Improved Asset Management of a Gas Processing Facility

By an Automated Corrosion Management System

Neal McGarry
Westcoast Energy Inc
Pine River, British Columbia
Canada

Allan Perkins
Rohrback Cosasco Systems
A Corrpro Company
Santa Fe Springs, California
USA

ABSTRACT

A case study is presented of a complete corrosion management system installation at a Western Canadian gas processing facility. This system provides on-line input of corrosion monitoring probes, process parameters, coupon data, ultrasonic measurements, and laboratory analysis data all in one integrated system. Examples are presented of some of the corrosion problems that were exposed by the system and the remedies that were taken. Major economic savings were achieved through analysis of the data, and consequential changes that were made to the operation of the plant. Many aspects of operation are still under investigation as further operational data is gathered. Based on just these early examples of corrosion control, the cost of the system has been quickly recovered.

Keywords: gas processing, amine contactor, amine solution, on-line monitoring, corrosion monitoring, corrosion monitoring with computers, corrosion management systems, corrosion economics.

INTRODUCTION

The cost impact of corrosion in process plants is often only understood as significant in a very general sense. Beyond this point, it is not always easy to identify the specific plant operating conditions that give rise to the worst corrosion conditions, so that a real impact is not made on the problem. On-line corrosion monitoring can identify the periods of highest corrosion, but without direct correlation with process parameters it can be difficult to identify the cause of the corrosion upsets. An additional problem is that most process plant Distributed Control Systems (DCS) are designed for fast response to suit process control. To view several days or weeks of data quickly and easily, or data that is more two days old often requires extracting data from an historian file. This tends to be slow and cumbersome and usually does not make correlation between parameters very easy. With this in mind, the corrosion management system described below integrates data collection of corrosion and process parameters to address these problems, and makes the information easily available over the network to all concerned parties.

Gas processing facilities are a good example of a process that can have major swings in corrosion rates. The mechanism(s) of corrosion in gas processing plants is in most cases understood and well documented. Even with this knowledge the vast majority of gas processing plants will still encounter severe corrosion problems. Often there is a fine line between an acceptable and unacceptable corrosion rate. To maintain an acceptable corrosion rate all process variables need to be monitored and maintained. Many documented cases exist of how small process changes result in severe corrosion. Unfortunately in many corrosion events the problem is acknowledged with the appearance of a pin hole leak or worse. In the absence of on-line corrosion data the residue or sales gas quality dictate where the process variables should be maintained.

An on-line corrosion monitoring system will allow early detection of corrosion events and the ability to manage the corrosion rates by fine-tuning of the process.

CORROSION MANAGEMENT SYSTEM

The system comprises a corrosion monitoring DCS system interlinked to the main process control computer and the company's system-wide network.

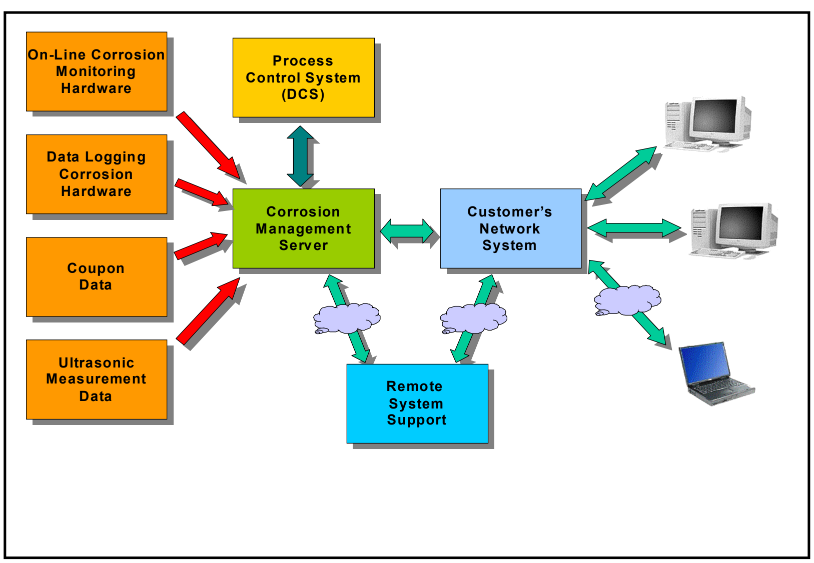

Figure 1 Corrosion Management Block Diagram

The Corrosion Management server is the heart of the system, and typically located adjacent to the Process Control Computer near the main control room. A typical server is shown in Figure 2.

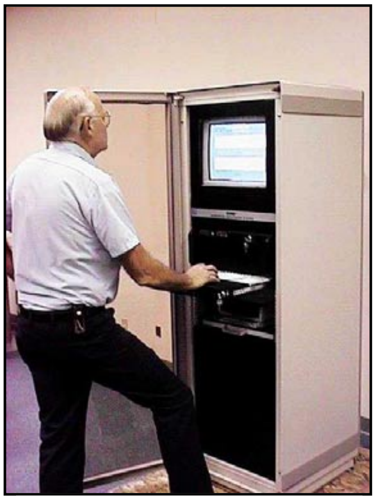

Figure 2 Corrosion Management Server

It is an industrial computer running Windows NT[(1)] and ICMS3[(2)]/Amulet[(3)] Corrosion Management Software. The main software program comprises a database and an operator interface. Input into the database from all of the various sources, such as the on-line corrosion monitoring hardware, and a Modicon Modbus interface to the DCS system, are controlled by independent drivers. The Corrosion Server is set up on the Network of the Site, which is usually accessible companywide. Client versions of the software allow viewing of all of the data from anywhere on the Network. Remote operation of the server for administration and software support is possible over the Network or via dial-up modem.

