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Wellbore permeability estimates from vertical interference testing of existing wells

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Abstract

Wellbore integrity is considered an important risk factor for leakage of CO_2 and formation fluids out of geological CO_2 storage sites. Quantifying the effective hydraulic parameters that control vertical migration of fluids along the wellbore involves data collection through numerous field and laboratory experiments. The vertical interference test (VIT) is a downhole test designed to measure hydraulic communication of the outside-of-casing wellbore barrier system over a selected well section. Results from these tests can be analyzed numerically to determine the average permeability of the section. Several field surveys of existing wells have resulted in 9 VIT datasets, of which three are presented here. The effective permeability estimates for the three tests span two orders of magnitude, from approximately 1 mD to more than 100 mD. When compared with companion sidewall core analyses of the cement matrix that have permeabilities in the microD range, the VIT data suggest that interfaces or defects in the cement sheath are responsible for flow. Initial analysis of the remaining 6 datasets suggests an even larger range in effective permeability values, as low as microD to more than 1 D, indicating that well permeability can be highly variable from well to well and that high values of permeability are possible. These data provide important insights into realistic wellbore integrity of typical wells in N. America, and help us constrain models for understanding and mitigating risk of leakage during CO_2 storage operations.

Keywords: Wellbore integrity; vertical interference test; effective wellbore permeability; parameter estimation; CO_2 leakage.

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1. Introduction

Wellbore integrity has been identified as a key storage security concern for geological CO_2 sequestration [1,2]. Leakage of CO_2 and other formation fluids along old or abandoned wells could lead to contamination of overlying groundwater aquifers or other subsurface resources (e.g. petroleum reservoirs) and may adversely affect flora and fauna if leakage reaches the ground surface [1]. Significant leakage could also release CO_2 to the atmosphere, thus compromising the principal objective of storage operations. In North America, millions of oil and gas wells have been drilled over the last century, and many penetrate prospective CO_2 storage sites [3]. Vertical migration of fluids is mitigated by the wellbore barrier system, which consists of the cement sheath that fills the annulus around the outer casing. The cement bonds to the casing (the cement-casing interface) and to the formation (the cement-formation interface). The cement and/or cement bond may be compromised by poor well construction or long-term degradation of the wellbore materials due to production and injection activities [4]. Understanding leakage potential through existing wells requires data on the *in-situ* integrity of the barrier system, which can be obtained from field and laboratory experiments [4-8]. Relevant data can then be used in risk assessment models to mitigate leakage from large-scale CCS operations in sites with many existing wells [9].

A concerted field campaign started in 2006 to perform in-situ testing on existing wellbores in several fields in North and South America [4]. This is the first such effort to quantify the effective hydraulic parameters that control vertical fluid migration through the wellbore barrier system. The barrier system consists of several components, each with individual and possibly heterogeneous hydraulic properties that can lead to multiple flowpaths either through the components or along micro-fractures, channels and interfaces within this system [3]. Therefore, it is the integrated measure of hydraulic properties that determines vertical leakage over large scales. One key parameter is the *effective wellbore permeability*, which is the average permeability of the entire barrier over a vertical section of the well that is meant to isolate two permeable formations. A field test was designed to measure this key parameter, called the vertical interference test (VIT) [10], and each field survey conducted in the field campaign consisted of at least one VIT. The VIT measures vertical pressure communication between two isolated intervals, typically separated by three to thirteen meters, by applying pressure in the upper interval and measuring the transient pressure response in the lower interval. If good isolation is maintained inside the casing, then any detectable pressure signal indicates fluid flow along the exterior of the casing. The pressure signal can be inverted using standard parameter estimation methods to quantify wellbore permeability [11].

