Economic Analysis of CCUS: Accelerated Development for CO_2 EOR and Storage in Residual Oil Zones Under the Context of 45Q Tax Credit

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Highlights

- Residual oil zone development improves CO_2 utilization and storage economics
- Joint development of MPZ and underlying ROZ are the best production strategy
- Ideal water-gas injection ratio depends on a balance of oil prices and carbon credit

Abstract

Residual oil zones (ROZ) undergoing CO_2-EOR may benefit from specific strategies to maximize their value. We evaluated several strategies for producing from a Permian Basin, West Texas, USA field's ROZ. This ROZ lies below the main pay zone (MPZ) of the field. Such brownfield ROZs occur in the Permian Basin and elsewhere. Since brownfield ROZs are hydraulically connected to the MPZs, development sequences and schemes influence oil production, CO_2 storage, and net present value (NPV). We conducted economic assessments of various CO_2 injection/production schemes in the stacked ROZ-MPZ reservoir based on flow simulations of a high-resolution geocellular model built from wireline logs and core data and calibrated through production history matching. Flow simulations of water alternating gas (WAG) injection, such as switching injection from the MPZ to the ROZ, commingled production was studied. The simulation results showed that simultaneous CO_2 injection into the MPZ and ROZ lead to the highest oil production and, generally, the highest NPV. If instead, CO_2 was simultaneously injected into the MPZ and ROZ, then into the ROZ alone, this maximized CO_2 storage. CO_2 storage can be used as a tax credit under the Internal Revenue Code Section 45Q. Storage performance depended on the development approach and WAG ratio. Developing the ROZ increased storage compared to remaining in the MPZ. The WAG ratio to maximize oil production did not always yield the largest NPV. These findings can be applied to other Brownfield ROZs, which are common below San Andres reservoirs in the Permian Basin and other basins. ROZ development can increase oilfields' NPV and carbon storage potential. Our study is an analog for similar reservoirs. This work provides valuable insights into the further optimization of brownfield ROZ development and information for operators to plan to develop stacked ROZ-MPZ reservoirs.

Introduction

CO_2 enhanced oil recovery (CO_2-EOR) is an established technology that can provide a revenue stream and an option for long-term CO_2 storage (IPCC, 2005). CCUS (carbon capture utilization and storage) is based on integration of CO_2-EOR with long term storage of anthropogenic CO_2 (CO_2-sequestration). Also, if the CO_2 used in the CCUS is anthropogenic, Section 45Q of the US Internal Revenue Code provides tax credits for capturing and sequestering the carbon during EOR.

In Section 45Q, the US Internal Revenue Service lays out ways in which companies can receive tax credits if they capture CO_2 that would otherwise be in the atmosphere and geologically sequester it. There are different rates depending on when the carbon capture equipment began service and whether it was used in CO_2-EOR. For instance, a facility that began construction before 2026 and was finished in

2026 could earn $50/ton credits if the CO_2 was subsequently geologically sequestered, and $35/ton if it was used to enhance oil recovery.

Most CO_2 injection projects in oilfields target the main pay zones (MPZs) that were under primary production or being waterflooded. However, operators have also used this technology to target residual oil zones (ROZs). ROZs cannot be waterflooded but can be produced by CO_2-EOR. ROZs are a candidate for CO_2 EOR and storage. In ROZs, the oil saturation is too low for oil to flow without intervention (Melzer, 2017; Roueché and Karacan, 2018; Ren and Duncan, 2019a). However, with CO_2 flooding they can become productive. Brownfield ROZs underlie and connect to conventional oil reservoirs, whereas greenfield ROZs are laterally far from traditional MPZs (Harouaka et al., 2016). Many brownfield ROZs occur in the Permian Basin (Melzer et al., 2006; Melzer, 2017) and around the world (Webb, 2019). CO_2 injection has produced oil from ROZs in several San Andres reservoirs in the Permian Basin (Melzer, 2017). There are disagreements about how to exploit the ROZ reservoirs. Koperna et al. (2006) concluded that "simultaneously implementing the flood in both the ROZ and MPZ" is a superior approach to "separately completing either the MPZ or the ROZ" in term of cumulative oil production. Jamali and Ettehadtavakkol (2017), however, asserted that early expansion into brownfield ROZs compromises project economics.

A future challenge in utilizing CO_2 injection will be to balance two economic drivers, producing oil and sequestering anthropogenic CO_2. The best strategy will be different for the ROZ versus the MPZ. Thus, there are advantages and disadvantages for co-developing the zones versus developing them in sequence. Since these ROZs are connected to MPZs, the interaction between the two zones will influence both production performance and the best development strategies. Such strategies include:

1) Co-developing the MPZ and ROZ
2) Developing only the MPZ
3) Expanding to the ROZ years or decades after developing the MPZ
4) Co-developing the MPZ and ROZ, but eventually stopping MPZ injection.

Selecting between these strategies should be based on:

- understanding the reservoir and geological characteristics,
- estimating the potential for CO_2 EOR and storage in the reservoirs, and
- strategic goals for oil production and carbon storage.

Several groups have performed economic analysis of CO_2 sequestration associated with CO2-EOR. This has been studied by van 't Veld et al. (2013), Wang et al. (2018), and Farajzadeh et al. (2020), among others. Ettehadtavakkol et al (2014) evaluated the impact of carbon tax credits for sequestration on economics of CO_2-EOR in conjunction with sequestration. Tayari et al. (2018) investigated the impact of reservoir heterogeneity on the economics of CO_2 floods. They created a model based on three cost modules: injection, production, and CO_2 recycling for valuing EOR projects. They then identified key model parameters including "production rate and composition, injection fluid rate and composition, and bottom-hole pressure," combined with reservoir simulations to enable estimating injection, production, and CO2 recycling, and thus the costs and revenue for specific development scenarios for different types of reservoirs.

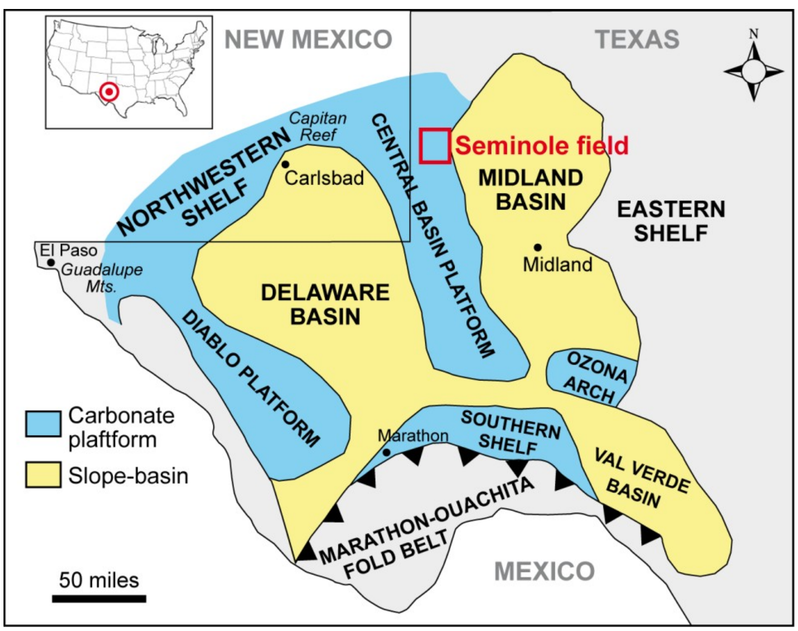
A number of studies have evaluated the economics of different strategies for CO_2 injection (Zekri and Jerbi, 2002; Tayari et al. 2018; Jiang et al., 2019). Zekri and Jerbi determined that the nature and structure of the tax regime is critical to the viability of many EOR projects. Some projects are profitable only if there are tax incentives. Although the study of Tayari et al. (2018) largely focused on CO_2 foam flooding, a topic outside the focus of the current study, these authors did explore how reservoir heterogeneity impacts project economics.