Electrical Resistance probes (ER) and Linear Polarization probes (LPR) are the most commonly used for on-line monitoring on these process plant systems, but the software also supports many other technologies such as corrosion coupons, ultrasonics thickness measurements, and electrochemical noise. In this gas processing facility, the amine plant gives the main corrosion problems. A diagram of the layout of one of the trains, as displayed in the mimic diagram of the corrosion management software, is shown in figure 3. Since the Amine system is water-based with around a 25% water content, electrochemical methods such as LPR probes are well suited to on-line monitoring in the liquid phase areas of the plant. However, in areas of the re-boiler continued presence of a liquid phase is not so obvious. It is not always appreciated that for any electrochemical measurements to be quantitative, the electrodes need to be fully wetted, and there needs to be a continuous liquid phase between the electrodes. In vapor areas this may not be the case, so initially tests were made with LPR probes in these areas with both flush and projecting electrodes. The flush electrodes are more likely to be fully covered with a continuous liquid film in areas of the boiling liquid, than with projecting electrodes. If the monitoring extends even further into the vapor area, then the electrochemical probes can become very erratic and essentially non-functional. In these cases, it is necessary to move over to electrical resistance probes. However, where LPR probes can be used it is preferable because of the immediate response to corrosion rate changes that these probes will show over the electrical resistance probes. In this instance, at the chosen locations

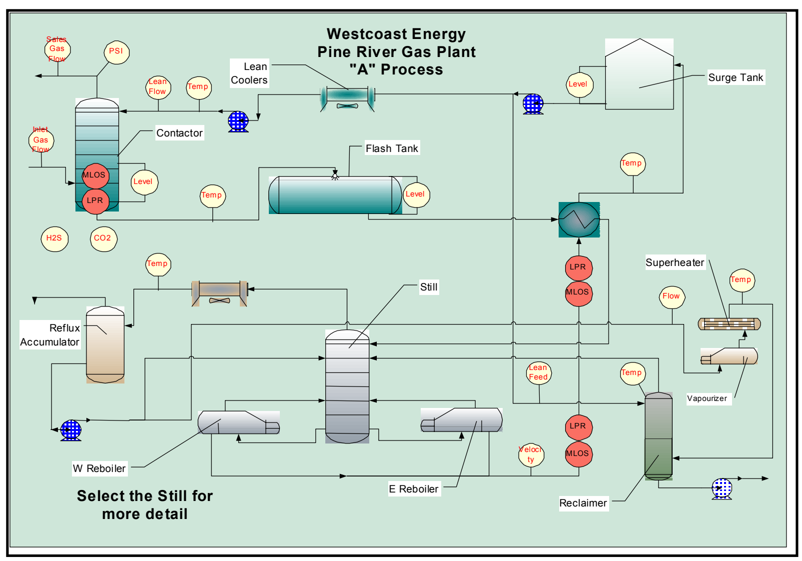

Figure 3 Amine Plant

---

(1) Windows NT is a registered trademark of Microsoft Corporation

(2) ICMS3 is a registered trademark of Rohrback Cosasco Systems Inc, a Corrpro Company.

(3) Amulet is a registered trademark of Corrosion and Condition Control Ltd

projecting electrode LPR probes were found to be effective. Correlation of integrated corrosion rates from the instrumentation to actual mass loss on the electrodes showed greater than 80%. It is suprising how often electrochemical measurements are made in the laboratory or in the field, without validating the results against actual material loss. Some operators will measure the B value from Tafel slope measurements. This is less effective than continuing to repeat these mass loss measurements on the electrodes, whenever they are replaced, to ensure the continuing validity of the LPR to corrosion rate conversion constants. This can only be done, of course, on probes with replaceable electrodes.

The LPR monitoring electronics used in this system also incorporated patented Solution Resistance Compensation to correct for any low conductivity in the solution that would otherwise reflect in lower corrosion rates than were present.

One of the most important aspects of corrosion probe monitoring is the need for the probe to be representative of what is happening on the actual plant. The measurement of actual metal loss on the probe electrodes gives the first stage of auditing the measured corrosion rate to actual corrosion rate on the probe. The second stage of the auditing process is to compare the integrated metal loss from the probe with actual metal loss on the plant. For this purpose, ultrasonic measurements on the plant adjacent to the probe locations are being taken every six months, and automatically transferred to the Corrosion Management software from the hand-held measurement instrument.

Corrosion monitoring inputs may be from several different instrument configurations depending on the plant layout. The configuration applied here was a series of 4-channel Probe Interface Modules (PIM's), that are connected to the corrosion server over an RS 485 multi-drop communication line. This helps reduce the cabling required for many applications. The PIM's are available for either Electrical Resistance probes or Linear Polarization Resistance probes for systems where the requirements are mixed. A diagram of this arrangement is shown in figure 4. For other systems, where the probe locations are more widely spaced transmitters may be used on the system as shown in figure 5.

Mass loss measurements on the electrodes are made whenever the probe electrodes are replaced, typically every three to six months. This information is treated like any other coupon data, and manually loaded into the corrosion management software for on-going logging and correlation with the on-line corrosion rate measurements.

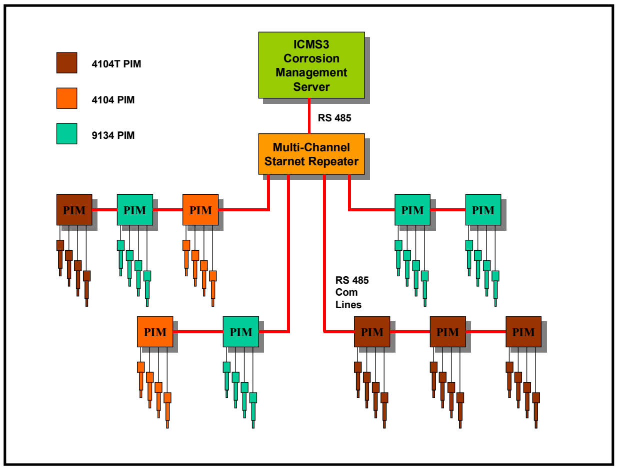

Figure 4 PIM's with RS485 Communications

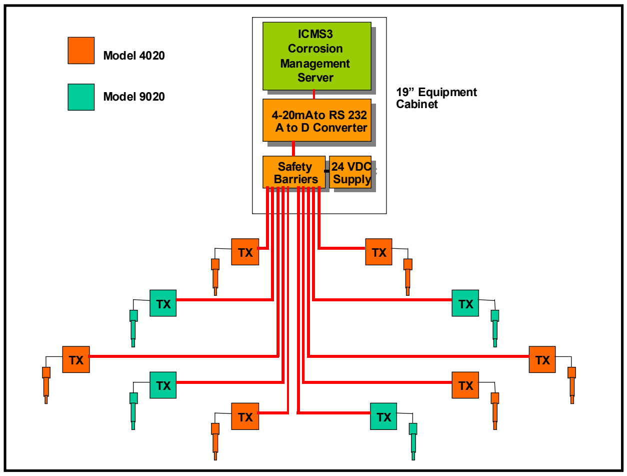

Figure 5 Transmitter System

The ultrasonic measurements are made with a Panametrics 36DL data-logging unit. The collected data is then transferred directly to the corrosion management software through an RS 232 connection.

