

## **Management of Corrosion in Shale Development**

Bruce Craig  
MetCorr  
100 Fillmore St.  
Denver, CO 80206

David Blumer  
BlumCorr  
5624 E. 40<sup>th</sup> Avenue  
Anchorage, OK 99504

Sytze Huizinga, David Young, Marc Singer  
Institute for Corrosion and Multiphase Technology  
Department of Chemical & Biomolecular Engineering, Ohio University  
342 West State Street,  
Athens, OH 45701

### **ABSTRACT**

In recent years, production of oil and gas from shale formations has multiplied and now contributes significantly to oil and gas supply. This type of unconventional production differs from historical conventional approaches, with far reaching consequences for asset integrity management. The present paper outlines corrosion threats associated with shale development, including acidizing, fracturing, flowback, CO<sub>2</sub> and H<sub>2</sub>S in produced fluids and artificial lift. Usually little detailed information about corrosive exposure is available upfront. The production mode contributes to complex and highly variable environmental conditions. Corrosion cracking and weight loss corrosion of well completion materials are known to have occurred. Whereas classical asset integrity management is usually rolled out over many years, the typical timescale in shale production ranges from just months to a few years, driving low-cost, quick earn-back scenarios. This paper discussed the consequences for materials selection and corrosion control.

Keywords: Shale, unconventional, fracturing, corrosion control, integrity management, material selection

### **INTRODUCTION**

The United States has abundant natural gas resources that play a major role supplying energy to homes and businesses. Data for 2017 collected by the U.S. Energy Information Administration (EIA) showed that petroleum and natural gas supplies approximately 66% of the nation's energy, with natural gas alone delivering about 26%. <sup>1</sup> Shale gas resources extend across the lower 48

U.S. states, with an estimated potential of 324 trillion cubic feet.<sup>2</sup> However, development of these shale-based resources has also generated numerous technical challenges related to well integrity.

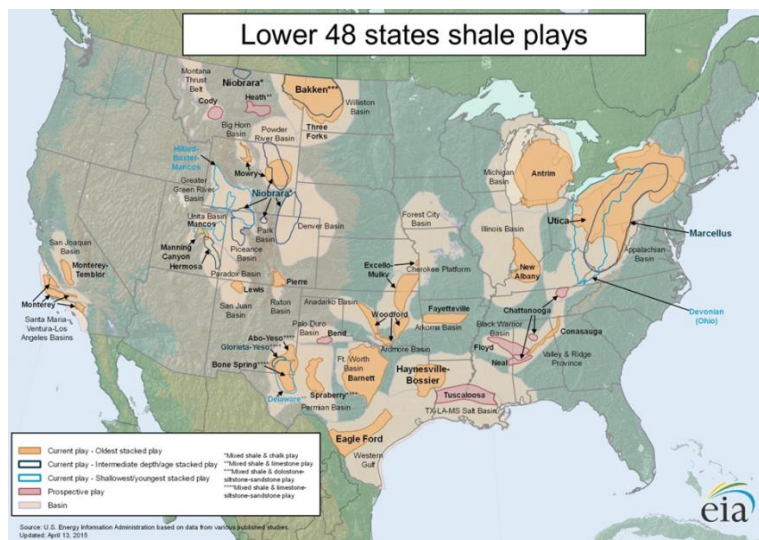
The management of corrosion in downhole environments is a serious challenge for the oil and gas industry in general. Downhole conditions, mainly pressure and temperature, can change dramatically over operating life, especially in the first several months, as the hydrocarbon resource depletes. The chemistry, and volume, of flowback/produced water after hydraulic fracturing will change. Although water is expected to condense at some point along tubing for gas wells, formation water may appear only later in the production life, increasing water cut and bringing additional issues related to water wetting, scaling and under-deposit corrosion. Wells may require acidizing or artificial lift to maximize production, changing fluid compositions and altering the nature of the corrosion threat.

## SHALE PLAYS AND PRODUCTION IN THE UNITED STATES

The Bakken Austin Chalk Eagle Ford Permian Basin (Wolfcamp and Delaware) and Spraberry plays are forecast to dominate domestic oil production. Shale gas has been steady in some areas such as the Barnett and Marcellus with the Haynesville gaining renewed production to provide gas to the Gulf coast to feed LNG exports. Moreover shale gas is often rich in natural gas liquids (NGLs), in particular propane and butane, which are key precursors for the petrochemical industry.

### Gas composition

There are numerous shale basins around the world, however, those located in North America are better characterized due to their development and, therefore, more information is available for these plays. Figure 1 shows select key tight oil and shale gas regions. The Marcellus and Utica are aggregated therein, due to their having geographically overlapping geologic formations.



**Figure 1: Shale gas plays, Lower 48  
(Reproduced from <sup>3</sup> – © USEIA 2015)**

However, these shale plays are by no means homogeneous and, in fact, can have highly variable production and fluid properties. It is not the purpose here to catalog all the shale basins and their variations, but Table 1 and Table 2 present some typical values for parameters important to corrosion evaluation and control for several of them. The data are derived from various published reports for the Barnett, New Albany, Antrim, Bakken, Marcellus, and Utica shale gas plays and from the authors own work in various shales.

**Table 1**  
**Key data for the Barnett, New Albany, Antrim, Bakken, Marcellus, Hyanesville, Eagle Ford and Utica shale plays**

Formation	Barnett	New Albany	Antrim	Bakken	Wolfcamp	Marcellus	Utica
Location	Texas	Illinois	Michigan	N. Dakota, Montana	Texas, New Mexico	Pennsylvania, New York, Ohio, West Virginia	Appalachian basin
Depth, ft	6,500 – 8,500	500 – 2,000	600 – 2,200	7,000 – 11,000	16000	4,000 – 8,500	4,000 – 11,500
Thickness, ft	100 – 600	50 – 100	70 – 120	-	-	50 – 200	-
% methane	80 - 94	88 – 93	27 – 86	-	-	80 – 96	-
% CO <sub>2</sub>	0.3 – 3	5 – 10	3 – 9	-	0.4	0.1 – 0.9	nil

