FIELD EXPERIENCE WITH A NEW HIGH RESOLUTION PROGRAMMABLE DOWNHOLE CORROSION MONITORING TOOL

David J Blumer
ARCO Alaska Inc.
700 G St.
Anchorage, AK 99501

Randy L Barnes
ARCO Alaska Inc.
Box 100360 PRB 5
Anchorage, AK 99501

Allan Perkins
Rohrback Cosasco Systems Inc.
a Corrpro Company
11841 E. Smith Ave
Santa Fe Springs, CA 90670

ABSTRACT

Details of a new tool are presented for monitoring real time corrosion in downhole situations. This battery-powered data logging systems generates continuous corrosion history, which is transfered to a PC for analysis. A case study of this Downhole Corrosion Monitoring System (DCMS) is described. The tool is set at any required well depth, and is sensitive enough to show the period of inhibitor film persistency, effectiveness of different treatment chemical and application methods, enabling a realistic economic assessment to be made.

Keywords: Downhole Corrosion, Corrosion Monitoring, Downhole Inhibitors, Electrical Resistance, CO_2 Corrosion, Tubing Displacement, Velocity Assisted Corrosion

INTRODUCTION

A real time assessment of downhole corrosion has been a problem for many years. A number of methods are utilized, but the information provided is crude, unreliable, and can be costly, both in acquisition and impacts due to bad decisions. Probably, the most common method used was Caliper surveys for inspection purposes. However, the sensitivity or calipers is such that corrosion can only be measured typically over a one or two year period at minimum. In this time a tremendous amount of damage may have occurred. The caliper inspection may provide sufficient information over that time to trigger implementation of a new treatment program, but is not suited to provide data to help regulate the treatment program. Trying to select new inhibitors or optimize treatment methods could take longer than the lifetime of the field.

Continuous corrosion monitoring at the surface may be of some help, but conditions at the surface are frequently so different from the downhole conditions that the surface monitoring is frequently un-representative. Similarly metal ion analysis (or iron counts) can be even more difficult to interpret. Table 1 shows a summary of the benefits and limitations of metal ion analysis.

A few years ago, Rohrback Cosasco Systems undertook in conjunction with their Downhole Division, now Nova Technology Corporation the design of a patented [1,2,3] Downhole Corrosion Monitoring System (DCMS[(1)]). Subsequent flow testing, and development of field operations was carried in conjunction with Arco Alaska Inc. The concept was to adapt the existing CORRDATA[(1)] Electrical Resistance data logging system for surface corrosion monitoring to a design suitable for use downhole. The physical layout of the tool was to be similar in principle to existing pressure and temperature monitoring gauges already used by the downhole division of the company. However, the main variations were that there were significant differences in the actual monitoring technology, and secondly that it was essential that the downhole corrosion probe be suitable for location at any level in the tubing string. This is not generally the case for pressure and temperature monitoring, which is typically done at the bottom of the hole. In addition, the tool was required to be run with slick wireline units and not reduce the production capacity of the well while it was installed downhole.

Adaption of the data logging concept for electrical resistance probes to the aggressive conditions of the downhole environment was an attractive proposition that would enable the benefits of continuous corrosion history to be obtained. Changes in corrosion rates over days and weeks would be determined at any level at which the tool was set. A target was set to allow collection of up to 90 days of corrosion rate and temperature data before it was necessary to pull out the tool and retrieve the data.

DESIGN OF THE DOWNHOLE CORROSION MONITORING TOOL

The development of the DCMS required the following major considerations to be addressed.

1. Operation at pressures up to 10,000 psi
2. Operation at temperatures up to 350 F (177 C)
3. Durability under multiphase flow conditions, and consequent vibration
4. Probe element design to permit flow dynamics similar to that over tubing

---

(1) Registered Trademark of Rohrback Cosasco Systems

Table 1
Summary of characteristics of metal ion analysis (iron counts)

Metal Ion Analysis (Iron, Copper, Nickel, Zinc, Manganese)
Definition and Scope Metal ion analysis of a flow stream is used as a method of determining the amount of metal lost, that has dissolved in the process stream, or been carried along in the process stream as corrosion product. Analysis is normally done on the water phase. Analysis of hydrocarbon samples is done by some users.
Relationship to Corrosion 1. Metal ion analysis of corrosion products. 2. Affects fluid chemistry. 3. Can be integrated in a chemical balance for total metal loss in low corrosion rates (used in the nuclear industry).
Characteristics and Requirements of the Method 1. It is most useful when applied to closed systems. 2 .In open systems, changes in concentration from one location to another are most accurate. 3. Obtaining a representative sample of the aqueous phase requires much care in the sampling point design and use, since the sampling point may accumulate corrosion products. 4. Iron counts must be related to flow rates of water to determine changes in corrosion rates. 5. A history must be established to interpret the data.
Benefits 1. The analysis can be done easily, inexpensively, and quickly in the field.
Limitations 1. In open systems, single point monitoring (e.g.:- at wellheads) may reflect changes in corrosion rate upstream (downhole) but the input flow will affect the results. 2. An assumption must be made that metal loss occurred over the total surface area, which may be very unrepresentative. It is only a trend indication. 3. Precipitation upstream of the sample will affect the measurement.
Additional limitations of Iron Analysis 1. The method is generally not reliable in sulfide containing fluids because of precipitation of iron sulfide, or in alkaline solutions because of precipitation or ferric hydroxide. 2. Corrosion of sample pot may contribute to iron count. 3. Increased level of sulfate reducing bacteria activity can reduce the iron count by increasing the precipitation of iron sulfide. 4. An increase is a warning of an increased corrosion rate. Low rate is not a guarantee of low corrosion, due to pitting. 5. It can only be related directly to corrosion rates in special circumstances.

