Temperature and pressure measurements in CO_2 wells

Anders Kiær

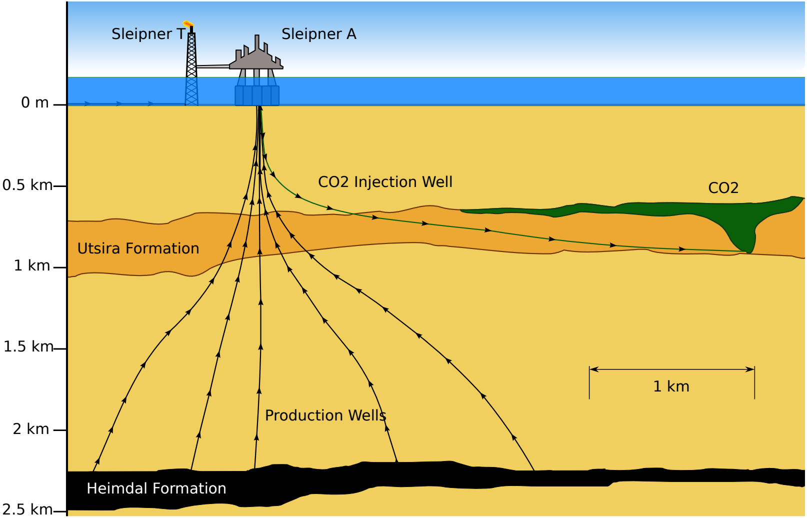
April 23th 2013 (10:50-11:10)

Statoil

NTNU
Innovation and Creativity

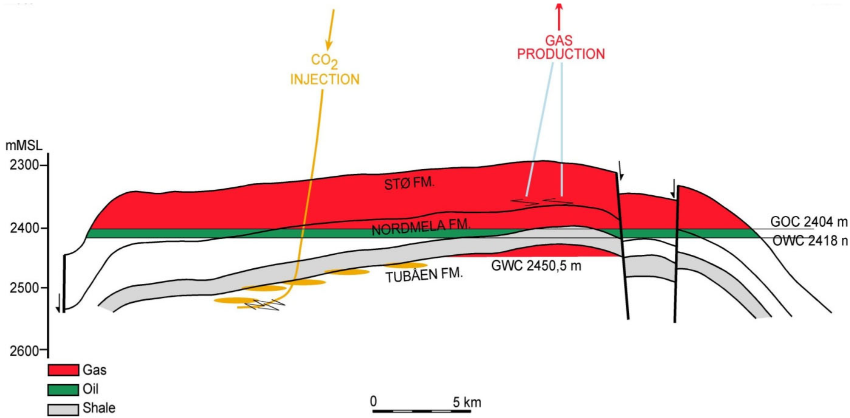
Outline

Sleipner



Sleipner T
Sleipner A
0 m
0.5 km
1 km
1.5 km
2 km
2.5 km
CO2 Injection Well
CO2
Utsira Formation
1 km
Production Wells
Heimdal Formation

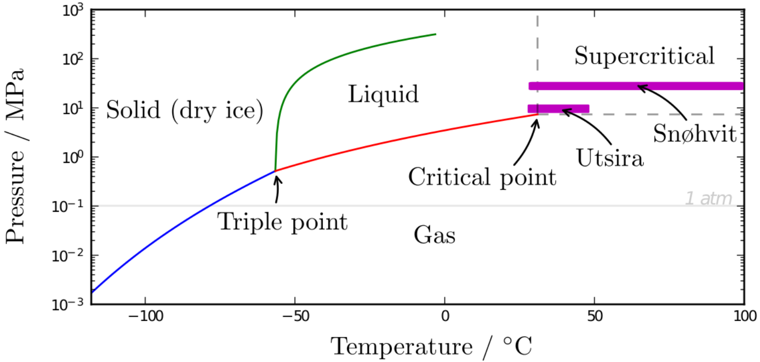
Snøhvit


CO2
INJECTION
GAS
PRODUCTION
mMSL
2300
2400
2500
2600
STØ FM.
NORDMELA FM.
TUBÅEN FM.
GOC 2404 m
OWC 2418 m
GWC 2450,5 m
Gas
Oil
Shale
0
5 km

