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Comment on "Potential for environmental impact due to acid gas leakage from wellbores at EOR injection sites near Zama Lake, Alberta", by D.M. LeNeveu (2012)

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Abstract

This comment concerns the potential hazards identified by LeNeveu[1] concerning acid gas injection at the Zama Lake oil and gas field in northwestern Alberta. Acid gas is injected both as an enhanced oil recovery method and for geologic disposal. The results found by LeNeveu[1] suggest a high likelihood for serious and widespread release of H_2S by leakage through wellbores. We critically examine LeNeveu's[1] assumptions regarding well leakage response, wellbore seal degradation, and wellbore permeability, and identify more realistic and defensible assumptions. Utilizing these more credible assumptions leads to expectations for greater atmospheric dispersal and reduced acid gas leakage rates as compared to the findings by LeNeveu[1].

1. Introduction

The paper by LeNeveu[1] addresses potential hazards associated with the use of acid-gas injection for enhanced oil recovery (EOR) coupled with geologic disposal of the acid gas at the Zama Lake oil and gas field in northwestern Alberta. The paper is useful in that it motivates further consideration of and planning for the possibility of acid-gas leakage via wells long after field operations have ceased. With injected acid gas at Zama Lake composed of 70% CO_2 and 30%

H_2S, leakage becomes a very serious hazard due to the high toxicity of H_2S. LeNeveu's[1] results suggest a high likelihood for serious and widespread release of H_2S to the atmosphere and groundwater at Zama Lake in the future.

In this comment, we discuss three of the assumptions made by LeNeveu[1], one each concerning well-blowout response, likelihood of seal degradation, and flow resistance in the wellbore. The assumption regarding flow in the wellbore is examined quantitatively by extending the wellbore leakage model to evaluate the impact of wellbore flow resistance on LeNeveu's[1] results. As we will discuss below, the use of more defensible assumptions than those of LeNeveu[1] brings one to significantly different conclusions regarding the long-term hazards of acid-gas injection at the Zama Lake oil and gas field.

2. Uncontrolled Well Leakage and Response

LeNeveu[1] assumes that "the wellbore seals have failed to the extent that permeability of the reservoir rock controls leakage." We show below that the flow equation used by LeNeveu[1] does not actually implement this assumption. Setting that aside and accepting the assumption though, the quote describes a well condition allowing a blowout, if there is a driving force such as gas in contact with the well.

A blowout that occurred in 2001 appears to lend support to this view of well degradation. The blowout was in the Shekilie Basin, which is adjacent to the Zama Basin and also contains pinnacle reef reservoirs.[2] The blowout was from Cube Shekilie 5-31-116-10W6, which was installed in 1983 and suspended in 1984. Sour gas with a H_2S concentration of 36% flowed at an initial rate of 7.8 million cubic feet per day 1984.[3] While details regarding the cause of this blowout are not available, degradation of well integrity was noted.[4] The time elapsed between installation and blowout is consistent with the leading edge probability distribution of well failure versus time posited by LeNeveu[1].

However, the fate of this blowout provides a counterpoint to the LeNeveu[1] assumption of no remedial response to such events. When the Cube Shekilie blowout could not be controlled after 11 days, it was intentionally ignited (the blowout was brought under control 21 days later). The resulting combustion converted the H_2S to SO_2. Because SO_2 in air is actually slightly more toxic to humans than H_2S, the benefit of this is not a reduction in toxicity. Rather, the benefit is that the heat from the combustion lifts the resulting SO_2 higher into the atmosphere and disperses it relative to the fate of H_2S without combustion. This significantly reduces the human health hazard, which is why the Energy Resource Conservation Board requires operators in sour gas areas to be prepared to ignite any uncontrolled gas flows that occur during well work, even at the expense of their rig.[5]

Of course, the Cube Shekilie blowout and well-blowout ignition regulations concern sour gas, whereas LeNeveu[1] concerns acid gas. Acid gas containing 30% H_2S, as well as higher and lower concentrations, is also flammable when mixed with air.[6] Given the relatively low cost and effort associated with igniting a well blowout, it seems likely that future societies would have the capacity to implement this mitigation as a first means to prevent development of the ground level H_2S plumes predicted in LeNeveu[1], if they should turn out to be correct.

But it is unlikely these predictions will turn out to be correct. For instance, Harju et al.[2] discusses the background and conduct of the Zama Field Validation Test, and rated 41% of wells at extreme to high risk of leakage, not failure as defined by LeNeveu[1]. It is doubtful that these terms are equivalent, because the Zama Field Validation Test would almost certainly not have gone forward with an expectation that 41% of the wells were going to blow out. This calls into question the assumption in LeNeveu[1] that wellbore seals degrade to the point of providing no resistance to flow.

