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The University of Queensland Surat Deep Aquifer Appraisal Project (UQ-SDAAP)

Scoping study for material carbon abatement via carbon capture and storage

China Engagement: Special Edition

30 April 2019

Research team

Prof Andrew Garnett, The University of Queensland

Prof Peta Ashworth, The University of Queensland

Prof Jim Underschultz, The University of Queensland

Mr Vahab Honari, The University of Queensland

Prof Ray Johnson, , The University of Queensland

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1. Executive summary

Fossil fuels are critical to economic and social development across the globe, particularly in the fast-developing Asia-Pacific region. Australia is a leading exporter of fossil fuels to primary markets in Asia that are increasingly moving to reduce greenhouse gas emissions.

The University of Queensland (UQ) undertakes scientific research to inform a more sustainable energy future, and has developed a number of research programs targeting Carbon Capture and Storage (CCS) in recent years.

The University of Queensland Surat Deep Aquifer Appraisal Project (UQ-SDAAP) was a three year, $5.5 million project funded by UQ, Coal21, and the Australian Government through its Carbon Capture and Storage Research Development and Demonstration (CCS RD&D) fund. The CCS RD&D funding program required that UQ create and engage in international collaborations. Both parts of the UQ-SDAAP project, described in more detail below, have a strong collaborative connection with China. The CCS RD&D program has no mechanism to support collaboration beyond its end date.

China both produces and imports a wide range of fuel types. The UQ-SDAAP project has connections with China through a range of research and industry organisations. These include the China University of Mining Technology Beijing (CUMT) that conducts research across the energy spectrum, and Shaanxi Yanchang Petroleum, a leading Chinese petroleum company focused on both upstream and downstream development of hydrocarbon resources of Shaanxi Province.

This Special Edition Report is a summary of a key collaboration with China.

The UQ-SDAAP research has two main parts:

1. A social science program that explored attitudes to CCS and trade-offs in terms of making future energy choices
2. Developing a low-cost, low-impact testing methodology of deep aquifer conditions to inform geotechnical and techno-economic studies on the suitability of CO_2 storage in specific deep underground geology

The research aimed to better inform public debate and policy makers on whether or not large-scale CCS could be a real option in Queensland and China, more specifically in the Surat Basin and Ordos Basin respectively.

The social science highlighted that attitudes to key energy sources (e.g. coal, gas or nuclear) differ significantly between the two countries as does support for Carbon Capture and Storage. Attitudes are somewhat historically, context or path dependent with local environmental issues dominating. Chinese community attitudes to coal were less positive than in Australia, but Chinese attitudes to CCS were more favourable. Across both countries, renewable energy technologies, including solar PV, solar thermal, wind, hydroelectricity and wave, were the technologies that gained the most support. Chinese respondents expressed more support for nuclear and biomass compared to Australian responses.

The geotechnical research focused on the acquisition of dynamic flow test data from a Chinese oil and gas asset provided by Shaanxi Yanchang Petroleum in the Ordos Basin. This included access to certain wells from the Wuqi Reservoir in the Yanchang Field area, Shaanxi province of China. The reservoir is characterised by very low permeability formations. It is somewhat analogous to the Australian Northern Dennison Trough reservoirs investigated during the ZeroGen project (Garnett, Greig & Oettinger 2012) and to older reservoirs elsewhere in Australia. The result is very low injection rates, high rates of pressure build-up or injection fall-off with time. Consequently, large numbers of wells are needed (and need to be continuously drilled or converted from producers to injectors) to maintain a plateau injection rate (ibid pp 343-345). In ZeroGen a rate of 2 million tonnes p.a. could not have been sustained for more than 12 years, even with 252 wells. In an Enhanced Oil Recovery (EOR) scheme there is the opportunity for pressure relief via oil production. Nevertheless, a rate of 0.4 million tonnes p.a. for 10 years may require more than 188 wells.

This report forms the initial investigation and modelling of the Wuqi Reservoir in the Ordos Basin and the field trial test design. The modelling includes a history match to existing production data and is the basis of the well test design. The nature of the geology in the Ordos Basin is such that very long test durations are required. Execution of the field trial has begun, with instrumentation of wells with the injection test sequence to be run in 2019. CUMT and Shaanxi Yanchang Petroleum will use the field test results to design field-wide implementation of CO_2-enhanced oil recovery and determine the associated carbon storage potential from such operations.

2. Social science program with China

There has been a number of collaborations through the social sciences program of the UQ-SDAAP project with Chinese colleagues. Working with Associate Professor Yan Sun from the Key Laboratory of Behavioural Science, Institute of Psychology, Chinese Academy of Science (CAS), a comparative survey was undertaken to investigate factors of acceptance of CCS and other energy technologies. The study compared responses of citizens across Australia and China. The survey asked key questions about preferences for a range of energy technologies, levels of factual and perceived knowledge, perceptions of risks and benefits (for both CCS and solar thermal technology), as well as environmental, economic and cultural orientations.

In the Chinese sample, a total of 1352 surveys were completed by Chinese urban residents in six regions. Of these, 1266 were included in the final dataset. While the Chinese sample aimed to be broadly representative geographically, there was a focus on examining the attitudes of the general public who were highly educated.

The Australian sample was comprised of 49% male and 51% female participants, while the Chinese data was comprised of 40% male and 60% female (refer Table 1). The Chinese data was particularly skewed towards the younger population, with the mean age being 30 years, compared to the Australian mean of 47 years. Almost 35% of the Chinese sample identified as full-time students, compared with only 5.75% of the Australian sample.

Table 1 Demographic profile of respondents in both countries.

		Australia	China
Gender	Male	48.7%	39.5%
	Female	51.3%	60.5%
Age (years)	Mean (SD)	47.5 (16.8)	30.2 (10.4)
Age Group	18-34	28.9%	68.4%
	35-54	35.4%	30.1%
	55+	35.7%	1.5%
Total participants		**2383**	**1266**

When participants were asked to rate their knowledge of the various energy technologies (1 = no knowledge to 7 = expert knowledge), in all instances the Chinese sample were more likely to rate their knowledge higher than the Australian sample. Consistent with earlier studies of the 12 energy sources and technologies, respondents in both countries indicated they had the least level of knowledge about CCS and biomass (AU: CCS, M = 2.5 & biomass, M = 1.9; CH: CCS, M = 3.0 & biomass, M = 3.0). Participants were then provided with simple definitions of each generation source and technology and asked to rate how strongly they agreed or disagreed with these different options for meeting their country's energy needs (1 = strongly disagree to 7 = strongly agree). Across both countries, renewable energy technologies, including solar PV, solar thermal, wind, hydroelectricity and wave, were the technologies that gained the most support (Table 2). In addition, Chinese respondents expressed more support for nuclear (M = 4.6) and biomass (M = 4.5) when compared to the Australian responses (nuclear M = 3.7; biomass M = 3.6). China is a big agricultural country with a wide range of biomass resources. The Chinese people are familiar with the use of biomass and have a positive attitude towards it. As well as producing clean electricity, biomass energy production alleviates two major environmental problems: the open-field incineration of straw; and accumulation of urban biowaste. In the process, biomass energy can increase farmers' income. However, the Chinese were less supportive of coal (CH: M = 3.2, AU: M = 3.7). Coal was by far the least preferred energy source in China, whereas in Australia coal seam gas was least preferred.

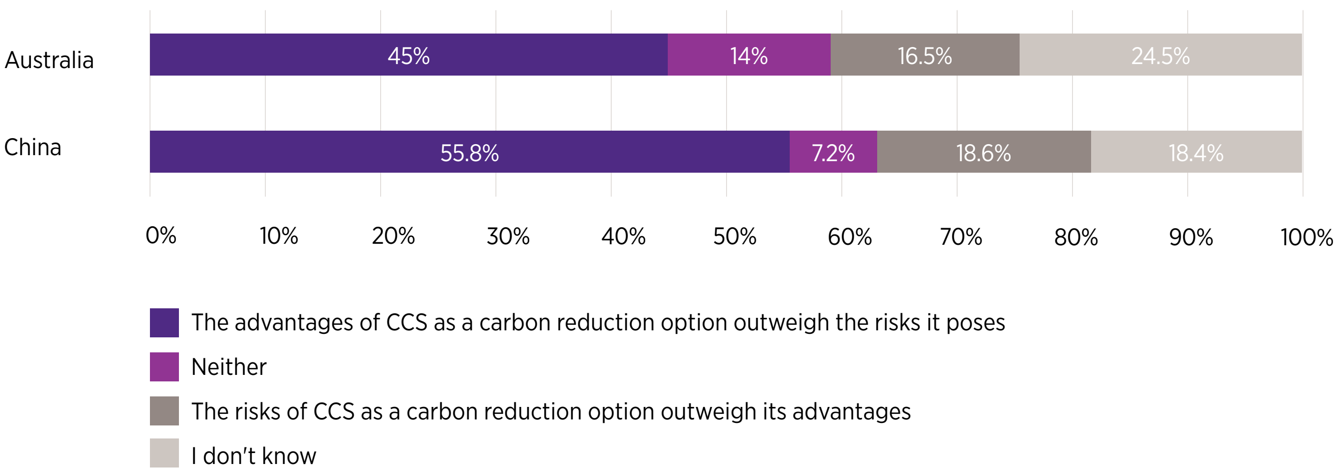
Table 2 Mean support for energy sources/technologies.

	Australia		China		
	Mean	(SD)	Mean	(SD)	Difference in means*
Solar (PV)	5.59	(1.36)	5.64	(1.51)	0.403
Solar (thermal)	5.41	(1.37)	5.55	(1.55)	0.008
Wind	5.39	(1.51)	5.59	(1.54)	0.000
Hydroelectric	5.33	(1.31)	5.32	(1.54)	0.828
Wave	5.11	(1.48)	5.22	(1.64)	0.043
Geothermal	4.32	(1.55)	4.85	(1.63)	0.000
Gas	4.15	(1.55)	4.63	(1.68)	0.000
CCS	3.81	(1.56)	4.29	(1.69)	0.000
Coal	3.75	(1.79)	3.23	(1.71)	0.000
Nuclear	3.67	(1.94)	4.63	(1.80)	0.000
Biomass	3.55	(1.56)	4.55	(1.90)	0.000
Coal Seam Gas	3.50	(1.71)	3.52	(1.65)	0.755

* Two-sample t-test with unequal variances, $p < 0.05$

A short video (Australia) and descriptive text (China) were shared that discussed the roles of CCS, renewable energy and energy efficiency, as options for mitigating CO_2. Participants were then asked to respond with whether they felt the advantages outweigh the risks as a carbon reduction option for both CCS and renewable energy. The two questions were randomised to prevent order bias. A higher percentage of the Chinese sample rated advantages over risks for CCS (Adv:56%, R:19%) when compared to the Australian sample (Adv:45%, R:16.5%). However, Australia had a larger portion that responded 'neither' (AU:14%, CH: 7%) or 'did not know' (AU: 24%, CH:18%) compared to the Chinese sample (see Figure 1). While these results demonstrate some tolerance for CCS, based on the larger percentage in Australia who are ambivalent or don't know, it is unlikely that people will embrace CCS in their backyard without some additional benefits that are, to date, yet to be defined.

Figure 1 Advantages versus risks of CCS.



For CCS, the highest perceived benefit for the Chinese sample was a decrease in the dependency of energy supply from other countries (M=4.95). This may be related to the successful application of CCS Enhanced Oil Recovery (CCS-EOR) technology in China. This initiative will not only reduce CO_2 emissions but also improve domestic oil production, which can reduce China's dependency on importing energy (CNPC 2018; Global CCS Institute 2018). For the Australian sample, the highest perceived benefit was to decrease CO_2 emissions (AU: M=4.83). This was also rated the second highest benefit for the Chinese sample (M=4.83). Both the Australian and Chinese samples perceived the most likely potential risk to be the transport of CO_2 in pipelines (AU: M=4.37; CH: M=4.48).

The results of the survey were shared in a presentation in China at the 9th Australia – China Joint Coordination Group on Clean Coal Technology Meeting and Research and Development Workshop on 14-15 June 2018 in Xi'an. It has also been presented at the 14th International Conference Greenhouse Gas Control Technologies (GHGT14: 22–26 October 2018) in Melbourne, and The University of Queensland Energy Express Seminar (15 February 2018).

There has also been ongoing collaboration with the UK-Guangdong urban innovation challenge relating to a Carbon Capture Utilisation and Storage (CCUS) project, to which Professor Ashworth is an adviser. This collaboration continues on an ad hoc basis, and information is openly shared between projects.

The project included a Chinese PhD student, Kai Jiang who has also received a China Scholarship Council (CSC) scholarship as part of this. The title of his thesis is "Understanding Carbon Capture Utilisation and Storage (CCUS) and the Impact of Social Media on Attitudes in China".

3. Technical collaboration with China

3.1 Yanchang test

Opportunities for high-rate CCS in China are generally characterised by "tight" or low permeability continental reservoirs. In these types of reservoirs, it has been previously demonstrated that maintaining high CO_2 injection rates is very challenging and likely to require numerous wells (James et al. 2010; Kumar et al. 2010; Garnett et al. 2012, chapters 3 & 8). It has also been shown that when storage capacity is based on static volume calculations, they do not assist in estimating rate-matched capacity (ibid p 353).

Shaanxi Yanchang Petroleum (Group) company has active oil field assets in the Shaanxi province of China that are the location for the field trial. UQ-SDAAP has run a series of models to history match the available production and injection data for the Wuqi Reservoir in the Yanchang Field area in the Shaanxi province. Based on this history match, a field trial was designed to examine the dynamic CO_2 storage capacity and enhanced oil recovery of the field. Of a number of test design options, the optimal design includes keeping the existing production and water injection as continuous as possible, with three wells selected for a water injection falloff interference test, followed by a CO_2 injection test.

The Yanchang Field trial has the objective of establishing the large-scale bulk reservoir characteristics and constraining the estimate of dynamic CO_2 storage capacity of the reservoir within a reasonable testing time (less than one year). The injection falloff interference test with two monitoring wells gives the largest pressure response at the observation wells in two different directions within the reservoir. It also allows for decisions to alter the length of each phase (depending on actual pressure response) while running the test, if a real-time readout can be achieved with installed gauges. This test is to be followed with a CO_2 injection test option. This testing sequence was optimised to have the highest chance of achieving the test objectives. Currently, the largest uncertainty is the bulk reservoir permeability. Depending on assumptions about high, medium and low permeability, the likely duration required to achieve adequate pressure response at both injection and observation wells for each phase of testing will vary.

The phases of testing are:

- "A" days initial shut-in relaxation at the 38-101 and 38-103 observation wells
- "B" days injection (INJ) of water at a rate of 7 m^3/day (44 STB/day)
- "C" days falloff period (FO)
- "D" CO_2 injection
- "E", CO_2 falloff, respectively

Based on the Eclipse model, the estimated duration of each test phase for a given permeability assumption is presented in Table 3. Note that all possibilities achieve test results in less than a year. Also note that as the test is being run and real-time Pressure/Temperature (P/T) readout is observed, we will be able to determine which permeability scenario is most likely, and then make decisions on test segment duration "on the fly", accordingly.

Table 3 Interference test sequence design matrix with two monitoring wells and follow-up CO_2 injection test phases (A-E) with low, medium and high bulk permeability assumptions. The matrix is populated with the forecast test phase duration required to achieve the test objectives. The last column (F) is a sum of the entire test sequence duration.

Average permeability (mD)	Initial shut-in time (day)	Injection period (day)	Falloff period (day)	CO_2 injection period (day)	CO_2 falloff period (day)	Total testing period (day)
2	60	120	30	60	90	360
5	15	60	30	60	90	255
10	15	30	30	60	90	225
	A	B	C	D	E	F

This report provides detail of the reservoir simulation and history matching, the test design options, and the operational plan for executing the test.

3.1.1 Data and methodology

The Wuqi field is a generally low permeability reservoir (less than 10 mD) with a history of oil production, secondary-recovery water floor, and a pilot trial of tertiary-recovery CO_2 injection. As such, the various present day wellhead and bottomhole pressures show a complex pattern resulting from historical oil field operations. Discussions between UQ-SDAAP, CUMT and Yanchang determined that the optimal location for a pilot test using Wuqi well infrastructure would be on the northern edge of the field, having the least pressure transient effects from historical and ongoing production and injection operations. The first part of the UQ-SDAAP analysis was dynamic simulation of the field to gain an understanding of how long this specific region of the Wuqi Reservoir needs to be shut in to adequately stabilise before any well testing operations can be conducted. The dynamic behaviour of the reservoir dictates the length of this time period. In addition, if the model is sufficiently accurate, we can estimate the duration of draw-down and build-up (or injection falloff) periods required for a successful well testing that can achieve an accurate estimate of dynamic CO_2 storage capacity.

The area selected for this study is shown in the Wuqi Reservoir map below (green circle in Figure 2), including 10 producing wells (38-100, 38-101, 38-102, 38-103, 38-104, 38-105, 38-107, 38-164, 38-167 and 38-247) and four injecting wells (38-106, 38-8, 38-163 and 38-248) in an area of ~4 km^2 on the northern edge of the larger oil field. The reservoir description is summarised in Figure 2 below. The model inputs are provided by Shaanxi Yanchang Petroleum. The oil viscosity and formation volume factor (Bo) used in this study are plotted in Figure 3. The wireline logs provided by Shaanxi Yanchang Petroleum mostly consist of GR-Sonic-Res. They were interpreted using the UQ-SDAAP documented methodology (Harfoush et al. 2019a) and the reservoir units were identified. The petrophysical properties were then upscaled to 10 layers and utilised to parameterise the reservoir static model. The histograms of populated properties in the model are shown in Figure 4. The Eclipse dynamic model was then initialised using the information listed in Table 4 below. Figure 5 shows oil-water relative permeability used in the Eclipse dynamic model.

Figure 2 Wuqi Reservoir map (from Shaanxi Yanchang Petroleum, 2017).

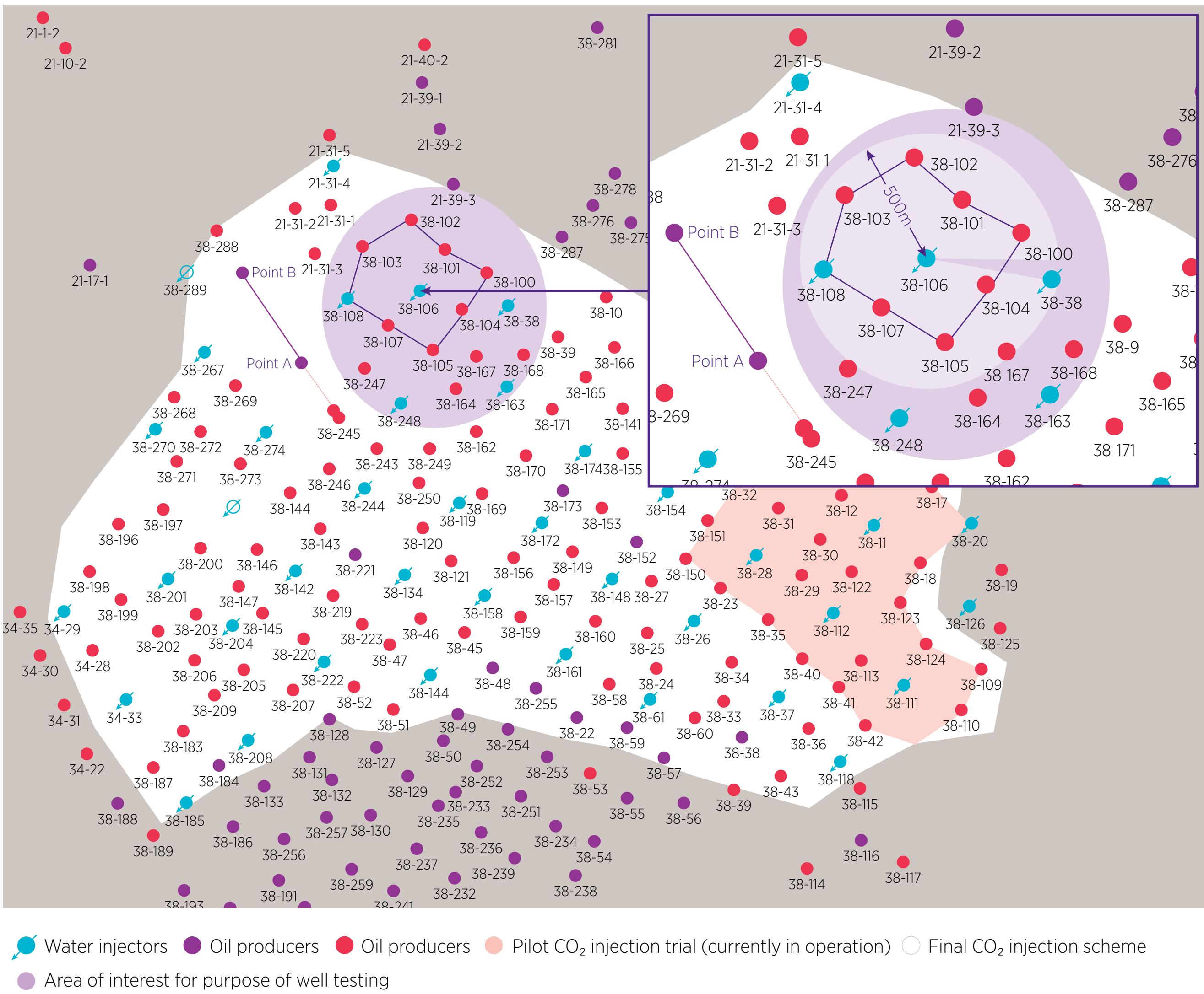


Table 4 Representative reservoir properties for the Wuqi Reservoir (from Shaanxi Yanchang Petroleum, 2017).

Properties		
Rock compressibility	1.12E-05	bar-1
Connate water	45	%
Reservoir Description		
model size	2000x2000	m^2
No. of grids	80x80x10	
Pi @ -360 m (SSTVD)	130	bar
T	59.94	°C
Fluid Properties		
Pbubble	54	bar
Oil density	783	kg/m^3
Oil viscosity	shown in Bo vs. Pressure plot	cP
Bo (FVF)	shown in Viscosity vs. Pressure plot	bbl/STB
Water salinity	123900	ppm

Figure 3 Oil viscosity and formation volume factor at different pressures for the Wuqi Reservoir (from Shaanxi Yanchang Petroleum, 2017).

