Active Feedback Control as a Solution to Severe Slugging

Kjetil Havre, SPE, and **Morten Dalsmo,** SPE, ABB

Summary

Severe slugging in multiphase pipelines can cause serious and troublesome operational problems for downstream receiving production facilities. Recent results demonstrating the feasibility and the potential of applying dynamic feedback control to unstable multiphase flow like severe slugging and casing heading have been published.[1–5] This paper summarizes our findings on terrain-induced slug flow.[5] Results from field tests as well as those from dynamic multiphase flow simulations are presented. The simulations were performed with the pipeline code OLGA2000.*

The controllers applied to all of these cases aim to stabilize the flow conditions by applying feedback control rather than coping with slug flow in the downstream processing unit. The results from simulations with feedback control show stable process conditions at both the pipeline inlet and outlet in all cases, whereas without control, severe slug flow is experienced. Pipeline profile plots of the liquid volume fraction through a typical slug flow cycle are compared against corresponding plots with feedback control applied. The comparison is used to justify the internal stability of the pipeline. In many cases, feedback control enables a reduced pipeline inlet pressure, which, again, means an increased production rate.

This paper summarizes the experience gained with active feedback control applied to severe slugging. The focus is on extracting similarities and differences between the cases. The main contribution is demonstrating that dynamic feedback control can be a solution to the severe slugging problem.

Introduction

Multiphase pipelines connecting remote wellhead platforms and subsea wells are already common in offshore oil production, and there will be even more of them in the years to come. In addition, the proven feasibility of using long-distance tieback pipelines to connect subsea processing units directly to onshore processing plants makes it likely that these will also appear in the future. Such developments are turning the spotlight on one of the biggest challenges for control and operation of offshore processing facilities and subsea separation units—controlling the feed disturbance to the separation process (that is, smoothing or avoiding flow variations at the outlet of multiphase pipelines connecting wells and remote installations to the processing unit).

Common forms of flow variations are slug flow in multiphase pipelines and casing heading in gas-lifted oil wells. In both cases, the liquid flows intermittently along the pipe in a concentrated mass called a slug. The unstable behavior of slug flow and casing heading has a negative impact on the operation of offshore production facilities. Severe slugging can even cause platform trips and plant shutdown. More frequently, the large and rapid flow variation causes unwanted flaring and limits the operating capacity in separation and compression units. This reduction is caused by the need for larger operating margins for both separation (to meet the product specifications) and compression (to ensure safe operation with minimum flaring). Backing off the plant's optimal operating in this way reduces its throughput.

A lot of effort and money have been spent trying to avoid the operational problems with severe slugging and reduce the effects of the slugs. Roughly speaking, there are three main categories of principles for avoiding or reducing the effects of slugs.

- Design changes.
- Operational changes and procedures.
- Control methods, including feed-forward control, slug choking, and active feedback control.

An example of a typical slug-handling technique involving design changes is to install slug catchers (onshore) or increase the size of the first-stage separator(s) to provide the necessary buffer capacity. A different, compact, process-design change is reported in Ref. 6, in which the authors introduce an additional small, pressurized, closed vessel upstream of the first-stage separator to cope with slug flow. An example of operational change is to increase the flowline pressure so that operation of the pipeline/well is outside the slug flow regime.[7,8] This is not a viable option for older wells with reduced lifting capacity. For gas-lifted wells, an option would be to increase the gas injection rate (see Ref. 2). These design and operational changes may not be appropriate for already existing installations with slug flow problems or for compact separation units.

Control methods for slug handling are characterized by the use of process and/or pipeline information to adjust available degrees of freedom (pipeline chokes, pressure, and levels), reducing or eliminating the effect of slugs in the downstream separation and compression units. The idea of feed-forward control is to detect the buildup of slugs and prepare the separators accordingly to receive them (e.g., via feed-forward control to the separator level and pressure control loops). The aim of slug choking is to avoid overloading the process facilities with liquid or gas. These methods make use of a topside pipeline choke by reducing its opening in the presence of a slug, thereby protecting the downstream equipment. The slug choking may use measurements in the separation unit and/or the output from a slug-detection device/algorithm. For a more complete assessment of the current technology for slug handling, refer to Ref. 9. In this assessment, however, active control methods are not properly addressed.

Recently, results have been published that demonstrate the feasibility and potential of applying dynamic feedback control to unstable multiphase flow like severe slugging and casing heading.[1–5] Like slug choking, active feedback control makes use of a topside choke. With dynamic feedback control, however, the approach is to solve the slug problem by stabilizing multiphase flow. Despite the promising results first reported in 1990,[1] the use of active slug control on multiphase flow has been limited. To our knowledge, only two installations in operation have stabilizing controllers. These are the Dunbar-Alwyn[5,2] and the Hod-Valhall pipelines.[5] One reason for this might be that control engineering and fluid flow dynamics usually are separated technical fields (i.e., the control engineers have limited knowledge about multiphase flow and the experts in fluid flow dynamics have limited insights into what can be achieved with feedback control). Indeed, when presenting the results on the Hod-Valhall pipeline,[5] we had a hard time convincing several of the fluid-flow-dynamics engineers that one can avoid slug formation in severe slugging by active control. Hence, one objective of this paper is to provide insight and understanding into how feedback control can be used to avoid severe slugging, thereby contributing to bridging the gap between control and petroleum engineering.

Previous Work

Elimination of terrain and riser-induced slug flow by choking was first suggested by Schmidt *et al.*[8] Taitel[6] states that stable flow can

* OLGA2000 is trademarked to Scandpower Petroleum Technology AS, Kjeller, Norway (2001).

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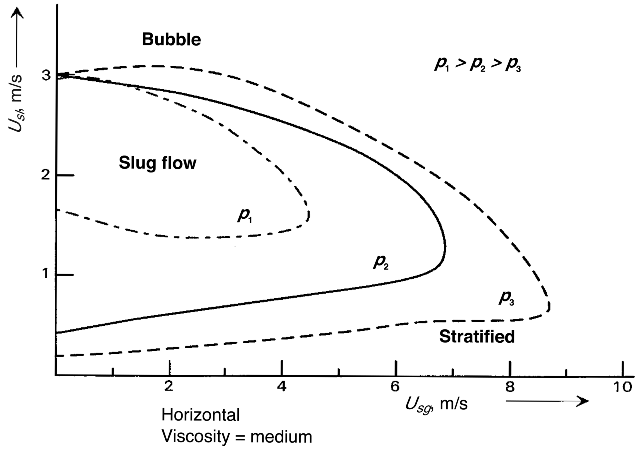

Fig. 1—Horizontal flow map.

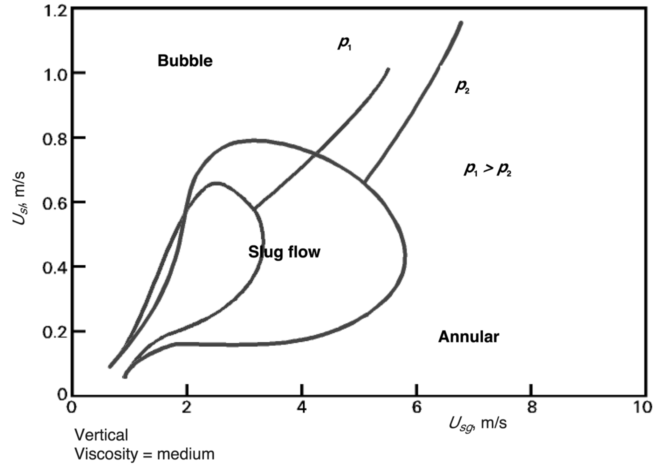

Fig. 2—Vertical flow map.

be achieved with a choke to control the pipeline backpressure and that an unstable system still can operate at around a steady-state equilibrium provided a feedback control system is used to stabilize the system. Furthermore, he refers to Ref. 9, in which the possibility of stabilizing flow by choking at the top of the riser upstream of the separator was experimentally found. Taitel used stability analysis to define a theoretical control law, relating the backpressure to the propagation of the slug tail into the riser. Taitel claims (sic), "It is interesting to observe that, to a good approximation, little movement of the choking valve is needed for such a control system. This makes it possible to set the valve in a pre-calculated constant value."[6] No feedback control system is used in the experiments. Instead, the choke is fixed in a precalculated position. Note that the derived stability condition is related to quasi-equilibrium flow conditions, with bubble flow in the riser and no or limited propagation of the slug tail into the riser. From control theory it is well known that feedback control is needed to operate at an unstable operating point, otherwise disturbances will push the operation out of the desired point. Our conclusion is that the quasi-equilibrium flow conditions comprise a stable operating point with an unnecessarily high riser base pressure that must be higher than the corresponding pressure, which can be achieved by stabilizing feedback control. Furthermore, we believe that the riser base pressure at quasi-equilibrium flow conditions is equal to or larger than the peak riser base pressure with slug flow. Typical flow maps showing the slug flow region's dependency on pressure justify these statements; the slug flow region shrinks with increasing pressure, and the bubble flow region lies above it (see **Figs. 1 and 2**).

