THE UNIVERSITY of TULSA

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Hydrate Flow Performance

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Investigations of Flow Behavior Formation in Well-Head Jumpers During Restart with Gas and Liquid

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Final Report

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CHAPTER 1

INTRODUCTION

As oil companies are moving to deeper waters, production strategies are becoming more challenging due to the hostile environment and the problems associated with deeper waters. Production instabilities are undesirable, and can limit the lifetime and ultimate recovery of a reservoir.

Limited space and higher costs are typical problems associated with offshore operations, but another important aspect is the risk associated with flow assurance issues such as: scale, corrosion, asphaltenes, wax deposition and hydrate formation. An engineer's challenge is to identify possible problems and design a production system and operational procedures to manage them. Some common solutions include insulation and chemical injection.

Hydrates are the most prevalent flow assurance issue. They are crystalline compounds that form when water (host molecule) and methane, ethane, propane, etc (guest molecule) are present at low temperatures and high pressures. Seawater temperatures can get down to just above freezing temperatures resulting in significant heat loss from the fluids to the environment. When producing hydrocarbons (oil and gas) and water at these temperatures and relatively high pressures, the risk of forming hydrates is present. The risk of hydrate formation brings the possibility of hydrate plug formation in the line. Therefore, systems are designed to avoid the formation of hydrate plugs, which can take a long time to dissociate.

There is a high risk of hydrate plug formation in jumper sections during restart operations. The jumper is a section of pipeline that connects the wellhead with the manifold. It is usually not insulated and has low spot sections where the water can accumulate, especially during shut down operations. Upon restart, gas contacts and displaces the water, creating hydrates plugs if no inhibitor is used.

One of the objectives of this investigation is to design and construct a jumper-like facility that operates at atmospheric conditions where experiments with oil, gas and water can be run to permit the study of different operating parameters and then to gain a better understanding of the water displacement during restart to predict the operating conditions that are risky for hydrates formation. Even though flow loop testing is a very good alternative to compare and predict field data, it is not feasible to cover all possible field scenarios, especially the geometries. Software packages have been developed to use and cover very specific conditions. Results of this project will be compared to the transient simulator OLGA.

The following chapters will present a literature review of the topics related to hydrate management during restart, followed by a description of the fluids used and the experimental set up. Finally, experimental and simulation results will be presented and conclusions and recommendations will be given.

CHAPTER 2

LITERATURE REVIEW

Some of the topics of relevance in this thesis are subsea systems and hydrates. The first section covers the basic definitions of hydrates such as: what are hydrates? How do they form? How can they be prevented? Hydrate formation is very relevant to offshore operations therefore a review of subsea systems specifically focused on wellhead jumpers will follow. Then, operating considerations will be covered together with a review of some cases and field studies.

2.1 Hydrates

It is well known that offshore production can be very costly, not only because the oil is in remote places, but also because of flow assurance problems due to the cold water encountered at the sea floor. Flow assurance has become a very important discipline to determine technical feasibility and cost effectiveness of a deep water project.

Some of the most common flow assurance issues are: wax deposition on the pipe wall reducing the pipe diameter until the flow is reduced so much that it can kill the well or simply plug the pipe; hydrate formation, which can also plug the pipe; asphaltene deposition; scale precipitation; corrosion problems; and severe slugging. Some of these - such as scale, corrosion and hydrates are a consequence of water production. Removing the water will eliminate most of these problems but it may be neither practical nor economical.

This thesis focuses on hydrate formation in a jumper. Hydrates are crystalline compounds formed when a hydrocarbon gas and water are combined at high pressures and low temperatures. Three crystal structures have been identified: structure I, II and structure H. The type of structure formed depends on the gas molecules trapped by the water molecules.

From the composition of the fluids, a software program such as PVTSim or Multiflash can be used to create the hydrate curve (See Figure 2-1). The P-T hydrate curve plot indicates that hydrates form in the region to the left of the line. Assuming equilibrium, the area to the right of the curve will be free of hydrates during operations. An operator needs to monitor production for any anomalies.

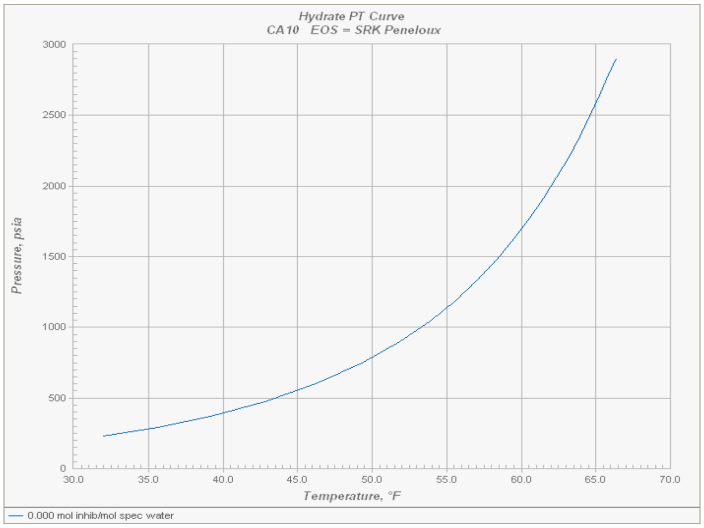

Figure 2-1: Typical Hydrate Curve

Hydrate blockages in an offshore production line are more likely to be formed at low spots where water can accumulate. They can also form in valves where gas expands and causes the Joule-Thompson cooling effect. Moreover, for larger water depths, the operating pressure increases due to higher hydrostatic head increasing the chance of forming hydrates.

Once a hydrate plug forms, it may take very long to dissociate, resulting in costly production losses. This is why all precautions are taken to prevent formation of hydrate plugs. Hydrate plugs can be formed through two mechanisms: they may agglomerate and accumulate in the pipe to form plugs, or they can form in the bulk and flow as a slurry until the slurry viscosity is so high that the flow stops.

The most commonly used hydrate prevention strategies are insulating the pipe and chemical injection. The popular insulation methods are cast-in-place where layers of insulating material surround the pipe, and pipe-in-pipe where the production line is put into another pipe and the annulus is filled with insulating material. Pipe in pipe is usually more expensive.

During steady state production, pipeline insulation may keep the system outside the hydrate zone, but if a shutdown occurs the temperature of fluids in the pipe may reach down to sea temperatures. If the shutdown duration does not exceed the “no-touch” time (minimum cool down time), no action needs to take place before the restart. If it is longer, the conditions are already inside the hydrate region and a mitigation process needs to be implemented.

Chemical injection is a very effective but also very costly method to prevent or delay hydrate formation. There are two types of hydrate inhibitors: thermodynamic inhibitors and low dosage hydrate inhibitors. Thermodynamic inhibitors such as methanol and ethylene glycol (MEG) will shift the hydrate curve to lower temperatures making the hydrate region smaller. Low dosage hydrate inhibitors are classified as kinetic inhibitors which delay the hydrate crystal nucleation and growth, and anti-agglomerants (AA) which allow hydrates to form but not to agglomerate. Other methods to prevent hydrate plugs are low pressure operations, water removal and active heating but they are either not practical or too expensive.

Even with these precautions, sometimes a hydrate plug stills forms and the most common practice to dissociate it is to flow methanol. Other possible solutions to dissociate a plug include two sided depressurization, and heating the line. In all cases, dissociation needs to be done in a safe manner; for example, one sided dissociation may free the plug making it a projectile in the pipeline.

The first pages of the book titled *Hydrate Engineering* by Sloan (2000) present a few case studies where the equipment was severely damaged and lives were lost during an attempt to dissociate a hydrate plug. There was an incident in 1991 where operators were attempting to clear a plug in a sour-gas flow line when the plug dissociated. The line was ruptured due to the impact of the hydrate plug and lives were lost. In another incident that same year, the two sided depressurization technique was used but multiple plugs might have lead to the failure of a 3 inch Schedule 40 pipe. Even though engineers try to design a hydrate free well, they still do happen occasionally and cause losses of life and property.

2.2 Subsea Systems

Since known reservoirs are depleting, oil and gas companies are exploring in deeper waters with more hostile environments. Prevention of possible environmental damage and preparations for possible natural disasters are the responsibilities of the offshore production engineer when the facility is being designed.

Pipelines are used to transport hydrocarbons, water, or chemicals between platforms and manifolds, satellite wells and onshore facilities. A complete pipeline design will include the size of the pipe and the grade of the material, taking into consideration insulation layers, riser geometry, and stress analysis.

This project investigates the hydrate risk in a jumper. A jumper is a short pipe that connects a flow line to a subsea structure or two subsea structures located close to one another. It can be flexible or rigid, and it is more commonly used to connect the wellhead with the manifold. Jumpers are usually not insulated and constitute both a cold spot and a low spot where water can accumulate. Cold spots pose a high risk for hydrates and thus they limit the system's overall reliability.

Each jumper must be specifically designed to connect the wellhead and the manifold. When the jumper is manufactured it must be rigged precisely so that it can be lowered into the sea and land into the connection points on the sea floor. When the pipeline is being installed subsea, the process introduces torsion into the pipeline which may have to be rotated to alleviate some of that torsion. Current state of the art requires pipeline installation contractors to land the pipeline within an angle window relative to horizontal. The following figures show an example of a jumper installation. Figure 2-2 is a Vertical Tie-in System, and Figure 2-3 represents a Horizontal Tie-in System. (The pictures were taken from the FMC Technologies website)

