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# Improved Primary Cement Job Design Methodology for Mitigation of Vent Gas Flow

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## Abstract

Mitigating annular gas migration, at times referred to as surface casing vent flow (SCVF), has been an identified issue for the industry since the 1970s. In the 1980s, considerable progress was achieved in understanding and overcoming this issue for the first time. Since then, the industry has had a clear understanding of the problem, its origins, and what must be done to prevent or at least minimize annular leakage following a cement job.

When current best practices are followed, the success rate for preventing post-cementing annular leakage is relatively high when the problem is minor or low-to-moderate in severity. Success is not guaranteed if the problem is in the high-to-moderate or in the severe range, even if the best practices from the past are applied.

In this paper, case histories will be presented to demonstrate how the success rate in avoiding post-cementing flow can be greatly increased by utilizing a new methodology that is the subject of this paper. This new methodology, Wellbore Shielding (WBS) Technology will be utilized in the spacer in tandem with best practices that have been previously known and understood. This paper will also offer a condensed summary of the theory that is currently accepted as the driving force behind the reasons for post-cementing annular flow, in addition to a discussion of the best practices that are currently available for preventing such flow.

## Background

When cementing casing and liners into the ground, it is critical to form an effective seal between the outside of the pipe and the penetrated formation. As the wellbore is drilled, discrete layers, that are normally isolated from one another, are now in direct contact with each other via the wellbore. These layers could contain fresh water, brine water, oil, gas, $CO_2$, $H_2S$, or formations sensitive to these materials. During the drilling process the drilling fluid, or 'mud', is engineered to a specific density in order that the fluid column exerts sufficient force on the individual layers to keep what is in the individual layers contained and what is not supposed to be there out. When the drilling fluid is replaced with cement, it then becomes the cement's job to keep these layers isolated. If an effective seal is not formed, production can be lost into non-productive zones and/or lower pressured zones can become pressurized which can cause future problems drilling neighboring wells. The worst scenario is when a communication path is allowed to be formed allowing gas to escape all the way back to the surface. If that occurs, in the best case scenario, a slight pressure is observed on the backside; in the worst case scenario, a well control incident is created.

There are many aspects to an effective cement job design (Clark and Carter, 1973; Haut and Crook, 1979; Smith, 1989 and 1990; Sabins, 1990; Smith and Ravi, 1991; Jakobsen et al., 1991; Calvert et al, 1992; Guzman et al., 2018). Only the factors dealing with spacer design and preventing gas migration are discussed in this paper. The related topics on cement job design have been discussed extensively in the literature.

## Spacer Design for Effective Drilling Fluid Removal

In order to create an effective cement seal, the drilling fluid must be completely, or at least mostly, displaced from the wellbore allowing cement to fully fill the annular space between the formations and the pipe. To accomplish the task of removing the drilling fluid, the spacer must be at least somewhat compatible with both the drilling fluid and the cement (which are often incompatible with each other). It is also important to maintain both density and rheological hierarchy. Rheological hierarchy entails having each successive fluid that is being pumped into the well be at least slightly heavier and slightly thicker than the previous fluid.

Thus, a good spacer system must be capable of being mixed at any density and any viscosity. The density of a "good" spacer can be adjusted by simply adjusting the quantity of the weighting material. A "less-than-optimal" spacer may also require gelation loadings to be adjusted simultaneously with the changing of the weighting material concentration. This additional adjustment is not optimal because it complicates the design process and application.

The viscosity of a preferred spacer design can be adjusted by simply adjusting the quantity of the base spacer blend. A "less-than-optimal" spacer will require adjustments to the ratios of the components to achieve the proper density and gelation. This is "sub-optimal", because it complicates the design process and provides an opportunity for some of the components to be loaded-out at the wrong ratio.

The circulation rate also plays a role in the spacer's capability to effectively displace the drilling fluid from the annular space. The rate at which the spacer is mixed and pumped is not critical. *It is the circulation rate at the time the spacer exits the shoe and is entering the annulus that is of consequence.* The pump rate during this portion of the job (when the spacer is flowing through the interval to be cemented) needs to be as fast as safely possible to effectively remove the drilling fluid.

