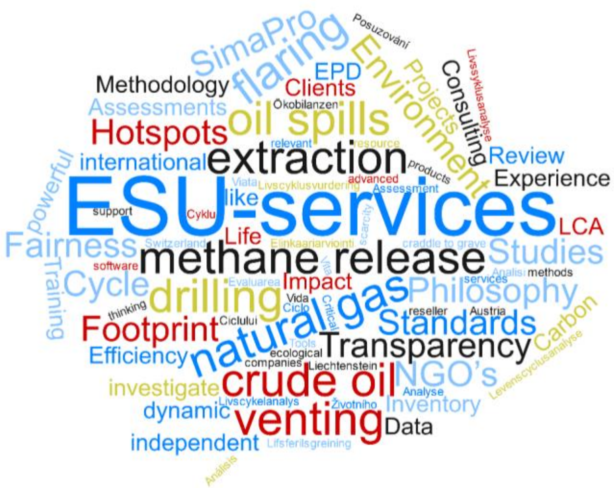
ESU-services
fair consulting in sustainability

2025

Life cycle inventories of crude oil and natural gas extraction



Federal Office for the Environment (FOEN)

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
https://www.esu-services.ch/

Commissioned by
Federal Office for the Environment (FOEN)

Schaffhausen, 16. October 2025

Imprint

Citation	Christoph Meili; Niels Jungbluth; Maresa Bussa (2025) Life cycle inventories of crude oil and natural gas extraction. ESU-services Ltd. commissioned by Federal Office for the Environment (FOEN), Schaffhausen, Switzerland, https://esu-services.ch/data/public-lci-reports/
Contractor	ESU-services Ltd., fair consulting in sustainability Vorstadt 10, CH-8200 Schaffhausen www.esu-services.ch Phone 0041 44 940 61 32 info@esu-services.ch
Financing	This report update was financed by Federal Office for the Environment (FOEN)
About us	ESU-services Ltd. has been founded in 1998. Its core objectives are consulting, coaching, training, and research in the fields of life cycle assessment (LCA), carbon footprints, water footprint in the sectors energy, civil engineering, basic minerals, chemicals, packaging, telecommunication, food and lifestyles. Fairness, independence, and transparency are substantial characteristics of our consulting philosophy. We work issue-related and accomplish our analyses without prejudice. We document our studies and work transparency and comprehensibly. We offer a fair and competent consultation, which makes it for the clients possible to control and continuously improve their environmental performance. The company worked and still works for various national and international companies, associations, and authorities. In some areas, team members of ESU-services performed pioneering work such as development and operation of web based LCA databases or quantifying environmental impacts of food and lifestyles.
Copyright	All content provided in this report is copyrighted, except when noted otherwise. Such information must not be copied or distributed, in whole or in part, without prior written consent of ESU-services Ltd. or the customer. This report is provided on the website https://www.esu-services.ch/ and/or the website of the customer. A provision of this report or of files and information from this report on other websites is not permitted. Any other means of distribution, even in altered forms, require the written consent. Any citation naming ESU-services Ltd. or the authors of this report shall be provided to the authors before publication for verification.
Liability Statement	This report was prepared under contract to Federal Office for the Environment (FOEN). The contractor bears sole responsibility for the content. Information contained herein have been compiled or arrived from sources believed to be reliable. Nevertheless, the authors or their organizations do not accept liability for any loss or damage arising from the use thereof. Using the given information is strictly your own responsibility.
Version	16.10.25 09:25 https://esuservices-my.sharepoint.com/personal/jungbluth_esu-services_ch/Documents/ESU-intern/565 Beratung BAFU/Bericht/meili-2025-FOEN-LCI of oil and gas extraction.docx

Contents

CONTENTS II

ABBREVIATIONS V

1 INTRODUCTION 1

2 GOAL AND SCOPE 1
2.1 Overview 1
2.2 Allocation for combined gas and oil production 4

3 METHODS FOR OIL AND NATURAL GAS EXTRACTION 8
3.1 Conventional crude oil production 8
3.2 Secondary and tertiary crude oil production 8
3.3 Natural gas production 9
3.3.1 Gas drying 10
3.3.2 Desulphurisation 10

4 PRODUCTION AND MARKET DATA 10
4.1 Proportion of offshore oil and natural gas production 11
4.2 Proportion of enhanced oil recovery (EOR) 15

5 CHARACTERISTICS AND PROPERTIES 15
5.1 Crude oil 15
5.1.1 Classification 15
5.1.2 Net calorific value and density 18
5.1.3 Hydrocarbons 18
5.1.4 Components other than hydrocarbons 19
5.1.5 Sulphur components 19
5.1.6 Oxygen compounds 19
5.1.7 Nitrogen compounds 19
5.1.8 Porphyrins 20
5.1.9 Further trace elements 20
5.1.10 Mercury 20
5.1.11 Summary of properties used in this study 20
5.2 Natural Gas 21
5.2.1 Net calorific value and density 21
5.2.2 Classification of fuel gases 21
5.2.3 Fuel data of raw natural gas 22

6 MATERIAL USE AND LAND OCCUPATION FOR INFRASTRUCTURE 25
6.1 Number and length of wells 25
6.2 Well drilling 29
6.3 Offshore platform 31
6.4 Onshore production plant 33
6.5 Gas treatment plants 34
6.6 Onsite pipelines 35

7 OPERATING MATERIALS 35
7.1 Chemicals 35
7.2 Water use 36

7.2.1 Amount 36
7.2.2 Allocation 37

8 ENERGY DEMAND 37
8.1 Data sources 37
8.2 Regional energy demand by type 38

9 EMISSIONS TO AIR 42
9.1 Flared natural gas 42
9.1.1 Definition 42
9.1.2 Allocation 43
9.1.3 Amount of flared gas 43
9.1.4 Composition and emissions 45
9.2 Vented and fugitive natural gas emissions 46
9.2.1 Definition 46
9.2.2 Allocation 46
9.2.3 Technical scope 47
9.2.4 Amount of emissions 47
9.2.5 Composition of emitted natural gas 49
9.2.6 Future emissions of abandoned oil and gas fields 49
9.3 Energy supply with diesel aggregates 49
9.3.1 Efficiency, energy, and material requirements 50
9.3.2 Direct emissions 50
9.4 Natural gas burned in gas turbine 51
9.5 SO_2 and NO_x 52
9.6 Use and emissions of Halon and other chemicals in firefighting equipment 53

10 EMISSIONS TO WATER & SOIL 55
10.1 Water balance and discharge of produced water 55
10.1.1 What is produced water? 55
10.1.2 Treatment and discharge 56
10.1.3 Amounts of discharged produced water 56
10.1.4 Allocation 57
10.1.5 Composition and pollutants 57
10.1.6 Method for LCI and LCIA of water flows 62
10.1.7 Water balance 63
10.1.8 Outlook 66
10.2 Production chemicals 66
10.3 Oil spilled and discharged 66
10.3.1 Emissions to water 66
10.3.2 Emissions to soil 67

11 WASTE 67
11.1 Deposition 67
11.2 Other wastes 68

12 SUMMARY OF LIFE CYCLE INVENTORY DATA 68

13 DATA QUALITY 75

14 LIFE CYCLE IMPACT ASSESSMENT AND INTERPRETATION 76

15 OUTLOOK 76

16 REFERENCES 78

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 life cycle inventory data as submitted to the commissioners. Changes made by the commissioners to implement the data in their own databases are not described in this report but may be described in a separate report. The content of this document therefore might not fully reflect the LCI data as provided by the commissioner to its customers and end users.

In the current project commissioned by the FOEN, also the reports for the transport of crude oil to refineries in different regions (Meili et al. 2025), the transport of natural gas to end users (Bussa et al. 2025) and production of plastics (Rajabihamedani et al. 2025) are updated in view of an integration in the UVEK database.

In general, only subchapters on process steps that are assessed as relevant in former LCIA results (Ecological Scarcity) 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.

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. 2025, Tab. 1.1 and Bussa et al. 2025, chapter 2.

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. 2025, Tab. 1.1 and Bussa et al. 2025, chapter 2, are described. Reference year for the update of these datasets is 2023.

Based on the analysis of existing datasets it is known, which LCI components have the highest influence e.g. for the life cycle impact assessment (LCIA) method “ecological scarcity”).

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. For such aspects, generic data are used to complete the LCI.

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 (EI 2024; IOGP 2024; World Bank 2024; IEA 2024).[1]
- 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.

[1] If no specific production data is listed for the reference year in EI 2024, data from other sources is used (see Tab. 2.1 for details).

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

Data are inventoried for 50 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. Meili et al. 2025, Tab. 1.1 and Bussa et al. 2025, 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. 2025) and “Life cycle inventories for long-distance transport of crude oil” (Meili et al. 2025).

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 2023 (EI, 2024; Enerdata 2024).[2,3,4,5,6]
Energy production is calculated based on energy contents mentioned in chapter 2.2. Crude oil production in mega-tons per year (Mt/a), natural gas production in billion cubic meters per year (bcm/a).

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	1.8E+2	5.6E+1	EI 2024
Argentina	AR	Latin America	RLA	5.1E+1	4.2E+1	EI 2024
Angola	AO	Africa	RAF	5.6E+1	5.3E+0	Oil: EI 2024, Gas: Assuming same production as in 2022, according to https://www.iea.org/countries/angola/natural-gas
Australia	AU	Asia and the Pacific	RAS	1.6E+1	1.5E+2	EI 2024
Azerbaijan	AZ	Former Soviet Union	FSU	3.0E+1	3.6E+1	EI 2024
Belgium	BE	Europe	RER	4.2E-2	1.4E-2	Enerdata 2024
Bolivia	BO	Latin America	RLA	1.2E+0	1.2E+1	Oil: https://www.statista.com/statistics/1171529/bolivia-crude-oil-production/, Gas: EI 2024
Brazil	BR	Latin America	RLA	1.8E+2	2.3E+1	EI 2024
Canada	CA	North America	RNA	2.8E+2	1.9E+2	EI 2024
China	CN	Asia and the Pacific	RAS	2.1E+2	2.3E+2	EI 2024
Colombia	CO	Latin America	RLA	4.1E+1	1.2E+1	EI 2024
Germany	DE	Europe	RER	2.8E+0	3.8E+0	Oil: Enerdata 2024, Gas: EI 2024
Algeria	DZ	Africa	RAF	6.0E+1	1.0E+2	EI 2024
Ecuador	EC	Latin America	RLA	2.5E+1	5.1E-1	Oil: EI 2024, Gas: Assuming same production as in 2022 according to https://www.eia.gov/international/content/analysis/countries_long/Ecuador/Ecuador.pdf --> 18 bcf =~ 0.5 bcm
Egypt	EG	Africa	RAF	3.0E+1	5.7E+1	EI 2024
Spain	ES	Europe	RER	6.7E-4	3.5E-2	Enerdata 2024
France	FR	Europe	RER	8.4E-1	1.8E-2	Enerdata 2024
United Kingdom	GB	Europe	RER	3.3E+1	3.4E+1	EI 2024
Equatorial Guinea	GQ	Africa	RAF	4.0E+0	7.7E+0	Oil: EI 2024, Gas: Assuming same production as in 2022, according to https://www.iea.org/countries/equatorial-guinea/natural-gas
Indonesia	ID	Asia and the Pacific	RAS	3.1E+1	6.4E+1	EI 2024
India	IN	Asia and the Pacific	RAS	3.3E+1	3.2E+1	EI 2024
Iraq	IQ	Middle East	RME	2.1E+2	9.9E+0	EI 2024
Iran	IR	Middle East	RME	2.1E+2	2.5E+2	EI 2024
Italy	IT	Europe	RER	4.3E+0	2.8E+0	EI 2024
Japan	JP	Asia and the Pacific	RAS	4.8E+0	4.7E+0	Enerdata 2024
South Korea	KR	Asia and the Pacific	RAS	1.7E+1	3.4E-1	Enerdata 2024
Kuwait	KW	Middle East	RME	1.4E+2	1.4E+1	EI 2024
Kazakhstan	KZ	Former Soviet Union	FSU	8.4E+1	3.1E+1	EI 2024
Libya	LY	Africa	RAF	6.0E+1	1.6E+1	EI 2024
Mexico	MX	North America	RNA	1.0E+2	3.6E+1	EI 2024
Malaysia	MY	Asia and the Pacific	RAS	2.6E+1	8.1E+1	EI 2024
Nigeria	NG	Africa	RAF	7.4E+1	4.4E+1	EI 2024
Netherlands	NL	Europe	RER	6.5E-1	9.9E+0	Oil: Enerdata 2024, Gas: EI 2024
Norway	NO	Europe	RER	9.5E+1	1.2E+2	EI 2024
Oman	OM	Middle East	RME	5.1E+1	4.3E+1	EI 2024
Peru	PE	Latin America	RLA	5.1E+0	1.5E+1	EI 2024
Poland	PL	Europe	RER	1.2E+0	3.6E+0	Oil: Enerdata 2024, Gas: EI 2024
Qatar	QA	Middle East	RME	7.4E+1	1.8E+2	EI 2024
Romania	RO	Europe	RER	3.0E+0	8.9E+0	EI 2024
Russian Federation	RU	Former Soviet Union	FSU	5.4E+2	5.9E+2	EI 2024
Saudi Arabia	SA	Middle East	RME	5.3E+2	1.1E+2	EI 2024
Thailand	TH	Asia and the Pacific	RAS	1.1E+1	2.6E+1	EI 2024
Turkmenistan	TM	Former Soviet Union	FSU	9.2E+0	7.6E+1	EI 2024
Turkey	TR	Middle East	RME	5.1E+0	8.1E-1	Enerdata 2024
Trinidad and Tobago	TT	Latin America	RLA	3.3E+0	2.5E+1	EI 2024
Taiwan	TW	Asia and the Pacific	RAS	7.0E-1	9.9E-2	Enerdata 2024
Ukraine	UA	Europe	RER	2.1E+0	1.8E+1	Oil: Assuming same production as in 2022 (as reported on https://www.iea.org/countries/ukraine/oil, 18.02.2025), Gas: EI 2024
United States	US	North America	RNA	8.3E+2	1.0E+3	EI 2024
Uzbekistan	UZ	Former Soviet Union	FSU	2.0E+0	4.4E+1	EI 2024
Venezuela	VE	Latin America	RLA	4.4E+1	3.0E+1	EI 2024
Global	**GLO**	**Global**	**GLO**	**4.5E+3**	**4.1E+3**	**EI 2024**

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 relevant to get full transparency on the model and might be used for a different way of import to a specific database of the commissioner. Thus, in total 450 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} U	LY	oil	production	a	2023	2025
Combined gas and oil production offshore {LY} U	LY	oil	production	a	2023	2025
Combined gas and oil production onshore {LY} U	LY	oil	production	a	2023	2025
Crude oil, at production offshore {LY} U	LY	oil	production	kg	2023	2025
Crude oil, at production onshore {LY} U	LY	oil	production	kg	2023	2025
Natural gas, at production offshore {LY} U	LY	natural gas	production	Nm^3	2023	2025
Natural gas, at production onshore {LY} U	LY	natural gas	production	Nm^3	2023	2025
Crude oil, at production {LY} U	LY	oil	production	kg	2023	2025
Natural gas, at production {LY} U	LY	natural gas	production	Nm^3	2023	2025

2.2 Allocation for combined gas and oil production

Crude oil and natural gas production are often linked, and data are provided for combined production[7]. 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/Nm^3 (or Sm^3 respectively) is applied. Further details regarding these values are presented in chapters 5.1.2 and 5.2.1.

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 the reference year (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 vented and fugitive emissions of natural gas specific allocation factors are applied (c.f. chapter 9.2).

[2] Angola, gas production: No data found for 2024-Assuming amount from 2022 according to https://www.iea.org/countries/angola/natural-gas.

[3] Bolivia, oil production: No data found for 2024-Assuming amount from 2023 according https://www.statista.com/statistics/1171529/bolivia-crude-oil-production/.

[4] Ecuador, gas production: No data found for 2024-Assuming amount from 2022 according to https://www.eia.gov/international/content/analysis/countries_long/Ecuador/pdf/ecuador.pdf.

[5] Equatorial-guinea, gas production: No data found for 2024-assuming amount from 2022 according to https://www.iea.org/countries/equatorial-guinea/natural-gas.

[6] Ukraine, oil production: No data found for 2024-Assuming amount from 2022 according to https://www.britannica.com/science/sedimentary-rock/Oil-and-natural-gas, online 19.10.2017

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 (EI, 2024). 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.