**Table 2**  
**Gas composition, chloride content and initial production conditions from several major shale plays**

Location	Well Type (Oil/Gas)	Initial Production		H <sub>2</sub> S (ppm)	CO <sub>2</sub> (%)	Cl <sup>-</sup> ppm
		BHP, psi	BHT, °F			
Bakken	Oil	7,500	240	0-1000	~ 1	20,000-170,000
Haynesville	Gas	9,000	350	0-5000	2-6	50,000 -175,000
Fayetteville	Gas	2,000	150	5-200	1 - 7	~100,000
Eagle Ford	Oil & Gas	4,000	250	20 – 40,000	2- 5	20,000 – 160,000
Woodford	Gas	4,000	235	0-5	1-5	20,000-100,000
Horn River	Gas	4,000	300	5-20	10-15	~ 25,000
Permian	Oil & Gas	7,500	160	0 - 2000	1-2	40,000 – 100,000
Barnett	Gas	4,000	180	0 - 750	2.5	~ 40,000

### Oil composition

Shale oils can range from condensates to more viscous crudes (35-60° API gravity). Compositionally, they are often closer to condensates than conventional black oil, with a high wax content and low asphaltene fraction. The oils tend to be poorly wetting on steel and other surfaces, primarily due to the low concentration of polar compounds. The oil volatility can have an effect on the solubility of the acid gases in the hydrocarbon phase, which can change the fugacity of CO<sub>2</sub> and H<sub>2</sub>S in the vapor phase as the production stream flows from the reservoir through the well. This behavior makes it more difficult for the corrosion engineer to predict potential threats based on past experience with conventional oil wells, without running a comprehensive model which incorporates the PVT behavior of the production stream.

The water cut may also be increasing as the oil production wanes, increasing the corrosivity. Other factors complicating the shale oil and gas recovery is the entrainment of solids in the production stream, which include hydraulic fracturing proppant/sand, formation rock solids/fines, and precipitates from scale formation and corrosion products. Also waxy solids are often observed in shale oil, that can precipitate when the temperature cools below the oil's Wax Appearance Temperature (WAT), and which can occur both downhole and on the surface.

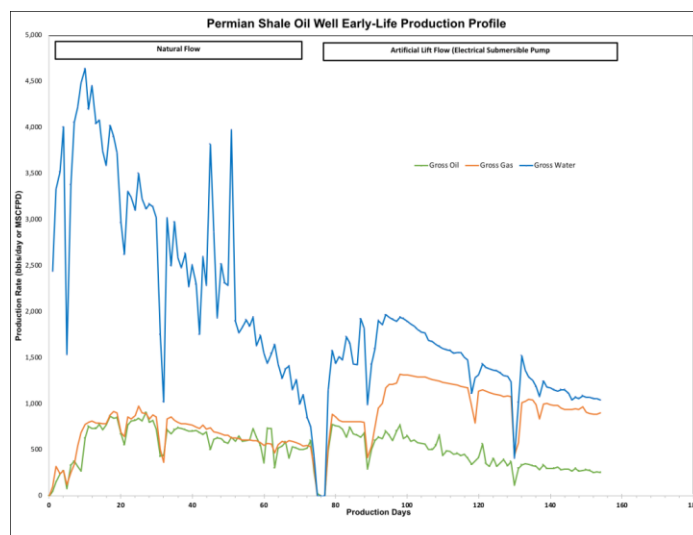
### **Production profiles and related corrosion issues**

Production rate forecasting, oil & gas prices, and reserve estimation drive both the budget and the required asset lifetime to recover the booked reserves of shale wells. The water production rate strongly drives the demand for corrosion control chemicals while the oil & gas production provides the revenue for their purchase. It is an unfortunate circumstance when these move out of phase, which is not uncommon. If the reserve estimates are grossly incorrectly low, then the capital required to install corrosion resistant alloys or chemical treating equipment will be economically unjustifiable.

Generally, shale oil and gas wells and facilities are not designed for long life, simply because the financial rules do not recognize any substantial value for the long term, making investment in corrosion-resistant designs financially irrational, for example.

Note the example production profile below (Figure 2) of a high-liquids shale well and the complete loss of flow to the surface after only 74 days, falling from a peak of 877 BOPD, 4638 BWPD and 921 MSCFPD over days 12-27. During this period, the well was flowing to the surface without any assistance through the P-110 5.5" production casing (no tubing present), driven solely by the pressure of the shale reservoir. The well produced a total of 44 Mbbbls of oil, 189 Mbbbls of water and 48 MSCF of natural gas during these 74 days. Generally any additional production requires a rig workover to install artificial lift equipment and tubing to bring the fluids to the surface. After installing artificial lift (an Electrical Submersible Pump or ESP in this case) production rates rise with oil peaking at over 700 BOPD and gas bumping 1400 MSCFPD, with water jumping to 2000 BWPD; the rates go on a steady decline thereafter.

The high strength steel casing is unprotected from corrosion during that initial flow period, simply due to the lack of any way to deliver corrosion inhibitor chemicals downhole. Solids production, consisting of hydraulic fracturing proppant and formation fines, commonly accompanies that initial flow and leads to erosion and erosion/corrosion at the high velocities at the peak rates. It has not been common industry practice to inspect the well casing prior to running the tubing and artificial lift, so little is known regarding the location and amount of damage, if any, incurred during this brief production period when the produced fluids flow up the casing. In the example shown above, the workover occurred almost immediately after the natural flow stopped, with only a few days of well shut-in.



**Figure 2: Example of production history (180 days)  
green: gross oil; orange: gross gas; blue: gross water**

### Stages of fracking and related corrosion issues

Horizontal drilling followed by hydraulic fracturing is key to facilitating production from shale. Once the well has been drilled the casing, and cement in the annular space, is then perforated in the intended production zones. The well is then fraced, in a multi-stage process, with high pressure water containing various additives, including a proppant (to keep the fractures open) and various chemicals (acid, corrosion/scaling inhibitors, etc.). A significant volume of this introduced frac fluid is produced as flowback water along with shale gas and shale/tight oil, requiring treatment and disposal. Significant corrosion issues can be encountered associated with production, particularly relating to the composition of produced gas.

Also, some erosion and corrosion damage are likely during the frac job itself, considering the typical high frac pump rates (~100 bbl/minute or ~144,000 bbls/day) down the 5.5" casing and enormous volumes (>300,000 bbls in this case) of sand/proppant slurry at ~2 lb/gallon (approximately 5,000 tons proppant total) injected. These volumes are divided amongst each stage of the job. The number of stages is variable but can range from 10 – 125, with more recent shale wells often having >100 stages as technology has advanced. The water used is usually saturated with air, so oxygen corrosion is expected; seldom are oxygen scavengers or corrosion inhibitors added to the frac water, though friction reducers, viscosifiers/gels, biocides, gel breakers, scale inhibitors and surfactants are common chemical additives. In most shale frac jobs, an initial slug of hydrochloric acid (15% commonly) precedes each stage of the frac treatment to reduce the pressure required to start the crack in the rock, which can total 50,000 gallons of acid or more, usually along with a special acid corrosion inhibitor and other additives. The large quantity of HCl has been the suspected source of some of the environmental cracking failures of P110 casing and couplings during the first stage frac. The procedure may require 7-15 days to complete and then the well may be shut-in until the surface facilities are ready to accept the

production flow, which can vary from a few days to months. The pressure in the well declines quickly immediately after the frac pumps are stopped.

