Techno-Economic Reservoir Modelling Final Report

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The views and opinions expressed by authors in this publication are those of the authors and do not necessarily reflect those of the project sponsors.

Contents

Introduction

The work reported here was carried out as part of a Joint Industry Project (JIP) established to undertake a collaborative programme of work developing an understanding of Enhanced Oil Recovery (EOR), with the aim of creating a commercial use for CO_2 captured from power plants and industry. The technology, which has been used in North America for many years, could potentially store millions of tonnes of CO_2 from power plant CCS projects and increase the amount of oil recovered from UK North Sea reservoirs

The CO_2-EOR process, involves injecting supercritical CO_2 into partially depleted oilfields to force out additional volumes of oil, with the prospective aim of the CO_2 remaining permanently stored deep underground. Although to date, there has been no supply of CO_2 to support implementation of industrial scale CO_2-EOR in the North Sea, the arrival of CCS could significantly change this.

The project, led by SCCS, a partnership between British Geological Survey, Heriot-Watt University and the University of Edinburgh, is focussed on areas of work that address issues of major importance to project developers, looking to link CO_2-EOR in the North Sea with CCS projects.

The particular work described in this report was the development of a reservoir simulation model of enhanced oil recovery by CO_2 injection in a representative North Sea oilfield. The injection of CO_2 was modelled using a full field model, following primary/secondary production of the field by water-flooding. A technical review was conducted of a representative CO_2-EOR reservoir model linked to the economics. The model was based on a real North Sea reservoir model donated by an oil & gas operator for this study.

The aim of the work was to develop a CO_2 injection strategy to optimize hydrocarbon recovery. Features to be investigated in the modelling included injection type (comparing between injecting only seawater, only CO_2, or mixtures in various proportions – either WAG, SWAG or simultaneously, but kept apart in separate wells), EOR timing in field life, choice of wells and injection rates.

A representative CO_2-EOR reservoir model was to be developed with the aim of linking it to the economics, including step changes in the carbon floor price from now until 2020 and investigating what impact this would have on CO_2 storage. Different injection scenarios, including optimising hydrocarbon recovery and optimising CO_2 storage were studied. The model could thereafter be linked to project economics, including CAPEX, OPEX, CO_2 price and oil price.

Background

The idea of utilising CO_2-EOR in the UK North Sea has been around from the late eighties and nineties, as some smaller fields in the province began to mature, and thoughts turned to tertiary or enhanced recovery schemes to prolong field life. Many of the concepts came from oil field experience in North America, and although there were obvious differences in both surface and subsurface settings, it was thought that there might be prospects worth considering where similar techniques could be applied. From the start it was recognised that, although reservoir screening tools could be developed, the application of CO_2-EOR would likely need to be treated on a case by case basis and that detailed reservoir simulation would be necessary to inform the case for operator investment.

The then main drawback to CO_2-EOR in the North Sea was seen to be the lack of ready availability of sufficient quantities of carbon dioxide. However, with the growing interest in geological storage of CO_2 as a potential means of mitigating climate change, and the proposal of various CCS schemes to providing adequate supply, the case for CO_2-EOR in the North Sea has persisted. The following references illustrate some of the work that has been carried out on the concept of combining CO_2-EOR with CO_2 storage on the UKCS since the millennium, with a focus on reservoir simulation. The list is not intended to be exhaustive but to give a general sense of the way the topic has been approached.

A comprehensive early review of opportunities for "improved" oil recovery from the UKCS using EOR techniques[1] was presented by Jayasekera and Goodyear[1]. Comments made regarding CO_2 injection referred to the challenges involved e.g. supply of CO_2 in sufficient quantities, purity, delivery offshore and cost of infrastructure refurbishment. The added benefit of CO_2 sequestration was alluded to, but it was pointed out that commercial incentives such as a comprehensive emissions trading scheme would need to be implemented to make such projects viable. At this stage, screening studies by some operators on their fields had proceeded to detailed reservoir simulation in one or two cases.

An early description in the literature of a CO_2-EOR evaluation, carried out using reservoir simulation of a UK North Sea field – Forties – is given by Turan et al. [2]. The study used a detailed compositional finite difference simulator (CFDS) of a small area followed by an upscaling method to obtain the full field EOR estimate through a single layer model front-tracking streamline simulation. The authors argued that a full field large grid block model would not have the necessary grid resolution to capture the highly complex multi-contact miscible displacement process, and that grid refinement would lead to impractical model run times. For this method, developed by ARCO, normalized recovery curves were developed for a typical producer/injector pair and these were then applied to full field model. Incremental reserves were calculated at around 145 and 200 MMstb for CO_2 supply rates of 100 and 200 MMscf/day (5.3 and 10.6 kt CO_2/day) respectively.

A similar modelling exercise to the above was carried out by Agustsson and Grinestaff [3] on the Norwegian NS Gullfaks Field. Here a refined layer full field streamline front tracking model was developed from the primary history matched black oil water-flood finite difference model. This was then used to identify miscible gas injection target areas where 2D reference or "truth" models of characteristic flood locations were extracted and further refined for compositional simulation. These models were run in various WAG configurations and the results used to develop dimensionless performance curves, quantifying incremental oil recovery in relation to solvent injection parameter e.g. slug size and injection rate. A further 3D reference streamline front tracking model was built to quantify the effect of lateral fluid movement absent from the 2D models. Finally a full field 3 layer streamline tracer model can be scaled up from the refined layer full field streamline front tracking model. The purpose of the tracer option is to scale up the miscible displacement process.

The simulation predicted 302 and 365 MMstb incremental oil production after ~13 and ~23 years

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[1] EOR (Enhanced Oil Recovery) normally refers to the use of chemicals (surfactants, polymers, microbes etc.) or injection of gases (hydrocarbon, nitrogen, carbon dioxide) in the tertiary phase of oil production from a reservoir. Pressure maintenance by water-flooding is excluded.

miscible WAG, with net CO_2 utilisation of 0.24 and 0.32 tCO_2/stb oil respectively. The authors also commented that despite advances in computing power, full field compositional simulation at the required grid resolution would present a challenge.

A more focussed review of the potential for CO_2 flooding of UKCS reservoirs was presented by Goodyear et al. [4]. The work was carried out on behalf of the UK Department of Trade and Industry Sustainable Hydrocarbon Additional Recovery Programme (SHARP). The paper was mainly aimed at investigating incremental oil recovery, rather than CO_2 storage potential. They reviewed current results from onshore CO_2-EOR projects in North America and proceeded to outline the significant differences between those and UKCS fields. A refined sector model extracted from an unspecified UKCS field model was run in compositional mode to investigate WAG injection, varying both reservoir temperature and injection pressure. Incremental oil recoveries varied in the range ~7–11% with net gas utilisation improved at reduced pressure, without significantly affection incremental production. This latter result was also observed in a generic 2D compositional model of crestal injection of CO_2 in to a tilted fault block in GSGI mode.

Both a generic and a sector model, the latter based on field geology were utilised in a study on UKCS type reservoirs by Cidoncha and Wikramaratna [5]. These models were essentially 2D representations of injector/producer well pairs used to investigate the flood characteristics of both continuous gas injection (CGI) and WAG CO_2 floods. The grid resolution of the models was fairly coarse areally, but had a finer vertical resolution. The type of simulator used was not specified but miscible floods were indicated and no comments were made about capturing miscibility with the grids used. The study focussed on well completion strategies and WAG ratios. Optimisation of injector rather than producer completions were shown to be more effective in increasing IOR, because of improved sweep characteristics, CGI being more sensitive to well controls than WAG. The authors also concluded that optimisation was sensitive to reservoir heterogeneity and therefore each case may need to be considered individually.

A further general review of CO_2-EOR and CO_2 storage in oil reservoirs with particular reference to the North Sea was given by Gozalpour et al.[6]. Besides describing and reviewing the screening parameters for ranking oil reservoirs suitability for CO_2-EOR, they cited the relevant reservoir properties of North Sea fields that had been studied to date, and proceeded to present in detail the CO_2 injection characteristics and likely dependent economics for the Fulmar field. In the 20 year CGI injection scenarios presented incremental oil recovery varied between 6.7 and 10.7%. Although not quoted directly for the case study field, approximate gas utilisation values are given as 6–8 Mscf/stb (0.3–0.4 tCO_2/stb) for most CO_2 injection projects.

Based on work originating from SINTEF Petroleum Research, a techno-economic model for injection in to oil reservoirs (and aquifers) using large-scale infrastructure for CO_2 transportation to the Norwegian oil province was presented by Holt et al. [7]. The method of calculating additional oil recovery expected due to CO_2 injection into water-flooded reservoirs was by means of an "EOR module". The approach taken was to set up a generic sandstone reservoir model with realistic heterogeneities and use a reservoir simulator (ECLIPSE 100 with Todd-Longstaff mixing parameters) to predict the performance of water injection followed by miscible CO_2 injection (CGI). Response functions, depending on six parameters characterising the injection process, the fluids and reservoir geology, were then fitted to the simulated production profiles and were further used to provide rapid predictions of EOR response for any field. Although some data on the simulation model were given, details are referenced to a confidential report. The study focussed on a set of 18 primary Norwegian oil fields and derived a project wide base incremental oil recovery factor of 7.9%. A sensitivity analysis was performed varying oil price, CO_2 cost, investment/operation costs, injection/production rates and project lifetime. With modest fluctuations in both oil price and CO_2 cost, project outcomes in terms of oil recovery, CO_2 stored and CO_2 utilization were not significantly altered.

Besides SINTEF in Norway, the other organization keenly working on CO_2-EOR (in the UK) has been ECL Technology Ltd, now RPS Energy. There is an extensive online resource available http://www.og-

relating to work carried out in CO_2 injection. Two particular reservoir modelling focussed papers by Balbinski and Folorunso [8], and Balbinski and Goodfield [9] describe work relevant here. In these both continuous CO_2 and WAG scenarios were considered, injecting in to an unspecified full field model with UKCS type geology. The model, which included 21 producers and 12 peripheral injectors, was initially water-flooded for 18 years, maintaining average field pressure through voidage replacement. The simulations, carried using an in-house techSIM code, used the Todd-Longstaff model for miscible CO_2 injection. The injection period was six years from the end of the water-flood. The best technical compromise as regards IOR in terms of CO_2 utilisation and recycling for this particular geology was found to be WAG with ratio in the range 1:3 to 1:1. The authors also considered a period of post-CO_2 injection, with no associated oil production, for sequestration purposes only.

The same reservoir model was utilised in the second phase of the work. Here the black oil model with Todd-Longstaff mixing parameters was converted to a compositional simulation and the results compared. However a major focus of the work concerned the observation that, although previous studies with the UKCS based geology model gave incremental recoveries over extended water-flood of up to 8% STOIIP for 20 years injection (CGI and WAG), some operators of US onshore CO_2-EOR projects had expected incremental recoveries 15–20% from high rate continuous CO_2 injection. To investigate this, a sector model was extracted from the full field model and the maximum reservoir thickness was set to approximately 50 feet[2], and run in compositional mode. Higher recoveries were achieved in this case by relocating injectors, but at the expense of increasing back-produced CO_2

The previous work on the CO_2-EOR and storage potential of the Norwegian sector of the North Sea was updated with cost estimates and extended to include prospective fields in the UK sector, by Holt et al. [10]. This work also used the EOR (CGI) module referred to previously, but here an additional WAG module, based on a suite of WAG simulations was utilised. An additional parameter based on the difference between the drainage and imbibition oil relative permeability endpoints was then available to predict the response of fields to both CGI and WAG. The overall EOR potential for the fields considered is quoted as being in the range 8.5 to 9.0% HCPV, with a calculated overall project net CO_2 utilisation of 0.53 tCO_2/stb.

Recent work using the SINTEF generic North Sea reservoir model (as used in the their EOR modules) has been reported by Akervoll and Bergmo [11] and Vuillaume et al. [12]. The former investigated the likely differences in recoveries with CO_2 injection between reservoirs with shallow marine and fluvial depositional environments. The extensive range of model parameters included dip, injection rate, saturation endpoints, kv/kh ratio, gas-oil ratio, CO_2 injection start time and WAG cycle length. On average, incremental oil recovery was slightly higher for the shallow marine (10.0% CGI, 16.6% WAG) over the fluvial (9.0% CGI, 13.4 WAG) cases after 2.5 HCPV injected fluid.

The latter paper reported work on further extending the generic model to a chalk reservoir. The authors point out that whereas capillary pressure, gravity drainage, viscous forces and diffusion are the main recovery mechanisms in sandstone reservoirs, in chalk, diffusion of CO_2 from the fracture network into the matrix will be a major recovery mechanism. This will potentially make the flood sweep characteristics quite different to sandstone reservoirs.

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[2] Typical US CO_2-EOR reservoir thickness, as compared to UKCS 100–500 ft.

Model development

A reservoir simulation full-field model (FFM) of a representative North Sea oilfield undergoing water-flood supported oil production was provided as input data files for two ECLIPSE 100 (E100) black oil simulations:

- a simulation history matched to observed production/injection from the start of production for 2072 days (5 years 8 months)
- a predictive simulation restarting from the end of the above for a further ~20 years water-flood production.

The input data for the simulations consisted of a suite of main and nested INCLUDE files which had been generated in PETREL, some of which had been edited manually. However, apart from the Eclipse SCHEDULE section data, the two models utilised identical data.

History matched simulation model

The history matched simulation was converted to an ECLIPSE 300 (E300) compositional simulation using a 6 component fluid model which was provided along with the Eclipse 100 FFM data. In this preliminary fluid model CO_2 was lumped with ethane as one of the components and as such was not suitable for CO_2 EOR studies. However use of the preliminary fluid model enabled the conversion of E100 input data to E300 data.

