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Model-based cost analysis for pressure and geochemical-based monitoring methods in CO_2-EOR fields: application to field A

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Model-based cost analysis for pressure and geochemical-based monitoring methods in CO_2-EOR fields: application to field A

by

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Thesis

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Energy and Earth Resources

The University of Texas at Austin

May, 2016

Dedication

I dedicate this thesis to my husband and best friend, Seyyed A. Hosseini, for his invaluable support and encouragement. Thanks for always being there when I needed you the most. My sincere thanks go to my beloved parents Abdollah Bolhassani and Golabatoon Khaki for their unconditional love and support through every academic and personal endeavor in my life. I am also indebted to my sisters Nasrin and Marzieh Bolhassani for their love and unwavering support. Finally I would like to thank all my close friends and family who put their faith in me.

Acknowledgements

This thesis would not have been completed without support and guidance of many people. I am grateful to my advisor Dr. Michael H. Young for his invaluable support, guidance, and encouragement throughout this work. It is a pleasure to work under his kind supervision. I express my sincere thanks to Dr. Susan D. Hovorka for serving in my committee and for her guidance and wisdom. I am indebted to her for her support and unwavering patience in working with me.

I would like to express my sincere appreciation to my other thesis committee members Dr. Alexander Sun for his support and insight. My sincere thanks go to Dr. Seyyed A. Hosseini, Jacob S. Anderson, and Dr. Changbing Yang for allowing me to use their models. Without access to their models this thesis would not have been possible. Last but not least, I am thankful for the financial support from the Gulf Coast Carbon Center at the Bureau of Economic Geology.

Abstract

Model-based cost analysis for pressure and geochemical-based monitoring methods in CO_2-EOR fields: application to field A

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The University of Texas at Austin, 2016

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Decision making using monitoring data from CO_2 geological storage (GS) projects can be multifaceted and complex because of geological, environmental, political, and economic factors. This study primarily focuses on economic and technical aspects of monitoring projects for CO_2. The focus of this research is to compare the economic effectiveness of pressure-based monitoring (PBM) and geochemical-based monitoring (GBM) on CO_2 leakage detection in CO_2-EOR sites where risk for leakage assumed to be plugged and abandoned (P&A) wells, however methodology can be easily applied to CO_2 storage in saline aquifers as well. PBM can detect leakage from pressure anomalies, while GBM method detects leakage from alteration in fluid chemistry. In this paper, analytical and semi-analytical models for PBM and GBM techniques were applied to calculate the number of monitoring wells required for monitoring anomalies, which could be due to leakage of CO_2. In this study, we assumed that leakage through P&A wells represents the main risk factor. The goals of this study are to determine the cost

effectiveness of PBM and GBM as a means to maximize the spatial coverage of the monitoring network in the vicinity of P&A wells.

We used different analytical models for PBM and GBM, and overlaid the spatial coverage of each well onto a typical Texas Gulf Coast field site (known as Field A), thus identifying the intersection of each monitoring well and potentially leaking P&A well. Then, based on the available cost data, the costs of each PBM and GBM well were estimated and the two monitoring techniques were compared economically, assuming a pre-determined budget is available to invest on monitoring. The results showed that the spatial coverage of each PBM well was much higher than each GBM wells, and that the total capital and operational cost per PBM well was lower than each GBM well. For theoretical site used in this work, only 29 PBM wells were needed for full coverage of the field site, while 169 GBM wells were required. Therefore, we concluded that PBM technique is a more cost effective option, considering the parameters and assumption in this case study.

Table of Contents

List of Tables xi

List of Figures xii

List of Acronyms and Abbreviations xiv

Chapter 1: Introduction 1

1.1 Climate change and importance of CO_2 storage 1

1.2 Thesis organization 5

Chapter 1 references 7

Chapter 2: Literature Review 9

2.1 Monitoring techniques 9

2.1.1 Seismic monitoring 9

2.1.2 Gravimetric monitoring 10

2.1.3 Electromagnetic monitoring.....10

2.1.4 Well logs 11

2.1.5 Pressure-based monitoring (PBM).....12

2.1.7 Geochemical-based monitoring (GBM) 14

2.2 Cost analysis.....17

Chapter 2 references 21

Chapter 3: Model-based cost analysis for Field A 25

3.1. Introduction 26

3.1.1 Pressure-based monitoring (PBM).....28

3.1.2 Geochemical-based monitoring (GBM) 29

3.1.3 Effectiveness of monitoring plans and economic assessment 30

3.2. Materials and methods 33

3.2.1 Pressure-based monitoring model (PBM).....33

3.2.2 Geochemical-based monitoring model (GBM) 35

3.2.3 Analysis of effectiveness of monitoring methods.....38

3.2.3.1 Probable Correctness Model (PCM)..... 38

3.2.3.2 Frequency of well blow-outs (T) 40

3.2.3.3 Financial cost of a catastrophic event (L)..... 41

3.2.4 Cost Assessment-PBM and GBM Costs.....42

3.2.5 Present Value of Costs 43

3.2.6 Field description.....43

3.2.7 Sensitivity analysis and Monte Carlo simulation.....44

3.2.8 Device Failure in PBM 44

3.3 Results and discussion.....46

3.3.1 Application of PBM.....46

3.3.2 Application of GBM 46

3.3.3 Cost effectiveness analysis 47

3.3.4 Sensitivity analysis and Monte Carlo simulation for PCM 48

3.3.5 Sensitivity Analysis for leakage detection time.....49

3.3.6 Sensitivity Analysis for CO_2 leakage rate.....50

3.3.7 Device Failure in PBM 50

3.3.8 Conclusions.....51

3.3.9 Acknowledgments.....52

Chapeter 3 references.....70

Chapter 4: Discussion 73

4.1 Model limitations in PBM and GBM.....73

4.1.2 Model limitation in PCM 74

4.2 GBM in shallow aquifers 75

4.3 Final statements.....78

Chapter 4 references 84

BIBLIOGRAPHY 85

List of Tables

Table 3.1: Texas well blow-outs records collected from RRC for period 1998-2011..... 64

Table 3.2: Capital costs and operational costs of per PBM or GBM monitoring well (EPA, 2010b). We assumed the depth of each monitoring well is 1,524 meters.. 65

Table 3.3: The present value of capital costs and operational costs of per PBM/GBM monitoring using Eqn. (20). 66

Table 3.4: Selected input parameters for PBM model. 67

Table 3.5: Selected input parameters for GBM model. 68

Table 3.6: Sensitivity analysis for PCM using Eqn. (19)..... 69

Table 4.1: Capital costs of per PBM/GBM monitoring well (EPA, 2010b)..... 79

Table 4.2: Operational costs of per PBM/GBM monitoring well (EPA, 2010b)..... 80

Table 4.3: Specific capital and operational costs for PBM & GBM using field data (SECARB, 2014). 81

Table 4.4: The present value of capital costs and operational costs of each GBM well at depth of 152.4 meters, calculated using Eqn. (20)..... 82

Table 4.5: The present value of capital costs and operational costs of each GBM well depths of 1524 meters and 152.4 meters using fiber optic sensors, calculated using Eqn. (20). 83

List of Figures

Fig. 1.1: Atmospheric CO_2 level since 1960 (NOAA, 2015). 6

Fig. 3.1: Cross-sectional cutaway of hypothetical field site used in analysis. 53

Fig. 3.2: Schematic of P&A wells (dark blue dots) and hypothetical pressure anomalies after CO_2 leakage from P&A wells. Triangles represent locations of monitoring well with a higher chance of leakage detection. 54

Fig. 3.3: Schematic of P&A wells (dark dots) and hypothetical CO_2 plumes after leakage from P&A wells (light blue circles). Triangles represent locations of monitoring well with a higher chance of leakage detection. 55

Fig. 3.4: Scatterplot showing the coverage of P&A wells as a function of the number of monitoring wells, using the PBM and GBM techniques. 56

Fig. 3.5: Field A is located in Texas Gulf Coast area and currently is under development for commercial EOR. As shown, about 740 P&A wells have been drilled in this field. 57

Fig. 3.6: Results using PBM (a) and GBM (b) techniques. Red dots are the location of PBM and GBM monitoring wells in both plots. 58

Fig. 3.7: Scatterplot showing the number of monitoring wells needed to intersect plumes, using PBM and GBM techniques. 59

Fig. 3.8: Results of Monte Carlo modeling, to demonstrate the frequency distribution (FD) and the percent of leakage detection for each premium. 60

Fig. 3.9: Sensitivity analysis for leakage detection time in PBM (a) and GBM (b) models. 61

Fig. 3.10: Sensitivity analysis for leakage rate in PBM (a) and GBM (b) models. 62

Fig. 3.11: Loss of monitoring coverage because of device failure in the PBM technique. 63

List of Acronyms and Abbreviations

AZMI	Above-Zone Monitoring Interval
CCUS	Carbon Capture, Utilization, and Sequestration
DOE	Department of Energy
EPA	Environmental Protection Agency
EOR	Enhanced Oil Recovery
GBM	Geochemical Based Monitoring
GS	Geological Storage
GSM	Geological Storage Monitoring
MVA	Monitoring, verification and accounting plan
P&A	Plugged and Abandoned
PBM	Pressure Based Monitoring
PV	Present Value
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey

Chapter 1: Introduction

1.1 CLIMATE CHANGE AND IMPORTANCE OF CO_2 STORAGE

Between 1970 and 2004, the global greenhouse gas (GHG) emissions including CO_2, CH_4, N_2O, SF_6, etc. grew by 70% (from 28.7 to 49 metric gigatons of CO_2 equivalents) (IPCC, 2007). Carbon Dioxide (CO_2) is the dominant GHG, accounting for 77% of global GHG emissions in 2004, and is considered as the main climate change factor (IPCC, 2007). Figure 1.1 shows atmospheric CO_2 levels since 1960; it is apparent from this trend that CO_2 concentrations are still increasing. One method to reduce potential global temperature rise is to develop methods to decrease atmospheric CO_2 emissions. Some approaches to reduce CO_2 emission to the atmosphere include: 1) reducing carbon-intensive fuels consumption by employing fuel-efficient technologies; 2) increasing renewable energy such as solar, wind, geothermal, etc.; 3) using Carbon Capture, Utilization, and Sequestration or storage (CCUS) to reduce atmospheric emissions of CO_2 from large power plants and industrial sources.

CCUS can play a potentially important role in reducing concentrations of CO_2 in the atmosphere by its usage and permanent storage. The primary goal of CCUS is to stabilize the level of GHG in the atmosphere to mitigate the climate change effects. According to International Energy Agency (IEA), CCUS is a fundamental technology that is required to reach considerable GHG emissions reduction. This technology is estimated to potentially account for approximately one-sixth of CO_2 emissions reduction plan or 14% of overall goals in reducing the carbon emission by 2050 (IEA, 2013).

CCUS consists of three basic steps:

1) Capture - CO_2 is captured from large power plants and industrial sources. After collecting the CO_2, it is compressed into a dense-phase fluid.

2) Transportation - The compressed CO_2 fluid is then transported to the utilization sites by pipeline, but it can also be transported by train, truck, or ship.

3) Utilization/sequestration - the process of utilizing CO_2 to either produce new products (e.g., cement production) or store it in subsurface repositories (either CO_2 geological storage or deep ocean storage).

Geological storage of CO_2 has become increasingly attractive because of substantial experience in building the required infrastructure, characterizing subsurface, and understanding of fluid flow in hydrocarbon and brine reservoirs. Injection of CO_2 for Enhanced Oil Recovery (EOR) has been implemented for more than 40 years in the Permian Basin (Logan & Venezia, 2007). Moreover, there is a huge potential for CO_2 storage in the U.S. According to the U.S. Department of Energy (DOE) assessment, between 1,800 to 20,000 billion metric tons of CO_2 can be stored underground in the United States, equal to 600 to 6,700 years of CO_2 emissions from large stationary sources in the U.S. based on 2011 CO_2 emission rates (NACSA, 2012).

In geologic storage (GS), compressed CO_2 is injected under high pressure into deep geologic formations, which are sealed with impermeable layers of rock that trap the CO_2 and retard its upward migration toward the surface (Logan et al., 2007). The injected CO_2 is stored in the pores between mineral grains that are typically filled with brine (or hydrocarbons) so that it will be safely and permanently trapped. Four mechanisms are generally thought to represent most CO_2 trapping in subsurface reservoirs: structural trapping, solubility trapping, capillary trapping, and mineral trapping. (Han et al., 2010)

Five major structure types are known to trap CO_2: 1) oil and gas reservoirs, 2) unmineable coal seams, 3) saline formations, 4) organic-rich shales, and 5) basalt formations (NETL, 2010). The first three types have been historically evaluated for CO_2 storage and the last two are under more investigation to increase our understanding of

governing physical processes in the presence of CO_2. Saline and basalt formations are important because of their availability in most parts of the country that may not have access to depleted oil and gas reservoirs. For instance, of the seven major CCS partnerships organized by the U.S. Department of Energy (DOE), three are focused on saline formations and the other four are focused on a combination of saline and depleted oil and gas reservoirs, with no major project defined in other types of formations. In this paper, our focus will be on GS in depleted oil and gas reservoirs.

DOE's Regional Carbon Sequestration Partnerships' (RCSPs) and National Carbon Sequestration Database and Geographic Information System (NATCARB) have estimated the global potential for CO_2 storage in the U.S. reservoirs as of May 2012. Depleted oil and gas reservoirs have the storage capacity of 226 billion metric tons of CO_2. Saline formations have the largest capacity with an average of 11,072 billion metric tons, and unmineable coal sites have an average capacity of 85 billion metric tons (DOE, 2012). The formula used by DOE to calculate these capacities is the product of the reservoir area, thickness, porosity, and storage efficiency. Storage efficiency is typically assumed to be between 1% to 5% that accounts for physical limitations on complete substitution of the pore volume by CO_2, including gravity segregation of CO_2 and the effect of heterogeneity on sweep efficiency of CO_2 (Tian et al., 2013).

One of the risks of geological CO_2 sequestration is the stored carbon may leak and escape into the atmosphere and underground drinking water sources. The Intergovernmental Panel on Climate Change (IPCC), however, believes that CO_2 can be stored for millions of years with retention rates of more than 99% over 1000 years (Van Engelen, 2009). Their claim is mostly based on historical accumulation and storage of oil and gas in deep formations for millions of years.

Large amount of CO_2 (8-10 metric gigatons/year) should be injected into deep (greater than ~1 km) storage formations to make GS a feasible alternative for climate change mitigation (IEA, 2013; Wilson et al., 2003). However, large injection volumes of CO_2 could increase the formation pressure, which may create new fractures or activate faults by altering the geo-mechanics of the formation (Zhou et al., 2010; Zhou & Birkholzer, 2011; Rutqvist, 2012). Increasing formation pressure could cause CO_2 leakage through permeable leakage pathways such as P&A wells, or through new fractures and faults. Therefore, a risk assessment followed by implementation of a Monitoring, Verification, and Accounting (MVA) plan is recommended by most jurisdictions. Risk assessment will identify the possible failures in creating effective storage and MVA will determine that these failures are avoided and the storage is effective in isolating CO_2 from the atmosphere. The U.S. Environmental Protection Agency (EPA) has developed Federal requirements for CO_2 injection for GS purposes. Regulations for construction and operation of Class VI wells, which relate to CO_2 injection, ensure that wells meet proper performance criteria for protecting underground sources of drinking water (USDW).

