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Removal of Heavy Slugging in Subsea Wells by Automatic Control

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SUMMARY

This paper reports field observations and simulation results from the StatoilHydro operated Åsgard fields offshore Norway. Heavy slugging from a well resulted in large variations in downhole pressure and topside rates and temperature. An OLGA study was performed on the well-pipeline system trying to reproduce the heavy slugging. A new application of slug control was developed and implemented offshore to remove heavy slugging in a remote subsea well. Downhole pressure measurements were utilised in a control loop. Both the topside choke and the subsea well head choke were found to be good candidates for slug control. The implemented solution gave very good results as the pressure variations downhole were reduced from more than 30 bars to less than 1 bar with only very small adjustments by the chokes. The implemented solution opens up possibilities for increased production and recovery from this and similar fields.

INTRODUCTION

New technologies open up possibilities for more cost effective production of oil and gas from offshore fields. One such technology is slug control. Oil and gas fields offshore Norway are typically developed by subsea templates with long multiphase tie-in lines to existing infrastructure.

Heavy Slugging An important problem in oil and gas production from some satellite fields is heavy slugging. This is observed at the receiving processing platform as significant variations in pressures and flow from the satellite field. Heavy slugging is characterised by periods with almost zero liquid flow followed by periods of very high liquid flow (slugs). During heavy slugging the pressure in the flow line can vary in the range of several tens of bar depending on liquid density and geometry. The largest variation in pressure in a pipeline-riser system will be in cases where the riser is completely filled by liquid for a period followed by a period of only gas in the riser. The pressure variations at the seabed are mainly caused by the difference in weight between the liquid filled and the gas filled riser. For example, for a 200 m high riser with a liquid density of 600 kg/m3 and gas density of 100 kg/m3, the pressure variation at the riser base will be approximately $\Delta\rho \bullet g \bullet h = (600-100) \bullet 10 \bullet 200$ Pa = 10 bar. Heavy slugging can cause operational problems to the downstream facilities, such as high or low level or pressure in a separator. Heavy slugging can be generated in gravity dominated systems with low velocities, either in a well, a flow line with a vertical riser or an inclined line to shore with local low points.

Hydrodynamic Slugging Often, the slug patterns are not so heavy, but characterised by shorter slugs moving after each other up the riser. This slug pattern is typical for the StatoilHydro operated fields Gullfaks and Heidrun and others, and the pressure subsea typically varies less than one bar. The pressure variations are smaller since the slugs are shorter, but also because typically several slugs are travelling up the riser at any time. This is known as a slug train. The slug train pattern will attenuate the pressure variations. Such shorter slugs are often a result of hydrodynamic slugging in the flow line. Several hydrodynamic slugs can be combined into longer slugs in a rugged terrain with local ups and downs. Hydrodynamic slugs typically appear at higher velocities.

Slug Avoidance Heavy slugging can be avoided by design or operational changes. The most common solution is to choke back the production to get out of the heavy slug flow region resulting in reduced production. Smaller diameter pipelines can also reduce slugging, but will restrict the production by increased pressure loss. The installation of several pipelines in parallel can be one expensive solution to increase the capacity. Another expensive solution often used on-shore is to install a big slug catcher at the receiving facilities.

Slug Control Slug control is an inexpensive and efficient tool that is applicable for design of systems, where heavy slugging can be expected. Active use of the topside choke has been shown to prevent heavy slugging in several industrial installations as well as in laboratory experiments and OLGA® simulations. The goal of a slug controller is to prevent heavy slugs from developing. Slug control has been applied on pipeline-riser systems and gas lifted platform wells. The first reported applications of slug control were

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based on pressure measured upstream the slug formation point. A feedback controller stabilised this pressure at its set-point and removed the heavy slugging by adjusting the opening of a topside control choke.

Theoretical and experimental work on riser slugging removal by active control started in the late seventies, with the work of Schmidt et. al. (1979). Hedne and Linga (1990) ran the first large scale experiments on slug control in cooperation with StatoilHydro at Sintef's Multiphase flow laboratory. They showed how riser slugs can be removed by feedback control. Courbot (1996) reported a field installation, where automatic control of the subsea pressure stabilised the flow by manipulating the topside choke. Later a number of slug control systems have been developed and set into operation (see e.g. Hollenberg et.al. 1995, Henriot et.al. 1999; Havre et.al. 2000; Havre and Dalsmo 2002; Konvalev et.al. 2003) The first offshore application in StatoilHydro was at the Heidrun platform offshore Norway for the two Heidrun Northern Flank tie-ins in 2001 (Skofteland and Godhavn 2003). This application included flow control, which efficiently attenuated shorter slugs (slug trains). Slug control experiments were performed in 2001 (Skofteland and Godhavn 2003) and 2002 (Godhavn et.al. 2005). A low-dimensional dynamic model was developed by Storkaas et.al (2003) for control analysis. At Tordis (Godhavn et.al. 2005) slug control and model predictive control were combined for improved slug handling in the topside separators. A slug control study was also part of the Tordis subsea separation development (Sivertsen et.al. 2005 and 2006). The latest development has been called extended slug control. This has been included in the design of the 43 km tie-in Tyrihans (Storkaas and Godhavn 2005) and set into operation for the 9 km tie-in Urd.

At this point it could be appealing to conclude that the problem of heavy slugging removal from satellite fields is solved. This is supported by the extensive experience from StatoilHydro's field installations in continuous operation since 2001. However, autumn 2005 the StatoilHydro operated Åsgard A platform faced a slugging problem that could not be readily solved. Typical flow patterns indicating heavy slugging were observed. Long periods of merely liquid from the pipeline were followed by shorter periods of

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only gas. Pressure variations of more than 10 bars were observed at the subsea template 13 km away from the Åsgard A production ship. The production from well Q2-AH was hampered. The StatoilHydro R&D Integrated Operations and Process Control group was contacted in order to come up with up a solution for slug suppression.