The final major contributing factor to the spacer's success or lack thereof, in the drilling fluid removal process, is volume. It is critical that sufficient spacer be pumped. Imagine the leading edge of the spacer as it is first entering the annulus. It will start intermingling with the drilling fluid; it is supposed to be displacing. As time goes on, the length of this contaminated leading edge of the spacer grows. Once the cement enters the annulus, if the density and rheological hierarchy are correct, it will displace the spacer up the annulus. As this happens a portion of the trailing edge of the spacer will become contaminated with cement. As the displacement process continues more and more of the trailing edge of the spacer will become contaminated with cement. With sufficient spacer volume, at the end of the job, there will remain some uncontaminated spacer between the 'muddy' spacer at the leading edge of the spacer and the cement-contaminated spacer at the trailing edge. Figure 1 illustrates the contaminated leading and trailing edge contaminations of the spacer as well as a section of 'pure' spacer (blue) in the middle separating the drilling fluid and cement contaminated portions.

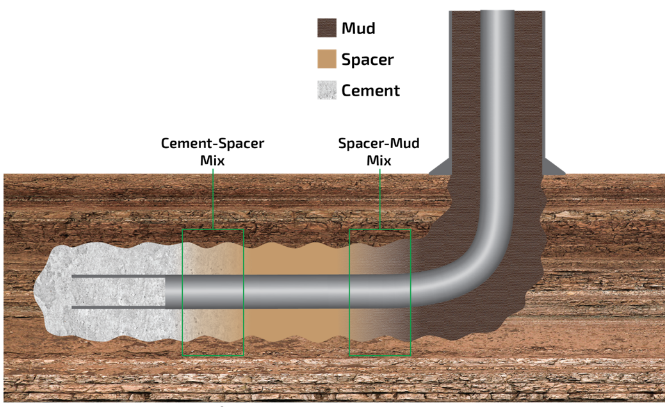


**Figure 1 – Spacer contamination over time.**

If the volume of spacer is too small, the spacer will be incapable of removing all or at least the vast majority of the drilling fluid. If the spacer does not remove the removable drilling fluid, the cement may do so. Since drilling fluid and cement are typically incompatible, this is something that really needs to be avoided.

Consider drilling fluid removal in five phases (Figure 2).

1. The first phase happens over a very short time period following when circulation is first broken to start the mud conditioning process. Based on the quality of the drilling fluid, its long-term gel strength development, and circulation rate somewhere between 40 and 100% of the drilling fluid will flowing at the end of this phase. The remaining drilling fluid will remain static along the wellbore face and/or in the narrow side of an eccentric annulus.
2. The second phase is a much slower process and will occur during the remainder of the mud conditioning phase. As this time passes, some of the less mobile drilling fluid that didn't initially start flowing when circulation was first broken will be eroded.
3. The third phase of the mud removal process occurs with the switch-over from mud to spacer. If the spacer is sufficiently thick or viscous, most of the portion of the remaining drilling fluid will begin to circulate.
4. If the volume of spacer is sufficient, by the time phase four is completed, almost all of the drilling fluid will be circulating.
5. In Phase 5, a portion of any remaining mud will be removed by the cement. If almost all of the mud was already circulating, this amount of mud contamination, to the cement, will be insignificant. If the volume and rheology of the spacer were lacking and a significant amount of drilling fluid remains after Phase 4 is completed, allowing the thicker cement to remove substantial amounts of drilling fluid will likely result in cement contamination problems.

