International Journal of Greenhouse Gas Control 15 (2013) 163–173

Contents lists available at SciVerse ScienceDirect

International Journal of Greenhouse Gas Control

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

Injection operation and operational pressure–temperature monitoring at the CO_2 storage pilot site Ketzin, Germany—Design, results, recommendations

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ARTICLE INFO

Article history:
Received 23 November 2012
Received in revised form 11 February 2013
Accepted 19 February 2013
Available online 22 March 2013

Keywords:
CO_2 storage
Pilot site
Ketzin
Pressure–temperature monitoring
Injection operation

ABSTRACT

The Ketzin pilot site for geological storage of CO_2 in the German Federal State of Brandenburg about 25 km west of Berlin is the only German CO_2 storage site and has been the first European pilot site for on-shore storage of CO_2 in saline aquifers. Continuous injection of CO_2 started on June 30th, 2008, and a total of 61,396 t of CO_2 have been injected by September 2012. The injected CO_2 was predominantly food-grade with a purity > 99.9%, only from May to June 2011, 1515 t CO_2 from the Schwarze Pumpe oxyfuel pilot plant with a purity of >99.7% have been injected. The injection is accompanied by a comprehensive operational monitoring program. The program includes continuous measurements of flow rate, fill levels of intermediate storage tanks 1 and 2, outlet pressure and temperature for the injection plant, wellhead pressures (WHP) and casing pressures 1 and 2 for all wells, bottom hole pressure (BHP), bottom hole temperature (BHT) and distributed temperature sensing (DTS) along the injection tubing for the injection well Ktzi 201, BHP for the two observation wells Ktzi 202 (from March 2010 to October 2011) and Ktzi 200 (since October 2011), and above-zone pressure monitoring in shallow observation well P300. This operational pressure–temperature monitoring successfully ensured and proved a safe, smooth and reliable injection operation. A vital part of the operational P–T data comes from the downhole P–T measurements, which are recommended for any CO_2 storage site. Without this downhole information, it would not have been possible to provide the complete picture of CO_2 injection. The recommended downhole installation design of P–T tools distinguishes CO_2 storage from the operational engineering of underground storage of natural gas, where BHP monitoring can be done via WHP recording. The DTS safety monitoring along the injection tubing supported typical operational processes as conditioning of the CO_2 and improvement of injection rate and injection temperature and will be beneficial to any CO_2 storage project. The above-zone pressure monitoring gives no hints to any hydraulic connection or CO_2 leakage through or failure of the cap rock.

1. Introduction

One of the most promising techniques to restrict regional and global carbon dioxide emissions and to slow global warming is the capturing of CO_2 at large stationary sources and the subsequent injection and storage in deep geological formations (e.g., Holloway, 2005; IPCC, 2005). Although very promising, this technique is rather challenging as so far no comprehensive experiences have been gained on the subsurface storage of CO_2. Subsurface storage of natural gas is a widespread and well-developed technology, however, the physicochemical properties of CO_2 and its potential chemical reactivity within the storage complexes make it difficult to directly transfer the knowledge gained from natural gas storage to CO_2 storage. Likewise, the use of CO_2 for enhanced oil and gas recovery is a widespread and mature technology but aims at stimulation of the reservoir and not at permanent storage of the injected CO_2. It therefore has specific operational requirements that may not meet the requirements of CO_2 storage. In order to understand the fundamental physical and chemical processes that may occur during the geological storage of CO_2 and to establish a sound knowledge of

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http://dx.doi.org/10.1016/j.ijggc.2013.02.019

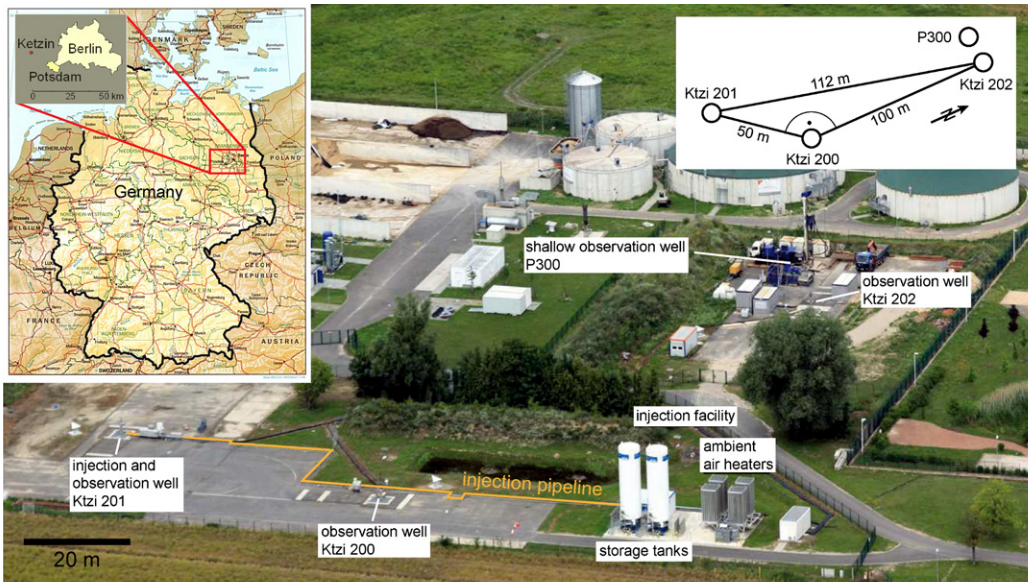

Fig. 1. Aerial view, geographic location (left upper inlet) and well-bore layout (right upper inlet) of the Ketzin pilot site. The site is located in the Federal State of Brandenburg (Germany) about 25 km west of Berlin. The site infrastructure consists of the injection facility itself including two intermediate CO_2 storage tanks and four large ambient air heaters, the injection pipeline, one injection well (Ktzi 201) and two observation wells (Ktzi 200 and 202). The three wells form the corners of a right-angled triangle (perspectively distorted in right upper inlet) with distances of 50 and 112 m between injection and observation wells. Well P300 is a shallow observation well for above zone monitoring.

technical and operational aspects of the geological storage of CO_2, pilot sites form an integral and essential part of most roadmaps for the implementation of CO_2 storage on an industrial scale. Such pilot sites allow performing field experiments and testing different technological and operational strategies that may be difficult to realize at demo or industrial scale projects.

Geological formations most suitable for storage of CO_2 include depleted oil and gas reservoirs (van der Meer, 2005; Jenkins et al., 2012) and deep saline formations (Bentham and Kirby, 2005; Michael et al., 2009); storage of CO_2 in depleted oil and gas reservoirs may under specific circumstances nevertheless be accompanied by enhanced oil and gas recovery. Among these two options, deep saline formations exhibit the larger storage capacities and wider regional distribution and availability. Therefore, the successful use of these deep saline formations is crucial for the implementation of geological storage of CO_2 (Bachu, 2000; Zemke et al., 2003; IPCC, 2005; Bradshaw et al., 2007). However, despite the use of deep saline formations for strategic and/or seasonal natural gas storage operations much less is known about deep saline formations than about oil and gas reservoirs due to the so far lower economic potential of the former. Thus, there is a general need for active CO_2 storage projects in deep saline formations and for the scientific and technological experiences gained within these projects. Pilot sites for storage of CO_2 in on-shore deep saline formations that prove safe and reliable storage operations are even more important, as on-shore storage of CO_2 typically occurs in populated or agriculturally used areas and is often confronted with severe public concerns. Here, successful research oriented pilot sites with a high commitment to transparency will help to provide public confidence in secure and sustainable implementation of geological CO_2 storage.

