OPTIMIZING THE HC RECOVERY ALONG WITH CO_2 STORAGE

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Abstract

Several strategies•were•tested•and•studied•to•find•injection•and•production•procedures•that•"co-optimize"•oil•recovery•and•CO_2 storage. The results show that traditional reservoir engineering techniques such as injecting CO_2 and water in a sequential, so-called water-alternating-gas process are not conducive to maximize CO_2 stored within the reservoir. A well control process that shuts in wells producing large volumes of gas and allows shut-in wells to open as reservoir pressure increases was a successful strategy for co-optimization. This result holds for immiscible and miscible gas injection and can be improved when miscible gas injection is followed by pure CO_2 injection. Combining this strategy with well-control technique produced the maximum amount of oil and simultaneously stored the most CO_2 giving robust results.

KEYWORDS: CARBON SEQUESTRATION, HYDROCARBON RECOVERY, INJECTION SCENARIOS, WATER ALTERNATING GAS TECHNIQUE, GAS AFTER WATER TECHNIQUE, WELL CONTROL TECHNIQUES, SOLVENT INJECTION, GAS INJECTION TECHNIQUE, ENHANCED OIL RECOVERY, HYBRID EOR AND GS

INTRODUCTION

Storage of CO_2 deep within the earth or in the ocean instead of releasing it to the atmosphere by capturing CO_2 from stationary sources, such as factories and power plants, and introduce it into the ocean and underground in oil and gas reservoirs is one option to reduce the amount of CO_2 released to the atmosphere. Carbon dioxide injection has been used in enhanced oil recovery processes since the 1970s; the traditional approach is to reduce the amount of CO_2 injected per barrel of oil produced. This minimizes the purchase cost of CO_2. However, for a proposed process, the aim is to maximize both the amount of oil produced and the amount of CO_2 stored to reduce the threat of global warming. It is not readily apparent how this aim is achieved in practice.

Even though the greenhouse effect helps earth to retain an average temperature that is suitable for life, problems may appear due to the increase of atmospheric concentration of greenhouse gases.

Since the beginning of the industrial age, atmospheric concentrations of greenhouse gases have increased significantly. Despite the fact that other greenhouse gases, such as methane and nitrous oxide, contribute to radioactive forcing, experts project that carbon dioxide Emissions will account for about two thirds of potential global warming.The objective of this paper was to test the different approaches available for achieving the co-optimization of Geologic sequestration and Hydrocarbon Recovery and eventually after considering the pros and cons, three different techniques have been proposed in this paper to be used in combination in order to co-optimize the CO_2 sequestration and oil recovery. Using well control technique along with the solvent and CO_2 injection proved to be superlative for co-optimization. 80% of oil can be recovered with maximum storage of CO_2 within the earth through this strategy. CO_2 emissions in the environment can be reduced this way.

Measured atmospheric CO_2 concentrations for the last two hundred and fifty years are shown in (Fig.1). The figure illustrates that in the last two and a half centuries the atmospheric concentration of CO_2 has increased from 270 to 370 parts per million (ppm).

As can be seen, the significant increase in CO_2 concentrations begins around 1850 with the start of the industrial age, and there is a sharp increase during the last fifty years.

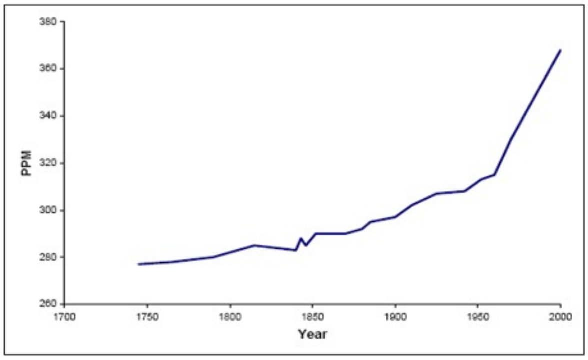

***Figure 13*:** Atmospheric carbon dioxide concentrations in the last 250 years (Source: Keeling, C.D. and Whorf, T.P., 1998.)

Manufacturing of cement, and clearing of forests, also, have played smaller but still significant roles in the increase of atmospheric CO_2 concentration. Even though the magnitude of temperature response of the earth to increasing CO_2 concentrations is still being debated, it seems clear that CO_2 emissions into the atmosphere must be decreased if upward trend in Fig. 1 is to be decreased to reduce the threat of global warming.

MATERIAL AND METHODS

There are several approaches to the problem of CO_2 concentration in the atmosphere. Because increasing CO_2 emissions are mainly caused by the combustion of fossil fuels, the first proposed solution is to increase energy efficiency and to use alternative energy sources such as wind, solar, or nuclear power. Given increases in world population and expanded use of energy in developing economies like China and India, this solution cannot be adequate alone.

A second potential solution is increasing the CO_2 absorbed by plants by planting more trees. Today, plants all around the world store around one tetra-tons of carbon. Even though this method sounds environmentally friendly, the potential of trees to retain CO_2 is limited (because they have limited lifetimes and they take up carbon at a limited rate).

A third approach is CO_2 sequestration. Sequestration is summarized as the storage of CO_2 deep within the earth or in the ocean instead of releasing it to the atmosphere. The strategy of this method is to capture CO_2 from stationary sources, such as factories and power plants, and introduce it into the ocean and underground. Currently, 26 geologic storage projects and 74 geologic research and development projects are in place around the world. The largest of these projects include Sleipner (Norway), In-Salah (Algeria), and Weyburn (Canada) with annual injection rates of approximately 1.0 million metric tons (MMT) of CO_2 (IEA 2006). Despite their size, these operations represent only a small fraction of global CO_2 emissions, which currently exceed 13,500 MMT annually.

Scientists estimate that 3,500 new GS projects worldwide—each comparable in size to the largest existing projects—must be operational within a few decades to have a meaningful impact on global emissions reductions Note that carbon dioxide is already injected into oil reservoirs to increase oil recovery.

Oil reservoirs are good candidates for sequestration because physical and legal infrastructure already exists for CO_2 injection. Carbon dioxide has been injected in EOR processes since the 1970s. The main factor setting the efficiency of EOR with CO_2 injection is the miscibility of CO_2 in the oil phase. At pressures greater than minimum miscibility pressure (MMP), oil and CO_2 are mutually soluble. The dissolved CO_2 reduces the viscosity of the oil and also causes swelling of the oil phase. Thus, CO_2 injection projects are preferred for oil with densities ranging from 29 to 48 °API (882 to 788 kg/m3) and reservoir depths from 760 to 3700 m below ground surface. If the only considerations are depth and gravity, 80 % of the world's reservoirs qualify for EOR with CO_2.