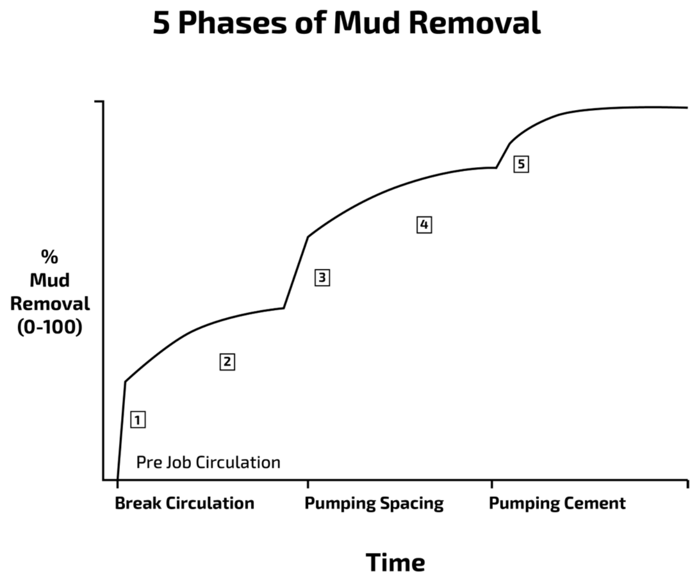


**Figure 2 – Drilling fluid removal over time.**

There are two standard rules-of-thumb regarding spacer volume. The first is referred to as "feet-of-fill". This translates to how many barrels of spacer will be required to fill some length of the annular space in the cemented interval. The target most often used for feet-of-fill is 1,000 to 1,500 feet.

The second rule-of-thumb is for contact time. Contact-time refers to the time the spacer is in contact with the most critical section of the formation to be cleaned. To calculate contact time, simply take the volume of spacer and divide that volume by the rate at which the spacer will be flowing when it is passing the critical section of the interval.

Conversely, one can take the desired contact time and multiple it by the pump rate during that part of the job to calculate ideal spacer volume.

If a two- or three-part spacer system is being utilized on the job, the volumes or lengths can be added together for *contact time* or *feet-of-fill* calculation purposes. The problem with these two rules-of-thumb is that neither wellbore geometry nor cemented interval length is considered. While the two methods just mentioned are still the best simple options, a better but more complicated methodology exists.

If the job specifics are programmed into a 3D Computational Fluid Dynamics (CFD) simulator, ideal spacer volume can be simulated (Chen et al., 2014, Al Ghafri and Turner, 2022). If one watches fluid progression during the job, initially the fluid volume fraction will be 100% mud. As the spacer enters the annulus its volume fraction will climb, as the mud's falls. Eventually the cement will enter the annulus and its faction will climb and the spacers will start to decline. If the spacer volume fraction never plateaus before it starts to fall, not enough spacer is being pumped. Keep increasing the spacer volume and rerunning the simulator until a plateau is simulated. Ideally it plateaus at 100% or at least in the high 90s. If not, the job design needs to be changed. Three simple ways to improve the effectiveness of the spacer are: increase the yield point of the spacer, use higher pump rates, and/or improve the drilling fluid properties.

In addition to the above necessities, effective mud removal also benefits from: proper pre-job mud circulation and conditioning, pipe centralization, pipe rotation and/or reciprocation, and higher pump rates.

## Gas Migration Theory

In a properly designed cement job, the final hydrostatic pressure at the potential gas entry depth(s) will always be greater than the pore pressure at that/those depth(s). Despite this initial overbalanced pressure and physics dictating that fluids do not flow from lower pressure to a higher pressure, it is a common problem in the industry to see gas pressure at the surface post cementing even when the job completes in an over-balanced condition. In the late 1970s and early 1980s much research effort was spent trying to understand this phenomenon and develop solutions (Tinsley et al., 1980). Eventually it was determined that as the pug lands and for some period of time thereafter, the cementing system still behaves as a fluid, meaning the local pressure can be calculated by summing up the individual weights of all of the fluids above. However, after some period, which is now commonly referred to as the zero-gel time, the cement starts to develop gel strength. It is this gel strength which inhibits the transmission of hydrostatic pressure and stops or leads to the annular migration of the gas.