Converting the E100 history matched simulation to E300 was not a straight-forward process because of differences in the interpretation of input data keywords between the two programs. Whilst there were some obvious parts of the data that needed to be changed completely e.g. the fluid properties, some individual keywords had slight variations within their syntax and interpretation, depending on the program being used. Also for this particular FFM as there was no gas phase present in the E100 simulation, and because E300 assumes gas is present, dummy gas saturation function data were required. In addition, modifications made to the grid transmissibilities for the purposes of history matching, carried out in the EDIT section had to be moved to the SCHEDULE section, again because of variations in the interpretation of the data between the two programs. The modification of the input data files was carried out by manual editing as it was not possible to import the complete dataset in to PETREL. The water-flood history matching simulations for both E100 and E300 were then run and compared.

When the oil saturation distributions for the original black oil and converted compositional history matched water-flood phase simulations were compared, there was seen to be a generally good match in the progression of the water-flood across the field at the same time-steps throughout the simulations. However there were more significant differences in pressure changes in some parts of the field. This is illustrated by Figure 1 which shows the field average pressure throughout the simulations. By the end of 2072 days the field average pressure for the compositional simulation is ~450 psi below that of the black oil simulation. Some of the well bottom-hole pressures in the two simulations show considerably greater differences. The pressure differences are partly explained by the differences in cumulative produced and injected reservoir volumes between the simulations as shown in Figure 2. The E300 simulation shows a greater difference between production and injection than the E100 simulation.

The next stage in the development of the reservoir simulation model was to refine the three phase relative permeability data and to change the fluid model for one in which CO_2 was a separate component to permit CO_2-flood predictions to be simulated. The first task was accomplished by the use of data contained in a supplied SCAL report of laboratory measured gas/oil relative permeability data. The gas/oil data was taken from measurements made by a nitrogen gas flood on a composite core. The laboratory data was manipulated to derive the saturation function data shown in Figure 3. Note, there are two ECLIPSE data tables since there are two SATNUM or saturation function regions within the model. It should also be pointed out that the relative permeability curves do not include hysteresis, so

the calculations will tend to underestimate the amount of incremental oil recovery.

The subsequent calculation of three phase permeability within the model can be performed using either a default method in ECLIPSE or one of Stone's methods. The default method is based on an assumption of complete segregation of the water and gas within each grid cell and provides a simple but effective formula which avoids the problems associated with other methods (poor conditioning, negative values etc.). The default model for the three-phase oil relative permeability was chosen to be used in the simulations.

The second and more significant modification was that made to the fluid model, changing to a six component compositional model with a separate CO_2 component. The ECLIPSE equation of state input data for this fluid model was provided by the field operator. Besides incorporating this data in to the FFM, subsidiary calculations were made using this data in a "slim-tube" simulation model to determine the minimum miscibility pressure MMP of the fluid. The MMP for the fluid determined by this method was 2970 psi.

The field pressure and produced and injected reservoir volumes for this simulation using a six component compositional model with a separate CO_2 component are shown in Figures 4 and 5. In this case there is a slightly greater difference with the previous fluid model, in that by the end of 2072 days, the field average pressure for the compositional simulation is ~650 psi below that of the black oil simulation. It can also be seen from the history matching simulations with this fluid model that the field pressure, starting at an initial pressure of 4622 psi, declines to 3247 psi, undergoing 1375 psi drawdown. The final field (average) pressure is only 277 psi above MMP. Hence it can be anticipated that parts of the reservoir in the simulation model can be expected to be at or below MMP.

The difference between the reservoir volumes produced and injected for the compositional simulation as compared to the black oil simulation are essentially the cause of the greater pressure drawdown in the former simulation. Because cumulative totals (and rates) fail to match exactly at reservoir conditions this would lead to the conclusion that the fluid models are not identical – either the relative permeability functions are treated differently, or the difference between how the black oil and compositional model handle the fluid PVT is leading to differences in the calculations.

This issue, was not addressed further, as the objective was not to begin with a fully history matched model of the field, and thus it was decided to continue with CO_2 injection simulations with the compositional model as is. Although the E300 simulation was not an exact replication of the E100 history matched simulation it was decided to accept the model as it was and proceed to the predictive simulations since the project was primarily concerned with the differences in simulated predictions, where CO_2 injection is compared to extended water-flood with the history matched simulation merely as a starting point.

Predictive simulation model

The predictive water-flood simulation was converted in a similar manner to the history matched simulation. Many of the ECLIPSE INCLUDE input data files were common between the simulations.

After reasonable progress made in the preliminary stages of the work, converting the initial Eclipse 100 black oil history matched water-flood phase simulation to an Eclipse 300 compositional simulation, two major difficulties arose with the model successively. The first concerned the well group controls which caused the restarted model predictive phase to fail. The second was the use of the Eclipse CO_2SOL keyword which caused pressure anomalies to appear in the model with excessive pressures predicted in parts of the model. On a more positive note, a new six-component fluid model with CO_2 as a separate component was received from the project sponsor. This saved the effort required to develop a fluid model in house, from the 22-component data already supplied.

The issue of group control of the wells on restart of the model could not be resolved directly and was eventually worked around by dispensing with group controls. All the wells in the simulation model were stopped on restart and then only those wells active at the end of the water-flood phase were reinstated.

The production wells were controlled by previously specified liquid production rate targets. The injection wells were controlled initially by surface water injection rates and then reservoir volume injection rates that matched the former to aid the specification of CO_2 (gas) injection rates. The vertical flow performance (VFP) tables for the wells were also dispensed with.

Considerable efforts were made to identify the causes of the pressure anomalies in the restarted simulations. Eventually, disabling the CO2SOL keyword (which allows CO_2 to dissolve in the aqueous phase) was the only effective measure. It is still not clear if this is an issue related to the simulation restart functionality – a possible Eclipse bug – or intrinsically related to the model data.

A further issue with the compositional model is poor convergence, and therefore very small incremental time steps down to 1/10th of a day are required. This means that simulation run times are considerably extended, taking many hours and making the model realistically impractical for sensitivity studies. The projected predictive simulation has been reduced from a projected 30 year period to 10 years, to enable some results to be obtained.

Finally modifications were made to the ECLIPSE input data SUMMARY section in order that the complete range of CO_2 component run vectors in the simulations could be tracked and reported. It was decided to only track the CO_2 hydrocarbon component as tracking the complete suite of 6 components would have made the storage requirements too large.

Examples of the results of the predictive simulations are shown in Figures 6 – 9. In the first two figures the field surface rates and water cut have been plotted, and in the second two figures, the field reservoir volume rates and pressure have been plotted for the water-flood and CO_2-floods respectively. In the case of the water-flood it can be seen that there is a gradual decline in the oil production rate as the simulation progresses. After 10 years (from the start of production) the rate is about one third of the rate during the initial phase of production. By this time the water-cut is ~80% and increasing. By comparison for the CO_2-flood at the same time, the oil production rate is slightly less at around one quarter of the initial production, but the water-cut is just over 50% and unchanging. Obviously this is because water is no longer being injected, the injection fluid having been replaced by CO_2.

As regards the reservoir volume rates, it can be seen that for the water-flood, the injection and production rates are generally the same during the predictive simulations and hence the field pressure remains constant. However for the CO_2-flood, although the injection rate is constant (and the same as the water-flood) and the production rate is generally less than the injection rate, the field pressure declines. It is thought that this effect may be due to the difference in compressibility between water and supercritical CO_2. The compressibility of water is nearly constant with a value 3×10^{-6} psi^{-1} (4.4×10^{-5} bar^{-1}) over the pressure range and temperature here, whereas the compressibility of supercritical CO_2 varies and is several orders of magnitude greater, typically 1.7×10^{-4} psi^{-1} (2.5×10^{-3} bar^{-1}). This is illustrated in Figure 10.

Oil production and recovery

The total oil production and oil recovery factors for the prediction simulations were compared. These showed relatively small differences in oil production/recovery between the two floods i.e. low incremental oil recovery. There was also an apparent discrepancy between the total oil production and oil recovery factor parameters. For total oil production, the water-flood simulation predicts greater values than the CO_2-flood. However for oil recovery factor, the CO_2-flood predicts greater values, i.e. the oil production total (Eclipse FOPT vector) predicts negative incremental oil but the oil recovery factor (Eclipse FOE vector) predicts positive incremental oil. The reason for this discrepancy has not been established, but it was decided to use the Eclipse FOE vector for further calculations. The definition of incremental oil – oil produced in excess of existing or conventional operations – is illustrated by Figure 11.

It is also instructive to look at cross-section plots of the fluid saturation distributions during the floods. Examples of these are presented in Figures 12 and 13 which show the oil, gas and water saturations

at the start and end of the extended water-flood and CO_2-flood respectively. Two zones A and B, are identified on the plots. In the case of the extended water-flood it can be seen that both zones have been swept. However in the case of the CO_2-flood zone A has been more fully swept but zone B not so. These types of differences in sweep efficiency for different floods in different parts of the reservoir, can lead apparent inconsistencies in incremental oil recovery when comparing floods.

Run times

There was a considerable increase in simulation runtimes in converting the initial history-match phase 2072 day water-flood simulation from a black oil model to a 6 component compositional model. This characteristic of the modelling persisted for the predictive phase simulations, which were limited to less than 10 years to enable practical results to be obtained. A comparison of simulation run times is given in Table 1.

Modelling scenarios

Initial scenarios

The modelling of different predictive CO_2 injection commenced with three simple scenarios whereby the commencement of CO_2 injection was delayed by 1, 2 and 3 years, water-flooding continuing during these times. The overall duration of the simulations was kept the same as the original CO_2-flood. Two further simple scenarios to set up were localised CO_2-floods where type of flood is varied in different field locations. Water-flooding was conducted through the field central area injectors and concurrently CO_2-flooding was conducted through the southern area injectors and vice versa.

The results of running these simulations are shown in Figure 14 where the incremental oil recovery has been plotted. It can be seen that the incremental recovery for all these scenarios is very low, within the range 1–2%. The delayed CGI floods show the same characteristics as the original CO_2- flood (except that the curves are translated by one year) and the water-flood central/CGI southern area is slightly better than the opposite combination.

The field pressure for the scenarios is plotted in Figure 15. The field pressure in all these simulated scenarios is below the water-flood case, except for the localised CO_2 flood case with water-flooding in the southern area where the field pressure exceeds the water-flood case for about one year near the start.

Further CGI scenarios

In an attempt to increase field pressure in the model, the CO_2 injection rate was increased. This was accomplished first by multiplying the overall field injection rate – through factors ×1.5 and ×2.0 on the individual well reservoir injection rates. The results of these trials are shown in Figure 16. It can be seen that there is a transient increase in field pressure in these cases, with the pressure increasing by ~500 psi in the former case and ~1300 psi in the latter case. However, these pressure increases begin to drop after a year and within a further 5 years the field pressures have declined to the same level as the base CGI case.

As a more realistic increased injection rate scenario, the individual well reservoir injection rates were factored each year to include the annual base case produced gas, to represent CO_2 re-injection. This was done on a "one-step" basis, i.e. not iteratively. An automated iterative annual increase in injection rates was also carried out using ECLIPSE User Defined Quantities (UDQs). These results are also shown in Figure 16. It can be seen that the approximate method does not significantly lead to an increase in field pressure, whereas the UDQ method leads to an "exponential" rise in pressure due to very large volumes of gas being re-injected.

WAG scenarios
Water alternating gas (WAG) injection scenarios were modelled with three different WAG ratios:
- WAG ratio 1:3 – 9 months **CO_2**-flood : 3 months water-flood
- WAG ratio 1:1 – 6 months **CO_2**-flood : 6 months water-flood
- WAG ratio 3:1 – 3 months **CO_2**-flood : 9 months water-flood.

The WAG floods were all carried out on a field-wide basis, except one case with counter-posed cycles in the central and southern injectors with a WAG ratio 1:1. The WAG cycle in all cases was one year.

The above cycle durations and ratios were chosen to unify the timestep DATES in the ECLIPSE Schedule module as an aid to manipulating the model SUMMARY output. Also as an aid to setting up the well controls, the injector wells (WELSPECS AND WCONINJE keyword data) were replaced so that coincident duplicated gas and water injectors were present. The WAG scenarios could then be easily set up by opening or shutting the respective wells.

Besides field wide WAG scenarios (all wells on the same cycle) a case was run whereby the WAG

cycles (WAG ratio 1:1) in the Central and Southern injectors were counter-posed, so that while one group of injectors was on gas on injection, the other group was injecting water. This scenario was considered to be an particularly advantageous, because it entails a more uniform demand for CO_2.

Re-pressurisation scenarios

Following a review of the reservoir modelling already carried out in the project, it was suggested that further simulation cases were run which incorporated a period of water-flooding repressurisation of the field i.e. water injection without production. The repressurisation simulation was first run "open-ended" to establish the overall field pressure response. The change in field pressure is shown in Figure 17.

After 3 months repressurisation there is an 812 psi gain in field pressure and after 6 months a 1574 psi gain (which actually increases the field pressure above initial conditions before any production). Further CO_2 injection scenarios were then run as follows:
- CGI after 6 months re-pressurisation water-flood
- CGI after 3 months re-pressurisation water-flood
- WAG 3:1 after 6 months re-pressurisation water-flood
- WAG 1:3 after 6 months re-pressurisation water-flood.

