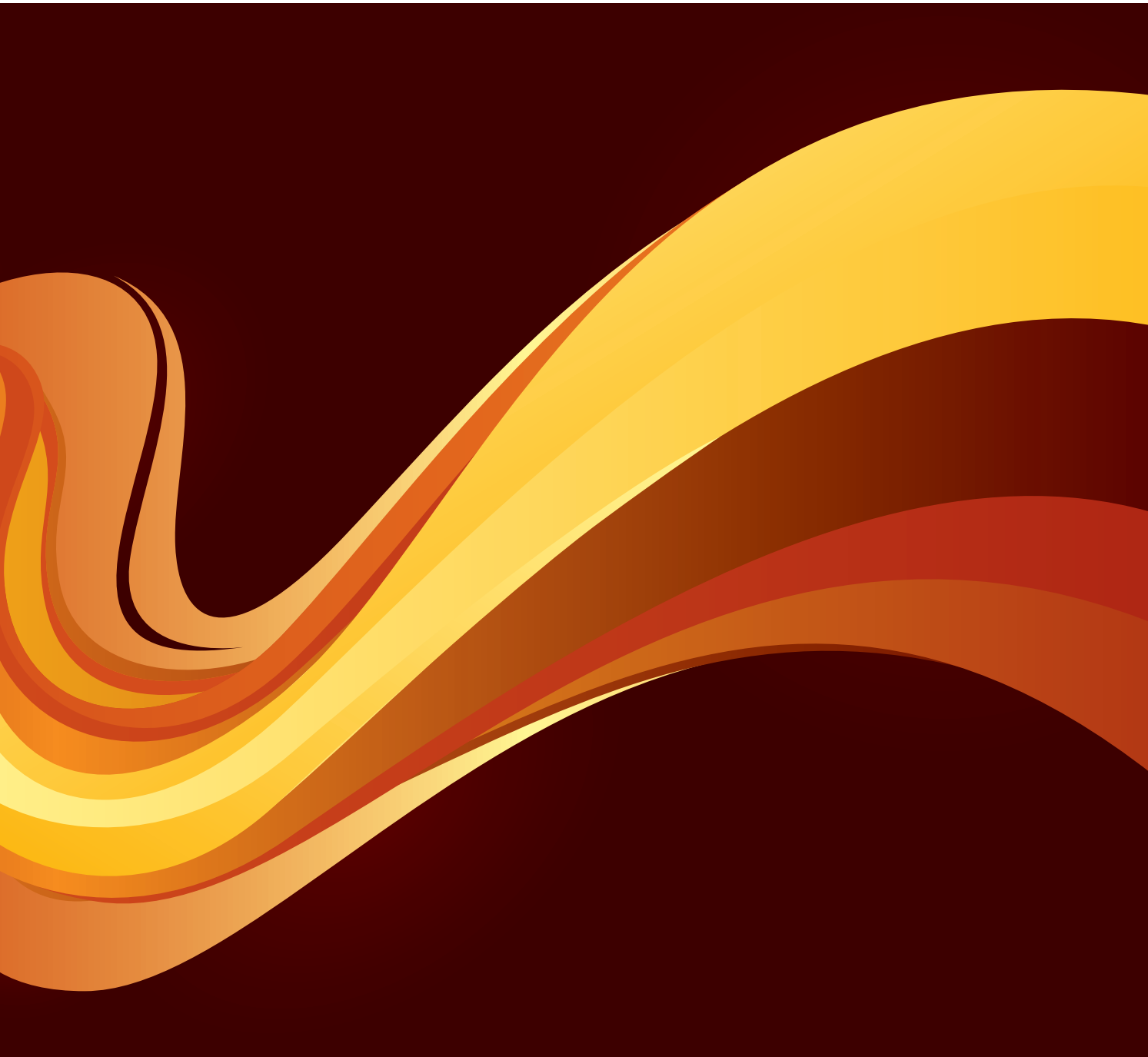




# From chaos to calm

Disrupted, unpredictable flow from oil and gas wells – ‘slugging’ – has long been a bane of production operators’ lives. But now BP has invented a new way to control slugging which will help improve the company’s output from its assets worldwide. *Michelle Brown* reports