To date, injection processes have been designed to minimize the amount of CO_2 injected per barrel of oil produced, thereby minimizing the purchase cost of CO_2.

However, when the aim is to store carbon dioxide, the strategy changes significantly. Oil recovery processes need to be modified to leave the maximum amount of CO_2 in the reservoir at the completion of operations as well as maximizing oil recovery.

Enhanced Oil Recovery (EOR) minimizes the amount of CO_2 injected for a given amount of oil recovered, whereas Geologic Sequestration (GS) maximizes CO_2 stored. Therefore, any transition from EOR to GS in the framework of projects would occur as lifetime project costs and benefits shift, changing the incentives from minimizing CO_2 injected to maximizing CO_2 stored. In this paper, I will discuss different strategies showing the inter relation between the CO_2 storage and maximum oil recovery. In this study, my main goal is to persuade carbon dioxide injection strategies leading to co optimization. The focus here is effective methods that co-optimize CO_2 storage and oil recovery for a given reservoir and fixed well placement. Then, I focus on mounting CO_2 injection scenarios leading to co-optimization and then results of the various injection schemes are presented. Finally, the conclusions are given.

The primary aim of EOR operations is to maximize the amount of oil extracted per unit CO_2 injected, whereas the goal of GS is to maximize the amount of CO_2 stored. Although GS and EOR projects have fundamentally different aims, they share common processes (Fig.2). The main elements of EOR include the transportation of CO_2 to a mature oil field, injection of pressurized CO_2 at the site, and extraction of oil. GS projects also include CO_2 transportation and injection components, but additionally involve sheltering CO_2 safely and permanently underground and monitoring a site over a very long period of time.

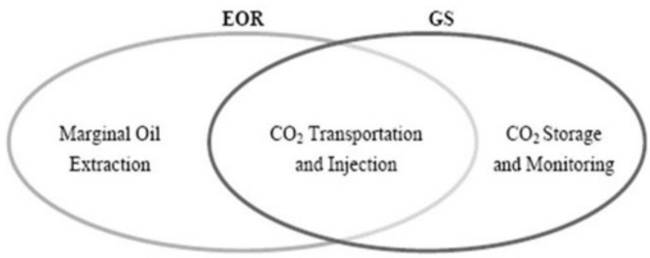

Figure 14: Shared components of EOR and GS Projects (Source: RFF DP 08-29; Alexander J. Bandza and Shalini P. Vajjhala)

CO_2 Injection as an EOR

As reported, EOR projects using a variety of methods and injection materials have operated worldwide for more than 30 years. Currently, CO_2 is the predominant medium used for EOR, making these operations the nearest technical analogues for GS projects. Most EOR operations employ miscible CO_2 injection, a process in which CO_2 is injected above a certain pressure to create a single homogeneous phase of CO_2. Mixing CO_2 and oil in a single phase above the minimum miscibility•pressure•reduces•the•oil's•viscosity and causes it to swell, facilitating extraction. In this process, much of the CO_2 is returned to the surface as oil is extracted, and it is often separated and re-injected. As a result, EOR minimizes the amount of CO_2 required. At the end of an EOR project, site operators currently have no financial incentive to store CO_2, and they typically recycle or sell any remaining amount.

Geological Carbon Sequestration

Whereas most EOR operations use CO_2 from natural sources, GS operations are intended to store CO_2 captured only from anthropogenic sources. CO_2 is most commonly captured by chemically scrubbing a combustion stream from burning fuels in electric power generation, refining fossil fuels or producing various carbon-intensive industrial materials, such as iron, steel, hydrogen, ammonia, and cement (IPCC 2005).5 In a typical GS project, captured CO_2 is transported to storage site by pipeline, ship, or road and then injected deep underground into a secure geological formation, such as a depleted hydrocarbon reservoir or a saline aquifer. At most GS sites, CO_2 injection is expected to occur over a period of decades. After injection operations are complete and a site is closed, monitoring and verification of the stored CO_2 must then occur over many more decades, possibly centuries, to ensure its environmental integrity.

CO_2 transportation and injection for GS rely on mature technologies and practices developed for EOR. Additionally, monitoring techniques from ongoing EOR operations, such as seismic imaging and surveying, can also be adapted for GS projects. The primary difference between EOR and GS is the total amount of CO_2 injected, retained, and secured over the lifetime of a project; at these phases, differences in leakage risks, and therefore regulatory options, emerge for specific types of GS projects within the full technology portfolio.

Risk Management for EOR and GS

Although EOR and GS projects will most likely operate concurrently in the coming decades, it is unclear how policy proposals to set a price for CO_2 and provide incentives for GS could shape the framework of both EOR and GS projects over the long term. For example, depending on long-term average prices of CO_2 and oil, one might expect to see a greater number of hybrid EOR–GS projects at lower CO_2 prices and higher oil prices, with stand-alone GS projects emerging only at higher prices of CO_2. If sequestration becomes profitable more gradually, EOR and GS operations could exist simultaneously in the same reservoir, with CO_2 storage occurring as an afterthought to oil extraction with EOR.

Each type of GS project has a different risk profile. Designing an effective legal and regulatory framework requires a basic characterization of the full range of possible projects.

Currently, GS regulatory design is in its childhood. Governments around the world are implementing efforts to promote GS, but existing regulatory structures for related problems, such as underground injection and drinking water regulations, are insufficient or inappropriate for developing standards for GS. Depending on the incentives and uncertainties surrounding new GS projects, the composition of any GS range could vary significantly over time. Regulations intended to trim down the overall risk of GS technologies are based on dynamic financial conditions, such as market prices for CO_2 and oil. This framework-level view is especially critical when evaluating how the earliest GS projects could evolve from current EOR operations.

Classifying Strategies for EOR and GS

There has been little attention to possible shifts from EOR to hybrid and then GS projects. Here, we use a scenario-analysis approach to evaluate such framework-level transitions.
To illustrate the key points along this transition, we develop the following four strategies:
EOR based: Optimization for oil recovery
Hybrid EOR–GS Strategies:
Step by step: Optimization for oil recovery, then optimization for CO_2 storage
Co-optimization: of oil recovery and CO_2 storage
GS based: Optimization for CO_2 storage (GS projects only)

These strategies characterize the major types of projects likely to compose the larger framework of EOR and GS sites in coming decades. We use a simplified lifetime cost–benefit analysis approach to evaluate which types strategies are likely to dominate, in that they generate the greatest revenues for a fixed amount of CO_2 injected, leakage rates, and costs for a range of oil and CO_2 prices.