For the post-repressurisation response to CGI, the field pressure was observed to fall rapidly back to the base CGI case i.e. the increase in field pressure was not maintained. To overcome this, the reservoir volume production rate was limited to a fraction less than the oil formation volume factor times the surface liquid production rate. This was initially tried at 1.15 and 1.13 for the 6 months re-pressurisation case, and then reducing from 0.8 to 0.5 for the 3 months re-pressurisation. The response to these limits is shown in Figure 18. It can be seen that for the 0.6 and 0.55 ×LRAT cases the field pressure, although initially declines from the re-pressurised value, stabilises and stays more nearly constant.

1 MtCO$_2$/year injection/storage scenario

An additional simulation was requested in which the CO_2 injection rate was set at 1Mt/year, such as the CO_2 supply might be anticipated from a hypothetical CCS project. The scenario was also intended to maintain voidage replacement.

For this scenario, in order to set up the well constraints (ECLIPSE control mode RESV specification) it was necessary to derive a correlation between CO_2 reservoir volume and mass injected. This was derived by plotting the cumulative CO_2 injection summary vectors FVIT(rb) and FGIT(Mscf) versus mass(t) injected for the base CGI case as shown in Figure 19. The conversion factor derived is not precise because it does not take in to account the different pressures at well locations, but was considered adequate for practical purposes.

The injection well locations were then inspected and 4 wells were chosen through which to inject CO_2. These were 2 wells in each of the central and southern panels located the furthest down-dip in each group of injectors. The required reservoir volume injection rates per day to achieve the 1 MtCO$_2$/year target was then apportioned between the wells based pro-rata on their original injection rates. The water injection rates in the remaining wells were then increased on a similar basis, in order to maintain voidage replacement.

As this scenario does not correspond exactly to taking and storing exactly 1 MtCO$_2$/yr within the field, since the produced CO_2 would need to be otherwise disposed of, a further case was set up in which the additional produced CO_2 was added to the injected CO_2, achieving a 1 MtCO$_2$/yr storage rate. This case was set up by means of ECLIPSE UDQs.

Results

A list of various scenarios modelled is summarised in Table 2 where each has been allocated a case number. The simulation results for each case are then presented in Table 3. The cases are grouped:

- Continuous gas injection including localised CO_2-floods:
- Increased CO_2 injection rates
- Field wide WAG floods
- Re-pressurised floods
- 1 $MtCO_2$/yr rates.

The results for each case have been processed in terms of:

- Incremental oil recovery (% STOIIP)
- Net CO_2 stored ($MtCO_2$)
- Net CO_2 utilisation (tCO_2/stb).

Incremental oil recovery is the difference in oil recovery between the case considered and the extended water-flood case (over the same time interval). Net CO_2 utilisation is the net CO_2 stored divided by the incremental oil produced where net CO_2 stored is the difference between the cumulative CO_2 injected and CO_2 produced. These outputs were calculated from SUMMARY vectors produced during the simulations. These derived outputs obviously vary over time and for the purposes of comparison their values have been evaluated at times 10 years life of field (LOF) and 20 years LOF (see Figure 14 for explanation). For the cases where the CO_2 injection commences after 5 years and 8 months, these represent injection times of 4 years and 4 months and 9 years and 4 months respectively.

These values are given numerically in Table 3 and presented graphically in Figures 20 – 22.

Incremental Oil Recovery

The cases of continuous gas injection of CO_2 all resulted in incremental oil recovery less than 2% STOIIP. The base case CGI was virtually the same at 1% at 10 years LOF and 15 years LOF. Delaying the CO_2 injection by 1, 2 or 3 years made very little difference to the recovery at the 10 and 15 years LOF times. There was a slight difference between CGI in just the central and just the southern part of the field, with CO_2 injection in just the central part resulting in 1.6% recovery as opposed to 0.4% incremental recovery when injecting in to just the southern part at 15 years LOF.

Increasing the injection rate of CO_2 considerably improved the incremental oil recovery. For the case of ×1.5 base this was 5.6% STOIIP and for the case of ×2.0 base this was 9.7% STOIIP at 15 years LOF. The case with the annual injection rate increments also improved incremental recovery. However the case set up using ECLIPSE UDQs gave unrealistic recoveries because of very high injector BHPs.

Incremental oil recovery for the WAG cases was slightly improved over the CGI cases. The best WAG recovery was actually the counter-posed case at 2.9% STOIIP and the worst was WAG ratio 1:3 at 2.3% at 15 years LOF. The re-pressurisation cases also produced a slight improvement in recovery over the original CGI cases with the WAG ratio 1:3 case again the best at 3.2% at 15 years LOF.

The 1 $MtCO_2$/yr injection cases resulted in incremental oil recoveries just over 1% STOIIP at 15 years LOF, with the "storage" case the highest at 1.4% STOIIP.

Net CO_2 Stored

The net CO_2 stored for the base CGI case was 27 $MtCO_2$ and 40 $MtCO_2$ for the 10 years LOF and 15 years LOF times respectively. The net CO_2 stored for the continuous gas injection cases showed a predictable response in that delayed injection commencements resulted in reduced CO_2 stored at the 10 and 15 years LOF times. Although less again, CGI injection in the central part of the field resulted in more CO_2 stored than just the southern part.

Increased gas injection rates resulted in increased CO_2 store, the net storage rising to 61 and 49 $MtCO_2$

at 10 years LOF and 15 years LOF times respectively in the case of ×2.0 base injection rate. Again the case with annual injection rate increments also increase net storage and the case set up using ECLIPSE UDQs gave an unrealistic very high value (203 $MtCO_2$) at the 15 years LOF time.

Predictably the WAG cases resulted in generally less net CO_2 stored than the CGI cases, given that the overall volumes of gas injected was reduced due to the combined water injection. The least CO_2 stored was for the WAG ratio 3:1 case at 13 $MtCO_2$ at the 15 years LOF time.

The re-pressurisation cases resulted in a very similar net storage values to the original CGI cases with the WAG ratio 3:1 again the least at 12 $MtCO_2$ at the 15 years LOF time.

The net CO_2 stored in the 1 $MtCO_2$/yr injection cases was significantly reduced from the previous cases, with the "injection" case sequestering 6.3 $MtCO_2$ and the "storage" case 9.9 $MtCO_2$ at 15 years LOF time

Net CO_2 Utilisation

There was a considerable range in the values of net CO_2 utilisation in the simulations, both between cases and values calculated at different times. For the initial CGI cases this varied from 0.9 tCO_2/stb to 4.4 tCO_2/stb. The increased injection rate cases had much lower values e.g. 0.5 tCO_2/stb at 15 years LOF in the case of ×2.0 base injection rate.

The WAG cases were also better in terms of net CO_2 utilisation than the initial CGI cases with the case WAG ratio 3:1 only 0.4 tCO_2/stb at 15 years LOF.

The repressurised CGI cases did not result in any significant improvement in net CO_2 utilisation over the initial CGI cases, but there was a reduction for the WAG ratio 3:1 case where it further reduced to 0.3 tCO_2/stb at 15 years LOF.

The net CO_2 utilisation in the 1 $MtCO_2$/yr cases was fairly constant between ~0.5 and 0.6 tCO_2/stb over the injection period.

Conclusions

There were several challenges in converting the full field black oil reservoir simulation of a water-flood to a compositional simulation for CO_2-EOR with continuous gas injection and WAG. Conversion of a water-flood model to a CO_2-EOR model of a field is non-trivial, requiring additional experimental data, modification to parts of the input data deck that are directly related to CO_2 properties (e.g. PVT properties) and possibly other parts of the data deck also, running of simple supporting models (e.g. slimtube and box models) and potential much longer run times for the full field model. Complexity of the model, led to longer times to both debug the model and longer simulation run times. This was exacerbated by poor convergence in the simulations.

The incremental oil recovery factors for the CO_2 injection scenarios considered for this field varied in the range ~1% to ~10% depending on the type of injection programme (continuous CO_2 injection, CO_2 WAG, CO_2 SWAG, etc.). Generally WAG incremental recovery was greater than CGI, without much variance seen for different WAG ratios. The greatest increase in recovery was observed when the CO_2 injection rate was significantly increased.

Regardless of the type of injection programme chosen, maintaining the reservoir pressure high enough to ensure CO_2 miscibility is key to achieving higher recovery factors. Due to the higher compressibility of CO_2 than water, and due to the impact of CO_2 dissolution, this pressure maintenance may involve injection at higher bottom-hole rates than would be required for the equivalent water-flood.

Despite the fact that injected CO_2 will be produced and will therefore need to be re-injected, in general higher CO_2 injection rates and earlier start of CO_2 injection resulted in higher recovery factors and greater quantify of CO_2 remaining in the reservoir at the end of the field life.

Maximising recovery factor is generally consistent with maximising CO_2 storage - the greater the pore volume occupied by CO_2, the greater the displacement of oil from that pore volume - provided there is facility to re-inject produced CO_2.

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Tables and Figures

Simulation description	Platform	Runtime (hr)
E100 black oil history-match initial phase 2072 days	Desktop PC	1.7
E300 compositional history-match initial phase 2072 days	Desktop PC	61.1
E300 compositional water-flood prediction ~9 years	Desktop PC	55.6
E300 compositional water-flood prediction ~9 years	Cluster	72.5
E300 compositional CO_2-flood prediction ~9 years	Cluster	102.2

Table 1. Simulation runtimes.

Case No.	Model description
	History match simulations
00	Black oil water-flood
0	Compositional water-flood (with no CO₂SOL)
	Predictive simulations (all compositional)
1	Extended water-flood
2	Continuous gas injection (base case)
2a	~CO_2-flood starts after 1 year
2b	~CO_2-flood starts after 2 years
2c	~CO_2-flood starts after 3 years
	Localised CO_2-floods
3a	Water-flood Central injectors : CO_2-flood Southern injectors
3b	CO_2-flood Central injectors : Water-flood Southern injectors
	Increased CO_2 injection rates
4a	CO_2-flood ~injection rates × 1.5 base
4b	CO_2-flood ~injection rates × 2.0 base
5a	CO_2-flood ~produced CO_2 re-injected
5b	CO_2-flood ~produced CO_2 re-injected using UDQs
	Field wide WAG floods
6a	WAG ratio 1:3 – 9 months CO_2-flood : 3 months water-flood
6b	WAG ratio 1:1 – 6 months CO_2-flood : 6 months water-flood
6c	WAG ratio 3:1 – 3 months CO_2-flood : 9 months water-flood
6d	Counter-posed WAG cycles in Central and Southern panels
	Re-pressurised floods
7	Re-pressurisation water-flood (no production)
7a	CGI CO₂_flood after 6 months re-pressurisation water-flood
7b	CGI CO₂_flood after 3 months re-pressurisation water-flood
8a	WAG ratio 1:3 after 6 months re-pressurisation water-flood
8b	WAG ratio 3:1 after 6 months re-pressurisation water-flood
	1 MtCO_2/yr rates
9a	Injection rate in 4 injectors
9b	Storage rate in 4 injectors with produced CO_2 re-injected (set up with UDQs)

Table 2. Summary of modelled scenarios

Case No.	@ 10 years LOF[3]			@ 15 years LOF		
	Inc. Oil Recovery	Net CO_2 Stored	Net CO_2 Utilisation	Inc. Oil Recovery	Net CO_2 Stored	Net CO_2 Utilisation
	% STOIIP	$MtCO_2$	tCO_2/stb	% STOIIP	$MtCO_2$	tCO_2/stb
2	1.09	26.6	1.90	1.00	40.1	3.14
2a	1.35	22.4	1.31	0.68	38.1	4.38
2b	1.49	17.9	0.94	0.74	35.6	3.79
2c	0.91	11.5	0.98	0.62	33.1	4.27
3a	0.66	14.9	1.78	1.57	24.0	1.20
3b	0.76	11.1	1.15	0.39	13.4	2.69
4a	4.85	37.1	0.59	5.60	50.8	0.71
4b	9.07	48.5	0.42	9.72	61.4	0.50
5a	3.11	33.9	0.86	5.30	51.8	0.77
5b	4.94	42.6	0.68	22.90	203.4	0.70
6a	1.32	20.3	1.21	2.25	30.5	1.06
6b	1.72	15.3	0.69	2.74	22.3	0.64
6c	1.62	9.5	0.44	2.72	13.1	0.37
6d	1.82	14.7	0.64	2.88	21.2	0.58
7a	1.18	25.0	1.66	1.17	39.5	2.71
7b	1.59	25.7	1.27	1.38	39.8	2.26
8a	2.30	19.8	0.66	3.11	30.2	0.78
8b	2.20	7.7	0.27	3.18	11.6	0.29
9a	0.44	3.54	0.63	1.11	6.30	0.45
9b	0.60	4.32	0.57	1.39	9.87	0.56

Table 3. Incremental oil recovery, net CO_2 stored and net CO_2 utilisation for modelled injection scenarios.

