THE SKY IS PINK:

ANNOTATED DOCUMENTS

— Southwestern Energy
— Oilfield Review | Schlumberger
— Watson | Bacchu
— Dusseault, Gray + Nawrocki | SPE International
— Archer
— Colorado Oil and Gas Conservation Commission [COGCC]

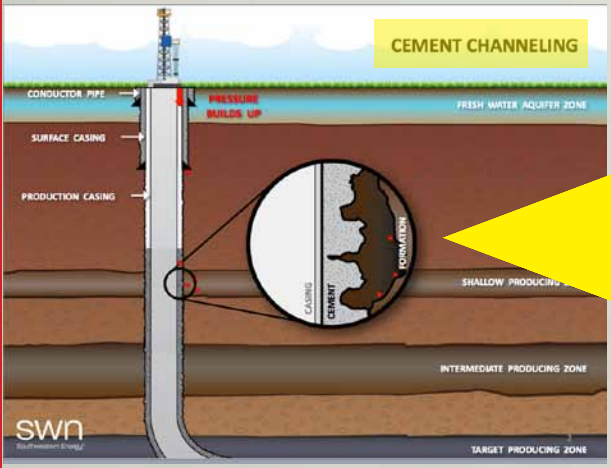
If it is not possible for gas to migrate from targeted formations, why does industry show so much evidence to the contrary in these, their very own documents?

GASLAND

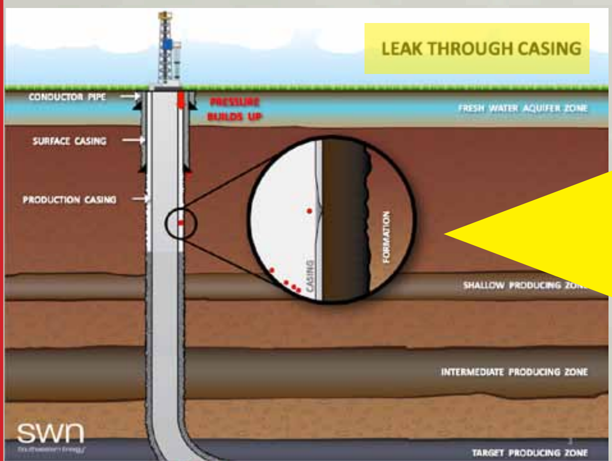
SOUTHWESTERN ENERGY

The gas industry asserts that the target formation is thousands of feet from water supply aquifers and that the aquifers therefore cannot be contaminated by migration of natural gas, radioactivity, VOCs and other chemicals.

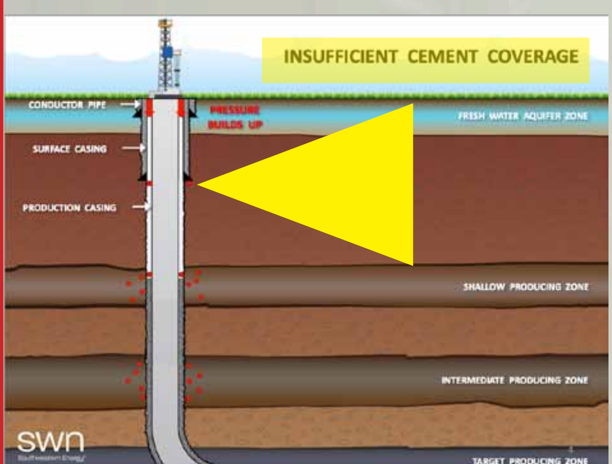
However, SOUTHWESTERN ENERGY'S own powerpoint deck shows three ways that just such a scenario can occur



CEMENT CHANNELING
The cement forms incomplete bond to the casing, sometimes caused by exposure while curing to pressurized gas.



LEAK THROUGH CASING
The casing itself starts to corrode over time due to exposure to moisture and chemicals.



INSUFFICIENT CEMENT COVERAGE
The annulus around a casing string is not cemented to the surface, allowing pressurized fluids access upwards to a freshwater aquifer.

GASLAND

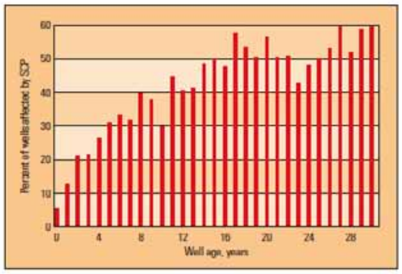
The science of constructing gas wells is thousands of years old. Legend has it that the Chinese dug the first natural gas well before 200 BC and transported the gas through bamboo pipelines.[1] Subsequent well-construction history is unclear until 1821, the year of the first US well drilled specifically for natural gas.[2] This well, in Fredonia, New York, USA, reached a depth of 27 ft [8.2 m] and produced enough gas to light dozens of burners at a nearby inn. Eventually the well was deepened and produced enough gas to provide lighting for the whole town of Fredonia. By this time, well-casing technology in the form of hollowed-out wooden logs had been developed for salt dome drilling, but it is not known whether such casing was used in the gas wells drilled during this era. In all likelihood, these first gas wells were leak-prone.

During the rest of the 19th Century, natural gas became an important energy source for many communities. Techniques for locating, exploiting and transporting natural gas to our homes and industries have had huge advances since the early days.

Despite these advances, many of today's wells are at risk. Failure to isolate sources of hydrocarbon either early in the well construction process or long after production begins has resulted in abnormally pressured casing strings and leaks of gas into zones that would otherwise not be gas-bearing.

Abnormal pressure at the surface may often be easy to detect, although the source or root cause may be difficult to determine. Tubing and casing leaks, poor drilling and displacement practices, improper cement selection and design, and production cycling may all be factors in the development of gas leaks.

Planning for gas by acknowledging the interdependencies of various well-construction processes is critical to building gas wells for the future. This article focuses on an early phase in the gas journey—constructing the gas well. Case studies from South America, the Irish Sea, Asia and the Middle East demonstrate effective methods for selecting drilling muds, displacing mud before cementing, and constructing long-lasting wells with high-integrity cement.



^ Wells with SCP by age. Statistics from the United States Mineral Management Service (MMS) show the percentage of wells with SCP for wells in the outer continental shelf (OCS) area of the Gulf of Mexico, grouped by age of the wells. These data do not include wells in state waters or land locations.

