

OTC 8196

Prevention of Severe Slugging in the Dunbar 16" Multiphase Pipeline A. Courbot, TOTAL, Total Oil Marine, Aberdeen, U.K.

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This paper was prepared for presentation at the Offshore Technology Conference held in Houston Texas, 6-9 May 1996.

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Abstract

The occurrence of the severe slugging phenomenon in multiphase pipelines can cause serious and troublesome operational problems within the receiving process facilities.

This paper describes: the pipeline operability studies on the Dunbar to Alwyn multiphase pipeline regarding riser-induced severe slugging; the control scheme selected to prevent this phenomenon; and the subsequent operating experience.

The pipeline operability studies involving dynamic simulations concluded that riser-induced severe slugging could occur over a wide range of production rates, in particular when the Ellon gas is unavailable.

The challenge for TOTAL was to develop an operating strategy and a control scheme in order to eliminate severe slugging and operate the pipeline without significant process upset.

An automatic control scheme was selected which offered a cost effective solution and ensured the safety of the existing process installations. Its originality was that it was based on a Riser Base Pressure Control.

Since the initial start-up in December 1994, this selected scheme has proven to be successful and has enabled the pipeline operations in the riser-induced severe slugging region to be carried out without any difficulty.

Introduction

The Dunbar field is situated in the UK sector of the northern North Sea, approximately 22 km to the South of Alwyn North field which has been operated since the end of 1987 (Fig. 1 and Fig. 2).

The recent development of the Dunbar field and its satellite Ellon comprises a production platform linked to the Alwyn North platform by a 16" multiphase pipeline (Fig. 3). The gas from Ellon (Subsea wells) and the oil and gas from Dunbar are co-mingled and the overall well-fluid production is routed without separation to the Alwyn North processing and treatment facilities.

The Dunbar 16" Multiphase Pipeline has been designed to export the Dunbar and Ellon production to Alwyn North (NAB platform) at a maximum flow of 49 000 BOPD and 7.9 MM-SCMD. Over a wide range of production rates, in particular when the Ellon gas is unavailable, the pipeline operation is in an unstable region where riser-induced severe slugging occurs.

The purpose of this document is :

1. to give a short description of the flow regimes predicted in the DUNBAR 16" Multiphase Pipeline and in particular of the severe slugging phenomenon.

2. to present the operating strategy and the control system developed by TOTAL in order to prevent severe slugging and to operate the pipeline without occurrence of significant process upsets.

3. and to give a feed-back of the pipeline operation at low flow rates.

1. Flow regimes and severe slugging

The pipeline profile of the Dunbar 16" pipeline is represented in **Fig. 4.** The flow regime map for this pipeline operated at a NAB riser-base pressure of 74 barg is given in **Fig. 5**. This map was based on the results of dynamic simulations performed with the OLGA pipeline software.

The different pipeline flow regimes that can be encountered in the operations of the Dunbar pipeline are: stable flow, hydrodynamic slug flow at high flowrates and riser-induced severe slugging flow at low flowrates.

The Dunbar Pipeline flow regime map shows that hydrodynamic slugging is predicted well above the maximum design capacity of the pipeline and is therefore not a concern for the receiving process facilities.

On the other hand it shows that the Dunbar 16" Multiphase Pipeline is subject to riser-induced severe slugging over a wide range of production rates, in particular when the Ellon gas is unavailable.

The severe slugging phenomenon occurs in multiphase pipelines at low flow and low GOR production when the gas rate is insufficient to continuously lift liquid up the riser. It is not the object of this document to go into details regarding the severe slugging phenomenon. However a summary of its behaviour is given in **Fig. 6.** References 1 through 4 provide more details of how the severe slugging phenomenon occurs and behaves.

The studies of the Dunbar 16" Multiphase Pipeline concluded that riser-induced severe slugging phenomenon would cause unacceptable upsets in the NAB process, with equipment overpressure and flare over-load due to huge gas flows occurring in the gas blowdown phase of the severe slugging cycle (Fig. 7). Therefore an operating strategy and a slug control scheme were required in order to eliminate severe slugging and to operate the pipeline without significant process upset.

2. Operating Strategy for Severe Slugging Prevention

The most obvious means for flow stabilisation in the Dunbar 16" Multiphase Pipeline consists in increasing the Ellon gas production rate or in increasing the Dunbar production rate. This will displace the operating conditions into the stable flow region as indicated in the predicted flow pattern map (**Fig. 5**).

However, over a wide range of production rates the operating conditions remain in the severe slugging region. Thus, the prevention of severe slugging in this region depends solely on a slug control system modifying the severe slugging phenomenon.

