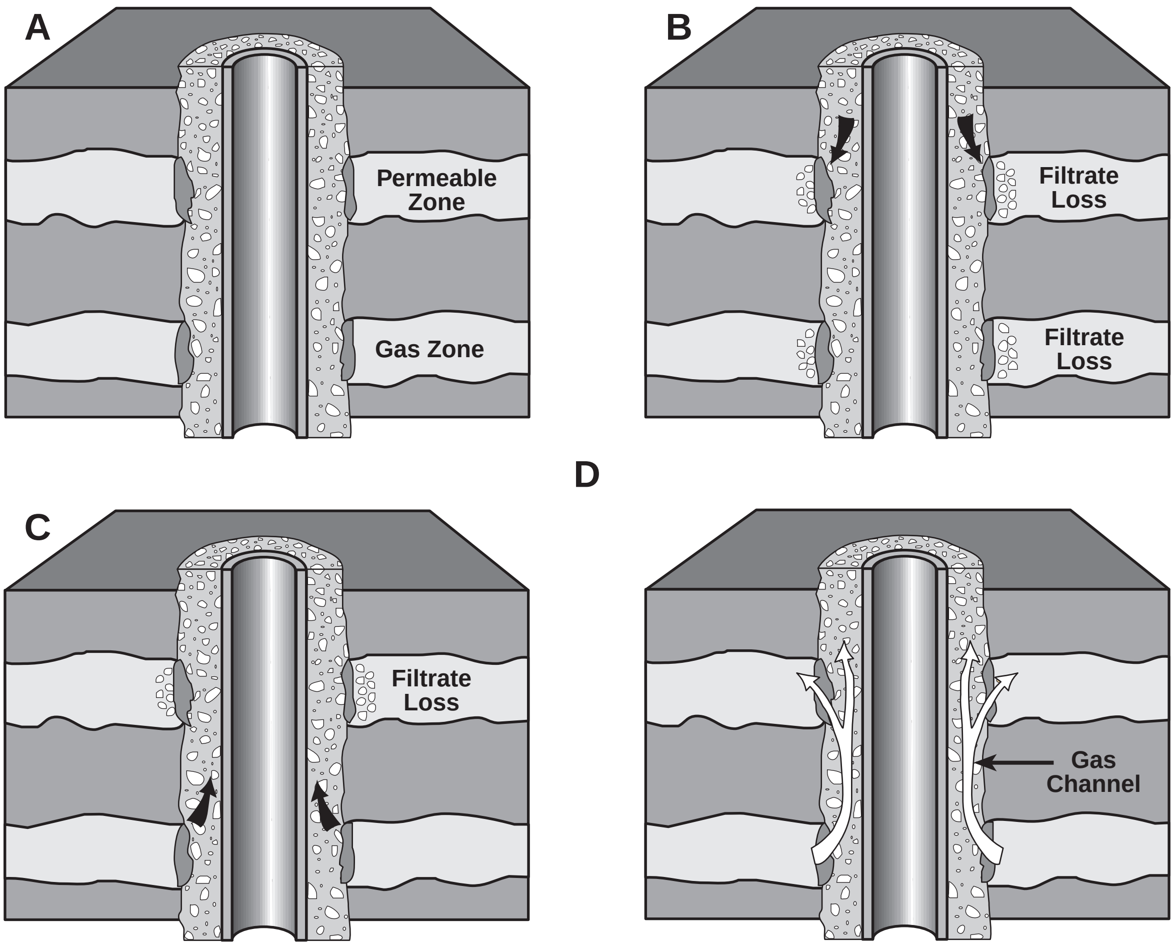

Figure 1: Gas channel migration: Gas migration creates permanent channels in cement columns, decreasing cement strength and contributing to continuing gas-flow problems. The most widely accepted explanation for short-term migration is the cement column's inability to maintain overbalance pressure. This pressure loss depnds on the cement's development of static gel stength, transition time and hydration volume reduction. There are 2 suspected causes of long-term migration: inadequate drilling fluid displacement and cement debonding. Inadequately displaced drilling fluid can prevent good bond formation between the pipe and cement and/or the cement and the formation. Incomplete displacement or excessive filter-cake buildup can create drilling fluid channels in the cement. Over time, gas flow causes the drilling fluid and cake to dehydrate and shrink, resulting in a highly permeable pathway for gas.