This paper identifies development strategies for brownfield ROZs that maximize either oil recovery, CO_2 storage, or NPV. A San Andres oilfield, which has a long history of commercial-scale ROZ production, is used as a case study. Unlike previous works by Wang et al. (1998), Koperna et al. (2006), Jamali and Ettehadtavakkol (2017), and Webb (2019), our analysis uses a high-resolution, geologic model for both the MPZ and ROZ from a comprehensive database of subsurface information, including well logs, an extensive collection of cores, detailed petrographic data, and per-well production and injection data. We then conducted simulations to evaluate the influence of the four strategies on oil production as well as the utilization and retention (sequestration) of CO_2 in the reservoir. In comparison to many published studies, this high-quality reservoir model enabled decreasing the uncertainties in both our history match and prediction of oil production and CO_2 storage associated with CO_2 EOR.

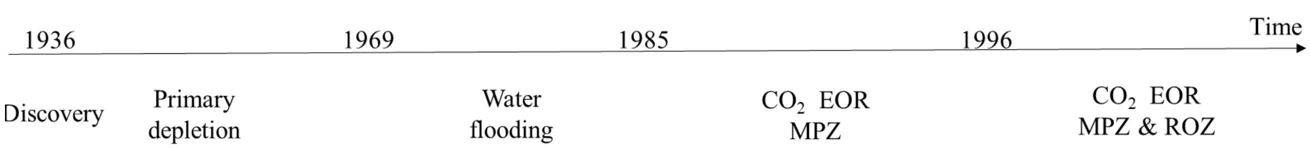
In addition, we conducted an extensive investigation of how various reservoir development scenarios impact the economic viability of brownfield ROZ projects. Our analysis models the oil production and mass of CO_2 stored as a function of the WAG ratio and development scenarios. For each scenario, we focused on managing the development of brownfield ROZ to achieve the best financial outcome for the project, considering plausible values for carbon credits. We compared the optimal WAG ratios for NPV and cumulative oil production. The factors influencing economic results were used to conduct an economic sensitivity analysis. We also examined how tax credits impact economics. The whole work enhances our understanding of the economics of CO_2 EOR and storage in ROZs.

Background and Methods

The field studied is in the northeast corner of the Central Basin Platform (Fig. 1a). The field has experienced primary production, waterflooding, and CO_2 injection (Fig. 1b). By 2010, the field had produced approximately 700 million barrels of oil, mostly from the MPZs of the Permian carbonate San Andres Formation. Fig. 2 shows a brief history of the field. CO_2 injection into the MPZ, begun in the early 1980s, slowed the production decline associated with the mature water flood operation. The operator began ROZ exploitation full-field ROZ development in 2007.



(a)



(b)

Fig. 1— (a) Tectonic map of the Permian Basin showing the location of the study area (red box) in west Texas. Modified from Ruppel et al. (1995) and Dutton et al. (2005). (b) brief production history of the oilfield.

Geological Characterization

The San Andres Formation is one of the several shallow water platform carbonates and mixed siliciclastic-carbonate units that developed on shelves of the Permian basin in west Texas and New Mexico during the Permian (Leonardian-Guadalupian) (Ward et al., 1986). This formation hosts the Upper Permian (Guadalupian) oil play. The sequence stratigraphy of the reservoir sequences by Kerans et al. (1994) and Lucia et al. (1995) found multiple shallowing-up cycles. These cycles consist of mudstones and wackestones grading upward into grain-dominated packstones and grainstones. True crossbedded ooid grainstones are rare, but grain-dominated packstones and grainstones are common. The uppermost part of these cycles consists of fenestral peritidal deposits, and in some cases, anhydrite was precipitated. The reservoir caprock is a thick anhydrite layer. Seven carbonate microfacies and one anhydrite dominated microfacies have been described from 10 continuous cores in the northern and central part of the field (Duncan and Baqués in prep). The cores exhibit well-developed cyclic depositional sequences, with at least five cycles of sedimentation. The identified microfacies include: i) crinoidal-fusilinid packstones and grainstones and fusilinid mudstones/packstones representing deep-water facies (into the ROZ); ii) bryozoan packstones/wackestones and boundstones (bafflestones); iii) peloidal-oolitic packstones/grainstones representing near-shoal and shoal deposition; iv) dascyclad-peloidal packstones that are capped by tidal flat deposits with fenestral fabrics; v) restricted subtidal peloidal deposits, overlying tidal flat deposits, grade up into well-developed tidal flat deposits with pisolites, fenestral fabric, mud clasts, storm layers and anhydrite. In summary, the cores exhibit a very thick lower cycle of sedimentation, dominated almost entirely by open-marine facies. Upper cycles are thinner and exhibit a greater proportion of shallow restricted subtidal and tidal flat facies.

The facies in the San Andres within the reservoir studied are pervasively dolomitized. Ruppel and Cander (1988) suggested that porosity preservation in these reservoirs was a consequence of dolomitization. Fusilinid mudstones/packstones exhibit variably preserved porosities. The crinodal-rich facies, prevalent into the ROZ, contains moderate to large amounts (up to greater than 20%) of preserved porosity. Most of this porosity is secondary in origin. Intercrystalline porosity is variably occluded by anhydrite cement. Bryozoan facies in the lower part of the cores have moderate porosities, generally ranging between 10-15%. Peloidal-oolitic shoal deposits have quite variable porosities, ranging from a few percent up to 22%. Most of the grainstones have their primary porosity reduced by anhydrite cements. Packstones exhibit high intercrystalline and leached dolomite rhomb porosity. The study by Duncan and Baqués et al. (in prep) reveals no significant change in the nature of the facies or diagenesis between the MPZ and the ROZ in the reservoir,

Reservoir Modeling

We integrated information from well logs, and core descriptions into a 3-D geological model. The cored-wells' logs (including spontaneous potential, gamma, density porosity, and neutron porosity) were analyzed, and through this we assigned facies to non-cored wells. Next, we conducted semi-variogram analysis of each facies group in each zone, adopting an exponential variogram model. Then, we used sequential indictor simulation to generate facies for the geomodel and sequential Gaussian simulation to generate porosity fields. The corresponding permeability fields were estimated as described in Ren and Duncan (2019a and b) and Ren et al. (2019).

After building a full-field high resolution (cell size 20×20×2 ft) geological model, we generated a coarse model with cell sizes of 100×100×2 ft. We then cut a sector model and used it to history match the primary depletion and waterflooding for calibration of the MPZ portion of the reservoir model reservoir model. More details are included in Appendix A.

Multiphase Flow Simulation of CO_2 Injection and Injection Scenarios

The calibrated reservoir model was then used for the prediction of CO_2 EOR and storage potentials. For the simulation input, the rock/fluid interaction models (including fluid properties, relative permeability, and capillary pressure curves) refer to Ren et al. (2019).

When predicting the performance of CO_2 EOR and storage, water alternating gas (WAG) injection was considered. Inverted 9-spot 80-acre patterns were adopted, which are currently being used in some cases for the development of the MPZ (see for example Honarpour et al., 2010). The CO_2 injection rate is set to 3000 Mscf/day, and water injection rate is 1400 rb/day (reservoir barrel/day). The injection target pressure is at the reservoir fracturing pressure of 3900 psi (Alcorn et al., 2019). Bottom hole pressure for producers is set to be the minimum miscibility pressure, which was measured as 1400 psi (based on the examples provided by Honarpour et al., 2010). The WAG ratio (i.e., reservoir volume ratio between injected water and CO_2) was varied from 0 to 4, through changing water injection duration while keeping CO_2 injection duration unchanged in each WAG cycle. The WAG ratio equal to 1 (base case) corresponds to 90 days of water injection alternating with 70 days of CO_2 injection. We run simulations of WAG injection for 40 years.

In our model scenarios, all injectors and producers involved in simulations are vertical and perforated according to the development scenarios as shown in Table 1. Different switching schedules and injection/production schemes were considered. Buffered boundary conditions as described by Ren and Duncan (2019a) were used in all simulations to mimic realistic flow scenarios.