Deleted: OLGA® simulations had been performed in the design phase for the field, and here a potential for riser slugging was identified for low production rates. However, no potential for heavy well slugging was identified in the dynamic simulation study. It turned out later that the actual well geometry was different from the planned geometry used in the OLGA® well model. This might be an explanation for the unidentified potential for heavy slugging from the well.¶
Simulations with active slug control showed that the identified riser slugging could be removed by feedback control. However, it was decided to wait and see if it was necessary to install a slug control system. The inlet and test separators at Åsgard A are large and able to handle quite long slugs.

ÅSGARD

The overall Åsgard project ranks as one of Norway's giant offshore developments, on par with Ekofisk and Troll. The StatoilHydro operated Åsgard fields lie on the Halten Bank in the Norwegian Sea, about 200 kilometres off mid-Norway. It comprises the large Midgard, Smørbukk and Smørbukk South discoveries. The oil and gas is processed at the Åsgard A production ship since 1999 and the Åsgard B platform since 2000. The Åsgard C storage vessel is also a part of the Åsgard fields. The world's largest set of subsea production installations has been placed on the fields, embracing a total of 52 wells drilled through 16 seabed templates. The partners in the Åsgard fields are Petoro (35.69%), StatoilHydro (34.57%), Eni (14.82%), Total (7.6 %) and ExxonMobil (7.24%).

The Åsgard Q project involves the installation of a third template (Åsgard Q) on the Smørbukk South deposit (**Fig. 1**), tied back to the Åsgard A production ship. Åsgard Q is expected to produce an additional 26 million barrels of oil. This project was one of the fastest subsea developments on the Norwegian continental shelf, taking just over a year to complete from decision to first oil production.

FIELD RESULTS

Problems with heavy slugging started shortly after start-up of production from the Q2-AH well transported in the Q-102 pipeline. Large pressure variations in the well were a major concern for both the reservoir and the production engineers. High pressure could kill the well and low pressure could also be damaging. The operators were also concerned about low temperatures in the pipeline during periods with low flow rates, with a minimum close to the hydrate temperature. A solution for slug removal using active control was therefore desired. A more detailed description of how this slug control system was set into operation is given in Skofteland et. al. (2007).

Field measurements of the large pressure variations without active control are shown in **Fig. 2**. Here the topside choke opening is fixed at 53%. The downhole pressure varies as much as 40 bar (220 - 260 bar). The pressure at the seabed downstream the subsea choke varies between 85 and 98 bar, while the pressure upstream the topside choke varies between 58 and 74 bar. All pressures in are given in bar gauge.

Fig. 1 illustrates three possible slugging initiation points that have been identified from the well-pipeline-riser system. The field measurements (Fig. 2) show a high frequent and low amplitude slugging cycle that could originate from the low point in the S-riser. The typical period is 5 minutes and a 1 bar pressure variation is seen downstream the subsea choke. This slugging may also be hydrodynamic slugs generated in the flow line. A medium frequent and medium amplitude slugging cycle is expected to originate from the riser base. Here the typical period is 30 minutes and the pressure variation is 5-10 bar downstream the subsea choke. This can be seen in **Fig. 2** for the period 03:00 – 06:00 06.11.2005. The most heavy, low frequent and high amplitude slugging cycle originates from the well with a typical period of 6-7 hours between each slug and 20-40 bar variation in the downhole pressure. This heavy slugging could originate from accumulation of liquid in the low point in the well as shown in **Fig. 1**. It could also be accumulation in a near well section of the reservoir.

The slug control solution for Åsgard Q is based on standard feedback control using the same PID (Proportional, Integral and Derivative) control software used on the topside control system for control of temperature, level, flow, pressure, etc.

The basic slug controller is a standard PID (proportional and integral, here with no derivative term) controller,

$$u = u_P + u_I .$$

The controller output u, the commanded choke position, is given by the sum of a proportional term u_P and an integral term u_I given by

$$u_P = K_p\left(p - p_{ref}\right)$$
$$u_I = \frac{K_p}{T_i}\int\left(p - p_{ref}\right)dt ,$$

where K_P is the controller gain, p is the measured inlet pressure, p_{ref} is the desired (reference) pressure, and T_i is the integral time. The proportional term increases if the difference between the measured and the reference pressure increases, while the integral term will increase as long as the measured is higher than the reference pressures. In this way, the slug controller will adjust the choke opening to avoid pressure build-up and liquid accumulation in the flow line. For slug control, the measured pressure should be taken from upstream the slug is generated and the choke should be located downstream this point.

The slug control application at Åsgard Q had three special features: the long distance (13 – 17 km) between the measurement and the actuator; the use of downhole pressure measurements in a well; and the use of a subsea choke. Several combinations of measurements and chokes have been applied, and these will be described below. This system was brought into operation in September - December 2005.

Flowline Pressure Control Using the Topside Choke. First, it was assumed that the pressure and flow variations described above stemmed from heavy slugging in the pipeline-riser system (riser slugging). The standard solution to remove riser slugging was, therefore, initiated first: A conventional PID controller was implemented to regulate the subsea pressure (downstream the subsea choke) to its set point by means of the topside choke. StatoilHydro has considerate experience with this from earlier projects. This control scheme was able to stabilise the subsea pressure as shown in **Fig. 3**. The pipeline pressure downstream the subsea choke variations were reduced to less than 2 bar (92 - 94 bar). According to StatoilHydro's 15 years of experience it should also stabilise the flow. Nevertheless, the operators offshore reported that the flow out of the riser continued to vary between gas and liquid. This slugging cycle was also seen on the pressure upstream the topside choke. Why did this happen? Was it the long distance between the controlled variable (pressure at subsea template) and the topside choke? This hypothesis was discarded, since the pressure variations subsea could be controlled with a maximum deviation of +-1 bar. A more likely explanation would be that the heavy slug pattern stemmed from the well itself. And indeed, the downhole well pressure measurements supported this. The pressure variations in the well varied more than 30 bars in periods of six - seven hours (**Fig. 2**) without active control, and the variations were only slightly reduced (220 – 250 bar) by regulating the pressure at the sea bed (**Fig.** 3) with active control. Hence, it can be concluded that the slugging continued in the well. The choke opening varied between 20 and 70 %.