Laboratory analysis information, such as water analysis, or the concentration of the amine solution constituents, that are typically recorded in spreadsheet format, may also be imported into the corrosion management software. This provides a convenient storage place and allows immediate correlation with corrosion parameters.

Perhaps one of the most important parts of the system is the Modicon Modbus link to the distributed control system (DCS) for transfer of process parameters. The simultaneous logging of corrosion and process data every five minutes greatly simplifies correlation of corrosion upsets with process conditions. In principle, it would be possible to do this by taking the corrosion data directly into the DCS system, and this is done on many occasions. The difficulty with this approach is that DCS systems in general are naturally designed primarily for process control. As such the system must respond in fractions of a second for control of pressure, flow or temperature. Consequently, logging of data over days and weeks is less important and is typically archived onto backup recording after more than two days. Recall of data for days and weeks is then consequently rather slow and cumbersome. In addition add-on programs to improve this performance and allow easy correlation of data over longer periods of time tend to be significantly more expensive than this system. In addition, these systems do not also allow the entry of other important corrosion related data such as coupon measurements, ultrasonic measurements, and laboratory data. For the corrosion engineer, he needs all of this data to be effective, and having this information immediately available saves a considerable amount of time.

Since the system is connected to the network, access can be readily be provided to anyone on the system. A dial-up modem is also used for remote access and software support by the use of pcAnywhere[(4)] software, which allows trouble-shooting if required.

THE PLANT

The Pine River Gas Plant is located in the foothills of the Canadian Rockies, just west of the town Chetwynd in Northeast British Columbia. Feed to the plant is dry (4lbs/mmscf) sour gas (12.5% H2S, 10% CO2) from the Monkman area 150 km to the southeast. The plant comprises three Sulfinol[(5)] 'D' gas processing trains, three MCRC sulfur plants and associated utilities systems. Design through put is 560 MMSCF/D raw gas at 9.27 mole % H2S and 7.52 mole % CO2 with a sulfur capacity of 1999 tonnes/day

Like many gas processing plants Pine River has at times experienced severe corrosion in the low pressure lean piping, Still, Lean Coolers and Reboilers. The original monitoring methods of coupons and ultrasonic thickness measurements are effective in determining long term corrosion rates, however correlation of process parameters and long term corrosion rates proved to be impossible.

A system expansion in 1994 changed the inlet acid gas composition from 17% (9% H2S, 8% CO2) to an average of 22.5% (12.5% H2S, 10% CO2). After a year or more of the increased acid gas concentration corrosion, related problems appeared in the amine trains. Problems such as pinholes in the lean piping and fouled lean/rich plate frame exchangers.

[(4)] pcAnywhere is a registered Trademark of Symantec Corporation
[(5)] Sulfinol is a licensed process of Shell Oil Company

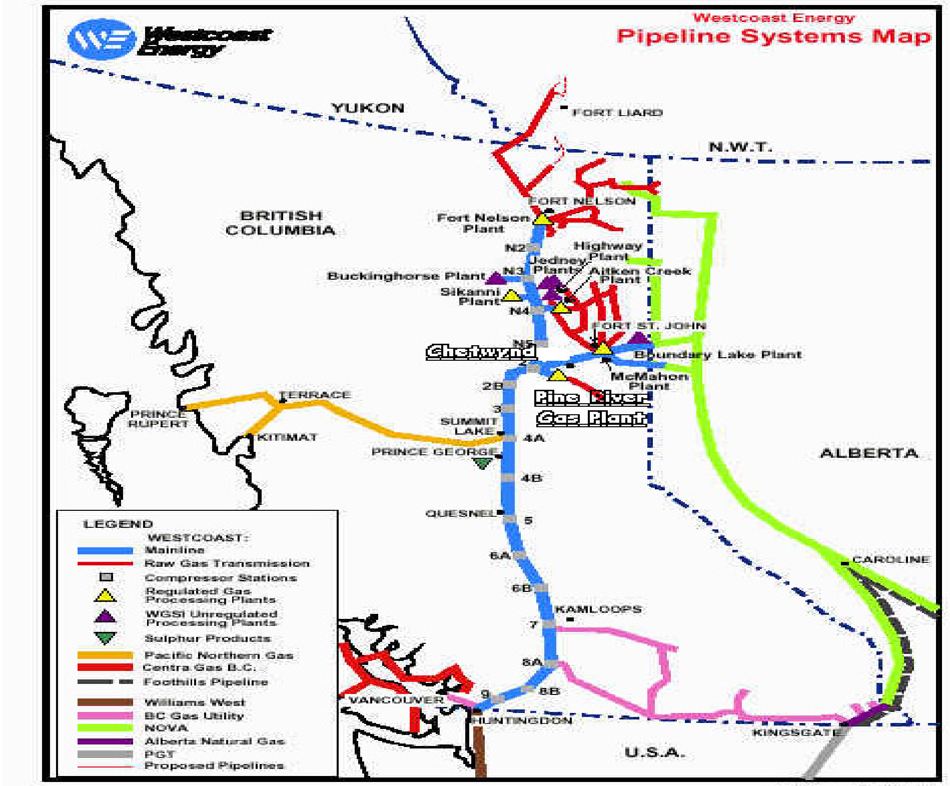

Figure 6 British Columbia System Map

These problems in turn resulted into more scheduled and unscheduled shutdowns and early retirement of some equipment. The need for improved corrosion monitoring was very apparent, a decision to move from the dark ages of coupons to a real time corrosion monitoring system was required to improve plant reliability and reduce costs.

