CONTROLLING CORROSION OF CARBON STEEL IN SWEET HIGH TEMPERATURE AND PRESSURE DOWNHOLE ENVIRONMENTS WITH THE USE OF CORROSION INHIBITORS

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ABSTRACT

The design of a downhole chemical treatment method for corrosion is a challenging process. These efforts are made even more challenging with recent advancements in acquiring natural gas from shale formations. Traditional methods of corrosion inhibition are being challenged by the severe bottom-hole conditions presented. At increasing depths, high temperatures and pressures create conditions which can be difficult to mitigate with chemical inhibitors. In addition to corrosion protection; inhibitors must have the ability to withstand extreme temperatures and pressures. Proper treatment strategies and inhibitor selection become increasingly vital under these conditions.

Sweet corrosion at high temperatures was studied and the effects of inhibitors were analyzed. Corrosion testing using batch and continuous inhibitors were studied using laboratory performance techniques as well as field case studies. These studies showed that specialized corrosion inhibitors were able to inhibit in conditions up to 175°C.

This paper discusses the risks associated with high temperature and pressure downhole conditions and the successful corrosion mitigation strategies needed in order to maintain operating equipment.

KEY WORDS: Down-hole Corrosion, High Temperature/High Pressure, Flow Modeling

INTRODUCTION

The economic potential of both the Horn River Basin shale gas and the Deep Basin sedimentary gas formations have made recovery of natural gas from these plays highly attractive. The combination of high downhole temperature and pressure conditions and the hydraulic fracturing procedures required to recover this tight natural gas, however, augment system corrosivity. These conditions necessitate the implementation of corrosion mitigation strategies for the protection and longevity of downhole equipment. **Table 1** shows possible system conditions for Western Canadian Shale Gas regions.

Unconventional sweet gas reservoirs of Northwestern Alberta and Northeastern British Columbia are characterized by their low matrix permeability and most often require artificial stimulation around well bores for sufficient production. Hydraulic fracturing methods require water, which is obtained from surrounding sources, to be injected into the reservoir. With saline water flowback into the wellbore, an electrolyte for internal corrosion is provided. Temperature effects on corrosion have been the topic of study in the past[1-5] and are applicable to these cases as the kinetics of corrosion reactions are accelerated by the inherent high temperature conditions which downhole equipment is exposed to. System pressures contribute to internal corrosion as higher downhole pressures increases the partial pressures or solubility of naturally occurring corrosive acid gases, such as CO_2 and H_2S, in flowback waters.

The corrosivity of downhole environments is further complicated by the presence of naturally occurring corrosion by-products, such as $FeCO_3$ and FeS. In sweet systems, the formation of $FeCO_3$ on metal surfaces produces a semi-protective layer. It has been found that operating temperatures affect the occurrence and morphology of the carbonate surface film[6,7]. Zhang et al.[1] attributed carbonate scale thickness to the pressure changes of the system with well depth. Given that temperature and pressure change with well depth, the occurrence and characteristics of the protective carbonate scale layer can influence the likelihood of corrosion along the length of the tubing. In other words, less protective film formation means a higher potential for corrosion. In the case of sweet downhole corrosion, increasing temperature and pressure would increase the amount of scale deposition as dictated by increasing corrosion rates and the increased solubility of CO_2 within flowback water.

Pure downhole corrosion is generally augmented by the addition of erosional factors. The fluid flow regime of downhole systems contributes significantly to corrosion when considered with water chemistry. **Figure 1** describes the typical general downhole flow patterns and their erosional effects on naturally occurring protective surface films. The "slip and holdup" concept is often used for evaluating two phase gas well corrosion where slip describes higher flow of the lighter, less dense, phase (gas) while in the presence of a denser fluid (water). Holdup refers to the in-situ volume fraction ratio of the heavier phase to the lighter phase in a low velocity flow stream and dictates the amount of water accumulation within a well, where pure corrosion is likely to occur. Downhole fluid flow can be characterized by "slip and holdup" where there are high fluid velocities (annular or mist flow) with water entrained within the gas phase or high volumes of water that accumulate as bands (bubbly or slug flow). Pure internal erosion by fluid flow or pure internal corrosion by electrolyte, or a combination of both, in downhole gas systems must be considered in order to determine the likelihood of downhole failures in high temperature and pressure environments.

Downhole chemical inhibition application methods have been a topic of discussion before[9,10]. Oil-soluble corrosion inhibitors are batch applied, often through the 'Batch and Fall' method, allowing them to coat the tubing and form a protective film. Where batch inhibitors are adsorbed physically and chemically to downhole pipe surfaces, erosion removes physically adsorbed constituents while active components remain chemically adsorbed on the surface. Batch inhibitors need to be re-applied as erosional effects exceed the filming tendencies with time. Water-soluble corrosion inhibitors are applied via continuous inhibition methods and provide excellent protection by forming and re-forming films along the tubing surface as it is carried up with the water production. However, set-up costs and maintenance can become issues in the oilfield for continuous methods. Treatment of downhole environments by batch or continuous inhibition depend upon the engineering design and corrosion contributions of both the erosional velocity of the fluid and the presence of water for pure corrosion.
Studies demonstrating the effectiveness of specific downhole chemical corrosion inhibitors are limited. This is especially true for high temperature and pressure downhole applications, where chemical stability might be an issue. Furthermore, all downhole corrosivity factors discussed above can also affect mitigation strategies.

The focus of this paper explores chemical inhibition of sweet corrosion in high pressure and temperature environments similar to conditions found in the Horn River and Deep Basin fields of Western Canada. Untreated corrosion rates were determined through laboratory testing and supported by microscopic and diffraction studies of corrosion scale. A field case study complements those results found in a laboratory environment for untreated conditions and is presented here. In addition, the effectiveness of both, batch and continuous inhibitors, in these environments was examined via laboratory study utilizing a high temperature and pressure autoclave apparatus. Finally, a mathematical method for the field case study was completed to assess the corrosion risk of tubing in untreated conditions.