During this critical time, a volume reduction in the cement is also occurring. The volume reduction is caused by two primary mechanisms: fluid loss and the hydration volume reduction associated with cement hydration – the chemical reaction that causes the cement to turn from a liquid to a solid. It is the cement's diminished ability to transmit hydrostatic pressure coupled with a volume reduction that allows the annular pressure to decrease from the safe design value all the way down to the pore pressure, which is then at the point at which gas can enter the annulus and form a channel allowing communication to a lower pressure zone or worse, all the way back to the surface.

Research also determined that there is a limited time frame during which gas channel formation can occur. At the end of this time frame (which has become known as the end of transition time), the cement is now so thick (typically taken as a static gel strength of 500 lb/100 $ft^2$) that the gravity forces are no longer sufficient to push the cement particles apart allowing gas bubbles to migrate upward, which is the cause of the formation of a gas channels..

The time from the end of the zero-gel time, when the cement begins to gel, until the cement has become sufficiently thick to prevent the formation of a new channel, is known as the transition time (TT). Thus, it is during the transition time that engineering efforts must be focused, to avoid annular gas migration from occurring.

With this basic understanding, one can model the potential severity of a given situation's often referred to as the gas flow potential (GFP). Often wells are considered to have either a minor, moderate, or severe gas flow potential. When trying to design a cement job that will avoid post cementing flow, it is important to have an idea of the severity of the situation in order to effectively control the problem without having to applying solutions substantially more expensive or cumbersome than is required for prudent and effective design.

## Job Designs to Control Gas Flow

Since the early 1980s when the theory behind post-cementing gas migration was first presented to the industry, many solutions have been offered (Tinsley et al., 1980). The following is a comprehensive, but by no means a complete list of methodologies to minimize post-cementing gas migration:

- ***Fluid Loss Control*** – Since this design strategy is so basic to the gas flow theory, it should be part of all strategies. The most common way to implement this strategy is to simply increase the concentration of the planned fluid loss additive to be used in the cement slurry design or use a better one. By increasing the fluid loss additive concentration, the volume of fluid lost from the cement slurry will be decreased. This will result in a reduction of the amount of pressure lost due to volume reduction is decreased.
- ***Shorting the Transition Time*** (Sabins et al., 1982; Sepos and Cart, 1985) – The volume lost during the TT directly relates directly to the amount of pressure lost. By shorting the TT, the total amount of fluid loss is reduced during the critical period and hence the pressure lost is reduced. A thixotropic slurry gains gel strength rapidly. Thus, the more thixotropic the cement slurry is, the less likely it will be for the job to result in a problematic gas flow, assuming everything else is equal. It is important to keep in mind that a slurry can be too thixotropic. It is critical that gel

strength development not be so rapid that if the pumps were to stop for a relatively short time prior to landing the plug, the gel strength can be broken and the entire system be put back into motion without over pressurizing the weakest link in the system.