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[3] LOF – Life of field.
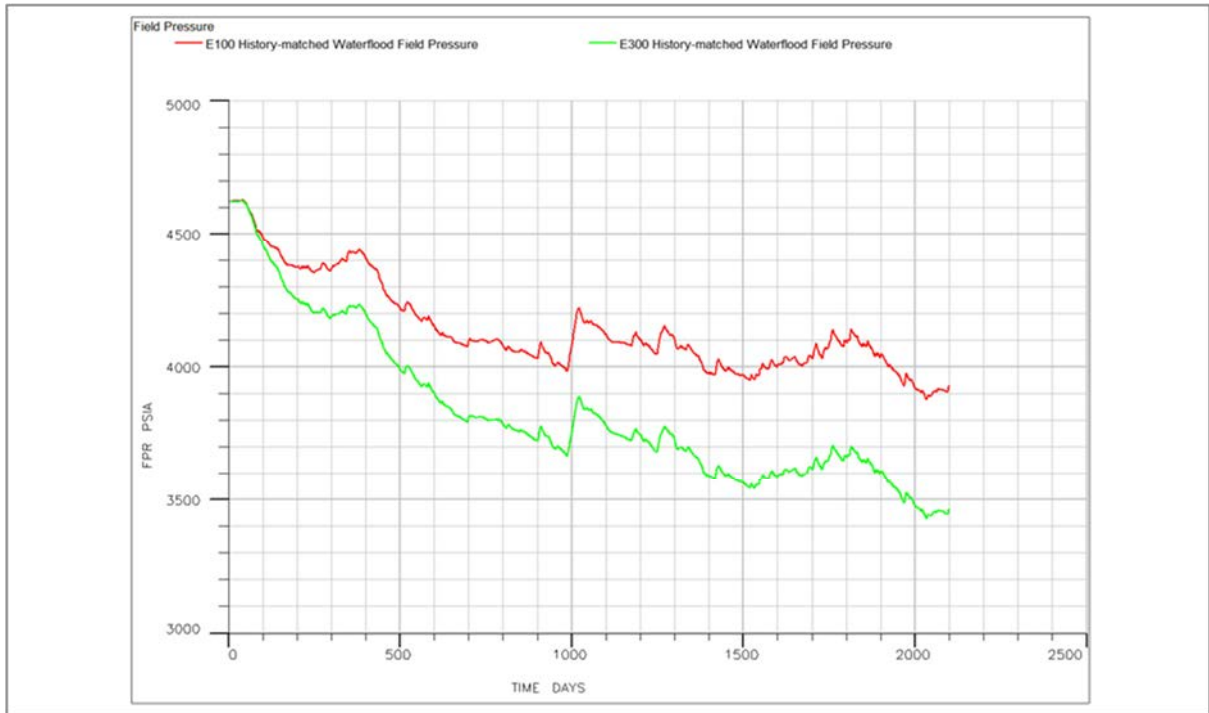
Figure 1. Comparisons of field pressure through history matched water-flood phase – black oil simulation red line and compositional simulation (preliminary fluid model) green line.
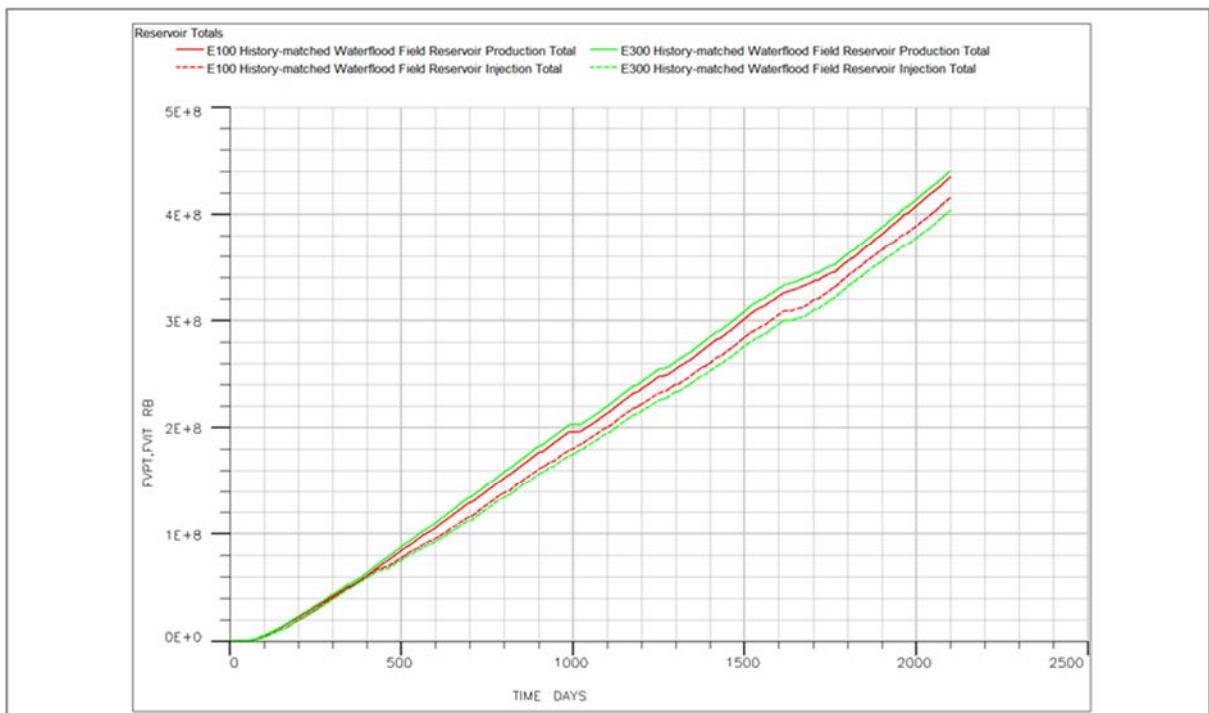
Figure 2. Comparisons of cumulative field liquids production and water injection at reservoir conditions through history matched water-flood phase – black oil simulation red lines and compositional simulation (preliminary fluid model) green lines.
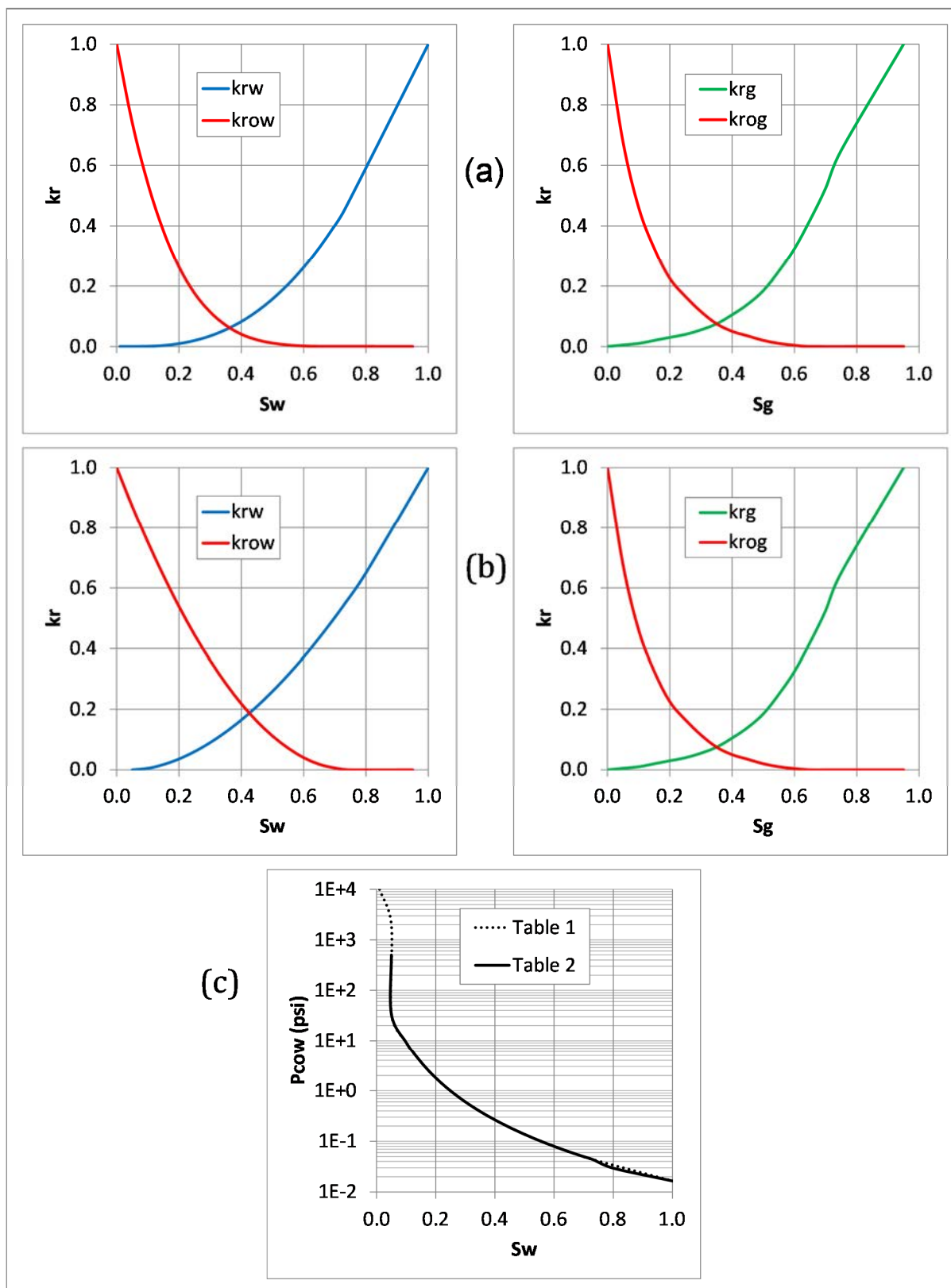
Figure 3. Saturation function data – (a) Table 1 (SATNUM region 1) water/oil and gas/oil relative permeability, (b) Table 2 (SATNUM region 2) water/oil and gas/oil relative permeability and (c) Table 1 and 2 water/oil capillary pressure curve.
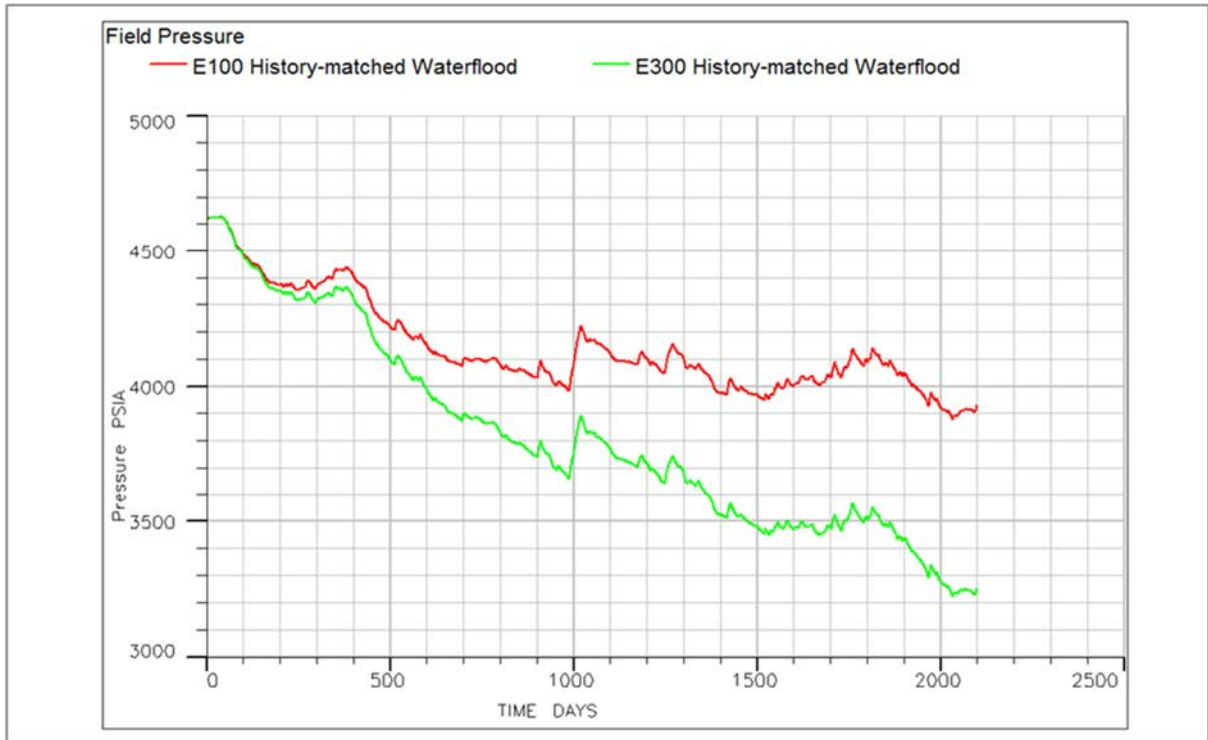
