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Detecting leakage of brine or CO_2 through abandoned wells in a geological sequestration operation using pressure monitoring wells

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Abstract

For risk assessment, policy design and GHG emission accounting it is extremely important to know if any CO_2 or brine has leaked from a geological sequestration (GS) operation. As such, it is important to understand if it is possible to use certain technologies to detect it. This detection of leakage is one of the most challenging problems associated with GS due to the high uncertainty in the nature and location of leakage pathways. In North America for example millions of legacy oil and gas wells present the possibility of CO_2 and brine to leak out of the injection formation. The available information for these potential leaky wells is very limited and the main parameters that control leakage, like permeability of the sealing material are not known. Here we propose to explore the possibility of detecting such leakage by the use of pressure-monitoring wells located in a formation overlying the injection formation. The detection analysis is based on a system of equations that solve for the propagation of a pressure pulse using the superposition principle and an approximation to the well function. We explore the questions of what can be gained by using pressure-monitoring wells and what are the limitations given a specific accuracy threshold of the measuring device. We also try to answer the question of where these monitoring wells should be placed to optimize the objective of a monitoring scheme. We believe these results can ultimately lead to practical design strategies for monitoring schemes, including quantitative estimation of increased probability of leak detection per added observation well.

Keywords: Leakage Detection, Abandoned Wells

1. Introduction

Detecting CO_2 or brine leakage in a geological sequestration operation is crucial for accounting purposes, for assessing the risk of the operation and for preventing environmental damage that any leakage might cause. The time for detection and spatial location of this detection varies according to the objective of the monitoring scheme. For instance, the IPCC Guidelines for National Greenhouse Gas Inventories [1] suggest that leakage for accounting

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purposes is only of concern if CO_2 leaks back to the atmosphere, which puts the boundary of the system at ground surface. On the other hand, under draft regulations of the Safe Drinking Water Act in the United States [2] any leakage that could endanger underground sources of drinking water (USDW) is prohibited, putting the boundary somewhere below the surface. USDW are defined as formations with a total dissolved solids (TDS) concentration of 10,000 mg/L or less. Moreover, in the United States regulations at the state level require monitoring of permeable formations overlying the injection formation of any geological sequestration operation [3].

These regulations and guidelines help to define the objectives for different types of monitoring technologies and schemes. In the past several years many studies have considered the use and applicability of different monitoring techniques such as time-lapse 3-D seismic data acquisition [4], satellite-borne synthetic aperture radar to detect surface deformation [5], remote sensing of vegetation reflectance [6], carbon isotope analyzers [7], the use of eddy covariance towers, flux accumulation chambers, soil gas sampling and groundwater sampling among a broad range of additional techniques [8]. Each of these has its strengths and weaknesses. For instance, most of the techniques that rely on surface level acquisition or are remotely sensed are of great use for accounting and inventory purposes but fall short in trying to reduce the risk of environmental damage of USDW by brine or CO_2, because they usually detect any significant leakage only when it has already passed through USDW and reached the surface.

The issue of leakage into USDW is of special interest in the United States because geological sequestration of CO_2 in North America is likely to occur in areas where substantial knowledge of the stratigraphy and lithology of the formations is correlated with the presence of old and current exploration/production wells that are a product of more than a century of oil production [9, 10]. These wells, which can cross several USDW on their way down to a hydrocarbon reservoir, serve as possible conduits for brine and CO_2 leakage. Any leakage into overlying formations could be detected through the use of pressure-monitoring wells and geochemical sampling because each leakage point (abandoned well) has a pressure pulse and a possible CO_2 plume associated with it. However, with a limited number of monitoring wells, detection of a CO_2 plume is much detect than an associated pressure pulse because a CO_2 plume will have a very small spatial footprint compared to a pressure pulse. As an explanation we can look at a previous study [11] where we analyzed thousands of stochastic simulations using a semi-analytical model [12-14] to understand the risk profile associated with leakage across abandoned wells in a geological sequestration operation. Results from a sub-set of these thousands of simulations are shown in Figure 1a. which show a 100 km^2 domain and the location of 10 abandoned wells with the average extent of the corresponding pressure pulses and CO_2 plumes after 50 yrs of injection. We see that after 50 years of injection the pressure pulses due to leakage cover 98% of the area while the CO_2 plumes only cover 3.5% of the domain. In Figure 1b we can see the evolution of the extent of the area covered by these pulses if different accuracy thresholds are used for the measurement of pressure. The accuracy threshold refers to the value of change in measured pressure that can be considered large enough that a measured value can be distinguished from background noise. For instance, an accuracy threshold of 0.01 MPa means that the measuring instrument would have to record a change in pressure of this magnitude from initial or background conditions to indicate that an anomaly was not being measured. The results show why monitoring for pressure changes is better than searching for CO_2 plumes, when the instrument of choice is a monitoring well.

