of AIS stations; the world's largest, and satellite AIS data. From this database Lloyd's List Intelligence extracts movements' details for all tankers and combination carriers in excess of 10,000 DWT. These data is then analysed by a team of analysts who identify the laden voyages which are then inputted into the APEX database.

Even though the APEX database is probably one of the most comprehensive commercial information tools for the analysis of maritime crude oil shipments it has been considered as insufficient for the purpose of this study, as in several cases the precise type of the shipment is not explicitly mentioned or stated as “multiple cargo” which does not allow for further analysis. Furthermore, despite its depth of information regarding maritime transport, the database does not contain information regarding pipeline oil transport. However, it must be stated that the database contains a wealth of information relevant to:

- Vessel name
- Cargo type and tonnes
- Crude type
- API of crude transported
- Loading port and date
- Discharge port and date
- Refinery capacity at place
- Refinery location, capacity and owner
- Distance

- Dead Weight Tonnage

Other useful programs for identifying ships vessel movements carrying crude oil is the Sea Web tool by IHS, combining comprehensive data regarding ships, ports, real-time positions and historic vessel movements. A similar tool including ship vessel movements is FleetMon.

However, it has still been impossible to fully contemplate the EU refineries input blend by the shipments arriving in relevant ports as most of the times several crudes are loaded from the loading port making it impossible to fully analyse the exact type of crude a vessel is carrying. Furthermore, there is also the probability of double counting of vessels particularly for voyages off Rotterdam.

In order to mitigate this uncertainty, the Consultant has finally used the information filled in by Member States to DG ENER and elaborated it to identify which MCONs are imported by each Member State **on a country basis**. Furthermore, the ports which have crude oil terminals have been linked to the nearby refineries; therefore we may approximate minimum and maximum distances of MCONs transportation from loading port to the gates of EU refineries.

Pipeline transport

As discussed during Step 5, Europe is supplied crude oil via a complex pipeline system of thousand kilometres starting from Western Siberia and supplying Central Europe. The exact type of crude of the Druzhba pipeline cannot be defined with precision as crude oil from various fields enters the pipeline and oil is unloaded in various refineries on its length. Our analysis based on information from Argus and Platts has concluded that the crude oil, with the same physical properties, transported via the Druzhba pipeline is transported to 5 EU destinations. Background analysis of the upstream Russian oil sector has indicated that the Druzhba pipeline carries on average 2/3 of oil from the Urals area and 1/3 from the Western Siberia in general.

Modelling of midstream emissions in OPGEE

Following the identification of major pathways of imported oil in Europe, the GHG emissions due to crude oil transport have been calculated using the OPGEE model. Taking into consideration that each MCON, either via marine transport or pipeline, is exported to several EU countries, the Consultant identifies the minimum, weighted average and maximum distance of the followed route. In the context of the Interim Report we have estimated the GHG emissions of the 5 most significant MCONS - in terms of quantities delivered in EU. In this exercise the upstream and midstream calculations for CI have been carried out and the indicative results will be presented in the next Sections.

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
Arab	Gwahar		MIN	Ghawar oil field -	93	4,375	100,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
Light				Ras Tanura - Agioi Theodoroi			
			CENTRAL	Ghawar oil field - Ras Tanura - Le Havre	93	7,171	200,000
			MAX	Ghawar oil field - Ras Tanura - Rotterdam	93	7,456	100,000
Bonny light	Agbada		MIN	Agbada oil field - Bonny terminal - Huelva	42	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5,704	135,000
			MAX	Agbada oil field - Bonny terminal - Gothenburg	42	6,311	135,000
Bonny light	Caw Thorne Channel		MIN	Caw Thorne Channel oil field - Bonny terminal - Huelva	17	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5,704	13,500
			MAX	Caw Thorne Channel oil field - Bonny terminal - Gothenburg	17	6,311	135,000
Siberia Light	Samotlor	Novorossisk	MIN	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,880	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,881	1,850	135,000
			MAX	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,880	4,999	135,000
		Primorsk	MIN	Samotlor - Perm - Primorsk - Gdansk	1,862	699	100,000
			CENTRAL	Samotlor - Perm - Primorsk -	1,862	1,495	100,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Rotterdam			
			MAX	Samotlor - Perm - Primorsk - Megara oil terminal	1,862	5,495	100,000
		Germany		Samotlor - Surgut - Perm - Plock - Leuna	2,912	0	-
		Poland		Samotlor - Surgut - Perm - Plock	2,528	0	-
		Czech Republic		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2,751	0	-
		Slovakia		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2,983	0	-
		Hungary		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,692	0	-
Urals	Romashkino	Novorossisk	MIN	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,036	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,036	1,850	135,000
			MAX	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,036	4,999	135,000
		Primorsk	MIN	Romashkino - Perm - Primorsk - Gdansk	1,838	699	100,000
			CENTRAL	Samotlor - Perm - Primorsk -	1,838	1,495	100,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Rotterdam			
			MAX	Romashkino - Perm - Primorsk - Megara oil terminal	1,838	5,495	100,000
		Germany		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock - Schwedt - Leuna	1,888	0	-
		Poland		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock	1,504	0	-
		Czech Republic		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	1,727	0	-
		Slovakia		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	1,960	0	-
		Hungary		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,040	0	-
Troll	Troll B/C	Troll B/C	MIN	Troll - Mongstad - Gothenburg port - Gotheburg refinery	86	439	80,000
			CENTRAL	Troll - Mongstad - Gothenburg port - Wilhelshaven	86	583	80,000
			MAX	Troll - Mongstad - Trieste port - Trieste refinery	86	4,055	80,000

Table 3.12 presents the main information collected and assumed for the pathways of the 5 most significant MCONs imported in EU.

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
Arab Light	Gwahar		MIN	Ghawar oil field - Ras Tanura - Agioi Theodoroi	93	4,375	100,000
			CENTRAL	Ghawar oil field - Ras Tanura - Le Havre	93	7,171	200,000
			MAX	Ghawar oil field - Ras Tanura - Rotterdam	93	7,456	100,000
Bonny light	Agbada		MIN	Agbada oil field - Bonny terminal - Huelva	42	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5,704	135,000
			MAX	Agbada oil field - Bonny terminal - Gothenburg	42	6,311	135,000
Bonny light	Caw Thorne Channel		MIN	Caw Thorne Channel oil field - Bonny terminal - Huelva	17	4,215	135,000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5,704	13,500
			MAX	Caw Thorne Channel oil field - Bonny terminal - Gothenburg	17	6,311	135,000
Siberia Light	Samotlor	Novorossisk	MIN	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,880	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,881	1,850	135,000
			MAX	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,880	4,999	135,000
		Primorsk	MIN	Samotlor - Perm - Primorsk - Gdansk	1,862	699	100,000
			CENTRAL	Samotlor - Perm -	1,862	1,495	100,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Primorsk - Rotterdam			
			MAX	Samotlor - Perm - Primorsk - Megara oil terminal	1,862	5,495	100,000
		Germany		Samotlor - Surgut - Perm - Plock - Leuna	2,912	0	-
		Poland		Samotlor - Surgut - Perm - Plock	2,528	0	-
		Czech Republic		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2,751	0	-
		Slovakia		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2,983	0	-
		Hungary		Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,692	0	-
Urals	Romashkino	Novorossisk	MIN	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Costanza	1,036	504	135,000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Trieste	1,036	1,850	135,000
			MAX	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossisk- Rotterdam	1,036	4,999	135,000
		Primorsk	MIN	Romashkino - Perm - Primorsk - Gdansk	1,838	699	100,000
			CENTRAL	Samotlor - Perm - Primorsk -	1,838	1,495	100,000

Representative MCON	Oil field	Pathway	Min/max	Comments	Pipeline Total (miles)	Marine Total (miles)	Tanker size (DWT)
				Rotterdam			
			MAX	Romashkino - Perm - Primorsk - Megara oil terminal	1,838	5,495	100,000
		Germany		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock - Schwedt - Leuna	1,888	0	-
		Poland		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock	1,504	0	-
		Czech Republic		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	1,727	0	-
		Slovakia		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	1,960	0	-
		Hungary		Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2,040	0	-
Troll	Troll B/C	Troll B/C	MIN	Troll - Mongstad - Gothenburg port - Gotheburg refinery	86	439	80,000
			CENTRAL	Troll - Mongstad - Gothenburg port - Wilhelshaven	86	583	80,000
			MAX	Troll - Mongstad - Trieste port - Trieste refinery	86	4,055	80,000

Table 3.12: Major pathways of the 5 most significant MCONs imported in Europe

3.3.4 Downstream

Step 7: Estimation of GHG emissions during the refining process

This step refers to the calculation of the GHG emissions that are related to the refining of crude oil. Figure 3.20 illustrates the location of the major refineries in EU. It can be seen from the map that refineries are typically built close to ports or have their own port terminals to ensure crude oil supply. Refineries located in Central Europe are supplied crude oil primarily via the Druzhba pipeline or via small pipelines that are connected to port terminals.

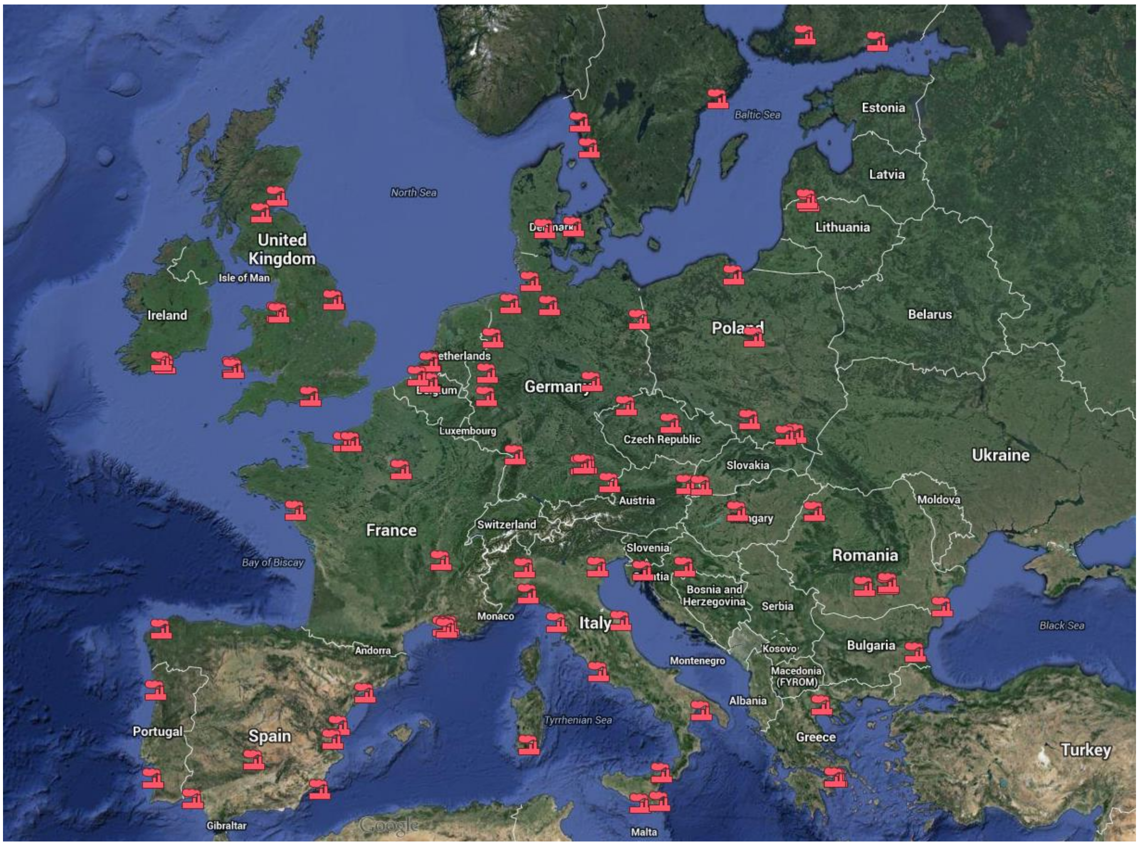


Figure 3.20: Location of major refineries in Europe

Actual emission data for the refining stage are available by each EU country from the Environmental Energy Agency (EEA) and refer to the total emissions due to energy branch consumption of fossil fuels by refineries. However, these emissions are not assigned to each refinery output as it is required to calculate emissions over the life cycle of mineral oil fuels. In addition, the refineries consume electricity and steam which are partly self-produced and so involve GHG emissions directly as part of the statistics on energy branch consumption of refineries and partly due to energy purchased from the market; in this case the related GHG emissions are indirect. Also refineries may also sell electricity and steam to third parties, as their own production facilities may be larger than refining needs require. Therefore, two more calculation issues arise:

- firstly to calculate total GHG emissions that directly and indirectly are associated to refining needs in total;
- secondly to allocate reasonably GHG emissions to each fuel output.

Allocation of direct and indirect emissions of a refinery

The first calculation requires data which are not directly available by Eurostat as the statistics do not show separately sales of electricity and steam by the refineries but only purchases of distributed steam and electricity. The fuels used for on-site generation of steam in refineries are provided in statistics; however they are not distinguished from similar fuels consumed by refineries for other purposes (e.g. in boilers). Therefore, total steam generated by refineries is not known in the statistics. So the methodology can rely only on Eurostat statistics for the assessment of the total GHG emissions in the refining system of each European country. To fill this gap the PRIMES model database has performed enrichment of the data on steam using the CHP surveys by country available by Eurostat and other information sources (plant inventory from Platts and other sources including a survey over concrete refinery companies). Based on these extended statistics and using modelling of the entire steam and electricity sector the PRIMES REFINERIES model calibration routine has performed reconstitution of statistical data for past years (latest calibration year is 2010) in which the calibration routine estimates in detail how steam is produced in refineries and which are the amounts of input and output of electricity as well as the sales and purchases of these energy forms at the level of the entire refinery sector in each European country. Based on these calibrated data for 2010 it is thus possible to calculate total direct and indirect GHG emissions for the refinery sector in each European country.

Allocation of GHG emissions to each product output

The second calculation stage is to allocate the total GHG emissions (direct and indirect) to each product output from the refineries in each European country. This requires a methodological approach because the allocation cannot be straightforward as refining is a process using energy and feedstock to produce multiple product outputs. The methodologies proposed in the literature range from simple approaches based on average emission factors leading to an allocation on total emissions in proportion to energy equivalent amounts of product outputs up to complex approaches based on marginal emission factors derived from a modelling of the refinery process. The second approach is generally superior from a methodological perspective but requires more complex modelling and detailed information.

The intention of the Consultant is to apply the second approach and to exploit the existing refining modelling framework of the PRIMES-Refineries model. For this purpose the Consultant proceeded intensively in an extension of the model in order to accommodate multiple crude oil types as inputs to the refinery modelling and also to separate stylised refinery types and so capture more adequately the emission estimation and the allocation of emissions to output products. Therefore, to calculate the GHG emissions that occur during refining, the Consultant will use an extended modelling tool of the PRIMES-Refineries sub-model which has been developed and maintained by E3MLab. The main purpose of following a model based analysis is mainly to allocate to each refined petroleum product (for our analysis: diesel, petrol, kerosene) a specific carbon intensity factor based on the estimation of marginal emissions.

Refining of crude oils involves a range of different energy intensive processes that produce multiple petroleum products. A large difference can be observed in product yield, energy use and emissions between different refinery types depending on the type of crude and the complexity of the refining technology. Model calibration techniques are used to estimate product yields and the associated energy consumption and emissions in stylised refinery types by country. The capacity data of refining processes have been from the OGJ database which has been acquired for use in this study.

The use of a single configuration for European refineries is not appropriate because of the diversity of refinery units, the crude feedstock and production yields. To account for the large diversity, the PRIMES-Refineries model simulates stylised representative refinery types to reflect the average flow scheme met in European refineries and to capture the diversity. The refinery configuration includes major process units related to separation, upgrading and conversion of crude oil. The modelling approach is based on the fact that different products go through different processes within the refinery, thus production flows are used to simulate the various streams leading to the products of interest (petrol, diesel and kerosene).

The GHG emissions resulting from the feedstock refining are relevant to the type of feedstock used by the refinery. The resulting GHG emissions from the petroleum refining are therefore influenced by the energy intensity and the energy use by process. In reality, a variety of crudes of different quality is fed in the refining industry. Refineries process blends of crudes and adjust their processing conditions for the optimization of products yields. In order to gain a better evaluation of the carbon intensity of crudes with different characteristics, E3MLab will extend the PRIMES-Refinery model to include different types of crude oils as an input to the stylised refinery types. In this context, three broad categories have been already identified based on the API gravity and sulphur content (Heavy, Medium, Light).

The reason for selecting API gravity and sulphur content as the key criteria for distinguishing the crude types is that they indicate the quality of the crude and influence the level and the conditions of processing. According to engineering data the API gravity and sulphur content are the main features which can explain the diversity of fossil fuel consumption, hence emissions, in the various types of refining processing.

Average emissions need to be partitioned to each individual petroleum fuel produced. Most common approaches involve the emission allocation to the individual refinery products based on the product proportion to the total quantity produced or based on the energy content of the commodities. In order to associate emission factors with the concrete refinery output products (diesel, petrol, kerosene) in a more adequate manner, a methodology developed by the Institut Français du Pétrole (IFP) will be used. This method includes allocation of emissions to individual products based on marginal emission content.

Step 8: Estimation of GHG emissions during transportation of refined products

This step presents the approach that is followed by the Consultant for calculating the GHG emissions that take place during the transportation of the refined petroleum products from the production point (i.e. the refinery) to the consumption point (i.e. filling station). The transportation of the refined petroleum products from the refineries to the filling stations in EU countries usually takes place via three modes: road freight, freight rail and inland waterways, which are currently operating mainly on fossil fuels. The share of each transport mode participating in the transportation of the refined petroleum products differs by EU country; this implies that the carbon intensity during transportation is different by country. The Consultant has further considered the fugitive GHG emissions at the stage of the filling stations.

Data on the refined petroleum products transported by transport mode at a national level (in tons and ton-kilometers) have been retrieved from EUROSTAT. Data on the average carbon intensity per transport mode are drawn from the PRIMES-TREMOVE[1] transport model, developed and maintained by E3MLab. The values used have also been validated with the values reported in the TRACC[2]S database. Regarding the fugitive GHG emissions at the level of the filling stations, the Consultant has used typical emission factors from literature as illustrated in Table 3.13:

Period	Reloading of tankers, kg NMVOC per tonne gasoline	Refuelling of vehicles, kg NMVOC per tonne gasoline	Sum of reloading and refuelling, kg NMVOC per tonne gasoline	Source
1985-1990	1.26	1.52	2.80	Fennmann &Kilde, 1994
1991	0.64	1.52	2.16	Fennmann &Kilde, 1994
1992-1995	0.08	1.52	1.60	GB EMF, Fennmann & Kilde, 1994
1996			1.38	Interpolation between 1995 and 2000
1997			1.17	Interpolation between 1995 and 2000
1998			0.96	Interpolation between

[1] http://www.e3mlab.ntua.gr/e3mlab/PRIMES%20Manual/PRIMES%20TREMOVE_v3.pdf
[2] http://traccs.emisia.com/

Period	Reloading of tankers, kg NMVOC per tonne gasoline	Refuelling of vehicles, kg NMVOC per tonne gasoline	Sum of reloading and refuelling, kg NMVOC per tonne gasoline	Source
				1995 and 2000
1999			0.75	Interpolation between 1995 and 2000
2000-2007	0.08	0.46	0.53	GB EMF

Table 3.13: Emission factors of gasoline used for estimating fugitive emissions from filling stations in Denmark (Source: NERI, 2009)

3.3.5 GHG emissions of refined products

The assessment of GHG emissions of refined products imported in EU has usually been overlooked in relevant studies. In the context of this study, the emissions of refined products imported from the United States and Russia will be assessed, as these constitute significant part of EU final fuel supply as illustrated in Figure 3.21 below. It has to be mentioned also that some negligible quantities of refined products are imported in EU from other countries (MENA) - which are constantly decreasing over the years – so they are not taken into account in the analysis.

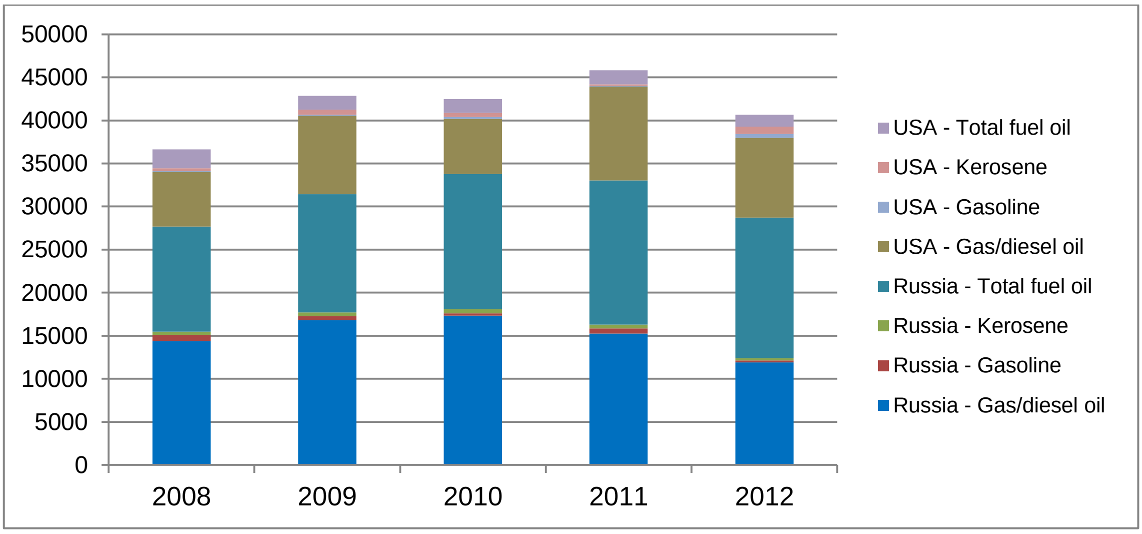


Figure 3.21: EU 28 imports of refined products (in barrels of oil per day) for specific refined products from Russia and USA (source: Eurostat)

The methodology for the assessment of emissions from refined products is shown in Figure 3.22. The approach for the assessment of GHG emissions of imported refined oil products is identical to that of conventional crude oil for the upstream and midstream processes. The upstream emissions will be assessed through the collection of actual data and in the absence of these via the OPGEE model. Based on the analysis of the midstream sector and given the locations of the Russian refineries it has been considered that the MCON used for refining is exclusively Urals crude oil, while refineries in USA use a blend of several MCONs. Thus, there are two major streams of refined products to Europe: one from Russian and one from USA. In order to account for the GHG emissions of these imported fuels during the refining process in Russia and USA, the Consultant will use proxy values of emission factors based on calculation of emissions for refineries in European countries provided that they have similar refinery configuration to Russia and USA and other emission factor estimates based on literature for refineries in Russia and USA which are different from European refineries. Emissions due to the distribution of refined products will be assessed using the same approach for oil products refined in EU. In all cases, a minimum and maximum methodology will be used so as to represent a range of carbon intensity values where applicable.

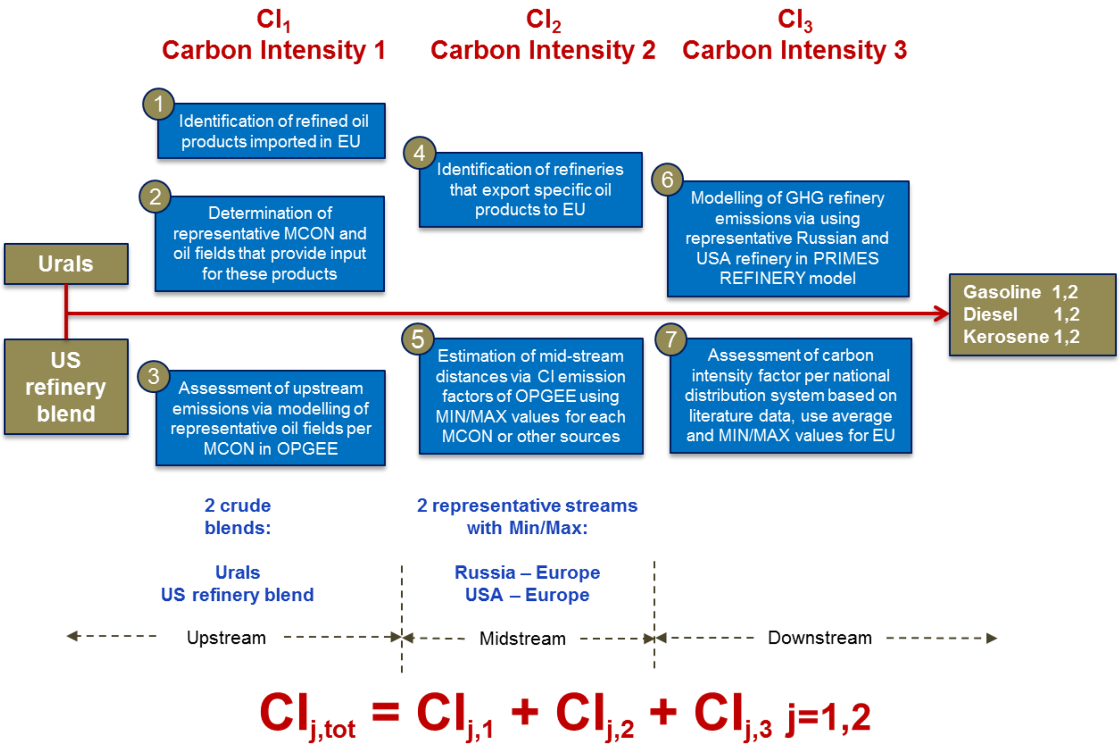


Figure 3.22: Methodology for the assessment of emissions from refined products

Imported products from Russian refineries

Table 3.14 summarizes the most significant Russian refineries supplying refined products to Europe with their key characteristics such as capacity, crude type feedstock, crude oil supply mode and ULSD compliance. It is worth considering that all Russian refineries presented in Table 3.14 export or will start exporting Euro V - ULSD compatible diesel to Europe.

Refinery	Transport mode of final product	Owner	Capacity (b/d)	Crude supply	Crude feedstock	ULSD compliance
Volgograd refinery	Petroleum products are shipped by rail, road and river transport	Lukoil	225,200	Crude oil is supplied to the Refinery via the Samara – Tikhoretsk pipeline	Refines a blend of light West-Siberian and Lower-Volga crudes	Euro 5 compatible
Kirishi refinery	Sever pipeline	Surgutneftegas	335,900			Euro 5 compatible
Perm refinery	Rail road and river transport and also via the Perm Andreyenka –Ufa pipeline	Lukoil	279,142	Crude oil is supplied to the Refinery via the Surgut–Polotsk pipeline &the Kholmogory –Klin pipeline	Refines a blend of crudes from the northern part of Perm Region and from Western Siberia	Output of Euro 5 ULSD fuel will increase by 325,000 tons per year.
Yaroslavl	Sever pipeline	TNK-BP and Gazprom Neft,	8,700		The refinery processes West Siberian Crude	From January 2012, the Refinery, intends to stop producing motor fuels, which do not conform to the Euro 4/ Euro 5 standards
Nizhnekamsk Refinery		TAIF-NK	120,493		The refinery processes locally produced crude oil & gas condensate The crude is medium heavy & sour	Since May 2008, TAIF-NK completely shifted to the production of motor gasoline, environmental standards EURO 4 Since June, 2012 TAIF-NK switched to 100% diesel fuel, quality standard EURO 5

Table 3.14: Russian refineries exporting ULSD to Europe (source: OGJ, company websites)

Figure 3.23 below shows the location of Russian refineries on the map and links them to major crude oil pipelines. It can be obtained that all of them are supplied oil primarily from the Urals region and therefore the Urals MCON has been considered as their main feedstock. Moreover, the largest part of refined products is supplied to Europe via the Sever product pipeline which runs alongside the Baltic pipeline System. The conduit links several refineries in European Russia to the Baltic Sea, thereby giving them a means of exporting ULSD fuel. More specifically the pipeline runs from Kstovo to Primorsk via Yaroslavl and Kirishi with a total length of 1056 km. From Primorsk the refined products are shipped to several European countries.

Imported products from USA refineries

In the context of the Interim Report, the Consultant has focused particularly on the refined products arriving to Europe from Russia, because of the fact that less work has been conducted in the analysis of the Russian upstream and midstream sector and therefore more effort is required. On the contrary, for the United States there is a wealth of information regarding upstream, midstream and downstream sector, as well as their emissions. For refined products arriving from the United States the Consultant will assume that these are refined in a High Conversion refinery located on the US Gulf Coast and exporting diesel oil to Europe, with main discharge port being Rotterdam. A typical input blend of a US refinery based on the work conducted by Jacobs[3] is illustrated in Table 3.15.

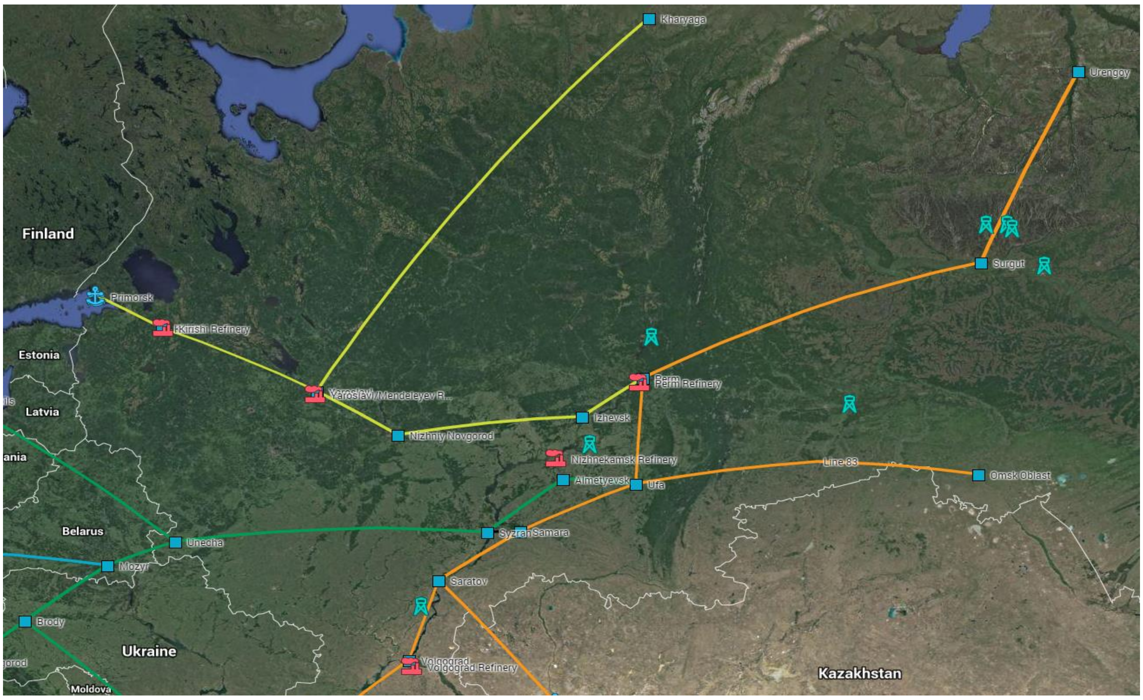


Figure 3.23: Map of Russian Refineries supplying refined products to EU

[3] EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context, Jacobs Consultancy, 2012

MCON	High conversion US Gulf Coast
Forties	√
Arab Medium	√
Bonny Light	√
Tupi	√
Bachaquero	√
Urals	√
SCO from Coking upgrader processing mined bitumen	√
Athabasca dilbit	√
Athabasca bitumen	√
Mariner	√

Table 3.15: Overview of feedstock input of representative US refinery (adopted by Jacobs, 2012)

3.3.6 GHG emissions of unconventional crude oil and natural gas

At the end of the baseline year of the study (2012) unconventional fuels are not traced in the EU energy balance. However, it is expected that unconventional crude oil and natural gas will definitely be imported in Europe in the future. Therefore, the GHG emissions assessment is not priority regarding the estimations and analyses of Tasks b and c, but it will be helpful and complementary to the projections of Task f. The PRIMES model will indicate the quantities of unconventional crude oil and natural gas that Europe will be importing by 2030.

The rationale for the assessment of the GHG emissions from unconventional crude oil is similar to that of crude oil. The Consultant based on current market trends, literature survey and its own assessments will determine the MCONs and the gas streams which constitute reasonable options for the EU relevant demand projected by the PRIMES model. Indicatively, key unconventional MCONs or gas streams that are representative will be analyzed could be the following:

- Alberta Oil Sands
- Venezuela Bitumen
- US Barnett Shale Gas
- Marcellus Shale Gas

Actual emission data for the assessment of upstream emissions of unconventional crude oil have been searched and collected for all the above mentioned characteristic cases. Due to the CARB analyses and the studies assigned by the US and Canadian authorities, expressing their interest to promote the unconventional oil and gas resources, there is availability of actual data and measurements carried out by reliable institutions. The OPGEE model might be also used for the modelling of upstream emissions of unconventional crudes, since it has already incorporated five production techniques specified by the type of extraction and the upgrading technology, namely:

- Bitumen mining with integrated upgrading;

- Bitumen mining with non-integrated upgrading;
- In situ production via non-thermal methods;
- In situ production via steam assisted gravity drainage;
- In situ production via cyclic steam stimulation.

It has to be noted that there are several techniques for processing and upgrading unconventional crude oils and gases but it is anticipated that processes internally built in OPGEE and GHGenius will suffice for modelling the GHG emissions of certain MCONs and gas streams. In addition to the two models, there is a large variety of information regarding the upstream emissions of unconventional crudes that can be utilized for the assessment of GHG emissions, as well as for comparative and validation purposes. Several studies, particularly from the USA and Canada, have assessed the LCA GHG emissions.

The midstream GHG emissions occurring due to the transport of crude oil and gas (in principle through LNG) from the extraction point to the refineries or the transmission systems will be assessed utilizing the same approach as for conventional crude oil and natural gas. In the case that three unconventional fuels are considered 3 representative upstream cases with relevant minimum and maximum values will be assessed. Eventually, the emissions of approximately 10-15 streams will be considered in total:

- two per final oil product (petrol, diesel and kerosene), 6 in total and
- 8 in total for CNG/LNG distributed to the four EU regions, in compliance to the study assumptions.

Lastly, distribution emissions will be calculated by using the approach and the emission factors as for conventional crude oil and natural gas.

3.4 Methodological Approach for Natural Gas GHG Assessment

3.4.1 Natural gas supply chain

Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user, which can generally be broken out into five sectors. Each sector is defined as follows:

- **Production**, focuses on taking raw natural gas from underground formations.
- **Processing**, focuses on stripping out impurities and other hydrocarbons and fluids to produce pipeline grade natural gas that meets specified tariffs (pipeline quality natural gas is 95-98 % methane).
- **Transport**, focuses on the movement of natural gas from the producing region to the consuming region. After processing, gas is often transported over very large distances. Most of this transport takes place through pipelines, although,

there is a significant amount of gas that is liquefied at the producing region, transported via marine vessels as LNG (Liquefied Natural Gas) and finally regassified at the delivery point. Therefore, we distinguish two options for natural gas transport:

- Via Pipeline,
- Via LNG

- **Transmission and Storage**, focuses on delivery of natural gas from the interconnection point to city gate stations or industrial end users. Transmission occurs through a network of high-pressure pipelines. Natural gas storage also falls within this sector. Natural gas is typically stored in depleted underground reservoirs, aquifiers, and salt caverns.
- **Distribution**, focuses on the delivery of natural gas from the major pipelines to the end users (e.g., residential, commercial and industrial).

In the oil industry, some underground crude contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, **associated or solution natural gas** is produced. In case the exploration field produces in principle natural gas, then this gas might be called **non-associated gas**. Both associated and non-associated gas are considered conventional natural gas as part of this work. The basic pathways of the typical natural gas supply chain are presented in Figure 3.24.

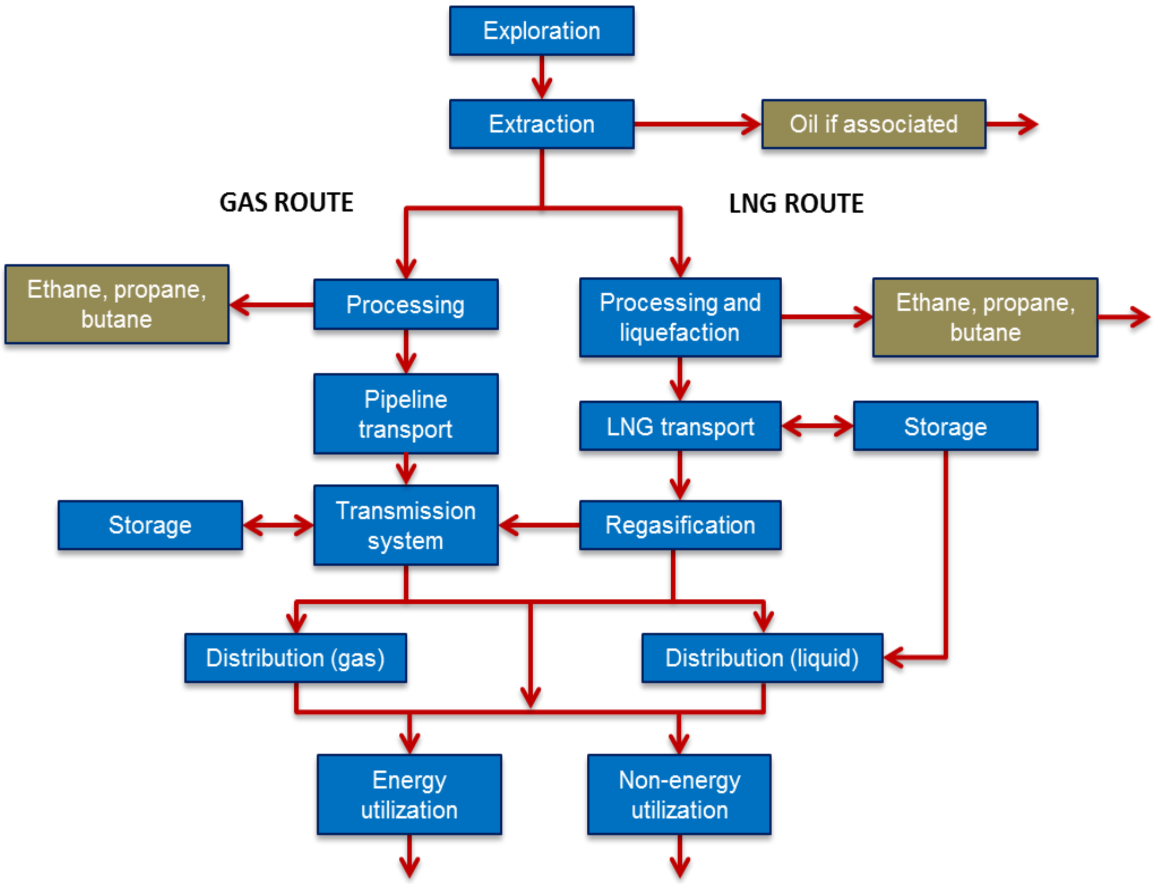


Figure 3.24: Natural gas supply chain (Source: CE, Delft)

3.4.2 Methodology for assessing GHG emissions

The main stages of the natural gas value chain to be examined for the purpose of the present study are presented in Figure 3.25. As shown in this Figure, the lifecycle of natural gas is divided into 3 main stages: upstream, midstream and downstream.

The upstream stage contains the natural gas production and processing sectors.

The midstream stage contains the transport of natural gas from the producing region to the consuming region for which there are three options:

- Option 1: The gas produced outside the EU is transported via pipeline to the corresponding EU regions;
- Option 2: The gas produced outside the EU is liquefied and transported by vessels to the corresponding EU LNG terminals, where it is re-gasified and fed to the transmission system;
- Option 3: The gas produced indigenously in the EU is either consumed within the producing country, or transported to other EU countries through the interconnected transmission systems.

Finally, the downstream stage contains the transmission and distribution of natural gas inside the EU regions.

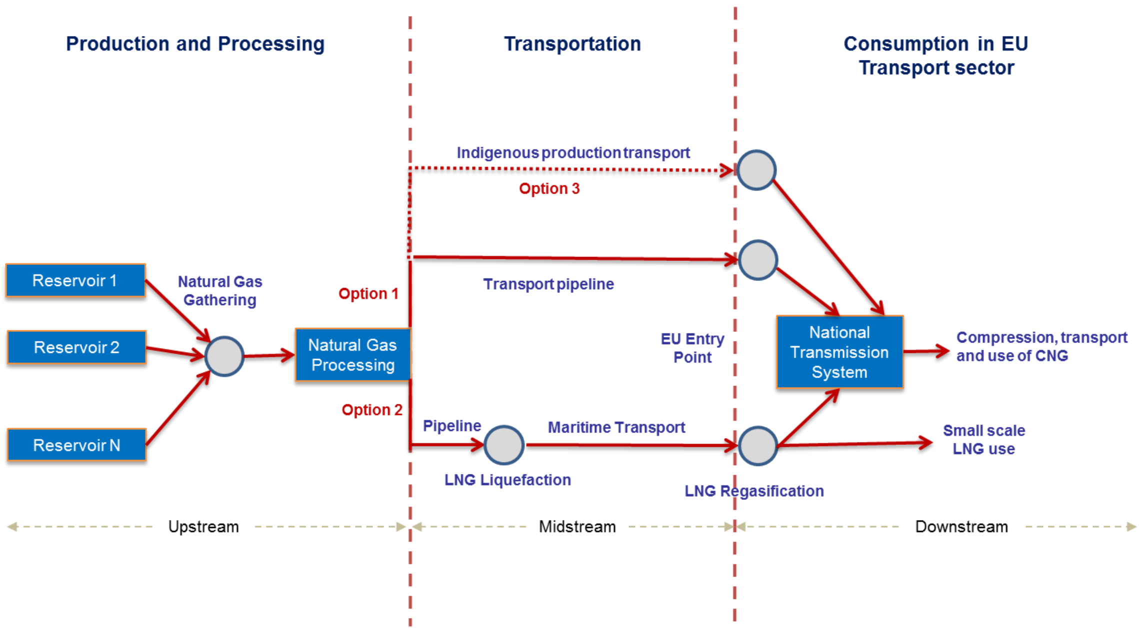


Figure 3.25: Natural gas streams methodological approach

Following this approach, the EU natural gas supply has been distinguished into main **streams** according to their origin, mode of transport and delivery point within the EU that will be presented in the following Sections. The carbon intensity (CI) of the considered natural gas streams is estimated as the sum of the carbon intensities of each of the corresponding separate stages (upstream, midstream, downstream) that characterise each stream.

3.4.3 Natural Gas Streams

Step 1: Assumption for EU regions

The starting point for assessing the GHG emissions of natural gas supplied to the EU is to define the main gas streams arriving to the consumption regions. We need to keep a rational number of gas streams that will allow obtaining a reasonable and representative picture of GHG emissions of the main gas streams supplying EU and on the other hand maintaining the necessary detail by distinguishing the CI performance and differentiation of various gas streams. To this end we need to make a number of assumptions, and under the most significant of them, EU has been divided into 4 consuming regions, namely South East EU, Central EU, North EU and South West EU. The four groups were selected in principle on the basis of common natural gas characteristics, e.g. common transportation pipelines or LNG suppliers. Thus in our analyses the gas streams under assessment are driven to 4 destinations instead of 26; with this aggregation we achieve relevant grouping of similar, more or less, CI cases in downstream and midstream, without losing in detail and differentiation of results.

In the context of the present study, Cyprus and Malta were not taken into account for the assessment of GHG emissions in the natural gas value chain, as they were not natural gas consuming countries in 2012.

Step 2: Natural gas producing countries

In order to determine the major natural gas suppliers of the EU, the Consultant has elaborated on the annual IEA data for 2012 regarding natural gas imports and indigenous production by country of origin. These imports and EU production are transported to the national transmission systems either through LNG or by transportation pipelines. Small quantities of gas imports or production (in general less than 500 million cubic meters per year) were considered negligible and will be not examined in detail in this study. Such small quantities are generally transacted in the spot market and thus are not representative of the EU natural gas supply. Following this analysis, the major natural gas suppliers to the EU are presented in Table 3.16.

Step 3: Finalization of the natural gas streams

After eliminating the negligible quantities of natural gas consumed within the EU, the Consultant has identified the main streams of natural gas arriving to each of the four EU regions. The final streams are illustrated in Figures Figure 3.26 to Figure 3.28. Therefore 29 transport pipeline streams and 9 LNG streams are considered for GHG emissions assessment. Since there are 4 main pipeline systems supplying EU with Russian natural gas, this fact is taken into consideration and either distinguished streams by pipeline are considered or in case of small differences in CI the streams are aggregated and the min, max approach is used to cover small differences and uncertainties.

Mode of transport	Supplier	Share in the EU gas supply In 2012
Local production	Germany	2.59%
	Denmark	1.17%
	Netherlands	17.08%
	Poland	1.25%
	Hungary	0.29%
	Italy	1.74%
	Romania	2.21%
	UK	8.23%
Transport by pipeline	Russia	22.61%
	Norway	20.34%
	Algeria	6.84%
	Libya	1.30%
	Other	3.93%
LNG transported by marine vessels	Algeria LNG	2.05%
	Norway LNG	0.53%
	Nigeria LNG	2.22%
	Qatar LNG	5.63%

Table 3.16: Major natural gas suppliers of the EU

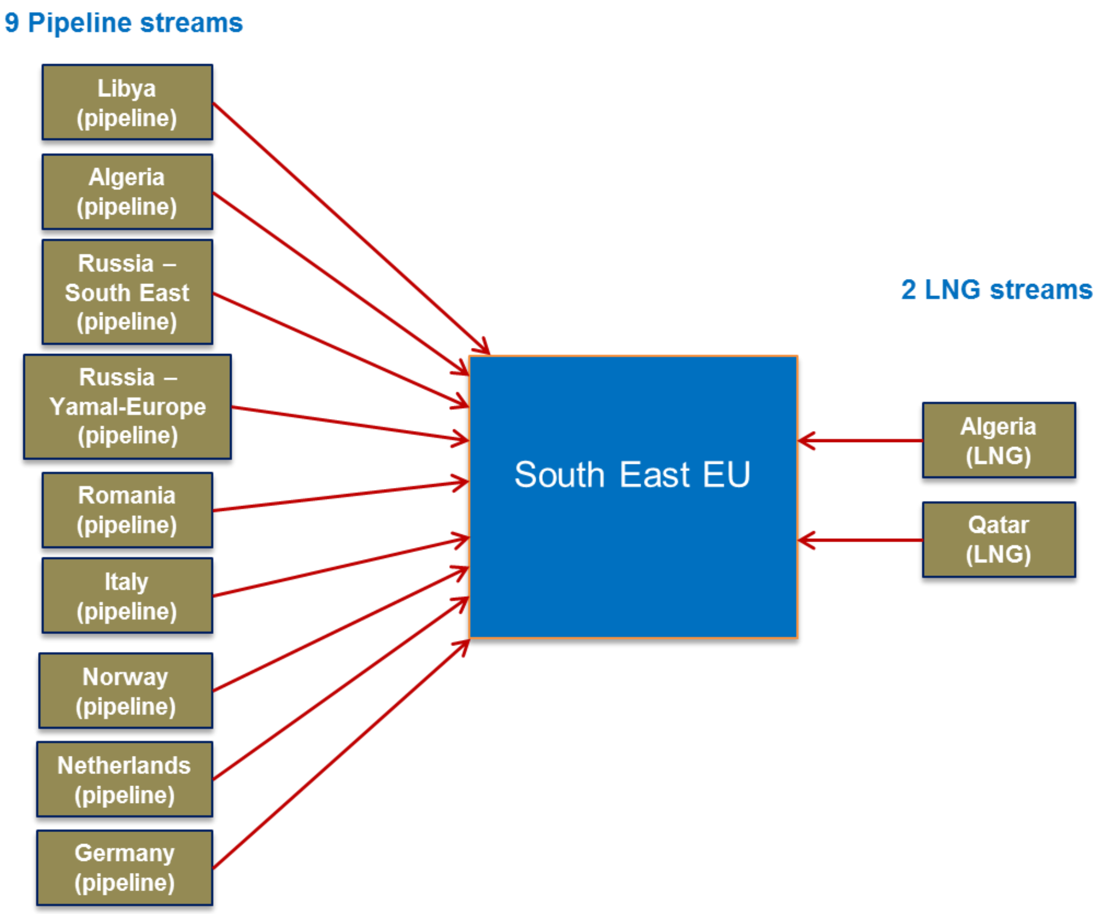


Figure 3.26: Natural gas streams arriving to the South East EU region

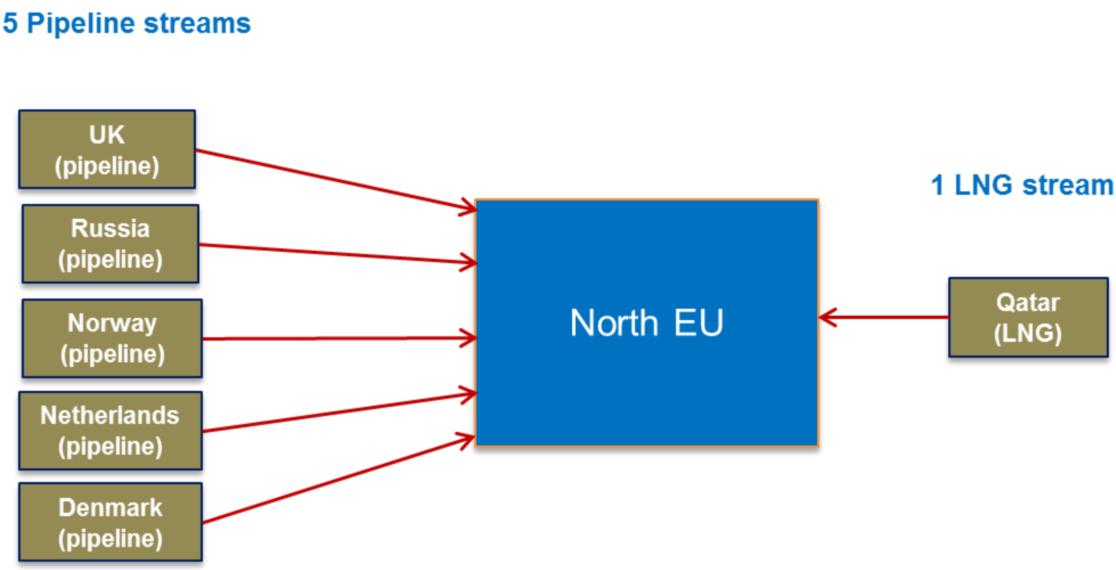


Figure 3.27: Natural gas streams arriving to the North EU region

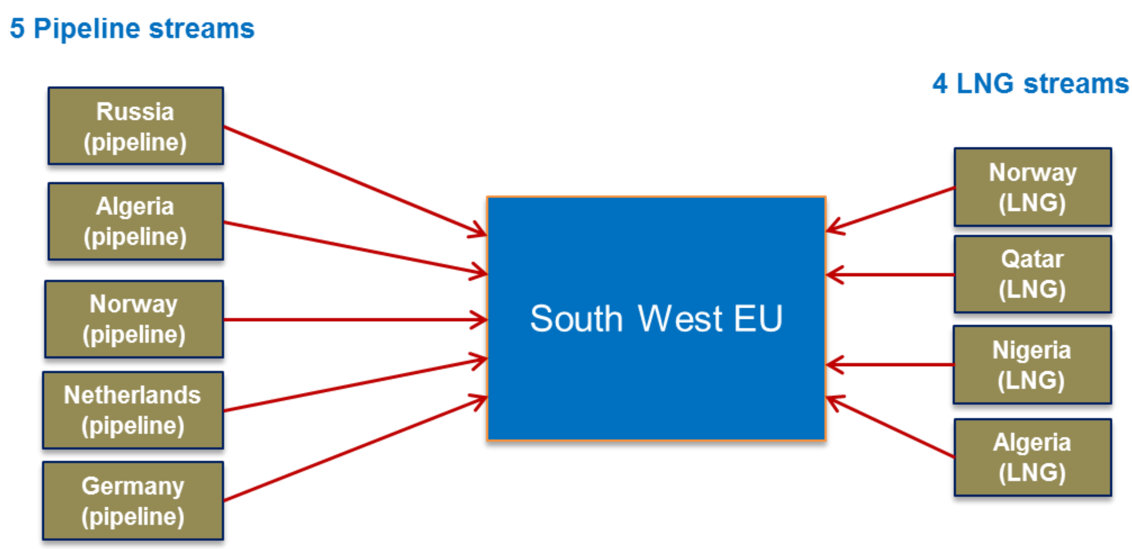


Figure 3.28: Natural gas streams arriving to the South West EU region

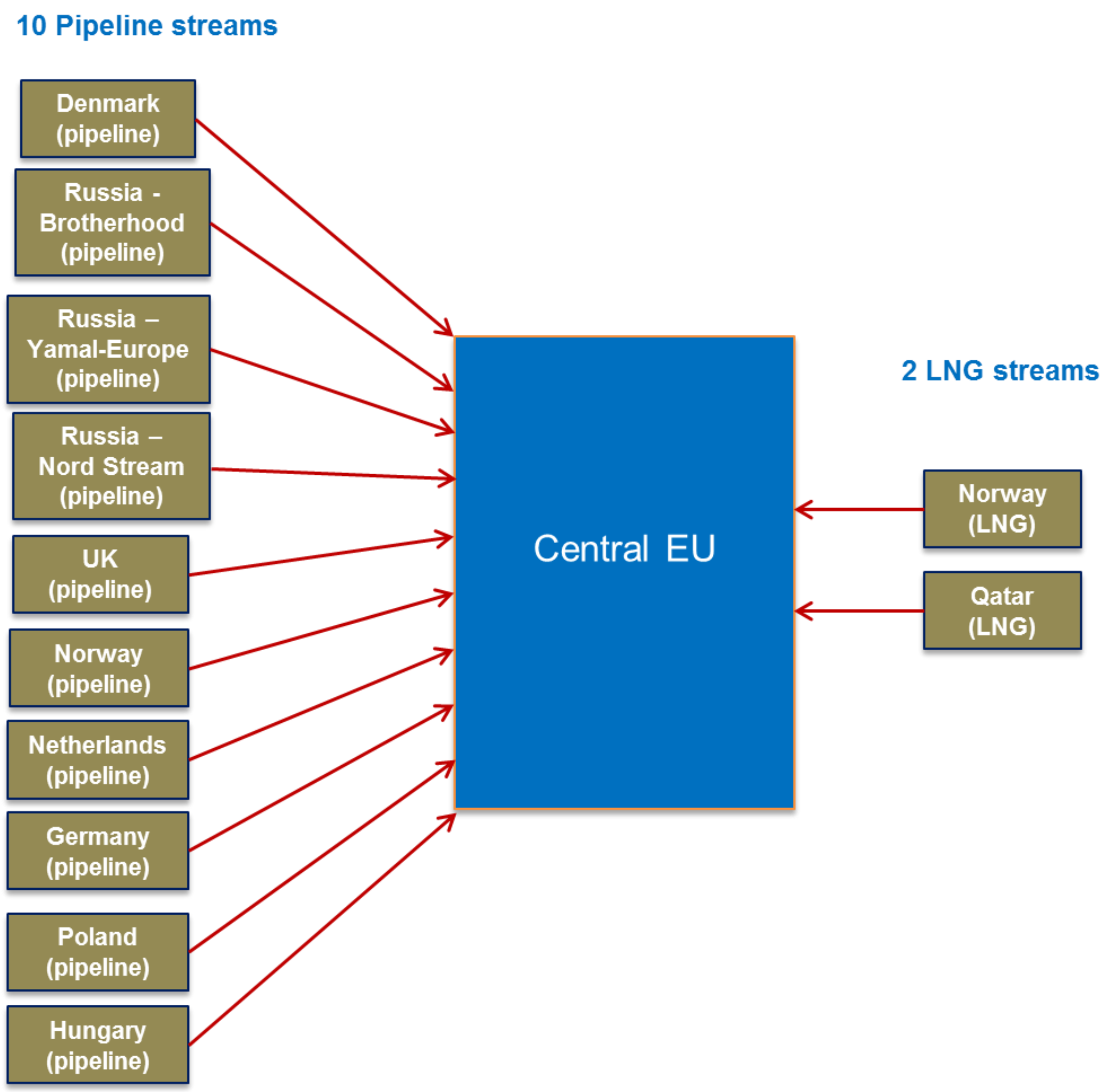


Figure 3.29: Natural gas streams arriving to the Central EU region

3.4.4 Upstream

The upstream stage includes exploration and drilling, extraction of natural gas and processing.

