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Fault Leakage Detection From Pressure Transient Analysis

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Summary

Leakage of reservoir fluids from injection site, e.g. through faults, is one of the key risks associated with long-term CO2 geological storage. Leakage monitoring technologies applied at different levels: in-situ, groundwater and surface, are necessary to ensure safe CO2 storage. Development and testing of the monitoring technologies is an objective of the ENOS project. In this paper, in-situ leakage detection from analysis of well bottom hole pressure is discussed. Modern CO2 injection wells are usually equipped with Permanent Downhole Gauges (PDGs), providing pressure measurements during the whole well life-span including injection and shut-in periods. A practical way to apply Pressure Transient Analysis (PTA) to such measurements for leakage detection is in the focus. A simulated well test of near-fault water injection into saline aquifer was employed to evaluate capabilities of PTA in detecting leakage through the fault. These mechanistic reservoir simulations were followed by similar simulations on an actual geological setting. A reservoir segment of the potential LBr-1 injection site containing a fault was used to demonstrate PTA-based leakage detection under actual geological conditions. Both simulation studies have confirmed that the PTA-based detection may be a useful component of the multi-level leakage monitoring technologies relying on readily available facilities (PDGs).

Introduction

CO_2 reservoir containment is a necessary condition for a long-term CO_2 sequestration in geological formations. The main question addressed in this paper is possibility to detect and monitor leakage through initially sealing fault from well pressure monitoring data. This question has become of practical interest, since the most of modern wells injecting CO_2 are or may be equipped (at marginal costs) with Permanent Downhole Gauges (PDGs) measuring pressure and temperature in real-time. Pressure Transient Analysis (PTA) is the standard tool for converting the pressure monitoring data into information about well and reservoir, which is continuously progressed by increasing availability of PDGs. PTA (Bourdet, 2002) applied in a time-lapse mode is a good candidate for revealing fault leakage from interpreting of PDG data. Recent publications demonstrated revitalizing interest in using PTA and interference well testing in evaluating leaking faults (Mosaheb & Zeidouni, 2017) and detecting the leakage (Hosseini, 2014).

The concept of fault leakage detection using time-lapse PTA

Time-lapse PTA is employed in oil and gas industry to evaluate and monitor changes of well and reservoir parameters (Shchipanov, Berenblyum, & Kollbotn, 2014). The principle of monitoring such changes is based on deviation of pressure transient responses (mainly their derivatives) to rate changes with time. Here, analysis of the pressure derivative families in log-log scale is quite informative, highlighting changes in well and reservoir performance including impact of distant reservoir areas such as boundary effects and interference with nearby wells.

Derivatives of pressure transients are quite sensitive to changes in boundary conditions and this may be used to detect and monitor leakages through faults bounding the well drainage area. A concept of fault leakage detection from time-lapse PTA may consist of: (1) no-leakage case is the reference point providing base-line pressure and derivative responses; (2) following responses are compared to the base-line and (3) deviations indicate appearance of the leakage. In this work, two simulated cases were utilized to demonstrate feasibility of this concept.

Testing of the concept on a mechanistic reservoir model

A 2D mechanistic reservoir model of a saline aquifer with a well injecting water nearby a fault was used as a first testing case (Figure 1). All simulated scenarios included one-month injection followed by one-month shut-in, while monitoring the pressure fall-off (Figure 2). The fault leakage was emulated using a fractured well, where the fracture plane follows the fault plane. The fracture conductivity was initially adjusted to mimic pure reservoir response (as in the case without any fracture). In the following runs, the fracture conductivity was gradually increased to simulate escalating leakage. The bottom hole pressure of the fractured well was kept constant at initial (hydrostatic) pressure condition.