- ***Increasing Cement Slurry Density*** – If the formations involved will allow a higher equivalent circulating density (ECD), increasing the cement density will increase the initial overbalance pressure and decrease the GFP. The initial overbalance pressure can also be looked at as your safety factor. This is how much pressure can be lost during the TT without causing problems. By increasing the slurry density, which is increasing the overbalance pressure, the safety factor is also being increased and the GFP decreased.
- ***Increasing the Length of Zero-Gel Time*** – Increasing the length of zero-gel time will decrease the amount of fluid that is lost during the TT as long as the TT remains the same or decreases. The fluid loss rate of standard cement slurries, be they high or low fluid loss designs, decreases exponentially with time. Thus, if you delay the start of the transition time and keep the actual TT constant or decrease it, the total fluid lost during the TT will decrease. A smaller potential volume loss equates to a smaller pressure loss, minimizing the chances for SCVF to occur.
- ***Shortening the Cement-Column Measured Length*** – Often the cement-column length cannot be shortened, but if it can be shortened, it will reduce the well's GFP. Each linear foot of gelled cement can support affixed amount of potential pressure reduction at the end of the transition time, which can be calculated based on wellbore geometry. Thus, the shorter the column length, the lower the GFP and the less likely it will be for annular gas migration to occur.
- ***Delayed-Gel Lead Cement*** – In wells where the cement-column length cannot be shorten by any significant amount, the effective cement-column length (for GFP calculation purposes) can be decreased by implemented a specialized lead and tail cement design where the zero-gel time of the lead slurry is extended to correspond or exceed the TT for the tail slurry. If designed properly, the lead cement-column length can be ignored for GFP calculations purposes while still delivering the required Top-of-Cement (TOC). With a delayed-gelling lead slurry, the full desired/designed top of cement can be provided while at the same time drastically reducing the well's GFP. If the lead cement is not across from the potential gas in-flux zone and it is not gelling up during the tail's transition time, 100% of its potential pressure reduction can be ignored.
- ***Increased Compressibility*** – Standard cement slurries are relatively incompressible. That is why small volume loss can cause large pressure reductions. If the cement's compressibility is increased, each unit of volume loss will equate to a smaller unit of pressure loss. If the pressure reduction is sufficiently limited, SCVF will not occur. Two different methodologies for increasing slurry compressibility have shown useful, in the oilfield. If the cement is foamed, before being pumped into the wellbore, the nitrogen phase in the cement slurry provides the required increase in compressibility. The second proven methodology would be to introduce a gas generating chemical (typically aluminum) into the cement slurry. With time and temperature, the aluminum hydrolyzes some the water in the cement slurry, oxidizing the aluminum and liberating hydrogen gas. Like the nitrogen (in the famed cement), it is this hydrogen gas that provides the required increase in compressibility. This method has pluses and minuses compared to foam cementing. The major advantage is the gas generation not only adds compressibility, but the gas generation will increase localized pressure reaction allowing this solution to handle the most severe cases. The negative of this methodology is the reaction must take place before too much pressure is lost, otherwise it is of no value.
- ***Back Pressure*** – In order to make back pressure be a useful tool, it must be applied as close as possible to the landing of the plug. If applied after the start of TT it will have little to no value, as very little of that pressure will actually be transmitted all the way down to the critical depth. (The gel strength development in the cement-column will inhibit this transmission of applied pressure). If applied in-time, it will directly add to the initial overbalance pressure, increasing the safety factor, and decreasing the GFP. In wells where the ECD and fracture gradient are close and increasing cement density significantly is not possible, this methodology allows the same affective result without increasing the ECD. As soon as pumping has been completed, the frictional component of the ECD is eliminated and can be replaced with backpressure, increasing the safety factor without increasing the ECD.

In wells where SCVF is of concern, safety conscience operators implement at least one, and often several, of the above methodologies.

## New Methodology

More than 10 years ago, a highly specialized WellBore Shielding (WBS) spacer technology was developed. During the ensuing years, it has been used all over the world to help eliminate lost circulation events while successfully cementing more than 10,000 jobs. Recently it was hypothesized and then proven that the same technology that allows this WBS spacer system to combat losses would also combat annular gas migration. As the spacer flows through the annulus, this system deposits a relatively impermeable membrane or shield along all the permeable portions of the wellbore face (Jordan et al., 2019;