Exploration and drilling represent a small percentage of the total GHG emissions of the lifecycle of natural gas and in addition, emissions data for this stage are very hard to identify. Exploration cannot be directly linked to production. Some exploration will lead to production, some will not. This means that it is hard to include exploration in a lifecycle approach that tries to assess environmental impacts associated with a unit of natural gas. Therefore, exploration is the least significant stage in the lifecycle of natural gas, in terms of GHG emissions.

Extraction of non-associated natural gas requires little more energy than letting the gas flow from the reservoir. Extraction of non-associated natural gas gives a mixture of raw gas, condensed higher hydrocarbons, free water and carried along particles. The raw gas is isolated from solids and fluids by flashing, the so-called primary separation. The isolated raw gas will have an elevated temperature due to the higher temperatures in the reservoirs and a pressure of several to several hundreds of bars. It does not yet have sufficient quality to allow transportation to the consumer for application.

Further processing basically involves the separation of the methane fraction (CH_4) in the raw gas from co-products or pollutants such as:

- Water vapour
- Acid gases (CO_2, sulphurous compounds)
- Nitrogen (N_2)
- Condensable hydrocarbons (C5+)
- Ethane, propane, butane.

Which processes are applied depends on raw gas quality as well as required standard for the processed gas. Energy consumption and emissions at the processing stage depend on the quality of the raw natural gas. Gas from fields yielding low calorific gas may be mixed with high calorific gas to match required market standards. The hydrocarbons heavier than methane but lighter than pentane do not necessarily have to be separated, except for the production of some chemicals. They may be separated for economic reasons, as ethane and LPG (propane/butane) are excellent naphtha cracker feedstock and LPG (as well as C5+) may be sold as automotive fuels. Isolation of the so-called **Natural Gas Liquids (NGL)** can be economically viable in certain regions with a high demand and low (alternative) supply. The chemical composition of these hydrocarbons (NGL) is similar, yet their applications vary widely. Ethane occupies the largest share of NGL field production. It is used almost exclusively to produce ethylene, which is then turned into plastics. Much of the propane, by contrast, is burned for heating, although a substantial amount is used as petrochemical feedstock. A blend of propane and butane, sometimes referred to as LPG or autogas is a popular fuel in some parts of Europe, Turkey, and Australia; however LPG is not among the transport fuels considered in this study. Natural gasoline (pentanes plus) representing 10-15% of NGL can be blended into various kinds of fuel for combustion engines, and is useful in energy recovery from wells and oil sands. Natural Gas Liquids (NGL) representing partly a feedstock used in refineries or blended to produce petrol have not been considered as independent streams in this study, but are considered as contributing to the GHG emissions produced in the oil refining process.

In the case of **associated gas**, the natural gas may already be separate from the oil (free gas) or it may be dissolved in the oil (dissolved gas). Extra steps are involved in either case to separate the gas before processing takes place.

Most treatment processes require electricity for valves, pumps, etc. The electricity is often produced on site in case of off shore production and treatment or in case of fields located in remote areas. Otherwise electricity may be taken from the grid.[4]

Venting and flaring gas

One of the most important GHG emitting activities of the upstream stage is gas flaring and venting. Flaring is the controlled burning of natural gas in the course of routine oil and gas production operations. This burning occurs at the end of a flare stack or boom. Gas processing plants remove the water, H_2S, CO_2 and natural gas liquids from the raw natural gas to produce the market-ready natural gas. Flares are used to dispose of the unmarketable gases. All gas plants have flares to burn off gas safely during emergencies or "upset" conditions that interrupt the normal day-to-day operations. Many of the small plants are licensed to flare H_2S rich gas after it has been removed.

Venting is the controlled release of gases into the atmosphere in the course of oil and gas production operations. These gases might be natural gas or other hydrocarbon vapours, water vapour, and other gases, such as carbon dioxide, separated in the processing of oil or natural gas.

Flaring produces predominantly carbon dioxide emissions, while venting produces predominantly methane emissions. The two gases have different effects, however. The global warming potential of a kilogram of methane is estimated to be twenty five times that of a kilogram of carbon dioxide when the effects are considered over one hundred years (GWP 2007). When considered in this context, flaring will generally be preferred over venting the same amount of gas in the design of new facilities where sufficient amounts of gas will be produced to run a flare.[5]

Natural gas producers

The main natural gas producers for the EU 28, apart from indigenous production, are Russia, Norway, Algeria, Nigeria, Qatar and Libya. Intra-EU producers include the Netherlands, Germany, the UK, Denmark, Italy, Hungary, Poland and Romania. Figure 3.30 illustrates the main natural gas producing fields supplying the EU.

[4] The Natural Gas Chain - Toward a global life cycle assessment, Delft, CE, 2006

[5] Flaring & venting in the oil & gas exploration & production industry, OGP Report No: 2.79/288 January 2000

Each producing country has its own characteristics regarding their upstream activities, which are summarized in Table 3.17.

Figure 3.30: Map of natural gas producing fields supplying the EU

Producing country	Major natural gas fields	Characteristics
Russia	Yamburg – Urengoy Yamal Medvezh'ye	Russia's reserves account for about a quarter of the world's total proven reserves. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for more than 40% of Russia's total reserves, while other significant deposits are located in northern Russia.
Norway	Troll	The majority of Norwegian gas fields are offshore platforms located in the North Sea. Despite maturing major natural gas fields in the North Sea, Norway has been able to sustain increases nearly every year in total natural gas production since 1993 by continuing to develop new fields. Norway's largest producing natural gas field is Troll, which according to estimates from the NPD represented about 27% of Norway's total natural gas production in

Producing country	Major natural gas fields	Characteristics
		2013. The three other largest producing fields in 2013 were Ormen, Lange Asgard and Kvitebjorn. These four fields accounted for just over 60% of Norway's total dry natural gas production in 2013.
Algeria	Hassi R'Mel	Algeria's largest natural gas field, Hassi R'Mel, was discovered in 1956. Located in the center of the country to the northwest of Hassi Messaoud, it holds more than half of Algeria's total proved natural gas reserves. According to the Arab Oil & Gas Journal, Hassi R'Mel accounted for three-fifths of Algeria's gross natural gas production in 2012. The remainder of Algeria's natural gas reserves is located in associated and non-associated fields in the southern and south eastern regions of the country. Hassi R'Mel also serves as a gathering point for natural gas from other gas fields located in the Algerian desert.
Nigeria	Escravos	Nigeria is the largest holder of natural gas proven reserves in Africa and the ninth largest holder in the world, while ranked as the world's 25th largest natural gas producer. Natural gas production is restricted by the lack of infrastructure to monetize natural gas that is currently being flared. The majority of the natural gas reserves are located in the Niger Delta.
Qatar	North field	Qatar was the world's fourth largest dry natural gas producer in 2012 (behind the United States, Russia, and Iran), and has been the world's leading liquefied natural gas (LNG) exporter since 2006. Qatar is also at the forefront of gas-to-liquids (GTL) production, and the country is home to the world's largest GTL facility. Nearly all of Qatar's natural gas production comes from the North Field, which is part of the largest non-associated natural gas field in the world. The Qatari North Field contains about 25 trillion cubic meters (Tcm), which accounts for 14% of worldwide natural gas reserves. The South Pars field, a geologic extension of the North field, contains an estimated 8 trillion cubic meters (Tcm) of natural gas. Thus, this single accumulation contains about 20% of the world's natural gas reserves. Based on current production capacity, the North field has reserve-production ratio of more than 400 years.
Libya	Wafa Bahr Es Salam	Libya is the fourth largest natural gas reserve holder in Africa. Libya’s natural gas production and exports increased considerably after 2003 with the development of the Western Libya Gas Project and the opening of the Greenstream pipeline to Italy. Flows through the

Producing country	Major natural gas fields	Characteristics
		Greenstream pipeline were disrupted during most of the 2011 civil war.
Netherlands	Groningen	The Netherlands is the second-largest producer and exporter of natural gas in Europe, following Norway. Most of its natural gas fields are located offshore in the North Sea, although a number of them are located onshore, including Groningen, one of the ten largest natural gas fields in the world. The government has capped production at Groningen, which accounts for approximately 75% of the country's natural gas output as part of a policy to stem reserve declines and encourage production from smaller fields.
UK	Shearwater-Elgin area SAGE	The UK is the second largest producer of natural gas in EU. Most of the UK natural gas reserves occur in three distinct areas: 1) associated fields in the UKCS; 2) non-associated fields in the Southern Gas Basin, located adjacent to the Dutch sector of the North Sea; and 3) non-associated fields in the Irish Sea. The largest concentration of natural gas production in the UK is the Shearwater-Elgin area of the Southern Gas Basin. The area contains five gas fields: Elgin, Franklin, Halley, Scoter, and Shearwater. UK's largest share of natural gas production among all fields and gathering systems comes from the Scottish Area Gas Evacuation (SAGE) system, which produced a total of 6.9 billion cubic meters (bcm) in 2011. In addition to SAGE, the Shearwater-Elgin Area Line (SEAL) produced more than 5.6 bcm of natural gas during the year.
Germany, Denmark, Italy, Hungary, Poland and Romania	multiple	These EU countries have small domestic oil and natural gas production and rely heavily on imports. However, their indigenous production covers an important share of their internal natural gas demand while in some cases export to their neighboring countries.

Table 3.17: Key characteristics of natural gas producing countries supplying the EU 28

3.4.5 Midstream

The midstream stage concerns the transport of natural gas from the producing region to the consumption region. There are two ways of transportation of natural gas to the EU entry points: long distance pipelines from third countries and LNG tankers, whereas indigenous production flows through the EU transmission systems. The latter will be considered in the downstream stage as it utilizes the interconnected transmission systems of EU countries to reach its destination, therefore the related GHG emissions are linked to the transmission network of each EU country.

In the case of **transport via pipeline**, the midstream stage includes the route carrying the natural gas from the processing plant to the EU entry point. The total pipeline "system" may consist of the pipeline, compression stations, import/export stations and metering. Normally, pipeline diameters range from 25 to 150 cm.

Before transport, gas is compressed to pressures of approximately 70 bar. In the case of subsea pipelines, the initial pressure may be higher (more than 200 bar) due to the impossibility of intermediate transfer compression. Pressure loss due to friction of gas along the pipeline wall is compensated by intermediate compressor stations along the pipeline. Compressors are almost always driven by natural gas, as this is obviously easily available.

Apart from energy consumption for the transport itself, maintenance and check-up activities – especially in remote areas – may require energy. Another source of gas 'consumption' during transport is leakage. As the gas, methane, is a powerful greenhouse gas, leaks may have a significant environmental effect.

For international gas pipelines, the major environmental impact comes from the gas combustion to run the compressor stations. The impact is larger with increased distance. Some of the critical points in the transmission process for gas consumption are turbine compressors that burn natural gas at compressor stations along the way, electric motors and gas engines, power generation, and leaks of methane gas – fugitive emissions – during transmission. Fugitive emissions are a major component of GHG emissions from natural gas systems, however they are often difficult to accurately identify.

In the case of **LNG production**, the midstream stage includes also the transportation of natural gas to the liquefaction plant and the process of liquefaction. Liquid natural gas (LNG) is natural gas cooled to a low temperature (-162^{o}C) so it becomes a liquid that hence occupies a much smaller volume. It can be transported over long distances without the need for a fixed infrastructure. The LNG process consists of several steps: liquefaction, transport, storage, and regasification.

Liquefaction of LNG means cooling the natural gas to below its condensation temperature of –162°C. The heavier hydrocarbon components in the natural gas condense at higher temperatures and are therefore liquefied – and removed – during the process. LNG often consists of both methane and ethane, the latter re-added to fluid methane after methane liquefaction (ethane liquefying before methane does). By-products of LNG production are LPG and gasoline, the heavier fractions of the raw natural gas.

The LNG is stored in full containment tank normally consisting of a concrete outer tank and an inner tank of 9% nickel steel. The boil-off gas and pre-cooling and loading vapours are compressed and used as fuel gas for the liquefaction units or flared. Transportation to and from storage is driven by pumps. Storage may also take place at other stages in the LNG chain (after international transport or before regasification). Again, boil-off gas is mostly put to use, but may be vented in emergencies.

Long-distance transport of LNG takes place primarily by cargo ships with an insulation system to keep the temperature at -162°C. The LNG is often carried in separate tanks. Boil-off gas provides a large fraction of the fuel need for the ship, also on the return journey when some LNG is left in the tanks to ensure that the gas concentration in the tanks is above the upper explosion limit (UEL).

Regasification consists of increasing the LNG temperature often by heat exchange with (sea) water at roughly ambient temperature or heated. The gas is then ready to be transported in the regular regional transmission and distribution network after quality control. The major functions of LNG receiving terminals are: (1) regasification of liquefied natural gas, (2) in some countries, calorific value adjustment by adding LPG, and (3) pressurization of the natural gas for supply to customers. These processes all use energy.

The above described two supply chains differ not only from the physical and economical point of view, but also from the environmental one. In order to transport the gas from the production fields to Europe, energy is required and its overall amount differs according to the way and the path the gas is imported. Furthermore other factors, like methane fugitives and nitrous oxide emissions, are affected not only by the physical characteristics of the chain, but also from the technology used and from obsolescence of installations.[6]

Figure 3.31 presents the geographical locations of liquefaction plants supplying the EU 28 with LNG, as well as the EU importing terminals.

In the following paragraphs, the major natural gas supply routes to the EU are presented according to the corresponding producing country and mode of transport.

[6] The Natural Gas Chain - Toward a global life cycle assessment, Delft, CE, 2006

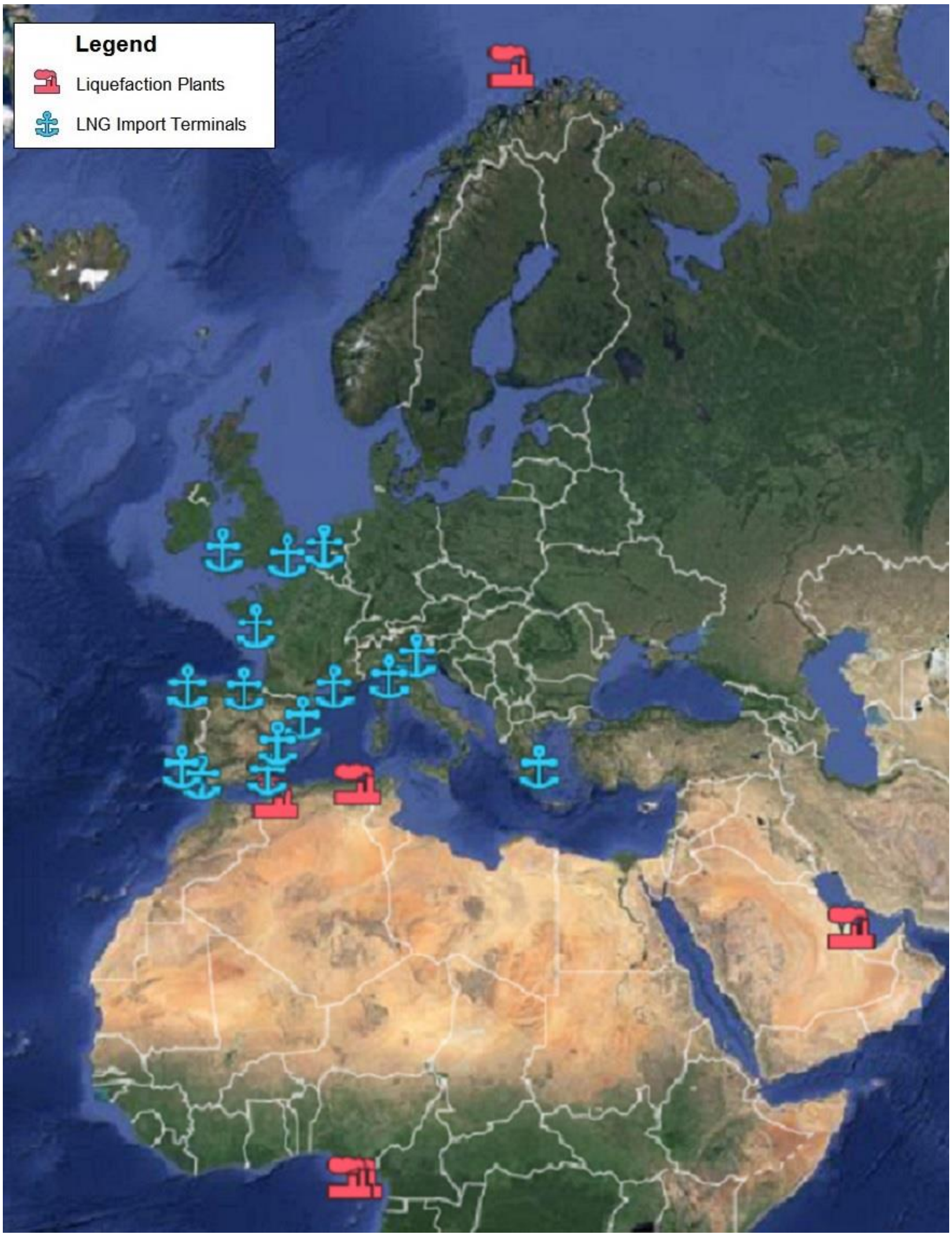


Figure 3.31: Map of LNG supply of the EU including liquefaction plants and importing terminals

Russia

Transportation of Russian natural gas to Europe proceeds through several pipelines, connecting gas fields in the North of Russia through the United Gas transportation system to the European countries. Figure 3.32 presents the main natural gas export pipelines from Russia to Europe.

Figure 3.32: Map of major Russian natural gas pipelines arriving to Europe (Source: Wikipedia)

The "Brotherhood" pipeline (Urengoy-Pomary-Uzhgorod) is the largest gas transportation route. It can carry over 100 bcm gas per year, transiting Ukraine and running to Slovakia. In Slovakia, the pipeline is split and one branch goes to the Czech Republic. Russian gas transported through the Czech Republic flows in the direction of Waidhaus and Hora Svaté Kateřiny via Uzhgorod, as well as from the Yamal-Europe gas pipeline, with Olbernhau and Brandov as entry points. Its second branch goes to Austria. This country plays an important role in the delivery of Russian natural gas to Italy, Hungary, Slovenia and Croatia. Gas deliveries through this pipeline started in 1967.

The Yamal-Europe pipeline runs across Russia, Belarus and Poland reaching Germany. Its length is beyond 2,000 km, 14 compressor stations are operational along it. The pipeline construction began in 1994 close to the German and Polish borders, and first sections of the pipeline were brought online as early as in 1996. The Belarusian part where Gazprom has become the sole investor was commenced in 1997. Upon commissioning of the last compressor station in 2006, Yamal – Europe reached full capacity – 33 billion m^3 per annum.

The South East gas transportation route through Romania carries Russian gas to this country, transiting Ukraine and Moldova, and runs further to the Balkan countries and Turkey. The pipeline construction began in 1986, and the second line was added in 2002.

Furthermore, the consumers in Finland receive Russian gas through the gas transportation system in the Leningrad Region.

The Nord Stream offshore pipeline laid on the bottom of the Baltic Sea with capacity of 55 bcm per year allows direct gas transportation for clients in Western Europe, primarily in Germany, bypassing transit states.[7]

Norway

All gas pipelines on the Norwegian Continental Shelf with third party customers are owned by a single joint venture, Gassled, with regulated third party access. The Gassled system is operated by the independent system operator, Gassco AS, a company wholly owned by the Norwegian State. In 2010, the Gassled system transported 97.3 bcm of gas to Europe.

Norway operates several important natural gas pipelines that connect directly with EU countries, specifically France, the United Kingdom, Belgium, and Germany. The most important pipelines are:

- Franpipe, with a capacity of 19.85 bcm/y, exports gas to Dunkirk, France.
- Zeepipe I, IIA, and IIB have a total capacity of 68.18 bcmy and transport gas to Zeebrugge, Belgium.
- Europipe I and II, with a total capacity of 42.2 bcm/y, export to Dornum, Germany.
- Norpipe, with a total capacity of 11.54 bcm/y, runs to Emden, Germany.
- Vesterled, capacity 14.06 bcm/y, links to St. Fergus, Scotland.
- Langeled, capacity 25.98 bcm/y, links to Easington on the east coast of England.

In 2010, the Gassled system was again expanded through the merger with the Gjøa Gas Pipeline. When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted in relation to the relative value of the assets and each owner's relative interest.[8]

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[7] Gazprom website
[8] Statoil website

Figure 3.33 depicts the natural gas pipelines reaching the EU from the Norwegian Continental Shelf.

Figure 15.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

Figure 3.33: Map of the Norwegian Continental Shelf natural gas pipelines

Algeria

Algeria was the first country in the world to export LNG in 1964. Algeria exports natural gas to Europe via pipelines and on tankers in the form of liquefied natural gas (LNG). It has three transcontinental export gas pipelines: two natural gas transport pipelines to Spain and one to Italy. Algeria's LNG plants are located in the coastal cities of Arzew and Skikda. Figure 3.34 presents the map with the main locations and pipelines of the Algerian gas system. In this map, the MEDGAZ pipeline appears as "under construction", although it has been operating since 2011.

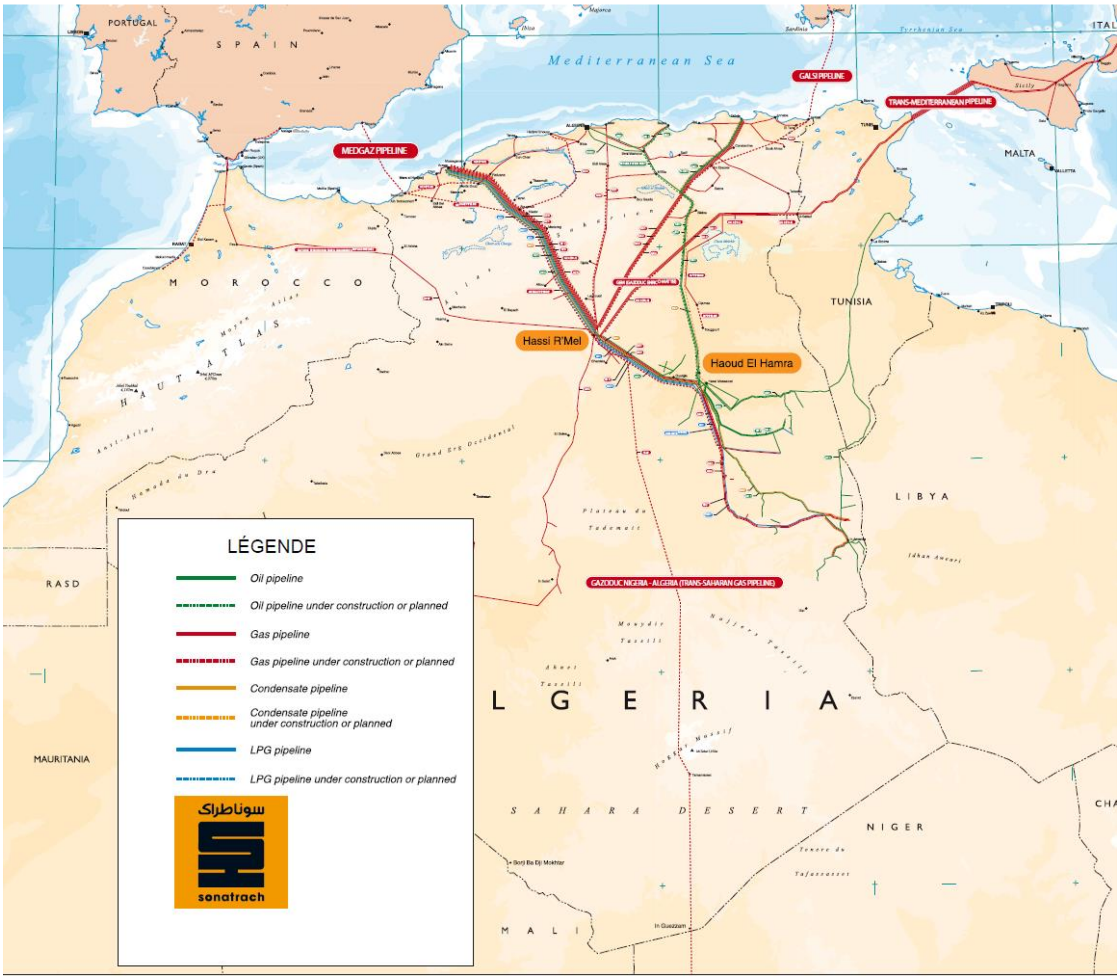


Figure 3.34: Algerian natural gas transport pipelines map (Source: Sonatrach)

LNG production

In 2013, Algeria was the world's seventh-largest exporter of LNG, accounting for about 5% of the world's total exports. Algeria has liquefaction units located along the Mediterranean Sea at Arzew and Skikda, with a total design capacity to process almost 96 million cubic meters per day of natural gas. The considered LNG streams from Algeria arriving to Europe consist of a pipeline leading the natural gas from the producing fields to the liquefaction plants and secondly marine vessel transportation. The corresponding GHG emissions of these streams will be estimated as a combination of these two modes of transport.

Algeria's domestic natural gas pipeline system transports natural gas from the Hassi R'Mel fields and processing facilities, owned by Sonatrach, to export terminals and liquefaction plants along the Mediterranean Sea. There are two main domestic pipeline systems transporting natural gas to the liquefaction terminals: (i) the Hassi R'Mel to Arzew system which is a collection of pipelines that move natural gas from Hassi R'Mel to the export terminal and the LNG plant at Arzew and the Hassi R'Mel to Skikda system which transports natural gas from the Hassi R'Mel fields to the Skikda LNG plant.

Pipeline transport

Besides LNG, Algeria transports natural gas to Spain and Italy via three major pipelines. The largest pipeline, Pipeline Enrico Mattei (GEM), came online in 1983 and runs 1,650 km from Algeria to Italy via Tunisia. GEM's capacity is more than 36 bcm per year and it is jointly owned by Sonatrach, the Tunisian government, and Eni. The Pedro Duran Farell (GPDF) pipeline started in 1996 and travels 525 km to Spain via Morocco. GPDF's capacity is about 11 bcm per year. The newest pipeline, MEDGAZ, came online in 2011 and is owned by Sonatrach, Cepsa, Endesa, Iberdrola, and GDF Suez. It stretches 200 km onshore and offshore, from Algeria to Spain via the Mediterranean Sea.

Qatar

Qatar is the world's largest producer of (LNG), accounting for about 15% of world liquefaction capacity. Nearly all of Qatar's natural gas production comes from the North Field, which is part of the largest non-associated natural gas field in the world, although some smaller fields contribute production volumes as well.

Most of the field lies about 3,300 meters below the Arabian Gulf in water depths of about 65 meters, and is intersected by the Qatar-Iran border. The field spans 9,700 square kilometres. The Qatari North Field portion covers an area of over 6,000 square kilometres, almost half of the entire surface area of Qatar.

With a limited demand for domestic consumption, Qatar Petroleum (QP), the state-owned company, and its international business partners have aggressively developed export markets. Most exports are in the form of liquefied natural gas (LNG).

Qatar's natural gas liquefaction facilities and related industries are located in Ras Laffan Industrial City, site of the world's largest LNG export facility. Ras Laffan is a self-contained city built by the government to support the processing and export of natural gas.

Figure 3.35 presents the major energy infrastructure in Qatar.

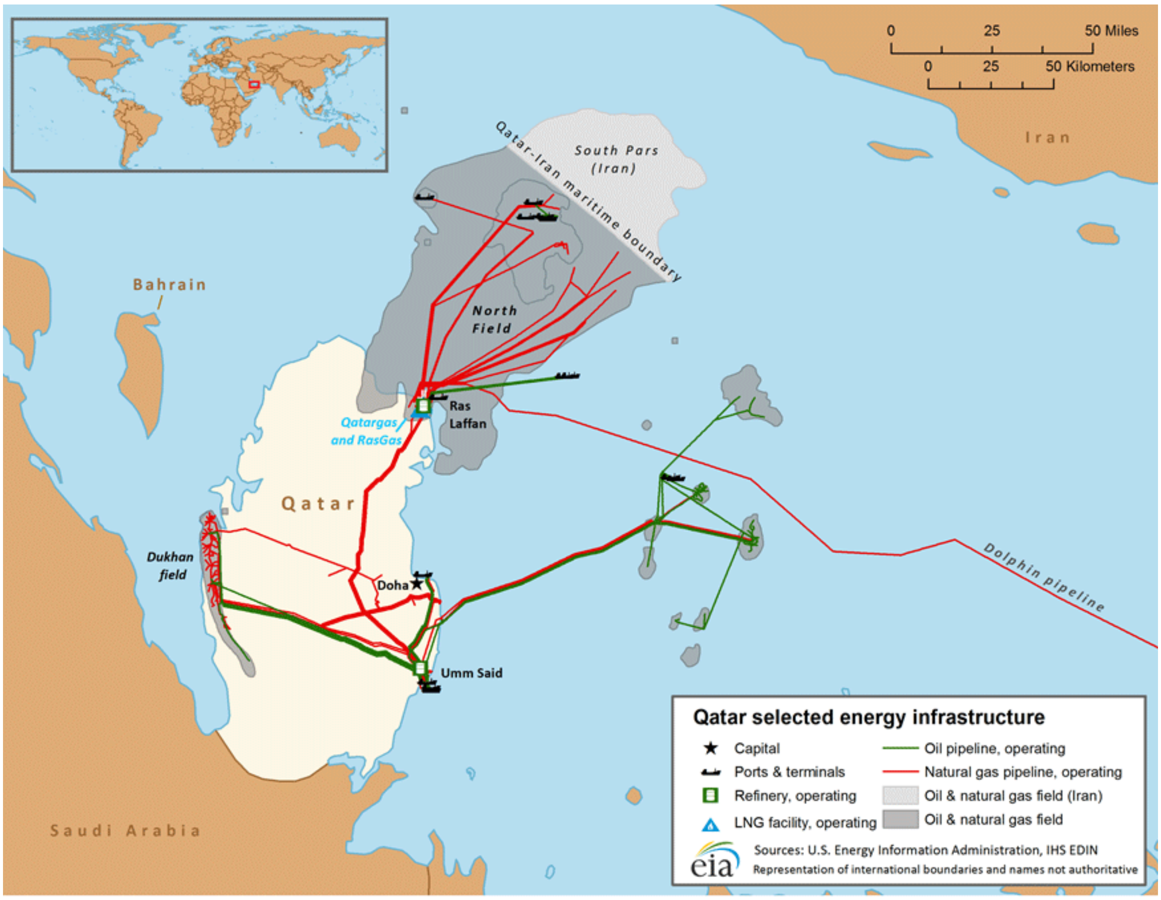


Figure 3.35: Qatar energy infrastructure map (Source: EIA)

Libya

Libya's rank as a producer and reserve holder is less significant for natural gas than it is for oil. Most of its natural gas production is exported to Italy via pipeline. OGJ estimated that Libya's proved natural gas reserves were 1.5 trillion cubic meters, making it the fourth largest natural gas reserve holder in Africa.

Libya's capacity to export natural gas increased dramatically after October 2004, when the 595 km Greenstream pipeline came online. The pipeline starts in Mellitah, where natural gas piped from the onshore Wafa and offshore Bahr Es Salam fields is treated for export. It runs underwater to Gela, on the island of Sicily, and the natural gas flows onward to the Italian mainland (Figure 3.36). The Greenstream pipeline is operated by Eni in partnership with NOC. According to PFC Energy, total capacity is 11 billion cubic meters per year since the most recent capacity expansion.

Natural gas exports via Greenstream were completely suspended for nearly eight months from March 2011 to mid-October 2011 due to the civil war. Exports partially recovered to 228 Bcf in 2012, albeit lower than the 2010 level of 332 Bcf, according to the BP 2013 Statistical Review.

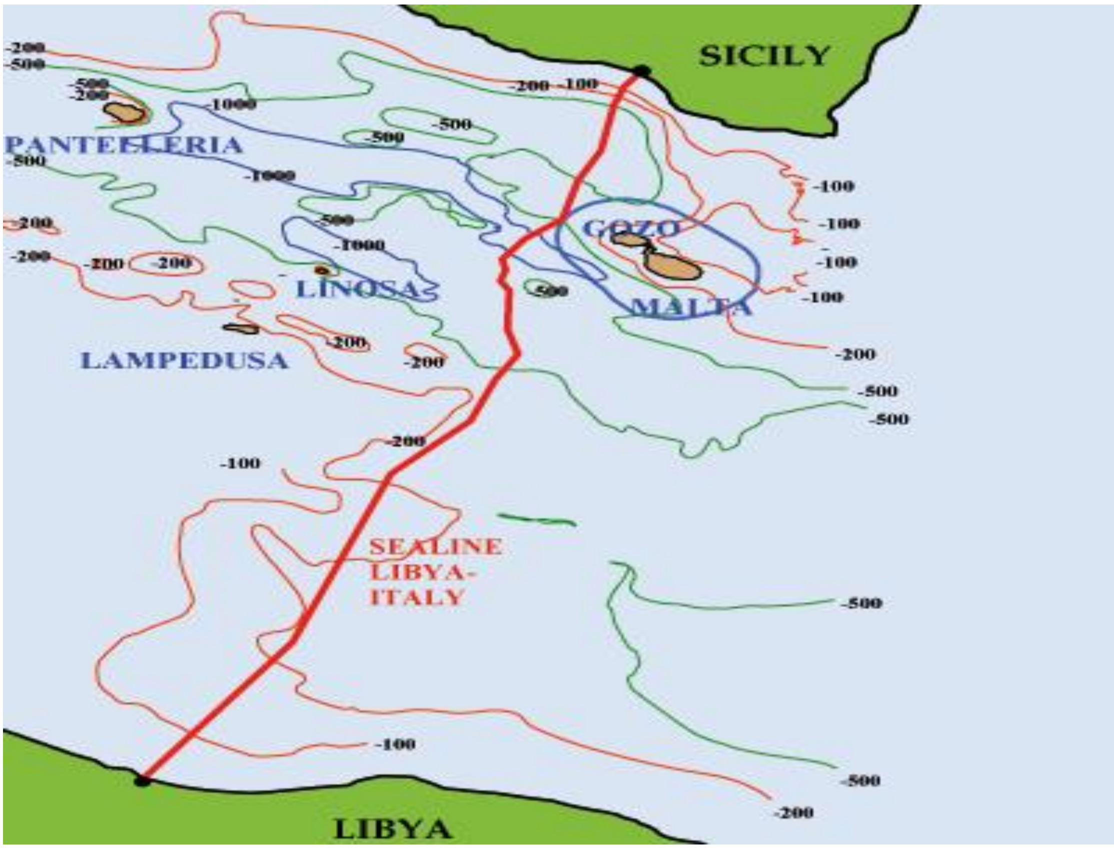


Figure 3.36: Map of the Greenstream pipeline

UK

The UK, in spite of being an EU 28 country, because of its geographical characteristics (not part of inland Europe), has several international pipelines, interconnecting it to the rest of the EU. The main pipeline exporting natural gas from the UK to the rest of the EU is the Interconnector pipeline which runs between Bacton, England and Zeebrugge, Belgium.

The Interconnector, inaugurated in 1998, is capable of bidirectional operation, meaning either it can export natural gas from the UK to continental Europe ("forward mode"), or it can import natural gas into the UK ("reverse mode"). Since it began operating, the Interconnector has mostly operated in forward mode, however during late fall and winter seasons, the pipeline has tended to operate in reverse mode. The pipeline has undergone three phases of expansion, with additional capacity and compression added between 2005 and 2007. The interconnector is currently capable of transporting 60 million cubic meters per day in forward mode and 75 million cubic meters per day in reverse mode. The international pipelines connecting the UK to other European countries are illustrated in Figure 3.37

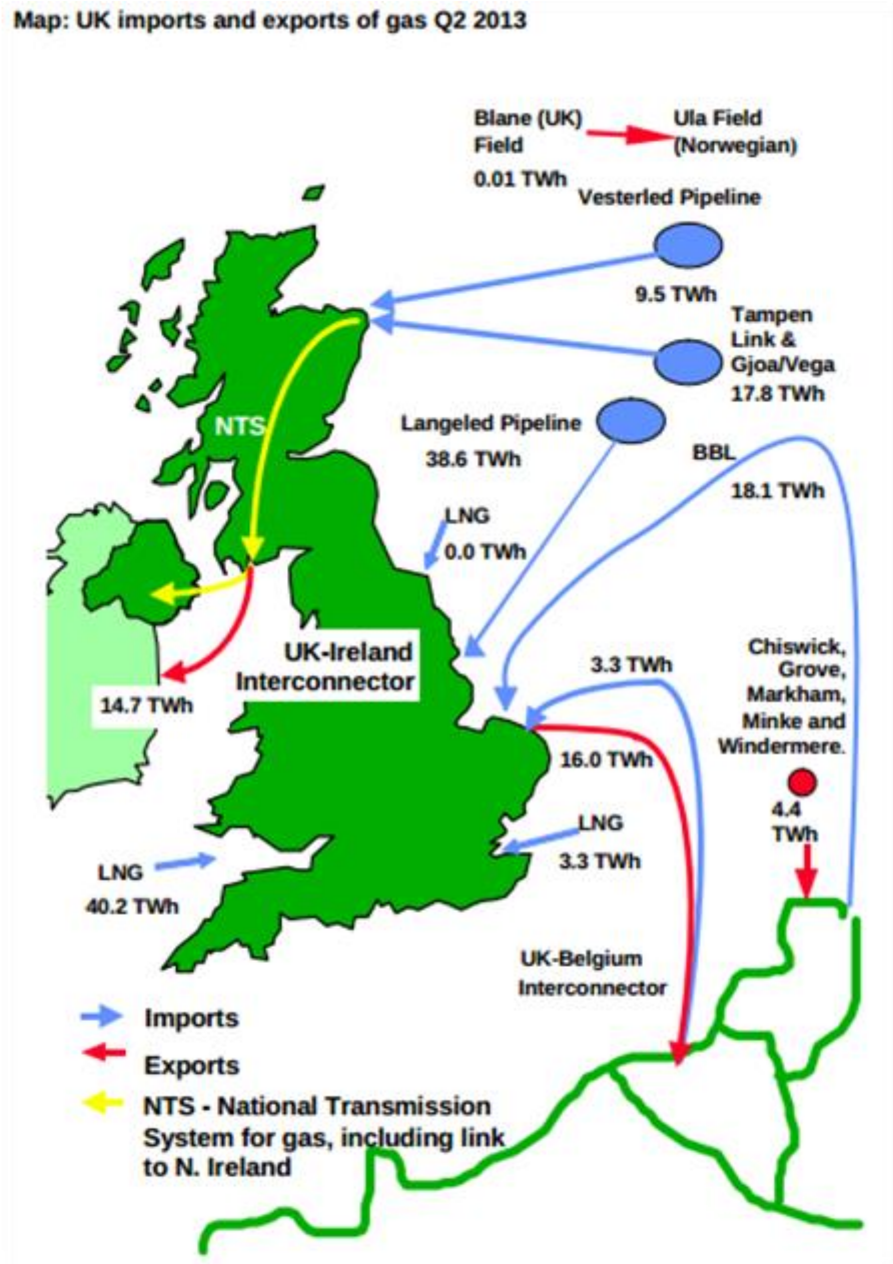


Figure 3.37: Map of the UK Natural gas international pipelines

Netherlands

Most of the Dutch natural gas fields are located offshore in the North Sea, although a number of them are located onshore, including Groningen, one of the ten largest natural gas fields in the world.

Natural gas produced in the Netherlands is shipped via an extensive domestic and export pipeline system, which connects the country with United Kingdom, Germany, and Belgium. In addition to pipeline natural gas, the Netherlands now serves as a transport hub for liquefied natural gas (LNG). The Gas Access to Europe (GATE) LNG import terminal became operational in September 2011, with imported volumes purchased by Austrian, Danish, and German distribution and utility companies.

On December 1, 2006, the Balgzand-Bacton Line (BBL), the first pipeline to link the Netherlands and the United Kingdom, began operating and supplying the UK with natural gas from the Dutch mainland. The 236 km pipeline has a capacity of approximately 45 Bcm per day.

Figure 3.38 presents the main pipelines departing from Groningen, Netherlands transmitting natural gas.

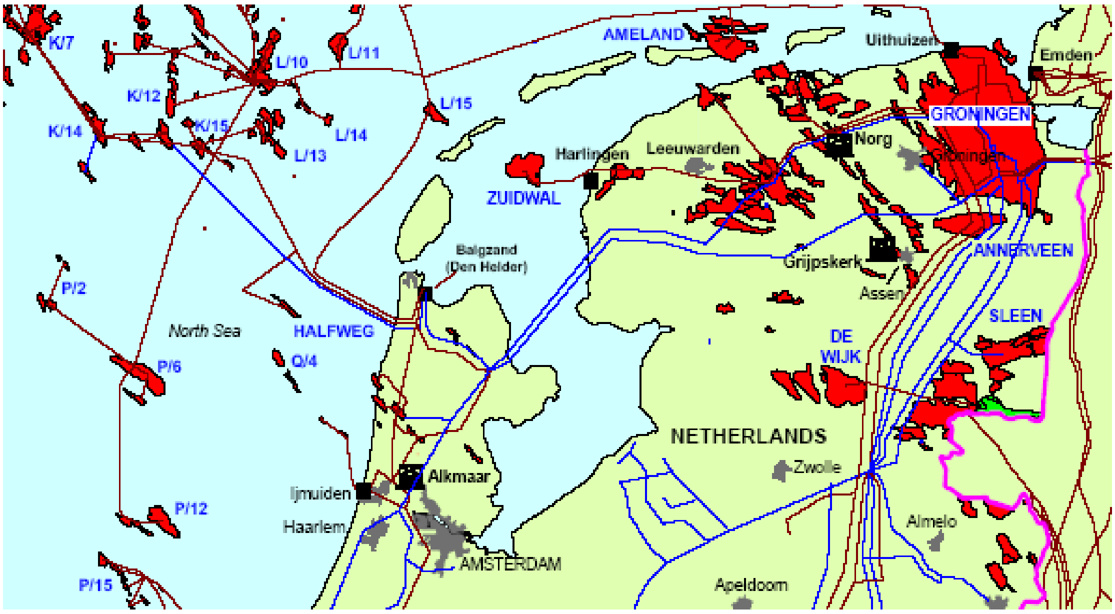


Figure 3.38: Netherlands gas transmission map

3.4.6 Downstream

The downstream stage is the final step in the natural gas supply chain and includes transmission, storage and distribution of gas to the end-users.

Natural gas is introduced into a pipeline transmission system at various points such as liquefied natural gas (LNG) terminals, processing plants near indigenous gas production fields, and interconnections with other natural gas transmission pipelines and long transportation pipelines. Gas storage sites are also connected to the transmission systems. The transmission and transportation pipelines are supported by gas fuelled compressors.

The delivery of natural gas to the end user by a distribution system does not contain any compression as distribution involves moving smaller volumes of gas at much lower pressures over shorter distances to a great number of individual users. The medium pressure distribution network is normally operated at a pressure below 15 bar and the electric compressors of CNG production are usually connected at this pressure.

Transmission and distribution networks are equipped with a high number of valves (safety valves and operating valves). Meters and customer lines are also part of the distribution network.

Venting and fugitive emissions

Natural gas can be released to the atmosphere during operation of transmission systems. This is problematic not only in terms of product loss, but also due to the fact that the primary component of natural gas is methane, a powerful greenhouse gas 25 times more potent than carbon dioxide. Generally natural gas emissions are divided into intended releases (venting) and unintended emissions (fugitive). Intended releases highly depend on the technology involved in the process. For example, compressor seals try to minimize the flow of natural gas between the rotating shaft and the casing of the compressor. Emission levels depend on the technology used, the age of equipment and the availability of new technology. Often retrofitting is not possible due to space requirements or other local circumstances.

Pressure controllers and other such equipment periodically release a certain amount of gas, but this can be used for purposes such as preheating of gas before pressure reduction. Maintenance of equipment is necessary, but this often requires internal inspections of parts containing natural gas. This gas must be released first for worker safety. All extensions or repairs of the pipeline network, for example by welding, can only be executed if the natural gas is purged and replaced by air to avoid incidents. Those releases contribute a high percentage of the total emissions of gas companies.

The unintended releases can be the result of leakage from equipment in use or damage to pipelines. All flange connections between parts should in theory be tight, but in some cases there are gaps that allow gas to escape into the atmosphere. Also, valves are intended to seal completely to restrict the flow of gas, but this does not always happen. Finding these leaks is an important Task for worker safety but also helps both the environment and profitability.

Pipe damage can either be caused by material failures or corrosion, but the main cause is third-party damage, commonly during excavation. Companies take care to prevent such damage, e.g. through internal pigging or cathodic corrosion protection and through educating people doing excavation.[9]

EU natural gas consumption in road transport

For the purpose of the present project, only natural gas that is consumed in the transport sector will be considered for 2012, which is the baseline year. It is considered that the use of natural gas by transport means could be either as Compressed Natural Gas (CNG) or as LNG through small-scale LNG systems. In 2012 CNG could be actually traced as transportation fuel, whereas LNG is expected to be consumed as fuel for big trucks and vessels in the forthcoming years.

[9] Reduction of Greenhouse gases - A Technology Guide, Produced by: International Gas Union, 2012

As it is shown in Table 3.18, the majority of EU countries do not present any consumption of natural gas for road transport and even in the countries that do have vehicles powered by natural gas, the corresponding quantities of fuel consumed are rather small. The only countries where the consumption of natural gas for road transport represented a substantial percentage of the total natural gas consumption in 2012 are Sweden, Bulgaria and Italy. Actually quantities of gas fuelled to other transport means are negligible.

The GHG emissions assessments, and therefore the gas streams, will not be restricted to the countries where there is gas consumption in transport in 2012 but will consider all natural gas streams supplied to EU 28 countries will be considered, as gas use in transport will be projected to 2030 (Task f of the study) and thus might be assessed in these projections.

