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Comparative study of different Methods for Slug control

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Preface

This is a Master's thesis in flow assurance as part of the study program Subsea Technology at NTNU. It was carried out during the spring semester of 2014. The desired field of study was to combine cybernetics and subsea technology. My supervisor Olav Egeland then came up with a task creating a dynamic model in Matlab of a pipeline-riser system simulating riser slugging.

Trondheim, 2014-06-10

Eskil Hove Meringdal

Acknowledgment

I would like to thank my supervisor, Olav Egeland, for his contributions during the task. During the thesis he got a very good insight into the model and always had some good solutions to my problems.

I would also like to thank Tore Galta for his help regarding temperature distribution in the system, and Geir T. Kristiansen for general discussions regarding the active slug control.

Last I would thank everyone in Subsea Technology 2014 for a good and social working environment.

E.H.M.

Abstract

This thesis looks into how to create a dynamic model of riser slugging. The model created is a six-state model based on mass conservation of the gas and liquid phases in the well, pipeline and riser. Matlab is used to create the model. The model is created in such a way that the process uses an integrator with variable step length while the sampling of data uses a fixed sampling rate. This gives the model properties resembling a real scenario. The model is used to test out different control systems based around the top side valve. A subsea valve was also tested, but gave poor results. The model worked very well when testing out the control solutions. It is easy to get the data required, and very intuitive to use. The active control of the top side valve gave an average increased production of 8.43%. Control based on the well head pressure had problems with flow spikes in the transitions every time the set point changed. The control based on the mass flow out fixed this problems, but was not able to stabilize already slugging flow.

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Abbrevations

liq	liquid
w	well
p	pipeline
r	riser
wb	well bottom
wh	well head
in	inlet for pipeline
rb	riser bottom
rt	riser top
sl	superficial liquid
sg	superficial gas
res	reservoir
sep	separator
nom	nominal
SISO	single in, singel out
MISO	Multi in, singel out

1. Introduction

In petroleum production, oil, gas and water is produced from wells located far from the oil rig. When transporting multiphase flow over long distances, slugs might occur. They are characterized by long periods of liquid flow separated by gas pockets. Especially in the transition from a pipeline to a riser, a type of slugging called severe slugging or riser slugging is a problem. A way to reduce the slugging flow is to use a choke valve at the top side to reduce the flow. This is usually set to a fixed position, which reduces the potential production. With a system controlling the top side valve, it is possible to increase production.

1.1 Objectives

The objectives, as they were presented by the supervisor:

> *In this paper, slug control for multiphase flow is studied. The task will be based on previously published methods for slug control, and perform a comparative study on the different methods in Simulink.*
>
> 1. *Present a dynamic model for slug flow in a multiphase pipeline with a valve at the bottom and a valve on the top, and show typical flow regime with and without slugs by simulation in Simulink.*
> 2. *Provide an overview of published methods for slug control.*

3. *Test out different methods for slug control in Simulink and provide an evaluation of the performance of the different methods.*

1.2 Goals for the project

Based on the objectives, some goals for the project where created. They are separated into two different categories. Learning goals is the knowledge acquired during the project, while result goals are what is achieved or produced during the project.

Learning goals

1. Get an increased understanding of how multiphase flow behaves.
2. Learn about different methods of removing slug flow while keeping high production.
3. Increase my abilities in Matlab programming and model development.

Result goals

1. Create a six-state model for a well-pipeline-riser system with multiphase flow in Matlab.
2. Test different control solutions on the six-state model and present my thoughts on the solutions based on simulation results.

Existing literature

Several papers and thesis's have discussed different approaches to reduce slug flow with active choking. One of the most recent is Esmaeil Jahanshasi who published his phd-thesis in October 2013 [1]. He presents a model and some approaches to slug control. In 2012 he supervised Mats Lieungh during hes masters study regarding slug control using a subsea choke valve [2]. He presents several control structures with the subsea choke valve as the manipulative, but with poor results. Hes conclusion was that the subsea choke valve only could be used to remove unstable flow originating in the well. Statoil

1.3 Approach

A model which was partly developed during the project assignment will be improved. The model will be extended from a four-state model to a six-stated model, which includes the behavior of the flow in the well. Valve equations and control systems will be included and a matlab integrator will be used to make the model closer to a real "analog" system. This makes it possible to simulate how a valve at the well head can influence the flow, and possibly reduce slug flow.

1.4 Limitations

With a discrete model, exact results are not possible to produce. The real process will always be analog, and it is not possible to recreate this in Matlab. The higher the resolution is, the closer to a real scenario the model gets. But high resolution requires a significant amount of computing power and time. When a valve has been used for some time problems like stiction and dead band become an issue and may cause problems to the control system. These are not accounted for in the model. Also the model created has not been confirmed accurate against any other model, and might deviate from a real scenario. But since its based on the same parameters and formulas as a model that is confirmed against OLGA, it schould be accurate. When comparing control systems, some of the solutions might be better tuned than others. Since I have limited knowledge to tuning techniques for control systems, the optimalization of the tuning will vary between the different set ups.

1.5 Structure of the Report

The rest of the report is structured as followed. First, a general introduction to the oil and gas industry, with a focus on flow assurance and slug control. In chapter three, the model will be presented. Chapter four contains the solutions and challenges which occured when implementing the model in matlab. Then, in chapter five the results from the simulations is presented, and the different control solutions are compared. In the last chapter, a conclusion based on the three previous chapters are presented along with suggestions for future work.

2. Theory and background

The oil and gas business is expanding to locations longer north, with deeper and more hazard environments in the search for petroleum. This is much more costly and the margins are smaller than it has been the last decades. To cope with the smaller margins flow assurance have become an important subject. It focuses on keeping the downtime to a minimum and the flow rate as high as possible. By increasing the production with some few percent, there is a high income potential.

2.1 Flow assurance of Multiphase flow

Figure 2.1: Multiphase flow containing two liquid phases and one gas phase.

Multiphase flow consists of two or more phases(figure 2.1) where they either is not chemically related, like water and oil, or where two different phases are present, like oil(liquid form) and methane(gas form). In the oil business, the flow in the well and pipelines usually contains oil, hydrocarbon gas, water and some sand. Earlier a platform was built over the well, and the phases were separated before the oil and gas were sent to shore. Today this is usually too expensive, and subsea installations where the well stream is sent untreated to an existing platform, or in long pipelines to the shore is the prefered solution. Then the pipeline and the system has to be able to handle multiphase flow. Typical flow assurance problems that may occur are:

Wax depositions in the pipeline. When the well stream is transported in a pipeline along the seabed, the temperature rapidly decrease to the same level as the surroundings. When the temperature gets low enough, some of the substances with a high molecular weight deposits on the wall. This results in limited flow.

Hydrates are ice like crystals formed by the hydrocarbons at low temperature, high pressure conditions. They may damage valves and process equipment and even grow big enough to plug the pipeline(Figure 2.2).

Figure 2.2: A hydrate plug getting removed from a pipeline [3]

Slug flow are periods of liquid flow followed by peiods with almost only gas flow. Slug flow is thoroughly explained later in the thesis.

2.2 Flow regimes in multiphase flow

The different flow regimes in multiphase flow(figure 2.3) are dependent on the velocity of the liquid and gas flow, the distribution of the phases and the inclination of the pipe.

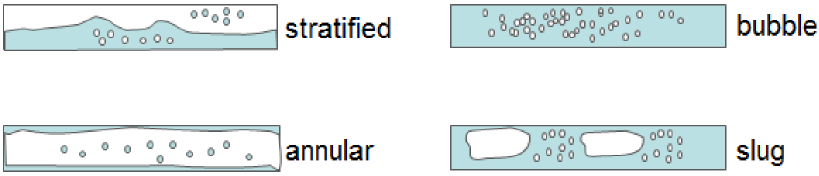

Figure 2.3: Flow regimes in multiphase flow

2.2.1 Vertical flow

In vertical flow, there will always be some kind of mixed flow. At high superficial velocities, slug flow is avoided, and bubble flow will occur. The type of bubble flow depends on the distribution between the liquid and the gas.(Figure 2.4 Superficial velocity is the volume flow per pipe area.

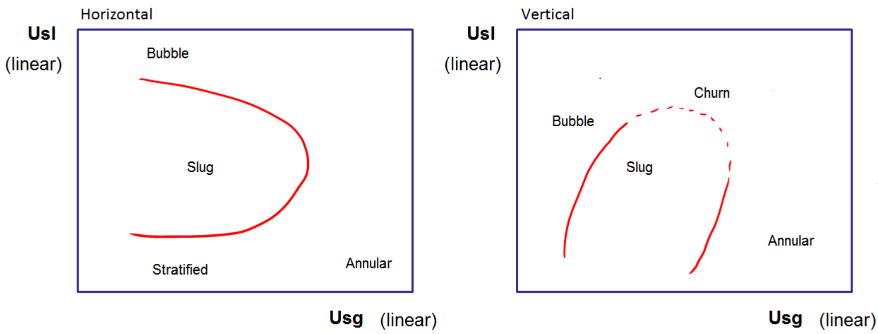

Figure 2.4: Flow regimes in multiphase flow [4]

2.2.2 Horizontal flow

In horizontal flow at low velocities, the flow will be gravity dominated, resulting in a stratification of the flow. At higher pressures, which results in higher velocities, the friction and mixing forces will create bubble or slug flow. When the flow consists of mostly gas, the liquid will collect along the pipe at high velocities, and create annular flow.

2.3 Slug flow

With multiphase transport, slugging flow has become a problem. Slug flow is the result of the liquid layer of the mixture filling up the whole area of the pipe, blocking the gas flow. This creates a pressure buildup, which then pushes the liquid slug with an increased velocity. Such slugs may lead to reduced production, erosion on the pipeline or in some cases damage to the topside equipment. Slug flow may be the result of unstable wavy flow or the design of the pipeline/riser leading to liquid accumulations. Different methods for modeling and prediction of slug flow have been tested, but the problem has proven to be very difficult to simulate, due to the complexity of multiphase flow. Slug flow may be generated by different mechanisms in the pipeline, such as hydrodynamic slugging, slugs due to pigging and riser slugging.

Hydrodynamic slugging is caused by the gas flowing with a higher velocity than the liquid. This forms waves on the top of the liquid layer, which create slugs if they cover the whole cross section of the pipeline. The slugs created this way are usually small, and are not considered a threat to the process. It might lead to erosion and reduced production.

Slugs due to pigging (2.5) are caused by the pig, which is designed to push the liquid in front of itself to the outlet, while cleaning the pipe for wax depositions.

Figure 2.5: Slugs due to pigging

Riser slugging or severe slugging is caused by the transition between a pipeline and the riser as seen in Figure 2.6. The liquid will accumulate at the bottom of the riser until enough pressure is generated to push the liquid all the way up through the riser. Gas will flow after the liquid slug until new liquid has built up enough volume to block the cross section at the bottom of the riser again. The slugs may be as long as the riser and this causes the topside facilities to receive long periods of only liquid, followed by a period of almost only gas. Equipment like the separator can not handle this kind of flow. Severe slugging is by Statoil considered as slugs with a period of 10-180 min[5].