Corrosion exposure for the production casing exists throughout the completion and fracture stimulation process due to the introduced fluids and subsequent flow up casing during early production. It has not been common practice to inspect the condition of the casing after the end of the shale well completion process or even after flowback.

If there is a “gap” shut-in period immediately at the end of the frac job and prior to putting the well into production, the well pressurizes with gas, saturating the water in contact with the production casing with corrosive gases, specifically CO<sub>2</sub> and H<sub>2</sub>S, if present. These pressures may reach several thousand psi, with surface pressures around 6,000-7,000 psi observed, though this is not usually known in advance. Thus, the partial pressures of the corrosive gases may be high, even if their concentration is low.

In these wells, the horizontal section usually contains a liner, which may be smaller diameter than the production casing, for instance a 4.5” liner with a 5.5” casing. In most cases, it will also be high strength carbon steel, such as P-110 or something similar but higher strength such as High Collapse (HCP)-110, to ensure the pressure capability during the frac job. In virtually every “horizontal” or lateral section, there are undulations in the vertical dimension, much like a pipeline that follows topography. This creates local “hills” where gas bubbles develop and “valleys” where water and solids may collect. Seldom is accommodation made in the design phase for corrosion mitigation of this part of the well. The common attitude of the production engineers is that the long-term integrity of the lateral liner is not important; once its function during the frac job is done, it is disposable. However, for the corrosion engineer, a certain consequence is that the free unmitigated corrosion of the long lateral carbon steel liners for the life of the well introduces large quantities of dissolved iron (sometimes >300 mg/l) and manganese into the produced water. This has knock-on effects upon the rest of the production system that require consideration, since the produced water chemistry is substantially altered. These details of the well construction lay the traps for the corrosion engineer for the future.

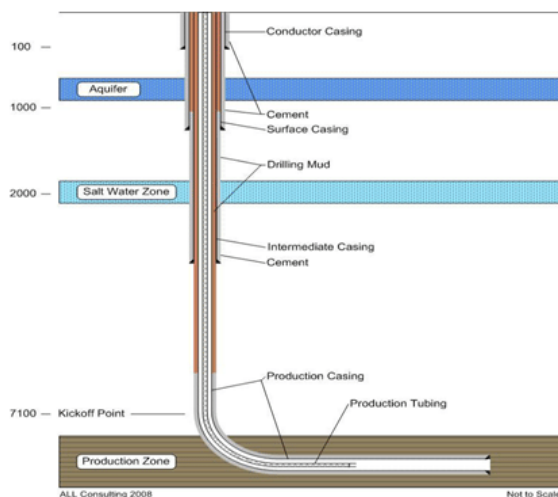
## **BASICS OF HORIZONTAL DRILLING AND RESERVOIR FRACTURING**

### **Drilling and well completion process**

Horizontal drilling holds an important role in the development of shale gas plays. It constitutes an effective means of stimulating production in otherwise low-permeability rock formations. <sup>4</sup> Figure 3 shows a typical horizontal well schematic. <sup>5</sup>

Casing strings of decreasing diameters are inserted into the hole while cement is injected to fill the space between the outside of the casing and the hole. Typically, a well will have a surface casing, an intermediate string and a production casing. The latter is commonly 4½” or 5½”, 20 ppf or 23 ppf P110 casing and in many cases high collapse P110 (HCP), although other grades such as L80 are also used. More details on the use of high strength casing and the risks involved are presented in Section 3.2.3. Smaller diameter production tubing is inserted inside the casing together with associated packing. Material selection for the tubing also depends on the downhole

conditions (CO<sub>2</sub>/H<sub>2</sub>S content, bottomhole temperature, chloride content, etc.). Martensitic stainless steels (i.e., 5CT L80 13Cr, 13Cr-6Ni-2Mo) are used for the most aggressive wells. However, these materials are expensive, and the use of plain carbon steels will offer considerable cost savings as long as the corrosion threat is assessed and managed properly.



**Figure 3: Typical well configuration**  
(Reproduced from <sup>5</sup> – © Ground Water Protection Council and ALL Consulting 2009)

### Fracturing fluids and additives

Pressurized fracturing (fracing) fluids are injected into the wellbore in order to fracture the rock formation, creating cracks through which petroleum products can flow more easily. Fracing fluids are typically a mixture of water (90%), proppant (9.5%) and additives. The proppant comprises of silica based compounds that prevent the collapsing of rock fractures created by the injected fluids. Several types of fracing fluids are used (gel, foam or slickwater based) depending on the desired fracturing type and are selected based on the desired balance between high viscosity, which keeps proppant in suspension, and low friction, which allow higher pumping rates. Table 3 presents a summary of the main components of fracing fluids and their associated purpose. <sup>6,7</sup>

**Table 3**  
**Typical composition of slickwater fracing fluids <sup>6,7</sup>**

Type	Purpose	Concentration
Water	Main solvent	90-95 vol%
Proppant – <i>silica sand</i>	Prevents collapsing of created fractures	4.5-9.5 vol%
Chemical additives		<0.5 vol.%
<i>Friction reducers</i>	Reduces friction as the fluid is pumped	
<i>Gelling agents</i>	Increases fluid viscosity for proper transportation of proppant	
<i>Crosslinkers</i>	Increases molecular weight of polymers, viscosity	
<i>Breakers</i>	Reduces molecular weight and viscosity Ideally should be inactive during treatment and only kick off when production is ready	
<i>Buffers</i>	Controls pH	
<i>Surfactants/Mutual solvents</i>	Reduces surface tension	
<i>Biocide/Bactericides</i>	Minimizes enzymatic attack of polymer and growth of bacteria	
<i>Corrosion inhibitor</i>	Protects casing and equipment	
<i>Scale inhibitor</i>	Prevents precipitation of mineral scales on the casing wall	

## Flowback and produced water

After hydraulic fracturing of a shale formation takes place, large volumes of water return to the wellhead along with the produced gas. This can be described as flowback water or produced water, the former being what is immediately returning post-fracing whereas the latter is the longer-term aqueous product, *i.e.*, after prolonged contact with the geologic components of the fractured shale.