Consuming country	Road consumption (million cubic meters)	Road consumption/ Total NG consumption %
BG - Bulgaria	79.03	2.66
EL - Greece	17.50	0.41
HR - Croatia	1.01	0.03
IT - Italy	924.04	1.23
RO - Romania	0.00	0.00
SI - Slovenia	0.84	0.10
BE - Belgium	10.37	0.06
CZ - Czech Republic	15.25	0.18
DE - Germany	259.03	0.30
EE - Estonia	0.00	0.00
LV - Latvia	0.00	0.00
LT - Lithuania	3.60	0.11
LU - Luxembourg	0.00	0.00
HU - Hungary	1.37	0.01
NL - Netherlands	24.21	0.05
AT - Austria	9.01	0.10
PL - Poland	0.00	0.00
SK - Slovakia	0.00	0.00
DK - Denmark	0.00	0.00
IE - Ireland	0.00	0.00
FI - Finland	6.72	0.18
SE - Sweden	59.48	5.05
UK - United Kingdom	0.00	0.00
ES - Spain	93.12	0.29
FR - France	98.60	0.23
PT - Portugal	13.76	0.31

Table 3.18: EU 28 Natural gas consumption for road transport in 2012 (source Eurostat)

3.5 APPROACH FOR DATA COLLECTION

3.5.1 Correspondence with oil and gas companies

As discussed in previous sections, a key target of this study is the collection of actual GHG emissions data. Thus, in line with the ToR requirements, the Consultant has come in direct communication with oil and natural gas production companies, national authorities as well as international organizations, in order to request actual data regarding field specific GHG emissions from the oil and gas upstream operations by each specific company. Specifically, GHG emissions data were requested on a field basis for the following activities both for oil and natural gas:

- Exploration, production and processing
- Venting, flaring and fugitive gas
- Transportation

The communication with the companies has been done both in a formal and informal manner. After establishing a contact with the relevant persons within each company, either by telephone or by e-mail, a formal letter was sent to them (a template of which is presented in Annex D). The purpose of this letter, which was signed by the Project Manager, was to request the provision of actual (emissions) data. The letter also mentioned the scope and the objectives of the project and stated the relevant support and interest of the European Commission. Onwards, follow-up communication by telephone and e-mail were made to the responsible persons within the oil and gas companies in order to establish a direct line of communication.

It should be mentioned as a general conclusion that oil and gas companies and their associations have been proven to be reluctant in providing actual emissions data till present and most of those who replied to the request for data, have guided us to look through their sustainability and environmental reports (if they exist). Unfortunately, these reports usually include aggregated and cumulative data covering the whole range of the company's activities, with few exceptions, and sometimes extending beyond oil activities.

Similarly, national authorities responsible for oil and gas activities or environmental authorities in key countries were contacted (e.g. Norwegian Petroleum Directorate, Association of Oil and Gas Producers, etc.) even though these institutions typically publish most of the data they have available from their members or participating oil and gas companies. Table 3.19: Overview of the correspondence with oil and gas associations, agenciesand companies

summarizes the correspondence with companies and institutions contacted, the departments contacted (if applicable), the way of communication and their response.

Generally the data collection output based on direct communication and request of existing actual data was very poor and it was disappointing that most of the contacted responsible officials tried to avoid replying or pass the request to other organizations, sometimes not so relevant to provide detailed information.

Oil Company	Position/Department	Letter sent by e-mail	Letter sent by post	Comments	Data provided
Oil					
Statoil	Senior Advisor Sustainability	yes	yes	Redirected to the Norwegian Petroleum Directorate	Not yet
Maersk	Group Sustainability, Head of Positioning & Strategic Risk Management, Lead, Climate Change	yes	yes	Redirected to the competent persons from Maersk oil, who did not reply	Not yet
Total	Director Sustainable Development and Environment	yes	yes	Letter sent to his assistant but no reaction	Not yet
ENI	Environment Manager	yes	yes	No reaction	Not yet
Shell	CO2 Policy Manager	yes	no	No reaction	Not yet
BP	Head of Energy & Carbon Policy and Strategy	yes	no	No reaction.	Not yet
Lukoil	Contact in the Refining department	yes	no	Asked for a contact person in the Environmental Department but no reaction	Not yet
Chevron	Principal Advisor, Climate Change	yes	no	Redirected us to OGP	Not yet
Conoco Phillips	Various	no	no	Never managed to contact anyone within Conoco Phillips	
Nexen	HSE and Assurance manager	yes	yes	Redirected us to OGP	Not yet
Repsol	Deputy Director of Corporate Responsibility	no	no	Never managed to contact anyone within Repsol	
Saudi Aramco	Environmental Coordinator	yes	No	No reaction	Not yet
Natural gas					
Gazprom	Junior Environmental Researcher	yes	no	No reaction	Not yet
Qatargas	Head of Environment	yes	no	No reaction	Not yet
Sonatrach	Various	yes	no	No reaction	Not yet
Associations and organizations					
OGP	Environmental Director	yes	yes	No reaction. Only reaction when redirected by Chevron, but no further data provided	Not yet
CDP	Director, Global Operations	yes	yes	A long communication	Not yet

Oil Company	Position/Department	Letter sent by e-mail	Letter sent by post	Comments	Data provided
				was established with the CDP, who were willing to help but did not have the authorization to provide us with data or contact details from the reporting companies	
National authorities					
NPD	Various	yes	no	Contacted them by telephone, but they informed us that all data they can provide are already public in their website	Not yet

Table 3.19: Overview of the correspondence with oil and gas associations, agenciesand companies

3.5.2 Approach for actual emissions data collection

According to the data collection priority described in Section 3.2.2 the first step of the study was to collect actual data from oil companies and organizations regarding the carbon intensity of specific MCONs or crude oils extracted from specific fields. For the MCONs for which poor or unreliable emission data were collected, the GHG emissions will be also assessed via the OPGEE model. Similarly, for natural gas sources and streams when actual data have been considered as insufficient GHG emissions will also be assessed via GHGenius. In any case actual emission sources are extremely useful for comparisons with emissions calculated via models.

The progress of the correspondence with oil and gas companies has clearly indicated that the receipt of few actual data should be expected. Therefore, the Consultant has chosen to adapt its data collection strategy and search for actual data from published documents of national authorities, public organizations and company reports. It should be noted that the collection of actual data continues after the formal finalization of Task b. Furthermore, due to the fact that the reply from most oil companies is still pending, there is always the possibility that actual data might be obtained beyond the scheduled duration of Task b. These data will be adapted and utilized appropriately by the Consultant.

The Table is organized on the basis of the targeted country or region. This way of presentation of the collected actual data has been preferred due to the fact most of the times information is found on a country basis. Furthermore, the data source is mentioned as well as the data type (flaring, venting, fuel consumption, refining, etc.) and the scope they cover (country or field specific).

The literature sources where actual data were found till present are summarized in Table 3.20.

Country/ Region	Source	Actual data type	Coverage
EU wide or various countries			
Russia, Norway, UK, Netherlands	UNFCCC Annex I country reports for 2012	Emissions and co-efficient factors for the following activities regarding crude oil: ▪ Production ▪ Flaring and venting ▪ Transport ▪ Refining ▪ Distribution	Country data
Worldwide	National Oceanic and Atmospheric Administration (NOAA)	▪ Flaring volumes for oil and natural gas	Country level and field level
EU wide	Environmental Energy Agency – European Trading Scheme	▪ Refining emissions	Country data
National reporting			
UK	National Atmospheric Emission Inventory	▪ Upstream oil activities ▪ Upstream gas ▪ Gas leakage ▪ Venting ▪ Flaring ▪ Refining	Country data
	Department of Energy and Climate Change (DECC)	▪ Quantities of gas flared	Country data
Norway	Norwegian Oil and Gas association	Emissions for the following oil activities: ▪ Well testing ▪ Flaring ▪ Boilers ▪ Engines ▪ Turbines	Country data
	Norwegian Environment Agency	Data regarding all Norwegian oil and gas fields and facilities: ▪ Energy use ▪ Production volumes ▪ Emissions	Oil and gas field specific data
Denmark	Oil and gas production	▪ Fuel consumption (gas) per	Country level and

Country/ Region	Source	Actual data type	Coverage
	Annual Report 2013, DEA	field ▪ CO2 emissions from production facilities in the North Sea ▪ CO2 emissions from consumption of fuel per m. toe ▪ Gas flaring	field-specific level
Russia and the Caspian Region	Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan, EBRD (2012)	▪ Flaring emissions ▪ Flared quantities of natural gas	Country data
	Associated Gas Utilization in Russia Annual Report 2011, KPMG	▪ Flaring emissions per region ▪ Flaring emissions per company ▪ APG utilization rates	Country data
Nigeria	Nigerian National Petroleum Corporation Annual Report 2013 (NNPC)	▪ Flaring quantities for a large number of fields	Field specific data
Company reporting			
Carbon Disclosure Project	Carbon Disclosure Project (CDP)	▪ Exploration, production & gas ▪ processing ▪ Storage, transportation & ▪ distribution ▪ Speciality operations ▪ Refining	Data provided per company
BP	BP Sustainability report 2012 Azerbaijan	▪ Flaring emissions ▪ Flaring volumes ▪ Production emissions	Country specific data as well field specific data particularly for Azeri Chirag Gunashli
Nexen Petroleum	Nexen Petroleum U.K. Limited Environmental Statement 2012	▪ Flaring and production GHG emissions	For company oil fields (Buzzard, Ettrick, Scott)
CNR International	CNR International UK Operations Environmental programme Annual Report 2013	▪ Combustion ▪ Flaring	Field specific data for Ninian System Oil fields
BP	BP Sustainability report 2012 Angola	▪ Actual direct emissions ▪ Actual indirect emissions ▪ Flaring volumes	Country data for (oil and gas) assets owned by

Country/ Region	Source	Actual data type	Coverage
			the specific company

Table 3.20: Overview of actual data sources, type of data collected and data coverage

The Table is organized on the basis of the targeted country or region. This way of presentation of the collected actual data has been preferred due to the fact most of the times information is found on a country basis. Furthermore, the data source is mentioned as well as the data type (flaring, venting, fuel consumption, refining, etc.) and the scope they cover (country or field specific).

3.6 Actual Data for Crude Oil

A valuable data source including reliable information for oil and gas for various lifecycle stages have been the UNFCCC country reports. However, it has to be noted that the available data regard only Annex I countries and more specifically Russia, Norway, UK and the Netherlands (from the oil producing countries). The National Oceanic and Atmospheric Administration (NOAA) has conducted an extensive work on the elaboration of actual data for flaring both on a country and field level. However, it must be stated that data provided per field regard flaring both from oil and gas activities and a tailor made methodology has to be developed in order to disaggregate emissions for further analysis. Actual data for the European refining sector have been found per country by the European Environmental Agency, as those reported and verified for the European Trading Scheme.

The main sources of actual data for the UK oil and gas sector are included in the National Atmospheric Emission Inventory created by maintained by DEFRA. Norway has been the country for which the most actual data have been found for oil and gas both on country and field specific level. The main source of data for Norway has been the Norwegian Environment Agency and the Norwegian Petroleum Directorate (NPD), while Statoil published a wealth of data in line with national regulatory requirements. For Denmark, the Danish Energy Agency (DEA) in its annual reports includes actual emission data for oil and gas activities in its annual reports. Another significant source of actual data has been a study conducted by EBRD regarding the flaring emissions for Russia, Kazakhstan, Turkmenistan and Azerbaijan, which has collected statistics from national authorities from the aforementioned countries. This study is particularly important as in these countries there a remarkable difficulty for obtaining reliable data. Lastly, actual data regarding gas flaring volumes per oil field and company for Nigeria are included in the Annual Statistical Bulletin published by the National Nigerian Petroleum Company (NNPC).

Other sources of actual data include environmental and sustainability reports from oil and gas companies. More specifically, BP in its sustainability report for Azerbaijan provides actual emission data per asset (field, pipeline) as well as cumulative figures, while for Angola it provides only cumulative figures for the entire company. NEXEN petroleum provides actual data for the oil fields it operates in UK and particularly for Buzzard which is a representative field.

In the following Sections 3.6.1 – 3.7.7 the actual data that have been collected by various sources for oil and gas activities till present are presented exhaustively per region or country. Followingly, in Section 3.6.8 the emissions from oil and gas activities of various companies are presented per lifecycle process, as those have been reported to the Carbon Disclosure project. In Section 3.6.9 the actual emissions of the European refining sector are presented per country. Finally, in Section 3.6.10 an overview of the actual data that have been collected is being made in order to evaluate the needs for data collection for the OPGEE and GHGenius models.

3.6.1 Russia and FSU countries

Country data

In general, few actual GHG emission data from upstream activities are available for Russia and FSU countries, with the exception of flaring emissions. The analysis of flaring emissions from Russian oil fields is of particular importance because these are extremely high - the largest among all oil producing countries as illustrated in Figure 3.39. Furthermore, as it can be obtained by the Figure 3.39, Russia has one of the largest flaring to oil ratio among countries studied by NOAA (i.e. associated gas flared volume per unit of oil extracted). The relevant ratio has been calculated by using gas flared volumes by NOAA/GGFR estimated and EIA oil production volumes per country and is also an important input for the modelling of GHG emissions in OPGEE.

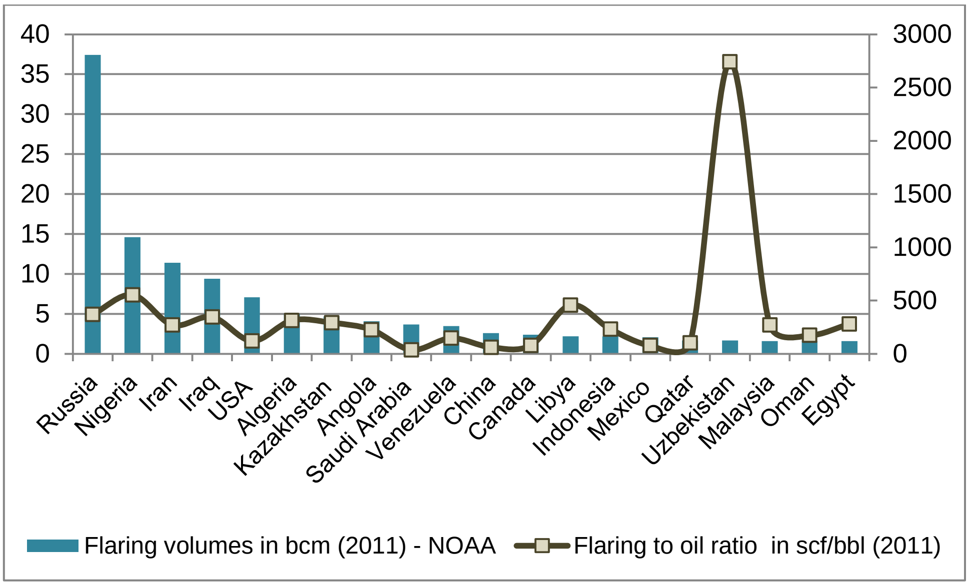


Figure 3.39: Flaring emissions (in bcm) according to the NOAA/GGFR database and flaring to oil ratio (scf/bbl) for the calculated based on EIA production volumes for 2011

Besides the NOAA database, there are several studies dealing with flaring emissions both for Russia and FSU countries. Particularly a study conducted by Carbon Limits on behalf of EBRD provided a comprehensive overview of Russian and other FSU countries' flaring emissions (Figure 3.40) presenting official statistics from FSU countries. Another study dealing with Russia's flaring emissions has been elaborated by KPMG on behalf of WWF Russia, which has collected several actual GHG emission data via request from oil companies.

Figure 3.40 summarizes the associated petroleum gas flaring volumes for Russia and other FSU countries. Data for Russia have been taken from the Central Dispatch Office of the Russian Fuel and Energy Industry (CDU TEK), for Kazakhstan from the Ministry of Oil and Gas, for Turkmenistan from NOAA/GGFR and Carbon Limits estimates based on IHS data sources. For Azerbaijan figures have been taken from BP's sustainability reports. As expected, Russia has by far the largest emissions among the examined countries. Furthermore, despite Russia's commitments for taking policy action regarding flaring reduction, emissions increase steadily since 2009.

A significant issue relevant to Russian and other FSU countries' flaring emissions is the inconsistency among published data by various sources, as there are large differences in flaring volumes published between national statistics, company figures and NOAA estimates. The discrepancy in flaring volumes between official statistics and NOAA assessments for Russia and Kazakhstan is clearly illustrated in Figure 3.41**.**

The gap between NOAA values and official statistics can be attributed to three factors (EBRD, 2013):

- Difficulties in converting luminosity to flaring volumes. This is related to several factors such as the possibility of overestimating or underestimating flaring volumes via appropriate conversion factors. Furthermore, NOAA satellite images capture only specific snapshots - and not measurements - and therefore do not take into account seasonal variations.

- Flaring volumes do not consider only flaring from associate petroleum gas but also other sources such as non-associated gas from gas processing plants or refineries.
- Underestimates of flaring from national statistics.

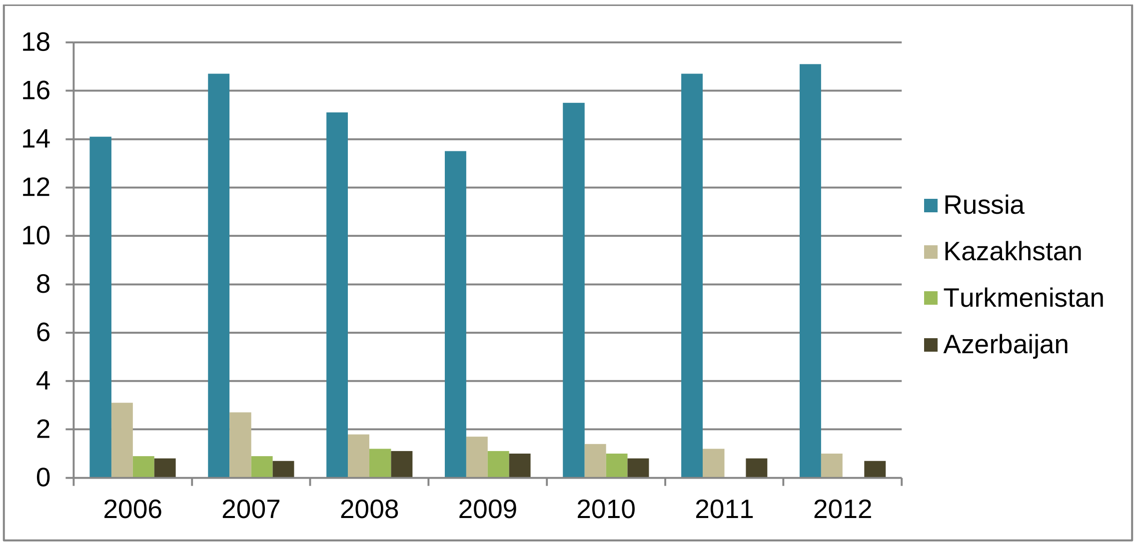


Figure 3.40: Flaring of associated gas in target countries in bcm according to national statistics for the years 2006 – 2012, in billion cubic meters (source: EBRD)

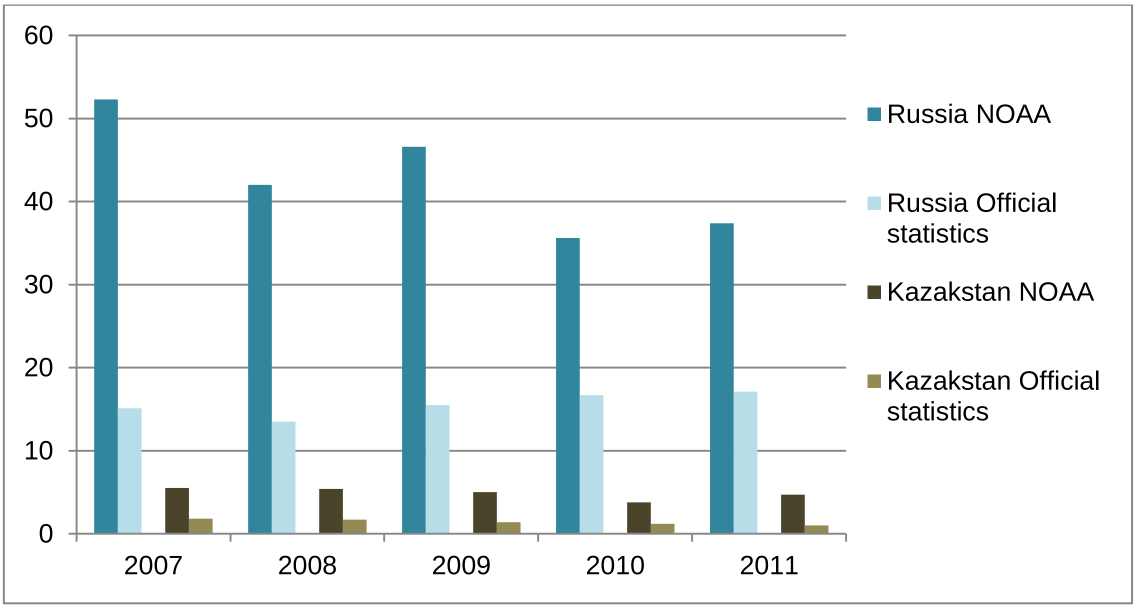


Figure 3.41: Comparison of associated flaring volumes in bcm between national statistics and NOAA estimates (source: EBRD)

Regional dispersion of Russian flaring volumes

Figure 3.42 illustrates the Associated Petroleum Gas (APG) production volume per region and the APG flared volumes. It is evident that the largest fraction of APG production comes from Western Siberia with more than half of it being produced in Khanty-Mansi Autonomous Okrug. Large part of this APG is flared – approximately 5 bcm, with Eastern Siberia having the same flaring volumes. Together these two areas accounted for approximately 80% of Russian flaring emissions as it can be obtained by Figure 3.42. Further analysis of these data can be used for the assessment of flaring emissions for Urals and Siberia Light MCONs, even though it is doubtful whether these emissions can be reliably attributed to specific MCONs and oil fields.

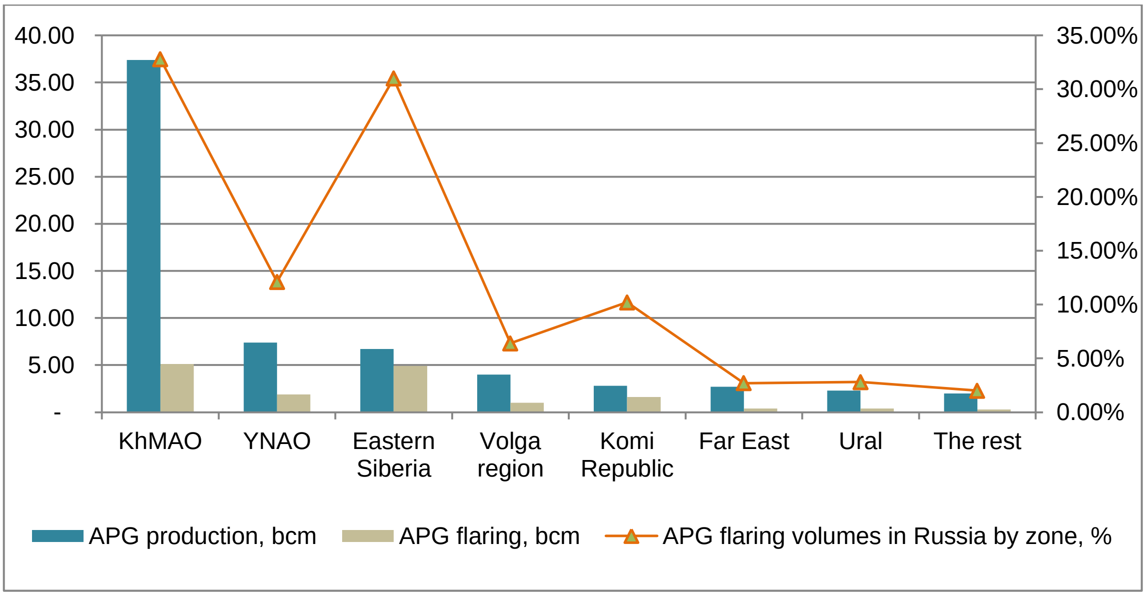


Figure 3.42: APG production and flaring in Russia by zone in bcm, 2010 (KPMG)

UNFCCC emissions data for Russia

A significant source of reported GHG emission data are the Annex I country reports submitted to UNFCCC. These include actual data both for oil and natural gas for key processes i.e. exploration, production, transport, refining, distribution, flaring and venting. The fact that figures are presented also in the form of emission factors (i.e. total emissions per well, emissions per ton of oil produced or refined, etc.) is particularly important, because they can be used directly in OPGEE and in GHGenius which calculates GHG emissions by use of proper emission factors. Table 3.21 summarizes the UNFCCC reported data for Russia and indicates the level of detail of analysis of these reports.

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						204A58	908A40
I. Exploration	*number of*	1000	181.70	220,845.96	74,454.96	40.13	13.53

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
	producing and capable wells	numb.					
ii. Production(4)	*oil produced*	Mt	497.43	314,758.69	1,690,370.7	156.57	840.83
iii. Transport	*(oil transported in pipelines)*	Mt	523.35	571.23	6,295.17	0.30	3.29
iv. Refining / Storage	*oil refined*	Mt	271.45	NE	36,871.12	NE	10.01
v. Distribution of Oil Products	*oil refined*	kt	271,453.00	NE	NE	NE	NE
vi. Other	*(NGL production)*	kt	21,322.00	355.79	1,910.72	7.59	40.74
1. B. 2. b. Natural Gas						84.34	13,525.23
i. Exploration	*number of producing and capable wells*	1000 numb.	9.79	172,553.69	72,163.80	1.69	0.71
ii. Production / Processing	*gas produced*	10^6 m^3	654,650.00	121.98	3,629.24	79.85	2,375.88
iii. Transmission	*(total gas transmission)*	kt	541,054.50	5.18	8,915.31	2.80	4,823.67
iv. Distribution	*gas consumed*	10^6 m^3	137,236.60	NE	20,908.30	NE	2,869.38
v. Other leakage	*gas consumed*	10^6 m^3	388,079.50	NE	8,904.32	NE	3,455.59
at industrial plants and power stations	*(gas consumed)*	10^6 m^3	343,301.70	NE	9,450.51	NE	3,244.38
in residential and commercial sectors	*(gas consumed)*	10^6 m^3	44,777.80	NE	4,716.82	NE	211.21
1. B. 2. c. Venting						8.78	839.62
i. Oil	*oil produced*	kt	497,425.00	13.99	1,609.93	6.96	800.82
ii. Gas	*length of pipelines*	km	175,100.00	8.50	IE	1.49	IE
iii. Combined	*(NGL production)*	kt	21,322.00	15.81	1,819.80	0.34	38.80
Flaring						36,594.35	219.95
i. Oil	*oil production*	kt	497,425.00	IE	IE	IE	IE
ii. Gas	*gas production*	10^6 m^3	654,650.00	3,725.88	22.94	2,439.15	15.01
iii. Combined	*(Assotiated gas flaring)*	10^6 m^3	17,077.60	2,000,000.0	12,000.00	34,155.20	204.93

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category

Table 3.21: Russian reported emissions per lifecycle stage for 2012 for oil and natural gas (source: UNFCCC)

3.6.2 Azerbaijan

Additional data for Azerbaijan have been found in the website of BP, which publishes detailed GHG emission data in its Sustainability Report for 2012.

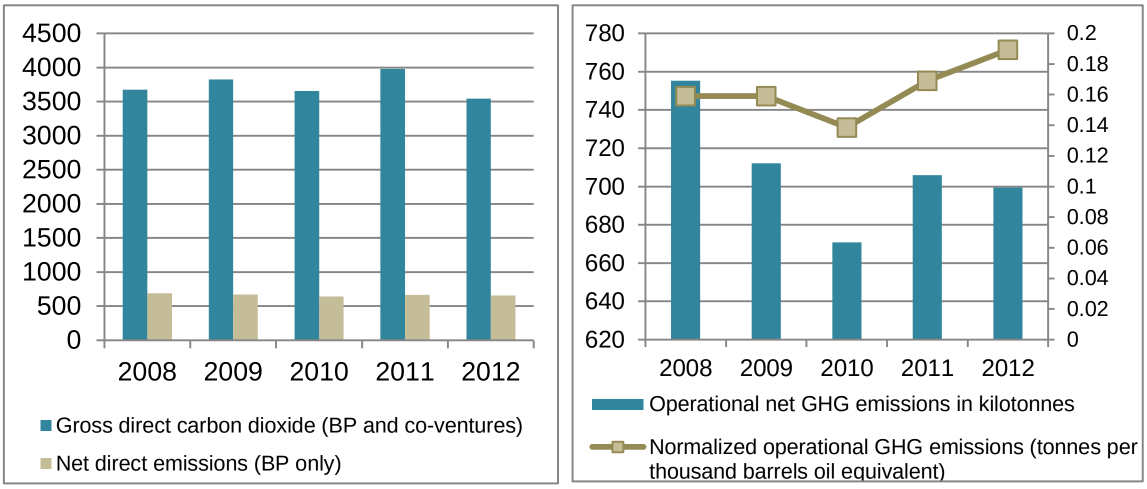


Figure 3.43 illustrates BP's and its co-ventures' direct CO_2 emissions in Azerbaijan as well as its net GHG emissions. It is evident that both company emissions and cumulative emissions including co-ventures have remained relatively steady over the period examined (2008 - 2012).

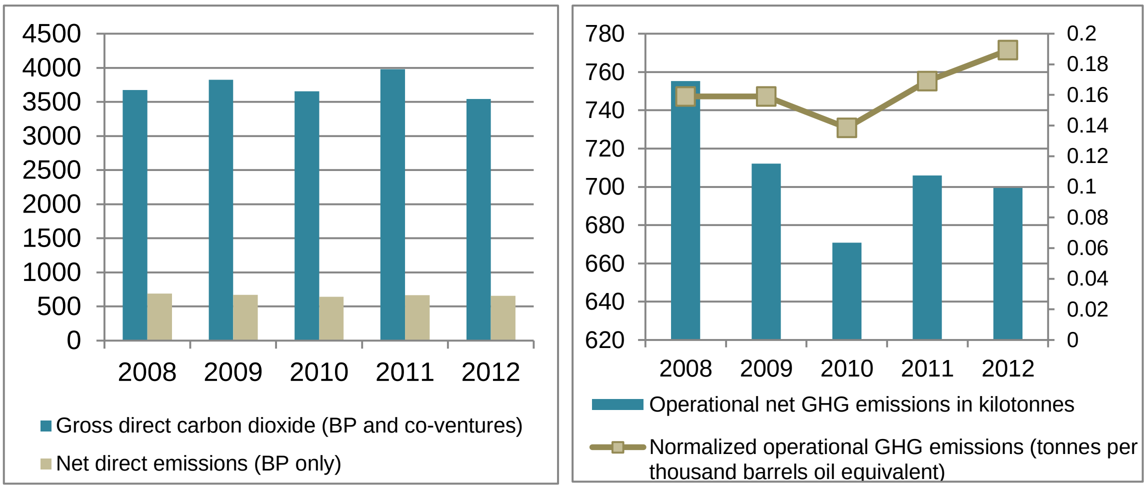


Figure 3.43: BP's emissions in Azerbaijan for 2012 (emission in kilotonnes)

Table 3.22 summarizes BP's net GHG emissions per asset. It is worth mentioning that the Azeri oil field has the largest cumulative emissions, followed by the fields of Chirag and Gunashli (also known cumulatively as ACG field). There are extremely useful data as they can be compared with the emissions calculated for ACG field in OPGEE, which is a representative oil field for two MCONs.

Asset / Facility	2011	2012
Central Azeri	130.0	117.2
West Azeri	52.6	44.0
East Azeri	44.6	46.0
Chirag	36.6	54.3

Asset / Facility	2011	2012
Deepwater Gunashli	88.8	70.6
Shah Deniz	1.9	2.1
Istiglal rig	3.4	3.8
Dada Gorgud rig	2.0	3.6
Sangachal terminal (Azeri-Chirag-Deepwater Gunashli)	247.8	252.5
Sangachal terminal (Shah Deniz)	41.8	44.8
Baku-Tblisi-Ceyhan pipeline in Azerbaijan	22.7	19.4
South-Caucasus Pipeline in Azerbaijan	0.2	0.2
Western Route Export Pipeline in Azerbaijan	4.0	4.3

Table 3.22: BP in Azerbaijan net GHG emissions per asset (in kilotonnes)

In 2012, about 475.9 kilotonnes of hydrocarbons were flared from BP's operations in Azerbaijan. By implementing measures such as improving the reliability of the flash gas compressors at offshore installations, replacing existing engines on gas injection compressors and a gas export compressor at Central Azeri compression and water injection platform with more reliable and higher capacity engines, repairing flare valve at Chirag, post-turnaround flaring minimization at Deepwater Gunashli, BP claims that the overall level of flaring in 2012 compared to 2011 was reduced by 19%. Nevertheless, Figure 3.44, presents gross flaring by asset in kilotonnes, from where it can be obtained that Chirag had the highest flaring volumes in 2012.

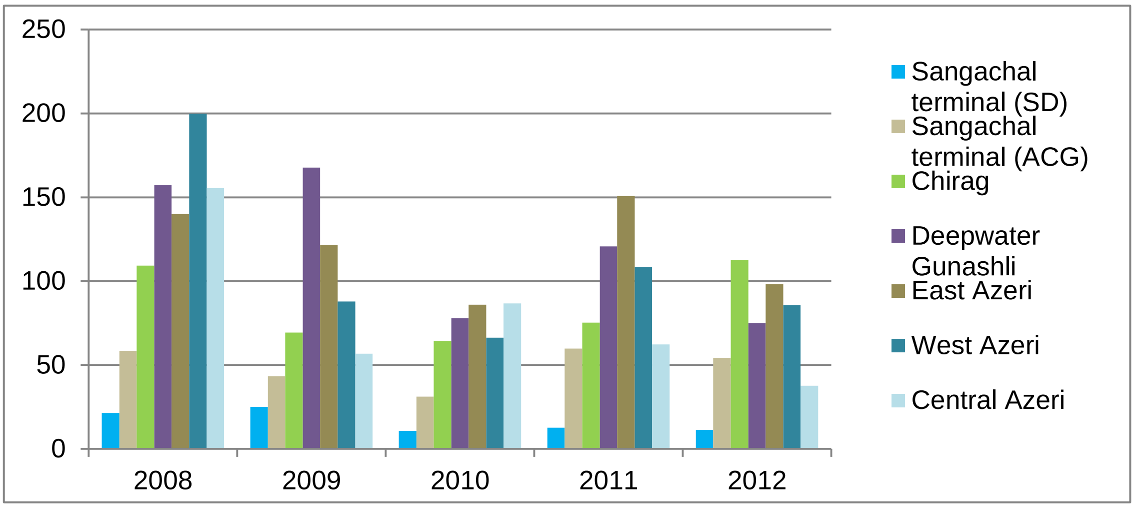


Figure 3.44: BP in Azerbaijan gross flaring volumes by asset in kilotonnes (source: BP)

3.6.3 Norway

The environmental performance of the Norwegian petroleum sector compared to other oil producing regions worldwide is illustrated in Figure 3.45, from where it be obtained that it is one of the cleanest. This has been the result of a number of policy instruments and regulations deployed by the Norwegian government to regulate emissions from the oil and gas business. The most important of these are the carbon tax, Norway's participation in the EU emission trading market, flaring provisions in the Petroleum Activities Act, the requirement to assess power from shore when planning developments, emission permits and the Best Available Techniques (BAT) requirement. These instruments have prompted a number of measures by the petroleum sector that led to significant emissions reductions over the last years.

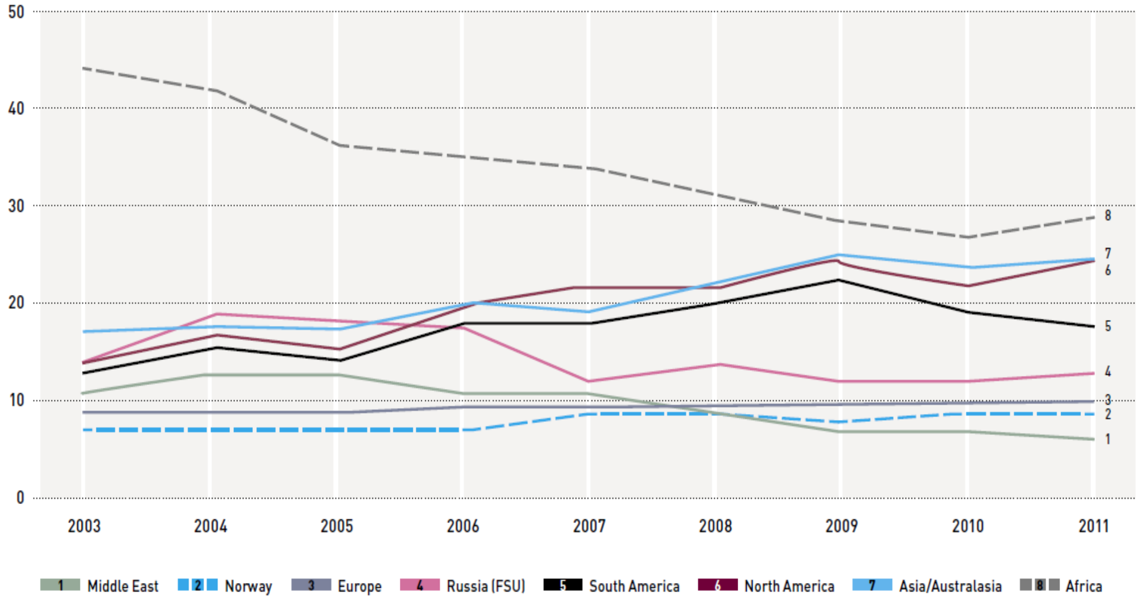


Figure 3.45: GHG emissions produced for petroleum from various origins (in kg of carbon equivalent per barrel of oil produced) (source OGP, Environment Web)

The Climate and Pollution Agency, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database for reporting emissions to air and discharges to sea from the petroleum activities under the name «Environmental Web» (EW). In addition, all operators on the Norwegian continental shelf report GHG emissions and discharge data directly into the database. All these data are characterized by high consistency and transparency.

A major source of actual data for Norway has been the Annual Environmental Report published the Norwegian Petroleum Directorate, which includes detailed emissions for all major pollutants (CO_2 NO_X, CH_4, VOC etc.). After a peak in 2008 GHG emissions have been steadily declining until 2012, as it can be seen in Figure 3.46. The main source of atmospheric emissions has been power generation using natural gas and diesel. The level of these emissions depends mainly on energy consumption by the facilities and the energy efficiency of power generation. The second largest source of this emission type is gas flaring. Flaring takes place to only a limited extent and is constantly decreasing pursuant to the provisions of the Petroleum Activities Act, but is permitted for safety reasons and in connection with certain operational problems.

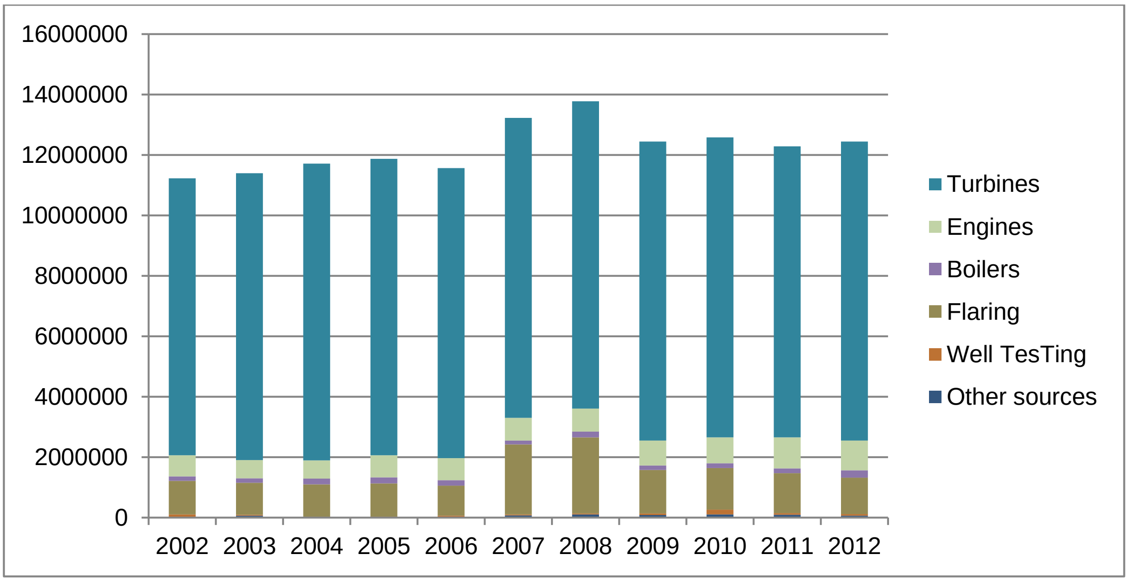


Figure 3.46 : Breakdown of GHG emissions by source in metric tonnes CO_2 equivalent for Norway (source: NPD)

For Norway a detailed source of actual emission data has been the Norwegian Environment Directorate, including total cumulative emissions and fuel consumption for all representative oil fields that are studied. Figure 3.47, illustrates the GHG emissions for these representative oil fields. As it can be observed in the Figure, the fields that exhibit the largest emissions are Oseberg followed by Gullfaks. Despite the adoption of stringent environmental regulations by Norway and the adoption of more energy efficient technologies by companies active in the Norwegian Continental Shelf, the GHG emissions from representative oil fields remained either stable, decreased or increased in absolute values by the time.

The increase of GHG emissions of representative oil fields can be better perceived by estimating the emissions per unit of output of oil from each oil field, which is illustrated in Figure 3.48. Given the fact that production in the specific fields steadily decreases over time, a general conclusion that can be drawn is that as fields become mature and depleted the energy intensiveness of oil extraction increases in order to maintain pressure at acceptable levels, which results in higher emissions per unit of output of oil over time. The GHG emissions per unit of oil produced are extremely useful for comparisons with the outputs of OPGEE, when these will be produced at a later stage of the project.

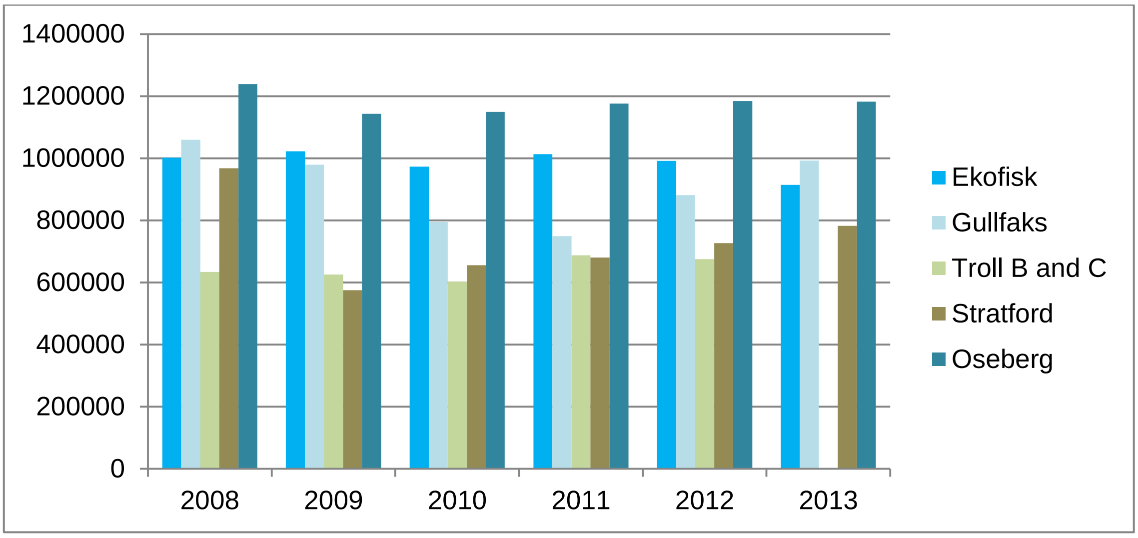


Figure 3.47: GHG emissions of representative Norwegian oil fields in tonnes of CO2 equivalent (source: Norwegian Environmental Directorate)

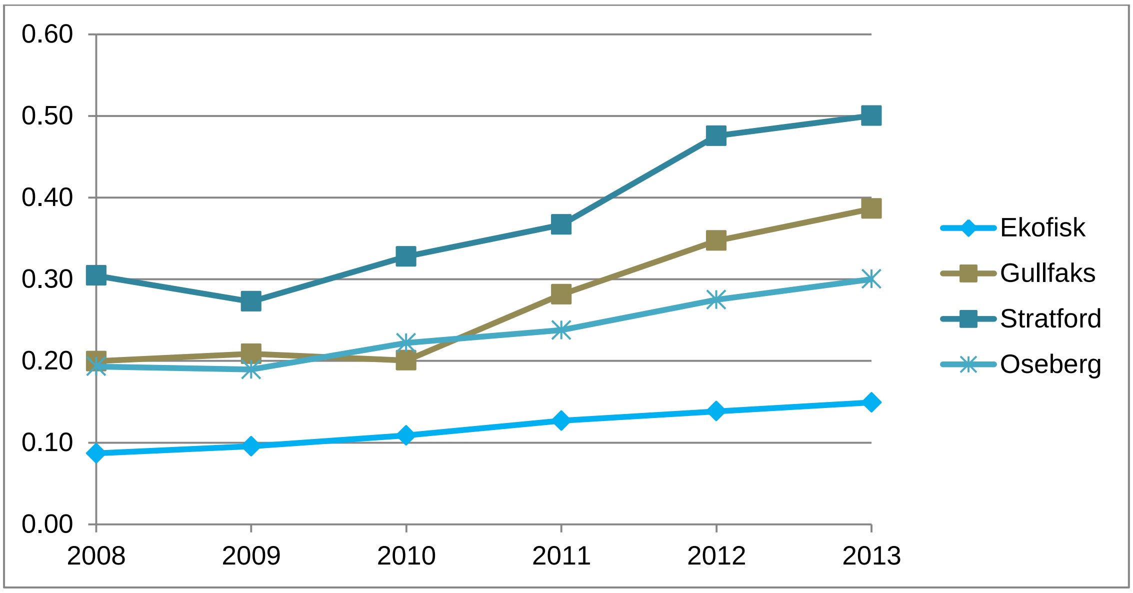


Figure 3.48: GHG emissions per unit of output of oil (in tonnes CO2 equivalent per m3 of oil) (source: NPD and own elaboration)

As discussed, reporting of GHG emissions in Norway is detailed, transparent and mandated by national legislation. In this context, all companies are obliged to report the emissions from their upstream activities. Detailed emission figures per asset have also been provided by Statoil (including oil and gasification terminals apart from oil and gas fields). Table 3.23 summarizes the GHG emissions of the 20 facilities owned by Statoil with the highest Scope 1 and Scope 2 GHG emissions (see paragraph 3.6.8 for explanations), according to CDP, which are equivalent to direct emissions according to the system boundaries defined in this study.

Facility	Scope 1 emissions (metric tonnes CO_2eq)	Scope 2 emissions (metric tonnes CO_2eq)	Total Emissions (metric tonnes CO_2eq)
Mongstad Drift PA	1,656,310		**1,656,310**
KÅRSTØ	1,049,019	4,766	**1,053,785**
MELKØYA	897,690		**897,690**
SLEIPNER	833,527		**833,527**
Mongstad - Kraftvarmeverket	606,209	210,897	**817,106**
Oseberg feltsenter	744,972		**744,972**
ÅSGARD B	716,617		**716,617**
KALUNDBORG	518,678	102,421	**621,099**
GULLFAKS A	471,987		**471,987**
HEIDRUN	394,343		**394,343**
ÅSGARD A	347,539		**347,539**
TJELDBERGODDEN	345,576	471	**346,047**
Troll C	336,883		**336,883**
NORNE	282,587		**282,587**
SNORRE A	279,780		**279,780**
Troll B	274,739		**274,739**
CPF	268,292		**268,292**
STATFJORD B	261,563		**261,563**
Peregrino FPSO	256,409		**256,409**
GULLFAKS C	236,620		**236,620**

Table 3.23: Overview of Statoil's 20 facilities (terminals and platforms) with the highest GHG emissions (Scope 1 and Scope 2), as those reported to CDP.

Another source of data for the Norwegian oil sector is the Norwegian UNFCCC report. Data are provided both for oil and gas regarding all major lifecycle stages excluding the combustion stage. These data are presented at country level and have been developed based on the methodology of UNFCCC. Emissions reported to UNFCCC will be compared with national statistics in order to assess their consistency. Table 3.24 presents these data for the Norwegian oil and gas sectors.

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	ACTIVITY DATA			IMPLIED EMISSION FACTORS			EMISSIONS	
	Description	Unit	Value	CO_2	CH_4	N_2O	CO_2	CH_4
				(kg/unit)			(Gg)	
1. B. 2. a. Oil							1,252A136	8A893
i. Exploration	*number of wells drilled*	kg	NE	IE	IE	NO	IE	IE
ii. Production	*oil produced*	$10^3 m^3$	111,523	IE	IE		IE	IE
iii. Transport	*oil loaded in tankers*	PJ	3,959.922	21,350.109	1,674.20		84.545	6.630
iv. Refining / Storage	*Oil refined*	PJ	551.619	2.093	4.104	N.	1,154.670	2.264
v. Distribution of Oil Products	*Gasoline sold*	PJ	45.353	284,906.605	N.		12.921	N.
1. B. 2. b. Natural Gas							13.512	1.842
i. Exploration	*specify*		NE	IE	IE		IE	IE
ii. Production / Processing	*gas produced*	$10^6 m^3$	114,727.0	IE	IE		IE	IE
iii. Transmission	*gas consumed*		NE	IE	IE		IE	IE
iv. Distribution	*gas consumed*		NE	IE	NE		IE	0.030
v. Other Leakage	*(specify)*		NE	NE	NE		13.512	1.812
at industrial plants and power stations	*specify*		NE	NE	NE		13.512	1.812
in residential and commercial sectors	*specify*	km	N.	NO	NO		NO	NO
1. B. 2. c. Venting							119.833	14.676
i. Oil	*(e.g. PJ oil produced)*		IE	IE	IE		IE	IE
ii. Gas	*(e.g. PJ gas produced)*		IE	IE	IE		IE	IE
iii. Combined	*Oil and gas produced*	PJ	7,967.106	15,041.019	1,842.12		119.833	14.676
Flaring							1,359.733	0.726
i. Oil	*Oil flared*	PJ	0.461	75,650,118	9,456.26	709.22	34.853	0.004
ii. Gas	*Gas flared*	PJ	18.178	72,883,963	39,686.4	559.16	1,324.881	0.721

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category
NO (Not Occurring): For emissions and removals of GHG that do not occur for a particular gas or source/sink category

Table 3.24: Emission data for Norway for oil and natural gas

3.6.4 United Kingdom

Country data

Actual emission data on a national level for the oil and gas activities of the United Kingdom are being collected by the National Atmospheric Emission Inventory that has been developed by the Department of Environment, Food and Rural Affairs (DEFRA). Such data are presented in Figure 3.49. As it can be obtained from theFigure, the most significant emission source is flaring, which accounted for approximately 85% of total emissions of the UK oil sector in 2012, followed by venting which accounted for 7% of total emissions in 2012.

Another major source of actual emissions data for the UK has been the country's report under the UNFCCC, which is presented in Table 3.25. As discussed for Russia and Norway, UNFCCC is a useful source of information, since each country is obliged to submit data periodically in a consistent and reliable manner. However, the same limitations apply, including the difficulty to use data that are presented on an aggregated level. Generally the UNFCCC data are anticipated to be more useful for the assessment of natural gas GHG emissions via the GHGenius model and also for verification and comparison with other data sources at aggregated level.

The Department of Energy and Climate Change (DECC) also publishes flaring volumes per oil field. Table 3.26 illustrates the 20 oil fields with the largest flaring volumes in 2013. Flaring volumes are reported for Buzzard, Ninian and Captain, which are the three representative fields for UK crudes in the context of this study.