We hypothesize that, as the price of CO_2 rises relative to the price of oil, the portfolio will shift from EOR based to hybrid projects first, and will then shift from co-optimization to GS based projects as forgoing oil recovery to increase CO_2 storage potential generates greater total revenues. If the price of oil rises in relation to the price of CO_2, we would expect a reverse shift. Below, we describe the main features of each strategy.

EOR

In this strategy, which is based on current EOR practices, we assume that CO_2 from nearby, naturally occurring underground reserves is extracted and transported by pipeline to an oil field. This strategy maximizes transportation costs restrictions. No payments are provided for any CO_2 that remains underground at the end of the EOR operation, and oil is the sole source of revenues.

Hybrid 1

The strategy, a step by step operation, should dominate an EOR strategy when the price of CO_2 relative to the price of oil is sufficiently high that a site operator could achieve higher net revenues by storing CO_2 toward the end of EOR operations than through EOR alone. CO_2 leakage risks are assumed to be greatest at this site, the integrity of which has been compromised for oil extraction without any consideration of future GS.

Hybrid 2

This strategy dominates when the price of CO_2 relative to the price of oil is high enough that a site operator would consider co-optimizing oil production with long-term CO_2 storage over the lifetime of the project. Cakici (2003) develops a model co-optimizing oil recovery and CO_2 storage through modified EOR practices that sacrifice a fraction of total oil output (e.g. by lowering the ORR) to preserve site integrity and reduce long-term CO_2 leakage

GS Based Strategy

This strategy is most closely associated with the GS project being widely discussed as a climate change mitigation option. Here, we focus on CO_2 storage in deep saline aquifers, which are widely available and less geologically disturbed than depleted oil reservoirs. Payments for CO_2 storage represent the only source of revenue in this strategy, which should dominate only when the price of CO_2 is high enough that the marginal benefit of avoided long-term CO_2 leakage by shifting away from depleted oil reservoirs in the Hybrid strategies exceeds the marginal cost of oil recovery altogether.

Integrating the Considerations

By integrating engineering and economic considerations in this cost–benefit analysis, the transitions between strategies resulting from changing prices of oil and CO_2 are examined. A scenario with a high price of oil and a low price of CO_2 will result in a preference for oil extraction over long-term CO_2 storage. Conversely, a scenario with a low price of oil and a high price of CO_2 will favor• preservation• of• the• site's• integrity, thereby ensuring greater profits from increased CO_2 stored at the expense of less—or even no—oil extracted. These four strategies generally characterize, for regulatory design purposes.

We focus solely on the dominant strategy under different ranges of oil and CO_2 prices. This is not to say that, at given prices of oil and CO_2, the dominant strategy is the only profitable one, but rather to emphasize the points at which specific types of projects could sensibly take hold and move forward. All of our strategies could have positive net revenues under a wide range of oil and CO_2 prices, and specific projects or sites could be even more profitable, and thus financially valid. However, investors faced with technical, legal, and regulatory uncertainties typically require high returns on investment to justify the long-term financial risks associated with deploying a new technology. This scenario-analysis framework provides a strong characterization of where and when the highest revenues are possible along the transition from EOR to GS.

Oil Response Ratios

The ORR is well understood from decades of industry experience with EOR. The ratio of the amount of oil recovered to the amount of CO_2 injected is referred to as the *oil response ratio* (ORR). Researchers have found that the typical ORR for EOR projects is 0.6 metric tons of oil recovered per metric ton of CO_2 injected, but variations also exist. These estimates can directly be applied to hybrid step by step strategy, using a mean value of 0.6 and upper and lower bounds of 1.04 and 0.24, respectively.

Lifetime Leakage Rates

We define leakage broadly as the total amount of injected CO_2 lost from a reservoir. The lifetime leakage rate is the percentage of injected CO_2 that is lost over the lifetime of the project. Therefore, it indicates the long-term storage potential of the reservoir. Ha-

Duong and Keith (2003) consider an annual leakage rate of 0.1% to be essentially perfect storage, but suggest that an annual leakage rate of 0.5% is too great for effective climate change mitigation. After 100 years, an annual leakage rate of 0.1% would result in the retention of approximately 90% of the original CO_2 injected, corresponding to an LLR of 10%, and an annual leakage rate of 0.5% is equivalent to 60% retained or an LLR of 40%. Therefore, using 0.10 and 0.40 as lower and upper bounds, respectively, of LLR across all strategies will be valid.

TOTAL PROJECT COST

We consider three main categories of costs for each strategy:

1. CO_2 transportation
2. Storage (injection)
3. Monitoring

These costs will be discussed individually below; all costs are in US$ per metric ton of CO_2 unless otherwise noted.

Pipelines

Pipelines, the most common form of CO_2 transportation used today, are well-established for EOR projects, and their operation has historically been very safe. Total transportation costs for any given project are a function of pipeline distance from a CO_2 source to an injection site (Bielicki 2008; McCoy and Rubin 2008). Thus, we calculate the mean cost for each strategy by finding the average distance between CO_2 sources and sinks specific to each strategy. In the Indifferent strategy, we assume that EOR operators would continue the business-as-usual practice of using CO_2 from natural sources. Pipelines from natural CO_2 sources to EOR projects are, on average, 600 km long (Gale and Davison 2004). For the Hybrid strategies, pipelines from industrial CO_2 sources to EOR projects average 225 km (Gale and Davison 2004). In the GS based strategy, pipelines from industrial sources to deep saline aquifers are estimated to be 100 km long because of the greater number and geographic spread of aquifers compared to EOR sites (McCoy and Rubin 2008).

Anderson and Newell (2004) estimate that the mean transportation cost for EOR with CO_2 from natural deposits (EOR based) is \$42.00 per ton of CO_2 injected. For EOR with CO_2 from industrial sources (Hybrid), the average transportation cost is \$15.75 per ton of CO_2 injected (Anderson and Newell 2004) For GS in saline aquifers (GS based), McCoy and Rubin (2008) estimate that total transportation costs are \$1.16 per ton of CO_2 injected, within a range from \$1.03–\$2.63 per ton (90% confidence interval). In the absence of robust estimates of upper- and lower-bound transportation costs for the EOR based and Hybrid strategies, we use a range of ±\$5 around the mean for each strategy.

