COMPARATIVE ANALYSIS OF FEASIBILITY OF DIFFERENT CO_2 STORAGE SCENARIOS

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Abstract: *Carbon dioxide injection is the most used enhanced oil recovery (EOR) method and the benefit, besides additional oil recovery, which lies in the fact that in this process carbon dioxide retention in the reservoir occurs. Depleted reservoirs are more promising candidates for the carbon dioxide storage than aquifers and other geological formations since they are well characterized i.e., the reservoir properties are more certain because of the data gathering and reservoir model improvement during production lifetime. Since the hydrocarbon reservoirs retained fluids through geological time scale, they can be considered as proven traps that can retain fluids for a long time.*

Possibilities for CO_2 storage (CCS) and usage for EOR (carbon utilization and storage, CUS) have been extensively evaluated, but comparison of economic parameters is hard to perform. This paper presents the impact of key parameters on hydrocarbon production and stored carbon dioxide. The threshold values for operating costs, capital investments, and discount rate were tested by ESCOM application, enabling the evaluation of different reservoir sizes and conditions in the reservoir for CCS and CUS.

Keywords: *CO_2-EOR, CUS, CO_2 storage, flaring emissions.*

1. INTRODUCTION

Although CO_2 Capture and Storage (CCS) is considered a key solution for CO_2 emission mitigation, it is currently not economically feasible. CO_2 enhanced oil recovery can play a significant role in stimulating CCS deployment because CO_2 is used to extract additional quantities of oil. CO_2-EOR projects are CCUS (carbon capture utilization and storage) projects. CCUS is a new concept, actual over the last few years, and CO_2-EOR due to additional oil recovery has the greatest commercial perspective (Ettehadtavakkol et al., 2014; Bachu, 2016; Tapia et al., 2016). There is remarkable progress in the knowledge of CO_2 storage capacities related to hydrocarbon deposits (Novak et al., 2013; Novak et al., 2014; Vulin et al., 2018; Lekić et al., 2019), but they do not give economic comparison of possible storage scenarios.

Compernolle et al. (2017) showed the CO_2 and EOR investments separately in two different companies, the opportunity to invest in power plants and in the oil company. They showed that when uncertainty is integrated into the economic analysis, CO_2 and oil price threshold levels at which investments in CO_2 capture and enhanced oil recovery will take place, are higher than when a net present value approach is adopted. They also demonstrate that a tax on CO_2 instead of an emission trading system results in a lower investment threshold level for the investment in the CO_2 capture unit.

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Ferguson et al. (2010) studied the effect of "Next Generation" technologies on CO_2 storage and oil production potential of CO_2-EOR. They specified CAPEX of current application in the amount of \$2.20 /bbl oil and OPEX in the amount of \$3.10 /bbl oil. For the next generation technology specified CAPEX was \$3.0 /bbl and OPEX was \$5.20 /bbl.

Gaspare at al. (2005) presented an economic feasibility study for small Brazilian oilfield considering two complementary issues:

1) application of CO_2-EOR in order to extend the oilfield life i.e., displace residual oil left in place after primary and secondary oil production phase;
2) storing CO_2 in the oil reservoir. A discount rate of 12% was assumed for the project for which estimation of total CAPEX CO_2 sequestration can be described with the following equation:

$$CAPEX_t = CAPEX_{cap} + CAPEX_{comp} + CAPEX_{transp} + CAPEX_{stor} \quad (1)$$

where $CAPEX_t$ – total capital expenditure; $CAPEX_{cap}$ – capture costs; $CAPEX_{comp}$ – compression cost; $CAPEX_{transp}$ – transportation cost; $CAPEX_{stor}$ – storage cost.

The total OPEX is estimated similarly to the CAPEX approach:

$$OPEX_t = OPEX_{cap} + OPEX_{comp} + OPEX_{transp} + OPEX_{stor} \quad (2)$$

where $OPEX_t$ – total operational expenditure; $OPEX_{cap}$ – capture costs; $OPEX_{comp}$ – compression cost; $OPEX_{transp}$ – transportation cost; $OPEX_{stor}$ – storage cost.

Compression capacity is often estimated in units of capital investment per horsepower (HP). Smith et al. (2001) use a value of \$1060 per HP. Ettehad et al. (2010) report a range of 1500-3000\$ per HP. Luyben (2018) states that (if simplified analysis is performed) the most commonly used correlation for CO_2 compression is a function of maximum required compressor power:

$$\text{Compressor Cost } (\$) = 5840(kW)^{0.82} \quad (3)$$

Calado (2012) analyzed compression trains for sequestration of carbon dioxide and proposed correlations for stainless steel compressors and electric motor drives:

$$\text{Compressor Cost } (\$) = 2.5^{[7.58+0.8\ \ln(hp)]} \quad (4)$$

$$\text{Motor Cost } (\$) = 2049 + 668.16(hp) \quad (5)$$

Luo and Zhao (2012) established the operating cost prediction model based on production decline law and learning curves through analyzing the impact of resource depletion and technological advances on unit operating cost.