Detecting CO_2 leakage is needed to reduce the economic losses of operators and possible environmental damage, and to fulfill regulatory requirements. Monitoring methods such as 3-D seismic, well logs, LIDAR airborne survey, remote sensing, eddy covariance, etc. have been tested to monitor leakage (Rütters et al., 2013). An effective MVA program should be able to detect CO_2 leakage out the reservoir as early as possible. For this purpose monitoring for pressure or geochemical changes above the injection zone are being tested. A variety of monitoring methods are suitable potentially for different types of formations including seismic, gravimetric, pressure, etc. Some of these monitoring technologies will be briefly discussed in the next chapter, but the goals of this

study are to 1) compare pressure-based monitoring (PBM) and geochemical-based monitoring (GBM) techniques, economically and technically; 2) identify the most cost-effective monitoring option using a cost analysis model.

1.2 THESIS ORGANIZATION

The remainder of this thesis is organized into three additional chapters. Chapter 2 consists of a literature review explaining various monitoring techniques focusing on PBM, GBM and the cost analysis. Chapter 3 contains the Model-based cost analysis of PBM and GBM methods in CO_2-EOR fields with application to a specific field. Chapter 3 was planned to stand alone as a manuscript, outside of this thesis, which was submitted on May 2016 for review and publication in the journal Greenhouse Gases: Science and Technology. For this reason, some discussion may be repeated within this thesis. Lastly, Chapter 4 discusses limitations and uncertainties involved with the methodologies used in Chapter 3, and it compares PBM and GBM in deep and shallow subsurface environments.

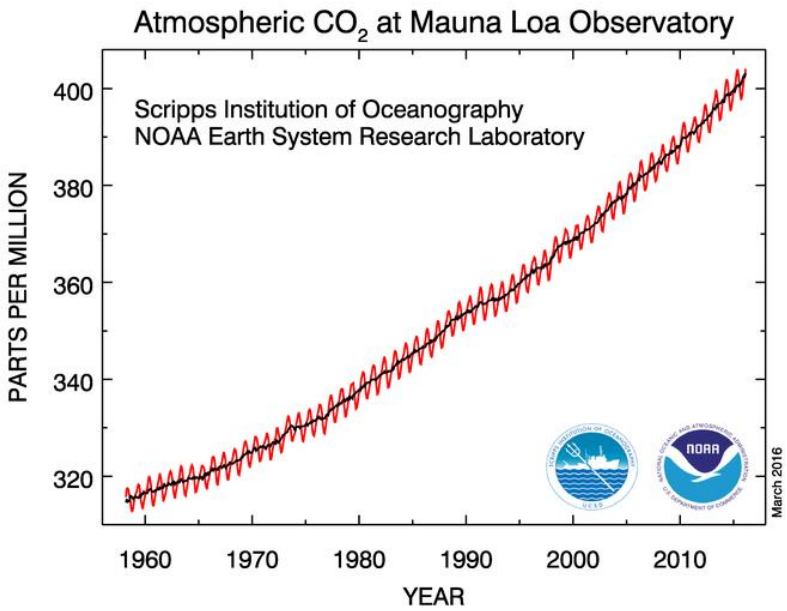

Fig. 1.1: Atmospheric CO_2 level since 1960 (NOAA, 2015).

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Chapter 2: Literature Review

2.1 MONITORING TECHNIQUES

The goal of a monitoring network is to minimize the impacts of geological CO_2 storage by the early detection of leakage. Different types of monitoring systems are suitable for different types of formations, but the focus in this thesis will be on PBM and GBM techniques.

2.1.1 Seismic monitoring

This technology uses acoustic waves that are transmitted through rocks. Based on the rock and fluid properties, a portion of the energy will be reflected back to the surface and will be recorded by receivers. By placing an array of sources and receivers, a 3-D seismic image can be generated. The two-way travel time for the sound waves is interpreted as depth by knowing the sound velocities. 3-D seismic imaging technique has been historically used in exploration of oil and gas (Lonergan & White, 1999). Repeated 3-D surveys leads to what is known as the 4-D seismic method, which can be used to assess change over time as a result of CO_2 storage, oil and gas extraction, or other geological processes. Seismic waves are affected by static geological properties such as porosity, permeability, lithology, etc., as well as dynamic properties of reservoir such as pressure, temperature, fluid flow and fluid saturation. Therefore, the strength of seismic signals is subject to compressibility of the formation and the rock fluids (Liu, 2012). So, formations with high compressibility, porosity, and greater compressibility contrast between the pore fluids can transmit seismic signal more effectively.

2.1.2 Gravimetric monitoring

In this monitoring method, changes in fluid density caused by CO_2 injection could be identified by considering changes in the gravitational field near the reservoir, before and after CO_2 injection. To implement this in the field, the gravimetric sensors are installed at ground surface and in boreholes, depending on whether the assessment is done for onshore or offshore monitoring. The gravity gradient of the formation is then measured and used as baseline, for subsequent comparison with time-lapse measurements after CO_2 injection. The difference between these gravity field can provide an estimate of CO_2 movement in the subsurface in both vertical and horizontal directions (Goldberg, 2013; Liu, 2012).

2.1.3 Electromagnetic monitoring

Electromagnetic monitoring technologies measure the bulk electrical conductivity of the rock and fluid system. Conductivity can be measured by sending and receiving electromagnetic sources to the formation and contrasting the response differences. Because the resistivity of CO_2 is lower than water, the electromagnetic technique can identify conductivity differences after CO_2 injection. (Börner et al., 2010) tested electrical resistivity of CO_2 and water under reservoir pressure and temperature in the laboratory, and showed that the electrical resistivity of a porous medium saturated by a fluid is very sensitive to the presence of CO_2 (existence of CO_2 increases the electrical resistivity of the formation). Therefore, electromagnetic techniques can be a potential option for monitoring CO_2 in the subsurface.

2.1.4 Well logs

This method is performed by lowering geophysical or logging tools into the well to take the profile of physical properties of the rocks and fluids near the well. Logs can measure a variety of properties, including well construction, rock properties, and pore fluids. Gamma ray, acoustic, neutron, and temperature logs are some of the most common well logging methods (Benson et al., 2004). Time-lapse well logging can be useful in measuring the changes in the formation over time.

Time-lapse well logging with the Schlumberger Reservoir Saturation Tool (RST) is a method used to determine the formation saturation (Hovorka et al., 2013). The RST combines thermal decay time and carbon/oxygen (C/O) methods of saturation measurement to overcome their deficiencies. Thermal decay time logging is used when salinity is high but this method is restricted to non-tubing wells. The C/O logging is used to evaluate the oil saturation of formation that is restricted to water salinity levels. RST allows measurements of both thermal decay time and C/O in a single trip to the well (Adolph et al., 1994).

Well logging technology has advanced significantly due to the extensive application in oil and gas industry. Well logging can be appropriate for CO_2 storage projects in various ways, including (1) site characterization to assess the properties of the formation and seal; (2) developing a pre-injection baseline for the formation parameters; (3) detecting the salinity and hydrocarbon content of the site to develop a baseline against future changes; and (4) evaluating the injection and monitoring well integrity (Benson et al., 2004).

2.1.5 Pressure-based monitoring (PBM)

A common technique to assess fluid flow, especially in hydrocarbon reservoirs, involves collecting and interpreting pressure variation data. Downhole PBM can provide information with higher level of accuracy compared to wellhead pressure data, because it eliminates uncertainties associated with fluid density and type and amount of the fluids (gas/liquid) in the tubing (Eliasson et al., 1999). Measuring pressure at the monitoring well can help identify the location, onset and volume of CO_2 leakage with relatively high accuracy and wide-ranging coverage (Sun et al., 2013a). Although Zeidouni and Pooladi-Darvish (2012) revealed that using pressure data to detect CO_2 leakage pathway location is ill-conditioned and error in model parameters or noise in measurements can possibly result in improper estimates of leakage location, they determined that PBM can diagnose possible CO_2 leakage from a leaky well or fault when model parameters are known (Zeidouni & Pooladi-Darvish, 2012).

Pressure-based monitoring can be performed in both in-zone (storage formation) and above-zone locations. In-zone monitoring is conceptualized to determine that the injected CO_2 remains in the intended areas or CO_2 is inside the reservoir (no out-of-zone leakage from edges of the storage formation), and in CO_2-EOR sites, the reservoir pressure has reached levels high enough to initiate CO_2-oil miscibility.

In this work, PBM wells are completed in permeable zones above the CO_2 storage formation, which hereafter is called the Above Zone Monitoring Interval (AZMI). Storage formation and AZMI are separated by a confining layer or seal. The AZMI can respond rapidly to small pressure as well as geo-mechanical changes because it is situated above the injection zone (Kim & Hosseini, 2014). However, the selection of continuity,

thickness, and boundary conditions of the AZMI can greatly alter its response to the leakage.

Several studies have used pressure data from the AZMI as a leakage detection technique that could be helpful in early warning of CO_2 leakage (Benson et al., 2006) and (Nogues et al., 2011). This is because pressure anomalies travel faster than the leaked CO_2 plumes, under the same conditions; therefore, pressure anomalies will reach the monitoring wells faster and potentially be detected ahead of the CO_2 plume (Zhou et al., 2010). In this way, pressure data can be useful in detecting CO_2 leakage in early stages (Jung et al., 2013, 2015; Sun & Nicot, 2012; Sun et al., 2013a; Sun et al., 2013b; Zeidouni & Pooladi-Darvish, 2012)

In the PBM, pressure gauges are installed in the subsurface, typically tens of meters above the injection zone, and frequently measure pressure during CO_2 injection and possibly the post-injection periods. PBM wells can include permanently- or temporarily-installed downhole equipment to measure pressure and temperature in the injection and containment zones. The permanently-installed gauges have a higher equipment cost compared to temporarily-installed gauges but their lower operational costs could offset initial (capital) costs in long-term monitoring programs. However, permanently-installed gauges installed in deep formations are prone to failure due to high temperature or pressure. One major challenge in manufacturing pressure gauges is to provide a gauge that is durable enough to withstand high temperature and pressure changes and at the same time maintain sensitivity to small changes in pressure.

Using high-precision gauge can increase the chance of leakage detection but gauge resolution is inversely proportional to its range of detection. The suggested pressure resolution is about 0.01 psi, depending on the formation conditions and pressure variations (Benson et al., 2006). Commercial gauges are available that measure pressures

reaching 30,000 psi or any other rugged downhole conditions (e.g., elevated temperatures) where differences less than 0.005 psi can be detected (Besson, 2011). A variety of pressure sensors can be used to measure pressure such as strain gauges, piezo-electric transducers, diaphragms, fiber optic sensors, and capacitance gauges (Wilson, 2003)

Another advantage of PBM is that it has a wide range of coverage compared to other monitoring methods, due to pressure diffusivity. Pressure waves in general have short wavelength and they obey an accumulation-depletion law instead of reflection-refraction law (Yang et al., 2015b).

Nogues et al. (2011) proposed detecting brine or CO_2 leakage through abandoned wells by using the PBM method located above their injection zone. They determined the average time needed to detect the leakage and where PBM wells should be located to optimize the monitoring outcomes (Nogues et al., 2011). Sun et al. (2013a) applied a model to optimize monitoring network design to enhance leakage detection. They formulated a Binary Integer Programming Problem (BIPP) to minimize the number of monitoring locations. Hosseini and Alfi (2015) showed that pressure data can be used in monitoring intervals to detect CO_2 leakage and they estimated the amount of leaked CO_2 by measuring the changes in physical properties of monitoring zone (e.g., compressibility). In this study, we used the simple single phase diffusion equation to simulate the extent of a pressure anomaly due to leakage of fluids from reservoir to the monitoring zone (Theis, 1935).

2.1.7 Geochemical-based monitoring (GBM)

GBM can be used in-zone to detect CO_2 arrival at production/extraction wells and to identify groundwater changes as an environmental protection measure. In this study we

define the underground water bodies as freshwater as well as brackish and saline groundwater sources. GBM methods can also be used in AZMI to detect CO_2 by direct measurement of change in chemical signatures. The focus of this study is on GBM in AZMI which is less common in the literature compared to shallow aquifer and in-zone monitoring. Geochemical monitoring traces the changes in groundwater chemistry due to CO_2 injection inside the injection zone and around the monitoring area. Water samples can be collected either by pumping water upward from the wells perforations to ground surface or by collecting samples at the well perforations using various sampling strategies to preserve pressure conditions. The sampling can be done in regular time intervals throughout the CO_2 injection process, as well as prior to CO_2 injection, to characterize the baseline signal.

The samples can be analyzed for a diverse suite or geochemical indicators including pH, major ions (e.g., Na, K, Mg, Ca, HCO_3^-, SO_4, Cl, Si), alkalinity, isotopes (e.g., ^{13}C, ^{14}C, ^{18}O, and ^{2}H), and gases including hydrocarbons and CO_2 (Benson et al., 2004). Instruments to indirectly measure various geochemical parameters in well fluids in place are in development (Delgano et al., 2013). In recent years, understanding the interactions between CO_2 and subsurface minerals has attracted attention of the scientific community. Therefore, studies about kinetics and extent of CO_2 and mineral reactions in natural CO_2 reservoirs are being used to evaluate the geochemical reactions (Benson et al., 2004).

Monitoring CO_2 by inspecting tracers is an alternative that can be implemented in groundwater and the vadose zone for leakage detection. The tracers can be selected from natural or artificial elements. For instance, isotopes like C, O, H gases are the natural tracers used in CO_2 sequestration sites (Stalker et al., 2009). Others, like SF_6, CD_4 (deuterated methane is not a naturally occurring substance), and perfluorocarbons are

examples of artificial tracers (Hortle et al., 2011). Nevertheless, any tracer should be assessed to be appropriate for environmental safety and reservoir conditions.

GBM is a powerful tool for identifying fluid source and physicochemical processes, based on isotopic compositions. Fluid source can be evaluated based on isotopic compositions e.g., it can trace the origin of CO_2 leakage based on its isotopic fingerprint (Holloway et al., 2014). GBM can be used to identify and measure physicochemical processes during CO_2 storage by using reactive and conservative tracers. The reactive tracers (e.g. ^{14}C) will track chemical reactions while conservative tracers (e.g., noble gas, SF_6) will monitor physical processes (Eloide & Philippe, 2012). However, it is very challenging for GBM to detect small leaks because CO_2 concentration in the Earth's crust differs by location. Conservative tracers, such as noble gas, perfluorocarbons, SF_6, etc. are widely used to monitor CO_2 plume migration. These tracers need to be non-toxic, persistent, stable, and environmentally safe (Stalker et al., 2009). Before CO_2 injection, single-well push-pull and inter-well tracer tests are often performed to determine the CO_2-brine-rock interface processes, the reservoir boundaries, size, and the heterogeneities (Ghergut et al., 2011).

Water chemistry will be affected by interaction of rocks and CO_2 through changes in pH, alkalinity, Total Dissolved Solid (TDS), etc. For instance, geochemical monitoring in the Weyburn CO_2-EOR field in Canada indicated increase in alkalinity and decrease in pH levels compared to baseline levels, which is sign of reaction with carbonate minerals. Based on chemical and isotopic data, this change has been due to the dissolution of calcite as a result of water–rock reactions driven by CO_2 (Emberley et al., 2005).

