Development and Assessment of Well Control Procedures for Extended Reach and Multilateral Wells Utilizing Computer Simulation

by

Dr. Jerome J. Schubert, Texas A&M University
Dr. Jonggeun Choe, Seoul National University, Korea
Mr. Bjorn Gjorv, Texas A&M University
Mr. Max Long, Texas A&M University

Final Project Report
Prepared for the Minerals Management Service
Under the MMS/OTRC Cooperative Research Agreement
1435-01-99-CA-31003
Task Order 85222
Project Number 440

December 2004

OTRC Library Number: 12/04-A146

For more information contact:

Offshore Technology Research Center
Texas A&M University
1200 Mariner Drive
College Station, Texas 77845-3400
(979) 845-6000

or

Offshore Technology Research Center
The University of Texas at Austin
1 University Station C3700
Austin, Texas 78712-0318
(512) 471-6989

A National Science Foundation Graduated Engineering Research Center

DEVELOPMENT AND ASSESSMENT OF WELL CONTROL PROCEDURES FOR EXTENDED REACH AND MULTILATERAL WELLS UTILIZING COMPUTER SIMULATION

EXECUTIVE SUMMARY

Project Description

This project included four tasks.

Task 1 - Perform a literature search of the state of the art in well control for vertical, directional, horizontal, extended reach, and multi-lateral wells.

Task 2 - Modify an existing Windows-based well control simulator that has been developed by Dr. Jonggeun Choe for use in more conventional wellbores to model extended reach and multilateral wells.

Task 3 - Use the simulator to evaluate, compare, and contrast the current well control procedures utilized for vertical, directional, horizontal, extended reach, and multi-lateral wells.

Task 4 - Based on the results of the simulation study, recommendations will be made to improve well control for any situations that warrant improvement, especially for the extended reach and multilateral wells.

Progress

Task 1 – The literature review of the state of the art in well control for vertical, directional, horizontal, extended reach, and multi-lateral wells was completed.

Task 2 – The Windows-based simulator was modified as follows in accordance with the specifications in the project proposal:

- Modify and update an existing conventional simulator using Visual Basic v.6.0
- Modify the simulator to model extended reach wells
- Take into account gas compressibility factor on casing pressure and drill pipe pressure
- Take into account compressibility of mud and formation on well stabilization
- Modify the simulator to handle multilateral wells
- Use the simulator to evaluate and compare current and new procedures, if any, from this study
- Develop a Windows-based well control program with the following capabilities:
  - Ability to modify, save, and retrieve input data files

– Ability to save results as an output files
– Graphical presentation of results

For a full description of the simulator see Part I

Task 3 – We have completed our comparison of well control for vertical, horizontal, extended reach, and multilateral wellbores. A full description can be found in Part II and Part III.

Surface Gas Flow Rates - In Part II, Bjorn Gjerv used the Multilateral/Extend Reach Well Control Simulator to study the effect of different water depth, well depth (vertical and measured), influx volume, circulation rates, and horizontal displacement on the anticipated wellbore pressures during kick circulation for non vertical wells, and compared their differences. Possible instantaneous surface gas flow rates and pressures were reported for the various well scenarios. Results indicated that instantaneous gas flow rates in excess of 7MMSCF/Day could be expected. These results can be used to compare the design capabilities of mud/gas separation to determine the safest and most efficient circulation rates for a specific drilling rig.

Annular Velocities - Part III contains the results of work done by Max Long to determine the minimum annular velocity required to remove gas from a horizontal or near horizontal wellbore. "Olga", a well known multiphase simulator, was used to study the effects of varied hole and pipe size combinations, and hole angles from 80 degree from vertical to 100 degrees from vertical on the efficient removal of gas kicks. Results show that annular velocities of up to 3.4 ft/sec may be required to efficiently remove gas from near horizontal wellbores with relatively large annular spaces.

Task 4 – Work on Task 4 has begun, but has not been completed at this date. Dr. Jonggeun Choe is scheduled to arrive in College Station in early January, 2005, where he and Dr. Schubert will complete this task. This work will be reported in a supplemental report that will be provided to the MMS in mid February, 2005.

Conclusions

Results from this study can be useful in planning well kill operations. The planning process can be summarized as follows:

1. Determine the capacities of the mud/gas separation equipment to determine the maximum circulation rate that this equipment can tolerate.
2. Compare this rate to the optimum circulation rate to remove gas from the horizontal portion of the hole.
    a. If the minimum rate to remove gas from the horizontal section exceeds the maximum rate that can be handled by the surface equipment, the

kill operation should begin at the higher kill rate to remove gas from the horizontal section.
   b. Once the casing pressure begins to rise due to the gas entering the non-horizontal section, the kill rate should be reduced.
3. This dual kill rate would require that a kill rate pressure be taken at more than one rate, and the kill sheet should reflect these kill rate/kill rate pressure combinations.

A thorough explanation can be found in Parts II and III.

Contacts:

Dr. Jerome J. Schubert Department of Petroleum Engineering Texas A&M University, M.S. 3116 College Station, TX 77843-3116 979/862-1195, j-schubert@.tamu.edu fax 979/845-1307 Dr. Jonggeun Choe Seoul National University School of Civil and Geosystems Engineering Seoul 151-742, Korea (82-2)880-8081, jchoe@geofluid.snu.ac.kr fax (82-2)871-8938

Part I

Modifications to an Existing Windows-Based Well Control Simulator to Model Extended Reach and Multilateral Wells

by
Dr. Jonggeun Choe, Seoul National University

As summarized in this report, Task 2 the scope of work has been completed. We have completed the following:

-Modify and update an existing conventional simulator using Visual Basic v.6.0
-Modify the simulator to model extended reach wells
-Take into account gas compressibility factor on casing pressure and drill pipe pressure
-Take into account compressibility of mud and formation on well stabilization
-Modify the simulator to handle multilateral wells
-Use the simulator to evaluate and compare current and new procedures, if any, from this study
-Develop a Windows-based well control program with the following capabilities:

- Ability to modify, save, and retrieve input data files
- Ability to save results as an output files
- Graphical presentation of results

The following is a description of the work performed in Task 2 – Modify an existing pc based well control simulator to model extended reach and multilateral wells. The description is in outline form.

1. The layout of the main menu has been changed for better management and use of the program. It has four groups of command buttons (Fig. 1). Some of the commands are also available from "File" menu on the top of the screen.

1. Input file management
2. Run simulator
3. Simulation results management
4. Exit program

-Now, a user can save current input data as a file (with an extension of *.dat) and retrieve an input data file.
-A user can print out current input data using "Print Input Data" command.
-Input file I/O is valid for conventional well, extended-reach well, and multilateral well trajectories.
-After retrieving any data file, a user can view the current trajectory and wellbore profile using the "Show" menu from the top of the "Main Menu" screen.

2. From the “Main Menu” screen of the simulator, a user can review or change input data. If a user clicks the “Change Input Data” command, the user can see all the input data, currently in use (Fig. 2). It has 9 tabs for input data:

-Option Data
-Fluid and Bit Data
-Pump Data
-Well Geometry Data
-Example of Well Trajectory
-Choke and Formation Data
-Casing and Offshore Data
-Pore and Fracture Pressure Data
-Multilateral Data

Note that the “Multilateral Data” tab is accessible when a user selects the “Multi-Lateral” option from the “Option Data” tab. For multilateral wells, a user can specify 6 lateral wellbores (Fig. 3).

3. For well control simulation of conventional and extended reach wells, a user can use a form shown in Fig. 4. This form is loaded, if a user clicks the “Run Simulator” button from the main menu, when “Single well” option is selected from the input data. For detailed simulation, it can simulate the following scenario. A user can specify the simulation ratio, which implies the ratio simulation speed is greater than real time. For realistic simulation, a user may upload a wellbore profile from the “Menus/Wellbore/Show” menu on the top of the screen in Fig. 4.

-Drilling
-Taking a kick while drilling
-Kick detection by several kick indicators
-Well shut-in
-Well stabilization

4. For well control simulation of tripping pipe and kicks during trips, a user can use a form shown in Fig. 5. This form is loaded, if a user clicks the “Run Simulator” button from the main menu when the “Multi-Lateral” option is selected. As we can see from Fig. 5, a user can simulator tripping operations in detail by selecting any of the available options or operation modes. It can simulate the following:

-Tripping
-Taking a kick while tripping
-Kicks can occur from the main wellbore and from any other branch wellbores if bottomhole pressure is less than the formation pressure
-Kick detection by the combination of several kick indicators
-Well shut-in and stabilization
-Snub/ Strip drillstring back to the bottom of the main wellbore.

The following points out some important features programmed for multilateral well control simulation and tripping.

-The simulator is valid for tripping out (POH: pulling out of hole) and tripping in (TIH: tripping into the hole).
-A user can specify acceleration and maximum trip velocity.
-The simulator computes trip velocity based on given time duration and the simulation ratio.
-A user can run or pause the trip operation at any time.

From a Tab for "Trip Simulation" (Fig. 5),

- A user can select automatic or manual connection
- A user can specify automatic or manual trip tank fill-up
- For any manual operations, a user should take proper actions required. Otherwise, the simulator waits for the user's response.
- The simulator shows detailed operations of tripping (e.g. drillstring movement, trip stand movement, and trip joint movement) as shown Fig. 5.
- The simulator also shows the trip tank and its volume change.
- The program also shows detailed information using four tabs:
    - Trip Simulation
    - Pressure Information
    - Velocity Information
    - Pore/Fracture Pressures

For the Tab for "Pressure Information" the simulator shows:

-Detailed pressure information including surge and swab pressures
-Effective bottomhole pressure (BHP) and formation pressure for multilateral.
-Two plots:
• Surge and Swab pressures (psig) vs. time (minutes)
• Casing seat pressure and bottomhole pressure (psig) vs. time (minutes)

For the Tab for "Velocity Information", the simulator shows a plot of trip velocity (ft/s) and acceleration (ft/s2) vs. time in minutes. All the plots in the simulator such as surge/swab pressure, casing seat pressure, BHP, velocity and acceleration are updated as simulation time goes on.

After detecting a kick by observing several kick indicators, a user can shut the well in. Then the simulator shows the system pressure buildup due to additional influx from the main wellbore (where the drillstring lies) and/or multilateral wellbore.

After well stabilization, a user can trip the drillstring back to the bottom by clicking the "Snub/Strip" command button.

-A user can still choose automatic or manual connection
-A user can specify automatic or manual trip tank fillup

-The simulator can simulate pressure buildup and bleed off due to drillstring movement.

One of the better features of the simulator is that a user can save simulation results in a Microsoft Excel spreadsheet by clicking the “Save Trip Data to MS Excel” command button. The following data are exported. Fig. 6 shows an example of the exported simulation results in MS Excel. Fig. 6 only shows part of the output to demonstrate its usage.

-Total elapsed time (min.)
-Surge and swab pressures (psig)
-Velocity (ft/s) and acceleration (ft/s2)
-Casing seat pressure (psig)
-Bottomhole pressure (psig)

After well stabilization, when the drillstring is tripped back to the bottom, current simulation conditions can be saved using the “Files/Save shut in data” menu. It has extension *.SID and a user can retrieve the “shut in data” for a fast run, without running the entire tripping or conventional well control procedures from this mode. This will be very helpful for sensitivity runs.

5. Complete kick killing procedures for conventional, extended reach, and multilateral wells are now available. For all three cases, it uses the same form as shown in Fig. 7. Similar to other simulation modes, the followings are available.

-A user can specify simulation rate from 1 to 40 times faster than real time.
-A user can load or unload wellbore profile.
-A user can pause or continue the simulation any time.
-Five plots below are updated every 5 minutes but the user can change the interval

- Standard kill sheet pressure
- Pump pressure vs. time
- Surface choke pressure vs. time
- Casing shoe pressure vs. time
- Kick volume in the wellbore vs. time

6. After running the program successfully, a user can review the results in several forms. This is clearly seen from the “Main Menu” in Fig. 1. One of improvements of the program is the capacity to export current results to MS Excel spreadsheet.

-Graphical plots
-Export to MS Excel spreadsheet
-Save the results as a file (*.out)
-Print out the results

Eighteen variables in twelve plots are available for output display (Fig. 8).

-Standpipe pressure and surface choke pressure vs. time
-Casing shoe pressure and BHP vs. time
-Top and bottom locations of the kick in the wellbore vs. time
-Mud return rate (gpm) and gas return rate (Mscf/day) vs. time

-Pump pressure and mud volume pumped vs. time
-Pressures at the top of the kick and at mud line vs. time
-Kick density vs. time
-Height of kick in the well vs. time
-Kick volume vs. time
-Choke open % vs. time
-Kick influx vs. time
-Standard kill sheet pressure vs. time

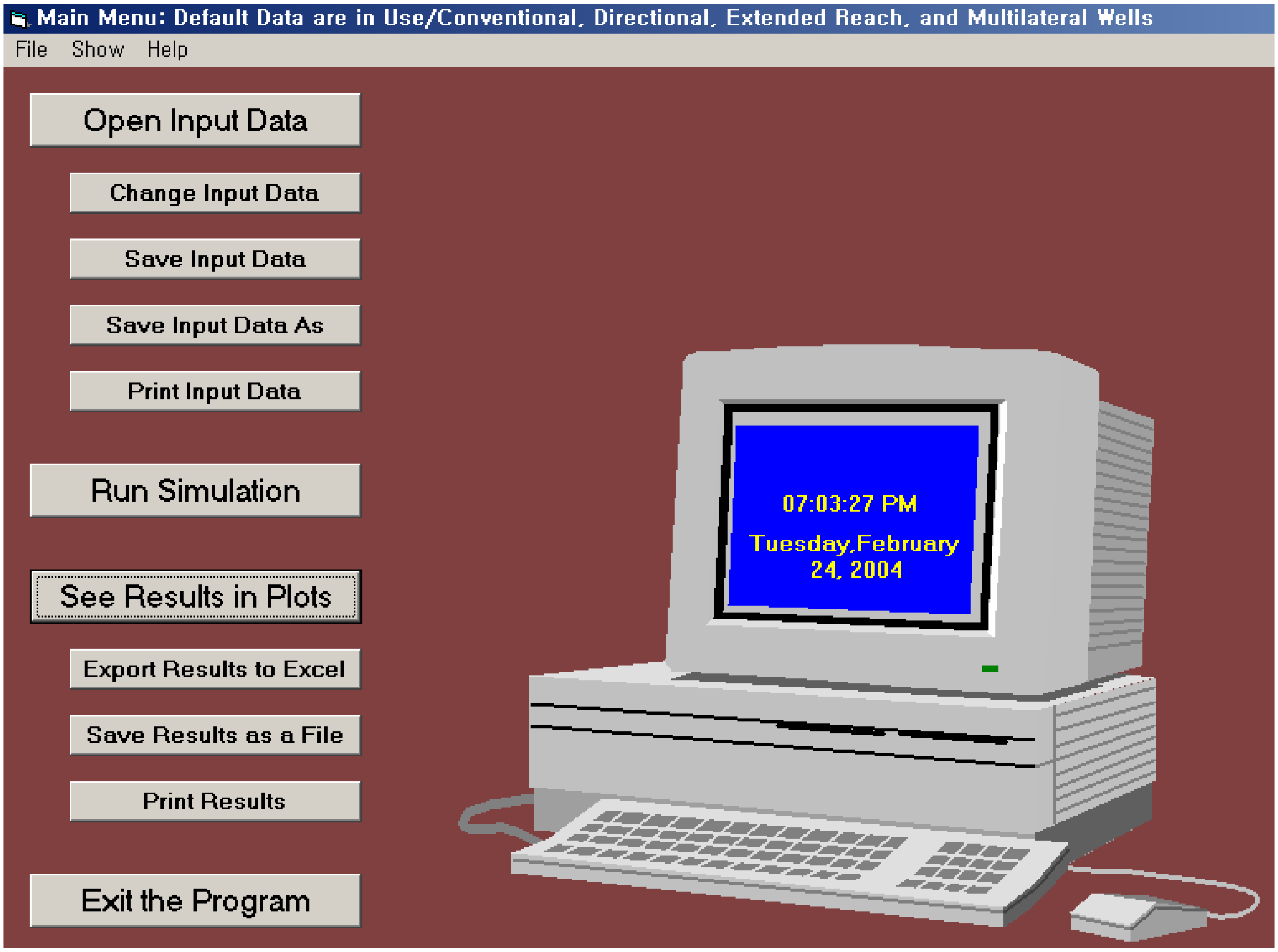


Fig. 1 – “Main Menu” screen.

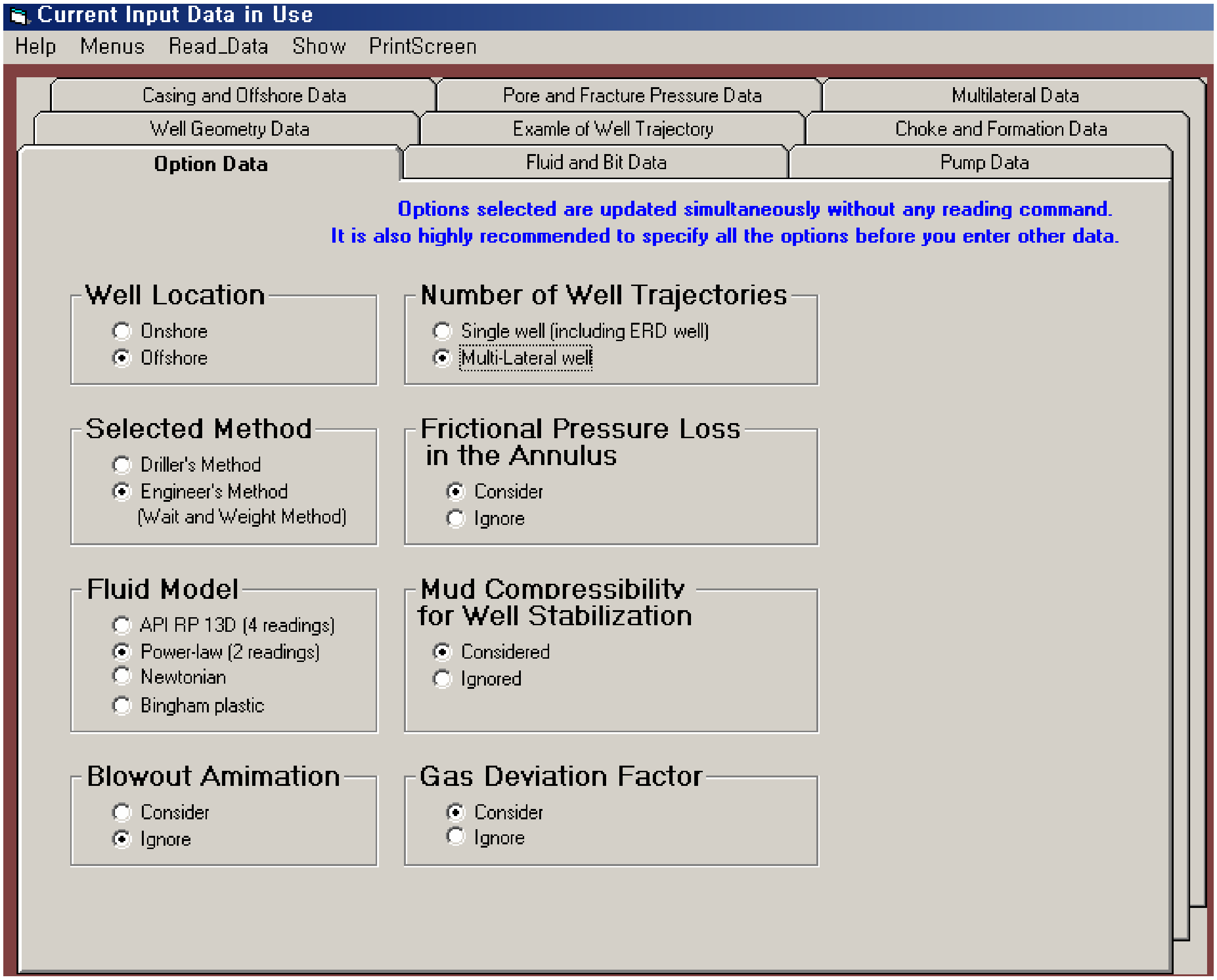


Fig. 2 – Input data screen with nine tabs. Note that each tab is accessible by clicking with the mouse.

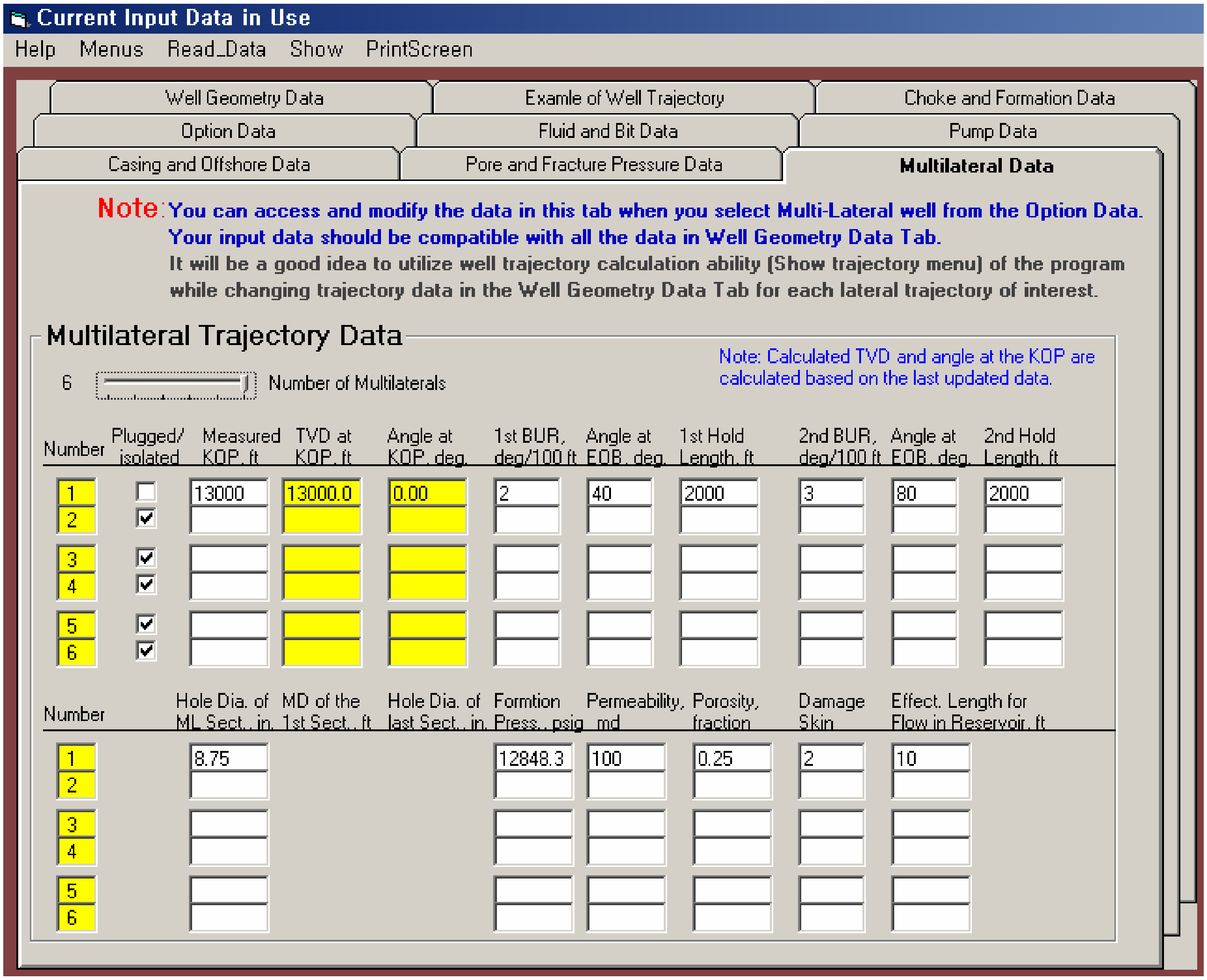


Fig. 3 – A tab for multilateral well trajectories. Note that a user can specify 6 laterals with different specifications.

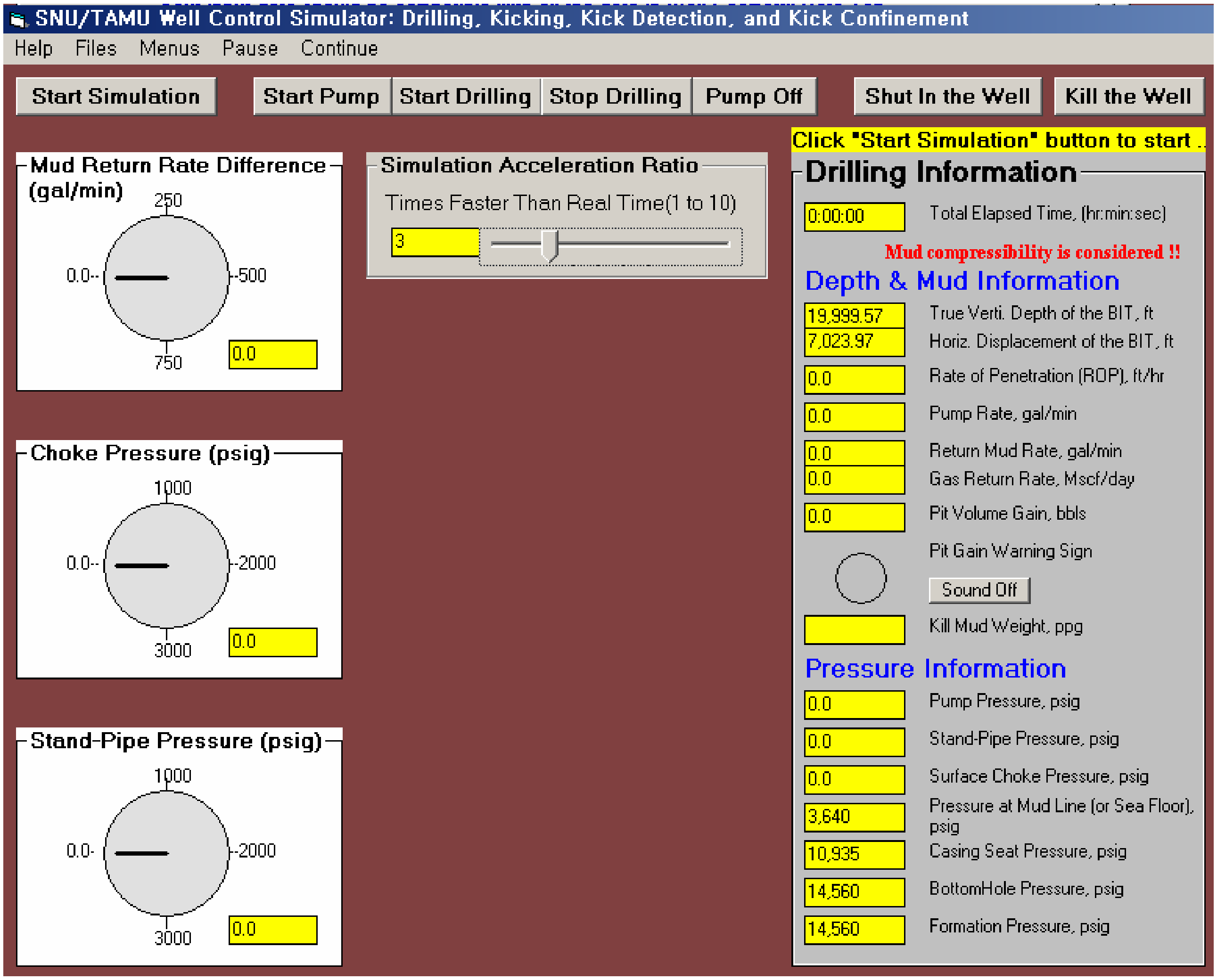
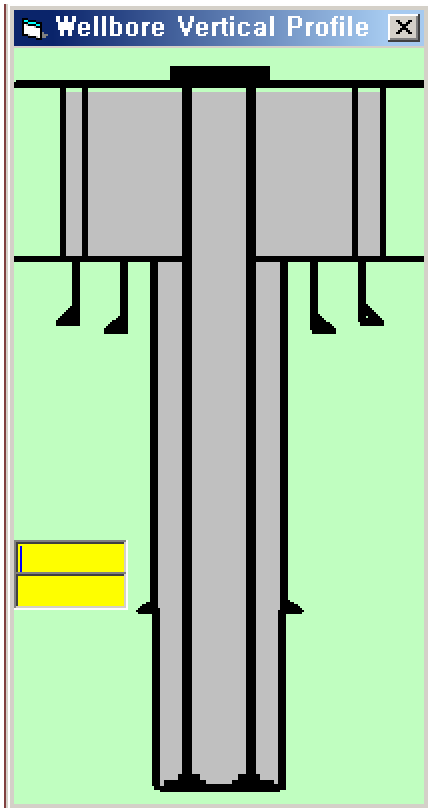


Fig. 4 – A screen for conventional and extended reach well trajectories.



Wellbore profile: This form can be loaded or uploaded during well control simulation.

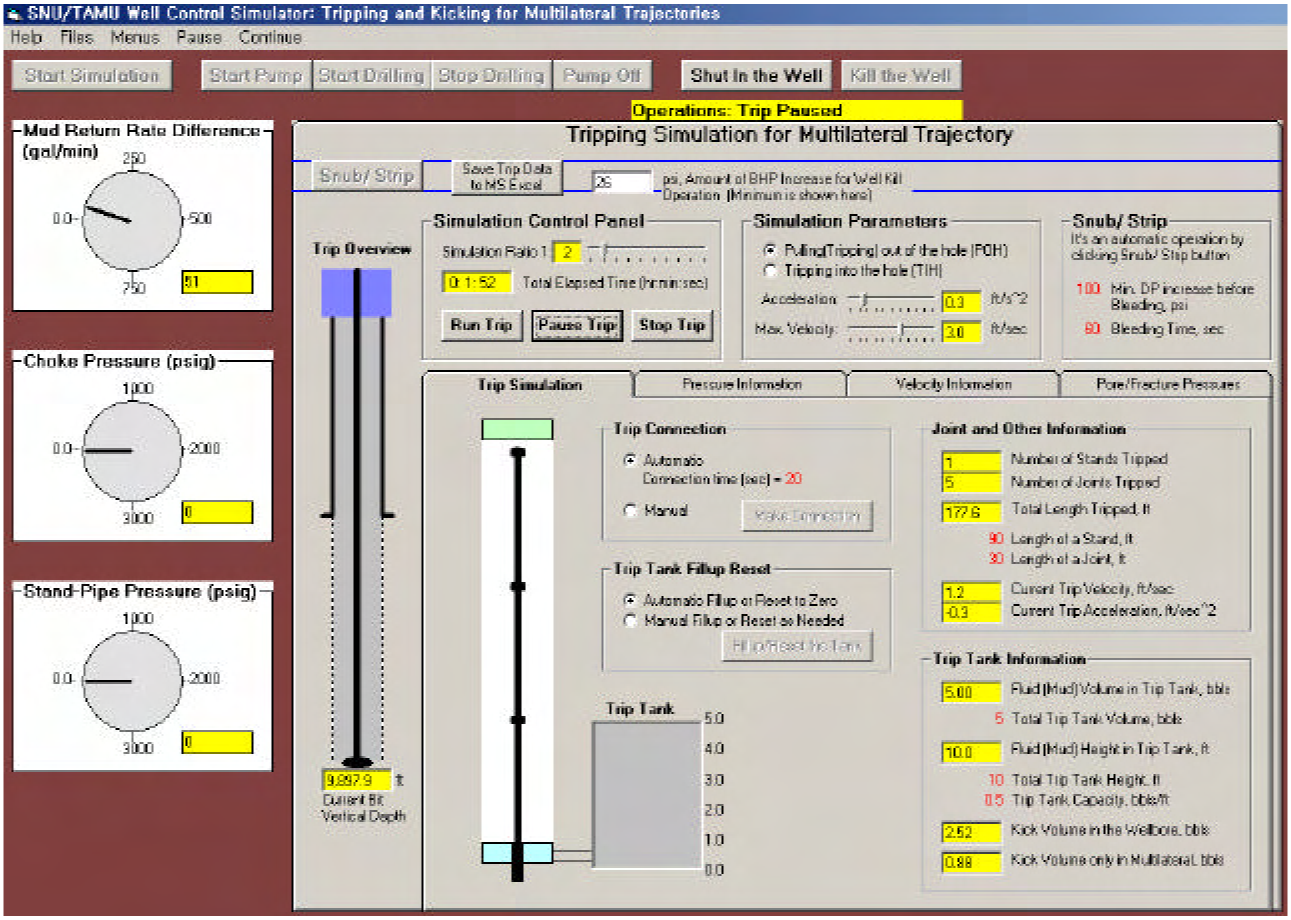
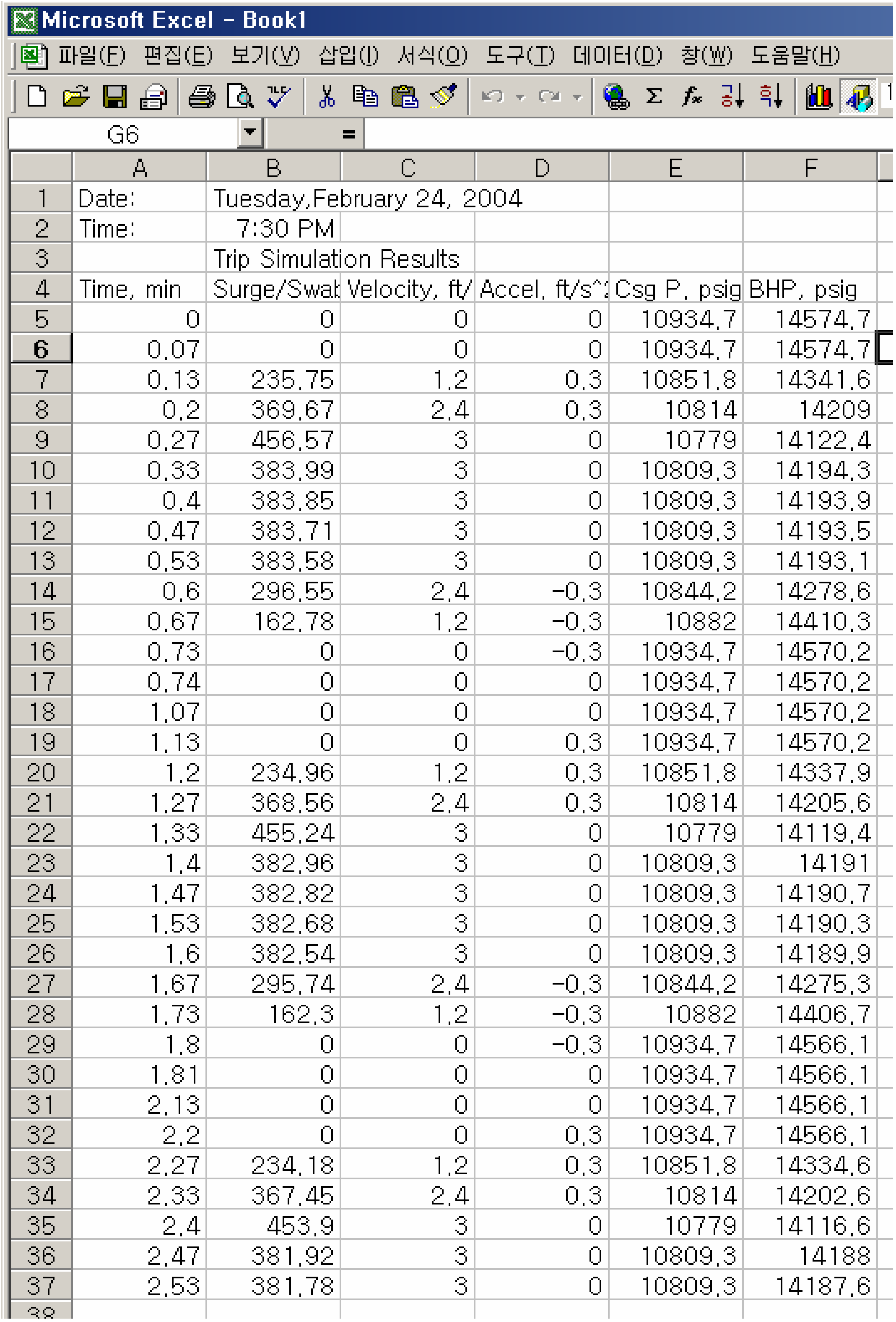


Fig. 5 – The screen for the simulation of tripping. Note that there are four tabs for additional information.



	A	B	C	D	E	F
1	Date:	Tuesday,February 24, 2004				
2	Time:	7:30 PM				
3		Trip Simulation Results				
4	Time, min	Surge/Swat	Velocity, ft/	Accel, ft/s^	Csg P, psig	BHP, psig
5	0	0	0	0	10934,7	14574,7
6	0,07	0	0	0	10934,7	14574,7
7	0,13	235,75	1,2	0,3	10851,8	14341,6
8	0,2	369,67	2,4	0,3	10814	14209
9	0,27	456,57	3	0	10779	14122,4
10	0,33	383,99	3	0	10809,3	14194,3
11	0,4	383,85	3	0	10809,3	14193,9
12	0,47	383,71	3	0	10809,3	14193,5
13	0,53	383,58	3	0	10809,3	14193,1
14	0,6	296,55	2,4	-0,3	10844,2	14278,6
15	0,67	162,78	1,2	-0,3	10882	14410,3
16	0,73	0	0	-0,3	10934,7	14570,2
17	0,74	0	0	0	10934,7	14570,2
18	1,07	0	0	0	10934,7	14570,2
19	1,13	0	0	0,3	10934,7	14570,2
20	1,2	234,96	1,2	0,3	10851,8	14337,9
21	1,27	368,56	2,4	0,3	10814	14205,6
22	1,33	455,24	3	0	10779	14119,4
23	1,4	382,96	3	0	10809,3	14191
24	1,47	382,82	3	0	10809,3	14190,7
25	1,53	382,68	3	0	10809,3	14190,3
26	1,6	382,54	3	0	10809,3	14189,9
27	1,67	295,74	2,4	-0,3	10844,2	14275,3
28	1,73	162,3	1,2	-0,3	10882	14406,7
29	1,8	0	0	-0,3	10934,7	14566,1
30	1,81	0	0	0	10934,7	14566,1
31	2,13	0	0	0	10934,7	14566,1
32	2,2	0	0	0,3	10934,7	14566,1
33	2,27	234,18	1,2	0,3	10851,8	14334,6
34	2,33	367,45	2,4	0,3	10814	14202,6
35	2,4	453,9	3	0	10779	14116,6
36	2,47	381,92	3	0	10809,3	14188
37	2,53	381,78	3	0	10809,3	14187,6

Fig. 6 – Example of trip simulation results exported into MS Excel spreadsheet..

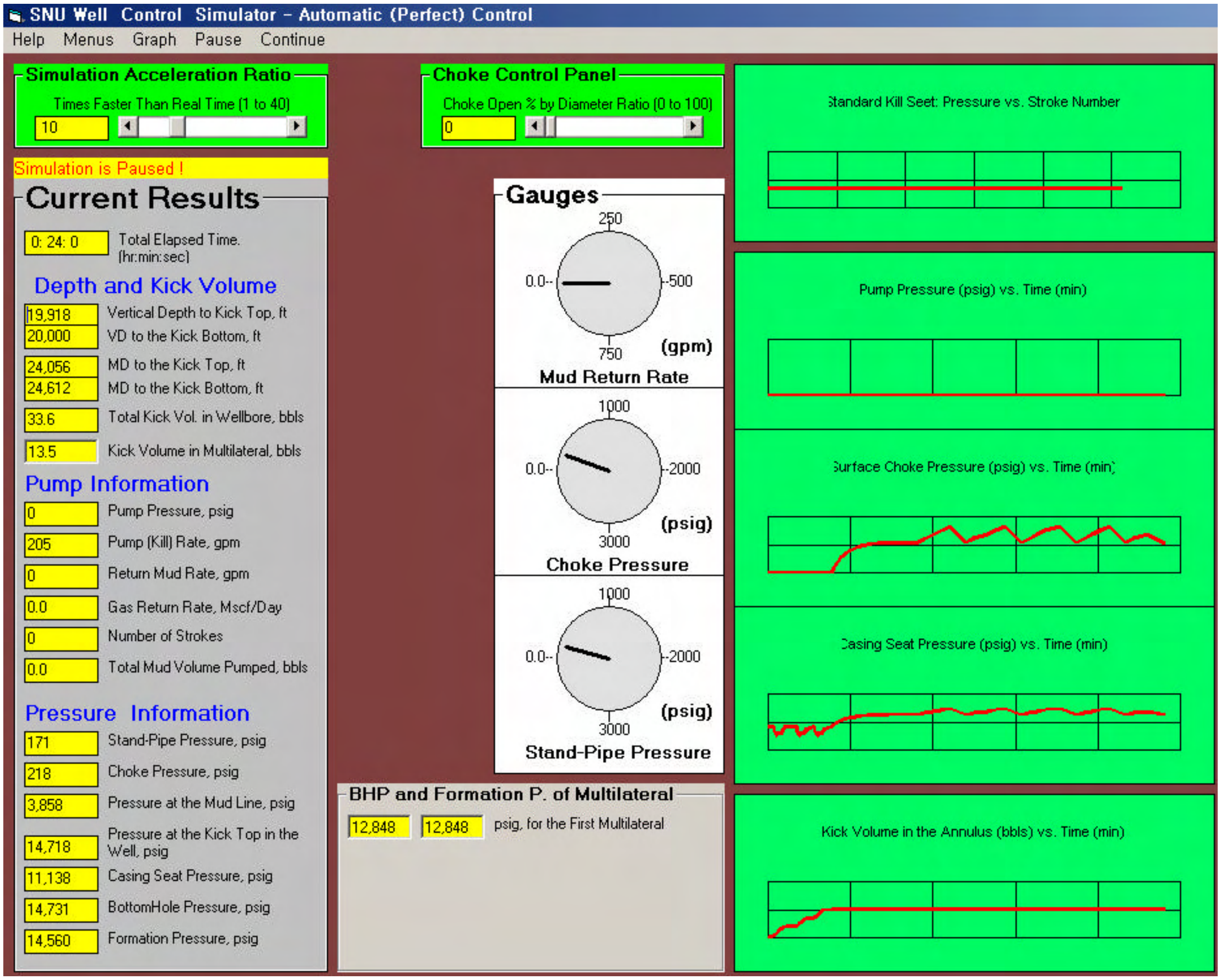


Fig. 7 – The screen for the simulation of kick circulation out and well kill procedures. Note that we can also see BHP and formation pressure of multilateral wellbores, if any.

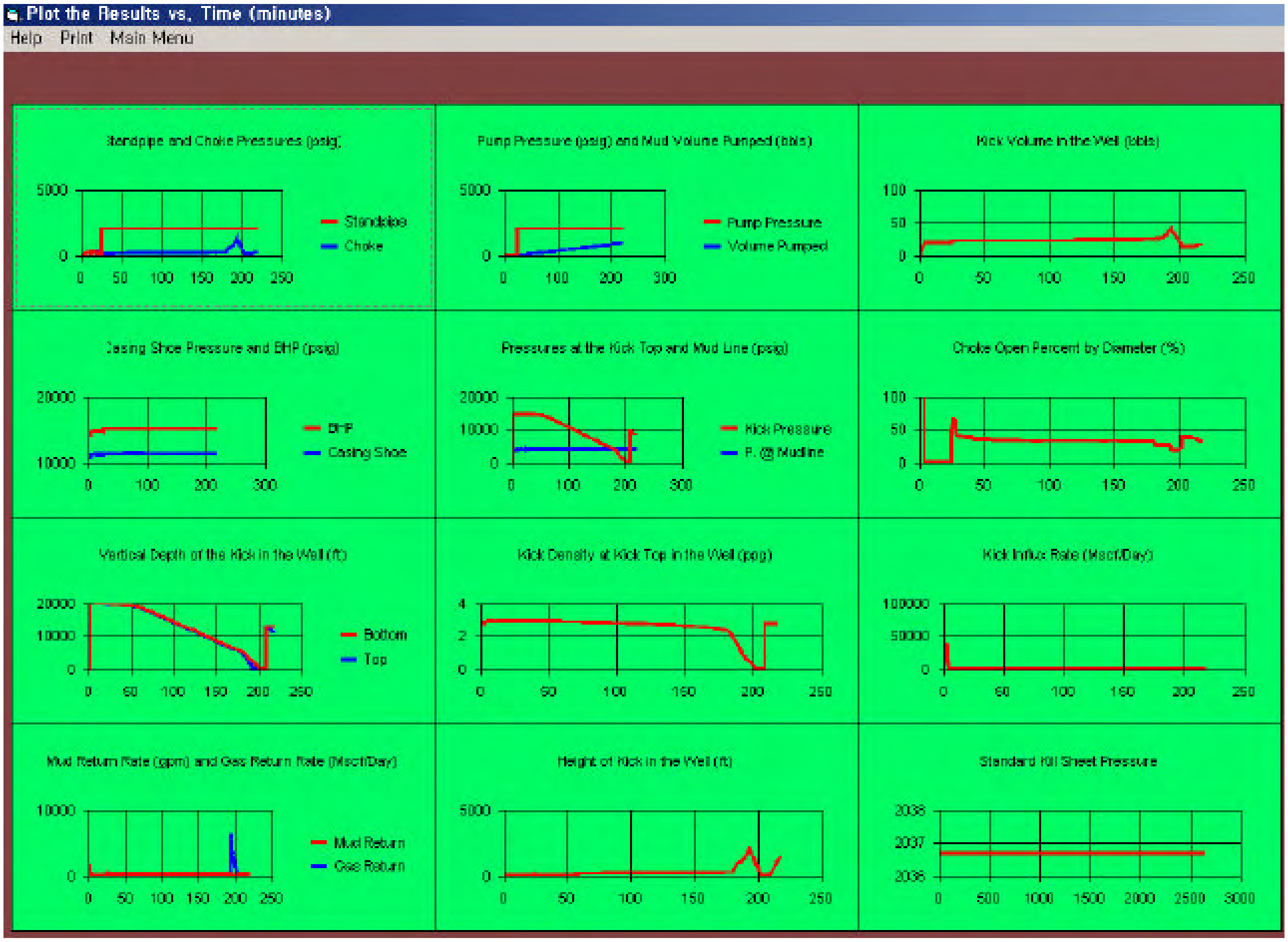


Fig. 8 – Twelve plots for results display. Total 18 variables are available and a user can see enlarged plot by double-clicking each plot.

PART II

WELL CONTROL PROCEDURES FOR EXTENDED REACH WELLS

A Thesis

By

BJORN GJORV

Submitted to the Office of Graduate Studies of Texas A&M University in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2003

Major Subject: Petroleum Engineering

WELL CONTROL PROCEDURES FOR

EXTENDED REACH WELLS

A Thesis

by

BJORN GJORV

Submitted to Texas A&M University
in partial fulfillment of the requirements
for the degree of

MASTER OF SCIENCE

Approved as to style and content by:

Hans C. Juvkam-Wold (Chair of Committee)	Jerome J. Schubert (Member)
Jean-Louis Briaud (Member)	Hans C. Juvkam-Wold (Head of Department)

August 2003

Major Subject: Petroleum Engineering

ABSTRACT

Well Control Procedures for Extended Reach Wells.

(August 2003)

Bjorn Gjorv, B.S., Stavanger University College, Norway

Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

The limits of directional drilling continue to be pushed back as horizontal or near-horizontal reservoir sections are being drilled, cased, cemented and completed to tap reserves at extreme distances. Continuous development of new technology and adopting a technical-limit approach to performance delivery are key elements for the success and further development of extended-reach drilling projects.

For this study a two-phase well control simulator was used to evaluate different kick scenarios that are likely to occur in extended-reach wells. An extensive simulation study covering a vide range of variables has been performed. Based on this investigation together with a literature review, well-control procedures have been developed for extended-reach wells. The most important procedures are as follows:

- Perform a “hard” shut-in when a kick is detected and confirmed.
- Record the pressures and pit gain, and start to circulate immediately using the Driller’s Method.
- Start circulating with a high kill rate to remove the gas from the horizontal section.
- Slow down the kill circulation rate to ½ to $^{1}/_{3}$ of normal drilling rate when the choke pressure starts to increase rapidly.

The simulator has been used to validate the procedures.

DEDICATION

This work is dedicated to my grandfather, Bjarne L. Rabbe, for his support and love throughout the years.

ACKNOWLEDGMENTS

Sincere thanks go to my advisor, Dr. Hans C. Juvkam-Wold, for his continuous support and encouragement, and mostly, for his intellectual advice.

Dr. Jerome Schubert, thank you for giving this project to me and for the support you have provided.

Dr. Jean-Louis Briaud, thanks for all your help and for being part of my committee.

To my family back home, thank you for the support while I have been here.

I would like to thank Martin Alvarado and his family for the complete support and hospitality; your friendship has been of invaluable importance for me the two years I stayed here.

Ray Tommy Oskarsen, thank you for being such a cooperative office mate and giving me the moral and intellectual influence I needed to finish.

I would also like to thank Minerals Management Service and OTRC for funding this project.

TABLE OF CONTENTS

Page

Page

LIST OF TABLES

Page

LIST OF FIGURES

Page

INTRODUCTION

Introduction to Extended Reach Drilling (ERD)

Extended reach (ERD) wells are defined as wells that have a horizontal departure (HD) at least twice the true vertical depth (TVD) of the well.[1] ERD wells are kicked off from vertical near the surface and built to an inclination angle that allows sufficient horizontal displacement from the surface to the desired target. This inclination is held constant until the wellbore reaches the zone of interest and is then kicked off to near horizontal and extended into reservoir. This technology enables optimization of field development through the reduction of drilling sites and structures, and allows the operator to reach portions of the reservoir at a much greater distance than possible with a conventionally drilled directional well. These efficiencies increase profit margins on viable projects and can make the difference whether or not the project is financially viable.[2]

It is well known that ERD introduces factors that can compromise well delivery, and the first challenge prior to drilling an ERD well is to identify and minimize risk.[3] Technologies that have been found to be critical to the success of ERD are torque and drag, drillstring design, wellbore stability, hole cleaning, casing design, directional drilling optimization, drilling dynamics and rig sizing.[4] Other technologies of vital importance are the use of rotary steerable systems (RSS) together with measurement while drilling (MWD) and logging while drilling (LWD) to geosteer the well into the geological target.[5] Many of the wells drilled at Wytch Farm would not have been possible to drill without RSS,[6] because steering beyond 8,500 m was not possible as axial drags were too high to allow the orientated steerable motor and bit to slide.[7]

Drilling ERD wells in deep waters is the next step, even though there are some experiences offshore, they are related to wells drilled on shallow waters from fixed platforms. In Brazil, where the major oil fields are located in deep waters, ERD wells might be, in some cases, the only economically viable solution.[8]

This thesis follows the style and format of *SPE Drilling & Completion.*

BP's Wytch Farm oilfield

The Wytch Farm field was discovered in 1974 and is located southwest of London on the UK coastline near Poole, England. It is an area of outstanding natural beauty with many sites of special scientific interest. About a third of the Sherwood reserves are under Poole Bay, where an artificial island was first planned to be developed **(Fig. 1)**. Drilling ERD wells from an onshore location may have reduced the development costs by as much as $150 million.[4]

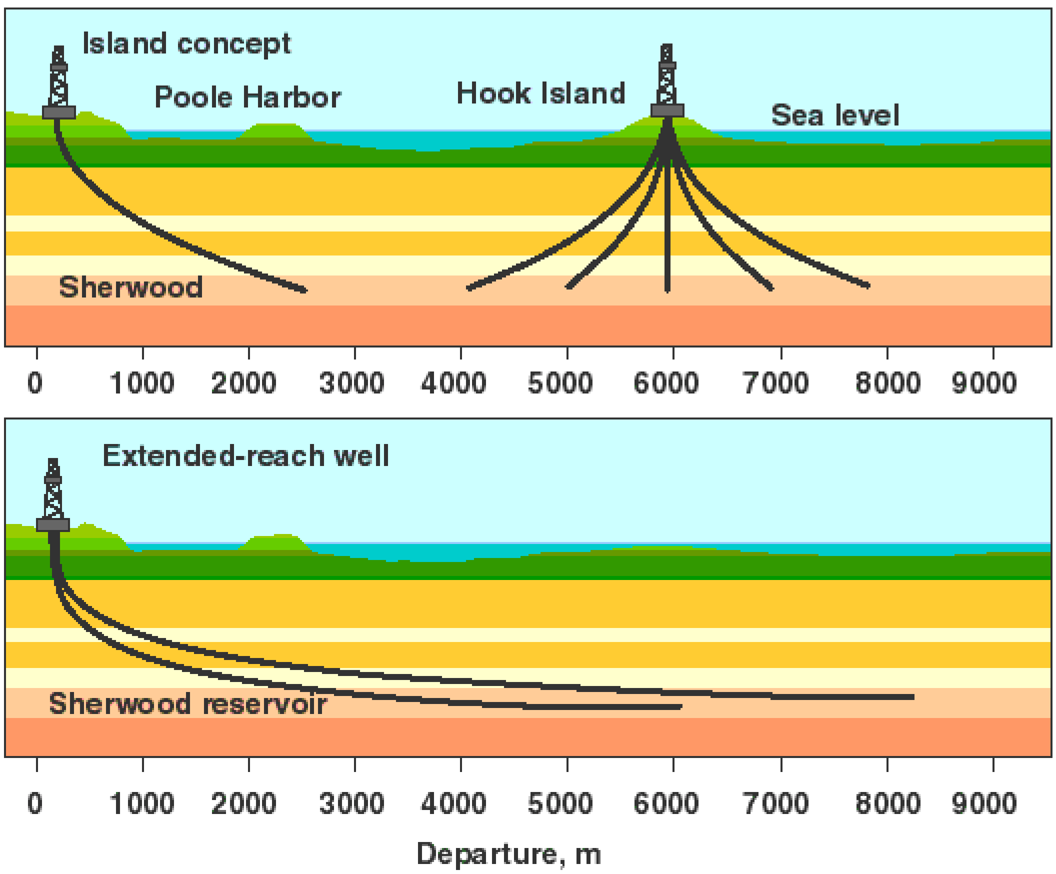


Fig. 1 – The artificial island development concept versus the ERD wells (from Allen *et al.*[9]).

The step-out of wells has increased dramatically during the years. The first well in 1993 had a departure of 3.8 km, M5 in 1995 reached 8 km, M11 in 1997 broke the 10-km milestone, and M16 in 1999 became a record breaking well drilled to 11,278 m.[7] **Fig. 2** shows the industry comparison of ERD wells, where the Wytch Farm wells have the most extreme ratio of departure to TVD.

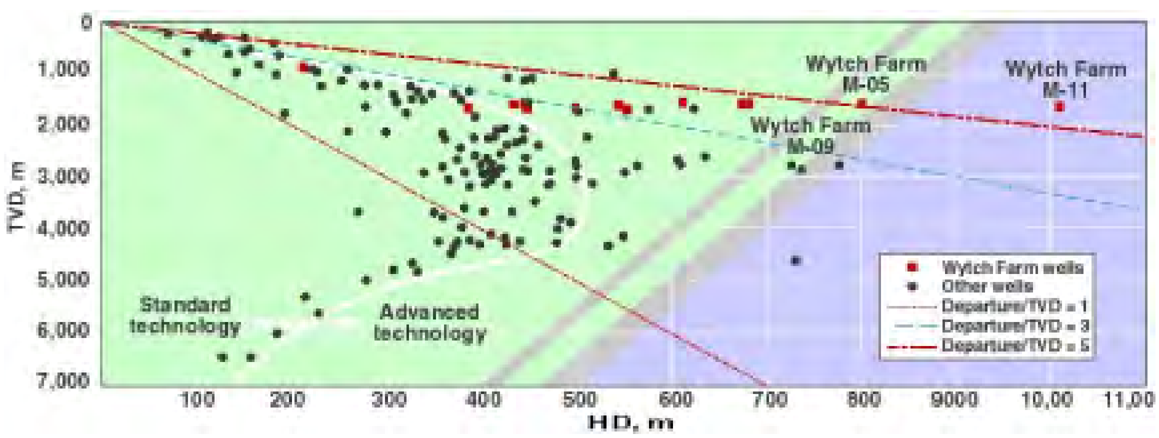


Fig. 2 – Industry comparison of ERD wells (from Allen *et al.*[9]).

Well-control challenges in ERD wells

A gas kick represents probably the most dangerous situation that can occur when drilling a well since it can easily develop to a blowout if it is not controlled promptly. ERD wells are more prone to kicks and lost-circulation problems than more conventional and vertical wells, but have some advantages when the well takes a kick because gas migration rates are lower.[10] The maximum migration velocity occurs at 45^o inclination and the velocity rapidly drops to zero as the wellbore approaches horizontal,[11] and a kick will rise faster in a viscous mud than in water.[12] Significant migration rates are found at inclinations up to 80^o; the inclination which efficiently stops migration is close to 90^o in smooth wellbores and may be as low as 70^o if the wellbore is extremely rugged.[13] The gas will then be trapped and accumulate in the top side of the hole until its original volume is depleted **(Fig. 3)**. The trapped gas may be brought out of the traps and circulated up in the well when the normal drilling operation resumes. This may lead to an underbalanced situation that could result in another kick.

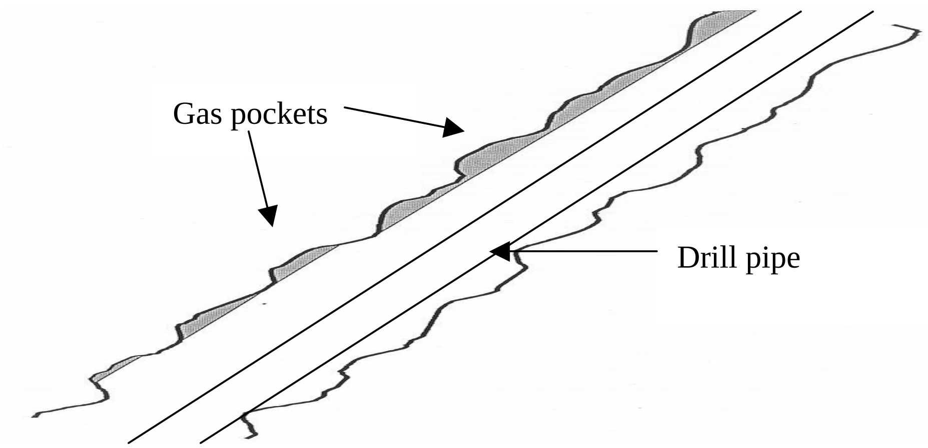


Fig. 3 – Gas migration in a highly inclined and rugose wellbore.

In ERD and horizontal wells the maximum casing-shoe pressure during a well control procedure is usually smaller and the choke pressures remain lower for a longer period of time than in a vertical well. The reason for this is that the TVD at casing shoe is often very close to the TVD of the influx zone. As long as the kick is in the horizontal section, the shut-in casing pressure (SICP) and shut-in drill pipe pressure (SIDPP) are about the same because hydrostatic pressure on both sides of the U-tube are the same. **Fig. 4** shows a horizontal well that has taken a kick and is shut-in.

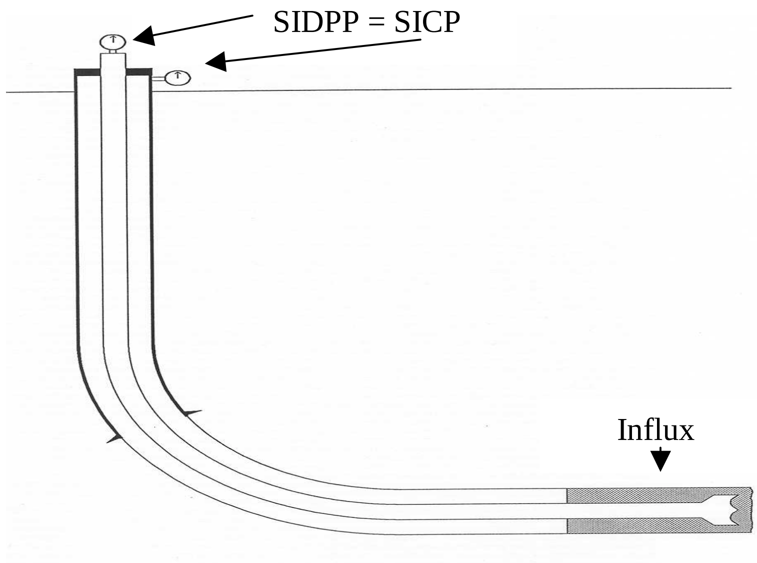


Fig. 4 – Well shut in after taken a kick in a horizontal well.