Predicting potential gas-flow rates to help determine the best cementing practices

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GAS MIGRATION CREATES permanent channels in cement columns, decreasing cement strength and contributing to continued gas-flow problems. However, operators can accurately predict the potential of their wells to be troubled by gas flow. Based on the severity of the gas flow problems expected, the operator can avoid remedial squeeze jobs by determining the most effective cementing strategy for the situation.

"Annular gas flow", "gas migration", and "gas leakage" are all terms that refer to formation gas that enters a cemented casing/borehole annulus, creating permanent channels and weakening cement compressive strength. There are two major types of gas migration: short-term and long-term. Short-term gas migration occurs before the cement sets, and long-term gas migration develops after the cement has set. **Sutton**, **Sabins** and **Faul**[1,2] published definitive work in 1984 presenting (1) annular gas-flow theory and evaluation for annular gas-flow potential, and (2) tracing the evolution of gas-flow theory and preventive practices.

CAUSES OF SHORT-TERM MIGRATION

The most widely accepted cause of short-term gas migration is the cement column's inability to maintain overbalance pressure. This pressure loss depends on 3 factors: the cement's development of static gel strength (SGS), transition time, and hydration volume reduction.

Static Gel Strength. In a true fluid system, hydrostatic pressure is present. After the cement slurry is placed downhole, it initially acts as a fluid and exerts hydrostatic pressure on the gas-bearing formation. This overbalance pressure helps prevent

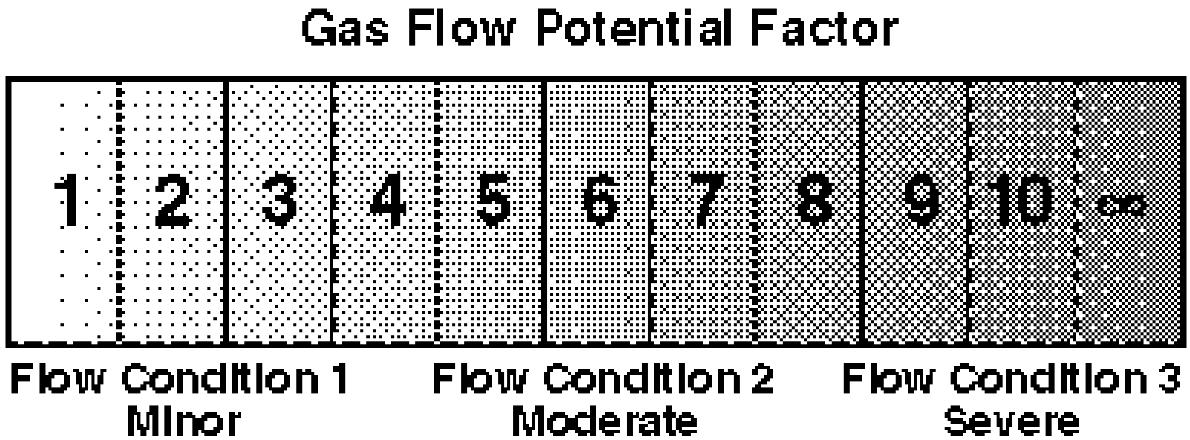

Figure 2: The gas-flow potential factor (GFP) is the estimated amount of gas flow that can be expected from a formation. Operators can use this factor to help determine the most effective cementing system for controlling gas migration. The system should produce effective control at the least expense without producing technological "overkill". The GFP is proportional to the product of the maximum pressure loss and the overbalance pressure.

gas from percolating up through the cement slurry. However, the cement slurry eventually begins to develop static gel strength (SGS) as it sets. Gelation causes the slurry to adhere to the casing and the formation, allowing it to support its own weight. This process reduces the capability of the cement column to transmit hydrostatic pressure and allows gas to enter the annulus and percolate through the gelled cement (Figure 1). Once the gas begins to migrate, it will continue to percolate at a rate proportional to the volume reductions occurring in the slurry until the cement has developed enough gel strength to prevent further percolation. Once a flow channel develops, there is no level of gel strength that can cause the channel to heal; the channel is permanent and can be removed only by remedial (squeeze) cementing.

