HOW TO CONTROL SLUGGING IN OILFIELD PIPING

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ABSTRACT

Gas and liquid are frequently transported simultaneously in the same pipe. Common occurrences include pipelines for gas and oil fields, piping in refineries and process plants, and steam injection and geothermal production systems. When two-phase flow (i.e. gas-oil-water) occurs in a pipeline, the phases separate geometrically in the pipe into various flow patterns. In general, the flow pattern that results depends upon several flow parameters, of which phase velocities and pipe inclination are the most important.

When the flow pattern at the exit of a pipe consists of alternating slugs of gas and liquid (i.e. slug or intermittent flow), special operating procedures are frequently required. Processing such slugs can require first passing the gas-liquid mixture through a larger diameter conduit (i.e. slug catchers) to promote segregation or stratification of the phases. Only then can gas liquid separators be operated properly to minimize pressure fluctuations and assure an acceptable low volume fraction of liquid in the gas or gas in the liquid that leaves the separator. The cost of constructing and locating slug catchers can be extremely high, especially when dealing with large diameter pipelines terminating on offshore platforms. A method to eliminate long slugs of liquid economically is of great interest to companies operating the above types of facilities.

It has been found that slug flow in a pipeline-riser pipe system can be eliminated or minimized by careful choking that results in little or no change in either flow rate or pressure level and elimination of pressure fluctuations. The careful choking can be accomplished automatically with a unique control system consisting of a combination of electronic and pneumatic devices. Such a system has been tested using kerosene and air on a 2-in. diameter pipeline-riser pipe test facility at Tulsa University. Slug flow was eliminated automatically in every test conducted. The devices were also installed in a specially designed facility consisting of approximately 60 ft of 1-in. pipe configured with several rises and falls to simulate a hilly terrain pipeline. Slug flow was eliminated here also in every test conducted.

INTRODUCTION

Gas and liquid are frequently transported simultaneously in the same pipe. Common occurrences include pipelines for gas and oil fields, piping in refineries and process plants, and steam injection and geothermal production systems. When two-phase flow (i.e. gas-oil or gas-water) or three-phase flow (i.e. gas-oil-water) occurs in a pipeline, the phases separate geometrically in the pipe into various flow patterns. In general, the flow pattern that results depends upon several flow parameters, of which phase velocities and pipe inclination are the most important.

When the flow pattern at the exit of a pipe consists of alternating slugs of gas and liquid (i.e. slug or intermittent flow), special operating procedures are frequently required. Processing such slugs can require first passing the gas-liquid mixture through a larger diameter conduit (i.e. slug catchers) to promote segregation or stratification of the phases. Only then can gas liquid separators be operated properly to minimize pressure fluctuations and ensure an acceptable low-volume fraction of liquid in the gas or gas in the liquid that leaves the separator. The cost of constructing and locating slug catchers can be extremely high, especially when dealing with large diameter pipelines terminating on offshore platforms.

A method to eliminate long slugs of liquid economically is of great interest to companies operating the above types of facilities. Slug elimination by choking the flow at the exit with a valve was reported by Yocum[1] and by Cady.[2] An undesirable result was large reductions in volumetric flow rates and higher operating pressures. Schmidt[3] discovered that slug flow in a pipeline-riser pipe system could be eliminated or minimized by careful choking that resulted in little or no change in either flow rate or pressure level and elimination of pressure fluctuations.

After achievement of success with manual choking, it was postulated that careful choking could be accomplished automatically with a unique control system consisting of a combination of electronic and pneumatic devices. A design was conceived and the pipeline-riser pipe test facility was modified to test the design.

SEVERE SLUGGING

Severe slugging is the most undesirable flow pattern encountered in two-phase flow through pipeline riser pipe systems. It is characterized by generation of liquid slugs ranging in length from one to several riser-pipe heights. Severe slugging occurs only for low gas and liquid flow rates and for negative pipeline inclinations.

The description of severe slugging phenomena starts when the liquid slug has just passed into the separator. Part of the liquid which follows the liquid slug falls back through the riser and starts to accumulate against the bottom of the riser (Figure 1). Since the increase in the gas pressure in the pipeline, P, per unit time is less than the possible hydrostatic pressure gain per unit time in the riser pipe due to the incoming flow and the fall-back, the liquid begins to accumulate simultaneously in both the pipeline and the riser (Figure 2). When the liquid reaches the top of the riser pipe, the pressure in the pipeline reaches the maximum value (Figure 3). The pressure in the pipeline then starts to drop because the slug length gradually decreases as the slug passes out of the riser and into the separator (Figure 4). When the tail of the slug has reached the top of the riser pipe, the pressure in the pipeline starts to drop to its minimum, at or near the separator pressure.