Table 1—Designed development scenarios for the brownfield ROZ

Scenario #	Injection Schemes	Production Schemes	Notes
1	MPZ & ROZ 40 yr commingled injection	MPZ & ROZ 40 yr comingled production	Develop MPZ & ROZ at the start
2	MPZ 40 yr injection	MPZ 40 yr production	Develop only MPZ
3	MPZ 20 yr injection + MPZ & ROZ 20 yr injection	MPZ 20 yr + MPZ & ROZ 20 yr	Develop MPZ initially and then develop MP & ROZ
4	MPZ & ROZ 20 yr injection + ROZ 20 yr injection	MPZ & ROZ 40 yr	Develop MPZ & ROZ and then develop ROZ

Techno-Economic Modeling

The economics of CO_2 floods were studied by Flanders et al. (1993) and are well understood. For most economic analyses of oil and gas projects the key approach is the estimation of the Net Present Value (NPV). The NPV is based on estimating the projects annual cash income; subtracting the capital and operational expenditures (CAPEX and OPEX); discounting the resultant cash flow to the time of the beginning of the project; and finally summing the annual estimates to compute the NPV. In some applications, a discount rate is based on the cost of borrowing money. In oil production projects, a higher rate is typically used to account for risk, particularly the risk that oil prices or the value of sequestering CO_2 may decrease during the lifetime of the project. In traditional CO_2-EOR projects, the cost of CO_2 has dominated the economics. When sequestration is considered, with some combination carbon credits and tax abatements, the economics can be changed significantly. In traditional CO_2-EOR operations, the CAPEX includes the cost of: (1) infill drilling (where required); installation of a CO_2 cleanup plant; installation of a CO_2 compression system and pipeline networks for of water and CO_2; well workovers (where required); and other surface installation expenses. OPEX includes the following major cost drivers: the costs of CO_2 purchase and costs of electricity for running compressors to recycle CO2 and pumps to produce fluids and to reinject water.

Project revenues come from: sales of crude oil, short chain hydrocarbon liquids (recovered from CO_2 cleanup plant); and natural gas; as well as tax credits and carbon sequestration payments from the incidental storage of CO_2. For the purposes of this analysis, the NPV is assumed to consist of four ~~componen~~ts: oil revenue, carbon credits, operational expenses, and cost of well deepening into the ROZ. The OPEX (operational expenses) include CO_2 purchase, CO_2 recycling, produced water management, and liquid lifting costs.

The formula used to estimate NPV is in equation 1. The following equations 2-9 show how to calculate all these components. The cost assumptions are listed in Table 2. Sensitivity analysis of these parameters was also conducted using the range in Table 2.

Carbon credits were varied from 0 to 90 \$/ton. This covers the range of credit rates in Section 45Q. According to the Congressional Research Service (2021), the carbon credit is \$11.91/Ton for equipment set up before 2018 to \$35/Ton for equipment set up in 2026. Additionality, carbon credits can impact the oil prices, just as oil prices currently impact CO_2 costs. We examined the influence of this interaction on the optimal WAG ratio and optimized NPV.

We calculated the differences in cumulative net present values (NPV) between the various development scenarios. For these scenarios, we assumed the capital expenditures or CAPEX for MPZ development are sunk costs. This study focuses on the difference in calculated NPV that will be attributed exclusively to the development of brownfield ROZ projects. The current study investigates the impact of different CO_2 injection strategies on the project's NPV. It is assumed that the CAPEX for ROZ projects is limited to the cost of deepening wells from the MPZ to ROZ.

Table 2—The settings of economic parameters in NPV calculation. These settings are based on the publications by Chen and Reynolds (2016), Godec (2014), Hultzsch et al. (2007), and Tayari et al. (2018).

Component	Base Settings	Range
Oil price (\$/STB)	60	30-90
Oil price basis (\$/STB)	1	-
Gas price (\$/Mscf)	1.80	1.2-5
Gas price basis (\$/Mscf)	0.25	-
Tax credit for carbon sequestration (\$/Tonne)	0	0-80
CO_2 purchase price (\$/Tonne)	Oil price × 0.42*	Oil price × (0.33-0.50)
Gas recycling cost (\$/MSCF)	Oil price × 1%	-
**Produced water management cost (\$/STB)†	0.85	-
Liquid lifting cost (\$/STB) ‡	0.19	0.10-0.40
Deepening cost (\$/ft)	150	-
Annual discount rate	0.12	-
CO_2 Section 45Q Tax credit (\$/Ton)§	0	0-90

*the price of CO_2 sold varies according to oil price.
†produced water management cost consists of water injection, water recycling, and water disposal.
‡this is the liquid lifting cost for wells perforated in the MPZ only. The cost for other wells perforated in the ROZ or both the MPZ and ROZ is assumed to linearly increase with reservoir depth.
§only applicable to anthropogenic CO_2, which costs more than natural CO_2.

$$NPV = \sum_{n=1}^{N} \frac{Oil_{revenuen} + Carbon_{pricen} - Recurrent_{costn} - Welldeepen_{costn}}{(1+r)^n} \tag{1}$$

$$Oil_{revenuen} = \left[Q_{op(n)} - Q_{op(n-1)}\right] \times Oil_{price} \tag{2}$$

$$Carbon_{price}\, n = \left(\left[Q_{gi(n)} - Q_{gi(n-1)}\right] - \left[Q_{gp(n)} - Q_{gp(n-1)}\right]\right) \times Storagetax \tag{3}$$

$$Recurrent_{cost\,n} = Gaspurn + Gasrecyn + Water_{cost}\, n + Liquid_{lift}\, n \tag{4}$$

$$Gaspurn=\left(\left[Q_{gi(n)}-Q_{gi(n-1)}\right]-\left[Q_{gp(n)}-Q_{gp(n-1)}\right]\right)\times Gaspur_{price} \quad (5)$$

$$Gasrecyn=\left[Q_{gp(n)}-Q_{gp(n-1)}\right]\times Gasrecy_{cost} \quad (6)$$

$$Water_{cost}n=\left(\left[Q_{\wp(n)}-Q_{\wp(n-1)}\right]-\left[Q_{wi(n)}-Q_{wi(n-1)}\right]\right)\times Water_{cost} \quad (7)$$

$$Liquid_{Lift}n=\left(\left[Q_{op(n)}-Q_{op(n-1)}\right]+\left[Q_{\wp(n)}-Q_{\wp(n-1)}\right]\right)\times Lift_{cost} \quad (8)$$

$$Welldeepen_{costn}=Cost_{perft} * Deepen_{length} \quad (9)$$

In the above equations,
$Oil_{revenuen}$, revenue from oil production at the n_{th} year, $
$Carbon_{pricen}$, price of carbon as incentive for carbon storage at the n_{th} year, $
$Recurrent_{cost\,n}$, recurrent operation cost at the n_{th} year, $
$Welldeepen_{costn}$, well deepening cost for ROZ development at the n_{th} year, $
r, annual discount rate
n, year numbering since the start of development
$Q_{op(n)}$, cumulative oil production till the n_{th} year, STB
$Q_{op(n-1)}$, cumulative oil production till the $(n\text{-}1)_{th}$ year, STB
Oil_{price}, the price of oil, $/STB
$Q_{gi(n)}$, cumulative gas injection till the n_{th} year, MSCF
$Q_{gi(n-1)}$, cumulative gas injection till the $(n\text{-}1)_{th}$ year, MSCF
$Q_{gp(n)}$, cumulative gas production till the n_{th} year, MSCF
$Q_{gp(n-1)}$, cumulative gas production till the $(n\text{-}1)_{th}$ year, MSCF
$Storagetax$, carbon credit for storage, $/Tonne
$Gaspurn$, CO_2 purchase cost at the n_{th} year, $
$Gasrecyn$, CO_2 recycling cost at the n_{th} year, $
$Water_{cost}n$, produced water management cost at the n_{th} year, $
$Liquid_{lift}n$, produced liquid lifting cost at the n_{th} year, $
$Gaspur_{price}$, CO_2 purchase price, $/Tonne
$Gasrecy_{cost}$, CO_2 recycling cost, $/MSCF
$Q_{\wp(n)}$, cumulative water production till the n_{th} year, STB
$Q_{\wp(n-1)}$, cumulative water production till the $(n\text{-}1)_{th}$ year, STB
$Q_{wi(n)}$, cumulative water injection till the n_{th} year, STB
$Q_{wi(n-1)}$, cumulative water injection till the $(n\text{-}1)_{th}$ year, STB
$Water_{cost}$, cost of produced water management, $/STB
$Lift_{cost}$, cost of liquid lifting, $/STB
$Cost_{perft}$, cost of deepening wells into ROZ, $/ft
$Deepen_{length}$, depth of deepening for wells into ROZ, $

Metrics Used to Evaluate CO_2 EOR and Storage Performance

In addition to traditional EOR performance metrics (e.g., cumulative oil production), we also calculated metrics used to measure the performance of CO_2 storage in the brownfield ROZ.