A cement column's loss of the capability to transmit hydrostatic pressure is directly proportional to its level of static gel strength (SGS) development. The length and diameter of the cement column also affect hydrostatic pressure loss. The relationship between expected maximum pressure restriction and SGS development can be expressed by the following equation:

$$MPR = SGS/300 \times L/D$$

Where

MPR = Theoretical maximum pressure restriction, psi
SGS = Static gel strength, lb/100 sq ft
300 = Conversion factor (to obtain MPR in psi), lb/in.
L = length of the cement column, ft
D = effective diameter of the cement column, in. (hole diameter minus pipe diameter)

In this case, MPR is a change in hydrostatic pressure that results from the development of static gel strength.

The development of static gel strength is not completely detrimental. A certain level of SGS can prevent gas from percolating through the unset cement matrix. The exact SGS level is unknown; however, laboratory and field results show that a 500 lb/100 ft2 SGS can prevent gas from percolating or channeling through unset cement. If the hydrostatic pressure falls below the formation pressure before this SGS develops, gas will usually begin to percolate through the cement matrix, forming a permanent channel.

Transition Time. Transition time is the time interval between the development of the first measurable SGS and the point at which the cement slurry is so rigid that a new gas channel cannot form. Cement slurries undergo a phase transformation from liquid to solid after placement. During this transformation, the cement behaves neither as a solid nor as a fluid, but it retains some of the properties of each. In this stage, the SGS of the cement slurry steadily increases as a result of hydration. The first measurable SGS development occurs as the slurry starts the transition from a true hydraulic fluid, capable of transmitting full hydraulic loads, to a solid having compressive strength. The point at which the slurry loses the capability to fully transmit hydrostatic pressure is referred to as the "start of transition time." Throughout the rest of the transition time, the slurry will continue to gain SGS.

Cement Slurry Volume Reductions. Reduced cement-slurry volume also reduces hydrostatic pressure. Hydrostatic pressure remains constant in a true fluid system where no fluid loss occurs. However, cement slurries do not behave as true fluids; instead, they develop SGS before setting, preventing full transmission of hydrostatic pressure. Any fluid loss from the fluid system during the transitional period causes a corresponding loss in hydrostatic pressure. This pressure loss can be substantial enough to cause complete loss of overbalance pressure. Fluid loss additives limit the rate and volume of fluid loss from the cement slurry, thereby limiting the hydrostatic pressure losses caused by slurry volume reductions.