Figure 7 Pine River Gas Plant

THE SYSTEM

The corrosion monitoring system at Pine River Gas Plant consists of eight Linear Polarization Resistance (LPR) probes per process train for a total of twenty-four for the site. Each probe will supply corrosion rate, pitting index, cumulative metal loss, and coupon corrosion data. Probe locations are as follows:

1) Still bottom (in piping from Still to Reboiler).
2) Still tray 1 (in the liquid area).
3) Still tray 3 (in the liquid area).
4) Lean piping down stream of the Reboilers.
5) Reboiler #1 shell liquid area.
6) Reboiler #2 shell liquid area.
7) Hot rich line to Still.
8) Contactor surge area.

The above locations were chosen based on local inspection, local process history and industry process history.

The system has been designed to allow probe movement within each process train, as the probes are retractable they can easily be moved to any 1 inch full port fitting.

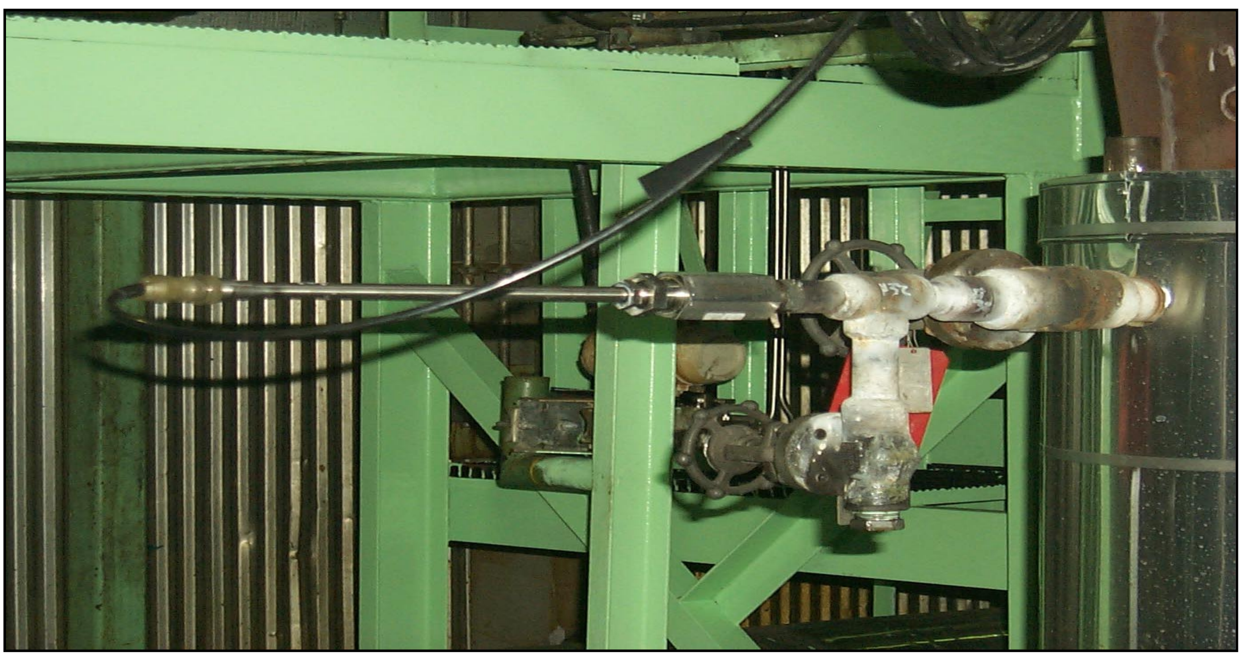

Figure 8 Typical Probe Location

The power of this on-line corrosion monitoring system is the ability to correlate corrosion rates and process variables in real time. Raw inlet gas flow and Contactor corrosion rate is a good example of a direct correlation of a process variable and a corrosion rate.

The trends indicate the negative effects that an overloaded Amine solution can have on Contactor corrosion rates. In this case, the Amine solution concentration was increased with a DIPA addition lowering both the rich loading and corrosion rate.

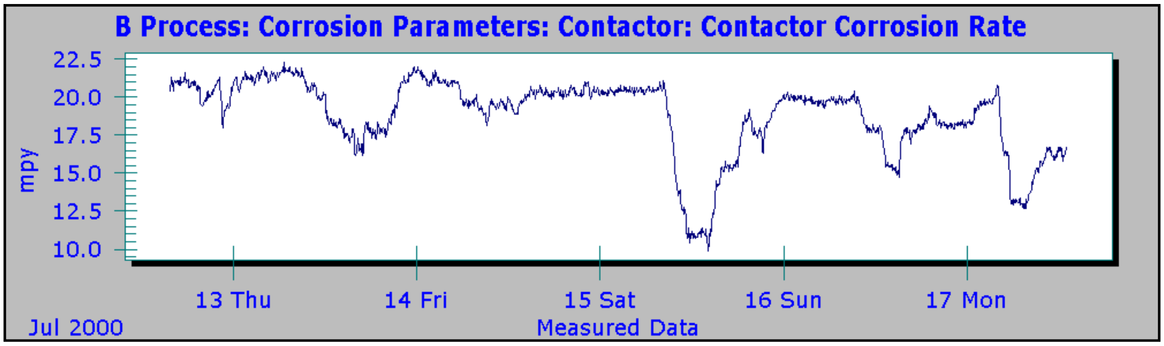

Figure 9 Contactor corrosion rate (Before DIPA addition)