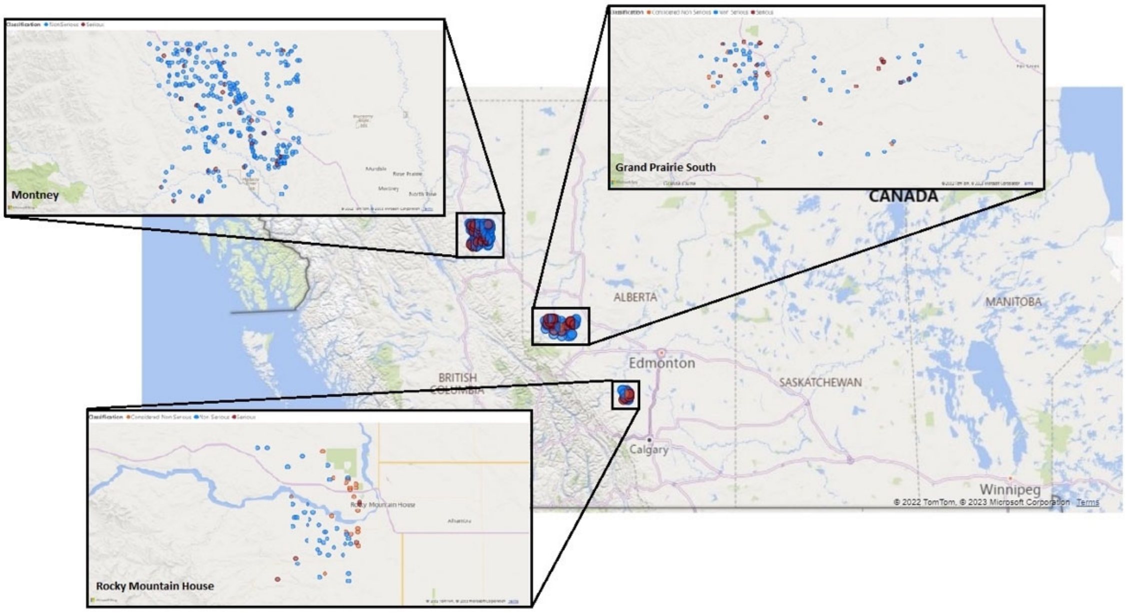


**Figure 3 – Location of wells discussed in case histories.**

Kulakofsky et al., 2020). By creating a relatively pressure-tight and fluid-tight barrier, the WBS has proven time and again its capability to allow circulation of cement in conditions where side-by-side untreated wells have face lost circulation issues.

Since this shield is only held in place by differential pressure, conventional wisdom thought it would be ineffective at preventing gas influx to the annulus as it is designed lift off on its own during production without any remedial efforts.

However, it can be reasoned that if a relatively non-permeable barrier is applied to the permeable formation face before cement is introduced, the fluid loss into those permeable zones can be reduced during the cement transition time to a level not possible with conventional fluid loss additives. While the WBS spacer's barrier is not directly capable of preventing gas influx if the pressure in the annulus is drawn down to that of the pore pressure, it is capable of reducing the fluid loss to an extent that the volume losses during the transition time are so insignificant that the annular pressure can be maintained above the pore pressure as long as all of the other the typical best practices are followed.

While in theory this sounded reasonable enough, it was difficult to convince any operator to test this hypothesis in their wells. Fortunately, for this study, there is a region in Colombia where, when certain conditions are presented, nothing had ever worked. Apparently if the problem is bad enough, people seem more open to trying something new. A full report of this work was presented at the AADE 3 years ago (Kulakofsky et al., 2020). With a positive case study already obtained, this technology was taken to Canada, to address their all too prevalent SCVFs.

## Surface Casing Vent Flow Study

In Western Canada much of the data from all wells, is public record. This database lists 37,045 wells drilled since 1971 with SCVF problems. Since 2013 there have been 34,030 wells drilled in Alberta, 8,758 wells have reports SCVF since 2013 or 25.7%. Since 2013 there have been 2,375 wells drilled in British Columbia; 1,766 wells have reported SCVF since 2013 or 74.3%. Admittedly, some of these post 2013 reports of SCVF problems could have been from older wells that only failed after 2013, bringing down that percentage. However, **of the 115 wells cemented utilizing this new Wellbore Shielding spacer technology, to date, none have reported any SCVF issues**. The following three case studies summarize 89 of these 115 wells.

### *Rocky Mountain House*

Historically, this region has proven to be one of most difficult areas in which to control SCVF, as this area has the highest percentage of drilled wells having reported SCVF. The main problem is the Cardium Gas which is typically encountered at ~2,500 m (8,200 ft). Rocky Mountain House is in west central Alberta, between Calgary and Edmonton (Figure 3). Public records report 74 wells with SCVF, out of the ~197 wells that were drilled since 2013 (38%). In six of these wells the gas flows have been considered serious.