Moreover, this slug control system had to be designed to meet specific conditions outlined below:

• The new multiphase pipeline had to be connected to existing facilities.

• The capacity of these facilities was smaller than the expected flow surges induced by severe slugging when operating at low flow.

• The operating range was partially within the riser-induced severe slugging region.

• The risk of equipment over-pressure and flare-overload due to huge gas flows were high in the gas blowdown phase of severe slugging.

• The platform manning had to be minimised.

Therefore the essential criteria for the control system were that it had to :

1. Prevent severe slugging from occurring.

2. Be automatic. A manual control relies on operator skill and experience with higher risks of surge. It relies also on operators dedicated full time to the slug control, which is incompatible with the NAB process operation and the concept of minimal manning.

3. Include a back-up method.

Riser-base gas injection (reference 6) was considered in the preliminary investigations as a suitable alternative. However, this method, although guaranteeing success, was not selected because of the substantial modifications and investment required.

The selected slug control scheme consists in throttling the pipeline sufficiently to maintain the pressure at or above the peak pressure to prevent liquid blockage at the riser base as explained in References 2 to 5. For the Dunbar pipeline, a minimum pressure of 84 barg is required to break the severe slugging cycle.

The originality of the slug control scheme is that it is based on a riser base pressure control. Fig. 8 depicts the process by which the severe slugging phenomenon, with a complete blockage due to liquid filling the riser, is eradicated.

During the design study of the slug control system a number of alternative control schemes were considered but not selected for the following reasons:

1. Riser Top Pressure was investigated in order to avoid a subsea transmitter and was studied in dynamic simulation. The results showed that it would have driven the pipeline into unstable severe slug flow. This is mainly because the pressure at the top of the riser fluctuates within a very small range and in the reverse direction to the pipeline pressure when liquid hold-up increases in the riser.

2. Separator pressure and level override controls were studied and implemented in the design. However, it was clear from the simulation results that it does not stop severe slugging or gas blowdown and therefore only helps to avoid emergency shutdown trips. Such control schemes are only suitable when the capacity of the downstream process is large enough to safely cope with the income of large liquid slugs and gas blowdown.

3. An automatic control based on multiple variables had also been considered. At the time of the Dunbar project these techniques were still under development and would have required a thorough investigation through dynamic simulations of not only the pipeline and riser but also the NAB process. Therefore the studies were not pursued.

3. Slug Control System Description

The details of the operating strategy and the slug control system which were developed from simulation work are presented in Figs. 9 & 10 and are outlined hereafter.

Primary function : severe slugging prevention

Reduced production mode. The slug control valve PV1 mounted on the inlet of the Dunbar Receiving Separator is controlled from the riser base pressure transmitter to a value of 89 Barg, with the Proportional, Integral and Derivative loop PC1. The riser base pressure transmitter is located subsea at the riser base, 150 m away from the platform for safety.

A hand controller HIC1 is provided to smooth the transfer to automatic riser base control and limit the inflow in situations where a large liquid hold-up initially in the pipeline has to be produced, during re-start for instance.

In addition, HIC1 is set to limit the opening of PV1 so that the valve fatigue due to small fluctuations is limited and the consequential swings in the process are avoided.

The back-up method to cope with the situation if the riser base pressure transmitters fail is also ensured by HIC1.

High production mode. At high production modes, the pipeline flow regimes becomes very stable, with no potential for riser-induced severe slugging, so there is no longer a requirement to maintain 89 Barg at the NAB riser base. The 16" main inlet valve, PV2 must be opened to reduce the riser base pressure to 73 barg so that the maximum operating pressure of 129 barg at Dunbar is not exceeded. In this mode PV2 is opened by means of the hand controller HIC2.

Secondary function : over-ride controls

The function of PX3 (Riser Top Pressure Over-ride Control of the slug control valve PV1) is to limit the opening of this start-up valve at high pipeline pressures in order to limit the inflow of gas and provide extra security against flare overload.

The function of LC4 A/B (Level Over-ride Control of PV1 & PV2) and PC4 A/B (Pressure Over-ride Control of PV1 & PV2) is to limit the inflow of a liquid slug and the following gas blowdown. These two controls will not protect against NAB process upset but will prevent an Emergency Shutdown or Over Pressure Protection System trip on high level or high pressure in the receiving separator.

Indicators and alarms

Signals and alarms (indicated in **Fig. 10**) are displayed to assist the operators with pipeline operation and detailed operating instructions are provided.