Yang et al. (2015a) reported on a semi-analytical approach to forward model CO_2 leakage into brine aquifers. Although implementing fully numerical solutions are more accurate, decoupling transport and reaction calculations by this semi-analytical approach

reduced computational expense while still generating similar results (Yang et al., 2015a). Yang et al.'s semi-analytical model is being used in this paper to determine the location and the number of required GBM wells.

2.2 COST ANALYSIS

The goal of a monitoring network is to monitor change in environmental conditions, like early detection of leakage, so that environmental and health risks can be minimized and value from storage of CO_2 in isolation from the atmosphere be documented. A reliable and cost effective monitoring technique can ensure that geological storage is a safe and effective technology. This is very important, especially for the public acceptance of GS. Therefore, the challenge is to keep the monitoring costs low while optimizing the efficiency of monitoring systems. Many cost analyses have been reported for GS projects such as EPA and DOE cost models (NETL, 2014) (EPA, 2010b).

The DOE, Office of Fossil Energy (FE), National Energy Technology Laboratory (NETL) developed a cost model for CO_2 storage in saline formations (NETL, 2014). Their cost model was intended to mimic the CO_2 sequestration process and to calculate the revenue and costs for the operator of a typical GS project. The model can be used in three modes: 1) the user sets the price of CO_2 and the model calculates the net present value of returns; 2) the model calculates the price of CO_2 when the net present value of returns is zero, and the user sets CO_2 costs at this price or higher to meet the minimum internal rates of return; or 3) the model calculates the break-even price of CO_2 for all storage sites during the first year of operation and develops cost supply curves for potential CO_2 storage.

As another example, EPA also analyzed cost for geologic CO_2 sequestration for specific monitoring technologies (EPA, 2010b). Their analysis describes the associated unit costs for different geologic CO_2 sequestration technologies in two types of geologic formations: saline formations and oil and gas reservoirs. However, no previous cost analysis has interconnected the costs to the geotechnical and site-specific parts of GS projects to optimize the monitoring by cost considerations

When limited financial resources are available, maximizing the efficiency and effectiveness of monitoring plans is crucial. The GS Rule (EPA, 2010a) requires the owners and operators of projects to periodically monitor groundwater quality and geochemical changes above the confining zone to track changes relative to baseline geochemical data. PBM and GBM methods can detect leakage from pressure pulses and CO_2 plume, respectively.

In this work, we use analytical and semi-analytical models for PBM and GBM techniques, respectively, to calculate the number of wells needed for full coverage of the major leakage risk factor, which we assume to be P&A wells. Then, the per-well costs of PBM and GBM will be estimated. Assuming funding levels remain the same for monitoring, a robust cost analysis should reveal which monitoring technique is more cost-efficient. To do so, we need a cost analysis method to compare these monitoring techniques. Some of the common cost analysis methods are explained below.

Cost-Benefit Analysis (CBA) and Cost-Effectiveness Analysis (CEA) are two evaluation approaches that measure the financial outcomes of different projects or programs. CBA places dollar values on both the costs and benefits of projects, assessing the incurred costs of projects against its benefits (Mechler & The Risk to Resilience Study Team, 2008). CEA evaluates the project's effectiveness considering its costs. In CEA, there is no need to monetize costs and benefits; the method measures the

outcomes/effects that are produced from the incurred costs (Wholey et al., 2010). Both CBA and CEA approaches can help decision makers evaluate the efficiency of various projects and allocate the resources to the right one.

However, applying CBA and CEA analyses in assessing GS monitoring projects is challenging, because it is not easy to evaluate the effectiveness of monitoring against its costs, or to monetize all its associated costs and benefits. For instance, ICF International evaluated the costs and benefits for U.S. offshore CO_2 storage (Vidas et al., 2012). Based on their analysis, offshore CO_2 storage has a cumulative net benefit to the US economy of $0.26 billion between 2015 and 2030 and $16.9 billion between 2015 and 2050. Ongoing issues with these analyses are uncertainties in estimating the net benefits of CCUS because the benefits depend on assumptions such as oil/gas prices, energy demand, regulations, etc.

Instead, we can evaluate GS monitoring plan by considering the financial risks of CO_2 leakage and assign a premium for investment. The financial risks of CO_2 leakage can be quantified by evaluating the probability, the costs of CO_2 leakage, etc. In this study, the probable correctness theory model introduced by Hamlet is employed to decide how much money is ideal to be invested on monitoring based on the financial risks of CO_2 leakage (Hamlet, 1987). Here, we assume that operators of GS projects would invest in monitoring plans as a kind of insurance to detect and prevent possible leakages before resulting in a possible but unlikely loss of CO_2 from the storage reservoir. Thus, a premium is calculated that indicates the optimum amount of money the operator can invest on the monitoring plan each year throughout the life of the project.

There are two types of risks: speculative and pure. Speculative risks can cause either a loss or a profit, while pure risk only causes a loss (Voas et al., 1992). An example of speculative risk is investing in the stock market. The risk of CO_2 leakage in CCUS

projects is a pure risk because the outcome (e.g., leakage) can only lead to loss (here we do not consider CO_2 storage as a monetary benefit). Insurance provides companies the chance to hedge against pure risks or catastrophic events through regular premium payments. In our context, premium is the ideal amount of money spent by operating companies on monitoring programs to avoid possible catastrophic events. On the other hand, insurance companies need to make profit to keep in business; therefore, they use premiums to compensate for risks under uncertainties, which must first be assessed. Therefore, they need a tool to quantify the financial risks of CO_2 leakage and to calculate the optimal amount of premium.

In the next chapter, PBM and GBM models used in this study will be described in details. Then, Hamlet's theory approach that is used to calculate premiums will be explained. Finally, these models will be integrated to compare PBM and GBM techniques technically and economically to identify the most cost-effective monitoring option.

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Chapter 3: Model-based cost analysis for Field A

Model-based cost analysis for pressure and geochemical-based monitoring methods in CO_2-EOR fields: application to field A

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3.1. INTRODUCTION

Carbon Capture, Utilization, and Sequestration (CCUS) represents a set of technologies that can reduce carbon dioxide (CO_2) emissions from large power plants and industrial sources. CCUS can play a potentially important role in reducing concentrations of CO_2 in the atmosphere by its usage and permanent storage. CCUS consists of three basic steps: 1) Capture - CO_2 is captured from large power plants and industrial sources. After collecting the CO_2, it is compressed into a dense-phase fluid. 2) Transportation - The compressed CO_2 fluid is then transported to the utilization sites by pipeline, but it can also be transported by train, truck, or ship. 3) Utilization/sequestration - the process of utilizing CO_2 to either produce new products (e.g., cement production) or storing it safely in subsurface repositories (either CO_2 geological storage in aquifer or use for CO_2-EOR).

Geological storage of CO_2 has become increasingly attractive, because of substantial experience in building the required infrastructure, characterization of subsurface, and understanding of fluid flow in hydrocarbon and brine reservoirs. Injection of CO_2 for Enhanced Oil Recovery (EOR) has been implemented for more than 40 years in the Permian Basin (Logan & Venezia, 2007). Moreover, there is a huge potential for CO_2 storage in the US. According to the US Department of Energy (DOE) assessment, between 1,800 to 20,000 billion metric tons of CO_2 can be stored underground in the United States, equal to 600 to 6,700 years of CO_2 emissions from large stationary sources in the US based on 2011 CO_2 emission rates (NACSA, 2012). It is estimated that CO_2 geological storage could potentially account for 14% of overall goals in reducing the carbon emission by 2050 (IEA, 2013).

In geologic storage (GS), compressed CO_2 is injected under high pressure into deep geologic formations. These formations are sealed with impermeable layers of rock that trap the CO_2 and retard its upward migration toward the surface (Logan et al., 2007). The injected CO_2 is trapped in the pores between rocks that are typically filled with brine (or hydrocarbons) so that it will be safely and permanently trapped. Four mechanisms are generally thought to represent most CO_2 trapping in subsurface reservoirs: structural trapping, solubility trapping, capillary trapping, and mineral trapping (Han et al., 2010).

The US Environmental Protection Agency (EPA) has developed Federal requirements for CO_2 injection for GS purposes. Regulations for construction and operation of Class VI wells (EPA, 2012), which relate to CO_2 injection, ensure that wells meet proper performance criteria for protecting underground sources of drinking water (USDW). Therefore, to ensure that injecting CO_2 in geological formations is safe for humans and the environment, and to prevent CO_2 leakage into the atmosphere, a monitoring, verification and accounting (MVA) plan is required. An effective MVA program should be able to detect CO_2 leakage from the reservoir.

Detecting CO_2 leakage is critical to reduce the economic losses of operators, possible environmental damage, and to fulfill regulatory requirements. The GS Rule (EPA, 2010a) requires owners and operators to periodically monitor groundwater quality, geo-mechanical and geochemical changes above the confining zone using a network of monitoring wells and to track changes relative to baseline data. In this study, we focus on operational and post-injection monitoring using pressure-based monitoring (PBM) and geochemical-based monitoring (GBM) techniques, and we assume that P&A wells are the main pathways for CO_2 leakage. These two techniques will be discussed briefly in the next section.

3.1.1 Pressure-based monitoring (PBM)

One of the challenges of CO_2 leakage detection is that most monitoring techniques lack enough spatial coverage to effectively conduct surveillance over large CO_2 plumes that, in large GS projects, could be tens to hundreds of square kilometers in size. Fortunately, PBM has a wider spatial range of coverage compared to other monitoring methods, making it suitable for large-scale monitoring projects (Hosseini & Alfi, 2015).

Pressure has been a useful tool to understand extraction of hydrocarbons (e.g., oil, gas, CO_2, etc.) and confining system performance (Hovorka et al., 2011). PBM is one of the monitoring methods with the ability to detect CO_2 leakage in early stages, from pressure anomalies which migrate considerably faster than the CO_2 migration itself (Jung et al., 2013). Sun and Nicot (2012) presented a linear inversion approach to identify CO_2 leakage locations into AZMI by using anomalous pressure signals. They concluded that the PBM technique can be deployed to discover the location of leaky wells (Sun & Nicot, 2012). Pressure anomalies can be defined as any change in recorded pressure that cannot be attributed to known or controlled operational processes. Early detection of CO_2 can have a significant importance in managing the risks of geologic CO_2 storage and deployment of the remediation plans.

In this method, pressure gauges will be installed in the subsurface, typically tens to hundreds of meters above the injection zone, to frequently measure the pressure during CO_2 injection and post-injection periods. The PBM wells generally are outfitted with permanent or temporary installed downhole equipment to measure pressure and temperature in the injection and containment zones. A variety of pressure sensors can be used to measure pressure, such as strain gauges, piezo-electric transducers, diaphragms,

fiber optic sensors, and capacitance gauges (Wilson, 2003). Commercial gauges are available that measure pressures reaching 30,000 psi or any other rugged downhole conditions (e.g., elevated temperatures) where differences less than 0.005 psi can be detected.

Nogues et al. (2011) proposed detecting brine or CO_2 leakage through abandoned wells by using the PBM method located above their injection zone. They then determined the average time needed to detect the leakage and where PBM wells should be located to optimize the monitoring outcomes (Nogues et al., 2011). Sun et al. (2013a) applied a model to optimize the monitoring network design to enhance leakage detection. They formulated a Binary Integer Programming Problem (BIPP) to minimize the number of monitoring locations. Hosseini and Alfi (2015) have shown that pressure data can be used in monitoring intervals to detect the CO_2 leakage and to estimate the amount of leaked CO_2 by measuring the changes in physical properties of monitoring zone (e.g., compressibility). In this study, we used the simple single phase diffusion equation to simulate the extent of a pressure anomaly due to leakage of fluids from reservoir to the monitoring zone (Theis, 1935).

3.1.2 Geochemical-based monitoring (GBM)

GBM methods can detect leakage of CO_2 by measurement of change in chemical signatures. Geochemical monitoring traces the changes in water chemistry due to CO_2 injection within the injection zone as well as leakage into any zone within the monitoring area. Water samples can be collected either by pumping water upward from the perforated intervals of wells to ground surface or sampled downhole at reservoir depth using various tools. The sampling can be done at regular time intervals throughout the CO_2 injection process, as well as prior to CO_2 injection, to characterize the baseline

signal. The samples are generally analyzed for pH, major ions (e.g., Na, K, Mg, Ca, HCO_3^-, SO_4, Cl, Si), alkalinity, isotopes (e.g., ^{13}C, ^{14}C, ^{18}O, and ^{2}H), and dissolved and free-phase gases including hydrocarbons and CO_2 (Benson et al., 2004). In recent years, understanding the interactions between CO_2 and subsurface minerals has attracted attention of the scientific community. Therefore, studies about kinetics and extent of CO_2 and mineral reactions in natural CO_2 reservoirs are being used to evaluate the geochemical reactions (Benson et al., 2004).

Monitoring CO_2 by inspecting tracers is an alternative that can be implemented in groundwater and the vadose zone for leakage detection. The tracers can be selected from natural or artificial elements. For instance, isotopes like C, O, H gases are the natural tracers used in CO_2 sequestration sites (Stalker et al., 2009). Others, like SF_6, CD_4 (deuterated methane is not a naturally occurring substance), and perfluorocarbons are examples of artificial tracers (Hortle et al., 2011). Any tracer should be assessed to be appropriate for environmental safety and reservoir conditions.

Yang et al. (2015a) reported on a semi-analytical approach to forward model plume migration of CO_2 leakage into brine aquifers. Although implementing fully numerical solutions are more accurate, decoupling transport and reaction calculations by this semi-analytical approach reduced computational expenses while still generating similar results (Yang et al., 2015a). Yang et al.'s semi-analytical model is being used in this paper to determine the location and the number of required GBM wells.

3.1.3 Effectiveness of monitoring plans and economic assessment

The goal of a monitoring network is to monitor changes indicative of leakage. Early detection is desirable because the value of storage (in terms of isolation of CO_2 from atmosphere) is assured and environmental and health risks can be minimized. A

reliable and cost effective monitoring technique can ensure that geological storage is a safe and effective technology. This is very important, especially for the public acceptance of GS. Therefore, the challenge is to keep the monitoring costs low while optimizing the efficiency of monitoring system. Many cost analyses have been reported for GS projects such as EPA and DOE cost models (NETL, 2014) (EPA, 2010b).

The DOE, Office of Fossil Energy (FE), National Energy Technology Laboratory (NETL) developed a cost model for CO_2 storage in saline formations (NETL, 2014). Their cost model was intended to mimic the CO_2 sequestration process and to calculate the revenue and costs for the operator of GS project. The model can be used in three modes: 1) the user sets the price of CO_2 and the model calculates the net present value of returns; 2) the model calculates the price of CO_2 when the net present value of returns is zero, and the user sets CO_2 at this price or higher to meet the minimum internal rates of return; or 3) the model calculates the break-even price of CO_2 for all storage sites during the first year of operation and develops cost supply curves for potential CO_2 storage.

As another example, EPA analyzed costs for geologic CO_2 sequestration for specific monitoring technologies (EPA, 2010b). Their analysis describes the associated unit costs for different geologic CO_2 sequestration technologies in two types of geologic formations: saline formations and oil and gas reservoirs. However, no previous cost analysis has interconnected the costs to the geotechnical and site-specific parts of GS projects to optimize the monitoring by cost considerations

When limited financial resources are available, maximizing the efficiency and effectiveness of monitoring plans is crucial. The GS Rule (EPA, 2010a) requires the owners and operators of projects to periodically monitor groundwater quality and geochemical changes above the confining zone to track changes relative to baseline

geochemical data. PBM and GBM methods can detect leakage from pressure pulses and CO_2 plume, respectively.