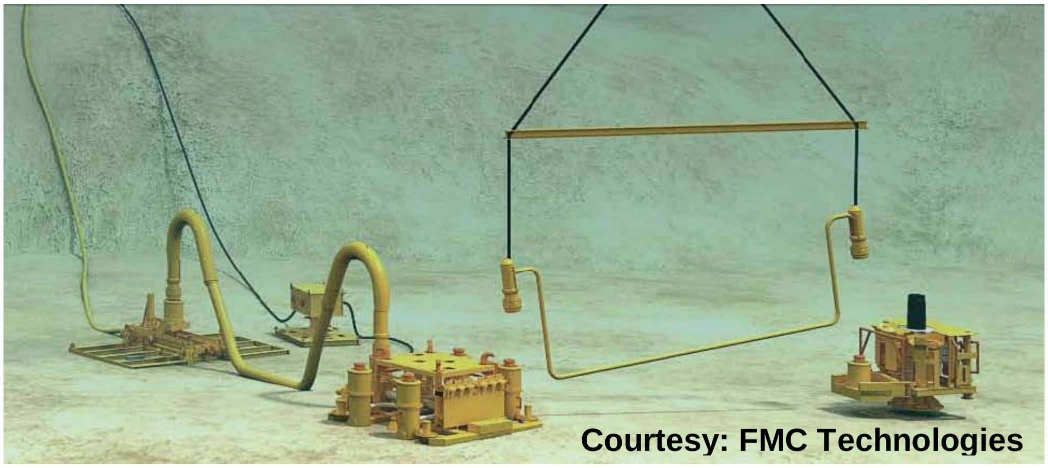

Figure 2-2: Jumper Installation – Vertical Tie-in System

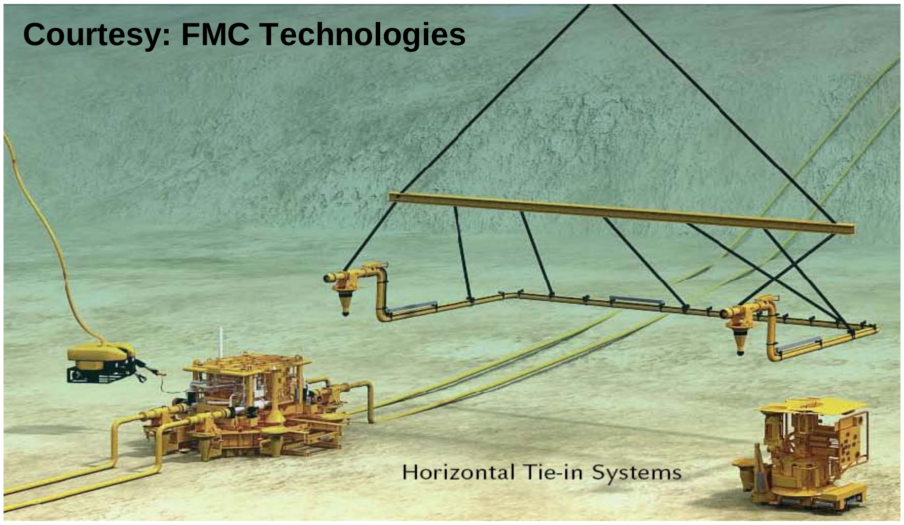

Figure 2-3: Jumper Installation – Horizontal Tie-in System

As shown in the picture, the jumper geometry includes a low spot section because the pipe needs to rest on the seafloor for better system stability and a vertical section leading to the connection points. The jumper has pull heads attached to each end. When lowered to the seafloor, it will be first connected to the manifold and then to the wellhead.

During installation, the jumper is usually filled with water. This will promote a dangerous scenario when production starts with the presence of water at low temperatures.

2.3 Operational Issues

Hydrate prevention and mitigation strategies are an important part of the OPEX and CAPEX of a project. From the design phase where the appropriate insulation design and chemical injection equipment need to be considered, to the regular operations where constant injection of chemicals may be required.

As mentioned earlier, during unplanned shutdown longer than the “no touch” time, chemical injection will be required before opening the well to flow again. If chemicals were not injected during regular operations, then they need to be injected just before the restart. The most commonly used chemical is methanol, but the specific operational procedures to better inhibit the water are unknown. The most critical operational variables are the amount of chemicals needed and the flow rate at which it is injected.

Cagney *et al.* (2006) covered hydrate inhibition for different operating parameters in a 6 inch jumper. Some of the most relevant parameters were the inclination of the jumper, the gas flow rate required to remove all the liquid from the jumper, and the required liquid rates to remove uninhibited water with methanol. Results showed that by inclining the pipe to -5 degrees, considerably more liquids can be removed than with the horizontal orientation. Gas velocities higher than 30 ft/s were required in the 6 in jumper to sweep all liquid from a horizontal section. Liquid velocities of 1 ft/s were required to remove all the water from the jumper, even though lower rates (0.25 to 0.5 ft/s) could remove most of it.

Herrmann *et al.* (2004) performed similar studies in a header facility with an 8 inch diameter PVC pipe. Once again this study focused on the amount of water inhibited after varying parameters such as the water cut, header inclination, oil density and various gas volume fractions. Observations showed that in all the test runs with different inclinations and at 20% water cut or lower, the water was not contacted by the methanol. At higher water cuts, not much mixing between water and methanol occurred until entering the first riser. Furthermore, the experiments showed that there is more mixing during higher gas restart operations.

Some of Estanga's (2007) work at The University of Tulsa was dedicated to restarts in low spots. Results showed that at lower restart velocity less permeable plugs were formed. Also, plugs developed during segregated conditions appeared to travel and form further downstream. Moreover, higher salinities did not prevent plugging but they delayed the formation of plug. Anti-agglomerants were found to be effective if injected prior to shut-in.

2.4 Design Considerations

Since the jumper is going to be exposed to multiphase flow, it is very important to understand the different flow patterns that can be present in the facility. Flow pattern refers to the distribution of gas and liquid phases in the pipe. Even though flow patterns need longer pipe sections to stabilize, in this thesis they are used as a reference for visual observations. The flow pattern observations help this research understand how the water is distributed and how much mixing is taking place. From the results, the conditions that are going to be risky in terms of hydrate formation and blockage can be determined. Changing the inclination of the pipe will also change the possible flow patterns encountered. Figure 2-4 and 2-5 provide the basic classifications of the horizontal and vertical flow patterns.

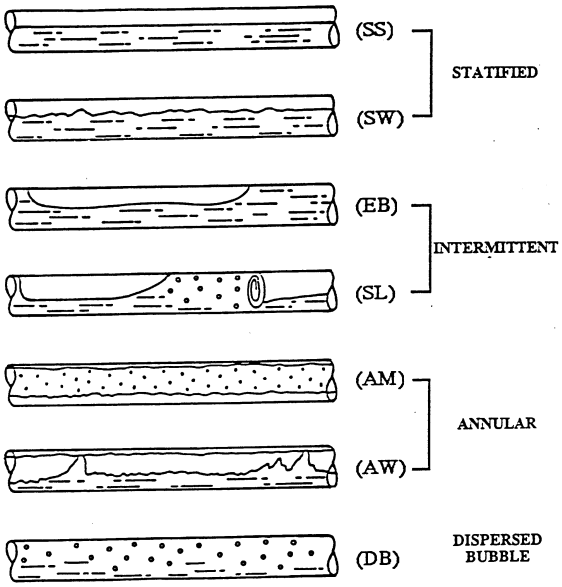

Figure 2-4: Flow Pattern – Horizontal Flow

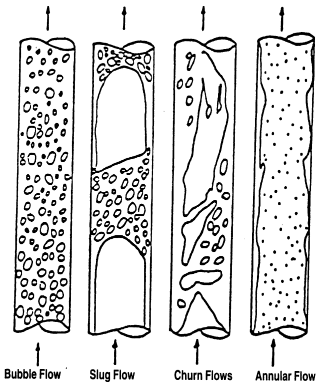

Figure 2-5: Flow Pattern - Vertical Upward Flow

Flow loop testing is an alternative to compare and predict field data. Large facilities such as the new Tulsa University Jumper facility, can be used to test possible field scenarios and to observed the flow behavior under those conditions. However, no matter how many tests are done, it is not possible to cover all possible application ranges. Models and simulation tools must be built to model specific cases. The jumper flow loop experiments were compared to simulations by a transient flow simulator, OLGA.

OLGA is a state of the art transient flow simulator and has been used in many projects. It can be used as a means to compare studies, for *what if* cases and for facility design. Many examples where OLGA has been used can be found in the literature: Nennie *et al.* (2007) used OLGA to couple it to a well reservoir simulator; Chin *et al.* (2000) used it to determine the pipe insulation design; Simon *et al.* (2008) presented a module to be used in OLGA that predicts the formation of a hydrate plug.

CHAPTER 3

TEST FLUIDS AND EXPERIMENTAL SETUP

3.1 Experimental Facility

This thesis focuses on the transient simulation, design and assembly of a 3-inch jumper-like test section to gather data on liquid (oil and water) displacement from the low-spot formed by the jumper as a function of several operating parameters, such as water cut, liquid loading, oil viscosity, restart velocity and restart phase. Figure 3-1 shows the equipment layout, and Figure 3-2 shows the details of the test section.

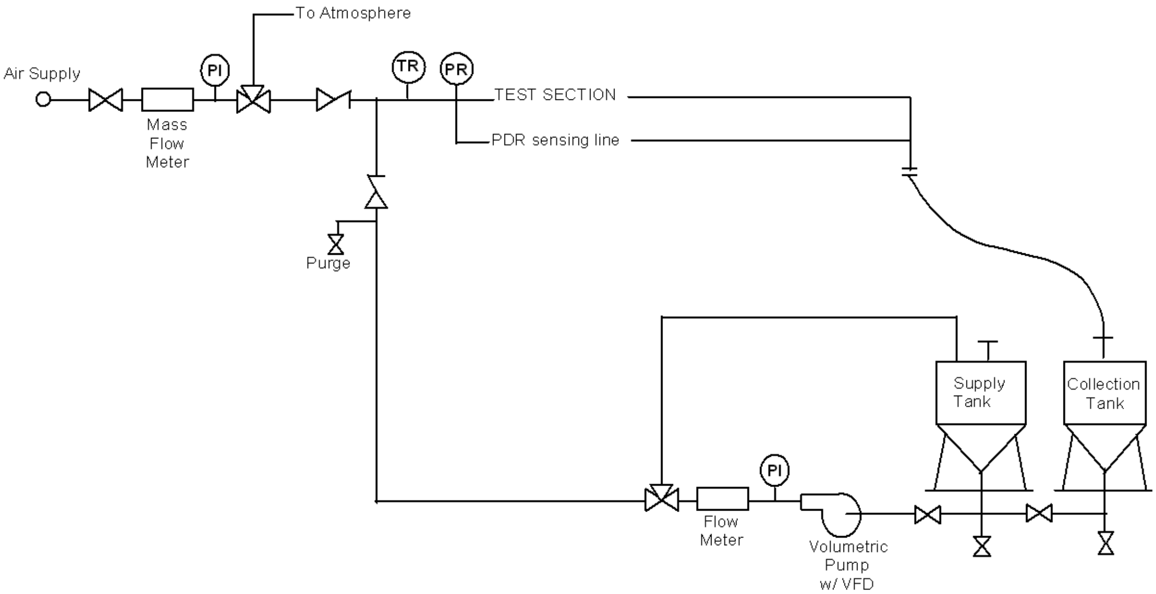

Figure 3-1: Equipment Layout

The geometry of the jumper facility was selected to mimic typical jumper configurations encountered in the Gulf of Mexico. Dimensions from a typical flow line jumper, as well as a well-head/manifold jumper were taken into consideration in the selection of the geometry. Also considered was the size criterion (diameter and length) to make this facility feasible at The University of Tulsa.

