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EXPERIMENTAL STUDY OF THE EROSIONAL/CORROSIONAL VELOCITY CRITERION FOR SIZING MULTIPHASE FLOW LINES

PHASE I - EXPERIMENTAL FACILITY CONSTRUCTION REPORT

By

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EXECUTIVE SUMMARY

This report documents the design and construction of a two-phase erosion/corrosion facility that will be used to provide data to aid in modifying the erosional velocity for multiphase flow lines in offshore piping defined in API-RP-14E [1]. The erosional velocity limit defined in API-RP-14E is considered too conservative for some applications, so the Minerals Management Service of the Department of the Interior and the American Petroleum Institute have jointly funded a program to review and revise the present criteria.

The first project was to develop improved erosional velocity guidelines based on data available in the open literature. The second project was to modify these improved guidelines using internal industry data obtained from surveying API member companies. The first two projects were funded by the MMS and have been successfully completed.

The third project is an experimental effort to supplement the data obtained in the literature and company surveys. The third project is broken down into two phases. Phase I is the design and construction of an experimental facility, and Phase II is for testing in the erosion/corrosion facility. A description of the experimental facility built during Phase I is contained in this report. The results of testing performed under Phase II will provide the data needed to define the erosional velocity limit for corrosive (solids free) two-phase flow in carbon steel pipe.

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1.0 INTRODUCTION

There continues to be a significant amount of controversy regarding the API specification related to velocity limits [1] for horizontal two-phase flow lines for offshore production piping. Many investigators [2, 3, 4] have reviewed the velocity limits specified by API-RP-14E and concluded that the limits are too conservative. To investigate possible changes to the existing erosional velocity criteria, a series of projects were initiated by the Minerals Management Service and the API. The first project reviewed the information in the open literature on erosion/corrosion as it pertains to multiphase flow. The second project was conducted to review pipe wear data provided by API member companies and use this information to guide changes to the existing erosional velocity equation in API-RP-14E. The third project is an experimental program to supplement the data obtained in the literature and company surveys. The third project is broken down into two phases: Phase 1 is for design and construction of the experimental facility; and Phase 2 is for conducting the erosion/corrosion testing. This report covers design and construction of the experimental facility that will be used to perform corrosion tests. Experimental testing will be performed to document pipe wear rates in a corrosive two-phase flow environment. The rest of this section briefly reviews the existing erosional velocity criteria and the results of the first two projects. The rest of the report summarizes the design and construction of the experimental facility.

Presently, the design guidelines recommend limiting the fluid velocity in two-phase flow lines to an erosional velocity (V_e (ft/sec)) defined by [1]:

$$V_e = \frac{c}{\sqrt{\rho}} \qquad (Eq.\ 1)$$

C = 100 for continuous service,
= 125 for intermittent service
ρ = mixture density (lbm/ft^3)

The recommendations also require reducing the erosional velocity below the above calculated velocity if corrosion or solids (sand) are present. Guidelines on the amount of reduction to the calculated erosional velocity are not given.

Based on the data reviewed during the first two projects [5, 6] (funded by the MMS), it is apparent the present form of the API erosional velocity equation is too simple to cover the wide range of conditions encountered in field piping. This should be expected because many factors, including corrosive fluids, solids production, water production, and temperature, are not included in the present criterion. Because different wear mechanisms dominate in different flow streams, one simple equation of the form of the present API-RP-14E erosional velocity criteria is inadequate.

For two-phase flow streams with solids production and no corrosion, the most important parameters affecting wear rates are the mass flow rate of solids, the liquid production rates, and flow velocity. For two-phase flow in a corrosive atmosphere without solids, the primary parameters that control the wear rate are CO_2 and H_2S concentration, flow properties, water content, temperature, fluid pH, and fitting material. In "clean service," the wear is primarily governed by flow velocity and two-phase flow regimes. In flow streams with both corrosion and solids, the prediction of wear is significantly more complex because of the interactions of erosion and corrosion. It is expected that all of the parameters outlined for erosion only and corrosion only would need to be considered to accurately predict wear under combined erosion/corrosion. To cover this wide variety of flow conditions, it is recommended that the sizing criterion for multiphase flow lines be divided into four different groups based on the different wear mechanisms. The reason for this is that each different wear mechanism will have a different set of controlling parameters that needs to be evaluated to limit pipe wear. The four different wear categories are:

(1) Clean Service (no solids or corrosion),
(2) Erosive Service (solids (sand) present in flow stream with no corrosion),
(3) Corrosive Service (corrosion without solids),
(4) Erosive and Corrosive Service (both solids and corrosive media present).

Preliminary recommendations for erosional velocity in Clean Service and Erosive Service were outlined in the final report to the MMS [6]. More work is required to obtain the data necessary to develop the erosional velocity limits for Corrosive Service and Erosive/Corrosive Service. Based on the data reviewed during the first two projects [5, 6] and observations of others [7, 8], it appears the erosional velocity limit for Corrosive Service coincides with the flow regime transition to the annular flow regime. The mechanism of accelerated pipe wear appears to be related to droplet impact produced fatigue on the brittle corrosion products. The testing to be performed on this program is designed to test this theory in a controlled laboratory environment.

2.0 EXPERIMENTAL FACILITY DESIGN AND CONSTRUCTION

2.1 Facility Design

A number of trade-offs were investigated during the facility design phase of the project. Important parameters in the facility design include: gas and liquid flow rates; number of fittings tested at one time; flow loop pressure; oil-less versus lubricated compressor; various thermal control methods; flow loop instrumentation; operating and maintenance costs; and liquid inventories. Several iterations on the design were necessary to provide a test loop that was as close to field operating conditions as possible but was still within the project budget. The final design calls for a relatively short test section that will limit the pressure drop in the loop. The limited pressure drop reduces the size and, therefore, the cost of the compressor and liquid pump.