Simulating wellbore pressures during a kill procedure

As a result of studies conducted for several years, well-control procedures have been developed to prevent such incidents from occurring, or if a kick is taken, how to control it.[14] These studies of the kick development and the factors influencing the mechanisms that control the kick usually include full-scale kick experiments,[15] kick simulators,[16-21] or physics like gas-rise velocity.[11-13] Another phenomenon that also has been investigated through experiments is counter-current and co-current gas kick migration in high angle wells.[22-23] Further there has been conducted an experimental and theoretical study of two-phase flow in horizontal or slightly deviated fully eccentric annuli.[24]

The two-phase well-control simulator used for this research was developed by Choe and Juvkam-Wold.[25, 26] The simulator can handle vertical wells, directional wells, extended-reach wells, and horizontal wells with different buildup rates for onshore or offshore wells. The simulator also provides the theoretical kill sheet for any selected well geometry. It demonstrates the basic concepts of well control and shows the pressure and volume responses of the kick with time.

WELL CONTROL METHODS

Introduction

Well control has always been a very important issue in the oil and gas industry because it involves enormous amount of money, people's safety, and environmental issues. Well-control fundamentals have been understood and taught for almost half a century, but still well control problems and blowouts occur in the industry. Substantially, all blowouts are related to human failure and error relative to well operations.[27] **Table 1** shows the incidents of loss of well control reported to Mineral Management Service (MMS) from 1992 to June 2003. Loss of well control means either of the following[28]:

- Uncontrolled flow of formation or other well fluids. Flow may be between two or more exposed formations or it may be at or above the mudline. Includes uncontrolled flow resulting from failures of either surface or subsurface equipment or procedures.
- Flow of formation or other well fluids through a diverter.

Table 1 – Losses of well control in the Gulf of Mexico and Pacific Region (from MMS[28]).

Losses of Well Control												
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
GOM	3	3	0	1	4	5	6	5	8	9	6	3
PAC	0	0	0	0	0	0	1	0	1	1	0	0
Total	3	3	0	1	4	5	7	5	9	10	6	3

Kick causes

A kick is defined as an unscheduled entry of formation fluids into the wellbore which must be contained initially by shutting in the surface equipment and removed from the wellbore in controlled manner.[10, 14] A blowout might occur if the kick is not controlled properly. Blowouts cause valuable resources to be wasted, harm the environment, damage equipment, and even endanger the lives of rig personnel. Blowouts can be surface blowouts or underground blowouts.

A surface blowout is an uncontrolled flow of formation fluids to the surface, and the consequences are sometimes catastrophical. If formation fluids flow into another formation, and not to the surface, the result is called an underground blowout. This crossflow from one zone to another can occur when a high-pressure zone is penetrated, the well flows, and the drilling crew reacts promptly and closes the blowout preventers (BOPs). The pressure in the annulus builds up until a weak zone fractures, and depending on the pressure, the flowing formation can continue to flow to the fractured formation. Underground blowouts are historically the most expensive problem in the drilling arena, surpassing even the cost of surface blowouts. In many cases the only technique to kill an underground blowout is to drill a secondary relief well.

Kicks may occur if two requirements are fulfilled. The wellbore pressure has to be lower than the pore pressure, and the formation has to be sufficiently permeable for the formation fluids to flow at a significant rate. **Fig. 5** shows the influx rate for various kick sizes, illustrating that the influx rate increases rapidly with increased kick size.

While circulating, the pressure at any point in the wellbore is obtained by adding the hydrostatic pressure to the annular friction losses of above the depth of interest. This additive pressure can be converted to a convenient mud weight equivalent termed the equivalent circulating density (ECD).

The main reason kicks occur while drilling is an insufficient ECD. Drilling into abnormally pressured permeable zones can cause a sudden pressure differentiation where the formation pressure is higher than the bottomhole pressure (BHP), or in in the term of density, the ECD is too low. Increasing the ECD is usually not difficult, and can easily be done by increasing the mud weight and/or increase pump rate. Heavier mud weight increases the hydrostatic pressure, and higher pump rate increases the system pressure loss.

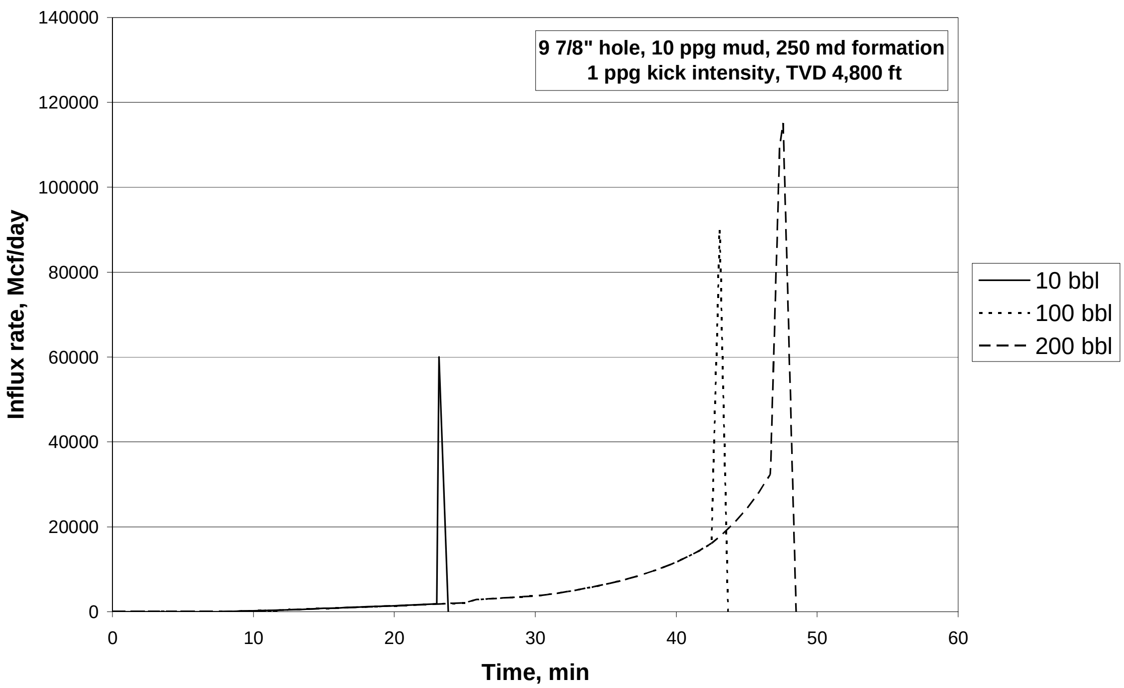


Fig. 5 – Influx rate for various kick sizes in an onshore ERD well.

Swabbing is another common reason for taking a kick. The drillpipe acts like a piston when it is moved in a wellbore filled with mud. When pulling out of the hole, the mud has to be displaced past the bit. If the drillstring is pulled too fast, the pressure is immediately reduced below or behind the bit. This swabbing effect can cause the formation to flow. The best way to avoid swabbing is to keep the hole full at all time and pull slowly until the casing shoe is reached.

Severe lost circulation is a more difficult problem to deal with. Lost circulation occurs when drilling into natural fissures, fractures, caverns, or a depleted formation, and mud flows into the newly available space. If the hole does not remain full of fluid, the vertical height of the fluid column is reduced and the pressure exerted on the open formations is reduced. This reduction in hydrostatic pressure can cause formation fluids to flow from another zone into the wellbore while the loss zone is taking mud, which can result in a catastrophic loss of well control. If an overbalance is not obtained by continuously pumping drilling fluid or water into the annulus, an underground blowout is most likely to be the result.

Kick detection and verification

Detecting a kick early is the most critical factor in determining whether or not the situation is manageable, because early shut-in limits the volume of influx taken.

One of the first indications of a kick to occur is a sudden increase in rate of penetration (ROP), termed drilling break. The influx of formation fluids tends to clean the bottom hole very efficiently, and in combination with the underbalanced condition, the bit cuts the rock more easily and faster. An increase in ROP does not necessarily mean that a kick is occurring, but could just indicate that another formation is encountered.

If the return flow rate from the wellbore increases to a greater level than what is pumped into the wellbore, there is an influx of formation fluids into the wellbore. The difference in pump rate and return rate is the rate at which the influx is entering the wellbore at bottomhole conditions. This excessive volume of mud that the influx displaced over a period of time is called the pit gain. Constantly monitoring the balance between well inflow and outflow is very important in early kick detection.

While tripping out of the hole, the drillstring is removed from the wellbore. The drillstring represents a specific volume of steel displacing an equal volume of mud. To prevent the BHP from dropping below pore pressure, this volume of steel has to be replaced with mud to make sure that the hydrostatic column in the wellbore is not dropping. If the wellbore takes less mud than the displacement of the pipe pulled out from the well, it may be an indication of swabbing. Action has to be taken immediately to prevent the well from flowing with the pipe off bottom or out of the hole.

Another indication that a kick is taking place is an increase in hook load. This reduced buoyancy in the wellbore is caused by the influx of fluid with a lower density than the mud. This weight indicator may not be a good kick detector, because the change in hook load will probably not be seen until the well has taken a large kick.

MWD is a relatively new technology that can be helpful in early detection of kicks. The mud-pulse telemetry tool takes downhole measurements, converts the data to coded binary signals, and transmits the information via mud pulses to the surface where a receiver decodes the signals so the information can be viewed and analyzed on a computer. The great advantage of MWD is that it delivers the desired information in real time while drilling.

Shut-in procedures

As soon as an influx is detected and confirmed, the well shut-in procedure must be performed. Situations when shutting in the well is not an option include shallow gas kicks and when the surface casing has not been set. In those cases the well has to be killed “on the fly” by increasing the ECD, which involves increasing mud weight and circulation rate. A diverter is used to guide the returning wellbore fluids away from the rig, following the direction of the wind. If the well is shut in, the outcome is most likely to be a combination of underground and surface blowout, where the conductor casing shoe is fractured and the blowout breaks through the formation up to the surface.

The two principal methods for shutting in the well are the “hard” shut-in and the “soft” shut-in. The “hard” shut-in is done by closing the blow-out preventer (BOP) with the choke valve shut. This procedure generates a pressure wave, called a “water hammer,” through the mud. It was believed that in some circumstances this increase in wellbore pressure could provoke formation damage and lead to an underground blowout.[29] Many operators prefer the “soft” shut-in, which is accomplished by closing the BOP with the choke valve open, and then closing the valve slowly. The drawback of the delay in closing the choke to obtain complete shut-in of the well is the additional influx from the formation.

An experimental and theoretical study concluded that the “hard” shut-in was a better alternative than the “soft” shut-in.[30] The reason for this was that the water hammer caused a pressure increase that was negligible, at least in deep water and long wellbores. With the risk of taking a larger kick as a result of longer closing time and human error associated with closing and opening the valves, the “hard” shut-in is the preferred method.

Circulation kill techniques and procedures

After the well is shut-in, the pit gain is recorded while the surface pressures start to build up. When the pressures have stabilized, SICP and the SIDPP are recorded. These values are then used to identify the kick fluid, estimate the height of the kick column, and calculate the new kill-mud weight needed to stabilize the formation pressure.

Several different kill methods have been developed during the years, but the two most common kill procedures are the Driller’s Method and the Engineer’s Method (Wait-and-Weight Method). There are some differences, but they are both based on the same principles: keeping the bottomhole pressure constant while circulating out the kick and replacing the old mud with kill-weight mud. Kill sheets are very helpful when planning and executing a well kill. The prerecorded data are used to calculate the kill-weight mud density and generate the desired circulating drillpipe pressure schedule as a function of pump strokes. A standard kill sheet will show a straight line between the initial circulating pressure (ICP) and the final circulating pressure (FCP). This approach is valid only for vertical wells and could cause an excessive overbalance if used on a horizontal or ERD well.[31] This overbalance could fracture the formation and complicate the well kill operation with loss of circulation. An example of a kill sheet and pressure decline schedules for vertical, horizontal, and ERD wells are presented in Appendix A.

The Driller's Method uses the old mud to circulate out the influx and requires two circulations to kill the well. The first circulation displaces the influx with old mud from the pits, and the second circulation replaces the old mud with new kill mud.

The Engineer's Method uses only one circulation to kill the well. We have to wait while the kill-weight mud is weighted up before starting to circulate out the influx and replacing the old mud with new kill mud, all in just one circulation.

Which circulating kill technique to use varies from situation to situation; no well control problems are the same, and it all depends on the circumstances. The maximum surface pressure with a gas kick will be greater when using Driller's Method, so if the concern is the pressure rating of the BOP, the Engineer's Method may be preferrable. On the other hand, if mixing kill weight mud is expected to take a long time, and there have been problems with hole cleaning, the Driller's Method may be the best option because of the early start of circulation.

Special well control situations might occur if the bit is plugged, the pipe is off-bottom, or the annulus cannot handle the backpressures during a conventional kill. In these cases the BHP cannot be recorded from the drillpipe gauge, nor can the kick be circulated out conventionally. The well-control methods to apply when the traditional concepts cannot be followed are presented in Appendix B.

OBJECTIVES AND PROCEDURES

Research objectives

The objective of this research is to perform an extensive simulation study of vertical, directional, horizontal, and ERD wells. Based on the simulation study recommendations will be made to improve well control for situations that warrant improvement, especially for ERD wells. The simulator will again be used to validate the procedures.

Procedures

The two-phase well control simulator developed by Choe and Juvkam-Wold was used to complete this simulation study. These simulation runs include land, shallow water, intermediate water, deep water and ultradeep water. Other factors that were considered follow:

- Kick size.
- Circulation rate.
- Kick intensity.
- Wellbore trajectory.
- Water depth.
- Hole size, casing and drillstring dimension.

TWO-PHASE WELL CONTROL SIMULATOR

Description of the simulator

The well-control simulator used for this research was developed by Choe and Juvkam-Wold at Texas A&M University.[24, 25] The main objectives of the two-phase well control model are to simulate the behavior of kicks on the basis of realistic assumptions of unsteady two-phase flow and to integrate this into a user-friendly, Windows-based, well-control simulator for use in well control training and education. This model is based on the following assumptions:

- Unsteady-state two-phase flow.
- One-dimensional flow along the flow path.
- Water-based mud, where gas solubility is negligible.
- Known mud temperature gradient with depth.
- Kick occurring at the bottom of the well while drilling.
- Gas influx rates calculated from the formation assuming an infinite-acting reservoir.

Simulator input

The simulator takes a set of user input data and incorporates it through a well-control situation from the drilling mode and the well takes an influx until the kick is completely circulated out of the hole. Once the simulation is completed, the results are available as graphical presentations and the output data can be saved as a file for future investigation.

The default data used in this investigation are listed in **Table 2**. Even though offshore location is listed as default, the study also included onshore simulations runs. The gas deviation factor was also not considered in some runs, and the wellbore profiles were actively changed for different situations. Strokes per minute at kill rate were also changed for different cases. In very deep water the offshore temperature gradient was changed to a value that represented a realistic water temperature at the mudline.

Table 2 – Default input data.

```
      --- Input Data ---
      ------------------

 Rig Location     (1:On Shore)   =      2
 Selected Method (1:Driller)     =      2
 Pump Type        (2:Duplex)     =      2
 Friction Loss    (1:Condsider)  =      1
 Fluid Model      (1:Power law)  =      1
 Gas Deviation    (1:Consider)   =      1
 Direc. Well Type(0:Vertical)    =      4

 Shear Stress @ 600 rpm          =      35.
 Shear Stress @ 300 rpm          =      25.
 Old Mud Density                 =      10.            ppg
 Mud compressibility             =      6.0E-06        1/psi
 Critical Reynolds number        =      2100.
 Bit Nozzle Size 1,2,3,4         =      12.            /32nd in
 Roughness of Pipe               =      0.             in

 Liner Size of Pump              =      6.             in
 Rod Size of Pump                =      2.5            in
 Stroke Length of Pump           =      18.            in
 Pump Efficiency                 =      0.85           fraction

 Strokes # @ Drilling Rate       =      60.            st/min
 Strokes # @ Kill Rate           =      30.            st/min
 Flow Rate @ Drilling            =      410.44         gal/min
 Flow Rate @ Kill                =      205.22         gal/min

 Pit Warning Level               =      10.            bbls
 Kick Intensity                  =      1.             ppg
 Specific Gravity of Gas         =      0.65           (air=1)
 Mole Fraction of CO2            =      0.             fraction
 Mole Fraction of H2S            =      0.             fraction
 Surface Temperature             =      70.            'F
 Mud Temperature Gradient        =      1.1            'F/100 ft
 Off Shore Temperature Gradient  =      -0.3           'F/100 ft

 Formation Permeability          =      250.           md
 Formation Skin Factor           =      2.
 Formation Porosity              =      0.25           fraction
 Rate of Penetration             =      60.            ft/hr

 Choke Valve Status  (1:open)    =      1
 Kill Valve Status   (1:open)    =      0
 ID of Choke Line                =      4.             in
 ID of Kill Line                 =      3.             in
 ID of Marine Riser              =      19.            in
```

Simulator output

The results from the simulation are presented graphically under the main menu right after the circulation is successfully completed. The results can also be saved as an output file for future investigation. **Table 3** shows the data that are available after a completed run:

- Time.
- Xtop = distance to top of kick.
- Xbotm = distance to bottom of kick.
- Px@top = pressure at top of kick.
- Pit Vol = pit gain.
- Kick density.
- Pump P = pump pressure.
- Stand PP = stand pipe pressure.
- Choke P = choke pressure.
- CsgSeat = casing seat pressure.
- P BHP = bottomhole pressure.
- P@Mudline = pressure at the mudline.
- Number of pump strokes.
- Volume circulated.
- Surface choke valve opening in percent.
- Influx rate.
- Mud-return rate at surface.
- Gas-return rate at surface.

Table 3 – Output data after a completed run.

Output from the Well Control Simulator

Time (mins)	Xtop (ft)	Xbotm (ft)	Px@Top (psig)	Pit Vol (bbls)	Kick Densi (ppg)	ity
------	----	-----	------	-------	-------	-----
0	0	0	0	0	0	
8	3987.9	4000	2123.8	7.49	1.16	
16.25	3979.5	3989.7	2264.5	13.54	1.24	
30.92	3963.6	3973.1	2248.9	13.62	1.23	
45.58	3706.8	3953.3	2129.4	13.82	1.17	
60.25	2093.7	2822.9	1386.4	19.17	0.78	
71.58	436.1	1618	602.2	33.33	0.31	
84.97	0	858.1	508.3	11.34	0.25	
101.62	0	0	0	0	0	

Time (mins)	Pump P (psig)	Stand PP (psig)	Choke P (psig)	CsgSeat (psig)	P BHP (psig)	P@Mudlin (psig)
------	------	--------	-------	-------	-- ------	---------
0	0	0	0	1025.3	2065.3	520
8	2489.1	2489.1	0	1046.6	2142.2	520.9
16.25	819.5	819.5	144.4	1210	2288	685.7
30.92	706.2	706.2	148.4	1210.4	2288	686.7
45.58	758.2	758.2	169.6	1231.6	2288	708
60.25	758.2	758.2	271.9	1337	2288	813.2
71.58	758.2	758.2	363.5	1203.3	2288	848.2
84.97	758.2	758.2	508.3	1184.4	2288	660.8
101.62	758.2	758.2	64.9	1126.8	2288	603.2
116.29	758.2	758.2	18.8	1101.6	2288	557
130.87	823.6	823.6	0	1167.1	2353.4	591.4

Time (mins)	Strokes (#)	Vol Circ (bbls)	ChK Open Dia Rat ---(%)-	InFlux io (Mcf/D -- -------	Mud Rate) (gpm) - -------	Gas Rate (Mcf/Day) - ---------
------	-------	--------				
0	0	0	0	0	0	0
8	0	0	0	6661.6	514.7	0
16.25	182.5	29.72	35	0	228	0
30.92	622.5	101.39	33.1	0	205.5	0
45.58	1062.5	173.05	32.1	0	206.2	0
60.25	1502.5	244.71	30.3	0	228.3	0
71.58	1842.5	300.09	30.6	0	268.7	0
84.97	2244	365.48	18.9	0	30.8	1306.2
101.62	2743.6	446.86	39.5	0	205.2	0
116.29	3183.6	518.53	49.1	0	205.2	0
130.87	3621	589.76	100	0	205.2	0

Simulation procedures

Drilling. After turning on the pump we start drilling, and a kick is taken when the bit reaches the planned target. The drilling rate can be increased up 10 times the regular speed. The alarm goes off when the pit gain reaches 10 bbl.

Pump off. The mud-return rate increases when taking a kick, and this can be confirmed by shutting down the pump to see if the well is flowing.

Shut-In. The next important step after the kick is detected is to shut in the well. This prevents more influx into the wellbore, but still there is some flow from the formation until the bottomhole pressure (BHP) builds up to formation pressure. When the BHP equals formation pressure, the system reaches equilibrium and the shut-in drillpipe pressure (SIDPP) and shut-in casing pressure (SICP) are recorded. The shut-in data can be saved as a file when the BHP is within 5 psi of formation pressure. This makes it possible to circulate with other rates and compare the results for the exact same shut-in conditions.

Circulation. The choke can be manipulated either manually or automatically by the computer (perfect control). In this investigation perfect control was chosen for all the cases, and the clock speed was set to 40 times more than normal. After the circulation is completed the results can be viewed and saved as a file. Each output file was then opened and saved as an Excel file, which made it possible to plot the results of interest.

SIMULATION RESULTS FOR THE EXTENDED REACH WELLS

Effect of varying kick sizes and true vertical depth

Introduction

For this investigation I used the M-16 well drilled at Wytch Farm in 1999 as the base case for the typical extended reach well profile. I rebuilt the wellbore profile with data from the actual well. Assuming that varying kick sizes would have the most effect on maximum choke pressure and gas rate at surface when circulating out the kick, I performed several simulation runs for different kick sizes with the original TVD and with the TVD doubled. I lowered only the kick-off point; the wellbore profile remained the same. The results are presented in **Figs. 6 and 7.**

Discussion of the results

From **Figs. 6 and 7** we can see that the increase in kick size causes an increase in the maximum choke pressure. It can also be seen that the maximum choke pressure increases with TVD of the well. A 10 bbl gas kick taken in a deep well is more compressed by the higher hydrostatic pressure and will expand more as it approaches the surface than a kick taken in a shallower well. This expansion is reflected in the choke pressure at the surface. The figures also show that there is not much difference in maximum choke pressure for kick sizes of 100 and 200 barrels; the most significant increase is from 10 bbl to 50 bbl. From 10 to 50 barrels mud and gas will be mixed together through the choke, and for larger kick sizes only dry gas will be circulated through the choke when the highest pressure is observed.

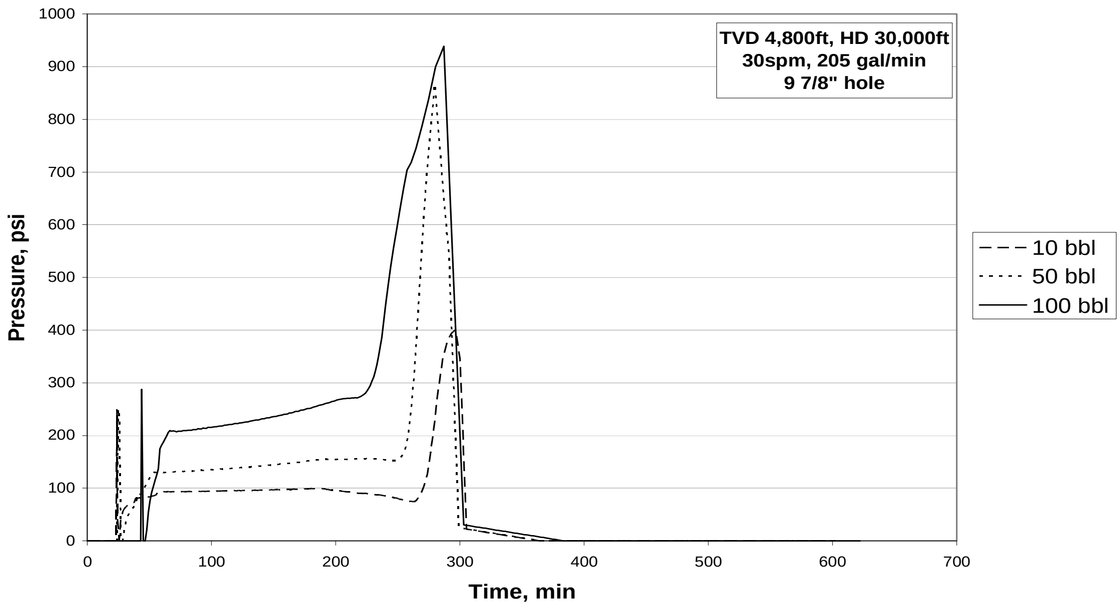


Fig. 6 – Choke pressure for various kick sizes (original TVD).

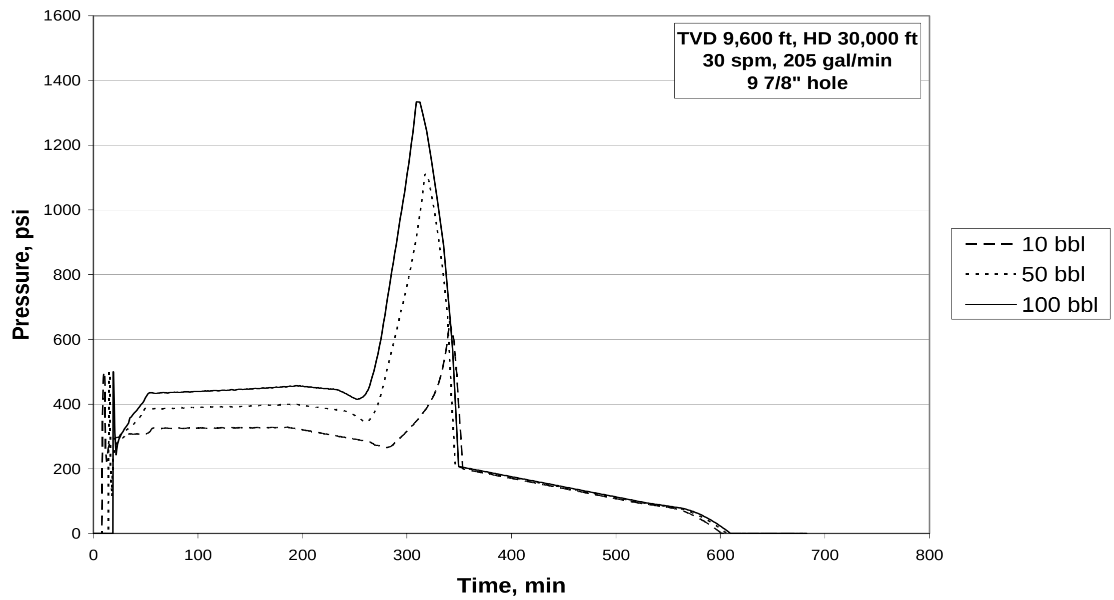


Fig. 7 – Choke pressure for various kick sizes (2X original TVD).

Effect of varying water depth and kick size

Introduction

Even though there are some experiences of drilling extended-reach wells from offshore locations, they are mostly related to shallow waters from fixed platforms. It is believed that in the near future there will be drilled several ERD wells in deep – and ultradeep water.[8] Therefore, I performed many simulation runs in water depths of 5,000, 10,000 and 15,000 ft to try to understand the scenarios that could occur when drilling under these conditions. The same M-16 Wytch Farm wellbore profile was used for this study by just adding water depth.

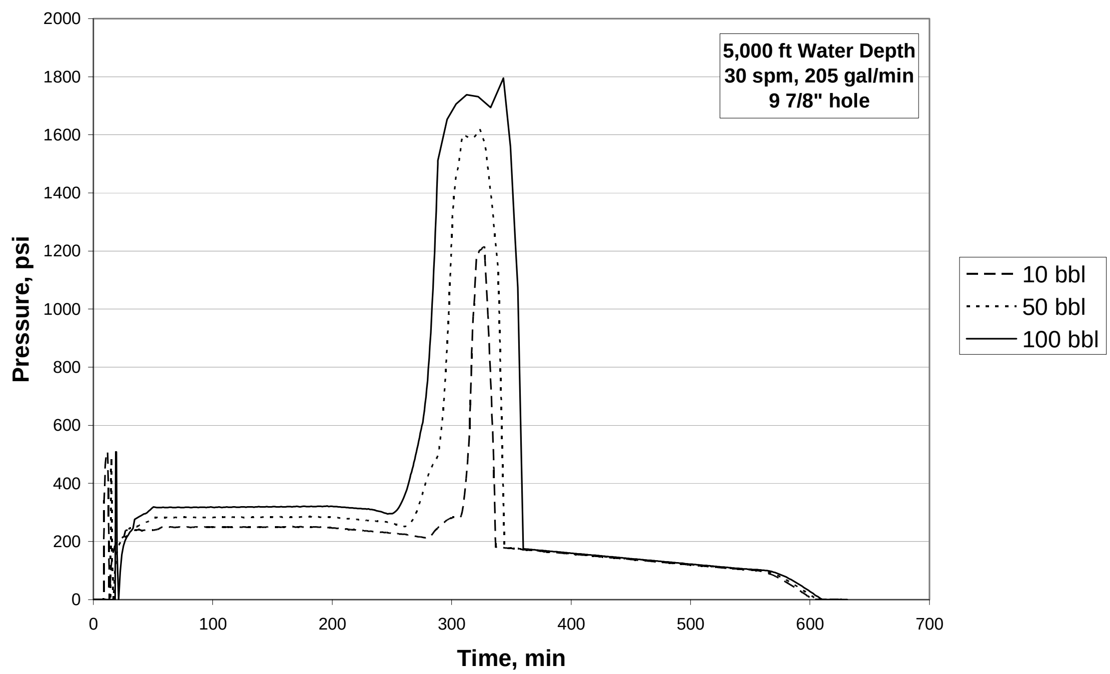


Fig. 8 – Choke pressure for various kick sizes in 5,000 ft of water.

Discussion of the results

Figs. 8, 9, and 10 show the maximum choke pressure obtained for 10-, 50-, and 100-bbl kicks taken in water depths of 5,000, 10,000 and 15,000 ft. We can see from the figures a considerable increase in choke pressure as the water depth increases. This is because of the change in depth of the hydrostatic column, similar to when increasing TVD of a well.

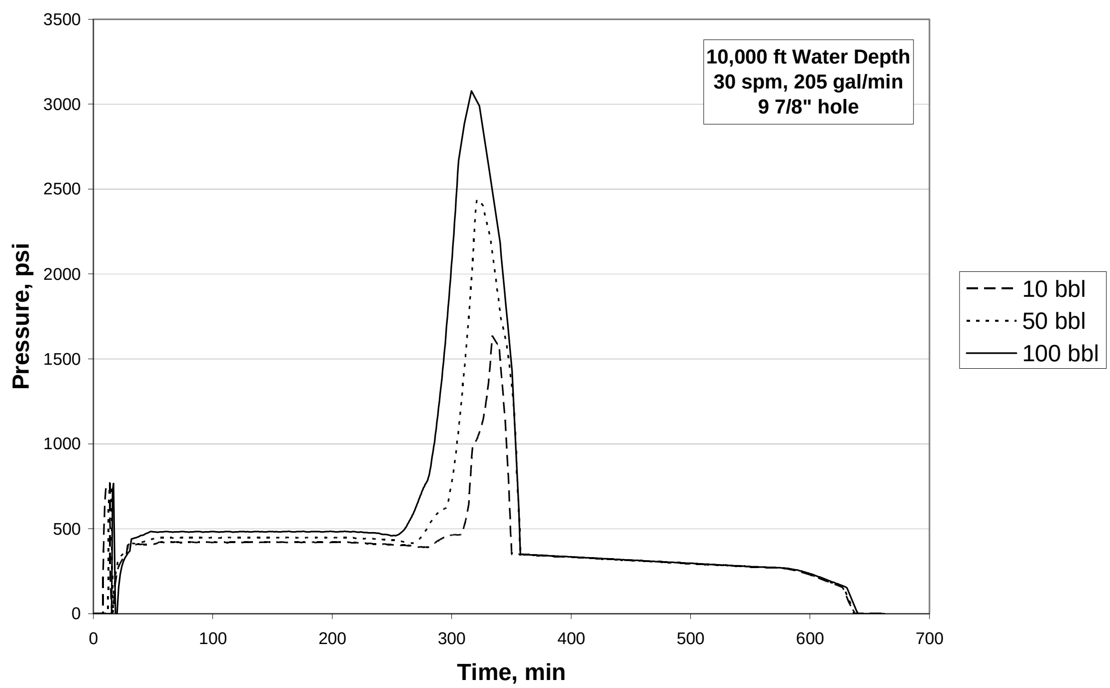


Fig. 9 – Choke pressure for various kick sizes in 10,000 ft of water.

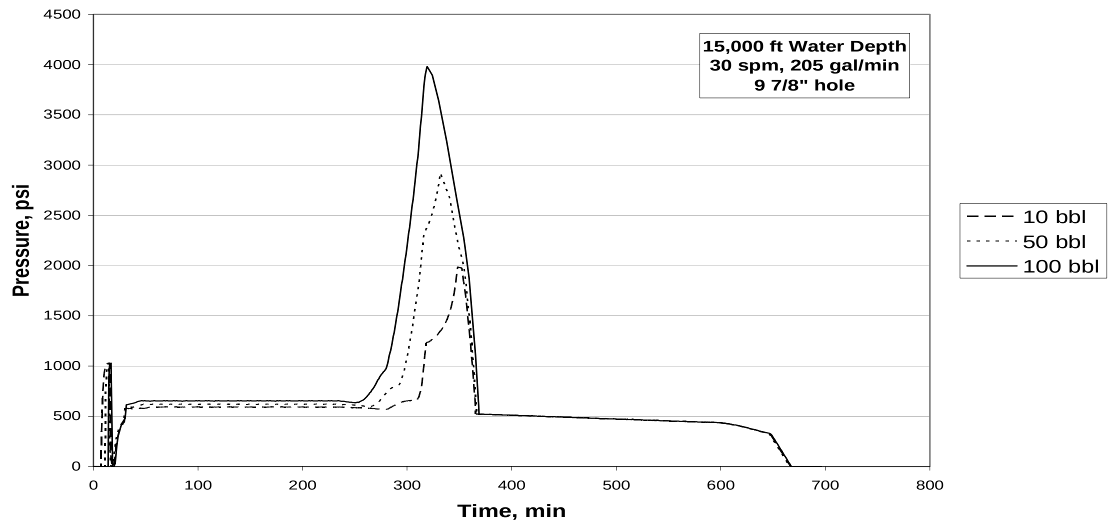


Fig. 10 – Choke pressure for various kick sizes in 15,000 ft of water.

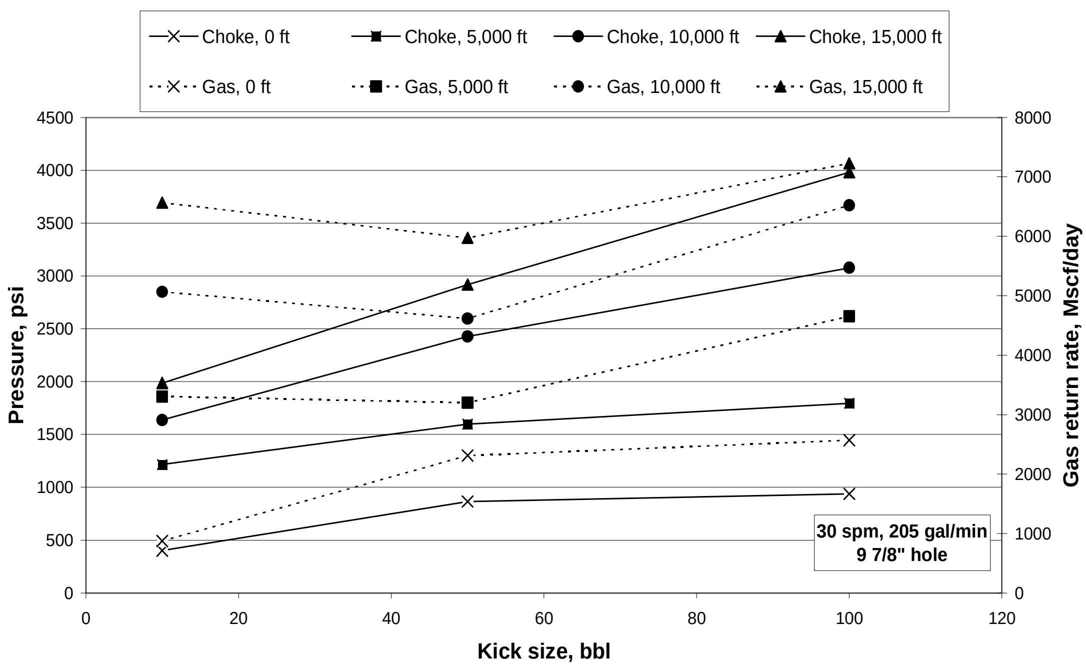


Fig. 11 – Maximum choke pressure and gas return rate for various kick sizes and water depths.

Fig. 11 shows the maximum choke pressure and gas-return rate at surface observed for 10-, 50-, and 100-bbl kicks in water depths of 0, 5,000, 10,000, and 15,000 ft. Here the choke pressure increases more rapidly in deep water than in more shallow water as the kick size increases. We can see that for all offshore cases the gas-return rate at the surface is greater when circulating out a 10-bbl kick than it is for the 50-bbl kick, but then rises and reaches its highest value at the 100-bbl kick size. I expected the maximum gas rate to increase with larger kick sizes, but in these cases the peak gas rate seems to have occurred between two time steps in the simulator, resulting in recorded values less than the real values. On the other hand, the onshore cases follow the predicted pattern where the maximum gas rate increases with greater kick size.

Effect of varying kick sizes and circulation rates for different hole sizes

Introduction

It believed that the hole size would be of great importance in a well-control situation. A given kick size will displace a greater length interval of mud in a slim hole than it will for a larger hole. This can cause a rapid loss of hydrostatic pressure even for relatively small kick sizes, which again can cause the well to flow even more. Another important parameter is the kill-circulation rate. Obviously a large hole would require a higher circulation rate than a slim hole to maintain the desired annular fluid flow velocity. During a well-kill operation, the circulation rate should be high enough to remove the gas out from the hole, which can be a problem in highly inclined wellbores. On the other hand, too high circulation rate could lead to an excessive ECD, fracturing the formation with the subsequent fluid loss. Also circulating too fast could cause large amounts of gas to approach the surface too fast, which could lead to hazardous pressure on surface equipment and a gas peak rate that exceeds the maximum rate the gas/mud separator can handle.

Discussion of the results

From **Fig. 12** we can see that the trend is a bit different for the 6½-in. hole than the larger hole sizes. The maximum choke pressure increases with larger kick size for all cases, as expected. As the kick size increases from 50 bbl to 100 bbl, note the significant increase in gas return rate for the 6½-in. hole. The reason for this, as mentioned in the introduction, is the higher annular velocity in the slim hole that causes a rapid approach of gas to the surface.

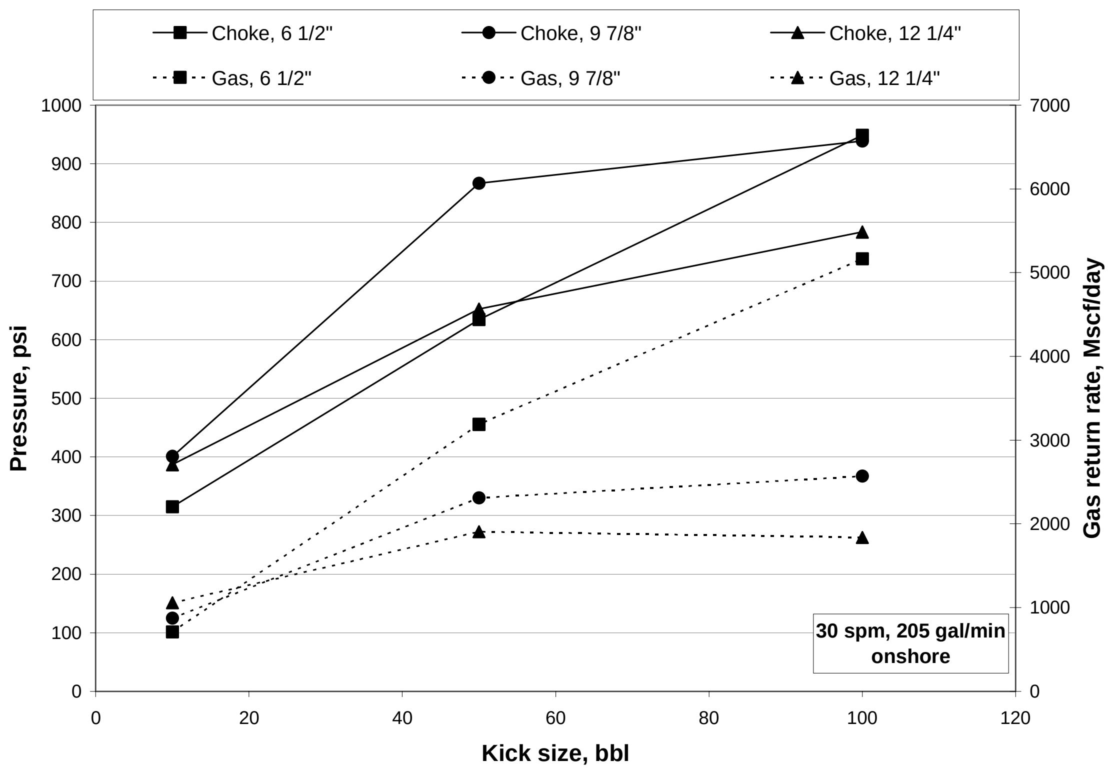


Fig. 12 – Maximum choke pressure and gas return rate for various kick and hole sizes.

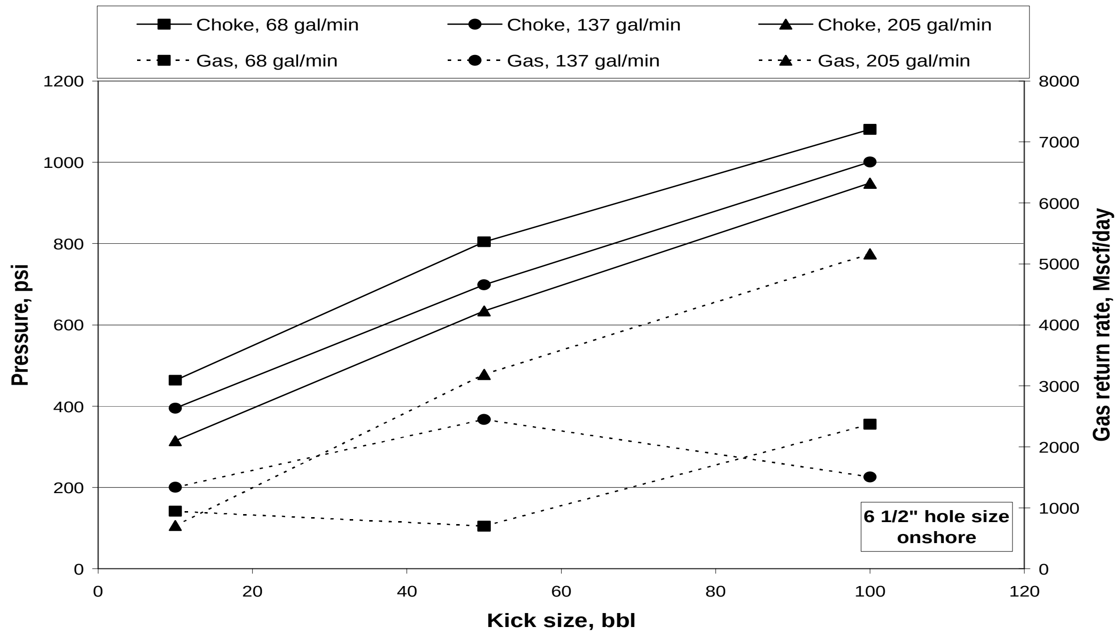


Fig. 13 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 6½-in. hole.

Figs. 13, 14, and 15 show maximum choke pressure and peak gas return rate at surface recorded for different kick sizes. Each kick was circulated out with three different kill rates. For the 6½-in. hole, the chosen kill rates were 68, 137, and 205 gal/min. Any higher kill rate would be unrealistically high, and was not tested. For the $9^7/_8$-in. and 12¼-in. hole the selected circulation rates were 137, 205, and 274 gal/min. The maximum choke pressure increases as the circulation rate increases, also as expected. But another quite consistent pattern cannot fully be explained are the maximum gas return rates in **Fig. 14 and 15.** We can see that the gas return rates increase to the largest value for the 50-bbl kicks, and then decrease to a lower value for the 100-bbl kicks. I expected the gas return rates to increase with larger kick sizes all the way, not only the step from 10 to 50 bbl. Results of a further investigation are presented later in this section.

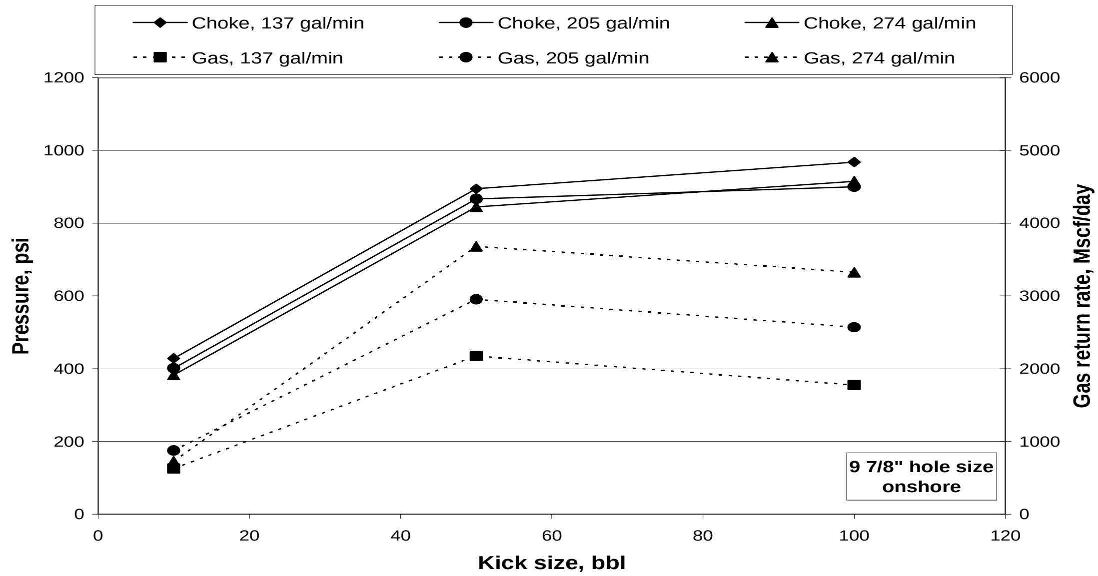


Fig. 14 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 9⁷/₈-in. hole.

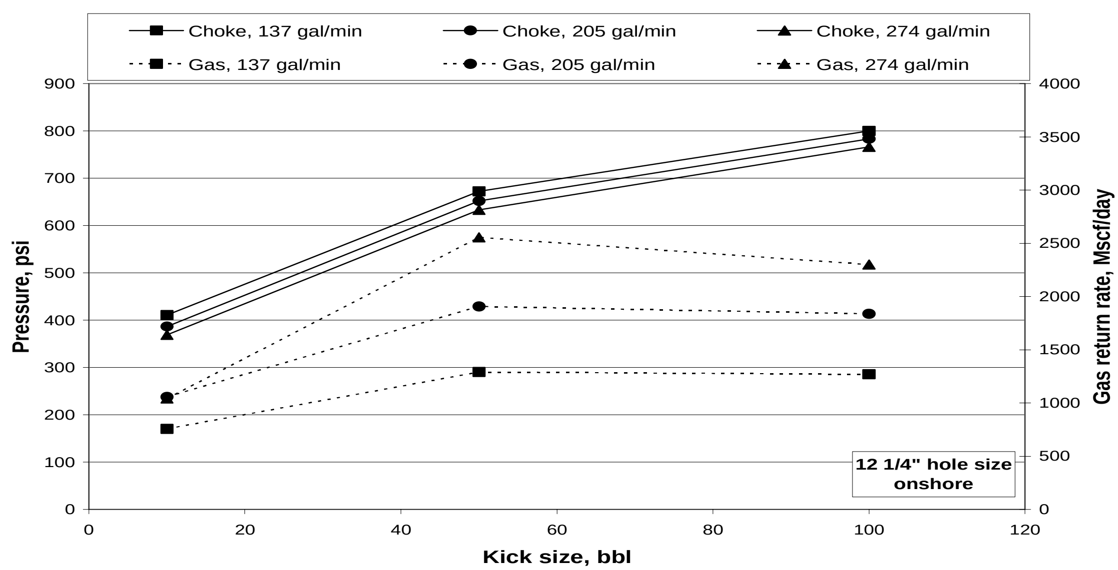


Fig. 15 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 12¼-in. hole.

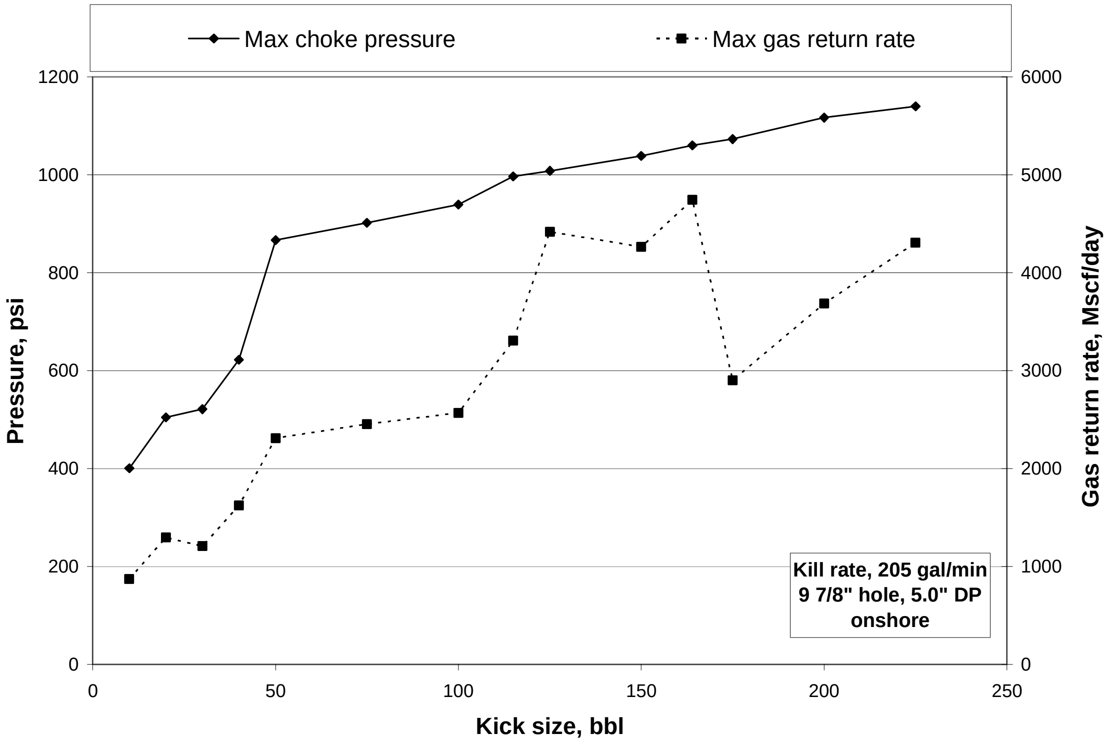


Fig. 16 - Maximum choke pressure and gas return rate for various kick sizes in a 9 ⁷/₈-in. hole.

To get a more detailed overview of the development of the maximum choke pressure and gas rate, I performed many more simulation runs for the 9⁷/₈-in. and 12¼-in. holes. The kill circulation rate was set to 205 gal/min for all the runs, and the kick sizes ranged from 10 to 225 bbl. From **Fig. 16** we can clearly see the jump in choke pressure as the kick size get close to 50 bbl. The reason for this is that kick sizes of 50 bbl or more will have dry gas through the whole choke when the maximum choke pressure is recorded. **Fig. 17** does not show the same tendancy as clearly, the choke pressures increase almost linearly with increased kick size. Also the maximum gas return rates show a more even trend than **Fig. 16**, which is much more crooked. The time steps used in the simulator make the recorded values for maximum gas-return rates less accurate than the choke-pressure values. The peak gas rates occur only for a very short period of time, and are most likely to fall between two time steps.

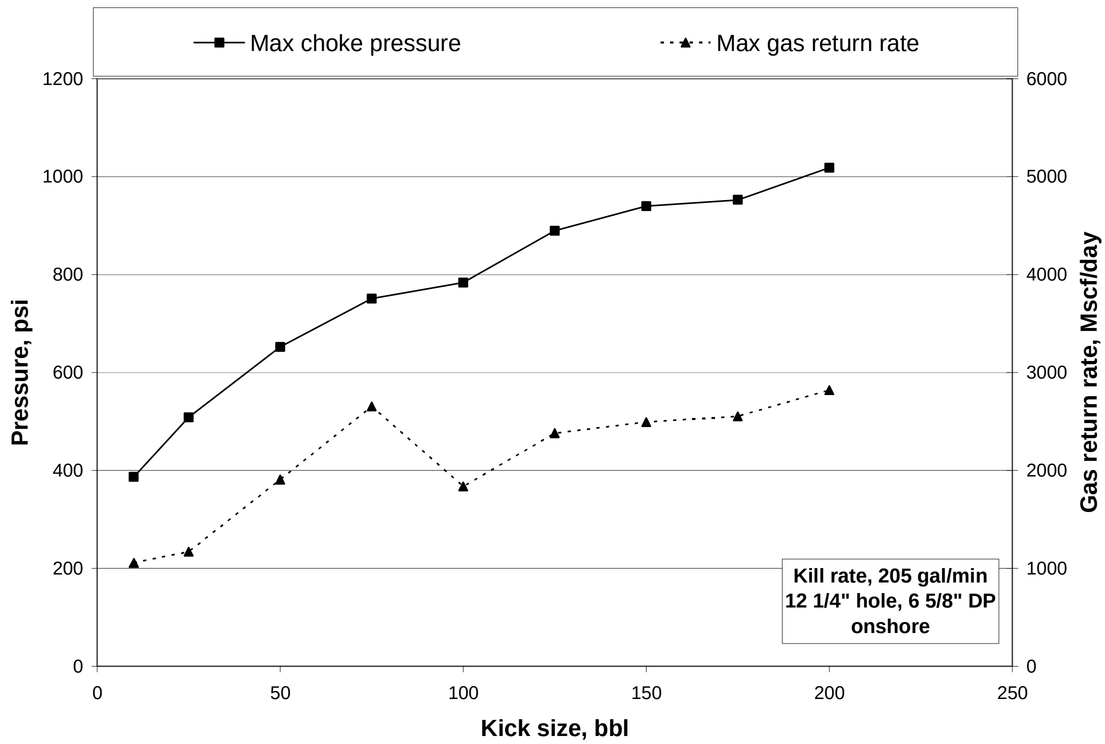


Fig. 17 - Maximum choke pressure and gas return rate for various kick sizes in a 12¼-in. hole.

Effect of varying kick intensity for different water depths

Introduction

The kick intensity is a measure of the amount of density increase necessary to balance the formation pressure. That means for a 1 ppg kick intensity, the mud weight has to be raised by 1 ppg to increase the BHP enough to stabilize the formation pressure. For this investigation, cases were run for 0.5 ppg, 1.0 ppg, and 1.5 ppg for onshore and offshore wells. The water depths for the offshore wells were 5,000 ft, 10,000 ft , and 15,000 ft. All the cases are for a 100-bbl kick size. **Fig. 18** shows the effect on choke pressure for various kick intensities and water depths.

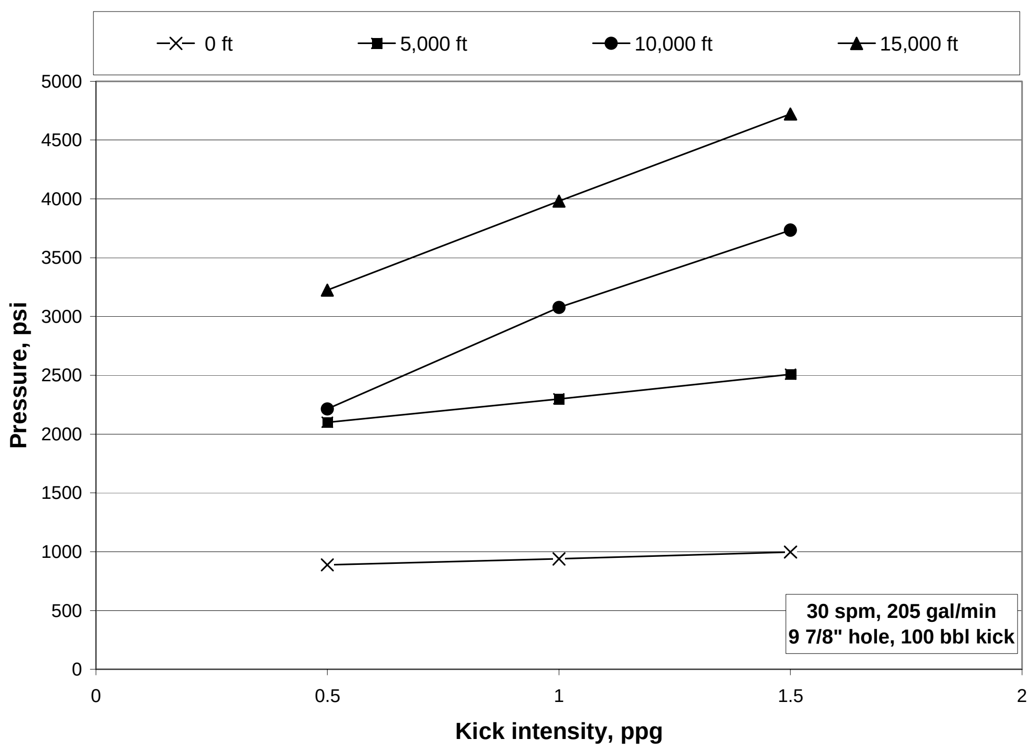


Fig. 18 – The effect on choke pressure when varying kick intensity and water depths.

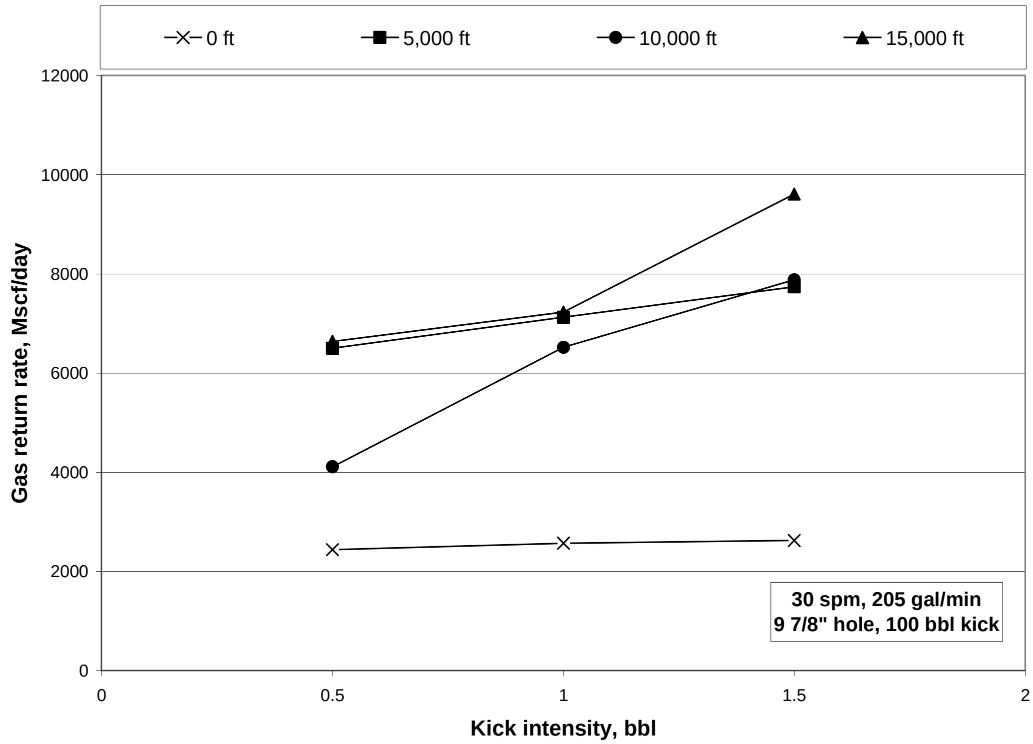


Fig. 19 – The effect on gas return rate at surface when varying kick intensity and water depths.