Quick comparison between Sleipner and Snøhvit

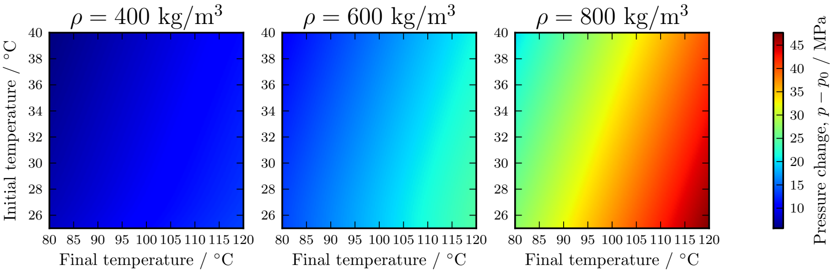
	Depth	Initial temperature	Initial pressure	T_{CO_2} at IP
Sleipner	1000 m	35 °C	10 MPa	48 °C
Snøhvit	2600 m	100 °C	29 MPa	26 °C

Phase plot of CO_2



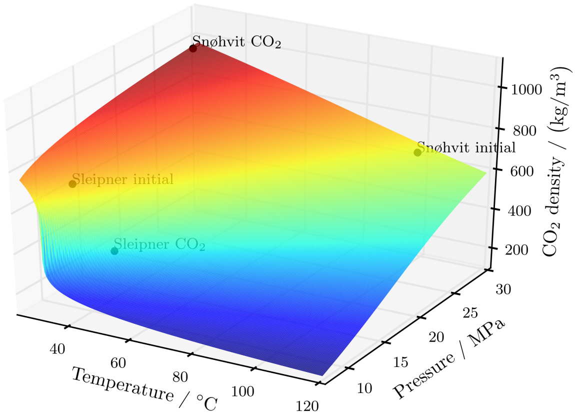
Span & Wagner (1996)

Closed box illustration



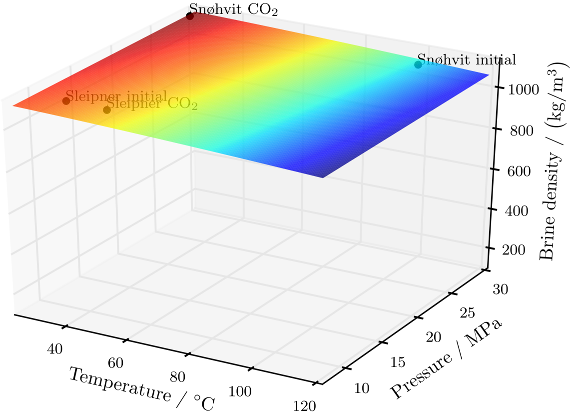
Span & Wagner (1996)

CO_2 density



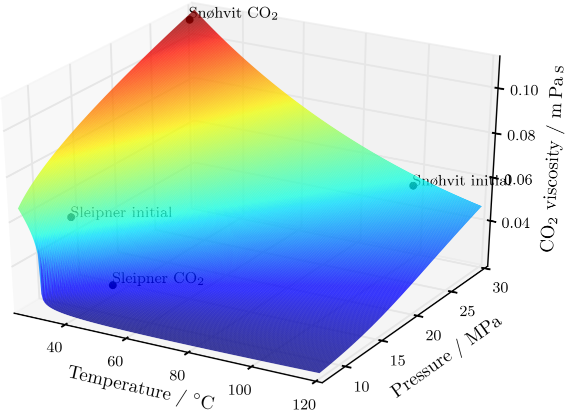
Span & Wagner (1996)