In Ref. 1, experiments on suppressing terrain-induced slugging by means of a remote-controlled control valve installed in the riser top are presented. Manual valve closure of approximately 80% was necessary to remove the terrain-induced slugging with a pressure difference approximately 7 bar greater than the valve. In automatic mode, the valve was controlled by a productivity index (PI) algorithm with the pressure over the riser as the input signal. Terrain-induced slugging was successfully alleviated with the PI control algorithm operating the valve. The resulting pressure difference across the valve was typically 1 to 2.5 bar. From Fig. 7 in Ref. 1, it appears that they were able to split terrain-induced slugs into several smaller slugs.

In Ref. 2, riser base pressure control is used to avoid riser-induced slug flow at low flow rates in the Dunbar-Alwyn pipeline. Besides having pressure control in the riser base, the control schemes include necessary override and manual controls to implement the developed operating strategies. The control scheme uses a control valve in parallel with the pipeline choke to control the riser base pressure (see Fig. 8 in Ref. 2). At low flow rates in which riser-induced slug flow occurs as a problem, the pipeline choke is closed and the control valve is used to control the pressure at riser base according to a proportional integral and derivative (PID) algorithm. The pressure difference across the control valve with the slug-control algorithm in operation was designed to be 15 bar. The selected control scheme consists of throttling the pipeline sufficiently to maintain pressure greater than the peak (approximately 81 bar), preventing liquid blockage at the riser base. Therefore, the set point to the riser base pressure was set to 89 bar. It is reasonable to believe that this results in controlled bubble flow in the riser, which might be acceptable if the necessary backpressure/lifting capacity is available. The large differential pressure across the control valve was chosen to obtain a robust system with a large margin for instability.

Ref. 4 presents simulation studies on the Dunbar-Alwyn pipeline with the TACITE** multiphase simulator. In this work, the authors look at several operational schemes to avoid riser-induced slug flow. Of the most interest for this paper is the simulation of riser base pressure control to avoid liquid blockage in the riser base. The difference between this work and the work on the real pipeline[2] is that the set point to the riser base pressure controller is less than the peak value in the slug flow regime. Actually, the set point is put as low as 77 bar, which is approximately 4 bar less than the slug release pressure (approximately 81 bar).

In Ref. 5, the use of feedback control to remove terrain-induced slug flow in the Hod-Valhall pipeline is presented with results from both simulations and field tests. The main differences between the work on the Hod-Valhall pipeline and that on the Dunbar-Alwyn pipeline[2,4] are

- A pressure transmitter at the pipeline inlet replaces the pressure measurement at the riser base in the Dunbar case. This means that the pressure transmitter is moved 12 km upstream of the riser base. Knowing that it is possible to stabilize riser-induced slug flow with riser base pressure control, it is by no means obvious that stabilizing control can be achieved by moving the pressure transmitter to the pipeline inlet (12 km upstream).
- The pressure at the pipeline outlet is used in the control algorithm.
- The pressure set point at the pipeline inlet is always less than the slug release pressure with severe slug flow in the pipeline.

In Ref. 10, the authors present work on active control of riser-induced slug flow. Here, the pressure is measured at the base of the riser, and a control system is used to adjust the gas outlet valve of the first-stage separator. Experimental results show a reduction in the pressure variations caused by slugging.

The combination of a small, pressurized vessel or a compact cyclone separator in which the gas outlet valve is used for slug control seems to be the most feasible solution for hydrodynamic slug flow. The reason for this is that a single-phase gas valve can be made much smaller and faster than a control valve for multiphase flow. In addition, the extra volume has the ability to cut/filter the large, rapid flow peaks appearing in hydrodynamic slug flow.

Despite the structural differences between gas-lifted oil wells and multiphase pipelines, the instability in riser- and terrain-

** TACITE is a registered trademark of IFP Drilling & Production, Cedex, France.

induced slug flow is very similar to the instability that occurs in deep casing heading in gas-lifted oil wells. In Ref. 3, casing heading in gas-lifted oil wells is studied. Thus, the Casing Heading section in this paper is devoted to comparing casing heading with severe slug flow. The work reported in Ref. 3 was partly based on a simple, first-principles, nonlinear model of a gas-lifted well with the ability to describe casing heading. Clearly, some of the insights provided by this model can be transferred to severe slug flow.

Riser- and Terrain-Induced Slug Flow Cycle

For a full description of riser and terrain-induced slug flow, refer to Refs. 1, 7–9, and 11. The following description is a modified version of the description given in Ref. 4.

Riser and terrain-induced slug flow is initiated by a period (**Fig. 3,** $t=1$ h) during which liquid, in terms of oil and water, accumulate in the lower parts of the pipeline or at the bottom of the riser. After some time (Fig. 3, $t=1.1$ h), the liquid will block the passage of the gas. Some gas will bubble through the liquid plug, but most of it accumulates upstream, causing a pressure buildup. The plug continues to grow until the forces acting on it are large enough to accelerate the plug.

At a certain pressure, the liquid plug starts to move (Fig. 3, $t=1.6$ h) because of forces acting on it. This can be identified as a pressure decrease upstream of the liquid plug and a pressure increase downstream of the liquid plug followed by a constant liquid production rate. Depending on the pipeline geometry downstream of the liquid plug and the operating conditions, the plug may either die out or be transported to the outlet of the pipeline. In the slug-movement period, the pipeline pressure is almost constant. When the tail of the slug reaches the riser base or the low point (dip) in the pipeline (Fig. 3, $t=3.1$ h), gas starts to penetrate into the riser/upward parts of the pipeline. This causes the pressure at the riser base/low point to decrease as the hydrostatic pressure decreases. This causes more gas to flow into the riser/upward parts of the pipeline, with the consequence that the flow rate increases rapidly. As the gas and liquid are transported out of the pipeline, the upstream pressure continues to decrease. At $t=3.2$ h (see Fig. 3), the gas behind the plug starts to penetrate into and escape from (pass) the liquid plug. The liquid flow from the pipeline then ceases, and any remaining liquid in the riser/upward parts of the pipeline falls back to the riser base/low point of the pipeline.

The process then starts over again, resulting in an unstable multiphase flow pattern in which the liquid flow rate varies from zero to a significant constant value followed by a large peak value in a cycle.

During the blowout/pressure reduction, the pipeline is exponentially unstable, and the trajectory passes from an exponentially unstable manifold (zone) to a stable one. The classic riser-induced slug flow cycle contains all the stages described previously, and the slug grows until its head reaches the top of the riser and is produced into the separator. At that point, the cycle goes from pressure buildup to slug movement. However, the slug may start to move before the head reaches the top of the riser. From trends in the pipeline inlet and outlet pressures, it is not always possible to observe the slug movement phase. Riser-induced slug flow in which the slug movement phase is not present is often regarded as terrain-induced slug flow.

Riser- and terrain-induced slug flow typically occurs for relatively low liquid and gas flow rates and is dependent on the gas/oil ratio. Typically, an increase in the gas/oil ratio (GOR) improves the stability, and a decrease makes the flow unstable for a constant total flow rate.

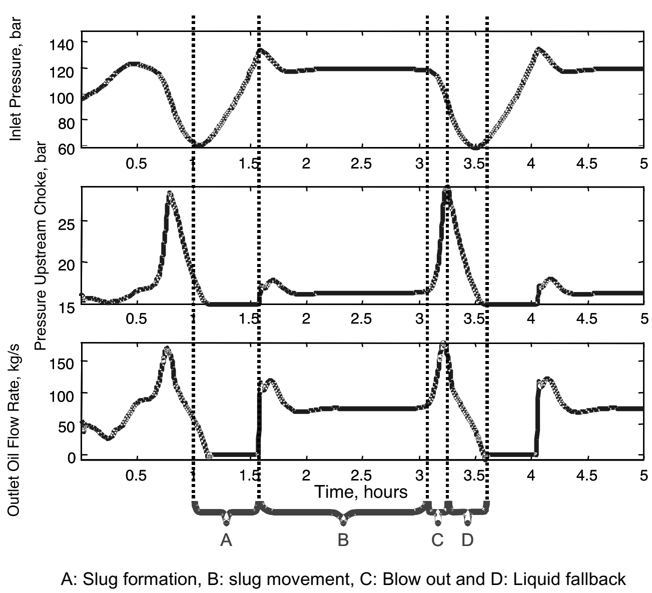

Fig. 3—Riser-induced slug flow cycle in the deepwater case.