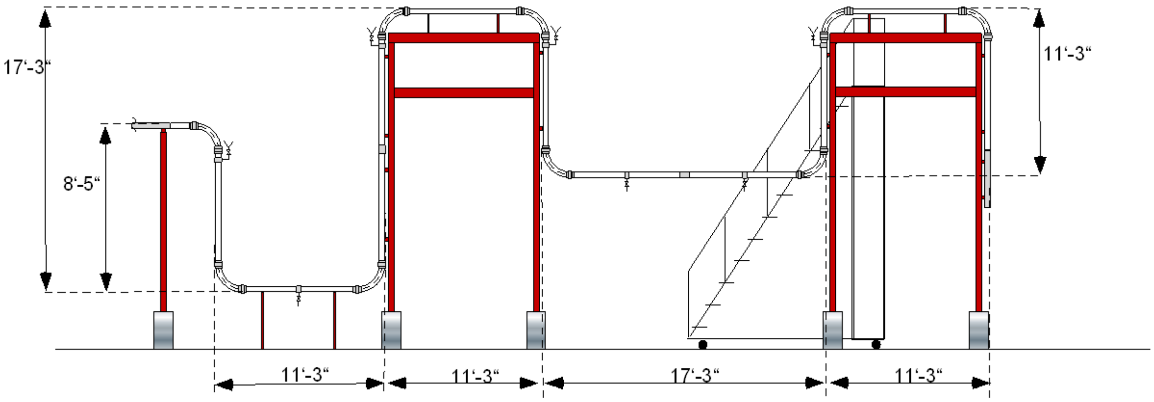

Figure 3-2: Test Section Layout

The test section was made with 3-inch acrylic pipe, with a total length of about 100 feet. The instruments used in the test sections are two differential pressure transducers, one pressure transducer, and two temperature transducers. A high definition digital camera was used to record the fluid displacement during the restart experiments.

3.1.1 Gas Restart System

The gas restart system consists of an electric-motor-driven single stage screw dry air compressor from Ingersoll Rand. It is capable of generating flows with velocities up to 30 ft/s in the 3-inch line. Air flows through a ball valve and then through a needle valve to control the flow rate. Gas rate is measured with a Micro-Motion Coriolis flow meter, followed by a three-way valve to direct flow to atmosphere or to the test section. Right after the 3-way valve, a check valve was installed to prevent any back flow of liquid into the gas system.

3.1.2 Liquid Restart System

The fluid to be used is stored in 300 gallon supply tanks. A valve is located at the bottom of each tank which then connects to the pump suction. The pump used in this facility is a 3-inch positive displacement Blackmer pump model X3E capable of generating velocities in the pipe from 0 to 6 ft/s. The fluid is circulated through a positive displacement meter and a bypass line until the desired flow rate is reached. Then the 3-way valve directs the flow to the test section.

3.1.3 Charge and Drain System

Four fill ports located along the test sections are used to charge the facility. Measured volumes of liquid are poured into the facility for all tests except for the full filling in which the loop was charged directly from the fluid storage tank. To do so, a small air pump was used to pump the fluids through one of the DP lines.

The experimental liquid loadings ranged from 25 to 90% of the pipe diameter in the low spot section, and half full, and full to the riser. Figure 3-3 illustrates the liquid loadings. Figure 3-4 shows how the phases are distributed in the water/oil mixture experiments.

The test section also contains three drain ports; one located on the first low spot, and two on the second low spot. These are used to drain liquids after each test so that remaining water and oil can be quantified.

Liquid Loading	1st Low Spot (liters)
25%	3
50%	7
75%	10
90%	11.5
Half Full	23
Full	36-45

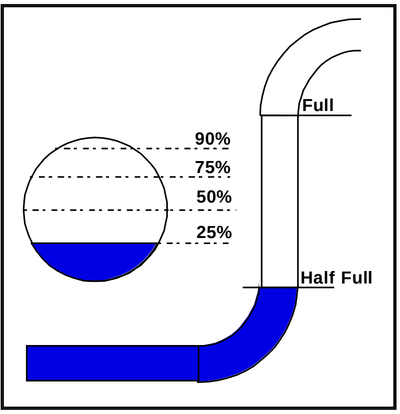

Figure 3-3: Liquid Loading Representation

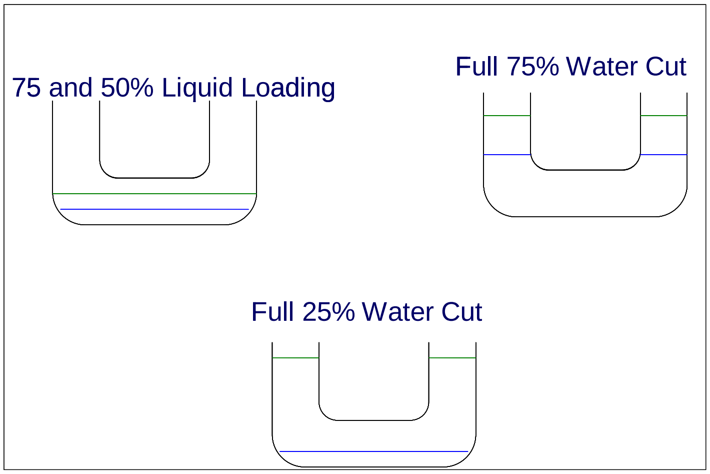

Figure 3-4: Initial Charge Phase Distribution – Mixture Experiments

3.1.4 Instrumentation

Even though this facility operates at ambient conditions, two temperature transducers located on each low spot section are used to take into account ambient temperature changes into the test analysis by adjusting the temperature in the simulations.

Differential pressures are measured for each low spot. Figure 3-5 shows a layout of the test section instrumentation. There is also a pressure transducer at the inlet of the test section and a flow meter on both the gas restart system and the liquid restart system. All the instruments were connected to a data acquisition system using LabVIEW, where it was possible to record all data for alter analysis.

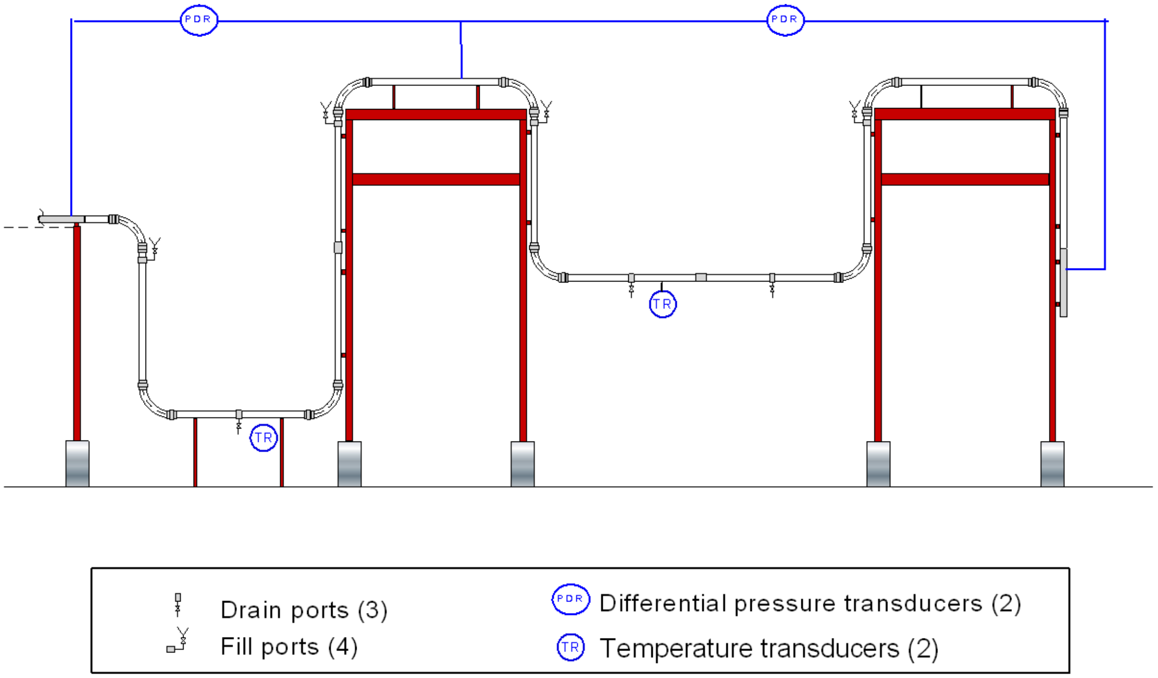

Figure 3-5: Jumper Section Instrumentation

3.1.5 Video Capabilities

A Sony high resolution digital HD video camera (model HDR-SR10) was used to record every experiment. All of the videos were converted into MPEG files so that they can be played using a computer's media player.

3.2 Operational Procedure

3.2.1 Gas Restart Test

For the gas restart tests, the flow loop was filled with the desired liquid loading. After the gas flow rate was set and stabilized through the bypass, it was diverted to the test section. Gas flow continued until no more liquid carry over from the low spot is observed.

Operating procedure for gas restart:

1. Measure desired quantity of fluids to be used in the run.
2. Load test fluids.
3. Close the fill port valve.
4. Check the loop. All the valves are closed, and the gas system three-way valve is on bypass.
5. Turn on the compressor.
6. Open feed and flow setting valves until desired gas flow rate is stabilized.
7. Set video camera.
8. Change three-way valve from bypass to test section.
9. Observe and video tape flow in test section.
10. Once fluids are not carried over anymore, stop the video camera and the gas flow to the test section by switching the three way valve back to bypass.
11. Close feed and flow setting valves.
12. Using the drain ports drain all liquid from the flow loop into a bucket.
13. Let the fluids in bucket rest until water and oil are separated.
14. Record results on data base, and convert video file.

3.2.2 Liquid Restart Test

Similar as gas restart experiments, the liquid restart tests start by filling the low spot with the desired liquid loading. The desired liquid flow rate is set by flowing through the bypass. The liquid is then diverted to the test section for the desired time duration. Finally, liquids are drained and quantified.