In this publication we present a comprehensive overview of the injection operation and the operational pressure and temperature monitoring for the first 50 months of operation at the Ketzin pilot site, Germany. The Ketzin pilot site is the longest operating European on-shore and the only national CO_2 storage project (Würdemann et al., 2010; Martens et al., 2011, 2012). Like in natural gas storage activities, pressure and temperature monitoring is also a key task in CO_2 storage to ensure reservoir and cap rock integrity and also safe and reliable CO_2 injection. Therefore, the focus of this publication lies on the different types of pressure and temperature monitoring applied at Ketzin. Based on this data, we will evaluate the observed pressure data in terms of reservoir and injection behaviour and discuss the usefulness of the applied monitoring techniques for CO_2 storage and give recommendations.

2. Site characteristics

Detailed descriptions of site geology, site infrastructure, and wellbore design are given in Prevedel et al. (2008, 2009), Förster et al. (2010) and Norden et al. (2010) and are summarized here only briefly. The Ketzin pilot site is located in the German Federal State of Brandenburg about 25 km west of Berlin (Fig. 1). At the injection site, one combined injection-observation well (labelled CO_2 Ktzi 201/2007) and two pure observation wells (labelled CO_2 Ktzi 200/2007 and CO_2 Ktzi 202/2007) have been drilled to depths of about 750–800 m and are abbreviated here as Ktzi 200, 201, and 202. All wells have 5 1/2 in. production strings. The two observation wells are at 50 m (Ktzi 200) and 112 m (Ktzi 202) distance to the injection well. The three well sites form the corners of a right angled triangle (Fig. 1). Slotted liners with filter screens connect the wells with the reservoir formation at reservoir depths. All wells have been completed with a “smart casing” concept to allow for permanent monitoring (see Prevedel et al., 2008, 2009; Schmidt-Hattenberger et al., 2011). The injection well Ktzi 201 is additionally equipped with a 3 1/2 in. injection tubing down to a depth of 560 m. For above-zone pressure, temperature and chemical monitoring a shallow observation well labelled Hy Ktzi P300/2011 and abbreviated as P300 has been drilled to a depth of 446 m in 2011 reaching the first aquifer above the cap rock. The injection facility consists of two intermediate storage tanks with capacities of 50 t CO_2 each, five standard plunger pumps for liquid CO_2 and a 300 kW_{max} electrical heater to heat up the liquid CO_2 from −18 °C, as delivered by trucks and stored in the intermediate storage tanks, to the desired injection temperature of about 35 °C. Four ambient air heaters are installed and connected upstream of the electrical heater to pre-heat the CO_2 and to reduce the electrical power need. Injection rates can be adjusted from a few hundred up to a maximum (set point) of 3250 kg CO_2/h resulting in monthly injection rates between 700 and 2340 t CO_2. The injection facility is connected to the injection well Ktzi 201 by an about 100 m long 1 in. (DN 30) pipeline.

Geologically, the pilot site is located at the southern flank of the Roskow–Ketzin double-anticline, a roughly east-west striking salt structure. The target reservoirs are sandstone horizons of the Upper Triassic Stuttgart Formation, which was deposited in a fluvial environment and is made up by sand- and siltstones that are interlayered with mudstones. The uppermost, main sandstone horizon has a thickness of about 10–20 m and its top is at 630 m (Ktzi 200, Ktzi 201) and 627 m (Ktzi 202) depth. The immature sandstones are well to moderately well sorted and dominantly fine-grained with a total porosity between 13 and 26 vol.% (Förster et al., 2010). Experimental measurements and NMR data on core samples and on-site hydraulic testing indicate permeabilities around 100 mD for the channel sandstones (Wiese et al., 2010; Zemke et al., 2010; Zettlitzer et al., 2010; Kummerow and Spangenberg, 2011). The target reservoir sandstone horizons are overlain by about 165 m thick sequence of mud- and claystones of the Weser and Arnstadt Formations forming the first cap rock of the multi-barrier system at the Ketzin pilot site. The uppermost, final seal of the multi-barrier system is the Rupelian clay at the base of the Tertiary at about 150 m depth, which also separates the groundwater horizons above from the deep saline aquifers below. Although the Ketzin pilot site was approved according to the German Mining Law, the storage complex as defined in the EU CCS directive can be defined as follows: the vertical extension of the storage complex includes the Stuttgart Formation and the overlying first cap rock sequence of the Weser and Arnstadt Formations. The lateral extension is given by the deepest, closed Top-Stuttgart isobath of the Ketzin part of the Roskow–Ketzin double-anticline, which is at 710 m depth.

Continuous injection of CO_2 started on June 30th, 2008. Until September 2012, the operation period covered by this contribution, a total of 61,396 t CO_2 have been injected. The CO_2 was predominantly food-grade from Linde AG with a purity > 99.9%. Only from May 5th to June 12th, 2011, 1515 t CO_2 from the Schwarze Pumpe oxyfuel pilot plant with a purity of >99.7% have been injected. Due to drilling of a new observation well Ktzi 203 in summer 2012, injection was stopped by May 2012 and was re-started by January 2013.

3. Operational monitoring – design and methods

To allow for steering and monitoring the injection operation as well as the pressure response of the reservoir the following operational data are recorded: *injection facility*: nominal and actual flow rate, fill levels of intermediate storage tanks 1 and 2, outlet pressure and temperature; *combined injection-observation well Ktzi 201*: wellhead pressure (WHP; only until stop of injection in May 2012; at that time wellhead has been disconnected from the injection pipeline and isolated from the lower parts of the injection well), bottom hole pressure (BHP), bottom hole temperature (BHT), distributed temperature sensing (DTS) along injection tubing, and casing pressures 1 and 2; *observation well Ktzi 200*: WHP and BHP (wireline measurement since October 2011) and casing pressures 1 and 2; and *observation well Ktzi 202*: WHP and BHP (wireline measurement from March 2010 to October 2011) and casing pressures 1 and 2. All data are stored by the site Supervisory Control And Data Acquisition (SCADA) system as the arithmetic mean over a time span of 5 min. The data are displayed and updated on the operator's screen. The complete set of the operational data can be found in data publication Möller et al. (2012). All pressure data for WHP and BHP are recorded by the installed sensors and stored in the SCADA system relative to atmospheric pressure and are re-calculated in this contribution to absolute values [bara] by addition of an assumed constant atmospheric pressure of 1 bar.

3.1. Flow rate and cumulative CO_2 mass flow

The actual flow rate [kg/h] is measured with a type "Micro Motion" coriolis mass flow metre from Emerson, installed in the injection pipeline about 8 m upstream of injection well Ktzi 201. Measurement is performed on gaseous CO_2 after heating in the injection plant. The flow metre has an accuracy of ±0.35% of the measured value. The cumulated mass of CO_2 injected at a certain time is then calculated by integrating the actual mass flow over time. Additionally, the cumulative mass of injected CO_2 is calculated based on the CO_2 delivery tickets (calibrated mass flow metre) in combination with the tank fill levels (off the SCADA) at a certain time.

3.2. Temperature monitoring

Outlet temperature at the injection facility and WHT of Ktzi 201 are measured with two Tematec "WT7490-1161" temperature gauges with class B accuracy. To monitor BHT of Ktzi 201, the downhole temperature is measured by a fibre-bragg grating sensor that forms part of the Weatherford pressure/temperature gauge installed at the end of the injection tubing at a depth of 550 m. The P/T gauge is connected to the Weatherford Reservoir Monitoring System (RMS) by two single-mode fibres for temperature and pressure, respectively, as part of a ¼-in. diameter optical cable designed for permanent downhole deployment and running along the outside of the injection tubing. Temperature profiles along the entire length of the injection tubing are recorded by the Weatherford unit SUT-6 as DTS (distributed temperature sensing) logs down to a depth of 550 m with the multimode fibre line of the ¼-in. diameter optical cable. These temperature profiles are measured every 3 min with a spatial resolution of 1 m and a temperature resolution of about 0.1 °C. The RMS that operates the P/T gauge and the DTS system acquires real-time downhole information from the multiple fibre optical tools, and interfaces seamlessly with the existing SCADA system.