Fracturing fluid itself, as also discussed above, consists of a variety of components including water (>90%), silica sand as a proppant, acids such as HCl to facilitate mineral dissolution in the shale matrix, clay stabilizers to prevent swelling, scale inhibitor, surfactants to enhance viscosity, drag reducers, biocides, gels to entrain proppant, chelators to prevent precipitation, and corrosion inhibitors.<sup>4-8</sup>

Consequently, flowback water will, to varying degrees, contain higher concentrations of species associated with the original fracturing fluid than produced water. In comparison with flowback water, produced water will possess higher concentrations of shale-derived suspended/entrained solids, heavy metal ions, organic species and even, potentially, naturally occurring radioactive materials (NORM).

Entrained solids in both flowback and produced water can potentially initiate erosion-corrosion or deposit on pipe walls, leading to underdeposit corrosion and challenges with corrosion inhibition. Both flowback and produced waters will contain dissolved CO<sub>2</sub> and, potentially, H<sub>2</sub>S; their presence being governed by the compositional characteristics of the shale that has been fractured as well as the produced gas. Dissolved CO<sub>2</sub>, which forms H<sub>2</sub>CO<sub>3</sub> in the presence of H<sub>2</sub>O, and H<sub>2</sub>S are acidic species which readily corrode carbon steel surfaces. Organic species that occur are derived from paraffinic or kerogenic components within the shale, these can also be deposited on metal surfaces. 'Naturally Occurring Radioactive Material' (NORM) is most likely present as radium or uranium compounds, the former having a tendency to precipitate with barium as a sulfate. Barbot, *et al.*, demonstrated the presence of both the aforementioned radionuclides in produced water from hydraulically fractured Marcellus shale.<sup>9</sup>

Given their composition and high volumes, the generated flowback and produced waters present particular environmental risks, including contamination of near surface aquifers used for drinking water. This necessitates best practices are followed for their disposal, or potential reuse. Disposal is frequently by injection into deep wells, although different strategies for wastewater management have been increasingly utilized including reuse and on-site treatment.<sup>10</sup>

## CORROSION RISKS

### Risk assessment at the heart

In oil and gas production, there are very few cases where corrosion can be ignored. Water and acidic gases are normally co-produced with oil and gas, causing steel to degrade from aqueous corrosive attack. Next to metal loss corrosion, corrosion cracking can come into play for certain environmental and construction material combinations. It is therefore recommended, already in



the design phase of a project, to carefully assess the possible corrosion degradation modes throughout the life of the production facilities, from well to plant. Risk assessment is at the heart of this exercise, minimizing risk of damage to people, environment, assets and reputation to an acceptably low level by considering all credible failure scenarios in terms of their likelihood and consequence. Unfortunately, this effort is far from being a common practice for most small/medium size shale companies who lack the resources for such undertakings.

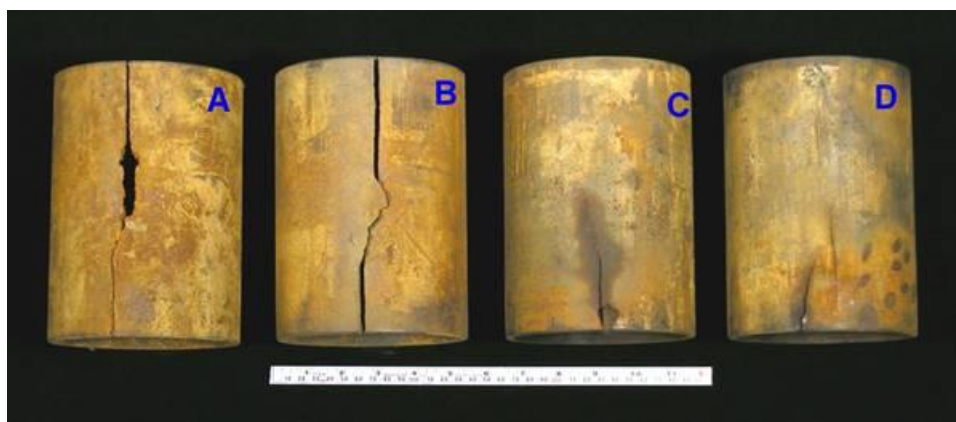
## Experiences specific to shale development

### Limited resources and cost saving approach

Due to the rapid decline in production from shale wells, the industry makes every effort to minimize the cost of all well operations and construction of wells and facilities. To this end, multiple wells are drilled from one pad using the minimum number of casing strings. By standardizing on casing, and other well components, millions of feet of casing can be purchased at one time to save cost. The same is true for tubing and other downhole jewelry. Facilities (*i.e.*, separators, piping, flowlines, etc.) are all low strength carbon steel for the same reason of cost effectiveness. Of course, none of these low cost items has any inherent corrosion resistance, therefore, corrosion control must be considered from day one using other methods.

### Hydraulic Fracturing

By and large, there are not many corrosion and materials issues encountered during and soon after fracing but there have been and continue to be notable failures, primarily environmental cracking of casing and occasionally some surface equipment (e.g., pumps, valves, etc.). Burns and Buehler presented several failures of P110 casing that occurred around the time of fracing and, many times, as a longitudinal split (see Figure 4).<sup>11</sup>



**Figure 4: Four cracked couplings from a single casing string  
(Reproduced from<sup>11</sup> – © ASM 2010).**

Others have observed the same problem often in the couplings, especially for 8–Rd connections. It is known that API 8– Rd connections can attain stresses beyond yield thereby further increasing the risk of environmental cracking from which all the failures were attributed. Many such casing failures, while attributed to environmental cracking, are expected to be from hydrogen stress

cracking but the source of hydrogen is not easily determined. In many cases, there is no H<sub>2</sub>S in the wells or during the frac so classic sulfide stress cracking (SSC) is not always the mechanism. However, it is common practice to use a preflush of 15% HCl acid before the water-based frac fluid is pumped, as described above, and this could be one of the sources of hydrogen. Determining the source of environmental cracking is further complicated by the fact that the majority of shale well casing failures are on the outside of the casing, predominately in the couplings, although the change to lower stress premium connections by some operators has lessened the number of failures. Still, the location of cracking on the OD of the casing suggests poor cement jobs or other extenuating causes.