Finally, LeNeveu[1] assumes that out of a well population of several wells in each of 800 pinnacle reefs, one well in each of 350 reefs will fail. LeNeveu[1] states, "This is consistent with the estimated 41% of wellbores that are rated for extreme and high risk to fail," as determined by Harju et al.[2]. LeNeveu[1] also states that each reef "will have several wellbores." If the failure probability of a single well is 41%, the probability of a failure affecting a reef intersected by several wellbores is greater than 41%. For instance, if there are three wells per reef and the probability of well failure is 41%, the probability of any of the wells failing and affecting a reef is 79% $(1-(1-0.41)^3)$. LeNeveu[1] correctly recognizes that application of the well failure rate to the reefs rather than to the well population underestimates the number of reefs likely to be intersected by a failing well, but he does not carry out the calculation to estimate the extent of the underprediction.

3. Likelihood of Wellbore Seal Degradation

LeNeveu[1] cites several references to support this total-wellbore-seal breakdown assumption. Some of these references appear to have little relevance. For example, Kusnetz[7] refers to the condition of wells that were drilled before records were kept and abandonment was conducted using “stumps, rocks or nothing at all.” Lesage et al.[8] is also cited to support wellbore seal breakdown, but they conclude that “volatile aromatics that were conspicuously present in the deep disposal zone, e.g., ethyl toluenes and trimethyl benzene, were not detected in the shallow monitoring wells”—indicating that leakage was not detected. LeNeveu[1] cites Condor and Asghari[9] to support the statement that “stresses caused by corrosion of the steel casing could cause early seal failure.” Although Condor and Asghari[9] found that “the most possible path for CO_2 leakage in a wellbore might be between the cement plug and casing,” they also found that “the effect of sulfates and CO_2 can be beneficial for the plugging purposes due to the reduction of permeability.”

LeNeveu[1] cites an experimental study conducted by Bachu and Bennion[10] concerning leakage through wellbore cements. Bachu and Bennion[10] reported on permeability variations from 10^{-21} m^2 for a good cement seal to a maximum level of 10^{-15} m^2, caused by the presence of annular gaps or cracks. As will be seen, this is substantially lower permeability than that required by the assumptions in LeNeveu’s[1] leakage analysis. Furthermore, Bachu and Bennion[10] found that cement permeability decreased over time in contact with CO_2-saturated brine, and did not comment on the time-evolution of permeability caused by annular gaps between cement and casing or cracks in the cement. Nevertheless, LeNeveu[1] goes on to state that “Geochemical reactions in such enhanced pathways could lead to further degradation and increase in permeability.” A citation is not provided for this statement and does not appear to be consistent with the results of Bachu and Bennion[10], or Condor and Asghari[9], as indicated above.

More recent laboratory results further call into question LeNeveu's[1] assumption of well seal degradation to the point that flow resistance in the well can be neglected. Kutchko et al.[11] exposed cement experimentally to 79% supercritical CO_2-21% H_2S, as well as brine exposed to this gas mixture, and did not observe significant degradation. Jacquemet et al.[12] investigated low-brine-to-cement ratio conditions with dissolved CO_2 and H_2S. Such systems are representative of well seals passing through low permeability rocks where water flow is low, so that pH will remain high as a result of buffering by the cement. In these systems, the cement tended to carbonate rather than simply hydrolyze. Jacquemet et al.[12] found this can "have a beneficial impact on the properties of cement or at least . . . less severe damage than hydrolysis." Observed beneficial impacts included armoring of the cement surface and porosity reduction due to precipitation of calcite.

Thus, the literature regarding cement alteration due to exposure to CO_2, and CO_2-H_2S mixtures does not support the assumption by LeNeveu[1] that such exposure will degrade well seals to the extent that flow resistance in the well can be neglected. Rather, these results call into question the flow equation used by LeNeveu[1], which does not include well permeability.