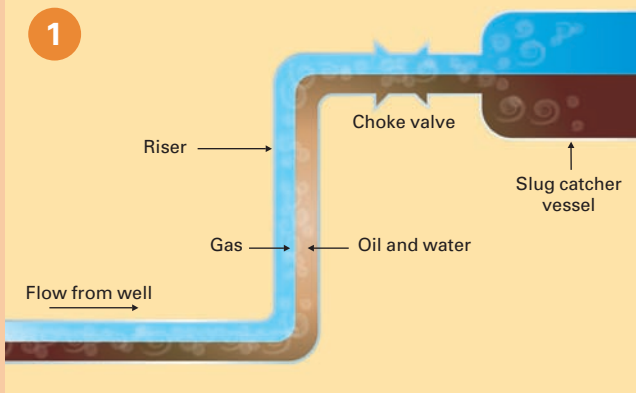
**I**deally, letting oil and gas flow through a well should be a bit like turning on a tap. But thanks to a phenomenon known in the industry as slugging, it's sometimes more like turning on the tap only to find that nothing emerges from the well for some hours – after which all the oil and gas you were expecting comes gushing out in the space of five minutes.

“To imagine the “no flow then blow” cycle, just think of the Old Faithful geyser in Yellowstone National Park,” says Paul Oram, engineering technical authority for control and automation in BP’s exploration and production business

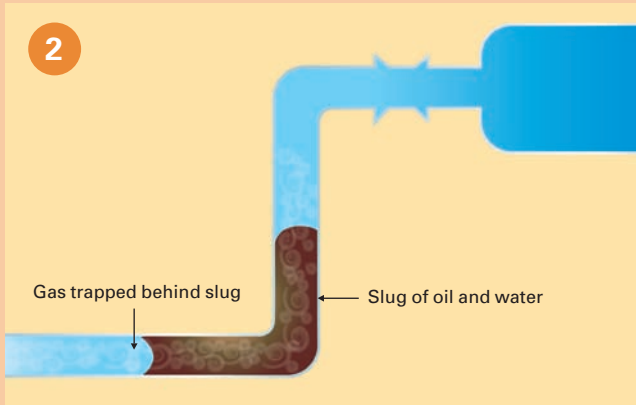
in Sunbury, UK. “There is a dormant period followed by a huge eruption of water and steam. Translated to hydrocarbon production facilities, and particularly to offshore installations in deep water, severe slugging of this nature can seriously disrupt platform operations.”

A combination of circumstances is required to induce slugging. Most hydrocarbon wells produce a mixture of oil, gas and water in varying proportions, depending on the field and how long it has been operating. Offshore, a well may be situated very close to the production platform, or it may be connected to the facility >

