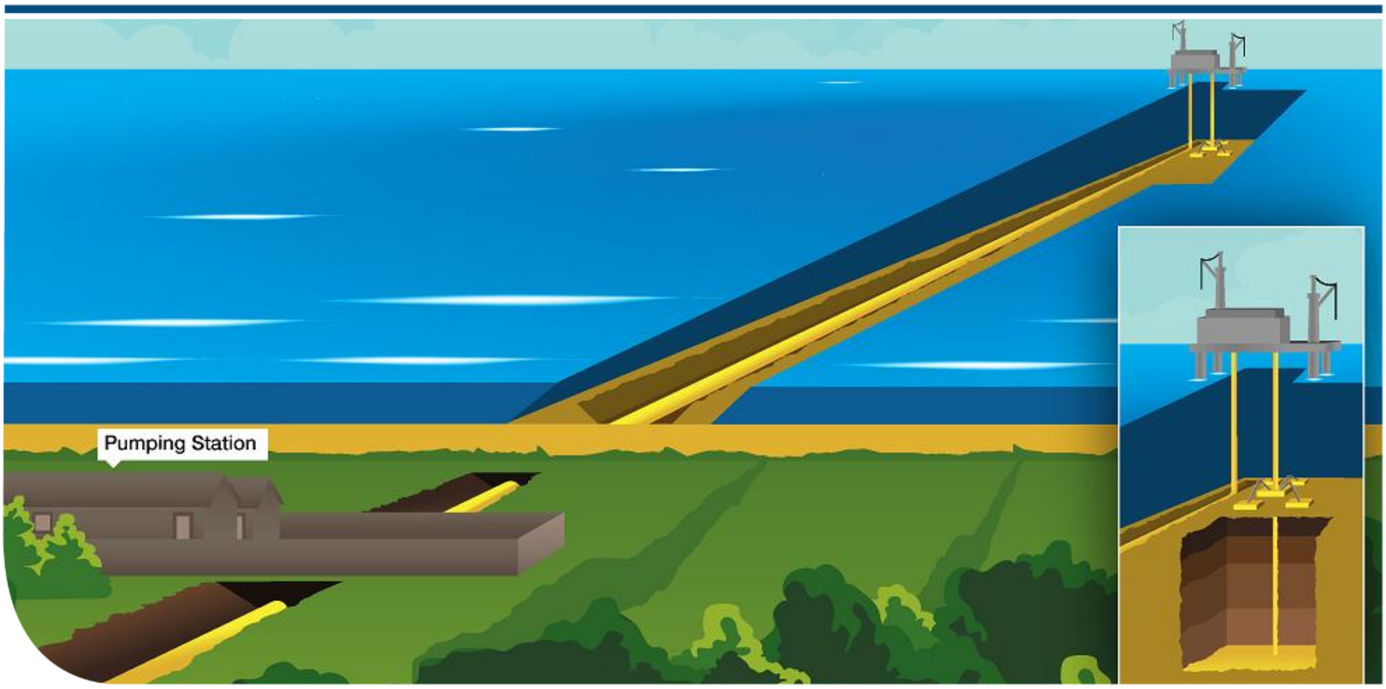
November 2015

WHITE ROSE

K34: Flow Assurance

Technical Transport



CAPTURE POWER

drax

BOC
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IMPORTANT NOTICE

Contents

Key Words

Key Word	Meaning or Explanation
Carbon	An element, but used as shorthand for its gaseous oxide, CO_2.
Capture	Collection of CO_2 from power station combustion process or other facilities and its process ready for transportation.
Dense Phase	Fluid state that has a viscosity close to a gas while having a density closer to a liquid. Achieved by maintaining the temperature of a gas within a particular range and compressing it above a critical pressure.
Key knowledge	Information that may be useful if not vital to understanding how some enterprise may be successfully undertaken
Storage	Containment in suitable pervious rock formations located under impervious rock formations usually under the sea bed.
Transport	Removing processed CO_2 by pipeline from the capture and process unit to storage.
Heat and Mass Balance	Heat and mass balance is a document produced by process design engineers while designing a process plant. A heat and mass balance sheet represents every process stream on the corresponding process flow diagram in terms of the process conditions.
Process Flow Diagram	Process Flow Diagram (PFD) is a drawing which essentially captures the process flow for a processing plant. PFD is used to capture the main process items of equipment, main process stream, process/design conditions in these items of equipment and the basic process control scheme in a single drawing.
Full Chain	Reports described as "full chain" would cover the complete process from the capture of the carbon at the emitter plant to its injection into the storage reservoir.
Flow Assurance	Ensuring successful and economical flow of a fluid stream through a pipework system.

Executive Summary

This report is one of a series of reports; these “key knowledge” reports are issued here as public information. These reports were generated as part of the Front End Engineering Design Contract (FEED) agreed with the Department of Energy and Climate Change (DECC) as part of the White Rose Project.

White Rose seeks to deliver a clean coal-fired power station using oxy-fuel technology, which would generate up to 448MWe (gross), integrated into a full-chain Carbon Capture and Storage (CCS) Project. CCS technology allows 90% of the carbon dioxide produced during combustion to be captured, processed and compressed before being transported to permanent storage in dense phase. The dense phase carbon dioxide would be kept under pressure while it is pumped through an underground pipeline to the seashore and then through an offshore pipeline to be stored in a specially chosen rock formation under the seabed of the southern North Sea.

Delivery of the full-chain project is be provided by National Grid Carbon, which is responsible for the Transport and Storage (T&S) network, and Capture Power Limited (CPL), which is responsible for the Oxy Power Plant (OPP) and the Gas Processing Unit (GPU).

This document presents flow assurance results for the transportation and storage scheme, covering both steady and transient modelling of flow. It addresses the analysis of transient conditions which are likely to occur during operation of the CCS system. The results will inform the control philosophies.

1 Introduction

National Grid Carbon Limited (NGC) is a wholly owned subsidiary of the National Grid group of companies. Capture Power Limited (CPL) is a special purpose vehicle company, which has been formed by a consortium consisting of ALSTOM, Drax and BOC, to pursue the White Rose CCS Project (the WR Project).

CPL have entered into an agreement (the FEED Contract) with the UK Government's Department of Energy and Climate Change (DECC) pursuant to which it will carry out, among other things, the engineering, cost estimation and risk assessment required to specify the budget required to develop and operate the WR Assets. The WR Assets comprise an end-to-end electricity generation and carbon capture and storage system comprising, broadly: a coal fired power station utilising oxy-fuel technology, carbon dioxide capture, processing, compression and metering facilities; transportation pipeline and pressure boosting facilities; offshore carbon dioxide reception and processing facilities, and injection wells into an offshore storage reservoir.

CPL and NGC have entered into an agreement (the KSC) pursuant to which NGC will perform a project (the WR T&S FEED Project) which will meet that part of CPL's obligations under the FEED Contract which are associated with the T&S Assets. The T&S Assets include, broadly: the transportation pipeline and pressure boosting facilities; offshore carbon dioxide reception and processing facilities, and injection wells into an offshore storage reservoir.

A key component of the WR T&S FEED Project is the Key Knowledge Transfer process. A major portion of this is the compilation and distribution of a set of documents termed Key Knowledge Deliverables (KKDs). This document is one of these KKDs and its specific purpose is summarised below.

The steady state flow assurance analysis of the White Rose transportation system has been conducted at a range of flowrates across the life of the project at both summer and winter conditions.

The fluid pressures, temperatures and densities will be used as a basis for the design of the onshore and offshore pipelines, and for boundary conditions for various process simulations and designs. The differential pressure requirements will be used as a basis for selecting the pump design. The well performance data will be used for further reservoir modelling work.

The findings of the steady state analysis are presented to answer two fundamental questions:

- What pipeline operating pressures are required to achieve the target injection flowrates?
- What injection rates can be achieved by the system?

Flow Assurance transient studies were conducted for the full length (end to end) of the pipeline system, from the outlet of the Oxy Power Plant (OPP) Carbon Dioxide Capture Plant to the reservoir including 3 wells at the 5/42 platform and future wells located at another location. The model incorporated wellhead pressure controls and pump efficiency curves and determined the effects of such transient situations resulting from shutdown, emergency shutdown, initial start, restarts, turndown, ramp-up, Pipeline Inspection Gauge (PIG) operations, depressurising and booster pump trips.

2 Purpose

The findings of this analysis are presented to answer two fundamental questions:

- What pipeline operating pressures are required to achieve the target injection flowrates?
- What injection rates can be achieved by the system?

It will address through separate chapters the following areas:

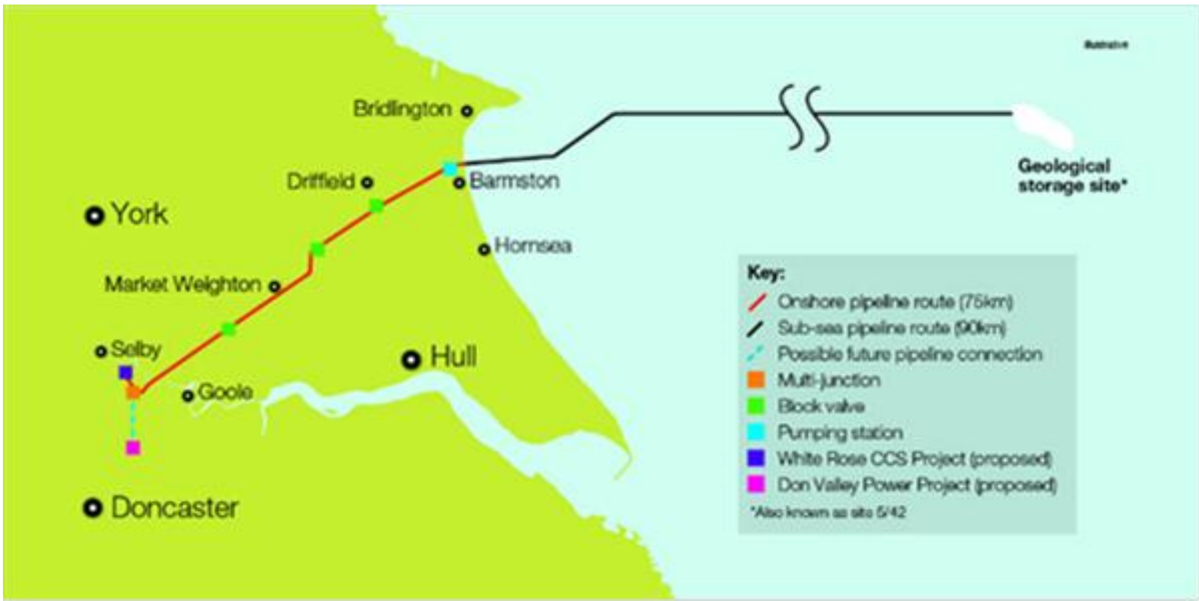
- The pipeline and well operating envelopes and capacity; and
- pipeline transient issues such as:
  - pipeline and well start up;
  - shutdown;
  - depressurisation;
  - deployment of PIGs;
  - buffering capacity;
  - turndown issues; and
  - surge analysis.

3 Overview

The White Rose CCS Project is to provide an example of a clean coal-fired power station of up to 448 MW gross output, built and operated as a commercial enterprise.

The project comprises a state-of-the-art coal-fired power plant that is equipped with full CCS technology. The plant would also have the potential to co-fire biomass. The project is intended to prove CCS technology at a commercial scale and demonstrate it as a competitive form of low-carbon power generation and as an important technology in tackling climate change. It would also play an important role in establishing a CO_2 transportation and storage network in the Yorkshire and Humber area. Figure 3.1 below gives a geographical overview of the proposed CO_2 transportation system.

Figure 3.1: Geographical overview of the transportation facility

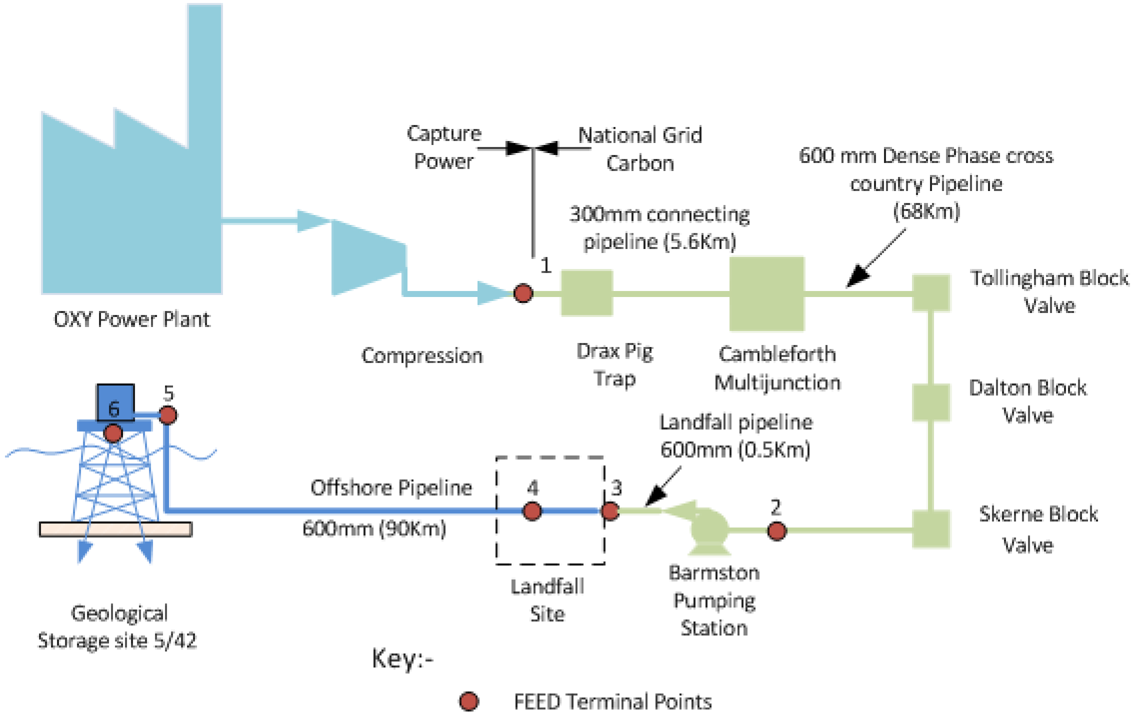


The standalone power plant would be located at the existing Drax Power Station site near Selby, North Yorkshire, generating electricity for export to the Electricity Transmission Network as (the "Grid") well as capturing approximately 2 million tonnes of CO_2 per year, some 90% of all CO_2 emissions produced by the plant. The by-product CO_2 from the OPP would be compressed and transported via an export pipeline for injection into an offshore saline formation (the reservoir) for permanent storage.

The power plant technology, which is known as Oxyfuel combustion, burns fuel in a modified combustion environment with the resulting combustion gases being high in CO_2 concentration. This allows the CO_2 produced to be captured without the need for additional chemical separation, before being compressed into dense phase and transported for storage.

The overall integrated control of the End-to-End CCS chain would have similarities to that of the National Grid natural gas pipeline network. Operation of the Transport and Storage System would be undertaken by NGC. However, transportation of carbon dioxide presents differing concerns to those of natural gas; suitable specific operating procedures would be developed to cover all operational aspects including start-up, normal and abnormal operation, controlled and emergency shutdowns. These procedures would include a hierarchy of operation, responsibility, communication procedures and protocols. Figure 3.2 below provides a schematic diagram of the overall end-to-end chain for the White Rose CCS Project.

Figure 3.2: End To End Chain Overall Schematic Diagram



This report is to presents the findings of the steady state (where it is assumed that the temperature, pressure and flowrate of the fluid released into the transport system is unchanging, no changes are made to the transport equipment settings and the condition at the well do not change) thermohydraulic (temperature/pressure/flowrate) analysis of the White Rose CO_2 transportation system from Drax Above Ground Installation (AGI) to an offshore injection facility (from point 1 to point 5 on Figure 3.2, above). This report also includes discussions of transient operations.

The T&S system would be designed for the transport of dense-phase CO_2 of varying purity and consists of the following:

- a 12 inch onshore pipeline from Drax AGI to Camblesforth Multi Junction (nominally called the 300 mm onshore pipeline); maximum allowable operation pressure is 135 barg;
- a 24 inch onshore pipeline from Camblesforth Multi Junction to the Barmston pumping station (nominally called the 600 mm onshore pipeline);maximum allowable operation pressure is 135 barg;
- a CO_2 booster pump located at the Barmston pumping station.; and
- a 24 inch offshore pipeline from the Barmston pumping station to the injection platform (nominally called the 600 mm offshore pipeline); maximum allowable operation pressure is 182 barg.

The system would be designed to operate in the dense-phase region to prevent separation of gas and liquid, as this could cause cavitation in the pumps. The pipeline pressure is controlled such that CO_2 remains in the dense phase during normal (steady state) operation. Figure 3.3 and Figure 3.4 show the onshore pipeline geometry from Drax AGI to Barmston and Barmston to the injection platform respectively.

Figure 3.3: Onshore Pipeline Geometry

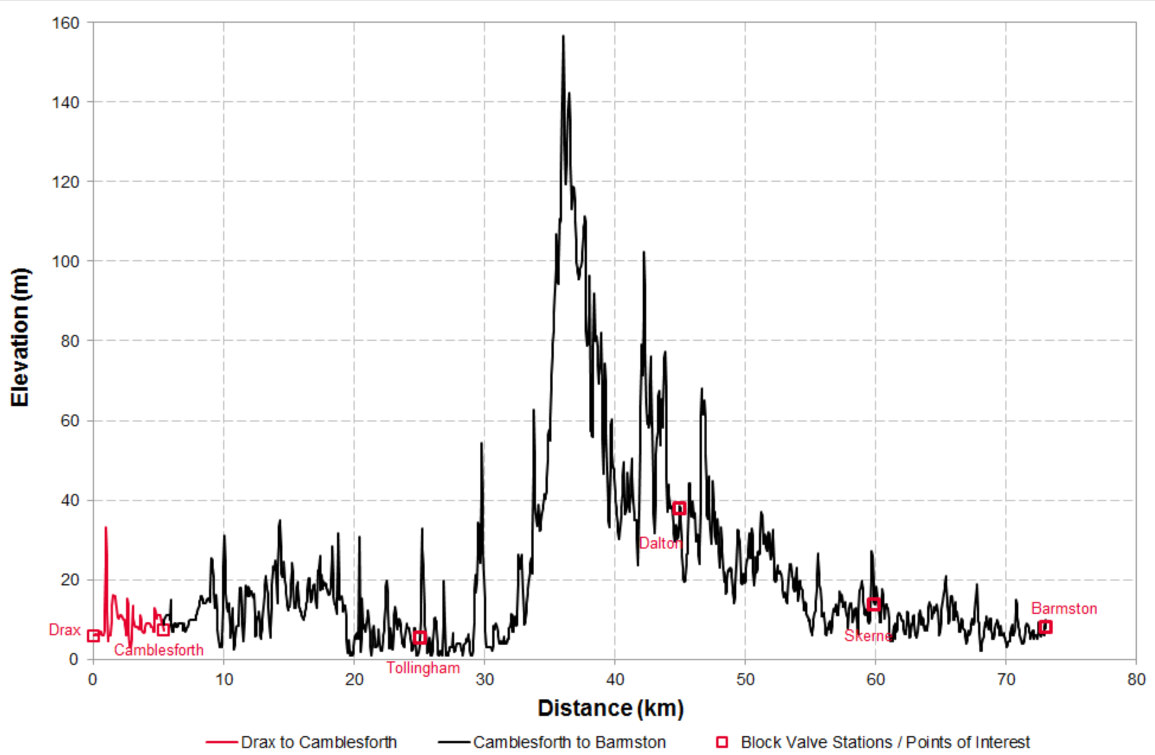
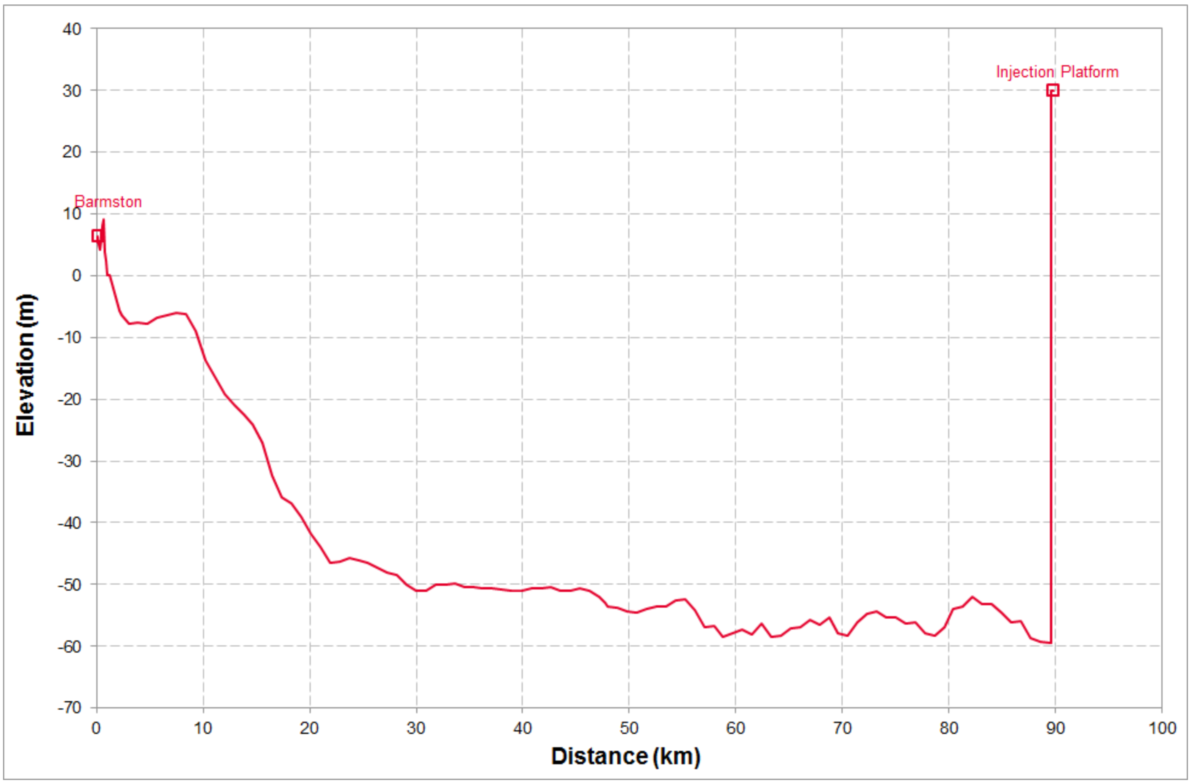


Figure 3.4: Offshore Pipeline Geometry



4 Pipeline and Well Operating Envelope and Capacity

4.1 Modelling

Steady state modelling work is to verify the flowrates, which can be supported by the pipeline and the wells, and to validate the operating conditions for the full chain.

The steady state model simulates the expected flowrates from the capture plant as well as the future loads anticipated by other emitters joining the system. Also considered were results for various ambient conditions (summer/winter), fluid composition and increasing reservoir pressures.

For the steady state analysis the system was simulated using a specialised computer programme OLGA 7.3 together with a particular multiphase flow correlation (OLGA-S) and data files for the fluid, which were generated using the GERG 2008 equation of state programme. Simulations were run from initial conditions until temperatures, pressures, and flowrates throughout the system had reached steady state conditions.

Simulations were conducted at a range of different flowrates representing minimum and maximum flows through the life of the storage site and for both summer and winter ambient conditions detailed in Table 4.1, below.

Table 4.1: Flowrates at Various Field Life Points

	Minimum Flowrate (MTPA)			Maximum Flowrate (MTPA)		
Field Life	Drax AGI	Camblesforth Multi Junction	Total	Drax AGI	Camblesforth Multi Junction	Total
Year 1	0.58	0	0.58	2.68	0.00	2.68
Year 5	0.58	0	0.58	2.68	7.32	10.00
Year 10	0.58	0.32	0.90	2.55 (1)	14.46	17.01

(1) Drax AGI can flow up to 2.68 MTPA, but normal flowrate is 2.55 MTPA

There are 6 well slots on the injection platform near the subsea storage site (block 5/42). Currently 3 wells have been planned. These wells have deviated trajectories (spread out) and vary in depth. The planned deepest well is referred to as P5W2; the other two as P5W1 and P5W3. All three would have a tubing diameter of 5½ inch.

The calculations assume that at Year 5 the flow from Drax AGI is commingled with further flow sources at the Camblesforth Multi Junction for a total maximum flowrate of 10 MTPA and that in Year 10, the total flow is increased to 17 MTPA. When this maximum flow rate is reached it is planned the target rate of 10 MTPA would be injected at the platform wells (block 5/42), while the remaining 7 MTPA is routed to a future injection site. Once the platform reservoir had been filled, the entire flow would be diverted to the additional wells that would be located at a remote storage site.

4.2 Fluid Phase Envelopes

Fluid property files were generated using Multiflash 4.1 with the GERG 2008 equation of state. A total of 3 fluid compositions have been considered for this study:

- First Load (Drax AGI only, early field life);

- Full Load (Drax AGI combined with Camblesforth Multi Junction, mid to late field life); and
- Full Load with maximum Impurities (a sensitivity composition, based on the NGC pipeline entry specification).

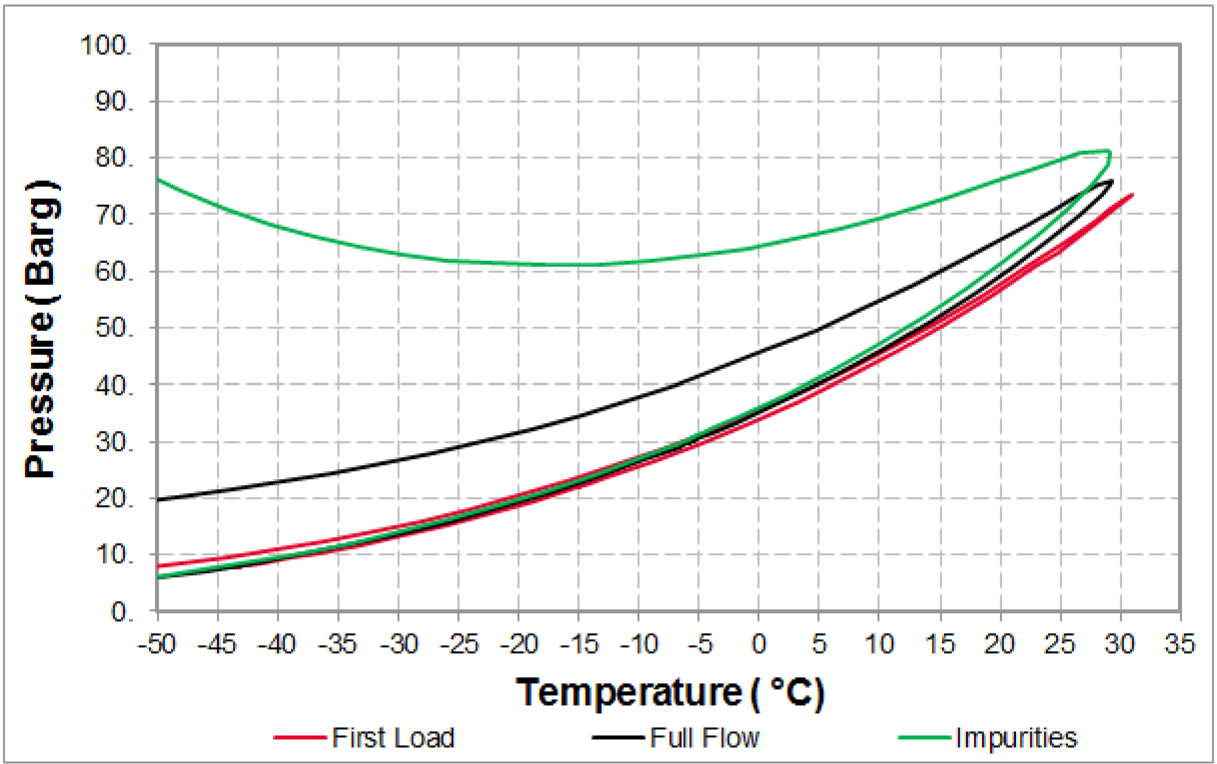
The First Load, Full Flow (sometimes called generic) and Impurities (sometimes called sensitivity) compositions are shown below in Table 4.2.

Table 4.2: Fluid Composition

	First Load	Full Flow (generic)	Impurities (sensitivity)
Component	**mol%**	**mol%**	**mol%**
Carbon-Dioxide	99.700	97.400	96.000
Argon	0.068	0.599	0.411
Nitrogen	0.226	1.995	1.371
Oxygen	0.001	0.001	0.001
Water	0.005	0.005	0.005
Hydrogen	0.000	0.000	2.000
Hydrogen-Sulphide	0.000	0.000	0.002
Carbon-Monoxide	0.000	0.000	0.200
Methane	0.000	0.000	0.010
Total	**100.000**	**100.000**	**100.000**

As the amount of impurities increases, the phase envelope becomes wider so there is a greater range of pressures and temperatures at which the fluid can be in the two-phase region. The Impurities composition represents the worst-case phase envelope expected. Figure 4.1:Fluids Phase Envelopes below shows the phase envelopes for all of the fluid compositions considered in this study.

Figure 4.1: Fluids Phase Envelopes



4.3 Operating Pressure Envelope

The pressure constraints for the onshore and offshore pipelines are shown in Table 4.3. The minimum operating pressure would be set such that the fluid, during steady state operation, should always remain in the dense phase), thereby avoiding two-phase conditions (liquid and gas).

Table 4.3: System Pressure Constraints

Pipeline	Minimum Operating Pressure	Maximum Allowable Operating Pressure
Onshore	90 barg	135 barg
Offshore	90 barg	182 barg

For the flowrates shown in Table 4.1 above, the setpoints in the system (pump suction pressure or platform arrival pressure, depending on the case) would be controlled to ensure the pressure constraints are not transgressed. The CO_2 booster pumps at Barmston were assumed to have an efficiency of 75% (isentropic/adiabatic). A preliminary generic pump curve, which indicates this assumption was reasonable, is presented in Figure 4.3.

The reservoir pressures during the First Load cases are not expected to vary greatly; therefore a reservoir pressure sensitivity analysis was performed only for flowrates from Year 5 (10 MTPA) onwards. The reservoir pressure would increase with cumulative injection from the First Load onwards. The impact of additional injection wells drilled in the 5/42 block on reservoir pressure over time has not been assessed.

After Year 5 the pressure in the reservoir varies based on the assumed reservoir model properties. A conservative estimate was used for a finite volume aquifer, with a pressure increase of 27 bar from the Year 1 reservoir pressures at the perforation datum point (1300m below sea-level) by Year 5. A less conservative estimate was also considered, where the volume of an adjacent aquifer was not confined. This resulted in a reservoir pressure increase of 21 bar.

By Year 10 the conservative reservoir pressure would have increased by 44 bar and the less conservative reservoir pressure would have increased by 28 bar compared to Year 1.

Table 4.4 shows the average reservoir pressures considered in this analysis.

Table 4.4: Average Reservoir Pressures over Life of the Storage Site

Well	Year	Flowrate (MTPA)	Low Pressure (barg)	High Pressure (barg)	Injectivity MTPA/bar
P5W1	1	0.58 - 2.68	150	150	
P5W2	5	10	171	177	0.0442
P5W3	10	17	178	194	

As shown in Table 4.5 and Table 4.6 below, if operating above 1 MTPA (which would be just 37% of the design flowrate from Drax AGI), two-phase flow would not be predicted. It should also be noted that the Impurities composition, which was used in this analysis, represents the pipeline entry specification and that the composition during normal operation may be significantly less onerous, particularly when operating from Drax AGI only (which would have a very narrow phase envelope and therefore is unlikely to present a two-phase flow risk). By inspection of the phase envelopes in Figure 4.1, it can be seen that at the pressure-temperature conditions shown below, the First Load composition would be outside the phase envelope. As this is the most likely composition when the reservoir pressure is ≤170 barg, the risk of two-phase flow in the wells would be small. Those cases where two-phase flow is predicted are highlighted.