Downhole Pressure Control Using the Topside Choke. A new control philosophy was proposed to solve the problem, where the pressure measured down hole in the well itself (**Fig. 4**) is controlled. This pressure transmitter is located 4 km below the sea floor (true vertical depth) and almost 18 km from the choke at the outlet of the pipeline topside at Åsgard A. The control loop remained unchanged except for some adjustments of the controller parameters. The results were remarkably good as shown for the first 6 hours to the left of **Fig. 4**. The downhole well pressure was stabilised promptly to its set point (229 bar) and the topside choke position converged to about 33%. The variations of rates, temperatures and pressures both subsea and topside were significantly reduced. **Fig. 4** also illustrates a test that was performed to show that the controller was stabilising what is called an open loop unstable equilibrium. By open loop unstable it means that the pressure will start to oscillate if the controller is turned off. The equilibrium would be open loop stable if the pressure in the well remained stable (without oscillations) with the choke in a fixed position (deactivated controller). Initially the downhole pressure was stabilised at 229 barg with a choke opening of about 33%. A new instability grew immediately, when the control was deactivated at 12:00 and the inlet pressure and other variables started to oscillate severely at once. The slug control stabilised the flow when turned on again 9 hours later at 21:00. It could then be concluded that the equilibrium was open loop unstable. The only remaining variations were the fast (5 minute periods) slugging, that can be induced in the S-riser or be a result of hydrodynamic slugging in the flowline.

This is the first case reported, where a subsea oil and gas production well without gas lift and with heavy slugging is stabilised by active control. Mere use of the downhole pressure measurement and automatic control by manipulating the topside choke gave good results. It is also, to the knowledge of the authors, an extension for the range (distance from controlled pressure to choke) of active slug control. Here the topside choke (located at the outlet of the well-pipeline-riser system) controls the inlet pressure (located down hole in the well), and between these there is a 13 km flow line with a 340 m high riser and a 6 km long well more than 4 km deep!

Downhole Pressure Control Using the Subsea Choke. The next challenge was to come up with a control solution that could handle a case with several wells producing into the same pipeline, possibly with simultaneous heavy slugging in several wells at the same time. It would be practically impossible to use the topside choke and a single PID controller to control two or more downhole pressures. **Fig. 5** shows the proposed solution, where the subsea wellhead choke is used actively in feedback control. This has not been reported before to the knowledge of the authors. The subsea choke is closer to where the well slugs are being formed, and therefore a preferred candidate for active control of well slugging. After some discussions related to whether the subsea chokes would work and not be worn out in a control loop, a new PID controller was implemented, tuned and set into operation. **Fig. 5** shows the results for the first two days with the new control solution. Initially the flow was stabilised using the downhole pressure and the topside choke. At about 9:00 the control was switched from the topside choke to the subsea choke. At about 13:00 the process shut down. This was not related to slugging or slug control. The subsea choke was used to stabilise the flow after the start-up. The downhole pressure is stabilised at 225 bar, using the subsea choke. The topside choke ran in manual. Pressures upstream and downstream the subsea choke and upstream the topside choke were also stabilised.

DYNAMIC SIMULATIONS WITH OLGA®

The slugging potential was evaluated prior to start-up in an OLGA® simulation study, where the slug tracking option was used. The simulation results indicated that the slugging potential for the Åsgard Q field was relatively moderate. The production forecast for the Åsgard Q-102 pipeline was dominated by liquids in the first few years, with a gradual transition to gas dominated flow. The simulations prior to start-up predicted that short hydrodynamic slugs were expected at nominal rates. These flow variations were not considered to be a problem for the topside process facilities with a quite large inlet separator. Simulations also showed that riser slugging was expected for low rates (below 60% of nominal rate). However, no potential for heavy well slugging was identified in the dynamic simulation study.

The actual well geometry turned out to be different from the planned geometry used in the OLGA® simulations prior to start-up. The actual well geometry has a low point in the horizontal section of the well with a potential for liquid accumulation at low rates. This was a possible explanation for the unidentified potential for heavy slugging from the well. Therefore, a new set of OLGA® simulations were run with the updated well geometry integrated with the Q-102 pipeline. The goal for this study was to see if OLGA® could reproduce the heavy well slugging and if the slug control system could remove this slugging similarly to what was achieved offshore.

A parametric OLGA® study with variations in the following parameters were carried out: reservoir pressure, productivity index, GOR and interfacial friction. The oil rate inflow to the well from the reservoir is modelled in OLGA by

$$Q_{oil} = ProdI \cdot (P_{res} - P_{dh}),$$

Where Q_{oil} is the oil rate, *ProdI* is the productivity index, P_{res} is the reservoir pressure and P_{dh} is the downhole pressure. An increased productivity index (*ProdI*) makes the inflow more dependent on the well pressure, reduced GOR reduces the gas rate, while a change in the tuning coefficient for the interfacial friction factor between liquid and gas will change the hold-up in the well and the pipeline.

Nominal. This OLGA® simulation used the assumed values for reservoir pressure and GOR. The *ProdI* was tuned to get the same rate as offshore and the friction tuning coefficient was set to its nominal value (1.0). **Fig. 6** shows the results of this simulation. Both the topside and the subsea chokes were 100% open. It can be seen that the downhole pressures varies approximately 20 bar, while the wellhead pressure varies approximately 10 bar with a period of about 25 minutes. The flow into and out of the well vary much less than the flow out of the flow line, hence, it was concluded that in this case OLGA® predicts riser slugging and not heavy well slugging. This riser slugging period corresponds well with the riser slugging experienced in field (as seen in **Fig. 2** for the period 03:00 – 06:00 06.11.2005).