Discussion of the results

Fig. 18 shows that the higher the kick intensity, the higher the choke pressure will be. The reason for this is that when the kick intensity increases, the bottomhole pressure has to be increased enough to stop the influx, and that means higher choke pressure. For the onshore well there is just a moderate increase in choke pressure with increased kick intensity. As the water depths get deeper, the pressure gradients are steeper. This is because of the formation overpressure which increases with water depth and kick intensity. The same trends are also observed for the gas rates at the surface (**Fig. 19**).

GAS REMOVAL IN HIGHLY INCLINED AND HORIZONTAL WELLBORES

Introduction

Gas kicks in highly inclined and horizontal wellbores introduce some special problems not present in more conventional vertical wells. Buoyancy of the gas may cause the gas to accumulate and get trapped in the end of the well if that section is inclined upwards. The gas can also get trapped in gas pockets in the high-lying parts of the well trajectory or in washouts. These gas pockets may not be possible to circulate out with the lower kill rate, but could become mobile when normal drilling resumes, which itself can cause new well control problems.[32]

Baca *et al.*[33] studied counter current and co-current gas kicks in horizontal wells, but their results do not provide a complete basis for determining superficial velocities that would ensure removal of all gas from either an accumulation or a continuous formation feed-in.

Recommendations for gas removal in ERD wells

All the authors who have studied gas-kick removal in horizontal wells conclude that high superficial liquid velocities are needed to circulate gas out of the horizontal or highly inclined wellbores.[10,15-24,29,32,33] Rommetveit *et al*.[15] concluded that in general, mud velocities up to 0.9 m/s are needed to clean out gas from sections inclined up to 4^o upwards. In a 9.875-in. hole and 5.0-in. drillpipe a kill rate of 524 gal/min is required to obtain an annular velocity of 0.9 m/s. That is almost 40% faster than the drilling mode used in the simulation runs, and would not be realistic for an ERD well. A more detailed description of this calculation is presented in Appendix C.

A general recommendation when circulating out a gas kick in an ERD well is to start the circulation with a high rate, maybe close to normal drilling. The reason for this is to get the gas out of the horizontal and into the inclined hold section. An ERD well has a very long wellbore, and should be able to handle a high kill rate for a short period of time without causing excessive surface pressures and gas rates. The casing shoe is usually set close to TVD of the target, and the risk of fracturing the casing shoe should be minimal. When the gas is expected to be circulated out of the horizontal section and into the hold section, the kill rate can be reduced to a normal rate, usually $^1/_3$ to ½ of normal drilling rate. In the hold section, the gas will migrate and flow co-currently, and a normal kill rate should be sufficient to circulate the gas out of the well.

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Introduction

The main purpose of this research was to determine which factors have a significant effect on choke pressures and gas-return rates for various kick scenarios. The variables were kick size, true vertical depth of the well, water depth, circulation kill rate, hole sizes, and kick intensity. The tool used for this research is the two-phase well-control simulator developed by Choe and Juvkam-Wold at Texas A&M University.

Effect of kick size

One of the most important parameters in well control is the initial pit volume gain. Kick size was the most frequently changed variable, and the results indicate that it affects the magnitude of the choke pressure and gas return rate throughout the well-control operation.

Effect of water depth

The hydrostatic pressure increases with water depth, so changing both water depths and TVDs has the same trend for the results. The small inner diameter of the choke lines for offshore wells represents a small volume capacity and high flow frictions during well-control operations. From the results we can see that the choke pressures and gas rates increase with water depth. There is a significant difference in choke pressures for onshore and offshore wells, and the reason for this is that the choke pressure increases rapidly to compensate for hydrostatic-pressure reduction when the gas kick starts to fill the choke line, and this becomes more significant the deeper the water is.

Effect of circulation kill rate

The main trend for all the cases is that an increase in kill rate increases the choke pressures and the gas-return rates. Higher circulation means faster arrival of gas to the surface, which leads to greater pressure. The annular friction-pressure loss increases with higher kill rate and reduces the choke pressure; however, this reduction is negligible compared to the effect of gas returning to the surface at a faster rate.

Effect of hole size

Three different hole sizes were used in this investigation, mostly 9 $^{7}/_{8}$-in. but also some cases with 6½-in. and 12¼-in. just to see the effect. Obviously the hole volume capacity increases with hole size, and a 10-bbl kick in a slim hole will displace more feet of mud in the wellbore than in a larger hole size. This results in higher choke pressure and gas return rate for slim holes as long as the circulation rate is constant for all hole sizes.

Effect of kick intensity

With an increase in kick intensity, higher BHP is required to stop the influx of kick fluids into the wellbore. This results in higher choke pressure and gas return rate, which can also be seen from the results.

Recommendations for well control procedures in ERD wells

Based on the literature review and the simulation study, the following recommendations have been made for well-control procedures in ERD wells:

- Once a kick is detected and confirmed, take a "hard" shut-in of the well. Wait until the pressures have stabilized, then record SIDPP, SICP and pit gain.
- Start immediately to circulate using the Driller's Method. In an ERD well, the casing shoe is close to TVD and should not affect the choice of kill methods. Also the wellbores in ERD wells are very long, and waiting for the kill weight-mud to be prepared will take a long time. If there are problems with hole

cleaning, it is best to resume circulating as soon as possible.

- Start circulating at a high rate for a short time to remove gas from the horizontal section of the wellbore. Once the choke pressure starts to increase rapidly, slow down the pumps and continue the circulation with a kill rate $^1/_3$ to ½ of the rate in drilling mode.

- The drillpipe pressure decline schedules are prepared for one pre-determined kill circulation rate. If various circulation rates are used, pressure decline schedules have to be made for each circulation rate. The reason for this is the friction pressure loss which increases with higher circulation rate.

Recommendations for future work

The next step would be to investigate kick scenarios for multilateral wells, which will also be done shortly.

NOMENCLATURE

ERD	Extended reach drilling
HD	Horizontal departure
TVD	True vertical depth
RSS	Rotary steerable systems
MWD	Measurement while drilling
LWD	Logging while drilling
SICP	Shut-in casing pressure
SIDPP	Shut-in drillpipe pressure
BOP	Blowout preventer
ECD	Equivalent circulation density
BHP	Bottomhole pressure
ROP	Rate of penetration
ICP	Initial circulating pressure
FCP	Final circulating pressure
ppg	pound per gallon
spm	strokes per minute
bbl	barrel
CDPP	circulating drillpipe pressure
P_{ch}	Pressure at the choke
ΔP_{ma}	Hydrostatic column of mud in annulus
ΔP_{md}	Hydrostatic column of mud in drillpipe
ΔP_{kb}	Hydrostatic column of kick fluid in annulus
ΔP_{dp}	Total friction pressure loss in drillpipe
ΔP_{a}	Total friction pressure loss in annulus
ΔP_{bit}	Pressure drop through the bit

REFERENCES

1. Economides, M.J., Watters, L.T., and Dunn-Norman, S.: *Petroleum Well Construction*, John Wiley & Sons Ltd., London (1998).
2. Al-Suwaidi, A.S., El-Nashar, R.A., Allen, F., and Brandao, F.J.: “World Class Extended-Reach Drilling Performance in Abu Dhabi – A Case Study in How to Beat the Learning Curve,” paper SPE 72279 presented at the 2001 IADC/SPE Middle East Drilling Technology, Bahrain, 22-24 October.
3. Kamaruddin, S., Lah, M.Z.C., Sering, L., Good, A., and Khun, L.H.: “Pushing the Envelope – Extending the Limits of Current Drilling Technology,” paper SPE 64696 presented at the 2000 SPE International Oil and Gas Conference and Exhibition, Beijing, China, 7-10 November.
4. Payne, M., Cocking, D.A., and Hatch, A.J.: “Critical Technologies for Success in Extended Reach Drilling,” paper SPE 28293 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, 25-28 September.
5. Tribe, I.R., Burns, L., Howell, P.D., and Cickson, R.: “Precise Well Placement Using Rotary Steerable Systems and LWD Measurements,” paper SPE 71396 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, 30 September–3 October.
6. Colebrook, M.A., Peach, S.R., Allen, F.M., and Conran, G.: “Application of Steerable Rotary Drilling Technology to Drill Extended Reach Wells,” paper SPE 39327 presented at the 1998 IADC/SPE Drilling Conference, Dallas, 3-6 March.
7. Meader, T., Allen, F., and Riley, G.: “To the Limit and Beyond – The Secret of World-Class Extended-Reach Drilling Performance at Wytch Farm,” paper SPE 59204 presented at the 2000 IADC/SPE Conference, New Orleans, 23-25 February.

8. Cunha, J.C., Martins, A.L., Sa, C.H.M., and Fernandes, P.D.: "Planning Extended Reach Wells for Deep Water," paper SPE 74400 presented at the 2002 SPE International Petroleum Conference and Exhibition, Villahermosa, Mexico, 10-12 February.

9. Allen, F., Tooms, P, Conran, G., Lesso, B., and Van de Slijke, P.: "Extended-Reach Drilling: Braking the 10-km Barrier," http://www.slb.com/ Hub/Docs/connect/reference/oilfield_review/ors97/win97/pdf/ex_drilling.pdf, Winter 1997.

10. Watson, D., Brittenham, T., and Moore, P.: *Advanced Well Control Manual*, SPE Textbook Series, SPE, Richardson, TX (2003).

11. Rader, D.W., Bourgoyne, A.T. Jr., and Ward, R,H.: "Factors Affecting Bubble-Rise Velocity of Gas Kicks," *JPT* (May 1975) 571.

12. Johnson, A.B. and White, D.B.: "Gas-Rise Velocities During Kicks," *SPE Drilling Engineering* (December 1991) 257.

13. Johnson, A.B, and Cooper, S.: "Gas Migration Velocities During Gas Kicks in Deviated Wells," paper SPE 26331 presented at the 1993 SPE Annual Technical Conference and Exhibition, Houston, 3-6 October.

14. Schubert, J.J.: "Well Control Procedures for the Proper Identification and Handling of Kicks for the Prevention of Blowouts," MEng report, Texas A&M University, College Station, Texas (1995).

15. Rommetveit, R., Bjorkevoll, K.S., Bach, G.F., Aas, B., Hy-Billiot, J. *et al.*: "Full Scale Kick Experiments in Horizontal Wells," paper SPE 30525 presented at the 1995 SPE Annual Technical Conference & Exhibition, Dallas, 22-25 October.

16. Nunes, J.O.L., Bannwart, A.C., and Ribeiro, P.R.: "Mathematical Modeling of Gas Kicks in Deep Water Scenario," paper SPE 77253 presented at the 2002 IADC/SPE Asia Pacific Drilling Technology, Jakarta, 9-11 September.

17. Santos, O.L.A.: "Important Aspects of Well Control for Horizontal Drilling Including Deepwater Situations," paper SPE 21993 presented at the 1991 SPE/IADC Drilling Conference, Amsterdam, 11-14 March.

18. Santos, O.L.A.: "Well Control Operations in Horizontal Wells," paper SPE 21105 presented at the 1990 SPE Latin American Petroleum Engineering Conference, Rio de Janeiro, 14-19 October.
19. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part I," paper SPE 29345 presented at the 1995 SPE/IADC Drilling Conference, Amsterdam, 28 February-2 March.
20. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part II," paper SPE 29860 presented at the 1995 Middle East Oil Show, Bahrain, 11-14 March.
21. Wang, Z., Peden, J.M., and Lemanczyk, R.Z.: "Gas Kick Simulation Study for Horizontal Wells," paper SPE 27498 presented at the 1994 IADC/SPE Drilling Conference, Dallas, 15-18 February.
22. Baca, H.E.: "Counter Current and Co-Current Gas Kick Migration in High Angle Wells," MS thesis, Louisiana State University, Lafayette, Louisiana (1999).
23. Ustun, F.: "The Effect of High Liquid Flow Rates on Co-Current and Counter-Current Gas Kick Migration in High Angle Wells," MS thesis, Louisiana State University, Lafayette, Louisiana (2000).
24. Lage, A.C.V.M., Rommetveit, R., and Time, R.W.: "An Experimental and Theoretical Study of Two-Phase Flow in Horizontal or Slightly Deviated Fully Eccentric Annuli," paper SPE 62793 presented at the 2000 IADC/SPE Asia Pacific Drilling Technology, Kuala Lumpur, 11-13 September.
25. Choe, J. : "Dynamic Well Control Simulation Models for Water-Based Muds and Their Computer Applications," PhD dissertation, Texas A&M University, College Station, Texas (1995).
26. Choe, J. and Juvkam-Wold, H.C.: "A Modified Two-Phase Well-Control Model and Its Computer Applications as a Training and Educational Tool," *SPECA* (February 1997) 14.

27. Westergaard, R.H.: “All About Blowouts,” *Norwegian Oil Review* (1987) **23**, 103.

28. “Losses of Well Control,” Minerals Management Service, http://www.mms.gov/incidents/blowouts.htm, 4 June 2003.

29. Lage, A.C.V.M., Nakagawa, E.Y, and Cordovil, A.G.D.P.: “Well Control Procedures in Deep Water,” paper SPE 26952 presented at the 1994 Latin American/Caribbean Petroleum Engineering Conference, Buenos Aires, 27-29 April.

30. Jardine, S.I., Johnson, A.B., and White, D.B.: “Hard or Soft Shut-In: Which Is the Best Approach?” paper SPE/IADC 25712 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, 23-25 February.

31. Al-Shammari, H.A. and Nordquist, D.G.: “Revised BOP and Well Control Policies in the Kingdom of Saudi Arabia,” paper SPE 77227 presented at the 2002 IADC/SPE Asia Pacific Drilling Technology, Jakarta, 9-11 September.

32. Aas, B., Bach, G., Hauge, H.C. and Sterri, N.: "Experimental Modelling of Gas Kicks in Horizontal Wells," paper SPE/IADC 25709 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, 23-25 February.

33. Baca, H., Nikitopoulos, D.E., Smith, J.R., and Bourgoyne, A.T.: “Counter Current and Co-Current Gas Kicks in Horizontal Wells: Non-Newtonian Rheology Effects,” *JERT*, (March 2003) **125**, 51.

APPENDIX A

PLANNING A KILL

Calculating bottomhole pressure

The bottomhole pressure is the pressure at the surface plus the total hydrostatic pressure between the surface and the bottom.

- Calculating bottomhole pressure before taking a kick:
  BHP = Hydrostatic pressure in DP
- Calculating bottomhole pressure after taking a kick:
  BHP = SIDPP + Hydrostatic pressure in DP

The static bottomhole pressure as determined from the drillstring and annulus legs for the U-tube are:

<u>Annulus</u> <u>Drillstring</u>

$BHP = SICP + \Delta P_{ma} + \Delta P_{kb} = SIDPP + \Delta P_{md}$

The circulating drillpipe pressure (CDPP) is the sum of the pressure losses in the drillstring, bit, and annulus. When killing a well, the hydrostatic pressures are no longer balanced and additional backpressure is created at the choke.

The circulating bottomhole pressures are then defined as:

<u>Annulus</u> <u>Drillstring</u>

$BHP = P_{ch} + \Delta P_{ma} + \Delta P_a = CDPP + \Delta P_{md} + \Delta P_{kb} - \Delta P_{dp} - \Delta P_{bit}$

Fig. 20 shows typical drillpipe pressures for a well before and after taking a kick in static condition and CDPP as a function of depth.

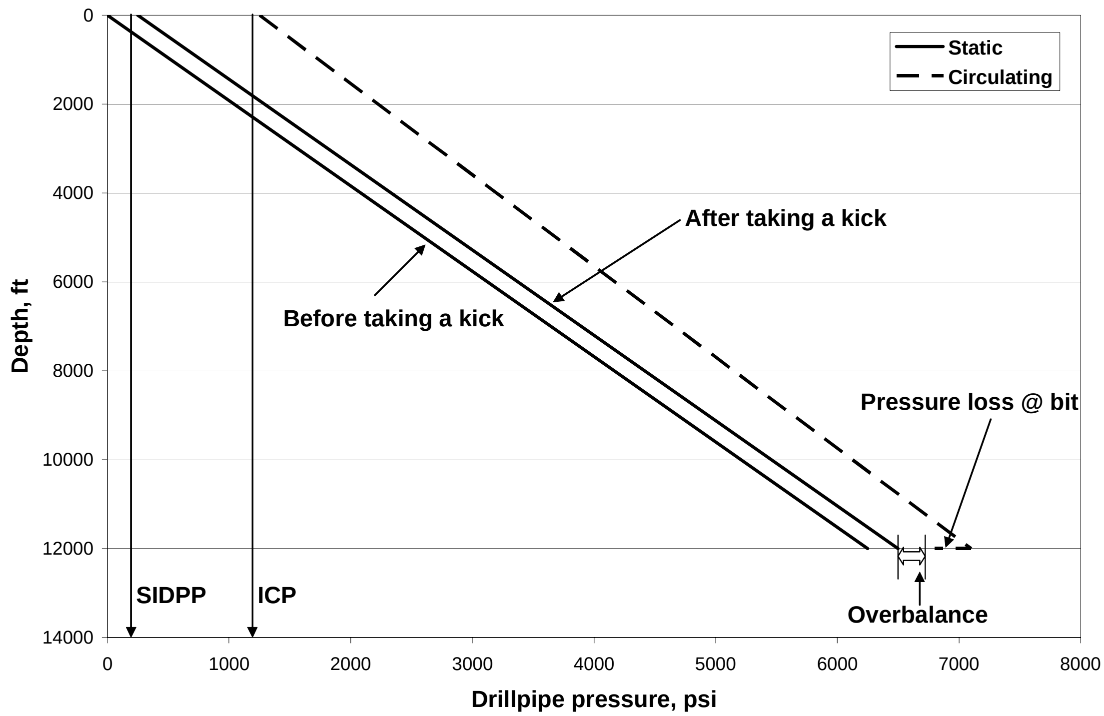


Fig. 20 – Drillpipe pressure vs. depth for circulating and static conditions.

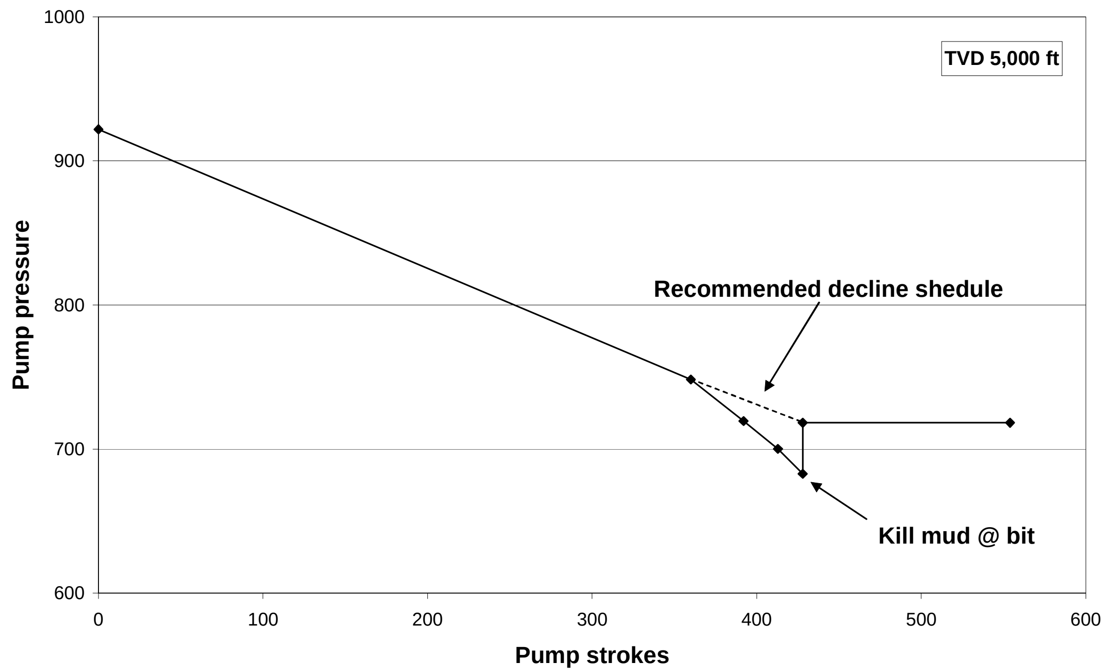


Fig. 21 – Pressure-decline kill sheet for a vertical well.

Figs. 21 – 23 are theoretical drillpipe pressure decline schedules for various wellbore profiles. In **Fig. 21** we have a vertical well, and we can see that the CDPP follows a straight-line decline. This is because it is a vertical well, and since the hydrostatic pressure is a function of TVD and mud weight only, there will be a straight line.

In **Fig. 22** we have a horizontal well, and we have a straight decline line for the horizontal section, and almost a constant pressure in the horizontal section. The slight increase in pressure in the horizontal section is because of the friction pressure loss.

In **Fig. 23** we have an ERD well. The pressure decline is steep for the vertical and the build-up section, but changes to a more constant pressure in the hold section. The TVD increases as we go down the hold section, and so will the hydrostatic pressure. As we reach the horizontal section, the hydrostatic pressure remains constant, but the friction pressure loss causes the pressure to rise slightly. The friction pressure loss is a function of measured depth only, not TVD.

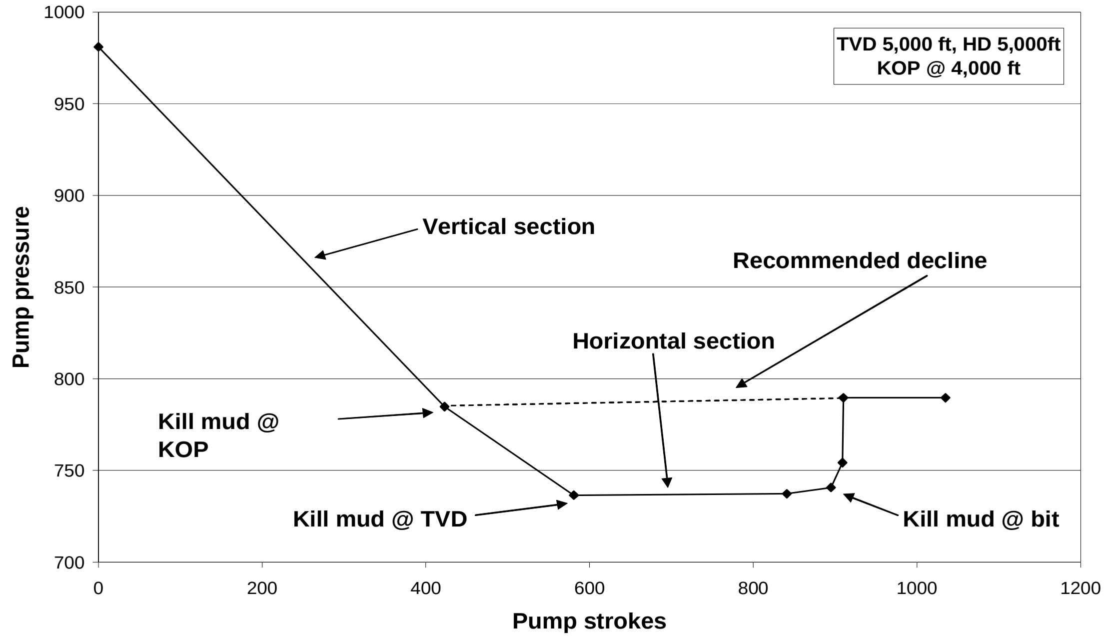


Fig. 22 – Pressure-decline kill sheet for a horizontal well.

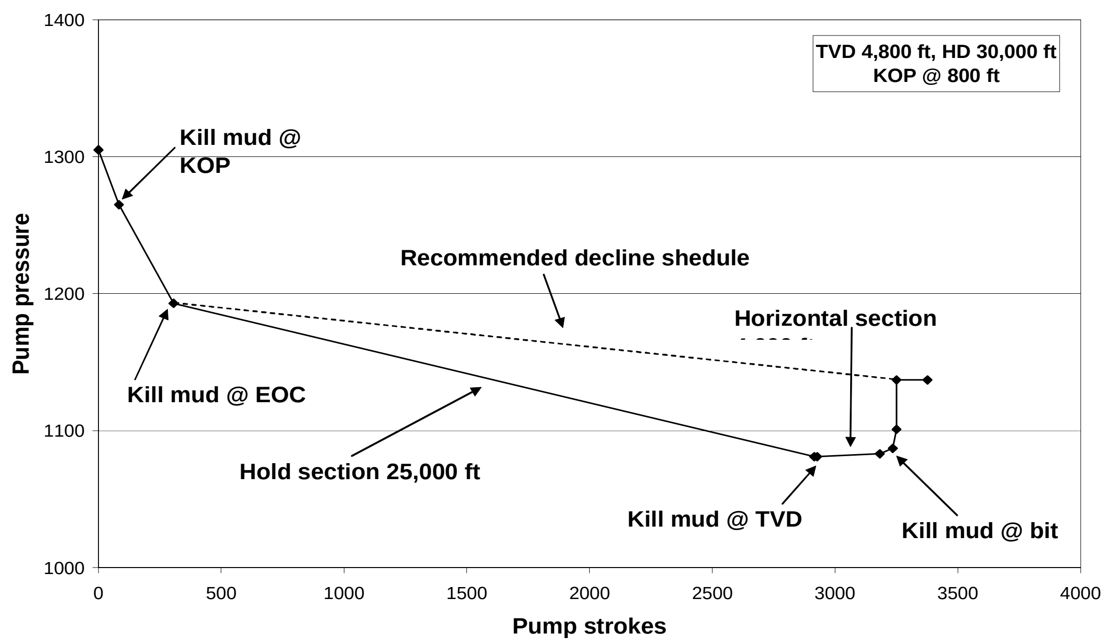


Fig. 23 – Pressure-decline kill sheet for an ERD well.

APPENDIX B
WELL CONTROL COMPLICATIONS

Introduction

The well-control operations presented earlier in this thesis are only for those cases where the drillstring is below the influx, the well can be shut-in without any major complications, the BHP can be read from the drillpipe gauge, and the kick can be circulated out safely. However, there are situations when the conventional circulation kill techniques cannot be applied. These situations could be:

- Drillbit is plugged.
- Migrating influx is beneath the bit or the pipe is out of the hole.
- Drillpipe has parted or has a hole above the influx.
- Annulus cannot withstand the backpressures imposed during kick circulation.
- Well is shut-in with the blind rams.
- Pumps are malfunctioning and the drillstring is not filled with mud.
- Gas has entered the drillstring.

Volumetric method

The volumetric method can be used on a well that is shut in and a migrating influx is indicated, but the bottomhole pressure cannot for some reason be read confidently. Volumetric control is mostly the same as the Driller's Method; the only fundamental difference is that the buoyancy of the kick is the primary drive mechanism rather than the pump.

After the well is shut in, the gas migration will start to drive up the casing pressure from its initial shut-in reading. The casing pressure is allowed to rise to a predetermined safety margin. Reaching the working margin pressure indicates the point when the choke operator starts to bleed mud from the well. He tries to maintain a constant casing pressure while cracking the choke periodically and removing mud from the well. The gas expands, and the idea is to remove enough volume so that the hydrostatic pressure in the removed mud is equivalent to the working margin buildup. After the removal of this amount of mud, the gas influx has expanded by an amount equal to the incremental mud volume removed from the well, and the BHP is reduced back to the original shut-in recording. This operation is continued until the choke pressures stabilize or secondary control can be regained. If the influx reaches the surface and gas is coming through the choke, the bleeding process is stopped. The annulus is then monitored for further pressure buildup. The casing pressures for a typical volumetric procedure are plotted against cumulative pit gain in **Fig. 23**. From the figure we can see that the initial pit gain is 20 bbl and the SICP is 100 psi. The pressure is then allowed to increase by the predetermined safety margin (100 psi) and a further increase of 100 psi which is the working margin. When the maximum working margin is reached, approximately 16 bbl of mud is bled off to reduce the bottomhole pressure back to its initial shut-in value, 4,600 psi (**Fig. 24)**. The casing pressure increases as the procedure continues, because the gas expands as it approaches the surface. These steps are repeated until the casing pressure has stabilized, in this example at 700 psi. The bleeding process is stopped if the gas exits the choke, and the annulus pressure is monitored for further build-up.

Lubrication

Lubrication is a method to replace gas at the surface with mud in a controlled manner without circulation. A calculated mud volume is pumped directly into the gas column, and the mud has to fall through the column before the gas is bled until the casing pressure falls to a calculated level. This procedure is repeated until all the gas has been removed.

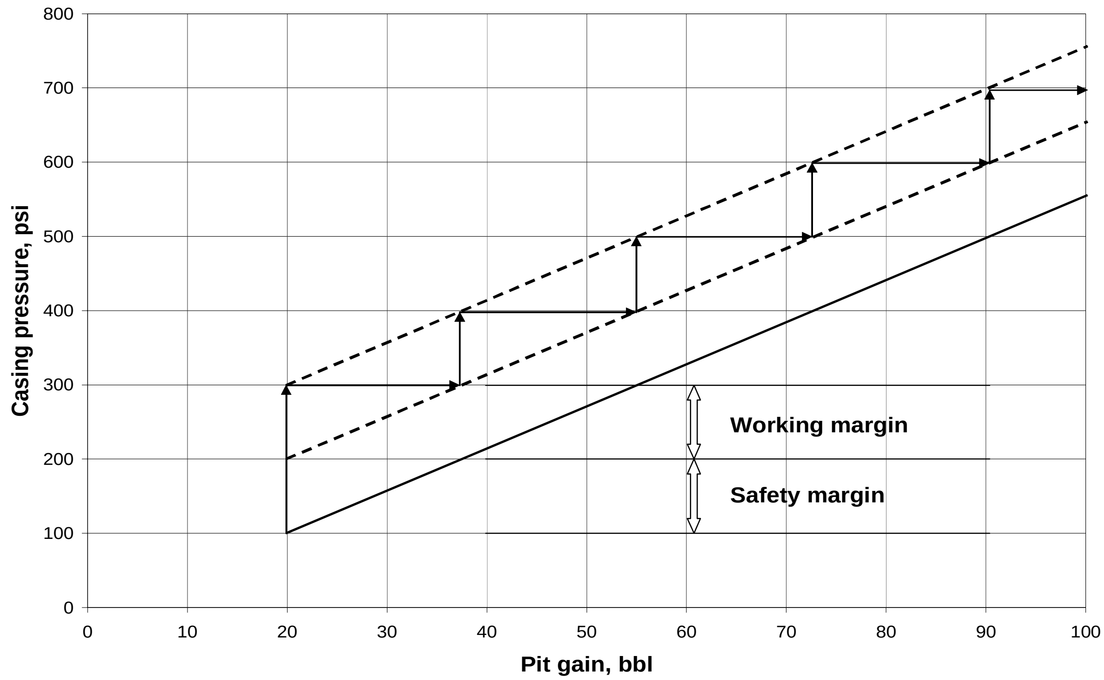


Fig. 24 – Casing pressure during a volumetric procedure.

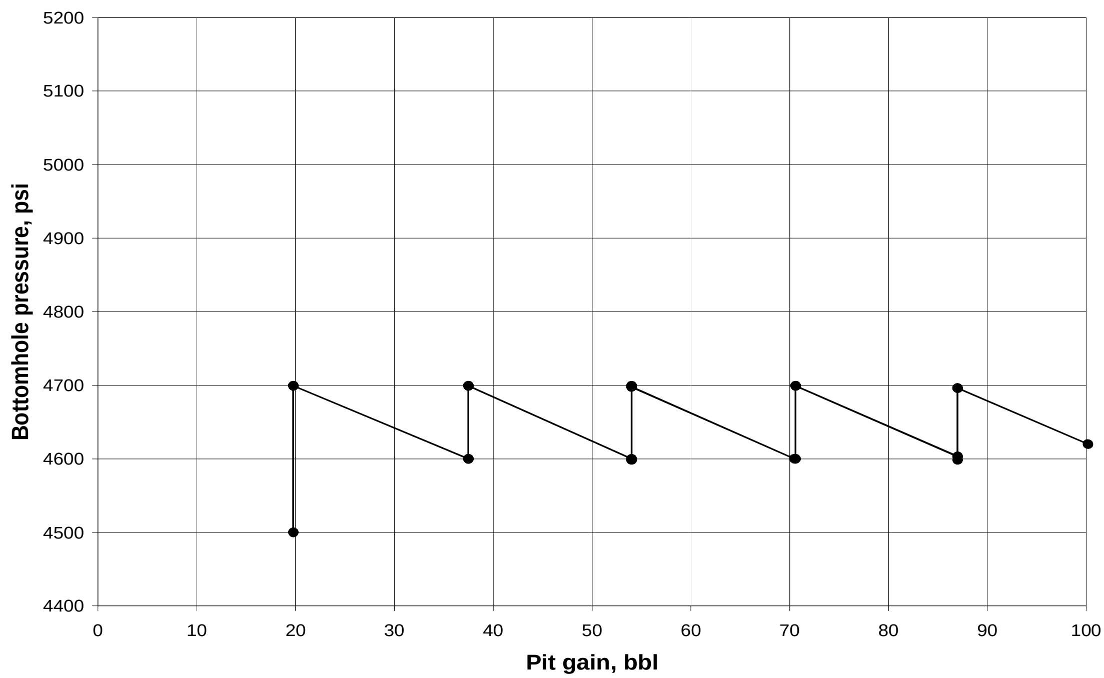


Fig. 25 – Bottomhole pressure during a volumetric procedure.

Staging in the hole

Staging in the hole is used in off-bottom well-control operations. The main idea behind this method is to place heavy enough mud to balance pore pressure from the depth where the bit is located. When the drillpipe is run into the hole, the heavy mud is displaced from the well and lighter mud is replaced from below. This has to be taken into account when calculating the density of the heavy kill-mud.

Reverse circulation

Reverse circulation procedures are most often used during workovers and completion operations, but may be advisable in some situations to circulate out a kick in drilling operations. Fluid is pumped into the annulus and the returns are taken from the drill string. The main advantage of this is that a gas kick is kept within the drill string and protects the formation and casing from excessive pressures. The disadvantages are many; the most important is the friction pressure loss in the drillstring that is much higher than it would be in the annulus. This acts directly on the ECD and the bottomhole conditions, and the ECD can easily get too high resulting in fracture of the formation and loss of circulation.

Bullheading

When applying bullheading, fluid is pumped into the annulus of a shut-in well at a sufficient rate and pressure to fracture the formation and force the kick fluids into the loss zone. This method is fairly common in completed wells, but is not a conventional way of killing a well in standard drilling mode. However, under some circumstances this method may be a good alternative. Reasons for bullheading could include H_2S kicks, inability to circulate on bottom, or a well that is not able to handle a conventional kill.

APPENDIX C

CONVERSION OF ANNULAR VELOCITY TO FLOW RATE

The desired annular velocity = 0.9 m/s.

$V = 0.9 \text{ m/s} \times 3.28 \text{ ft/m} = 2.95 \text{ ft/sec}$.

D_2 = inside diameter of wellbore = 9.875 in.

D_1 = outside diameter of drillpipe = 5.000 in.

$Q \text{ (gal/min)} = V \text{ (ft/sec)} \times 2.448 \times [D_2(\text{in})^2 - D_1(\text{in})^2]$.

$Q = 2.95 \times 2.448 \times [(9.875)^2 - (5.000)^2] =$ **524 gal/min**.

VITA

Name:	Bjorn Gjorv
Address:	Krokenteig 11
	5760 Roldal
	Norway
Date of birth:	November 7, 1978. Odda, Norway.
Parents:	Mr. Svein Gjorv
	Mrs. Margit Rabbe Gjorv
Education:	Texas A&M University, College Station, TX
	M.S. in Petroleum Engineering, August 2003
	Stavanger University College, Norway
	B.S. in Petroleum Engineering, June 2000

Part III

Final Report for Task 2. Results of a parametric study to determine the most efficient annular velocity to remove gas from near horizontal wellbores.

By

Mr. Max Long, Texas A&M University

PART III

KICK CIRCULATION ANALYSIS FOR EXTENDED-REACH AND HORIZONTAL WELLS

A Thesis

by

MAXIMILIAN M. LONG

Submitted to the Office of Graduate Studies of Texas A&M University in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2004

Major Subject: Petroleum Engineering

KICK CIRCULATION ANALYSIS FOR

EXTENDED-REACH AND HORIZONTAL WELLS

A Thesis

by

MAXIMILIAN M. LONG

Submitted to Texas A&M University
in partial fulfillment of the requirements
for the degree of

MASTER OF SCIENCE

Approved as to style and content by:

Hans C. Juvkam-Wold (Chair of Committee)	Jerome J. Schubert (Member)
Malcolm J. Andrews (Member)	Stephen A. Holditch (Head of Department)

December 2004

Major Subject: Petroleum Engineering

ABSTRACT

Kick Circulation Analysis for Extended-Reach and Horizontal Wells.

(December 2004)

Maximilian M. Long, B.S., LeTourneau University

Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

Well control is of the utmost importance during drilling operations. Numerous well control incidents occur on land and offshore rigs. The consequences of a loss in well control can be devastating. Hydrocarbon reservoirs and facilities may be damaged, costing millions of dollars. Substantial damage to the environment may also result. The greatest risk, however, is the threat to human life.

As technology advances, wells are drilled to greater distances with more complex geometries. This includes multilateral and extended-reach horizontal wells. In wells with inclinations greater than horizontal or horizontal wells with washouts, buoyancy forces may trap kick gas in the wellbore. The trapped gas creates a greater degree of uncertainty regarding well control procedures, which if not handled correctly can result in a greater kick influx or loss of well control.

For this study, a three-phase multiphase flow simulator was used to evaluate the interaction between a gas kick and circulating fluid. An extensive simulation study covering a wide range of variables led to the development of a best-practice kick circulation procedure for multilateral and extended-reach horizontal wells.

The simulation runs showed that for inclinations greater than horizontal, removing the gas influx from the wellbore became increasingly difficult and impractical for some geometries. The higher the inclination, the more pronounced this effect. The study also showed the effect of annular area on influx removal. As annular area increased, higher circulation rates are needed to obtain the needed annular velocity for efficient kick

removal. For water as a circulating fluid, an annular velocity of 3.4 ft/sec is recommended. Fluids with higher effective viscosities provided more efficient kick displacement. For a given geometry, a viscous fluid could remove a gas influx at a lower rate than water. Increased fluid density slightly increases kick removal, but higher effective viscosity was the overriding parameter. Bubble, slug, and stratified flow are all present in the kick-removal process. Bubble and slug flow proved to be the most efficient at displacing the kick.

DEDICATION

This work is dedicated to my father, Louis H. Long, for his love, support, constant encouragement, and sound advice.

ACKNOWLEDGMENTS

Dr. Hans C. Juvkam-Wold, thank you for your excellent instruction in class and advice regarding this project.

Dr. Jerome Schubert, thank you for providing me with this project and for your guidance and friendship along the way.

Dr. Dick Startzman, thank you for your hospitality and friendship.

To my friends, thank you for your friendship and all the fun times at Texas A&M.

Ray Oskarsen, thank you for answering my many questions and sharing your office with me.

I would also like to thank Minerals Management Service and the Offshore Technology Research Center for funding this project, and the support staff at OLGA for providing technical insight and support and for your interest in this work.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Page

Page

Page

INTRODUCTION

Hydrocarbon production from a wellbore first began in the United States in 1859. Titusville, located in the northwest corner of Pennsylvania, became the home of the first oil boom. Employed by the Seneca Oil Company, E.L. Drake was commissioned with the task of drilling the first oil well. On 27August 1859, at a depth of 69 ft, that well struck oil. The well produced approximately 20 bbl/D.[1]

Technology and experience have rapidly increased since the days of E.L. Drake, allowing greater amounts of hydrocarbons to be reached and produced with greater efficiency. However, drilling still remains the primary and conventional method implemented to bring the hydrocarbons from the ground to earth's surface.

Hydrocarbons are located in the pore volume of clastic or carbonate reservoirs. The pressure of a given reservoir can be dependent upon a myriad of factors, some of which include stress regime, compaction, diagensis, tectonics, and depositional environment. When drilling, this pressure must be controlled to avoid a blowout or influx of formation fluids. Conventionally, the wellbore is filled with a fluid of a given density to obtain a desired bottomhole pressure. This hydrostatic head is used to offset the reservoir or formation pressure.

The process of controlling the formation pressure in a reservoir is called *well control*. The formal definition of well control is the prevention of uncontrolled flow of formation fluids into the wellbore.[2] In that definition, emphasis should be placed on the uncontrolled flow element; wells are often drilled in an underbalanced condition, which allows formation fluids to flow into the wellbore, to obtain increased penetration rate and minimize formation damage.

Well control is of the utmost importance during drilling operations.[3] **Fig. 1** illustrates losses of well control in the Gulf of Mexico and Pacific Coast regions. These offshore

This thesis follows the style and format of *SPE Drilling and Completion*.

U.S. data, however, account for only a small fraction of well-control incidents. Numerous additional well-control incidents occur on land rigs and in foreign countries. The consequences of a loss in well control can be devastating. Hydrocarbon reservoirs and facilities may be damaged, costing millions of dollars. Substantial damage to the environment may also result. The greatest risk, however, is the threat to human life.

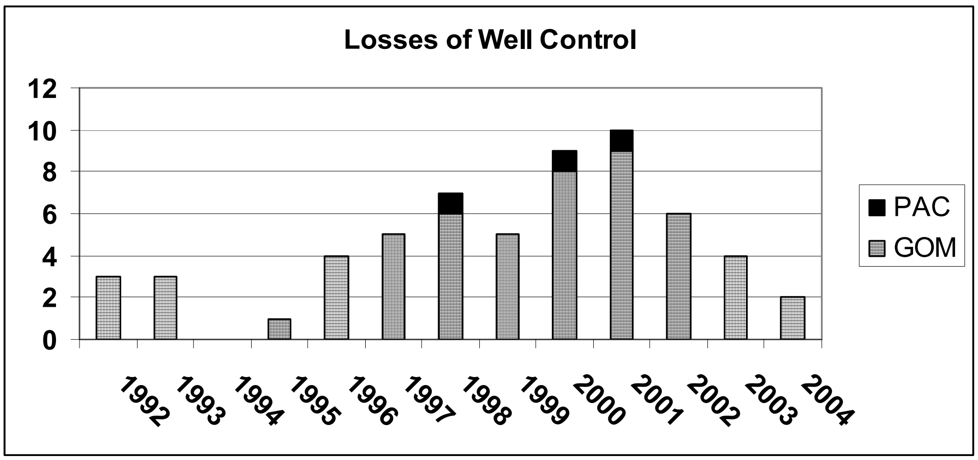


Fig. 1—Losses of well control in the Gulf of Mexico and Pacific Coast.[4]

Well-Control Methods

Unplanned flow of reservoir fluids into the wellbore is commonly called a *kick*. In the event a kick is taken while drilling, drilling operations are suspended and the well is shut in using blowout preventers. Stabilized casing and drillpipe pressures are recorded and used to calculate a new bottomhole pressure and new mud weight to offset the formation's pressure.[3] The kick is then usually circulated from the wellbore using one of two methods: the Wait and Weight method or the Drillers method. Both methods circulate drilling mud down the drillpipe and up the annulus to displace the kick. The bottomhole pressure is kept constant adjusting the choke to hold backpressure at the surface, which prevents an additional influx from entering the wellbore.[3] Upon removal of the kick and placement of the new drilling mud, drilling operations can resume as normal. These methods are conventional well-control procedures. Specialty procedures, such as volumetrics, bull heading, dynamic kills, and relief wells, may also be employed if needed.

Horizontal and Near-Horizontal Well-Control Problems

From the standpoint of well control, it is desirable to transport the kick though the wellbore as one continuous unit. In a vertical or slightly deviated well, buoyancy forces will naturally push the kick fluid upward as a unit. This is not a valid assumption for extended-reach wells, multilateral wells, or horizontal wells, some of which are drilled at inclinations slightly below or above horizontal. **Fig. 2** illustrates a possible well trajectory. In this case, buoyancy forces will cause the kick fluids to remain at the high side of the inclined section. If the correct displacement velocity or flow regime is not present, the buoyancy forces will be the dominant forces and the kick will remain in the wellbore. Washouts (wellbore sections with larger diameter than normal) may also trap gas hydrocarbons and prevent them from being removed by circulation. This is an increasingly important aspect of well control as more horizontal and multilateral wells are drilled with increasingly complex geometries.

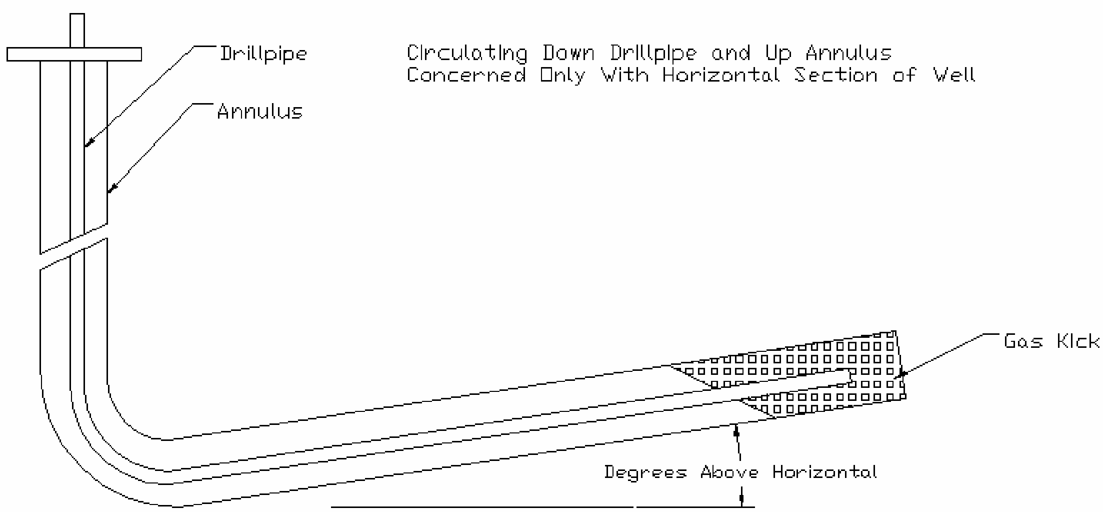


Fig. 2—Horizontal well trajectory may incline upward, trapping kick fluids at toe of wellbore.

LITERATURE REVIEW

Kick Simulators

Although a considerable amount of work has been done in well control, little attention has been given to the issue of kick-removal dynamics. Numerous kick simulators have the capability to model various kick sizes and intensities for any given geometry.[5-11] These simulators are extremely useful in predicting pressure profiles during the kick-removal circulation. The majority of these simulators model the kick circulation as a piston-like displacement process, meaning the kick is displaced by a continually advancing front of drilling mud. This does not allow the drilling and formation fluids to mix appropriately. In reality, a two-phase flow system exists in which the phases flow at differing velocities. This phenomenon is called multiphase flow. Santos[5,6] and Verfting[7,8] have both developed kick simulators capable of modeling the multiphase-flow region. Both simulators use multiphase-flow correlations and complex systems of equations solved numerically.

Physical Experiments

Extensive physical experiments have been conducted using flow loops and test apparatus.[12-17] The majority of this research is aimed at efficiently producing existing wells, alleviating petroleum processing-equipment problems, and gathering and transportation concerns. Baca[16] used a 45-ft test loop to study gas removal in horizontal wellbores with an inclination greater than horizontal. His test setup consisted of outer pipe with an inner diameter of 6.37 in. and inner pipe with an outer diameter of 2.37 in. As gas and liquid were flowed through the test structure at various rates, the flow regime and flow direction of the gas phase, either co-current or concurrent, were recorded. Ustan[17] continued this research with a wider range of gas and liquid rates. These works concluded that a minimum annular superficial liquid velocity for a given gas rate is needed for avoidance of counter-current flow.

Multiphase Flow

Multiphase flow is defined as two or more phases flowing simultaneously through a given area. Flow behavior becomes considerably more complex when two or more phases are present. Differing densities and viscosities lead to phase separation, which facilitates the phase travel at differing velocities in the pipe. The velocities of the different phases determine the flow regime that will occur. **Fig. 3** depicts the various flow regimes for the multiphase horizontal flow.

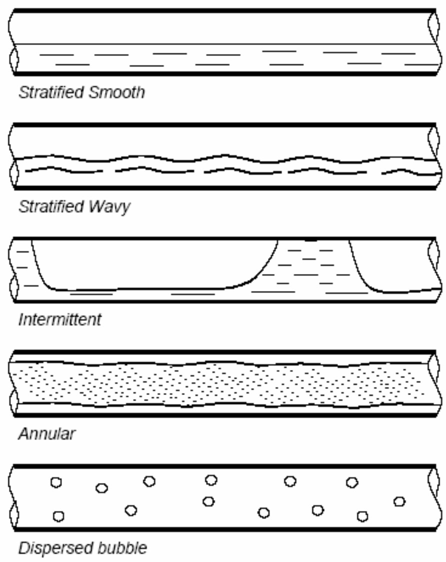


Fig. 3—Horizontal flow may exhibit widely varying patterns.[18]

Flow Patterns

Brill and Mukherjee[19] defined the significant flow patterns used in discussing fluid flow in the wellbore:

Stratified flow is characterized a steady flow of both gas and liquid. The contact area between the two phases can be smooth or wavy.

Slug flow or *intermittent flow* is characterized by a series of slug units. Each unit is composed of a gas pocket called a Taylor bubble, a plug of liquid called a slug, and a film of liquid around the Taylor bubble. The liquid slug, carrying distributed gas bubbles, bridges the pipe and separates two consecutive Taylor bubbles.

Annular flow is characterized by the axial continuity of the gas phase in a central core with the liquids flowing along the walls and as dispersed droplets in the core.

Bubble flow is characterized by a uniformly distributed gas phase and discrete bubbles in a continuous liquid phase. The presence or absence of slippage between the two phases further classifies bubble flow into bubbly and dispersed bubble flows. In bubbly flow, relatively fewer and larger bubbles move faster than the liquid phase because of slippage. In dispersed bubble flow, numerous tiny bubbles are transported by the liquid phase, causing no relative motion between the two phases.

Liquid holdup is defined as the fraction of a pipe cross-sectional area that is occupied by the liquid phase. Empirical correlations can predict liquid holdup for a range of liquid and gas velocities. **Fig. 4** provides a visual of the mechanics of liquid holdup, where HL is the fraction of liquid in the pipe.

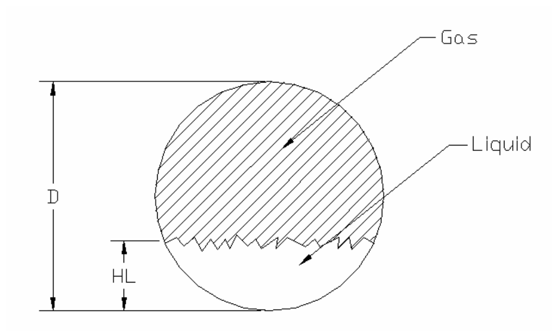


Fig. 4—Liquid holdup diagram.

Superficial velocity is defined by considering a single phase of a multiphase system and assuming it occupies the entire pipe area. The superficial velocity of the liquid phase is defined by dividing the liquid volumetric flow rate by the entire pipe area. The equations for gas and liquid superficial velocities are given below. The previously mentioned flow patterns may also be defined by the superficial velocities for a given geometry. **Fig. 5** illustrates a generic flow pattern map for a given geometry.

$$V_{sg} = \frac{Q_g}{A_t} \qquad\qquad V_{sL} = \frac{Q_L}{A_t}$$

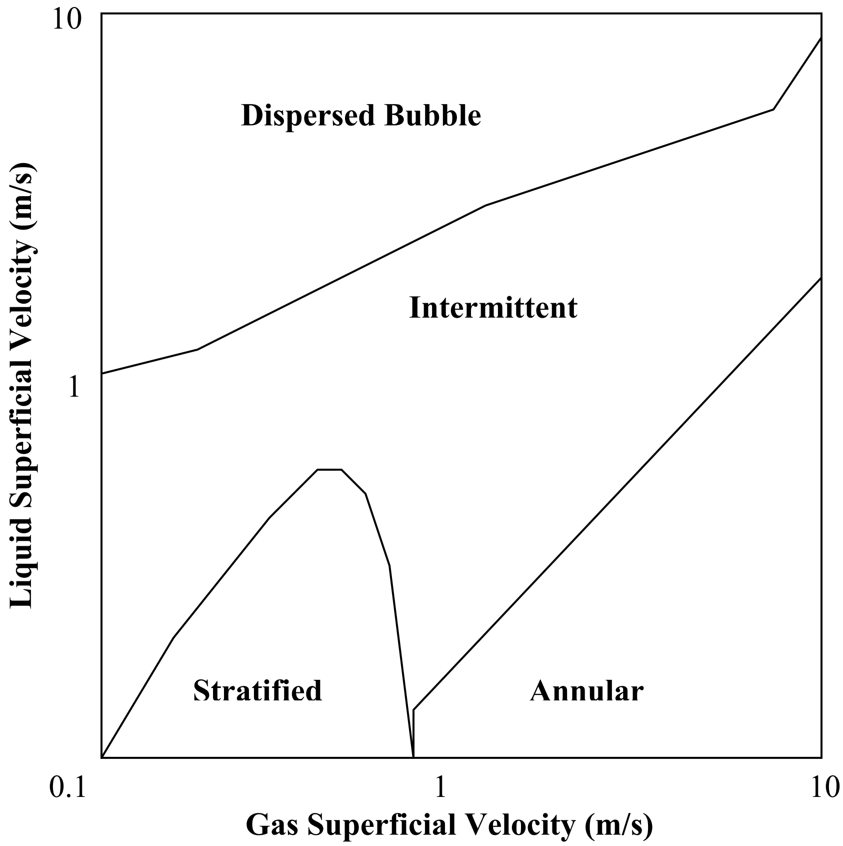


Fig. 5—Generic flow pattern map illustrates effects of superficial velocities.

OBJECTIVES AND PROCEDURES

Research Objectives

The main objective of this work was to accurately model the kick-removal circulation procedure for horizontal wells at varying inclinations above and below true horizontal. The procedures used to reach this objective follow:

- Determine the effects of circulation rate and superficial velocities on kick removal for a given inclination and geometry.
- Determine the flow regimes present during the removal of a kick.
- Determine the effects of wellbore friction on kick removal.
- Generate correlations that model the interaction between annular area and annular velocity.
- Model the effects of mud properties on kick removal
- Provide data that can be used to create a best-practice well-control procedure.

METHODOLOGY OF STUDY

OLGA

OLGA,[15] an industry recognized multiphase computer simulator, was used to model the system. OLGA is capable of modeling a wide range of scenarios by varying fluid properties, pressure, temperature, geometry, trajectory, influx rate, circulation rate, friction, etc. OLGA is based on a one-dimensional, two-fluid model. For the gas and liquid phases, the model consists of separate conservation equations for both mass and momentum. A single energy conservation equation is used for the liquid and gas phase. Solving the system of conservation equations requires averaging and simplification; closure laws are used to replace the information lost in the simplification process. The closure laws describe transfer of heat and momentum between the phases and between the walls of the wellbore and drillpipe. The partial differential equations are solved by using a numerical finite-differencing method. A given number of computational sections is defined along the trajectory of the wellbore, and the solution is advanced in discrete time steps. Multiple runs made by varying input parameters produce a wide spectrum of data. These data compose a data matrix, predicting needed circulation rates for efficient kick removal.

OLGA Input Data

OLGA operates on a system of keyword tabs. Each keyword tab contains information pertaining to a certain aspect of the simulator. For instance, the geometry tab contains information regarding the trajectory of the wellbore, hole size, and friction factor. Once an input file has been generated, multiple cases can be run with varying input values for several parameters.

OLGA Output Data

OLGA is capable of recording a wide range of variables. Liquid holdup, superficial gas and liquid velocities, accumulated liquid and gas at outlet, and flow regime were of primary interest for this study. OLGA outputs data in two forms: trend data and profile data. Trend data are plotted with respect to time for a given location along the wellbore.

Profile data are plotted with respect to distance along the wellbore for a given time. The profile plot also allows time steps through the simulation for monitoring changes in liquid holdup or other parameters.

Test Setup

The trajectory used in the simulation runs has already been illustrated in Fig. 2. The vertical section of the well is 1,500 ft and the horizontal section is 2,500 ft inclined at 10, 5, 0, -5, and -10 degrees. An inclination of zero corresponds to a completely horizontal well. **Table 1** lists horizontal and vertical departures for each inclination. Three commonly used geometries were considered for the simulations. **Table 2** lists hole size, drillpipe size, and effective annular area. The annulus was modeled by a single pipe with a geometrical cross-sectional area equivalent to that of a conventional annulus. As in conventional drilling, water or mud was circulated down the drillpipe and returned up the annulus. A pressure-boundary condition was defined at the outlet of the vertical annular section to maintain a constant pressure at the annular outlet of the horizontal section. For all runs the annular pressure of the horizontal sections at the outlet was kept at 6,000 psi.

Table 1—Horizontal and Vertical Departures

Section Measured Length (ft)		2500
Degrees Above Horizontal	**Horizontal Length (ft)**	**Vertical Height (ft)**
10	2,462	434
5	2,490	218
0.0	2,500	0
-5.0	2,490	-218
-10.0	2,462	-434

Table 2—Geometry Data

Geometry	Hole Size (in)	Drill Pipe OD (in)	Weight (lb/ft)	Drill Pipe ID (in)	Annular Area (sq. in)
1	5	3.5	8.5	3.063	10.01
2	7.875	5.0	19.5	4.276	29.07
3	9.875	5.0	19.5	4.276	56.95

Table 3 lists kick-fluid properties used in the simulations. The gas-kick fluid composed of methane, ethane, and propane had a specific gravity of 0.5974. Using a PVT simulator, a table of temperature and pressure was constructed for the dependent gas properties. OLGA uses this table to accurately model gas behavior.

Table 3—Gas Composition

Component	Component	Mole Fraction	Molecular Weigth	yiMi
Nitrogen	N2	0.0000	28.0130	0.0000
Carbon Dioxide	CO2	0.0000	44.0100	0.0000
Hydrogen Sulfide	H2S	0.0000	34.0760	0.0000
Methane	CH4	0.9400	16.0430	15.0804
Ethane	C2H6	0.0300	30.0700	0.9021
Propane	C3H8	0.0300	44.0970	1.3229
Isobutane	i-C4H10	0.0000	58.1240	0.0000
Butane	n-C4H10	0.0000	58.1240	0.0000
Isopentane	i-C5H12	0.0000	72.1510	0.0000
n-Pentane	n-C5H12	0.0000	72.1510	0.0000
n-Hexane	C6H14	0.0000	86.1780	0.0000
Heptane	C7+	0.0000	114.2000	0.0000
		1.0000		17.3054
	Average Molecular Weight			17.3054
	Specific Gravity		γ_g	0.5974

Mud Properties

Water was used as the circulating fluid for the majority of the runs. The remainder of the runs were performed with water-based muds of varying density, plastic viscosity (PV), and yield point (YP). These values were selected from **Fig. 6**[20] and **Table 4,** which depict appropriate plastic viscosity and yield point values for a given mud density. From the PV and YP values, Fanning viscometer numbers were computed and used in calculating the flow-behavior index *n* and the consistency index *K* of the power law. The power law is used to model non-Newtonian fluids and predict their effective viscosity.