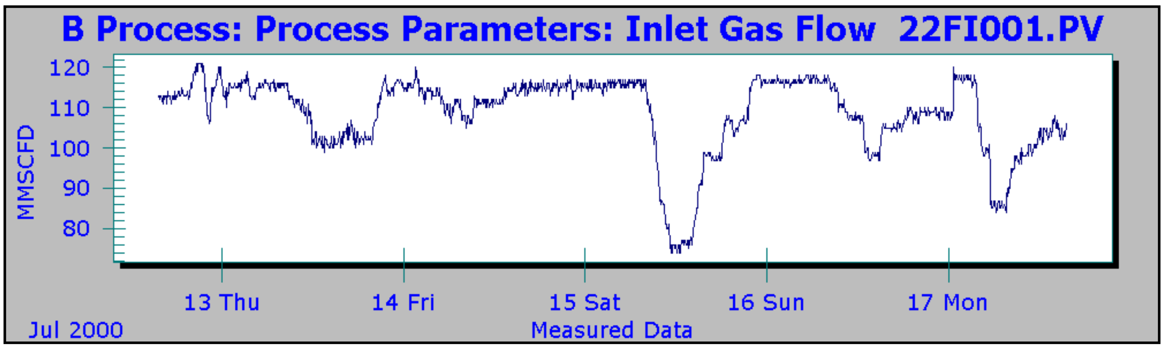

Figure 10 Inlet gas flow

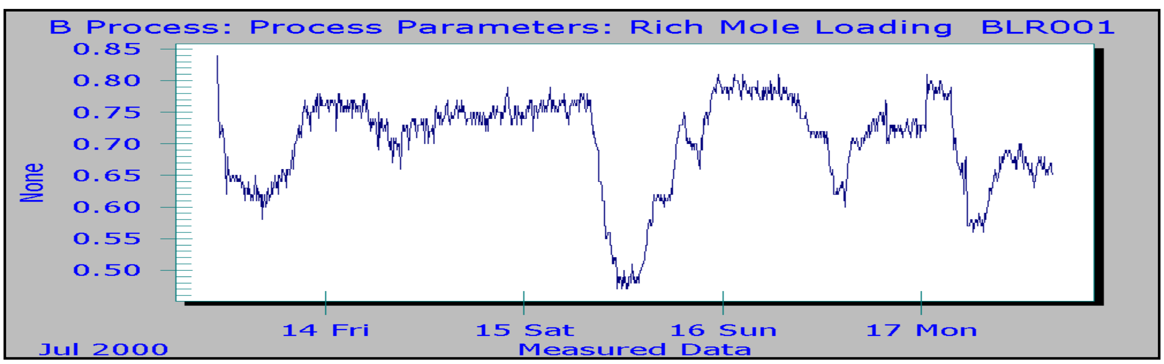

Figure 11 Rich mole loading before DIPA addition

From the on-line corrosion data, it was clear we were maintaining too low a concentration of Diisopropanolamine (DIPA) in our amine solution. By increasing the concentration, we were able to reduce the Contactor corrosion rates by a factor of four, from 20 mpy to 5 mpy. Without on-line corrosion data, the effects of the overloaded amine solution are not so apparent. If this situation had been allowed to proceed, the results, at the very least, would have been unnecessary metal loss in the Contactor, and could possibly result in future Contactor repairs. The above correlation between rich loading and corrosion rates is an illustration of a known fact.

