SUBJECT: A CORROSION MITIGATION PROGRAM FOR THE REDWATER OIL FIELD

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A Corrosion Mitigation Program for the Redwater Oil Field

Abstract

Serious corrosion by hydrogen sulphide and carbon dioxide attack of the North Two-Phase gathering line, flowlines and downhole equipment, became evident in the Redwater oil field during the period 1972 through 1973.

Corrosion in the North Two-Phase gathering line was successfully mitigated by the continuous injection of corrosion inhibitor. Corrosion in downhole equipment and flowlines was successfully mitigated by batching inhibitor into the annulus of each oil well while circulating the well fluids for a ten minute period.

Iron counts on samples of produced water, combined with the careful observation of corrosion attack to hardware, made it possible to measure the effect of the mitigation program and to optimize the economics.

Corrosion in the North Two-Phase Gathering Line

Without doubt the most significant failure which clearly identified the existence of a corrosion problem in the Redwater Field was the failure of a section of 8 inch diameter, 0.157 inch wall electrically resistance welded pipe in the North Two-Phase gathering line in June 1972.

This gathering line, which is 9 miles long, begins in Opal as a 4 inch diameter line, then increases to 6 inches, 8 inches and finally 12 inches at the fieldgate and gas plant as shown in Figure 1.

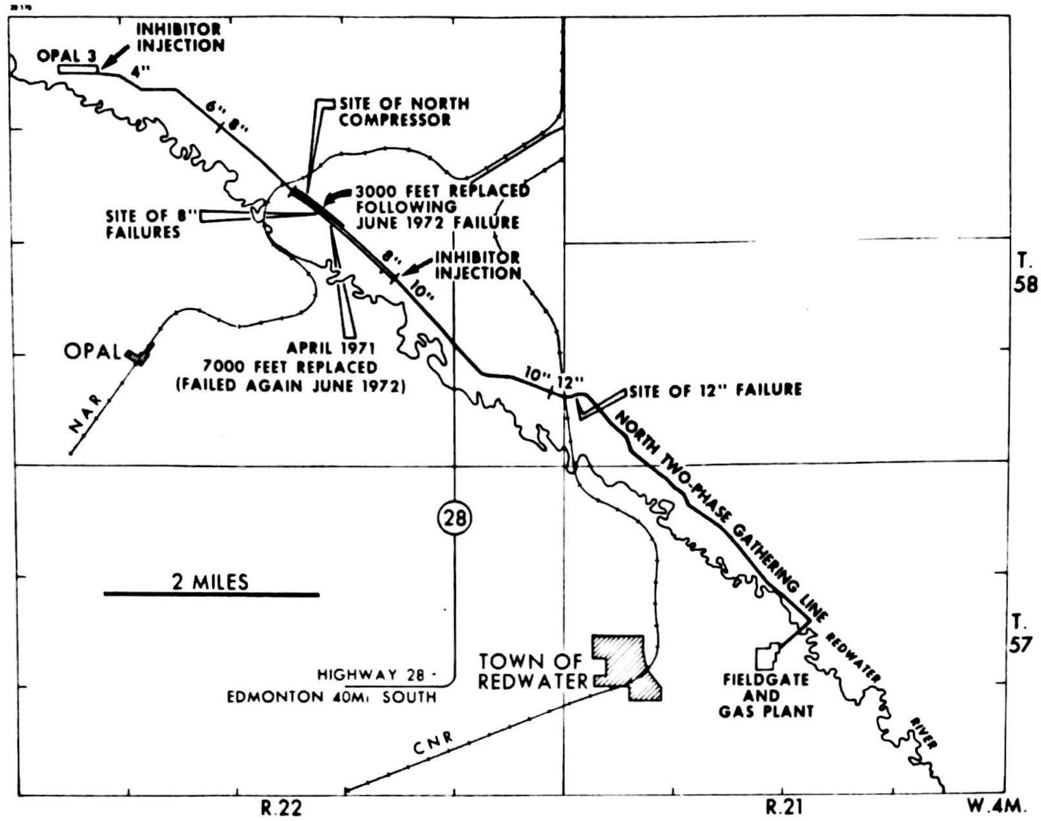


Figure 1 - Map of the Redwater North oil field showing failure locations and inhibitor injection points on North Two-Phase gathering line.