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 2024). 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

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

Tab. 2.3 Factors applied for allocation of resource and energy use and most direct emissions. The factors are derived from the calorific energy content according to EI, 2024 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	79.3%	20.7%	79.3%	20.7%
Argentina	59.8%	40.2%	59.8%	40.2%
Angola	92.7%	7.3%	92.7%	7.3%
Australia	11.1%	88.9%	11.1%	88.9%
Azerbaijan	50.6%	49.4%	50.6%	49.4%
Belgium	78.5%	21.5%	78.5%	21.5%
Bolivia	0.0%	0.0%	10.8%	89.2%
Brazil	90.4%	9.6%	90.4%	9.6%
Canada	63.8%	36.2%	63.8%	36.2%
China	51.8%	48.2%	51.8%	48.2%
Colombia	80.4%	19.6%	80.4%	19.6%
Germany	47.4%	52.6%	47.4%	52.6%
Algeria	0.0%	0.0%	41.8%	58.2%
Ecuador	67.0%	33.0%	99.5%	0.5%
Egypt	38.6%	61.4%	38.6%	61.4%
Spain	2.3%	97.7%	2.3%	97.7%
France	98.3%	1.7%	98.3%	1.7%
United Kingdom	53.9%	46.1%	53.9%	46.1%
Equatorial Guinea	38.6%	61.4%	0.0%	0.0%
Indonesia	36.9%	63.1%	36.9%	63.1%
India	55.4%	44.6%	55.4%	44.6%
Iraq	0.0%	0.0%	96.3%	3.7%
Iran	50.7%	49.3%	50.7%	49.3%
Italy	64.6%	35.4%	64.6%	35.4%
Japan	55.0%	45.0%	55.0%	45.0%
South Korea	98.3%	1.7%	98.3%	1.7%
Kuwait	92.6%	7.4%	92.6%	7.4%
Kazakhstan	76.7%	23.3%	76.7%	23.3%
Libya	81.5%	18.5%	81.5%	18.5%
Mexico	77.6%	22.4%	77.6%	22.4%
Malaysia	27.5%	72.5%	27.5%	72.5%
Nigeria	67.1%	32.9%	67.1%	32.9%
Netherlands	7.4%	92.6%	7.4%	92.6%
Norway	49.5%	50.5%	0.0%	0.0%
Oman	0.0%	0.0%	58.6%	41.4%
Peru	28.7%	71.3%	28.7%	71.3%
Poland	27.9%	72.1%	27.9%	72.1%
Qatar	33.1%	66.9%	33.1%	66.9%
Romania	28.8%	71.2%	28.8%	71.2%
Russian Federation	52.7%	47.3%	52.7%	47.3%
Saudi Arabia	84.9%	15.1%	84.9%	15.1%
Thailand	34.5%	65.5%	34.5%	65.5%
Turkmenistan	12.7%	87.3%	12.7%	87.3%
Turkey	88.4%	11.6%	88.4%	11.6%
Trinidad and Tobago	13.8%	86.2%	13.8%	86.2%
Taiwan	89.5%	10.5%	89.5%	10.5%
Ukraine	12.6%	87.4%	12.6%	87.4%
United States	82.1%	17.9%	45.9%	54.1%
Uzbekistan	0.0%	0.0%	5.1%	94.9%
Venezuela	64.0%	36.0%	64.0%	36.0%
Global	57.2%	42.8%	57.2%	42.8%

Tab. 2.4 Energy production from oil and gas, per country, for the reference year 2023, in Mega Joule and kg oil equivalent per year (with conventional energy content of 41.868 MJ/kgOE, according to EI, 2024). Related production in megatons and billion cubic meters per years is shown in Tab. 2.1 (EI, 2024).[8,9] 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	9.6E+12	79.3%	20.7%	2.3E+11	EI 2024	3.9%	1.4%
Argentina	3.7E+12	59.8%	40.2%	8.9E+10	EI 2024	1.1%	1.0%
Angola	2.6E+12	92.7%	7.3%	6.2E+10	Oil: EI 2024, Gas: Assuming same production as in 2022, according to https://www.iea.org/countries/angola/natural-gas	1.2%	0.1%
Australia	6.1E+12	11.1%	88.9%	1.5E+11	EI 2024	0.3%	3.7%
Azerbaijan	2.6E+12	50.6%	49.4%	6.2E+10	EI 2024	0.7%	0.9%
Belgium	2.3E+9	78.5%	21.5%	5.5E+7	Enerdata 2024	0.0%	0.0%
Bolivia	4.8E+11	10.8%	89.2%	1.2E+10	Oil: https://www.statista.com/statistics/1171529/bolivia-	0.0%	0.3%
Brazil	8.8E+12	90.4%	9.6%	2.1E+11	EI 2024	4.1%	0.6%
Canada	1.9E+13	63.8%	36.2%	4.5E+11	EI 2024	6.2%	4.7%
China	1.8E+13	51.8%	48.2%	4.2E+11	EI 2024	4.6%	5.8%
Colombia	2.2E+12	80.4%	19.6%	5.3E+10	EI 2024	0.9%	0.3%
Germany	2.6E+11	47.4%	52.6%	6.2E+9	Oil: Enerdata 2024, Gas: EI 2024	0.1%	0.1%
Algeria	6.3E+12	41.8%	58.2%	1.5E+11	EI 2024	1.3%	2.5%
Ecuador	1.1E+12	98.4%	1.6%	2.7E+10	Oil: EI 2024, Gas: Assuming same production as in 2022 according to https://www.eia.gov/international/content/analysis/countries_long/Ecuador/Ecuador.pdf --> 18 bcf =~ 0.5 bcm	0.6%	0.0%
Egypt	3.3E+12	38.6%	61.4%	8.0E+10	EI 2024	0.7%	1.4%
Spain	1.3E+9	2.3%	97.7%	3.0E+7	Enerdata 2024	0.0%	0.0%
France	3.7E+10	98.3%	1.7%	8.9E+8	Enerdata 2024	0.0%	0.0%
United Kingdom	2.7E+12	53.9%	46.1%	6.4E+10	EI 2024	0.7%	0.8%
Equatorial Guinea	4.5E+11	38.6%	61.4%	1.1E+10	Oil: EI 2024, Gas: Assuming same production as in 2022, according to https://www.iea.org/countries/equatorial-guinea/natural-gas	0.1%	0.2%
Indonesia	3.7E+12	36.9%	63.1%	8.8E+10	EI 2024	0.7%	1.6%
India	2.5E+12	55.4%	44.6%	6.1E+10	EI 2024	0.7%	0.8%
Iraq	9.6E+12	96.3%	3.7%	2.3E+11	EI 2024	4.7%	0.2%
Iran	1.8E+13	50.7%	49.3%	4.4E+11	EI 2024	4.8%	6.2%
Italy	2.9E+11	64.6%	35.4%	6.9E+9	EI 2024	0.1%	0.1%
Japan	3.8E+11	55.0%	45.0%	9.0E+9	Enerdata 2024	0.1%	0.1%
South Korea	7.4E+11	98.3%	1.7%	1.8E+10	Enerdata 2024	0.4%	0.0%
Kuwait	6.6E+12	92.6%	7.4%	1.6E+11	EI 2024	3.1%	0.3%
Kazakhstan	4.8E+12	76.7%	23.3%	1.1E+11	EI 2024	1.9%	0.8%
Libya	3.2E+12	81.5%	18.5%	7.6E+10	EI 2024	1.3%	0.4%
Mexico	5.7E+12	77.6%	22.4%	1.4E+11	EI 2024	2.3%	0.9%
Malaysia	4.0E+12	27.5%	72.5%	9.6E+10	EI 2024	0.6%	2.0%
Nigeria	4.8E+12	67.1%	32.9%	1.1E+11	EI 2024	1.6%	1.1%
Netherlands	3.8E+11	7.4%	92.6%	9.1E+9	Oil: Enerdata 2024, Gas: EI 2024	0.0%	0.2%
Norway	8.3E+12	49.5%	50.5%	2.0E+11	EI 2024	2.1%	2.9%
Oman	3.7E+12	58.6%	41.4%	9.0E+10	EI 2024	1.1%	1.1%
Peru	7.8E+11	28.7%	71.3%	1.9E+10	EI 2024	0.1%	0.4%
Poland	1.8E+11	27.9%	72.1%	4.3E+9	Oil: Enerdata 2024, Gas: EI 2024	0.0%	0.1%
Qatar	9.7E+12	33.1%	66.9%	2.3E+11	EI 2024	1.6%	4.5%
Romania	4.5E+11	28.8%	71.2%	1.1E+10	EI 2024	0.1%	0.2%
Russian Federation	4.5E+13	52.7%	47.3%	1.1E+12	EI 2024	12.0%	14.4%
Saudi Arabia	2.7E+13	84.9%	15.1%	6.5E+11	EI 2024	11.8%	2.8%
Thailand	1.4E+12	34.5%	65.5%	3.4E+10	EI 2024	0.2%	0.6%
Turkmenistan	3.1E+12	12.7%	87.3%	7.5E+10	EI 2024	0.2%	1.9%
Turkey	2.5E+11	88.4%	11.6%	6.0E+9	Enerdata 2024	0.1%	0.0%
Trinidad and Tobago	1.0E+12	13.8%	86.2%	2.5E+10	EI 2024	0.1%	0.6%
Taiwan	3.4E+10	89.5%	10.5%	8.1E+8	Enerdata 2024	0.0%	0.0%
Ukraine	7.3E+11	12.6%	87.4%	1.7E+10	Oil: Assuming same production as in 2022 (as reported on https://www.iea.org/countries/ukraine/oil, 18.02.2025), Gas: EI 2024	0.0%	0.4%
United States	7.3E+13	49.1%	50.9%	1.7E+12	EI 2024	18.3%	25.5%
Uzbekistan	1.7E+12	5.1%	94.9%	4.0E+10	EI 2024	0.0%	1.1%
Venezuela	3.0E+12	64.0%	36.0%	7.1E+10	EI 2024	1.0%	0.7%
Global	**3.4E+14**	**57.2%**	**42.8%**	**8.2E+12**	**EI 2024**	**100.0%**	**100.0%**

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 m^3 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 (H_2S) 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. % H_2S-content is sour, sweet gas has a lower H_2S 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 H_2S is directed to a sulphur production plant (Claus plant). In the Claus plant the H_2S is transformed to SO_2 with partial combustion and in the following catalytic reaction of H_2S/SO_2 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.

Various flue gases are burned in a production flare, often with the addition of natural gas or vapour. Hereby the SO_2 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” (Meili et al. 2025 and Bussa et al. 2025).

For this study, LCI datasets for crude oil and natural gas production in the 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, they were historically relevant for former projects (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, Switzerland or other countries and regions is not analysed for this study.

It must be emphasized that the above-mentioned market model does not represent the real supply situation in Switzerland or any other country. It is a simplification assuming only one average European / regional refinery. The real supply situation is more complex. In 2016, e.g., in Switzerland, 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 and other regions to better reflect the real situation for supplies to different countries or regions. 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 50 countries cover about 98% of global crude oil and natural gas production in 2023 (EI 2024).

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. [10]

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.[10] On the other side countries like Russia and Iraq[11] 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 based on different literatures sources (cf. Tab. 4.1). The share of on- and offshore production was last revised for all analysed regions in the year 2023.

[10] U.S. EIA 2016, https://www.eia.gov/todayinenergy/detail.php?id=28492, online: 10.10.17
[11] https://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. 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
Angola	30%	70%	30%	70%	No data found - assuming global average
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	4%	96%	4%	96%	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	60%	40%	60%	40%	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. 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
Equatorial Guinea	100%	0%	100%	0%	Assuming 100% offshore as no methane emissions are reported by IEA for onshore production.
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
South 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	90%	10%	90%	10%	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. 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	35%	65%	35%	65%	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-gas
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	30%	70%	30%	70%	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).[12] 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.

[12] 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 (EI 2024)

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)
Angola	0.05	54.57	Other Asia countries according to EC 2020 (reference year 2014)
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)
Equatorial Guinea	0.05	54.57	Other Asia countries according to EC 2020 (reference year 2014)
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	**1.36**	**32.65**	**Weighted average based on overall production (EI 2024, reference year 2023)**

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 ((EI 2024)). 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/m^3. 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 (EI 2024).

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:
  CH_4 – C_5H_{12}, methane, ethane, propane etc. (gaseous),
  C_6H_{14}- $C_{21}H_{44}$, hexane, heptane, octane etc. (liquid)
  >= $C_{22}H_{46}$, pentacosane, triacontane etc. (solid).
  Cyclic saturated (alicyclic) HC (naphthene, cyclo-paraffines, and cyclo-alkanes).

- **Unsaturated HC (alkenes or olefins or alkines).**
  Chemical formula: C_nH_{2n}, or C_nH_n
  Examples:
  C_2H_4 (IUPAC: ethene),
  C_3H_6 (IUPAC: propene),
  C_2H_2 (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:

C_6H_6 (benzene),
C_7H_9 (toluene),
C_8H_{12} (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 poly-cyclic 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 derivates 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. 2018).

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

Porphyrins 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 porphyrins (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 porphyrins. They can also occur as non-porphyrin, metallic chelates (Speight 1990). Porphyrins are concentrated in the asphalt fraction. Therefore, deasphalted crude oils do have smaller concentrations of porphyrins 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 (EI 2024).

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 (EI 2024)

	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/Nm^3 (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/Nm^3).

However, in global statistics used for the current study, for all countries, a generic gross calorific value (GCV) of 40MJ/Nm^3, respectively the net calorific value of 36.0 MJ/Nm^3 is used (EI 2024). Therefore, this value and the related density of 0.735kg/Nm^3 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 widely used LCA software use the unit Nm^3 to represent gas, the name of this unit is kept but values represent in fact the conditions for Sm^3. 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/Nm^3.

5.2.2 Classification of fuel gases

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.

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. Globally, natural gas is responsible for 23% of the primary energy consumption in 2023 (EI 2024).

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_2H_6	C_3H_8	C_4H_{10}	Other C_XH_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	
Biomethane[1)]			>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/Nm^3, hydrogen sulphide content needs to be below 5 mg/Nm^3. 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 (CS_2) other organic sulphites, disulphides, mercaptaines 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_2H_6	up to 8	2.80	0.30	0.60	4.80	0.10
Propane C_3H_8	up to 3	0.40			1.70	0.01
Butane C_4H_{10}		0.14	<0.01		0.70	0.02
Higher C/H	up to 4	0.14			0.70	0.00
H_2S	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/Nm^3 <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 (µg/Nm^3)
Algeria	58-193
The Netherlands (North Sea)	180
Germany	Up to 11'000*)
Russia (Dnjepr-Donetzk)	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 µg/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 µg/Nm^3, the mercury concentration dropped down to 20 µg/Nm^3. In the German pipeline system, the concentration is further reduced to 2 to 3 µg/Nm^3. Only when natural gas from German production is fed into the pipeline the concentration remains as high as 19 µg/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 µg/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/l[13] 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 µg/Nm^3 and a radon-222 concentration of 10 pCi/l or roughly 0.4 kBq/Nm^3. The calorific values and CO_2 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.

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_2S		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

13 1 Ci = 3.7*10^{-7} KBq

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.

		Raw gas DE	Raw gas RU	Raw gas NO	Raw gas NL	Raw gas NAC	Raw gas NG
	Unit	Nm^3	Nm^3	Nm^3	Nm^3	Nm^3	Nm^3
Sour gas	%	50	20	5	0	0	0
CH_4 Methane	kg	0.555	0.588	0.6045	0.61	0.61	0.61
CO_2 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
H_2S 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
N_2 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 (2b1stconsulting[14]) 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).

[14] 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 (EIA[15]) and 2400 m in Iraq (FAS[16]).

For offshore production typically, well lifetime lies between 5 to 10 years and for onshore production it lies between 15 to 30 years.[17]

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.[18] Additionally, country-specific data for 2021 was found for Canada.[19] To allocate these drilling lengths to on- and offshore production, data on wells drilled on- and offshore in 2019 is used.[20] This data is extrapolated to the refence year 2021 by using the forecast from 2020.[21] Well length drilled per year and region are then divided by the amount of oil equivalents extracted in the related year (EI 2024). 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

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

16 FAS: https://fas.org/sgp/crs/mideast/RS21626.pdf, online 19.10.17

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

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

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

20 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.

