Technical and environmental viability of a European CO_2 EOR system

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Abstract

Captured CO_2 from large industrial emitters may be used for enhanced oil recovery (EOR), but as of yet there are no European large-scale EOR systems. Recent implementation decisions for a Norwegian carbon capture and storage demonstration will result in the establishment of a central CO_2 hub on the west-coast of Norway and storage on the Norwegian Continental Shelf. This development may continue towards a large-scale operation involving European CO_2 and CO_2 EOR operation. To this end, a conceptual EOR system was developed here based on an oxyfuel power plant located in Poland that acted as a source for CO_2, coupled to a promising oil field located on the Norwegian Continental Shelf. Lifecycle assessment was subsequently used to estimate environmental emissions indicators. When averaged over the operational lifetime, results show greenhouse gas (GHG) emissions of 0.4 kg CO_2-eq per kg oil (and n kWh associated electricity) produced, of which 64 % derived from the oxyfuel power plant. This represents a 71 % emission reduction when compared to the same amount of oil and electricity production using conventional technology. Other environmental impact indicators were increased, showing that this type of CO_2 EOR system may help reach GHG reduction targets, but care should be taken to avoid problem shifting.

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1. Introduction

Emissions of CO_2 can be reduced using carbon capture and storage (CCS), a set of technologies considered part of the global solution to mitigate climate change. It may prove to be particularly important in the interim as a more environmentally friendly energy solution in countries currently heavily reliant on fossil fuel energy (World Energy Council 2017). Applying CCS entails that the CO_2 produced from burning of fuels (predominantly fossil fuels in power and industrial plants) is captured, transported and permanently stored in underground reservoirs, thereby preventing the CO_2 formed during combustion from entering the atmosphere.

Considering that there is both real and potential demand for the CO_2 stream, captured CO_2 from large industrial emitters such as power plants may be used for various purposes such as for enhanced oil recovery (CO_2 EOR). For the majority of carbon capture utilisation and storage (CCUS) options – i.e. where CO_2 is used as a raw material for other products and stored - the offset of CO_2 emissions is limited. CO_2 EOR, however, could not only potentially offset large amounts of CO_2, but also consequently contribute to increased oil production. This generates additional revenue that may significantly improve the overall economy and overcome the challenges associated with high operational cost (IEA 2012, Compernolle, Welkenhuysen et al. 2017).

Globally (as of the year 2018), a total of 13 large-scale CO_2 EOR projects were in operation, with a total CO_2 capture capacity of 26 Mtpa (Global CCS Institute 2018). Many large-scale CO_2 EOR projects were also in construction, advanced development or early development. The technology was pioneered in North America, and as such, Europe does not currently have any large-scale CO_2 EOR projects either in operation, construction or development (Global CCS Institute 2018). Nevertheless, the scale of natural gas injection activity in the North Sea, and the several operating large-scale Norwegian geological CO_2 storage projects, suggest that European CO_2 EOR is also feasible (Cavanagh 2014, SCCS 2015). The Norwegian Government decided in May 2018 to continue with the Norwegian CCS demonstration project (Ministry of Petroleum and Energy 2018). At the time of writing two of the three emission plants are still involved in the project, and with full involvement from these plants, 800 kt of CO_2 will be captured annually, transported to a hub at Kollsnes via ship and permanently stored in the Lower Jurassic Johansen Formation (Northern North Sea). Implementation of the Norwegian CCS demonstration will result in the establishment of a central hub on the west coast of Norway and storage on the Norwegian Continental Shelf. From this, one can foresee a continued development towards a large-scale operation involving CO_2 from Europe and CO_2 EOR due to the economic merits discussed previously.

Although commercialising CO_2 capture and CO_2 EOR is not a technical challenge, effective design and management is still difficult. For conceptual projects, simulation methods may be used for addressing management issues, and for technical optimisation of CO_2 capture, transport and injection (Mustafiz and Islam 2008, Ravagnani, Ligero et al. 2009, Kamari, Nikookar et al. 2014, Mehregan, Jafarnejad et al. 2014, Cai, Dong et al. 2016, Van and Chon 2017). According to Meltzer (2012) between 90 – 95% of the fresh CO_2 supplied to CO_2 EOR projects is retained in the reservoir and the processing units, as these are connected in a closed loop. Any leakage is expected to be minimal, and mainly related to short and infrequent power outages during recondition of the CO_2 and CO_2 migration from the reservoir. Other than technical viability, critical project parameters include economic, socio-political and environmental viability.

The environmental performance of CCS and CO_2-EOR systems (both modelled and actual cases), have been assessed in the literature using lifecycle assessment (LCA), a technique used to assess environmental impacts of a technological system over the full lifecycle and by incorporating the full

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value chain. By assessing all parts of the lifecycle, the environmental benefits of CO_2 reduction can then be weighed up against the environmental impacts of the extra resources, emissions and processes required. LCA studies show that CO_2 capture at large industrial facilities reduces greenhouse gas (GHG) emissions (indicated by the 'Global Warming Potential'), mostly due to the decrease in direct CO_2 emissions (Pehnt and Henkel 2009, IEAGHG 2010, Modahl, Askham et al. 2012, Singh, Stromman et al. 2012, Viebahn, Daniel et al. 2012, Zapp, Schreiber et al. 2012, Corsten, Ramirez et al. 2013, Turconi, Boldrin et al. 2013, Singh, Bouman et al. 2015, Petrescu, Bonalumi et al. 2017, Petrescu and Cormos 2017). LCA studies investigating use of captured CO_2 for CO_2 EOR generally also conclude that lifecycle GHG emissions of both facility operation and oil production are reduced (Hertwich, Aaberg et al. 2008, Jaramillo, Griffin et al. 2009, Cuellar-Franca and Azapagic 2015, Lacy, Molina et al. 2015, Mora, Vergara et al. 2016, Mora, Vergara et al. 2017). Highest generation of GHG emissions in a CO_2 EOR project are often found at the facility because of energy consumption and associated upstream fuel supply chain, whilst dehydration, compression and transport of CO_2 are often found to contribute negligibly (Lacy, Molina et al. 2015). For both CCS and CCUS cases, impact categories other than GWP may be increased; this issue of 'problem shifting' is often seen in LCA literature.

In this article, a conceptual EOR system was developed based on an oxyfuel power plant located in Poland that acted as a source for CO_2, coupled to a promising oil field located on the Norwegian Continental Shelf in the North Sea. All parts of the systems were process modelled, with results used as input for LCA. Results from the technical modelling and LCA work are presented here and compared to a reference system comprising of conventional electricity and oil production. This provides a partial evaluation of the implementation potential for the CO_2 EOR system in Europe.

2. Methods

2.1 Process modelling

The CO_2 EOR system was based on an oxyfuel power plant with CO_2 capture, with CO_2 transported by ship and used for EOR, and is shown in Figure 1. The system was designed to ensure that CO_2 production equalled CO_2 demand (by e.g. adjusting the oxyfuel power plant operating time), and was assumed operational between the years 2020 and 2038. The years 2020 and 2021 were considered as the investment phase, with oil production beginning from the year 2022. Whilst power plant and ship operation were assumed constant over time, operational parameters of oil production were assumed to vary each year due to the evolving profile of the oil field with time. The Reference system was based on a conventional pulverised coal combustion (PC) power plant and conventional oil production (with no coupling between), and is shown in Figure 2.

All parts of the CO_2 EOR and Reference systems were process modelled as part of the work. For power plant modelling, thermoflex software was used to assess key parameters and flows. Aspen Hysys software and Excel models were used to model CO_2 ship transport and oil production.

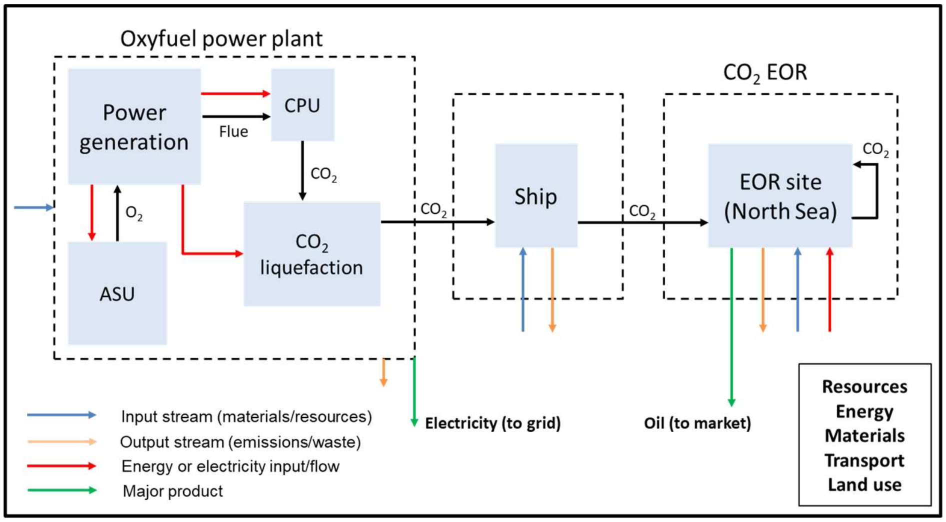

Figure 1: Enhanced oil recovery (EOR) system boundaries.

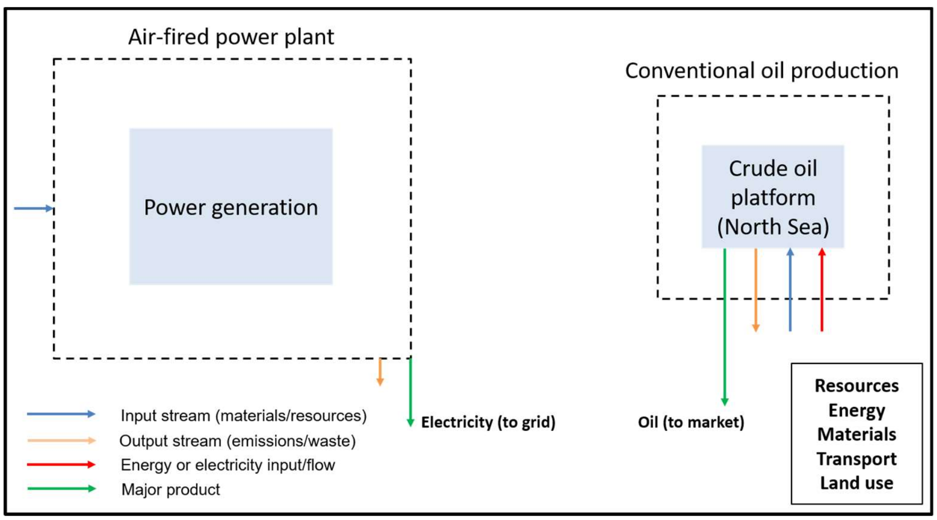

Figure 2: Reference case system boundaries.