Casing Heading

Deep casing heading in gas-lifted oil wells undergo a limit cycle that is very similar to terrain-induced slug flow. The heading cycle is described in more detail in Ref. 3. When comparing the two cycles, the following observations are important. The casing in gas-lifted oil wells plays the role of the pipe upstream of the liquid plug. The gas injection choke plays the role of the plug. The tubing plays the role of the pipe downstream of the liquid plug (the riser). Finally, the production choke plays the role of the pipeline valve. The pressure cycle in the casing corresponds to that at the inlet or riser base, and the pressure cycle at the tubing outlet corresponds to that at the outlet or riser top. When gas starts to penetrate into the tubing, a blowout similar to the blowout in riser- and terrain-induced slug flow appears. For gas-lifted wells, the following apply.

- Fixed gas-injection point. The point where gas starts to penetrate into the tubing is fixed and clearly defined by design in gas-lifted oil wells.
- Unidirectional flow. There is a check valve in combination with the gas injection nozzle that makes sure the fluid does not flow from the tubing into the casing.
- Two vs. one degree of freedom for control. The gas-injection valve might be used as an extra degree of freedom for control, leading to a multivariable control problem, whereas only one manipulated variable (actuator) is available in riser- and terrain-induced slug flow problems.

A simplified model describing the dynamics of casing heading was derived in Ref. 3. This model made it possible to analyze the stability of casing heading at different operating conditions. The analysis shows that during a tubing blowout situation, the gas-lift system is exponentially unstable. This experience can be directly transferred to severe slug flow because the mechanisms in the two blowout situations are similar for the two cases. Therefore, the results from this paper can be applied to casing heading. A second use of the simplified gas-lift model is to synthesize robust controllers, taking the coupling between several variables in the system into account (see Ref. 3 for further details).

Slug Control

The intuitive approach to the problem of slug flow is to detect the slug and try to limit its size to restrict the effect it has on the separator train and compressors at the production facility. The active slug controller described here solves the slug problem by stabilizing riser- and terrain-induced slug flow in terms of a fixed profile plot of the liquid volume fraction. The method involves active actuation of the production choke, in which it is moved in accordance with a dynamic feedback control algorithm. By applying feedback control from pressure upstream of where the slug is generated, it is possible to avoid slugging with an average pipeline pressure lower than the pressure typically introduced by simple constant choking. Furthermore, it is possible to achieve a stable pipeline inlet pressure that is less than the peak inlet pressure with severe slug flow.

The present slug controller has the following main functionalities.

Slug Control.

• Dynamic feedback control to ensure stable operation of the pipeline on the basis of feedback from the pressure upstream of where the slug is generated.

• Slug choking to limit the effect the slug has on the separation and compression units on the basis of pressure feedback at the pipeline outlet.

• Feed-forward control to adjust the nominal operating point and parameters in the dynamic feedback controller, with the pipeline inlet flow rate and the mean pipeline choke opening as inputs.

• Slug controller startup condition. When the operator requests "active slug control" by selecting automatic mode, a particular startup condition has to be fulfilled before the controller starts updating the slug control valve on the pipeline.

Slug Signature. The slug signature is a calculated measure to identify liquid completely blocking the buildup of a slug. The operators are intended to use this to monitor the dynamic feedback controller's performance. The calculation is driven by pipeline inlet and outlet pressures upstream of the valve and pressure differences across the valve. These signals are filtered, the time derivatives are calculated, and both are filtered to remove noise. The filtered pressure and time derivatives are used to drive a state machine reflecting the severe slug flow cycle described in the preceding section.

Interface to Separator Train Control.

• Output to separator feed-forward control.

• Override slug control (in case of a critical situation or an error in the separator train).

Operator Interface.

• Starting and stopping the controller.
• Starting/stopping logging.
• Monitoring the performance of the feedback controller.
• Trends and graphs.
• Accessing controller parameters.

The slug controller configuration is presented in **Fig. 4,** which shows pressure measurements at the pipeline inlet and outlet are used to adjust the pipeline valve. If flow measurements are available, they may also be used for feed-forward control of the nominal operating point and for adjusting tuning parameters in the controller. The tuning parameters are gains, and they filter time constants in the feedback controller.

There are several reasons measuring the pressure upstream of the slug generation point (the liquid blockage point) is critical. First, pressure has the capability to propagate upstream as long as liquid blockage is avoided (i.e., closing the valve at the outlet has an effect on pressure in the upstream parts of the pipeline). From the control theory, it is necessary to observe any instability so the system is stable. In the blowout situation in which the tail of the slug penetrates the riser, the signs of the instability are first observed in the riser base pressure as a pressure reduction. The instability's characteristic is then a continuing pressure reduction until the slug ceases. The underlying approach to counteract the instability is to close the valve, stopping this pressure reduction. The pressure reduction propagates upstream, against the flow direction, with the speed of sound. However, downstream of the plug, in the upper part of the riser, the pressure increases until the tail of the plug has passed the observation point. When the slug tail passes the observation point in the riser, the pressure decreases; at this moment, it might be too late to apply feedback control to counteract the pressure reduction. Note that the time to slow the slug and stabilize the system gets shorter the further up the pressure measurement is located in the riser, not only because of the shorter distance to the top of the riser but also because the instability increased the velocity of the plug. Moving the pressure measurement in the opposite direction does not impose the same degree of conflict.

Slug choking, in the present version of the slug controller, consists of closing the valve when the pressure in the upper part of the riser increases. We note that this has a positive feedback effect, because closing the valve further increases the pressure. Therefore, we use a control law that has no steady-state effect from the outlet pressure to the valve. This means that slug choking only reacts on rapid outlet variations, whereas feedback stabilization reacts on slower inlet variations. The effect of slug choking has been studied with dynamic simulations in which a stabilizing effect on the pipeline flow in connection with controller startup it has been observed. One needs to close the valve rapidly to conserve the energy and then release (open the valve) the energy in a controlled manner to stabilize the pipeline during startup of the controller. Otherwise, the slug may easily carry with it too much liquid and gas to stabilize the flow.

Taming Riser-Induced Slug Flow in Deepwater Riser

In this section, we present some results from a deepwater pipeline-riser system that has been simulated with OLGA2000. **Fig. 5** shows the pipeline geometry. The total length is approximately 6.5 km, with a 5-km pipeline on the seabed and a 1.5-km-long riser. The inclination from wellhead to riser base is 1° downward slope. Sea depth at the riser base is 1320 m. A source is located at the inlet of the pipeline. The boundary conditions at the inlet are closed, and the pressure is set equal to 15 bar at the outlet. A control valve is located at the top of the riser that is used to control the multiphase flow. Two different inlet conditions have been simulated.

• The start of the production profile. The GOR is 125 Sm^3/Sm^3, and the input flow rate is set to 6000 Sm^3/D. The results from the simulations are given in Fig. 3 and **Figs. 6 through 10.**

• The GOR is 250 Sm^3/Sm^3, and the flow rate is reduced to 2000 Sm^3/D. The results from the simulations are given in **Fig. 11.**

In both cases the water cut is zero (i.e., only two-phase simulations are considered).

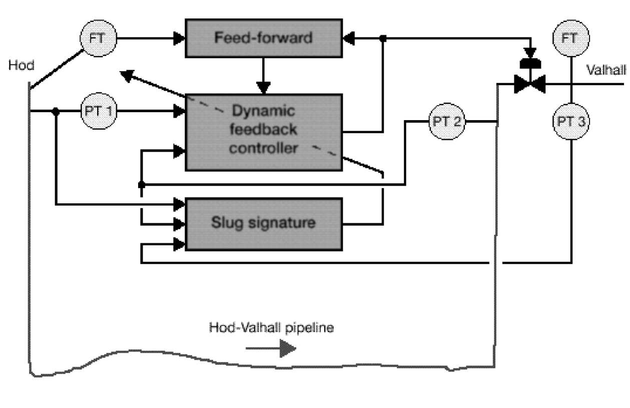

Fig. 4—Slug controller feedback structure for flow stabilization.