21 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.[18,20,21]

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.18[,19,]20[,]21

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	9.42E-7	4.62E-6	Regional estimate for 2023
Argentina	2.65E-7	8.10E-6	Regional estimate for 2023
Angola	1.62E-6	3.04E-6	Regional estimate for 2023
Australia	2.38E-7	5.82E-6	Country-specific estimate for 2023
Azerbaijan	1.68E-6	3.42E-5	Regional estimate for 2023
Belgium	1.64E-6	2.36E-6	Regional estimate for 2023
Bolivia	2.65E-7	8.10E-6	Regional estimate for 2023
Brazil	2.65E-7	8.10E-6	Regional estimate for 2023
Canada	3.42E-7	3.22E-5	Regional estimate for 2023 in combination with country-specific length of oil and gas wells in 2021, according to statista.com
China	1.68E-6	3.42E-5	Regional estimate for 2023
Colombia	2.65E-7	8.10E-6	Regional estimate for 2023
Germany	1.64E-6	2.36E-6	Regional estimate for 2023
Algeria	1.62E-6	3.04E-6	Regional estimate for 2023
Ecuador	2.65E-7	8.10E-6	Regional estimate for 2023
Egypt	1.62E-6	3.04E-6	Regional estimate for 2023
Spain	1.64E-6	2.36E-6	Regional estimate for 2023
France	1.64E-6	2.36E-6	Regional estimate for 2023
United Kingdom	1.64E-6	2.36E-6	Regional estimate for 2023
Equatorial Guinea	1.62E-6	3.04E-6	Regional estimate for 2023
Indonesia	1.68E-6	3.42E-5	Regional estimate for 2023
India	1.68E-6	3.42E-5	Regional estimate for 2023
Iraq	9.42E-7	4.62E-6	Regional estimate for 2023
Iran	9.42E-7	4.62E-6	Regional estimate for 2023
Italy	1.64E-6	2.36E-6	Regional estimate for 2023
Japan	1.68E-6	3.42E-5	Regional estimate for 2023
South Korea	1.68E-6	3.42E-5	Regional estimate for 2023
Kuwait	9.42E-7	4.62E-6	Regional estimate for 2023
Kazakhstan	1.68E-6	3.42E-5	Regional estimate for 2023
Libya	1.62E-6	3.04E-6	Regional estimate for 2023
Mexico	5.42E-7	5.10E-5	Regional estimate for 2023
Malaysia	1.68E-6	3.42E-5	Regional estimate for 2023
Nigeria	1.62E-6	3.04E-6	Regional estimate for 2023
Netherlands	1.64E-6	2.36E-6	Regional estimate for 2023
Norway	1.64E-6	2.36E-6	Regional estimate for 2023
Oman	9.42E-7	4.62E-6	Regional estimate for 2023
Peru	2.65E-7	8.10E-6	Regional estimate for 2023
Poland	1.64E-6	2.36E-6	Regional estimate for 2023
Qatar	9.42E-7	4.62E-6	Regional estimate for 2023
Romania	1.64E-6	2.36E-6	Regional estimate for 2023
Russian Federation	7.40E-8	2.54E-5	Country-specific estimate for 2023
Saudi Arabia	9.42E-7	4.62E-6	Regional estimate for 2023
Thailand	1.68E-6	3.42E-5	Regional estimate for 2023
Turkmenistan	1.68E-6	3.42E-5	Regional estimate for 2023
Turkey	9.42E-7	4.62E-6	Regional estimate for 2023
Trinidad and Tobago	2.65E-7	8.10E-6	Regional estimate for 2023
Taiwan	1.68E-6	3.42E-5	Regional estimate for 2023
Ukraine	1.64E-6	2.36E-6	Regional estimate for 2023
United States	6.35E-7	5.99E-5	Calculation based on region specific estimates for 2023 and country-specific estimate for Canada.
Uzbekistan	1.68E-6	3.42E-5	Regional estimate for 2023
Venezuela	2.65E-7	8.10E-6	Regional estimate for 2023
Global	**9.78E-7**	**2.28E-5**	**Regional estimate for 2023**

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 original 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 2000m. 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 and water use for well drilling is covered in the general data on energy and water consumption and is therefore not recorded here.

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

	Name	Location	Infrastructure	Unit	well for exploration and production, onshore	UncertaintyTy	StandardDeviation95%	GeneralComment
	Location				GLO			
	InfrastructureProcess				1			
	Unit				m			
product	well for exploration and production, onshore	GLO	1	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	0	1	1.51	(2,3,5,3,1,BU:1.05); ; Excluded here, as it is considered in oil and natural gas production data.
technosphere	lignite, at mine	RER	0	kg	2.00E-1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	barite, at plant	RER	0	kg	2.70E+2	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	bentonite, at processing	DE	0	kg	2.00E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	chemicals inorganic, at plant	GLO	0	kg	4.22E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	chemicals organic, at plant	GLO	0	kg	9.05E+0	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	lubricating oil, at plant	RER	0	kg	6.00E+1	1	1.51	(2,3,5,1,1,BU:1.05); ; Literature
	reinforcing steel, at plant	RER	0	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	0	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	0	tkm	8.11E+1	1	2.99	(4,5,5,5,5,BU:2); ; Standard distance 100km
	transport, freight, rail	RER	0	tkm	4.87E+2	1	2.99	(4,5,5,5,5,BU:2); ; Standard distance 600km
	crude oil, used in drilling tests	GLO	0	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	0	MJ	0	1	1.64	(3,5,5,3,3,BU:1.05); ; Excluded here, as it is considered in oil and natural gas production data.
	natural gas, vented	GLO	0	Nm3	0	1	1.58	(4,4,5,3,1,BU:1.05); ; Excluded here, as it is considered in oil and natural gas production data.
	disposal, drilling waste, 71.5% water, to landfarming	CH	0	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	0	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	0	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	-	-	kg	4.78E-7	1	1.79	(3,3,5,1,1,BU:1.5); ; Environmental report
	Arsen, Ion	-	-	kg	4.20E-4	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond
	Barium (II)	-	-	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 (II)	-	-	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 (III)	-	-	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 (II)	-	-	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 (II)	-	-	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
	Kalium, Ion	-	-	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 (I)	-	-	kg	6.00E+0	1	5.35	(3,4,5,5,3,BU:5); ; Literature, effluent sludge pond, basic uncertainty estimated with 3
	Strontium (II)	-	-	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 (II)	-	-	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	StandardDeviation95%	GeneralComment
	Location				OCE			
	InfrastructureProcess				1			
	Unit				m			
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	0	1	3.07	(3,5,3,1,na,BU:1.05); Excluded here, as it is considered in oil and natural gas production data.
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 here, as it is considered in oil and natural gas production data.
	natural gas, vented	GLO	0	Nm3	0	1	3.11	(4,5,3,1,na,BU:1.05); Excluded here, as it is considered in oil and natural gas 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 here, as it is considered in oil and natural gas 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	-	-	kg	4.78E-7	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Arsen, Ion	-	-	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, Ion	-	-	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 (III)	-	-	kg	1.72E-3	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Copper, ion	-	-	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 (II)	-	-	kg	1.32E-2	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Mercury (II)	-	-	kg	2.79E-4	1	7.10	(3,5,1,1,na,BU:5); Environmental report
	Nickel (II)	-	-	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
	Kalium, Ion	-	-	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 (II)	-	-	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). Electricity mix is adjusted to global mix (instead of ENTSO or UCTE in former versions).

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

	Name	Location	InfrastructureProcess	Unit	platform, crude oil, offshore	UncertaintyType	StandardDeviation95%	GeneralComment
	Location				OCE			
	InfrastructureProcess				1			
	Unit				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 unspecified	-	-	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 GLO, at grid	GLO	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 uncertainity 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 uncertainity 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 uncertainity 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 uncertainity 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 uncertainity 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 construction waste 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 population density	Heat, waste	-	-	MJ	3.30E+7	1	1.83	(5,5,5,3,1,BU:1.05); Calculation
emission water, ocean	Aluminium	-	-	kg	1.16E+5	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Iron (II)	-	-	kg	1.47E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Silicon	-	-	kg	1.84E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Copper, ion	-	-	kg	7.34E+0	1	3.50	(5,5,5,1,1,BU:3); Estimation 85% utilisation of anode
	Zinc (II)	-	-	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 (based on Schori et al. 2012).

	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	plant offshore, natural gas, production	UncertaintyType	StandardDeviation95%	GeneralComment
	Location						OCE			
	InfrastructureProcess						1			
	Unit						unit			
Product	plant offshore, natural gas, production	OCE	-	-	1	unit	1.00E+0			
Resources, land	Transformation, from seabed, unspecified	-	resource	land	-	m2	1.60E+3	1	2.25	(2,4,5,1,1,BU:2); Greenpeace report, one platform
	Transformation, to sea and ocean	-	resource	land	-	m2	1.60E+3	1	2.25	(2,4,5,1,1,BU:2); Greenpeace report, one platform
	Transformation, from industrial area, benthos	-	resource	land	-	m2	1.60E+3	1	2.25	(2,4,5,1,1,BU:2); Greenpeace report, one platform
	Transformation, to industrial area, benthos	-	resource	land	-	m2	1.60E+3	1	2.25	(2,4,5,1,1,BU:2); Greenpeace report, one platform
	Occupation, industrial area, benthos	-	resource	land	-	m2a	1.76E+4	1	1.79	(2,4,5,1,1,BU:1.5); Greenpeace report, one platform
Technosphere	diesel, burned in building machine, average	CH	-	-	0	MJ	1.16E+8	1	1.54	(3,4,5,1,1,BU:1.05); calculated based on data from 1980
	tap water, unspecified natural origin RER, at user	RER	-	-	0	kg	2.83E+6	1	1.54	(3,4,5,1,1,BU:1.05); calculated based on data from 1981
	electricity, medium voltage, production GLO, at grid	GLO	-	-	0	kWh	2.12E+7	1	1.54	(3,4,5,1,1,BU:1.05); calculated based on data from 1982
	steel, low-alloyed, at plant	RER	-	-	0	kg	1.31E+7	1	1.58	(2,4,5,1,3,BU:1.05); Greenpeace report, one platform, standard module
	epoxy resin, liquid, at plant	RER	-	-	0	kg	7.30E+4	1	1.81	(3,4,5,2,4,BU:1.05); Data for wind turbines
	polyvinylchloride, at regional storage	RER	-	-	0	kg	3.00E+4	1	1.58	(2,4,5,1,3,BU:1.05); Greenpeace report, one platform, standard module
	aluminium, production mix, at plant	RER	-	-	0	kg	2.53E+5	1	1.58	(2,4,5,1,3,BU:1.05); Greenpeace report, one platform, standard module
	cast iron, at plant	RER	-	-	0	kg	3.03E+2	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainity estimated = 10
	MG-silicon, at plant	NO	-	-	0	kg	3.79E+2	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainity estimated = 11
	copper, at regional storage	RER	-	-	0	kg	1.52E+1	1	10.80	(5,5,5,1,1,BU:10); Estimation for aluminium anode, basic uncertainity estimated = 12
	zinc, primary, at regional storage	RER	-	-	0	kg	7.82E+3	1	1.58	(2,4,5,1,3,BU:1.05); Greenpeace report, one platform, standard module
	concrete, normal, at plant	CH	-	-	0	m3	4.09E+3	1	1.53	(2,4,5,1,1,BU:1.05); Greenpeace report, one platform, standard module
	transport, freight, lorry 16-32 metric ton, fleet average	RER	-	-	0	tkm	1.80E+6	1	2.32	(4,5,5,na,na,BU:2); standard distance
	transport, freight, rail	RER	-	-	0	tkm	2.70E+6	1	2.32	(4,5,5,na,na,BU:2); standard distance 600km
	transport, transoceanic freight ship	OCE	-	-	0	tkm	2.81E+6	1	2.32	(4,5,5,na,na,BU:2); standard distance
	Heat, waste	-	air	low. pop.	-	MJ	7.62E+7	1	1.53	(2,4,5,1,1,BU:1.05); Greenpeace report, one platform, standard module
emission water, ocean	Aluminium	-	water	ocean	-	kg	2.15E+5	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Iron (II)	-	water	ocean	-	kg	2.58E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Silicon	-	water	ocean	-	kg	3.22E+2	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Copper, ion	-	water	ocean	-	kg	1.29E+1	1	3.50	(5,5,5,1,1,BU:3); Estimation 85% utilisation of anode
	Zinc (II)	-	water	ocean	-	kg	6.65E+3	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode
	Titanium	-	water	ocean	-	kg	5.37E+1	1	5.57	(5,5,5,1,1,BU:5); Estimation 85% utilisation of anode

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 m^2/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). Electricity mix is adjusted to global mix (instead of ENTSO or UCTE in former versions). 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.[22] 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	Category	SubCategory	InfrastructureProcess	Unit	production plant crude oil, onshore	UncertaintyType	StandardDeviation95%	GeneralComment
	Location						GLO			
	InfrastructureProcess						1			
	Unit						unit			
product	production plant crude oil, onshore	GLO	-	-	1	unit	1.00E+0			
resource, land	Occupation, industrial area	-	resource	land	-	m2a	2.00E+6	1	1.53	(3,4,1,3,1,BU:1.5); Life time 20a
	Transformation, from forest, unspecified	-	resource	land	-	m2	1.00E+5	1	2.26	(3,4,5,3,1,BU:2); Literature
	Transformation, to mineral extraction site	-	resource	land	-	m2	1.00E+5	1	2.26	(3,4,5,3,1,BU:2); Literature
resource, in water	Water, unspecified natural origin, GLO	-	resource	in water	-	m3	8.28E+1	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report
technosphere	electricity, medium voltage, production GLO, at grid	GLO	-	-	0	kWh	3.67E+6	1	1.84	(5,4,5,3,3,BU:1.05); Literature
	diesel, burned in building machine, average	CH	-	-	0	MJ	6.75E+5	1	1.51	(2,3,5,3,1,BU:1.05); Environmental report
	reinforcing steel, at plant	RER	-	-	0	kg	7.20E+5	1	1.54	(3,4,5,3,1,BU:1.05); Literature
	transport, freight, lorry 16-32 metric ton, fleet average	RER	-	-	0	tkm	3.60E+5	1	2.38	(4,5,5,5,3,BU:2); Estimation 500km
	transport, freight, rail	RER	-	-	0	tkm	1.44E+5	1	2.38	(4,5,5,5,3,BU:2); Standard distance 600km
	disposal, municipal solid waste, 22.9% water, to municipal incineration	CH	-	-	0	kg	7.20E+2	1	1.51	(1,3,5,3,1,BU:1.05); Environmental report
emission air, low population density	Heat, waste	-	air	high. pop.	-	MJ	1.32E+7	1	1.83	(5,5,5,3,1,BU:1.05); 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			GLO			
	InfrastructureProcess			1			
	Unit			unit			
product	plant onshore, natural gas, production	GLO	unit	1.00E+0			
resource, land	Transformation, from forest, unspecified	-	m2	7.50E+3	1	2.30	(3,4,5,3,3,BU:2); Area according to Schori 2012
	Transformation, to mineral extraction site	-	m2	7.50E+3	1	2.30	(3,4,5,3,3,BU:2); Area according to Schori 2012
	Occupation, industrial area	-	m2a	1.50E+5	1	1.85	(3,4,5,3,3,BU:1.5); Adjusted life time 20a according to Oklahoma Watch 2018
technosphere	diesel, burned in building machine, average	CH	MJ	1.50E+6	1	1.64	(4,4,5,3,3,BU:1.05); Schori 2012
	electricity, medium voltage, production GLO, at	GLO	kWh	8.25E+5	1	1.64	(4,4,5,3,3,BU:1.05); Schori 2012
	reinforcing steel, at plant	RER	kg	1.50E+6	1	1.64	(4,4,5,3,3,BU:1.05); Schori 2012
	transport, freight, lorry 16-32 metric ton, fleet	RER	tkm	1.50E+5	1	2.99	(4,5,5,5,5,BU:2); Estimation 500km
	transport, freight, rail	RER	tkm	3.00E+5	1	2.99	(4,5,5,5,5,BU:2); Standard distance 600km
emission air, low population density	Heat, waste	-	MJ	2.97E+6	1	1.60	(3,4,5,3,3,BU:1.05); Schori 2012

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.

[22] Oklahoma Watch: https://nondoc.com/2017/07/12/horizontal-wells-first-three-years/, online 03.01.2018

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						GLO			
	InfrastructureProcess						1			
	Unit						unit			
Resources, land	Transformation, from pasture and meadow	-	resou	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, to pasture and meadow	-	resou	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, from industrial area	-	resou	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Transformation, to industrial area	-	resou	land	0	m2	2.86E+06	1	2.06	(2,3,1,3,1,5); personal communication, Statoil
	Occupation, industrial area	-	resou	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 popula		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. 2025 and Bussa et al. 2025.

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 2024). 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 2024, Tab. A.34).

fresh water use intensity	Average 2021 to 2023	Source
Region	m3/kg OE	
Africa	7.26E-5	IOGP 2024
Asia	8.42E-5	IOGP 2024
Europe	3.52E-5	IOGP 2024
Middle East	3.32E-5	IOGP 2024
North America	2.09E-4	IOGP 2024
Russia & Central Asia	1.00E-4	IOGP 2024
South & Central America	6.33E-5	IOGP 2024
Global	**8.88E-5**	**IOGP 2024**

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 2024).

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 CO_2 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 2024). 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 2024,Tab. A8 & A.9)

Total fossil energy consumption	Average 2021 to 2023	Source
Region	MJ/kg OE	
Africa	1.61E+0	IOGP 2024
Asia/Australia	1.85E+0	IOGP 2024
Europe	1.19E+0	IOGP 2024
Middle East	8.86E-1	IOGP 2024
North America	1.81E+0	IOGP 2024
Russia & Central Asia	1.42E+0	IOGP 2024
South & Central America	1.31E+0	IOGP 2024
Global	**1.48E+0**	**IOGP 2024**

Electricity demand is assumed to be represented by the share of energy which is purchased from elsewhere (IOGP 2024, 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).