In this work we aim to study some of the implications of using pressure-monitoring wells in a formation overlying the injection formation to try to detect leakage. We specifically try to address the simple issues of what can be gained by monitoring for pressure changes and what are the limitations given a certain accuracy threshold. We also investigate the question of what should be the optimal placement of the monitoring wells given a certain objective function. We do this by modeling the propagation of a pressure pulse across the injection formation, through leaky wells and into the overlying formation where possible monitoring wells are located. The modeling is done by using a system of equations [15] that rely on the fact that the governing equation for the propagation of pressure in a homogenous aquifer is linear. In the case where leaky wells can serve as a source of a pressure pulse the superposition principle is applied. The leakage flow rates will change with time, so a convolution integral becomes part of the solution. We use a previously developed approximation for this time-varying system. The resulting system of equations applies to an arbitrary number of leaky wells across an arbitrary number of layers.

We note that we consider leakage into an overlying formation through abandoned wells as the main source of leakage and do not take into account other mechanism like diffuse leakage through aquitards. This approach is justified in part by the work done in [16], which showed that during the injection period, in the absence of localized pathways, the displaced brine is more likely to be accommodated by pore and fluid compressibility than by diffuse leakage or lateral flow out of the boundary. This conclusion could be taken to mean that if brine or CO_2 were to leak during the injection period it would most likely occur through localized pathways like abandoned wells and faults.

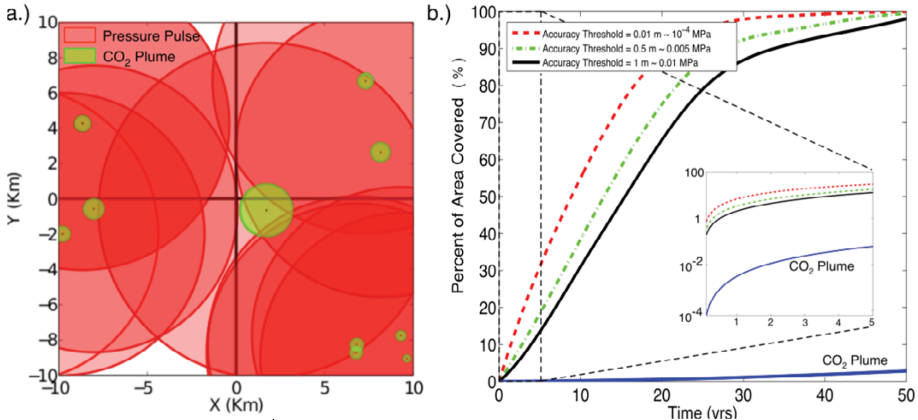

Figure 1. a.) Aerial view of a 100 km^2 domain with 10 possible leaky wells showing the average size of pressure pulses and CO_2 plumes after 50 years of injection. For these simulations the injection well was located in the canter of the domain (0,0) and edge of the pressure pulse corresponds to a 1 m (~0.01 MPa) change in head from initial conditions. b.) The area covered by the pressure pulse versus time, depending on the accuracy threshold used.

