



WELLBORE EVALUATION OF THE BASAL CAMBRIAN SYSTEM

Plains CO₂ Reduction (PCOR) Partnership Phase III Task 16 – Deliverable D90

Prepared for:

Andrea T. McNemar

National Energy Technology Laboratory
U.S. Department of Energy
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

DOE Cooperative Agreement No. DE-FC26-05NT42592

Prepared by:

Kyle A. Glazewski
John A. Hamling
Wesley D. Peck
Thomas E. Doll
Jason D. Laumb
Charles D. Gorecki
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

EERC DISCLAIMER

LEGAL NOTICE This research report was prepared by the Energy & Environmental Research Center (EERC), an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy (DOE). Because of the research nature of the work performed, neither the EERC nor any of its employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the EERC.

ACKNOWLEDGMENT

This material is based upon work supported by the DOE National Energy Technology Laboratory under Award Number DE-FC26-05NT42592.

The Plains CO₂ Reduction (PCOR) Partnership team would like to thank David Nakles of Carnegie Mellon University and Nicholas Azzolina of the CETER Group, Inc., for their review and comments on this report.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

NDIC DISCLAIMER

This report was prepared by the EERC pursuant to an agreement partially funded by the Industrial Commission of North Dakota, and neither the EERC nor any of its subcontractors nor the North Dakota Industrial Commission nor any person acting on behalf of either:

- (A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

- (B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the North Dakota Industrial Commission. The views and opinions of authors expressed herein do not necessarily state or reflect those of the North Dakota Industrial Commission.

TABLE OF CONTENTS

LIST OF FIGURES	iii
LIST OF TABLES	iv
EXECUTIVE SUMMARY	v
INTRODUCTION	1
WELLBORE INTEGRITY BACKGROUND	2
Data Acquisition.....	4
REVIEW OF LEAKAGE RISK FACTORS	5
Deep Well Leakage Factors	6
Fracture and Acid Treatments	6
Abandonment Types.....	6
Completions	7
Omitted Deep Well Leakage Factors	7
Cement/Additive Types	7
Shallow Well Leakage Factors.....	8
Spud Date.....	8
Well Type	8
Well Total Depth	9
Additional Plug near Surface.....	9
Cement to Surface.....	9
Omitted Shallow Leakage Factors	9
Surface Casing Size	9
Abandonment Date	9
Geographic Location	10
SCVF or GM.....	10
Casing Failure	10
OVERVIEW OF THE BASAL CAMBRIAN WELL INTEGRITY STUDY.....	10
RESULTS	13
Deep Well Leakage Evaluation.....	13
Fracture Treatments.....	13
Acid Treatments	15
Abandonment Types	15
Completions	15
Deep Well Leakage Potential Scoring	15
Shallow Well Leakage Evaluation	20

Continued...

TABLE OF CONTENTS (continued)

Spud Date	20
Well Type	22
Total Depth.....	22
Additional Plug near Surface	22
Cement to Surface	22
Shallow Well Leakage Potential Scoring.....	26
Comparison of Deep Well and Shallow Well Leakage Potential	26
SUMMARY	30
REFERENCES	31

LIST OF FIGURES

1	Location of basal Cambrian system	3
2	Conceptual illustration of the potential leakage pathways for CO ₂ in a well.....	4
3	Well spud dates by decade across the study area	11
4	Fracture treatments across the study area.....	14
5	Acid treatments across the study area	16
6	Abandonment types across the study area.....	17
7	Perforation intervals across the study area	18
8	Deep well risk scores for the study area.....	19
9	Spud dates across the study area	21
10	Well types across the study area	23
11	Total depth of wells across the study area.....	24
12	Distribution of wells in the study area with additional plug near the surface	25
13	Cement-to-surface well distribution for the entire study area.....	27
14	Shallow leakage potential score distribution for wells in the study area	28
15	Moderate- or higher-potential scores for deep and shallow leakage across the study area.....	29

LIST OF TABLES

1	Spud Dates by Decade for Each State	12
2	Casing Records for Basal Cambrian Study Area Wells	12
3	Cement Records for Basal Cambrian Study Area Wells.....	12
4	Deep Leakage Risk Factors	13
5	DLP Score Rankings	13
6	Fracture Treatments for the Study Area.....	14
7	Acid Treatments for the Study Area	16
8	Abandonment Types Across the Study Area	17
9	Number of Completions Across the Study Area.....	18
10	Deep Well Leakage Scores for All of the Study Area	19
11	Shallow Leakage Risk Factors	20
12	Ranking of SLP Scores	20
13	Spud Dates for Wells Across the Study Area	21
14	Well Types for the Study Area.....	23
15	Total Depth for the Study Area	24
16	Wells with Additional Plug near the Surface for the Study Area	25
17	Cement to Surface for the Study Area	27
18	Shallow Leakage Potential Scores for the Study Area.....	28
19	Wells with Moderate- or Higher-Potential Scores for Deep and Shallow Leakage.....	29



WELLBORE EVALUATION OF THE BASAL CAMBRIAN SYSTEM

EXECUTIVE SUMMARY

The Plains CO₂ Reduction (PCOR) Partnership performed a wellbore integrity assessment to evaluate the relative leakage potential of 826 wells penetrating the basal Cambrian system in the United States, drilled between 1921 and 2010. The basal Cambrian system is a deep saline reservoir that has been identified by the U.S. Department of Energy as a potential carbon dioxide (CO₂) storage site. The ability of the basal Cambrian system to retain injected CO₂ over an extended period of time is, in part, dependent on the integrity of wellbores that penetrate the target reservoir. Wellbore integrity is the ability of a well to maintain hydraulic isolation of geologic formations and prevent the vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). This study's evaluation of wellbore integrity involves analyzing wellbore characteristics (i.e., cement types, cement additives, completion techniques, well depths, and well casing) to derive a relative leakage potential score using methods similar to Bachu and others (2012). Wells were assigned a classification of minimal, lower, moderate, or higher based on their relative leakage potential. This study provides a screening-level evaluation to compare and rank wells for further detailed evaluation. Site-specific risk analysis within these target areas would trigger a more detailed assessment of those wells identified for further investigation. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies or appropriate monitoring during CO₂ injection.

The results of this regional screening-level evaluation determined that 15% of the wells assessed were classified as moderate or higher potential for deep well leakage, and 6.0% of the wells were classified moderate or higher for shallow well leakage. Of the wells assessed, 3.4% exhibited moderate or higher potential for both shallow and deep leakage. The majority of the moderate- or higher-potential wells are located in western North Dakota and eastern Montana in areas of intensive oil and gas exploration and production. The practice of producing oil and gas from these wells has increased the relative well leakage potential (based on the available data and methods utilized). The ranking of the relative leakage potential provides a mechanism to screen wells for detailed evaluation in areas targeted for CO₂ injection.

References

Bachu, S., Faltinson, J., Hauck, T., Perkins, E., Peterson, J., Talman, S., and Jensen, G., 2012, The basal aquifer in the prairie region of Canada—characterization for CO₂ storage: Final report for Stage I (Phases 1 and 2), Alberta Innovates Technology Futures.

- Crow, W., Carey, J.W., Gasda, S., Williams, B., and Celia, M.A., 2010, Wellbore integrity analysis of a natural CO₂ producer: *International Journal of Greenhouse Gas Control*, v. 4, p. 186–197.
- Zhang, M., and Bachu, S., 2011, Review of integrity of existing wells in relation to CO₂ geological storage—What do we know?: *International Journal of Greenhouse Gas Control*, v. 5, no. 5, p. 826–840, doi:10.1016/j.ijggc.2010.11.006.



WELLBORE EVALUATION OF THE BASAL CAMBRIAN SYSTEM

INTRODUCTION

The process of carbon capture and storage (CCS) in geologic media has been identified as an important means for reducing anthropogenic greenhouse gas emissions into the atmosphere (Bradshaw and others, 2007). Several categories of geologic media for the storage of carbon dioxide (CO₂) are available, including depleted oil and gas reservoirs, deep brine-saturated formations, CO₂ flood enhanced oil recovery (EOR) operations, and enhanced coalbed methane recovery (ECBM). The U.S. Department of Energy (DOE) is pursuing a vigorous program for the demonstration of CCS technology through its Regional Carbon Sequestration Partnership (RCSP) Program, which entered its third phase (Phase III) in October 2007. Phase III is planned for a period of ten years (October 2007 to September 2017). One of the principal elements of the DOE effort is core research and development (R&D), which includes a significant effort to identify geologic formations that can safely and efficiently store CO₂ over long periods of time.

The storage of anthropogenic CO₂ in geologic media is a technique that is immediately applicable as a result of the experience gained through oil and gas exploration and production and deep waste disposal. Studies have shown that geologic media have a large potential for CO₂ storage, with retention times of centuries to millions of years (Intergovernmental Panel on Climate Change [IPCC], 2005). Geologic storage of CO₂ is being actively investigated and pursued at multiple locations across the United States, Canada, and the world, including several sites in the Plains CO₂ Reduction (PCOR) Partnership region.

Three geologic media have been identified by the RCSPs as primary targets for CO₂ storage: uneconomic coal beds, depleted oil and gas reservoirs, and deep (>800 meters) saline formations (also referred to as deep saline aquifers). Storage of CO₂ in coal beds has the smallest potential in terms of storage resource and is an immature technique that has not yet been proven commercially viable (Bachu and others, 2012). Depleted hydrocarbon reservoirs have demonstrated storage and confinement properties by having previously stored oil and/or gas resources for millions of years. The quest to discover and extract hydrocarbon resources has provided a broad base of understanding about the subsurface in oil- and gas-producing areas. A potential challenge associated with the use of depleted oil and gas reservoirs for CO₂ storage is the numerous wells drilled in these areas which may impact storage security (Bachu and others, 2012). Deep saline formations are more widespread and, theoretically, have correspondingly larger storage capacities. Deep saline formations may have fewer wellbore penetrations in areas without oil and gas exploration and production activities, which may improve storage security.

The basal Cambrian system is a deep saline reservoir that has been identified by DOE as a potential CO₂ storage site. The basal Cambrian system spans a region that includes parts of both the United States and Canada. On the U.S. side of the border, the basal Cambrian system covers an area of approximately 507,155 square kilometers (195,814 square miles) and occurs in the states of Montana, North Dakota, and South Dakota (Figure 1); on the Canadian side of the border, it encompasses nearly 811,345 square kilometers (313,285 square miles) in the provinces of Alberta, Saskatchewan, and Manitoba. This work evaluates one component of CO₂ storage in the basal Cambrian system – the integrity of wellbores that penetrate the system.

WELLBORE INTEGRITY BACKGROUND

For CCS to be successful, a CO₂ storage formation needs to meet three fundamental conditions: 1) capacity, 2) injectivity, and 3) confinement (Zhang and Bachu, 2011; Bachu, 2003, 2010; Intergovernmental Panel on Climate Change, 2005). The targeted CO₂ storage formations in the basal Cambrian system have demonstrated the capacity and ability to hold materials such as oil, natural gas, or saline water. Wellbore integrity is the ability of a well to maintain isolation of geologic formations and prevent the vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). Wellbore integrity is crucial because any leakage of CO₂ poses a potential risk to surrounding groundwater, vegetation, and wildlife. In addition, it diminishes the quantity of CO₂ for which storage credits can be claimed as part of either monetary agreements or regulatory compliance. For the purposes of this study, leakage will be defined as a loss of CO₂ or other fluid from its intended storage formation and not necessarily losses to the atmosphere.

For a CO₂ leak to occur, there are three elements that must exist: 1) a leak source, 2) a driving force such as buoyancy or head differential, and 3) a leakage pathway (Watson and Bachu, 2007). When evaluating the potential of CO₂ leakage at a carbon storage site, the first two elements are presumed to already exist. The injected CO₂ is the leak source, and the driving force is CO₂ buoyancy and, potentially, the increased subsurface pressure caused by the CO₂ injection (Watson and Bachu, 2007). The leakage pathway is the third element required for a leak to occur.

Wells are one possible pathway for CO₂ to escape the storage formation (Celia and others, 2004) (Figure 2). CO₂ could leak along interfaces between different materials, such as the steel casing and cement interface (2a), cement plug and steel casing interface (2b), or rock and cement interface (2f). Leakage could also occur through cement (2c) or fractures in the cement (2d and 2e). Finally, leakage may also occur because of casing corrosion and subsequent failure leading to large leakage pathways, with the wellbore as a conduit.

The goal of this study is to assign a relative risk score for deep and shallow well leakage for wells penetrating the basal Cambrian system on the U.S. side of the U.S.–Canadian border as part of DOE efforts to identify potential CO₂ storage sites. It is important to note that the assignment of these relative leakage potential scores is solely for purposes of internally comparing and contrasting the different wellbores within this portion of the system. Stated differently, the assignment of individual relative leakage potential scores to the wellbores means



Figure 1. Location of basal Cambrian system.