EXPERIMENTAL PROCEDURE

High Temperature and Pressure Autoclave Testing

High temperature and pressure testing was carried out by Corrtrol Services of Tomball, Texas using closed static autoclaves containing corrosion coupons in synthetic brine to quantify corrosion rates in uninhibited and inhibited sweet conditions. Test fluids were prepared synthetically using specified ion concentrations and the addition of salts to de-ionized water. Salt concentrations reflected those found in downhole corrosive waters found in the Horn River and Deep Basin gas formations of Western Canada and is shown in **Table 2**. Test fluids were adjusted to pH 5 using $NaHCO_3$ after a 2-hour CO_2 brine saturation prior to corrosion testing. Autoclaves were pressurized with 2,896 kPa

(21%) of bone-dry CO_2 and balanced to 13,790 kPa using N_2 (**Table 2**) after immersion of corrosion test coupons. The test vessels were then placed into a calibrated rotating oven pre-heated to test temperatures (30, 60, 90, 120 150, and 175°C) and exposed to these conditions for 24 hours. All tests contained the same water and gas concentrations with temperature being the only variable factor.

The corrosion coupons were made of C1018 steel of ¼ x 1 inch dimension and 1/16th inches thick. Preservation of the new coupons was carried out using a mineral oil to prevent rusting and to increase their shelf life. Prior to corrosion testing, coupons were degreased using a series of solvent rinses. Coupons were sandblasted with 120 grit abrasive in order to achieve a clean, reproducible finish and were analytically weighed to the nearest 0.1 mg before exposure to test conditions. One coupon was used for each autoclave apparatus, which was situated such that the coupon was continuously immersed in solution and with the likelihood of mechanical damage minimized. Three coupons were used to determine average weight loss data and two were preserved for post test analysis for all temperature conditions.

To simulate batch treatment of inhibitors, coupons were dipped into inhibitor, which was diluted 1:1 with diesel, for a total contact time of 10 seconds and immediately rinsed in de-gassed test fluids to remove excess chemical. The coupons were placed in autoclave test fluids and allowed to corrode under test conditions for 24 hours. For continuous inhibition, chemical was added directly to the volume of test fluid in the vessel to achieve a concentration of 500 ppm.

Post Test Coupon Analysis by Weight Loss, SEM and XRD

To determine the effect of temperature on the extent of corrosion of the C1018 coupons, weight loss, SEM and XRD analytical tools were utilized. The mass lost for the duration of autoclave testing provided data in order to trend the effects of temperature. In addition, analysis of the corrosion products on preserved coupons provided supportive observations for the mass loss data and provided insight to the severity of CO_2 corrosion at a given temperature. After the 24-hour autoclave test duration, coupons reserved for corrosion rate calculations were cleaned and evaluated for weight loss. Upon removal from the depressurized test vessels, the coupons were de-greased using a toluene/isopropanol mixture and then soaked in inhibited HCl for removal of corrosion scale and soaked in sodium bicarbonate solution to neutralize the acid. Coupons were then stored in a dessicator for 30 minutes in order for them to dry. Cleaned and dried coupons were re-weighed to 0.1 mg to determine corrosion rates.

Post-test coupons reserved for microscopy or diffraction studies were removed carefully from the vessels in order to preserve any scale on the coupon surface. These were immediately dried in a dessicator and preserved for analysis (by Scanning Electron Microscopy (SEM) or X-Ray Diffraction (XRD)). SEM was carried out for surface topography analysis and facilities were accommodated by the Microscopy Imaging Facility at the University of Calgary. XRD analysis was provided by DNX Inc. in Calgary, Alberta in order to identify the scale composition on the coupon surface as a result of the exposed test conditions.

Visual Inspection of Failed Tubing from Deep Basin Area

Tubing failed from an untreated downhole gas well was inspected and internal corrosion mechanisms and the failure mechanism were identified and photographed. The average production data was obtained from production monitoring equipment and water chemistries were determined by analytical techniques for gas and salt content. A summary of system well conditions is summarized in **Table 3**.

ULL (University of Louisiana at Lafayette) Gas Well Corrosion Model

Sundaram et al[11] described the mathematical aspects of downhole and flow-induced corrosion. Production data and water chemistries play an important part in this predictive model and the authors were able to accurately predict corrosion rates under scale-protected and non-scale protected downhole equipment using caliper surveys. In the current study, a high temperature and pressure downhole sweet corrosive environment was evaluated using flow modeling software to determine the corrosion risk and aid in the mitigation strategy. The well evaluated (Failed tubing from Deep Basin Area) was unmitigated and lead to eventual failure of production tubing.

The University of Louisiana at Lafayette (ULL) Gas Well Corrosion model was employed to determine the corrosion risk and tubing life for the unmitigated field case[12]. The modeling utilized gas composition, water analysis, production rates, tubing dimensions, and operating conditions for evaluation of the well. The goal of the modeling was to find the minimum gas rate and minimum water content in the well that would show severe corrosion and tubing failures between 1600 and 2100 m, the depths where failures were observed. Modeling for this well was done at 4 different rates of gas and water production (Minimum, Maximum, Average rates, and a Sensitivity Run (**See Table 4**)) to cover a broad spectrum of flow regimes.

There are important pieces of information that can be obtained from ULL modeling that identify the “slip and holdup” concept discussed earlier. The model takes into consideration the temperature and pressure profile of the well in order to determine the depth at which water is condensed which is a minimum requirement for corrosion. The model also reveals the changes of the fluid flow regime within the system and its effect on corrosion rates and tubing life. When high temperatures and pressures are coupled with turbulent flow regimes in downhole systems, corrosion mitigation can be challenging, however, such tools as the ULL corrosion program can help determine the best mitigation strategy.

RESULTS

Uninhibited Corrosion Test Results

The results of high temperature and pressure autoclave results under sweet conditions are presented in **Figure 2** and are summarized below.

Uninhibited coupons showed an increase of their final corrosion rate as the temperature was increased, indicating the effect of temperature on corrosion rate given that all other conditions remain the same. The blank corrosion rates increased through six data points from 208.2 MPY at 30℃ to 639.1 MPY at 175℃ . All coupons showed general corrosion and no localized pitting corrosion. The severities of these corrosion rates show that it is necessary to determine the proper corrosion mitigation strategy for downhole corrosive environments.