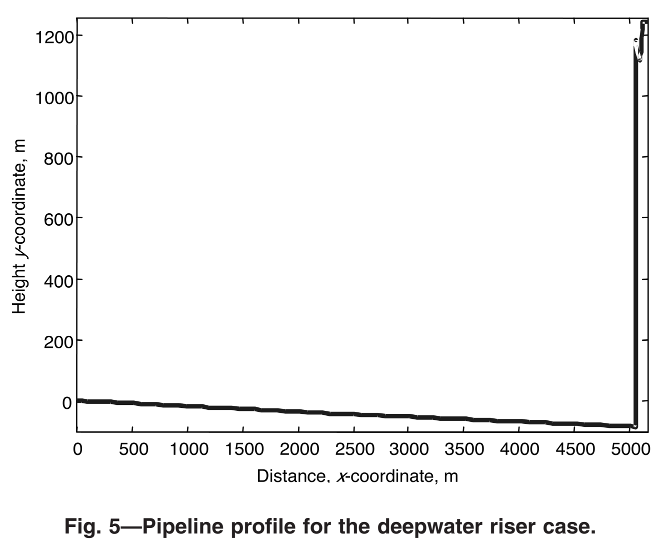

Fig. 5—Pipeline profile for the deepwater riser case.

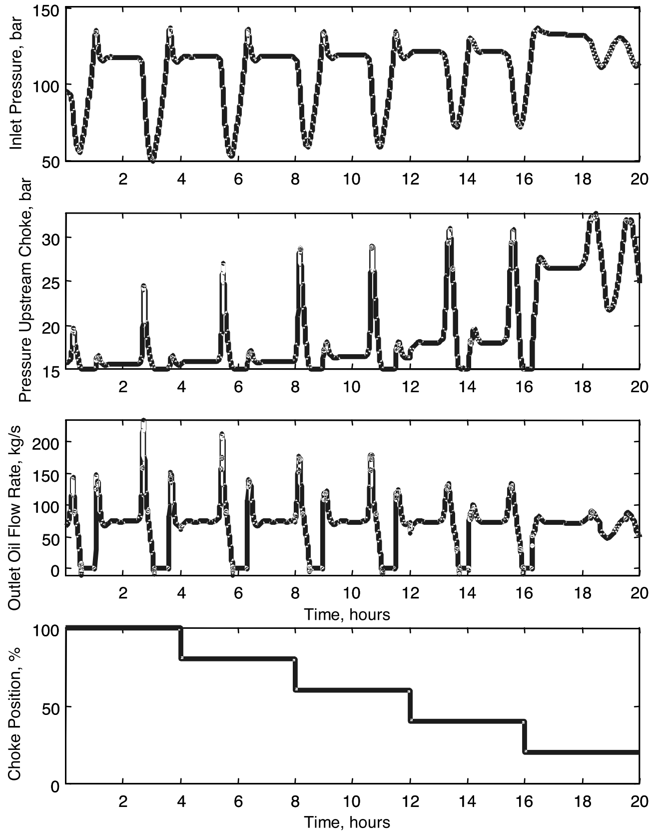

Fig. 6—Severe slugging in deepwater riser, stepwise closing the valve from 100 to 200%.

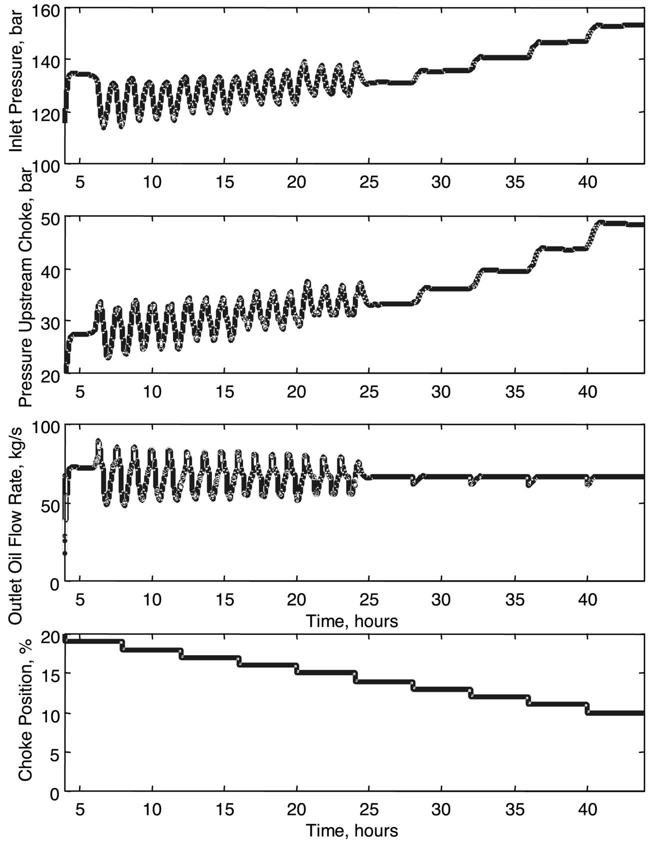

Fig. 7—Severe slugging in deepwater riser, stepwise closing the valve from 19 to 10%.

Fig. 3 shows severe riser-induced slug flow. The following facts should be noted.

• Large variations in the pipeline inlet pressure and outlet pressure.

• The outlet oil flow rate is nonzero for a large portion of the time, as opposed to terrain-induced slug flow, because the liquid plug extends far into the nearly horizontal pipeline before the riser, and it takes some time to produce the liquid in the pipeline.

• The first peak in the outlet oil flow rate is because of gas flashing in the riser. The latter, larger peak in the oil outlet flow rate is related to the riser blowout.

Fig. 6 shows the effect of a stepwise closing of the pipeline valve from 100 to 20%. To reduce the peak in the outlet oil flow rate significantly by constant choking, the valve opening needs to be closed by more than 40%. From Fig. 7 we find that to achieve stable flow conditions by constant choking, the valve opening needs to be 14% or less. The corresponding pipeline inlet pressure is 135 bar. Fig. 8 shows profile plots (900 lines lying on top of each other) of liquid volume fraction through one slug flow cycle. The profile plots are sampled every 10 seconds, illustrating the span in the amount of liquid in different parts of the pipeline. The following conclusions can be made.

• The liquid plug covers a distance of 1.3 km upstream of the riser base.

• The liquid volume fraction in the local top point in the S-shaped riser is never larger than 50%.

For the same pipeline inlet conditions, the simulations were repeated but with slug control applied to the pipeline. First, the controller is in manual with a valve opening of 70%. Then, at $t=5$ h, the slug controller is activated. The controller waits for the best startup condition to occur, which is at approximately $t=6$ h, and at this point the controller starts updating the valve. During slug control, the flow is stabilized, and from Fig. 9, the controller eventually seems to reach a constant output of approximately 43%. However, this is not what actually happens. If the controller output is magnified, it becomes clear that it constantly makes small movements (varying in the range of 43.1 to 43.2%) around its mean value. The small movements in the valve position are necessary to keep the flow stable. This is illustrated at time $t=16$ h, when the controller is put into manual mode with a fixed output of 43%. In this position, one might expect the pipeline to stay stable; however, riser-induced slug flow again builds up. We note that no other changes are made. Slug flow with approximately the same valve opening (40%) is also predicted from the simulations without control (see Fig. 6). Note that the inlet pressure with the controller in operation is lower (103 bar) than for stable flow achieved by constant choking (136 bar). Fig. 10 shows the profile plot of liquid volume fractions during slug control. The plot shows 360 profile plots 10 seconds apart. They all lie on top of each other, implying that the pipeline is indeed stable. Other important observations include the following.

• Less pressure drop over the pipeline with control than the mean pressure drop without control (this also applies to terrain-induced slug flow).

• Increased pressure upstream of the choke with control, resulting in a larger pressure drop over the valve. This is necessary to obtain an effect of the movements in the valve.

• With control, liquid plugs do not occur, only minor movements in the profile plot of liquid volume fraction can be observed during control.

All the simulations were repeated, but with the total flow rate reduced to 2000 Sm^3/D and the GOR set equal to 250 Sm^3/Sm^3. The simulation results from reducing the choke opening stepwise show that the valve opening needs to be less than 10% to achieve stable flow conditions by constant choking. The corresponding pipeline inlet pressure is then approximately 65 bar. The reason for the lower pipeline inlet pressure in this case is the larger GOR. Other observations are as follows.

• The characteristics of riser-induced slug cycles are different from the first case. From the simulation, we see that the mass transportation period with a constant outlet flow rate is also missing. Large oscillations in the inlet and outlet pressures still appear.