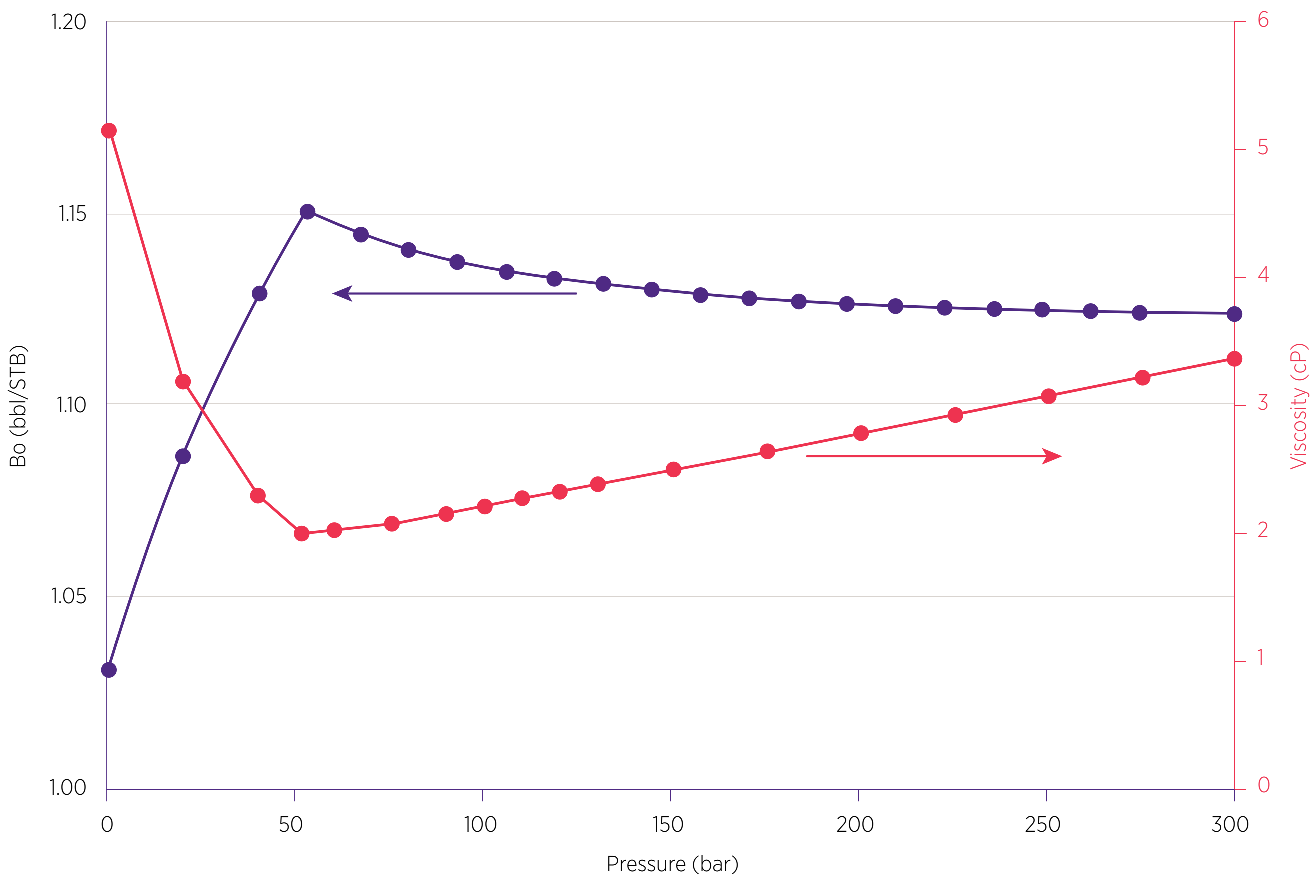


Figure 4 Reservoir property distribution in the Wuqi subregion model: porosity (v/v) (top), permeability (mD) (middle) and net to gross (ratio) (below).

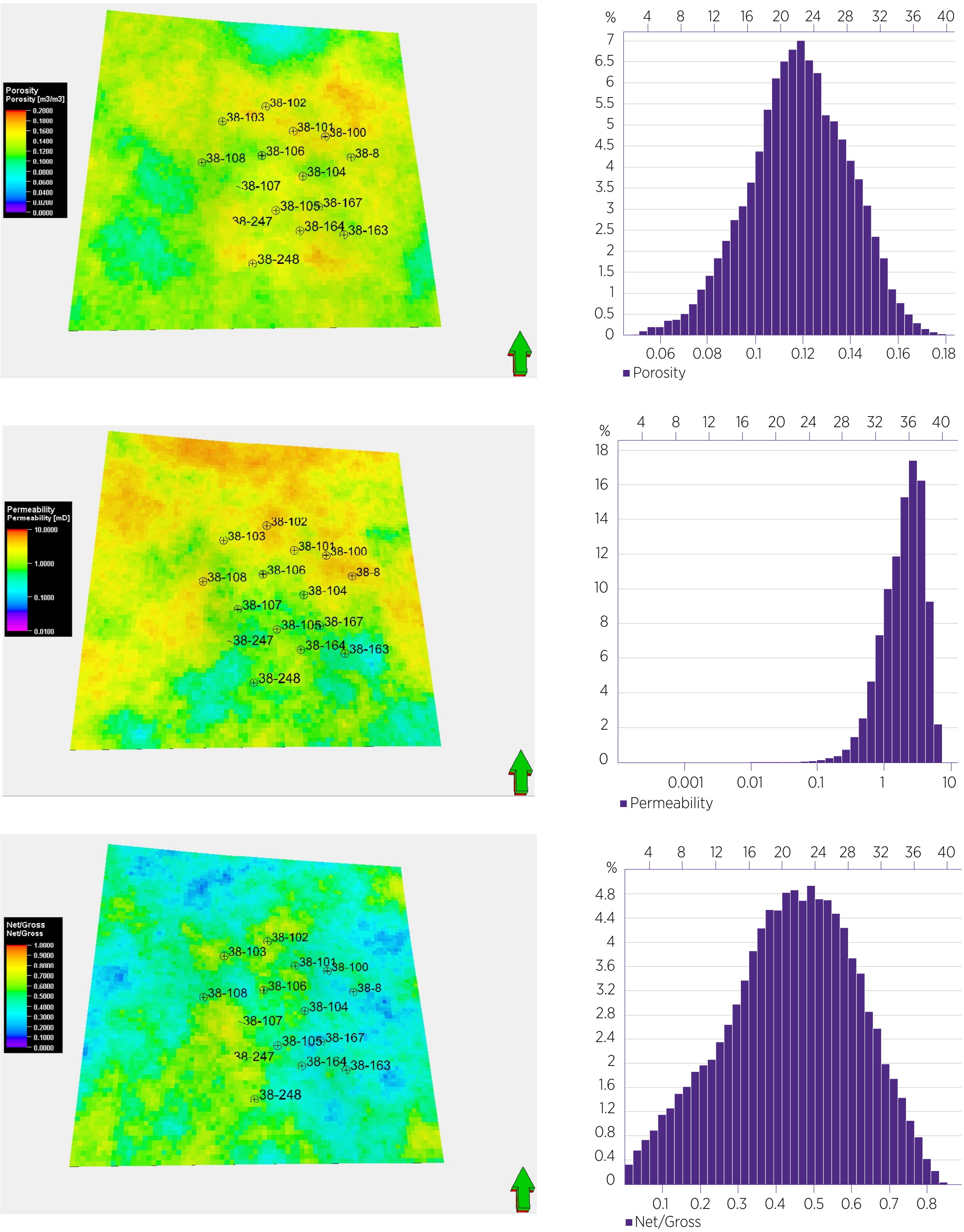
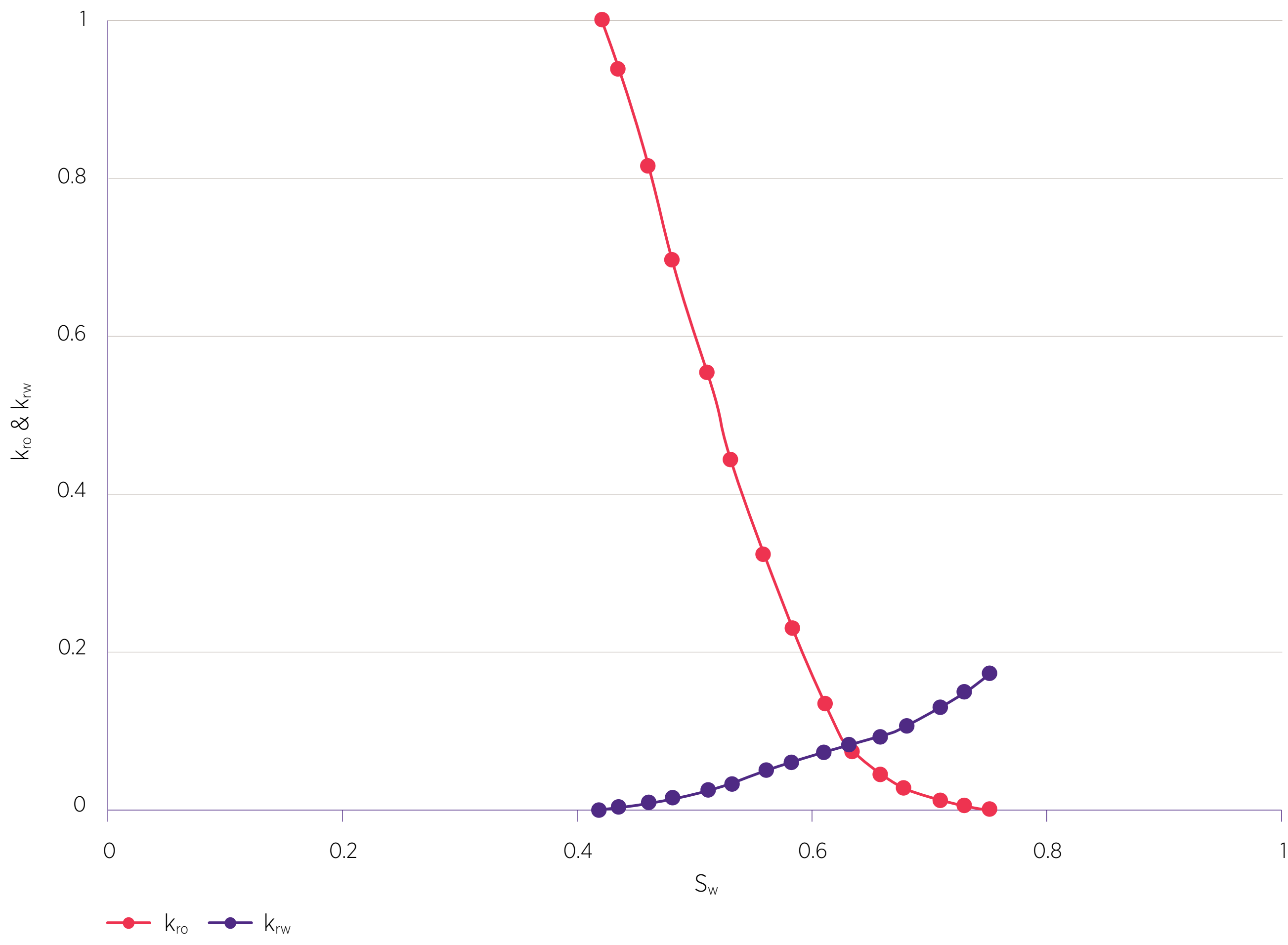


Table 5 Dynamic model initial conditions and well completion assumptions (from Shaanxi Yanchang Petroleum, 2017).

Initial conditions		
Pressure	130	bar
Datum depth	-360	m (SSTVD)
Well completions		
Casing	5.5	in
Perforation	Various	m
Stimulation		
Skin	-3	
Average Hyd Frac properties		
Frac height	13	m
Frac length	200	m
Frac perm	220	mD
Frac width	0.008	m

Figure 5 Oil-water relative permeability curve for the Wuqi Reservoir (from Shaanxi Yanchang Petroleum, 2017).



The Eclipse model was history matched (HM) using monthly historical production and injection rates provided by Shaanxi Yanchang Petroleum (2017). The results indicated a relatively good overall history match for wells with oil production, where the modelled and historical oil rates were in good agreement for over 90% of wells' production period. However, the modelled and historical water production rates were not matched for at least 50% of the wells' production period. The HM is consistent with what has been reported by Shaanxi Yanchang Petroleum previously. The HM model was then used to design several alternative well test scenarios that could be considered for the field trial. These included draw-down build-up (DD-BU), injection-falloff (INJ-FO), interference and pulse tests using a producing (or injecting) well and two shut-in monitoring wells located 270 m and 325 m away from the central producing (or injecting) well. Transient well test software IHS was used to interpret the pressure responses generated by the Eclipse dynamic model and estimate the bulk permeability and Radius of Investigation (ROI) for various test designs. The Eclipse dynamic model revealed that due to the reservoir's generally low permeability (less than 1 mD), significant pressure transient relaxation effects occur if long-term producing or injection wells are shut in. Rather than being able to achieve reservoir pressure stabilisation, complex pressure interference effects continue to occur over long periods of time. It was determined that for successful dynamic test interpretation, it is better to maintain (as constant as possible), the background transient state of the reservoir over which to impose the new dynamic test sequence. To minimise the pressure relaxation effects around the proposed testing and monitoring wells, only the two monitoring wells were shut in during the test period.

3.1.2 Results and discussion

Various reservoir testing options were evaluated and results from different approaches and scenarios reviewed. The most appropriate well test design, based on test duration and interpretability, has been ranked according to the overall objectives of: 1) establishing the large scale bulk reservoir characteristics; 2) constraining the estimated dynamic CO_2 storage capacity of the Wuqi Reservoir; and, 3) completing the test sequence within a reasonable testing time (less than one year). UQ-SDAAP considered a number of testing options for evaluation of reservoir performance. This included both a Phase 1 using reservoir fluids or water and a Phase 2 using CO_2. Note that the overall location of the wells used for the field trial was suggested by UQ-SDAAP to be on the edge of the Yanchang Field where there would be a minimum of pressure interference from nearby normal oil field operational activity. Shaanxi Yanchang Petroleum had a number of practical operational constraints to consider and they suggested wells that could be used for testing that would meet UQ-SDAAP's requirements.

3.1.2.1 Phase 1: Using reservoir fluids or water

The test options evaluated for Phase 1 include: 1) draw-down build-up (DD-BU); 2) injection-falloff (ING-FO); 3) pulse; and 4) interference testing.

3.1.2.1.1 Draw-down – build-up (DD-BU) test design

38-101 well was considered as the pumping well, and the 38-102 well located ~240 m to the northwest as the monitoring well. These wells are on the far northern edge of the reservoir being least disturbed by other field operations. Initially, an inner ring of wells (38-100, 38-102, 38-103, 38-104 and 38-106) were modelled to be shut in to see if the reservoir pressure in this region would stabilise before starting the test sequence. After running several scenarios with different initial shut-in relaxation periods and DD-BU durations, it was determined that a very long initial shut-in relaxation (up to 270 days) would be necessary for the area of interest to sufficiently stabilise before running the actual test. This was determined to be operationally impractical, and failed the objective of completing the total test sequence within one year.

The model showed that even a test with 270 days initial shut-in relaxation, 180 days DD at a rate of 1.5 m^3/day (9.4 bbl/day) (choice based on maximum well deliverability), and 120 days BU would not provide enough pressure disturbance from the test sequence to be interpretable at the observation well (38-102) due to flow rate limitations and ongoing relaxation pressure interference effects. The ROI of only 140 m was reached at the pumping well before the reservoir pressure relaxation interfered with the BU signal. Figure 6 highlights the pressure responses in pumping and monitoring wells along with an interpretation (Figure 7) of the Figure 6 data. The bulk permeability calculated at the pumping well was 0.64 mD. This test design did not achieve the test objectives (too long and low ROI) and is therefore not recommended.

Figure 6 Pressure response for both pumping (1.5 m³/day or 9.4 bbl/day) at the 38-101 well, and monitoring at the 38-102 well. Wells were modelled in Eclipse.

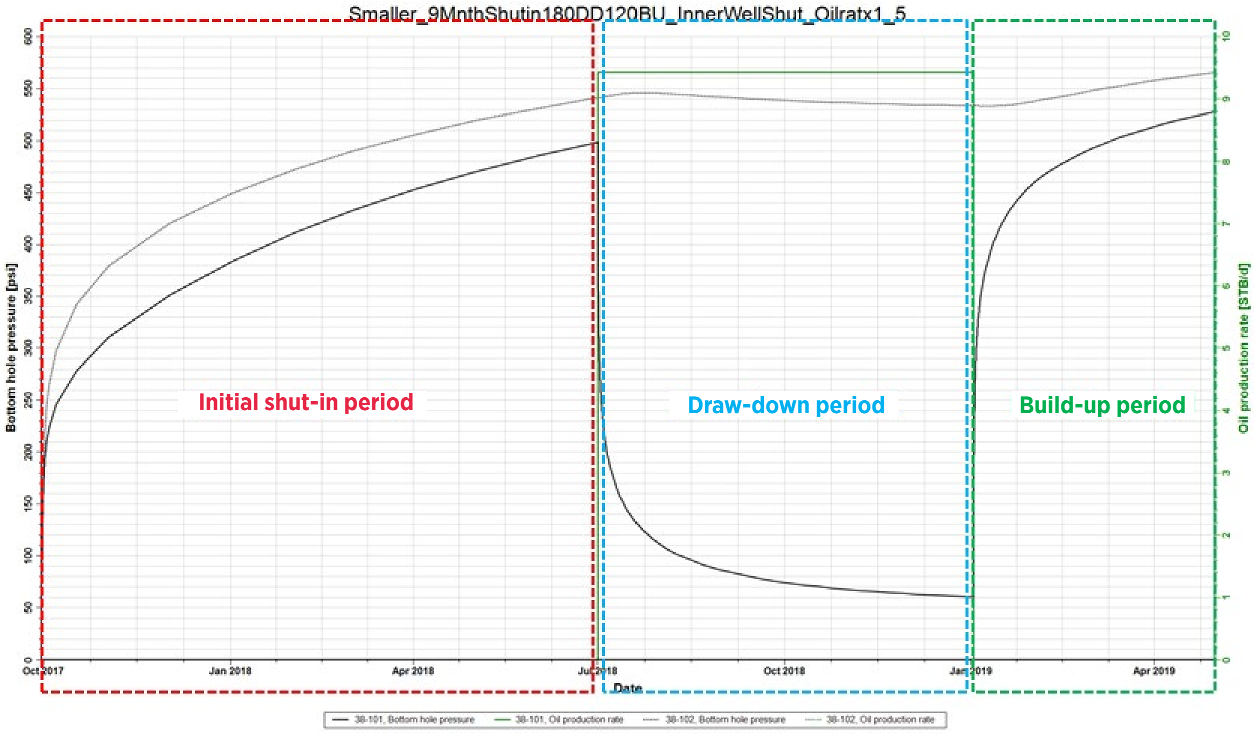


Figure 7 Interpretation of the BU pressure response at the pumping (1.5 m³/day or 9.4 bbl/day) well (38-101) using IHS WellTest software (top), and interpretation of the usable portion of DD pressure response shown in yellow ellipse at the observation well (38-102) using type-curve matching (bottom) described by Earlougher (1977).

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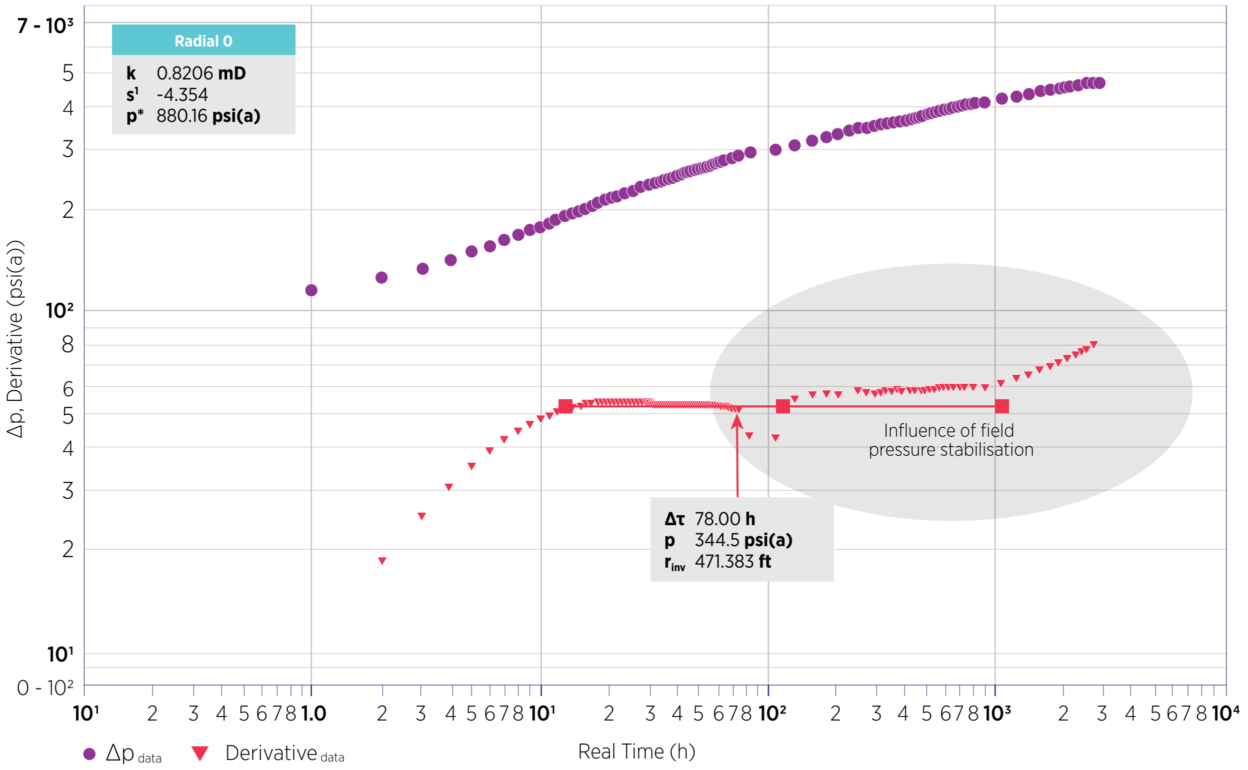
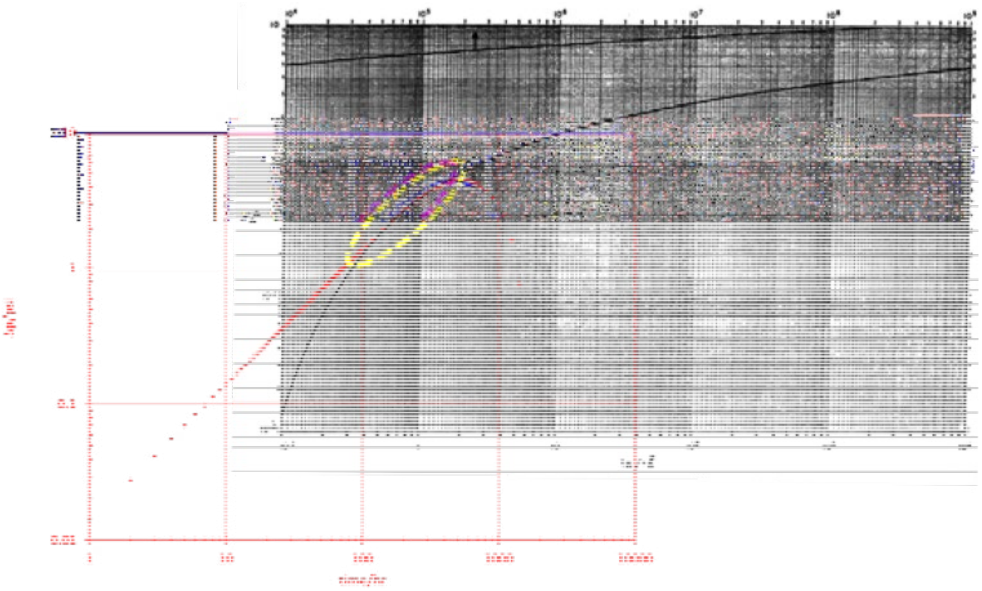




3.1.2.1.2 Injection-Falloff (INJ-FO) test design

The 38-106 well was considered as the injection well (since it's already utilised as an injection well), and the 38-101 well located ~270 m to the northeast as the monitoring well. The inner ring of wells (38-100, 38-102, 38-103, 38-104, 38-105 and 38-107) were shut in to see if the reservoir pressure in this region would stabilise in the model during the test. Several scenarios with various injection rates were considered to check the possibility of shortening the initial shut-in relaxation period. Of the options reviewed, an initial shut-in relaxation of 180 days with 180 days INJ and 120 days FO seems to be the most suitable combination of test periods. To acquire an interpretable pressure response at the observation well, a water injection rate of 10 m^3/day (62.9 bbl/day) is required. At this rate, appropriate steps, such as stepwise increase of injection rate and continuous sandface pressure monitoring, had to be taken to avoid the fracture propagation pressure being reached in the reservoir during the test.