From 1956 to November 1968 this line had been in gas gathering service. In April 1971 internal corrosion problems, which were attributable to the gas gathering service period, made it necessary to replace 7000 feet of 8 inch pipe. The failure which occurred in June 1972 was again within that same 7000 foot section. Now a 3000 foot section of pipe had to be replaced within that same area. This indicated that the corrosion was very active and very aggressive.

Another internal corrosion failure occurred in the 12 inch section in August 1972.

Laboratory analysis proved the failures to be the result of internal pitting on the bottom of the line. Furthermore this analysis indicated that the pitting was due to a hydrogen sulfide in water corrosion mechanism.

Figure 2 shows an example of the pitting.

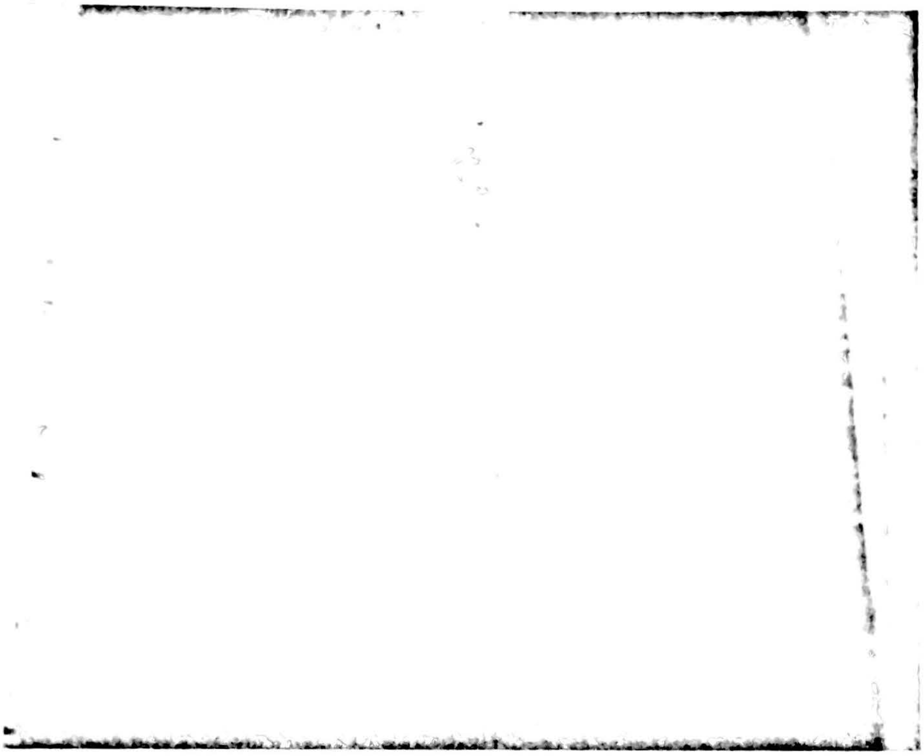


Figure 2 - An example of the pitting found in the North Two-Phase line.

A number of items were considered to be significant to the failure analysis. Two failures had occurred in the same section of line and the hydrogen sulfide and water content of the production was increasing with time. At the time of the June 1972 failure the line was transporting 9600 barrels/day of product and 1500 barrels/day of water. Also significant was that a compressor station was injecting gas into the North Two-Phase line at a point which was upstream of the failure locations (Figure 1).

The gas/oil ratio changed from 187 standard cubic feet/barrel upstream of the compressor station to 467 standard cubic feet/barrel downstream of the compressor station. The gas/oil ratio then dropped again to 181 standard cubic feet/barrel downstream of the problem area as a result of the injection of quantities of dead oil into the line.

It was considered that this gas compressor provided a warming trend and a sour wet gas phase which scrubbed the pipe wall free of its natural protective films of iron-sulphide.

Following the failure in the 8 inch section in June 1972, it was decided that an inhibitor program be commenced immediately by injecting continuously a water and oil dispersible corrosion inhibitor. The program consisted of batch treating the line at the North end of the 4 inch section and at the junction of the 8 inch and 10 inch sections at a concentration of 200 ppm. Following the batch treatment a continuous inhibitor injection rate of 20 ppm was injected at the same locations.

To date a corrosion failure has not occurred since the inhibition program was started. During this period of time (over three years) the inhibition rate has been maintained at 20 ppm.

Since it is necessary to pig the line regularly to remove wax deposition it is not practical to install corrosion monitoring probes.