Interfacial friction tuning. Two OLGA® simulations were run with both increased and decreased interfacial friction. The other parameters were kept as in the nominal case above. Both decreased and increased interfacial friction resulted in similar severe riser slugging as for the nominal case, with a period of 25 minutes. This parameter has therefore limited effect on the slugging potential in this case.

Reduced gas rate. A simulation was run with the same oil rate, but reduced gas rate (50% of nominal). The results were similar severe riser slugging as for the nominal case, with a period of 25 minutes.

Productivity index. A simulation with an increased productivity index was run. The reservoir pressure was reduced accordingly to get the same oil rate as in the nominal case. The result was similar severe riser slugging as for the nominal case, with a period of 25 minutes.

Reduced rate. Two simulations with reduced rate (about 30% of nominal rate) were run, one with low *ProdI* and nominal reservoir pressure and one with nominal *ProdI* and reduced reservoir pressure. **Fig. 7** shows the results of the simulation with low *ProdI*. Both the topside and the subsea chokes were 100% open. It can be seen that the slugging is more severe than in the nominal case with bigger slugs. The downhole pressure varies approximately 30 bar, while the wellhead pressure varies approximately 12 bar with a period of 70-90 minutes.

Parametric study conclusion. None of the simulations above reproduced the severe well slugging as observed in the field. Several other simulations were also run to try to recapture the heavy well slugging. A set of simulations of only the well (no flowline) gave very little slugging, even with an increased well diameter and low rates.

Slug control. Slug control was tested on all the cases above. A PID controller was able to stabilize the downhole pressure and remove the severe slugging in the well by active use of the topside choke for all the cases. **Fig. 8** shows the results from a simulation of the nominal case with active slug control. It is seen that the downhole pressure is kept almost constant at the set point (227 bar). **Fig. 9** shows the results from a simulation of the low rate case with low *ProdI* with active slug control. It is seen that the downhole pressure is kept almost constant at the set point (245 bar). In both cases the severe slugging has been removed effectively by slug control.

FUTURE WORK

The control system presented in this paper was developed for Åsgard Q. The solution can be generalised for other fields with a number of control loops for various control challenges. A control solution for a network of wells, pipelines and risers is shown in **Fig. 10**. Here subsea chokes are used to remove heavy well slugging by controlling the downhole pressures in each well, while the topside chokes are used to remove riser slugging by controlling the manifold pressure at the inlet of each pipeline. Multiphase meters have become more common for new wells both topside and subsea, e.g. for the StatoilHydro operated Heidrun field. Measurements of gas, oil and water rates from these meters can also be utilised in automatic control loops as shown in **Fig. 10**.

This application of automatic control goes beyond slug control, and enters the region of oil and gas production optimisation. By applying this method a reservoir or production engineer can control and adjust the downhole pressure in the well to optimise the production. He is enabled to operate the well closer to the limits defined for example by the bubble point pressure.

Our hypothesis for the source of the severe slugging reported in this paper is that the liquid accumulation and pressure build-up seen in the field takes place upstream the well, i.e. in a near well section of the reservoir. Sagen et. al. (2007) introduces a coupled dynamic reservoir and pipeline model. They show simulation results for a well similar to the one in this paper, with a coupled model of a well and a near well reservoir. The simulation of the coupled model results in severe slugging due to gas-coning in the reservoir and varying gas-oil ratio in the influx to the well, while a simulation with constant productivity index (no reservoir model) results in no slugging. The severe slugging has a period of 6-7 hours, the same as we experienced at Åsgard Q. A coupled model of the near well reservoir and the well-pipeline-riser system will be investigated to see if that can reproduce the heavy slugging observed in the field.

CONCLUSION

This paper reports field results of heavy slugging from a subsea well. An extensive OLGA parametric simulation study resulted in severe riser slugging at low rates, but we were not able to recapture the heavy slugging in the simulations. The proposed explanation is that the heavy slugs accumulate upstream the well, i.e. in the near-well reservoir. This was outside the scope for the OLGA simulation study.

In this paper the application of slug control has been extended into deep wells and longer distances. Results from the Åsgard fields demonstrate that it is possible to stabilise wells by controlling the downhole pressure by using a PID controller and by manipulating either the topside or the subsea choke. Heavy slugging from the well was removed by feedback control. Stabilisation of the downhole pressure opens up for increased production and recovery of oil and gas, since it is possible to produce close to actual constraints, for example, bubble point pressure, max sand free rate and hydrate temperature. Reduced start-up time can be achieved by avoiding large variations in pressure, rate and temperature. A slug control solution for a network of wells and pipelines has also been presented.

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FIGURE CAPTIONS

NB! Figures 1-9 shall be in color!