Apart from data presented on a national basis, actual emission data for specific oil fields are also available by specific companies, which operate specific oil and gas fields, through their environmental reports. NEXEN petroleum in its Environmental Statement for 2012 publishes data for 3 key oil and gas fields that operates i.e. Buzzard, Ettrick and Scott, as it is presented in Figure 3.50. According to the company's report, the main combustion GHG emission from these sources is carbon dioxide (CO_2), along with smaller emissions of oxides of nitrogen, nitrous oxide, sulphur dioxide, carbon monoxide, methane and volatile organic compounds. The largest portion of carbon dioxide emissions offshore comes from combustion of fuels for energy production on-board the installations.

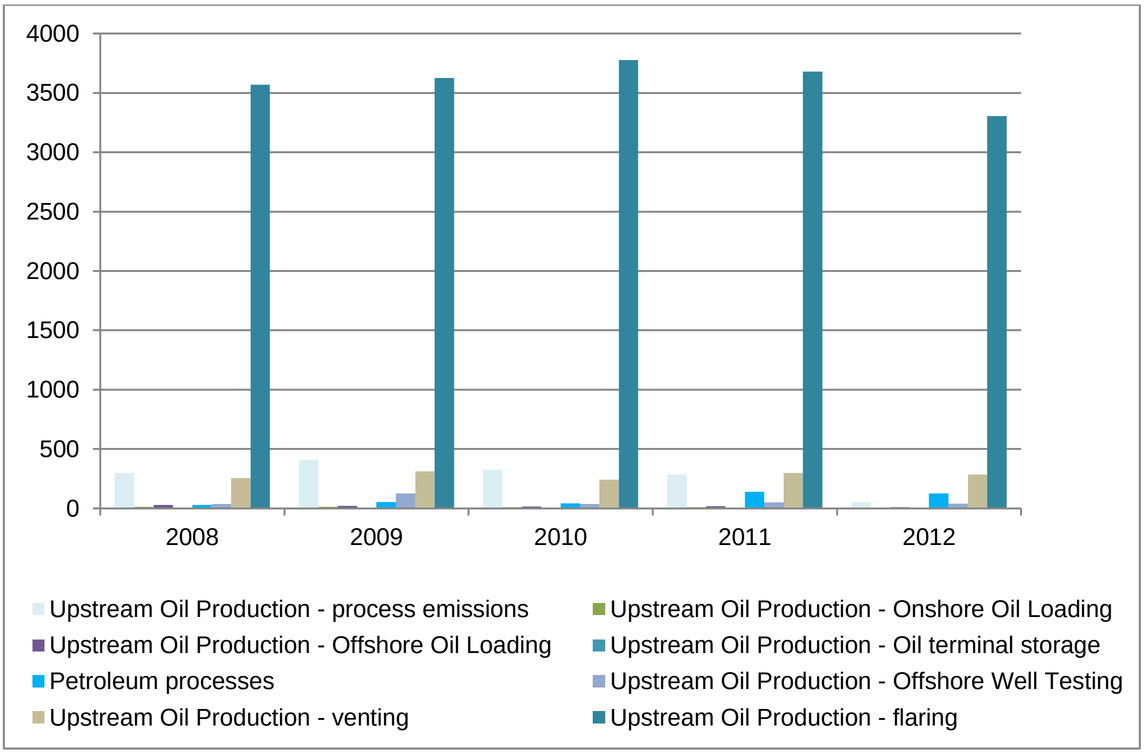


Figure 3.49: Breakdown of emissions of the UK oil sector by source (in million metric tonnes) (source: DEFRA)

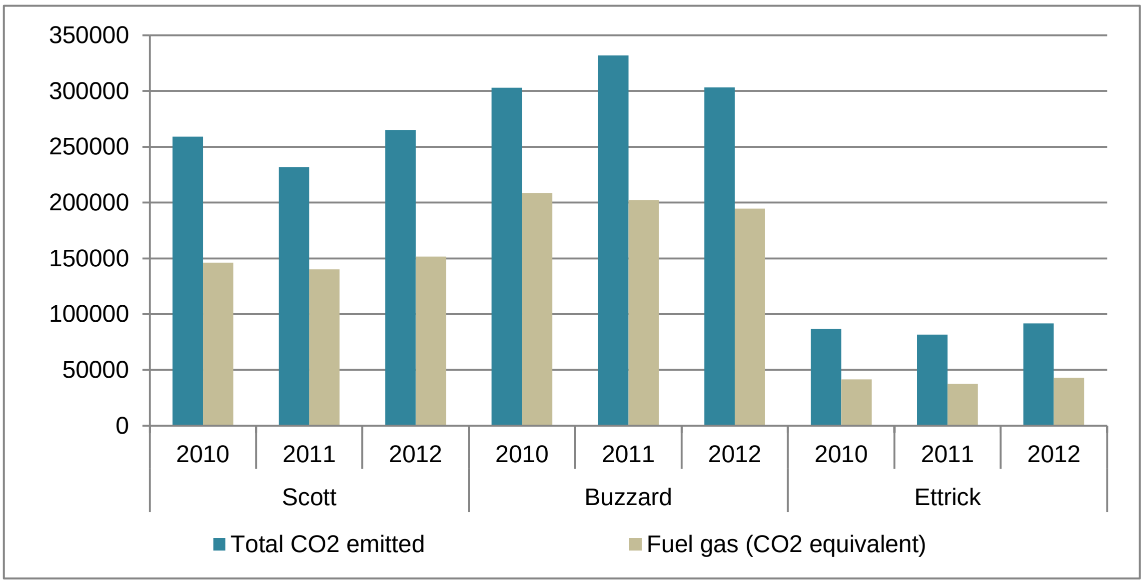


Figure 3.50: Total atmospheric CO2 emissions and emissions due to consumption of fuel gas for energy production (in tonnes CO2 equivalent) for three oil fields (source: NEXEN).

GREENHOUSE GAS SOURCE AND	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
SINK CATEGORIES	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						35.43	9.66
i. Exploration	*Well testing fuel use*	t	11,003.84	3,200.00	25.00	35.21	0.28
ii. Production	*Oil produced (net)*	PJ	1,941.49	110.84	1,320.70	0.22	2.56
iii. Transport	*Offshore loading of oil only*	t	7,704,447.21	NO	60.55	NO	0.47
iv. Refining / Storage	*Oil refinery throughput (net)*	PJ	2,989.07	NO	2,013.11	NO	6.02
v. Distribution of Oil Products	*(e.g. PJ oil refined)*		NA	NO	NO	NO	NO
vi. Other	*Onshore loading of oil*	PJ	2,034.99	NO	166.63	NO	0.34
1. B. 2. b. Natural Gas						248.55	189.47
i. Exploration	*Well testing fuel use*	t	36,670.50	2,800.00	45.00	102.68	1.65
ii. Production / Processing	*Natural gas production (net)*	PJ	1,464.78	95,344.39	2,201.52	139.66	3.22
iii. Transmission	*Final gas consumption*	GWh	553,368.15	0.12	3.47	0.23	6.92
iv. Distribution	*Final gas consumption*	GWh	553,368.15	2,960.79	87,953.71	5.90	175.21
v. Other Leakage	*Total gas use*	TJ	1,597,035.52	0.05	1.54	0.08	2.46
at industrial plants and power stations	*Not applicable*	PJ	NO	NO	NO	NO	NO
in residential and commercial sectors	*Total gas use*	PJ	1,597.04	0.05	1.54	0.08	2.46
1. B. 2. c. Venting						9.13	35.89
i. Oil	*None*		NA	NA	NA	8.54	13.15
ii. Gas	*None*		NA	NA	NA	0.58	22.73
iii. Combined	*None*		IE	IE	IE	IE	IE
Flaring						3,257.35	13.34
i. Oil	*Mass of gas flared*	t	1,155,734.92	2,604.16	10.63	3,009.72	12.28
ii. Gas	*Mass of gas flared*	t	107,241.69	2,309.02	9.86	247.62	1.06
iii. Combined	*Mass of gas flared*	Mg	IE	IE	IE	IE	IE

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category
NO (Not Occurring): For emissions and removals of GHG that do not occur for a particular gas or source/sink category
NA (Not Applicable): For activities in a given source/sink category that do not result in emissions or removals of a specific gas

Table 3.25: UNFCCC Emission data for United Kingdom for oil and natural gas

Producing Oil Fields	Average Flare million m^3 per day	Average Flare million ft^3 per day
CHESTNUT	0.12	4.32
BRENT	0.12	4.15
FOINAVEN	0.09	3.11
NINIAN	0.09	3.03
BRAE SOUTH	0.08	2.97
BUZZARD	0.08	2.72
THISTLE	0.07	2.58
ALBA	0.07	2.42
FORTIES	0.07	2.39
CAPTAIN	0.06	2.18
BLAKE	0.05	1.79
ORION	0.05	1.70
BERYL	0.05	1.62
CLAIR	0.04	1.55
BALLOCH	0.04	1.49
BRUCE	0.04	1.48
AFFLECK	0.04	1.45
STARLING	0.04	1.39
LENNOX	0.04	1.39
MURCHISON	0.04	1.37

Table 3.26: The twenty oil fields with the largest flaring volumes per day in UK for 2013 (source: DECC)

3.6.5 Nigeria

In general, no actual data have been found for Nigeria apart from flaring which is one of the most significant emission sources of the Nigerian oil sector. According to the National Oceanic and Atmospheric Administration (NOAA), Nigeria flared slightly more than 515 Bcf of natural gas in 2011 - or more than 21% of gross natural gas production in 2011. Natural gas flared in Nigeria accounts for approximately 10% of the total amount flared globally. The amount of gas flared in Nigeria has decreased in recent years, from 575 Bcf in 2007 to 515 Bcf in 2011.

According to Shell, one of the largest gas producers in the country, the impediments to decreasing gas flaring has been the security situation in Niger Delta and the lack of partner funding that has slowed progress on projects to capture associated gas. The company recently reported that it was able to reduce the amount of gas it flared in 2012 because of improved security in some Niger Delta areas and stable co-funding from partners that allowed the installation of new gas-gathering facilities and repair of existing facilities damaged during the militant crisis of 2006 to 2009.

Table 3.27 illustrates the 20 Nigerian fields with the largest flaring volumes, according to NNPC. It is obvious that the percentage of gas flared varies significantly per field and company, making it difficult to draw uniform conclusions.

Field	Company	Gas produced (in mscf)	Gas utilized (in mscf)	Gas flared (in mscf)	Percentage of gas flared (in mscf)
UTOROGU/UGHELI	NPDC	27,569,340	0	27,569,340	100%
UTOROGU/UGHELI	ND WESTERN	22,556,733	0	22,556,733	100%
IDU FIELDS	NAOC	36,747,486	25,197,140	11,550,346	31%
OFON	Total E&P	11,499,725,25	369,991	11,129,734	97%
KWALE FIELDS	NAOC	32,221,463	21,351,330	10,870,133	34%
OKONO/OKPOHO	NPDC	11,009,360	563,254	10,446,106	95%
AMENAM/KPONO	Total E&P	108,950,287,53	98,541,400	10,408,888	10%
AKRI FIELDS	NAOC	12,754,634	2,796,994	9,957,640	78%
ERHA	ESSO	112,226,569	102,889,639	9,336,930	8%
OBR/OBI FIELDS	NAOC	183,725,459	175,018,183	8,707,276	5%
USAN	TUPNI	14,874,000	6,539,000	8,335,000	56%
DELTA	Chevron	7,253,193	51,274	7,201,919	99%
MEREN	Chevron	15,115,125	8,093,216	7,021,909	46%
OSHI FIELDS	NAOC	18,830,177	11,903,725	6,926,452	37%
OBEN/SAPELE/AMUKPE	NPDC	6,819,131	0	6,819,131	100%
QIT	Mobil	8,638,294	1,980,359	6,657,935	77%
PARABE/EKO	Chevron	6,978,580	382,997	6,595,583	95%
OSO	Mobil	86,660,679	80,170,335	6,490,344	7%
AGBAMI	STARDEEP	93,068,067	86,700,089	6,367,978	7%
EDOP	Mobil	42,521,467	36,178,579	6,342,888	15%
EBOCHA FIELDS	NAOC	21,531,182	15,433,333	6,097,849	28%

Table 3.27: Twenty Nigerian fields with the largest flaring volumes

3.6.6 Denmark

With regard to the climatic and environmental impact of the Danish oil and gas sector, the Danish Energy Agency (DEA) manages the atmospheric emissions of CO_2 from the combustion and flaring of natural gas and diesel oil, the effects of offshore oil and gas activities, the conditions in established international nature protection areas and the impact of oil and gas projects on the marine environment. Emissions, discharges and any marine spills are managed by the Ministry of the Environment, partly on the basis of regulations issued under the auspices of the international collaboration under the Oslo and Paris Convention (OSPAR). The Danish Subsoil Act regulates the volumes of gas flared, while CO_2 emissions (including flaring) are regulated by the Danish Act on CO_2 Allowances.

The evolution CO_2 emissions from the North Sea production facilities since 2003 are presented in Figure 3.51. It can be shown that CO_2 emissions totaled at about 1.695 million tons in 2012, the lowest level in the past ten years, with both the quantity of fuel and gas flared being reduced. Gas used as a fuel accounted for approximately 90% of total gas consumption offshore in 2012, while the remaining 10% was flared. The development in the use of gas as fuel on Danish production installations is illustrated in Figure 3.53. The general increase until 2007 can be attributed to the rising oil and gas production and ageing fields. The main reason for the sharp drop from 2008 onwards is energy-efficiency measures taken by the operators, as reported by DEA.

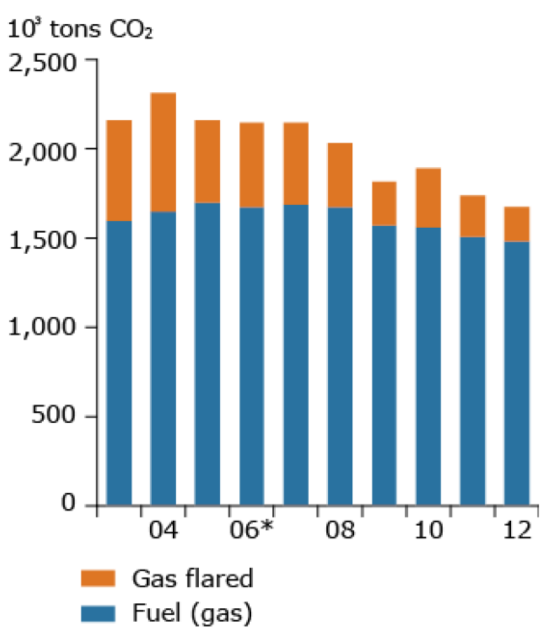


Figure 3.51: CO_2 emissions from production facilities in the North Sea (source: DEA)

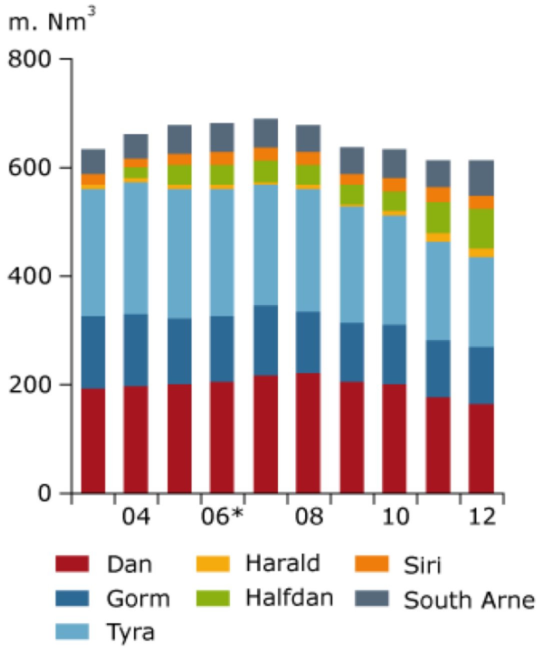


Figure 3.52: Fuel consumption (gas) for upstream activities (source: DEA)

CO_2 emissions due to fuel consumption have increased relative to the size of hydrocarbon production over the past decade, as illustrated in Figure 3.54.The reason for this increase is that oil and gas production has dropped more sharply than fuel consumption; this means that CO_2 emissions due to fuel consumption have increased relatively to the size of production.

The flaring of gas declined substantially from 2006 to 2012 in all fields with the exception of the Harald Field where flaring has remained unchanged. This development is attributable to more stable operating conditions on the installations, changes in operations and focus on energy efficiency. As appears from Figure 3.55, which shows the volumes of gas flared, flaring varies considerably from one year to another. The large fluctuation in 2004 is partially due to the tie-in of new fields and the commissioning of new facilities. In 2012, gas flaring totaled 71 million Nm^3.

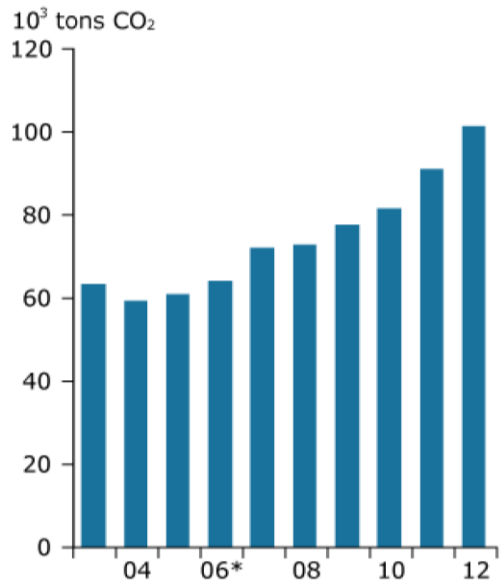


Figure 3.53: CO2 emissions from consumption of fuel per mtoe (source: DEA)

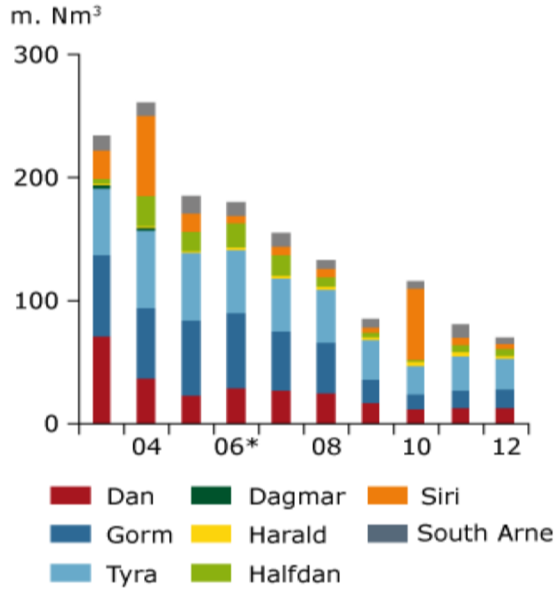


Figure 3.54: Gas flared (source: DEA)

3.6.7 Angola

BP in its 2012 Sustainability Report published actual data regarding the emissions from its activities of oil extraction activities in Angola. These data are illustrated in Table 3.28, where it is observed that the company's total emissions have decreased by approximately 10% in 2012 compared to 2011. Similarly, flared gas quantities have decreased slightly in 2012.

Environment	2006	2007	2008	2009	2010	2011	2012
Total hydrocarbons produced (million barrels oil equivalent per day)	133	140	202	211	170	123	149
Equity share direct carbon CO_2 (tonnes)	484,666	940,541	1,208,764	1,162,490	1,055,204	1,006,583	898,618
Equity share indirect CO_2 (tonnes)	0	0	0	0	0	0	0
Equity share direct methane (CH_4) (tonnes)	1,643	4,160	2,644	2,502	2,444	2,079	3,220
Equity share direct GHG (tonnes CO_2 equivalent)	519,169	1,027,811	1,264,288	1,215,032	1,106,528	1,050,242	966,229
Total gas flared (tonnes)	1,987	148,882	200,221	138,093	227,851	323,693	308,095
Sulphur dioxide (SO_x) (tonnes)	108	232	206	259	98	298	559
Nitrogen oxides (NO_x) (tonnes)	1,587	5,800	2,923	1,849	928.4	1,060	3,828
Non-methane hydrocarbons (NMHC) (tonnes)	260	825	6,210	4,789	6,766	11,391	1,568

Table 3.28: Environmental data by BP's activities in Angola for the years 2006-2012 (source: BP)

3.6.8 Carbon Disclosure Project (CDP) reports

CDP is an international, not-for-profit organization providing a global system for companies and cities to measure, disclose, manage and share vital environmental information. The CDP reported emissions are organized per company into 3 Scopes for the emissions for oil and natural. Scope 1 emissions include the total global direct emissions from sources owned or controlled by the reporting organization and more specifically:

- Stationary combustion: boilers, furnaces, engines, etc;
- Mobile combustion: automobiles, planes, ships, trains, etc;
- Process emissions: cement manufacturing, aluminum smelting, gas and oil production, refining, etc;
- Fugitive emissions: equipment leaks, hydrofluorocarbon emissions from refrigeration, etc

Scope 2 emissions include indirect GHG emissions that the company has caused through its consumption of energy in the form of electricity, heat, cooling or steam.

Scope 3 emissions include indirect emissions that arise as a consequence of an organization's activities from sources that are owned or controlled by others.

It must be noted that the distinction between Scope 1, 2 and 3 emissions does not align with the definition of direct and indirect emissions set in the context of this study. Thus, Scope 1 and 2 emissions of CDP correspond to the direct emissions as those have been defined in this study. Table 3.29 provides the Scope 1 and Scope 2 emissions (sum) for four companies. It can be seen that EXXON and CHEVRON have the largest emissions. It can also be observed that large part of the companies' emissions comes from refining activities. However, the reporting methodology of companies to CDP has not been studied or evaluated.

Company	Segment	2008	2009	2010	2011	2012
CHEVRON	Exploration, production & gas processing	0	0	42,482,952	41,785,072	39,593,574
	Refining	0	0	22,978,452	23,328,912	21,553,218
	Speciality operations	0	0	1,158,459	789,899	1,261,745
	Total	**0**	**0**	**66,619,863**	**65,903,883**	**62,408,537**
EXXON	Exploration, production & gas processing	62,000,000	60,000,000	63,000,000	68,000,000	68,000,000
	Refining	59,000,000	58,000,000	60,000,000	59,000,000	55,000,000
	Total	**121,000,000**	**118,000,000**	**123,000,000**	**127,000,000**	**123,000,000**
REPSOL	Exploration, production & gas processing	0	0	23,566	21,288	27,522
	Storage, transportation & distribution	0	0	46,562	57,168	45,264
	Speciality operations	0	0	1,233,028	404,448	327,788
	Refining	0	0	505,224	558,076	1,115,982
	Retail & marketing	0	0	134,752	91,886	105,930
	Total	**0**	**0**	**1,943,132**	**1,132,866**	**1,622,486**
STATOIL	Exploration, production & gas processing	13,059,999	11,524,551	11,629,031	11,649,562	0
	Storage, transportation & distribution	118,924	106,470	75,661	89,178	0
	Refining	2,101,460	2,346,222	2,877,636	3,094,512	0
	Total	**15,280,383**	**13,977,243**	**14,582,328**	**14,833,252**	**0**

Table 3.29: Scope 1 and Scope 2 reported values for oil and gas emissions for specific companies (source: CDP)

3.6.9 Refining

Actual data for the emissions of the European refining sector[10] for 2012 are illustrated in Figure 3.55 These data are verified emissions of the European Trading Scheme (ETS) and therefore fully reliable. It can be seen that the largest refining emissions take

[10] http://www.eea.europa.eu/data-and-maps/data/data-viewers/emissions-trading-viewer

place in Germany, Poland and Italy. These figures can be used for comparisons with the outputs of PRIMES-Refineries, once these have been produced.

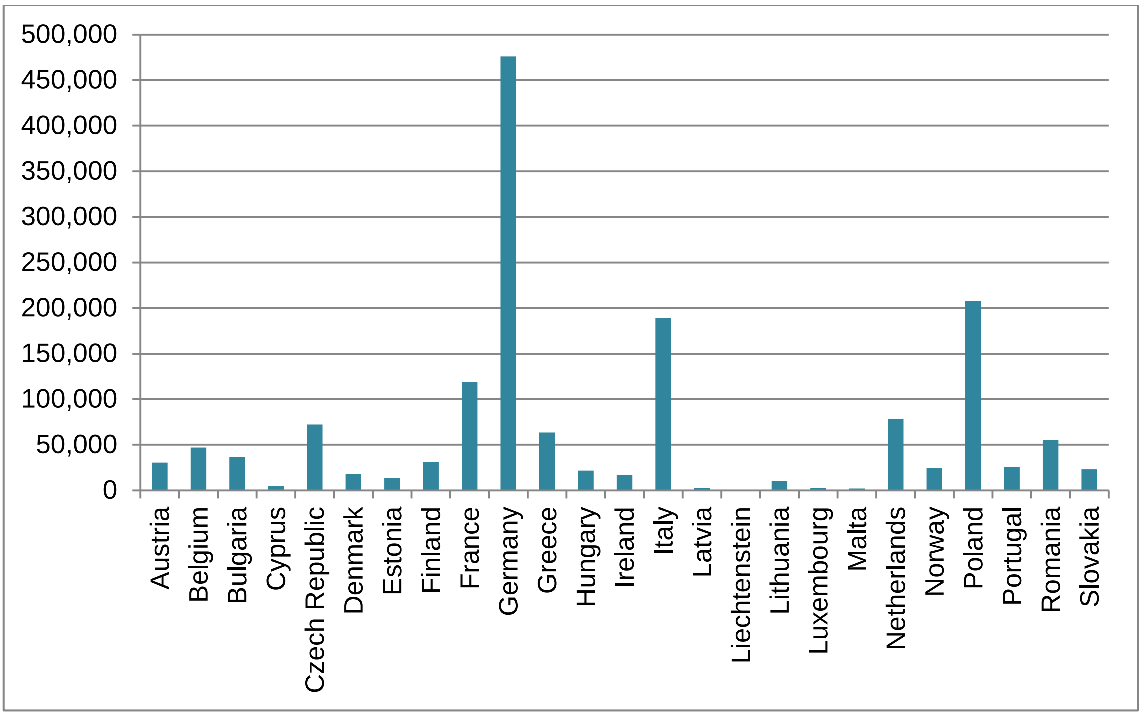


Figure 3.55: Emissions of the refinery sector per country for 2012 in kt CO2 equivalent as verified by the European Trading Scheme – ETS (source: European Environmental Agency)

3.6.10 Overview and evaluation of actual data collection progress for oil

As it has been evident till present, the Consultant has reviewed a large number of resources for the collection of actual emission data. Ideally, information should have been found on an MCON or oil field basis. However, given the reluctance of oil and gas companies to provide actual data, often data have been found **on a country basis** with few exceptions. Unfortunately, cumulative emission data found on a country basis cannot be directly used for the purpose of comparisons without further analysis (apart from cross-country comparisons) but given the scarcity of information, these country level data are extremely valuable. There are also cases where actual emission data are found **per company** as published in sustainability and environmental reports, which usually refer to company's entire activities or the data are poorly broken down. This type of information can be used for comparisons of the carbon intensity of specific lifecycle stages (e.g. production of oil) between companies.

Following the identification of actual data sources, the Consultant has classified the information collected by **lifecycle stage both on a country and MCON level** i.e. production, venting flaring fugitive, transport refining and distribution, as illustrated in Table 3.30. The purpose of this systematization is to identify the MCONs for which no actual data have been found (green colour marking) and inevitably its GHG emissions will have to be assessed using the OPGEE model.

As a general conclusion, significant actual information on **a country level** has been found for Norway, Denmark and United Kingdom for most lifecycle stages. Partial information for flaring has been found for Russia and FSU countries. Lastly few data have been found for Nigeria regarding only flaring emission and Angola.

The collection of **field specific data** has been a more difficult Task, because when oil companies have no legal obligation to report them officially they have no actual incentive. Actual GHG emission data have been found for Norwegian representative fields. For representative fields located in UK i.e. (Buzzard, Captain and Forties) flaring emissions have been found, as well as total emissions for the Buzzard oil field. Surprisingly, significant data have been found for total emissions and flaring for the ACG field in Azerbaijan. Flaring volumes are also available for all Nigerian fields, as well as production and flaring emission for key Danish fields comprising the DUC MCON.

Country	Actual emission data sources												
	Country level data						Representative MCON	MCON (or field) specific data					
	Production	VFF	Transport	Refining	Distribution	Total		Production	VFF	Transport	Refining	Distribution	Total
Iran							Iranian Heavy						
Iraq							Basrah Light						
							Kirkuk						
Kuwait							Kuwait Blend						
Saudi Arabia							Arab Light						
							Arab Heavy						
Algeria							Saharan Blend						
Angola	BP	BP				BP	Dalia						
							Girassol						
							Greater Plutonio						
Libya							Es Sider						
							El Sharara						
Nigeria		NNPC					Bonga		NNPC				
							Forcados		NNPC				
							Bonny light		NNPC				
							Escravos		NNPC				
Azerbaijan		EBRD, BP				BP	Azeri light	BP	BP				BP
							Azeri BTC	BP	BP				BP
Kazakhstan		EBRD, BP				BP	Tengiz	BP	BP				BP
							CPC blend	BP	BP				BP
Russia		EBRD, KPMG, UNFCCC	UNFCCC		UNFCCC		Druzhba						
							Siberia Light						
							Urals						
Denmark	DEA	DEA	UNFCCC	EEA	UNFCCC		DUC	DEA		DEA			MAERSK OIL
Norway	NPD, UNFCCC	NPD, UNFCCC	UNFCCC	EEA, UNFCCC	UNFCCC	NPD	Stratfjord						
							Ekofisk						CDP/STATOIL
							Troll						CDP/STATOIL
							Asgard Blend						CDP/STATOIL
							Oseberg						CDP/STATOIL
							Gullfaks blend						CDP/STATOIL
UK	DEFRA, UNFCCC	DEFRA, UNFCCC	UNFCCC	DEFRA, EEA, DECC, UNFCCC	UNFCCC	DEFRA	Forties	NEXEN	DECC, NEXEN				NEXEN
							Brent Blend		DECC				
							Captain		DECC				
Mexico							Maya						
Venezuela							Boscan						

Table 3.30: Sources of measured and reported emission data organized per process country and MCON

3.7 ACTUAL DATA FOR NATURAL GAS

The sources of actual data for natural gas are largely the same as those of oil. In addition, given the fact that several fields produce both oil and natural gas, GHG emissions provided by several sources are addressed both to oil and natural gas. Thus, any further allocation of emissions to either oil or gas requires the development of appropriate methodology. The main sources of actual data for natural gas are summarized in Table 3.31 and analysed accordingly in the following sections.

Significant sources of actual data have been identified in the UNFCCC Annex I country reports for Russia, Norway, Germany, Netherlands and United Kingdom. A significant source of actual measurements of the Russian pipeline system and relevant emission assessments comes from the work carried out by the Wuppertal Institute. Additionally in United Kingdom, DEFRA published detailed data for major natural gas activities at a country level. Furthermore, field specific data have been found for certain Norwegian gas fields. Lastly, partial actual emission data for Qatar natural gas derive from the involved gas companies' reports. The actual data that have been collected are presented in the Sections below.

Country/ Region	Source	Actual data type	Coverage
EU wide or various countries			
Russia, Norway, UK, Netherlands	UNFCCC Annex I country reports for 2012	Emissions and co-efficient factors for the following activities regarding natural gas: ▪ Exploration ▪ Production/processing ▪ Flaring and venting ▪ Transport ▪ Distribution ▪ Other leakages	Country data
Worldwide	National Oceanic and Atmospheric Administration (NOAA)	▪ Flaring volumes for oil and natural gas fields	Country level and field level
National reporting			
Russia	Wuppertal's study on GHG Emissions from the Russian Natural Gas Export Pipeline System	▪ CO_2 emissions ▪ CH_4 emissions ▪ NOX emissions	Data regard the entire Russian pipeline system
UK	National Atmospheric Emission	CO_2 emissions for the following natural gas activities: ▪ Upstream gas activities	Country data

Country/ Region	Source	Actual data type	Coverage
	Inventory	▪ Gas leakage at natural gas supply ▪ Gas leakage at transmission ▪ Gas leakage at point of use ▪ Venting ▪ Flaring	
Norway	Norwegian Environment Agency	Data regarding all Norwegian oil and gas fields and facilities: ▪ Energy use ▪ Production volumes ▪ Emissions	Oil and gas field specific data
Nigeria	Nigerian National Petroleum Corporation Annual Report 2013 (NNPC)	▪ Flaring quantities for a large number of oil and gas fields	Field specific data
		Company reporting	
Carbon Disclosure Project	Carbon Disclosure Project (CDP)	▪ Exploration, production & gas ▪ processing ▪ Storage, transportation & ▪ distribution ▪ Speciality operations ▪ Refining	Data provided per company
BP	BP Sustainability report 2012 Azerbaijan	▪ Total emissions ▪ Flaring emissions ▪ Flaring volumes ▪ Production emissions	Country specific data as well field specific data particularly for Shaz Deniz field
RasGas	Company Sustainability Report for 2013	▪ Direct CO2 emissions ▪ Indirect CO2 emissions ▪ Flaring emissions ▪ Venting emissions	Data regarding the entire company
QatarGas	Company report	▪ Flaring emissions ▪ GHG intensity	Data regarding the entire company for the 1st semester of 2014

3.7.1 Table 3.31: Overview of natural gas actual data sourcesRussia

Apart from the UNFCCC data for the Russian natural sector emissions, very significant actual data result from the Wuppertal's institute study for GHG emissions from the Russian Natural Gas Export Pipeline System that has been based on actual measurements.

Table 3.32 shows the GHG emissions of Russian natural gas transport pipelines exporting to Europe in 2003 by gas and source. It shows that almost 70 % of GHG emissions from gas transportation are CO_2, primarily the exhaust from the gas turbines used to drive the compressors, and the CO_2 from Russian power generation which is supplied to the electric motors used by the gas transportation pipelines. CO_2 emissions from ignited gas from breakdowns by contrast are of almost no relevance. The same is also valid for N_2O emissions which comes from the turbine exhausts or the power supply, and accounts for some 1 % of greenhouse gas emissions along the export corridors.

According to the study, the total CH4 losses accounted for slightly below 31% of GHG emissions. Two thirds of this were emitted from leaks on fittings of the machines, compressor stations and valve nodes on the pipelines. Another significant proportion is due to the venting (i.e. the discharging of gas to atmosphere) of shop and pipelines for maintenance and repair purposes; taking the worst-case assumptions that were made, venting accounts for a good 5 % of GHG emissions along the export corridors.

GHG Emissions by plant section/mode	Million t CO2 equivalent	Share
CO_2		
Turbine exhaust	37.27	63.0%
Power supply (for electric drives)	3.03	5.1%
Breakdowns (ignited)	0.03	0.1%
Total CO_2	**40.33**	**68.2%**
N_2O (turbines and power generation)	**0.58**	**1.0%**
CH_4		
Leaks from fittings and vents	**12.42**	**21.0%**
Leaks from compressors	11.07	18.7%
Other leaks from compressor stations	0.04	0.1%
Leaks from pipelines	1.31	2.2%
operational (measured)	1.32	2.2%
Fuel gas, startup gas and pulse gas supply	0.57	0.9%
Seal oil systems (shaft seals)	0.75	1.3%
operational (calculated)	**3.48**	**5.9%**
Compressor startup/shutdown	0.37	0.6%
Methane in turbine waste gas	0.09	0.2%
Maintenance/repairs to stations (incl. the (incl. the venting of fittings and pipeline pigging)	1.05	1.8%
Maintenance/repairs to pipelines	1.97	3.3%
CH_4 from breakdowns	0.15	0.3%
CH_4 from underground storage (pro rata)	0.36	0.6%
CH_4 from power supply	0.48	0.8%
Total CH_4	**18.21**	**30.8%**
Total of greenhouse gas emissions overall	59.12	100.0%

Table 3.32: GHG actual emissions from the Russian export pipelines to Europe (in million tonnes of CO2 equivalent) (source: Wuppertal Institute)

3.7.2 The Netherlands

Given the scarcity of actual data for natural gas compared to oil, the UNFCCC Annex I country reports for 2012 are a significant source of actual emissions. The relevant Tables have been presented both for oil and natural gas in Section 3.6.1, 3.6.3, 3.6.4, for Russia, UK and Norway including emissions and co-efficient factors for exploration, production/processing, distribution, leakages flaring and venting. UNFCCC actual emission data for the Netherlands - which is mainly a gas producing country - are presented in Table 3.33.

GREENHOUSE GAS SOURCE AND	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
SINK CATEGORIES	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						728.47	0.89
i. Exploration	*number of wells drilled/tested*		IE	IE	IE	IE	IE
ii. Production	*Refery input: crude oil, NGL*	PJ	NA	IE	IE	IE	IE
iii. Transport	*oil transported by pipeline*	Gg	43.82	0.53	5.85	0.02	0.26
iv. Refining / Storage	*Refery input: crude oil, NGL*	PJ	2,329.47	312,708.25	272.96	728.44	0.64
v. Distribution of Oil Products	*(e.g. PJ oil refined)*		NE	NE	NE	NE	NE
vi. Other	*(specify)*		NE	NE	NE	NE	NE
1. B. 2. b. Natural Gas						0.58	19.27
i. Exploration	*number of wells drilled/tested*	number	NA	IE	IE	IE	IE
ii. Production / Processing	*gas produced*	PJ	2,409.00	IE	IE	IE	IE
iii. Transmission	*gas transported*	PJ	3,250.52	58.58	2,062.75	0.19	6.71
iv. Distribution	*natural gas distribution network*	10^3 km	124.47	3,105.78	100,952.8	0.39	12.57
v. Other Leakage			IE	NE	IE	NE	IE
at industrial plants and power stations			IE	NE	IE	NE	IE
in residential and commercial sectors			IE	NE	IE	NE	IE
1. B. 2. c. Venting						2.46	14.55
i. Oil	*oil produced*	10^6 m^3	1.27	IE	IE	IE	IE
ii. Gas	*gas produced*	PJ	2,419.00	IE	IE	IE	IE
iii. Combined		PJ	IE	IE	IE	2.46	14.55
Flaring						59.14	0.31
i. Oil	*oil produced*	10^6 m^3	1.27	IE	IE	IE	IE

GREENHOUSE GAS SOURCE AND	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
SINK CATEGORIES	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
ii. Gas	*gas produced*	PJ	2,419.00	IE	IE	IE	IE
iii. Combined	*(specify)*		IE	IE	IE	59.14	0.31
NE (Not Estimated): For existing emissions and removals which have not been estimated *IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category* *NA (Not Applicable): For activities in a given source/sink category that do not result in emissions or removals of a specific gas*							

Table 3.33: UNFCCC country data for the Netherlands (source: UNFCCC)

3.7.3 Germany

Likewise, Table 3.34 illustrates the UNFCCC data from natural activities for Germany which is also an important gas producing country.

GREENHOUSE GAS SOURCE AND	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
SINK CATEGORIES	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						57.75	14.22
i. Exploration	*number of wells drilled*	number	26.00	0.48	64.00	0.00	0.00
ii. Production	*oil produced*	Gg	2,622.82	0.31	0.01	0.82	0.02
iii. Transport	*oil transported in pipelines*	Mt	102.92	NA	0.06	NA	5.66
iv. Refining / Storage	*oil refined*	Mt	95.84	0.59	0.09	56.93	8.54
v. Distribution of Oil Products	*distribution of oil products*	kt	79,533.00	NO	NA	NO	NA
1. B. 2. b. Natural Gas						990.01	255.64
i. Exploration	*numbers of wells drilled*	number	IE	IE	IE	IE	IE
ii. Production / Processing	*production and processing*	TJ	341,510.00	2,898.92	5.53	990.01	1.89
iii. Transmission	*high pressure pipelines*	km	64,023.00	NO	249.11	NO	15.95
iv. Distribution	*distribution net*	km	439,466.00	NO	423.22	NO	185.99
v. Other Leakage	*gas consumed*	TJ	1,301,080.0	NO	39.82	NO	51.81
at industrial plants and power stations	*gas consumed*	TJ	IE	NO	IE	NO	10.14
in residential and commercial sectors	*gas consumed*	TJ	1,301,080.00	NO	32.03	NO	41.67
1. B. 2. c. Venting						IE	IE

i. Oil		m^3	IE	IE	IE	IE	IE
ii. Gas	*vented natural gas*	m^3	IE	IE	IE	IE	IE
iii. Combined		m^3	IE	IE	IE	IE	IE
Flaring						406.64	6.41
i. Oil		Gg	IE	IE	IE	385.94	0.13
ii. Gas	*flared natural gas*	m^3	11,648,066	1,777.00	539.84	20.70	6.29
iii. Combined		m^3	IE	IE	IE	IE	IE
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category *NO (Not Occurring): For emissions and removals of GHG that do not occur for a particular gas or source/sink category* *NA (Not Applicable): For activities in a given source/sink category that do not result in emissions or removals of a specific gas*							

Table 3.34: Breakdown of emissions of the UK gas sector by source in million metric tonnes (source: DEFRA)

3.7.4 Norway

Table 3.35 illustrates the releases of major pollutants to the air (CO_2, CH_4 and NO_X) for two major natural gas fields Snøhvit and Troll. It is evident that CO_2 emissions for Snøhvit have significantly decreased over the last decade, while for Troll field CO_2 emissions have dropped down by 35% from 2009 to 2013.

Year	Snøhvit: Releases of major pollutants to the air (in 1000 tonnes per year)			Year	Troll : Releases major pollutants the air (CO_2) (in 1000 tonnes per year)		
	CO_2	CH_4	NO_x		CO_2	CH_4	NO_x
2004	1.60	0.00	35.08	2004	-	-	-
2005	29.64	0.00	447.82	2005	-	-	-
2006	51.75	3.25	449.26	2006	-	-	-
2007	-	-	-	2007	-	-	-
2008	-	-	-	2008	-	-	-
2009	-	-	-	2009	689.35	1,594.24	4,498.87
2010	-	-	-	2010	705.61	1,446.13	4,396.74
2011	2.11	0.00	46.61	2011	713.37	1,441.18	5,438.67
2012	-	-	-	2012	685.46	1,435.92	4,631.69
2013	0.24	0.00	5.27	2013	443.50	1,560.64	3,852.90

Table 3.35: Releases of major pollutants for Snøhvit and Troll oil fields (source: Norwegian Environment Directorate)

The emissions from two other significant Norwegian gas fields, Kvitebjørn and Åsgard, are illustrated in Table 3.36. The cumulative emissions from Kvitebjørn have increased over the last years as a result of increased gas production, even though it has to be stated that emissions per unit of gas produced have decreased from 25 tonnes CO_2

equivalent per million cubic meter in 2008 to approximately 11 tonnes CO_2 equivalent per million cubic meter in 2013. On the other hand, the emissions from Åsgard gas field have slightly decreased over time, but have increased per unit of output. In general emissions per unit of output for Åsgard are much higher compared to Kvitebjørn.

Year	Kvitebjørn			Åsgard		
	Emissions in CO_2-equivalents (in tonnes per year)	Production volume of gas (in m³ per year)	Emissions per unit of gas produced (tonnes/million m^3 per year)	Emissions in CO_2-equivalents (in tonnes per year)	Production volume of gas (in m³ per year)	Emissions per unit of gas produced (tonnes/million m^3 per year)
2008	77,176	3,139.538	24.58	1,008,090	21,694.066	46.47
2009	80,112	5,310.39	15.09	1,041,109	21,413.73	48.62
2010	77,324	6,331.126	12.21	1,011,688	20,189.455	50.11
2011	65,975	6,745.399	9.78	1,011,383	18,090.706	55.91
2012	65,961	7,232.191	9.12	1,058,664	18,453.788	57.37
2013	81,029	7126.765	11.37	933,613	15,829.225	58.98

Table 3.36: Carbon emissions for Kvitebjørn and Åsgard oil fields (source: Norwegian Environment Directorate)

3.7.5 United Kingdom

Actual emissions data for the natural gas sector in United Kingdom are illustrated in Figure 3.56. It can be obtained that total atmospheric emissions of the UK gas sector are higher compared to the oil sector. More specifically, the sum of emissions of the gas sector have decreased with a slow pace from approximately 5,400 kilotonnes CO_2 to 5,000 kilotonnes in 2012. The highest emissions are due to gas leakages at gas supply points which in 2012 comprised 74% of the total gas emissions. The second highest source is venting which in 2012 accounted for 10% of total emissions of the sector.

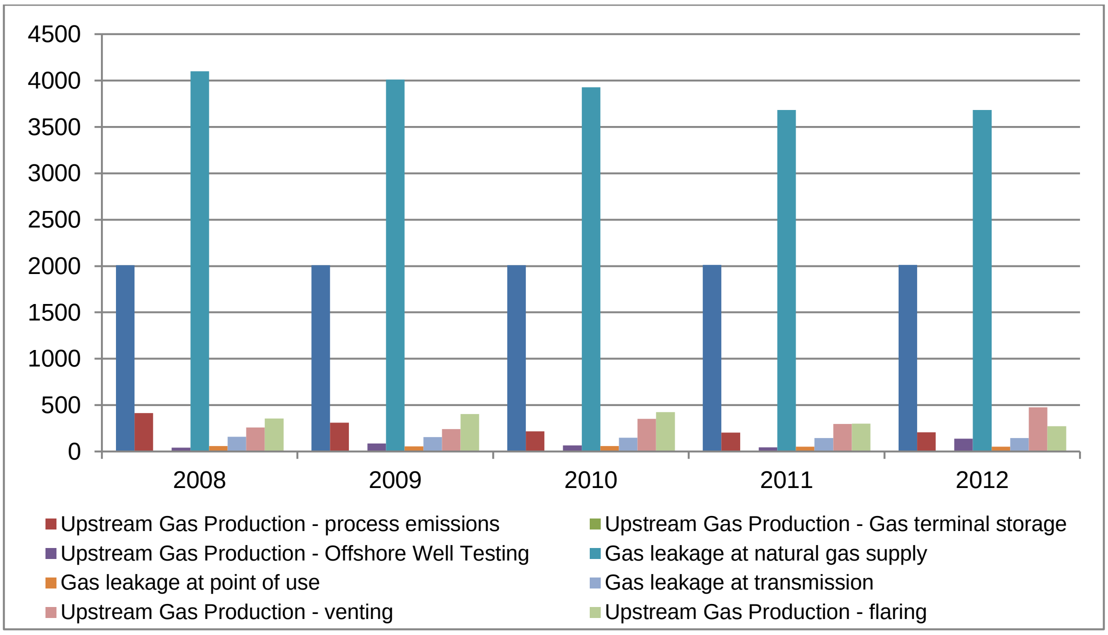


Figure 3.56: Breakdown of emissions of the UK gas sector by source in kilotonnes CO_2 (source: DEFRA)

3.7.6 Qatar

Qatar is another significant gas producing country. No actual official statistics have been identified from national authorities. However, actual emissions data have been found by Qatargas and RasGas companies. Data for RasGas are summarized in Table 3.37 from where it is clear that GHG emissions in the period 2007-2013 have almost doubled. However, it has to be noted that flaring emissions have decreased from 1.4 to 1.1 million tonnes of CO_2

RasGas emissions 2007-2013							
GHF emissions (million tonnes)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Total GHG emissions of CO_2 equivalent	9.4	9.3	8.9	16.8	18.8	18.7	17.9
Total direct GHG emissions	9	9.2	8.6	15.9	18.4	18.3	17.7
from purchased electricity	0.3	0.1	0.3	0.4	0.4	0.4	0.2
CO_2 from flaring	1.4	1.5	1.1	1.4	1.7	1.4	1.1
CO_2 removal from feed and vented	0.7	0.8	0.8	2.1	2.4	2.5	2.5
CO_2 from combustion	6.6	6.6	6.4	12.4	13.8	13.9	13.6
Total CO_2	8.7	8.8	8.3	15.9	17.9	17.8	17.2
Methane (CH_4)	0.01	0.01	0.008	0.01	0.01	0.0009	0.0008
Nitrous oxide (N_2O) (tonnes)	435	449	432	860	945	931	898
Tonnes GHG per tonne hydrocarbon	0.286	0.269	0.248	0.28	0.287	0.281	0.271

Table 3.37: RasGas company cumulative emissions 2007-2013

Figure 3.57 and Figure 3.58 present Qatargas's flaring emissions and GHG intensity respectively until May 2014 for the industry average, the company's target and the company's emissions. For flaring it can be seen that company emissions are below industry average and well below company targets. Similarly, the company exhibits satisfactory performance for GHG intensity which lies also below industry average and company targets.

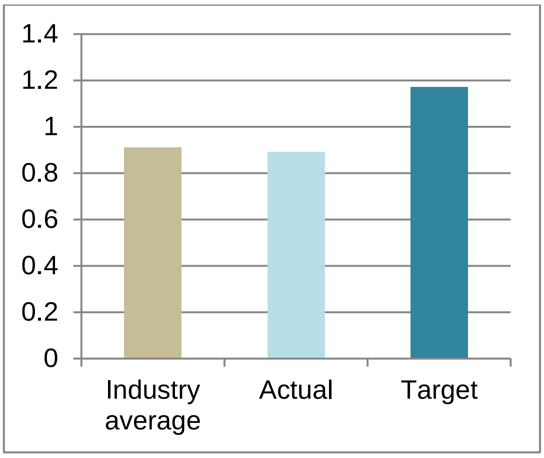


Figure 3.57: Flaring (% of sweet gas) for Qatargas for the 1st half of 2014

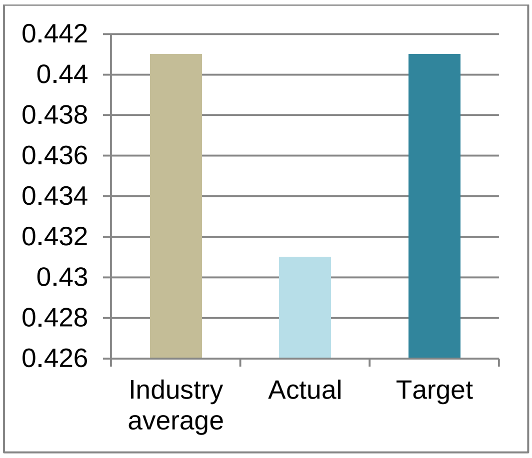


Figure 3.58: GHG intensity (tonne CO2 eq. GHG/ tonne LNG) for Qatargas for the first half of 2014

3.8 Data for Models

3.8.1 Data for OPGEE

According to the data collection strategy, in the absence of direct GHG emissions the Consultant will use the OPGEE model for the assessment of GHG emissions for the upstream and midstream life cycle stages. OPGEE is a complex engineering model that requires a large amount of data as inputs. The collection of such data has been a rather time consuming Task since it requires research in a large amount of sources, as well as validation of their reliability. The effort and the resources that have been committed by the Consultant for the collection of OPGEE inputs have been based on the parametric analysis which is described in Section 4.1.3. For the missing inputs smart default values or Consultant's estimations have been used based on country averages and expert opinion.

The most significant source of information for filling in OPGEE inputs has been the **companies' websites.** Usually these included detailed data regarding partners and their share on specific oil fields, crude oil assays, API, sulphur content, field depth, commingling fields comprising an MCON, the terminal that oil is loaded etc. Furthermore, it can be assumed that these data are up-to-date and fully reliable. In addition, crude oil assays for MCONs are found published on company websites.

Another significant and fully reliable source of information has been **public databases of national authorities** and more specifically DECC for UK, DEA for Denmark, NPD for Norway and NNPC for Nigeria. These include information regarding oil production volumes, gas production volumes, water production for all major fields in the relevant countries, field depth, gas injected water and other critical parameters for an oil field.