Assuming we have a fixed level of funding for monitoring, cost analysis should reveal the most cost-effective monitoring technique and the optimal number of monitoring wells for leakage detection. Thus, a cost analysis method to compare these monitoring techniques is needed. Here, we evaluated GS monitoring plan by considering the financial risks of CO_2 leakage and assigning a premium for investment. The financial risks of CO_2 leakage can be quantified by evaluating the probability, the costs of leakage, etc. The probable correctness theory model introduced by Hamlet (1987) was used to calculate the premium for monitoring based on the financial risks of CO_2 leakage. We assume that operators of GS projects would invest in monitoring plans as a kind of insurance to detect and prevent possible but unlikely leakages before resulting in catastrophic events like losses to surface or significant CO_2 exposures with subsurface resources, such as groundwater. Thus, the calculated premium indicates the optimum amount of money the operator can invest on the monitoring plan each year throughout the life of the project.

The goal of this work is to maximize the detection coverage over P&A wells, while minimizing cost. We use analytical and semi-analytical models for PBM and GBM techniques, respectively, to calculate the number of required wells to have a full coverage of the P&A wells. Then, we interconnect the cost analysis to the technical aspects (e.g., leakage rate and static properties of the monitoring zone) of the hypothetical GS project to systematically identify the most cost-effective monitoring technology option, comparing the two techniques.

3.2. MATERIALS AND METHODS

3.2.1 Pressure-based monitoring model (PBM)

The analytical pressure model discussed below is developed by Dr. Seyyed A. Hosseini who is a researcher at the Gulf Coast Carbon Center (GCCC) at Bureau of Economic Geology (BEG). The pressure leakage model defines a relationship between the pressure anomaly, formation parameters, and leakage volume. Later, this pressure anomaly can be related to the number of monitoring wells needed to monitor plugged and abandoned (P&A) wells, which we assume are the main source of leakage. To find this relationship, we use a pressure diffusion equation.

$$\Delta p = \left(\frac{q_l\,\mu}{4\pi\,k_m h_m}\right) ei\left(\frac{\left(\frac{r}{r_w}\right)^2}{4\,\frac{k_m\,t_m}{\phi m\,\mu m\,c_m\,r_w^2}}\right) \tag{1}$$

where Δp is the detection threshold (Pa), q_l is the leakage rate (m^3/s), μ_m is the viscosity (Pa.s), k_m is the permeability of the monitoring field (m^2), h_m is height or thickness of the monitoring zone (m), r is the radius of detection around the P&A well (m), r_w is the radius of P&A well (m), t_m is the monitoring detection time (s), ϕ_m is the porosity, and c_m is the compressibility (Pa^{-1}). In Eqn. (1), all the parameters are known, either from rock and fluid properties or set by the operator (q_l and t_m), except r. This equation assumes that the monitoring formation is homogenous and isotropic. The equation can be simplified by defining a set of dimensionless parameters, such as dimensionless radius (r_D), dimensionless time (t_D) and dimensionless leakage (Q_D) to get:

$$1 = Q_D ei\left(\frac{r_D^2}{4t_D}\right) \tag{2}$$

where ei is exponential integral function and

$$r_D = \frac{r}{r_w} \tag{3}$$

$$t_D = \frac{k_m t_m}{\phi_m \mu_m c_m r_w^2} \tag{4}$$

$$Q_D = \frac{q_l \mu_m}{4\pi k_m h_m \Delta p} \tag{5}$$

The Δp or detection threshold (amount of abnormal pressure observed in pressure gauge that can be interpreted as possible leakage) is important in finding the r in PBM. The higher the defined detection threshold, the less sensitive the monitoring wells are to the leakage, which means more monitoring wells are needed to detect the leakage or more time is needed to detect the leakage. All the parameters in Eqn. (1) are static properties from the monitoring zone, except the monitoring time and the leakage rate, which has to be set in the monitoring plan.

To demonstrate the PBM method, we assume 10 P&A wells (dark blue dots shown in Fig. 3.2), any of which may be improperly completed, connecting the injection and the monitoring zone and providing a leakage path. We want to monitor to determine if such a leakage path exists by installing a network of PBM wells. We assume no prior information on probability of leakage from each well; consequently, likelihood of leakage from all P&A wells is the same. For given reservoir properties, monitoring time and leakage rate, we first use Eqn. (1) to calculate the radius of increase in pressure due to CO_2 leakage from each P&A well (light blue circles in Fig. 3.2). We then sequentially place our monitoring wells (triangles in Fig. 3.2), starting with locations of maximum intersection of pressure signals until all the P&A wells are intersected by the monitoring wells, leading to a network that can completely detect leakage from any P&A well. This procedure is similar to the Sun et al. (2013a) approach, but is simpler and faster to implement as it does not consider the dependence of leakage rate to injection rate in the

injection zone. This process of placing the monitoring wells is advantageous because it ensures that the first few monitoring wells provide the maximum coverage possible. Therefore, in the event that the monitoring network cannot achieve 100% coverage (e.g., due to lack of funding), we still know that the monitoring wells are placed in locations that intersect the largest number of P&A wells.

In this case, the first PBM well is can detect leakage signals four P&A wells (Fig. 3.2). The second PBM well would be situated to intersect leakage signals from three of the remaining six P&A wells, and so on. Our criterion to define the effectiveness of PBM is based on the percentage of P&A wells being monitored for a given number of monitoring wells that can be economically deployed in the field.

3.2.2 Geochemical-based monitoring model (GBM)

The semi-analytical geochemical model was developed by Dr. Changbing Yang who is a researcher at GCCC at BEG. The original code was in FORTRAN which was converted into MATLAB by Jacob Anderson (Ph.D. candidate at GCCC). In this semi-analytical geochemical model, we focus on areas where brine containing dissolved CO_2 is assumed to be leaking from a deeper, homogenous and isotropic storage zone. Initial and boundary conditions in the model are defined as concentrations of reactive ($CO_{2\,(aq)}$, H^+, HCO_3^-, CO_3^{-2}, OH^-, Ca^{+2}) and conservative (Na^+, K^+, Mg^{+2}, Cl^-, SO_4^{-2}) components at initial time and at infinite boundaries. Leakage can be modeled from a point source (i.e., P&A well). The second step calculates solute transport from a point source, following an analytical solution (Bear, 1972). Rather than solving for pressure, groundwater flow is a function of two user-defined parameters: leakage rate of CO_2 saturated brine (q) and average groundwater velocity (v). The transport equation assuming point source leakage (Eqn. (6)) is integrated using Gaussian integration at a user-defined time step (t) and

locations (x and y). Practically, the modeled location can be a monitoring well or iterated along grid-blocks for map view results.

$$\xi(x,y,t) = \frac{q*c_b}{4\theta d\pi\sqrt{D_X D_Y}} \int_0^t \frac{1}{t-\tau} exp\left(-\frac{\left(x-x_0-v\,(t-\tau)\right)^2}{4D_x(t-\tau)} - \frac{(y-y_0)^2}{4D_Y(t-\tau)}\right) d\tau \tag{6}$$

where, v is regional groundwater flow velocity (L/T), D_X and D_Y are hydrodynamic dispersion coefficients (dm^2/day), d is aquifer thickness (dm), x is the location on the x axis (dm), y is the location on the y axis (dm), t is total simulation time (days), τ is integration parameter, q is the leakage flux (mol/day). We used the following formula to calculate hydrodynamic dispersion:

$$D_{HD} = D_e + \alpha_L * v \tag{7}$$

where D_{HD} is hydrodynamic dispersion (L^2/T), D_e is effective diffusion coefficient (L^2/T), α_L is dispersivity (L). For this modeling, we assumed a dispersivity length (200 dm) and that the effective diffusion coefficient is 0. Therefore, the hydrodynamic dispersion is just $\alpha_L * v$ (we did not consider transverse dispersivity).

Then, the following formula was used to convert hydraulic conductivity to permeability:

$$k = \frac{K\mu}{\rho g} \tag{8}$$

where k is permeability (L^2), K is hydraulic conductivity (L/T), ρ is fluid density (M/L^3), μ is dynamic viscosity of the fluid (M/ (L*T)), and g is gravity (9.8 m/s^2). We used a simple form of Darcy's law to calculate velocity:

$$q_d = -K * \frac{dh}{dl} \tag{9}$$

$$v = \frac{q}{\phi} \tag{10}$$

where q_d is discharge per unit area (L/T), K is hydraulic conductivity (L/T), *dh/dl* is average hydraulic gradient (dimensionless), ϕ is porosity (dimensionless). This analytic approach is sufficient for conservative species, but groundwater reactions must be addressed numerically. During CO_2 dissolution into groundwater, CO_2 lowers pH and redistributes carbonate species (Eqns. (11)-(14)).

$$CO_{2(aq)} + H_2O <-> HCO_3{}^- + H^+ \tag{11}$$

$$CO_{2(aq)} + H_2O <-> CO_3{}^{-2} + 2H^+ \tag{12}$$

$$4\,H_2O <-> OH^- + H^+ \tag{13}$$

$$CaCO_3 - CO_{2(aq)} + 2H^+ + H_2O <-> Ca^{+2} \tag{14}$$

Thus, the third step of this workflow calculates carbon speciation following the mass action law (Bagshaw, 2013), using known equilibrium constants, activity coefficients, and ionic strength of each species (Eqns. (11)-(14)). The Newton-Raphson method iterates these calculations until equilibrium conditions are reached. In terms of model verification, the semi-analytical solution in Eqn. (6) produced very similar results compared with fully numerical solutions (Yang et al., 2015a); though the limited nature of the solution cannot account for natural variation of carbonate speciation, carbonate precipitation dissolution, or organic matter decomposition in CO_2 exsolution. The above approach has been reproduced by Yang et al. (2015a) using PHREEQC (Parkhurst & Appelo, 1999) across a wide range of groundwater reactions, including $NaHCO_3$ precipitation.

Using the same scenario as above, except for GBM wells, we first use Eqn. (6) to calculate x and y of the boundary of CO_2 plume in brine based on groundwater movement and velocity. The area of the CO_2 plume after leakage is skewed due to groundwater movement and hydraulic gradient (light blue circles in Fig. 3.3). We then sequentially place our monitoring wells (triangles in Fig. 3.3), starting from the locations with the largest intersection of CO_2 plume and ending with full intersection of all P&A wells. The aforementioned process ensures that the monitoring wells are prioritized based on the amount of coverage they provide (Fig. 3.4).

3.2.3 Analysis of effectiveness of monitoring methods

With the monitoring points better identified, we next connect the monitoring network to the economics of the monitoring program and availability of the financial resources. The goal is to determine the number of PBM or GBM wells needed, based on the premium the operator is willing to spend for the monitoring project. The same amount of premium is used to compare the two monitoring methods.

3.2.3.1 Probable Correctness Model (PCM)

CCUS liability concerns can be divided to two aspects: 1) how large is the project liability and 2) who is responsible in case of CO_2 leakage. Therefore, numbers corresponding to the probability of leakage and the costs of CO_2 leakage are required to quantify the financial risks of CO_2 leakage. In this paper, the PCM introduced by Hamlet (1987) will be used to calculate the premium based on the financial risks of CO_2 leakage (Hamlet, 1987). We assume the operator of the project wants to invest in a GS monitoring plan to insure against a catastrophic event (e.g., leakage to surface or into USDW), but without the profit for the operating company because insurer and insuree are

the same. The plan provides operators with an opportunity to take preventive actions to avoid the costs of any probable leakage.

Though CCUS is a relatively new technology, without a long history on the probability of CO_2 leakage or a blow-out, information about the frequency of leakage in previous storage sites can be used. Blow-outs can occur in different phases of CO_2 storage such as drilling, completion, workover, production, injection, shut in, plugging, and abandonment periods. Since in this paper, the focus is on monitoring of CO_2 storage, only the leakage during production, injection, shut in, plugging, and abandonment periods are considered for risk assessment. Eqn. (15) for PCM can be used to calculate γ, which acts as the upper bound for the probability of CO_2 leakage (Hamlet, 1987).

$$C = Prob\ (\theta \leq \gamma) = 1 - (1 - \gamma)^T \tag{15}$$

where θ is the actual probability of leakage, $0 < \gamma \leq 1$, C is the confidence that $\theta \leq \gamma$ (expressed between 0 and 1), and T is the number of successful injection wells drilled during the above-mentioned monitoring period with no leakage incident. The formula can be rewritten as:

$$\gamma = 1 - (1 - C)^{\frac{1}{T}} \tag{16}$$

After assessing the risks of leakage, the company can calculate the premium using the following formula:

$$P = L\, X_L + Profit \tag{17}$$

where P is the insurance premium, L is the maximum financial loss from a catastrophic event (e.g. blow-out), X_L is the probability of catastrophic event (loss distribution), profit is 0 (operator is the insurer). If we use γ in Eqn. (16) to define the probability of catastrophic event ($X_L = \gamma$), Eqn. (17) becomes:

$$P = L\left[1 - (1 - C)^{\frac{1}{T}}\right] \tag{18}$$

No monitoring system can fully identify when or if CO_2 leakage occurs. Therefore, Eqn. (18) will be multiplied by the probability of CO_2 leakage detection by the implemented monitoring method:

$$P = L\left[1 - (1 - C)^{\frac{1}{T}}\right] P_D(L) \tag{19}$$

where $P_D(L)$ is the probability of monitoring method to detect a catastrophic event of size L.

3.2.3.2 Frequency of well blow-outs (T)

Collecting well blow-out data from various states is challenging because no standard reporting format exists at federal or state levels. Thus, different states have different reporting requirements, ranging from organized and solid databases to unorganized and unavailable data (Porse et al., 2014). Texas well blow-out records for the period 1998-2011 are used to estimate the probability of blow-outs in this study (Porse et al., 2014). All data are collected online from Texas Railroad Commission (RRC), the agency that keeps records of all oil and gas operations in Texas. District 8 and 8A located in Permian Basin and district 3 located southwest Texas are chosen among

other districts because they represent operational and geographical dichotomies and have more active CO_2 injection wells.

Table 3.1 shows that the probability of well blow-outs is higher during production/operation and abandonment periods, though in general, the likelihood of a blow-out is low. For this study, we used the probability of blow-outs in different periods to calculate *T*, which is calculated as the reciprocal of total blow-out fraction. To find an average *T* for all the events, we take the harmonic average of all the *T* values. The harmonic average of *T* is equal to 591, indicating that 591 successful wells will operate before a blow-out occurs.

3.2.3.3 Financial cost of a catastrophic event (L)

Another important parameter in Eqn. (19) to address is the financial cost of a catastrophic event (*L*) such as a well blow-out. EPA cost analyses only include the unit costs related to GS technologies and do not include probable CO_2 leakage or remediation costs (EPA, 2010b). Remediation costs generally depend on the type of formation into which CO_2 is injected. CO_2 stored in depleted oil and gas fields are easier to monitor and remediate because the storage traps are structurally confined. On the other hand, CO_2 stored in saline formations are more challenging to remediate due to the lack of structural closure (IEA GHG, 2007). In saline formations that are not structurally confined, leakage might take place when CO_2 migrates from the injection zone and reaches potential leakage pathways toward potable groundwater, the vadose zone, or atmosphere.