Storage

Storage costs encompass all costs incurred by site operators in the injection, operation, maintenance, and closure of a site secured for long-term GS. These costs are largely a function of the amount of CO_2 initially injected. Building on a 2002 Tennessee Valley Authority report (EPRI 2002), Anderson and Newell (2004) estimate an average cost of \$15.00 per ton for CO_2 stored in a depleted hydrocarbon reservoir; this is applicable to the Hybrid and EOR based strategies. Anderson and Newell (2004) further estimate that the mean storage cost for GS in a saline aquifer is \$10.00 per ton of CO_2 stored, applicable to the GS based strategy. All costs are in \$/ton of CO_2 injected.

Monitoring

The final category of project costs in GS operations is long-term monitoring to ensure site integrity. According to 2005 estimates, the total costs of monitoring are \$0.10–\$0.30 per ton of CO_2 injected. For the EOR based strategy, where no CO_2 is stored, monitoring costs are set to zero. For the step by step strategy, we assume that monitoring costs are at the higher end of the given range, to reflect additional costs associated with monitoring a greater number of wellheads or otherwise compromised areas associated with past EOR operations. Under this strategy, we use a lower bound of \$0.20, a mean of \$0.25, and an upper bound of \$0.30 per ton of CO_2 injected. For the co-optimized and GS based strategies, we assume that monitoring costs are at the lower end of the range; for both strategies, we use a lower bound of $0.10, a mean of $0.15, and an upper bound of $0.20 per ton of CO_2 injected.

I will consider and prefer the third strategy i.e.; co-optimization (oil recovery and CO_2 storage) as both EOR and GS goes along with each other optimally in this strategy but here I have assumed that the price of CO_2 relative to the price of oil is high enough and will discuss the possible injection scenarios with results obtained accordingly, and showing that miscible gas injection when followed by pure CO_2 injection and combining this strategy with well-control technique will produce the maximum amount of oil and simultaneously stored the most CO_2.

The main goal is to find injection scenarios leading to maximum oil recovery with simultaneous maximum emplacement of CO_2 in the reservoir.

A variety of schemes were tested that are summarized as

1. continuous gas injection
2. gas injection after water flooding (GAW)
3. water alternating gas drive (WAG)
4. gas injection with active production and injection well constraints (well control)

Table 14: Well control parameters

Name	Injection Gas A	Injection Gas B
CO_2	0.6667	1
Ethane	0.1250	0
Propane	0.1250	0
i- Butane	0.0533	0

Injection fluid 1 and 2 are referred to as solvent and pure CO2, respectively in Table 1. The first of the schemes listed above is an intuitive approach to maximize the CO2 storage in a reservoir. Since gas injection is continuous, CO_2 injection time is maximized and there is no other injection fluid occupying volume in the reservoir.

The second and third schemes resemble conventional oil recovery methods. Gas injection after water flooding represents a project where water is used to maintain pressure and drive oil from the reservoir. After some volume of water injection, the project is converted to gas injection as a means of sequestering CO_2.

The WAG scheme injects water and CO2 in alternating slugs. CO_2 and injection gas have relatively low viscosity compared to the oil phase. This causes the displacement with CO_2 and gas to be unfavorable. WAG processes were developed to overcome this problem. Specified volumes of gas and water are injected alternately; and the simultaneous flow of the two fluids within the reservoir results in the reduction of the mobility of each phase.

The combined mobility of the two phases is lower than the injected gas alone and the mobility ratio in the process is improved. Also, in many situations gravity plays an important role. The gas displaces oil in the upper part of the reservoir and water invades lower parts. The combined effect is to give overall better vertical sweep and displacement efficiency. Equal volumes of water and gas are injected during each slug because the optimal WAG ratio (volume of water to that of gas in a slug) is approximately 1 for reservoir and fluid models in consideration.

The last scheme aims to maximize the mass of CO_2 injected while not reducing oil recovery. The main idea is to shut-in a well when the gas production reaches a certain rate. Closed wells are put back on production when any of the injection well BHP or average reservoir pressure exceeds a predetermined value. Injector BHP is chosen as the criterion for opening wells, because it ensures that the maximum allowable reservoir pressure is not exceeded. This approach helps us in two ways. First, while wells producing with a high GOR are turned off, more CO_2 stores in the reservoir. Second, closing some of the producers and leaving the rest open changes the flow path of the fluid within the reservoir. Thus, the reservoir is swept better and a higher recovery is achieved. In this proposed well control approach, there are three main parameters: producing GOR of the wells; injector BHP or average reservoir pressure; and GOR increment. The last parameter is the value added to the maximum allowable producing GOR every time the well is turned on. If the allowable GOR is not increased as time progresses, the well is turned on and off with great frequency. This scenario does not result in significant incremental oil production and improved sweep of the reservoir volume.

In a co-optimization scheme, it may be appropriate to allow some volume of gas to cycle through the reservoir as a means of obtaining maximum CO_2 storage. Any produced gas, however, must be recompressed to injection pressure before it can be re-injected into the reservoir. That is, there is an energy penalty associated with gas cycling. To allow the possibility of gas cycling but also account for the energy penalty, the net cumulative oil recovery, *Np** is defined as

$$Np^* = Np - E \qquad (1)$$

Where *Np* is the cumulative oil recovery. The second term on the right in (1) is the energy needed, in oil equivalent units, to compress the produced injection gas to injection pressure. It is expressed as

$$E = [3.1815 \times 10^{-7} / \gamma] \times P_{in} \times Q_{in} [\{P_{out}/P_{in}\}^{\gamma} - 1] \times t \qquad (2)$$

Where
γ is the compressibility factor (0.23 for CO_2),
P is pressure (lbf/ft2),
Q is flow rate (ft3/min),
The subscripts in and out refer to the low and the high pressure sides of the compressor.

In Eq. 2, *E* has units of barrels of oil and *t* is in days. Thus, *Np** is the net production of oil discounted by the amount of energy needed to cycle gas. The performance of different production scenarios are compared using the following objective function

$$f = w_1 [N^*_p/OOIP] + w_2 [V^R_{CO2}/PV] \qquad (3)$$

Where;
w_1 ($0 \le w_1 \le 1$) and w_2 ($= 1 - w_1$), are weights,
OOIP is the original oil in place,
V^R_{CO2} is the volume of CO2 stored in the reservoir,
PV is the pore (void) volume of the reservoir.