2. Methods

It has been shown [15] that a general analytical solution can be used to estimate the flow rates across multiple leaky wells into overlying formations as well as the corresponding pressure pulse propagation. The analytical solution is based on an approximation of the well function and the principle of superposition. We can explain this analytical solution by first presenting the well-known problem of one injection well with constant flow rate into a homogenous isotropic confined aquifer. This problem has the analytical solution known as the Theis solution [17]. Similarly, if more than one injection well is considered the principle of superposition can be used to solve the system. When a layer is added on top of the injection formation and the wells are considered to be leaky wells instead of injection wells the system still can be solved through the use of the superposition principle but instead of having constant flow rates out of the formation a time varying flow has to be determined, and the solution now involves convolution integrals. The general solution takes the following form,

$$h_l(R,t) = h_{init} + \frac{1}{4\pi T}\sum_{i=1}^{M} Q^{i}_{inj.} W_{inj.} + \frac{1}{4\pi T}\sum_{j=1}^{N}\int_0^t \frac{\partial Q(t')}{\partial t'} W(u(R,t-t'))dt' \quad (1)$$

where, M is the number of injection wells and N the number of leaky wells. The main unknown is the head value, h_l, located a distance R away from the injection well and time t. T represents the transmissivity of the aquifer and h_{init} refers to the initial head value. Q_{inj} represents the constant flow rate from injection wells and the well function for the constant injection rates takes the symbol W_{inj}. The third term on the right hand side of the equation is the summation of N convolution integrals that integrate the varying flow rate across the leaky wells through time t.

The simplification presented in [15] and used in this work converts the complex solution presented in Equation (1) to a much simpler expression by replacing the convolution integral with a Heavisde step function that maintains the proper integral but whose derivative becomes a Dirac delta function evaluated at $t'=t^*$, where t^* is the time of interest modified by a constant value $\gamma=0.92$, that is $t^*=0.92t$. For the simplest case of only one injection well with constant flow rate, Equation (1) is rewritten as follows,

$$h_l(R,t) = h_{init} + \frac{1}{4\pi T} Q_{inj.} W_{inj.} + \frac{1}{4\pi T}\sum_{j=1}^{N} K_j \pi r_{well}^2 \frac{h_{l+1}(R,t) - h_l(R,t)}{B_{l+}} W^* - \frac{1}{4\pi T}\sum_{j=1}^{N} K_j \pi r_{well}^2 \frac{h_l(R,t) - h_{l-1}(R,t)}{B_{l-}} W^* \quad (2)$$

where the well flux term (that is, the leakage rate), Q, has been replaced using the Darcy flow equation to represent flow (leakage) along the wells. The variables h_{l+1} and h_{l-1} represent the head values in formations above and below respectively. Similarly B_{l+} and B_{l-} are widths of the impermeable aquitards between the injection formation and the top and bottom formations, respectively. The area of flow is that of the leaky well with an effective radius r_{well} and an effective hydraulic conductivity K. W^* is the modified well function, which is a function of the value u,

$$W^* = W(u = \frac{r^2 S}{4Tt^*}) \tag{3}$$

In Equation (3) the variable S refers to the storativity of the system.

Equation (2) is written once for each unknown value of head. For instance in order to solve a system with one injection well (with known constant flow rate), two leaky wells and one monitoring well located in an overlying formation, Equation (2) is written 5 times: One for the head in the monitoring well located in the formation above the injection formation, one equation for the head in each leaky well in the injection formation and one equation for the head in the leaky wells evaluated in the overlying formation. Similarly, a system with X leaky wells going through Y layers, and N monitoring wells placed in Y, layers would require a total of XY+NY equations.

In this study we constrain our analysis to a two layered system: A bottom formation, which we identify as the injection formation, and an overlying formation where a monitoring well is placed. Both layers are separated by an impermeable aquitard. The formation parameters as well as general values used in the analysis are shown in Table 1. These values correspond to the Alberta basin in Canada [18] which has been identified as a possible location for geological sequestration.

