A REGIONAL WELLBORE EVALUATION OF THE BASAL CAMBRIAN SYSTEM

Kyle A. Glazewski,[1] John A. Hamling,[1] Wesley D. Peck,[1] Thomas E. Doll,[1] Jason D. Laumb,[1] Charles D. Gorecki,[1] Nicholas A. Azzolina,[2] David V. Nakles,[2] Edward N. Steadman,[1] and John A. Harju[1]

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

[2] The CETER Group, Inc.
4952 Oakhurst Avenue
Gibsonia, Pennsylvania 15044

Introduction

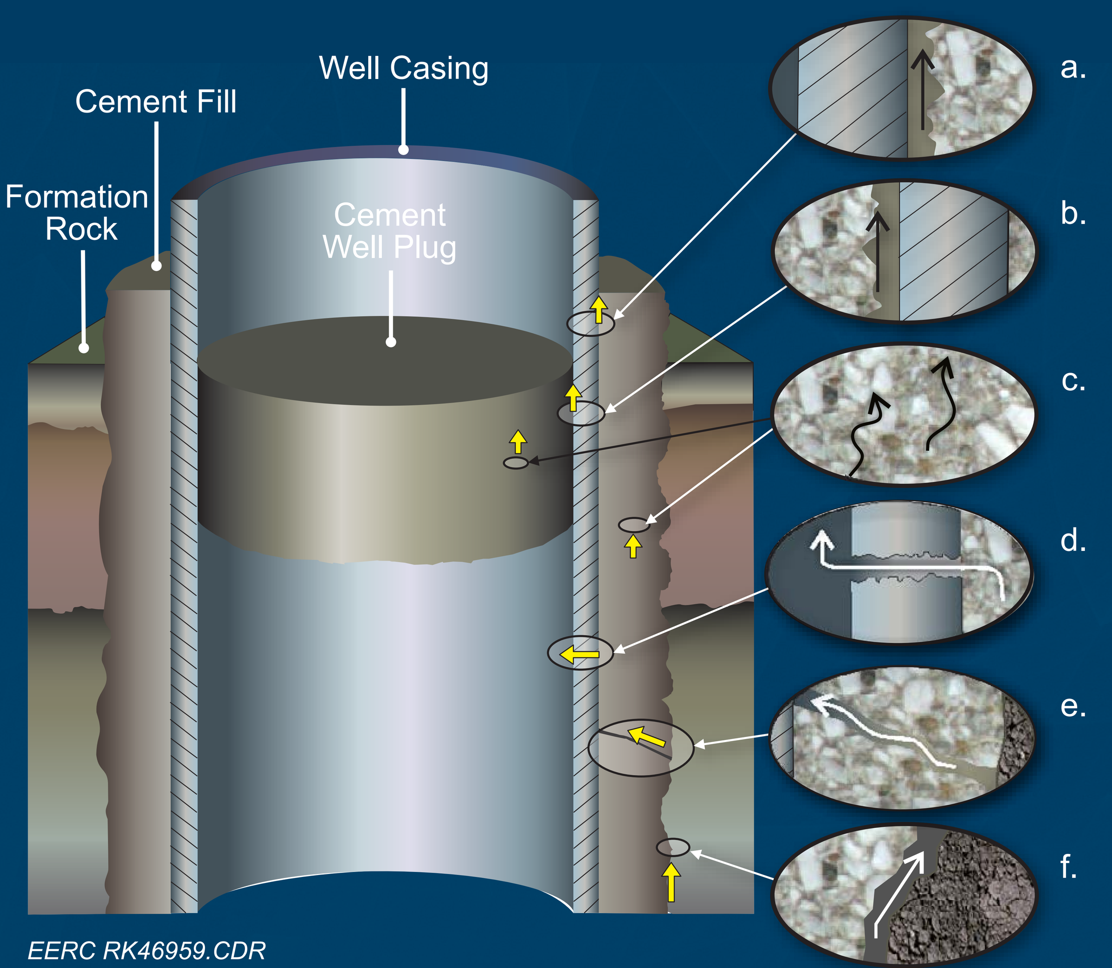
The process of carbon capture and storage (CCS) in geologic media has been identified as an important means for reducing anthropogenic greenhouse gas emissions into the atmosphere.[1] Several categories of geologic media for the storage of carbon dioxide (CO_2) are available, including depleted oil and gas reservoirs, deep brine-saturated formations, CO_2 flood enhanced oil recovery (EOR) operations, and enhanced coalbed methane (ECBM) recovery. 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. 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 CO_2 over long periods of time.