2.2 Lifecycle Assessment

Lifecycle environmental impacts were calculated using a process based LCA model. The goal of this work was to compare the CO_2 EOR system with the Reference system (no CCUS option applied). Since a number of different products are produced by the system, the system was studied in two parts (with different functional units) allowing the power plant facility operation and oil production components to be studied separately and impacts allocated to the different products, before the system was studied collectively as a whole. Operation of the power plant was assumed constant over time, but due to the evolving profile of the oil-field with time, analysis involving oil production required each year to be treated separately (i.e. an individual LCA was performed for each year using different parameters).

The following LCA comparisons were therefore performed:

1. The production of electricity from the PC or oxyfuel coal power plant, with a functional unit of 1 kWh of electric energy produced and ready for delivery to the grid.

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2. The production of oil between the years 2022-2038 from conventional means or using CO_2 EOR, with a functional unit of 1 kg oil produced. Any natural gas co-product produced had emissions attributed based on the respective chemical energies (LHV) of crude oil and natural gas.
3. The production of oil and electricity between 2022-2038 in the whole CO_2 EOR system, or the production of oil and electricity in the Reference system, with a functional unit of 1 kg oil (and n kWh associated electricity) produced.

The LCAs were modelled using SimaPro Analyst v8.1.1.16, and aimed to include the contributions from all relevant lifecycle processes. Data on resource (materials and energy) input, emissions and waste was modelled for foreground processes or collected from the literature. For background processes or where there was no primary data, standardized data available in the LCI database ecoinvent v3.1 was used, containing all the input resources and energy, emissions and waste resulting from production of different commodities. Background processes were attached to the foreground processes to build the cases (normalising all inputs and outputs per the functional unit). The ReCiPe Midpoint (Hierarchist) impact assessment method was selected for analysing the impact of lifecycle emissions (Goedkoop, Heijungs et al. 2013). Impact results are presented for four categories. These impact categories, and their corresponding impact indicators, are: climate change (GWP_{100} in kg CO_2-eq), particulate matter formation (in kg PM_{10}-eq), terrestrial acidification (in kg SO_2-eq) and human toxicity (in kg 1,4 DB-eq). These were selected (out of a possible 18 categories) since they reflect key issues and give comparability with much other LCA literature, as well as avoiding the additional uncertainty associated with endpoint categories.

Infrastructure and decommissioning of the facilities were included in the LCA analysis although differences in required construction materials between the oxyfuel and PC power plants, and CO_2 EOR and conventional oil production, were considered negligible (per kWh and kg oil produced, respectively). In addition, the system boundary did not extend to include use of the produced products, to minimize uncertainties.

In the subsequent subsections the key characteristics of the power plants, ship transport and oil production are described in more detail. Inventory model details are given in the supplementary information.

3. Results and Discussion

3.1 Process Modelling

3.1.1 Power plant

The reference PC power plant was modelled as a newly built facility on the Baltic Sea coast in Poland, with a gross power of 300 MWe (Figure A1). It was based on best available technologies (BAT) including a supercritical steam cycle (600/620 °C, 25 MPa), with a pulverized fuel boiler. NO_x and SO_x emissions were modelled below 150 mg Nm^{-3}.

The oxyfuel power plant case was adapted from the Reference case in terms of the basic steam cycle and turbine technology, but modified for a CO_2 compression and purification unit (CPU) (Figure A2). Aside from the CPU to purify CO_2 to EOR requirements, other adaptations include a cryogenic air separation unit (ASU), and flue gas recirculation for temperature control. This resulted in a conceptual system with the same boiler size, but with lower net power. Operational parameters were set to result in annual capture of 1.2 Mt CO_2 available for liquefaction, transport and CO_2 EOR. This equals the quantity of fresh CO_2 required for injection at the EOR site.

Selected simulation model results for both the PC and oxyfuel power plant cases are shown in Table 1. Annually, the PC and oxyfuel plants produced net electricity of 1,782,500 MWh and 1,392,687.5 MWh, respectively. The output of the oxyfuel CPU was a compressed and purified flow of CO_2 plus contaminants (54.8 kg/s at 74 bar and 298.15 K), composed of 99.9 mol% CO_2, 0.01 mol% O_2, 0.0039 mol% N_2 and 0.1 mol% Ar. Calculated efficiencies (based on a coal lower heating value of 23,429 kJ/kg) were 46.2 % and 36.9 % for the PC and oxyfuel power plants, respectively.

Table 1: Simulation results for the pulverized coal combustion (PC) and oxyfuel power plant cases.

Parameter		Unit	Value		
			Oxyfuel plant	PC plant	Delta (PC-oxyfuel)
Design	Gross power	MW	300.0	300.0	0.0
	Net power	MW	222.9	285.2	62.3
	Lifetime	yr	25	25	0.0
	Annual operating time	hr/yr	6250	6250	0.0
Input materials	Coal consumption	kg/s	25.74	26.33	0.59
	Ambient air	kg/s	205.4	256.2	50.8
	Water consumption	kg/s	7.2	6.682	0.518
	Sea water (cooling)	kg/s	14,236.5	7,384,3	-6,852.2
	Limestone consumption	kg/s	1 076	1 039	-0.037
	Ammonia consumption	kg/s	0.0257	0.0204	-0.0053
	Technological O_2	kg/s	50.05	0.00	-50.05
Flue gas mitigation	Flue gas desulphurisation efficiency	% SO_2 removed	99.3	94.3	-5.0
	Selective catalytic reduction efficiency	% NO_x removed	94.0	62.5	-31.5
	Electrostatic precipitator efficiency	% PM removed	99.9	99.9	0.0
Emissions to atmosphere	Flue gas (mass flow)	kg/s	10.03	289	278.97
	CO_2	mol%	8.083	13.224	5.141
	H_2O	mol%	0.563	10.1	9.537
	O_2	mol%	14.99	3.967	-11.023
	N_2	mol%	58.853	71.84	12.987
	Ar	mol%	17.506	0.864	-16.642
	SO_2	mol%	0.0040	0.005	0.001
	NO_x	mol%	0	0.005	0.005
Waste	Ash production	kg/s	2.897	2.964	-0.066
	Gypsum	kg/s	1.901	1.837	-0.064

3.1.2 CO_2 transport

Ship transport from the oxyfuel power plant to the CO_2 EOR site was modelled based on a two ship solution (maximum size 12,000 t each) with offshore unloading, over a distance of 677 nautical miles (Figure A3 and Figure A4). CO_2 transport is not relevant for the Reference system.

Diesel ships were modelled, with heat exchanger and seawater pump. A liquefaction plant was also modelled on the Polish mainland coast (5.5 MW net power requirements) along with shore storage. CO_2 unloading at the platform was modelled using a 3.3 MW pump. CO_2 losses during transport, liquefaction and onshore storage were considered negligible.

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Selected simulation model results for CO_2 liquefaction and ship transport (between the oxyfuel power plant and the CO_2 EOR site) are shown in Table 2. The liquefaction plant was assumed to operate the same number of hours annually as the oxyfuel power plant, resulting in an annual energy requirement of 35,561.5 MWh (supplied with electricity from the Polish grid).

Table 2: Simulation results for CO_2 liquefaction and transport.

Parameter		Unit	Value
CO_2 liquefaction plant	Capacity	Mt CO_2/yr	1.2
	Annual operating time	hr/yr	6,250
	Power requirements compression	kW	6,349
	Cooling water heat exchanger	m^3/hr	774.61
	Power requirements expander	kW	-878.00
	Net power requirement	MW	5.5
CO_2 ship transport	Capacity	Mt CO_2/yr	1.2
	Transport distance (one way)	km	1,254
	Ship speed	km/hr	22
	Loading time	hr	12
	Port manoeuvring time	hr	4
	Transit voyage (laden, outward journey)	hr	56
	Connection offshore time	hr	3
	Discharge offshore time	hr	48
	Disconnection time offshore	hr	3
	Transit voyage (ballast, return journey)	hr	56
	Total roundtrip time	hr	183
	Idle time per roundtrip	hr	9
	Annual number of ship roundtrips required	No.	44
	Roundtrip fuel consumption per ship	t/ship	109

3.1.3 Oil production

Conventional oil production was modelled on the Brage field in the North Sea (Figure A5), using publicly available data (Andersen, Halvorsen et al. 2000, Wintershall 2016, NPD 2018). The water/oil production ratio, reinjected water/oil ratio, natural gas/oil production ratio and proportion of natural gas sold were modelled as for the year 2015 at Brage (Wintershall 2016). Water modelling involved partial reinjection in the Statfjord manifold, with the rest released to sea. If the volume for injection in the Statfjord manifold was not sufficient, it was supplemented with water produced from the neighbouring Utsira formation. Produced natural gas was recompressed/compressed for reinjection and gas lift, flared, or exported and sold. For the initial operational phase (years 2022 and 2023) it was also used for on-site electricity production via turbines. For conventional oil production, 60 % of natural gas produced was considered sold (Wintershall 2016). Power was required for water, gas and oil components. The total power needed for the Utsira system and reinjected water at Brage was 4.1 MW and 3.5 MW, respectively. Power was also required for gas recompression (0.87 kW/m^3 gas) and gas compression (1.3 kW/m^3 gas), as well as for the oil export pump (0.234 kW/bbl oil, 1 to 30 bar). To meet this power demand during the main operational phase (years 2024-2038), platform electrification was assumed, with power supply via Oseberg from the Norwegian mainland (25 MW capacity).

It was assumed that electrification of the Brage platform is necessary if CO_2 EOR is to be applicable. This is due to the added complexity of the platform separation process if natural gas turbines are to provide the power needed for platform operation. In such a scenario a separation of CO_2 and natural gas is needed. New equipment would be needed either on the platform or on a floating production storage and operation (FPSO). It is also likely that installing such equipment will result in unwanted, and possibly, lengthy stops in oil production.