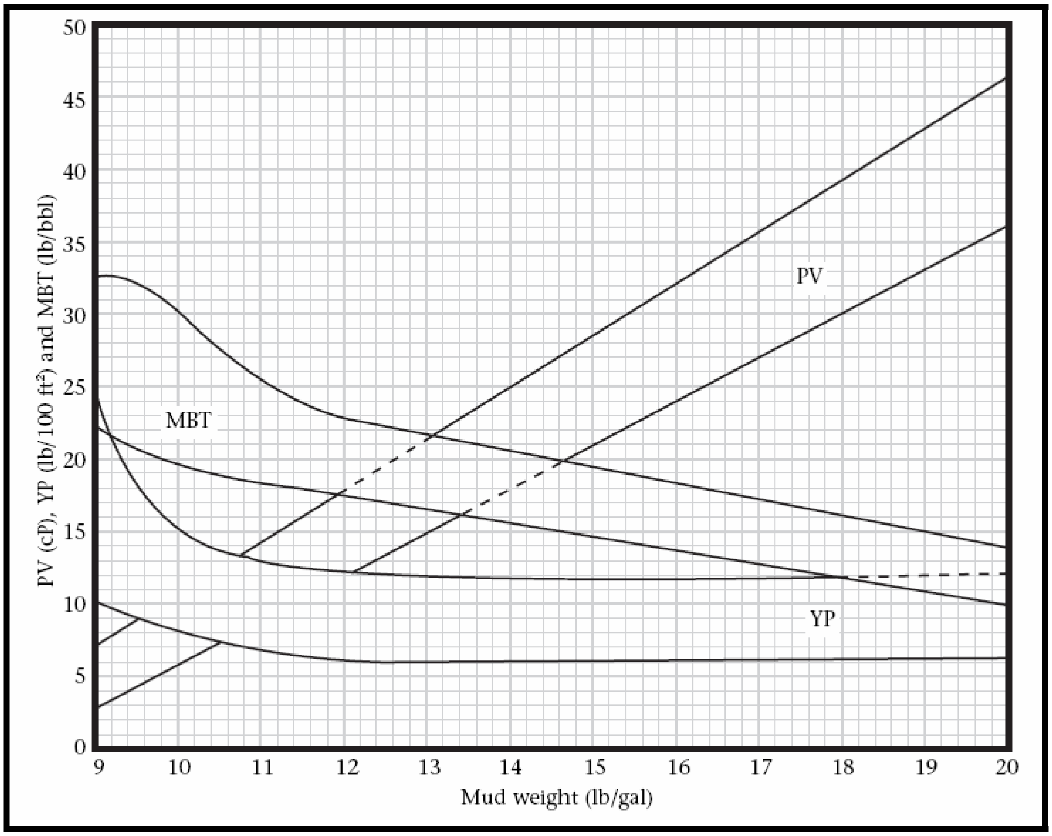


Fig 6—PV and YP for water-based muds.[20]

Table 4—Mud Properties

Density (lb/gal)	PV (cp)	YP (lb/(100 ft^2))	Theta 600	Theta 300	n	K
10	9	12	30	21	0.514	4.344
12	15	9	39	24	0.700	1.559
14	22	9	53	31	0.773	1.275
16	28	9	65	37	0.812	1.192

Simulation Procedure

The simulator may be started as soon as an input file has been entered. For a period of 1,800 seconds the simulator remains idle. This allows the simulator to reach equilibrium from the input data. At 1,801 seconds, gas kick begins to flow into the far end of the horizontal section. The gas kick flows for 300 seconds, accumulating to 15 barrels of net influx. At 3,600 seconds, the circulation procedure begins and does not end until the end of the simulation. This sequence of events was selected to model true-to-life circumstances as closely as possible.

RESULTS

Introduction

The following results were generated from OLGA simulations. Accumulated gas out, liquid holdup, and liquid superficial velocities were measured at the outlet of the annular horizontal section for each of the three geometries at five inclination angles. These figures show the efficiency of kick removal versus time for a specific circulation rate. Similar figures depict the effects of mud properties and wellbore friction. The figures also depict liquid holdup and flow regime versus the length of the horizontal section at a given time.

Runs Performed With Water

Geometry 1

Geometry 1 consists of a 5-in. hole size with 3.5 in. outer-diameter drillpipe. The effective annular area is 10.01 sq. in. **Figs. 7-21** illustrate the results for the five inclinations.

Inclination 10°

Fig. 5 shows the effects of circulation rate on kick removal. The 50-GPM rate is the only circulation rate that does not successfully remove the kick from the horizontal section, as evidenced by the curve lying on top of the x-axis. The 100-GPM rate efficiently transports the kick from the wellbore in approximately 6,800 seconds from the start of the simulation. The simulated kick removal times from the figures can be compared against calculated piston-like displacement times. From **Table 5**, calculated piston-like displacement times may be determined for a given wellbore geometry and circulation rate. A time of 3,600 seconds is added to the calculated piston-like displacement times so the values may be easily compared to the number read directly from the figures. For the 100 gpm for geometry 1, a value of 4,380 seconds is read from Table 5. The difference between the two numbers illustrates the interaction of the gas kick's buoyancy forces opposing the forces of the circulating fluid. For the 50 gpm case, the drag force of the circulating fluid is not sufficient to overcome the buoyancy of the gas kick. The kick will remain in the hole. The 200- and 300-gpm rates remove the kick in times approximately equal to that of piston-like displacement.

Fig. 7 depicts the liquid holdup at the outlet, but also is an indication which flow regime is present for each rate case. For the 75- and 100-GPM cases, a jagged line is present. This is representative of slug flow. The 200- and 300-GPM cases show a smooth up-and-down increase and decrease of the liquid holdup line. The liquid holdup nearly reaches a value of zero, meaning the annulus would be completely filled with gas. These features correspond to bubble flow. Fig. 8 shows that an annular velocity of 2.4 ft/sec can remove the kick from the wellbore, and an annular velocity of 3.25 ft/sec can do it efficiently.

Table 5—Kick Removal Time for Horizontal Section Assuming Piston-Like Displacement (Adjusted for circulation starting at 3,600 seconds)

Circulation Rate	Well Geometry		
	1	2	3
15	8802	18702	33186
45	5334	8634	13462
60	4900	7376	10997
75	4640	6620	9517
100	4380	5865	8038
125	4224	5412	7150
150	4120	5110	6559
175	4046	4894	6136
200	3990	4733	5819
225	3947	4607	5572
250	3912	4506	5375
275	3884	4424	5214
300	3860	4355	5079
350	3823	4247	4868
400	3795	4166	4709
450	3773	4103	4586
500	3756	4053	4488
550	3742	4012	4407
600	3730	3978	4283
650	3720	3949	4283
700	3711	3924	4234

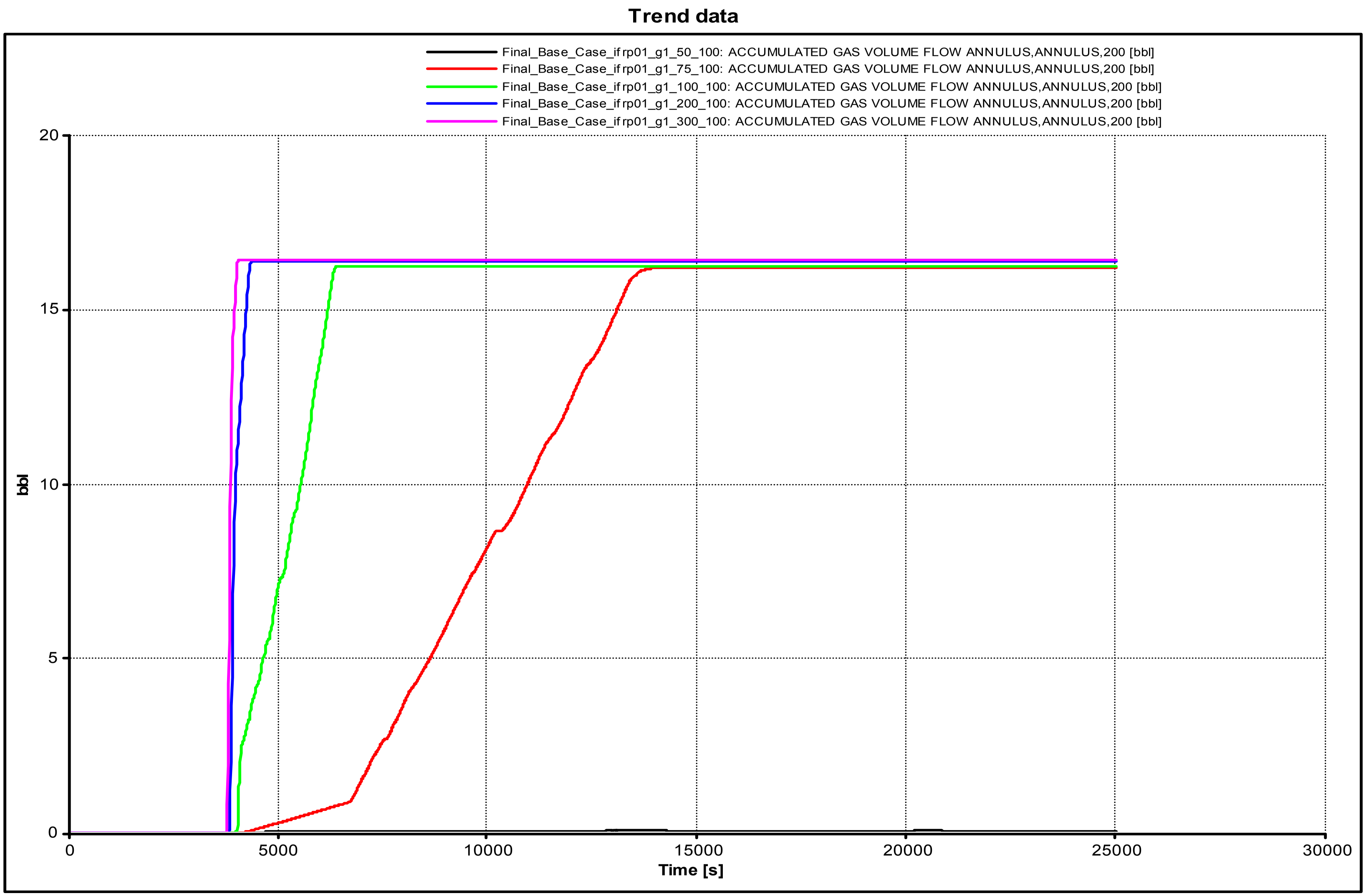


Fig. 7—Accumulated gas out at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

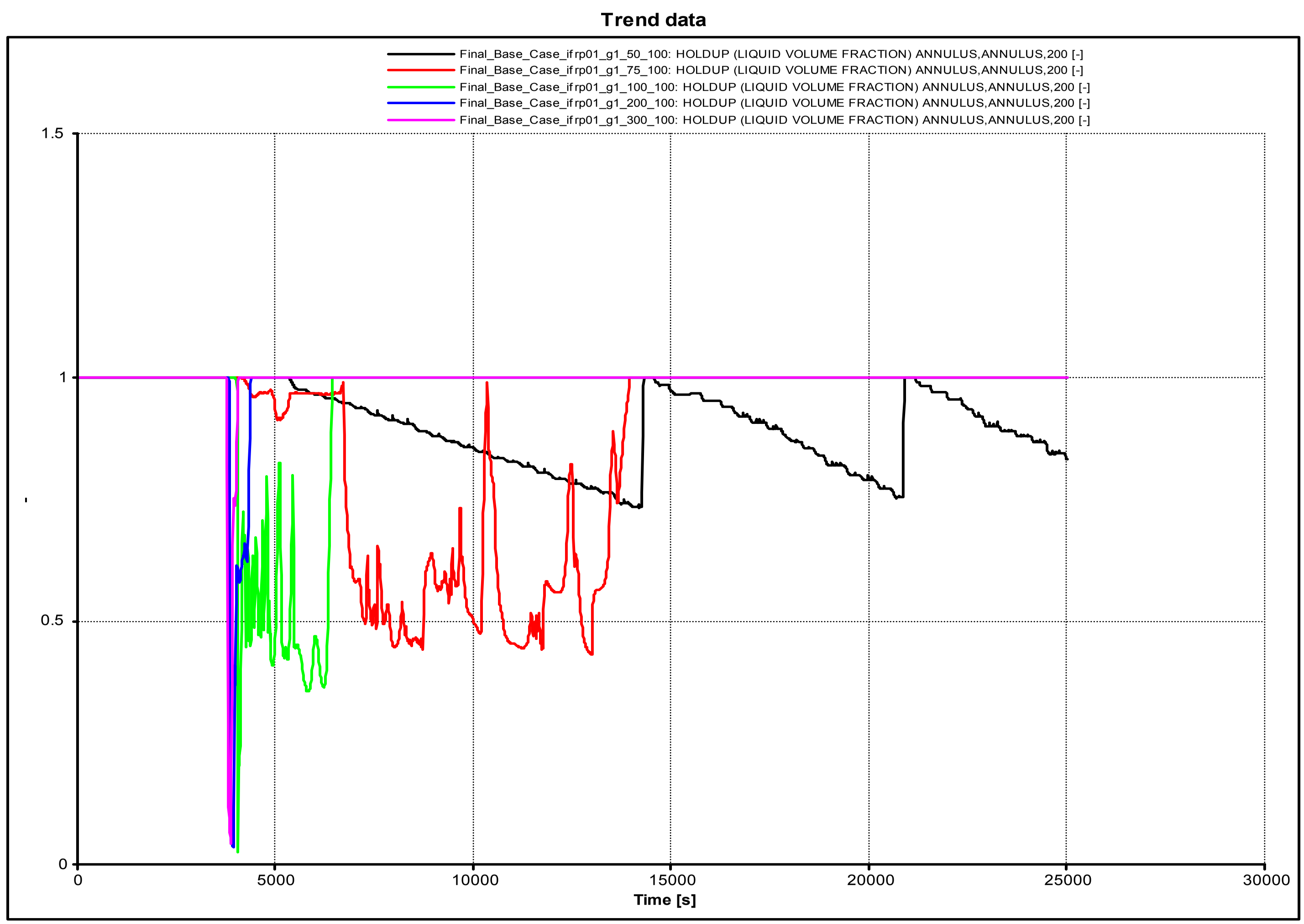


Fig. 8—Liquid holdup at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

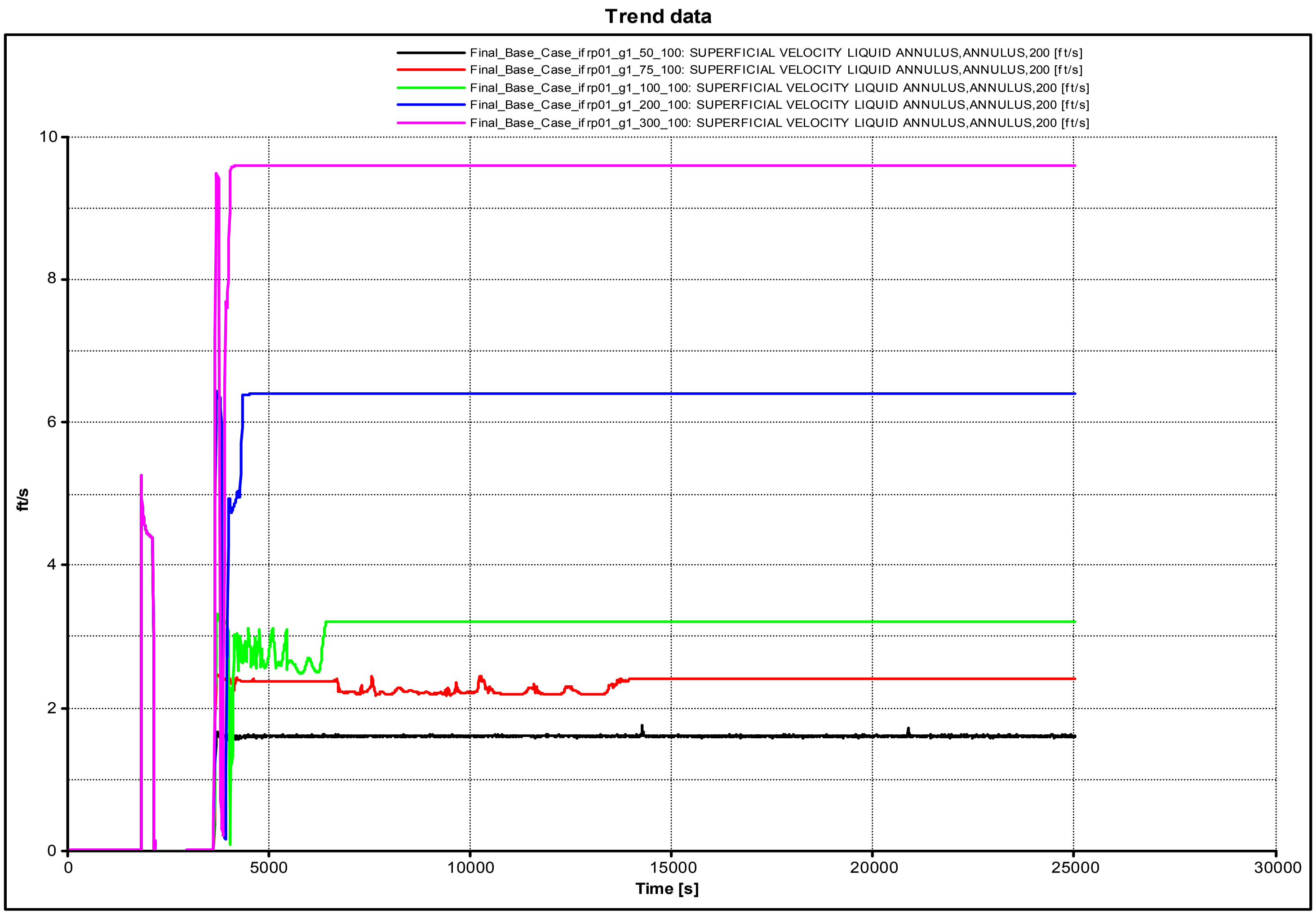


Fig. 9—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

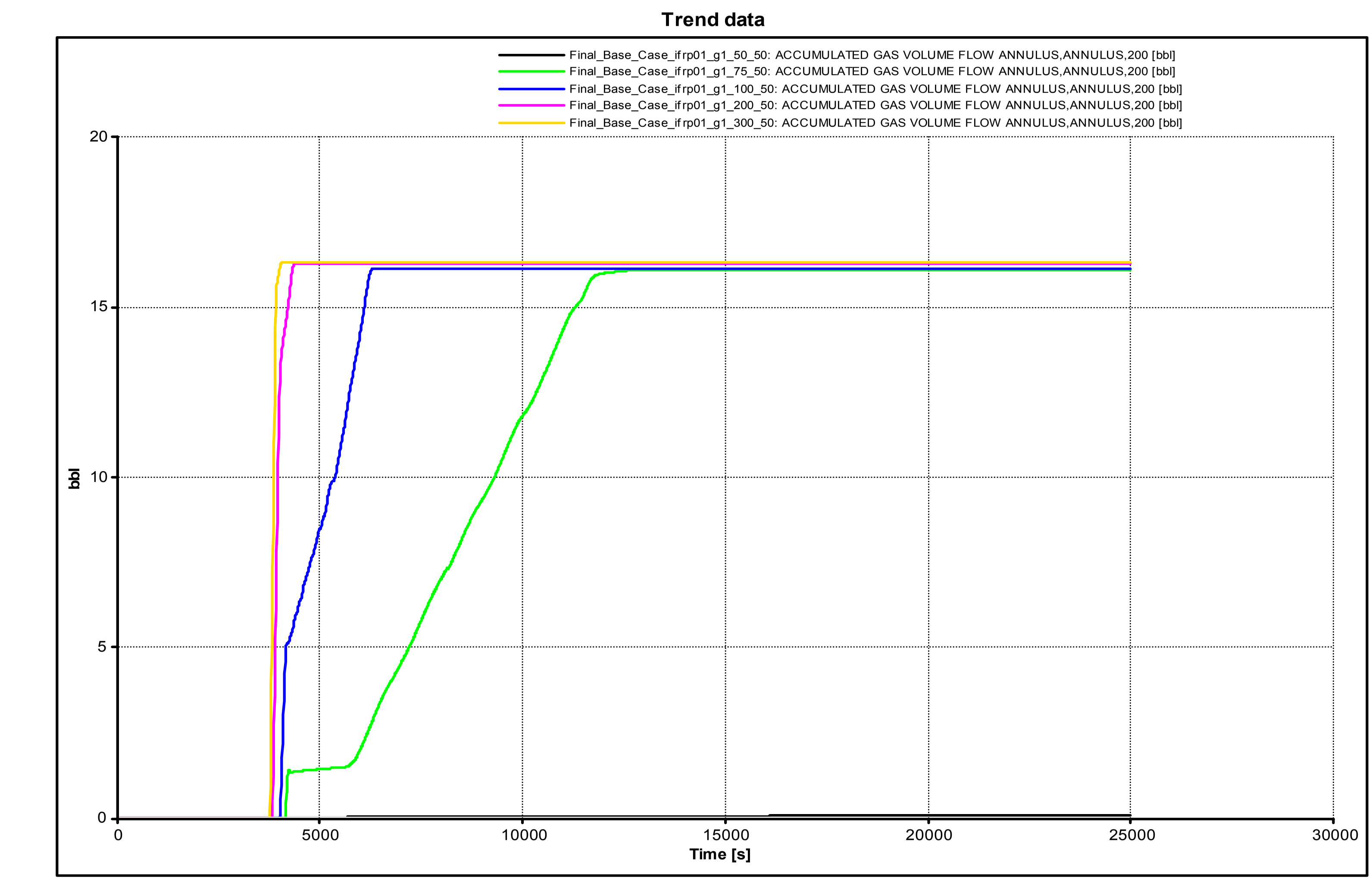


Fig. 10—Accumulated gas out at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

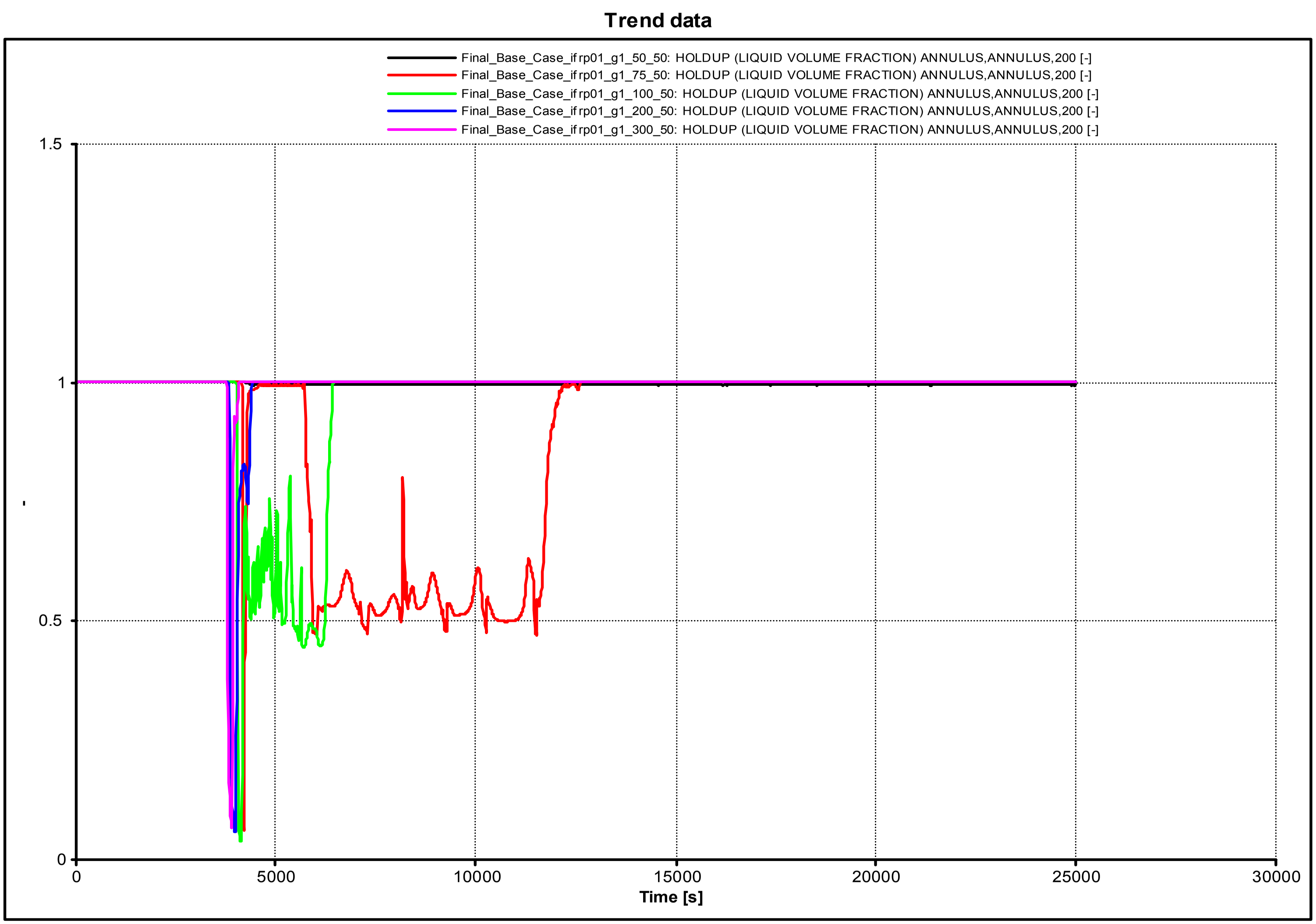


Fig. 11—Liquid holdup at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

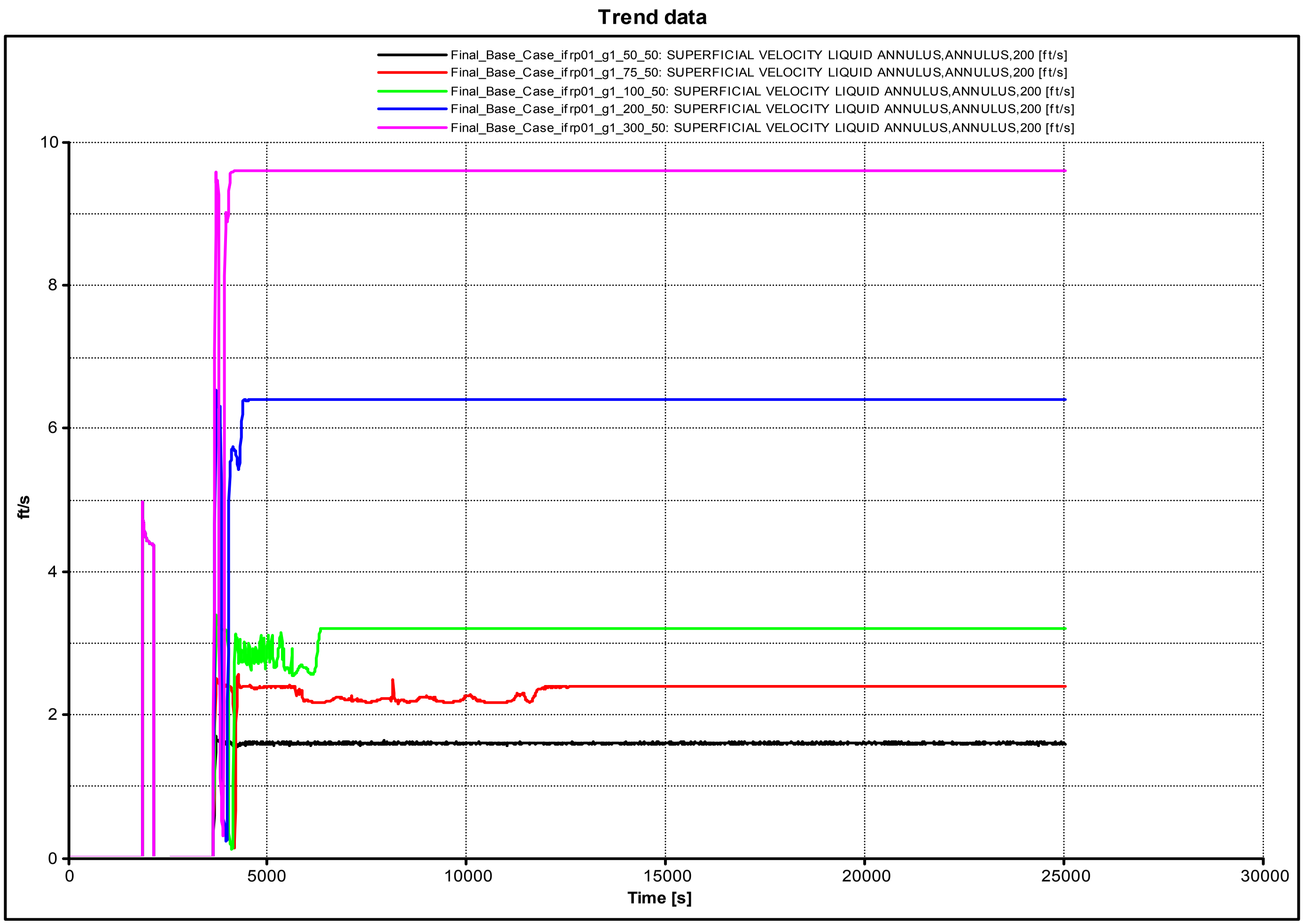


Fig. 12—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

Inclination 5°

Figs. 10 to 12 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case. However, the curves in Fig. 10 are shifted to the left when compared to Fig. 7. This reflects a decrease in gas-kick buoyancy forces resulting from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 13 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 14 shows smoothly increasing and decreasing liquid holdup curves. This is consistent with a stratified flow regime. It is important to note that this model assumes a completely smooth annulus with no undulations or washouts.

Inclination -5°

For an inclination of 5º below horizontal, the gas begins migrating up the annulus instantaneously. When circulation begins at 3,600 seconds, the majority of the gas kick has left the horizontal section. During the gas-kick influx, a small amount of gas begins to migrate up the drillpipe instead of the annulus. Once circulation begins, the gas is displaced from the drillpipe into the annulus and removed from the annular horizontal section. This phenomenon is depicted in Fig. 16 by the irregular top portion of each curve. The shape or slope of the top portion of these curves is dependent on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 17 and Fig. 18.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. However, the steeper slope of the horizontal section causes the curves in Fig. 19 to shift slightly to the left in comparison to Fig. 16. Fig. 20 is similar to Fig. 18 and is therefore of little interest.

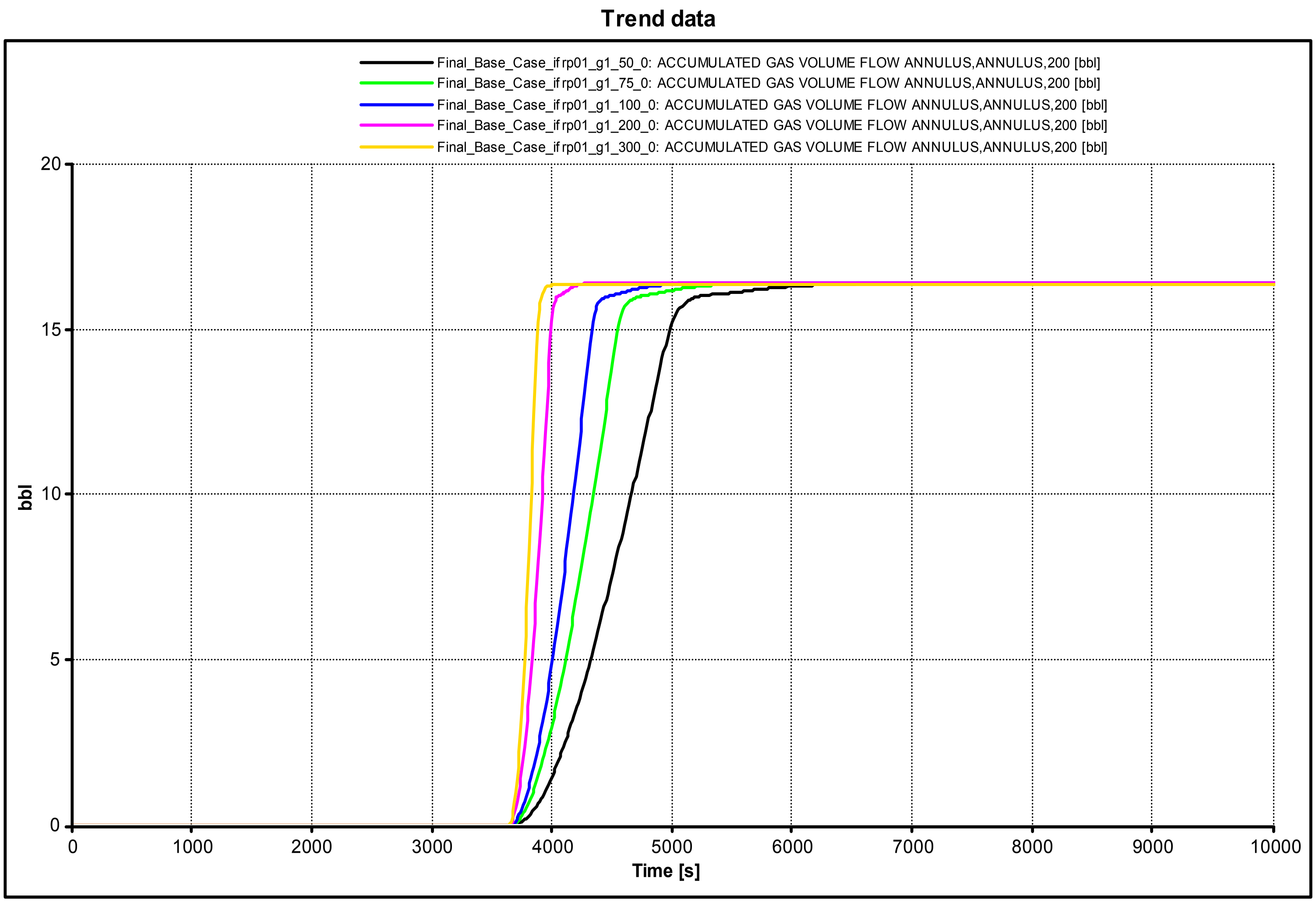


Fig. 13—Accumulated Gas out at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

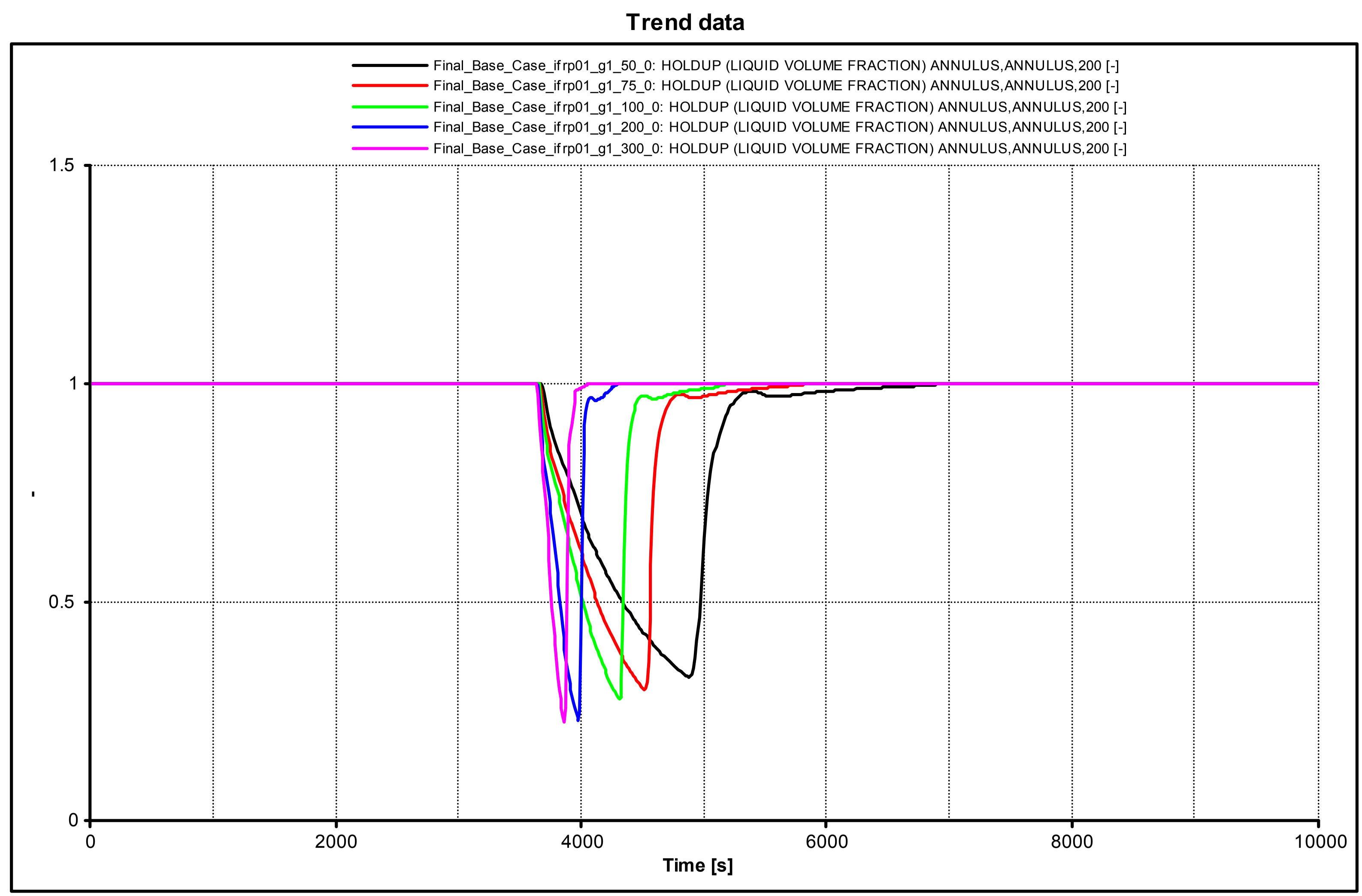


Fig. 14—Liquid holdup at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

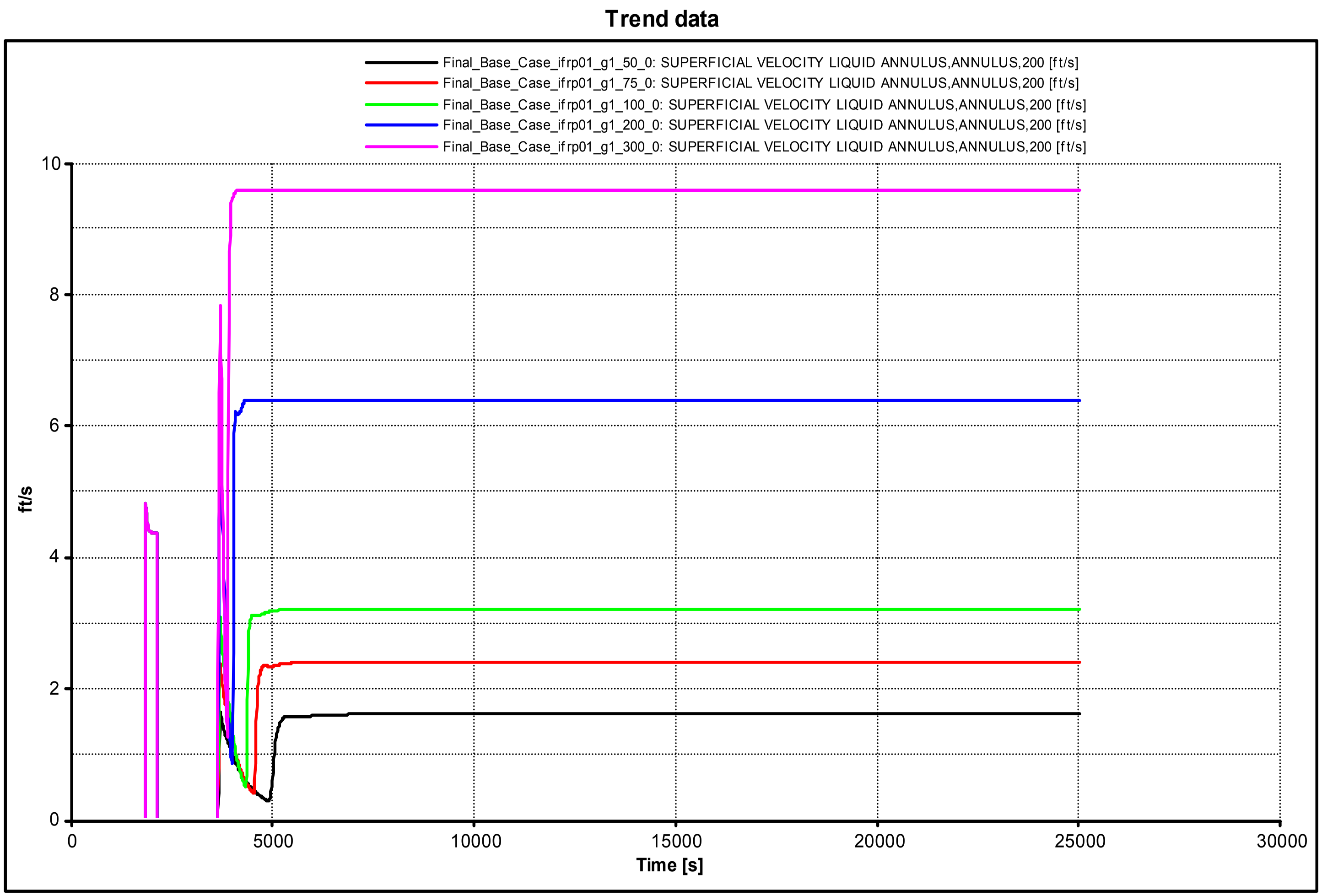


Fig. 15—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

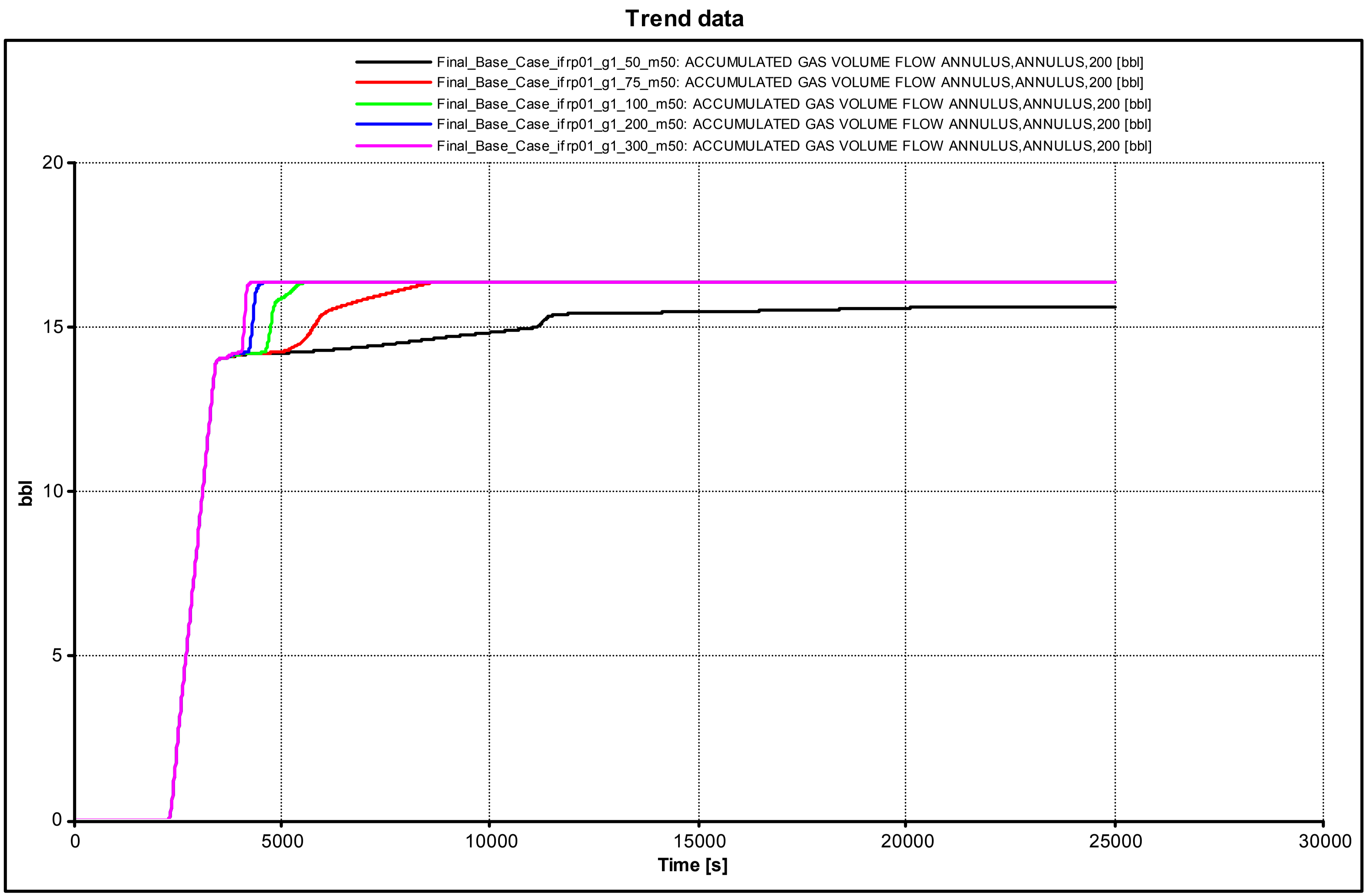


Fig. 16—Accumulated gas out at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

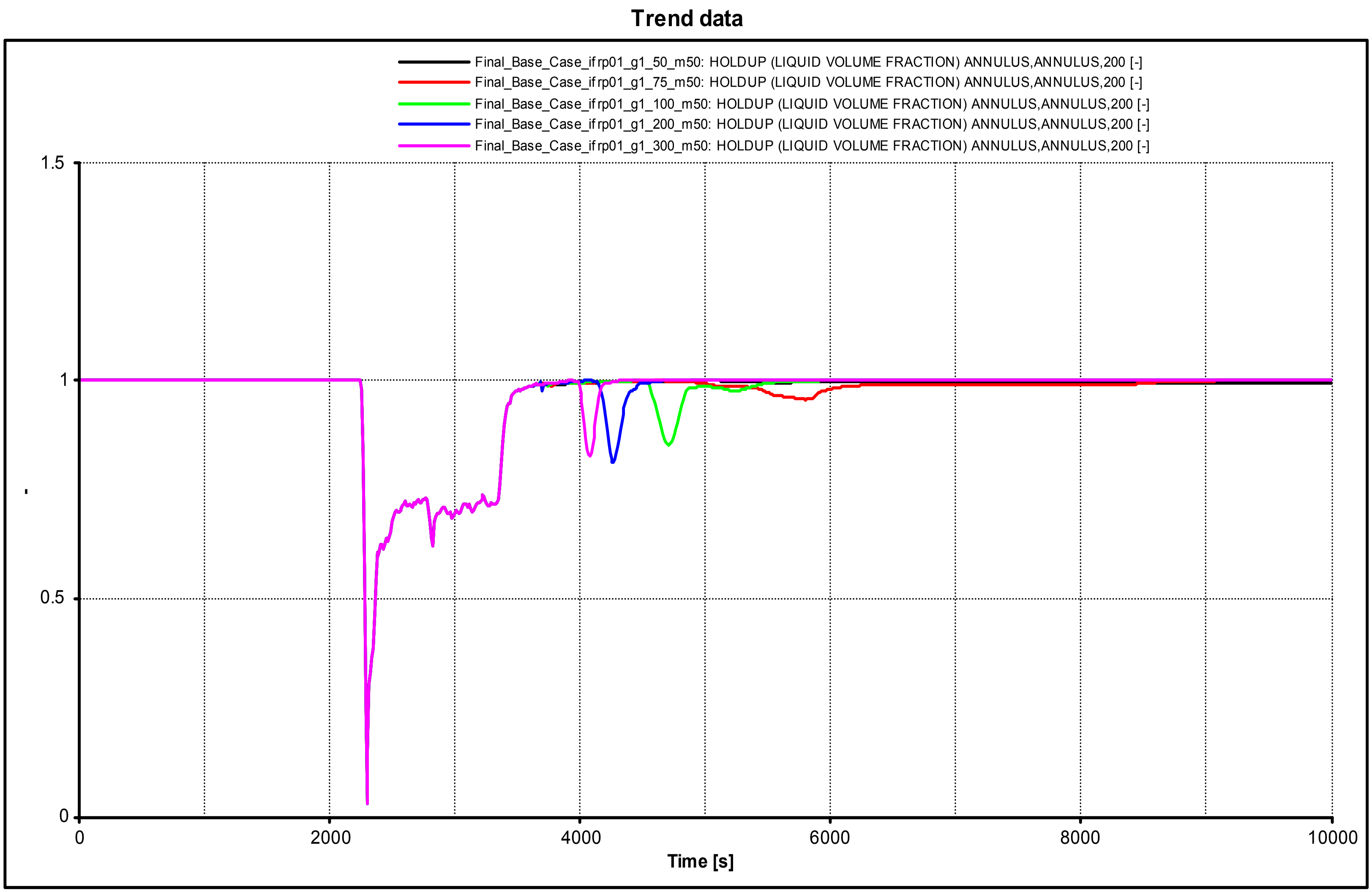


Fig. 17—Liquid holdup at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

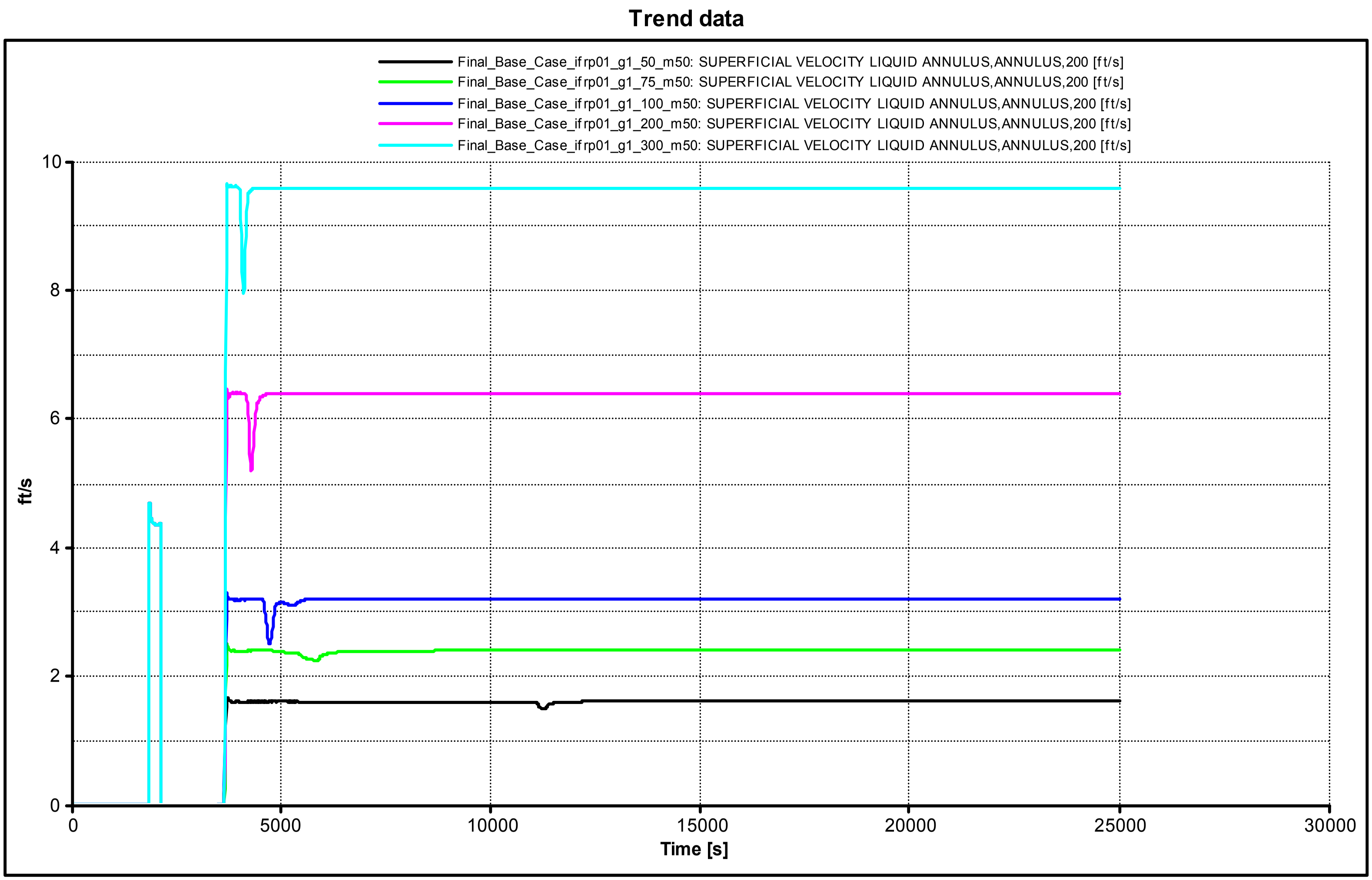


Fig. 18—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

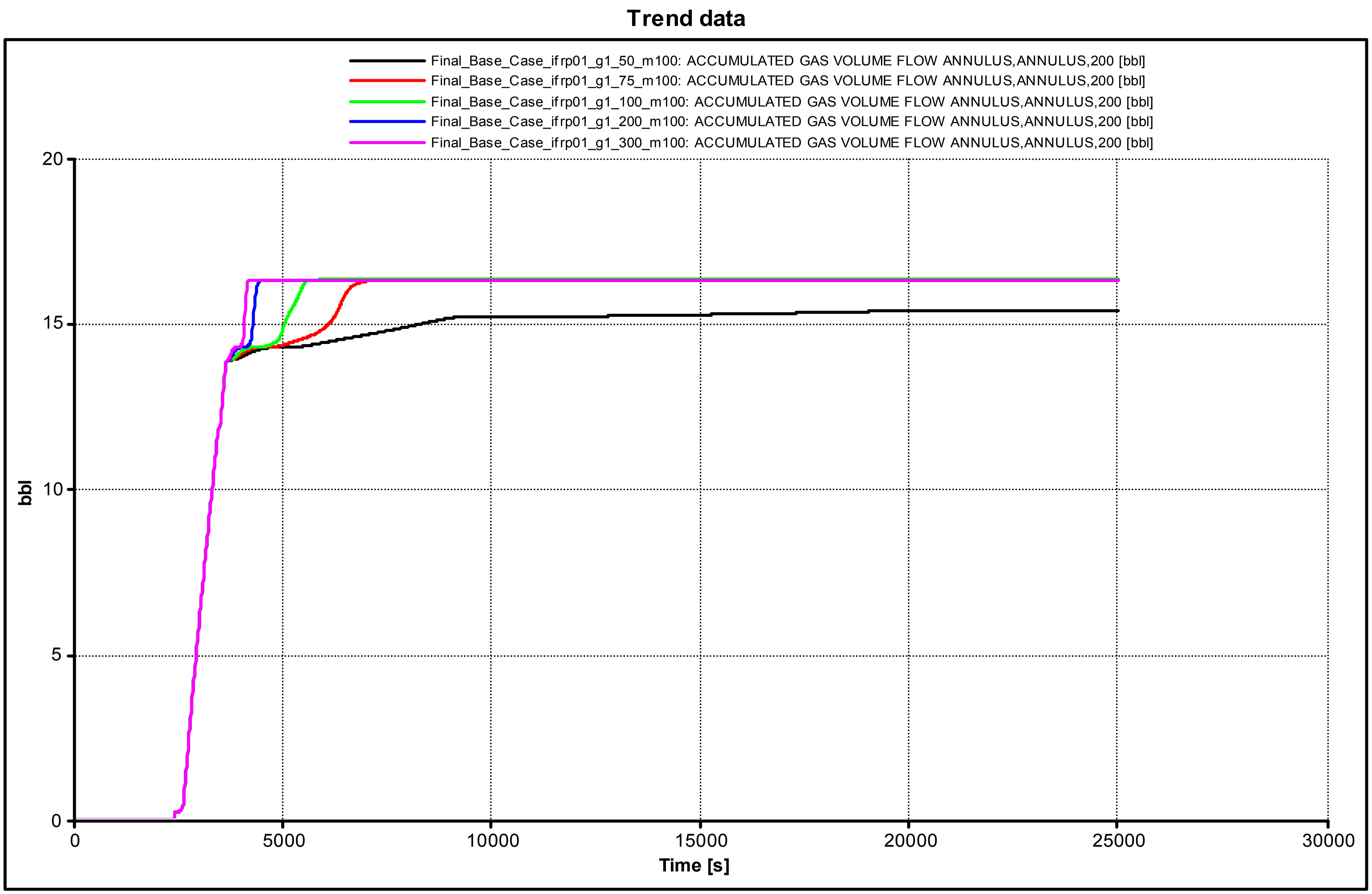


Fig. 19—Accumulated gas out at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

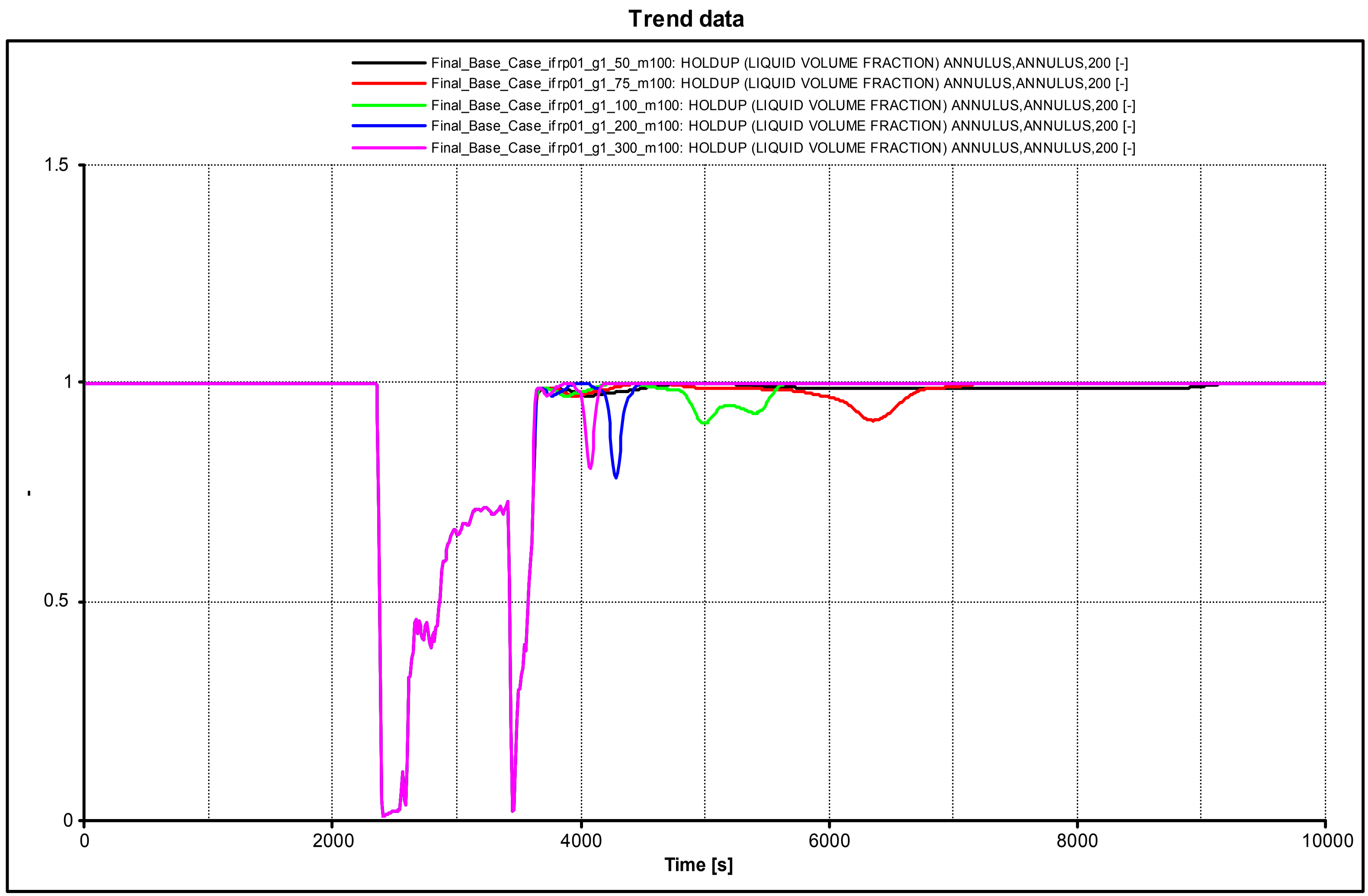


Fig. 20—Liquid holdup at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

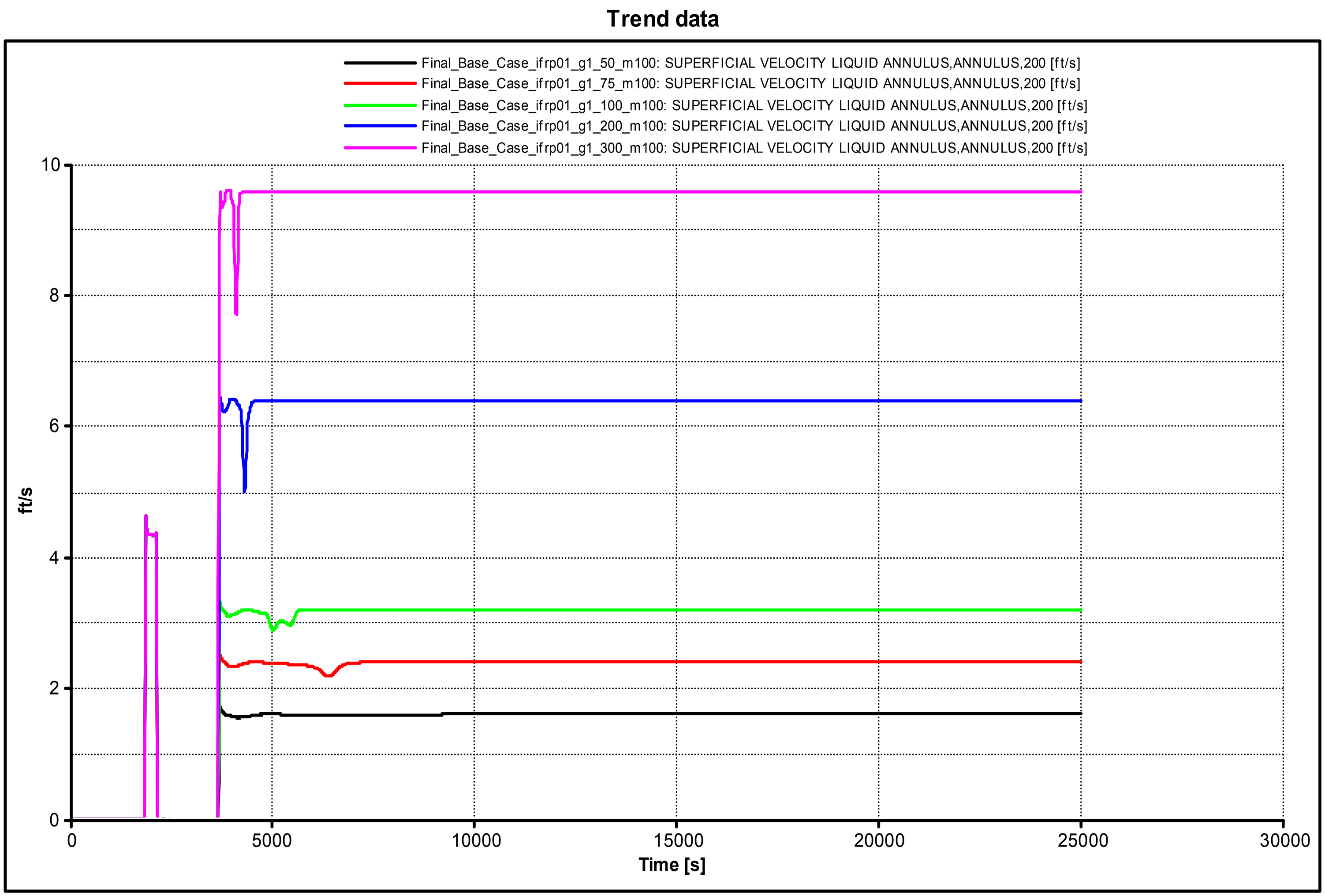


Fig. 21—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

Geometry 2

Geometry 2 consists of a 7.875-in. hole size with 5 in. outer-diameter drillpipe. The effective annular area is 29.07 sq. in. **Figs. 22 to 36** illustrate the results for the five inclinations.

