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Impact Of CO2-WAG Design Optimisation On Coupled CO2-EOR And Storage Projects In Carbonate Reservoirs

H. Rodrigues[1]*, E. Mackay[1], D. Arnold[1]
[1]Heriot-Watt University

Summary

CO2-WAG injection has been applied in offshore Brazilian carbonate reservoirs aiming to improve oil recovery and promote a safe destination to CO2 naturally being produced alongside with hydrocarbon gas. A gas re-utilisation strategy can potentially lead to multiple benefits: residual oil saturation reduction, maintenance of reservoir pressure, avoidance of gas flaring and development of the infrastructure and expertise necessary to make CO2 storage more accessible once oil production is complete, paving the path for a low carbon future, whereas mature basins can be a potential hub for Carbon Capture, Utilisation and Storage (CCUS). This study aims to develop a methodology to design CO2-WAG projects that not only achieve a high Net Present Value (NPV) but also maximizes the capacity and safety of geological CO2 storage.

Introduction

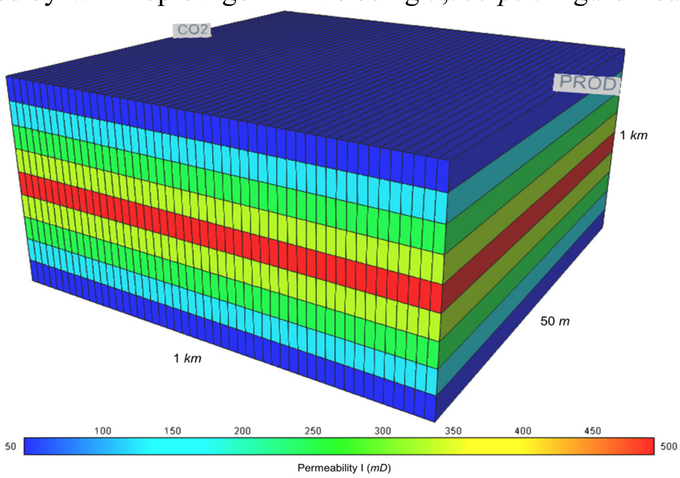
CO_2-WAG is a promising recovery method for supergiant oilfields located in the Brazilian Pre-Salt Cluster (BPSC). The high pressure and low temperature reservoir conditions combined with a crude oil mainly formed of light components make these reservoirs suitable for miscible displacement techniques. In this context, the CO_2 source is the reservoir itself, since its original oil contains a considerable amount of CO_2 contaminant, about 8 to 15% of the solution gas (Pizarro & Branco, 2012), and a long distance to the shore (around 300 km) restrains CO_2 transportation of any sort.

Injected CO_2 will tend to be very mobile at high saturation, which requires an effective design of WAG operational parameters for control of the CO_2 front (better sweep) and delay of its breakthrough in the production wells, especially in heterogeneous carbonate reservoirs. Improving the geological storage of CO_2 recycled for EOR purposes represents an opportunity not only to increase oil productivity but also to mitigate the carbon footprint of current oilfield projects and prevent flow assurance hazards (inorganic scale, wax, asphaltene and hydrate formation) and corrosion issues. Therefore, it is in the best interest of operators to determine CO_2-WAG design parameters that accommodates both the project's Net Present Value (NPV) and CO_2 storage efficiency (CSE).

Methodology

A synthetic 9-layer 2D reservoir model with horizontal resolution of 50 grid-cells was simulated in CMG's compositional reservoir simulator, GEM 2017.10. The middle layer presents a high horizontal permeability value of 500 *mD* which monotonically decreases towards the extreme layers, to a minimum of 50 *mD*. The permeability distribution of the bottom half is mirroring the top half. Porosity of 8% and *kv/kh* equal to 0.1 were applied. Initial reservoir pressure and temperature are 8,032 *psi* and 140 *°F*, respectively.

A 24 pseudo-components (PC) light oil from Moortgat *et al.* (2010) was lumped into 6 PC using CMG's EoS software, WinProp 2017.10. Minimum miscibility pressure (MMP) of CO_2 in this oil was estimated to be 4,500 *psi*, by simulating 1D slim-tube test procedures. Bubble point pressure was estimated by WinProp's algorithm as being 5,553 *psi*. Figure 1 summarises reservoir data.