When modelling the CO_2 EOR oil production, the strategy for fresh CO_2 supply is also a key parameter. Generally, a substantial increase in oil production rates shortly after CO_2 injection starts is preferred. However, such a scenario necessitates that large volumes of CO_2 are injected over the first few years, with gradually smaller volumes over the remaining years. The decline in fresh CO_2 needs is both due to the initially flooding of the reservoir with CO_2 and since parts of the CO_2 injected will be reproduced with the oil. This CO_2 is reinjected into the reservoir, thereby reducing the need for fresh CO_2. The challenge with this scenario is the added complexity of the fresh CO_2 supply chain. In the current investigation, it was decided that a constant supply of fresh CO_2 over the project lifetime should be adopted for the CO_2 EOR case. This resulted in a predictable fresh CO_2 supply chain (from power plant to offshore injection), although it comes at the expense of delayed increased oil production. Beyond the decision of constant fresh CO_2, other key assumptions made up the main basis for the calculation. These were that the CO_2 EOR oil production profile was equal to the historical oil production curve at Brage, that 10 % of original oil in place could be recovered through CO_2 EOR, that 40 % of injected CO_2 is produced (Andersen, Halvorsen et al. 2000, Hegerland, Eldrup et al. 2010), and that 1 t of CO_2 injected could recover 3 bbl of oil. With these assumptions, the CO_2 injection rates (both fresh and recycled) were calculated over the project lifetime to match the expected oil production for each year. This resulted in a CO_2 injection requirement from the year 2022 of 1.2 Mt fresh CO_2 per yr. No fresh CO_2 injection was assumed to occur during the investment phase (2020-2021). The assumed injection of fresh and recycled CO_2, and resulting additional oil production, are shown in Figure 3. Over the lifetime of the CO_2 EOR case, 98.7 million bbl of additional oil were assumed recovered.

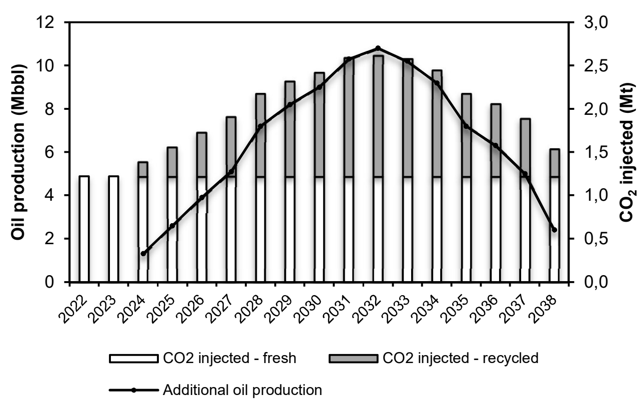

Figure 3: Key model assumptions for the CO_2 EOR case: annual injected fresh and recycled CO_2, and annual additional oil production compared to the conventional oil production case.

No new oil production (or CO_2 injection) wells were modelled, with reuse of existing unmodified wells for CO_2 injection. The maximum injection capacity per well was assumed as 342 t/hr (3 Mt/yr). It was also assumed there was sufficient capacity in topside separation units for the extra water, oil and gas produced. CO_2 breakthrough (CO_2 produced with the oil) was modelled from 2024, with 98 % produced gas (natural gas and CO_2) reinjected (i.e. no separation) using a one stage recompression from 1 bar to 7.5 bar, and further three stage compression after the drying and H_2S removal unit from

7 bar to 220 bar. Therefore, natural gas sales were assumed as normal up until 2024, and subsequently ceased, and for both the CO_2 EOR and conventional oil production cases, no natural gas was used for onsite power after the year 2024. It is also to be expected that some of the produced gas is lost, due to operational instability and keeping the pilot flame burning as a safety measure. To represent this loss, 2 % of produced gas was assumed burned in the flare. Fresh CO_2 injection required a 0.8 MW pump (70-220 bar). Straight CO_2 injection was assumed, and not a water alternating gas (WAG) injection regime, as the Brage field currently injects water into the reservoir through a separate system; it was assumed that this water injection regime would be continued during CO_2 EOR oil production and that it would therefore be kept separate from the CO_2/gas injection system.

Figure 4 shows a summary of the key material flows for the conventional and CO_2 EOR oil production cases. Most produced natural gas was reinjected (along with CO_2) for the CO_2 EOR case, but sold in the conventional case (Figure A6). Total power requirements were higher for the CO_2 EOR case, mostly due to gas compression and recompression requirements (Figure A7). Resulting simulation model results of total oil production using conventional or CO_2 EOR means are shown in Figure 5. Over the operational lifetime, total oil production using CO_2 EOR was 4.5 times higher than for the conventional case. Due to the high oil production for the CO2 EOR case, energy requirements per kg oil produced are lower for the CO_2 EOR than the conventional oil production (Figure 6).

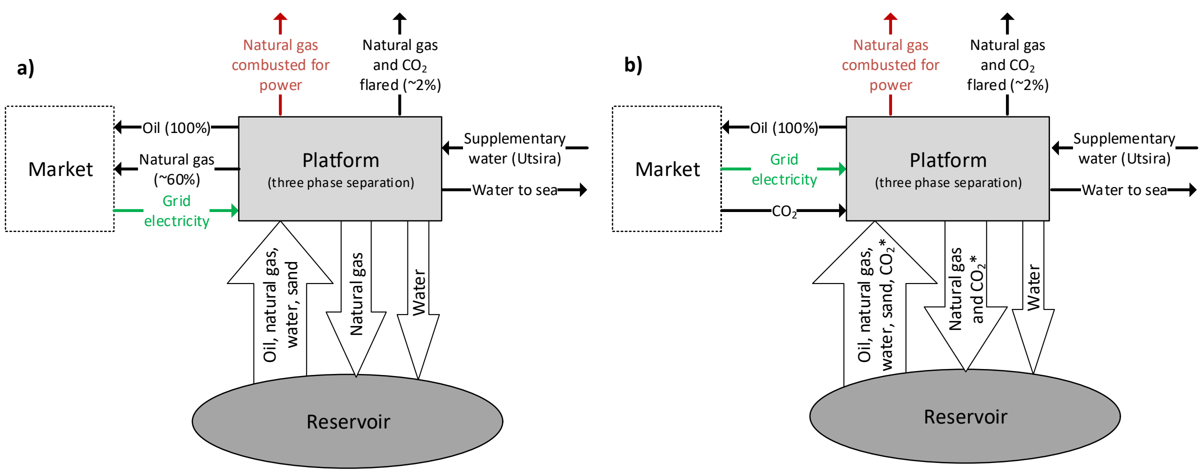

*Figure 4: Schematics of the key material flows for a) conventional and b) CO_2 EOR oil production, during the operational lifetime (years 2022-2038). Flows indicated in red are only applicable for the early operational phase (2022-2023), whilst flows indicated in green are only applicable for the main operational phase (2024-2038). *Note that for the CO_2 EOR case, whilst CO_2 is injected from the year 2022, it is only produced from the year 2024.*

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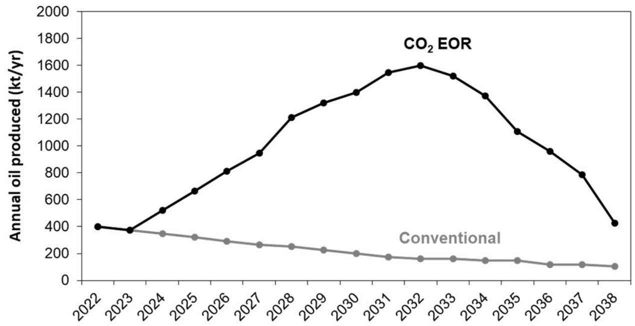

Figure 5: Simulation results of annual oil production between the years 2022 and 2038 for the conventional and CO_2 EOR cases.

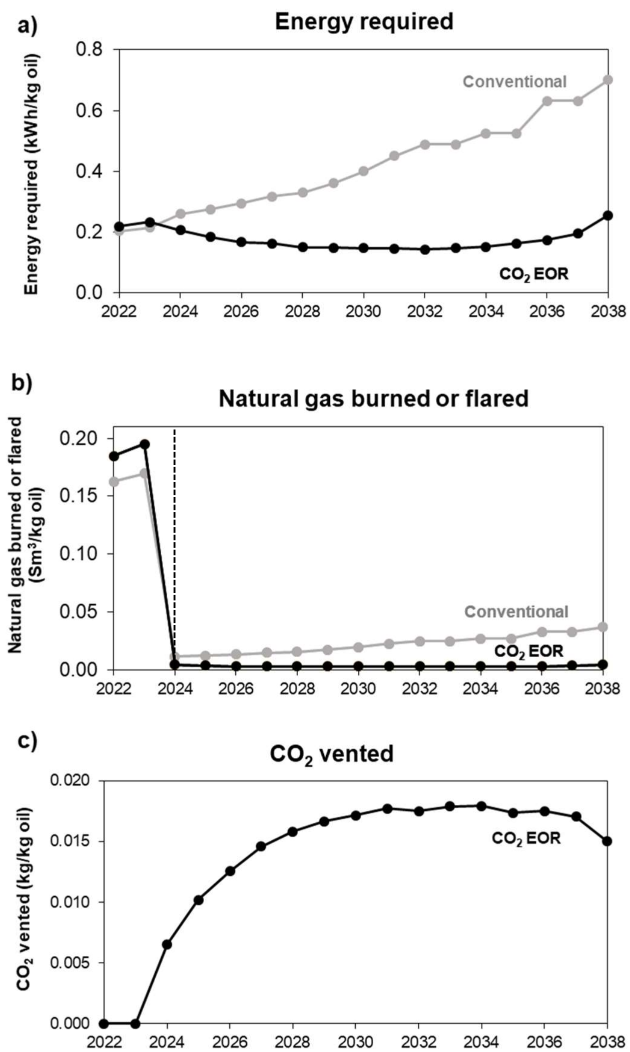

Figure 6: Key statistics for the conventional and CO_2 EOR production cases; a) energy requirements, b) natural gas burned or flared and c) CO_2 vented, per kg oil produced. Note: Where relevant, the dotted line marks the transition from power produced on site (from combustion of natural gas) to platform electrification. CO_2 venting is not applicable for conventional oil production.

3.2 Lifecycle Assessment

3.2.1 Power plant and CO_2 transport

An overview of the relative environmental impacts resulting from the production of 1 kWh from the PC or oxyfuel power plants alone, is given in Figure 7. Since a CPU is installed at the oxyfuel power plant, this was included as part of the oxyfuel facility operation. Additionally on the figure are the relative environmental impacts for the oxyfuel power plant with system boundaries expanded to include liquefaction and ship transport of the CO_2 produced. This was included with the facility since in practice the CO_2 transport component would be coordinated by the Polish mainland in tandem with power plant operation. Impacts per kWh produced for these cases were assumed to remain constant throughout the power plant lifetime (i.e. also over the operational period of the oil field between the years 2022-2038).