They would be essential in case of manual control to help the operator to correctly assess the pipeline state and to adjust the valve appropriately in case of unavailability of the riser base pressure indication.

4. Dunbar operational feed-back

Initial operation of the 16" Multiphase Pipeline between the Dunbar and Alwyn North (NAB) platforms commenced on the 7th December 1994 with production of two DUNBAR wells at flow rates approximately 20 000 BOPD and 1.27 MMSCMD gas.

As expected (see Flow Regime Map in **Fig 4.**), at such operating points, the pipeline was clearly in an unstable region where riser-induced slugging occurs, based on the fluctuations experienced when tuning the controls.

Also later in the year, pipeline tests were carried out to see if severe slugging with a full blockage due to liquid filling the riser would occur at low flowrates.

Test without slug control. A test was carried out at flowrates of 12 000 BOPD and 1.0 MMSCMD gas with both the main inlet valve and the slug control valve fully open. The flow conditions were achieved after a flow reduction and the corresponding pipeline operating pressure was 69.2 Barg.

Test presentation. The variations in the riser base pressure, riser top pressure, riser differential pressure, gas outflow and oil outflow from the receiving separator versus time were recorded during the test and are reported in Fig. 11.

These trends show the first blockage of the riser and the subsequential no gas or oil inflow to the receiving separator followed by the pressure build-up in the pipeline. When the differential pressure in the NAB riser reached 9 Barg it was decided to close the main inlet valve and to cut back the slug control valve to 12 % in order to stop the severe slug growing and to produce it in a controlled manner.

The pipeline pressure went on rising until the NAB riser base pressure reached 82.6 barg. At that point the liquid production started, followed by a gas surge. The oil and gas peak flows were 45 000 BOPD and 2.31 MMSCMD respectively.

Immediately after, another slug started to build up at the base of the riser. This slug was produced when the pressure reached 81.8 Barg at the NAB riser base without any further intervention due to the fact that the pipeline outlet was already throttled.

It was then decided to slowly re-open both the main inlet valve and the slug control valve. Two other slugs were produced without any intervention and then a second severe slug with complete blockage of the riser started to form. In the same way as for the first severe slug, it was decided to close the main inlet valve and to cut back the slug control valve to 16 % when the differential pressure in the NAB riser reached 9 Barg. The pipeline pressure went on rising until the NAB riser base pressure reached 81.5 barg. At that point the liquid production started, followed by a gas surge. The oil and gas peak flows were 55 000 BOPD and 2.43 MMSCMD respectively.

The Dunbar production was then increased to 14 000 BOPD and 1.12 MMSCMD to see if the pipeline flow stabilised. The slug control valve was then re-opened to 66 %, the main inlet valve remaining closed. Two slugs were produced without any intervention and then a third severe slug with complete blockage of the riser started to form. As before, the slug control valve was cut-back to 18 % and the slug was produced in a controlled manner.

At that time it was decided to stop the test in order not to disturb any further the downstream process and not to risk a plant shut-down.

Also the test results were sufficient to confirm that severe slugging, with full blockage of the riser, does indeed occur at low flowrates.

Moreover, they show that it would be very difficult, if not impossible, to operate the pipeline in the riser-induced severe slugging region without any slug control device.

Pipeline operation using the slug control system. Fig. 12 shows the pipeline main data when operated with the slug control system at flow rates approximately 16 000 BOPD and 1.1 MM-SCMD gas.

As foreseen from the pipeline simulations, the limit opening of the slug control valve to control the valve oscillations and the consequential transient effects, allowed the pipeline pressure to stabilise. Fig. 12 shows the pipeline stabilisation just after setting the limit opening at mean control output from the automatic controller. The pipeline pressure is then almost linear and the maximum variations of the gas and oil inflows are less than 4 % and 3 % respectively.

It was thought that setting of a limit opening could be avoided by an additional tuning of the control parameters. In particular, a modification of the oil level control in the receiving separator was recommended on order to avoid any transient effects induced by the oil level control. However, no other provision was made to modify the present slug control system, as the system fully satisfies the operator.

The Dunbar pipeline has now been operated for more than one year. The operating strategy and the slug controls described above have proven to be particularly successful and have enabled multiple problem-free pipeline operations within the low flow rate region.

Severe slugging is effectively eliminated by an automatic slug control system based on riser base pressure control, as outlined above.

Our operational experience has confirmed the two benefits of this system:

1. Prevention of severe slugging when operating at low flowrates. 2. Breakdown of severe slug growth and flow stabilisation in the event of a sudden flow decrease when operating at high flowrates, due for instance, to a well shut-down.