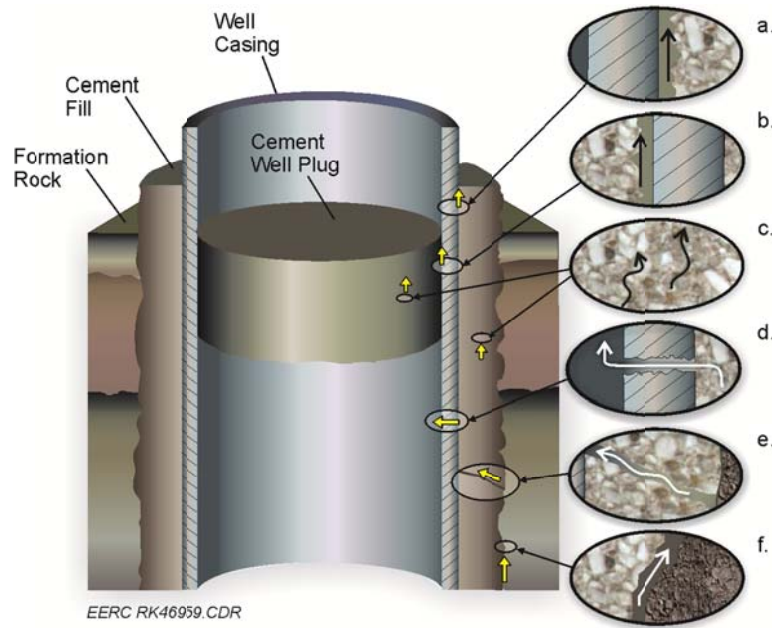


Figure 2. Conceptual illustration of the potential leakage pathways for CO₂ in a well along the casing–cement interface (a and b), within the cement (c), through the casing (d), through fractures (e), and along the cement–formation interface (f) (from Celia and others, 2004).

that a particular wellbore can be compared to the other wellbores and assigned a priority for further investigation, analysis, and monitoring in areas targeted for CO₂ injection. Site-specific risk analysis within these target areas would trigger a more detailed assessment of those wells identified for further investigation. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies. As such, it is an internal assessment of the potential associated with that wellbore relative to all of the other wellbores and does not represent an absolute assessment of its potential to impact the proposed carbon storage within the basal Cambrian system.

Data Acquisition

The first step in the evaluation was to identify all of the wells that penetrated the basal Cambrian system. These wells were identified from multiple state oil and gas regulatory agency databases where the total depths of the wells reached the basal Cambrian system. Once the wells were identified, the well files were acquired from each respective state regulatory office. The well files contain numerous documents detailing the drilling and completion activities at each well site including, but not limited to, well completion reports, sundry notices, pressure test records, wellbore diagrams, cementing records, permits, well inspections, technical reports, and correspondence. From the well files, information pertinent to identifying the potential for well leakage was extracted. The information included well completion dates (drilling and/or abandonment dates), casing depths, casing diameters, casing weights, casing grades, cement types, amount of cement used, top of cement (TOC), completions, plug and abandonment procedures, fracture treatments, acid treatments, and any other relevant information about the

well. The well information was entered into a database for subsequent analysis and relative risk scoring of the individual wellbores. All wells were spatially referenced to permit the assessment of local or regional trends.

REVIEW OF LEAKAGE RISK FACTORS

Leakage pathways can be created during well construction, completion, production, and abandonment (Zhang and Bachu, 2011). In addition to material selection and engineering design, the physical implementation and accurate reporting of drilling, completion, and workover activities are equally important factors in assessing the integrity of an individual well, albeit they are difficult to quantify. For example, wellbore integrity could be compromised during cementing operations by a variety of factors such as poor mud displacement prior to cementing, gas migration during the cement setting, stress crack and microannulus formation during well operation, inaccurate cement volume calculations, or incomplete mud removal resulting in poor bonding to formation rock.

The available well files offer information related to operations, such as notes from the field crew operating the well. However, data sets are often incomplete, lending to difficulties in determining the quality of cement placement during installation. An indication of the quality of cement placement may be found in pressure tests, cement bond logs, or operator notes. While the information may indicate a compromise in integrity, it also indicates that the operator was aware of the problem and most likely tried to rectify the situation, although the success of the repair may or may not be verified in the available documentation. There is also the uncertainty that the available well files may not always include information regarding problems with a well and may or may not include an indication of the quality of work performed.

Despite the challenges in classifying the potential for well leakage based on well files, methodologies have been developed (Watson and Bachu, 2007, 2008; Bachu and others, 2012). These papers outlined an approach that was implemented in the Canadian province of Alberta based on similar well data and, importantly, surface casing vent flow (SCVF) and gas migration (GM) data beginning in 1995. These data were used to verify the methods developed to evaluate shallow well leakage potential. SCVF is leakage of gas to the surface casing vent valve (always open) on the wellhead, and GM is a measurement of leakage of gas out of the ground around the wellhead (Bachu and others, 2012).

Watson and Bachu (2007) evaluated data for approximately 316,000 wells in Alberta in an area known to be subject to leaks to assess wellbore leakage risk based on a variety of criteria. They found that 4.5% of the wells evaluated had identified leaks, with SCVF accounting for 3.9% and GM accounting for 0.6% of the identified leaks. After identifying the wells that had indications of leakage, they evaluated the specific well file data to determine which factors may be associated with the leak.

Watson and Bachu (2008) and Bachu and others (2012) attempted to quantitatively classify the potential for shallow and deep wellbore leakage based on risk factors identified from their previous work in Watson and Bachu (2007). Shallow leakage refers to compromised hydraulic

well integrity in the upper portion of the well, where shallow gas, if present, may leak upward, along the outside of the casing/wellbore annulus to shallow freshwater aquifers or through a casing leak and along the inside of the production casing to the surface (Bachu and others, 2012). Deep leakage pertains to leakage along the deep part of the well from the CO₂ storage zone to adjacent permeable horizons (Bachu and others, 2012). The deep and shallow leakage factors are described as follows.

Bachu and others (2012) provided a numerical score for deep and shallow leakage potential. This score indicates the relative likelihood that any one well may leak based on the factors evaluated; however, the score does not reflect the volume or impact of the leak. Significant factors such as the quality of the cementing work were not included because of the lack of such data. As a result, Bachu and others (2012) identified low-risk wells that had a measured SCVF or GM leak. Likewise, wells ranked as higher-risk did not necessarily have a measured SCVF or GM leak identified. Therefore, it should be recognized that this method is useful as a screening-level evaluation for the leakage potential of a group of wells but is limited by the nature and extent of the available data. Areas targeted for CO₂ injection should be evaluated and/or monitored on a site-by-site basis based on the unique risk factors for the given project.

Deep Well Leakage Factors

Deep leakage is defined as leakage (cross-flow) from a target production zone or CO₂ injection zone back into the wellbore (or outside the casing) where it moves upward into an adjacent permeable zone (productive zone or aquifer) (Bachu and others, 2012). The criteria that were used to assign deep leakage potential scores are described as follows.

Fracture and Acid Treatments

Fracture and acid criteria refer to the number of fracture and acid stimulation treatments performed in a well. These treatments are executed at high pressure and are believed to contribute to degradation of local hydraulic isolation (Bachu and others, 2012). Fracture treatments are designed to open cracks in the formation to allow oil or natural gas to flow back to the well. Matrix-acidizing treatments are used for two main purposes: 1) to stimulate a well to greater-than-ideal matrix reservoir flow or 2) to remove skin damage.

Abandonment Types

Wells in the study area are typically abandoned by using either cement plugs or cast iron bridge plugs. Cement plugs are generally considered more reliable; multiple cement plugs are placed to seal the well and prevent migration between formations. They are also considered more reliable in drilled and abandoned holes where there is no production casing run to the bottom of the hole because the cement plugs have been shown to bond and seal more efficiently to the irregular surface of the openhole environment (Watson and Bachu, 2007). Bridge plugs have been found to be more prone to corrosion and seal failure in the presence of CO₂ (Bachu and others, 2012) because of CO₂ effects on the elastomers and metal used in the mechanical plugging device (Watson and Bachu, 2007; Schremp and Roberson, 1975).

Completions

Well perforations provide a communication pathway through the production casing in order to access the formation. However, perforations could compromise well integrity as the casing may not be sealed when squeezing cement into the perforations during abandonment. As the number of perforations increase, the statistical risk of leakage increases proportionately.

Omitted Deep Well Leakage Factors

Bachu and others (2012) formulated a list of well attributes that were considered indicators of potential deep wellbore leakage if present in the well. However, not all of these leakage factors were applicable in this particular study. These omitted leakage criteria are described as follows.

Cement/Additive Types

Numerous studies have focused on the interaction between cement and CO₂, but these studies have been inconclusive (Bachu and others, 2012). On one hand, bench tests of cement exposed to CO₂ and CO₂-brine mixtures (e.g., Duguid and others, 2005; Duguid and Scherer, 2010; Kutchko and others, 2007) indicate that the CO₂ or CO₂-saturated brine will react vigorously with the cement, degrading the cement's ability to maintain vertical hydraulic isolation in the casing. However, other studies (Carey and others, 2007; Zhang and Bachu, 2011) suggest that cement with no fractures, voids, annulus gaps, etc., exposed to CO₂ will form a carbonated, impermeable residue composed of Na-Al-Si. This impermeable residue forms a CO₂ barrier, limiting degradation.

Oil and natural gas industry cement practices have been influenced by advances in technology. Ide and others (2006) found that cement additives, used since the early 1950s, reduced the likelihood of well leakage. Cement additives fall into five categories: 1) density reduction material, 2) weight materials that increase density, 3) viscosifiers, 4) filtration control, and 5) accelerators and retarders. These cement additives enable significant improvement to cementing practices, including the improvement to the curing of well cement. By targeting the cement system design to individual well requirements, the probability of well leakage is decreased.

More recent studies (Watson and Bachu, 2008) found the addition of some additives, such as bentonite, increases the water-to-cement ratio, which may increase the cement porosity. The increased porosity leaves the cement vulnerable to an increase in the degradation rate of cement in CO₂-brine solutions (Watson and Bachu, 2008; Kutchko and others, 2007). However, gels such as bentonite can improve the performance of cementing practices in the field, which could offset the risk of increased porosity.

There is still debate as to cement's role in wellbore integrity. While the type of cement and additives used may be important in determining the likelihood for leakage, the quality of the cement placement has an even higher impact on a well's integrity. This factor was omitted as the

well files in the basal Cambrian study area lacked sufficient cement and additive data to evaluate wellbore integrity.

Shallow Well Leakage Factors

Shallow leakage refers to the well integrity in the upper portion of the well, where shallow gas, if present, may leak along the outside of the casing/wellbore annulus to shallow freshwater aquifers or through a casing leak and along the inside of the production casing to the surface (Bachu and others, 2012). It is important to note that potential gas leakage in this part of the well generally excludes CO₂ gas. Potential CO₂ injection would occur in basal Cambrian layers that are found in the deeper portions of the well, which would be accounted for in deep well leakage, with the exception of a potential fracture in the cap rock of the target formation, thus allowing CO₂ to migrate from the intended storage zone.

Within the realm of CCS, shallow well integrity is important in wells that potentially have a deep well leakage issue. In the hypothetical event that there was a CO₂ leak from the bottom of the wellbore, the shallow well integrity could contribute to the location and impact of a fluid migration.

Spud Date

Oil prices can be used as a proxy for the level of drilling activity (Watson and Bachu, 2007). As oil prices increase, the level of drilling activity increases, and with the increased activity, resources can become stressed. Watson and Bachu (2007) correlated increased leakage rates for plugged and abandoned wells in their study area with periods of increased activity. However, they noted that this trend tends to diverge after the year 2000 since the well spuds after this date, which is still within their productive lifespan, have a lower abandonment rate.

Well Type

The presence of hydrocarbons influences the characteristics of a well. Wells that are drilled and abandoned (D&A) reflect the fact that no hydrocarbons were found (or the hydrocarbons were not economically feasible to recover). Because of the lack of hydrocarbons, these wells have a surface casing but do not have production casing extending to the bottom of the hole. D&A wells are generally less prone to leakage (Bachu and others, 2012) because the cement plugs tend to bond and seal better against the irregular surface of the open hole.

Cased well abandonments (CWAs) are wells abandoned after production casing has been cemented to partial or total depth and are found to be more prone to leakage (Bachu and others, 2012; Watson and Bachu, 2007). CWAs are statistically more prone to leakage because the cement casing contains more potential leakage pathways (as illustrated in Figure 2) versus the cement plug in a D&A well.

Drilled and cased wells contain production casing and are production or injection wells. These wells are considered susceptible to leakage (based on this study's methods) since there have been no plugs placed in the well. However, these wells are more closely monitored and

remediated because of regulatory requirements if an issue arises, and the active wells will be plugged and abandoned at the end of their productive life. After abandonment, a reassessment of the well's plug and abandonment procedures should be done to assign an updated relative leakage potential score.

Well Total Depth

As the total depth of a well surpasses 2500 meters (8202 feet), Bachu and others (2012) found that there is a slightly greater potential for leakage. This correlation was attributed to deeper wells having generally larger uncemented intervals between the top of the cement in the production string and surface casing, leaving potential hydrocarbon-bearing horizons above the target injection/production formation open to flow (Watson and Bachu, 2007).