The pressure response characteristics of a "composite reservoir" for a "non-unit mobility ratio" were observed during this test. The ROI of 120 m was achieved in the water-flooded zone before the pressure response reaches the waterfront edge. The bulk permeability of the water-flooded zone was estimated to be 0.23 mD. The pressure response at the observation well was matched with a type-curve (Earlougher, 1977), resulting in an estimated bulk permeability of k=0.15 mD. The results are summarised in Figure 8 and Figure 9. This test design is an improvement on the DD-BU but still does not achieve the desired objectives (too long and low ROI) and is not recommended.

Figure 8 Pressure response for both injecting (10 m^3/day or 62.9 bbl/day) well (38-106) and monitoring well (38-101). Wells are modelled in Eclipse.

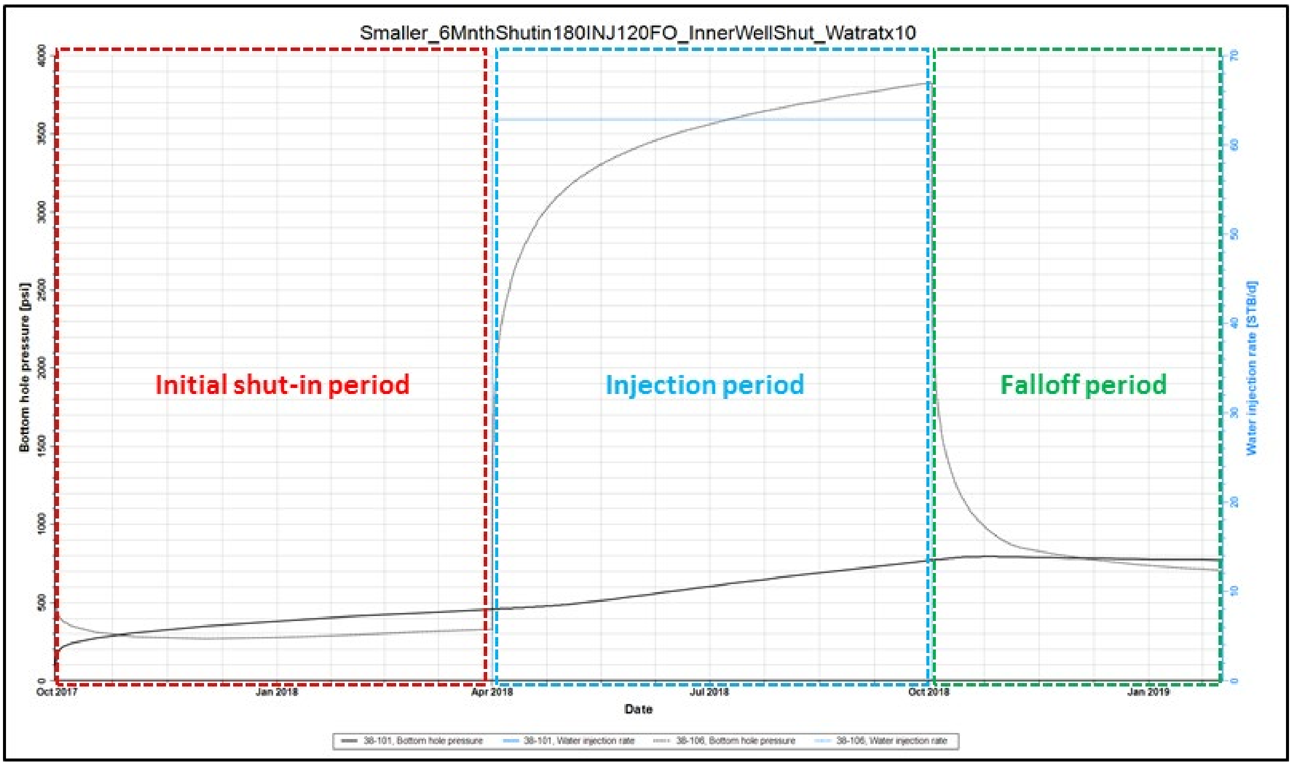
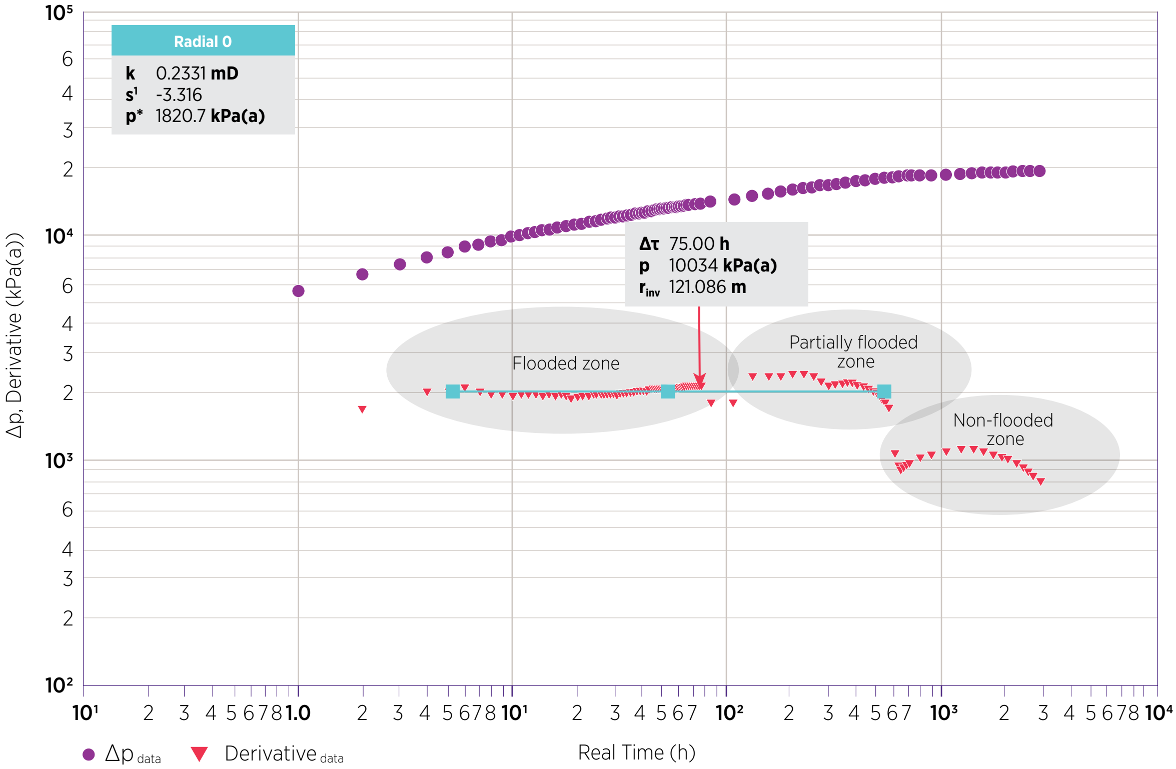
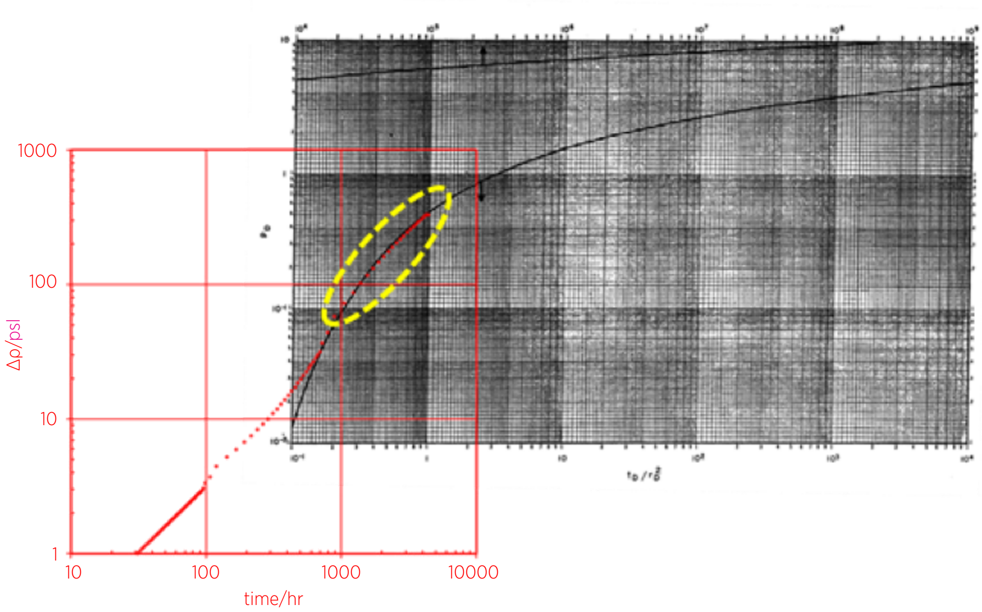


Figure 9 Interpretation of the BU pressure response at the injecting (10 m³/day or 62.9 bbl/day) well (38-106) using IHS WellTest software (top), and interpretation of the usable portion of DD pressure response shown in yellow ellipse at the observation well (38-101) using type-curve matching described by Earlougher (1977) (bottom).

Typecurve



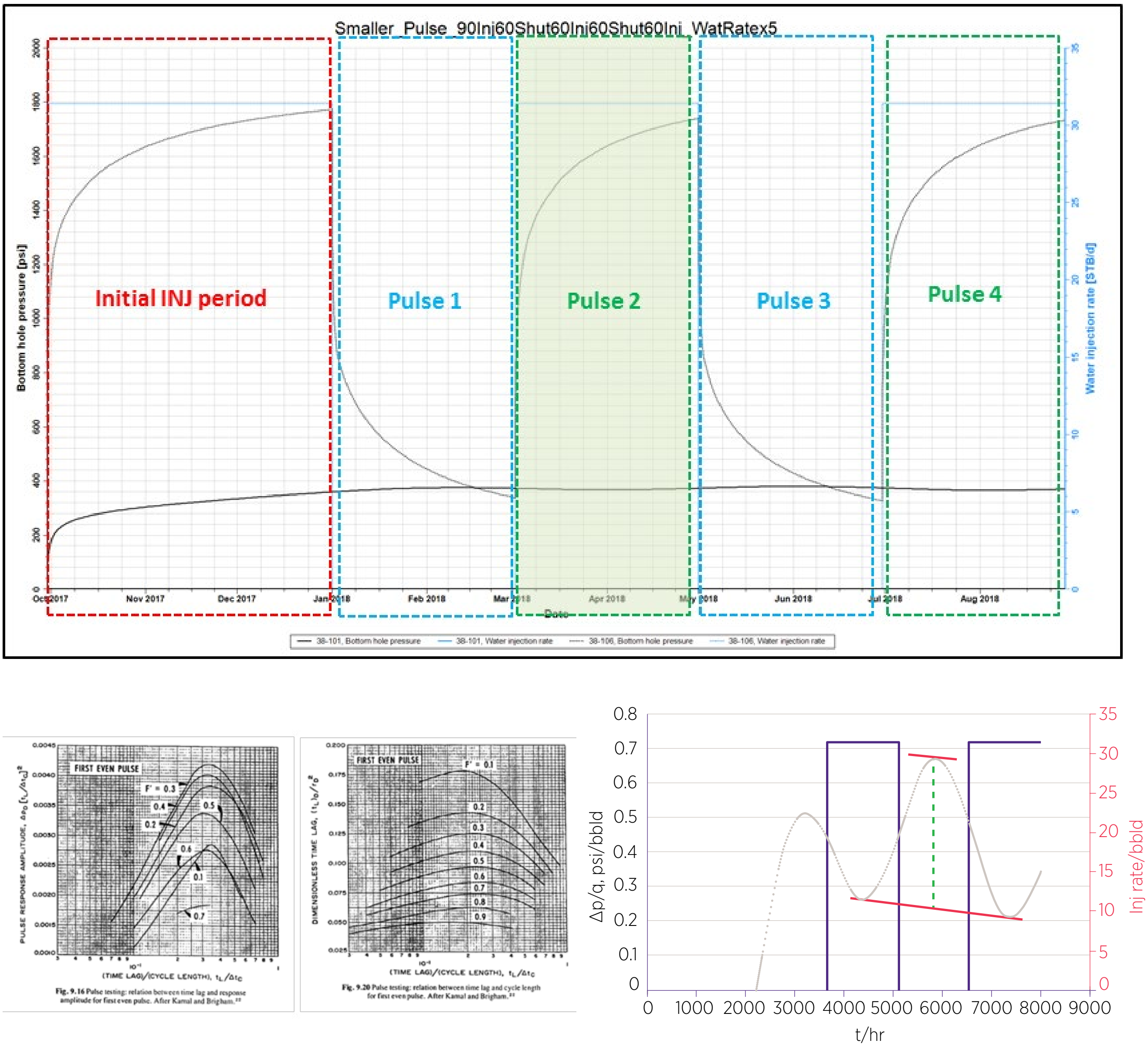


3.1.2.1.3 Pulse test design

The pulse test is where the flow rate at the injecting (or producing) well is changed over time in a series of alternating flow and shut-in periods (Kamal 1983). The pressure response at the observation well is then analysed to calculate the bulk permeability. In this study, the 38-106 well was considered as the injection well (since it was already used as an injection well) and the 38-101 well was used as the monitoring well. Several scenarios with various ratios of INJ period to FO period were modelled to optimise the test. The results showed that an initial injection period of 90 days at 5 m^3/day (31.4 bbl/day) followed by two more pulses, alternating between 60 days FO and 60 days INJ period at 5 m^3/day (31.4 bbl/day), would provide adequate data at the observation well to characterise the formation.

As shown in Figure 10, the methodology was adopted from Earlougher 1977 where data from the second pulse (i.e. the first even pulse) was selected for analysis, generating a bulk permeability estimate of 0.28 mD. Other pulse-testing scenarios with a different ratio of the INJ pulse period to the FO pulse period resulted in permeability estimations within the same range (average of 0.24 mD).

Figure 10 Pressure response in both the injection well (38-106) and monitoring well (38-101) modelled in Eclipse (top). The interpretation of the pressure response for pulse two (first even pulse) using pulse-type curves described by Earlougher (1977) (bottom left), and drawing the tangents between the two valleys and the peak in the middle (red dashed lines) to calculate pulse response amplitude (Δp/q – green dashed line) at the observation well (38-101) (bottom right).



With the pulse test design, it is difficult to generate a usable injection well ROI due to the short injection period and interference from background reservoir pressure recovery. However, a pressure response is interpretable from the observation well, and the total test duration is shortened to less than one year (330 days). On this basis, some but not all of the set test objectives can be achieved. This test is therefore not recommended.

3.1.2.1.4 Interference test design

The interference test is a multiple-well transient test where one well is active and pumps fluid from or into the reservoir to create pressure disturbance and one or more well(s) remains idle as monitoring well(s). The pressure response in both pumping and monitoring wells are used to calculate the reservoir properties. In this study, the 38-106 well was considered as the injection well (since it's already utilised as an injection well) and the 38-101 well as the monitoring well. In this scenario, only well 38-101 was shut-in in the model during the test. All other wells were allowed to continue at normal injection and pumping rates as they had been during previous oil field operations. This helped in reducing the degree of reservoir relaxation pressure stabilisation effects that were observed during the previously described DD-BU and INJ-FO tests. Several scenarios with various shut-in relaxation times (from zero to 60 days) as well as different INJ and FO periods were examined to check the possibility of reducing the entire test duration.

The results showed that the initial shut-in relaxation period of at least 60 days (for the base case bulk reservoir permeability assumption of 2 mD) for the 38-101 and 38-106 wells would be essential in order to acquire interpretable data at the observation well during the injection period. This needs to be followed by 120 days of injection at the rate of 5 m^3/day (31.4 bbl/day) and 30 days of FO. Figure 11 illustrates the pressure response generated by the Eclipse run at the injecting and monitoring wells along with their interpretation (Figure 12).

Figure 11 Pressure response in both the injection (5 m^3/day or 31.4 bbl/day) well (38-106) and monitoring well (38-101). The well response is modelled in Eclipse.

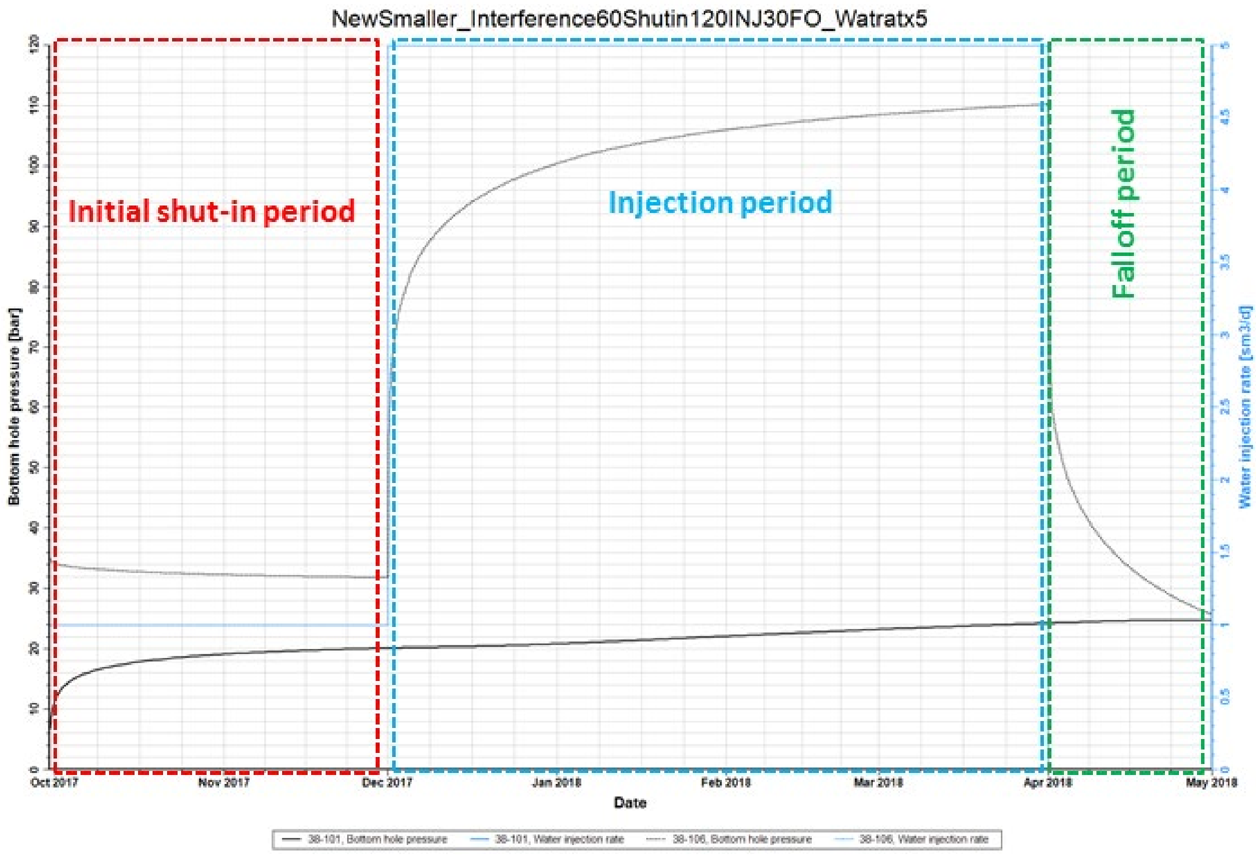


Figure 12 Pressure interpretation of the FO pressure response at the injection well (38-106) using IHS WellTest software (top), and interpretation of the usable portion of FO pressure response shown in yellow ellipse at the observation well (38-101) using type-curve matching described by Earlougher 1977 (bottom).