Brine density



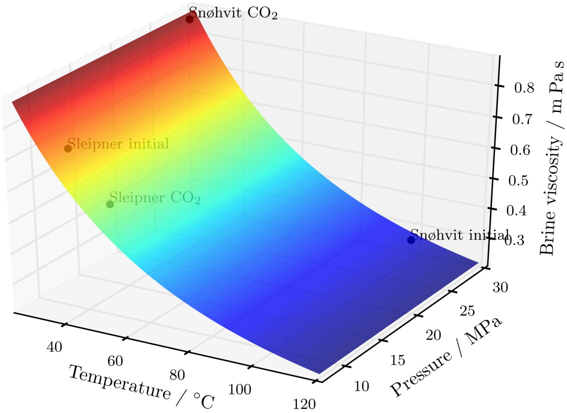
IAWPS (1997), Batzle & Wang (1992)

CO_2 viscosity



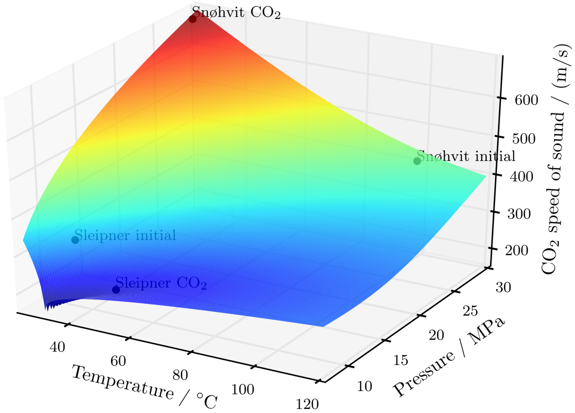
Fenghour et al. (1998)

Brine viscosity



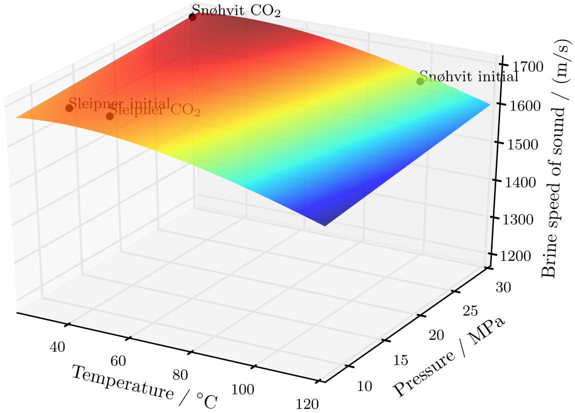
Batzle & Wang (1992)

CO_2 speed of sound



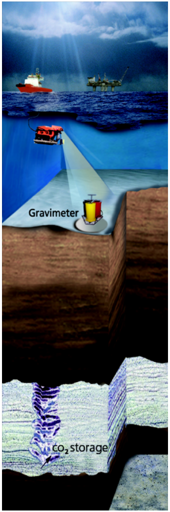
Span & Wagner (1996)

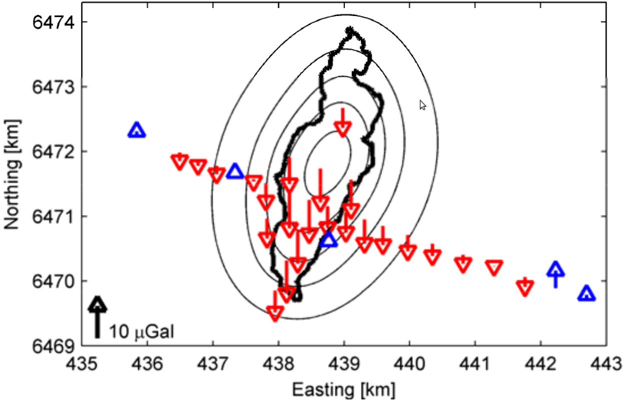
Brine speed of sound



IAWPS (1997), Batzle & Wang (1992)

Time lapse gravimetry (2005-2002)



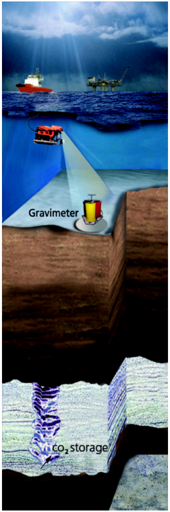


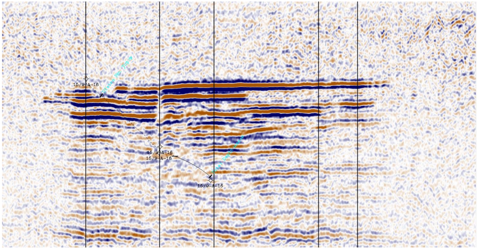
(Alnes et al. 2011)