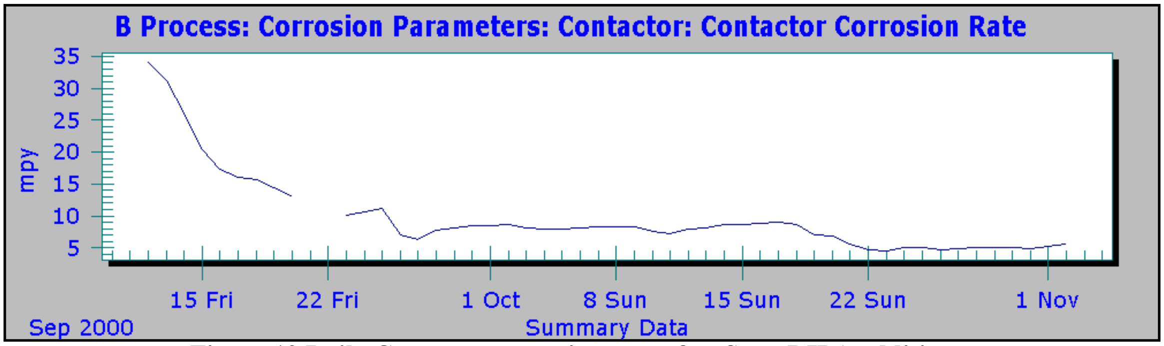

Figure 12 Daily Contactor corrosion rate after Sept. DIPA addition

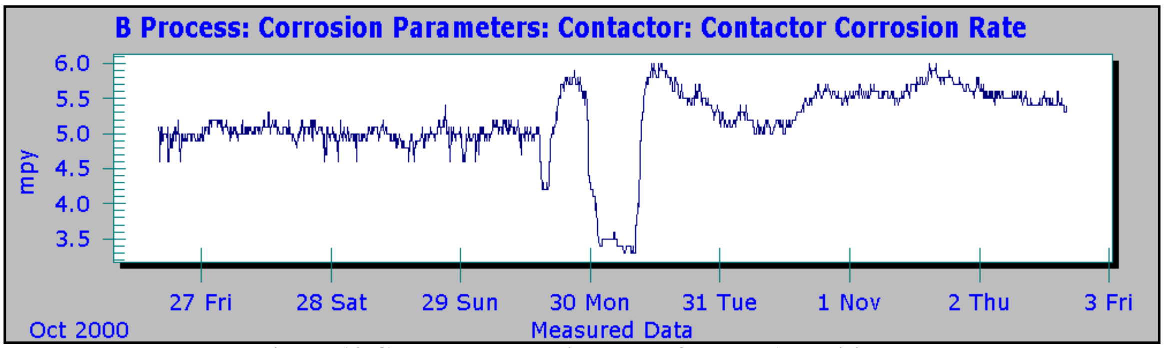

Figure 13 Contactor corrosion rate after DIPA addition

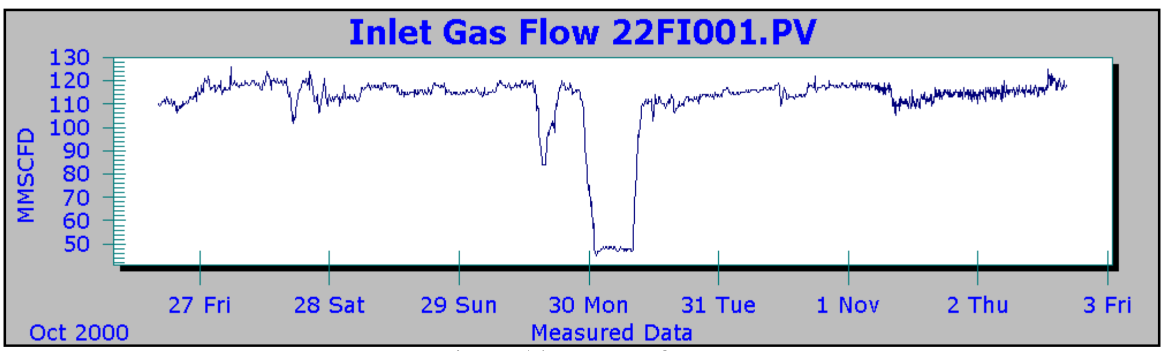

Figure 14 Inlet gas flow

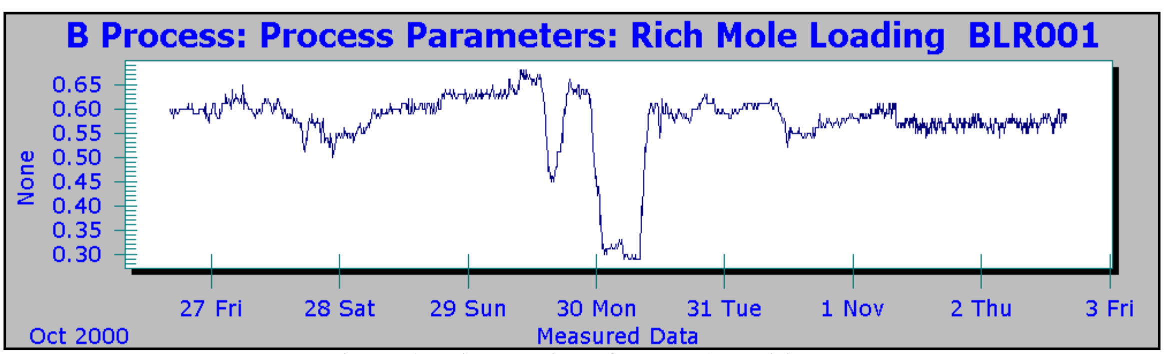

Figure 15 Rich loading after DIPA addition

A fact that is not so widely known is how a slip-stream Reclaimer can effect the corrosion rates in the Still. The ‘A’ and ‘B’ process trains each operate a slipstream Amine Reclaimer where 1.54 usgpm of lean amine flow down through a packed column. Heated Still reflux (420 F) flows up through the column and contacts the lean amine flowing down. Steam and reclaimed amine vapor leave the top of the column and enter at the sixth tray of the Amine Still. During normal operation, the steam and reclaimed vapors will elevate the Still top temperature. To compensate for this Still top temperature rise, Reboiler steam flow would be reduced. The result as seen by figure 16 is a dramatic increase in the Still corrosion rate.

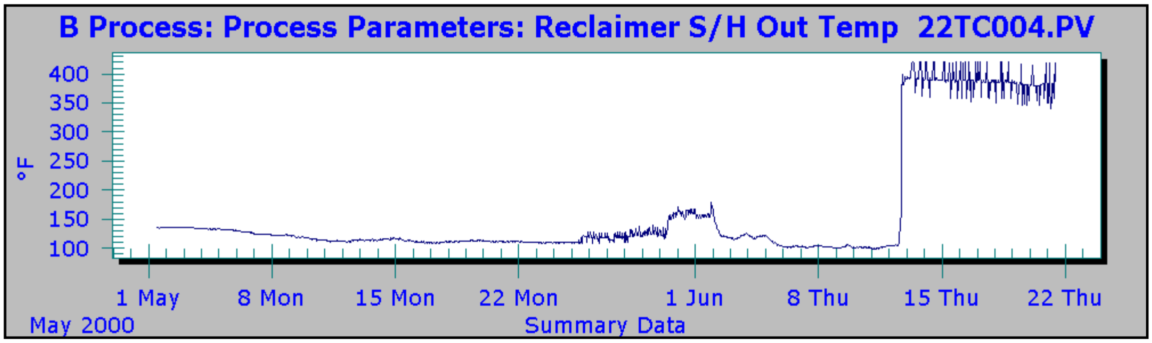

Figure 16 Reclaimer Super Heater outlet temp.

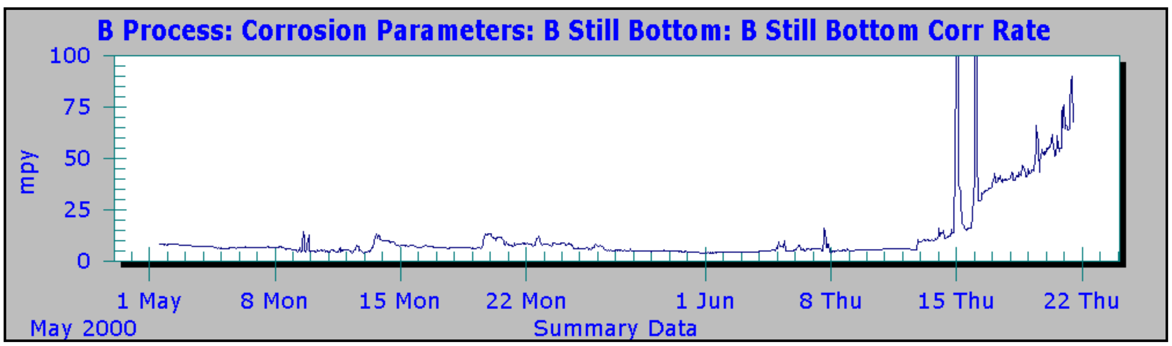

Figure 17 Still bottom corrosion rate.