II Corrosion in Oil Wells and Flowlines

From 1964 through 1972.minor and infrequent corrosion of downhole equipment became apparent. Figure 3 shows the well locations at which the initial downhole corrosion problems occurred.

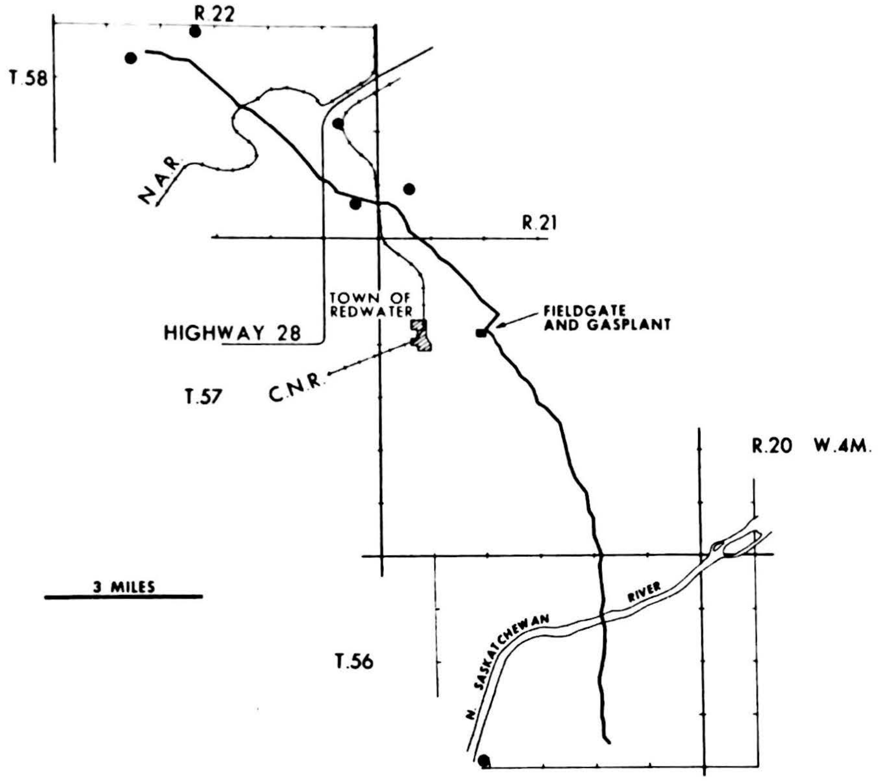


Figure 3 - Map of the Redwater oil field showing location of wells where downhole corrosion occurred prior to 1973.

Beginning in 1973 the frequency of corrosion related damage of downhole pumps and sucker rods in the Northern section of the field where produced fluids contain 90% water began to increase at an alarming rate. Within twelve months the downhole corrosion spread across the complete field inclusive of those areas where the produced fluid contained less than 1% water. Figure 4 shows the location of those additional problem wells.