Time lapse gravimetry

$$
\begin{aligned}
g &= \frac{Gm_{\text{polarbear}}}{r^2} \\
&= \frac{(6.67 \cdot 10^{-11}\ \mathrm{m^3 kg^{-1} s^{-2}}) \cdot (600\ \mathrm{kg})}{(2\ \mathrm{m})^2} \\
&= 10^{-8}\ \mathrm{m/s^2} \equiv 1\mu\mathrm{Gal}.
\end{aligned}
$$

Time lapse gravimetry





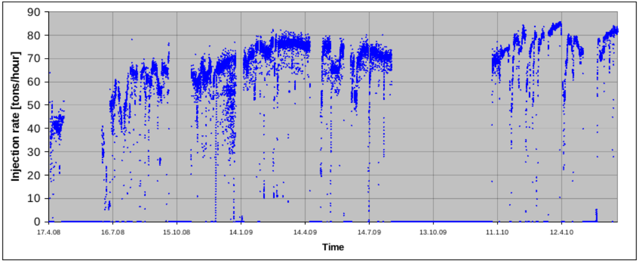
- Observed in-situ CO_2 density from gravity measurements: $720 \pm 80\ \mathrm{kg/m^3}$ (Alnes et al. 2011).
- Using seismic data and tuning relationship to estimate volume.

Some available Snøhvit data (Tubåen)

WH

DS (1.8 km)

IP (2.6 km)

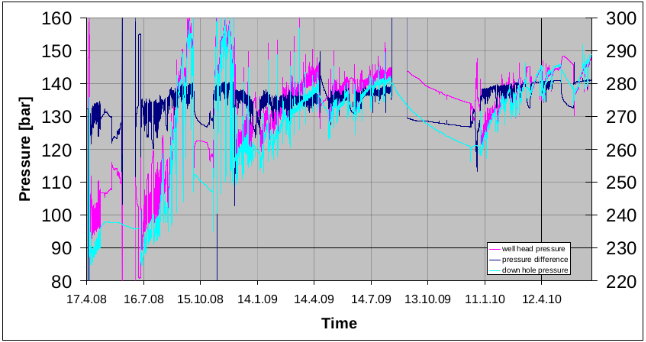


Some available Snøhvit data (Tubåen)

WH

DS (1.8 km)

IP (2.6 km)

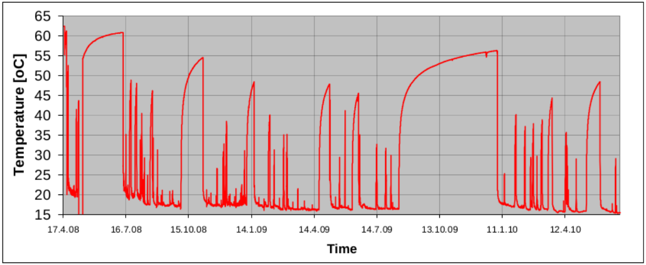


Some available Snøhvit data (Tubåen)

WH

DS (1.8 km)

IP (2.6 km)



Existing literature

Cronshaw & Bolling (1982):

- Develops a simple finite difference model for the well.
- Calculates pressure/temperature at well head for different reservoir pressures/temperatures/flow rates.

Assumptions:

- Radial heat exchange between formation and well.

SPE

Society of Petroleum Engineers of AIME

SPE 10735

A Numerical Model of the Non-Isothermal Flow of Carbon Dioxide in Wellbores

by Mark B. Cronshaw and John D. Bolling, *ARCO Oil and Gas Co.*

Members SPE-AIME

This paper was presented at the 1982 California Regional Meeting of the Society of Petroleum Engineers held in San Francisco, CA, March 24–26, 1982. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write: 6200 N. Central Expwy., Dallas, TX 75206.