Two important parameters in the experimental design were not "compromised" in the trade-off analysis. These two parameters are: 1) the diameter of the test section piping was not reduced significantly below "field" piping; and 2) the liquid flow stream had to be corrosive. While considerable cost savings could be realized by either going to a smaller diameter, two-phase flow loop, or by making the loop noncorrosive, these options were not considered. The need to test at least 2-inch diameter pipe and fittings stems from the inability to scale the results of multiphase flow tests to larger diameters through normal scaling parameters. Because most flow lines in the field are at least 2 inches in diameter, test results from 1-inch diameter pipe or smaller would require verification tests in larger pipe and would, therefore, be of little value. Many erosion/corrosion tests performed in the past have utilized pre-corroded test specimens in a flow loop and looked at the wear of the corrosion products. While the advantage here is significant in terms of cost savings in the test loop construction (that is, it is much cheaper to build a flow loop for noncorrosive fluids), the measured wear rate for this type of testing is significantly different from simultaneous erosion/corrosion. The previously mentioned method is a corrosion test followed by an erosion test. Measurement of the acceleration of corrosion caused by erosion and corrosion acting simultaneously is what is desired for this test program. The experimental flow loop is, therefore, designed to handle corrosive fluids.

A piping and instrumentation diagram of the experimental facility is given in Figure 2.1. As shown in the figure, the facility consists of a liquid flow loop and a gas flow loop that merge before flowing through the test section and then separate after flowing through the test section. The test section consists of straight runs of horizontal pipe and test fittings. The length of the test section runs and number of test fittings have been minimized

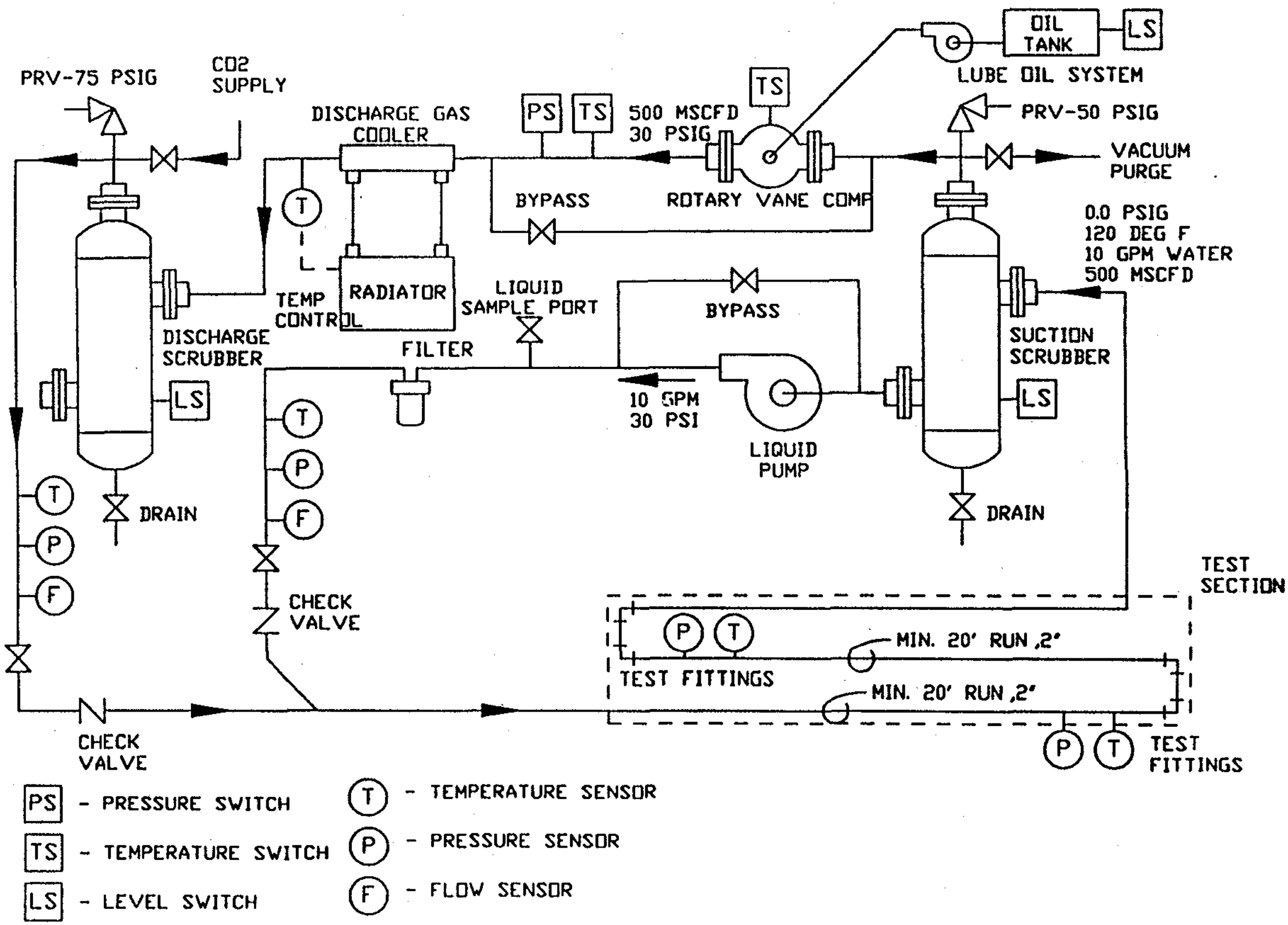

Figure 2.1 Experimental Facility Test Parameters

to limit the pressure drop (so a reasonable sized compressor can be used). For this reason, the test section is limited to two fittings located after a 20-foot straight run and two fittings located 3 feet downstream of the first fittings. This allows testing on both fully developed flow as well as seeing how the wear is affected when fittings are installed one after another.

The major components of the facility are the compressor, liquid pump, scrubber to separate the gas and liquid, and the test section where the fittings will be tested for wear. The compressor is a 60 HP rotary vane compressor capable of delivering 500,000 SCFD with a 15 psia suction pressure and a discharge pressure of 45 psia. The fluid pump is a centrifugal pump designed for 10 GPM at 30 psid. The scrubber is designed to separate the liquid from the two-phase flow stream before it enters the compressor. The scrubber will also act as the liquid reservoir for the approximately 20 gallons of brine in the flow loop. A scrubber downstream of the compressor is necessary to remove the lubrication oil coming from the compressor. A cooling system is also required to cool the compressor case and the gas at the compressor exit.