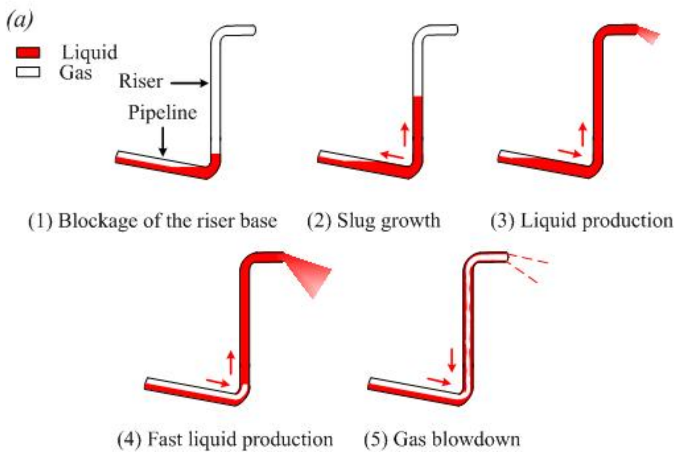

Figure 2.6: How severe slugging is created

2.4 Measures against slug flow

2.4.1 Slug catcher

A slug catcher (Figure 2.7) is a vessel with sufficient volume to store the largest slugs expected from the well. It is placed as a buffer between the outlet of the riser and the process facilities. This is possible because of the period between the slugs, providing enough time to drain the slug catcher in a controlled manner. However the disadvantages of the slug catcher are that it is expensive and occupies a lot of area.

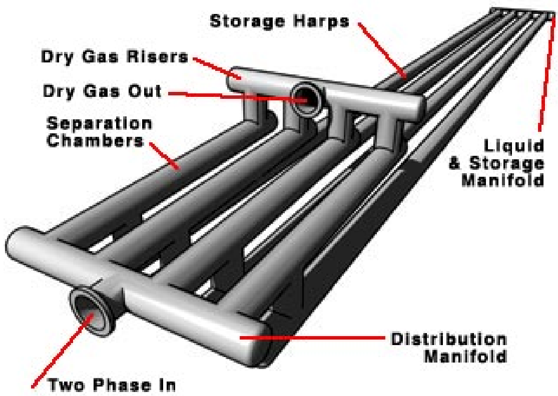

Figure 2.7: Slug catcher

2.4.2 Topside chocking

By closing the topside choke valve, severe slugging might be avoided, but this will reduce production. Topside chocking is one of the first solutions proposed for the severe slugging problem. By chocking, the back pressure will increase, and help push the liquid up the riser.

2.4.3 Riser base gas injection

Gas injection at the riser base increases the back pressure and might eliminate the severe slugging. This requires large amounts of gas injected. The amount of pressured gas needed results in this method alone not being economical, but a combination where topside chocking is used, and has given some usable results[1].

2.4.4 Full separation

Full separation of the phases subsea would also solve the problem. However the subsea separation technology is fresh and it is not economical to do this compared to the other solutions. Subsea separation is considered the most important technology to be developed by a study by FMC Technology Inc.[6]. This is due to the cost savings related to putting some of the process facilities on the sea bottom.

2.4.5 Active chocking

Active chocking is used to stabilize the production at a higher rate than what is possible when setting the choke valve opening to a static value. As seen in Figure 2.8, it is possible to increase production with control. The red line is production with slug-control and the blue dotted line is average production with slugging. The conventional method is to control the opening of the topside choke valve based on the well head pressure. (Figure 2.9)

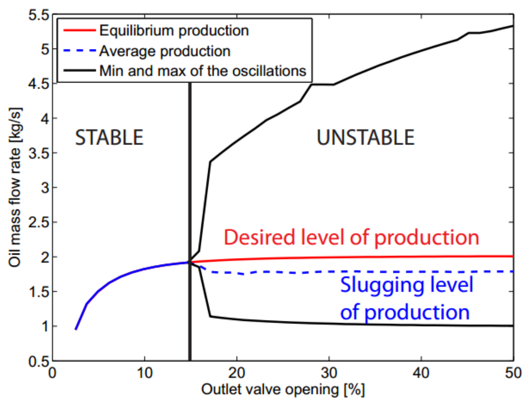

Figure 2.8: Active chocking for slug control

2.5 Different model approaches

Different types of models are used for simulating multiphase flow. The models can be based on mass-, momentum- or energy conservation. The goal of the model may differ; some may focus on maximum stability, while others focus on the production efficiency.

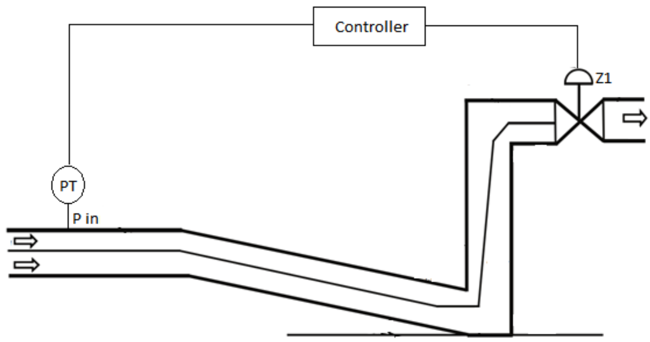

Figure 2.9: Active chocking for slug control

2.5.1 OLGA-model

The OLGA model was first developed by Dag Malnes and Kjell Bendiksen from IFE with support from Statoil, and was completed in 1980. Further developments have been done by a collaboration of IFE, SINTEF and Statoil. Today, SPT Group owns the rights to OLGA. It is seen as one of the main reasons why Norwegian petroleum could develop oil and gas fields at great depths and a long way from shore. The OLGA-Model is the most used model in the business. Experiments at realistic conditions are the basis for the OLGA-model. High pressure and large diameters are used at the SINTEF multiphase flow laboratory in Trondheim, Norway (Figure 2.10). It uses five mass, two momentum equations, three slip relations and the mixture energy equation, as conservation equations [7]

2.5.2 FlowManager by FMC

FlowManager simulates all aspects of the field and process equipment in both steady state and transient situations. The dynamic part is used for testing control system and philosophy, and for testing of the different procedures such as

Figure 2.10: Multiphase flow test laberatory in Trondheim.

startup, shut down, etc. For the multiphase simulations in FlowManager, the Idun model is used. It was made by Dag Malnes in 1993 and is based on his earlier work with OLGA [8].

2.5.3 Model by Ole Jorgen Nydal

Nydals model is based on momentum conservation, and divides the pipe into small boxes where the transfer of momentum is calculated between the parts [7].

2.5.4 Model by Esmaeil Jahanshahi

This model is made with the purpose of testing control systems and is based on mass conservation. When compared to the OLGA-model, it has shown reliable results.[1] The equations used in his six-state model will be the basis for the model in this thesis. Only severe slugging is detected by this model, so it is not suiteable for other flow assurance problems.

3. Well-pipeline-riser model

The first task of this thesis is to present a model in matlab for slug control of multiphase flow. The chosen type of model is a six-state model presented by Esmaeil Jahanshahi in his PhD-thesis published in October 2013 [1]. In the paper all the required formulas to describe how the phases behave in the pipes and in the transistions of the system are supplied. By using these formulas I have produced a dynamic model of the system in Matlab. This models focus is to have few state variables. The six state differential model presented, is the mass conservation for the liquid and gas in the well, pipeline and riser.

$$\frac{dm_{gas-well}}{dt} = \omega_{gas,reservoir} - \omega_{gas,wellhead} \tag{3.1a}$$

$$\frac{dm_{liquid-well}}{dt} = \omega_{liquid,reservoir} - \omega_{liquid,wellhead} \tag{3.1b}$$

$$\frac{dm_{gas-pipeline}}{dt} = \omega_{gas,wellhead} - \omega_{gas,riser} \tag{3.1c}$$

$$\frac{dm_{liquid-pipeline}}{dt} = \omega_{liquid,wellhead} - \omega_{liquid,riser} \tag{3.1d}$$

$$\frac{dm_{gas-riser}}{dt} = \omega_{gas,riser} - \omega_{gas,out} \tag{3.1e}$$

$$\frac{dm_{liquid-riser}}{dt} = \omega_{liquid,riser} - \omega_{liquid,out} \tag{3.1f}$$

The state variables are:

- Mass of gas in well
- Mass of liquid in well

- Mass of gas in pipeline
- Mass of liquid in pipeline
- Mass of gas in riser
- Mass of liquid in riser

The reservoir pressure is used as a boundry condition and is constant, this is an acceptable assumption as the reservoir pressure wont change at a day to day basis. It will though change during a period of some months, and the control settings must be tuned to compensate for this during the lifetime of the reservoir. The other boundry condition is the separator pressure. The separator has it own control system keeping it relatively stable. All the data regarding the reservoir and the well-pipeline-riser system is the same as in Esmaeil's model[1]. This can be easily changed to match different scenarios. The model used during the simulations is of a reservoir at 3000 meters below the seabed. The reservoir pressure is 320 bar. From the well head goes a 4300 meter long pipeline to the riser base. The riser goes 300 meters to the surface, followed by 100 meters horizontal pipe before the topside choke valve. All the parameters are listed in appendix c.

3.1 Well model

The flow from the reservoir can be constant or pressure driven, I have chosen pressure driven to be able to see the increase in production with active chocking compared to a fixed choke valve. Then the flow rate is found using the differential pressure into the well and the production index.

$$\omega_r = PI(P_{res} - P_{bh}) \tag{3.2}$$

The gas-oil-rato is used to calculate the flow of the different phases.

$$\omega_{gas,r} = \left(\frac{gor}{gor+1}\right)\omega_r \tag{3.3a}$$

$$\omega_{liq,r} = \left(\frac{1}{gor+1}\right)\omega_r \tag{3.3b}$$

The bottom hole pressure is found by adding the pressure lost due to gravity and friction, to the well head pressure.

$$P_{bh} = P_{wh} + \bar{\rho}_{mix,w} g L_w + \Delta P_{fw} \tag{3.4}$$

The well head pressure is found by using the ideal gas law

$$P_{wh} = \frac{m_{gas,w} R T_{wh}}{M_{gas} V_{gas,w}}, \tag{3.5}$$

where

$$V_{gas,w} = V_w - \frac{m_{liq,w}}{\rho_{liq}}. \tag{3.6}$$

The pressure lost due to friction is found with the formula

$$\Delta P_{f,w} = \frac{\bar{\alpha}_{liq,w} \lambda_w \bar{\rho}_{mix,w} \bar{U}_{sl,w}^2 L_w}{2D_w} \tag{3.7}$$

where the average liquid volume fraction is

$$\bar{\alpha}_{liq,w} = \frac{m_{liq,w}}{V_w \rho_{liq}}, \tag{3.8}$$

the superficial velocity is

$$\bar{U}_{sl,w} = \frac{4\omega_{mix,nom}}{\pi D_w^2 \rho_{liq}}, \tag{3.9}$$

and the density of the mixture is

$$\bar{\rho}_{mix,w} = \frac{m_{gas,w} + m_{liq,w}}{V_w}. \tag{3.10}$$

λ_w is the friction factor, and is found using the Haaland equation [9].

$$\frac{1}{\sqrt{\lambda_w}} = -1.8log\left[\left(\frac{\epsilon/D_w}{3.7}\right)^{1.11} + \frac{6.9}{Re_w}\right] \tag{3.11}$$

ϵ/D_w is the relative roughness and is found by dividing the roughness on the diameter of the pipeline. The roughness for commercial steel is approximatly $45\mu m$ acording to efunda [10]. The Reynolds number is found with

$$Re_w = \frac{\rho_{liq}\bar{U}_{sl,w}D_w}{\mu}, \tag{3.12}$$

where μ is the viscosity of the liquid.