Figure 4. Comparisons of field pressure through history matched water-flood phase – E100 black oil simulation (red line) and E300 compositional simulation with CO_2 separate component fluid model (green line).
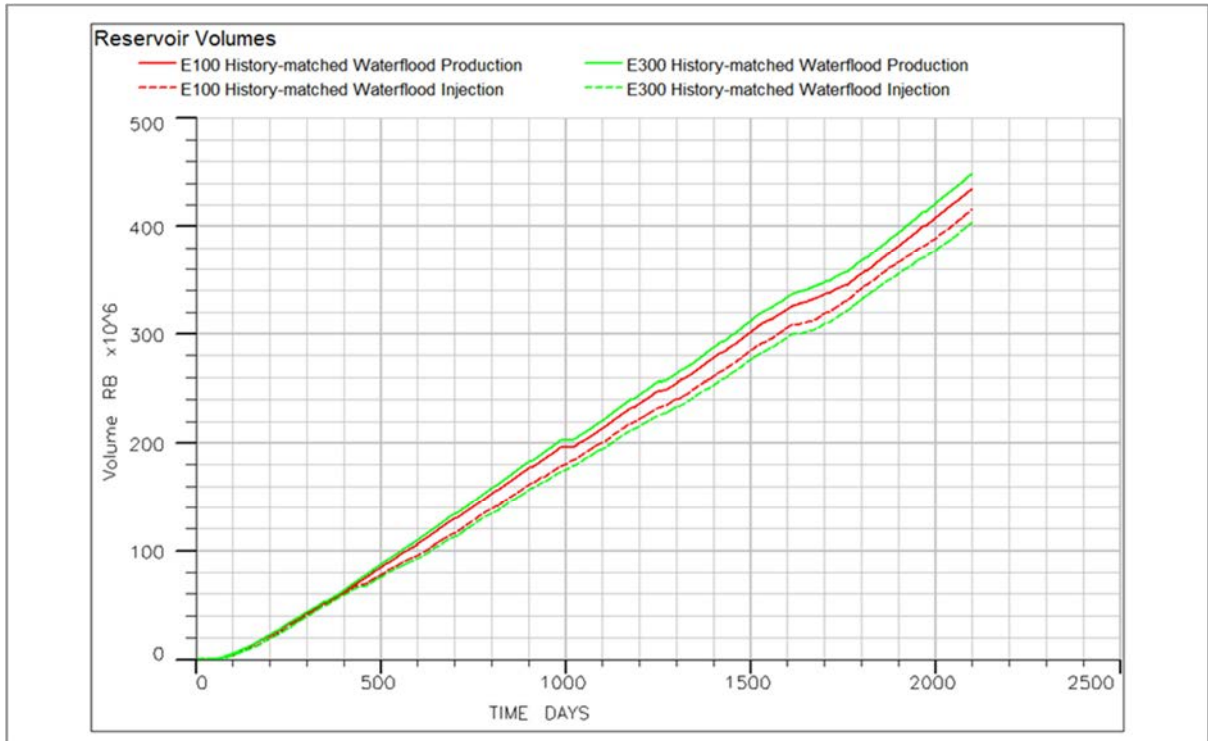
Figure 5. Comparisons of reservoir volumes production and injection through history matched water-flood phase – E100 black oil simulation (red lines) and E300 compositional simulation with CO_2 separate component fluid model (green lines).
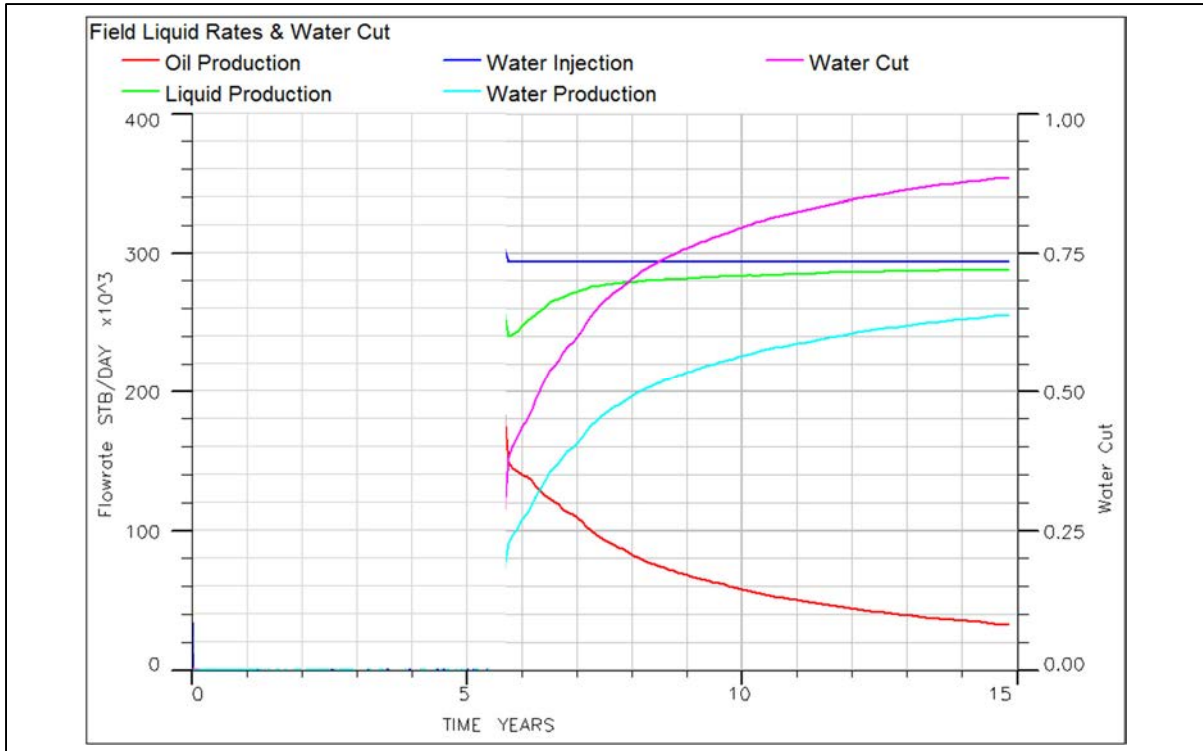
Figure 6. Field liquid rates and water cut for the predictive water-flood case.
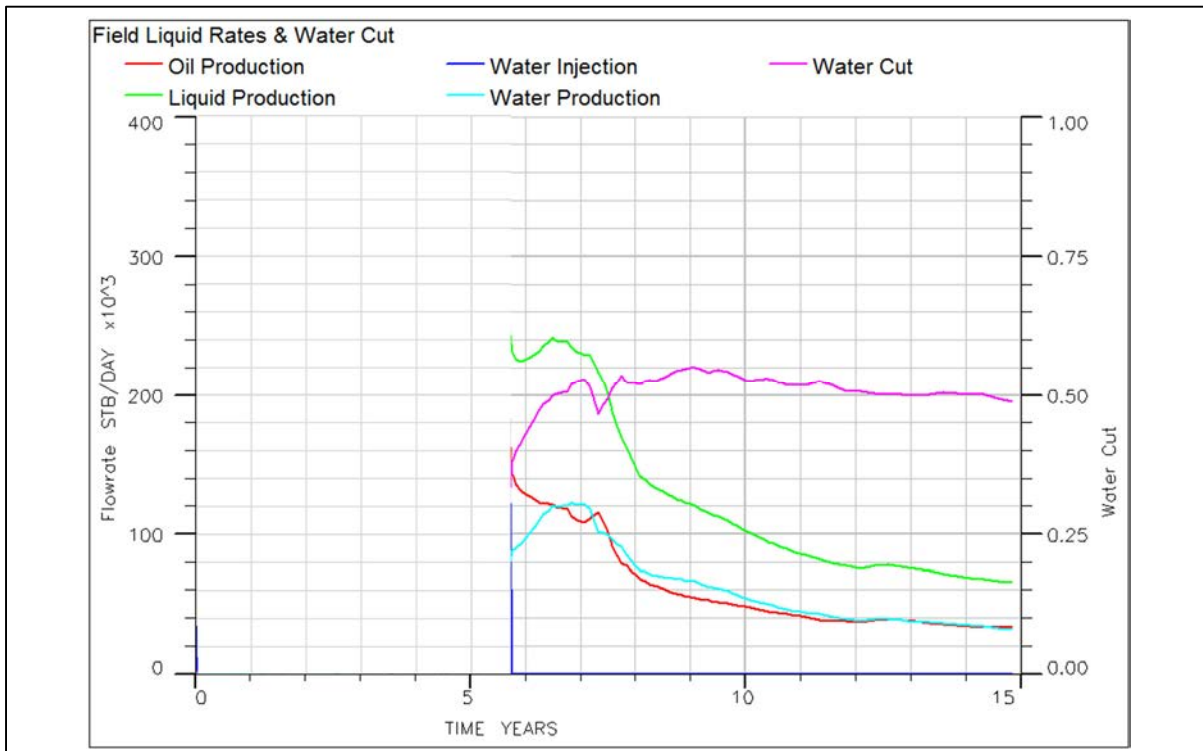
Figure 7. Field liquid rates and water cut for the predictive CO₂-flood case.
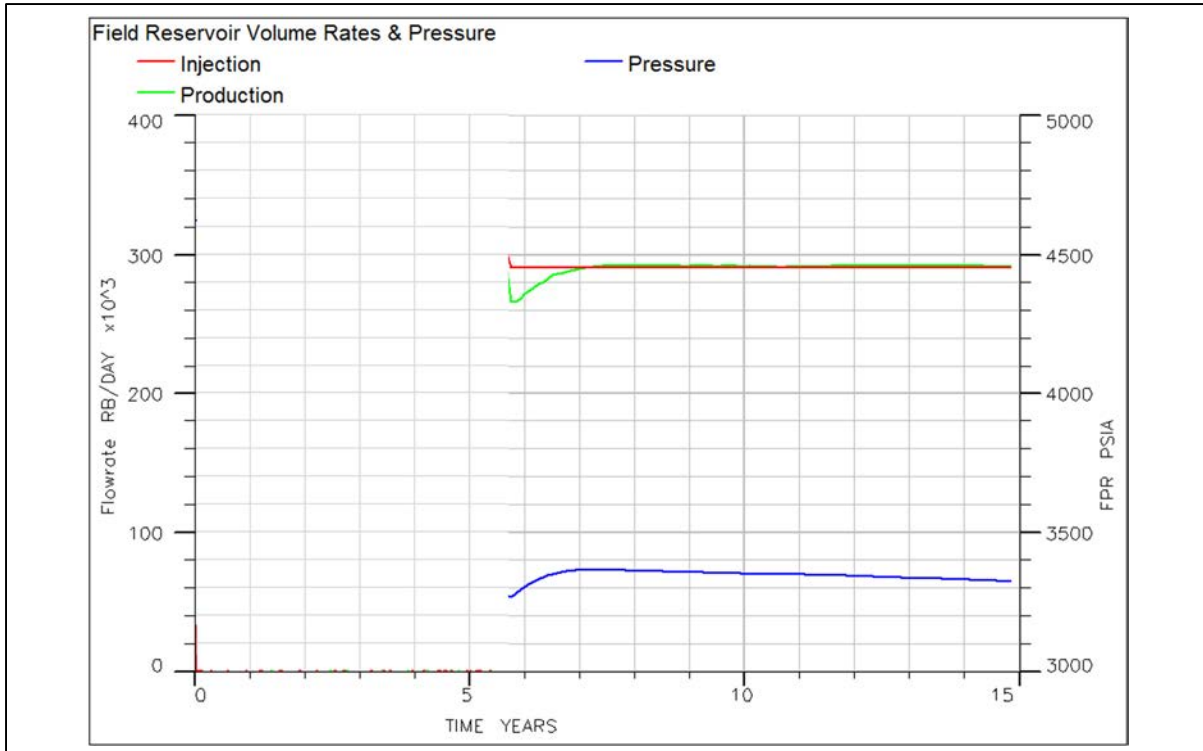
Figure 8. Field reservoir volume rates and pressure for the predictive water-flood case.
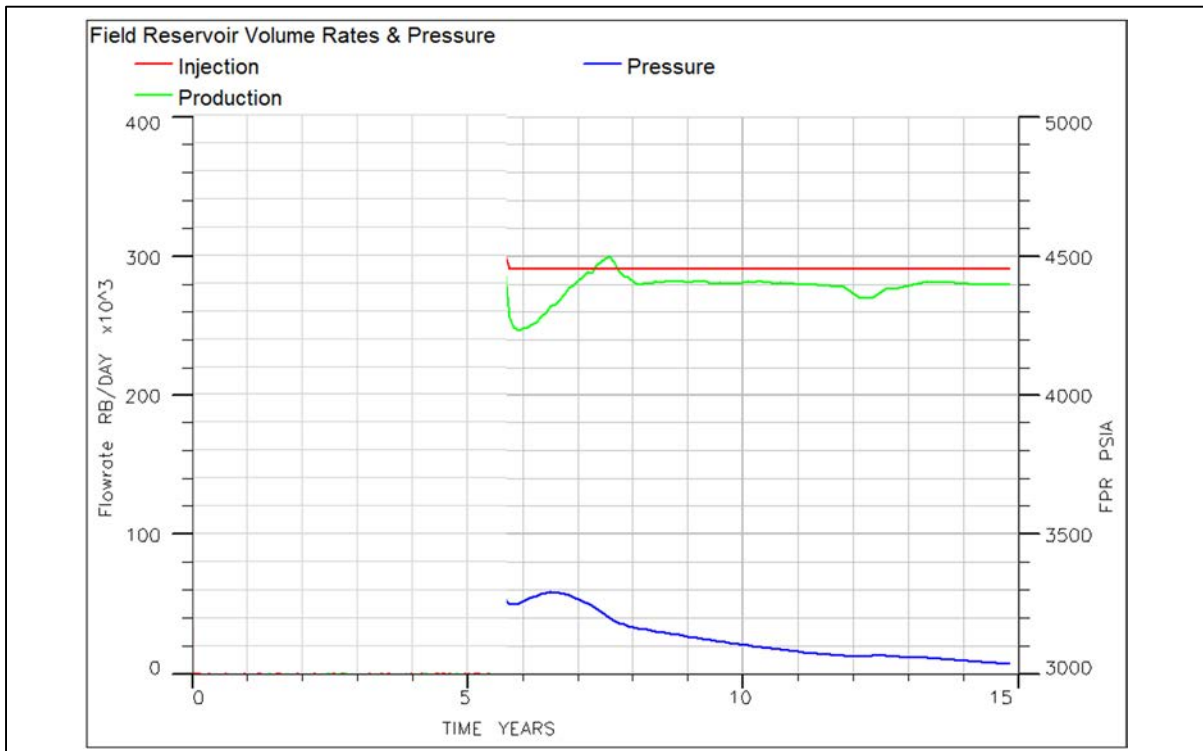
Figure 9. Field reservoir volume rates and pressure for the predictive CO_2-flood case.
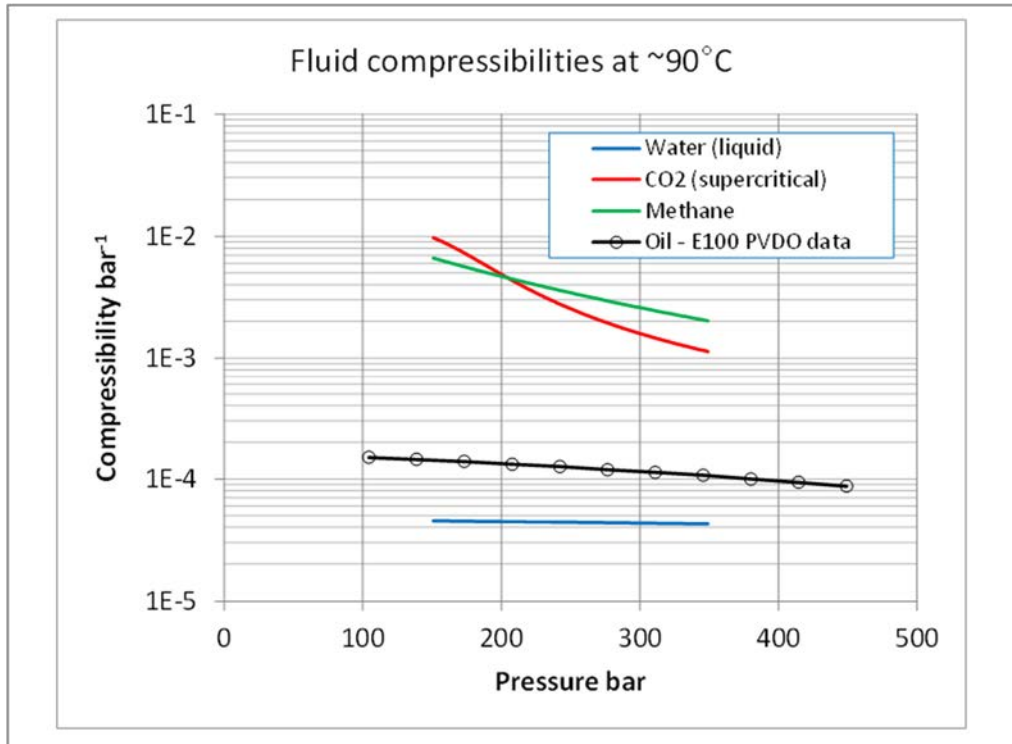
Figure 10. Fluid compressibility comparisons4.

