A Novel Approach to Detect Tubing Leakage in Carbon Dioxide (CO_2) Injection Wells via an Efficient Annular Pressure Monitoring

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Abstract: Due to the unique corrosion potential and safety hazards of carbon dioxide (CO_2), tubing leakage of CO_2 in a CO_2 injection well may occur and lead to undesired consequences to environment, human being and facility. As a result, quick detection of any carbon dioxide leakage and accurate identification of leakage location are extremely beneficial to obtain critical information to fix the leakage in a prompt manner, prevent incidents / injury / casualty, and achieve high standards of operational safety. Annular pressure monitoring has been identified as an effective and reliable approach for detecting tubing and casing leakage of fluids (including hazardous gas like CO_2) in a well. Accurate prediction of annular pressure change associated with the leakage will certainly help the operation. In an effort to assess annular pressure characteristics and thus improve understanding of tubing leakage, a multiphase dynamic modeling approach has been applied to simulate the carbon dioxide, completion brine and formation water's flow and associated heat transfer processes along wellbore, tubing and annulus in carbon dioxide injection wells designed for carbon capture and sequestration (CCS) [1] projects. Two operational scenarios – one for routine CO_2 injection and another for well shut-in – have been considered in the investigation. Key parameters that may have significant impacts on the process have been investigated. On the basis of the investigation, a novel approach has been proposed in the paper for quickly detecting the leakage of carbon dioxide in a CO_2 injection well. Two simple equations have been developed to pinpoint the leakage location by means of real-time measurement and monitoring of the change in annular pressure. Recommendations based on a series of dynamic simulation results have been provided and can be readily incorporated into detailed operating procedures to enhance carbon dioxide injection wells' operational safety.

Keywords: Annular pressure, carbon capture and sequestration, carbon dioxide, injection well, OLGA, tubing leakage.

1. INTRODUCTION

All well operations inherently carry an element of risk. Nevertheless, carbon dioxide (CO_2) injection wells for carbon capture and sequestration (CCS) projects [1] may encounter additional and unique risks not normally experienced in conventional oil and gas field operations – potential exposure to CO_2 at undesired high concentrations, which may lead to irreversible damage to environment, injury and cause casualty to human beings and animals. At normal atmospheric concentrations (around 0.037%) CO_2 is nontoxic; however as concentrations rise, adverse effects on the human body become progressively more noticeable and debilitating. Prolonged exposure to CO_2 concentrations above 6% will result in unconsciousness and if the resultant oxygen level drops below 16% death will even occur [2]. The lack of odor and color of carbon dioxide further compounds the risks.

People with normal cardiovascular, pulmonary (respiratory) and neurological functions are able to tolerate CO_2 concentrations up to 1.5% for several hours without any ill effects. Above that level impairment of functions is progressive as the CO_2 concentration continues to rise and length of exposure increases. Under an unfortunate circumstance of CO_2 leakage, the CO_2 concentration may reach and progress further beyond the limits in a short time.

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Loss of wellbore and pipeline integrity is often the root cause of many CO_2-related incidents, including a number of fatal ones all over the world in the past. Most of the incidents are associated with CO_2 leakage caused by wellbore and/or flowline failures. CO_2, in combination with water will generate carbonic acid and cause severe corrosion of conventional steels, which will eventually lead to leakage of hazardous gas (i.e., CO_2 in this case) and introduce severe dangers to human being's health and even life. As such, all these issues must be appropriately addressed, all potential scenarios investigated and necessary mitigation steps planned and incorporated into the applicable field operating procedures before starting up any carbon dioxide injection operation.

As more and more CCS projects are being planned and executed all over the world to address the global warming issue [3], more and more CO_2 injection wells will be designed, drilled, completed and applied to inject CO_2 to applicable underground geological aquifers. Substantial risks are anticipated with more CO_2 exposure to human being and environment as a result of potential hazardous gas leakage originated from a CO_2 injection well. Hence, it becomes critical and beneficial to have competent tools and approaches developed for quickly detecting any potential CO_2 leakage and accurately locating the leakage position and source of the leakage. In order to achieve the objective, a comprehensive investigation has been conducted for improving our understanding of the important characteristics of CO_2 leakage in a wellbore and the results are to be presented in

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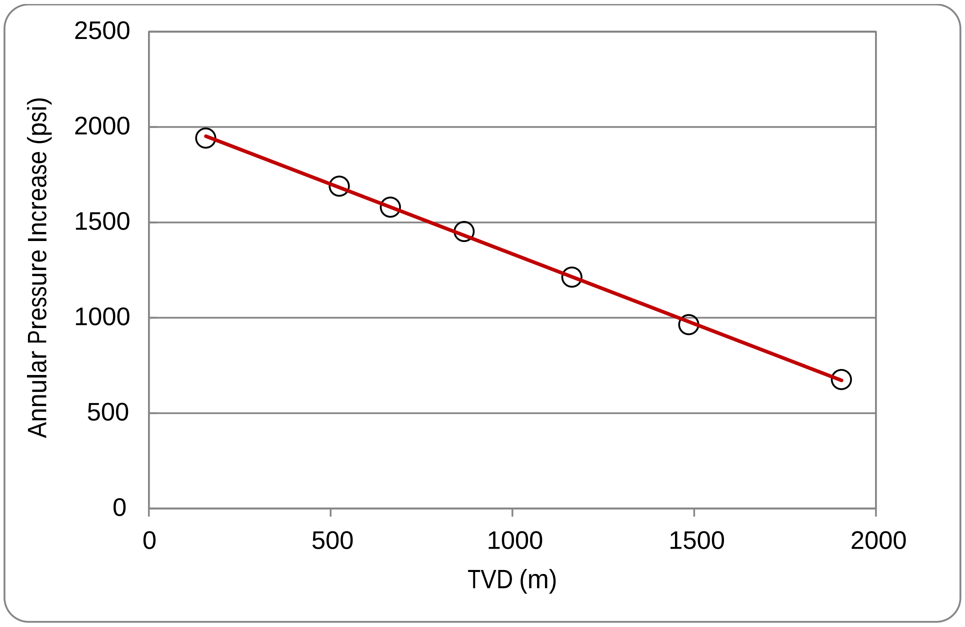

Fig. (5). Variation of Annular Pressure Change with Leakage Depth (Well Shut-in Scenario).