To calculate the volume fractions at the top of the well, we assume that there is a close to linear relationship between the liquid volume fraction and the pressure. We also assume that the pressure gradient along the riser is near constant when we dont have slug flow. With these assumptions we can say that

$$\bar{\alpha}_{liq,w} = \frac{\alpha_{liq,wb} + \alpha_{liq,wh}}{2} \Rightarrow \alpha_{liq,wh} = 2\bar{\alpha}_{liq,w} - \alpha_{liq,wb} \tag{3.13}$$

Because of the high pressue at reservoir level, the fluid is assumed to be saturated and the liquid volume fraction is $\alpha_{liq,wb} = 1$. The average density of the gas in the well is found with

$$\rho_{gas,w} = \frac{m_{gas,w}}{V_w - m_{liq,w}/\rho_{liq}} \tag{3.14}$$

Next is to calculate the density of the mixture at the well head

$$\rho_{mix,wh} = \alpha_{liq,wh}\rho_{liq} + (1-\alpha_{liq,wh})\rho_{gas,w}, \tag{3.15}$$

and the gas mass fraction at the top of the well

$$\alpha^{m}_{gas,wh} = \frac{(1-\alpha_{liq,wh})\rho_{gas,w}}{\alpha_{liq,wh}\rho_{liq} + (1-\alpha_{liq,wh})\rho_{gas,w}} \tag{3.16}$$

The mass fraction, mixed density and well head pressure will be used later to calulate the flow through the choke valve located at the well head.

3.2 Pipeline model

To be able to find the mass transfer of liquid in the pipeline, the liquid fraction has to be determined. Since gas is compressible, its density has to be calculated. By knowing the mass of gas in the different parts of the system, and at the same time knowing how much of the volume is occupied by the liquid, it is possible to calculate the density of the gas.

$$\rho_{gas,p} = \frac{m_{gas,p}}{V_{gas,p}} \tag{3.17}$$

Since the mass of gas is a state variable, it is available. And the volume of the gas is found using the mass of the liquid divided by the density.

$$V_{liquid,p} = \frac{m_{liquid,p}}{\rho_{liq}} \tag{3.18}$$

$$V_{gas,p} = V_{pipe} - V_{liquid,p} \tag{3.19}$$

When we have the density of the gas we are able to find the pressure at the inlet of the pipeline.

$$P_{in} = \frac{\rho_{gas,p} R T_p}{M_g} \tag{3.20}$$

Next is the pressure lost due to friction along the pipeline. Only the liquid phase is considered to have an effect.

$$\Delta P_{f,p} = \frac{\bar{\alpha}_{l,p} \lambda_p \rho_l \bar{U}_{sl,in}^2 L_p}{2 D_p} \tag{3.21}$$

λ_p is the friction factor, and is found using the Haaland equation [9]. The superficial velocity of the liquid into the pipeline is

$$\bar{U}_{sl,in} = \frac{4 \omega_{liq,in}}{\pi D_p^2 \rho_{liq}} \tag{3.22}$$

The average liquid volume fractions is then

$$\bar{\alpha}_{liq,p} = \frac{\bar{\rho}_{g,p} \omega_{liq,in}}{\bar{\rho}_{g,p} \omega_{liq,in} + \rho_{g,p} \omega_{gas,in}} \tag{3.23}$$

To find the average gas density in the pipeline Esmaeil [1] uses a steady state initialization of the process, this will not be accurate when the operating point changes, but have proven good enough for this simulations. Another solution not depending on a constant gas density might be better.

$$\bar{\rho}_{g,p} = \frac{P_{in,nom} M_{gas}}{R T_p} \tag{3.24}$$

I have set $P_{in,nom} = 70 bar$ which equals a steady state pressure with a valve opening of 9% .

3.3 Riser model

The riser model is a lot like the well model, and most of the values are found in a similar way. The pressure at the riser top is found using the ideal gas law.

$$P_{rt} = \frac{\rho_{gas,r} R T_r}{M_g} \tag{3.25}$$

where the density of the gas is found with

$$\rho_{gas,r} = \frac{m_{gas,r}}{V_r - m_{liq,r}/\rho_{liq}}. \tag{3.26}$$

The pressure lost due to friction is found in a similiar way as with the well model, only with mixed flow instead of liquid:

$$\Delta P_{f,r} = \frac{\bar{\alpha}_{liq,r} \lambda_r \bar{\rho}_{mix,r} \bar{U}_{sl,r}^2 (L_r + L_h)}{2D_r} \tag{3.27}$$

where the average liquid volume fraction is

$$\bar{\alpha}_{liq,r} = \frac{m_{liq,r}}{V_r \rho_{liq}}. \tag{3.28}$$

The mixed superficial velocity is found by adding the superficial velocity for the gas and liquid together

$$\bar{U}_{mix,r} = \bar{U}_{sl,r} + \bar{U}_{sg,r} \tag{3.29}$$

$$\bar{U}_{sl,r} = \frac{\omega_{liq,rb}}{\rho_{liq} A_r} \tag{3.30}$$

$$\bar{U}_{sg,r} = \frac{\omega_{gas,rb}}{\rho_{gas,r} A_r} \tag{3.31}$$

The density of the mixture is

$$\bar{\rho}_{mix,r} = \frac{m_{gas,r} + m_{liq,r}}{V_r}. \tag{3.32}$$

λ_r is found using the Haaland equation [9] as in the well and pipeline model.

$$\frac{1}{\sqrt{\lambda_r}} = -1.8log\left[\left(\frac{\epsilon/D_r}{3.7}\right)^{1.11} + \frac{6.9}{Re_r}\right] \tag{3.33}$$

$$Re_r = \frac{\rho_{mix,r}\bar{U}_{mix,r}D_r}{\mu} \tag{3.34}$$

To calculate the volume fractions at the top of the riser we use the same assumptions as for the volume fractions in the well model.

$$\alpha_{liq,rt} = 2\bar{\alpha}_{liq,r} - \alpha_{liq,rb} = \frac{1m_{liq,r}}{V_r\rho_l iq} - \frac{A_{liq}}{A_p} \tag{3.35}$$

$$\alpha_{liq,rb} = \frac{A}{} \tag{3.36}$$

$$\rho_{gas,w} = \frac{m_{gas,w}}{V_w - m_{liq,w}/\rho_{liq}} \tag{3.37}$$

Next is to calculate the density of the mixture at the well head

$$\rho_{mix,wh} = \alpha_{liq,wh}\rho_{liq} + (1-\alpha_{liq,wh})\rho_{gas,w}, \tag{3.38}$$

and the gas mass fraction at the top of the well

$$\alpha^m_{gas,wh} = \frac{(1-\alpha_{liq,wh})\rho_{gas,w}}{\alpha_{liq,wh}\rho_{liq} + (1-\alpha_{liq,wh})\rho_{gas,w}} \tag{3.39}$$

3.4 Flow at the well head

The well and pipeline model supplies the required data to calculate the flow through the valve at the well head.

$$\omega_{mix,wh} = Cv_3z_3\sqrt{\rho_{mix,wh}(P_{wh} - P_{in})} \tag{3.40}$$

Cv_3 is the valve constant and z_3 is the valve opening. This give the following flow rates

$$\omega_{gas,wh} = \omega_{mix,wh}\alpha_{gas,wh}^{m} \tag{3.41a}$$

$$\omega_{liq,wh} = \omega_{mix,wh}\left(1-\alpha_{gas,wh}^{m}\right) \tag{3.41b}$$

3.5 Flow at riser base

When the various pressures and distributions along the pipeline and riser are calculated, we are able to estimate accumulation of liquid at the riser base. This is the reason for the severe slugging and therefore what should be avoided when looking at the control solutions for the pipeline-riser system. When the fraction of liquid in the pipeline increases, it will accumulate at the riser base due to the downwards inclination of 1 degree. When the liquid covers the whole cross section of the pipeline, the gas will stop flowing through and the pressure behind the liquid will start rising.

When the gas and liquid in the pipeline are distributed homogeneously, the height of the liquid in the cross section is

$$\bar{h} = K_h h_d \bar{\alpha}_p \tag{3.42}$$

Where h_d is the height of the opening at the riser bottom. The height when the liquid starts to accumulate is

$$h = \bar{h} + \frac{m_{liq,p} - \bar{m}_{liq,p}}{A_p(1-\bar{\alpha}_p)\rho_{liq}} sin\theta \tag{3.43}$$

Only $m_{liq,p}$ varies, all other parameters are constant. In the code, a test is done when calculating the flow between the pipeline and the riser. If the height is greater than h_d, the gas flow is set to zero. If it is lower, the flow is calculated using the pressure at the riser base, gas density, the area it flows through and a model tuning factor K_g.

$$\omega_{gas,rb} = K_g A_g \sqrt{\rho_{gas,p} \Delta P_g} \tag{3.44}$$

$$\Delta P_g = P_{in} - \Delta P_{f,p} - P_{rt} - \bar{\rho}_{mix,r} g L_r - \Delta P_{f,r} \tag{3.45}$$

The flow of the liquid is found in a similar way.

$$\omega_{liquid,rb} = K_l A_l \sqrt{\rho_{liquid} \Delta P_l} \tag{3.46}$$

$$\Delta P_l = P_{in} - \Delta P_{f,p} + \rho_{liq} g h - P_{rt} - r\bar{h}o_{mix,r} g L_r - \Delta P_{f,r} \tag{3.47}$$

The area for gas and liquid flow is found using an quadratic approximation

$$A_g = A_p \left(\frac{h_d - h}{h_d} \right)^2 \tag{3.48}$$

$$A_l = A_p - A_g \tag{3.49}$$

3.6 Flow at riser top

The flow at the riser top goes through a choke valve and into the separator. Since the pressure in the separator is one of the boundary conditions it is set as constant. The valve is similar to the subsea choke valve.

$$\omega_{mix,out} = Cv_1 z_1 \sqrt{\rho_{mix,rt}(P_{rt} - P_{sep})} \tag{3.50}$$

which gives

$$\omega_{gas,out} = \omega_{mix,out} \alpha^m_{gas,rt} \tag{3.51a}$$

$$\omega_{liq,out} = \omega_{mix,out} \left(1 - \alpha^m_{gas,rt}\right) \tag{3.51b}$$

4. Implementation i Matlab

Instead of using Simulink, which was proposed in the project description, I chose to use Matlab code. It is several reasons for this. When creating a system with so many equations, Matlab is a much better solution since Simulink have a tendency to get very disorganized. It is much easier to keep a good structure, and later debug Matlab code. A combined solution, where the model was written in code, and the control system in matlab was considered. But since I am most familiar with matlab, and all simulink functions are available in matlab code, a solution without Simulink was chosen.

