

OPTIMIZING CORROSION INHIBITOR INJECTION RATE IN FLOW LINES

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ABSTRACT

A mechanistic chemical dispersion model was developed to aid in optimizing corrosion inhibitor injection. The mechanism of corrosion inhibition is attributed to the adsorption of inhibitor to the pipe wall to create a hydrophobic layer. The mechanistic corrosion inhibitor dispersion model, which is linked to a commercial flow simulator, was developed to account for the mechanisms governing the distribution of corrosion inhibitor including the gross distribution of oil/water/gas in the pipeline, turbulent dispersion in the free water phase, partitioning of inhibitor between oil and water phases, and the adsorption/desorption of inhibitor on the pipe wall. This model can be used to calculate the inhibitor concentration in the liquid phases as well as on the wall in the flow line. Therefore, this mechanistic model should be a useful tool in the design of optimal corrosion inhibitor injection for corrosion control, i.e., determining the minimum inhibitor concentration required to provide the maximum inhibition protection.

The model was tested by conducting numerous simulation runs using different scenarios including injection rates, number and location of injection points, and inhibitor partition characteristics based on the flowing characteristics of the pipeline. Major factors, which can affect the treatment optimization methodology, are identified.

Keywords: Corrosion Inhibitor, Distribution, Adsorption/Desorption, Mechanistic Model, Numerical Method

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INTRODUCTION

Chemical corrosion inhibition is one of the most common ways to control corrosion in a pipeline. The mechanism of corrosion inhibition is attributed to the adsorption of the inhibitor on the pipe wall to form a hydrophobic layer, thus preventing water from contacting the pipe wall. A minimum inhibitor concentration¹ generally exists to provide the required inhibition efficiency. Below this minimum inhibitor concentration, the inhibitor performance may not provide acceptable protection. Inhibitor concentrations significantly above the minimum required concentration provide little or no additional performance benefits, waste chemical, and may cause negative effects such as chemical incompatibility and formation of emulsion. These negative effects can downgrade the inhibition performance and cause oil/water separation problems. Therefore, it is essential that the inhibitor treatment concentration be maintained close to and above the minimum required in order to effectively control corrosion in the multiphase flowing pipeline in the most cost-effective manner.

Theoretically, monitoring inhibitor residue in the pipeline can be done by measuring the inhibitor concentration in the produced fluid.² This is a difficult if not impossible task analytically because the inhibitor treatment concentration is generally in the range of 10-100 ppm for continuous treatment and 1,000–5,000 ppm for batch treatment based on the total produced liquids. With the active inhibitor component being about 15-20 %, the active inhibitor concentrations are in the range of 1.5-20 ppm and 150–1,000 ppm for continuous and batch treatment, respectively, which stretches the limits of detectability. An alternative approach to understand the changes in the inhibitor concentration in the pipe is by numerical modeling of the inhibitor distribution process. Thus, we decided to develop a mechanistic inhibitor simulator to model the distribution of corrosion inhibitor in the production pipeline, as well as the adsorption of the inhibitor on the pipe wall.

We developed a numerical method to compute the distribution of corrosion inhibitors in multiphase flow in a pipe. In general, the mechanisms governing the distribution of corrosion inhibition include turbulent dispersion, molecular diffusion, partitioning of inhibitor between water and oil, adsorption/desorption of inhibitor³⁻⁶ on the wall and chemical reactions at the pipe wall. In this application, we assume that molecular diffusion can be neglected and that there are no chemical reactions. Most of the published literature⁷⁻¹⁰ has focused on the dispersion of a solute in single phase flow in a circular pipe where the effective dispersion coefficients could be rigorously derived. Since modeling of multiphase flow in pipes is still under development, and the current models contain large uncertainty in predicting flow patterns and momentum transfer, a rigorous approach is too difficult, if not impossible, and beyond the scope of this work. Instead, we calculate the flow pattern of multiphase flow and then the cross-section averaged advection-diffusion equation is solved for each phase. The effective adsorption, desorption and dispersion rates of inhibitors are computed from single phase flow in a pipe, instead of a rigorous derivation from complex multiphase flow in a pipe. We employ a simple first-order rate for adsorption/desorption of inhibitors between the fluid phase in contact and the pipe surface. We anticipate that the models will be improved in the future as our understanding of multiphase flow progresses.

A detailed description of the numerical methods used for model development is not the focus point of this paper; however, a brief description is provided below. The focus of this paper is the application of the model for optimizing the chemical injection rate in flowing pipeline. We used a commercial steady-state multiphase flow simulator to generate the flowing parameters required as inputs to the inhibitor simulator¹¹ which then computes the distribution of inhibitor in the pipeline. Key factors that affect the inhibitor distribution in the pipeline were investigated and results are presented. This

mechanistic model will be validated and improved by benchmarking with the field and the laboratory data.