Table 4.5: Top Hole Pressures for Range of Well Flows and Reservoir Pressures

Tubing Size	Flowrate (MTPA)	Top Hole Pressure for a range of Reservoir Pressure (150 barg to 190 barg)				
		150 barg	160 barg	170 barg	180 barg	190 barg
5½ inch	0.58	** 57.5 barg	** 63.7 barg	** 71.5 barg	80.4 barg	89.3 barg
	1.00	** 69.2 barg	77.9 barg	86.7 barg	95.7 barg	104.6 barg
	1.50	91.8 barg	100.6 barg	109.5 barg	118.4 barg	127.4 barg
	2.00	119.4 barg	128.2 barg	137.0 barg	145.9 barg	154.9 barg

** These cases are where two-phase flows would be predicted.

Table 4.6: Top Hole Temperatures for Range of Well Flows and Reservoir Pressures

	Flowrate (MTPA)	Top Hole Temperature (C) for a range of Reservoir Pressure (150 barg to 190 barg)				
		150 barg	160 barg	170 barg	180 barg	190 barg
C5½ inch	0.58	** 7.5	** 9.9	** 12.2	13.3	14.1
	1.00	** 11.6	13.1	13.9	14.7	15.3
	1.50	14.4	15.1	15.7	16.3	16.8
	2.00	16.4	16.9	17.4	17.8	18.2

** These cases are where two-phase flows would be predicted.

4.4 Reservoir Pressure Sensitivity

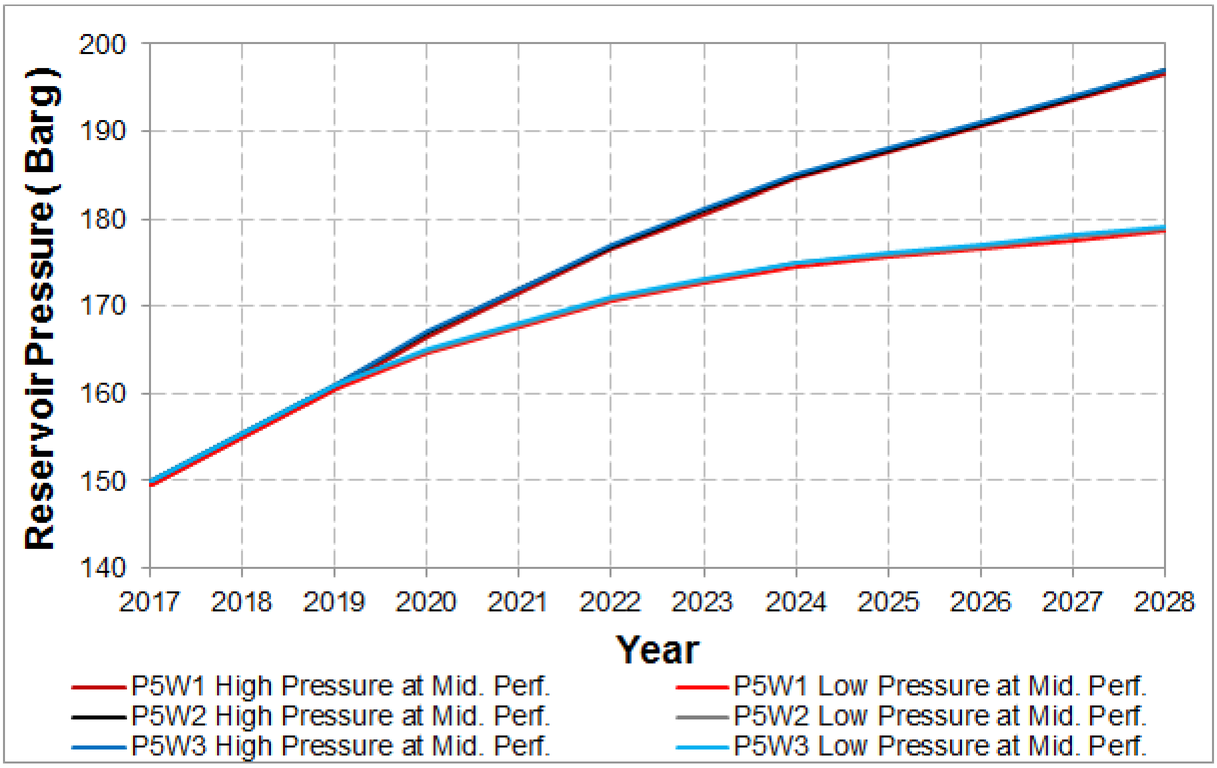
The reservoir pressures during first load are not expected to vary greatly, therefore a reservoir pressure sensitivity analysis was performed for flowrates from Year 5 (10MTPA) onwards. The early life reservoir conditions are given in Table 4.7 below.

Table 4.7: Year 1 Reservoir Conditions

Well	Pressure at Top Perforation (barg)	Temperature at Top Perforation (C)
P5W1	140.1	56.9
P5W2	140.3	56.9
P5W3	140.7	57.1

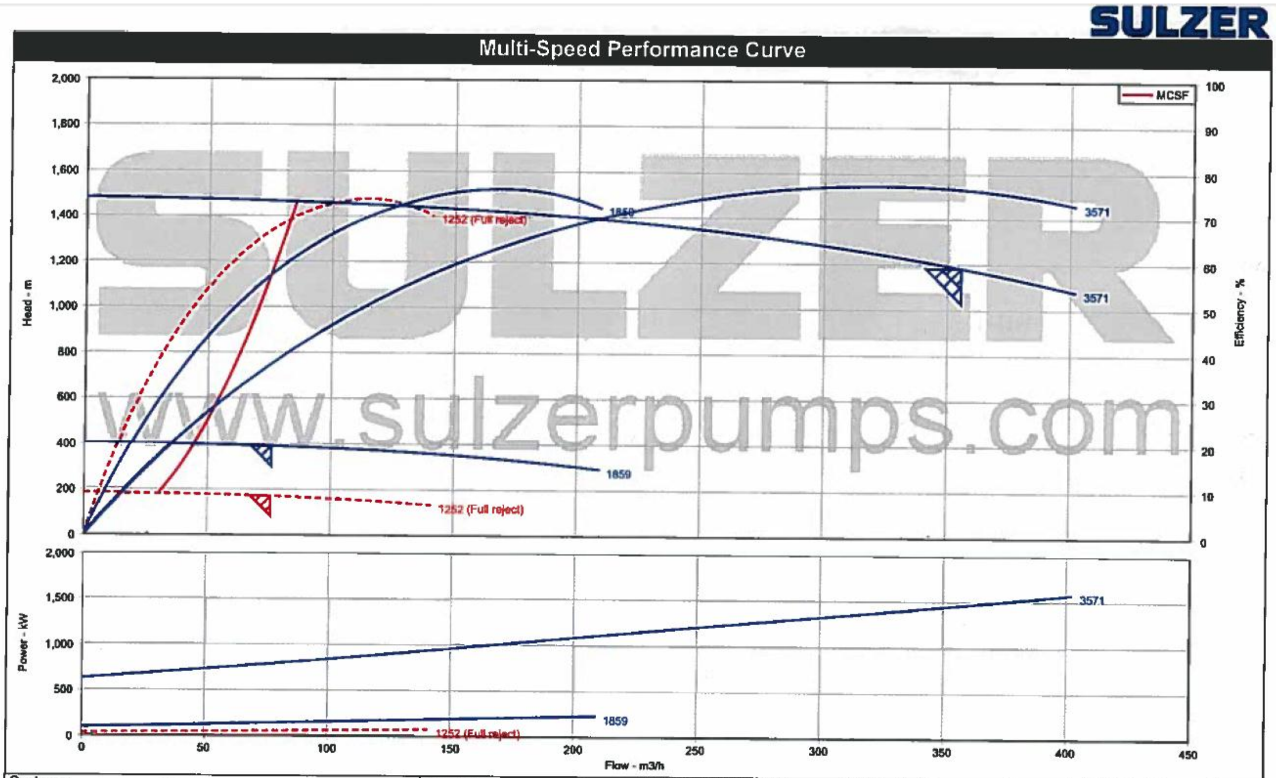
The reservoir pressure will increase with cumulative injection. Reservoir pressures are illustrated in Figure 4.2 below. It should be noted that the reservoir curves provided are based on injection rates of 2.68MTPA. Larger flowrates will have a significant impact on reservoir pressures however this work is ongoing.

Figure 4.2: Reservoir Pressure over Field Life



After Year 5 the pressure in the reservoir can vary based on the assumed reservoir model properties. A conservative estimate was used for a finite volume aquifer, with a pressure increase from the Year 1 reservoir pressures of 27bar at the top of each perforation. A less conservative estimate was also considered, where the volume of an adjacent aquifer was not confined. This resulted in a reservoir pressure increase of 21bar. By Year 10 the conservative reservoir pressure will have increased by 44bar and the less conservative reservoir pressure will have increased by 28bar compared to year 1.

Figure 4.3: Preliminary Pump Performance Curve



Customer	:	Type / Size	: GSG 100-300 (C)(Bd)	Flow, rated	: 355.7 m3/h
Inquiry Number/ID	:	Stages	: 8	Differential head / pressure, rated	: 1,182.0 m
Item number	: Default	Speed, rated	: 3,570 rpm	Fluid density, rated / max	: 0.779 / 0.971 kg/dm3
Service	:	Based on curve number	: 4611.04.421-01	Viscosity	: 1.00 cSt
Quantity	: 1	Efficiency	: 76.56 %	Cq/Ch/Ce/Cn [ANSI/HI 9.6.7-2010]	: 1.00 / 1.00 / 1.00 / 1.00
Sulzer Reference ID	:	Power, rated	: 1,453 kW	Impeller diameter, rated	: 293 mm
Date of Last Update	: 05 Sep 2014 09:08	NPSH (3% head drop)	: 5.98 m		

5 Steady State Operation

This section provides the pipeline hydraulics for the CO_2 transportation system assuming that the flowrate to each well and the number of wells at the injection platform is fixed and the system is at the maximum pressure requirements. This is based on up to 10 MTPA being injected at the injection platform, with an additional 7 MTPA (when applicable) routed to a remote location, yet to be defined.

5.1 Years 1 to 5 (0.58 – 2.68 MTPA)

Table 5.1 and Table 5.2, below, show the pressure profiles for the First Load composition (Year 1) for the minimum flow case and the peak Years 1 to 5 flowrate for summer and winter conditions respectively (well P5W2 was used as it would have the longest well tubing geometry and therefore presents the worst-case for pressure drop). As the flowrates were relatively low in these cases, the CO_2 booster pumps at Barmston would not be required. However, to avoid the CO_2 entering the 2-phase region in the pipeline the pressure would be controlled at the platform. A setpoint of 100 barg would be selected to ensure that the pipeline contents would not enter the two-phase region during steady state conditions. As the composition would have a high purity (as per the First Load composition) the two phase region is very narrow (see Figure 4.1, above) and so the risk of entering into it would be very low. However, the observations from this analysis could be applied to less pure compositions when operating at low flowrates.

Table 5.1: Years 1 to 5 Pressure Profiles – Summer Conditions and First Load Composition

Flowrate		Pressure (barg)							Bottomhole Pressure (barg)			Well Flowrate (MTPA)		
(MTPA)	Wells	Drax	Camb.	Peak Elevation	Barmston	Platform	Choke DP (bar)	Reservoir Pressure (barg)	P5W1	P5W2	P5W3	P5W1	P5W2	P5W3
0.58	P5W2	102.2	102.0	89.7	102.2	100.0	41.4	150	-	166.9	-	-	0.58	-
** 2.68	** P5W1	** 157.6	155.5	142.4	154.9	152.1	0.9	150	214.3			2.68		
2.68	P5W1, P5W2	106.2	104.1	91.6	103.4	100.0	24.9	150	184.0	184.3	-	1.34	1.34	-
2.68	P5W1, P5W2, P5W3	106.2	104.1	91.6	103.4	100.0	43.3	150	173.6	173.9	175.1	0.88	0.88	0.91

** In these cases the flow rate exceeded the capacity of just one well the onshore pipeline MAOP of 135 barg was exceeded.

Table 5.2: Years 1 to 5 Pressure Profiles – Winter Conditions and First Load Composition

Flowrate		Pressure (barg)							Bottomhole Pressure (barg)			Well Flowrate (MTPA)		
(MTPA)	Wells	Drax	Camb.	Peak Elevation.	Barmston	Platform	Choke DP (bar)	Reservoir Pressure (barg)	P5W1	P5W2	P5W3	P5W1	P5W2	P5W3
0.58	P5W2	102.4	102.2	89.1	102.4	100.0	21.5	150	-	167.0	-	-	0.58	-
** 2.68	** P5W1	** 144.8	142.7	129.4	142.2	139.3	0.7	150	214.6			2.68		
2.68	P5W1, P5W2	106.3	104.1	91.2	103.6	100.0	36.8	150	184.3	184.7	-	1.34	1.34	-
2.68	P5W1, P5W2, P5W3	106.3	104.1	91.2	103.6	100.7	54.5	150	173.9	174.3	175.6	0.88	0.88	0.92

** In these cases the flow rate exceeded the capacity of just one well the onshore pipeline MAOP of 135 barg was exceeded.

As the flowrates were well below the pipeline design capacity when only Drax AGI is supplying the pipeline, the net pipeline pressure drop was small in both summer and winter. The minimum pressure in both cases occurs at the highest/peak elevation point along the pipeline, which would be between the Tollingham and Dalton block valve stations, at approximately 36 km from the inlet.

The minimum flowrate of 0.58 MTPA could be injected into a single well (the P5W2 well was used in this analysis as it would have the longest well tubing geometry and therefore is the most conservative) with the pressure controlled at the platform. The pressure drop (2.2 bar) through the pipeline was very low, so there would be some scope for adjusting the pressure setpoint at the platform upwards if desirable. The setpoint should not be adjusted below 100 barg as the minimum pressure (at the highest elevation point) would be just below 90 barg, which would be the minimum pipeline operating pressure. Reducing the pressure below 90 barg would risk two-phase operation during injection or following shutdown. It was recognised however, that for the First Load composition the risk of entering the two-phase region would be low due to the purity of CO_2 giving rise to a very narrow phase envelope.

Injecting 2.68 MTPA (design flowrate from Drax AGI) into a single well would not be possible, as the indicated pipeline pressure exceeds the maximum onshore pipeline operating pressure of 135 barg by over 22 bar. A minimum of two injection wells would be required in Years 1 to 5 to meet the maximum operating pressure constraint. The P5W1 and P5W2 wells were used as they are longer than the P5W3 well and therefore present a more conservative basis.

The fluid would reach ambient temperature by 40 km from the platform at these low flowrates. It is worth noting that the temperature profile in the offshore section changes: the first 25 km would be concrete-coated, so would have relatively good insulating properties giving a near linear heat loss. Where the pipeline was not concrete-coated, the temperature drops much more quickly as the heat retention is much poorer.

A range of minimum theoretical CO_2 temperature may be calculated using the Multiflash programme, assuming a fluid temperature of -7°C (minimum ambient air temperature) with and an isentropic (adiabatic) flash downstream of the choke valve, for a range of platform pressures upstream of the injection choke valve. The minimum theoretical temperature downstream of the choke valve for a pressure of 33.9 barg at the top of the tubing (minimum steady state pressure) would range from -11°C to -21°C depending on the pressure upstream of the choke and composition. The impurities composition exhibits a greater expansion-cooling effect due to the level of impurities and wider phase envelope.

The normal operating temperature for the First Load composition at minimum flowrate was above the minimum theoretical as the temperature at the platform was significantly higher than the minimum ambient. Even taking the worst-case minimum theoretical temperatures, a minimum design temperature downstream of the choke of -25°C should be sufficient to accommodate all likely operating conditions.

5.2 Years 5 to 10 (10 MTPA)

The flowrate through the injection system would be expected to increase in Year 5, when additional sources of CO_2 would be supplied to the Camblesforth Multi Junction and the total flowrate increased to 10 MTPA. To manage the increased flowrate, an additional number of wells would be required to maintain the pipeline pressure within the maximum allowable operating pressure (MAOP) constraint. Up to three additional wells are considered at the injection platform, with these wells drilled into the same reservoir (block 5/42) as the P5W1, P5W2 and P5W3 wells (hence having the same reservoir properties). It was noted that additional wells may not all be located at the same facility, but for the purposes of this analysis, it was assumed that they are local to the platform due to significant uncertainty in location of future storage site(s). For the purposes of this analysis, it was assumed that the wells had the same well trajectory as P5W2 (the longest of the first three wells) with 5½ inch tubing. The final well completion design would have some impact on the injection rates to the future wells and impact the backpressures required or flowrates that could be achieved; the different injection rates between P5W1, P5W3 and the future (local) wells (in the 5/42 area) would give an indication of the sensitivity (impurity factor).

A pump suction pressure setpoint of 95 barg was selected for this analysis.

The pressure profiles for summer and winter conditions are presented in Table 5.3 and Table 5.4 respectively for the Full Flow/Generic and Impurities/Sensitivity compositions at low and high reservoir pressures. It is assumed that P5W1, P5W2 and P5W3 (3 wells) were used with a varying number of additional local wells (+1, +2 or +3), drilled into the 5/42 area. In Years 5 to10 for a 3 + 2 wells at the 5/42 storage site the pipeline MAOPs were not exceeded for all the scenarios considered.

Table 5.3: Years 5 to 10 Pressure Profiles (10 MTPA) – Summer Conditions

	Reservoir Pressure		Pressure (barg)					
Composition	(barg)	Wells	Drax AGI	Camb.	Peak Elevation	Pump Suction	Pump Discharge	Platform
Full Flow	171	3 + 1	109.7	107.7	90.4	95.0	178.5	159.6
		3 + 2					149.0	130.2
		3 + 3					131.9	113.0
	177	**3 + 1	109.7	107.7	90.4	95.0	183.4	165.3**
		3 + 2					154.1	135.4
		3 + 3					137.0	118.1
Impurities	171	**3 + 1	110.5	108.4	91.3	95.0	185.2	165.6**
		3 + 2					155.5	136.1
		3 + 3					138.2	118.7
	177	**3 + 1	110.5	108.4	91.3	95.0	190.0	170.5**
		3 + 2					160.7	141.3
		3 + 3					143.3	123.8

** In these cases the platform control valve was fully open, but with only four wells the offshore pipeline MAOP of 182 barg was exceeded.

Table 5.4: Years 5 to 10 Pressure Profiles (10 MTPA) – Winter Conditions

	Reservoir Pressure		Pressure (barg)					
Composition	(barg)	Wells	Drax AGI	Camb.	Peak Elevation	Pump Suction	Pump Discharge	Platform
Full Flow	171	3 + 1	109.7	107.7	90.4	95.0	178.5	159.6
		3 + 2					149.0	130.2
		3 + 3					131.9	113.0
	177	3 + 1	109.7	107.7	90.4	95.0	183.4	165.3
		3 + 2					154.1	135.4
		3 + 3					137.0	118.1
Impurities	171	3 + 1	110.5	108.4	91.3	95.0	185.2	165.6
		3 + 2					155.5	136.1
		3 + 3					138.2	118.7
	177	3 + 1	110.5	108.4	91.3	95.0	190.0	170.5
		3 + 2					160.7	141.3
		3 + 3					143.3	123.8

Typically 5 wells (the original P5W1, P5W2 and P5W3 wells plus 2 additional local wells) would be required to inject 10 MTPA while maintaining the pressure in the offshore pipeline within the 182 barg MAOP level for all operating scenarios considered (reservoir pressure, fluid composition and ambient temperature). It would be possible to inject at just 4 wells only in winter conditions.

5.3 Year 10 Onwards (17 MTPA)

From Year 10 onwards, it would be anticipated that CO_2 will be supplied, into the Camblesforth Multi Junction (Camb.), by additional power stations or other emitters for onwards transport to Barmston, taking the maximum flowrate up to a total of 17 MTPA. $CO_{2,}$ which would be injected at a remote facility, would be pumped offshore; therefore the pressure requirements shown below were irrespective of the ultimate location of this remote facility.

Table 5.5 and Table 5.6 show the pressure profiles through the system for 17 MTPA in summer and winter conditions respectively. The Full Flow and Impurities compositions are shown at low and high reservoir pressures. For the purposes of this analysis, it is assumed that 10 MTPA is injected at the injection platform and 7 MTPA is sent to a remote injection facility. Figure 5.1and Figure 5.2 show the minimum and maximum pipeline pressure and temperature profiles respectively in Year 10 onwards for a 3 + 3 well scenario at the 5/42 area.

Table 5.5: Year 10 Onwards Pressure Profiles (17 MTPA) – Summer Conditions

Composition	Reservoir Pressure (barg)	Wells	Pressure (barg) Drax AGI	Camb.	Peak Elevation	Pump Suction	Pump Discharge	Platform
Full Flow	178	**3 + 1	130.4	128.4	91.0	92.0	214.7	**165.7
		**3 + 2					188.1	**136.9
		3 + 3					170.0	119.2
	194	**3 + 1	130.4	128.4	91.0	92.0	241.3	**187.3
		**3 + 2					197.4	**150.6
		**3 + 3					184.4	**133.0
Impurities	178	**3 + 1	132.1	130.0	92.3	92.0	251.4	**193.0
		**3 + 2					195.7	**142.4
		3 + 3					177.5	124.8
	194	**3 + 1	132.1	130.0	92.4	92.0	257.4	**200.3
		**3 + 2					212.1	**158.5
		**3 + 3					191.0	**138.7

** In these cases the platform control valve was fully open, but with only four or five wells the offshore pipeline MAOP of 182 barg was exceeded and with a higher reservoir pressure even six would be insufficient.

Table 5.6: Year 10 Onwards Pressure Profiles (17 MTPA) – Winter Conditions

Composition	Reservoir Pressure (barg)	Wells	Pressure (barg) Drax AGI	Camb.	Peak Elevation	Pump Suction	Pump Discharge	Platform
Full Flow	178	**3 + 1	130.0	128.0	91.2	92.0	204.7	155.3
		**3 + 2					175.8	126.8
		3 + 3					159.0	109.6
	194	**3 + 1	130.0	128.0	91.2	92.0	218.4	169.9
		**3 + 2					190.1	141.3
		3 + 3					173.2	124.1
Impurities	178	**3 + 1	131.7	129.7	92.1	92.0	212.0	161.6
		**3 + 2					183.4	132.6
		3 + 3					166.4	115.2
	194	**3 + 1	131.7	129.7	92.1	92.0	229.6	179.0
		**3 + 2					197.5	147.1
		3 + 3					180.4	129.6

** In these cases the platform control valve was fully open, but with only four or five wells the offshore pipeline MAOP of 182 barg was exceeded.

Table 5.5 and Table 5.6 show that a flowrate of 17 MTPA could only be achieved when injecting 10 MTPA at the injection platform and sending the remaining 7 MTPA to a remote injection facility to attain a lower reservoir pressure. Therefore, either the pump discharge and the offshore pipeline design pressure would need to be increased or more of the CO_2 would need to be sent to the remote injection facility to maintain the offshore pipeline maximum operating pressure ≤182 barg for most of the scenarios analysed.

The onshore pipeline has sufficient capacity for 17 MTPA, as the maximum pressure is below the MAOP of 135 barg for a pump suction pressure of 92 barg.

Figure 5.1: Year 10 Onwards Pressure Profiles with Injecting 10 MTPA at 5/42 Injection Platform

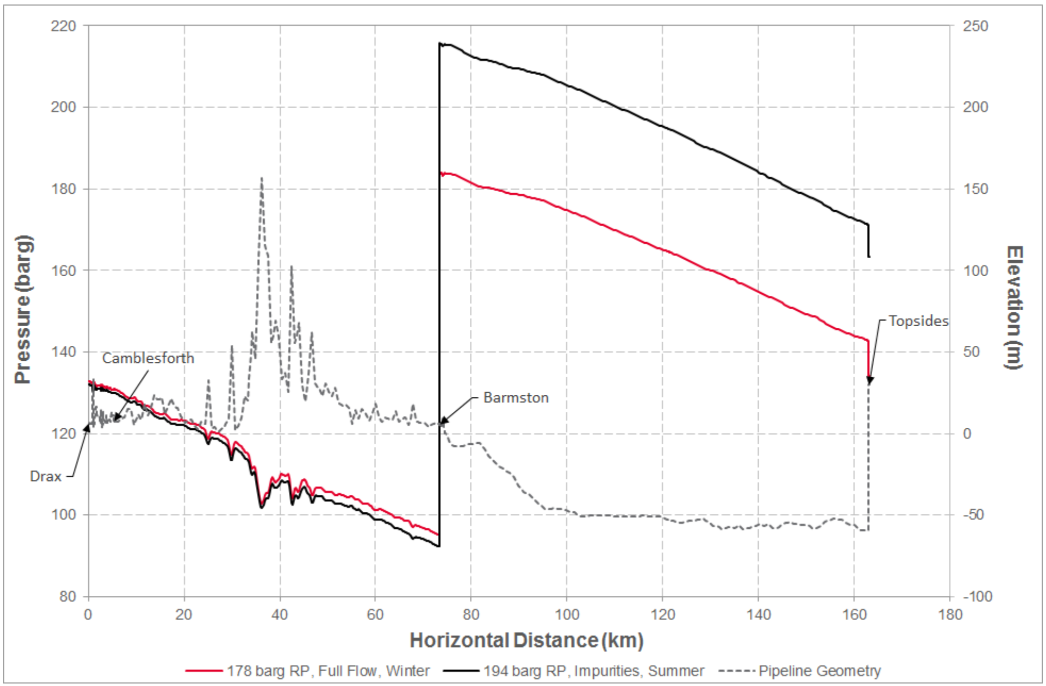
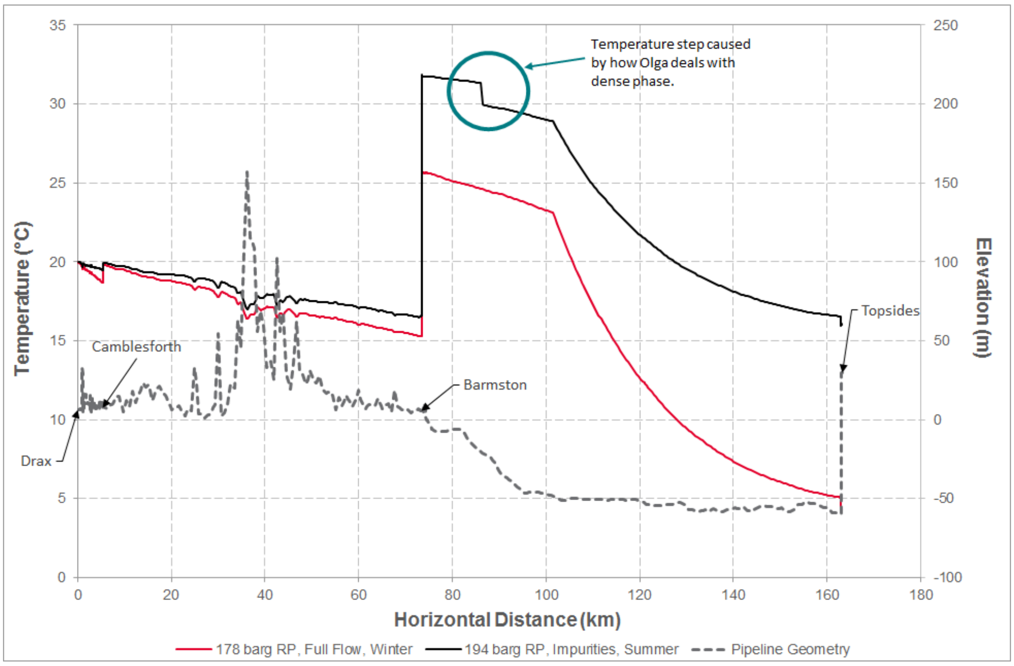


Figure 5.2: Year 10 Onwards Temperature Profiles with Injecting 10 MTPA at 5/42 Injection Platform



6 Steady State System Constraints

The aim of this section is to identify system capacity and constraints over life of the field (the T&S system). Section 5, above, focussed on specific target flowrates (0.58, 2.68, 10 and 17 MTPA). The analysis below seeks to determine the injection rates the system would be able to achieve, whether that be greater or less than the desired target rates.

6.1 Years 1 to 5 (0.58 – 2.68 MTPA)

This section provides estimates for the maximum flowrate that the system can operate without the use of the booster pumps at Barmston for a given well availability configuration. The key parameter would be the pressure at Drax AGI, as this is the maximum pipeline operating pressure for the system when operating without the booster pumps and should not exceed 135 barg (MAOP). The First Load and Impurities compositions are the extremes of the range considered (these would have the lowest and highest pressure drops). The maximum reservoir pressure of 194 barg was assumed for the Impurities composition to ensure the flowrates presented are conservative.

Table 6.1 shows the maximum flowrates that can be achieved without using the Barmston booster pumps for the various well configurations for the P5W1, P5W2 and P5W3 wells, assuming 135 barg at Drax AGI (onshore pipeline MAOP).

Table 6.1: Peak Flowrates without Using the Barmston Booster Pump

	Maximum Flowrate (MTPA)	
Well Configuration	**First Load (150 barg)**	**Impurities (194 barg)**
P5W1	2.34	1.50
P5W2	2.34	1.50
P5W3	2.52	1.60
P5W1 + P5W2	4.44	2.88
P5W1 + P5W3	4.59	2.96
P5W2 + P5W3	4.59	2.96
P5W1 + P5W2 + P5W3	6.26	4.09

The minimum flowrate of 0.58 MTPA could be injected into a single well without the use of the Barmston booster pumps over the life of the storage site. The design flowrate from Drax AGI (2.68 MTPA) could also be injected without the use of the Barmston booster pumps assuming that there are no halite precipitates in the reservoir which could have an impact on the injectivity.

6.2 Years 5 to 10 (10 MTPA)

Table 6.2 (summer conditions) and Table 6.3 (winter conditions) show the injection rates to each well for low and high reservoir pressures and for Full Flow and Impurities compositions for Years 5 to 10 for summer and winter conditions respectively, assuming a pump discharge pressure of 182 barg (offshore pipeline MAOP). This assumes that all the CO_2 is injected at the platform and that there is no remote injection facility available.

Table 6.2: Peak Flowrates to Each Well for Years 5 to 10 for Offshore Pipeline MAOP of 182 barg – Summer

Composition	Reservoir Pressure (barg)	Number of Future Local Wells in 5/42	Flowrate (MTPA) P5W1	P5W2	P5W3	Local Future	Total
Full Flow	171	0	2.4	2.4	2.6	0.0	7.5
		** 1				2.4	10.0
		** 2				4.9	12.4
		** 3				7.3	14.9
	177	0	2.2	2.2	2.4	0.0	6.9
		1				2.2	9.2
		** 2				4.5	11.4
		** 3				6.7	13.7
Impurities	171	0	2.4	2.4	2.5	0.0	7.3
		1				2.4	9.6
		** 2				4.7	12.0
		** 3				7.1	14.3
	177	0	2.2	2.2	2.3	0.0	6.6
		1				2.2	8.8
		** 2				4.3	11.0
		** 3				6.5	13.1

** In these cases the total injection rate is greater than the target of 10 MTPA.

Table 6.3: Peak Flowrates to Each Well for Years 5 to 10 for Offshore Pipeline MAOP of 182 barg – Winter

Composition	Reservoir Pressure (barg)	Number of Future Local Wells in 5/42	Flowrate (MTPA) P5W1	P5W2	P5W3	Local Future	Total
Full Flow	171	0	2.6	2.6	2.8	0.0	8.0
		** 1				2.6	10.5
		** 2				5.2	13.1
		** 3				7.7	15.7
	177	0	2.4	2.4	2.6	0.0	7.3
		1				2.4	9.7
		** 2				4.8	12.1
		** 3				7.2	14.5
Impurities	171	0	2.5	2.5	2.7	0.0	7.7
		** 1				2.5	10.2
		** 2				5.0	12.7
		** 3				7.5	15.2
	177	0	2.3	2.3	2.5	0.0	7.1
		1				2.3	9.4
		** 2				4.6	11.7
		** 3				6.9	14.0

** In these cases the total injection rate is greater than the target of 10 MTPA.

A flowrate of 10 MTPA could be injected into the 5/42 block provided that at least 5 wells are available, irrespective of ambient conditions and fluid composition. As reservoir pressure increases (a greater push-back), the peak injection flowrate would decrease, as should be expected, and higher levels of impurities in the fluid would reduce the peak injection rates.

The flowrates injected into the local future wells (in the 5/42 block) would be a function of the well tubing geometry assumed (for this analysis it was assumed the future wells are the same as well P5W2 as this is the most onerous well). Based on the difference in flowrates to the P5W1 and P5W3 wells, it is reasonable to assume the flowrate could increase by up to 0.2 MTPA if a more favourable well geometry is used for the future wells in the 5/42 block.

6.3 Year 10 Onwards (17 MTPA)

Table 6.4 and Table 6.5 show the flowrate to each well and the minimum flowrate that would need to be routed to the remote facility for summer and winter conditions respectively, assuming a pump discharge pressure of 182 barg (offshore pipeline MAOP). The number of future local wells (in addition to P5W1, P5W2 and P5W3) were varied to show the system constraints (and flowrate required to be sent to the remote injection facility) if less than 6 wells were available at the injection facility. CO_2 that is injected at a remote facility would be pumped offshore, therefore the pipeline pressure requirements shown below are irrespective of the ultimate location of this remote facility.

Table 6.4: Peak Flowrates to Each Well for 17 MTPA for Offshore Pipeline MAOP of 182 barg – Summer Conditions

	Reservoir Pressure		Flowrate (MTPA)					
Composition	(barg)	Number of Future Local Wells in 5/42	P5W1	P5W2	P5W3	Local Future	Remote Future	Total
Full Flow	178	0	1.9	1.9	2.1	0.0	11.1	17.0
		1				1.9	9.2	
		2				3.8	7.3	
		** 3				5.7	5.4	
	194	0	1.6	1.6	1.8	0.0	11.9	17.0
		1				1.6	10.3	
		2				3.3	8.6	
		** 3				4.9	7.0	
Impurities	178	0	1.8	1.8	1.9	0.0	11.6	17.0
		1				1.8	9.8	
		2				3.5	8.0	
		** 3				5.3	6.2	
	194	0	1.5	1.5	1.6	0.0	12.4	17.0
		1				1.5	10.9	
		2				3.0	9.4	
		3				4.5	7.9	

** In these cases 10 MTPA would be injected into the platform wells (which would mean that the flowrate to the remote storage site must be less than 7 MTPA).

Table 6.5: Peak Flowrates to Each Well for 17 MTPA for Offshore Pipeline MAOP of 182 barg – Winter Conditions

Composition	Reservoir Pressure (barg)	Number of Future Local Wells in 5/42	Flowrate (MTPA) P5W1	P5W2	P5W3	Local Future	Remote Future	Total
Full Flow	178	0	2.1	2.1	2.3	0.0	10.5	17.0
		1				2.1	8.4	
		** 2				4.2	6.3	
		** 3				6.3	4.2	
	194	0	1.8	1.8	2.0	0.0	11.3	17.0
		1				1.8	9.5	
		2				3.7	7.7	
		** 3				5.5	5.8	
Impurities	178	0	2.0	2.0	2.1	0.0	10.9	17.0
		1				2.0	9.0	
		** 2				3.9	7.0	
		** 3				5.9	5.0	
	194	0	1.7	1.7	1.8	0.0	11.8	17.0
		1				1.7	10.1	
		2				3.4	8.3	
		** 3				5.1	6.6	

** In these cases 10 MTPA would be injected into the platform wells (which would mean that the flowrate to the remote storage site must be less than 7 MTPA).

An injection rate of 17 MTPA could only be met with 6 wells at storage site (in the 5/42 block) in all cases, except the most onerous (high reservoir pressure, summer conditions and Impurities composition).