Additional Plug near Surface

Setting an additional abandonment plug inside the well casing near the surface will augment shallow well integrity (Bachu and others, 2012) by providing another barrier to contain leakage that may occur in the well.

Cement to Surface

This criterion is a measure of how high in the casing borehole annulus production string cement was circulated. Bachu and others (2012) found that low cement tops are a major contributing factor to SCVF or GM leaks as drilling mud occupies the casing borehole annulus above the cement top. Drilling mud is a less effective barrier to gas leakage than cement (Bachu and others, 2012).

Omitted Shallow Leakage Factors

Bachu and others (2012) formulated a list of well attributes that were considered indicators of potential shallow wellbore leakage if present in the well. However, not all of these leakage factors were applicable in this particular study. These omitted leakage criteria are described as follows.

Surface Casing Size

Larger-diameter surface casing (greater than or equal to 244.5 mm, or 9.625 in.) has been observed to have a higher incidence of SCVF/GM leakage (Bachu and others, 2012). While there was an observed correlation in the SCVF/GM data, there was not sufficient research or other documentation providing insight as to the reasons for the correlation. Because of the inability to determine applicability to the study area, this factor was omitted.

Abandonment Date

Prior to 1995, the Canadian province of Alberta's abandonment regulatory requirements did not include testing for SCVF/GM or groundwater protection. Bachu and others (2012) found

that wells that were abandoned prior to this year had a greater potential for wellbore leakage. However, this leakage factor only applies to Alberta and was omitted from this study.

Geographic Location

Bachu and others (2012) found a greater incidence of SCVF/GM within their “special test area” in Alberta. This special test area does not apply outside of their defined study and was omitted from this study.

SCVF or GM

Bachu and others (2012) assigned a leakage factor value if a well had measured SCVF or GM. The basal Cambrian study area wells do not have any data containing SCVF or GM, thus this factor was omitted from shallow leakage potential scoring.

Casing Failure (leak)

Bachu and others (2012) assigned a leakage factor value if a well had a documented casing failure or leak. While the basal Cambrian well files may have some documented cases of a casing collapse or other failure, the incidents noted in the well files often result in an attempt by the well’s operator to remedy the casing failure with pressure tests performed after these repairs to evaluate the success of the repair effort. If repairs to the wellbore are successful, the integrity of the repaired well relative to wells with no documented issues is difficult to assess. Based on these considerations, this leakage factor was omitted in this study.

OVERVIEW OF THE BASAL CAMBRIAN WELL INTEGRITY STUDY

Information was collected for 826 wells penetrating the basal Cambrian system across the states of Montana, North Dakota, and South Dakota, and available well files were analyzed. Well data were collected from each state agency as follows: Montana Board of Oil and Gas (MTBOG), North Dakota Industrial Commission (NDIC) Oil and Gas Division, and South Dakota Department of Environment and Natural Resources (SD DENR).

Wells penetrating the basal Cambrian system were drilled between 1921 and 2010 (Figure 3 and Table 1). The 1950s and 1980s yielded the highest frequency of wells drilled into the basal Cambrian system, ranging in depth up to 16,000 feet. Eighty-five percent of the wells are classified as plugged and abandoned; 14% are classified as active wells (production or injection); and the remaining 1% of the wells have been converted to water wells, been temporarily abandoned, or their status is unknown.

Well completions were classified into three types (Table 2). D&A wells were drilled to depth and subsequently abandoned without running production casing. D&A wells with casing are similar to CWA (Bachu and others, 2012). These wells are drilled to depth, have production casing set, and are subsequently abandoned at the end of the well’s lifespan. Drilled and cased wells are active wells (production or injection wells) that contain a production casing.

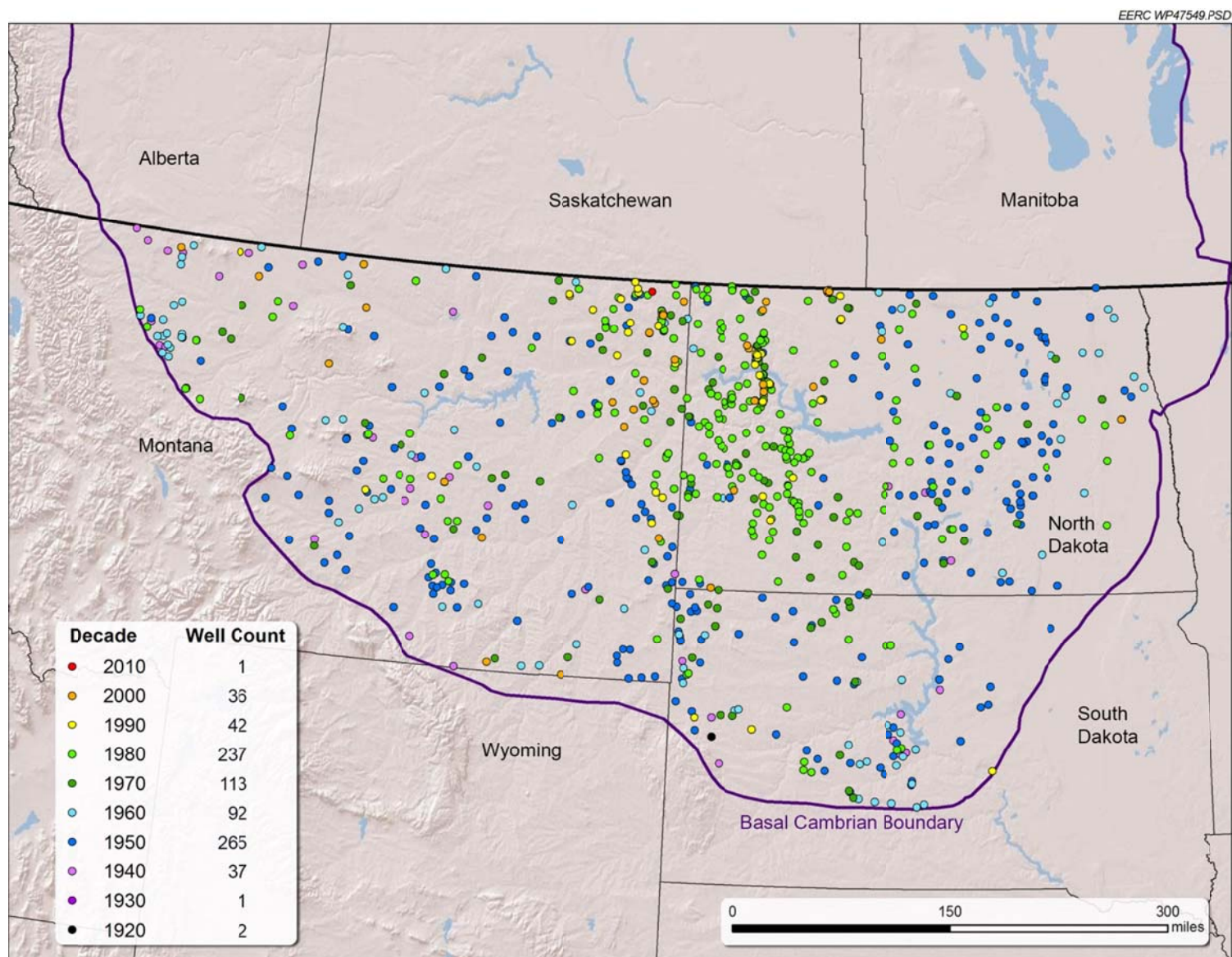


Figure 3. Well spud dates by decade across the study area (sources: MTBOG, NDIC, and SD DENR).

Table 1. Spud Dates by Decade for Each State*

Area	Spud Date by Decade									
	1920	1930	1940	1950	1960	1970	1980	1990	2000	2010**
Montana										
Number of Wells	1	0	24	106	45	37	59	21	22	1
Percentage of Wells	0.3	0.0	7.6	33.5	14.2	11.7	18.7	6.7	7.0	0.3
North Dakota										
Number of Wells	0	0	4	112	25	59	165	18	14	0
Percentage of Wells	0.0	0.0	1.0	28.2	6.3	14.9	41.6	4.5	3.5	0.0
South Dakota										
Number of Wells	1	1	9	47	22	17	13	3	0	0
Percentage of Wells	0.9	0.9	8.0	41.6	19.5	15.0	11.5	2.7	0.0	0.0
Total										
Number of Wells	2	1	37	265	92	113	237	42	36	1
Percentage of Wells	0.2	0.1	4.5	32.1	11.1	13.7	28.7	5.1	4.4	0.1

* Sources: MTBOG, NDIC, and SD DENR.

** Limited data available for 2010 at time of data acquisition.

Table 2. Casing Records for Basal Cambrian Study Area Wells

Casing Record	Number of Wells	Percentage of Wells
D&A	516	62.4
Drilled, Abandoned, and Cased (CWA)	193	23.4
Drilled and Cased (active)	117	14.2

Records of cement type were lacking, with nearly 62% (Table 3) of the well files containing no data on cement type or additives. Of the wells with cement data available, 27% used a Class G cement (most common), 20% used “regular” cement (second most common), and the remaining 53% consisted of a variety of cement types. Regular cement most likely is a Class G, H, or C cement, although uncertainty exists. As a result, regular cement was not classified because of the lack of additional cement information.

Table 3. Cement Records for Basal Cambrian Study Area Wells

State	Total Number of Wells	Number of Wells with No Cement Record	Percentage of Wells with No Cement Record
South Dakota	113	82	72.5
Montana	316	193	61.1
North Dakota	397	235	59.2
Total	826	510	61.7

RESULTS

Deep Well Leakage Evaluation

The risk factors that were evaluated are shown in Table 4. Each well received one score for each risk factor. The assignment of these scores is explained below. Individual scores were multiplied together to produce a final relative risk score for the well. The score is indicative of the relative potential for any one well to leak based upon the factors evaluated; it does not indicate the size or impact of a leak that may occur. The relative ranking of the deep leak potential (DLP) scores is shown in Table 5.

Fracture Treatments

Fracture treatments across the basal Cambrian study wells were rare (Table 6). South Dakota had only one well that received a fracture treatment, while Montana and North Dakota had 12 and 20 wells with fracture treatments, respectively. The fracture treatments appeared to focus in the western North Dakota and eastern Montana area (Figure 4). Fracture scores were calculated by counting the number of times a fracture treatment was performed at the well. Wells that received one fracture treatment were scored a 1.5, and wells with more than one fracture treatment were scored a 2.0 (Table 4).

Table 4. Deep Leakage Risk Factors

Deep Leakage Factor	Criterion	Meets Criterion Value	Default Value
Fracture	Count = 1	1.5	1
Fracture	Count > 1	2	1
Acid	Count = 1	1.1	1
Acid	Count = 2	1.2	1
Acid	Count > 2	1.5	1
Abandonment Type	Bridge plug	3	1
Abandonment Type	Not abandoned	2	1
Abandonment Type	Unknown	2	1
Number of Completions	Count = 1	1.5	1
Number of Completions	Count > 1	2	1

* Modified from Bachu and others, 2012.

Table 5. DLP Score Rankings

DLP	Score
Minimal Potential	<2
Lower Potential	2–6
Moderate Potential	6–10
Higher Potential	>10

* Based on Watson and Bachu, 2008.