The analysis showed that per kWh, oxyfuel electricity production has lower lifecycle CO_2-eq (-81 %), PM_{10}-eq (-12 %), and SO_2-eq (- 41 %) emissions than PC electricity production, whilst toxicity related impacts are increased (+ 22 %). When liquefaction and transport of the produced CO_2 is included with the oxyfuel electricity the balance shifts for particulate matter and acidification predominantly due to the high amount of PM and SO_2 emissions associated with combustion of heavy fuel oil during ship transport. This concept of problem shifting is common in LCA analysis. The reduction in GHG emissions for the oxyfuel case mostly occurs due to the decrease in direct emissions at the plant, since it has an effective CO_2 capture efficiency of 98 %. Note that before CO_2 capture the total (lifecycle) CO_2 emissions produced per kWh at the oxyfuel plant are higher than the PC power plant, since the lower plant efficiency requires more coal to be combusted per kWh electricity. However, after CO_2 capture, the oxyfuel plant releases 0.02 kg CO_2 per kWh to the atmosphere compared to 0.73 kg for the PC power plant. Ship transport of the captured 0.88 kg CO_2 per kWh in the oxyfuel case does not significantly increase the overall lifecycle CO_2-eq.

The bar charts in Figure 7 indicate the contributions from the coal feedstock, power plant and ship to total lifecycle emissions. In addition, the contribution of the power plant is divided into indirect (including infrastructure, non-coal resource requirements and waste treatment), and direct (i.e. emissions to the atmosphere) categories. For the oxyfuel power plant, most impacts derive from the hard coal feedstock (with direct emissions from the plant also playing a significant role for particulate matter formation potential), whilst for the PC power plant, most impacts derive from direct emissions in the flue gas.

These trends are similar to those found in other oxyfuel power plant studies. Literature reviews (IEAGHG 2010, Zapp, Schreiber et al. 2012, Corsten, Ramirez et al. 2013, Cuellar-Franca and Azapagic 2015) report that climate change potential (kg CO_2-eq) may be around 80-90 % lower for oxyfuel power plants than for PC power plants without CCS. Simultaneously, other impact categories (such as human toxicity potential) may increase, depending on the technology (and system boundaries) used for the study. This fits well with the results of this study, where lifecycle CO_2-eq was decreased by - 81 % compared to a power plant with no CO_2 capture, whilst lifecycle 1,4 DB-eq emissions increased per kWh. As here, it is also reported that fuel supply and direct CO_2 emissions are the main contributors to lifecycle CO_2-eq, due to the upstream (indirect) effects of fuel mining and production.

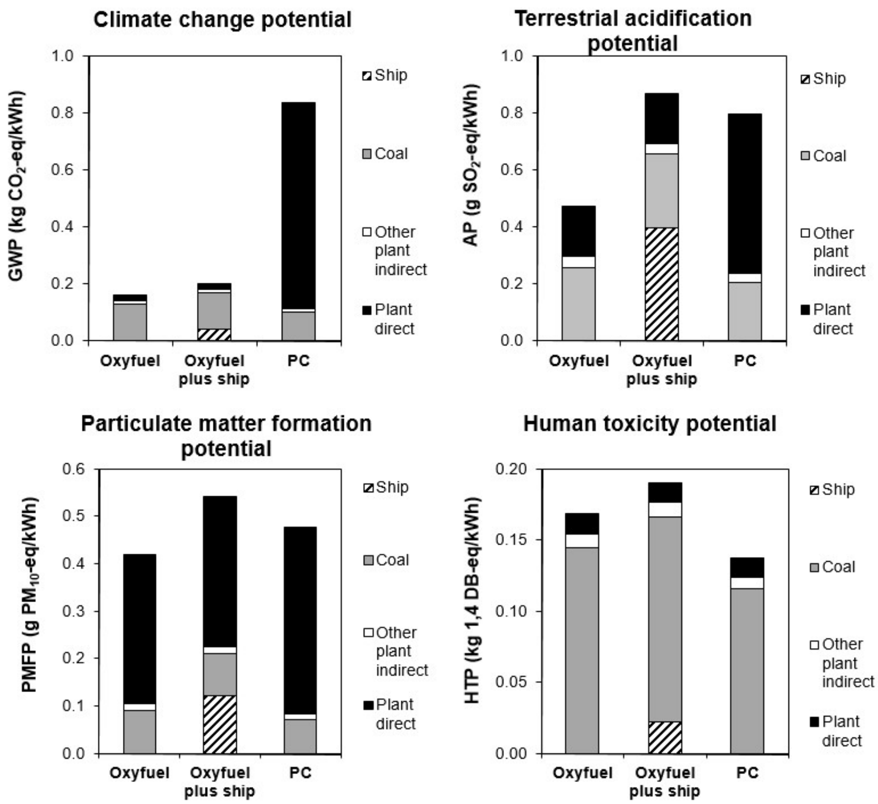

Figure 7: Key contributions towards environmental impact indices for the production of 1 kWh from the pulverized coal combustion (PC) power plant, oxyfuel power plant, or the oxyfuel power plant plus liquefaction and transport by ship of the CO_2 produced.

3.2.2 Oil production

A selection of environmental impacts resulting from the production of 1 kg oil from conventional or CO_2 EOR means between the years 2022-2038 is given in Figure 8. Directly comparing lifecycle impacts per kg oil produced assumes that the total oil production at Brage will remain constant, despite the extra potential oil produced due to use of CO_2 EOR. This is valid if it is considered that the market demand for oil remains the same as for the conventional case. Since the oil production (and resource requirement) profile changes with time, each year was modelled separately using LCA. To reflect this level of detail, resulting impacts are presented in Figure 8 per year rather than as averages over the full lifecycle. In the conventional case (and years 2022 and 2023 of the CO_2 EOR case) where a quantity of natural gas is produced along with oil, emissions were attributed to the natural gas co-product based on the respective chemical energies (LHV) of crude oil and natural gas.

The figures show that whilst in the year 2022 CO_2 EOR oil production has higher emissions than conventional oil production, by the year 2038 CO_2 EOR oil production has lower lifecycle CO_2-eq, PM_{10}-eq, SO_2-eq and 1,4 DB-eq, per kg oil produced. The year when CO_2 EOR oil production becomes favourable compared to conventional oil production varies with impact, but is around the year 2030. At this point in time, modelled oil production is around 7 times higher for CO_2 EOR oil production than conventional oil production (see Figure 5). This indicates that the increased resource and power requirements for CO_2 EOR are offset by the larger quantity of oil produced at this point.

Figure 9 shows the impacts divided into their contributions from the production and reinjection of water onsite and from Utsira, the production and reinjection of natural gas and/or CO_2 (including flaring and venting), the operation of the oil export and CO_2 ship pump, and other indirect contributions (including platform infrastructure and decommissioning, other resources and waste). It should be noted that infrastructure, other resource requirements and waste were kept constant per kg oil produced in the model. Results for the year 2022 (with production of on-site power) and 2030 (with platform electrification) are shown. For the year 2022, most impacts derived from water use, switching to 'other' indirect contributions for the year 2030. The exception was for human toxicity potential where most impacts derived from other indirect contributions both in the year 2022 and 2030.

At a more detailed level, further analysis showed that most impacts in the year 2022 derive from combustion of natural gas for production of on-site power. This explains why the impact potentials are higher for the years 2022 and 2023 since for these years the platform produced power using on-site turbines using natural gas. In addition, water use is the significant contributor towards impacts since it is the pumping processes that requires the most energy in the year 2022 (76 % and 82 % of the total energy for the CO_2 EOR and conventional oil production cases, respectively, per kg oil produced). For the CO_2 EOR case, 89 % of lifecycle CO_2-eq, 68 % of lifecycle SO_2-eq and 65 % of lifecycle PM_{10}-eq derive from on-site power production (and associated fossil fuel emissions). In contrast most toxicity impacts derive from platform waste (33 %) and the platform infrastructure (38 %), as a result of the steel used. With platform electrification (using the year 2030, as an example), the key source of lifecycle CO_2-eq switches to CO_2 venting (32 % of lifecycle CO_2-eq) and natural gas flaring (14 % of lifecycle CO_2-eq). For SO_2-eq and PM_{10}-eq, most lifecycle emissions derive from the platform infrastructure (with 35-40 % from the associated diesel use during production). Most toxicity impacts (37 %) derived from electricity usage as a result of copper used in the transmission network, with similar contributions from the materials for construction and decommissioning of the platform, and other input materials and waste for oil production.

Due to these relationships, lifecycle CO_2-eq, SO_2-eq and PM_{10}-eq emissions in Figure 8 show a dependency with the total natural gas burned or flared (Figure 6b), whilst lifecycle 1,4-DB-eq emissions in Figure 8 show a dependency with the quantity of energy (electricity) required (Figure 6a).

These results correlate with other LCA studies, which find that CO_2 EOR can have a favourable effect on certain impact categories per unit oil produced. Over the lifetime of the oil field, Hertwich et al. (2008) found that lifecycle CO_2-eq per unit of oil produced was lower for the EOR case than with normal operation, and that with platform electrification, lifecycle CO_2-eq emissions for the CO_2 EOR case were further reduced. When the functional unit of this study was converted for comparison, lifecycle CO_2-eq emissions equaled 0.21 kg, 0.15 kg, and 0.02 kg per kg oil for normal operation and the EOR cases (with on-site power, and platform electrification), respectively. Similarly, Lacy et al. (2015) reported equivalent lifecycle CO_2-eq emissions of 0.28 kg per kg oil produced. Although direct comparison of results is difficult due to changes in system boundaries between the studies, these values are within the range of those found in this study, when comparing to years 2022-2023 with on-site power production and from 2024 with platform electrification. Without platform electrification, significant emissions from CO_2 EOR have been shown to derive from fuel combustion for on-site power generation. The contribution of on-site power generation reported by Hertwich et al. (2008) to lifecycle CO_2-eq per unit of oil produced was 88 %, similar to that described here (89 %). Results are highly linked to differences in annual oil production rate, meaning that the allocation method (e.g. normalising impacts according to the quantity of oil produced) has a large influence on results (Hertwich, Aaberg et al. 2008, Jaramillo, Griffin et al. 2009).