3.3. Pressure monitoring

To monitor the pressure evolution during injection operation, each wellhead has been equipped with a standard pressure transducer from Endress and Hauser type "T PMP 131" with a relative error < 0.5%. The BHP of injection well Ktzi 201 is measured with the fibre-bragg grating sensor of the P/T gauge from Weatherford at the end of the injection tubing at 550 m depth. The error of the Weatherford pressure sensor is <±1 bar. To calculate the BHP at the injection depth of 630 m, the dynamic pressure difference to the Weatherford gauge at 550 m depth is numerically simulated with the commercially available ASPEN PLUS program by AspenTech applying a Peng–Robinson equation of state (EOS). Calculations have shown that only the CO_2 weight column contributes to the pressure extrapolation while other effects, e.g., friction can be neglected (Wiese et al., 2012). For simplicity, in this contribution the pressure at 630 m is calculated by a constant addition of 2 bars to the pressure measured at 550 m depth. But the reader has to be aware that the so-calculated BHP at 630 m is an approximate value and that the actual pressure difference between 550 and 630 m fluctuates around the assumed 2 bars depending on injection rate and injection temperature. The so-calculated BHP data at 630 m are not stored in the SCADA system. From March 2010 to October 2011 the observation well Ktzi 202 was additionally equipped with a wireline pressure gauge type "PK 201" from Leutert at a depth of 620 m to record the BHP. The error of PK 201 is <0.5%. Since October 2011

Table 1
Overview of logging campaigns performed until June 2013 with measured pressure and temperature well conditions.

Date	Ktzi 200		Ktzi 201		Ktzi 202	
	Pressure (bara)	Temperature (°C)	Pressure (bara)	Temperature (°C)	Pressure (bara)	Temperature (°C)
21.07.2008	66.53	33.35				
10./12.12.2008	72.18	32.78			70.44	32.99
25./26.03.2009	76.46	32.92			73.90	32.69
24./25./26.06.2009	76.91	33.28	77.92	38.02	75.91	33.18
22./23.03.2010	76.39	34.01	76.89	38.74	75.79	33.49
02./03.03.2011	73.14	30.98	73.39	35.51	72.98	31.07
12./13.10.2011	70.78	29.47			71.88	30.10

Note: Data for Ktzi 200 refer to 620 m, for Ktzi 201–630 m and for Ktzi 202–620 m depth.

this wire-line pressure gauge is installed in observation well Ktzi 200 at a depth of 620 m.

3.4. Additional pressure–temperature monitoring

Additional pressure and temperature data come from wellbore wire-line logging campaigns. Table 1 summarizes the details of all logging campaigns performed between June 2008 and September 2012. These pressure and temperature data are not part of the SCADA system but are used to validate the continuously recorded pressure and temperature data of the operational monitoring. Detailed descriptions of the pressure and temperature wire-line logging data will be presented in a separate publication. Here we only refer to the data measured at depths of 620 m in Ktzi 200 (i.e. depth of installed wire-line Leutert pressure sensor), 630 m in Ktzi 201 (i.e. top of main sandstone layer or uppermost injection level), and 620 m in Ktzi 202 (i.e. depth of installed wire-line Leutert pressure sensor). All measured pressure data from wellbore wire-line logging campaigns are recorded as absolute pressure values.

Above-zone pressure–temperature monitoring in well P300 is done for BHP and BHT with a combined P–T gauge type Leutert "PK 201" installed at 417.8 m depth and for WHP with a P gauge type Leutert "PK 221"; for detailed P monitoring an additional Leutert P gauge is installed at 20.55 m depth. A detailed presentation and evaluation of the P300 data will be presented elsewhere; here we only refer to the measured BHP data. These are recorded relative to atmospheric pressure and are re-calculated in this contribution to absolute values [bara] by addition of an assumed constant atmospheric pressure of 1 bar.

4. Results

4.1. Injection regime and overall pressure evolution

Before the start of continuous injection of CO_2 on June 30th, 2008, several mechanical tests of the injection facility were run during the commissioning phase. The commissioning phase also included first injections of small amounts of CO_2 to test the shut-in and re-start procedures as well as admission of N_2 during shut-in phases. The test run with continuous injection of CO_2 then started on June 30th, 2008, and lasted until September 24th, 2008, when injection entered normal operation. During test run, injection is characterized by varying injection rates and several shut-in phases of different durations due to seismic campaigns or technical reasons (Figs. 2 and 3A). With onset of normal operation the injection becomes steadier. The mean monthly injection rate from start of normal operation until March 2010 was 1690 t CO_2/month and lowered to 1124 t CO_2/month from March 2010 to May 2012. From December 1st, 2009 to January 11th, 2010, a modified isochronal test and from August 23rd to October 17th, 2010, a four-cycle injection and pressure response test were performed with accordingly adjusted injection rates (see below). By May 2012 the injection was stopped due to the drilling activities for the fourth observation well Ktzi 203.

During test run, the pressure evolution as recorded for Ktzi 201 is highly unsteady due to the varying injection rates and several shut-in phases (Figs. 2 and 3A). With start of CO_2 injection on June 30th, 2008, initial reservoir pressure of about 62 barsa increases to 73 barsa already after 5 days of injection. However, during subsequent shut-in phases pressure drops are likewise fast. With onset of normal operation and continuous injection, extrapolated BHP at 630 m of Ktzi 201 stabilizes between 73 and 79 barsa corresponding to an increase in reservoir pressure by 11–17 bars due to injection. Stabilization of reservoir pressure with onset of normal operation is also mirrored by results from wire-line pressure measurements (Fig. 2 and Table 1). Sudden and notable increases in WHP of Ktzi 201 by about 7 bars in July, August and December 2008 and June and July 2009 (see purple bars in Fig. 2) are due to N_2 admission of Ktzi 201 during shut-in phases. No N_2 was imposed on the injection well during later shut-in phases and these shut-in phases are characterized by sudden drops in WHP of Ktzi 201 (Fig. 2). Lowering the mean monthly injection rate by March 2010 resulted in a continuous smooth decrease of the reservoir pressure as recorded by BHP in Ktzi 201 by about 2 bars (Fig. 2). With stop of the injection in May 2012 due to the drilling work for the fourth observation well Ktzi 203 reservoir pressure dropped to about 69 barsa in observation well Ktzi 200 and to about 71 barsa in injection well Ktzi 201.

4.2. Above-zone pressure monitoring

The BHP of well P300 has been recorded since September 2011; short-term data gaps exist for February, June and August 2012 (Fig. 3B). Throughout the recording period BHP of P300 is almost constant at 42.05–42.12 barsa showing only very minor pressure fluctuations. None of the pressure fluctuations or pressure signals from the reservoir as determined for BHP of Ktzi 201 can be traced in the BHP of P300 (Fig. 3B). Especially the notable decrease of reservoir pressure by about 3 bars due to the stop of injection in May 2012 is not detectable in BHP of P300.