Table 6. Fracture Treatments for the Study Area

Area	Number of Fracture Treatments		
	0	1	2
Montana			
Number of Wells	304	9	3
Percentage of Wells	96.2	2.8	0.9
North Dakota			
Number of Wells	377	20	0
Percentage of Wells	95.0	5.0	0.0
South Dakota			
Number of Wells	112	1	0
Percentage of Wells	99.1	0.9	0.0
Total			
Number of Wells	793	30	3
Percentage of Wells	96.0	3.6	0.4

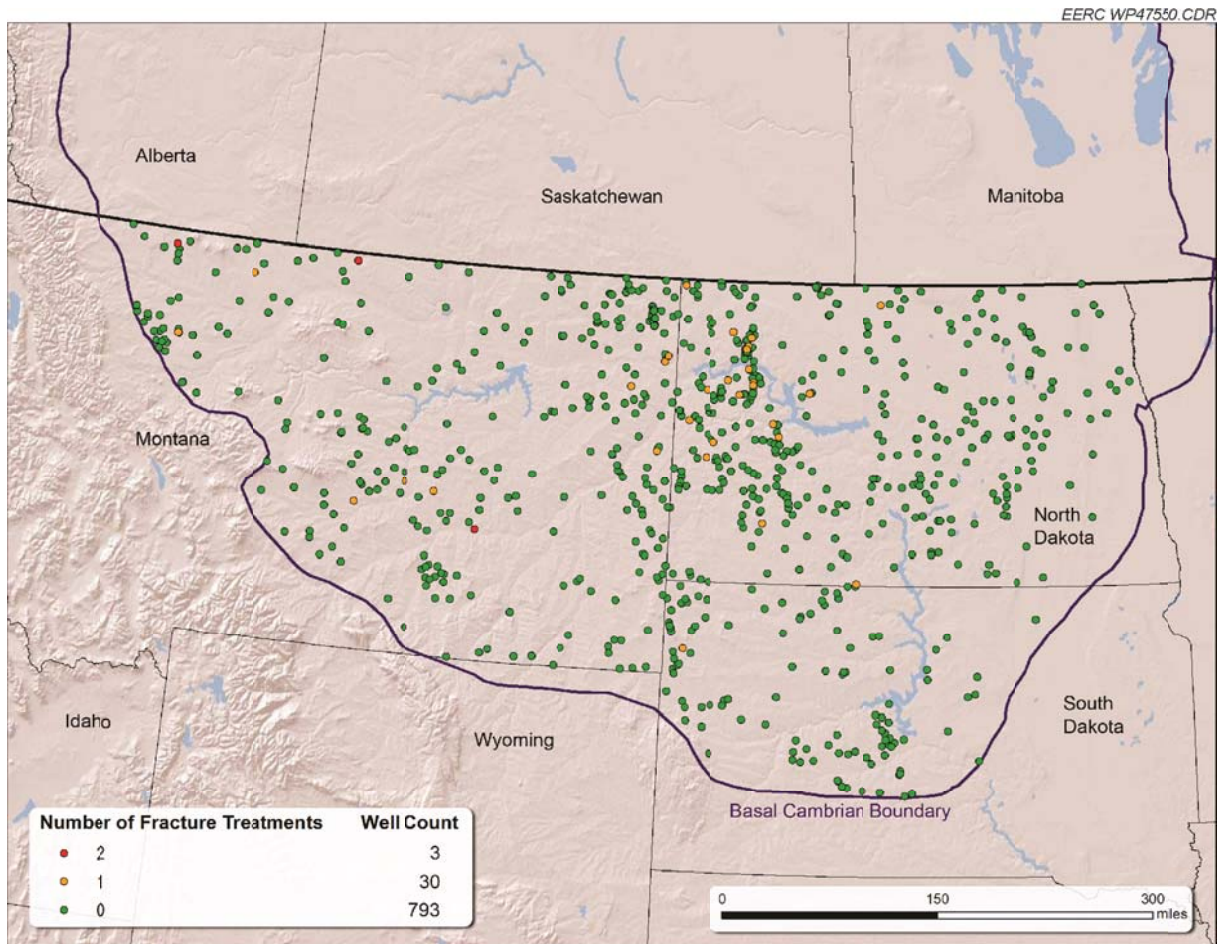


Figure 4. Fracture treatments across the study area.

Acid Treatments

Acid treatments were more frequent compared to fracture treatments. South Dakota had the least number of acid treatments, while North Dakota had the most (Table 7). Similarly to the fracture treatments, western North Dakota and eastern Montana show the greatest concentration of acid treatments for the area (Figure 5). Acid treatment scores were calculated by counting the number of times an acid treatment was performed at a well. Wells that received one acid treatment were scored a 1.1, two acid treatments were scored a 1.2, and more than two acid treatments were scored a 1.5 (Table 4).

Abandonment Types

Abandonment type was divided into four categories: bridge plug, unknown, cement plug, and active without plugs. Bridge plugs can be contained in abandoned wells (with or without cement plugs present) or active wells where bridge plugs were used to adjust the plug back depth. The bridge plugs carry the greatest risk for leakage as they are susceptible to corrosion and failure in the presence of CO₂. Unknown wells were abandoned wells that had no abandonment procedures noted in the well files. Cement plugs, which are the least likely to result in loss of wellbore integrity, were the most common abandonment method in this study. Active wells without plugs are active producing or injecting wells where there is no cement or bridge plugs.

The breakdown of abandonment types is shown in Table 8, and the spatial distribution is shown in Figure 6. The use of bridge plugs followed a similar pattern to fracture and acid treatments, with the greatest number of bridge plugs used in western North Dakota and eastern Montana. Abandonment type scores were determined by analyzing the plug and abandonment procedures given in the records available.

Completions

Perforations provide a communication pathway between the wellbore and formation. The risk for leakage is assumed to increase with the number of perforations. The highest concentration in perforations is found in western North Dakota and eastern Montana (Table 9 and Figure 7). Completion scores were determined by counting the number of perforation intervals indicated in each well file's completion reports. Wells with one completion interval were scored a 1.5, and wells with more than one completion interval were scored a 2.0 (Table 4).

Deep Well Leakage Potential Scoring

The overall deep well leakage score was calculated by multiplying the values for each of the deep well risk factors (Table 4). The overall score was then categorized as minimal potential, lower potential, moderate potential, and higher potential for deep well leakage (Table 5) (modified from Bachu and others, 2012). The deep well leakage scores for each state and overall are listed in Table 10. From Figure 8, it can be seen that the moderate-potential and higher-potential wells are concentrated in western North Dakota and eastern Montana.

Table 7. Acid Treatments for the Study Area

Area	Number of Acid Treatments			
	0	1	2	>2
Montana				
Number of Wells	227	27	22	40
Percentage of Wells	71.8	8.5	7.0	12.7
North Dakota				
Number of Wells	273	52	23	49
Percentage of Wells	68.8	13.1	5.8	12.3
South Dakota				
Number of Wells	106	5	2	0
Percentage of Wells	93.8	4.4	1.8	0.0
Total				
Number of Wells	606	84	47	89
Percentage of Wells	73.4	10.2	5.7	10.8

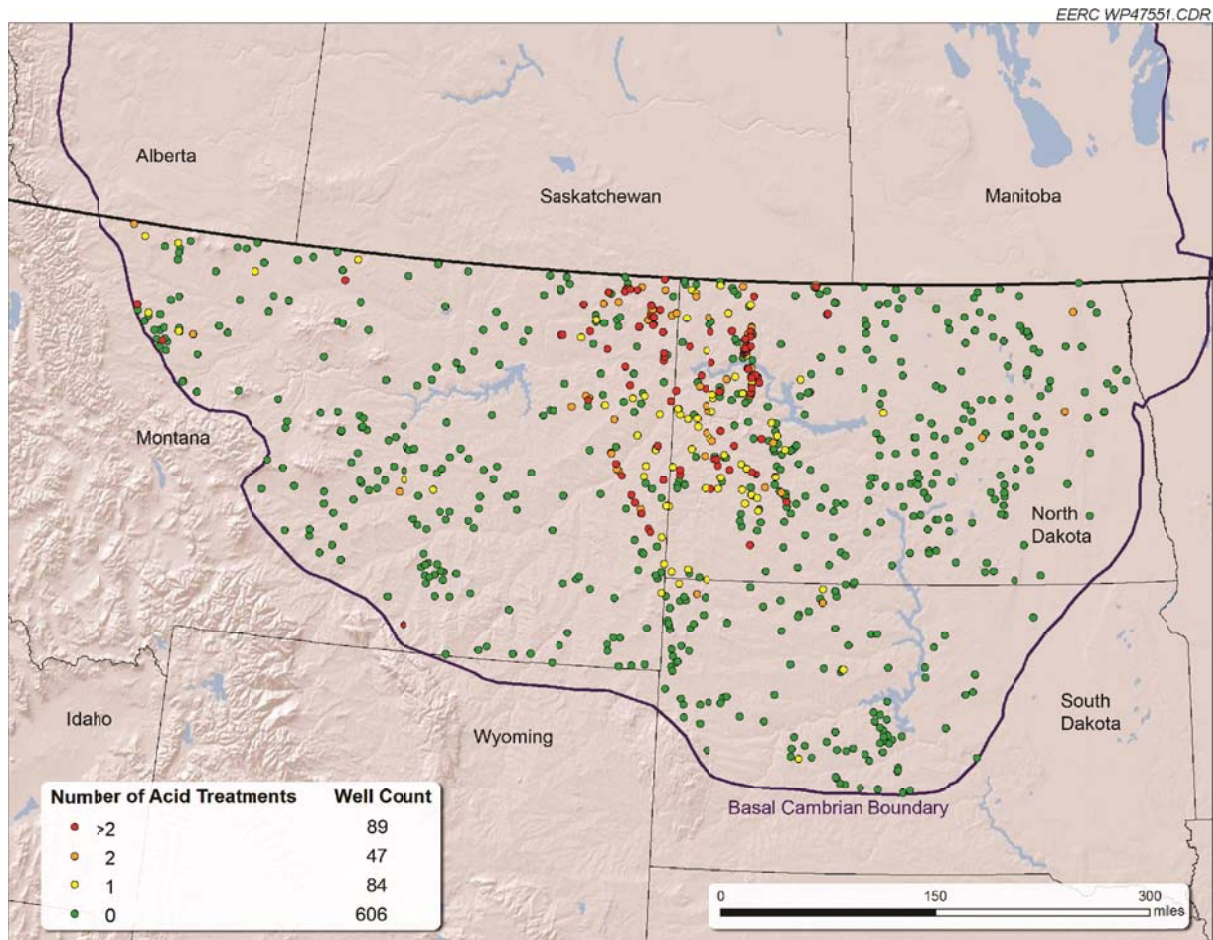


Figure 5. Acid treatments across the study area.

Table 8. Abandonment Types Across the Study Area

Area	Abandonment Plugs			
	Bridge Plug	Unknown	Cement Plug	Active Without Plugs
Montana				
Number of Wells	38	19	222	37
Percentage of Wells	12.0	6.0	70.3	11.7
North Dakota				
Number of Wells	78	2	286	31
Percentage of Wells	19.7	0.5	72	7.8
South Dakota				
Number of Wells	6	2	102	3
Percentage of Wells	5.3	1.8	90.3	2.7
Total				
Number of Wells	122	23	610	71
Percentage of Wells	14.8	2.8	73.9	8.6

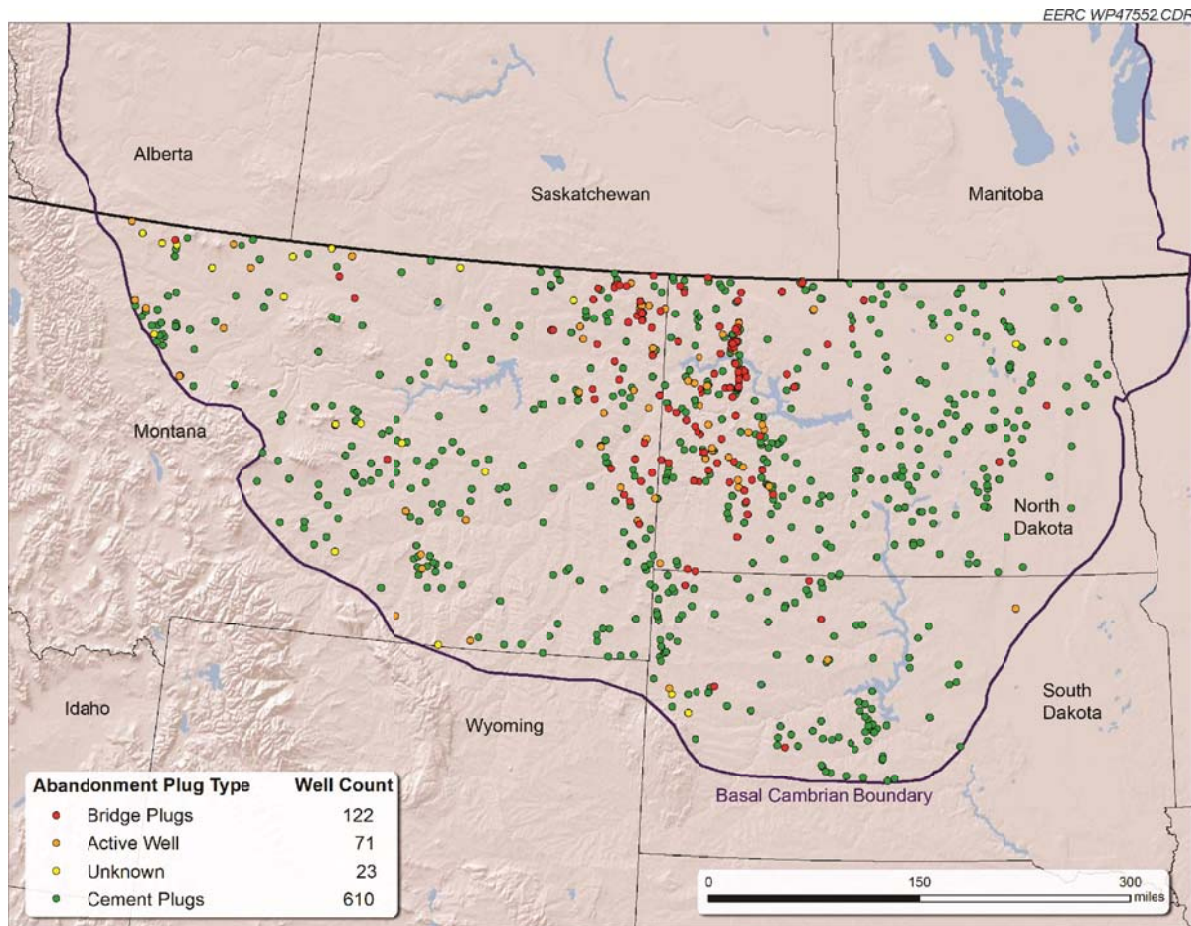


Figure 6. Abandonment types across the study area.