Severe slugging in the riser pipe, shown in Figures 5 and 6 as severe slugging region I, has been found to dissipate with either a change in liquid flow rate, or with an increase in gas flow rate. In either case, a point is eventually reached where the increase in the pipeline pressure per unit time is equal to or greater than the possible hydrostatic pressure gain per unit time in the riser pipe due to incoming liquid flow and the fall back. As a result, liquid slugs will be formed in the riser pipe rather than in the pipeline. At this point a new flow pattern starts, designated in

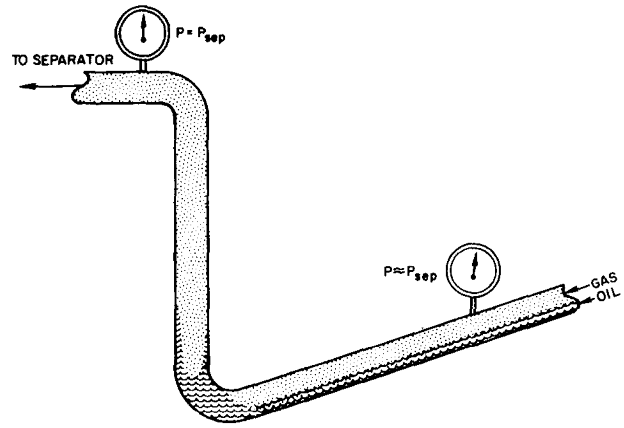

FIGURE 1 INITIAL ACCUMULATION OF LIQUID AT BOTTOM OF RISER

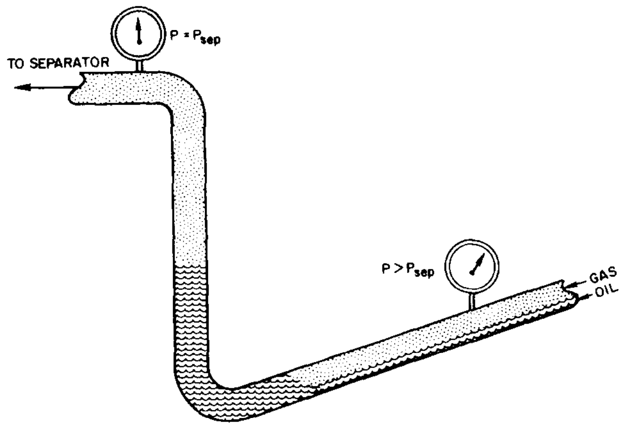

FIGURE 2 SIMULTANEOUS FORMATION OF SLUG IN PIPELINE AND RISER

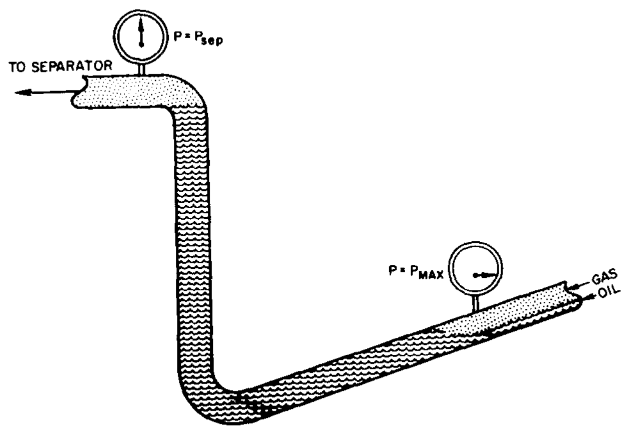

FIGURE 3 MAXIMUM SLUG LENGTH WHEN LIQUID REACHES TOP OR RISER

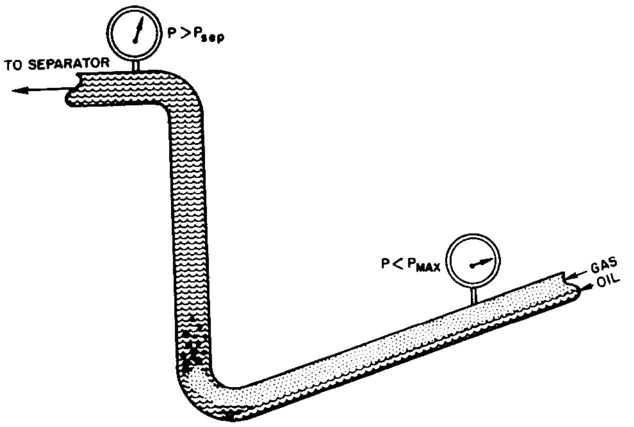

FIGURE 4 PRODUCTION OF LIQUID SLUG INTO SEPARATOR

Figures 5 and 6 as severe slugging region II. The characteristics of this flow pattern are almost the same as those of severe slugging region I except that the liquid slugs are slightly aerated and do not exceed the riser pipe height in length.