Note: halite precipitation may increase the pressure drop across the formation (i.e. reduce the well injectivity), requiring greater pressure from the pumps or water wash operations for remediation.

6.4 Summary of Conclusions

High ambient temperatures and high levels of impurity in the CO_2 would increase the pressure drop through the system, thereby decreasing the rate of CO_2 that can be injected at the offshore injection facility.

It would possible to operate the CO_2 transportation system without the use of the CO_2 booster pumps at Barmston in Years 1 to 5 when supply is expected from Drax AGI only (which has a design flowrate of 2.68 MTPA). There is additional capacity beyond 2.68 MTPA, depending on the composition of the CO_2 supply and the number of wells in operation (initially 3 wells are planned). It should be noted however, that other factors, such as halite precipitation, could impact on the injectivity of the wells and hence increase the pressures required for injection (thus decreasing the peak injection rates).

When additional supply from future emitters feeding into the network via Camblesforth Multi Junction is available (predicted to be during Year 5-10), the expected CO_2 flowrate would be 10 MTPA, which can be transported provided at least 5 wells were available for injection. The CO_2 booster pumps would be required at this stage to allow the system to maintain this flow without the pressure in the onshore pipeline being pushed above the MAOP of 135 barg.

From Year 10 onwards, it is predicted that CO_2 would be supplied by additional sources up to a total of 17 MTPA and a significant proportion of the CO_2 would need to be routed via offshore pumping to a remote injection facility (location etc. to be determined). As the reservoir pressure increases following prolonged CO_2 injection, the pressure required to transport the CO_2 and maintain injection rates of 10 MTPA at the injection platform would need to exceed the offshore pipeline MAOP of 182 barg for all cases except for low reservoir pressure and/or winter conditions when 6 wells are available for injection. The injection rate at the platform would be limited to 9.1 – 12.8 MTPA, depending on the conditions (composition, reservoir pressure and ambient conditions) with the remainder being pumped to the remote facility.

The pressure control scheme for the CO_2 transportation system would be two-fold:

- pressure controlled at the platform for low flow operation (typically when the CO_2 booster pumps were not in operation, but could conceivably be used with the pumps if desired); and
- pressure controlled at the booster pump suction to ensure the pressure in the onshore pipeline does not transgress the pressure constraints on the system.

Table 6.6 shows the recommended system pressure setpoints to ensure the pipeline contents would stay out of the two-phase region during steady state and shutdown conditions.

Table 6.6: System Pressure Setpoints

Year	Flowrate (MTPA)	Pump Suction Pressure Setpoint (barg)	Platform Pressure Setpoint (barg)
1 to 5	0.58	Not Required	100
1 to 5	2.68	Not Required	100
5 to 10	10	95	100 to 160 (flowrate dependent)
10 Onwards	17	92	
Turndown Operation with Pumps Operating		100	

It would be possible for the CO_2 to fall below the 90 barg minimum operating pressure during shutdown conditions, particularly at the peak elevation point between Camblesforth Multi Junction and Barmston. The pump suction pressure setpoints are determined to ensure that gas break-out does not occur as the CO_2 cools and contracts and the CO_2 stays in the dense-phase or liquid-only region of the phase envelope. The pump suction pressure setpoints above are set to be 2 bar above the minimum pressure required to avoid entering the two-phase region under these conditions.

Operating at low flowrates early in the life of the storage site, when reservoir pressure would be low, could result in two-phase flow downstream of the injection choke valves if the CO_2 purity is low (i.e. the Impurities composition), but the pressure and flowrates downstream of the choke should be steady (not oscillating), and should cause instability issues in the well tubing. When the CO_2 purity was high (First Load composition as expected in Years 1 to 5, when reservoir pressure is ≤170 barg) the fluid stays single phase as the phase envelope would be very narrow so two-phase flow downstream of the choke valves would not be anticipated under normal circumstances.

7 Pipeline Transient Scenarios

The flow assurance model was used to simulate steady state conditions in order to validate the operating conditions of the system and to verify the capacity that could be supported in the pipeline and wells. The steady state results provided the input data which was used as part of the transient analysis.

The flow assurance model was also be used as part of the transient analysis which covered various scenarios that were considered likely to occur during operation of the CCS system. The results from the analysis governed the design conditions and the requirements for the control philosophies.

7.1 Initial Start-up

The purpose of this analysis is to determine the following:

- time required for displacing the air left in the pipeline following pre-commissioning activities;
- time required for filling each section of the onshore and offshore pipelines with CO_2, starting from an air-filled system;
- the Drax to Camblesforth section was pressurised to 50 barg; and
- The remainder of the pipeline was pressurised to 25 barg.

The pipeline was set-up with air using the initial conditions functionality in OLGA. CO_2 was then introduced at Drax at the minimum and maximum flowrates. With the block valves at each block valve station closed, each section was pressurised to 65 barg before bypassing (and ultimately opening) the block valves to pressurise the downstream section.

The air pressure in the CO_2 transportation system (i.e. onshore and offshore pipelines) prior to initial start-up should be minimised. Therefore, the system was filled to 25 barg with air and the isolation block valves closed throughout the system. The Drax to Camblesforth pipeline was then pressurised to 55 barg with air to avoid operating with 2-phase CO_2 when introducing CO_2 into the pipeline. As the First Load CO_2 is almost pure, the phase envelope is very narrow (as shown in Figure 4.1) and 55 barg is approximately 15 bar above the bubble point at 4°C (minimum ambient buried pipeline temperature), and above the phase envelope for maximum ambient conditions. The risk of operating in the 2-phase region during commissioning is therefore low.

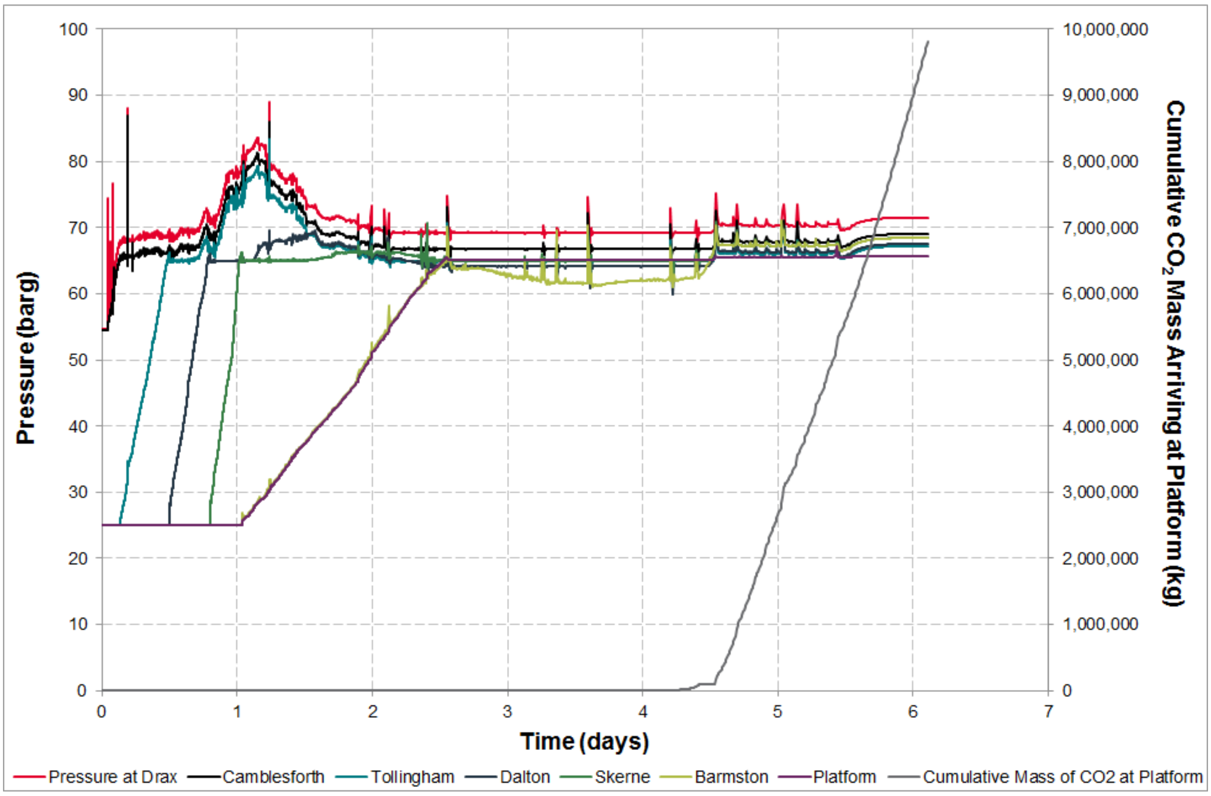
The block valves were controlled to open once the pressure upstream of them had reached 65 barg, so each isolated section was pressurised in turn.

7.1.1 Initial Start-up without PIG Operations

7.1.1.1 Maximum Flowrate from Drax (2.68 MTPA)

Figure 7.1: Pressure at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.68 MTPA without PIG Operations – 55barg Drax to Camblesforth with Remainder of Pipeline System at 25barg shows the pressure at the various block valve locations and at the platform during initial start-up at 2.68 MTPA, without PIG operations, with the majority of the pipeline initially pressurised with air to 25 barg and the Drax to Camblesforth section pressurised to 55 barg, as stated above. The mass flowrate of CO_2 arriving at the platform is also shown. Note that CO_2 is introduced into the pipeline at simulation time = 1 hour.

Figure 7.1: Pressure at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.68 MTPA without PIG Operations – 55barg Drax to Camblesforth with Remainder of Pipeline System at 25barg

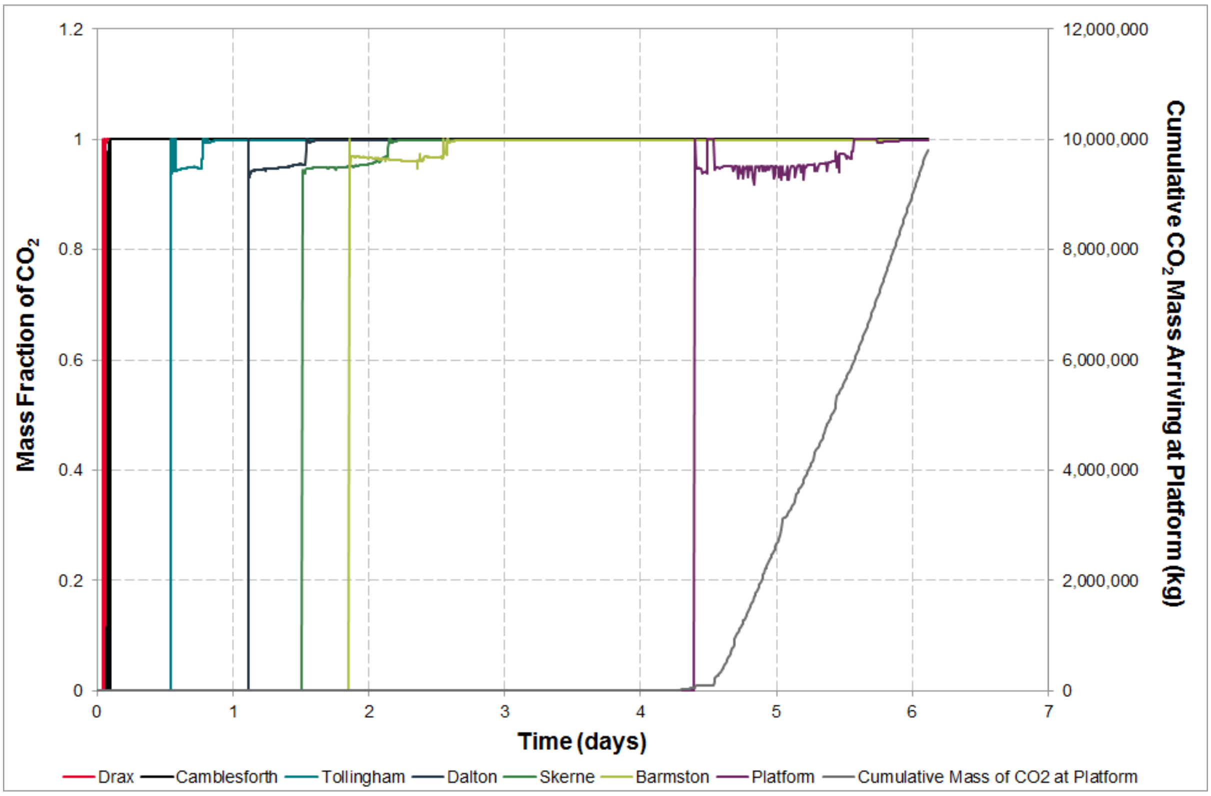


The pressure downstream of each block valve station increases sequentially as each valve is bypassed when the upstream pressure reaches 65 barg. The pump station at Barmston is bypassed after approximately 1 day and the pressure in the entire offshore pipeline increases almost simultaneously. The pressure drop through the pipeline is low due to the low flowrate, hence the negligible difference between the pressure at Barmston and the platform. Note that instantaneous pressure spikes are a result of some instabilities in the OLGA model and do not represent actual events.

Through the first day, the pressure at Drax builds up as the CO_2 inventory in the system increases and each section of the onshore pipeline is pressurised. Once the isolation valve to the offshore pipeline opens, the pressure at Drax reduces because the pressure in the onshore and offshore pipelines equalise once the valve opens and there is considerable volume in the offshore pipeline.

Figure 7.2 shows the mass fraction of CO_2 in the liquid phase at the various block valve locations and at the platform during initial start-up without PIG Operations with the majority of the pipeline initially pressurised with air to 25 barg, as stated above.

Figure 7.2: Mass Fraction of CO_2 at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.68 MTPA without PIG Operations – 55 barg Drax to Camblesforth with Remainder of Pipeline System at 25 barg

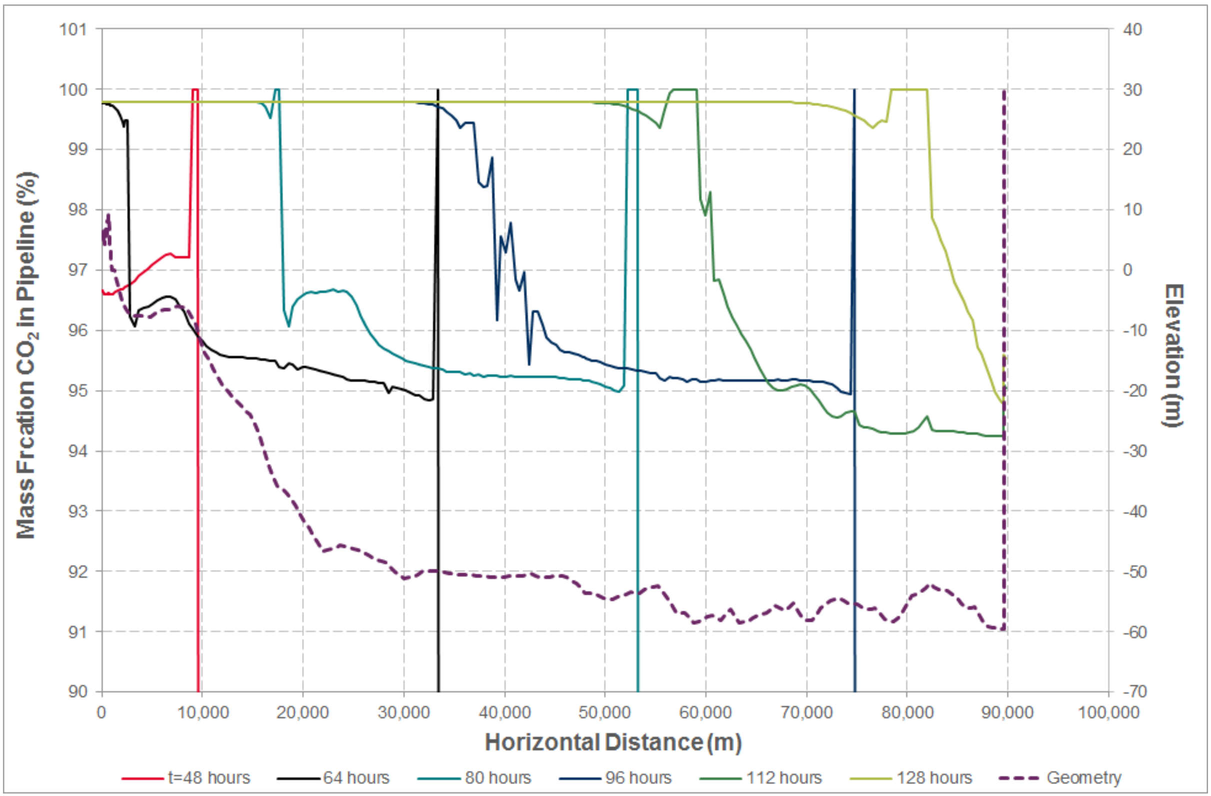


The time between liquid CO_2 arriving at the block valve stations and all the air to be displaced (when the mass fraction of CO_2 equals 1) increases the further down the pipeline the block valve station lies; it takes over 1 day for all the air to be displaced at the platform after CO_2 starts to arrive. Note that the CO_2 fraction never actually reaches 1 due to impurities in the CO_2. Additionally, there is fluctuation in the mass fraction of CO_2 arriving at each section as it gets close to 100% CO_2 (the mass fraction appears to spike at approximately 1 (virtually pure CO_2), drops slightly to approximately 0.95 before reaching approximately 1 again). This is due to an air pocket travelling along the pipeline becoming trapped behind the front of the CO_2. This air pocket is caused by instability in the OLGA model, rather than any physical phenomena and the initial spike can be ignored.

Flowing CO_2 at a flowrate of 2.68 MTPA, it takes approximately 4.3 days for CO_2 to arrive at the platform and 5.6 days from the start of the operation for air to be fully displaced from the pipeline.

Figure 7.3 shows the CO_2 mass fraction along the offshore pipeline during initial start-up at 2.68 MTPA without PIG Operations.

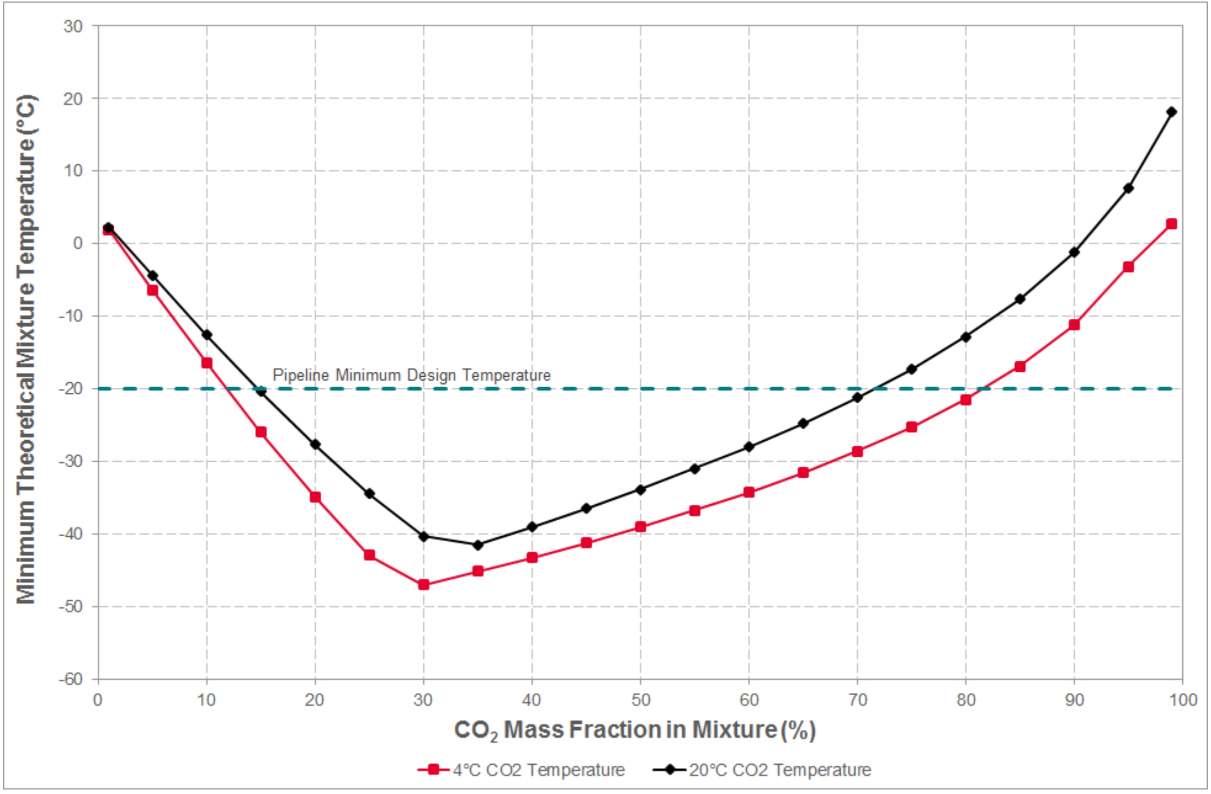
Figure 7.3: CO2 and Air Interface in the Offshore Pipeline during Initial Start-up Without PIG Operations at 2.68 MTPA



The CO_2-air interface appears to be a solid front at approximately 100% CO_2, with a pocket of CO_2-air mixture behind it. However, this spike in CO_2 mass fraction is caused by numerical errors in OLGA as it attempts to deal with gaseous air mixing with liquid / dense phase CO_2 and can be ignored. The CO_2-air mixture at approximately 95% CO_2 extends for approximately 30 km in the offshore pipeline when PIG operations are not used for initial start-up.

As the incoming CO_2 contacts the air in the pipeline, there is likely to be a cooling affect as the two are mixed. The numerical sensitivity of OLGA in this scenario, in terms of temperature calculation, is significant and therefore no weight can be given to the predictions of the temperature at the CO_2-air interface. Instead, a theoretical approach has been taken to determine likely minimum temperatures at the interface. Figure 7.4 shows the minimum theoretical fluid temperature (calculated using HYSYS) of a CO_2-air mixture at 65 barg, with air temperature at 4°C (minimum ambient temperature) and CO_2 at 4°C and 20°C (Drax export temperature). These two CO_2 temperatures were considered as they represent the minimum and maximum possible CO_2 temperatures when it contacts air.

Figure 7.4: Minimum Theoretical Temperature on CO2-Air Mixtures at 65barg during Initial Start-up



In an isolated system with no heat transfer, the mixture temperature could theoretically fall below the pipeline minimum design temperature of -20°C in CO_2-air mixtures when the CO_2 mass fraction falls below 70% to 80%. Figure 7.3 suggests that for most of the interface between CO_2 and air, the CO_2 mass fraction will be above 90%, meaning that the minimum fluid temperature would not fall below approximately -10°C. There is likely to be some part of the interface that has lower CO_2 mass fractions however, as the fluids are in motion and mixing will occur. However, because the fluids are in motion, moving at approximately 0.4 m/s in the 600 mm nominal diameter pipelines at 2.68 MTPA, there is likely to be insufficient time for the metal in the pipeline to cool down below the minimum pipeline design temperature as the cold front of CO_2/air passes along the pipeline. The cold fluid passing through a given section of the pipeline would quickly move on and be replaced by warmer fluids coming behind it.

Table 7.1 shows the time to displace air from the three main pipeline sections in the CO_2 transportation system during initial start-up at 2.68 MTPA without PIG operations.

Table 7.1: Time to Displace Air during Initial Start-up at 2.68 MTPA without PIG Operations

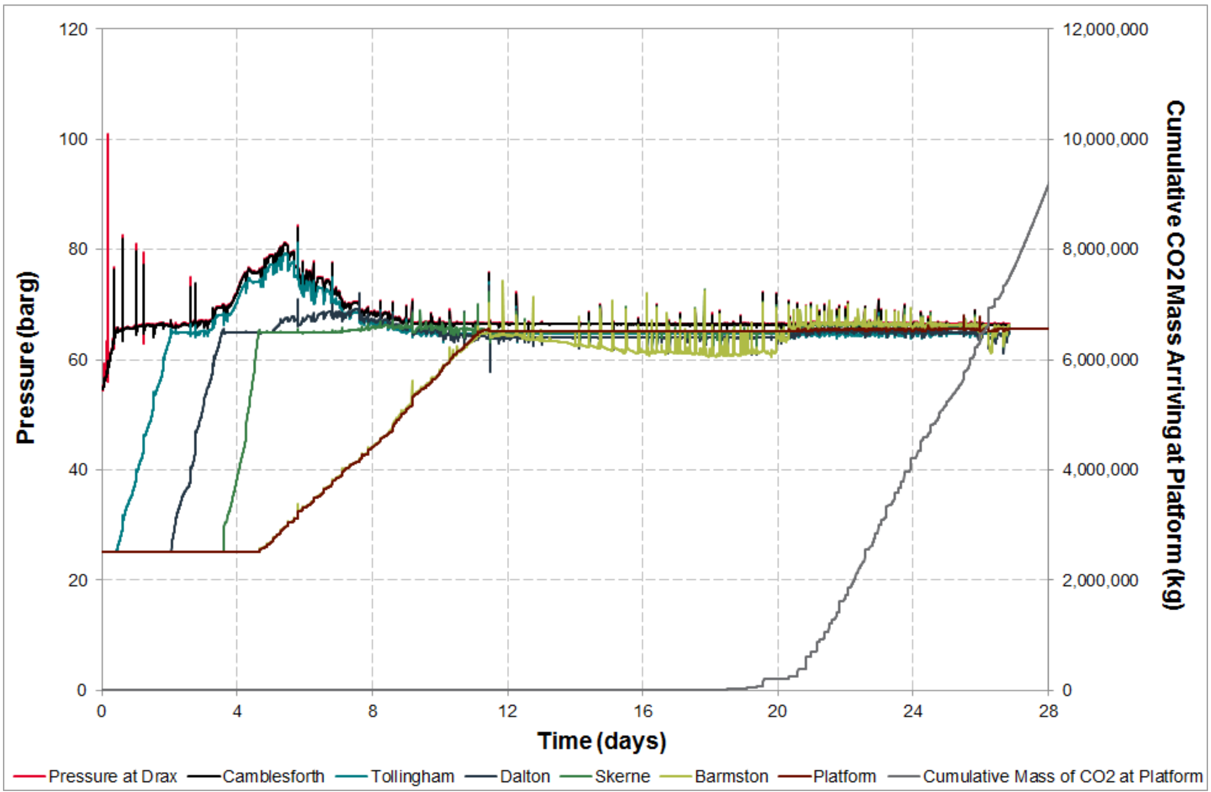
Section	Time from Start of Commissioning to Fully Displace Air from Section	Time from Arrival of CO_2 at Section Inlet to Fully Displace Air from Section	Total Time Pressure to Fully Stabilise from Start of Commissioning
	days	days	days
Drax to Camblesforth	0.1	0.1	6
Camblesforth to Barmston	2.8	2.0	6
Barmston to Platform	5.6	2.8(1)	6

(1) It takes approximately 1.2 days from the time CO_2 first arrives at the platform for air to be displaced fully from the entire pipeline system.

7.1.1.2 Minimum Flowrate from Drax (0.58 MTPA)

Figure 7.5 shows the pressure at the various block valve locations and at the platform during initial start-up at 0.58 MTPA without PIG Operations with the majority of the pipeline initially pressurised with air to 25 barg, as stated above.

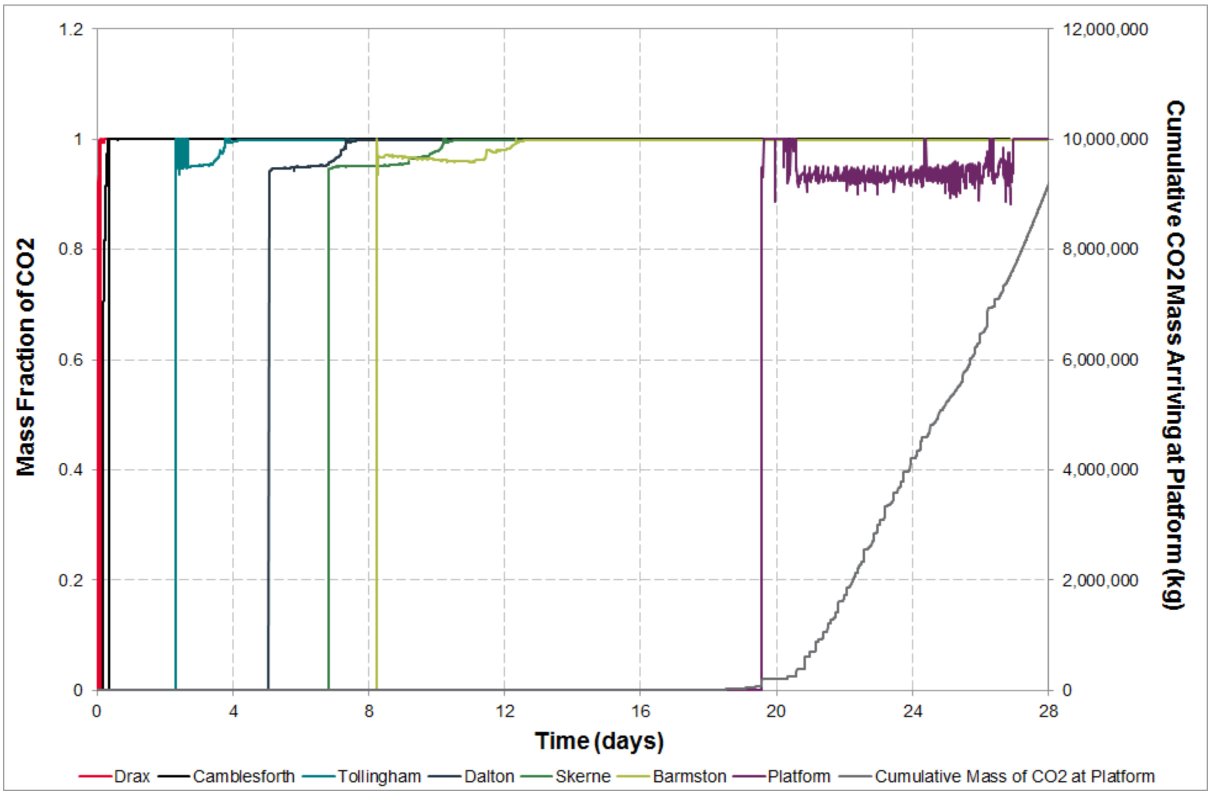
Figure 7.5: Pressure at Various Locations in the CO_2 Transportation System during Initial Start-up at 0.58 MTPA without PIG Operation – 55 barg Drax to Camblesforth with Remainder of Pipeline System at 25 barg



The CO_2 starts to arrive at the platform after almost 3 weeks and would need to be vented at the platform for at least a week before full displaced has been achieved – steady operation has not been achieved after 4 weeks.

Figure 7.6 shows the mass fraction of CO_2 in the liquid phase at the various block valve locations and at the platform during initial start-up without PIG Operations with the majority of the pipeline initially pressurised with air to 25 barg, when flowing CO_2 at 0.58 MTPA from Drax.

Figure 7.6: Mass Fraction of CO_2 at Various Locations in the CO_2 Transportation System during Initial Start-up at 0.58 MTPA Without PIG Operations – 55 barg Drax to Camblesforth with Remainder of Pipeline System at 25barg



It takes approximately four weeks to displace air fully from the onshore and offshore pipelines when flowing at 0.58 MTPA from Drax.

Note that instantaneous pressure spikes are a result of some instabilities in the OLGA model and do not represent actual events.

Table 7.2 shows the time to displace air from the three main pipeline sections in the CO_2 transportation system during initial start-up at 0.58 MTPA without PIG operations.

Table 7.2: Time to Displace Air during Initial Start-up at 0.58 MTPA Without PIG Operations

Section	Time from Start of Commissioning to Fully Displace Air from Section	Time from Arrival of CO_2 at Section Inlet to Fully Displace Air from Section	Total Time Pressure to Fully Stabilise from Start of Commissioning
	days	days	days
Drax to Camblesforth	**0.3**	**0.3**	**28**
Camblesforth to Barmston	**11.2**	**7.6**	**28**
Barmston to Platform	**28**	**24**	**28**

7.1.2 Initial Start-up with PIG Operations

Initial start-up with PIG operations was only considered at the design flowrate of 2.68 MTPA from Drax. Initial start-up at the minimum flowrate of 0.58 MTPA was not considered due to the very low PIG velocities in the 600 mm nominal diameter pipelines (in the region of <0.1 m/s).

7.1.2.1 Maximum Flowrate from Drax (2.68 MTPA)

For the purposes of this analysis, it is assumed that PIGs are launched into the pipeline section (i.e. into 600 mm nominal diameter onshore pipeline or 600 mm nominal diameter offshore pipeline) immediately after receipt of the PIG into the PIG receiver from the upstream pipeline section.

Figure 7.7 shows the pressure at the various block valve locations and at the platform during initial start-up with PIG Operations with the majority of the pipeline initially pressurised with air to 25 barg, as stated above. The mass flowrate of CO_2 arriving at the platform is also shown. Note that CO_2 is introduced into the pipeline at simulation time = 1 hour.