5. Special batteries for the power demand suitable for elevated temperatures
6. Design and adaption of running tools to allow positioning at any level in the tubing string under normal well flow conditions
7. Logistics of installing and retrieving the DCMS tool.

Downhole conditions present some of the most challenging conditions anywhere in which to operate electronic equipment. The temperatures are in excess of most military specifications, requiring specialized components and construction. To achieve the design requirements of fitting the electronics in a slim 1.25" diameter profile required expensive multi-layer circuit boards and a construction capable of enduring 30 G of acceleration without damage.

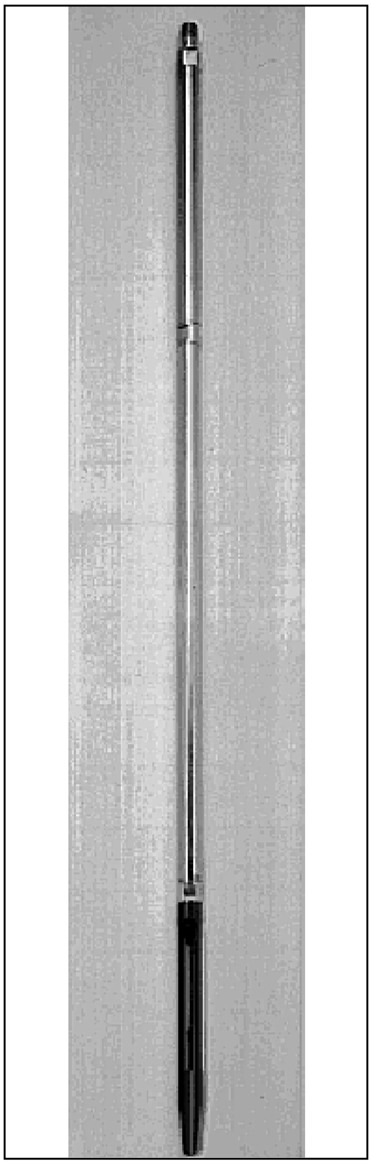


Figure 1 DCMS Tool

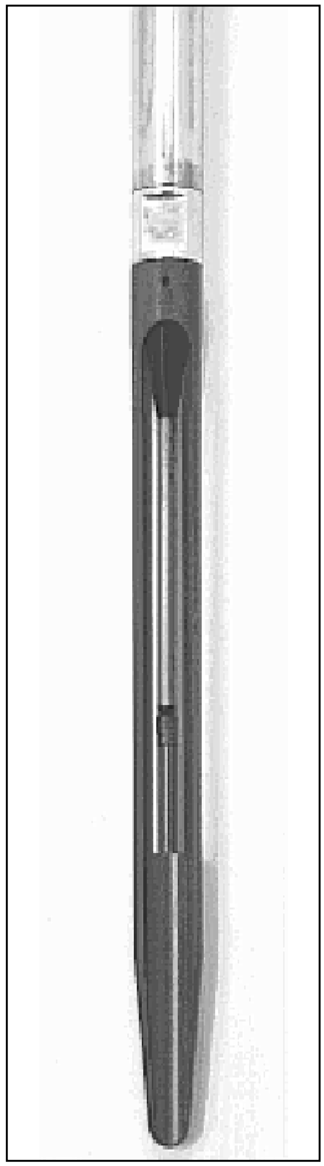


Figure 2 Probe Head

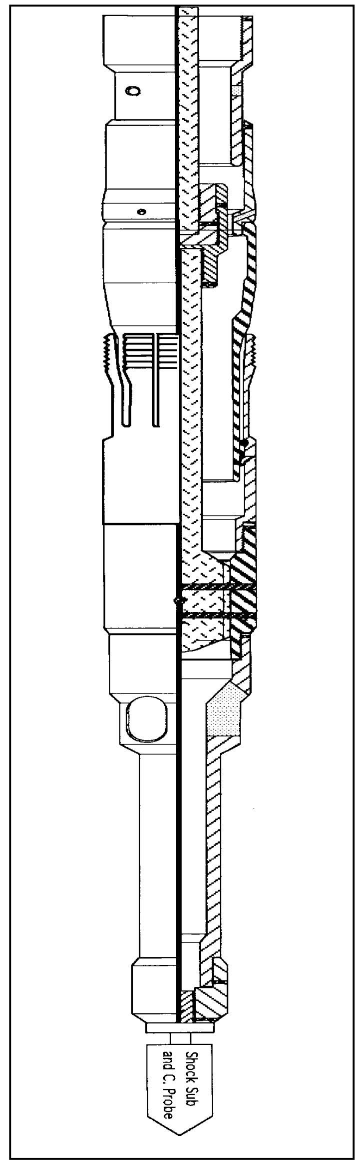


Figure 3 DCMS Tool Hanger

The layout of the tool is shown in Figures 1 and 2. The probe measurement element is a relatively small diameter at the bottom of the probe, Figure 2. A protective yet streamlined shield provides support, protection from damage, yet provides minimum restriction to the flow in this measurement area. The orientation of the measurement surface is similar to that of the pipe so as to make the measurement surface as representative as possible of the adjacent tubing surface. This can be particularly important in gas wells with misting flow conditions where condensation on the probe measurement surface is a major factor in the corrosion conditions. The electronic module is positioned above the probe element and the battery above that. These are housed within the outer pressure housing that provides the 10,000 psi rating. The standard attached at the top of the tool is a 5/8" API Sucker Rod connection.

Initial Testing

The prototype tools underwent initial static testing in a special laboratory autoclave at Rohrback Cosasco at conditions in excess of the operating specification. After some modifications and successful completion of these tests, flow vibration testing was carried out at the Arco Plano Research laboratory to evaluate the effect of multi-phase flow at various flow rates and angles of deviation of the well. The tests showed only slight vibration of about 0.125" at the tip of the probe under highly deviated wells (near horizontal orientation of the tool) due to the probe "surfing" the slug flows that did not completely fill the tubing string. These dynamic tests were as close as we were able to simulate the downhole conditions with the test facilities available. We were now ready to proceed with live downhole testing. The initial field tests were static tests in the Middle East at the bottom of a 11,300 ft. well, and in a shallow well in Louisiana. Results were encouraging although some major deviations in readings at time were not explainable. By this time the total design and development costs excluding field trials alone cost in the region of half a million dollars.