Post test coupon results – SEM/XRD

The results of the XRD post test analysis are shown in **Table 5** for uninhibited coupons exposed to sweet autoclave testing at various temperatures and findings are summarized below.

The formation of siderite was increased as the test temperature was increased. When coupons were exposed to 30°C, the composition was analyzed to be 60-70% cohenite and 15-25% siderite. The tendency for siderite formation was lower than cohenite formation as the availability of free iron for iron carbonate precipitation was low in this case. XRD showed that an increase in temperature to 60°C resulted in a scale composition of 100% siderite. At 90°C and 120°C, siderite remained as the dominant species within the scale. Results show that the availability of free iron for iron carbonate precipitation was increased as temperature increased from 30°C to 60°C.

The SEM surface topography images of scale formed under sweet autoclave conditions with varying temperatures can be summarized as follows.

The scale formation at 30°C is relatively fine with no definite crystal structure observed at 2500X magnification as shown in **Figure 3**. As the temperature condition was increased to 60°C, the scale appears to form more defined boundaries (**Figure 4**). XRD analysis suggests that the higher tendencies for iron carbonate precipitation at 60℃ are attributed to the differences in the surface topography with increased temperature from 30°C. The surface profile image of scale at 90°C reveals more defined scaling as edging is more prevalent (**Figure 5**). The composition of siderite scale is similar in the cases for 60°C and 90°C, however, the visual differences can be attributed to the increased tendency for iron carbonate formation. Observations were found to be similar in the cases of scale formed at 90°C and 120°C (**Figure 6**) with defined edging. Cross sectional SEM analysis was not composed on these coupons which would be a good indicator of the extent of iron carbonate precipitation when comparing the scale exposed to 90°C and 120°C.

Case History - High temperature and pressure downhole failure (Deep Basin Area)

The visual inspection of untreated failed tubing is summarized below. The high temperature and pressure environment which this tubing was exposed to is evident in **Figure 7**, which shows deformation and shear lips, consistent with ductile failure (highlighted in red). Internal corrosion decreased the tubing thickness thereby weakening the tubing to the extent of when the temperature and pressure were high enough to cause such a failure.

The corrosive effects of fluid flow and velocity on the coupling region of the tubing wall is described below. The female connection (**Figure 8**) shows a ring of concentrated corrosion had occurred as well as corrosion penetration through the male connection (**Figure 9**), evidenced by the perforations. Fluid travelling though the coupling region will experience the inherent change in diameter, therefore changing the fluid flow regime and increasing the severity of corrosion within this region. These characteristics make the coupling region susceptible for preferential CO_2 attack as the protective scale is continuously broken down and therefore regenerating the corrosion reaction. The visual inspection of this failure shows the need for an effective chemical inhibition program, which can be validated by corrosion testing and proper risk assessment.

The result of the ULL prediction model for this well, which was untreated and led to a downhole failure, is shown in **Figure 10**. It is important to note that the model predicts corrosion rates associated with *pitting* corrosion, which results from a different mechanism than *general* corrosion. When the pitting corrosion rate is high, the lifespan of the tube is low, resulting in a worst case scenario.

Field observations indicated that severe corrosion and failures were occurring at tubing depths of 2100 to 1600 m. The ULL model predicts that the tubing life throughout this region and up to the wellhead is expected to be short, suggesting that failures are most likely to occur between 2100 m and the wellhead. The corrosion rates in this region (2100 m - 0 m) vary from 117 mpy to 333 mpy; however, the expected tubing life does not vary widely, which indicates that there is a minimum pitting corrosion rate that may result in a failure.

The ULL model also predicts that water condensation begins at 3000 m, where a change in the system temperature and pressure occurs and the dew point is reached. This is evident in **Figure 10**, where a significant drop in tubing life occurs between 3000 m to 2500 m. The location where water condensation occurs is important since water is a necessary component for corrosion.

Proceeding up the well to a depth of 2200 m, the tubing life decreases significantly and the corrosion rate sharply increases, which is attributed to the change in flow pattern. Annular flow of fluids from the bottom of the well changes to mist flow at 2200 m and continues upward toward the wellhead. Erosion is caused by the gas and water travelling up the well at similar velocities, which is observed as an increase in corrosion rate above 2200 m. In this case, the ULL model provided accurate results that were consistent with the field observations. Both the field observations and ULL model illustrate the severity of the corrosion risk in an untreated well that is operating under high temperatures and pressures.

Inhibited Corrosion Test Results

Continuous inhibitor A at 500 ppm decreased corrosion rates compared to blank conditions. Corrosion rates ranged from 7.20 MPY at 30℃ to 42.16 MPY at 175℃ (**Figure 2**). The effect of increasing temperature is still shown here with less protection with increasing temperature from 30℃ up to 175℃. However, the percent protection of Continuous inhibitor A is still maintained above 93% at 175℃ as shown in **Figure 11**.
Batch inhibitor A also showed a decrease in corrosion rates compared to blank conditions. Corrosion rates ranged from 12.66 MPY at 30℃ to 29.93 MPY at 175℃ (**Figure 2**). Again, the effect of temperature is still evident here as corrosion rates increase with increasing temperature, however, percent protection at the highest temperature conditions (175℃) was above 95% (**Figure 11**).

Results for inhibitor autoclave testing specific to downhole Horn River Basin shale gas recovery[14] are shown in **Figures 12 and 13** and are summarized below.

Continuous inhibitors U, V, and W showed to maintain a high percent protection with increasing temperatures. At a temperature of 175℃, the percent protection maintained above 80% for all continuous inhibitors (**Figure 12**). Batch inhibitors Y and X also showed to maintain percent protection above 85% at the highest tested temperature of 175℃ (**Figure 13**).