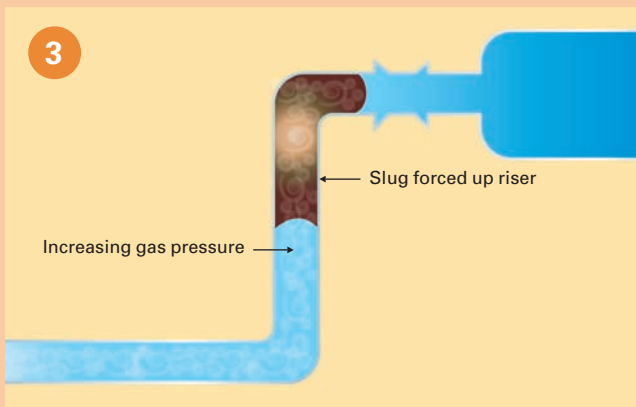
## HOW SLUGGING OCCURS



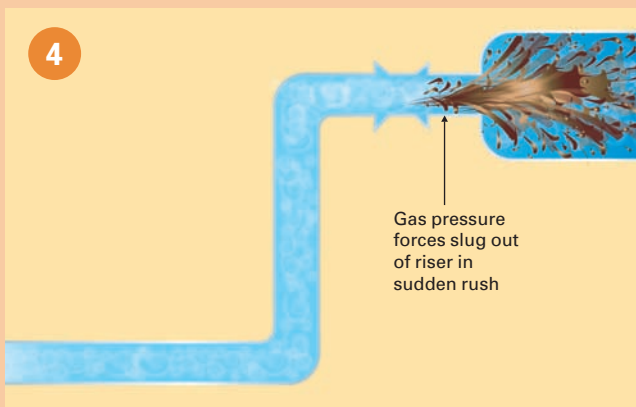
As this simplified graphic shows, the multiphase flow of fluids (oil, gas and water) from a hydrocarbon well must make a steep climb through the 'riser' section of the pipeline to reach the platform topsides



Sometimes the liquids (oil and water) do not have enough momentum to make the climb, and fall back on themselves to make a liquid 'slug' at the base of the riser



Gas pressure builds up behind the slug



The slug is forced up the riser, causing gas and liquids to arrive at the topsides in a sudden rush. The process is cyclical, creating instability in the flow as the well 'spasms'

► by a pipeline passing over undulating terrain on the seabed for many kilometres. The well itself may be several kilometres deep. Severe slugging happens when liquid in the well, or in a steep section of the pipeline such as the 'riser' coming up from the seabed to the platform, does not have enough energy to make the climb. The liquid begins to fall back on itself and forms a plug. Gas then builds up behind the plug until its pressure is great enough to blow the liquid out of the line and the cycle begins again.

A facility that suffers from this type of slugging can have its output reduced by up to 10 per cent, either through disruptions in production or because it forces operators to try to pre-empt problems by restricting the flow from the well. According to Oram, most producing assets will experience slugging at some point – this becomes progressively more likely as production declines with time, and the composition of well fluids changes, notably as the amount of gas reduces while water increases over the lifetime of a reservoir.

Slugging is also more likely to cause problems on assets located in deep water. In BP's assets offshore Angola, for example, some of the risers climb almost two kilometres from the seabed to the floating platform on the surface, and are 30 centimetres in diameter. 'Imagine the kinetic energy that the liquid has to have to climb the riser,' Oram points out.

Another factor contributing to the occurrence of slugging is the increasing popularity of directional drilling of wells. This technology enables engineers to change the direction of the well to take advantage of subsurface geology, for example by drilling along rock seams. But subsequently it also makes slugging more likely because the wellhead is often a long way from the reservoir and the topology of the well is more complex.

'Taken together, deeper wells and directional drilling mean that, as an industry, we're actually making the slugging problem worse,' says Oram.

### Slug solver

Topside facilities are designed to mitigate the effects of slugging as far as possible, with large 'slug catcher' vessels receiving the well fluids as they come onboard, and associated safety systems set to choke off the well if the pressure or liquid levels rise too sharply. But the resulting production downtime, and the likelihood of downstream instabilities in the subsequent treatment processes, can still have a significant impact on overall output.

Many approaches to solve slugging have been proposed and tried, including mechanical and process solutions. One of the most popular is gas lift, used to combat riser-induced slugging. This involves compressing gas and injecting it at the foot of the riser to raise the pressure and keep the liquid moving. It's effective, but it is also expensive in terms of energy consumption and extra equipment needed on the platform.

There are also a number of commercial, off-the-shelf software packages that try to

control the downhole pressure in the well by automatically manipulating the choke valve located at the top of the riser, although these have not met with universal success.

Faced with the industry-wide problem of slugging, BP began working on a new approach to solve the problem in 2006, resulting in an innovative solution which looks set to meet the tricky challenge of controlling slugging.