ABSTRACT

A numerical model of non-isothermal flow in pure carbon dioxide production or injection wells was developed. The model includes single or two-phase flow, heat transfer between the wellbore and its surroundings, and an accurate representation of the thermophysical properties of carbon dioxide, even near its critical point. Model predictions matched pressures measured during a field production test to within 30 psi and temperatures to within 3°F for flow rates between 4 and 22 MMscf/D. Sensitivities to wellhead conditions and flow rate for a pure carbon dioxide injector were examined with the model. Explanations of behavior during production and injection should improve our understanding of the use of carbon dioxide in the oil field.

INTRODUCTION

Carbon dioxide injection for miscible and immiscible oil recovery projects is becoming more common as interest in enhanced oil recovery grows. Concurrent with the increased interest in injection, carbon dioxide production from natural deposits (for example in southern Colorado) is receiving more attention. Because the nature of carbon dioxide is sufficiently different from other oil field fluids, a computer model of flow in carbon dioxide wells can greatly aid in the design of equipment and field procedures. This is particularly true since typical applications often require handling of the carbon dioxide near its critical point (1070 psia, 88°F) where its physical properties are sensitive to changes in pressure and temperature. Furthermore, the use of carbon dioxide confronts the engineer with problems of hydrate formation and corrosion.

References and illustrations at end of paper

We have developed a numerical model which describes the two-phase flow, the heat transfer with the surroundings, and the carbon dioxide phase behavior including its vapor-liquid phase transition. An analytic model such as described by Ramey[1] is not suitable due to nonuniform fluid properties near the critical region. Nor is the temperature formulation of Chierici et al.[2] suitable since derivatives such as heat capacity become infinite at the critical point. Our model includes the strong coupling of the wellbore momentum and energy balances as in Gould's[3] or Hickox's[4] steam well models. However, it uses a finite-difference solution to the conduction equation for energy flow in the wellbore surroundings as do Wooley[5] and Farouq Ali[6]. Unlike Wooley, we do not solve the entire wellbore and surrounding temperature field simultaneously. A semi-implicit integration technique is used which avoids excessive computation associated with the solution of the conduction equation while iterating on the wellbore balance equations.

This paper will examine predictions for both production and injection cases. The model should reduce the degree of uncertainty associated with the increased use of carbon dioxide in the oil industry.

MODEL DEVELOPMENT

The model equations can be separated into two parts: a set of macroscopic balance equations and a conduction equation. The macroscopic balance equations describe the fluid flow through the tubing string, which we designate as the wellbore balance equations. Mass, momentum, and energy balances are included. Heat conduction through the wellbore assembly and formation are described by a radial conduction equation. The balance equations and conduction equation are coupled via a heat flux term at the wellbore and wellbore assembly interface.

173

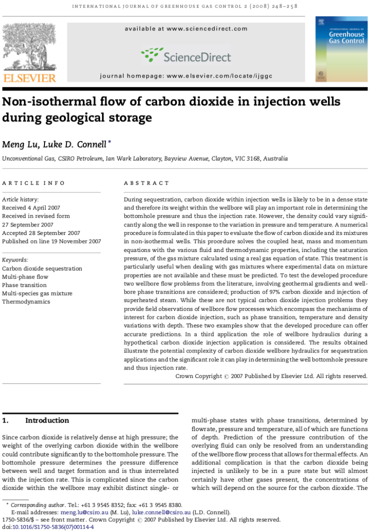
Existing literature

Lu & Connell (2008):

- Calculates pressure/temperature at the injection point for different well head conditions pressures/temperatures/flow rates.

Assumptions:

- Quasy-steady flow (i.e. time derivatives in the well equations are neglected).