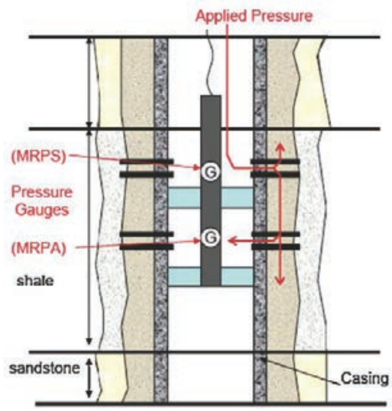
The field campaign resulted in surveys of three existing wells, while a follow-up project tested two additional wells [12]. A total of 9 VITs were performed, with two wells having multiple VITs run sequentially. In all well surveys except one, fluid and/or sidewall core samples were retrieved from the wellbore for companion laboratory analyses [4,12]. In addition, acoustic bond logs were available in most cases for comparison with VIT data and subsequent permeability estimates. The comparison of the first VIT dataset with other in-situ data has been addressed in a previous study [4]. In this paper we only discuss three VIT datasets—one from the first survey [4] and two of the follow-up surveys [12]. The additional VIT data from the remaining two wells from the first field campaign are still in the process of being analyzed and reviewed.

2. Methodology

The VIT test involves perforating the well casing in two separate intervals, both of which are located within the shale caprock and bracket a zone of cement (Figure 1a). Once the intervals are isolated with an inflatable packer, the system is pressurized from surface and held at a constant pressure for a number of hours or days. For these wells the pressure was measured using modules of Schlumberger's MDT* modular formation dynamics tester. Pressure is monitored in the upper zone with a modular reservoir probe-single (MRPS) module gauge. Simultaneously, the transient pressure response in the lower isolated zone is measured using a second modular reservoir probe-dual packer assembly (MRPA) gauge. The transient data are used to infer the extent of hydraulic communication, i.e. flow, through the barrier system.

The effective wellbore permeability can be estimated through numerical analysis of the VIT data within the shuffled complex evolution metropolis (SCEM-UA) global optimization algorithm parameter estimation framework. The SCEM-UA algorithm, based on Markov chain Monte Carlo methods for sampling the parameter space, determines a probability distribution of the parameter or set of parameters that produces the closest match to the data [14]. This algorithm is a robust and reliable method for VIT data analysis [11]. The parameter estimation is automated, which is superior to time-consuming manual estimation and allows for fast analysis of multiple datasets or for use in real-time field settings. The SCEM-UA employs a forward model that solves an axially symmetric single-phase flow equation with a standard numerical method [10]. The model simulates the pressure and flow that develop exterior to the casing due to an imposed pressure pulse in the upper isolated well section.

(a)



(b)

Assigned Parameters		Wells		
		CCP	TPX	CC1
Shale	Top (ft)	4511	3805	2090
	Permeability (nD)	1	60	60
	Compressibility (GPa^{-1})	1	0.02	0.02
MRPS	Depth (ft)	4522	4010	2980
Cement	Top (ft)	3050	2278	surface
	Compressibility (GPa^{-1})	0.6	0.02	0.02
MRPA	Depth (ft)	4533	4020	2990
Production zone	Top (ft)	4690	4078	4000
	Permeability (mD)	100	100	100
	Compressibility (GPa^{-1})	0.1	0.6	0.6

Fig. 1. (a) Schematic of VIT performed across a well section in the shale interval above the production zone (indicated as sandstone); (b) List of VIT details specific to each reported dataset as well as the secondary parameter values used in the parameter estimation analysis.

For the VIT data analysis, wellbore permeability is the primary parameter of interest, but estimation can be sensitive to secondary parameters of the system, such as the host rock properties (e.g. shale permeability and compressibility) and other wellbore effective parameters (e.g. compressibility and porosity). These values can be estimated simultaneously with wellbore permeability if good estimates are not available prior to the analysis. However, the parameter estimator works most effectively with fewer free parameters, and in this analysis, we fix the secondary parameters when estimating wellbore permeability.