Flanders et al. (1993) investigate the economic viability of conducting CO_2-EOR operations in small to medium-size fields under market conditions. Total start-up costs vary from 16 000 \$ to 99 000 \$ per active well.

Algharaib and Al-Soof (2008) developed an efficient and fast model to predict the economics of CO_2-EOR projects. The developed model consists of five modules (performance prediction module, capturing cost module, compression cost module, transportation cost, and storage cost module) that predict the major economical constituents of CO_2-EOR projects. The model was used to predict the economics involved in capturing and storing CO_2 in a Middle Eastern reservoir. The results showed that drilling new wells and preparing the field for injection causes most of the expenditures. The model was subjected to sensitivity analyses to evaluate the effects of several parameters on the various cost components encountered in CO_2-EOR projects and the net present value. The effect of capturing CO_2 from different types of power plants on the capturing cost was investigated. The results also showed that CO_2 recycling has a significant impact on CO_2-EOR projects.

Fukai et al. (2016) presented a cost-benefit analysis in order to evaluate the economic feasibility of CO_2-EOR projects in Ohio. The analysis is applied to two Ohio oil fields (East Canton and Morrow Consolidated) to illustrate how the methodology can be used to constrain project economics and profitability. A simplified stream tube reservoir performance model (CO_2 – PROPHET) was used to estimate incremental oil recovery from CO_2 injection. The regression derived from the CO_2 break-even price calculated for a range of oil prices indicates that the change in the unit value of CO_2 for EOR is approximately four times the corresponding change in the unit value of oil. The presented break-even correlation represents a standalone metric that can be applied for projects screening purposes to determine the price conditions at which CO_2 becomes a feasible purchase for EOR and marketable asset for power plants with a capture technology.

Tayari et al. (2015) focused on developing a preliminary assessment of the economic feasibility of CO_2 storing in depleted unconventional natural gas-bearing shale formations. They presented site scale estimates of long-term CO_2 sequestration costs in depleted shale gas formations and discussed the likelihood of major cost drivers using a surrogate reservoir model and flexible environment for techno-economic analysis. Their approach includes techno-economic analysis with reservoir simulation models to estimate costs associated with transportation, injection, CO_2 separation and post-injection monitoring of CO_2 storage permanence from large industrial point sources in depleted shale-gas reservoirs. Also, they considered potential revenue from incremental methane recovery (effectively enhanced gas recovery, EGR) in reservoir scenarios where such production is significant. Under an operational scenario where a gas well is in primary production for 42 years prior to the initiation of CO_2 injection, it is estimated that CO_2 could be transported and stored at a levelized cost of \$40–\$80 (€35−€70) per ton. Costs are shown to be highly sensitive to well spacing, bottom-hole pressure (BHP), CO_2 transport distance and the future price of natural gas. In most of the scenarios considered, transportation and injection costs were dominant factors, while CO_2 separation and post-injection site care/monitoring did not significantly influence levelized costs.

Jablonowski and Singh (2010) organize and consolidate information on capital and operational costs for CO_2 storage projects. Drilling and completion costs depend on the number of wells to be drilled, sidetracked, or reworked and other important factors include the pressure overburden, reservoir depth and well design. Surface facilities comprise the other major share of capital investment for CO_2 projects and costs depend on the number of wells and their depth, the capacities and complexity of equipment, location and distribution of wells.

CO_2 injection and recycling (in the case of CO_2-EOR) including on-site separation, processing, and compression is shown in Figure 17.

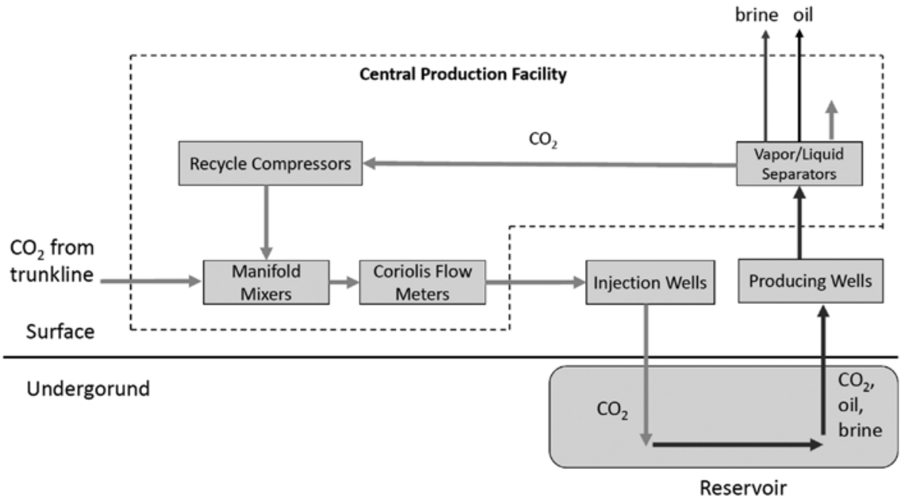

Figure 17: Simplified diagram showing components of CO_2 injection and recycling operations (modified from Fukai et al., 2016)