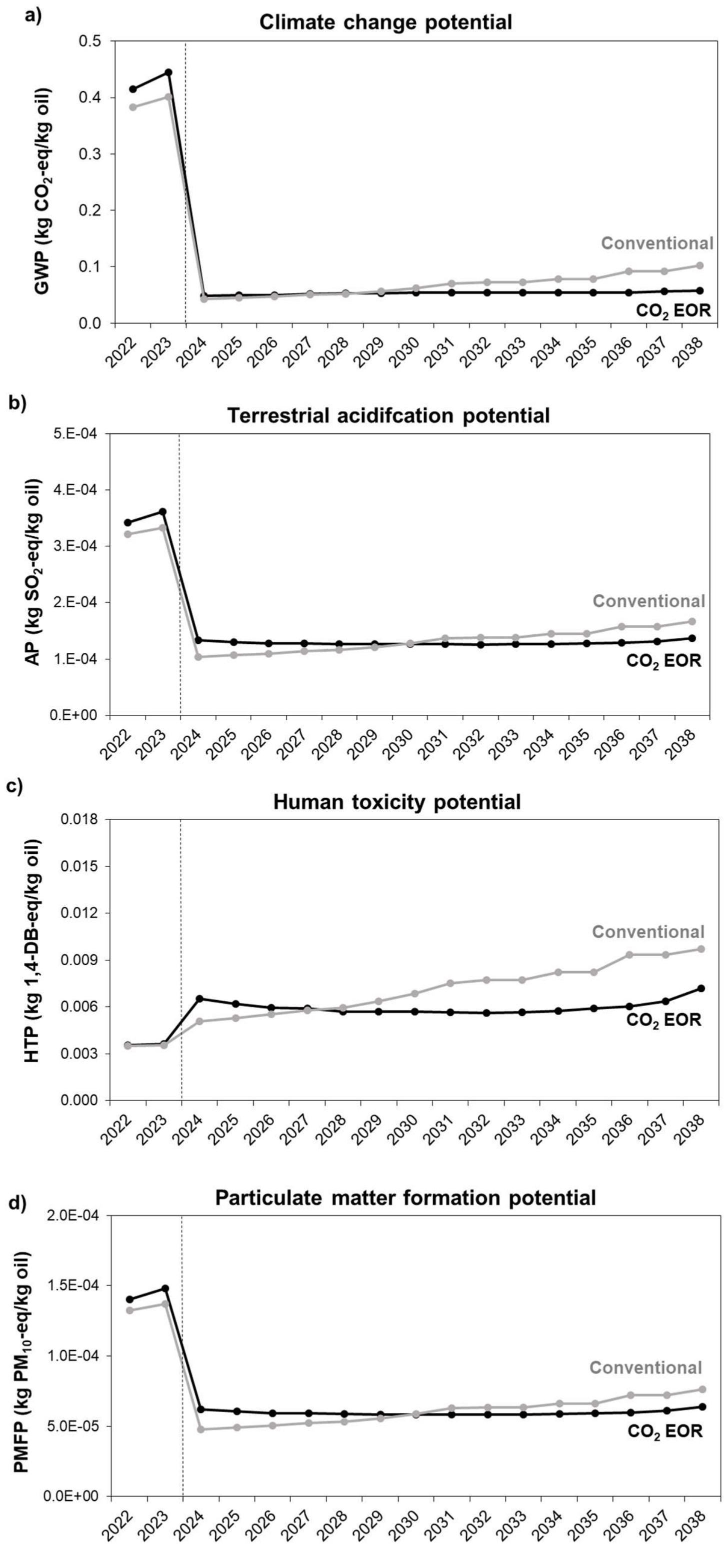

Figure 8: Relative a) climate change potential, b) terrestrial acidification potential, c) human toxicity potential and d) particulate matter formation potential for the production of 1 kg oil from conventional or CO_2 EOR means. The dotted line marks the transition from power produced on site to platform electrification.

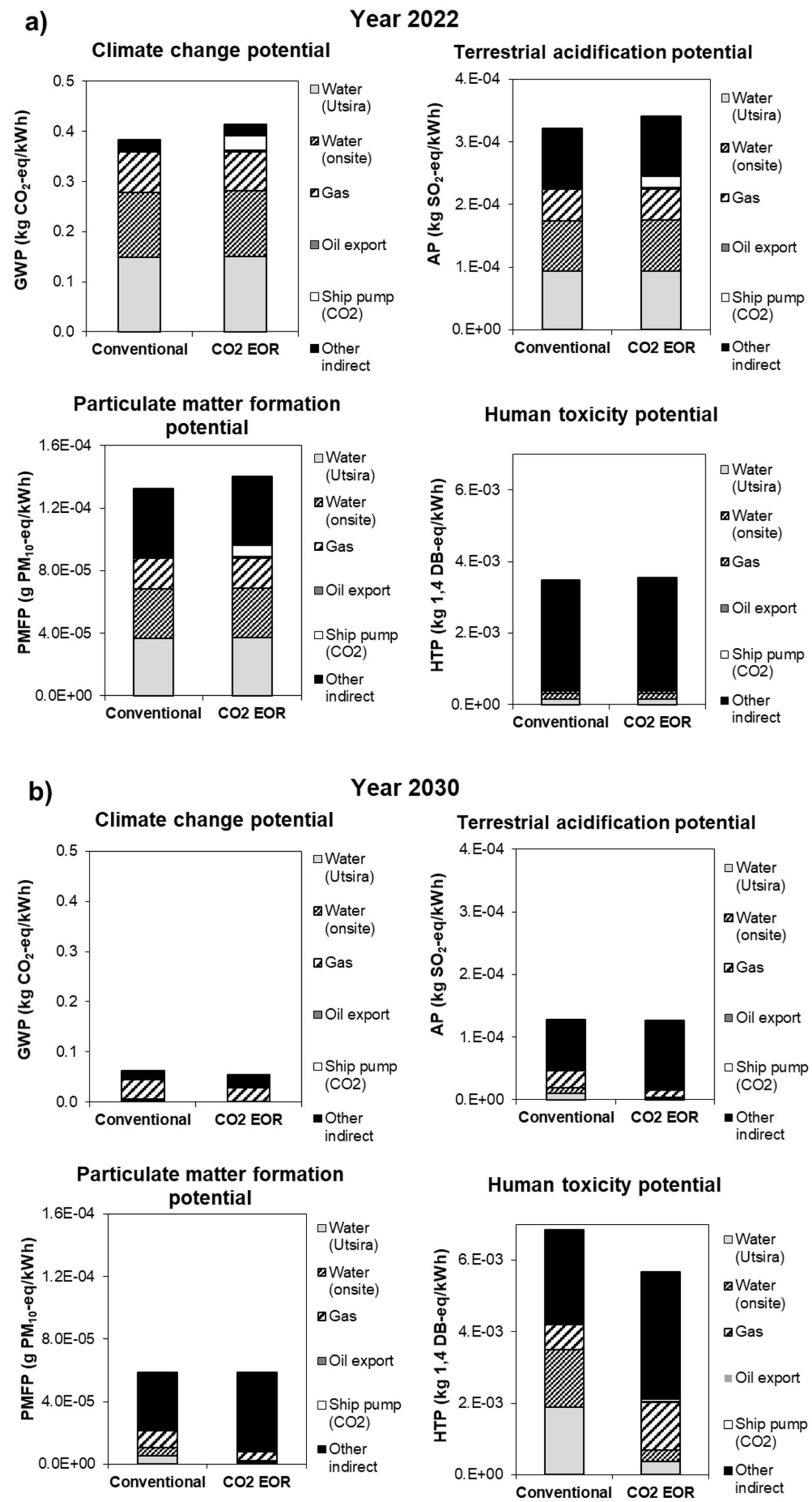

Figure 9: Key contributions towards environmental impact indices for the production of 1 kg oil from conventional or CO_2 EOR means, for the years a) 2022 and b) 2030. The contributions include the production and reinjection of water onsite, the production and reinjection of water from Utsira, the production and reinjection of natural gas and/or CO_2, the operation of the oil export and CO_2 ship pump, and other indirect contributions.

3.2.3 Whole CO_2 EOR system

To perform whole chain analysis of the CO_2 EOR system, the operation of the oxyfuel power plant and ship transport were normalized according to the amount of oil produced, assuming that the combined production of electricity and fresh (captured) CO_2 at the power plant is matched to EOR injection demands. A summary of the normalized calculated annual parameters (the quantity of electricity produced, CO_2 transport and fresh CO_2 injection required per kg oil produced) is found in Figure 10. This figure also indirectly shows the functional unit of the whole CO_2 EOR system changing over time (i.e. 1 kg oil, n kWh electricity).

Although the Reference system represents separated electricity and oil production, assuming market demands for oil and electricity remain the same as for the CO_2 EOR system, impacts associated with the same quantity of oil and electricity as in the CO_2 EOR case (shown in Figure 10) may be calculated for comparison.

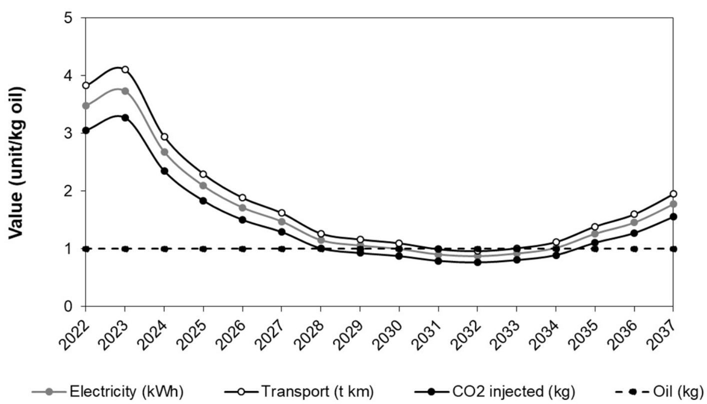

Figure 10: Summary of facility operation required (kWh electricity), CO_2 transport required (t km), and fresh CO_2 injected at CO_2 EOR site (kg), annually between 2022 and 2037 per kg oil produced. The year 2038 was not included on the figure since no CO_2 injection occurred for this year.

A selection of environmental impacts resulting from the production of 1 kg oil (and n kWh electricity) from the CO_2 EOR or Reference system is given in Figure 11 for the years 2022-2037. For year 2038, since there was no CO_2 injection, there was effectively no 'whole-chain system' due to the disconnection between the oxyfuel power plant and the CO_2 EOR platform (i.e. the operation of the power plant could not be normalised according to oil production). The year 2038 was therefore not included in the whole chain analysis. Impacts deriving from the co-product of electricity in the system are included here with the production of 1 kg oil, which represents the overall product of the system. The analysis shows that the CO_2 EOR system has lower lifecycle CO_2-eq for all years compared to the Reference system, per kg oil (and n kWh electricity) produced. However, terrestrial acidification, human toxicity and particulate matter formation potential values are increased. When averaged over the operational lifetime, lifecycle CO_2-eq was reduced by 71 % to 0.4 kg CO_2-eq per kg oil (and n kWh electricity) produced, whilst SO_2-eq, PM_{10}-eq and 1,4 DB-eq increased by 8 %, 13 % and 37 %, respectively.