Tab. 8.2 Electricity demand, per kg oil equivalent (IOGP 2024, Tab. A.8 and A.9)

Electricity at grid	Average 2021 to 2023	Source
Region	kWh/kg OE	
Africa	5.61E-3	Purchased energy according to IOGP 2024.
Asia/Australia	4.49E-2	Purchased energy according to IOGP 2024.
Europe	3.00E-2	Purchased energy according to IOGP 2024.
Middle East	3.35E-2	Purchased energy according to IOGP 2024.
North America	4.87E-2	Purchased energy according to IOGP 2024.
Russia & Central Asia	1.68E-2	Purchased energy according to IOGP 2024.
South & Central America	4.22E-3	Purchased energy according to IOGP 2024.
Global	**2.79E-2**	**Purchased energy according to IOGP 2024.**

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 2024). This value is multiplied by the generic estimate for fuels (diesel), as shown in Tab. 8.3.[23]

[23] The generic share for diesel is calculated by dividing the average MtOE for"fuels" by the sum of MtOE „energy resourcesresources" + „fuels".

Tab. 8.4 Energy demand of diesel, burned in equipment, per kg oil equivalent (IOGP 2024, Tab. A.8 and A.9, multiplied with generic factor).

Diesel, burned in equipment	Average 2021 to 2023	Source
Region	MJ/kg OE	
Africa	1.87E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
Asia/Australia	1.98E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
Europe	1.27E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
Middle East	8.99E-2	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
North America	1.92E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
Russia & Central Asia	1.60E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
South & Central America	1.52E-1	Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified.
Global	**1.70E-1**	**Calculation based on data from IOGP 2024, 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 2024). This value is multiplied by the generic estimate for oil, as shown in Tab. 8.3.[24]

Tab. 8.5 Energy demand of heavy fuel oil, burned in equipment, per kg oil equivalent (IOGP 2024, Tab. A.8 and A.9, multiplied with generic factor).

Heavy fuel oil, burned in equipment	Average 2021 to 2023	Source
Region	MJ/kg OE	
Africa	3.50E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
Asia/Australia	3.70E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
Europe	2.37E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
Middle East	1.68E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
North America	3.59E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
Russia & Central Asia	2.99E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
South & Central America	2.84E-2	Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified.
Global	**3.18E-2**	**weighted average of regions with reported values**

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

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 plus unspecified (IOGP 2024). This value is multiplied by the generic estimate for gas, as shown in Tab. 8.3.[25]

Tab. 8.6 Energy demand of natural gas, burned in gas turbines, per kg oil equivalent (IOGP 2024, Tab. A.8 and A.9, multiplied with generic factor).

Gas, burned in gas turbine, production	Average 2021 to 2023	Source
Region	MJ/kg OE	
Africa	1.37E+0	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
Asia/Australia	1.45E+0	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
Europe	9.28E-1	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
Middle East	6.59E-1	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
North America	1.41E+0	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
Russia & Central Asia	1.17E+0	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
South & Central America	1.11E+0	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified.
Global	**1.24E+0**	**weighted average of regions with reported values**

For the current study, SO_2 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 2024; IEA 2008).

[25] 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 2024, 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%	0.78	0.59	Calculation based on data from IOGP 2024, 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%	0.83	0.62	Calculation based on data from IOGP 2024, 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%	0.53	0.40	Calculation based on data from IOGP 2024, 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%	0.26	0.40	Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified. for total amount burned, multiplied by share IEA 2008
North America	57%	43%	0.80	0.60	Calculation based on data from IOGP 2024, 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%	0.77	0.40	Calculation based on data from IOGP 2024, 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%	0.64	0.48	Calculation based on data from IOGP 2024, 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%**	**0.71**	**0.54**	**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 reasons[26]:

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

[26] https://www.earthworks.org/issues/flaring_and_venting 05.05.2021

- **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 2024; IOGP 2024). 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 Defence[27]. These measured flaring data is provided publicly for the reference year (World Bank 2024). Another study provides regional flaring intensities for the same year based on preselected company data. The global average intensity derived from these company data is on average about 50% 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.

[27] Flare gas volume: https://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 2024; IOGP 2024).

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	2023	2023	2023	
Unit	$Nm^3/kgOE$	$Nm^3/kgOE$	$Nm^3/kgOE$	
United Arab Emirates	3.94E-3	1.05E-2	3.94E-3	Worldbank 2024
Argentina	1.23E-2	7.53E-3	1.23E-2	Worldbank 2024
Angola	2.95E-2	2.89E-2	2.95E-2	Worldbank 2024
Australia	4.52E-3	1.82E-2	4.52E-3	Worldbank 2024
Azerbaijan	5.62E-3	5.21E-3	5.62E-3	Worldbank 2024
Belgium	n.a.	3.03E-3	3.03E-3	no data available, assuming regional average according to IOGP 2024
Bolivia	3.53E-3	7.53E-3	3.53E-3	Worldbank 2024
Brazil	5.76E-3	7.53E-3	5.76E-3	Worldbank 2024
Canada	2.45E-3	6.04E-3	2.45E-3	Worldbank 2024
China	5.72E-3	1.82E-2	5.72E-3	Worldbank 2024
Colombia	6.07E-3	7.53E-3	6.07E-3	Worldbank 2024
Germany	0	3.03E-3	-	Worldbank 2024
Algeria	5.46E-2	2.89E-2	5.46E-2	Worldbank 2024
Ecuador	5.89E-2	7.53E-3	5.89E-2	Worldbank 2024
Egypt	2.34E-2	2.89E-2	2.34E-2	Worldbank 2024
Spain	0	3.03E-3	-	Worldbank 2024
France	0	3.03E-3	0	Worldbank 2024
United Kingdom	1.04E-2	3.03E-3	1.04E-2	Worldbank 2024
Equatorial Guinea	1.92E-2	2.89E-2	1.92E-2	Worldbank 2024
Indonesia	2.17E-2	1.82E-2	2.17E-2	Worldbank 2024
India	2.50E-2	1.82E-2	2.50E-2	Worldbank 2024
Iraq	7.71E-2	1.05E-2	7.71E-2	Worldbank 2024
Iran	4.66E-2	1.05E-2	4.66E-2	Worldbank 2024
Italy	0	3.03E-3	-	Worldbank 2024
Japan	0	1.82E-2	0	Worldbank 2024
South Korea	0	1.82E-2	-	Worldbank 2024
Kuwait	4.21E-3	1.05E-2	4.21E-3	Worldbank 2024
Kazakhstan	8.90E-3	5.21E-3	8.90E-3	Worldbank 2024
Libya	8.96E-2	2.89E-2	8.96E-2	Worldbank 2024
Mexico	4.01E-2	6.04E-3	4.01E-2	Worldbank 2024
Malaysia	1.55E-2	1.82E-2	1.55E-2	Worldbank 2024
Nigeria	5.07E-2	2.89E-2	5.07E-2	Worldbank 2024
Netherlands	6.59E-4	3.03E-3	6.59E-4	Worldbank 2024
Norway	6.35E-4	3.03E-3	6.35E-4	Worldbank 2024
Oman	2.11E-2	1.05E-2	2.11E-2	Worldbank 2024
Peru	3.63E-3	7.53E-3	3.63E-3	Worldbank 2024
Poland	5.16E-3	3.03E-3	5.16E-3	Worldbank 2024
Qatar	4.96E-3	1.05E-2	4.96E-3	Worldbank 2024
Romania	2.76E-3	3.03E-3	2.76E-3	Worldbank 2024
Russian Federation	2.67E-2	5.21E-3	2.67E-2	Worldbank 2024
Saudi Arabia	3.83E-3	1.05E-2	3.83E-3	Worldbank 2024
Thailand	6.24E-3	1.82E-2	6.24E-3	Worldbank 2024
Turkmenistan	1.57E-2	5.21E-3	1.57E-2	Worldbank 2024
Turkey	7.39E-3	1.05E-2	7.39E-3	Worldbank 2024
Trinidad and Tobago	5.79E-3	7.53E-3	5.79E-3	Worldbank 2024
Taiwan	n.a.	1.82E-2	1.82E-2	no data available, assuming regional average according to IOGP 2024
Ukraine	6.65E-3	3.03E-3	6.65E-3	Worldbank 2024
United States	5.51E-3	6.04E-3	5.51E-3	Worldbank 2024
Uzbekistan	9.87E-3	5.21E-3	9.87E-3	Worldbank 2024
Venezuela	1.17E-1	7.53E-3	1.17E-1	Worldbank 2024
Global	**1.81E-2**	**1.19E-2**	**1.81E-2**	**Worldbank 2024**

9.1.4 Composition and emissions

Flaring losses 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.

Flaring releases greenhouse gases like CO_2, CH_4, NO_x and other gases like SO_2 into the atmosphere. Furthermore, unburned hydrocarbons, black carbon, particles, benzene etc. are of concern. In this study, region specific emission data for the overall production of crude oil and natural gas are considered for CH_4, NO_x and SO_2(c.f. chapters 9.2 and 9.5). Therefore, for the composition of flared gas, only the remaining gases are estimated in a separate LCI for sweet gas burned in production flare, per Nm^3 as presented in Tab. 9.2.

A literature review has been conducted in 2024. It considers the following sources:

- Jacob T. Shaw, Amy Foulds, Shona Wilde, Patrick Barker, Freya A. Squires, James Lee, Ruth Purvis, Ralph Burton, Ioana Colfescu, Stephen Mobbs, Samuel Cliff, Stéphane J.-B. Bauguitte, Stuart Young, Stefan Schwietzke, and Grant Allen (2023). Flaring efficiencies and NOx emission ratios measured for offshore oil and gas facilities in the North Sea. European Geosciences Union – Atmospheric Chemistry and Physics, Volume 23, issue 2, ACP, 23, 1491–1509, 2023 https://doi.org/10.5194/acp-23-1491-2023
- Kristin Böttcher, Ville-Veikko Paunu, Kaarle Kupiainen, Mikhail Zhizhin, Alexey Matveev, Mikko Savolahti, Zbigniew Klimont, Sampsa Väätäinen, Heikki Lamberg, Niko Karvosenoja (2021). Black carbon emissions from flaring in Russia in the period 2012–2017. Atmospheric Environment, Volume 254, 2021, 118390, https://doi.org/10.1016/j.atmosenv.2021.118390
- Tran, H., Polka, E., Buonocore, J. J., Roy, A., Trask, B., Hull, H., & Arunachalam, S. (2024). Air quality and health impacts of onshore oil and gas flaring and venting activities estimated using refined satellitebased emissions. GeoHealth, 8. https://doi.org/10.1029/2023GH000938

Measurements of emissions at the flare are rarely available. Several publications observe more the ambient air quality and do not relate back to the amount of flared gas. Furthermore large variations can be observed which makes it difficult to estimate average values.

Tab. 9.2 LCI data for natural gas, sweet, burned in production flare per Nm³.

	Name	Unit	natural gas, sweet, burned in production flare	UncertaintyType	StandardDeviation95%	GeneralComment
	Location		GLO			
	InfrastructureProcess		0			
	Unit		Nm3			
resource, in ground	Gas, natural/m3	Nm3	1.00E+0	1	1.05	(1,1,1,1,1,BU:1.05);
emission air, low population density	Methane, fossil	kg	0	1	2.74	(5,5,5,5,5,BU:1.5); Excluded. Country-specific overall-emissions need to be assessed separately
	Carbon dioxide, fossil	kg	2.45E+0	1	1.24	(2,2,3,3,3,BU:1.05); Faist 2007, in ecoinvent v3.6, Allocation, cut-off (2019)
	Carbon monoxide, fossil	kg	2.74E-3	1	5.07	(2,2,3,3,3,BU:5); Standard emission factor (EFDB 2011)
	NMVOC, non-methane volatile organic compounds	kg	1.52E-04	1	1.62	(2,2,4,3,3,BU:1.5); Emissions of biogas flares
	Benzene	kg	3.05E-07	1	3.10	(2,2,4,3,3,BU:3); Update 2024, rough estimate with AI-generated answer 0.1-0.3% of NMVOC (https://www.perplexity.ai/search/bitte-erstelle-eine-ubersicht-DYx9ONO.S3mkZHYRREk05Q)
	Ammonia	kg	1.06E-8	1	1.38	(2,2,4,3,3,BU:1.2); Tran, H., Polka, E., Buonocore, J. J., Roy, A., Trask, B., Hull, H., & Arunachalam, S. (2024). Air quality and health impacts of onshore oil and gas flaring and venting activities estimated using refined satellitebased emissions. GeoHealth, 8, e2023GH000938. https://doi.org/10.1029/2023GH000938
	Nitrogen oxides	kg	0	1	2.74	(5,5,5,5,5,BU:1.5); Excluded. Country-specific overall-emissions need to be assessed separately
	Dinitrogen monoxide	kg	2.00E-5	1	1.62	(2,2,4,3,3,BU:1.5); Standard emission factor (EFDB 2011)
	Particulates, < 2.5 um	kg	5.40E-4	1	3.28	(2,2,5,3,3,BU:3); Estimation for refinery flare from (Jungbluth 2003)
	Particulates, > 10 um	kg	2.35E-3	1	1.62	(2,2,4,3,3,BU:1.5); Update 2024, average literature data for carbon black
	Sulfur dioxide	kg	0	1	2.52	(5,5,5,5,5,BU:1.05); Excluded. Country-specific overall-emissions need to be assessed separately
	Mercury (II)	kg	2.00E-7	1	5.11	(2,2,4,3,3,BU:5); Estimation, average value (Schori 2012)
	Radon-222	kBq	4.00E-1	1	3.10	(2,2,4,3,3,BU:3); Estimation, average value (Schori 2012)
	Heat, waste	MJ	3.60E+1	1	1.05	(1,2,1,1,1,BU:1.05); Lower heating value according to BP 2020

9.2 Vented and fugitive natural gas emissions

9.2.1 Definition

Venting is the word used to describe the release of unburned natural gas to the atmosphere during the production and processing of crude oil and natural gas.

Venting is defined by the industry as intended release of natural gas in the technical process chain. Venting occurs at several points in the oil and gas development process (well completion; well maintenance; pipeline maintenance; tank maintenance; etc.). However, unintended natural gas emissions may also occur due to incomplete flaring and fugitive emissions e.g., due to leakages or forced changes in geological structures during fracking)[28;29]. For this study intended and unintended releases of methane from all known sources are considered.

9.2.2 Allocation

Data for vented and fugitive methane emissions are available specifically for on- and offshore oil and gas extraction in most countries under study (IEA 2024).

[28] https://www.nrdc.org/sites/default/files/fracking-air-pollution-IB.pdf, online 27.09.2018

[29] https://earthworks.org/issues/flaring_and_venting/, online 27.09.2018

However, for some countries, when setting these emission values in relation to the estimated share of off- and onshore production (c.f. chapter 4.1), unrealistically high or low intensities per kg oil or m^3 gas are calculated. To avoid such inconsistencies, values for on- and offshore emissions are added for oil and gas respectively and then set in relation to production data as described in chapter 2.1 (Tab. 2.1).

9.2.3 Technical scope

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 (EI 2024).

9.2.4 Amount of emissions

Country-specific, robust and consistent data for upstream methane emissions for off- and onshore crude oil and natural gas production are available for the reference year (IEA 2024). 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 (c.f. Tab. 9.3).

These newly derived figures for methane emissions are used to estimate the total upstream natural gas emissions. To do so, the numbers are divided by a volumetric share of 0.585 kg methane per Nm^3 of natural gas according to the composition presented in chapter 9.2.5.

For this calculation, the net calorific values and densities are used consistently with extraction data provided in EI 2024 (c.f. chapter 5.1.2 and 5.2.1).