Table 9. Number of Completions Across the Study Area

Area	Number of Perforation Intervals		
	0	1	>1
Montana			
Number of Wells	212	37	67
Percentage of Wells	67.1	11.7	21.2
North Dakota			
Number of Wells	231	28	138
Percentage of Wells	58.2	7.1	34.8
South Dakota			
Number of Wells	105	3	5
Percentage of Wells	92.9	2.7	4.4
Total			
Number of Wells	548	68	210
Percentage of Wells	66.3	8.2	25.4

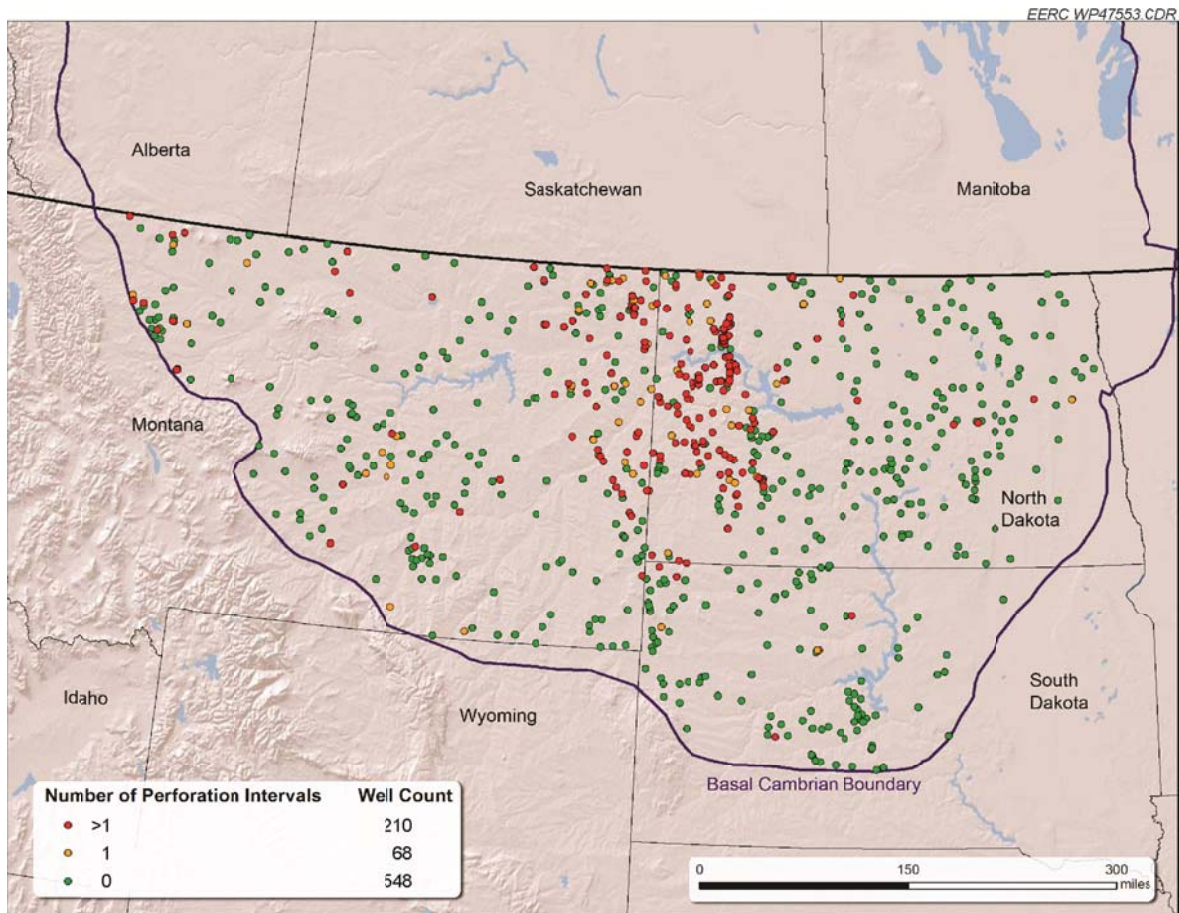


Figure 7. Perforation intervals across the study area.

Table 10. Deep Well Leakage Scores for All of the Study Area

Area	Deep Well Leak Potential Score			
	Higher Potential >10	Moderate Potential 6–10	Lower Potential 2–6	Minimal Potential <2
Montana				
Number of Wells	3	39	75	199
Percentage of Wells	1.0	12.3	23.7	63.0
North Dakota				
Number of Wells	6	75	75	241
Percentage of Wells	1.5	18.9	18.9	60.7
South Dakota				
Number of Wells	0	3	11	99
Percentage of Wells	0.0	2.7	9.7	87.6
Total				
Number of Wells	9	117	161	539
Percentage of Wells	1.1	14.2	19.5	65.3

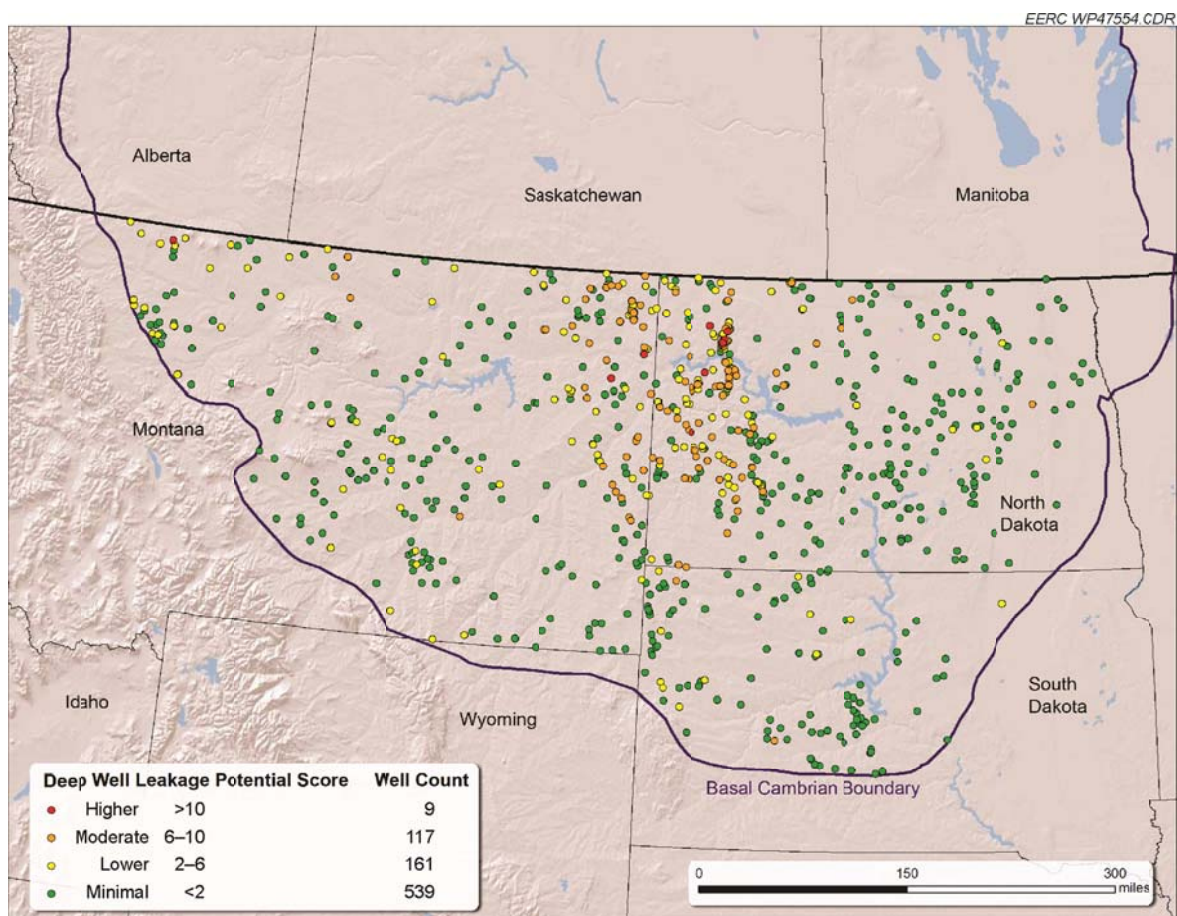


Figure 8. Deep well risk scores for the study area.

Shallow Well Leakage Evaluation

The risk factors that were evaluated for shallow leakage potential are shown in Table 11. Each well received one score for each risk factor. These individual factor scores were then multiplied together to produce a final relative risk score for the well. The ranking of these shallow leakage potential (SLP) scores is shown in Table 12.

Spud Date

As oil prices increase, the level of drilling activity increases, and resources are often stressed, resulting in the potential for a decrease in the quality of work on wells drilled and completed. The years 1974–1986 correspond with a significant rise in oil prices and a large number of oil wells being drilled. Wells with spud dates in this range are considered to have a higher potential risk for well leakage (modified from Bachu and others, 2012).

Approximately 38% of the wells (Table 13) drilled in the basal Cambrian system were drilled during the years 1974–1986. While there is a wide spatial distribution of wells across the study area during this time period, the highest concentrations of these wells were drilled in western North Dakota and eastern Montana (Figure 9).

Table 11. Shallow Leakage Risk Factors*

Shallow Leakage Factor	Criterion	Meets Criterion Value	Default Value
Spud Date	1974–1986	3	1
Well Type	Drilled and cased	8	1
Well Type	D&A with casing	3	1
Well Total Depth	>2500 m (8202 ft)	1.5	1
Additional Plug	No	3	1
Additional Plug	Unknown	2	1
Cement to Surface	No	5	1
Cement to Surface	Unknown	3	1

* Modified from Bachu and others, 2012.

Table 12. Ranking of SLP Scores*

SLP	Score
Minimal Potential	<50
Lower Potential	50–200
Moderate Potential	200–400
Higher Potential	>400

* Based on Watson and Bachu, 2008.

Table 13. Spud Dates for Wells Across the Study Area

Area	Spud Date	
	1974–1986	Other
Montana		
Number of Wells	81	235
Percentage of Wells	25.6	74.4
North Dakota		
Number of Wells	203	194
Percentage of Wells	51.1	48.9
South Dakota		
Number of Wells	26	87
Percentage of Wells	23.0	77.0
Total		
Number of Wells	310	516
Percentage of Wells	37.5	62.5

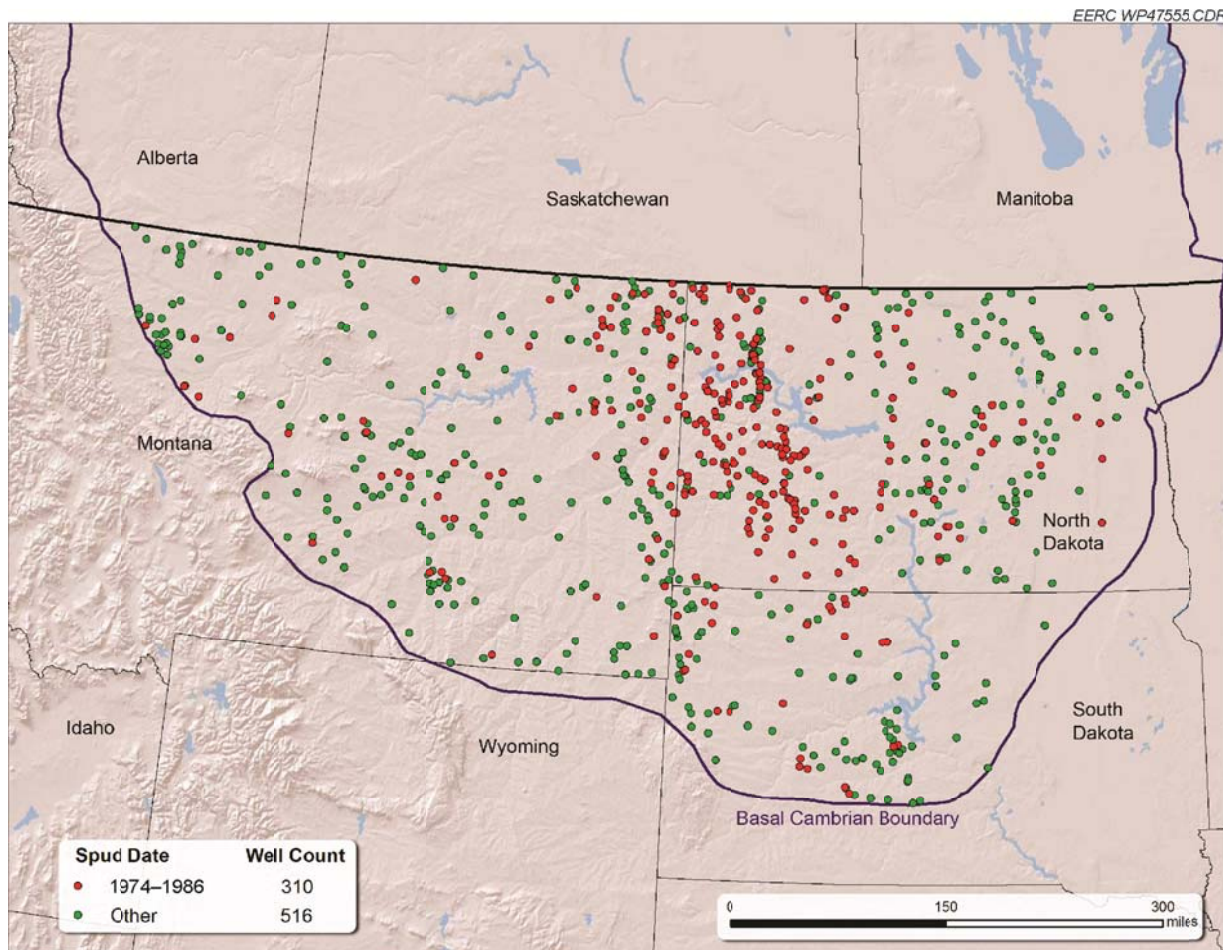


Figure 9. Spud dates across the study area.