Definition of Incremental Oil

Oil produced in excess of existing or conventional operations

- Point A   EOR operations commence (note delay in production response at point A´)
- Curve A → B   Decline curve with existing operations e.g. water-flood
- Curve A → C   Decline curve with EOR
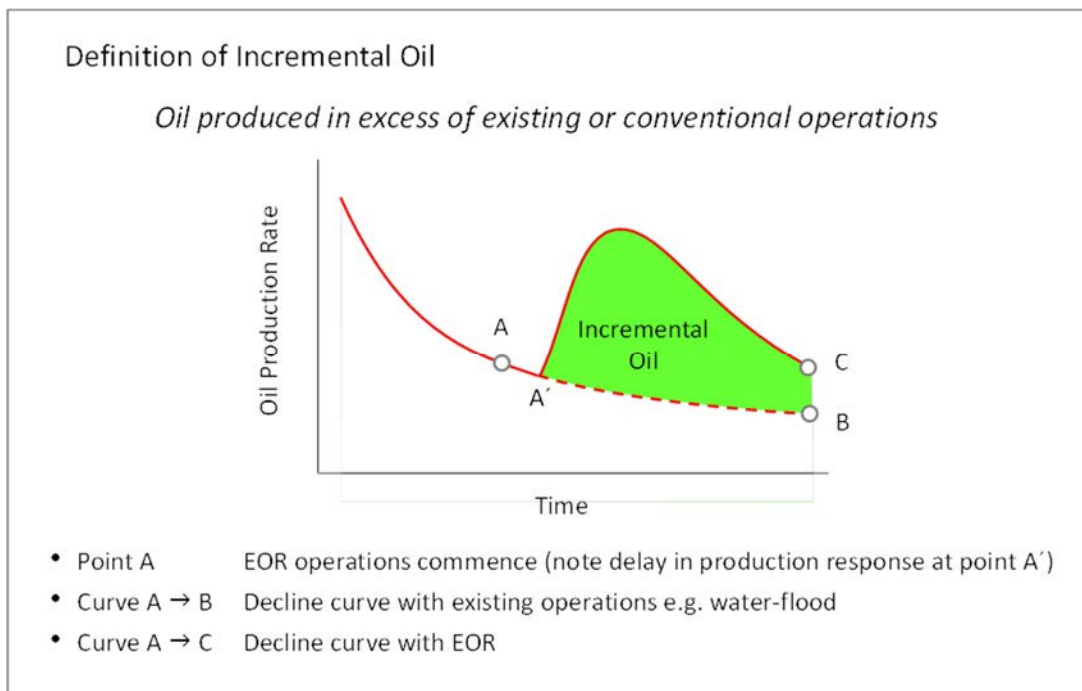
Figure 11. Definition of incremental oil.