3. Wellbore information

Three VIT datasets and subsequent analysis discussed here were obtained during field surveys of three separate wells—CCP, TPX and CC1. The first field survey has been presented previously [4], while the second (TPX) and third (CC1) are discussed in more detail in this issue [12]. All three field surveys included other downhole tests, such as logging, coring and fluid sampling, in addition to the VIT. The wells range in age from 30 yrs (CCP) to 8 yrs (CC1) at the time the survey was completed. CCP was a CO_2 production well, while the TPX and CC1 wells were drilled as oil production wells that have never been exposed to CO_2. All three wells were drilled to depths between 4000 ft. and 5275 ft. The VITs were performed using MDT along well sections located in the shale interval above the production zone. The tool tested two perforated 1-foot zones spaced 10 feet apart in each well. Some data on the VIT and secondary parameters assigned to the domain during the data analysis are presented in Figure 1.

Experience from performing VITs in the field shows that two possible cases exist that represent the realistic endpoints of wellbore integrity data. The first is the best-case scenario where no detectable pressure increase is recorded by MRPA gauge over the course of the test, which indicates minimal flow through the barrier system and a low effective permeability. The second, worst-case scenario occurs when essentially instantaneous equilibration is obtained with the MRPS pressure, which indicates nearly unimpeded flow through the barrier system. These endpoint scenarios can be used to estimate the lower and upper bounds on wellbore permeability that can be measured in the field. Additional hypothetical cases were analyzed for the CCP well in which the “datasets” included zero-increase and maximum-increase datasets to explore the bounds on measurable permeability.

4. Results

The best-fit model results for the CCP (Figure 2) were obtained using the parameter estimation described above. Two different approaches to estimating wellbore permeability are compared. The first is similar to past analyses [4,11], where the latter portion of the VIT data is weighted in the estimation algorithm. This is due to residual pressure contamination during the initial 3000 seconds of the recorded MRPA pressure when an initial attempt to perform the VIT failed [4]. Weighting the data in this manner results in an estimated wellbore permeability of 1.6 mD (Figure 5a). This estimate has been shown to be sensitive to shale permeability [4] and estimated wellbore compressibility [11]. However, the range of estimated wellbore permeability values due to uncertainty in secondary parameters is within an order of magnitude.

The second estimation adds an additional element to the forward model to account for the initial sharp increase in pressure recorded in the MRPA gauge (between the packers) that is caused by pressure transfer through the fluid-filled rubber packers and not due to flow. In the MRPA data, this corresponds an increase from 1950 psi to 2230 psi over the first 180 seconds of the test that mimics the MRPS gauge

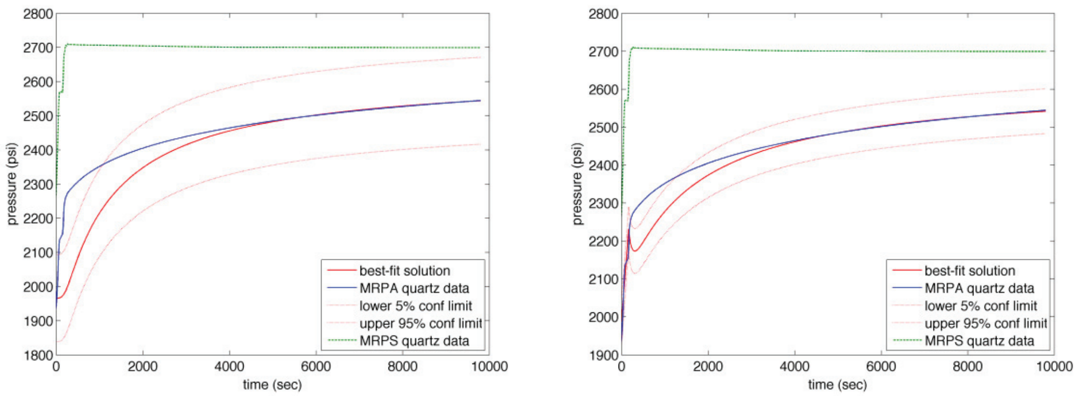


Figure 2 Best-fit model results to VIT data for the CCP well using two approaches for modelling the pressure transient: without (left) and with (right) the influence of the packers. In each figure the measured MRPA data are in blue and the model results obtained from parameter estimation are in red. The uncertainty of the best-fit solution is tied to the PDF of estimated wellbore permeability values produced by the parameter estimation algorithm [11]. The 95% confidence in the best-fit solution is bracketed by the dotted red lines.