DISCUSSION

Downhole corrosion in the Horn River and Deep Basin regions are characterized by their high temperatures and pressures, acid gas content and their flowback water content from the process of hydraulic fracturing. These characteristics contribute to the likelihood of downhole failures and its resultant economic impact. This study determined the corrosive effects of high temperature and pressure conditions on carbon steel under sweet conditions, reflective of environments found in the Horn River and Deep Basin regions. Laboratory autoclave testing revealed a positive proportional relationship between temperature and corrosion rate under uninhibited sweet conditions, representative of a possible temperature profile with increasing well depths. Microscopic and scale analysis studies support that the kinetics of the corrosion reaction are enhanced with increasing temperature. Any scale analysis in this study, however, did not find the effect of the changes in pressures with scaling behavior. Determining scaling behaviors and corrosion rates as pressure is decreased from bottomhole to wellhead would be indicative of the effect of decreased acid gas content within fluid on the corrosion products. The protective nature of the corrosion products cannot be relied upon alone for protection of downhole equipment from the corrosive environment, as pitting will ensue and will ultimately lead to downhole failures.

Laboratory testing of highly corrosive environments was supplemented by the field case involving untreated failed tubing. Temperature and pressure contributed to both the corrosion mechanism, evidenced by internal corrosion pitting, and the eventual failure of the tubing, as shown by the ductile shear lips. The most interesting observation taken from this case is the severe corrosion present in the coupling region, which was attributed to the change in annular to mist fluid flow. The change in fluid flow within the coupling region of the tubing is an environment where it is likely for critical liquid holdup, thereby initiating internal corrosion. As the corrosion reaction is allowed to proceed, there is the formation of protective scaling, however, with the inherent high velocities, the protective layer will be stripped away and the corrosion reaction is regenerated. The ULL modeling procedure linked closely with field observations of the failure and proved to predict the corrosion risk and tubing life as it determined the temperature and pressure profile for the maximum, minimum and average rates of gas and water production. It is recommended that, in addition to laboratory testing of uninhibited conditions, the ULL program be utilized to determine the appropriate application of corrosion inhibitor.

Corrosion prevention of downhole equipment under harsh conditions can be achieved through materials selection, engineering or operational design changes, or with the selection of corrosion inhibitors. Inhibitors must not only be designed to withstand downhole temperature and pressure environments, but also provide protection against internal corrosion, as was the case found for the tubing failure. Laboratory results presented here along with the field case study outlines the temperature range, such as those found in bottomhole to surface depths, where corrosion inhibitor is to remain stable and provide protection. Batch or continuous inhibitor application in laboratory testing provided a high level of protection within the specified temperature range up to 175°C. Inhibitors have also been developed for similar conditions found in downhole corrosive environments in the Horn River shale gas play.

The results of laboratory testing recommends that chemical inhibitor be applied continuously or through batch inhibition to sweet downhole corrosive environments such as that found in the downhole failure case study. Capillary string has been the most effective method for continuously treating tubing surfaces in gas wells as this method ensures chemical application through the tubing intake. The batch and fall method for batch inhibitors is relatively simple and ensures protection of both annular and tubing surfaces. Monitoring programs for chemical inhibitors, however, must be continuously evaluated as downhole conditions can change gradually over time or instantly with changes in production rates.

CONCLUSIONS

1. Severe corrosion occurs in downhole sweet environments up to a temperature of 175°C.
2. The deposition of iron carbonate scale in downhole sweet environments increases as temperature is increased due to the enhanced kinetics of reaction.
3. High temperature and pressure in downhole sweet environments influence corrosion mechanisms that can lead to equipment failure.
4. The changes in flow regimes of flowback fluids in downhole systems contribute to the enhancement of corrosion.
5. ULL modeling system is an accurate tool to determine the depth of condensation of water and to determine the depths most likely at risk of failure.
6. Inhibitors must be designed to withstand downhole temperature and pressure environments and provide protection against internal corrosion.

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TABLE 1:
WELL PRODUCTION: General Characteristics of the Horn River and Deep Basin of Western Canada

Gas (e^3m^3/day)	Water (m^3/day)	Condensate (m^3/day)	H_2S (ppm)	CO (%)	Chloride (ppm)	Temperature (˚C)	Pressure (kPa)
DEEP BASIN							
1-500	1-3	0	≤ 2500	≤ 21	100-25,000	50-120	2,000-28,000
HORN RIVER BASIN							
40 - 226	0.3 - 103	0	≤ 128	≤ 21	10 – 21,000	35 – 175	2,000 - 44,000