2. METHODS

All previously mentioned published works have their advantages and disadvantages. The advantages are in details of the analyses - when multiple parameters are optimized to make certain conclusions about one part of the system (e.g. CO_2 capture, or transport system, or CO_2 preparation and compression at the injection site, or reservoir/aquifer where the CO_2 is considered for injection). Sophisticated software and numerical models usually can simulate such segments, however, when it comes to integration of several parts of the system, the definition of the objective function is hard, and the number of independent input parameters increase rapidly. In this work ESCOM application (http://escom.rgn.hr), developed as a part of scientific project sponsored by Croatian Science Foundation and Environmental Protection and Energy Efficiency Fund, was used to integrate the economical parameters (prices, discount rates, CAPEX and OPEX), physical properties of a CO_2 injection site (petrophysical properties, reservoir size, porosity, fluid properties etc.) and oil production features (rate of oil production, i.e. reservoir depletion, rates of petroleum gas production, parameters for CO_2 injection in CO_2-EOR observations) with three objective functions:

- Maximization of oil production,
- Minimization of CO_2 emissions during production,
- Maximization of CO_2 reduction (i.e. energy efficiency and CO_2 storage).

These three objectives are comparable in terms of economic feasibility, so in this work, neglecting the energy policies related to greener industries and reduction of carbon emissions to some extent - the main comparison parameter was net present value of each process, assessed based on energy (oil and gas) production, energy required for CO_2 injection and the value of CO_2 storage.

The problem was divided to two sections:

Small oil field *without measures*. The economics of oil production at the field does not allow petroleum gas transport and selling, so it is flared. Algorithm assesses the emissions of CO_2 based on produced petroleum gas density. The amounts of gas are calculated by material balance equations (Schilthuis, 1936; Tracy, 1955; Ramagost and Farshad, 1981; Ahmed and McKinney, 2011; Lyons and Plisga, 2011), and then the flaring CO_2 was assessed by stochiometric approximation based on gas density. The oil is produced at an existing field (because CO_2 emissions occur mostly at existing fields, because oil-field production life could range from 40 to more than 100 years), so CAPEX for oil production is not taken into account (only OPEX and royalty and discount factor).

In this case, two options can be considered - (a) using simple cycle peaking electricity generator (small power plant) for produced gas utilization and (b) CO_2 storage, but only after the reservoir oil production falls below economic limit.

Based on U.S. Energy Information Administration (EIA) analysis the cost of a conventional natural gas–fired combined cycle plant is $931/kW (Breeze, 2019).

Oil field that is a *good candidate for CO_2-EOR*. In this work (and ESCOM project) - screening for feasibility of EOR methods have not been performed. There is some screening criteria (Taber et al., 1997; Al-Adasani and Bai, 2010; Gao and Pan, 2010; Yin, 2015) but this would make the inputs within ESCOM application (which is free access web application) too complex, and the intention was to make the tool for simple assessments for those that are not reservoir or mechanical engineering experts. Parameter sensitivity study of CO_2-EOR is possible with ESCOM application, and CO_2 retention, additional oil recovery and NPV data can be observed as well.

3. INPUT DATA AND THE RESULTS

Two oil reservoir volumes and two production times were observed for two above mentioned sections, which results in four reservoir production scenarios (Table 10).

Table 10: Reservoir production scenarios

Scenario number	Reservoir volume (m^3)	Production time (years)
1	6 000 000	30
2	6 000 000	50
3	3 000 000	30
4	3 000 000	50

The number of scenarios increases rapidly, firstly by observing separately flaring, CO_2 storage and CO_2-EOR, thus the resulting observed parameters are:

Small field *without measures*:

- Electricity production from petroleum gas:
- NPV of a small power plant
- NPV of oil produced
- NPV of CO_2 cost (in this case, this is the expenditure, as CO_2 is released into the atmosphere)
- CO_2 storage after the oil production abandonment
- NPV of CO_2 stored
- NPV of oil produced

A *candidate field for CO_2-EOR*:

- NPV of oil produced
- NPV of additional CO_2-EOR recovery (CO_2-EOR OPEX and CAPEX included)
- NPV of CO_2 stored during EOR production

All discount rates, CAPEX and OPEX used in sensitivity study are summarized in Table 11.

Table 11: Sensitivity study values

Parameter	Tested values
Oil price	\$45 /bbl and \$70 /bbl
CO_2 price	€20 /t, €30 /t and €40 /t
IRR	9%, 12% and 15%
OPEX oil	15%
OPEX SCP	5%
OPEX EOR	15% and 25%
OPEX CO_2	9%
CAPEX SCP	€400 000, €500 000 and €600 000
CAPEX EOR	€8 000 000, €15 000 000 and €25 000 000
CAPEX CO_2	€5 000 000

Figures (2 to 5) show the results for flaring scenarios *without measures*, which are all combinations of respective parameters (Table 11).