THEORETICAL FORMULATION

Multiphase flow in a pipe can exhibit complex flow patterns, namely, annular flow, stratified flow, bubbly flow, churn flow, slug flow and fully dispersed flow. A correct model for a solute (corrosion inhibitor) distribution entails an accurate calculation of velocity and phase distribution in a pipe. However, due to the complexity of the physical process, we are currently only able to compute cross-section averaged values of phase fraction and velocity. The three-dimensional flow phenomenon is modeled by a one-dimensional approximation. Thus, we solve the distribution of solute in terms of the cross-section averaged variables. The multiphase advection-diffusion equation for averaged saturations for a three-phase system of gas, oil and water can be written as

$$\frac{\partial C_i}{\partial t} + U_i \frac{\partial C_i}{\partial z} + Q(C_i, z, t) = D_i^{eff} \frac{\partial^2 C_i}{\partial z^2} \quad \text{for } i = g, o, w \quad (1)$$

Here, C_i is a cross-section averaged concentration of corrosion inhibitor in phase i , Q is the source-sink rate/volume due to injection, adsorption, desorption at the wall and D_i^{eff} is the longitudinal dispersion coefficient. Here we assume that the longitudinal dispersion is much larger than the molecular diffusion. This assumption is justified because of the non-uniform flow field in a tube. We also assume that the chemical injection does not change the multiphase flow field, and that there are no chemical reactions. The partition of inhibitors between fluid phases is in equilibrium and a first-order equation for adsorption and desorption rate is employed.

$$\frac{\partial C_s}{\partial t} = -a(C_s - C_s^*) \quad (2)$$

Here, C_s is the inhibitor surface concentration on the pipe and C_s^* is the equilibrium surface concentration in contact with the fluid with inhibitor concentration, C_i . The a is the adsorption / desorption rate constant.

NUMERICAL METHOD

Multiphase pipeflow simulations are used to obtain the averaged velocities, phase fraction, and flow patterns. The contact area between the fluid and the pipe surface can be computed from the flow pattern and the phase volume fraction. Based on this information, we determine the effective longitudinal dispersivities and the source/sink strength at the pipe wall. These values are approximated with the values derived from single phase flow.

The discretization of equation (1)¹² for phase i , grid j , and time step $(n+1)$ yields

$$\begin{aligned} \frac{C_i^{n+1} - C_i^n}{\Delta t} + \frac{U_i}{2} [(1 - \theta) \frac{C_{i,j+1}^n - C_{i,j}^n}{\Delta z_{j+1/2}} + \theta \frac{C_{i,j+1}^{n+1} - C_{i,j}^{n+1}}{\Delta z_{j+1/2}}] + Q(C_i^n, z_j, t^n) = \\ \frac{D^{eff}}{2\Delta z_j} \left[\frac{(C_{i,j+1}^n - C_{i,j}^n + C_{i,j+1}^{n+1} - C_{i,j}^{n+1})}{\Delta z_{j+1/2}} - \frac{(C_{i,j}^n - C_{i,j-1}^n + C_{i,j}^{n+1} - C_{i,j-1}^{n+1})}{\Delta z_{j-1/2}} \right] \end{aligned} \quad (3)$$

where

$$\Delta z_{j+1/2} = \frac{1}{2}(\Delta z_j + \Delta z_{j+1})$$

Note that equation (3) employs a Crank-Nicholson formula for the diffusion term and a general explicit and implicit formula for the convection term (i.e., $\theta = 0$: explicit and $\theta = 1$: implicit). As the pipe is discretized in the axial direction, equation (3) will yield a tridiagonal matrix for $C_{i,j}^{n+1}$.

RUNNING THE CORROSION INHIBITOR SIMULATOR

One important feature of the corrosion inhibitor simulator is its ability to link to the flow simulator. Originally the inhibitor simulator was programmed to link to an internal steady-state multiphase simulator installed on a Unix work station. The program was recently modified to link to a commercial multiphase flow simulator for the purpose of reaching more users. In order to link the two simulators, a computer code was written to extract the required data from the output of the multiphase flow simulator to generate an input file expected by the corrosion inhibitor simulator.

The corrosion inhibitor simulator uses data generated from the pipeflow simulation as part of its input, which include temperature, pipe length, pipe diameter, gas/oil/water rates in the flowing pipeline, liquid holdup and the flow pattern.

For a typical simulation run, in addition to the data generated from the flow simulator, other input parameters are required. These include molecular weight of inhibitor, the amount of inhibitor injection, number and location of injection points, the partition coefficients of inhibitor, and the inhibitor performance isotherm. The output file displays the calculated inhibitor concentrations in oil and water phases and the corresponding fractions of the pipe wall covered by inhibitor adsorption with respect to the pipe wall exposed to water.

RESULTS AND DISCUSSION

The inhibitor simulator was tested by conducting many simulation runs under various conditions. Key factors that can affect the inhibitor distribution in the pipeline were investigated. These factors include the amount of inhibitor injection, the number and location of injection points, and the physical and chemical characteristics of the corrosion inhibitor chemistries. To be effective in multiphase flow, the inhibitor has to be able to reach the pipe wall surface exposed to water and to adsorb on the metal surface to give a protective film for corrosion control. Thus, the partition characteristic of an inhibitor between oil and water phases is an important factor and was included in the investigation. In these sensitivity studies, the multiphase flowing conditions and the inhibitor performance isotherm were kept

constant. In the near future, we plan to investigate the effect of these parameters under different flowing conditions.