The financial losses can be two-fold: 1) the penalty that the operator pays to the state due to failure to meet the regulatory requirements, and 2) the remediation costs of the incident, including shutdown and infrastructure repair. It is difficult to estimate these financial losses as they can vary from case to case. However, two previous incidents

Ernst v. EnCana Corporation (2013) and Denbury (2013) showed that the sum of penalty costs and remediation costs for above mentioned incidents were about $315 million. This does not include any penalty for loss of storage benefit for CO_2, as a monetary benefit for this activity is hard to determine. Using this very small number of previous incidents, we consider a wider range of possible cost for a catastrophic event (L) as between $100-$1,000 million.

3.2.4 Cost Assessment-PBM and GBM Costs

The associated costs for each monitoring well are extracted from EPA (EPA, 2010b) and some 2014 data (SECARB, 2014) taken from an operating field, to be referred to as Field A here and below. All costs extracted from EPA are reported in 2007 US dollars. Table 3.2 shows the costs of one monitoring well in the first year of the CO_2 sequestration project for PBM and GBM, assuming that the depth of each monitoring well is held fixed at 1,524 meters. Capital expenditures are one-time costs and the operational expenditures are incurred each year throughout the life of the project (assumed here at 30 years). Therefore, the time value of the expenditure should be taken into account. The capital costs of each GBM and PBM well is $1,001,094 and $1,021,894, respectively. Although the capital cost of GBM is $20,800 less than PBM, annual operational costs for GBM wells are $72,650 more than PBM wells.

To extract the total costs (capital plus operational) of a PBM or GBM well, the total cost are needed in either present or future value (FV). Because the initial investment (Capex) is being made in 2016 dollars, it is easier to understand present value (PV) than FV (Pavlock, 2000). Therefore, we calculated the PV of all future operational costs for the 30-year timeframe of the project, enabling us to sum these two types of costs and calculate the costs of each monitoring well for the entire 30 year monitoring project.

3.2.5 Present Value of Costs

The concept of PV relies on the idea that a specific amount of money available at the present time is worth more today than the same amount in the future, because money will lose value due to inflation. Here, the average US inflation rate for 1961-2014 is used for inflation rate over next 30 years and US lending interest rate from 1960 to 2014 is used for expected interest rate (WorldBank, 2014). In our case, the capital costs have the present value because they are going to be spent at the beginning of the project. However, the operational costs will increase because of the reduced value of money and increased costs for goods and services with time. We considered interest rate of 7.42% and inflation rate of 3.96% in this paper (WorldBank, 2014) and calculated the PV of growing annuity as (Teall & Hasan, 2002):

$$PV_{GA} = \frac{P}{i-g}\left[1 - \left(\frac{1+g}{1+i}\right)^{n}\right] \tag{20}$$

where PV_{GA} is the present value of growing annuity, P is the annual payment, i is interest rate, g is inflation rate, n is the number of periods. After calculating the PV of investment, the total costs of a PBM and GBM well including capital costs and operational costs was calculated.

3.2.6 Field description

This field site, hereafter called Field A, is located in Texas Gulf Coast area and currently is under development for commercial EOR. The model-based cost analysis assumed an average porosity of 25% and permeability of 9.87e-13 m^2. Around 740 P&A

wells are installed in this field (Fig. 3.5), and Tables 3.4 and 3.5 show selected input parameters used in PBM and GBM models, respectively.

3.2.7 Sensitivity analysis and Monte Carlo simulation

We applied a sensitivity analysis technique to determine how different values of parameters in Eqn. (19) would affect the premium. This enabled us to create a table of predicted premiums based on different scenarios. We also ran the sensitivity analysis for leakage detection time and CO_2 leakage rate for both PBM and GBM models to evaluate their impact on the number of required monitoring wells.

Further, we applied a Monte Carlo simulation (MCS) technique to estimate a range of values for the premium, and how coverage of P&A wells can be obtained by spending different amounts of premium annually. MCS performs risk analysis and provides a range of outcomes and the probability of their occurrence (Thomopoulos, 2012). We assumed in Eqn. (19), T ranges between 200 and 3,000, L ranges between \$100 and \$1,000 million, C ranges between 0.999 and 0.9, and P_D ranges between 0.3 and 0.7. The simulation was repeated 10,000 times to estimate the frequency of each premium.

3.2.8 Device Failure in PBM

Pressure gauges are prone to failure in high temperature or pressure conditions, and hence we can expect that pressure gauges used in the PBM technique will eventually fail to provide reliable readings. Random device failure could have an uneven impact on the monitoring effectiveness, because some PBM wells intersect multiple P&A wells, while other PBM wells intersect only one P&A well. Thus, if a specific pressure gauge malfunctioned for any reason; one or more P&A wells might be unmonitored. Assuming

that a number of pressure gauges may malfunction over time, we are interested to predict how these failures might degrade our monitoring system at different times in the post-injection period.

The degradation of monitoring effectiveness depends largely on the order that PBM gauges failure. Based on the optimization of well location by PBM model, the first monitoring well has the maximum intersection of P&A wells and is the most effective monitoring well. The second monitoring well is less effective than first monitoring well but it is still has more intersection of P&A wells than the third monitoring well and so on. As more PBM wells are added, the per-well coverage of P&A wells decreases gradually. Consequently, in case device failure happens in PBM wells with more intersection of P&A wells, the impact on monitoring system degradation is more and vice versa. Therefore, we considered best case and worst case scenario for device failure. The best case scenario is when monitoring wells with the lowest intersection of P&A wells stop working first and the worst case scenario is when the monitoring wells with the largest amount of coverage fail earliest.

3.3 RESULTS AND DISCUSSION

3.3.1 Application of PBM

As seen in Figs. 3.6 (a) and 3.7, 29 PBM wells are needed for full coverage of all P&A wells. Maximum time allowed to detect the leakage is assumed to be one year. The results show that the measurement range of the first PBM well intersects 86 P&A wells (11.6% of all wells) and the second well will increases the percentage to 22.6%. A third well adds only 8.5% to the coverage (approximately 31%). It is clear that the per-well increase in coverage of P&A wells becomes slower gradually, as more PBM wells are added, because the location of monitoring wells are optimized in the model. For instance, adding the last (29th) monitoring well increases the coverage from 99.86% to 100%.

3.3.2 Application of GBM

Figs. 3.6 (b) and 3.7 show the distribution of GBM wells at Field A, and how percent coverage changes as more wells are added to the network, respectively. It is clear that many more wells are needed for geochemical monitoring than pressure monitoring. Here, the first GBM well installed will intersection a potential leakage signal from 14 P&A wells (1.9% of the P&A wells). Adding a second GBM well increases coverage to 26 P&A wells (3.5% of total). For 100% coverage of P&A wells, 169 GBM wells are required.

The results show that adding monitoring wells initially increases the coverage rapidly, but similar to PBM, the percent coverage diminishes as more wells are added. We note that 46 GBM wells are needed to cover 50% of the P&A wells, but that only 6 PBM wells are needed for the same 50% coverage. When we compare PBM and GBM

monitoring techniques, the area represented by a PBM well is much larger than by a GBM well, especially toward the beginning of the monitoring program, because PBM wells can detect pressure anomalies that travel faster than the actual CO_2 plume (i.e., the leaked dissolved CO_2 plume has not migrated far from the P&A wells).

3.3.3 Cost effectiveness analysis

The annual cost of a PBM well is lower than a GBM well because it has lower annual operational costs per well. After calculating the present value of PBM and GBM well costs using Eqn. (20), the present value of each PBM and GBM well cost is $2,008,021 and $3,300,623, respectively, applied during the course of 30-year monitoring program.

With the number of required wells established and the percent coverage for both PBM and GBM techniques, we can calculate the premium needed to determine then number of monitoring wells needed for an is economical program for the operator. We used the highlighted values in Table 3.6 for the parameters in the PCM equation (Eqn. (19)), and assumed C=0.99, L=$500, PD = 0.5, T= 600, yielding the premium of $1.91 million per year ($57.3 million for a 30-year lifespan of the project). The present value of this premium is $34.5 million for a 30-year time frame. Dividing the premium by the present value of total costs of PBM and GBM wells, the result is that the operator can afford 17 PBM wells and 10 GBM wells.

As illustrated in Fig. 3.7, 29 PBM wells are needed to have a full coverage of the P&A wells, whereas 17 PBM wells will provide 91.4% coverage. Obtaining full coverage with 29 PBM wells will increase the cost of monitoring to $58.2 million over 30 years, or

an annual premium of $3.22 million. These results indicate that, to increase coverage by 8.6%, the operator must increase spending by $1.31 million annually, or a 68% increase.

Considering the GBM technique, we note that the 10 GBM wells, affordable to the operator, provides only 15% coverage of the Field A. If full coverage of P&A wells is needed using GBM method, then the cost of installing and maintaining 169 wells increases to $557.8 million, an annual premium of $30.8 million per year (Eqn. (20)). Overall, under this scenario, to achieve full coverage of the field site, PBM technique is more cost effective than the GBM technique.

3.3.4 Sensitivity analysis and Monte Carlo simulation for PCM

Results for the sensitivity analysis, using Eqn. (19), are shown in Table 3.6. The premium has an inverse relationship with T, while it has a direct relationship to L, C, and P_D. For example, when T was increased by two times, the premium reduced in half, because T is found in the exponent, but when L increased by ten times, the premium increased by ten times as well. We also observed that when C decreased from 0.999 to 0.99, the premium reduced by 33% and when P_D. increased from 30% to 50%, the premium increased by 66%.

The results of the Monte Carlo simulations are illustrated in Fig. 3.8 by the frequency of each premium and the Normalized Cumulative Frequency Distribution (NCFD), which in this case is the equivalent of leakage detection percentage. According to Fig. 3.8, 80%, 90% and 99% leakage detection rate would require $2.29, $2.9, and $4.55 million annual investment, respectively. Leakage detection rate refers to the percentage of possible leakage scenarios that will be covered by our monitoring method by spending the respected premium amount.

For an average premium of $2.29 million per year, the monitoring program could be equipped with either 21 PBM wells or 13 GBM wells, providing 96.3% and 18.6% coverage of P&A wells, respectively. As show above, full coverage require 29 PBM wells, which increases the amount of coverage by less than 3.7%, but increases the annual premium to $3.22 million per year, or a 41% increase in cost. The 13 GBM wells, on the other hand, would provide only 18.6% coverage. Increasing to full coverage of all P&A wells would require 169 GBM wells at a cost of $30.8 million per year. It is obvious that PBM is a better option with the parameters in this case.

3.3.5 Sensitivity Analysis for leakage detection time

To further understand PBM and GBM efficiency as a function of time of leakage detection, we compared a base case of one year, to monitoring scenarios of various durations (Figs. 3.9 (a) and (b)). In all these cases, we assumed that the combination of T, L, C, and P_D would provide the same amount of premium. The results indicate that 50 monitoring wells are needed to detect leakage within 6 months while only seven monitoring wells are needed to detect a leakage signal after 10 years. The same trend was observed in the GBM model, where 267 monitoring wells are required to detect leakage within 6 months while only 21 monitoring wells are needed to detect the leakage signal after 10 years. Both PBM and GBM models are sensitive to the leakage detection time, but noticeably fewer monitoring wells are needed in the PBM technique to detect a leakage signal in any of those time frames than GBM technique. Of course, the downside to the reduced monitoring intensity is that more CO_2 is released to the environment before the leakage signal is detected. Thus, the analysis must include the risk of environmental impacts (e.g., release of CO_2 to the USDW) given the longer leakage period.

3.3.6 Sensitivity Analysis for CO_2 leakage rate

Sensitivity analysis was performed for the PBM and GBM models using the CO_2 leakage rate. In the base case, the leakage rate was set at 0.0001 m^3/s at standard condition, or the equivalent of 3,154 metric tons of CO_2 per year. Figs. 3.10 (a) and (b) illustrate that, in the PBM model, 29 monitoring wells are needed to detect leakage with the rate of 0.0001 m^3/s after one year, while only one monitoring well is required to detect leakage at a release rate of 0.00018 m^3/s (5,676 metric tons per year). The results show that an 80% increase in leakage rate led to a 29-fold reduction in the number of monitoring wells needed using the PBM technique. The range of variation in studied parameter is selected to keep the number of required monitoring wells meaningful (i.e., more than zero wells and less than the number of P&A wells). Obviously for leakage rates larger than 0.00018 m^3/s, only one PBM monitoring well is needed.

The sensitivity of the GBM model to leakage rate is different, however. For example, where 169 monitoring wells are required to detect leakage with the rate of 0.0001 m^3/s after one year, 148 monitoring wells are needed to detect leakage when the rate increases to 0.00018 m^3/s. The results thus indicate that an 80% increase in leakage rate led to a 14% decline in the number of wells needed using the GBM technique. Thus, GBM model is not as sensitive as PBM model is to the CO_2 leakage rate.

3.3.7 Device Failure in PBM

Considering the sensitivity analysis in Fig. 3.9 (a), it is apparent that the number of PBM wells is inversely related to leakage detection time. We have already shown that 29 PBM wells are needed to monitor 740 P&A wells in case of leakage within one year and that we need fewer PBM wells to monitor leakage within two years. Therefore, if

pressure gauges are lost after the first year of monitoring, the monitoring system would degrade slightly. But, after ten years of post-injection monitoring, when only seven PBM wells are maintained, loss of any of PBM wells could significantly degrade the monitoring system effectiveness.

Fig. 3.11 illustrates the best case and worst case scenario for device failure in the case of the PBM technique. The best case occurs when devices fail in the reverse order they were added to the monitoring program (i.e., monitoring wells with the lowest amount of coverage fail earliest). In this case, failure of last-installed PBM well reduces coverage from 100% to 99.86%. The worst case scenario represents the case when monitoring wells covering the largest areas stop working first (i.e., failure occurs in the same order as installation). Recall that the first PBM well intersects 11.6% of the P&A wells; if monitoring ceases at this well, the monitoring system effectiveness would degrade considerably (from 100% to 88.4%). Although a percentage of coverage loss can be compensated by intersecting from other wells, our case still will be the worst case scenario. In case of random device failure, degradation of the monitoring effectiveness would fall anywhere within the shaded area in Fig. 3.11.

3.3.8 Conclusions

We noted that with the parameters in our case, the PBM technique requires fewer monitoring wells than the GBM technique to detect CO_2 leakage, because of the relatively lower spatial coverage of each GBM well. Because operational costs for each PBM well is lower than a GBM well, the PBM technique is a more cost effective option, and would provide more coverage of P&A wells, with the same amount of money invested.

We also noted that both PBM and GBM methods are sensitive to the monitoring detection time and this parameter is inversely related to the number of required monitoring wells. The GBM method is not as sensitive as the PBM method to the CO_2 leakage rate, where an 80% increase in leakage rate led to a 29-fold reduction in the number of PBM wells needed for detection. However, applying these two approaches in any geologic framework may result in different ranges of the required number of monitoring wells to achieve the same coverage.

3.3.9 Acknowledgments

Many thanks to the Gulf Coast Carbon Center at the Bureau of Economic Geology for funding this research.