Equation (3) combines parameters that we wish to optimize. The first term on the right is a dimensionless oil recovery factor and the second term is a dimensionless reservoir utilization term. Because the energy needed to compress produced gas is included, the net cumulative recovery accounts for the efficiency of the injection process. The weights for both terms are chosen with respect to the goals of the recovery process. If the aim is to maximize oil recovery, w_1 is taken as 1, whereas if the goal is to increase CO_2 storage w_2 is taken as 1. Equal weighting ($w1 = w2 = 0.5$) places equal emphasis on oil recovery and CO_2 storage. Because our aim is to co-optimize both recovery and storage, equal weighting is used. This allows identification of the effects of the injection process on oil recovery and CO_2 storage individually.

RESULTS

Now, I will discuss the results for each of the injection scenarios proposed and will show the one suitable for optimal co-optimization.

Continuous Gas Injection

The performances of continuous CO_2 and solvent injection are compared in Fig.3, Fig. 4, and Fig.5. As seen from Fig.3, solvent injection recovers more oil than CO_2 injection, as expected. Roughly 70% of the OOIP is recovered after 15000 days of solvent injection, whereas CO_2 injection recovers only 54% of OOIP. On the other hand, when the performances of these two schemes are compared with respect to the volume of the reservoir utilized for CO_2 storage, Fig.4, CO_2 injection performs better. CO_2 injection utilizes 52% of the reservoir pore volume at 15000 days, while reservoir utilization is 37% in solvent injection. Again, this is an expected result; because CO_2 composition in the solvent gas is only two thirds that of pure CO_2. When the objective function in Eq. 3 is used by giving equal weights to recovery and utilization ratios, Fig.5 is obtained. As shown, both scenarios perform almost the same with respect to co-optimization of recovery and CO_2 storage.

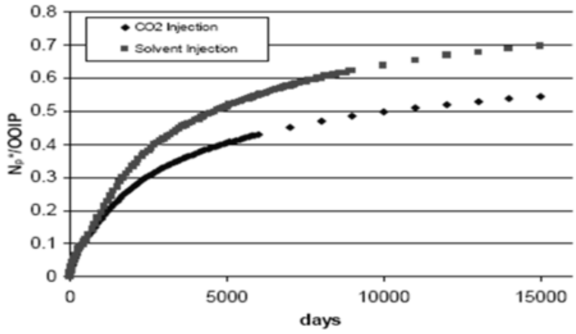

Figure 15: %age of the oil recovered (Np* / OOIP) for continuous CO_2 and solvent injection, w_1 = 1

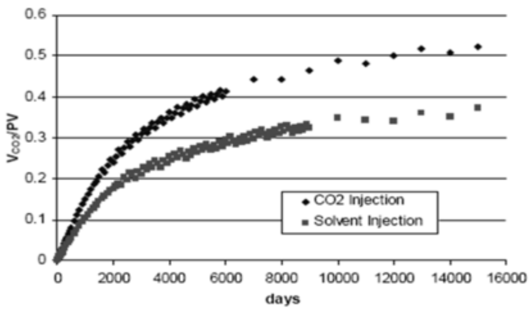

Figure 16: %age of the reservoir pore volume filled with CO_2 for continuous CO_2 and solvent injection, w2 = 1

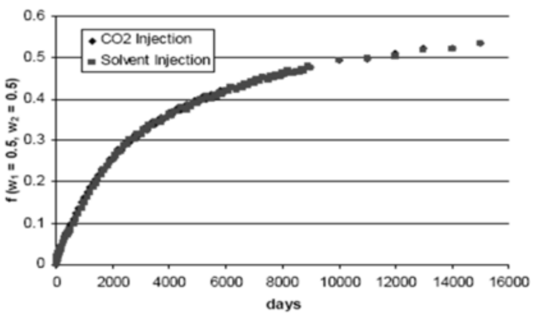

Figure 17: Objective function results for CO_2 and solvent injection, w1 = 0.5 and w2 = 0.5

An alternative approach to the methods discussed above it to use solvent gas and CO_2 alternately. Intuitively, a method that starts with solvent injection and continues with CO_2 injection may increase the value of *f* when equal weights are given to both parameters. Starting with solvent injection causes solvent to contact the oil. In this way, miscibility develops at the solvent/oil contact. Later, switching from solvent to CO_2 helps us in two ways: maintaining the pressure and filling the pores behind solvent with CO_2. Figure 6 shows the recovery performances of gas injection scenarios in which• this• “switching”• approach• is• used.• This figure shows that the oil recovery is greater for later•“switching”•times.•However,•the•difference between the percentages of OOIP recovered for switching from solvent to CO_2 after 6000 days and 14000 days is only 5%.

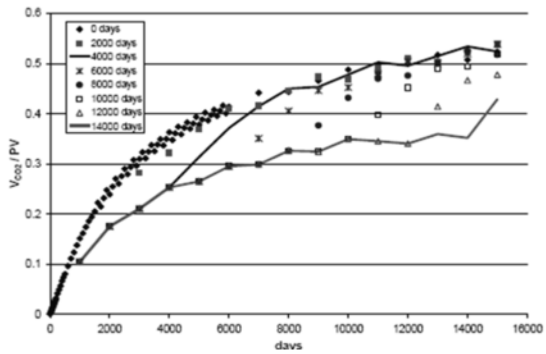

Figure 18: Reservoir utilization ratio (VCO2 / PV) for injection scenarios in which injection fluid is switched from CO_2 to solvent, w2 = 1

From the results above, we conclude that it is more effective to inject solvent until about 6,000 to 10,000 days and then change the injection gas to CO_2. This conclusion is supported by Fig. 7 in which the objective function results with equal weighting of recovery and utilization parameter are shown.

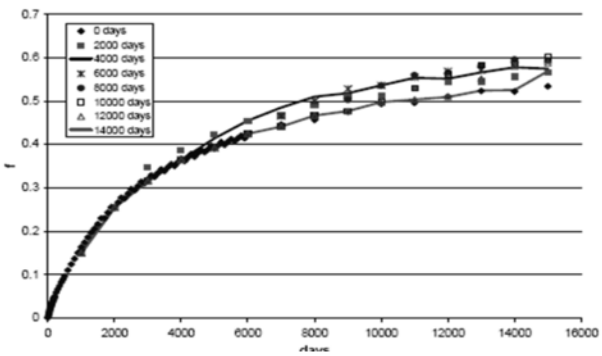

Figure 19: Objection function results for injection scenarios in which injection fluid is switched from CO_2 to solvent, w1 = 0.5 and w2 = 0.5.