Since the mechanism of inhibition is the adsorption of inhibitor on the metal surface to provide a hydrophobic film to prevent water contact of the pipeline, the performance of inhibitor is therefore related to the inhibitor concentration in the water phase and the inhibitor covered pipe fraction in which water is the wetting phase. The higher the fraction of water-wetted pipe wall covered by inhibitor, the better the inhibitor performs assuming that the inhibitor film integrity is very similar once adsorbed.

Thus, the simulator can be used to optimize the chemical treatment process by optimization of the amount of chemical injection and/or injection point for corrosion control. The optimization involves the determination of the minimum inhibitor concentration required to provide the maximum inhibition protection/coverage to achieve cost-effective operation. For this paper, the effects of inhibitor partition coefficient, the amount of inhibitor injection, number and location of injection points for a constant pipe flow scenario were compared and reported. Tables 1, 3, 5, and 7 describe the simulation runs conducted to study these effects.

Figures 1-3 show the typical simulation results for a simulation run with a total inhibitor injection of 0.25 lb at the pipeline inlet over a period of one hour and the inhibitor partition coefficient of 0.8 (T2). Figures 4-6 show similar results from a simulation run when the inhibitor partition coefficient was 0.2 and the number of injection points was 2 with 0.125 lb of inhibitor injected at each point (T3). The first injection point was conducted at the pipeline inlet over a one-hour period similar to T2 mentioned above, and the second injection was at the mid-point of the pipeline for another hour. The distribution of inhibitor concentration in the water phase at various times over the entire pipeline for T2 and T3 are shown in Figures 1 and 4, respectively. Figures 2 and 5 illustrate the corresponding inhibitor covered pipe fraction in the water phase versus time at various pipe fractions. Figures 3 and 6 show the inhibitor covered pipe fraction in the water phase versus the pipe fraction at different times after inhibitor injection. These results demonstrate that the inhibitor distribution and the inhibitor covered pipeline in the water phase for the entire pipeline vary depending on the number and location of injections and/or the partition constant of the inhibitor. Key factors that affect the inhibitor distribution in the pipeline are investigated in more detail and are described below. Note that the similar injection scheme was applied for all the simulation runs reported below and will not be repeated. One injection was conducted at the inlet of the pipeline during a one-hour period and two injections were conducted at both the inlet and the mid-point of the pipeline for a one-hour period each. However, the total amount of inhibitor injection for one and two injections was kept the same when the comparison was to be made.

Effect of Inhibitor Partition Characteristics on Inhibitor Distribution

Table 1 lists the simulation runs conducted for studying the effect of partition constant on inhibitor distribution. Table 2 and Figures 7-8 show the simulation results obtained from inhibitors with different partition characteristics. The inhibitor partition characteristic is expressed in terms of a ratio of inhibitor concentrations in oil phase to water phase ($V_{k_{ow}}$). Values of $V_{k_{ow}}$ at 0.8 and 0.2, which represent the different degree of oil/water solubility for inhibitors, were used in simulations and results are summarized in Table 2. Notice that an inhibitor is more soluble in water than oil for $V_{k_{ow}} < 1$ and that an inhibitor with $V_{k_{ow}}$ of 0.8 is more oil soluble than that of $V_{k_{ow}}$ of 0.2.

Figure 7 compares the effect of partition coefficient on the inhibitor covered pipe fraction in the water phase at 87 and 164 minutes after an injection with a total inhibitor amount of 0.25 lb at the inlet

of the pipeline in one hour. As shown in Table 2 or Figure 7, 87 minutes after inhibitor injection, the inhibitor covered pipe fraction in the water phase for T6 is 0.94–0.83 and 0.82–0.63 for T2. At 164 minutes after inhibitor injection, V_{kow} of 0.2 (T6) gives an inhibitor covered pipe fraction in the water phase in a range of 0.79–0.93, as opposed to 0.69–0.72 for V_{kow} of 0.8 (T2). T6 gives a higher overall inhibitor covered pipe fraction than T2, suggesting that, as expected, the inhibitor with a lower partition coefficient is a better inhibitor because of higher inhibitor concentration partitioned into the water phase.

Figure 8 is the similar plot with a total inhibitor injection amount of 0.25 lb, but with 2 injection points at 0.125 lb each instead. Results indicate that V_{kow} of 0.2 (T7) gives a better inhibitor covered pipe fraction in the water phase than V_{kow} of 0.8 (T3) at both times of 87 minutes and 164 minutes after inhibitor injection. There is a significant distinction between T7 and T3 at 87 minutes after injection with no inhibitor coverage at the end of pipeline for T3. This is due to the fact that there is no inhibitor partitioned into the water phase.

Thus, the simulation results indicate that inhibitor with a partition constant of 0.2 (Tests 6 and 7) gives a better inhibition performance than that with a partition constant of 0.8 (Tests 2 and 3). The results are in good qualitative agreement with what are commonly observed in laboratory experiments.