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[4] Data developed from calculations using NIST Chemistry Web-Book – Thermophysical Properties of Fluid Systems. http://webbook.nist.gov/chemistry/fluid/.
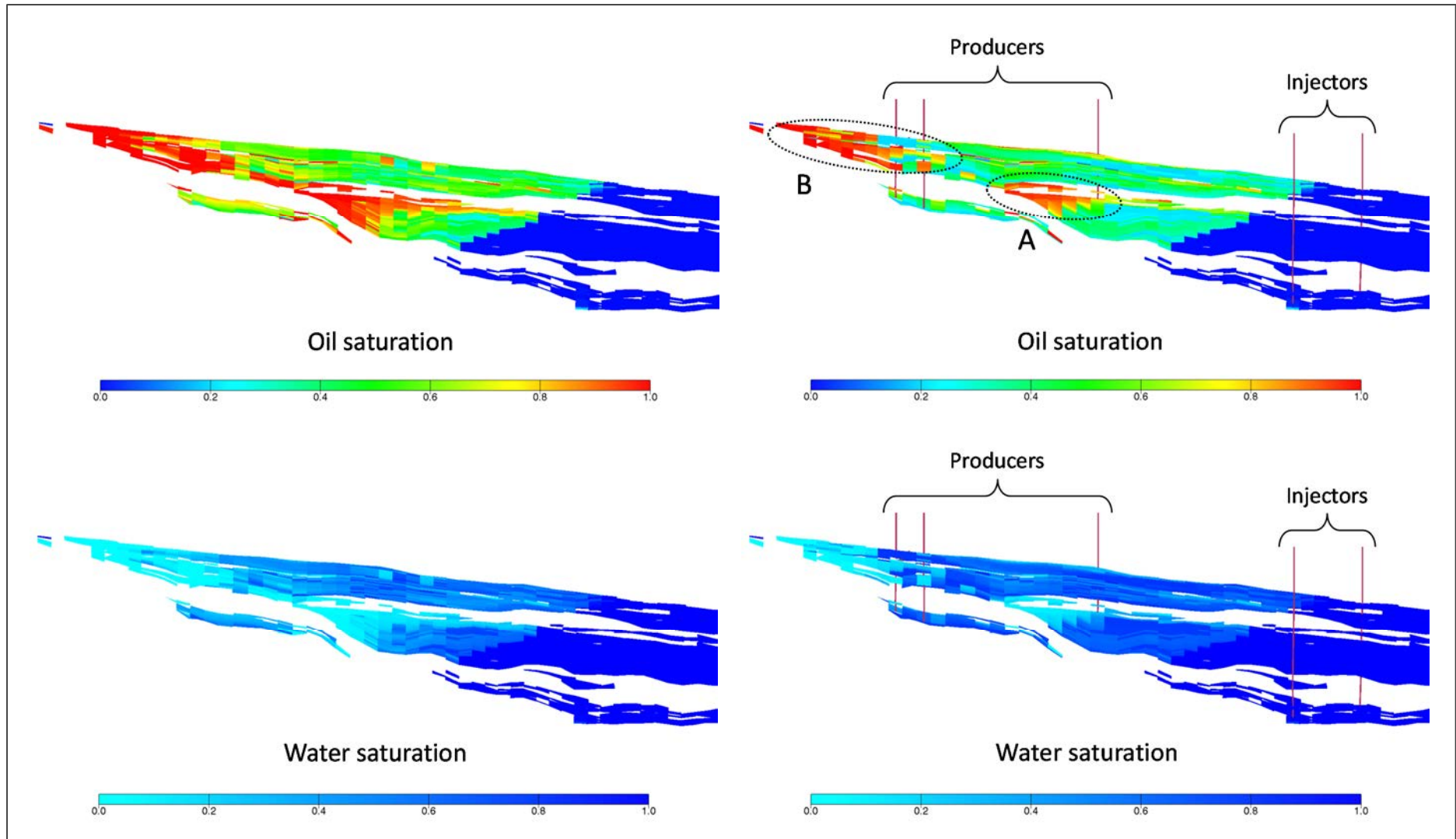
Figure 12. Example of extended water-flood fluid distributions in a model cross-section at start (left hand side graphics) and end (right hand side graphics) of simulation.
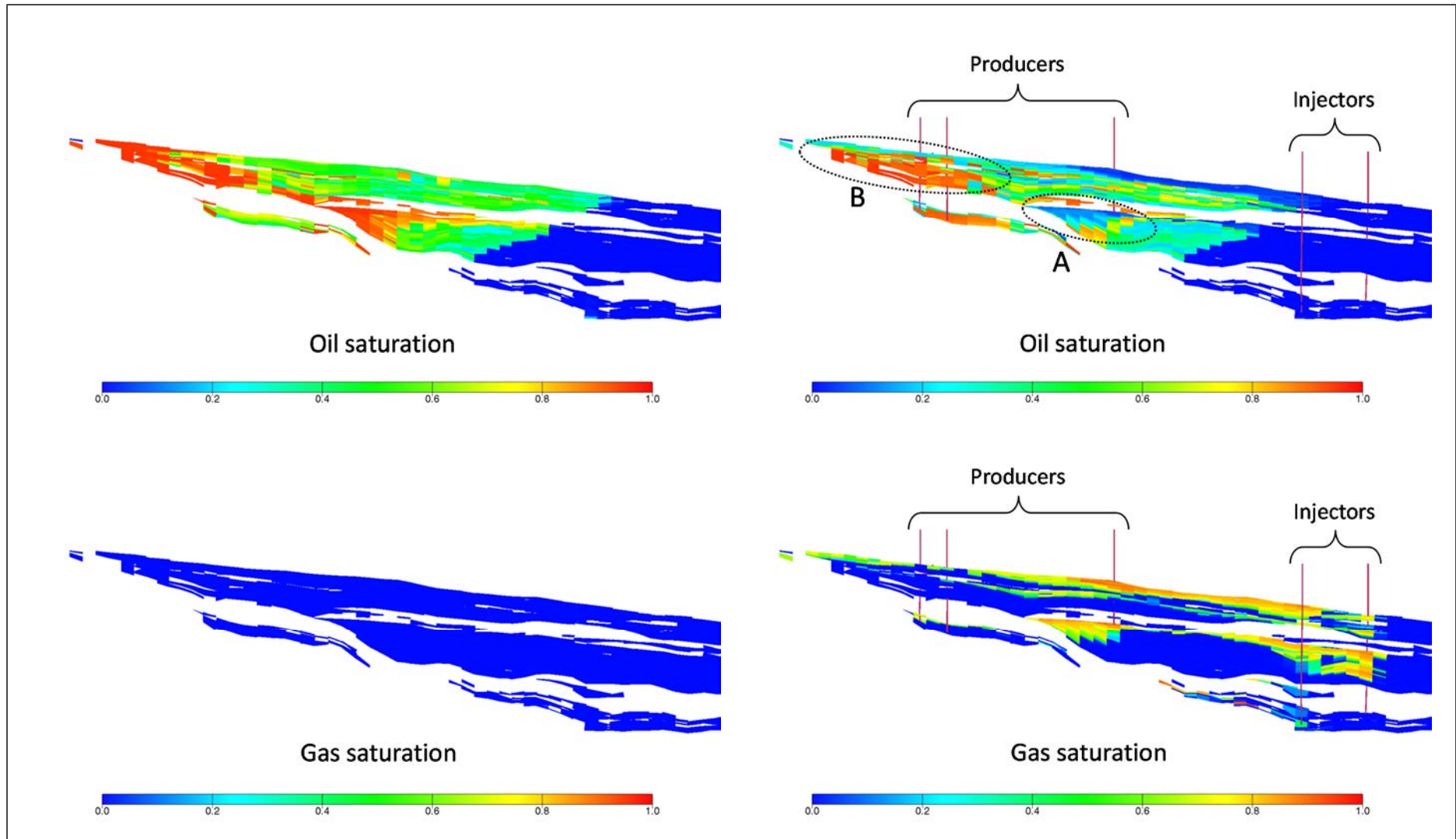
Figure 13. Example of CO$_2$-flood fluid distributions in a model cross-section at start (left hand side graphics) and end (right hand side graphics) of simulation
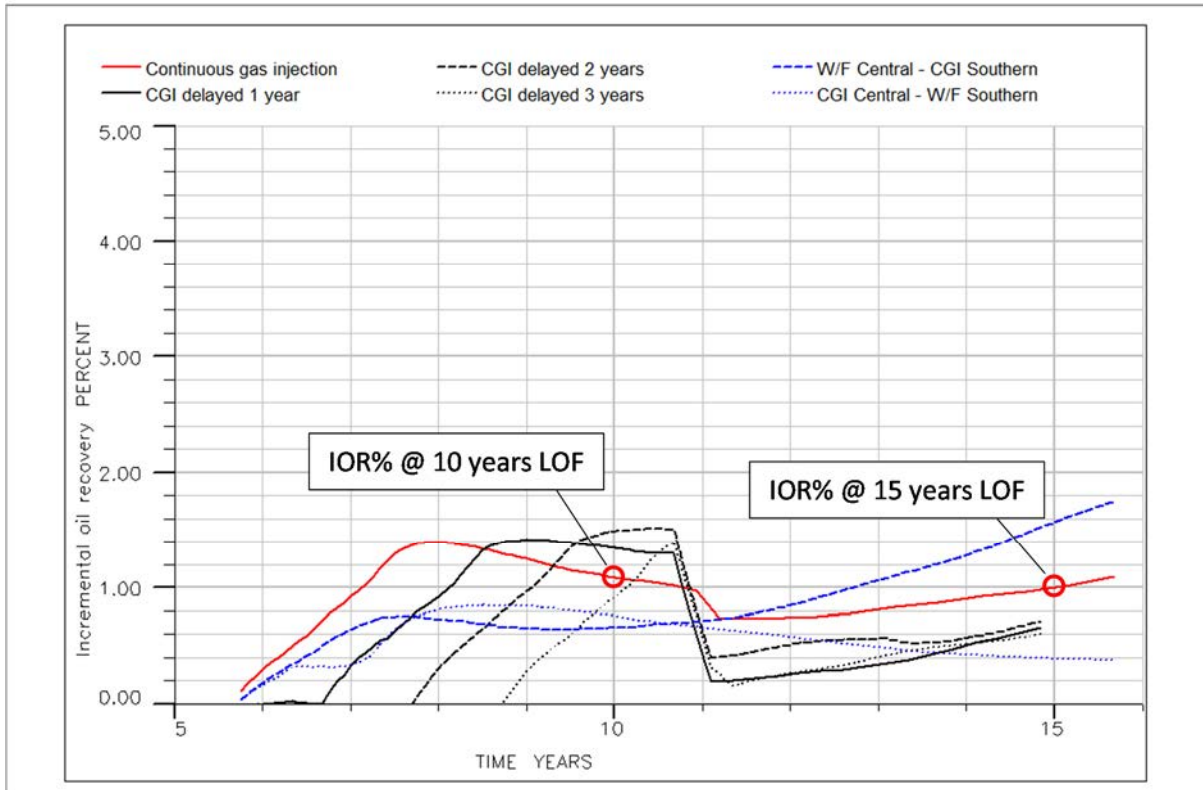
Figure 14. Incremental oil recovery for initial modelled scenarios.
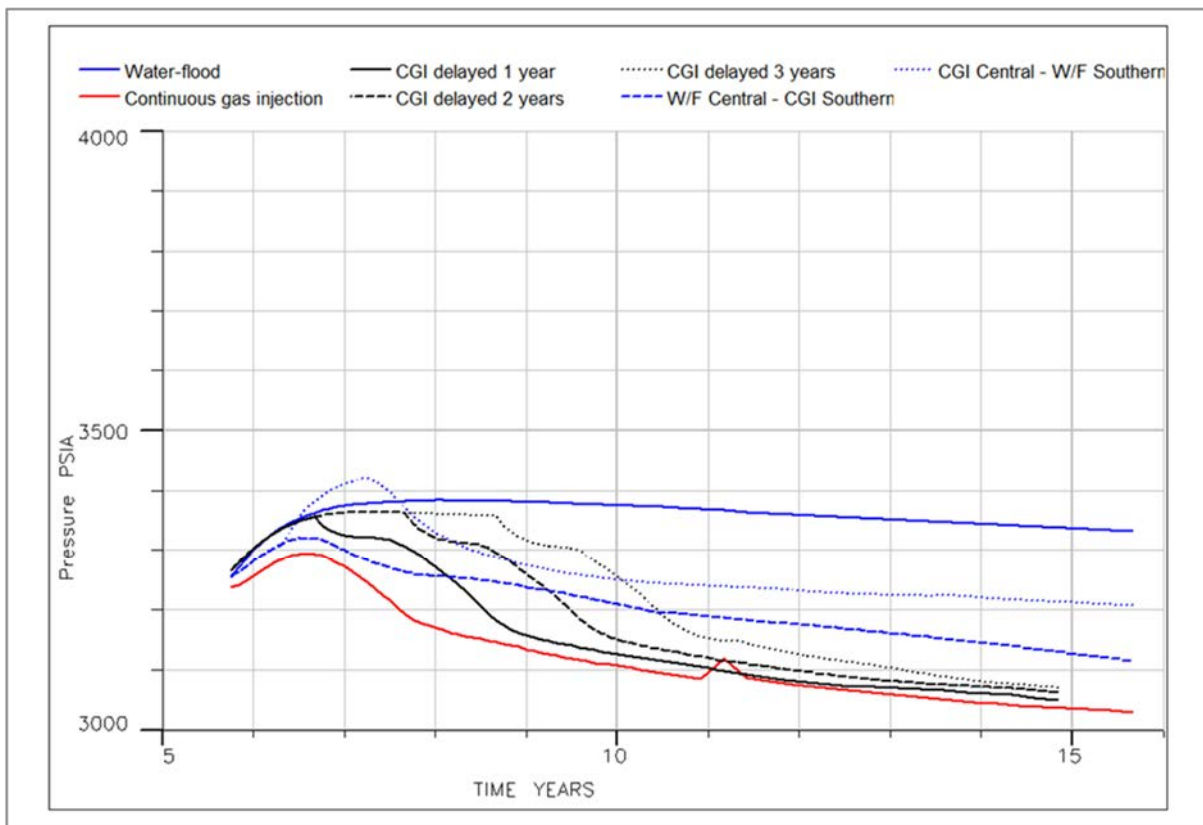
Figure 15. Field pressure for initial modelled scenarios.
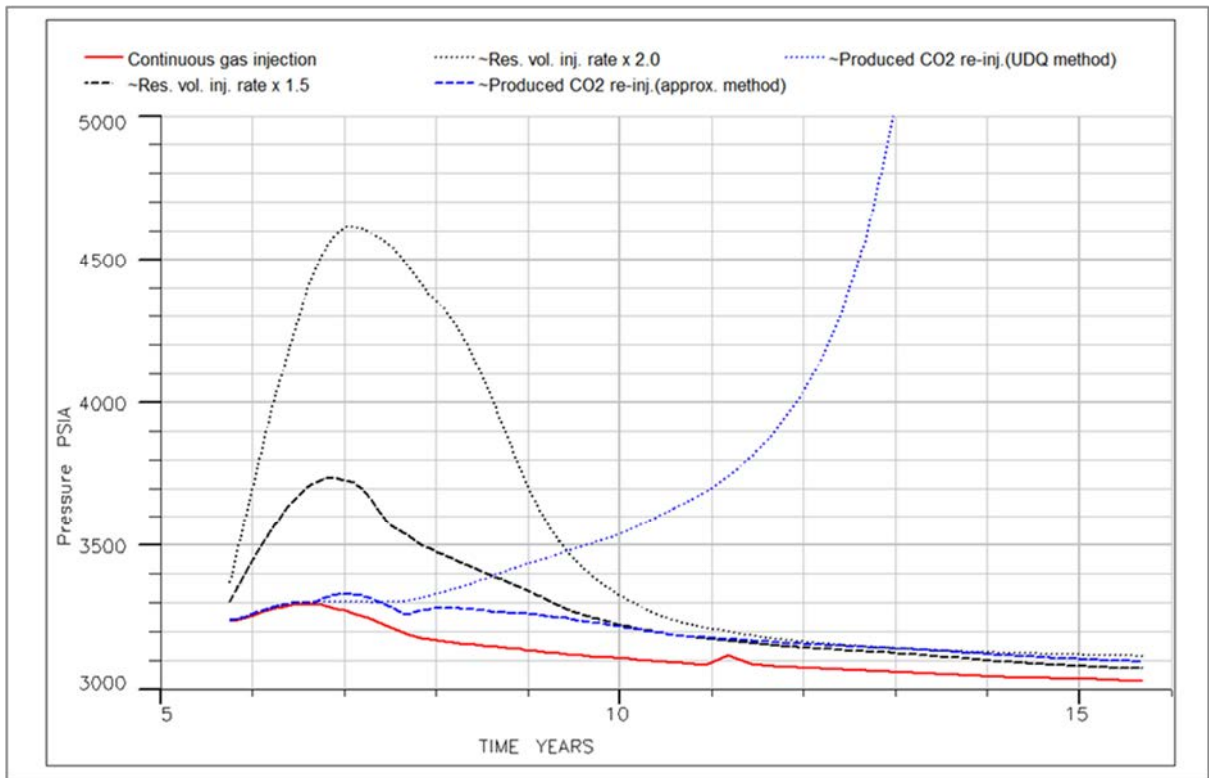
Figure 16. Field pressure for further modelled scenarios.
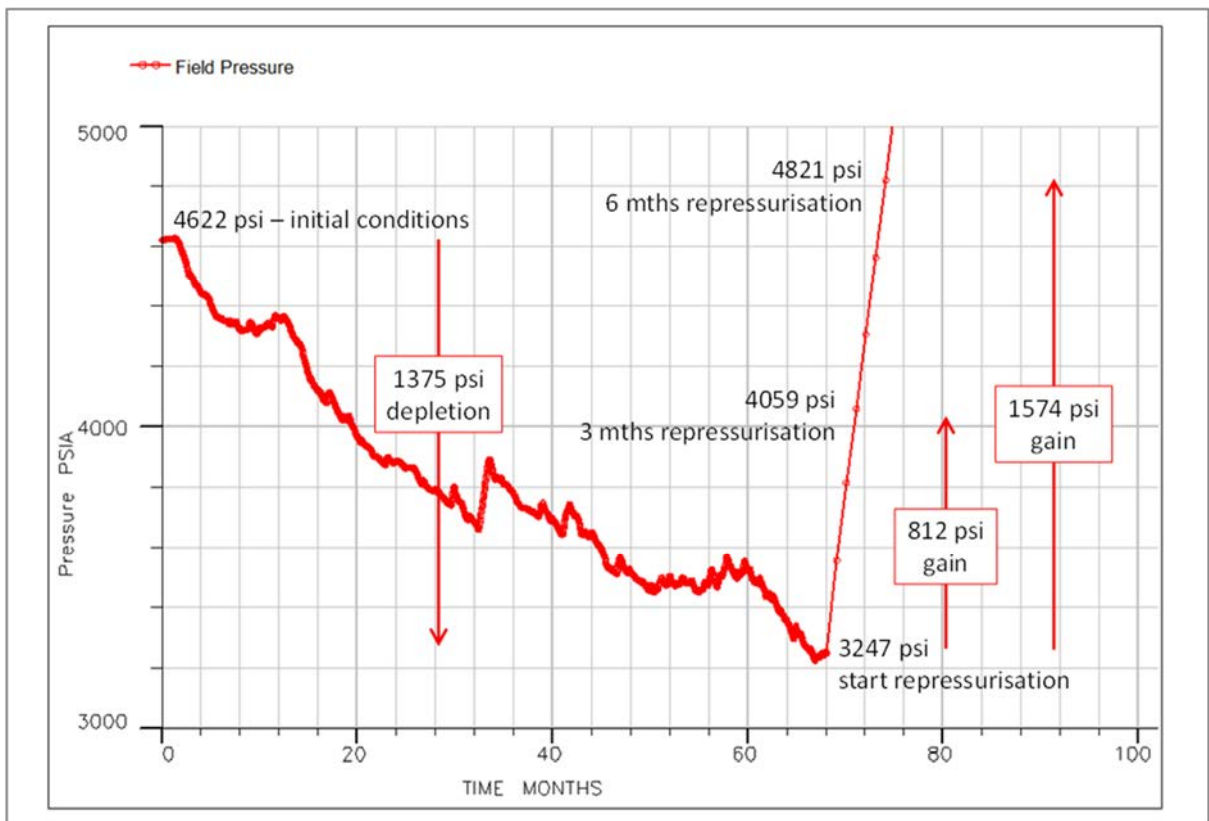
Figure 17. Field re-pressurisation response.
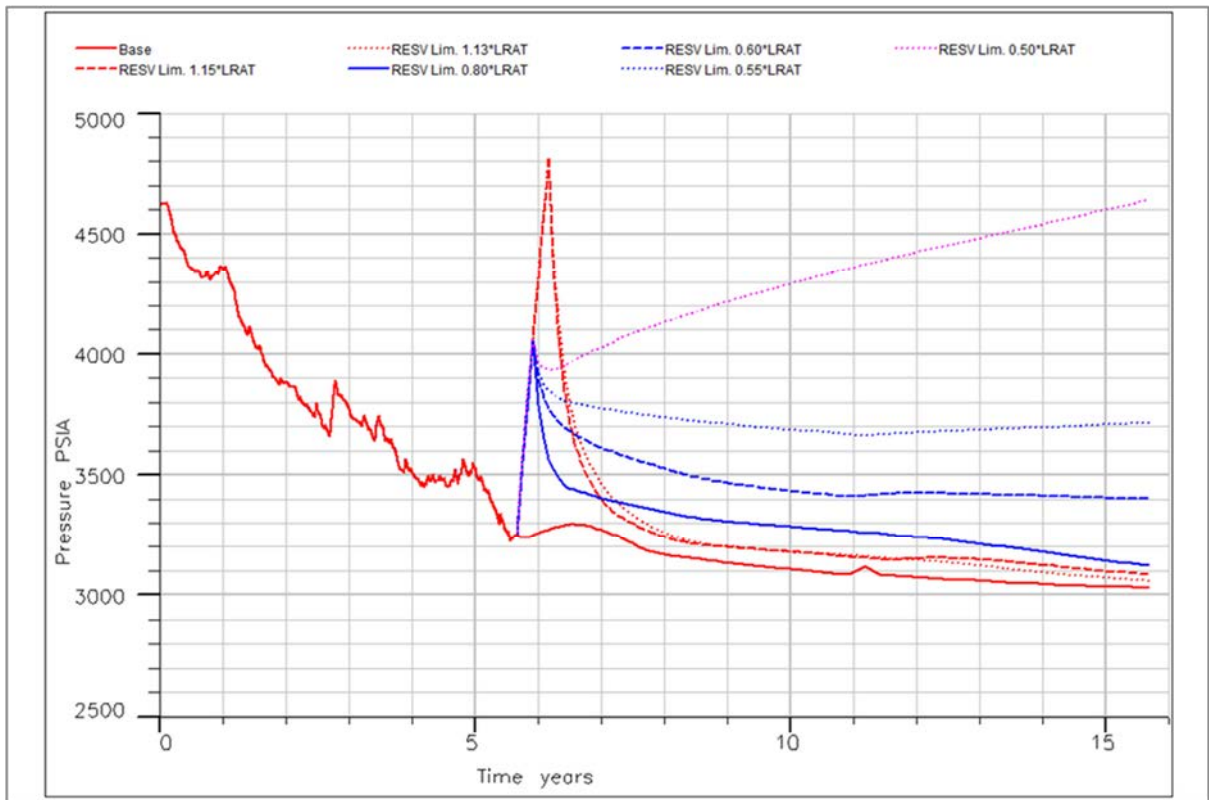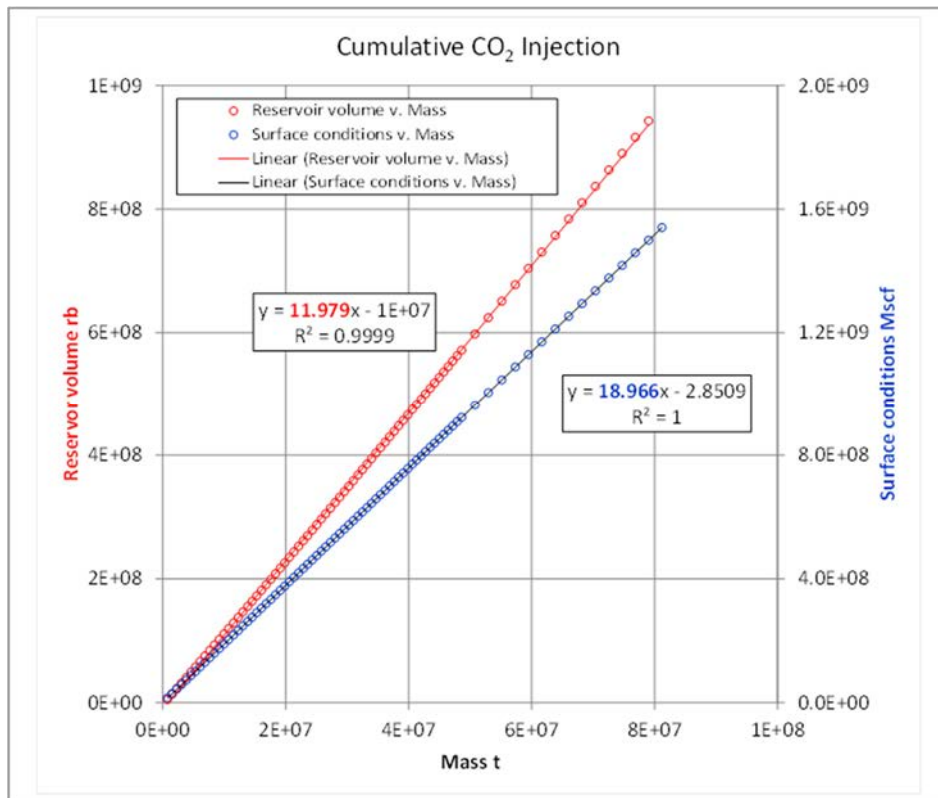
Figure 18. Post re-pressurisation response to continuous gas injection.

