

Life cycle inventories of crude oil and natural gas extraction

Report

Christoph Meili;Niels Jungbluth;Maresa Bussa

ESU-services Ltd.

Vorstadt 10

CH-8200 Schaffhausen

Tel. +41 44 940 61 32

info@esu-services.ch

www.esu-services.ch

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Abbreviations

a	year (annum)
API	American Petroleum Institute
AZ	Azerbaijan
bbl.	Barrel
bcm	billion cubic meters
bld	below limit of detection
bn	Billion
BOD5	Biochemical oxygen demand for 5 days of microbial degradation
BTU	British Thermal Unit (1 BTU = 1055 J)
BTX	Benzene, Toluene, and Xylenes
Bq	Becquerel
CEL	Central European Pipeline
cf	Cubic Feet
CH4	Methane
CHP	Combined Heat and Power
Ci	Curie
CIS	Commonwealth of Independent States
CMC	Carboxymethyl Cellulose
CO	Carbon monoxide
CO ₂	Carbon dioxide
COD	Chemical oxygen demand
Concawe	Conservation of Clean Air and Water in Europe (the oil companies' European organization for environmental and health protection, established in 1963)
d	day
DE	Germany
DeNOx	Denitrification method (general)
DM	Dry matter
DoE	Department of Energy, US
DZ	Algeria
E5/10/15/85•	Petrol with 5%/10%/15%/85% ethanol
EdP	Electricidade de Portugal S.A.
EMPA	Swiss federal material testing institute
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency, US
GB	Great Britain
GGFR	Global Gas Flaring Reduction Partnership
GWP	Global Warming Potential
HC	Hydrocarbons
HEC	Hydroxyethyl cellulose
IEA	International Energy Agency
IMO	International Maritime Organization
IPCC	International Panel on Climate Change
IQ	Iraq
J	Joule

KBOB	Koordinationsgremium der Bauorgane des Bundes
KZ	Kazakhstan
LCI	Life cycle inventory analysis
LCIA	Life cycle impact assessment
LY	Libyan Arab Jamahiriya
M.	Million
MJ	Megajoule
Mt	Megaton = 1 million tons
MTBE	Methyl tert-butyl ether
MW	Megawatt
MX	Mexico
NCI	Nelson complexity index
NG	Nigeria
NGL	Natural Gas Liquids
NL	Netherlands
Nm ³	Normal-cubic metre (for gases)
NMVOC	Non-Methane-Volatile Organic Compounds
NO	Norway
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally Occurring Radioactive Materials
NOX	Nitrogen oxides
NR	Not Reported
Ns	not specified
OE	Oil equivalent
OECD	Organisation for Economic Cooperation and Development
PAH	Polycyclic Aromatic Hydrocarbons
PC	Personal Communication
PM	Particulate Matter
QA	Qatar
Rn	Radon
RO	Romania
RU	Russia
SA	Saudi-Arabia
SN	Smoke number
TDS	Total Dissolved Solids
TEL	Tetraethyl lead
toe	Ton Oil Equivalent
TSS	Total Suspended Solids
UCTE	Union for the Co-ordination of Transmission of Electricity
ULCC	Ultra Large Crude Carrier
ULS	Ultra low sulphur
UNEP	United Nations Environment Programme
US (A)	United States of America
VOC	Volatile Organic Compounds

1 Introduction

The goal of this study is to report the data as submitted to ecoinvent for the implementation in their database release version 3.10. Changes made by the commissioner to implement the data in the ecoinvent v3-database are not described in this report but will be described in a separate report.¹ The content of this document therefore does not fully reflect the LCI data as provided with ecoinvent v3.10.

This document is based on the last update of the life cycle inventory data for crude oil extraction (Meili et al. 2022a).

Between 2018 and 2022 different projects were finalized, in which the LCI for mineral oil and natural gas products delivered to Switzerland, Europe and other regions was updated. Several 100 datasets have been updated or investigated newly in projects financed by different organisations. A part of these updates has been implemented in ecoinvent data v3.9. The following stages were included in these updates:

- Crude oil and natural gas extraction in several countries onshore/offshore/mix (Meili et al. 2022a), integrated in ecoinvent v3.9
- Transport of crude oil to refineries including the import mixes for Switzerland and Europe (Meili et al. 2022b), integrated in ecoinvent v3.9
- Transport of natural gas via pipeline and LNG to several markets, Natural gas import mix and transport in high- and low-pressure network (Bussa et al. 2022), integrated in ecoinvent v3.9
- Refining of crude oil to crude oil products in Swiss and European refineries (Jungbluth et al. 2018a, not yet integrated in ecoinvent v3.x)
- Distribution of mineral oil products to the Swiss and European market including imports and blending with biofuels (Jungbluth & Meili 2018, not yet integrated in ecoinvent v3.x)
- Heating with fuel oils (Jungbluth et al. 2018b, not yet integrated in ecoinvent v3.x)

All data are implemented in the ESU database, which is based on UVEK 2018 (ESU-services 2023).

In the current project, also the reports for the transport of crude oil to refineries in different regions (Meili et al. 2023) and the transport of natural gas to end users (Bussa et al. 2023) were updated in view of an integration in ecoinvent v3.

In general, only subchapters on process steps that are assessed as relevant in former LCIA results (ecological scarcity 2013) were kept or updated in this report (c.f. Meili & Jungbluth 2018).

If the numbers did not change considerably or no new numbers were available, the former text was kept for this report to provide this relevant information (c.f. Meili et al. 2022a).

The following chapters analyse crude oil and natural gas extraction from the perspective of production regions relevant for Switzerland, the EU-28 states, the global market and other regional and country-specific markets, as listed in Meili et al. 2023, Tab. 1.1.

¹ See for example the version for implementation to ecoinvent 3.9 in Moreno Ruiz et al. 2022. When ready, the „Report of changes“ is provided on <https://ecoinvent.org/the-ecoinvent-database/data-releases/> in the „Relevant Documents & Files“ section of the latest ecoinvent version.

2 Goal and scope

2.1 Overview

In this report the life cycle inventory (LCI) of crude oil and natural gas extraction in countries with target market Switzerland, the EU-28 states, the global market and other regional and country-specific markets, as listed in Meili et al. 2023, Tab. 1.1., are described.

Based on the analysis of existing datasets it is known, which LCI components have the highest influence for the life cycle impact assessment (LCIA) method ‘ecological scarcity 2013’. Generic data from previous studies are used to complete the LCIs Meili et al. 2022a).

The market situation for crude oil and natural gas supplies to Europe, Switzerland, North America, and the global market is updated for the reference year 2021 and new inventories are developed for extraction in some countries. Most relevant for the update are methane emissions (vented, fugitive and flaring), discharge of produced water and the direct energy uses during oil extraction including drilling and flaring. Furthermore, the emissions due to these practices are updated. Other, less important aspects are e.g., construction materials and the use of chemicals for enhanced oil recovery. Such aspects of lesser importance were not updated.

Updates are made mainly according to the following data sources:

- Methane and flaring emissions, consumption of energy, production figures and other key indicators with the latest version of key data sources used in the update of crude oil and natural gas extraction (BP 2022; IOGP 2022; World Bank 2023; IEA 2022). For methane emissions, data are aligned to ensure that the total inventoried methane emissions for crude oil and natural gas do match the global total reported in actual studies.
- Changes documented for ecoinvent v3.4 are included (Faist-Emmenegger et al. 2015)
- Available updates and changes proposed by commissioners or validators at the project start are discussed in this report.
- The reduction for offshore emissions and emissions from transportation for ozone depleting substances is based on assumptions in the study for oil extraction (Meili & Jungbluth 2018)

Besides the data sources mentioned above, no further literature is searched for.

Data are inventoried for 48 countries as shown in Tab. 2.1. These countries cover the most relevant datasets necessary to update the present data for crude oil and natural gas supply mixes (c.f. Bussa et al. 2023, chapter 2 and Meili et al. 2023, Tab. 1.1 and chapter 2). Transport and distribution are discussed in the related reports on “Life cycle inventories for long-distance transport and distribution of natural gas” (Bussa et al. 2023) and “Life cycle inventories for long-distance transport of crude oil” (Meili et al. 2023).

Tab. 2.1 Countries for which oil and gas production is updated or newly modelled in this study. Production data for these countries for the reference year 2021 (BP 2022).^{2,3} Energy production is calculated based on energy contents mentioned in chapter 2.2. Crude oil production in mega-tons per year, natural gas production in billion cubic meters per year, energy production in mega-joules per year

Origin	short code	Global region	short code	crude oil production	natural gas production	Source production
Unit				Mt/a	bcm/a	
United Arab Emirates	AE	Middle East	RME	1.6E+2	5.7E+1	BP 2022
Argentina	AR	Latin America	RLA	2.9E+1	3.9E+1	BP 2022
Australia	AU	Asia and the Pacific	RAS	1.8E+1	1.5E+2	BP 2022
Azerbaijan	AZ	Former Soviet Union	FSU	3.5E+1	3.2E+1	BP 2022
Belgium	BE	Europe	RER	5.1E-2	4.8E-3	Enerdata 2022
Bolivia	BO	Latin America	RLA	1.6E+0	1.5E+1	BP 2022
Brazil	BR	Latin America	RLA	1.6E+2	2.4E+1	BP 2022
Canada	CA	North America	RNA	2.7E+2	1.7E+2	BP 2022
China	CN	Asia and the Pacific	RAS	2.0E+2	2.1E+2	BP 2022
Colombia	CO	Latin America	RLA	3.9E+1	1.3E+1	BP 2022
Germany	DE	Europe	RER	3.1E+0	4.5E+0	Enerdata 2022
Algeria	DZ	Africa	RAF	5.8E+1	1.0E+2	BP 2022
Ecuador	EC	Latin America	RLA	2.5E+1	3.4E-1	Oil: BP 2022, Gas: EIA 2022 (for 2020!)
Egypt	EG	Africa	RAF	3.0E+1	6.8E+1	BP 2022
Spain	ES	Europe	RER	5.9E-3	4.0E-2	Enerdata 2022
France	FR	Europe	RER	7.9E-1	2.2E-2	Enerdata 2022
United Kingdom	GB	Europe	RER	4.1E+1	3.3E+1	BP 2022
Indonesia	ID	Asia and the Pacific	RAS	3.4E+1	5.9E+1	BP 2022
India	IN	Asia and the Pacific	RAS	3.4E+1	2.9E+1	BP 2022
Iraq	IQ	Middle East	RME	2.0E+2	9.4E+0	BP 2022
Iran	IR	Middle East	RME	1.7E+2	2.6E+2	BP 2022
Italy	IT	Europe	RER	4.8E+0	3.2E+0	BP 2022
Japan	JP	Asia and the Pacific	RAS	3.7E-1	1.8E+0	Enerdata 2022
Korea	KR	Asia and the Pacific	RAS	1.8E-1	5.1E-2	Enerdata 2022
Kuwait	KW	Middle East	RME	1.3E+2	1.7E+1	BP 2022
Kazakhstan	KZ	Former Soviet Union	FSU	8.6E+1	3.2E+1	BP 2022
Libya	LY	Africa	RAF	6.0E+1	1.2E+1	BP 2022
Mexico	MX	North America	RNA	9.6E+1	2.9E+1	BP 2022
Malaysia	MY	Asia and the Pacific	RAS	2.6E+1	7.4E+1	BP 2022
Nigeria	NG	Africa	RAF	7.8E+1	4.6E+1	BP 2022
Netherlands	NL	Europe	RER	1.1E+0	1.8E+1	Oil: Enerdata 2022, Gas: BP 2022
Norway	NO	Europe	RER	9.4E+1	1.1E+2	BP 2022
Oman	OM	Middle East	RME	4.7E+1	4.2E+1	BP 2022
Peru	PE	Latin America	RLA	5.3E+0	1.1E+1	BP 2022
Poland	PL	Europe	RER	1.4E+0	3.9E+0	Oil: Enerdata 2022, Gas: BP 2022
Qatar	QA	Middle East	RME	7.3E+1	1.8E+2	BP 2022
Romania	RO	Europe	RER	3.3E+0	8.5E+0	BP 2022
Russian Federation	RU	Former Soviet Union	FSU	5.4E+2	7.0E+2	BP 2022
Saudi Arabia	SA	Middle East	RME	5.2E+2	1.2E+2	BP 2022
Thailand	TH	Asia and the Pacific	RAS	1.4E+1	3.2E+1	BP 2022
Turkmenistan	TM	Former Soviet Union	FSU	1.2E+1	7.9E+1	BP 2022
Turkey	TR	Middle East	RME	4.3E+0	4.0E-1	BP 2022
Trinidad and Tobago	TT	Latin America	RLA	3.5E+0	2.5E+1	BP 2022
Taiwan	TW	Asia and the Pacific	RAS	5.3E-1	1.1E-1	Enerdata 2022
Ukraine	UA	Europe	RER	2.5E+0	1.9E+1	Enerdata 2022
United States	US	North America	RNA	7.1E+2	9.3E+2	BP 2022
Uzbekistan	UZ	Former Soviet Union	FSU	2.7E+0	5.1E+1	BP 2022
Venezuela	VE	Latin America	RLA	3.3E+1	2.4E+1	BP 2022
Global	GLO	Global	GLO	4.2E+3	4.0E+3	BP 2022

For each of these countries, the 9 datasets, as exemplary shown for Libya, in Tab. 2.2, are updated or newly investigated. The first 3 datasets are multi-output processes for the combined delivery of crude oil and natural gas. They show the LCI before allocation and cannot be directly imported to SimaPro. However, they are needed for an import to the ecoinvent v3 database. Thus, in total 432 datasets are provided for crude oil and natural gas extraction in different countries.

Tab. 2.2 List of provided datasets for crude oil and natural gas extraction, per country (exemplary for Libya)

Name	Location	Category	SubCategory	unit	StartDate	EndDate
combined gas and oil production	LY	oil	production	a	2021	2023
combined gas and oil production offshore	LY	oil	production	a	2021	2023
combined gas and oil production onshore	LY	oil	production	a	2021	2023
crude oil, at production offshore	LY	oil	production	kg	2021	2023
crude oil, at production onshore	LY	oil	production	kg	2021	2023
natural gas, at production offshore	LY	natural gas	production	Nm ³	2021	2023
natural gas, at production onshore	LY	natural gas	production	Nm ³	2021	2023
crude oil, at production	LY	oil	production	kg	2021	2023
natural gas, at production	LY	natural gas	production	Nm ³	2021	2023

2.2 Allocation for combined gas and oil production

Crude oil and natural gas production are often linked, and data are provided for combined production⁴. Therefore, multioutput processes are generated for several regions under investigation.

A net calorific value of 43.4 MJ/kg is used for crude oil and related products like condensates and liquefied natural gas liquids. For natural gas an average value of 36 MJ/Sm³ (standard cubic meters, measured at 15°C and 1013 mbar, according to BP 2022, c.f. chapters 5.1.2 and 5.2.1 in this study).

The life cycle impacts from combined crude oil and natural gas production are mainly allocated based on these net calorific values. These values are used for newly created and updated data sets together with the annual production data for 2021 (cf. Tab. 2.1) and shares for off- and onshore oil- and gas production (c.f. chapter 4.1). Based on these values, the allocation factors shown in Tab. 2.3 are calculated. For venting the share of natural gas and crude oil for the total emissions is known and allocation is based on these known shares (c.f. chapter 9.2).

For many tables in this study, energy and resource uses are provided per kg oil equivalent (kgOE). There, the conventional energy content of 41.868 MJ/kgOE is applied (BP 2022). This energy content is also used in this study for the calculation of the base flow which is then allocated by using the allocation factors shown in Tab. 2.3.

² Enerdata 2022, <https://yearbook.enerdata.net/crude-oil/world-production-statistics.html>, online 12.12.2022

³ Ecuador, gas production: No data found for 2021 - Assuming amount from 2020 according to https://www.eia.gov/international/content/analysis/countries_long/Ecuador/Ecuador.pdf

⁴ <https://www.britannica.com/science/sedimentary-rock/Oil-and-natural-gas>, online 19.10.2017

For example, data on fresh water use are provided in m^3 per kg OE for a sample of oil and gas producing companies in world regions (IOGP 2022). These values are then used to estimate the combined production in the countries under study (c.f. Equation 2.1).

Equation 2.1 Example of equation used to calculate annual flows of resources, energy and emissions

$$\begin{aligned}
 & \text{Freshwater use}_{onshore} \left(\frac{m^3}{year} \right) \\
 & = \text{freshwater use} \left(\frac{m^3}{kg_{OE}} \right) * \left(\frac{kg_{(oil,on)}}{year} \right) * \frac{\frac{MJ}{kg_{oil}}}{\frac{MJ}{kg_{OE}}} + \left(\frac{Nm^3_{(gas,onshore)}}{year} \right) * \frac{\frac{MJ}{Nm^3_{gas}}}{\frac{MJ}{kg_{OE}}}
 \end{aligned}$$

In a former version of this study, the calorific value of 43.4 MJ/kg for oil was used to calculate oil equivalents. The correction of this error leads to 3.7% higher inventory data for most entries compared to the former study (Meili et al. 2022a).

Tab. 2.3 Factors applied for allocation of resource and energy use and emissions based on calorific energy content according to BP 2022 and off- and onshore production of oil and gas (c.f. chapter 4.1)

Origin	oil offshore	gas offshore	oil onshore	gas onshore
Unit	%	%	%	%
United Arab Emirates	77.7%	22.3%	77.7%	22.3%
Argentina	47.6%	52.4%	47.6%	52.4%
Australia	12.9%	87.1%	12.9%	87.1%
Azerbaijan	57.1%	42.9%	57.1%	42.9%
Belgium	92.7%	7.3%	92.7%	7.3%
Bolivia	0.0%	0.0%	11.3%	88.7%
Brazil	88.6%	11.4%	88.6%	11.4%
Canada	65.1%	34.9%	65.1%	34.9%
China	53.4%	46.6%	53.4%	46.6%
Colombia	78.9%	21.1%	78.9%	21.1%
Germany	45.0%	55.0%	45.0%	55.0%
Algeria	0.0%	0.0%	41.0%	59.0%
Ecuador	67.1%	32.9%	99.7%	0.3%
Egypt	34.5%	65.5%	34.5%	65.5%
Spain	15.1%	84.9%	15.1%	84.9%
France	97.7%	2.3%	97.7%	2.3%
United Kingdom	60.1%	39.9%	60.1%	39.9%
Indonesia	40.7%	59.3%	40.7%	59.3%
India	59.0%	41.0%	59.0%	41.0%
Iraq	0.0%	0.0%	96.3%	3.7%
Iran	44.1%	55.9%	44.1%	55.9%
Italy	64.7%	35.3%	64.7%	35.3%
Japan	20.0%	80.0%	20.0%	80.0%
Korea	80.8%	19.2%	80.8%	19.2%
Kuwait	90.1%	9.9%	90.1%	9.9%
Kazakhstan	76.4%	23.6%	76.4%	23.6%
Libya	85.3%	14.7%	85.3%	14.7%
Mexico	79.9%	20.1%	79.9%	20.1%
Malaysia	29.6%	70.4%	29.6%	70.4%
Nigeria	67.2%	32.8%	67.2%	32.8%
Netherlands	6.9%	93.1%	6.9%	93.1%
Norway	49.7%	50.3%	0.0%	0.0%
Oman	0.0%	0.0%	57.5%	42.5%
Peru	35.8%	64.2%	35.8%	64.2%
Poland	30.6%	69.4%	30.6%	69.4%
Qatar	33.3%	66.7%	33.3%	66.7%
Romania	32.1%	67.9%	32.1%	67.9%
Russian Federation	48.0%	52.0%	48.0%	52.0%
Saudi Arabia	84.1%	15.9%	84.1%	15.9%
Thailand	34.8%	65.2%	34.8%	65.2%
Turkmenistan	15.4%	84.6%	15.4%	84.6%
Turkey	92.9%	7.1%	92.9%	7.1%
Trinidad and Tobago	14.5%	85.5%	14.5%	85.5%
Taiwan	85.4%	14.6%	85.4%	14.6%
Ukraine	13.7%	86.3%	0.0%	0.0%
United States	81.3%	18.7%	44.7%	55.3%
Uzbekistan	0.0%	0.0%	6.0%	94.0%
Venezuela	62.7%	37.3%	62.7%	37.3%
Global	55.8%	44.2%	55.8%	44.2%

Tab. 2.4 Energy production from oil and gas, per country, for the reference year 2021, in Mega Joule and kg oil equivalent per year (with conventional energy content of 41.868 MJ/kgOE, according to BP 2022). Related production in megatons and billion cubic meters per years is shown in Tab. 2.1 (BP 2022).^{5,6} Energy production is calculated based on energy contents mentioned in chapter 2.2.

Origin	energy production	Share energy oil	Share energy gas	oil equivalent (oil+gas)	Source production	Share oil on global production	Share gas on global production
Unit	MJ/a	%	%	kgOE/a		% m3	% m3
United Arab Emirates	9.2E+12	77.7%	22.3%	2.2E+11	BP 2022	3.9%	1.4%
Argentina	2.7E+12	47.6%	52.4%	6.3E+10	BP 2022	0.7%	1.0%
Australia	6.1E+12	12.9%	87.1%	1.5E+11	BP 2022	0.4%	3.6%
Azerbaijan	2.7E+12	57.1%	42.9%	6.4E+10	BP 2022	0.8%	0.8%
Belgium	2.4E+9	92.7%	7.3%	5.7E+7	Enerdata 2022	0.0%	0.0%
Bolivia	6.1E+11	11.3%	88.7%	1.5E+10	BP 2022	0.0%	0.4%
Brazil	7.7E+12	88.6%	11.4%	1.8E+11	BP 2022	3.7%	0.6%
Canada	1.8E+13	65.1%	34.9%	4.3E+11	BP 2022	6.3%	4.3%
China	1.6E+13	53.4%	46.6%	3.9E+11	BP 2022	4.7%	5.2%
Colombia	2.1E+12	78.9%	21.1%	5.1E+10	BP 2022	0.9%	0.3%
Germany	3.0E+11	45.0%	55.0%	7.1E+9	Enerdata 2022	0.1%	0.1%
Algeria	6.2E+12	41.0%	59.0%	1.5E+11	BP 2022	1.4%	2.5%
Ecuador	1.1E+12	98.9%	1.1%	2.7E+10	Oil: BP 2022, Gas: EIA 2022 (for 2020!)	0.6%	0.0%
Egypt	3.7E+12	34.5%	65.5%	8.9E+10	BP 2022	0.7%	1.7%
Spain	1.7E+9	15.1%	84.9%	4.1E+7	Enerdata 2022	0.0%	0.0%
France	3.5E+10	97.7%	2.3%	8.4E+8	Enerdata 2022	0.0%	0.0%
United Kingdom	3.0E+12	60.1%	39.9%	7.0E+10	BP 2022	1.0%	0.8%
Indonesia	3.6E+12	40.7%	59.3%	8.6E+10	BP 2022	0.8%	1.5%
India	2.5E+12	59.0%	41.0%	6.0E+10	BP 2022	0.8%	0.7%
Iraq	9.1E+12	96.3%	3.7%	2.2E+11	BP 2022	4.8%	0.2%
Iran	1.7E+13	44.1%	55.9%	3.9E+11	BP 2022	4.0%	6.4%
Italy	3.2E+11	64.7%	35.3%	7.8E+9	BP 2022	0.1%	0.1%
Japan	8.0E+10	20.0%	80.0%	1.9E+9	Enerdata 2022	0.0%	0.0%
Korea	9.5E+9	80.8%	19.2%	2.3E+8	Enerdata 2022	0.0%	0.0%
Kuwait	6.3E+12	90.1%	9.9%	1.5E+11	BP 2022	3.1%	0.4%
Kazakhstan	4.9E+12	76.4%	23.6%	1.2E+11	BP 2022	2.0%	0.8%
Libya	3.0E+12	85.3%	14.7%	7.2E+10	BP 2022	1.4%	0.3%
Mexico	5.2E+12	79.9%	20.1%	1.3E+11	BP 2022	2.3%	0.7%
Malaysia	3.8E+12	29.6%	70.4%	9.1E+10	BP 2022	0.6%	1.8%
Nigeria	5.0E+12	67.2%	32.8%	1.2E+11	BP 2022	1.8%	1.1%
Netherlands	7.0E+11	6.9%	93.1%	1.7E+10	Oil: Enerdata 2022, Gas: BP 2022	0.0%	0.4%
Norway	8.2E+12	49.7%	50.3%	2.0E+11	BP 2022	2.2%	2.8%
Oman	3.5E+12	57.5%	42.5%	8.4E+10	BP 2022	1.1%	1.0%
Peru	6.4E+11	35.8%	64.2%	1.5E+10	BP 2022	0.1%	0.3%
Poland	2.0E+11	30.6%	69.4%	4.8E+9	Oil: Enerdata 2022, Gas: BP 2022	0.0%	0.1%
Qatar	9.6E+12	33.3%	66.7%	2.3E+11	BP 2022	1.7%	4.4%
Romania	4.5E+11	32.1%	67.9%	1.1E+10	BP 2022	0.1%	0.2%
Russian Federation	4.9E+13	48.0%	52.0%	1.2E+12	BP 2022	12.7%	17.4%
Saudi Arabia	2.7E+13	84.1%	15.9%	6.3E+11	BP 2022	12.2%	2.9%
Thailand	1.7E+12	34.8%	65.2%	4.2E+10	BP 2022	0.3%	0.8%
Turkmenistan	3.4E+12	15.4%	84.6%	8.1E+10	BP 2022	0.3%	2.0%
Turkey	2.0E+11	92.9%	7.1%	4.8E+9	BP 2022	0.1%	0.0%
Trinidad and Tobago	1.0E+12	14.5%	85.5%	2.5E+10	BP 2022	0.1%	0.6%
Taiwan	2.7E+10	85.4%	14.6%	6.5E+8	Enerdata 2022	0.0%	0.0%
Ukraine	7.8E+11	13.7%	86.3%	1.9E+10	Enerdata 2022	0.1%	0.5%
United States	6.4E+13	47.9%	52.1%	1.5E+12	BP 2022	16.8%	23.1%
Uzbekistan	2.0E+12	6.0%	94.0%	4.7E+10	BP 2022	0.1%	1.3%
Venezuela	2.3E+12	62.7%	37.3%	5.5E+10	BP 2022	0.8%	0.6%
Global	3.3E+14	55.8%	44.2%	7.8E+12	BP 2022	100.0%	100.0%

⁵ Enerdata 2022, <https://yearbook.enerdata.net/crude-oil/world-production-statistics.html>, online 12.12.2022

⁶ Ecuador, gas production: No data found for 2021 - Assuming amount from 2020 according to https://www.eia.gov/international/content/analysis/countries_long/Ecuador/Ecuador.pdf

3 Methods for oil and natural gas extraction

This section gives a basic overview on the technologies in use, mainly based on the description of the first database version (Frischknecht et al. 1996; Jungbluth 2007). Information on production methods in this report has not been updated for current developments.