In this on-line example the added heat at tray 6 combined with the Reboiler steam flow decrease has had a negative effect on the amine regeneration resulting in higher corrosion rates at the bottom of the still. Currently the Reclaimer operation in our A & B process units have been shutdown and their operation is under review. We have had Reclaiming success with a portable vacuum batch unit operated by CCR Industries.

Without the on-line corrosion data, this event would have carried on undetected for some time most likely resulting in Still damage. Because from a process point a view all things appear to be fine, Still top temperature is with in design limits, the Reclaimer is running and thought to be removing corrosive degradation product. However, with the addition of on-line corrosion data, the picture is much different. Instead of improving the process we find that the Reclaimer can be a direct source of higher corrosion rates in the Still.

With the help of the on-line corrosion system, we have fine-tuned the water concentration in the circulating amine solution. The original design at Pine River Gas Plant called for an amine solution with a concentration of 50% DIPA, 25% Water, 25% Sulfolane. Over time the actual amine solution averages concentrations of 38% DIPA, 25% water, 19% Sulfolane, 12% DIPA-OX (DIPA degradation products) and 6% other degradation products. Therefore, the original 2:1 design ratio of DIPA to water becomes over time 1.5:1.

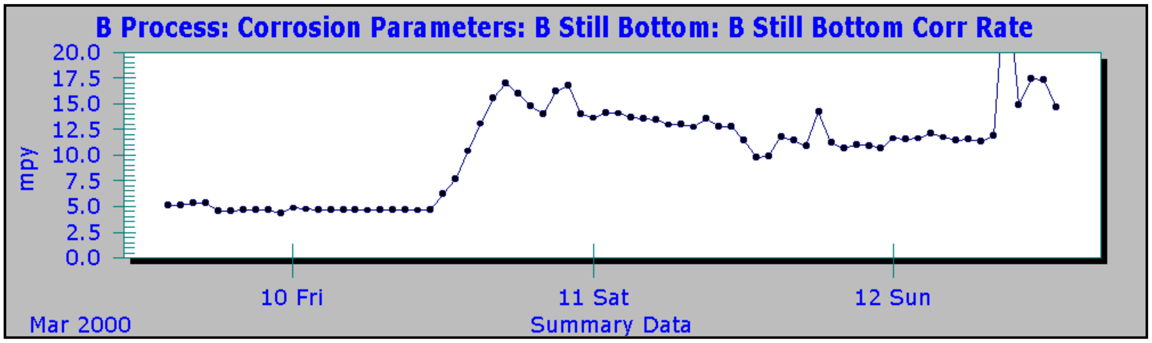

Figure 18 Still corrosion rate.

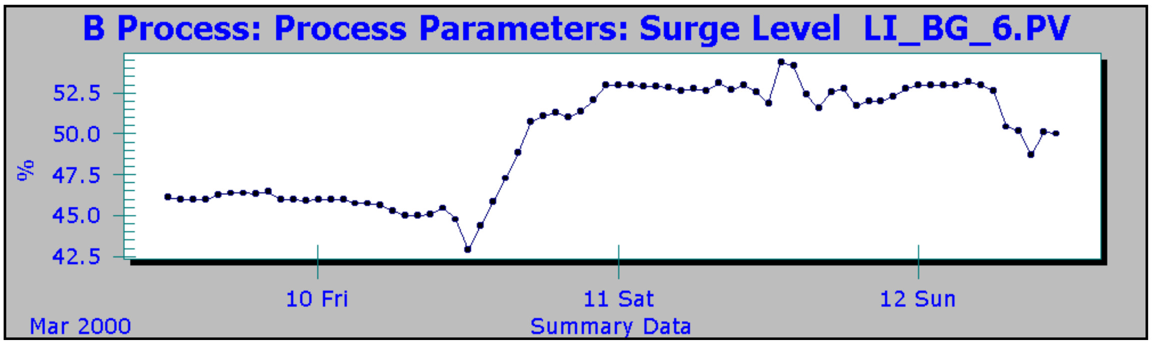

Figure 19 Water make-up to system

In the absence of on-line corrosion data the water concentration can be an overlooked minor process detail. However, comparing the Still bottom corrosion rate with water concentration, the effects from a corrosion perspective are anything but minor. The importance of maintaining the correct water concentration in a circulating amine solution is common knowledge for proper adsorption and regeneration.

Usually the water maintenance number is the original design number, which in our case is 25%. As most gas processors know there can be a discrepancy between design numbers and actual process variables. Based on information from the on-line corrosion monitoring system we have found that a water number of 22% reduces the overall corrosion rate in the amine solution based on our actual DIPA concentration.

Often the active alkalinity (DIPA concentration) of the amine solution is based on the ability to process specification gas and a rich-loading value. Usually over time the actual DIPA concentration seems to become a lower value instead of higher value, as the negative effects of maintaining lower DIPA concentrations (although well documented), are not visible on a daily basis. With on-line corrosion data the negative effects of maintaining a low DIPA concentration become visible on a daily basis.

As seen by figures 19,20 & 21 the gas cut on July 15 corresponds to a drop in the lean pipe corrosion rate. As the gas cut was relatively short in duration the solution flow was not reduced, resulting in a drop in the rich loading (see figure 10). It is also interesting to note how the lower rich loading effect the lean pipe pitting tendency (figure 22).