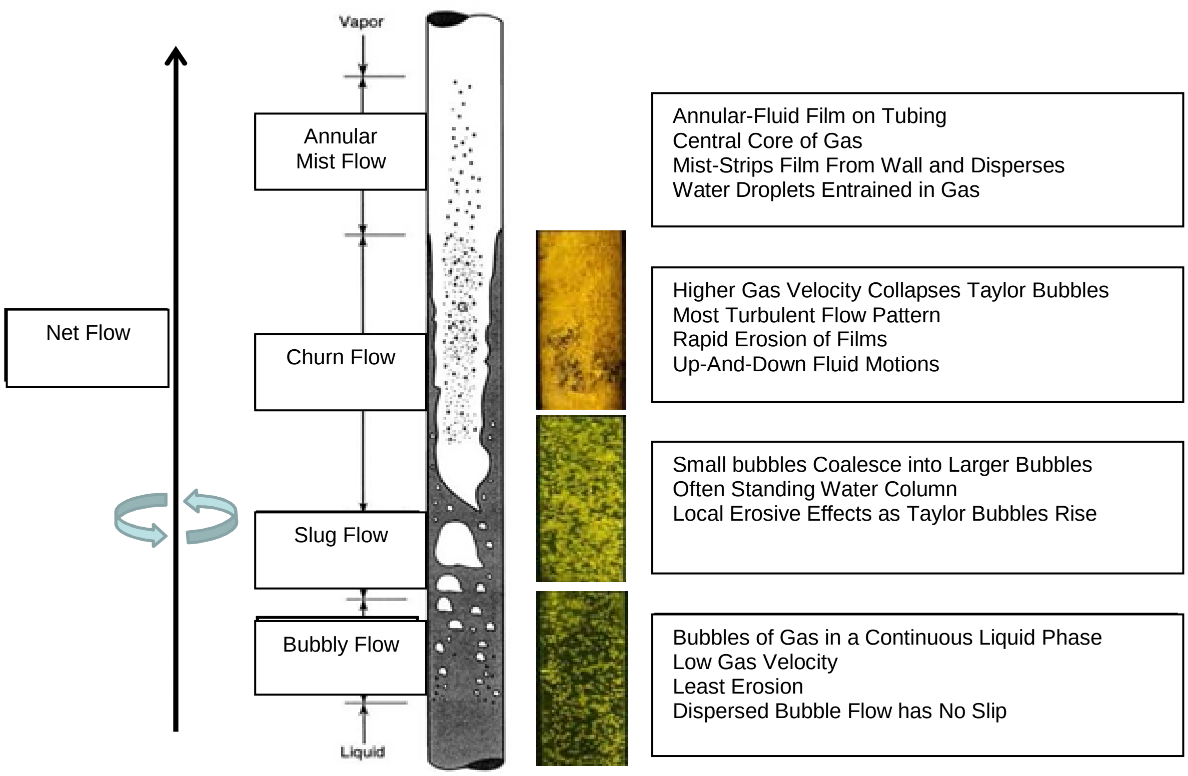

FIGURE 1 – General schematic for typical downhole flow patterns[8]

TABLE 2:
Test conditions for all High Temperature and Pressure Static Autoclave tests

Temperature (℃)	30, 60, 90, 120, 150, 175
Partial/Total Pressures (kPa)	2896, CO_2 (21%) 0, H_2S (0%) 13790, N_2
Test Duration (hrs)	24
Coupon	C1018
Brine	506 ppm Calcium 81 ppm Magnesium 15,253 ppm Chlorides 1 ppm Sulfates Buffer to pH 5 with $NaHCO_3$
Inhibitors	Blank, Batch (1:1 with Diesel or Neat), Continuous (500 ppm)

TABLE 3:
Average production data for downhole tubing failure

Gas (mmscf/d)	$240e^3m^3$
Water (bwpd)	$1m^3$
WHT	25℃
BHT	93℃
SI BHP	28 000 kPa
CO2 (mole %)	5.7
H2S (mole %)	0
Chloride (mg/L)	1100
pH	6.10 STP
Tubing Depth	3290 m

TABLE 4:
Flow rates utilized for ULL corrosion risk assessment model

Flow Condition	**Gas Production (e^3m^3/day)**	**Water Production (m^3/day)**
Maximum	350	3
Minimum	130	1
Average	240	1
Sensitivity Analysis	190	1.5

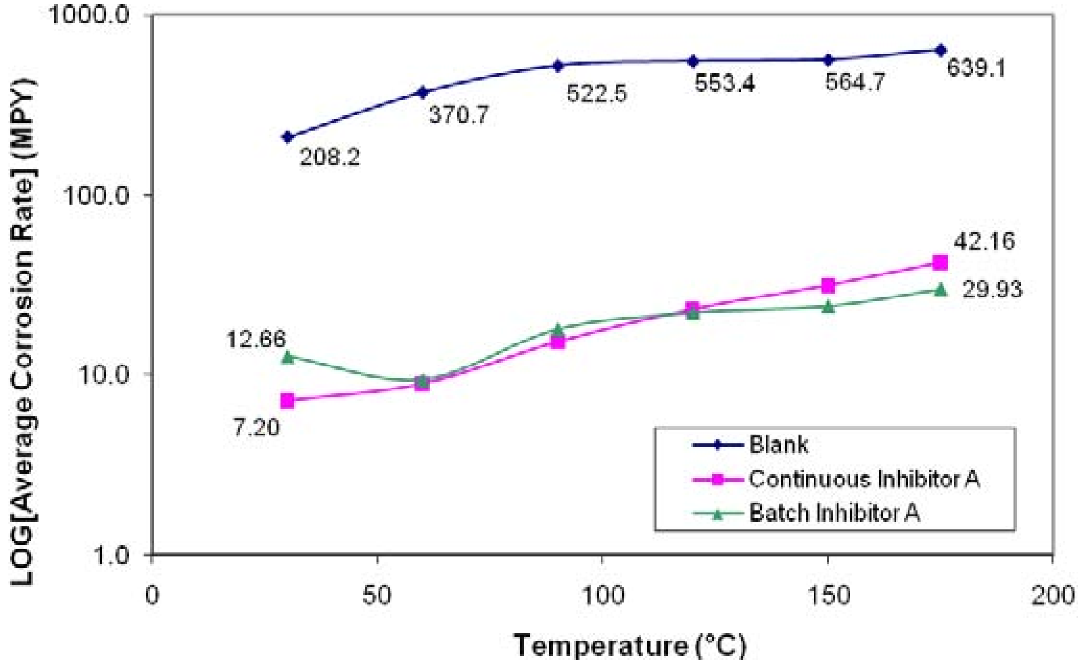

FIGURE 2 - Average corrosion rate comparison of coupons under uninhibited, continuous inhibitor treatment (500 ppm), and batch inhibitor treatment (1:1 with diesel) conditions (Logarithmic Scale)

TABLE 5:
XRD results for untreated coupons exposed to 21% CO_2 in high temperature and pressure static autoclaves

Test Temperature, °C	Compound/ Chemical Formula	Abundance
30	Cohenite/Fe_3C Siderite/$FeCO_3$	60-70% 15-25%
60	Siderite/$FeCO_3$	100%
90	Siderite/$FeCO_3$	100%
120	Siderite/$FeCO_3$	90-99%