3.1 Conventional crude oil production

Depending on the variety of crude oils and their properties, the production processes to be used and further treatments are different. While thick, viscous oil must be pumped to the surface, condensate erupts under the high storage site pressure without any additives. The reservoir energy can last for a few days, weeks, months or, as with the oil fields of the Middle East, for years. If the total energy is no longer enough to overcome gravity and friction losses, additional energy must be supplied from outside. Two fundamentally different methods are used:

- The gas lift process and
- Deep-pump pumping

In the gas lift process, the energy is supplied in the form of compressed gas (natural gas or exhaust gas). This foams the oil column and makes it correspondingly lighter. Piston pumps with external drive or, more recently, electric centrifugal pumps are used for deep-pump pumping.

The crude oil produced is separated from any gas and water produced. Gas separation plants are usually built in several stages to separate the valuable fractions, such as butane and pentane, from the less economically interesting ones. The pressure in the individual separators is reduced in stages (up to seven stages).

If the oil contains saltwater (formation water) after separation of the gas, it must be reduced to a value compatible with the transport system and the refinery (corrosion problems).

3.2 Secondary and tertiary crude oil production

If the pressure in the oil field is not enough to transport the oil to the bottom of the borehole, secondary techniques such as water flooding or gas injection must be used. During water flooding, large quantities of water are pressed into the oil field. Water drives oil towards the bottom of the borehole. It compensates for the required but insufficient deposition energy.

For gas injection, in-situ produced oil-associated gases are pressed into the deposits, which requires a compressor with a capacity of several MW - gas turbines (operated with the produced gases) and electric compressors (operated with diesel-electric generators).

Deposits with highly viscous crude oil and in rocks with low permeability are only conditionally suitable for conventional secondary processes. Tertiary recovery methods must be used at an early stage. Three categories can be roughly distinguished (Speight 1991).

- chemical methods,
- thermal methods and
- mixing methods

Within the chemical methods, three methods can be distinguished. Flooding with polymers is a conceptually simple and cost-effective method, but the additional yield is low. Surfactant flooding is complex, expensive and requires extensive preliminary investigations. It has

excellent improvement properties for low and medium viscosity oils. Alkaline flooding processes are only used in deposits with strongly acidic crude oils.

Thermal processes are mainly used in America and Indonesia. There heat is used to reduce the viscosity of the oil or to evaporate the oil. In this way, however, the pressure and thus the energy in the deposit is also increased. A distinction is made between cyclic steam injection, steam flooding and in-situ combustion. Steam processes are often carried out in containers with highly viscous or tarred oils instead of (or after) primary or secondary recovery. Only a few projects were realised in the field of in-situ combustion.

3.3 Natural gas production

Most information mentioned in this chapter is taken from a former study (Schori et al. 2012).

As mentioned in chapter 2.2, crude oil and natural gas production are often very closely linked, and data are often provided for combined production. Like for crude oil, the production of natural gas is preceded by the exploration of reservoirs. Electromagnetic and seismic studies are followed by exploratory drillings. If the size of the reservoir and the quality of the gas is satisfactory, production drillings are carried out for the extraction of the natural gas. Exploration drillings are included in the production of natural gas (stated as meter drilled per m³ produced gas, see chapter 6).

Onshore and offshore drilling takes place in unique drilling environments, which require special techniques and equipment. The most frequently used technology for onshore exploratory and production drillings is rotary drilling with a drilling tower. For offshore production drilling platforms need to be constructed with concrete and steel.

Usually, a first cleansing of the natural gas takes place immediately after the production (processing in the field). This is especially necessary for natural gas containing hydrogen sulphides and/or water. Free liquids are separated with cyclone cutters, expansion vessels and cooling equipment. In some cases, further unwanted gases (H₂S) are separated before the gas is fed into the pipeline for further transport.

Such by-products are not addressed in the model for this study. It is assumed that they would be allocated based on the energy content as described in chapter 2.2.

To reach the required final quality the natural gas sometimes needs to be processed in a further treatment plant before it is fed into the transport pipelines and the supply network.

The following processing stages are distinguished:

- Separation of free water and oil
- Separation of higher hydrocarbons
- Natural gas drying
- Desulphurisation and recovery of elementary sulphur by means of a Claus plant.
- (possibly) additional drying of higher hydrocarbons

The choice of the treatments and their sequence depends mainly on the composition of the raw gas, which can vary considerably.

The amount of processing needed depends on the quality of the produced gas. In general, sour gas is more complex to process because of the additional desulphurisation step. Energy use and direct emissions related to these processing steps are accounted for in chapter 8 and 9.

3.3.1 Gas drying

Water and water vapour contained in raw gas must be eliminated, because otherwise, at certain pressures and temperatures they would form crystalline, snow-like compounds – so-called gas hydrates – that can lead to a clogging of pipelines and equipment. Gas hydrates can further cause corrosion. Water vapour can be separated by one of the following tested methods:

- Deep freezing by expansion cooling (Joule-Thomson effect) or external cooling
- Drying with liquid organic absorption agents
- Drying with solid absorption agents

For the separation of water by external cooling large amounts of heat are necessary. Therefore, the preferred way is to profit from the Joule-Thomson-Effect, where the natural gas has a sufficiently high pressure at the drill hole.

3.3.2 Desulphurisation

Raw gas is classified as “sour gas” (also called lean gas), or “sweet gas” based on the sulphur content. Natural gas with more than 1 vol. % H₂S-content is sour, sweet gas has a lower H₂S content (see also chapters 9.1.4 and 9.5).

The most used desulphurisation process is the chemical gas scrubbing. The used suds contain very reactive compounds such as Purisol, Sulfinol, Rectisol (trademarks) and ethanolamine. After decompression and pre-heating, the suds are regenerated by adding steam. The separated H₂S is directed to a sulphur production plant (Claus plant). In the Claus plant the H₂S is transformed to SO₂ with partial combustion and in the following catalytic reaction of H₂S/SO₂ transformed to elementary sulphur. It is assumed that the retained sulphur is a by-product that comes burden free and is neither an emission nor a waste which needs further treatment (modelled according to the allocation-approach “Cut-off”).⁷

Various flue gases are burned in a production flare, often with the addition of natural gas or vapour. Hereby the SO₂ emissions are of special interest.

4 Production and market data

Information on market data is given in a more comprehensive way in the reports “Life cycle inventories for long-distance transport and distribution of natural gas” and “Life cycle inventory for long distance transport of crude oil” (Bussa et al. 2022; Meili et al. 2022b).

For this study, LCI datasets for crude oil and natural gas production in the 27 countries shown in Tab. 2.1 are either updated or newly modelled.

These selected countries have either a share higher than 1.5% of total imports of crude oil or natural gas either to Switzerland, the EU-28-states, the region North America or the global situation in 2019, or they were historically relevant for datasets available in ecoinvent (e.g. Germany, Netherlands), or they are assumed to be relevant for future analysis, e.g. for modelling an import mix for Latin America or Asia.

The import of refined products to Europe and Switzerland is not analysed for this study.

⁷ Allocation cut-off by classification: <https://www.ecoinvent.org/database/system-models-in-ecoinvent-3/cut-off-system-model/allocation-cut-off-by-classification.html>, online 08.03.2021

It must be emphasized that the above-mentioned market model does not represent the real supply situation in Switzerland. It is a simplification assuming only one average European refinery. The real supply situation is more complex. In 2016, e.g., more products were imported from refineries in the North Sea region (mainly light crude oil) than from Eastern European refineries (mainly heavy crude oil). It would be necessary to investigate more different refinery regions in Europe to better reflect the real situation for supplies to Switzerland. This is outside of the scope of this project.

The countries selected for this study also play an important role on the global market. Together, these 27 countries cover about 84% of global crude oil and natural gas production in 2019 (BP 2022).

4.1 Proportion of offshore oil and natural gas production

Global offshore crude oil production (including lease condensate and hydrocarbon gas liquids) accounted for nearly 30% of total global crude oil production in e.g., 2015.⁸

More than 27 million barrels of oil were produced offshore in 2015 in more than 50 different countries. In 2015, five countries provided 43% of total offshore oil production: Saudi Arabia, Brazil, Mexico, Norway, and the United States.⁸ On the other side countries like Russia and Iraq⁹ only produce onshore (EIA 2016). This means, the proportion of offshore production varies largely between different producing regions.

Independent of the share of onshore and offshore production, also the amount of natural gas extracted in the joint production varies largely between different producing regions.

As no comprehensive data collection is available in the analysed sources, the country- and fuel-type-specific shares for offshore and onshore production are estimated for the reference year 2021 based on different literatures sources (cf. Tab. 4.1).

⁸ U.S. EIA 2016, <https://www.eia.gov/todayinenergy/detail.php?id=28492>, online: 10.10.17

⁹ http://www.opec.org/opec_web/en/about_us/164.htm, online, 09.10.2017

Tab. 4.1 Estimates for share of offshore and onshore-production crude oil and natural gas production in 2021. Part 1

Origin	oil offshore	oil onshore	gas offshore	gas onshore	source for share on- vs. offshore
Unit	%	%	%	%	
United Arab Emirates	44%	56%	44%	56%	Assumption based on https://iclg.com/practice-areas/oil-and-gas-laws-and-regulations/united-arab-emirates
Argentina	30%	70%	30%	70%	No specific data available. Assuming global average seems ok according to https://www.equinor.com/where-we-are/argentina
Australia	75%	25%	75%	25%	https://www.ga.gov.au/digital-publication/aecr2021/oil
Azerbaijan	90%	10%	90%	10%	https://www.eia.gov/beta/international/analysis.php?iso=AZE
Belgium	30%	70%	30%	70%	No data found - assuming global average
Bolivia	0%	100%	0%	100%	Country has no direct access to the sea.
Brazil	97%	3%	97%	3%	https://www.trade.gov/energy-resource-guide-brazil-oil-and-gas
Canada	7%	93%	7%	93%	Calculation based on onshore-share of Alberta and Saskatchewan. Data from https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/estimated-production-canadian-crude-oil-equivalent.html , cited on https://en.wikipedia.org/wiki/Petroleum_industry_in_Canada#cite_note-NEB_2015-11
China	5%	95%	5%	95%	Assessed based on share of gas production: https://www.eia.gov/international/content/analysis/countries_long/China/china.pdf
Colombia	13%	88%	13%	88%	Share assessed based on https://www.cccarto.com/oil/colombiaoil/#5/17.015/-95.493
Germany	56%	44%	56%	44%	2Mm3/a: https://www.bmwi.de/Redaktion/EN/Artikel/Energy/petroleum-oil-imports-and-crude-oil-productions-in-germany.html
Algeria	0%	100%	0%	100%	https://www.trade.gov/country-commercial-guides/algeria-oil-and-gas-hydrocarbons
Ecuador	2%	98%	70%	30%	Mainly gas produced offshore: https://www.offshore-technology.com/comment/ecuador-exploration-and-production-outlook/
Egypt	22%	78%	22%	78%	https://www.statista.com/statistics/972671/egypt-share-crude-oil-production-by-area/
Spain	30%	70%	30%	70%	No data found - assuming global average
France	30%	70%	30%	70%	No data found - assuming global average

Estimates for share of offshore and onshore-production crude oil and natural gas production in 2021. Part 2

Origin	oil offshore	oil onshore	gas offshore	gas onshore	source for share on- vs. offshore
Unit	%	%	%	%	
United Kingdom	98%	2%	98%	2%	https://en.wikipedia.org/wiki/Oil_and_gas_industry_in_the_United_Kingdom#cite_note-3
Indonesia	36%	64%	36%	64%	Estimate based on number of blocks according to https://pwypindonesia.org/en/understanding-the-onshore-and-offshore-schemes-in-the-upstream-oil-and-gas-industry/
India	45%	55%	45%	55%	https://www.eia.gov/international/analysis/country/IND
Iraq	0%	100%	0%	100%	https://www.eurasiareview.com/28042016-iraq-energy-profile-opecs-second-largest-crude-oil-producer-analysis/
Iran	16%	84%	16%	84%	Calculation based on largest oil fields according to https://en.wikipedia.org/wiki/Oil_reserves_in_Iran
Italy	30%	70%	30%	70%	No data found - assuming global average
Japan	30%	70%	30%	70%	No data found - assuming global average
Korea	30%	70%	30%	70%	No data found - assuming global average
Kuwait	1%	99%	1%	99%	Nearly all onshore: https://www.eia.gov/international/analysis/country/KWT
Kazakhstan	13%	87%	13%	87%	https://www.eia.gov/international/analysis/country/KAZ
Libya	20%	80%	20%	80%	Assumption based on proven reserves according to https://www.eia.gov/beta/international/analysis.php?iso=LBY
Mexico	95%	5%	95%	5%	Calculation based on graph on https://www.eia.gov/todayinenergy/detail.php?id=28492
Malaysia	99%	1%	99%	1%	"Nearly" all offshore according to https://www.eia.gov/international/content/analysis/countries_long/Malaysia/malaysia.pdf
Nigeria	90%	10%	90%	10%	https://www.eia.gov/beta/international/analysis_includes/countries_long/Nigeria/nigeria.pdf
Netherlands	90%	10%	90%	10%	https://www.eia.gov/international/overview/country/NLD
Norway	100%	0%	100%	0%	https://www.eia.gov/international/analysis/country/NOR
Oman	0%	100%	0%	100%	Assumption based on map on https://www.eia.gov/international/content/analysis/countries_long/Oman/oman_bkgd.pdf
Peru	10%	90%	10%	90%	Assumption based on https://www.eia.gov/international/analysis/country/PER
Poland	30%	70%	30%	70%	No data found - assuming global average
Qatar	69%	31%	69%	31%	Calculation based on https://www.eia.gov/international/analysis/country/QAT
Romania	30%	70%	30%	70%	No data found - assuming global average

Estimates for share of offshore and onshore-production crude oil and natural gas production in 2021. Part 3

Origin	oil offshore	oil onshore	gas offshore	gas onshore	source for share on- vs. offshore
Unit	%	%	%	%	
Russian Federation	18%	82%	18%	82%	100 MT of 563.3MT in 2018 from Sakhalin-1 and North Chaivo: https://www.mordorintelligence.com/industry-reports/russian-federation-oil-and-gas-market
Saudi Arabia	36%	64%	36%	64%	Calculation based on graph on https://www.eia.gov/todayinenergy/detail.php?id=28492
Thailand	80%	20%	80%	20%	Mostly from offshore production according to https://www.eia.gov/international/analysis/country/THA
Turkmenistan	26%	74%	26%	74%	Share based on reserves stated in https://www.trade.gov/country-commercial-guides/turkmenistan-oil-
Turkey	5%	95%	5%	95%	No specific data available. Assuming global share based on information from https://www.trade.gov/energy-resource-guide-turkey-oil-and-gas
Trinidad and Tobago	30%	70%	30%	70%	No data found - assuming global average
Taiwan	30%	70%	30%	70%	No data found - assuming global average
Ukraine	100%	0%	100%	0%	No data found - assuming global average
United States	15%	85%	3%	97%	https://www.eia.gov/energyexplained/oil-and-petroleum-products/where-our-oil-comes-from.php
Uzbekistan	0%	100%	0%	100%	Country has no direct access to the sea.
Venezuela	30%	70%	30%	70%	No data found - assuming global average
Global	30%	70%	30%	70%	global share: https://www.eia.gov/todayinenergy/detail.php?id=28492

4.2 Proportion of enhanced oil recovery (EOR)

Enhanced oil recovery is used to enhance the recovery factor of oil fields. The tendency to EOR methods is increasing because aging wells are running dry and new discoveries are often only of smaller sizes.

The maturity of production is an important driver of emissions through time. Simply said, this means, an aged oil field is harder to exploit than a young one and therefore, resource and energy needs are higher and lead to higher emissions. Emissions from the same field 20 years after first production can increase by as much as a factor of 10 to 20 over emissions at the start of production (Energy-Redefined 2010). This increase is driven by several factors, including but not limited to:

- Gas and water injection for secondary and tertiary recovery
- Oil flow rates
- Water cut/water production

Using EOR, 30 to 60%, or more, of the reservoir's original oil can be extracted, compared with 20 to 40% using primary and secondary recovery (Abubaker 2015).¹⁰ This means, by using EOR up to 30% more crude oil can be yielded from a certain oil field. Depending on the market price of crude oil and the availability of easily accessible oil fields, EOR is used intensively.

As current data is not available publicly on a country or global level, it is assumed for the new and updated regional datasets, that 15% of crude oil production is done with EOR. In a former assessment, EOR accounted for 3.2% of total production, assuming to be done mainly with chemical methods (Jungbluth 2007). The estimated increase leads to a factor of 4.7 (15% divided by 3.2%) for chemical use per kg of crude oil and therefore to an amount of 0.55g inorganic and 0.42g organic chemicals per kg oil equivalent.

5 Characteristics and properties

5.1 Crude oil

This section describes the main properties of crude oil.

5.1.1 Classification

Within natural resources, oil belongs to the subgroup of naturally occurring hydrocarbons. In contrast to coal, whose elemental composition is very well investigated and documented, the classification of oil is much more difficult because of the lower number of extensive analyses. The ratios of the elements C and H in oil fluctuate only slightly within rather tight limits – despite the big variation in physical characteristics between light mobile hydrocarbons and oils and bitumen (Speight 1991).

Classifying crude oil can be done from different perspectives (Speight 1991):

- Based on proportion of paraffin, naphthenic, aromatic, wax and asphalt components.
- By a correlation index. It describes the correlation of density and boiling temperature on the one hand, and the chemical composition on the other hand.

¹⁰ <https://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery>, online 12.10.17

- By carbon distribution. The distribution of fractions as a function of their volatility is an important parameter. Furthermore, the fractions of aromatic, naphthenic and paraffinic hydrocarbons are determined, whereby paraffinic is subdivided into normal and iso-paraffin.

Another measure to classify crude oil is the American Petroleum Institute gravity, or API gravity. It measures how heavy or light a petroleum liquid is compared to water: If the API gravity of crude oil or an oil product is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks.

For API and sulphur content, country-specific values shown in Tab. 5.1, derived from European import statistics are found (EC 2020).

Tab. 5.1 Sulphur content and API for crude oil imports from selected countries to Europe (EC 2020). Weighted global average calculated using production for these countries, according to Tab. 2.1 (BP 2022)

Origin	Sulphur content	American Petroleum Institute gravity	source/comment
Unit	(%vol)	(API)	
United Arab Emirates	6.69	15.50	Other Middle East Crude according to EC 2020 (reference year 2018)
Azerbaijan	0.17	36.92	Azerbaijan Crude according to EC 2020 (reference year 2019)
Brazil	0.99	22.30	Brazil Crude according to EC 2020 (reference year 2019)
Canada	1.28	27.78	Weighted average Canadian Heavy and Light Sweet according to EC 2020 (reference year 2019)
China	0.05	54.57	Other Asia countries according to EC 2020 (reference year 2014)
Colombia	1.53	19.51	Other Colombia Crude according to EC 2020 (reference year 2019)
Germany	2.15	28.22	Other European Crude according to EC 2020 (reference year 2019)
Algeria	0.09	44.75	Weighted average Other Algeria Crude and Saharan Blend according to EC 2020 (reference year 2019)
Ecuador	1.61	21.35	Weighted average Oriente and Other Ecuador Crude according to EC 2020 (reference year 2014)
United Kingdom	0.55	31.50	Weighted average of different GB-blends according to EC 2020 (reference year 2019)
Indonesia	0.05	54.57	Other Asia countries according to EC 2020 (reference year 2014)
India	2.84	29.42	Weighted average of different IQ-blends according to EC 2020 (reference year 2019)
Iraq	2.84	29.42	Weighted average of different IQ-blends according to EC 2020 (reference year 2019)
Iran	1.96	30.74	Weighted average of different Iranian blends according to EC 2020 (reference year 2018)
Kuwait	2.51	30.83	Kuwait Blend according to EC 2020 (reference year 2019)
Kazakhstan	0.62	45.15	Kazakhstan Crude according to EC 2020 (reference year 2019)
Libya	0.39	38.43	Weighted average of different Libyan blends according to EC 2020 (reference year 2019)
Mexico	3.62	21.36	Oil field Maya according to EC 2020 (reference year 2019)
Malaysia	1.24	32.23	Other Malaysia Crude according to EC 2020 (reference year 2014)
Nigeria	0.18	33.53	Weighted average of different Nigerian blends according to EC 2020 (reference year 2019)
Netherlands	2.15	28.22	Other European Crude according to EC 2020 (reference year 2019)
Norway	0.28	37.15	Weighted average of different Norwegian blends according to EC 2020 (reference year 2019)
Qatar	1.17	36.03	Qatar Marine according to EC 2020 (reference year 2014)
Romania	2.15	28.22	Other European Crude according to EC 2020 (reference year 2019)
Russian Federation	1.27	32.24	Weighted average of different Russian blends according to EC 2020 (reference year 2019)
Saudi Arabia	1.90	32.97	Weighted average of different Saudi Arabian blends according to EC 2020 (reference year 2019)
United States	0.25	42.42	Weighted average of different US blends according to EC 2020 (reference year 2019)
Venezuela	2.87	14.85	Weighted average of different Venezuelan blends according to EC 2020 (reference year 2019)
Global	1.40	33.33	Weighted average based on overall production (BP 2022, reference year 2021)

5.1.2 Net calorific value and density

The calorific value, as well as the density of crude oil and natural gas products varies, depending on its composition and external conditions. In former studies, a net calorific value of 43.2 MJ/kg for crude oil is used for modelling (Meili & Jungbluth 2018; Jungbluth 2007; Schori et al. 2012). This value is used in the Swiss energy statistics (BFE 2017).

Global consumption data shows net calorific values for crude oil consumed in different countries ranging from 41.9 to 45.5 MJ/kg with a weighted average of 43.4 MJ/kg (BP 2022). This figure also includes condensates and natural gas liquids. In the same source the average density of crude oil is defined as 858.1 kg/m³. These global average values are used for modelling in this study.

Please note: For some tables, energy contents are also provided per kg oil equivalent. There, the conventional energy content of 41.868 MJ/kgOE is applied (BP 2022).

If the LCI data provided in this study shall be used for an analysis of the cumulative energy demand, the characterisation factor for “oil, crude” should be adjusted to a new gross calorific value of 46 MJ/kg.