Safety and control hardware is incorporated in the flow loop to ensure safe operation when the flow loop is operating unattended. Pressure relief valves are located on each scrubber and liquid level, pressure, and temperature switches monitor the compressor and liquid pumps. All of the flow loop piping (except the test section) is internally plastic coated for corrosion resistance. A filter is installed in the liquid pump discharge line to remove any solids in the liquid stream so wear in the test section will not be from solids flowing in the pipe.

Instrumentation on the flow facility includes sensors for measuring gas flow rate, gas temperature, gas pressure, liquid flow, liquid temperature, and the test section temperature and pressure. Measurements of the pipe wall thickness at the test fittings will be made with an ultrasonic probe. The pipe wall thickness measurements will be made initially on a daily basis and then less frequently if the wear rate is low. Water pH will also be monitored periodically. The test articles and test conditions are summarized in Table 2.1.

Table 2.1 Experimental Facility Test Parameters

Pipe	Horizontal, 2" SCH 40, ASTM A106-B
Fittings	Long Radius Elbow, 2" SCH 40, A234 Grade WPB, Weld
Gas	CO_2 with water vapor (saturated)
Liquid	Water with 3.5% by weight NaCl
Temperature	120°F
Pressure	15 to 30 psig

2.2 Major Facility Equipment

The following sections contain descriptions of the major mechanical and control equipment incorporated into the erosion/corrosion test facility. All of the major equipment was mounted on a skid that was placed outside the building containing the erosion/corrosion test section piping. For this reason, the equipment and electrical connections were all weather proofed. The pumps, compressor and cooling fan are all controlled by an array of sensors so the facility can run for extended periods without the need for an attendant.

2.2.1 Compressor

The compressor is a single stage sliding vane compressor built by A-C Compressor Corporation. The model 10GB water-cooled compressor was designed to provide 546 MSCF/D CO_2 at a pressure rise of 30 psig. The compressor required 51.8 BHP at 961 RPM. The compressor is belt driven through a jackshaft assembly by a 60 HP 460 VAC motor. The compressor lubrication system is driven off of the compressor motor drive shaft and provides oil flow to the 7 lubrication ports on the compressor.

2.2.2 Heat Exchanger

Two heat exchangers are used to provide cooling fluid flow to the compressor case and to cool the gas discharged from the compressor. The FINX Model VT36-5 heat exchangers are air cooled finned tubes with box headers. The compressor cooling water portion is designed to reject 40,000 BTU/hour, and the compressor gas cooling section can reject 125,000 BTU/hour from the gas stream. The compressor gas cooling tubes are made of 304 stainless steel to provide some corrosion resistance to the corrosive gas stream. A pneumatically operated damper controls the gas discharge temperature from the heat exchanger by varying the cooling air flow over the finned tubes.

2.2.3 Scrubbers

Two scrubbers are used in the flow facility to separate liquids from the gas stream. The suction scrubber is used to remove the liquid from the gas stream before the gas is recirculated to the compressor. A discharge scrubber is used to remove as much of the compressor-lubricating oil from the flow stream as possible. Each vertical scrubber has a stainless steel mist extractor pad mounted in the top flange, and the vessels are plastic coated to limit corrosion of the walls. The suction scrubber is 16" OD x 48" from seam to seam, and the discharge scrubber is 12 3/4" OD and 48" seam to seam.

2.2.4 Pump

The liquid circulating pump is used to pump the liquid from the suction scrubber and inject it into the gas line upstream of the test section piping. The Price model SC100-100FM centrifugal pump is sized to deliver 10 gpm at 30 psi. The pump body and impeller are made of stainless steel to limit the corrosion within the pump.

2.2.5 Safety and Controls

A variety of safety and control equipment is used to provide automated operation of the flow loop. The entire loop is controlled with a General Electric Series One programmable logic controller that operates the motor starters (compressor, compressor cooling water pump, liquid pump, and the heat exchanger fan motor) and monitors the control sensors for hazardous operating conditions. The following list identifies the hazard sensors that are continuously monitored, and if a fault exists, the system is shut down.

Low Pressure in Suction Scrubber
Suction Scrubber Liquid Level High
High Compressor Discharge Temperature
High Compressor Discharge Pressure
High Compressor Coolant Temperature
Compressor Lubrication Oil No-Flow Switch
Compressor Lubrication Oil Low Level
Discharge Scrubber Liquid Level High

In addition to these hazard sensors, pressure relief valves are located on each scrubber to relieve pressure in case of an overpressure event. Check valves are located in the compressor discharge line and the liquid discharge line, and level switches in the scrubber control the dump valves that automatically maintain the level of the scrubbers below the high level hazard switches.

3.0 INSTRUMENTATION

Instrumentation is used to monitor and record the flow conditions in the test section piping. The gas is metered through one of two different-sized orifice meter runs, depending upon the flow rate. The liquid flow rate is metered with a turbine-type flow meter, and several thermocouples are used to monitor the temperature within the flow loop. A summary of the instrumentation is given in Table 3.1. A data acquisition system was assembled to record the instrumentation readings, convert the data into engineering units, and store the data. The individual instrument readings were converted from analog signals to digital information with a Fluke Hydra 2620A, and the digital information was transferred to a PC over an RS232 port. A custom program converted the digital data to engineering units, performed some calculations, and wrote the data to a file on disk. Part of the computer program implemented the orifice calculation method presented in Chapter 14.3 of the API Manual of Petroleum Measurement Standards.

Table 3.1 Instrumentation on the Erosion/Corrosion Test Loop

Description	Manufacturer	Model No.
Orifice Plate #1	Daniel Industries	3" Pipe, 1.450" Bore
Orifice Plate #2	Daniel Industries	1.5" Pipe, 0.600" Bore
Orifice Pressure Drop (Flange Taps)	Rosemount	3051CD2A52A1A
Orifice Upstream Static Pressure	Foxboro	1125-09A-C54
Test Section Static Pressure	Foxboro	1125-09A-C54
Barometric Pressure	Foxboro	1125-09A-C54
Orifice Gas Temperature	Omega Engineering	Thermocouple TMQSS-062U-6
Water Supply Temperature	Omega Engineering	Thermocouple TMQSS-062U-6
Test Section Temperature	Omega Engineering	Thermocouple TMQSS-062U-6
Room Temperature	Omega Engineering	Thermocouple TMQSS-062U-6
Water Flow Rate	Halliburton	Turbine Meter 458.8506

4.0 PRELIMINARY CORROSION SCREENING TESTS

Benchtop corrosion tests were performed to verify that the selected flow loop operating conditions produce a protective film on the surface of the pipe steel. If a protective film is not formed, the corrosion rates will be very high and the contribution of the erosive action to accelerating the corrosion will be difficult to determine. Therefore, initial corrosion tests were conducted in a non-flowing system to verify that the selected operating conditions allowed rapid corrosion to occur until a protective film formed, thereby decreasing the corrosion rate.