INTERNATIONAL JOURNAL OF GREENHOUSE GAS CONTROL 2 (2008) 248–258

ELSEVIER

available at www.sciencedirect.com

ScienceDirect

journal homepage: www.elsevier.com/locate/ijggc

Greenhouse Gas Control

Non-isothermal flow of carbon dioxide in injection wells during geological storage

Meng Lu, Luke D. Connell *

Unconventional Gas, CSIRO Petroleum, Ian Wark Laboratory, Bayview Avenue, Clayton, VIC 3168, Australia

ARTICLE INFO

Article history:
Received 4 April 2007
Received in revised form
27 September 2007
Accepted 28 September 2007
Published on line 19 November 2007

Keywords:
Carbon dioxide sequestration
Multi-phase flow
Phase transition
Multi-species gas mixture
Thermodynamics

ABSTRACT

During sequestration, carbon dioxide within injection wells is likely to be in a dense state and therefore its weight within the wellbore will play an important role in determining the bottomhole pressure and thus the injection rate. However, the density could vary significantly along the well in response to the variation in pressure and temperature. A numerical procedure is formulated in this paper to evaluate the flow of carbon dioxide and its mixtures in non-isothermal wells. This procedure solves the coupled heat, mass and momentum equations with the various fluid and thermodynamic properties, including the saturation pressure, of the gas mixture calculated using a real gas equation of state. This treatment is particularly useful when dealing with gas mixtures where experimental data on mixture properties are not available and these must be predicted. To test the developed procedure two wellbore flow problems from the literature, involving geothermal gradients and wellbore phase transitions are considered; production of 97% carbon dioxide and injection of superheated steam. While these are not typical carbon dioxide injection problems they provide field observations of wellbore flow processes which encompass the mechanisms of interest for carbon dioxide injection, such as phase transition, temperature and density variations with depth. These two examples show that the developed procedure can offer accurate predictions. In a third application the role of wellbore hydraulics during a hypothetical carbon dioxide injection application is considered. The results obtained illustrate the potential complexity of carbon dioxide wellbore hydraulics for sequestration applications and the significant role it can play in determining the well bottomhole pressure and thus injection rate.

1. Introduction

Since carbon dioxide is relatively dense at high pressure; the weight of the overlying carbon dioxide within the wellbore could contribute significantly to the bottomhole pressure. The bottomhole pressure determines the pressure difference between well and target formation and is thus interrelated with the injection rate. This is complicated since the carbon dioxide within the wellbore may exhibit distinct single- or multi-phase states with phase transitions, determined by flowrate, pressure and temperature, all of which are functions of depth. Prediction of the pressure contribution of the overlying fluid can only be resolved from an understanding of the wellbore flow process that allows for thermal effects. An additional complication is that the carbon dioxide being injected is unlikely to be in a pure state but will almost certainly have other gases present, the concentrations of which will depend on the source for the carbon dioxide. The

* *Corresponding author*. Tel.: +61 3 9545 8352; fax: +61 3 9545 8380.
E-mail addresses: meng.lu@csiro.au (M. Lu), luke.connell@csiro.au (L.D. Connell).

1750-5836/$ – see front matter. Crown Copyright © 2007 Published by Elsevier Ltd. All rights reserved.
doi:10.1016/S1750-5836(07)00114-4

Existing literature

Paterson et al. (2008):

- Uses the formulations of Lu & Connell (2008) on different scenarios, including a blow out case.

Assumptions:

- The same as for Lu & Connell

SPE 115946

Numerical Modeling of Pressure and Temperature Profiles Including Phase Transitions in Carbon Dioxide Wells

Lincoln Paterson, SPE, CO2CRC, CSIRO; Meng Lu, SPE, CSIRO; Luke D. Connell, SPE, CSIRO; and Jonathan Ennis-King, SPE, CO2CRC, CSIRO

This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

Geological storage of carbon dioxide will usually be at conditions above the critical temperature and pressure, so the carbon dioxide will exist as a single dense phase. However, conditions in the upper part of a carbon dioxide well with surface temperatures below the critical point of 31 C can lead to boiling and condensation in the well. The consequences of this are most apparent when flow rate changes, for example when a well is shut-in or if there is a well blowout.

We have calculated density profiles for wells experiencing different thermal conditions to determine how bottom-hole pressures are related to wellhead pressures. There are two limiting cases, one when the fluid is in thermal equilibrium with the rock at the same horizon, the other when there is no heat exchange with the casing or the rock. We find that in deeper wells static columns can exist in a stable state with liquid to the surface, but for shallower wells or wells in depleted reservoirs that a static column can be initially unstable with two-phase conditions near the surface.