The **California Air Resources Board (CARB)** has published in its website the bulk assessment sheet of OPGEE for the crudes imported in California, which does not only provide technical information for a number of fields, but also methodologies for estimating inputs for OPGEE when no values are available. Apparently this approach is available for MCONs, which are imported in California; however several of these MCONs are also imported in Europe. Similarly, reservoir parameters for significant crude oils can be found in other studies (e.g. Jacobs).

The **NOAA/GGFR database** has been a typical source of flared natural gas volume (in bcm) used in several studies. Using the EIA crude oil production volumes the flaring to oil ratio (FOR) has been calculated on a country basis, which provides a sufficient approximation of the FOR compared to the generic values, when there are no field specific data. Actual flaring to oil ratio has been available only for Nigerian Oil fields, provided by NNPC. Another source of flaring and venting emissions has been the submitted **UNFCCC reports** of countries of Annex I (UK, Russia, Germany, Netherlands and Norway). The UNFCCC data include also reported data for exploration, production, transport, refining/storage and distribution of oil products on a country basis.

Private websites[11] dealing with offshore oil and gas engineering, construction projects and procurement have also been useful for data collection. These websites included detailed data for several oil fields as well as a better understanding of oil extraction and production techniques used specifically for each field.

Table 3.38 summarizes the main sources of OPGGE input parameters and the ease of finding the specific type of information. The last column of the Table indicates whether the Consultant has used own estimations based on background data in order to better approach the input, compared to OPGEE's default values.

[11] Offshore technology and Subsea IQ

OPGEE input	Ease of finding information	Operator's Website	OGJ	NOAA	UNFCCC	Offshore tech.	Subsea IQ	DECC	NPD	NNPC	DEA	CARB	Own estimation
1. Production methods													
1.1 Downhole pump													√
1.2 Water reinjection								√			√		√
1.3 Gas reinjection										√			√
1.4 Water flooding													√
1.5 Gas lifting													√
1.6 Gas flooding													√
1.7 Steam flooding													√
2. Field properties													
2.1 Field location (Country)		√	√			√	√	√	√	√	√	√	
2.2 Field name		√	√			√	√	√	√	√	√	√	
2.3 Field age		√	√			√	√	√	√	√	√	√	
2.4 Field depth						√	√				√	√	
2.5 Oil production volume		√	√			√	√	√	√	√	√	√	
2.6 Number of producing wells						√	√				√	√	
2.7 Number of water injecting wells											√	√	
2.8 Well diameter													
2.9 Productivity index													
2.10 Reservoir pressure												√	
3. Properties													
3.1 API gravity		√				√	√			√			
3.2 Gas composition													
4. Production practices													
4.1 Gas-to-oil ratio (GOR)								√	√	√	√	√	√
4.2 Water-to-oil ratio (WOR)								√		√	√	√	

OPGEE input	Ease of finding information	Operator's Website	OGJ	NOAA	UNFCCC	Offshore tech.	Subsea IQ	DECC	NPD	NNPC	DEA	CARB	Own estimation
4.3 Water injection ratio											√		
4.4 Gas lifting injection ratio													
4.5 Gas flooding injection ratio													
4.6 Steam-to-oil ratio (SOR)													
4.7 Fraction of required electricity generated onsite													
4.8 Fraction of remaining gas re-injected													
4.9 Fraction of water produced water re-injected													
4.10 Fraction of steam generation via cogeneration													
5. Processing practices													
5.1 Heater/treater											√		
5.2 Stabilizer column													
5.3 Application of AGR unit													
5.4 Application of gas dehydration unit													
5.5 Application of demethanizer unit													
5.6 Flaring-to-oil ratio				√	√					√	√		√
5.7 Venting-to-oil ratio					√								
5.8 Volume fraction of diluent													

Table 3.38: Overview of literature sources for OPGEE inputs

3.8.2 Data for PRIMES-Refinery

The key input data that are required for the PRIMES-Refinery model are the capacities of the refining processes within the refinery configuration per EU country and the various amounts of MCONs that enter European refineries. The Oil and Gas Journal Worldwide Refining Survey presents analytical data for the worldwide refineries and their capacities. A list of the refineries located in the EU countries is presented in Table 3.39. In particular, the survey provides information on the number of active refinery industries in Europe, the main operations as well as charge and production capacity for every single refinery. The various MCONs are aggregated and characterised by their API gravity and sulphur content. This part is particularly important for allocating the different MCONs entering the refinery gates of each EU country with the representative crude type categories simulated in the PRIMES-Refinery model.

Feedstock supply for the refineries operations, as well as consumption of electricity and gas are derived from the EUROSTAT energy balances. The total refined petroleum products that are produced at a national level over the EU countries is also provided by the EUROSTAT balances. The quantities of refined petroleum products imported in the EU are provided in the Section 3.1.2. The survey of Oil and Gas Journal and the study of Jacobs Consultancy will be used for the identification of the representative configuration of the refineries exporting refined products to EU. A more detailed presentation of the key input data to the PRIMES-Refinery model is included in Section 3.8.2.

Country	Number of refineries	Company	Location
Austria	1	OMV AG	Schwechat
Belgium	4	AB Nynas Petroleum NV	Antwerp
		ExxonMobil Refining & Supply Co.	Antwerp
		Vitol Group	Antwerp
		Total SA	Antwerp
Bulgaria	1	Neftochim	Bourgas
Croatia	3	Ina-Industrija Nafte d.d.	Rijeka
		Ina-Industrija Nafte d.d.	Sisak
		Ina-Industrija Nafte d.d.	Zagreb
Czech Republic	3	Czech Refining Co.	Kralupy
		Czech Refining Co.	Litvinov
		Paramo AS	Pardubice
Denmark	2	AS Dansk Shell	Fredericia
		Dansk Statoil AS	Kalundborg
Finland	2	Neste Oil	Naantali
		Neste Oil	Porvoo

Country	Number of refineries	Company	Location
France	10	Calos	Dunkirk
		ExxonMobil Refining & Supply Co.	Fos sur Mer
		ExxonMobil Refining & Supply Co.	Port Jerome/NDG
		Petrolneos Refining Ltd.	Lavera
		LyondellBasell Industries	Berre l'Etang
		Total SA	Donges
		Total SA	Feyzin
		Total SA	Gonfreville l'Orcher
		Total SA	Grandpuits
		Total SA	La Mede
Germany	15	Bayernoil Raffineriegesellschaft GMBH	Vohburg/Ingolstadt/Neustadt
		BP PLC	Gelsenkirchen
		Hestya Energy BV	Wilhelmshaven
		Deutsche BP AG Erdol Raffinerie GMBH	Lingen
		Deutsche Shell AG	Rheinland
		Deutsche Shell AG	Harburg
		H&R Chemisch-Pharmazeutische Spezialitaeten GMBH	Salzbergen
		H&R Oelwerke Schindler GMBH	Hamburg
		Holborn Europa Raffinerie GMBH	Harburg
		Klesch & Co.	Heide
		Mineraloelraffinerie Oberrhein GMBH	Karlsruhe
		OMV AG	Burghausen
		PCK Raffinerie GMBH	Schwedt
		Gunvor Group Ltd.	Ingolstadt
		Total SA	Leuna, Spergau
Greece	4	Hellenic Petroleum SA	Aspropyrgos
		Hellenic Petroleum SA	Elefsis
		Hellenic Petroleum SA	Thessaloniki
		Motor Oil (Hellas) Corinth Refineries SA	Aghii Theodori
Hungary	1	MOL Hungarian Oil & Gas Co.	Szazhalombatta
Ireland	1	Phillips 66	Whitegate
Italy	15	Eni SPA	Gela, Ragusa
		Enii SPA	Livorno
		Enii SPA	Sannazzaro, Pavia
		Eni SPA	Taranto

Country	Number of refineries	Company	Location
		Api Raffineria di Ancona SPA	Falconara, Marittima
		Arcola Petrolifera SPA	La Spezia
		ERG Reffinerie Medditerranee North	Priolo, Sicily
		ERG Reffinerie Medditerranee South	Melilli, Sicily
		ExxonMobil Refining & Supply Co.	Augusta, Siracusa
		ExxonMobil Refining & Supply Co.	S. Martino Di Trecate
		Iplom SPA	Busalla
		Italiana Energia E Servizi SPA	Mantova
		Raffineria di Milazzo SPA	Milazzo, Messina
		Raffineria di Roma SPA	Rome
		Saras SPA	Sarroch
Lithuania	1	AB Mazeikiu Nafta	Mazeikiai
Netherlands	6	BP PLC	Rotterdam
		ExxonMobil Refining & Supply Co.	Rotterdam
		Kuwait Petroleum Europoort BV	Rotterdam
		Shell Nederland Raffinaderij BV	Pernis
		Smid & Hollander Raffinaderij BV	Amsterdam
		Total SA	Vlissingen
Poland	4	Grupa Lotos SA	Gdansk
		Nafta Polska SA	Gorlice
		Nafta Polska SA	Jaslo
		PKN Orlen SA	Plock/Trezebina
Portugal	2	Galp Energia	Leca da Palmeira, Porto
		Galp Energia	Sines
Romania	9	Astra SA	Ploiesti
		Petrobrazi SA	Ploiesti
		Petrolsub SA	Bacau
		Petromidia SA	Midia
		Petrotel SA	Ploiesti
		Rafinaria Darmanesti SA	Darmanesti
		Rafo SA	Onesti, Bacau
		Rompetrol SA Vega Refinery	Ploiesti
		Steaua Romania SA	Cimpina
Slovakia	1	Slovnaft Joint Stock Co.	Bratislava
Slovenia	1	Nafte Lendava	Lendava
Spain	9	BP PLC	Castellon de la Plana
		Cia. Espanola de Petroles SA	Cadiz

Country	Number of refineries	Company	Location
		Cia. Espanola de Petroles SA	Huelva
		Cia. Espanola de Petroles SA	Tenerife
		Petronor SA	Muskiz Vizcaya
		Repsol YPF SA	Cartagena Murcia
		Repsol YPF SA	La Coruna
		Repsol YPF SA	Puertollano, Ciudad Real
		Repsol YPF SA	Tarragona
Sweden	5	AB Nynas Petroleum	Gothenburg
		AB Nynas Petroleum	Nynashamn
		Preem Raffinaderi AB	Brofjorden-Lysekil
		Preem Raffinaderi AB	Gothenburg
		Shell Raffinaderi AB	Gothenburg
United Kingdom	9	AB Nynas Petroleum	Eastham
		Phillips 66	South Killingholme
		Essar UK Ltd.	Stanlow
		ExxonMobil Refining & Supply Co.	Fawley
		Total SA	Killingholme South Humberside
		AB Nynas Petroleum	Dundee
		Petrolneos Refining Ltd.	Grangemouth
		Murco Petroleum Ltd.	Milford Haven
		Valero Energy Corp.	Pembroke, Dyfed

Table 3.39: List of refineries located in the EU countries (Source: Oil and Gas Journal, 2013)

3.8.3 Data for GHGenius

In the following Sections the most significant sources of data to be used as input to the GHGenius model are presented.

Regional Natural Gas Supply/Demand

Natural gas supply and demand data for each EU country have been extracted and elaborated from IEA database for the year 2012. The model input will be the quantities of gas supplied by each producer. The data are shown in Table 3.40.

Consuming countries - EU28	Producing countries																
	Germany	Denmark	Netherlands	Poland	Hungary	Norway	Norway LNG	UK	Italy	Romania	Russia	Algeria pipeline	Algeria LNG	Libya	Nigeria LNG	Qatar LNG	Other	TOTAL
Bulgaria	0	0	0	0	0	0	0	0	0	0	2485	0	0	0	0	0	0	**2485**
Greece	0	0	0	0	0	0	0	0	0	0	2453	0	734	0	0	0	0	**3187**
Croatia	60	0	0	0	0	0	0	0	667	0	0	0	0	0	0	0	0	**727**
Italy	2904	0	2466	0	0	2726	0	0	7.877	0	18071	20843	1110	6469	0	5925	3850	**72241**
Romania	0	0	0	0	0	0	0	0	0	10935	2469	0	0	0	0	0	0	**13404**
Slovenia	0	0	0	0	0	0	0	0	61	0	365	139	139	0	0	0	0	**704**
Belgium	0	0	6780	0	0	7009	0	1690	0	0	0	0	0	0	0	2158	2158	**19795**
Czech Republic	0	0	0	0	0	3	0	0	0	0	7468	0	0	0	0	0	0	**7471**
Germany	5239	0	25952	0	0	24482	0	0	0	0	32632	0	0	0	0	0	5335	**93640**
Estonia	0	0	0	0	0	0	0	0	0	0	670	0	0	0	0	0	0	**670**
Latvia	0	0	0	0	0	0	0	0	0	0	1716	0	0	0	0	0	0	**1716**
Lithuania	0	0	0	0	0	0	0	0	0	0	3320	0	0	0	0	0	0	**3320**
Luxembourg	0	0	14	0	0	627	0	0	0	0	290	0	0	0	0	0	129	**1060**
Hungary	0	0	0	0	1.456	0	0	0	0	0	3576	0	0	0	0	0	4597	**9629**
Netherlands	586	1309	30.223	0	0	15868	761	4380	0	0	2931	0	0	0	0	0	0	**56058**
Austria	0	0	0	0	0	1981	0	0	0	0	8950	0	0	0	0	0	3239	**14170**
Poland	1888	0	0	6193	0	0	0	0	0	0	9769	0	0	0	0	0	0	**17850**
Slovakia	0	0	0	0	0	0	0	0	0	0	4801	0	0	0	0	0	0	**4801**
Denmark	0	3.345	0	0	0	622	0	0	0	0	0	0	0	0	0	0	0	**3967**
Ireland	0	0	0	0	0	0	0	4522	0	0	0	0	0	0	0	0	0	**4522**
Finland	0	0	0	0	0	0	0	0	0	0	3683	0	0	0	0	0	0	**3683**
Sweden	0	1130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1130**
United Kingdom	0	0	9566	0	0	26812	0	30222	0	0	0	0	0	0	0	13091	0	**79691**
Spain	0	0	0	0	0	2348	1684	0	0	0	0	10835	4014	0	5422	4675	0	**28978**
France	2156	0	9664	0	0	18380	158	0	0	0	6441	0	4160	0	3715	1886	0	**46560**
Portugal	0	0	0	0	0	0	0	0	0	0	0	2090	0	0	1853	164	0	**4107**
TOTAL	**12833**	**5784**	**84665**	**6193**	**1456**	**100858**	**2603**	**40814**	**8605**	**10935**	**112090**	**33907**	**10157**	**6469**	**10990**	**27899**	**19308**	**495566**

Table 3.40: EU Gas Supply (million cm)

Table A.Table A.Regional Electric Power – EU

Electric power will be used for the compression of the natural gas to be used in CNG compressors. This requires the emission profile for the average mix of electric power used in each of the 26 countries considered by the model. These data are being extracted and compiled from Eurostat data for the year 2012. The data are analysed by country and are aggregated by EU region as it is shown in Table 3.41.

EU Region	Electric Power Supply								
	Coal	Oil	Gas	Nuclear	Wind	Other Carbon	Biomass	Hydro	Other
North	0.100	0.025	0.120	0.523	0.104	0.007	0.015	0.104	0.001
Central	0.385	0.016	0.175	0.168	0.081	0.029	0.065	0.078	0.002
SE	0.247	0.069	0.333	0.048	0.102	0.017	0.029	0.152	0.002
SW	0.277	0.007	0.436	0.000	0.024	0.008	0.002	0.237	0.000

Table 3.41: Regional EU Power Supply (the percentage of power supplied by each type of generation)

The electric power calculations also require the efficiency of the thermal power plants; these data are also extracted from Eurostat. Power plants that are combined heat and power plants have their efficiencies calculated by allocating the energy input to the heat and power on an energy basis. The results are analysed by country and aggregated to EU regions as it is shown in Table 3.43

EU Region	Electric Power Efficiency							
	Coal	Oil	Gas	Nuclear	Wind	Other Carbon	Biomass	Hydro
North	0.395	0.615	0.557	0.350	1.000	0.395	0.329	1.000
Central	0.394	0.685	0.540	0.350	1.000	0.394	0.373	1.000
SE	0.354	0.461	0.548	0.350	1.000	0.354	0.191	1.000
SW	0.357	0.452	0.501	0.350	1.000	0.357	0.250	1.000

Table 3.42: Regional EU Power Generation Efficiency

Finally the electrical distribution losses are calculated on a country basis and aggregated on a regional basis. The results are shown in Table 3.43. The GHGenius model will use all of this information to calculate the GHG emission intensity of the power consumed in each region.

EU Region	Power Distribution Losses
North	8.03%
Central	5.69%
SE	8.19%
SW	9.45%

Table 3.43: Electric Power Distribution Losses

Regional Electric Power – Gas Producers

Some electricity is used in the natural gas upstream stage, i.e. in gas production and processing stages. The power generation mix will be added to the model for all of the producing regions, but the model will use the distribution efficiency and the generation efficiency from the consuming region. Some of the producing countries have the information required as they are part of the Eurostat's database. The rest of the data for other producers have been obtained from the IEA database. The power mix for all considered natural gas producing countries is presented in Table 3.44.

	Coal	Oil	Gas	Nuclear	Other Carbon	Renewables		
						Wind	Biomass	Hydro
UK	0.39	0.01	0.28	0.19	0.01	0.06	0.04	0.02
Norway	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.96
Netherlands	0.24	0.01	0.54	0.04	0.05	0.05	0.07	0.00
Denmark	0.34	0.01	0.14	0.00	0.02	0.34	0.15	0.00
Germany	0.46	0.01	0.12	0.16	-	0.08	0.08	0.04
Italy	0.09	0.38	0.42	0.00	-	0.11		
Romania	0.34	0.01	0.12	0.19	-	0.33		
Poland	0.90	0.02	0.02	0.00	-	0.01	0.04	0.01
Hungary	0.17	0.01	0.31	0.42	-	0.08		
Algeria	0.00	0.06	0.94	0.00	-	0.00	0.00	0.01
Libya	0.00	0.00	0.98	0.00	-	0.00	0.00	0.00
Nigeria	0.00	0.00	0.80	0.00	-	0.00	0.00	0.20
Qatar	0.00	0.00	1.00	0.00	-	0.00	0.00	0.00

Table 3.44: Natural Gas Producers Power Mix

Energy Consumption Gas Producers

The energy consumed in the production and processing of the natural gas is a key input into the emission calculations. Data will be collected on the energy use in well drilling, gas extraction, and gas processing stages for each gas producing region. The input data table in the GHGenius model looks like the following table. Not all fuels will be used in all stages in all producing regions. It is expected that the energy use will be mostly natural gas, while some electricity and diesel fuel will also be consumed. Typical values are shown in Table 3.45.

EU Region	Energy Use in Gas Production Stages		
	Well Drilling, Testing and Servicing	Gas Extraction	Gas Processing
	Fuel used, kJ/tonne gas		
Crude oil	0	0	0
Diesel fuel	35,792	0	0

EU Region	Energy Use in Gas Production Stages		
	Well Drilling, Testing and Servicing	Gas Extraction	Gas Processing
Residual fuel	0	0	0
Natural gas	43,541	2,200,000	1,755,137
Coal	0	0	0
Electricity	0	0	79,741
Gasoline	93	0	0
Coke	0	0	0
Total	**79,426**	**2,200,000**	**1,834,877**

Table 3.45: Typical Energy Consumption Data for NG Stages

Gas that is supplied as LNG will be tracked separately in the model. The liquefaction energy and any regasification energy will be added to the gas processing energy requirements.

Methane Losses Gas Producers

Methane losses from the natural gas supply chain are a key differentiator in the emission profile of different gas producing regions. GHGenius inputs the methane emission losses as a percentage of gas produced for the well drilling and gas extraction stage, the gas processing stage, the gas transmission stage, the gas distribution stage and during the gas compression and dispensing stage. These data will need to be collected for every gas producer in the model.

Wherever possible the data that will be used will be consistent with the year 2012. Some of the developed producing countries do report this data by year. The following Figure 3.59 on gas leakage reported for UK gas production shows how these emissions can change over time.

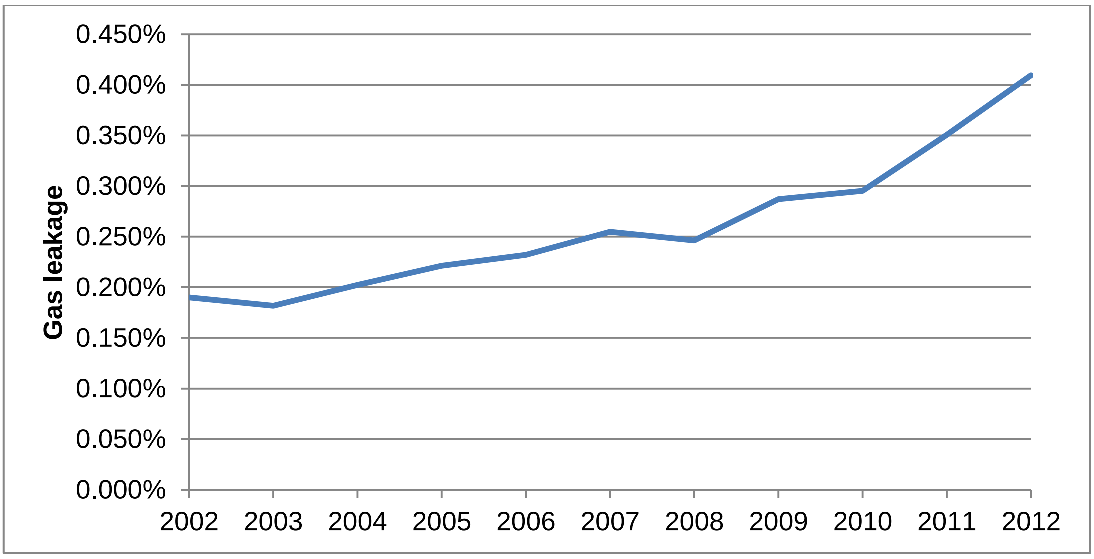


Figure 3.59: UK Gas Leakage Rate over the years 2002 – 2012 (source: DECC)

LNG losses will be dealt with in a similar manner to the energy consumption for LNG production. Any additional losses will be added to the gas processing losses for each LNG producer.

Solution Gas

A gas processing plant can remove higher hydrocarbons and contaminates from the raw field gas. Some gas fields can have CO_2 contents of 10% or greater. The CO_2 content of these fields must be reduced to between 1 and 2% before the gas can enter the pipeline system. This source of GHG emissions need to be identified for every gas producer. For some producers the rate will be zero.

Transportation Distances

The energy consumed for gas transport and transmission is generally a difficult exercise since natural gas pipelines can cross many transmission systems before reaching delivery points. It may be necessary to calculate this energy use and emissions from the transport and transmission line distances and an energy consumption rate. A matrix has been developed with the transport distances of each major pipeline transporting natural gas to the EU from every gas producing region to the main delivery points and transmission system lengths for every EU consuming region. The model will calculate the appropriate distance and energy use based on the sources of gas used in each consuming region.

In order to calculate the GHG emissions related to natural gas transport from producing countries to the EU, the transport distances have to be calculated for both modes of transport: major pipelines and LNG. Separate matrices are developed for pipeline and LNG supply systems. LNG shipping distances and an assumed size of the tankers is used to calculate the energy consumption and emissions associated with these gas sources.

Pipeline distances

The starting and ending points and lengths of all major pipeline routes arriving to the EU are presented in Table 3.46. These distances derive from various sources, notably the pipelines' operators' websites. After arrival to the corresponding ending point, the natural gas flows in the interconnected EU transmission systems.

Producing Country	Pipeline name	Starts	Ends	Length (km)
Algeria	MEDGAZ	Hassi R'Mel, Algeria	Almeria, Spain	787
	TRANSMED	Hassi R'Mel, Algeria	Bologna, Italy	2,283
	MEG Pipeline	Hassi R'Mel, Algeria	Cordoba, Spain	1,327
Russia	Brotherhood	Urengoy, Russia	Baumgarten, Austria	3,963
	Yamal-Europe	Yamal, Russia	Germany	4196
	Nord Stream	Vyborg, Russia	Greifswald, Germany	1,140
	Southeastern Europe transport route	Urengoy, Russia	Greece	4,500
	Franpipe	North Sea	Dunkirk, France	840

Producing Country	Pipeline name	Starts	Ends	Length (km)
Norway	Zeepipe (total)	North Sea	Zeebrugge, Belgium	1,416
	Europipe (total)	North Sea	Dornum, Germany	1,328
	Norpipe	North Sea	Emden, Germany	354
	Vesterled	North Sea	Peterhead, Scotland	360
	Langeled	North Sea	UK	1,666
UK	Interconnector	UK	Zeebrugge, Belgium	153
Libya	Green Stream	Melita	Sicily	516

Table 3.46: Lengths of major natural gas pipelines supplying the EU

LNG transportation distances

The distances between the major LNG exporting terminals of the LNG suppliers and the major LNG importing terminals in the EU are presented in Table 3.47 and are calculated based on the distances between the relevant ports.

LNG transportation distances to the EU in kilometers				LNG Producers				
				Norway	Algeria		Nigeria	Qatar
				Liquefaction terminals				
LNG Importers				Snohvit	Arzew	Skikda	Bonny	Ras Laffan
South East EU	GR - Greece	Receiving Terminals	Revithoussa	-	-	1963	-	-
	IT - Italy		Adriatic LNG	-	-	-	-	9310
			La Spezia	-	-	978	-	-
	SI - Slovenia		La Spezia	-	-	978	-	-
Central EU	BE - Belgium		Zeebrugge	-	3502	-	9099	13290
	NL - Netherlands		Rotterdam	2571	-	-	9160	-
North EU	UK - United Kingdom		Isle Of Grain	-	3317	-	-	-
			Milford Haven	-	-	-	-	12614
South West EU	ES - Spain		Ferrol (Mugardos)	-	1880	-	-	-
			Barcelona	6595	-	876	7791	9728
			Cartagena	-	278	783	7195	9806
			Bilbao	-	-	-	7902	12093
			Huelva	5274	-	1428	6787	10560
			Sagunto	-	-	-	7532	9819
	FR - France		Fos-sur-Mer	-	-	954	8230	-
			Montoir de Bretagne	3850	2698	-	8295	12486
	PT - Portugal		Sines	-	-	-	6765	10838

Table 3.47: LNG transport distances from LNG suppliers to importers in the EU

It must be noted that the LNG streams from Algeria and Libya to the EU include also a transport distance by pipeline from the main gas producing field to the liquefaction plants, in addition to the distance travelled by LNG carrying vessels. These distances are presented in Table 3.48.

Producing Country	Pipeline	Starts	Ends	Distance (km)
Algeria	Hassi R'Mel - Arzew	Hassi R'Mel, Algeria	Arzew	515
	Has Rmel Si - Skikda	Hassi R'Mel, Algeria	Skikda	616
Libya	Wafa - Melita	Wafa, Libya	Melita, Libya	598

Table 3.48: Pipeline lengths from gas fields to liquefaction plants in Algeria and Libya

Transmission systems

As mentioned previously, the GHG emissions related to natural gas transmission and distribution will be calculated as a function of the total pipeline length, by using emission factors. Table 3.49 provides the natural gas transmission systems length for each of the 26 EU countries supplied by gas. In addition to fugitive natural gas losses in transmission pipelines, the self-consumption of gas for transmission compressors will be assessed for the 26 national transmission systems based on EUROSTAT data.

Country	Natural gas transmission system length (km)
Bulgaria	2,645
Greece	1,218
Croatia	2,184
Italy	31,531
Romania	13,000
Slovenia	1,018
Belgium	3,900
Czech Republic	3,643
Germany	29,216
Estonia	878
Latvia	320
Lithuania	2,007
Luxembourg	300
Hungary	5,564
Netherlands	11,500
Austria	1,595
Poland	9,709
Slovakia	2,270
Denmark	800
Ireland	2,105

Country	Natural gas transmission system length (km)
Finland	1,186
Sweden	620
United Kingdom	7,880
Spain	9,236
France	37,200
Portugal	1,299

Table 3.49: The 26 Natural gas transmission systems length (Source: ENTSOG)

Distribution Systems

The methane losses for the distribution systems have to be developed for the 26 EU countries. These are the losses for the gas once it leaves the high pressure transmission system up to the CNG compressors through the local distribution systems. The 2012 Eurostat data regarding distribution losses in EU countries are presented in Table 3.50. These data concern both transmission and distribution pipeline losses of natural gas. As shown in the table, some countries do not report the losses of their networks and therefore relevant estimations have to be carried out. The missing data will be sought from the corresponding system operators and their associations.

Country	Natural gas network losses (million cubic meters)
Bulgaria	12.63
Greece	22.84
Croatia	52.89
Italy	534.17
Romania	415.21
Slovenia	-
Belgium	-
Czech Republic	-
Germany	-
Estonia	-
Latvia	-
Lithuania	0.11
Luxembourg	-
Hungary	158.00
Netherlands	-
Austria	2.67
Poland	149.80
Slovakia	-
Denmark	3.17

Country	Natural gas network losses (million cubic meters)
Ireland	71.85
Finland	-
Sweden	-
United Kingdom	1,115.29
Spain	181.33
France	363.82
Portugal	21.27

Table 3.50: Natural gas distribution losses in EU countries for 2012 (Source: Eurostat)

Distribution of CNG and small scale LNG

The final step in the lifecycle of natural gas required for transport is the distribution of CNG and small scale LNG to end consumers. CNG compressors are usually connected to the medium pressure distribution system and use electricity for compression. In most cases the fuel is consequently transported to the CNG refilling stations by trucks. Small scale LNG, on the other hand, is taken directly from the LNG receiving terminals and transported to the corresponding small scale filling stations by trucks or vessels. The associated GHG emissions to this lifecycle stage will be calculated as a function of distances to potential CNG and small scale LNG refilling stations by using emission factors.

In order to estimate GHG emissions associated to the compression of natural gas to produce CNG, the study will be based on Eurostat's data about electricity consumption in pipeline transport in the EU. These data are presented in Table 3.51. It is assumed that the most significant amount of electricity consumed in national gas networks is being used for natural gas compression.

Country	Electricity consumption in gas networks (terajoules)
Bulgaria	108
Greece	0
Croatia	68
Italy	1,616
Romania	68
Slovenia	0
Belgium	148
Czech Republic	133
Germany	0
Estonia	0
Latvia	86
Lithuania	83

Country	Electricity consumption in gas networks (terajoules)
Luxembourg	0
Hungary	0
Netherlands	0
Austria	518
Poland	1,109
Slovakia	166
Denmark	0
Ireland	0
Finland	0
Sweden	0
United Kingdom	0
Spain	0
France	0
Portugal	50

Table 3.51: Electricity consumption in pipeline transport in EU countries for 2012 (Source: Eurostat)

In addition, CE Delft provides calculated emissions for CNG and small scale LNG processing and transport in its report "*The Natural Gas Chain - Toward a global life cycle assessment*". These emissions are presented in Table 3.52.

It is worth mentioning that in the baseline year of 2012 only CNG activity to transport means might be traced and consequently will be assessed in terms of GHG emissions. The use of LNG as transport fuel will only be considered as an option within the projections of the PRIMES model and therefore will be assessed as part of Task f.

Average data for CNG and LNG GHG emissions (electricity not included)		
	Processing (gr CO_2eq/MJ)	Long distance (gr CO_2eq/MJ)
CNG - High pressure network	0.17	5.41
CNG - Low pressure network	0.17	5.41
LNG	10.95	0.36 (transport 1,000 km assumed)

3.9 TABLE 3.52: EMISSIONS DATA PROVIDED BY CE DELFT FOR CNG AND SMALL SCALE LNGLITERATURE DATA

According to the data collection strategy, in the absence of actual data and when major difficulties related to data collection do not allow for reliable modelling in OPGEE, the Consultant would use literature data from work previously done in order to assess GHG emissions of certain MCONs. The collection of actual data and the data for the inputs till present has made evident that there is sufficient information for the assessment of GHG emission of the MCONs that fall within the scope of the analysis and therefore there is no purpose for utilizing pre-calculated carbon intensities from previous studies.

4 TASK C: GHG EMISSIONS MODELLING

The presentation of the work carried out in the context of Task c concentrates on the main methodological aspects of the models prepared for the calculation of the WTT GHG emissions of petroleum fuels (diesel, petrol and kerosene) and natural gas. Three models, namely OPGEE, GHGenius and PRIMES-Refinery, have been employed for the estimation of total GHG emissions of the aforementioned refined petroleum products and natural gas from the stage of the extraction process to their production and distribution to the fill tanks in every EU country. The models will largely depend on the data collected, as presented in Task b. Due to the large uncertainty endorsed to the reliability of certain areas of data, minimum and maximum values of the GHG emissions associated with the WTT supply chain of diesel, petrol, kerosene and natural gas will be provided. The WTT supply chain of the petroleum products and natural gas, as has already been stated, is divided into three sections:

- **Upstream emissions** are classified into three broad categories: emissions during exploration and field development, emissions during production and surface processing emissions. The OPGEE model is a spreadsheet tool which covers the feedstock extraction emissions and provides calculations of emissions relevant to the exploration and drilling, the production and surface separations, the secondary and tertiary recovery, water treatment and waste disposal and the venting, flaring and fugitive emissions. The OPGEE model has the capability to also calculate GHG emissions from unconventional oil sources such as oil sands. The GHGenius model includes a module for the estimation of the emissions resulting from the natural gas life cycle chain (e.g. producing, processing, transporting and transforming the gas for use). The GHGenius model, for the purposes of the current study, has been expanded to simulate the region of the European Union.
- **Midstream emissions** pertain to emissions resulting from the feedstock transportation from the extraction source to the refinery gate. Emissions mainly occur due to the energy consumption during the transportation of petroleum and its products. Emissions from oil transportation are derived using the OPGEE model which has been updated with actual Origin-Destination Matrices data and the methods used to transport oil to Europe from extra-EU regions. GHGenius is able to calculate GHG emissions related to the transportation of natural gas from the gas supplier to the gas consuming region. The model is able to calculate both emissions related to the transportation of natural gas through pipelines and through shipping (the case of LNG).
- **Downstream emissions** refer to the emissions during the processing of crude oil in the refineries. The resulting GHG emissions from the crude oil refining are influenced by specific crude oil properties, the amount of processing required and the energy input. Energy consumption in the refineries refers to both own consumption and purchased fuels (mainly electricity and natural gas). To

allocate the GHG emissions during refining to each petroleum product the PRIMES-Refinery model will be used. The allocation of the emissions to individual products will be based on the marginal emission content following the methodology developed by the Institut Français du Pétrole (IFP). Furthermore, the present analysis will take into account emissions from transportation of both refinery feedstock and of ready-to-use fuels. The latter case applies mainly where refined petroleum products are imported to EU from Russian or US refineries. This study will also provide estimates on the GHG emissions which take place during the transportation of the refined petroleum products from the European refineries to the European filling stations, as well as the fugitive emissions at the stage of the filling stations.

4.1 THE OPGEE MODEL

4.1.1 Model rationale and structure

The Oil Production Greenhouse gas Emissions Estimator (OPGEE) is an engineering based life cycle assessment (LCA) spreadsheet tool that estimates greenhouse gas (GHG) emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery gate.

The development of the OPGEE model was funded by the California Air Resources Board. The model has been incorporated into the California's Low Carbon Fuel Standard (LCFS) and has been applied for the calculation of the GHG intensity for crude oil baseline analysis. For the purposes of the present study, the OPGEE model is modified to account for the EU petroleum fuel supply system, by using specific input data related to the various MCONs imported to the European refineries.

The OPGEE model provides a very detailed platform for the evaluation of carbon intensity and energy consumption at the upstream and midstream stages. OPGEE includes emissions from all production operations required to produce and transport crude hydrocarbons to the refinery gate. The production technologies included are the: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion. The OPGEE model makes all the calculations and correlations of the values utilizing various standard data about fuels specifications, emissions factors and other conversion factors. A schematic chart showing the various stages of the lifecycle assessment included in the OPGEE model are presented in Figure 4.1 below:

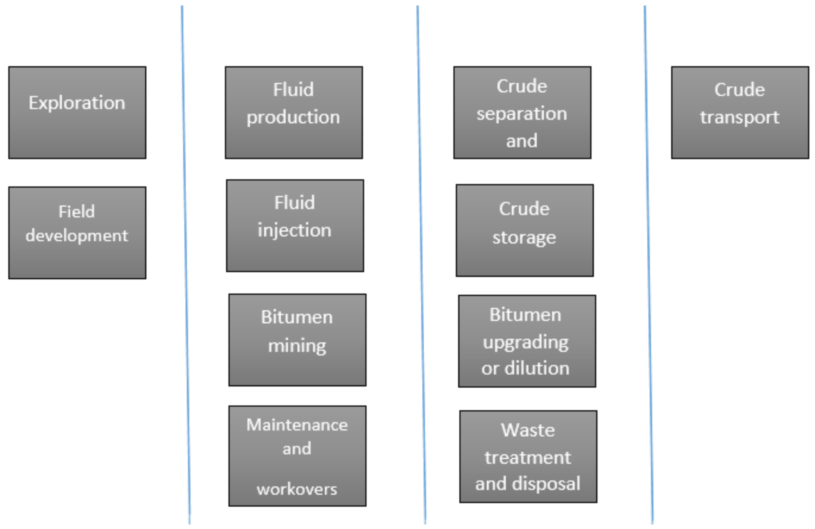


Figure 4.1: Schematic chart with the various stages of the LCA analysis included in the OPGEE model (Source: OPGEE model documentation)

Type of processes included in OPGEE

OPGEE is modular in structure, with interlinked worksheets representing each production stage. Within each major production stage, a number of activities and processes occur (e.g., fluid production or fluid injection). The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional unit is held constant across different production and processing pathways included in OPGEE. OPGEE uses data from a variety of technical reference works and its spreadsheet structure makes it a fully transparent modelling tool. The main calculations for the total carbon intensity estimation focus on the following processes:

- **Exploration**, which contains pre-production emissions that occur during primary exploration for petroleum.
- **Drilling and development,** including emissions that occur during development of crude oil production facilities.
- **Production and extraction**, which models the work required to lift fluids from the subsurface and to inject fluids into the subsurface.
- **Surface processing**, which models handling of crude, water, and associated gas with a set of common industry technologies.
- **Maintenance**, regarding the venting and fugitive emissions associated with maintenance.
- **Waste disposal,** referring to the emissions about waste disposal.
- **Crude transport,** allowing variation in the transport modes used to transport crude oil from extraction to the refinery stage and the distance travelled.
- **Bitumen extraction and upgrading,** modelling the extraction of crude bitumen separately from the production of conventional crude oil.

All the processes of the upstream stage contribute to the total carbon intensity of each MCON with its own percentage of GHG emissions.

Flaring, venting and fugitive emissions represent the most important source of GHG emissions from oil production operations. Venting and fugitive emissions arise from oil field operations and devices. Sources include well work-overs and clean-ups, compressor start-ups and blowdowns, pipeline maintenance, gas dehydrators, AGR units, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). Flaring of gas, either as a means of disposal or as a safety measure, is a significant source of air emissions from oil and gas installations. Even if continuous flaring ended, occasional burning of small amounts of gas will still be necessary for safety reasons.

Another major factor is the use of the energy-intensive secondary and tertiary recovery technologies, such as water flooding, gas lifting, gas flooding etc. For the application of these technologies, additional energy is required in order to lift the crude oil from oil well. Other emissions take place due to increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio). At the midstream level, GHG emissions due to transportation can have a significant share in the total GHG emissions assessed, especially when considering crudes imported from distant world areas to the EU refineries.

4.1.2 Required Inputs

Key input data

In order to calculate the carbon intensity of the imported MCONs in European refineries, a significant amount of data is needed to make the OPGEE model functional. The data required relate to:

- **Production methods,** such as downhole pump, water reinjection, gas reinjection, water flooding, gas lifting, gas flooding, and steam flooding. The selection of the production method depends on the difficulty that crude oil appears in pumping up of the oil well.
- **Field properties** referring to the field location, field name, field age, field depth, oil production volume, number of producing wells, well diameter, productivity index and average reservoir pressure. These field properties are determining characteristics for the production process of the oilfield.
- **Fluid properties** considering API gravity of crude oil, which characterize the crude oil as “heavy” or “light” and composition of produced associated gas.
- **Production practices** including gas-to-oil ratio (GOR), water-to-oil ratio (WOR), water-injection ratio, gas lifting injection ratio, gas flooding injection ratio, steam-to-oil ratio (SOR), fraction of required electricity generated on site, fraction of remaining gas reinjected, fraction of water produced reinjected, fraction of steam generation via co-generation and volume fraction of diluent. The information about the production practices correlate with these of the production methods and have significant role in the resulting emissions.
- **Processing practices** that represent the use of heater/treaters, stabilizer columns and gas processing units (AGR, dehydrator and demethanizer), the ratio of gas flared to oil produced, and the ratio of gas vented to oil produced. According to the quality of produced oil mixture, certain treating processes are

applied for further treatment of gas, oil and water, which include in the oil mixture.

- **Land use impacts** including ecosystem carbon richness and relative disturbance intensity. This parameter relates to the additional emissions of the wider oilfield that are caused due to the disturbance of land during the drilling and production processes.
- **Crude oil transport** which determine transport modes and distances. Crude oil transport covers the tracks (marine or by road) from the oil well to the European refineries gates presenting the distances as well as the suitable mode that is utilized for each distance.

The user is allowed to insert the desired data in the “User Inputs” section of the ‘User Inputs & Results’ worksheet. This sheet enables the calculation of the carbon intensity of one specific MCON. However, OPGEE has a built-in capability to analyse a number of fields or oil production projects and bookkeep the results for comparison and further analysis. The ‘Bulk Assessment’ worksheet has a similar structure to the ‘User Inputs & Results’ worksheet, but is expanded to allow multiple projects to be assessed in one computational run. In addition to running a number of fields in sequence, the bulk assessment machinery has a built-in feature to programmatically resolve errors that arise from input data inconsistencies.

All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given facility, most input values will remain equal to defaults. Otherwise, if detailed field-level data are available, a more accurate emissions estimate can be generated.

Table 4.1 presents the actual form of the input data required to operate the OPGEE model and produce the lifecycle GHG emissions per field type. The table presented includes the input data of the generic field type included in the OPGEE model.

4.1.3 Parametric significance

The Consultant has performed a sensitivity analysis over the most critical parameters that can influence the outcome of the carbon intensity of the various crude types. The scope of this analysis is to show the importance of specific oil field characteristics for the calculations of the GHG emissions. A sensitivity analysis has been performed over specific parameters while keeping all other inputs unchanged; the calculations refer to the generic type of field considered in OPGEE (for the typical characteristics of the generic type of field see Table 4.1). The main parameters included in the sensitivity runs are the following:

- API gravity
- Water to oil ratio (WOR)
- Flaring to oil ratio (FOR)
- Venting to oil ratio (VOR)
- Marine transport distance

Parameter	Unit	Value
Downhole pump		1
Water reinjection		1
Gas reinjection		1
Water flooding		0
Gas lifting		0
Gas flooding		0
Steam flooding		0
Field location (Country)		Generic
Field name		Generic
Field age	yr.	35
Field depth	ft	7,240
Oil production volume	bbl/d	1,500
Number of producing wells	[-]	8
Number of water injecting wells	[-]	5
Well diameter	in	2.775
Productivity index	bbl/psi-d	3
Reservoir pressure	psi	1,557
API gravity	deg. API	30
Gas composition		
N_2	mol%	2
CO_2	mol%	6
C_1	mol%	84
C_2	mol%	4
C_3	mol%	2
C_4+	mol%	1
H_2S	mol%	1
Gas-to-oil ratio (GOR)	scf/bbl oil	908
Water-to-oil ratio (WOR)	bbl water/bbl oil	4.31
Water injection ratio	bbl water/bbl oil	5.31
Gas lifting injection ratio	scf/bbl liquid	1,500
Gas flooding injection ratio	scf/bbl oil	1,362
Steam-to-oil ratio (SOR)	bbl steam/bbl oil	3
Fraction of required electricity generated onsite	[-]	0
Fraction of remaining gas reinjected	[-]	0
Fraction of water produced water reinjected	[-]	1
Fraction of steam generation via cogeneration	[-]	0
Heater/treater	NA	0
Stabilizer column	NA	1
Application of AGR unit	NA	1
Application of gas dehydration unit	NA	1
Application of demethanizer unit	NA	1
Flaring-to-oil ratio	scf/bbl oil	182

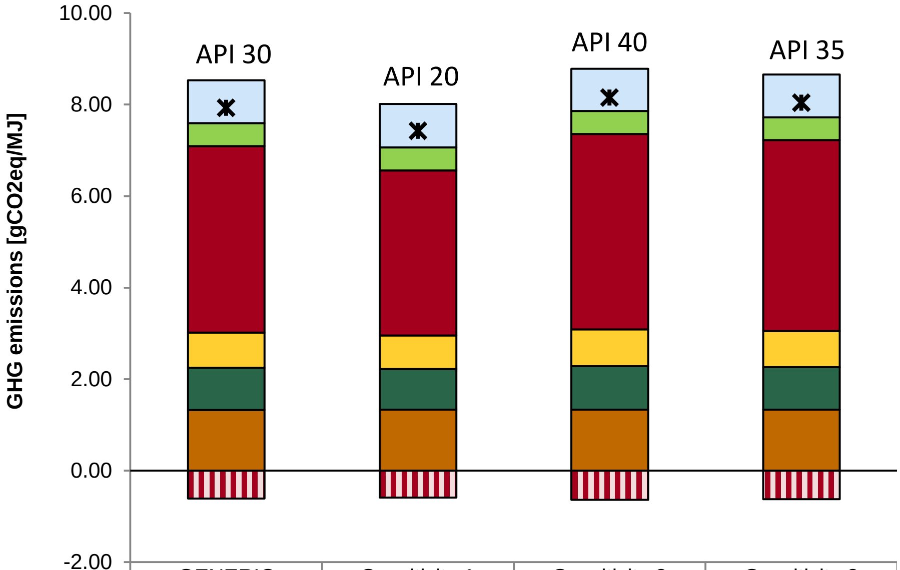
Parameter	Unit	Value
Venting-to-oil ratio	scf/bbl oil	0
Volume fraction of diluent	[-]	0
Transport distance (one way)		
Ocean tanker	Mile	5,082
Rail	Mile	800
Ocean tanker size, if applicable	Ton	250,000
Small sources emissions	gCO_2eq/MJ	0.5

Table 4.1: Typical input to the OPGEE model for the calculation of the GHG emissions per field (values for the generic type of field included in OPGEE

Sensitivity analysis on the API gravity

API gravity is a measure of how “heavy” or “light’ the crude oil is relative to water. The generic field considered has an API equal to 30. The resulting carbon intensity of this field is equal to 7.93 gr CO_2eq/MJ according to the OPGEE results shown in Figure 4.2. Three sensitivity runs have been performed for the API values while keeping all other input unchanged relative to the generic field. The values picked for the API sensitivity analysis are within the range found in literature; the range of API provided in Task b for the various fields range from 22 to 44. In the 1st sensitivity, an API of 20 has been considered which eventually results in a carbon intensity of 7.43 gr CO_2eq/MJ and represents a reduction of about 6% relative to the generic field (see Figure 4.2). In the 2nd sensitivity run, an API of 40 has been assumed resulting to a carbon intensity of 8.15 gr CO_2eq/MJ which represents an increase of about 3% relative to the generic field. In the 3rd sensitivity test, an API of 35 was assumed resulting to a carbon intensity of 8.04 gr CO_2eq/MJ which represents an increase of about 1% relative to the generic field.

According to the model runs, it has been observed that an increase in the API gravity (lighter crude oil), results in an increase of the total carbon intensity. This happens because in the sensitivity runs the OPGEE model calculates the emissions without changing any other parameter. However, in reality, oil fields with lower API gravity usually involve different production methods and processes which will eventually results in overall higher carbon intensity than lighter oil.

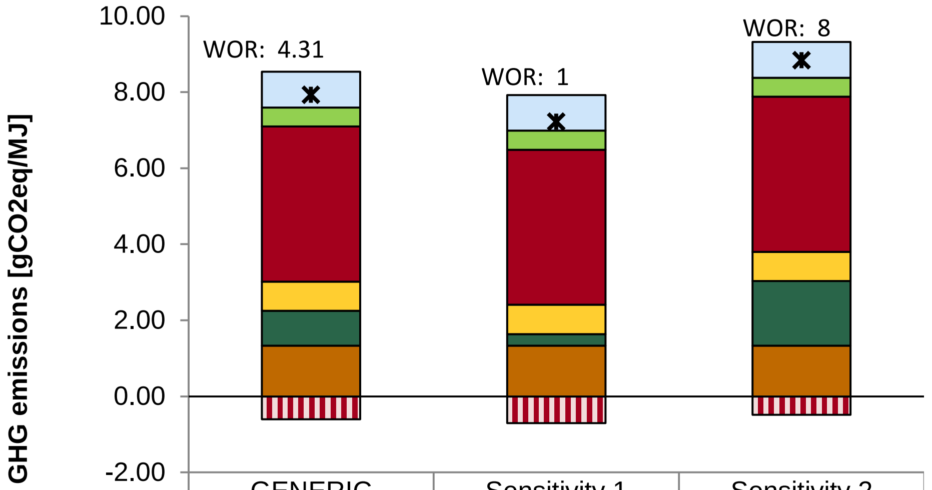


	GENERIC	Sensitivity 1	Sensitivity 2	Sensitivity 3
Offsite emissions	-0.61	-0.58	-0.64	-0.62
Transport	0.94	0.96	0.93	0.93
Misc.	0.50	0.50	0.50	0.50
Diluent	0.00	0.00	0.00	0.00
VFF	4.08	3.60	4.27	4.17
Waste	0.00	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00	0.00
Processing	0.77	0.73	0.80	0.79
Production	0.92	0.89	0.95	0.93
Drilling	1.33	1.34	1.34	1.33
Exploration	0.00	0.00	0.00	0.00
Net lifecycle emissions	7.93	7.43	8.15	8.04

Figure 4.2: Sensitivity analysis on the API gravity: results obtained using the OPGEE model

Sensitivity analysis on the Water to Oil Ratio (WOR)

Water-oil-ratio (WOR) is the ratio between the volume of water that comes out of the crude oil mixture and the volume of oil at standard conditions. The generic field considered has a WOR equal to 4.31 bbl water/bbl oil. The resulting carbon intensity of this field is equal to 7.93 gr CO_2eq/MJ according to the OPGEE results shown in Figure 4.3. Two sensitivity runs were performed on the WOR values. The values picked for the WOR sensitivity analysis are within the range found in literature; the range of WOR provided in Task b for the various fields range from 0,6 to 8,3 bbl water/bbl oil. In the 1st sensitivity, a WOR of 1 bbl water/bbl oil and eventually results in a carbon intensity of 7.22 gr CO_2eq/MJ which represents a reduction of about 9% (see Figure 4.3). In the 2nd sensitivity test performed, a WOR of 8 bbl water/bbl oil was assumed resulting to a carbon intensity of 8.84 gr CO_2eq/MJ which represents an increase of about 11% relative to the generic field. Increasing the WOR implies that additional operations are required during the production process which results in an increase in the GHG emissions during the production phase and eventually the overall GHG emissions.