Wells at Risk

Since the earliest gas wells, uncontrolled migration of hydrocarbons to the surface has challenged the oil and gas industry. Gas migration, also called annular flow, can lead to sustained casing pressure (SCP), sometimes called sustained annular pressure (SAP). Sustained casing pressure can be characterized as the development of annular pressure at the surface that can be bled to zero, but then builds again. The presence of SCP indicates that there is communication to the annulus from a sustainable pressure source because of inadequate zonal isolation. Annular flow and SCP are significant problems affecting wells in many hydrocarbon-producing regions of the world.[3]

In the Gulf of Mexico, there are approximately 15,500 producing, shut-in and temporarily abandoned wells in the outer continental shelf (OCS) area.[4] United States Minerals Management Service (MMS) data show that 6692 of these wells, or 43%, have reported SCP on at least one casing annulus. In this group of wells with SCP, pressure is present in 10,153 of all casing annuli: 47.1% of the annuli are in production strings, 26.2% are in surface casing, 16.3% are in intermediate strings, and 10.4% are in conductor pipe.

The presence of SCP appears to be related to well age; older wells are generally more likely to experience SCP. By the time a well is 15 years old, there is a 50% probability that it will have measurable SCP in one or more of its casing annuli [above]. However, SCP may be present in wells of any age.

In the Gulf of Mexico OCS area, SCP generally results from either direct communication of shallow gas-bearing sands with the surface or poor primary cementing that exposes deeper gas-bearing sands through gas migration. Most wells in the Gulf of Mexico have multiple casing strings and produce through production tubing, making locating and repairing leaks difficult and expensive.

In Canada, SCP occurs in all types of wells—shallow gas wells in southern Alberta, heavy oil producers in eastern Alberta and deep gas wells in the foothills of the Rocky Mountains.[5] Most of the pressure buildup is due to gas, although, in fewer than 1% of all wells, oil and sometimes salt water also flow to surface.

Continued demand for natural gas coupled with increasingly more difficult drilling environments has heightened operator awareness worldwide to the short- and long-term implications of poor zonal isolation. Whether

For help in preparation of this article, thanks to Raafat Abbas and Daniele Petrone, Abu Dhabi, UAE; and Matima Ratanapinyowong, Bangkok, Thailand

CBT (Cement Bond Tool), CemCADE, CemCRETE, DensCRETE, FlexSTONE, GASBLOK, LiteCRETE, USI (UltraSonic Imager), Variable Density and V are marks of Schlumberger. SILDRIL, VERSAD Virtual Hydraulics are marks of M-I L.L.C.

1. For an overview of natural gas history: http://r0.unctad.org/infocomm/anglais/g characteristics.htm (accessed August http://www.naturalgas.org/ove (accessed August 20, 2003).
2. For a chronology of oil- and gas Pennsylvania: http://www.dep. deputate/minres/reclaiMPa/int chronologyofoilandgas (access
3. Frigaard IA and Pelipenko S: "E Strategies for Mud Removal an paper SPE 80999, presented at and Caribbean Petroleum Engi Port-of-Spain, Trinidad, West I
4. United States Minerals Manag http://www.gomr.mms.gov (acc
5. Alberta Energy and Utilities Bo http://www.eub.gov.ab.ca (acc

In this article from *Oilfield Review*, it is stated that sustained casing pressure is an indication of communication to the annulus from a sustainable pressure source because of inadequate zonal isolation, caused by gas migration due to faulty cement or casings.

This chart shows the number of wells in the Gulf of Mexico with SCP - or the failure rate - by age. As you can see, 6% fail immediately, and within 15 years, over 50% have failed.

Migration is a common problem in Canada. Most of the SCP/migration is due to gas.

It is acknowledged that the search for energy in ever more remote locations — "extreme energy" — will push technology and operators to the limit: the consequences of "poor zonal isolation" are more failures.

SCP can result from direct communication with gas in shallow formations as well as the target formations, usually caused by poor primary cementing.

There are 4 commonly understood causes of SCP, although identifying the precise cause is often difficult, likely for the same reason that remediating is difficult.

A — Tubing | migration leaks. If they lead to a failure of production casing, the outcome can be catastrophic, jeopardizing personnel safety, production facilities and the environment.

B — Poor mud displacement leads to poor zonal isolation and gas migration.

C — Cement loses volume as it sets, leading to unbalanced hydrostatic pressure.

constructing a gas well, an oil well, or both, long-term, durable zonal isolation is key to minimizing problems associated with annular gas flow and SCP development.[6]

Identifying Causes of Gas Migration

Annular gas may originate from a pay zone or from noncommercial, gas-bearing formations.[7] Some of the most hazardous gas flows have originated from unrecognized gas behind conductor, surface or intermediate casing. Typically, gas flow that occurs immediately after cementing or before the cement is set is referred to as annular gas flow, or annular gas migration. This flow is generally massive and can be interzonal, charging lower-pressured formations, or can flow to the surface and req ntrol procedures. Flow to surface occu er in the life of the well is known as SC er flow also can be from gas-bearing form ons to formations of lower pressure, generally at shallower depths.

Determining the precise source of annular flow or sustained casing pressure is often difficult, although likely causes can be divided into four primary categories: tubing and casing leaks, poor mud displacement, improper cement-slurry design and damage to primary cement after setting (below).

Tubing and casing leaks—Production tubing failures may prese t the most serious SCP problem.[3] Leaks can sult from poor thread connection, corrosio ermal-stress cracking or mechanical rupture of the inner string, or from a packer leak. Production casing is typically designed to handle tubing leaks, but if the pressure from a leak causes a failure of the production casing, the outcome can be catastrophic. With pressurization of the outer casing strings, leaks to surface or underground blowouts may jeopardize personnel safety, production-platform facilities and the environment.

A

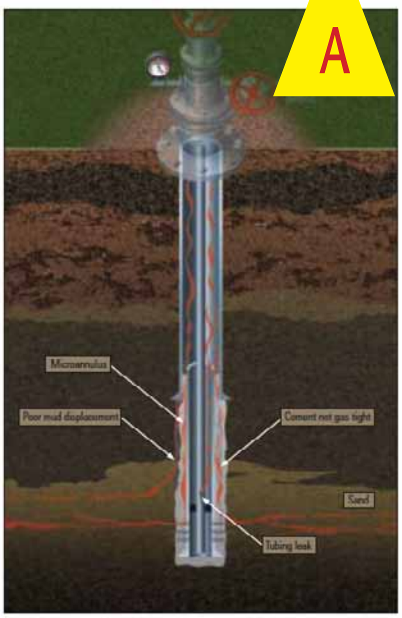
Poor mud displacement—Inadequate removal of mud or spacer fluids prior to cement placement may result in failure to achieve zonal isolation. There are several reasons for mud-removal failure, including, but not limited to, poor borehole conditions, improper displacement mechanics and failures in displacement process or execution. Inadequate removal of mud from the borehole during displacement is a major contributing factor to poor zonal isolation and gas migration. Mud displacement is discussed in greater detail (see "From Mud to Cement," page 66).