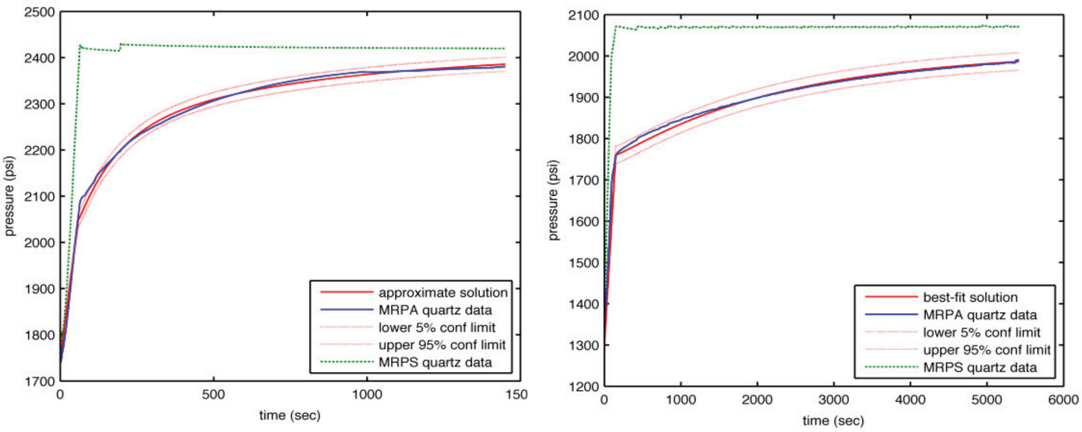


Figure 3 Best-fit model results to VIT data from the TPX (left) and CC1 (right) wells. Shown are the measured MRPA data in blue and the model results obtained from parameter estimation in red. The uncertainty of the best-fit solution is tied to the PDF of estimated wellbore permeability values produced by the parameter estimation algorithm [11]. The 95% confidence in the best-fit solution is bracketed by the dotted red lines.

increase as pressure is imposed from surface. The pressure increase due to the test's effect on the packers was modeled by imposing an increasing pressure condition in the lower perforated zone that matches the MRPA data. The pressure condition was removed once the MRPS pressure stabilized, allowing the pressure transient to evolve naturally due to flow in the cemented annulus. The resulting best-fit estimate is 1.45 mD (Figure 5b). The best-fit solution in this case has an anomalous dip in pressure near the beginning, but has a better match to the later time data. Regardless, the different approaches lead to nearly the same estimated value for wellbore permeability.

The best-fit results for the TPX and CC1 wells (Figure 3) both use the second approach to estimating permeability by modeling the influence of the packers on the MRPA gauge data. The artificial pressure increase is imposed in the forward model until the MRPS pressure stabilized in the upper perforated zone, about 60 s into the test for TPX and 150 s into the test for CC1. The TPX data matched best when using a wellbore permeability of 170 mD, while the CC1 data matched best with a wellbore permeability of 25 mD.

The final results consist of the hypothetical best- and worst-case scenarios for the CCP well. The first case implies that there is no pressure signal within the detection limits of the instrument. Given a reasonable measurement error of 0.1 bar = 1.5 psi [11], the resulting analysis gives a minimum permeability of 0.01 mD. All values above this lower bound will lead to a detectable pressure increase, while values below this threshold will give the same undetectable pressure transient. It should be noted that the lower bound is greater than the permeability of intact cement (1 nanoD to 1 microD). On the other hand, the worst-case scenario implies that the MRPA data would be equivalent to the imposed MRPS pressure data. The analysis results in a maximum permeability of 100 Darcy and represents a well with no integrity or ability to prevent flow through the annular region.