There is considerable speculation in the industry surrounding the presence of H<sub>2</sub>S in shale wells. Many believe the appearance of H<sub>2</sub>S is due to bacterial activity introduced with frac water or other sources during drilling but this seems an oversimplification and, in fact, cannot explain such high H<sub>2</sub>S contents as observed in the Eagle Ford.

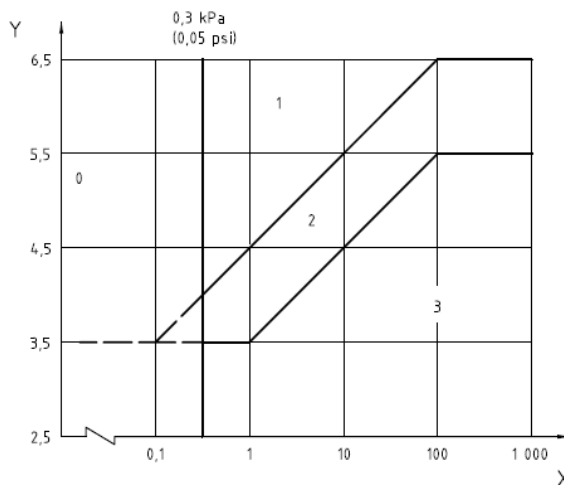
In some areas of the Eagle Ford, very high concentrations of H<sub>2</sub>S were encountered which necessitated advanced analytical studies, including isotope analyses. The high reservoir temperatures (107-135 °C or 225-275 °F) made microbial activity there less likely but not entirely out of the question. The most likely source (though not completely proven) is tied to another formation with very high H<sub>2</sub>S which is being connected via the hydraulic fracture system. The actual concentrations observed in those wells is quite variable, depending on the relative flow contribution from that high-H<sub>2</sub>S zone. Among a group of wells, some fractures will have more connection to that zone than others. Also, as the well's pressure drawdown changes, more or less flow will be drawn from that zone, making future predictions highly uncertain.

A significant unknown and concern from a corrosion and cracking standpoint is the industry trend to re-frac wells. This has serious ramifications from a well integrity standpoint for several reasons that presently cannot be quantified. For sour wells in which P110 casing has been exposed to H<sub>2</sub>S for months or years without cracking from SSC, there still exists a high concentration of trapped hydrogen in the steel that, while not critical at the low stresses of normal production, could cause failure when the well is re-fraced at a high pressure. Another potential problem is the amount of wall thickness loss incurred on the production casing from corrosion after flow has occurred up the casing for 6 months to one year. If it is significant the casing may not withstand the high re-frac pressure.

### Wells and Production

As previously mentioned many shale wells are drilled and completed with HCP110 production casing. However, in areas where H<sub>2</sub>S is known to be present many operators, but not all, try to comply with the requirements of NACE MR0175/ISO 15156 (Figure 5) which severely restricts the use of P110 casing. These operators therefore use T95 casing or more recently, depending on the sour region in the NACE standard, will run one of the mildly sour versions of P110. It is a conundrum as to why so many wells with P110 casing exposed to H<sub>2</sub>S in excess of the NACE limit do not develop failures from SSC, especially since there are millions of feet of the casing exposed. One possible reason is the shorter time of exposure in shale wells compared to

conventional oil and gas production. The rapidly declining partial pressures of H<sub>2</sub>S in shale environments may not allow the required critical hydrogen content needed to initiate SSC to be reached for enough time. However, the required parameters related to hydrogen content and time to failure cannot be quantified at this time so the risk of SSC is still a consideration.



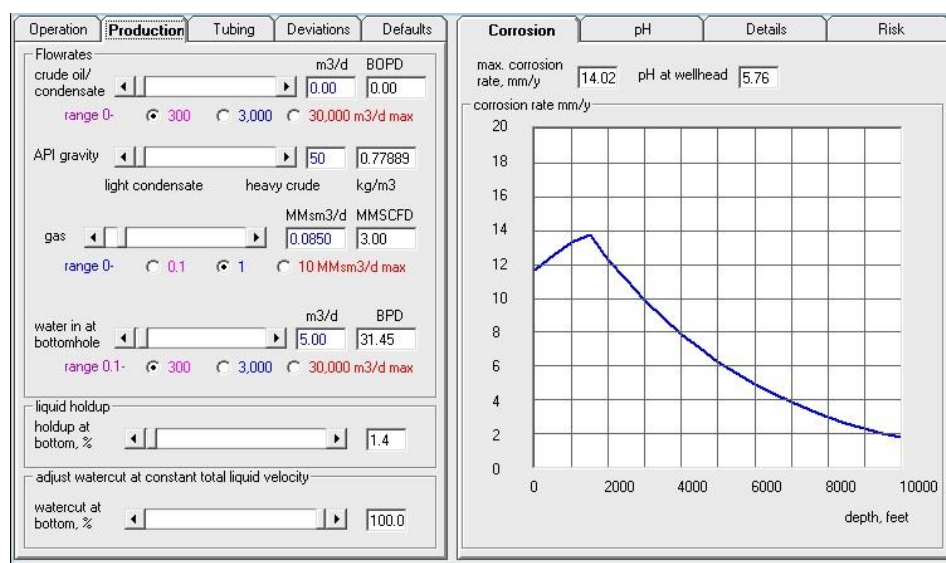
**Figure 5: Regions of severity with respect to SCC of carbon steels**  
**X: pH<sub>2</sub>S (kPa), Y: *in situ* pH,**  
**(Reproduced from <sup>12</sup> – © NACE 2003)**

Besides the H<sub>2</sub>S levels, the *in situ* pH of the water encountered is an important parameter in SSC. An in-depth study of wells with levels of H<sub>2</sub>S that exceed 0.05 psia (Region 0) showed that there was a wide range of pH conditions, even with 1.5 psia H<sub>2</sub>S, which pushed some wells into Region 1 or on the boundary, while others were solidly in Region 2 and Region 3. Thus, whether a well is going to have SSC issues requires an understanding of both the pH and H<sub>2</sub>S fugacity, as well as the actual hoop (circumferential) and axial stress conditions.