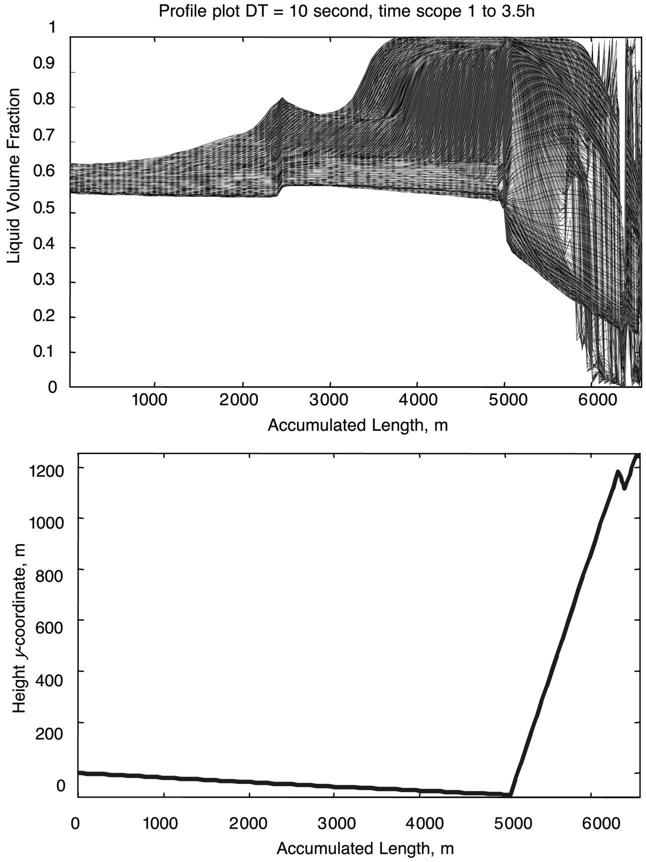

Fig. 8—Profile plots (900 lines) of liquid volume fraction through one riser-induced slug cycle.

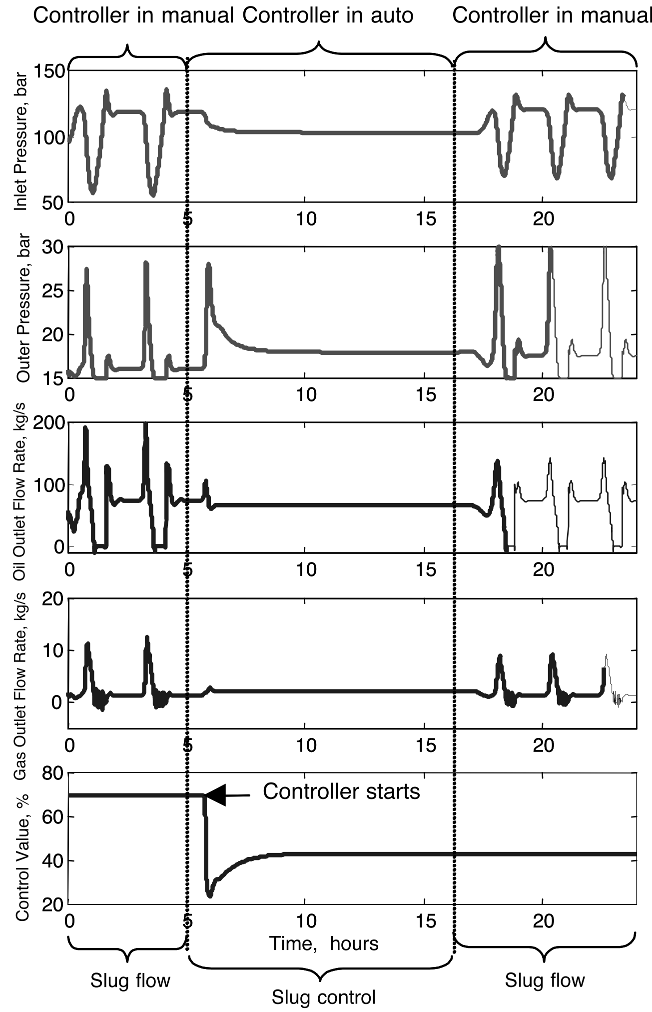

Fig. 9—Severe riser-induced slugging with slug control.

• The liquid flow rate is zero for a larger portion of the time, and the slug cycles in this case are much more similar to terrain-induced slug flow.

Fig. 11 shows active slug control for the deepwater case with an input flow rate of 2000 Sm^3/D and GOR = 250 Sm^3/Sm^3. From this figure, we see that the controller is able to stabilize the flow with the controller valve varying in the range from 34 to 35% and an inlet pressure of 41 bar, which is much less than the corresponding 65 bar that can be achieved with constant choking (10%). Other observations include the following.

• Less pressure drop over the pipeline with control than the mean pressure drop without control.

• Increased pressure, upstream choke with control, resulting in larger pressure drop over the valve. This is necessary to obtain an effect of the movements in the valve.

Taming Terrain-Induced Slug Flow in Pipelines

Hod-Valhall Site. The Hod-Valhall site consists of an unmanned, remote-controlled wellhead platform, Hod, a 13-km-long multiphase pipeline, and the main production platform, Valhall. The gas, oil, and water produced at Hod are transported through the pipeline to the Valhall platform, where they merge with the oil produced by the Valhall wells (see **Fig. 12**). The combined stream then enters the separation unit, which consists of two first-stage and two second-stage separators in parallel. At the Hod and Valhall platforms, the water depth is approximately 70 m. The pipeline diameter is 12 in., and the pipeline profile is shown in **Fig. 13.** Included in the pipeline instrumentation are pressure and temperature transmitters at Hod and a pressure transmitter upstream of the pipeline choke at Valhall. The gas and liquid flows from the Hod wells are measured separately at the outlet of a test separator before the streams enter the pipeline to Valhall. In this case, the effect of the test separator on the terrain-induced slug flow cycle is minor.

Despite the fact that the Hod platform produces less than 5% of the total produced by the wells at the Valhall platform, the slugs are large and intense enough to cause considerable operational problems in the separation unit.

• Large disturbances in the separator train, causing poor separation (water carry-over to the export pipeline because of rapidly varying separator feed rates) and varying water quality at the separator water outlets, leading to major problems in the downstream water-treatment system and possible violation of environmental restrictions.

• Large and rapidly varying compressor loads, causing inefficient compressor operation, limited compression capacity caused by a larger margin being needed to handle gas holdup behind the liquid, and unwanted flaring (a result of the limited compression capacity).

The pressure variations at the Hod end of the pipeline are also visible in the Hod wells, resulting in limited production from wells suffering from reduced lifting capacity.

Simulation Results. Fig. 14 shows the performance of the slug controller with the pipeline simulated in OLGA2000. During the first 8 hours, the controller is in manual mode, as indicated by the characteristic pressure fluctuations in the pipeline inlet and outlet pressures. The controller starts at $t = 28$ h and spends the next 5 to 7 hours stabilizing the pipeline. The controller seems to have settled at a constant output value at $t = 38$ h; however, this is not true. If the control value is magnified, it is easily seen that it moves constantly around its mean value. The controller is set to manual at $t = 45$ h, with its output equal to the mean value during the previous 3 hours. Afterward, the slug flow builds up slowly. It seems reasonable to conclude from Fig. 14 that the pipeline flow is stable at least at the input and output because the pressures are stable in these locations. However, because of the pipeline length,

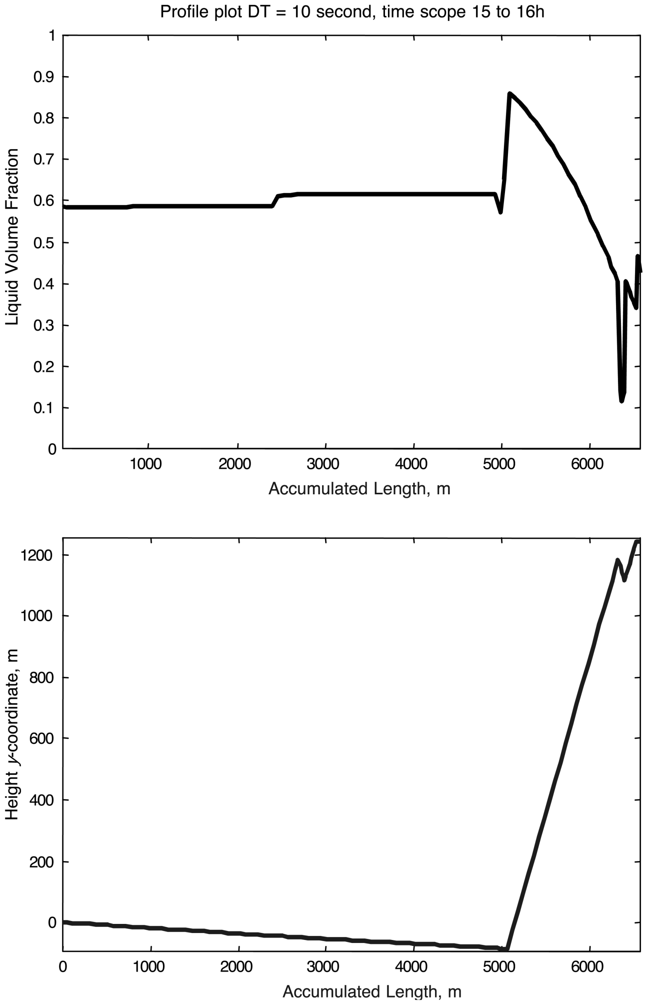

Fig. 10—Profile plots (360 lines) of liquid volume fraction with slug control.