4.3. Wellhead versus bottom-hole pressure

The installation of the additional wire-line pressure gauge in observation wells Ktzi 202 and Ktzi 200 at a depth of 620 m allows detailed assessment of reservoir pressure evolution and comparison between recorded WHPs and BHPs (Fig. 4). The evolution of BHPs in Ktzi 201 and Ktzi 202 from March 2010 to October 2011 (Fig. 4A upper part) and in Ktzi 201 and Ktzi 200 since October 2011 (Fig. 4A lower part) parallel each other and are directly related to injection rate. However, any short-term fluctuations seen in BHP of Ktzi 201 are notably attenuated in Ktzi 202 and Ktzi 200, respectively, or even absent. On overall, BHPs in Ktzi 202 and Ktzi 200 are about 1–2 bars lower than in Ktzi 201, potentially reflecting combined effects of pressure relaxation with distance to the injection

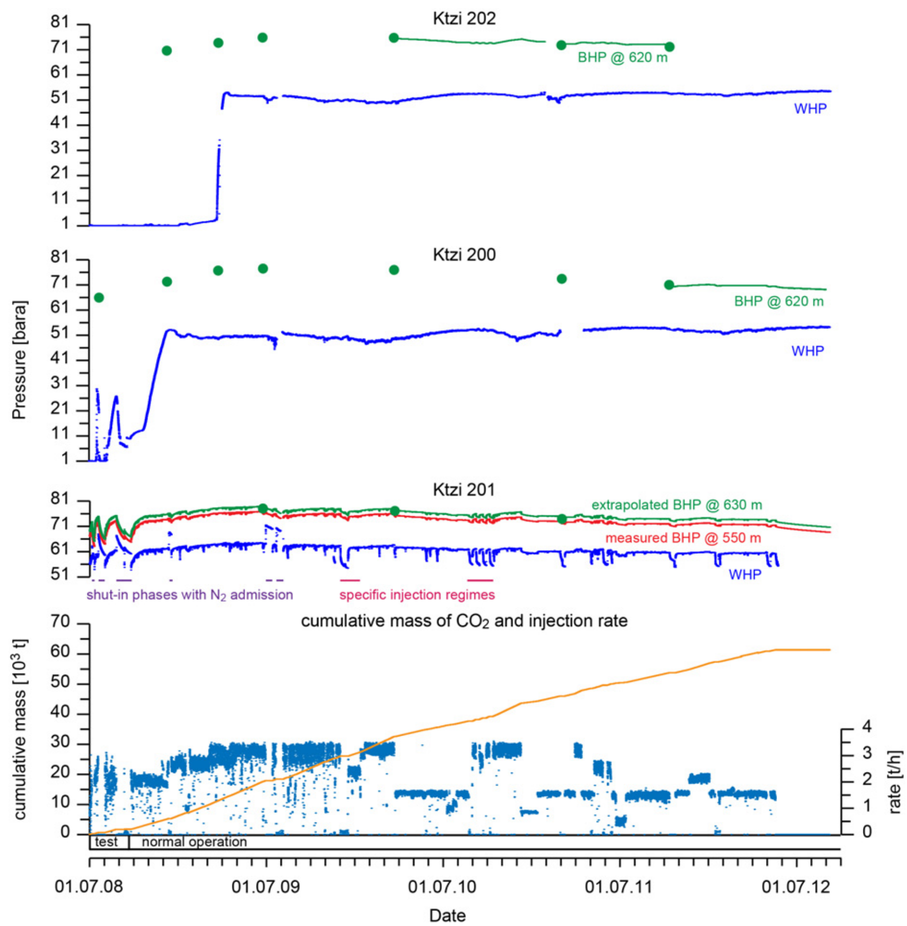

Fig. 2. Injection rate, cumulative mass of injected CO_2, and measured and extrapolated wellhead [WHP] and bottom hole [BHP] pressures in injection well Ktzi 201 and observation wells Ktzi 200 and 202 at the Ketzin pilot site from July 2008 to September 2012. Dots refer to pressure measurements during logging campaigns (see Table 1). Test run lasted from June 30th to September 24th, 2008, when normal operation started. Except for few short shut-in phases for monitoring campaigns or due to research demands, CO_2 was continuously injected at rates typically between 1 and 3 t/h. The notable increase in WHP at Ktzi 201 during some of the shut-in phases is due to admission of the well with nitrogen (purple bars). The extrapolated BHP at 630 m in Ktzi 201 has been calculated by constant addition of 2 bars to the measured BHP at 550 m (see text for details). BHP in Ktzi 200 and 202 have been measured by a wire-line pressure sensor at 620 m depth. [red bars denote timing and duration of specific injection regimes "modified isochronal test" and "cyclic pressure response test"].

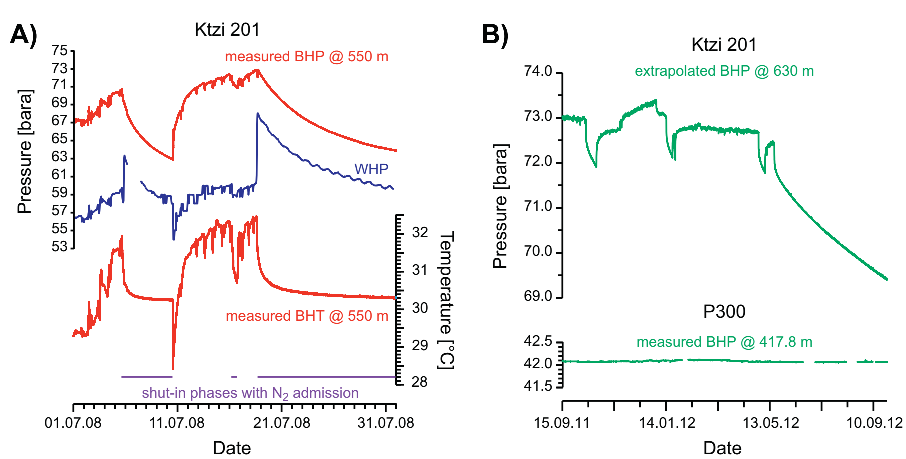

Fig. 3. (A) Detailed presentation of wellhead pressure and bottom hole pressure and temperature evolution at the end of the injection tubing in Ktzi 201 as determined by the Weatherford P–T gauge at 550 m depth from July 1st to August 1st, 2011. Downhole P–T data were taken every 5 seconds. Data show the highly unsteady and flickering P–T behaviour during these first weeks of injection. At the on-set of shut-in phases, pressure and temperature show a notable, instantaneous decrease. (B) Comparison between extrapolated BHP of Ktzi 201 reflecting reservoir's response to the injection operation and recorded BHP of well P300 for above-zone monitoring from September 15th, 2011 to September 25th, 2012. The BHP of P300 is completely unaffected by the injection operation and proves lack of hydraulic connection between reservoir and first above-zone aquifer.