PC	Mole fraction (%)
CO_2	8.24
N_2+C_1	51.66
C_2-C_4	14.63
iC_5-C_{10}	9.56
C_{11}-C_{14}	4.58
C_{15}-C_{20}	11.33
Total	**100**

Figure 1 *Reservoir horizontal permeability and initial oil composition.*

A three phase hysteresis model (Figure 2) was included to allow water and gas relative permeability reductions due to repeated WAG injection cycles (Larsen and Skauge, 1998). The gas (non-wetting phase) hysteresis model follows the theory of Land and Carlson, while the water (wetting phase) hysteresis is interpolated between two- and three-phase relative permeability curves, where the latter happens after gas flooding. Stone's first model is applied for three-phase oil relative permeability.

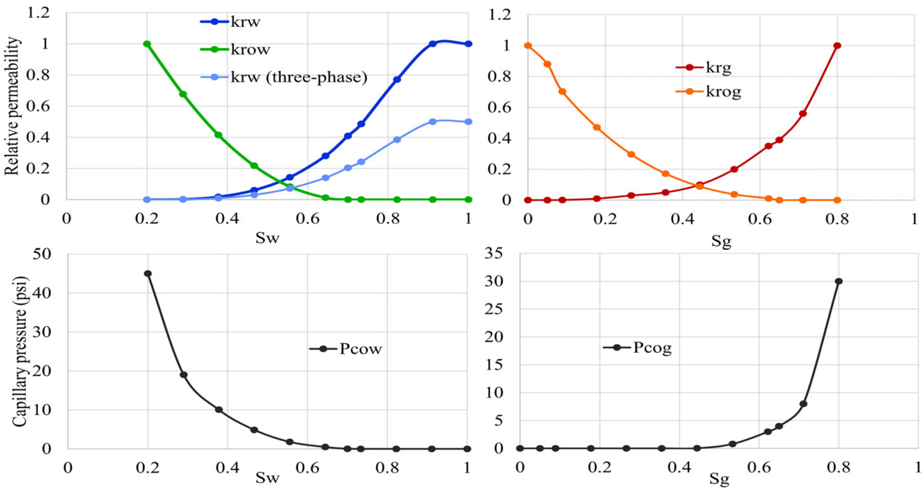


***Figure 2** Relative permeability curves and capillary pressure data.*

Geochemical reactions were also included in order to track inorganic scale deposition near wells and to account for additional CO_2 trapping mechanisms: solubility trapping (when CO_2 dissolves in brine), ionic trapping (dissociation in carbonate and bicarbonate ions) and mineral trapping. Calcite is the only mineral include and it represents 80% of the initial bulk volume of rock.

The injection well is controlled by injection rate (assuming Darcy's velocity of 0.5 *ft/d*) while the producer is controlled using a bottom hole pressure (BHP) constraint of 5,700 *psi*. A total of 1PV of fluids is injected throughout a period of almost 13 years. No previous waterflood is performed and the WAG scheme always start with a gas slug, inasmuch as a first contact miscible gasflood could potentially result in a lower residual oil saturation. Low-sulphate seawater is used for water slugs. An equivalent continuous CO_2 injection case was simulated for comparison purposes.

Two optimisation studies were carried out with distinctive objective functions: the first one aimed at maximising the project's NPV, a conventional approach for EOR applications, while the second study focused on the maximisation of CSE, here defined as the percentage of injected CO_2 that remains in the reservoir. CMG CMOST Designed Exploration Control Evolution (DECE) algorithm is applied and required 508 experiments to find the optimum NPV and 207 for the CSE optimum. The key input variables to be designed are shown in Table 1 alongside their respective ranges of possibilities, calculated according to field experience and literature review.

CO_2-WAG design variables	Range	
	Low	High
CO_2 concentration in injection stream	20%	80%
CO_2 half-cycle (days)	3	464
Water half-cycle (days)	3	2320