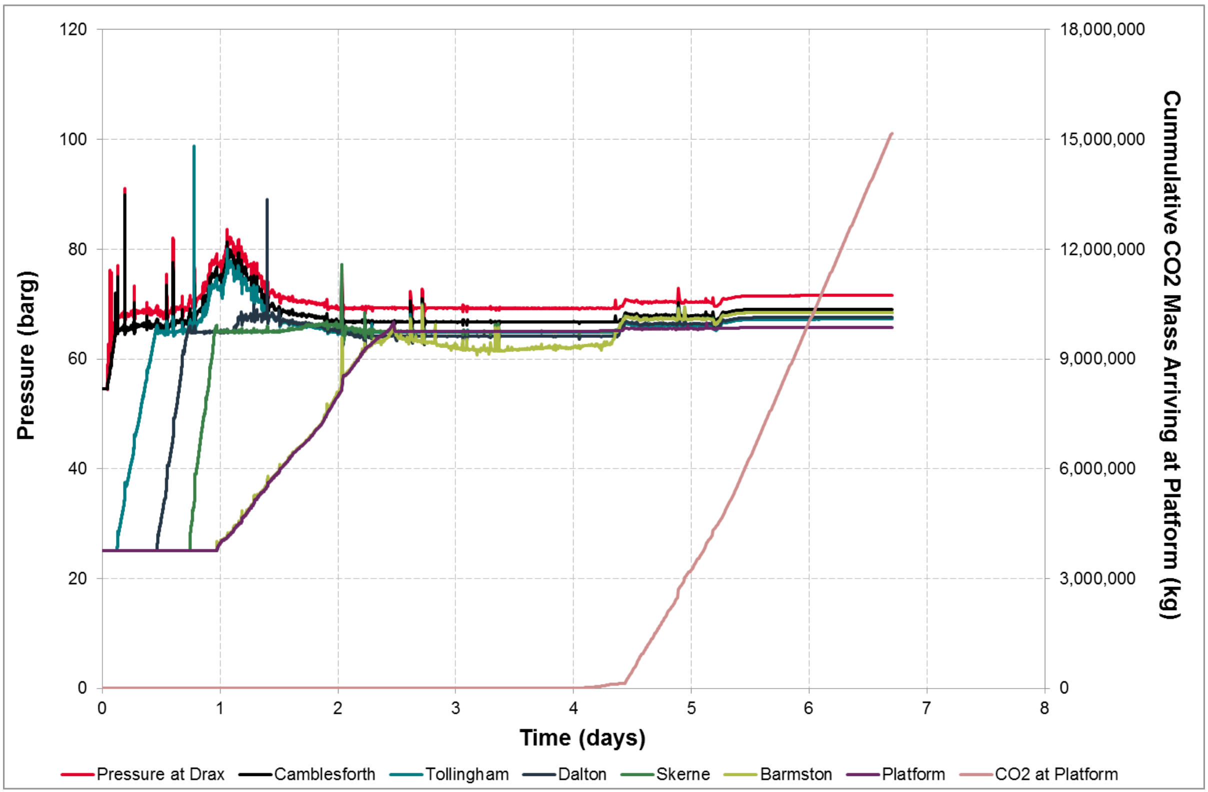
The pressure results are similar to the no-PIG start-up operation except that the amount of CO_2 increases faster due to the reduction of interfacial mixing. A degree of CO_2 leakage past the PIG has been modelled (from upstream to downstream) during the simulation, with CO_2 arriving at the platform after approximately 4 days and the PIG not arriving until approximately 5.25 days. In reality there will also be a degree of CO_2 slipping past the PIG, and at the pipeline transition at Camblesforth and Barmston, however without knowing specific details of the PIG it is not possible to confirm the quantities.

Due to the lack of specific PIG data, the default OLGA PIG Operations parameters were used:

- PIG Diameter — Pipeline ID minus 2 x pipe roughness.
- PIG Mass — 140 kg.
- Static Force (force to tear PIG from wall) — 1,000 N.

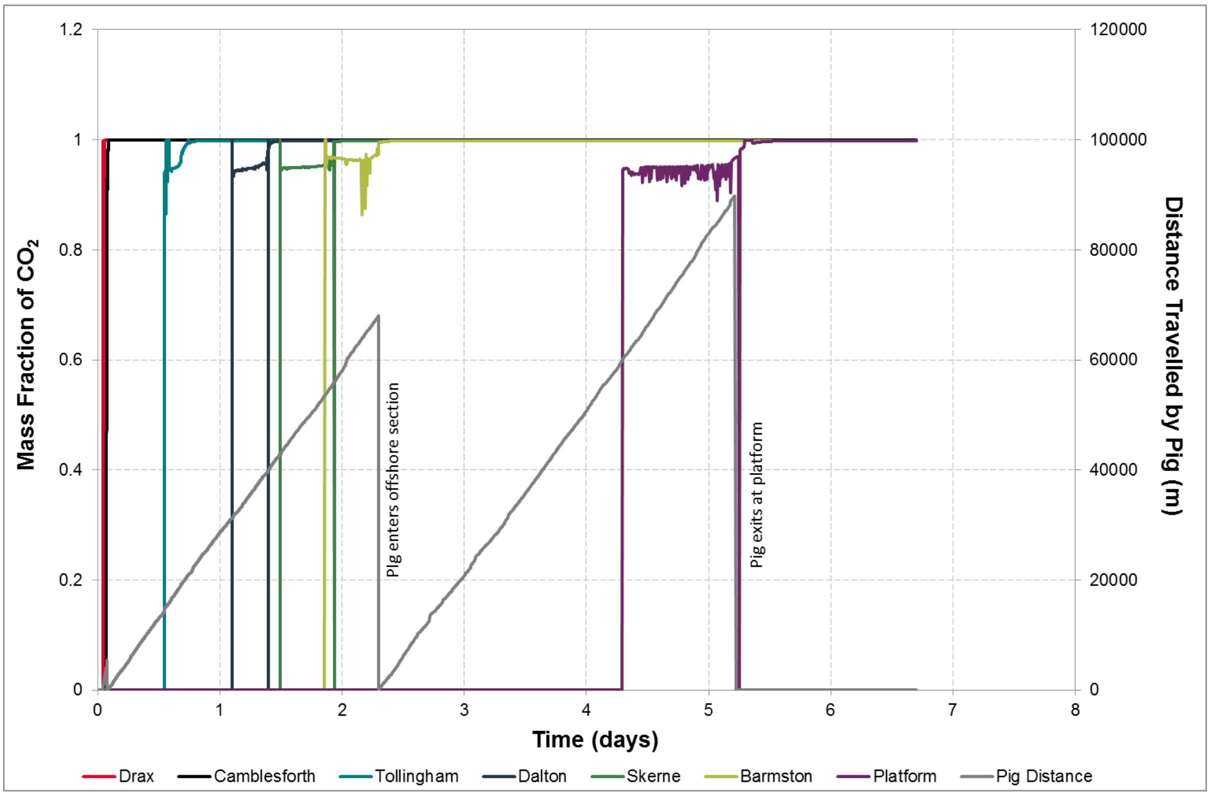
Figure 7.8 shows the mass fraction of CO_2 in the various pipeline sections, and the distance travelled by the PIG in the Drax-Camblesforth, Camblesforth-Barmston, and offshore sections. The PIG arrives at Barmston after ~2.25 days, and at the platform at ~5.25 days (assuming continuous PIG travel, i.e. PIGs are launched into downstream pipeline sections immediately on receipt of the PIG into the receiver from the upstream pipeline section).

Figure 7.7: Pressure at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.68MTPA with PIG Operations – 55barg Drax to Camblesforth with Remainder of Pipeline System at 25barg



Note that instantaneous pressure spikes are a result of some instabilities in the OLGA model and do not represent actual events.

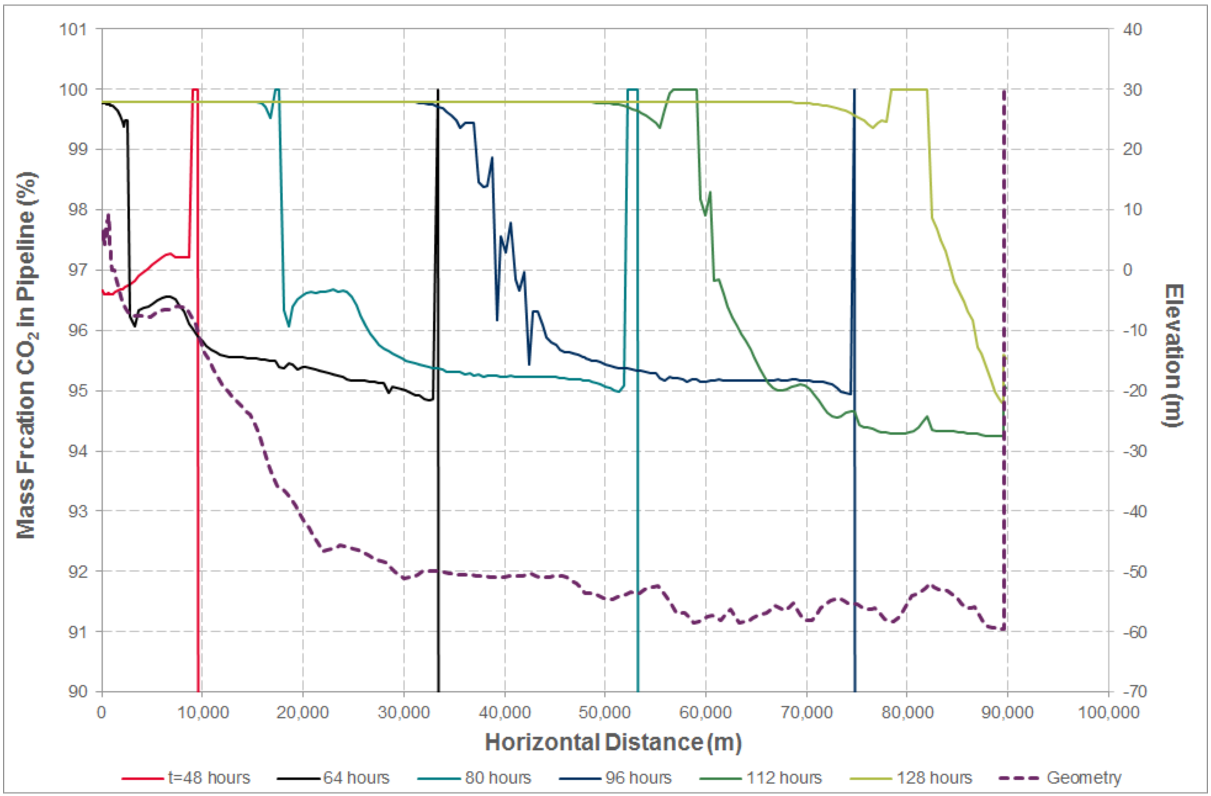
Figure 7.8: Mass Fraction of CO_2 at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.6 MTPA with PIG Operations – 55barg Drax to Camblesforth with Remainder of Pipeline System at 25barg



During the opening of each of the block valves, the pressure from the upstream section will cause the velocity of the PIG to increase suddenly until the pressure is equalised. In reality this operation will need to be carefully managed to ensure that the pressure equalisation occurs in a controlled manner. Some of the CO_2 supplied from Drax AGI starts to travel ahead of the PIG, with it starting to arrive at the platform approximately 1 day prior to the PIG arrives. This is due to leakage of the CO_2 past the PIG. As the pipeline system is so long (approximately 160 km), the mass of CO_2 that leaks past the PIG is significant. The actual mass of CO_2 arriving ahead of the PIG will ultimately be a function of the PIG properties and the timing between reception of one PIG (say at Camblesforth) and launch of the next into the downstream section of the pipeline system. The J-T effect across the PIG as CO_2 leaks past it results in a temperature drop of about 2°C (caused by 2 to 3 bar pressure drop across the PIG), therefore low temperatures are not anticipated in the pipeline system during initial start-up when utilising PIG Operations. The pressure drop across the PIG is dependent on the physical properties of the PIG (essentially, the amount of force required to move the PIG along the pipeline). However, with a minimum ambient temperature of 4°C in the onshore and offshore pipelines (thus representing the minimum fluid temperature upstream of the PIG), the pressure drop across the PIG would need to be an order of magnitude higher than 2 to 3 bar for the pipeline minimum design temperature to be transgressed due to excessive J-T cooling. (For an indication on the J-T cooling caused by pressure drop see Table 7.11).

Figure 7.9 shows the CO_2 mass fraction along the offshore pipeline during initial start-up at 2.68 MTPA with PIG operations.

Figure 7.9: CO_2 and Air Interface in the Offshore Pipeline during Initial Start-up with PIG Operations at 2.68MTPA



As in Figure 7.3 the CO_2-air interface appears to be a solid front at approximately 100% CO_2, with a pocket of CO_2-air mixture behind it. However, this spike in CO_2 mass fraction is caused by numerical errors in OLGA as it attempts to deal with gaseous air mixing with liquid / dense phase CO_2 and can be ignored. The CO_2-air mixture at approximately 95% CO_2 extends for approximately 30 km, although this is somewhat dependent on the time delay between receiving a PIG in one PIG receiver from the upstream pipeline and launching the next PIG into the downstream pipeline.

Table 7.3 shows the average PIG velocity in each section of the CO_2 transportation system during initial start-up at 2.68 MTPA CO_2 flowrate from Drax.

Table 7.3: Average PIG Velocities during Initial Start-up at 2.68MTPA

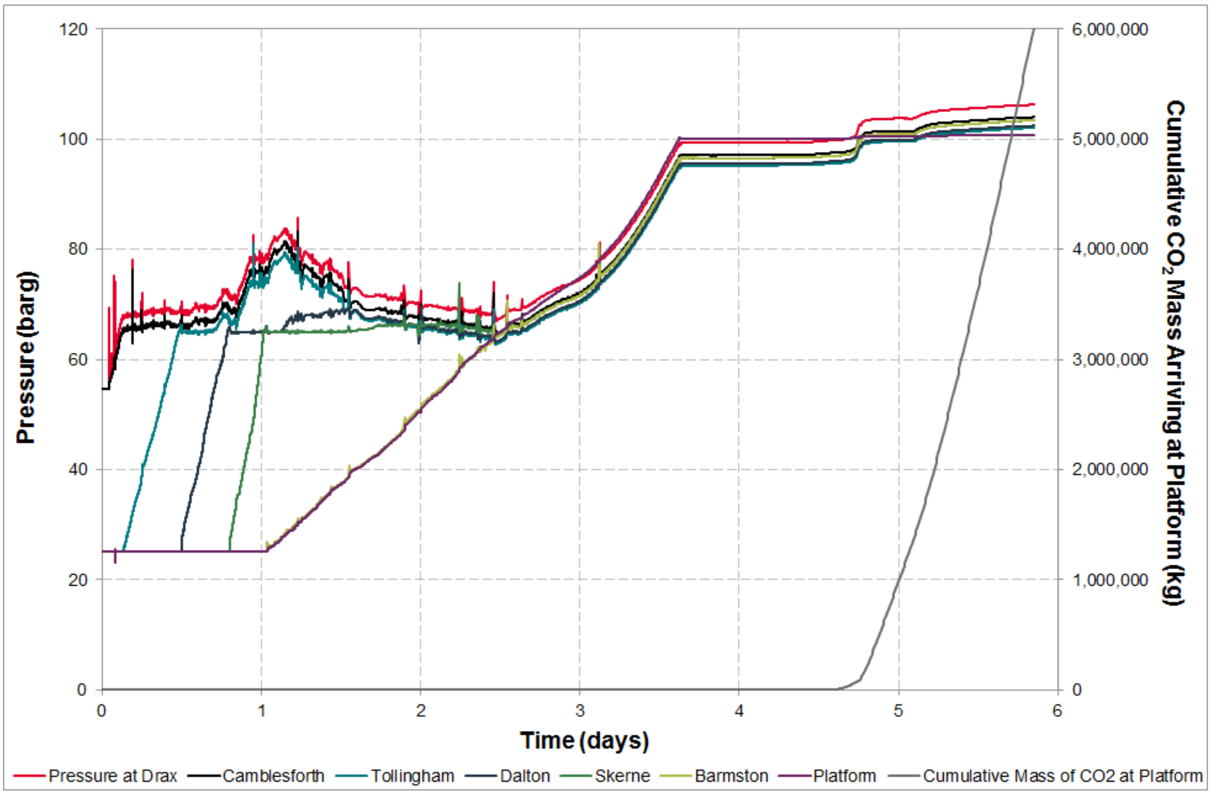
PIG Launcher	Average PIG Velocity (m/s)
Drax	1.2
Camblesforth	0.4
Barmston	0.4

7.1.3 Pressurisation up to 100 barg

Pressurisation up to 100 barg is considered, as this is the recommended minimum platform pressure controller setpoint. In this case, each section of the pipeline system is pressurised to 65 barg before opening the bypass around each block valve station. When each block valve has been bypassed / opened the pressure in the pipeline builds up to a pressure of 100 barg upstream of the platform pressure control valve so that the pipeline is at the required pressure for steady state operation. For this analysis it was assumed that there is no PIG operation ahead of the introduction of CO_2 into the pipeline system.

Figure 7.10 shows the pressure at the various block valve locations and at the platform during initial start-up at 2.68 MTPA without PIG Operations with the majority of the pipeline initially pressurised with air to 25 barg, with the system being pressurised up to 100 barg at the platform.

Figure 7.10: : Pressure at Various Locations in the CO_2 Transportation System during Initial Start-up at 2.68MTPA Without PIG Operations – 55barg Drax to Camblesforth with Remainder of Pipeline System at 25barg, Pressurisation up to 100 barg



The initial pressurisation upstream of each block valve occurs in a similar manner as shown in Figure 7.5. It takes a further 27 hours to pressure the pipeline system up to 100 barg from 65 barg measured at the platform when CO_2 is flowing at 2.68 MTPA.

7.1.4 Initial Start-up Summary

Table 7.4 shows the time to pressurise each isolated section during initial start-up to 65 barg (upstream of the block valves), prior to opening the bypass around them. Also shown is the time it takes to displace air from each section of the pipeline system with the CO_2 introduced at Drax.

Table 7.4: Pressurisation Times and Time to Displace Air for Isolated Sections during Initial Start-up at 2.68MTPA with and without PIP Operations

Block Valve	Time from Introduction of CO_2 that Pressure Upstream of the Valve Reaches 65 bar (hours)		Time from Introduction of CO_2 to Displace Air from Section (days)	
	Without PIG Operations	With PIG Operations	Without PIG Operations	With PIG Operations
Camblesforth	3.0	2.7	0.1	0.1
Tollingham	3.0	2.7	0.7	0.7
Dalton	18.8	17.4	1.6	1.4
Skerne	24.4	22.8	2.2	2.0
Barmston	55.3	52.0	2.8	2.3
Platform	60.4	57.8	5.6	5.3

7.2 PIG Operations

The purpose of this analysis is to understand the system behaviour during PIG operations at high and low PIG Operations velocities, specifically the pressure drop across the PIG and any subsequent issues with design pressure, and heating of the CO_2 due to the compression effects. Typical PIG operations require a PIG operations velocity between 0.5 m/s and 3 m/s to prevent the PIG from holding up in the pipeline, or from going too fast and damaging itself or the pipeline – note that consultation with PIG vendors may change the operational velocity range. Based on the steady state analysis, the flowrates 2.68 MTPA to 17 MTPA approximately cover this range and have therefore been used for the simulations. PIG operations are normally carried separately on each section:

- Drax to Camblesforth (300 mm nominal diameter onshore pipeline);
- Camblesforth to Barmston (600 mm nominal diameter onshore pipeline); and
- Barmston to Platform (600 mm nominal diameter offshore pipeline).

Due to the lack of specific PIG data, the default OLGA PIG Operations parameters, listed in Section 7.1.2.1 above, were used.

Table 7.5 shows the average PIG velocities and transit times for the main flowrate cases considered, using the First Load and Impurities compositions.

Table 7.5: PIG Velocities and Transit Times for Main Flowrate Cases

Flowrate	Reservoir Pressure				PIG Transit Time	Average PIG Velocity
MTPA	barg	Composition	PIG Launcher	PIG Receiver	hours	m/s
2.68	150	First Load	Drax	Camblesforth	1	1.2
			Camblesforth	Barmston	50	0.4
			Barmston	Platform	65	0.4
17	178	Impurities	Drax	Camblesforth	1	1.2
(2.68 MTPA from Drax)			Camblesforth	Barmston	7	2.6
			Barmston	Platform	10	2.6

At the First Load flowrate of 2.68 MTPA, the PIG velocity is within the accepted limits in the Drax to Camblesforth pipeline and has a 1 hour transit time. However, at this flowrate, the average PIG velocity falls below 0.5 m/s when conducting PIG operations on the 600 mm nominal diameter pipelines (onshore and offshore), which may increase the risk of a stuck PIG. The average PIG velocities in the 600 mm nominal diameter pipelines at 17 MTPA are within the acceptable PIG velocity range.

Table 7.6 shows the flowrate range for each pipeline that ensures the average PIG velocity is within the 0.5 – 3 m/s velocity limit.

Table 7.6: Flowrates Required for PIG Velocity Limits

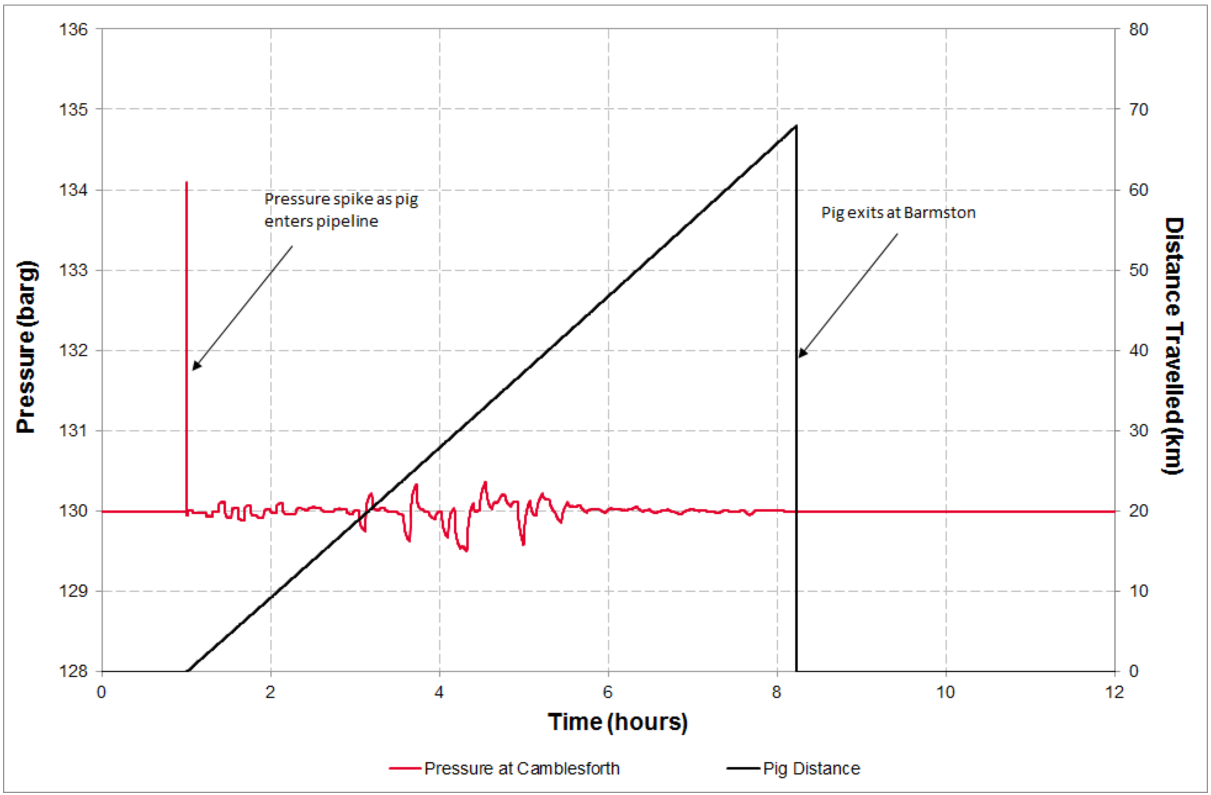
	Flowrate for PIG Velocity Limit (MTPA)	
PIG Launcher	with a velocity limit of 0.5 m/s	with a velocity limit of 3 m/s
Drax	1.0	5.9
Camblesforth	3.7	22.3
Barmston	3.8	23.0

The flowrates required to achieve an average PIG velocity of 3 m/s are >17 MTPA, therefore PIG operations can be carried out at the design flowrate and the supplies from Drax and Camblesforth do not need to be turned down.

Analysis of the pressures and temperatures during PIG operations shows a negligible impact. A typical plot is shown in Figure 7.11 Pressure Behaviour during Pigging Camblesforth to Barmston at 17 MTPA for a PIG operations operation from Camblesforth to Barmston at 17 MTPA. There is a small pressure spike as the PIG is launched, followed by some fluctuations of less than 1 bar as the PIG traverses the elevation changes specific to this section of pipeline. However there is no appreciable rise in pressure at Camblesforth when the PIG is in the pipeline, as there is negligible pressure drop across the PIG. Consequently there is negligible change in temperature across the PIG.

Pressure drop across the PIG is dependent on the PIG properties used within OLGA (wall friction, mass, etc.). It is therefore recommended that once specific PIG data is available these simulations be re-run to confirm the impact on pressures and temperatures on the system.

Figure 7.11 Pressure Behaviour during Pigging Camblesforth to Barmston at 17 MTPA



7.2.1 Pigging Summary

- PIG velocities when only Drax (at up to 2.68 MTPA) is supplying CO_2 to the pipeline are below 0.5 m/s in the 600 mm nominal diameter pipelines.
- PIG velocities when operating at 17 MTPA are below 3 m/s, which is a typical maximum limit, therefore turndown is unlikely to be required during pigging operations.
- Confirmation of acceptable PIG velocity range (assumed to be 0.5 m/s to 3 m/s) with pig vendors is required.
- The pipeline pressure does not transgress the minimum and maximum operating pressure constraints during pigging.

7.3 Turndown

The purpose of this analysis is to determine the time for the pipeline pressure and temperature to settle following a turndown from the maximum rate. Two different turndown rates were considered:

- turndown at 2% of the maximum rate (2.68 MTPA) per minute (equivalent to 0.054 MTPA per minute); and
- turndown at a linear rate over 24 hours.

The turndown was for the Drax facility only, with any flow from Camblesforth remaining constant (due to uncertainty in the specific quantities of CO_2 supplied by various potential emitters at Camblesforth).

7.3.1 Year 1-5 (2.68 – 0.58 MTPA)

7.3.1.1 Turndown at 2% of the Maximum Rate

Figure 7.12 shows the pressures at different locations for a turndown operation at the controlled 2% of maximum flowrate per minute (summer conditions are shown, but winter conditions (not shown) follow an almost identical trend). The flow is turned down at t=1 hour. It takes less than 2 hours for the pressure to settle following turndown from maximum to minimum flowrate. The behaviour of the system temperature is shown in Figure 7.13 for winter conditions and Figure 7.14 for summer conditions. The arrival temperature at the platform reaches thermal steady state quickly due to the arrival temperature being close to ambient. The temperatures along the pipeline take longer to reach thermal equilibrium due the thermal inertia of the surrounding soil, and have not reached steady state after 48 hours.

Figure 7.12: Pressure at Selected Locations along the Pipeline System during Turndown from 2.68 to 0.58 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Summer

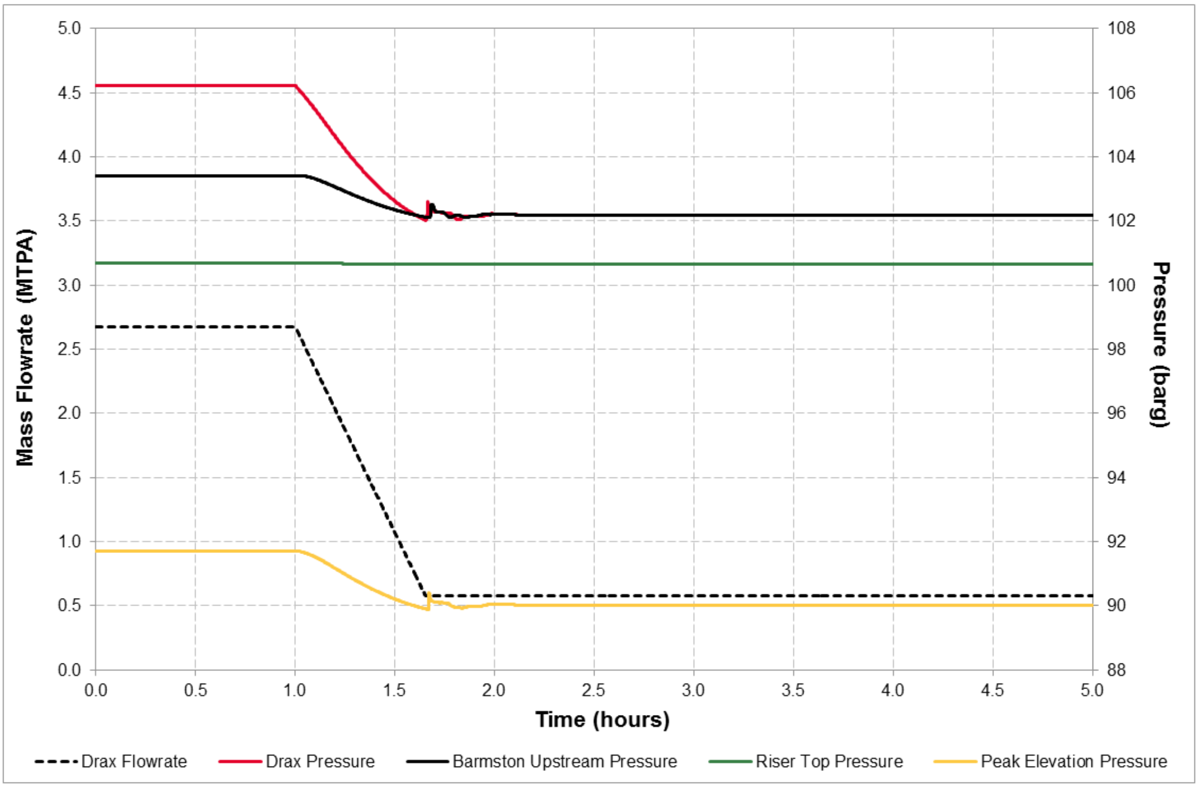


Figure 7.13: Temperature at Selected Locations along the Pipeline System during Turndown from 2.68 to 0.58 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Winter

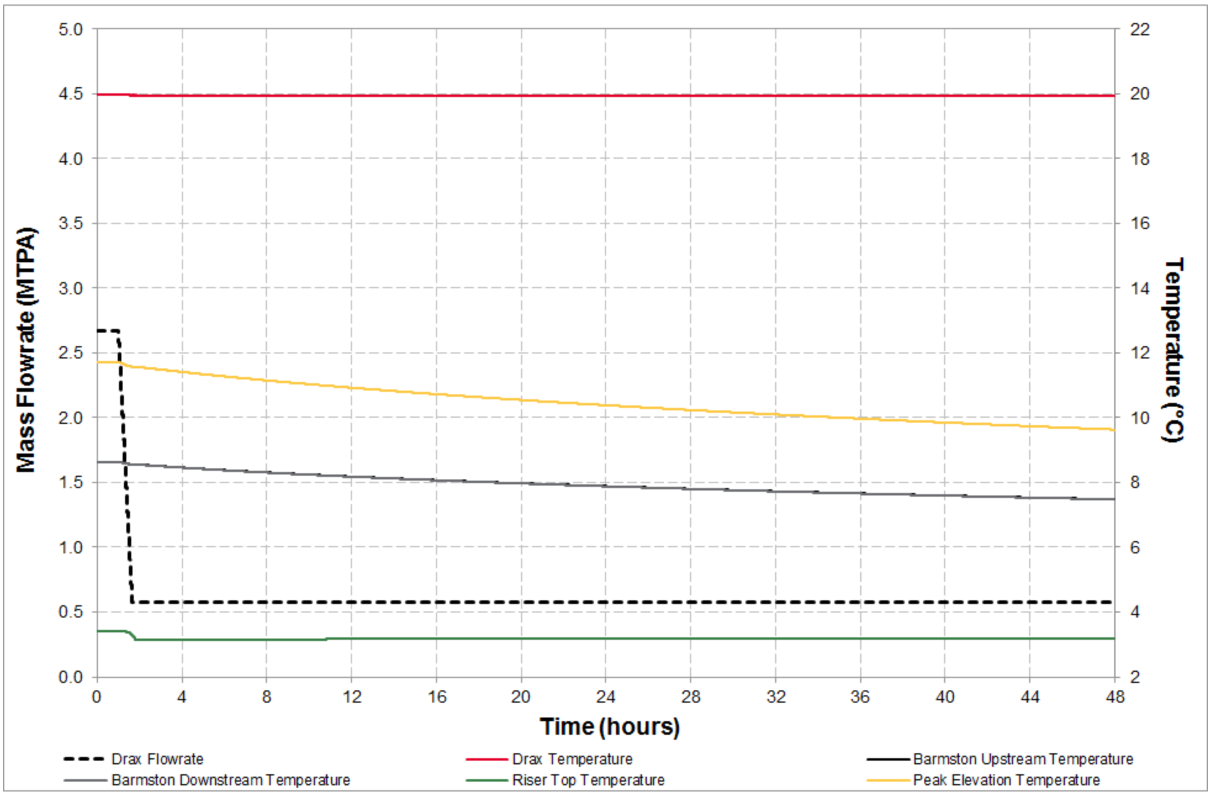
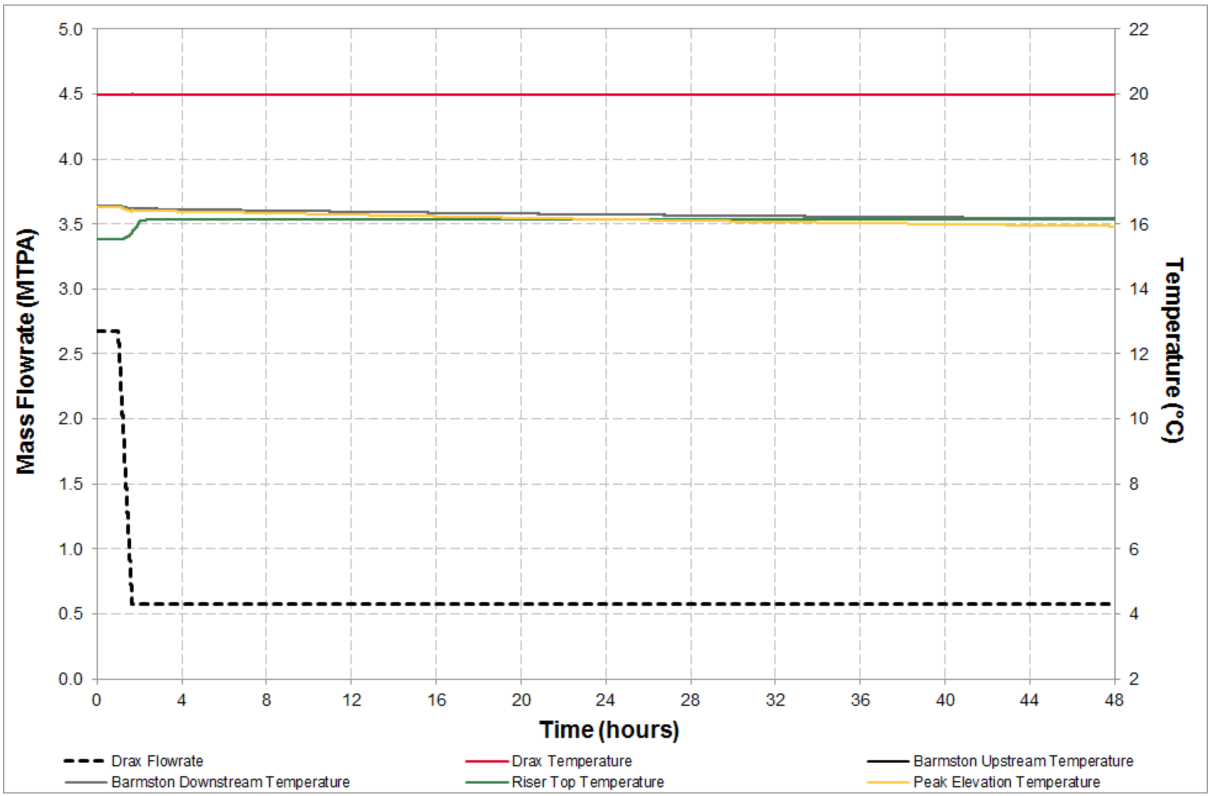


Figure 7.14: Temperature at Selected Locations along the Pipeline System during Turndown from 2.68 to 0.58 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Summer



The temperatures in the pipeline system have not settled after 2 days; the temperature change is relatively small (2°C to 3°C) in the first two days following turndown. The steady state temperature at the peak elevation in the onshore pipeline in winter conditions at 0.58 MTPA is 4°C (i.e. ambient temperature). It is clear therefore that it will take several days for the temperature in the pipeline to settle at the new steady state.