Inclination 10°

For Geometry 2, considerably higher circulation rates were needed to displace the kick than for Geometry 1. In Fig. 22 at a circulation rate of 250 GPM, the gas kick is not displaced. Increasing the rate to 275 GPM allows the gas kick to be removed from the upwardly inclined horizontal section. For the rate of 275 GPM, the simulated kick removal time was approximately 2.11 hrs. This is considerably more than the calculated piston-like displacement value of 0.229 hrs. Again, the presence of the gas kick's buoyancy forces can be seen. The higher circulation rates of 350 and 400 GPM more efficiently displace the kick and come closer to the piston-like displacement times. The widths of the downward protruding humps of the liquid holdup curves in Fig. 23 represent the efficiency of the kick removal. The higher the circulation rate is, the narrower the hump and the lower the liquid holdup value. It is also worth noting that the gas kick is being transported as a continuous unit. Fig. 242 depicts liquid superficial velocities. A superficial velocity of 3 ft/sec is required to displace the gas kick. This value is close to the superficial velocity needed in Geometry 1.

Inclination 5°

Figs. 25 to 27 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case.

However, the curves in Fig. 25 are shifted farther to the left than in Fig. 22. This reflects the decrease in gas-kick buoyancy forces that result from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 28 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 29 shows smoothly increasing and decreasing liquid-holdup curves. This is consistent with a stratified flow regime.

Inclination -5°

For an inclination of 5º below horizontal, the gas migrates up the annulus before circulation beings. This effect is responsible for the identical overlapping portions of the curves in Fig. 31. The nonoverlapping portion of the curves is a result of the migrating up the drillpipe. Once circulation begins, the kick is displaced from the drillpipe. The shape or slope of the top portion of these curves is dependent on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 32 and Fig. 33.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. Figs. 34 to 36 depict the results.

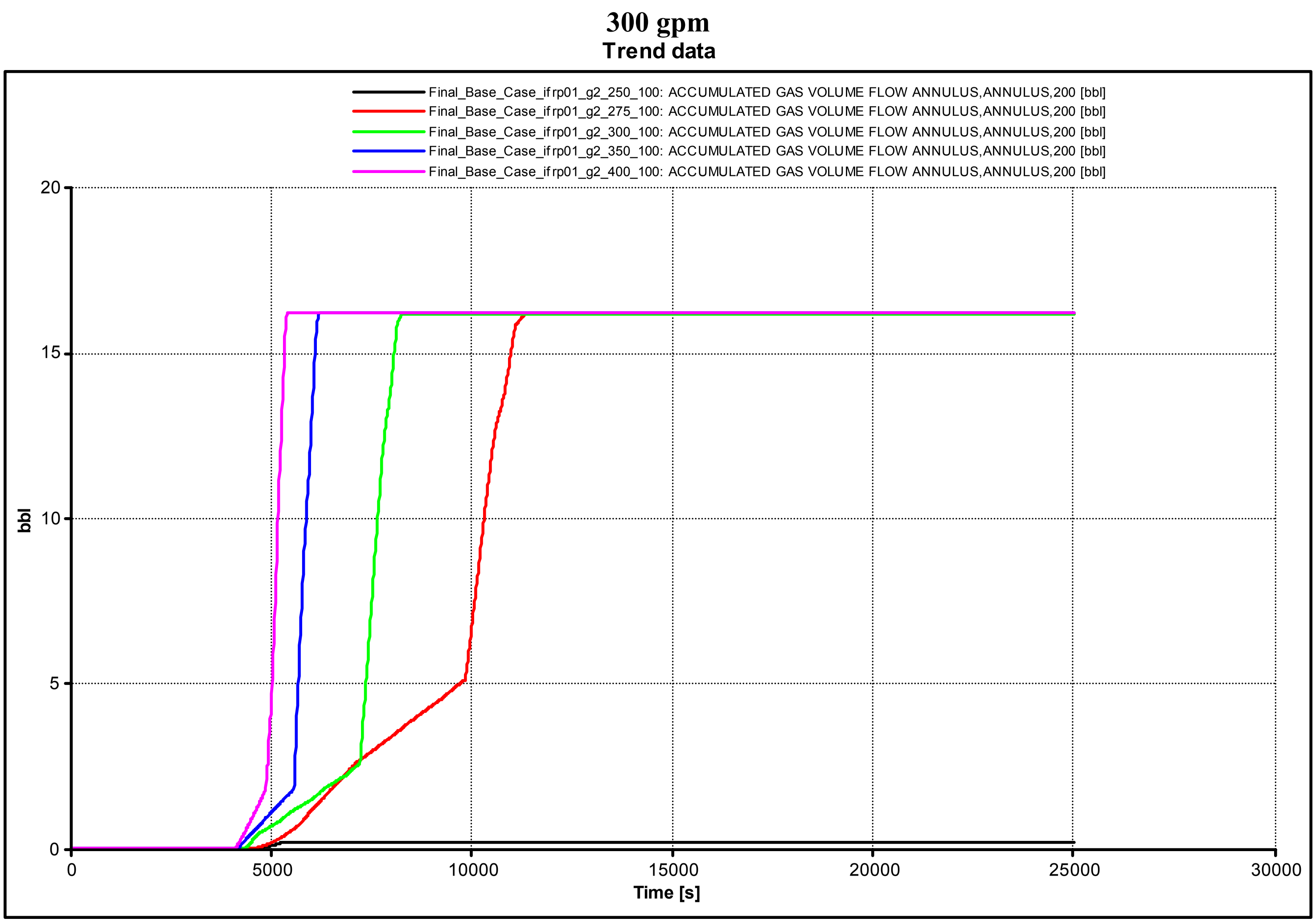


Fig. 22—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

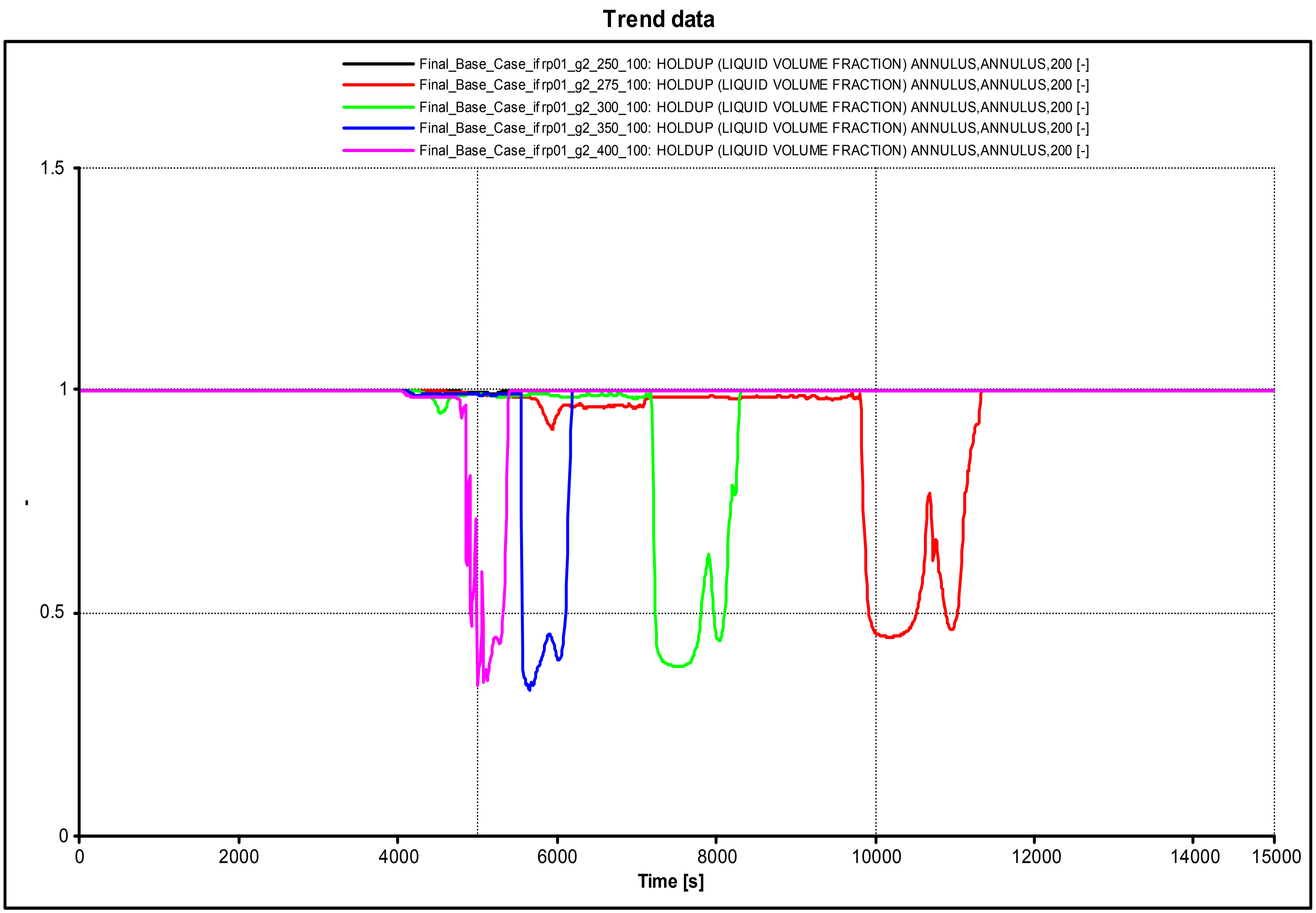


Fig. 23—Liquid holdup at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

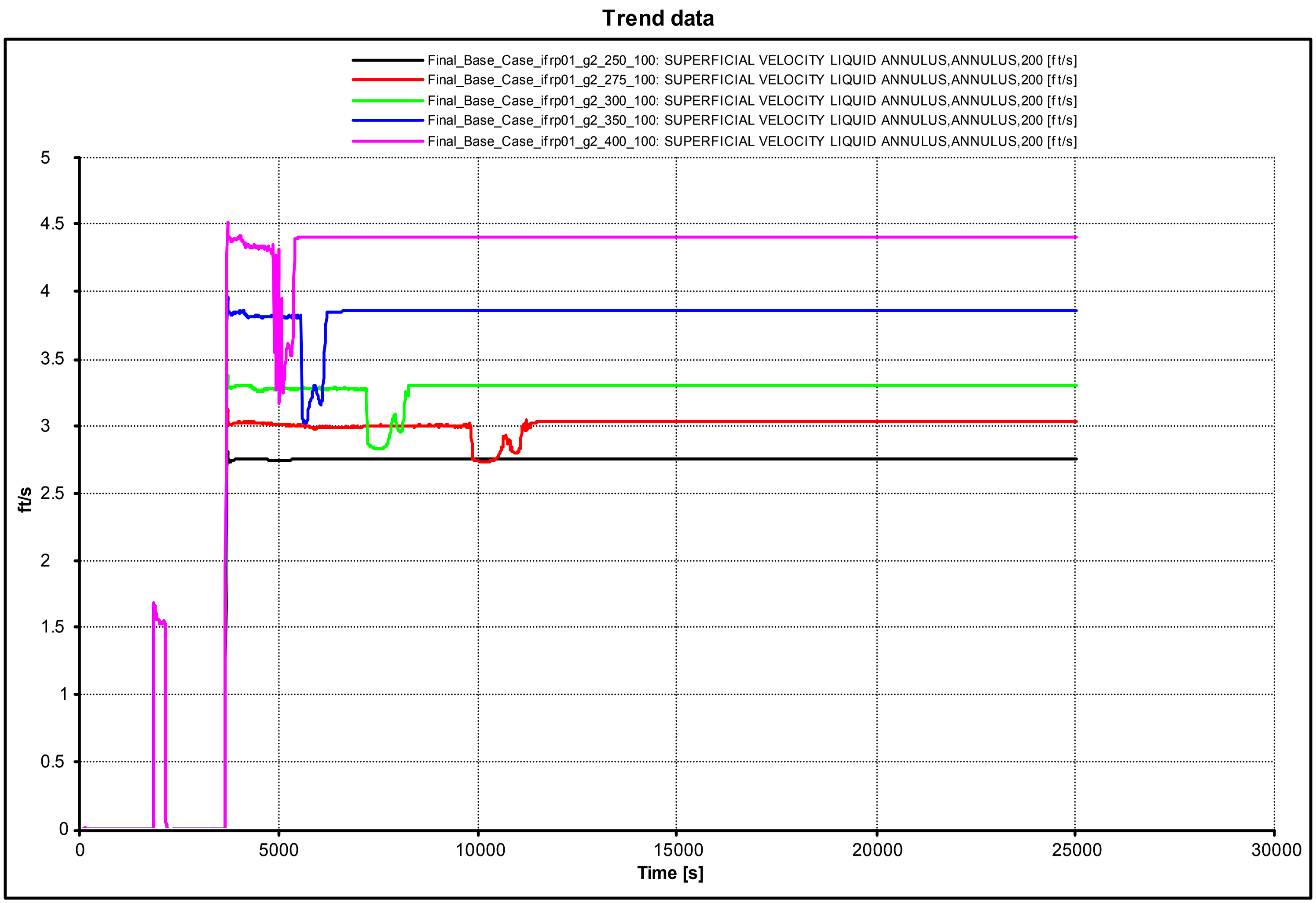


Fig. 24—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

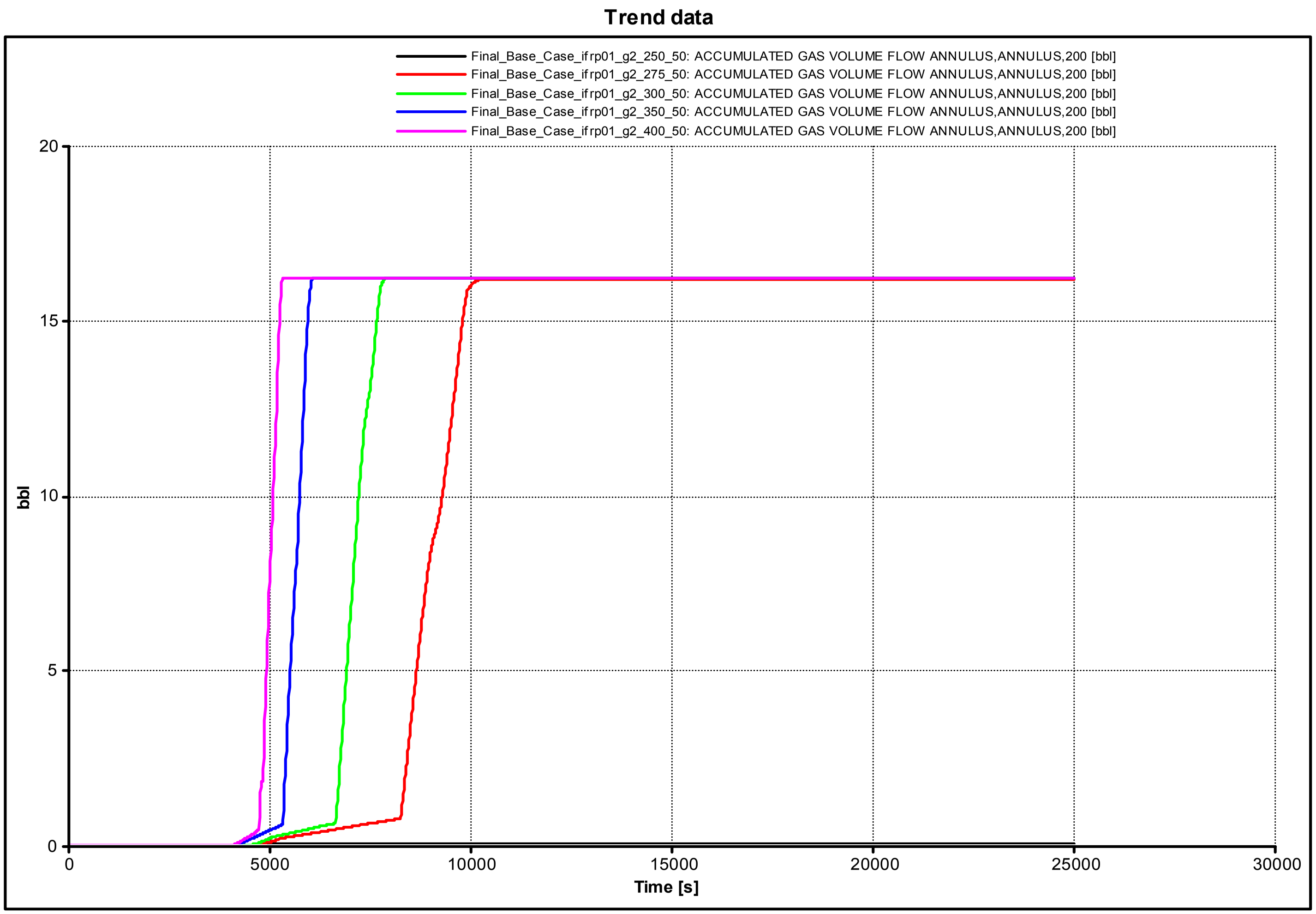


Fig. 25—Accumulated gas out at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

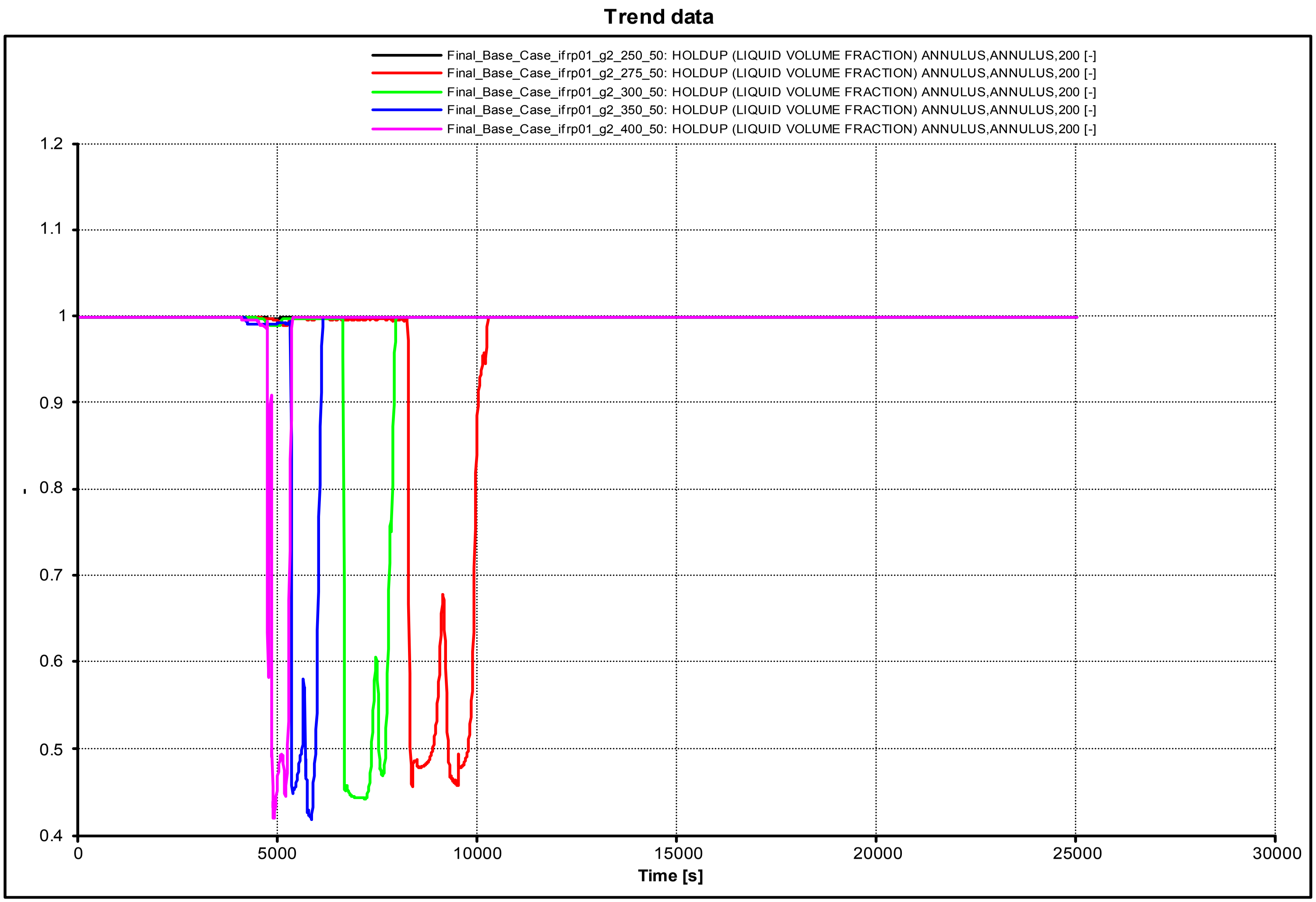


Fig. 26—Liquid holdup at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

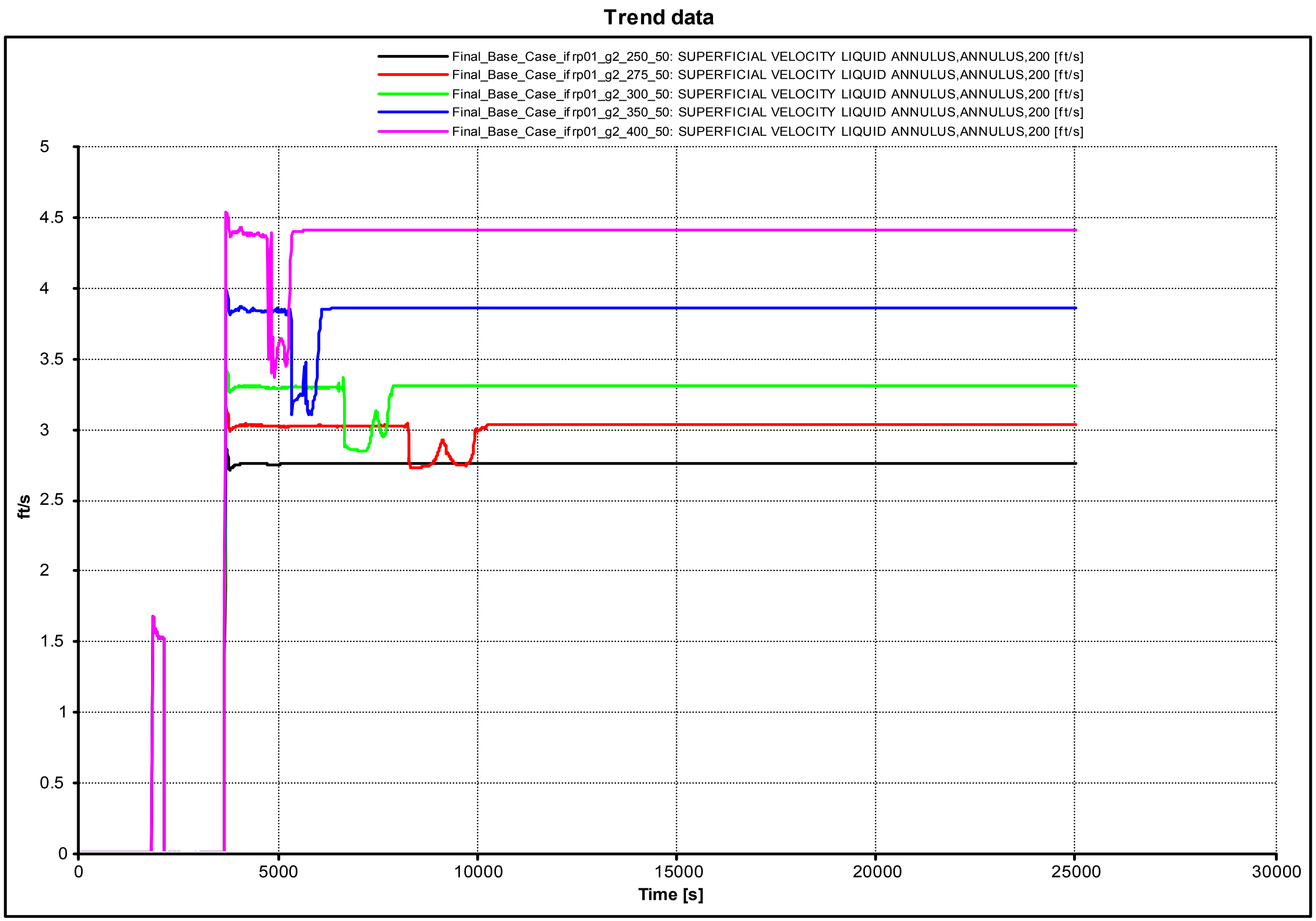


Fig. 27—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

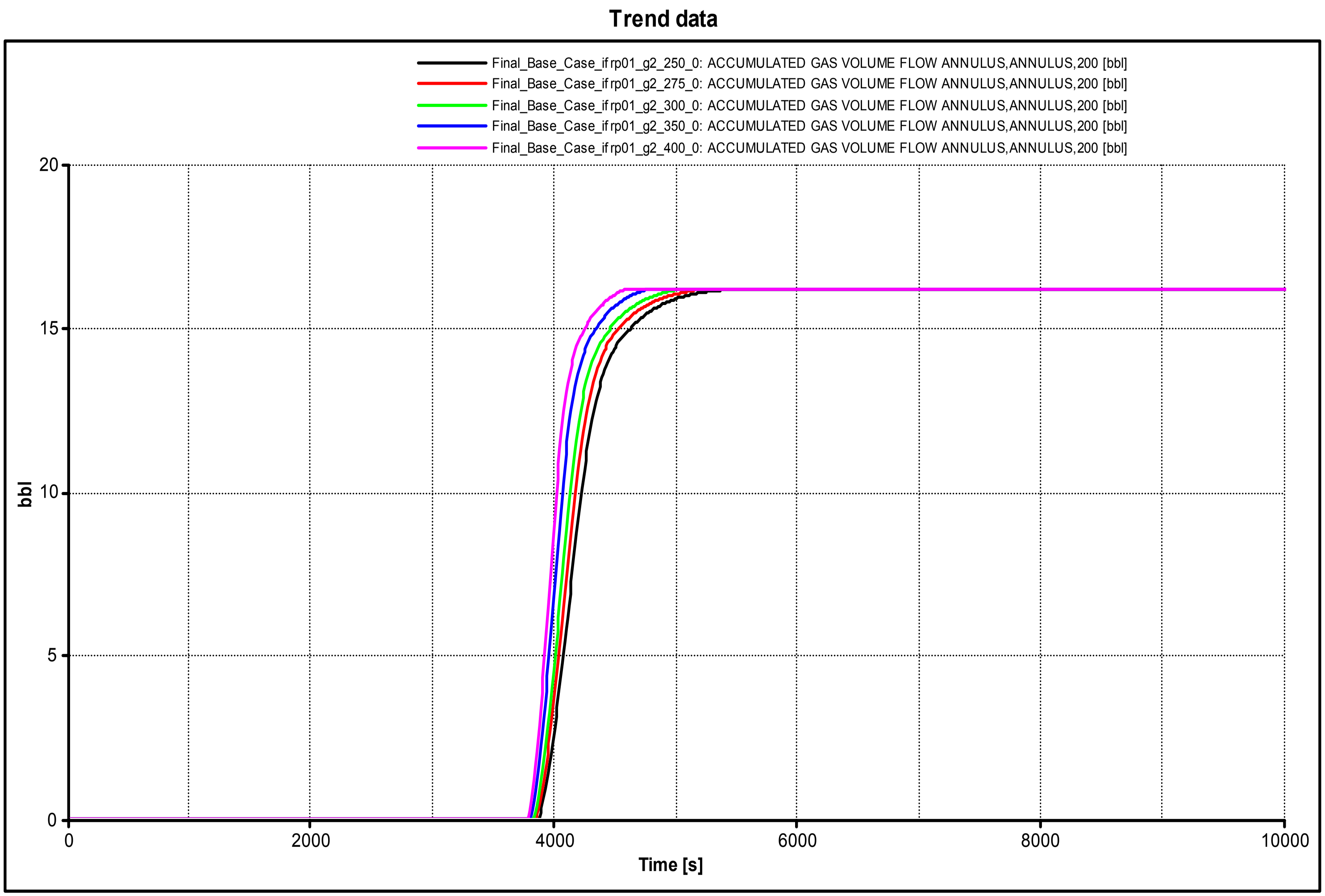


Fig. 28—Accumulated gas out at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

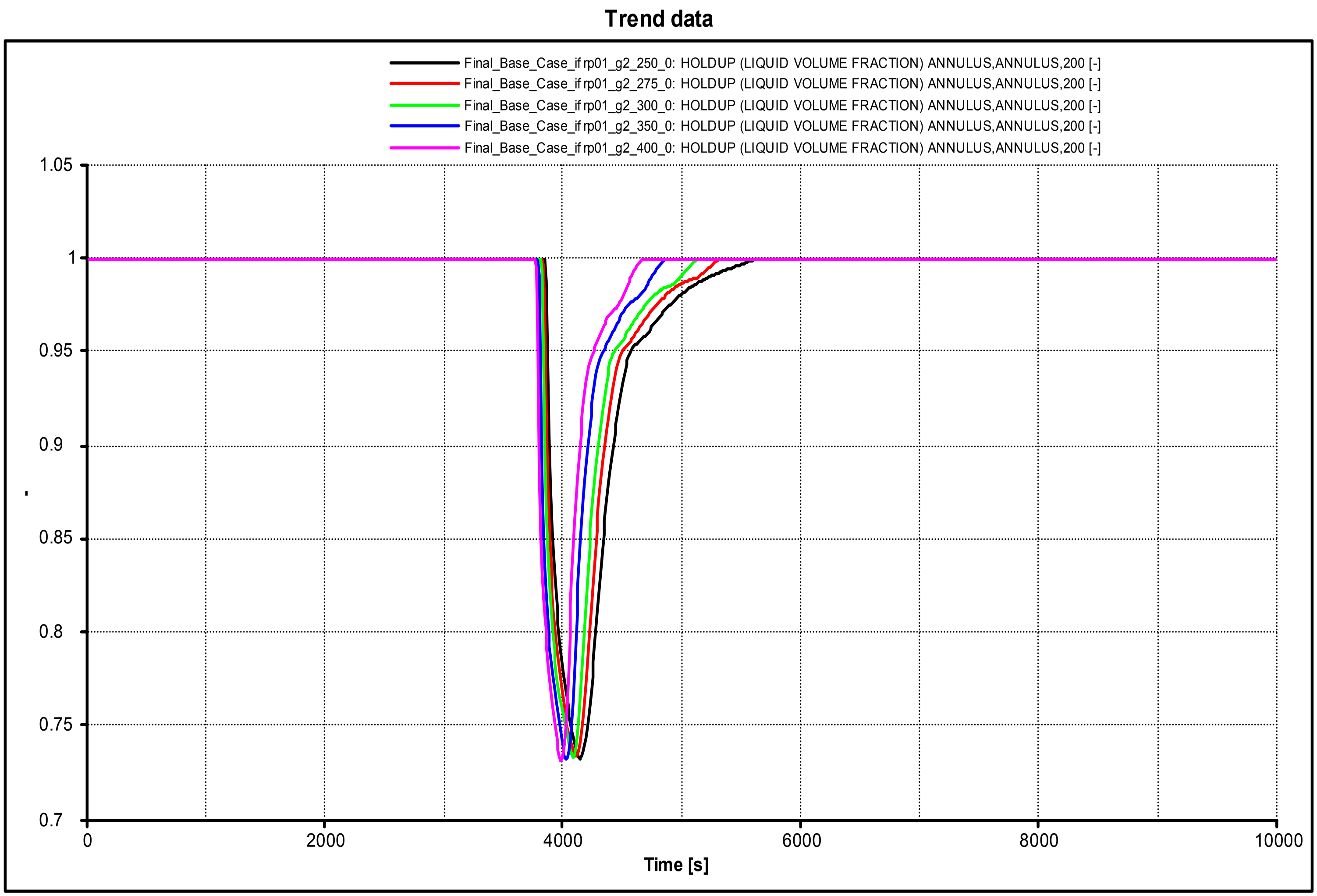


Fig. 29—Liquid holdup at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

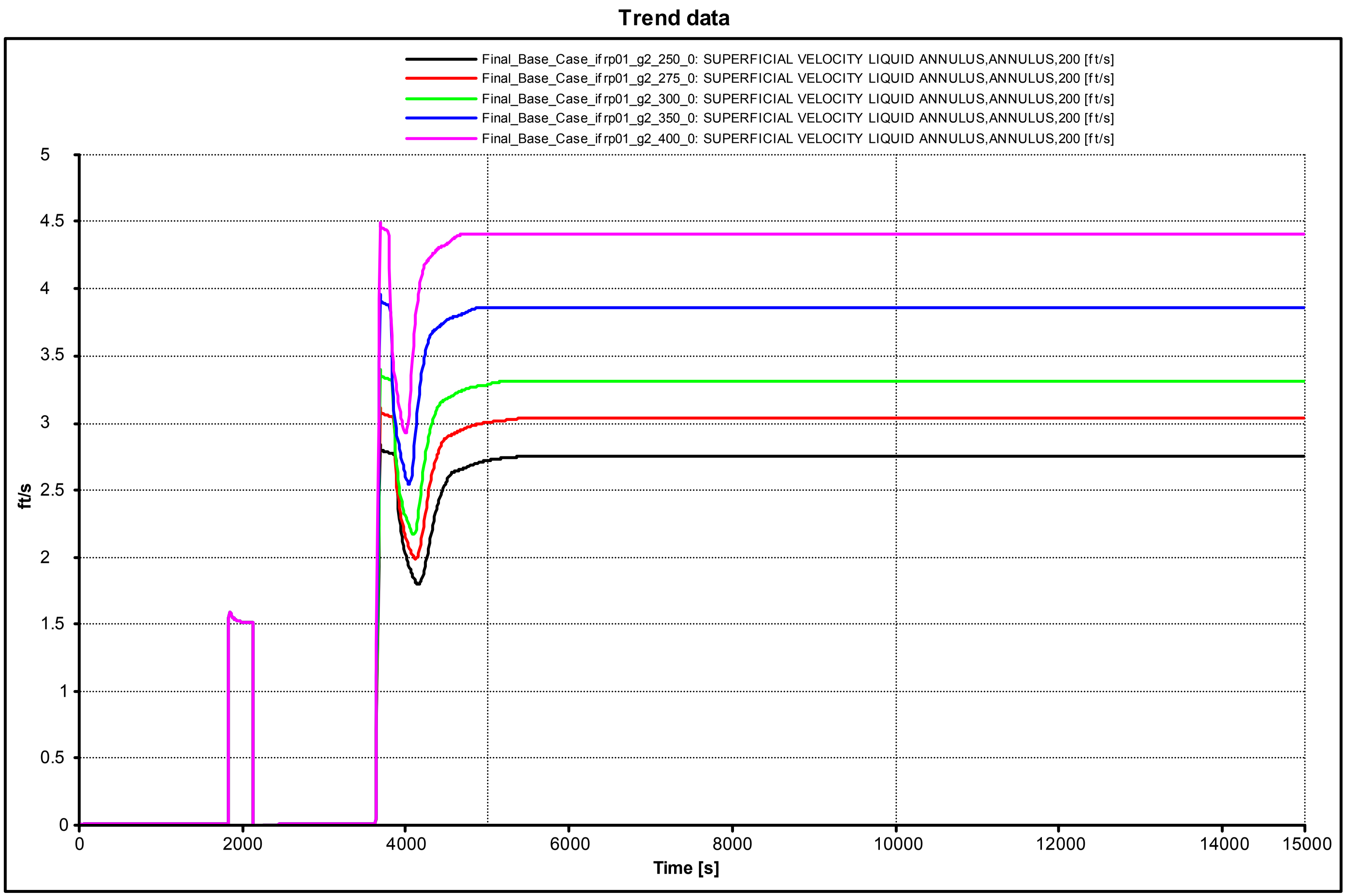


Fig. 30—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

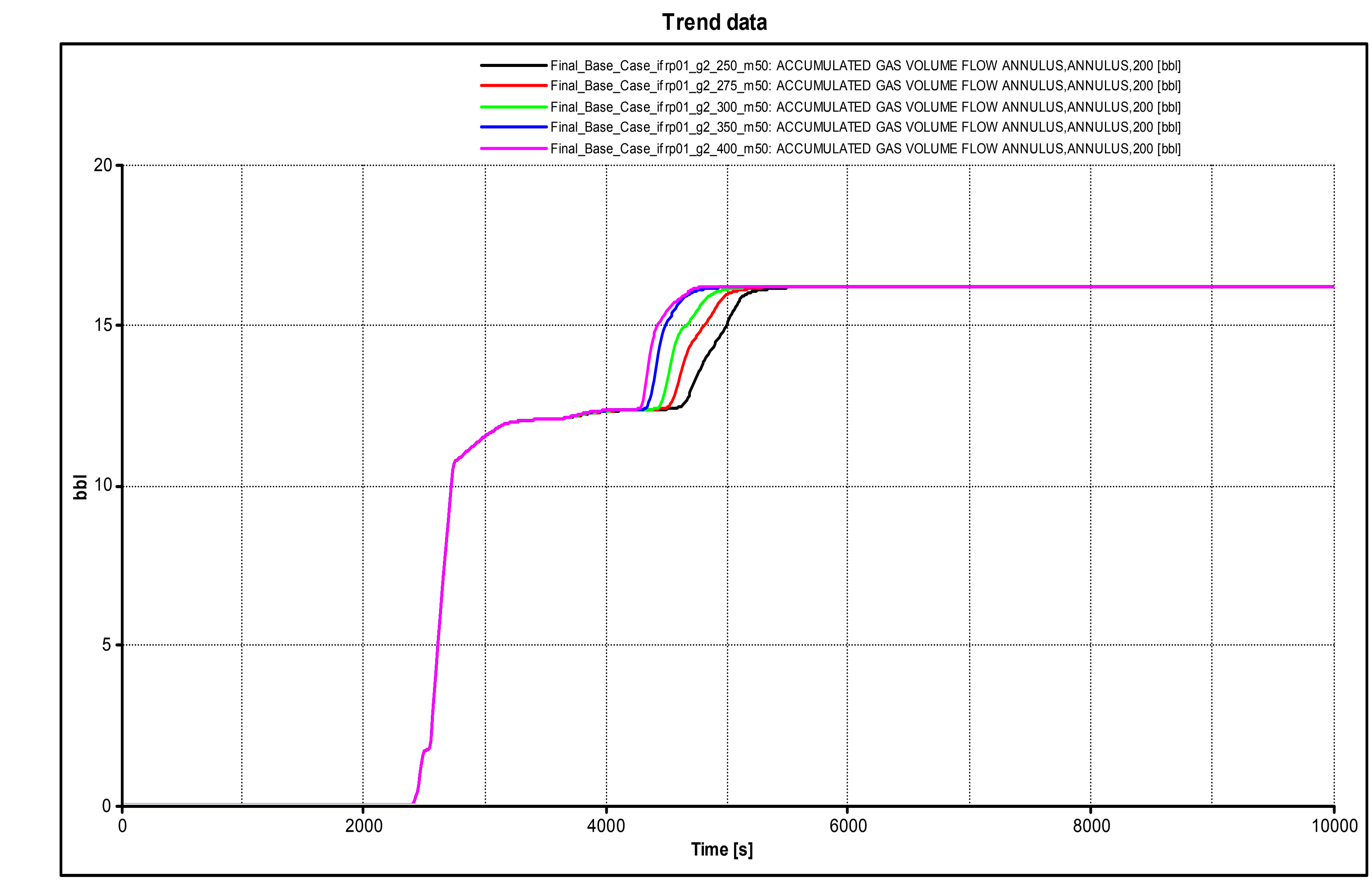


Fig. 31—Accumulated gas out at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

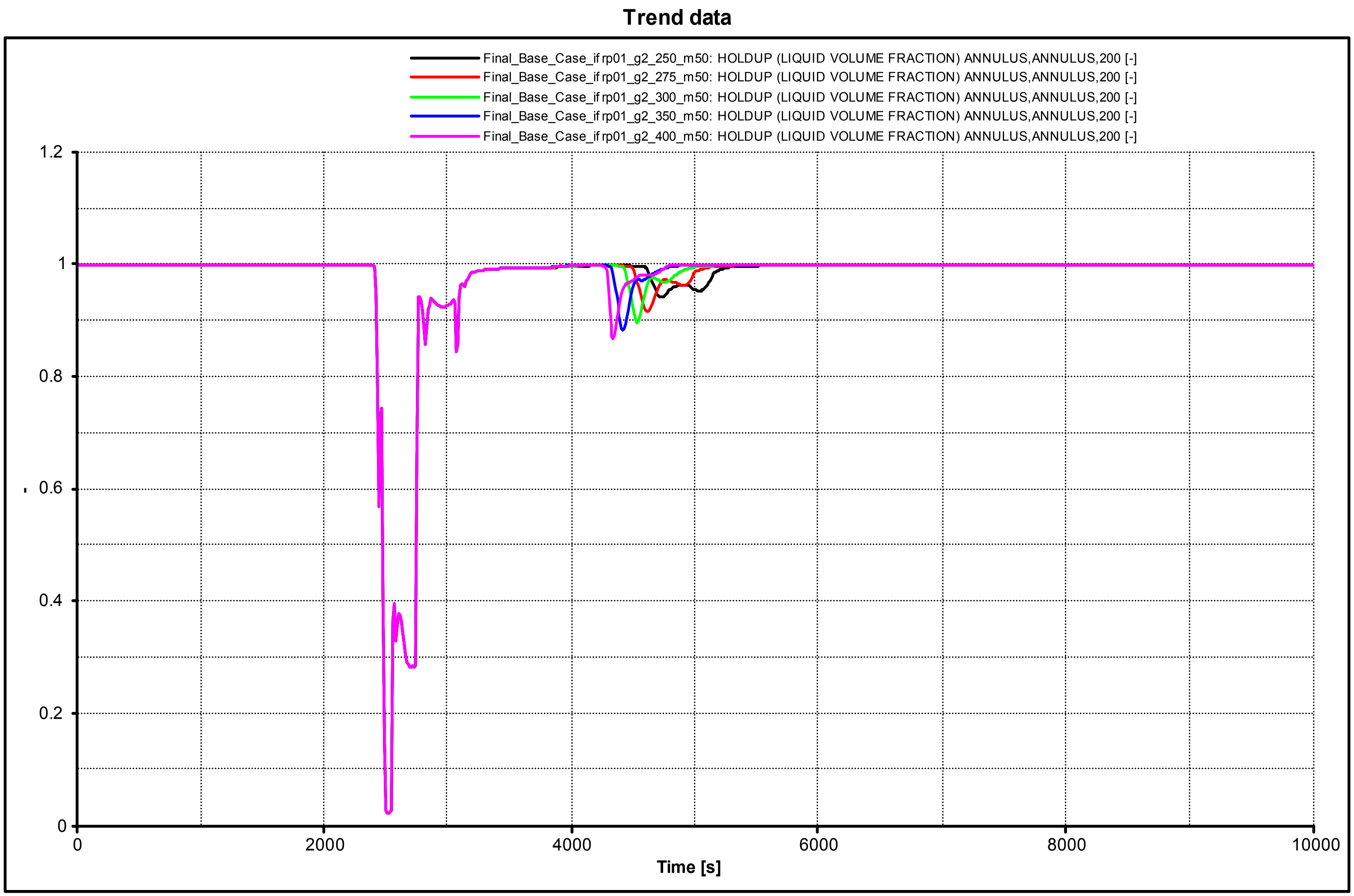


Fig. 32—Liquid holdup at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

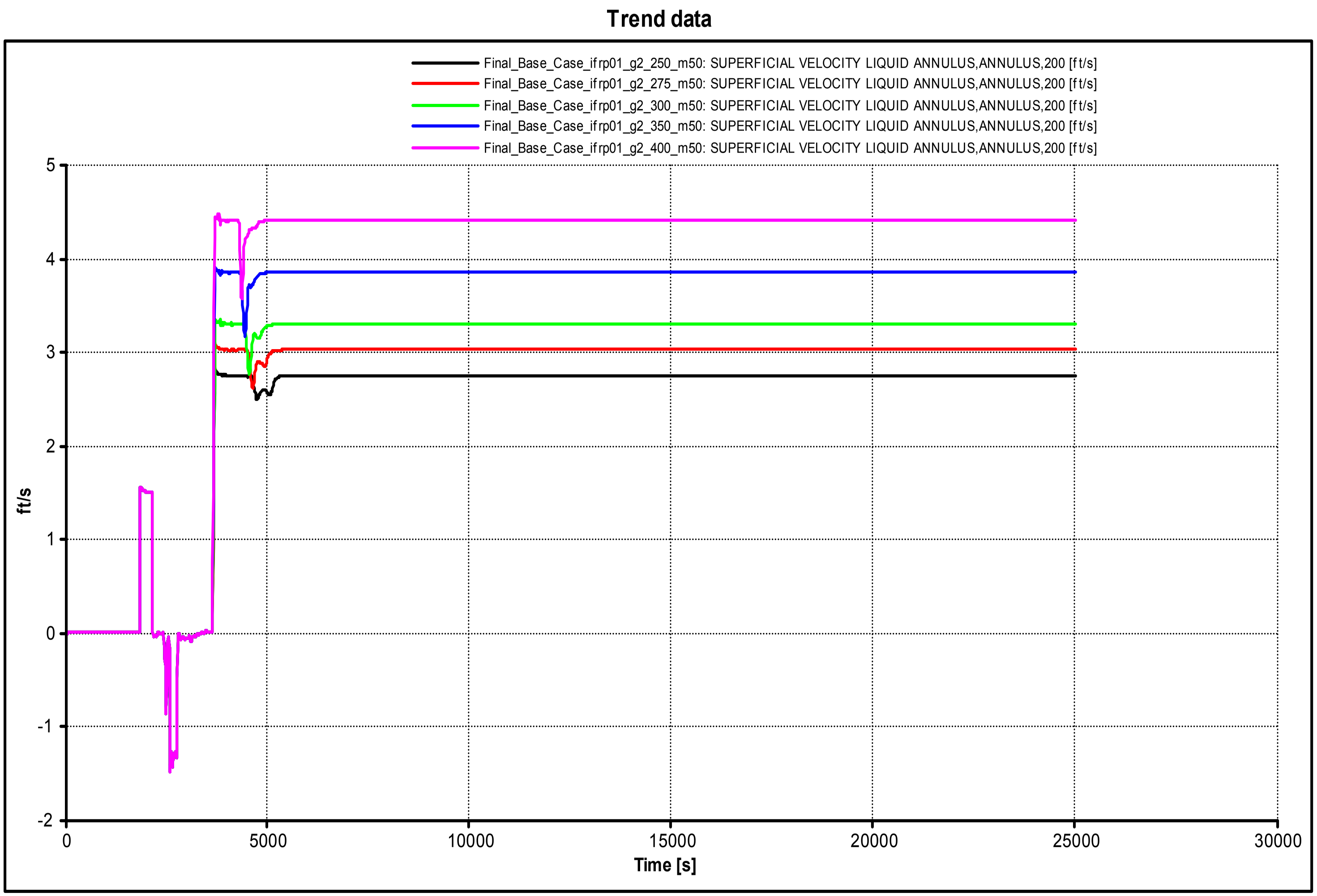


Fig. 33—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

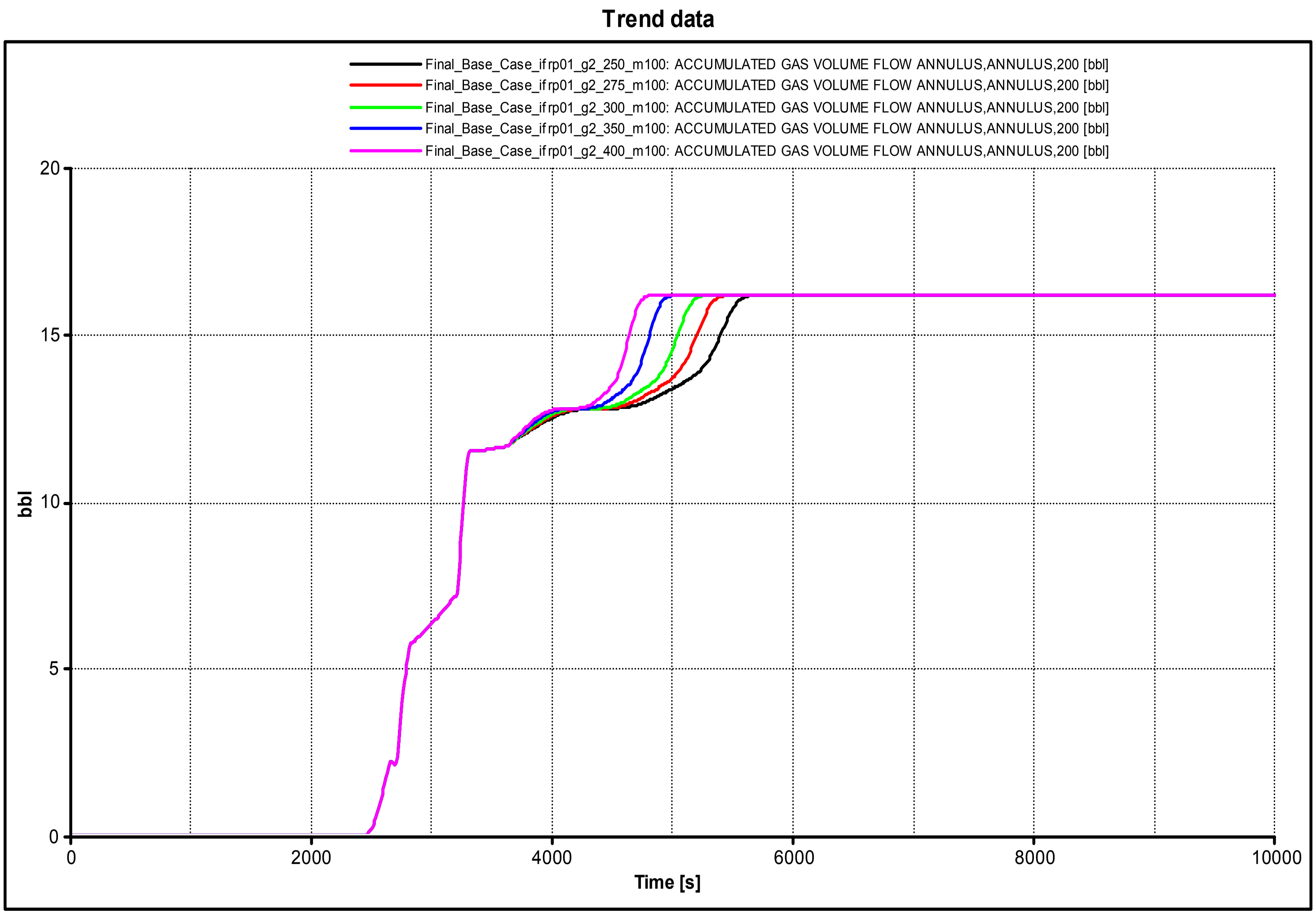


Fig. 34—Accumulated gas out at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

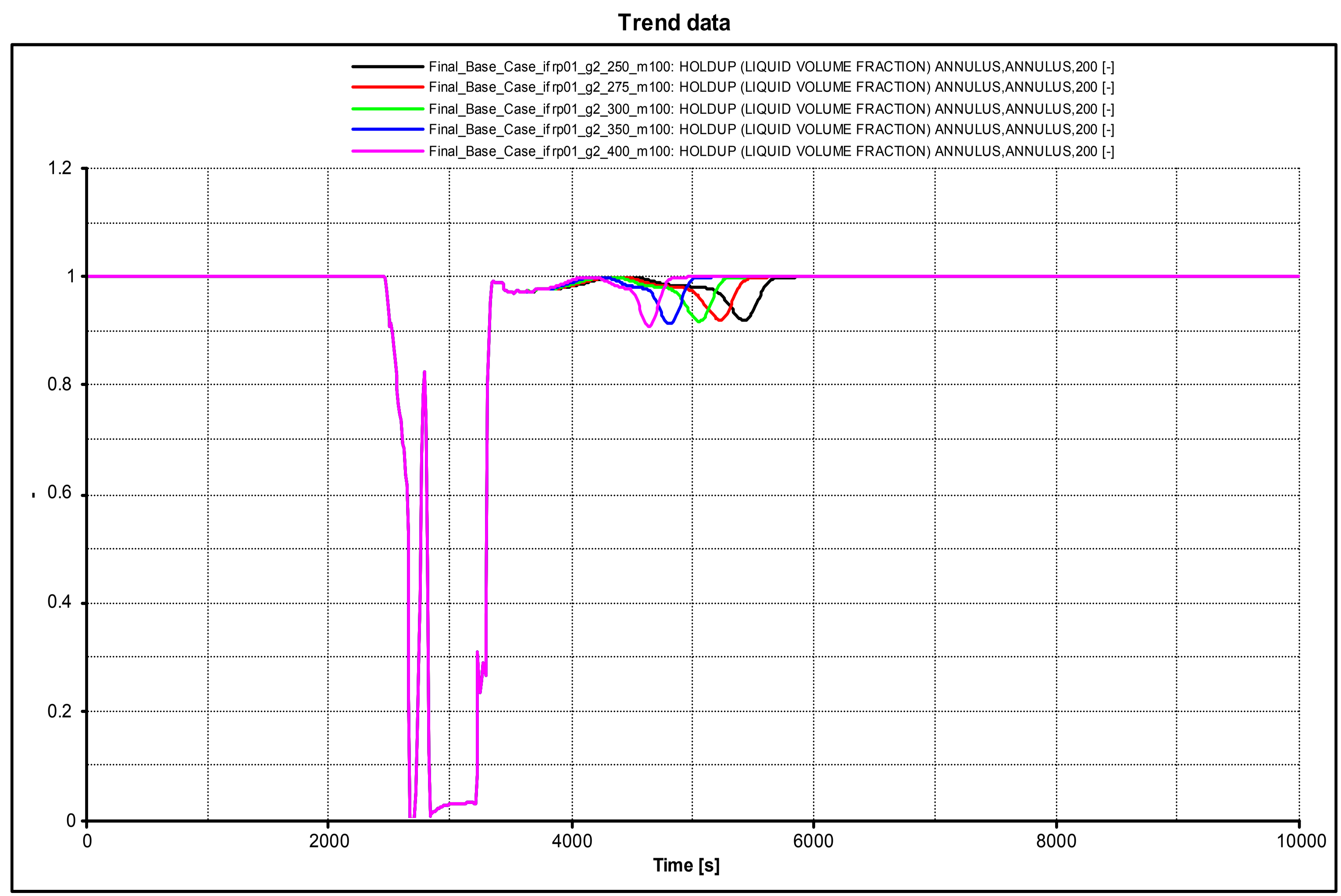


Fig. 35—Liquid holdup at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

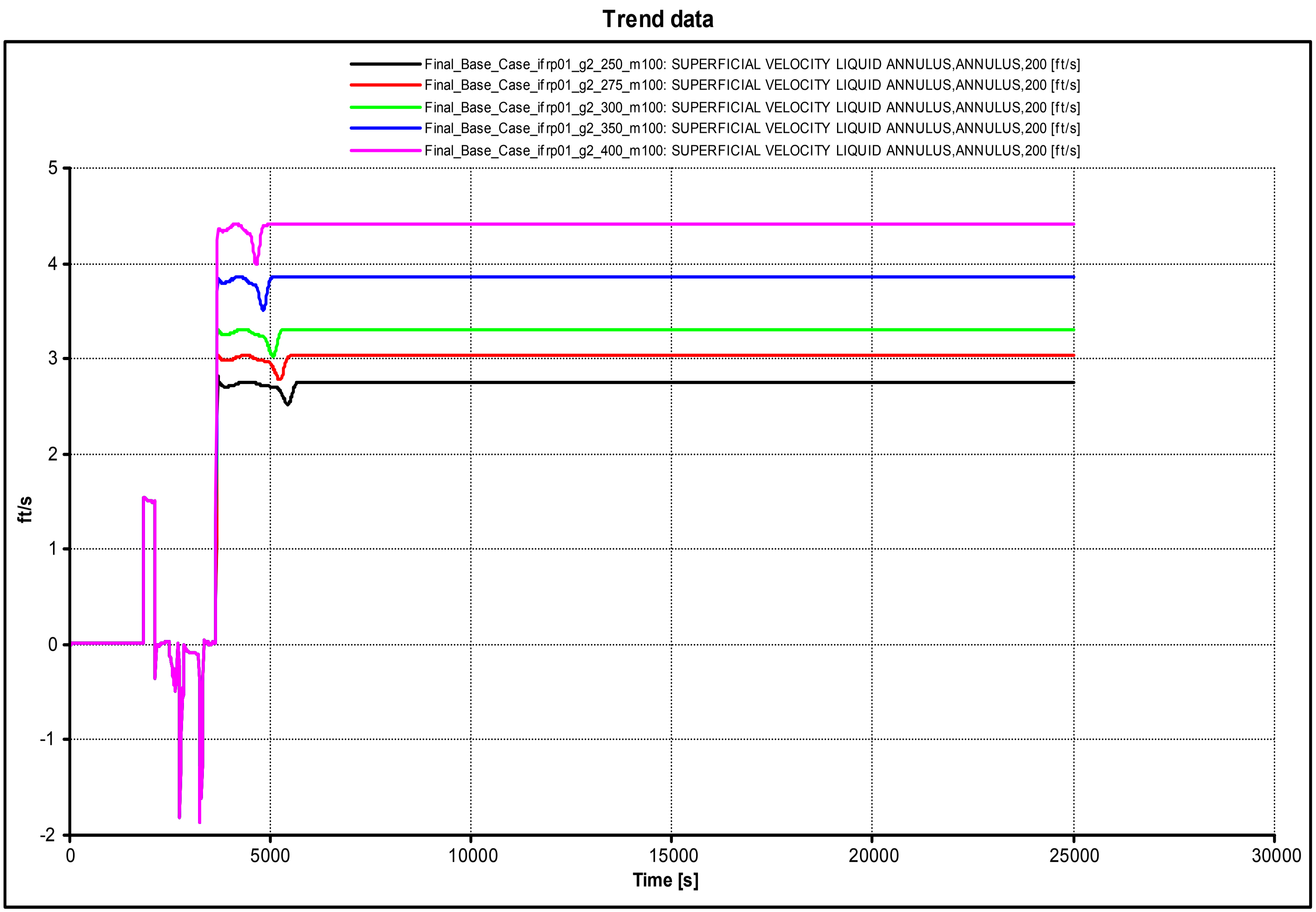


Fig. 36—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

Geometry 3

Geometry 3 consists of a 9.875-in. hole size with 5-in. outer-diameter drillpipe. The effective annular area is 56.95 sq. in. **Figs. 37 to 51** illustrate the results for the five inclinations.