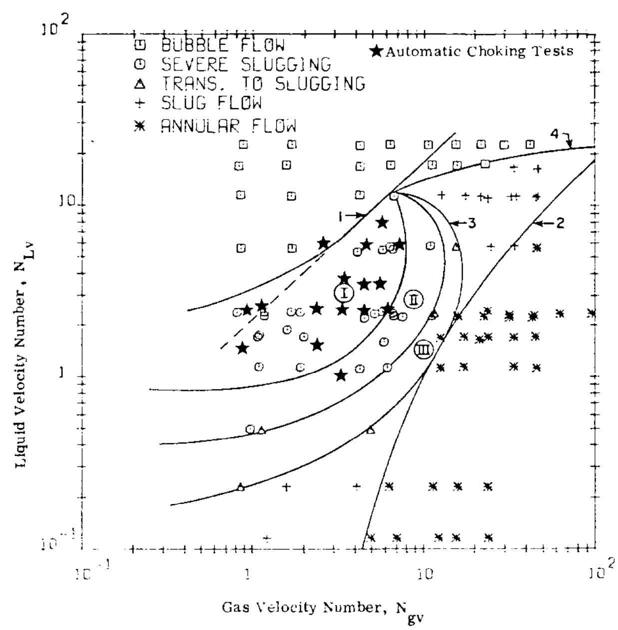

FIGURE 5 RISER PIPE FLOW PATTERN MAP WITH -5° PIPELINE INCLINATION (AFTER SCHMIDT[3])

Increasing the gas flow rate above that for severe slugging region II causes the gas from the pipeline to penetrate into the riser pipe, thus separating the liquid slugs by gas bubbles. The characteristic of the flow pattern then changes from that described earlier as "severe slugging" to a new flow pattern termed "transition to severe slugging." The new flow regime is similar to normal slug flow in wells except that the flow becomes more chaotic. Regions in the riser pipe are continuously filled and emptied of foamed liquid slugs. The slugs formed at the bottom of the riser pipe do not retain their identity as they move up the riser. Depending on the liquid flow rate, an increase in the gas flow rate further results in either slug flow or annular flow.

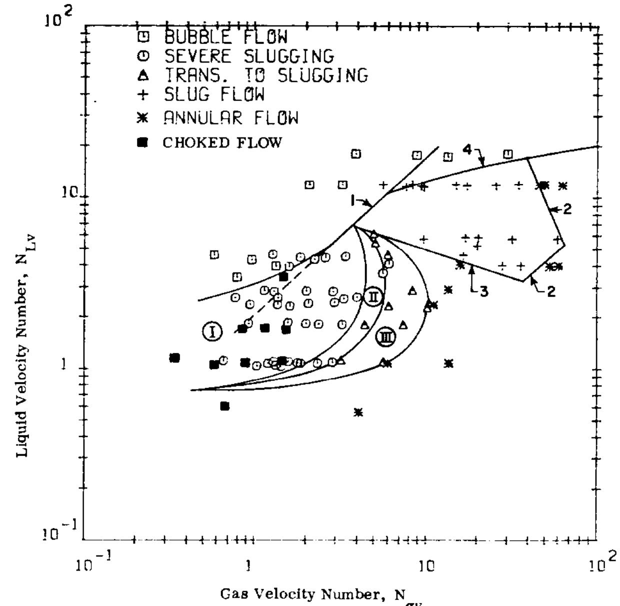

FIGURE 6 RISER PIPE FLOW PATTERN MAP WITH -2° PIPELINE INCLINATION (AFTER SCHMIDT[3])

The above description of severe slugging in a riser pipe is applicable only to negative pipeline inclinations. Severe slugging in the riser pipe was not encountered when the preceding pipeline was horizontal or positive (upward flow).