5.1.3 Hydrocarbons

Hydrocarbons (HC), which are the main component of crude oil and which only consist of carbon and hydrogen, can be divided into three groups according to their chemical characteristics:

- **Saturated HC (paraffines and alkanes):**

They form the main components of crude oil.

Chemical formula: C_nH_{2n+2}

Examples:

CH₄ – C₅H₁₂, methane, ethane, propane etc. (gaseous),

C₆H₁₄- C₂₁H₄₄, hexane, heptane, octane etc. (liquid)

>= C₂₂H₄₆, pentacosane, triacontane etc. (solid).

Cyclic saturated (alicyclic) HC (naphthene, cyclo-paraffines, and cyclo-alkanes).

- **Unsaturated HC (alkenes or olefins or alkynes).**

Chemical formula: C_nH_{2n} , or C_nH_n

Examples:

C₂H₄ (IUPAC: ethene,ecoinvent: ethylene),

C₃H₆ (IUPAC: propene,ecoinvent: propylene),

C₂H₂ (ethyne, etc.)

Unsaturated HC are of subordinate importance for natural crude oils. They form in the refineries during cracking processes as valuable by-products, which improve fuel characteristics and partially attained high importance as starting material for many syntheses. Because of their reactivity they have a high significance for the formation of tropospheric ozone.

- **Aromatic HC as aromatics is called unsaturated, ring-shaped HC.**

Examples:

C₆H₆ (benzene),
C₇H₈ (toluene),
C₈H₁₀ (ortho-, meta- and para-xylene)

The share of different components of HCs varies among different crude oils. Generally, it can be said that heavier crude oils (Latin America, Middle East) show higher proportions of polycyclic naphthenic and poly-nuclear aromatics, but lower shares of paraffins and monocyclic naphthene (Speight 1991). Among other things, this also leads to higher metal contents (Ni, V).

5.1.4 Components other than hydrocarbons

Next to the high number of pure hydrocarbons, crude oil contains a variety of organic components other than hydrocarbons. Mainly they are sulphur-, nitrogen-, or oxygen compounds. In smaller amounts, also dissolved organo-metallic components and inorganic salts in different colloidal suspension are present. These components occur within the entire boiling range of crude oil, but mainly they are concentrated in the heavier fraction and the non-volatile residues (Speight 1991).

These components can have a major impact in technical processes, despite the relatively low quantity. This entails thermal decomposition of inorganic chlorides to free hydrochloric acid and thus to corrosion problems in distillation. Also, the presence of organic acidic components such as mercaptans and acids can cause metal corrosion. In catalytic processes, e.g., by nickel and vanadium deposits or by chemisorption of compounds containing nitrogen, a passivation or poisoning of the catalyst can occur, which leads to frequent regeneration or premature replacement of the catalyst.

5.1.5 Sulphur components

Sulphur content correlates, as first approximation, with the density of crude oil. It fluctuates between 0.04% for light paraffin oil and 5% and more for heavy crude oil. Sulphur in oil products can lead to corrosion in many applications. For instance, mercaptan in hydrocarbon solutions leads to corrosion of copper and brass if oxygen is present. The sulphur compounds vary from simple thiols (mercaptans) via sulphides, poly-cyclic sulphates and thiophenes to derivatives of benzo-thiophenes (Speight 1991). For the main production areas, the sulphur contents as shown in chapter 5.1.1, Tab. 5.1 can be reported (EC 2020). Sulphur contents of final products depends on processing in the refinery (Jungbluth et al. 2018a).

5.1.6 Oxygen compounds

The oxygen compounds are alcohols (phenols), ethers, carboxylic acids, ketones and furans. Thereby, ketones, esters, ethers and anhydrides can rather be found in heavy, non-volatile residues. They can originate from residues and do not need to be original components of crude oil (cf. Jungbluth 2007, chapter 9).

5.1.7 Nitrogen compounds

Nitrogen compounds can be divided into alkaline or non-alkaline. Nitrogen content tends to increase with asphalt content of crude oil. Therefore, nitrogen is more likely to be found in those fractions and remains which are higher boiling. Increasing refinement of residues to lighter fractions ("whitening of the Barrel") can lead to harmful effects of nitrogen on crack-catalysts in refineries (Speight 1991).

5.1.8 Porphyrins

Porphyryns are cyclic, conjugated components, which occur usually in the non-alkaline part of the nitrogen-containing concentrate. Nearly all crude oils contain vanadyl and nickel porphyryns (metal chelates). Other metals were hardly found in such compounds, probably for geochemical reasons. However, by far not all vanadium and nickel is incorporated in porphyryns. They can also occur as non-porphyrin, metallic chelates (Speight 1990). Porphyryns are concentrated in the asphalt fraction. Therefore, deasphalted crude oils do have smaller concentrations of porphyryns and usually also very small concentrations of non-porphyrin metals.

5.1.9 Further trace elements

For processing but also for emission inventories of oil-energy systems, next to calorific value and sulphur content, also information on concentrations of other trace elements of crude oil and its products are of interest.

From the point of view of the oil processor and oil customer, trace elements in the oil are not desired. On the one hand, because they impair the effect of the catalyst in the refinery; on the other hand, for example they can lead to ash formation and corrosion in turbines. The trace elements which occur in significant concentrations in oil can be divided into two groups. Zinc, titanium, calcium and magnesium and others are present as organometallic soaps; while e.g., vanadium, copper, nickel and iron occur as components soluble by oil.

By distillation processes, trace elements are generally concentrated in the residues. Thus, the content of trace elements tends to increase from light to heavy products and is higher in heavy fuel oils and bitumen than in processed crude oil.

Various publications contain results and analyses on trace elements or their emission factors in crude oils and products. The extent to which element contents in crude oil can fluctuate is shown in a former study (Jungbluth 2007, Table A.1). The high concentration of zinc and iron in the composition of oil indicate an enrichment during oil processing (separation of water and gases) and transport (Pacyna 1982, Jungbluth 2007, appendix Tab A.1).

5.1.10 Mercury

Amount of mercury in this study is assessed as 0.030 mg/kg of crude oil (Jungbluth 2007).

5.1.11 Summary of properties used in this study

The LCI data for extraction processes modelled in this study is calculated for crude oil with the physical and chemical properties as defined in Tab. 5.2 (BP 2022).

Tab. 5.2 Physical and chemical properties of crude oil as assessed for this study according to lower heating value and density used in global statistics (BP 2022)

	unit	This study
Lower heating value (LHV)	MJ	43.4
Higher heating value (HHV)	MJ	46.0
Density at 20°C	kg/m ³	858.1
	% by weight	
C-content	83 - 87	84.0%
H-content	10 - 14	10.0%
O-content	0.05 - 1.5	1.5%
N-content	0.1 - 2.0	2.0%
S-content	0.05 - 6	2.5%
Total		100.0%

5.2 Natural Gas

5.2.1 Net calorific value and density

Net calorific value, density and other physical properties of natural gas vary depending on the origin / specific source, mixture, state of processing, etc.

In former studies an average net calorific value of 36.3 MJ/Nm³ (45.7 MJ/kg) for natural gas is used (Meili & Jungbluth 2018 Jungbluth 2007; Schori et al. 2012). This value was then consistent with a former version of the Swiss energy statistics (BFE 2017).

According to confidential/internal calculation of SGWA, between 1990 and 2018, the net calorific value of natural gas imported to Switzerland fluctuates between 45.7 and 47.6 MJ/kg (BAFU 2020, Tab. 3-11). In a current factsheet, for the Swiss greenhouse gas inventory, the value calculated for 2017, 47.3 MJ/kg, for natural gas with density of 0.783kg/m³ is used (=37.0 MJ/Nm³). As another example, in ecoinvent v3 a gross calorific value of 39 MJ/Nm³ is used as default for all calculations related to raw gas (c.f. Faist-Emmenegger et al. 2015).

However, in global statistics used for the current study, for all countries, a generic gross calorific value (GCV) of 40MJ/Nm³, respectively the net calorific value of 36.0 MJ/Nm³ is used (BP 2022). Therefore, this value and the related density of 0.735kg/Nm³ is used for all calculations related to raw natural gas in this study. These values are valid for standard conditions of 15°C and 1013 mbar. As ecoinvent and widely used LCA software use the unit Nm³ to represent gas, the name of this unit is kept but values represent in fact the conditions for Sm³. If the LCI data provided in this study shall be used for an analysis of the cumulative energy demand, the characterisation factor for “gas, natural/m³” should be adjusted to a new gross calorific value of 39.9 MJ/Nm³.

5.2.2 Classification of fuel gases

This chapter is not updated and kept the same as in a former study (Schori et al. 2012). Various fuel gases are available on the market, some of which are natural gas, coke-oven gas and blast furnace gas. The following chapters describe the natural gas system. The production of coke-

oven gas is described in Röder et al. (2007). Blast furnace gas is recovered as a by-product of blast furnaces and is described in Classen et al. 2007.

In the first half of the 20th century gas won through gasification of hard coal was commonly used. After the introduction of natural gas, coal gas - also known as city gas or illumination gas - lost its importance. The exploration of the Dutch natural gas field in the vicinity of Groningen led to a boom in the demand of natural gas in Europe from 1965 onwards. Today natural gas makes up 25% of the primary energy consumption in Europe (BP 2011).

The relevance of coke oven gas and blast furnace gas is decreasing. In Germany for example the share of coke oven gas of the total gas supply has dropped below 3% (Cerbe et al. 1999). Blast furnace gas provides about 4.6% of the fuel gases used in Germany.

Biogas is a fuel gas gaining importance. Processed biogas with sufficiently high methane content can be fed into the natural gas distribution network.

Natural gas, coke oven gas, furnace gas and biogas differ substantially with regard to their chemical composition. Tab. 5.3 shows typical values of the composition of the five fuel gases. Additional country-specific properties and newer composition data might also be found in Juhrich 2016. Please note, these data, as well as the old ones, might not be consistent with the natural gas volumes extracted for the reference year and the related numbers (c.f. chapter 4)

Tab. 5.3 Composition of fuel gases (reference values) (Cerbe et al. 1999; Bruijstens et al. 2008);
1) The composition of biogas can vary depending on the feedstock. The data shown here is for upgraded biogas (biomethane) from a plant in Stockholm, Sweden.

	H ₂	CO	CH ₄	C ₂ H ₆	C ₃ H ₈	C ₄ H ₁₀	Other C _x H _y	CO ₂	N ₂	O ₂
	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %
Blast furnace gas	4.1	21.40						22.0	52.5	
Coke oven gas	54.5	5.50	25.3				2.3	2.3	9.6	0.5
Natural gas L			81.8	2.8	0.4	0.2		0.8	14.0	
Natural gas H			93.0	3.0	1.3	0.6		1.0	1.1	
Biomethane¹⁾			>97					< 2	< 0.8	0.2

Natural gas is rich in methane. The high content of nitrogen and carbon monoxide is typical for blast furnace gas. Coke-oven gas on the other hand shows high levels of hydrogen. Natural gas is classified as high-calorific (H-gas or High-gas) and low-calorific gas (L-gas or Low gas) based on the methane content. H-gas contains between 87 and 99 vol. % and L-gas between 80 and 87 vol. % methane.

In Germany the properties and composition of commercial fuel gases are regulated according to the DIN and DVGW directives, in Switzerland according to the SVGW directives. A number of secondary gas substances are limited by threshold values. "Common business practices" for non-odorized high-calorific gas in transboundary traffic in Europe are stated as follows: the total sulphur content must not exceed 30 mg/Nm³, hydrogen sulphide content needs to be below 5 mg/Nm³. Further threshold values exist for different hydrocarbons, water, dust, liquids, mercaptans, nitrogen oxides, ammoniac and hydrogen cyanide.

5.2.3 Fuel data of raw natural gas

This chapter is not updated and kept the same as in a former study, original sources might be retrieved there (Schori et al. 2012). This section shows the composition of natural gas after the extraction and before processing, for the so-called raw gases. These compositions are used to calculate emissions at the extraction and processing of natural gas. The resource use is quantified as "Gas, natural, in ground". This covers both natural gas from carbonification and natural gas formed in association with crude oil (also known as associated petrol gas, APG). The natural gas is processed to ensure the purity and quality needed for end-use. During the transport and distribution, the composition of the natural gas changes only slightly.

The composition of raw gases from different origins varies considerably. The main component is methane; other important components are ethane, propane, nitrogen, carbon dioxide, helium, sulphurous substances and higher hydrocarbons (higher C/H). The sulphurous compounds are mainly hydrogen sulphide, as well as carbonyl sulphide (COS), carbon disulphide (CS₂) other organic sulphites, disulphides, mercaptanes and thiopenes. Among the higher hydrocarbon's benzene, toluene and xylene are of importance because of their toxicity <Nerger et al. 1987>.

Tab. 5.4 shows the chemical composition of various raw gases prior to processing. A differentiation is made between so-called "sour" gases (with high sulphur content) and "sweet" gases.

Tab. 5.4 Chemical composition of raw gases prior to processing

Substances	Range of fluctuation	Raw gas from Groningen (NL)	Raw gas from Süd Oldenburg	Raw gas from Bentheim (DE)	Mean raw gas (NO)*	Raw gas from Urengoy „C“, West-Siberia
	vol. %	vol. %	vol. %	vol. %	vol. %	vol. %
Methane	>80	81.50	79.10	93.20	88.80	99.00
Ethane C ₂ H ₆	up to 8	2.80	0.30	0.60	4.80	0.10
Propane C ₃ H ₈	up to 3	0.40			1.70	0.01
Butane C ₄ H ₁₀		0.14	<0.01		0.70	0.02
Higher C/H	up to 4	0.14			0.70	0.00
H ₂ S	0-24		6.90			8.5 E-06
CO ₂	up to 18	0.92	9.10		1.60	0.09
N ₂	up to 15	14.10	4.60	6.20	1.40	0.79
Source	Infras 1981	Infras 1981	Infras 1981	Landolt Börnstein 1972	Statoil, 2001	Müller, 1997

*) Weighted mean value for natural gases processed in the plants Kollsnes and Kårsto.

In addition to the substances mentioned above natural gas may contain further substances that are of importance from an environmental point of view. Raw gas can be enriched with other substances in trace concentrations up to 10⁻³ bis 10⁻⁶ g/Nm³ <Nerger et al. 1987>. In the United States and Europe, natural gas is tested for mercury since the 1930'ies. Steinfatt & Hoffmann 1996 reports mercury concentrations of natural gas from Algeria, the Netherlands and Germany. The mercury contents are shown in Tab. 5.5.

Tab. 5.5 Mercury contents of natural gas from Algeria, the Netherlands and Germany (Steinfatt & Hoffmann 1996)

Region	Elemental mercury ($\mu\text{g}/\text{Nm}^3$)
Algeria	58-193
The Netherlands (North Sea)	180
Germany	Up to 11'000 ^{*)}
Russia (Dnjepr-Donetz)	53

^{*)} The mercury content of German deposits is in the range of the Dutch ones, however in rare cases it can reach up to 11'000 $\mu\text{g}/\text{Nm}^3$.

The investigation of pipeline gases revealed a rapid decrease in the Hg-content in pipelines <Tunn 1973>. The study examined gas transported from the Netherlands to Germany. A large share of the mercury contained in the Groningen-gas was removed on the way to the Dutch-German border due to processing and condensate separation. From an initial concentration of 180 $\mu\text{g}/\text{Nm}^3$, the mercury concentration dropped down to 20 $\mu\text{g}/\text{Nm}^3$. In the German pipeline system, the concentration is further reduced to 2 to 3 $\mu\text{g}/\text{Nm}^3$. Only when natural gas from German production is fed into the pipeline the concentration remains as high as 19 $\mu\text{g}/\text{Nm}^3$. However, by the time the natural gas reaches the end consumer, the mercury concentration is reduced to very low levels, often below the detection limit (1 to 2 $\mu\text{g}/\text{Nm}^3$).

The raw gas of certain deposits shows traces of Radon-222, a radioactive gaseous decomposition product of uranium. <Gray 1990> summarised the results of various studies. Radon concentrations in natural gases at the production site range from 1 to 10 pCi/l¹¹ in Germany, from 1 to 45 pCi/l in the Netherlands and from 1 to 3 pCi/l in offshore production in the North Sea. In this study the radon emissions are reported in kilobecquerel (kBq) units.

A more precise declaration of the various natural gases is not possible due to local and temporal variations, as well as a lack of data. For this study plausible standard gas compositions are defined, based on the data in Tab. 5.4 and the information mentioned above. The composition is given for important countries of origin for the Swiss and European natural gas supply: The standard composition is applied e.g., for the leakages in the exploration and processing of the natural gas. For the raw gas prior to processing plausible mean values from Tab. 5.4 are used: a mercury concentration of 200 $\mu\text{g}/\text{Nm}^3$ and a radon-222 concentration of 10 pCi/l or roughly 0.4 kBq/ Nm^3 . The calorific values and CO₂ emission factors were calculated assuming complete combustion.

Tab. 5.6 shows the chemical composition and the fuel data of the auxiliary modules "leakage raw gas sweet" and "leakage raw gas sour" which are used to calculate the composition of raw natural gases from different countries and regions (see Tab. 5.7). The latter composition data are used to model the leakage emissions of produced natural gas.

¹¹ 1 Ci = 3.7*10⁷ KBq

Tab. 5.6 Fuel data for raw gases prior to processing. Sources: Tab. 5.4 and notes in the text.

Gas type	Unit	Raw gas "sour" prior to processing	Raw gas "sweet" prior to processing	Raw gas "sour" prior to processing	Raw gas "sweet" prior to processing
Country of origin		Germany, Russian Federation	Norway, Netherlands, Germany, Russian Federation, Algeria	Germany, Russian Federation	Norway, Netherlands, Germany, Russian Federation, Algeria
Unit		vol. %	vol. %	kg/Nm ³	kg/Nm ³
Methane		70	85	0.50	0.61
Ethane		8	3	0.11	0.04
Propane		5		0.10	
Butane			1		
C5+		1	1	0.04	0.04
Carbon dioxide		5	10	0.10	0.02
Nitrogen		5		0.06	0.13
H ₂ S		6		0.09	
Mercury	µg/Nm ³			200	200
Radon-222	kBq/Nm ³			0.4	0.4
Gross calorific value GCV	MJ/Nm ³			41	38
Net calorific value NCV	MJ/Nm ³			37	34
Density	kg/Nm ³			1.00	0.84
EF-CO ₂ Hu *)	kg/GJ			89.2	88.7

*) Assumption: complete combustion

Tab. 5.7 Average composition of raw natural gas from DE, NAC, NL, NO and RU prior to processing based on their share of sour gas. Source: Tab. 5.6.

	Unit	Raw gas DE	Raw gas RU	Raw gas NO	Raw gas NL	Raw gas NAC	Raw gas NG
Sour gas	%	50	20	5	0	0	0
CH₄ Methane	kg	0.555	0.588	0.6045	0.61	0.61	0.61
CO₂ Carbon dioxide	kg	0.06	0.036	0.024	0.02	0.02	0.02
Ethane	kg	0.075	0.054	0.0435	0.04	0.04	0.04
H₂S Hydrogen sulphide	kg	0.045	0.018	0.0045	0	0	0
Hg Mercury	kg	2.00E-07	2.00E-07	2.00E-07	2.00E-07	2.00E-07	2.00E-07
N₂ Nitrogen	kg	0.0365	0.0224	0.01535	0.013	0.013	0.013
NMVOC	kg	0.04	0.04	0.04	0.04	0.04	0.04
Propane	kg	0.05	0.02	0.005	0	0	0
Radioactive Rn 222	kBq	0.4	0.4	0.4	0.4	0.4	0.4

6 Material use and land occupation for infrastructure

The LCI modules “well for exploration and production, onshore”, “well for exploration and production, offshore”, “production plant crude oil, onshore”, “platform, crude oil, offshore”, “plant offshore, natural gas, production” and “plant onshore, natural gas, production” are used to model infrastructure expenses. Details about data collection are provided in a former study (Jungbluth 2007). The infrastructure is allocated to natural gas and crude oil production based on the quantity produced (in calorific value).

It is assumed that these inventories are still accurate for this model. However, as described in chapters 3.2 and 4.2 oil fields get more depleted globally, which means, that wells need to get deeper, the number of wells increases, and new/ enhanced oil recovery methods must be used. Data for these factors are investigated and updated in this study.

6.1 Number and length of wells

The inventory for well drilling was revised in the year 2023.

In a former study, only estimates based on crude oil extraction were used to calculate the well length for combined production. In this study, if available, newer, as well as values from gas extraction were considered.

The number of wells needed to maintain a steady flow of crude oil and natural gas highly depends on regional aspects. E.g., in the Rumaila oil field in Iraq, 350 wells are sufficient to extract 1.5 million barrels per day (b/d), leading to a productivity of 4’300 barrel per day and well (2b1stconsulting¹²) On the other hand, in the U.S., in 2021, 917’000 producing wells to produce about 11.2 million barrels of crude oil and condensate per day. The distribution is generally skewed. Many wells produce smaller volumes per day and fewer wells produce very large volumes per day. In 2021, about 80% of the U.S. oil and gas wells produced 15 or fewer barrels oil equivalent per day (BOE/day), and about 5% of the wells produced more than 100 BOE/day (EIA 2019, 2022).

¹² 2b1stconsulting: <https://www.2b1stconsulting.com/bp-and-cnpc-tender-iraq-rumaila-produced-water-re-injection-prwi/>, online 19.10.17

The national average length of the wells seems to have a smaller variability with an average of 1820 m for exploratory and development wells in US in 2008 (EIA¹³) and 2400 m in Iraq (FAS¹⁴).

For offshore production typically, well lifetime lies between 5 to 10 years and for onshore production it lies between 15 to 30 years.¹⁵

Well drilling is assumed to be an ongoing task in all oil fields and not an investment for a longer period of time. For this study the wells drilled within one year are assumed to be used within this year. Thus, the environmental impacts caused in this year are directly accounted for. If well drilling would stop or decrease, oil and gas can still be produced for some time, but the productivity will likely decrease with decreased establishment of new wells.

Estimates for well length drilled in the years 2019 to 2023 in world regions is provided by Rystad energy well cube.¹⁶ Additionally, country-specific data for 2021 was found for Canada.¹⁷ To allocate these drilling lengths to on- and offshore production, data on wells drilled on- and offshore in 2019 is used.¹⁸ This data is extrapolated to the reference year 2021 by using the forecast from 2020.¹⁹ Well length drilled per year and region are then divided by the amount of oil equivalents extracted in the related year (BP 2022). An overview of the considered region-specific values is provided in Tab. 6.1.

By using the region specific values for North America and Canada, also region-specific values for the US are calculated. The well lengths used for each country assessed in this study are provided in

Tab. 6.2

¹³ EIA: https://www.eia.gov/dnav/pet/pet_crd_welldep_s1_a.htm, online 17.01.2023

¹⁴ FAS: <https://fas.org/sgp/crs/mideast/RS21626.pdf>, online 19.10.17

¹⁵ <https://www.planete-energies.com/en/medias/close/life-cycle-oil-and-gas-fields>, published 8.11.2015

¹⁶ Rystad energy well cube, cited on <https://oilnow.gy/featured/new-wells-drilled-to-the-moon-and-back-by-2023/>, estimates based on graph.

¹⁷ Combined length of oil and gas wells in 2021: <https://www.statista.com/statistics/479760/canada-well-drilling-depth-by-province/>

¹⁸ Rystad energy well cube, cited on <https://oilprice.com/Energy/Energy-General/118500-Oil-Gas-Wells-To-Be-Drilled-Worldwide-Through-2022.html>, estimates based on graph.

¹⁹ Rystad energy well cube, cited on <https://www.oklahomaminerals.com/drilling-set-for-20-year-low> Numbers estimated based on graph.