Inclination 10°

For Geometry 3, extremely high circulation rates were required to transport the gas kick. In Fig. 37 a circulation rate of 300 gpm was insufficient in removing the kick. Rates of 600 and 700 GPM efficiently removed the kick from the horizontal section. Fig. 38 illustrates the liquid-holdup curves. Fig. 39 shows that a superficial velocity of 3.3 ft/s is needed to effectively remove the gas influx. Interestingly, this value is only slightly higher than the value required for Geometry 2.

Inclination 5°

Figs. 40-42 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case. However, the curves in Fig. 40 are shifted to the left more than in Fig. 37. This reflects the decrease in gas-kick buoyancy forces resulting from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 43 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 44 shows smoothly increasing and decreasing liquid holdup curves, is consistent with a stratified flow regime.

Inclination -5°

For an inclination of 5º below horizontal, the gas begins migrating up the annulus instantaneously. When circulation begins at 3,600 seconds, the majority of the gas kick has left the horizontal section. During the gas-kick influx, a small amount of gas begins to migrate up the drillpipe instead of the annulus. Once circulation begins, the gas is displaced from the drillpipe into the annulus and removed from the annular horizontal section. This phenomenon is depicted in Fig. 46 by the irregular top portion of each curve. The shape or slope of the top portion of these curves depends on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 47 and Fig. 48.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. Figs. 49 to 51 depict the results.

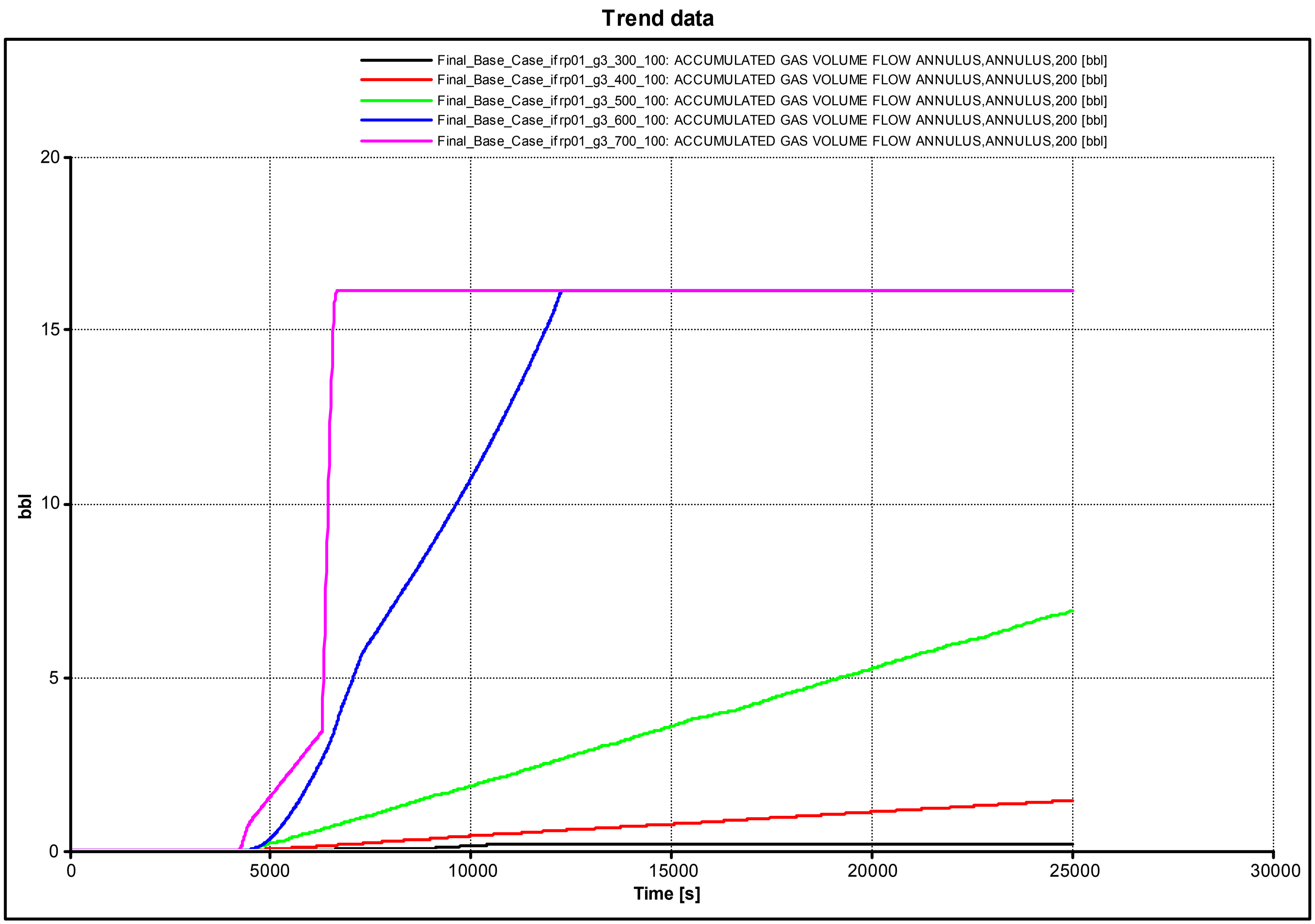


Fig. 37—Accumulated gas out at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600 & 700 GPM.

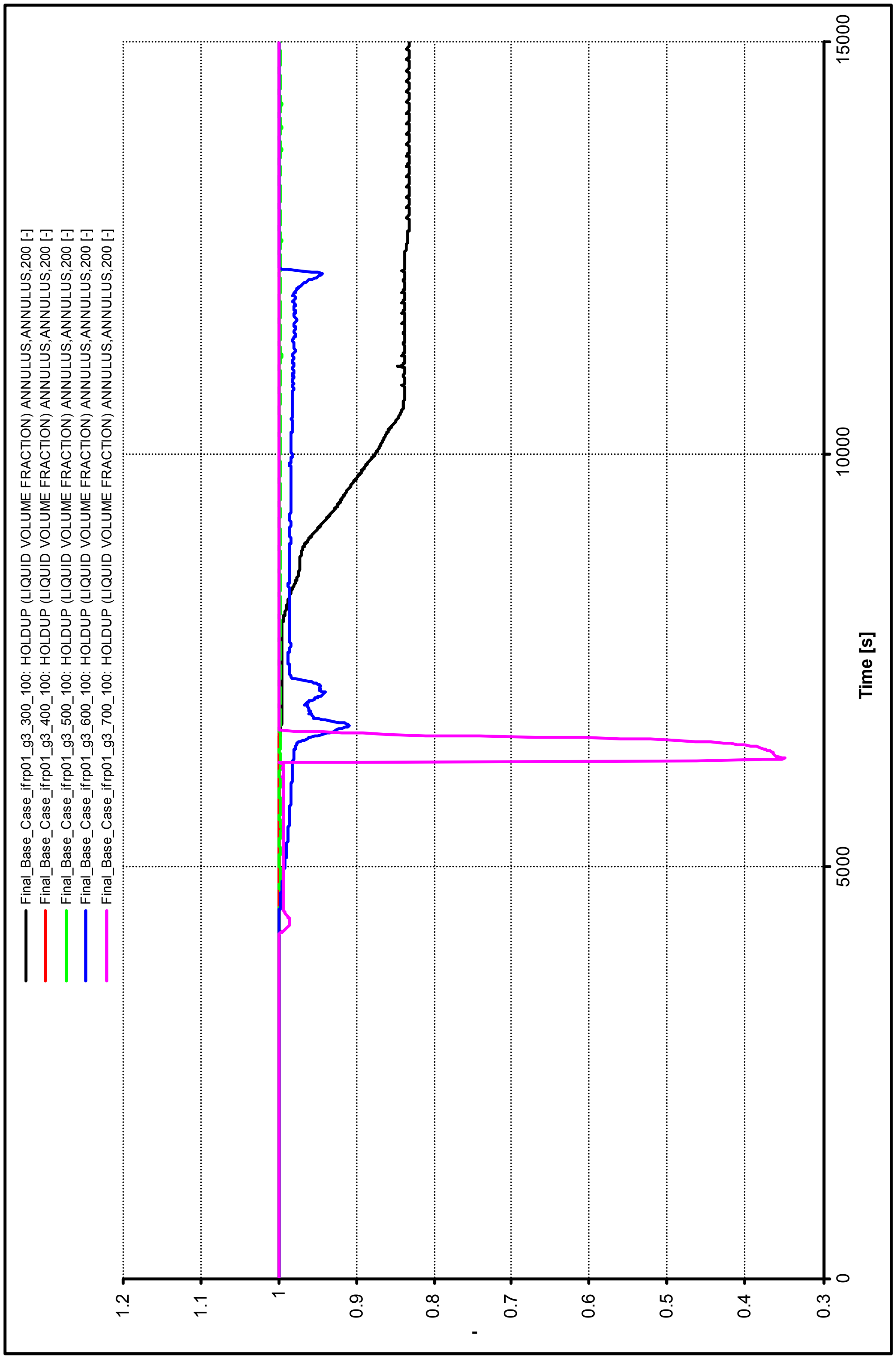


Fig. 38—Liquid holdup at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600, & 700 GPM.

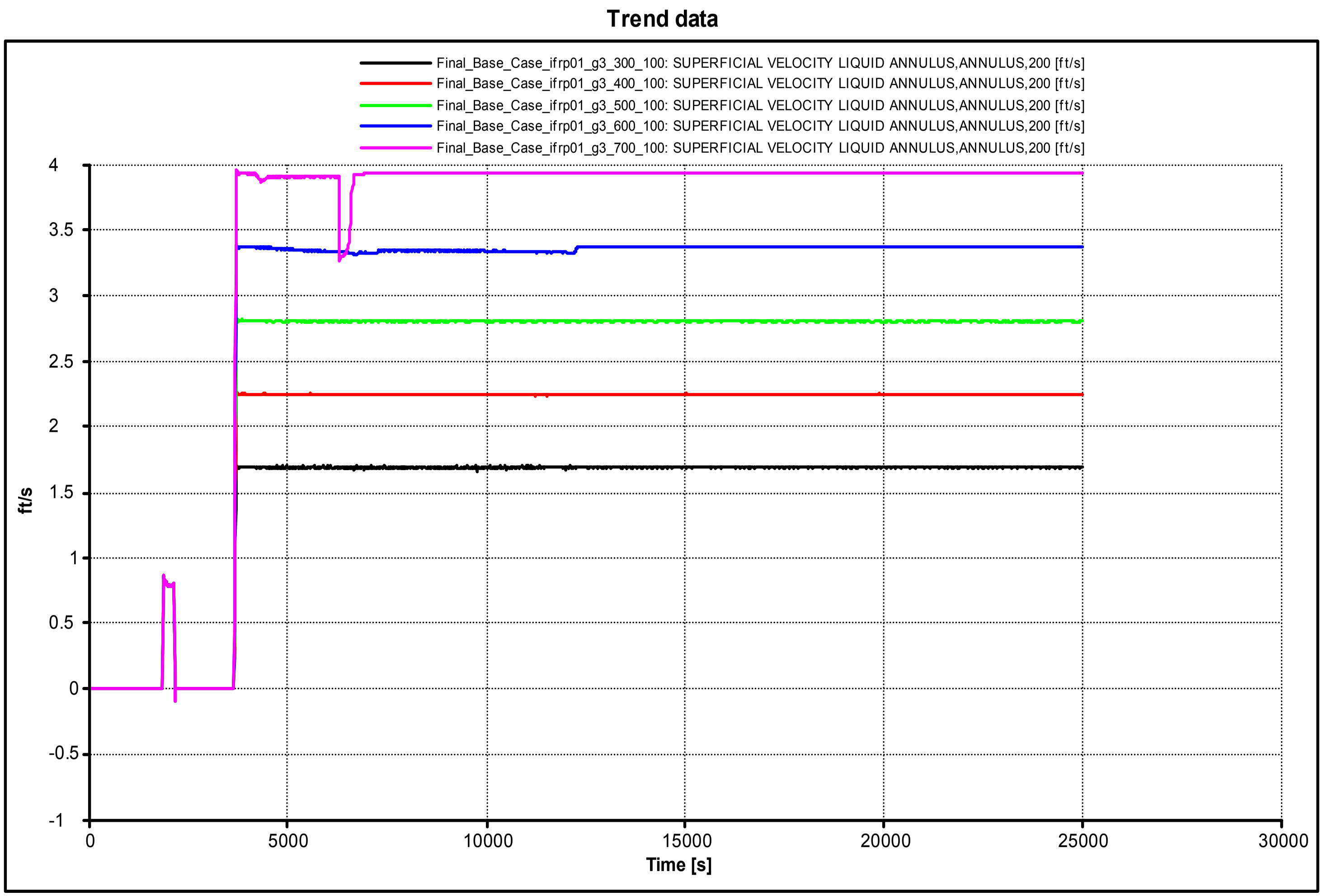


Fig. 39—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600, & 700 GPM.

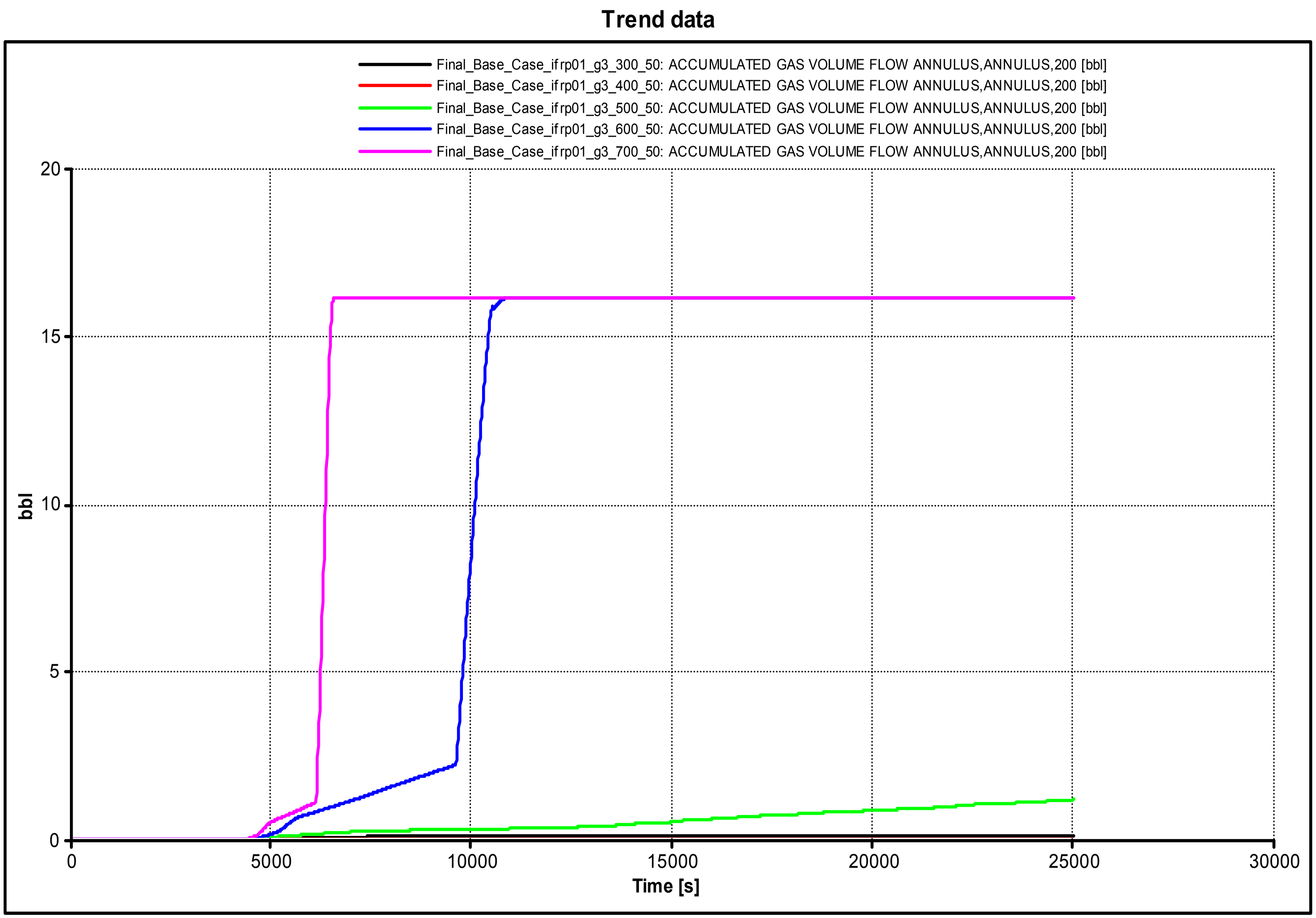


Fig. 40—Accumulated gas out at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600 & 700 GPM.

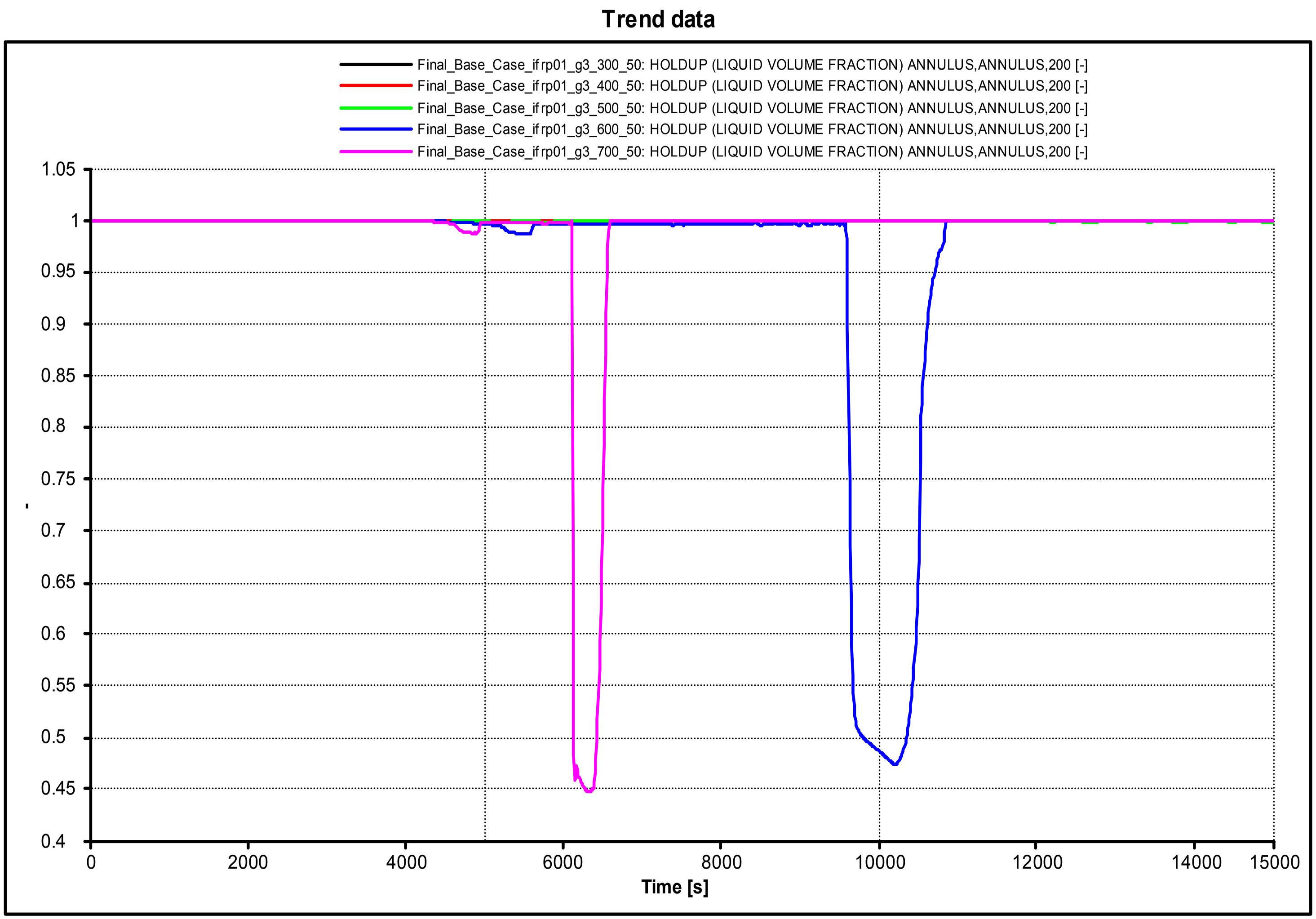


Fig. 41—Liquid holdup at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600, & 700 GPM.

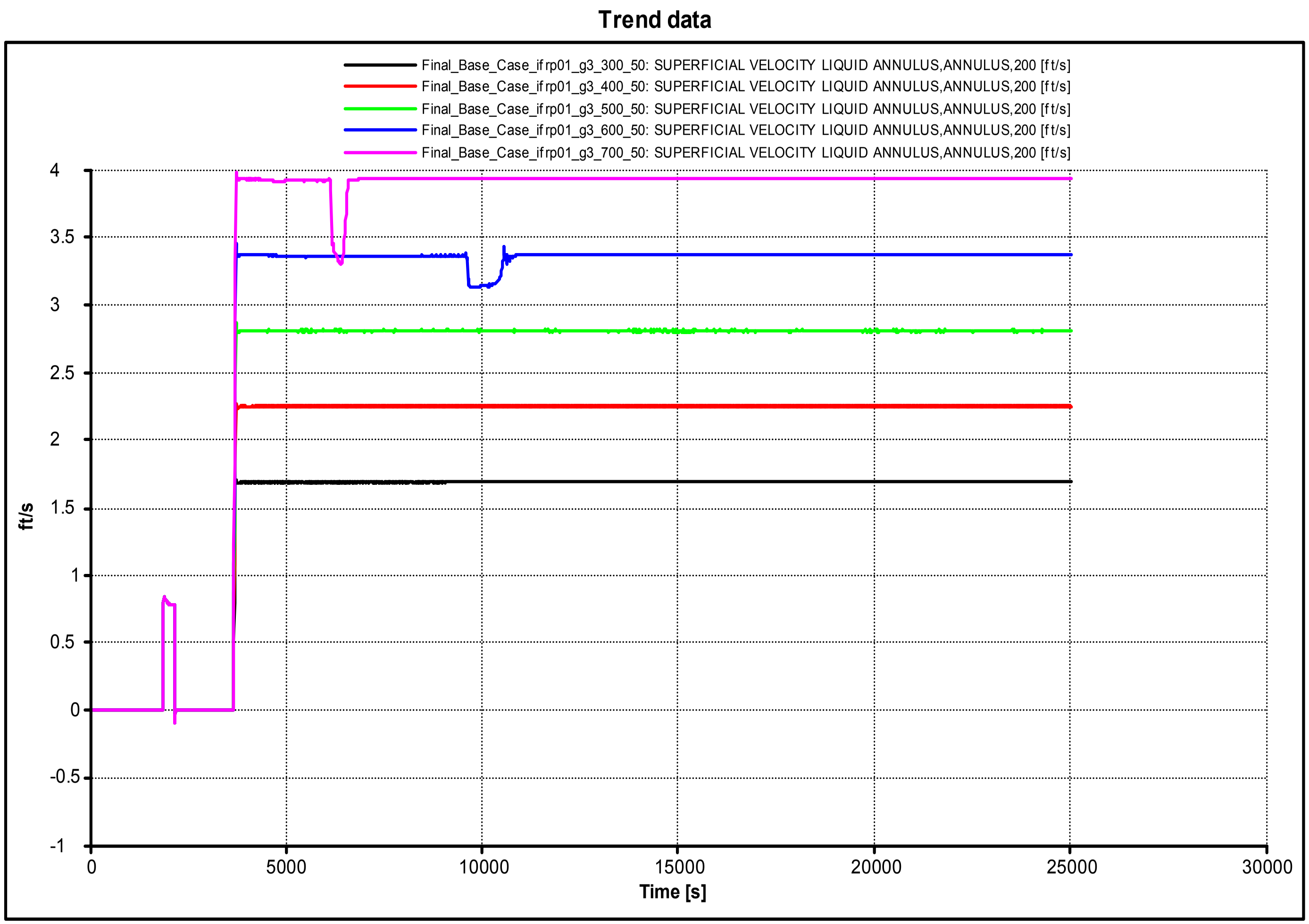


Fig. 42—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600, & 700 GPM.

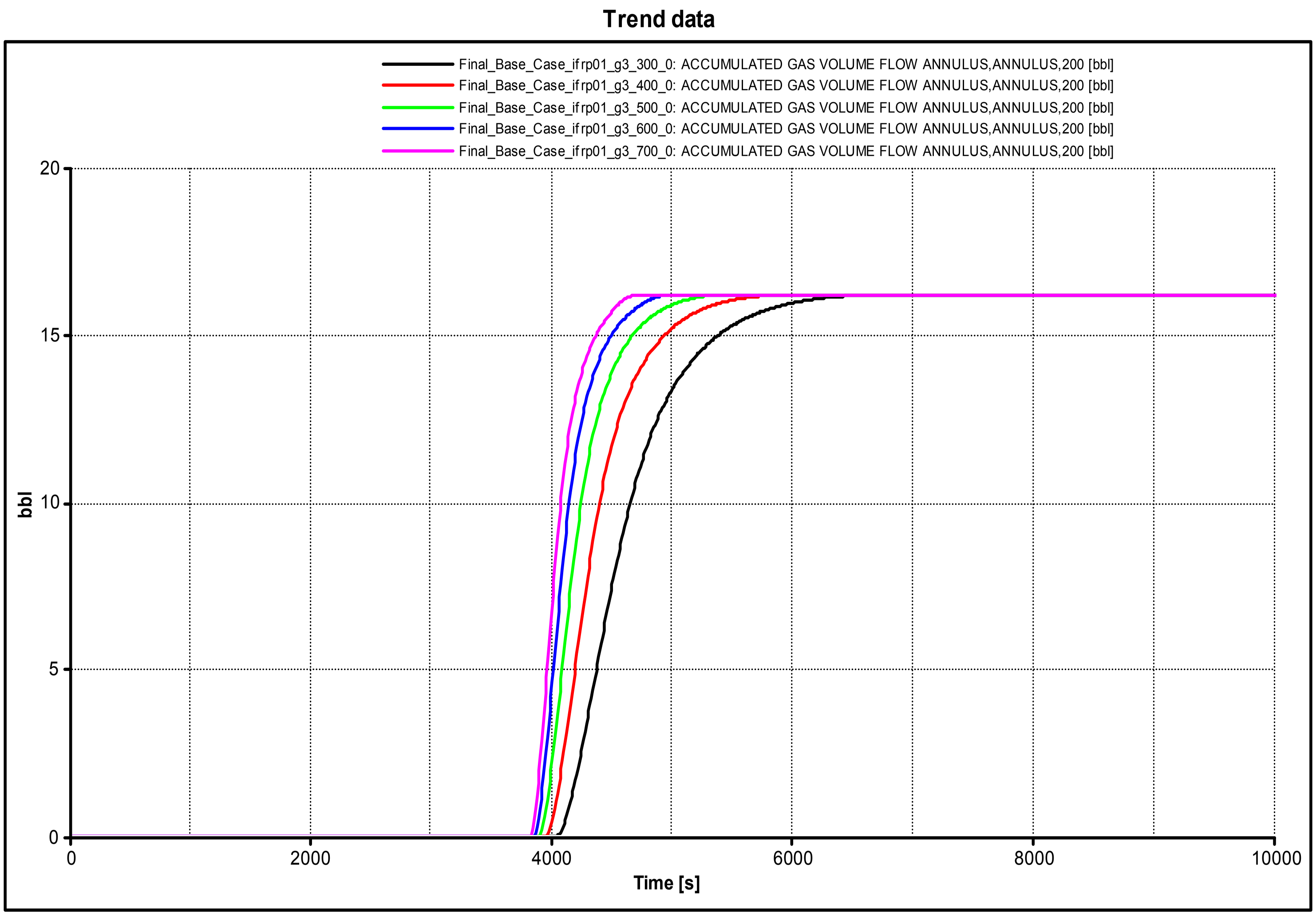


Fig. 43—Accumulated gas out at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600 & 700 GPM.

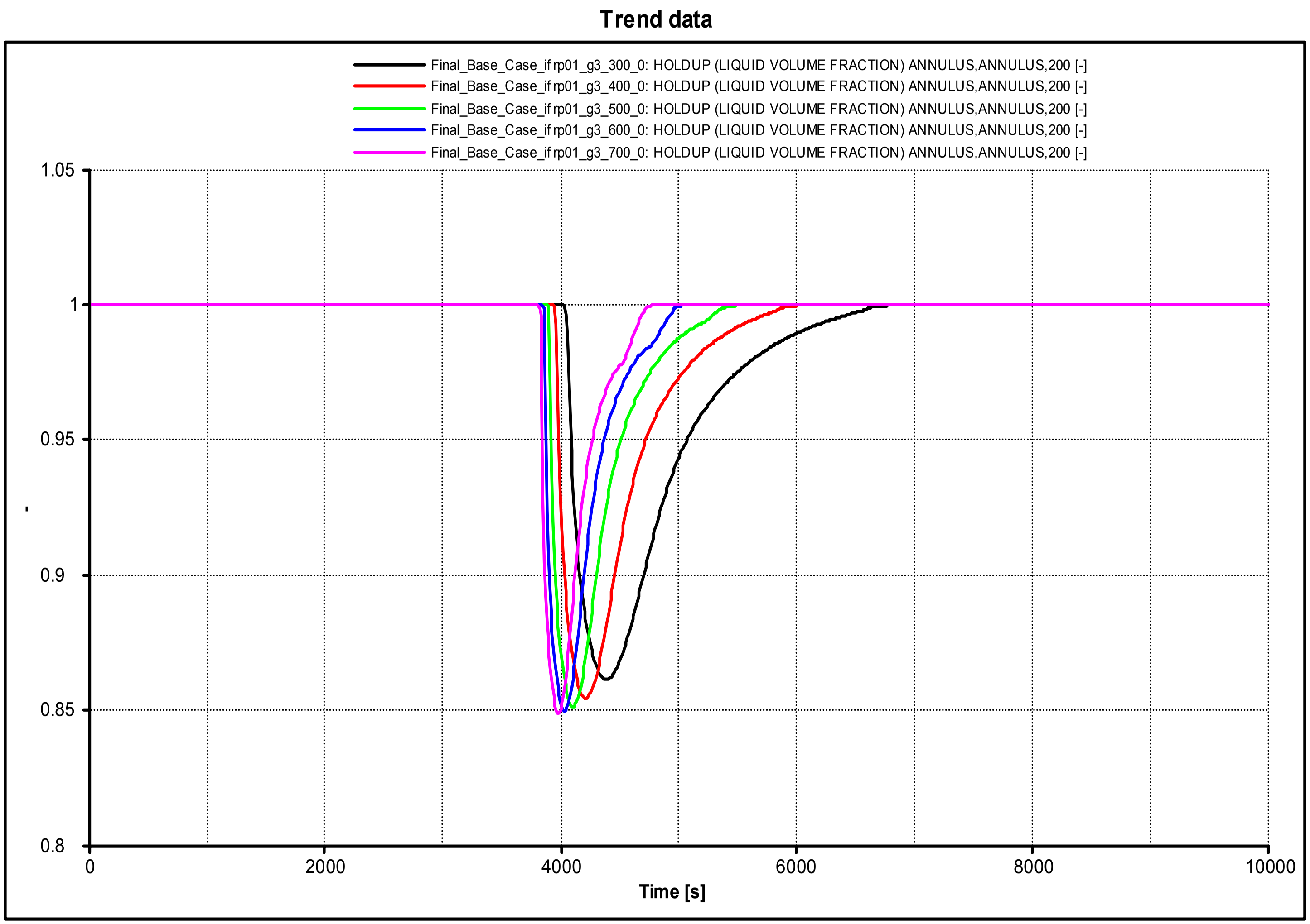


Fig. 44—Liquid holdup at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600, & 700 GPM.

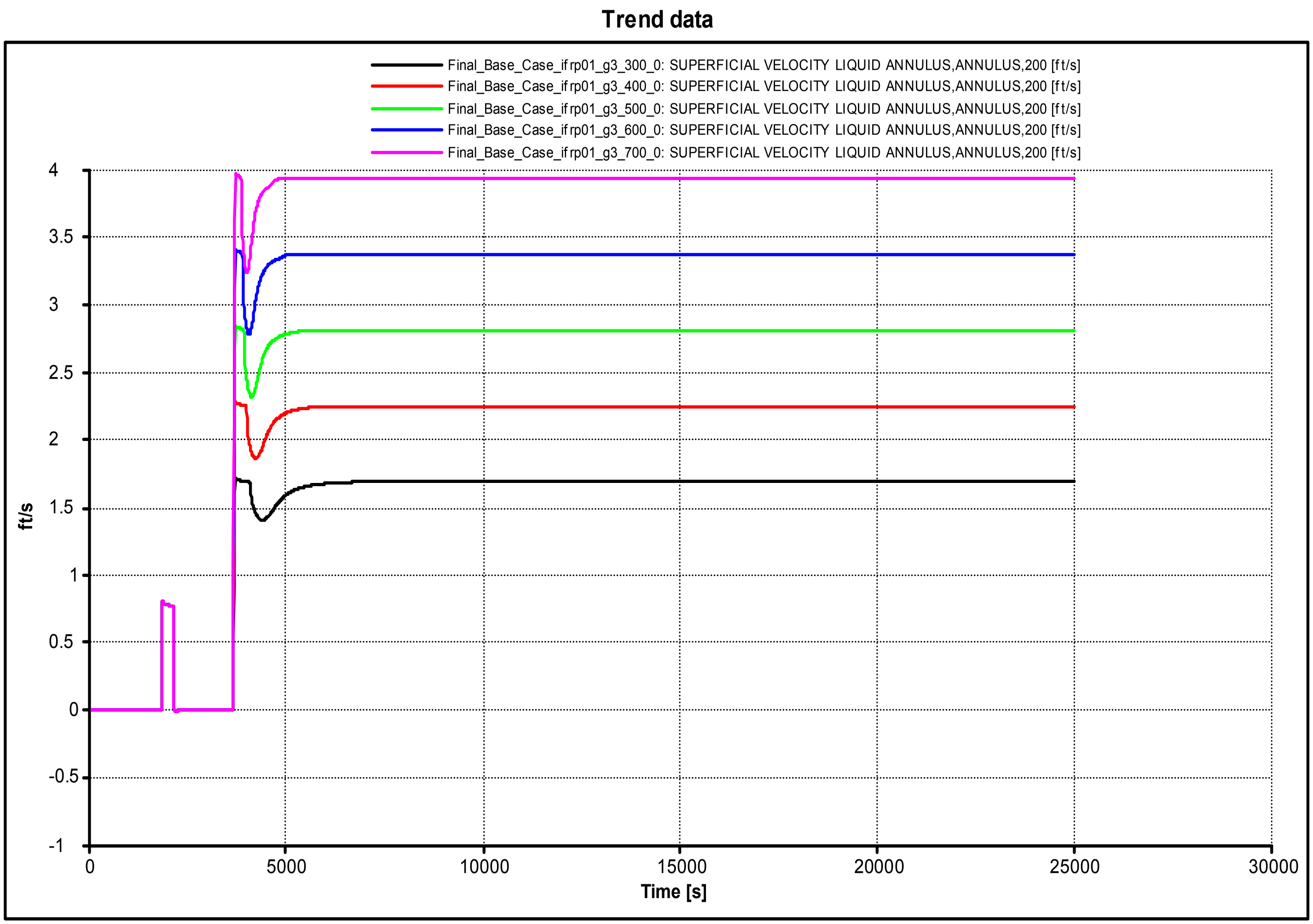


Fig. 45—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600, & 700 GPM.

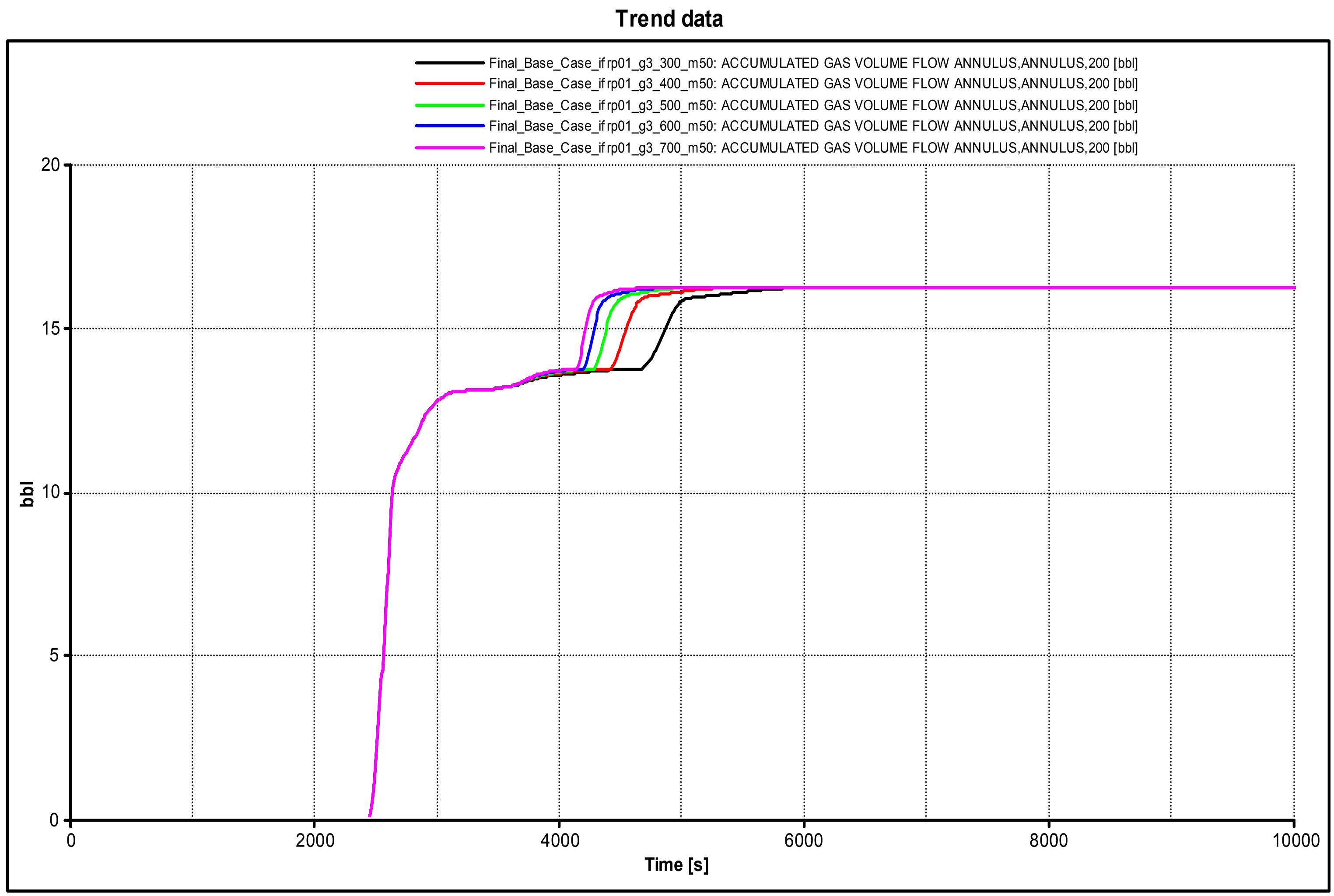


Fig. 46—Accumulated gas out at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600 & 700 GPM.

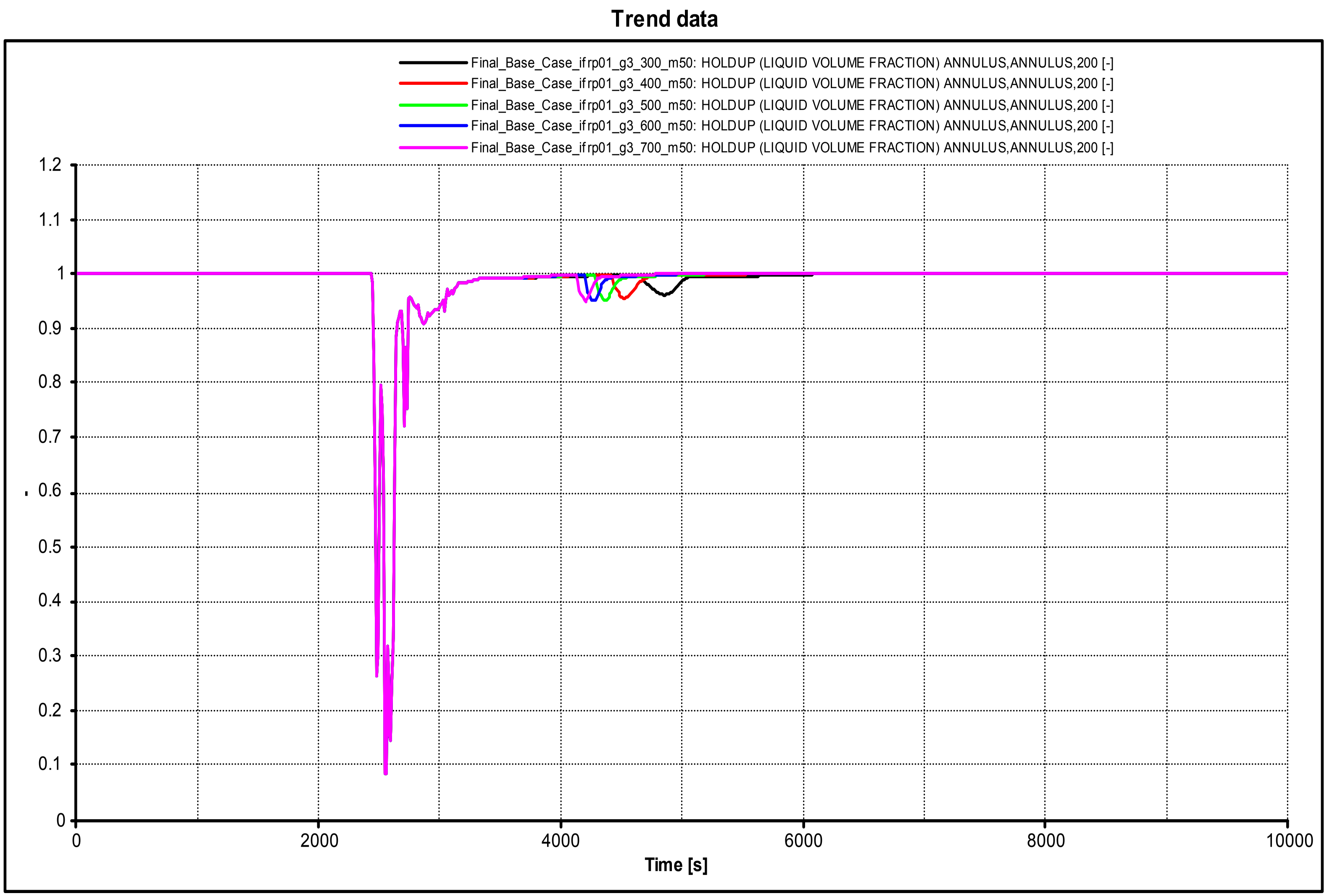


Fig. 47—Liquid holdup at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600, & 700 GPM.

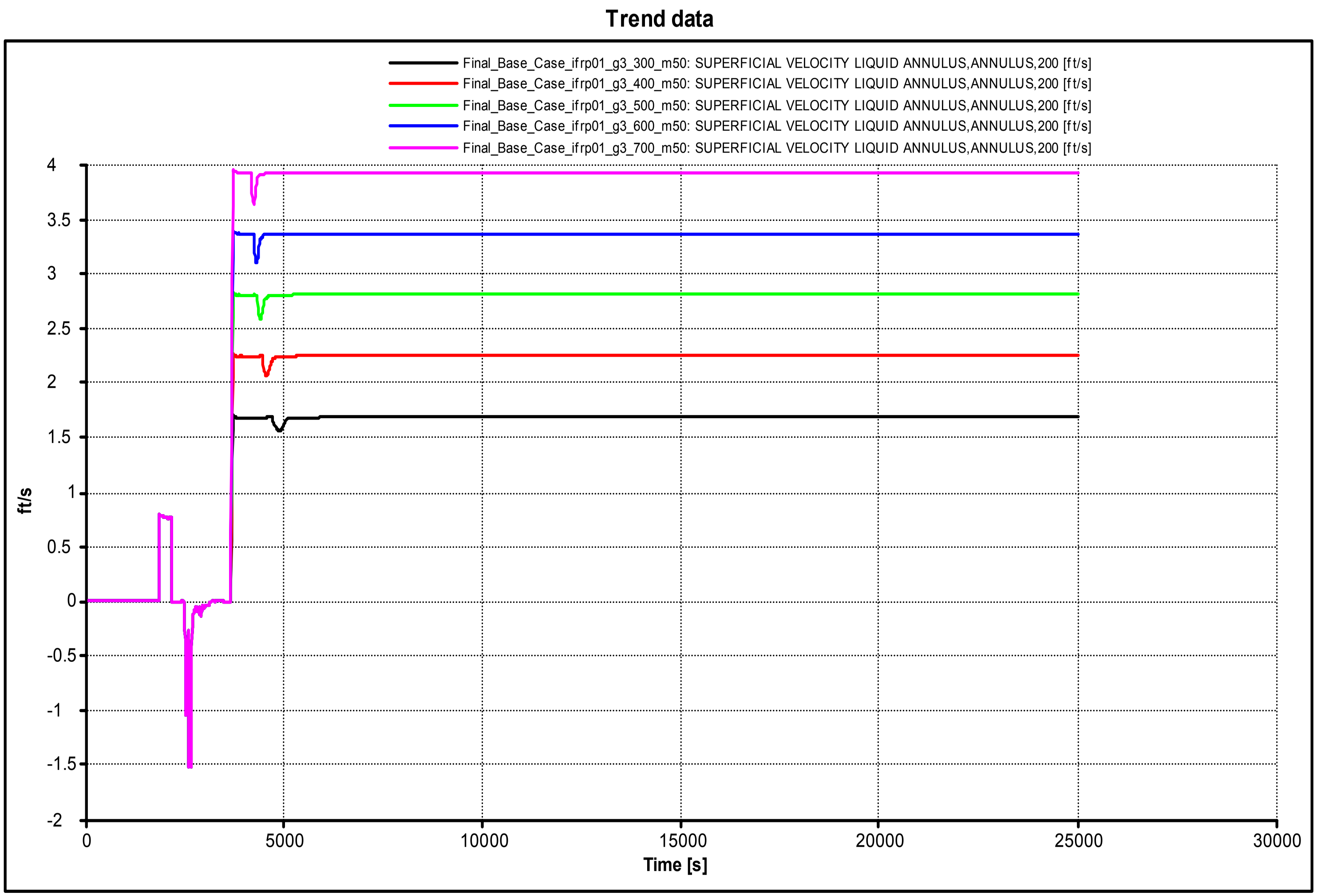


Fig. 48—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600, & 700 GPM.

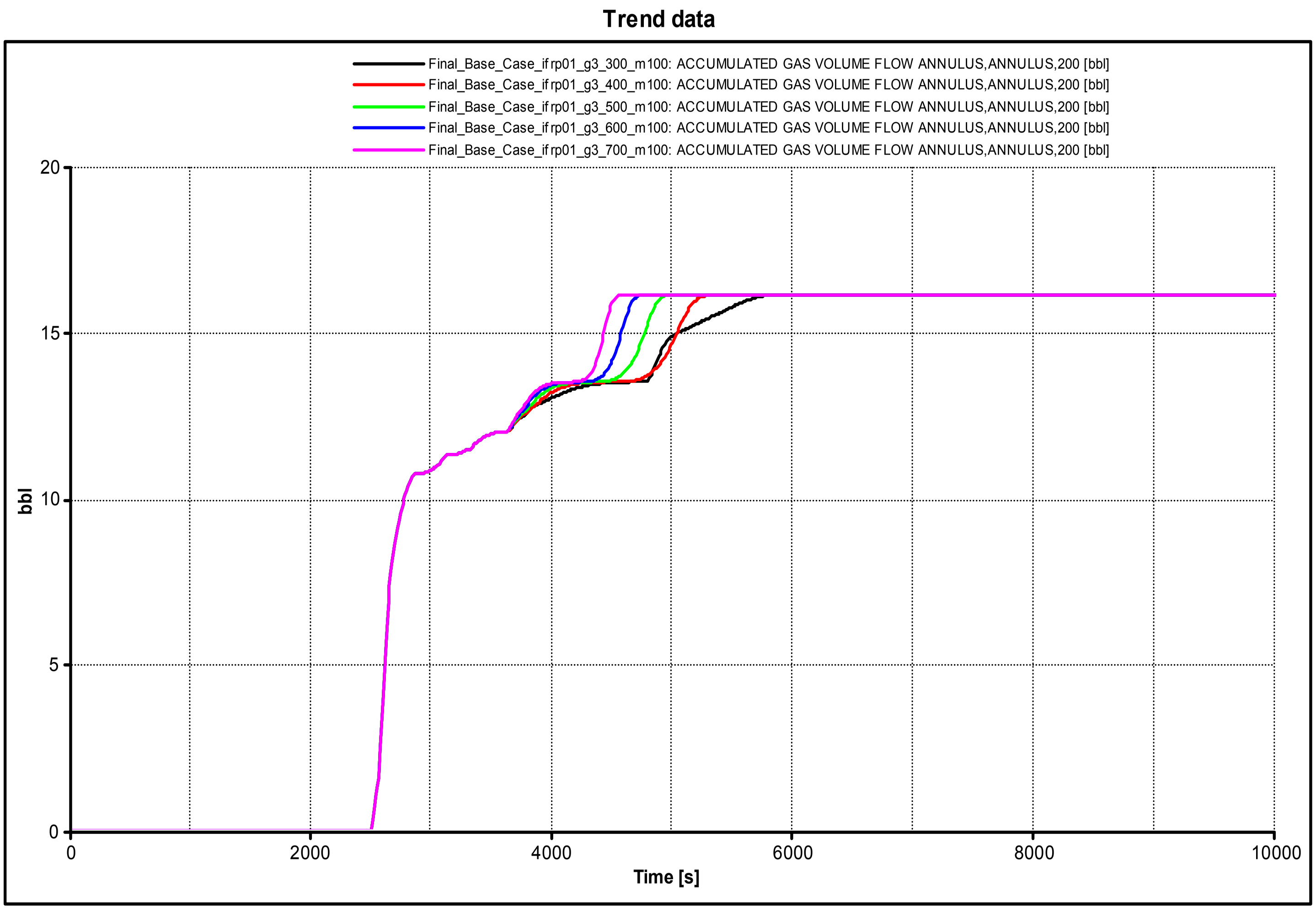


Fig. 49—Accumulated gas out at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600 & 700 GPM.

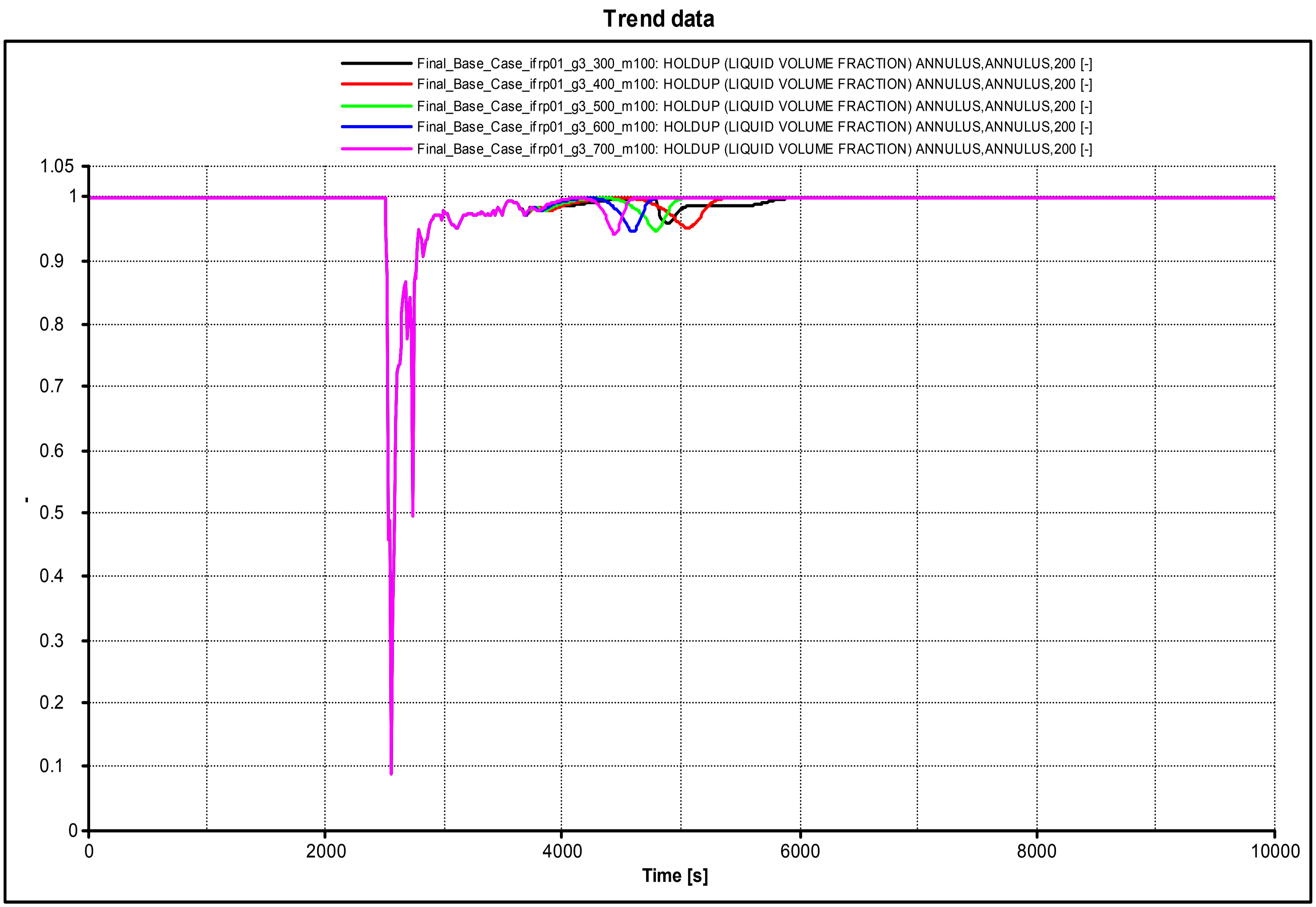


Fig. 50—Liquid holdup at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600, & 700 GPM.

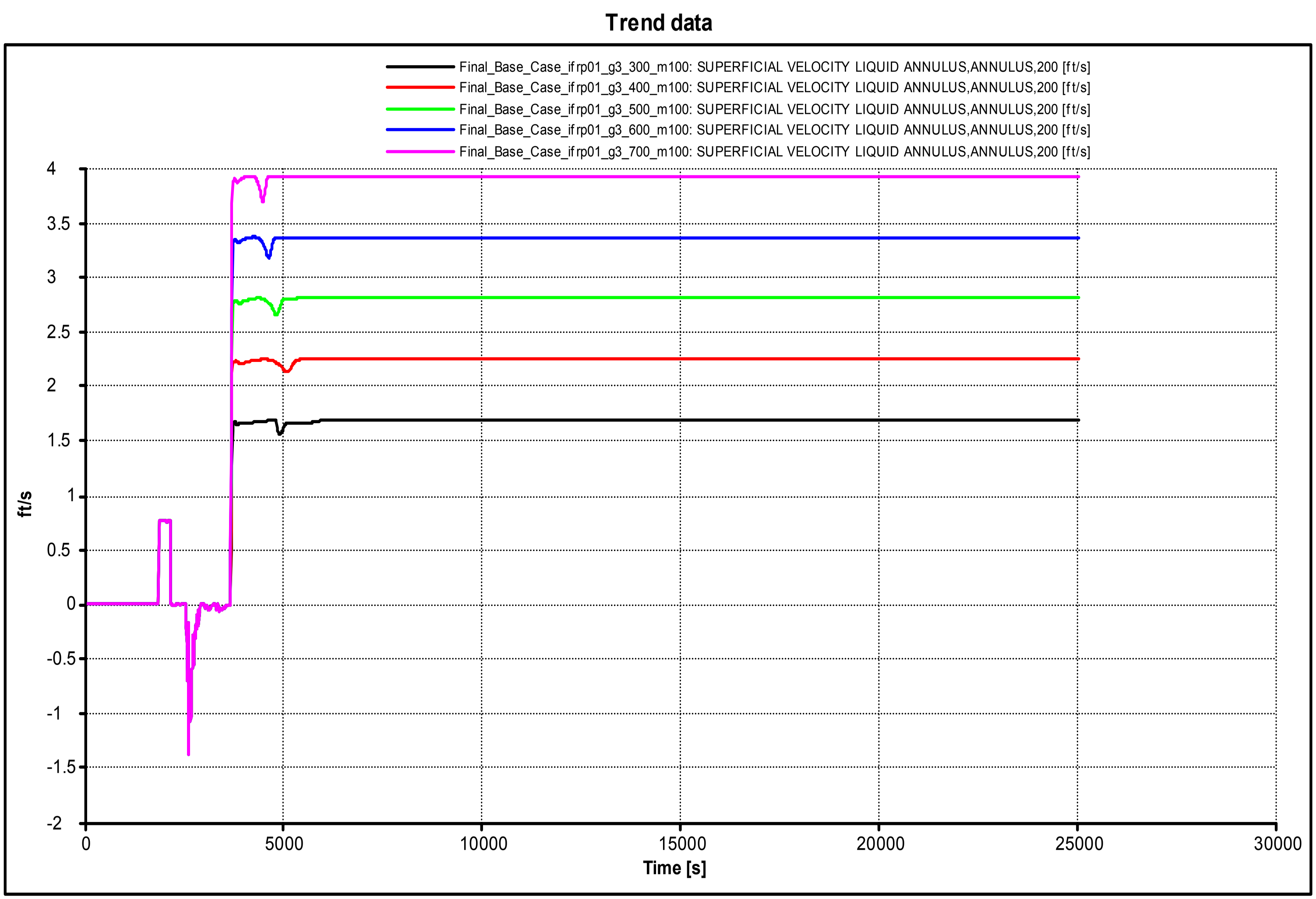


Fig. 51—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600, & 700 GPM.

Liquid-Holdup and Flow-Regime-Indication Profiles

Figs. 52 to 60 illustrate liquid holdup and flow regime for a given circulation rate, geometry, and inclination. The following numeric values correspond to the flow regimes: Stratified Flow = 1, Annular Flow = 2, Slug Flow = 3, and Bubble Flow = 4. For inclinations greater than horizontal, several flow regimes are present. Bubble flow is observed in front of the migrating gas kick. Slug flow or stratified flow is present in the portion of the wellbore where the majority of the gas is present, and a stratified flow regime exists behind the gas influx. Figs. 52, 55, and 58 represent these data. For horizontal cases, a stratified flow regime is present throughout the removal of the gas influx. Figs. 53, 56, and 59 represent these data. For inclinations below horizontal, slug flow or stratified flow may be present in the portion of the wellbore the majority of the gas occupies. A region of bubble flow follows this until stratified flow is reached. Figs. 54, 57, and 60 represent these data.

Wellbore Friction

Fig. 61 illustrates the simulation study varying annular friction. As the relative roughness value increased, the kick removal process became more efficient.

Runs Performed With Various Mud Properties

Effects of Mud Properties

Figs. 62 to 66 depict the results of runs with varying mud properties. These runs were simulated using Geometry 2 with an inclination of 10° at a circulation rate of 275 GPM. Fig. 62 illustrates the effect of viscosity on kick removal. It shows that a fluid with a higher effective viscosity is more efficient at transporting the kick. All of the fluids are significantly better than water. Fig. 64 illustrates the effect of density coupled with viscosity. The variance in accumulated gas out reflect slight differences in outlet pressure resulting from the hydrostatic head of the muds. Fig. 66 compares the effects of mud density and mud viscosity. The weighted muds are slightly more efficient at removing the kick from the wellbore. However, viscosity is the overruling parameter.