Tab. 9.3 Country specific upstream methane emissions and emission factors for natural gas from crude oil and natural gas production according to IEA 2024 related to production data from EI 2024 (reference year 2023)

Origin	Methane emissions, upstream, oil	Methane emissions, upstream, gas	Natural gas emissions, upstream, oil	Natural gas emissions, upstream, gas
Source	IEA 2024	IEA 2024	IEA 2024, upstream (2023); Production: EI 2024 (2023)	IEA 2024, upstream (2023); Production: EI 2024 (2023)
Unit	kt/a	kt/a	$Nm^3/kgOil$	Nm^3/Nm^3gas
United Arab Emirates	1.34E+3	1.95E+2	1.30E-2	5.99E-3
Argentina	6.69E+2	3.47E+2	2.23E-2	1.43E-2
Angola	7.80E+2	2.04E+1	2.39E-2	6.62E-3
Australia	6.79E+1	3.11E+2	7.41E-3	3.50E-3
Azerbaijan	2.23E+2	1.03E+2	1.26E-2	4.96E-3
Belgium	n.a	n.a.	n.a	n.a.
Bolivia	2.78E+1	7.66E+1	3.95E-2	1.10E-2
Brazil	1.44E+3	1.21E+2	1.34E-2	8.82E-3
Canada	1.36E+3	8.37E+2	8.39E-3	7.52E-3
China	1.51E+3	8.71E+2	1.23E-2	6.36E-3
Colombia	2.86E+2	4.21E+1	1.20E-2	5.97E-3
Germany	8.37E+0	1.29E+1	5.03E-3	5.81E-3
Algeria	1.96E+3	6.87E+2	5.55E-2	1.16E-2
Ecuador	2.98E+2	1.71E+0	2.00E-2	5.73E-3
Egypt	4.26E+2	2.49E+2	2.44E-2	7.45E-3
Spain	n.a	n.a.	n.a	n.a.
France	3.34E+0	1.00E-1	6.78E-3	9.68E-3
United Kingdom	8.67E+1	2.90E+1	4.43E-3	1.44E-3
Equatorial Guinea	4.69E+1	4.33E+1	1.99E-2	9.61E-3
Indonesia	5.05E+2	3.92E+2	2.77E-2	1.04E-2
India	5.69E+2	2.50E+2	2.99E-2	1.35E-2
Iraq	2.25E+3	2.67E+1	1.80E-2	4.60E-3
Iran	4.39E+3	1.19E+3	3.50E-2	8.10E-3
Italy	1.33E+1	2.97E+0	5.28E-3	1.78E-3
Japan	1.63E+0	1.49E+1	5.86E-4	5.42E-3
South Korea	0	0	0	0
Kuwait	9.16E+2	7.45E+1	1.12E-2	9.41E-3
Kazakhstan	1.56E+3	2.32E+2	3.16E-2	1.29E-2
Libya	1.62E+3	5.60E+1	4.65E-2	5.87E-3
Mexico	9.36E+2	1.35E+2	1.56E-2	6.46E-3
Malaysia	3.09E+2	3.30E+2	2.07E-2	6.95E-3
Nigeria	1.53E+3	2.49E+2	3.54E-2	9.76E-3
Netherlands	1.20E-1	1.06E+0	3.16E-4	1.84E-4
Norway	7.32E+0	5.99E+0	1.32E-4	8.78E-5
Oman	4.77E+2	1.52E+2	1.61E-2	6.00E-3
Peru	4.09E+1	8.02E+1	1.36E-2	8.89E-3
Poland	6.12E+0	1.64E+1	9.06E-3	7.79E-3
Qatar	4.20E+2	5.06E+2	9.69E-3	4.78E-3
Romania	6.56E+1	9.72E+1	3.76E-2	1.87E-2
Russian Federation	6.91E+3	3.28E+3	2.18E-2	9.55E-3
Saudi Arabia	2.14E+3	1.91E+2	6.87E-3	2.85E-3
Thailand	1.72E+2	1.32E+2	2.63E-2	8.79E-3
Turkmenistan	1.87E+3	3.15E+3	3.47E-1	7.06E-2
Turkey	n.a	n.a.	n.a	n.a.
Trinidad and Tobago	3.38E+1	9.22E+1	1.74E-2	6.31E-3
Taiwan	n.a	n.a.	n.a	n.a.
Ukraine	0	1.45E+2	0	1.40E-2
United States	6.69E+3	4.79E+3	1.38E-2	7.90E-3
Uzbekistan	1.42E+2	5.53E+2	1.24E-1	2.14E-2
Venezuela	2.68E+3	2.05E+2	1.05E-1	1.18E-2
Global	**4.98E+4**	**2.02E+4**	**1.89E-2**	**8.49E-3**

For countries where no country-specific data is mentioned in IEA 2024 (marked with "n.a." in Tab. 9.3), the global average methane emission values for oil and gas are considered.

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 emitted 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 SO_2-emissions are assessed separately according to chapter 9.5. The respective emissions are presented in Tab. 9.4.

Tab. 9.4 Unit process raw data for the direct release of natural gas (Jungbluth 2007)

	Name	Location	InfrastructureProcess	Unit	natural gas, vented	UncertaintyType	StandardDeviation95%	GeneralComment
	Location				GLO			
	Unit				Nm3			
resource, in ground	Gas, natural/m3	-	-	Nm3	1.00E+0	1	1.53	(3,3,5,3,1,na); Calculation
emission air, low population density	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). However, e.g. emission values based on IEA 2020 data are also higher than what is reported to UNFCCC.[30] Therefore, it is assumed, that in this study, current emissions from abandoned oil and gas fields are appropriately represented with data from IEA 2024.

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

[30] https://unfccc.int/ghg-inventories-annex-i-parties/2020, online 07.12.2020

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. 9.6.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. 9.5 Life cycle inventory data for a 10MW diesel-electric generating set

	Name	Location	Unit	diesel-electric generating set production 10MW	UncertaintyType	StandardDeviation95%	GeneralComment
	Location			RER			
	InfrastructureProcess			1			
	Unit			unit			
product	diesel-electric generating set production 10MW	RER	unit	1.00E+0			
technosphere	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. 9.6 and mainly explained in a former study (Jungbluth 2007). To avoid double counting, emissions of CH_4, SO_2 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. 9.6 Life cycle inventory for diesel, burned in diesel-electric generating set, without CH_4, SO_2 and NO_x-emissions

	Name	Location	InfrastructureProce	Unit	*Diesel, burned in diesel-electric generating set, at extraction site*	UncertaintyType	StandardDeviation 95%	GeneralComment
	Location				*GLO*			
	InfrastructureProcess				*0*			
	Unit				*MJ*			
product	Diesel, burned in diesel-electric	GLO	0	MJ	1.00E+0			
technosphere	diesel, at regional storage	RER	0	kg	2.34E-2	1	1.82	(3,3,5,3,1,BU:1.05); Calculation
	lubricating oil, at plant	RER	0	kg	6.70E-5	1	2.29	(3,5,5,3,5,BU:1.05); Rough estimation with data for cogen 200kWe
	diesel-electric generating set production 10MW	RER	1	unit	1.85E-10	1	3.33	(3,5,5,3,3,BU:3); Estimation
Disposal	disposal, used mineral oil, 10% water, to hazardous waste incineration	CH	0	kg	6.70E-5	1	2.29	(3,5,5,3,5,BU:1.05); Rough estimation
emission air, low population density	Benzene	-	-	kg	2.00E-8	1	3.24	(3,3,5,3,1,BU:3); Extrapolation
	Benzo(a)pyrene	-	-	kg	1.00E-10	1	3.24	(3,3,5,3,1,BU:3); Extrapolation
	Carbon dioxide, fossil	-	-	kg	7.30E-2	1	1.51	(2,3,5,3,1,BU:1.05); Literature
	Carbon monoxide, fossil	-	-	kg	6.80E-4	1	5.28	(3,3,5,3,1,BU:5); Literature
	Dinitrogen monoxide	-	-	kg	6.00E-6	1	1.79	(3,3,5,3,1,BU:1.5); Literature
	Mercury (II)	-	-	kg	4.67E-10	1	5.33	(3,3,5,3,3,BU:5); Literature on content in diesel
	Methane, fossil	-	-	kg	0	1	1.78	(2,3,5,3,1,BU:1.5); Set 0 as assessed in overall emissions for extraction
	Nitrogen oxides	-	-	kg	0	1	1.78	(2,3,5,3,1,BU:1.5); Set 0 as assessed in overall emissions for extraction
	NMVOC, non-methane volatile organic compounds	-	-	kg	9.24E-5	1	1.78	(2,3,5,3,1,BU:1.5); Environmental report
	Particulates, < 2.5 um	-	-	kg	1.70E-4	1	3.24	(3,3,5,3,1,BU:3); Literature
	Sulfur dioxide	-	-	kg	0	1	1.51	(2,3,5,3,1,BU:1.05); Set 0 as assessed in overall emissions for extraction
	Cadmium (II)	-	-	kg	2.34E-10	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions
	Copper, ion	-	-	kg	3.97E-8	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions
	Chromium, ion	-	-	kg	1.17E-9	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions
	Chrom-VI	-	-	kg	2.34E-12	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions, 0.2% share of Cr is Cr VI
	Nickel (II)	-	-	kg	1.64E-9	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions
	Selenium	-	-	kg	2.34E-10	1	5.32	(2,3,5,1,3,BU:5); Literature for automobile emissions
	Zinc (II)	-	-	kg	2.34E-8	1	5.32	(2,3,5,1,3,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. 9.7. Emissions of methane, SO_2 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. 9.7 Unit process raw data for burning of sour natural gas in gas turbine

	Name	Location	InfrastructureProce	Unit	sweet gas, burned in gas turbine, production	UncertaintyType	StandardDeviation 95%	GeneralComment
	Location				GLO			
	InfrastructureProcess				0			
	Unit				MJ			
product	sweet gas, burned in gas turbine, production	GLO	0	MJ	1.00E+0			
Input from nature	Gas, natural/m3	-	-	Nm3	2.78E-2	1	1.92	(3,3,5,3,3,BU:1.05); environmental report for Norway
technosphere	gas turbine, 10MWe, at production plant	RER	1	unit	3.37E-10	1	3.29	(3,3,5,3,3,BU:3); environmental report for Norway
emission air, low population density	Methane, fossil	-	-	kg	0	1	1.84	(3,3,5,3,3,BU:1.5); Set 0 as assessed in overall emissions for extraction
	Carbon dioxide, fossil	-	-	kg	6.69E-2		1.58	(3,3,5,3,3,BU:1.05); environmental report for Norway
	Carbon monoxide, fossil	-	-	kg	1.39E-4	1	5.33	(3,3,5,3,3,BU:5); environmental report for Norway
	NMVOC, non-methane volatile organic compounds, unspecified origin	-	-	kg	3.07E-6	1	1.84	(3,3,5,3,3,BU:1.5); environmental report for Norway
	Nitrogen oxides	-	-	kg	0	1	1.84	(3,3,5,3,3,BU:1.5); Set 0 as assessed in overall emissions for extraction
	Dinitrogen monoxide	-	-	kg	2.50E-7	1	1.84	(3,3,5,3,3,BU:1.5); Assumption Faist-Emmenegger 2007
	Sulfur dioxide	-	-	kg	0	1	1.58	(3,3,5,3,3,BU:1.05); Set 0 as assessed in overall emissions for extraction
	Mercury	-	-	kg	2.78E-9	1	5.33	(3,3,5,3,3,BU:5); Assumption Faist-Emmenegger 2007
	Radon-222	-	-	kBq	5.56E-3	1	3.29	(3,3,5,3,3,BU:3); Assumption Faist-Emmenegger 2007

9.5 SO_2 and NO_x

Sulphur oxide (SO_2) emissions arise through oxidation during combustion of sulphur naturally contained within fuel gas or flared gas (H S content) and within diesel and other liquid fuels (sulphur content). Emissions of nitrogen oxides, (principally nitric oxide and nitrogen dioxide, expressed as NO_x), occur almost exclusively from the combustion of natural gas or other fuels. These emissions are heavily influenced by energy use and are also a function of the combustion equipment, loading and technology.

Regional emission data reported to the international organization of oil and gas producing companies are listed in Tab. 9.8 and Tab. 9.9 (IOGP 2024). These data are directly considered in the inventories for oil and gas extraction. The emissions are not accounted for in the combustion processes applied within these inventories (c.f. chapters9.1.4, 9.3.2 and 9.4).

Tab. 9.8 Sulphur dioxide (SO_2) emissions in kg per kg oil equivalent (IOGP 2024, Tab. A.4)

Sulphur dioxide released	Average 2021 to 2023	Source
Region	kg/kg OE	
Africa	6.00E-5	IOGP 2024
Asia	3.00E-5	IOGP 2024
Europe	2.67E-5	IOGP 2024
Middle East	8.60E-4	IOGP 2024
North America	3.00E-5	IOGP 2024
Russia & Central Asia	2.30E-4	IOGP 2024
South & Central America	3.67E-5	IOGP 2024
Global	**1.22E-4**	**weighted average of regions with reported values**

Tab. 9.9 Nitrogen oxide (NO_x) emissions in kg per kg oil equivalent (IOGP 2024, Tab. A.4)

NOx released	Average 2021 to 2023	Source
Region	kg/kg OE	
Africa	4.50E-4	IOGP 2024
Asia	4.17E-4	IOGP 2024
Europe	2.57E-4	IOGP 2024
Middle East	2.10E-4	IOGP 2024
North America	3.27E-4	IOGP 2024
Russia & Central Asia	1.67E-4	IOGP 2024
South & Central America	4.43E-4	IOGP 2024
Global	**3.47E-4**	**weighted average of regions with reported values**

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.[31] 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.[32]

- Halon is only required to support legacy facilities; all new facilities are halon - free.

[31] https://ozone.unep.org/treaties/montreal-protocol/annex-group-ii-halons-halon-1211-halon-1301-and-halon-2402, online 01.07.2025

[32] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010R0744&from=EN, online 01.11.2017

- 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.
- 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 $mg_{halon}/t_{crude\ oil}$ is emitted, for the remaining areas 58 $mg_{halon}/t_{crude\ oil}$. 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 no specific dataset is available in the database of the commissioner 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 1[33]. 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 database of the commissioner, 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. [34]

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.[35]

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

---

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

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

35 https://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.[36]

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 2024).

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 water[35] (Agip Division 2001; ANL 2009; Tiedeman et al. 2012; UKOOA 2001; IOGP 2024).

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	[36]
US	5.0	2014	[39]
US	4.0	2018	[37]
Global	3.0	2007	[40]
Global	3.5	2013	[36], 70% onshore

[36] https://www.researchgate.net/publication/330971905_Geothermal_Potential_of_the_Global_Oil_Industry, 16.3.2023

[37] https://blog.veolianorthamerica.com/produced-water-joins-the-circular-economy, 16.3.2023

[38] https://ifsolutions.com/what-is-produced-water-injection-disposal-methods-in-oil-and-gas/, 16.3.2023

[39] https://btuanalytics.com/shale-production/produced-water-volumes-climb-driven-by-unconventional-oil/, 16.3.2023

[40] 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 (IOGP 2024, 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)[35]. These were the basis in some previous studies. 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 2024, derived from Tab. A.18 and A.19)

Produced water, discharged, Average 2021 to 2023	Offshore	Onshore	Source
Region	kg/kg OE	kg/kg OE	
Africa	0.79	0.27	IOGP 2024
Asia	1.78	3.83	IOGP 2024
Europe	0.68	0.37	IOGP 2024
Middle East	0.51	0.17	IOGP 2024
North America	0.38	0.00	IOGP 2024
Russia & Central Asia	0.00	0.00	IOGP 2024
South & Central America	0.35	0.04	IOGP 2024
Global	**0.73**	**0.35**	**IOGP 2024**

For regions where a 0-value is reported, it is assumed that emissions are missing due to the small sample size. Therefore, global average is assumed for countries in such regions.

10.1.4 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.

10.1.5 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 society[35] 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
    - 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	InfrastructureProcess	Unit	discharge, produced water, offshore	*Waly et al. 2023*	*Neff 2011, average*	*Neff 2011, average*	*Neff 2011, average*	*Jungbluth 2007*
Location				OCE	*US*	*MX*	*IN*	*OCE*	*OCE*
InfrastructureProcess				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

Tab. 10.4 Life cycle inventory for the chemical composition of discharged produced water in off-shore production. Data for offshore emissions are recorded with category water, ocean.