Tab. 6.1 Regional averages for total well length drilled, wells and well length drilled off- and onshore per year and well length drilled per kilogram oil equivalent (kg OE). Estimates based on Rystad energy well cube.^{16,18,19}

Origin	well length drilled per year, total	Wells drilled offshore	Wells drilled onshore	well length drilled per year, offshore	well length drilled per year, onshore	well length offshore (m) per kg OE, this study	well length onshore (m) per kg OE, this study
Unit	m/a	unit/a	unit/a	m/a	m/a	m/kg OE	m/kg OE
Africa	2.67E+6	255	481	9.25E+5	1.74E+6	1.60E-6	3.01E-6
Asia and the Pacific	3.42E+7	1'040	21'143	1.60E+6	3.26E+7	1.71E-6	3.48E-5
Australia	8.89E+5	20	481	3.49E+4	8.54E+5	2.40E-7	5.87E-6
Europe	1.33E+6	333	481	5.46E+5	7.87E+5	1.57E-6	2.27E-6
Middle East	1.16E+7	589	2'883	1.96E+6	9.60E+6	9.90E-7	4.85E-6
North America	1.20E+8	255	24'026	1.27E+6	1.19E+8	6.05E-7	5.70E-5
Russian Federation	2.71E+7	20	6'727	7.88E+4	2.70E+7	6.80E-8	2.33E-5
Latin America	4.44E+6	78	2'403	1.41E+5	4.30E+6	3.15E-7	9.64E-6
Global	1.94E+8	2'511	58'623	7.99E+6	1.86E+8	1.02E-6	2.38E-5

Tab. 6.2 Well length in meters per kilogram of oil equivalent estimated for countries under study, for onshore and offshore production. Estimates based on Rystad energy well cube.16.17.18.19

Origin	well length offshore (m) per kg OE, this study	well length onshore (m) per kg OE, this study	Source
Unit	m/kg OE	m/kg OE	
United Arab Emirates	9.90E-7	4.85E-6	Regional estimate for 2021
Argentina	3.15E-7	9.64E-6	Regional estimate for 2021
Australia	2.40E-7	5.87E-6	Country-specific estimate for 2021
Azerbaijan	1.71E-6	3.48E-5	Regional estimate for 2021
Belgium	1.57E-6	2.27E-6	Regional estimate for 2021
Bolivia	3.15E-7	9.64E-6	Regional estimate for 2021
Brazil	3.15E-7	9.64E-6	Regional estimate for 2021
Canada	3.64E-7	3.43E-5	Regional estimate for 2021 in combination with country-specific length of oil and gas wells in 2021, according to statista.com
China	1.71E-6	3.48E-5	Regional estimate for 2021
Colombia	3.15E-7	9.64E-6	Regional estimate for 2021
Germany	1.57E-6	2.27E-6	Regional estimate for 2021
Algeria	1.60E-6	3.01E-6	Regional estimate for 2021
Ecuador	3.15E-7	9.64E-6	Regional estimate for 2021
Egypt	1.60E-6	3.01E-6	Regional estimate for 2021
Spain	1.57E-6	2.27E-6	Regional estimate for 2021
France	1.57E-6	2.27E-6	Regional estimate for 2021
United Kingdom	1.57E-6	2.27E-6	Regional estimate for 2021
Indonesia	1.71E-6	3.48E-5	Regional estimate for 2021
India	1.71E-6	3.48E-5	Regional estimate for 2021
Iraq	9.90E-7	4.85E-6	Regional estimate for 2021
Iran	9.90E-7	4.85E-6	Regional estimate for 2021
Italy	1.57E-6	2.27E-6	Regional estimate for 2021
Japan	1.71E-6	3.48E-5	Regional estimate for 2021
Korea	1.71E-6	3.48E-5	Regional estimate for 2021
Kuwait	9.90E-7	4.85E-6	Regional estimate for 2021
Kazakhstan	1.71E-6	3.48E-5	Regional estimate for 2021
Libya	1.60E-6	3.01E-6	Regional estimate for 2021
Mexico	6.05E-7	5.70E-5	Regional estimate for 2021
Malaysia	1.71E-6	3.48E-5	Regional estimate for 2021
Nigeria	1.60E-6	3.01E-6	Regional estimate for 2021
Netherlands	1.57E-6	2.27E-6	Regional estimate for 2021
Norway	1.57E-6	2.27E-6	Regional estimate for 2021
Oman	9.90E-7	4.85E-6	Regional estimate for 2021
Peru	3.15E-7	9.64E-6	Regional estimate for 2021
Poland	1.57E-6	2.27E-6	Regional estimate for 2021
Qatar	9.90E-7	4.85E-6	Regional estimate for 2021
Romania	1.57E-6	2.27E-6	Regional estimate for 2021
Russian Federation	6.80E-8	2.33E-5	Country-specific estimate for 2021
Saudi Arabia	9.90E-7	4.85E-6	Regional estimate for 2021
Thailand	1.71E-6	3.48E-5	Regional estimate for 2021
Turkmenistan	1.71E-6	3.48E-5	Regional estimate for 2021
Turkey	9.90E-7	4.85E-6	Regional estimate for 2021
Trinidad and Tobago	3.15E-7	9.64E-6	Regional estimate for 2021
Taiwan	1.71E-6	3.48E-5	Regional estimate for 2021
Ukraine	1.57E-6	2.27E-6	Regional estimate for 2021
United States	7.21E-7	6.79E-5	Calculation based on region specific estimates for 2021 and country-specific estimate for Canada
Uzbekistan	1.71E-6	3.48E-5	Regional estimate for 2021
Venezuela	3.15E-7	9.64E-6	Regional estimate for 2021
Global	1.02E-6	2.38E-5	Regional estimate for 2021

6.2 Well drilling

Tab. 6.3 and Tab. 6.4 show the life cycle inventory for the drilling of one meter of well for exploration and production of crude oil and natural gas onshore and offshore, respectively. Data in general is kept similar to the former study (Jungbluth 2007). For onshore production land must be transformed to drill the well and access it. For this model it is estimated that a smaller area of 50m times 50m is needed for a well with depth 2000m²⁰. This estimation is applied in all the datasets in this study.

Emissions due to venting and flaring during drilling are excluded from this inventory as they are covered with the overall data for venting and flaring applied to oil and gas extraction. Also, the energy use for well drilling is covered in the general data on energy consumption and not recorded here.

²⁰ <http://www.ecoinvent.org/support/ecoinvent-forum/topic.html?&tid=410>, online 11.01.2018

Tab. 6.3 Life cycle inventory data for the drilling of wells for exploration and production of crude oil, onshore

	Name	Location	InfrastructureProcess	Unit	well for exploration and production, onshore	UncertaintyType	StandardDeviation95%	GeneralComment
product	well for exploration and production, onshore	GLO		m	1.00E+0			
resource, land	Occupation, mineral extraction site	-	-	m2a	1.88E+1	1	1.80	(3,4,5,3,1,BU:1.5); ; Lifetime of well 15a
	Transformation, from forest, unspecified	-	-	m2	1.25E+0	1	2.03	(3,4,1,3,1,BU:2); ; Estimation 50*50 metre area for a 2000 m well
	Transformation, to mineral extraction site	-	-	m2	1.25E+0	1	2.03	(3,4,1,3,1,BU:2); ; Calculation
resource, in water	Water, well, GLO	-	-	m3	3.34E+0	1	1.51	(2,3,5,3,1,BU:1.05); ; Literature, basic uncertainty estimated with 2
technosphere	lignite, at mine	RER		kg	2.00E-1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	barite, at plant	RER		kg	2.70E+2	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	bentonite, at processing	DE		kg	2.00E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	chemicals inorganic, at plant	GLO		kg	4.22E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	chemicals organic, at plant	GLO		kg	9.05E+0	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	lubricating oil, at plant	RER		kg	6.00E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	reinforcing steel, at plant	RER		kg	2.10E+2	1	1.54	(3,4,5,3,1,BU:1.05); ; Literature
	portland cement, strength class Z 52.5, at plant	CH		kg	2.00E+2	1	1.54	(3,4,5,3,1,BU:1.05); ; Literature
	transport, freight, lorry 16-32 metric ton, fleet average	RER		tkm	8.11E+1	1	2.99	(4,5,5,5,5,BU:2); ; Standard distance 100km
	transport, freight, rail	RER		tkm	4.87E+2	1	2.99	(4,5,5,5,5,BU:2); ; Standard distance 600km
	crude oil, used in drilling tests	GLO		kg	3.16E+1	1	1.60	(3,4,5,3,3,BU:1.05); ; Estimation with data for offshore, basic uncertainty estimated with 2
	diesel, burned in diesel-electric generating set	GLO		MJ	0	1	1.64	(3,5,5,3,3,BU:1.05); ; Excluded as part of production data
	natural gas, vented	GLO		Nm ³	0	1	1.58	(4,4,5,3,1,BU:1.05); ; Excluded as part of production data
	disposal, drilling waste, 71.5% water, to landfarming	CH		kg	2.37E+2	1	1.51	(2,3,5,3,1,BU:1.05); ; Environmental reports and literature
	disposal, drilling waste, 71.5% water, to residual material landfill	CH		kg	1.58E+2	1	1.51	(2,3,5,3,1,BU:1.05); ; Environmental reports and literature
	disposal, hazardous waste, 25% water, to hazardous waste incineration	CH		kg	5.00E+0	1	1.53	(2,4,5,3,1,BU:1.05); ; Environmental reports and literature
emission air, low population density	Particulates, > 10 um	-	-	kg	1.49E-2	1	1.84	(3,5,5,3,1,BU:1.5); ; Literature, use of barite
emission water, river	Aluminium	-	-	kg	6.00E-2	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	AOX, Adsorbable Organic Halogen as Cl	-	-	kg	4.78E-7	1	1.79	(3,3,5,1,1,BU:1.5); ; Environmental report
	Arsenic	-	-	kg	4.20E-4	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Barium	-	-	kg	6.00E-3	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	BOD5, Biological Oxygen Demand	-	-	kg	3.00E-1	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Boron	-	-	kg	9.00E-3	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Calcium	-	-	kg	6.00E-1	1	3.31	(3,4,5,5,3,BU:3); ; Literature, effluent sludge pond
	Chloride	-	-	kg	6.00E+0	1	3.31	(3,4,5,5,3,BU:3); ; Literature, effluent sludge pond, basic uncertainty estimated with 3
	Chromium	-	-	kg	6.00E-4	1	3.31	(3,4,5,5,3,BU:3); ; Literature, effluent sludge pond
	COD, Chemical Oxygen Demand	-	-	kg	3.00E+0	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Fluoride	-	-	kg	3.00E-3	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Hydrocarbons, aromatic	-	-	kg	3.00E-3	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Iron	-	-	kg	1.80E-1	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Magnesium	-	-	kg	1.20E-1	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Manganese	-	-	kg	3.00E-3	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Methane, dichloro-, HCC-30	-	-	kg	6.00E-2	1	3.31	(3,4,5,5,3,BU:3); ; Literature, effluent sludge pond
	Phosphorus	-	-	kg	1.20E-3	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Potassium	-	-	kg	9.00E-1	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond, basic uncertainty estimated with 3
	Silicon	-	-	kg	3.00E-2	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Sodium	-	-	kg	6.00E+0	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond, basic uncertainty estimated with 3
	Strontium	-	-	kg	1.80E-2	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Sulfur	-	-	kg	1.20E-1	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	DOC, Dissolved Organic Carbon	-	-	kg	3.00E-1	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	TOC, Total Organic Carbon	-	-	kg	3.00E-1	1	1.87	(3,4,5,5,3,BU:1.5); ; Literature, effluent sludge pond
	Zinc	-	-	kg	1.20E-3	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond

Tab. 6.4 Life cycle inventory data for the drilling of wells for exploration and production of crude oil, offshore

	Name	Location	InfrastructureProcess	Unit	well for exploration and production, offshore	UncertaintyType	StandardDeviation%	GeneralComment
product	well for exploration and production, offshore	OCE	1	m	1.00E+0			
resource, land	Occupation, dump site, benthos	-	-	m2a	2.60E+2	1	3.33	(4,5,3,1,na,BU:1.5); Estimation 1 year use
	Transformation, from seabed, unspecified	-	-	m2	2.60E+2	1	3.77	(4,5,3,1,na,BU:2); Literature
	Transformation, to dump site, benthos	-	-	m2	2.60E+2	1	3.77	(4,5,3,1,na,BU:2); Literature
resource, in water	Water, salt, ocean	-	-	m3	1.73E+0	1	3.07	(3,5,3,1,na,BU:1.05); Environmental report of Saipem, basic uncertainty estimated with 2
technosphere	lignite, at mine	RER	0	kg	2.00E-1	1	3.06	(3,5,1,1,na,BU:1.05); Literature, drilling chemical
	barite, at plant	RER	0	kg	2.70E+2	1	3.06	(3,5,1,1,na,BU:1.05); Literature, drilling chemical
	bentonite, at processing	DE	0	kg	2.00E+1	1	3.06	(3,5,1,1,na,BU:1.05); Literature, drilling chemical
	chemicals inorganic, at plant	GLO	0	kg	4.22E+1	1	3.06	(3,5,1,1,na,BU:1.05); Literature, drilling chemical
	chemicals organic, at plant	GLO	0	kg	9.05E+0	1	3.06	(3,5,1,1,na,BU:1.05); Literature, drilling chemical
	lubricating oil, at plant	RER	0	kg	6.00E+1	1	3.06	(3,5,1,1,na,BU:1.05); Literature
	reinforcing steel, at plant	RER	0	kg	2.10E+2	1	3.11	(4,5,3,1,na,BU:1.05);
	portland cement, strength class Z 52.5, at plant	CH	0	kg	2.00E+2	1	3.11	(4,5,3,1,na,BU:1.05); Literature, used in bore hole
	transport, freight, lorry 16-32 metric ton, fleet average	RER	0	tkm	8.11E+1	1	3.90	(5,na,na,na,na,BU:2); Standard distance 100km
	transport, freight, rail	RER	0	tkm	4.87E+2	1	3.90	(5,na,na,na,na,BU:2); Standard distance 600km
	crude oil, used in drilling tests	GLO	0	kg	3.16E+1	1	3.11	(4,5,3,1,na,BU:1.05); Environmental report NO, basic uncertainty estimated with 2
	diesel, burned in diesel-electric generating set	GLO	0	MJ	0	1	4.84	(4,5,3,3,na,BU:3); Excluded as part of production data
	natural gas, vented	GLO	0	Nm3	0	1	3.11	(4,5,3,1,na,BU:1.05); Excluded as part of production data
	natural gas, sour, burned in production flare	GLO	0	MJ	0	1	3.11	(4,5,3,1,na,BU:1.05); Excluded as part of production data
	disposal, drilling waste, 71.5% water, to residual material landfill	CH	0	kg	3.00E+1	1	3.07	(3,5,3,1,na,BU:1.05); Environmental reports and literature
	disposal, hazardous waste, 25% water, to hazardous waste incineration	CH	0	kg	4.00E+0	1	3.11	(4,5,3,1,na,BU:1.05); Literature
emission air, low population density	Particulates, > 10 um	-	-	kg	1.49E-2	1	3.96	(5,5,3,1,na,BU:2); Literature, use of barite
emission water, ocean	AOX, Adsorbable Organic Halogen as Cl	-	-	kg	4.78E-7	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Arsenic	-	-	kg	3.78E-3	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Barite	-	-	kg	1.62E+2	1	7.16	(4,5,3,3,na,BU:5); Literature (Barite and Bentonite) from mud
	Cadmium	-	-	kg	3.02E-4	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Carboxylic acids, unspecified	-	-	kg	1.70E+0	1	7.16	(4,5,3,3,na,BU:5); Literature, emulgator
	Chloride	-	-	kg	1.30E+0	1	3.33	(4,5,3,1,na,BU:1.5); Literature, anorg. salt, basic uncertainty estimated with 3
	Chromium	-	-	kg	1.72E-3	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Copper	-	-	kg	9.15E-3	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Glutaraldehyde	-	-	kg	2.00E-2	1	7.16	(4,5,3,3,na,BU:5); Literature
	Hydrocarbons, aromatic	-	-	kg	2.31E-1	1	4.84	(4,5,3,1,na,BU:3); Literature, 5% of oil emission
	Hydrocarbons, unspecified	-	-	kg	3.00E+0	1	4.84	(4,5,3,1,na,BU:3); Literature, polymers
	Lead	-	-	kg	1.32E-2	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Mercury	-	-	kg	2.79E-4	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Nickel	-	-	kg	3.44E-4	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Oils, unspecified	-	-	kg	4.39E+0	1	4.81	(3,5,3,1,na,BU:3); Literature
	Phenol	-	-	kg	4.02E-7	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Potassium	-	-	kg	1.60E-1	1	3.33	(4,5,3,1,na,BU:1.5); Literature, anorg. salt, basic uncertainty estimated with 3
	Silicon	-	-	kg	3.06E-5	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Sulfate	-	-	kg	6.00E-1	1	3.33	(4,5,3,1,na,BU:1.5); Literature, lignosuphonate
	BOD5, Biological Oxygen Demand	-	-	kg	1.39E+1	1	3.28	(na,5,3,1,na,BU:1.5); Extrapolation for sum parameter
	COD, Chemical Oxygen Demand	-	-	kg	1.39E+1	1	3.28	(na,5,3,1,na,BU:1.5); Extrapolation for sum parameter
	DOC, Dissolved Organic Carbon	-	-	kg	3.80E+0	1	3.28	(na,5,3,1,na,BU:1.5); Extrapolation for sum parameter
	TOC, Total Organic Carbon	-	-	kg	3.80E+0	1	3.33	(4,5,3,1,na,BU:1.5); Literature, lignite
	Nitrogen	-	-	kg	3.39E-3	1	3.33	(4,5,3,1,na,BU:1.5); Literature
	Suspended solids, unspecified	-	-	kg	5.70E+2	1	3.30	(3,5,3,1,na,BU:1.5); Literature, drillings, wastes subtracted
	Zinc	-	-	kg	2.86E-2	1	7.10	(3,5,1,1,na,BU:5); Environmental report OLF 2001, corrected in 2020

6.3 Offshore platform

Material costs for production drillings are inventoried in the process step “exploration” and must be requested under the respective life cycle inventory. For offshore production, at this place, material requirements for the platforms and further production installations are assessed and described in more detail in former studies (Jungbluth 2007; Schori et al. 2012). The inventory is created for an average platform with a total weight of 2500 t.

Tab. 6.5 and Tab. 6.6 show the life cycle inventory for the construction and disposal of production platforms for crude oil and natural gas production offshore. Construction occurs onshore. Thereafter the platform is transferred to its destination. Transports of the mentioned materials are estimated using standard distances. Transport of platforms to the destination could not be considered here (Jungbluth 2007).

Tab. 6.5 Material input and construction costs for drilling platforms for crude oil, used in this study (Jungbluth 2007).

	Name	Location	InfrastructureProcess	Unit	platform, crude oil, offshore	UncertaintyType	StandardDeviation95%	GeneralComment
	Location							
	InfrastructureProcess							
	Unit							
product	platform, crude oil, offshore	OCE	1	unit	1.00E+0			
resource, land	Occupation, industrial area, benthos	-	-	m2a	4.50E+4	1	2.03	(5,4,5,3,1,BU:1.5); Life time 15a
	Transformation, from seabed, unspecified	-	-	m2	3.00E+3	1	2.47	(5,4,5,3,1,BU:2); Literature
	Transformation, to industrial area, benthos	-	-	m2	3.00E+3	1	2.47	(5,4,5,3,1,BU:2); Literature
	Occupation, industrial area	-	-	m2a	1.50E+4	1	2.03	(5,4,5,3,1,BU:1.5); Life time 15a
	Transformation, from unknown	-	-	m2	1.00E+3	1	2.47	(5,4,5,3,1,BU:2); Literature
	Transformation, to industrial area	-	-	m2	1.00E+3	1	2.47	(5,4,5,3,1,BU:2); Literature
resource, in water	Water, unspecified natural origin, GLO	-	-	m3	1.11E+2	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report
technosphere	electricity, medium voltage, production ENTSO, at grid	ENTSO	0	kWh	9.18E+6	1	1.83	(5,5,5,3,1,BU:1.05); Estimation, plus 25% for disposal
	diesel, burned in building machine, average	CH	0	MJ	1.65E+7	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report, plus 25% for disposal
	concrete, exacting, with de-icing salt contact, at plant	CH	0	m3	6.14E+2	1	1.53	(3,3,5,3,1,BU:1.05); Literature
	chromium steel 18/8, at plant	RER	0	kg	7.51E+3	1	1.53	(3,3,5,3,1,BU:1.05); Literature
	steel, low-alloyed, at plant	RER	0	kg	1.14E+6	1	1.53	(3,3,5,3,1,BU:1.05); Literature
	aluminium, production mix, cast alloy, at plant	RER	0	kg	1.36E+5	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainty estimated = 10
	cast iron, at plant	RER	0	kg	1.73E+2	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainty estimated = 10
	MG-silicon, at plant	NO	0	kg	2.16E+2	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainty estimated = 10
	copper, at regional storage	RER	0	kg	8.64E+0	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainty estimated = 10
	zinc, primary, at regional storage	RER	0	kg	7.20E+3	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainty estimated = 10
	transport, freight, lorry 16-32 metric ton, fleet average	RER	0	tkm	2.64E+5	1	2.09	(4,5,na,na,na,BU:2); Standard distance 100km
	transport, freight, rail	RER	0	tkm	7.76E+5	1	2.09	(4,5,na,na,na,BU:2); Standard distance 600km
	disposal, concrete, 5% water, to inert material landfill	CH	0	kg	1.35E+6	1	1.53	(3,3,5,3,1,BU:1.05); Estimation
	disposal, hazardous waste, 25% water, to hazardous waste incineration	CH	0	kg	4.75E+4	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report
	disposal, municipal solid waste, 22.9% water, to municipal incineration	CH	0	kg	5.25E+4	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report
emission air, low	Heat, waste	-	-	MJ	3.30E+7	1	1.83	(5,5,5,3,1,BU:1.05); Calculation
population density	Aluminium	-	-	kg	1.16E+5	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
emission water,	Iron	-	-	kg	1.47E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
ocean	Silicon	-	-	kg	1.84E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Copper	-	-	kg	7.34E+0	1	3.50	(5,5,5,1,1,BU:3); Estimation 85% utilisation of anode
	Zinc	-	-	kg	6.12E+3	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Titanium	-	-	kg	3.06E+1	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode

Tab. 6.6 Material input and construction costs for drilling platforms for natural gas production, used in this study (Schori et al. 2012).

Explanations	Name	Location	Infrastructu reProcess	Unit	plant offshore, natural gas, production	Unc ertai ntyT ype	StandardD eviation95 %	GeneralComment	
	Location InfrastructureProcess Unit				OCE 1 unit				
Resources, land	Transformation, from sea and ocean	-	0	m2	1.60E+3	1	2.03	(2,4,2,1,1,4); Greenpeace report, one platform	
	Transformation, to sea and ocean	-	0	m2	1.60E+3	1	2.03	(2,4,2,1,1,4); Greenpeace report, one platform	
	Transformation, from industrial area, benthos	-	0	m2	1.60E+3	1	2.03	(2,4,2,1,1,4); Greenpeace report, one platform	
	Transformation, to industrial area, benthos	-	0	m2	1.60E+3	1	2.03	(2,4,2,1,1,4); Greenpeace report, one platform	
	Occupation, industrial area, benthos	-	0	m2a	1.76E+4	1	1.54	(2,4,2,1,1,4); Greenpeace report, one platform	
Technosphere	diesel, burned in building machine	GLO	0	MJ	1.16E+8	1	1.28	(3,4,4,1,1,4); calculated based on data from 1980	
	tap water, at user	RER	0	kg	2.83E+6	1	1.28	(3,4,4,1,1,4); calculated based on data from 1980	
	electricity, medium voltage, production UCTE, at grid	UCTE	0	kWh	2.12E+7	1	1.28	(3,4,4,1,1,4); calculated based on data from 1980	
	steel, low-alloyed, at plant	RER	0	kg	1.31E+7	1	1.27	(2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	epoxy resin, liquid, at plant	RER	0	kg	7.30E+4	1	1.61	(3,4,3,2,4,5); Data for wind turbines (2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	polyvinylchloride, bulk polymerised, at plant	RER	0	kg	3.00E+4	1	1.27	(2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	aluminium, production mix, at plant	RER	0	kg	2.53E+5	1	1.27	(2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	cast iron, at plant	RER	0	kg	3.03E+2	1	10.43	(5,5,1,1,1,na); Estimation for aluminium anode, basic uncertainty estimated = 10	
	MG-silicon, at plant	NO	0	kg	3.79E+2	1	10.43	(5,5,1,1,1,na); Estimation for aluminium anode, basic uncertainty estimated = 10	
	copper, at regional storage	RER	0	kg	1.52E+1	1	10.43	(5,5,1,1,1,na); Estimation for aluminium anode, basic uncertainty estimated = 10	
	zinc for coating, at regional storage	RER	0	kg	7.82E+3	1	1.27	(2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	concrete, normal, at plant	CH	0	m3	4.09E+3	1	1.27	(2,4,2,1,3,4); Greenpeace report, one platform, standard module	
	transport, lorry 32t	RER	0	tkm	1.80E+6	1	2.09	(4,5,na,na,na,na); standard distance	
	transport, freight, rail	RER	0	tkm	2.70E+6	1	2.09	(4,5,na,na,na,na); standard distance 600km	
	transport, transoceanic freight ship	OCE	0	tkm	2.81E+6	1	2.09	(4,5,na,na,na,na); standard distance	
	Heat, waste	-	-	-	MJ	7.62E+7	1	1.17	(2,4,2,1,1,4); Greenpeace report, one platform, standard module
	emission water, ocean	Aluminum	-	-	kg	2.15E+5	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode
		Iron, ion	-	-	kg	2.58E+2	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode
		Silicon	-	-	kg	3.22E+2	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode
Copper, ion		-	-	kg	1.29E+1	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode	
Zinc, ion		-	-	kg	6.65E+3	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode	
Titanium, ion		-	-	kg	5.37E+1	1	10.43	(5,5,1,1,1,na); Estimation 85% utilisation of anode	
Outputs	plant offshore, natural gas, production	OCE	1	unit	1.00E+0				
	weigh				2.25E+7				

6.4 Onshore production plant

For onshore production, several hundred production sites are summarized to one production field. The inventory is estimated for a field with 100 drilling sites and described in more detail in former studies (Schori et al. 2012; Jungbluth 2007). Oil and gas refining are done centrally, which requires pipes and pumps.