Stored CO_2 amount = injected CO_2 amount – produced CO_2 amount.

CO_2 retention fraction = stored CO_2 amount / injected CO_2 amount.

All these CO_2 EOR and storage metrics change with time; the results given here are the values after ~~40 years.~~

Results

In this section, we show results for the simulation and economic metrics from developing a sector of the field in several different ways over 40 years. First are the development scenario comparisons, then we show the sensitivity to several uncertain economic variables.

Comparing Different Development Scenarios

Fig. 2 compared the CO_2 EOR and storage metrics for each development scenario (Table 1). Comingled injection and production (scenario #1) yield the largest oil production and NPV at all WAG ratios, and comingled injection followed by ROZ injection only (scenario #4) leads to the highest CO_2 storage amount for each WAG ratio. The lowest NPV is for scenario #2, MPZ development only. Not developing the ROZ leads to the lowest oil production and CO_2 storage.

Injecting into the ROZ (scenarios #1, 3, and 4) increases the volume CO_2 accesses compared to MPZ injection only (scenario #2). Scenario 4 has the largest CO_2 storage because MPZ perforations were squeezed after 20 years of production, limiting CO_2 recycling. In some cases, the WAG ratio impacts project economics via oil sales. In scenarios 1 and 2, oil production depends on WAG ratio, but scenarios 3 and 4 do not display this sensitivity (Fig. 2a). For most scenarios, a WAG ratio of 1 achieves optimal or near-optimal NPV.

Storage is heavily dependent upon WAG ratio (Fig. 2b). As WAG ratio increases, less CO_2 is sequestered because less CO_2 is purchased, leading to increasing CO_2 retention fractions (Fig 2c). This WAG effect on CO_2 retention is strongest when ROZ and MPZ are co-developed (scenario #1). At a WAG ratio of 1, constant MPZ+ROZ production leads to 40% more oil being produced, but roughly the same amount of CO_2 sequestered as stopping MPZ production after 20 years. We examined the CO_2 saturation at the end of simulation, and it appears that CO_2 did not largely migrate from the ROZ to the MPZ.

The highest NPV came from adopting a WAG ratio of 1 and jointly developing the ROZ and MPZ. The lowest NPVs came from never developing the ROZ. The main difference between these extremes came from oil sales; operating costs were comparable (Figure 3).

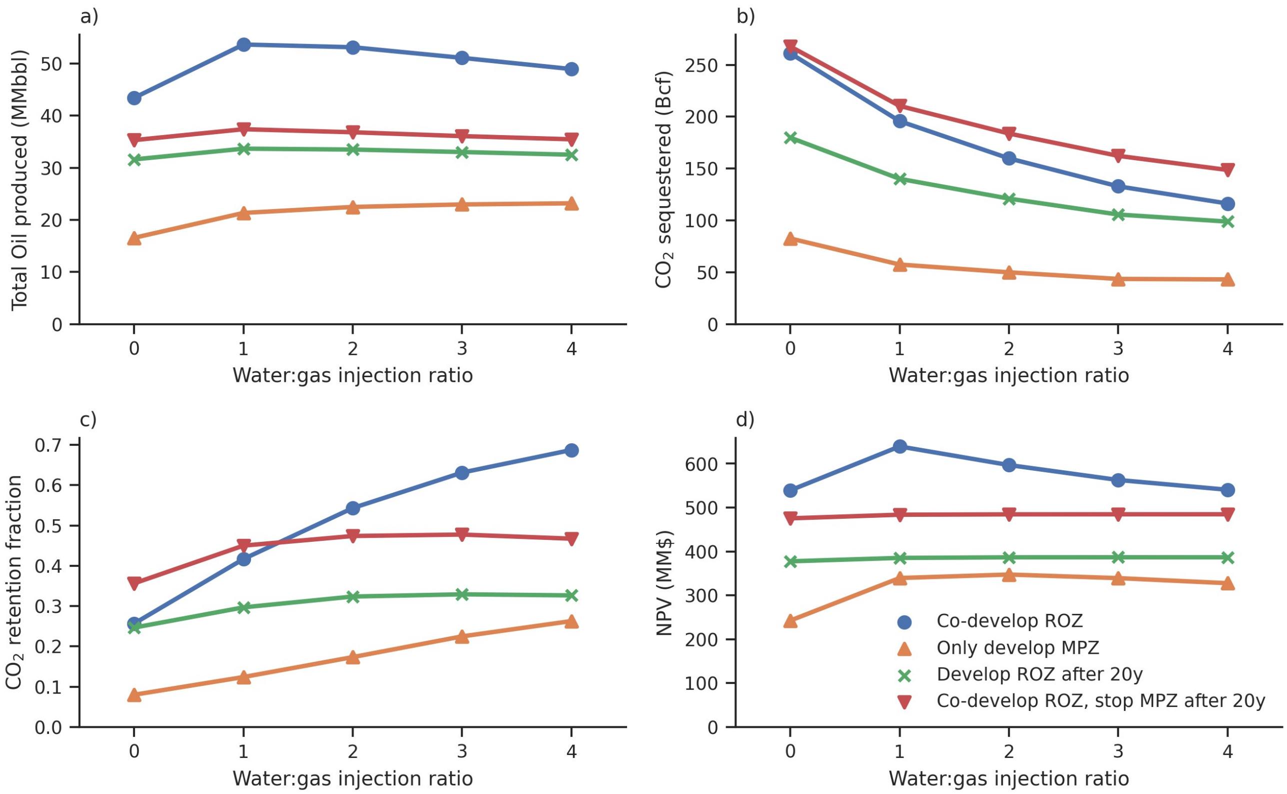


Fig. 2— Comparison of CO_2 EOR and storage metrics for different development scenarios at the end of WAG injection (at 40 years). Blue shows scenario #1, orange scenario #2, green scenario #3, and red scenario #4. (a) final oil production; (b) final amount of CO_2 stored; (c) final retention fraction of CO_2; (d) final NPV. The WAG ratio is in the range of 0-4. The final NPV is calculated using the base settings in Table 2.

Operational costs far outweigh capital costs when considering developing the ROZ after having built an MPZ CO_2 flood. It costs roughly $150/ft to deepen vertical wells in a conventional onshore field (not including lost production). The cost of deepening all 119 wells into the ROZ 4.5 million dollars. This is equivalent to purchasing about 200 thousand tons of CO_2, whereas in scenario #1, 6-15 million tons of CO_2 are purchased.

Most of the costs for all scenarios come from recycling and purchasing of CO_2. Fig. 3 shows the operational cost bar charts after 40 years of development, given a WAG ratio of 1. The total OpEx of the scenario #1 is the most ($871 million), and scenario 2 is the least ($700 million. The other two are in between. For MPZ-only development (scenario #2), CO_2 purchasing costs are far lower than recycling cost. When moving from the MPZ to ROZ development, the large ROZ water saturation does not greatly increase lifting and water management costs. Therefore, there are few differences in these costs between scenarios, except some water management savings in scenario #3 from delayed ROZ development.