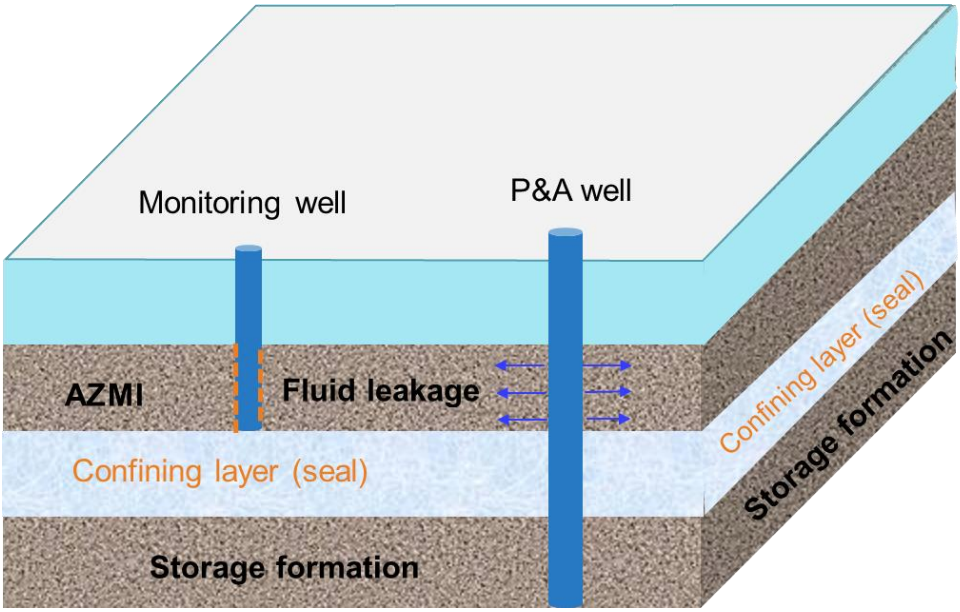

Fig. 3.1: Cross-sectional cutaway of hypothetical field site used in analysis.

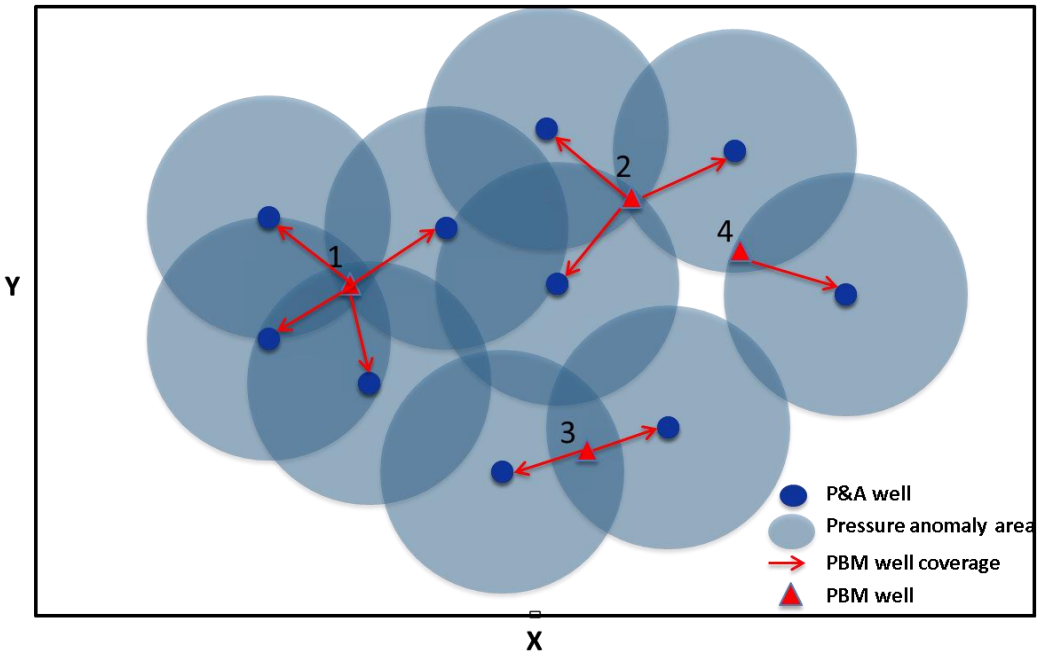

Fig. 3.2: Schematic of P&A wells (dark blue dots) and hypothetical pressure anomalies after CO_2 leakage from P&A wells. Triangles represent locations of monitoring well with a higher chance of leakage detection.

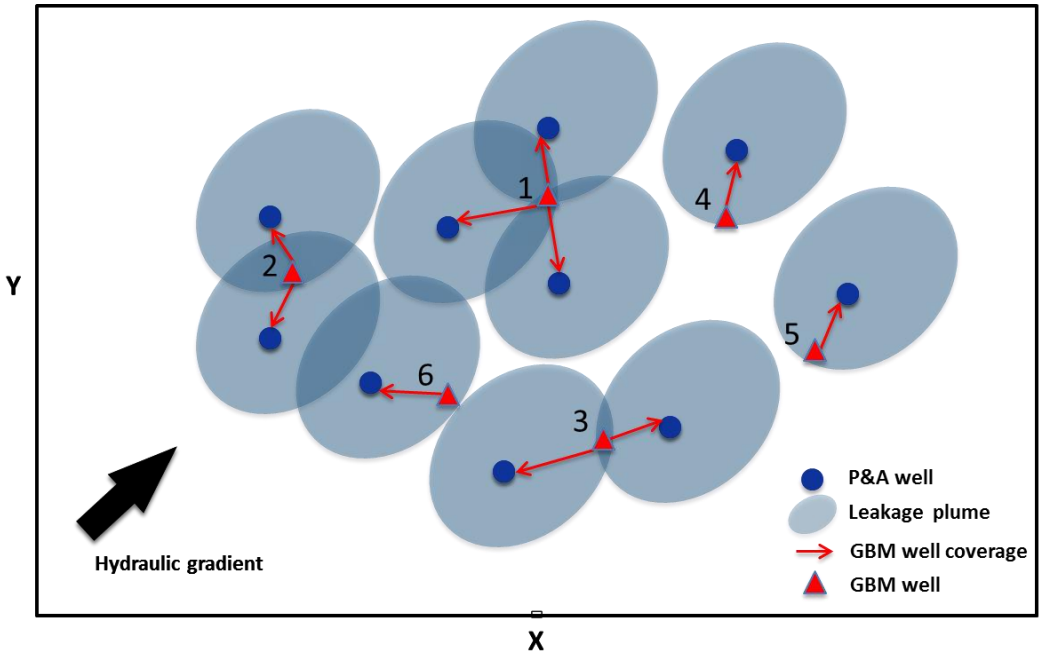

Fig. 3.3: Schematic of P&A wells (dark dots) and hypothetical CO_2 plumes after leakage from P&A wells (light blue circles). Triangles represent locations of monitoring well with a higher chance of leakage detection.

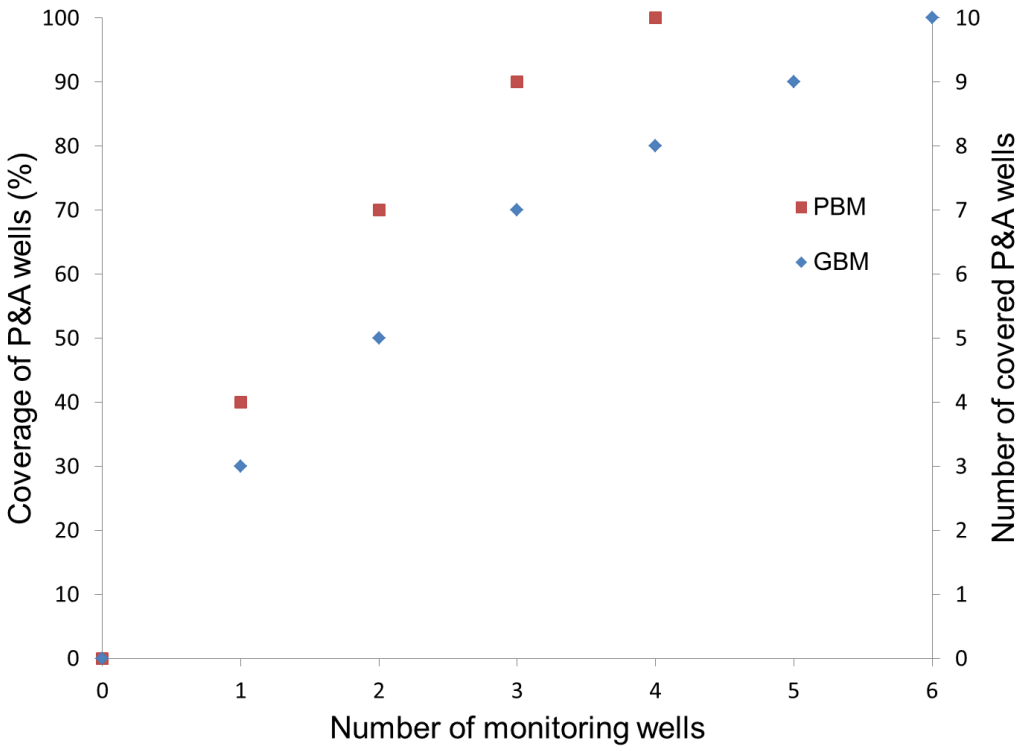

Fig. 3.4: Scatterplot showing the coverage of P&A wells as a function of the number of monitoring wells, using the PBM and GBM techniques.

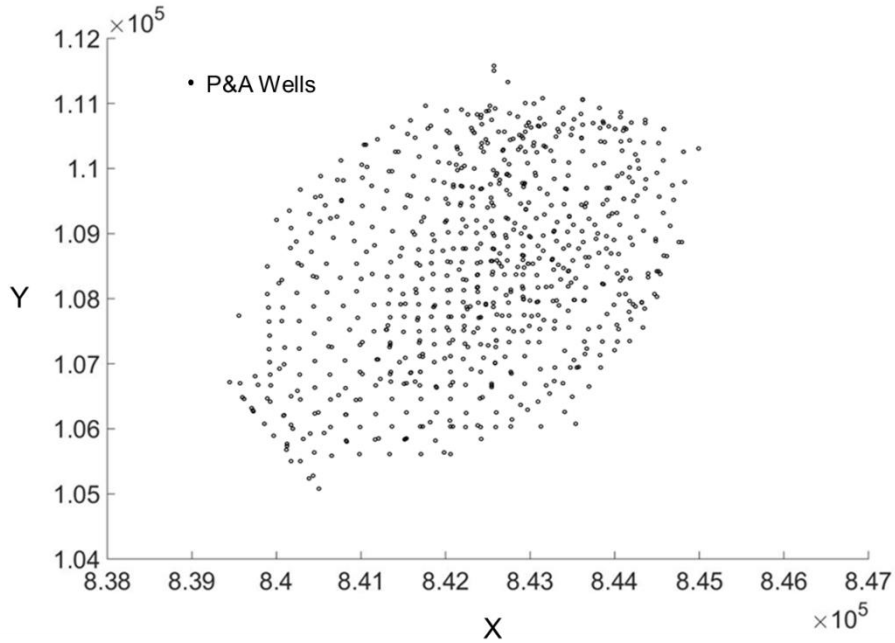

Fig. 3.5: Field A is located in Texas Gulf Coast area and currently is under development for commercial EOR. As shown, about 740 P&A wells have been drilled in this field.

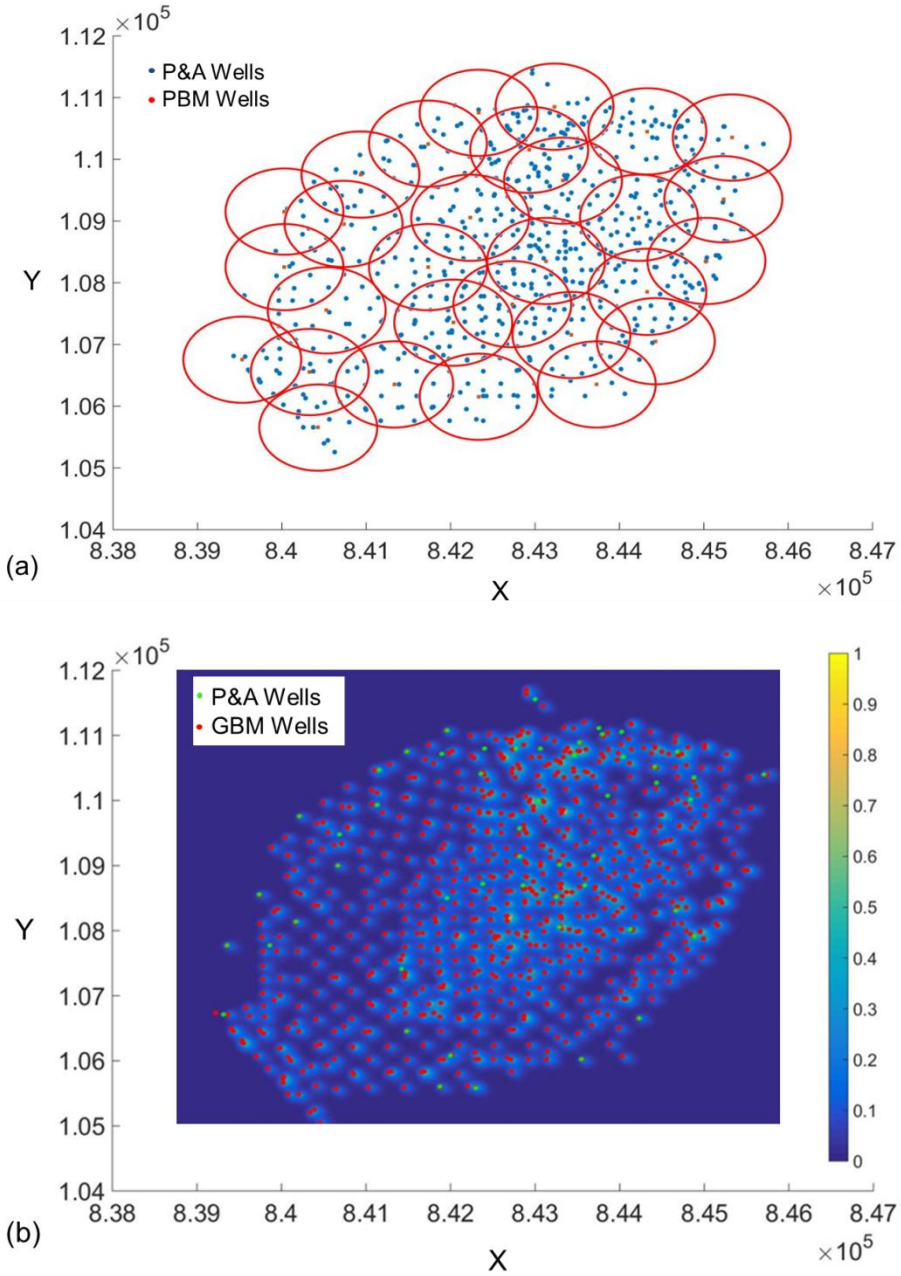

Fig. 3.6: Results using PBM (a) and GBM (b) techniques. Red dots are the location of PBM and GBM monitoring wells in both plots.