'We approached the problem by looking at it from a process control point of view,' says Oram. 'When trying to control something automatically in a closed loop, the first thing you look for is a cause and effect relationship. We knew there was a relationship between slugging and the choke valve position because operators close the choke to help tackle slugging.'

BP's solution is based on a control algorithm first developed using computer simulation – the design is proprietary and precise details are not being broadcast. Although some existing commercial solutions attempt to establish a control loop between the choke valve and the downhole pressure, BP's approach is believed to be unique in relating the action of the valve to the flow regime and pressure fluctuations across the slugging zone. By identifying the formation of the slug sooner in the slugging cycle, the control action doesn't need to be as aggressive in its response. The result is an improvement in the overall level of stability and higher production rates.

Following the conceptual design and simulation work at Sunbury, next came experiments to test the algorithm on a laboratory-scale multiphase flow loop at Cranfield University in the UK. The trials proved the concept would work.

### Tough trial

In 2007, the algorithm was ready for its first full-scale trial in the BP-operated Valhall field off the coast of Norway. Valhall has eight platforms and began production in 1982 – it was chosen for the trial because some of its wells are subject to severe slugging, especially those around the two platforms taking production from the flanks of the field.

Production from most of the flank wells is cyclic. A well will start up and operate trouble-free for several days or weeks before slugging begins as the pressure in the reservoir starts to drop away. Eventually the well must be shut down to allow the pressure to build up again. 'It's a problem for the well itself and for its neighbours, because the pressure fluctuations from slugging in one well can start to induce surging in other wells,' says BP petroleum engineer Bjørnar Tjønn.

Slugging presents a potentially costly problem for Valhall since the reservoir formation is in very unstable chalk. If the pressure fluctuations



from slugging become too violent they can cause a large chalk influx that blocks the well. 'It has happened many times on the main platforms over the years and it costs a lot to clean it out,' says Tjønn.

The initial slugging control trial was carried out on a single well on the southern flank of the field. According to Tjønn, the team effort between BP's exploration and technology group and engineers in Norway soon had the system up and running. 'It didn't take long till it was really working well,' he says. 'We then implemented the solution on more wells and now we are achieving slug prevention on all the wells across the Valhall flanks.'

The situation at Valhall is complex, with different wells slugging intermittently, but Tjønn says that overall production has already increased by around 10 per cent, or several thousands of barrels of oil per day, as a direct result of the project.

One of the great benefits of the new system is that it should be very cost effective to implement. Many wells already have all the necessary sensors installed, so no new hardware is needed. Instead, it simply requires BP's new software to be installed on the control system. 'It is truly good value,' says Tjønn.

### Deploying a winner

In December 2008, that value was recognised by BP when the success of the slugging control system won the company's Helios innovation award for Oram and his team.

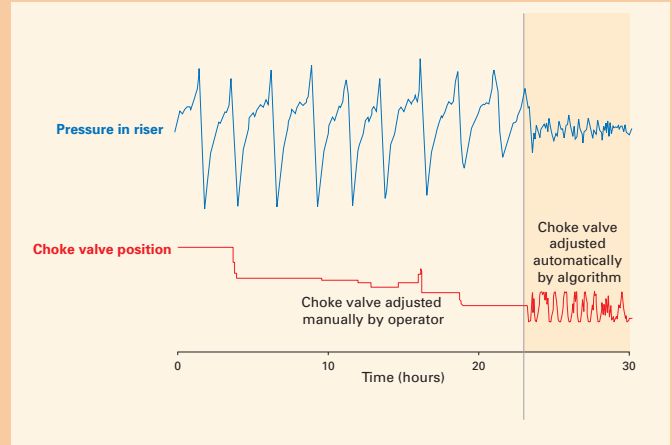
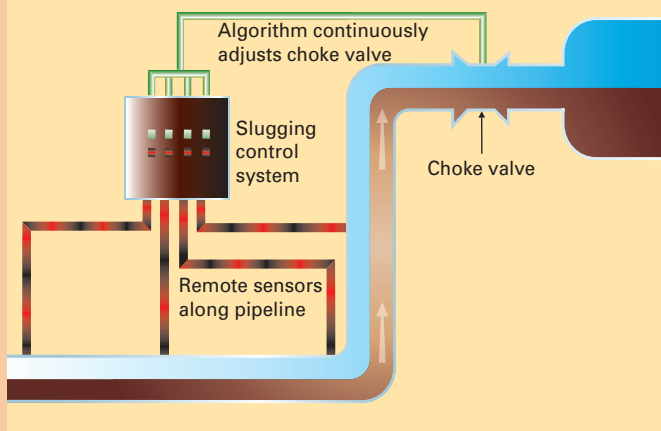
With the fundamentals of the slugging control algorithm proven, BP's *Field of the Future* team >