Operating procedure of liquid restarts:

1. Measure desired quantity of water/oil to be used in the run.
2. Load test facility.
3. Close the fill port valve.
4. Check the loop. All the valves are closed, and the liquid pump is on bypass mode.
5. Turn on the liquid pump.
6. Set up camera
7. Once desired flow rate is reached, switch three-way valve to flow to test facility.
8. Observe and video tape flow in test section.
9. After desired time has passed, stop video camera.
10. Set liquid pump to bypass and turn it off.
11. Drain all the liquid from test section into a bucket.
12. Let the fluids rest until water and oil are separated.
13. Record results in data base, and convert video file.

3.3 Test Fluids

The model oils: Citgo 19, and Lube 220 with viscosities of 19 cP, and 220 respectively, were used in the experiments. They were selected in order to test the effect of viscosity on the displacement, and also because they offer better transparency for visualization. Air was used as the gas phase and fresh tap water as the water phase. Table 3-1 shows a summary of the fluid properties, and Table 3-2 shows the compositions of the Citgo 19 and the Lube 220.

Table 3-1: Citgo 19 and Lube 220 Chemical Composition

Component	Weight (%)	
	Citgo 19	**Lube 220**
C5	0	0
C6	0.05	0
C7	0.02	0
C8	0	0
C9	0	0
C10	0	0
C11	0	0
C12	0	0
C13	0	0
C14	0.01	0
C15	0.11	0.01
C16	0.02	0.01
C17	0.01	0.05
C18	0.03	0.19
C19	0.04	0.64
C20	0.05	1.72
C21	0.17	2.72
C22	0.25	7.27
C23	0.34	12.3
C24	0.5	14.33
C25	0.53	13.63
C26	0.78	11.87
C27	0.84	11.36
C28	1.25	8.93
C29	1.55	5.67
C30	93.42	3.36
C31	0	1.78
C32	0	1.26
C33	0	0.71
C34	0	0.59
C35	0	0.42
C36	0	0.29
C37	0	0.27
C38	0	0.2
C39	0	0.21
C40	0	0.13
C41	0	0.08
Total	100	100

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Table 3-2: Summary Fluid Properties

	API°	ρ	μ @ 40°C
		kg/m3	*cP*
Water	10	998	1
Citgo 19	34.8	860	19
Lube 220	28.7	883	220

3.4 Simulation Set-up

3.4.1 Overview

The transient simulator OLGA was first used in this research to help with the facility design. Simulations were run to determine key parameters such as possible types of flow and the duration of the experiments. The results also helped size the compressor and liquid pump. After the facility was built, simulations were run to model and compare with experimental results. The objective is to evaluate the simulator performance for this application.

The main functions used in the simulations were the boundary conditions, geometry editor, and the fluid PVT.

Experiments were run at ambient conditions, therefore, in the simulator the boundary conditions were set to 70° F and 14.7 psia and a void fraction of 1 (empty pipe). OLGA uses a geometry editor where, by inputting the X and Y coordinates of each section of pipe, the final geometry is created. A number of sections can then be specified for each pipe, which will make the calculations more detailed. In this study an average of 3 sections were created for each pipe.

Samples of the fluids used were sent to a laboratory in order to get a compositional analysis. Results were input into the software PVTsim to create a look up table that contains all the fluid properties at the specified operational range. OLGA uses this file as a look-up table for the fluid properties.

CHAPTER 4

EXPERIMENTAL AND SIMULATION RESULTS

The experimental and simulated results will be classified in four groups:

- Single phase - gas restart
- Oil/water mix – gas restart
- Oil/water mix – liquid restart
- Comparisons with simulator

Almost one hundred experiments were run covering gas and liquid restarts. The primary fluids studied in the single phase experiments were the water and the 19 and 220 cP oils. For the single phase experiments, different liquid loadings were set to each low spot individually and combined, and three primary restart rates of 1, 15 and 30 ft/s were tested.

The two phase restart experiments were primarily conducted with the 19 and the 220 cP oils. The experiments were run using three different liquid loadings, three water cuts, and three restart velocities. Both of them resulted in different behaviors.

The liquid restart experiments were run using the 19 cP oil. The main operational parameter changes included the number of jumper volumes displaced and the restart velocity.

4.1 Single Phase Experiments with Gas Restart

4.1.1 Water Only

18 experiments using water with gas restarts were run. The final liquid holdup is affected mainly by velocity. Figure 4-1 shows how for different initial holdup, the final holdup reaches a value for each velocity, unless the velocity is not sufficient to displace any liquid. During the restart, if the velocity is not high enough to carry the water over, most of it will be located in the riser section, especially in the bottom elbow. This is shown in more detail on Figure 4-2.

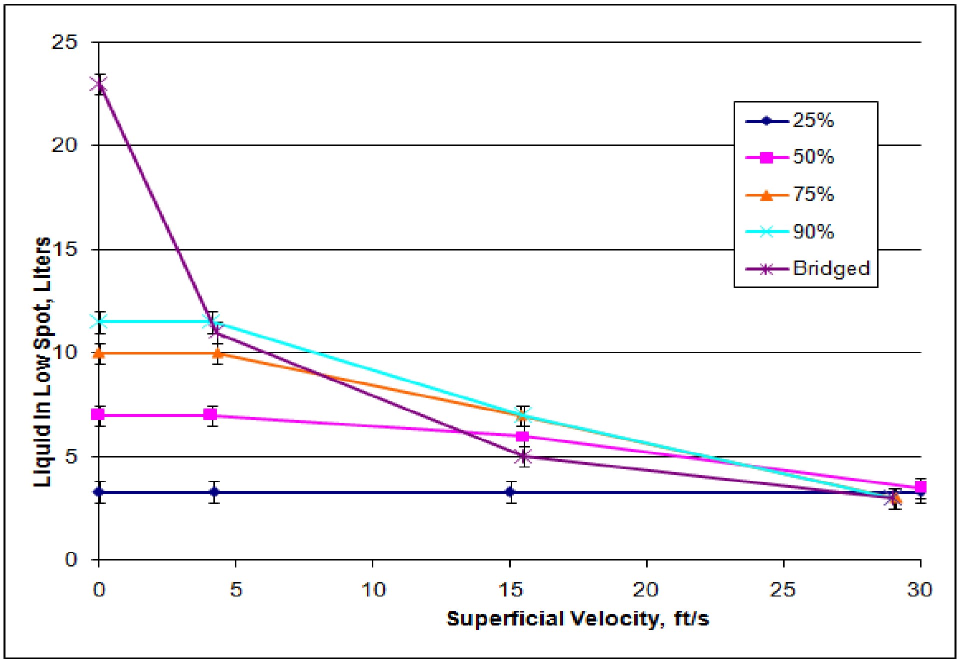


Figure 4-1: Experimental results for the first low spot

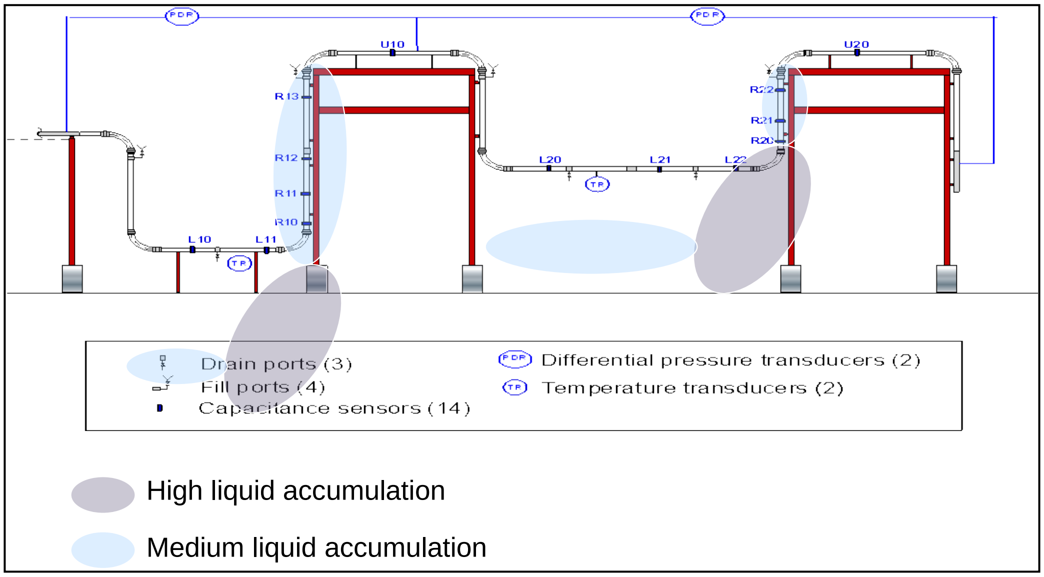


Figure 4-2: Liquid accumulation zones

At low velocities and low liquid loadings most of the water will be located in the lower horizontal section either undisturbed or as wavy flow. For higher liquid loadings and low velocities, most of the water would have been displaced in the first 10 seconds. After that, the water that remains in the riser falls back into the horizontal section and, occasionally, intermittent slugs originate from the lower horizontal section and sweep more water out of the riser. Figure 4-3 shows a step by step sketch of this behavior.

At higher flow rates, the water accumulation is mainly in the riser. For low liquid loading experiments not much water was carried over, but all of it was located in the riser as churn flow while at the top riser elbow, swirl flow was observed. For the high liquid loading experiments, most of the water was removed in the first 10-20 seconds, and reaches final equilibrium similar to the low liquid loading experiments described in Figure 3-3, but without much water in the horizontal section (Figure 4-4).