***Table 1** CO_2-WAG design variables and ranges of investigation.*

Figure 3 shows a schematic drawing of the economic model and assumptions for the NPV calculation, where r is the yearly discount rate (10%), t is the time step and T is the total time. The cash flow term is given by the sum of the cost (red) and revenue (green) terms shown, where $\$_o$ and $\$_{NG}$ are the oil and natural gas prices after royalties, taxes and operating deductions (assumed as \$50/STB and \$7.96/million Btu, respectively); $\$_{wp}$ is the water handling cost (\$1.5/STB); $\$_{gp}$ denotes the gas separation costs (\$23.3/tCO_2); $\$_{ct}$ is the carbon tax (\$60/ tCO_2); $\$_{CO2c}$ ans $\$_{NGc}$ stands for the CO_2 and NG compression costs (\$0.1527/tonne of either gas); $\$_{wi}$ is the water injection cost, including desulfation treatment (\$2/STB); q_o^t, q_{wp}^t, q_{gp}^t, q_{NGp}^t and q_{CO2p}^t is the oil, water, gas, NG (methane) and CO_2 production rates, respectively; subscript i refers to injection. Appropriate conversion factors are applied. Cost values based on Ettehadtavakkol (2013).

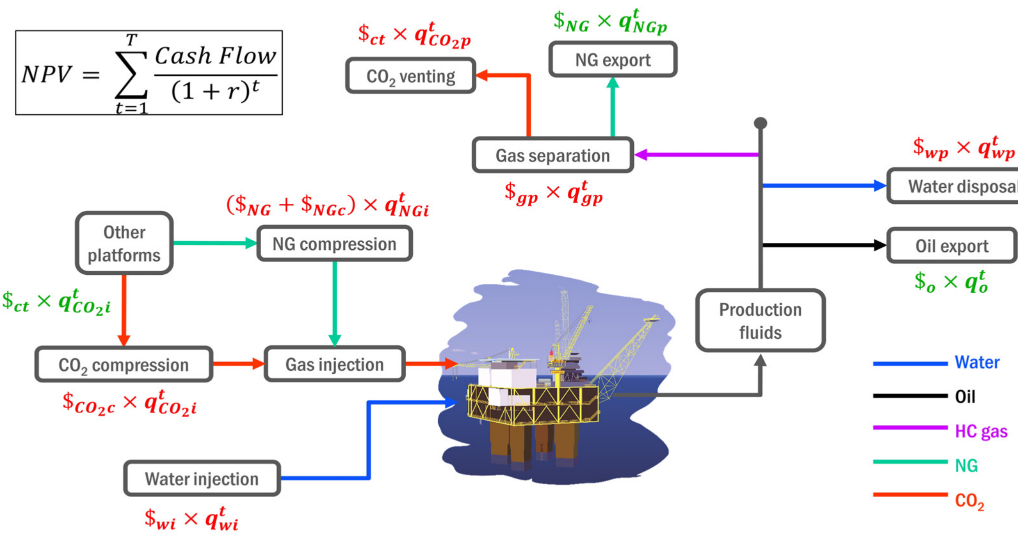


Figure 3 *Economic model schematic diagram.*

It is assumed that all the CO_2 produced is vented, which results in a carbon tax payment, but the reinjection of CO_2 is a revenue that acts as a "refund" of taxes in case CO_2 re-utilization takes place. Note that the CO_2 and NG comes from neighbour platforms solely in order to eliminate possible supply restrictions.

Results and discussions

The first study determined that a WAG ratio of 0.53:1 (volume of water per gas injected, in reservoir conditions), a CO_2 purity of 80% (the remaining percentage being NG) and every WAG cycle composed by 137 days of CO_2-rich gas followed by 72.5 days of seawater (23 cycles in total) would yield the maximum NPV for this reservoir. On the other hand, if a maximum CSE is aimed, a WAG ratio of 1.95:1, with the same CO_2 injection concentration and half-cycles of 102 days of CO_2-rich gas followed by 200 days of seawater should be applied (16 cycles in total), according to the second study. The maximised NPV was 16.52% larger than the one associated with the optimum CSE, while the former's oil recovery was 14% better than the latter's.

Regarding CSE, as expected, the optimum CSE case presented a higher storage efficiency compared to the optimum NPV case (89.3% versus 69%, respectively), although counterintuitively the optimum NPV case stored a total mass 44.3% larger than the optimum CSE. The lower efficiency on the optimum NPV case was due to a higher production of CO_2 while its larger total storage is a result of bigger gas volumes injected. The CO_2 recycle ratio is even higher in the continuous CO_2 case, with more than half of the CO_2 injected being produced again (Figure 4).