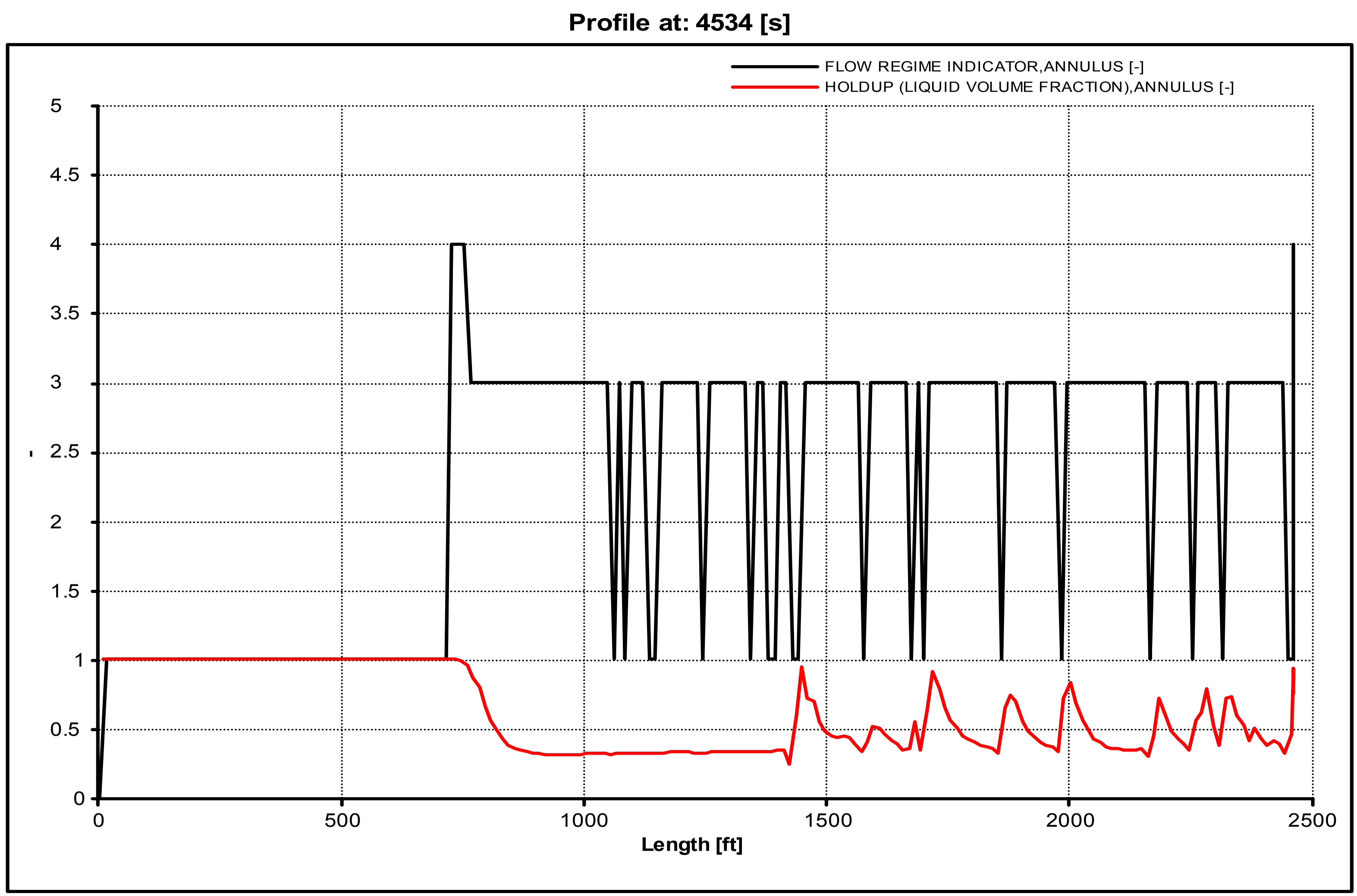


Fig. 52—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 100 GPM.

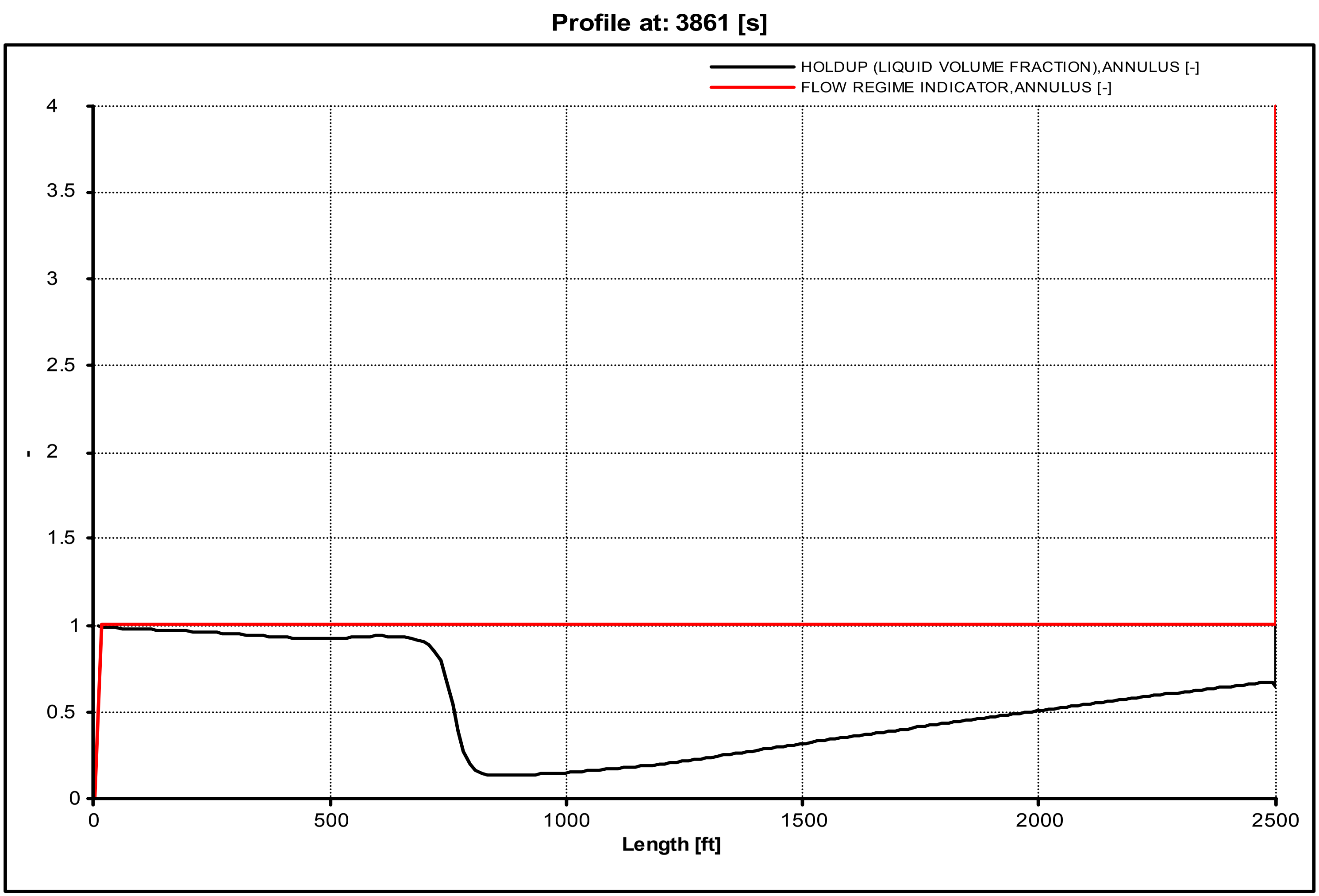


Fig. 53—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 0°, circulation rate 100 GPM.

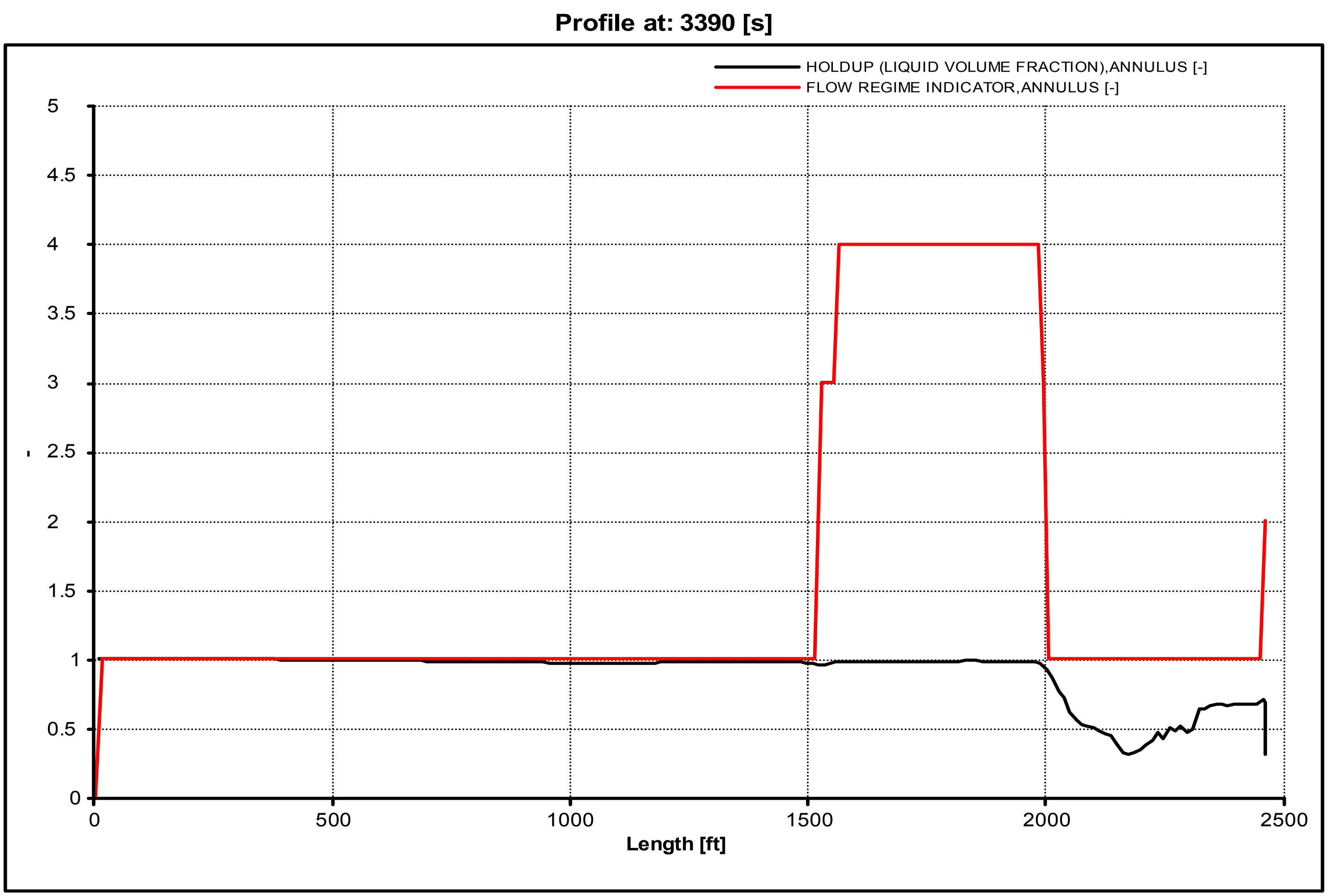


Fig. 54—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination -10°, circulation rate 100 GPM.

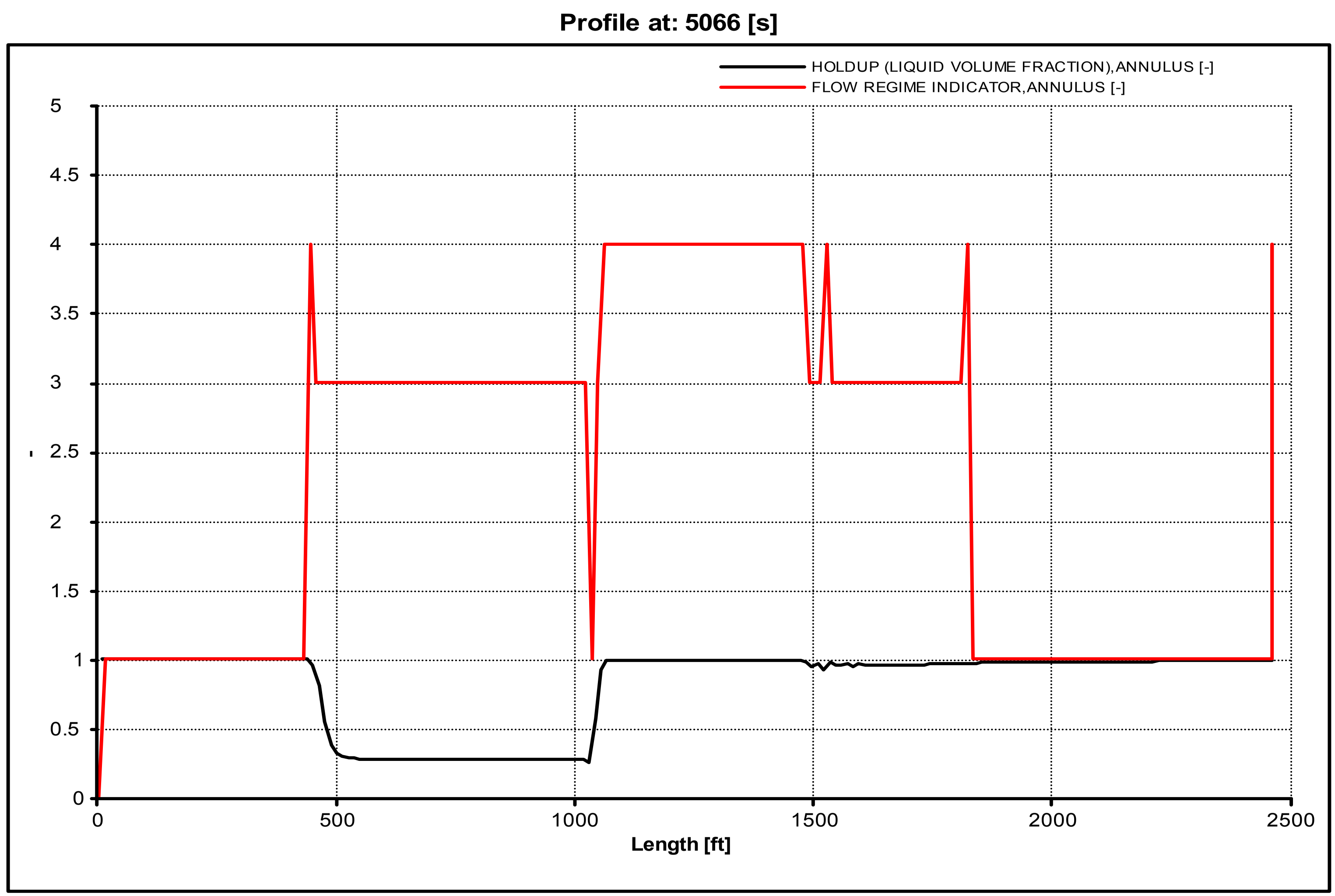


Fig. 55—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

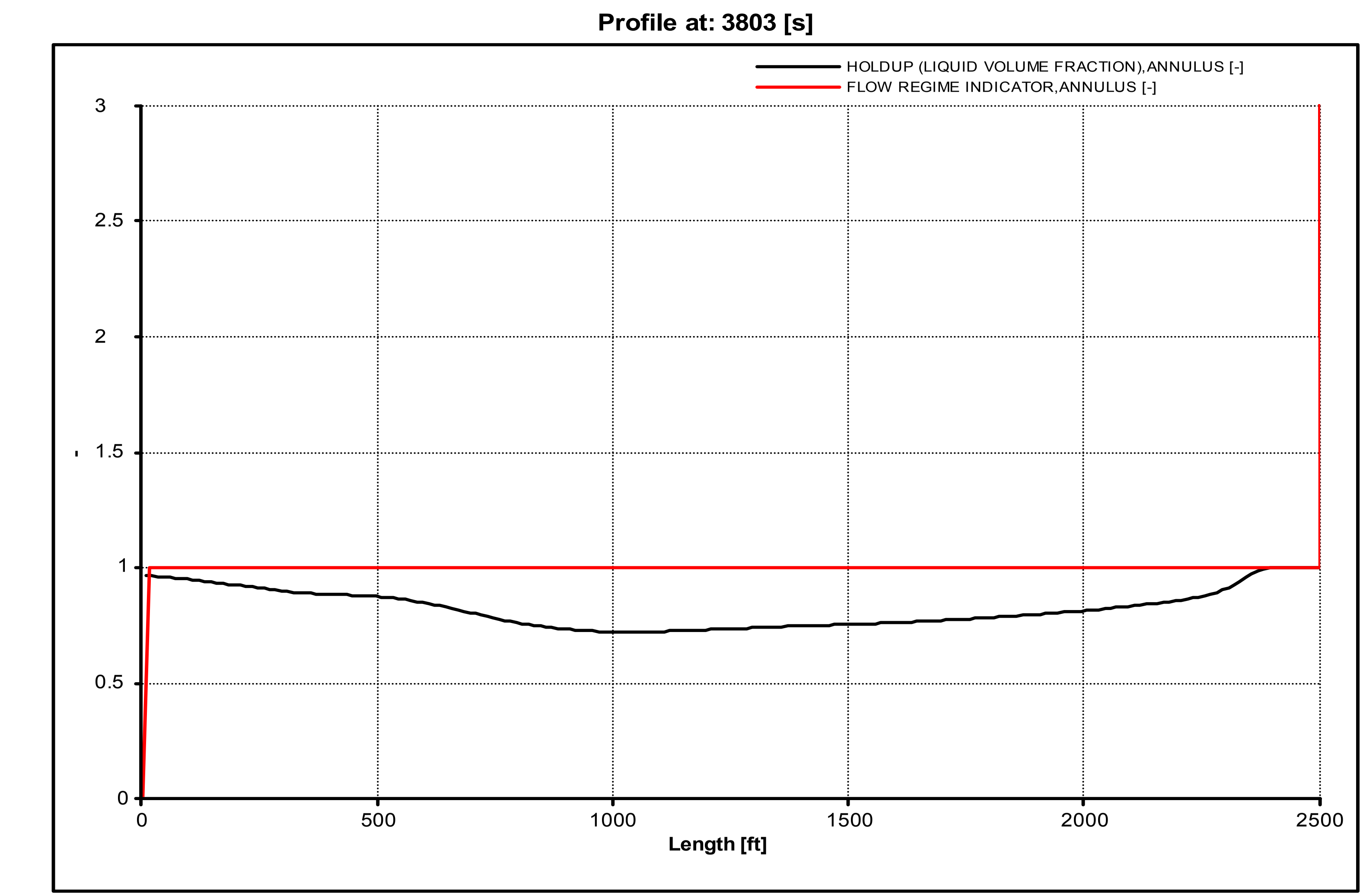


Fig. 56—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 0°, circulation rate 275 GPM.

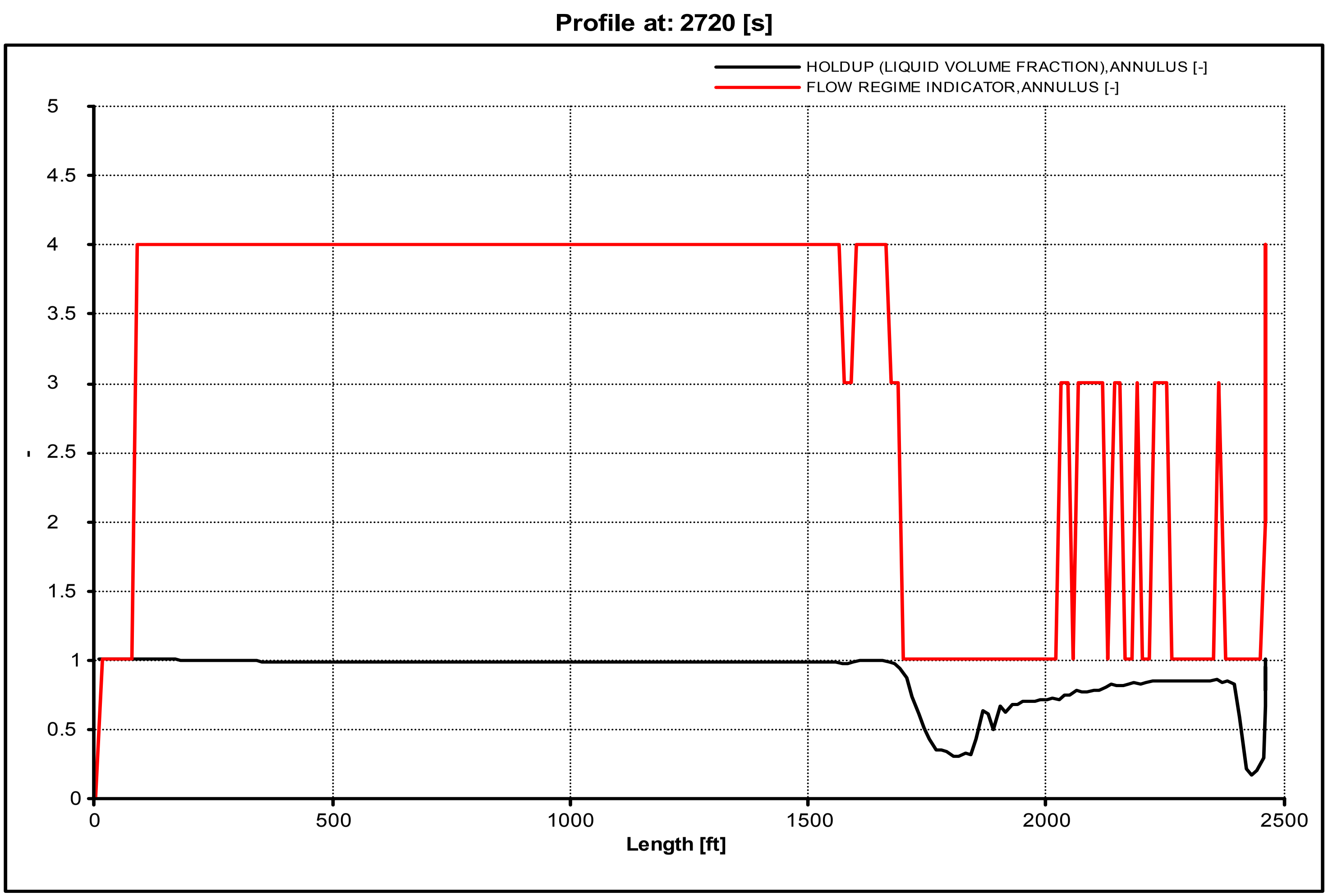


Fig. 57—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination -10°, circulation rate 275 GPM.

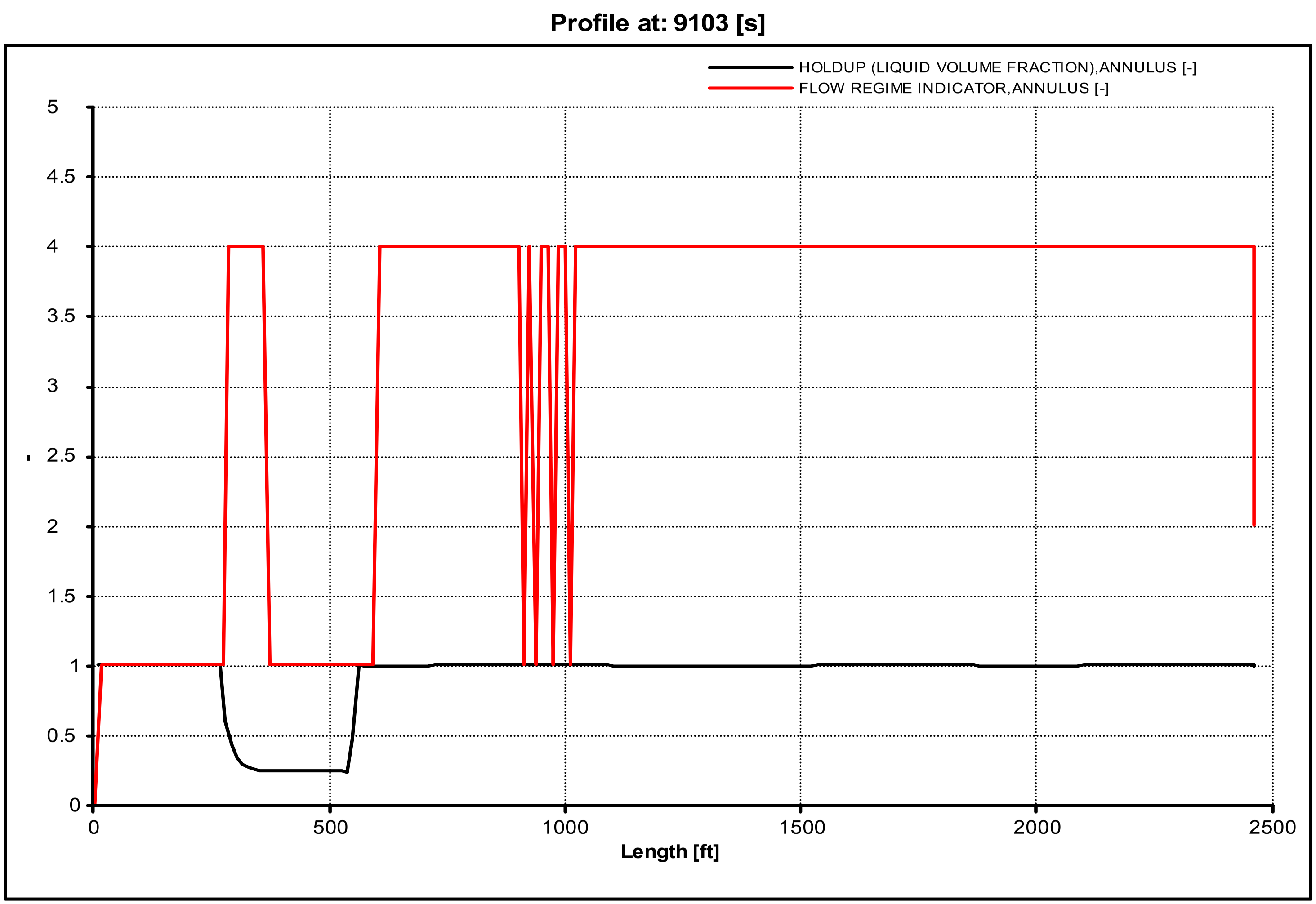


Fig. 58—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 500 GPM.

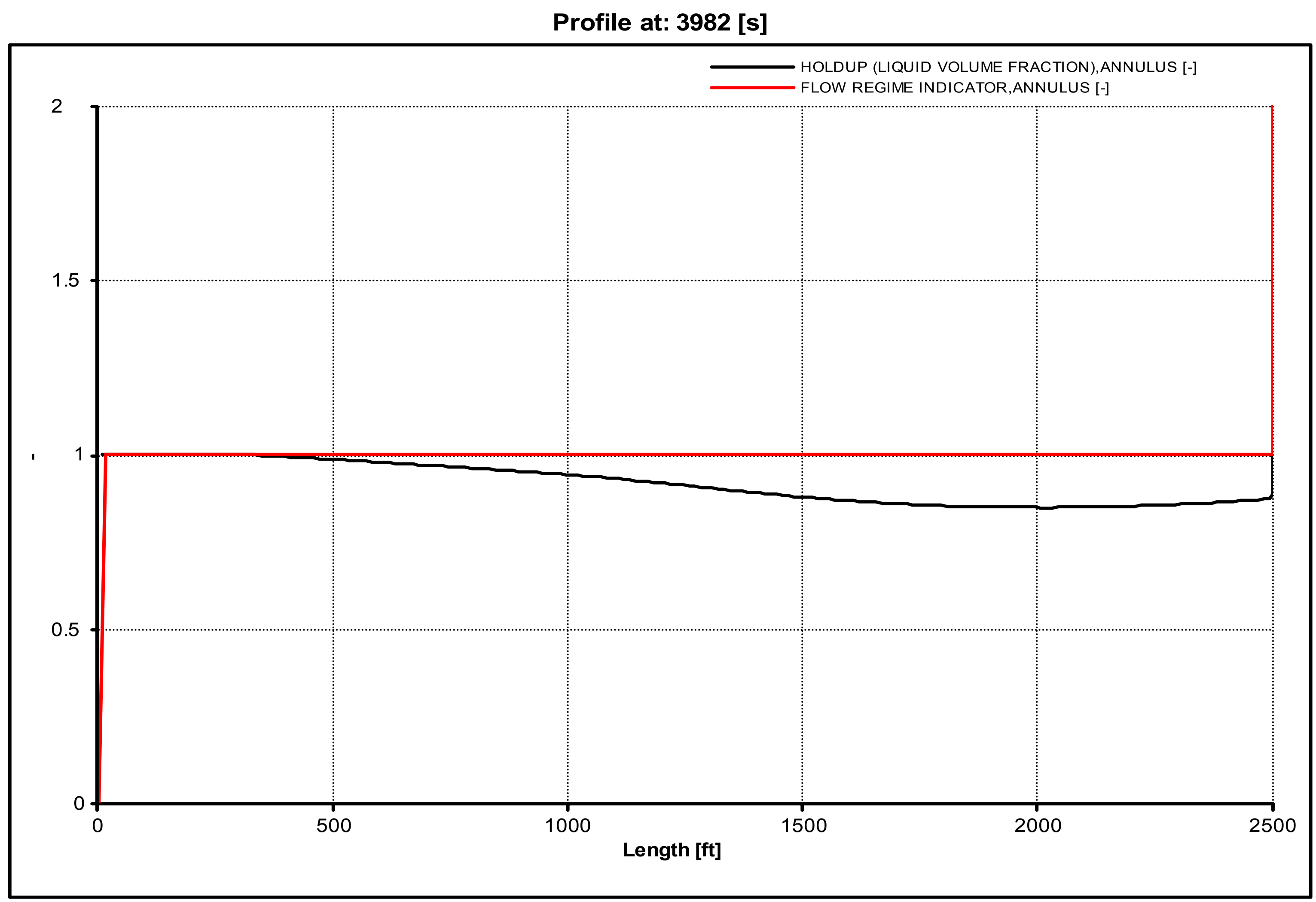


Fig. 59—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 0°, circulation rate 500 GPM.

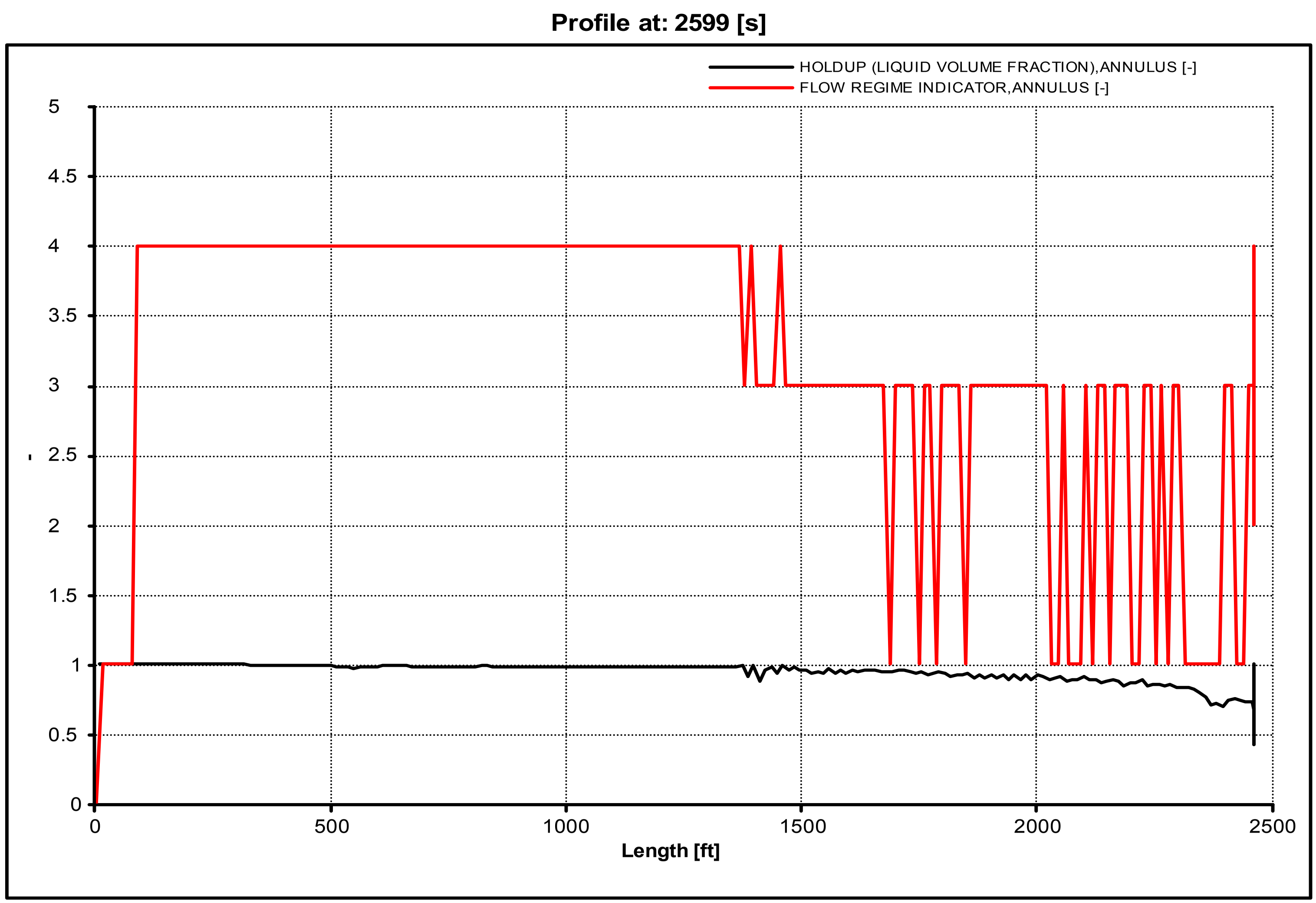


Fig. 60—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination -10°, circulation rate 500 GPM.

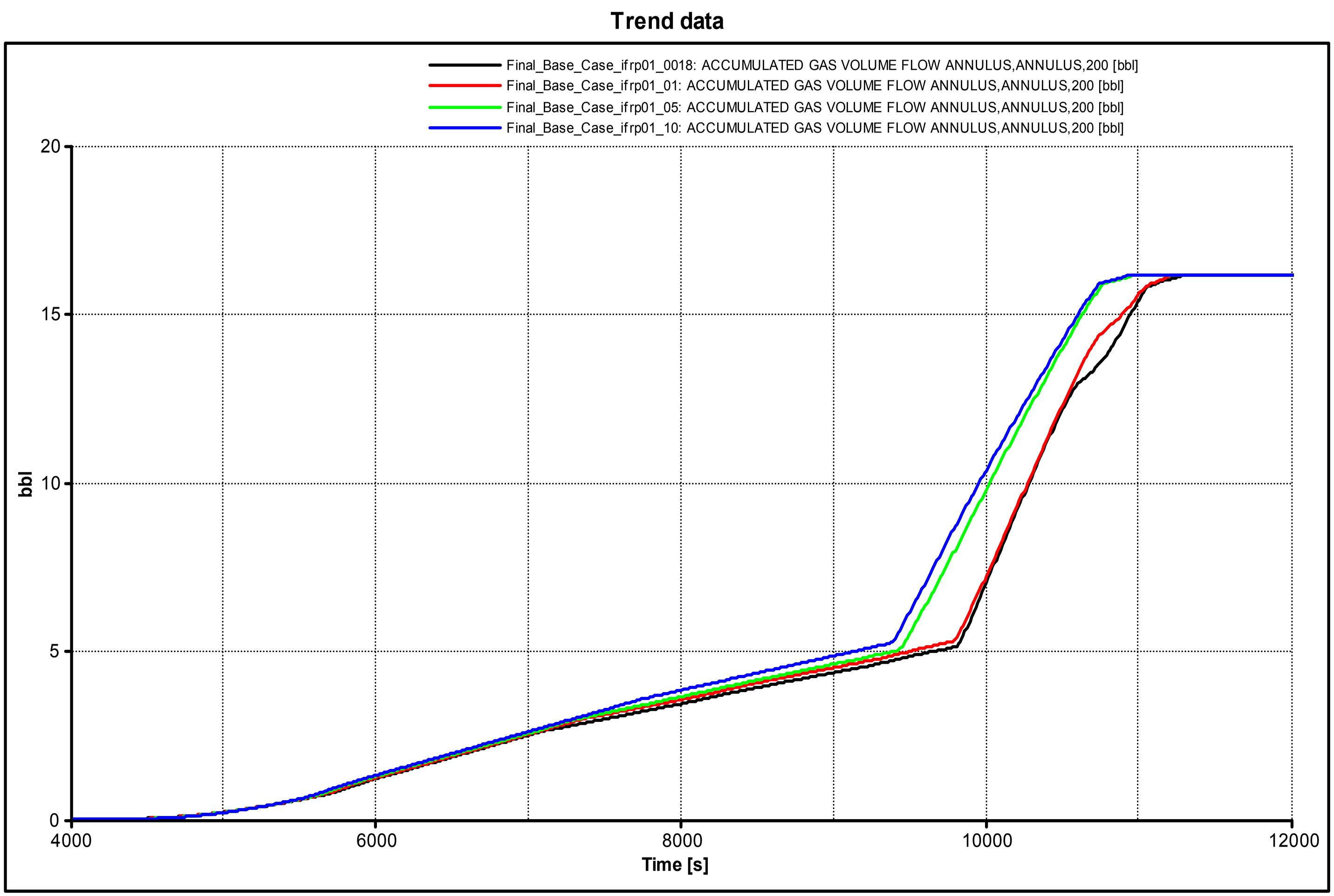


Fig. 61—Friction profile plot, Geometry 2, inclination 10°, circulation rate 275 GPM, relative roughness 0.0018, 0.01, 0.05, & 0.10.

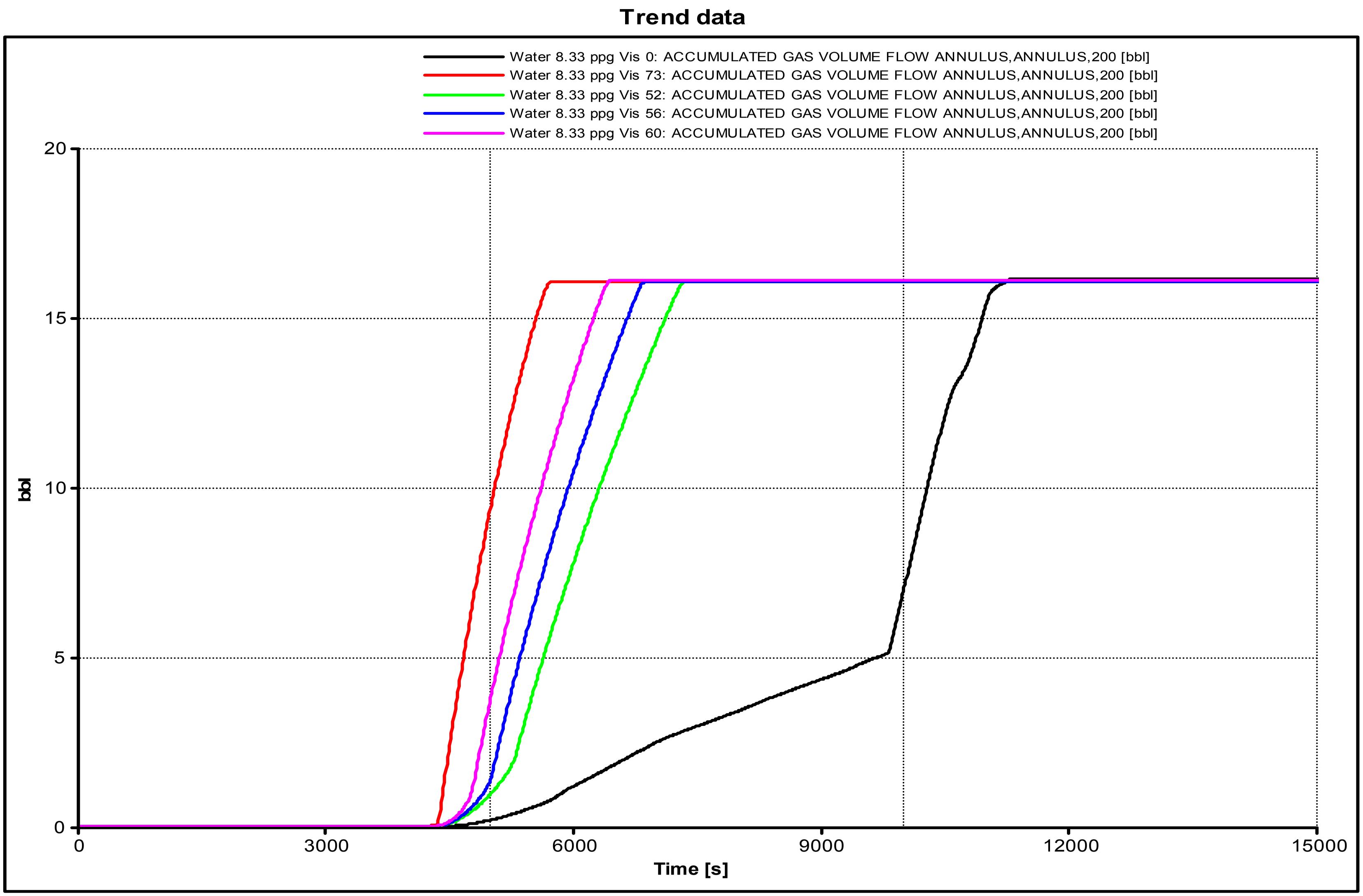


Fig. 62—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

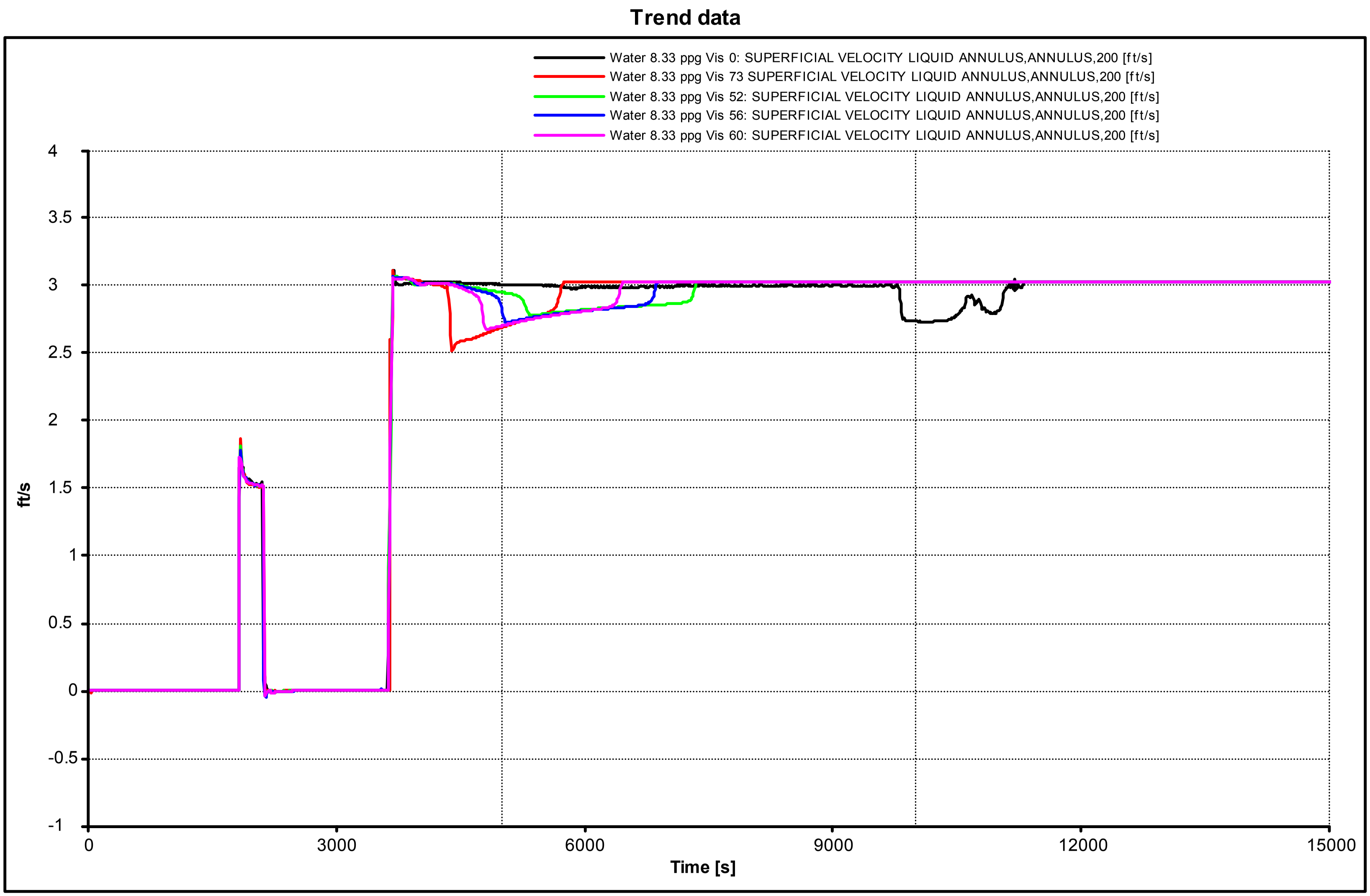


Fig. 63—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

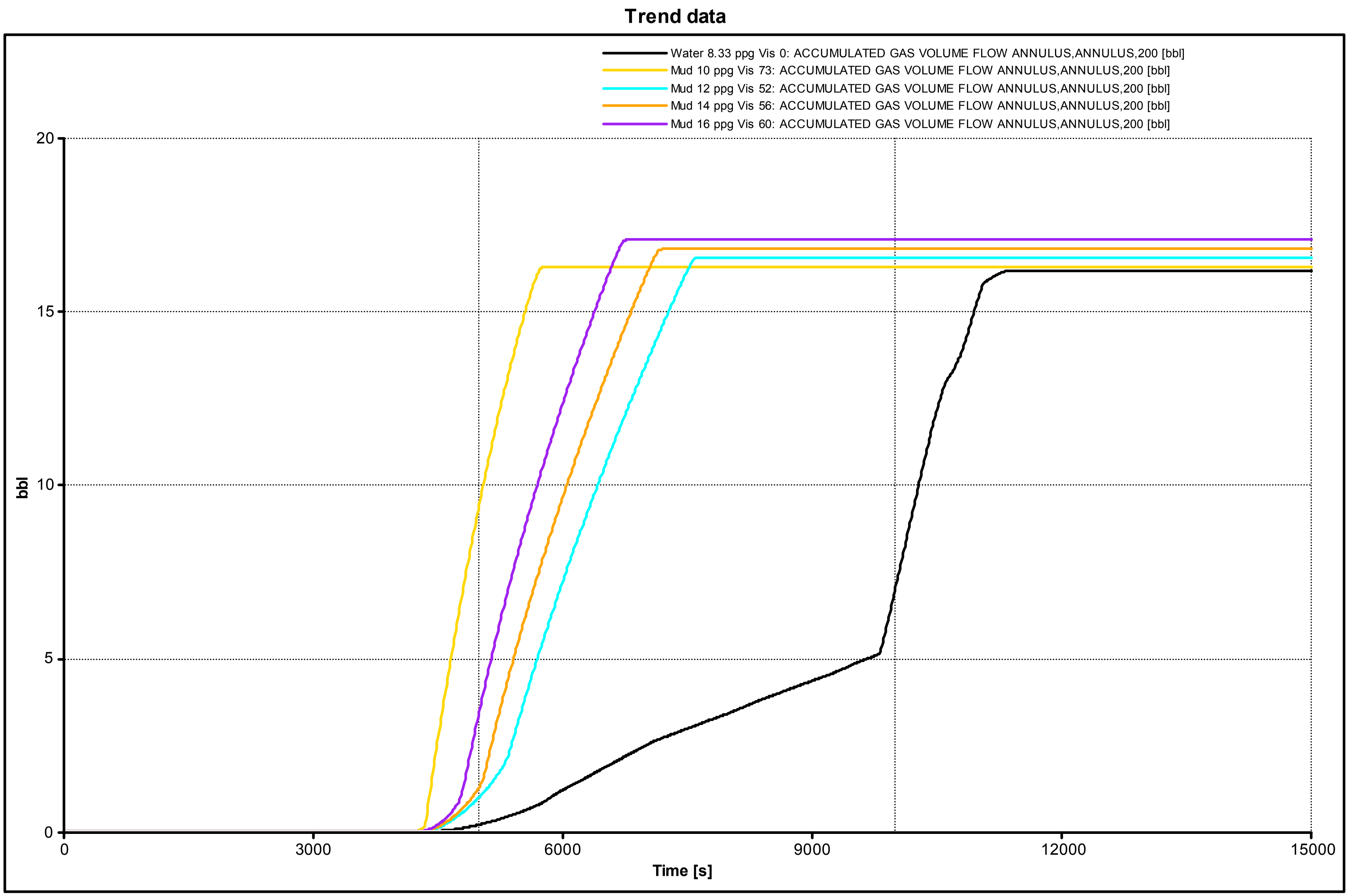


Fig. 64—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

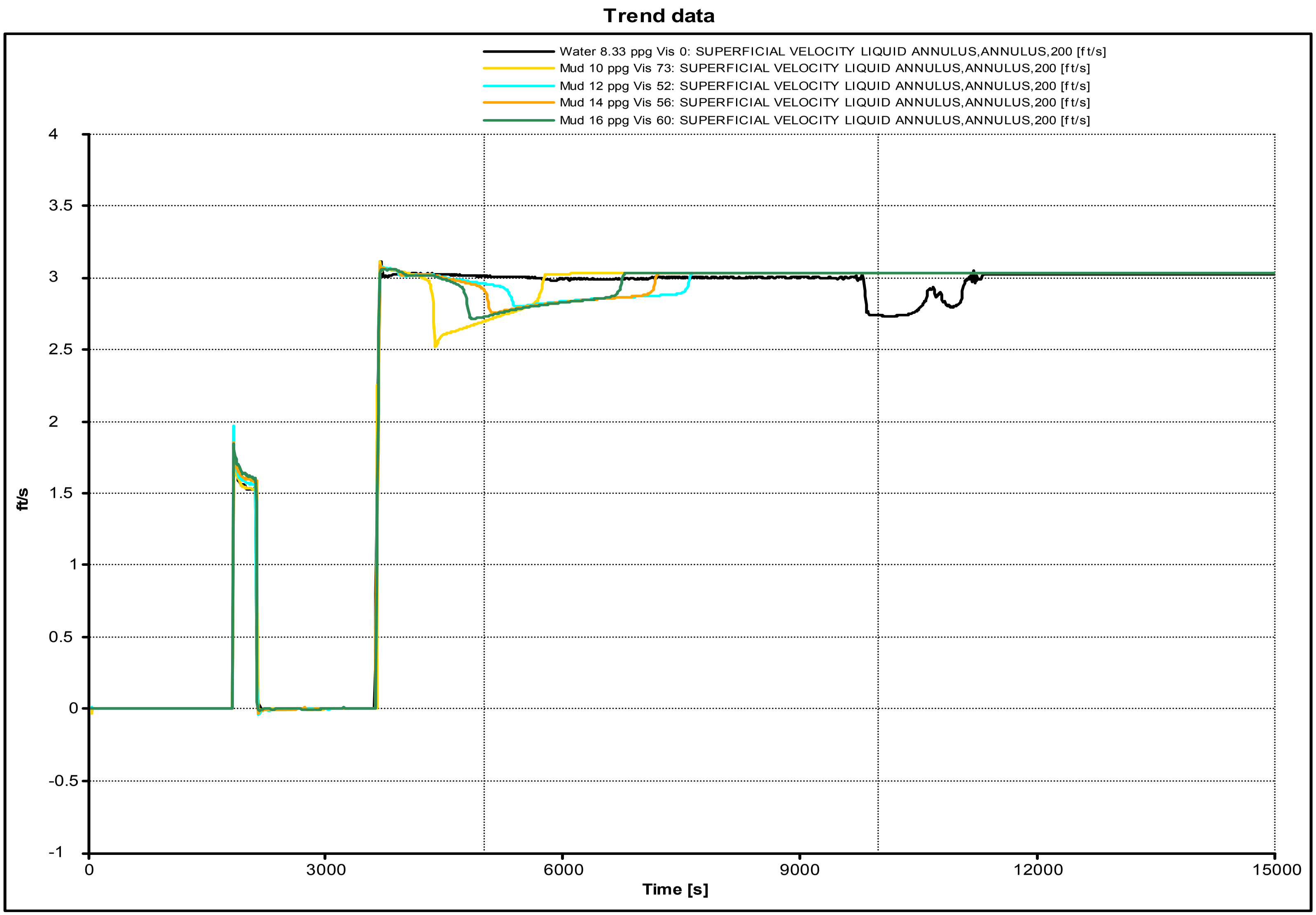


Fig. 65—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

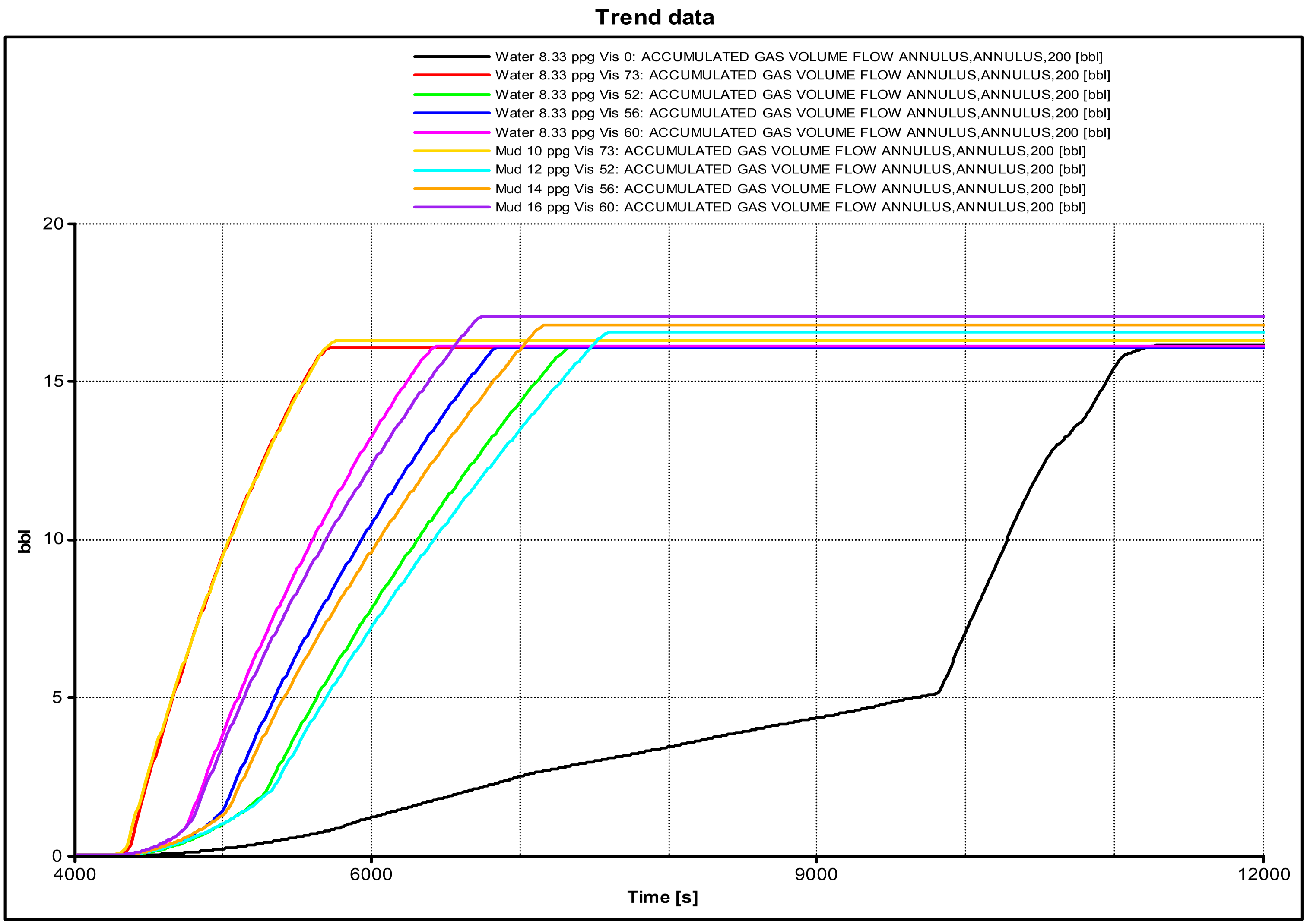


Fig. 66—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

Geometry 1

Figs. 67-70 represent data for simulation runs performed using a 14-ppg mud with *n* and *K* values of 0.773 and 1.275 respectively. Using the power-law coefficients, OLGA calculates the effective viscosity, which is dependent upon circulation rate. Comparing Figs. 67 and 68 to Figs. 7 and 9, the viscous fluid transports the gas kick more efficiently and at lower annular velocity. A rate of 100 GPM and annular velocity of 3.2 ft/sec were required to remove the kick with water. For the mud, a rate of 60 GPM and annular velocity of 1.9 ft/sec were required to remove the kick. The ability to use a slower circulating kill rate is desirable, as it allows more precise control of the well. Figs. 69 and 70 illustrate the liquid holdup and flow regime for a given time. The flow regime was stratified flow, which is considerably different from the slug-flow regime depicted in Fig. 7 for the water run. The difference in flow regime is attributed to mud properties affecting the transition between laminar and turbulent flow.

Geometry 2

The results in **Figs. 71 to 74** exhibited the same development as for the previous geometry. For the run performed with water, a circulation rate of 275 GPM and annular velocity of 3.1 ft/sec was required to remove the kick. Using the 14-ppg mud, these values were lowered to a circulation rate of 250 GPM and an annular velocity of 2.75 ft/sec. Figs. 73 and 74 show the flow regimes for circulation rates of 200 and 250 GPM. Again, stratified flow is exhibited as opposed to slug flow for the water case.

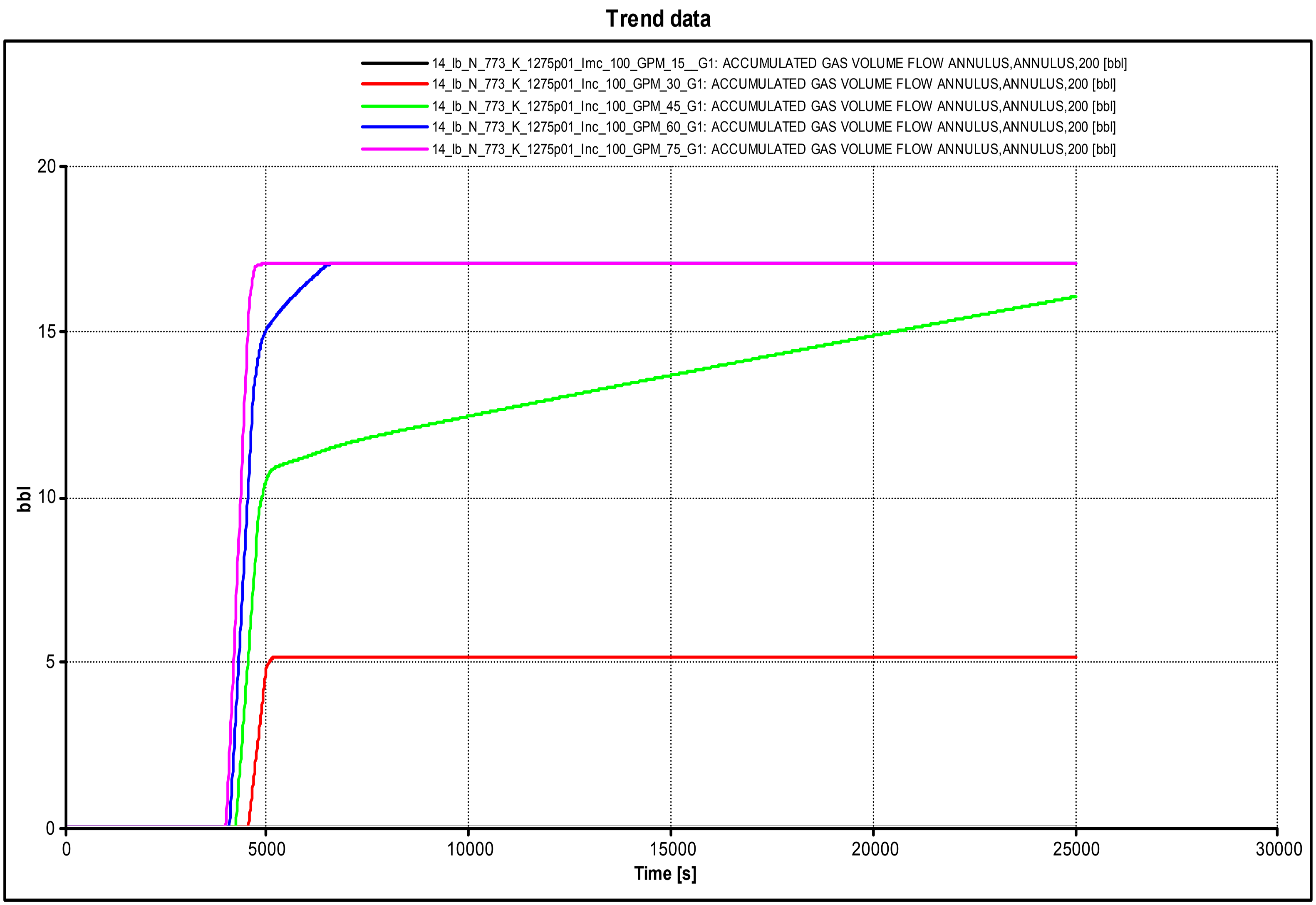


Fig. 67—Accumulated gas out at outlet of annulus, Geometry 1, inclination 10°, circulation rate 15, 30, 45, 60, & 75 GPM.