Onshore production requires space for pumps, separators, tanks, pipes, energy generation (for internal electricity production) as well as cleaning processes (particularly wastewater cleaning). In this study a value of 1000 m²/drilling is used. Like this, the production sites which are mostly situated in a remote area, are transforming a virtually unaffected area into a developed area. Therefore, for all production sites, transformation of forest to industrial area is assumed. There is no information on recultivation after production ceased, for the regions investigated here.

Tab. 6.7 and Tab. 6.8 show the life cycle inventories for production plants for crude oil and natural gas, based on former studies (Schori et al. 2012; Jungbluth 2007). It is assumed that the lifetime of the land use change is only 20 instead of the formerly estimated 30 (oil) or 50 (gas) years. This assumption is based on analysis done for horizontal wells in Oklahoma US. In the

US, more than half of the production of oil and gas, which is projected for the total lifetime occurs during its first three years.²¹ As an estimate, 20 years of lifetime might be too low for exceptionally large oil fields as Rumaila in Iraq. Therefore, by using this estimate, the impact of land use might be slightly underestimated for the dataset for Iraq. However, for most of the globally accessible, smaller oil fields, this estimate seems appropriate.

Tab. 6.7 Material input and construction costs for onshore crude oil production.

	Name	Location	Unit	production plant crude oil, onshore	UncertaintyType	StandardDeviation95%	GeneralComment			
								Location		
								InfrastructureProcess		
								Unit		
resource, land	Occupation, industrial area	-	m2a	2.00E+6	1	1.53	(3,4,1,3,1,na); Life time 20a			
	Transformation, from forest, unspecified	-	m2	1.00E+5	1	2.26	(3,4,5,3,1,na); Literature			
	Transformation, to mineral extraction site	-	m2	1.00E+5	1	2.26	(3,4,5,3,1,na); Literature			
resource, in water	Water, unspecified natural origin, GLO	-	m3	8.28E+1	1	1.13	(1,3,3,3,1,na); Environmental report			
technosphere	electricity, medium voltage, production ENTSO, at grid	ENTSO	kWh	3.67E+6	1	1.84	(5,4,5,3,3,na); Literature			
	diesel, burned in building machine	GLO	MJ	6.75E+5	1	1.14	(2,3,3,3,1,na); Environmental report			
	reinforcing steel, at plant	RER	kg	7.20E+5	1	1.54	(3,4,5,3,1,na); Literature			
	transport, lorry >16t, fleet average	RER	tkm	3.60E+5	1	2.38	(4,5,5,5,3,na); Estimation 500km			
	transport, freight, rail	RER	tkm	1.44E+5	1	2.38	(4,5,5,5,3,na); Standard distance 600km			
	disposal, municipal solid waste, 22.9% water, to municipal incineration	CH	kg	7.20E+2	1	1.51	(1,3,5,3,1,na); Environmental report			
emission air, low population density	Heat, waste	-	MJ	1.32E+7	1	1.83	(5,5,5,3,1,na); Literature			

Tab. 6.8 Material input and construction costs for onshore natural gas production.

	Name	Location	Unit	plant onshore, natural gas, production	UncertaintyType	StandardDeviation95%	GeneralComment			
								Location		
								InfrastructureProcess		
								Unit		
product	plant onshore, natural gas, production	GLO	unit	1.00E+0						
resource, land	Transformation, from forest, unspecified	-	m2	7.50E+3	1	2.09	(3,4,3,3,3,BU:2); Area according to Schori			
	Transformation, to mineral extraction site	-	m2	7.50E+3	1	2.09	(3,4,3,3,3,BU:2); Area according to Schori			
	Occupation, industrial area	-	m2a	1.50E+5	1	1.59	(3,4,1,3,3,BU:1.5); Adjusted life time 20a according to Oklahoma Watch 2018			
technosphere	diesel, burned in building machine, with particle filter	GLO	MJ	1.50E+6	1	1.34	(4,4,3,3,3,BU:1.05); Schori 2012			
	electricity, medium voltage, production GLO, at	GLO	kWh	8.25E+5	1	1.34	(4,4,3,3,3,BU:1.05); Schori 2012			
	reinforcing steel, at plant	RER	kg	1.50E+6	1	1.34	(4,4,3,3,3,BU:1.05); Schori 2012			
	transport, freight, lorry 16-32 metric ton, fleet average	RER	tkm	1.50E+5	1	2.78	(4,5,3,5,5,BU:2); Estimation 500km			
	transport, freight, rail	RER	tkm	3.00E+5	1	2.78	(4,5,3,5,5,BU:2); Standard distance 600km			
emission air, low population density	Heat, waste	-	MJ	2.97E+6	1	1.29	(3,4,3,3,3,BU:1.05); Schori 2012			

²¹ Oklahoma Watch: <https://nondoc.com/2017/07/12/horizontal-wells-first-three-years/>, online 03.01.2018

6.5 Gas treatment plants

The inventory is not updated and kept the same as in a former study (Schori et al. 2012). Data for material use and construction expenditures as well as the land use is shown in Tab. 6.9.

Tab. 6.9 Material input and construction costs for natural gas treatment plants (Schori et al. 2012)

Explanations	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	production plant, natural gas	UncertaintyType	Standard Deviation 95%	GeneralComment
	Location InfrastructureProcess Unit						GLO 1 unit			
Resources, land	Transformation, from pasture and meadow	-	resol	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, to pasture and meadow	-	resol	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, from industrial area	-	resol	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, to industrial area	-	resol	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Occupation, industrial area	-	resol	land	0	m2a	1.71E+08	1	1.57	(2,3,1,3,1,5); personal communication, Statoil
Technosphere	diesel, burned in building machine	GLO	-	-	0	MJ	5.07E+09	1	1.64	(3,3,5,3,3,5); extrapolation from German data
	electricity, medium voltage, production UCTE, at grid	UCTE	-	-	0	kWh	2.82E+09	1	1.64	(3,3,5,3,3,5); extrapolation from German data
	reinforcing steel, at plant	RER	-	-	0	kg	5.07E+09	1	1.64	(3,3,5,3,3,5); extrapolation from German data
	concrete, normal, at plant	CH	-	-	0	m3	9.82E+05	1	1.64	(3,3,5,3,3,5); extrapolation from German data
	transport, lorry 32t	RER	-	-	0	tkm	6.15E+08	1	2.09	(4,5,na,na,na,na); standard distance
	transport, freight, rail	RER	-	-	0	tkm	1.01E+09	1	2.09	(4,5,na,na,na,na); standard distance
	Heat, waste	-	air	low popul		MJ	1.01E+10	1	1.64	(3,3,5,3,3,5); extrapolation from German data
Outputs	production plant, natural gas	GLO	-	-	1	unit	1.00E+00			

6.6 Onsite pipelines

For onsite pipelines, for most countries and regions, generic distances are considered as shown in Tab. 6.10. The lifecycle inventory data for the pipelines are described in Meili et al. 2023 and Bussa et al. 2023.

Tab. 6.10 Generic estimates for pipeline distances onsite, for off- and onshore crude oil and natural gas production.

Unit				kg OE	
pipeline, crude oil, offshore	OCE	km		7.70E-09	Generic estimation based on estimate for Nigeria 2018
pipeline, crude oil, onshore	RER	km		1.99E-08	Generic estimation based on estimate for Kazakhstan 2016
pipeline, natural gas, long distance, high capacity, offshore	GLO	km		8.88E-09	Estimation based on values for crude oil pipeline
pipeline, natural gas, long distance, high capacity, onshore	GLO	km		1.99E-08	Estimation based on values for crude oil pipeline

7 Operating materials

7.1 Chemicals

As operating materials, those production chemicals are considered which fulfil different functions. Generally, in oil production, three process steps are distinguished that require chemicals:

- Production and separation
- Water flooding
- Stimulation and workover

For gas production, to treat the gas chemicals are used too. The production can be disturbed by depositions and corrosion. An overview over troubles and chemicals used to fight them, can be found in the appendix of the former report (Jungbluth 2007).

As chemicals for stimulation and workover, acids and corrosion inhibitors are used. Investigations for the former report led to 90g of organic chemicals and 118g of inorganic chemicals per ton of crude oil extracted (Jungbluth 2007). As described in chapter 4.2, a factor of 4.7 is applied on these values to model the increased demand due to more depleted oil fields.

Transport of these chemicals is assumed with 100 km by lorry and 600 km by rail.

7.2 Water use

Water use in oil production varies substantially by geography, geology, and recovery-technique and reservoir depletion. Water in oil extraction is mainly used for enhanced oil recovery (EOR), where a reservoir is flooded with water or steam to displace or increase the flow of oil to the surface. Oil extraction also generates large volumes of produced water (cf. chapter 10.1). After treatment, the produced water can be used for reinjection as part of EOR activities. Consumed water is thus total water injected minus produced water used for injection (Mielke et al. 2010; Wu et al. 2009).

7.2.1 Amount

For this study, average values for fresh water use reported for the latest 3 years are used, as shown in Tab. 7.1. The data source applied is the environmental report for different oil producing regions (IOGP 2022). Depending on regional aspects, other country and company data show an even larger variation as presented in a former report (Meili & Jungbluth 2018). To stay consistent and to simplify updates the newer values from one single source are chosen.

In arid regions like Saudi Arabia mostly desalinated seawater and brackish water is used for oil recovery (Wu et al. 2009) which explains the lower use of freshwater in Middle East.

Tab. 7.1 Fresh water use intensity in cubic meter per kg of crude oil extracted onshore per region, average of 3 latest years reported (IOGP 2022, Tab. A.34).

fresh water use intensity	Average 2019 to 2021	Source
Region	m3/kg OE	
Africa	5.36E-5	IOGP 2022
Asia	7.59E-5	IOGP 2022
Europe	3.79E-5	IOGP 2022
Middle East	1.55E-5	IOGP 2022
North America	3.25E-4	IOGP 2022
Russia & Central Asia	1.27E-4	IOGP 2022
South & Central America	7.32E-5	IOGP 2022
Global	9.25E-5	IOGP 2022

Some differentiation would be available for the type of freshwater used (ground water, surface, rainwater). But, this is not relevant for the present LCIA methods. Thus, the full amount of freshwater is recorded as water from rivers.

For offshore, typically saltwater from the ocean is used. No information is available for salt water used. Salt water is also not relevant for the impact assessment of water scarcity. Therefore, for offshore operations no water use is accounted for.

7.2.2 Allocation

For natural gas extraction alone, lower water injection might be necessary, and most of the water is used for and released due to enhanced oil recovery (EOR).

Impacts of freshwater use are accounted for crude oil and natural gas with the same amounts per kg OE, because no differentiation is possible with the available data.

8 Energy demand

For the direct energy uses of fuel oil, gas and electricity, region specific average values reported for the latest 3 years are applied (IOGP 2022).

8.1 Data sources

Operations which are to be **included** in data IOGP reporting are E&P (exploration and production) activities for which the reporting company has operational control. Examples include (IOGP 2019, page 6 explanations):

- Oil and gas extraction and separation (primary production)
- Primary oil processing (water separation, stabilisation)
- Crude oil transportation by pipeline to storage facilities
- Offshore crude oil ship loading from primary production
- Onshore crude oil storage connected by pipeline to primary production facilities
- Gas transportation to processing plant (offshore/onshore)
- Primary gas processing (dehydration, liquids separation, sweetening, CO₂ removal) performed with the intent of making the produced gas meet sales specifications
- Floating Storage Units (FSUs)
- Offshore support and standby vessels
- Exploration (including seismic) activities
- Activities related to geologic storage of CO₂ from natural gas processing
- Mining activities related to the extraction of hydrocarbons

Operations which are to be **excluded** in IOGP reporting are non-E&P activities and those that fall outside the operational control of the reporting company. Examples include:

- Gas processing activities with the primary intent of producing gas liquids for sale (unless data cannot be separated out)
- Secondary liquid separation (i.e., Natural Gas Liquids extraction using refrigeration processing)
- Ethane, Propane, Butane, Condensate (EPBC) fractionation
- Liquefied Natural Gas (LNG) and Gas to Liquids (GTL) operations (LNG data are being compiled separately from the E&P data using this same process)
- Transportation of personnel

- Transportation of oil and gas, after sales metering devices (LACT units) or after ship loading at the primary production site
- Storage of refined products
- Partners' operations
- Non-operated joint ventures, except when the operator is not an IOGP member, and the joint venture has agreed that one company should take the lead on data reporting
- Upgrading activities related to the extraction of hydrocarbons. All other non-E&P activities

Most of these mentioned, excluded operations are assessed separately in the current or former studies. Outside of the scope of the life-cycle inventory are only the transportation of personnel.

8.2 Regional energy demand by type

Tab. 8.1 to Tab. 8.7 give an overview of the values for energy demand per kg crude oil extracted which are used for this study.

In the data sources listed in Tab. 8.1, it is not stated, if energy losses due to oil spills, flaring and venting are considered (IOGP 2022). For this study it is assumed that they are not included in these figures published for the total energy consumption. Modelling assumptions for oil spills are described in chapter 10.3. It must be noted that in this study, the oil loss is also accounted for in the calculation of the cumulative energy demand (see chapter 14.2).

Tab. 8.1 Total fossil energy consumption per kg crude oil extracted (IOGP 2022, Tab. A8 & A.9)

Total fossil energy consumption	Average 2019 to 2021	Source
Region	MJ/kg OE	
Africa	1.59E+0	IOGP 2022
Asia/Australia	1.70E+0	IOGP 2022
Europe	1.32E+0	IOGP 2022
Middle East	5.42E-1	IOGP 2022
North America	2.53E+0	IOGP 2022
Russia & Central Asia	1.71E+0	IOGP 2022
South & Central America	1.40E+0	IOGP 2022
Global	1.49E+0	IOGP 2022

Electricity demand is assumed to be represented by the share of energy which is purchased from elsewhere (IOGP 2022, Tab. A.8). It is calculated by multiplying the total energy consumption according to Tab. 8.1 by the share of purchased energy. The values are converted from MJ to kWh (see Tab. 8.2).

²² <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4687841/>

²³ <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4687841/figure/pone.0144141.g002/>, online 15.01.2018

²⁴ <http://carnegieendowment.org/2015/03/11/know-your-oil-creating-global-oil-climate-index-pub-59285>, online 15.01.2018

²⁵ <http://carnegieendowment.org/files/Brief-OCI.pdf>, online 15.01.2018

Tab. 8.2 Electricity demand, per kg oil equivalent (IOGP 2022, Tab. A.8 and A.9)

Electricity at grid	Average 2019 to 2021	Source
Region	kWh/kg OE	
Africa	4.40E-3	Purchased energy according to IOGP 2022.
Asia/Australia	1.90E-2	Purchased energy according to IOGP 2022.
Europe	3.44E-2	Purchased energy according to IOGP 2022.
Middle East	5.11E-2	Purchased energy according to IOGP 2022.
North America	4.67E-2	Purchased energy according to IOGP 2022.
Russia & Central Asia	1.81E-2	Purchased energy according to IOGP 2022.
South & Central America	5.10E-3	Purchased energy according to IOGP 2022.
Global	2.61E-2	Purchased energy according to IOGP 2022.

For energy from onsite combustion generic shares for use of gas, diesel and heavy fuel oil are considered as shown in Tab. 8.3. They are based on average data for Russia in the years 2005 to 2012 (Safronov & Sokolov 2014).

Tab. 8.3 Share of energy consumption from gas, oil and fuels for specific Russian oil producers in the years 2005 to 2012 (Safronov & Sokolov 2014). Used as generic factors in this study.

Title	Unit	2005	2006	2007	2008	2009	2010	2011	2012	Average 2005 to 2012
Production										
Oil production	Mt.	470.0	480.3	490.7	487.8	494.1	505.1	512.2	518.5	494.8
Gas production	MtOE	516.9	529.4	525.5	535.6	471.0	525.4	541.1	528.1	521.6
Total production	MtOE	986.9	1009.6	1016.2	1023.4	965.0	1030.5	1053.3	1046.6	1016.4
Consumption										
Energy resources	MtOE	8.9	8.9	13.1	12.3	9.5	9.1	8.5	10.1	10.1
Gas		8.8	8.7	12.7	11.7	9.2	8.7	8.3	10.0	9.8
Oil		0.1	0.1	0.4	0.6	0.3	0.3	0.1	0.1	0.3
Fuels	MtOE	1.6	1.9	1.6	1.5	1.1	1.5	0.8	0.7	1.3
Electricity	MtOE	14.2	16.4	17.1	18.5	18.9	19.7	20.8	21.7	18.4
Thermal Energy	MtOE	2.4	2.5	2.2	2.2	2.4	2.2	2.1	2.0	2.3
Total consumption	MtOE	27.2	29.6	34.0	34.5	31.9	32.4	32.2	34.5	32.0
Own calculation										
Share gas	%	83.8%	80.6%	86.4%	84.8%	86.8%	82.1%	89.2%	92.6%	85.7%
Share oil (assuming heavy fuel oil)	%	1.0%	0.9%	2.7%	4.3%	2.8%	2.8%	1.1%	0.9%	2.2%
Share fuels (assuming diesel)	%	15.2%	17.6%	10.9%	10.9%	10.4%	14.2%	8.6%	6.5%	11.7%

The amount of diesel, burned onsite, shown in Tab. 8.4, is calculated based on the overall energy consumption multiplied by the percentage of onsite combustion plus unspecified (IOGP 2022). This value is multiplied by the generic estimate for fuels (diesel), as shown in Tab. 8.3.²⁶

²⁶ The generic share for diesel is calculated by dividing the average MtOE for "fuels" by the sum of MtOE "energy resources" + "fuels".

Tab. 8.4 Energy demand of diesel, burned in equipment, per kg oil equivalent (IOGP 2022, Tab. A.8 and A.9, multiplied with generic factor).

Diesel, burned in equipment	Average 2019 to 2021	Source
Region	MJ/kg OE	
Africa	1.85E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
Asia/Australia	1.92E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
Europe	1.41E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
Middle East	4.21E-2	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
North America	2.77E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
Russia & Central Asia	1.93E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
South & Central America	1.62E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.
Global	1.92E-1	Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified.

The amount of heavy fuel oil burnt is assessed as shown in Tab. 8.5. It is calculated based on the overall energy consumption multiplied by the percentage of onsite combustion plus unspecified (IOGP 2022). This value is multiplied by the generic estimate for oil, as shown in Tab. 8.3.²⁷

Tab. 8.5 Energy demand of heavy fuel oil, burned in equipment, per kg oil equivalent (IOGP 2022, Tab. A.8 and A.9, multiplied with generic factor).

Heavy fuel oil, burned in equipment	Average 2019 to 2021	Source
Region	MJ/kg OE	
Africa	3.47E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
Asia/Australia	3.58E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
Europe	2.63E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
Middle East	7.86E-3	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
North America	5.18E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
Russia & Central Asia	3.61E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
South & Central America	3.03E-2	Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified.
Global	3.58E-2	weighted average of regions with reported values

The amount of natural gas burnt in gas turbines is assessed as shown in Tab. 8.5. It is calculated based on the overall energy consumption multiplied by the percentage of onsite combustion

²⁷ The generic share for heavy fuel oil is calculated by dividing the average MtOE for "oil" by the sum of MtOE „energy resources“ + „fuels“.

plus unspecified (IOGP 2022). This value is multiplied by the generic estimate for gas, as shown in Tab. 8.3.²⁸

Tab. 8.6 Energy demand of natural gas, burned in gas turbines, per kg oil equivalent (IOGP 2022, Tab. A.8 and A.9, multiplied with generic factor).

Gas, burned in gas turbine, production	Average 2019 to 2021	Source
Region	MJ/kg OE	
Africa	1.36E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
Asia/Australia	1.40E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
Europe	1.03E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
Middle East	3.08E-1	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
North America	2.03E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
Russia & Central Asia	1.42E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
South & Central America	1.19E+0	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified.
Global	1.40E+0	weighted average of regions with reported values

For the current study, SO₂ emissions from the combustion of sour gas are directly implemented in an overall figure shown in chapter 9.5. Nevertheless, it might be interesting to have a rough estimate of the share of sweet and sour gas extracted by region. Such an estimate is provided in Tab. 8.7, based on share of overall gas burned in gas turbines and regional shares of sweet and sour gas reserves (IOGP 2022; IEA 2008).

²⁸ The generic share for gas is calculated by dividing the average MtOE for "gas" by the sum of MtOE „energy resources“ + „fuels“.

Tab. 8.7 Energy demand of sweet and sour gas burned in gas turbines, in MJ per kg oil equivalent (IOGP 2022, Tab. A.8 and A.9). Share of sweet and sour gas based on information from IEA 2008.

Gas, burned in gas turbine, production	share sweet gas	share sour gas	sweet gas	sour gas	Source
Region	%	%	MJ/kg OE	MJ/kg OE	
Africa	57%	43%	0.83	0.62	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share global share according to IEA 2008
Asia/Australia	57%	43%	0.87	0.65	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share global share according to IEA 2008
Europe	57%	43%	0.55	0.41	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share global share according to IEA 2008
Middle East	40%	60%	0.13	0.19	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share IEA 2008
North America	57%	43%	0.95	0.72	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share global share according to IEA 2008
Russia & Central Asia	66%	34%	1.11	0.57	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share IEA 2008
South & Central America	57%	43%	0.35	0.27	Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share global share according to IEA 2008
Global	57%	43%	0.68	0.50	weighted average of regions with reported values for total amount burned, multiplied by share IEA 2008

9 Emissions to air

9.1 Flared natural gas

9.1.1 Definition

Flaring is the controlled and intentional burning of natural gas as part of production and processing of crude oil and natural gas.

Flaring is mainly done for the following reasons²⁹:

- **Flaring for safety**

By burning excess natural gas, flaring protects against the dangers of over-pressuring industrial equipment. Natural gas can be stored and transported instead of flared, but it is highly flammable. Transporting natural gas from a rig to homes and businesses is high risk and many companies choose flaring as the alternative.

- **Flaring for disposal**

One of the main reasons for gas flaring is the disposal and burning of natural gas as waste. Typically, when there are large volumes of hydrogen sulphide in natural gas, it cannot be safely extracted. To dispose of this gas, it is burned off. It is common to flare natural gas

²⁹ https://www.earthworks.org/issues/flaring_and_venting 05.05.2021

that contains hydrogen sulphide (i.e., sour gas), to convert the highly toxic hydrogen sulphide gas into less toxic compounds.

- **Flaring for remote locations**

When petroleum crude oil is extracted and produced from onshore or offshore oil wells, natural gas associated with the oil is also brought to the surface. If companies do not have the infrastructure in place to capture natural gas and safely transport it – such as when oil rigs are in deep waters – natural gas is often flared.

- **Flaring for economics**

There is a significant gap between oil and natural gas prices. Natural gas costs more than oil to produce on an energy-equivalent basis. For this reason, drillers are searching for oil, not gas, and companies are reluctant to invest in costly projects to capture and transport natural gas from oil wells to the market.

9.1.2 Allocation

Much of the flaring is done for maximizing profits in crude oil extraction and pure natural gas extraction facilities strive to keep flaring to a minimum and sell as much natural gas as possible. Therefore, it could be argued that all the emissions related to flaring should be allocated to the oil extraction.

However, many extraction sites sell oil and gas at the same time (e.g. 50% of APG in Russia in 2010) and the remaining gas must be flared as well (Carbon Limits 2013). Also, initially the dataset for flaring was created for the natural gas extraction (Faist Emmenegger et al. 2007, chapter 6.3.13).

Therefore, in this study, emissions from flaring (and venting) are allocated to crude oil and natural gas extraction as explained in chapter 2.2.