Well Type

The presence of production casing can have a significant impact on the potential for well leakage. Wells with production casing and no abandonment plugs are the most likely to leak, followed by wells with production casing and abandonment plugs. The preferred abandonment is an open hole with no production casing run, where cement plugs are more likely to bond and seal tightly against the irregular surface of the open hole (Bachu and others, 2012).

Wells containing production casing (abandoned, active, or other) account for about 47% of the wells in the study area (Table 14), which are more prone to leakage compared to their openhole counterparts. A majority of these cased wells are found in the area of high oil well-drilling activity, i.e., along the Montana–North Dakota border (Figure 10).

Total Depth

Bachu and others (2012) found that there is a slightly greater potential for leakage as the total depth of a well exceeds 2500 meters (8202 feet). The deeper wells typically have a larger uncemented interval between the top of the production string and surface casing, leaving potential hydrocarbon-bearing horizons above the target injection/production formation open to flow (Watson and Bachu, 2007). Approximately 53% of the wells in the study area exceeded 2500 meters (Table 15). Wells exceeding 2500 meters were found primarily in western North Dakota and eastern Montana (Figure 11). As expected, this follows the contour of the Williston Basin, which is deepest in western North Dakota and eastern Montana.

Additional Plug near Surface

Setting an additional abandonment plug inside the well casing near the surface will augment shallow well integrity (Bachu and others, 2012) by providing another opportunity to contain any potential leaks within the well. An additional plug near the surface is a “last line of defense” in containing any leaks that may have infiltrated the wellbore.

Twenty-six percent of the wells across the study area do not have an additional plug near the surface to improve well integrity (Table 16). However, it is important to note that 57.5% of these wells are currently active or temporarily abandoned; thus this number most likely will be reduced as wells are abandoned at the end of their productive life. The wells without a plug near the surface are uniformly distributed across the study region (Figure 12). There are a number of wells in the western North Dakota–eastern Montana area that correspond to active wells.

Cement to Surface

Bachu and others (2012) found that low cement tops are a significant contributing factor to SCVF and GM leaks. However, in general, data are lacking regarding the TOC in the study area. Some of the well files provide measured or calculated TOC, while others provide the number of sacks that were used during the cementing of the wellbore. Calculating TOC based on sacks of cement introduces a degree of uncertainty in the calculations. The exact cement type, cement density, annulus volume, and sacks of cement need to be correct for an accurate calculation.

Table 14. Well Types for the Study Area

Area	Well Type		
	Cased and Not Abandoned (active)	D&A with Casing	D&A Without Casing
Montana			
Number of Wells	46	72	198
Percentage of Wells	14.6	22.8	62.7
North Dakota			
Number of Wells	69	107	221
Percentage of Wells	17.4	27.0	55.7
South Dakota			
Number of Wells	2	14	97
Percentage of Wells	1.8	12.4	85.8
Total			
Number of Wells	117	193	516
Percentage of Wells	14.2	23.4	62.5

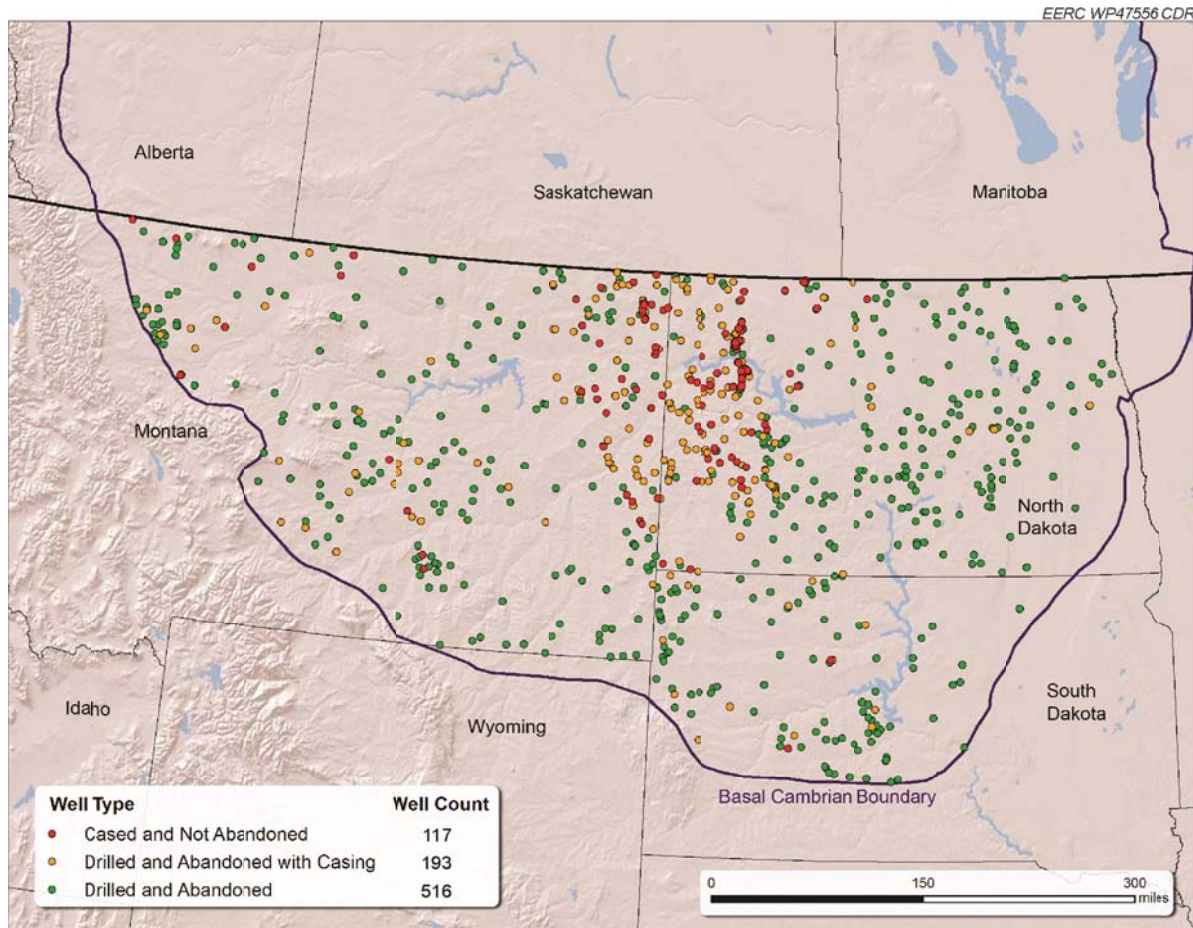


Figure 10. Well types across the study area.

Table 15. Total Depth for the Study Area

Area	Total Depth, meters	
	>2500	<2500
Montana		
Number of Wells	160	156
Percentage of Wells	50.6	49.4
North Dakota		
Number of Wells	256	141
Percentage of Wells	64.5	35.5
South Dakota		
Number of Wells	20	93
Percentage of Wells	17.7	82.3
Total		
Number of Wells	436	390
Percentage of Wells	52.8	47.2

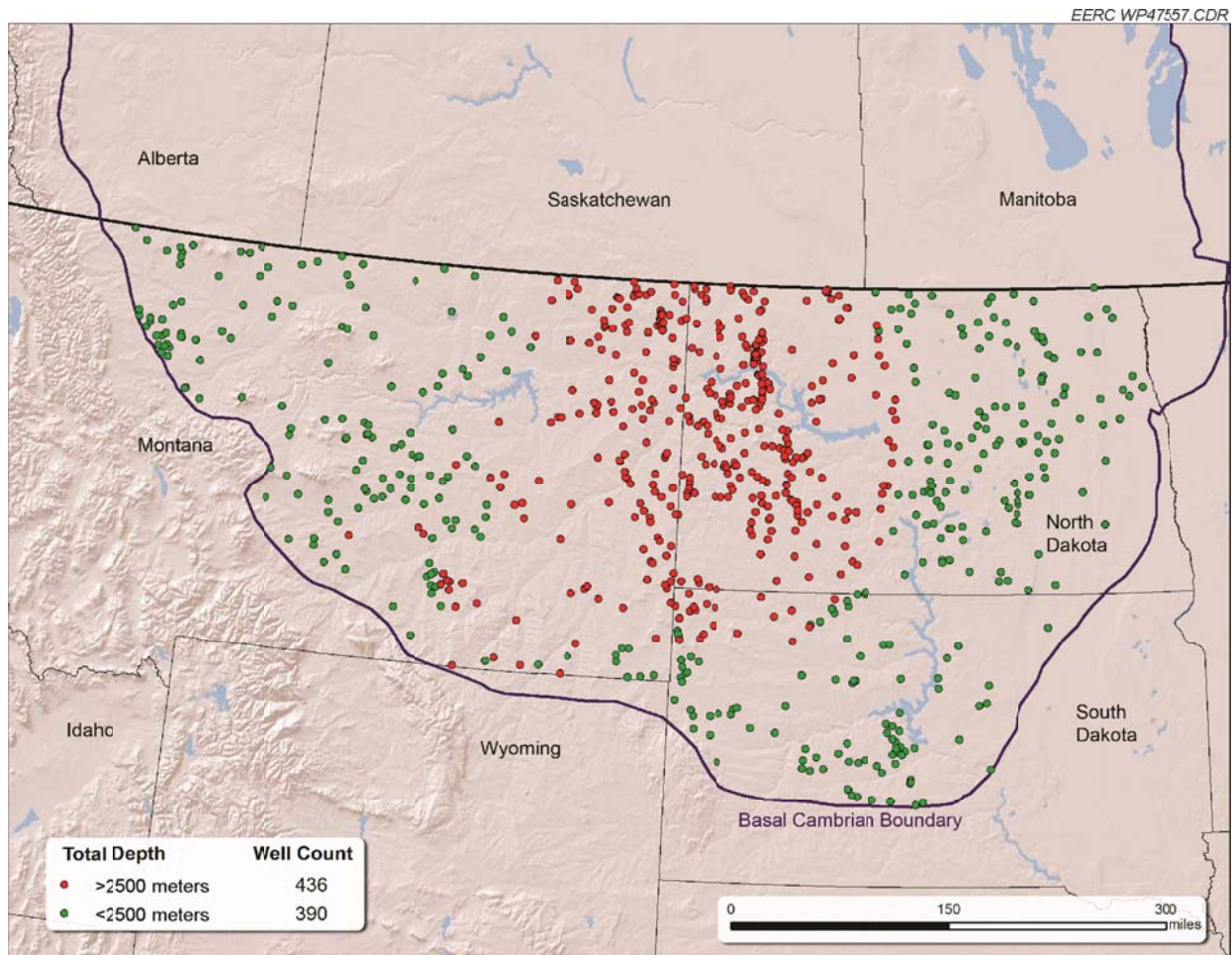


Figure 11. Total depth of wells across the study area.