Part of the Valhall platform complex offshore Norway, where BP's slugging control algorithm was successfully trialled, leading to increased oil production

Production from Valhall has already increased by around 10 per cent as a direct result of the project

Trials of BP's algorithm in the multiphase test loop at Cranfield University proved the concept would work





BP's computer-based algorithm stabilises the pressure profile along the pipeline. This is achieved by using sensors to provide pressure readings across the slugging zone. The information is analysed and used to actively manipulate the choke valve at the top of the riser during the slugging cycle to create a stable flow regime.

The graph shows the effect of the algorithm when applied to flow from a well in the Valhall field. The blue trace shows the pressure fluctuations

in the riser, and the red trace shows the position of the choke valve at the top of the riser. Manual control of the valve by an operator only partially attenuates the pressure fluctuations. When BP's software algorithm is switched on, the choke valve is dynamically and automatically adjusted, reducing the pressure fluctuations significantly and delivering a stabilised flow regime. In the absence of flow disturbances, increased production can be achieved.

► – focused on getting BP's production assets to 'work smarter' – has now taken on ownership of the technology to help deploy it into BP's assets around the world (*Frontiers*, December 2006).

'The scale of the solution is really exciting,' says Patrick Calvert, an optimisation engineer within BP's *Field of the Future* team. 'If you look at typical control loops within BP they usually act over a distance in metres across the equipment involved.

For slugging we are now looking at control loops that might be 10 or 15 kilometres long.

'My job is to help optimise operations, but this is difficult if slugging is occurring. This technology has great potential to stabilise the flow – it is designed to handle even the largest slugging events – which in turn will help improve the performance of our assets, particularly in deep water.'

The first candidate for implementation is the Na Kika field in the Gulf of Mexico, which is scheduled to start using the slug prevention system in the second quarter of 2009. BP hopes that Greater Plutonio, offshore Angola, and Milne Point, Alaska, will follow later in the year. In addition to these existing brownfield assets, the system is also being incorporated into the design of new greenfield developments, including Skarv offshore Norway, Quadrant 204 to the west of the Shetland Islands, and offshore Angola.

As well as improving production rates, there is potential in the longer term for BP's slug prevention solution to have a substantial impact on the costs of developing future greenfield projects. For example, if the system can guarantee that slugging will be less extreme, it presents the opportunity to reduce the size of slug catcher vessels. Similarly, it could alleviate the need for gas lift, reducing the size of the

heavy, energy-hungry compressors that are currently incorporated into topside designs. 'The potential is clear if you consider the size of the equipment we currently use to provide flow stability,' says Calvert.

But everyone acknowledges that it is far too early to start stripping out potentially vital pieces of equipment.

The system will need to prove itself more widely before engineers will be willing to rethink their platform designs. 'We are still building confidence about the control solution,' Oram observes, 'but there could be major capital cost savings in the longer term.'

What is certain is that BP's innovative approach to slugging control can give existing platforms a production boost and help take a significant step towards trouble-free 'silent running'.

'Working on a field day-to-day doesn't give you a lot of time to think about innovation,' explains Tjønn. 'We're very thankful for the work that's been done.' ■

## BP's slugging control algorithm is being applied in brownfield and greenfield assets

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