Figure 12 shows the relative (%) contributions of oil production, oxyfuel power plant operation, and ship transport of CO_2 towards total lifecycle CO_2-eq, PM_{10}-eq, SO_2-eq and 1,4 DB-eq for the production of 1 kg oil (and n kWh electricity) from the CO_2 EOR case. Results showed that the oxyfuel power plant was the greatest contributor to these impacts (due to the coal feedstock in particular, as Figure 7 revealed), and reflects some of the trend in Figure 10. Oil production had a relatively low contribution towards impacts aside from for the years 2022 and 2023, where production of on-site power occurred through combustion of natural gas. When averaged over the operational lifetime, the contributions of the oxyfuel power plant, ship transport and oil production towards total lifecycle CO_2-eq per 1 kg oil (and n kWh electricity) produced were 64 %, 16 % and 20 %, respectively.

Other studies have also found that whole CO_2 EOR systems are favourable compared to conventional production, both for specific systems, and when modelling multiple CO_2 EOR systems into a market (Turk, Reay et al. 2018). When looking at GWP for a similar CCUS system where electricity (natural gas combined cycle power plant) and oil production are linked, Lacy et al. (2015) calculated total lifecycle CO_2-eq of 1.8 kg per kg oil. Although this is higher than reported here, values are not directly comparable due to changes in the system and its boundaries. As found here, Lacy et al. (2015) determined that the largest contribution towards total lifecycle CO_2-eq per kg oil was the power plant, and in particular, its fuel supply (56 % of the total). When CO_2 is stored instead of used for EOR, research also supports that highest GHG emissions in a CCS project derive from the power plant because of energy consumption (Modahl, Askham et al. 2012, Singh, Stromman et al. 2012, Zapp, Schreiber et al. 2012), and that the contribution of transport, injection and storage of CO_2 is much less.

Despite the potential of whole CO_2 EOR systems, it should be remembered that if results are expressed by the quantity of oil produced, a critical parameter is the crude oil recovery ratio (Cooney, Littlefield et al. 2015). This describes how much crude oil is recovered for a fixed amount of CO_2, and is therefore key to normalising results for comparisons with conventional technology. If not normalized for the increased quantity of oil produced, the favourability of total (i.e. absolute) lifecycle emissions for the CO_2 EOR systems vs. conventional technology is greatly reduced.

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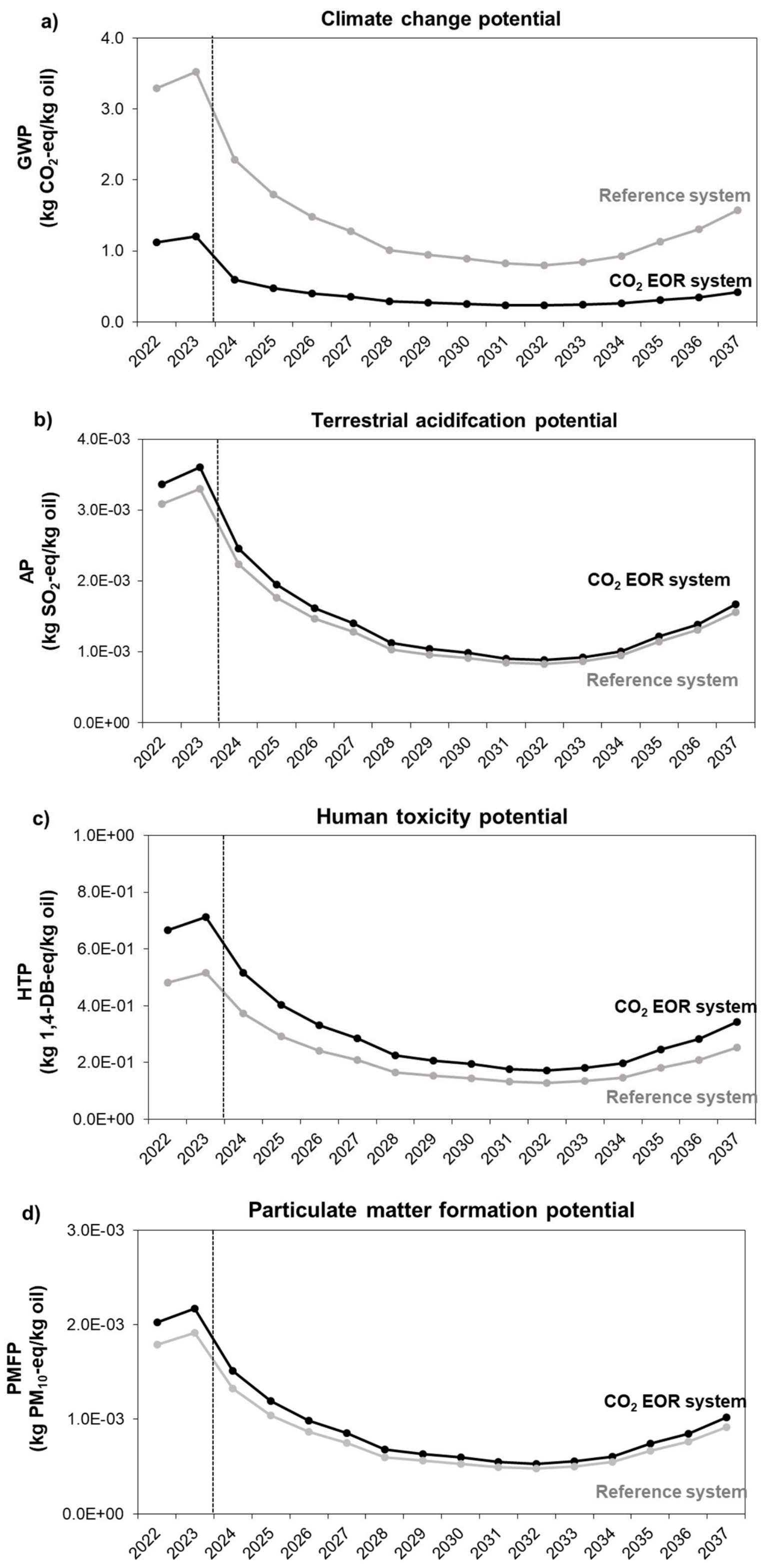

Figure 11: Relative a) climate change potential, b) terrestrial acidification potential, c) human toxicity potential and d) particulate matter formation potential for the production of 1 kg oil (and n kWh electricity) from the whole Reference or CO_2 EOR system. Impacts associated with the production of a quantity of electricity are included here based on the quantity of CO_2 required for injection at the EOR site. The dotted line marks the transition from power produced on site to platform electrification.

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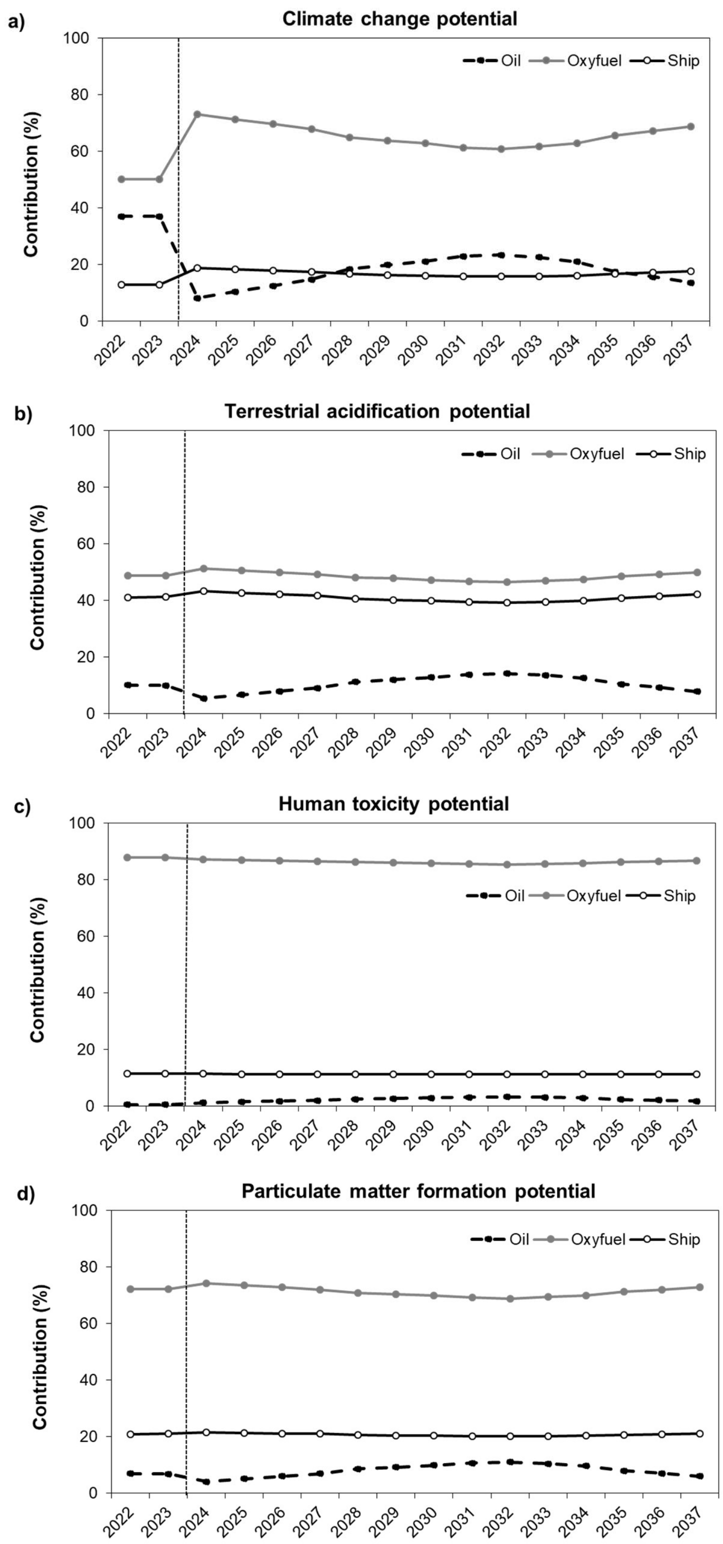

Figure 12: Contribution of oil production, oxyfuel power plant operation, and ship transport of CO_2, towards total a) climate change potential, b) terrestrial acidification potential, c) human toxicity potential and d) particulate matter formation potential for the production of 1 kg oil (and n kWh electricity) from the CO_2 EOR system. Impacts associated with the production of a quantity of electricity are included here based on the quantity of CO_2 required for injection at the EOR site. The dotted line marks the transition from power produced on site to platform electrification.