Gas Injection after Water Flooding (GAW)

The performance of water flooding and pure CO_2 injection will be different because the reservoir pressure is below the minimum miscibility pressure; the main difference between these two processes is the greater mobility of CO_2 than water. An approach to reduce this effect is to water flood the reservoir for a certain time and then start gas injection after water flooding. In short, this process will be referred to as GAW.

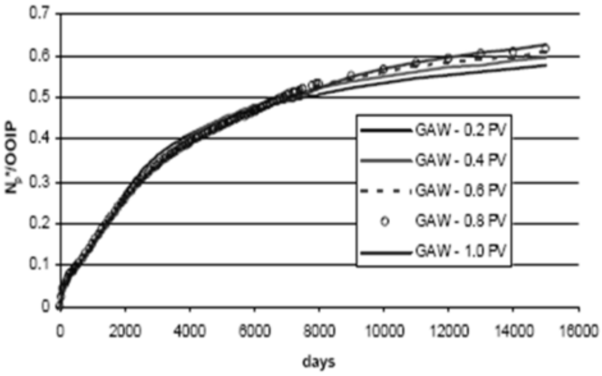

Figure 20: Percentage of OOIP recovered for GAW with CO_2 injection, w1 = 1

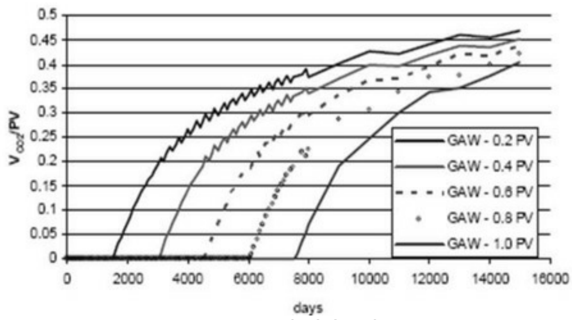

Figure 21: Percentage of CO_2 filled reservoir pore volume for GAW with CO_2 injection, w2 = 1

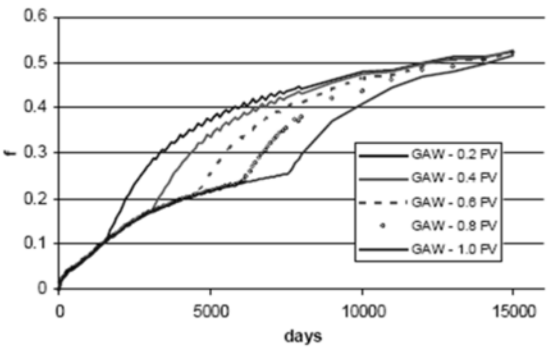

Figure 22: Objective function results for GAW with CO_2, w1 = 0.5 and w2 = 0.5

Fig. 8, 9, and 10 give the results for water flooding followed by CO_2 injection. Fig. 8 shows that the ratio of net recovery to OOIP is greatest for 1 pore volume of water injection followed by CO_2 injection. Also, Fig. 8 teaches that, the later the start of the CO_2 injection, the higher the ratio of recovered oil to OOIP. However, this increase is relatively small. Fig. 9 shows the percentage of CO_2 filled reservoir pore space. One expects intuitively that the storage is greater for a longer period of CO_2 injection. We can see that 48 % is the maximum utilized reservoir pore volume. This is obtained when CO_2 injection starts after 0.2 PV of water injection. The lowest utilization percentage occurs when the CO_2 injection starts after 1 PV of water injection. The resulting objective function values versus time for w1 = w2 = 0.5 are given in Fig.10. At the end of 15000 days the results are nearly the same for all cases and the maximum value is for CO_2 injection starting after 0.4 PV of water injection.

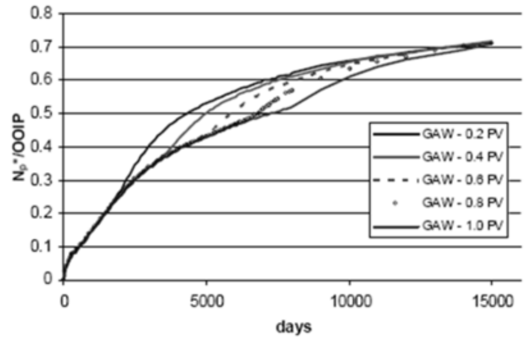

Figure 23: Percentage of OOIP recovered for GAW with solvent injection, w1 = 1

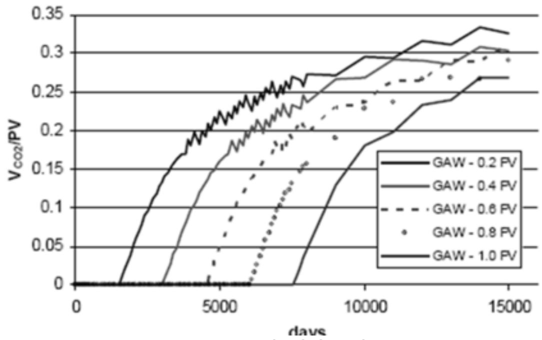

Figure 24: Percentage of CO_2 filled reservoir pore volume for GAW with CO_2 injection, w2=1

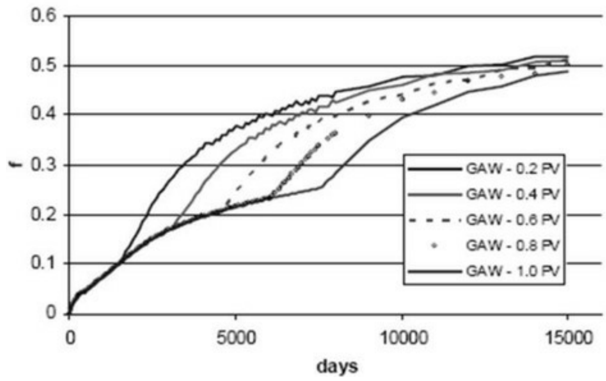

Figure 25: Objective function results for GAW with solvent, w1 = 0.5 and w2 = 0.5

Figs. 11, 12 and 13 show the results for solvent injection following water flooding. Figure 11 shows the ratio of the net recovery to OOIP. Because, the solvent is miscible in the oil phase at reservoir conditions, injection of solvent results in a significant increase in the oil recovery. The net recovery at 15000 days is about 0.70 of the OOIP for all cases in Fig. 11, but in Fig. 8, the net recovery averages only 0.60 of the OOIP at the same time. Fig. 12 shows the percentage of the utilized reservoir pore volume. The results in this case are similar in form to GAW with CO_2 in Fig. 9. The fractions are less in Fig. 12 as compared to Fig. 9 because the solvent is only 2/3 CO_2 by mole. In addition to these figures, Fig. 13 shows the resulting objective function values for w1 = w2 = 0.5. The greatest value is obtained when the solvent injection starts after 0.2 PV of water injection. These results provide a benchmark for further cases to be judged against.