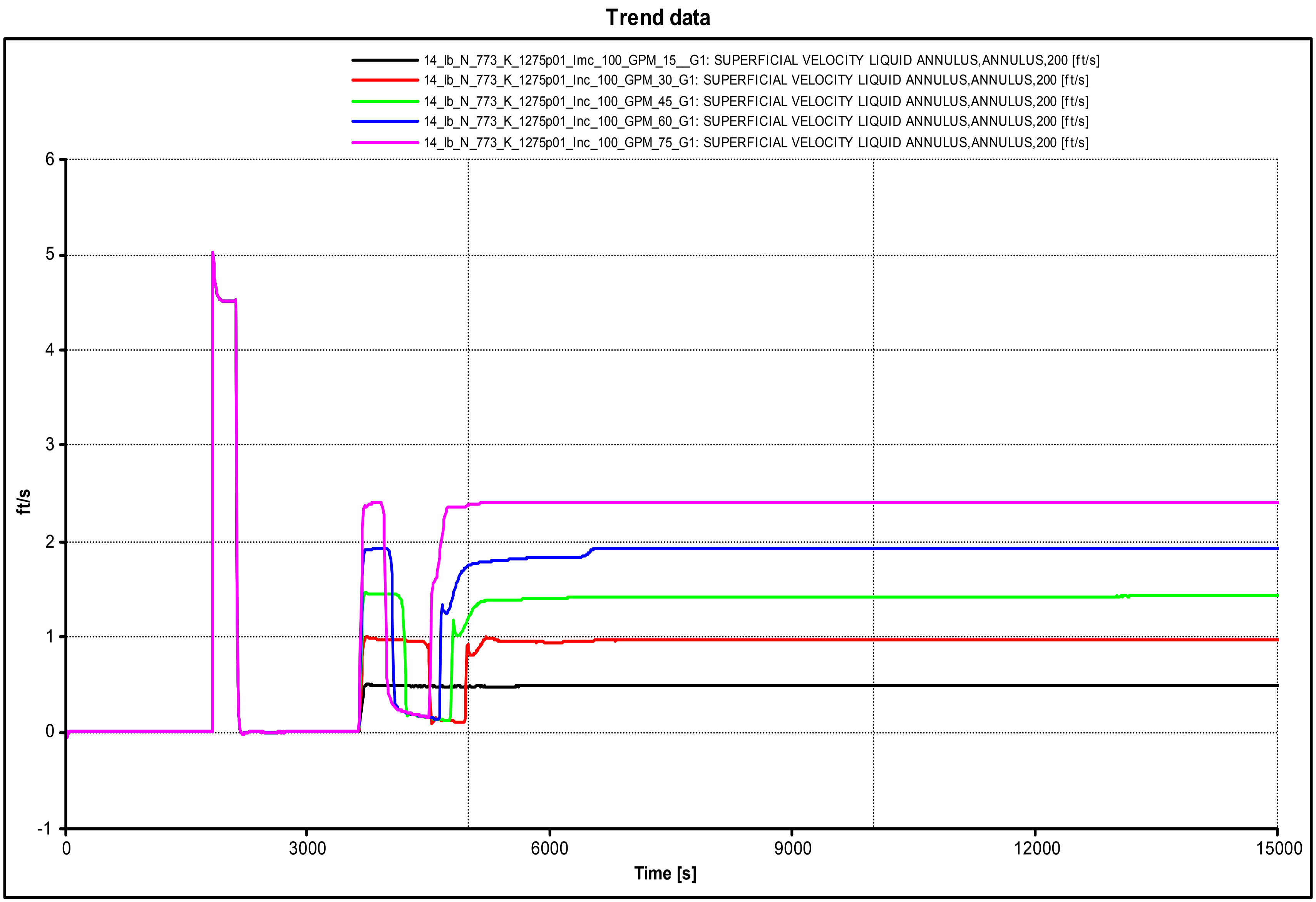


Fig. 68—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 10°, circulation rate 15, 30, 45, 60, & 75 GPM.

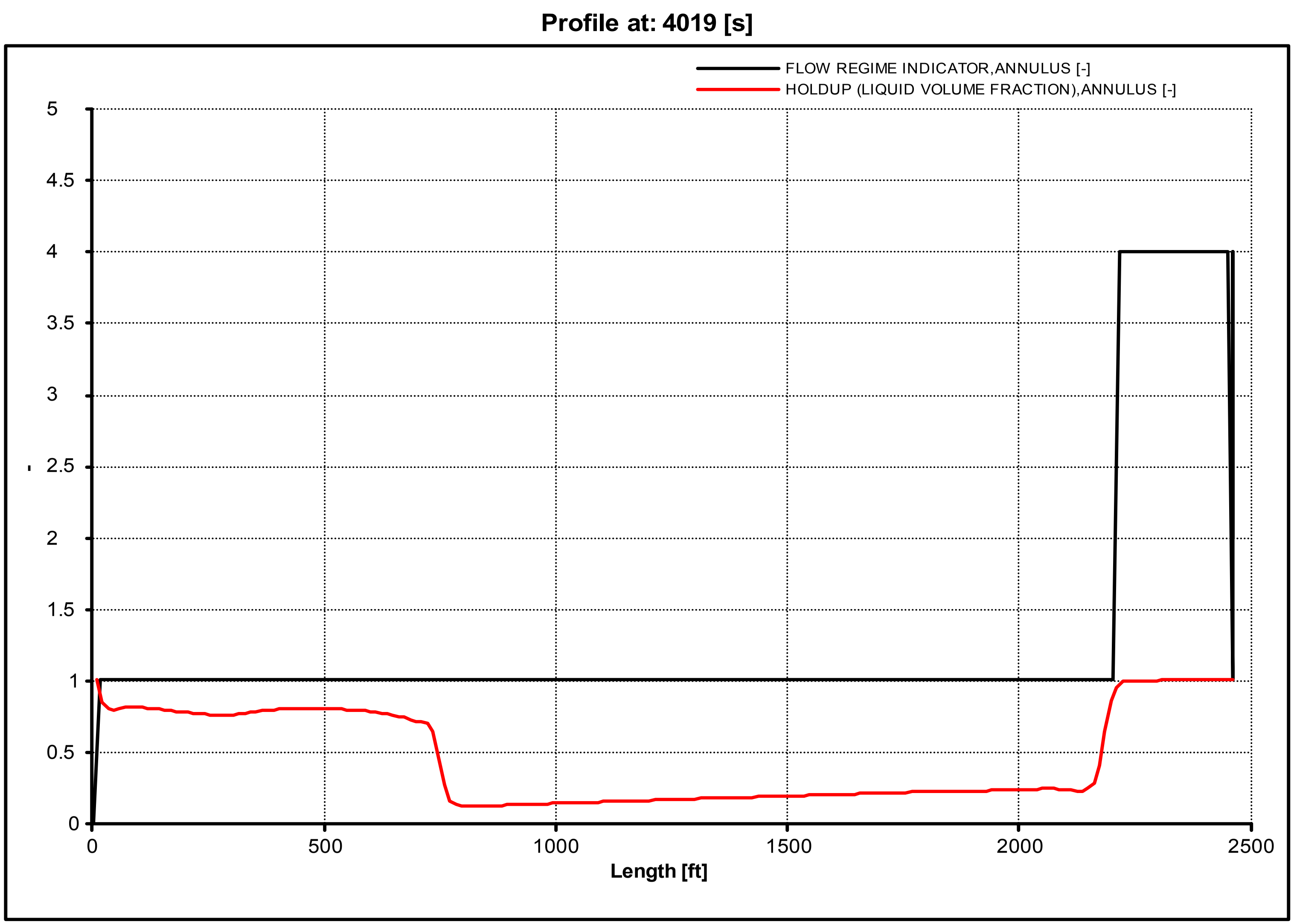


Fig. 69—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 45 GPM

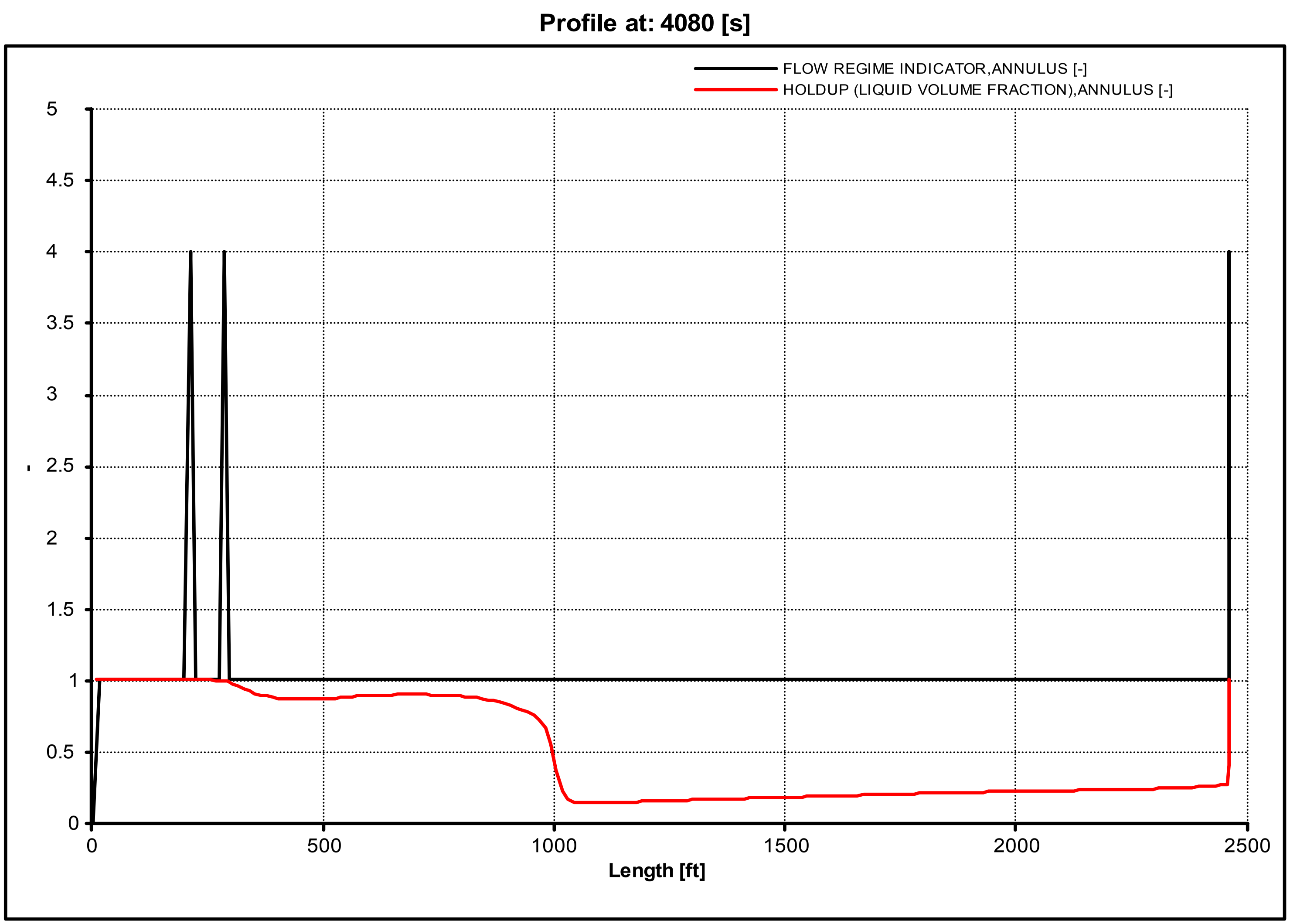


Fig. 70—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 60 GPM.

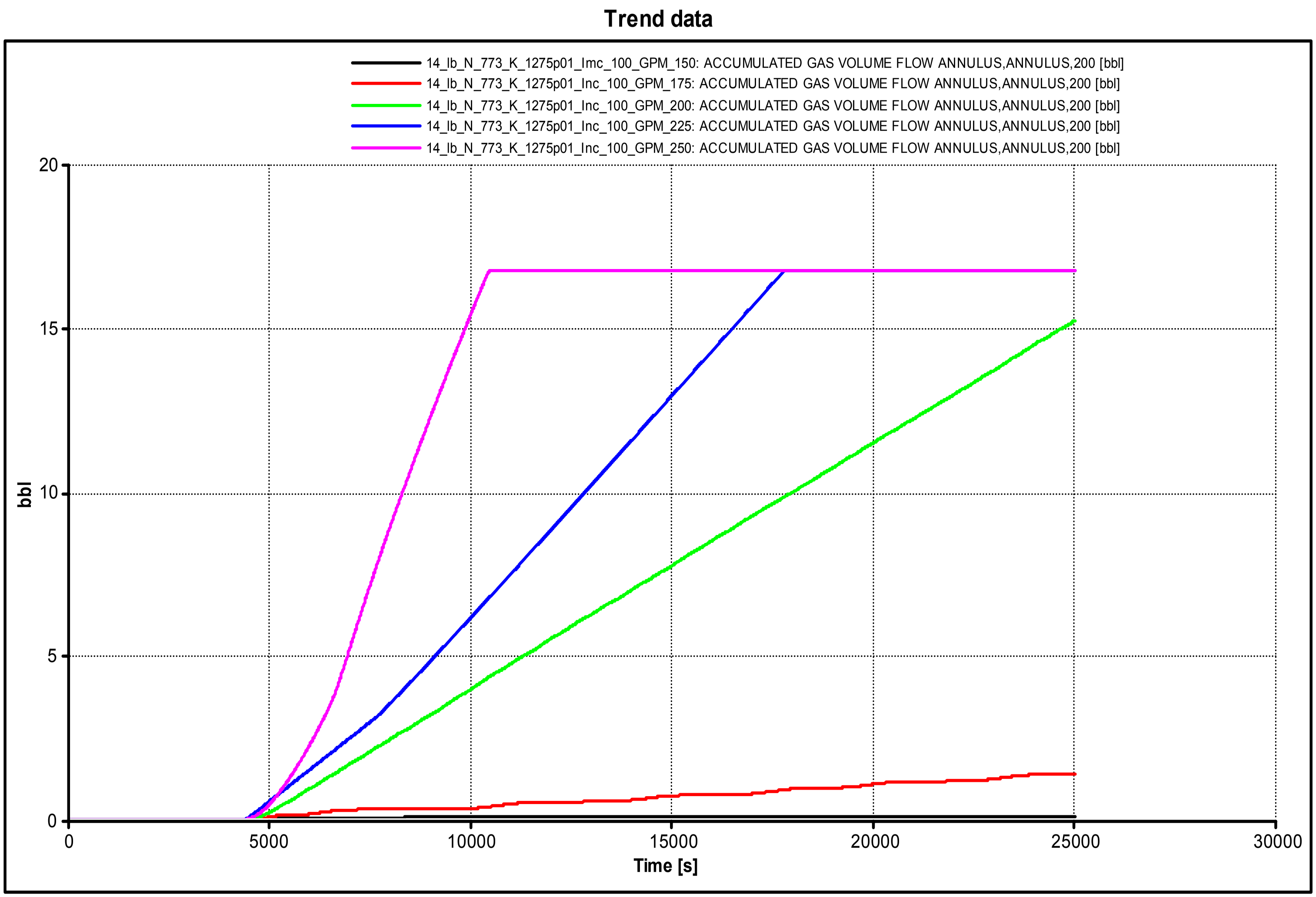


Fig. 71—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 150, 175, 200, 225, & 250 GPM.

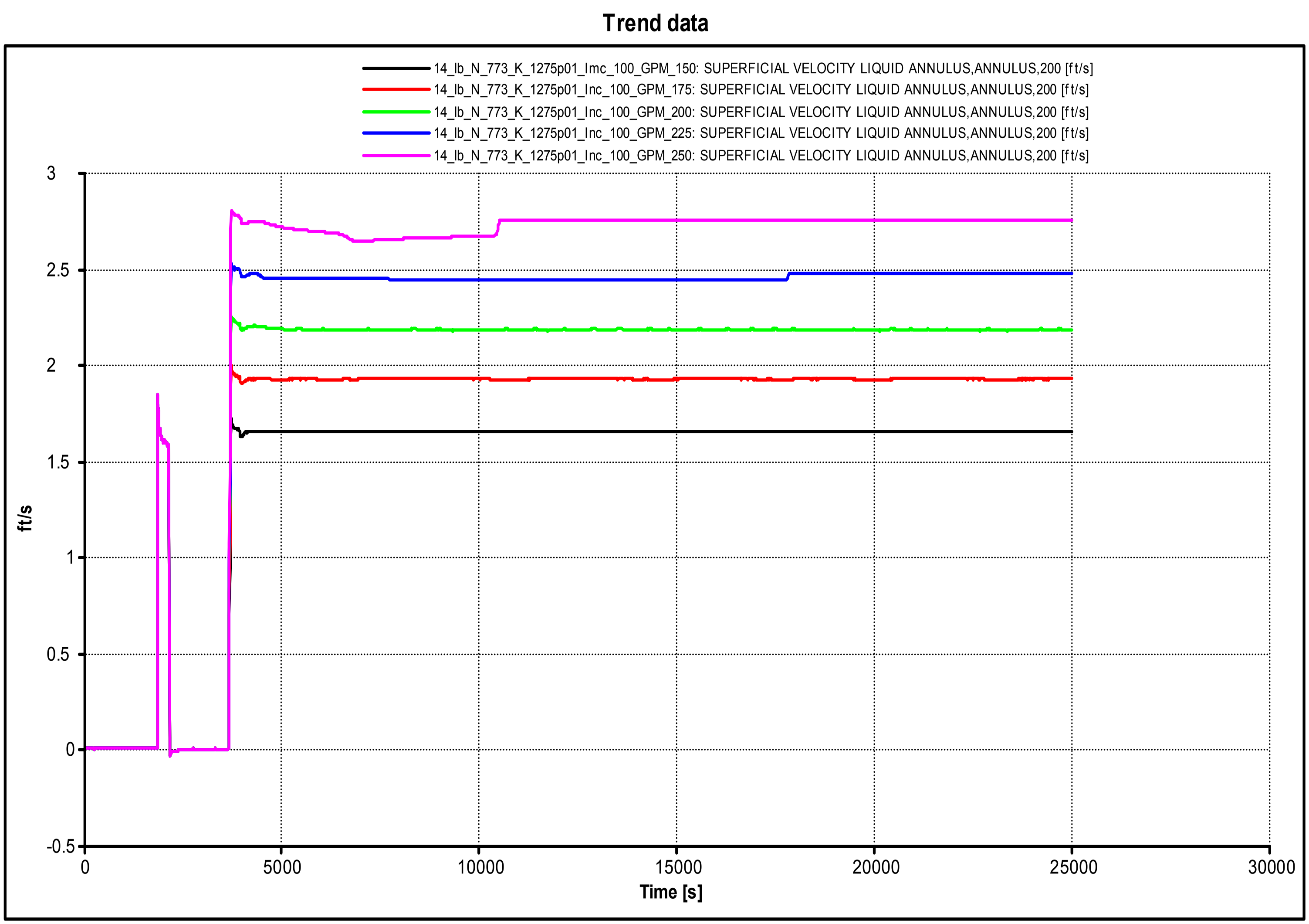


Fig. 72—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 150, 175, 200, 225, & 250 GPM.

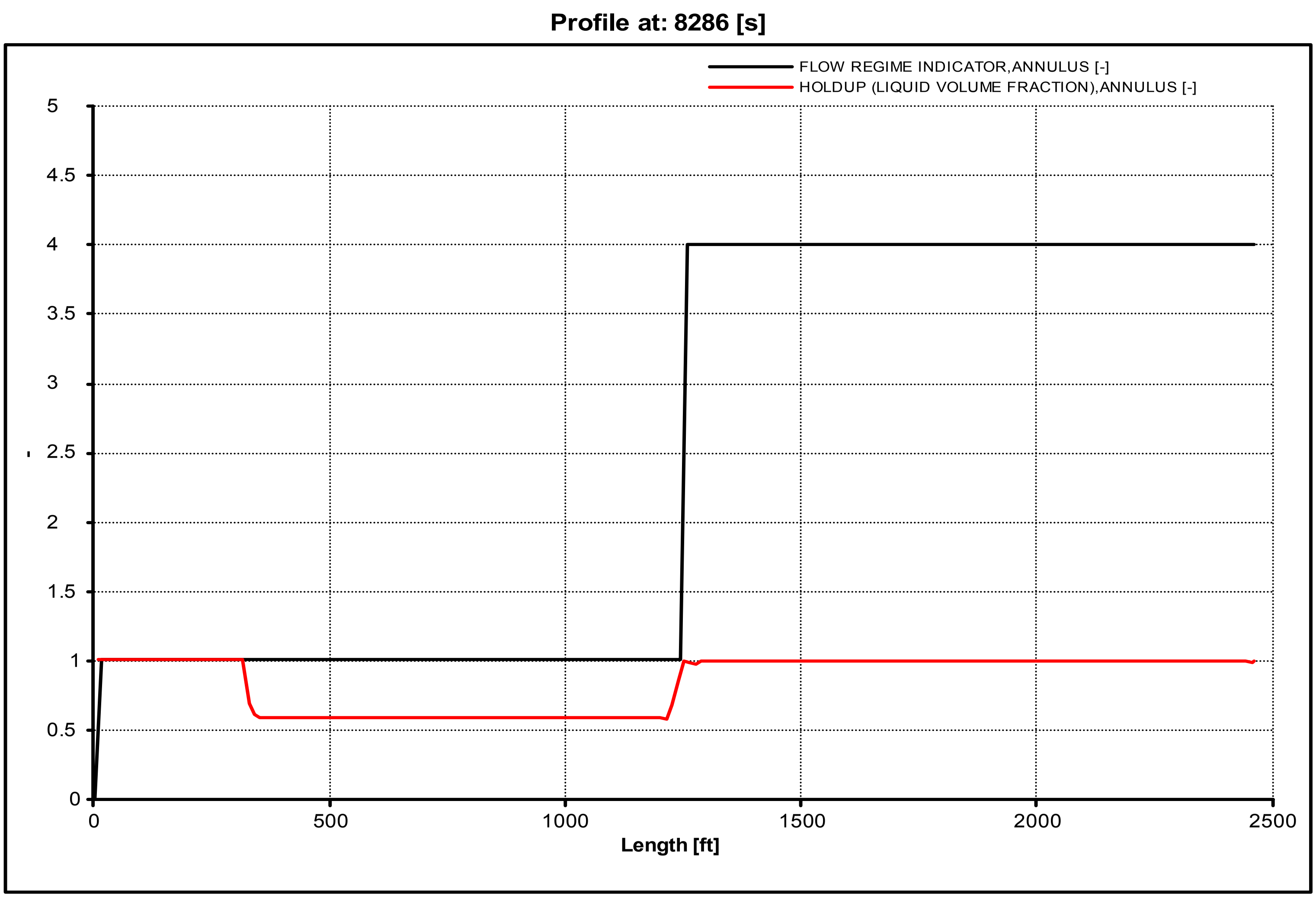


Fig. 73—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 200 GPM.

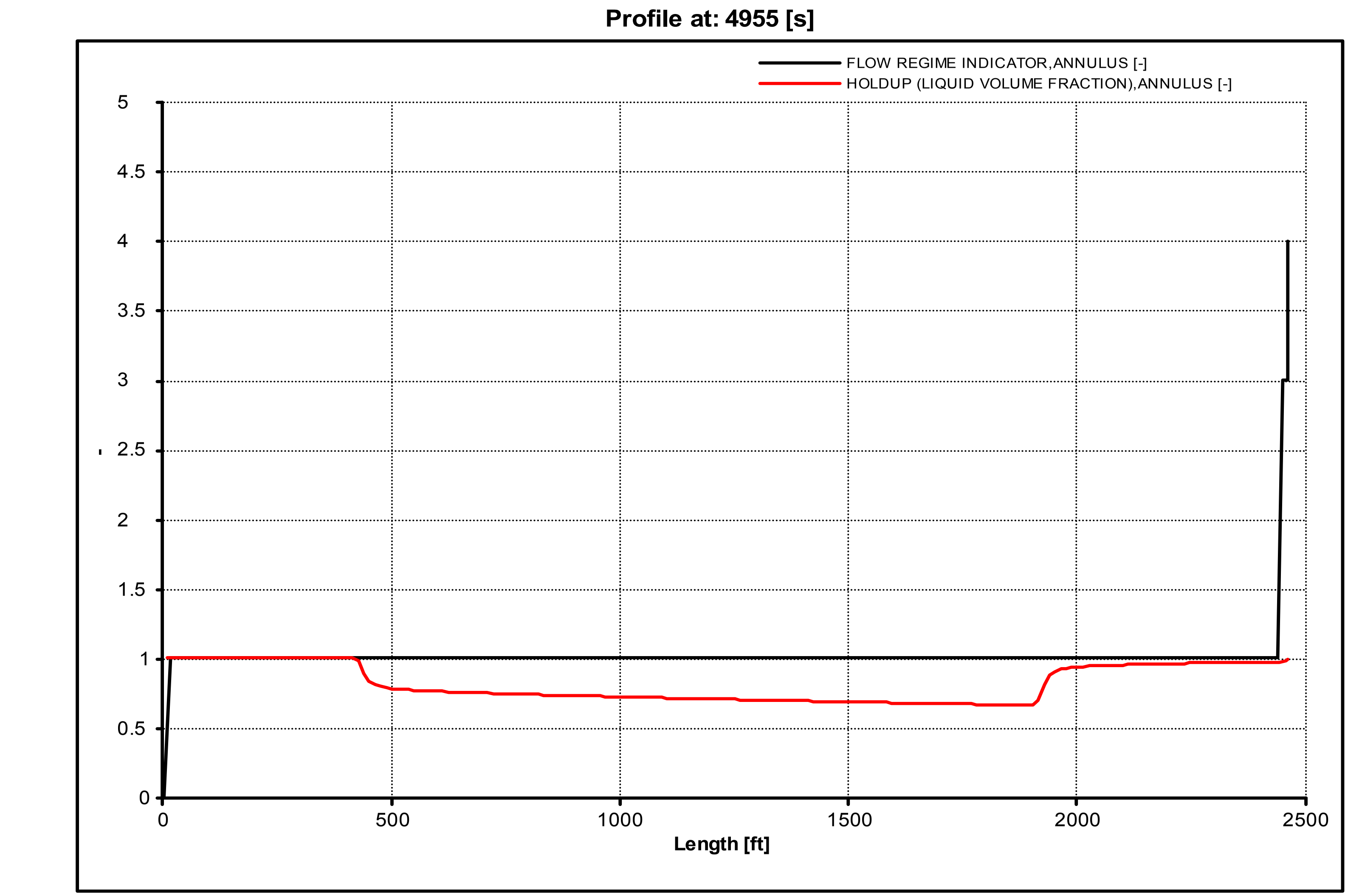


Fig. 74—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250 GPM.

Geometry 3

Figs. 75 to 78 represent the data for Geometry 3. Similarly to the two previous geometries, lower circulation rates and annular velocities were obtained using the 14-ppg viscous mud. For the run performed with water, a circulation rate of 600 GPM and annular velocity of 3.4 ft/sec were required to remove the kick. These values were lowered to a circulation rate of 500 GPM and an annular velocity of 2.75 ft/sec. From Figs. 77 and 78, several flow regimes are present. A region of bubble flow is present in advance of the majority of the gas kick. In gas-kick region the flow alternates between slug and stratified flow.

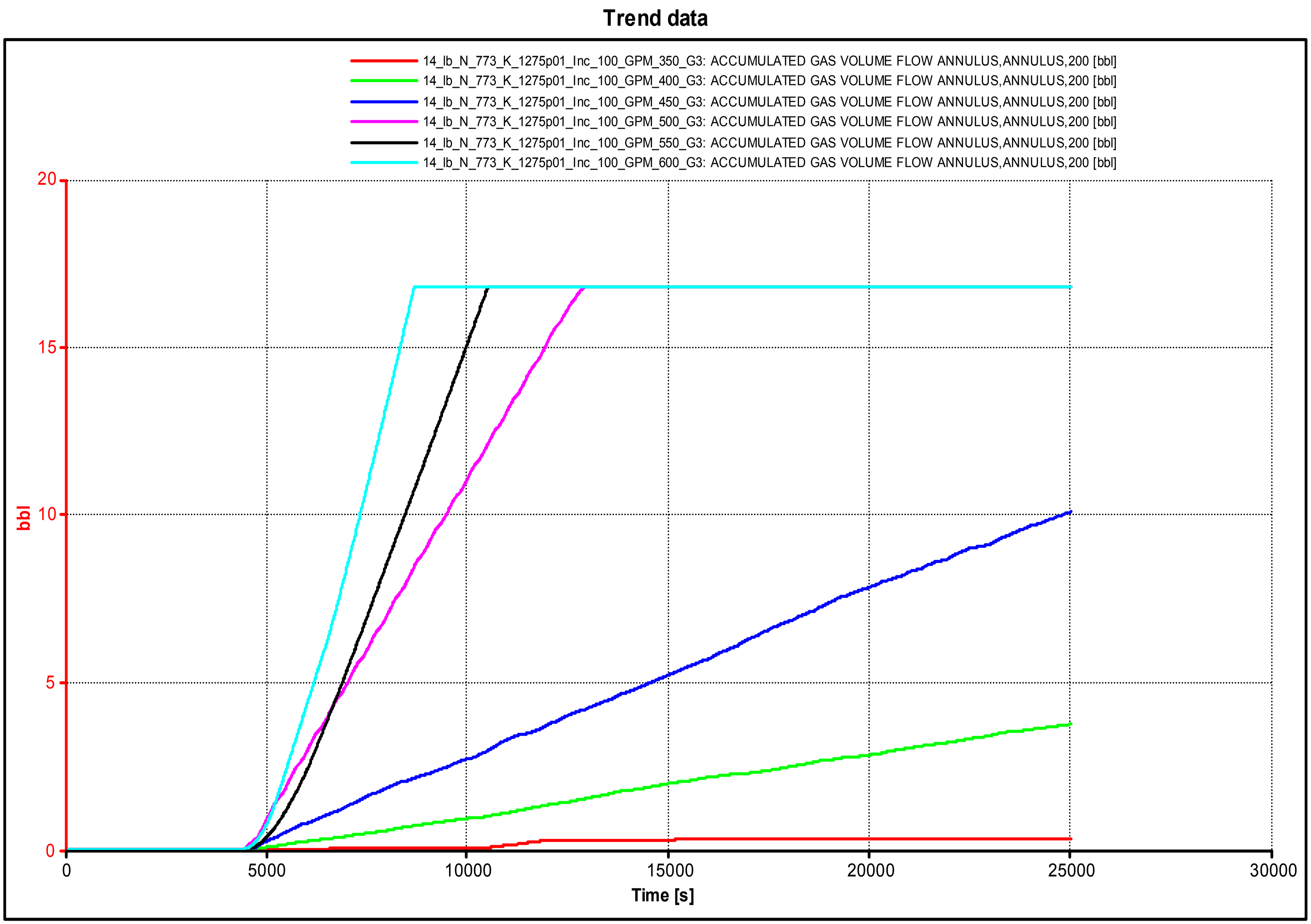


Fig. 75—Accumulated gas out at outlet of annulus, Geometry 3, inclination 10°, circulation rate 350, 400, 450, 500, & 600 GPM.

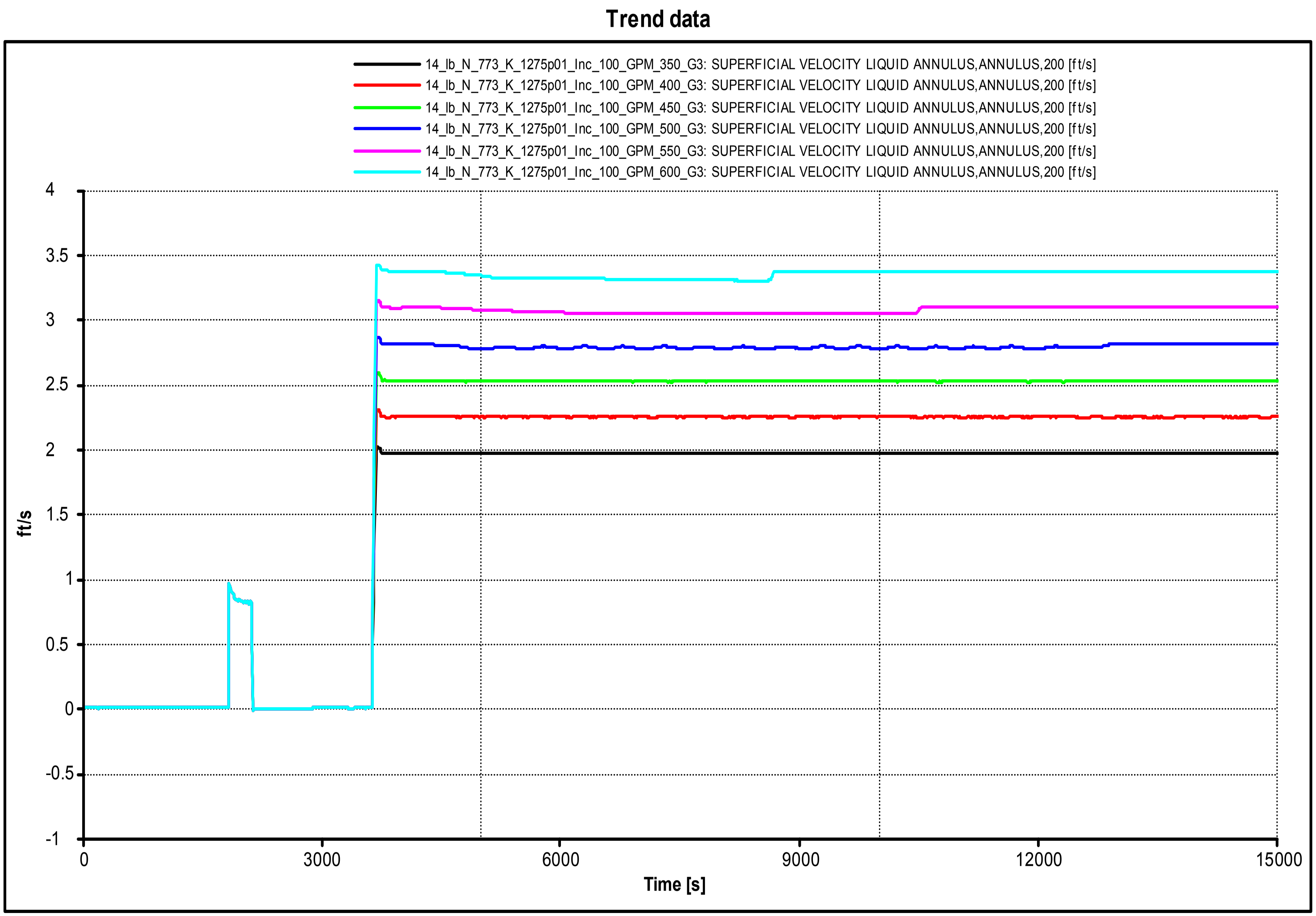


Fig. 76—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 10°, circulation rate 350, 400, 450, 500, & 600 GPM.

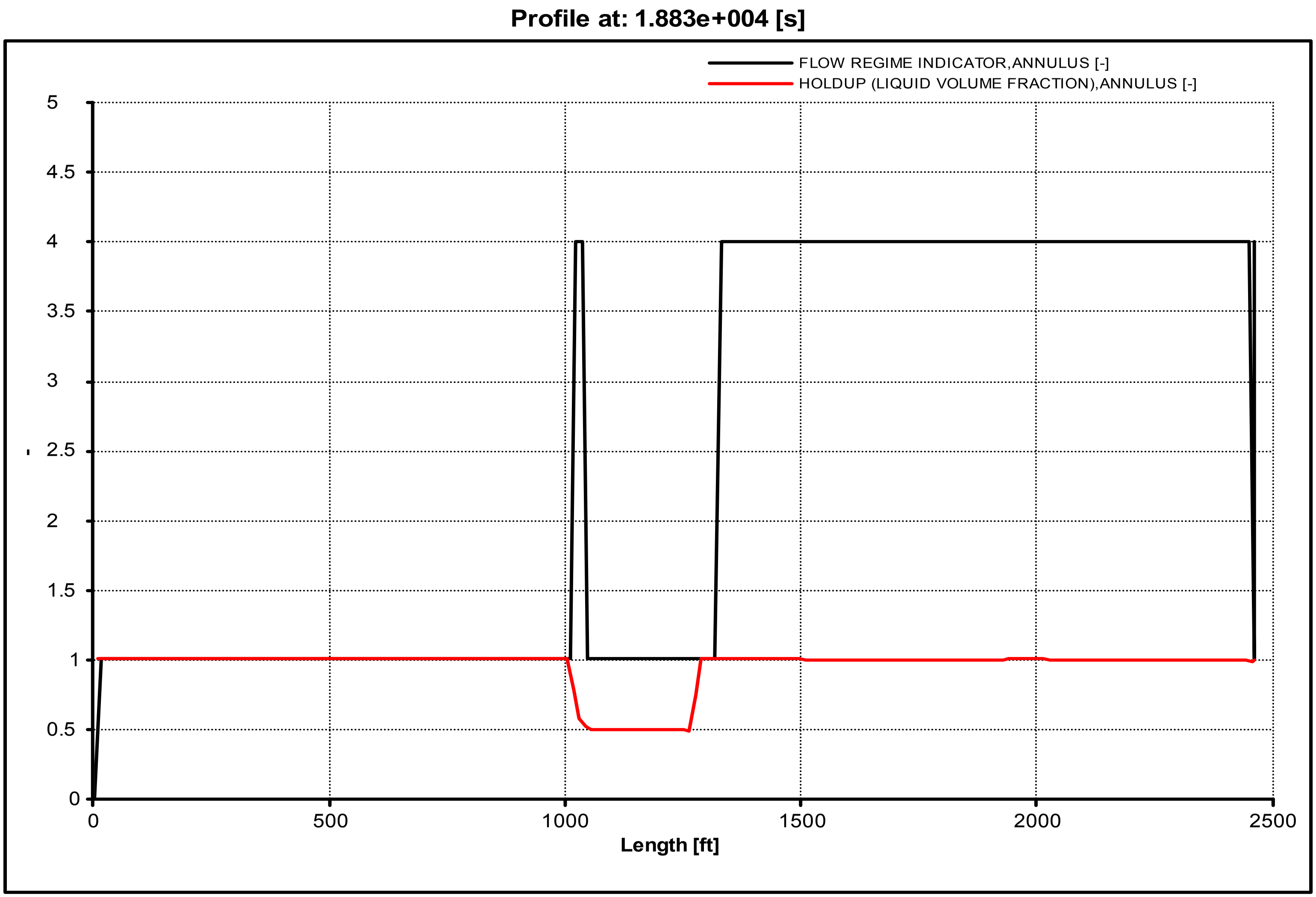


Fig. 77—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 450 GPM.

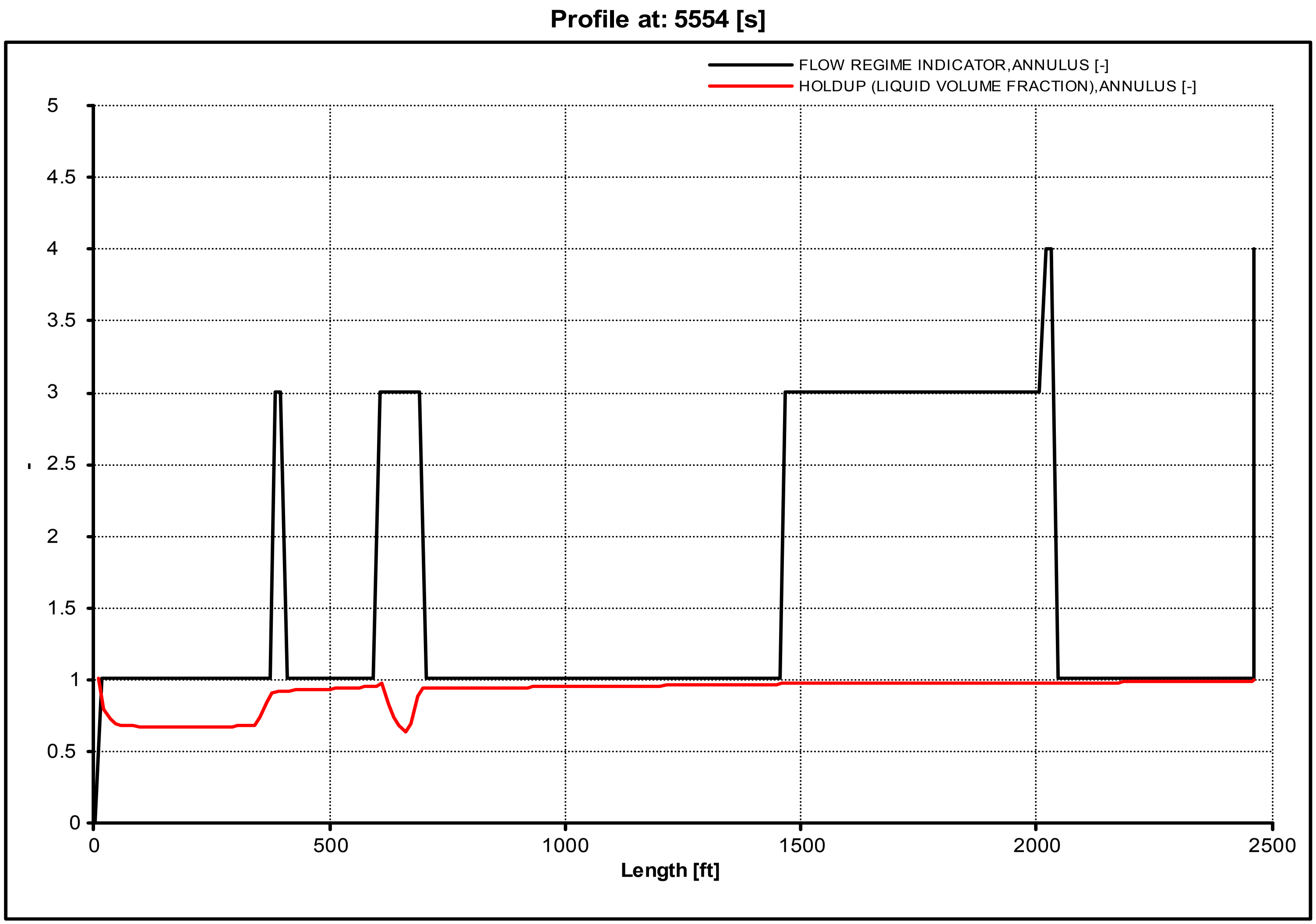


Fig. 78—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 550 GPM.

SUMMARY OF RESULTS

Effects of Horizontal Section Inclination

Cases in which the wellbore inclination is greater than horizontal needed an increased circulation time and circulation rate to efficiently transport the kick. The higher the inclination, the more difficult it becomes to remove the gas kick from the high side of the wellbore. In horizontal wells with inclinations of zero, the kick is easily removed from the wellbore at all circulation rates. For wells with inclinations lower than horizontal, the gas migrated out of the horizontal section before the circulation began. A nonuniform section located at the top of each trend of accumulated gas out reflects some of the gas influx migrating up the drillpipe. Once circulation begins, the gas is displaced from the drillpipe and circulated through the annulus. Table 5 lists kick removal times assuming piston-like displacement for a given circulation rate for each geometry; wellbores with higher inclinations take considerably more time to displace the kick influx. Circulation rate also affects kick removal. The higher the circulation rate, the closer the removal time is to the mode of piston-like displacement.

Effects of Annular Area and Annular Velocities

As hole size or annular area increases, displacing the gas kick from the wellbore for inclinations greater than horizontal becomes more difficult. **Fig. 79** illustrates needed annular velocities for efficient removal of the kick for the three given geometries. The figure shows that increasing annular area requires a higher annular velocity. In geometries of larger annular areas, it may be difficult or impossible to achieve circulation rates high enough to yield the desired kick-removal annular velocity.

Effects of Friction

The majority of runs, if not otherwise specified, were performed with a relative roughness value of 0.0018. **Fig. 80** illustrates the simulation study varying annular friction. As the relative roughness value increased, the kick-removal process became more efficient.

Effects of Mud Properties

Several simulations were run varying mud properties. Power-law coefficients *n* and *K* were inputted into the simulator, which computed the effective viscosities on the basis of circulation rates and annular geometries. The higher the effective viscosity, the more efficiently the influx was transported from the wellbore. A simulation varying the density and power-law coefficients of the circulating fluid showed that with increasing density, gas removal efficiency became more effective. However, the overriding parameter was effective viscosity. These results are shown in Figs. 62 to 68.

Observed Flow Regimes

For inclinations greater than horizontal, several flow regimes are present. Bubble flow is observed in front of the migrating gas kick. Slug flow or stratified flow is present in the portion of the wellbore where the majority of the gas is present. A stratified flow regime exists behind the gas influx. For horizontal cases, a stratified flow regime is present throughout the removal of the gas influx. For inclinations below horizontal, slug flow or stratified flow may be present in the portion of the wellbore the majority of the gas occupies. This is followed by a region of bubble flow until stratified flow is reached. These results are illustrated in Figs. 52 to 60, 69, 70, 73, 74, 77, and 78.

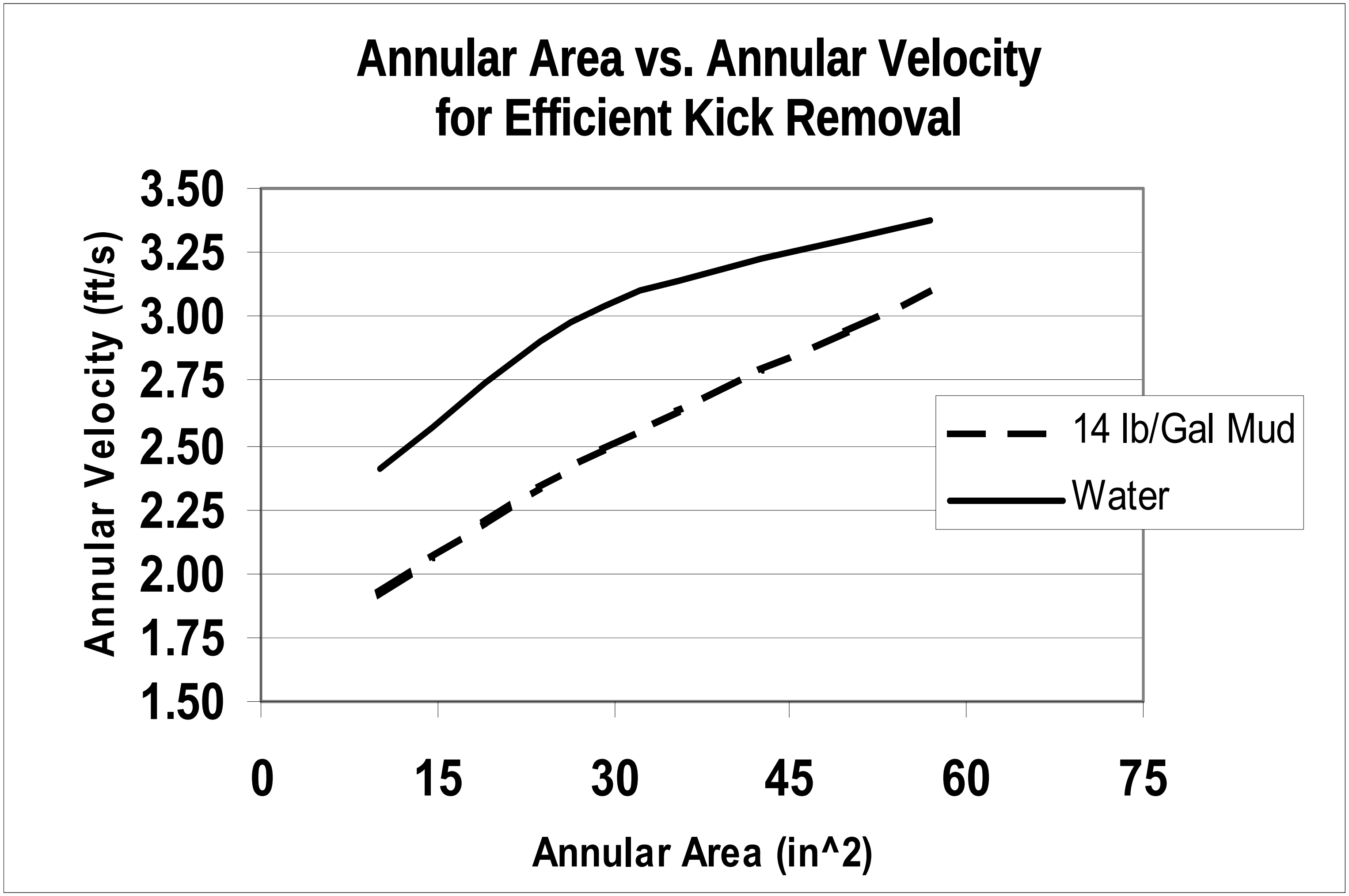


Fig. 79—Annular area vs. annular velocity for efficient kick removal.

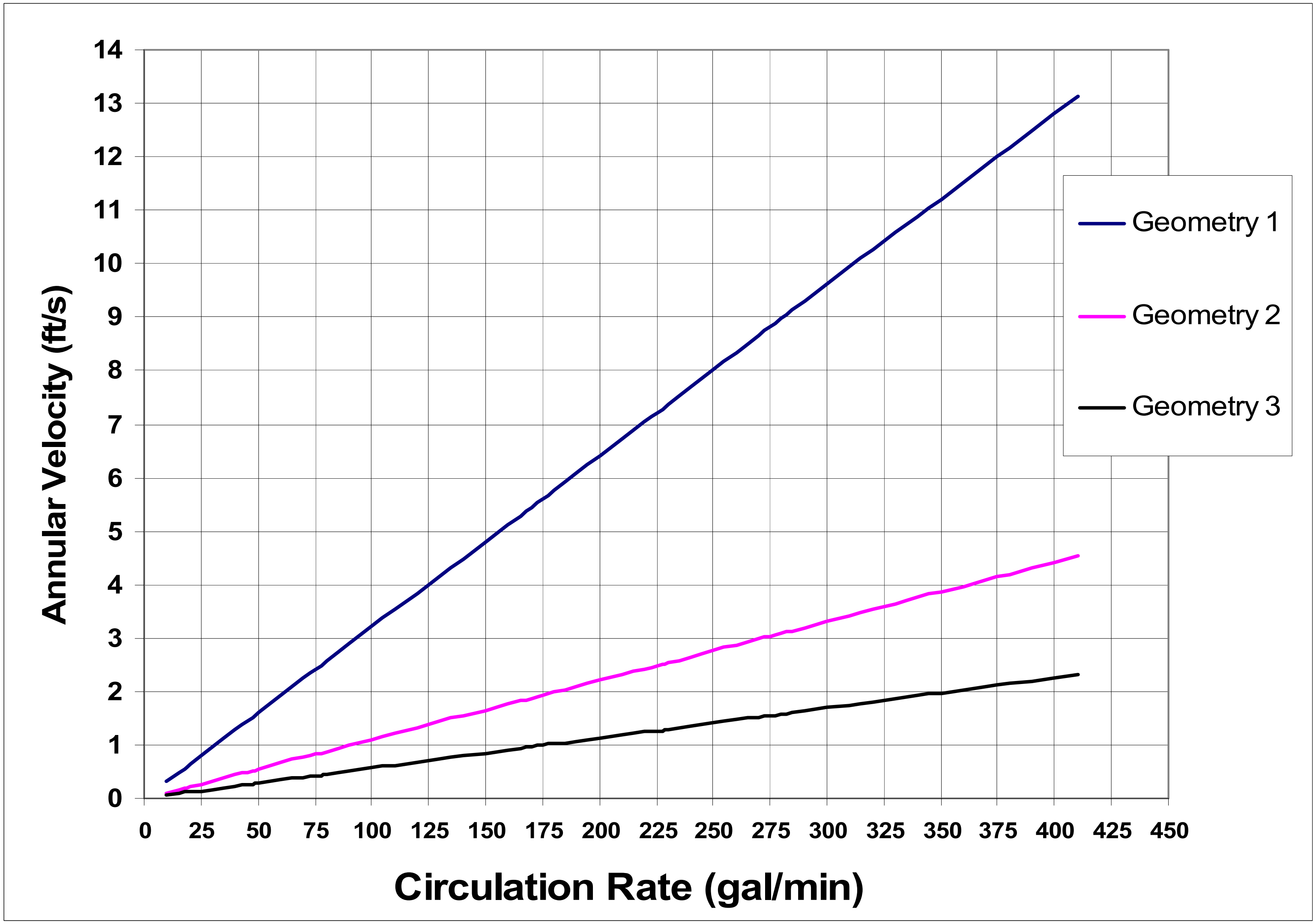


Fig. 80—Circulation rate vs. annular velocity for specific geometries.

CONCLUSIONS

The results from the simulation runs are summarized in the following list:

- Difficulty removing gas kicks may be encountered in wellbores with inclination greater than horizontal. The higher the inclination, the more pronounced this effect.

- As annular area increases, higher circulation rates are needed to obtain the needed annular velocity for efficient kick removal. For water as a circulating fluid, an annular velocity of 3.4 ft/sec is recommended.

- Lower kick-removal annular velocities may be obtained by altering mud properties. Fluid density slightly increases kick removal, but higher effective viscosity is the overriding parameter.

- Increasing relative roughness slightly increases kick-removal efficiency.

- Bubble, slug, and stratified flow are all found to be present in the kick-removal process. Slug and bubble flow are the most efficient at transporting the gas kick.

RECOMMENDATIONS

Recommendations to Industry

From this study several recommendations to industry can be made. The negative effect of horizontal sections at inclinations greater than horizontal can clearly be seen. These trajectories are often unavoidable in mountainous or uneven terrain, lease boundaries, and location of producing formation. However, these inclinations should be avoided wherever possible. Hole size and completion methods should also be considered when planning an inclined horizontal section. Larger annular areas require higher circulation rates to obtain the needed annular velocity to displace the gas kick. If the annular area is too large, the needed circulation rate may be unobtainable because of pump limitations. In this situation, fluids with greater effective viscosities may be used to remove the kick at lower circulation rates.

In general removing a gas kick from an inclined horizontal well is considerably more difficult than in vertical and deviated wells. This is a result of the buoyancy forces opposing the direction of circulation. To overcome this effect, circulation should occur at a sufficiently high value to reach the required annular velocity to efficiently displace the kick. Once the kick influx reaches the vertical section and the choke pressure begins to rise, the circulation rate may be decreased. This procedure is expounded upon in the work of Gjorv,[11] which discusses well-control procedures and the effects of kick size, intensity, and kill rate.

Recommendations for Further Research

Further research could be conducted in several areas. A wider range of inclination values could be modeled. Studies investigating the effects of fluid properties could also be performed. This would include pumping slugs of viscous and oil-based fluids, and considering the effects of gas kicks going into solution. OLGA also lends itself to being used for a complete well-kill simulator along with an under balanced drilling simulator.

NOMENCLATURE

k	=	power law consistency index
n	=	power law exponent
γ_g	=	specific gravity

REFERENCES

1. Clark, S.: *The Oil Century,* U. of Oklahoma Press, Norman, Oklahoma (1958).
2. Bourgoyne A.T. Jr., Chenevert, M.E., Millheim, K.K. and Young, F.S. Jr.: *Applied Drilling Engineering*, Vol. 2, Text Book Series, SPE, Richardson, Texas (1991).
3. Watson, D., Brittenham, T., and Moore, P.: *Advanced Well Control Manual*, SPE Textbook Series, SPE, Richardson, Texas (2003).
4. "Losses of Well Control," Minerals Management Service, http://www.mms.gov/ incidents/blowouts.htm, 4 May 2004.
5. Santos, O.L.A.: "Important Aspects of Well Control for Horizontal Drilling Including Deepwater Situations," paper SPE 21993 presented at the 1991 SPE/IADC Drilling Conference, Amsterdam, 11-14 March.
6. Santos, O.L.A.: "Well Control Operations in Horizontal Wells," paper SPE 21105 presented at the 1990 SPE Latin American Petroleum Engineering Conference, Rio de Janeiro, 14-19 October.
7. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part 1," paper SPE 29345 presented at the 1995 SPE/IADC Conference, Amsterdam, 28 February – 2 March.
8. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part II," paper SPE 29860 presented at the 1995 Middle East Oil Show, Bahrain, 11-14 March.
9. Sotomayer, G. and Santos, O.: "PROKICK – an Integrated Software for Supporting Deepwater Well Control Operations," paper SPE 38960 presented at the 1997 Latin American and Caribbean Petroleum Engineering Conference, Rio de Janeiro, Brazil, 30 August – 3 September.
10. Wang, Z., Peden, J.M., and Lemanczyk, R.Z.: "Gas Kick Simulation Study for Horizontal Wells," paper SPE 27498 presented at the 1994 IADC/SPE Drilling Conference, Dallas, 15-18 February.

11. Gjorv, B.: “Well Control Procedures for Extended Reach Wells,” MS thesis, Texas A&M U., College Station, Texas (2003).
12. Rommetveit, R., Bjorkevoll, K.S., Bach, G.F., Aas, B., Hy-Billiot, J. *et al.*: “Full Scale Kick Experiments in Horizontal Wells,” paper SPE 30525 presented at the 1995 SPE Annual Technical Conference & Exhibition, Dallas, 22-25 October
13. Lage, A.C.V.M., Rommetveit, R., and Time, R.W.: “An Experimental and Theoretical Study of Two-Phase Flow in Horizontal or Slightly Deviated Fully Eccentric Annuli,” paper SPE 62793 presented at the 2000 IADC/SPE Asia Pacific Drilling Technology Conference, Kuala Lumpur, Malaysia, 11-13 September.
14. Johnson, A.B. and Cooper, S.: “Gas Migration Velocities During Gas Kicks in Deviated Wells,” paper SPE 26331 presented at the 1993 SPE Annual Technical Conference and Exhibition, Houston, 3-6 October.
15. Bendiksen, K., Maines, D., Moe, R., and Nuland, S.: “The Dynamic Two-Fluid Model OLGA: Theory and Application,” *SPEPE* (May 1991) 171.
16. Baca, H.E.: “Counter Current and Co-Current Gas Kick Migration in High Angle Wells,” MS thesis, Louisiana State U., Lafayette, Louisiana (1999).
17. Ustun, F.: “The Effect of High Liquid Flow Rates on Co-Current and Counter-Current Gas Kick Migration in High Angle Wells,” MS thesis, Louisiana State U., Lafayette, Louisiana (2000).
18. Shippen, M.E.: “A Neural Network Model for Prediction of Liquid Holdup in Two-Phase Horizontal Flow,” paper SPE 77499 presented at the 2002 SPE Annual Technical Conference and Exhibition, San Antonio, 29 September - 2 October.
19. Brill, J. P., and Mukherjee, H.: *Multiphase Flow in Wells*, SPE Monograph Volume 17, SPE, Richardson , Texas (1999).
20. *MI Drilling Fluids Engineering Manual*, Version 2.0, Great Yarmouth, United Kingdom (1996).

VITA

Name:	Maximilian M. (Max) Long
Address:	PO Box 52101 Midland, TX 79710
Phone:	432-638-7227
Employer:	Oxy Permian

Education:	Texas A&M University, College Station, TX M.S. in Petroleum Engineering, December 2004
	LeTourneau University, Texas B.S. in Mechanical Engineering, May 2002