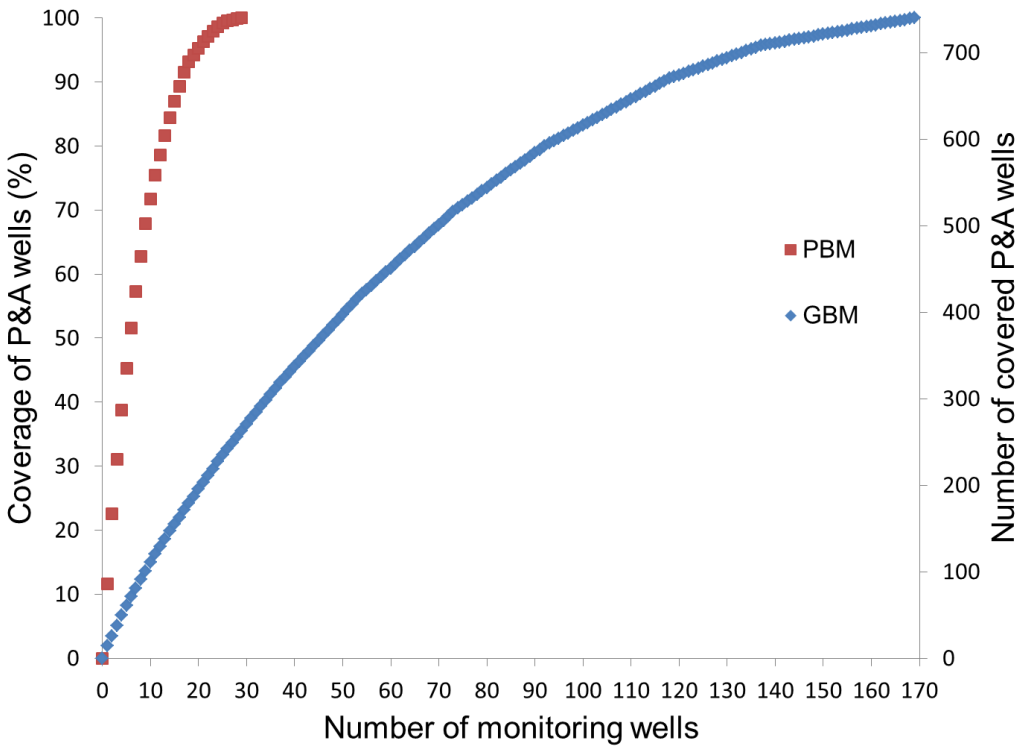

Fig. 3.7: Scatterplot showing the number of monitoring wells needed to intersect plumes, using PBM and GBM techniques.

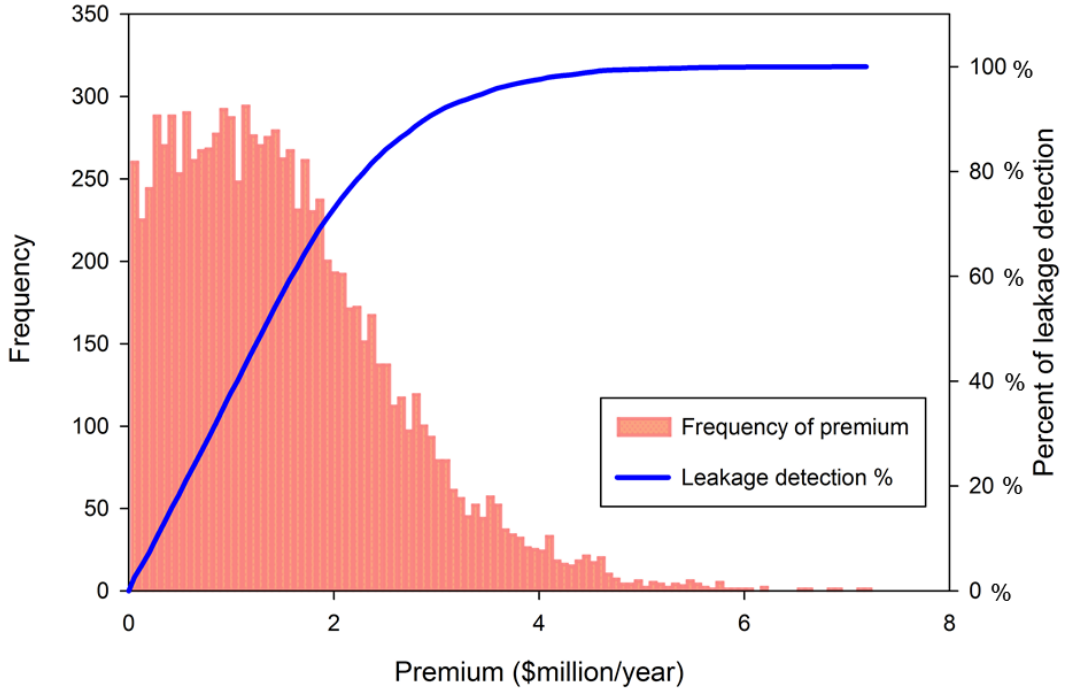

Fig. 3.8: Results of Monte Carlo modeling, to demonstrate the frequency distribution (FD) and the percent of leakage detection for each premium.

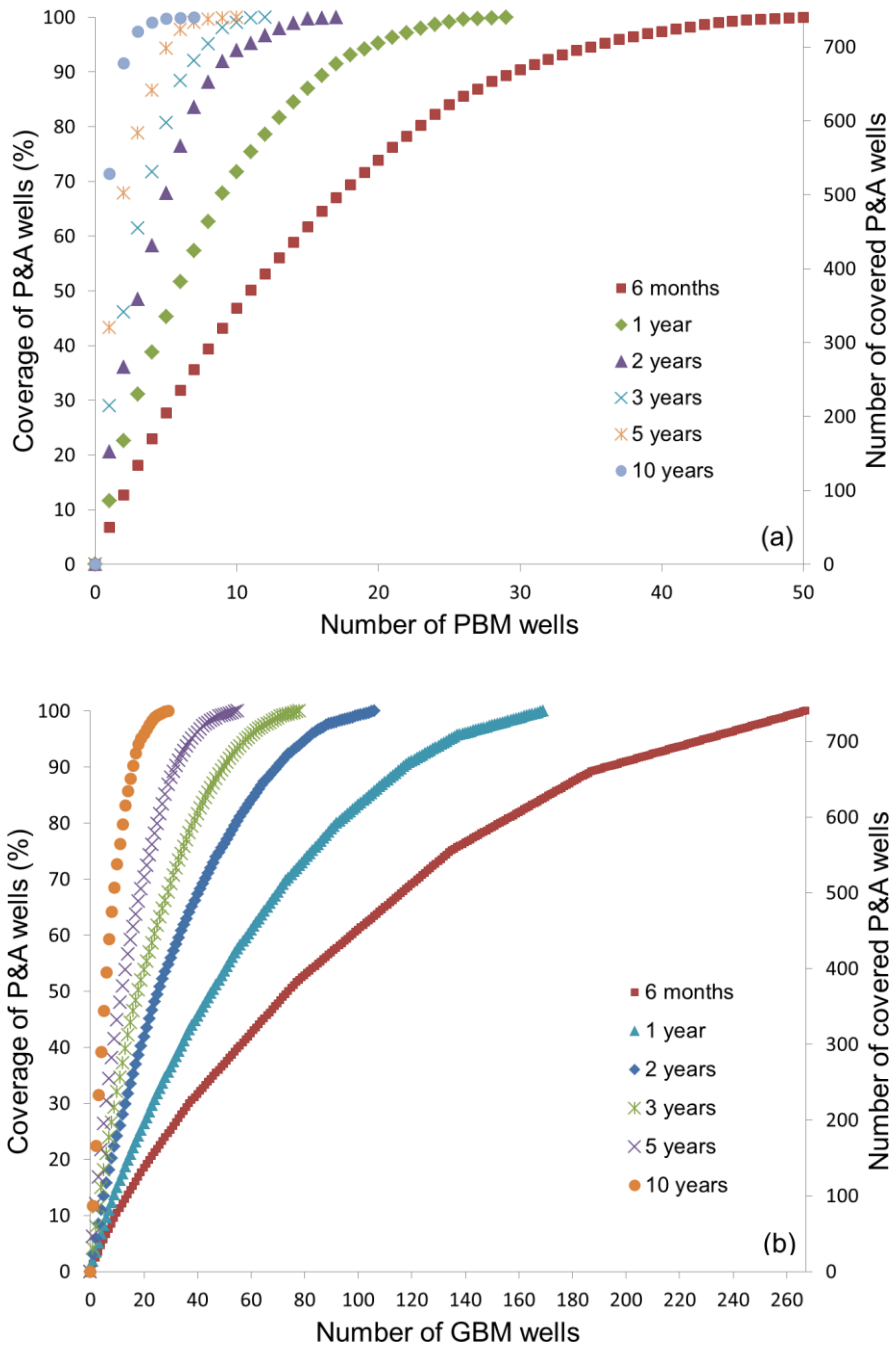

Fig. 3.9: Sensitivity analysis for leakage detection time in PBM (a) and GBM (b) models.

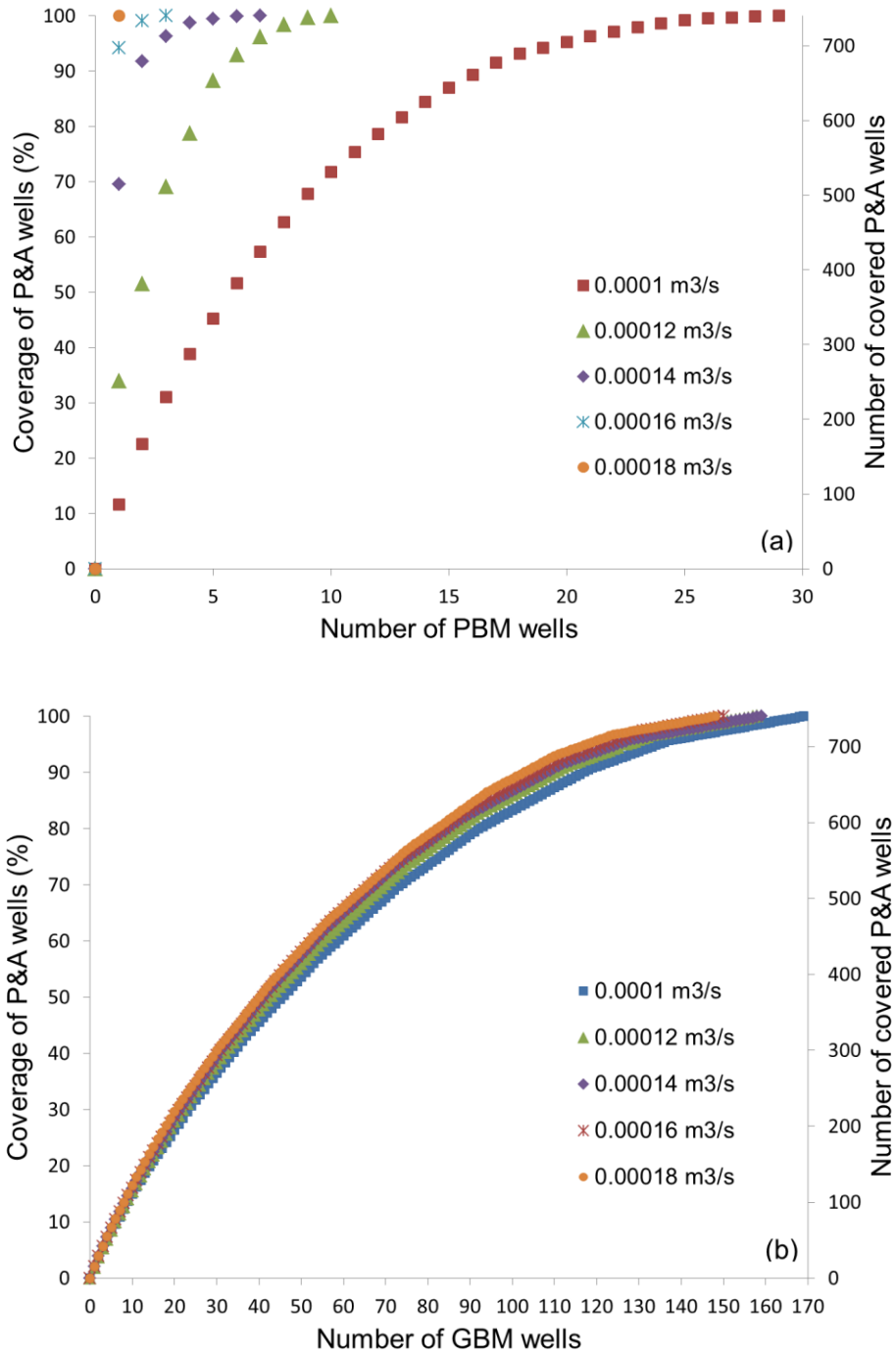

Fig. 3.10: Sensitivity analysis for leakage rate in PBM (a) and GBM (b) models.

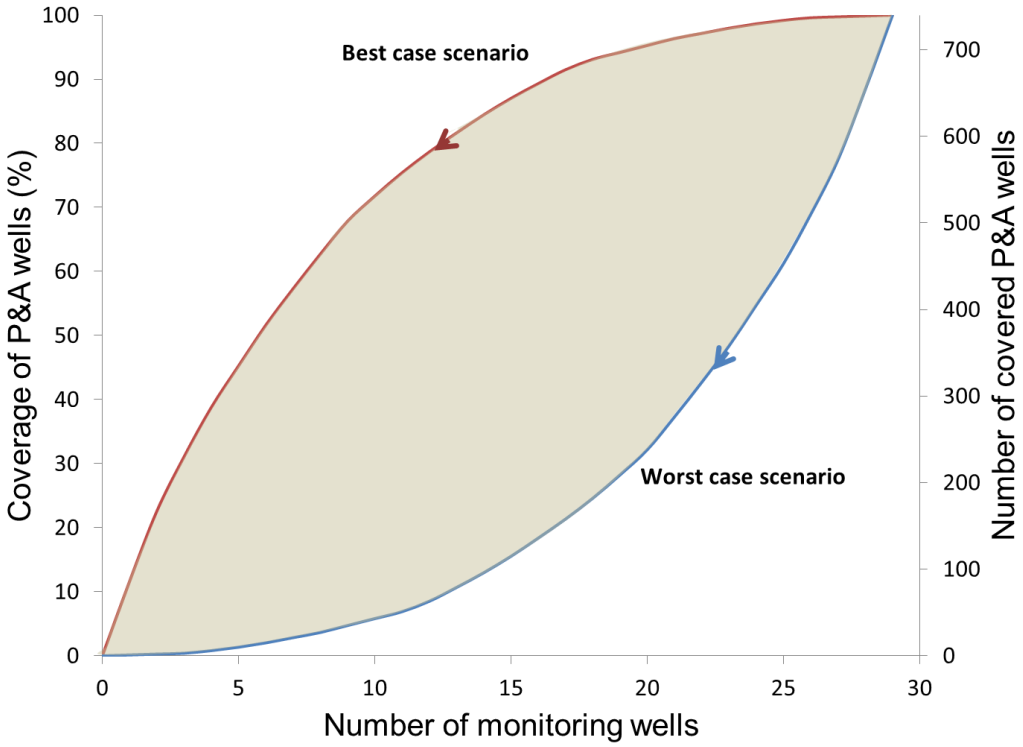

Fig. 3.11: Loss of monitoring coverage because of device failure in the PBM technique.

Table 3.1: Texas well blow-outs records collected from RRC for period 1998-2011.