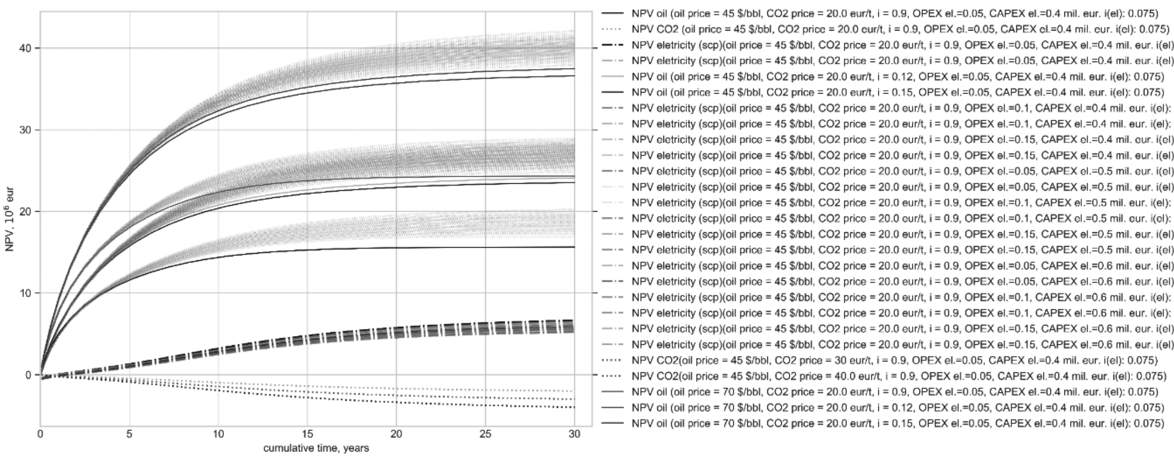

Figure 18: Net present value of flaring scenario 1

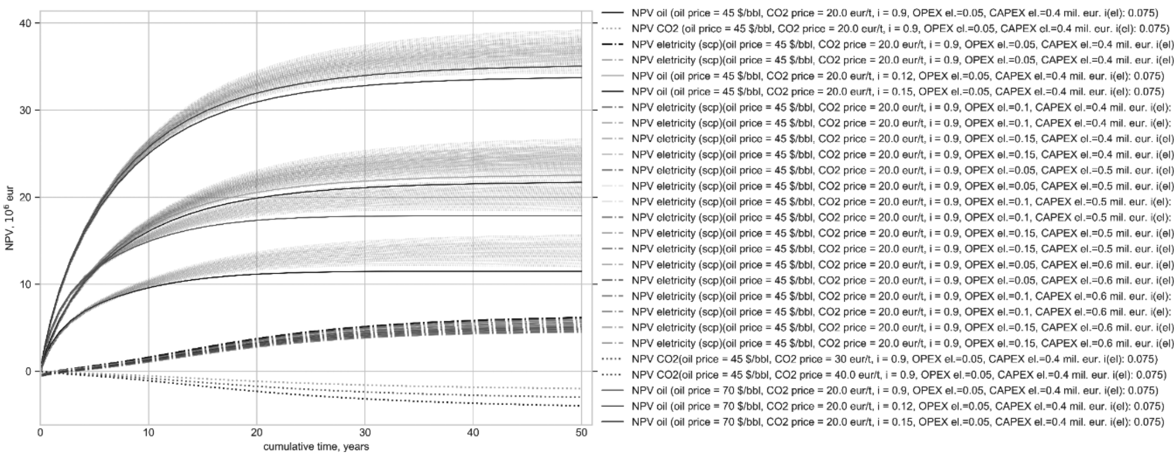

Figure 19: Net present value of flaring scenario 2

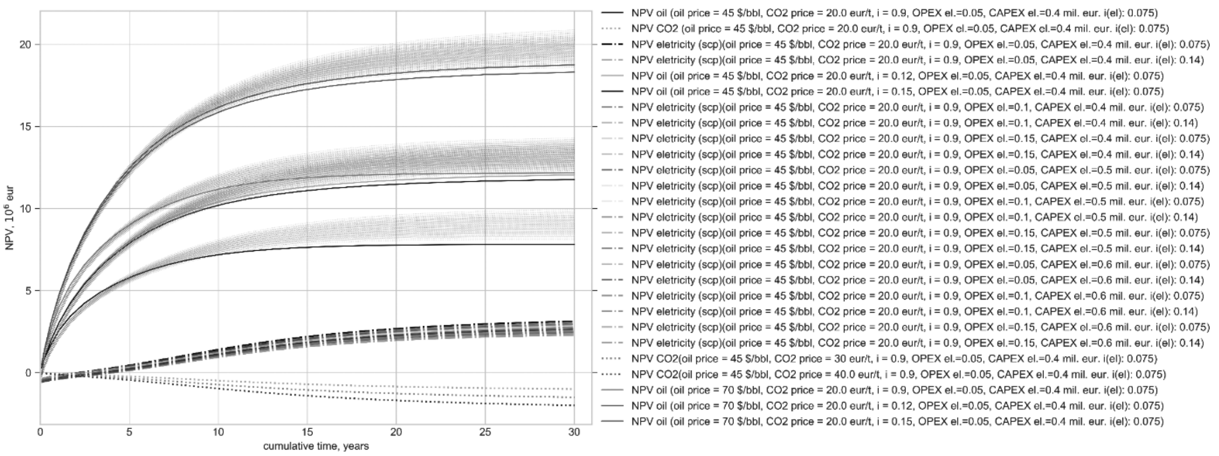

Figure 20: Net present value of flaring scenario 3

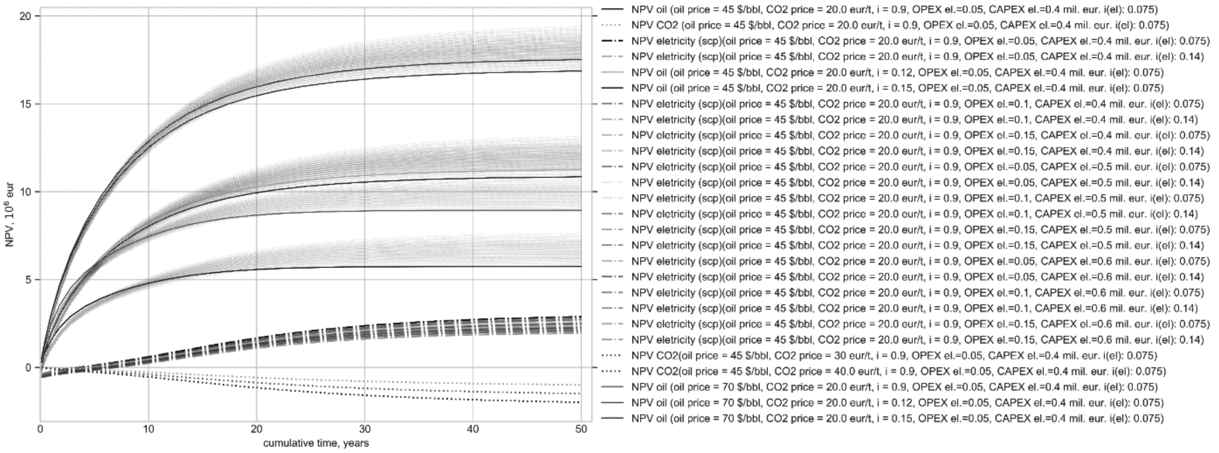

Figure 21: Net present value of flaring scenario 4

Figures (6 to 9) show results with all combinations of parameters for CO_2 storage scenarios after production from field *without measures*.