The basal Cambrian system is a deep saline reservoir that has been identified by DOE as a potential CO_2 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 km², while the Canadian side of the border encompasses nearly 811,345 km². This work evaluates one component of CO_2 storage in the basal Cambrian system: the integrity of wellbores that penetrate the system.

Background

The targeted CO_2 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.[2,3] Wellbore integrity is crucial because any leakage of CO_2 poses a potential risk to surrounding groundwater, vegetation, and wildlife. In addition, it diminishes the quantity of CO_2 for which storage credits can be claimed as part of either monetary agreements or regulatory compliance.

For this study, leakage is defined as a loss of CO_2 or other fluid from its intended storage formations and not necessarily losses to the atmosphere. Wells are one possible pathway for CO_2 to escape the storage formation (Figure 1).[4] A relative risk score for deep leakage potential (DLP) and shallow leakage potential (SLP) was created, based on methods from Bachu and others (2012),[5] for wells penetrating the basal Cambrian system on the U.S. side of the U.S.–Canadian border. These score assignments for leakage potential are solely for the purposes of internally comparing and contrasting the different wellbores within this portion of the system. The evaluation of leakage potential as deep or shallow refers to the relative location of the leakage potential in the wellbore itself and does not represent a specific depth.



Conceptual illustration of the potential leakage pathways for CO_2 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[4]).

Results

Fifteen percent of the wells assessed were classified as moderate or higher potential for deep well leakage, and 6.0% of the wells classified the same for shallow well leakage. The majority of the moderate- or higher-potential wells, for both DLP and SLP, are located in western North Dakota and eastern Montana. 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 deep well leakage potential is examined, 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 increased focus in the western North Dakota and eastern Montana areas as oil was discovered and the demand was high, as indicated by 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.

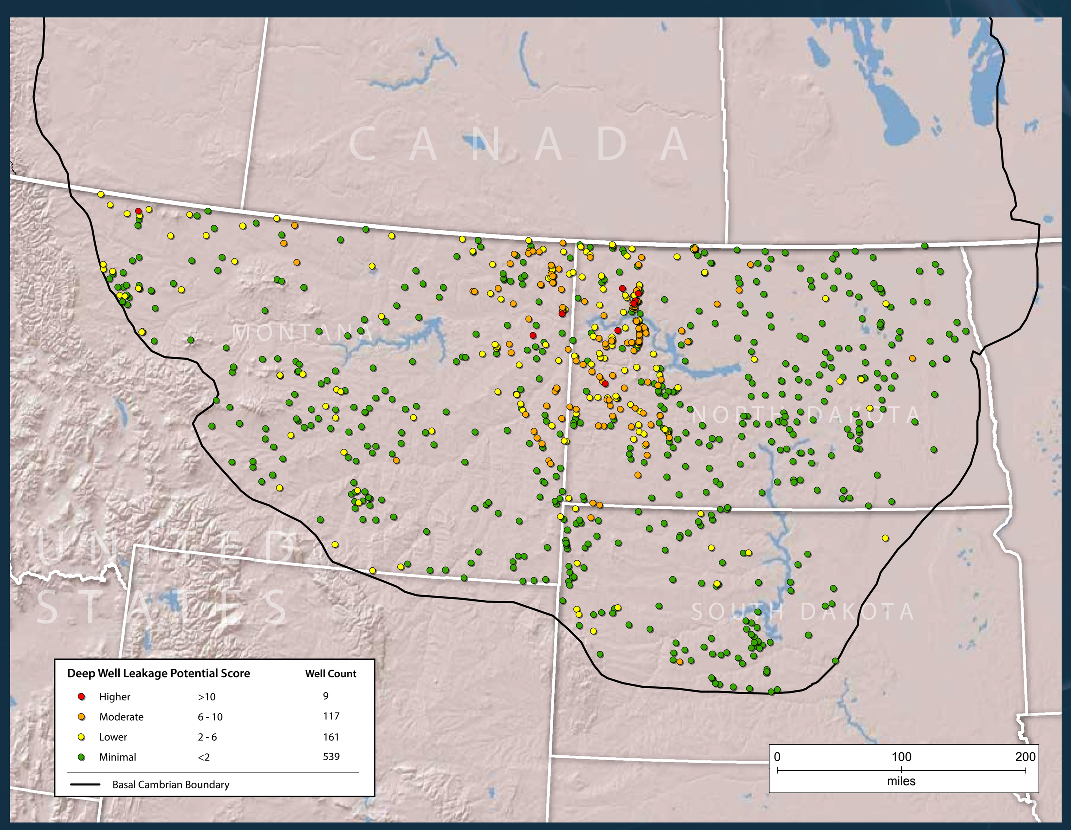
While these methods indicate a higher relative potential for well leakage (based on the analysis assumptions and scoring assigned), the quality of the drilling, casing, cementing, and completion practices is extremely important in determining the actual (as opposed to relative) potential of a well leaking. 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 CO_2 injection. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies or appropriate monitoring during CO_2 injection.