Percent frequency				
	District 3	District 8	District 8A	Average
Production/operation	0.00173	0.00006	0.00049	0.00076
Injection	0.00000	0.00020	0.00000	0.00006
Shut in	0.00000	0.00000	0.00000	0.00000
Plugging	0.00080	0.00008	0.00000	0.00029
Abandoned	0.00171	0.00000	0.00000	0.00057
Total	0.00424	0.00034	0.00049	0.00169
T	236	2941	2041	591

Table 3.2: Capital costs and operational costs of per PBM or GBM monitoring well (EPA, 2010b). We assumed the depth of each monitoring well is 1,524 meters.

Pressure-based Monitoring**		**Geochemical based Monitoring*****	
General costs		General costs	
CAPEX*	OPEX**	CAPEX	OPEX
$1,001,094	$54,547	$1,001,094	$54,547
Specific costs		Specific costs	
CAPEX	OPEX	CAPEX	OPEX
$20,800	-	-	$72,650
Total		Total	
CAPEX	OPEX	CAPEX	OPEX
$1,021,894	$54,547	$1,001,094	$127,197

* Capital costs
** Operational costs

Table 3.3: The present value of capital costs and operational costs of per PBM/GBM monitoring using Eqn. (20).

Pressure-based Monitoring		**Geochemical based Monitoring**	
CAPEX (first year)	OPEX (per year)	CAPEX (first year)	OPEX (per year)
$1,021,894	$54,547	$1,001,094	$127,197
Present value (30 years)		Present value (30 years)	
PV of CAPEX	PV of OPEX	PV of CAPEX	PV of OPEX
$1,021,894	$986,127	$1,001,094	$2,299,529
CAPEX+OPEX		CAPEX+OPEX	
$2,008,021		$3,300,623	

Table 3.4: Selected input parameters for PBM model.

Pressure-based Model Parameter	Value	Unit
Permeability	9.87e-13	(m^2)
Porosity of monitoring reservoir	0.25	-
Leakage rate at reservoir condition	0.0001	(m^3/s)
Total compressibility	1e-9	(Pa^{-1})
Temperature	47.78	°C
Pressure	9,652,660	(Pa)
Thickness of monitoring reservoir	25	(m)
Monitoring detection time	365	(day)
Radius of leaky well	0.05	(m)
Viscosity	0.000578	(Pa.s)
CO_2 viscosity	0.0000302	(Pa.s)
CO_2 density	401	(kg/m^3)
Pressure gauge detection threshold	10000	(Pa)

Table 3.5: Selected input parameters for GBM model.

Geochemical-based Model Parameter	Value	Unit
Dispersion coefficient	400	dm
Hydraulic gradient	0.05	-
Cpi1 (CO_2 initial concentration)	0.716e-3	mol/day
Cpi2 (H^+ initial concentration)	0.618e-7	mol/day
Cpi3 ($HCOE^-$ initial concentration)	0.475e-2	mol/day
Cpi4 ($CO3^{-2}$ initial concentration)	0.307e-5	mol/day
Cpi5 (OH^- initial concentration)	0.151e-6	mol/day
Cpi6 (Ca^{+2} initial concentration)	0.779e-3	mol/day
Leakage detection limit	10*cpi	mol/day

Table 3.6: Sensitivity analysis for PCM using Eqn. (19).

T	L ($ million)	C	P_D	Premium ($ million/year)
200	$100	0.99	50%	$1.14
600				$0.38
3,000				$0.08
600	$500	0.99	30%	$1.15
			50%	$1.91
			70%	$2.68
600	$100	0.99	50%	$0.38
	$500			$1.91
	$1,000			$3.82
600	$500	0.999	50%	$2.86
		0.99		$1.91
		0.9		$0.96

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Chapter 4: Discussion

4.1 MODEL LIMITATIONS IN PBM AND GBM

Limitations and uncertainties exist in the models described in Chapter 3, as they do in all models. For example, in the PBM model, we assumed that the leakage rate is constant, but in fact it can be variable. In addition, we assumed the risk of leakage is only from the P&A wells in the location of the field. More information (e.g. age of the wells, their distance to injection wells, or their cement bond quality) could be used to weight the risk of leakage from P&A wells and then to apply those weights when considering placement of monitoring wells. Of course, risks of CO_2 leakage from faults or other leakage pathways would widen the applicability to actual field sites.

We also assumed that the monitoring area is homogenous and isotropic. However, in reality, reservoirs are heterogeneous and anisotropic. In both models, we assumed that CO_2 will leak as dissolved phase not gaseous phase. This assumption simplifies the solution for both PBM and GBM models, but in future studies the use of more accurate models should account for multi-phase flow leakage scenarios.

Moreover, we assumed a pressure anomaly in the PBM technique of more than 10,000 kPa, and a 10-fold increase in carbonate species concentrations above baseline condition in the GBM technique, as thresholds. Obviously, changing these thresholds will affect the number of needed monitoring wells significantly. The benefit of using these simple models is that they provide insights into monitoring needs and allow us to efficiently conduct sensitivity analyses and Monte Carlo simulations.

4.1.2 Model limitation in PCM

In our cost model, we estimated the probability of a blow-out, the amount of financial loss, probability of leakage detection, etc. Companies, in general, do not reveal information about their blow-out incidents. Our estimates were thus based on public data about the previous experiences related to frequency of blow-out incidents from RRC. Obviously, if we could access organized and solid information about the frequency of blow-outs from various states beside Texas, we could improve these estimates and the model. Also for evaluating the financial losses from a blow-out, we relied on two cases which occurred in Mississippi and Louisiana states. We could make a better assessment of associated economic losses if we could access more data on financial losses from leakage or blow-out incidents. The most relevant case, that loss of CO_2 from storage would trigger a reversal of the value of storage cannot be realistically assessed because such a value for CO_2 storage has not been set. However, the methods presented in this study could be intersected with a scenario including a value for storage to determine a related cost of monitoring.

Based on the sensitivity analysis done for leakage detection time, there is an incentive to start the monitoring late because there is an economic advantage to waiting years before detecting the leakage (larger plumes can be intersected by a smaller number of monitoring wells). However, the delay in implementing a monitoring program comes at the expense of larger volumes of CO_2 released to the environment. At current state of this study we did not consider this interaction. However, this issue could be potentially addressed by defining financial losses (L) from a leakage used in Eqn. (19) as a function of total volume of leaked CO_2 ($q_l \times t_m$). This would require having decent estimates on financial losses per metric ton of leaked CO_2.

In this study, we tried to show how uncertainties cascade down to the results by implementing Monto Carlo simulation. The simulations allowed us to consider a wider range of values for each parameter in the cost analysis model. For example, we assumed that losses can range between $100-$1,000 million and a probability of leakage detection between 30%-70%, etc. Practically, the probability of leakage detection by our monitoring techniques is likely to be less than 100%, and this likelihood would decrease further if the monitoring programs focus on formations above the deepest AZMI zone.

Although in this study we assumed that the operator would invest in monitoring as a kind of insurance, in the event of a blow-out, the operator must still pay for the losses. Even if substantial sums of money are invested on monitoring plan, leakage could still occur. Therefore, operators should decide to put aside some percentage from the amount of premium to compensate for any probable leakage or blow-out.

4.2 GBM IN SHALLOW AQUIFERS

As mentioned in previous chapter, analytical and semi-analytical models for PBM and GBM were implemented to calculate the number of required wells to monitor all 740 P&A wells in Field A, which is assumed to be the main pathway for CO_2 leakage. To achieve a full coverage of P&A wells, 29 PBM and 169 GBM wells were needed (assuming separate monitoring techniques) based on reservoir properties and an assumed leakage rate of 0.0001 m^3/s and monitoring detection time of one year.

Based on the sensitivity analysis we ran for leakage rate and monitoring detection time parameters, PBM was a better option, because each well covers a larger area compared to GBM wells. Also based on PCM, we showed that the total cost of a GBM well is higher than PBM (total cost of a PBM well is about 61% of a GBM well for the same depth). Thus, we concluded that PBM technique is more cost effective than GBM

because: 1) the coverage area of a single PBM well is larger than a single GBM well and 2) the total cost of each PBM well is less than a GBM well.

In this study, we ran sensitivity analysis only for leakage rate and monitoring detection time parameters, keeping reservoir parameters fixed when comparing these two technologies. We did not study the effects of reservoir parameters (e.g., permeability, porosity, etc.) on our models. Keating et al. (2014) compared PBM and GBM in a shallow formation in Edwards Aquifer (Keating et al., 2014). They calculated the probability of leakage detection by GBM and PBM from the existing shallow drinking water wells in Edwards Aquifer, and reported that PBM was less effective than GBM due to unconfined condition and high permeability of the aquifer. In this case, the pressure signals dissipate quickly in higher permeability formations. This example shows that PBM is not always the lowest cost solution for subsurface monitoring.

In our analyses, costs associated from both models were based on monitoring performed in the AZMI area with depth of 1,524 meters (Tables 4.1-4.3). However, we also considered a scenario where PBM wells are completed in the deeper monitoring zone and GBM wells are completed in shallower aquifers. This configuration is mostly because PBM in deeper aquifers is more favorable due to lack of variation in pressure and noise, while GBM is less sensitive background variations.

So, we compared these two monitoring techniques, assuming PBM is being performed in AZMI zone of 1,524 meters and GBM is implemented in shallow aquifer with depth of 152.4 meters, keeping all other the same as given in Table 3.5. This scenario reduced the per-well cost of GBM, because some cost items scale with depth (e.g., the cost of drilling decreases by $594 per meter), reduces the overall capital cost of a GBM well from $1,001,094 to $163,329. The operational costs would also decrease in

the shallower GBM well, from $127,197 to $110,457 per year (we still have to pay for nitrogen lift and sampling costs every year (Table 4.3)).

Using the shallower depth, the PV of each GBM well cost would go down to $2,160,224 (Table 4.4), now only slightly higher than PV of PBM well cost ($2,008,021). Based on the premium of $1.91 million per year or $34,529,909 million for a 30-year time frame, we can choose between 17 PBM wells in AZMI, 10 GBM wells in AZMI, or 16 GBM wells in shallow subsurface. As shown in Fig 3.7, 17 PBM wells cover 91.4%, 10 GBM wells cover 15% and 16 GBM wells cover 22% of Field A. By reducing the cost of each GBM well through shallower monitoring, we can add 6 more GBM wells, increasing the coverage by 7% (from 15% to 22%) compared to 91.4% of coverage by PBM wells. Thus, PBM is still a better technology to be employed because of broader range of coverage with the same amount of investment.

To lower the cost of repeated geochemical sampling in deep AZMI, Delgado et al. (2013) proposed using a fiber optic based geochemical system to detect gaseous CO_2 or CO_2 dissolved in water. These sensors are coated with a polymer casing that contains a colorimetric indicator that changes color when exposed to CO_2. Installation cost of a fiber optic sensor for a shallow well at a depth of 61 to 100 meters is about $30,000 plus a maintenance cost of $10,000 per year. And, the installation cost for a deep well with depth of 914 meters, is about $100,000 plus $10,000 maintenance costs per year (Hovorka S.D., personal communication, 2016).

Therefore, using fiber optic sensors as part of the GBM technique, the capital and operational costs of each deep well in AZMI with depth of 1524 meter will be $1,101,094 and $16,867 respectively. This means that the present value of the total cost of one well will be $1,326,824 for 30 years of monitoring (Table 4.5). Based on $1.91 million annual

premium (PV of $34.5 million for a 30-year), this increases the number of GBM wells to 26, providing coverage of 32.7%.

Once more, we applied fiber optic sensors in GBM at the shallower depth of 152.4 meters, and the capital cost of each shallow well was reduced to $193,329, and the operational costs would be reduced to $16,867. Thus, the present value of the total cost of one well will be $498,259 for 30 years of monitoring for this scenario (Table 4.5). Considering annual premium of $1.9 million, about 69 GBM wells can be installed in the shallow subsurface, providing 67% coverage of P&A wells. Although implementing fiber optic sensors for geochemical analyses reduces the costs of GBM well considerably, the PBM technique is still more cost effective.

4.3 FINAL STATEMENTS

Before implementing a monitoring technique, it must be suitable for the site environs and safe for the environment. Sometimes, the operator may decide to incorporate two or more monitoring technologies to optimize the effects of monitoring. In this study, we compared two monitoring technologies separately, but using both technically and economically, based on the available data. Although we concluded that, under conditions studied herein, PBM is more cost-effective than GBM, an operator might choose GBM over PBM, in part because of public concern about groundwater contamination. For the same reason, federal agencies (e.g., EPA, USGS, etc.) encourage and emphasize investment in the GBM technique, rather than tracking pressure changes (NRC, 1980). Future research and field experiences in this area could provide information needed to better monitor CCUS sites.

Table 4.1: Capital costs of per PBM/GBM monitoring well (EPA, 2010b).

Cost Item	Cost Algorithm
Conduct front-end engineering and design (AZMI)	$20,700/well
Obtain rights-of-way for surface uses. (AZMI)	$10,400 per monitoring well site
Standard monitoring well stopping above the injection zone.	$/foot = average of $181 per foot typical down to 9,000 ft.
Perform a mechanical integrity test prior to plugging to evaluate integrity of casing and cement	$2,070 plus $4.15/foot
Plug monitoring wells (AZMI)	$6,700 to plug and $5,700 to log
Remove surface equipment, structures, restore vegetation (AZMI)	$10,400/monitoring well
Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, post-closure report)	120 hours of engineers @$110.62/hr = $13,274 per site
Flush wells with a buffer fluid before closing	$1000 + $0.085/inch-foot casing diameter

Table 4.2: Operational costs of per PBM/GBM monitoring well (EPA, 2010b).

Cost Item	Cost Algorithm
Annual reports to regulators and recordkeeping for all data gathering activities.	44 hrs of engineers @$110.62 = $4,867 per report
Monitoring well Operating and Maintenance costs (O&M) in AZMI	Annual O&M costs are $25,900 + $3.10/ft per well per year
Operating General and Administrative costs (G&A)	20% of annual operating costs

Table 4.3: Specific capital and operational costs for PBM & GBM using field data (SECARB, 2014).

Cost Item	Cost Algorithm
Pressure, temperature, and related equipment for monitoring wells AZMI (applies to PBM)	$20,800/well
Purging the well (Nitrogen lift) and disposal of fluids (applies to GBM)	$44,600/well
Geochemical sampling cost (applies to GBM)	$28,050 /sample

Table 4.4: The present value of capital costs and operational costs of each GBM well at depth of 152.4 meters, calculated using Eqn. (20).

Geochemical based Monitoring	
CAPEX (first year)	OPEX (per year)
$163,329	$110,457
Present value (30 years)	
PV of CAPEX	PV of OPEX
$163,329	$1,996,895
CAPEX+OPEX	
$2,160,224	

Table 4.5: The present value of capital costs and operational costs of each GBM well depths of 1524 meters and 152.4 meters using fiber optic sensors, calculated using Eqn. (20).

Geochemical-based Monitoring (1524m)		**Geochemical-based Monitoring (152.4m)**	
CAPEX (first year)	OPEX (per year)	CAPEX (first year)	OPEX (per year)
$1,101,094	$16,867	$193,329	$16,867
Present value (30 years)		Present value (30 years)	
PV of CAPEX	PV of OPEX	PV of CAPEX	PV of OPEX
$1,101,094	$304,930	$193,329	$304,930
CAPEX+OPEX		CAPEX+OPEX	
$1,326,824		$498,259	

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