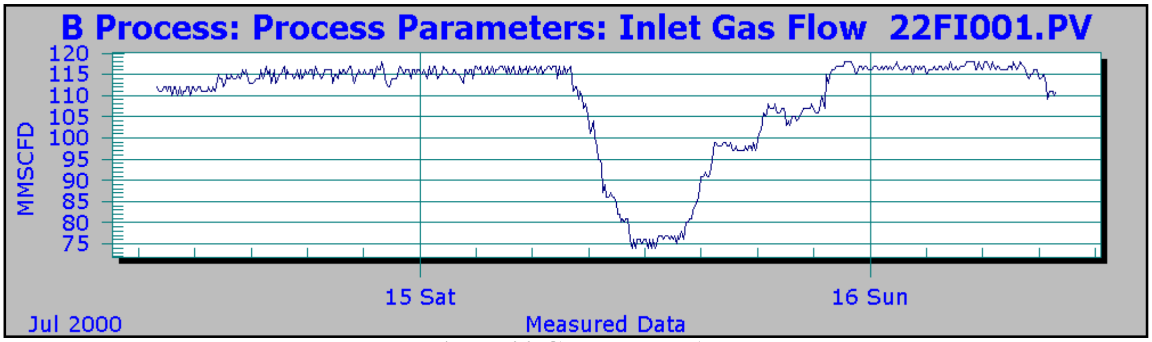

Figure 20 Gas cut July 15

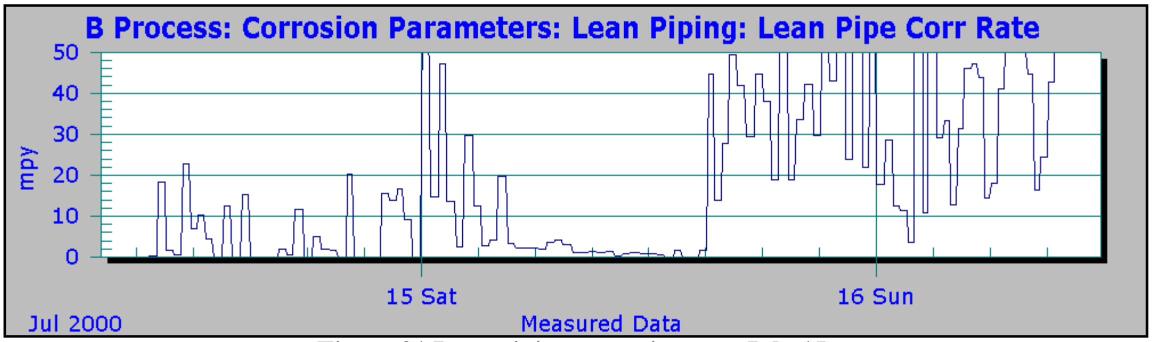

Figure 21 Lean piping corrosion rate July 15

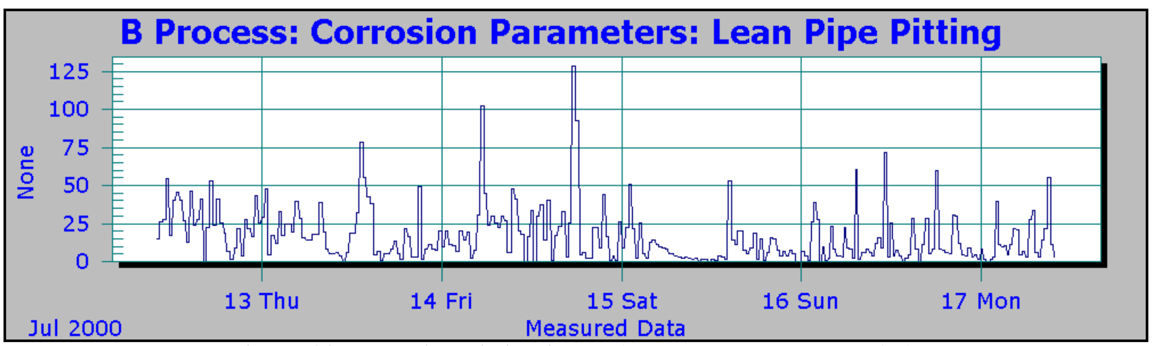

Figure 22 Lean pipe pitting index (note decrease on July 15)

The fact that higher rich loading can lead to higher corrosion rates is not surprising or new. The ability to observe corrosion rates and rich loading in real time is very powerful and useful information.

THE SAVINGS

If we look at the example in figure 17, where the Still bottom corrosion rate increased from 7 mpy to 75 mpy due to poor Reclaimer operation, savings based on early vessel retirement can be calculated. Had the corrosion rate been allowed to continue at 75 mpy the time to t_{min}. (retirement thickness) would be 3.3 years. Fortunately, the event was detected and corrected. Therefore, the retirement date of the Still based on a 7 mpy corrosion rate, is 36 years.

One could say that in this case the savings were equal to the replacement cost of the Still, which could amount to $3 million. However, in reality, this corrosion event would eventually be detected by ultrasonic or internal inspection. Unfortunately, by this time, considerable damage would have already taken place. A more realistic savings amount in this case would be the cost of a Still repair, and perhaps an unplanned shutdown, an amount of $300,000 to $500,000. This is a substantial saving, which more than pays for the $250,000 (Canadian) total cost of the on-line system. The savings will probably be considerably higher as the knowledge gained from this corrosion event can be applied to the other process units.

Savings have also been achieved in the Contactor as show by figure 10. Using a Contactor corrosion rate of 20 mpy (Fig.9) the 0.125" corrosion allowance would be consumed in 6.25 years. By reducing the corrosion rate to 5 mpy (figures 12,13) the corrosion allowance of 0.125" will remain for 25 years.

The actual amount of dollars saved as a result of the installation of the on-line corrosion monitoring system at Pine River Gas Plant range from $3,000,000 to $300,000 depending on how you treat the data. Based on the two examples above from just one process unit, the dollars saved have more than paid for the original system cost of $250,000 (Canadian).

CONCLUSIONS

The ability to monitor process variables and corrosion rates in real time has given the personnel at Pine River Gas Plant a better understanding of what process variables/conditions are contributing to corrosion. With this knowledge, we have been able to significantly reduce the corrosion rates on all three process trains.

Although the system will never eliminate corrosion in our gas processing plant, we now have the ability to detect and respond to corrosion events at the early stages. The combination of corrosion/process knowledge and early corrosion detection reduces our maintenance costs and improves plant reliability.

ACKNOWLEDGEMENTS

The authors would like to thank those that assisted in this project, without which this paper could not have been presented. From Westcoast Energy Pine River Gas Plant were Sheila Buckle P.Eng. Plant Engineer, and Anthony Bozzi. From Corrpro Canada was Ken White, Manager Internal Corrosion Monitoring. From Corrosion and Condition Control Ltd was Neil Rothwell, Sales Director, and software systems support from Graham Herbert, Rod Macleod, Sonia MacDonald, Norman Matheson, and John McKee.