While pursuing the H<sub>2</sub>S question, a new issue has arisen with respect to measurement of actual H<sub>2</sub>S versus organosulfur compounds and implications for corrosion and SSC modeling. When discussing SSC, it is assumed that the H<sub>2</sub>S measurement is accurately reflecting the true concentration of H<sub>2</sub>S in the gas phase. Upon investigation, it was discovered that many of the analytical methods used to measure H<sub>2</sub>S are non-specific, but also respond to organosulfur compounds. This artifact is not a minor adjustment; in many cases, the H<sub>2</sub>S is actually the minor species in a mixture of many organosulfur compounds when the gas sample is analyzed using a specialized gas chromatograph with a sulfur-selective detector.<sup>13</sup> In the case of an Eagle Ford well, the headspace vapor from an oil sample received in the laboratory was analyzed with a Dräger gas detection tube (a standard field H<sub>2</sub>S analysis method), with a measured value of 82 ppm H<sub>2</sub>S. A sample of this vapor was then analyzed by gas chromatography (GC SSD). The GC found the actual H<sub>2</sub>S concentration was only 11 ppm, with the remaining sulfur compounds distributed among over 20 organosulfur species, including mercaptans, organosulfides and disulfides, alkylthiophenes, benzothiophenes, etc. This observation raised a question: if a field measured H<sub>2</sub>S value is not really just H<sub>2</sub>S, then how can an assessment of the SSC threat be properly performed? It is not common to perform a GC speciation analysis on field samples. In the highly volatile shale oils, how much of the H<sub>2</sub>S being reported is actually other compounds?

Does this account for some of the puzzling cases where SSC would be expected, but is not observed?

Once shale wells are fraced the initial production (IP) pressures are typically high enough for free flowing production, most often accomplished up the casing without tubing in the hole. Once production declines to a certain level, tubing is run as well as some form of artificial lift utilized. The main driver for corrosion in all the shale wells is CO<sub>2</sub> corrosion, which can be modeled, at least as it pertains to gas wells, with many of the industry software programs. However, very few models properly take into account multiphase hydrocarbon-water mixtures and the effect of oil/water wetting. Figure 6 shows an output from one such model for a Haynesville gas well at IP. Note the maximum corrosion rate was predicted at a depth of approximately 1500 ft. As predicted by the model the tubing failed by CO<sub>2</sub> corrosion in just a few months. This in fact has been, and continues to be, a significant problem in the Haynesville shale play. Some operators have opted to run 13Cr tubing or the various hyper/super 13Cr alloys to combat this. Once the production pressures fall from the high IP, the corrosion rates also significantly drop.



**Figure 6: Example of corrosion modeling results for a Haynesville gas well. <sup>14</sup>**

The choice of artificial lift methods is dependent on many factors including operator preference. However, rod pumping is common in the Eagle Ford and electric submersible pumps (ESPs) in the Bakken. Other methods are plunger lift for gas wells and, in some basins, jet pumps. Most often equipment such as rod pumps and ESPs are set in the vertical section of the well just above the kickoff point. These methods of producing oil and gas are difficult to model or predict corrosion for because of the intermittent nature of lift methods, and for rod pumping and plunger lift the additional factor of wear on the tubing ID. Furthermore, none of the currently existing corrosion models satisfactorily models the entire life of a shale well from initial production (IP) to low production with artificial lift, even though the ability to do so would greatly benefit economics over the life of shale wells.

Another difficulty in shale wells is the means and effectiveness of corrosion management which is primarily done with chemical inhibition. The challenges boil down to choosing the best inhibitor for the life-stage of a well, determining the optimum dose, applying it where it will reach and protect the steel, and getting accurate and timely monitoring information to verify its efficacy, while spending the least amount of money. That list seems to be orthodox, but there are some nuances particular to shale oil and gas production. Not the least is the historical framework of the shale revolution, which developed so fast that very little of the front-end corrosion engineering technology and expertise normally applied in modern major oilfield development projects was included. The role of microbial action downhole in shale wells is another challenge. As mentioned earlier, some shale plays, e.g., the Eagle Ford, have areas with very high reservoir temperatures, above 149°C (300°F), which many experts believe constrains the viability of microorganisms and makes MIC of downhole equipment and tubulars unlikely. On the other hand, shale reservoirs in the Permian, Niobrara, and the Bakken do not have the benefit of such high temperatures and are in the zone where microbial viability and MIC is well established in conventional fields.

One risk factor for active microbial activity is the presence of volatile organic carboxylic acids (e.g., formic, acetic, propionic, butyric, etc.) in the produced water, since these compounds are excellent microbial food sources along with direct effects on corrosion and scale deposition. In most large-scale conventional oil and gas fields, the water sampling and analysis protocols include organic acid constituents since these are acknowledged to play important roles. However, there is a dearth of information on the organic acid content of shale derived produced waters, so it is difficult to assess the degree of risk. The reasons for the lack of information seems to primarily stem from the lack of accurate analysis of water samples for these organic acids, along with recognition of their importance, lack of obtaining stabilized water samples, availability of the laboratory instrumentation, analytical methods adapted to these water compositions and the analytical chemistry expertise required.

There is some information, however, which suggests that organic acid concentrations are not negligible. After identification of suspected MIC in downhole rod pumps and tubing, coupled with rather low 0.3% CO<sub>2</sub> and H<sub>2</sub>S (10-50 ppm) concentrations, a corrosion driven hole was observed to develop over a 189-day period (~430 mpy) in a Wolfcamp Midland Basin well in West Texas; the produced waters were sampled and found to range from 150-600 mg/L in organic acids, strongly dominated by acetic acid. In this case, the downhole temperature was 60°C (150°F), which is well within the microbial viability zone. Conventional bacterial serial dilution monitoring for SRB and APB at the wellhead had all four inoculated SRB bottles turn positive. Unfortunately, this means that the actual bacterial levels were not established, just the lower bound of 10<sup>4</sup> SRB. Later testing of the same wells showed all 6 bottles inoculated were positive for SRB, indicating a population of at least 10<sup>6</sup> bacteria. These wells were treated weekly with a batch corrosion inhibitor, with a record of all scheduled treatments pumped. These rapid corrosion failure rates were not universal, with only approximately 20% of the 200+ wells affected. The economic impact of this is considerable, with significant production losses, workover rig costs, chemical treatment costs, and operations as well as engineering manpower demands that can push operating profit margins negative in low oil price conditions.



**Figure 7: MIC attack and hole in 2 3/8" tubing experienced in downhole environment of Midland Basin Wolfcamp well (189-days after completion).<sup>15</sup>**

Similar downhole rapid failures in other operators' wells in the Wolfcamp Shale zone and in the Permian Delaware Basin suggests that corrosion challenges remain unmet, despite what might be considered relatively low CO<sub>2</sub>-corrosion risk conditions and involving aggressive batch and, sometimes, continuous downhole injection corrosion inhibitor treatments. In addition, H<sub>2</sub>S levels of some of those Delaware Basin wells range from 5 ppm up to over 2,000 ppm. Special water sampling of a limited well population has shown that the organic acid levels average about 180 mg/L, which is sufficient to be considered a risk factor for MIC given the moderate downhole reservoir temperatures.