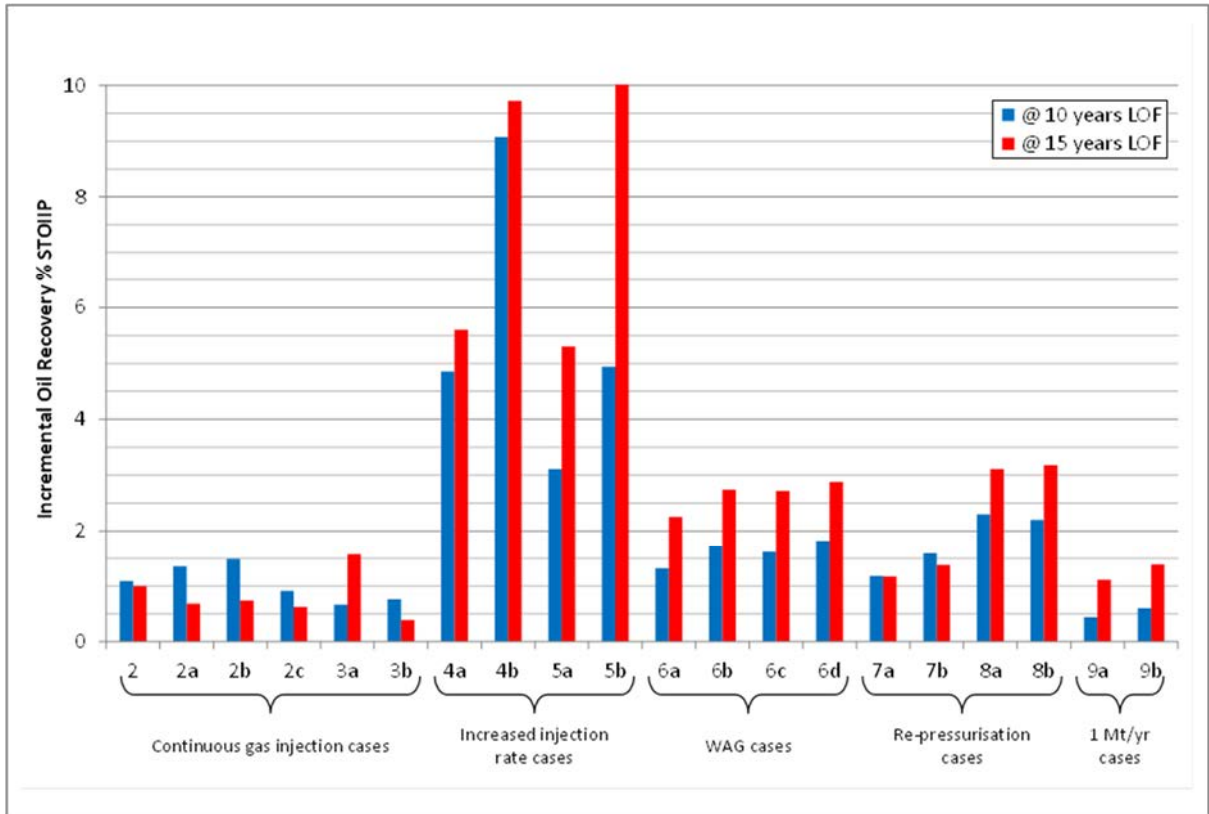**Figure 19.** Chart for converting CO_2 mass and volumes.
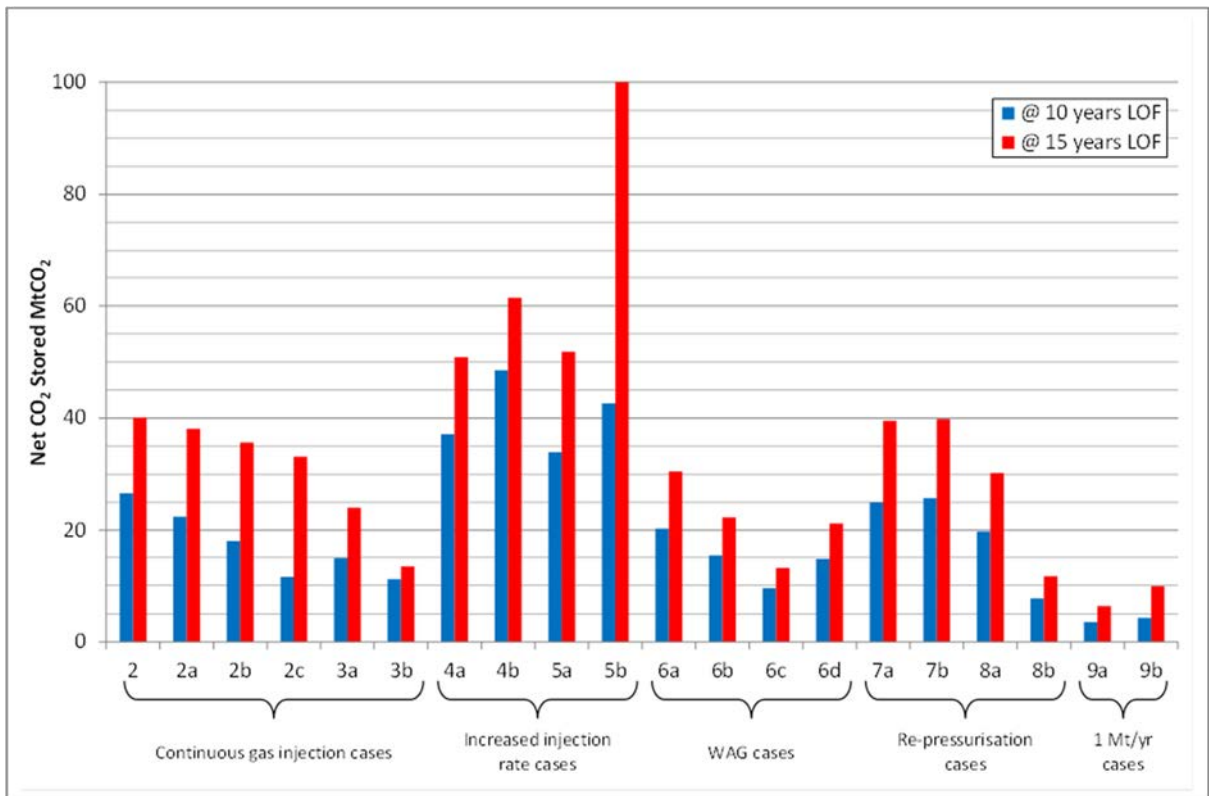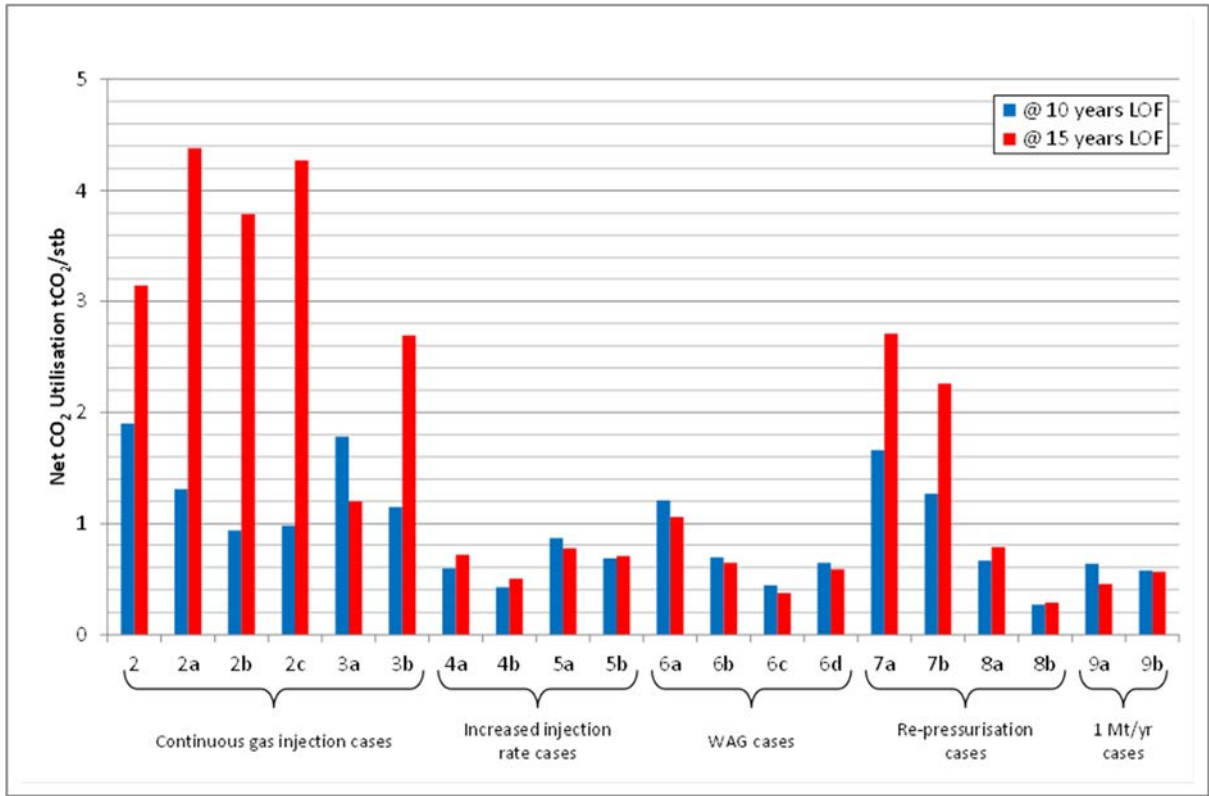
Figure 20. Incremental oil recovery.

Figure 21. Net CO₂ stored.

Figure 22. Net CO₂ utilisation.