Table 16. Wells with Additional Plug near the Surface for the Study Area

Area	Additional Plug Near Surface		
	No	Unknown	Yes
Montana			
Number of Wells	93	23	200
Percentage of Wells	29.4	7.3	63.3
North Dakota			
Number of Wells	99	4	294
Percentage of Wells	24.9	1.0	74.1
South Dakota			
Number of Wells	22	2	89
Percentage of Wells	19.5	1.8	78.8
Total			
Number of Wells	214	29	583
Percentage of Wells	25.9	3.5	70.6

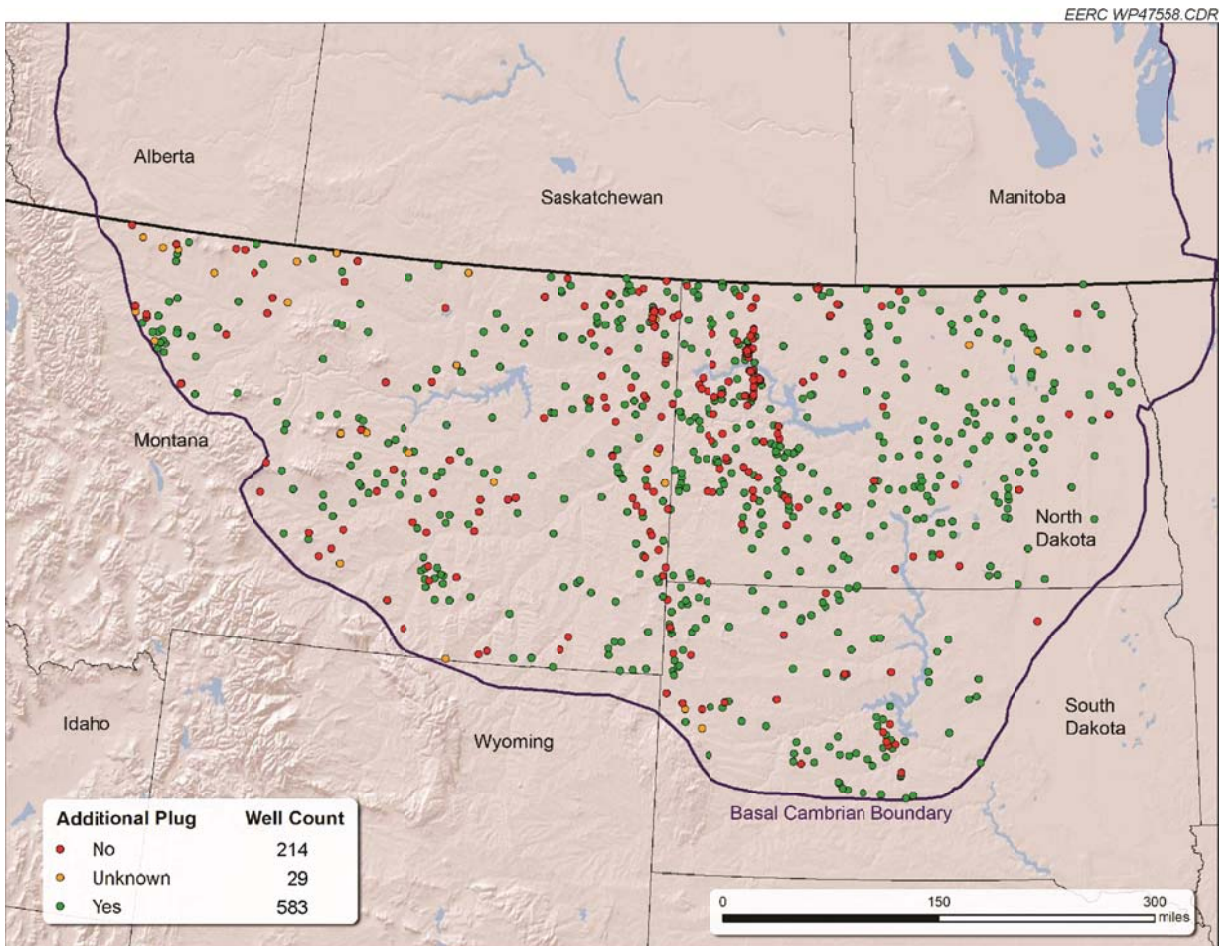


Figure 12. Distribution of wells in the study area with additional plug near the surface.

Errors in calculating TOC may occur as many wells did not identify the cement type, which would lead to an estimated density, and others only provided estimates of the number of sacks of cement that were used, with not all sacks of cement actually being placed in the hole. These errors can lead to estimates of the TOC that could affect the calculated TOC by 200 feet or more. Unless the TOC was given in the well file, TOC values were not calculated as part of this study.

The breakdown of wells that were cemented to the surface is shown in Table 17. Wells that contained no production casing were identified as being cemented to the surface, since the surface casing reached the top of the well. Wells that received a “no” have production casing present, and the given TOC value did not reach the surface casing shoe. Unknown wells contained a production casing but did not have TOC values provided. The distribution of wells that were not cemented to the surface were concentrated in the western North Dakota–eastern Montana region where a large percentage of wells contain production casing (Figure 13). The cementing program used for these deep wells often led to TOC values below the base of the surface casing.

Shallow Well Leakage Potential Scoring

Shallow leakage refers to the well integrity in the upper portion of the well, above the TOC, where shallow gas may leak along the outside of the casing/wellbore annulus to shallow freshwater aquifers or through a casing leak and along the inside of the production casing to the surface (Bachu and others, 2012). The shallow leakage potential score was calculated by multiplying the values of the six shallow leakage factors. The score is indicative of the potential for any one well to leak based on the factors evaluated; it does not indicate the size or impact of a leak that may occur.

Of the wells evaluated, 6.0% have a moderate or higher potential for shallow leakage (Table 18) based on the study methods and available data. Figure 14 shows that the majority of higher- and moderate-potential wells are found in the western North Dakota–eastern Montana area. The locations of these wells are known to be an area of intensive oil and gas exploration and production. The practice of producing oil and gas from these wells has increased the shallow well leakage potential scores.

Comparison of Deep Well and Shallow Well Leakage Potential

Deep and shallow well leakage potential scores provide a means of screening relative leakage potential in either the deep or shallow portions of a well. However, these scores may be combined to assess the complete leakage potential, i.e., deep to shallow leakage, for a well. One concern during the geological storage of CO₂ is the fate of the CO₂ in the subsurface following injection. A well that poses a higher potential for both deep well leakage and shallow well leakage would be more likely to impact groundwater aquifers and/or result in surface releases than would a well with only a higher potential for deep or shallow leakage. To assess this potential, the number of wells in the study area that have moderate- or higher-potential deep and shallow well leakage scores is presented in Table 19; spatial distribution of these wells across the study area is presented in Figure 15.

Table 17. Cement to Surface for the Study Area

Area	Cement to Surface		
	No	Unknown	Yes
Montana			
Number of Wells	19	99	198
Percentage of Wells	6.0	31.3	62.7
North Dakota			
Number of Wells	94	73	230
Percentage of Wells	23.7	18.4	57.9
South Dakota			
Number of Wells	2	15	96
Percentage of Wells	1.8	13.3	85.0
Total			
Number of Wells	115	187	524
Percentage of Wells	13.9	22.6	63.4

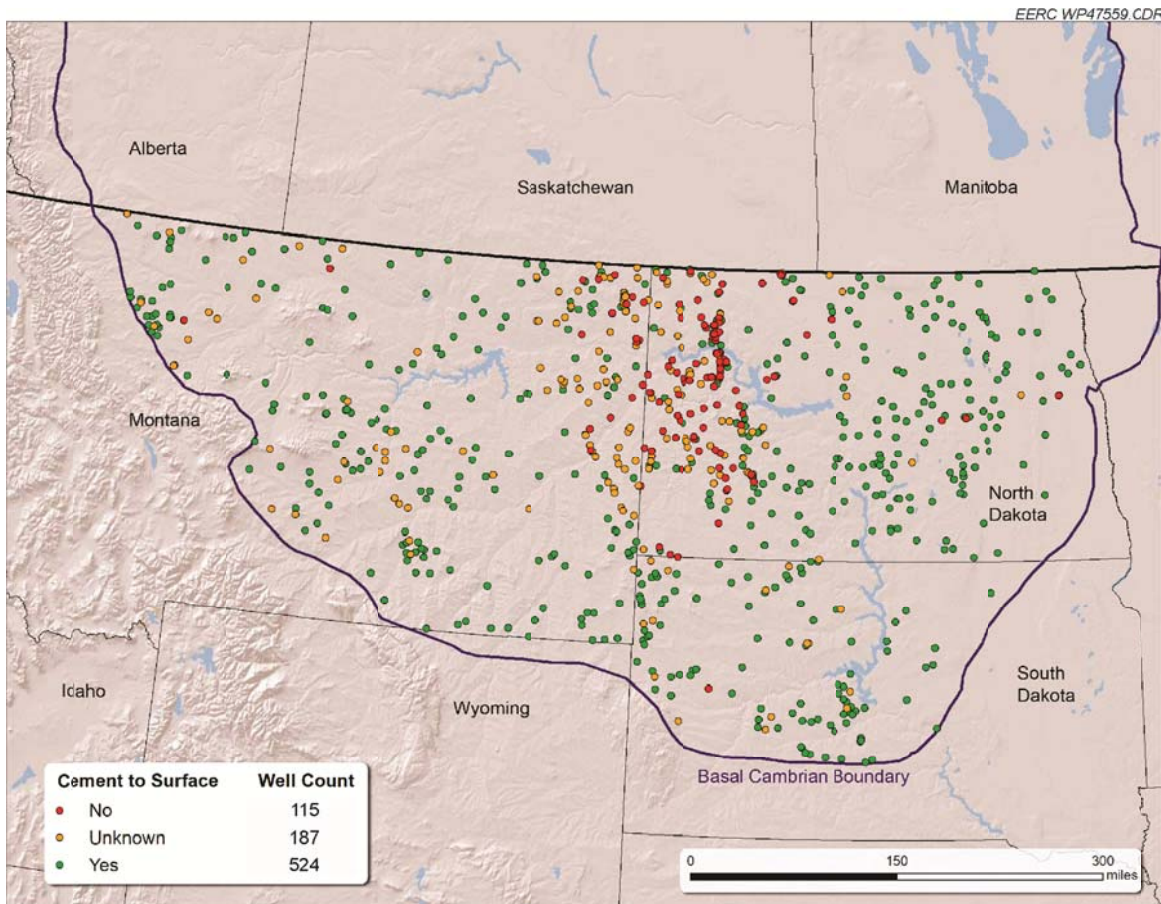


Figure 13. Cement-to-surface well distribution for the entire study area.

Table 18. Shallow Leakage Potential Scores for the Study Area

Area	Shallow Well Leakage Potential Score			
	Higher Potential >400	Moderate Potential 200–400	Lower Potential 50–200	Minimal Potential <50
Montana				
Number of Wells	5	14	37	260
Percentage of Wells	1.6	4.4	11.7	82.3
North Dakota				
Number of Wells	15	15	80	287
Percentage of Wells	3.8	3.8	20.2	72.3
South Dakota				
Number of Wells	0	1	3	109
Percentage of Wells	0.0	0.9	2.7	96.4
Total				
Number of Wells	20	30	120	656
Percentage of Wells	2.4	3.6	14.5	79.4

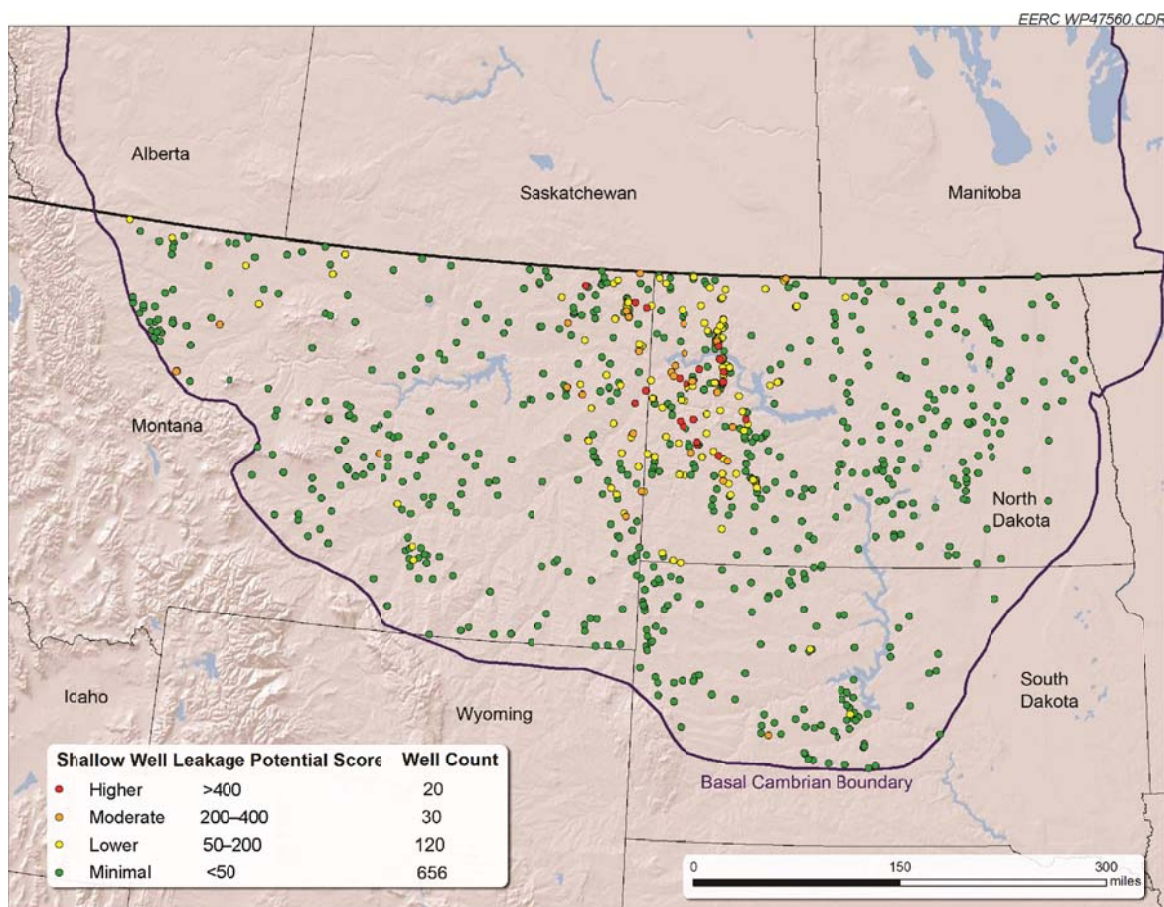


Figure 14. Shallow leakage potential score distribution for wells in the study area.