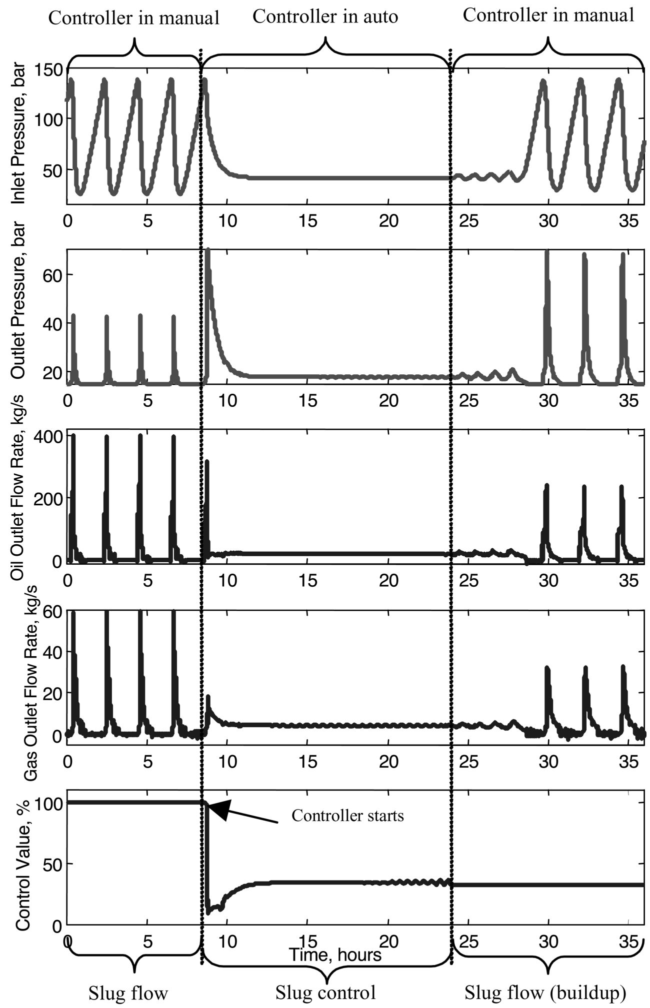

Fig. 11—Slug control applied to severe riser-induced slug flow.

it could be claimed that internal instability might occur in it. **Fig. 15** shows profile plots of the liquid volume fraction, sampled at 60-second intervals between $t=41$ and 45 h. In total, 241 plots are shown. They all lie on top of each other, implying that stability is achieved throughout the pipeline.

Field Tests. The prototype of the slug controller was tested twice in 1999 and has been operating at the Hod-Valhall site since the end of January 2000. **Figs. 16 through 23** show some of the slug controller test results. The x-axis in Figs. 16 through 23 shows the time of the day and the date. Each tick mark on the x-axis represent +4 hours, and for every three tick marks, +12 (hours) is written on the axis.

1. Figs. 16 and 17 show typical pipeline operation without slug control.
2. Figs. 18 and 19 show the controller startup and operation on low pipeline flow rate, including the startup of two wells.
3. Figs. 20 and 21 show controller startup and operation on a high pipeline flow rate.
4. Figs. 22 and 23 show controller operation, startup of a large producer, and stop on high pipeline flow rate.

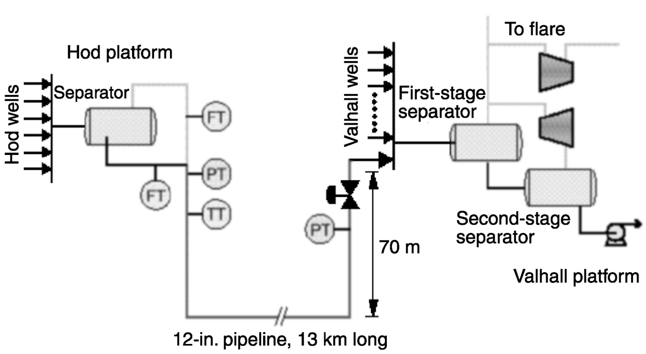

Fig. 12—Schematic of the Hod-Valhall offshore site. The pipeline instrumentation includes flow transmitters (FT), pressure transmitters (PT), and temperature transmitters (TT).

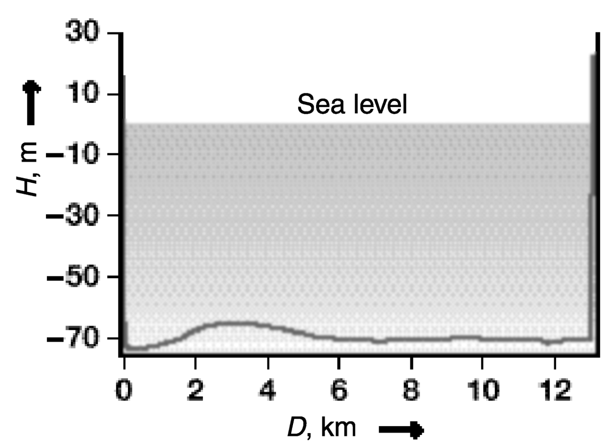

Fig. 13—Hod-Valhall pipeline profile.

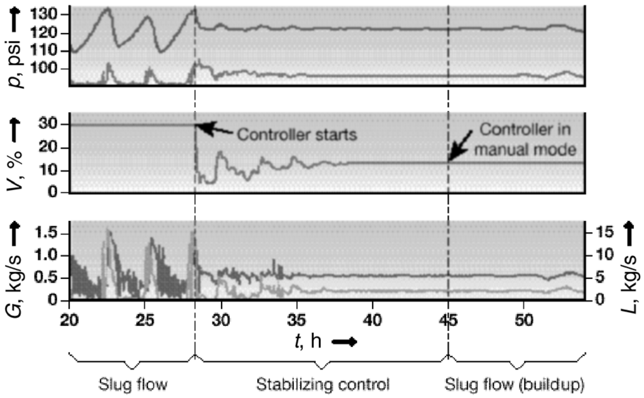

Fig. 14—Active control of terrain-induced slug flow. The controller starts up at *t*=28 h and runs until *t*=45 h, after which the valve position is kept constant and slug flow slowly builds. Pressure at pipeline inlet and outlet.

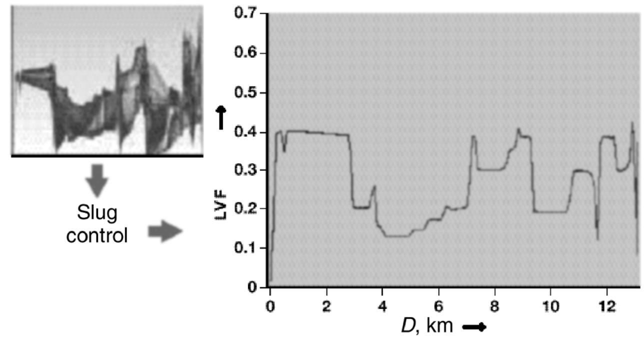

Fig. 15—Pipeline profile of the liquid volume fraction with slug control; 241 profile plots are shown. The sampling interval is 60 seconds. All lines lie on top of each other, implying that the whole pipeline is stable.

For all four cases presented, the figures show the same variables. The first figure in each case shows the pipeline inlet and outlet pressures in relation to the choke opening. The second figure shows the pipeline inlet gas and liquid flow rates. Both 30-minute and 8-hour moving averages (MA) are shown. The 30-minute MA shows that the pipeline inlet flow rates vary a lot in all cases because of slugging in the wells connected to the Hod platform.

To understand the test results, it is important to know that the wells at Hod are operated cyclically as the well's flow rate decreases over time. When production from a well has reached a lower limit, the well is put on hold. The operating and the hold times differ from well to well; some wells only remain in operation for a couple of days before being put on hold.

Figs. 16 and 17 show the pipeline in operation without the slug controller. In Fig. 16, one clearly sees the characteristic oscillations in the pressure for terrain-induced slug flow.