When transforming an analog system to a digital one, some rules had to be used to avoid the system calculating itself into impossible scenarios.

- Use limits to prevent the model from calculating fraction values lower than zero or higher than one. In a real scenario this is limited by fysical boundries like the walls in the pipeline, while in a mathematical model it might calculate past the boundries because of the model being discrete.

- Never take the square root of negative numbers. When calculating the flow through the valves, the model will not accept flow in the wrong direction. The differential pressure will then be set to zero, resulting in no flow.

- Make sure its not possible to divide by zero. This will crash the simulations.

4.1 Structure of Code

A main file called *start.m* is used to initiate the code. It begins defining arrays and set some parameters related to the control system. The parameters related to the process is located in a parameters file called *para.m*. Then a technique making it possible to have a close to analog system, while still sampling data values at a given rate is used. An integrator is used for only a short time interval at a time, with variable step length inside this period. The resulting masses is then set as the initial value for the next time interval. Between every time the integrator is used , the reauired variables is found running the current masses through the system model(figure 4.1). This gives a variable step length on the system, while keeping a fixed sampling rate on the control system. This is done to get as close to a real scenario as possible.

4.2 Integrator

To be able to have a close to analog system an ode-integrator is used. The regular integrators, like the *ode45*, were not able to solve the system in a satisfying way. Because of this, some other integrators were tested, with *ode15s* giving good results. This is an integrator ment for stiff systems. Stiffness of a system is hard to determine, but it usually occurs when a process is able to make very sudden changes in its solutions[10]. This system is stiff because of the sudden changes in gas flow happening when the cross section is covered by liquid at the riser base.

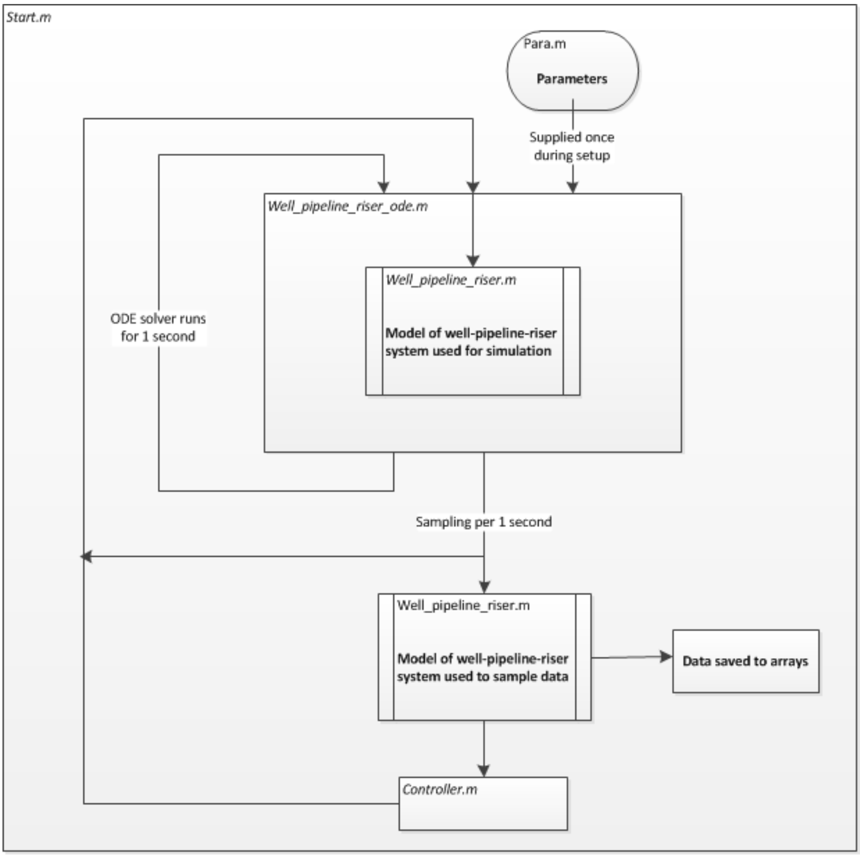

Figure 4.1: Overview of how the code is organized

4.3 Controller

The controller is a basic PID-controller coded during my bachelor thesis [11].

$$u = K_p \left(e(t) + \frac{1}{T_i} \int_0^t e(\tau)\, \mathrm{d}\tau + T_d \frac{d}{dt} e(t) \right) \tag{4.1}$$

In slug control a problem occurred where the integral would go towards infinite if the slugging started. This happened because of the pressure changes didn't oscillate evenly around the set point. Instead the top peaks where much higher than the low peaks(Figure 4.2) This leeds to the controller opening the valve to decrease the pressure at the well head. The integral part of the controller then increases until it dominates the controller, and keeps it fully open. This prevents the controller from stabilizing whenever the flow got close to the set point. To

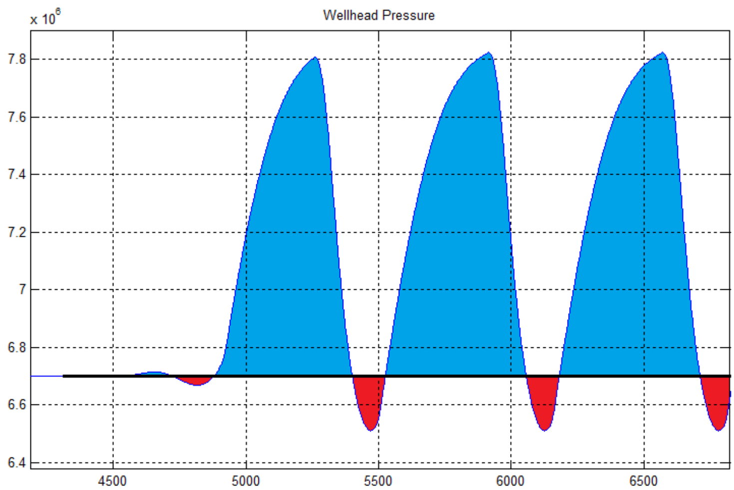

Figure 4.2: The area above the set point is much bigger than what is below

cope with this the integral is disconnected whenever the controller reaches the saturation of the valve, and reconnected when the signal is within the saturation limits[12].

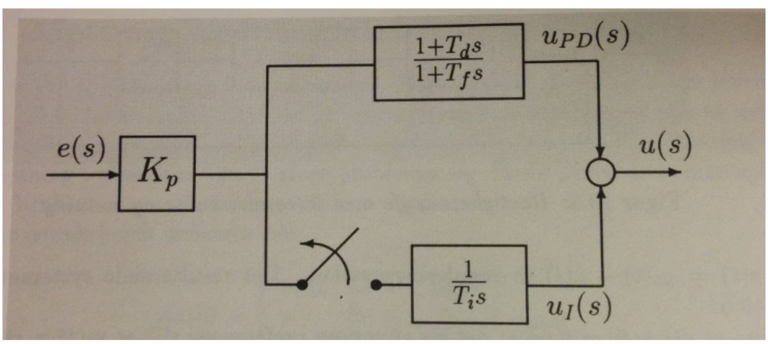

Figure 4.3: Disconnecting the integral effect from the controller when it gets saturated[12, p. 296]

5. Control solutions

The goal with active slug control is to remove the slugs while keeping a high production. The response of the system without control is shown in Figure 5.1 The red line is the mean production. When the valve opening reaches the critical value of about 10%, it splits into three lines where the blue and green are the high and low points of the oscillations. This is because of the riser slugging. When the slugging starts the average production falls, indicating that chocking with fixed position of the valve is a better solution than a big separator or a slug catcher. Figure 5.2 and 5.3 is the corresponding graphs for the pressure at the riser top and the pressure at the well head. For all the control solutions the same test is run. First the choke valve is set to a static value inside the stable