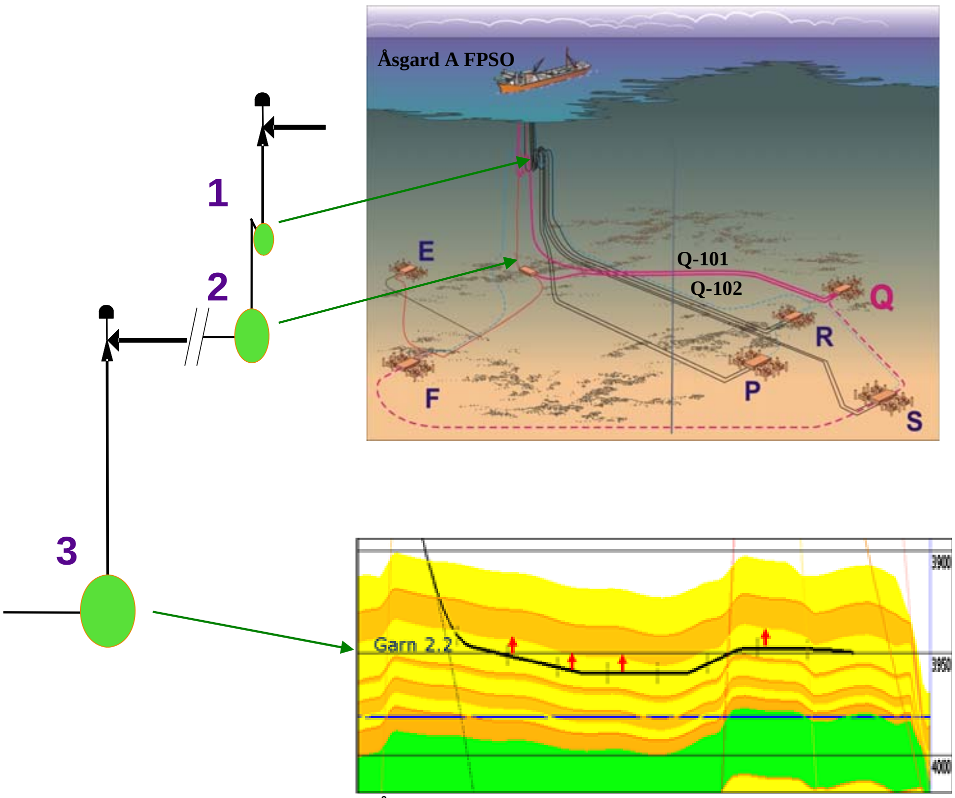

Fig. 1 — The Q template is tied back to Åsgard A (Illustration: StatoilHydro). Three types of slugging have been identified from the well-pipeline-riser system: 1. A high frequent (5min) and low amplitude (1 bar) slugging cycle could originate from the low point in the S-riser or the flowline. 2. A medium frequent (30 min) and medium amplitude (5-10 bar) slugging cycle could originate from the riser base. 3. A low frequent (6-7 hours) and high amplitude (20-40 bar) slugging cycle could originate from the well or near-well reservoir. The well profile for Q2-AH has a low point. The true vertical depth for the well is 4 km and the length is 6.1 km. A downhole pressure sensor is located at 3.9 km true vertical depth.

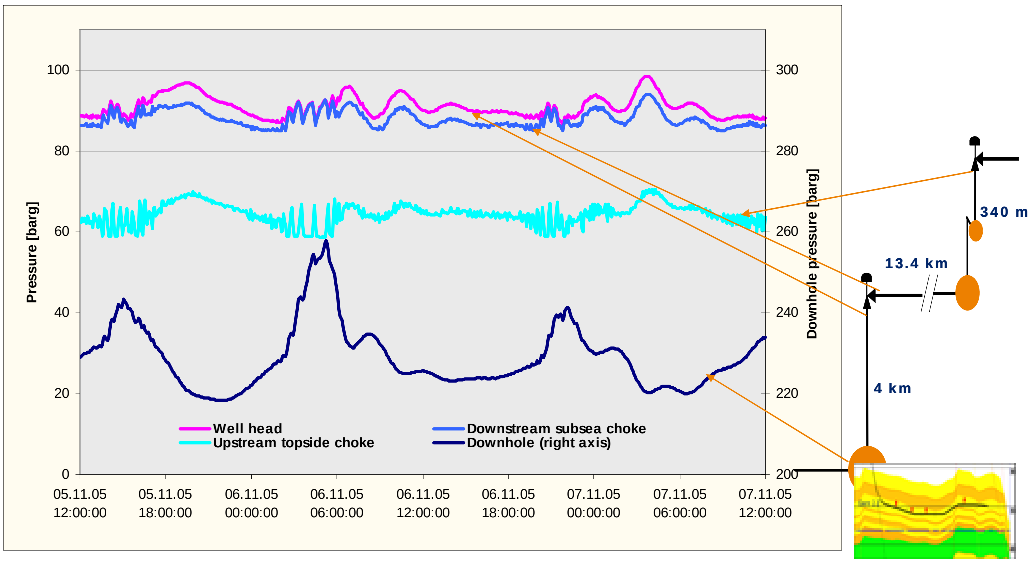

Fig. 2 — Field case with large variations without active control: downhole pressure (dark blue line, right axis), pressure up- (blue line, left axis) and downstream the subsea choke (pink line, left axis), and pressure upstream the topside choke (cyan line, left axis).

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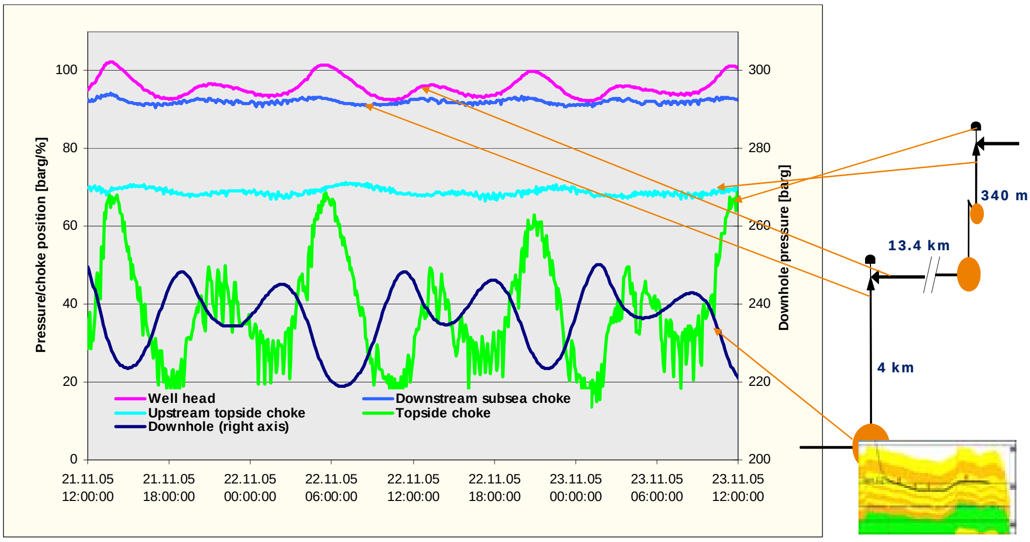