Figs. 18 and 19 show the slug controller in operation. During the first 8 hours, the choke (see Fig. 18) is operated manually 20% open. In this situation, we see the terrain-induced slug flow cycle. The controller is started 2 October, just after 8 a.m., and then moves the pipeline choke to 25% open, keeping it in this position until the startup condition is satisfied. At 11:18 a.m., the startup condition is fulfilled and the controller starts updating the choke, which is allowed to be only 5 to 35% open. The controller stabilizes the pipeline for the next 36 hours. From Fig. 18, the mean pipeline inlet pressure decreases with a few psi when no slug cycles appear. During the 4 days and 6 hours shown in the figures, two of the Hod wells, which have been on hold, were put into operation. The first one is put into operation 4 October at 4 a.m., and the second one on 5 October at noon. The wells' startup can be seen in Fig. 18 as large pressure spikes both at the inlet and outlet of the pipeline. A well startup is a large disturbance to the slug controller, which can introduce instability into the pipeline, and from Fig. 18, a terrain-induced slug flow cycle appears just after the first well startup. Fig. 19 shows the pipeline input flow rates. During the first 19 hours, the Hod wells bypassed the test separator, which is the reason for the missing pipeline inlet flow rates in that period. Each Hod well has its own characteristics. The frequent changes in the flow rates are caused by one well, whereas the large peaks are caused by slugging in another well. After the first well startup, the frequent changes in the flow rate become different because of interactions between the wells. The changes in pipeline input flow rates, together with well startup, are major disturbances to the slug controller. However, the slug controller handles these disturbances satisfactorily, which proves that the chosen control scheme is robust with respect to such changes.

Figs. 20 and 21 show a controller startup for a much larger mean pipeline flow rate. First, Well H8, one of the two largest producers at Hod, is put into operation. Next, the slug controller is started, stabilizing the pipeline. Experience shows that for this well, it takes only a few terrain-induced slug flow cycles before the

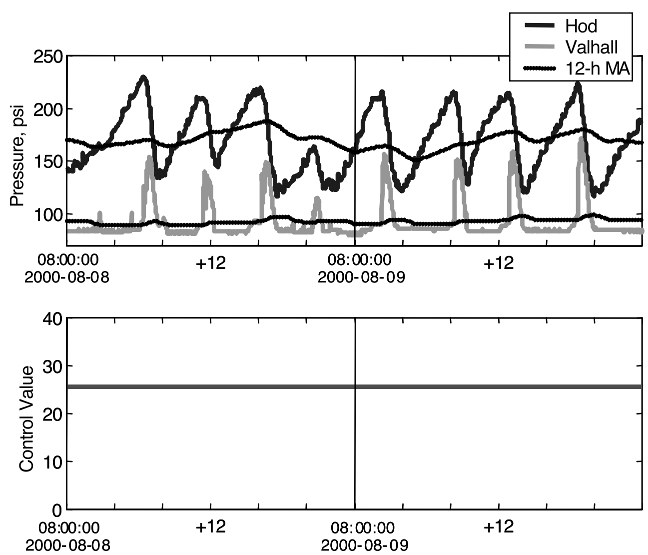

Fig. 16—Low pipeline flow rate without slug control. Pressure at the pipeline inlet and outlet and at choke position C as well as the 12-h MA of the pipeline pressures is shown.

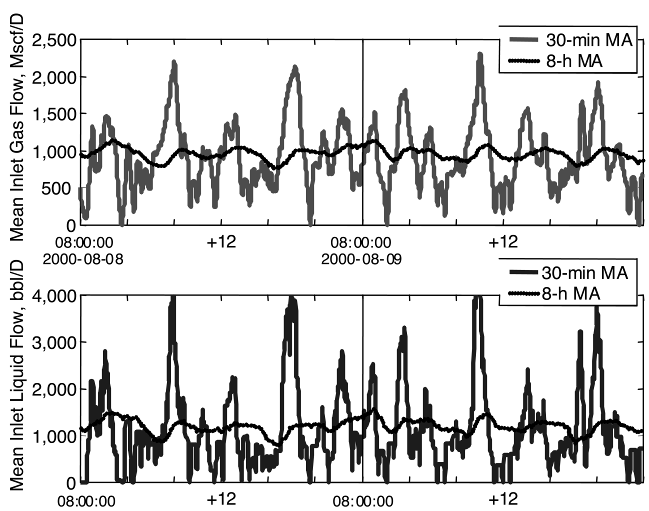

Fig. 17—Low pipeline flow rate without slug control at the pipeline inlet (Hod) for 30-min and 8-h MAs of the gas and liquid flow rates.

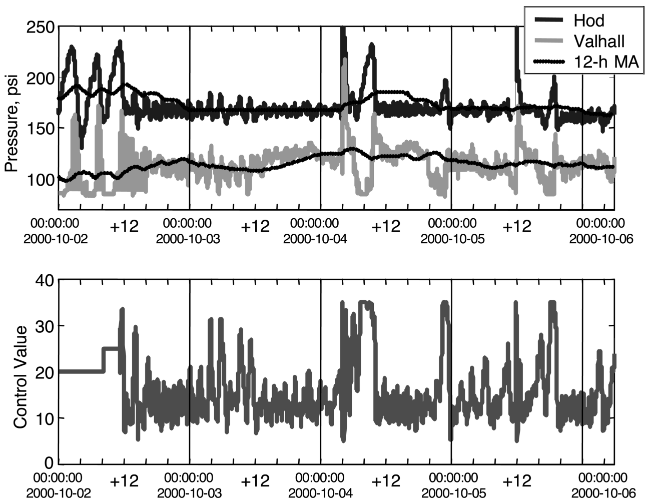

Fig. 18—Low pipeline flow rate, slug controller, and well startup. Pressure is indicated at the pipeline inlet and outlet and choke position C as well as the 12-h MA of the pipeline pressures.

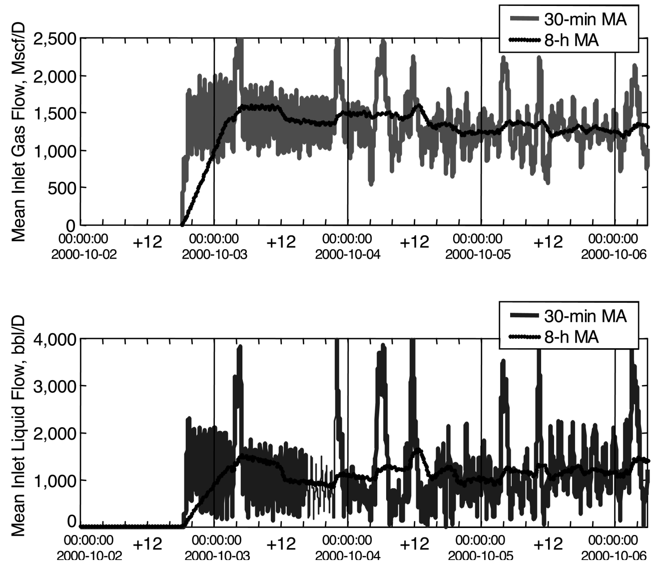

Fig. 19—Low pipeline flow rate, slug controller, and well startup with 30-min and 8-h MAs of the gas and liquid flow rates at the pipeline inlet (Hod).

production rate from the well starts to drop. After a couple days of operation, the well is normally put on hold. However, with the slug controller operating the pipeline choke, it has been verified that this well can be kept in operation longer.

Figs. 22 and 23 show the slug controller in operation. Well H8 is put into operation 1 May at 10 a.m., and the pipeline inlet flow increases and a large spike in the pressure appears. The controller is already in auto when this happens. The large pressure causes the controller to saturate at 35%. When the pressure drops, the pipeline is stable. The controller is stopped on 2 May at 8 p.m. Terrain-induced slug flow with growing amplitude in the pressure swings appears for the remainder of the time period. Also notice how the pipeline inlet liquid flow rate drops when terrain-induced slug flow appears.

Summary of Experience. ***Implications to the Hod Wells.*** The varying flow rates and the cyclic operation of the Hod platform wells make it very difficult to finally conclude to what extent the slug controller affects the Hod wells (i.e., whether the wells produce less, more, or approximately the same as before the slug controller was installed). Experience shows that it is possible to keep the wells in operation longer, thereby indirectly increasing the production by increasing the fraction of the time the wells are in operation. This is particularly true for Well H8. This well has been in continuous operation for as long as 2 weeks with the slug controller in operation, compared to a typical mean operation time of only a few days without the slug controller.