Water Alternating Gas Drive (WAG)

The WAG process is a traditional EOR method. It aims to reduce the mobility of CO_2 within the reservoir making CO_2 a more effective displacement agent. The injection ratio chosen is 1 volume of water per volume of CO_2 injected. However, an important issue is the size of the slugs of CO_2 and water. In order to gauge the effects of the slug size on the CO_2 storage and the net recovery, different cases are studied for the following scenarios using pure CO_2 as the injection fluid

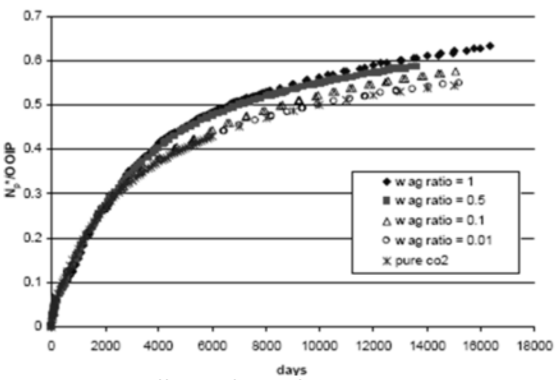

Figure 26: Effect of WAG ratio on oil recovery for WAG with CO_2

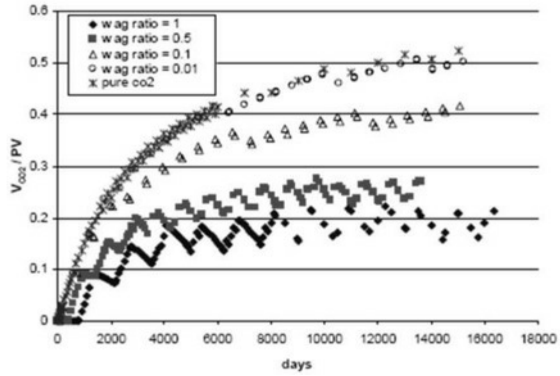

Figure 27: Effect of WAG ratio on reservoir utilization for WAG with CO_2

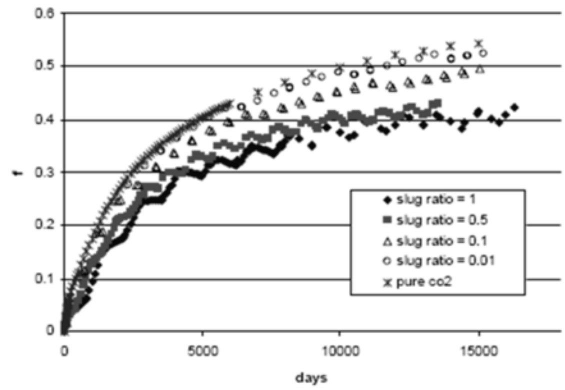

Figure 28: Effect of WAG ratio on objective function (w1 = w2 = 0.5) for WAG with CO_2.

In order to analyze the effects of WAG ratio on co-optimization process, 3 different WAG ratios are considered: 0.5, 0.1 and 0.01. All WAG ratios chosen are lower than 1, since values larger than 1 will only cause more pore volume to be filled with water and this will not improve the results listed above. Fig.14 shows the oil recovery performances of WAG with different ratios. It is seen that WAG ratio of 1 performs the best. In addition, the same figure shows that recovery performance of the WAG processes increase with increasing WAG ratio, i.e. more water injection means more oil production. However, as expected, reservoir volume utilized for CO_2 storage decreases with increasing WAG ratio (Fig.15).When the results are plotted for objective function with equal weights given to recovery and utilization parameters, the results fall in a range between water flooding and CO_2 injection (Fig.16). Again, the results are more dependent on the reservoir utilization term, because oil recovery results for all cases fall in a narrow range.

Well Controlled Injection and Production

Figures 17 to 19 show results for the CO_2 injection with injection and production well controls. In Fig.17 the ratio of net recovery to OOIP is increased by 10 % by controlling the wells to prevent large producing GOR. Fig.18 shows that the storage of CO_2 is almost equal in all cases and approaches 0.5 of the reservoir volume. Thus, as Fig.19 reflects, the well-controlled injection processes yield larger objective function values than the pure CO_2 injection and WAG scenarios.

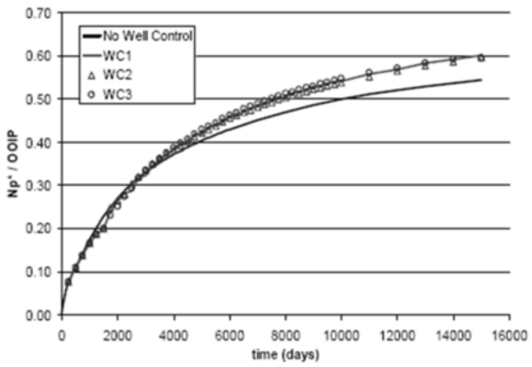

Figure 29: Percentage of OOIP recovered for well-controlled CO_2 injection, w1 = 1

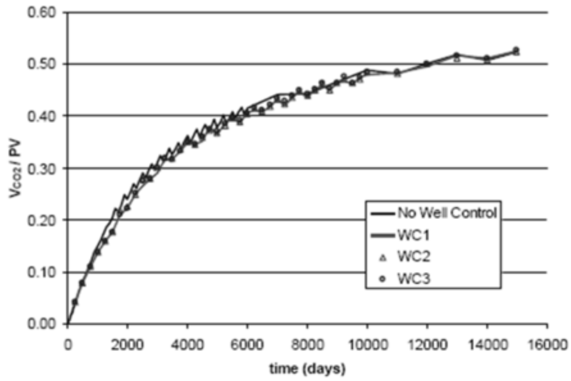

Figure 30: Percentage of the reservoir pore volume filled with CO_2 for well-controlled CO_2 injection, w2 = 1