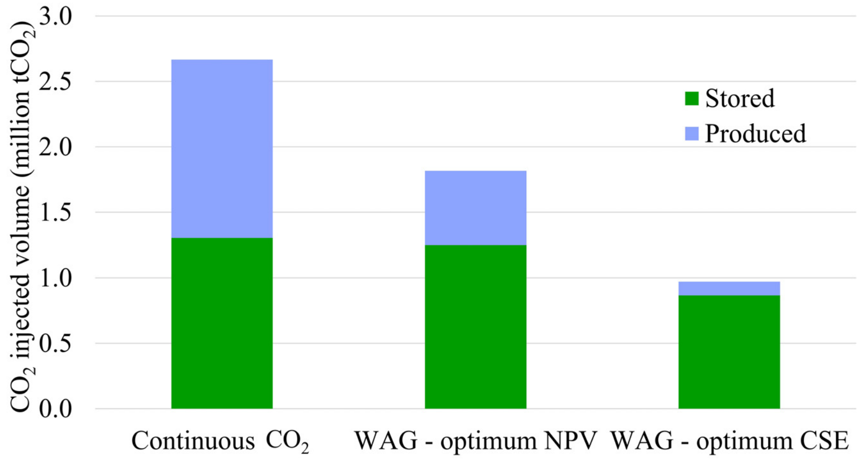


Figure 4 *Destination of CO_2 injected for the two optimum cases and continuous CO_2 injection.*

If this was a pure CCS project, a continuous CO_2 would yield the largest amount of CO_2 stored, even with seawater promoting hydrogeological storage. However, since production wells are operating, the optimum design is dependent on how efficiently the mobility control fluid (seawater) can hold back the CO_2 front and avoid over-production of gas, especially in high permeability zones and reservoir top layers (due to buoyance effects). For this reason, the optimum CSE involves injecting two times more water than gas to reduce flow segregation. The choice of design would depend on the operator's priority and operational constrains (supply and produced gas handling capacity). This trade-off between NPV and CSE can be observed in Figure 5.

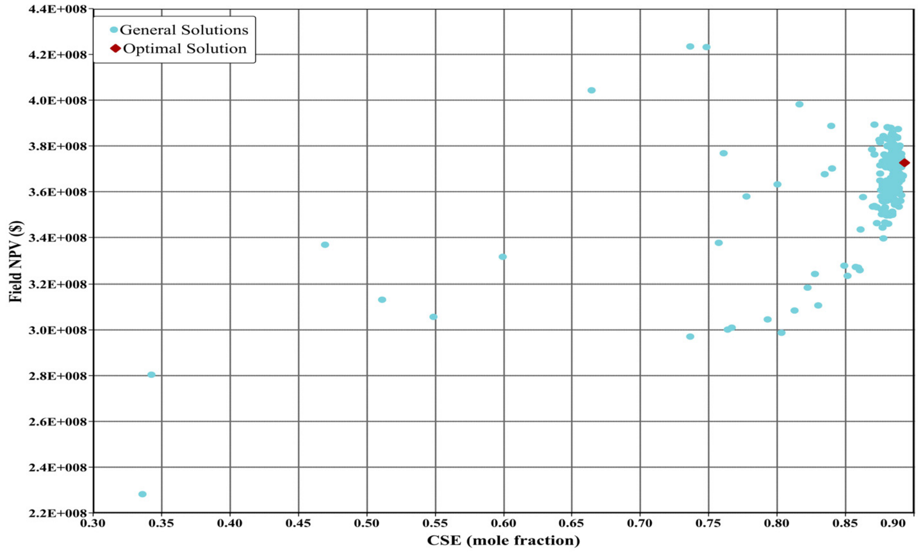


Figure 4 *Field NPV versus CO_2 storage efficiency in the second study (maximisation of CSE).*

Conclusions

Results of this study showed the impact of application of an optimised WAG design on CO_2 mobility control and promotion of a more uniform macroscopic sweep that yields higher NPV and oil recovery values. It was observed that higher concentration of CO_2 in the injection gas and delay of CO_2 breakthrough using certain WAG ratios improves both NPV and CSE. Optimum CSE does not guarantee the maximum total amount of CO_2 storage. In the light of CCUS applications, not only In this particular project, the optimum NPV case (WAG ratio of around 0.5:1) seems to be the most advantageous, since it yields the highest profitability and a larger total CO_2 storage, although with the onus of producing larger amount of gas to be dealt with.

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