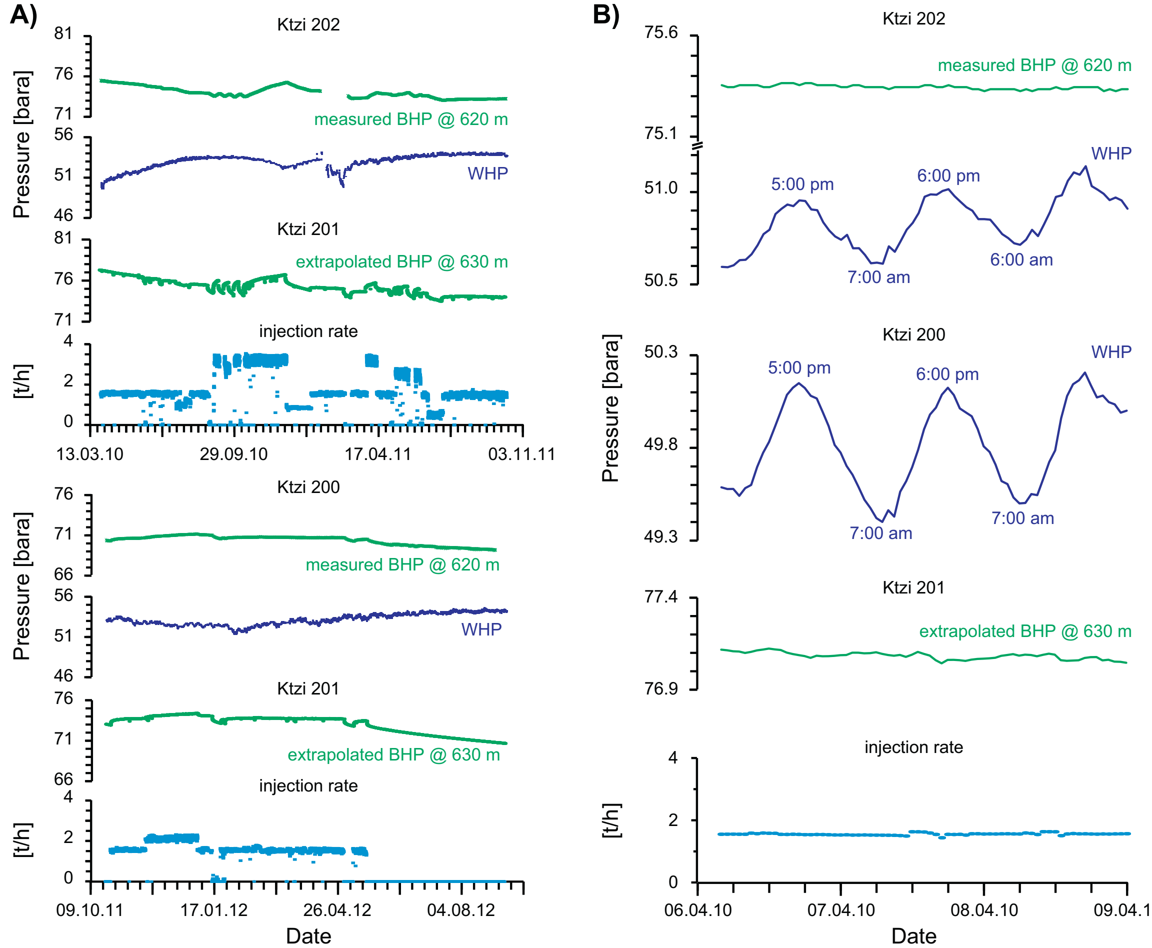

Fig. 4. (A) Enlarged presentation of injection conditions and pressure monitoring from March 2010 to October 2011 (upper part) and since October 2011 (lower part), those time intervals for which also the BHPs of Ktzi 202 and Ktzi 200, respectively, have been measured with the additionally installed pressure sensor at 620 m depth. BHPs of the observation wells parallel BHP of Ktzi 201 although any change in BHP of Ktzi 201 is notably attenuated in BHPs of the injection wells. However, the wellhead pressures of observation wells Ktzi 200 and 202 correlate inversely with the corresponding BHPs (see text for details). (B) Detailed presentation of regular diurnal variations in WHP at Ktzi 200 and Ktzi 202. Maximum and minimum pressures are consistently recorded between 5:00–6:00 pm and 6:00–7:00 am, respectively, reflecting day-time heating and night-time cooling of the wellheads. Diurnal pressure variations as recorded in WHP at Ktzi 202 are completely attenuated by the well and are absent in recorded BHP.

well and the about 10 m shallower measurement point of the wireline pressure sensor. Counterintuitive, WHPs recorded at Ktzi 200 and Ktzi 202 evolve in opposite direction than the respective BHPs and are inversely related to injection rate; the absolute changes in WHP roughly double those recorded for BHPs (Fig. 4). Recorded WHPs of Ktzi 200 and 202 also display regular short-term variations with magnitudes between about 0.4 and 0.7 bars (Fig. 4B). These variations occur on a diurnal basis with maximum pressures between 5:00 and 6:00 pm and minimum pressures between 6:00 and 7:00 am and are absent from the BHP data.

4.4. Pressure evolution during specific injection regimes

From December 1st, 2009, to January 11th, 2010, a modified isochronal test and from August 23rd to October 17th, 2010, a four-cycle injection and pressure response test was performed (Fig. 5). Prior to the isochronal test, injection was stopped from December 1st to 16th, 2009 (Fig. 5A). The isochronal test itself then consisted of four 8 h cycles each of which consisting of 4 h of injection at rates of 900 kg/h, 1600 kg/h, 2400 kg/h and 3200 kg/h, respectively, followed by 4 h of shut-in. After cycle 4, injection rate was held constant at about 2800 kg/h until January 11th, 2010. The recorded pressure data were then fitted with a radial symmetric standard model assuming a vertical well, a homogeneous reservoir and infinite model resulting in an average permeability of 29.6 mD; the derived Pi is 73.8 barsa. The pressure response test to evaluate the reservoir behaviour and the dynamic coupling between BHPs in Ktzi 201 and Ktzi 202 started on August 23rd, 2010, and consisted of four 14-days cycles with one week of shut-in followed by one week with maximum injection rate (Fig. 5B). The principal pressure evolution of BHPs in both wells is comparable. However, the pressure impulses imposed in Ktzi 201 are attenuated and smeared out in BHP of Ktzi 202 and their arrivals exhibit about one day delay at Ktzi 202 as compared to Ktzi 201. The pressure impulses as recorded by BHP in Ktzi 202 are completely attenuated within the well and are not visible in WHP of Ktzi 202. Here, only the diurnal variations are measurable (see Fig. 4B).

4.5. Pressure effects during CO_2 arrival at observation wells

Arrival of CO_2 in both observation wells has been detected on July 15th, 2008, in Ktzi 200 and on March 21st, 2009, in Ktzi 202 with a gas membrane sensor installed at 150 m depth in the wells (Zimmer et al., 2011). Arrival times correspond to injected amounts of CO_2 of 530 t for Ktzi 200 and 11,200 t for Ktzi 202 as calculated based on the flow-metre data. First slight pressure increase in WHP of Ktzi 200 due to arrival of CO_2 started on July 14th, 2008, and predates detection of free CO_2 by the gas membrane sensor by

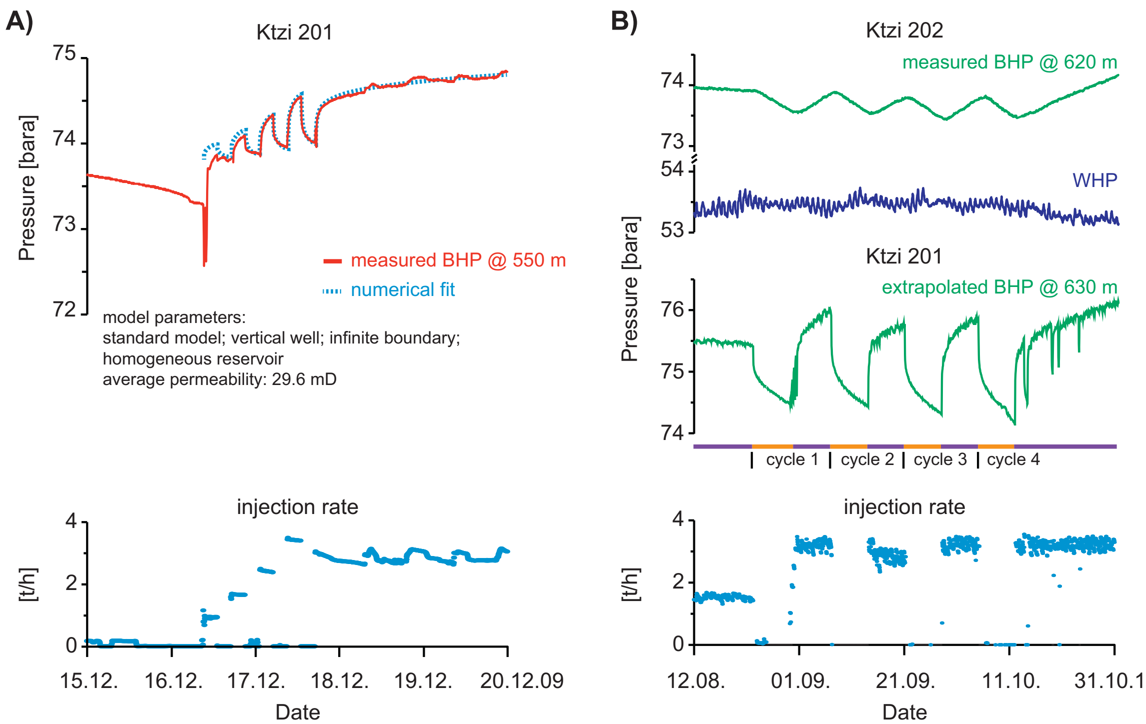

Fig. 5. (A) Pressure recording of BHP at 550 m depth in Ktzi 201 during modified isochronal test. Blue dotted line represents results from numerical modelling of the recorded pressure data. Except for the first cycle, measured pressure data are fairly well reproduced by the fit. (B) Pressure recording during the four-cycle injection and pressure response test. Differences between minimum and maximum pressures recorded within the different cycles is about 1.5 bar for BHP at Ktzi 201 but only 0.5 bar for BHP at Ktzi 202. Besides this attenuation of the pressure impulse, arrival of minimum and maximum pressures exhibit about one day delay at Ktzi 202 as compared to Ktzi 201. The regular short-term pressure fluctuations recorded by WHPs at Ktzi 200 and Ktzi 202 reflect diurnal variations (see Fig. 4).