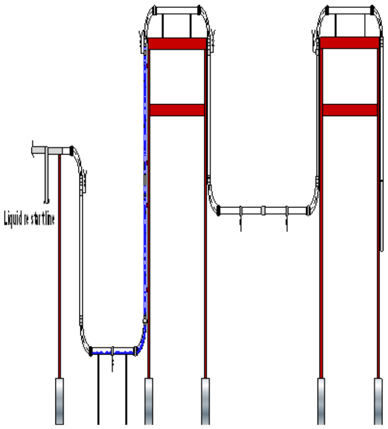
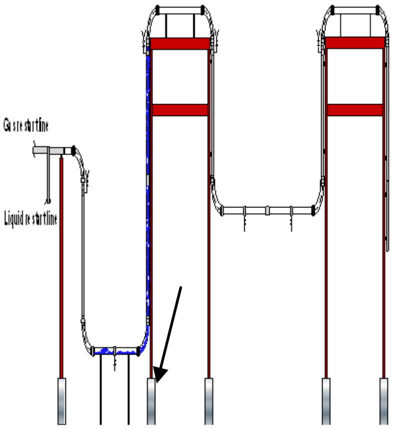
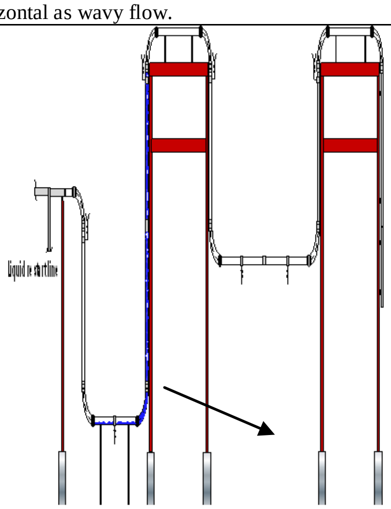
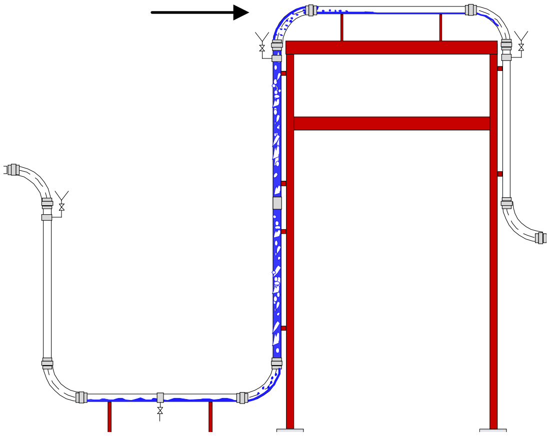
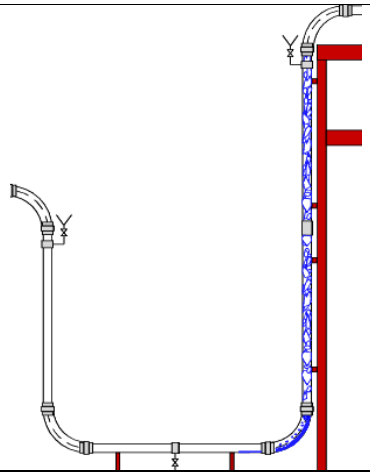
	
A. As the gas starts to flow to the low spot section most of the liquid will be removed from the low spot. Liquid left will be located in the riser as churn flow, and in the horizontal as wavy flow.	**B.** With time, some of the liquid will accumulate in the horizontal until it reaches a level of about 60% full. At this point a slug will form at the horizontal section.
	
C. The slug will be displace all the way through the riser	**D.** Slug reaches the top of the riser, and some of the water is carry over to the second low spot. Liquid falls back and process repeats itself in B, until there is not enough liquid to create slugging. This is when the experiment is stopped.

Figure 4-3: Sketch of Water Distributions with Gas Restart: Medium Restart Velocity



Most of the liquids will be removed from the low spot within the first 20 seconds. After that, there will be no significant carry over. The liquid left in the low spot will be located between the riser and the lower riser's elbow as churn flow.

Figure 4-4: Sketch of Water Final State with Gas Restart: High Restart Velocity

A flow pattern map was developed based on operating conditions that shows the conditions where the risk of generating hydrates is either low or high. The conditions where the flow pattern was observed to be stratified wavy or smooth, such as that observed at low liquid loadings and low restart rates, are considered to be of low risk since there is not much disturbance to the water. Areas of high risk are considered to be those conditions that include a lot of mixing (churn flow), which are the operations with high liquid loading or high flow rates, as shown in Figure 4-5.

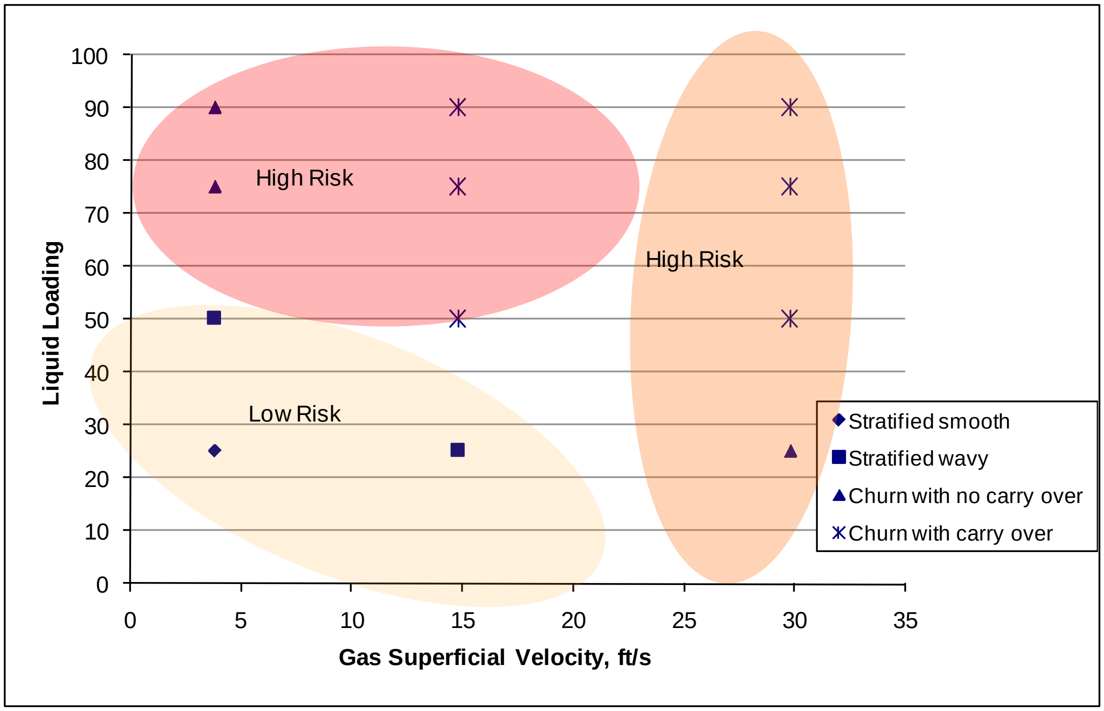


Figure 4-5: Flow Pattern Map. High and Low Risk Areas Indicated

4.1.2 Single Phase Oils

Similarly to the water experiments, 31 additional experiments were run, using the the 19 and 220 cP oils as a single phase with gas restart. The results show that for the high viscosity oil, 220 cP, the final liquid holdup is considerably higher than that for the water and the 19 cP oil. On the other hand, at the low velocity (4ft/s) the 19 cP oil had a holdup higher than the water, but at the high velocity (30ft/s) more liquid is actually removed than the water showing that the density also plays an important role in displacing the liquid as shown in Figure 4-6.

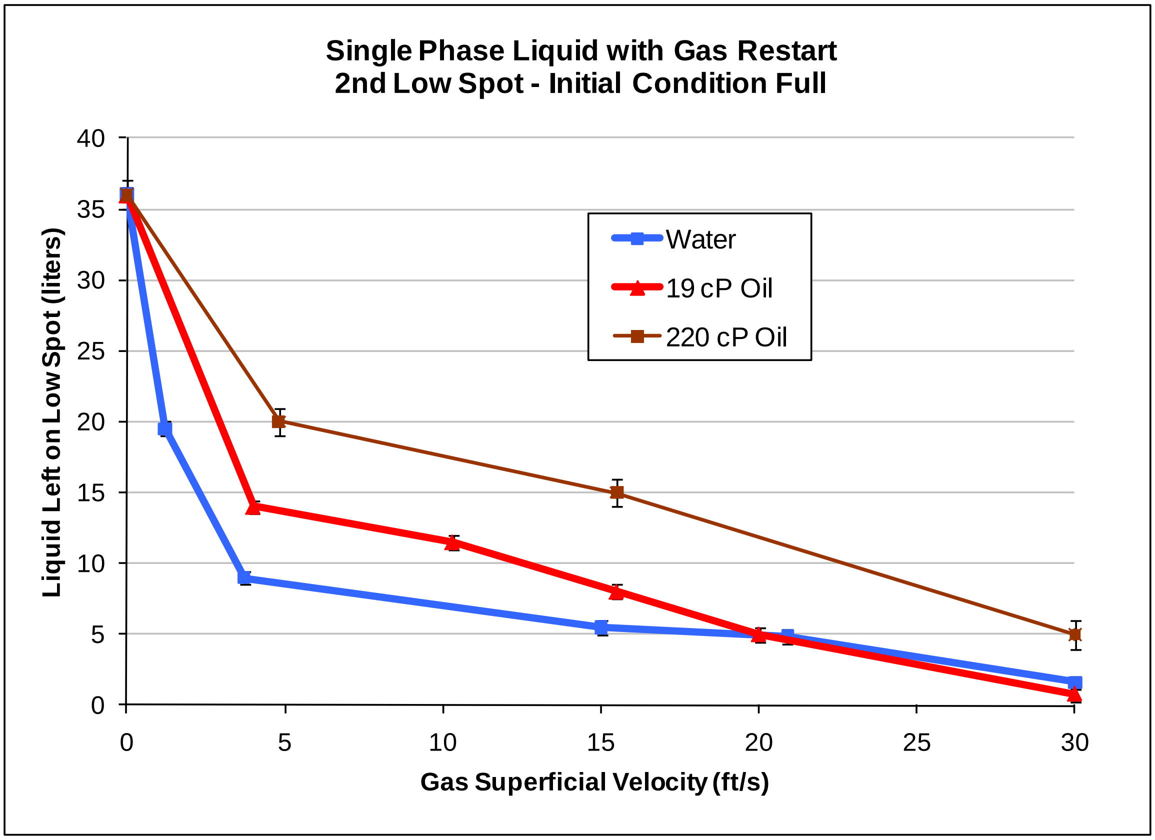


Figure 4-6: Water vs. oil results - Comparison of single phase experiments.

Observations with the flows of the 19 cP oil are similar to those for water. On the other hand, the 220 cP oils is considerably different due to its viscosity. For low to medium velocities, the 220 cP oil moves very slowly up the riser sticking to the pipe walls. At 15 ft/s, the oil flowed to the top of the riser, and then it took about 1 minute for some of the oil to be displaced across the top portion of the 11 foot horizontal section.

4.2 Two-phase Experiments with Gas Restart

Gas restart experiments were conducted with oil/water mixtures loaded at the bottom of the jumper. Oils tested were the 19 and 220 cP oils.