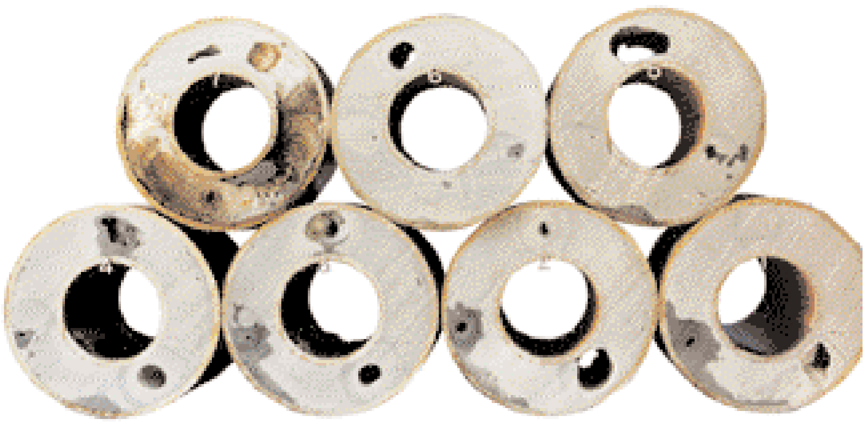

Figure 3: Test cores of cement subjected to gas flow of 6 liter/min before the slurry achieved adequate gel strength. Controling gas flow depends on the severity of the problem. For small gas-flow potentials, fluid-loss control may be sufficient. For moderate GFPs, exceptional fluid-loss control techniques are called for. In severe cases, especially high-temperature wells, fluid-loss control additives, job modifications and delayed gelling agents alone are not enough. Highly compressible cements are needed in these situations.

LONG-TERM GAS MIGRATION

Long-term or "delayed-onset" gas migration occurs some time after the cement job has been performed and is considered successful. As with short-term gas migration, once gas flow channels have set in the cement, they can only be removed by remedial squeeze cementing.

Long–term gas migration is generally indicated by flow at the surface through the annulus. Sometimes this becomes apparent as early as a few weeks after the cement job has been performed. Flow volumes are slight-to-moderate and become more severe over time.

Causes of Long-Term Gas Migration. There are two suspected causes of long-term gas migration: inadequate drilling fluid displacement and cement debonding. Inadequately displaced drilling fluid can prevent a good bond from forming between the pipe and the cement and/or the cement and the formation. Incomplete displacement or excessive filter-cake buildup can create drilling fluid channels in the cement. As time passes, gas flow causes the drilling fluid and cake to dehydrate and shrink, resulting in a highly permeable pathway for gas migration.

Long-term gas migration can also occur when set cement separates from the casing. One reason for this loss of bond is that the casing diameter changes during workovers or stimulation treatments. The resulting long-term gas migration occurs through a discontinuity in the cement sheath, either through micro-flow channels in the drilling fluid or through microannuli between the pipe and the cement or between the formation and the cement.

When gas is flowing through drilling fluid channels and filter cake, the flow volume can usually be expected to increase as the drilling fluid dehydrates and shrinks. Cement also naturally undergoes a minor volume reduction during the setting process. The magnitude of this volume reduction increases further when fluid is lost from the cement slurry. For these reasons, fluid-loss values should be set at low but realistic levels to help prevent excessive volume reductions. Operators should also pay close attention to obtaining the highest drilling fluid displacement efficiency possible.

GAS-FLOW POTENTIAL

The gas-flow potential factor (GFP) is the estimated amount of gas flow that can be expected from a formation (Figure 2). Operators can use this factor to help determine the most effective cementing system for controlling gas migration. The system should produce effective control at the least expense to the customer without producing technological "overkill." The following equation can be used to determine the gas-flow potential factor:

GFP = MPR/OBP

Where

GFP = Gas-flow potential factor

MPR = 1.67 LD (maximum pressure loss possible at 500 lb/100 sq ft static gel strength value), psi

OBP = Overbalance pressure (hydrostatic pressure minus the formation pressure), psi

GFP is a dimensionless number indicating the estimated severity or potential for encountering gas migration. This equation uses a static gel strength value of 500 lb/100sq ft because SGS of this magnitude will not permit gas percolation.

GFP Ranges. A gas-flow potential factor of less than 1.0 theoretically signifies no gas leakage problem. Nominal fluid loss control and mud displacement techniques should help prevent any gas leakage problems in such a situation. If the GFP is in the range of 1 to 5, changes in the cement job parameters, including mud densities, cement densities, cement column length, and back pressure can lower the GFP to an acceptable level. When job changes cannot produce a GFP of less than 1.0, operators can increase slurry compressibility or its thixotropic properties to help prevent gas migration. Thixotropic slurries that produce low fluid losses have been used successfully in formations with high GFP values (over 10). For a GFP greater than 5.0, a combination of low fluid loss additives, special thixotropic cement and increased slurry compressibility can result in high success rates. Some 70% of all compressible cement jobs are for well conditions showing GFP values between 1.0 and 9.0; in this range, the success ratio is above 90%. Successful compressible cement applications have even been performed for conditions showing GFP values up to 15.0.