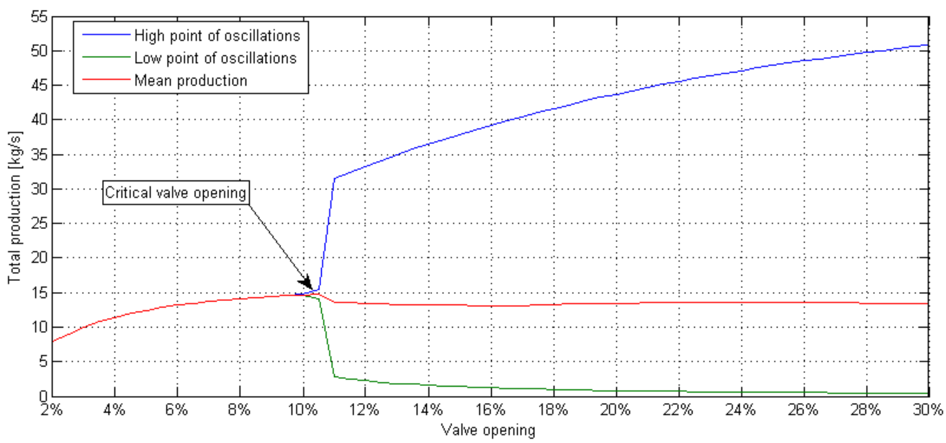

Figure 5.1: Bifurcation diagram of production

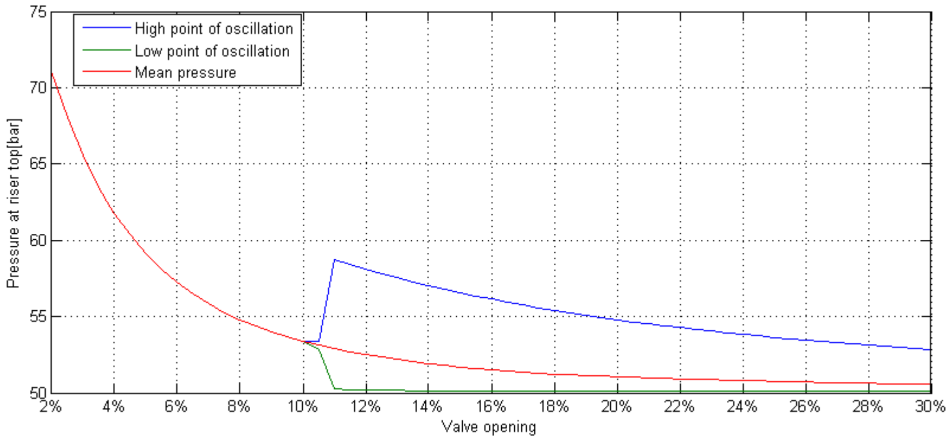

Figure 5.2: Bifurcation diagram of pressure at riser top

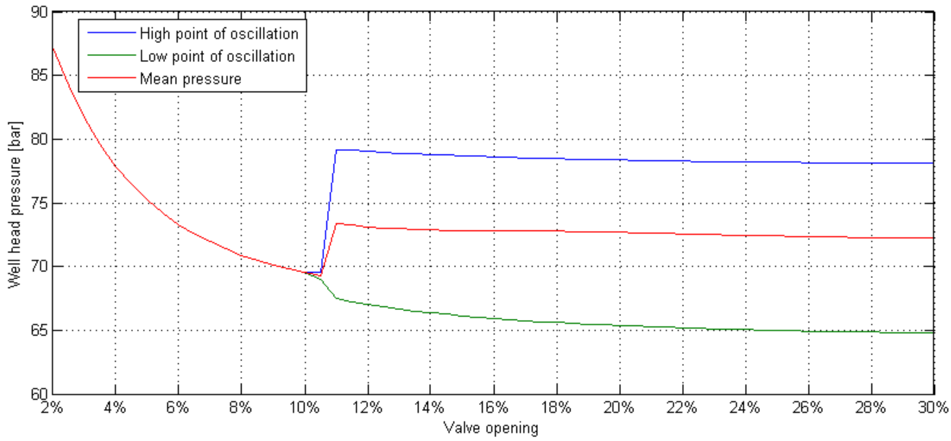

Figure 5.3: Bifurcation diagram of pressure at well head

area. Then after 1000 seconds the control system is activated. After running for another 1000 seconds the set point is changed to the value with the highest stable production I was able to get. To prove that the control system is keeping the process stable in an unstable area the valve opening is fixed to its current position after 4000 seconds, and slugging appears.

5.1 Well head pressure as input - top side valve as output

Controlling the top side valve using the well head pressure as the control variable (figure 5.4) is the most mentioned and probably most used control solution for slug control. It has a very fast response and is able to keep the production at a very high level. The problem with this solution is that when the set point is changed and during initialization, some slug like flow forms which may be problematic for the top side equipment. In figure 5.5 the control solution is tested in the matlab model. After 2000 seconds the set point is changed from 70 bar to 67 bar. When the control system is activated after 1000 seconds, and

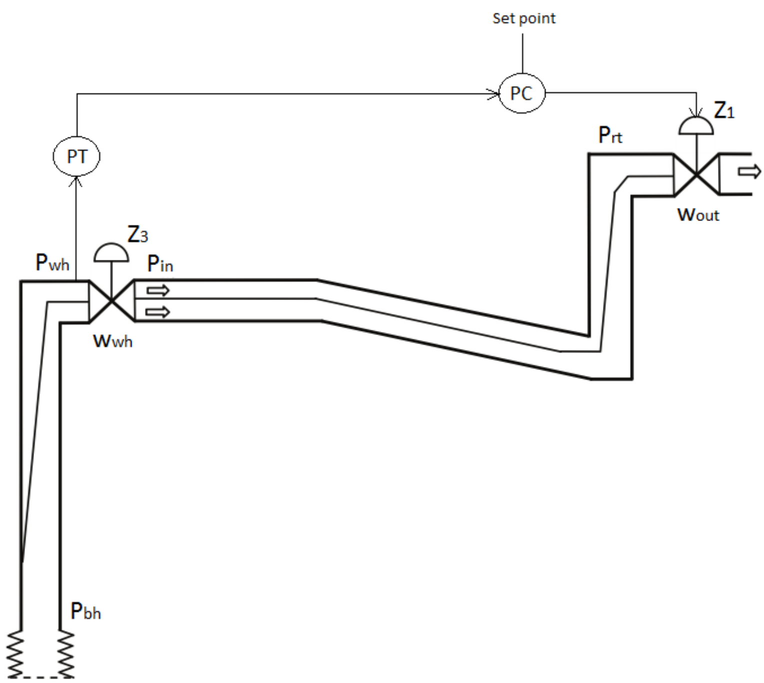

Figure 5.4: SISO control using well head pressure

when the set point is changed after 2000 seconds, some high peaks of out flow is produced. This may flood the separator, if it is not dimensioned for short periods with high flow. With this control solution the production increases from

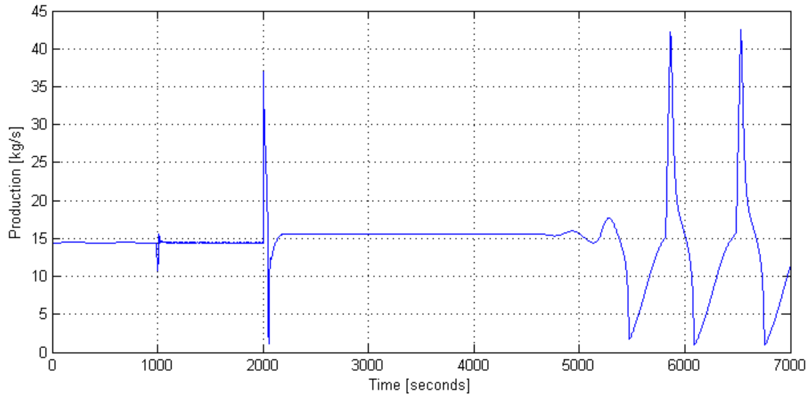

Figure 5.5: Production when controlling the top valve based on the well head pressure

14.41 kg/s to 15.54 kg/s. This gives 7.8% higher production with active chocking instead of a fixed choke valve. Figure 5.6 shows the well head pressure response. As seen in figure 5.7, this control solution is able to stabilize slugging flow.

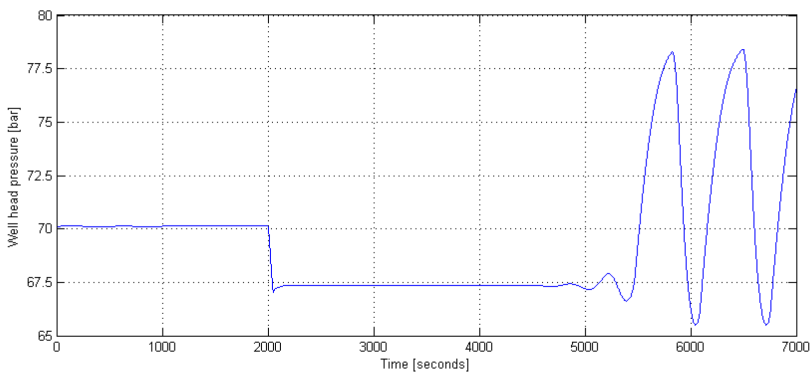

Figure 5.6: Well head pressure respons.

5.2 Mixed flow out as input - top side valve as output

When controlling the top valve using the mixed flow out as input(Figure 5.8) the flow spikes occuring with the pressure driven control is avoided.(Figure 5.9) It

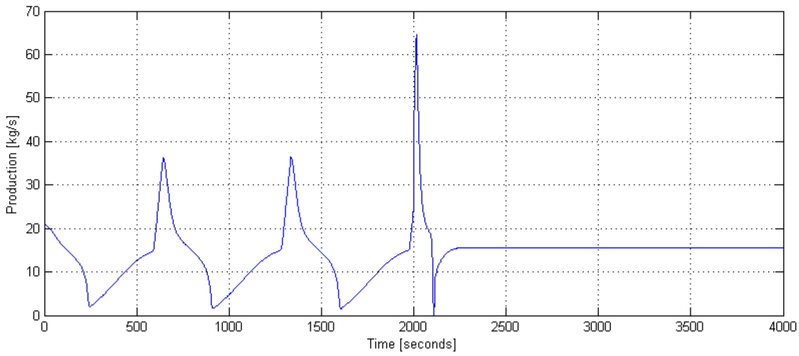

Figure 5.7: Stabilizing already slugging flow.

is very fast and increases production from 14.41 kg/s to 15.74 kg/s. This gives 9.2% higher production with active chocking compared to a fixed choke valve.

A problem with this control solution is that it is not able to stabilize already

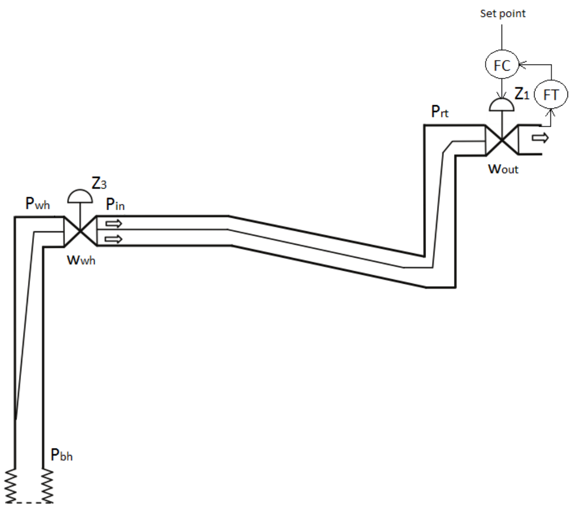

Figure 5.8: SISO control using the flow out of the top side valve

slugging flow. With high mass flows through the valve, the changes in the valve opening influence the flow so much that it starts oscillating(Figure 5.10). It might have some problems with disturbances in the flow, but this schould be further investigated.

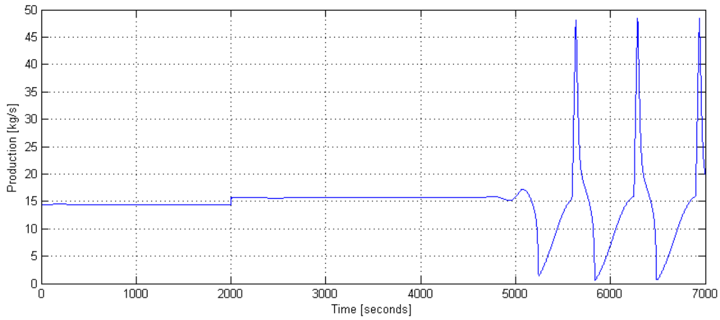

Figure 5.9: SISO control using the flow out of the top side valve

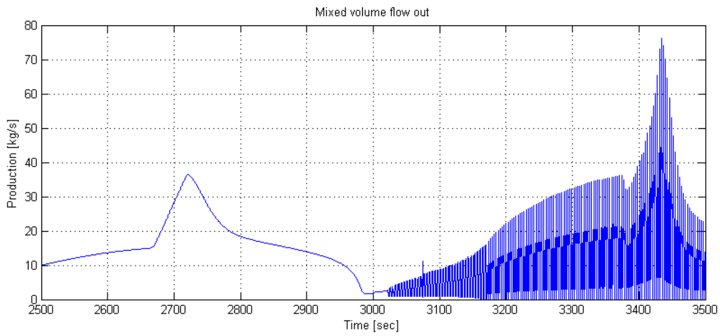

Figure 5.10: SISO control using the flow out of the top side valve

5.3 Cascade control using well head pressure and mixed flow out as input - top side valve as output

By combining the pressure control and the flow control in a cascade system, a system without the transient slugs is created. The well head pressure is compared to a set point, and the control output is used as set point for the flow control. Compared to the SISO flow control system, this set up seems more unstable and much slower. What schould be further investigated is how it responds to disturbance and unstable flow, that I belive is a problem for the flow control. This solution increases production from 14.41 kg/s to 15.61 kg/s. This gives 8.3% higher production with active chocking instead of a fixed choke valve.