ALLEVIATION OF SEVERE SLUGGING

Several methods of eliminating slugging in riser pipes have been proposed. One objective of this study was to convert the flow pattern in the riser pipe and in the preceding pipeline into a flow pattern which would exist had they not been coupled together. This was accomplished by choking the flow at the top of the riser pipe.

When properly choked, severe slugging was virtually eliminated and a stable flow resulted, which was primarily bubble flow verging on normal slug flow in the riser pipe and segregated flow in the pipeline (Figure 7). Both flow patterns could have been predicted from the existing vertical and near horizontal flow pattern maps. Once the stable flow pattern was established, pressure in the pipeline became lower than the maximum present during severe slugging and input mass flow rates did not change.

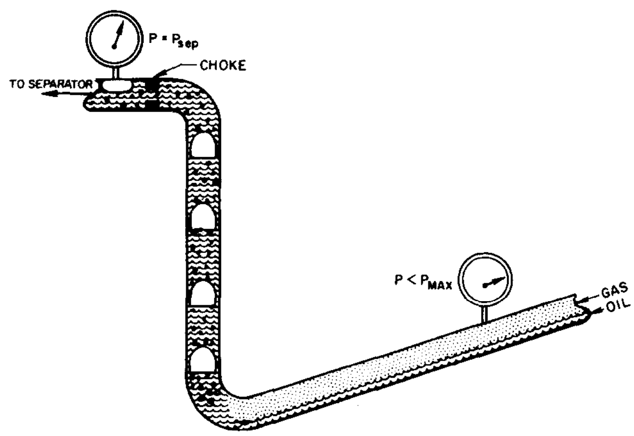

FIGURE 7 FLOW PATTERNS IN RISER AND PIPELINE AFTER SUCCESSFUL CHOKING

Choking the flow at the top of the riser pipe was initially accomplished by manually regulating a gate valve. The degree to which the gate valve was closed was based on the pipeline pressure and differential pressure fluctuations in the riser pipe. It was possible to eliminate severe slugging in every test conducted. Successful manual choking tests for a -2° pipeline inclination are shown in Figure 6.

EXPERIMENTAL PROGRAM

An experimental facility was designed and constructed to permit study of flow in a pipeline-riser pipe system. The fluids flowed through a 100-ft long 2-in. diameter pipeline and then up a 50-ft long 2-in. diameter vertical riser. All pipe was transparent and made of lexan. A schematic diagram of the test facility is shown in Figure 8. Both sections are supported by aluminum I beams that can be pivoted at their free ends through angles of ±5° to the horizontal and vertical. This study was conducted at pipeline angles of -5°, -2°, 0° and +5°, while keeping the riser pipe vertical.

Fluids used in the study were air and kerosene. The fluids were mixed at the entrance of the test section. At the end of the test section, the air-kerosene mixture was separated in a horizontal separator. The air was vented and the kerosene was returned to a storage tank.

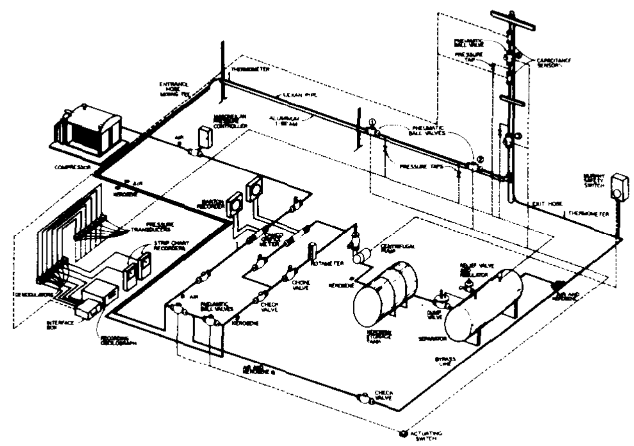

FIGURE 8 SCHEMATIC DIAGRAM OF PIPELINE-RISER PIPE TEST FACILITY

Kerosene was stored in a 58 bbl tank and was pumped from the tank into the system by means of a single-stage Gould centrifugal pump. The liquid flow rate was metered with a Camco 4-in. orifice meter and a Brooks rotameter.