B

Improper cement-slurry design—Flow occurring before cement has set is a result of loss in hydrostatic pressure to the point that the well is no longer overbalanced—hydrostatic pressure is less than formation pressure. This decrease in hydrostatic pressure results from several phenomena that occur as part of the cement-setting process.[3] The change from a highly fluid, pumpable slurry to a set, rock-like material involves a gradual transition of the cement from fluid to gel and finally to a set condition. This may require several hours, depending on the temperature, quantity and characteristics of retarding compounds added to prevent setting of the cement prior to placement. As the cement begins to gel, bonding between the cement, casing and borehole allows the slurry to become partially self-supporting.

C

This self-supporting condition would not be a problem if it occurred alone. The difficulty arises because, while the cement becomes self-supporting, it loses volume as a result of at least two factors. First, where the formation is permeable, the hydrostatic pressure overbalance drives water from the cement into the formation. The rate of water loss depends on the pressure differential, formation permeability, the condition and permeability of any residual mudcake and fluid loss characteristics of the cement. A second cause of volume loss is hydration volume reduction as the cement sets. This occurs because set cement is denser and occupies less volume than the liquid slurry. Volume loss is relatively small at first, since little solid product forms during early hydration. However,



^ Scenarios for gas flow. Shown are possible scenarios of gas migration to the surface resulting in SCP. Tubing and packer leaks may allow gas to migrate. Microannului may develop soon or long after cementing operations. Poor mud displacement may result in inadequate zonal isolation. Gas may slowly displace residual nondisplaced drilling fluid, eventually pressurizing the annular space between tubing and casing strings. Gas may also flow through poorly designed nongas-tight permeable cement.

D — Even after a flawless cement job, the cement can still be damaged by the routine operation of the well. Also, the mechanical properties of casing and cement vary over time: differential expansion and contraction due to temperature, pressure or vibration can cause the bond between casing and cement to fail.

D

ultimately the volume loss can be as much as 6%.[10] Volume loss coupled with the interaction between partially set cement, borehole wall and casing causes a loss of hydrostatic pressure, leading to an underbalanced condition.

While the hydrostatic pressure in the partially set cement is below formation pressure, gas may invade. If unchecked, the invasion of gas may create a channel through which gas can flow, effectively compromising cement quality and zonal isolation.

Free water in cement may also cause a channel. Under static conditions, slurry instability may lead to water separating from a cement slurry. This water may migrate to the borehole wall and collect, forming a channel. This is of particular concern in deviated wellbores where gravity may drive density separation and fluid inversion, resulting in the development of a free-fluid channel on the top side of the borehole.

Cement damage after setting—SCP can occur long after the well-construction process. Even a flawless primary cement job can be damaged by rig operations or well activities occurring after the cement has set. Changing stresses in the wellbore may cause microannuli, stress cracks, or both, often leading to SCP.[11]

The mechanical properties of casing and cement vary significantly. Consequently, they do not behave in a uniform manner when exposed to changes in temperature and pressure. As the casing and cement expand and contract, the bond between the cement sheath and casing may fail, causing a microannulus, or flow path, to develop.

Decreasing the internal casing pressure during completion and production operations may also lead to microannuli development. Underbalanced perforating, gas-lift operations or increased drawdown in response to reservoir depletion all reduce internal casing pressure.

Any of these conditions—tubing or casing leaks, poor mud displacement, improper cement system design or damage to cement after setting—may result in flow paths for gas in the form of discrete conductive cement fractures, or microannuli. Once the gas-migration mechanism is understood, steps can be taken to mitigate the process.

Controlling Gas Migration

As the borehole reaches deeper into the earth, previously isolated layers of formation are exposed to one another, with the borehole as the conductive path. Isolating these layers, or establishing zonal isolation, is key to minimizing the migration of formation fluids between zones or to the surface where SCP would develop. Crucial to this process are borehole condition, effective mud removal, and cement-system design for placement, durability and adaptability to the well life cycle.

Wellbore condition depends on many factors, including rock type, formation pressures, local stresses, the type of mud used and drilling operational parameters, such as hydraulics, penetration rate, hole cleaning and fluid-density balance.

The ultimate condition of the borehole is often determined early in the drilling process as drilling mud interacts with newly exposed formation. If mismatched, the interaction of the drilling mud with formation clays can have serious detrimental effects on borehole gauge and rugosity. Once a well is drilled, displacement, cementing and ultimately, zonal-isolation efficiency are dependent on a stable borehole with minimal rugosity and tortuosity.

Mud companies have created high-performance water-base muds that incorporate various polymers, glycols, silicates and amines, or a combination thereof, for clay control. Today, water-base and nonaqueous invert-emulsion fluids account for 95% of all drilling fluids used. The majority, about 70%, are water-base and range from clear water to mud that is highly treated with chemicals.

Drilling fluid engineers and related technical specialists have applied various techniques to investigate rock response to drilling fluid chemistry; these include exposing core samples to drilling fluids under simulated downhole conditions and physical examination of core and cuttings with scanning electron microscopy.[12] The results are often inconsistent, so drilling fluid selection often is based simply on field history. Many times, particularly in new fields where formation clay chemistry may be unknown, effective field development may hinge on understanding the nature of formation clays as they vary with depth [above].

^ Cuttings response to drilling fluids. Cuttings samples were taken from a well in the southern Gulf of Mexico drilled with oil-base mud; these cuttings had not been exposed to water-base mud prior to testing. After cleaning oil from the cuttings surface, Schlumberger laboratory technicians sorted the rock pieces. Three initially identical samples of rock were photographed after receiving a different treatment. Sample A (*left*) was placed in tap water, Sample B (*middle*) into a generic lignosulfonate drilling fluid and Sample C (*right*) was immersed in a glycol-polymer-potassium chloride fluid. Each sample was rolled in a stainless-steel cell in a hot-roll oven for 16 hours at 250°F [121°C] to simulate drilling and transport up the borehole to surface. The sample in tap water, Sample A, was most damaged, and Sample C in the glycol-polymer-potassium chloride fluid was essentially undamaged. The lignosulfonate system generated intermediate damage for Sample B. Drilling with a mud having low inhibition values would be expected to generate borehole instability and washout. In contrast, excellent clay control would be obtained by a more advanced chemistry, such as glycol-polymer-potassium chloride.