Downhole Corrosion Probe Field Testing and Demonstration

The field testing of the tool was carried out at the Eastern Operating Area of Prudhoe Bay. The tests were conducted to demonstrate that 1) the probe could be run, set and retrieved without damage to either the probe or the well, 2) no production impairment of the well occurred with the probe installed, 3) corrosion metal loss and temperature data could be recorded, stored in memory, and retrieved for up to 90 days, 4) the probe was accurately measuring corrosion downhole, 5) the probe responds reproducibly to the corrosion environment, 6) the probe would respond to chemical inhibition treatments, and 7) the probe could be used to monitor and optimize downhole corrosion inhibition treatments.

Prudhoe Bay, located on the North Slope of Alaska, is the largest oilfield in North America. Recovery mechanisms include gravity drainage from gas cap expansion, waterflood, and enhanced oil recovery (EOR) project using a miscible injectant (MI) solvent in a water-alternating-gas procedure. Corrosion, both surface and downhole, is aggressive due to the 12% CO_2 content of the gas combined with water production as the waterflood matures. The primary corrosion mechanism is velocity-assisted CO_2 corrosion. The waterflood areas have also become more sour with time, with H_2S rising from the original 5-8 ppm to over 2000 ppm in some wells. The high GOR combines with high fluid production rates (up to 25,000 bpd) to yield high velocities, up to 150 fps. Water cuts range from 0% in the gravity drainage area to 99% in the mature waterflood area. Downhole temperatures range from 170-210°F. The downhole corrosion problem is exacerbated by the active wireline work program, which leads to a lot of mechanical wear on the tubing due to the wire running in and out. Many strings of tubing come out of the hole with a slot cut down the low side due to the wireline damage combined with corrosion.

CORROSION TREATMENT PROGRAM AT PRUDHOE BAY

The wells were all originally completed with 4 1/2" or 5 1/2" L-80 carbon steel tubing. Early corrosion failures before the start of the waterflood lead to implementation in the early '80s of a downhole corrosion treating program using a tubing displacement (TD) method. A macro-film forming corrosion inhibitor which is somewhat oil soluble and water insoluble was used. The TD treatments are done at 90 day intervals on the wells. This interval was picked for reasons of economics and the ability to treat all of the wells with the equipment available.

The procedure is carried out as follows. The well is shut in and a 10 bbl. spearhead of methanol is pumped downhole. Next, 110 gallons of the inhibitor is mixed with 18 bbl. of dead crude oil and pumped downhole. This pill is displaced with dead crude oil at 2 bpm to the end of the tubing. The well is then immediately put back on production.

Some variations on this procedure have been applied. Currently, instead of mixing the inhibitor and crude in a tank, it is being mixed on-the-fly as it is being pumped. Also, towards the end of the displacement, a slug of demulsifier is pumped to reduce upset problems in the facilities.

Despite the Tubing Displacement treating program, wells fail due to corrosion. Over the years, the failure rate has averaged about 29 per year. This is a problem of considerable expense, since workover costs over this time have averaged about $1MM per failure. The currently favored alternative is to replace the tubing using 13Cr steel, though this is fairly expensive. Other alternatives including downhole treater strings and gas lift inhibition have been applied, but were not successful One of the most troubling side effects of the TD program have been upsets in the separation facilities, leading to lost oil production. This has been partially mitigated by using an emulsion breaker tail-in during pumping the treatment, but upsets still occur.

Improved Downhole Corrosion Treatment Study

Several years ago, an effort to improve the downhole corrosion mitigation program was initiated[1]. The original goal was to find more effective inhibitors with improved corrosion protection and longer life. The primary difficulty with this program was the lack of rapid, precise, and inexpensive monitoring methods for corrosion in the tubing under producing conditions. The program defaulted to using a surface horizontal well flowline to simulate conditions in the downhole tubing. Thus, questions still remained after the conclusion of this work as to whether the test was actually valid downhole.

The referenced work is thus a prelude to the present report. Briefly, a well flowline 2300 ft. long was instrumented with 5 electrical resistance (ER) corrosion probes equipped with continuous remote reading devices. Readings were taken hourly. After preparing the line by blowing it dry with gas, it was packed with crude oil. A Tubing Displacement treatment was then pumped, using different inhibitors as the variable.

An example of the results is shown in Figure 10 of Reference 4, which was performed with the incumbent inhibitor at the time. The curves show the response of the five electrical resistance (ER) corrosion probes installed along the length of the well flowline after the TD treatment. This data clearly showed that the treatment did not last close to 90 days, at least in this high rate, high (90%) water cut well. Rather, lifetimes of 3-10 days were observed. Obviously, this result was disappointing considering the 90 day treatment interval between TD treatments on all the wells.

Well Failure Statistics

Upon evaluation of the experiments with the well flowline, an extensive evaluation of the downhole corrosion control program ensued. The goal was to see if any benefit was accruing to the lifetime of the wells from the TD treatment program.

Failure statistics were the primary measure of the value of the program. After looking at correlations with all conceivable parameters, the only significant correlation was found with the total amount of water or, equivalently, the water rate multiplied by the time of exposure. The cumulative probability of failure plot showed that after production of 6-8 million barrels of water, the wells had 50% probability of failing due to corrosion. The data set was divided into three groups depending on water production: <100 bwpd, 100<x<2000 bwpd, and >2000 bwpd. Further the wells were divided into those treated with TDs and untreated wells.

