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 CO₂ 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: CO₂-EOR, CUS, CO₂ storage, flaring emissions.

1. INTRODUCTION

Although CO₂ Capture and Storage (CCS) is considered a key solution for CO₂ emission mitigation, it is currently not economically feasible. CO₂ enhanced oil recovery can play a significant role in stimulating CCS deployment because CO₂ is used to extract additional quantities of oil. CO₂-EOR projects are CCUS (carbon capture utilization and storage) projects. CCUS is a new concept, actual over the last few years, and CO₂-EOR due to additional oil recovery has the greatest commercial perspective (Ettehadavakkol et al., 2014; Bachu, 2016; Tapia et al., 2016). There is remarkable progress in the knowledge of CO₂ storage capacities related to hydrocarbon deposits (Novak et al., 2013; Novak et al., 2014; Vučić et al., 2018; Lekić et al., 2019), but they do not give economic comparison of possible storage scenarios.

Compernolle et al. (2017) showed the CO₂ 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, CO₂ and oil price threshold levels at which investments in CO₂ 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 CO₂ instead of an emission trading system results in a lower investment threshold level for the investment in the CO₂ capture unit.
Ferguson et al. (2010) studied the effect of “Next Generation” technologies on CO₂ storage and oil production potential of CO₂-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 et al. (2005) presented an economic feasibility study for small Brazilian oilfield considering two complementary issues:
1) application of CO₂-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 CO₂ in the oil reservoir. A discount rate of 12% was assumed for the project for which estimation of total CAPEX CO₂ sequestration can be described with the following equation:

\[ \text{CAPEX}_t = \text{CAPEX}^{\text{cap}} + \text{CAPEX}^{\text{comp}} + \text{CAPEX}^{\text{transp}} + \text{CAPEX}^{\text{stor}} \]  

where CAPEX – total capital expenditure; CAPEX^{\text{cap}} – capture costs; CAPEX^{\text{comp}} – compression cost; CAPEX^{\text{transp}} – transportation cost; CAPEX^{\text{stor}} – storage cost.

The total OPEX is estimated similarly to the CAPEX approach:

\[ \text{OPEX}_t = \text{OPEX}^{\text{cap}} + \text{OPEX}^{\text{comp}} + \text{OPEX}^{\text{transp}} + \text{OPEX}^{\text{stor}} \]

where OPEX – total operational expenditure; OPEX^{\text{cap}} – capture costs; OPEX^{\text{comp}} – compression cost; OPEX^{\text{transp}} – transportation cost; OPEX^{\text{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 CO₂ compression is a function of maximum required compressor power:

\[ \text{Compressor Cost} (\$) = 5840(kW)^{0.82} \]  

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

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

\[ \text{Motor Cost} (\$) = 2049 + 668.16(hp) \]

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 CO₂-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 CO₂-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 CO₂-EOR projects. The model was used to predict the economics involved in capturing and storing CO₂ 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 CO₂-EOR projects and the net present value. The effect of capturing CO₂ from different types of power plants on the capturing cost was investigated. The results also showed that CO₂ recycling has a significant impact on CO₂-EOR projects.

Fukai et al. (2016) presented a cost-benefit analysis in order to evaluate the economic feasibility of CO₂-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 (CO₂ – PROPHET) was used to estimate incremental oil recovery from CO₂ injection. The regression derived from the CO₂ break-even price calculated for a range of oil prices indicates that the change in the unit value of CO₂ 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 CO₂ 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 CO₂ storing in depleted unconventional natural gas-bearing shale formations. They presented site scale estimates of long-term CO₂ 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, CO₂ separation and post-injection monitoring of CO₂ 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 CO₂ injection, it is estimated that CO₂ 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), CO₂ transport distance and the future price of natural gas. In most of the scenarios considered, transportation and injection costs were dominant factors, while CO₂ 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 CO₂ 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 CO₂ projects and costs depend on the number of wells and their depth, the capacities and complexity of equipment, location and distribution of wells.

CO₂ injection and recycling (in the case of CO₂-EOR) including on-site separation, processing, and compression is shown in Figure 17.
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. CO₂ capture, or transport system, or CO₂ preparation and compression at the injection site, or reservoir/aquifer where the CO₂ 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 CO₂ 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 CO₂ injection in CO₂-EOR observations) with three objective functions:

- Maximization of oil production,
- Minimization of CO₂ emissions during production,
- Maximization of CO₂ reduction (i.e. energy efficiency and CO₂ 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 CO₂ injection and the value of CO₂ 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 CO₂ 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).

| 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 CO₂-EOR:
- NPV of oil produced
- NPV of additional CO₂-EOR recovery (CO₂-EOR OPEX and CAPEX included)
- NPV of CO₂ 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                                                        |
| CO₂ 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 CO₂         | 9%                                                                           |
| CAPEX SCP        | €400 000, €500 000 and €600 000                                              |
| CAPEX EOR        | €8 000 000, €15 000 000 and €25 000 000                                       |
| CAPEX CO₂        | €5 000 000                                                                   |

Figures (2 to 5) show the results for flaring scenarios without measures, which are all combinations of respective parameters (Table 11).
Figures 6 to 9 show results with all combinations of parameters for CO₂ storage scenarios after production from field without measures.
Figures (10 to 13) show CO₂-EOR performance with combination of all respective input parameters (Table 11).
COMPARATIVE ANALYSIS OF FEASIBILITY OF DIFFERENT CO₂ STORAGE SCENARIOS

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
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 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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