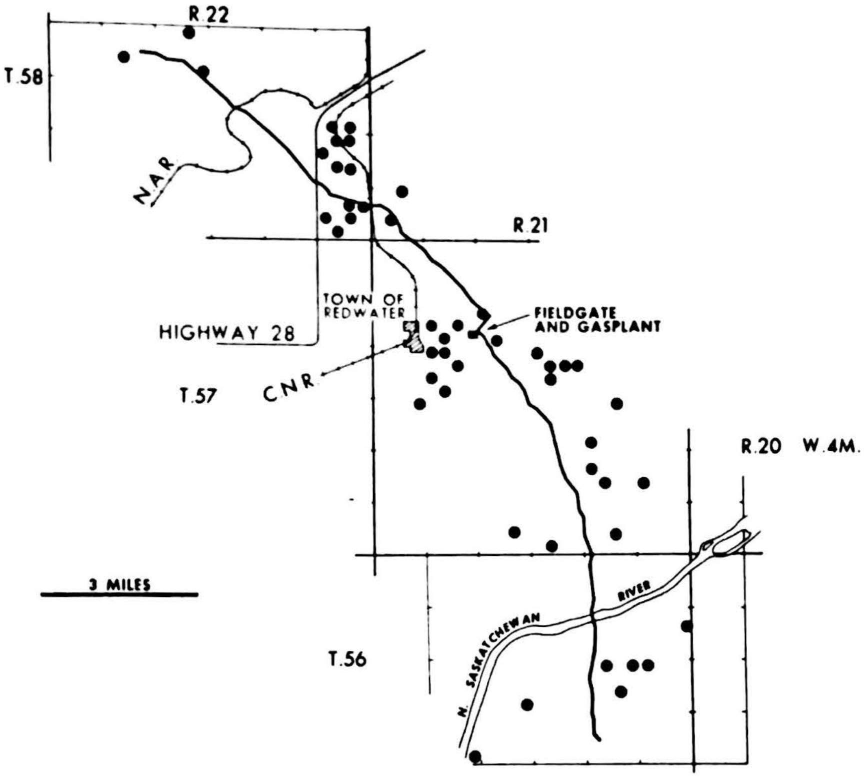


Figure 4 - Map of the Redwater oil field showing location of wells having downhole corrosion by the end of 1973.

Problem Analysis

An extensive investigation of the corrosion problem revealed the following:

1. The initial metallurgical analysis of corroded downhole hardware indicated that the corrosion was characteristic of hydrogen sulfide pitting attack (as in the Two-Phase line).

Figure 5 shows a typical sucker rod corrosion pit.

TABLE I

COMPOSITION OF GAS SAMPLES FROM GAS SEPARATORS

Sample Location	Mole % H_2S	Mole % CO_2	H_2S/CO_2 Mole Ratio	Total Acid Gas Mole % H_2S & CO_2
Separator No. 1	1.7	5.9	0.29	7.6
Separator No. 2	1.3	6.0	0.22	7.3
Separator No. 3	1.3	4.7	0.28	6.0
Separator No. 4	1.1	3.9	0.28	5.0
Separator No. 5	1.1	4.9	0.22	6.0
Separator No. 6	1.4	4.3	0.33	5.7
Separator No. 7	1.8	4.4	0.41	6.2
Separator No. 8	1.8	4.3	0.42	6.1
Separator No. 9	1.5	3.1	0.48	4.6
Separator No. 10	1.5	3.3	0.45	4.8
Separator No. 11	0.8	2.7	0.30	3.5
Separator No. 12	1.5	3.3	0.45	4.8
Separator No. 13	0.8	2.6	0.31	3.4
Separator No. 14	1.1	3.4	0.32	4.5
Separator No. 15	1.3	3.5	0.37	4.8
Separator No. 16	1.2	2.6	0.46	3.8
Separator No. 17	1.3	4.6	0.28	5.9
Separator No. 18	1.3	4.9	0.27	6.2
Separator No. 19	1.5	4.3	0.35	5.8
Separator No. 20	1.4	4.8	0.29	6.2
Separator No. 21	1.2	3.7	0.32	4.9

Contour plots of the gas composition revealed that 32 of the 40 wells with the most serious corrosion problems fell within areas bordered by either hydrogen sulfide/carbon dioxide mole ratios of 0.48 or total acid gas contents of 6.0 or greater mole percentage. Previous studies conducted by Imperial Oil's Production Research and Technical Service Laboratory showed that hydrogen sulfide/carbon dioxide mole ratios of 0.4 to 1.2 caused the most extreme corrosion rates. (See figure 6)