Name	Unit	discharge, produced water, offshore	UncertaintyType	StandardDeviation95%	GeneralComment
Location		OCE			
InfrastructureProcess		0			
Unit		kg			
Acenaphthene	kg	2.36E-9	1	3.06	(2,3,3,3,3,BU:3); Literature, specific PAH
Acenaphthylene	kg	1.17E-9	1	3.06	(2,2,3,3,3,BU:3); Literature, specific PAH
Aluminium	kg	1.00E-8	1	5.06	(2,2,1,3,3,BU:5); Literature
Ammonium, ion	kg	8.55E-5	1	1.58	(2,2,3,3,3,BU:1.5); Literature
Antimony	kg	1.00E-8	1	5.06	(2,2,1,3,3,BU:5); Literature
Arsenic	kg	2.19E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Barium	kg	8.64E-5	1	5.07	(2,2,3,3,3,BU:5); Literature
Benzene	kg	3.72E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Benzene, ethyl-	kg	1.34E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Boron	kg	8.00E-6	1	5.07	(2,2,3,3,3,BU:5); Literature
Bromine	kg	3.50E-5	1	5.33	(3,3,5,3,3,BU:5); Literature
BOD5 (Biological Oxygen Demand)	kg	3.52E-4	1	1.63	(4,2,3,3,3,BU:1.5); Threshold limit for IN
Cadmium	kg	5.67E-9	1	3.06	(2,2,3,3,3,BU:3); Literature
Calcium	kg	8.58E-3	1	3.07	(3,2,3,3,3,BU:3); Literature
Carbonate	kg	2.79E-4	1	3.06	(2,2,3,3,3,BU:3); Literature
Carboxylic acids, unspecified	kg	1.84E-4	1	1.83	(2,3,5,3,3,BU:1.5); Environmental report for NO
Cesium	kg	5.00E-8	1	3.29	(3,3,5,3,3,BU:3); Literature
Chloride	kg	7.18E-2	1	3.07	(3,2,3,3,3,BU:3); Literature
Chromium	kg	1.06E-8	1	3.06	(2,2,3,3,3,BU:3); Literature
Cobalt	kg	1.00E-8	1	3.05	(2,2,1,3,3,BU:3); Literature
COD (Chemical Oxygen Demand)	kg	3.83E-5	1	1.88	(4,3,5,3,3,BU:1.5); Threshold limit for IN
Copper	kg	4.29E-8	1	3.06	(2,2,3,3,3,BU:3); Literature
Fluoride	kg	3.50E-7	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Hydrocarbons, aliphatic, alkanes, unspecified	kg	7.47E-6	1	3.29	(3,3,5,3,3,BU:3); Literature
Hydrocarbons, aliphatic, unsaturated	kg	6.00E-7	1	3.29	(3,3,5,3,3,BU:3); Literature
Hydrocarbons, aromatic	kg	2.60E-5	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Iodide	kg	5.83E-5	1	5.08	(3,2,3,3,3,BU:5); Literature
Iron	kg	8.02E-6	1	5.07	(2,2,3,3,3,BU:5); Literature
Lead	kg	1.08E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Lead-210	kBq	4.75E-2	1	3.06	(2,2,3,3,3,BU:3); Literature
Lithium	kg	1.33E-5	1	5.07	(2,2,3,3,3,BU:5); Literature
Manganese	kg	2.55E-6	1	5.08	(3,2,3,3,3,BU:5); Literature
Magnesium	kg	1.46E-3	1	5.08	(3,2,3,3,3,BU:5); Literature
Mercury	kg	2.00E-9	1	5.07	(2,2,3,3,3,BU:5); Literature
Molybdenum	kg	6.25E-10	1	5.07	(2,2,3,3,3,BU:5); Literature
Nickel	kg	7.57E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Nitrogen	kg	4.65E-5	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Oils, unspecified	kg	-	1	1.58	(2,2,3,3,3,BU:1.5); Directly reported for the single country
PAH, polycyclic aromatic hydrocarbons	kg	1.09E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Phenol	kg	2.72E-6	1	3.28	(2,3,5,3,3,BU:3); Environmental report for NO
Phosphate	kg	1.59E-6	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Polonium-210	kBq	1.62E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Potassium	kg	1.01E-3	1	5.08	(3,2,3,3,3,BU:5); Literature
Radium-224	kBq	1.26E-2	1	3.07	(3,2,3,3,3,BU:3); Literature
Radium-226	kBq	3.04E-1	1	3.06	(2,2,3,3,3,BU:3); Literature
Radium-228	kBq	5.00E-2	1	3.07	(3,2,3,3,3,BU:3); Literature
Rubidium	kg	5.00E-7	1	5.33	(3,3,5,3,3,BU:5); Literature
Silver	kg	3.00E-8	1	5.33	(3,3,5,3,3,BU:5); Literature
Sodium	kg	3.51E-2	1	5.08	(3,2,3,3,3,BU:5); Literature
Strontium	kg	3.42E-4	1	5.08	(3,2,3,3,3,BU:5); Literature
Sulfate	kg	3.45E-4	1	1.58	(2,2,3,3,3,BU:1.5); Literature
Sulfide	kg	5.00E-8	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Suspended solids, unspecified	kg	1.80E-4	1	1.88	(4,3,5,3,3,BU:1.5); Threshold limit for IN
Thorium-228	kBq	1.00E-2	1	3.29	(3,3,5,3,3,BU:3); Literature
Thorium-232	kBq	3.24E-7	1	3.06	(2,2,3,3,3,BU:3); Literature
DOC, Dissolved Organic Carbon	kg	2.00E-2	1	1.84	(3,3,5,3,3,BU:1.5); Literature
TOC, Total Organic Carbon	kg	3.05E-3	1	1.59	(3,2,3,3,3,BU:1.5); Literature
Toluene	kg	5.85E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Vanadium	kg	3.25E-10	1	5.07	(2,2,3,3,3,BU:5); Literature
VOC, volatile organic compounds, unspecified origin	kg	1.75E-5	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Uranium-238	kBq	2.50E-5	1	3.06	(2,2,3,3,3,BU:3); Literature
Xylene	kg	4.88E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Zinc	kg	6.73E-6	1	5.07	(2,2,3,3,3,BU:5); Literature

Tab. 10.5 Life cycle inventory for the chemical composition of discharged produced water in onshore production. Data for onshore emissions are recorded with category water, river.

Name	Unit	discharge, produced water, onshore	Uncertainty	StandardDeviation95%	GeneralComment
Location		GLO			
InfrastructureProcess		0			
Unit		kg			
discharge, produced water, onshore	kg	1.00E+0			
Acenaphthene	kg	2.36E-9	1	3.06	(2,3,3,3,3,BU:3); Literature, specific PAH
Acenaphthylene	kg	1.17E-9	1	3.06	(2,2,3,3,3,BU:3); Literature, specific PAH
Aluminium	kg	1.00E-8	1	5.06	(2,2,1,3,3,BU:5); Literature
Ammonium, ion	kg	8.55E-5	1	1.58	(2,2,3,3,3,BU:1.5); Literature
Antimony	kg	1.00E-8	1	5.06	(2,2,1,3,3,BU:5); Literature
Arsenic	kg	2.19E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Barium	kg	8.64E-5	1	5.07	(2,2,3,3,3,BU:5); Literature
Benzene	kg	3.72E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Benzene, ethyl-	kg	1.34E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Boron	kg	8.00E-6	1	5.07	(2,2,3,3,3,BU:5); Literature
Bromine	kg	3.50E-5	1	5.33	(3,3,5,3,3,BU:5); Literature
BOD5 (Biological Oxygen Demand)	kg	3.52E-4	1	1.63	(4,2,3,3,3,BU:1.5); Threshold limit for IN
Cadmium	kg	5.67E-9	1	3.06	(2,2,3,3,3,BU:3); Literature
Calcium	kg	8.58E-3	1	3.07	(3,2,3,3,3,BU:3); Literature
Carbonate	kg	2.79E-4	1	3.06	(2,2,3,3,3,BU:3); Literature
Carboxylic acids, unspecified	kg	1.84E-4	1	1.83	(2,3,5,3,3,BU:1.5); Environmental report for NO
Cesium	kg	5.00E-8	1	3.29	(3,3,5,3,3,BU:3); Literature
Chloride	kg	1.20E-7	1	3.07	(3,2,3,3,3,BU:3); Literature
Chromium	kg	1.06E-8	1	3.06	(2,2,3,3,3,BU:3); Literature
Cobalt	kg	1.00E-8	1	3.05	(2,2,1,3,3,BU:3); Literature
COD (Chemical Oxygen Demand)	kg	3.83E-5	1	1.88	(4,3,5,3,3,BU:1.5); Threshold limit for IN
Copper	kg	4.29E-8	1	3.06	(2,2,3,3,3,BU:3); Literature
Fluoride	kg	3.50E-7	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Hydrocarbons, aliphatic, alkanes, unspecified	kg	7.47E-6	1	3.29	(3,3,5,3,3,BU:3); Literature
Hydrocarbons, aliphatic, unsaturated	kg	6.00E-7	1	3.29	(3,3,5,3,3,BU:3); Literature
Hydrocarbons, aromatic	kg	2.60E-5	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Iodide	kg	5.83E-5	1	5.08	(3,2,3,3,3,BU:5); Literature
Iron	kg	8.02E-6	1	5.07	(2,2,3,3,3,BU:5); Literature
Lead	kg	1.08E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Lead-210	kBq	4.75E-2	1	3.06	(2,2,3,3,3,BU:3); Literature
Lithium	kg	1.33E-5	1	5.07	(2,2,3,3,3,BU:5); Literature
Manganese	kg	2.55E-6	1	5.08	(3,2,3,3,3,BU:5); Literature
Magnesium	kg	1.46E-3	1	5.08	(3,2,3,3,3,BU:5); Literature
Mercury	kg	2.00E-9	1	5.07	(2,2,3,3,3,BU:5); Literature
Molybdenum	kg	6.25E-10	1	5.07	(2,2,3,3,3,BU:5); Literature
Nickel	kg	7.57E-8	1	5.07	(2,2,3,3,3,BU:5); Literature
Nitrogen	kg	4.65E-5	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Oils, unspecified	kg	0	1	1.58	(2,2,3,3,3,BU:1.5); Directly reported for the single country
PAH, polycyclic aromatic hydrocarbons	kg	1.09E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Phenol	kg	2.72E-6	1	3.28	(2,3,5,3,3,BU:3); Environmental report for NO
Phosphate	kg	1.59E-6	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Polonium-210	kBq	1.62E-6	1	3.06	(2,2,3,3,3,BU:3); Literature
Potassium	kg	1.01E-3	1	5.08	(3,2,3,3,3,BU:5); Literature
Radium-224	kBq	1.26E-2	1	3.07	(3,2,3,3,3,BU:3); Literature
Radium-226	kBq	3.04E-1	1	3.06	(2,2,3,3,3,BU:3); Literature
Radium-228	kBq	5.00E-2	1	3.07	(3,2,3,3,3,BU:3); Literature
Rubidium	kg	5.00E-7	1	5.33	(3,3,5,3,3,BU:5); Literature
Silver	kg	3.00E-8	1	5.33	(3,3,5,3,3,BU:5); Literature
Sodium	kg	3.51E-2	1	5.08	(3,2,3,3,3,BU:5); Literature
Strontium	kg	3.42E-4	1	5.08	(3,2,3,3,3,BU:5); Literature
Sulfate	kg	3.45E-4	1	1.58	(2,2,3,3,3,BU:1.5); Literature
Sulfide	kg	5.00E-8	1	1.57	(2,2,1,3,3,BU:1.5); Literature
Suspended solids, unspecified	kg	1.80E-4	1	1.88	(4,3,5,3,3,BU:1.5); Threshold limit for IN
Thorium-228	kBq	1.00E-2	1	3.29	(3,3,5,3,3,BU:3); Literature
Thorium-232	kBq	3.24E-7	1	3.06	(2,2,3,3,3,BU:3); Literature
DOC, Dissolved Organic Carbon	kg	2.00E-2	1	1.84	(3,3,5,3,3,BU:1.5); Literature
TOC, Total Organic Carbon	kg	3.05E-3	1	1.59	(3,2,3,3,3,BU:1.5); Literature
Toluene	kg	5.85E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Vanadium	kg	3.25E-10	1	5.07	(2,2,3,3,3,BU:5); Literature
VOC, volatile organic compounds, unspecified origin	kg	1.75E-5	1	1.84	(3,3,5,3,3,BU:1.5); Literature
Uranium-238	kBq	2.50E-5	1	3.06	(2,2,3,3,3,BU:3); Literature
Xylene	kg	4.88E-6	1	3.07	(3,2,3,3,3,BU:3); Literature
Zinc	kg	6.73E-6	1	5.07	(2,2,3,3,3,BU:5); Literature

10.1.6 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.[41]

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.[42] 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.

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 systems [43] 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).

Nevertheless, if more freshwater is needed than produced water is released, the freshwater input is not balanced, as water scarcity is increased due to this input.

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.

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

42 https://pubs.acs.org/doi/10.1021/es802423e

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

10.1.7 Water balance

Kommentiert [CM1]: Adjust in other reports as well (including order of subchapters...

In summary, there are 3 potential sources of water that are adding to the water balance:

- Fresh water from e.g. rivers or lakes, mainly used onshore e.g. for enhanced oil recovery (amounts c.f. chapter 7.2.1).
- Fossil water, extracted together with crude oil: Calculated as difference of produced water output minus fresh water input, if the amount of produced water released in a region (c.f. chapter 10.1.3) is higher than the freshwater input in the same region (c.f. chapter 7.2.1). If freshwater input is higher than produced water released, the amount is assumed to be 0.
- Ocean and/or brackish water: Are not considered in the balance, as no information is available for the amount water used. This type of water is also not relevant for the impact assessment of water scarcity (According to the ecological scarcity method 2021). Therefore, for offshore operations no water use is accounted for.

On the other side, there are 2 types of water outflows:

- Produced water that is reinjected in the oil field
- Produced water that is emitted/discharged to either surface water or ocean

These 5 flows might differ depending on the local situation, e.g. with regard to the water content in the extracted oil or the technology used to extract oil. E.g. in depleted oil fields, more freshwater might be needed for enhanced oil recovery than in well saturated fields where little effort is needed for extraction. Also, in some regions, besides or instead of fresh water, ocean or brackish water is used.

As explained in chapter10.1.6, the model is adjusted so the water flows are balanced for cases where fresh water input is lower than discharged water. An example of how this is done is shown in Tab. 10.6. In this example for the US in 2023, freshwater use (c.f. Tab. 7.1) is lower than produced water discharged in the same region (assuming global average, as explained in chapter 10.1.3). Another example for the opposite case with higher water input compared to produced water discharged is given in Tab. 10.7

Tab. 10.6 Example for the water balance for onshore production in 2023 in the US (region North America, RNA), per kg of oil equivalent. In this case, fresh water input is lower than the reported amount of produced water discharged.

US	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	Data for this scenario	GeneralComment
2023	Location						US	US
all data available	InfrastructureProcess						2023	
	Unit						kg OE	
water resource	Water, unspecified natural origin, US	-	resource	in water	-	m3	2.09E-04	Fresh water withdrawn, Average 2021 to 2023, IOGP 2024
	Water, fossil	-	resource	in water	-	m3	1.40E-04	Water resource used, calculated value - if, according to consulted sources, the amount of discharged produced water is higher than fresh water withdrawn.
water emission	Water, US	-	water	river	-	m3	2.09E-04	Calculated emission to balance freshwater withdrawn - input and emission are assumed to occur in the same region.
	Chemically polluted water	-	water	river	-	kg	1.40E-01	Calculated emission to balance fossil water use, if , according to consulted sources, the amount of discharged produced water is higher than the amount of freshwater withdrawn.
	discharge, produced water, onshore	GLO	-	-	0	kg	3.48E-01	Produced water discharged. As sample size for the considered region is small, and a 0-value is not realisitic, global average is assumed according to IOGP 2024. Dataset represents chemical composition of produced water, without water (water in- and outputs are balanced above).

Tab. 10.7 Example for the water balance for onshore production in 2023 in Brazil (region Latin America, RLA), per kg of oil equivalent. In this case, fresh water input is higher than the reported amount of produced water discharged.

BR	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	Data for this scenario	GeneralComment
2023	Location						BR	BR
all data available	InfrastructureProcess						2023	
	Unit						kg OE	
water resource	Water, unspecified natural origin, BR	-	resource	in water	-	m3	6.33E-05	Fresh water withdrawn, Average 2021 to 2023, IOGP 2024
water emission	Water, BR	-	water	river	-	m3	3.64E-05	Calculated emission to balance freshwater withdrawn - input and emission are assumed to occur in the same region.
	discharge, produced water, offshore	OCE	-	-	0	kg	3.48E-01	Average 2021 to 2023, IOGP 2024
	discharge, produced water, onshore	GLO	-	-	0	kg	3.64E-02	Produced water discharged. Average 2021 to 2023, IOGP 2024. Dataset represents chemical composition of produced water, without water (water in- and outputs are balanced above).

10.1.8 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 2024, Tab. A.16 and A.23). The values are derived by adding the oil discharge and spill rates of the last 3 years and dividing the sum by 3.

10.3.1 Emissions to water

Tab. 10.8 Amount of oil discharged or spilled to sea per kg of oil equivalent extracted per region, average of latest 3 years reported (offshore, IOGP 2024, Tab. A.16)

Oils, discharged and spilled to sea, offshore	Average 2021 to 2023	Source
Region	kg/kg OE	
Africa	2.29E-5	IOGP 2024
Asia/Australia	2.16E-5	IOGP 2024
Europe	8.44E-6	IOGP 2024
Middle East	1.24E-5	IOGP 2024
North America	5.70E-6	IOGP 2024
Russia & Central Asia	2.00E-8	IOGP 2024
South & Central America	8.42E-6	IOGP 2024
Global	**1.29E-5**	**IOGP 2024**

Tab. 10.9 Amount of oil discharged and spilled to rivers per kg of oil equivalent extracted per region, average for 3 latest years (onshore, IOGP 2024, Tab. A.16).

Oils, discharged and spilled, to river, onshore	Average 2021 to 2023	Source
Region	kg/kg OE	
Africa	2.90E-5	IOGP 2024
Asia/Australia	1.24E-6	IOGP 2024
Europe	8.23E-6	IOGP 2024
Middle East	5.98E-6	IOGP 2024
North America	2.89E-6	IOGP 2024
Russia & Central Asia	2.63E-7	IOGP 2024
South & Central America	4.80E-6	IOGP 2024
Global	**5.11E-6**	**IOGP 2024**

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 2024). Values used in the model are shown in Tab. 10.10.

Tab. 10.10 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 2024, Tab. A.23). For regions without reported values, weighted average of reporting regions is considered.