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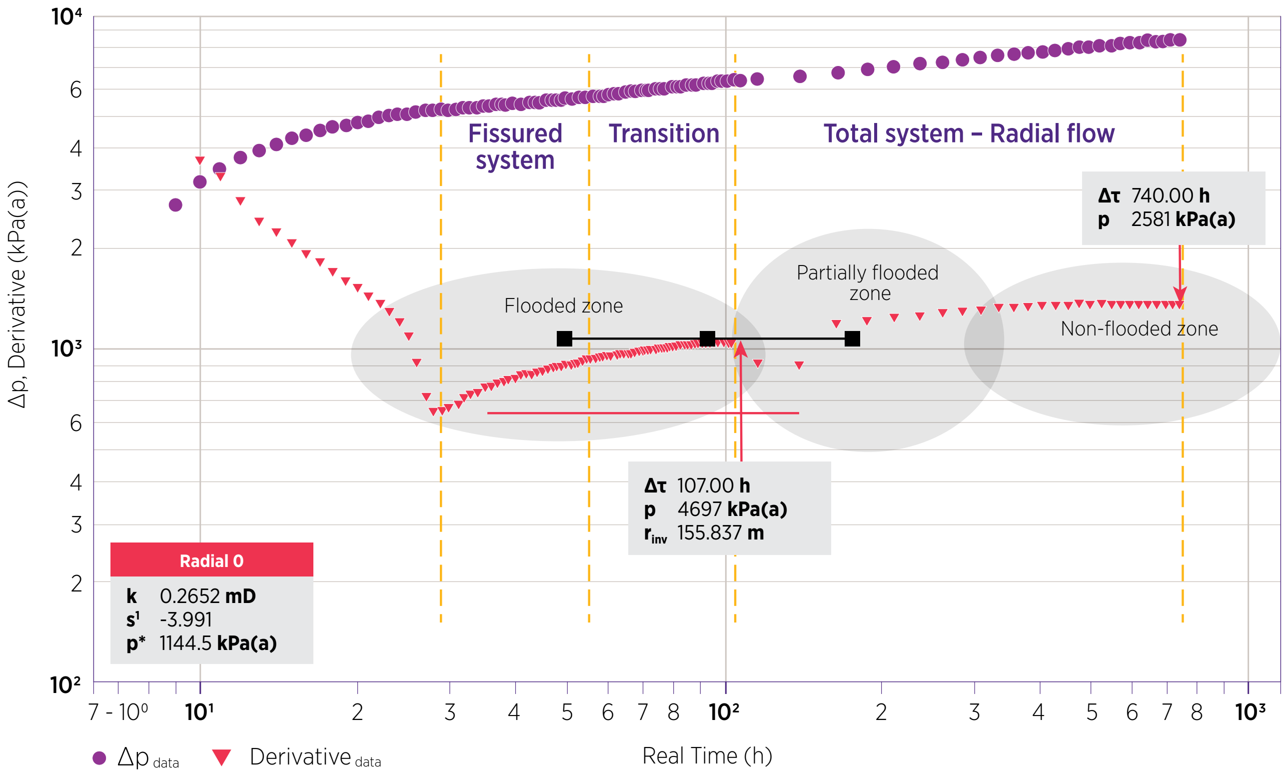
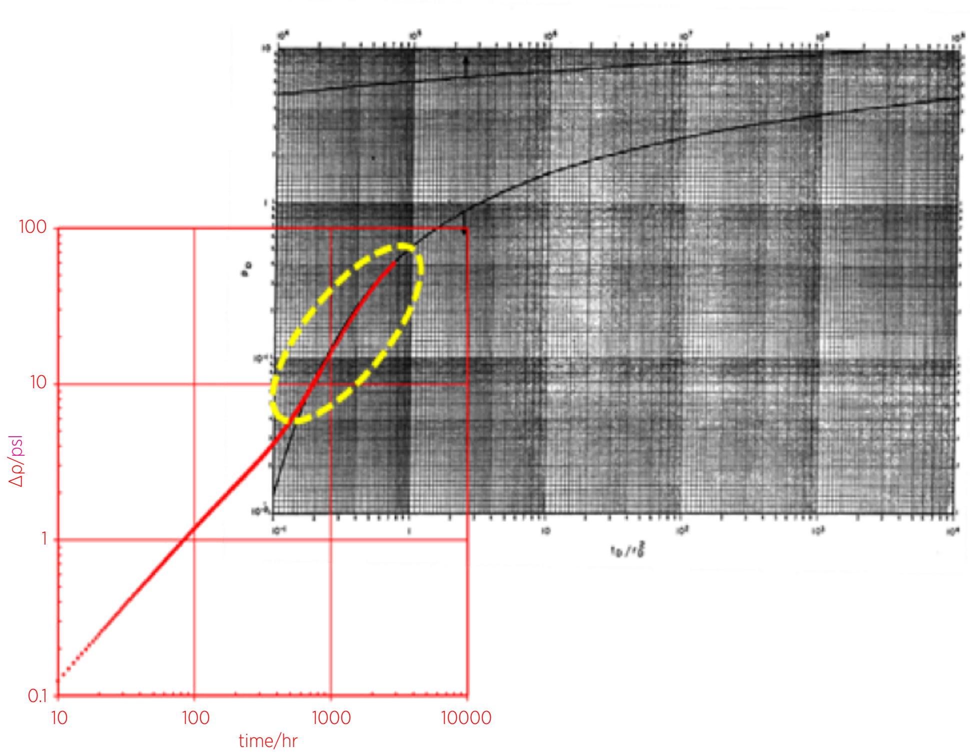
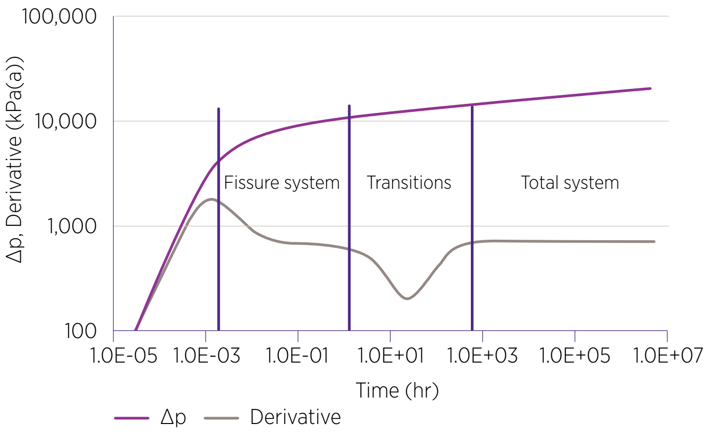
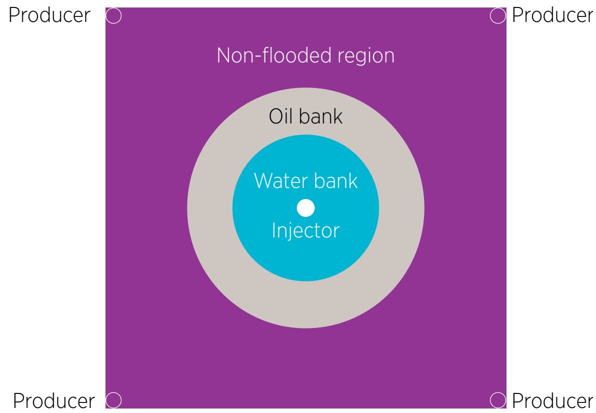




Fissured reservoir behaviour was observed during the modelled test (Figure 12, top) with three different regimes: 1) a fissure flow period when the main flow contributor is a fissure (fracture in this study); 2) a transition period (a "valley" signature in the pressure derivative curve) when the matrix starts to produce into the fissures; and 3) a stabilisation period where the pressure of the matrix blocks and the fissures are equalised (Bourdet 2002). The fissured-type behaviour was then followed by "flooded" and "non-flooded" zones creating the pressure response corresponding to a composite reservoir (Bourdet 2002; Chaudhry 2004) (shown in Figure 13).

Figure 13 The typical pressure response of a fissured reservoir (Bourdet 2002) (left), and a schematic diagram of a composite reservoir (Chaudhry 2004; Honari et al. 2018) (right).



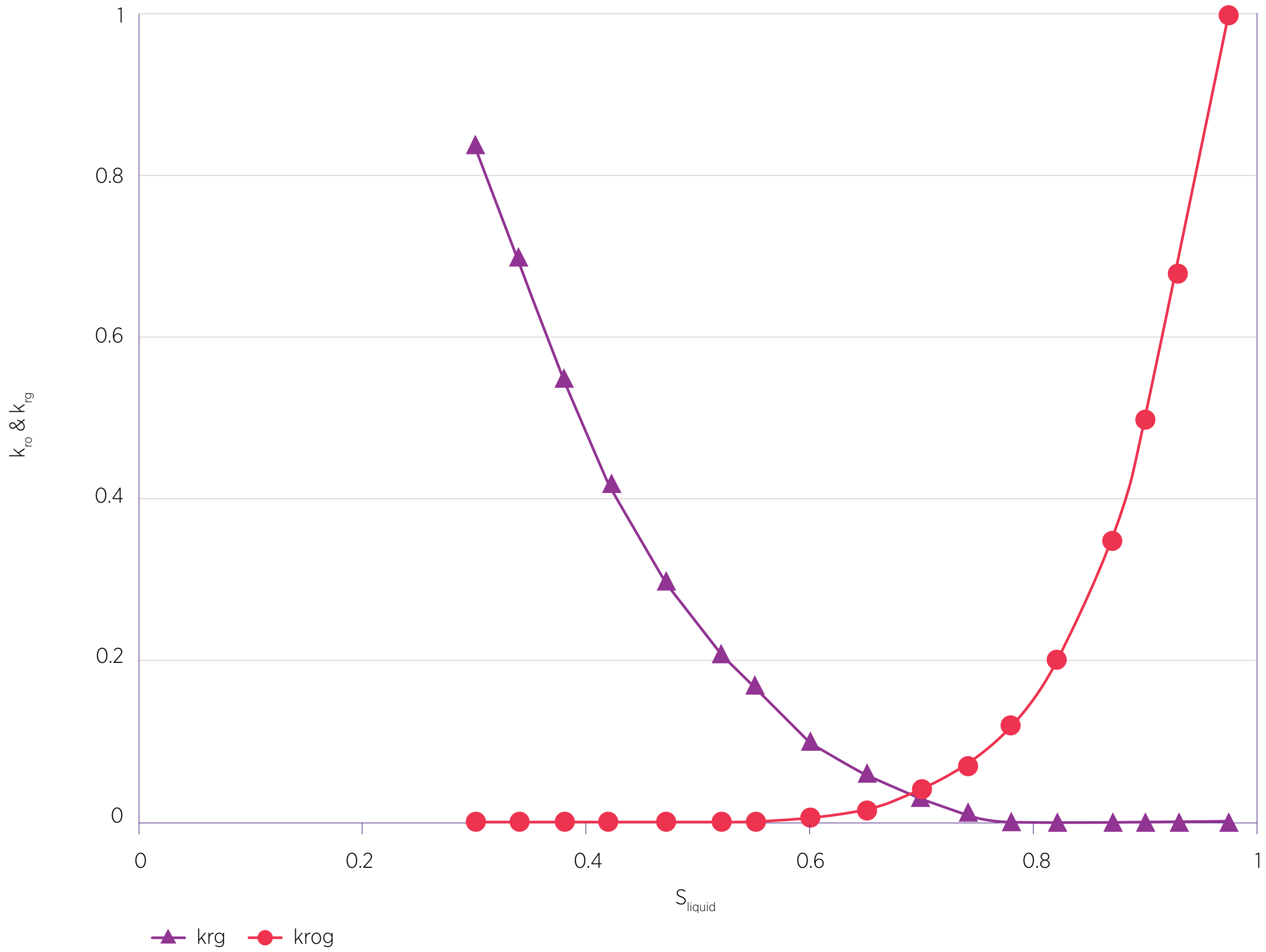


The ROI estimated at the injecting well was about 150 m. This is located just at the outer edge of the water-flooded zone. Calculated bulk permeability at the injection well was 0.26 mD. The INJ data at the observation well was matched with the type-curve, resulting in k=0.55 mD. This test meets the objectives of establishing the large-scale bulk reservoir characteristics and constraining the estimate of dynamic CO_2 storage capacity of the reservoir within a reasonable testing time (less than one year).

3.1.2.2 Phase 2: CO_2 injecting test trial option

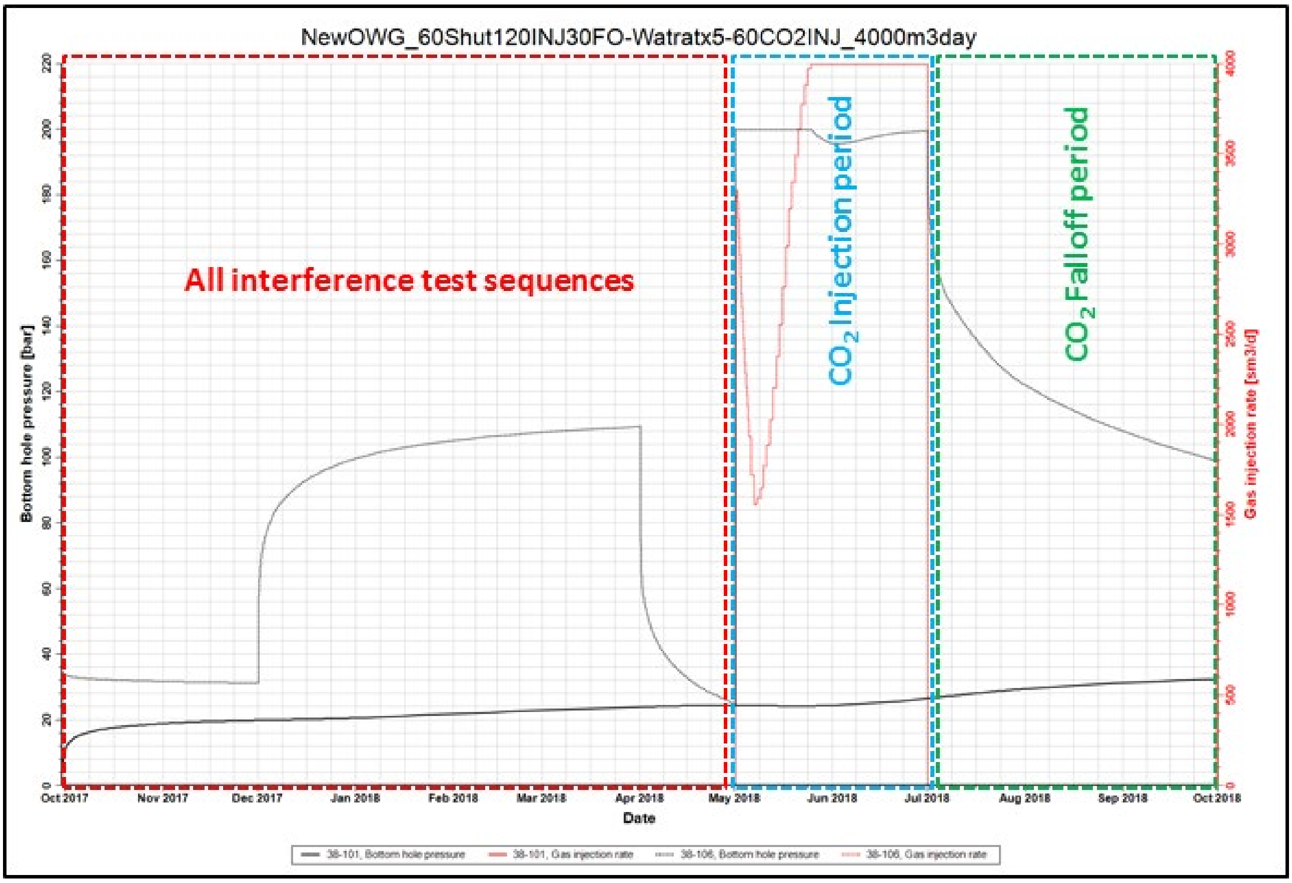
As part of the UQ-SDAAP/CUMT/ Shaanxi Yanchang Petroleum collaboration, Shaanxi Yanchang Petroleum had a requirement to include a CO_2 injection phase to the overall testing sequence. This is to help confirm the methodology of using a large-scale pumping or injection test to achieve a large ROI and estimation of bulk reservoir dynamic storage capacity, particularly for the conversion of the water pumping/injection test results to an equivalent for CO_2. In this case, Phase 2 CO_2 injection test options that could be added to the previously described Interference Test (210 days in Section 3.1.2.1.4) were evaluated. Here, the 38-106 well was considered as the injection well and the 38-101 well as the monitoring well. The gas-oil relative permeability used in the Eclipse model is shown in Figure 14.

Figure 14 Gas-oil relative permeability used in the Eclipse model (Yu et al. 2015).



Several scenarios with various shut-in relaxation times as well as different INJ and FO periods were modelled to check the possibility of reducing the entire test duration. The results showed that the CO_2 injection period of 60 days at a CO_2 injection rate of about 4000 sm³/day followed by 90 days of FO would be reasonable to acquire interpretable data at the injection well and optimise the test duration. Figure 15 illustrates both the pressure response during Phase 1 interference testing (previously described in Section 3.1.2.1.4) and Phase 2 CO_2 test periods.

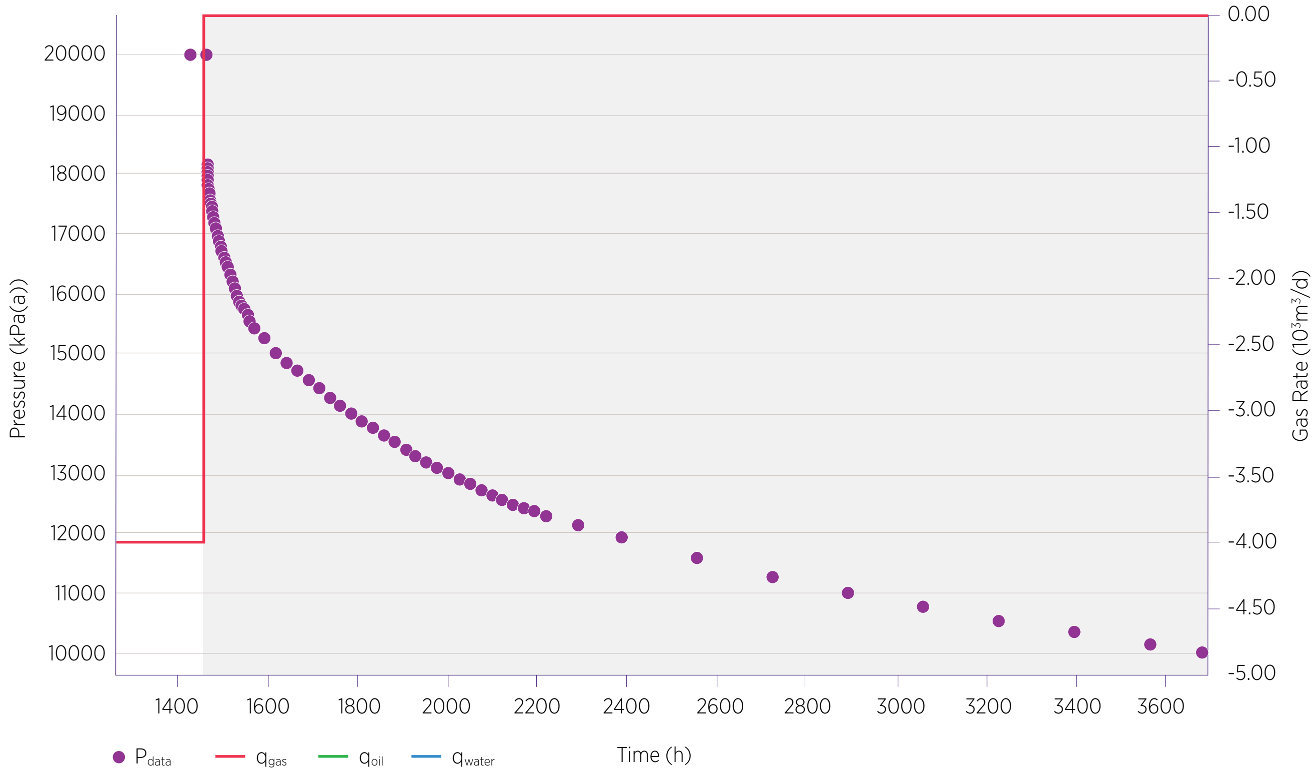
Figure 15 Pressure response in both injection (38-106) and monitoring (38-101) wells modelled in Eclipse for a Phase 1 interference test followed by a Phase 2 CO_2 injection test.



The gas and water fluid fronts, as well as permeability in the CO_2 flooded zone, can be estimated from the log-log plot (described in Figure 16). The calculated permeability in the CO_2 flooded zone was 0.03 mD, which corresponds to the gas-oil relative permeability defined for the Eclipse model. The gas front and water front were also characterised using the log-log plot derived from the CO_2 injecting well pressure response.

Figure 16 CO_2 FO pressure (top) with the log-log derivative plot (bottom).