Table 1. Formation and fluid values used in the model

Parameter	Value
Injection formation height (m)	72
Monitoring formation height (m)	160
Aquitard height (m)	93
Inj. Formation perm. (m^2)	170e-15 ~ 170 mD
Mon. formation perm. (m^2)	4e-15 ~ 4 mD
Compressibility (1/Pa)	4.6e-10
Injection rate (m^3/s)	0.1585
Initial head (m)	1881
Brine Density (Kg/m^3)	1045
Brine Viscosity (Pa-s)	2.53e-4
Well Radius (m)	0.5

Our analysis and results are constrained to a 5-year period and a 10 km by 10 km area, which we have taken as the extent of the first Area of Review (AoR) [2]. Under U.S. Environmental Protection Agency regulations, permit holders that are going to inject CO_2 have to identify any penetrations (i.e. wells) intersecting the injection formation and show that these penetrations are plugged and/or properly abandoned. The AoR can be defined as the edge of the imposed pressure pulse where the change in pressure is sufficient to push brine from the injection formation to the first USDW. This area of influence or AoR has to be redefined at least every 5 years. We calculated this area using the methods proposed by [19] and the Alberta Basin data [18]. We also constrain our analysis to an analytical solution that only considers single-phase flow under the assumption that the real two-phase flow pressure propagation can be closely approximated during the first 5 years of injection by simply using a single-phase expression for pressure.

3. Results

We first considered simple monitoring of the injection well and the conditions under which leakage can be inferred from such measurements. This is the first obvious monitoring choice, because regulations for underground injection in the U.S. [2] require constant monitoring of the bottom hole pressure at the injection well. In Figure 2 we show two cases where we used Equation (2) to solve for heads at the injection well. We placed a single leaky well at different radial distances from the injection well and calculated the difference in head at the injection well between a no-leakage case and a leakage case. In Figure 1a. we see that there is a significant change in head at the monitoring well from the no-leakage case when the permeability of the leaky well is on the order of 100 Darcy. We compare the change in expected head and "measured" head with the accuracy threshold of a typical pressure gauge [20], which is on the order of 0.01 MPa. For instance, if the there were a potential leaky well 150 m away a leakage could be detected after 4.5 days. On the other hand if a well is 3 km away and it is leaking it would not be detected in the first 5 years. In Figure 1b. we see that when the leaky well permeability is on the order of 1 Darcy there is no significant change in "measured" head at the monitoring well; even for a well that is 10 m away. We note that the permeabilities chosen are extremely high for a plugged well, in fact the American Petroleum Institute (API) recommends that well cement permeabilities should not exceed a value of $2x10^{-16}$ m^2 (~0.2 milli-Darcy). This means that significant leakage would only occur when the materials in the well do not conform to the standards. We note that the leak rates and the ability to detect leaks, depends on the parameters of the system including the formation permeability and the relative magnitude of the effective permeability of the leaky well. The results shown in Figure 1 can be understood to mean two main things: First, that given an accuracy threshold, there is a defined radial distance for how far a leaky well can be from the injection well and still be detected. In this particular case that distance would be around 2.6 km. Secondly, if the injection formation is very permeable, small localized leaks would not be detected at all because the pressure release across the leaky well would be minimal.

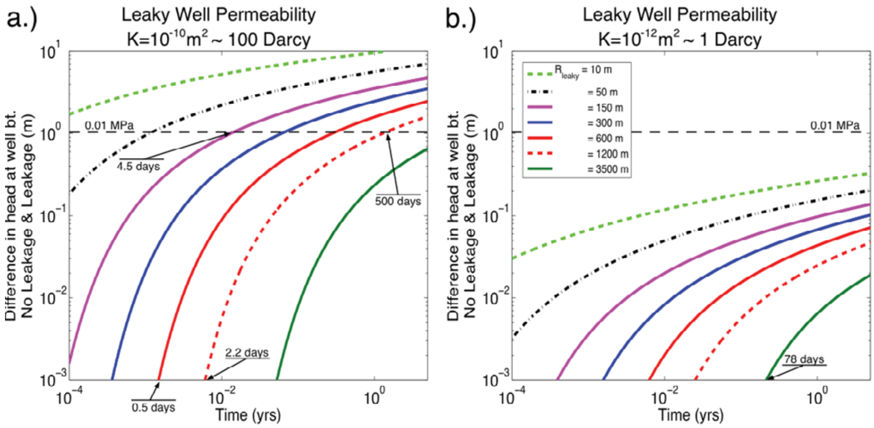

Figure 2. Difference in bottom hole pressure (head) between a no-leakage case and a case with leakage as measured at the injection well. Each line represents a leaky well at a different radial distances from the injection well. In case a. The permeability of the leaky well is set at 100 Darcy while in case b. the permeability is set at 1 Darcy and order of magnitude higher than the formation permeability. The dash line represents the accuracy threshold of 0.01 MPa.