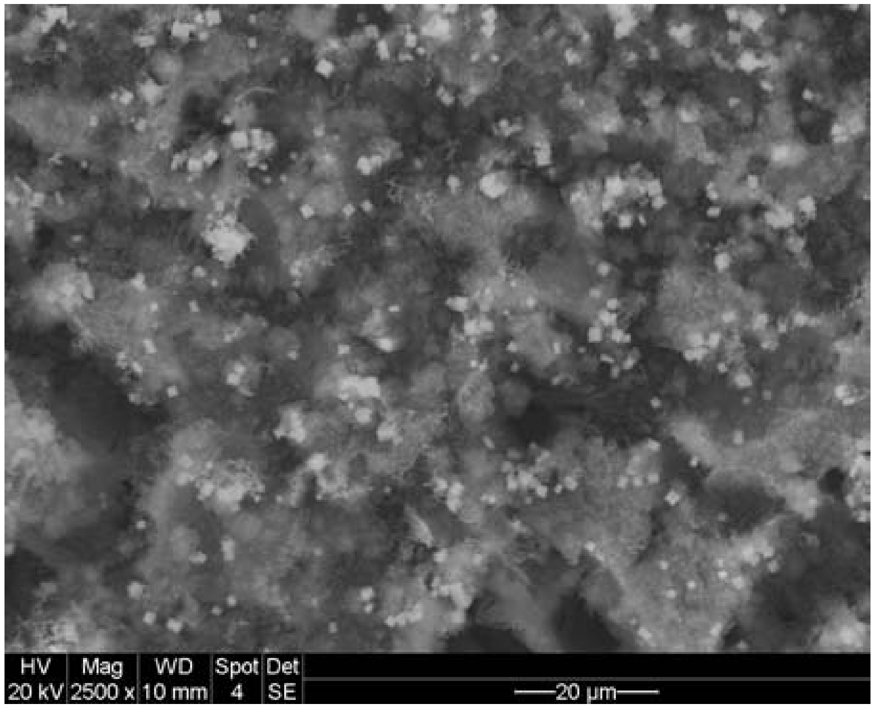

FIGURE 3 – SEM image of scale formed at 30°C in sweet autoclave testing

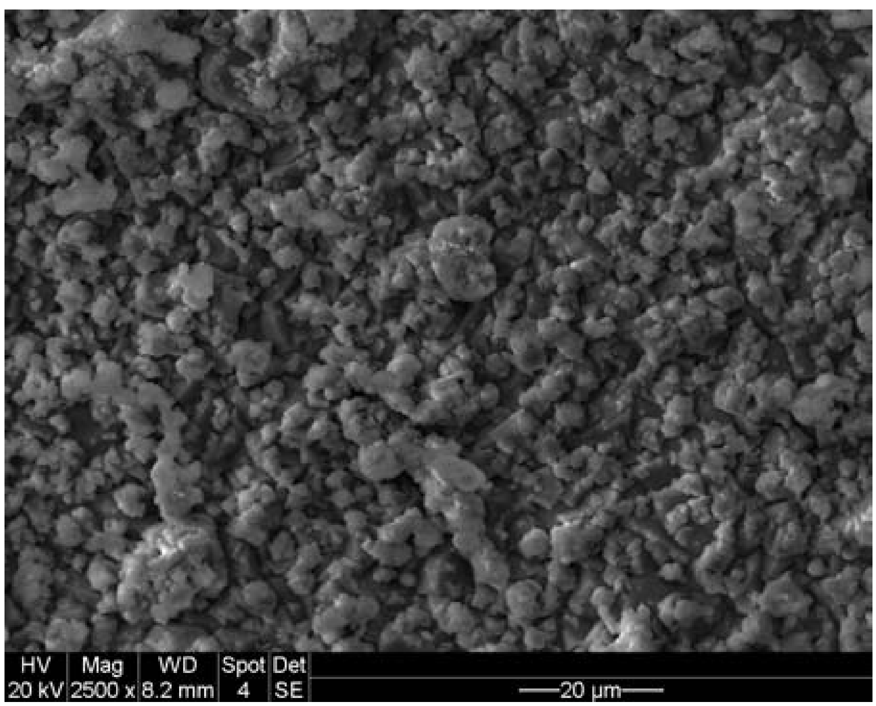

FIGURE 4 – SEM image of scale formed at 60°C in sweet autoclave testing

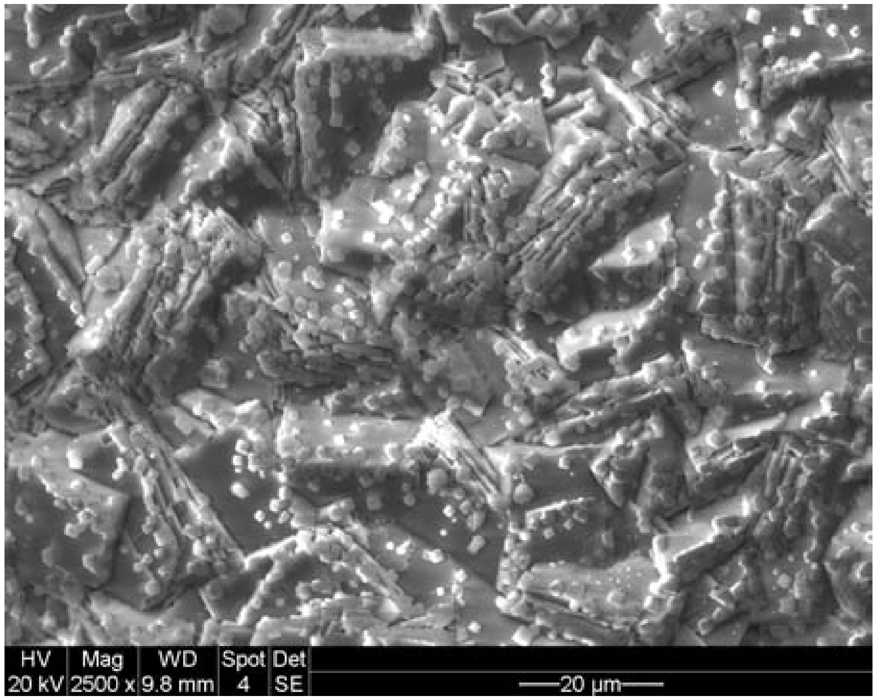

FIGURE 5 – SEM image of scale formed at 90°C in sweet autoclave testing

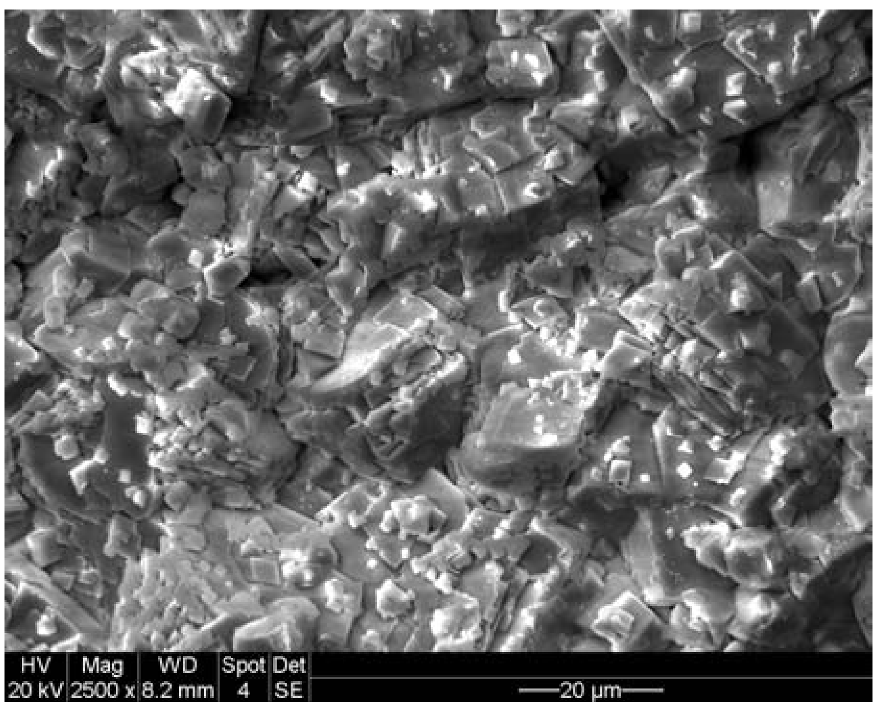

FIGURE 6 – SEM image of scale formed at 120°C in sweet autoclave testing

FIGURE 7 - Downhole corroded tubing showing characteristic ductile failure

FIGURE 8 - Internal corrosion of coupling area of downhole tubing (Female Connector)

FIGURE 9 - External view of corroded threaded area of downhole tubing (Male connector)