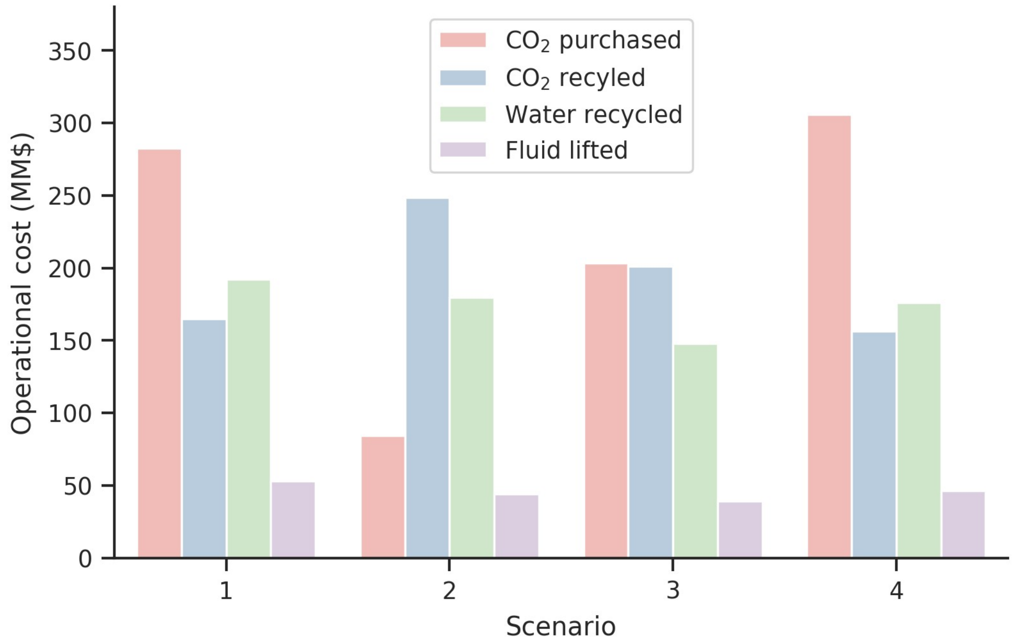


Fig. 3— Bar charts for 40 years of cost for development scenarios 1 through 4. The WAG ratio is 1 (70 days of CO_2 half-cycle alternating with 90 days of water half-cycle). Base settings for economic parameters in Table 2 were used. The scenarios are as follows: 1) Co-developing the MPZ and ROZ 2) Developing only the MPZ 3) Expanding to the ROZ years or decades after developing the MPZ 4) Co-developing the MPZ and ROZ, but eventually stopping MPZ injection.

Sensitivity Analysis

We performed a sensitivity analysis on the economic assumptions and WAG ratio. This included oil price, carbon sequestration tax credits, CO_2 purchasing price, and lifting cost. Geologic and fluid parameters were held fixed during this analysis since we focused on economic assessment. To focus on the effect of WAG ratio rather than the obvious (and linear) effect of price, we generated plots normalized to the lowest NPV WAG ratio to see the uplift for selecting a better water-gas injection ratio.

WAG ratios can significantly change the NPV for both EOR and CCUS applications (Figs. 4-5). This uplift varies from over 100% for only developing the MPZ and focusing on carbon tax credits to less than 1% for co-developing the ROZ and MPZ but stopping MPZ exploitation after 20 years. Without considering carbon credits, the benefit of selecting the best WAG ratio can be from 65% at high oil prices when developing only the MPZ to less than 2% at low oil prices when delaying ROZ development.

The optimal WAG ratio depends on the oil price and is not necessarily the WAG ratio for the largest oil production (Fig 4). When co-developing the ROZ, selecting a WAG ratio of 1 is consistently the best option, but when only developing the MPZ, at low prices a WAG ratio of 1 is ideal, but above \$30/bbl, a WAG ratio of 2 is better. When delaying development of the ROZ, higher WAG ratios improve the NPV.

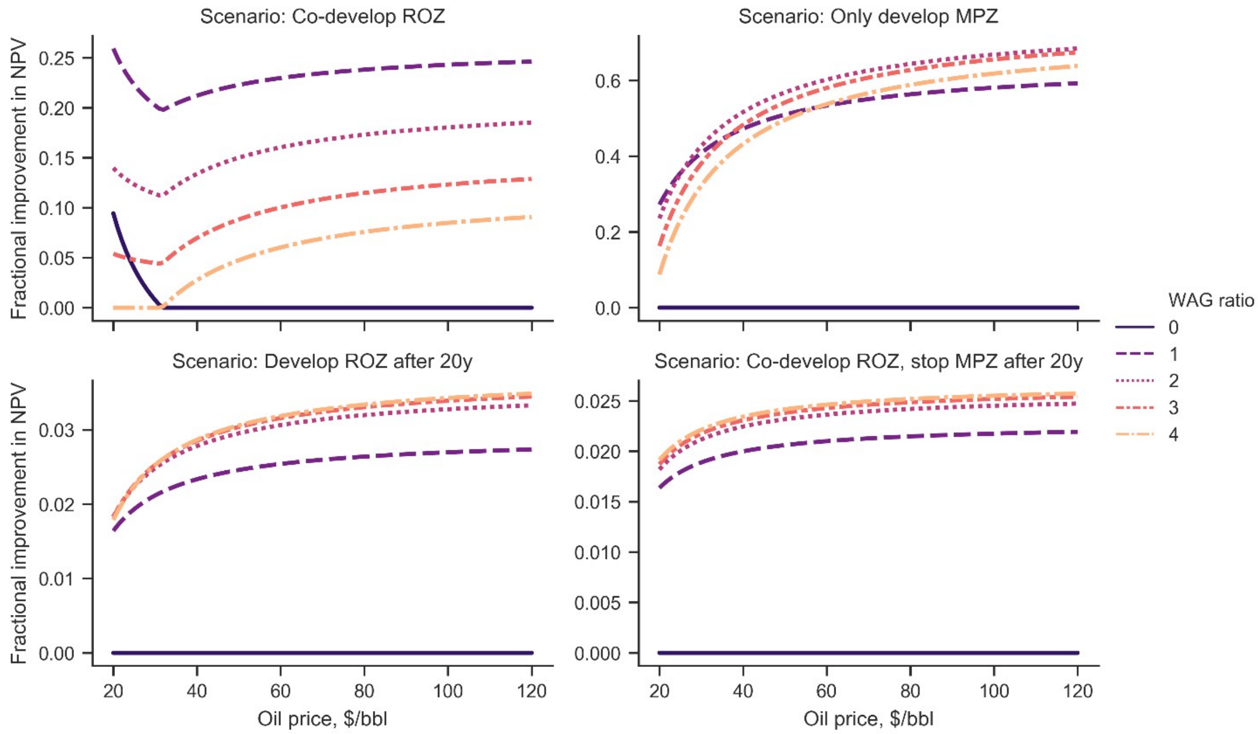


Fig. 4—Dependence of the NPV for different WAG ratios corresponding to maximum cumulative NPV on oil price. The vertical axis is the fraction improvement to the NPV compared to the worst WAG ratio (usually zero, for these cases). The settings for other economic parameters match the base case (refer to Table 2). Note the different vertical scales.

Tax credits for CCUS also affect the ideal WAG ratio (Fig 5). In Scenario #3, where the operator develops the ROZ 20 years after starting CO_2 injection in the MPZ, the ideal WAG ratio varies from 4 at no tax credit to 0 for a tax credit of greater than $70/ton carbon dioxide sequestered. The increase in NPV from optimizing WAG ratio can be from over 100% to about 1% for different scenarios and carbon tax credits.

The maximum CO_2-EOR related tax credit proposed in 45Q is $35/Ton. We show the NPV for different development scenarios and 45Q carbon credits in Fig. 6. At all carbon credit levels, co-developing the ROZ maximizes NPV, followed by co-developing the ROZ and stopping MPZ exploitation after 20 years, then developing the ROZ after 20 years, and finally, developing the MPZ has the lowest NPV.