9.1.3 Amount of flared gas

Estimates for flaring are available in different sources as shown in a former study (Meili & Jungbluth 2018). For the current study only estimates based on two different sources are compared as shown in Tab. 9.1 (World Bank 2023; IOGP 2022). For the countries under investigation, data is taken from the Global Gas Flaring Reduction Partnership (GGFR), which estimated the country specific amounts of flared gas based on satellite measurements done according to a methodology provided by the National Oceanic and Atmospheric Administration (NOAA), a part of the US department of Defence³⁰. These measured flaring data is provided publicly for the reference year 2021 (World Bank 2023). Another study provides flaring intensities for 2021 based on company data which cover about 10% of the world oil and gas production (IOGP 2022). The global average intensity derived from these company data is on average about 30% lower than the one reported according to satellite data. Therefore, this data source is only considered where no country-specific data is available in the primary source of information.

³⁰ Flare gas volume: <http://pubdocs.worldbank.org/en/251461483541510567/ACS.pdf>, 25.11.2020

Tab. 9.1 Intensities of natural gas flaring (norm cubic meters per kg oil equivalent) from considered sources (World Bank 2023; IOGP 2022).

Origin	flaring per kg oil equivalent	flaring per kg oil equivalent	Flaring per kg oil equivalent, this study	source
Source	Worldbank	IOGP	This study	
Reference year	2021	2021		
Unit	Nm ³ /kgOE	Nm ³ /kgOE	Nm ³ /kgOE	
United Arab Emirates	3.96E-3	6.96E-3	3.96E-3	Worldbank 2023
Argentina	1.95E-2	8.36E-3	1.95E-2	Worldbank 2023
Australia	5.59E-3	1.68E-2	5.59E-3	Worldbank 2023
Azerbaijan	2.11E-3	5.73E-3	2.11E-3	Worldbank 2023
Belgium	n.a.	2.92E-3	2.92E-3	no data available, assuming regional average according to IOGP 2022
Bolivia	2.23E-3	8.36E-3	2.23E-3	Worldbank 2023
Brazil	4.96E-3	8.36E-3	4.96E-3	Worldbank 2023
Canada	2.53E-3	5.93E-3	2.53E-3	Worldbank 2023
China	6.63E-3	1.68E-2	6.63E-3	Worldbank 2023
Colombia	6.41E-3	8.36E-3	6.41E-3	Worldbank 2023
Germany	-	2.92E-3	-	Worldbank 2023
Algeria	5.55E-2	3.63E-2	5.55E-2	Worldbank 2023
Ecuador	4.65E-2	8.36E-3	4.65E-2	Worldbank 2023
Egypt	2.34E-2	3.63E-2	2.34E-2	Worldbank 2023
Spain	-	2.92E-3	-	Worldbank 2023
France	7.00E-3	2.92E-3	7.00E-3	Worldbank 2023
United Kingdom	1.21E-2	2.92E-3	1.21E-2	Worldbank 2023
Indonesia	1.95E-2	1.68E-2	1.95E-2	Worldbank 2023
India	2.47E-2	1.68E-2	2.47E-2	Worldbank 2023
Iraq	8.27E-2	6.96E-3	8.27E-2	Worldbank 2023
Iran	4.38E-2	6.96E-3	4.38E-2	Worldbank 2023
Italy	5.03E-5	2.92E-3	5.03E-5	Worldbank 2023
Japan	0	1.68E-2	-	Worldbank 2023
Korea	1.43E-2	1.68E-2	1.43E-2	Worldbank 2023
Kuwait	4.48E-3	6.96E-3	4.48E-3	Worldbank 2023
Kazakhstan	1.29E-2	5.73E-3	1.29E-2	Worldbank 2023
Libya	8.27E-2	3.63E-2	8.27E-2	Worldbank 2023
Mexico	5.20E-2	5.93E-3	5.20E-2	Worldbank 2023
Malaysia	2.29E-2	1.68E-2	2.29E-2	Worldbank 2023
Nigeria	5.51E-2	3.63E-2	5.51E-2	Worldbank 2023
Netherlands	3.64E-4	2.92E-3	3.64E-4	Worldbank 2023
Norway	7.89E-4	2.92E-3	7.89E-4	Worldbank 2023
Oman	2.93E-2	6.96E-3	2.93E-2	Worldbank 2023
Peru	4.20E-3	8.36E-3	4.20E-3	Worldbank 2023
Poland	8.75E-3	2.92E-3	8.75E-3	Worldbank 2023
Qatar	4.18E-3	6.96E-3	4.18E-3	Worldbank 2023
Romania	1.90E-3	2.92E-3	1.90E-3	Worldbank 2023
Russian Federation	2.19E-2	5.73E-3	2.19E-2	Worldbank 2023
Saudi Arabia	3.35E-3	6.96E-3	3.35E-3	Worldbank 2023
Thailand	6.40E-3	1.68E-2	6.40E-3	Worldbank 2023
Turkmenistan	1.45E-2	5.73E-3	1.45E-2	Worldbank 2023
Turkey	2.88E-3	6.96E-3	2.88E-3	Worldbank 2023
Trinidad and Tobago	5.96E-3	8.36E-3	5.96E-3	Worldbank 2023
Taiwan	n.a.	1.68E-2	1.68E-2	no data available, assuming regional average according to IOGP 2022
Ukraine	6.75E-3	2.92E-3	6.75E-3	Worldbank 2023
United States	5.69E-3	5.93E-3	5.69E-3	Worldbank 2023
Uzbekistan	1.01E-2	5.73E-3	1.01E-2	Worldbank 2023
Venezuela	1.48E-1	8.36E-3	1.48E-1	Worldbank 2023
Global	1.83E-2	1.27E-2	1.83E-2	Worldbank 2023

leakages or forced changes in geological structures during fracking)^{31;32}. For this study intended and unintended releases of methane from all known sources are considered.

9.2.2 Allocation

Emissions from venting and fugitive natural gas emissions are directly available specifically for on- and offshore oil and gas extraction in all countries under study. The factors for oil and gas extraction are used directly for the allocation of total emissions between natural gas and crude oil. However, it was not possible to differentiate between on- and offshore production as consistent production amounts were not available (c.f. chapter 2.2).

9.2.3 Technical scope

Some data sources, consulted and described in previous studies, values on methane release are given for the whole product chain of crude oil products (c.f. Meili et al. 2022a). Therefore, these figures would need to be adjusted by subtracting emissions occurring in transportation, storage, and handling. According to the LCA methodology used for this and a former project they are reported at distinct stages of the life cycle (Meili et al. 2022a). However, the values chosen for this study are related to upstream emissions only. Therefore, no adjustment must be made for downstream estimates for methane emissions.

The assumed percentage of methane in emitted natural gas is shown in chapter 9.2.5.

To simplify comparison of values in the following chapter, values given in e.g., billion cubic meters (bcm) of methane are recalculated to kg per kg oil-equivalent using the properties defined in chapter 5.

Emission values used in this study are summarized in Tab. 9.3. The related crude oil and natural gas production data were taken from same data source as used in Tab. 2.1 (BP 2022).

9.2.4 Amount of emissions

Robust and consistent data is provided by different research institutes as described in Meili et al. 2022a. Therefore, it is possible to use country-specific methane emissions in the model (c.f. Tab. 9.3).

Net calorific values and densities are used consistently with extraction data provided in BP 2022 (c.f. chapter 5.1.2 and 5.2.1).

Country-specific upstream methane emissions according to IEA 2022 are available for on- and offshore crude oil and natural gas production for the reference year 2021. Additionally, emissions from satellite-detected large leaks are available. These emission values are added proportionally to the values for on- and offshore production of crude oil and natural gas.

The shares for on- and offshore production are estimated from different sources and therefore might be inconsistent with the reported emissions (c.f. chapter 4.1). To avoid such inconsistencies, values for on- and offshore emissions are added for oil and gas and set in relation to production data according to BP 2022 (reference year 2021).

The values for the methane emissions related to oil and gas production are used to estimate the total upstream natural gas emissions. To do so, the numbers are divided by a volumetric share

³¹ <https://www.nrdc.org/sites/default/files/fracking-air-pollution-IB.pdf>, online 27.09.2018

³² https://earthworks.org/issues/flaring_and_venting/, online 27.09.2018

of 0.585 kg methane per Nm³ of natural gas according to the composition presented in chapter 9.2.5.

To reflect the high uncertainty behind these estimates, a basic uncertainty of 2 is applied on this value in the EcoSpold format.

Tab. 9.3 Country specific upstream methane emissions and emission factors for natural gas from crude oil and natural gas production according to IEA 2022 (reference year 2021) related to production data from BP 2022 (reference year 2021)

Origin	Methane emissions, upstream, oil	Methane emissions, upstream, gas	Natural gas emissions, upstream, oil	Natural gas emissions, upstream, gas
Unit	kt/a	kt/a	Nm ³ /kgOil	Nm ³ /Nm ³ gas
United Arab Emirates	9.32E+2	2.88E+2	9.69E-3	8.64E-3
Argentina	4.44E+2	3.83E+2	2.61E-2	1.69E-2
Australia	8.10E+1	4.11E+2	7.64E-3	4.77E-3
Azerbaijan	2.03E+2	9.40E+1	9.88E-3	5.05E-3
Belgium	n.a.	n.a.	n.a.	n.a.
Bolivia	2.30E+1	8.60E+1	2.46E-2	9.74E-3
Brazil	9.56E+2	1.50E+2	1.04E-2	1.05E-2
Canada	9.54E+2	1.11E+3	6.11E-3	1.10E-2
China	1.06E+3	9.12E+2	9.13E-3	7.45E-3
Colombia	2.34E+2	4.30E+1	1.03E-2	5.85E-3
Germany	7.00E+0	2.00E+1	3.89E-3	7.54E-3
Algeria	1.69E+3	7.00E+2	4.98E-2	1.19E-2
Ecuador	2.59E+2	3.00E+0	1.75E-2	1.51E-2
Egypt	4.35E+2	3.86E+2	2.51E-2	9.73E-3
Spain	n.a.	n.a.	n.a.	n.a.
France	3.00E+0	0	6.46E-3	0
United Kingdom	9.40E+1	5.30E+1	3.93E-3	2.77E-3
Indonesia	3.90E+2	4.33E+2	1.97E-2	1.25E-2
India	4.12E+2	2.12E+2	2.07E-2	1.27E-2
Iraq	2.70E+3	6.86E+1	2.30E-2	1.25E-2
Iran	3.14E+3	1.63E+3	3.20E-2	1.09E-2
Italy	1.90E+1	1.20E+1	6.71E-3	6.44E-3
Japan	1.00E+0	1.20E+1	4.63E-3	1.15E-2
Korea	0	0	0	0
Kuwait	6.86E+2	6.86E+1	8.95E-3	6.75E-3
Kazakhstan	1.24E+3	4.07E+2	2.47E-2	2.17E-2
Libya	2.17E+3	1.88E+2	6.23E-2	2.60E-2
Mexico	9.06E+2	1.49E+2	1.61E-2	8.71E-3
Malaysia	1.87E+2	1.91E+2	1.23E-2	4.40E-3
Nigeria	1.47E+3	3.50E+2	3.22E-2	1.30E-2
Netherlands	0	2.00E+0	0	1.89E-4
Norway	1.30E+1	1.50E+1	2.37E-4	2.24E-4
Oman	4.44E+2	2.69E+2	1.62E-2	1.10E-2
Peru	2.80E+1	4.20E+1	9.02E-3	6.25E-3
Poland	5.00E+0	1.80E+1	6.03E-3	7.95E-3
Qatar	3.55E+2	7.11E+2	8.28E-3	6.87E-3
Romania	2.10E+1	4.10E+1	1.08E-2	8.28E-3
Russian Federation	6.67E+3	5.93E+3	2.13E-2	1.44E-2
Saudi Arabia	2.27E+3	3.56E+2	7.52E-3	5.19E-3
Thailand	1.21E+2	1.45E+2	1.48E-2	7.86E-3
Turkmenistan	1.23E+3	3.17E+3	1.75E-1	6.84E-2
Turkey	n.a.	n.a.	n.a.	n.a.
Trinidad and Tobago	3.90E+1	1.31E+2	1.91E-2	9.06E-3
Taiwan	n.a.	n.a.	n.a.	n.a.
Ukraine	3.54E+1	1.44E+2	2.46E-2	1.32E-2
United States	4.58E+3	6.60E+3	1.10E-2	1.21E-2
Uzbekistan	1.29E+2	6.69E+2	8.10E-2	2.25E-2
Venezuela	2.32E+3	1.63E+2	1.19E-1	1.16E-2
Global	4.18E+4	2.73E+4	1.69E-2	1.16E-2

For countries where no country-specific data is mentioned in IEA 2022 (c.f. Tab. 9.3), region-specific average values for the years 2019 to 2021 are considered (IOGP 2022). As this source only considers technical venting, the relation of global emissions according to IEA 2022 to global emissions according to IOGP 2022 is used to estimate the overall emissions for these regions (c.f. Tab. 9.4).

Tab. 9.4 Region-specific upstream methane emissions from technical sources and overall emission factors for natural gas from crude oil and natural gas production based on IOGP 2022, extrapolated using the global proportion IEA 2022 vs. IOGP 2022.

	Technical venting, upstream, oil and gas	Overall natural gas emissions, upstream, oil extraction	Overall natural gas emissions, upstream, gas extraction
Source	Average 2019 to 2021 (IOGP 2022)	Calculated using a factor of 18 for global emissions according to IEA 2022 vs. IOGP 2022 and energy contents according to BP 2022.	Calculated using a factor of 14.9 for global emissions according to IEA 2022 vs. IOGP 2022 and energy contents according to BP 2022.
Unit	kgCH ₄ /kg OE	Nm ³ Gas/kgOil	Nm ³ Gas/Nm ³ Gas
Africa	6.99E-4	2.23E-2	1.53E-2
Asia	3.68E-4	1.18E-2	8.03E-3
Europe	2.53E-4	8.08E-3	5.52E-3
Middle East	1.11E-4	3.56E-3	2.43E-3
North America	1.06E-3	3.39E-2	2.32E-2
Russia & Central Asia	1.04E-3	3.32E-2	2.27E-2
South & Central America	5.27E-4	1.68E-2	1.15E-2
Global	5.29E-4	1.69E-2	1.16E-2

9.2.5 Composition of emitted natural gas

Direct emissions of natural gas are modelled including the resource extraction from ground (which is not included in figures about natural gas production) and the emissions to air.

It is assumed, that the composition of the gas did not change compared to the former studies (Faist Emmenegger et al. 2007; Jungbluth 2007). No distinction is made between sweet and sour gas as SO₂-emissions are assessed separately according to chapter 9.5. The respective emissions are presented in Tab. 9.5.

Tab. 9.5 Unit process raw data for the direct release of natural gas (Jungbluth 2007)

	Name	Location	Infrastructure	Process	Unit	natural gas, vented			GeneralComment
	Location					UncertaintyType	StandardDeviation95%		
	Unit								
resource, in ground emission air, low population density	Gas, natural/m3	-	-		Nm3	1.00E+0	1	1.53	(3,3,5,3,1,na); Calculation
	Carbon dioxide, fossil	-	-		kg	1.40E-2	1	1.53	(3,3,5,3,1,na); Literature
	Helium	-	-		kg	1.00E-3	1	1.79	(3,3,5,3,1,na); Literature
	Mercury	-	-		kg	1.50E-8	1	5.28	(3,3,5,3,1,na); Literature
	Methane, fossil	-	-		kg	5.85E-1	1	1.79	(3,3,5,3,1,na); Literature
	NMVOC, non-methane volatile organic compounds, unspecified origin	-	-		kg	2.71E-1	1	1.79	(3,3,5,3,1,na); Literature
	Radon-222	-	-		kBq	1.00E-1	1	3.24	(3,3,5,3,1,na); Literature

9.2.6 Future emissions of abandoned oil and gas fields

A study published in Environmental Science and Technology finds that annual methane emissions from abandoned oil and gas (AOG) wells in Canada and the US have been greatly underestimated - by as much as 150% in Canada, and by 20% in the US compared to what national environmental protection agencies are reporting (Williams et al. 2021). Extraction from Canada is not analysed in the current study and for the US, the values based on IEA 2020 data are already higher than what is reported to UNFCCC (c.f Meili et al. 2022a, Tab.9.3). Therefore, it is assumed, that current emissions from abandoned oil and gas fields are appropriately represented in this study.

However, without proper maintenance of AOG, such emissions would continue for a long time after the extraction took place. Such prospective emissions are not yet included/allocated to the current production.

9.3 Energy supply with diesel aggregates

To produce electricity in oil and gas exploration and production, diesel generators with more than 9'000 cm³ cubic capacity are used. In groups of 3 to 5 machines they supply the required electrical energy. They are powered by diesel or in dual mode with 5% diesel and 95% gas (Jungbluth 2007).

9.3.1 Efficiency, energy, and material requirements

Inventory data to produce a diesel electric generating set is shown in Tab. 9.7. The efficiency of the aggregates used in this study is given as 36% (Jungbluth 2007).

The diesel requirement is 23.36 t/TJ_{in}. The steel requirement is estimated on the basis of data from the ship engine building industry (Jungbluth 2007). The specific weight of about 12 t/MW in the power range of engines from 9 to 13 MW (balance sheet size 10 MW) is assumed to be steel only (other materials neglected). The running time (service life) is assumed to be 150'000 h. To take the generator into account, the demand is increased by 50%. Furthermore, a share of 5% of high alloy steel and 10% copper is assumed.

Tab. 9.6 Life cycle inventory data for a 10MW diesel-electric generating set

product technosphere	Name	Location	Unit	diesel-electric generating set production 10MW	Uncertainty Type	Standard Deviation	95%	General Comment
	Location			RER				
	InfrastructureProcess			1				
	Unit			unit				
	diesel-electric generating set production 10MW	RER	unit	1.00E+0				
	copper, at regional storage	RER	kg	1.80E+4	1	3.05		(na,5,na,1,na,BU:1.05); Estimation
	chromium steel 18/8, at plant	RER	kg	9.00E+3	1	3.05		(na,5,na,1,na,BU:1.05); Estimation
	steel, low-alloyed, at plant	RER	kg	1.80E+5	1	3.05		(na,5,na,1,na,BU:1.05); Estimation
	transport, freight, lorry 16-32 metric ton, fleet average	RER	tkm	2.07E+4	1	3.95		(5,5,na,na,na,BU:2); Standard distance 100km
	transport, freight, rail	RER	tkm	1.24E+5	1	3.95		(5,5,na,na,na,BU:2); Standard distance 600km

9.3.2 Direct emissions

Direct emissions are estimated as shown in Tab. 9.7 and mainly explained in a former study (Jungbluth 2007). To avoid double counting, emissions of CH₄, SO₂ and NO_x were removed as they are assessed separately for overall extraction of crude oil and natural gas according to chapter 9.5. Other emissions are assessed in analogy to the engines of trucks. Benzene is assumed to be emitted with 0.02 kg/TJ_{In} and Benzo(a)pyrene with 0.1E-3 kg/TJ_{In} and heavy metal emissions corresponding to the content in diesel. For chromium VI, a share of 0.2% of overall chromium is assumed.

Tab. 9.7 Life cycle inventory for diesel, burned in diesel-electric generating set, without CH₄, SO₂ and NO_x-emissions

	Name	Location		Unit	Diesel, burned in diesel-electric generating set, without SO ₂ , Nox and CH ₄ -emissions	Uncertainty Type	Standard Deviation 95%	General Comment
		Infrastructure	Process					
		Location						
		InfrastructureProcess						
Unit								
product	Diesel, burned in diesel-electric generating set, without SO ₂ , Nox and CH ₄ -emissions	GLO	0	MJ	1.00E+0			
technosphere	diesel, at regional storage	RER	0	kg	2.34E-2	1	1.24	(3,3,3,3,1,BU:1.05); Calculation
	lubricating oil, at plant	RER	0	kg	6.70E-5	1	2.06	(3,5,1,3,5,BU:1.05); Rough estimation with data for cogen 200kWe
Disposal	diesel-electric generating set production 10MW	RER	1	unit	1.85E-10	1	3.12	(3,5,3,3,3,BU:3); Estimation
	disposal, used mineral oil, 10% water, to hazardous waste incineration	CH	0	kg	6.70E-5	1	2.06	(3,5,1,3,5,BU:1.05); Rough estimation
emission air, low population density	Benzene	-	-	kg	2.00E-8	1	3.03	(3,3,3,3,1,BU:3); Extrapolation
	Benzo(a)pyrene	-	-	kg	1.00E-10	1	3.03	(3,3,3,3,1,BU:3); Extrapolation
	Carbon dioxide, fossil	-	-	kg	7.30E-2	1	1.10	(2,3,2,3,1,BU:1.05); Literature
	Carbon monoxide, fossil	-	-	kg	6.80E-4	1	5.03	(3,3,3,3,1,BU:5); Literature
	Dinitrogen monoxide	-	-	kg	6.00E-6	1	1.54	(3,3,3,3,1,BU:1.5); Literature
	Mercury	-	-	kg	4.67E-10	1	5.08	(3,3,3,3,3,BU:5); Literature on content in diesel
	Methane, fossil	-	-	kg	0	1	1.51	(2,3,1,3,1,BU:1.5); Set 0 as assessed in overall emissions for extraction
	Nitrogen oxides	-	-	kg	0	1	1.51	(2,3,1,3,1,BU:1.5); Set 0 as assessed in overall emissions for extraction
	NM VOC, non-methane volatile organic compounds, unspecified origin	-	-	kg	9.24E-5	1	1.51	(2,3,1,3,1,BU:1.5); Environmental report
	Particulates, < 2.5 um	-	-	kg	1.70E-4	1	3.03	(3,3,3,3,1,BU:3); Literature
	Sulfur dioxide	-	-	kg	0	1	1.09	(2,3,1,3,1,BU:1.05); Set 0 as assessed in overall emissions for extraction
	Cadmium	-	-	kg	2.34E-10	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions
	Copper	-	-	kg	3.97E-8	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions
	Chromium	-	-	kg	1.17E-9	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions
	Chromium VI	-	-	kg	2.34E-12	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions, 0.2% share of Cr is Cr VI
Nickel	-	-	kg	1.64E-9	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions	
Selenium	-	-	kg	2.34E-10	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions	
Zinc	-	-	kg	2.34E-8	1	5.06	(2,3,1,1,3,BU:5); Literature for automobile emissions	

9.4 Natural gas burned in gas turbine

In this study, only the existing dataset for the combustion of sweet gas is adjusted as presented in Tab. 9.8. Emissions of methane, SO₂ and NO_x were removed as they are assessed separately for overall extraction of crude oil and natural gas according to chapter 9.5.

Tab. 9.9 Sulphur dioxide (SO₂) emissions in kg per kg oil equivalent (IOGP 2022, Tab. A.4)

Sulphur dioxide released	Average 2019 to 2021	Source
Region	kg/kg OE	
Africa	6.00E-5	IOGP 2022
Asia	3.93E-5	IOGP 2022
Europe	3.68E-5	IOGP 2022
Middle East	8.04E-4	IOGP 2022
North America	5.41E-5	IOGP 2022
Russia & Central Asia	9.89E-5	IOGP 2022
South & Central America	4.66E-5	IOGP 2022
Global	2.12E-4	IOGP 2022

Tab. 9.10 Nitrogen oxide (NO_x) emissions in kg per kg oil equivalent (IOGP 2022, Tab. A.4)

NO _x released	Average 2019 to 2021	Source
Region	kg/kg OE	
Africa	4.05E-4	IOGP 2022
Asia	3.02E-4	IOGP 2022
Europe	2.66E-4	IOGP 2022
Middle East	1.90E-4	IOGP 2022
North America	3.85E-4	IOGP 2022
Russia & Central Asia	1.47E-4	IOGP 2022
South & Central America	4.79E-4	IOGP 2022
Global	3.19E-4	IOGP 2022

9.6 Use and emissions of Halon and other chemicals in firefighting equipment

No updates are made in this chapter compared to Meili & Jungbluth 2018.

This means, a generic amount 1.16e-8 kg of “Methane, Bromo trifluoro-, Halon 1301” is emitted per kg oil equivalent and a generic amount of 4.66e-8kg of “Methane, trifluoro-, HFC-23” is emitted per kg oil equivalent. Both emissions are only allocated to offshore production.