In producing wells, as the flow rate increases from static conditions, the pressure and temperature at the wellhead increases until high production rates are reached when the wellhead temperature then decreases, which can be to very low values. For injection wells, bottom-hole conditions are confined between the wellhead and the reservoir temperature.

In general, phase change does not prevent carbon dioxide injection. Nevertheless care is needed in shallower or depleted reservoirs for the interpretation of reservoir pressure, the use of pressure for monitoring, and in all reservoirs for the management of blowouts.

Introduction

Carbon dioxide (CO_2) wells are used for both injection and production. Injection wells have been used in enhanced oil recovery (EOR) for many decades (Jarrell et al. 2002). CO_2 wells for production from underground natural accumulations have been used to provide a source of CO_2 for EOR and other industrial uses. Recently, however, interest in CO_2 wells has intensified as a result of investigation into geological storage as a means of reducing atmospheric greenhouse gases.

Accurate determination of downhole pressures is particularly important if pressure is being used to monitor the performance of a geological storage reservoir. Reliable knowledge of bottom hole pressure is also helpful in preventing injection above the pressures than can damage the formation (Kelly, 2006). While bottom-hole pressure can be measured using gauges, there is always the prospect that over a long period of time downhole gauges may fail. Hence it is convenient to be able to calculate downhole pressure from wellhead pressure. CO_2 has a critical pressure of 7.38 MPa [1071 psi] and critical temperature of 31.0 C, so if the fluid is near usual surface temperatures, conditions in the upper part of a well can cross the saturation line of CO_2 with boiling and condensation in the well if fluid pressures are in the vicinity of the critical pressure. Furthermore, near the saturation line of CO_2, fluid properties display severely nonlinear behavior that makes numerical simulation challenging. This parallels the situation in gas condensate wellbore modeling where retrograde condensation, liquid holdup and varying fluid composition make pressure drop calculations difficult (Sadegh et al 2006).

This issue of phase change is usually not of concern during injection of CO_2 for EOR, as EOR normally involves continuous columns of liquid to the surface because of the reservoir pressures required for minimum miscibility. For example, in the Denver Unit CO_2 flood, injection pressure is around 12.4 MPa (Fleming et al. 1992), far above the critical pressure at 7.38 MPa. As another example, measurements of pressure and temperature during EOR described by Kelly (2006) have surface pressures always above 8.6 MPa even though some of the wells have fluid temperatures at the surface around 27 C, hence below the critical temperature.

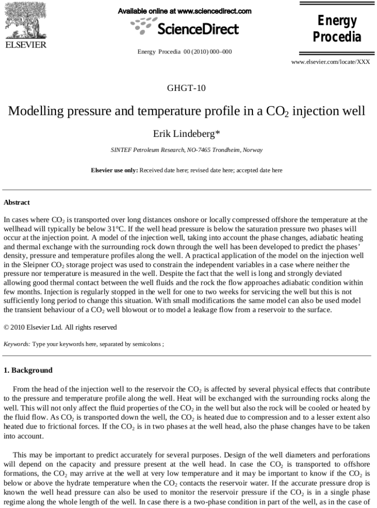
Existing literature

Lindeberg (2010):

- Finds that in the Sleipner case, adiabatic conditions are approached quickly.
- Calculates temperature/pressure at injection point given well head conditions.

Assumptions:

- Bernoulli's equation, with kinetic term neglected.



ELSEVIER

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 00 (2010) 000–000

Energy Procedia

www.elsevier.com/locate/XXX

GHGT-10

Modelling pressure and temperature profile in a CO_2 injection well

Erik Lindeberg*

SINTEF Petroleum Research, NO-7465 Trondheim, Norway

Elsevier use only: Received date here; revised date here; accepted date here

Abstract

In cases where CO_2 is transported over long distances onshore or locally compressed offshore the temperature at the wellhead will typically be below 31°C. If the well head pressure is below the saturation pressure two phases will occur at the injection point. A model of the injection well, taking into account the phase changes, adiabatic heating and thermal exchange with the surrounding rock down through the well has been developed to predict the phases' density, pressure and temperature profiles along the well. A practical application of the model on the injection well in the Sleipner CO_2 storage project was used to constrain the independent variables in a case where neither the pressure nor temperature is measured in the well. Despite the fact that the well is long and strongly deviated allowing good thermal contact between the well fluids and the rock the flow approaches adiabatic condition within few months. Injection is regularly stopped in the well for one to two weeks for servicing the well but this is not sufficiently long period to change this situation. With small modifications the same model can also be used model the transient behaviour of a CO_2 well blowout or to model a leakage flow from a reservoir to the surface.