6. For more on zonal isolation: Abbas R, Cunningham E, Munk T, Bjelland B, Chukwueke V, Ferri A, Garrison G, Hollies D, Labat C and Moussa O: "Solutions for Long-Term Zonal Isolation," *Oilfield Review* 14, no. 3 (Autumn 2002): 16–29.
7. Bonett A and Pafitis D: "Getting to the Root of Gas Migration," *Oilfield Review* 8, no. 1 (Spring 1996): 36–49.
8. Bourgoyne A, Scott S and Manowski W: "Review of Sustained Casing Pressure Occurring on the OCS," http://www.mms.gov/tarprojects/008/008DE.pdf (posted April 2000).
9. Wojtanowicz AK and Zhou D: "New Model of Pressure Reduction to Annulus During Primary Cementing," paper IADC/SPE 59137, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 23–25, 2000.
10. Parcevaux PA and Sault PH: "Cement Shrinkage and Elasticity: A New Approach for a Good Zonal Isolation," paper SPE 13176, presented at the 59th SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, September 16–19, 1984.
11. A microannulus is a small gap between cement and a pipe or a formation. This phenomenon has been documented by running sequential cement bond logs, first with no pressure inside the casing and then with the casing pressured. The bond log clearly indicates that applied pressure often closes a microannulus.
12. Galal M: "Can We Visualize Drilling Fluid Performance Before We Start?" paper SPE 81415, presented at the SPE 13th Middle East Oil Show & Conference, Bahrain, June 9–12, 2003.

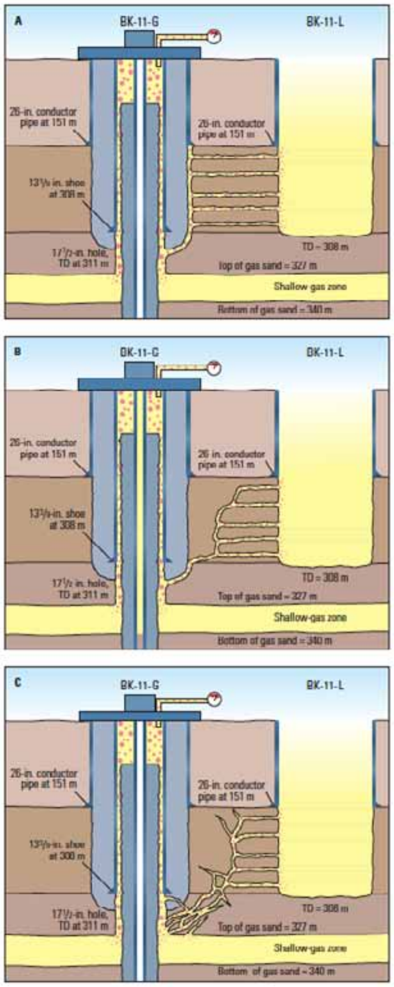
These three drawings illustrate a concern over migration from non-target shallow gas zones through vertical fractures into non-gas-bearing sand formations as a result of poorly bonded cement.

[1017 ft], then drill a 12¼-in. borehole through the shallow gas sand and set 9⅝ in. casing at about 500 m [1640 ft]. Zonal isolation behind the 9⅝-in. casing was critical to the success of the project. Even though a gas-tight, or gas-influx-resistant, cement-slurry design was used, the first three 9⅝-in. casing primary cement jobs failed, resulting in both SCP at the surface and gas charging of upper-zone normally pressured sands [right].

Although not under contract for the project, Schlumberger and M-I engineers working in conjunction with PTTEP and their partners, Total and BG, proposed a plan to integrate borehole stabilization with mud displacement and cement-system design.

The shallow formations in the 12¼-in. section consisted primarily of sand and shale, 30 to 40% of which was reactive clay. Historically, conventional water-base muds had been used to drill these formations, resulting in significantly washed-out sections, poor displacements, inadequate primary cement placement and loss of zonal isolation.

The M-I engineering team recommended controlling the borehole and cuttings integrity with SILDRIL mud, a sodium-silicate-base drilling fluid. The objective was to obtain a near-gauge borehole allowing optimized casing centralization, mud displacement and cement placement across the gas-bearing sand.



> Scenarios for upper-sand charging. In early drilling operations, previously nongas-bearing upper sands were charged with gas. Several scenarios were developed to explain gas crossflow between Wells BK-11-G and BK-11-L, and the development of SCP at surface. Gas is shown as red bubbles originating in the shallow-gas sand. In the three scenarios shown, gas migrates around poorly bonded cement (A). Gas moves around poorly bonded cement to vertical fractures (B). It migrates around poorly bonded cement and through a microfracture network (C). In all cases, primary cement failed to provide zonal isolation, resulting in gas migration to both upper sands and between casing strings, resulting in SCP.

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From Mud to Cement—Building Gas Wells

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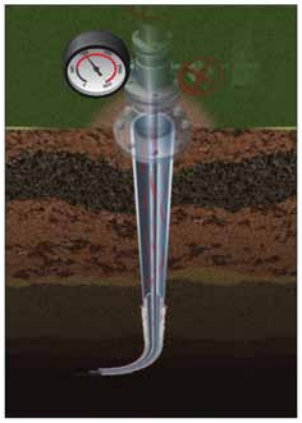
As demand for natural gas increases, wellbore construction across gas-bearing formations takes center stage. With few cost-effective remedial measures available, prevention of annular gas flow and sustained casing pressure is key to drilling and completing long-lasting gas wells.



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This and previous 2 pages from "From Mud to Cement—Building Gas Wells".

Evaluation of the Potential for Gas and CO_2 Leakage Along Wellbores

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Summary

Implementation of carbon dioxide (CO_2) storage in geological media requires a proper assessment of the risk of CO_2 leakage from storage sites. Leakage pathways may exist through and along wellbores, which may penetrate or be near to the storage site. One method of assessing the potential for CO_2 leakage through wells is by mining databases that usually reside with regulatory agencies. These agencies collect data concerning wellbore construction, oil and gas production, and other regulated issues for existing wells.

most likely to leak or have future abandonment liability and if these wellbores will impact CO_2-storage schemes adversely in the future. The analysis is based on data for more than 315,000 wells drilled up to the end of 2004 in the province of Alberta.