4.2.1 Water and 220 cP Oil

Twenty one experiments were run covering mixtures of water with the 220 cP oil as initial condition, and using gas as the restart phase. Results of the water/lube220 mixture show that at low water cuts the behavior is similar as that of the 220 cP oil, but at high water cuts the results are similar as those of water. Figure 4-7 shows that the 50% water cut test appears to be a transition phase. Only considering the water phase, the sweep efficiency (η = 1- Final holdup/Initial holdup) is higher at higher water cuts, lower at low water cuts, and considered to be in a transition stage at 50% water cut. See Figure 4-8. These results suggest that the flow behavior may be affected by the relative portions of the pipe wetted by oil (oil continuous) and water (water continuous – showing close to water behavior)

During the experiments there was not much mixing observed. In general, with either oil, water or both are displaced in separate slugs. In fact, in one experiment with a non-bridged initial condition, 50% water cut and high velocity (30 ft/s), almost all of the water was displaced up the riser as a single phase, and the oil stayed undisturbed in the lower horizontal section.

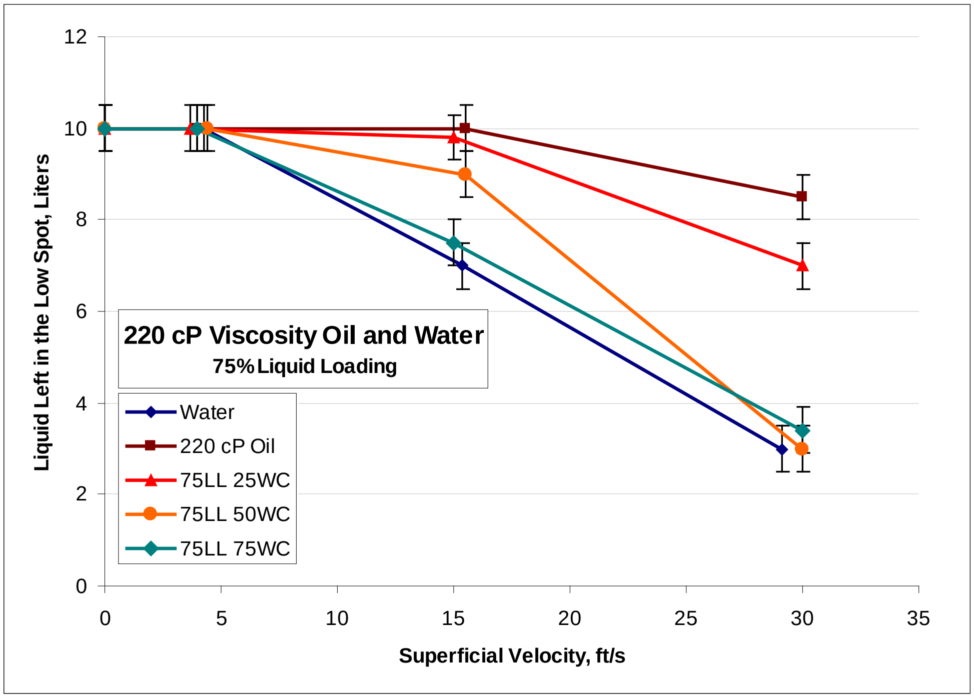


Figure 4-7: Water Cut Effect on Displacement. Water and 220 cP Oil Mixture.

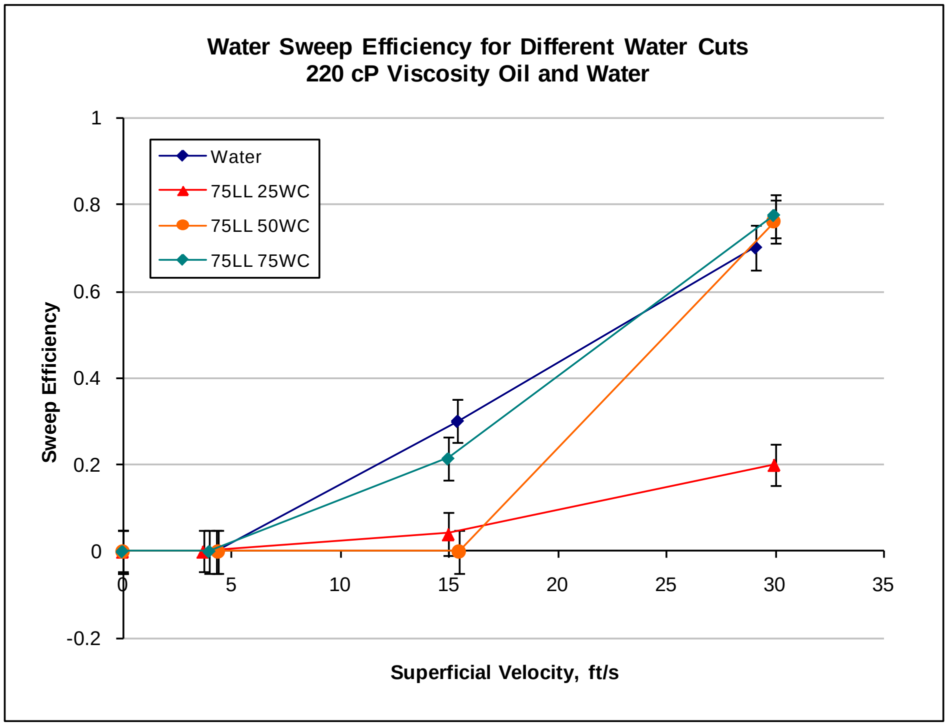


Figure 4-8: Water cut effect – Water Sweeping efficiency (220 cP oil and water)

4.2.2 Water and19 cP Oil

Twenty one more experiments were run with mixtures of water/Citgo19. Results show that at 25% water cut the final holdup is higher than for the water and oil experiments, suggesting that there is probably an emulsion/viscosity effect taking place. The 50 and 75 % water cuts fall in between the water and the oil trends (See Figure 4-9).

The water/Citgo19 experiment did experience considerable mixing. While running the experiment it was not possible to identify each phase separately but, after draining the two phases it took at least 30 minutes to separate them leaving a layer (about 0.5 liters) of an emulsion that never separated.

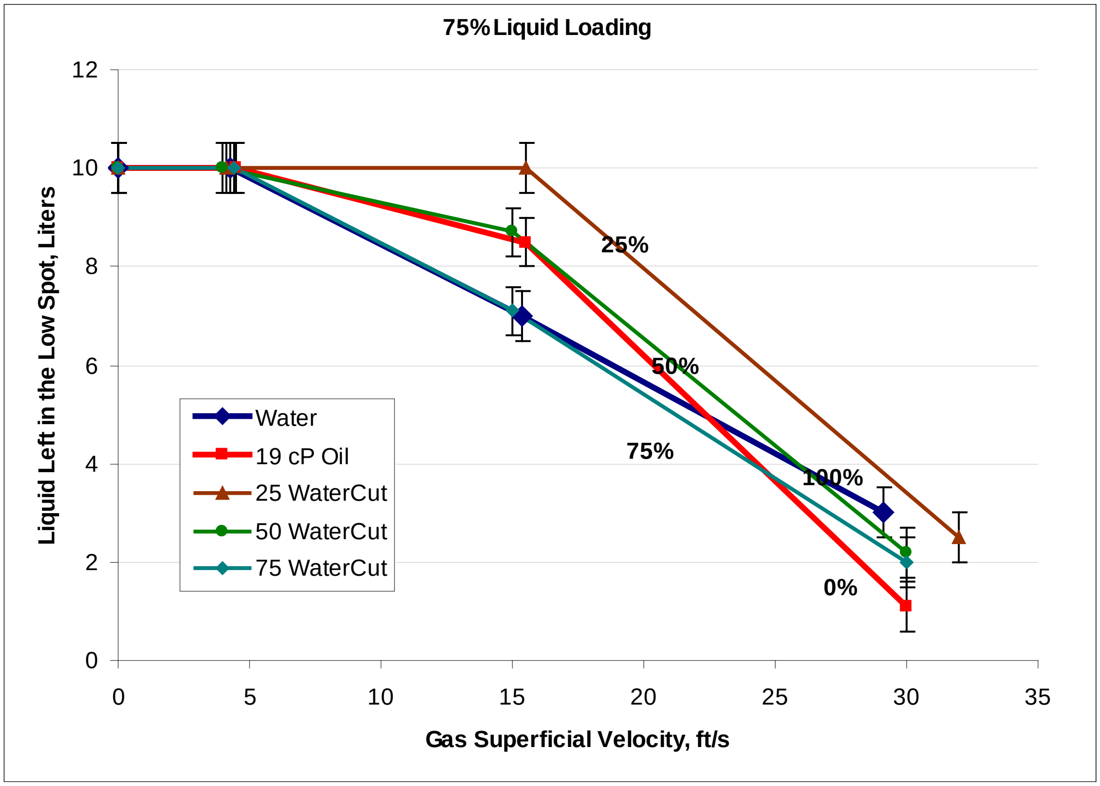


Figure 4-9: Water Cut Effect on Displacement. Water and 19 cP Oil Mixture.

4.3 Experiments with Liquid Restart

Experiments were conducted with liquid restarts to evaluate the water displacement in case the jumper was to be displaced by dead oil or in case the restart fluids were to be oil dominated. Liquid restart experiments were run only with the 19 cP oil as the restart phase.

4.3.1 Water with Citgo 19

To determine how the velocity and the number of jumper volumes displaced affect the results, five tests were run using a jumper full of water as the initial conditions. These conditions were chosen because they represent the worst case scenario.

Figure 4-13 shows that displacing one jumper volume at higher velocities is more efficient even though it was shown that for the lowest velocity tested (0.48 ft/s) most of the water was already removed from both low spots. Similarly, displacing more jumper volumes at the same velocity is more efficient (Figure 4-14). Results show that even for the worst case scenario tested, 0.48 ft/s and one jumper volume displaced, there is less than 10% water left on each low spot, making it a non bridged condition which will not be too risky in terms of possible hydrate plugs.