© 2010 Elsevier Ltd. All rights reserved

Keywords: Type your keywords here, separated by semicolons ;

1. Background

From the head of the injection well to the reservoir the CO_2 is affected by several physical effects that contribute to the pressure and temperature profile along the well. Heat will be exchanged with the surrounding rocks along the well. This will not only affect the fluid properties of the CO_2 in the well but also the rock will be cooled or heated by the fluid flow. As CO_2 is transported down the well, the CO_2 is heated due to compression and to a lesser extent also heated due to frictional forces. If the CO_2 is in two phases at the well head, also the phase changes have to be taken into account.

This may be important to predict accurately for several purposes. Design of the well diameters and perforations will depend on the capacity and pressure present at the well head. In case the CO_2 is transported to offshore formations, the CO_2 may arrive at the well at very low temperature and it may be important to know if the CO_2 is below or above the hydrate temperature when the CO_2 contacts the reservoir water. If the accurate pressure drop is known the well head pressure can also be used to monitor the reservoir pressure if the CO_2 is in a single phase regime along the whole length of the well. In case there is a two-phase condition in part of the well, as in the case of

Problem with existing literature

Main problem

Does not discuss uncertainties in calculated injection point pressure and temperatures due to uncertainties in input data or assumptions/simplifications in the model itself.

- Initial geothermal gradient.
- Pressure and temperature at the well head.
- Gas/liquid ratio at the well head.
- Injection rate at the well head.

- Heat transport between well and formation (radial/adiabatic).
- The quasi-steady approach.

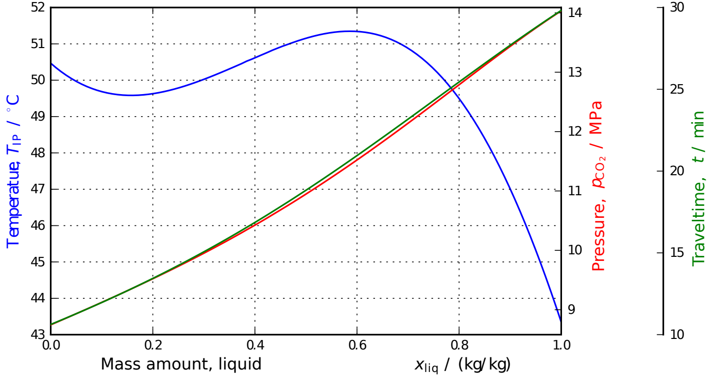
Well equations

$$\frac{\mathrm{d}p}{\mathrm{d}l} = \rho g \cos\theta - \frac{f\rho v^3}{2|v|D} - \frac{\partial(\rho v^2)}{\partial l} - \frac{\partial(\rho v)}{\partial t}.$$

$$\frac{\partial(\rho e)}{\partial t} - (h + v^2/2 - gz)\frac{\partial \rho}{\partial t} + \rho v\left[\frac{\partial h}{\partial l} + v\frac{\partial v}{\partial l} - g\cos\theta\right] = \dot{q}.$$

$$\boxed{\frac{\partial}{\partial t} \to 0, \quad \dot{M} = A\rho v, \quad \dot{q} = 0.}$$

Sleipner calculation example



Conclusions

- Accurate downhole temperature and pressure measurements might be important for many carbon storage scenarios.
- For the Sleipner case, the downhole pressure might change by as much as $\simeq 4$ MPa without pressure increase at the well head.
- Sensitivity analysis in the different input variables for the quasi-steady case should be done.
- Existing literature on the topic lack discussion of model and parameter uncertainties.

Acknowledgements

Statoil

NTNU
Innovation and Creativity