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.[5]

The risk factors that were evaluated for deep leakage potential are shown above. Each well received one score for each risk factor. 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.

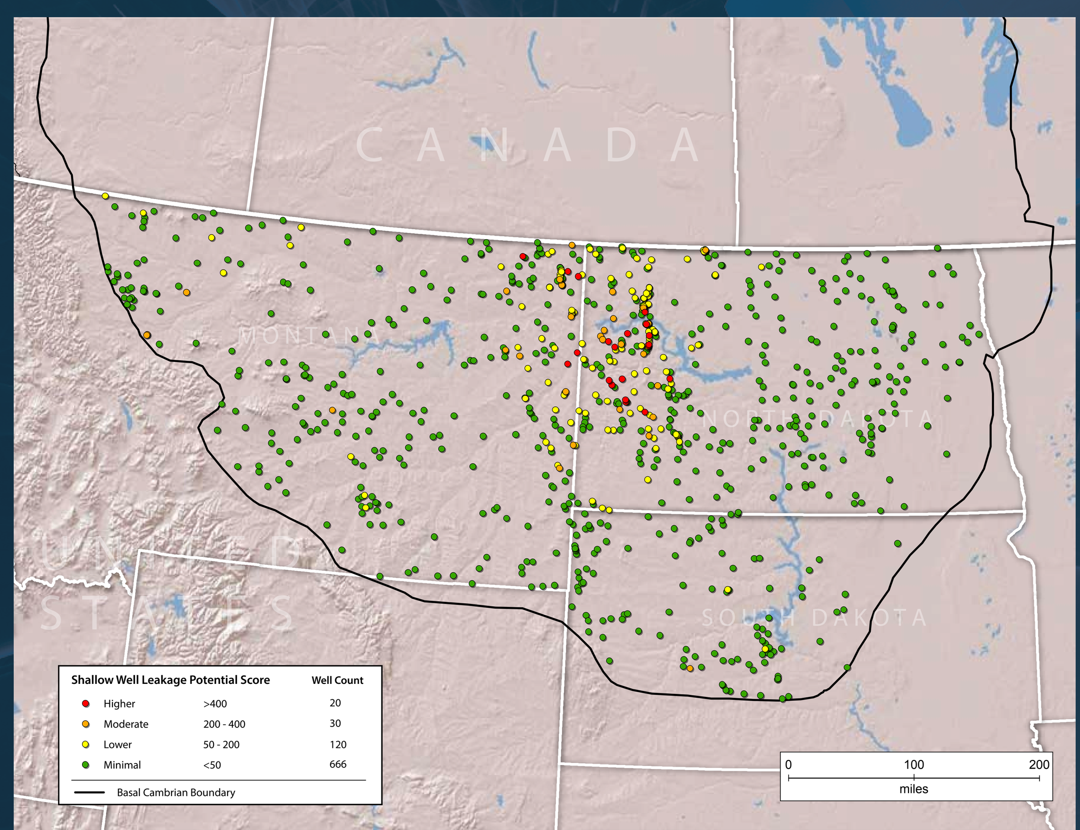


Shallow Leakage Risk Factors*

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.[5]
** Drilled and abandoned.

The risk factors that were evaluated for shallow leakage potential are shown above. 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.



PCOR Partnership 2003 – Present

References

1. Bradshaw, J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P., and Mathiassen, O.M., 2007, CO_2 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.
2. Zhang, M., and Bachu, S., 2011, Review of integrity of existing wells in relation to CO_2 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.
3. Crow, W., Carey, J.W., Gasda, S., Williams, B., and Celia, M.A., 2010, Wellbore integrity analysis of a natural CO_2 producer: International Journal of Greenhouse Gas Control, v. 4, p. 186–197.
4. Celia, M.A., Bachu, S., Nordbotten, J.M., Gasda, S.E., and Dahle, H.K., 2004, Quantitative estimation of CO_2 leakage from geological storage—analytical models, numerical models, and data needs: Proceedings of the 7th International Conference on Greenhouse Gas Control Technology, Vancouver, Canada.
5. 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 CO_2 storage: Final report for Stage I (Phases 1 and 2), Alberta Innovates Technology Futures.