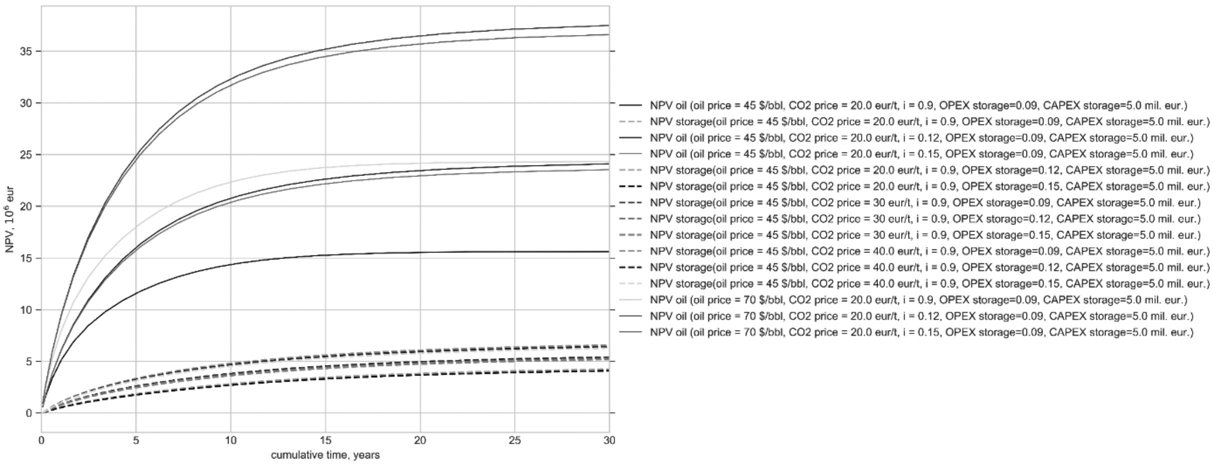

Figure 22: Net present value of storage scenario 1

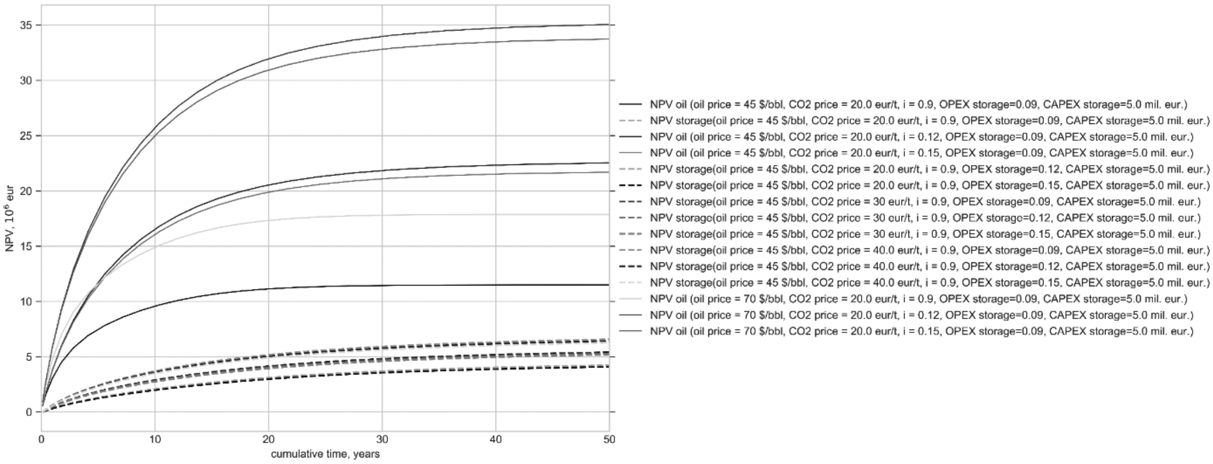

Figure 23: Net present value of storage scenario 2

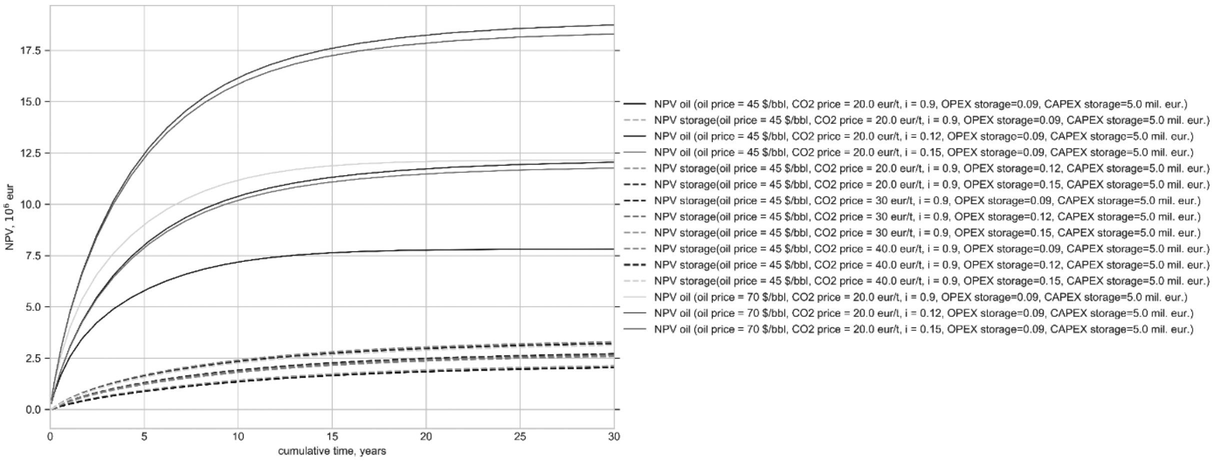