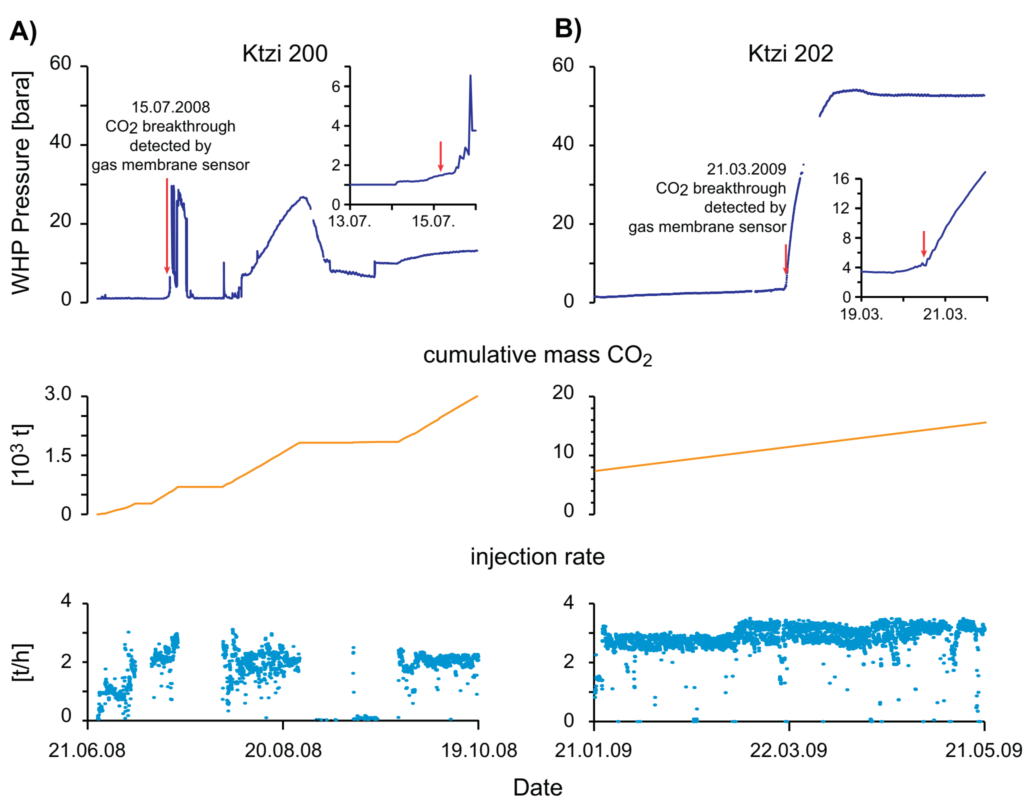

Fig. 6. Wellhead pressure recordings during arrival of CO_2 in observation wells (A) Ktzi 200 and (B) Ktzi 202. Arrival of CO_2 in both observation wells has been detected with a gas membrane sensor installed at 150 m depth in the wells.

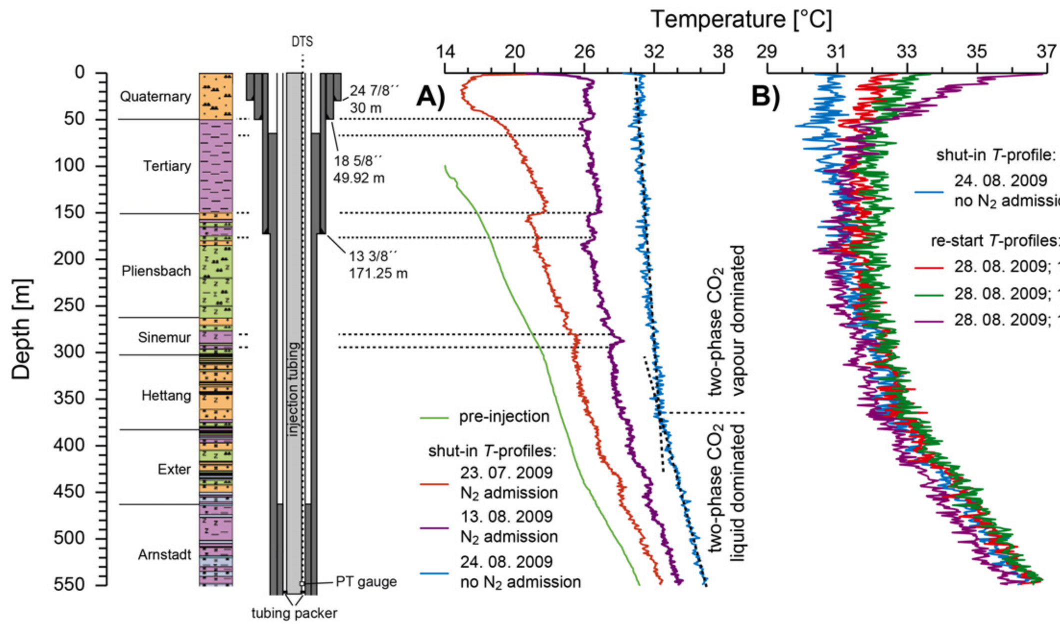

Fig. 7. Typical temperature profiles along the injection tubing in Ktzi 201 for different shut-in (A) and re-start (B) phases as measured with the Weatherford DTS system. On the left hand side, a schematic lithological profile of the Ktzi 201 as well as the technical installation of the injection well Ktzi 201 is shown. During shut-in phases with N_2 admission temperature decreases and temperature profiles tend to evolve towards the initial geotherm. During shut-in phases without N_2 admission internally controlled temperature profiles evolve due to two-phase fluid conditions in the well with heat-pipe effects (see text).

about one day (Fig. 6A). This first pressure increase coincides with the observed increase of gas concentrations for CH_4, He and N_2 as detected by the gas membrane sensor (Zimmer et al., 2011). About 12 h after the detection of free CO_2 by the gas membrane sensor, the rate of increase in WHP of Ktzi 200 notably increases. Owing to several subsequent shut-in phases of different durations, the final increase of WHP of Ktzi 200 only started on October 10th, 2008, until WHP stabilizes between 48.5 and 53.5 barsa by December 2008 (Fig. 2). In Ktzi 202 first flickering of WHP has been detected on December 30th, 2008, followed by a period of very minor fluctuations in pressure. A first phase of slight, linear build-up of WHP can be identified from January 25th to March 20th, 2009 (Fig. 6B). With breakthrough of free CO_2, a second more pronounced, near-linear build-up of WHP can be observed from March 20th to April 4th, 2009 (Fig. 6B). The data clearly show, that pressure build-up after arrival of free CO_2 is about five times faster in Ktzi 202 than in Ktzi 200, possibly indicating a better communication between Ktzi 202 and the reservoir and consequently higher CO_2 fluxes into the well. However, after complete filling of the wells with CO_2 a stable pressure regime establishes in both wells with WHPs of 47–54 barsa in Ktzi 200 and 49–55 barsa in Ktzi 202 (Fig. 2).