Test specimens were prepared from a long radius elbow (ASTM A234, Grade WPB) similar to the ones used in the flow facility. The specimens were nominally 0.50" x 0.50" x 0.15" thick (the wall thickness in the region of the elbow from which the specimens were taken). The specimens were surface ground with 220 grit silicon carbide paper, degreased in a detergent wash, rinsed with deionized water, and dried using acetone.

The tests were conducted in a solution consisting of 3.5% by weight of reagent grade NaCl in deionized water. The solution was deaerated with CO_2 prior to immersing the specimen. A one atmosphere pressurization with CO_2 was maintained by bubbling CO_2 through the solution for the duration of the test. The test temperature was 120°F.

The corrosion rate of the specimens was monitored as a function of time using linear polarization resistance, a technique which allows for the determination of the instantaneous corrosion rate of a freely corroding specimen. Measurements were made using an EG&G Model 173 potentiostat and the SoftCorr corrosion testing software. The specimen potential was swept through a range of ±20mV with respect to the open circuit potential of the specimen, and at a rate of 1000 mV/hour. A typical current versus potential plot for these tests is shown in Figure 4.1

The calculated corrosion rates for the first two tests which were conducted are summarized in the Table 4.1. The corrosion rates were determined from the linear polarization resistance data using the standard Stern-Geary relationship and tafel constants of ±120 mV/decade for both β_a and β_c.

In addition to the measurement of the corrosion rates by electrochemical means, the corrosion rate based on weight loss was determined for specimen 1. The weight loss observed corresponded to a corrosion rate of 56 mpy, which compares well with the rates measured using the electrochemical technique.

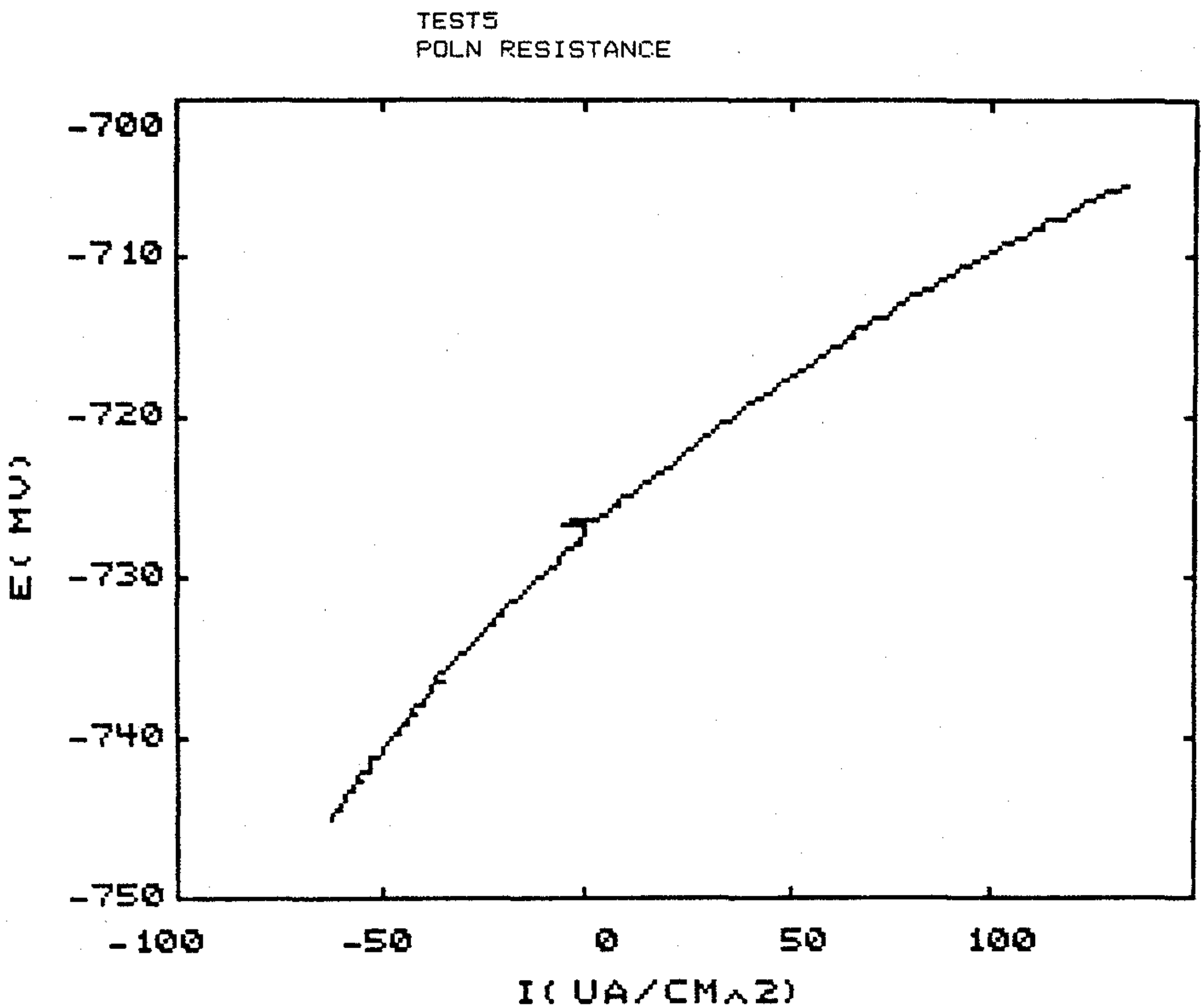

Figure 4.1 Typical Current versus Potential Plot

Table 4.1 Corrosion Rates for Tests 1 and 2

Time (Hours)	Test 1 (mpy)	Test 2 (mpy)
0.17	--	45.77
0.25	55.50	--
0.50	50.18	36.63
1.00	48.22	29.88
1.50	46.64	29.74
2.00	47.30	31.38
3.00	48.61	32.88
4.00	--	36.70
5.00	--	39.84
7.00	--	43.59
22.00	--	71.77
24.00	--	72.31