	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0.61	-0.71	-0.48
Transport	0.94	0.94	0.94
Misc.	0.50	0.50	0.50
Diluent	0.00	0.00	0.00
VFF	4.08	4.08	4.08
Waste	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00
Processing	0.77	0.77	0.77
Production	0.92	0.31	1.70
Drilling	1.33	1.33	1.33
Exploration	0.00	0.00	0.00
Net lifecycle emissions	7.93	7.22	8.84

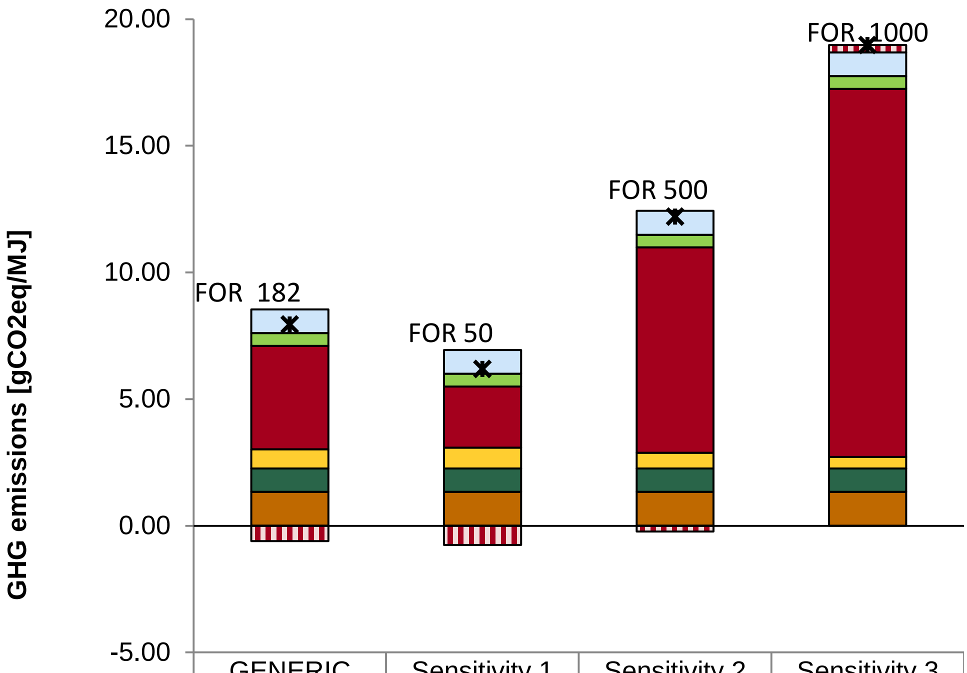
Figure 4.3: Sensitivity analysis on the Water to Oil Ratio (WOR): results obtained using the OPGEE model

Sensitivity analysis on the Flaring to Oil Ratio (FOR)

Flaring is used to dispose of associated natural gas where there is no economic use for the gas. Associated gas evolves from crude oil as it is brought to surface temperatures and pressures, and is separated from oil before transport. Flaring mainly produces carbon dioxide and water as waste products of combustion; however, combustion is often incomplete which can result in emissions of carbon monoxide, nitrous oxide, unburned hydrocarbons, particulate matter (including soot or black carbon), and VOCs. Because of the hydrocarbon content, a flaring rise results to a significant increase in the carbon intensity.

The generic field considered has a flaring to oil ratio equal to 182 scf/bbl oil. Three sensitivity runs were performed on the flaring to oil ratio values because the range of values found in literature varies between some hundreds of scf and thousands of scf. In the 1st sensitivity, a flaring to oil ratio of 50 scf/bbl oil was considered which results in a carbon intensity of 6.17 gr CO_2eq/MJ, a reduction of about 22% relative to the generic field. In the 2nd sensitivity, a flaring to oil ratio of 500 scf/bbl oil was assumed resulting to a carbon intensity of 12.19 gr CO2eq/MJ which represents an increase of about 54%

relative to the generic field (see Figure 4.4). In the 3rd sensitivity test performed a flaring to oil ratio of 1000 scf/bbl was performed resulting to a carbon intensity of 18.97 gr CO_2eq/MJ which represents an increase of about 139% relative to the generic field. It is evident from the modelling runs that the flaring to oil ratio is a critical parameter for the calculation of the total GHG emissions per MCON.



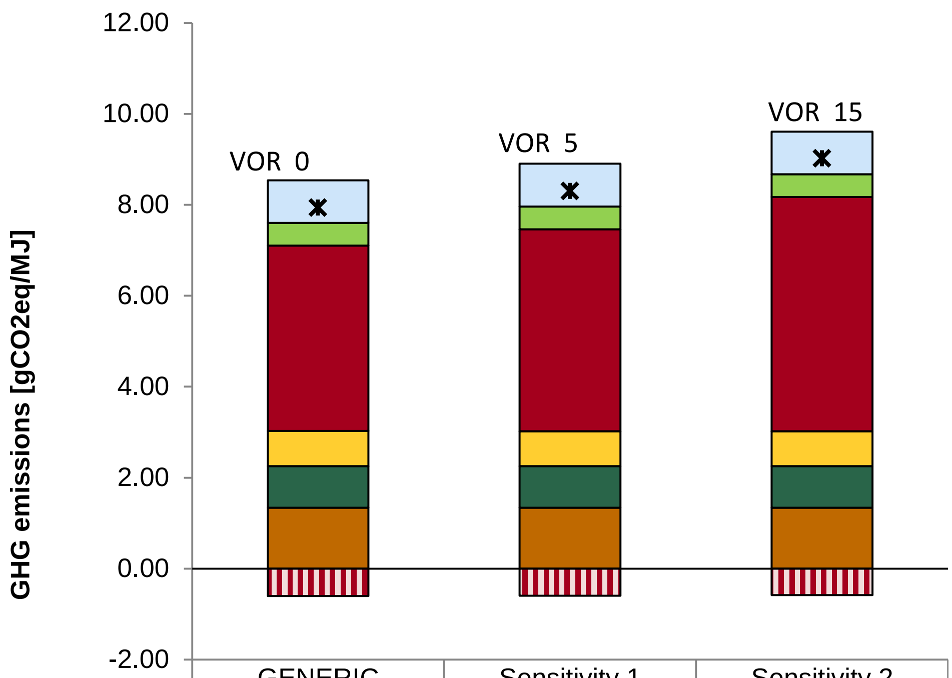
	GENERIC	Sensitivity 1	Sensitivity 2	Sensitivity 3
Offsite emissions	-0.61	-0.76	-0.23	0.28
Transport	0.94	0.94	0.94	0.94
Misc.	0.50	0.50	0.50	0.50
Diluent	0.00	0.00	0.00	0.00
VFF	4.08	2.41	8.11	14.54
Waste	0.00	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00	0.00
Processing	0.77	0.83	0.62	0.46
Production	0.92	0.92	0.92	0.92
Drilling	1.33	1.33	1.33	1.33
Exploration	0.00	0.00	0.00	0.00
Net lifecycle emissions	7.93	6.17	12.19	18.97

Figure 4.4: Sensitivity analysis on the Flaring to Oil Ratio (FOR): results obtained using the OPGEE model

Sensitivity analysis on the Venting to Oil Ratio (VOR)

Venting is the controlled release of gases into the atmosphere in the course of oil and gas production operations. These gases might be natural gas or other hydrocarbon vapours, water vapour, and other gases, such as carbon dioxide, separated in the processing of oil or natural gas. In venting, methane is released directly into the atmosphere.

The generic field considered has venting to oil ratio equal to 0 scf/bbl oil. Two sensitivity runs were performed on the venting-to-oil ratio values while keeping all other input unchanged relative to the generic field. In the 1st sensitivity, a venting to oil ratio of 5 scf/bbl oil was considered which eventually results in a carbon intensity of 8.30 gr CO_2eq/MJ which represents an increase of about 5% (see Figure 4.5). In the 2nd sensitivity run, a venting to oil ratio was assumed of 15 scf/bbl oil resulting to a carbon intensity of 9.02 gr CO_2eq/MJ, which represents an increase of about 14% relative to the generic field. Figure 4.5 illustrates the results obtained from OPGEE.



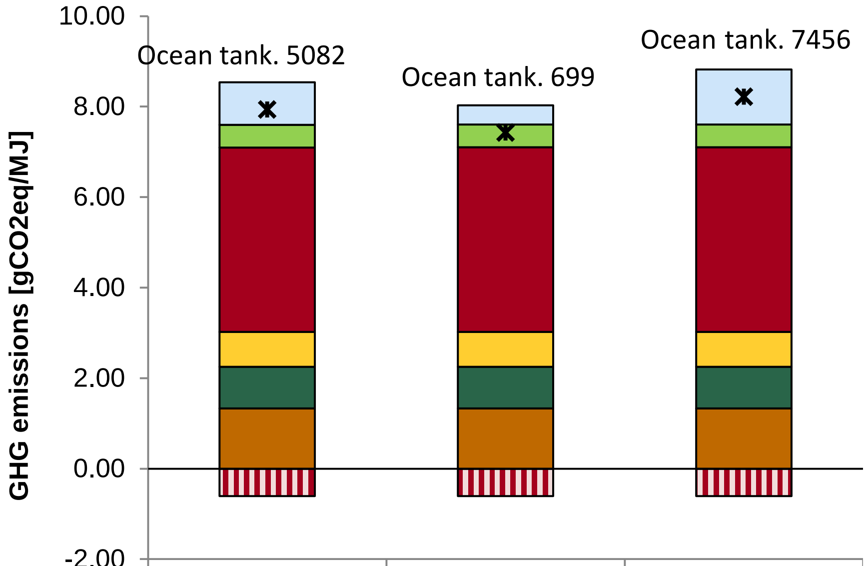
	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0.61	-0.60	-0.59
Transport	0.94	0.94	0.94
Misc.	0.50	0.50	0.50
Diluent	0.00	0.00	0.00
VFF	4.08	4.44	5.15
Waste	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00
Processing	0.77	0.77	0.76
Production	0.92	0.92	0.92
Drilling	1.33	1.33	1.33
Exploration	0.00	0.00	0.00
Net lifecycle emissions	7.93	8.30	9.02

Figure 4.5: Sensitivity analysis on the Venting to Oil Ratio (VOR): results obtained using the OPGEE model

Sensitivity analysis on the maritime shipping distance

The transportation of crude oil from the extraction point to the refinery of a European country is responsible for a part of the total lifecycle GHG emissions of this specific crude. GHG emissions occur due to the consumption of fossil-based fuels during the transportation usually by ocean tankers. An important variable for determining the GHG emissions due to transportation by ships is the actual Origin - Destination (O-D) distance. For the purposes of this sensitivity analysis, we have assumed different O-D distances for the generic field considered in OPGEE, while keeping all other variables unchanged.

The generic field considered has an O-D distance of 5082 km (ocean tanker). The resulting carbon intensity of this field is equal to 7.93 gr CO_2eq/MJ according to the OPGEE results shown in Figure 4.6. Two differentiated O-D distances have been considered for two sensitivity runs. The assumptions draw largely from data provided in Task b and refer to the distances from two major exporting countries to EU ports. For the 1st sensitivity run, the shipping distance was 699 miles from Samotlor to Gdansk. After running the OPGEE model, the resulting carbon intensity was found to be 7.43 gr CO_2eq/MJ, which represents a decrease of about 7% relative to the generic field (see Figure 4.6). In the 2nd sensitivity run, a distance of 7,456 miles from Ghawar to Rotterdam was considered. The overall carbon intensity of the crude considered increased to the levels of 8.22 gr CO_2eq/MJ which represents an increase of about 3% relative to the generic field. Indeed, the shipping distance does not represent an important variable for the calculation of the GHG emissions using the OPGEE model.



	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0.61	-0.60	-0.60
Transport	0.94	0.43	1.22
Misc.	0.50	0.50	0.50
Diluent	0.00	0.00	0.00
VFF	4.08	4.08	4.08
Waste	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00
Processing	0.77	0.77	0.77
Production	0.92	0.92	0.92
Drilling	1.33	1.33	1.33
Exploration	0.00	0.00	0.00
Net lifecycle emissions	7.93	7.43	8.22

Figure 4.6: Sensitivity analysis on the marine shipping Origin- destination (O-D) distance: results obtained using the OPGEE model

4.1.4 Produced outputs

Table 4.2 illustrates a typical presentation of the OPGEE model outputs. As it can be observed these are organized per lifecycle process and for each process the total energy consumption and total GHG emission are given.

Output variables	Level 1	Level 2	Unit	Values
Field name				Generic
2.1 Exploration (e)				
	2.1.1 Total energy consumption		MJ/MJ	0
	2.1.2 Total GHG emissions		gCO_2eq/MJ	0

Output variables	Level 1	Level 2	Unit	Values
		2.1.2.1 Combustion/land use	gCO_2eq/MJ	0
		2.1.2.2 VFF	gCO_2eq/MJ	0
2.2 Drilling & Development (d)				
	2.2.1 Total energy consumption		MJ/MJ	0.001
	2.2.2 Total GHG emissions		gCO_2eq/MJ	1.33
		2.2.2.1 Combustion/land use	gCO_2eq/MJ	1.33
		2.2.2.2 VFF	gCO_2eq/MJ	0
2.3 Crude production & extraction (p)				
	2.3.1 Total energy consumption		MJ/MJ	0.012
	2.3.2 Total GHG emissions		gCO_2eq/MJ	0.94
		2.3.2.1 Combustion/land use	gCO_2eq/MJ	0.92
		2.3.2.2 VFF	gCO_2eq/MJ	0.02
2.4 Surface processing (s)				
	2.4.1 Total energy consumption		MJ/MJ	0.046
	2.4.2 Total GHG emissions		gCO_2eq/MJ	4.74
		2.4.2.1 Combustion/land use	gCO_2eq/MJ	0.77
		2.4.2.2 VFF	gCO_2eq/MJ	3.97
2.5 Maintenance (m)				
	2.5.1 Total energy consumption		MJ/MJ	0
	2.5.2 Total GHG emissions		gCO_2eq/MJ	0.09
		2.5.2.1 Combustion/land use	gCO_2eq/MJ	0
		2.5.2.2 VFF	gCO_2eq/MJ	0.09

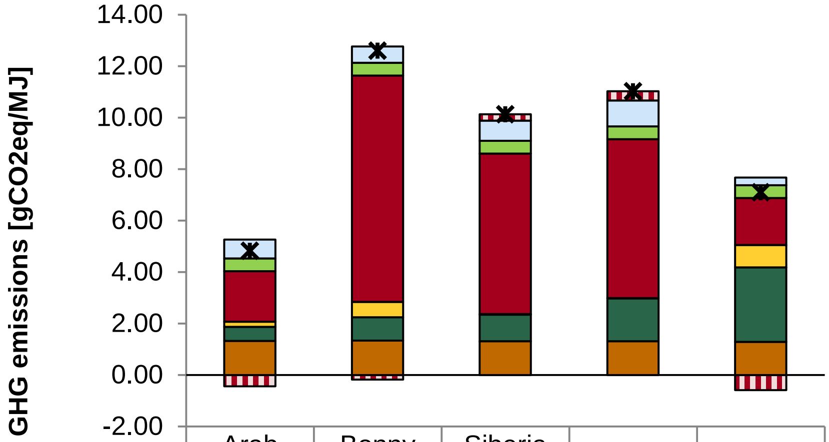
Output variables	Level 1	Level 2	Unit	Values
2.6 Waste disposal (w)				
	2.6.1 Total energy consumption		MJ/MJ	0
	2.6.2 Total GHG emissions		gCO_2eq/MJ	0
		2.6.2.1 Combustion\land use	gCO_2eq/MJ	0
		2.6.2.2 VFF	gCO_2eq/MJ	0
2.7 Diluent				
	2.7.1 Total energy consumption		MJ/MJ	0
	2.7.2 Total GHG emissions		gCO_2eq/MJ	0
2.8 Non-integrated upgrader				
	2.8.1 Total energy consumption		MJ/MJ	0
	2.8.2 Total GHG emissions		gCO_2eq/MJ	0
2.9 Crude transport (t)				
	2.9.1 Total energy consumption		MJ/MJ	0.013
	2.9.2 Total GHG emissions		gCO_2eq/MJ	0.94
	2.9.3 Loss factor		NA	1
2.10 Other small sources			gCO_2eq/MJ	0.5
2.11 Offsite emissions credit/debit			gCO_2eq/MJ	-0.61
2.12 Lifecycle energy consumption			MJ/MJ	0.071
2.13 Lifecycle GHG emissions			gCO_2eq/MJ	7.93

Table 4.2: Typical output of the OPGEE model

4.1.5 Draft results

Based on the data gathered so far in Task b, it was possible to calculate the GHG emissions of five major MCONs imported to the European refineries using the OPGEE model. Figure 4.7 presents the draft results for Arab light, the Bonny light, the Siberia light, the Urals and the Troll MCONs obtained with OPGEE. It has to be noted that these are initial runs and that final results will take into account various pathways and will presented in the form of a range with a minimum and a maximum.

The first MCON considered is the “Arab light” which is imported from Saudi Arabia. The resulting GHG emissions of this specific MCON was found to be about 4.82 gr CO_2eq/MJ. The second one is the “Bonny light” MCON from Nigeria. The Nigerian MCON has a carbon intensity of 12.59 gr CO_2eq/MJ, which is significantly higher than the Arab light. This increase is due to the much higher GHG emissions related with VFF that are related with the Nigerian MCON. Further, the carbon intensity of the “Siberian light”, imported from Russia, is calculated to be about 10.13 gr CO_2eq/MJ. Similarly, we observe that this Russian MCON shows a high carbon intensity originating from the VFF process, even though the GHG emissions during the processing stage are almost negligible. The picture is very similar regarding the “Urals” MCON, also originating from Russia but from different oilfield, with a calculated carbon intensity of 11.02 gr CO_2eq/MJ. VFF related GHG emissions are also responsible for more than half the overall carbon intensity of this particular MCON. The “Troll” MCON which comes from Norway has significantly lower VFF emissions in comparison with the Russian and the Nigerian MCONs, resulting in a carbon intensity of 7.09 gr CO_2eq/MJ. According to the OPGEE model, the transport related GHG emissions of the “Troll” MCON are found to be significantly lower than the other four MCONs as the transportation distance is relatively small. It is evident that the most significant differences among the five MCONs considered are due to the VFF emissions.



	Arab light	Bonny light	Siberia light	Urals	Troll
Offsite emissions	-0.44	-0.17	0.24	0.36	-0.58
Transport	0.73	0.63	0.78	1.00	0.30
Misc.	0.50	0.50	0.50	0.50	0.50
Diluent	0.0	0.0	0.0	0.0	0.0
VFF	1.96	8.79	6.24	6.17	1.82
Waste	0.00	0.00	0.00	0.00	0.00
Maintenance	0.00	0.00	0.00	0.00	0.00
Upgrading	0.00	0.00	0.00	0.00	0.00
Processing	0.20	0.59	0.02	0.02	0.88
Production	0.54	0.92	1.04	1.67	2.89
Drilling	1.33	1.33	1.31	1.31	1.29
Exploration	0.00	0.00	0.00	0.00	0.00
Net lifecycle emissions	4.82	12.59	10.13	11.02	7.09

Figure 4.7: Draft results on GHG emissions of five MCONs using the OPGEE model (input data from Task b)

4.2 THE PRIMES-REFINERY MODEL

The present study takes into consideration the GHG emissions during the refining stage of the crude oil in the European countries and the emissions associated to imported final mineral oil fuels. The GHG emissions that take place during the refining process are not included in the lifecycle analysis provided by the OPGEE model. Therefore, for the purposes of the present study we use the PRIMES-Refinery model for the estimation of GHG emissions resulting from the processing of petroleum in the refineries of Europe. The current section presents an overview of the main features of the PRIMES-Refinery model and a brief presentation of the main refining processes considered, as well as the ongoing extensions and upgrades of the model required for the purposes of the current study and some key required input data.

4.2.1 Model rationale and structure

Coverage of the model

The PRIMES-Refinery supply model is an economic supply modelling tool developed and maintained by E3MLab. The model takes demand for petroleum products as given, either from statistics of past years or from projection to the future by the other sub-models (demand models and power sector models) of PRIMES. The refinery sub-model optimises economically the structure of stylised refineries, the use of processes, the consumption of crude oil, feedstock and fossil fuels as needed to produce given demand. The model endogenously estimates investment in processing and refining capacity of needed to meet future demand. The model runs also for past years for data calibration purposes and so it produces detailed (pseudo) data on the past in order to estimate consumption of energy and emissions in detail. The refinery sub-model is linked with the PRIMES large scale energy system model and can be used either as a satellite model, thus forming a closed loop, or as a standalone model. The model is designed to perform sensitivity analyses based on different demand estimations, crude oil types and import-exports of refinery products, and includes representations to handle legislative and policy regulations on the refinery processes.

The model covers all EU-28 Member States. It provides dynamic projections in 5-year time periods with the time horizon of the model being 2050. Years 2000, 2005 and 2010 are reproduced by the model for calibration purposes a nd so the model is updated until 2010. Alongside with the calculation of GHG emissions at the refinery stage, the model seeks to minimise total cost so as to satisfy a fixed demand for petroleum fuels, which is derived from the PRIMES core model. It therefore determines the optimal use of resources and calculates the investment in technologies, the costs, and the pre-tax prices of final refinery fuels. The total petroleum commodity supply system cost includes annuity payments of capital cost, variable and energy costs, fixed O&M costs, as well as the cost of imports. The cost optimization is performed for all EU Member States in parallel and is inter-temporal thus having perfect foresight.

Model structure

In a nutshell, the refinery supply system is structured in the model as follows: the primary energy commodity (i.e. crude oil and other feedstock) is transformed into final commodities in a stepwise manner, via a variety of transformation processing units/technologies included in the model. The final commodities are then distributed to the fuel market of the EU Member States (final energy consumption) and to the EU power or heat production plants. The schematic representation of the representative refinery configuration is presented in Figure 4.8.

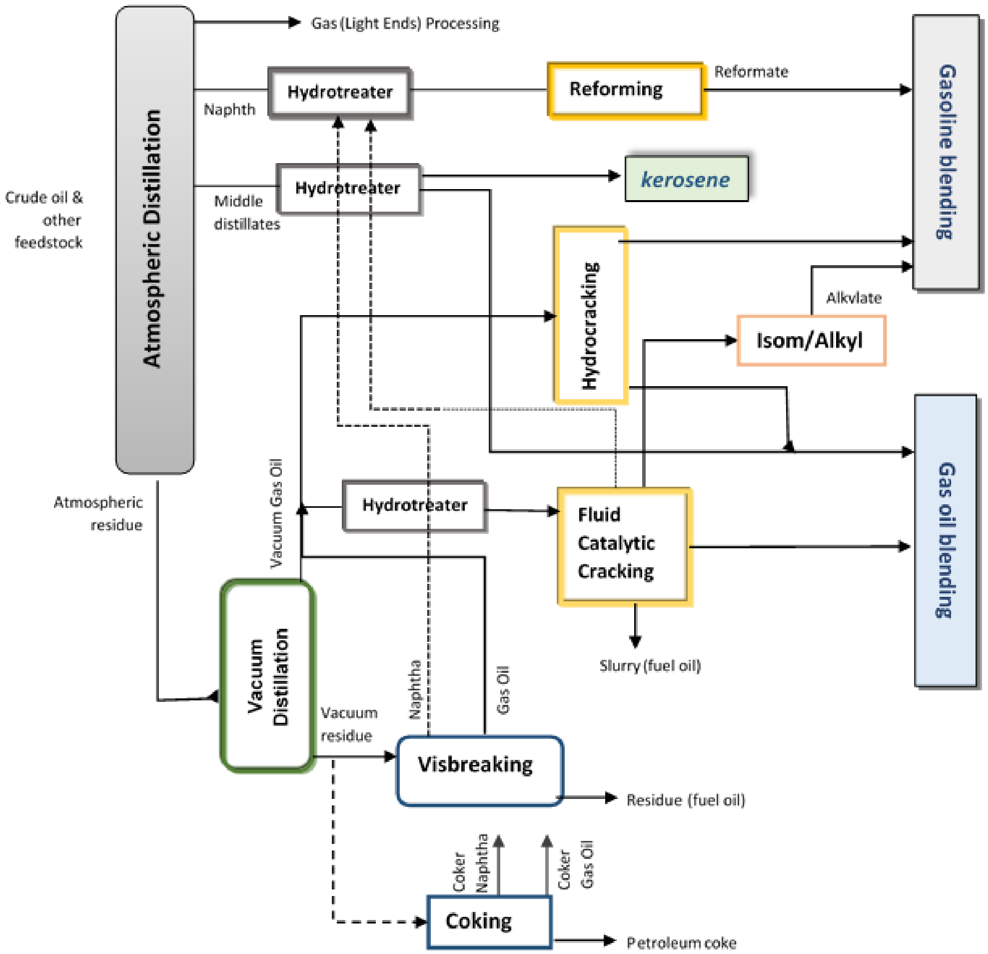


Figure 4.8: Schematic representation of the main processes included in the representative refinery structure of the PRIMES-Refinery model

The demand for petroleum products is met through domestic production in the EU refineries and through trade (imports-exports), the latter determined endogenously in the model based on relative prices and depending on elasticity parameters. Trading in the model includes both final refinery fuels and refinery feedstock, which is consequently used in the EU refineries, and is performed internally in the EU and internationally. EU countries and extra EU locations are connected through a transportation matrix that describes distances and transportation mean options. The international trade mainly simulates trade between the EU, the Middle East region, the North America region and a few other regions aggregated. The relation of imported quantities to the respective import prices is described via non-linear cost-supply curves, thus different market behaviours regarding import patterns can be simulated. The minimization problem is subject to constraints associated with limitations of the feedstock supply, as well as blending requirements on the crude oil and intermediate streams, product specifications and capacities.

The refinery feedstock in the model is divided into 2 main categories: crude oil and other feedstock. The feedstock supply is described by country specific cost-supply curves. Feedstock produced internally in the EU is subject to resource limitations. Given the large diversity of the various crude types imported at the European refineries, it was decided to improve the modelling and the resolution of the PRIMES-Refinery model regarding the crude types imported. E3MLab is currently in the process of upgrading the model to simulate three different crude oil types instead of the one category previously implemented. The ongoing extensions of the model towards this direction will be presented in more detail further in the current section.

The model includes a variety of refinery generic processing unit types used to separate the distillates from the crude feedstock and convert the intermediate products into lighter valuable products. Technology heat-rates (energy conversion factors) are assumed to improve over time following technology developments. Additional modelling work is also currently under way to include more refining processes in the PRIMES-Refinery model. This extension is essential to account for the various actual refining processes included in the European refineries; the main configuration types have been derived from the refining survey of Oil and Gas Journal. The main refining processes to be included in the model are presented further in the current section.

The model computes endogenously the investment in technologies and the respecting processing capacities, derived as a result of investment accumulation. Available capacity is a constraint to the petroleum commodities production. Technology vintages, that define the time a processing capacity was installed, are used for the specification of the technical characteristics of the processing units, as well as the decommissioning of capacities. To determine the prices of the final petroleum products, the PRIMES-Refinery model includes a pricing module. To this scope, the model formulates a Ramsey-Boiteux pricing rule which consist of two parts, namely a marginal cost pricing part and an average cost pricing one the latter being used to recover all fixed and capital costs.

Allocation of GHG emissions per refined petroleum product

The key objective of using a model based analysis for simulating the European refineries is to allocate the refinery GHG emissions to the following refined petroleum products: petrol, diesel and kerosene (all refinery outputs are included in the model). The allocation of the GHG emissions to the abovementioned petroleum products will be based on marginal emission coefficients for each refinery product. The refined fuel-specific emission factors will be calculated by allocating total refinery emissions based on the marginal emission content methodology (as developed by the Institut Francais du Pétrole).

The marginal emission coefficients for each refinery product are derived by the measuring of the variation of emissions after the marginal change of the demand for a specific fuel. Marginal content refers to the additional emissions generated from one additional unit of production of the specific product, which depends on refinery configuration that varies in the EU countries. The resulting coefficients are consequently applied to the average GHG emissions to receive an individual fuel-specific emission factor.

E3MLab will also provide estimates on the lifecycle GHG emissions of the major refined products imported to EU, apart from the calculations of the GHG emissions resulting from petroleum products refined in European refineries. The evaluation of the GHG emissions from the imported oil products, mainly from Russia and US, will be based on the methodology followed for the calculation of emissions generated in European refineries. To account for the GHG emissions of these imported fuels during their refining process in Russia and US, E3MLab will derive proxy values for their respective GHG emissions from other European countries with similar refinery configuration. According to the study of Jacobs Consultancy, the US refined products are derived from high conversion refineries, similar to European ones, while a hydroskimming configuration (with no gas oil and residue conversion capacity) is representative of Russian refineries that export finished products to Europe.

Ongoing extensions of the PRIMES-Refinery model related to crude oil types

For the purposes of the present study, E3MLab is currently performing modelling upgrades to allow for a more enhanced simulation of the refineries configuration in the EU. Drawing largely from data retrieved in Task b a number of different MCONs have been identified that enter the refinery gates of the various European refineries. The key characteristics of the various MCONs entering the EU refineries are related to the API gravity and the sulphur content.

To account for the large diversity of the various MCONs used in the EU refineries, E3MLab is currently extending the PRIMES-Refinery model to include three different categories of crude types entering the representative refinery configuration. The classification of the different crude types is based on the API gravity and sulphur, as can be seen in Table 4.3. The differentiation of the crude types allows the different handling and simulation of the respective processes, product yields and energy consumption by the properties of crude oil.

Representative crude oil types in PRIMES-Refinery	Classification by API gravity	Average API gravity	Classification by sulphur content (wt%)	Average Sulphur content (wt%)
Type 1 - Light	>35	40.7	<0.8	0.51
Type 2 - Medium	28-35	32.9	0.8-2	1.27
Type 3 - Heavy	<28	22.3	>2	2.47

Table 4.3: Representative crude oil types considered in the PRIMES-Refinery model: classification by API gravity and sulphur content

Heavier or lower quality crude oils (with lower API gravity) require energy intensive processing to upgrade the higher volume of the 'bottom of the barrel'. They go through expanded carbon rejection and hydrogen addition processing, thus the energy required for that additional processing increases the energy consumption of the refinery. Vacuum distillation, catalytic cracking (including fluid catalytic cracking and hydrocracking) and thermal cracking are the main processing units that are influenced by the API gravity of the crude oil. Processing of crudes with high sulphur content increases energy consumption as hydro-treating and desulphurization processes require additional hydrogen consumption and, as a consequence, additional energy use by the hydrogen production plant.

In the modelling, the level of processing and the blending constraints for the input and output of the various processes are differentiated by each type of crude. The three types of crude oil have different volume distribution between the fractions derived from the atmospheric distillation (i.e. naphtha, middle distillates and residue), different processing capacities and product yields. The calibration of the model will be updated in order to suite the scope of the study and determine the production level for each type of crude oil.

Ongoing extensions of the PRIMES-Refinery model related to the refining processes

This section presents the main refining processes that will be eventually considered in the PRIMES-Refinery model. Partitioning of the refinery's processes on a country basis largely draws on the refining survey of Oil and Gas Journal. The modelling approach is based on the fact that different products go through different processes within the refinery, thus production flows are used to simulate the various streams leading to the products of interest (petrol, diesel and kerosene). The typical refining processes included in the PRIMES-Refinery model are presented in Table 4.4.

Refining Process	Short description
Atmospheric Distillation	First separation of crude into a series of boiling point fractions
Vacuum Distillation	Separation of the bottom of the atmospheric distillation under reduced pressure (vacuum)
Thermal Cracking (Visbreaking / Coking)	Thermal conversion of high-molecular weight hydrocarbons into lighter products
Fluid Catalytic Cracking	Catalytic Conversion of high-molecular weight hydrocarbons into lighter more valuable products
Hydrocracking	Catalytic cracking of hydrocarbons under high pressure in the presence of hydrogen
Catalytic Reforming	Low octane straight run naphtha is converted into a high octane liquid reformate /Hydrogen production
Isomerization/Alkylation	Conversion of low-octane n-paraffins to high-octane iso-paraffins and conversion of olefins to highly branched iso-paraffins
Hydrotreating	Removal of contaminants (sulphur, nitrogen, metals etc.) of the intermediate products through their contact with hydrogen, aromatics saturation

Table 4.4: Main refining processes used in the PRIMES-Refinery model

The refining flow through the different processes is described as follows: the crude oil feed (including the crude and the other feedstock components) is initially separated into various fractions according to its boiling points in the *atmospheric distillation* unit. Light fractions including gas to C5 molecules of hydrocarbons and light and heavy naphtha are used to produce LPG and gasoline blending components. *Catalytic reforming* converts low octane straight run heavy naphtha into a high octane reformate. Middle distillates including kerosene and light gas oil are processed to produce refined products (kerosene and diesel).

Heavy fractions (atmospheric distillation residue) are further distilled under vacuum to obtain vacuum gas oil (feed to fluid catalytic cracking or hydrocracking) and vacuum residue. The F*luid Catalytic Cracking* unit converts high-molecular weight hydrocarbons into lighter products (light ends, naphtha, light cycle oil). Fluid catalytic cracking is combined with an *alkylation* unit to convert light olefins into highly branched isoparaffins (alkylates). *Hydrocracking*, similar to catalytic cracking, converts the heavy fraction of vacuum gas oil into lighter saturated products under high hydrogen pressure. Hydrocracking is considered to operate in competition with Fluid Catalytic Cracking as both units convert vacuum gas oil. The vacuum residue is fed to a thermal cracking unit; visbreaking is the most common process for the reduction of viscosity of the residue and the production of lighter products. A part of vacuum residue may be processed by *coking* in order to achieve higher conversion of heavy hydrocarbon molecules and obtain petroleum coke as a final product. Hydrocracking and coking are going to be selectively included in refining operations of EU countries that use these units according to the data provided by the survey of Oil and Gas Journal.

Petrol and diesel are anticipated to be produced in accordance with Euro V fuel specifications, requiring the sulphur content to be less than 10 ppm. In order to reach the sulphur specifications for gasoline and gas oil pools, various hydro-treating units are required. Three distinct hydro-treaters are considered in the model: naphtha hydro-treater, distillates (kerosene and diesel) hydro-treater and gas oil hydro-treater which prepares the feed for fluid catalytic cracking. For simplicity, whenever hydro-treating process is mentioned, it will refer to these three units.

Reforming produces high purity hydrogen to satisfy the needs of hydro-treating processes. A hydrogen production unit via steam methane reforming is also considered to supplement the requirements for hydrogen associated with hydro-treating and hydrocracking processes.

4.2.2 Required Inputs and Outputs of the model

The key inputs required for the PRIMES-Refinery model are the capacities of the refining processes within the refinery configuration per EU country. Oil and Gas Journal Worldwide Refining Survey includes analytical data for the worldwide refineries and their capacities. Valuable information is obtained regarding the number of active refinery industries, the main operations of European refineries and the capacity of each of them.

Apart from the crude oil capacity which is the main indicator of the size of the refinery, Oil and Gas Journal database provides information on the charge and production capacity in barrels per capital day (b/cd) for every single refinery worldwide. Production related capacities provide data associated with aromatics, lubes, oxygenates, hydrogen, sulphur, coke and asphalt production. The following charge processing units are included in the survey:

- vacuum distillation,
- coking,
- thermal operations,
- catalytic cracking,
- catalytic reforming,
- catalytic hydrocracking,
- catalytic hydro-treating.

Further, data on the various MCONs entering the European refineries have been collected within Task b. The various MCONs are further disaggregated by key characteristics such as the API gravity and the sulphur content. This part is particularly important for allocating the different MCONs entering the refinery gates of each EU country with the representative crude type categories simulated in the PRIMES-Refinery model. Feedstock supply for the refineries operations, as well as consumption of electricity and gas are derived from the EUROSTAT energy balances.

Electricity and gas consumption needs to be further disaggregated into quantities purchased directly from external sources and quantities produced within the refinery boundary system. This split is important for the calculation of the GHG emissions related to the electricity and gas consumed. Different emission factors will be used to derive the GHG emissions from the electricity and natural gas imported from external sources. For instance, in the case of electricity, the GHG emission factor assumed will be related with the structure of the power generation sector of the country. As regards, the electricity and gas produced within the refinery, the emission factor will be refinery specific and data will be drawn from the EUROSTAT balances and the calibration of PRIMES database to past years. The quantities of the refined petroleum products imported in the EU by major exporting countries such as Russia and US have already been identified during Task b. The total refined petroleum products that are produced at a national level over the EU countries is also provided by the EUROSTAT balances. Other techno-economic data regarding the heat-rates (conversion factors), utilization rates of the processes, operating and investment costs as well as the respective emission factors are also currently under update using sources from literature and technical refinery reports.

4.2.3 Estimating the GHG emissions due to transportation from refineries to filling stations

Methodology

The transportation of the refined petroleum products from the refineries to the filling stations in the EU Member States usually takes place via road freight, freight rail and inland waterways, which are currently operating mainly on fossil fuels. The use of fossil fuels is responsible for GHG emissions which take place during the transportation of the refined petroleum products and should be included in the lifecycle carbon emissions of diesel, petrol and kerosene. To calculate the carbon intensity $CI_{c,k}$ per transport mode k and country c used to transport the refined petroleum products Rpp we use the formula in Eq 1. This formula is based on the activity of the transport mode, usually measured in ton-kilometers (tkm), the emission factor of the mode (in gCO_2/tkm) and the total quantity of refined petroleum product transported (in MJ).

$$CI_{c,k} = \frac{Rpp\ transported_{c,k}(tkm) \times Emission\ factor_{c,k}(\frac{gCO2}{tkm})}{quantity\ transported_{c,k}(MJ)} \qquad \text{Eq 1}$$

To derive the average carbon intensity of the transportation of the refined petroleum products from the refinery to the filling stations, the weighted average is calculated based on the activity in tkm of each respective transport mode using the following formula (Eq 2).

$$CI_c = \frac{\sum_k CI_{c,k} \times Rpp\ transported_{c,k}}{\sum_k Rpp\ transported_{c,k}} \qquad \text{Eq 2}$$

Further, to account for the fugitive GHG emissions at the level of the filling stations, a typical emission factor has been used from literature. As these emissions are relatively small compared to the LCA GHG emissions, for simplicity, the same emission factor has been assumed for the fugitive GHG emissions for all the EU countries. The most recent emission factor found in the technical report published by the National Environmental Research Institute has been utilized; the emission factor used is equal to 0.46 kg NMVOC/ ton gasoline.

Input data

The required input for these calculations is the activity of each respective transport mode transporting refined petroleum products, the amount of products transported, and the emission factors per transport mode. The resolution of the data is at a national level.

Data on the activity of road freight, freight rail and inland waterways transporting refined petroleum products has been derived from EUROSTAT database. For road freight the element “road_go_na_tgtt” has been used which includes statistics on both the activity and the tons of refined petroleum products transported. As regards freight rail, EUROSTAT did not provide the activity and the tons of refined oil products transported at a national level. Therefore, shares were derived from the element “rail_go_natdist” which only reported data until 2002 and applied these shares to the total goods transported by rail at a national level in 2012 (element “rail_go_typeall”). Regarding inland waterways, the values on activity and the tons of refined petroleum products from the element “iww_go_atygo” were used from EUROSTAT. The emission factors per transport mode used in our calculations are drawn from the PRIMES-TREMOVE[12] transport model, developed and maintained by E3MLab. The values used

[12] http://www.e3mlab.ntua.gr/e3mlab/PRIMES%20Manual/PRIMES%20TREMOVE_v3.pdf

have also been validated with the values reported in the TRACC[13]S database.

Draft results

The resulting values of the carbon intensity due to the transportation of refined petroleum products from the refineries to the filling stations by EU country are presented in Table 4.5. According to calculations we observe some variations are observed in the resulting values which are attributed to the different shares of transport modes used to transport refined petroleum products to the filling stations and different emission factors per EU country. For the purposes of the present study an average value for the carbon intensity at the EU level which is estimated to be about 0.29 gr CO_2/MJ.

Country	Carbon intensity (grCO2/MJ)
Belgium	0.32
Bulgaria	0.26
Czech Republic	0.23
Denmark	0.50
Germany	0.18
Estonia	0.21
Ireland	0.50
Greece	0.33
Spain	0.37
France	0.29
Italy	0.46
Cyprus	0.53
Latvia	0.38
Lithuania	0.15
Luxembourg	0.66
Hungary	0.16
Netherlands	0.18
Austria	0.16
Poland	0.17
Portugal	0.32
Romania	0.42
Slovenia	0.19
Slovakia	0.11
Finland	0.31
Sweden	0.25
United Kingdom	0.42
Croatia	0.48

[13] http://traccs.emisia.com/

Country	Carbon intensity (grCO2/MJ)
EU average	0.29

Table 4.5: Estimated carbon intensity of refined petroleum products due to transportation from refineries to filling stations (also including fugitive emissions at the level of filling stations). Source: E3MLab calculations

4.3 The GHGenius model

4.3.1 Model rationale and structure

The GHGenius lifecycle model is a publicly available, Excel based, model that considers the lifecycle energy use and emissions from transportation fuels and vehicles. The model has been developed over the past 15 years by (S&T)[2] Consultants Inc. Most of the development work has been funded by Natural Resources Canada.

The model can perform a lifecycle assessment for specific regions (east, central or west) of Canada, the United States and Mexico or for India as a whole. For Canada, it is also possible to model many of the processes by province. It is also possible to model regions of North America. It is the regional nature of GHGenius that makes it an appropriate tool for studying the emissions of producing, processing, transporting and transforming the gas for use in the transportation sector for Europe.

The spreadsheet structure of GHGenius makes it relatively easy to expand the model to other regions of the world, in this case the European Union. The model is fully transparent and users can easily trace all stages of the calculations.

There are over 200 vehicle and fuel combinations possible with the model. Although the focus of this work is just the natural gas fuel supply chain up to the point that the natural gas would be dispensed to a vehicle.

4.3.2 Model parameters and structure modification

The structure of GHGenius has been changed to provide the desired results of this project. The number of regions that the model is capable of analysing has been expanded with the addition of 4 more regions for Europe. The expansion of the model has not resulted in any loss of functionality for any of the existing regions in the model.

The four new European regions are:

- **Northern Europe.** The gas supply in the region is from the North Sea fields, imported LNG, and some Russian gas.
- **Central Europe.** Significant gas suppliers to the region are Russia, the Netherland, and Norway. There are some indigenous supplies and imports of LNG as well.

- **South East Europe.** This region has Russia and Algeria as the major suppliers with a large number of smaller suppliers supplementing the two major suppliers.
- **South West Europe.** The significant gas suppliers include Norway, Algeria, the Netherlands, Russia and LNG from Qatar and Nigeria.

In addition to the four new consuming regions, new gas producers have been added to the model. Some of these gas supply regions were already in the model but the data was of very poor quality. That will be addressed as part of the project. The gas suppliers that will be included in the revised model are:

Countries with existing quality information:

- United States
- Canada
- Mexico
- India

Existing Countries that need updated information:

- Algeria
- Norway
- Russia
- United Kingdom

New Countries added to the model:

- Netherlands
- Denmark
- Libya
- Germany
- Belgium?
- Generic shale gas
- Other
- Qatar LNG
- Nigeria LNG
- Algeria LNG
- Trinidad and Tobago LNG
- Indonesia LNG
- Other LNG

Algeria will have two supply systems, pipeline gas and LNG. The model inputs for the two types of gas will be slightly different with the extra energy required to liquefy the gas included in the LNG supply options.

Not all of these LNG sources are currently gas suppliers to Europe, but they are large global suppliers and space has been made for them in the model. The other LNG suppliers will have average values so that the suppliers that contribute less than 1% of the gas supply can be accounted for. We will also add a generic EU shale gas supplier to the model so that can be considered as a future supply source as well. Data for this supply option may have more uncertainty.

Natural gas supply systems generally use mostly natural gas energy in the production system but there can also be electricity consumed and a small amount of liquid fuels. Electricity will also be used in the gas consuming regions for compression to CNG. The GHGenius model structure has therefore been expanded to include the specific regional electricity production data for the gas producing countries and the gas consuming regions. This will include the mix of energy sources used to produce the power, the efficiency of the thermal generating system, and the distribution losses in the grids.

The contribution of the production of liquid fuels to the complete lifecycle emissions is expected to be small and less effort will be expended to use regional specific data for liquid fuel production for this work.

GHGenius currently allows for the input of energy used for well drilling, gas production, and gas processing for gas production in Canada and the United States. The specific energy inputs that can be input are crude oil, diesel fuel, residual fuel, natural gas, coal, electricity, gasoline, and coke. Other gas producing regions are estimated on a total quantity of energy consumed relative to energy consumed in the US. This same structure used for Canada will be introduced for all of the other gas supply regions.

The model will be modified to include two tables of transportation distances from the gas supplier to the gas consuming region. One table will have pipeline distances and the other will have shipping distances for LNG. The average distance for each consuming region will be used to calculate the energy consumed and the emissions from the transmission and transport of the gas.

An important part of the natural gas supply chain is the rate of methane loss from the system, this can be through venting, flaring, or equipment leaks. The new structure of the model will accommodate separate inputs for all of these emissions for all gas producers and for the gas consumers for the transmission losses.

The final emission source that is included in the model is the emission of carbon dioxide that is removed from the gas during processing to bring the gas to pipeline quality.

4.3.3 Required Inputs

In order to model the lifecycle GHG emissions from the supply of natural gas in Europe a significant amount of data is required. The data required includes;

- The gas production, imports and consumption for each of the EU countries.
- The carbon intensity of the electric power used in each of the producing countries, as some electricity can be used to produce and process the natural gas in the producing country.
- The carbon intensity of the electric power used in each of the EU countries as electricity is used to compress the natural gas to CNG.
- For each supplier of natural gas the data that will ideally be required are those for three stages of gas production, well drilling, gas extraction, and gas

processing. The data required will include the quantity and type of energy required for each of the three stages, the methane loss rate of each stage, the quantity of gas flared, and the quantity of carbon dioxide released to the atmosphere to bring the field gas to pipeline specifications.

- For each supply source the pipeline or shipping distance of gas to the EU region will need to be identified so that the energy consumed in the gas transmission/transportation stage can be determined. For each of these activities the methane loss rate will be required.
- Within each of the EU countries energy use in gas distribution (medium pressure) and the relevant emissions will be assessed. Energy use in distribution is very small as compression is not required, like it happens in transmission; however the distribution gas loss as fugitive gas can be substantial.On the other hand electricity requirements of gas distribution systems are mostly related to compression of pipeline gas to CNG.

4.3.4 Parametric significance

There are three groups of GHG emissions in the natural gas supply chains. There are CO_2 emissions resulting from the purification of the raw gas to pipeline specifications. Depending on the gas composition of the specific fields these can be zero or some extreme cases these emissions might account for 4 or more gr CO_2eq/MJ. In some gas fields the CO_2 may be re-injected into the reservoir to help maintain the field pressure. This will lower the direct emissions of CO_2, but the re-injection process will increase the energy consumption and thus there will be some energy related emission increase that will offset the savings from the re-injected gas.

The second category of emissions is energy related; those emissions resulting from the use of energy in all stages of the supply chain. Field pressure, gas composition, transmission distances, and pipeline characteristics can all influence the energy consumed in the natural gas supply chain. Energy is used in the well drilling, gas production, gas processing, gas liquefaction and regasification (for LNG supply), gas transmission, but only in rare instances the gas distribution stage. The contribution of energy related emissions is typically 5 to 10 gr CO_2eq/MJ.

The third category of emissions is the leaks of methane from the system. Every stage has the potential for some methane emissions, and since methane has a GWP of 25, these emissions can become quite significant in “leaky” systems. In a few cases methane leaks are deliberate such as using the natural gas to actuate control values instead of using compressed air systems, but in most cases the methane emissions are unintended and could be fugitive type emissions. Methane emissions are difficult to quantify accurately since there can be literally thousands of individual points of potential leaks in a supply chain. Every valve, meter, compressor, relief station, and connection can be a source. Methane emissions from less than 0.5% to 1.5% can be expected in most supply chains. These emissions are equivalent to 4 to 12 gr CO_2eq/MJ.

4.3.5 Produced outputs

GHGenius can provide significant detail on the emissions for natural gas. The most common form of the output is the GHG emissions by stage per GJ of fuel. For natural gas systems the typical output is shown in Table 4.6. While the focus of the work is on the emissions for CNG, the model will also provide the natural gas emissions for gas supplied to power generators, fuel conversion facilities (e.g. methanol plants), and other end users.

Stage	Compressed Natural Gas	Natural Gas for Industry
	gr CO_2eq/GJ (LHV)	
Fuel dispensing	2,534	0
Fuel distribution and storage	961	862
Fuel production	2,787	2,778
Feedstock transmission	0	0
Feedstock recovery	3,007	2,997
Feedstock Upgrading	0	0
Land-use changes, cultivation	0	0
Fertilizer manufacture	0	0
Gas leaks and flares	3,214	1,605
CO_2, H_2S removed from NG	1,081	1,078
Emissions displaced	0	0
Total	**13,584**	**9,319**

Table 4.6: Typical GHGenius Output on the emissions of natural gas

The information can also be supplied by the total emissions of the individual gases as shown in Table 4.7. The emissions of these gases by stage can also be provided in a series of tables for each gas.

GHGenius also can report on the primary energy consumed for each stage of the process. Primary energy includes the energy required to produce the energy, it is the lifecycle energy used. Total primary energy and fossil primary energy can be reported. The typical energy use is shown in the Table 4.8. This output is only available on a higher heating value basis.

Stage	Compressed Natural Gas	Natural Gas for Industry
	gr CO_2eq/GJ (LHV)	
Carbon dioxide (CO_2)	9,251.1	6,718.3
Non-methane organic compounds (NMOCs)	3.7	3.0
Methane (CH_4)	170.6	102.2

Stage	Compressed Natural Gas	Natural Gas for Industry
Carbon monoxide (CO)	7.2	6.0
Nitrous oxide (N_2O)	0.2	0.2
Nitrogen oxides (NO_2)	52.7	44.6
Sulphur oxides (SOx)	15.9	7.0
Particulate matter (PM)	0.8	0.3
HFC-134a (mg)	0.0	0.0
CO_2-equivalent GHG emissions	**13,583.6**	**9,318.8**

Table 4.7: Typical GHGenius Output by Specific Gas

Stage	Compressed Natural Gas	Natural Gas for Industry
	Joules consumed/Joule Produced	
Fuel dispensing	0.0250	0.0000
Fuel distribution, storage	0.0143	0.0128
Fuel production	0.0392	0.0391
Feedstock transmission	0.0000	0.0000
Feedstock recovery	0.0416	0.0415
Feedstock Upgrading	0.0000	0.0000
Ag. chemical manufacture	0.0000	0.0000
Co-product credits	0.0000	0.0000
Total	**0.1202**	**0.0935**
EROEI (J delivered/J consumed)	**8.3186**	**10.7007**

Table 4.8: Typical GHGenius Output for the Total Energy Consumption

The type of energy used can also be provided as shown in Table 4.9. This energy use is reported as secondary energy. Secondary energy is the energy content of the electric power, or diesel fuel, or coal at the point that it is used.

Energy Type	Compressed Natural Gas	Natural Gas for Industry
	Joules consumed/Joule Produced	
Coal	0.0000	0.0000
Crude	0.0000	0.0000
Natural Gas	0.0832	0.0817
Diesel	0.0006	0.0006
Gasoline	0.0000	0.0000
Biomass	0.0000	0.0000

Energy Type	Compressed Natural Gas	Natural Gas for Industry
Electricity	0.0187	0.0017
Other	0.0000	0.0000
Total	**0.10**	**0.08**

Table 4.9: Typical GHGenius Output for the Secondary Energy Use by Type

5 TASK D: INDIRECT EMISSIONS

Regarding indirect emissions, the following activities have been conducted.

- Articles reviewed and uploaded to database;
- Method for calculation of indirect GHG emissions developed;
- Information on indirect GHG emissions partly developed/identified;
- Background data for calculation of average indirect GHG emissions established;
- Preliminary results for some indirect GHG emissions calculated.