3.3 Uncertainty analysis – CO_2 leakage

Uncertainties in this study are high, relating both to the technical modelling of the oxyfuel and PC power plants, CO_2 transport and injection/oil production, as well as to the background data used in the analysis for upstream and downstream processes.

Although section 3.2.3 demonstrated that the whole CO_2 EOR system is most sensitive to the oxyfuel power plant (i.e. the oxyfuel power plant, and the coal feedstock in particular, is the major contributor to impacts), one major concern regarding CO_2 EOR is CO_2 leakage from transport and storage due to the potentially large amounts of CO_2 that this can release. Although the environmental impact of CO_2 leakage is considered in some studies (Cooney, Littlefield et al. 2015, Lacy, Molina et al. 2015), for the primary LCA modelling in this article it was considered negligible, assuming optimum operation. For a sensitivity analysis, a degree of CO_2 leakage (between 1 % and 10 %) was thus considered from transport processes, as well as from transport and injection processes combined.

Results (Figure 13, using the CO_2 EOR system year 2030 as an example) show that even with 10 % leakage from both transport and injection processes, lifecycle CO_2-eq is still less than the Reference system, per kg oil (and n kWh electricity) produced. This analysis also accounts for increasing the operation of the facility, to replace leaked CO_2. Due to the uncertainties involved no leakage was investigated from CO_2 stored at the site over the long term.

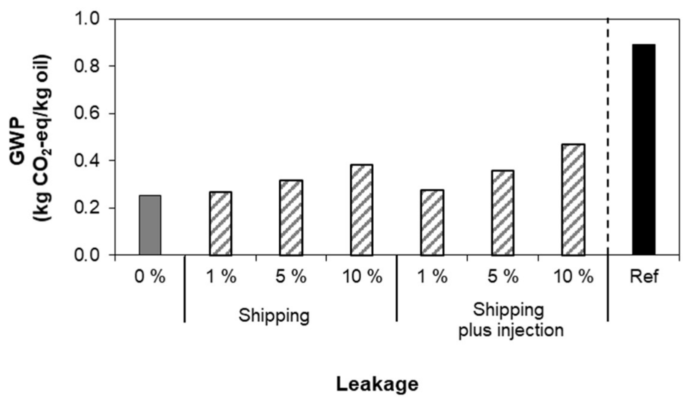

Figure 13: Climate change potential of the CO_2 EOR system with varying degrees of leakage, using Case 1 year 2030 as an example, per kg oil (and n kWh electricity) produced. The Reference case is shown for comparison.

4. Conclusions

Recent decisions for implementation of a Norwegian CCS demonstration will result in the establishment of a central hub on the west coast of Norway and storage on the Norwegian Continental Shelf, which may potentially continue towards a large-scale operation involving CO_2 from Europe and the operation of CO_2 EOR in the North Sea. To determine the environmental favourability of this concept, process and LCA modelling results of a European CO_2 EOR system are presented here and compared to a Reference system comprised of individual oil production and electricity production processes. All parts of the systems were modelled, assuming that market demands for oil and electricity remain the same for the Reference system as the EOR system.

Whilst the Reference system was based on a PC power plant and conventional oil production, the conceptual CO_2 EOR system (operating between 2022 and 2038) was based on an oxyfuel power plant located in Poland that acted as a source for CO_2, coupled to an oil and gas field located in the North Sea in Norway. CO_2 was transported from the oxyfuel power plant to the CO_2 EOR site based on a two ship solution with offshore unloading, over a distance of 677 nautical miles. Platform electrification was assumed from the year 2024, whilst for years 2022-2023, power was assumed produced using onsite turbines. CO_2 injection (1.2 Mt fresh CO_2/yr) resulted in 4.5 times higher oil production over the CO_2 EOR operational lifetime than for conventional oil production.

Power plant operation and oil production were first modelled separately, allowing attribution of impacts to the separate products. LCA results showed that oxyfuel electricity production was favourable to PC electricity production, per kWh produced, for most impact categories studied. GWP was also favourable when system boundaries were expanded to include the CO_2 transport from the oxyfuel power plant to the EOR site. However, other impacts (acidification potential, human toxicity, and particulate matter formation) were increased, per kWh electricity produced, which was primarily due to the decrease in net efficiency of the oxyfuel power plant compared to the PC power plant. For the oxyfuel power plant plus CO_2 and transport, most impacts derived from the hard coal feedstock, and shipping contributed a small amount, per kWh, whilst direct plant emissions played a significant role for the PC power plant. For oil production, LCA results showed that the CO_2 EOR case had lower GWP than conventional oil production per kg oil produced, but that other impacts were higher. Most impacts initially derive from the gas burned or flared, changing to gas production when the site was electrified (from CO_2 venting and natural gas flaring in particular).

For the whole CO_2 EOR system, including both the power plant and oil production operation and assuming CO_2 production of the CO_2 EOR system was matched to demand, LCA results showed that the CO_2 EOR system had lower GWP over its lifetime, per kg oil (and n kWh electricity) produced, than the Reference system. Acidification potential, human toxicity, and particulate matter formation were increased, per kg oil (and n kWh electricity) produced. When averaged over the operational lifetime, lifecycle CO_2-eq was reduced by 71 %, whilst SO_2-eq, PM_{10}-eq and 1,4 DB-eq were increased by 8 %, 13 % and 37 %, respectively. For the CO_2 EOR system, most impacts derived from the oxyfuel plant per kg oil produced (an average of 64 %), with smaller contributions from oil production and ship transport.

The favourability of the CO_2 EOR system study here supports the case for large-scale operation of CO_2 EOR in the North Sea using CO_2 from Europe, in order to work towards EU GHG emission reduction targets. However, as with the introduction of any new technology, care should be taken to avoid problem shifting, i.e., the increase of other types of impact.

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Supplementary Information

Conceptual designs of the Reference case power plant (with no CO_2 capture), the retrofitted oxyfuel power unit, CO_2 transport and CO_2 unloading at EOR site are shown in Figure A1, Figure A2, Figure A3 and Figure A4, respectively. A conceptual design of topside processing for oil production a) without, and b) with CO_2 EOR is shown in Figure A5.

Simulation results of the quantity of natural gas used for gas lift, injected, sold, burned or flared for conventional and CO_2 EOR oil production cases are shown in Figure A6, whilst simulation results of the power requirements for water production/injection, gas compression, oil export or fresh CO_2 injection for the conventional and CO_2 EOR oil production cases are shown in Figure A7.

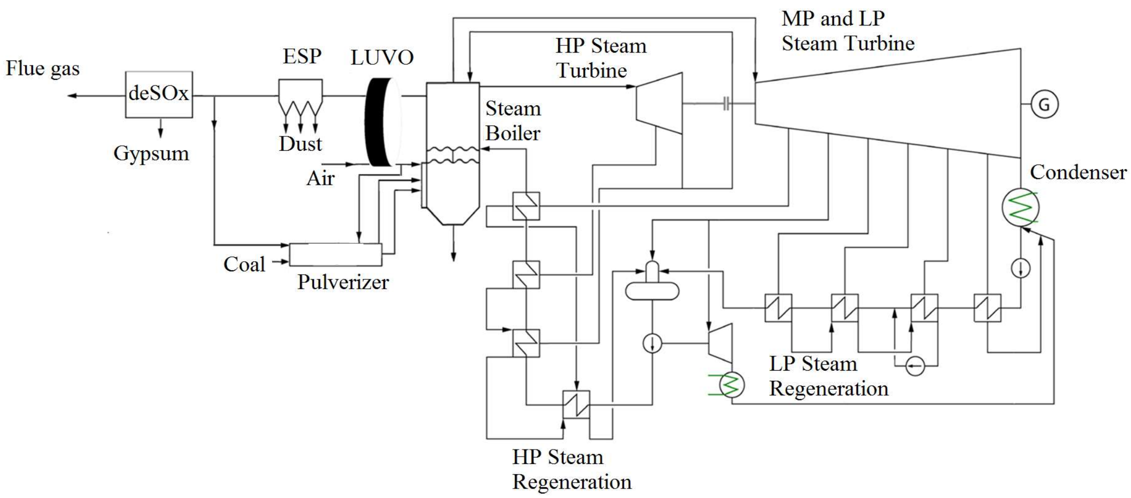

Figure A1: Reference case power unit, with no CO_2 capture.

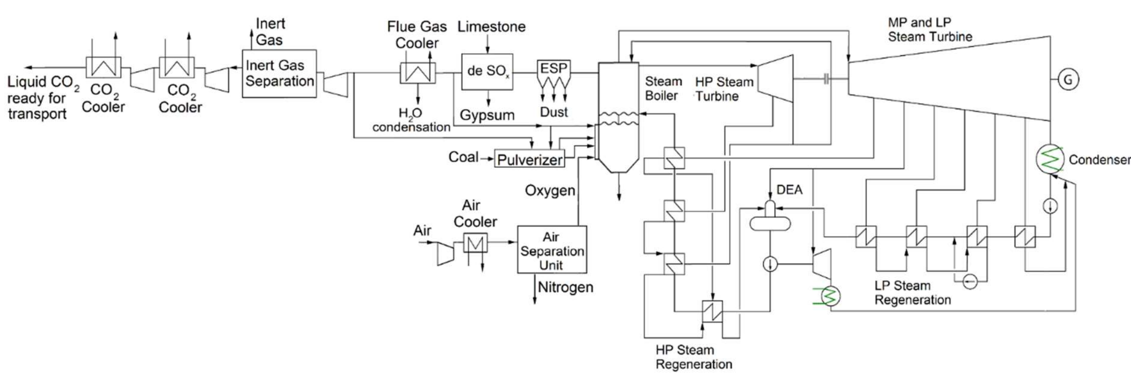

Figure A2: Retrofitted oxyfuel power unit, with CO_2 capture.