Typically, the corrosion rate of a metal immersed in an aqueous environment is initially very high, but then decreases rapidly as steady state reaction rates are established at the metal environment interface. The rapidity with which this steady state is established depends on the surface films which form, and the kinetics of the reactions which form in the formation of those films. These are a function of the specific metal and the environment. Based on the data from the first two tests, it appears as though a relatively steady corrosion rate is established within the first 10-15 minutes. A slight increase in the corrosion rate was observed for exposures over two hours in length, which may indicate the onset of a localized corrosion phenomena such as crevice or pitting corrosion. Examination of the specimen after the test using an optical microscope at magnifications of up to 20X revealed the presence of a few fairly large (for a 24 hour exposure), isolated pits.

In an attempt to determine the initial corrosion rate, and to further evaluate the possibility of localized corrosion, a third test was conducted. The initial corrosion rate measurements were taken as quickly as possible for immersion of the specimen in the solution. In order to accommodate these quicker readings, the tests were conducted using a scan rate of 4 mV/sec (14.4 v/hr), over a potential range of +20 mV to -20 mV with respect to the open circuit potential. This specimen was exposed for a period of 210 hours to determine if localized corrosion was occurring. This would be indicated by an increasing corrosion rate as a function of time, after the initial steady state was achieved.

The results of the third test are presented in Figure 4.2. As can be seen, the initial corrosion rate, measured 30 seconds after immersion of the specimen, was on the order of 61 mpy. This rate decreased slightly to 47 mpy after 2 hours, but then the corrosion rate began to slowly increase. This increasing corrosion rate continued through the measurement taken at 162 hours, at which time the corrosion rate was 207 mpy, the highest rate measured during this test. The corrosion rate began to slowly decrease, until the test was terminated after 210 hours, at which time the corrosion rate was measured as 193 mpy.

This type of corrosion rate as a function of time response is somewhat unusual. A much higher initial corrosion rate was expected. The slowly increasing corrosion rate which peaked around 162 hours would seem to indicate that a slow growing non-protective film was forming. An analysis of the composition of the film on the specimen from test 2 was performed using the energy dispersive spectrographic capability of the scanning electron microscope. There was no carbon present in the corrosion products which had formed, and a large oxygen peak was observed. This leads to the conclusion that the corrosion product was an iron oxide, and not the iron carbonate which was expected.

It is unlikely that this corrosion product will be suitable for the erosion corrosion studies planned. The iron oxide is not particularly protective, and the differences in corrosion rates is not suitable for distinction between filmed and unfilmed steel. Additional testing to determine conditions which will be conducive to the forming of a more protective scale such as iron carbonate will be necessary. One possible solution, that will be tested, is the addition of buffering agents to increase the solution pH and create conditions more favorable to iron carbonate formation. If a truly protective scale can be formed, rates of corrosion which are different by a factor of 10 or more between filmed and unfilmed steel should be achievable. This should allow for accurate determination of the flow conditions which are required for removal of the protective corrosion product films.