The temperature at the top of the riser actually increases in summer following turndown, as the ambient temperature is higher than the fluid temperature and the increased residence time in the pipeline causes more heat to be supplied by the surroundings to the CO_2.

7.3.1.2 Turndown at a Linear Rate Over 24 Hours

Figure 7.15 and Figure 7.16 show the pressures and temperatures through the pipeline system during turndown from 2.68 to 0.58 MTPA over 24 hours based on winter conditions (summer conditions are similar and therefore not presented). Whilst the pressures settle down at approximately 4 hours after turndown has finished, the temperatures take over 3 additional days to settle in parts of the pipeline system.

Figure 7.15: Pressure at Selected Locations along the Pipeline System during Turndown from 2.68 to 0.58 MTPA over 24 Hours, First Load Composition, Winter

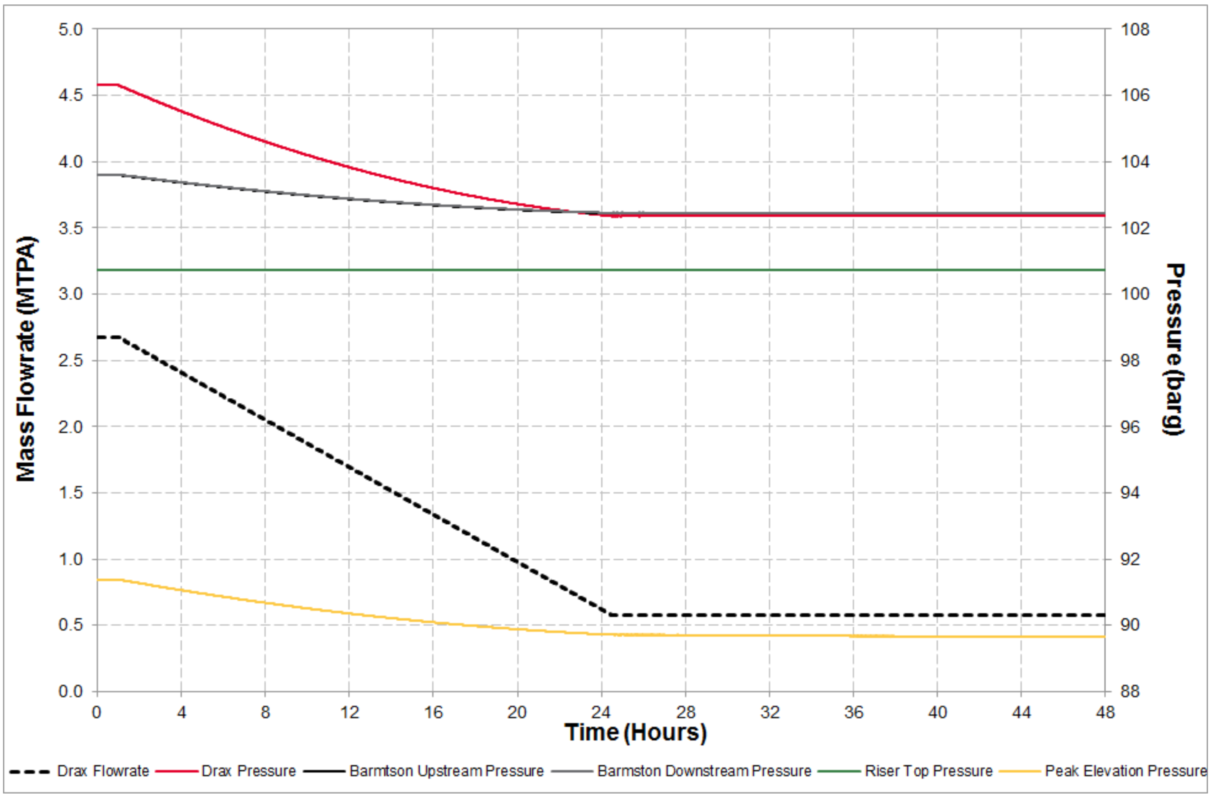
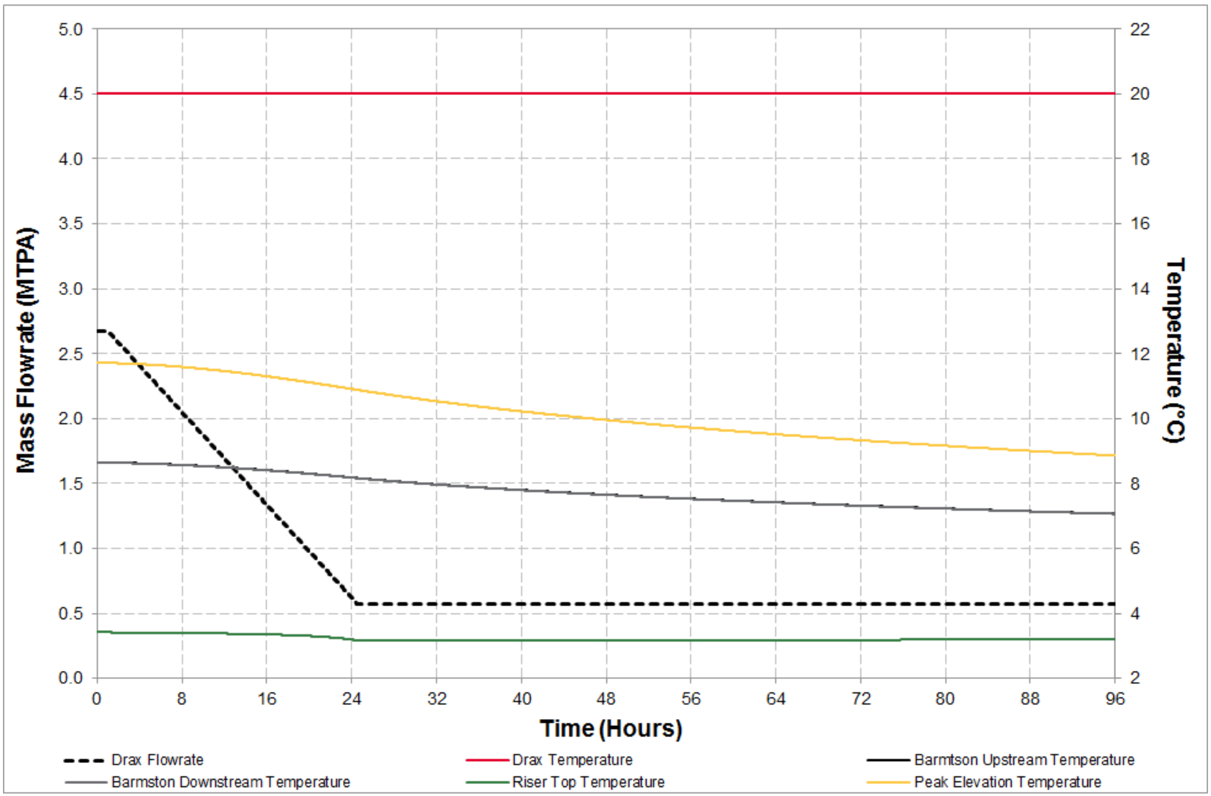


Figure 7.16: Temperature at Selected Locations along the Pipeline System during Turndown from 2.68 to 0.58 MTPA over 24 Hours, First Load Composition, Winter



7.3.2 Year 5-10 (10 – 7.9 MTPA)

Due to the lack of definition around the pump characteristics during transient operations, for this scenario the onshore and offshore sections were modelled separately. For the onshore section the outlet pressure was set at 95 barg (suction pressure at Barmston). Separating the models assumes a linear change in mass flowrate through the entire system.

The flowrate range is associated with turning down Drax from its maximum flowrate of 2.68 MTPA to its minimum flowrate of 0.58 MTPA. The Camblesforth flowrate remains constant.

Figure 7.17 shows the pressure at Drax, Barmston and the platform during turndown from 10 MTPA to 7.9 MTPA for the Full Flow composition. The flowrate was reduced at 2% of the maximum rate per minute. In this case, it takes less than 2 hours for the pressure to settle at Drax following turndown. It takes approximately 15 hours for the pressure to settle downstream of the pump at Barmston; the settle-out time here, however, is heavily influenced by the pump and control system configuration and therefore has a higher margin of error. The pressure control system responds such that a minimum pressure differential of 20 bar across the pump is maintained and an arrival pressure at the platform ≥100 barg is achieved. The response may not be exactly as modelled as it will depend on the control system settings, but this analysis gives a good indication of how the pipeline system would respond.

Figure 7.18 shows that the impact of turndown from 10 to 7.9 MTPA on temperature. The temperatures along the pipeline decrease slightly due to the drop in flowrate, with the locations furthest from the pipeline inlet taking longer to reach thermal steady state. Although not shown on the chart, the variation in temperature at the platform is very small due to the arrival temperature being very close to ambient temperature.

Figure 7.17: Pressure at Selected Locations along the Pipeline System during Turndown from 10 to 7.9 MTPA at 2% of Maximum Flow per Minute, Full Flow Composition, Winter

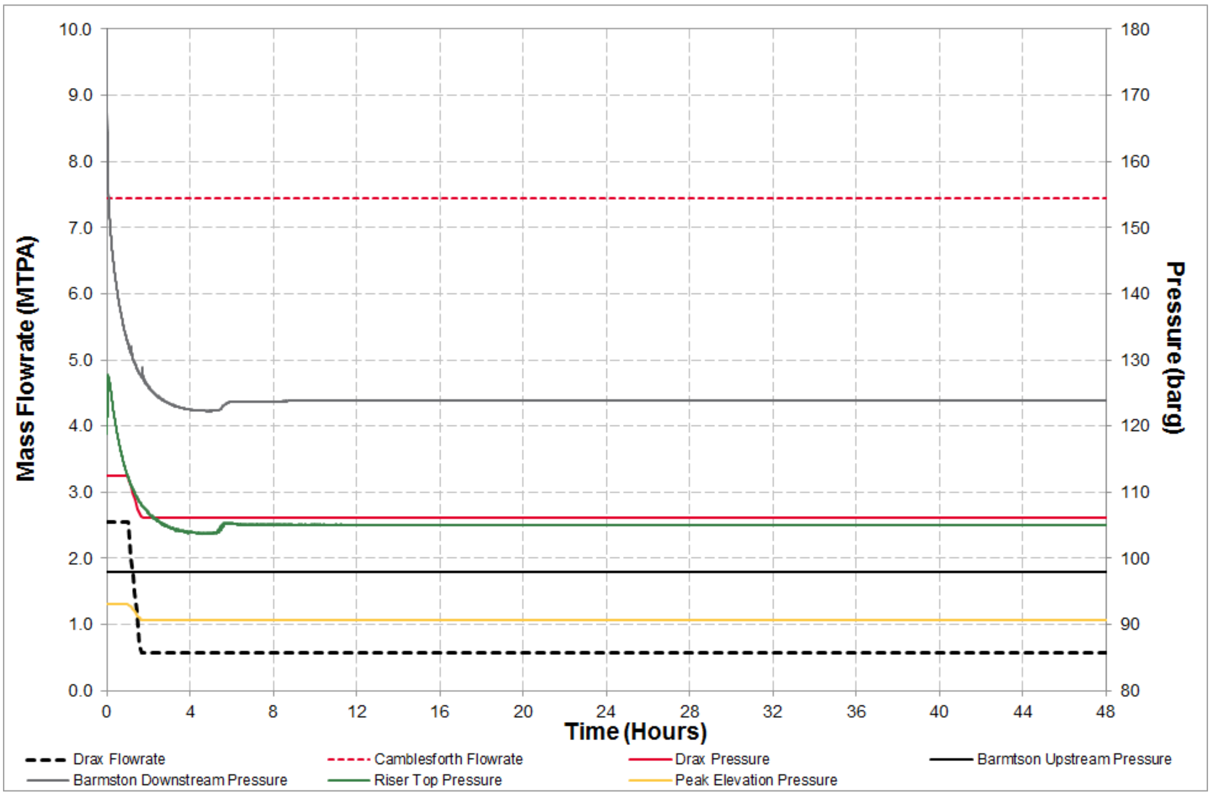
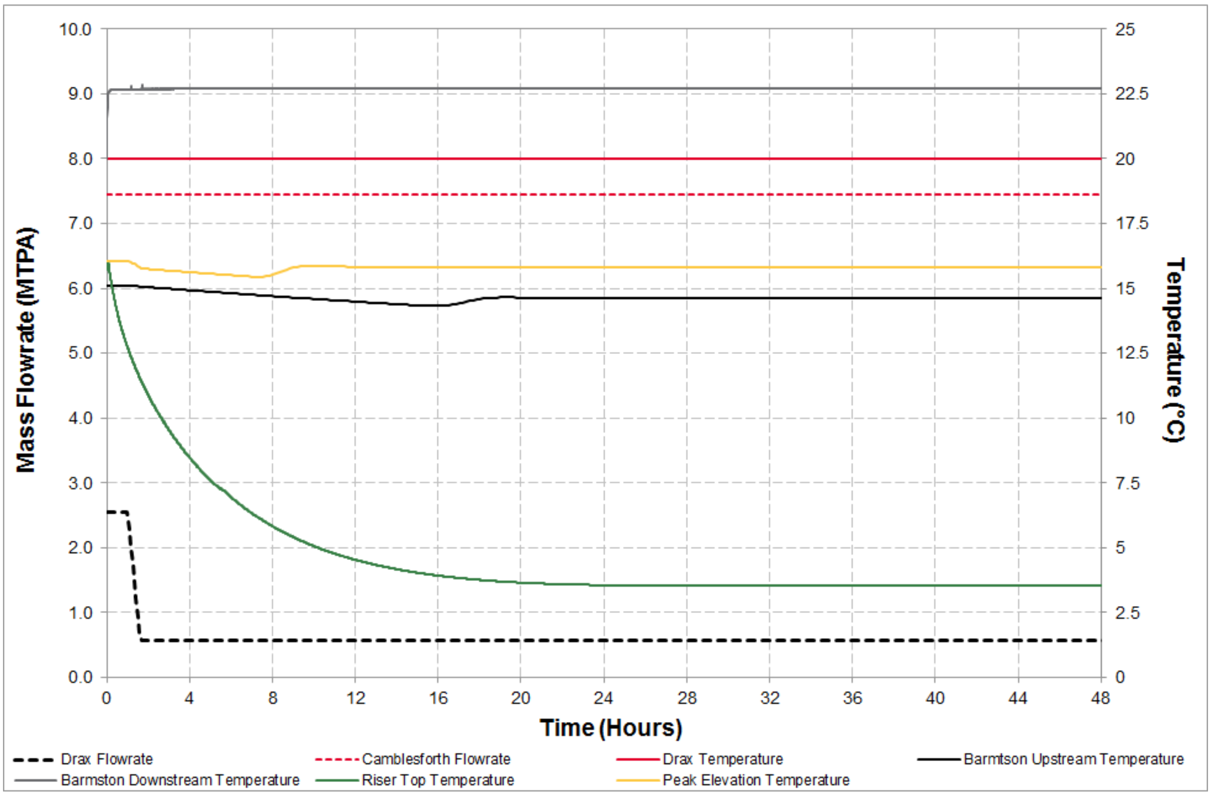
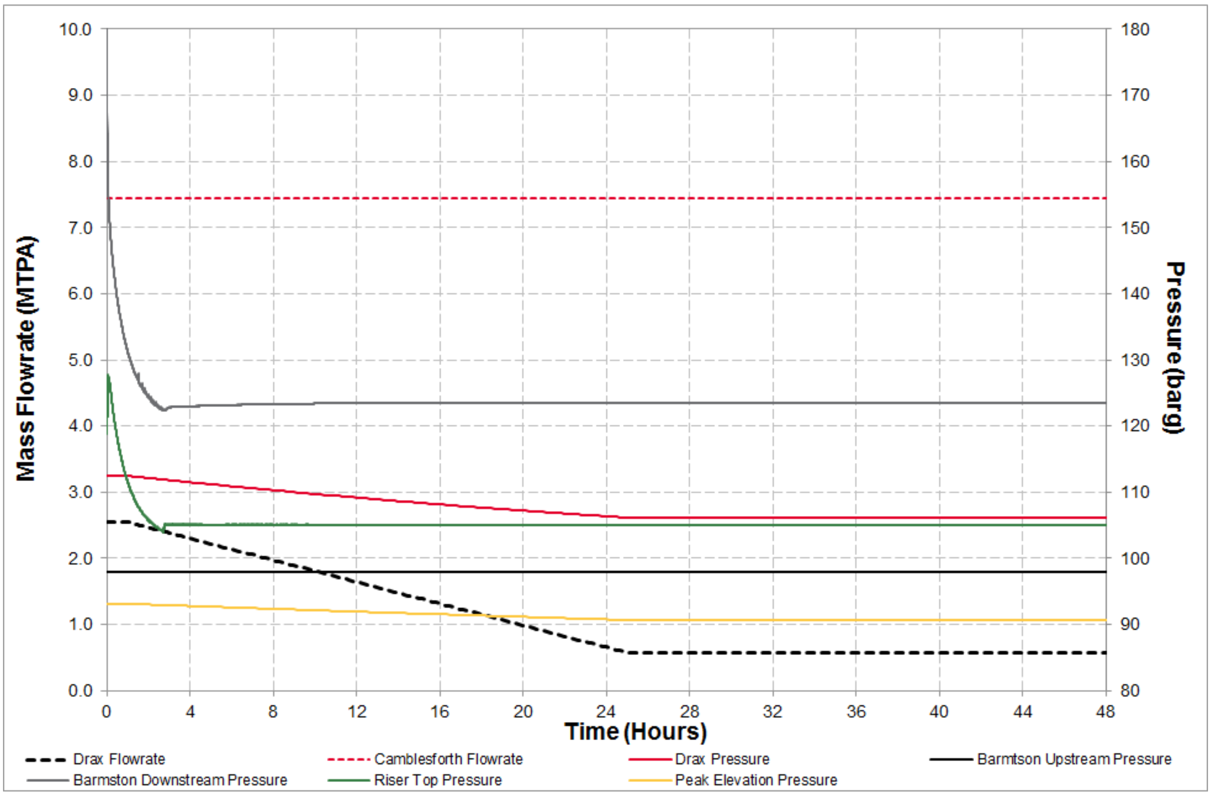


Figure 7.18: Temperature at Selected Locations in Pipeline System during Turndown from 10 to 7.9 MTPA at 2% of Maximum Flow per Minute, Full Flow Composition, Winter



When turndown is performed over 24 hours, the pressure at Drax settles almost immediately after the turndown is completed, while the pressure downstream of Barmston takes a further 8 to 10 hours to settle, as shown in Figure 7.19.

Figure 7.19: Pressure at Selected Locations along the Pipeline System during Turndown from 10 to 7.9 MTPA over 24 Hours, Full Flow Composition, Winter



7.3.3 Turndown Summary

- The pressure in the pipeline settles within a few hours of turndown, but the temperatures through the pipeline (particularly at low flowrates in winter conditions) can take several days to reach steady state.
- At higher flowrates, when the Barmston pump is operating, the pressure control settings need to be adjusted to the target conditions prior to turndown being carried out to ensure the pressure in the pipeline does not fall below 90 barg and to ensure there is sufficient pressure differential across the pump.
- Settle-out time in the offshore pipeline is highly dependent on the pump characteristics and control system settings.
- It is recommended that turndown of flow from Camblesforth be analysed in the next phase when more information about potential CO_2 emitters is available to ensure pump suction pressure control can adequately manage the operation.

7.4 Ramp-up

The purpose of this analysis is to determine the time for the pipeline pressure to settle following a ramp-up from turndown operation. Two different ramp-up rates were considered:

- ramp-up at 2% of the maximum rate (2.68 MTPA) per minute (equivalent to 0.054 MTPA per minute) from the minimum flowrate of 0.58 MTPA; and
- ramp-up at a linear rate over 24 hours.

A sensitivity case where an additional well is brought online before ramp-up was also considered.

As with the turndown simulations, the ramp-up operation focused on varying the Drax flowrate only, with the Camblesforth flowrate remaining constant.

7.4.1 Year 1-5 (0.58–2.68 MTPA)

Figure 7.20 illustrates the flow ramp-up to the maximum flowrate in Years 1-5 at 2% of the maximum rate per minute in summer conditions. The figure shows that pressures settle within 2 hours of the ramp-up. The behaviour of the temperature during the ramp-up operation is shown in Figure 7.21. The temperature arriving at the platform quickly re-established steady state temperature (as the fluid reaches ambient temperature in the offshore pipeline), while the temperatures at Barmston and at the high point on the onshore pipeline take considerably longer (>48 hours). The temperature along the pipeline system for ramp-up in summer conditions is shown in Figure 7.22.

Temperatures at Barmston and the high point on the onshore pipeline take over 4 days to settle following ramp-up over 24 hours. The temperature at the top of the riser in summer conditions reduces following ramp-up because heat supplied from the ambient air on the topsides does not raise the temperature of the CO_2 as much at the higher flowrate.

Figure 7.20: Pressure at Selected Locations along the Pipeline System during Ramp-up from 0.58 to 2.68 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Summer

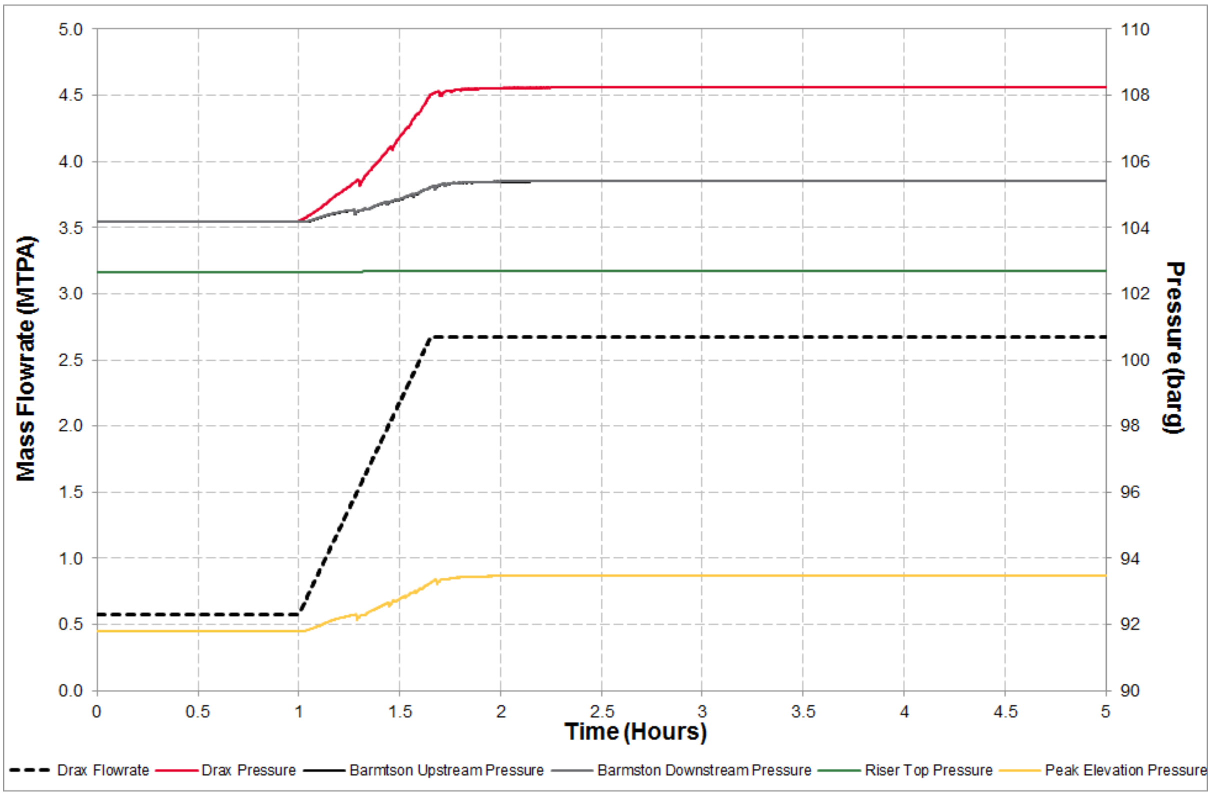


Figure 7.21: Temperature at Selected Locations along the Pipeline System during Ramp-up from 0.58 to 2.68 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Winter

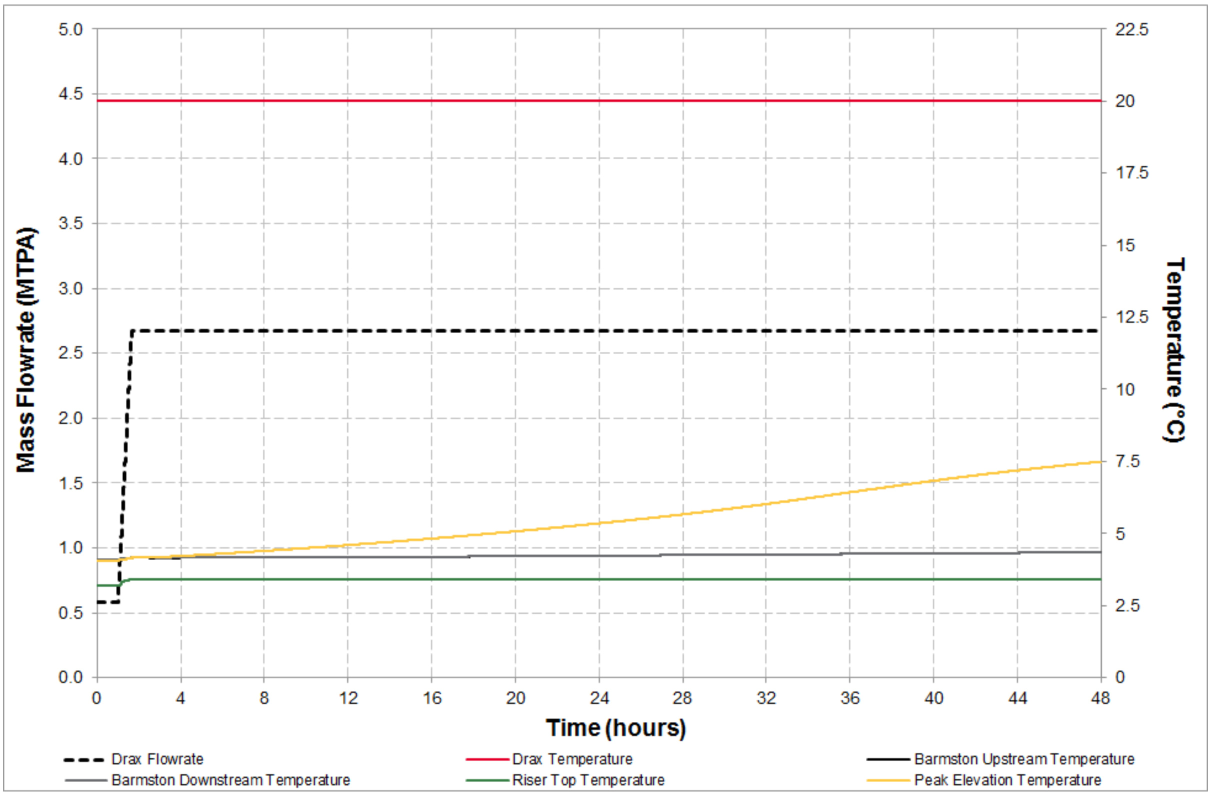
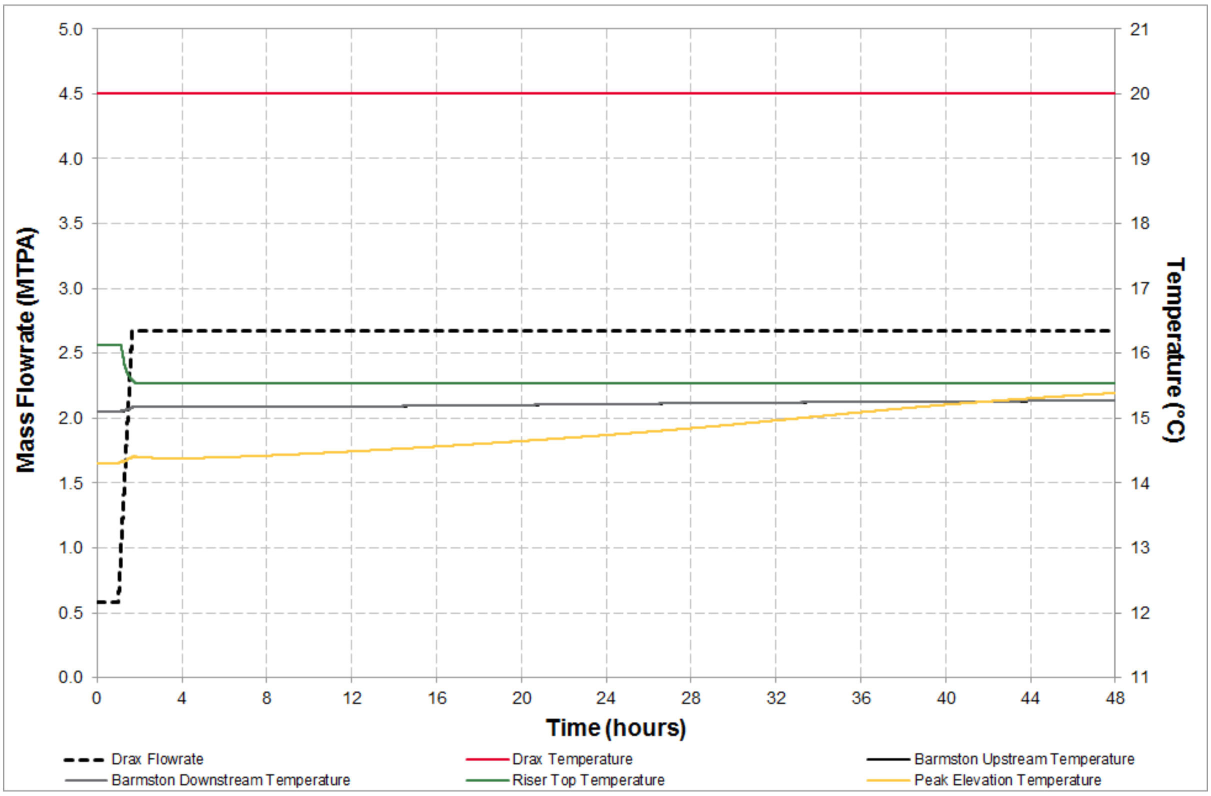


Figure 7.22: Temperature at Selected Locations along the Pipeline System during Ramp-up from 0.58 to 2.68 MTPA at 2% of Maximum Flow per Minute, First Load Composition, Summer



7.4.1.1 Ramp-up Following Additional Well (0.58 MTPA to 2.68 MTPA)

If an additional well is to be brought online, it could be done before ramping up the flowrate.

Figure 7.23 shows the changes in pressure and flowrate resulting from such a scenario. From initial steady state operation with a single well online (P5W1 in this case), P5W2 choke is opened gradually over 1 hour and the flow ramp-up begins 8 hours after the choke is fully opened, while the platform setpoint is kept at 100 barg. Flowrates and pressures settle within 2 hours from the opening of the additional well choke, but this will depend on the platform choke controller settings. The simulations show that as the P5W2 choke is opened the wellhead pressure in P5W1 (the operating well) drops, resulting in an increase in gas break out (however note that there was always gas present at the wellhead (see Figure 7.24) when flowrates and reservoir pressures are low).