This section presents the method for estimating indirect emissions and reveals some preliminary results regarding the magnitude of the indirect emissions.

5.1 System Boundary Definition

Along with the direct GHG emissions from the life cycle (well-to-tank) of transport fossil fuels (diesel, petrol, kerosene and natural gas); this study will also include the "indirect emissions" in the analysis.

More precisely, the indirect emissions will be identified and assessed, and where possible these emissions will be included in the total estimates of the GHG emissions from the fuels.

The relevant stakeholders have not clearly defined indirect emissions. For the purpose of the present study, the following definition will be used:

Direct emissions are emitted from the processes used to produce and transport the fuel along the life cycle. **Indirect emissions are those that are influenced or induced by economic, geopolitical or behavioural factors, but which are not directly related to extraction, processing, transportation and distribution of the fuels**[14].

In order to make sure that all relevant emission sources are covered by the project, there is need to define clearly what is considered direct and indirect emission sources respectively.

5.2 Attributional And Consequential Emissions

Indirect emissions can be divided into two types:

[14] Corresponding to the definition in the ICF report on Indirect Emissions (page 2)

- **Attributional emissions:** Emissions that can be said to be related to the production of the fossil fuels and thus can be added to the direct emissions estimated by the traditional LCA approach. An example of attributional emissions is the case of emissions related to military activities to protect the resources.
- **Consequential emissions:** Emissions arising from changes at the level of the production of fossil fuels. These are related to the forecasting of the future emissions but not in terms of estimating the emissions from today's fuels. An example of a consequential emissions source is “price effects”: Reduced demand for fossil fuels for transportation due to substitution with alternative fuels will lower fossil fuel prices, which in turn will tend to increase the demand for fossil fuels used for other purposes. Thus, the full positive impact from the fall in the demand for fossil fuels for transport will actually not occur.

Attributional emissions are associated with the full estimation of the actual lifecycle emissions, whereas the consequential emissions are associated with the projections on future GHG emissions. The study of indirect effects will focus on the attributional part, especially when it comes to the estimation.

Following a literature review, the indirect emissions sources identified and included in the study are listed below. These are described focusing on the boundaries to the direct emissions, where relevant.

- Attributional emissions sources:
    - Induced land development
    - Military involvement
    - Accidents.
- Consequential emission sources:
    - Marginal effects
    - Price effects
    - Co-product production.

Figure 5.1 below illustrates the indirect emission sources (marked in red) and the placement in the fossil fuel life cycle.

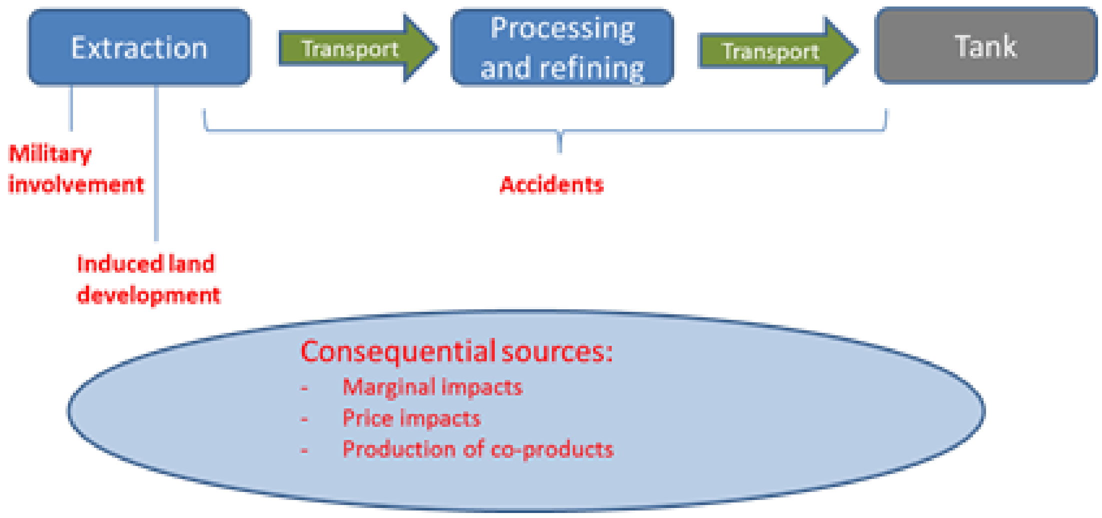


Figure 5.1: Identification of indirect emission sources related to oil and gas pathway from well to tank

5.3 MAIN INDIRECT EMISSIONS

5.3.1 Attributional emissions sources

Induced land development

This issue covers the induced land development caused by adjacent developments that are facilitated by oil and gas production in remote areas.

It is important to distinguish between direct and indirect emissions from land development:

- The **direct emission source** arises from the need for land to produce and transport fuels, thus the emissions related to clearing land for these purposes. These can be compared with the ILUC emissions for biofuels, although the impacts from fossil fuels are limited compared with the impacts from biofuels. The direct impacts of land use change are considered a direct effect and not covered in the study of indirect impacts.
- The **indirect emission source** referred to as “induced land development” covers the impacts caused by the access to remote areas. Extraction of the raw materials requires access to areas that would possibly otherwise be left untouched. The development of infrastructure will thereby cause disturbance to the area. The magnitude of the emissions impact will, among other things, depend on the type and location of the land involved. For example, it is generally accepted that oil activities opened up new agricultural frontiers in the northern Amazon region by building penetration roads into primary forest areas

(ICF, p. 28). Therefore, the question is naturally whether the deforestation is "additional" or whether a possible deforestation is just moved from one area to another.

In the study, into the possible effects of induced land development will be investigated. This will include, among other things, exploring the differences between various types of raw materials and the geographic location, and considering whether the induced land development is additional or a replacement.

Military involvement

This issue covers emissions from military activities to provide security and stability to oil-producing regions and to protect international oil supply routes. The key issue is to what extent military activities are motivated by efforts to secure petroleum and gas reserves?

Emissions from military activities arise from fuel combustion from military means of transport as well as from the energy used to construct military infrastructure and rebuild states that have been affected by conflicts.

The emission sources can be divided into two categories: security-related emissions (from long-term, sustained military presence in a geographic area) and conflict-related operations emissions (such as the Gulf War).

Accidents

Accidents may occur throughout the pathways followed by the fossil fuels and may have severe environmental impacts. Possible GHG emissions caused by accidents fall within the following categories:

- Blowouts (uncontrolled bursts or releases of oil and gas) during extraction. These certainly have a severe environmental impact, but they are not GHG emissions unless the oil is burnt or the blowouts involve release of methane.
- Accidents during transportation or storage at the ocean: clean-up may include surface burning of oil causing GHG emissions.

These possible impacts will be included in the analysis of indirect sources, where other possible emission sources caused by accidents will also be investigated.

Fugitive emissions from sources such as sealing, well completions and work-overs (i.e. retrofitting a well) are "engineered losses" that occur during normal operation. These are considered direct emissions and are consequently not included in the analysis of indirect emission sources.

5.3.2 Consequential emissions sources

Marginal impacts

This issue covers impacts on the fossil fuel lifecycle that would result from large-scale economy-wide changes in the supply and demand of fossil fuels.

This may result in at least two different consequences:

- Changes in demand will alter the marginal fossil fuel resource consumed. This will change the types of fossil fuels extracted and the operation of refineries, all affecting the GHG emission profile.
- Increased demand for natural gas for transportation may reduce the use in the electricity sector, resulting in changes in the mix of fuels used in electricity production.

These impacts are expected to be modelled in the forecast models and are therefore not included in this section of indirect emission sources.

Price impacts

Changes in the use of fossil fuels for transportation will affect the demand and thereby the prices, which in turn will affect the demand for fossil fuels in other sectors. This rebound effect is normally best modelled and assessed in economic models, especially in the field of “general equilibrium modelling”.

Price impacts need to be taken into account in the forecasting. It is expected that the models of E3M LAB will capture such impacts, and this issue will thus not be handled within the area of indirect effects.

Production of co-products

The refinery process also results in various co-products besides the fossil fuels. Without fossil fuels, these have to be produced in other ways or substituted by other products in the use.

Two aspects of the production of co-products have to be considered in the LCA.

First, it could be argued that some of the emissions throughout the life cycle should be assigned to the co-products, thus reducing the emissions from the fossil fuel part. There are different methods for doing that, and it is assumed that these emissions will be covered by the calculations of direct effects in the refinery model.

Secondly, changes in the production of fossil fuels will result in the need to find alternative ways of producing the co-products or substituting the use of the co-products with alternative products, which will affect the GHG emissions. This is an indirect and consequential emission source, which may be considered in this study.

5.4 METHODOLOGY FOR ASSESSMENT OF INDIRECT EMISSIONS

Oil and gas consumed in the EU come from different locations and are transported with different technologies. The indirect emissions are relevant only for some of these locations and technologies. For instance, induced land development will only be relevant in areas where there is a potential for deforestation and maybe also later for use of land for alternative purposes. Military CO_2 emissions may only be relevant in areas with politically unstable conditions like in the Middle East. In order to include these indirect GHG emissions, there is need to analyse which indirect GHG emissions are relevant for each of the locations from which we get the oil and gas.

Table 5.1 shows how we suggest breaking down fossil fuel extraction and transport to match specific, indirect emissions.

Region	Country of Origin	Name	Offshore /Onshore	Transport	Location	Political
	Iran	Gachsaran oil field	On	Pipeline / Tanker		Political issues
	Iraq	Rumaila (South)	On	Pipeline / Tanker		Political issues
		West Qurna	On	Pipeline / Tanker		Political issues
		Kirkuk	On	Pipeline / Tanker		Political issues
	Kuwait	Burgan	On	Pipeline / Tanker		Political issues
	Saudi Arabia	Kurais	On	Pipeline / Tanker		Political issues
		Manifa	On	Pipeline / Tanker		Political issues
Africa	Algeria	Hassi Messaoud	On	Pipeline / Tanker		
	Angola	Block 17/Dalia	Off	Tanker		Political issues
		Girassol	Off	Tanker		Political issues
		Greater Plutonio	Off	Tanker		Political issues
	Libyan Arab Jamahiriya	Es Sider	Off	Tanker		Political issues
		El Sharara	Off	Tanker		Political issues
	Nigeria	Bonga	Off	Tanker		
		Forcados Yorki	Off	Tanker		
		Agbada	On	Tanker	Rain forrest	
		Caw Throne Channel	On	Tanker	Rain forrest	
		Escravos Beach	On	Tanker	Rain forrest	
FSU	Azerbaijan	Azeri-Chirag-Gunashli (ACG) field	Off	Tanker		Political issues
		Tengiz	On	Pipeline / Tanker		Political issues
		Azeri-Chirag-Gunashli (ACG) field	Off	Tanker		Political issues
	Kazakhstan	Tengiz	On	Pipeline / Tanker		Political issues
	Russian Federation	Povkhovskoye	On	Pipeline		
		Tevlinsko-Russkinskoye	On	Pipeline		
		Uryevskoye	On	Pipeline		
		Vat-Yeganskoye	On	Pipeline		
		Pamyatno-Sasovskoye	On	Pipeline		
		Unvinskoye	On	Pipeline		
	Denmark	Tyra south east	Off	Tanker		
	Norway	Statfjord	Off	Tanker		
	Norway	Ekofisk	Off	Tanker		
	Norway	Troll B/C	Off	Tanker		
		Tyrihans	Off	Tanker		
		Oseberg	Off	Tanker		
		Gullfaks	Off	Tanker		
	UK	Buzzard	Off	Tanker		
		Ninian	Off	Tanker		
		Captain	Off	Tanker		
	Mexico	Cantarell	Off	Tanker		
	Venezuela	Boscan	On	Tanker	Rain forrest	

Table 5.1: Potential indirect GHG emissions for oil consumed in the EU

By combining the information from Table 5.1 with the amount of oil consumption from these locations, it will be possible to calculate the share that is relevant for the specific types of indirect GHG emissions. This is shown in Table 5.2.

Issues	Share of oil consumption in the EU (%)
Tanker transport	58 %
Rain forest	6 %
Political issues	31 %

Table 5.2: Share of oil production affected by specific indirect GHG emissions

As can be seen, more than half of the oil consumed is transported to the EU by oil tankers, with the potential risk of oil spills from oil tanker accidents. The rest is transported by pipeline from Russia.

Only a very small fraction of 6% of the oil consumed in the EU comes from areas with potential, induced land development effects in rain forest areas.

A percentage of 31% of the oil consumed comes from areas where politically unstable situations may justify military presence to secure stable energy supply.

A similar picture can be drawn for natural gas, pipeline transported as well as LNG transported by gas tankers.

The share of natural gas production of indirect GHG emissions is to be developed. However, it is expected that the major source of indirect GHG emissions from natural gas will be methane leaks from pipeline transport and tanker accidents and to a lesser extent military GHG emissions from military activities in areas with politically instable conditions.

5.5 DATA COLLECTION FOR INDIRECT EMISSIONS

The data collection for GHG emissions from different indirect GHG emissions is to be based on the literature survey. The section below gives an assessment of the different GHG emissions one by one. It contains a near-final description of induced land development and a more preliminary handling of other effects.

5.5.1 Induced land GHG emissions

The Induced land effect contains two elements of GHG emissions.

- GHG from harvesting rain forest
- GHG from using the land after it was harvested.

As defined, the indirect effect (or indirect emission source) termed induced land development - in the present context - comprises land development that is induced by developments in extraction of raw materials such as oil and gas for fossil fuel production.

Such developments might open up access to remote, otherwise inaccessible, areas, and besides the immediate deforestation they act as corridors and thereby open up for new activities such as:

- industrial forestry/logging, and subsequent
- farming and/or ranching

The most characteristic case is related to the area of Amazon River.

Different types of fossil fuels result in varying degrees of land disturbance depending on the type and location of land involved in the production of the fuel. Additionally, concerning the drivers behind induced land development, factors including but not limited to social changes, demographic shifts, political unrest, and economic incentives must be examined.

For example, Unnash et. al (2009), based on other work by among others Perz, Brilhante et al (2008) and Wunder (1997), argue that road construction and expansion triggers logging on areas along the road, and when the areas are "harvested", subsequent farming or ranching follows. Also, other infrastructure and derived economic activity might follow.

However, regardless of how well induced land development can be concretised and delimited, there are obviously difficulties in assessing the resulting GHG emissions, as:

- It is very difficult to assess whether the actual, induced developments are "additional" or alternatively would have occurred somewhere else, without/regardless of the direct development in oil and/or gas production.
- If part of the land development is actually "additional" in the sense that it would not have occurred somewhere else, it will still be quite difficult to isolate development of land that is specifically induced by oil and gas production in affected areas from other facilitators of land use change and development in those areas.
- The size/intensity of resulting GHG emissions will obviously depend on the geographical location of the induced land development – hereunder type of land affected.

The only actual estimate of such induced land development seems to be calculated by Unnasch et al. (2009).

Based on previously mentioned other work by among others Perz, Brilhante et al (2008) and Wunder (1997), Unnash et. al (2009) presume that road building for petroleum extraction and production, besides the initial relatively limited direct deforestation, facilitates further and more considerable, induced deforestation caused by industrial logging and/or subsequent agricultural activities.

Based on available data from a study by Viña, Echavarria et al. (2004) concerning such mechanisms along the border between Colombia and Ecuador, the extent of deforestation associated with road building is estimated based on the proximity of deforestation to the road network. The actual estimate obtained concerns a 5 km wide zone along specific roads and amounts to approximately 32,710 hectares.

Assuming that all deforestation within a certain distance from roads built for petroleum exploration and production in Ecuador is attributable to those roads during a certain time period, and using a carbon loss factor for Latin American rainforests, estimated to 422 Mgr CO_2eq/ha based on Searchinger, Heimlich et al. (2008), an estimate of the quantity of CO_2 released is calculated to approximately 13.8 Tgr CO_2eq.

Comparing this estimate with an estimate of the total production of oil from this area, during a related time period, Unnash et. al. (2009) estimated that the indirect emissions related to induced land development amount to approximately 0.6 gr CO_2eq /MJ to approximately 1.0 gr CO_2eq /MJ.[15]

This example clearly illustrates that it is not straightforward to estimate emissions from induced land development, the emissions will largely depend on various assumptions of the extent to which oil and gas development in an area facilities other indirect deforestation activities such as

- The extent to which road building in a given area is related to exploration and production of fossil fuels – or rather to other facilitators.
- The extent to which a certain activity such as deforestation, and eventually subsequent farming, is related to that road building, hereunder the extent in time.
- The level of carbon losses related to this certain activity such as deforestation
- The associated production of fossil fuels, hereunder the extent in time.

The above estimate of GHG emissions associated with induced land development – if assumptions are accepted – might be considered an upper estimate depending on the extent to which land development is additional. If not additional, the associated emissions might be considered zero.

5.5.2 Accidents

Accidents may occur along the full lifecycle of the fossil fuels, from extraction to tank. These accidents may have severe environmental impacts. The GHG emissions, caused by accidents fall in the following categories:

- Blowouts
- Tanker accidents.

[15] This estimate is obviously dependent on the underlying assumptions such as the fractions of the deforestation attributed to petroleum extraction, or size of the buffer used, as the estimate will increase or decrease accordingly to an increase or decrease in the aforementioned factors.

Blowouts (uncontrolled bursts or releases of oil and gas) during extraction certainly have a severe environmental impact, and they may require substantial clean-up activities resulting in additional GHG emissions. The release of oil itself may not result in GHG emissions, unless the oil is burnt or the blowouts concern release of methane.

Regarding GHG emissions related to outbursts, this effect should be calculated as gram of GHG per extracted tonne of crude oil or natural gas.

Tanker accidents may result in GHG emissions during clean-up activities and burning oil from the water surface.

The probability of tank ship accidents depends on the distance travelled. Therefore, it would give the most accurate results to calculate the costs of tanker accidents as the GHG for each km the oil is transported.

For pipeline natural gas and LNG, the major indirect GHG emissions in connection with accidents are caused by methane evaporation.

According to Wuppertal (2005), there are substantial leaks of methane from the compressor stations due to accidents. However, the question is whether these emissions are considered indirect or direct emissions.

The major share of CO_2 emissions from pipeline transport is due to CO_2 emissions from compressor stations. These emissions are parallel to for instance fuel emissions from tanker transport, which is assumed a traditional, upstream direct emission. However, there is also a substantial GHG emission due to leakages in the compressor stations.

In the Wuppertal study, the indirect emissions due to leakages amount to approximately 20% of 11 to 19 tonnes of CO_2eq. per TJ natural gas, amounting to 2.2-3.8 tonnes of CO_2eq per TJ. Still, a significant amount since the emissions from combustion of natural gas amounts to approximately 56 tonnes of CO_2eq per TJ Natural gas.

The total amount of leakages in compressor stations will depend on the distance and number of compressor stations. Therefore, it would be reasonable to calculate the emissions from natural gas relative to the length of the pipeline.

5.5.3 Military GHG emissions

The emissions from military activities arise from fuel combustion by military means of transport as well as from the energy used to construct military infrastructure and rebuild states that have been affected by conflicts.

There are two types of military effects.

- Military intervention in politically unstable areas
- Military enforcement to secure safe transportation of fuels.

The first type may be estimated by looking at the military GHG emissions from military interventions, like for instance the Iraq War. Based on literature studies, this effect is estimated to be at the level of 1gr CO_2eq/MJ oil produced in the Persian Gulf. This type of GHG emissions should only be applied in regions with politically unstable situation.

The other effect is due to military presence to secure safe transport of fossil fuels for instance from the Persian Gulf. This effect is also in the order of magnitude of approximately 1 gr CO_2eq/MJ fossil fuel.

In both cases, there is uncertainty for instance about the extent to which the military presence is solely due to secure safe fossil fuel deliveries. In the context of the Iraq War, there might be other purposes. Consequently, this argument would point to an overestimation of the indirect GHG emissions. On the other hand, the estimate referred to above only includes GHG emissions from the US military forces. Since other countries may also have contributed, this might lead to an underestimation of the GHG emissions here.

Considering the potential biases, it seems reasonable to assume an indirect GHG emission of approx. 1 gr CO_2eq/MJ for both presence in the area and transport of fossil fuels.

5.6 PRELIMINARY RESULTS

The average indirect GHG emissions are calculated by weighing the unit values for specific indirect GHG emissions with the share of oil and gas flow relevant for each type of indirect effect.

For instance, the induced land development may have a GHG emission of approximately 1 gram of CO_2 per MJ. However, since the induced land development effect is only relevant for oil and gas extracted in rain forest areas, this effect will only contribute with 6% of the 1 gr CO_2eq when we calculate the average indirect GHG emission.

This section will illustrate the idea and preliminary results of these calculations. In the final version, this section will be further developed with more explanations, numbers and discussions of the validity of the results.

The following Table 5.3 shows the unit GHG emissions for specific types of indirect GHG emissions.

Issues	Estimate
Induced land development	≈ 1 grCO_2 /MJ
Oil tanker accidents	
LNG Bunker accidents	

Issues	Estimate
LNG Bunker leaks	0 – 4.5 gram CO_2 /MJ
Military GHG emissions locations	≈ 1 gram CO_2 /MJ
Military GHG emissions transport	≈ 1 gram CO_2 /MJ

Table 5.3: Unit GHG emissions for specific indirect effects

Combining the above unit emissions with the share of total oil consumption in EU where the issue is relevant, the following total indirect GHG emissions are calculated from oil consumption in the EU. The relevant results for oil are presented in Table 5.4

Issues	Estimate (gr / MJ)	Weight	Avg. indirect GHG emissions (gr / MJ)
Induced land development	0.6 - 1	6%	0.036 - 0.06
Oil tanker accidents		58%	
Military GHG emissions locations	0.5 – 1.5	31%	0.155 – 0.465
Military GHG emissions transport	0.5 – 1.5	31%	0.155 - 0.465
Total			**0.346 - 0.99**

Table 5.4: Average indirect GHG emissions for oil consumption in EU

LNG amounts to 12% of the natural gas stream into Europe. It is assumed that LNG extraction takes place in and is transported from politically unstable regions. Just for illustrative purposes; to be further developed in the draft Interim report. Average indirect GHG emissions in EU for natural gas are presented in Table 5.5.

Issues	Estimate (gr / MJ)	Weight	Avg. indirect GHG emissions (gr / MJ)
Induced land development	0.6 - 1	0	0 - 0
LNG Bunker accidents			0 - 0
LNG Bunker leaks	0 – 4.5	12%	0 - 0.54
Military GHG emissions locations	0.5 – 1.5	12%	0.06 - 0.18
Military GHG emissions transport	0.5 – 1.5	12%	0.06 - 0.18
Total			**0.12 - 0.9**

Table 5.5 Average indirect GHG emissions for natural gas consumption in EU

6 TASK F: PROJECTIONS UP TO 2030

Within the context of Task f, the study focuses on emissions associated with fuels projected to be consumed in the EU up to 2030, with particular emphasis on the period up to year 2020. The projections on future demand for petroleum refined products will be based on projections drawn from the PRIMES model. Two scenarios already quantified using PRIMES will be used: the Reference scenario 2013[16] and the GHG40 scenario[17] used for the Impact Assessment by the European Commission for the policy framework for climate and energy in the period from 2010 up to 2030. This section presents an introduction to the methodological aspects of Task f and a brief overview of the PRIMES energy systems model.

6.1 INTRODUCTION TO THE METHODOLOGY

The current study will address the objective of Task f using the official projections provided by E3M-Lab to the European Commission in 2013 using the PRIMES energy systems model. Projections of demand and supply of oil fuels and natural gas will be used for a Reference and a Decarbonisation scenario as quantified using the PRIMES energy system model for the EC. The Reference scenario is based on the Reference scenario 2013, while the decarbonisation scenario is based on the GHG40 policy scenario.

Refineries inputs and outputs are also explicitly projected by the PRIMES model for 2020 and 2030. PRIMES also provides projections regarding net imports of refinery feedstock, ready-to-use refinery products and natural gas. PRIMES model is linked with the PRIMES-Refinery model; therefore the scenario projections of PRIMES (demand projections for the refined petroleum fuels) will be conveyed to the PRIMES-Refinery model. The PRIMES-Refinery model will therefore be used to project the EU refinery system in terms of refinery feedstock processing unit types used to distil and separate distillates from the crude feedstock and the respective capacities installed at EU Member State level.

The estimation of the GHG emissions associated with the petroleum fuels and natural gas WTT value chain will follow the methodology of Task c which will apply to the demand projected for years 2020 and 2030. GHG emissions that occur during the upstream, midstream and downstream sectors will be assessed with the use of the enhanced and modified OPGEE and GHGenius emission accounting models, as already presented in Task c. The projected net imports of refinery feedstock and ready-to-use petroleum products by PRIMES will be analysed based on country of origin and

[16] http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2050_update_2013.pdf
[17] http://ec.europa.eu/energy/observatory/oil/doc/refining/20140522_3nd_meeting_dgenergy.pdf

type, in order to obtain detailed commercial flows. The analysis for projection years will be based on assumptions relevant to current trends and to future production/import projections. These assumptions will be harmonized with latest IEA World Outlook projection of global oil/gas trade flows and regional production.

Similarly to Task c, the output of the analysis will be a range of GHG emissions resulting from the WTT supply chain due to the large uncertainty involved regarding the credibility and the availability of data. The range of emissions will then specify minimum and maximum emission factors of fuels.

6.2 THE PRIMES ENERGY SYSTEMS MODEL

6.2.1 Model structure

PRIMES is a modelling system that simulates a market equilibrium solution in the European Union and its Member States involving economic decision making of various stylised actors. It determines energy consumption, transformation and supply of various sectors, the costs involved and market prices. The PRIMES model simulates the response of energy consumers and the energy supply systems to different economic developments, exogenous constraints and drivers.

The model determines the equilibrium by finding the prices of each energy form such that the quantity producers find best to supply match the quantity consumers wish to use. The equilibrium is forward looking and includes dynamic relationships for capital accumulation and technology vintages. The model is behavioural, formulating agents' decisions according to microeconomic theory, at the same time representing, in an explicit and detailed way, the available energy demand and supply technologies as well as pollution abatement technologies. The system reflects considerations about market competition economics, industry structure, energy /environmental policies and regulation. These are conceived so as to influence market behaviour of energy system agents. The market integrating part of PRIMES simulates market clearing.

6.2.2 Model coverage

PRIMES is a partial equilibrium model simulating the entire energy system both in demand and in supply; it contains mixed representations of bottom-up and top-down elements. The PRIMES model covers the 28 EU Member States, as well as candidate and neighbour states (Norway, Switzerland, Turkey, South East Europe). The timeframe of the model is 2000 to 2050 by five-year periods; the years up to 2010 are calibrated to Eurostat data. The level of detail of the model is large as it contains:

- 12 industrial sectors, subdivided into 26 sub-sectors using energy in 12 generic processes (e.g. air compression, furnaces)

- 5 tertiary sectors, using energy in 6 processes (e.g. air conditioning, office equipment)
- 4 dwelling types using energy in 5 processes (e.g. water heating, cooking) and 12 types of electrical durable goods (e.g. refrigerator, washing machine, television)
- 14 transport means including private passenger road (cars, light duty vehicles, powered two-wheelers), public passenger road (buses and coaches), road freight (heavy duty vehicles, light duty vehicles) rail passenger and freight, inland navigation and aviation) and vehicle technologies (e.g. internal combustion engine by euro class, conventional hybrids by euro class, plug-in hybrids, electric vehicles, fuel cells and others)18.
- 14 fossil fuel types, new fuel carriers (hydrogen, biofuels) 10 renewable energy types
- Main Supply System: power and steam generation with 150 power and steam technologies and 240 grid interconnections
- Other sub-systems: refineries, gas supply, biomass supply, hydrogen supply, primary energy production
- 7 types of emissions from energy processing (e.g. SO_2, NO_x, PM)

CO_2 emissions from all energy-related processes and from industrial processes.

ANNEX A: COORDINATES

ANNEX A.1: OIL FIELDS

Oil field Name	Latitude	Longitude	Offshore/Onshore
Gachsaran	30,350	50,800	On
Rumaila (South)	30,156	47,408	On
West Qurna	31,051	47,423	On
Kirkuk	35,467	44,317	On
Burgan	29,111	47,967	On
Gwahar	25,430	49,620	On
Kurais	25,263	48,170	On
Manifa	27,711	48,971	On
Hassi Messaoud	31,661	6,055	On
Block 17/Dalia	-7,630	11,760	Off
Girassol	-7,633	11,683	Off
Greater Plutonio	-7,810	12,110	Off
Es Sider	30,613	18,282	On
El Sharara	26,510	12,260	On
Bonga	5,100	5,100	Off
Forcados Yokri	5,346	5,349	On
Agbada	5,010	7,037	On
Caw Thorne Channel	4,604	7,017	On
Escravos Beach	5,589	5,178	On
Azeri-Chirag-Gunashli (ACG)	40,018	51,266	Off
Azeri-Chirag-Gunashli (ACG)	40,018	51,266	Off
Tengiz	46,153	53,383	On
Tengiz	46,153	53,383	On
Tevlinsko-Russkinskoye	62,266	73,708	On
Uryevskoye	62,270	74,752	On
Samotlor	61,186	76,655	On
Vat-Yeganskoye	62,164	75,014	On
Povkhovskoye	57,246	66,793	On

Oil field Name	Latitude	Longitude	Offshore/Onshore
Romashkino	56,014	53,673	On
Unvinskoye	59,218	56,758	On
Pamyatno-Sasovskoye	50,663	45,131	On
Halfdan	55,710	4,800	Off
Statfjord	61,256	1,854	Off
Ekofisk	56,549	3,210	Off
Troll B/C	60,646	3,726	Off
Tyrihans	64,900	7,000	Off
Oseberg	60,500	2,500	Off
Gullfaks	61,100	2,100	Off
Buzzard	57,783	-1,248	Off
Ninian	60,860	1,450	Off
Captain	58,200	-1,900	Off
Cantarell	19,753	-92,516	Off
Boscan	10,456	-72,041	On

Table A.0.1: Geographical coordinates of representative oil fields (source: own elaboration)

Annex A.2: Terminals

Oil field	Terminal		
Name	Name	Latitude	Longitude
Gachsaran	Kharg Island	29,25	50,31
Rumaila (South)	Al Basrah Oil Terminal	29,68	48,81
West Qurna	Al Basrah Oil Terminal	29,68	48,81
Kirkuk	Ceyhan	36,86	35,94
Burgan	Mina al Ahmadi	29,06	48,15
Gwahar	Ras Tanura	26,64	50,16
Kurais	Ras Tanura	26,64	50,16
Manifa	Ras Tanura	26,64	50,16
Hassi Messaoud	Algiers	36,79	2,99
Block 17/Dalia	Dalia FPSO	-7,63	11,76
Girassol	Girassol FPSO	-7,63	11,68

Oil field	Terminal		
Name	Name	Latitude	Longitude
Greater Plutonio	Greater Plutonio FPSO	-7,81	12,11
Es Sider	Es Sider	30,64	18,37
El Sharara	Zawiya	32,79	12,70
Bonga	Bonga FPSO	5,10	5,10
Forcados Yokri	Forcados Terminal	5,35	5,35
Agbada	Bonny Terminal	4,40	7,17
Caw Thorne Channel	Bonny Terminal	4,40	7,17
Escravos Beach	Escravos Terminal	5,59	5,18
Azeri-Chirag-Gunashli (ACG)	Supsa	42,02	41,77
Azeri-Chirag-Gunashli (ACG)	Ceyhan	36,86	35,94
Tengiz	Ceyhan	36,86	35,94
Tengiz	Novorossiysk	44,78	37,72
Tevlinsko-Russkinskoye	Novorossiysk, Primorsk, Ventspills		
Uryevskoye	Novorossiysk, Primorsk, Ventspills		
Samotlor	Novorossiysk, Primorsk, Ventspills		
Vat-Yeganskoye	Novorossiysk, Primorsk, Ventspills		
Povkhovskoye	Novorossiysk, Primorsk, Ventspills		
Romashkino	Novorossiysk, Primorsk, Ventspills		
Unvinskoye	Novorossiysk, Primorsk, Ventspills		
Pamyatno-Sasovskoye	Novorossiysk, Primorsk, Ventspills		
Halfdan	Fredericia	55,56	9,74
Statfjord	Statford	61,26	1,85
Ekofisk	Teeside	54,61	-1,17
Troll B/C	Mongstad	60,81	5,02
Tyrihans	Trondheim	63,44	10,35
Oseberg	Sture	60,62	4,84
Gullfaks	Mongstad	60,81	5,02
Buzzard	Hound Point	56,04	-3,31
Ninian	Sullom Voe	60,46	-1,29
Captain	FPSO	58,200	-1,900
Cantarell	Caya Arcas	20,20	-91,96
Boscan	Punta Cardon	10,37	-70,13

Table A.0.2: Geographical coordinates of representative oil field terminals (source: own elaboration)

ANNEX A.3 PORTS

Port	Country	Latitude	Longitude
Aberdeen(GBR)	United Kingdom	57.1526	-2.11
Agioi Theodoroi	Greece	37.916667	23.083333
Algeciras	Spain	36.1275	-5.453889
Amsterdam	Netherlands	52.366667	4.9
Antwerp	Belgium	51.27	4.336667
Argostoli	Greece	38.183333	20.483333
Asnaesvaerkets Havn	Denmark	55.655213	11.097193
Aspropyrgos	Greece	38.066667	23.583333
Augusta	Italy	37.25	15.216667
Avonmouth	United Kingdom	51.501	-2.699
Barcelona	Spain	41.383333	2.183333
Bilbao	Spain	43.256944	-2.923611
Bourgas	Bulgaria	42.495278	27.471667
Brest	France	48.39	-4.49
Brofjorden	Sweden	58.348056	11.416667
Brunsbuttel	Germany	53.896389	9.138611
Cartagena(ESP)	Spain	37.6	-0.983333
Castellon	Spain	40.166667	-0.166667
Civitavecchia	Italy	42.1	11.8
Constantza	Romania	44.173333	28.638333
Copenhagen	Denmark	55.676111	12.568333
Corunna	Spain	43.365	-8.41
Coryton	United Kingdom	51.513	0.521
Cromarty Anch.	United Kingdom	57.681628	-4.037008
Donges	France	47.3242	-2.075
Dundee	United Kingdom	56.464	-2.97
Dunkirk	France	51.0383	2.3775
Eleusis	Greece	38.033333	23.533333
Enstedvaerkets Havn	Denmark	55.021283	9.442330
Escombreras	Spain	37.6	-0.983333
Falconara	Italy	43.633333	13.4
Fawley	United Kingdom	50.828	-1.352
Finnart	United Kingdom	56.115	-4.832
Fiumicino	Italy	41.766667	12.233333
Flushing	Netherlands	51.45	3.566667
Fos	France	43.2031	5.201
Fredericia	Denmark	55.566667	9.75
Frederikshavn	Denmark	57.441111	10.539722
Gela	Italy	37.066667	14.25
Genoa	Italy	44.411111	8.932778

Port	Country	Latitude	Longitude
Gothenburg	Sweden	57.7	11.966667
Hamble	United Kingdom	50.85694	-1.32084
Hamburg	Germany	53.565278	10.001389
Hook of Holland	Netherlands	51.981111	4.128611
Hound Point	United Kingdom	56.036117	-3.31225
Huelva	Spain	37.25	-6.95
Hvalfjordur	Iceland	64.383333	-21.666667
Immingham	United Kingdom	53.6139	-0.2183
Isle of Grain	United Kingdom	51.46	0.73
Kalamata	Greece	37.033333	22.116667
Kali Limenes	Greece	34.916667	24.8
Kalundborg	Denmark	55.681389	11.085
Karlshamn	Sweden	56.166667	14.85
La Pallice	France	46.158333	-1.227778
La Spezia	Italy	44.1	9.816667
Le Havre	France	49.49	0.1
Leghorn	Italy	43.55	10.316667
Leixoes	Portugal	41.183	-8.7
Liverpool	United Kingdom	53.4	-2.983333
Malta Anch.	Malta	35.818	14.54
Marsaxlokk	Malta	35.841667	14.544722
Megara	Greece	38	23.333333
Midia	Romania	44°05'.1N	028°43'.1E
Milazzo	Italy	38.216667	15.233333
Milford Haven	United Kingdom	51.71418	-5.04274
Naantali	Finland	60.466667	22.033333
Nigg Terminal	United Kingdom	57.705558	-4.029685
Nynashamn	Sweden	58.9	17.95
Oxelosund	Sweden	58.666667	17.116667
Pachi	Greece	37.974443	23.362741
Petit Couronne	France	49.3864	1.0283
Piraeus	Greece	37.95	23.633333
Portbury	United Kingdom	51.4699	-2.7163
Rostock	Germany	54.083333	12.133333
Rotterdam	Netherlands	51.916667	4.5
Rouen	France	49.44	1.1
Santa Panagia	Italy	37.122640	15.216326
Sarroch	Italy	39.066667	9.016667
Savona	Italy	44.3	8.483333
Setubal	Portugal	38.533333	-8.883333
Shell Haven	United Kingdom	51.5052	0.4902
Sines	Portugal	37.93	-8.77
Skoldvik	Finland	60.311737	25.541684

Port	Country	Latitude	Longitude
Stenungsund	Sweden	58.083333	11.816667
Sullom Voe	United Kingdom	60.451733	-1.310805
Taranto	Italy	40.466667	17.233333
Tarragona	Spain	41.115697	1.249594
Teesport	United Kingdom	54.604	-1.158
Terneuzen	Netherlands	51.333333	3.833333
Tetney Terminal	United Kingdom	53.499933	0.000533
Thessaloniki	Greece	40.646749	22.882513
Trapani	Italy	38.016667	12.516667
Trieste	Italy	45.633333	13.8
Tyne	United Kingdom	54.989907	-1.465280
Vassiliko Bay	Cyprus	34.724084	33.310287
Vasto	Italy	42.1118	14.7082
Venice	Italy	45.4375	12.335833
Wilhelmshaven	Germany	53.516667	8.133333

Table A.0.3: Geographical coordinates of major European oil importing ports (source: own elaboration)

ANNEX B: MAPS

ANNEX B.1: OIL FIELDS MAPS

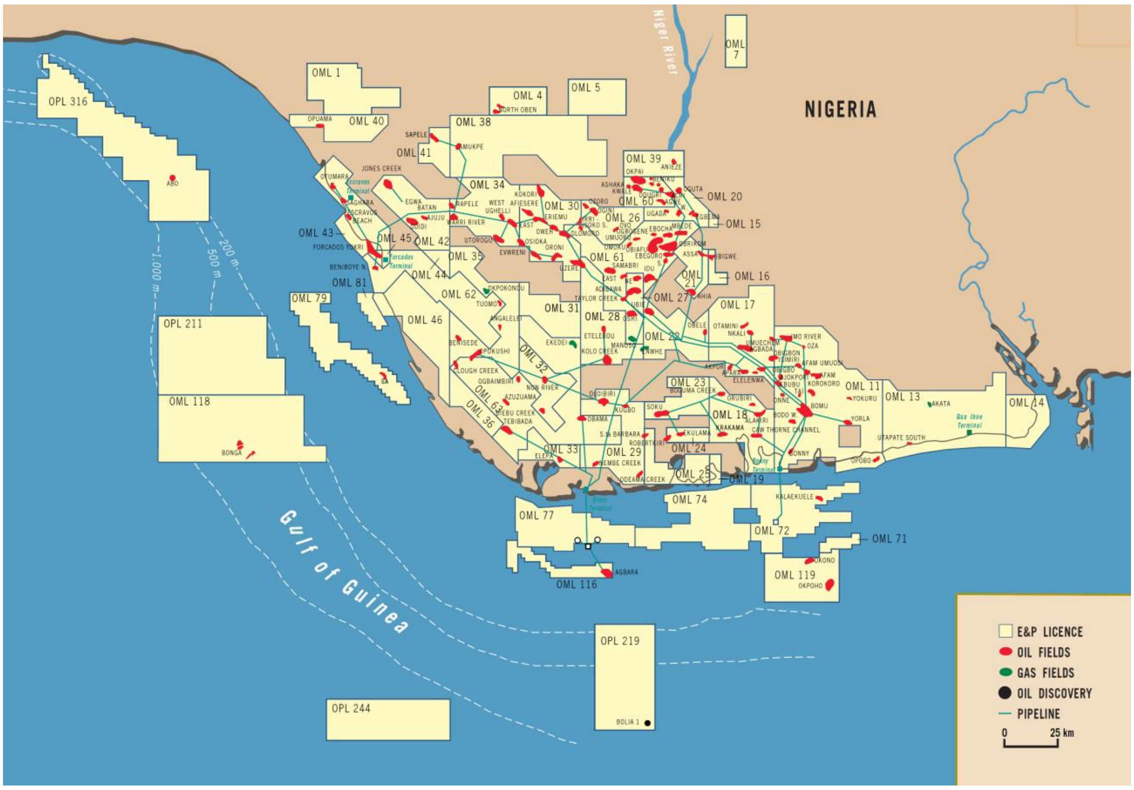


Figure B.1: Nigerian pipelines oil and gas fields map

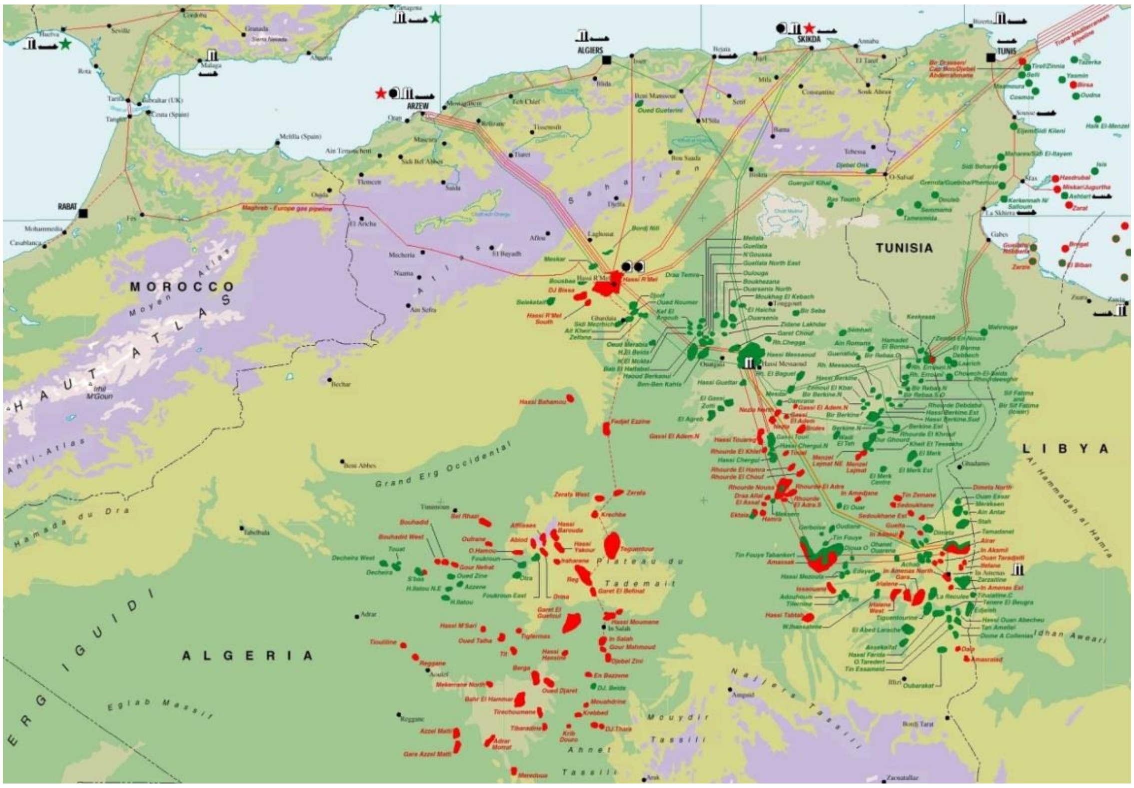


Figure B.2: Algerian pipelines, oil and gas fields map (source: Ministère de l'Energie et des Mines)

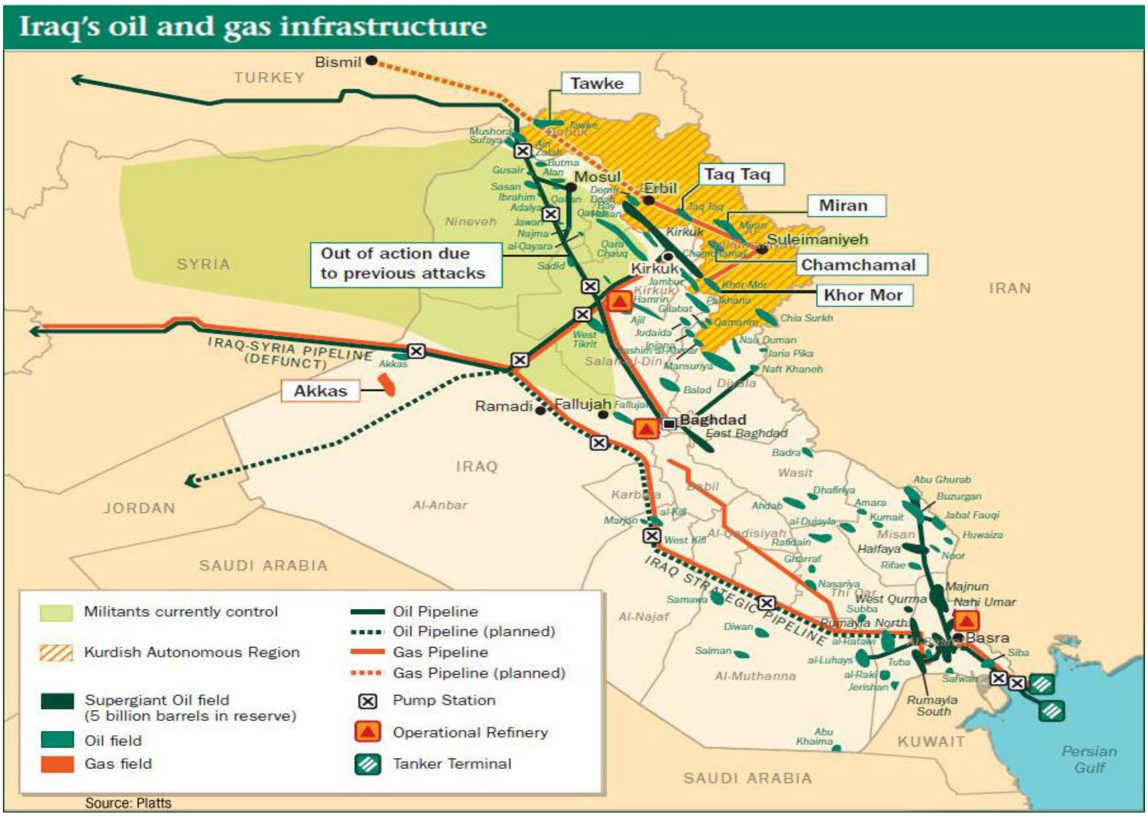


Figure B.3: Iraq's pipelines, oil and gas fields map (source: Platts)

Figure B.4: Arabian oil and gas pipeline system

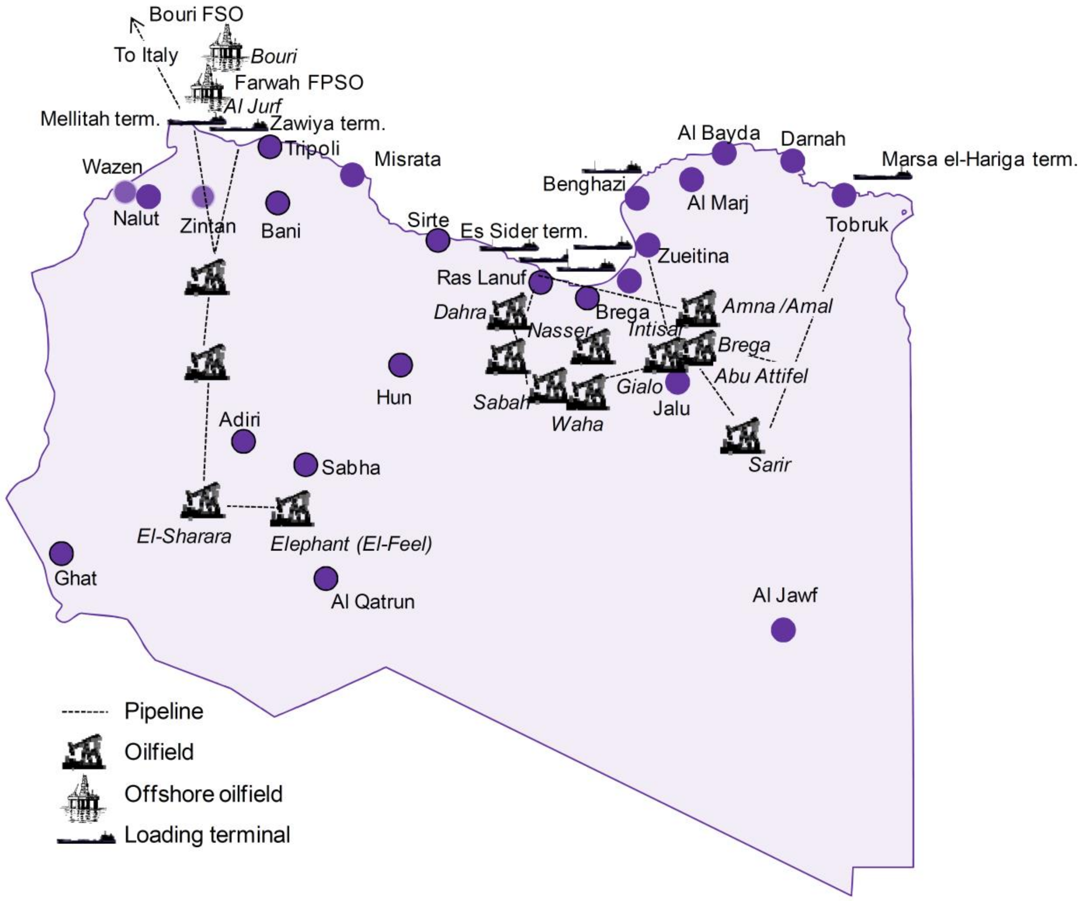


Figure B.5: Libyan pipelines, and oil fields map (source: Goldman Sachs)

ANNEX B.2: OIL PIPELINE MAPS

Figure B.6: Major Caspian oil and gas pipeline system (source: EIA)

Figure B.7: Russian oil and gas pipeline system (source: Theodora Maps)

Figure B.8: Balkan oil diesel and gas pipeline system (source: Theodora Maps)