History



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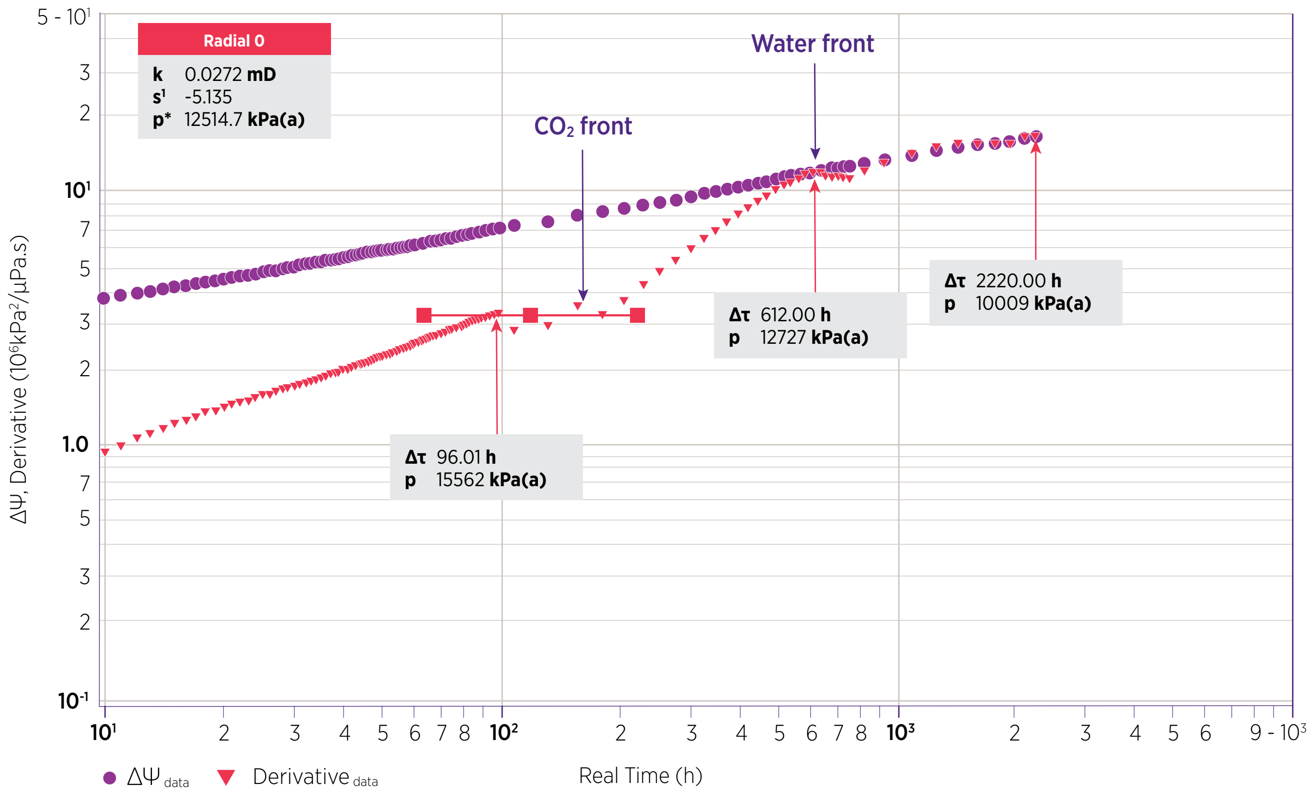


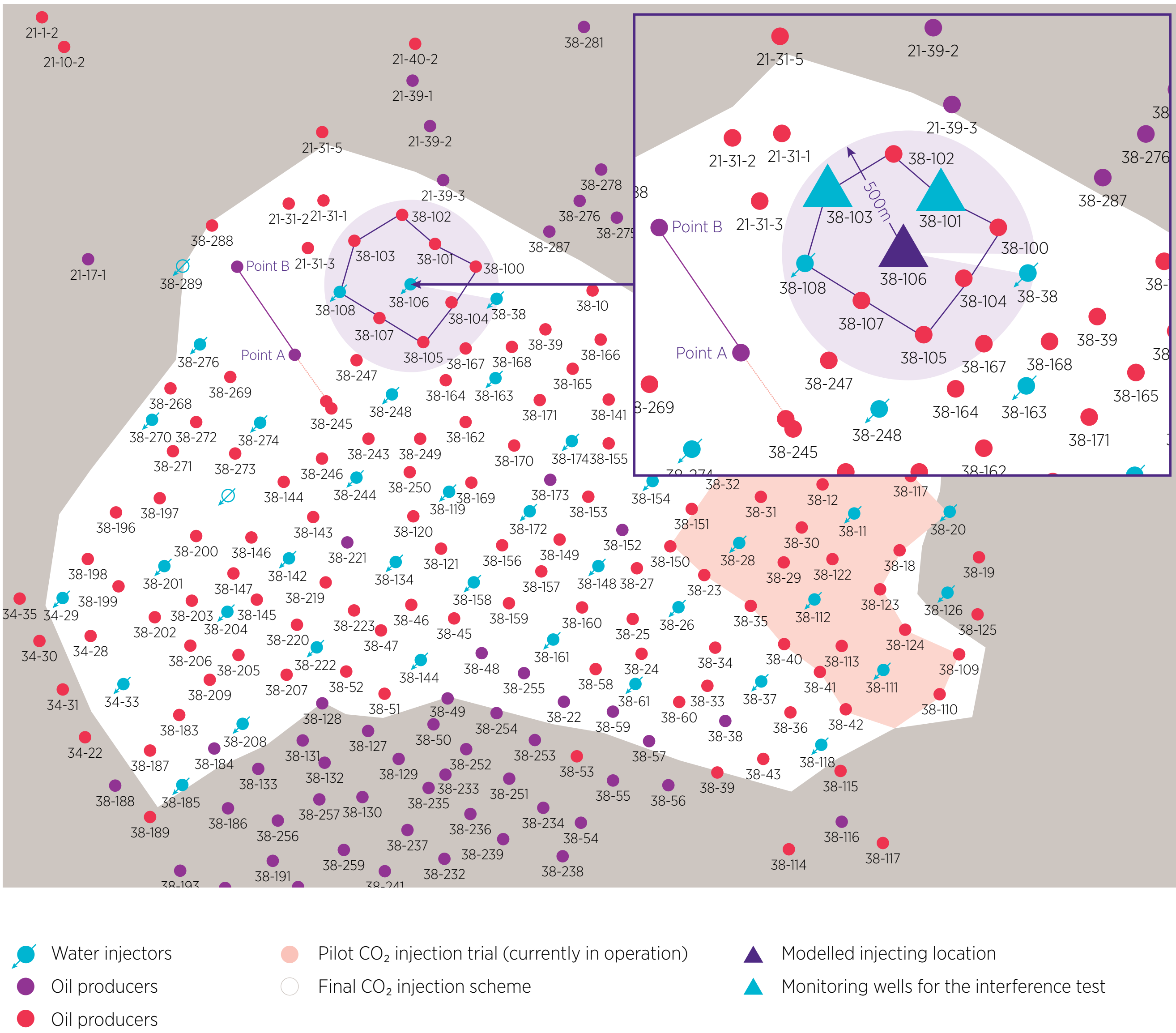
This modelled behaviour is consistent with a pressure response from a CO_2 flooded aquifer conducted in the Ordos Basin, China reported by Wei et al. (2016). However, the pressure response simulated by the Wuqi Reservoir Eclipse model has more complexity due to the existence of three phases: oil, water, gas (OWG).

In summary, the Phase 2 (CO_2 injection) test trial provides insights on relative permeability changes due to the introduction of a CO_2 phase into the reservoir, and it quantitatively predicts CO_2 injectivity and dynamic CO_2 storage capacity. This can also achieve the three main test objectives: 1) relatively large ROI; 2) quantify any existing heterogeneity or fracture in the reservoir; and 3) de-risk the prediction of carbon storage capacity and injectivity in less than a year.

3.1.2.2.1 Interference test with two monitoring wells followed by CO_2 injection

In order to improve the reservoir characterisation by increasing the ROI and also to identify the reservoir heterogeneity, a second monitoring well was added, and the various interference test scenarios were simulated using two observation points rather than one. This combines the interference test described in section 3.1.2.1.4 and the CO_2 injection Phase 2 described in section 3.1.2.2 with an extra observation well. The 38-106 well (blue star in Figure 17) was considered as the injection well (since it is already used as an injection well) and both the 38-101 (located ~270 m to the northeast) and 38-103 (located ~325 m to the northwest) wells (blue triangles) are considered as the monitoring wells (see Figure 17).

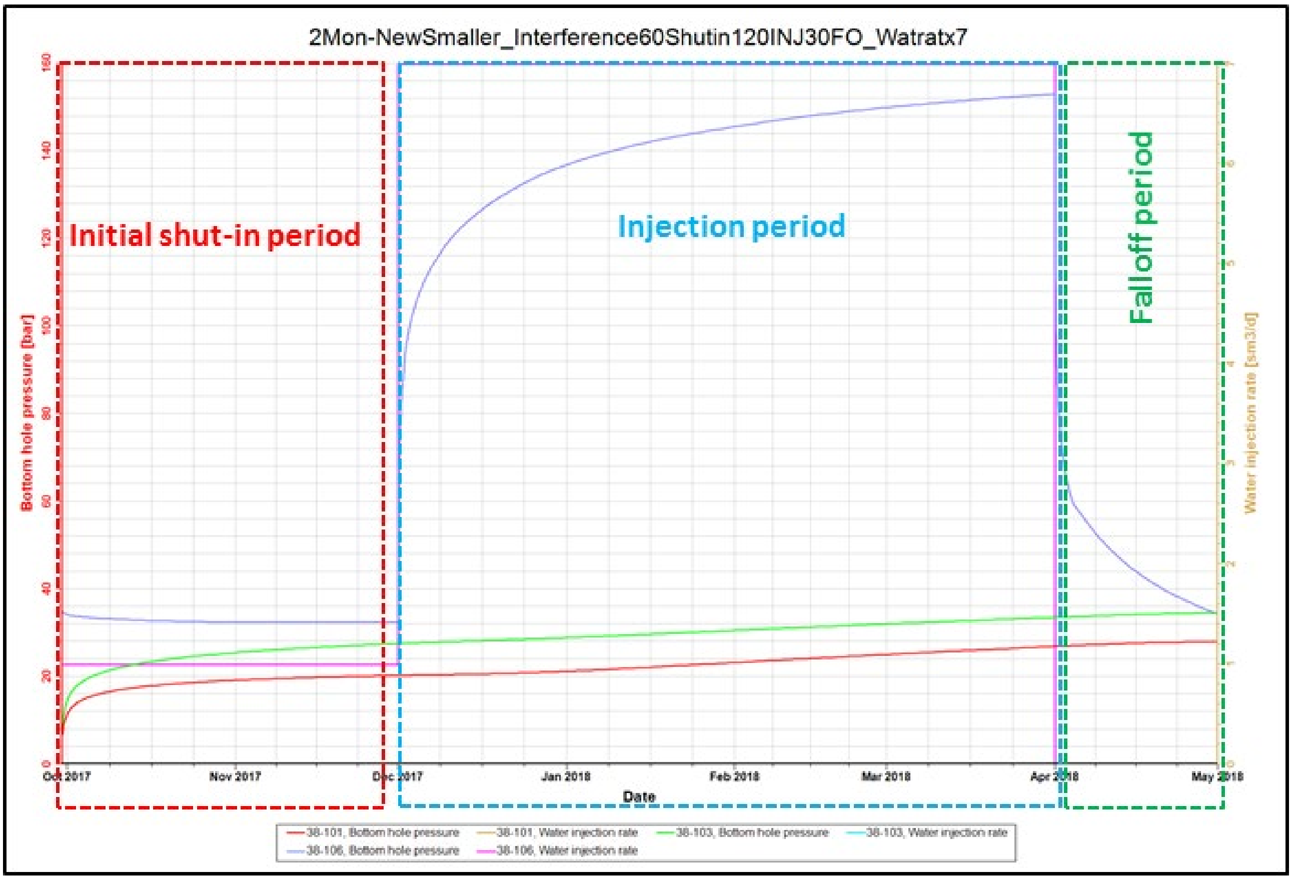
Figure 17 The location of modelled injecting (purple triangle) and monitoring wells (blue triangles) for the interference test with two monitoring wells.



In the model, only wells 38-101 and 38-103 were shut in during the test. All other wells are allowed to continue at normal injection and pumping rates as they were during previous oil field operations. Similar to the interference well test design, with one injection and one monitoring well (section 3.1.2.1.4), the initial shut-in relaxation period of at least 60 days (for the base case, bulk reservoir permeability assumption of 2 mD) would be essential in order to acquire interpretable data at the observation wells during the subsequent injection periods. This needs to be followed up with 120 days of water injection and 30 days of FO.

The injection rate in this case was required to be increased from 5 m^3/day (31.4 bbl/day) to 7 m^3/day (44 bbl/day) to generate enough pressure disturbance in the reservoir to be interpretable at the furthest observation point (i.e. the second observation well, 38-103). The pressure profile and the log-log derivative plot at the injecting well are shown in Figure 18. The ROI at the injecting well was about 140 m, which is just at the outer edge of the water-flooded zone. Calculated bulk permeability at the injection well is 0.29 mD.

Figure 18 Pressure response in the injection well (38-106) and two monitoring wells (38-101 and 38-103) simulated in Eclipse (below), and the interpreted log-log pressure derivatives of the FO pressure response at the injection well (38-106) using IHS WellTest software (opposite).



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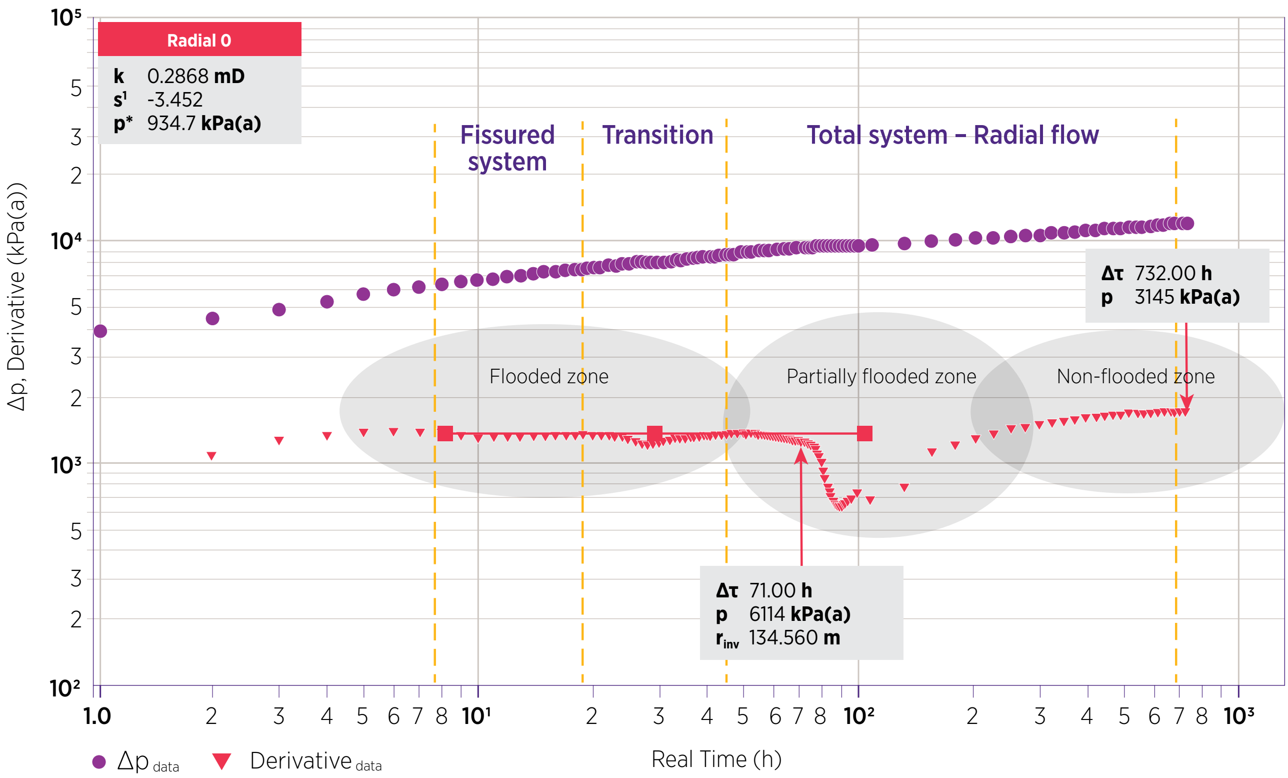
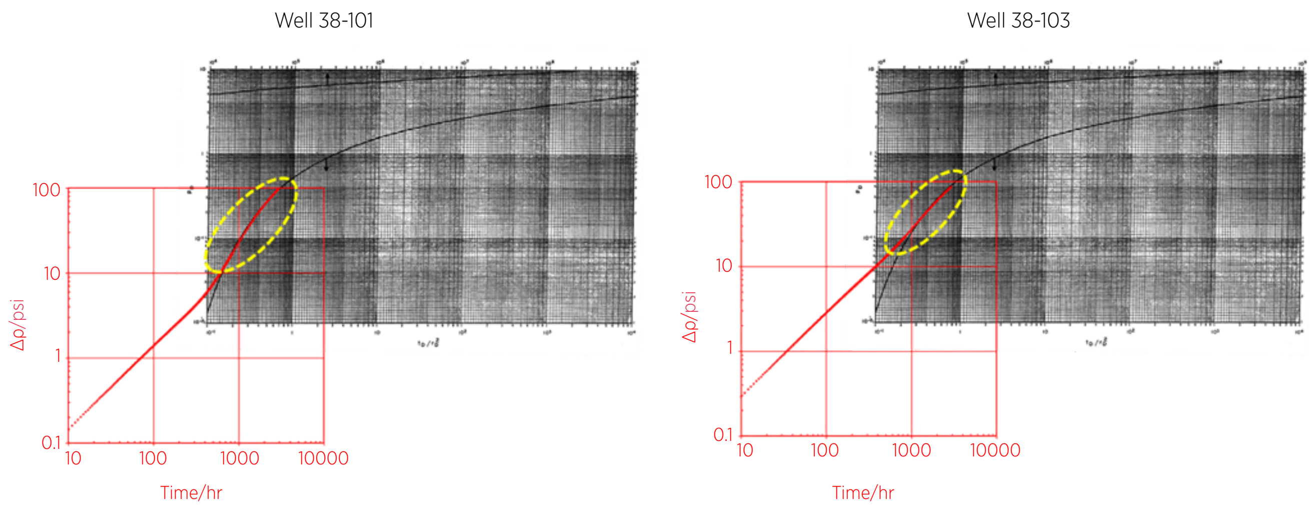


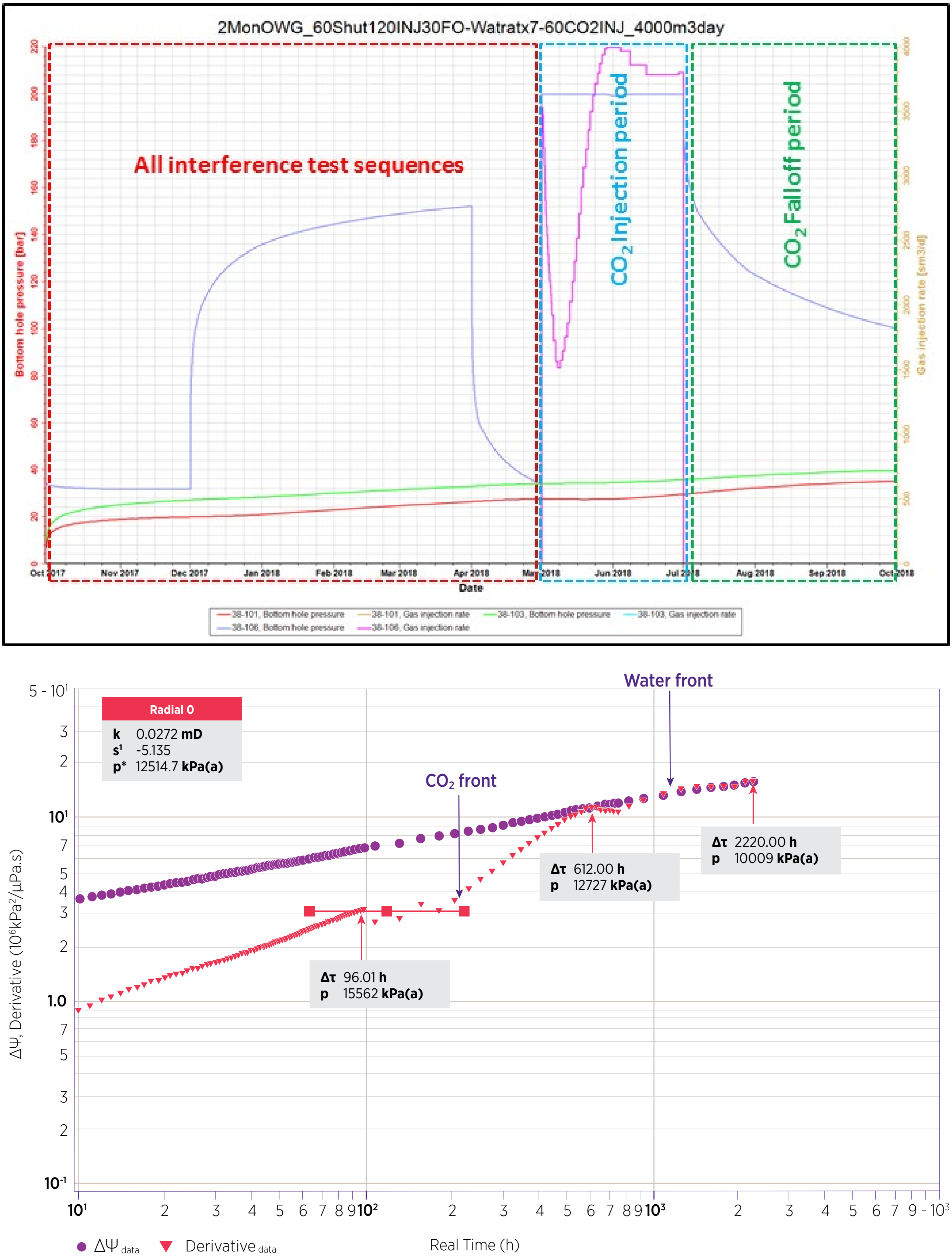
The INJ data at the observation wells was matched with the appropriate type-curve, resulting in an estimated bulk permeability of 0.45 mD and 0.51 mD at wells 38-101 and 38-103, respectively. As highlighted in Figure 19, the usable pressure response data at the observation well 38-103 is shorter than that at 38-101 because it is further away from the injecting well.

Figure 19 Interpretation of the usable portion of FO pressure response shown in yellow ellipse observed at the monitoring wells (38-101 and 38-103) for the interference test with two monitoring wells, using type-curve matching described by Earlougher (1977).



For the CO_2 injection part of the test and based on the model response, a CO_2 injection period of 60 days at a rate of about 4000 sm^3/day followed by 90 days of FO (shown in Figure 20) would be reasonable to acquire interpretable data at the injection well. The resultant bulk permeability in the CO_2 flooded zone at the injecting well was estimated to be 0.027 mD, and the CO_2 and water fronts were clearly identifiable in the pressure response.

Figure 20 Pressure response in both the injection well (38-106) and monitoring wells (38-101 and 38-103) modelled in Eclipse (top), with the interpreted log-log derivative plot (bottom).