Among the indicators provided to the operators for manual response, the differential pressure between the top and the base of the riser (which is a direct function of the liquid hold-up in the riser) has proven to be the most valuable. The gas flowrate and the oil flowrate (estimated from the oil level control valve position in the absence of a flowmeter) at the outlet of the receiving separator have also proven to be essential indications.

Conclusions

1. Even though the primary reason for the inclusion of a slug control system was for safety (to protect the receiving process facilities against equipment over-pressure and flare overload), our operating experience has shown that it would be extremely difficult to operate the pipeline in the riser-induced slugging region without any slug control device.

2. The operating strategy and the slug controls developed for the Dunbar multiphase pipeline have proven to be particularly successful and have enabled multiple problem-free pipeline operations within the riser-induced severe slugging region.

3. The riser base pressure has proven to be a viable signal to automatically control the slug control valve. Also the slug control valve with its equal percentage trim proved suitable for the purpose.

Nomenclature

Subscripts

- NAB = North Alwyn B platform
- PV1 = Slug Control Valve
- PC1 = Riser-Base Pressure Control
- HC1 = Hand Controller of the Slug Control Valve
- PV2 = Main Inlet Valve
- HC2 = Hand Controller of the Main Inlet Valve
- PX3 = Riser Top Pressure Over-ride Controller of the Slug Control Valve
- LC4 A/B = Level Over-ride Controller of the Slug Control Valve and the Main inlet Valve
- PC4 A/B = Pressure Over-ride Controller of the Slug Control Valve and the Main inlet Valve
 - GOR = Gas Oil Ratio

Acknowledgements

The Author wishes to thank: the Members of the Dunbar Task Force for valuable discussions on the slug control selection and helpful review and comments regarding the slug control design; R. Higham of Bellamy Engineering Ltd. for his intensive work on the interpretation of the dynamic simulations and on the detailed design of the slug control system; Alwyn Area Operations for their assistance in the pipeline tests.

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Fig. 1—Alwyn Area location map.







Fig. 3-Dunbar development scheme.



Fig. 4—Dunbar 16" multiphase pipeline profile.



Fig. 5—Dunbar Pipeline Flow Regime Map (for a riser base pressure of 74 Barg) based on predictions from dynamic simulations performed with the OLGA pipeline software.

100 % Dunbar : 36 900 BOPD and 2.6 MMSCMD

100 % Dunbar + Ellon : 43 100 BOPD and 6.6 MMSCMD



a) Liquid Sealing and Slug Growth. First, some liquid begins to fall downward in the riser because of the low velocity and the lack of support from the gas. As it accumulates at the base of the riser, it seals the pipeline and a severe slug will grow when the rate of gas pressure build-up behind is insufficient to lift it out.

b) Gas Pressure Build-up. The pressure increases in the pipeline while liquid continues to accumulate and the liquid level builds up in the riser. The slug will not be produced until the pipeline pressure has risen sufficiently to lift a full riser column of liquid. During this phase there is a complete flow blockage and consequently no outflow into the process.

c) Slug Production. When the pipeline pressure has risen sufficiently to lift a full riser column of liquid, the slug production will start gradually and will then accelerate as the gas travels up the riser, peaking at a very high flow rate for a short period. Without over-ride controls on the separator level this can swamp the vessel.

d) **Pipeline Gas Blowdown.** Finally, the pressure that has built-up behind the slug is rapidly blown down into the receiving platform process, resulting in process upset and flaring.

Fig. 6-Description of the riser-induced severe slugging phenomenon.



Fig. 7—Liquid and gas inflows into the NAB receiving separator predicted by the OLGA pipeline software for 50 % of the Dunbar 1995 maximum flow (18,500 BOPD and 1.3 MMSCMD).





Fig. 8-Riser-base pressure control.

When liquid starts to seal the pipeline at the riser base, the rate of outflow is reduced and consequently the pressure drop across the valve is reduced.

The available pressure is transferred to provide lift to the liquid, a short slug is produced and outflow is restored.

As a consequence liquid is lifted by the gas and produced as small slugs with a short regular cycle.



In the "Reduced Production Mode" the main inlet valve is closed and the slug control valve is controlled from the riser base pressure. Dunbar pressure range: 90 to 105 Barg. In the "High Production Mode" the main inlet valve is open.





Fig. 10-Dunbar pipeline slug control system.



Fig. 11—Data recorded during pipeline test at low flow without the slug control system. (N.B. The installed gas flowmeter is enable to indicate flowrates below 0.900 MMSCMD).



Fig. 12—Pipeline operation at low flow using the slug control system.