The Effect of Injection Amount on Inhibitor Distribution

In order to determine the true effect of the amount of inhibitor injection on inhibitor distribution, only the results from the same partition constant, under the similar injection application are compared. Table 3 shows all simulation runs conducted for this purpose. Table 4 lists the simulation results in terms of inhibitor covered pipe fraction in the water phase at three time intervals for the entire pipeline. Comparisons are made for simulation runs of T16, T2 and T4 with single injection location at the inlet of the pipeline, the amount of injection ranging between 0.5–0.025 lb for a one-hour period, and inhibitor partition coefficient of 0.8. Figures 9–11 compare the inhibitor covered pipe fraction in the water phase for T16, T2, and T4 at 43, 87 and 164 minute intervals after injection, respectively.

Simulation runs for T3 and T5 have two injection points with a total amount of inhibitor injection between 0.25–0.025 lb and the partition coefficient of 0.8. Simulations runs for T7 and T9 are similar to that of T3 and T5, but with a lower partition coefficient of 0.2, namely more water soluble. Figures 12–13 compare the results for T3, T5, T7, and T9 respectively.

Results from Figures 9–13 clearly show the effect of inhibitor injection amount on inhibitor covered pipe fraction in the water phase for the entire pipeline for either a single point or double injection points. In general, the higher the injected amount, the higher the inhibitor covered pipe fraction in the water phase as shown in Figures 9–11 at all three time intervals of 43 minutes, 87 minutes and 164 minutes.

Results suggest that the mechanistic model can be a practical tool in optimizing inhibitor injection amounts. The desired result is to have the higher inhibitor covered pipe fraction in the water phase for the entire pipe line after the chemical injections.

Effect of Inhibitor Injection Number on Inhibitor Distribution

There are several ways to inject chemicals into the pipeline for corrosion protection. Inhibitor can be injected in large quantities at one point or it can be injected in smaller doses at more injection

points. We would like to determine the effect of multiple injection points on the overall inhibitor distribution along the pipeline. Table 5 shows the simulations conducted for this purpose. T2 and T3 were the simulations with inhibitor partition coefficient of 0.8 and a total inhibitor injection quantity of 0.25 lb, but T2 had one injection point and T3 had two injection points with inhibitor injection doses of 0.125 lb at each injection. T6 and T7 were similar to T2 and T3 respectively, but with inhibitor partition coefficient of 0.2. T12 and T13 are similar to T6 and T7 except that the inhibitors have a ten times lower partition coefficient, V_{kow} of 0.02. Results of these simulation runs are shown in Table 6 and Figures 14–15.

As shown in Figure 14, 87 minutes after inhibitor injection, T2 shows an inhibitor covered pipe fraction of 0.82–0.63 as opposed to 0.65–0.00 observed for T3. At 164 minutes after chemical injection, T2 shows a better inhibitor covered pipe fraction in the water phase than T3 at the beginning of the pipe fraction. In Figure 15, 87 minutes after inhibitor injection, T6 shows an inhibitor covered pipe fraction of 0.94–0.83 which is better than 0.84–0.70 observed for T7. At 164 minutes after chemical injection, T6 also shows a better inhibitor covered pipe fraction in the water phase than T7 at the beginning of the pipe, especially a short time after chemical injection. However, for T12 and T13, the effect of the number of injection points on the inhibitor distribution for the entire pipeline is not as significant as that of T6 and T7 as shown in Figure 16. This is due to the fact that T12 and T13 are more water soluble than T6 and T7. Thus, more inhibitor is partitioned into the water phase. The effect of multiple injections was also examined for a more oil soluble inhibitor with partition coefficient of 0.8, but with a much lower total inhibitor injection of 0.025 lb, (T4 and T5 of Table 6). Again one point inhibitor injection is better than two injection points at the constant total inhibitor injection amount concentration for the simulations performed.

These results suggest that one injection at the inlet of the pipeline is more beneficial than two injection points with one-half the injection amounts each at both the inlet and mid-point of the pipeline for the cases investigated. Note that there are more injection scenarios than were examined here; however, these results demonstrate that this simulator can be used to optimize the chemical treatment injection point strategy and injection amount to give the optimal cost-effective chemical treatment operation.

Effect of Residue Inhibitor in the Pipe on the Inhibitor Distribution after Injection

After chemical injection begins, there will be inhibitor residue in the production system long after the corrosion inhibitor is shut off. We sought to determine how an inhibitor residue present in the pipeline affects the inhibitor distribution and effectiveness. The residue inhibitor concentrations were assumed to be 0.0013 lb/ft³ and 0.00013 lb/ft³ in the flowing pipeline. Table 7 shows the results of simulation runs conducted for this purpose. Table 8 or Figures 17–18 compare the inhibitor covered pipe fraction in the water phase for these simulation runs at 87 minutes and 164 minutes for runs T18 with no inhibitor residue and T19 and T20 with a residue inhibitor concentration of 0.00013–0.0013 lb/ft³. As expected, the inhibitor covered pipe fraction is higher when there is inhibitor residue in the flow line. The higher the baseline inhibitor residue in the flow line, the better the inhibitor pipe coverage is as shown in Figures 17–18. When a residue inhibitor concentration increases from 0.00013 to 0.0013 lb/ft³, the inhibitor covered pipe fraction increases from 0.56–0.53 to 0.91–0.87 for the entire pipe fraction at 164 minutes after injection.