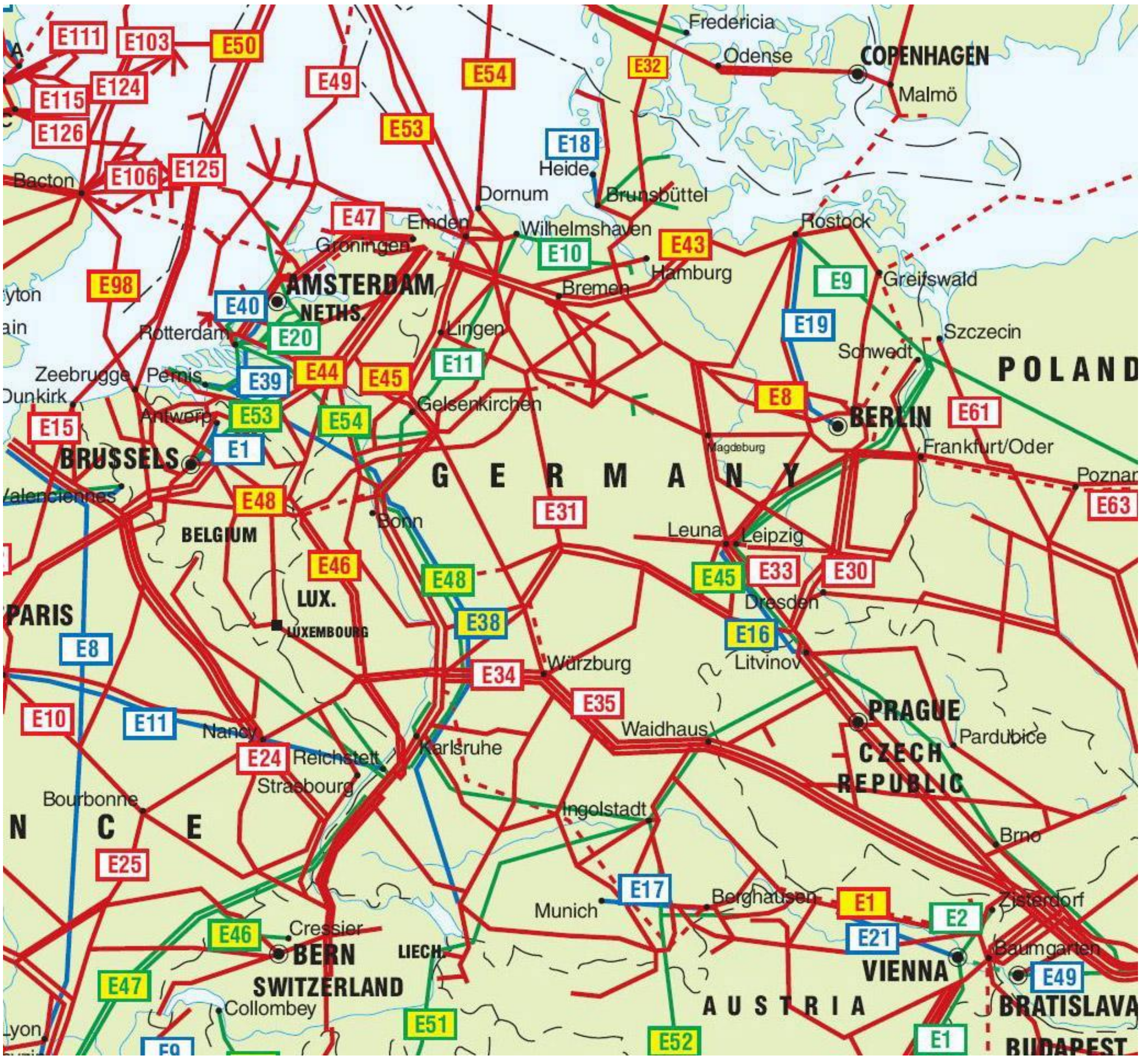


Figure B.9: Oil and gas pipeline system of Central Europe (source: Theodora Maps)

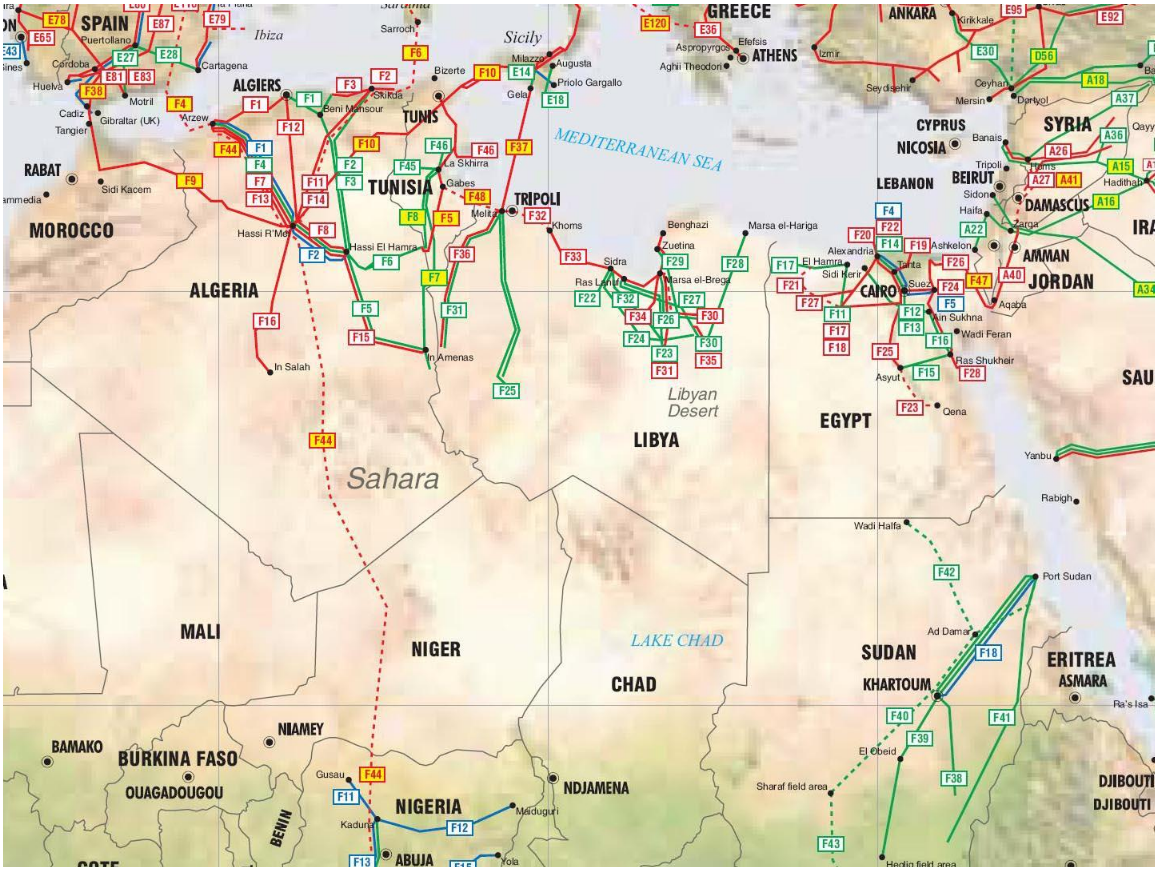


Figure B.10: Oil and gas pipeline system of North Africa (source: Theodora Maps)

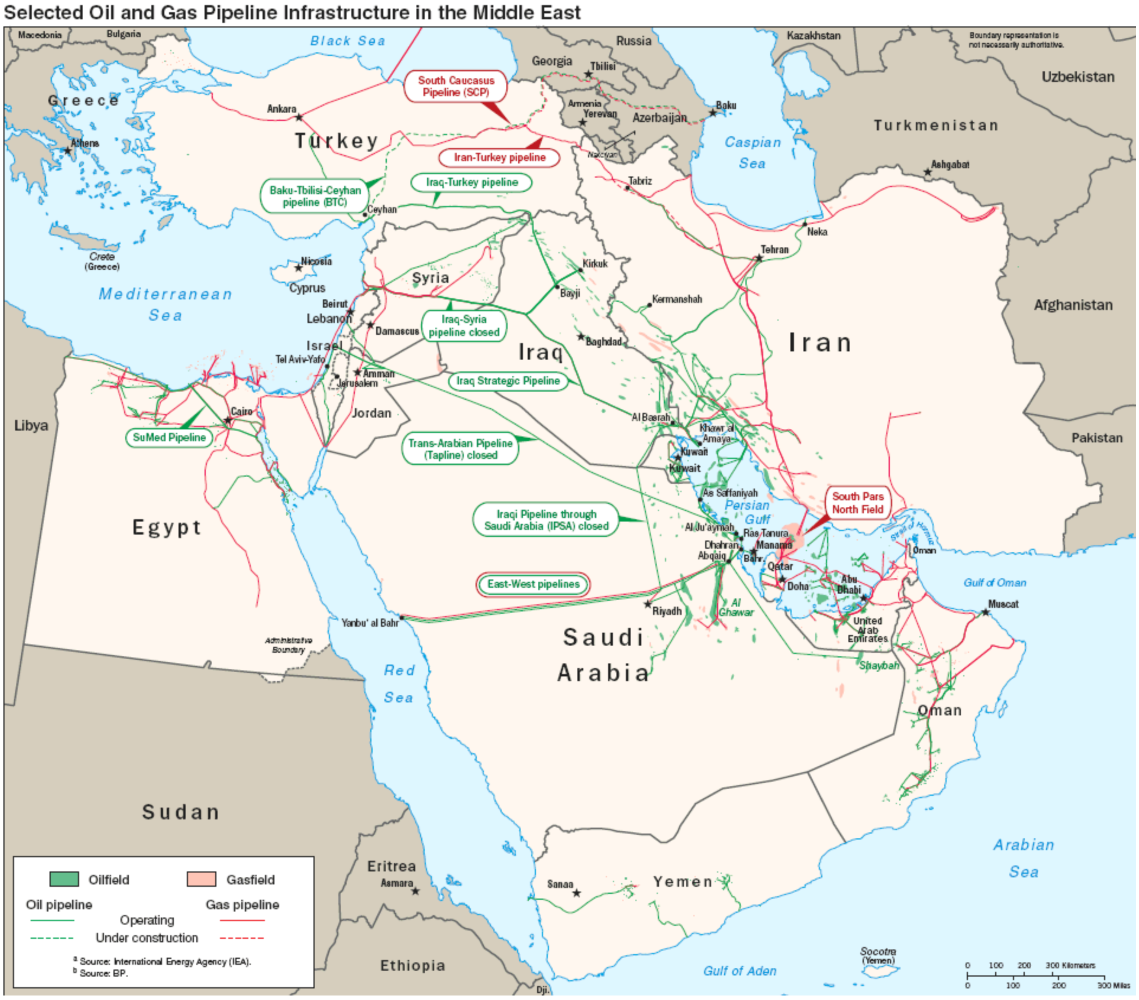


Figure B.11: Oil and gas pipeline system of Middle East (source: EIA)

ANNEX C: LITERATURE DATABASE EXTRACT

Date	Publishing Organisation	Author(s)	Document Type	Key points
1/1/2008	Greenhouse Gas Protocol	Greenhouse Gas Protocol	Datasheet	In this document, a table with the direct (except for CH4) 100-year time horizon global warming potentials (GWP) relative to CO2 is included. This table is adapted from table 2.14 of the IPCC Fourth Assessment Report, 2007. The 4th assessment report values are the most recent (2007), but the second assessment report values (1995) are also listed.
1/1/2010	Global Gas Flaring Reduction, A Public-Private Partnership	The World Bank Group, Oil & Gas Policy Division	Report/Study	A technical glossary of terms was commissioned by the Oil & Gas Methodology Workgroup1 (WG) to compile and explain how specific oil and gas terms found and/or required in relevant CDM/JI Methodologies, are understood and applied by industry, and how the concepts should be interpreted in the context of project activities. The document is intended to help reduce possible misinterpretations that can lead to delay and additional transactions costs during the formulation, validation, registration and verification of CDM/JI projects. The glossary features industry references as appropriate, and is meant to serve as a useful guide when suggesting improvement and/or requests for clarification and/or revisions of the approved methodologies.
1/1/2013	Organization of the Petroleum Exporting Countries (OPEC)	Organization of the Petroleum Exporting Countries (OPEC)	Datasheet	This is the 48th edition of the Annual Statistical Bulletin (ASB), one of OPEC's principal publications and an increasingly important source of data for the oil industry. The aim of this report is to make available reliable and timely historical data on the global oil and gas industry. It is a useful and frequently cited reference tool for those working in the energy industry. OPEC's 12 Member Countries — namely Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela — are the central focus of the ASB. However, as in previous editions, the ASB also provides information and statistical data about non-OPEC oil producing countries, bringing together data on exports, imports, pipelines and shipping, as well as the petroleum industry in general. It has collected statistical information about exploration and production, as well as transportation and refining, and has made this available to other energy stakeholders.
11/6/2013	Society of Chemical Industry and John Wiley & Sons, Ltd - Biofuels, Bioprod. Bioref.	Björn Pieprzyk, Paula Rojas Hilje and Norbert Kortlüke	Research Paper	In this report, the substitution of marginal oil with biofuels is analysed. For that, the effects that influence the substitution process in the short, mid and long term are evaluated. OPEC, resource nationalism, and geopolitical issues are identified as important influence factors. It is concluded that in the short term biofuels will replace mainly OPEC oil but not the most expensive petroleum.

Date	Publishing Organisation	Author(s)	Document Type	Key points
22/9/2013	InLCA/LCM 2003	Paul Worhach, Robert E. Abbott	Presentation	An important component of Life Cycle Assessment (LCA) is the methodology by which energy and emissions in multi-product production systems, such as petroleum refining, are attributed to the production of the different products. In this presentation, an alternative methodology called Co-Product Function Expansion (CFE) is proposed. CFE is an incremental approach in which selected co-products and a selected set of co-product functions are placed within the product system boundary, and the energy and emissions for upstream stages and co-product production are accounted for in the LCA. The downstream functions of the co-products are compared with alternative products serving the same functions, and the net energy and emissions, as either debits or credits, are assigned to the primary system products.
1/1/2014	IPCC WGIII AR5	Leon Clarke and Kejun Jiang	Report/Study	Stabilizing greenhouse gas (GHG) concentrations will require large-scale transformations in human societies, from the way that we produce and consume energy to how we use the land surface. A natural question in this context is what will be the 'transformation pathway' towards stabilization; that is, how do we get from here to there? The Document is primarily motivated by three questions: What are the near-term and future choices that define transformation pathways, including the goal itself, the emissions pathway to the goal, technologies used for and sectors contributing to mitigation, the nature of international coordination, and mitigation policies? What are the key characteristics of different transformation pathways, including the rates of emissions reduction sand deployment of low-carbon energy, the magnitude and timing of aggregate economic costs, and the implications for other policy objectives such as those generally associated with sustainable development? How will actions taken today influence the options that might be available in the future?
1/1/2014	IPCC WGIII AR5	Ralph Sims, Roberto Schaeffer	Report/Study	Reducing global transport greenhouse gas emissions will be challenging since the continuing growth in passenger and freight activity could outweigh all mitigation measures unless transport emissions can be strongly decoupled from GDP growth. Direct (tank-to-wheel) GHG emissions from passenger and freight transport can be reduced by: avoiding journeys where possible, modal shift to lower-carbon transport systems, lowering energy intensity (MJ/passenger km or MJ/tonne km) and reducing carbon intensity of fuels. Both short- and long-term transport mitigation strategies are essential if deep greenhouse gas emissions reduction ambitions are to be achieved. Barriers to decarbonizing transport for all modes differ across regions, but can be overcome in part by reducing the marginal mitigation costs (medium evidence, medium agreement). There are regional differences in transport mitigation pathways with major opportunities to shape transport systems and infrastructure around low-carbon options. A range of strong and mutually-supportive policies will be needed for the transport sector to decarbonize and for the co-benefits to be exploited.

Table C.0.1: Extract from the generic literature database until the interim report delivery

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
UK Production Data Release	1/10/2014	Department of Energy and Climate Change (DECC) - Energy Group	Department of Energy and Climate Change (DECC) - Energy Group	Datasheet	▪ Oil	▪ Upstream	Europe		Production data regarding UK fields. Monthly data for oil, water, condensate and gas production are provided for the period from July 2013 to June 2014.
Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States	29/5/2014	United States Department of Energy (DOE), National Energy Technology Laboratory (NETL)	Timothy J. Skone, Gregory Cooney, Matthew Jamieson, James Littlefield, Joe Marriott	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Natural Gas; ▪ Unconventional Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe; North America		A life cycle assessment of the greenhouse gas emissions for regional coal and imported natural gas power in Europe and Asia. Exported LNG from the U.S.A. is compared with regional coal for electric power generation in Europe and Asia. Furthermore, natural gas produced in Russia and delivered to Europe and Asia via pipeline is also evaluated.
Facts 2014, The Norwegian Petroleum Sector	5/5/2014	Yngvild Tormodsgard, Ministry of Petroleum and Energy	Yngvild Tormodsgard, Ministry of Petroleum and Energy	Report/Study	▪ Oil; ▪ Natural Gas	▪ Upstream	Europe		A report on Norvegian petroleum industry. A wide range of issues from Ekofisk, (the first discovered Norwegian oil field) to current industry status are analysed. Furthermore, future challenges and strategies are also provided.
Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil	1/5/2014	IHS Energy	IHS Energy	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		The purpose of this report is to inform the dialogue surrounding the GHG emissions from US crude oil supply and Canadian oil sands. The origin of US oil supply since 2005 has changed significantly. However, the GHG intensity of the average crude oil consumed in the United States did not materially change. Common GHG intensity baselines—such as the average crude consumed in the United States—provide a useful reference point for comparisons. However, they should be used with caution. They are theoretical values to enable comparisons, not absolute numbers. There are simply too many crude oils consumed in the United States to accurately track and quantify emissions for each. The almost 4% difference between the IHS and DOE/NETL results indicates the possible

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									margin of error in estimating the GHG emissions for the average crude oil. The study uses a hybrid bottom-up method for estimating the average GHG emissions for the average US crude oil. It is followed by an Appendix analysing the methodology, data and calculations utilized.
Appendix to IHS Special Report: Comparing GHG Intensity of Oil Sands to the Average US Crude	1/5/2014	IHS Energy	IHS Energy	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		Appendix to the referenced report including the methodology, data and calculations utilized.
OPGEE Documentation version 1.1b	11/3/2014	California Air Resources Board	Hassan M. El-Houjeiri, Kourosh Vafi, Scott McNally, Adam Brandt (Stanford University), James Duffy (CARB)	User's Manual	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream	Worldwide	OPGEE	Technical documentation to the Oil Production Greenhouse gas Emissions Estimator (OPGEE) explaining the calculations and data sources in the model.
An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions	23/1/2014	Congressional Research Service (CRS)	Michael Ratner, Mary Tiemann	Report/Study	▪ Policy; ▪ Unconventional oil; ▪ Unconventional Gas	▪ Upstream	North America		This report focuses on the growth in U.S. oil and natural gas production driven primarily by tight oil formations and shale gas formations. It reviews as well selected federal environmental regulatory and research initiatives related to unconventional oil and gas extraction. The motive for this study has been the rapid expansion of oil and gas extraction using hydraulic fracturing, both in rural and more densely populated areas. In general, this production method has raised concerns about its potential environmental and health impacts, i.e. groundwater and surface water quality,

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									public and private water supplies and air quality.
Reduction of Methane Emissions in The EU Natural Gas Industry	1/1/2014	Marcogaz, Eni S.p.A, E.ON Ruhrgas AG	Jürgen Vorgang (E.ON Ruhrgas AG, Germany), Angelo Riva (Eni S.p.A, G&P Div. G&P, Italy), Alessandro Cigni (Marcogaz, Belgium), Daniel Hec (Marcogaz, Belgium)	Research Paper	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Modelling; ▪ Natural Gas	▪ Midstream; ▪ Downstream	Europe		In the natural gas transmission sector, methane is released to the atmosphere. In this paper, a methodology for evaluating methane releases is proposed. Although the parameter values used for calculating methane releases vary from one transmission company to another, a specified range for such values is suggested. Furthermore data from seven major western European transmission companies are analysed. Finally suggestions for redaction of the methane releases are provided.
Upstream emissions of fossil fuel feedstocks for transport fuels consumed in the European Union	30/11/2013	EC / DG CLIMA	Chris Malins, Sebastian Galarza, Anil Baral, Drew Kodjak (International Council on Clean Transportation (ICCT)), Adam Brandt, Hassan El-Houjeiri (Stanford University), Gary Howorth	Report/Study	▪ Direct GHG Emissions; ▪ Policy; ▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream	Europe	OPGEE	The report analyses the results of several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions. It presents a new model for lifecycle analysis of crude oil extraction and provides an estimate using that model of the carbon intensity of crude oil supplied to the European Union. The objective is to calculate the carbon intensity (CI) for the most important types of crude oil entering the EU. More specifically the study provides a comprehensive Life Cycle Emissions analysis using the OPGEE model for a large number of crudes imported in Europe, using the DG ENER list of crude imports. The analysis has been done on oil-field basis by collecting key data for each oil field. There can be found detailed analyses about available data sources (Chapter 7), as well as a

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
			(Energy Redefined), Tim Grabiel (Defense Terre)						comprehensive summary of findings from other LCA studies on crude oil (Chapter 4).
Environmental Performance Indicators - 2012 Data	1/11/2013	International Association of Oil and Gas Producers (OGP)	OGP	Report/Study	▪ Direct GHG Emissions; ▪ Oil; ▪ Unconventional oil	▪ Upstream	Worldwide		OGP has been collecting environmental data from its member companies for the past 14 years on an annual basis. The present report summarises information on activities related to exploration and production (upstream) carried out by OGP member companies in 2012. Data coverage is relatively low – 32% of 2012 world production – while regional coverage varies from 96% in Europe to 8% in FSU. Overall, data from 78 countries are represented in the report.
Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan	1/11/2013	European Bank for Reconstruction and Development	Carbon Limits AS	Report/Study	▪ Direct GHG Emissions; ▪ Policy; ▪ Oil; ▪ Natural Gas	▪ Upstream	Former Soviet Union		This report summarizes the findings of the "Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan" which was initiated by the European Bank for Reconstruction and Development (EBRD) and co-managed by EBRD and the Global Gas Flaring Reduction Partnership (GGFR). The aim of the Study has been to review and analyse appropriate technical solutions for the use of the associated petroleum gas (APG) and to identify bankable projects in the four countries covered. Flaring data from NOAA and other sources are provided and analysed.
Independent Assessment of the European Commission's Fuel Quality Directive's "Conventional" Default Value	9/10/2013	Natural Resources Canada	ICF Consulting Canada	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream	Europe	OPGEE	Based on the new Fuel Quality Directive, this report analyses the lifecycle GHG emissions for diesel and petrol. The objective of this study is two-fold: 1) analyse the methodology that has been used in the JEC reports (JEC v3c and v4) to determine the default conventional crude oil gasoline and diesel GHG intensity values, 2) using that improved understanding, develop a more accurate default GHG intensity range

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									for gasoline and diesel from conventional crude oils (using OPGEE). Emphasis is given on data quality and availability which is limited. The study includes a number of MCONs imported in the EU given in the table of Appendix E.
Natural Gas Information 2013	13/8/2013	IEA	IEA	Book	▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		A detailed reference work on gas supply and demand covering not only the OECD countries but also the rest of the world, this publication contains essential information on LNG and pipeline trade, gas reserves, storage capacity and prices. The main part of the book, however, concentrates on OECD countries, showing a detailed supply and demand balance for each country and for the three OECD regions: Americas, Asia-Oceania and Europe, as well as a breakdown of gas consumption by end-user. Import and export data are reported by source and destination.
Desk study on indirect GHG emissions from Fossil Fuels	1/8/2013	DG Clima	ICF International	Report/Study	▪ Indirect GHG Emissions; ▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		The overall objective of the study is to provide an overview that enables the European Commission to evaluate the indirect GHG emissions from fossil fuel origin. In the study the direct emissions are defined as the ones emitted from the processes used to produce, transport and combust the fuel along the life cycle, whereas the indirect emissions are those that are influenced or induced by economic, geopolitical or behavioural factors, but which are not directly related to extraction, processing, distribution or final combustion of the fuels. The study identifies and evaluates six possible sources of indirect GHG emissions from fossil fuels: Induced land development, Military involvement, Accidents, Marginal effect, Price effects and Export of co-products. It is based on a thorough literature review in

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									the field of indirect emissions. Where possible, estimates on the emissions are provided. The study is a central source for analysing and estimating indirect emission and will also provide the basis for defining the boundaries between direct and indirect sources in the current project.
Oil Information 2013	23/7/2013	IEA	IEA	Datasheet	▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		A comprehensive reference book on current developments in oil supply and demand. The first part of this publication contains key data on world production, trade, prices and consumption of major oil product groups, with time series back to the early 1970s. The second part gives a more detailed and comprehensive picture of oil supply, demand, trade, production and consumption by end-user for each OECD country individually and for the OECD regions. Trade data are reported extensively by origin and destination.
WELL-TO-TANK Report Version 4.0	1/7/2013	JEC	Robert EDWARDS (JRC), Jean-François LARIVÉ (CONCAWE), David RICKEARD (CONCAWE), Werner WEINDORF (LBST)	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream	Europe	Other	This part of the study describes the process of producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains. It covers all steps from extracting, capturing or growing the primary energy carrier to refuelling the vehicles with the finished fuel. As an energy carrier, a fuel must originate from a form of primary energy which can be either contained in a fossil feedstock (hydrocarbons of fissile material) or directly extracted from solar energy (biomass or wind power). Generally a fuel can be produced from a number of different primary energy sources. In this study, we have included all fuels and primary energy sources that appear relevant within the timeframe considered (which broadly speaking is the next decade) and we have considered the issues and established comparisons from both points of view in order to assist the reader in answering the questions:

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									1) What are the alternative uses for a given resource and how can it best be used? 2) What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?
GHGenius Model 4.03 - Model Background and Structure - Data and Data Sources	15/6/2013	Natural Resources Canada	Don O'Connor	User's Manual	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Natural Gas; ▪ Unconventional oil; ▪ Unconventional Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide	GHGenius	Volume 1 of the report documents the development of the model and provides the user with an understanding of the primary functions of the model. Volume 2 is focused on the data that is used in the model, the sources and where the data is used.
BP Statistical Review of world energy	1/6/2013	BP	BP	Datasheet	▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Downstream; ▪ Combustion	Worldwide		It provides an annual opportunity to examine the latest data, country-by-country and fuel-by-fuel. This helps us discern the important trends and assess the challenges and the opportunities that lie before us. This edition of the review highlights the flexibility with which our global energy system adapts to rapid global change.
BP Statistical Review of World Energy June 2013	1/6/2013	BP	BP	Report/Study	▪ Oil; ▪ Natural Gas; ▪ Unconventional oil; ▪ Unconventional Gas	▪ Upstream; ▪ Downstream	Worldwide		Annual report providing data on oil and natural gas reserves, prices, production and consumption by country as well as trade movements.
Oil and Gas Production in Denmark and Subsoil Use, 2012	1/6/2013	Danish Energy Agency (Energi Styrelsen)	Danish Energy Agency (Energi Styrelsen)	Report/Study	▪ Oil; ▪ Natural Gas	▪ Upstream	Europe		A report on oil and gas production in Danish. An overview of licences and exploration is given. Other uses of subsoil, such as produce salt, produce geothermal heat and store of natural gas are mentioned. Production and development as well as classification of resources and economy are analysed. Health and safety regulations by the Danish Offshore

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									Safety Act and Climate and environment issues are provided. Furthermore detailed actual data are given.
Crude Oil in Europe: Production, Trade and Refining Outlook	1/3/2013	Wood Mackenzie	Steve Cooper	Presentation	▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		Production, Trade and Refining Outlook of 2013 for Crude Oil in Europe by Wood Mackenzie.
Guidance Document - Flaring Estimates Produced by Satellite Observations	1/1/2013	The World Bank / NOAA	Global Gas Flaring Reduction	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil; ▪ Natural Gas	▪ Upstream	Worldwide		This report provides general guidelines on the utilisation of satellite images in order to estimate the GHG emissions due to Associated Petroleum Gas (AGP) - flaring and venting emissions.
2012 Annual Statistical Bulletin of Nigerian oil and gas sector	1/1/2013	National Nigerian Petroleum Corporation	Corporate Planning & Strategy Division (CP&S)	Datasheet	▪ Oil; ▪ Natural Gas	▪ Upstream	Africa		The specific datasheet contains detailed information regarding the Nigerian oil and gas sector published by the national responsible authority for the oil and gas sector (NNPC). Specifically, it contains information on the quantity of oil and produced, quantity of water produced, number of wells, API gravity, gas to oil ratio per oil field and operator. Furthermore, it contains information regarding quantities of gas produced, gas re-injected and flared per oil field and operator.
HANDBOOK ON THE ENERGY SECTOR Fugitive Emissions	1/1/2013	UNFCCC	Consultative Group of Experts (CGE) – National GHG Inventory	Report/Study	▪ Direct GHG Emissions	▪ Upstream	Worldwide		The aim of this handbook is to improve skills and knowledge regarding the preparation of greenhouse gas inventories. Specifically, this handbook focuses on the fugitives portion of the energy sector, in keeping with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories and taking into consideration the Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Nexen Petroleum U.K. Limited Environmental Statement 2012	1/1/2013	Nexen	Nexen	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Policy; ▪ Oil; ▪ Natural Gas	▪ Upstream	Europe		Nexen is an upstream oil and gas company. The environmental performance of Nexen's UK offshore operations during 2012 are reported. Actual data regarding atmospheric emissions, produced water, waste generation, production chemical usage, unplanned releases and emissions associated with drilling operations are analysed. Finally environmental objectives of 2012 and 3013 are provided.
Environmental Report, The Environmental Efforts of the Oil and Gas Industry with Facts and Figures, 2013	1/1/2013	Norwegian Oil and Gas Association (Norsk olje&gass)	Norwegian Oil and Gas Association (Norsk olje&gass)	Report/Study	▪ Direct GHG Emissions; ▪ Policy; ▪ Oil; ▪ Natural Gas	▪ Upstream	Europe		The annual environmental report of the Norwegian Oil and Gas Association. Data on emissions/discharges are recorded continuously in Environment Web, a joint database for Norwegian Oil and Gas, Klif and the Norwegian Petroleum Directorate (NPD). Based on information from Environment Web, the Norwegian Oil and Gas environmental report provides an updated overview of reporting in 2012 on emissions to the air and discharges to the sea as well as waste generation from NCS operations. The report also contains data and research results from long-term projects related to the marine environment and environmental monitoring. All fields with production facilities on the NCS are included. Emissions/discharges from the construction and installation phase, maritime support services and helicopter traffic are excluded.
UK Operations, Environmental Performance, Annual Report 2012	1/1/2013	CNR International	CNR International	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Policy; ▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Combustion	Europe		The annual environmental report of the CNR International. CNRI operations and environmental aspects are provided. Significant environmental aspects of CNRI are Carbon dioxide emissions from power generation and flaring, oil discharged in produced water, oil and chemical spills, solid waste generation and disposal and chemical use and discharge.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
BP in Azerbaijan, Sustainability Report 2012	1/1/2013	BP Caspian	BP Caspian	Report/Study	▪ Direct GHG Emissions; ▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Midstream	Former Soviet Union		An annual report of BP in Azerbaijan for 2012. Business performance, environmental record, safety requirements and impact on Society are covered. Furthermore detailed actual data regarding performance are provided.
Oil Sands, Greenhouse Gases, and US Oil Supply	1/11/2012	IHS CERA	IHS CERA	Report/Study	▪ Policy; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		The purpose of this report is to generate a broad set of crude oil GHG emissions data to help inform the dialogue on GHG emissions from US crude supply. In these types of discussions, it is important that GHG estimates represent average values. It provides a meta-analysis of various GHG emissions estimates for crude oil, with a focus on oil sands, and concludes that differences between the carbon intensities calculated within each study depends on the unique assumptions made in each case. It is followed by an Appendix summarizing the method and data used for the meta-analysis.
Appendixes to IHS CERA Special Report, Oil Sands, Greenhouse Gases, and US Oil Supply—2012 Update	1/11/2012	IHS CERA	IHS CERA	Report/Study	▪ Policy; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		Appendixes summarizing the method and data used for the meta-analysis provided within the report entitled "Oil Sands, Greenhouse Gases, and US Oil Supply".
Life Cycle Greenhouse Gas Emissions of Natural Gas	1/10/2012	CNGI	ICF Consulting Canada	Report/Study	▪ Direct GHG Emissions; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		The goal of this paper is to review the recent scientific literature on life-cycle GHG emissions from coal and conventional and shale gas production and their use for electricity generation. The motivation of the study was the rapid increase in production of shale gas in North America in recent years, which has focused attention on the increased role that low-priced, abundant natural gas can play throughout the economy. The results show that all of the research other than the Howarth study finds that lifecycle

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									GHGs are less from gas than from coal and that there is relatively little difference between conventional and shale gas in life-cycle GHG emissions.
Lifecycle Assessment of Crude Oil Production within the LOW CARBON FUEL STANDARD	12/7/2012	California Air resources Board	John Courtis, Manager Alternative Fuels Section, Jim Duffy Air Resources Engineer Alternative Fuels Section	Presentation	▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream	North America	OPGEE	Presentation within public meeting concerning the status of the methodology under development for determining the carbon intensity of crude oil, according to newly developed policy. Updates to OPGEE and modelling methods are being presented.
From Ground to Gate: A lifecycle assessment of petroleum processing activities in the United Kingdom	1/6/2012	NTNU-Trondheim	Reyn OBorn	Report/Study	▪ Direct GHG Emissions; ▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe	GREET	The scope of the study is to introduce a lifecycle analysis on the UK petroleum refining sector and clarify where emissions occur along the process chain and which fuels cause the most pollution on a per unit basis. The motivation of the study has been the complexity of the petroleum process chain and the fact that the environmental impacts within the process chain are not always well understood. So, it is believed that a deeper understanding of where emissions come from along the process chain will help policy makers in the path towards a less carbon intensive society. Concluding, the results of the study show that the UK refining industry is typically more environmentally efficient than the average refinery in Europe according to Eco Invent data.
EU Pathway Study: Life Cycle Assessment of Crude Oils in a European	1/3/2012	Alberta Petroleum Marketing Commission	Bill Keesom, John Blieszner (Jacobs Consultnacy), Stefan Unnasch	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Oil; ▪ Unconvention	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe; North America	GREET	The goal of this Study is to evaluate the LCA GHG for potential pathways to Europe for producing gasoline and diesel from representative heavy crude oils from Alberta, Canada. Another goal was to evaluate the LCA GHG emissions of representative crude oils refined in representative refineries and

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Context			(Life Cycle Associates)		al oil				thereby gain a better understanding of the variability in LCA GHG emissions for different pathways for producing gasoline and diesel for the EU market. The intent of this work is to better understand the carbon intensity of pathways for gasoline and diesel from individual crude oils. Determining the carbon intensities of gasoline and diesel from an average crude oil refined in an average refinery risks losing some of the granularity that helps explain the range in carbon intensities for gasoline and diesel from different crude oils produced in different regions and refined in different refineries. Representative crude oils ranging from light to heavy crude oils from the major supply regions were selected for the Study. Therefore the Study does not cover all crude oils imported in Europe, but only the ones treated in 3 representative refineries: FCC-Coking refinery – situated in Germany, FCC-Visbreaking refinery – situated in France, Hydrocracking-Visbreaking refinery – situated in Italy.
Indirect Land Use Change - how good are the models?	28/2/2012	Biorefinery Conference 2012	Don O'Connor	Presentation	▪ Indirect GHG Emissions; ▪ Modelling	▪ Downstream	Worldwide		The scope of the presentation is a discussion of the indirect land use related to biofuels. Further the presentation looks at the issue of indirect impacts related to fossil fuel production, namely the issue of the production of co-products from fossil fuel production. The substitution of these products will result in emissions, and the magnitude depends of the source of substitution. For the purpose of the current project the presentation provides figures on the volume of the co-products and it refers to an European LCA study that have looked into to issue of taking into account alternative production of co-products.

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Variability and Uncertainty in Life Cycle Assessment Models for Greenhouse Gas Emissions from Canadian Oil Sands Production	14/12/2011	Environmental Science and Technology	Adam R. Brandt	Research Paper	▪ Direct GHG Emissions; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	North America	GHGenius; GREET; Other	The scope of this paper is to review factors affecting energy consumption and GHG emissions from oil sands extraction. For this purpose, the author uses publicly available data to analyse the assumptions made in the LCA models to better understand the causes of variability in emissions estimates. The motive of this paper has been the raising interest in greenhouse gas (GHG) emissions from transportation fuels production. A number of recent life cycle assessment (LCA) studies have calculated GHG emissions from oil sands extraction, upgrading, and refining pathways, but the results from these studies vary considerably. Concluding, it is found that the variation in oil sands GHG estimates is due to many causes, e.g. scope of modelling and choice of projects analysed, differences in assumed energy intensities of extraction and upgrading, differences in the fuel mix assumptions, treatment of secondary non combustion emissions sources, such as venting, flaring, and fugitive emissions and treatment of ecological emissions sources, such as land-use change-associated emissions.
Lifecycle analysis of Shale Gas and Natural Gas	1/12/2011	Argonne	C.E. Clark, J. Han, A. Burnham, J.B. Dunn, M. Wang	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Natural Gas; ▪ Unconventional Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide	GREET	The scope of this study is to examine the size of the environmental impacts of shale gas production, by comparing it to natural gas. The motivation has been the technologies and practices that have enabled the recent boom in shale gas production and the fact that shale gas will provide the largest source of growth in the U.S. natural gas supply through 2035. The results of the base case scenario show that shale gas life-cycle emissions are 6% lower than those of conventional natural gas. However, the range in values for shale and conventional gas overlap, so there is a statistical uncertainty regarding whether shale gas emissions are indeed lower than

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									conventional gas emissions.
Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production	24/10/2011	U.S. Department of Energy / NETL	Timothy J. Skone (NETL), James Littlefield, Dr. Joe Marriott (Booz Allen Hamilton, Inc.)	Report/Study	▪ Direct GHG Emissions; ▪ Natural Gas; ▪ Unconventional Gas	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy. The extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations.
Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for	18/1/2011	Stanford University	Adam R. Brandt	Report/Study	▪ Direct GHG Emissions; ▪ Oil; ▪ Unconventional oil	▪ Upstream; ▪ Midstream	Europe; North America	OPGEE	The report focuses on the following issues: First, it provides an overview and description of oil sands extraction, upgrading, SCO and bitumen, non-combustion process emissions and land use change associated emissions. Second, it compares a variety of recent estimates of GHG emissions from oil sands

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European refineries									and outlines the reasons for variations between the estimates in surface mining, in situ production, upgrading, refining and VFF. Finally, it outlines low, high and "most likely" estimates of GHG emissions from oil sands, given results from previously produced estimates, and compare these emissions to those of conventional EU refinery feedstock. This report focuses on the European context, and therefore uses EU-specific emissions factors for transport and refining of fuels. It results that, while the highest emissions conventional oil has higher upstream emissions than the lowest emissions oil sands estimate, the production-weighted emissions profiles are significantly different. The most important uncertainties mentioned are treatment of cogenerated electric power, treatment of refining and the interaction of markets with LCA results.
Petroleum industry guidelines for reporting greenhouse gas emissions	1/1/2011	IPIECA, Energy API, OGP	IPIECA, Energy API, OGP	Legislation	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Policy	▪ Upstream; ▪ Midstream; ▪ Downstream	North America		This report's objective is to fulfil the need for industry guidance focused specifically on the accounting and reporting of GHG emissions at the facility through to the corporate level, for member companies of the American Petroleum Institute. They have been developed as a complement to the Compendium and the IPIECA Sustainability Guidance The Compendium has been written and published in order to meet the need of the petroleum industry for GHG accounting and reporting guidance, specifically focused on operations. The member companies of the American Petroleum Institute first published the Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry in April 2001, with a third edition released in August 2009.

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LCA of the European Gas Chain: Challenges and Results	1/1/2011	International Gas Union Research Conference 2011	A. Prieur-Vernat (GDF Suez – France), P. Pacitto (GDF Suez – France), D. Hec (Marcogaz – BELGIUM), V. Bichler (GDF Suez – France)	Research Paper	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Modelling; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		A life cycle assessment of the European gas chain with respect to environmental performance. Data validated by the European Gas Industry are analysed. Additionally, suggestions in order to improve the environmental performance are provided.
Carbon Intensity of Crude Oil in Europe	1/12/2010	ICCT	Energy Redefined LLC	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		According to IEA projections in 2009, global consumption of crude oil will increase by 27% over the next two decades, from 83 million barrels per day in 2009 to 105 MMbbl/d in 2030. Since extracting, transporting, and refining crude oil on average account for about 18% of well-to-wheels greenhouse gas (GHG) emissions, on a global scale, that equates to a very large amount of GHG emissions: about 2.8 billion metric tonnes of CO2 equivalent per year. Therefore, improvements in the processes of extracting and refining crude oil would mean substantial progress toward reducing overall transportation-sector GHG emissions. The scope of the study is to accurately quantify the GHG emissions from the wellhead to the refinery output gate. For this purpose, they have developed emission factors for five components of production: extraction, flaring and venting, fugitive emissions, crude oil transport, and refining, in order to highlight the greatest potential opportunities for reducing or avoiding GHG emissions from oil extraction. Based on a life-cycle assessment of approximately 3100 oilfields in countries that supply oil to Europe, the study develops GHG emission factors for five elements of extraction-to-refining analysis:

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									crude oil extraction, flaring and venting, fugitive emissions, crude oil transport, and refining. The focus of the study is on the European market, as the European Commission seeks the best way to address extraction-to-refining emissions from petroleum fuels under the Fuel Quality Directive.
Results of Crude Oil Marketing Name Analysis	9/9/2010	California Energy Commission	Gordon Schremp	Presentation	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream	North America	OPGEE	Presentation on Marketable Crude Oil Names. Provides critical information on available data and information resources regarding crude oil extraction and transport.
Greenhouse gas emissions reporting from the petroleum and natural gas industry	1/1/2010	EPA		Report/Study	▪ Direct GHG Emissions; ▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	North America		A technical support document (TSD) that contains legally-binding requirements. It offers illustrative examples for complying with the minimum requirements indicated by the regulations, but it does not substitute for the regulations cited in this TSD, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA or the regulated community. The document describes the U.S. petroleum and natural gas life cycle of raw gas and crude oil from the wells to the delivery of processed gas and petroleum products to consumers. Since these segments use energy and emit greenhouse gases (GHG), the document provides information on the calculation of minimum GHG emissions.
DIRECTIVE 2009/30/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009	5/6/2009	European Parliament	European Parliament	Legislation	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Policy; ▪ Oil	▪ Natural Gas; ▪ Unconventional oil; ▪ Unconventional Gas	Europe		Fuel Quality Directive 2009/30/EC amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC. Specific attention should be given to Article 7a.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Life Cycle Analysis of GHG and Air Pollutant Emissions from Renewable and Conventional Electricity, Heating, and Transport Fuel Options in the EU until 2030	1/6/2009	European Topic Centre on Air and Climate Change (ETC/ACC)	Uwe R. Fritsche (Öko-Institut), Lothar Rausch (Öko-Institut)	Report/Study	▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		Life cycle emissions in Europe from fossil and nuclear energies as well as from renewable energies are identified. Furthermore, electricity generation technologies are compared. Future development prospects until 2030 are also provided.
An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions	27/3/2009	Department of Energy	National Energy Technology Laboratory	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Oil	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	South America; North America		The National Energy Technology Laboratory (NETL) has analysed the full life cycle greenhouse gas (GHG) emissions of transportation fuels derived from domestic crude oil and crude oil imported from specific countries. The study takes into account particularly the impact of crude oil source on WTT GHG emissions from: 1) flaring and/or venting of associated natural gas during the crude oil extraction process, 2) alternative crude oil extraction techniques and pre-processing requirements required for oil sands and bitumen, (3) ocean transport distances for delivery of crude oil and (4) varying processing requirements within the refinery for crude oils of different quality.
Methane Emissions from Natural Gas Transport	1/3/2009	Open University of the Netherlands	S. Murrath	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Natural Gas	▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		In the natural gas transport sector, methane is released to the atmosphere. Quantify methodologies for methane emissions on a natural gas grid at high pressure are analysed. Furthermore, several abatement options to reduce the methane emissions are studied.
Assessment of the Direct and Indirect GHG Emissions	1/2/2009	New Fuels Alliance	Life Cycle Associates, LLC	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG	▪ Upstream; ▪ Midstream; ▪ Downstream;	Worldwide	GREET	Assessment of the life cycle impact on GHG emissions from petroleum fuels. The estimation of the direct emissions is heavily based on the GREET model and

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Associated with Petroleum Fuels					Emissions	▪ Combustion			includes the emissions from exploration, production, flaring, refining and transportation. Indirect emissions include emissions from: Protection of supply, Land use and market-mediated impacts (economic impacts primarily from price pressures) and refinery of co-products. The study will provide input to the current project in regard to defining boundaries for direct and indirect emissions and in regard to the analysis of the indirect emissions.
European gas imports: GHG emissions from the supply chain	1/1/2009		Antonio Taglia, Nicola Rossi	Report/Study	▪ Direct GHG Emissions; ▪ Modelling; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		The aim of this paper is to analyse from the environmental and economical point of view the global impact of the gas that enters into Europe, investigating the contribution of all the chain steps, starting from the production of the gas until the consumption in a “combined cycle gas turbine” (CCGT) plant for power generation. For this purpose, six different real cases are studied: three regard a pipeline-based transport and three regard LNG production, transport through tankers and regasification. These six real cases are compared to the GHG emissions of a reference case: power generated in a CCGT plant in North Africa and imported to Europe. The environmental impact of energy production from gas must be evaluated from the impact analysis of the supply chains, since it can reach the 20% of the CO2 emissions from gas combustion. Therefore, Europe, which aims to cut GHG emissions, should consider also the supply chain emissions, given that a remarkable reduction of overall emissions would be feasible.
Allocation of CO2 Emissions in Joint Product Industries via Linear	1/1/2007	Institut français du pétrole (IFP)	A. Tehrani Nejad M.	Report/Study	▪ Direct GHG Emissions; ▪ Oil	▪ Midstream	Europe		The paper outlines the application of the marginal allocation methodology to the oil refinery LP model, to evaluate and compare the CO2 emissions associated with different oil products. Also, it distinguishes the

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Programming: a Refinery Example									allocation procedures in retrospective (accounting) and prospective (change-oriented) LCAs. As mentioned in the report, the allocation in joint product systems is among the most critical issues specific to LCA and the assumptions about the allocation procedures influence considerably the results. In general, allocation tools in LCA are based on linear homogeneous and unconstrained models to relate the environmental burdens associated with a product system to its economic outputs. Under particular conditions, the marginal allocation data generated by LP can also be applicable in retrospective LCA studies. Contrary to the arbitrary physical measurements (mass, volume, energy, etc.), the allocation coefficients which emerge from the LP model are based on realistic causal relations between oil products and the whole refinery system. In other words, the LP model itself detects the real type of causality between various inputs and outputs in the refinery and allocates the CO2 emissions accordingly without having to use any arbitrary measurements. The study uses an LP refinery model that describes a typical European fluid catalytic cracking refinery with predefined capacity. The oil production level of the refinery corresponds to the EU market structure of the year 2000 and the model is calibrated accordingly. The parametric results of the verification/calibration experiments confirmed the capability of the IFP model to correctly reproduce the logical evolution of the product mix. The study concludes that the allocated CO_2 emissions that are calculated are not fixed but change to reflect changes in the system parameters, such as the evolution of oil products demand and recommends to

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									perform a parametric analysis to fully compare the evolution of the CO_2 allocations of various oil products.
Life Cycle Assessment of the European Natural Gas Chain, A Eurogas–Marcogaz Study	1/1/2007	Eurogas–Marcogaz	Marion Papadopoulo (GDF SUEZ), Salam Kaddouh (GDF SUEZ), Alessandro Cigni (Marcogaz), Dirk Gullentops (Synergrid), Stefania Serina (Snam Rete Gas), Juergen Vorgang (EON-Ruhrgas), Tjerk Veenstra (Gasunie), François Dupin (DVGW)	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Europe		A life cycle assessment of the European Natural Gas Chain. Data for heat and electricity production in Europe in 2004 are collected. Furthermore impact assessment results and sensitivity analyses are provided. It is concluded that transmission distance affect the emissions significantly. Priorities to improve the natural gas chain environmental performances are suggested.
Fugitive emissions	1/1/2006	IPCC	John N. Carras (Coal Mining) et. al., David Picard (Oil and Natural Gas) et. al.	Research Paper	▪ Direct GHG Emissions; ▪ Oil; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream	Worldwide		As part of the "2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 4, Energy", the paper provides specific recommendations for improvements of the IPCC methodology for oil and gas systems. Furthermore, it identifies relevant new emission factors and methodological advancements made since the last update of the IPCC Guidelines. The paper also provides a summary of the

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									major oil and gas producers, a summary of useful conversion factors for various common oil and gas statistics and presents typical compositions of processed natural gas and liquefied petroleum gas. Summarizing, an opportunity has been provided to improve and build upon the existing IPCC methodology and to establish clearer directions on how to apply the IPCC Guidelines for the oil and gas sector (Chapter 4.2).
The Natural Gas Chain, Toward a Global Life Cycle Assessment	1/1/2006	CE Solutions for environment, economy and technology	M.N. Sevenster, H.J. Croezen	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Natural Gas	▪ Upstream; ▪ Midstream; ▪ Downstream; ▪ Combustion	Worldwide		A life cycle analysis of the entire gas chain related to the costs and environmental impact of natural gas. As opposed to venting and flaring, fugitive emissions can be reduced significantly. For the study high quality life-cycle data are used.
Flaring & venting in the oil & gas exploration & production industry	1/1/2000	OGP	John Kearns, Kit Armstrong, Les Shirvill, Emmanuel Garland, Carlos Simon, Jennifer Monopolis	Report/Study	▪ Direct GHG Emissions; ▪ Indirect GHG Emissions; ▪ Oil; ▪ Natural Gas	▪ Upstream	Worldwide		The option to release gas to the atmosphere by flaring and venting is an essential practice in oil and gas production, primarily for safety reasons. The essential point is that no single approach to dealing with associated gas will be appropriate for all projects or locations. Industry needs to be able to choose from among a variety of creative and common sense approaches to address flaring and venting concerns in specific operations. To achieve this, governments need to provide an energy policy framework which will encourage and allow companies to select from among very different approaches in order to achieve the best practicable outcome in particular circumstances. The specific report discusses various aspects of venting and flaring.

Table C.0.2: Extract from the specific literature database until the interim report delivery

ANNEX D: LETTER TEMPLATE FOR OIL AND GAS DATA REQUEST

exergia MEMBER OF SESMA TÜV CERT EN ISO 9001

Athens, *Date*	To: Mr./Ms. *Name* *Position* *Company*

Dear Mr./Ms. …………,

Subject: Request for data

Within the framework of the Renewable Energy Directive (RED) which sets a target of 10% renewables in transport and the Fuel Quality Directive (FQD), which sets a target of 6% reduction of Green House Gas (GHG) emissions from road transport, the Directorate General for Energy has assigned to a consortium of the companies EXERGIA, E3M-Lab and COWI the project entitled "Study on actual GHG data for diesel, petrol, kerosene and natural gas" under a Framework Contract tendering procedure.

The overall objective of the study is to define the lifecycle GHG emissions of petroleum and natural gas products consumed in the European transport sector from "well-to-tank". To this end, we are currently gathering actual GHG emissions data and information regarding the crude oil upstream process of the most common crude oil grades imported in the EU.

In this context, we are writing to you in order to request measured data regarding GHG emissions from the oil fields operated by your company. Specifically, GHG emissions data from the following activities are needed:

- Exploration, production and processing of crude oil
- Venting, flaring and fugitive gas
- Crude oil transportation

For the above mentioned data, please include in your communication the methodology and standards utilized for the measurements / calculations.

We would appreciate your contribution to the project either by providing to the address below* the requested data, or by introducing us to the right contact persons who could give us this kind of information.

Sincerely Yours

Dr. Theodor Goumas
Project Manager, Managing Director of EXERGIA

Cc: Dr. Kyriakos Maniatis
DG ENER

Technical Officer of contract: "Study on actual GHG data for diesel, petrol, kerosene and natural gas", Contract N°: ENER/C2/2013-643

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