Figure 24: Net present value of storage scenario 3

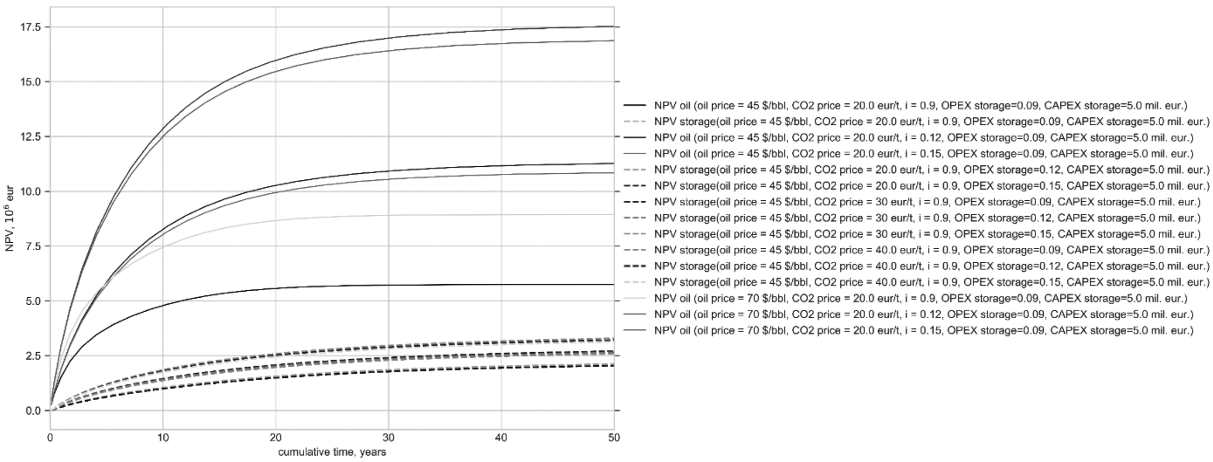

Figure 25: Net present value of storage scenario 4

Figures (10 to 13) show CO_2-EOR performance with combination of all respective input parameters (Table 11).