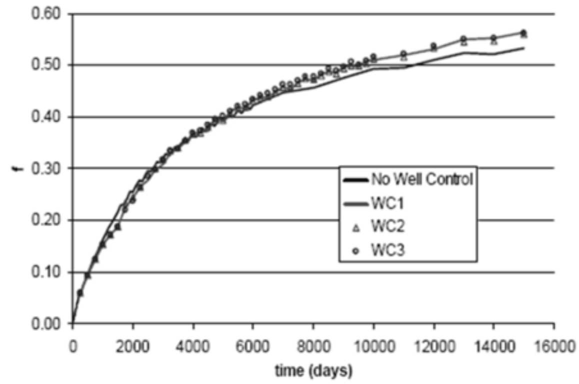

Figure 31: Objective function results for well-controlled CO_2 injection (w1 = 0.5 and w2 = 0.5)

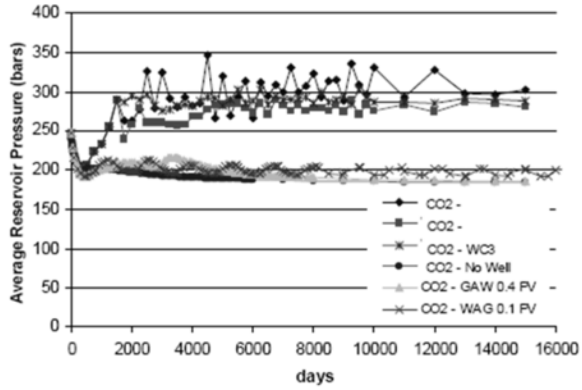

Figure 32: Comparison of average reservoir pressures of several CO_2 injection scenarios

The increase in the oil recovery is a result of two factors. First, aforementioned, shutting-in the wells to prevent recycling of CO_2 forces reservoir fluids to change their paths. This results in greater sweep efficiency. Second, as Fig.20 shows, well control scenarios keep the reservoir at larger reservoir pressure that causes greater recovery. While traditional EOR scenarios show a decrease in average reservoir pressure in early time and very slow pressure decrease at later times, the well control approach maintains pressure. For the cases studied average reservoir pressures fluctuate around 275 bars.

Overall Comparison of the Injection Processes

The production scenarios discussed above are compared in Fig.21. Equal weight is given to oil recovery and reservoir utilization. As seen in the figure, no matter the type of gas used, WAG performs the worst among all methods. This is caused by the injection of water through the production period, which results in limited reservoir pore volume utilization for CO_2 storage. Injection schemes that involve continuous injection and production with one kind of gas injection perform almost 25 % better than WAGs. However, results from well-controlled injection processes – both for CO_2 and solvent – are almost 8 % higher than these. Among all, processes that start with solvent injection and continue with CO_2 injection, i.e. switch, perform the best. Objective function results are 60 % or higher. The maximum value for objective function is obtained for a switch of injection gas with well control that uses the best of all three worlds: solvent injection, in which the miscibility increases oil recovery; CO_2 injection that focuses on the storage goal; and well-control that limits the recycling of the injection gas.

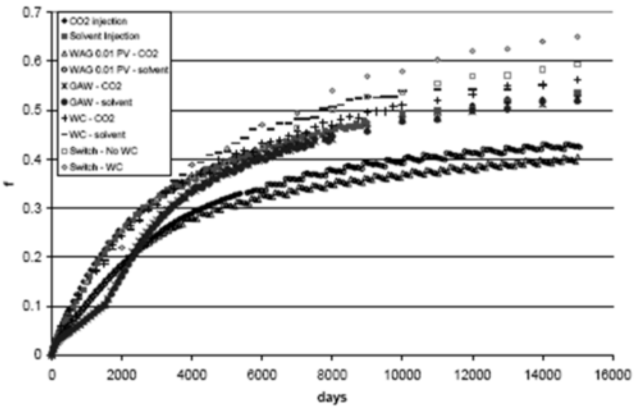

Figure 33: Comparison of the objection function results, w1 = w2 = 0.5.

CONCLUSIONS

The goal to sequester maximum carbon dioxide while not diminishing oil recovery rate or ultimate recovery from an oil reservoir is substantially different from the goals of recovery alone. A sufficient condition for maximizing storage is minimization of CO_2 production. Carbon dioxide is relatively mobile in reservoir media as compared to oil and water because CO_2 viscosity is low. A strategy for controlling the mobility of CO_2 must be applied to prevent excessive cycling of injected gas from injector to producer. In a traditional reservoir engineering approach water and gas are injected in alternating slugs. The simultaneous flow of gas and water yields, generally, a net mobility that is less than that of injection gas alone. Water injection, however, limits sequestration efforts. Pore space is filled with water that could otherwise be saturated with carbon dioxide. An effective process for co-optimization of CO_2 sequestration and oil recovery is a form of production well control that limits the fraction of gas relative to oil produced.

This work indicates that well control allows oil recovery by immiscible gas injection to recover virtually the same volumes as an optimized water-alternating-gas process while sequestering more than twice as much CO_2. Well control combined with solvent injection recovers 80 % of the oil in place while sequestering nearly the same volume as the optimized WAG recovery scheme. The well control process performs optimally for all reservoir models tested.

In addition, this study has shown that the start of the CO_2 injection time plays an important role on co-optimization. Ending a WAG process with a large slug of CO_2 results in 100 % increase in CO_2 stored than continuous WAG without affecting the recovery performance. More importantly, solvent gas injection followed by CO_2 injection produces the same amount of oil as solvent injection and sequesters almost the same amount of CO_2 as pure CO_2 injection. Also, most of the solvent components are recovered from the reservoir. This method is the most optimum when combined with the well-control approach.

Nomenclature

E	energy
f	objective function result
Np	cumulative oil recovery
Np*	net cumulative oil recovery
OOIP	original oil in place
Pin	pressure at low pressure side of compressor
Pout	pressure at high pressure side of compressor
Qin	flow rate at the low pressure side of compressor
Qout	flow rate at the high pressure side of compressor
t	time
$VRCO_2$	volume of the reservoir pore space filled with CO_2
w1	weight of recovery term in objective function
w2	weight of utilization term in objective function
γ	compressibility factor
HC	Hydrocarbons

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