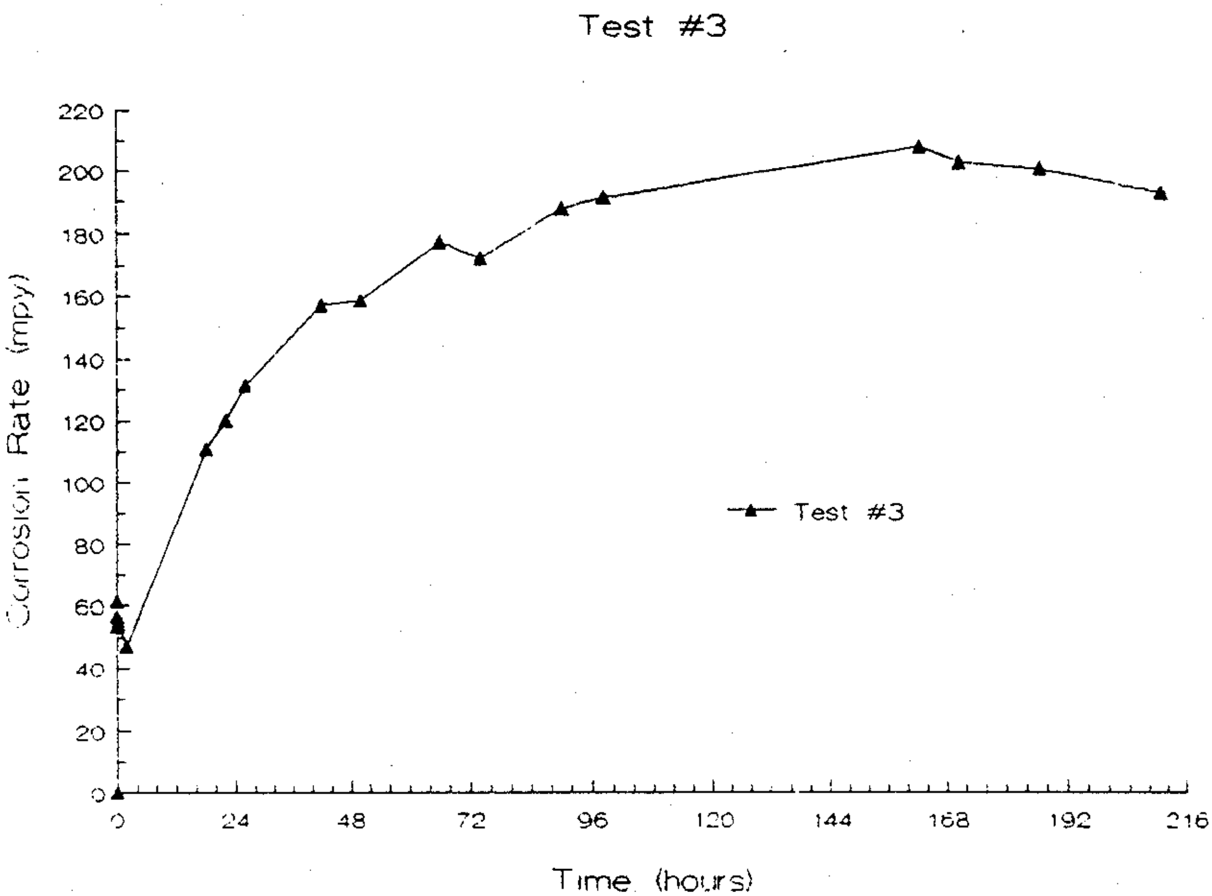

Figure 4.2 Corrosion Rate for Test 3

5.0 FACILITY CHECK-OUT AND FLOW REGIME MAPS

After the experimental facility construction was completed, the facility operation was checked, and the two-phase flow regimes were documented for a variety of gas and liquid flow rates. The facility check-out consisted of verifying the system safety and control features operated as designed and by running the system to find any problems that might develop after running the system for a while. During the check-out, a number of problems were discovered and subsequently corrected. Two problems that are still being investigated are leakage of the compressor lubrication level controller, and excessive liquid carry over from the suction scrubber. The compressor lubrication controller leakage is not a serious problem and should be fixed without too much difficulty. The problem with the suction scrubber is more difficult and the manufacturer has been notified and is looking into the problem.

The erosion/corrosion tests will focus on determining the effect two-phase of flow regime on the rate of pipe wall loss. For this reason, it is important to document where the transition from slug or stratified flow to annular flow occurs. This was done with both air-water and CO_2-water mixtures (because CO_2 has a considerably higher density that air at the same temperature and pressure) at about 100°F and a test section pressure about 10 psig. A clear pipe section was installed in place of the test section so visual determination of the flow regime could be made. The flow regime transition points were then determined by varying the gas and liquid flow rates and recording the flow regime for each setting. The results of the test are plotted in Figure 5.1 as superficial gas velocity versus superficial liquid velocity. From this plot it can be seen that the transition to annular flow occurs at about 60 or 70 ft/sec. Below this transition the flow is either stratified wavy or slug flow and above this transition the flow is annular.

A comparison between the flow regimes shown in Figure 5.1 and the transitions reported in the literature can be made by comparing the experimental data replotted in Figure 5.2 with the flow regime map of Barnea et al [9] in Figure 5.3. The data shown in Figure 5.3 is for air-water flow in 2.0 inch (5.2 cm) diameter pipe at atmospheric pressure. The units on Figures 5.2 and 5.3 are m/sec and both scale are logarithmic so a more direct comparison can be made. The comparison between the two figures show the flow regime transitions occur at generally the same velocities, or with superficial gas velocities of about 15 to 20 m/sec. The CO_2-water experimental data show a somewhat higher velocity for the transition to annular flow but the difference could be attributed to a number of factors that are different between the two data sets. One anomaly shown in Figures 5.1 and 5.2 is a data point labeled slug flow at the transition from stratified wavy to annular flow (gas velocity 68 ft/sec and liquid velocity 0.19 ft.sec). These flow conditions exhibited features of stratified wavy flow and annular flow as well as slug flow. For this point, an annulus of fluid