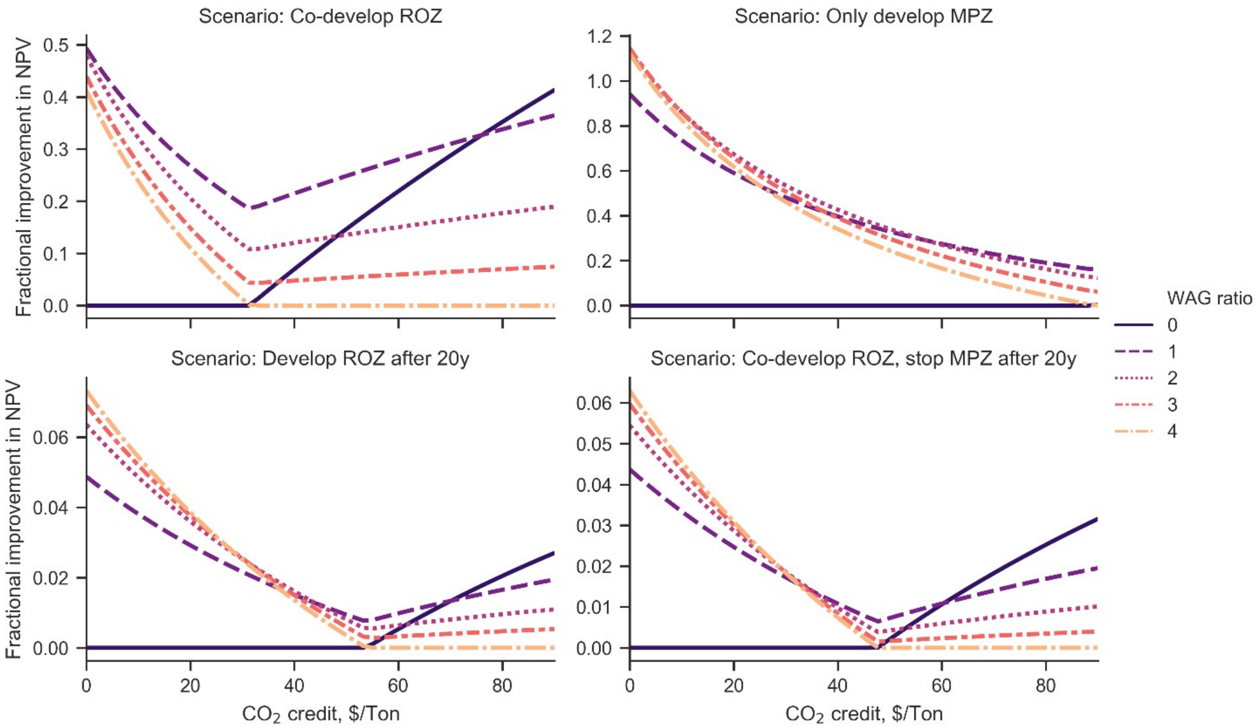


Fig. 5— Dependence of the NPV for different WAG ratios corresponding to maximum cumulative NPV on carbon credit. The vertical axis is improvement to the NPV compared to the worst WAG ratio. The CO_2 purchasing cost is $50/Ton. The settings for other economic parameters match the base case (refer to Table 2). Note the different vertical scales. Inflection points occur when CO_2 credits are high enough that oil production is less important.

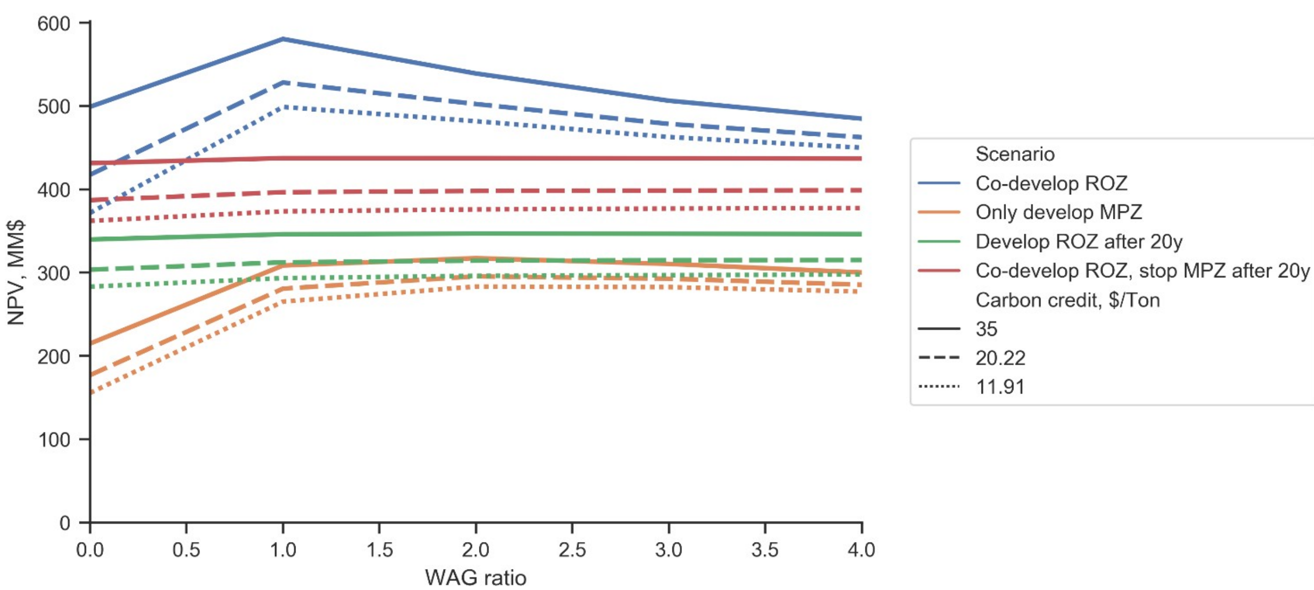


Fig 6— Dependence of the NPV on different WAG ratios and development scenarios for the three levels of carbon credit reported in Section 45Q. The x-axis is the water-to-gas injection ratio, where 0 is all gas injection and 4 is four reservoir bbl of water injection to one reservoir bbl of gas injection. The y-axis is the net present value in million dollars. Color of the lines indicate different development scenarios, and the line style is the carbon tax credit.

Fig. 7 shows the sensitivity of NPV to several economic parameters (i.e., oil price, natural gas sales price, lifting cost, and recycling water and CO_2 prices). We selected the WAG ratio that maximized NPV for each scenario. The most important parameters, in order, are oil price, CO_2 cost, and gas sales price. Co-developing the ROZ leads to the best NPV expectations at all oil prices greater than $6/bbl. After development costs for the MPZ CO_2 flood have been paid off, all scenarios have a breakeven price for oil prices between $2/bbl (MPZ only) and $5/bbl (develop ROZ, close MPZ after 20 years) for base case operating expenditures and the costs of extending to the ROZ (if the scenario includes ROZ development).