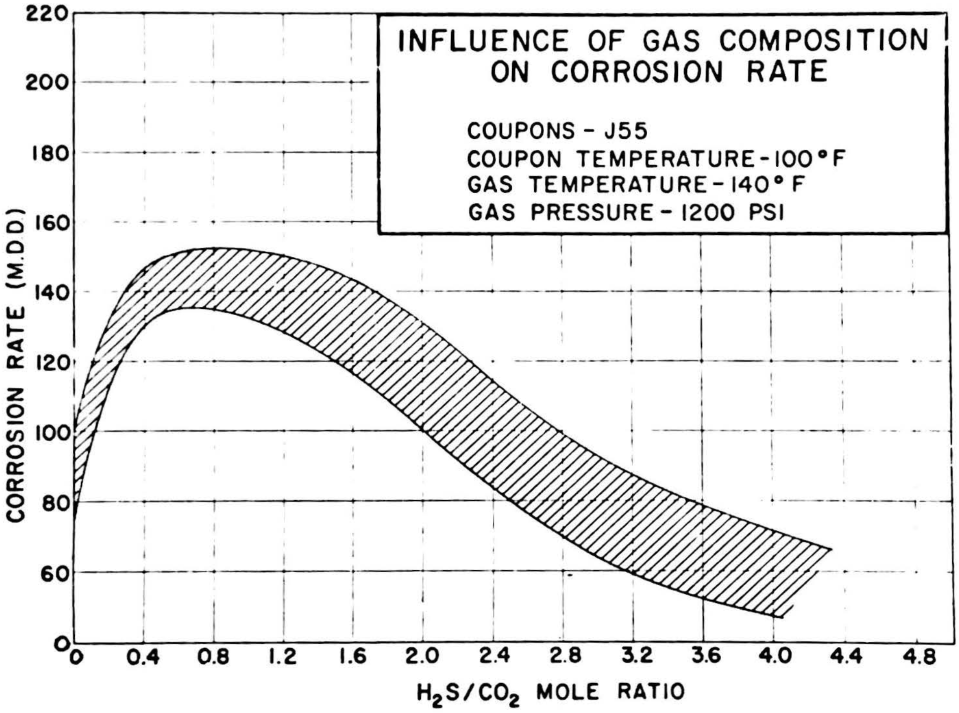


Figure 6 - Influence of gas composition on corrosion rate.

It was concluded that the corrosion failures were caused by a pitting attack from a hydrogen sulfide/carbon dioxide in water mechanism which was most severe in areas bordered by a hydrogen sulfide/carbon dioxide mole ratio of 0.48 or total acid gas concentration of 6.0 or greater mole percentage in the produced gas.

Corrective Action

It was decided initially to obtain control of the downhole corrosion problem by giving an inhibitor treatment to all wells within the recognized problem area that were producing fluids containing in excess of 35% water. It was further decided to inhibit all wells that were producing fluids containing in excess of 10% water with flowlines crossing the river. However, this criterion lost its significance very quickly when it became evident that the corrosion attack was also occurring in wells producing fluid containing as low as 1% water.

An analysis of well service reports of 75 wells which showed evidence of corrosion attack revealed that there was no recognizable correlation between the percentage of water in the produced fluids and corrosion attack. (See Table

TABLE II

Corrosion Attack versus Water Content of the Produced Fluid

Percentage of Water	Number of Wells Showing Corrosion Attack
less than 5	15
5 to 20	15
20 to 40	9
40 to 60	12
60 to 80	9
80 to 100	15

Therefore, the inhibition program was expanded to all wells in the defined problem area irrespective of the percentage of water in the produced fluid. In addition, also wells outside of the problem area were included in the corrosion inhibition program when relatively minor corrosion occurred on rods or pump parts.

A water and oil dispersible inhibitor was applied as follows:

itial treatment each well selected for inhibition received a 10-
tch of inhibitor followed by complete circulation of the well fluid.
on, the flowline was pigged where possible and then batched with
of inhibitor. In order to ensure maintenance of the initial
e film, each well received in subsequent treatments a 5-gallon batch
tor injected into the annulus weekly. During these subsequent treat-
well fluids were circulated only while injecting the 5-gallon batch
tor. Each injection takes approximately ten minutes.

The corrosion inhibitor is injected by means of a self-contained
sure pump truck as shown in Figures 7 and 8.

- A rear view of the high-pressure pump truck.

Five months after the placement of the first well on t

, corrosion failure records on 30 known problem wells wer

e the effectiveness of the corrosion mitigation program.

d rods or pumps failed due to corrosion before and after

or treatment on an equal time basis were 52 and 9 respect

ation of the Corrosion Inhibition Program

TABLE III

Comparison of Weekly and Bi-Weekly Treatment Schedule over Six Month Periods

	Weekly Treatment	Bi-Weekly Treatment	Increase (Decrease)
Number of failures due to corroded rods or pumps	9	12	3
6 month cost/well including inhibitor and corrosion failure repair costs	$945	$560	($385)

Even though the number of failures in the bi-weekly schedule is slightly higher than in the weekly scheme, the net result is that with the bi-weekly program over a period of six months a saving of $385 per well was achieved.

At the time of writing, the bi-weekly treatment schedule is still in use in order to gain additional evidence that it gives adequate downhole protection

Corrosion in Flowlines

Two failures in flowlines from wells occurred before the start of the inhibition program. On one of these wells a second failure of the flowline occurred two months after the well and the flowline received the first inhibitor treatment. This failure is shown in Figure 9.