4.6. Temperature monitoring along injection tubing

The DTS monitoring along the injection tubing started already prior to CO_2 injection and since then runs without any fatal errors. The recorded data cover the pre-injection well-testing phase, the initial injection phase as well as all shut-in and re-start phases during normal injection operation. The DTS monitoring along the injection tubing focuses on (i) the temperature evolution within the injection tubing of Ktzi 201 during shut-in phases to guarantee stable thermodynamic conditions and to avoid re-flushing of the well by formation brine, (ii) re-start phases to guarantee a smooth injection operation in one-phase state with minor oscillations (to avoid retrograde condensation which affects the facility performance), and (iii) the correlation of temperature data with variations in CO_2 injection operational parameters to optimize time efficiency and energy consumption of the pre-heating process. Typical DTS profiles during shut-in and re-start phases are shown in Fig. 7. During shut-in phases the DTS measurements allow a very detailed recording of the cooling inside the injection tubing with a high timely ($\Delta t = 3$ min) and spatial resolution ($\Delta l = 1$ m). For shut-in phases with N_2 admission, the recorded cooling temperature profiles evolve towards the initial pre-injection geotherm. However, the nature of the well completion and different adjacent lithologies result in different cooling rates at different depth intervals and give raise to unsteady temperature profiles (Fig. 7A; see below). In case of shut-in phases without N_2 admission, temperature profiles do not evolve towards the initial pre-injection geotherm but mirror the build-up of CO_2 two-phase fluid conditions in the well as they have also been observed in the two observation wells (Henninges et al., 2011; Liebscher et al., 2012; and see below). Cooling due to shut-in drives the CO_2 column in the well into the two-phase vapour–liquid region with vapour dominated conditions in the upper part and liquid dominated conditions in the lower part of the well and a corresponding build-up of a heat-pipe within the well. This heat-pipe then gives raise to internally controlled temperature profiles. During re-start phases the DTS profiles show the time- and depth-dependent re-heating of the well in high timely resolution (Fig. 7B). These data helped to optimize the operational parameters during the re-start phases. In general, during re-start the operator first heats up the CO_2 above the steady-state injection temperature to push a stream of hot CO_2 into the wellbore and heat up the injection string. After having restored the initial operational injection well temperature profile, the operator reduces the heater outlet temperature to the steady-state injection temperature. Due to the DTS data, this re-start operation became optimized over time and could be run with lower and more stable heater outlet temperatures and faster setting of the sought steady-state operation.

5. Discussion

5.1. Injection regime and overall operational pressure–temperature monitoring

The extensive operational pressure–temperature monitoring successfully ensured and proved a safe, smooth and reliable injection operation. The combination of surface and downhole measurements provided all data required for the operational and reservoir engineering. Beside the purely operational benefits, the recorded pressure–temperature data form a comprehensive, detailed data base for the scientific evaluation of CO_2 storage in saline aquifers. The recorded downhole pressure data proved good hydraulic coupling within the reservoir. Reservoir pressure correlates with the injection rate and show almost instantaneous response to any change in the injection operation. The mean monthly injection rate of 1690 t CO_2/month until March 2010 corresponds to a quasi-stationary bottom hole pressure of 77–78 barsa whereas the lower mean monthly injection rate of 1124 t CO_2/month from March 2010 until May 2012 resulted in a lower quasi-stationary bottom hole pressure of 73–74 barsa.

The BHP of well P300 is completely unaffected by the pressure behaviour in the reservoir and the injection operation. The observed fluctuations in BHP of P300 are about two orders of magnitude smaller than those observed for the reservoir and fully un-correlated to the injection operation. This proves the lack of any hydraulic connection between reservoir and first overlying aquifer and clearly indicates an intact cap rock without any leakage of CO_2 or displaced formation brine into overlying strata.

5.2. Injection tubing monitoring

The combination of the point P–T sensor at the lower end of the injection tubing with the installed DTS system along the injection tubing proved to be a very powerful tool for monitoring and optimizing the injection process. Based on these data, operational pre-conditioning of the CO_2 could be adjusted and optimized. Stable thermodynamic fluid conditions in the well during shut-in phases could be proved and N_2 admission during later shut-ins could be passed on. Beside these operational benefits of the injection tubing monitoring, especially the DTS data provide additional important information. As exemplified by the temperature profiles from July 28th to August 13th, 2009, the recorded cooling temperature profiles during shut-in phases are very sensitive to different lateral heat conductivities caused by different well completions and different neighbouring lithologies (Fig. 7A). Most prominent is the base of the Tertiary at ~150 m, which is characterized by slower cooling and higher well temperature in the Tertiary and faster cooling and lower temperature below. This drop in cooling temperature at the base of the Tertiary shows up in almost all recorded cooling temperature profiles and suggests lower heat conductivity of the Tertiary deposits. Another depth interval with slower cooling and lower heat conductivity appears in the Sinemurian deposits at depth between 280 and 295 m. The effect of well completion on cooling temperature is best seen in the temperature profile from August 13th at a depth of 171 m, i.e. the lower end of the 13 3/8 in. cementation. Here, the decrease in cement thickness results in faster cooling in the deeper parts. A detailed interpretation and discussion of these aspects of the DTS monitoring is beyond the scope of this paper and will be presented elsewhere, but the data clearly show that the DTS monitoring yields indirect information about the adjacent lithologies as well as the state of the well installation. Detailed inspection of recorded DTS data and their changes with time may thus provide information on cement degradation, well corrosion and wellbore leakage and contributes to well integrity and risk mitigation for the long term operation of the injection process.

5.3. Pressure evolution during specific injection regimes

The induced pressure impulses due to the varying injection rates during the modified isochronal test are notably smaller than those typically observed during "classical" isochronal tests in natural gas storage operations. This is due to the limitation in possible injection rates set by the injection facility. The technically achievable injection rates are too small to generate significant pressure signals in the reservoir. Also, contrary to "classical" isochronal tests that are typically done under gas withdrawal conditions the modified isochronal test was run under injection conditions. A "classical" interpretation of the data in terms of reservoir and/or injection well performance is therefore not possible and the derived data do not allow forecast maximum injection pressure or reservoir behaviour. The estimated reservoir permeability derived from the modified isochronal test of 29.6 mD is nevertheless of the same order as previous estimates of reservoir permeability at the Ketzin site based on hydraulic testing, which yielded permeabilities mainly between 50 and 100 mD (Wiese et al., 2010; Zettlitzer et al., 2010).