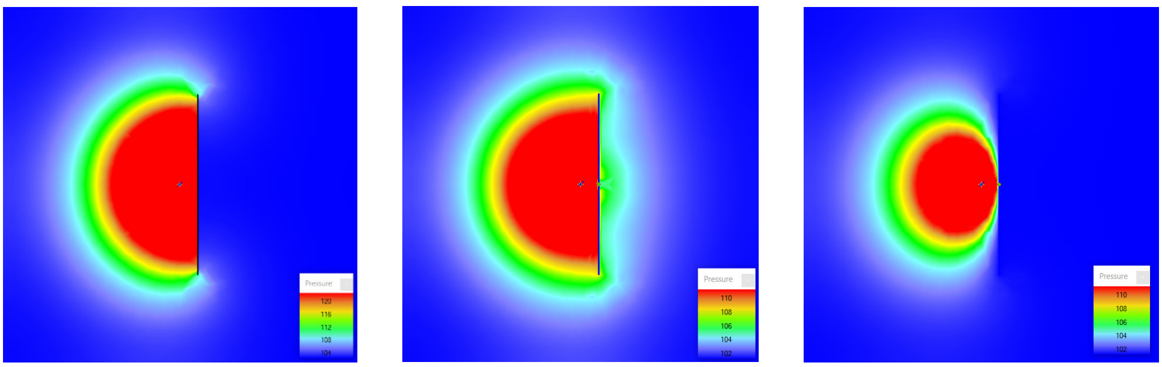

Figure 1 *Injection near fault simulated on mechanistic model (left-to-right): cases of sealing, finite (100 times larger than reservoir) and infinite conductivity faults.*

Figure 1 illustrates scenarios simulated: from sealing fault to the left, through the case where fault permeability is hundred times larger than the reservoir one, to the case of infinite fault plane permeability to the right. In the first case, the fault acts as flow barrier, causing a doubling of the stabilized derivative value as typical for a boundary (fault) dominated hemi-radial flow regime (Figure 3). Introducing permeability to the fault equivalent to the reservoir one (emulating a simple leaking point in the cap rock) led to appearance of moderate fault leakage (Figure 2). Increasing the fault permeability governs escalating leakage (Figure 2), also reflected in the pressure derivative approaching the behavior similar to a constant pressure boundary (Figure 3). It should be noted that opening the fault to flow resulted in two streams: vertical one is the leakage out of the formation (simulated by the well production) and horizontal stream across the fault (Figure 1: the middle case). These two streams are present in all the cases with finite fault permeability, while infinite permeability fault transfer all the fluids out of the reservoir (only vertical stream, Figure 1: the right case).

Figure 3 illustrates how escalating fault leakage causes changes in pressure derivatives making fault leakage detection from PTA possible. It should be noted that the injection and fall-off responses are quite similar, indicating that either may be used for leakage detection.

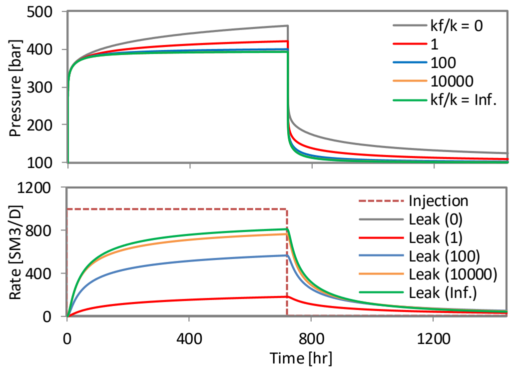

Figure 2 Well test simulated on mechanistic model: sequential injection and shut-in (pressure fall-off) responses (top) and injection / leakage rates (bottom). Index: ratio of fracture (along-fault) to reservoir permeability.

The results above confirmed the value of PTA in qualitative evaluation of fault leakage (detection). But is quantitative evaluation (monitoring) possible? Figure 4 may be used to answer this question: here the simulated leakage is compared with an estimate obtained from the pressure derivative deviation. This PTA-based estimate gives reasonable values of leakage at high-conductivity cases (with the error limited by 20%), while prediction for low-conductivity cases over-estimates leakage up to three times. The reason might be that the pressure derivative reflects the overall flow through the fault, i.e. the vertical (out of reservoir leakage) and horizontal (cross-fault) streams discussed above, where the horizontal one is naturally more dominant in the low-permeability cases (Figure 1).

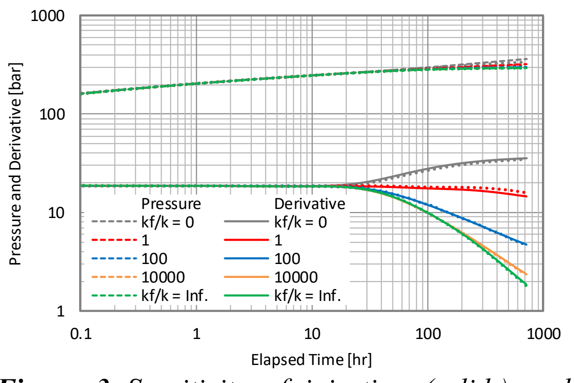

Figure 3 Sensitivity of injection (solid-) and fall-off (dot-line) responses to fault permeability (mechanistic model).