In this area, there have been 29 production casings successfully cemented using the above discussed WBS spacer in combination with well-engineered job designs. As of December 20, 2022, none of these 29 wells have reported any SCVF.

#### *Spacer Design for Rocky Mountain House*

Average volume of spacer per job = 10.2 $m^3$ (64.2 bbl)
Average spacer density = 1,200 $kg/m^3$ (10 lb/gal)
Average spacer pump rate = 0.8 $m^3/min$ (5 bbl/min)

Average spacer annular height = 781 m (2,562 ft)
Average spacer annular contact time = 12.5 min

### Grand Prairie South

This region has also proven to be a difficult area in which to control SCVF. If these wells have problems, they are serious. Note the average SCVF rate reported below. The two primary gas-bearing zones in this area are the Montney formation at ~ 3,000 m (9,840 ft) depth and the Duvernay formation at ~ 3,800 m (12,464 ft) depth. Grand Prairie South is in north-western Alberta about 100 km (60 mi) south of Grand Prairie (Figure 3). Public records report 77 wells with SCVF, out of the ~1,513 wells that were drilled since 2013. Eighteen of these well's flows have been considered serious. The average SCVF rate for these wells is 471 m$^3$/day (16,633 ft$^3$/day).

In this area, there have been 41 intermediate casings and 4 production casings cemented using the new WBS spacer technology in combination with well-engineered cement job designs. As of December 20, 2022, none of these wells have reported any SCVF.

#### *Spacer Design for Grand Prairie South*

Average volume of spacer per job = 9.1 m$^3$ (57.2 bbl)
Average spacer density = 1,260 kg/m$^3$ (10.5 lb/gal)
Average spacer pump rate = 0.9 m$^3$/min (5.7 bbl/min)
Average spacer annular height = 732 m (2,401 ft)
Average spacer annular contact time = 11.5 min

### Montney

The Montney region of British Colombia is our third case study region. This region has proven to be an area in which it has been equally difficult to control SCVF as Grand Prairie South. The primary gas-bearing zone in this area is the Montney Gas formation which is shallower here than in Grand Prairie South and is found at ~2,100 m (6,888 ft) depth. The Montney field can be found in north-eastern British Columbia about 80 km (50 mi) north-west of Fort St John (Figure 3). Public records report 286 wells with SCVF, out of the ~556 wells that were drilled since 2013, (51.4%). Twenty five of these well's flows have been considered serious. The average SCVF rate for these wells is 6.5 m$^3$/day (230 ft$^3$/day).

In this area, there have been 15 intermediate casings cemented using the above discussed WBS spacer in combination with well-engineered job designs. As of December 20, 2022, none of these wells have reported any SCVF.

#### *Spacer Design for Montney*

Average volume of spacer per job = 10 m$^3$ (62.9 bbl)
Average spacer density = 1,600 kg/m$^3$ (13.3 lb/gal)
Average spacer pump rate = 0.8 m$^3$/min (5 bbl/min)
Average spacer annular height = 715 m (2,345 ft)
Average spacer annular contact time = 12.5 min

## Conclusions

In order to be successful cementing past pressurized formations and avoiding surface casing vent flow, also known as annular gas migration, it is critical to understand the theory and options available.

With careful engineering and job execution surface casing vent flow can be avoided.

With the aid of a wellbore shielding spacer technology system, 115 wells (89 of which have been cemented in 3 different of Western Canada's most challenging formations) have all achieved 100% success at avoiding surface casing vent flow. In comparison, 437 of the wells cemented in these same three areas since 2013 without the inclusion of a wellbore shielding spacer as part of the job design have suffered surface casing vent flow.

If SCVF is of concern, the safest option would be to combine several of the 8 Job Designs to Control Gas Flow options with a wellbore shielding cementing spacer pumped ahead of the cement.

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## Nomenclature

CFD = Computational Fluid Dynamics
ECD = Equivalent Circulating Density
GFP = Gas Flow Potential
SCVF = Surface Casing Vent Flow
TT = Transition Time
WBS = Wellbore Shielding Technology

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