Background

Potential Wellbore-Leakage Pathways. Figs. 1a and 1b illustrate typical wellbore-construction and -abandonment profiles for Alberta. From these diagrams, one can identify potential leakage

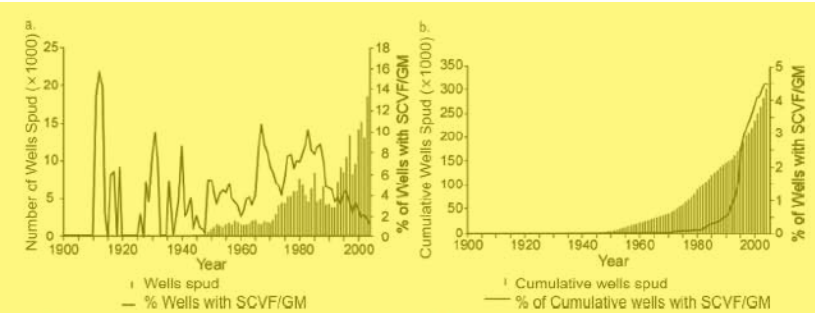


Fig. 8—Historical levels of drilling activity and SCVF/GM occurrence in Alberta: (a) by year of well spud and (b) by cumulative wells drilled.

These charts show a correlation of increased well failures over time, by year of well spud, and cumulatively.

Nonroutine-abandonment information includes reported openhole plug failures, re-entry information, and other special abandonment requests and approvals. This information was used to provide a baseline of known wellbore leakage against which potential indicators can be evaluated. **Fig. 8** shows historical drilling activity and occurrence of SCVF in Alberta over the last 100 years, both as a percentage of wells spudded in a given year and as cumulative over time.

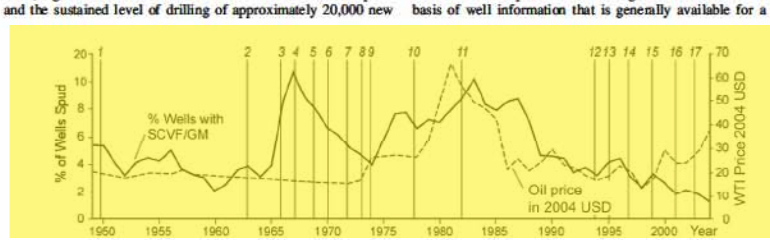
Historical documents within the ERCB's archive library were reviewed to determine regulatory changes that may have impacted the potential for wellbore leakage. **Fig. 9** indicates important historical regulatory changes against the occurrence of SCVF/GM in time. The archives were also used to develop an electronic-data table of historical primary-cementing requirements. Actual annular cement-top information was not available within the existing electronic information, and the historical-regulation requirement was used as a default for the cement top in the wellbore. The historical oil price, obtained from public sources and expressed in constant USD, was used as an indicator for the level of economic activity that potentially could have affected drilling, well completion, and well abandonment practices. Because the data mining was performed in 2005 based on the data to the end of 2004, Figs. 8 and 9 do not include the recent increase in oil price and the sustained level of drilling of approximately 20,000 new wells per year; however, the absence of these very recent data do not affect the conclusions of the study because very few of the newly drilled wells have been abandoned.

Casing-inspection logs that indicated both internal and external corrosion were evaluated against cement-bond logs (or equivalent). Data were collected for approximately 500 wells. These wells were selected for analysis on the basis of the existence of both SCVF/GM and casing failure in the same well or on the basis of geographic location in fields known to have a high incidence of SCVF/GM or casing failure. Information on casing and cement condition were recorded against a depth register to determine the effects of cementing on casing corrosion. A smaller subset of these wells (142) had adequate data to conduct full evaluations.

Alberta Environment, the provincial agency responsible for the protection of nonsaline groundwater, maintains and is currently updating a public database that indicates the depth, either in meters or by formation, to which groundwater must be protected. This information was used to determine groundwater depths compared to surface-casing, annular-cement, and casing-failure depths.

Results

Various factors were investigated using the assembled database to determine if the potential for leakage could be assessed on the basis of well information that is generally available for a large



1. Oil and Gas Act
2. First SC requirements
3. First cement requirements
4. Update of SC requirements
5. Update of SC and cementing requirements
6. Intermediate casing
7. Conductor pipe requirements
8. Update of SC requirements for SE Alberta
9. Update of SC requirements for south-central Alberta
10. Cementing guide
11. Update of cementing guide
12. Requirements for GW protection and SCVF checking
13. 10-year inactive well program initiated
14. Well abandonment guide, sour well licensing
15. Requirements for SCVF/GM testing
16. Long Term Liability program replaces 10-year inactive well program
17. Update of allowable gradient for serious SCVF

Fig. 9—Occurrence of SCVF/GM in Alberta in relation to oil price and regulatory changes (SC: surface casing, GW: ground water, WTI: West Texas Intermediate).

This chart shows a correlation of migration in wells with SCVF with oil price changes, suggesting a trend to less vigilance at times of increased financial pressure.

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TABLE 2—COMPARISON OF SCVF/GM OCCURRENCE IN THE PROVINCE TO THE TEST AREA				
	Alberta	Test Area	Percentage in the Test Area	Deviated Wells in the Test Area
Total number of wells	316,439	20,725	6.5%	4,560
Wells with SCVF	12,458	1,902	15.3%	1,472
Wells with GM	1,843	1,187	64.4%	1,550
Wells with GM/SCVF	176	116	65%	–
SCVF percentage	3.9%	9.2%	–	32.3%
GM percentage	0.6%	5.7%	–	34%
Combined percentage	4.6%	15.5%	–	66%

Table data on increased well failure rate in deviated (E. G. horizontal) wells over all wells.

the occurrence of wellbore leakage. In areas of high well density, well-to-well cross flow may occur and result in a single well leaking to surface through many nearby wellbores. However, this was not supported in the analysis of the test area. One possible reason is that areas with higher well density comprise newer wells that may not have been tested sufficiently or that are cemented better. Because this factor has been reported in other studies, it has been retained as a minor factor for this analysis.

Topography. Information about serious SCVFs and GM flows, saline-water flows, and liquid-hydrocarbon flows at wells located in or near river valleys has been reported anecdotally, and in some cases has been well documented, such as in the case of a well in the valley of Peace River in Alberta that discharged brine and natural gas for decades (Bellis et al. 2004). River valleys may facilitate GM and SCVF because of the removal of overburden. This reduction in elevation reduces the available hydrostatic pressure that controls flows to surface. The potentially shallow overpressured gas zones (in comparison to elevation at drill location) pose problems in well control and have a higher potential for GM through cement even in properly cemented wellbores (Gonzalo et al. 2005). However, data analysis did not find a strong correlation between topography and SCVF/GM occurrences.

Factors Showing Major Impact. ***Geographic Area.*** Fig. 5 indicates a specific test area within the province of Alberta. In the test area, it is required by regulation to conduct GM testing on all wells. **Table 2** summarizes the occurrence of SCVF/GM in the entire province compared to the test area. It is not clear if the extra testing requirements in this area result in a greater percentage of leaks being reported or if the occurrence rates are actually higher. It is presumed that the ERCB designated this area for special consideration because of observed problems, and thus, it is likely that the data accurately identify wells in this area as having a higher probability of leakage.