Oils, discharged and spilled, to soil	Average 2021 to 2023	Source
Region	kg/kg OE	
Africa	1.28E-6	IOGP 2024
Asia/Australia	4.67E-8	IOGP 2024
Europe	2.73E-7	IOGP 2024
Middle East	8.68E-7	weighted average of regions with reported values
North America	8.68E-7	weighted average of regions with reported values
Russia & Central Asia	8.68E-7	weighted average of regions with reported values
South & Central America	8.68E-7	weighted average of regions with reported values
Global	**8.68E-7**	**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 2023 are:

- Extension of the list of country-specific inventories to 50 countries (c.f. Tab. 2.1)
- Update of methane and flaring emissions, consumption of energy, production figures and other key indicators with the latest version of key data sources (EI 2024; IOGP 2024; World Bank 2024; IEA 2024).[44]

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 Canada (CA). 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 10.2.[45]

[44] If no specific production data is listed for the reference year in EI 2024, data from other sources is used (see Tab. 2.1 for details).

[45] Download is available on https://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 CA, part1

ReferenceFunction	Name	Combined gas and oil production {CA} U	Combined gas and oil production offshore {CA} U	Combined gas and oil production onshore {CA} U	Crude oil, at production offshore {CA} U	Crude oil, at production onshore {CA} U
Geography	Location	CA	CA	CA	CA	CA
ReferenceFunction	InfrastructureProcess	0	0	0	0	0
ReferenceFunction	Unit	a	a	a	kg	kg
	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
TimePeriod	StartDate	2023	2023	2023	2023	2023
	EndDate	2025	2025	2025	2025	2025
	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 CA.	Data valid for CA.	Data valid for CA.	Data valid for CA.	Data valid for CA.
Technology	Text	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production
	ProductionVolume	278 megatons of crude oil and 190 billion Nm3 natural gas per year in 2023.	20 megatons of crude oil and 14 billion Nm3 natural gas per year in 2023.	258 megatons of crude oil and 176 billion Nm3 natural gas per year in 2023.	20 megatons of crude oil per year in 2023.	258 megatons of crude oil per year in 2023.
	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	435.7	435.7	435.7	20.3	257.6
	ProductionVolumeText	Megatons of oil-equivalents produced in 2023	Megatons of oil-equivalents produced in 2023	Megatons of oil-equivalents produced in 2023	Megatons of oil produced in 2023	Megatons of oil produced in 2023

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

ReferenceFunction	Name	Natural gas, at production offshore {CA} U	Natural gas, at production onshore {CA} U	Crude oil, at production {CA} U	Natural gas, at production {CA} U
Geography	Location	CA	CA	CA	CA
ReferenceFunction	InfrastructureProcess	0	0	0	0
ReferenceFunction	Unit	Nm3	Nm3	kg	Nm3
	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
TimePeriod	StartDate	2023	2023	2023	2023
	EndDate	2025	2025	2025	2025
	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 CA.	Data valid for CA.	Data valid for CA.	Data valid for CA.
Technology	Text	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production	7 % offshore and 93 % onshore production
	ProductionVolume	14 billion Nm3 natural gas per year in 2023.	176 billion Nm3 natural gas per year in 2023.	278 megatons of crude oil per year in 2023.	190 billion Nm3 natural gas per year in 2023.
	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
ecoinvent v3	ProductionVolumeNumber	13.9	176.4	277.9	190.3
	ProductionVolumeText	Billion cubic meters of natural gas produced in 2023	Billion cubic meters of natural gas produced in 2023	Megatons of oil produced in 2023	Billion cubic meters of natural gas produced in 2023

Tab. 12.2 Unit process raw data, example for crude oil and natural gas production in CA, part 1

CA	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	Combined gas and oil production offshore {CA} U	Crude oil, at production offshore {CA} U	Natural gas, at production offshore {CA} U	Combined gas and oil production onshore {CA} U	Crude oil, at production onshore {CA} U	Natural gas, at production onshore {CA} U	Combined gas and oil production {CA} U	UncertaintyType	StandardDeviation95%	GeneralComment
2023	Location						CA	CA	CA	CA	CA	CA	CA			
data available	InfrastructureProcess						-	-	-	-	-	-	-			
	Unit						a	kg	Nm3	a	kg	Nm3	a			
products	Crude oil, at production offshore {CA} U	CA	-	-	0	kg	2.03E+10	100.0%					2.03E+10	1	1.00	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
	Crude oil, at production onshore {CA} U	CA	-	-	0	kg				2.58E+11	100.0%		2.58E+11	1	1.00	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
	Natural gas, at production offshore {CA} U	CA	-	-	0	Nm3	1.39E+10		100.0%				1.39E+10	1	1.00	(3,2,2,2,5,BU:1); Assumption based on share of crude oil extraction
	Natural gas, at production onshore {CA} U	CA	-	-	0	Nm3				1.76E+11		100.0%	1.76E+11	1	1.00	(3,2,2,2,5,BU:1); Assumption based on share of crude oil extraction
resources, in gro	Oil, crude	-	resources	in ground	-	kg	2.03E+10	100.0%	0.0%	2.58E+11	100.0%	0.0%	2.78E+11	1	1.05	(1,1,1,1,1,BU:1.05); EI 2024
	Oil, crude	-	resources	in ground	-	kg	3.11E+5	100.0%	0.0%	3.95E+6	100.0%	0.0%	4.26E+6	1	1.05	(1,1,1,3,1,BU:1.05); calculated losses due to oil spills
	Gas, natural/m3	-	resources	in ground	-	Nm3	1.39E+10	0.0%	100.0%	1.76E+11	0.0%	100.0%	1.90E+11	1	1.05	(1,1,1,1,1,BU:1.05); EI Statistical Review of World Energy 2024
water resource	Water, unspecified natural origin, CA	-	resources	in water	-	m3	0	63.8%	36.2%	8.73E+7	63.8%	36.2%	8.73E+7	1	1.05	(1,1,1,3,1,BU:1.05); Average 2021 to 2023, IOGP 2024
	Water, salt, ocean	-	resources	in water	-	m3	0	63.8%	36.2%	0	63.8%	36.2%	0	1	1.13	(3,3,1,3,1,BU:1.05); For offshore operations no water in- or output is accounted for.
	Water, fossil	-	resource	in water	-	m3	0	63.8%	36.2%	5.84E+7	63.8%	36.2%	5.84E+7	1	1.13	(3,3,1,3,1,BU:1.05); Resource use for produced water - if amount is higher than freshwater input.
water emission	Water, CA	-	emissions to water	river	-	m3	0	63.8%	36.2%	8.73E+7	63.8%	36.2%	8.73E+7	1	1.52	(3,3,1,3,1,BU:1.5); Balancing of freshwater input.
	Chemically polluted water	-	emissions to water	river	-	kg	0	63.8%	36.2%	5.84E+10	63.8%	36.2%	5.84E+10	1	3.02	(3,3,1,3,1,BU:3); chemically polluted water emission for released produced water - if amount is higher than freshwater input.
	Chemically polluted water	-	emissions to water	ocean	-	kg	0	63.8%	36.2%	0	63.8%	36.2%	0	1	3.02	(3,3,1,3,1,BU:3); Line stays empty (used to balance water input and output)
	Discharge, produced water, offshore {OCE} U	OCE	-	-	0	kg	2.93E+9	63.8%	36.2%	0	63.8%	36.2%	2.93E+9	1	1.31	(4,3,1,3,3,BU:1.05); Average 2021 to 2023, IOGP 2024
	Discharge, produced water, onshore {GLO} U	GLO	-	-	0	kg	0	63.8%	36.2%	1.46E+11	63.8%	36.2%	1.46E+11	1	1.31	As sample size for the considered region is small, and a 0-value is not realisitic, global average is assumed according to IOGP 2024.

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

CA	Name	Location	Unit	Combined gas and oil production offshore {CA} U	Crude oil, at production offshore {CA} U	Natural gas, at production offshore {CA} U	Combined gas and oil production onshore {CA} U	Crude oil, at production onshore {CA} U	Natural gas, at production onshore {CA} U	Combined gas and oil production {CA} U	UncertaintyType	StandardDeviation95%	GeneralComment
2023	Location			CA	CA	CA	CA	CA	CA	CA			
data available	InfrastructureProcess			-	-	-	-	-	-	-			
	Unit			a	kg	Nm3	a	kg	Nm3	a			
technosphere	Chemicals inorganic, at plant {GLO} U	GLO	kg	1.82E+7	63.8%	36.2%	2.32E+8	63.8%	36.2%	2.50E+8	1	1.32	(4,4,1,3,3,BU:1.05); Generic estimate according to Meili et al. 2018
	Chemicals organic, at plant {GLO} U	GLO	kg	1.39E+7	63.8%	36.2%	1.77E+8	63.8%	36.2%	1.91E+8	1	1.32	(4,4,1,3,3,BU:1.05); Generic estimate according to Meili et al. 2018
	Transport, lorry 16-32t, EURO6 {RER} U	RER	tkm	3.21E+6	63.8%	36.2%	4.08E+7	63.8%	36.2%	4.40E+7	1	2.07	(3,4,1,3,3,BU:2); Standard distance for chemical transport 100km
	Transport, freight, rail {RER} U	RER	tkm	1.93E+7	63.8%	36.2%	2.45E+8	63.8%	36.2%	2.64E+8	1	2.07	(3,4,1,3,3,BU:2); Standard distance for chemical transport 600km
Infrastructure	Well for exploration and production, offshore {OCE} U	OCE	m	1.13E+4	63.8%	36.2%	0	63.8%	36.2%	1.13E+4	1	3.07	Regional estimate for 2023 in combination with country-specific length of oil and gas wells in 2021, according to statista.com
	Well for exploration and production, onshore {GLO} U	GLO	m	0	63.8%	36.2%	1.35E+7	63.8%	36.2%	1.35E+7	1	3.07	Regional estimate for 2023 in combination with country-specific length of oil and gas wells in 2021, according to statista.com
oil	Pipeline, crude oil, offshore {OCE} U	OCE	km	1.71E+2	100.0%	0.0%	0	0.0%	0.0%	1.71E+2	1	3.07	(3,4,1,3,3,BU:3); Generic estimation based on estimate for Nigeria 2018
	Pipeline, crude oil, onshore {RER} U	RER	km	0	0.0%	0.0%	5.32E+3	100.0%	0.0%	5.32E+3	1	3.07	(3,4,1,3,3,BU:3); Generic estimation based on estimate for Kazakhstan 2016
	Platform, crude oil, offshore {OCE} U	OCE	unit	8.62E-1	100.0%	0.0%	0	0.0%	0.0%	8.62E-1	1	3.07	(3,4,1,3,3,BU:3); Lodewijkx et al. 2001
	Production plant crude oil, onshore {GLO} U	GLO	unit	0	0.0%	0.0%	1.37E+3	100.0%	0.0%	1.37E+3	1	3.30	(3,4,5,3,3,BU:3); Lodewijkx et al. 2001
gas	Plant offshore, natural gas, production {OCE} U	OCE	p	2.69E-1	0.0%	100.0%	0	0.0%	0.0%	2.69E-1	1	3.07	(3,4,1,3,3,BU:3); Average 2021 to 2023, IOGP 2024
	Plant onshore, natural gas, production {GLO} U	GLO	unit	0	0.0%	0.0%	4.34E+1	0.0%	100.0%	4.34E+1	1	3.07	(3,4,1,3,3,BU:3); Average 2021 to 2023, IOGP 2024
	Pipeline, natural gas, long distance, high capacity, offshore {GLO} U	GLO	km	1.05E+2	0.0%	100.0%	0	0.0%	0.0%	1.05E+2	1	3.07	(3,4,1,3,3,BU:3); Estimation based on values for crude oil pipeline
	Pipeline, natural gas, long distance, low capacity, onshore {GLO} U	GLO	km	0	0.0%	0.0%	3.02E+03	0.0%	100.0%	3.02E+3	1	3.07	(3,4,1,3,3,BU:3); Estimation based on values for crude oil pipeline

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

CA	Name	Location	Unit	Combined gas and oil production offshore {CA} U	Crude oil, at production offshore {CA} U	Natural gas, at production offshore {CA} U	Combined gas and oil production onshore {CA} U	Crude oil, at production onshore {CA} U	Natural gas, at production onshore {CA} U	Combined gas and oil production {CA} U	UncertaintyType	StandardDeviation95%	GeneralComment
2023	Location			CA	CA	CA	CA	CA	CA	CA			
data available	InfrastructureProcess			-	-	-	-	-	-	-			
	Unit			a	kg	Nm3	a	kg	Nm3	a			
energy	electricity, medium voltage, at grid {CA} U	CA	kWh	1.60E+9	63.8%	36.2%	2.04E+10	63.8%	36.2%	2.20E+10	1	1.24	(3,2,2,3,3,BU:1.05); Purchased energy according to IOGP 2024.
	Diesel, burned in diesel-electric generating set, at extraction site {GLO} U	GLO	MJ	6.32E+9	63.8%	36.2%	8.03E+10	63.8%	36.2%	8.66E+10	1	1.24	(3,2,2,3,3,BU:1.05); Calculation based on data from IOGP 2024, assuming a generic share of 11.7% of onsite combustion + unspecified. Average 2021 to 2023
	Heavy fuel oil, burned in industrial furnace 1MW, non-modulating {RER} U	RER	MJ	1.18E+9	63.8%	36.2%	1.50E+10	63.8%	36.2%	1.62E+10	1	1.24	(3,2,2,3,3,BU:1.05); Calculation based on data from IOGP 2024, assuming a generic share of 2.2% of onsite combustion + unspecified. Average 2021 to 2023
	Sweet gas, burned in gas turbine, production {GLO} U	GLO	MJ	4.63E+10	63.8%	36.2%	5.88E+11	63.8%	36.2%	6.35E+11	1	1.24	(3,2,2,3,3,BU:1.05); Calculation based on data from IOGP 2024, assuming a generic share of 85.7% of onsite combustion + unspecified. Average 2021 to 2023, SOx content of sour gas assessed separately in overall emissions.
waste	Natural gas, vented {GLO} U	GLO	Nm3	2.75E+8	62.0%	38.0%	3.49E+9	62.0%	38.0%	3.76E+9	1	1.22	(2,1,1,1,3,BU:1.05); Country specific methane emissions according to IEA 2024, 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} U	GLO	Nm3	8.09E+7	63.8%	36.2%	1.03E+9	63.8%	36.2%	1.11E+9	1	1.24	(3,2,1,1,3,BU:1.05); Total amount of flared gas per kg OE according to Worldbank 2024, SOx emissions from flared sour gas assessed separately in overall emissions.
	Disposal, hazardous waste, 0% water, to underground deposit {DE} U	DE	kg	6.59E+6	63.8%	36.2%	8.37E+7	63.8%	36.2%	9.03E+7	1	1.26	(3,4,1,3,3,BU:1.05); Generic estimate according to Meili et al. 2018
	Disposal, municipal solid waste, 22.9% water, to municipal incineration {CH} U	CH	kg	3.30E+6	63.8%	36.2%	4.19E+7	63.8%	36.2%	4.52E+7	1	1.26	(3,4,1,3,3,BU:1.05); Generic estimate according to Meili et al. 2018

Unit process raw data, example for crude oil and natural gas production in the CA, part 4