The maximum GFP limit for a specific technique is influenced by gas-zone productivity. Whether due to low permeability or formation damage, a gas source with very low productivity will tolerate a higher GFP without resulting in gas leakage. Although compressible and thixotropic cements owe their effectiveness to changing the slurry compressibility and/or the transition time, these changes do not change GFP or MPR values. Increasing the slurry compressibility and decreasing the transition time decreases initial hydrostatic overbalance (DP) (the maximum pressure loss caused by volume reduction during the transition time). This technique is effective when DP is reduced to a point below MPR.

GAS MIGRATION CONTROL SYSTEMS

A hands-on, interactive analysis system can model downhole conditions. For any gas flow situation, this program can help evaluate effective gas migration control techniques by using the gas flow potential factor. By employing these simple design factors, it is possible to help reduce gas-flow potentials at little or no added expense.

Minor Gas Flow Potential Conditions. When conditions indicate low gas-flow potential, it is possible to achieve migration control without using any special application additives. Any method that can control extreme conditions would be expected to control lower flow-potential conditions. However, most operators want effective control that is economical and does not produce technological overkill. By using fluid-loss control additives and altering elements of a job design, many minor flow conditions can be controlled. Fluid-loss control in the range of 50 cc/min is recommended.

Moderate Gas-Flow Potential Conditions. If the well has a moderate potential for gas flow, operators should use exceptional fluid-loss control techniques. Although the recommended fluid-loss value decreases as the gas-flow potential increases, a common cement slurry recommendation for high-temperature wells is 25 cc/30 min of fluid-loss control. For added gas-flow prevention, these designs can be supplemented with additives that delay the slurry's SGS development. This delay permits the cement slurry to transmit hydrostatic pressure much longer than with conventional designs. By the time the cement finally begins to gel, the rate of filtrate being lost to the formation drops to a low level. As a result, the pressure drop that occurs during the critical transition period is reduced.

Severe Gas-Flow Potential Conditions. For severe gas-flow conditions in high-temperature wells, fluid loss control additives, job modifications, or delayed gelling agents alone cannot sufficiently reduce flow potential. In these situations, highly compressible cements are necessary. One method is to utilize a cement system that reacts to generate and thoroughly disperse discreet gas bubbles throughout the cement column. A second method of creating a compressible system is to inject an inert gas into the cement system as it is being placed downhole. This action creates a highly compressible cement system that can compensate for volume decreases caused by filtrate loss and hydrate volume reductions. The following equation shows the effect of increasing slurry compressibility:

$$DP = DV/CF$$

Where

DP = Pressure loss from volume reduction
DV = Volume reduction caused by fluid loss and cement hydration
CF = Compressibility factor

The compressibility factor for standard cement slurries is the same as for water. By substituting higher values for the CF, the ratio between volume reduction M and CF can be significantly lowered, resulting in a lower P value. Relatively low gas volumes (2 ½ to 5%) can greatly increase CF and control P. Typically, only 2 ½ to 5% gas by volume is required downhole to produce enough compressibility to help prevent gas entry into the cement column.

CONCLUSION

Flow channels created by gas migration cannot be "healed." In these cases, operators will usually need to perform remedial squeeze jobs. However, by using analysis systems that help determine a formation's gas-flow potential factor, operators can better determine the most effective cementing practices for preventing gas migration problems.

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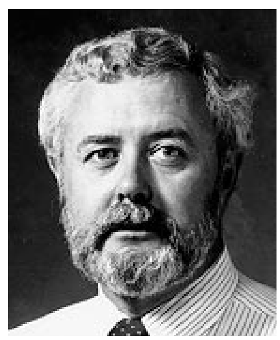

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