We next addressed the isuues of where to place a monitoring well in order to maximize the probability of detection. To begin, we reduced our system to the case of two possible leaky wells. From the Alberta basin data [18] for the Nisku formation, we identified the location of the two closest abandoned wells, to the center of the domain, which turned out to be 1.8 km and 8 km away. We ran our model for a 5-year period and assigned different combinations of leaky well permeabilities ranging from 10^{-9} to 10^{-12} m^2 (1000 Darcy to 1 Darcy) we considered different monitoring well locations in order to determine the probability that a monitoring well would detect the leakage. In Figure 3 we show the results of these runs. The top frames show the spatial probability of a monitoring well detecting a leakage if both wells were leaking. The different columns in the figure corresponds to the varying accuracy threshold. As one would expect, as the accuracy threshold is reduced the area of the domain which shows a greater probability of detection increases. More interestingly though, if we look at the right most frame in the top row we can conclude that if our measuring device had an accuracy threshold of 10^{-4} MPa there would be several regions where a monitoring well would always detect a leak. When the accuracy threshold is 0.01 MPa we see that the regions with highest probability of success (~75%) are next to each well and do not overlap. In fact the overlapping region shows a lower probability of success (~ 30%). In this case one would have to make a decision of placing two monitoring wells near the abandoned wells to maximize success of detection or placing one well in the overlapping region and risking a lower chance of detection.

The second row of frames in Figure 3 corresponds to a particular case where there are two abandoned wells but only one is leaking. The question follows, if a single monitoring well were to be placed in order to maximize detection probability knowing that there is a 50% chance that one if the wells would be leaking, where should this placement be? In the case where the accuracy threshold is around 10^{-4} MPa the optimal placement would be in between the two wells. Conversely, if the accuracy threshold were much higher, 0.01 MPa, there would not be one specific location where the maximum detection could be assured and no one well could be placed and be able to detect leakage from two possible abandoned wells. The combination of the top frames and the bottom frames in Figure 3 provide one objective function that can be used to know the placement of monitoring wells and the number needed given a certain accuracy threshold. This same approach could be expanded to N possible leaky wells.

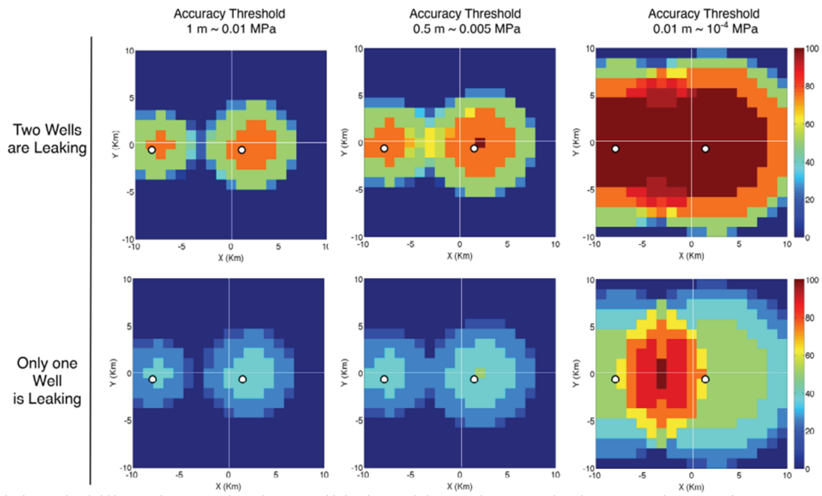

Figure 3. Spatial probability of a monitoring well being able to detect a leakage. The top frames correspond to the case where the two wells are leaking. The bottom frames correspond to a case where only one well had a define permeability at or above 1 Darcy and the other well has permeability value of zero. The circles in the frames correspond to the two closest abandoned wells to the center of the domain. Injection was simulated in the center of the domain. The distances to the center of the domain for these wells is of 1.8 km and 8 km.