Halon 1301 was used in stationery firefighting equipment for offshore operations. Because of its ozone depletion potential, industrial states stopped the production of halon in 1994, in line with the requirements of the Montreal Protocol.³³ The use, however, continues to be permitted for certain critical uses as set out in Annex VI to Regulation (EC) No 1005/2009. These critical uses also include the protection of spaces where flammable liquid or gas could be released in oil, gas and petrochemicals facilities.³⁴

- Halon is only required to support legacy facilities; all new facilities are halon - free.
- Legacy facilities in the far north (i.e., Alaskan North Slope in the United States and parts of the former Soviet Union) will continue to require the use of halons in occupied spaces owing to severe ambient (very low temperature) conditions.

³³ <http://www.ecoinvent.org/support/ecoinvent-forum/topic.html?&tid=279>, online 18.10.2017

³⁴ <http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010R0744&from=EN>, online 01.11.2017

- Facility owners neither own nor control the quantities of halons needed to support operations over the continually extended time horizons. This situation will continue to place demands on the level of available halon stocks. However, owing to the adoption of alternatives in new facilities, this sector has reduced its future demand for the diminishing supplies of halon (UNEP 2014)

In most cases, existing facilities with halon 1301 fixed systems were designed and constructed as an integral part of the safety system design as well as the physical layout of the facility. After extensive research, it has been determined that in some cases the retrofit of such facilities with currently available alternative systems is not economically feasible, and that current research is unlikely to lead to an economic solution. Thus, these facilities will likely rely on existing halon banks for their operating lifetimes (UNEP 2014).

For new facilities, companies are adopting an inherently safe design approach to the protection of their facilities. This means preventing the release of hydrocarbons and eliminating the availability of flammable or explosive materials. Only when all such measures have been considered, and a residual risk of the hazard remains, are other risk reducing measures considered. In most cases, new technology detection systems are employed to shut-down and blow-down processes and turn on high-rate ventilation systems rather than closing the space and trying to inert it with an extinguishing agent. However, where an inerting agent is still required in occupied spaces, halon 1301 has been replaced by Trifluoromethane (HFC-23) or FK-5-1-12, if temperatures permit. Currently, HFC-23 is the only alternative that can be used in very cold climatic conditions. Halon 1301 is also used for fire and explosion suppression systems that protect offshore oil exploration platforms in the tropical climatic zone in Asia (UNEP 2014).

Parties in the Asia Pacific region, including India, use halon 1301 systems in refineries, gas pumping stations and offshore oil platforms. Refineries and oil pumping stations have/are gradually switching over to dry powders in pumping stations, HFC-227ea, FK-5-1-12, and inert gases in refineries where it is technically feasible given space and weight concerns. For offshore oil platforms, space and weight are still a big concern and thus the replacement of old legacy systems and those systems on new platforms have been delayed. Thus, for such applications halon requirements still exist. Oil companies are obtaining this halon from local sources of recovered halon, which they use to refill existing cylinders.

However, there is no halon recycling, banking, or quality testing facility for such recovered halon in this part of Asia. Therefore, the quality and effectiveness of such recovered halon is currently a major concern. In onshore halon 1301 systems, where a clean agent is important, some oil companies are hesitating to switch over to HFCs because of their high GWP as they do not want to switch over twice. HFC-23 has never been used in this region by the oil industry (UNEP 2014).

It is assumed that for European offshore plants $0.7 \text{ mg}_{\text{halon}}/\text{t}_{\text{crude oil}}$ is emitted, for the remaining areas $58 \text{ mg}_{\text{halon}}/\text{t}_{\text{crude oil}}$. Because test flooding, false alarms, losses from filling and leakage cause 70-90% of the total emissions, halon demand to extinguish fires in case of accidents is not assigned (Jungbluth 2007).

Based on the above information it is assumed, that 20% of the oil platforms still use Halon 1301. As there is noecoinvent data available for the production of FK-5-1-12, the remaining share of flame retardants (80%) is modelled with Trifluoromethane (HFC-23).

HFC-23 has a high global warming potential compared to the other flame retardants while FK-5-1-12 has a GWP of 1³⁵. Therefore, this replacement will overestimate the impacts on climate change.

No such emissions are modelled for onshore operations.

The same amounts that are emitted are considered as an input for the products. As there is no dataset for the production of such flame retardants available in the current ecoinvent database, it is approximated with the general dataset for organic chemicals.

10 Emissions to water & soil

10.1 Water balance and discharge of produced water

The inventory for the water balance was revised in the year 2023.

10.1.1 What is produced water?

Produced water refers to water associated with the production of oil and/or natural gas from a well. Produced water may also include water produced from the reservoir or water injected into the wellbore to increase the formation pressure for improved hydrocarbon recovery. When the oil and gas flows to the surface, the produced water is brought to the surface with the hydrocarbons.³⁶

Produced water can be considered a by-product or waste product of the production process as produced water composition includes several toxic substances such as sulfates, chlorides, aluminum, and sodium due to chemicals introduced into the wellbore during production operations and exposure to saline subsurface geological conditions. As a result, produced water is often referred to as 'brine.' Due to its salinity (produced water is about 15 times saltier than seawater) and potentially hazardous impact on the environment, produced water must be properly treated before disposal or reuse (less-common as produced water is a costly process).

In some situations, additional water from other formations adjacent to the hydrocarbon-bearing layers may become part of the produced water that comes to the surface.

Most wells in unconventional oil and gas formations are stimulated using hydraulic fracturing, through which water is injected under pressure into the formation to create pathways allowing the oil or gas to be recovered in a cost-effective manner. Immediately following hydraulic fracturing in the well (a frack job), some of the injected water returns to the surface and is known as flowback water. Flowback water is often managed in a similar manner to produced water and some engineers in the industry consider it as part of the produced water flow stream.³⁷

At the beginning of production of a new field this fraction of co-produced water is usually small. If water content exceeds the maximal content tolerable for transport in the pipeline, water is separated with a separator. From ca. 10-20% watering, the drilling usually stops conveying automatically. Then, e.g., subsurface pumps need to be installed. In total, the entire load of

³⁵ Product documentation of special hazard fire protection fluid: https://web.archive.org/web/20110927030243/http://solutions.3m.com/wps/porta/3M/en_US/Novac/Home/Product_Information/Product_Navigator/?PC_7_RJH9U5230GE5D02J33P04L38E5_univid=1180599171161, online 14.12.2017

³⁶ <https://ifsolutions.com/what-is-produced-water-injection-disposal-methods-in-oil-and-gas/>, 16.3.2023

³⁷ <http://www.producedwatersociety.com/produced-water-101/>, online 19.10.2017

produced water can exceed the amount of produced oil in an oil field by ten times during the economic lifetime. If watering is 90 to 95% (i.e., 10-20 times more water than oil), production usually ceases for economic reasons (Jungbluth 2007).

Produced water normally is warm or hot. Thus, there is also a potential to use it for geothermal power production, which could be considered as a couple product of oil extraction. This is not evaluated further for this study.³⁸

10.1.2 Treatment and discharge

As oil, gas, and water are produced from a well, the fluids need to be separated into separate streams. This is typically done using some type of gravity separation, such as API separators, free water knockout tanks, or gun barrel separators. In addition to separating the fluids, these devices allow for large solid particles to settle out. When the oil and water are emulsified, they can be separated by applying heat or appropriate chemical treatments.

Produced water must be treated to remove oil and grease and toxic chemicals before it is disposed, reused, or otherwise managed. Most countries regulate the discharge of produced water, taking into account differing environmental conditions and sensitivities between onshore and offshore (IOGP 2022).

Many types of processes and technologies can be used to treat produced water depending on how clean the water must be before it moves on to its destination.

Produced water that is discharged to onshore freshwater rivers must be further treated to reduce salt content. Water that is injected for either enhanced recovery or for disposal is treated in a different way from water that is discharged. The treatment processes used prior to injection are designed to remove free oil, solids, and bacteria. Chemicals are often used to enhance treatment processes and to protect underground formations and equipment.

10.1.3 Amounts of discharged produced water

Information about the water-to-oil ratio from different literature sources is shown in Tab. 10.1. Depending on the region of production, most of the produced water is either reinjected to the ground or discharged to soil or surface water³⁷ (Agip Division 2001; ANL 2009; Tiedeman et al. 2012; UKOOA 2001; IOGP 2022).

Tab. 10.1 Information about the Water-to-oil ratio from different sources

Country, region	Water-to-oil	Year	Source, Footnote
UK, North Sea	3.5	2007	³⁸
US	5.0	2014	⁴¹
US	4.0	2018	³⁹
Global	3.0	2007	⁴²
Global	3.5	2013	³⁸ , 70% onshore

³⁸ https://www.researchgate.net/publication/330971905_Geothermal_Potential_of_the_Global_Oil_Industry, 16.3.2023

³⁹ <https://blog.veolianoorthamerica.com/produced-water-joins-the-circular-economy>, 16.3.2023

⁴⁰ <https://ifsolutions.com/what-is-produced-water-injection-disposal-methods-in-oil-and-gas/>, 16.3.2023

⁴¹ <https://btuanalytics.com/shale-production/produced-water-volumes-climb-driven-by-unconventional-oil/>, 16.3.2023

⁴² <https://www.spe.org/en/industry/challenges-in-reusing-produced-water/>, 16.3.2023

Region-specific data for reinjected produced water and share of reinjected water on overall amount of produced water is available for a sample of on- and offshore producers in the reference year 2021 (IOGP 2022, Tab. A.18 and A.19). These values are set in relation to calculate the amount of discharged produced water per kg oil equivalent as shown in Tab. 10.2.

For a few single countries, specific values are available (ANL 2009; Stolz & Frischknecht 2017; Targulian & Hirsch 2000; UKOOA 2001)³⁷. These were the basis for the previous studies (Meili et al. 2022a). Now they are not used anymore because of the availability of region-specific data from one study.

In most regions, the amount of discharged water is higher than the amount of freshwater used in the production process as shown in Tab. 7.1.

Tab. 10.2 Amount of produced water from off- and onshore production, disposed to surface water in different regions (IOGP 2022, derived from Tab. A.18 and A.19)

Produced water, discharged, Average 2019 to 2021	Offshore	Onshore	Source
Region	kg/kg OE	kg/kg OE	
Africa	0.65	0.29	IOGP 2022
Asia	1.11	0.48	IOGP 2022
Europe	0.73	0.47	IOGP 2022
Middle East	0.06	0.35	IOGP 2022
North America	0.26	0.01	IOGP 2022
Russia & Central Asia	0.00	0.00	IOGP 2022
South & Central America	0.51	0.04	IOGP 2022
Global	0.61	0.22	IOGP 2022

10.1.4 Method for LCI and LCIA of water flows

For evaluating the impacts of water flows on the water scarcity with LCIA methods like AWARE (Boulay et al. 2018) mainly the influence on the availability of freshwater, which is suitable for consumption by humans, animals, and plants, is relevant. To define a suitable approach for the inventory analysis the authors of this method have been contacted for advice.⁴³

Salty water is not relevant for the freshwater balance if its release does not decrease the availability of freshwater. The use of non-renewable, fossil-type water resources should be characterized as a resource depletion rather than water scarcity (but so far, no consensus exists on such indicator). There are some LCIA methods under development.⁴⁴ For this study it was not clear which inventory flows would be relevant for an analysis of the use of salty water resources.

If produced water would be used after treatment to increase the availability of freshwater this could lead in theory to positive impacts. This would be especially relevant in arid extraction regions like the Middle East. In this case the pollution level is important, since if it is too highly polluted, it cannot be considered beneficial for humans, plants, or animals.

⁴³ Personal communication with Anne-Marie Boulay and Stephan Pfister in autumn 2022 to summer 2023.

⁴⁴ <https://pubs.acs.org/doi/10.1021/es802423e>

The idea for using such water for irrigation has prompted studies testing things like crop yield, soil health, and contaminant uptake by plants, especially since produced water is often high in salts, and its chemistry varies greatly from region to region. Trials show that the use of treated produced water for irrigation may suppress plant immune systems⁴⁵ So far, no indication has been found that the quality of released water from oil and gas extraction could allow such beneficial effects.

The amount of produced water released to the environment is in most regions one order of magnitude higher than the use of freshwater accounted for (compare Tab. 7.1 and Tab. 10.2) Given the information available it is not clear if the full water balance at the end can be considered as a negative or positive environmental impact of oil and gas extraction. On the one side there might be an increase of available water, but on the other side pollution might lead to a decrease of the water quality.

For the time being it is assumed that the water balance is neutral for the environmental impact regarding water availability (i.e. not leading to negative impact on water scarcity due to extraction of produced water). The freshwater input according to Tab. 7.1 is balanced with the same amount of freshwater release in the same region to close the balance. If the amount of produced water is lower than the freshwater input, only the amount of produced water is released back (see chapter 12).

The remaining part of produced water is inventoried as “water, fossil” for the resource and “Chemically polluted water“ for the release to the environment. These two flows should not be considered for the water scarcity assessment.

The withdrawal of produced water from the ground and its reinjection is not accounted for as the water does not leave the production system.

10.1.5 Allocation

It can be assumed that most of the produced water stems from oil production, but the available data do not allow to quantify the differences between oil and gas production. Thus, the discharge of produced water is allocated to both products.

10.1.6 Composition and pollutants

The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geologic formation from which the water was produced, and the type of hydrocarbon product being produced. The major constituents of concern according to the produced water society³⁷ are:

- *Salt content (often expressed as salinity, conductivity, or total dissolved solids (TDS)).* Although some produced water is nearly fresh (<3,000 mg/L TDS), most produced water is saltier than seawater (~35,000 mg/L) and can be >300,000 mg/L). Removing salt is not difficult, but it is usually costly.
- *Oil and grease.* This is not a single chemical compound; the analytical method for oil and grease measures various organic compounds associated with hydrocarbons in the formation). Oil and grease can be found in different physical forms:
 - Free oil: large droplets - readily removable by gravity separation methods
 - Dispersed oil: small droplets - somewhat difficult to remove; and

⁴⁵ <https://phys.org/news/2019-10-oil-gas-wastewater-irrigation-suppress.html>, 17.3.2023

- Dissolved oil: hydrocarbons and other similar materials dissolved in the water stream - very challenging to eliminate.
- *Inorganic and organic toxic compounds*. The toxics may be introduced as chemical additives to improve drilling and production operations or they may leach into the produced water from the formation rock or the hydrocarbon.
- *Naturally occurring radioactive material (NORM)*. Some hydrocarbon-bearing formations contain natural radiation that leaches into the produced water. The presence and concentration of NORM varies between formations.

Because data on oil emissions is available for different production areas, this value is not used directly at discharge of produced water but is assessed in the inventory of crude oil production directly (see chapter 10.3).

Formation water contains radionuclides from natural decay processes. The contents strongly depend on the geologic situation. A correlation between content of dissolved solids and content of nuclides does not exist. In fact, the content of ^{238}U and ^{232}Th in the adjacent rock is decisive. For scale formation, however, contents of solid matter in the formation water are relevant due to the chemical relationship of radium with strontium and barium (c.f. chapter 11.1)

The data basis in the former study was narrow and therefore extended with new data to have more complete background-data (Neff et al. 2011; Waly et al. 2023). An additional discussion and compilation of information can be found in the appendix, in table A.12 and A.13 of a former study (Jungbluth 2007).

Considered literature is shown in Tab. 10.3. Tab. 10.4 and Tab. 10.5 show the life cycle inventory for the chemical composition of discharged produced water in off- and onshore production.

For the discharge onshore, in general the same data is used, but as subcategory for water emissions “to river” is indicated instead of “to ocean”. For chloride the lower figure reported by Waly et al. is assumed for onshore production only. Uncertainties of this estimation are relatively high because different values are expected for different regions and there are only values for a random sample of the various regions.

Tab. 10.3 Literature values considered for chemical composition of discharged produced water in offshore and onshore production (cf. Tab. 10.4 and Tab. 10.5).

Name	Location	Infrastructure/Process	Unit	discharge, produced water, offshore	Waly <i>et al.</i>	Neff 2011,	Neff 2011,	Neff 2011,	Jungbluth
					2023	average	average	average	2007
Location				OCE	US	MX	IN	OCE	OCE
Infrastructure/Process				0					
Unit				kg	kg	kg	kg	kg	kg
Acenaphthene	-	-	kg	2.36E-9		-	-	2.05E-9	6.22E-10
Acenaphthylene	-	-	kg	1.17E-9		-	-	1.15E-9	3.89E-11
Aluminium	-	-	kg	1.00E-8	1.00E-8				
Ammonium, ion	-	-	kg	8.55E-5	9.50E-6	-	-	1.62E-4	
Antimony	-	-	kg	1.00E-8	1.00E-8				
Arsenic	-	-	kg	2.19E-8	1.00E-8	1.58E-8	-	4.53E-8	1.03E-8
Barium	-	-	kg	8.64E-5	1.10E-6	-	-	1.71E-4	8.70E-5
Benzene	-	-	kg	3.72E-6		1.62E-6	1.19E-6	1.44E-6	6.00E-06
Benzene, ethyl-	-	-	kg	1.34E-6		2.84E-7	1.88E-7	2.84E-7	2.40E-6
Boron	-	-	kg	8.00E-6	1.00E-8	-	-	2.40E-5	-
Bromine	-	-	kg	3.50E-5		-	-	-	7.00E-5
BOD5 (Biological Oxygen Demand)	-	-	kg	3.52E-4	6.90E-6	-	-	1.02E-3	3.00E-5
Cadmium	-	-	kg	5.67E-9	1.00E-8	5.25E-10	-	5.01E-9	2.00E-9
Calcium	-	-	kg	8.58E-3		-	-	1.42E-2	3.00E-3
Carbonate	-	-	kg	2.79E-4		-	-	5.59E-4	-
Carboxylic acids, unspecified	-	-	kg	1.84E-4		-	-	-	3.68E-4
Cesium	-	-	kg	5.00E-8		-	-	-	1.00E-7
Chloride	-	-	kg	7.18E-2	1.20E-7	-	-	9.36E-2	5.00E-2
Chromium	-	-	kg	1.06E-8	1.00E-8	7.50E-10	-	1.71E-8	4.65E-9
Cobalt	-	-	kg	1.00E-8	1.00E-8				
COD (Chemical Oxygen Demand)	-	-	kg	3.83E-5	4.50E-5	-	-	-	7.00E-5
Copper	-	-	kg	4.29E-8	5.00E-8	2.00E-10	-	6.86E-8	1.00E-8
Fluoride	-	-	kg	3.50E-7	5.00E-8	-	-	-	1.00E-6
Hydrocarbons, aliphatic, alkanes, unspecified	-	-	kg	7.47E-6	9.40E-6	-	-	-	1.30E-5
Hydrocarbons, aliphatic, unsaturated	-	-	kg	6.00E-7		-	-	-	1.20E-6
Hydrocarbons, aromatic	-	-	kg	2.60E-5		-	-	-	5.20E-5
Iodide	-	-	kg	5.83E-5		-	-	1.07E-4	1.00E-5
Iron	-	-	kg	8.02E-6	3.00E-7	-	-	1.95E-5	4.30E-6
Lead	-	-	kg	1.08E-8	1.00E-8	1.41E-8	-	2.25E-8	7.00E-13
Lead-210	-	-	kBq	4.75E-2		-	-	9.49E-2	-
Lithium	-	-	kg	1.33E-5		-	-	2.65E-5	-
Manganese	-	-	kg	2.55E-6	1.00E-7	4.00E-6	-	3.54E-6	4.00E-6
Magnesium	-	-	kg	1.46E-3		-	-	2.42E-3	5.00E-4
Mercury	-	-	kg	2.00E-9	1.00E-9	1.05E-10	-	5.01E-9	1.90E-12
Molybdenum	-	-	kg	6.25E-10		-	-	1.25E-9	-
Nickel	-	-	kg	7.57E-8	1.00E-8	4.00E-9	-	2.10E-7	6.99E-9
Nitrogen	-	-	kg	4.65E-5	4.65E-5				
Oils, unspecified	-	-	kg	-	6.20E-6	-	-	3.45E-5	-
PAH, polycyclic aromatic hydrocarbons	-	-	kg	1.09E-6		-	-	1.09E-6	4.68E-7
Phenol	-	-	kg	2.72E-6	1.50E-7	-	-	-	8.00E-6
Phosphate	-	-	kg	1.59E-6	1.59E-6				
Polonium-210	-	-	kBq	1.62E-6		-	-	3.24E-6	-
Potassium	-	-	kg	1.01E-3		-	-	1.62E-3	4.00E-4
Radium-224	-	-	kBq	1.26E-2		-	-	2.02E-2	5.00E-3
Radium-226	-	-	kBq	3.04E-1		-	-	5.99E-1	8.00E-3
Radium-228	-	-	kBq	5.00E-2		-	-	9.01E-2	1.00E-2
Rubidium	-	-	kg	5.00E-7		-	-	-	1.00E-6
Silver	-	-	kg	3.00E-8		-	-	-	6.00E-8
Sodium	-	-	kg	3.51E-2		-	-	4.02E-2	3.00E-2
Strontium	-	-	kg	3.42E-4		-	-	5.04E-4	1.80E-4
Sulfate	-	-	kg	3.45E-4		-	-	6.90E-4	-
Sulfide	-	-	kg	5.00E-8	5.00E-8				
Suspended solids, unspecified	-	-	kg	1.80E-4	4.50E-4	-	-	-	9.00E-5
Thorium-228	-	-	kBq	1.00E-2		-	-	-	2.00E-2
Thorium-232	-	-	kBq	3.24E-7		-	-	6.48E-7	-
DOC, Dissolved Organic Carbon	-	-	kg	2.00E-2	5.95E-2	-	-	-	5.90E-4
TOC, Total Organic Carbon	-	-	kg	3.05E-3		-	-	5.50E-3	5.90E-4
Toluene	-	-	kg	5.85E-6		1.02E-6	4.45E-7	8.95E-7	1.08E-5
Vanadium	-	-	kg	3.25E-10		-	-	6.50E-10	-
VOC, volatile organic compounds, unspecified origin	-	-	kg	1.75E-5		-	-	-	3.50E-5
Uranium-238	-	-	kBq	2.50E-5		-	-	5.01E-5	-
Xylene	-	-	kg	4.88E-6		4.40E-7	2.47E-7	3.67E-7	9.40E-6
Zinc	-	-	kg	6.73E-6	2.00E-7	1.81E-6	-	1.30E-5	7.00E-6

10.1.7 Outlook

Further research seems to be necessary to fully understand the impact of water flows in natural gas and crude oil extraction on the water availability and scarcity. Such research goes beyond the scope of this update study.

10.2 Production chemicals

It can be assumed that the emissions of production chemicals were already recorded with the composition of production water. The amount of chemicals that are injected depends on the possibility to force produced water into abandoned oil and gas fields or aquifers (Jungbluth 2007).

10.3 Oil spilled and discharged

Operational oil spills include all types of spills that might occur during drilling and pumping and exclude spills related to transportation and refining.

Spills may have a number of causes such as equipment failure (including corrosion), operating errors, and unlawful third party damage such as sabotage, terrorism and theft.

Oil is also discharged as part of the produced water described in chapter 10.1.

Regional amounts of oil spilled and discharged per kgOE on- and offshore, to water and unspecified, are provided in an annual report from oil and gas producing companies (IOGP 2022, Tab. A.16 and A.23)

10.3.1 Emissions to water

Tab. 10.6 Amount of oil spilled to sea per kg of oil equivalent extracted per region, average of latest 3 years reported (offshore, IOGP 2022, Tab. A.16)

Oils, discharged and spilled to sea, offshore		Average 2019 to 2021	Source
Region		kg/kg OE	
Africa	kg/kg OE	2.27E-5	IOGP 2022
Asia/Australia	kg/kg OE	1.85E-5	IOGP 2022
Europe	kg/kg OE	9.61E-6	IOGP 2022
Middle East	kg/kg OE	9.32E-7	IOGP 2022
North America	kg/kg OE	4.89E-6	IOGP 2022
Russia & Central Asia	kg/kg OE	1.35E-7	IOGP 2022
South & Central America	kg/kg OE	2.24E-5	IOGP 2022
Global		1.42E-5	IOGP 2022

Tab. 10.7 Amount of oil spilled to rivers per kg of oil equivalent extracted per region, average for 3 latest years (onshore, IOGP 2022, Tab. A.16).

Oils, discharged and spilled, to river, onshore		Average 2019 to 2021	Source
Region		kg/kg OE	
Africa	kg/kg OE	2.73E-5	IOGP 2022
Asia/Australia	kg/kg OE	2.91E-6	IOGP 2022
Europe	kg/kg OE	4.22E-6	IOGP 2022
Middle East	kg/kg OE	2.73E-6	IOGP 2022
North America	kg/kg OE	1.27E-5	IOGP 2022
Russia & Central Asia	kg/kg OE	1.38E-7	IOGP 2022
South & Central America	kg/kg OE	2.38E-6	IOGP 2022
Global		7.57E-6	IOGP 2022

10.3.2 Emissions to soil

Direct emissions to soil are estimated based on the average amount of the latest 3 years of oil discharged and spilled classified as unspecified in an annual report of oil and gas producing companies (IOGP 2022). Values used in the model are shown in Tab. 10.8.