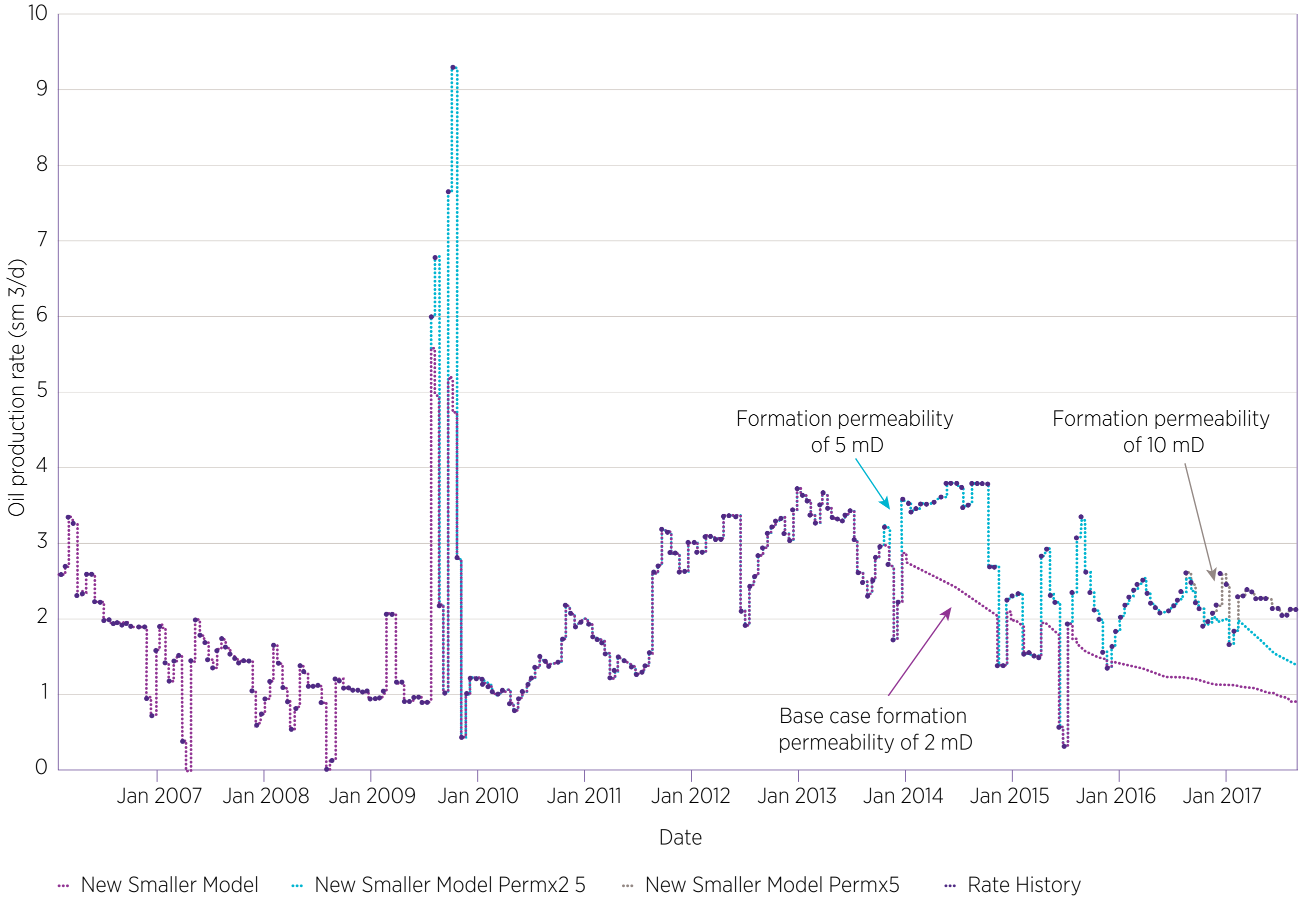


The test sequence of the interference test scenarios with two monitoring wells followed by a CO_2 injection test provides the most comprehensive reservoir test sequence. This can be accomplished within 360 days, which meets all the previously set test objectives and is the recommended test for the Wuqi Reservoir trial.

3.1.2.3 Sensitivity analysis on bulk permeability

One of the main uncertainties in the Wuqi Reservoir Petrel static model was bulk formation permeability. Recall that the history match to the production history was difficult to match – for both water and oil production. Thus, a sensitivity analysis of this parameter was conducted by multiplying the base case static Petrel Model permeability values by 2.5 and 5 (based on other observations reported in Shaanxi Yanchang Petroleum oil field reports). The mean value of bulk permeability increased from 2 mD (base case) to 5 mD and 10 mD, respectively. As shown in Figure 21, the model with the highest mean bulk permeability value (10 mD) resulted in the best history match with the reservoir observation data (small black circles). This helped improve the history match, particularly for the observed later time data and observed water production data.

Figure 21 History-matched oil production rates in the well (38-101) with different bulk permeability values (base case of 2 mD in red, 5 mD in blue, and 10 mD in green).



Higher formation permeability caused the signature of the “fissured” system to disappear due to the lower permeability contrast between the hydraulic fracture and the formation. Also, the water-flooded zone and non-flooded zone were more distinguishable in this scenario, resulting in the reservoir behaving as a composite reservoir with a non-unit mobility ratio. Figure 22 and Figure 23 describe the pressure response at the water injection well and their interpretations for both injecting and monitoring wells. A ROI of up to 160 m was reached for both high permeability scenarios, which was just at the outer edge of water-flooded zone. The calculated permeability at the injection well was 0.58 mD and 1.2 mD for the 5 mD and 10 mD mean bulk permeability scenarios, respectively. The pressure response at the observation well (38-101) resulted in a permeability estimation of 1.1 mD and 2.2 mD for the 5 mD and 10 mD mean bulk permeability scenarios, respectively.

Figure 22 Interference test pressure response in both the injection well (38-106) and monitoring well (38-101). Wells are simulated in Eclipse for the Wuqi subregion model with a mean bulk permeability of 10 mD.

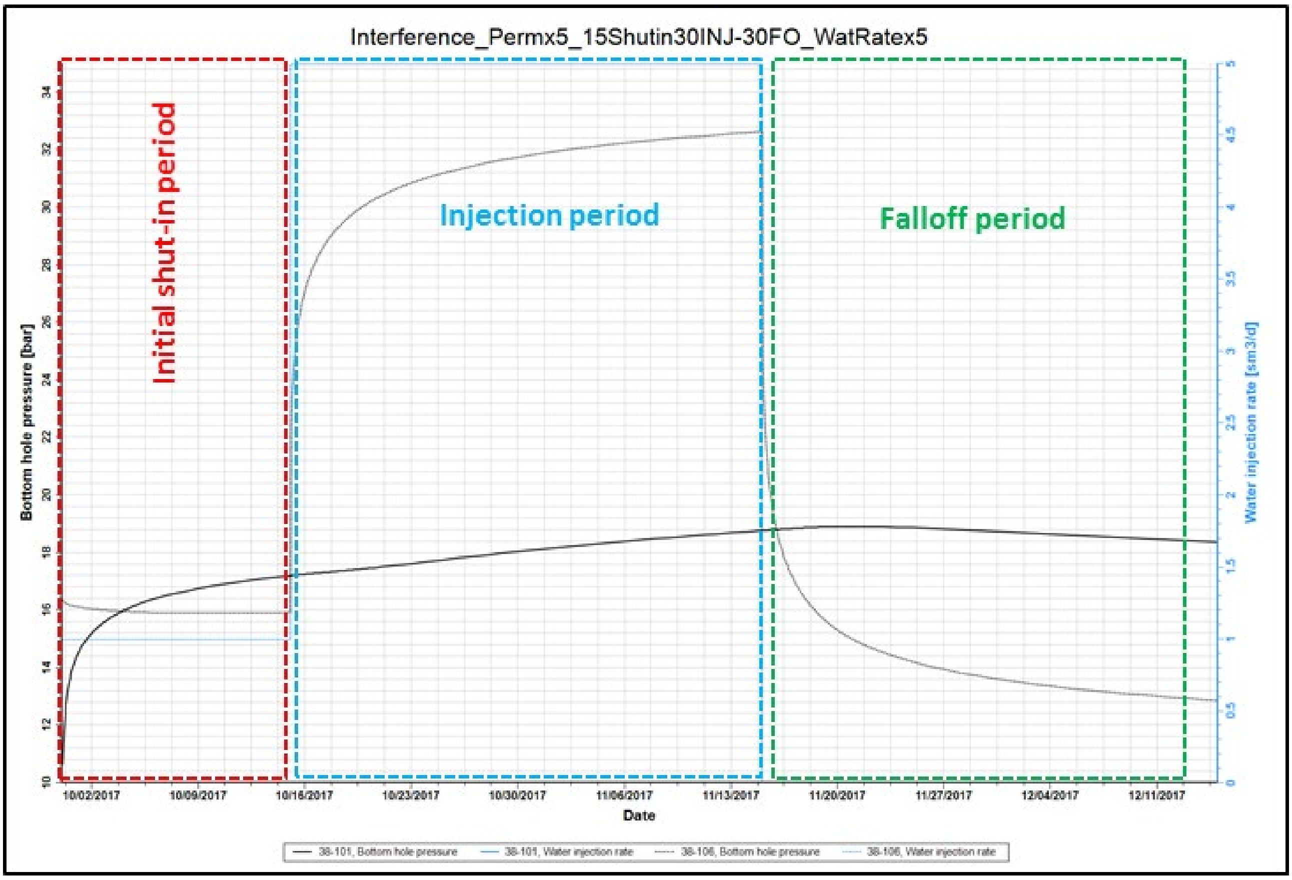
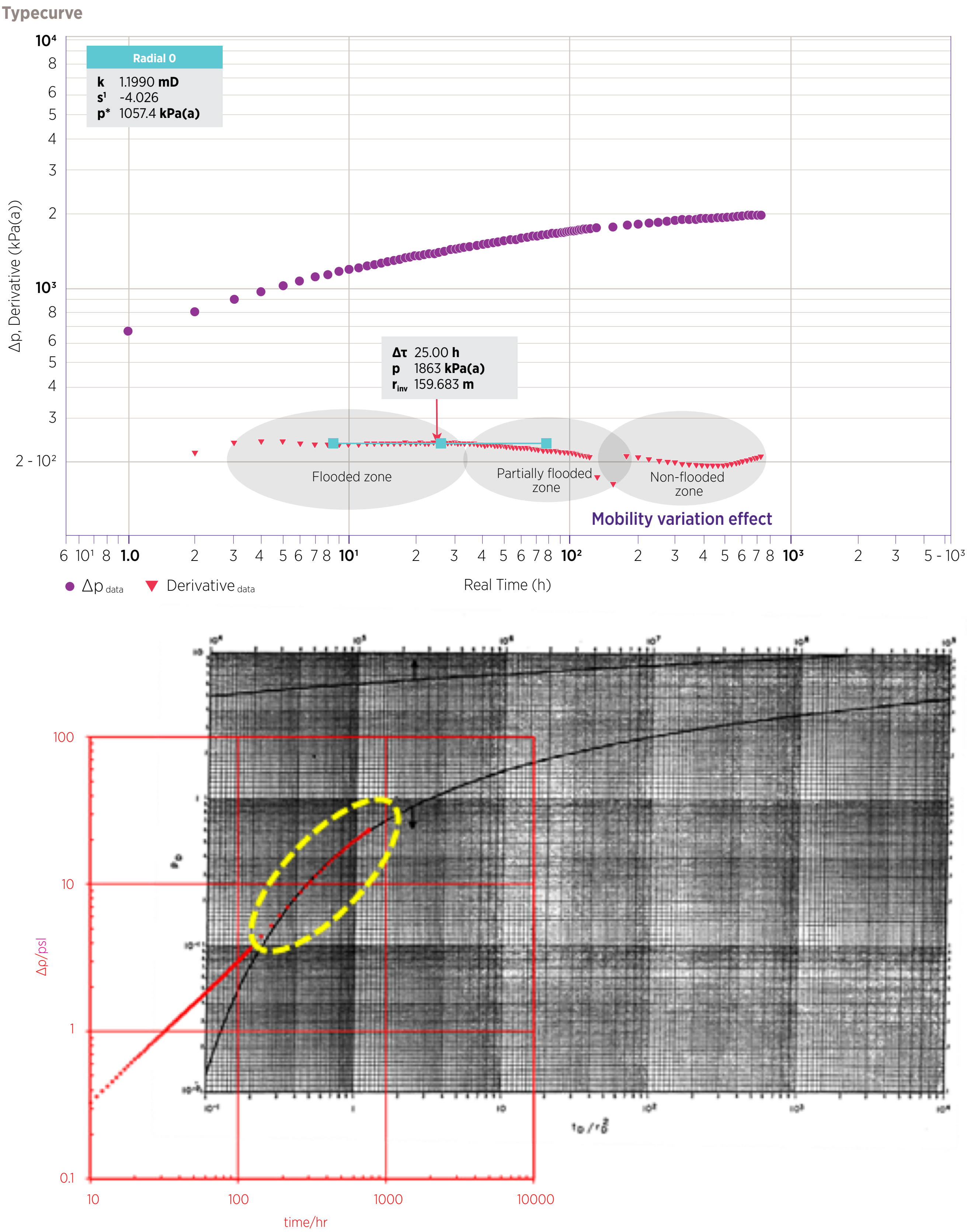


Figure 23 Pressure response in both the injection well (38-106) and monitoring well (38-101) with the interpretable portion of pressure response shown in yellow ellipse. Wells are simulated in Eclipse for the Wuqi subregion model, with mean bulk permeability of 10 mD.



As described in Figure 24 and Figure 25, the Phase 2 CO_2 injection test trial, assuming the higher bulk permeability model (10 mD), had more obvious composite reservoir character, with distinguishable CO_2 and water fronts. The total two-phase test (interference test plus CO_2 injection) duration required to achieve the test objectives decreased from 360 days for the base case (2 mD bulk permeability) to 255 and 225 days for 5 mD and 10 mD bulk permeability models, respectively.

Figure 24 Interference plus CO_2 injection test pressure response in both the injection well (38-106) and monitoring well (38-101). Wells are simulated in Eclipse for the Wuqi subregion model, with mean bulk permeability of 10 mD.

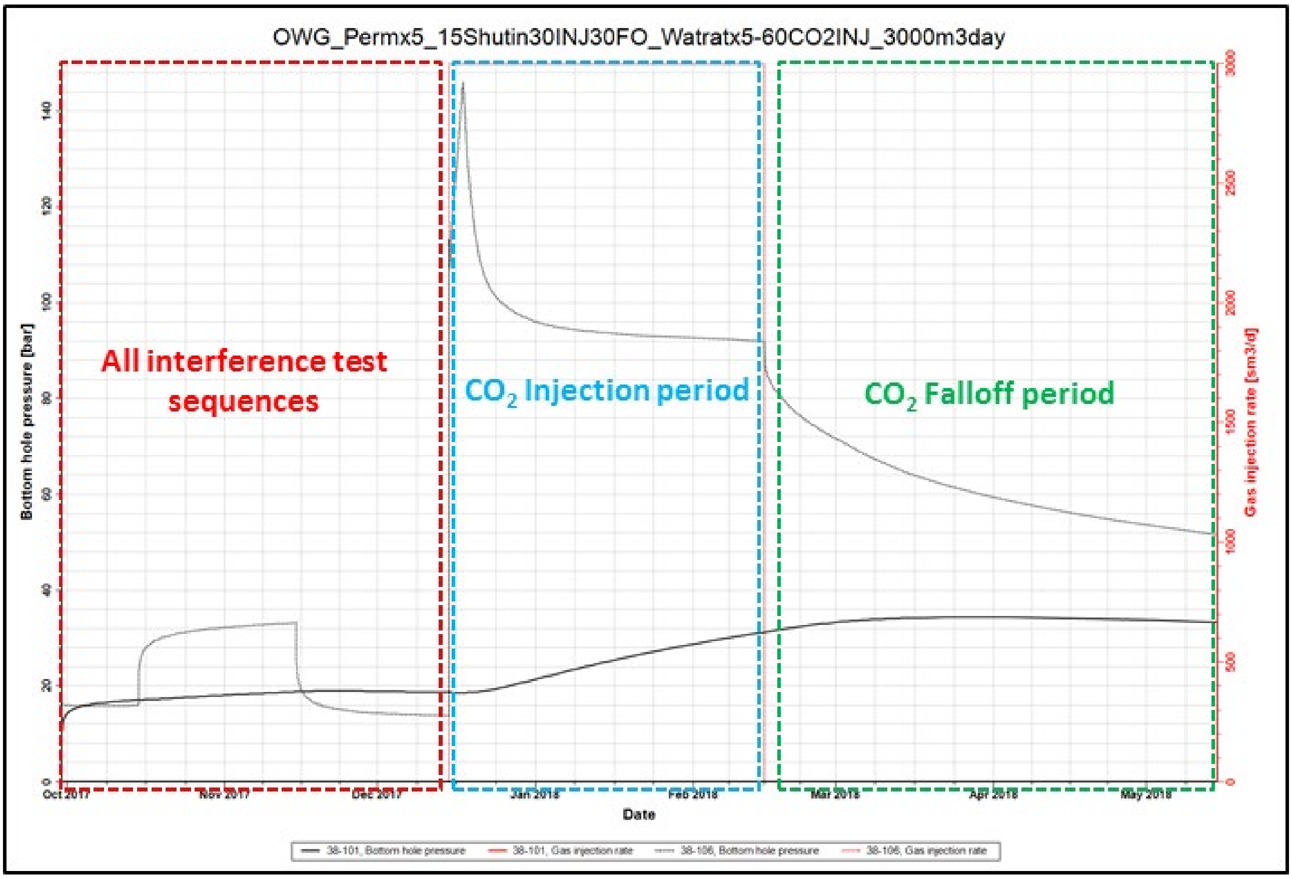
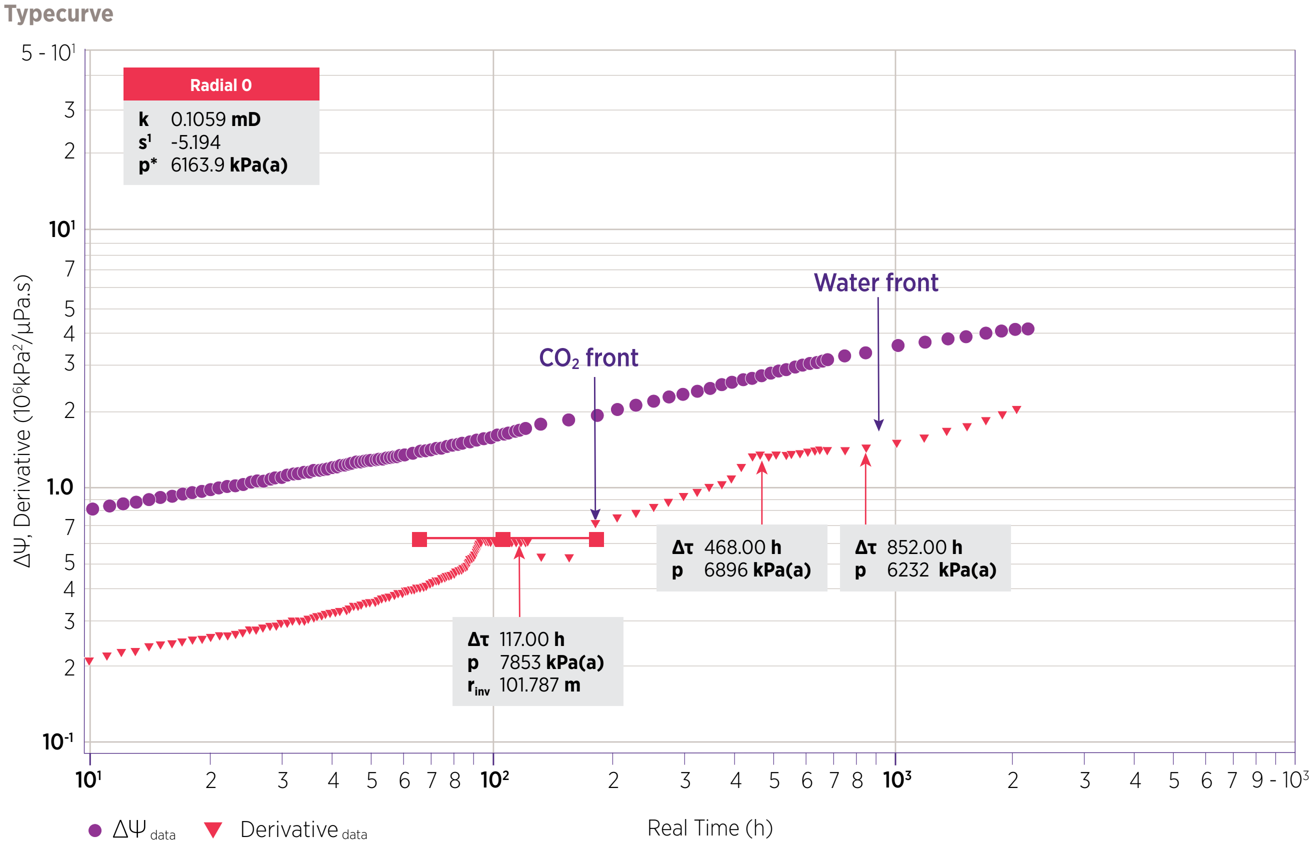


Figure 25 The log-log derivative plot for CO_2 FO pressure for the Wuqi subregion model with mean bulk permeability of 10 mD.



3.1.3 Summary

This Wuqi Reservoir represents a generally low permeability reservoir already undergoing secondary water flood-enhanced oil recovery and a pilot trial of tertiary CO_2 flood-enhanced recovery. Thus, any new disturbance to the reservoir system causes long lasting effects that makes data collection/interpretation challenging.

Conventional DD-BU and INJ-FO test design was attempted by shutting down the surrounding wells to "relax" the reservoir pressure in the vicinity of the testing wells. This resulted in a very complicated time-delayed distribution of disrupted data that made any pumping or injection test interpretation indeterminate.

As a different approach and in keeping with the generally low permeability, all the wells were kept producing/injecting with no change in their current rates except for the pressure monitoring wells. This resulted in a more stable background reservoir pressure over time, from which the well test pressure perturbations could be more confidently interpreted.

The INJ-FO interference test with two monitoring wells (Well Test Design described in section 3.1.2.2.1) is the most favourable design that meets all of the initially set test objectives. This gives the largest pressure response at the observation wells in two directions within the reservoir. It also allows for decisions to alter the length of each phase while running the test, if a real-time readout can be achieved on installed gauges. This test could be followed with a CO_2 injection test option.

The interference test with two monitoring wells sequence with a follow-up CO_2 injection test was the design that provided the highest chance of achieving the test objectives of establishing the reservoir characteristics and constraining dynamic CO_2 storage capacity within a testing time of less than a year. The largest current uncertainty is the bulk reservoir permeability. Depending on assumptions about high, medium and low permeability, the likely duration required to achieve adequate pressure response at both injection and observation wells for each phase of testing will vary. The phases of testing are:

- "A" days initial shut-in relaxation at the 38-101 and 38-103 observation wells
- "B" days INJ of water at a rate of 7 m^3/day (44 STB/day)
- "C" days FO
- "D" days CO_2 injection
- "E" days CO_2 falloff

Based on the Eclipse model, the estimated duration of each test phase for a given permeability assumption is presented in Table 3. Note that all possibilities provide a total test sequence of less than a year in duration. Also note as the test is being run and real-time P/T readout is observed, UQ-SDAAP will be able to determine which permeability scenario is most likely the case. Decisions on test segment duration "on the fly" can be made accordingly.