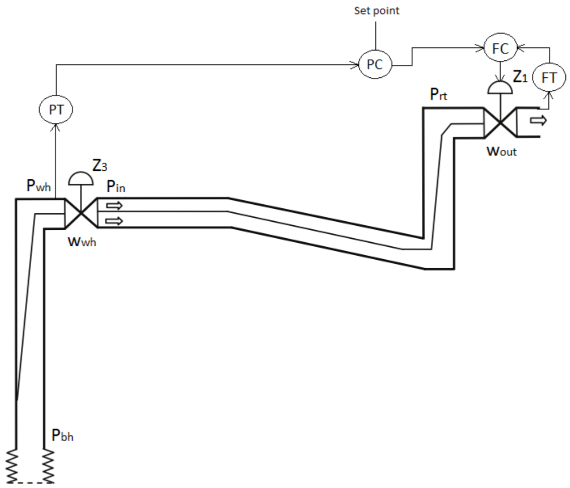

Figure 5.11: MISO cascade control using well head pressure and mixed out flow

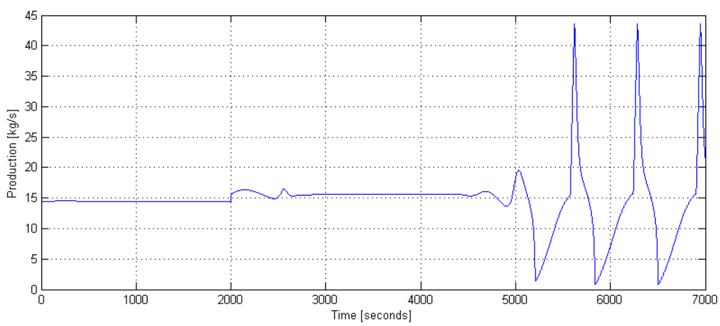

Figure 5.12: MISO control using well head pressure and mixed flow

5.4 Slug control using choke valve located at well head

After testing the subsea choke valve with different control structures I was never able to control the riser slugging. Since the slugs form after the valve it is not suited for this type of control. For unstability origininating in the well, this valve is probarly more suited. It might also be used to control the pressure if more than one well is connected in a manifold at the seabed. Different pressures from the different wells can give unstable flow, and control valves keeping them equal migh stabilize this.

6. Conclusion and Recommendations

6.1 Conclusion

The task of this thesis was to create a model suited for simulating riser slugging in a pipeline-riser system, and use this model to test out different control solutions for active slug control. The chosen model was a six-state model based on mass conservation. The implementation in matlab worked very well and I was able to use an integrator with variable step length on the process, while keeping the sampling for the control system at fixed rate. Control systems were successfully implemented and tested. The subsea choke valve were not suited for control of riser slugging, and I was never able to stabilize the flow using this valve. The top side valve where more suited, and stable flow was achived with all tested control solutions. Active chocking gave an average of 8.43% increased production compared to fixed chocking. Control using the mixed flow out gave the best results if the system already where stable. When there already where slugging the control solution using well head pressure as contol variable was the only who was able to stabilize it. Cascade control using the flow out in the inner loop and the well head pressure in the outer loop didnt give very good results here, but with proper tuning it might prove better.

6.2 Discussion

In this thesis a six-state model of a well-pipeline-riser system where programmed in matlab. The model is based on formulas and data provided in a phd-thesis [1]. Even though this was a model that have been made earlier, it was still a lot of work to code, debug and find solutions for the model. I am very pleased with the result. It is easy to change the parameters and to get the data desired for control solutions.

Since a lot of work were used making the model and the system around it, there ware not much time left for the testing of different control approaches. I have limited knowledge in optimalization of the control parameters, and combined with the limited time, this have probarly resulted in poor control. This migh have influenced the results, especially on the cascade controller.

6.3 Recommendations for Further Work

During my work I have found three areas that I think should be further investigated and implemented in the model:

1. Include a valve at the riser base in the model, and test control solutions using this valve. This is a solution that have been proposed in some literature, but almost not been investigated. Mats Lieungh did some tests using the OLGA simulator.[2, p. 39]

2. Include more than one well, where the flow is combined at the well head and flows through the pipeline and riser together. The different wells schould have different composition, pressure and production. This might create unstable flow in the pipeline, and solutions where each well has it own control valve at the well head schould be tested. This is a problem

mentioned during a guest lecture with Statoil at NTNU regarding flow assurance.

3. Test how typical control valve problems influence the controllability of the system. Problems like stiction, positioner overshoot, dead band, long closing time and low resolution should be implemented and tested. This was mentioned as one of the biggest problems in slug control during discussions I had with two Statoil employees at a career day at NTNU.