Cases investigated so far show just a few of the key factors which affect the inhibitor performance. In the near future, we plan to investigate other factors or combination of factors for the purpose of optimization.

CONCLUSIONS

A mechanistic inhibitor dispersion model was developed which can be used to calculate the inhibitor distribution in oil/water phases as well as the inhibitor adsorption on the pipe wall along the flowing pipeline at any time interval at constant flowing conditions after the corrosion inhibitor injection pulse. Examples show the sensitivity of effectiveness of corrosion inhibitors to various inhibitor properties and operation conditions. Consequently, this mechanistic model can be a practical tool in the operation design to optimize corrosion inhibitor injection for corrosion control, i.e., to determine inhibitor injection policy for achieving the minimum inhibitor injection dosage required to provide the maximum inhibition protection. The simulator can be further modified to track other treatment chemicals in the flow line.

ACKNOWLEDGEMENT

The authors would like to show their appreciation to Dr. Mel Wassermann, a retired Chevron employee for the development of the computer codes used in this model, Mr. Teh-Li Chang for modifying the Excel[®] output, Dr. Wen Chen for helpful discussion of the manuscript and Georgia Klock for typing this manuscript. The authors also express thanks to ChevronTexaco Exploration and Production Technology Company for permission to publish this paper.

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Table 1 Description of Simulation Runs for Determining the Effect of Inhibitor Partition Coefficient on Inhibitor Distribution

Run	Partition Coefficient, V_{kOW}	Total Inj. Amount, lb	No of Injection ^a
T2	0.8	0.25	1
T6	0.2	0.25	1
T3	0.8	0.125/0.125	2
T7	0.2	0.125/0.125	2

a One injection point at the inlet of pipeline over a period of one hour; 2 injections at the inlet & mid-point of the pipeline for one hour each

Table 2 Effect of Partition Coefficient on Inhibitor Distribution at Constant Total Concentration^a

Injection	Pipe Fraction	Inhibitor Covered Pipe Fraction in Water Phase, minute			
		T6- 87	T2- 87	T6-164	T2-164
1	0.05	0.94	0.82	0.79	0.69
	0.25	0.95	0.82	0.84	0.72
	0.45	0.95	0.80	0.89	0.73
	0.75	0.93	0.73	0.93	0.73
	0.95	0.83	0.63	0.93	0.72
		T7- 87	T3- 87	T7-164	T3-164
2	0.05	0.84	0.65	0.71	0.54
	0.25	0.84	0.64	0.73	0.56
	0.45	0.95	0.47	0.90	0.75
	0.75	0.85	0.14	0.94	0.75
	0.95	0.70	0.00	0.93	0.74

a Partition coefficient of 0.2 for T6 & T7, 0.8 for T7 & T3; total inhibitor injection = 0.25 lb

Table 3 Description of Simulation Runs for Determining the Effect of Injection Amount on Inhibitor Distribution

Run	Partition Coefficient, V_{kow}	Total Inj. Amount, lb	No. of Injection ^a
T16	0.8	0.5	1
T2	0.8	0.25	1
T4	0.8	0.025	1
T3	0.8	0.25	2
T5	0.8	0.025	2
T7	0.2	0.25	2
T9	0.2	0.025	2
a See foot note of Table 1			

Table 4 Effect of Amount of Injection on Inhibitor Distribution along the Pipe Line ^a

Pipe Fraction	Inhibitor Covered Pipe Fraction in Water Phase, minutes								
	T16-43	T2-43	T4-43	T16-87	T2 - 87	T4-87	T16-164	T2 - 164	T4-164
0.05	0.95	0.84	0.25	0.94	0.82	0.24	0.79	0.69	0.20
0.25	0.95	0.79	0.19	0.95	0.82	0.23	0.84	0.72	0.19
0.45	0.83	0.65	0.06	0.95	0.80	0.20	0.89	0.73	0.17
0.75	0.49	0.31	0.00	0.91	0.73	0.14	0.91	0.73	0.15
0.95	0.20	0.02	0.00	0.81	0.63	0.04	0.90	0.72	0.13
	T3-43	T5-43	T3-87	T5-87	T3-164	T5-164			
0.05	0.66	0.07	0.65	0.07	0.54	0.06			
0.25	0.61	0.02	0.64	0.05	0.56	0.04			
0.45	0.47	0.00	0.80	0.21	0.75	0.18			
0.75	0.14	0.00	0.66	0.06	0.75	0.16			
0.95	0.00	0.00	0.51	0.00	0.74	0.15			
	T7-43	T9-43	T7-87	T9-87	T7-164	T9-164			
0.05	0.86	0.27	0.84	0.26	0.71	0.21			
0.25	0.80	0.21	0.84	0.25	0.73	0.21			
0.45	0.67	0.08	0.95	0.40	0.90	0.36			
0.75	0.33	0.00	0.85	0.26	0.94	0.35			
0.95	0.04	0.00	0.70	0.11	0.93	0.34			
a Total Injection amount: T16 =0.5 lb, T2,T3 & T7 = 0.25 lb, T4 T5 & T9 = 0.025 lb									