The results were revealing. Only a few of the wells producing <100 bwpd had ever failed, making TD treatments uneconomic. Wells producing high water rates >2000 bwpd failed only slightly faster without TD treatments than with treatments, making the treatments uneconomic. The group of wells producing between 100 and 2000 bwpd showed significantly lower failure rates, so the treatments are economic for these wells. Approximately 34 wells out of the 475 wells treated previously fall into this category, which have received regular TD treatments, while remainder have not. Based on this study, only those wells falling into this “Treating” category were continued to received TD treatments. The remaining 441 wells at EOA of Prudhoe Bay received no further treatments after mid-1995. As a measure of insurance that this drastic reduction of the inhibition treatment was the correct path, the use of the downhole corrosion monitoring tool being developed to verify these results was undertaken vigorously.

RUNNING THE DOWNHOLE CORROSION MONITORING TOOL

The next major step was to test the tools in a flowing well on a locking system that permitted location of the probe anywhere in the tubing string without the luxury of a tubing stop Electronic pressure and temperature gauges are usually set at the bottom of the hole in existing nipples or side pocket mandrels. With a corrosion monitoring tool there is a need to be able to set the tool at the level of the severest corrosion as indicated by caliper or other survey. This requires tubing lock systems that can be placed at almost any depth in the tubing string, without restricting the flow too much. It also demands wire line running tools and procedures for setting and retrieving that do not impart loads that would damage the electronic tool.

The first runs in Alaska were run with standard wire line tools but problems experienced when removing the tool and the use of excessive jarring caused disintegration of the internal electronics although the external integrity of the tool was maintained. Subsequent analysis of damaged parts indicated loads in excess of 200 G had been experienced by the tool. A complete review of the running tools and procedures was conducted and the running tools were changed to the current mounting configuration used on this Alaska Site. It comprises a Halliburton G Stop, below which is a cross over adapter, a shock absorber, and then the electronic tool, set in a 4.5" tubing string (see fig 3). The cross over adapter a allows the flow from the outside of the tool to the inside of the G Stop with a cross sectional area matching the inside of the G Stop. The running tool is a slick line set and battery-operated with a timer. A picture of the DCMS tool being attached to the bottom of the shock absorber of the running tool is shown in figure 4. The retrieval is carried out with light "spangs" rather than heavy duty jars.

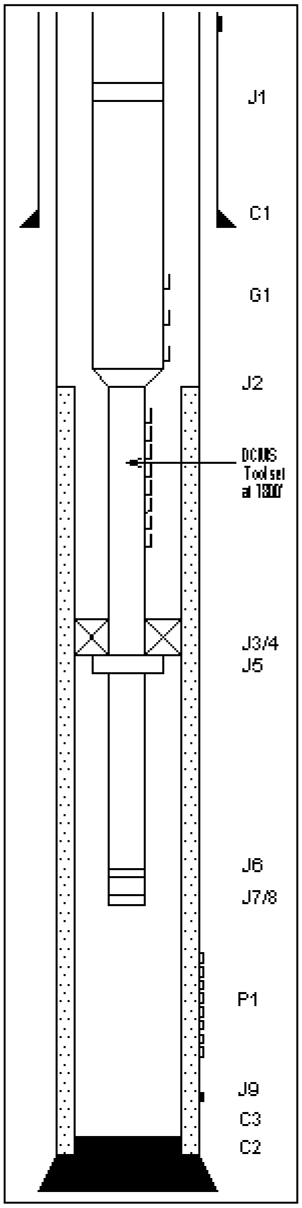
These running tools have been 100% mechanically successful in the Alaskan wells, with no sticking or failure-to-set problems. After making these modifications, no probe damage has been observed. Other running tool configurations have now been used in other fields, such as hydraulic setting tools and without the use of a shock absorber. The main criteria is to ensure shock transfer to the downhole corrosion monitoring tool is kept low so as not to damage the electronic tool.

On the second tool runs in Alaska of two tools in the same well, both tools had failed to record the data. This was subsequently found to be due to the battery design and the type of battery load demanded by the tool. This took some significant redesign of the battery and electronics to overcome along with a special battery de-passivation tool. This problem had shown up to a much lesser extent in the earlier runs and was the cause of the unexplained readings.

Figure 4 Preparing to run DCMS Tool

A repeat of the test with two tools in the same well after modification at 7200' and 7800' showed very good repeatability over a 14 day run. The follow up test run of 6 weeks through a chemical tubing displacement, fig 6, showed excellent if unexpected results, and cleared the way for the main case study described below. The well details where the first runs of the probe were made are shown in figure 5.

Figure 5
Well Information



Spud Date : 10/29/79	Last Test 9/28/94
Top of Formation: 10359'	Oil = 735
Annular Fluid: SW	Water = 2781
Completion: 12/13/90	GOR = 1906
Hanger Type: Gray Gen II Retro	BHT = 206 F
Max. Hole Angle: 45^{0} @ MD: 5300'	BHP = 3430 psi
Type: Producer	
Status: Workover	10^{0} Dogleg at 8200'
Hanger: 27'	
Angle @ TS: 28^{0}	
Angle @ TD: 29^{0}	

Jewelry (J)

	Depth	**Description**
1	2238'	5-1/2" Camco BAL-O SSSV Nipple ID=4.562"
2	6360'	Crossover 5-1/2" x 4-1/2"
3	10009'	4-1/2" Baker PBR Assembly
4	10030'	7-5/8" x 5-1/2" Baker SAB Packer
5	10034'	5-1/2" Baker Millout Extension
6	10125'	4-1/2" Otis XN No-Go Nipple ID=3.725"
7	10137'	4-1/2" Baker Shearout Sub
	10132'	ELM Tubing Tail (Logged 12/28/90)
9		FISH: 20" Sample Bailer (12/91)

Min ID: 4-1/2" Otis XN No-Go Nipple ID= 3.725"