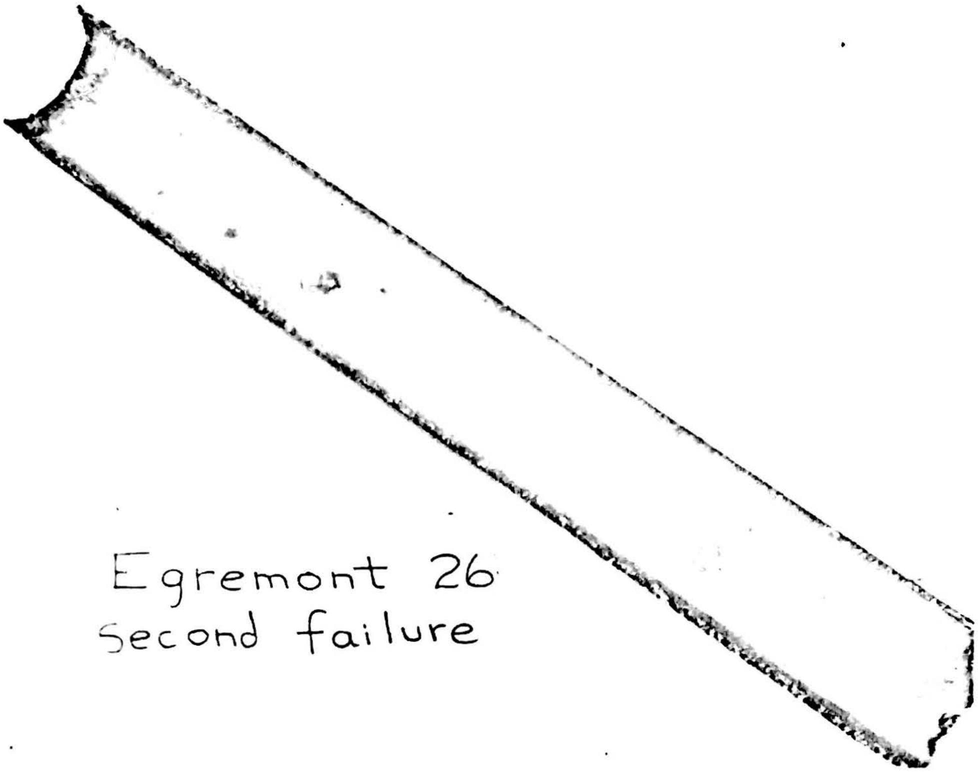


Figure 9 - The second failure of the flowline.

This second failure is suspected to have resulted from corrosion damage which occurred prior to inhibition aided by minor corrosion while on inhibition. In December 1975, two more flowlines failed as a result of internal corrosion. These flowlines (and their producing wells) had been on inhibition since mid 1974. These two flowlines which failed represent a small percentage of the 236 wells which are presently being inhibited. The two flowline failures are presently being investigated.

Monitoring Techniques

Three techniques are used to monitor the effectiveness of the inhibitor program.

Corrosion Coupons

Corrosion coupons installed in wellheads have shown low levels of general corrosion but not any evidence of the pitting type of corrosion observed on field hardware. The coupons also have failed to show any significant variance in the rate of corrosion with and without treatment. One of the reasons may be that the coupons are located in the upper quadrant of the wellhead piping and therefore, possibly, are protected from corrosive attack by an oil film.

Iron Counts

The water phase of samples of the produced fluids from the flowlines is carefully separated from the crude-oil phase with a separatory funnel and then collected in a 120-ml. bottle which is filled to the top to exclude air. It is essential to eliminate crude-oil from the water sample because undissolved iron can migrate from the water to the oil. The water sample is acidized and the sample bottle is washed with acid to recover all of the iron. The water is then analyzed for total dissolved iron (Fe +++) using the colorimetric dipyridyl method.

