Pressure Regime: Subsea to BGE

1. Introduction

This note presents an overview of the Pressure regime of the Corrib upstream pipeline system and the Bellanboy Gas Terminal through to delivery of sales gas to BGE downstream pipeline. The overview highlights the primary elements in the flow of gas from the subsea wells through to the BGE downstream pipeline.

2. System Overview

The daily demand for gas from the Corrib Fields is determined by the throughput of sales gas scheduled with BGE. For the purposes of this note the maximum flow of 350mmscfd at year one and 210mmscfd at year 5 will be used to describe the pressure regime of the Corrib system.

Flow from the subsea wells is via the individual well head choke valves. The total flow from the field is achieved by regulating the flow from each individual well stream into the subsea manifold.

From the subsea manifold, gas flows through the offshore pipeline, via the LVI, and through the onshore pipeline to the receipt facilities at the Gas Terminal.

Within the Terminal the following key processes condition the gas prior to compression and delivery into the BGE downstream pipeline.

- Inlet Receipt
- Slug Catcher
- Inlet Separator (3 phase)
- Cold Separator (J/T effect)
- Export Compressor Train (min suction pressure ~ 47 bar)
- Fiscal Metering
- Export to BGE pipeline

The delivery pressure into the BGE pipeline is nominally 85bar.

3. Representative Pressure Regimes

At start of field life the shut in well head pressure is 345 bar. At a flow of 350mmscfd the flowing well head pressure (upstream of the chokes) is around 280 bar.

Under these conditions, an overview of the pressure regime is illustrated in Table 1.

Table 1

Pressure Regime: Subsea to BGE

Location	Upstream Bar	Downstream Bar	Note
Wellhead Choke	280	140	Downstream at manifold
Upstream Pipeline	140	110	Settle out pressure ~125 bar.
Inlet Receipt / Slug catcher	<110	<110	
Inlet Separator (3 phase)	<110	105	
Cold Separator (J/T effect)	105	60	
Export Compressor Train/ Metering	60	77 to 85	Delivery to BGE

Around Year 5 the shut in well head pressure will reduce to ~140 bar. At a flow of 210 mmscfd the flowing well head pressure (upstream of the chokes) is around 85 bar.

Under these conditions, an overview of the pressure regime is illustrated in Table 2.

Table 2

Location	Upstream Bar	Downstream Bar	Note
W.H Choke	85	80	Downstream at manifold
Upstream Pipeline	80	60	Settle out pressure ~ 70 bar
Inlet Receipt (pig trap)/ Slug catcher	60	60	
Inlet Separator (3 phase)	60	58	
Cold Separator (J/T effect)	58	48	
Export Compressor Train/ Metering	48	77 to 85	Delivery to BGE

The offshore pipeline has been designed to 345 bar which is the maximum closed in tubing head pressure at the wellhead during year 1. Flowing conditions for year 1 are outlined in Table 1.

At year 4/5 the well shut in pressure reduces to 140 bar and the suction at the Export Compressor is reaching its minimum. Re-wheeling of the compressor is expected during year 5 to 6.

4. System Trip/Alarm Settings

Within the overall system there are a number of alarm and trip settings, which, if reached, initiate actions to alert the operator and protect items of equipment. The Terminal trip settings will operate first to shutdown the wells, together with the Terminal process, and ensure the design pressure of the onshore pipeline section is not exceeded.

The key settings are presented in Table 3. The overall settings and flow scheme for the wells to the BGE export line are indicated on the attached flow diagram "Corrib Key High Pressure Trips".

Table 3

Item	Location	Setting Bar	Action	Note
1	Upstream Onshore Pipeline	160	Close CV,MV,WV	OPP System
2	LVI Shutdown	136	Close LVI valves	OPP System
3	Inlet Receipt (pig trap)	75 LL	Close Terminal inlet ESD	Low onshore pipeline pressure
4		110	Ramp close CV	OPP System
5		128	Close CV,MV,WV	OPP System
6	Slug catcher Inlet	130	Terminal ESD	Was previously 140/135
7	Inlet Separator (3 phase)	110	Terminal ESD	
8	Cold Separator (J/T effect)	80	Terminal ESD	

Note: CV is Choke Valve, MV is Main Valve, WV is Wing Valve and ESD is Emergency Shutdown valve(s)

The Gas Terminal piping from the pig receiver to a control valve upstream of the Inlet Separator has a design pressure of 150 bar. Downstream of the control valve the pressure is 98 bar.

5. Selection of 144 bar

At the time of the safety review by Advantica the Terminal ESD trip (Item 6 in Table 3) was set to 140 (high integrity shutdown) and 135 bar (Terminal ESD).

To meet the Terminal operational design basis and achieve sufficient discrimination between alarm and trip settings, the design pressure of the incoming onshore pipeline needed to accommodate a shut in pressure of above 140 bar.

Advantica selected the design pressure of 144 bar.

The over pressurisation protection evaluation of the complete upstream pipeline and subsea pressure regime established the protection settings listed in Items 1 to 5 in table 3. This was established to allow flexibility in the daily operation, avoid nuisance trips and still prevent the onshore pipeline exceeding the design pressure of 144 bar selected by Advantica.

Subsequently the Terminal Design team reassessed the Gas Terminal Alarm and Trip systems, taking into consideration the settings adopted at the LVI etc, and adjusted the Terminal settings to suit the requirements of the upstream pipeline over-pressurisation protection system. The ESD trip setting (Item 6) was then adjusted to 130 bar.

6. Summary

Advantica selected the onshore design pressure of 144 bar taking into consideration the desire to reduce the design pressure of the onshore pipeline from the previous value of 345 bar and the operational design basis of the Terminal including its shutdown systems.

To maximise the efficiency of processing gas at the Terminal, the inlet pressure to the Terminal should be kept as high as practical. This reduces the power requirement of the gas export compressors and hence energy usage at the Terminal (minimises carbon footprint).

It is undesirable to trip the shutdown valves at the LVI during upset conditions at the Terminal. i.e. The LVI shutdown valves remain open (the Terminal closes and the subsea wells close) unless the resulting settle out pressure is above the LVI trip pressure of 136 bar. Trip conditions at the LVI can only be reset locally at the LVI. After a shutdown at the LVI any differential pressure between the offshore and onshore section of pipeline will need to be manually equalised via the bypass equalisation line.

The onshore pipeline over-pressurisation protection system provides discrimination between the Terminal shutdowns and the demand on the LVI shutdown valves. Well closure is initiated from detection of high pressure detection within the Terminal facilities. The first action (ramped closure of chokes) is taken at 110 bar. Should the Terminal inlet pressure continue to rise, a further action is taken at 128 bar (choke valve, xmas tree wing valves and master valves are also closed). This allows the pipeline pressure to settle out below the 136 bar autonomous trip of the LVI shutdown valves. Should the pressure continue to rise. the LVI shutdown valves will automatically close at 136 bar and ensure the onshore section of the pipeline will be maintained below the design pressure of 144 bar. This is outlined in the attached flow scheme “Corrib Key High Pressure Trips”.