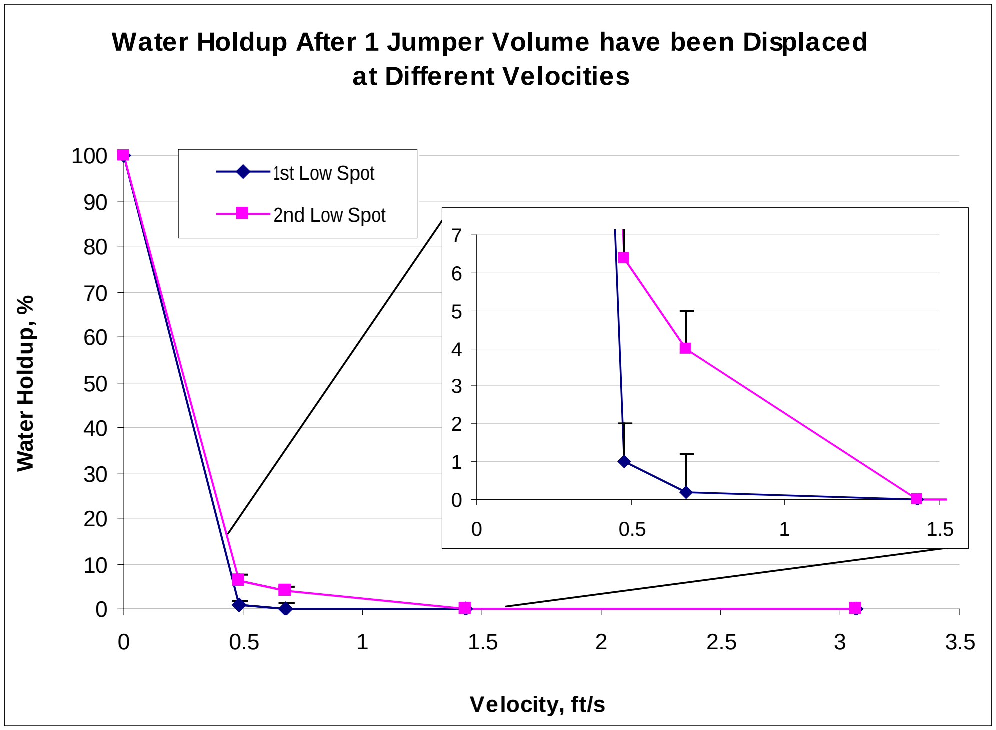


Figure 4-10: Velocity Effect with a 19 cP Oil Restart

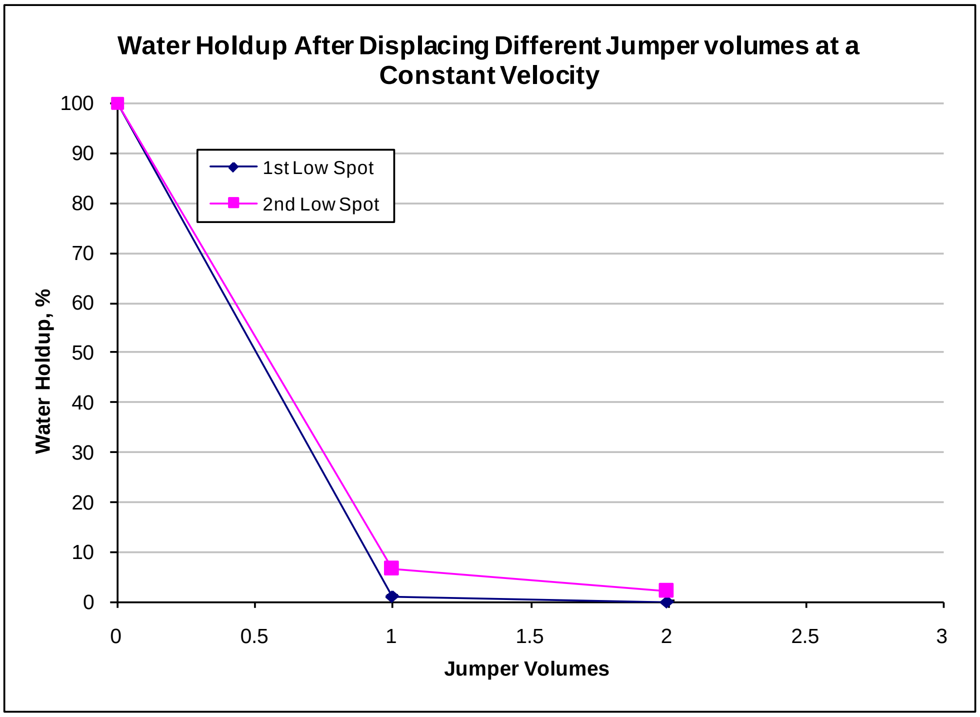
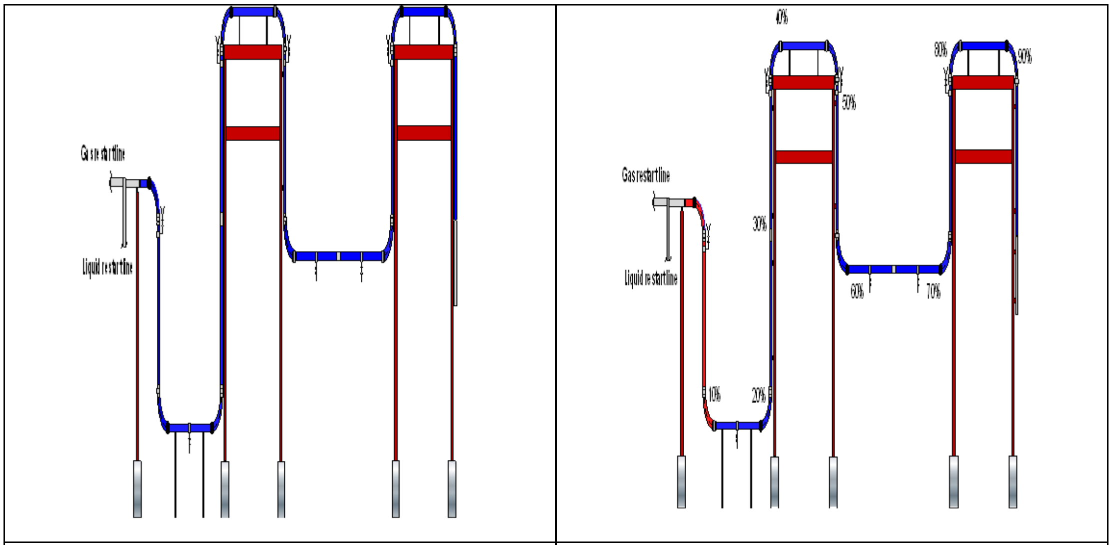


Figure 4-11: Jumper Volumes Displaced Effect with a 19 cP Oil Restart

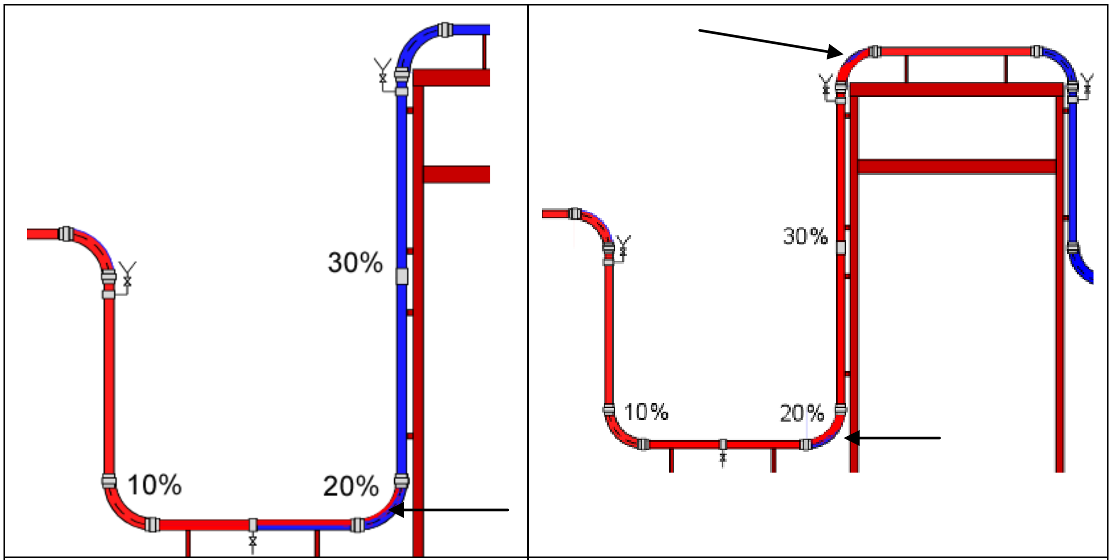
As these experiments were run, it was observed that the 19 cP oil was pushing the water out until it reached the riser lower elbow at which point the oil flowed on the upper-inner side of the elbow while some of the oil was entrained in the water as it was going up the riser. On top of the riser, some of the water accumulated on the outer side of the upper riser elbow for a few seconds before all the water was removed. As the experiment was continued, a free water phase at the outer side of the lower riser elbow was observed. The same behavior repeats as the oil goes in to the second low spot. The difference between the flow behaviors at different velocities is that at high velocities (30 ft/s) the oil is just pushing all of the water out with no apparent entrainment or mixing. Figure 4-15 and 4-16 provide the detailed diagrams of the flow observations.



A. The jumper starts full of water

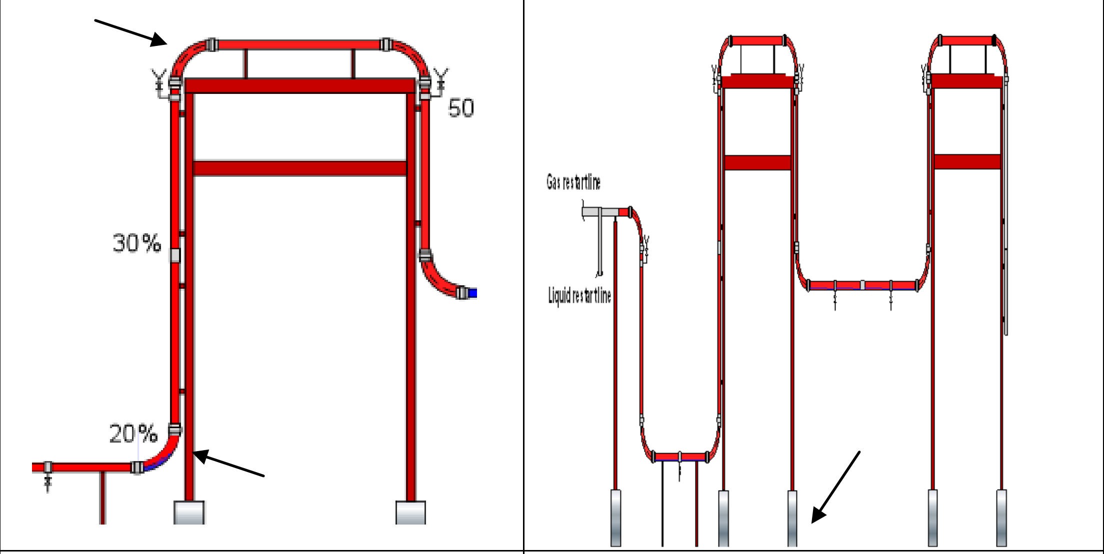
B. As the oil is open to flow to the low spot it starts to push the water out.
The numbers represent the jumper volume percentage displace at that point.