Wellbore Deviation. For the purpose of this study, any well with total depth greater than the true vertical depth was considered a deviated or slant well. Wells were investigated within the test area because both SCVF and GM testing is required in this area, hence the data set is more complete. Table 2 and **Fig. 11** summarize the data. From these results, it appears that well deviation does not significantly affect whether a well will have GM or SCVF because the occurrence rate is similar. However, the occurrence of GM and SCVF is higher in deviated wells than in vertical wells, indicating that wellbore deviation is a factor affecting overall wellbore leakage. Mechanical aspects such as casing centralization and cement slumping may contribute to the increased incidence of wellbore leakage in deviated wells (Jakobsen et al. 1991).

Well Type. Drilled and abandoned wells had reported SCVF/GM leakage-occurrence rates of approximately 0.5%. The overall leakage-occurrence rate reported for all wells, as shown in Fig. 8, is approximately 4.5%. Wells cased and abandoned have an overall leakage-occurrence rate of approximately 14%, with cased wells accounting for mo than 98% of all leakage cases reported. This difference may be ibuted to more-stringent abandonment requirements for drill abandoned wells historically.

Wells cased, completed, and abandoned have another potential leak path inside of the casing because of the perforated, or otherwise-completed, interval (see Fig. 1b).

Abandonment Method. The abandonment method in cased and completed wells in Alberta is predominately bridge plugs capped with cement. Investigations into the security of this abandonment method indicated that overall, bridge plugs held a pressure test of 7000 kPa in 90% of cases investigated in a small sampling of wells re-entered for production purposes. These bridge plugs had been in service for 5 to 30 years. Generally, the cement cap placed on top of the bridge plug was not evident, even though a tour-report review indicated that the cement had been dump bailed on the bridge plug. It is estimated from experience and from this small sample that, over a long period of time (hundreds of years), approximately 10% of these types of zonal abandonments will fail and allow formation gases to enter the wellbore. Other abandonment methods, such as placing a cement plug across completed intervals using a balanced-plug method or setting a cement retainer and squeezing cement through perforations, are expected to have lower failure rates long into the future.

In situations where CO_2 may have been injected for storage into depleted producing formations, bridge-plug failures may be higher because of CO_2 effects on the elastomers and metal used in the mechanical-plugging device (Schremp and Roberson 1975).

The final barrier to reservoir gases escaping to the overlying soil and the atmosphere is the welded casing cap. From investigations on well re-entry, these caps are highly unreliable. However, the casing-cap failures may in fact reduce the risk of overpressuring the surface-casing shoe, uncemented formations, and groundwater aquifers. Small leaks in the cap may act as an early warning that the wellbore integrity has been compromised. These leaks are generally identified as soil GM and are observed as dead vegetation directly above the abandoned wellbore.

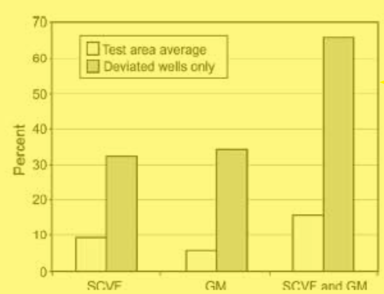

Fig. 11—Comparison of the occurrences of SCVF/GM in all the wells in the test area in Alberta (see Fig. 5) and in deviated wells only in the same region.

This bar graph shows increased well failure rate in deviated (E. G. horizontal) wells over all wells.

"The occurrence of SCVF is higher in deviated wells than vertical wells, indicating that well bore deviation is a factor affecting overall well leakage."

This study explores the issue of migration long after a well has ceased production and has been plugged:

"Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing.

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Why Oilwells Leak: Cement Behavior and Long-Term Consequences

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Abstract

Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing. Assuming this hypothesis is robust, it must lead to better practice and better cement formulations.

Introduction, Environmental Issues

This discussion is necessarily superficial, given the complexity of the issue and attendant practical factors such as workability, density, set retardation, mud cake removal, entrainment of formation gas, shale sloughing, pumping rate, mix consistency, and so on. A conceptual model will be developed in this article to explain slow gas migration behind casing, but we deliberately leave aside for now the complex operational issues associated with cement placement and behavior.

In 1997, there were ~35,000 inactive wells in Alberta alone, tens of thousands of abandoned and orphan wells[1], plus tens of thousands of active wells. Wells are cased for environmental security and zonal isolation. In the Canadian heavy oil belt, it is common to use a single production casing string to surface (Figure 1); for deeper wells, additional casing strings may be necessary, and surface casing to isolate shallow unconsolidated sediments is required. As we will see, surface casings have little effect on gas migration, though they undoubtedly give more security against blowouts and protect shallow sediments from mud filtrate and pressurization.

To form hydraulic seals for conservation and to isolate deep strata from the surface to protect the atmosphere and shallow groundwater sources, casings are cemented using water-cement slurries. These are pumped down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden (Figure 1). Casing and rock are prepared by careful conditioning using centralizers, mudcake scrapers, and so on. During placement, casing is rotated and moved to increase the sealing effectiveness of the cement grout. Recent techniques to enhance casing-rock-cement sealing may include vibrating the casing, partial cementation and annular filling using a small diameter tube.

Additives may be incorporated to alter properties, but Portland Class G (API rating) oil well cement forms the base of almost all oil well cements.[2] Generally, slurries are placed at densities about 2.0 Mg/m^3, but at such low densities will shrink and will be influenced by the elevated pressures (10-70 MPa) and temperatures (35 to >140°C) encountered at depth.

The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on.

Methane from leaking wells is widely known in aquifers in Peace River and Lloydminster areas (Alberta), where there are anecdotes of the gas in kitchen tap water being ignited. Because of the nature of the mechanism, the problem is unlikely to attenuate, and the concentration of the gases in the shallow aquifers will increase with time.

This implies that current standards for oilwell cementing and P&A are either not well founded, or the criteria are based on a flawed view of the mechanism. This is not a condemnation of industry: all companies seek to comply with standards.[3] Nevertheless, we believe that the AEUB Interim Directive 99-03[4] is flawed with respect to gas leakage around casings. To rectify this, the mechanisms must be identified correctly. Practise can then be based on correct physical mechanisms, giving a better chance of success (though we do not believe

"Strength is not the major issue in oil well cementing under any circumstances... cement cannot resist the shear that is the most common reason for oil well distortion and rupture during operation..."