Table 5 Description of Simulation Runs for Determining the Effect of Injection Number on Inhibitor Distribution

Run	Partition Coefficient, V_{kOW}	Total Inj. Amount, lb	No. of Injection ^a
T2	0.8	0.25	1
T3	0.8	0.125/0.125	2
T6	0.2	0.25	1
T7	0.2	0.125/0.125	2
T12	0.02	0.25	1
T13	0.02	0.125/0.125	2
T4	0.8	0.025	1
T5	0.8	0.0125/0.0125	2
a See footnote of Table 1			

Table 6 Effect of Inhibitor Injection Number on Inhibitor Distribution ^a

Injection No. ^a	Pipe Fraction	Inhibitor Covered Pipe Fraction in Water Phase			
		T2- 87 min	T3- 87 min	T2-164 min	T2-164 min
1 vs 2	0.05	0.82	0.65	0.69	0.54
	0.25	0.82	0.64	0.72	0.56
	0.45	0.80	0.47	0.73	0.75
	0.75	0.73	0.14	0.73	0.75
	0.95	0.63	0.00	0.72	0.74
		T6- 87 min	T7- 87 min	T6-164 min	T7-164 min
1 vs 2	0.05	0.94	0.84	0.79	0.71
	0.25	0.95	0.84	0.84	0.73
	0.45	0.95	0.95	0.89	0.90
	0.75	0.93	0.85	0.93	0.94
	0.95	0.83	0.70	0.93	0.93
		T12-87	T13-87	T12-164	T13-164
1 vs 2	0.05	0.95	0.93	0.80	0.78
	0.25	0.96	0.95	0.86	0.83
	0.45	0.96	0.96	0.91	0.92
	0.75	0.95	0.95	0.95	0.95
	0.95	0.94	0.81	0.95	0.95
		T4-87	T5-87	T4-164	T5-164
1 vs 2	0.05	0.24	0.070	0.201	0.06
	0.25	0.23	0.053	0.193	0.05
	0.45	0.20	0.205	0.173	0.18
	0.75	0.14	0.065	0.146	0.16
	0.95	0.04	0	0.131	0.15
a See footnote of Table 1					

Table 7 Description of Simulation Runs for Determining the Effect of Inhibitor Residue in the Pipe Line on Inhibitor Distribution

Run	Partition Coefficient, $V_{k_{ow}}$	Total Inj. Amount, lb	No. of injection ^a	Inhibitor Residue, lb/ft ³
T18	0.01	0.025	1	0
T19	0.01	0.025	1	0.0013
T20	0.01	0.025	1	0.00013
a See footnote of Table 1				

Table 8 Effect of Inhibitor Residue in the Pipe Line on Inhibitor Distribution^a

Inhibitor Residue, lb	Pipe Fraction	Inhibitor Covered Pipe Fraction in Water Phase, minute					
		T18- 87	T19- 87	T20-87	T18- 164	T19- 164	T20-164
0 (T18)	0.05	0.54	0.62	0.92	0.45	0.56	0.91
0.00013 (T19)	0.25	0.54	0.61	0.91	0.46	0.56	0.90
0.0013(T20)	0.45	0.51	0.58	0.89	0.45	0.55	0.86
	0.75	0.45	0.52	0.82	0.45	0.54	0.87
	0.95	0.35	0.42	0.71	0.44	0.53	0.87
a Inhibitor residue; T18/T19/T20 = 0/0.00013/0.0013 lb/ft ³ , respectively							

Figure 1 Inhibitor Distribution in the Water Phase along the Pipe for T2 (0.25/0.8)

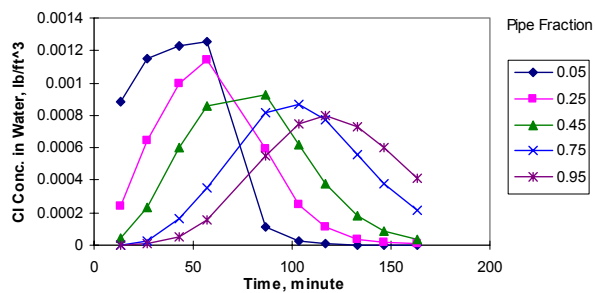


Figure 4 Inhibitor Distribution in the Water Phase Along the Pipe Vs Time for T3 (0.125/0.125/0.8)

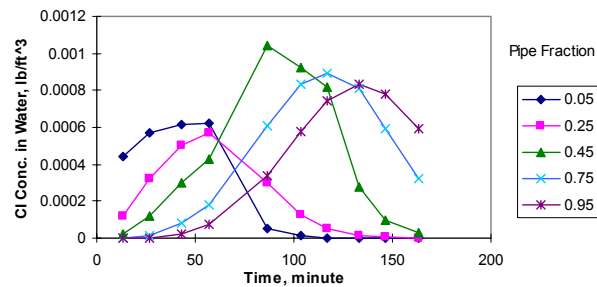


Figure 2 Inhibitor Covered Pipe Fraction in Water Phase Vs Time along the Pipe for T2