4. Modeling Leakage Including Wellbore Flow Resistance

As mentioned, the leakage model in LeNeveu[1] assumes that "the wellbore seals have failed to the extent that permeability of the reservoir rock controls leakage." Although not stated directly, the implication is that well permeability must be less than the reservoir permeability to reduce the leakage. This is implied through two statements: (1) "It is possible that leakage could be restricted by failed cement seals having a lower permeability than the reservoir rock"; and (2) "Retention of seal integrity such that the seals present a sufficiently lower permeability barrier to leakage that [sic] the reservoir rock might be more effective in reducing risk." But this implication turns out not to be considered in the analysis. The relationship used by LeNeveu[1] for the initial gas leakage rate in the reservoir is:

$$Q_0 = \frac{2\pi k k_{rs}(\rho_w - \rho_s) g h_0 r_b}{\nu_s}, \tag{1}$$

which indicates that flow is driven entirely by buoyancy, with resistance caused entirely by the reservoir. The equation is derived by integrating a radial-flow form of Darcy's law over a hemispherical spatial domain centered on the location where the borehole enters the reservoir. The reservoir permeability and relative permeability are denoted by k and k_{rs}, respectively, h_0 is the initial height of the free gas phase, and r_b is the well radius. The gas-phase density and kinematic viscosity are ρ_s and ν_s, respectively, and the aqueous phase density is ρ_w. The relationship for Q_0 requires that the pressure difference between the top and base of the free gas phase be equal to the static water pressure difference, such that flow is driven entirely by the buoyancy of the gas phase relative to water.

LeNeveu[1]does not discuss the processes involved in acid gas movement up the well if the seals are assumed to be completely ineffective such that any restriction on leakage is imposed by the reservoir. However, in references cited by LeNeveu[1], the process invoked for acid gas movement in the well is buoyancy-driven bubble rise through a stationary brine. This process is not applicable under conditions evaluated here for two reasons. First, bubble flow cannot occur in a permeable medium with permeability less than several hundred Darcies. Experimental evidence of this limitation is provided by Brooks et al. (1999)[13], in which bubble flow was found to be limited to granular materials with grain sizes greater than 1 mm. Utilizing the Carmen-Kozeny[14] model, a porous medium having this grain size and a porosity of 0.35 (as in the case of systems studied by Brooks et al. (1999)[13]) results in a permeability of about 570 Darcies. As already discussed, there is evidence that even degraded seals could retain permeabilities significantly lower than this level, such that gas flow would occur as a continuous phase, not as bubbles.

The second reason that bubble rise is not viable for this situation is that the flow rate of acid gas as found by LeNeveu[1] is too high for such a mechanism. LeNeveu[1] states that the acid gas flow rate is initially 7×10^6 kg/a for the reference case with intact casing. For a 0.07 m radius well at surface conditions (0° C and 0.1 MPa, giving a acid gas density ~ 1.8 kg/m^3), this results in a gas velocity of about 8 m/s over the entire well cross section. However, the maximum air bubble velocity in an otherwise fresh water-saturated porous medium is documented to be 0.185 m/s, and in a stationary fresh water phase, 0.3 m/s[15]. This indicates the gas flow calculated by LeNeveu[1] requires a flow regime resulting from higher gas velocities than possible with bubble flow. Flow through a porous medium, such as a degraded well seal, would require even higher linear velocities and lower liquid saturations to the point of the gas moving as a continuous phase, requiring expulsion of water from the well or well seal.

Aside from the flow regime error, situations involving a highly uncertain parameter, like well permeability for a leakage calculation, are usually treated by assessing the available information to develop a probability distribution to represent the uncertainty. In fact, several other uncertain parameters of the well leakage problem treated by LeNeveu[1] were addressed using probabilistic methods. However, for well permeability, a single, (and in our opinion, unlikely) value was instead selected as representative. Part of the reason this choice was made may be that the modeling method and its presentation tended to obscure the modeling assumption concerning well permeability.

To explicitly address well permeability, we determine the flow rate by integrating Darcy's law, analogous to the treatment of flow through the reservoir as used by LeNeveu[1]. However, the integration is over the well depth for one-dimensional, vertical flow rather than a reservoir volume. Using this approach requires a pressure boundary condition for the flow problem at the base of the well, corresponding to the top of the reservoir. The assumption of a hydrostatic pressure difference between the top and base of the reservoir used by LeNeveu[1] is not required and is not expected in general. For example, if the reservoir gas column were static, the pressure difference between the top and base of the column would be smaller than the hydrostatic pressure difference, because the gas density is lower than the brine density.

Pressure at the bottom of the well (top of the reservoir) under a leakage condition should be determined as a result of the solution for flow through the reservoir and well. Therefore, the pressure at the bottom of the well is allowed to deviate from hydrostatic pressure by an unknown amount, Δp. For these conditions, the steady-state gas flow rate in the well is given by

$$Q_0 = \frac{\pi r_b^2 k_{ws}\{(\rho_w - \overline{\rho_s})gL + \Delta p\}}{\overline{\nu_s}L} \quad (2)$$

where k_{ws} is the effective well permeability to gas at immobile water saturation in the well, L is the well depth, Δp is the variation in pressure from hydrostatic at the base of the well, and $\overline{\rho_s}$ and

$\overline{\nu_s}$ are depth-averaged values for the gas density and kinematic viscosity, respectively. The spatial variability of the gas density and viscosity are included for flow through the well, because of the large change in pressure and temperature over the borehole depth.