Cement Strength and Rigidity. API standards for oilwell cement specify certain strength criteria. Strength is not the major issue in oil well cementing under any circumstances. Based on extensive modelling, cement clearly cannot resist the shear that is the most common reason for oilwell distortion and rupture during active production.[13] If compaction or heave (from solids injection) is taking place, the cement itself provides minimal resistance to buckling (compression) or thread popping (tension). If the annulus could be filled with relatively dense sand, the resistance to shear would be better than current ordinary oilwell cement formulations.

Based on over 50 triaxial tests at various confining stresses, we have shown that 28-day cured oilwell cements are contractile (volume reduction during shear) at all confining stresses above 1 MPa (150 psi). This is also the case for 70% silica flour cements, and for the new products based on extremely finely ground cement. (Specimens were cured under water at 20°C or at 90°C.) However, dense concretes used in Civil Engineering are dilatant, and therefore resistant to shear, at all working stresses.

The stiffness modulus of typical oilwell cement is small compared to that of low porosity rocks, and vastly lower than that of steel.[14] The stiffness moduli are roughly 2-4% that of steel, though there is a wide range depending on density, content, and confining stress. Depending on depth (~stress) and induration (~porosity), rock moduli may vary from 2% to 50% of steel, and a reasonable value is 5-15% in most intermediate cases of moderate porosity (10-20%).

Bond. Cement will not bond to salt, oil sand, high porosity shale, and perhaps other materials. Also, bond strength (i.e. the tensile resistance of the cement-rock interface) is quite small; in fact, the tensile strength of carefully mixed and cured oilwell cement at recommended formulations is generally less than 1-2 MPa. Given that fluid pressures of 10's of MPa may have to be encountered, given that pressure cycling of a well can easily debond the rock and cement (there is strain incompatibility because of the different stiffnesses), and given that de-bonding is generally a fracturing process with a sharp leading edge rather than a conventional tensile pull-apart process, a large cement bond to rock cannot be assumed in any reasonable case. Initiation and growth of a circumferential fracture ("micro-annulus") at the casing-rock interface will not be substantially impeded by a cohesive strength at this interface.

The presence of "good bond" on a cement bond log is in fact not an indicator of bond, but an indicator of intergranular contact maintained by a sufficient radial effective stress. The lack of bond on a bond log is actually evidence of the inability to transmit high frequency sonic impulses because of the presence of an "open zone", that is, a circumferential fracture that is open by at least a few microns. Thus, maintaining "bond" actually means maintaining effective radial stress. Note that if effective radial stress cannot be maintained, then hydraulic fracturing conditions must exist at the interface.

The Gas Leakage Model

A good conceptual model must explain the following typical aspects of oilwell behavior that are observed in practice.

- Generally there are no open circumferential fractures detectable after a typical good quality cement job ("good bond" is observed on the log traces).
- Such fractures develop over time and with service.
- Even in cases where bond appears reasonable over substantial sections of the casing, gas leakage may be evidenced some years or decades later.
- The process is invariably delayed; thus, there must be physically reasonable rate-limiting processes.
- The gas often appears at surface rather than being pressure injected into another porous stratum encountered in the stratigraphic column.
- The presence of surface casing provides no assurance against gas leakage.

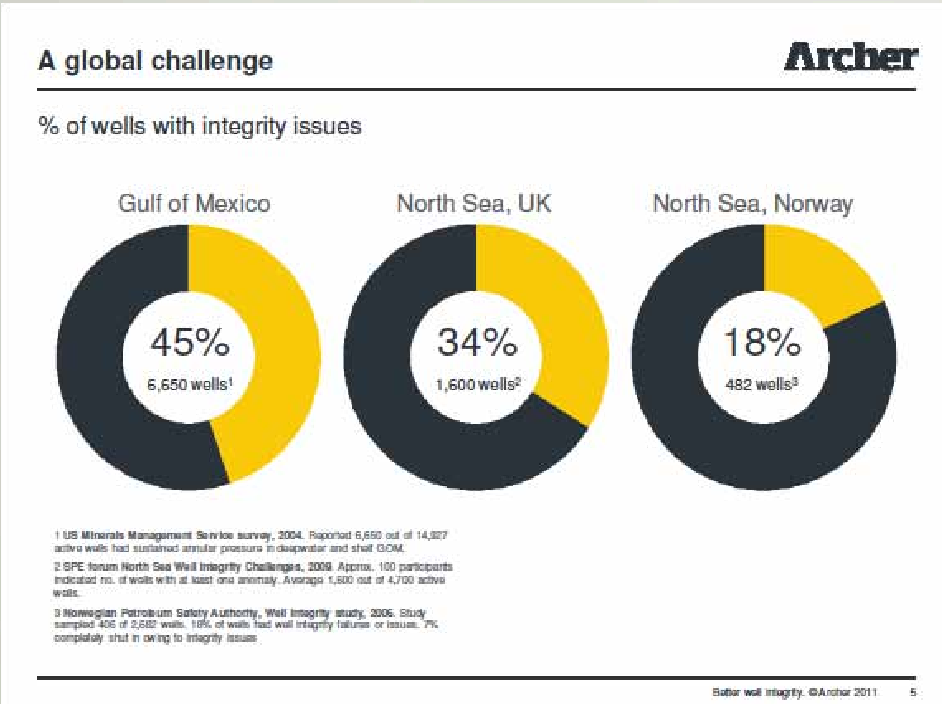
Whereas we do not deny that mud channeling, poor mud cake removal, gas channeling, and so on can occur in isolated cases, we believe that a better hypothesis exists to rationally explain the points listed above.

Figure 2 shows the effect of shrinkage on near-wellbore stresses. (Plots are qualitative, but have been confirmed by numerical modeling, to be published later.) Initially, cement pressure $p_c(z) = \gamma_c \cdot z$, almost always higher than p_o, but lower than σ_{hmin} (lateral minimum total stress). Set occurs and a small amount of shear stress develops between the rock and the cement; then, hydrostatic pressure in the cement is no longer transmitted along the annulus. Thereafter, even minor shrinkage (~0.1-0.2%) will reduce the radial stress ($\sigma_r = \sigma'_r + p_o$) between cement and rock because rock is stiff (4-20 GPa for softer rocks), and small radial strains (0.001-0.003) cause relaxation of σ_r and increase in σ_θ. A condition of $p_o > \sigma_r$ (σ_3) is reached; i.e. the hydraulic fracture criterion. A circumferential fracture (i.e. $\perp$ to $\sigma_3 = \sigma_r$), typically no wider than 10-20 µm, develops at the rock-cement interface.