Fig. 3 — Field case with active slug control of pressure downstream subsea choke using the topside choke: pressure downstream subsea choke (blue line, left axis), downhole pressure (dark blue line, right axis), pressure upstream topside choke (cyan line, left axis), wellhead pressure (pink line, left axis), and topside choke opening (green line, left axis).

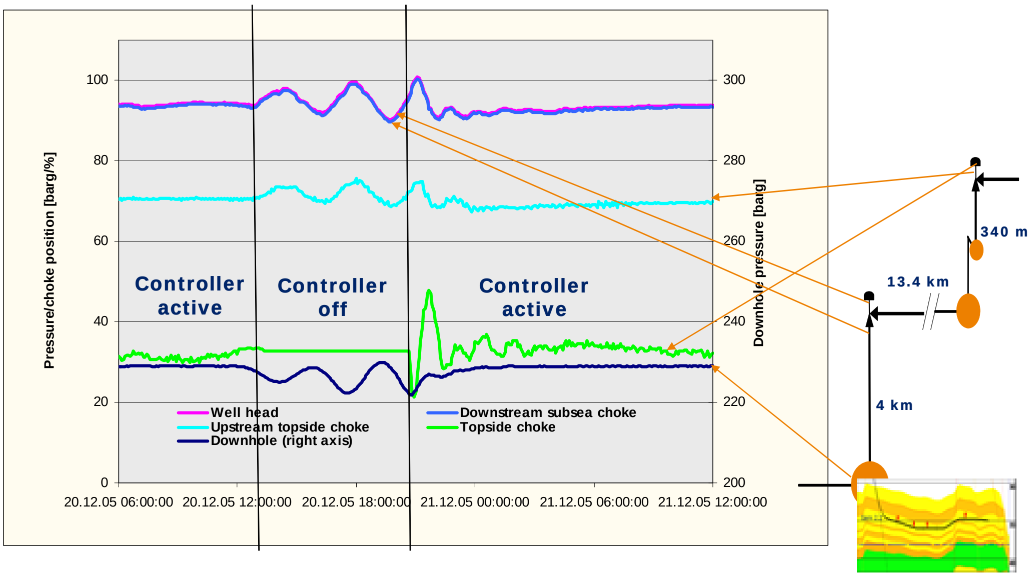

Fig. 4 — Field case where the downhole pressure controller is active and stabilises the production until the controller is deactivated at 12:00 Dec 20th 2005. The downhole pressure (dark blue line, right axis) is controlled to its set point 229 barg with almost constant choke opening (green line, left axis) at 35%. Also shown are pressure upstream (pink line, left axis) and downstream (blue line, left axis) the subsea choke, and the pressure upstream the topside choke (cyan line, left axis). The slug control is turned off at 12:00 and on at 21:00.

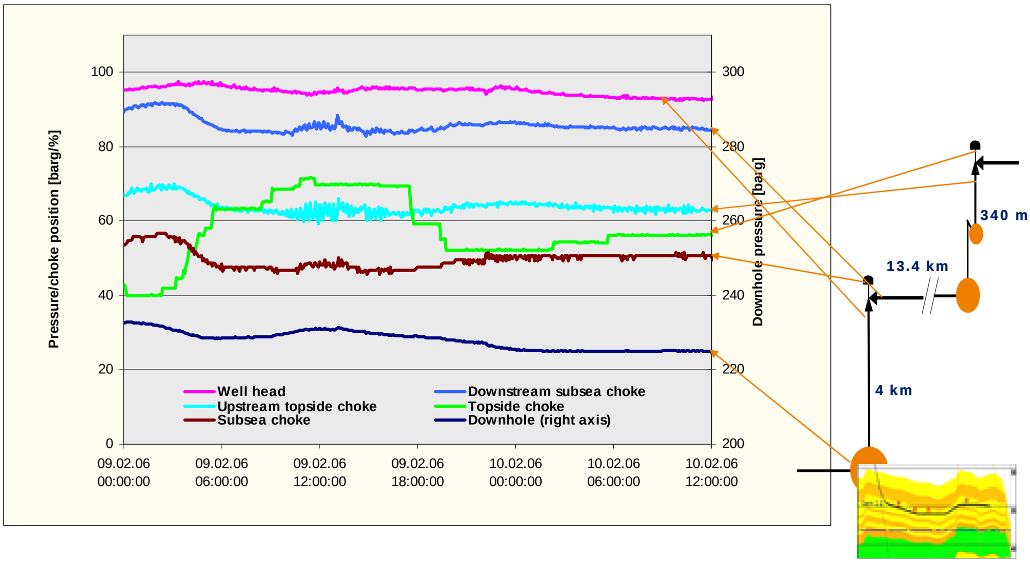

Fig. 5 — Field case that illustrates a new method for well slug removal. This is a better solution for removal of well slugging. The downhole pressure is stabilised by feedback control with the subsea choke. Slug control of downhole pressure using the subsea choke: downhole pressure (dark blue line, right axis), subsea choke (brown line, left axis), topside choke (green line, left axis), pressure upstream (pink line, left axis) and downstream (blue line, left axis) the subsea choke and upstream the topside choke (cyan line, left axis) .