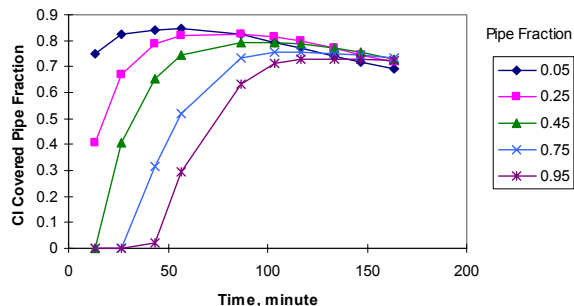


Figure 5 Inhibitor Covered Pipe Fraction in Water Phase Vs Time along the Pipe for T3

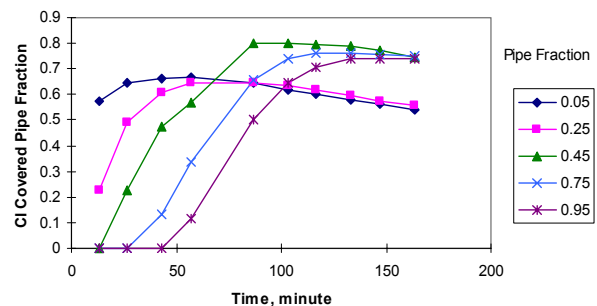


Figure 3 Inhibitor Covered Pipe Fraction in Water Phase Vs Pipe Fraction for T2

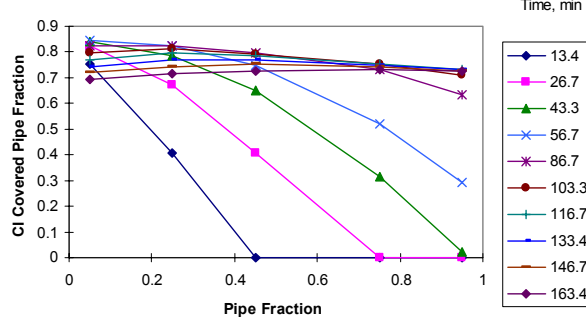


Figure 6 Inhibitor Covered Pipe Fraction in Water Phase Vs Pipe Fraction for T3

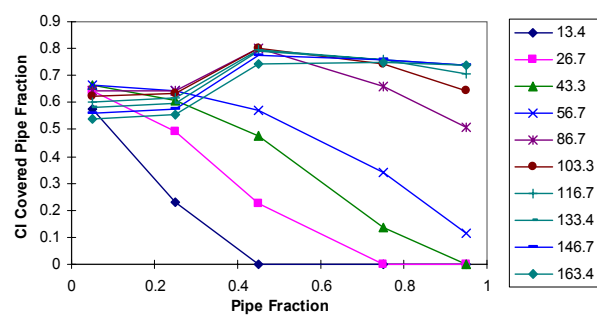


Figure 7 Effect of Partition Coefficient on CI Covered Pipe Fraction in Water Phase

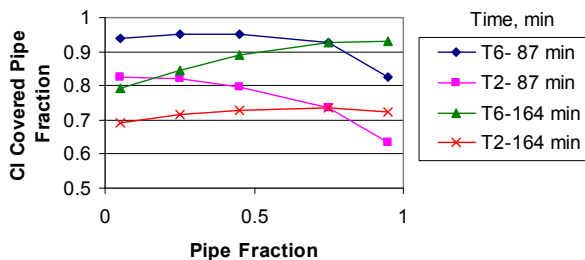


Figure 11 Effect of Injection Concentration on Inhibitor Covered Pipe Fraction in Water Phase

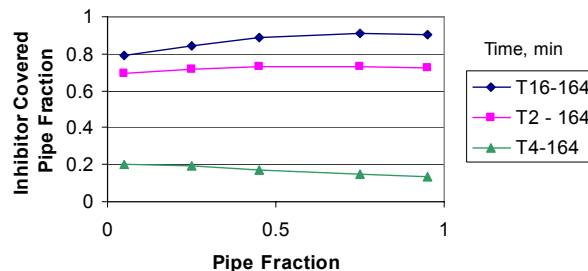


Figure 8 Effect of Partition Coefficient on CI Covered Pipe Fraction in Water Phase, 2 inj.