5.4. WHP versus BHP pressure monitoring in observation wells

The data clearly show that the WHPs of the observation wells are at least partly decoupled from their BHPs: (i) WHP and BHP display an overall inverse albeit non-predictable correlation (Figs. 2 and 4A), (ii) diurnal pressure variations recorded by WHP are absent from BHP (Fig. 4B), and (iii) pressure signals recorded at reservoir depth are notably attenuated and may be even absent from WHP (Fig. 5B). With this decoupling between WHP and BHP, the observation wells at the Ketzin pilot site differ from observation wells at natural gas storage sites where WHP and BHP show positive correlation and linkage. "Classical" pressure monitoring by extrapolating measured WHP into BHP values, as typically done in natural gas storage operations, is therefore not applicable. The reason for the observed decoupling between WHP and BHP are the two-phase fluid conditions within the observation wells (Henninges et al., 2011). Due to these two-phase fluid conditions, changes in either WHP or BHP can be accounted for within the wells by varying the relative amounts of liquid and vapour CO_2 and thus by varying the depth of the liquid CO_2 level in the wells. As is evident from phase relations, a decrease in BHP triggers evaporation and consequently increases the amount of vapour CO_2. Owing to the resulting lower overall density and therefore weight of the CO_2 column within the well, WHP increases. Vice versa, an increase in BHP triggers condensation, increases overall density and weight of the CO_2 column and results in a decrease of WHP. Besides these pressure effects, the two-phase fluid conditions also result in notable deviation of the wells' temperature profiles from the normal geotherm with higher temperatures in the upper, condensing well parts and lower temperatures in the lower, evaporating well parts (Henninges et al., 2011). Only in single-phase fluid parts of the wells, the temperature profiles adjust to the normal geotherm (Henninges et al., 2011). Without knowledge of the position of the liquid CO_2 level and the temperature distribution within the well, BHP cannot be calculated based on WHP measurements. However, increasing BHP increases the overall density of the fluid column in the well and ultimately drives the well into single-phase liquid CO_2 conditions. The observed two-phase fluid conditions therefore only establish in observation wells of reservoirs below a certain reservoir pressure or above a certain reservoir depth, respectively. To roughly estimate the reservoir pressure–depth range for which two-phase fluid conditions can be expected in observation wells, we calculate the CO_2 P–T profiles for hypothetical observation wells at the selected storage sites In Salah, Sleipner, Weyburn and Snovhit based on their respective initial reservoir pressure–depth conditions (Fig. 8). In Salah is taken as representative for a P–T gradient of ~2.3 bars/°C as defined by the storage sites Ketzin, Otway, In Salah and Gorgon whereas Sleipner, Weyburn and Snovhit are taken as representatives for a higher P–T gradient of ~3.2 bar/°C as defined by the storage sites Sleipner, Nagaoka, Frio, Weyburn and Snovhit (Fig. 8; for reservoir data see Table 2). Temperature–depth profiles are

Table 2
Pressure–temperature–depth conditions of selected CO_2 storage sites displayed in Fig. 8 and used for the calculation of CO_2 pressure–temperature profiles in hypothetical observation wells.

Site	Nos. in Fig. 8	Temperature (°C)	Pressure (bar)	Depth (m)	Source
Otway	1	83	178	2000	Jenkins et al. (2012)
In Salah	2	90	179	1850	Michael et al. (2010)
Ketzin	3	33	62	630	Own data
Gorgon	4	100	220	2300	Michael et al. (2010)
Frio	5	56	152	1546	Michael et al. (2010)
Sleipner	6	37	103	1000	Michael et al. (2010)
Nagaoka	7	46	119	1100	Michael et al. (2010)
Snovhit	8	98	290	2618	Courtesy Statoil
Weyburn	9	54	155	1450	Courtesy Cenovus

calculated by assuming a constant surface temperature of 8 °C and a linear temperature increase with depth up to the respective reservoir conditions. P–T profiles of the hypothetical CO_2 columns are then calculated in 0.1 m steps by starting at the respective P–T reservoir conditions. The temperature for each successive step is taken from the assumed linear temperature–depth profile and the pressure is calculated by subtracting the pressure caused by the weight of the 0.1 m CO_2 column using the EOS of Span and Wagner (1996) according to

$$P_{z_2} = P_{z_1} - \rho_{z_1} \times g \times (|z_1 - z_2|) \quad \text{with } |z_1 - z_2| = 0.1\ \text{m}.$$

The calculations clearly show that for Sleipner- or Nagaoka-like reservoir conditions of ~100–120 bars/1000–1100 m depth, observation wells will run into two-phase fluid conditions. Observation wells at slightly higher pressure and deeper seated reservoirs like Frio, Weyburn, Otway or InSalah (reservoir conditions ~ 150–180 bars/1500–2000 m depth) are single-phase over their entire length. However, their near-wellhead pressure–temperature conditions are very close to the liquid–vapour equilibrium of CO_2. Thus, even slight heating during, e.g., daytime may induce evaporation and drive the well into two-phase fluid conditions. Only at rather high pressure or deep seated reservoirs like Gorgon or Snovhit well and near-wellhead pressure conditions are generally above the critical pressure of CO_2 and these wells are single-phase throughout. Depending on the actual P–T conditions of a reservoir, two-phase fluid conditions in observation wells are most probable down to reservoir depths of ~1500 m, potentially occur at reservoir depths between 1500 and 2000 m and are probably absent from reservoir depths below 2000 m. In any case, the calculations show that observation wells inevitably establish inverted CO_2 density profiles in their single-phase fluid parts. For deep seated high-pressure reservoirs, such inverted density profiles will establish over the entire length of the observation wells. The data from the Ketzin pilot site show

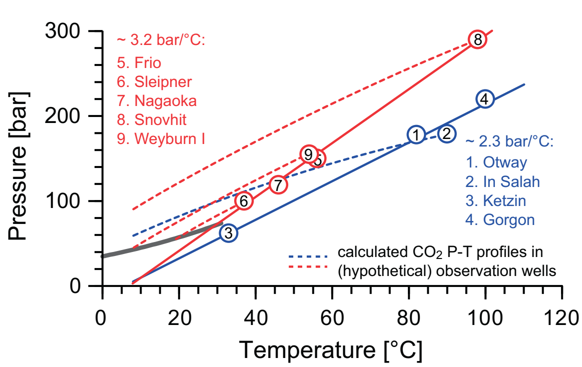

Fig. 8. Compilation of initial reservoir P–T conditions of different CO_2 storage sites and calculated exemplary CO_2 P–T paths in hypothetical observation wells (see text for details). The initial reservoir P–T conditions define two different initial pressure–temperature gradients of ~2.3 and 3.2 bar/°C, respectively.

that such inverted density profiles are fluid dynamically stable as long as the wells are confined. However, in case of sudden pressure drops, e.g. due to wellhead failure, the fluid column will become dynamically unstable and collapse, resulting in complex thermodynamic conditions and convections in the well.

6. Conclusions

The extensive operational pressure–temperature monitoring at the Ketzin pilot site successfully ensured and proved a safe, smooth and reliable injection operation. Above-zone pressure monitoring indicates intact cap rock and lack of any leakage of either CO_2 or displaced formation brine through the cap rock into overlying strata. It turned out that an important part of the operational P–T data comes from downhole measurements. At least at the Ketzin pilot site, pure wellhead P–T monitoring would not have been able to provide the complete picture of CO_2 injection. Based on the Ketzin experiences, additional downhole pressure monitoring is therefore recommended at least for shallow CO_2 injection sites at depths < 1500 m. However, once the site specific correlation between downhole formation pressure and wellhead pressure has been established, continuous wellhead pressure monitoring with sporadic wire-line downhole measurements might be sufficient. The data from the Ketzin pilot site also show that each storage site will call for a site-specific monitoring program individually adjusted to the site's specific geological and technological requirements. From the operational point of view, DTS safety monitoring along (i.e. outside) the injection tubing could be recommended for CO_2 injection in general. The real-time temperature logs in combination with downhole P–T measurements are very useful to support typical operational processes as conditioning and improvement of injection rate and injection temperature. On the long-term perspective, this monitoring technique may also support the control of CO_2 injection tubing integrity, which is a prerequisite for any secure long-lasting CO_2 injection and storage.

Acknowledgements

The authors gratefully acknowledge funding for the Ketzin pilot site by the German Ministry of Education and Science, the German Ministry of Economy and Technology, the 6th and 7th Framework Programme of the European Union (projects CO_2SINK, CO_2ReMoVe), as well as the different Industry partners. On-going research at Ketzin is funded within the GEOTECHNOLOGIEN program of the German Ministry of Education and Science with additional support by VNG Gasspeicher GmbH, RWE Power AG, Vattenfall Europe Technology Research GmbH, Statoil Petroleum AS, AG of Dillinger Hüttenwerke, Saarstahl AG as well as OMV Exploration and Production GmbH. This is GEOTECHNOLOGIEN publication GEOTECH-2055. The paper benefited from thorough reviews by two anonymous reviewers and the editorial handling by John J. Gale.

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