Figure 7.23: Pressure and Flowrate Changes following Well Opening and 0.58-2.68 MTPA Ramp-up at 2% of Maximum Flow per Minute, First Load Composition

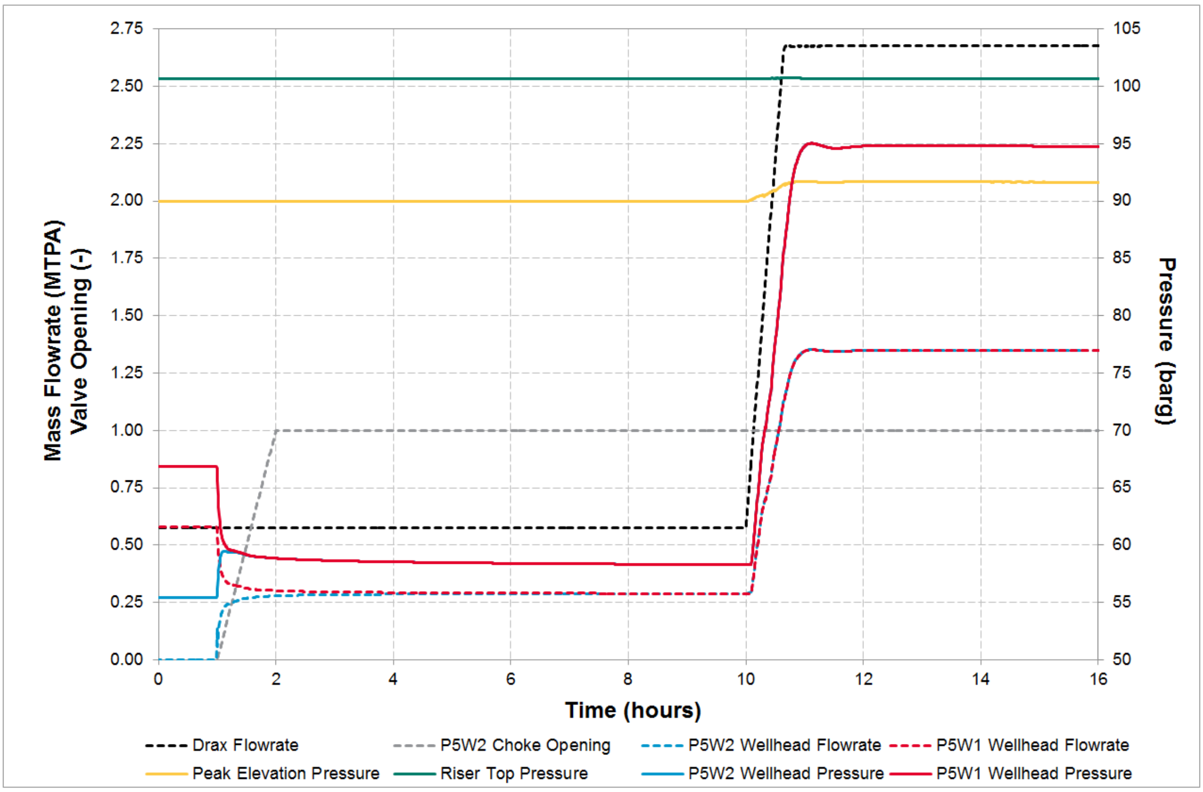
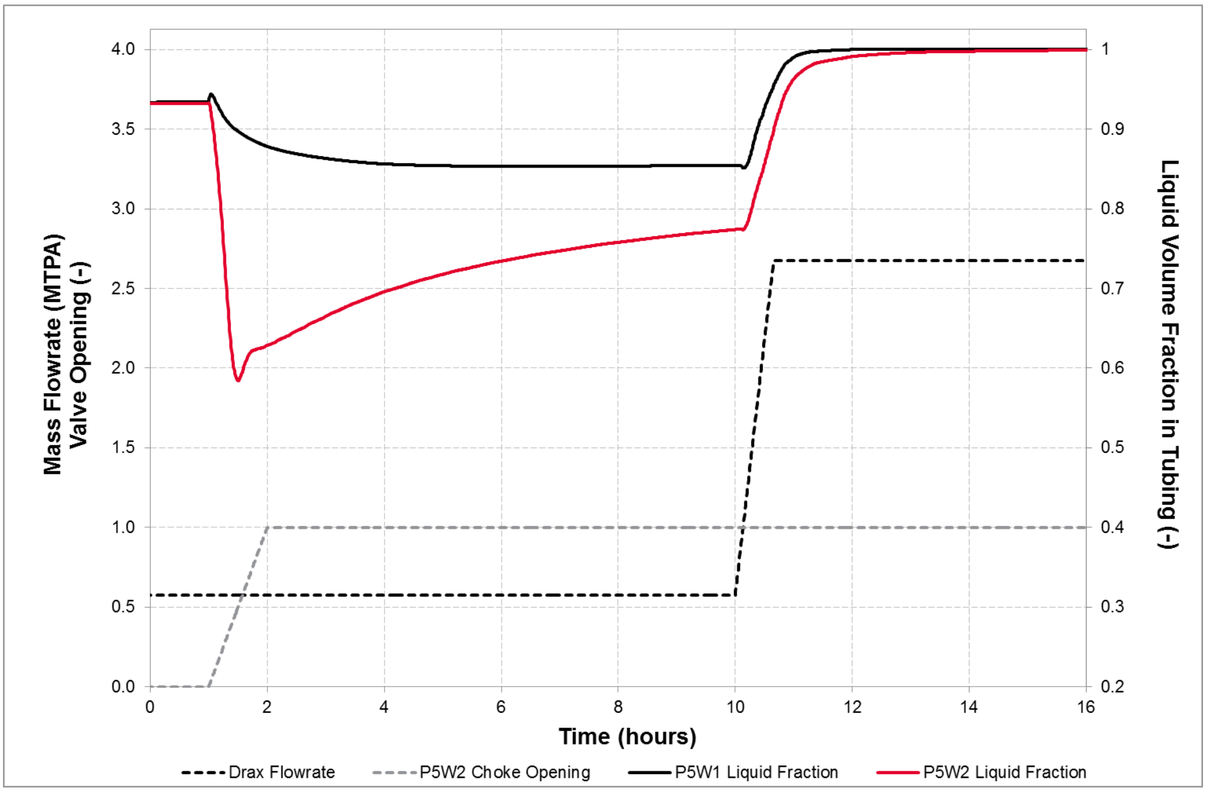
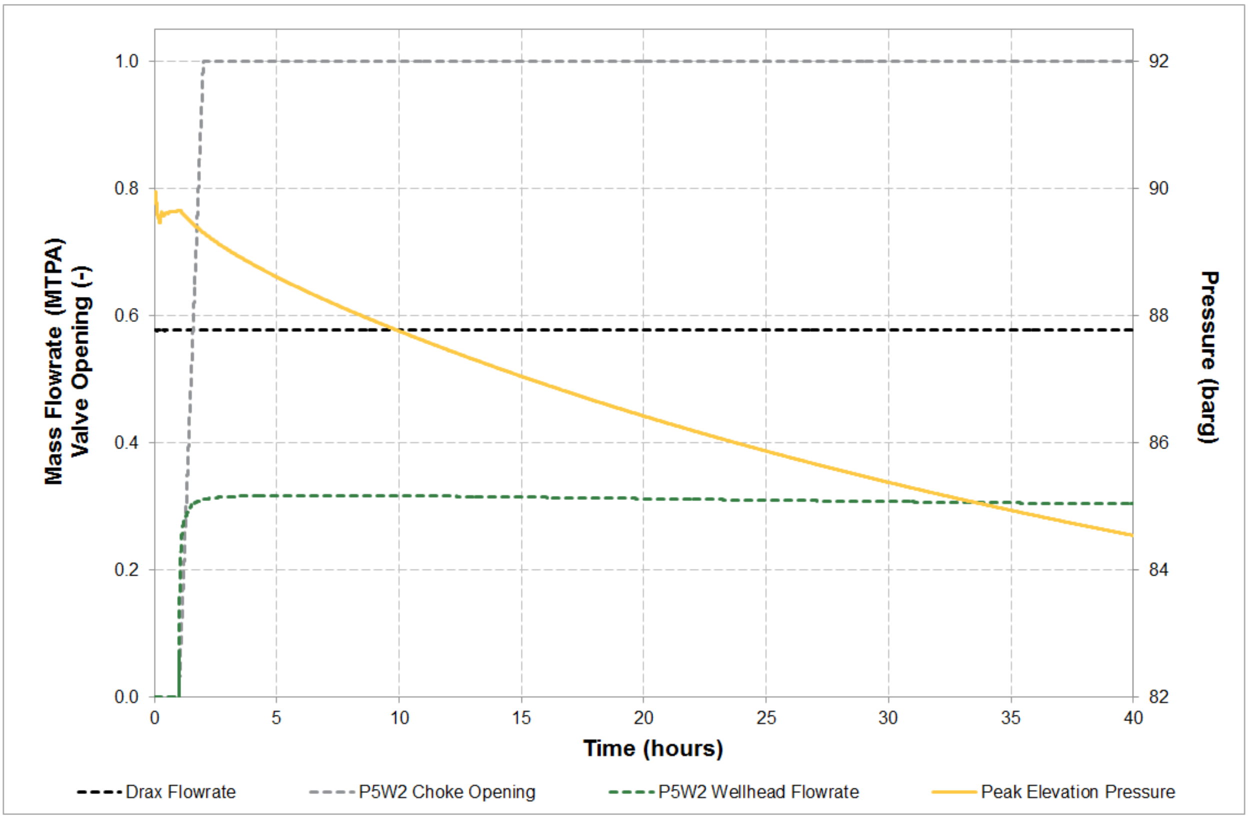


Figure 7.24: Liquid Fraction and Flowrate Changes following Well Opening and 0.58-2.68 MTPA Ramp-up at 2% of Maximum Flow per Minute, First Load Composition



If the platform choke is not adjusted to maintain the arrival pressure at 100 barg after opening the choke, the pipeline pressure is expected to decrease at a slow rate; it could take several days for the pressure at the maximum elevation to approach the cricondenbar (and therefore potentially enter the two-phase region) even without flow ramp-up. It is imperative that the platform pressure control continues to control the arrival pressure during this operation; this is shown in Figure 7.25.

Figure 7.25: Pressure Decline at Maximum Elevation Following the Opening of P5W2 Choke with No Platform Pressure Control



7.4.2 Year 5-10 (7.9-10 MTPA)

The onshore and offshore sections were modelled separately for the purposes of this analysis, as explained in section 7.3.2. The results from the ramp-up simulation from 7.9 to 10 MTPA for the two models are combined in Figure 7.26. A ramp-up rate of 2% of the maximum design flowrate of Drax per minute is used. The results indicate that the pressure in the pipeline section upstream and downstream of Barmston settles within 1 hour after ramp-up starts (ramp-up starts at time = 1 hour and the ramp-up duration is 40 minutes). The temperature behaviour of the system during the ramp-up operation in winter conditions is shown in Figure 7.27. Note that for this analysis, the following setpoints are assumed:

- The Barmston pump suction pressure setpoint is assumed to be 98 barg. This pressure is required at 7.9 MTPA to ensure the pressure at the high point in the onshore pipeline does not fall below 90 barg during steady state operation.
- The platform arrival pressure setpoint is assumed to be approximately 104 barg to ensure a minimum pressure differential of 20 bar across the pump is maintained to prevent cavitation. The pump discharge pressure at 7.9 MTPA therefore is 118 barg.

The pressure control system on the platform adjusts the platform choke valve to maintain the arrival pressure at 104 barg during and following ramp-up and the pressure in the pipeline quickly settles out to the new steady state pressures. The temperatures through the pipeline settle within approximately 15 hours of the ramp-up.

Figure 7.26: Pressure at Selected Locations along the Pipeline System during Ramp-up from 7.9 to 10 MTPA at 2% of Maximum Flow per Minute, Full Flow Composition

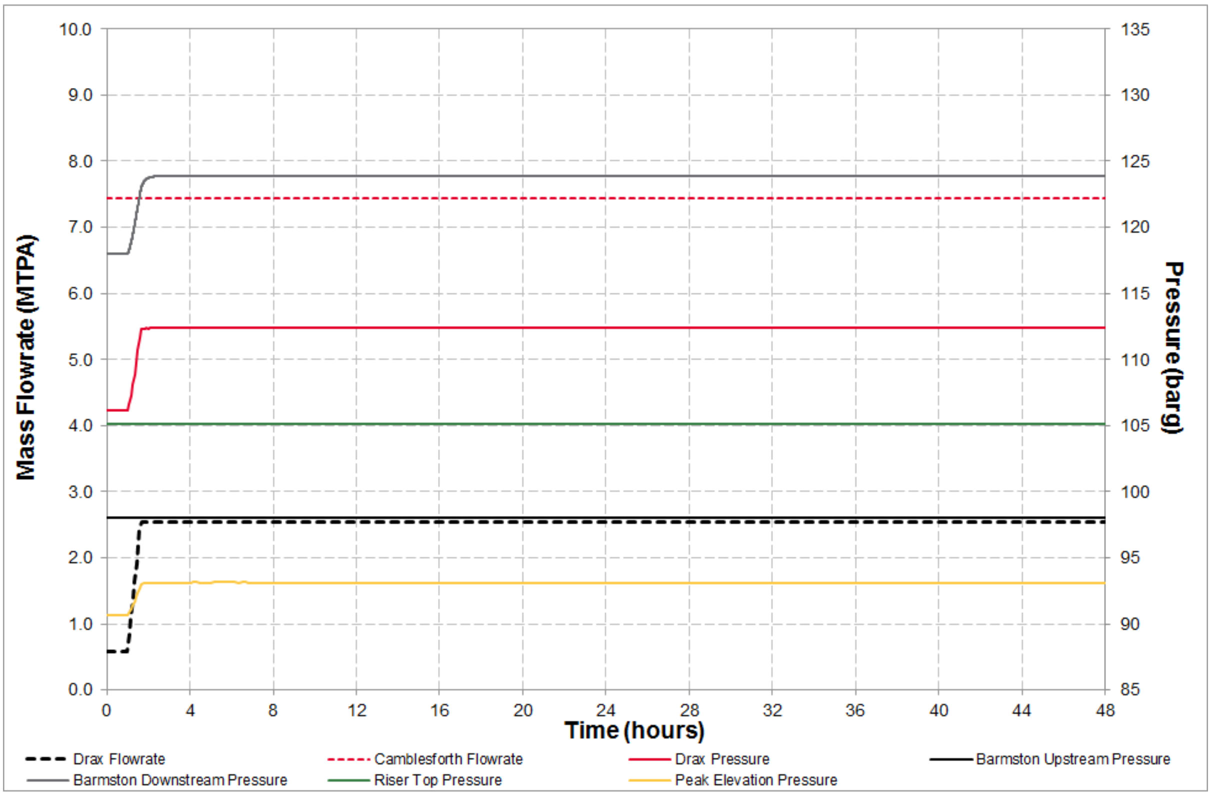
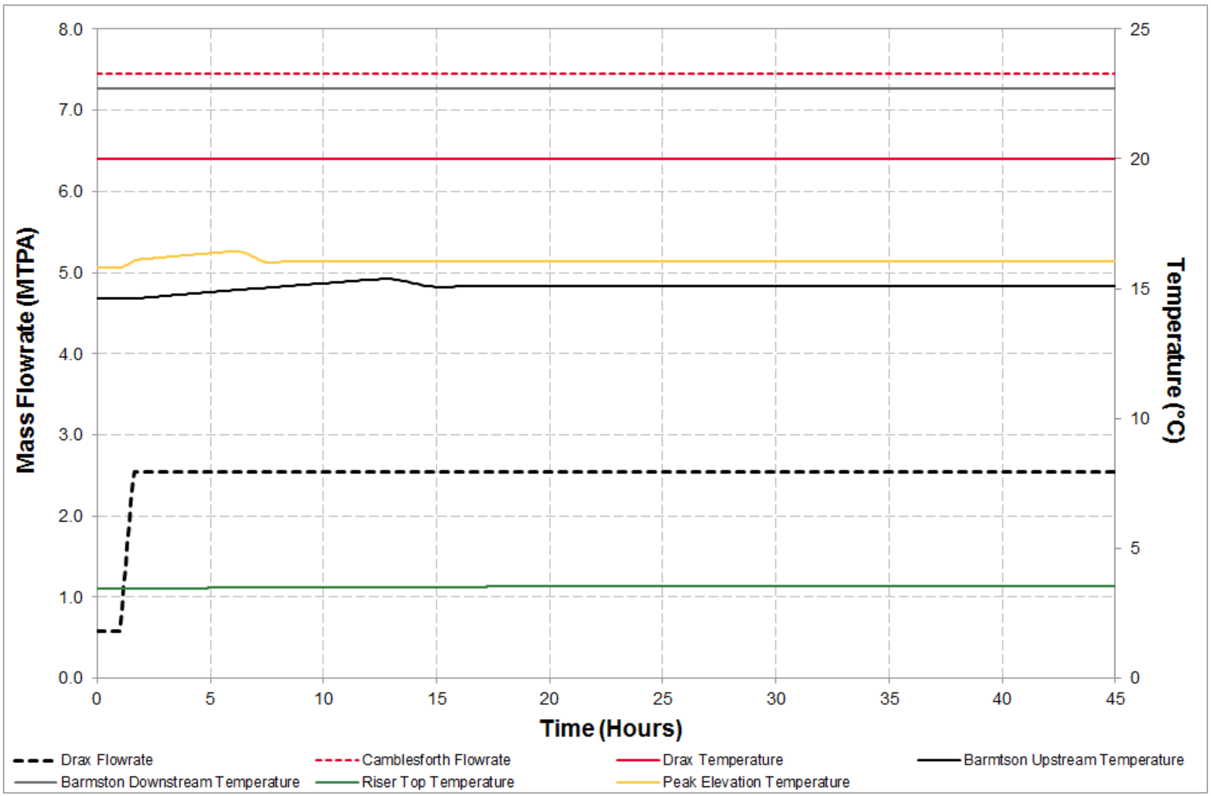


Figure 7.27: Temperature at Selected Locations along the Pipeline System during Ramp-up from 7.9 to 10 MTPA at 2% of Maximum Flow per Minute, Full Flow Composition, Winter



7.4.2.1 Ramp-up Following Additional Well (7.9 – 10 MTPA)

To observe the impact of bringing an additional well online, a scenario was simulated whereby a sixth well was opened after reaching steady state with five wells in operation, followed by flow ramp-up to 10 MTPA.

- At time = 1 hour – additional well is brought on line. Operation continues at 7.9 MTPA for a further 8 hours to allow the pipeline system to settle to the addition of this well.
- At time = 10 hour – ramp-up commences at 2% of the maximum rate (2.68 MTPA) per minute (equivalent to 0.054 MTPA per minute).

The results shown in Figure 7.28 indicate that the pressure in the pipeline sections downstream of Barmston, including the wellhead pressure of P5W1, drops by approximately 12 bar when the sixth well is brought online, and the injection rate into the well stabilises in about 5 hours. The pressure profile upstream of Barmston would not be affected as long as the pump suction pressure is kept at a fixed setpoint. Note that the riser top pressure is almost identical to the P5W1 wellhead pressure so is not clear in Figure 7.28.

Figure 7.28: Pressure and Flowrate Changes following Well Opening and 7.9-10 MTPA Ramp-up at 2% of Maximum Flow per Minute, Full Flow Composition

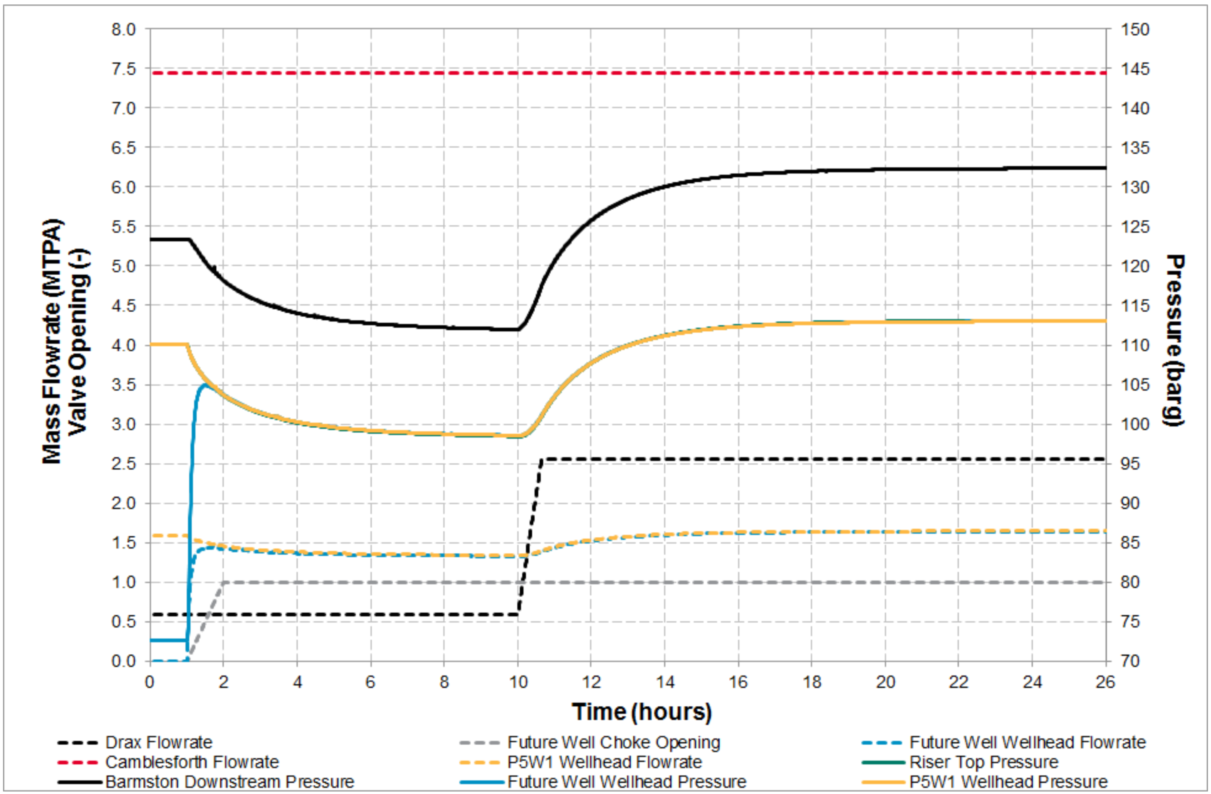
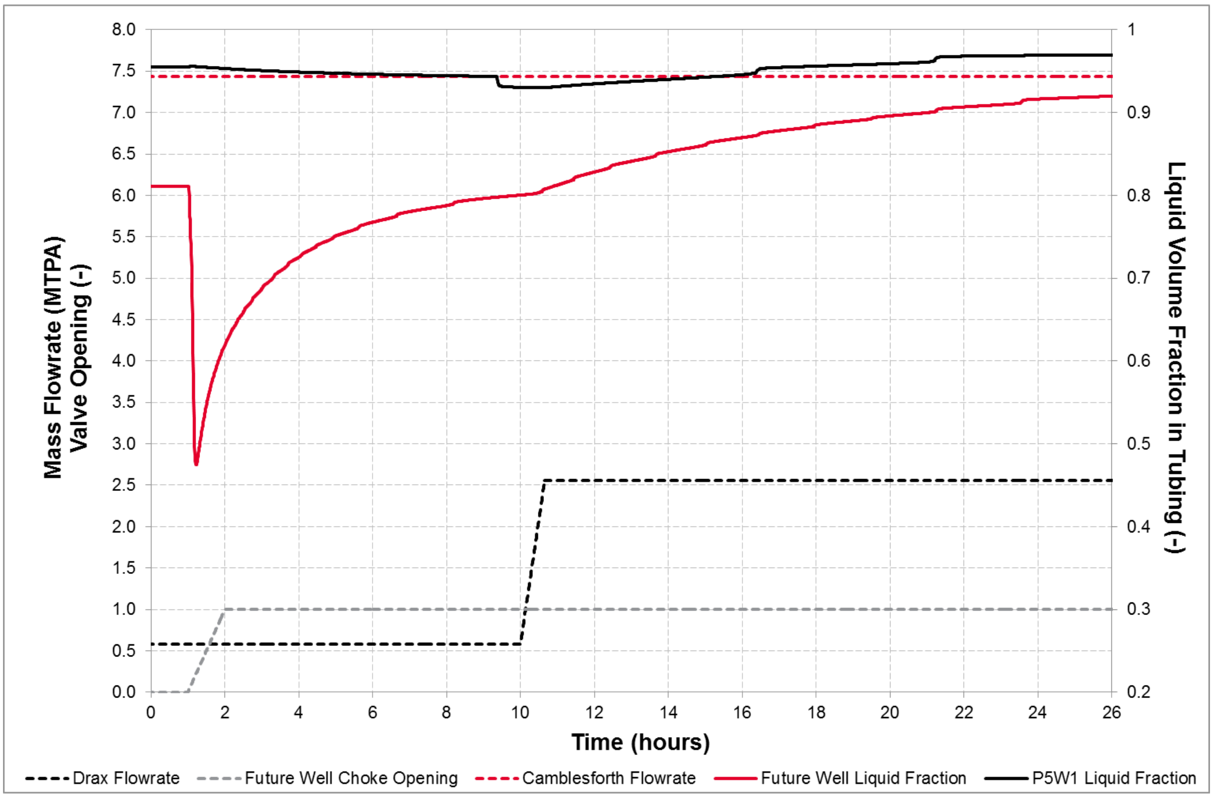


Figure 7.29: Liquid Fraction and Flowrate Changes following Well Opening and 7.9 MPTA to 10 MTPA Ramp-up at 2% of Maximum Flow per Minute, Full Flow Composition

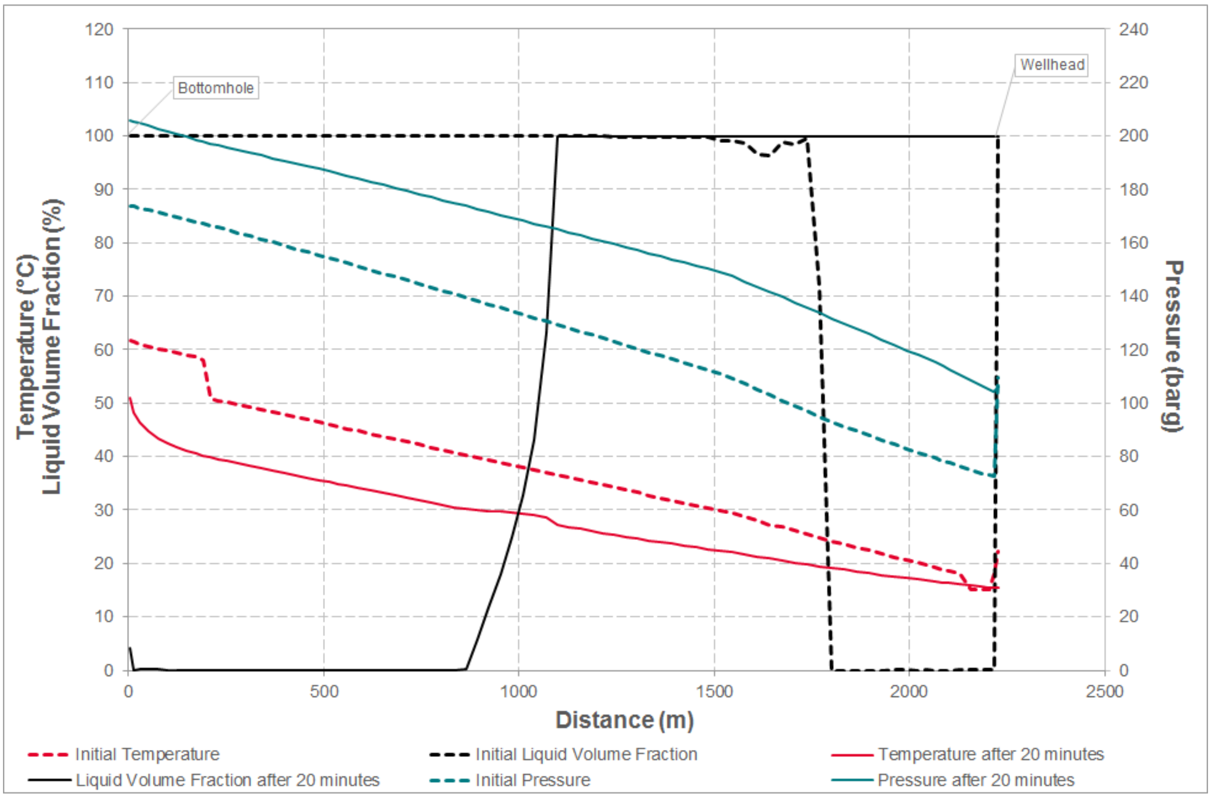


The liquid volume fraction in the tubing exhibits unexpected behaviour:

- Liquid and gaseous CO_2 is partitioned in the tubing prior to start-up (liquid CO_2 filling most of the tubing with a gas cap on top).
- When the choke valve opens, introducing CO_2 into the tubing, the liquid volume fraction drops to 50% liquid. This is caused by how OLGA interprets the CO_2 at temperatures above the cricondentherm. Now that the CO_2 is moving, OLGA interprets CO_2 at temperatures above the cricondentherm (highest temperature on the phase envelope, approximately 30°C) as vapour. As much of the fluid in the well tubing is above 30°C during this stage, due to the geothermal gradient, it is reported as gas. This results in the liquid volume fraction incorrectly being reported.

Figure 7.30 shows the conditions in the well tubing prior to and 20 minutes after opening the well to incoming CO_2.

Figure 7.30: Conditions in Well Tubing Before and Following Well Opening and 7.9 MTPA to 10 MTPA Ramp-up at 2% of Maximum Flow per Minute, Full Flow Composition



Prior to opening the well, the tubing is shown to be liquid-filled up to approximately 1800 m from the bottomhole. However, when the well is opened and the CO_2 in the well starts to move, the liquid volume fraction in the first 900m flips from 100% to 0% because the temperature in this section is above 30°C and OLGA interprets that as being "gaseous dense phase". However, the pressure in this section is above 80 barg and therefore is in the dense phase region. The incoming CO_2 from the wellhead is shown as "liquid dense phase" (liquid volume fraction is 100%), as the temperature is below the cricondentherm (approximately 30°C) and outside the phase envelope (OLGA interprets this as being liquid). Observing the pressure and temperature in this chart demonstrate that two-phase flow downstream of the choke valve is unlikely as these conditions are not in the two-phase region of the phase envelope. There may be some transition through the phase envelope in the well tubing. However, this is not expected to cause operational issues during this operation.

Pressure in the onshore pipeline (upstream of the Barmston pump) will respond in the same way as shown in Figure 7.26 as the pump suction pressure control system will respond to ensure the pump suction pressure remains constant.

7.4.3 Ramp-up Summary

- The pressure in the pipeline settles within a few hours of ramp-up, but the small changes in temperatures through the pipeline (particularly at low flowrates in winter conditions) can take several days to reach steady state.

- Bringing a new well online before ramp-up results in a drop in pressure downstream of the Barmston pump, but this is not expected to cause any concerns with effective platform arrival pressure control.
- The pump suction and platform arrival pressure setpoints should not be changed to the final desired values until after ramp-up has been completed to avoid the risk of the pressure in the pipeline falling below 90 barg.
- It is recommended that ramp-up of flow from Camblesforth be analysed in the next phase when more information about potential CO_2 emitters is available to ensure pump suction pressure control can adequately manage the operation.

7.5 Cooldown

The purpose of this analysis is as follows:

- determine the time for the pipeline temperature to settle to ambient conditions; and
- determine the risk of gas break out in the pipeline, specifically over the high point between Camblesforth and Barmston.

Table 7.7 and Table 7.8 show the cooldown times following unplanned shutdown for summer and winter operation respectively. The times are for the fluid to cooldown to 1°C greater than the ambient temperature as this is slightly more meaningful due to the asymptotic nature of the cooldown curves as they approach ambient temperature. The First Load composition was used for year 1 simulations, and the impurities composition was used for Years 5 and 10.

Table 7.7: Cooldown Times – Summer (15°C Ambient Onshore, 16°C Seabed)

		Initial Temperature (°C)		Time to Reach +1°C of Ambient Temperature	
Field Life	**Pipeline**	**Inlet**	**Outlet**	**Inlet**	**Outlet**
Year 1	Drax to Camblesforth	20.0	19.5	16 days	15 days
	Camblesforth to Barmston	19.5	16.6	15 days	2 days
	Barmston to Platform	16.6	14.8	2 days	<1 day
Year 5	Drax to Camblesforth	20.0	19.5	16 days	15 days
	Camblesforth to Barmston	19.9	17.7	21 days	15 days
	Barmston to Platform	27.0	15.7	>40 days	<1 day
Year 10	Drax to Camblesforth	20.0	19.5	15 days	12 days
	Camblesforth to Barmston	19.9	16.4	21 days	7 days
	Barmston to Platform	28.6	15.7	>40 days	<1 day

Table 7.8: Cooldown Times – Winter (4°C Ambient Onshore, 4°C Seabed)

		Initial Temperature (°C)		Time to Reach Ambient Temperature	
Field Life	**Pipeline**	**Inlet**	**Outlet**	**Inlet**	**Outlet**
Year 1	Drax to Camblesforth	20.0	18.8	37 days	35 days
	Camblesforth to Barmston	18.8	8.6	>40 days	19 days
	Barmston to Platform	8.6	1.5	19 days	<1 day
Year 5	Drax to Camblesforth	20.0	18.8	40 days	40 days

Field Life	Pipeline	Initial Temperature (°C) Inlet	Outlet	Time to Reach Ambient Temperature Inlet	Outlet
	Camblesforth to Barmston	19.7	15.1	>40 days	39 days
	Barmston to Platform	22.3	3.3	>40 days	<1 day
Year 10	Drax to Camblesforth	20.0	18.7	39 days	40 days
	Camblesforth to Barmston	19.8	14.8	>40 days	40 days
	Barmston to Platform	26.4	4.3	>40 days	<1 day

As the onshore pipeline is buried, it takes several days for the temperature to settle-out to ambient along its entire length, despite the pipeline operating temperature being relatively cool during normal operation. The offshore pipeline at low flow (First Load), in summer has inlet temperatures at just above ambient as the Barmston pump is not in operation and therefore does not supply additional heat to the CO_2. In addition, the Barmston to Platform pipeline is unburied for a significant portion resulting in temperatures arriving at the platform close to seabed ambient conditions. This allows the pipework on the platform (which is uninsulated) to rapidly cool to the ambient air temperature.