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Appendix A - Matlab code

```
%%
%This code is intial code for a well-pipeline-riser system, with a control
%system.
%
%It is based on formulas provided by Esmaeil Jahanshahi in his phd-thesis
%"Control Solutions for Multiphase Flow" from October 2013.
%
%Created by Eskil Hove Meringdal
%
%Created during his master thesis at NTNU "Comparative study of different methods for
%slug control" in 2014.
%
%Supervisor at NTNU: Olav Egeland
%
%
%

%% Description
% The setup provided uses cascade control with flow out in the inner loop,
% and pressure at the well head in the outer loop. They control the opening
% of a valve located topside.
%
% The control system is activated in a stable area with a reference
% pressure at 70 bar. After 1000 seconds it is changed to 67 bar which is
% inside the unstable area. After 4000 seconds the valve is locked in its
% current position, and the slugging starts after some time, proving that
% it is in the unstable area. It runs for 8000 seconds

%% clear exicting data and whipe screen
clear all
clc

%% Load parameters
par = para();

%% Number of times ode function runs
time=8000;

%% Create arrays for faster computing
Z1=ones(time,1)*0.09;
u=ones(time,1)*14.4;
Z3=ones(time,1)*1;
P_wh=zeros(time,1);
w_liq_out=zeros(time,1);
w_gas_out=zeros(time,1);
w_out_mix=zeros(time,1);
P_in=zeros(time,1);

%% Controller - inner loop(w_mix)
Kp=0.003;
Ti=5;
Td=0;
sat=0;
int=0.09;
y_b=0;
```

```
%% Controller - outer loop(P_wh)
Kp2=-0.00001;
Ti2=400;
Td2=0;
sat2=0;
int2=14.4;
y_b2=0;
P_ref=7000000;

%% Set initial values required by ode
m=par.m_init;
m_init=par.m_init;

t0=1;
tend=2;
n=100;
tspan=linspace(t0,tend,n);

options=odeset('RelTol',1e-6,'Stats','on');



%%  Run process
for k=1:time
    [t,m_ode]=ode15s(@(t, m) pipeline_riser_ode(t, m, par, Z1(k), Z3(k)), tspan,↙
m_init);
    m_init=(m_ode(length(m_ode),:))';
    m=[m;m_ode];

    %Find variables
    [dm_dt(k,:),P_wh(k),w_out_mix(k), P_all(k,:)] = pipeline_riser(t,m_init,par,Z1(k),↙
Z3(k));

    %Controllers
    if (k<4000)
        [u(k+1),y_b2,int2,sat2]= controller2(Kp2,Ti2,Td2,P_wh(k),int2,y_b2,P_ref,sat2);
        [Z1(k+1),y_b,int,sat]= controller(Kp,Ti,Td,w_out_mix(k),int,y_b,u(k+1),sat);
    else
        Z1(k+1)=Z1(k);
    end

    if k==1000
       P_ref=6700000;
    end

    %Display progress
    clc
    disp(k*100/time)
end


%% Display results
fig1=figure(1);
subplot(3,2,1);  plot(m(:,1)),title('Mass of liquid in well'), grid
```

```
subplot(3,2,2);  plot(m(:,2)),title('Mass of gas in well'), grid
subplot(3,2,3);  plot(m(:,3)),title('Mass of liquid in pipe'), grid
subplot(3,2,4);  plot(m(:,4)),title('Mass of gas in pipe'), grid
subplot(3,2,5);  plot(m(:,5)),title('Mass of liquid in riser'), grid
subplot(3,2,6);  plot(m(:,6)),title('Mass of gas in riser'), grid

fig5=figure(5);
plotyy(linspace(1,length(w_out_mix),length(w_out_mix)),w_out_mix,linspace(1,length(Z1),↙
length(Z1)),Z1),title('Valve opening(green) and Production(blue)'), grid

display('Pressures at end of simulation[Pa]:')
display(P_all(length(P_all)))
%
```

```
%%
%This function sets the parameters for the well-pipeline-riser system.
%
%It is based on values provided by Esmaeil Jahanshahi in his phd-thesis
%"Control Solutions for Multiphase Flow" from October 2013.
%
%Created by Eskil Hove Meringdal
%
%Created during his master thesis at NTNU "Comparative study of different methods for
%slug control" in 2014.
%
%Supervisor at NTNU: Olav Egeland
%
%

function par = para()

%Model correction factors
par.K_h=0.7; % level correction factor
par.K_g=3.49E-2; % orifice of gas flow at low point
par.K_l=2.81E-1; % orifice of liquid flow at low point
par.CV_1=1.16E-2; % production choke constant
par.CV_3=3.30E-3; % wellhead choke valve constant

%%
%Constans
par.R=8314; % Universal gas constant [J/(kmol*K)]
par.g=9.81; % gravity [m/s^2]

%liquid and gas data
par.visc_liq=1.426E-4; % viscosity [Pa*s]
par.rho_liq=832.2; % liquid density [kg/m^3]
par.M_g=20; % gas molecular weight [gr]
par.roughness=45E-6;

%%
%well data
par.T_w=369; % Well temperatur [K]
par.D_w=0.12; % Well diameter [m]
par.L_w=3000; % Well depth [m]
par.A_w=pi*(par.D_w/2)^2;
par.V_w=par.A_w*par.L_w; % Well volume [m^3]


%pipeline data
par.T_p=337; % Pipeline temperatur [K]
par.D_p=0.12; % pipeline diameter [m]
par.L_p=4300; % pipeline length [m]
par.A_p=pi*(par.D_p/2)^2;
par.V_p=par.A_p*par.L_p; % pipeline volume [m^3]
par.incl=1; % pipeline inclination in degrees
par.h_c=par.D_p/cos(par.incl*2*pi/360); % pipeline opening at riser base (critical)

%Riser data
par.T_r=298.3; % riser temperatur [K]
```

```
par.D_r=0.1; % diameter riser [m]
par.L_r=300; % length riser [m]
par.L_h=100; % length horizontal riser [m]
par.A_r=pi*(par.D_r/2)^2;
par.V_r=par.A_r*par.L_r; % volume riser [m^3]

%% Reservoir data
par.P_res=320E5; % reservoir pressure [bar]
par.PI=2.75E-6; % Productivity index [kg/(s*Pa)]
w_nom=9; % nominal mass flow from reservoir [kg/s]
par.w_nom=w_nom;
gor=0.04; % mass gas-liquid ratio
par.gor=gor;

%% Diverse ikke plaserte/definerte
par.P_s=50.1E5; % separator pressure [bar]



%Initial flow rates
par.w_gas_in=w_nom*gor/(gor+1); % mass flow of gas from reservoir [kg/s]
par.w_liq_in=w_nom*1/(gor+1); % mass flow of liquid from reservoir [kg/s]
w_gas_rb=w_nom*gor/(gor+1);
w_liq_rb=w_nom*1/(gor+1);
w_gas_out=w_nom*gor/(gor+1);
w_liq_out=w_nom*1/(gor+1);

w_mix_out=w_gas_out+w_liq_out;

%%
par.P_in_nom=70E5;
%Initial mass values

m_liq_init_w=22287;
m_gas_init_w=327;
m_liq_init_p=24285;
m_gas_init_p=968;
m_liq_init_r=979;
m_gas_init_r=51;


par.m_init(1)=m_liq_init_w;
par.m_init(2)=m_gas_init_w;
par.m_init(3)=m_liq_init_p;
par.m_init(4)=m_gas_init_p;
par.m_init(5)=m_liq_init_r;
par.m_init(6)=m_gas_init_r;

%%
par.Z3=1;



end
```

```
%%
%This function calculates the behaviour of a well-pipeline-riser system.
%
%It is based on formulas provided by Esmaeil Jahanshahi in his phd-thesis
%"Control Solutions for Multiphase Flow" from October 2013.
%
%Created by Eskil Hove Meringdal
%
%Created during his master thesis at NTNU "Comparative study of different methods for
%slug control" in 2014.
%
%Supervisor at NTNU: Olav Egeland
%
%

function [dm_dt,P_wh_noise, w_out_mix, P_all] = pipeline_riser(t,m,par,Z1,Z3)

m_liq_w=m(1,:);
m_gas_w=m(2,:);
m_liq_p=m(3,:);
m_gas_p=m(4,:);
m_liq_r=m(5,:);
m_gas_r=m(6,:);

%% %%%%%%%%%%%%%%%%%%%%%% Pipeline model %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
rho_gas_p_mean=par.P_in_nom*par.M_g/(par.R*par.T_p);
V_fraction_liq_p_mean=rho_gas_p_mean*par.w_liq_in/(par.rho_liq*par.↙
w_gas_in+rho_gas_p_mean*par.w_liq_in);

if V_fraction_liq_p_mean > 1
    V_fraction_liq_p_mean=1;
elseif V_fraction_liq_p_mean < 0
    V_fraction_liq_p_mean=0;
end


m_liq_p_mean=par.rho_liq*par.V_p*V_fraction_liq_p_mean;


h_mean=par.K_h*par.h_c*V_fraction_liq_p_mean; % mean height of liquid level in pipeline
h=max(h_mean+((m_liq_p-m_liq_p_mean)/(par.A_p*(1-V_fraction_liq_p_mean)*par.rho_liq)↙
*sin(par.incl*2*pi/360)),0);


V_gas_p=par.V_p-m_liq_p/par.rho_liq;
if V_gas_p > par.V_p
    V_gas_p=par.V_p;
elseif V_gas_p <= 0
    V_gas_p=0.0001;
end

rho_gas_p=m_gas_p/V_gas_p;
P_in=rho_gas_p*par.R*par.T_p/par.M_g;

Us_liq_in_mean=4*par.w_liq_in/(pi*par.D_p*par.D_p*par.rho_liq);
```

```
Re_p=par.rho_liq*Us_liq_in_mean*par.D_p/par.visc_liq;
frictionfactor_p=(1/(-1.8*log10((par.roughness/(par.D_p*3.7))^1.11 + 6.9/Re_p)))^2;

% Pressure change to to friction in pipeline
P_f_p=V_fraction_liq_p_mean*frictionfactor_p*par.rho_liq*Us_liq_in_mean^2*par.L_p/↙
(2*par.D_p);


%% %%%%%%%%%%%%%%%%%%%%%%% Riser model %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
V_gas_r=par.V_r-m_liq_r/par.rho_liq;
if V_gas_r > par.V_r
    V_gas_r=par.V_r;
elseif V_gas_r < 0
    m_gas_r=0;
end

rho_gas_r=m_gas_r/V_gas_r;

% Pressure riser top
P_rt=rho_gas_r*par.R*par.T_r/par.M_g;

V_fraction_liq_r_mean=m_liq_r/(par.V_r*par.rho_liq);
rho_mix_r_mean=(m_gas_r+m_liq_r)/par.V_r;
Us_liq_r_mean=par.w_liq_in/(par.rho_liq*par.A_r);
Us_gas_r_mean=par.w_gas_in/(rho_gas_r*par.A_r);
Us_mix_r_mean=Us_liq_r_mean+Us_gas_r_mean;
Re_r=rho_mix_r_mean*Us_mix_r_mean*par.D_r/par.visc_liq;
frictionfactor_r=(1/(-1.8*log10((par.roughness/(par.D_p*3.7))^1.11 + 6.9/Re_r)))^2;

% Pressure drop due to friction in riser
P_f_r=V_fraction_liq_r_mean*frictionfactor_r*rho_mix_r_mean*Us_mix_r_mean^2*(par.↙
L_r+par.L_h)/(2*par.D_r);


%% %%%%%%%%%%%%%%%%%%%%%%% well model %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
V_fraction_liq_w_mean=m_liq_w/(par.V_w*par.rho_liq);

if V_fraction_liq_w_mean > 1
    V_fraction_liq_w_mean=1;
elseif V_fraction_liq_w_mean < 0
    V_fraction_liq_w_mean=0;
end

% calculating friction factor
Us_liq_w_mean=4*par.w_nom/(pi*par.D_w*par.D_w*par.rho_liq);
Re_w=par.rho_liq*Us_liq_w_mean*par.D_w/par.visc_liq;
frictionfactor_w=(1/(-1.8*log10((par.roughness/(par.D_w*3.7))^1.11 + 6.9/Re_w)))^2;

% Pressure change due to friction in well
P_f_w=V_fraction_liq_w_mean*frictionfactor_w*par.rho_liq*Us_liq_w_mean^2*par.L_w/↙
(2*par.D_w);

rho_mix_w_mean=(m_gas_w + m_liq_w)/par.V_w;

%Pressure at well head
```

```
P_wh=m_gas_w*par.R*par.T_w/(par.M_g*(par.V_w-m_liq_w/par.rho_liq));

%Pressure at bottom hole
P_bh=P_wh+rho_mix_w_mean*par.L_w*par.g+P_f_w;

%% %%%%%%%%%%%%%%%%%%%%%%% Phase distribution at well head %%%%%%%%%%%%%%%%
V_fraction_liq_wb=1;
V_fraction_liq_wt=2*V_fraction_liq_w_mean - V_fraction_liq_wb;
if V_fraction_liq_wt > 1
    V_fraction_liq_wt=1;
elseif V_fraction_liq_wt < 0
    V_fraction_liq_wt=0;
end


rho_gas_w=m_gas_w/(par.V_w-m_liq_w/par.rho_liq);
rho_mix_wt=V_fraction_liq_wt*par.rho_liq + (1-V_fraction_liq_wt)*rho_gas_w;

m_fraction_gas_wt=(1-V_fraction_liq_wt)*rho_gas_w/rho_mix_wt;
if m_fraction_gas_wt > 1
    m_fraction_gas_wt=1;
elseif m_fraction_gas_wt < 0
    m_fraction_gas_wt=0;
end

%% %%%%%%%%%%%%%%%%%%%%%%% Flow at well head %%%%%%%%%%%%%%%%%%%%%%%%%%%%
w_mix_wh=par.CV_3*Z3*sqrt(rho_mix_wt*max(P_wh-P_in,0));

w_gas_wh=w_mix_wh*m_fraction_gas_wt;
w_liq_wh=w_mix_wh*(1-m_fraction_gas_wt);


%% %%%%%%%%%%%%%%%%%%%%%%% Flow at riser base %%%%%%%%%%%%%%%%%%%%%%%%%%%
% Gas
P_g=P_in-P_f_p-P_rt-rho_mix_r_mean*par.g*par.L_r-P_f_r;
if h >= par.h_c
    A_g=0;
    w_gas_rb=0;
else
    A_g=par.A_p*((par.h_c-h)/par.h_c)^2;
    w_gas_rb=par.K_g*A_g*sqrt(max(rho_gas_p*P_g,0));
end

% Liquid
P_l=P_in-P_f_p+par.rho_liq*par.g*h-P_rt-rho_mix_r_mean*par.g*par.L_r-P_f_r;
A_l=par.A_p-A_g;
w_liq_rb=par.K_l*A_l*sqrt(max(par.rho_liq*P_l,0));

%% %%%%%%%%%%%%%%%%%%%%%%% Phase distribution at choke %%%%%%%%%%%%%%%%%%%
V_fraction_liq_rb=A_l/par.A_p;

V_fraction_liq_rt=2*m_liq_r/(par.V_r*par.rho_liq)-V_fraction_liq_rb;
if V_fraction_liq_rt > 1
    V_fraction_liq_rt=1;
elseif V_fraction_liq_rt < 0
```

```matlab
    V_fraction_liq_rt=0;
end


%% %%%%%%%%%%%%%%%%%%%%%% Outflow conditions %%%%%%%%%%%%%%%%%%%%%%%%%%%%
rho_rt=V_fraction_liq_rt*par.rho_liq+(1-V_fraction_liq_rt)*rho_gas_r;
w_out_mix=par.CV_1*Z1*sqrt(rho_rt*max(P_rt-par.P_s,0));

%%%%%%%%%%%%%
m_fraction_liq_rt=V_fraction_liq_rt*par.rho_liq/(V_fraction_liq_rt*par.rho_liq+(1-V_fraction_liq_rt)*rho_gas_r);
if m_fraction_liq_rt > 1
    m_fraction_liq_rt=1;
elseif m_fraction_liq_rt < 0
    m_fraction_liq_rt=0;
end


%%%%%%%%%%%%%

w_liq_out=m_fraction_liq_rt*w_out_mix;
w_gas_out=(1-m_fraction_liq_rt)*w_out_mix;

%% %%%%%%%%%%%%%%%%%%%%%% Calculate flow from reservoir %%%%%%%%%%%%%%%%%
w_res_mix = par.PI*max(0,par.P_res-P_bh);

w_liq_res=1/(par.gor+1)*w_res_mix;
w_gas_res=(par.gor/(par.gor+1))*w_res_mix;

%%
P_wh_noise=(P_wh+100*(rand()-0.5));

%% %%%%%%%%%%%%%%%%%%%%%% Change in mass %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
delta_m_liq_w=w_liq_res-w_liq_wh;
delta_m_gas_w=w_gas_res-w_gas_wh;
delta_m_liq_p=w_liq_wh-w_liq_rb;
delta_m_gas_p=w_gas_wh-w_gas_rb;
delta_m_liq_r=w_liq_rb-w_liq_out;
delta_m_gas_r=w_gas_rb-w_gas_out;

dm_dt=[delta_m_liq_w; delta_m_gas_w; delta_m_liq_p; delta_m_gas_p; delta_m_liq_r; delta_m_gas_r];

%% Save different pressures
P_all.Separator=par.P_s;
P_all.riser_top=P_rt;
P_all.riser_bottom_gas=P_g;
P_all.riser_bottom_liquid=P_l;
P_all.innlet=P_in;
P_all.well_head=P_wh;
P_all.bottom_hole=P_bh;
P_all.reservoir=par.P_res;
P_all.friction_well=P_f_w;
P_all.friction_pipe=P_f_p;
P_all.friction_riser=P_f_r;
```

```
end
```

```matlab
%%
%This code makes the model function compatible with the ode-integrator.
%
%Created by Eskil Hove Meringdal
%
%Created during his master thesis at NTNU "Comparative study of different methods for
%slug control" in 2014.
%
%Supervisor at NTNU: Olav Egeland
%

function [dm_dt] = pipeline_riser_ode(t,m,par,Z1,Z3)
    [dm_dt] = pipeline_riser(t,m,par,Z1,Z3);
end
```

```
%%
%This function is a PID-controller with disconnection of integral if it
%gets saturated
%
%It is based on a controller created during my bachelor thesis at HiST.
%
%Created by Eskil Hove Meringdal
%
%Created during his master thesis at NTNU "Comparative study of different methods for
%slug control" in 2014.
%
%Supervisor at NTNU: Olav Egeland
%
%

function [u,y_b,int,sat]= controller(Kp,Ti,Td,y,int,y_b,yref,sat)
%% Controller settings
if Ti==0 || sat==1
    I=0;
    Ti=1;
else
    I=1;
end
r=yref;

%% Calculate controller output
e=r-y;

int=int+I*(Kp/Ti)*e;
der=Kp*Td*(y-y_b);
prop=Kp*e;

u=prop+(I*int)+der;

y_b=y;

%% Check limits (0-1)
if u < 0
    u=0;
    sat=1;
elseif u > 1
    u=1;
    sat=1;
else
    sat=0;
end

end
```