The air was obtained from a Joy two-stage compressor with a maximum output capacity of 0.6 MMscf D at 120 psig. A Masoneilan pressure controller was used to maintain a constant pressure of 110 psig prior to entering the orifice meter run. A Camco 2-in. orifice meter and a 0.75-in. Daniel orifice meter were used to measure the air flow rates.

On each test section there were two pressure taps separated by a 25-ft span. From each pressure tap, pressure was transmitted through a plastic tubing to a Validyne Model DP15 variable reluctance differential pressure transducer. Each transducer was connected to a Validyne Model DP15 Carrier demodulator for shaping of the transducer output signal. The outputs from the demodulators were recorded on Bristol strip-chart recorders.

For measurement of the liquid holdup in the riser pipe, two capacitance test cells [3] developed at the Tulsa University Fluid Flow Projects were used. The capacitance sensors were separated by a 25-ft span.

A broad range of tests were conducted in the test facility described above. For each test, a kerosene flow rate was first established which corresponded to a superficial liquid velocity in the 2-in. I.D. pipe in the range of 0.05-10.0 ft sec. Air was then introduced to the system at a rate corresponding to a superficial gas velocity in the range of 0.35-40.0 ft sec. After stabilized conditions were reached, outputs from the two capacitance sensors and various pressures and pressure drops were recorded. At the same time, the flow pattern was observed and, with the use of capacitance sensor measurements, the air bubble velocity, the air and liquid slug lengths, and the slug period were calculated. Occasionally after all temperatures, pressures, and flow rates were recorded, the ball valves were actuated and the holdup was measured to compare the results with those obtained from the upper capacitance sensor in the riser pipe. The flow rates were not altered during holdup measurement because a bypass system was opened when the holdup valves were closed to divert the two-phase mixture directly to the separator. At the conclusion of the above testing program, a limited number of manual choking tests were conducted and were described earlier.

The successful results from manual choking encouraged pursuit of similar results with automatic control of the choking process. The top of the riser pipe was modified as shown in Figure 9 by installing a regulating valve in place of the gate valve used for manual choking. A flow indicator to indicate presence of liquid slugs or gas bubbles was added essentially a microswitch triggered by a modified check valve.

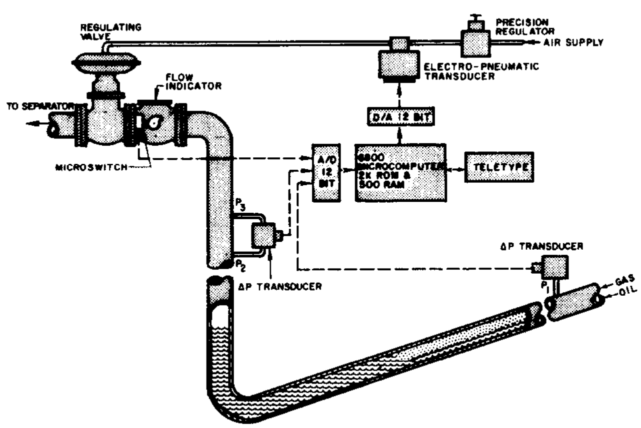

FIGURE 9 MODIFIED PIPELINE-RISER PIPE FACILITY FOR AUTOMATIC CHOKING

The analog signals from the microswitch, the differential pressure transducer in the riser pipe, and the absolute pressure transducer near the pipeline inlet were transmitted to an analog-to-digital converter. The digital signals were processed by a microcomputer using a specially designed logic program shown in flow chart form in Figure 10. Analysis of the digital signals results in an output signal which, after passing through a digital-to-analog converter and an electro-pneumatic transducer, is converted to a pressure which opens or closes the regulating valve. The steps in the logic program could be traced by both an LED and printed output on a teletype unit.