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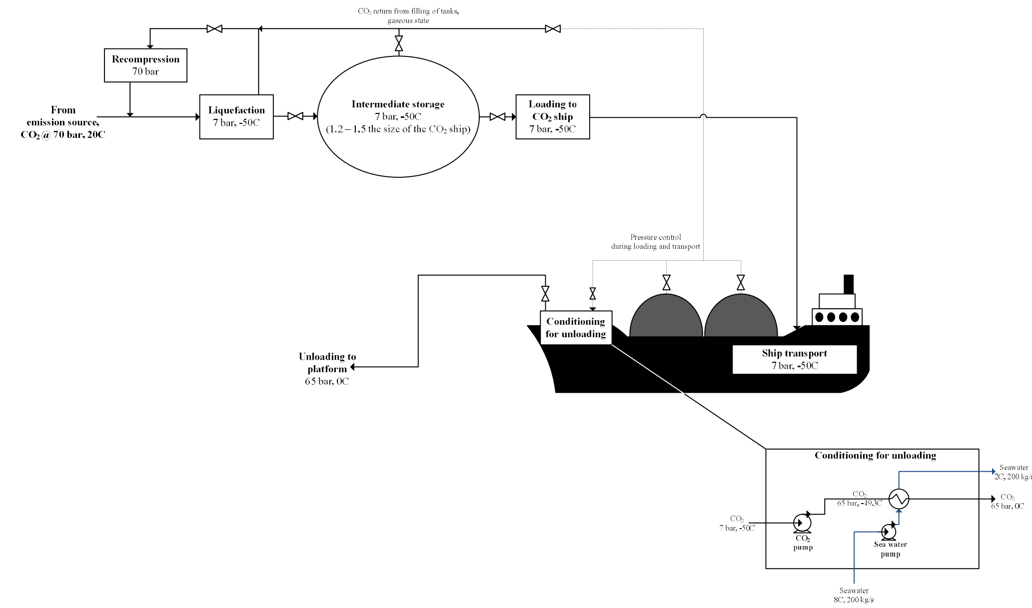

Figure A3: Conceptual design of CO_2 transport.

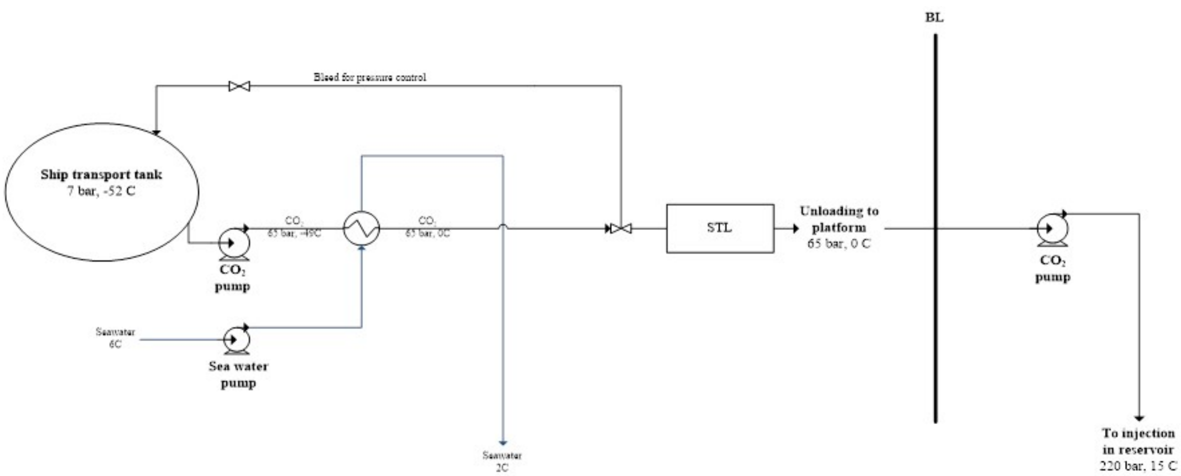

Figure A4: Conceptual design of CO_2 unloading at CO_2 EOR site.

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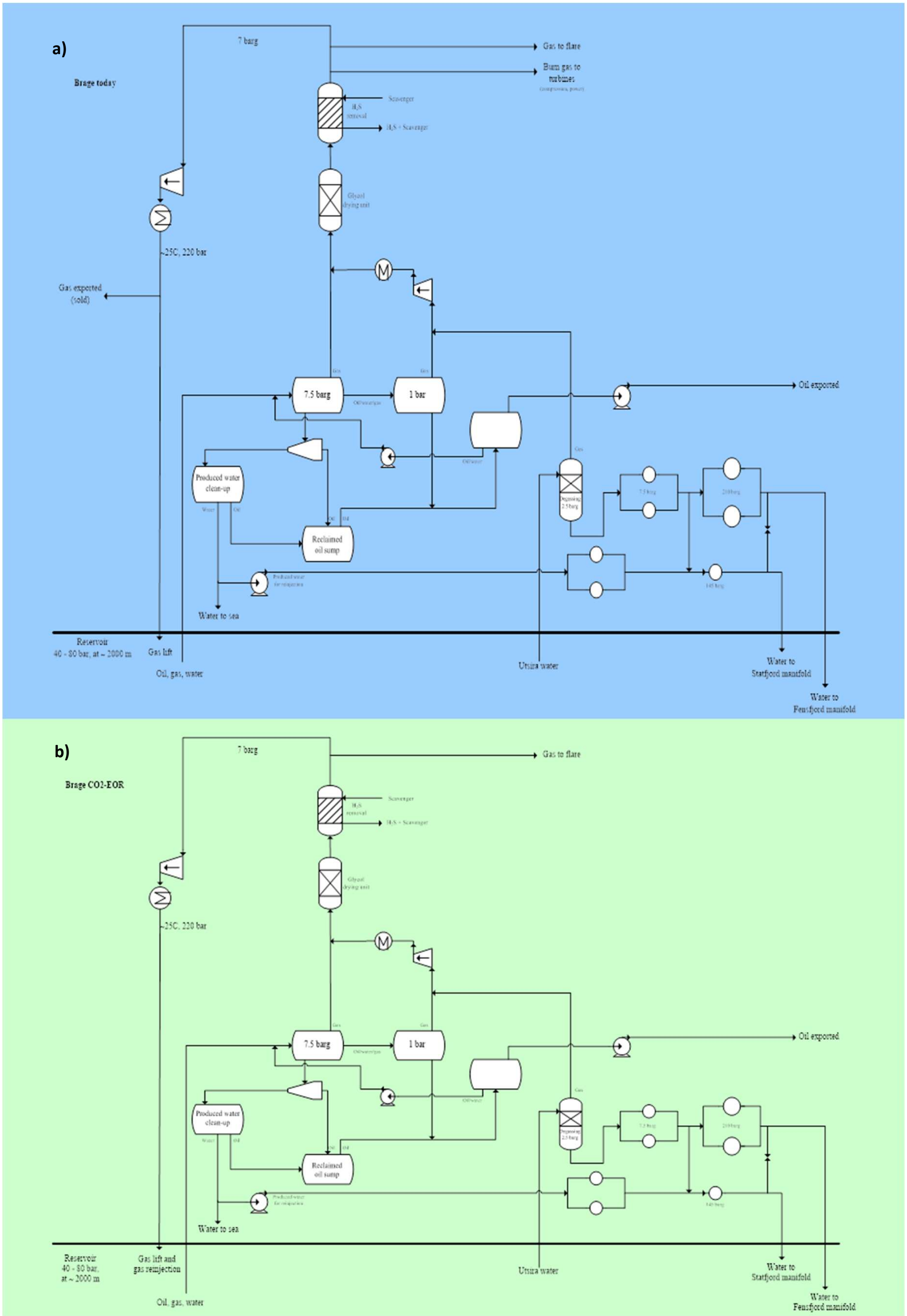

Figure A5: Conceptual design of topside processing for oil production a) without, and b) with CO_2 EOR, based on publicly available data (Andersen, Halvorsen et al. 2000, Wintershall 2016, NPD 2018, Hegerland, Eldrup et al. 2010).

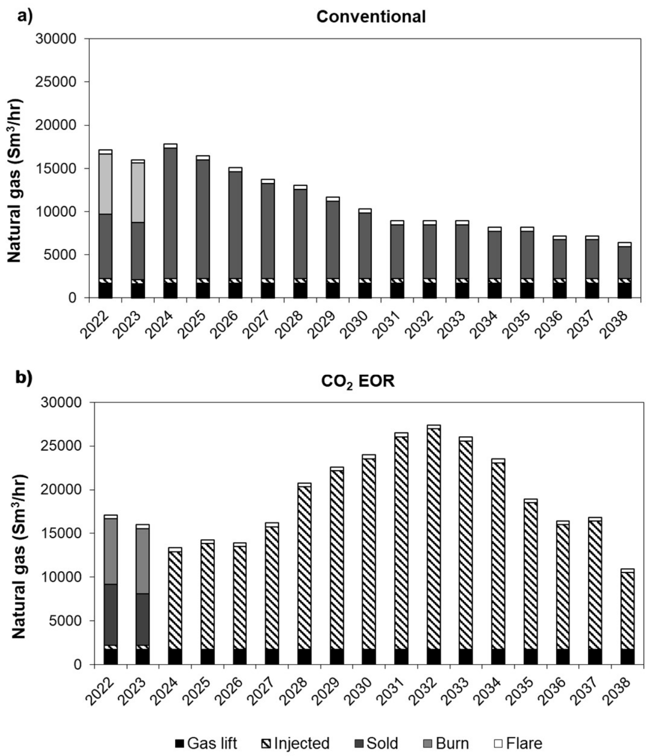

Figure A6: Simulation results of the quantity of natural gas used for gas lift, injected, sold, burned or flared for conventional and CO_2 EOR cases.

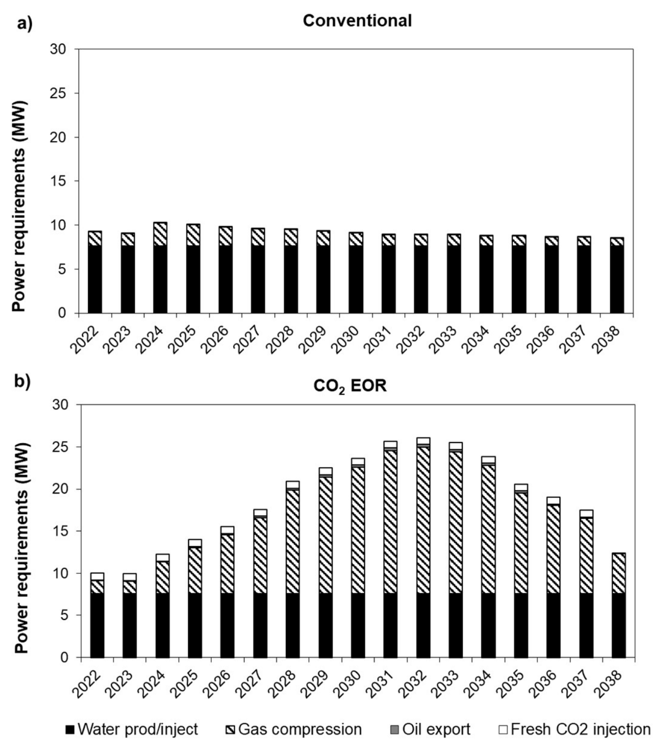

Figure A7: Simulation results of the power requirements for water production/injection, gas compression, oil export or fresh CO_2 injection for the conventional and CO_2 EOR cases.

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