Robustness To Rapidly Varying Pipeline Inlet Flow Rate and Well Startup. The field tests so far have shown that the chosen structure in the slug controller is robust with respect to large and rapid inlet flow variations (ranging from less than 1,000 bbl/D liquid throughput to 15 to 20 thousand bbl/D) because of slugging wells. We note that very little retuning of the controller has been required during the test period and between the different test cases. Well startup also represents large and rapid disturbances to the slug controller. However, we find that the controller handles well inclusions satisfactorily. The controller output is limited within selected bounds. We think that these bounds are important tuning factors and that the selection of these is one of several key issues for robust behavior. In addition, the way integral windup is implemented is of importance. Last, but not least, the knowledge about the tuning factors combined with the process knowledge is a large contributor to success.

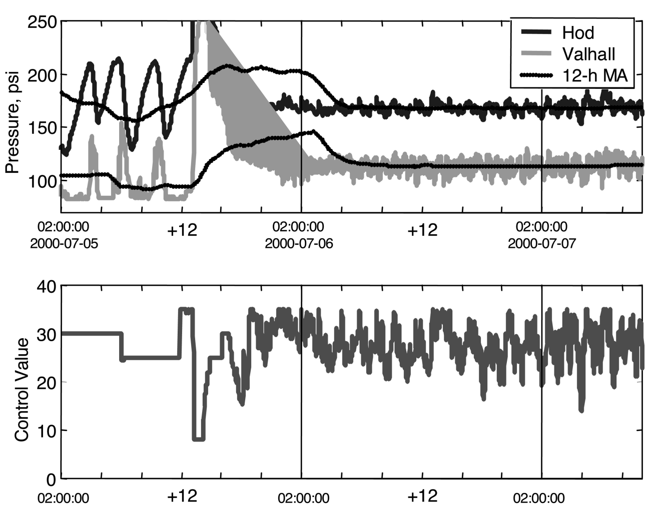

Fig. 20—High pipeline flow rate slug controller startup with the pressure at the pipeline inlet and outlet and choke position C as well as the 12-h MA of the pipeline pressures.

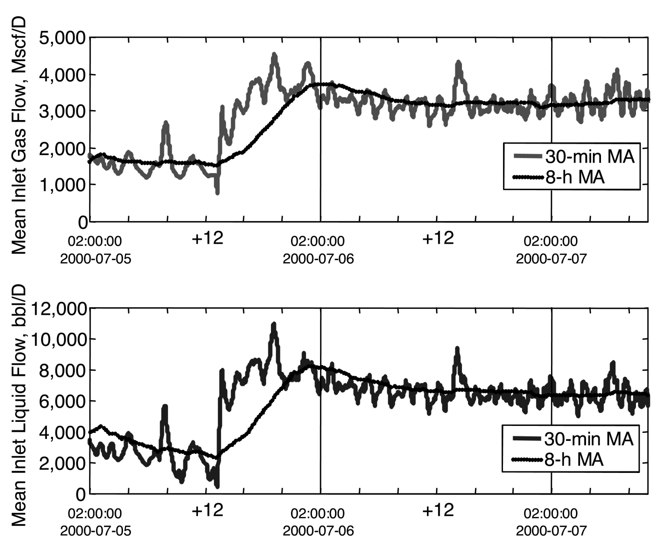

Fig. 21—High pipeline flow rate slug controller startup with 30-minute and 8-hour MA of the gas and liquid flow rates at the pipeline inlet (Hod).

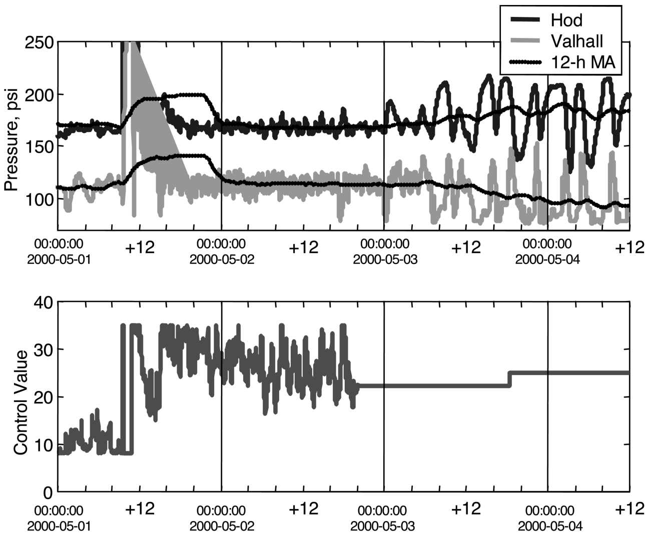

Fig. 22—High pipeline flow rate with slug control, well startup, and controller stop. Pressure at the pipeline inlet and outlet and choke position C as well as the 12-h MA of the pipeline pressures.

Occasional Slugging. Despite the controller's robustness to rapid changes, slugs appear occasionally. One theory is that the more stable flow condition resulting from active slug control may cause the water to be separated out and generate infrequent water slugs. This theory has been partly verified by a sudden increase in the water produced in the period following the such an occasional slug in the pipeline. To handle such events in a robust manner, the slug signature is implemented, which restarts the controller in the event of a severe slug (see Fig. 4). This approach has been tested manually, and it has been verified that such action results in a stable pipeline after controller restart.

Benefits of Applying Slug Control to the Downstream Production Plant. Additional benefits that the slug controller has brought to the Valhall production facility include the following.

- Smaller disturbances in the separator train, resulting in smoother operation, including improved separation and larger throughput.
- Smoother compressor operation, including increased compressor operational stability and reduced flaring.

By considering the stable inlet and outlet pipeline pressures and the insights provided by the multiphase flow simulation, it is reasonable to state that the slug controller greatly improves the stability of multiphase flow in the pipeline.

Conclusions

It has been known for some time that riser base pressure control can stabilize riser-induced slug flow. In this paper, we have demonstrated that severe riser- and terrain-induced slug flow can be stabilized with dynamic feedback control of the pipeline inlet pressure to a pipeline valve at the outlet. We have argued that moderate choking, triggered by a rapid pressure increase in the pipeline outlet, can improve stability and the robustness of the control scheme. Simulations have been used to verify this. From plots of inlet and outlet pressures in the simulations and field tests, it seems reasonable to state that the pipeline is stable at these two points at least. Profile plots of the liquid volume fractions in the simulations with control imply that the whole pipeline is stable. The actual minimum achievable pipeline inlet pressure depends on the inlet flow rate and the GOR (water cut). It has been shown in the case studies that this pressure is much less than the corresponding one achieved by constant choking and the peak inlet pressure with slug flow. This reduction in inlet pressure has great impact on the operation of the wells connected to the pipeline. For wells with a reduced lifting capacity, the variation in the pipeline pressure can cause the well to stop producing.

Besides demonstrating how active feedback control can be used to avoid riser- and terrain-induced slug flow without reducing oil production, the tests with the prototype algorithm further proved the beneficial effects that exist for applying active feedback control to multiphase fluid flow processes.

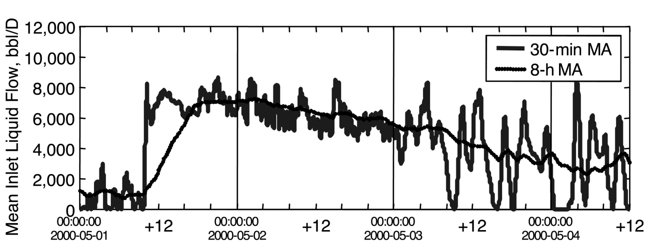

Fig. 23—High pipeline flow rate with slug control, well startup, and controller stop with 30-min and 8-h averages of the liquid flow rates at the pipeline inlet (Hod).

Nomenclature

D = distance, km
G = gas flow rate, kg/s
L = liquid flow rate, kg/s
p = pressure, psi
t = time, s, h
U_{sg} = superficial gas velocity, m/s
U_{sl} = superficial liquid velocity, m/s

Acknowledgments

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SI Metric Conversion Factors

bar × 1.0*	E = +05	=	Pa
bbl × 1.589 873	E–01	=	m^3
ft^3 × 2.831 685	E–02	=	m^3
in. × 2.54*	E+00	=	cm
psi × 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Kjetil Havre is currently a principal consultant for Scandpower Petroleum Technology AS. He was formerly employed by the Inst. of Energy Technology and by ABB Corp. Research as a research engineer. His interests include modeling and control of unstable systems, particularly multiphase flow and mathematical system theory. Havre holds a PhD degree in process control theory from Norwegian U. **Morten Salsmo** is currently a product manager for active well control for ABB Norway and is also acting as the program manager in the PETRONICS research program that involves five research institutes at Norwegian U. of Science and Technology. His interests include modeling and control of multiphase flow. Dalsmo holds a PhD degree in engineering cybernetics from Norwegian U.