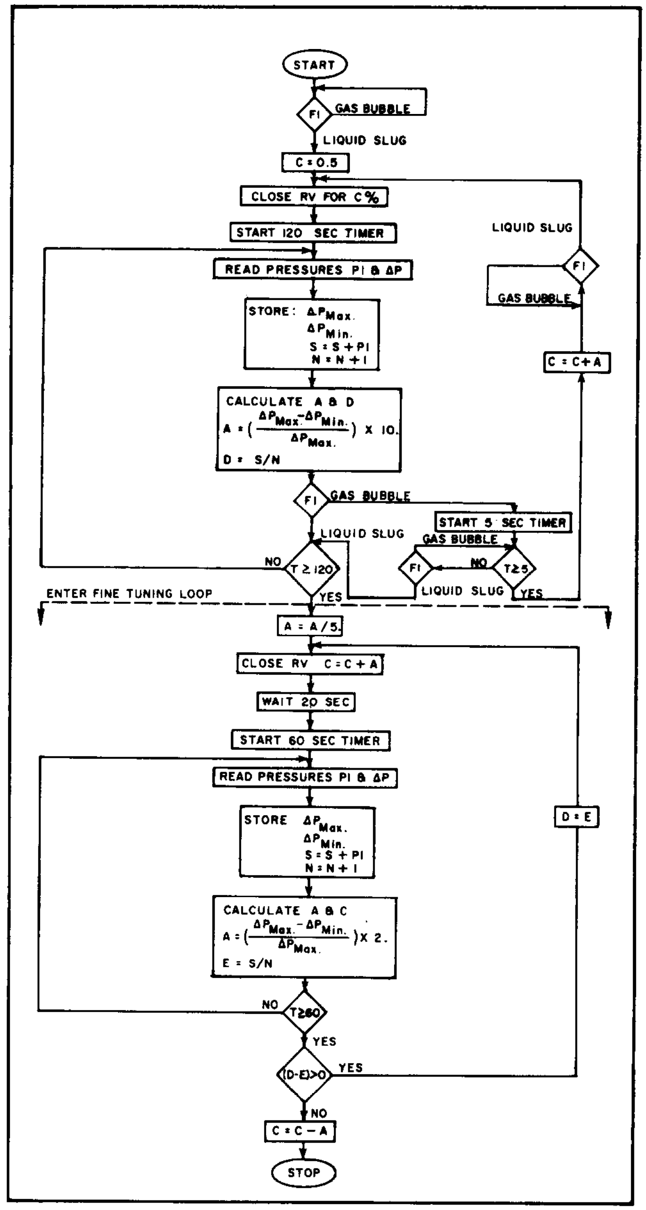

FIGURE 10—LOGIC FLOW CHART FOR AUTOMATIC CHOKING

The logic program consists of two parts. The first part controls choking required to change from severe slugging to transition to slugging. The second part, indicated as the fine tuning loop in Figure 10, controls the final choking to change from transition to slugging to a bubble flow pattern.

The first part begins with a 50 percent valve closure after a liquid slug has been detected by the flow indicator. This valve was selected because numerous tests proved that 50 percent closure did not result in over-choking of the fluids. The coordinates of Figures 5 and 6 are proportional to gas and liquid velocities. A reduction of 50 percent in valve area increases velocities by a factor of 2. Figures 5 and 6 can be used to show that doubling velocities will cause a shift in flow pattern from severe slugging to transition to slugging. Passage from the first part of the flow chart to the fine tuning loop can occur only after choking has caused a 120-second time period to elapse during which no gas bubble takes longer than 5 seconds to pass the flow indicator. These times are unique to the test facility used in this study and will no doubt be different for other geometries and fluid systems.

An example differential pressure recording from the transducer in the riser pipe is shown in Figure 11. Pressure fluctuations after choking began decreased as the slug lengths were reduced and aeration of liquid slugs increased. The flow patterns observed during automatic choking are also indicated in Figure 11.

The fine-tuning loop continues to choke with smaller choking increments until a choke change causes the pipeline inlet pressure to increase. At this point bubble flow has been achieved in the riser pipe. The last choke change is then reversed and the program is terminated.

Several automatic choking tests were conducted with a -5° pipeline inclination and all were successful. All tests were plotted in Figure 5.

The authors believe that choking can eliminate severe slugging in any pipeline-riser pipe system with appropriate geometry. Furthermore, other techniques can be used to detect presence and severity of slugging than were used in this study. For example, nuclear densitometers could replace both the flow indicator and the differential pressure transducer.