Figure 4-12: Sketch of Water with 19 cP Oil Restart: Low Restart Velocity



C. As the oil gets closer to the riser section it will start to flow on top of the water phase. Some of the oil will also entrain in the water phase, especially at the elbow.

D. As oil gets to top the top horizontal, free water phases can be observed at the riser elbows.



F. As the oil continues to the second low spot, the free water phase disappeared from the top riser elbow, but as experiment continues the lower elbow will continue to have a free water phase.

G. After the oil flow stops and liquids are segregated, just some water will be left and it will accumulate at the bottom of the low spot.

Figure 4-13: Sketch of Water with 19 cP Oil Restart: Low Restart Velocity

4.4 Simulation Results

All the experiments were simulated using OLGA, the Scand Power Technologies (SPT) transient flow simulator. OLGA was found to over-predict the liquid displacement for the gas restart experiments. Simulation results show similar behavior in terms of flow pattern and length of the transition, but the final liquid holdup is lower than that encountered in the experiments. See Figure 4-19 for the experimental and simulated results of the water with gas restart, and Figure 4-20 for the flow behavior comparison graph.

Similarly, the liquid restart simulations over-predict the water left. Simulations show no water left in the first low spot and less than 5% in the second low spot. By increasing the restart velocity or the number of jumper volumes displaced, the simulated final water holdup also decreased as seen in the experiments. The simulated trend was therefore correct but the simulations still over-predict water carry over.

OLGA was developed and validated for large scale systems such as large pipelines and risers. Its performance seems to be affected when predicting water left in the low spot of a jumper. SPT group is currently trying to improve their code to more closely represent these systems. Improvements in the software were not available at the time of the research.

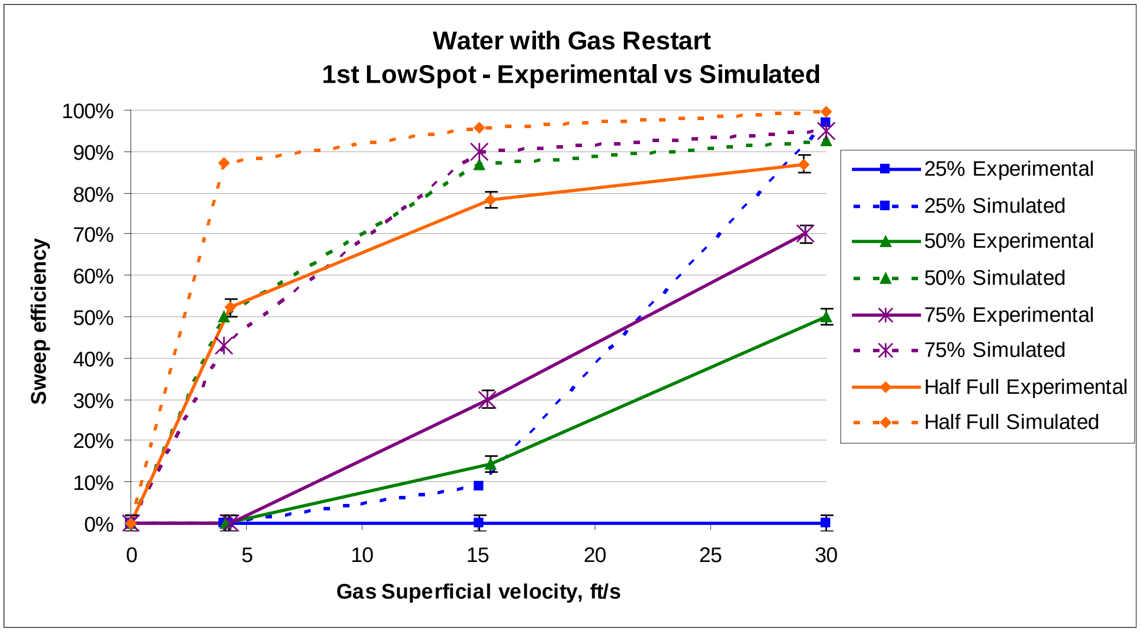


Figure 4-14: Simulated Versus Experimental Data

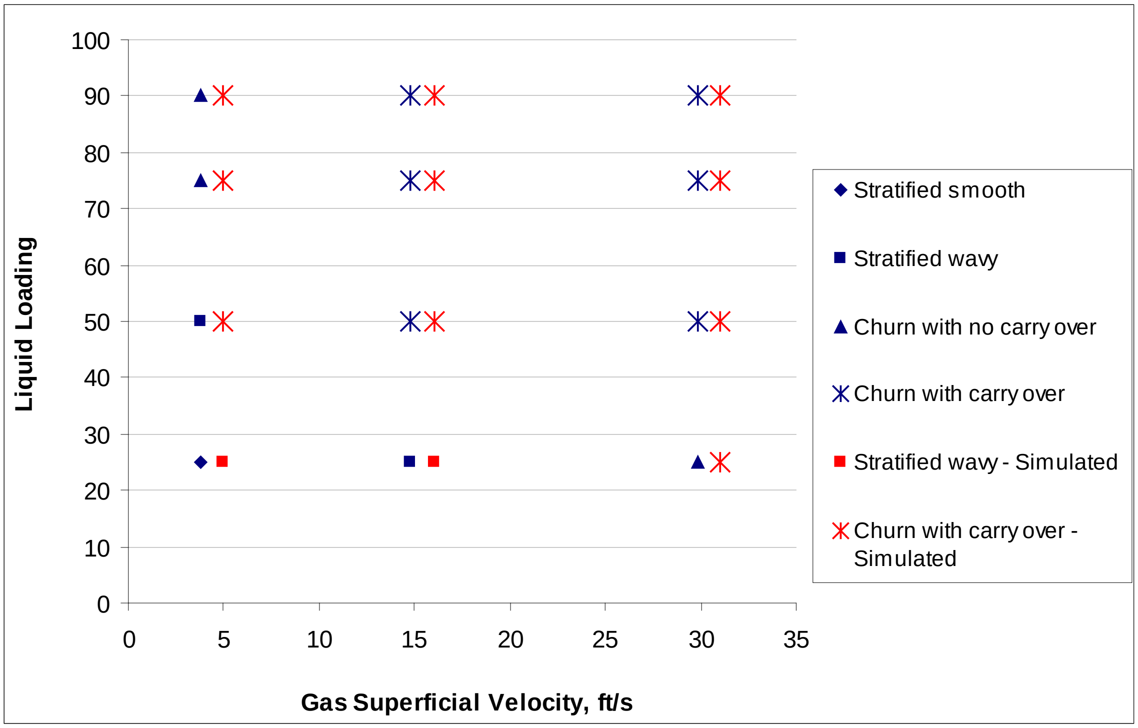


Figure 4-15: Flow Behavior – Simulated Versus Experimental Data

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

5.1.1 Single Phase Gas Restart Experiments

For the gas restart experiments the final liquid holdup is mainly affected by velocity; for the same fluid at the same velocity, the final liquid holdup will be the same regardless of the initial content unless the initial content was below the minimum value below which no liquid is displaced. Because the results are mostly dependent on velocity, similar results were obtained whether the low spots were considered individually or together.

The fluid density and viscosity play an important role in the liquid carry over. Viscosity offers resistance to flow, and density makes it harder to flow the liquids up the riser sections.

Depending on the restart velocity and the initial liquid loading, different flow behaviors were observed. Lower velocities at lower liquid loadings are considered less risky in terms of hydrates risk because their little disturbance to the water phase. If higher liquid loadings and higher flow rates are used, churn flow exists resulting in considerable mixing, which could be a very risky condition.

5.1.2 Two Phase Gas Restart Experiments

For the two phase experiments the final liquid holdup was affected not only by the velocity but also by the water cut. The actual behavior will depend on the oil phase properties. As for single phase experiments, density and viscosity play a more complex role. Higher density and viscosity makes it easier for the oil to induce momentum on the water phase. However, they also offer more resistance to flow of displacement.

Some conditions promoted oil/water separation during the test. This was observed while running experiments at low to medium velocities with the 19 cP oil and at high velocities with the 220 cP oil.

5.1.3 Liquid Restart Experiments

Even a jumper full of water flushed with one jumper volume using the lowest velocity tested (0.48 ft/s) removes at least 70% of the water from the jumper.

Higher liquid restart rates were more effective pushing all the water out of the jumper, but lower restart rates promoted more mixing. If pushing all the water out of the jumper is needed, the recommended procedure would be to use higher flow rates. If the goal is to mix the water with the inhibitor the recommended practice is to flow at lower flow rates (less than 0.5 ft/s) where more mixing was observed.

For the conditions tested, one jumper volume displacement will remove up to at least 70% of the water. More displacement can be obtained by displacing additional jumper volumes. However, each additional jumper volume results in only an additional 5% removal of water.

5.1.4 General

- From the fluids tested the 19 cP oil took the longest to separate; some oil remained as an emulsion (less than 5% of initial content).
- The most critical section in a jumper is the lower riser elbow, because it is where all the mixing takes place and where most of the water accumulates during a test.
- Simulations over predict carry over; more liquid is left in the experiments. Explanations to this phenomenon include: 1) a possible wall wettability effect, 2) the length of the pipe may be too small and 3) the use of pressures below 100 psia.

5.2 Recommendations

- Only 5 liquid restart experiments were run. To understand and determine the best operating parameter to inhibit water, more liquid restart experiments are needed using MEG and/or methanol.
- This thesis covered risky operating conditions and possible locations for hydrate formation. It will be interesting to build a new facility that will be able to form hydrates to identify the areas where the hydrate formation starts, and where they will actually accumulate.
- Cyclopentane should be considered as the hydrate former because it forms hydrates at atmospheric pressure.

- SPT Group should continue on to improve OLGA simulation results specifically for jumper applications.
- Since one of the possible factors affecting the simulations may be testing at atmospheric pressure, a high pressure jumper should be built and experiments conducted.

NOMENCLATURE

LL = Liquid loading

WC = Water percentage in initial liquid

HOL = Liquid hold-up

LS = Low spot of each “U” section

V_{sl} = Superficial liquid velocity

V_{sg} = Superficial gas velocity

ρ = Density

μ = Viscosity

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