Table 19. Wells with Moderate- or Higher-Potential Scores for Deep and Shallow Leakage

State	Number of Wells	Percentage of State's Wells
North Dakota	18	4.5
Montana	9	2.8
South Dakota	1	0.9
Total	28	3.4

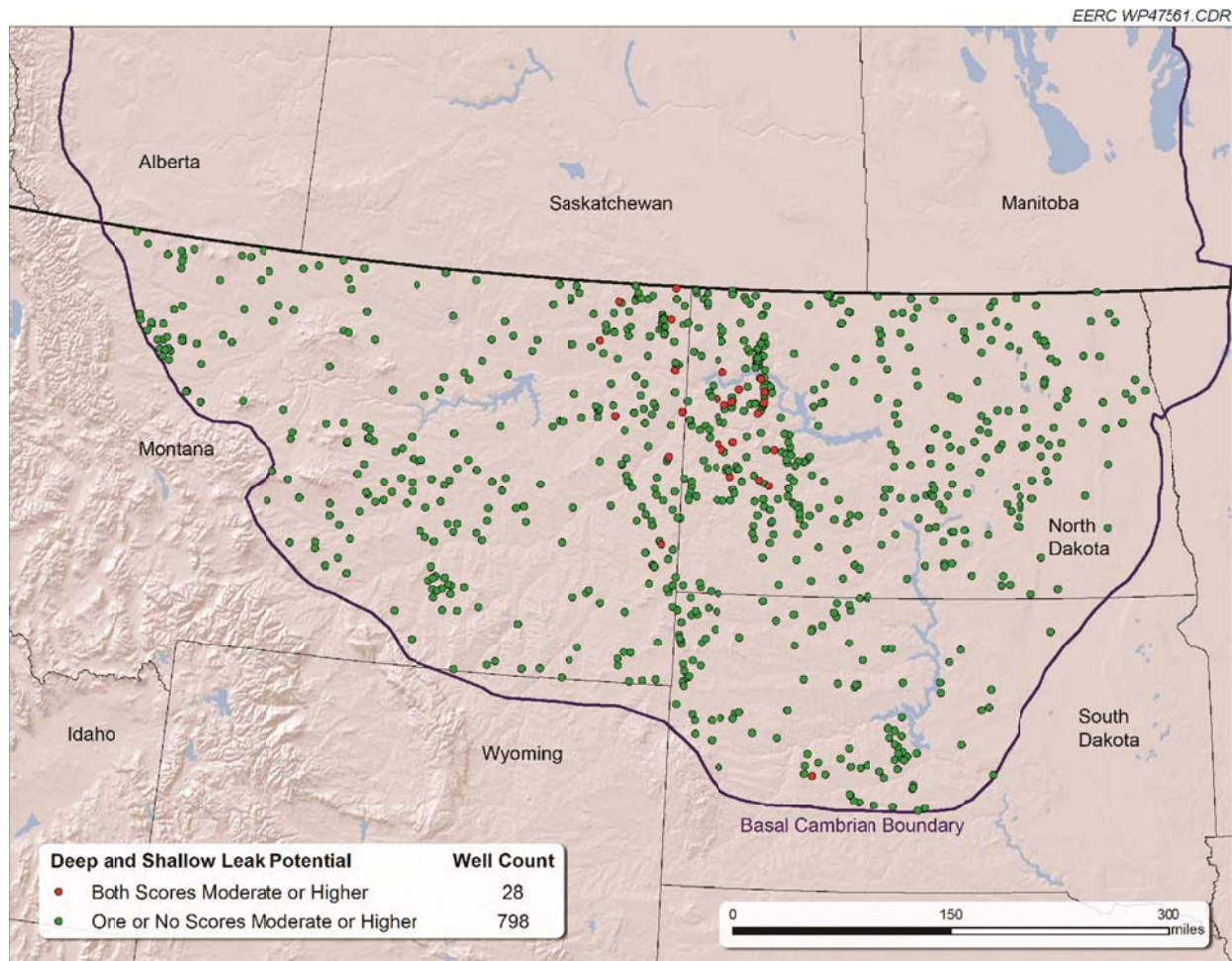


Figure 15. Moderate- or higher-potential scores for deep and shallow leakage across the study area.

Of the wells within the study area, 3.4% have moderate- or higher-potential scores for both shallow and deep leakage. These wells are found in the western North Dakota–eastern Montana region where there are generally higher levels of oil and gas production. The increased production activity results in practices that increase the deep and shallow well leakage potential scores. These well leakage potential scores indicate wells that, relative to one another, may have increased potential to leak. However, this is not an absolute ranking, and the methods are intended to provide a screening-level assessment to identify wells that may require further investigation in areas targeted for CO₂ injection.

SUMMARY

For CCS to be successful, a CO₂ storage formation needs to meet three fundamental conditions: 1) capacity, 2) injectivity, and 3) confinement (Zhang and Bachu, 2011; Bachu, 2003, 2010; Intergovernmental Panel on Climate Change, 2005). One component of confinement is evaluated based on the integrity of wellbores that penetrate the storage formation. Wellbore integrity is the ability of a well to maintain hydraulic isolation of geologic formations and prevent the vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). Wellbore integrity is crucial because leakage of CO₂ may pose a potential risk to surrounding groundwater, vegetation, or wildlife and to accurately account for injected CO₂.

Eight hundred twenty-six wells penetrate the basal Cambrian system across Montana, North Dakota, and South Dakota which were drilled between 1921 and 2010. These wells were analyzed to assess the deep and shallow well leak potential by modifying methods developed by Bachu and others (2012) and Bachu and Watson (2008). Deep leakage is defined as leakage (cross-flow) from a target production zone or CO₂ injection zone into the wellbore (or outside the casing) and vertically into an adjacent permeable zone (productive zone or aquifer) (Bachu and others, 2012). Deep leakage risk factors, including fracture and acid treatments, abandonment plug type, and completions, were used to compile an overall deep well leakage potential score. The deep well leakage potential is classified from minimal potential to higher potential (Table 5), which indicates the relative likelihood of a leak happening based on the evaluation criteria. Shallow well risk factors used to produce a shallow well leakage potential score include spud date, well type, total well depth, existence of an additional plug near the surface, and depth of TOC. The shallow well leakage potential is classified from minimal to higher potential (Table 12). The SLP and DLP scores do not indicate the size or impact of a leak that might occur but only the relative probability of a leak occurring.

Fifteen percent (Table 10) of the wells assessed were classified as moderate or higher potential for deep well leakage, and 6.0% of the wells (Table 18) classified the same for shallow well leakage. 3.4% (Table 19) of the wells exhibited moderate or higher potential for shallow and deep leakage. The majority of the moderate- or higher-potential wells, for both DLP and SLP, are located in western North Dakota and eastern Montana (Figures 9, 14, and 15). The locations of these wells are known to be an area of intensive oil and gas exploration and production. The practice of producing oil and gas from these wells has increased the well leakage potential (based on the available data and methods utilized), and, in the event of a future CCS project, would require additional screening criteria.

When looking at the deep well leakage potential, the wells with the lowest potential were frequently dry holes, which did not receive any perforations, fracture treatments, or acid treatments. These dry holes were frequently abandoned using cement plugs that seal more efficiently against the irregular wall of the open hole. Many of the minimal potential wells were drilled during the 1960s or earlier when a majority of wells were drilled in search of oil and often produced no hydrocarbons.

The 1970s and 1980s showed an increase in focus in the western North Dakota and eastern Montana area as oil was discovered and the demand was high, increasing oil prices. The success in finding oil in this area led to increased perforations, acid treatments, and occasional fracturing. This activity directly contributed to the increase in the shallow and deep well leakage potential score.

While these methods indicate a higher relative potential for well leakage (based on the analysis assumptions and scoring assigned), the quality of the drilling, casing, cementing, and completion practices is extremely important in determining the actual (as opposed to relative) potential of a well leaking. The study methods provide a good screening-level assessment to rank wells that may require further investigation as part of a CCS project. The ranking of the relative leakage potential provides a mechanism to screen wells for detailed evaluation in areas being targeted for CO₂ injection. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies or appropriate monitoring during CO₂ injection.

REFERENCES

- Bachu, S., 2003, Screening and ranking of sedimentary basins for sequestration of CO₂ in geological media in response to climate change: *Environmental Geology*, v. 44, p. 277–289.
- Bachu, S., 2010, Screening and selection criteria, and characterisation for CO₂ geological storage, in Maroto-Valer, M. (ed.), *Developments and innovation in carbon dioxide (CO₂) capture and storage technology*, Vol. 2: Woodhead Energy Series No. 16, United Kingdom, Woodhead Publishing Ltd., p. 27–56.
- Bachu, S., Faltinson, J., Hauck, T., Perkins, E., Peterson, J., Talman, S., and Jensen, G., 2012, The basal aquifer in the prairie region of Canada—characterization for CO₂ storage: Final report for Stage I (Phases 1 and 2), Alberta Innovates Technology Futures.
- Bradshaw, J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P., and Mathiassen, O.M., 2007, CO₂ storage capacity estimation—issues and development of standards: *International Journal of Greenhouse Gas Control*, v. 1, no. 1, p. 62–68, doi:10.1016/S1750-5836(07)00027-8.
- Carey, J.W., Wigand, M., Chipera, S.J., WoldeGabriel, G., Pawar, P., Lichtner, P.C., Wehner, S.C., Raines, M.A., and Guthrie, G.D., 2007, Analysis and performance of oil well cement with 30 years of CO₂ exposure from the SACROC unit, West Texas, USA: *International Journal of Greenhouse Gas Control*, v. 1, no. 1, p. 75–85.
- Celia, M.A., Bachu, S., Nordbotten, J.M., Gasda, S.E., and Dahle, H.K., 2004, Quantitative estimation of CO₂ leakage from geological storage—analytical models, numerical models, and data needs: *Proceedings of the 7th International Conference on Greenhouse Gas Control Technology*, Vancouver, Canada.

- Crow, W., Carey, J.W., Gasda, S., Williams, B., and Celia, M.A., 2010, Wellbore integrity analysis of a natural CO₂ producer: *International Journal of Greenhouse Gas Control*, v. 4, p. 186–197.
- Duguid, A., Radonjic, M., Braunt, R., Mandecki, T., Scherer, G., and Celia, M., 2005, The Effect of CO₂ sequestration on oil well cements: *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies*, Vancouver, Canada, September 5–9, 2004, Wilson, M., Morris, T., Gale, J.J., and Thambimuthu, K. (eds.), Elsevier, Vol. II – Part 2: 1997–2001.
- Duguid, A., and Scherer, G.W., 2010, Degradation of oil well cement due to exposure to carbonated brine: *International Journal of Greenhouse Gas Control*, v. 4, no. 3, p. 546–560.
- Ide, S., Friedmann, S., and Herzog, H., 2006, CO₂ Leakage through existing wells—current technology and regulations: *8th Greenhouse Gas Technology Conference*, Trondheim, Norway, June 19–22, 2006.
- Intergovernmental Panel on Climate Change, 2005, *Special report on carbon dioxide capture and storage*: Cambridge, United Kingdom, and New York, Cambridge University Press.
- Kutchko, B.G., Strazisar, B.R., Dzombak, D.A., Lowry, G.V., and Thaulow, N., 2007, Degradation of well cement by CO₂ under geologic sequestration conditions: *Environmental Science Technology*, v. 41, no. 12, p. 4787–4792.
- Schremp, F., and Roberson, G., 1975, Effect of supercritical carbon dioxide (CO₂) on construction materials: *Society of Petroleum Engineers Journal*, v. 15, no. 3, p. 227–233, SPE-4667-PA, OOI: 10.2118/4667-PA.
- Watson, T.L., and Bachu, S., 2007, Evaluation of the potential for gas and CO₂ leakage along wellbores: Presented at the Society of Petroleum Engineers (SPE) E&P Environmental and Safety Conference, Galveston, Texas, March 5–7, SPE Paper 106817.
- Watson, T.L., and Bachu, S., 2008, Identification of wells with high CO₂ leakage potential in mature oil fields developed for CO₂ enhanced oil recovery: Presented at the Society of Petroleum Engineers (SPE) Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 19–23, SPE Paper 112924.
- Zhang, M., and Bachu, S., 2011, Review of integrity of existing wells in relation to CO₂ geological storage—What do we know?: *International Journal of Greenhouse Gas Control*, v. 5, no. 5, p. 826–840, doi:10.1016/j.ijggc.2010.11.006.