3.1.4 Key attributes for a successful test

- Keep all production and injection rates (all testing and surrounding wells) as constant as possible
- Acquire accurate and frequent production/injection volume measurements over time
- Acquire accurate and frequent wellhead pressure measurements over time at injection and observation wells
- Procure the most accurate as possible downhole P/T gauges (need a redundant gauge) in the observation wells. Gauges are to be installed with a gauge carrier and wire to surface for real-time surface read out. Gauges to be located as close to the perforated interval as possible
- Procure the most accurate as possible downhole P/T gauges in the injection well with a low-flow pump that allows for the gauge cable. The gauges are to be installed with a gauge carrier and wire to surface for real-time surface read out. The well completion has to be designed to allow the cable to reach to the surface (e.g. clipped onto the outer side of the injection tubing). There should be a redundant dual P/T gauge system in the well, ideally located below the perforated interval (avoid disturbance from flowing fluids). If this is not possible, a few metres above the completed interval will be second-best choice.

Proposed test operational summary (well test design 3.1.2.2.1)

- Install the P/T gauges in the injection (38-106) and observation (38-101 and 38-103) wells
- Leave well 38-101 and 38-103 as observation wells with no pumping
- Resume injection at 38-106 at 1 m^3/day of water for “A” days
- Increase injection at 38-106 to 7 m^3/day of water for “B” days
- Shut-in the injection well 38-106, and continue observing the falloff for “C” days
- Inject CO_2 into 38-106 at flow rate of 2500–4000 m^3/day for “D” days
- Shut-in the injection well 38-106, and observe the falloff for “E” days
- The total test time is “F” days

Downhole gauge suggestions

Table 6 summarises the gauges with acceptable specifications. For the Wuqi test trial, the Eclipse-generated pressure change during Phase 1 interference test: between 75 to 210 days; and Phase 2 CO_2 injection: 150 days and therefore it becomes important to select a gauge with small drift over the test period. Taking this into consideration, any of the following gauges (Table 6) or equivalent would be suitable for the Wuqi test trial.

Table 6 Some examples of acceptable downhole gauges with their specifications proposed for Wuqi well test operations.

Provider	Product name	Pressure range (psi)	Accuracy (%full scale)	Resolution (psi)	Drift (%full scale/year)	Comment
Weatherford	xQuartzPT	0-25000	Not reported	0.006 (at 1 sec sample rate)	Not reported	Quartz gauge - Real time using OmniWell Data Acquisition Platform
Haliburton	DataShere ROC	0-10000	0.012	0.006 (at 1 sec sample rate)	<0.02	Quartz permanent downhole gauge - (Real time monitoring needs to be confirmed)
Schlumberger	XPQG-10	0-10000	0.02	0.005 (at 1 sec sample rate)	<0.01	Quartz permanent downhole gauge - (Real time monitoring needs to be confirmed)

Pump requirements

- The test requires a low-flow rate pump that can achieve a constant water pumping rate (capable of between 1 and 10 m^3/day)
- The CO_2 injection pump needs to meet the CO_2 flow rate requirement of (as low as) 2500-10,000 sm^3/day
- The water and CO_2 pumps must allow for the P/T gauge cable to pass down to the bottomhole location
- Existing pumps may be suitable although we do not have any technical specifications on them yet

3.1.5 Functional pilot test plan

3.1.5.1 Well test outline

Water injection

- Water will be injected into well 38-106, and the pressure responses will be recorded in injection well (38-106) and two monitoring wells (38-101 and 38-103)
- The duration of the test will be no more than 210 days. This will be 60 days initial shut-in, followed by 120 days injection, and followed by 30 days falloff
- The maximum estimated water injection rate will be 10 m^3/day
- The maximum total water requirement will be 1200 m^3
- The maximum required injection WHP is 70 bar, based on Pfrac of ~250 bar

Note:* The frac pressure to be confirmed by Shaanxi Yanchang Petroleum team

CO_2 injection

- CO_2 will be injected into well 38-106, and the pressure responses will be recorded in injection well (38-106) and two monitoring wells (38-101 and 38-103)
- The duration of the test will be no more than 150 days. This will be 60 days injection followed by 90 days falloff
- The maximum estimated CO_2 injection rate will be 8 tonnes/day
- The maximum total CO_2 requirement will be 480 tonnes
- The maximum required injection WHP is 150 bar, based on Pfrac of ~250 bar

Note:* The frac pressure to be confirmed by Shaanxi Yanchang Petroleum team

To proceed with this test, the selection criteria for required equipment are proposed in the following sections

3.1.5.2 Downhole gauges: measurement of (flowing) BHP and BHT vs. time

- A consistent, accurate time reference is needed for all measurements so that pump, wellhead (WH) and bottomhole (BH) gauges can all be compared accurately
- Redundant dual pressure/temperature gauges configuration; two gauges on two separate wires
- The gauges required to be installed as close as possible to the perforation interval
- The surface read out (SRO) setup is required for real-time data gathering/monitoring
- The gauge resolution needs to be 0.005 psi or better
- The maximum expected bottomhole pressure (BHP) at the injection well (38-106) is 225 bar, or 90% of fracture pressure (Pfrac≈250 bar; to be confirmed by Shaanxi Yanchang Petroleum team)
- The maximum expected BHP at the monitoring wells (38-101 and 38-103) is ~70 bar
- The minimum expected BHP is ~50 bar (Shaanxi Yanchang Petroleum to confirm the current BHP in the Wuqi Reservoir)
- Select the gauges to maximise the resolution and accuracy, and to minimise the drift
- The gauge specifications required to meet reservoir pressure/temperature (P/T) conditions
- The gauges, cables and mountings to be CO_2 resistant
- Shaanxi Yanchang Petroleum to decide on the conveyance method for the gauge installation and to manage/perform the operation

3.1.5.3 Downhole shut-in valve

- The downhole shut-in valve is to be placed above the downhole gauges and as close as possible to the gauges
- Made of CO_2-resistant material
- Shaanxi Yanchang Petroleum to manage/perform the operation of downhole shut-in valve installation

3.1.5.4 Pumps

Low rate water and CO_2 pumps that can pump at fixed pressure and stepped rate are required:

- Water pump required with capability of injection rate of between 1 and 10 m^3/day
- If in contact with CO_2, it needs to be CO_2 resistant
- CO_2 pump with capability of injecting about 8 tonnes of CO_2 per day
- Pump control should allow for stepped rate pumping
- Pump control should allow constant outlet pressure pumping
- Pumps are needed to be configured in order to allow the downhole gauges to wire up to the surface for real-time data recording-SRO
- Shaanxi Yanchang Petroleum to manage/perform the operation of water and CO_2 pump installation

3.1.5.5 Injecting fluid

Water should be pre-treated to avoid downhole scaling:

- Water to be treated for biological materials, such as plankton and bacteria, to eliminate any biological activity
- Solids (fines) to be removed/filtered (if a filter is used, pressure drop will have to be accounted for)
- De-oxygenising water to prevent corrosion and bacteria growth resulting in plugging the injection well
- Water to be treated for sulfate removal to prevent scales forming in well and surface facilities

In addition, water composition and temperature and pressure measurements are required, according to:

- Water composition should be measured after pre-treatment
- Wellhead temperature must be measured hourly to a data logger
- Wellhead pressure must be measured hourly to a data logger

CO_2 composition, and temperature and pressure measurements are required, as per the following:

- Composition of CO_2 and non-CO_2 components can be measured at the source
- Wellhead temperature of CO_2 must be measured hourly to a data logger
- Wellhead pressure of CO_2 must be measured hourly to a data logger
- Approximate CO_2 pressure and temperature at the wellhead and sandface (which in turn define the phase, i.e. liquid/gas/supercritical). These are measured with the downhole gauges
- Taking into account the thermal effect on reservoir fracture pressure, the downhole pressure should stay below the fracture pressure

3.1.5.6 Data collection and reporting

Upon field test commencement, high-frequency data monitoring will be essential to ensure the test is progressing appropriately. The UQ-SDAAP team recommends the data sampling rate to be set to an **hourly basis**. The UQ-SDAAP team also suggests for data to be compiled on a **daily basis** and sent to UQ by email for review.

The wellhead pressure and temperature, bottomhole pressure and temperature, and injection/production rates vs. time are required to be recorded throughout the test for the testing wells (38-106, 38-101 and 38-103) on an hourly basis. If possible, the surrounding wells also require wellhead pressure and temperature, and injection/production rates vs. time to be recorded on an hourly basis (38-100, 38-102, 38-104, 38-105, 38-107, 38-164, 38-167, 38-247, 38-8, 38-163 and 38-248).

Note: The frequency of data collection/reporting will be adjusted during the test, based on initial data acquired.

4. Risk register

In order to proceed with the proposed well test in the Wuqi Reservoir, UQ-SDAAP assessed associated risks before commencing wellsite operations. The risk matrix described in Figure 26 was used to score the risks. Reservoir-related, operational and logistical risks were registered along with their descriptions, consequences, probabilities, risk owner(s), action party(ies), and possible mitigation actions, as shown in Figure 27. Each risk category is described below in further detail.

Figure 26 Risk matrix score for the Wuqi Reservoir field trial.

Risk Matrix Scores						
Impact or consequence		**Probability or likelihood scale**				
		1	2	3	4	5
		Highly Unlikely Only in exceptional circumstances or no previous incidence or in direct control	**Unlikely** Could occur at some time. Rarely has. Checks and balances usually suffice. Early indications promising etc	**Likely** Material chance, (or out of direct control) treat as if at least 50:50 until reduced	**Very Likely** More likely than not to occur. Has happened often before. Or not in direct control	**Highly Likely** Treat as if almost certain to occur. A common or reasonably expected occurrence
	Consequences (below)	0-5%	5-20%	20-50%	50-80%	80-100%
5	**Catastrophic** Could make the project worthless					
4	**Major** Could significantly impact the project objectives					
3	**Important** Requires mitigation and management					
2	**Prefer to avoid** Needs some actions					
1	**Insignificant**					
0	Completely aligned	Project outcomes fully achieved, no degradation				

4.1 Reservoir-related risks

4.1.1 Low permeability at the injection well

The current base case estimation of reservoir bulk permeability is about 2 mD; however, there is a risk of encountering lower permeability values at the injection well. In the event of lower than expected permeability near the injection well, the injecting fluid (at volumes prescribed) during the testing period may create hydraulic fractures which cause CO_2 channelling between the injecting well and production or monitoring wells. Similarly, early CO_2 breakthrough at the production or monitoring wells can occur if there are pre-existing hydraulic fractures in the formation from previous oilfield operations. Fractures induced or pre-existing in the reservoir may also extend vertically into the overlying seal with water/CO_2 injection. The injection could also induce the re-activation of faults (should they be occurring), causing CO_2 to migrate out of the reservoir. Any of these scenarios could result in the observed pressure responses at the observation wells to be different from what has been modelled.

If the reservoir has a lower bulk permeability than expected (<1 mD) and there is no natural or induced fracturing, this could result in delays for the pressure response at the monitoring wells. This could lead to to a longer test period and lower the signal-to-noise ratio of the data. It could also make data interpretation more complex.

4.1.2 Geomechanical framework

An insufficiently defined reservoir geomechanical framework can lead to unexpected stress effects, such as fault reactivation and development of hydraulic fracturing. Poro-elastic effects, such as stress-dependent permeability, could also occur during the test as the formation pressure is changed and there is an equivalent change in effective stress.

4.1.3 Fluid and rock interactions

The minimum miscibility pressure experimental work conducted for this reservoir showed that CO_2 is immiscible at reservoir conditions. The injected immiscible CO_2 reduces interfacial tension (IFT) between water and oil, and generates in situ water in oil emulsions (Rojas and Ali 1988). Despite its favourable impact on ultimate oil recovery, emulsions may reduce the formation permeability (Kokal et al. 1992).

Injecting water and CO_2 into the reservoir can block/reduce the reservoir permeability to individual fluid phases due to incompatibility (immiscibility) between injected fluid and reservoir fluid. The injected CO_2 is soluble in the formation water and will reduce the pH (Benson and Cole 2008). This could lead to water-rock interactions that could either dissolve or lead to precipitation of minerals in the formation. The effect could be fine particle mobilisation that contributes to reservoir permeability reduction (fines migration or mineral precipitation or increase [mineral dissolution]).

In order to proceed with the proposed well test in the Wuqi Reservoir, UQ-SDAAP assessed associated risks before commencing well site operations.

4.2 Operational risks

4.2.1 Water/CO_2 quality

Injecting water into the reservoir can cause corrosion in surface facilities and wellbore assembly, resulting in particles becoming liberated into the water. Particulates are then carried into the well and can block the fluid pathways around the wellbore sandface. Low quality of injection water can also cause biological effects in the well and biomass creation that results in permeability reduction at the sandface.

Inappropriate water quality can also corrode downhole gauges/tools because of pH or oxygen levels, which can result in gauge or downhole shut-in valve failure during data collection. Injecting CO_2 that is not pure may result in some reactive gases, such as NOx or SOx, to be present, which can cause corrosion, scaling, and mineral precipitation that can ultimately reduce well injectivity.

4.2.2 Surface facilities

If the volume that water or CO_2 pumps deliver is measured incorrectly, or the pump-operating capacity is insufficient, then uncertainty in the actual injection rates (lower or higher) will result. Lower-than-expected rates will result in a longer testing period and lower signal-to-noise ratio. Higher-than-expected rates can generate high injection-well bottomhole pressure, possibly imposing unexpected geomechanical stress to the formation that could result in unwanted induced fracturing.

Inadequate liquid volumes stored in onsite water and CO_2 tanks affect the fluid volume available for injection that could result in unsustainable (lower) or fluctuating injection rates. This can delay the arrival of the pressure response at the monitoring wells, causing the test to run longer, as well as reducing the pressure resolution (fidelity) observed at the monitoring/injecting wells.

4.2.3 Downhole equipment

Corrosion of downhole tools, such as downhole shut-in valves or packers, can result in complete loss of data or failure of downhole shut off that can lead to poor data quality because of the resulting reliance on surface data. Corrosion can also affect the integrity of the injecting well where it generates leakage pathways in downhole strings, leading to loss of injectivity.

The downhole gauges and associated cables can also fail due to corrosion, short circuiting, pressure/temperature sensor damage or data transmitter damage. This situation can result in incomplete or null data collection.

Figure 27 Yanchang Petroleum Project Risk (Opportunity) Register.

ID	Headline	Risk or Opportunity (Narrative)	Consequence (Narrative)	Classification			
				THSE	EC	O	SPL
1	Low permeability in injection well	Creation of hydraulic fracture if perms lower than expected (<1 mD)	Streamlining of CO_2 between injector and producer, affecting data interpretation	X			
2	Low permeability in injection well	Breakage of reservoir seals, re-activation of faults	CO_2 leakage	X			
3	Low permeability in injection well	Delay in pressure response at monitoring well	Complex data interpretation (more ambiguity)	X	X		
4	Presence of existing HF	CO_2 streamlines down the existing HF	Poor sweep efficiency, premature CO_2 cycling	X			
5	Unexpected stress effects	Poorly defined geomechanical framework or data limitations lead to surprises!	Fault reactivation. HF fracture development or growth. Poro-elastic effects such as stress dependent permeability effects	X			
6	Emulsions & Oil properties	CO_2 is immiscible with oil phase or adversely effects oil phase	Relative permeability effects (especially reductions)	X			
7	Reservoir blockage	Incompatibility of injection water and CO_2	Decrease permeability, high injection pressures	X			
8	Reservoir blockage	Precipitant from injection reactant (e.g. dissolved iron, scale, etc.)	Decrease permeability, high injection pressures	X			
9	Fines mobilisation	Water salinity changes mobilises in-reservoir fines due to salinity or pH changes	Permeability blockages or reduction. Time dependent abhoration	X			
10	Channelling	Streamlining via natural and micro fracture	Poor sweep efficiency, premature CO_2 cycling	X			
11	Water Quality	Purity, compatibility of injection water and CO_2. WAG	Decrease permeability, high injection pressures	X			
12	Water Quality	Corrosion in facilities creates particulates which are carried into the well and block permeability	Decrease permeability, high injection pressures	X			
13	Water Quality	Wellbore corrosion creates particulates in water carry into the well	Decrease permeability, high injection pressures	X			
14	Water Quality	Biological affects in the well - biomass creation	Decrease permeability, high injection pressures	X			
15	Water Quality	Carryover of solids to injection system	Decrease permeability, high injection pressures	X			
16	Water Quality	Carryover of organics to injection system	Decrease permeability, high injection pressures	X			
17	Downhole Failure	Water quality affecting gauges	Gauges and tools corroded and data operations fail or downhole shut-off e.g. because of pH or oxygen levels	X			
18	Water surface pump delivery	Improper measurement or operating capacity of surface pumping equipment	Injection rates or volume (high or low) affecting results	X			
19	Water storage	Inadequate water storage from No.17 water source site	Can't meet the $7m^3/d$ requirements, and late pressure response at monitoring well				
20	Downhole Tool Failures	Packer Failure	Corrosion downhole/failure results in complete loss of data or failure of downhole shut off leads to poor data quality because of reliance on surface data				
21	Downhole Tool Failures	DH Shut-in Failure	Corrosion downhole/failure results in complete loss of data or failure of downhole shut off leads to poor data quality because of reliance on surface data				
22	CO_2 impurities	Non-CO_2 content with reactive gasses	Corrosion, scaling, mineral precipitation in reservoir, rel_perm effects				
23	Freezing during WAG	CO_2 inj. after water cause freezing at wellhead	Block on injectivity, overpressure or equipment failure by pumping 100% CO_2 at the wellhead				
24	Freezing during WAG	CO_2 inj. after water cause freezing at wellbore	Block on injectivity, overpressure or equipment failure by pumping 100% CO_2 directly into water column	X			
25	CO_2 surface pump delivery	Improper measurement or operating capacity of surface pumping equipment	Injection rates or volume (high or low) affecting results	X			
26	Sitepower outage	Power outage during test	Missing data or pump loss	X			
27	Pre-test shut-in time	Random transients effect interpretation of injection fall-off data	Inability to properly analyse test and therefore CCUS potential	X			
28	Inadequate shut-in times or incomplete test acquisition	Random transients effect interpretation of injection fall-off data — no infinite acting radial flow is formed	Inability to properly analyse test and therefore CCUS potential			X	
29	Operation in nearby well	Impacts from interference well operation (blockage, unplanned / emergency maintenance)	Impacts on pressure response	X			
30	Break in data transmission	Gauge, cable readout device damage	Unable to collect data	X			
31	Well integrity	downhole strings leakage caused by corrosion	Impact on injectivity				
32	Surface data transmission issue	data transmission break causd by climate, surface device damage	Data missing or collection issue				
33	Data server crash	internet or server crash	Data missing or collection issue				
34	Power outage of surface and downhole device	power outage or monitoring system circuit failure	Data missing or collection issue				
35	Gauge damage	Bad signal, corrosion, pressure sensor or data transmitter damage	Data missing or collection issue	X			
36	Cable corrosion	corrosion, break, short circuit	Data missing or collection issue	X			
37	Downhole gauge failure	corrosion, break, short circuit	Data missing or collection issue	X			

Rating when Registered								Mitigating Action / Response (Narrative)	Responsible Risk Owner	Action Party(ies) (plans, dates and deliverables to be addressed elsewhere)
Conseq. (1-5)	Probab. (1-5)	Result (CxP)	Rating			Assmnt Maturity	Time Frame			
			L	M	H	Low 1 High 5	Sh-Med-Lng Term			
3	2	6		X		3	ST	Provide UQ with data to review geomechanics and hydraulic fracturing potential and report to team	Yulong	Ray to provide requirements
4	1	4	X			5	LT	Long-term with larger action	Wong	Li
3	4	12		X		3	ST	Closely monitor pressures and alter test program as required	Vahab	Li
3	1	3	X			5	ST	Provide Ray with prior frac results (charts, pressures, etc.) from other injection in this area	Liu	Ray to analyse
3	2	6		X		3	ST	Provide UQ with data to review geomechanics and hydraulic fracturing potential and report to team	Gao	Ray
3	1	3	X			4	LT	Impact is on long-term storativity, based on experience in other two projects	Liu	Li
3	1	3	X			4	LT	Impact is on long-term storativity, based on experience in other two projects	Liu	Li
3	3	9		X		1	LT	Scaling tendencies? Iron reprecipitation (lab testing with existing samples) and test with produced waters at varying loadings of Fe^{3+} to assure downhole compatibility. Assure ompatibility	Zhang	Zhang
3	1	3	X			4	LT	Impact is on long-term storativity, based on experience in other two projects	Wong	Li
3	1	3	X			4	LT	Impact is on long-term storativity, based on experience in other two projects	Wong	Li, Vahab
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liu	Li
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liu	Li
4	1	4	X			5	ST	Inspection log in advance and will evaluate wall thickness results. However, an wall thickness inspection log in a current CO_2 injector for degree or evidences of corrosion in the future as no loss has occurred in other wells	Wang	Bai
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liu	Li
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liu	Li
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liu	Li
4	1	4	X			5	ST	Regular testing currently underway of intake and outflow from plant	Liang	Liang
5	2	10		X		5	ST	Until verification of <5% is produced investigation of (e.g, magnetic, coriolis effect, etc) flowmeter installation and intake	Liu	Li
5	1	5	X				ST	Water level is checked every 8 hrs	Li	Li
5	1	5	X				ST	Installation in other locations has been reliable	Wang	Liang
5	3	15			X	2	ST	In production well,-3/20 failures, no history of use on injection; therefore a 33% likelihood (16.6%/50%= 33.2% or 50%). Install a surface gauge and use static gas column for surface measurements and correct wellbore storage	Wang	Liang/Vahab
4	1	4	X			4	ST	Get lab reports with each load/delivery	Liu	Wong
5	1	5	X			5	ST	Not a problem at current sites	Wang	Gao
5	1	5	X			2	ST	Utilising a strategy of starting 100% water=> 100% to 0% water + 0% to 100% CO_2 =>100% CO_2 or pump 100% N2 to clear the wellbore	Wang	Gao
5	1	5	X			5	ST	Verification of flowmeter with vessel storage measurements	Wang	Gao
4	1	4	X			4	ST	Backup generators to assure only minimal effects (<2 hrs, <1/mo)	Wang	Gao
4	1	4	X			5	ST	Operating guidelines are in place to prevent	Wang	Liu
4	1	4	X			5	ST	Organisational commitment to complete the test to satisfaction of analyst	Gao	Vahab
3	1	3	X			5	ST	Operating guidelines are in place to prevent	Wang	Liu
4	1	4	X			2	ST	Review CO_2 signoff on the cable and gauge with manufacturer	Wang	Gao
5	1	5	X			5	ST	Well integrity audit procedure in place and will be performed and checked	Wang	Liang
4	1	4	X			5	ST	Backup plan made and reviewed	Wang	Qiang
4	1	4	X			5	ST	Backup plan made and reviewed	Wang	Qiang
5	1	5	X			5	ST	UPS installed to manage	Wang	Gao
4	2	8		X		2		CO_2 signoff on the cable and gauge. Install two additional downhole memory gauges hung from a packer	Wang	Gao
4	2	8		X		2		CO_2 signoff on the cable and gauge	Wang	Gao
4	2	8		X		2		CO_2 signoff on the cable and gauge. Install two additional downhole memory gauges hung from a packer	Wang	Gao

4.3 Logistical risks

4.3.1 Injection sequences

The proposed testing sequence consists of an initial water injection period followed by CO_2 injection. Pumping 100% CO_2 directly into a water column may cause fluid to freeze at the wellhead or down the wellbore that could result in a loss of injectivity, over-pressurisation and/or failure of the facilities.