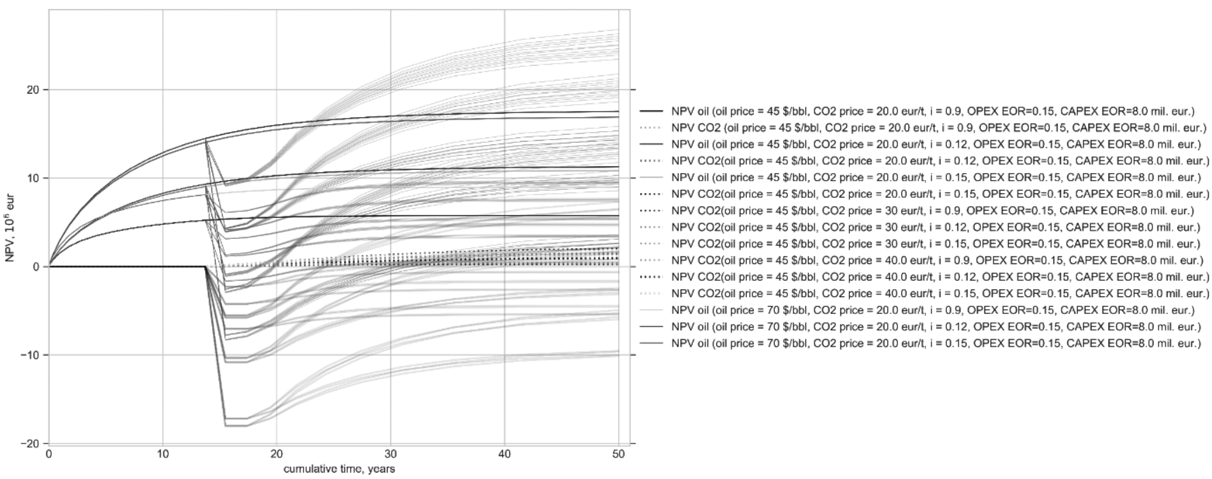

Figure 26: Net present value of EOR scenario 1

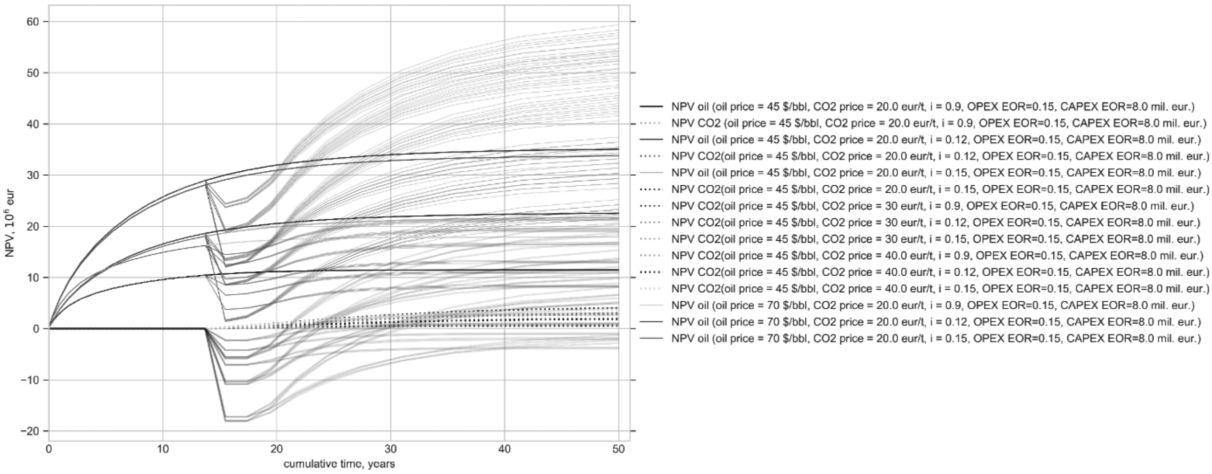

Figure 27: Net present value of EOR scenario 2

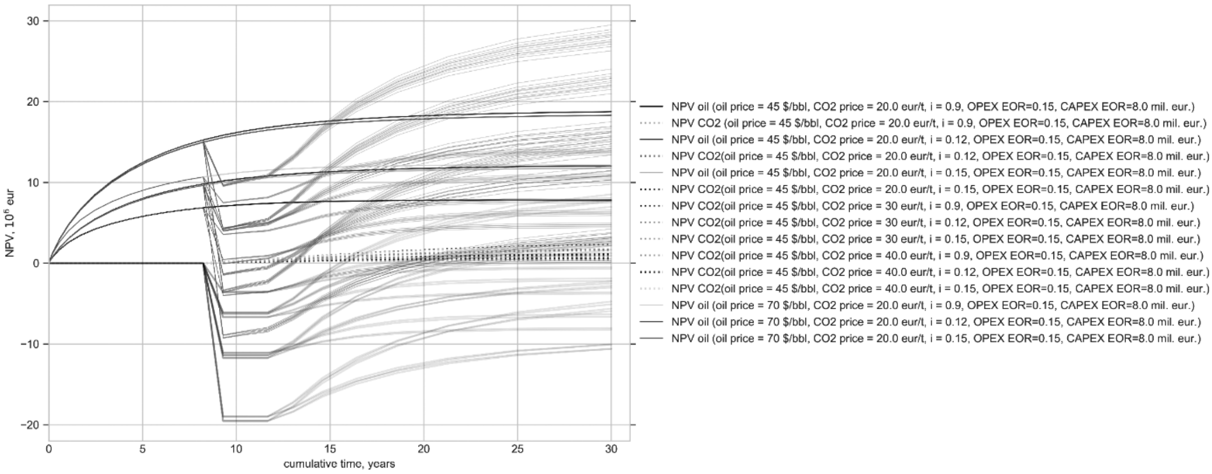

Figure 28: Net present value of EOR scenario 3

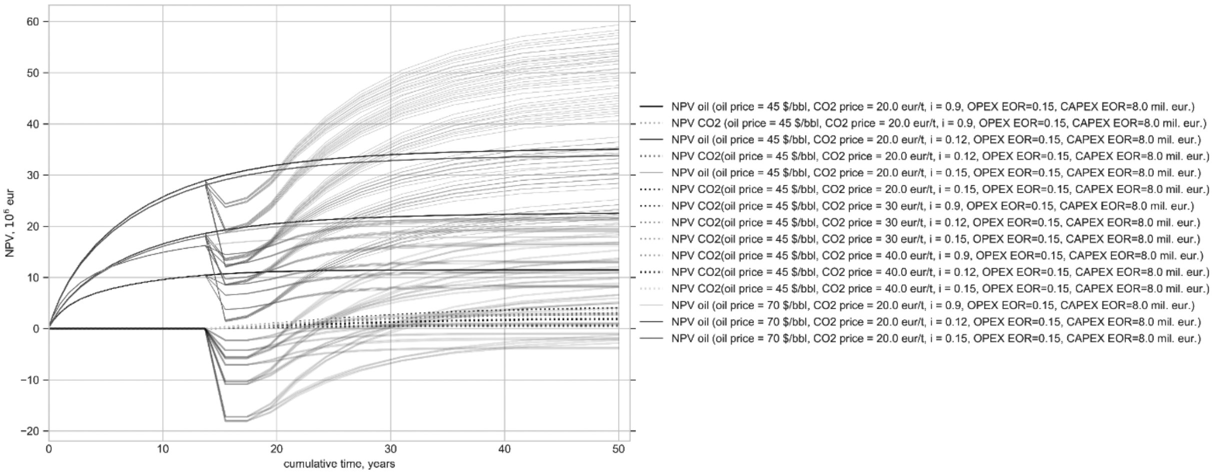

Figure 29: Net present value of EOR scenario 4

4 DISCUSSION OF THE RESULTS AND CONCLUSION

The results show that electric power generators might be feasible in case of small fields. However, in this case, the electricity demand is neglected i.e., the distance from electricity consumers is not considered. This can increase CAPEX significantly, and both the transport efficiency and the electrical grid connection can be crucial factors for implementation of simple cycle power plant.

When observing the NPV curve of CO_2 storage, it might be misleading - this NPV is achieved in a very short time, in the cases presented in this work (because of CO_2 injection rates) it is always in a less than a year. The CO_2 storage NPV curve shows how much value can be gained if the oil production is abandoned after respective number of years.

CO_2-EOR is an attractive option, but the process of CO_2-EOR project evaluation is slow and complex process, and additional recovery (AR) curve shows that it takes more than 5 years until the NPV becomes positive, which in terms of investments showed as discouraging factor for starting CO_2-EOR projects in EU.

Comparative analysis of different CO_2 storage scenarios proved that it is possible to achieve a higher profit by storing CO_2 applying CO_2-EOR methods in comparison with storage in an abandoned oil reservoir because more oil is produced and that provides greater pore volume available for CO_2 storage. Finally, it is important to point out that the application of CO_2-EOR method, besides a positive impact on the recovery and thus the revenue, also has a positive impact on the environment.

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