Here we assume that the pressure at the base of the reservoir is hydrostatic. This assumption is not necessary for the analysis, but is a simplifying assumption suitable for the purposes of this comment. Allowing for the same unknown pressure deviation, Δp, from hydrostatic pressure at the top of the reservoir in Equation (1) results in:

$$Q_0 = \frac{2\pi k k_{rs}\{(\rho_w - \rho_s) g h_0 - \Delta p\} r_b}{\nu_s} \tag{3}$$

Equations (2) and (3) may be solved for Δp. Using the result for Δp in Equation (3) gives:

$$Q_0 = \frac{2\pi k k_{rs}(\rho_w - \rho_s) g h_0 r_b}{\nu_s} \left\{ \frac{1 + \dfrac{(\rho_w - \overline{\rho_s})L}{(\rho_w - \rho_s)h_0}}{1 + \dfrac{2k k_{rs}\overline{\nu_s}L}{r_b k_{ws}\nu_s}} \right\} \tag{4}$$

Now, if

$$k_{ws} = \frac{2k k_{rs} h_0 \overline{\nu_s}(\rho_w - \rho_s)}{r_b \nu_s (\rho_w - \overline{\rho_s})} \tag{5}$$

then Equation (4) reverts to Equation (1). Therefore, Equation (5) provides the effective well permeability consistent with LeNeveu's[1] analysis.

Values of $\overline{\rho_s}$ and $\overline{\nu_s}$ are estimated using a linear geothermal gradient, based on a surface temperature[16] of 0 °C and a temperature of 80°C at 1500 m depth, which are the temperature and depth at the top of the reservoir given by LeNeveu[1]. Thermal effects of gas expansion during flow up the borehole are not included. Furthermore, the borehole pressure is approximated as hydrostatic for the purposes of computing $\overline{\rho_s}$ and $\overline{\nu_s}$. The resulting values for depth-average density and kinematic viscosity of a 70% CO_2 and 30% H_2S gas are about 330 kg/m^3 and 2.3 x 10^{-7} m^2/s, respectively. Using values presented in LeNeveu[1] for the remaining parameters in Equation (5), an effective well permeability of 4.5 x 10^{-10} m^2, or about 450 Darcies is required to be consistent with the initial leakage rate found by LeNeveu[1].

Some examples help to clarify the implications of LeNeveu's[1] assumption on well permeability. If we assume that the effective well permeability is the same as the reservoir permeability, or $k_{ws} = 3 \times 10^{-13}$ m^2, and the other parameters are the same as used by LeNeveu[1], we find the initial leakage rate would be about 1,400 times smaller than that determined by LeNeveu[1]. Therefore, the effective well permeability does not need to be lower than the reservoir permeability to significantly impact the leakage rate, and in fact, effective well permeabilities up to 4.5 x 10^{-10} m^2 result in some degree of reduced leakage rates relative to those determined by LeNeveu[1]. If the effective well permeability were limited to a value of 10^{-15} m^2, such as found by Bachu and Bennion[10] for a degraded wellbore seal condition, the initial leakage rate calculated by the model would be about 420,000 times lower than found by LeNeveu[1]. On the other hand, for effective well permeabilities in excess of 4.5 x 10^{-10} m^2, as might apply to an open wellbore, the initial leakage rate would be higher. The theoretical limit for the initial leakage rate is about

17 times higher than found by LeNeveu[1] as the effective permeability of the well becomes infinite.

5. Conclusion

The paper by LeNeveu[1] highlights the importance of understanding the long-term behavior of wellbore seals in order to constrain uncertainties for geologic disposal of acid gas. However, well seal degradation due to acid-gas exposure as envisioned by LeNeveu[1] is not supported by current research. Rather, current research suggests that such exposure will either be benign or positive in terms of well seal integrity. However, should these research results turn out to be incorrect and well seals do significantly degrade, even such degraded seals are likely to provide more resistance to flow than posited by LeNeveu[1]. Finally, even if both the research regarding well seal degradation and the findings of this comment regarding the effect of even degraded seals on flow rate are incorrect, such that a large number of wells do blow out acid gas, current practice indicates that ignition of the exiting gas stream provides a reasonable first response for future societies in preventing a health hazard from developing over a large area. Therefore, the results of LeNeveu's[1] analysis should not be considered a realistic appraisal of future consequences for acid-gas EOR/disposal activities at Zama Lake.

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