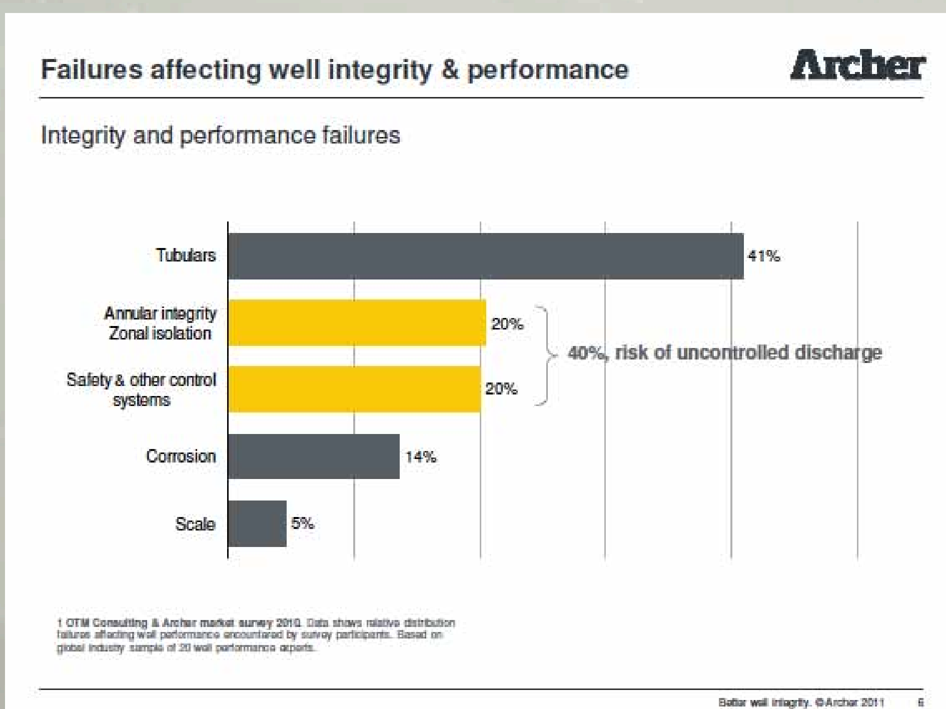
A thin fracture aperture is sufficient to appear as "loss of bond" in a geophysical bond log. Because in situ stresses are always deviatoric (e.g. $\sigma_{hmin} \neq \sigma_{HMAX}$), bond loss will usually appear first on one side of the trace, or on two opposite sides (direction of σ_{hmin}). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m.

A zone of $p_o > \sigma_r$ (σ_3) can extend for considerable heights. Nevertheless, this is still not a mechanism for vertical growth. To understand vertical growth, consider Figure 3, where a hypothetical case is presented. The static circumferential fracture of length L is filled with formation water of density γ_w, giving a gradient of about 10.5 kPa/m for typical oilfield brine, but the gradient of lateral stress ($\partial\sigma_h/\partial z$) is generally on the order of 18-24 kPa/m. This means that if the fracture contains a fluid pressure sufficient to just keep it open at the bottom, there is an excess pressure at the upper tip equal to ~L·(21-10.5) = about 10 kPa/m, in typical Alberta conditions, for example. Thus, because of the imbalance between the pressure gradient in the fracture and the stress gradient in the

"The presence of surface casing provides no assurance against gas leakage."



In this slide presentation, loss of well integrity is recognized as a ubiquitous and common problem.



20% of catastrophic well failures are due to loss of well bore integrity.

2010 REPORT TO THE

WATER QUALITY CONTROL COMMISSION
and
WATER QUALITY CONTROL DIVISION
of
THE COLORADO DEPARTMENT OF
PUBLIC HEALTH AND ENVIRONMENT

by
THE COLORADO OIL AND GAS CONSERVATION COMMISSION

provides quarterly reports on the status of the seep remediation and these status reports are available on the COGCC website (www.cogcc.state.co.us) under Library, Piceance Basin. The low-flow air sparge system designed to remediate shallow ground water contaminated with benzene, toluene, ethylbenzene, and total xylenes (BTEX), continues to decrease concentrations and areal extent of these compounds in the impacted area. The concentration and areal extent of thermogenic methane in the ground water in the impacted area also continues to decrease although at a lower rate than the BTEX compounds. There were no detections of BTEX compounds in any West Divide Creek surface water sample locations in 2010.

DeBeque Orphan Natural Gas and Oil Wells – Mesa County

The COGCC identified 11 orphaned natural gas or oil wells in Mesa County during 2010. Orphaned natural gas or oil wells are those for which the operators have gone out of business and no current operator of the wells can be located. Historic records were located for some of the orphaned natural gas wells indicating that they were drilled in 1911. Others are believed to have been drilled in the mid-1920's. Seven of the orphaned wells identified are discharging produced water to the ground surface from the surface casing; and water is flowing into nearby drainages, ditches or water features from four of those wells.

The COGCC has successfully plugged and abandoned one of the seven wells so that it is no longer discharging produced water. An attempt to plug and abandon a second orphan well was not successful because surface casing could not be located before the limits of the excavator were reached. The scope of work required to plug and abandon this orphan well exceeded that anticipated and funded. Funding from the COGCC emergency response appropriation will be used to plug this well and one of the others. The plugging and abandonment of the remaining orphan wells will be prioritized based on potential risk and impact to the environment, including ground and surface water resources, and public health and safety. Plugging and abandonment of these wells will proceed as time and funding allows.

Northeast Colorado

Oil and Gas E&P Activity

Oil and gas activity in the northeastern portion of the state remains high, although overall numbers of new permits are lower than previous years. In general this reflects the slowdown related to low natural gas prices. In 2010, approximately 36% of the total number of well permits approved by the COGCC was issued to operators in Weld County (Wattenberg Field), which has the largest number of active wells in the State. Smaller oil and gas fields with lower levels of activity are located in other counties throughout northeast Colorado. In 2010 approximately 172 billion cubic feet (BCF) of gas were produced in northeast Colorado (approximately 16% of the total gas production for the State) and 13 million barrels (bbls) of crude oil were produced (approximately 65% of the total crude oil production for the State).

Public Involvement

COGCC staff continues to receive and follow-up on complaints from the Weld County Department of Public Health & Environment, Tri-County Health Department, Larimer County Environmental Advisory Board, Morgan County Office of Emergency Management, Northeast Colorado Health Department, other municipalities, and the public throughout northeastern Colorado.

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Orphaned wells — wells that have been abandoned by their owners/operators and are no longer productive — are a migration pathway to aquifers and the surface.

Often, the original operator of a well is long gone, and there are insufficient funds to remediate these sources of contamination.

It is estimated that there are 35,000 abandoned wells in New York State. The locations of many are unknown.