Appendix B - Pilot Project

NTNU – Trondheim
Norwegian University of
Science and Technology

Comparative study of different methodes for slug control

Eskil Hove Meringdal

Januar 2014

Pilot Project
Department of Production and Quality Engineering
Norwegian University of Science and Technology

Supervisor: Professor Olav Egeland

Contents

Chapter 1

Project description

The master thesis will build on the earlier work done during the project task which was finished in december 2013. The desired field of study was a combination of subsea technology and cybernetics. This was expressed to the advisor, and he proposed a task investigating the problems associated with slug flow in multiphase pipelines.

1.1 Background

In the petroleum industry multiphase flow is considered one of the greatest inventions of all time. The technology made it possible to produce from the seabed. But one of the problems connected with this kind of flow is slug flow. Slug flow reduces the production and is a threat to topside equipment. By controlling the flow it is possible to reduce the consequences and increase production.

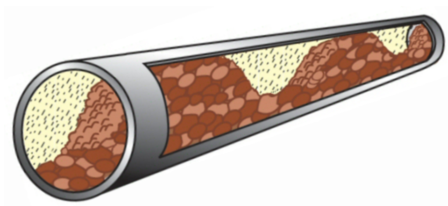


Figure 1.1: slug flow in multiphase pipeline

1.2 Objectives

In this paper slug control for multiphase flow is studied. The task will be based on previously published methods for slug control, and perform a comparative study on the different methods in Simulink.

1. Present a dynamic model for slug flow in a multiphase pipeline with a valve at the bottom and a valve on the top, and show typical flow regime with and without slugs by simulation in Simulink.
2. Provide an overview of published methods for slug control.

3. Test out different methods for slug control in Simulink and provide an evaluation of the performance of the different methods.

1.3 Approach

A model which was developed during the project assignment will be improved and tested against an already working model by comparing the results and the code. The model will be extended from a four-state model to a six-stated model, which includes the behaviour of the flow in the well. This makes it possible to simulate how a valve on the bottom can influence the flow, and possibly reduce slug flow. Further a control system will be programmed to be able to test active chocking on the model. Its the results from these tests that provides the basis for the thesis.

Chapter 2

Tools and routines

2.1 Tools

Matlab

Matlab is a strong mathematic program which will be used for modelling and simulation of the processes. It has it own programmning language based on C, which will be used to program the algorithms.

Dropbox

Dropbox is a online backup and sharing tool who automatically synchronise the content on the server and on the local hard drive. It synchronizes between chosen computers and a server continuously, making it easy to access data anywhere and at all time.

Latex and TeXnicCenter

Latex is a document preparation system and document markup language. TeXnicCenter is used to systemise and edit the latex files. Combined with dropbox, the project document will be always be available and backed up.

Team Gantt Project Manager

Team Gantt Project Manager is a project planner utility. It makes it possible to input all parts of the project, with meetings, goals, time-limits, project-phases, etc. With this data it makes a Gantt-diagram, describing the progress of the project

2.2 Routines

Timetable

To be able to know how many hours I have been working, a timetable is used. This timetable is made in Excel.

Journal

During the project a journal will be updated every day, including everything that have been done that day. It will make it much easier to analyze the amount of work for the different parts of the project.

Backup

All files will be backed up in Dropbox. The folder name will include the date of which it was backed up, making in possible to go back to earlier versions of the algorithm.

Meetings

Meeting with the advisor will be arranged every second week to discuss the progress of the project. Additional meetings may be arranged to cope with problems that occurs.

Chapter 3

Goals for the projects

The goals for the project are separated into two different categories. Learning goals is the knowledge acquired during the project, while result goals are what is achieved or produced during the project.

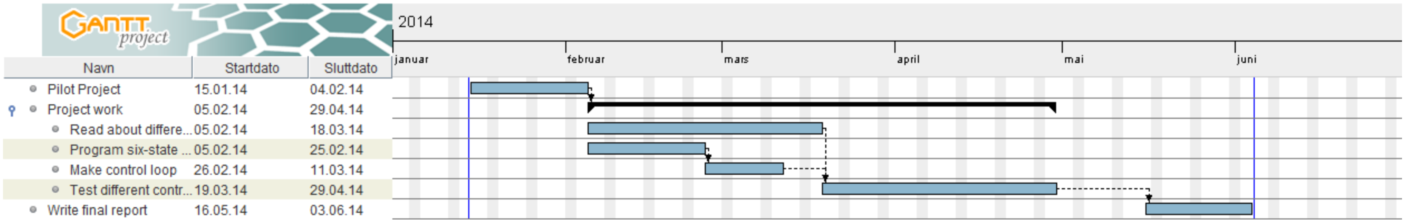
Learning goals

1. Get an increased understanding of how multiphase flow behaves.
2. Learn about different methods of removing slug flow while keeping high production.
3. Increase my abilities in Matlab programming and model development.

Result goals

1. Create a six-state model for a well-pipeline-riser system with multiphase flow in Matlab.
2. Test different control solutions on the six-state model and present my thoughts on the solutions based on simulation results.

Appendix A - Gantt Diagram


GANTT project
2014
januar
februar
mars
april
mai
juni
Navn
Startdato
Sluttdato
Pilot Project 15.01.14 04.02.14
Project work 05.02.14 29.04.14
Read about differe... 05.02.14 18.03.14
Program six-state ... 05.02.14 25.02.14
Make control loop 26.02.14 11.03.14
Test different contr... 19.03.14 29.04.14
Write final report 16.05.14 03.06.14

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Appendix C - Parameters used in the model

Contents

Model correction factors

```
par.K_h=0.7; % level correction factor
par.K_g=3.49E-2; % orifice of gas flow at low point
par.K_l=2.81E-1; % orifice of liquid flow at low point
par.CV_1=1.16E-2; % production choke constant
par.CV_3=3.30E-3; % wellhead choke valve constant
```

Constans

```
par.R=8314; % Universal gas constant [J/(kmol*K)]
par.g=9.81; % gravity [m/s^2]
```

Liquid and gas data

```
par.visc_liq=1.426E-4; % viscosity [Pa*s]
par.rho_liq=832.2; % liquid density [kg/m^3]
par.M_g=20; % gas molecular weight [gr]
par.roughness=45E-6;
```

Well data

```
par.T_w=369; % Well temperatur [K]
par.D_w=0.12; % Well diameter [m]
par.L_w=3000; % Well depth [m]
par.A_w=pi*(par.D_w/2)^2;
par.V_w=par.A_w*par.L_w; % Well volume [m^3]
```

Pipeline data

```
par.T_p=337; % Pipeline temperatur [K]
par.D_p=0.12; % pipeline diameter [m]
par.L_p=4300; % pipeline length [m]
par.A_p=pi*(par.D_p/2)^2;
par.V_p=par.A_p*par.L_p; % pipeline volume [m^3]
par.incl=1; % pipeline inclination in degrees
par.h_c=par.D_p/cos(par.incl*2*pi/360); % pipeline opening at riser base (critical)
```

Riser data

```
par.T_r=298.3; % riser temperatur [K]
par.D_r=0.1; % diameter riser [m]
par.L_r=300; % length riser [m]
par.L_h=100; % length horizontal riser [m]
par.A_r=pi*(par.D_r/2)^2;
par.V_r=par.A_r*par.L_r; % volume riser [m^3]
par.P_s=50.1E5; % separator pressure [bar]
```

Reservoir data

```
par.P_res=320E5; % reservoir pressure [bar]
par.PI=2.75E-6; % Productivity index [kg/(s*Pa)]
w_nom=9; % nominal mass flow from reservoir [kg/s]
par.w_nom=w_nom;
gor=0.04; % mass gas-liquid ratio
par.gor=gor;
```

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