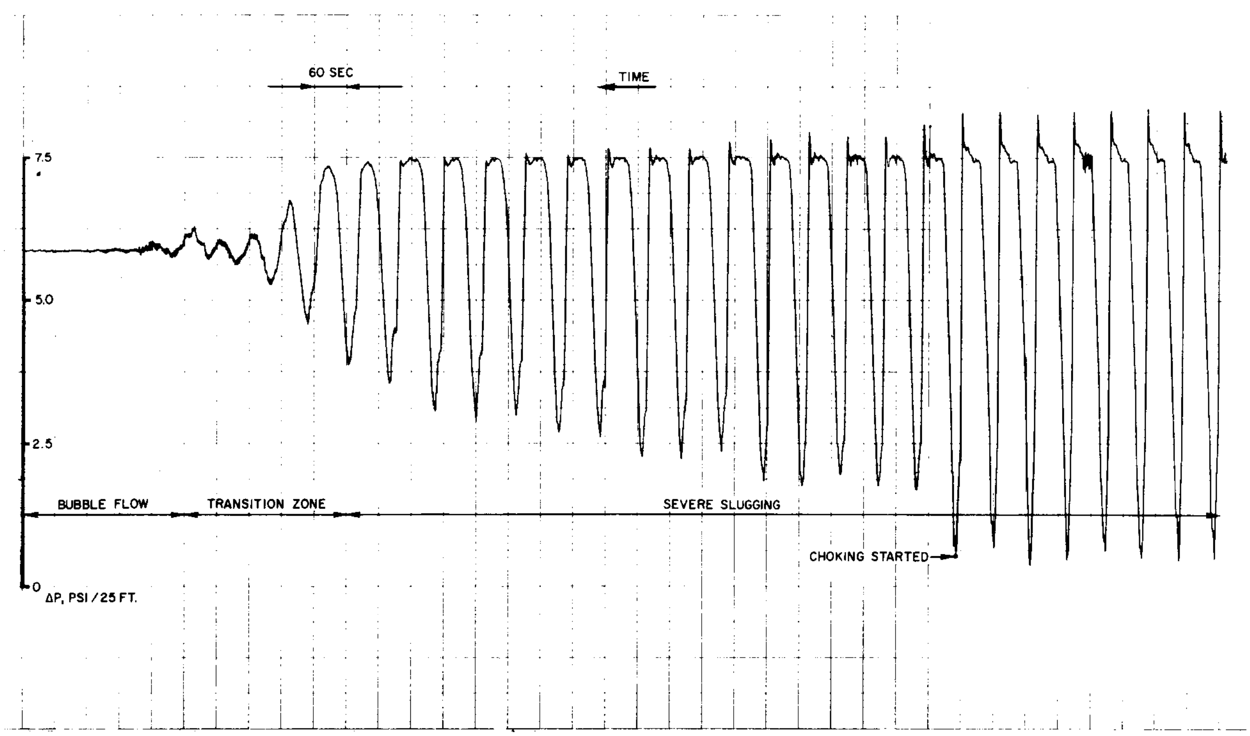

FIGURE 11 DIFFERENTIAL PRESSURE FLUCTUATIONS IN RISER-PIPE DURING AUTOMATIC CHOKING

NOMENCLATURES

SYMBOL ITEM

A = Fractional increase in valve closure, -
C = Fractional closure of valve, -
D,E = Average pipeline pressure
FI = Flow Indicator
g = Acceleration of gravity
N = Number of iteration increments
N_{gv} = Dimensionless gas velocity number

$$= v_{sg}\left(\frac{\rho_L}{\sigma_L}\right)^{1/4}$$

N_{Lv} = Dimensionless liquid velocity number

$$= v_{sL}\left(\frac{\rho_L}{g\sigma_L}\right)^{1/4}$$

P = Pressure
PI = Pipeline pressure
RV = Regulating valve
S = Sum of pipeline pressure
T = Time
v_{sg} = Superficial gas velocity in pipe
v_{sL} = Superficial liquid velocity in pipe
Δ = Difference
ρ_L = Liquid density
σ_L = Gas-liquid surface tension

SUBSCRIPTS

sep = Separator
MAX = Maximum

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3. Schmidt, Z.: "Experimental Study of Two-Phase Slug Flow in a Pipeline-Riser Pipe System," Ph.D. Dissertation, U. of Tulsa (Nov. 1977).