4.3.2 Test implementation

Inadequate pre-test relaxation shut-in time and/or insufficient injection and falloff periods carried out during the test can lead to uninterpretable pressure responses at the injection and monitoring wells. Unsuitable testing periods generate a low signal-to-noise ratio, leading to less reliable pressure transient analysis (PTA). Short testing periods can also hinder the development of an infinite acting radial flow regime, resulting in incomplete assessment of the CCUS potential of the Yanchang oil field. Also, unplanned operations in nearby wells, such as emergency workover/maintenance and significant changes in injection and pumping rates, can adversely impact the interpretation of the pressure response at monitoring bores due to added pressure transients.

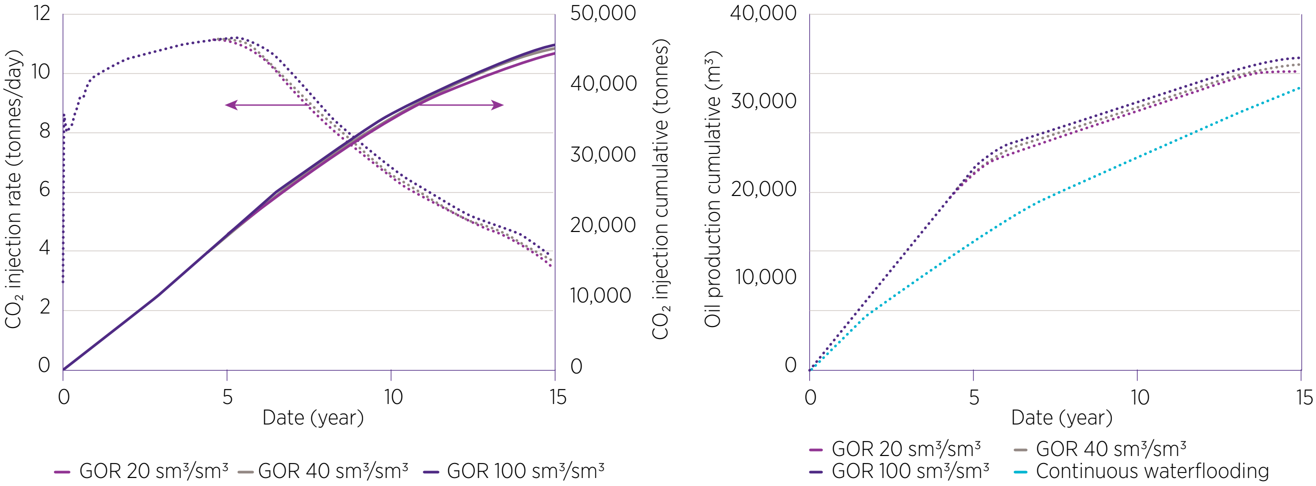
4.3.3 Injection site

Surface equipment, downhole devices or injection site power outages during the test can cause missing data, loss of equipment or variations in the injection rate, which can lead to increased uncertainty in data analysis and interpretation. Data collection issues also arise in the event of other onsite problems, such as internet/data server crashes or issues with surface data transmission.

4.3.4 CO_2 injection well count and EOR efficiency

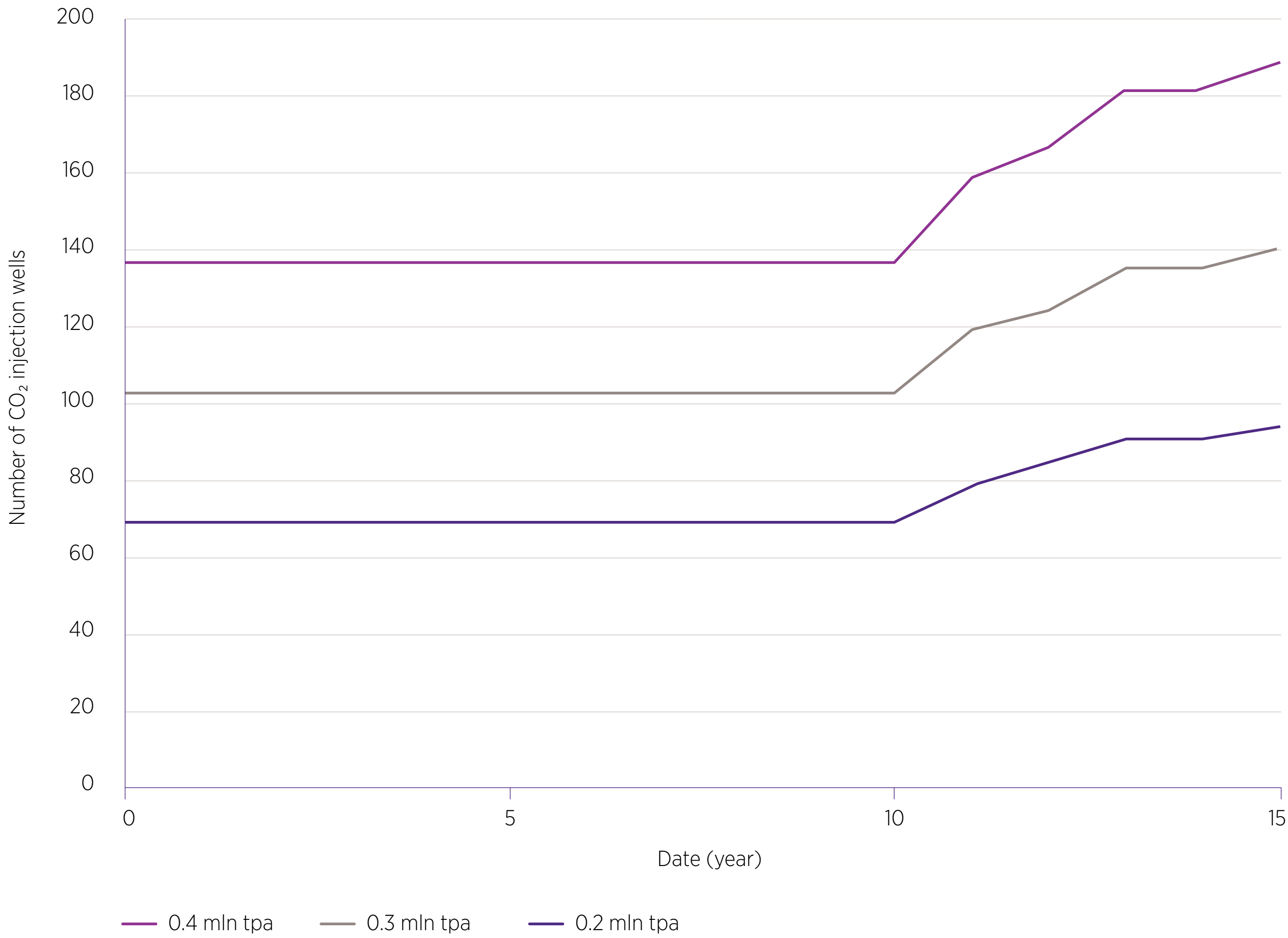
The Wuqi Reservoir sub-sector model (for the base case permeability assumption of 2 mD) was used to estimate the amount of CO_2 that could be injected per injection well over 15 years for both EOR and CO_2 sequestration purposes. Bottomhole pressure (BHP) at the injection well was considered to be the main constraint during the CO_2 injection simulation scenarios, and was chosen to be below the formation fracture pressure. Several scenarios with various gas-oil ratios (GOR) at the surrounding production wells were modelled, and the producing wells were shut in when the GORs reached 20, 40 or 100 sm³/sm³. Figure 28 shows that CO_2 could be injected at the maximum rate of 11.5 tonnes•day-1, and drops after five years of injection when five out of seven producing wells are to be shut in due to CO_2 breakthrough and high GOR values. Following the well shut-ins, the formation pressure ramps up rapidly, which further affects both the CO_2 injection and oil production rates. In this model, the total CO_2 produced with oil was limited to less than 300 tonnes, which makes up ~0.7% of the total CO_2 injected into the reservoir. As illustrated in Figure 28, the total oil produced using one CO_2 injection well and seven production wells over 15 years was about 35,000 m³, indicating that CO_2-EOR could result in ~10% incremental oil recovery compared to continuous waterflooding over a similar period.

Figure 28 CO_2 injection rate and cumulative CO_2 injected per well (left) and cumulative oil production during CO_2-EOR (or continuous waterflooding) for seven surrounding producing wells (right) estimated by dynamic simulation run.



The CO_2 injection profile described in Figure 28 was used to calculate the number of wells required to sequester 0.2, 0.3 or 0.4 million tonnes of CO_2 per annum (mtpa) for 15 years. The selection of annual CO_2 injection rates was based on current and upcoming CO_2 capture facilities to be built by Yanchang Petroleum, which can capture up to 0.4 mtpa. Figure 29 indicates that 69, 103 or 137 injection wells are needed to inject 0.2, 0.3 or 0.4 mtpa, respectively. The results also show that after 10 years, more wells need to be converted to CO_2 injection wells in order to maintain the injection rates of 0.2, 0.3 or 0.4 mtpa, with the well numbers increasing to 94, 141 or 188, respectively.

Figure 29 Number of CO_2 injection wells required for various annual CO_2 injection rates calculation is based on the CO_2 injection profile described in Figure 28 for a 15-year CO_2-EOR program.



5. Project 111

Engagement with China has been further strengthened through synergistic participation in a prestigious Chinese program known as the Higher Education Discipline Innovation Project. More commonly referred to as Project 111, the program was created by the Chinese Government to bring world-leading international scientists to China for collaboration. The program was launched in 2005 by China's Ministry of Education and the State Administration of Foreign Experts Affairs, with the aims being to:

- Establish 100 R&D and education bases in the Chinese universities
- Invite 1000 overseas talents from the top 100 universities and research institutes worldwide
- Form top-level research teams, foster development of frontier disciplines, and strengthen innovation capability, all helping to improve the overall competitiveness in China's leading universities

Hon Prof Suping Peng (Figure 30) from China University of Mining and Technology (CUMT) invited UQ researchers to participate in Project 111 to share their knowledge of carbon capture and storage science with CUMT researchers.

In September 2018, Professors Andrew Garnett, Jim Underschultz, Brian Towler, Ray Johnson, Joan Esterle, Xingjin Wang and Mike Hood conducted a series of well-received presentations at CUMT as part of this program.

Figure 30 Hon Prof Xingjin Wang, Prof Mike Hood, Prof Andrew Garnett, Prof Shuquan Zhu, and Hon Prof Suping Peng in China as part of the synergistic Project 111 engagement.

6. Next steps in the UQ-SDAAP China engagement

Shaanxi Yanchang Petroleum is proceeding with implementation of the field trial in the Ordos Basin. They have engaged equipment suppliers and contractors to instrument the injection and monitoring wells.

UQ Professors Andrew Garnett, Jim Underschultz and Xingjin Wang met with Yanchang Petroleum and CUMT in Beijing on 13 September 2018 to finalise well instrumentation and test procedures. UQ Professor Ray Johnson followed up with a meeting in Xi'an on 15–16 October 2018 to develop a risk register and conduct a HazOp process in advance of closing in the injection and monitoring wells and instrumenting them with appropriate monitoring. A further risking workshop occurred on 21–25 January 2019 led by UQ Professor Johnson and Dr Honari. The final CCS RD&D related workshop was held to discuss the Australian injection experience (at the CO_2 CRC Otway site, Port Campbell) in April 2019. This was followed immediately by a final technical workshop at UQ.

The Yanchang wells are in the process of being instrumented (Q1, 2019). The monitoring wells are being shut in for the two-month rest period. Water injection will start in April and continue for up to 12 months (subject to funding availability in China).

Further visits of Yanchang and CUMT staff to Australia, and UQ staff to China for field work or technical workshops are desirable to maintain the collaboration. The purpose would be to achieve the test objectives of: 1) relatively large ROI; 2) quantify any existing heterogeneity or fracture in the reservoir; and 3) improve confidence in the prediction of carbon storage injectivity. However, there are no CCS RD&D program funds available beyond 30 April 2019.

As planned, the CO_2 injection test trial would provide insights on relative permeability changes due to the introduction of a CO_2 phase into the reservoir, and allow a quantitative prediction of CO_2 injectivity, pressure build-up and steady rate. This data will be used to define the reservoir dynamic CO_2 storage capacity. CUMT and Shaanxi Yanchang Petroleum will use the field test results to design field-wide implementation of CO_2-enhanced oil recovery and determine the associated carbon storage potential from such operations.

A successful and productive relationship has been built between Australia (through UQ) and China, looking at the very important issue of evaluating sustainable injection in very tight reservoirs. CCS RD&D does not support this beyond April 2019.

Further visits of Yanchang and CUMT staff to Australia, and UQ staff to China for field work or technical workshops are desirable to maintain the collaboration.

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8. Appendices

8.1 Appendix 1: Listing of China engagements

Date	Delegation	Where	Why
23–25 May 2017	UQ, YP and CUMT	Xi'an, China	• First workshop on UQ-SDAAP project, including technical updates and progress on well testing in Surat Basin • Yanchang to present their CCUS projects in Ordos Basin • A visit to CO_2 capture plant and pilot CO_2 sequestration site • Sign the research agreement between UQ, YP and CUMT
28–29 March 2018	UQ, YP and CUMT	Brisbane, Australia	• Second workshop on UQ-SDAAP project, technical update and progress on well testing in Surat Basin • Yanchang to present their CCUS projects in Ordos Basin
14–15 June 2018	UQ, YP and CUMT	Xi'an, China	• Attended 9th Australia – China Joint Coordination Group on Clean Coal Technology Meeting and R&D Workshop to present UQ-SDAAP technical work • Meeting with YP team regarding their operational planning and downhole equipment selection
22–29 September 2018	UQ, YP AND CUMT	Beijing, China (Project 111)	• Attended a signing ceremony, laboratory tours, workshops and student training • Project meeting held with Yanchang and CUMT to provide an update on UQ-SDAAP
15–16 October 2018	UQ, YP and CUMT	Xi'an, China	• Third workshop on UQ-SDAAP project, including technical updates and progress on well testing in Surat Basin • Yanchang presented their CCUS projects in Ordos Basin. • Risk register and operational planning
21–24 January 2019	UQ and YP	Xi'an, China	• Workshop on Wuqi well testing, including progress, review risk registration in detail and "Recomplete the well on paper" exercise • Finalising the timeframe for each step of the program
10 April 2019	UQ, YP and CUMT	CO_2CRC visit – Otway site, Port Campbell	• Viewing an active CO_2 sequestration site in Australia
11 April 2019	UQ Workshop	UQ	• Three year project update, outcomes, learnings and next steps
30 April 2019	CCS RD&D Porgram	UQ	• End of Commonwealth funding

9. Glossary of terms, acronyms and abbreviations

Term	Definition
Abatement (carbon)	See definitions for Material Abatement and Feasible Abatement
BHP	Bottomhole pressure
BHT	Bottomhole temperature
Bo	Viscosity and formation volume factor
Carbon abatement	The reduction of the amount of carbon dioxide that is produced when coal and oil are burned
Carbon capture and storage (CCS)	Process by which carbon dioxide emissions are captured and removed from the atmosphere and then stored, normally via injection into a secure underground geological formation
CAS	Chinese Academy of Science
Casing	Thick-walled steel pipe placed in wells to isolate formation fluids (such as fresh water) and to prevent borehole collapse
CCS RD&D	Carbon Capture and Storage Research Development and Demonstration - A fund set up by the Australian Government for research, development and demonstration activities in supporting Australian industry to innovate and adapt new technologies and processes, in particular for transport and storage of CO_2. UQ-SDAAP is one of the projects funded under the scheme
CCS-EOR	Carbon capture and Storage — Enhanced Oil Recovery
CCUS	Carbon Capture Utilisation and Storage
CO_2 CRC	CO_2 Collaborative Research Centre
Connate water	In geology and sedimentology, connate fluids are liquids that were trapped in the pores of sedimentary rocks as they were deposited. These liquids are largely composed of water, but also contain many mineral components as ions in solution
CSC	China Scholarship Council
CUMT	China University of Mining and Technology
DD-BU	Draw-down build-up
Eclipse	Schlumberger reservoir simulation software
EOR	Enhanced oil recovery. One or more of a variety of processes that seek to improve recovery of hydrocarbon from a reservoir after the primary production phase
Feasible Abatement	UQ-SDAAP aimed to establish whether or not 'material' carbon Abatement was 'feasible' in the Surat Basin in southern Queensland via large-scale CCS. "Feasible Abatement" was defined to mean a combination of: i. Lowest risk: Non-technical risk factors are known and demonstrably minimised and there is a clear work plan to address them before any deployment ii. High technical confidence: High level of technical confidence that a high rate can be sustained for a long duration; and, that the CO_2 will be contained indefinitely iii. A robust, conservative capture scenario with minimum disruption to generation (minimum price impacts) iv. Pipeline routes possible with no obvious showstoppers v. Reasonable cost estimates: the unit costs of carbon abatement ($/t) and LCOE ($/Mwh) are in the range of published estimates for other CCS projects or literature

Term	Definition
Fossil fuel	A fuel source (such as oil, condensate, natural gas, natural gas liquids or coal) formed in the earth from plant or animal remains
GHG	Greenhouse gas
GOR	Gas-oil ratios
HazOp	A hazard and operability study (HAZOP) is a structured and systematic examination of a complex planned or existing process or operation in order to identify and evaluate problems that may represent risks to personnel or equipment
HM	History matching
IFT	Interfacial tension
IHS	Transient well test software
Immiscibility	Injecting water and CO_2 into the reservoir can block/reduce the reservoir permeability to individual fluid phases due to incompatibility (immiscibility) between injected fluid and reservoir fluid
Injection falloff interference test	A downhole reservoir pressure test
INJ-FO	Injection-falloff
Interference test	Is a multiple-well transient test where one well is active and pumps fluid from or into the reservoir to create pressure disturbance and one or more well(s) remains idle as monitoring well(s)
Logging (well)	Recording of information of subsurface formations. Logging includes records kept by the driller and records of mud and cutting analyses, core analyses, drill stem tests, and electric, acoustic and radioactivity logging
mD	Millidarcy
NOx	Oxides of nitrogen, especially as atmospheric pollutants
Ordos Basin	The Ordos Basin, China's second-largest sedimentary basin, covers an area of 370,000km^2 across Shaanxi, Gansu and Shanxi provinces and Ningxia
P/T	Pressure/Temperature
Permeability	The permeability of a rock is the measure of the resistance to the flow of fluid through the rock. High permeability means fluid passes through the rock easily
Permo-Triassic	Relating to the Permian to Triassic periods
Petrel	Software used for geological and reservoir engineering models
Petroleum	Petroleum is a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase
Petrology/ Petrophysics	The study of rocks, their origin, chemical and physical properties and distribution
Pipeline	A system of connected lengths of pipe, buried or surface laid for the transportation of fluids
PTA	Pressure transient analysis
Pulse test	Is where the flow rate at the injecting (or producing) well is changed over time in a series of alternating flow and shut-in periods (Kamal 1983)
Reservoir	A subsurface rock formation containing one or more individual and separate natural accumulations of moveable petroleum that is confined by impermeable rock and is characterised by a single-pressure system
Rock compressibility	Rock compressibility is called pore volume (PV), or pore compressibility and is expressed in units of PV change per unit PV per unit pressure change
ROI	Radius of investigation
Shaanxi Yanchang Petroleum	Leading Chinese petroleum company focused on both upstream and downstream development of hydrocarbon resources of Shaanxi Province

Term	Definition
Skin factor	Is a term introduced to account for any deviation from radial flow in the near well bore region and quantifies the pressure drop (positive skin) near the well bore due to formation damage induced during drilling operations, or flow improvement (negative skin) because of well stimulation such as acidisation
Solar PV	Solar photovoltaics
SOx	Oxides of sulfur, especially as atmospheric pollutants
SRO	Surface read out
STB/day	Stock tank barrels per day
Surat Basin	The Surat Basin is a geological basin in eastern Australia. It is part of the Great Artesian Basin drainage basin of Australia. The Surat Basin extends across an area of 270,000km^2 and the southern third of the basin occupies a large part of northern New South Wales, the remainder is in Queensland
UQ-SDAAP	The University of Queensland Surat Deep Aquifer Appraisal Project is part of the ongoing development of carbon capture and storage (CCS) to help reduce emissions from fossil fuel in Australia
WH	Wellhead
Wireline	Small-diameter metal line used in wireline operations; also called a slick line. A system in which a flexible cable and reel is used to lower a log or maintenance equipment into a well, rather than a rigid drill string, offering considerable savings of equipment, manpower and time
Wireline logs	See logging (wells)
Wuqi Reservoir	In the Yanchang Field, Shaanxi Province of China
Zerogen Project	The ZeroGen Project was a Queensland Government initiative established to develop, construct and operate an Integrated Gasification Combined Cycle (IGCC) and carbon dioxide capture and storage (CCS) power plant and storage facility in Central Queensland, Australia

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