In some Bakken wells in North Dakota, different downhole corrosion challenges are found. Some proportion of the wells produce, during a period of their life, brine that is supersaturated with respect to salt (NaCl) precipitation. Many operators resort to continuous downhole injection of "fresh water" to prevent plugging of the well downhole and surface facilities with salt deposits. Some wells require 40 bbls or more of fresh water daily to maintain plug-free production. Most typically, this water is injected at the wellhead into the casing-tubing annulus, falls to the bottom (~7,000-10,000 feet), mixes with the production stream downhole and then is produced back to the surface.

The source of the fresh water varies widely, ranging from surface sources (ponds, lakes, streams and rivers) to water wells producing from potable-to-brackish aquifers. Water treatment practices seem to vary, with some injecting biocides and oxygen scavengers while others forgo the chemicals entirely or only inject biocide to the atmospheric-vented water storage tanks on the well sites. Often, no monitoring of dissolved oxygen in the fresh water occurs, nor does there seem to be an established criterion for this application. Unpublished failure analyses by the authors have found that dissolved oxygen plays a role in the downhole corrosion failures, especially on ESPs. However, others suggest that any dissolved oxygen in the fresh water is rapidly scavenged when it mixes with the produced water downhole which contains high amounts of dissolved iron. This deserves further investigation, particularly of the Fe(II)/Fe(III) ratio, of the diluted produced water

at the surface, along with the effect of the Fe(III) on corrosion. Since many of these wells also have a low concentration of H<sub>2</sub>S, that may be also important.

Commonly though, the corrosion and scale chemicals are entrained into the fresh water stream “on the fly” as they are injected downhole, which provides a robust continuous delivery method for these treatment chemicals. Highly precise metering pumps have been locally developed and provide a continuous record of the inhibitor dosing, ensuring a good record of the actual dose. In certain cases, additional batch corrosion inhibitor treatments are also pumped down the annulus in an attempt to suppress the rapid corrosion activity. Again, rapid well corrosion failures downhole are not universal, but a substantial proportion do fail within 6 months to 2 years after initial completion or after a workover for a previous corrosion failure or for other reasons, such as replacing a mechanically-failed pump. It has been speculated that the very high chloride content of the produced water reduces the efficacy of the corrosion inhibitors, though another possibility lies in the unusually high dissolved iron concentration; often in the 300 ppm range.

It is apparent that the corrosion inhibitors developed for downhole application in conventional oil and gas wells are not performing very well in the new shale fields. The awareness of this deficiency is still developing, at least partially due to the minimal corrosion monitoring and inspection performed on these new shale wells and expectations based upon the chemical treatment volumes/frequency relative to nearby conventional wells. This apparent inhibitor performance gap is a topic requiring more investigation and understanding.

### Flowlines and Facilities

One of the greatest problems for flowlines and facilities is the need to design them to handle IP conditions but which only last for the first 6 months to one year. Thereafter, the produced fluids, especially oil and water, moving through what has become oversized equipment for the lower production rates often results in stagnant or low flow conditions. This makes chemical inhibition for corrosion control quite difficult, plus it enhances the chances for MIC which in fact is a common problem. Furthermore, there have been cases of pitting leading to stress corrosion cracking in flowlines in some fields.<sup>16</sup> These failures were attributed to spent H<sub>2</sub>S scavenger that reacted over time in the flowlines to form dithiazine and monoethanolamine (MEA). This is an unusual cause of stress corrosion cracking and a potential problem in other shales since H<sub>2</sub>S scavenger is widely applied in the treatment of gas from shale wells.

Almost all of the shale producing regions in the US have bacteria of various types in flowlines and facilities, similar to the downhole issues discussed above. Most often these are sulfate reducing bacteria (SRB) and acid producing bacteria (APB).<sup>17</sup>Error! Reference source not found. If not monitored and treated aggressively, they can lead to corrosion and safety issues; particularly in low-flow areas, tanks and wherever solids collect.

## **CORROSION MANAGEMENT**

It is evident that for different production conditions and environmental parameters, outcomes in terms of materials selection and corrosion control measures can vary tremendously thereby

impacting infrastructure lifespan. Typically, conventional production deals with a much longer required facility life than shale oil or gas production, leading to little use of capital intensive choices like corrosion resistant alloys for the latter. Even though production in shale plays turns out differently than in conventional production, the methodology used in the latter may serve to optimize integrity management from conception to abandonment. Using a structured and documented approach to integrity management also serves the important purpose of demonstrating to authorities and the public at large that risk is controlled, *i.e.*, that the operator deserves their license to operate.

To facilitate the corrosion management process, this section sketches the outline of the required approach; a so-called Corrosion Management Framework is described in items A) – G).

### **A) Define production conditions, from reservoir to plant**

An assessment of production conditions, starting with the reservoir and following the production stream, should facilitate an evaluation of the corrosivity of the produced fluids. Attention needs to be paid to parameters such as:

- Pressure, temperature
- Fluid composition, including water content and the presence of acidic gases such as CO<sub>2</sub> and H<sub>2</sub>S
- Fluid flow characteristics, multi-phase flow?

Production conditions usually vary with the age of a well. Even before production starts, the process of drilling and well completion presents challenges in terms of materials and corrosion. Then, next to regular production, excursions and occasional events such as acid treatments or fracturing fluid injection may occur. All of these need to be accounted for as corrosivity can change significantly.

### **B) Perform failure modes and effects analysis for all facilities throughout their life**

Usually, the initial phase of drilling and well completion is considered separately for its failure modes and compatibility of materials used with introduced fluids and chemicals.

Based on the defined production conditions, the possible associated failure modes are to be listed and linked to materials of construction that could be selected. Libraries exist for this purpose, but some of the more common modes are:

- CO<sub>2</sub> and organic acid corrosion of steel
- H<sub>2</sub>S corrosion of steel
- H<sub>2</sub>S cracking of steel (including higher strength steel) and corrosion resistant alloys

The possible occurrence and magnitude of these effects should be assessed from well, following the production stream, to plant. Additionally, the abovementioned change of production conditions as well as excursions and events need to be accounted for. To facilitate the process, it is useful to divide the production facilities into sections characterized by type of corrosion and material of construction, so-called corrosion loops, for instance downhole tubing exposed to production fluids or flowlines exposed to multiphase flow.