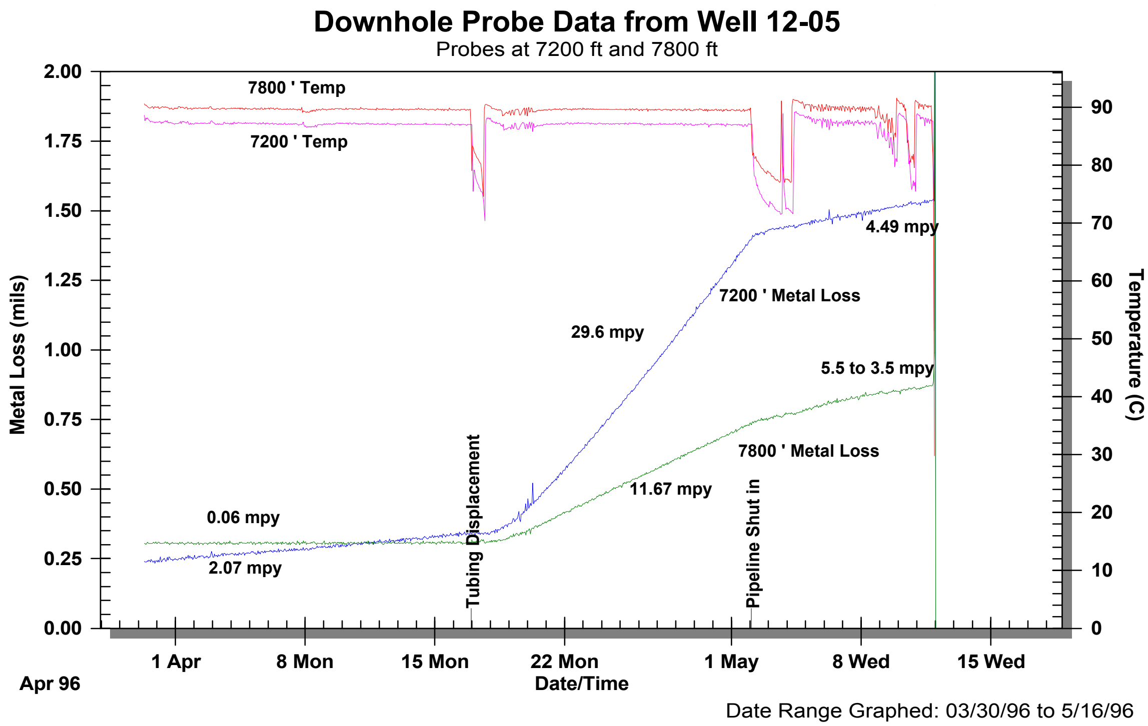
DCMS Corrosion Tool set at 7800' on Halliburton G Stop with shock sub. Tool set with Halliburton battery operated DPU. Tool retrieved with spang jars.

The initial test of the Downhole probe was constituted as follows: a well was selected which had a minimal dogleg to minimize the risk of sticking the probe in the well. To verify that the probe was recording similar data, two probes were run in, separated by about 600 feet The recorder was set to take data once every hour. The probes were successfully run and set at 7800’ and 7200’, respectively. the plan was to let the probes corrode for about a week and then pump a TD treatment. Due to the high water rate, this well does not normally get treated as explained previously.

Unfortunately, the well was shut in for about a day on the fourth day. The probes were pulled successfully aft 26 days in the hole and the data collected. The memory tool worked precisely as planned. The data from one of the tools is shown in Figure 6. The probe faithfully responded to the well events including the shut in periods and the TD treatment when it was pumped.

The data clearly supported the previous work on the horizontal well line, in that the TD treatment lifetime was only about 3 days. The probe corroded at a continuous rate after that until the well was shut in again after 26 days. The second probe responded similarly.

Figure 6



Multi-Probe /Single Well Test

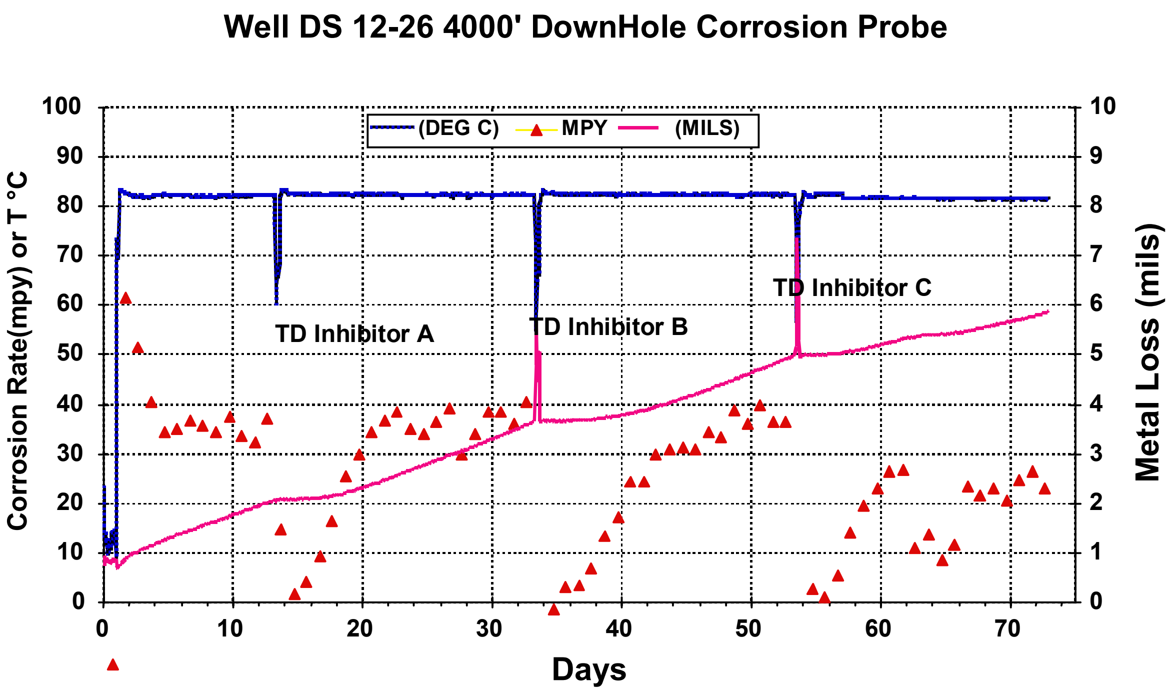
The next test was designed to answer the question about the effects of depth on the uninhibited rates of corrosion and the performance of the TD inhibition treatments. Well 12-26 was picked as a candidate which is not normally treated due to its water production of 5200 bwpd. The well is not excessively deviated for a Prudhoe bay well, making the risk of sticking a probe less.