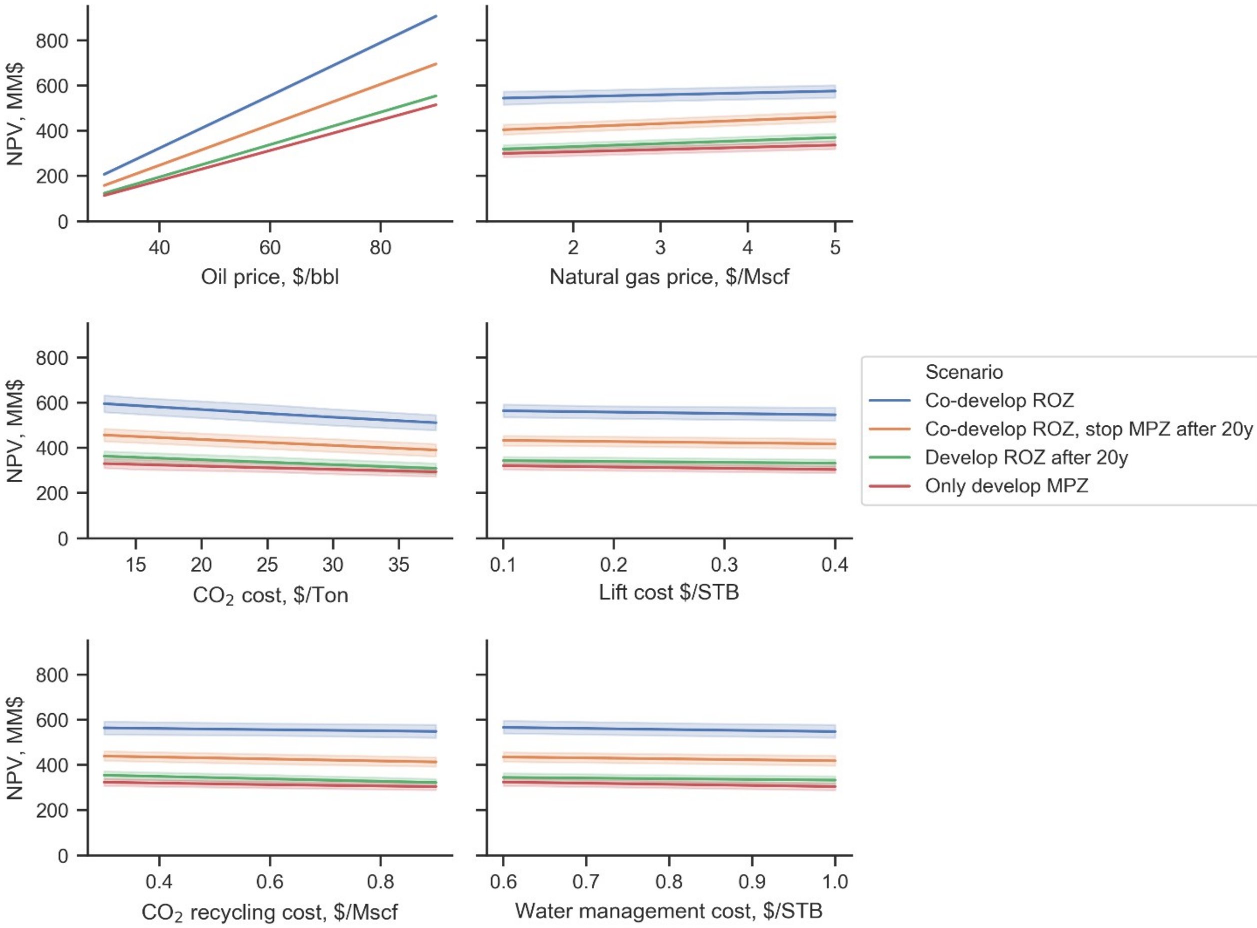


Fig. 7— Dependence of the NPV for high, low, and base cases of six key parameters, where the NPV-maximizing WAG ratio has been selected for each scenario. The x-axis of each subplot shows the modified variable. Along the y-axis is the project net present value (same scale for each plot). Different colors represent the different development scenarios. Shading shows the uncertainty in the average NPV for these sensitivities.

Discussion

The focus of this paper is on the economics, but the simulations of these different development scenarios tell us a few things about CO_2-EOR. For instance, for MPZ-only development, most of the injected CO_2 is very likely to channel into producers and be recycled (as illustrated in Fig. 2). This channeling is less prominent in the ROZ. A comparison between scenarios #1 and #4 shows a large difference in oil production (Fig. 2a) but similar CO_2 storage (Fig. 2b). The lack of CO_2 migration we see is consistent with surveys we conducted of the CO_2 saturation fields.

Economics for ROZ versus MPZ CO_2 Flood Projects

Brownfield ROZ projects are able to use the same recycle plant and other infrastructure as the original CO_2 EOR development in the MPZ. Therefore, expanding an MPZ CO_2 flood to the ROZ requires little capital expenditure. As a result, in the payback period (the time from the initiation of the project to the time at which positive cash flow begins) is shorter. Co-developing the ROZ also accelerates the oil production and maximizes the ultimate recovery (Fig. 2). Accelerating the production improves the NPV, further improving the economics over MPZ-only CO_2 floods.

Role of Varying the WAG Ratios on the Economics of CO2 Floods

Previous studies (e.g., Chen et al., 2010; Wu et al., 2004) of optimal WAG ratios for CO_2-EOR projects have largely ignored economics. As the WAG ratio represents the relative volume of CO_2 versus water being injected, CO_2 prices and tax breaks mean the ratio will significantly affect the operational expenses.

The NPV is more sensitive to the WAG ratio when only developing the MPZ than for scenarios where the ROZ is also developed (Fig. 3 and 4). In the MPZ, continuous CO_2 injection leads to early breakthrough and more CO2 recycling, thus increasing operational expenses while simultaneously decreasing oil production when compared to WAG. In the ROZ, the low mobility of oil slows channeling, which decreases the effect of the WAG ratio on the NPV.

CO_2 tax breaks affect the ideal WAG ratio by over 20% for much of the range of carbon credits when either only developing the MPZ or co-developing the ROZ (Fig. 4). There are complex interactions between the oil price, carbon credit, WAG ratio, and their effects on the NPV for both MPZ and ROZ project development.

Role of CO_2 Sequestration Tax Credits

Ettehadtavakkol et al. (2014) modeled the economics of different rates of fluid injection, WAG ratio and pattern flood duration. They examined the discounted cash flows from CO_2 EOR projects. They examined breakeven oil prices as CO_2 utilization, oil production rate and purchase price of CO_2 are varied. Significantly, they also considered the impact CO_2 sequestration payments. Their main findings included a recommended range (20 - \$40/tonne) of CO_2 storage tax for sustainable CO_2 EOR-storage operations.

We found that carbon tax credits could be a significant source of income for CO_2 EOR projects. Even when the carbon credit is significantly less than the cost of acquiring anthropogenic CO_2, this can make CO_2 EOR projects more profitable. Also, as said above, adding carbon credits can lead to changes in the NPV-maximizing WAG ratio.

A significant point in the applicability of tax credits appears to be when CO_2 storage becomes more important than oil sales for selecting the NPV (Figure 5). This is heavily scenario-dependent, and it happens at the lowest CO_2 credit for immediate ROZ development. Thus, we may conclude that ROZ development allows for more flexibility in selecting the best WAG ratio to balance oil sales with carbon credits.

Section 45Q requires projects to capture 500,000 metric tons/year to apply for this credit. In the most carbon-storage-intensive scenario, our whole field study uses 59 million metric tons for the first 20 years (note, our simulations only covered a portion of the field), or about 1.6 million metric tons/year. The least carbon-intensive development scenario would still sequester 0.2 million metric tons per year. For comparison, a 500-megawatt coal-fired power plant emits about 3 million metric tons a year (Li et al., 2015). Thus, it is possible to use the full CO_2 output of a power plant to supply CO_2 to a ROZ flood of this size and meet the minimum requirements for Section 45Q.

Sensitivity of Results to Variations in Income and Costs

The WAG ratio that yields the maximum oil production does not necessarily give the maximum NPV. Oil prices from \$40-80/bbl tend to have the same ideal WAG ratio (Fig. 4). For carbon storage, though at sufficiently high carbon credits, the ideal WAG ratio drops (Fig. 5). While oil prices, gas prices, and CO_2 costs affect the project NPV significantly, the best NPV always resulted from co-developing the ROZ when developing the MPZ CO_2 flood. The lift cost, CO_2 recycling cost, and water management cost did not greatly affect project economics (Fig. 7).

Conclusions

We evaluate different development strategies and their associated uncertainties through integrated full-physics flow simulation and economic assessment for a San Andres Unit Brownfield residual oil zone. The assessment is based on a high-resolution geological model with integrated geological and reservoir characterization and careful calibration through historical primary and secondary production data matches. To better compare development strategies, we defined and calculated a series of metrics for CO_2 EOR and storage. Water alternating gas (WAG) ratios were tuned to maximize either oil production or net present value (NPV). The influence of economic parameters (e.g., oil price and carbon credit) on favorable WAG ratios were examined. We found that:

i) Simultaneous WAG injection into both the MPZ and ROZ maximizes oil production and net present value.
ii) The NPV is more sensitive to the WAG ratio when co-developing the ROZ and MPZ than in MPZ-only flooding.
iii) When targeting CO_2 storage, switching from comingled injection to only ROZ injection after two decades of production is a viable strategy. The optimal switching time needs further study.
iv) As the CO_2 tax credit varies, the best WAG ratios to maximize NPV change to balance benefits from oil production and carbon storage.

This work provides a basis for future optimization of CO_2 EOR and storage in brownfield ROZs.

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Author Credits

Bo Ren: conceptualization, methodology, validation, writing - original draft. Frank Male: economic modeling, figure preparation, writing, editing. Ian Duncan: conceptualization, management, review, rewriting, and editing.

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Appendix A: Model construction and validation

Geological Models

Fig. 3 shows the full-field porosity and permeability, along with permeability for the sector model. We selected this porosity/permeability distribution from the batch of realizations that conform to geological characterizations and reservoir heterogeneity. The cut sector consists of 25 inverted 9-spot 80-acre patterns, with 25 vertical injectors and 94 vertical producers.