Tab. 10.8 Estimate of oil discharged and spilled to soil per kg of oil equivalent extracted per region, based on oil discharged and spilled, unspecified, average of 3 latest years reported (IOGP 2022, Tab. A.23). For regions without reported values, weighted average of reporting regions is considered.

Oils, discharged and spilled, to soil	Average 2019 to 2021	Source
Region	kg/kg OE	
Africa	3.42E-6	IOGP 2022
Asia/Australia	4.07E-8	IOGP 2022
Europe	1.96E-7	IOGP 2022
Middle East	1.13E-6	weighted average of regions with reported values
North America	1.13E-6	weighted average of regions with reported values
Russia & Central Asia	1.13E-6	weighted average of regions with reported values
South & Central America	1.13E-6	weighted average of regions with reported values
Global	1.13E-6	weighted average of regions with reported values

11 Waste

No updates are made in this chapter compared to Meili & Jungbluth 2018.

11.1 Deposition

In oil production, the mineral substances dissolved in water precipitate and are deposited in the equipment (pumps, separator, valves etc.). The deposition is estimated with a dataset for hazardous waste in underground deposits. For Norway, a country specific value of 0.16 g/t is

available (Schori et al. 2012). For all other countries, a generic value of 0.2 g/t as assessed in (Jungbluth 2007) is considered.

11.2 Other wastes

For disposal of other wastes that form during crude oil production, data from Nigeria: 363 g/t (Shell 2001) and Norway 86.6g/t (Schori et al. 2012) is available. For other countries, 100 g/t are used as generic assumption (c.f. Meili & Jungbluth 2018).

12 Summary of life cycle inventory data

For the updated datasets on crude oil and natural gas extraction, the most relevant changes for the reference year 2021 are:

- Harmonization of general assumptions between crude oil and natural gas production.
- Extension of the list of country-specific inventories to 48 countries (c.f. Tab. 2.1)
- Recent country specific data for share of on- and offshore production, well drilling, flaring and methane emissions (fugitive and technical venting combined)
- Regional 3-year-average for issues reported in IOGP 2022: Energy use, freshwater use, emissions of NO_x and SO₂ as well as oil to soil and water

The life cycle inventories for the newly modelled and updated processes are provided as multi-output or unit process raw data in the EcoSpold v1 format. The electronic data is including full EcoSpold v1 documentation.

Tab. 12.1 shows one example for the meta information and Tab. 12.2 shows one example for the modelled life cycle inventory (unit process raw data) for crude oil and natural gas extraction in the united states of America (US). Meta information for other processes updated in this study, as well as country-specific unit process raw data for crude oil and natural gas produced in other countries analysed in this study are available on request, from ESU-services in the electronic EcoSpold format or in an LCA-database generated in SimaPro 9.5.⁴⁶

⁴⁶ Download is available on <http://esu-services.ch/data/public-lci-reports/>

Tab. 12.1 Meta information for the investigated life cycle inventories, example for crude oil and natural gas production in the US, part 1

ReferenceFunction	Name	combined gas and oil production	combined gas and oil production offshore	combined gas and oil production onshore	crude oil, at production offshore	crude oil, at production onshore
Geography	Location	US	US	US	US	US
ReferenceFunction	InfrastructureProcess	0	0	0	0	0
ReferenceFunction	Unit	a	a	a	kg	kg
TimePeriod	IncludedProcesses	Production of oil and gas including energy use, infrastructure and emissions.	Production of oil and gas including energy use, infrastructure and emissions.	Production of oil and gas including energy use, infrastructure and emissions.	Production of crude oil including energy use, infrastructure and emissions.	Production of crude oil including energy use, infrastructure and emissions.
	GeneralComment	The multioutput-process 'combined offshore gas and oil production' delivers the co-products crude oil and natural gas. Allocation for co-products is based on heating value.	The multioutput-process 'combined offshore gas and oil production' delivers the co-products crude oil and natural gas. Allocation for co-products is based on heating value.	The multioutput-process 'combined offshore gas and oil production' delivers the co-products crude oil and natural gas. Allocation for co-products is based on heating value.	The offshore oil production delivers the product crude oil. The values are derived from a multioutput-process "combined offshore gas and oil production" by allocation based on heating values for crude oil and natural gas	The onshore oil production delivers the product crude oil. The values are derived from a multioutput-process "combined onshore gas and oil production" by allocation based on heating values for crude oil and natural gas
	InfrastructureIncluded	1	1	1	1	1
	Category	oil	oil	oil	oil	oil
	SubCategory	production	production	production	production	production
	StartDate	2021	2021	2021	2021	2021
	EndDate	2023	2023	2023	2023	2023
	DataValidForEntirePeriod	1	1	1	1	1
	OtherPeriodText	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.
	Geography	Text	Data valid for US.	Data valid for US.	Data valid for US.	Data valid for US.
Technology	Text	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production
	ProductionVolume	711 megatons of crude oil and 934 billion Nm ³ natural gas per year in 2021.	104 megatons of crude oil and 136 billion Nm ³ natural gas per year in 2021.	607 megatons of crude oil and 798 billion Nm ³ natural gas per year in 2021.	104 megatons of crude oil per year in 2021.	607 megatons of crude oil per year in 2021.
	SamplingProcedure	Statistics and use of generic data	Statistics and use of generic data	Statistics and use of generic data	Statistics and use of generic data	Statistics and use of generic data
	Extrapolations	A part of the data has been estimated with generic assumptions for on- and offshore production.	A part of the data has been estimated with generic assumptions for offshore production.	A part of the data has been estimated with generic assumptions for onshore production.	A part of the data has been estimated with generic assumptions for offshore production.	A part of the data has been estimated with generic assumptions for onshore production.
	UncertaintyAdjustments	none	none	none	none	none
ecoinvent v3	ProductionVolumeNumber	1486	1486	1486	103.8	607.3
	ProductionVolumeText	Megatons of oil-equivalents produced in 2021	Megatons of oil-equivalents produced in 2021	Megatons of oil-equivalents produced in 2021	Megatons of oil produced in 2021	Megatons of oil produced in 2021

Meta information for the investigated life cycle inventories, example for crude oil and natural gas production in the US, part2

ReferenceFunction	Name	natural gas, at production offshore	natural gas, at production onshore	crude oil, at production	natural gas, at production
Geography	Location	US	US	US	US
ReferenceFunction	InfrastructureProcess	0	0	0	0
ReferenceFunction	Unit	Nm3	Nm3	kg	Nm3
TimePeriod	IncludedProcesses	Production of natural gas including energy use, infrastructure and emissions.	Production of natural gas including energy use, infrastructure and emissions.	Production of crude oil including energy use, infrastructure and emissions.	Production of natural gas including energy use, infrastructure and emissions.
	GeneralComment	The offshore natural gas production delivers the product natural gas. The values are derived from a multioutput-process "combined offshore gas and oil production" by allocation based on heating values for crude oil and natural gas	The onshore oil production delivers the product natural gas. The values are derived from a multioutput-process "combined onshore gas and oil production" by allocation based on heating values for crude oil and natural gas	Oil production delivers the co-product natural gas. The values are derived from a multioutput-process "combined onshore gas and oil production" by allocation based on heating values for crude oil and natural gas	Oil production delivers the co-product natural gas. The values are derived from a multioutput-process "combined onshore gas and oil production" by allocation based on heating values for crude oil and natural gas
	InfrastructureIncluded	1	1	1	1
	Category	natural gas	natural gas	oil	natural gas
	SubCategory	production	production	production	production
	StartDate	2021	2021	2021	2021
	EndDate	2023	2023	2023	2023
	DataValidForEntirePeriod	1	1	1	1
	OtherPeriodText	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.	Time of most relevant publications and statistics. Other generic data, e.g. for infrastructure are based on older publications.
	Geography	Text	Data valid for US.	Data valid for US.	Data valid for US.
Technology	Text	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production	15 % offshore and 85 % onshore production
	ProductionVolume	136 billion Nm3 natural gas per year in 2021.	798 billion Nm3 natural gas per year in 2021.	711 megatons of crude oil per year in 2021.	934 billion Nm3 natural gas per year in 2021.
ecoinvent v3	SamplingProcedure	Statistics and use of generic data	Statistics and use of generic data	Statistics and use of generic data	Statistics and use of generic data
	Extrapolations	A part of the data has been estimated with generic assumptions for offshore production.	A part of the data has been estimated with generic assumptions for onshore production.	A part of the data has been estimated with generic assumptions for on- and offshore production.	A part of the data has been estimated with generic assumptions for on- and offshore production.
	UncertaintyAdjustments	none	none	none	none
	ProductionVolumeNumber	136.4	797.8	711.1	934.2
	ProductionVolumeText	Billion cubic meters of natural gas produced in 2021	Billion cubic meters of natural gas produced in 2021	Megatons of oil produced in 2021	Billion cubic meters of natural gas produced in 2021

Unit process raw data, example for crude oil and natural gas production in the US, part 2

US	Name	Location	Unit	combined gas and oil production offshore	crude oil, at production offshore	natural gas, at production offshore	combined gas and oil production onshore	crude oil, at production onshore	natural gas, at production onshore	combined gas and oil production	Uncertainty Type	Standard Deviation %	General Comment
	2021	Location		US	US	US	US	US	US	US			
	Infrastructure/Process			0 a	0 kg	0 Nm3	0 a	0 kg	0 Nm3	0 a			
	Unit			a	kg	Nm3	a	kg	Nm3	a			
oil	pipeline, crude oil, offshore	OCE	km	8.29E+2	100.0%	0.0%	0	0.0%	0.0%	8.29E+2	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Generic estimation based on estimate for Nigeria 2018
	pipeline, crude oil, onshore	RER	km	0	0.0%	0.0%	4.37E+3	100.0%	0.0%	4.37E+3	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Generic estimation based on estimate for Kazakhstan 2016
	platform, crude oil, offshore	OCE	unit	4.47E+0	100.0%	0.0%	0	0.0%	0.0%	4.47E+0	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Lodewijkx et al. 2001
gas	production plant crude oil, onshore	GLO	unit	0	0.0%	0.0%	7.82E+1	100.0%	0.0%	7.82E+1	1	3.30	(3,4,5,3,3,3,3,3,3,3,3); Lodewijkx et al. 2001
	plant offshore, natural gas, production	OCE	unit	5.56E-1	0.0%	100.0%	0	0.0%	0.0%	5.56E-1	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Average 2019 to 2021, IOGP 2022
	plant onshore, natural gas, production	GLO	unit	0	0.0%	0.0%	2.23E+2	0.0%	100.0%	2.23E+2	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Average 2019 to 2021, IOGP 2022
	pipeline, natural gas, long distance, high capacity, offshore	GLO	km	2.19E+2	0.0%	100.0%	0	0.0%	0.0%	2.19E+2	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Estimation based on values for crude oil pipeline
	pipeline, natural gas, long distance, high capacity, onshore	GLO	km	0	0.0%	0.0%	8.56E+3	0.0%	100.0%	8.56E+3	1	3.07	(3,4,1,3,3,3,3,3,3,3,3); Estimation based on values for crude oil pipeline
energy	electricity, medium voltage, at grid	US	kWh	6.18E+9	81.3%	18.7%	6.58E+10	44.7%	55.3%	7.19E+10	1	2.06	(3,2,2,3,3,3,3,3,3,3,3,2); Purchased energy according to IOGP 2022.
	Diesel, burned in diesel-electric generating set, at extraction site	GLO	MJ	3.67E+10	81.3%	18.7%	3.90E+11	44.7%	55.3%	4.27E+11	1	2.06	(3,2,2,3,3,3,3,3,3,3,3,2); Calculation based on data from IOGP 2022, assuming a generic share of 11.7% of onsite combustion + unspecified. Average 2019 to 2021
	heavy fuel oil, burned in industrial furnace 1MW, non-modulating	RER	MJ	4.78E+9	81.3%	18.7%	5.08E+10	44.7%	55.3%	5.56E+10	1	2.06	(3,2,2,3,3,3,3,3,3,3,3,2); Calculation based on data from IOGP 2022, assuming a generic share of 2.2% of onsite combustion + unspecified. Average 2019 to 2021
	sweet gas, burned in gas turbine, production	GLO	MJ	2.69E+11	81.3%	18.7%	2.86E+12	44.7%	55.3%	3.13E+12	1	2.06	(3,2,2,3,3,3,3,3,3,3,3,2); Calculation based on data from IOGP 2022, assuming a generic share of 85.7% of onsite combustion + unspecified. Average 2019 to 2021, SOx content of sour gas assessed separately in overall emissions.
waste	natural gas, vented	GLO	Nm3	1.49E+9	76.7%	23.3%	1.76E+10	37.9%	62.1%	1.91E+10	1	2.05	(2,1,1,1,1,3,3,3,3,3,3,2); Country specific methane emissions according to IEA 2022. includes all methane emissions from upstream production, recalculated using a share of 0.88 Nm3 methane per Nm3 natural gas. Allocation based on country specific emissions for oil and gas.
	natural gas, sweet, burned in production flare	GLO	Nm3	7.53E+8	81.3%	18.7%	8.01E+9	44.7%	55.3%	8.76E+9	1	2.06	(3,2,1,1,1,3,3,3,3,3,3,2); Total amount of flared gas per kg OE according to Worldbank 2023. Sox emissions from flared sour gas assessed separately in overall emissions.
	disposal, hazardous waste, 0% water, to underground deposit	DE	kg	2.65E+7	81.3%	18.7%	2.82E+8	44.7%	55.3%	3.08E+8	1	1.26	(3,4,1,3,3,3,3,3,3,3,3,1.05); Generic estimate according to Meili et al. 2018
	disposal, municipal solid waste, 22.9% water, to municipal incineration	CH	kg	1.32E+7	81.3%	18.7%	1.41E+8	44.7%	55.3%	1.54E+8	1	1.26	(3,4,1,3,3,3,3,3,3,3,3,1.05); Generic estimate according to Meili et al. 2018

Unit process raw data, example for crude oil and natural gas production in the US, part 3

US	Name	Location	Unit	combined gas and oil production offshore	crude oil, at production offshore	natural gas, at production offshore	combined gas and oil production onshore	crude oil, at production onshore	natural gas, at production onshore	combined gas and oil production	UncertaintyType	StandardDeviation95 %	GeneralComment
	2021	Location		US	US	US	US	US	US	US			
	InfrastructureProcess			0	0	0	0	0	0	0			
	Unit			a	kg	Nm3	a	kg	Nm3	a			
emission to water, river	Oils, unspecified	-	kg	0	81.3%	18.7%	1.79E+7	44.7%	55.3%	1.79E+7	1	1.56	(2,1,1,3,3, BU:1.5); Average 2019 to 2021, IOGP 2022
	BOD5 (Biological Oxygen Demand)	-	kg	0	81.3%	18.7%	5.63E+7	44.7%	55.3%	5.63E+7	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	COD (Chemical Oxygen Demand)	-	kg	0	81.3%	18.7%	5.63E+7	44.7%	55.3%	5.63E+7	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	DOC, Dissolved Organic Carbon	-	kg	0	81.3%	18.7%	1.55E+7	44.7%	55.3%	1.55E+7	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	TOC, Total Organic Carbon	-	kg	0	81.3%	18.7%	1.55E+7	44.7%	55.3%	1.55E+7	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	AOX, Adsorbable Organic Halogen as Cl	-	kg	0	81.3%	18.7%	1.84E+2	44.7%	55.3%	1.84E+2	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	Nitrogen	-	kg	0	81.3%	18.7%	1.38E+4	44.7%	55.3%	1.38E+4	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	Sulfur	-	kg	0	81.3%	18.7%	4.78E+4	44.7%	55.3%	4.78E+4	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
emission to water, ocean	Oils, unspecified	-	kg	6.47E+5	81.3%	18.7%	0	44.7%	55.3%	6.47E+5	1	1.56	(2,1,1,3,3, BU:1.5); Average 2019 to 2021, IOGP 2022
	BOD5 (Biological Oxygen Demand)	-	kg	2.04E+6	81.3%	18.7%	0	44.7%	55.3%	2.04E+6	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	COD (Chemical Oxygen Demand)	-	kg	2.04E+6	81.3%	18.7%	0	44.7%	55.3%	2.04E+6	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	DOC, Dissolved Organic Carbon	-	kg	5.60E+5	81.3%	18.7%	0	44.7%	55.3%	5.60E+5	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	TOC, Total Organic Carbon	-	kg	5.60E+5	81.3%	18.7%	0	44.7%	55.3%	5.60E+5	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	AOX, Adsorbable Organic Halogen as Cl	-	kg	6.66E+0	81.3%	18.7%	0	44.7%	55.3%	6.66E+0	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	Nitrogen	-	kg	5.00E+2	81.3%	18.7%	0	44.7%	55.3%	5.00E+2	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
	Sulfur	-	kg	1.73E+3	81.3%	18.7%	0	44.7%	55.3%	1.73E+3	1	1.56	(2,1,1,3,3, BU:1.5); Extrapolation for sum parameter
emission to soil	Oils, unspecified	-	kg	0	81.3%	18.7%	1.59E+6	44.7%	55.3%	1.59E+6	1	1.56	(2,1,1,3,3, BU:1.5); Average 2019 to 2021, IOGP 2022
emission to air, low population density	Sulfur dioxide	-	kg	7.16E+6	81.3%	18.7%	7.62E+7	44.7%	55.3%	8.34E+7	1	1.56	(2,1,1,3,3, BU:1.5); Average 2019 to 2021, IOGP 2022
	Nitrogen oxides	-	kg	5.09E+7	81.3%	18.7%	5.42E+8	44.7%	55.3%	5.93E+8	1	1.56	(2,1,1,3,3, BU:1.5); Average 2019 to 2021, IOGP 2022
	Methane, bromotrifluoro-, Halon 1301	-	kg	1.53E+3	81.3%	18.7%	0	44.7%	55.3%	1.53E+3	1	1.58	(3,3,1,3,3, BU:1.5); assuming 20% halon compared to Jungbluth 2007
	Methane, trifluoro-, HFC-23	-	kg	6.17E+3	81.3%	18.7%	0	44.7%	55.3%	6.17E+3	1	1.58	(3,3,1,3,3, BU:1.5); Assuming 80% replacement of halon 1301 with HFC-23 (amount according to Jungbluth 2007)

13 Data quality

The modules for crude oil and natural gas production are complete in terms of environmental impacts. However, the variation between different oil fields can be extremely high. A part of the data was just available for single oil fields, for regional averages or for globally operating companies. Thus, it is not possible to consider all types of data sources to establish good estimates on a country level.

To model the market situation, top-down data for the reference year 2021 are used (BP 2022). These data, in general, can be considered as reliable. However, also such data might receive updates. For example, a newer version of the datasheets shows about 40% higher natural gas production for Libya and Kazakhstan in the same reference year 2021 (BP 2022). For other countries considered in this study, the seen deviations are much lower (0 to 8%). The global gas production is reported to be 1% lower.

For other relevant inputs and outputs like energy consumption, flaring, fugitive methane release and oil spills, internationally consistent data sources are considered.

The demand for production chemicals is extrapolated based on studies in the North Sea. As enhanced oil recovery is getting more important every day, this value might increase in the future.

The quantities of production water and the proportion of water discharged into surface waters are also partly based on assumptions. The composition of the production waters is estimated based on several measurements and is subject to great fluctuations, which can hardly be estimated. For a potential next update, the focus might be limited to the four most important emissions (zinc, toluene, xylene and oil, unspecified).

For data expected to be of lower relevance according to former evaluations in Meili & Jungbluth 2018, with the ecological scarcity method 2013, generic data and data for regions, investigated in former reports were used as approximations (e.g. Jungbluth 2007; Stolz & Frischknecht 2017). This data includes e.g., LCI for infrastructure, content of trace elements in spilled oil, composition of chemicals used for EOR and disposal routes for several types of wastes.

In summary the data for single countries are a combination of different data sources and it is difficult to establish such inventories for single countries due to e.g., the following difficulties:

- Environmental impacts of oil and gas extraction depend to a substantial extent on local conditions at the single field (e.g., depth of the oil resource, oil per well, age of field, formation water, on- or offshore, etc.) and less on general technical issues such as energy efficiency or type of operation (onshore/offshore). Thus, they can be quite different per oil field or country.
- Environmental reports of single companies are often established for global operation and the system boundaries do not match the stages and regional boundaries investigated in this study. This makes it difficult to use this type of information for establishing a life cycle inventory.
- Summarizing information for flaring and venting was available from country specific estimates.
- Information by companies representing about one quarter of global oil production was available in regional figures for the energy use, emissions of oil and use of water.

The present data is an improvement compared to the former version because:

- Assumptions are harmonized, and cross checked between different countries. Thus, the former bias e.g., due to lack of information is avoided.
- Information for several single aspects was revised and checked again. Therefore, several new data sources were consulted.
- With the increased amount of information used for this study, possible uncertainties and variations of data are now known better.
- Data for additional countries relevant for the global supply situation were newly investigated.
- The background datasets for well production are revised and corrected.
- Estimates for the most important aspects like venting, flaring, energy use, emission of oil and use of water are each based on one consistent source of data.

The current model is a good compromise between consistency and accuracy of data. For the most relevant factors, country or region-specific values are used. For most other factors, generic estimates are considered sufficient.

14 Life cycle impact assessment and interpretation

No detailed impact assessment or impact related interpretation is commissioned for this project.

⁴⁷ The fundament of this database is ecoinvent v2.2. Updates and data published on www.lc-inventories.ch as well as further studies available on www.treeze.ch are incorporated in this database UVEK LCI Data 2018.

15 Outlook

With this study and the related background model, a harmonized way to model country-specific life cycle inventories for combined crude oil and natural gas production is available. For now, this model is built based on the UVEK database (UVEK 2018).

To cover the global production better it would be recommended to investigate the production in Australia.

So far, there is only a weak basis for distinguishing the LCI of onshore and offshore extraction. Therefore, it might be considered for future updates to simplify and reduce the LCI to summarize the two on- and offshore datasets to one overall production dataset per country and thus reduce the number of datasets considerably.

The methane emissions will be a hotspot for future updates. The International Methane Emissions Observatory (IMEO)⁴⁸ is a data-driven, action-focused initiative by the UN Environment Programme (UNEP) with support from the European Commission to catalyse dramatic reduction of methane emissions, starting with the energy sector. Data for methane emissions might in future be available also from this initiative.

A possible extension would be a distinction between conventional and unconventional oil and gas production. This could be helpful for political discussions related to future import policies, e.g., for LNG from countries with a high rate of shale gas extracted through fracking. But such data are not available with the information sources used in this study and thus would need a fully different approach of modelling. In the future the re-injection of CO₂ as a means of carbon capture storage (CCS) and a replacement of injected water might become more important and thus should be included in the analysis as soon as global or country specific data are available.

Considered market share and effective production amounts in combination with reported venting have a high impact on several LCIA-indicators. Depending e.g. on political and economical situation in the countries under study, both values might fluctuate a lot from year to year. Therefore, it might be considered for future updates to either do them in shorter intervals (e.g. each year) or using moving averages for e.g. the last 5 years.

As explained in chapter 9.6, due to lack of LCI data for the flame-retardant FK-5-1-12, the replaced Halon 1301 had to be modelled completely with direct emissions of HFC-23. Like this, the impacts on climate change due to the use of flame retardants might be overestimated. To fix this, the production of FK-5-1-12 should be modelled forecoinvent and global amounts for each flame retardant should be gathered.

The assessment of methane releases from oil and gas fields shows that abandoned or closed oil and gas fields still can lead to emissions of methane in the future. This is especially relevant in cases where the fields are badly maintained e.g., due to political reasons like war or lack of financial resources. These releases might even occur after the global society has managed to stop the use of fossil resources. So far, such future releases or technical measures to avoid them are not covered in the inventory and they would further increase the burden of the fossil resources extracted and used today.

The present update for natural gas is also quite relevant for LCI related to plastic products and other products made directly from oil and gas products. The data for plastics in the ecoinvent

⁴⁸ <https://www.unep.org/explore-topics/energy/what-we-do/imeo>

and UVEK database are not yet directly linked to these inventories. It would be recommended to establish new LCI data directly linked to the inventories presented in this report.

The stop of gas deliveries from Russia to Europe due to the war in Ukraine lead to unnecessary flaring of natural gas at the compressor stations. Such emissions should be addressed in the next update of these inventory data.

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