Three probes were run in the well and set at 4000 Ft., 6000 Ft., and 8000 Ft. Data points were collected every 2 hours on each probe. After a period of about 12 days, a series of 3 TD treatments were pumped, with a 20 day period between each treatment. Each treatment consisted of a different inhibitor, but each was pumped by the same procedure. After 90 days, the probes were pulled, the data downloaded and transferred to a spreadsheet, and daily average corrosion rates were calculated.

Figure 7 shows the corrosion rate data from the probe set at 4000 Ft., which was the shallowest probe in this test. Also plotted is the temperature data, which is an excellent indicator of the well events, including the TD treatments being pumped.

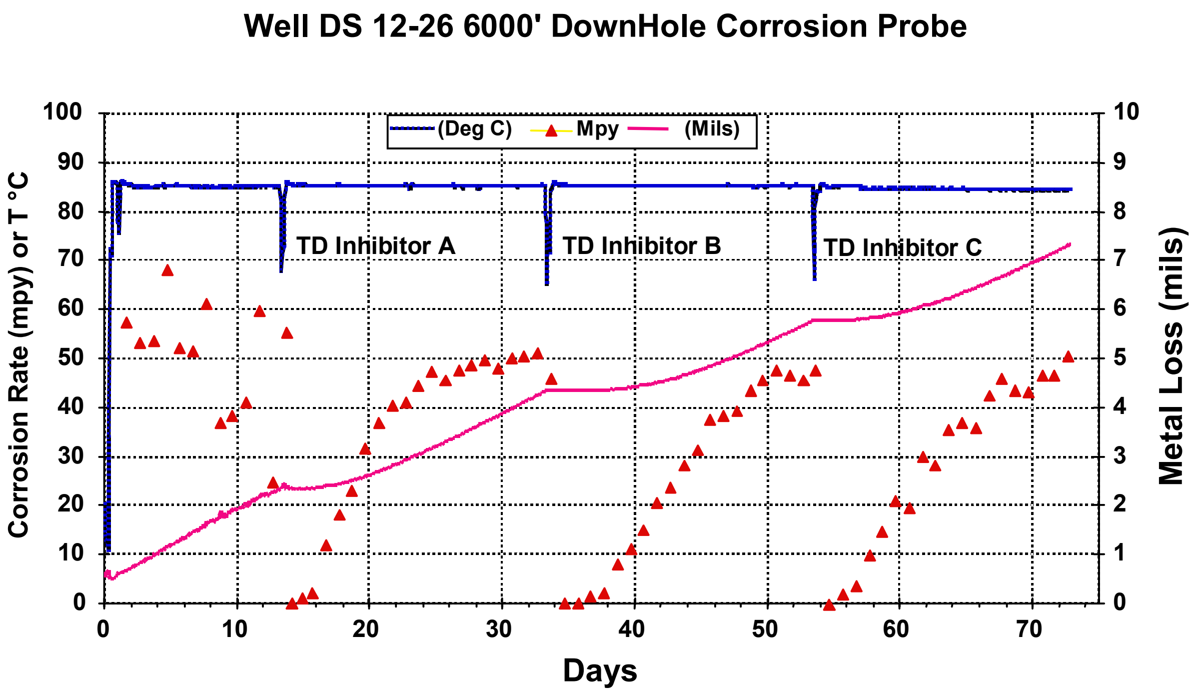
The uninhibited corrosion rate appears to be 35-40 mpy at 4000 Ft. This is the lowest rate of the three probes. When the TD treatment is pumped the corrosion rate declines to 0 mpy for a period of time and then rises over the space of about 10 days back to the uninhibited rate. All three of the inhibitors pumped showed this pattern with no major differences in the inhibited period.