Field experience is likely the most important source of information about degradation modes. If, for a new development, experience from similar fields is available this should be used to full



advantage. Unfortunately, this is not always the case. Sometimes experience, if not directly applicable, may be translated using corrosion models. If that is not an option, models need to be relied upon at this stage.

Hence, to decide the relevance and magnitude of degradation modes, corrosion modelling, sometimes supported by focused lab testing, is an important tool. Often corrosion rates have to be estimated based on limited field data sets. In such cases rates may be estimated using a model and sensitivities related to uncertainties can be evaluated. For CO<sub>2</sub> corrosion and to a lesser degree for CO<sub>2</sub>/H<sub>2</sub>S corrosion good models exist, albeit that they do not always adequately cover specific conditions. For instance, corrosion models are usually more geared to pipelines than to downhole tubing, but are useful anyway.

For corrosion cracking in sour service, rates can be fast and are always unpredictable. Hence, in a practical sense, cracking is unacceptable. Therefore, if expected conditions are within the sour regime, cracking resistant materials normally must be selected. Application windows in terms of pH and p<sub>H<sub>2</sub>S</sub> are used to indicate acceptable conditions for steels. For CRAs, temperature and chloride content are also important. Lab testing plays an important role if materials need to be qualified.

For each section and through its life, the mode of failure in terms of localization and consequence should be addressed. For instance, a small leak in a low pressure oil line due to CO<sub>2</sub> corrosion would be of much less consequence than a burst of a high pressure gas line due to 6 o'clock CO<sub>2</sub> corrosion. Cracking deserves particular attention because of its rapid, catastrophic nature.

### **C) Define corrosion mitigation, using corrosion control and materials selection**

Once relevant failure modes have been listed per section/segment of infrastructure, the corrosion mitigation for each to achieve an acceptable level of risk control is to be determined. This may include:

- Corrosion inhibition
- Removal of water/drying
- Use of corrosion resistant alloys or non-metallic materials instead of carbon steel
- Cracking resistant material selection

To determine if mitigation is effective, field experience, corrosion models and application windows again play an important role. For instance, to decide if inhibition is a proper approach, knowledge is needed of the uninhibited corrosion rate to estimate the consequence of (inadvertently) not injecting inhibitor, and combine that with the inhibited corrosion rate, which depends on inhibition efficiency and dosage needed to achieve that efficiency. Alternately, selecting a corrosion resistant alloy needs to be tuned to the corrosive environment to ensure that an alloy selected is suitable for the exposure, while at the same time aiming for using the most cost effective (least alloyed) material.

### **D) Assess if risk is acceptably low and economics are viable**

Considering the outcome of the analysis following A)-C) above, is the risk in terms of people, environment, assets and reputation acceptably low? Are materials selected adequately corrosion and/or cracking resistant and corrosion control measures effective in reducing risk?

Materials initially selected in C) may not be adequate and require reconsideration. Similarly, envisaged corrosion control may have to be enhanced to further reduce corrosion. Sometimes the lack of practical options for the latter drives selection of better corrosion resistant materials. Perhaps additional measures need to be taken, which may include measures to reduce consequence of failure. For instance, if a leak occurs, will escaping fluids be contained? If flammable liquids or gases escape, is detection sufficient and fire extinguishing equipment adequate? Are personnel quarters too close to production facilities? Depending on the outcome of this evaluation, C) may need to be reconsidered.

### **E) Define operational requirements and their implementation**

The choices made above should be expressed as clear guidance for operations. This regards all aspects of corrosion control, including inhibition, monitoring and inspection. Attention should be paid to proper hardware availability, such as inhibitor tanks, pumps and injection points, corrosion probes and inspection facilities.

While operations management is obviously wider than corrosion management, the latter can be laid down in a corrosion management or integrity management manual. The execution of corrosion control measures is to be detailed. Performance indicators are to be defined as well as actions to address below target performance. Corrosion models are made available as required.

### **F) Execution: Re-assess risk and adapt operation and control as necessary**

Once drilling and well completion have been executed successfully, production is the major phase in the life of the downhole and surface facilities. To ensure the required lifespan is met safely, reliably and effectively, corrosion management should be a continuous activity, guided by a devised facility/well specific manual. At regular intervals and whenever deemed necessary based on monitoring and inspection results, the integrity status of the facilities is to be assessed and associated risk re-evaluated.

Monitoring and inspection facilitate the necessary estimation of remaining life, which can be measured against the target lifespan and thereby drives additional measures if needed. For a proper quantification, both in understanding past performance and predicting future performance, corrosion models are essential. Although linear trending may have some use, models should allow changes in production conditions and adapted corrosion control methods.

Incidents, one-time events and equipment failures require special focus. More often than not corrosion control is affected in these instances, whether planned or unplanned. Proactive measures should be taken whenever possible, in corrosion control and/or consequence mitigation. If failure occurs, a “Learning From Incidents” process, even in its simplest form, is essential in helping to prevent reoccurrence and ensuring required facility life can be met.

The process of regular re-assessment of the integrity status may show that original assumptions are no longer valid.

### **G) The final phase: abandonment**

Due to the newness of shale production few wells have been abandoned. Yet it is important to take this into account, whether planned or unplanned. Abandonment needs to be managed with

a view to avoid environmental damage, be it immediate or in the future. This concerns all mentioned aspects of risk - people, environment, assets and reputation. If abandonment is not considered up front, it may in the end turn out to render a development project uneconomic. The details of integrity management for abandonment are sometimes far from trivial as they concern conditions very different from production and effects extending into the remote future. Even after abandonment, a form of monitoring may be needed to trigger action required for safeguarding integrity and maintaining acceptably low risk.

## CONCLUSIONS

Production of oil and gas from shale presents particular corrosion issues to well operators. On a technical standpoint, these issues are primarily associated with the corrosivity of frac fluids, flowback/produced water, CO<sub>2</sub>/H<sub>2</sub>S, SCC and MIC. This necessitates devising, on a case-by-case basis, corrosion management plans in order to mitigate risk associated with production. Effectively managing pipelines and related equipment improves profitability and returns while ensuring protection of the environment and the community. Mid-size companies often do not have the means to develop a comprehensive integrity management program. Additionally, most failures due to corrosion remain largely unreported in the literature, preventing sharing of valuable experience within the community. This paper is an effort to start this discussion.

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