A final issue we looked into was the time of detection for the same system explored above. In the case of two leaky wells, we analyzed the average time for detection of a leak. The top row in Figure 4 shows the average time for a leakage to be detected when both wells are leaking. Again, when the accuracy threshold is low enough the detection happens relatively fast. In the case where the accuracy threshold is on the order of 0.01 MPa we can expect the average detection time to drop significantly when moving away from the leaky well. These frames that explore the time associated with detection add yet another objective that can be use to decide where a monitoring well should be placed in order to maximize detection time and detection probability. The bottom row in Figure 4 answers a different question. The frames in the bottom row of Figure 4 show the average time it takes, from time of detection, to distinguish which well the leak is coming from, and the associated questions of what the leakage rate is and the effective permeability of the wells. Since the system being modelled is completely deterministic we can back calculate these parameters for any head value “measured”. But since there is an accuracy threshold that has to be met, it takes a certain amount of time in order to be able to identify the quantities of interest. In these frames the cells that take the values of 5 years mean that the model was not able to distinguish from which well the pulse was coming within the first five years.

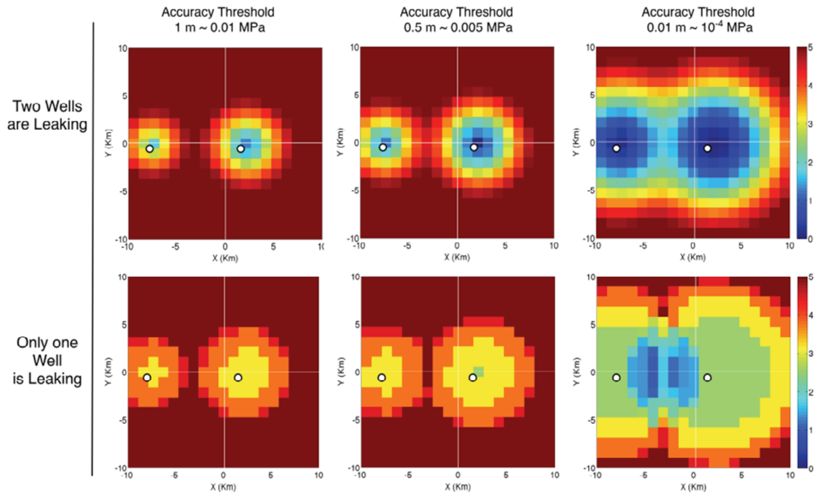

Figure 4. Average time required to detect a leakage by a monitoring well. A value of 5 years means that in the 5 years of simulation time the objective of detecting was not met. The top row shows the average time of detection of a leakage when both wells are leaking. The bottom row shows what is the average time it takes to distinguish which well is the leakage coming from. The circles in the frames correspond to the two closest abandoned wells to the center of the domain. Injection was simulated in the center of the domain. The distances to the center of the domain for these wells is of 1.8 km and 8 km.

4. Conclusion and future work

We have shown how a simple analytical solution we can be sued to analyze leakage monitoring and detection limits. Our results include the observation that the detection of leakage from measuring pressure at the injection well is possible but is limited to, for example, a maximum radial extent for detection within the first 5 years. We also showed that through a combination of several detection probability and time objectives one could identify the preferred location of a monitoring well. The examples used two leaky wells but the procedure could be expanded to more abandoned wells. One of the main observations is that the accuracy threshold of the instrument plays a major role in deciding how many wells are needed and where these wells should be placed.

The analysis in this work is limited to a simple system yet it can be expanded to include other complexities. In the future work we hope to first address a number of extensions including additional leaky wells, additional layers and more complex system including solutions for the full two-phase flow equation.

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