Figure 7



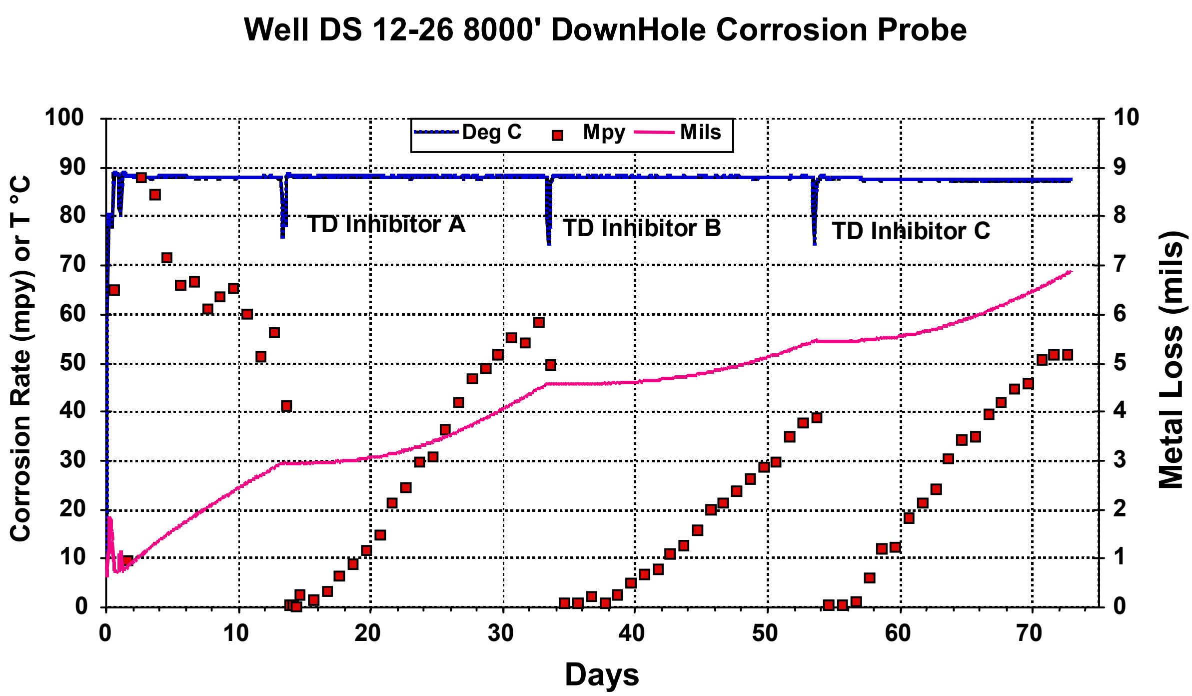
The probe set at 6000 ft,.Figure 8, responded similarly to the upper probe. The primary difference was that the uninhibited corrosion rate was higher, ~50 mpy compared to the ~40 mpy for the 4000 ft. probe. As can be clearly seen from Figure 7, the temperature signal responds to the TD treatments. This is due to the colder fluids being pumped into the well contacting the probe. Also, after each TD treatment, the corrosion rate goes to zero mpy for a few days and then recovers back to the uninhibited rate within 12-15 days. Three different inhibitors were used for the three TD treatments. The probe response for the treatments was all similar, indicating no significant performance difference between the different chemicals.

Figure 8



The probe set deepest in the well at 8000 ft., shown in Figure 9, responded just like the upper two probes, except that the uninhibited corrosion rate was the highest at ~60 mpy. Thus, the corrosion rate in the well increased with depth: 4000 ft.< 6000 ft. < 8000 ft. This observation is consistent with the pattern of the corrosion seen upon inspection of the tubing pulled from wells after failure. The response to the TD treatments was similar to the other two probes.

Figure 9

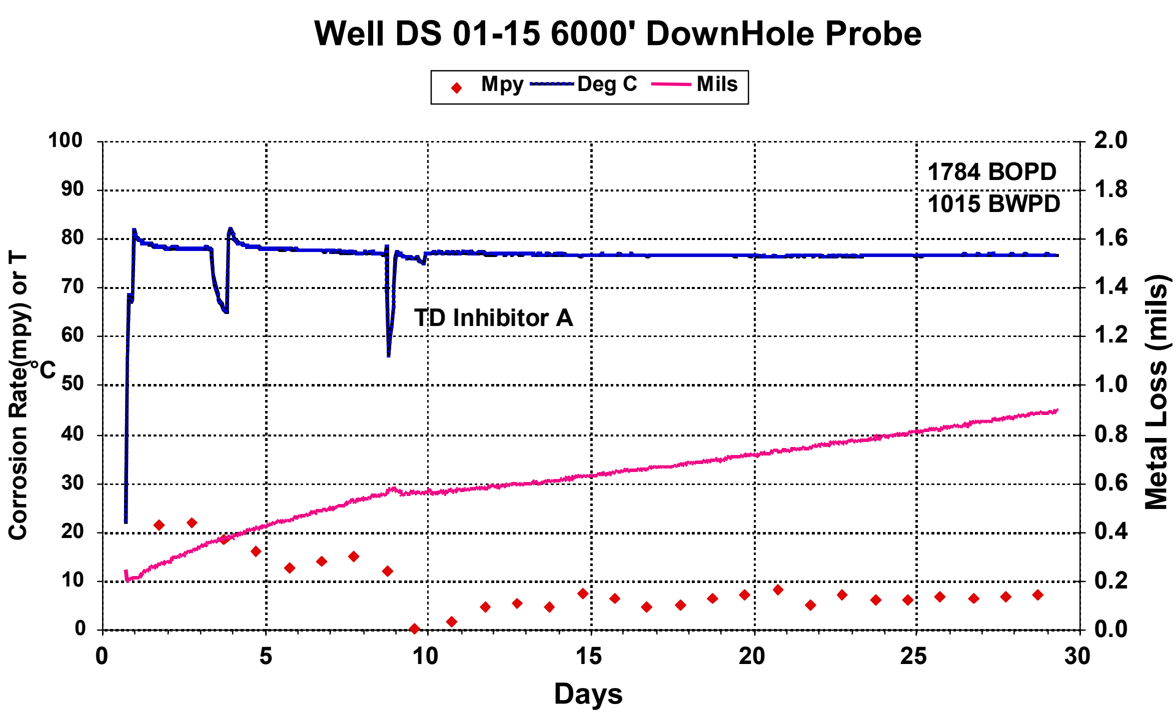


Tests on Normally Treated Wells

The next step was to test the longevity of the TD treatments in wells that normally are treated. To date, the probes had been run in wells with aggressive conditions including high water rates and high water cuts. In those wells, clearly the inhibition treatments have inadequate performance. However, as explained previously, failure statistics indicate increased longevity when wells producing between 100 and 2000 bwpd are treated regularly by the TD method. Four wells which fall into this class were selected and the probes run in and set at 6000' in each well. After a 10 -14 day period, the wells were each treated with a TD treatment. The time interval since the previous TD treatment on these wells varied, but exceeded 30 days in all cases. After a period of 30 days, the probes were pulled.