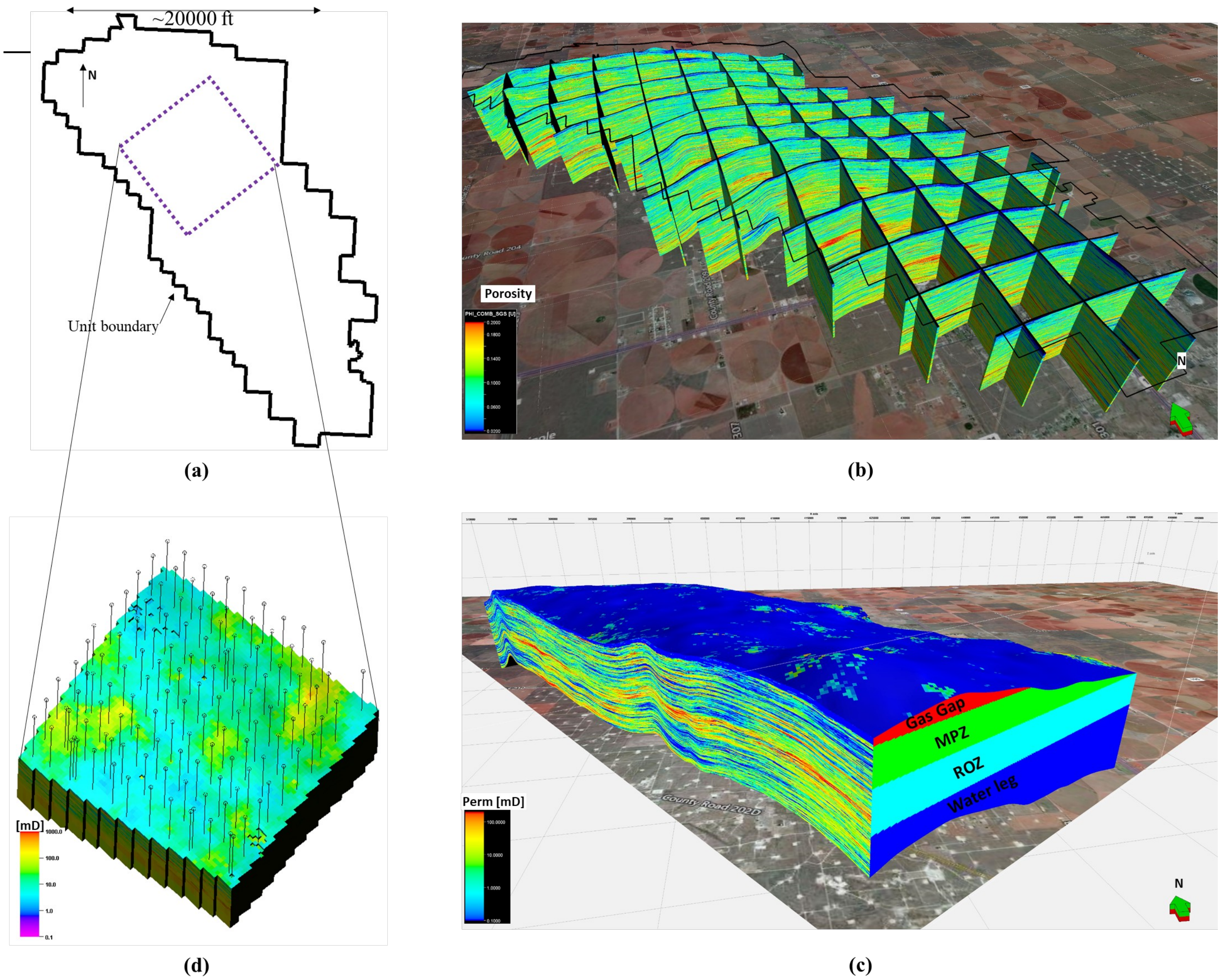

Fig. A1—(a) The Petrel unit boundary of full-field geological model for the field with the dashed square in (a) representing the outer boundaries of a cut sector model. (b) Porosity fence diagram. (c) Permeability field with the two sectional cut for direct visualization. Four zones (gas cap, MPZ, ROZ, and water leg) are differentiated with different colors for easy look. The depth cutoff for the three contacts are 1725 ft (gas-oil-contact), 1935 ft (producing water-oil-contact or the contact between the MPZ and ROZ), and 2200 ft (free water level). (d) Permeability field of the cut sector with all the vertical well locations shown on the top of model.

History Matching

The simulation in this study were based in part on a reservoir model for the MPZ that was used to history match the oil production, water cut, gas-oil-ratio (GOR), and mean reservoir pressure. The static model is calibrated and a good match was found for oil production rate, water cut, and reservoir pressure. The history match of GOR is challenging. GOR matching is hindered by the lack of both the information about the gas cap size and knowledge of the vertical fracture permeability of the reservoir. Still, the overall trend and peak GOR rates are captured.

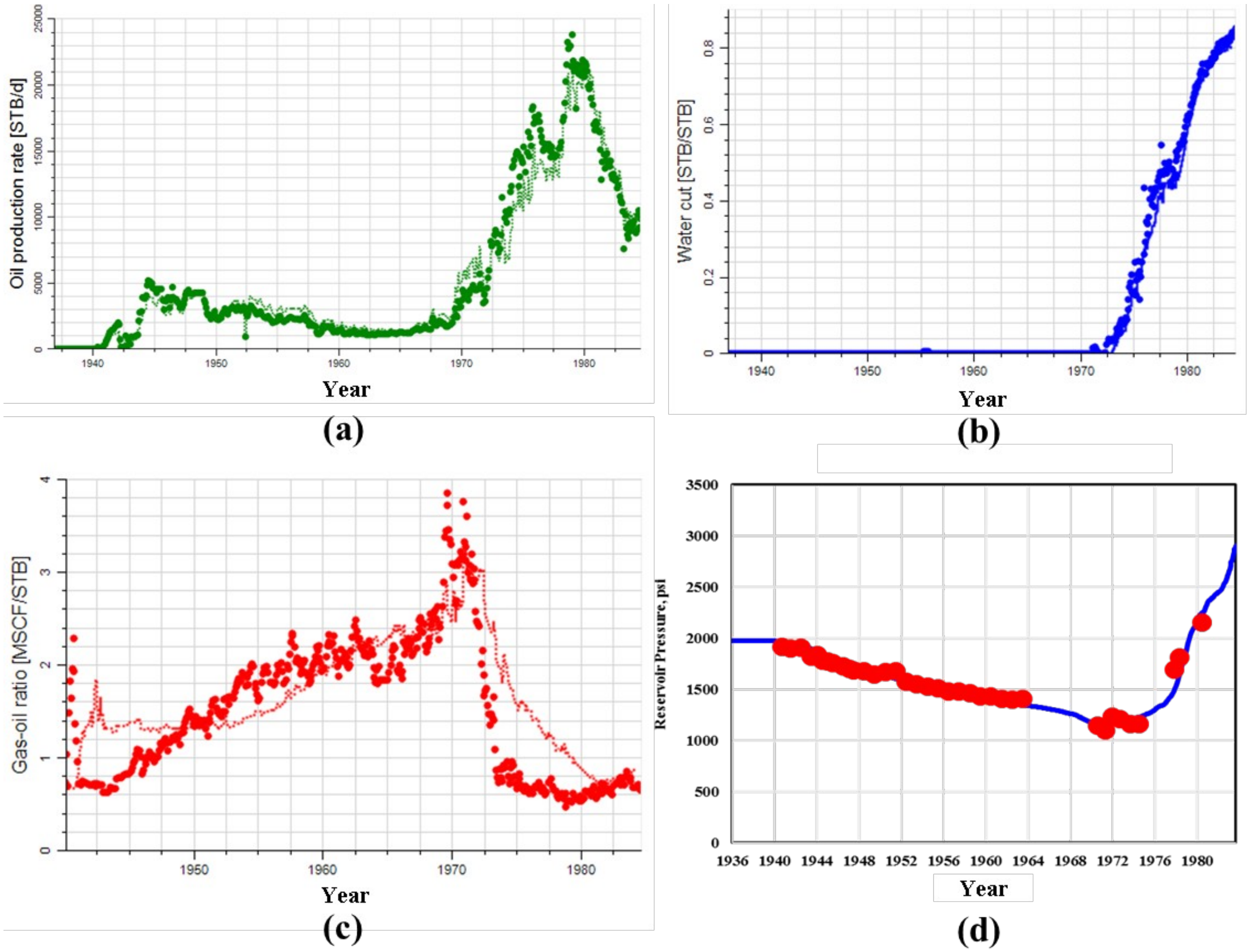

Fig. A2—History matching of oil production rate (a), water cut (b), gas-oil-ratio (c), and reservoir pressure (d) during primary depletion and waterflooding periods. Large dots are field measurements, and lines represent simulation results.