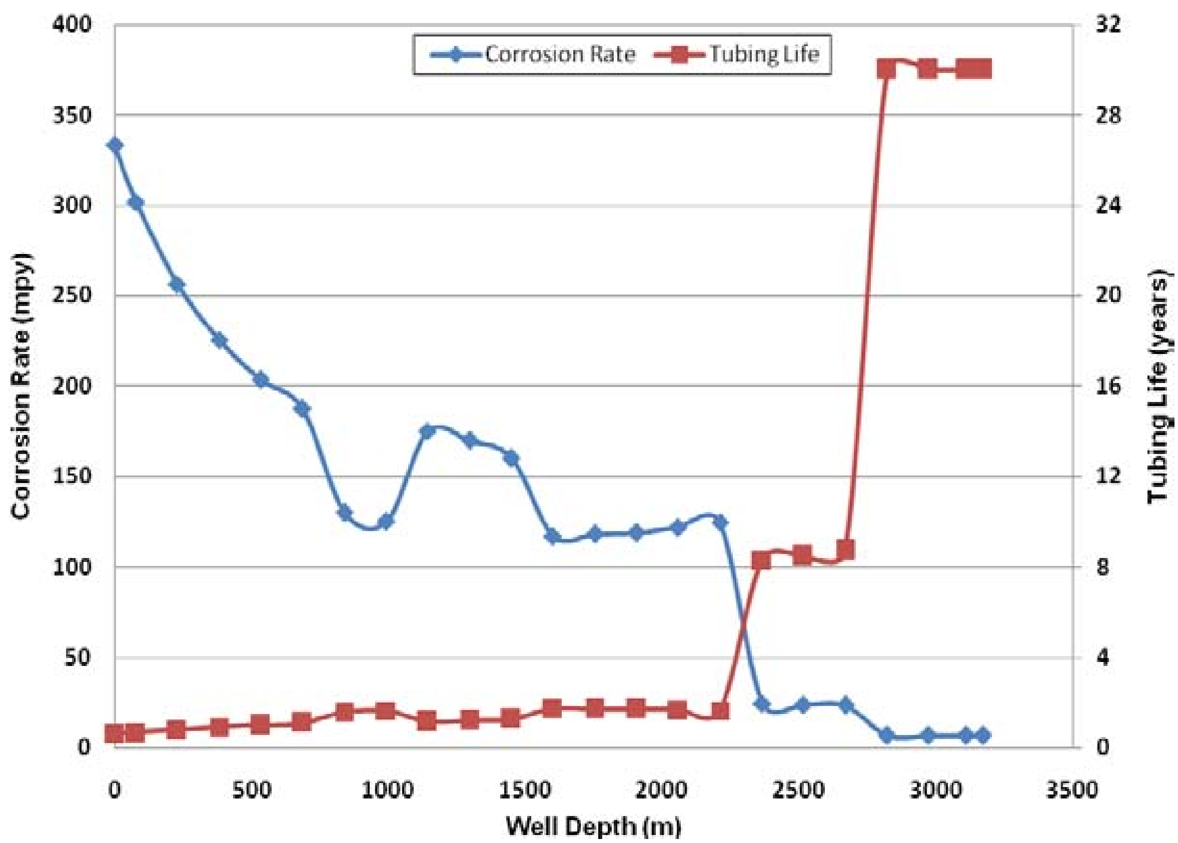

FIGURE 10 – ULL modeling profile for a sweet gas downhole system

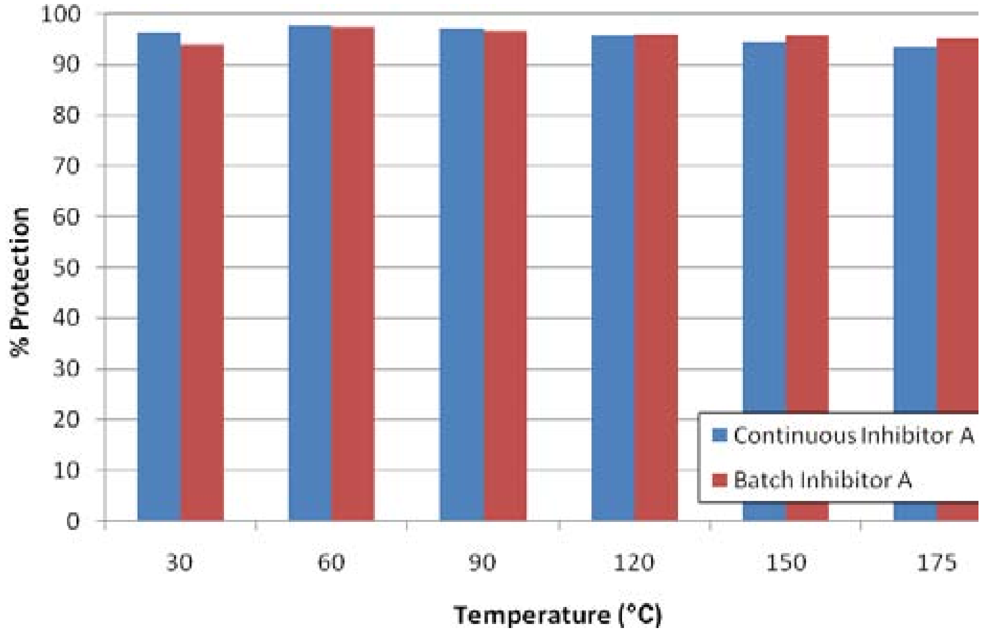

FIGURE 11 – Percent protection profile of continuous and batch corrosion inhibitors evaluated in high temperature and pressure autoclave tests.