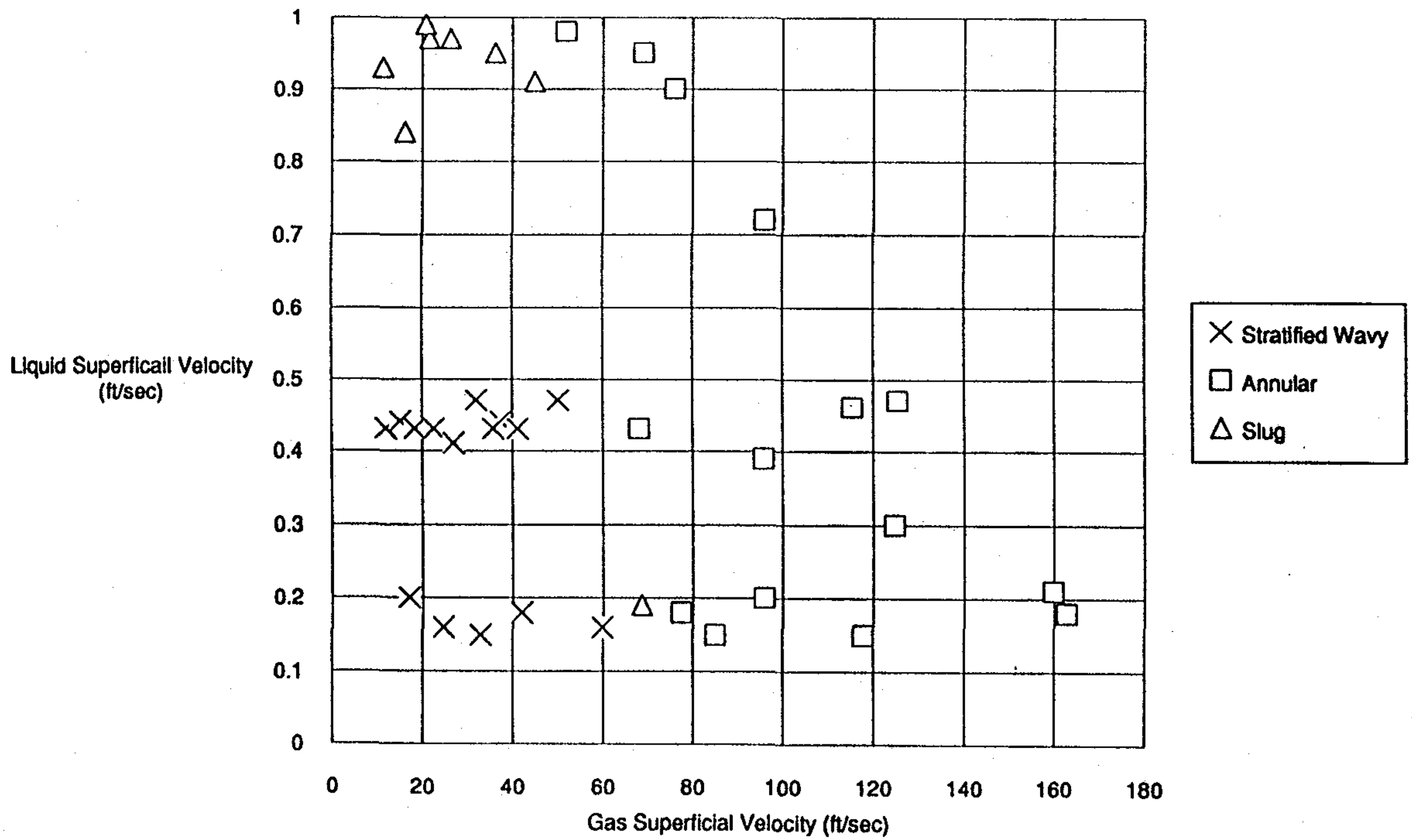

Figure 5.1 Flow Pattern Map for CO_2-Water in Horizontal 2" Pipe

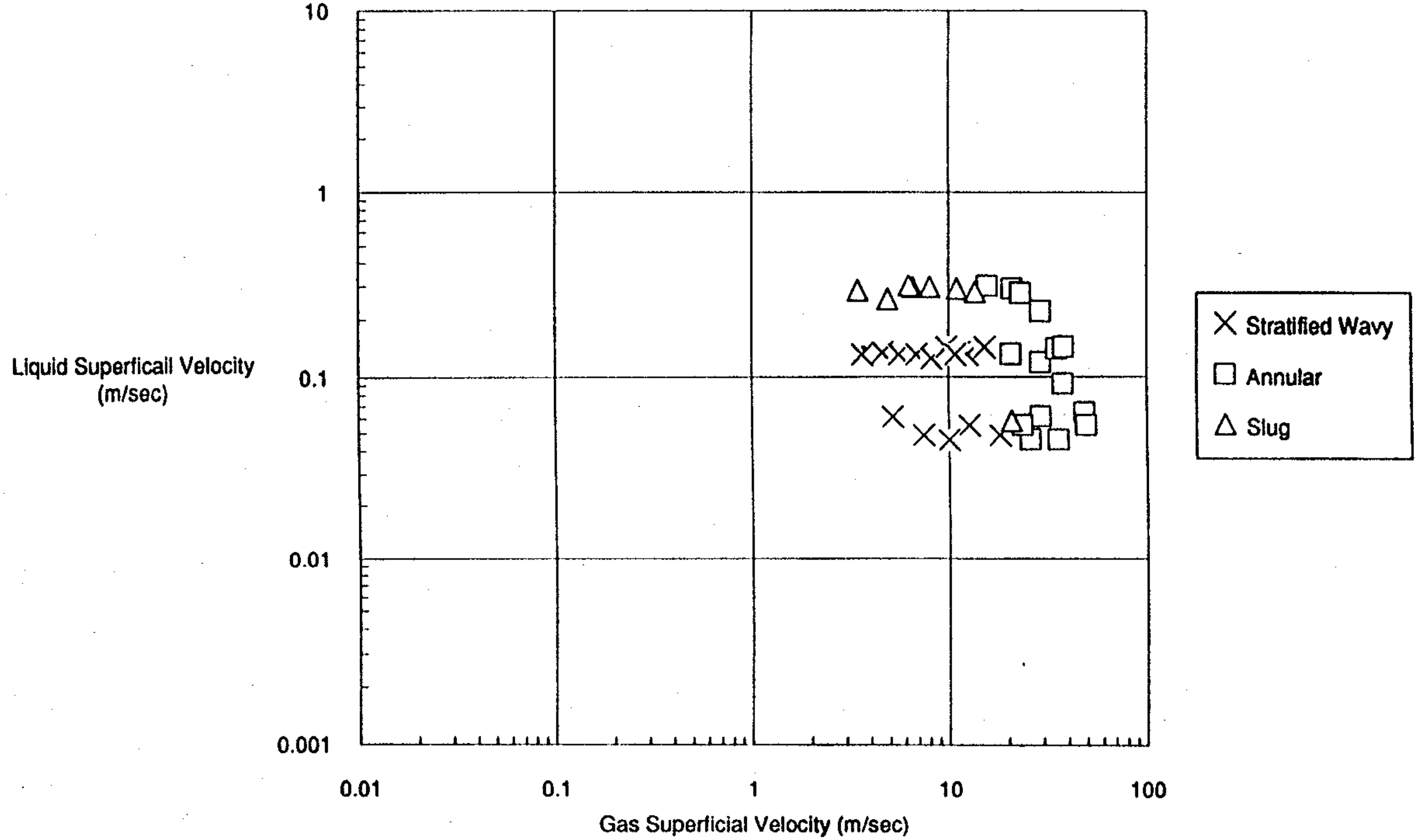

Figure 5.2 Flow Pattern Map for CO_2-Water in Horizontal 2" Pipe Plotted as Log Plot