CA	Name	Location	Category	SubCategory	InfrastructureProcess	Unit	Combined gas and oil production offshore {CA} U	Crude oil, at production offshore {CA} U	Natural gas, at production offshore {CA} U	Combined gas and oil production onshore {CA} U	Crude oil, at production onshore {CA} U	Natural gas, at production onshore {CA} U	Combined gas and oil production {CA} U	UncertaintyType	StandardDeviation95%	GeneralComment
2023	Location						CA	CA	CA	CA	CA	CA	CA			
data available	InfrastructureProcess						-	-	-	-	-	-	-			
	Unit						a	kg	Nm3	a	kg	Nm3	a			
emission to water	Oils, unspecified	-	emissions to water	river	-	kg	0	63.8%	36.2%	1.19E+6	63.8%	36.2%	1.19E+6	1	1.56	(2,1,1,3,3,BU:1.5); Average 2021 to 2023, IOGP 2024
	BOD5, Biological Oxygen Demand	-	emissions to water	river	-	kg	0	63.8%	36.2%	3.75E+6	63.8%	36.2%	3.75E+6	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	COD, Chemical Oxygen Demand	-	emissions to water	river	-	kg	0	63.8%	36.2%	3.75E+6	63.8%	36.2%	3.75E+6	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	DOC, Dissolved Organic Carbon	-	emissions to water	river	-	kg	0	63.8%	36.2%	1.03E+6	63.8%	36.2%	1.03E+6	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	TOC, Total Organic Carbon	-	emissions to water	river	-	kg	0	63.8%	36.2%	1.03E+6	63.8%	36.2%	1.03E+6	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	AOX, Adsorbable Organic Halogen as Cl	-	emissions to water	river	-	kg	0	63.8%	36.2%	1.23E+1	63.8%	36.2%	1.23E+1	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	Nitrogen	-	emissions to water	river	-	kg	0	63.8%	36.2%	9.19E+2	63.8%	36.2%	9.19E+2	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	Sulfur	-	emissions to water	river	-	kg	0	63.8%	36.2%	3.19E+3	63.8%	36.2%	3.19E+3	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
emission to water	Oils, unspecified	-	emissions to water	ocean	-	kg	1.87E+5	63.8%	36.2%	0	63.8%	36.2%	1.87E+5	1	1.56	(2,1,1,3,3,BU:1.5); Average 2021 to 2023, IOGP 2024
	BOD5, Biological Oxygen Demand	-	emissions to water	ocean	-	kg	5.89E+5	63.8%	36.2%	0	63.8%	36.2%	5.89E+5	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	COD, Chemical Oxygen Demand	-	emissions to water	ocean	-	kg	5.89E+5	63.8%	36.2%	0	63.8%	36.2%	5.89E+5	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	DOC, Dissolved Organic Carbon	-	emissions to water	ocean	-	kg	1.62E+5	63.8%	36.2%	0	63.8%	36.2%	1.62E+5	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	TOC, Total Organic Carbon	-	emissions to water	ocean	-	kg	1.62E+5	63.8%	36.2%	0	63.8%	36.2%	1.62E+5	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	AOX, Adsorbable Organic Halogen as Cl	-	emissions to water	ocean	-	kg	1.92E+0	63.8%	36.2%	0	63.8%	36.2%	1.92E+0	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	Nitrogen	-	emissions to water	ocean	-	kg	1.44E+2	63.8%	36.2%	0	63.8%	36.2%	1.44E+2	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
	Sulfur	-	emissions to water	ocean	-	kg	5.00E+2	63.8%	36.2%	0	63.8%	36.2%	5.00E+2	1	1.56	(2,1,1,3,3,BU:1.5); Extrapolation for sum parameter
emission to soil	Oils, unspecified	-	emissions to soil	unspecified	-	kg	0	63.8%	36.2%	3.87E+5	63.8%	36.2%	3.87E+5	1	1.56	(2,1,1,3,3,BU:1.5); Average 2021 to 2023, IOGP 2024
emission to air, lo	Sulfur dioxide	-	emissions to air	low. pop.	-	kg	9.89E+5	63.8%	36.2%	1.26E+7	63.8%	36.2%	1.35E+7	1	1.56	(2,1,1,3,3,BU:1.5); Weighted average 2021 to 2023, IOGP 2024
	Nitrogen oxides	-	emissions to air	low. pop.	-	kg	1.07E+7	63.8%	36.2%	1.36E+8	63.8%	36.2%	1.47E+8	1	1.56	(2,1,1,3,3,BU:1.5); Weighted average 2021 to 2023, IOGP 2024
	Methane, bromotrifluoro-, Halon 1301	-	emissions to air	low. pop.	-	kg	3.82E+2	63.8%	36.2%	0	63.8%	36.2%	3.82E+2	1	1.58	(3,3,1,3,3,BU:1.5); assuming 20% halon compared to Jungbluth 2007
	Methane, trifluoro-, HFC-23	-	emissions to air	low. pop.	-	kg	1.54E+3	63.8%	36.2%	0	63.8%	36.2%	1.54E+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 2023 are used (EI 2024). These data, in general, can be considered as reliable. However, also such data might receive updates/error corrections.

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.

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).

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 stay a hotspot for future updates. The International Methane Emissions Observatory (IMEO)[46] 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 CO_2 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 economic situation in the countries under study, both values might fluctuate a lot from year to year.

46 https://www.unep.org/explore-topics/energy/what-we-do/imeo

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 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 https://esu-services.ch/data/public-lci-reports/database are not yet directly linked to these inventories. Therefore, methane emissions are updated also for plastics as described in a related report (Rajabihamedani et al. 2025).

16 References

Abubaker 2015 Abubaker H. (2015) An Overview of Oil Production Stages: Enhanced Oil Recovery Techniques and Nitrogen Injection. *In: International Journal of Environmental Science and Development*, **6**(9), pp., retrieved from: https://www.ijesd.org/vol6/682-A3001.pdf.

Agip Division 2001 Agip Division (2001) Health Safety Environment: 2000 report. ENI Group, Rome, IT, retrieved from: https://www.eni.it.

ANL 2009 ANL (2009) Produced Water Volumes and Management Practices in the United States. Argonne National Laboratory, Chicago, retrieved from: https://www.osti.gov.bridge.

BAFU 2020 BAFU (2020) Switzerland's Greenhouse Gas Inventory 1990–2018.

BFE 2017 BFE (2017) Schweizerische Gesamtenergiestatistik 2016. Bundesamt für Energie (BFE), Bern, retrieved from: https://www.bfe.admin.ch/php/modules/publikationen/stream.php?extlang=de&name=de_457086409.pdf&endung=Schweizerische%20Gesamtenergiestatistik%202016.

Boulay et al. 2018 Boulay A.-M., Bare J., Benini L., Berger M., Lathuillière M. J., Manzardo A., Margni M., Motoshita M., Núñez M., Valerie-Pastor A., Ridoutt B., Oki T., Worbe S. and Pfister S. (2018) The WULCA consensus characterization model for water scarcity footprints: assessing impacts of water consumption based on available water remaining (AWARE). *In: Int J Life Cycle Assess*, **23**(2), pp. 368–378.

Bruijstens et al. 2008 Bruijstens A. J., Beuman W. P. H., Molen v. d. M., Rijke J. d., Cloudt R. P. M., Kadijk G., Camp O. o. d. and Bleuanus S. (2008) Biogas Composition and Engine Performance, Including Database and Biogas Property Model. BIOGASMAX, retrieved from: https://www.biogasmax.eu.

Bussa et al. 2025 Bussa M., Jungbluth N. and Meili C. (2025) Life cycle inventories of long-distance transport and distribution of natural gas. ESU-services Ltd. commissioned by FOEN, Schaffhausen, CH, retrieved from: https://esu-services.ch/data/public-lci-reports/.

Carbon Limits 2013 Carbon Limits (2013) Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan, retrieved from: https://www.ebrd.com/downloads/sector/sei/ap-gas-flaring-study-final-report.pdf.

Cerbe et al. 1999 Cerbe G., Carlowitz O., Kätelhön J. E., Köhler H., Lehmann J., Lendt B., Lethen H., Mauruschat H. and Pietsch H. (1999) Grundlagen der Gastechnik: Gasbeschaffung, Gasverteilung, Gasverwendung. 5., vollständig neubearbeitete Auflage Edition. Carl Hanser Verlag, ISBN 3-446-21109-8, München Wien.

EC 2020 EC (2020) Registration of Crude Oil Imports and Deliveries in the European Union (EU28), retrieved from: https://ec.europa.eu/energy/data-analysis/eu-crude-oil-imports_en?redir=1.

EI 2024 EI (2024) Energy Institute Statistical Review of World Energy. Energy Institute, London, retrieved from: https://www.energyinst.org/statistical-review/home.

EIA 2016 EIA (2016) Country Analysis Brief: Iraq. U.S. Energy Information Administration, retrieved from: https://www.eia.gov/beta/international/analysis_includes/countries_long/Iraq/iraq.pdf.

EIA 2019 EIA (2019) The Distribution of U.S. Oil and Natural Gas Wells by production rate. U.S. Energy Information Administration, retrieved from: https://www.eia.gov/petroleum/wells/pdf/full_report.pdf.

EIA 2022 EIA (2022) The Distribution of U.S. Oil and Natural Gas Wells by production rate. U.S. Energy Information Administration, retrieved from: https://www.eia.gov/petroleum/wells/pdf/full_report.pdf.

Enerdata 2024 Enerdata (2024) World Energy statistical yearbook. Enerdata, Grenoble, France, retrieved from: https://yearbook.enerdata.net/crude-oil/world-production-statistics.html.

Energy-Redefined 2010 Energy-Redefined L. (2010) Carbon Intensity of Crude Oil in Europe Crude, retrieved from: https://www.theicct.org/sites/default/files/ICCT_crudeoil_Europe_Dec2010.pdf.

Faist Emmenegger et al. 2007 Faist Emmenegger M., Heck T., Jungbluth N. and Tuchschmid M. (2007) Erdgas. In: *Sachbilanzen von Energiesystemen: Grundlagen für den ökologischen Vergleich von Energiesystemen und den Einbezug von Energiesystemen in Ökobilanzen für die Schweiz,* Vol. ecoinvent report No. 6-V, v2.0 (Ed. Dones R.). Paul Scherrer Institut Villigen, Swiss Centre for Life Cycle Inventories, Dübendorf, CH retrieved from: https://ecoinvent.org.

Frischknecht et al. 1996 Frischknecht R., Bollens U., Bosshart S., Ciot M., Ciseri L., Doka G., Dones R., Gantner U., Hischier R. and Martin A. (1996) Ökoinventare von Energiesystemen: Grundlagen für den ökologischen Vergleich von Energiesystemen und den Einbezug von Energiesystemen in Ökobilanzen für die Schweiz. 3. Gruppe Energie - Stoffe - Umwelt (ESU), Eidgenössische Technische Hochschule Zürich und Sektion Ganzheitliche Systemanalysen, Paul Scherrer Institut, Villigen, Bundesamt für Energie (Hrsg.), Bern, CH, retrieved from: https://www.energieforschung.ch.

IEA 2008 IEA (2008) World Energy Outlook 2008, Paris, retrieved from: https://www.iea.org/reports/world-energy-outlook-2008.

IEA 2020 IEA (2020) Methane Tracker 2020. IEA, Paris, retrieved from: https://www.iea.org/reports/methane-tracker-2020.

IEA 2024 IEA (2024) Methane Tracker for 2023. IEA, Paris, retrieved from: https://www.iea.org/articles/methane-tracker-data-explorer and https://iea.blob.core.windows.net/assets/b5f6bb13-76ce-48ea-8fdb-3d4f8b58c838/GlobalMethaneTracker_documentation.pdf.

IOGP 2019 IOGP (2019) Environmental data collection user guide (2019 data) – Definitions and exclusions. International Association of Oil & Gas Producers.

IOGP 2024 IOGP (2024) Environmental performance indicators – 2023 data. International Association of Oil and Gas Producers (IOGP), retrieved from: https://www.iogp.org/bookstore/product-category/environment/.

Juhrich 2016 Juhrich K. (2016) CO2 Emission Factors for Fossil Fuels. Umweltbundesamt.

Jungbluth 2007 Jungbluth N. (2007) Erdöl. In: *Sachbilanzen von Energiesystemen: Grundlagen für den ökologischen Vergleich von Energiesystemen und den Einbezug von Energiesystemen in Ökobilanzen für die Schweiz,* Vol. ecoinvent report No. 6-IV, v2.0 (Ed. Dones R.). Paul Scherrer Institut Villigen, Swiss Centre for Life Cycle Inventories, Dübendorf, CH.

Jungbluth et al. 2018 Jungbluth N., Meili C. and Wenzel P. (2018) Life cycle inventories of oil refinery processing and products. ESU-services Ltd. commissioned by BFE, BAFU, Erdöl-Vereinigung, Schaffhausen, Switzerland, retrieved from: https://www.esu-services.ch/data/public-lci-reports/.

Meili & Jungbluth 2018 Meili C. and Jungbluth N. (2018) Life cycle inventories of crude oil extraction. ESU-services Ltd. commissioned by BFE, BAFU, Erdöl-Vereinigung, Schaffhausen, Switzerland, retrieved from: https://www.esu-services.ch/data/public-lci-reports/.

Meili et al. 2025 Meili C., Jungbluth N. and Bussa M. (2025) Life cycle inventories of long-distance transport of crude oil. ESU-services Ltd. commissioned by Carbon Minds, Schaffhausen, Switzerland, retrieved from: https://esu-services.ch/publications/energy/.

Mielke et al. 2010 Mielke E., Anadon L. D. and Narayanamurti V. (2010) Water Consumption of Energy Resource Extraction, Processing and Conversion. Harvard Kennedy School - Belfer center for science and international affairs, Cambridge, MA 02138, retrieved from: https://www.belfercenter.org/sites/default/files/legacy/files/ETIP-DP-2010-15-final-4.pdf.

Neff et al. 2011 Neff J. M., Lee K. and DeBlois E. M. (2011) Produced Water: Overview of Composition, Fates, and Effects. *In: Springer*, pp., DOI: 10.1007/978-1-4614-0046-2_1.

Pacyna 1982 Pacyna J. M. (1982) Estimation of Emission Factors of Trace Metals from Oil-Fired Power Plants. Norvegian Institute for Air Research (NILU), Lillestrøm.

Rajabihamedani et al. 2025 Rajabihamedani S., Jungbluth N., Bussa M., Meili C. and Ulrich M. (2025) Life cycle inventories of plastics. ESU-services Ltd. commissioned by FOEN, Schaffhausen, Switzerland, retrieved from: https://esu-services.ch/data/public-lci-reports/.

Safronov & Sokolov 2014 Safronov A. and Sokolov A. (2014) Preliminary Calculation of the EROI for the Production of Crude Oil and Light Oil Products in Russia. *In: Sustainability*, **2014**(6), pp., 10.3390/su6095801, retrieved from: https://www.mdpi.com/journal/sustainability.

Schori et al. 2012 Schori S., Bauer C. and Frischknecht R. (2012) Life Cycle Inventory of Natural Gas Supply. Paul Scherrer Institut Villigen, Swiss Centre for Life Cycle Inventories, Dübendorf, CH.

Shell 2001 Shell (2001) Environmental Report. Shell Petroleum Development Company of Nigeria Limited (SPDC), retrieved from: https://www.shellnigeria.com.

Speight 1990 Speight J. G. (1990) "Fuel Science and Technology Handbook", New York & Basel.

Speight 1991 Speight J. G. (1991) "The Chemistry and Technology of Petroleum", New York.

Steinfatt & Hoffmann 1996 Steinfatt I. and Hoffmann G. G. (1996) Mobilisierung und Demobilisierung von Quecksilber in Erdgaslagerstätten. *In proceedings from: Aktuelle Fragen zum Umweltschutz bei Aufsuchung, Gewinnung und Verarbeitung von Erdöl und Erdgas. DGMK/IfE-GEmeinschaftstagung, 7. / 8. November 1996*, Deutsche Wissenschaftliche Gesellschaft für Erdöl, Erdgas und Kohle e.V., Hahnenklee.

Stolz & Frischknecht 2017 Stolz P. and Frischknecht R. (2017) Energieetikette für Personenwagen: Umweltkennwerte 2016 der Strom- und Treibstoffbereitstellung. Treeze im Auftrag Bundesamtes für Energie (BFE), Uster, CH, retrieved from: https://www.bfe.admin.ch/energieetikette/00886/index.html?lang=de&dossier_id=05113.

Targulian & Hirsch 2000 Targulian O. and Hirsch H. (2000) Russland: Öl- und Gaslecks abdichten - Atomkraftwerke abschalten! Ein Bericht von Greenpeace.

Tiedeman et al. 2012 Tiedeman K., Yeh S., Teter J. and Mishra G. S. (2012) INCREASING WATER USE INTENSITY AND PRODUCED WATER INTENSITY OF CALIFORNIA PETROLEUM EXTRACTION. University of California Davis.

UKOOA 2001 UKOOA (2001) Balancing Needs: 2000 Environmental Report. United Kingdom Offshore Operations Association, London, GB, retrieved from: https://www.oilandgas.org.uk.

UNEP 2014 UNEP (2014) The Montreal Protocol on Substances that Deplete the Ozone Layer - Report of the halons technical options committee. United Nations Environment Programme, retrieved from: https://conf.montreal-protocol.org/meeting/oewg/oewg-36/presession/Background%20Documents%20are%20available%20in%20English%20only/HTOC%202014%20Assessment%20Report.pdf.

UVEK 2018 UVEK (2018) UVEK-LCI DQRv2:2018. Bundesamt für Umwelt BAFU, Switzerland.

Waly et al. 2023 Waly M. M., Mickovski S. B. and Thomson C. (2023) Application of Circular Economy in Oil and Gas ProducedWater Treatment. *In: Sustainability*, **15**, pp. 2132, https://doi.org/10.3390/su15032132.

Williams et al. 2021 Williams J. P., Regehr A. and Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States. *In: Environmental Science & Technology*, **55**(1), pp. 563-570, 10.1021/acs.est.0c04265, retrieved from: https://doi.org/10.1021/acs.est.0c04265.

World Bank 2024 World Bank (2024) WorldDataBank for Global Gas Flaring Reduction, retrieved from: https://www.worldbank.org/en/programs/gasflaringreduction/global-flaring-data.

Wu et al. 2009 Wu M., Mintz M., Wang M. and Arora S. (2009) Water Consumption in the Production of Ethanol and Petroleum Gasoline. *In: Environmental Management*, **44**(5), pp. 981, 10.1007/s00267-009-9370-0, retrieved from: https://doi.org/10.1007/s00267-009-9370-0.