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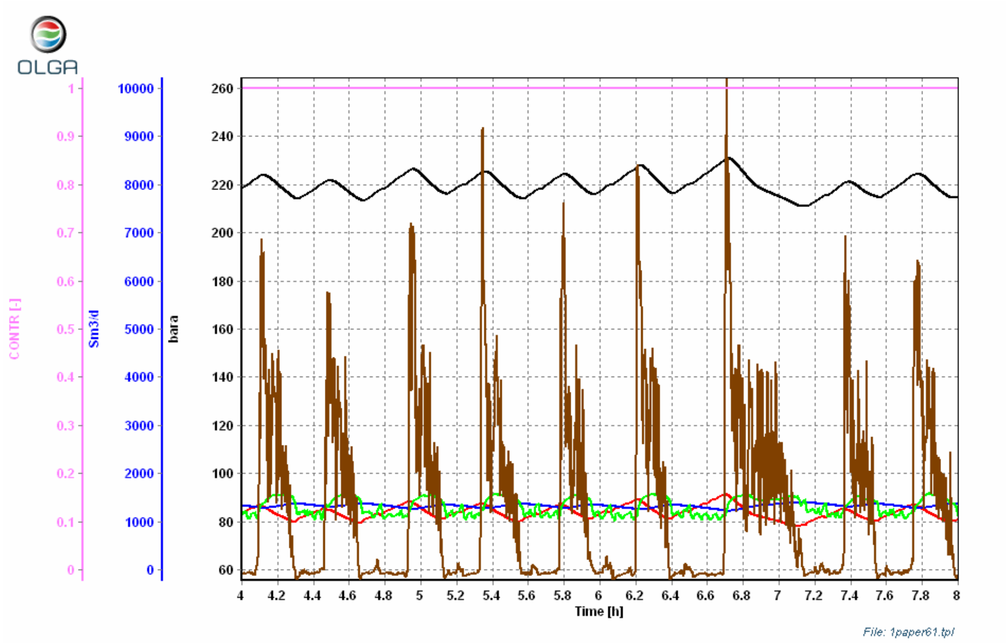

Fig. 6. Nominal simulation case without slug control: downhole pressure (black line), well head pressure (red line), downhole oil rate (blue line), well head oil rate (green line), topside oil rate (brown line) and topside choke position (pink line).

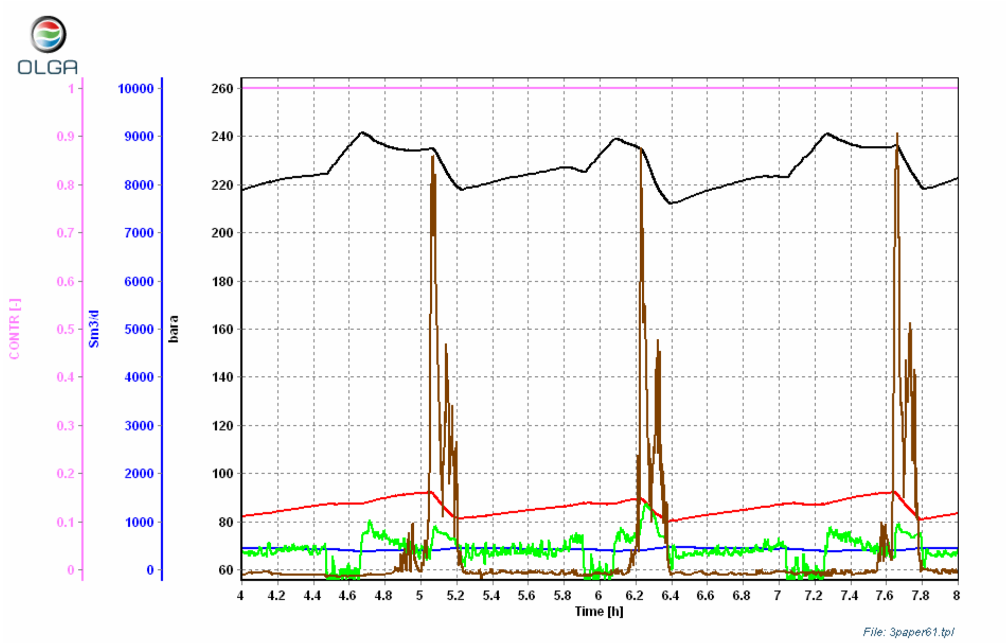

Fig. 7. Low rate simulation case with low *ProdI* , nominal reservoir pressure and no slug control: downhole pressure (black line), well head pressure (red line), downhole oil rate (blue line), well head oil rate (green line), topside oil rate (brown line) and topside choke position (pink line).

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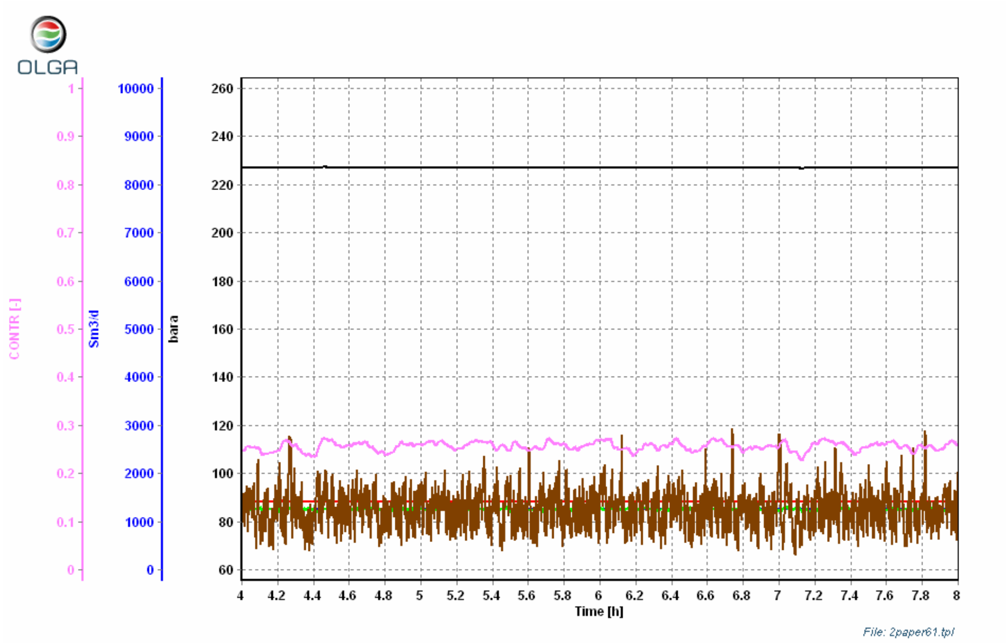