The results are shown in Figure 10 for one well. In each case, the TD treatments reduced the corrosion rates to low levels throughout the entire interval. In the case of well 01-15, it is apparent that the well was still inhibited prior to the treatment from the previous TD treatment. These results confirmed that, in the case of lower water production rates, TD treatment can inhibit corrosion for a substantial period of time sufficient to reduce tubing failure rates. Thus, continued treatment of these wells is economically justified.

Figure 10



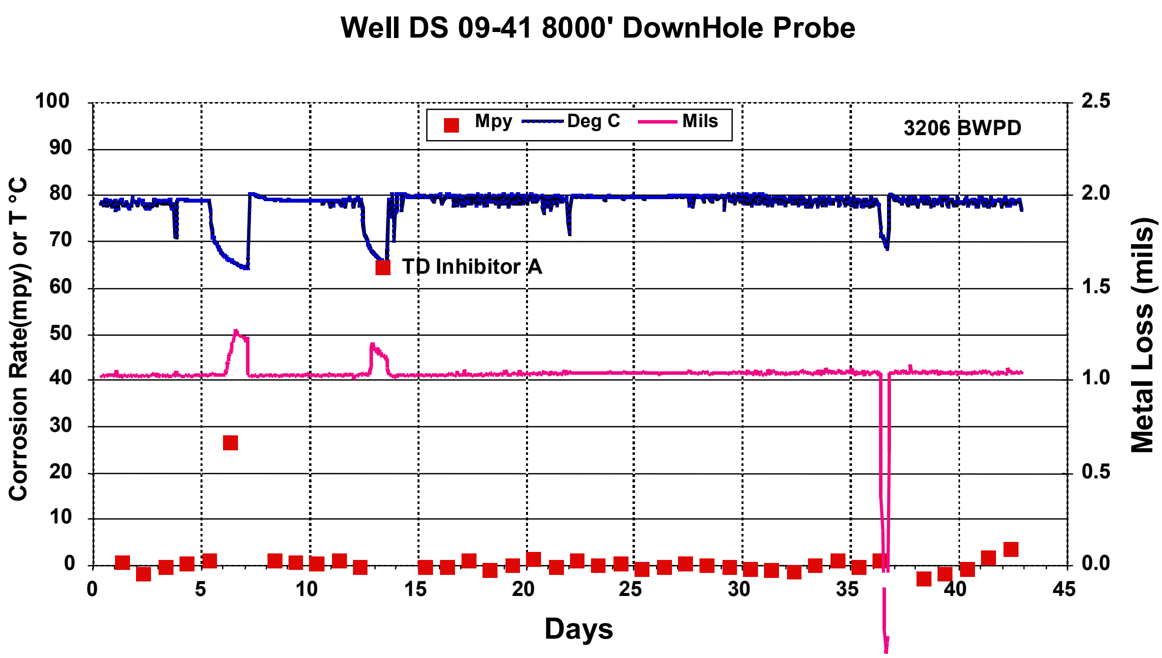
Tests on Wells outside of the "Treating" Boundary

As was described earlier, the decision on whether a well received TD treatments or not was based on the water production rate. The previous tests showed that wells that fell into the "Treating" category did respond to the treatments, whereas the first wells tested, which fell outside that category did not show significant film lifetimes. The question arose as to how sharp that boundary between "treatable" and "untreatable" really was.

Three wells which were slightly above the 2000 bwpd cut-off point were selected. Probes were run into each well and set at 8000'. Corrosion rate and temperature data was collected once every 2 hours and left downhole for 45 days. Also, as a test of battery life, the batteries used in the previous test (30 days) were re-used in 3 of the probes. One probe was outfitted with a new battery and left downhole for 90 days. After about 14 days, a TD treatment was pumped.

As seen in Figure 11, the wells remained inhibited for the entire period of the probe run. The implications of this data are far reaching, though at this point, the reasons for this behavior are not entirely clear. The criteria used to categorize the wells as to whether they receive corrosion treatments does not appear to be as well-defined as was earlier thought. Some wells definitely benefit from the treatments even though they produce more than 2000 bwpd.

Figure 11



CONCLUSIONS

For the first time, an electrical resistance corrosion probe capable of being run down a wellbore and set on slick wireline has been developed and demonstrated. The probe is capable of taking and storing measurements at short intervals and storing the data for later retrieval for up to 90 days. Multiple tools have been run in the same wellbore and can be set at any depth required. The wireline setting tools designed specifically for this tool have performed with 100% mechanical success

The utility of the probe was demonstrated in over 16 runs in different wells at Prudhoe Bay. The lifetime of Tubing Displacement corrosion treatments were measured for the first time downhole in these wells. The data both confirmed earlier work and illustrated new opportunities for protecting the wells. In aggressive wells, treatment lifetimes were short, of the order of 1-3 days. This data corroborated an earlier study on a well flowline as well as well failure statistics.

Under moderate conditions, well lifetimes were much longer, confirming that these treatments are an economically effective mitigation method. Little difference in performance was seen in tests of three different corrosion inhibitors.

Finally, the criteria used to differentiate wells to be treated for corrosion mitigation is not as clearly defined as previously thought from the failure statistics study. More wells need to be surveyed to refine the criteria.

REFERENCES

1. United States Patent No.5,627,749, Waterman et al, “Corrosion Monitoring Tool”, May 6, 1997.

2. U.K. Patent No. GB 2,286,844 B, Waterman et al, “Wellbore Monitoring Apparatus”, Sept 10, 1997.

3. Other foreign patents pending.

4. G. R. Chesnut, D. J. Blumer, H. J. Choi, **CORROSION/95**, **#135**, “The Measurement of Corrosion Inhibitor Film Life in High Velocity Flow, March, 1995, Orlando, FL.