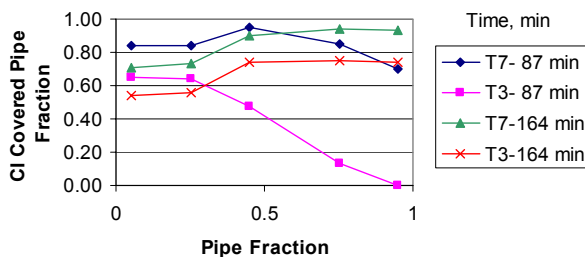


Figure 12 Effect of Injection Conc. on Inhibitor Covered Pipe Fraction in Water Phase

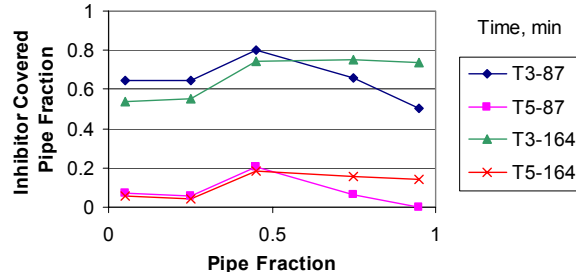


Figure 9 Effect of Injection Concentration on Inhibitor Covered Pipe Fraction in Water Phase

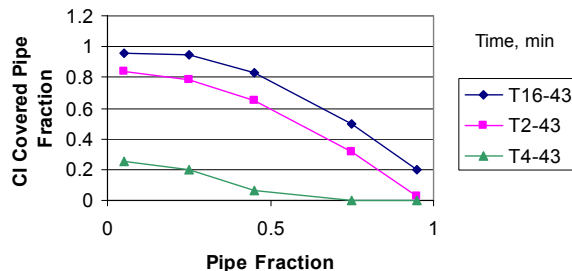


Figure 13 Effect of Injection Conc. on Inhibitor Covered Pipe Fraction in Water Phase

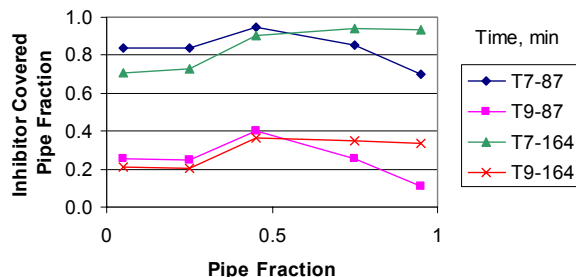


Figure 10 Effect of Injection Concentration on Inhibitor Covered Pipe Fraction in Water Phase

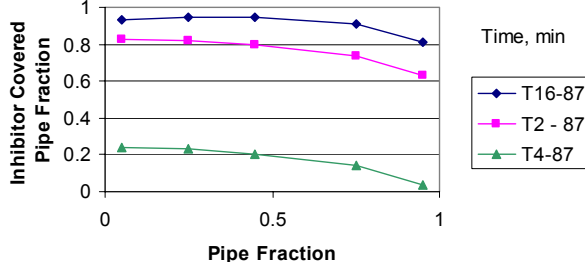


Figure 14 Effect of Injection No. on Inhibitor Covered Pipe Fraction in Water Phase

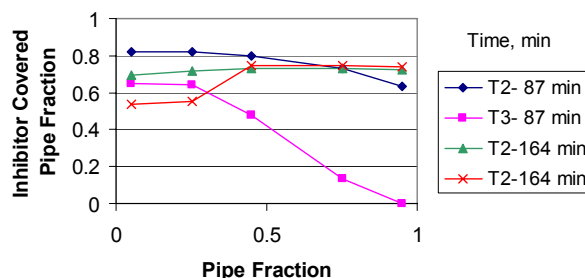


Figure 15 Effect of Injection No. on Inhibitor Covered Pipe Fraction in Water Phase

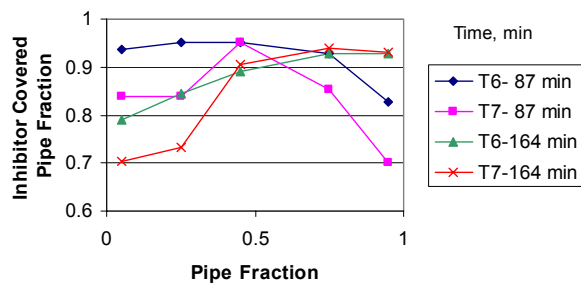


Figure 17 Effect of Inhibitor Residue on the Inhibitor Covered Pipe Fraction in Water Phase

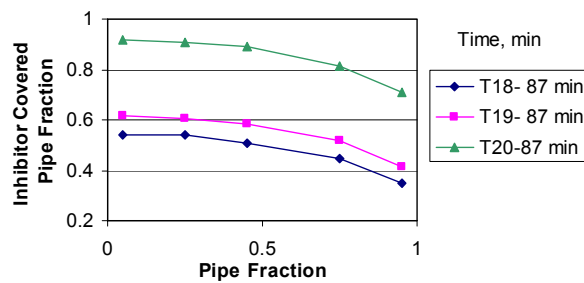


Figure 16 Effect of Injection No. on Inhibitor Covered Pipe Fraction in Water Phase

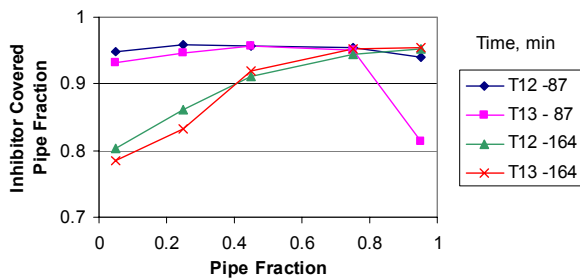


Figure 18 Effect of Inhibitor Residue on the Inhibitor Covered Pipe Fraction in Water Phase