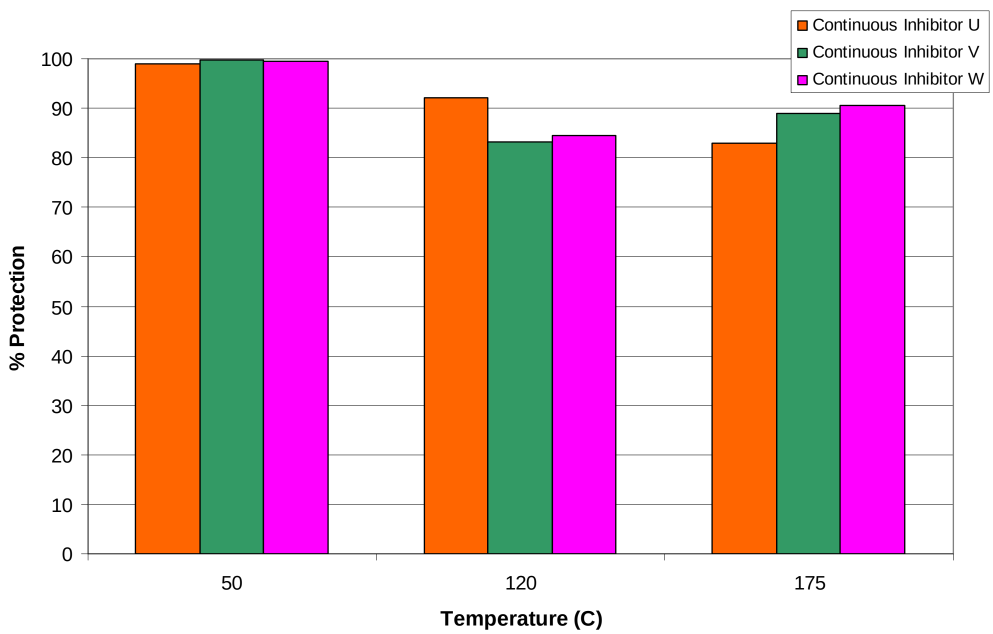

FIGURE 12 - Percent protection profile of continuous corrosion inhibitors for Shale Gas recovery in Western Canada

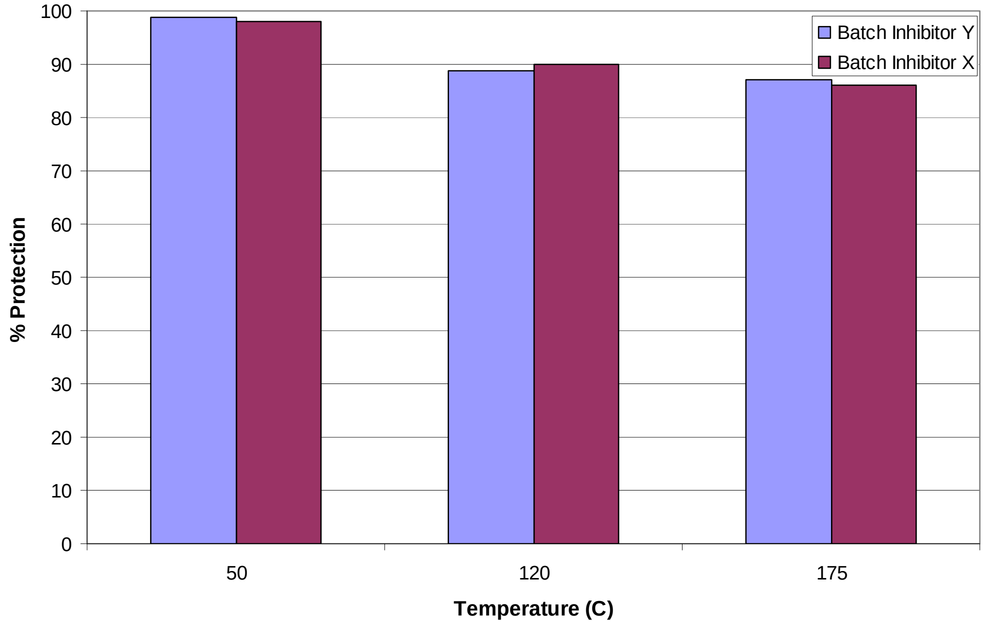

FIGURE 13 – Percent protection profile of batch corrosion inhibitors for Shale Gas recovery in Western Canada