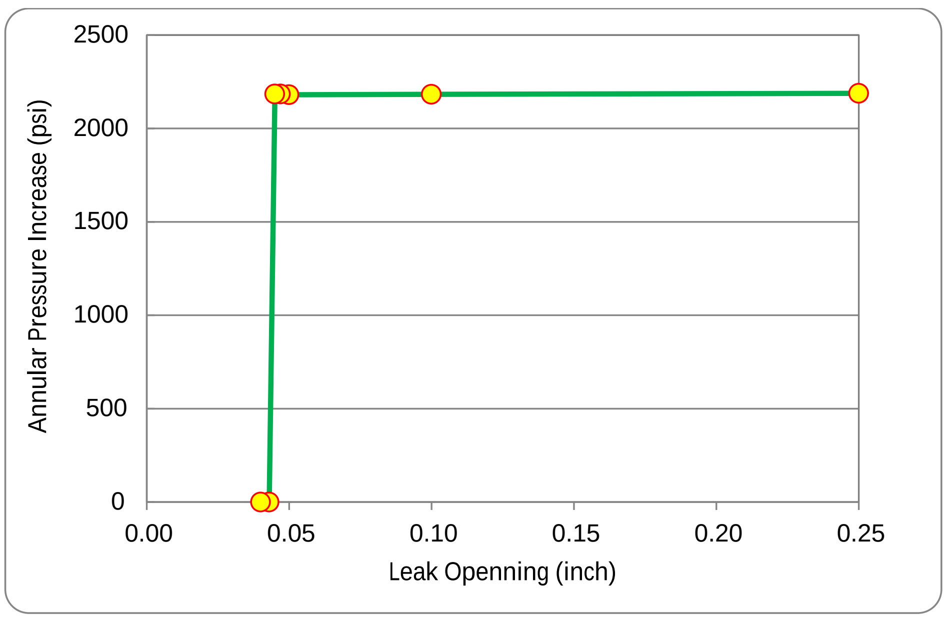

Fig. (6). Variation of Annular Pressure Change at 176m MD with the Size of Leakage Opening.

pressure. As has been shown so far in the present paper, depending on the leakage location, the tubing leak would potentially lead to an increase in the annular pressure at around 600 psi to 2000+ psi under the conditions investigated, all over a very short time period (in minutes). At high flowing fluid (CO_2 for CO_2 injection, and formation water or injected CO_2 during a well backflush operation) temperature, heat transfer could also result in substantial increase (1000s psi) in the annular pressure, but the increase would last much longer (in hours) and the increase appears to continue for a longer time period, although at a slower pace. As such, by constantly monitoring the annular pressure change over time, it may be possible to distinguish between an annular pressure increase caused by heat transfer and an annular pressure boost due to CO_2 leakage through tubing.

In this study, a quarter inch opening has been set in the majority of the dynamic modeling simulations presented in this paper. This setting was originated from a sensitivity study where different dimensions of the leakage opening – ranging from 0.02 inch to 0.25 inch – have been investigated. On the basis of the sensitivity study, it has been observed that as long as the opening is larger than a threshold for the fluid to flow, the annular pressure increase will be about the same, except for the time it takes to achieve the annular pressure increase. The smaller the opening, the longer the annular pressure increase would take. The threshold has been estimated at around 0.045 inch – a very small value – on the basis of the simulation results as shown in Fig. (**6**).

CONCLUSION AND RECOMMENDATIONS

Tubing leak and heat transfer have been identified as the two major factors that would contribute to the change (increase) in an annular pressure in a carbon dioxide injection well. Depending on the leak location, the tubing leak would potentially lead to an increase in the annular pressure at around 600 psi to 2000+ psi under the conditions investigated, all over a very short time period (in less than five minutes).

It is interesting to note that for either a flowing or a shut-in CO_2 injection well, the amount of pressure boost in the annulus associated with a CO_2 tubing leak correlates extremely well with the leakage depth. This feature may be potentially applied to estimate the location of tubing leak in the future based on the real-time measurement and monitoring of the annular pressure in a CO_2 injection well. It is believed that such practise will help field operators and engineers to detect CO_2 leakage and estimate the leakage point on a timely basis, take necessary and prompt measures accordingly to fix the leakage, and thus reduce the risk of damage to human beings and environment.

It is highly recommended to calibrate and fine-tune the applicable OLGA models to available field measurement to improve the accuracy of the prediction by the approaches and the four equations [Eqs. (1) – (4)] presented in the present paper.

The annular pressure change is expected to be closely related to fluid (completion brine in particular) density which in turn relies on pressure and temperature. Fortunately, insignificant variation of the completion brine density is anticipated under the pressure and temperature conditions to be seen for most of the carbon dioxide injection wells designed for a CCS project. Therefore, the new equations proposed in the paper should yield reasonable predictions of either the amount of the annular pressure increase or the leakage location.

CONFLICT OF INTEREST

The authors confirm that this article content has no conflict of interest.

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Declared none.

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