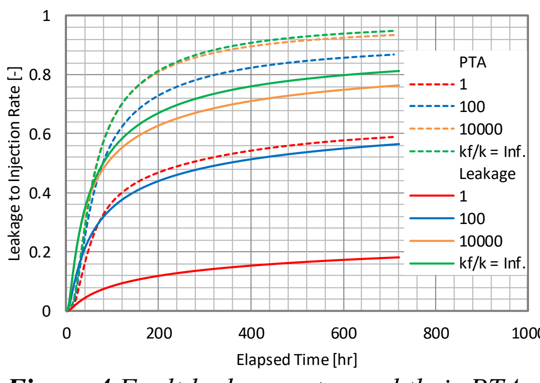

Figure 4 Fault leakage rates and their PTA-based estimates, normalized to injection rate (mechanistic model).

Testing of the concept on a field case

The feasibility of PTA-based fault leakage detection indicated by the mechanistic reservoir model motivated further testing of the concept on an actual geological setting. The LBr-1 site was chosen as a field example in this study following previous reservoir characterization and simulation study (Berenblyum, et al., 2017). A reservoir segment, containing an injection well near a seismic fault on the North (assumed to be sealing) and active aquifer support from the South, was cut from the full-field model (Figure 5). A water injection test was simulated in this study and the reservoir segment was assumed to be water-filled, ensuring single-phase flow.

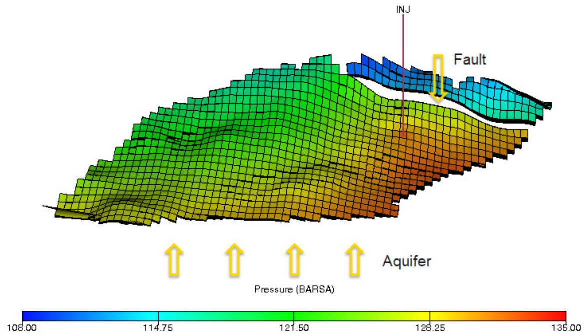

Figure 5 *LBr-1 reservoir segment model with an injection well located near the fault in focus.*

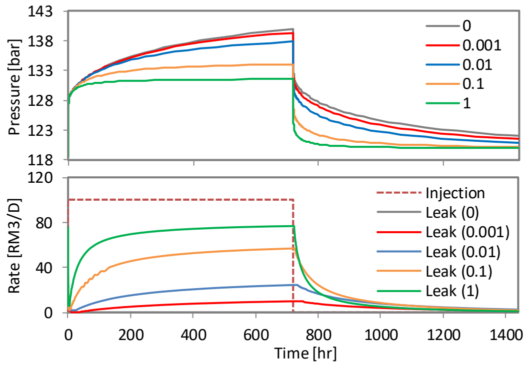

Figure 6 *Similar well test (see Figure 2) simulated on the LBr-1 model. Index: ratio of cross-fault to reservoir permeabilities.*

The fault leakage was further simulated for testing the concept. An artificial production well was connected to the 'fault' grid blocks, where vertical and along-the-fault permeabilities were increased to simulate close-to-infinite fault plane conductivity. Cross-fault permeability in the 'fault' blocks was varied to simulate leakage of different intensity. The well was operated at constant hydrostatic pressure.

Figure 6 illustrates well tests simulated with different cross-fault permeabilities (introduced as fraction of the reservoir permeability). Fault leakage rates are illustrated in Figure 6, varying from 10% to 80% of injection depending on the cross-fault permeability. Analysis of the pressure derivatives (Figure 7: the case '0') indicates that the no-flow boundary (sealing fault) governs the derivative upward trend in the period of 3 to at least 100 *hr* followed by the aquifer impact afterwards governing change to downward trend. As in the mechanistic simulations above, pressure derivative clearly reacts to the escalating leakage rate (Figure 7). Similar picture is observed for well shut-in pressure derivatives, i.e. fall-off responses also echo leakages.