It should be noted that these cooldown times start from steady state conditions, i.e. the soil surrounding the pipeline has been heated by the pipeline contents and heat transfer to the surroundings is at equilibrium. It could take several weeks from initial start-up for this to occur in practice due to the thermal mass of soil surrounding the pipeline, so cooldown times in the pipeline could be shorter than shown above if shutdown occurs within the first few days/weeks after the previous start-up/restart.

Table 7.9 shows the initial and settle-out pressures following unplanned shutdown for summer and winter operation. As the pressure is linked to the temperature, for those cases where temperature is still falling, the pressure at 40 days is reported. The reservoir pressures used for each case in this analysis are assumed to follow the normal pressure curves shown in Figure 4.2 as this minimises the initial pressure in the offshore pipeline, therefore is closer to the phase envelope prior to shutdown.

Table 7.9: Settle-Out Pressures at Section Inlet

Ambient Conditions	Field Life	Initial Flowrate (MTPA)	Drax		Camblesforth (d/s tie-in)		Hill Top		Barmston (d/s pumps)	
			Initial Pressure and Settle-out Pressure (barg)							
Winter	Year 1	2.68	106.3	70.6	104.1	70.4	91.4	57.8(1)	103.6	70.7
Winter	Year 5	10	110.3	71.7	108.1	71.7	91.2	65.6(2)	144.4	85.1
Winter	Year 10	17	131.7	71.7	129.6	71.8	101.5	66.1(2)	166.4	75.4
Summer	Year 1	2.68	106.2	95.5	104.1	95.4	91.7	83.4	103.4	95.7
Summer	Year 5	10	110.5	86.8	108.4	86.7	91.5	76.0	155.5	120.6
Summer	Year 10	17	132.1	98.0	129.9	97.9	101.9	86.9	177.5	118.3

(1) Although this is the lowest pressure, due to the narrow phase envelope for the First Load composition, the system remains outside of the two-phase region.
(2) Conditions at peak elevation in onshore pipeline are in the two-phase region for the impurities composition only.

During summer operation at low flow (First Load) the settle-out pressures are in the liquid-only part of the phase envelope. For the high flowrate cases at maximum ambient conditions, the settle-out pressure is either in the dense phase (>90 barg) or in the liquid-only region of the phase envelope, therefore outside the 2-phase region. Therefore, there will be no partitioning of vapour and liquid, even for the Impurities composition with its wider phase envelope.

However for the winter cases the pressures fall to approximately 72 barg at Drax and Camblesforth, which is below the cricondenbar (the maximum pressure at which two phases, for example, liquid and vapour, can coexist or the maximum pressure above which no gas can be formed regardless of temperature). At 72 barg and 4°C the fluid is still outside the phase envelope, however at the high point between Camblesforth and Barmston the pressure drops to 65 barg and 66 barg for the Year 5 and Year 10 cases respectively. This is just inside the phase envelope for the impurities composition and therefore results in two-phase conditions. The settle-out pressure at Barmston is actually higher in Year 5 (when operating at 10 MTPA), whereas it might be expected to be even greater when operating at a higher flowrate (i.e. in Year 10 when operating at 17 MTPA), particularly when the initial pressures are greater at the higher flowrate. However, the temperatures are also greater initially (25°C at 17 MTPA compared with 22°C at 10 MTPA in winter conditions) at the higher flowrate (as the pump is working harder, therefore impacting greater heat to the fluids), so on cooling the pressure falls further.

Table 7.10 shows the pressures at the top of the well tubing prior to and following shutdown for the low reservoir pressure curves. Ambient air temperature at the top of the tubing is -7°C and 28°C in summer

Table 7.10: Settle-Out Pressures in Well Tubing

Ambient Conditions	Field Life	Initial Flowrate MTPA)	P5W1		P5W2		P5W3	
			Initial Pressure and Settle-out Pressure (barg)					
Winter	Year 1	2.68	63.9	41.2	63.9	41.2	-	-
Winter	Year 5	10	125.2	80.1	125.2	80.1	125.0	80.2
Winter	Year 10	17	115.0	81.0	115.0	81.0	114.9	81.1
Summer	Year 1	2.68	75.7	53.9	75.7	53.8	-	-
Summer	Year 5	10	135.8	73.0	135.8	73.0	135.6	73.0
Summer	Year 10	17	124.6	74.2	124.6	74.2	124.5	74.2

The CITHPs (Closed in Tubing Head Pressures) following shutdown tend to be lower for winter conditions as the colder temperatures in the well tubing result in a higher density of CO_2, therefore there is greater static head (hence lower CITHP). The flowing pressure is greater than shut-in pressure as these are injection wells and the frictional pressure drop through the well tubing and the pressure drop across the sandface when flowing increases the pressure required to inject.

7.5.1 Cooldown Summary

- Cooldown durations are between 15 and 21 hours for the onshore sections during summer ambient conditions, but fluid at the platform end of the offshore section reaches ambient within 1 hour.
- Cooldown during winter ambient conditions takes ~40 days due to the higher initial difference in operating and ambient temperatures.
- During cooldown to winter ambient temperatures, with the impurities composition, the lower temperatures results in operating pressures and temperatures entering the two-phase region. Pressures as low as 65 barg are predicted for the high point between Camblesforth and Barmston.

7.6 Restart

The purpose of this analysis is to determine the system behaviour during a restart operation, specifically the pressure rise with increasing flowrates (and the implications for the pump at Barmston), and the time taken to re-establish steady state conditions. Two scenarios are considered:

- warm restart – 1 hour after a shutdown; and
- cold restart – system at ambient conditions (or after 40 day shutdown).

The start-up sequence is to initially start up flow from Drax from zero to 40% flow almost instantaneously, followed by a slower ramp-up of 2% design flow per minute. Once Drax is operating at the desired flowrate, the additional flow from Camblesforth is ramped up following the same ramp-up rate of 2% design flow per minute. Due to the uncertainties surrounding the control logic, performance curves, and characteristics of the Barmston pump, an assumption has been made about the start-up time and the PID (roportional-integral-derivative automated control loop feedback mechanism) control setpoints. The pump was modelled as starting up at the same time as the flow from Camblesforth. This is probably earlier than would be in reality, as there is a possibility that the suction pressure will drop too quickly and result in a pump trip (this should be investigated when the pump and control system data are available). Restart simulations were carried out for a Year 5 (10MTPA) case.

7.6.1 Cold Restart

Figure 7.31 shows the pressure data at a number of locations for a cold restart for Year 5 (up to 10 MTPA) for winter conditions with a high reservoir pressure. The flow is started at time = 1 hour. It should be noted that the tuning around the control of the pumps and the choke valve on the platform has not been optimised, hence the fluctuating nature of the results. However, the pressure downstream of the pumps and at the offshore platform reach a steady value after approximately 8 to 12 hours. The system temperatures take longer to reach steady state, due to the pipeline burial and the heat capacity of the surrounding soil. Figure 7.32 shows the temperature behaviour during a restart for the same case (summer conditions are not shown as the settle-out time for temperatures through the pipeline would be quicker as the ambient temperature is much closer to the steady state operating temperatures). After 5 days the temperature upstream and downstream of the Barmston pump station is still just increasing to the steady state values of 15.1°C and 22.3°C, while the temperatures at Drax and the platform reach steady state quickly. This is because the onshore pipeline sections are buried and the surrounding soil takes time to achieve thermal equilibrium, while the offshore pipeline is mainly unburied and therefore does not have the thermal mass of its surrounding to heat up.

The high point between Camblesforth and Barmston, which was shown to enter the two-phase region during cooldown based on minimum ambient conditions, quickly exits the phase envelope, moving into the dense phase. Within 1.7 hours of the start-up operation, the pressure at the high point has increased to above 90 barg.

Figure 7.31: Pressure Trends for Cold Restart for Year 5 to 10MTPA, High Reservoir Pressure, Winter

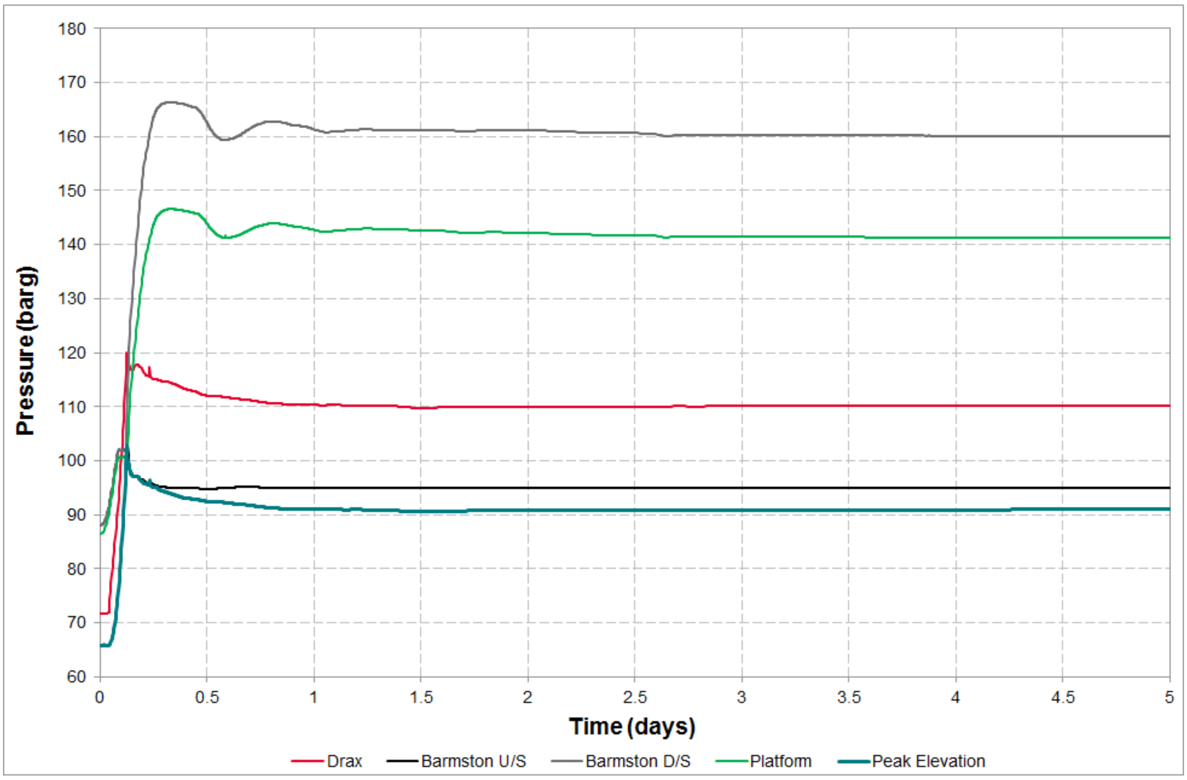
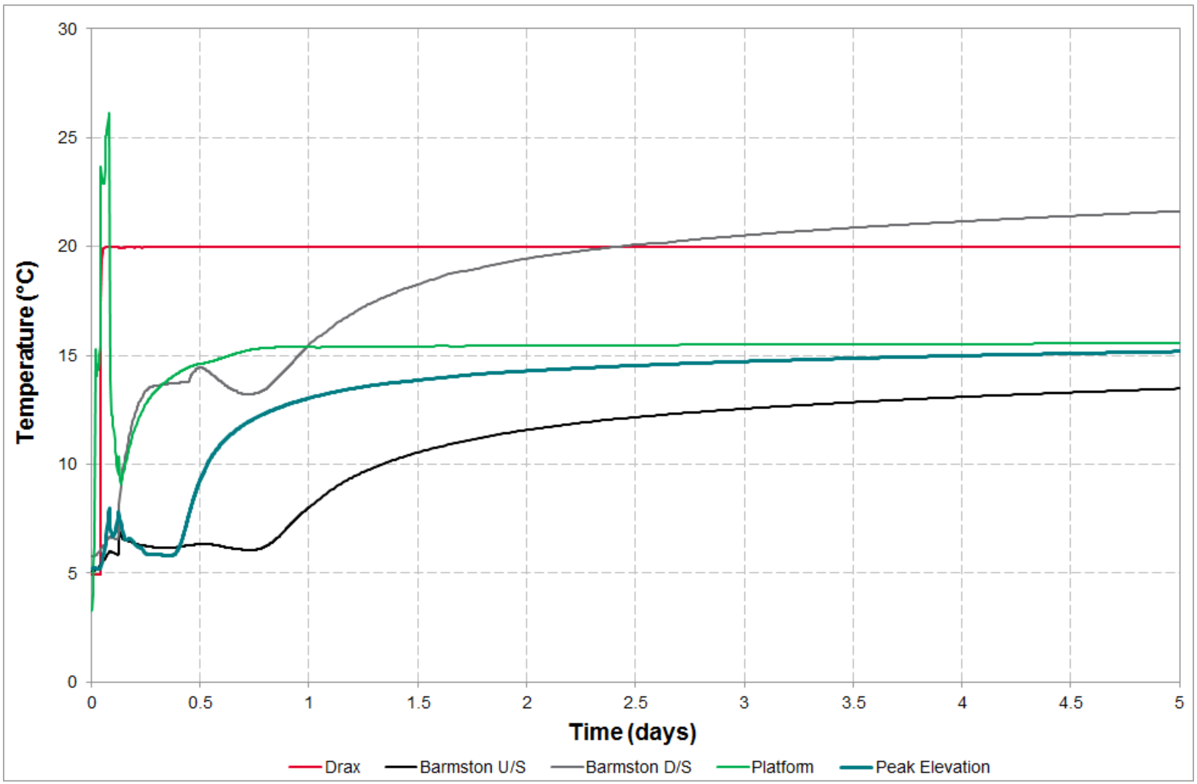


Figure 7.32: Temperature Trends for Cold Restart for Year 5 to 10MTPA, High Reservoir Pressure, Winter



The temperature spikes at the platform as the CO_2 in the pipeline is compressed against the platform valve before the hydraulics in the system start to become established and the fluid starts to flow.

Table 7.11 shows the temperature downstream of the choke (in the well tubing) during restart. For this case, the pipeline pressure is set to the MAOP of 182 barg to ensure the maximum pressure drop across the valve (hence maximum J-T cooling). The pressure downstream of the choke was set to the minimum CITHP of 32.5 barg, as shown for the First Load composition. It is unlikely that the CITHP will be so low when the pipeline is operating with the Full Flow and Impurities compositions, therefore it is not anticipated that vapour break-out will occur in the well tubing during cold restart. This set of conditions represents the operating extreme in the system (pipeline has inadvertently packed up to MAOP at the start of field life (Full Flow and Impurities compositions are shown)).

An isentropic (adiabatic) flash was performed to determine the worst-case fluid temperature ignoring heat supplied from the surroundings, thereby giving a worst-case temperature prediction. Actual temperatures downstream of the chokes are expected to be higher than those given in Table 7.11 they represent worst-case.

Table 7.11: Minimum Theoretical Fluid Temperatures Downstream of Choke Valve during Restart

		Pressure (barg)		Temperature (C)	
Fluid	**Case**	**U/S of Choke**	**D/S of Choke**	**U/S of Choke**	**D/S of Choke**
Full Flow	Warm Restart	182	32.5	5	-11.3
	Cold Restart	182	32.5	-7	-16.9
Impurities	Warm Restart	182	32.5	5	-14.6
	Cold Restart	182	32.5	-7	-20.2

The minimum fluid temperature that can occur in the well tubing during restart, assuming no heat is supplied by the surroundings, is -20.2°C, which is well within the typical minimum design temperature constraints of carbon steel. Therefore, considering low temperature issues, carbon steel is likely to be acceptable downstream of the choke valves.

The wells will have vapour-liquid partitioning early in field life following extended shutdown due to the lower reservoir pressure. However, restarting injection into the wells, if carried out in a slow, controlled manner, should not result in significant turbulence within the well tubing as incoming CO_2 mixes with the settled gas / liquid / dense phase. It is recommended that wells be brought on sequentially so that pressures downstream of the injection valves can be monitored for excessive oscillation as injection rate increases.

7.6.2 Warm Restart

For the warm start-up case, the pressure recovery follows a similar pattern to that of the cold start-up, with steady values achieved within 8-12 hours. The temperatures reach steady state much faster due to shortened cooling time. Temperatures throughout the system reach steady state after approximately 5 hours.

Figure 7.33 and Figure 7.34 show the pressure and temperature respectively at selected points through the CO_2 transportation system during short shutdown (1 hour) and warm restart.

Figure 7.33: Pressure Trends for Warm Restart for Year 5 to 10MTPA, High Reservoir Pressure, Winter

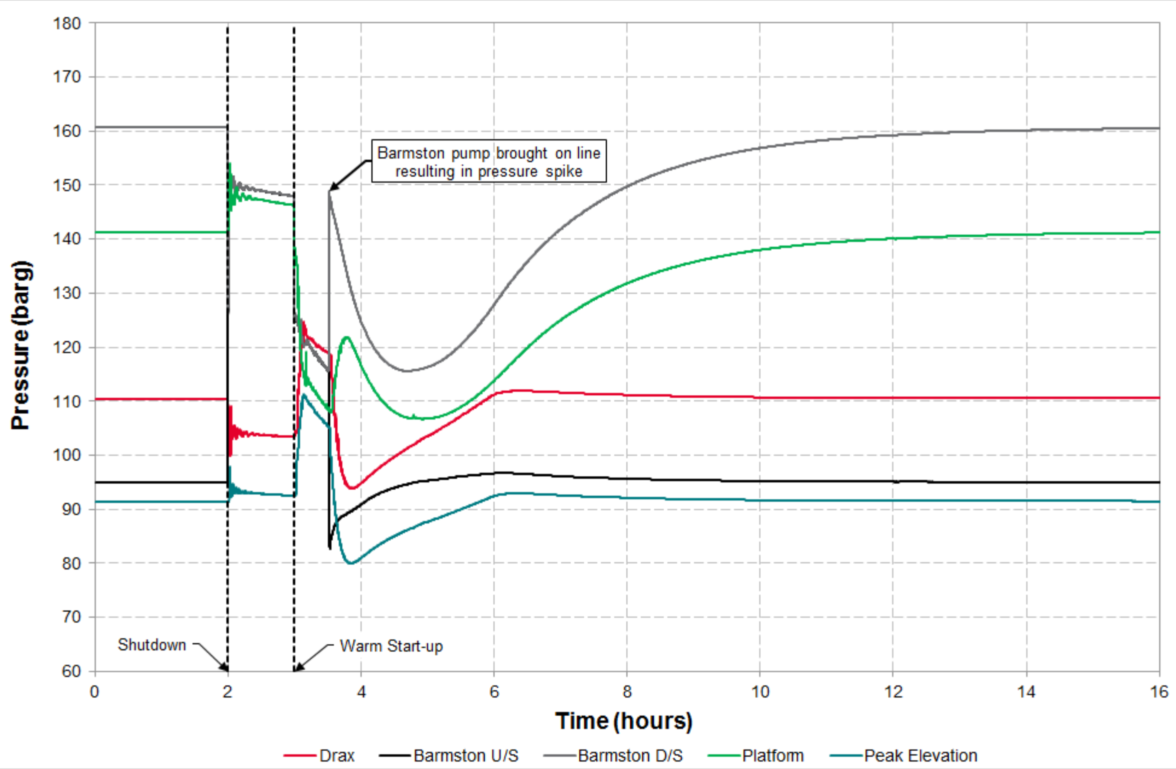
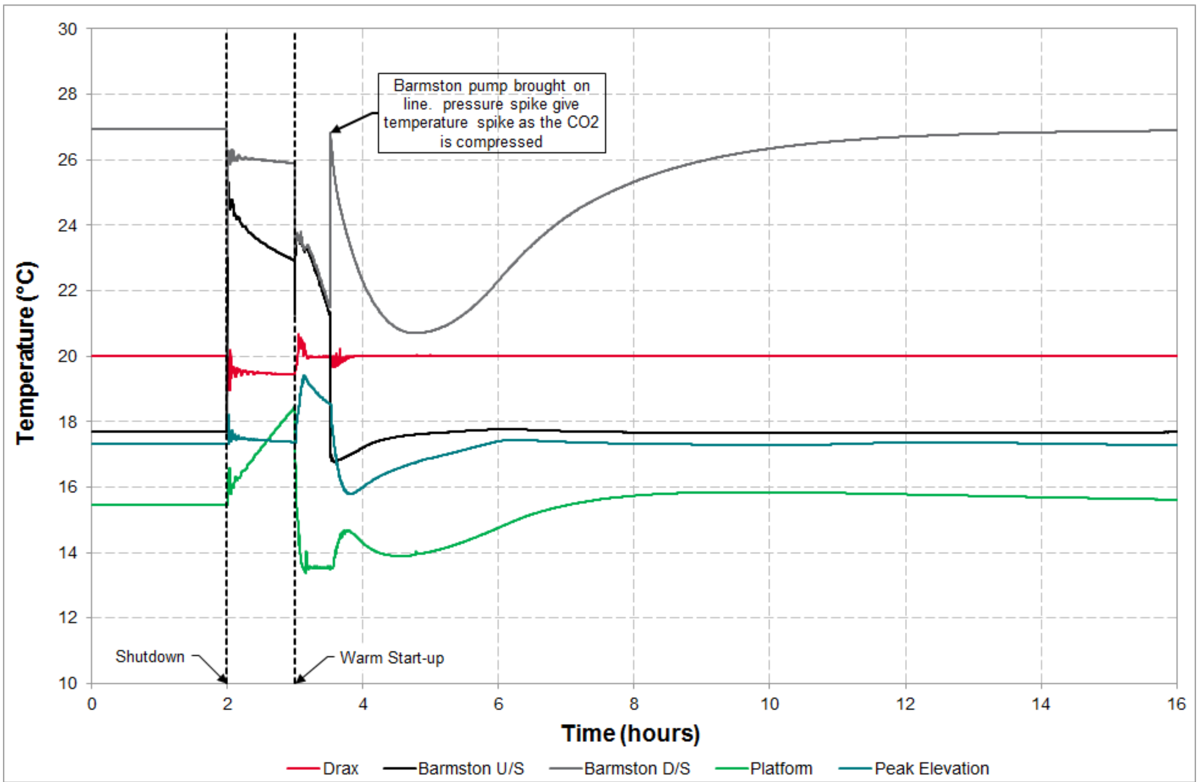


Figure 7.34: Temperature Trends for Warm Restart for Year 5 to 10MTPA, High Reservoir Pressure, Winter



When the Barmston pump comes on-line there is a pressure spike with an associated temperature spike that occurs due to the relative incompressibility (compared to gas) of the CO_2. There is a subsequent drop in pressure and temperature as the pump control system and system hydraulics start to respond and colder CO_2 is pumped.

7.6.3 Restart Summary

- Restart from a warm start-up reaches thermal steady state after approximately 10 hours, with the pressure reaching steady state in a similar time.
- Cold restart simulations (starting from a pipeline at minimum ambient temperature) took in excess of 5 days to reach thermal steady state due to the time required to heat the soil surrounding the onshore (and part of the offshore) pipeline, but reached a steady pressure within approximately 10 hours.

7.7 Depressurisation

The main aim of this analysis is to determine the minimum temperature that the pipeline will experience during a controlled, planned, blowdown. If the depressurisation is performed too quickly, the J-T expansion of the CO_2 could result in excessively cold temperatures in the pipeline.

The onshore pipeline can be isolated at each block valve station so that individual sections can be depressurised either as part of a full system depressurisation or to enable isolated depressurisation of a section without the need to blow down the entire pipeline. The following sections were considered in this analysis:

- Drax to Camblesforth;
- Camblesforth to Tollingham;
- Dalton to Skerne;
- Skerne to Barmston;
- Drax to Barmston;
- Barmston to Platform; and
- Drax to Platform.

Depressurisation of long CO_2-rich dense fluid pipelines is a complex process where, generally speaking, the following phenomena take place:

- due to pressure reduction, boiling of liquid CO_2 will commence causing heat to be absorbed from the surrounding metal (pipe wall) and surrounding soil to supply the latent heat of vaporisation, thereby reducing the metal temperature to (close to, but not below) the fluid temperature. J-T cooling will occur as the CO_2-rich gas expands and the pipeline inventory is reduced through venting; and
- due to the terrain profile, gas pockets will be trapped between liquid columns causing pressure differences on both sides of the high elevation points. Trapped liquid will continue to boil. Once the pressure on the side closest to the vent is low enough for the gas to sweep the trapped liquid, additional J-T cooling may occur.

For the purposes of this assessment, minimum ambient (winter) conditions have been assumed throughout as these give rise to lowest fluid temperatures. Summer conditions produce very similar results and the operating philosophy of depressurisation operation needs to be robust to the full range of operating conditions and therefore would not be different for summer from winter.

For all the cases investigated, the initial condition (before starting to depressurise) is the pipeline packed to the MAOP (135 barg in the onshore pipeline and 182 barg in the offshore pipeline) and the fluid temperature settled to ambient conditions. Initially, the fluid is motionless. It is noted that it may be preferable to reduce the pressure in the pipeline to as low as practical (whilst staying above 90 barg) prior to performing depressurisation to minimise the inventory of CO_2 vented to the atmosphere. However, this analysis considers the worst case for mass of CO_2 vented.

The target pressure of the onshore and offshore system has been set to 5 barg (using an assumed vent stack backpressure of 0.5 barg (i.e. downstream of the blowdown orifice), which is a typical assumption when venting to atmosphere).

The minimum design temperature of the pipeline is 0°C. However, this value will be transgressed because, as discussed earlier, the fluid will experience much lower temperatures due to the extensive J-T cooling. Therefore, it is recommended that additional Charpy testing be carried out to ensure the pipeline is capable of maintaining integrity at lower temperatures. For the purposes of this analysis, a minimum fluid temperature of -20°C has been assumed as Charpy testing to this temperature is expected to be comfortably achieved. It is assumed that the pipeline wall temperature is equal to the fluid temperature in this analysis.

The depressurisation process in almost all cases needs to be carried out in a step-wise fashion in order to control the extent of the J-T cooling. In this analysis, if the temperature anywhere along the pipeline reaches -20°C, the vent is then closed and the pipeline inventory allowed to settle and warm-up before again opening the vent. The waiting time between each blowdown period can be several days due to the insulating properties of the surrounding soil inhibiting heat transfer from the ambient surroundings to the CO_2 in the pipeline.

It should be noted that, due to inherent challenges in modelling depressurisation of impure CO_2 in OLGA (caused mainly by the narrow phase envelopes associated with impure CO_2), the depressurisation procedure has not been optimised. The time to depressurise the various sections are therefore indicative (particularly when depressurising very long sections). See section 7.7.3 for further details.

The following sections describe the various findings of this assessment. The Camblesforth to Tollingham section is used to illustrate the main points, although the conclusions from analysis on this section of the onshore pipeline are applicable to most of the scenarios investigated.

Note that the Impurities composition has been used throughout this analysis as it has the widest phase envelope and therefore presents the greatest challenge as the pipeline inventory remains in the two-phase region for longer during this operation. The other compositions present similar challenges with low temperatures but as the phase envelopes are narrower they pass through the two-phase region more quickly during depressurisation.

7.7.1 Depressurisation – A Multistage Process

This section explains the necessity to depressurise the pipeline in a multi-stage process. Figure 7.35 and Figure 7.36 show the vent rate and the minimum fluid temperature when depressurising the Camblesforth to Tollingham section through a 1 inch orifice. The minimum pressure in the section and pressure measured at Camblesforth are shown to demonstrate the progress of the depressurisation.

Figure 7.35: Vent Rate during Depressurisation of Camblesforth to Tollingham through a 1 inch Orifice

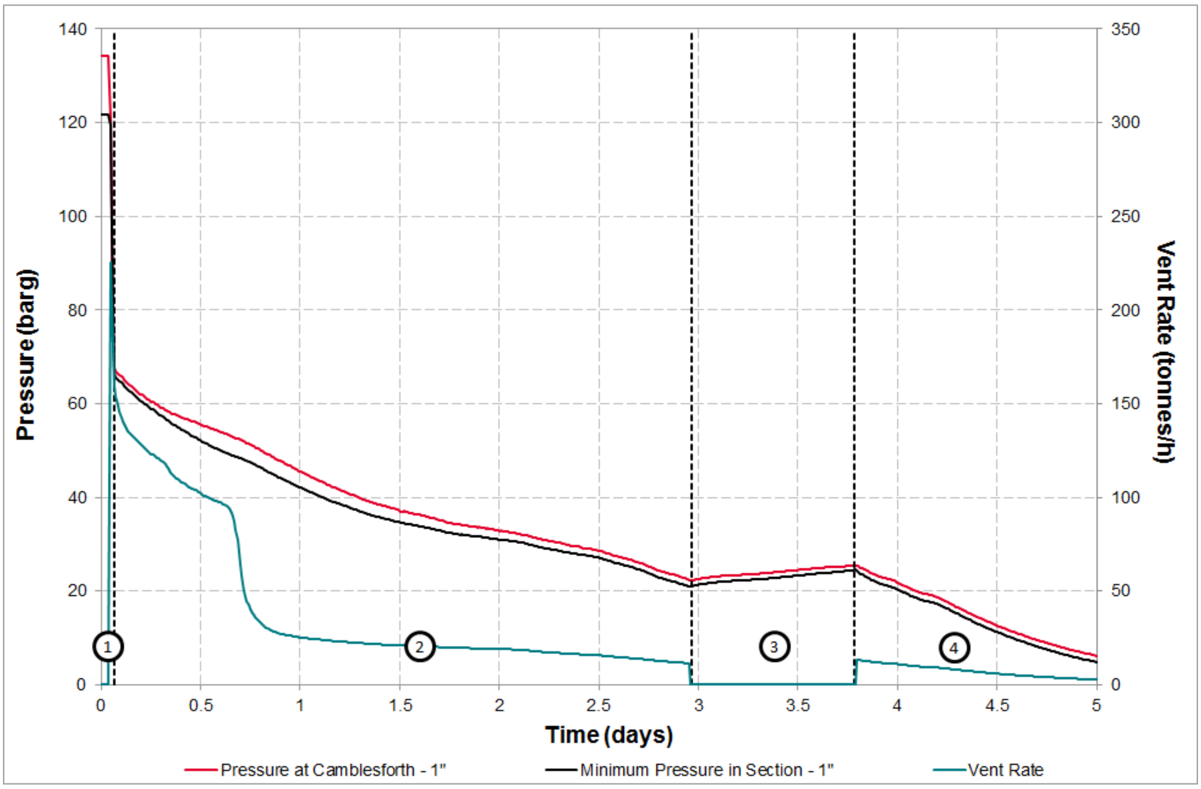
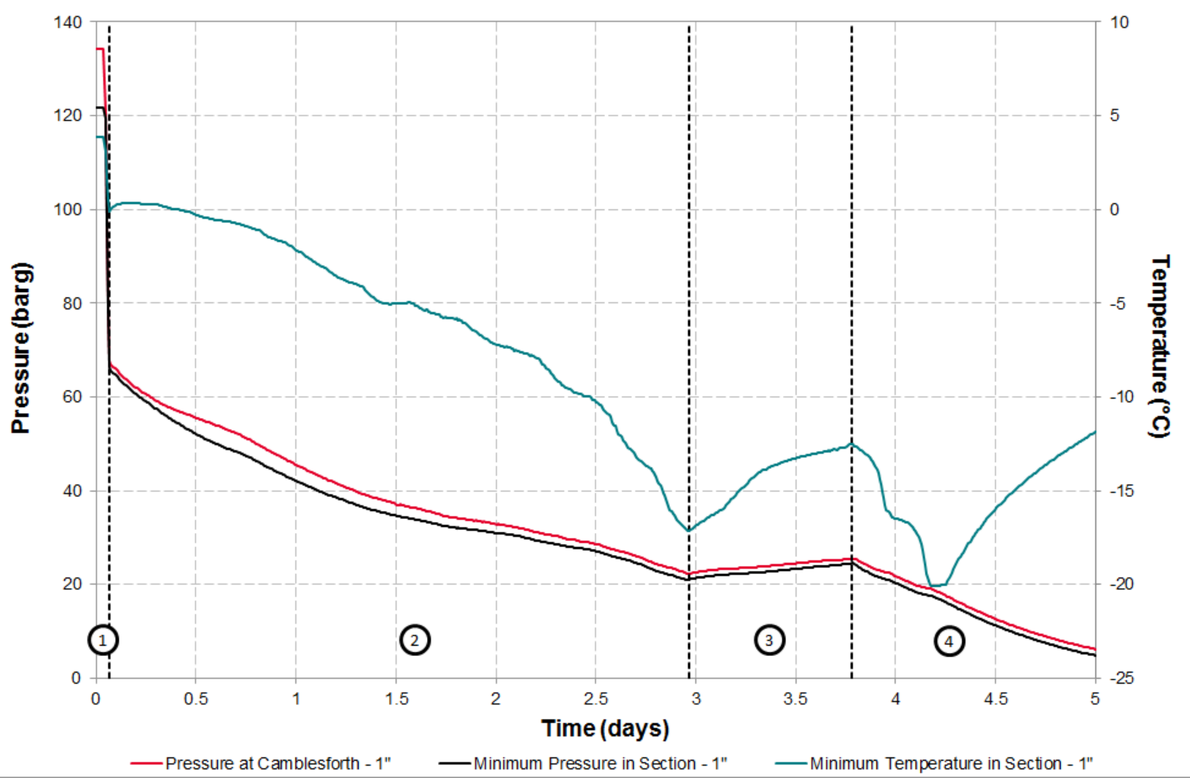


Figure 7.36: Minimum Temperature during Depressurisation of Camblesforth to Tollingham through a 1 inch Orifice



The depressurisation follows four distinct phases; these are described below.