Table 1. Summary of wellbore permeability estimates for reported VIT datasets, hypothetical upper and lower bounds, and unreported VIT data (still under review).

Reported VIT data	Estimated Wellbore permeability	Measured Cement permeability
CCP	1.7 mD	0.1 – 32 microD
TPX	170 mD	0.1 – 449 microD
CC1	25 mD	0.001 – 4.63 mD
Hypothetical VIT data		
CCP upper bound	100 D	--
CCP lower bound	0.01 mD	--
Unreported VIT data		
3 datasets	6 mD – 3 D	--

5. Discussion

A summary of estimated wellbore permeabilities is given in Table 1 for the datasets discussed here; as the table also includes our preliminary analysis of additional, unreported data that are still under review but we include here to indicate the range of apparent values associated with these data. We observe that the estimates obtained from the CCP, TPX, and CC1 datasets range from 1.7 mD to 170 mD, which is variation over two orders of magnitude and is in the range of permeability values often associated with reservoir rocks. Preliminary analysis of the 3 additional datasets (unreported) results in permeability estimates from 6 microD to 3 D, while the 3 other datasets reported either instantaneous pressure equilibrium (>100 D) in one case or undetectable pressure (< 0.01 mD) in the 2 other tests. These latter data are undergoing further analysis but the initial estimates suggest that relatively large values (greater than 100 mD) for effective permeability may exist in the region immediately outside of well casings in other wells.

In the case of the reported wells, comparison with the measured cement permeabilities, taken from side cores from those wells, shows that the effective permeability is at least 2 orders of magnitude greater than that of the cement alone. This indicates that poor bonding at the casing-cement or cement-rock interfaces or defects through the cement sheath, and not the cement itself, are the likely source of hydraulic communication through the barrier system. The existence of these flowpaths could be due to poor cement placement in the annulus during completion or long-term debonding over the lifetime of the well.

We note that VIT perforations in all cases were spaced less than 50 feet (15 m) apart, while the caprock intervals spanned several tens to hundreds of meters in thickness. Therefore, the estimates quoted here indicate only local values of wellbore permeability (local defined over the scale of 3 to 13 meters) and cannot necessarily be extrapolated to the entire caprock interval. Because leakage risk is determined by the harmonic average of vertical permeability across the caprock, a low permeability estimate obtained at any depth reduces the risk of wellbore leakage across that caprock interval. Therefore the measured VIT data, while on a scale much larger than the core measurements, still requires an upscaling analysis in order to be applied to the full field scale.

Carrying out the VIT on existing wells is an intensive field test involving specialized equipment, and depending on the well, can sometimes use large volumes of formation water or several days of rig time for each survey to be completed. Although it would be advantageous to perform hundreds of similar tests in different fields around the world, we cannot always expect operators to expend the resources to do so. Therefore, it is necessary to infer as much as possible from the handful of currently available datasets. To do so, we seek to correlate the VIT data with other sources of information about the individual well, which can be loosely categorized as “hard” and “soft” data [13]. Hard data can consist of available borehole logs and other in-situ gas/fluid/rock analyses, while soft data is any other paper or electronic information contained in drilling logs and private or public databases. If this correlation is feasible, then wells become easier to evaluate and the potential to populate statistical distributions of well properties is greatly increased.

6. Conclusions

The wellbore integrity data presented in this paper provide valuable insights into the range of possible well permeability values in typical wells drilled over the past several decades. These data can be used to begin to constrain probabilistic distributions of wellbore permeability used in modeling studies for leakage risk assessment. The VIT data can also be correlated with other “soft” data related to construction, age and life cycle of the wells, which allows for extrapolation of results to other wells without the need for expensive and time-consuming downhole testing. Ultimately, analysis of more accessible information using correlations based on field data will be the best approach for reducing the uncertainty associated with wellbore integrity.

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