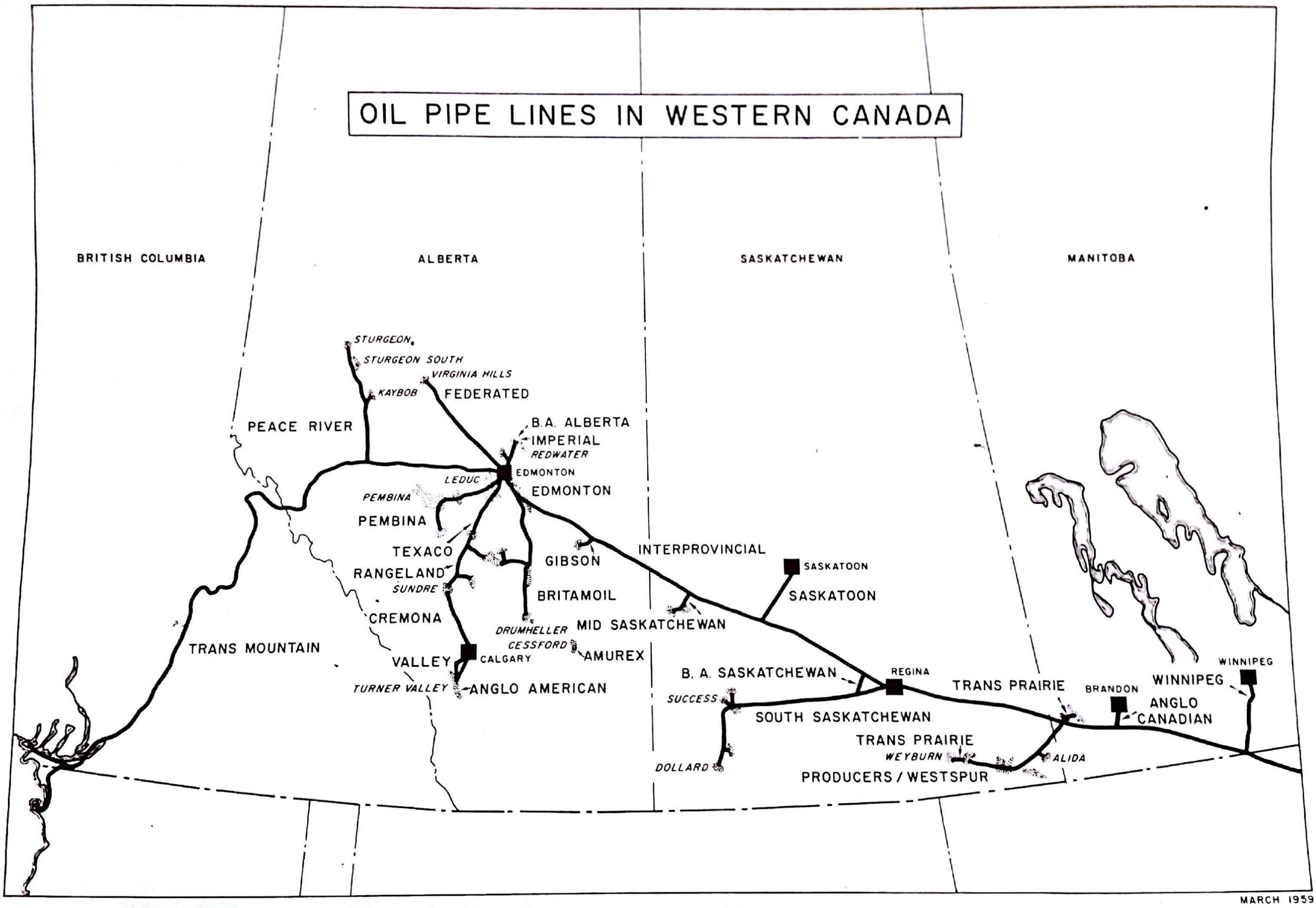
Although individual iron counts fluctuate widely, it is possible to identify trends in the many analysis results collected over an extended period of time.

This method of monitoring, expanded to aid in the identification of additional wells experiencing corrosion attack, is still in use.

Failure Records

The most conclusive technique for monitoring the effectiveness of a corrosion mitigation program is the accurate recording of corrosion occurrences. Accordingly all service rig and pump repair personnel are instructed to carefully observe and report any evidence of corrosion in order to assess the effectiveness of the program.

It is concluded that earlier recognition of the problem would have resulted if improved observations had been recorded initially.



OIL PIPE LINES IN WESTERN CANADA
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
STURGEON
STURGEON SOUTH
VIRGINIA HILLS
KAYBOB
FEDERATED
PEACE RIVER
B.A. ALBERTA
IMPERIAL
REDWATER
EDMONTON
LEDUC
EDMONTON
PEMBINA
PEMBINA
TEXACO
GIBSON
INTERPROVINCIAL
SASKATOON
RANGELAND
SUNDRE
BRITAMOIL
SASKATOON
CREMONA
DRUMHELLER
MID SASKATCHEWAN
TRANS MOUNTAIN
CESSFORD
AMUREX
VALLEY
CALGARY
TURNER VALLEY
ANGLO AMERICAN
B. A. SASKATCHEWAN
REGINA
TRANS PRAIRIE
BRANDON
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