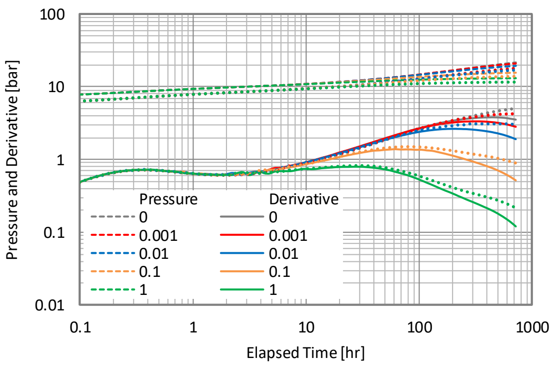

Figure 7 *Sensitivity of injection (solid-) and fall-off (dot-line) responses to cross-fault permeability (LBr-1 model).*

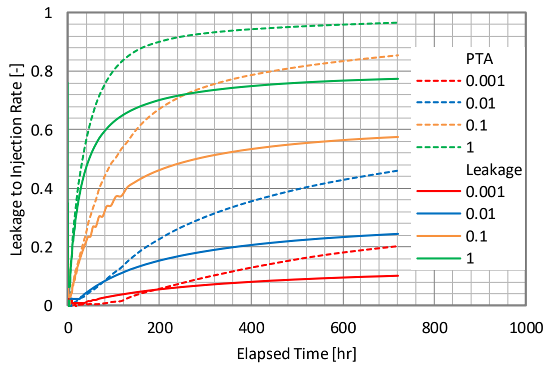

Figure 8 *Fault leakage rates and their PTA-based estimates, normalized to injection rate (LBr-1model).*

Comparison of the leakage estimates based on pressure derivative with the actual (simulated) values are shown in Figure 8. The PTA-based estimates are close to actual values for high leakage rates (~20% difference), while over-estimating significantly for the low rates (about double). Start of the leakage is reasonably captured for all the rates, except for the lowest rate case. The low-rate over-estimation seems to be related to the fact that two factors actually govern the pressure derivative: the fault leakage and the aquifer support, where change in one can impact the role of the other. Three cases were simulated to illustrate this idea (Figure 9 and Figure 10): the reference case '1' is the case '0.01' from Figure 8, '2' – the same case without the aquifer support and '3' – the case '2' with the total compressibility reduced three times. Comparison of the cases showed that the aquifer has an impact on (1) the leakage rate in combination with the injector, and also on (2) the derivative deviation as one of the boundaries. As a result, removal of the aquifer reduced the difference between actual and PTA-predicted leakage rates. Lowering the compressibility reduces the difference further (Figure 10).

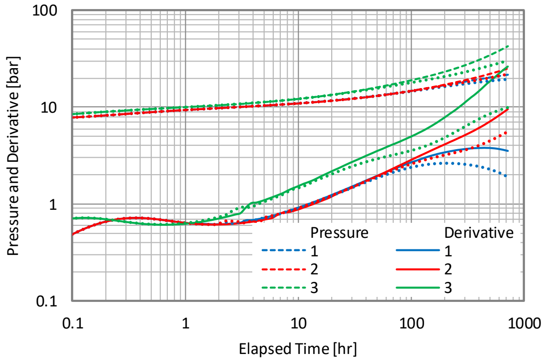

Figure 9 *Sensitivity of injection responses to fault leakage (LBr-1 model). Solid- and dash-lines correspond to no-leakage scenarios, while dot-line – with leakage.*

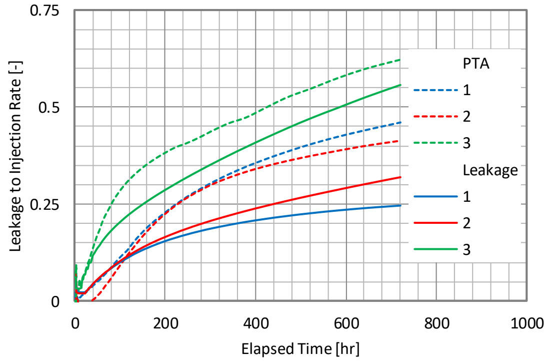

Figure 10 *Fault leakage rates and their PTA-based estimates (LBr-1model) for the cases in Figure 9.*

Conclusions

The following conclusions may be drawn based on the examples simulated in this study:

- The fault leakage may be detected from PTA of injection and shut-in pressure transients of an active injector, at least for the case of dominating single-phase flow in reservoir, e.g. when injected fluid (like CO_2) is localized near wellbore.
- A qualitative PTA-based estimation of leakage rate is possible in the case, when the leakage governs the change only of the fault boundary condition, but not other active boundaries.
- The fault leakage detection is therefore case specific: no-leakage base-line pressure response should be obtained (e.g. from a well test prior to the main injection phase) and impact of all reservoir boundaries should be clarified.
- Pressure monitoring with PDGs during the main injection phase may then be used to detect initiation of a fault leakage, where sequential pressure transients are compared to the base-line response.

Acknowledgements

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