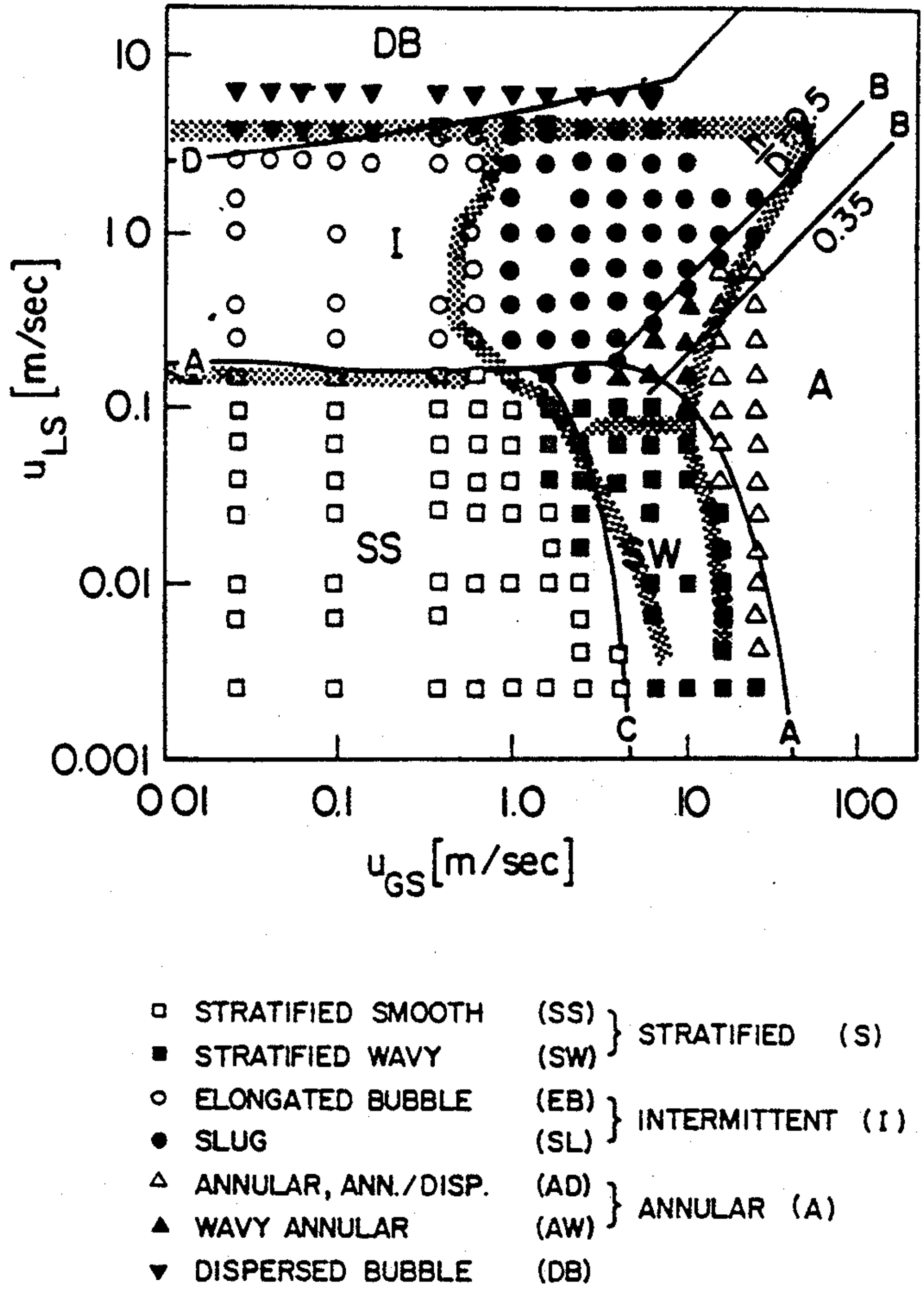

Figure 5.3 **Flow Pattern Map for Air-Water Flow in 2" Diameter from Barnea, et al. [9]**

formed on the pipe as a very large wave (that bridged the pipe like a slug) swept along the pipe. This annulus of liquid would start to disappear about the time the next slug passed. This transition point was labeled slug flow during testing but it could have been labeled any one of the three flow regimes.

Based on the flow regime tests performed, the erosion/corrosion tests that are to be performed in the annular flow regime must have a superficial gas velocity in the range of 90 to 160 ft/sec. For tests that are to be performed in the slug or stratified wavy regimes, the gas superficial velocity should be kept below about 40 ft/sec. Because the transition from one flow regime to the next is not abrupt, the testing should be done significantly above or below the transition region so there is no question about which flow regime exists.

6.0 EXPERIMENTAL TEST PLAN

Experimental testing, during the next project phase, will be conducted in a flow loop designed to provide corrosive conditions in two-phase flow lines. Corrosive conditions for the carbon steel pipe will be provided by a mixture of carbon dioxide gas and a NaCl brine solution. During each different test, the fitting wall thickness will be measured periodically to determine the steady state wear rate under the test flow conditions. The steady state wear rate will be measured for flow in the stratified, intermittent, and annular mist flow regimes. By operating in the same corrosive environment and only varying the flow regime (by changing the gas velocity), the effect of the flow regime on the wear rate can be determined. An outline of the initial set of tests and test conditions is given in Table 6.1. The initial set of tests is designed to determine if pipe wear is accelerated in the annular mist regime compared to the stratified or intermittent flow regimes. After the initial tests are completed, test conditions for subsequent tests will be selected based on the data from the initial tests.

Table 6.1 Test Conditions

Flow Conditions	Superficial Gas Velocity (ft/sec)	Superficial Liquid Velocity (ft/sec)	Flow Regime
Test 1	150	0.1	Mist Flow
Test 2	15	0.1	Stratified Wavy
Test 3	150	1.0	Mist Flow
Test 4	15	1.0	Intermittent Flow

7.0 CONCLUSIONS AND RECOMMENDATIONS

The facility design and construction phase has been successfully completed with the construction of the experimental facility. The facility is capable of handling corrosive fluids with velocities in excess of 150 ft/sec. This will allow erosion/corrosion testing in the stratified wavy, slug, and annular two-phase flow regimes. The experimental facility is fully automated to provide safe operation without the need for an attendant. This will allow long-term testing to be done without the expense of a full-time operator. The data acquisition system installed on the facility automatically records the system temperatures and pressures, and the gas and liquid flow rates. During experimental testing, the only activities requiring an operator are periodically checking the fluid chemistry (pH, O_2, and iron counts) and measuring the pipe wall thickness at the test locations.

There are two remaining issues that were identified during this phase of the project that have not yet been satisfactorily addressed. The first issue is in providing a corrosive environment that forms a passivating corrosion product that effectively reduces the corrosion rate after formation. The preliminary, benchtop, corrosion test results indicate the corrosion products that are formed do not effectively passivate the surface. Efforts continue to resolve this issue by looking at several different options. These options include checking the experimental methods used in the initial tests (sample preparation, solution deaeration,...), buffering the solution to provide a less acidic, more favorable environment for iron carbonate formation, and varying the CO_2 pressure and operating temperature. The second unresolved issue is the liquid carryover from the suction scrubber to the compressor. The resolution of this issue should be relatively straightforward and the supplier of the vessel is presently working on identifying the cause and implementing a solution. These two issues should be resolved early in the next phase of the project.

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