Fig. 8. Nominal simulation case with active slug control with set point 227 bara downhole: downhole pressure (black line), well head pressure (red line), downhole oil rate (blue line), well head oil rate (green line), topside oil rate (brown line) and topside choke position (pink line).

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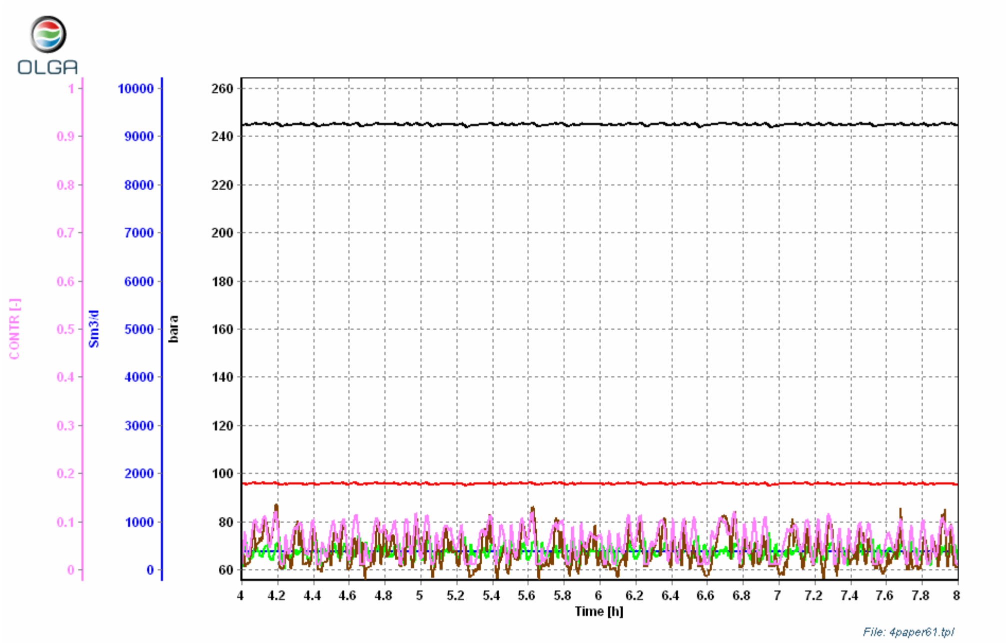

Fig. 9. Low rate simulation case with low *ProdI* , nominal reservoir pressure and active slug control: downhole pressure (black line), well head pressure (red line), downhole oil rate (blue line), well head oil rate (green line), topside oil rate (brown line) and topside choke position (pink line).

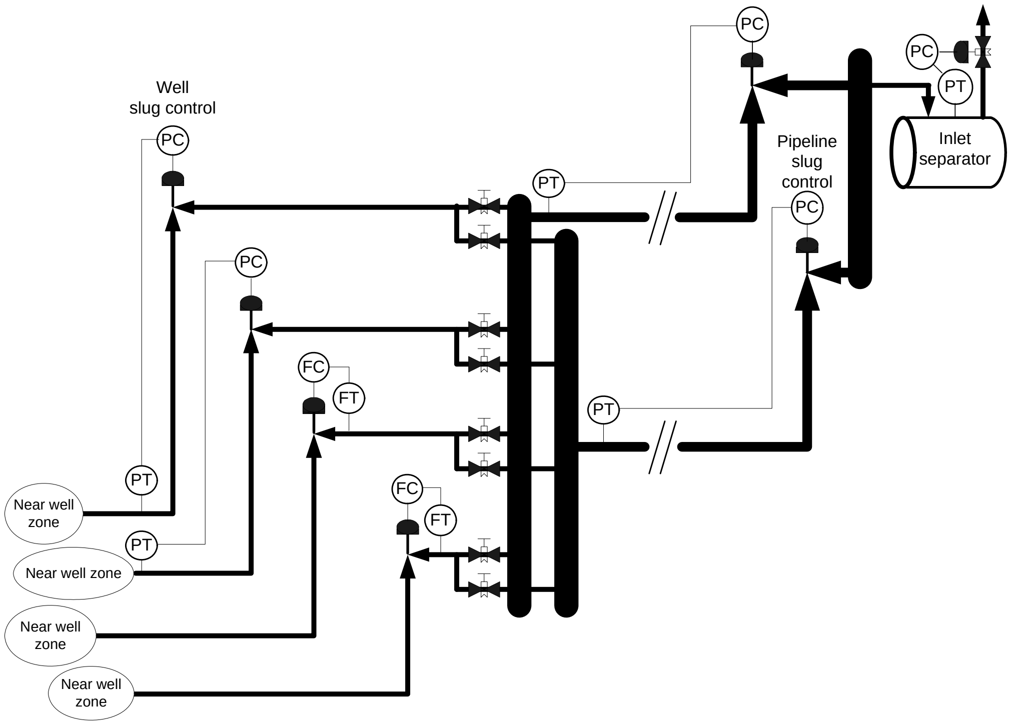

Fig. 10 — Proposed control structure for network of wells and pipelines.