1. The pressure drops quickly initially when the fluid is in the dense or liquid phase, as a small reduction in inventory results in a relatively large reduction in pressure (due to relatively low compressibility compared to gaseous CO_2).
2. When the pressure falls sufficiently for the fluid to enter the phase envelope, the pressure reduction slows significantly as gas breakout occurs and compressibility increases – gaseous CO_2 is now being vented as opposed to dense-phase CO_2. The fluid temperature drops sharply due to J-T expansion of gaseous CO_2 and vaporisation of liquid CO_2. For a 1 inch orifice, the initial depressurisation step takes approximately 3 days.
3. When the fluid temperature approaches -20°C, the depressurisation is stopped to allow heat recovery from the surroundings. During this time the pressure increases slightly as the gas heats up and expands. If the depressurisation were not stopped at this stage then the temperature would fall sharply, with a high temperature drop for a small pressure reduction, as indicated by the shape of the temperature curve.
4. The depressurisation process starts again with the minimum fluid temperature in this section reaching -20°C. The temperature recovers as the pressure continues to drop as the fluid leaves the phase envelope and is now in the gas-only region and heat supplied from the surroundings has a greater impact on the fluid temperature due to the lower heat capacity of gas compared with liquid or two-phase CO_2.

With a 1 inch orifice, the depressurisation of the Camblesforth to Tollingham section takes approximately 5 days to complete.

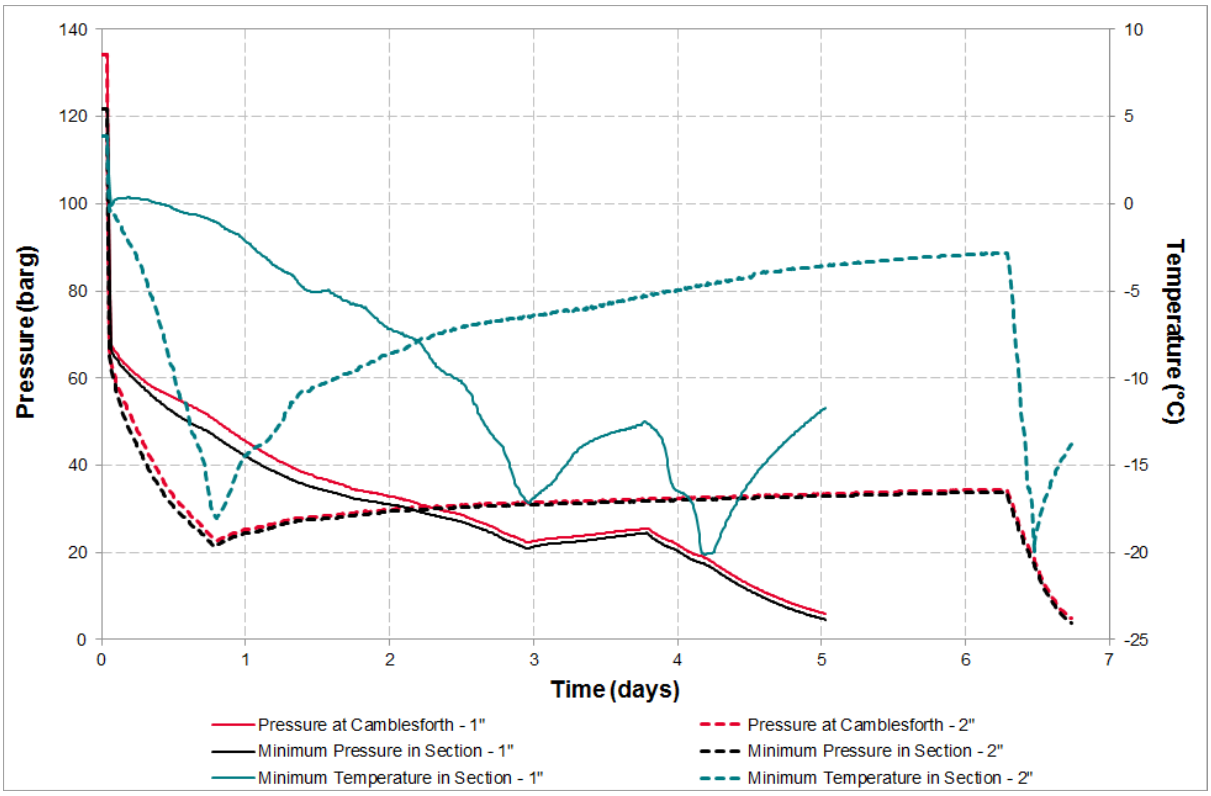
Note that the minimum temperature does not occur at a single location. The minimum temperature moves in the liquid phase along the pipeline as the liquid is vaporised (the gas-liquid interface moves as more liquid CO_2 is vaporised). This is shown in more detail in Figure 7.43.

7.7.2 Impact of Orifice Size

If it takes approximately 5 days to complete the depressurisation of Camblesforth to Tollingham with a 1 inch orifice, analysis was carried out to determine whether it could it be depressurised quicker with a 2 inch orifice.

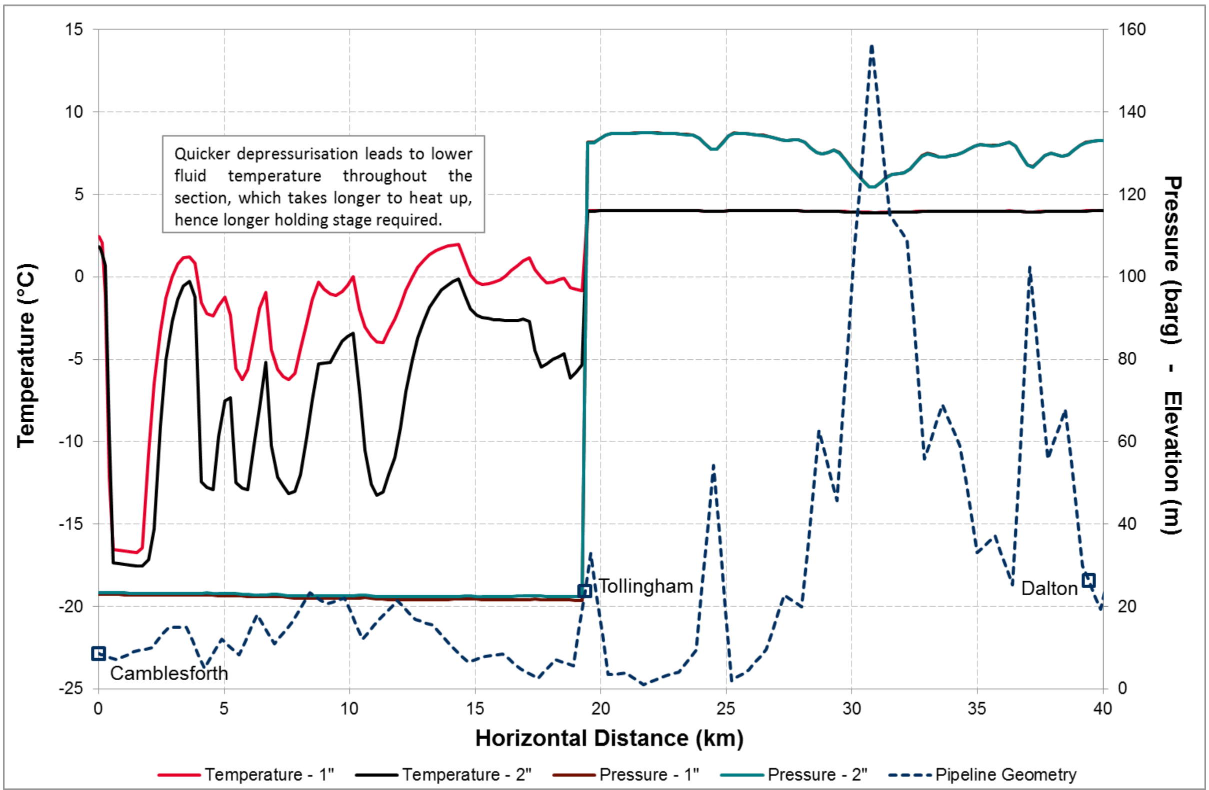
Figure 7.37 shows the minimum fluid temperature when depressurising the Camblesforth to Tollingham section through a 1 inch and 2 inch orifice.

Figure 7.37: Minimum Temperature during Depressurisation of Camblesforth to Tollingham through 1 inch and 2 inch Orifices



The initial pressure reduction down to 20 barg is much quicker with a 2 inch orifice, as expected. The minimum fluid temperature is similar to that of the 1 inch orifice at the same pressure (it is slightly lower for the 2 inch orifice as the surroundings have had less time to heat up the fluid). However, the holding stage, where the fluid heats up before reducing the pressure further is much longer (>5 days, compared with <1 day for a 1 inch orifice). Figure 7.38 shows the impact of quicker depressurisation on the temperature throughout the Camblesforth to Tollingham section. The temperatures and pressures are taken from the point that depressurisation is stopped (pressure is approximately 20 barg). Note the step change in pressure downstream of Tollingham occurs because the block valve at Tollingham is closed so only an isolated section is depressurised.

Figure 7.38: Temperature along the Pipeline during Depressurisation of Camblesforth to Tollingham Section



The pressure reduces significantly quicker for the 2 inch orifice resulting in the fluid temperature throughout the section falling approximately 5°C more than for a 1 inch orifice. However, the minimum temperature in the section is approximately equal for each orifice size (as the pressures at this point are approximately equal – the small difference in minimum temperature is caused by the 1 inch orifice taking longer to reduce the pressure and more heat is supplied to the fluid from the surroundings). Therefore it takes some additional time for the fluid in this section to warm up sufficiently before the depressurisation operation can recommence. This is discussed further in subsequent sections. Note that the variation in fluid temperature is due to the pipeline elevation profile – temperatures are lowest at the localised low points in the pipeline, where liquid tends to pool, as the vaporisation of the liquid causes the liquid temperature to fall (as the liquid provides the energy to achieve the vaporisation).

The fluid temperatures for the 1 inch and 2 inch orifices vary by up to 10°C in places, despite the pressures in these sections being almost identical. This is because time is a factor – depressurisation through the 1 inch orifice takes much longer to reach 20 barg than for the 2 inch and therefore more heat is supplied by the surroundings to the cold sections. Note that the largest differences in temperature tend to occur closer to the vent location, meaning that these sections depressurised (and cooled down) earlier in the depressurisation process. This means that for longer overall durations, these sections (that become essentially gas-filled) warm up as the gas has a lower specific heat capacity than liquid. The more time the fluid has to absorb heat from the surroundings during this process, the closer to ambient temperature it will be when the pressure though this isolated section of pipeline reaches 20 barg. When you then compare the section that remains liquid-filled for the longest duration (furthest location from the vent), there is only a small difference in fluid temperatures for the two orifice sizes– this is due to the liquid not being heated as much as the gas-filled sections further downstream.

Thermal load on the pipeline caused by rapid temperature change during depressurisation should be considered in the next phase of the project.

7.7.3 Impact of Restarting Depressurisation Too Quickly

Whilst the depressurisation process has not been optimised, a case was run to determine what would happen if the second stage of depressurisation (20 barg down to 5 barg) started earlier than 6.25 days (as shown in Figure 7.37). In this instance, it was started three days after the initial depressurisation phase started, as opposed to >6 days when using a 2 inch orifice. Figure 7.39 shows the conditions in the Camblesforth to Tollingham section immediately before the second stage of depressurisation for a “short” and “long” holding stage. Figure 7.40 shows the minimum fluid temperature in the section for the “short” and “long” holding stage cases.

Figure 7.39: Temperature along the Pipeline during Depressurisation of Camblesforth to Tollingham Section – Short and Long Holding Stage

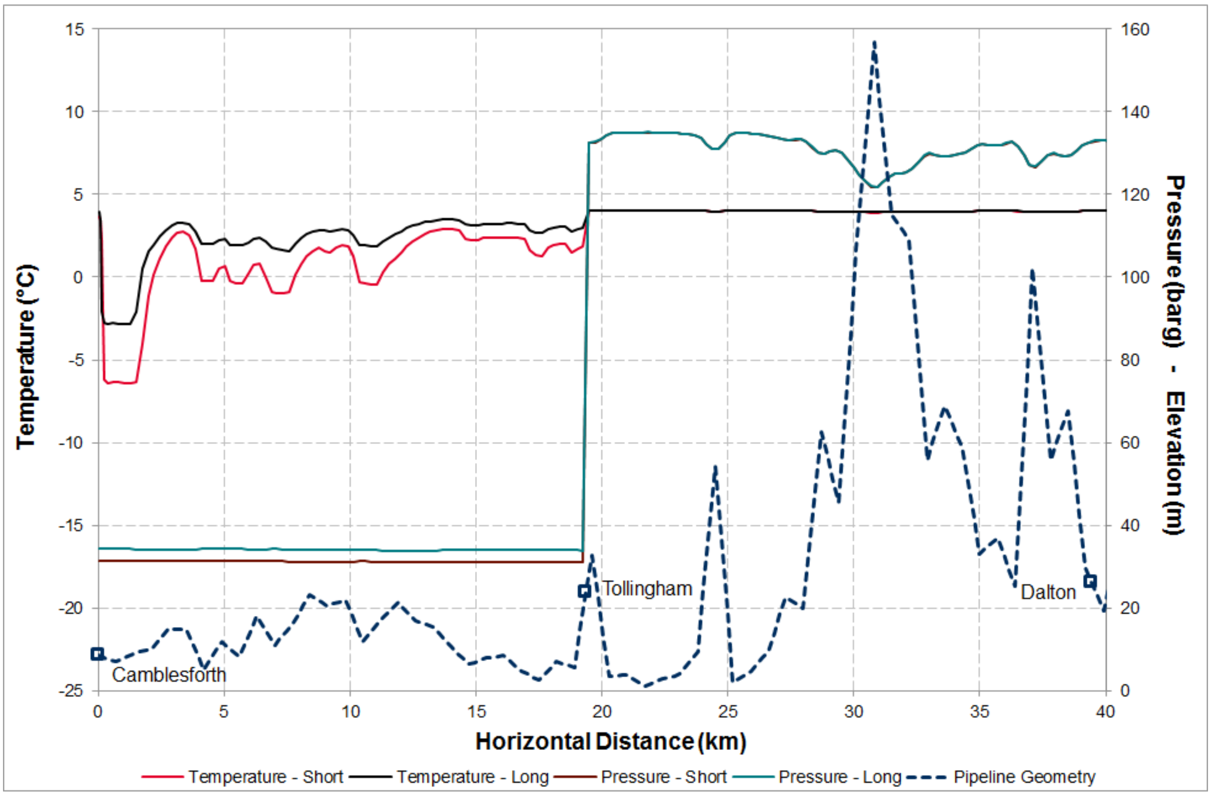
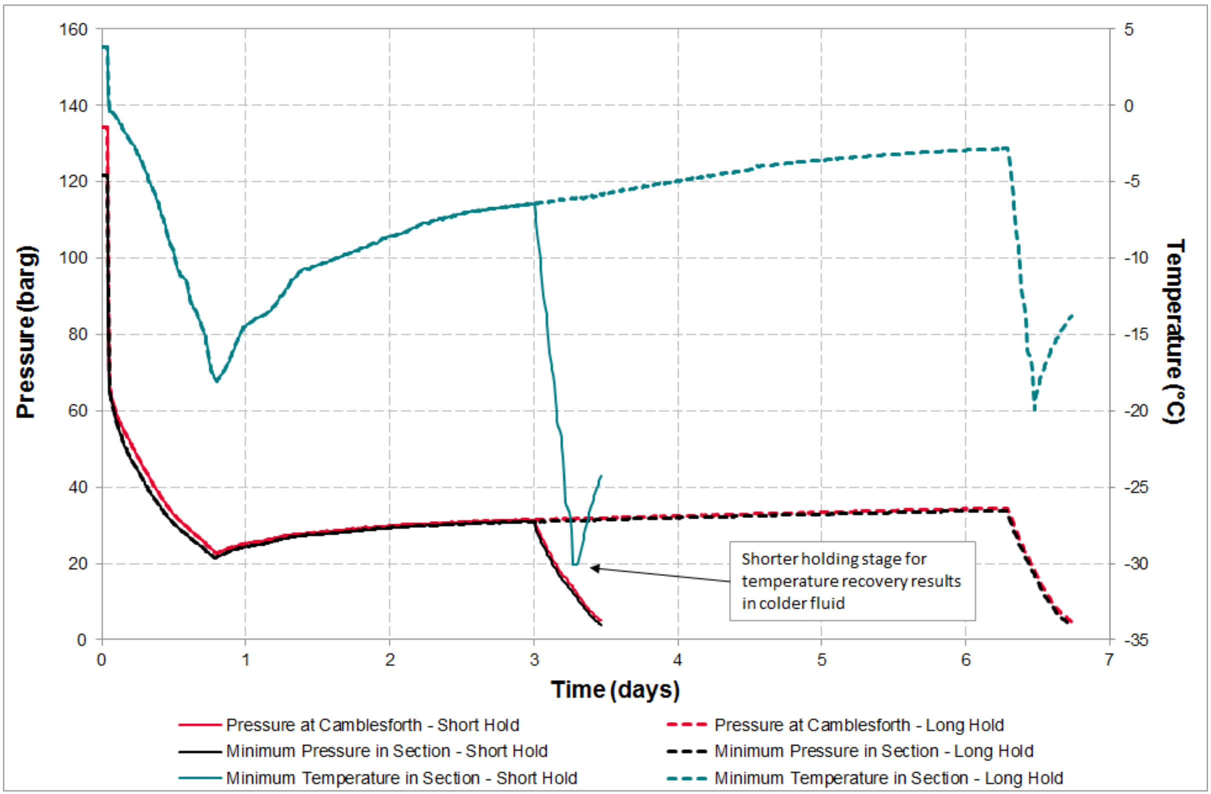


Figure 7.40: Minimum Temperature during Depressurisation of Camblesforth to Tollingham through a 2 inch Orifice – Short and Long Holding Stage

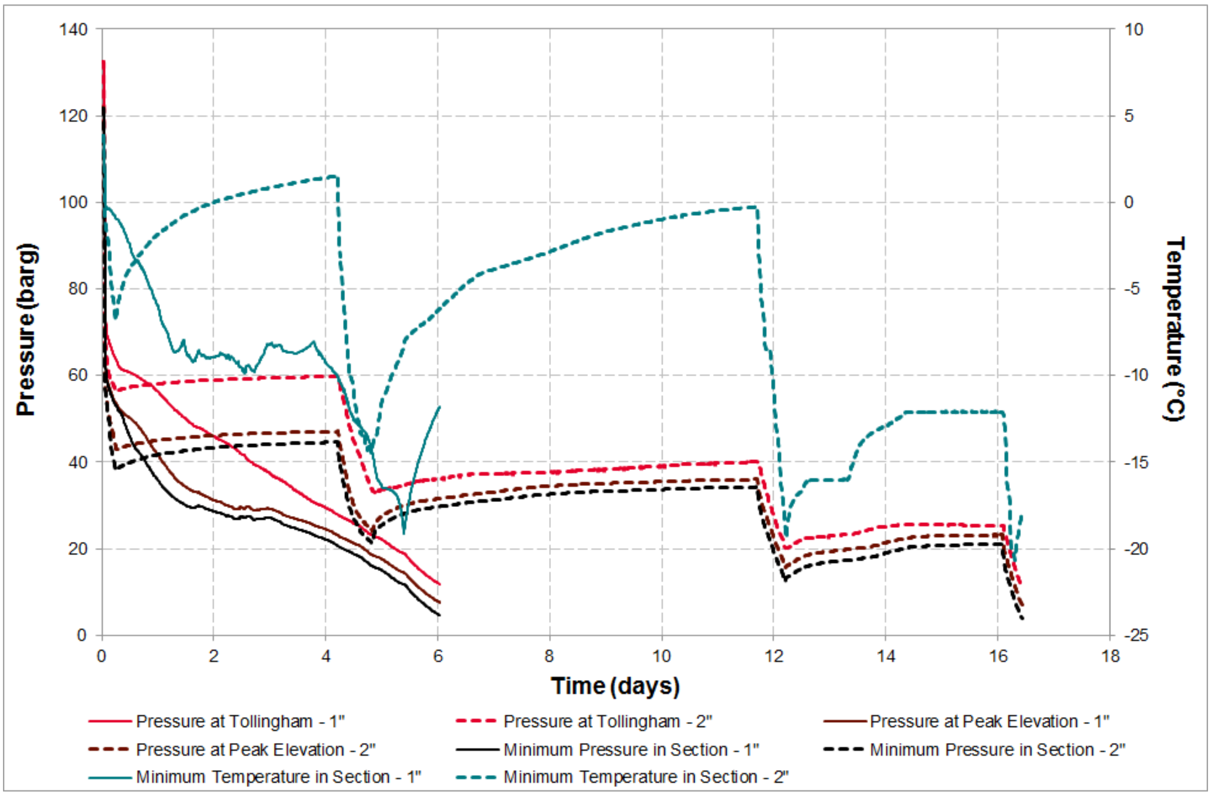


The additional 3 days of holding time only increases the fluid temperature in the Camblesforth to Tollingham section by approximately 3°C to 5°C. However, that relatively small difference is exacerbated when depressurising such that the minimum fluid temperature drops to -30°C following the short holding stage as opposed to -20°C for the longer holding stage. This is due to where the pressure and temperature throughout the pipeline sit on the phase envelope. It is not just a function of the minimum temperature in the pipeline – it is a function of how the temperature throughout the pipeline increases during the additional holding time (the temperature along the entire length of the depressurised section increases and results in the minimum temperature not getting quite as cold during the next depressurisation stage). Therefore, it is imperative to allow sufficient time for temperature recovery in the holding phases prior to recommencing depressurisation.

7.7.4 Depressurisation at the Peak Elevation

The peak elevation in the pipeline route lies between Tollingham and Dalton block valve stations and presents the most challenging depressurisation due to the pipeline elevation changes in this section. Figure 7.41 shows the minimum temperature during depressurisation of the section between Tollingham and Dalton through a 1 inch and 2 inch orifice.

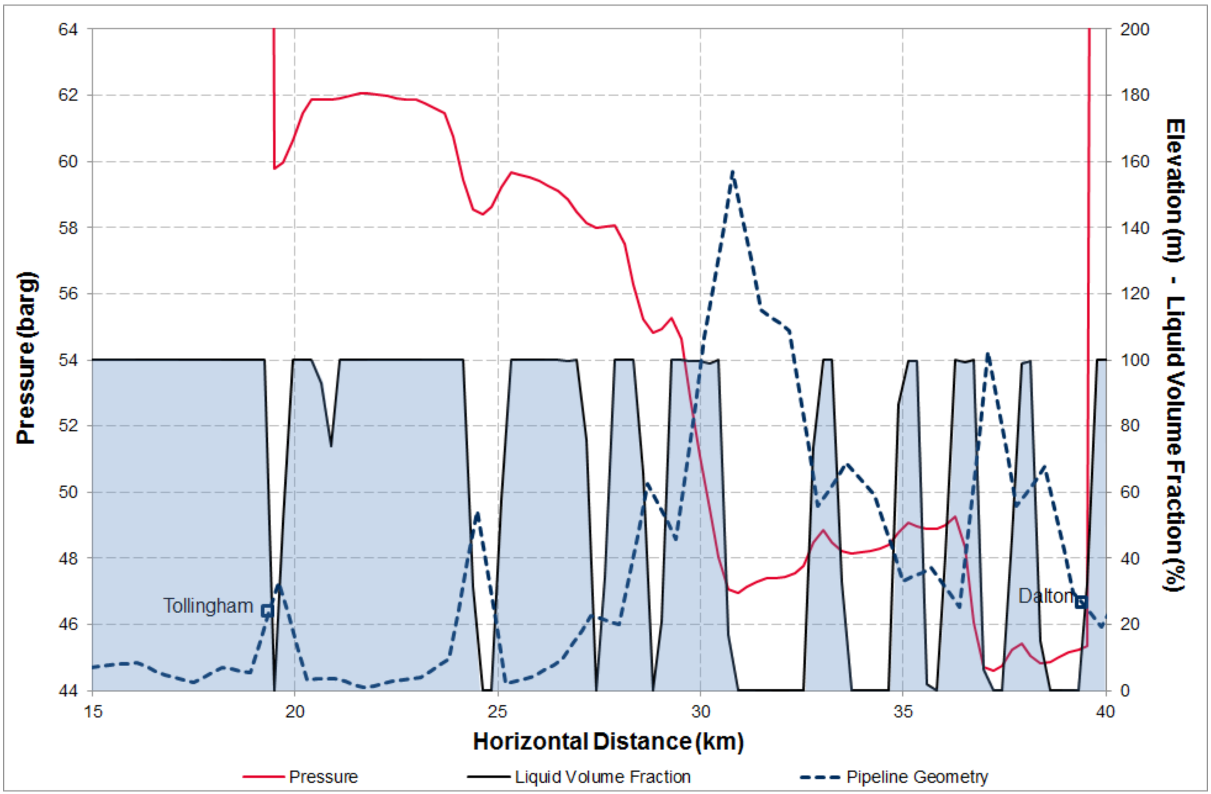
Figure 7.41: Minimum Temperature during Depressurisation of Tollingham to Dalton through 1” and 2” Orifices



As with the Camblesforth to Tollingham section, depressurising the Tollingham to Dalton section through a 2 inch orifice takes significantly longer due to the fluid temperature in the whole pipeline section dropping further for the same reduction in pressure compared with a 1 inch orifice. In this case, a 1 inch orifice can actually depressurise the pipeline section without a holding stage where the fluid temperature is allowed to recover. In this case, using a 2 inch orifice requires at least two holding stages (it is acknowledged that the pressure selected for the first holding stage has not been optimised and could potentially be reduced).

It is also interesting to note the difference in pressure observed at Tollingham and at the peak elevation point. In the first holding stage, the difference is approximately 19 bar. This is due, in part, to the high CO_2 liquid density, which is 900 kg/m³ to 1,000 kg/m³ at the in-situ pressures and temperatures. It is also due to the Camblesforth side of the peak elevation being liquid-locked caused by the high point near the middle of this section of the onshore pipeline. Additionally of note is that the minimum pressure in the pipeline section does not occur at the peak elevation point in this holding stage. Figure 7.42 shows the Tollingham to Dalton pipeline section at the end of the first holding stage during depressurisation through a 2 inch orifice. Note the pipeline section is vented from Dalton (upstream of the block valve). A liquid volume fraction of 100% indicates the area concerned is entirely liquid-filled (a liquid volume fraction of zero indicates being entirely gas-filled).

Figure 7.42: Pressure and Liquid Volume Fraction at End of First Holding Stage during Depressurisation of Tollingham to Dalton through a 2 inch Orifice



The pressure on the upstream side of the peak elevation is at a higher pressure than downstream due to liquid-filled sections at the local low points along the pipeline trapping some of the vapour (and therefore pressure). Liquid locking is also the reason why the minimum pressure in the section is not at the highest elevation point – it is at a local high point much closer to the Dalton vent.

One of the concerns during depressurisation (before this analysis was performed), particularly around the peak elevation point, is the potential for cold temperatures as the liquid CO_2 vaporises, causing localised cold metal temperatures. Figure 7.43 shows the fluid temperature variation with time in the pipeline close to the peak elevation when depressurising the Tollingham to Dalton pipeline section through a 1 inch orifice. Figure 7.44 shows the minimum fluid temperature observed over the duration of the depressurisation along the pipeline around the peak elevation when depressurising the Tollingham to Dalton pipeline section through a 1 inch orifice. The 1 inch orifice results are shown as this was carried out as a single operation (no holding stage), so best illustrates the issue.

Figure 7.43: Fluid Temperature around Peak Elevation during Depressurisation of Tollingham to Dalton through a 1 inch Orifice

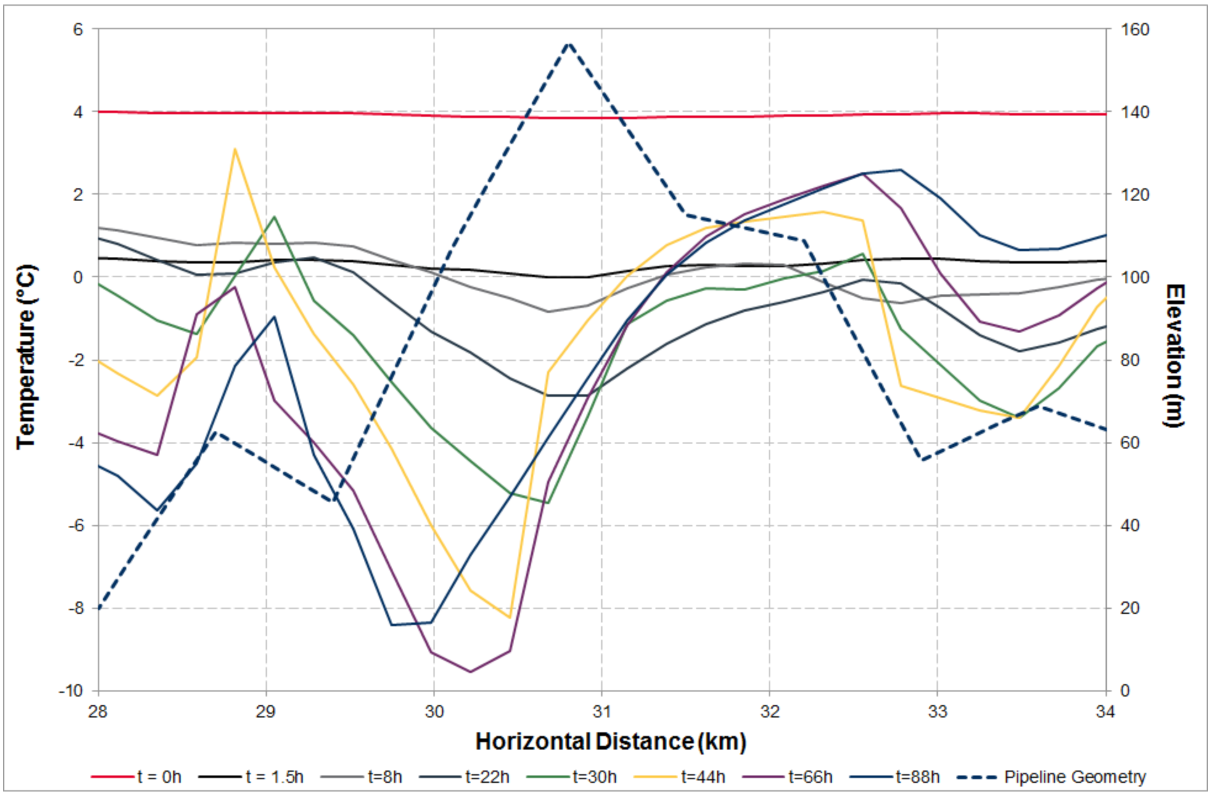
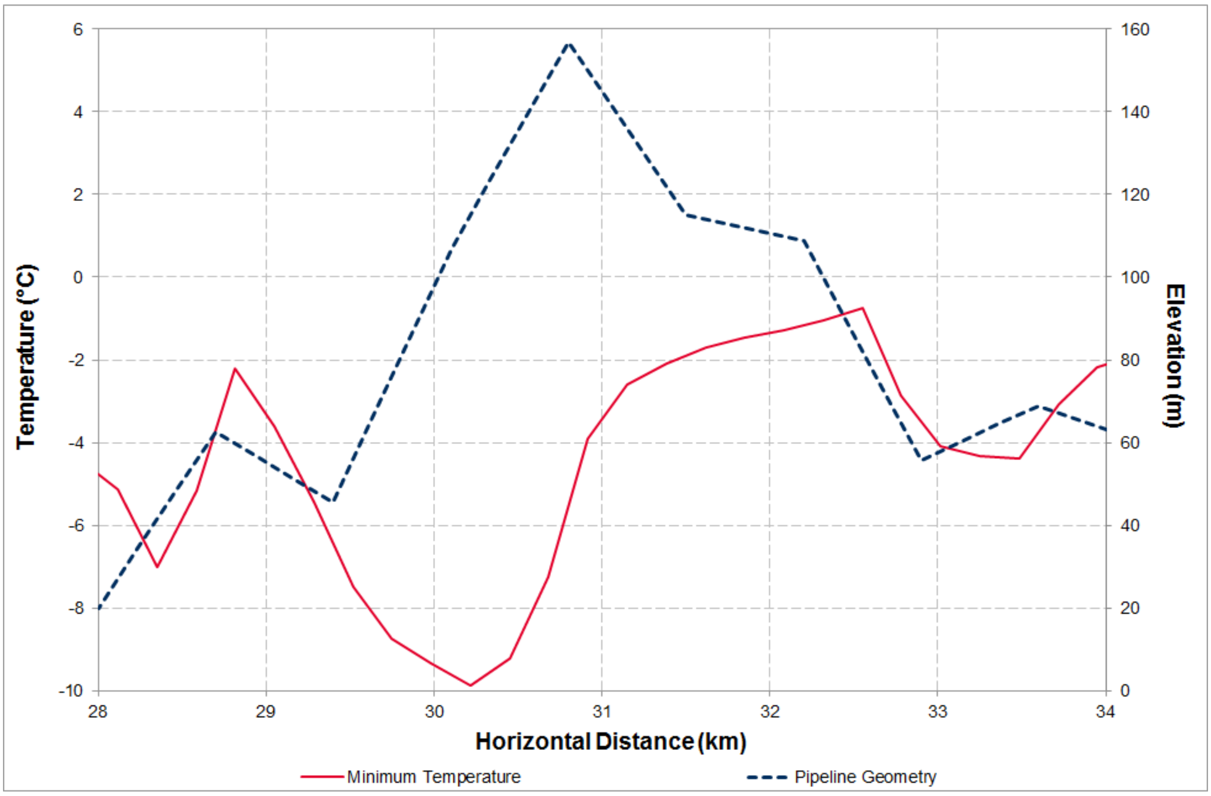


Figure 7.44: Minimum Fluid Temperature around Peak Elevation during Depressurisation of Tollingham to Dalton through a 1 inch Orifice



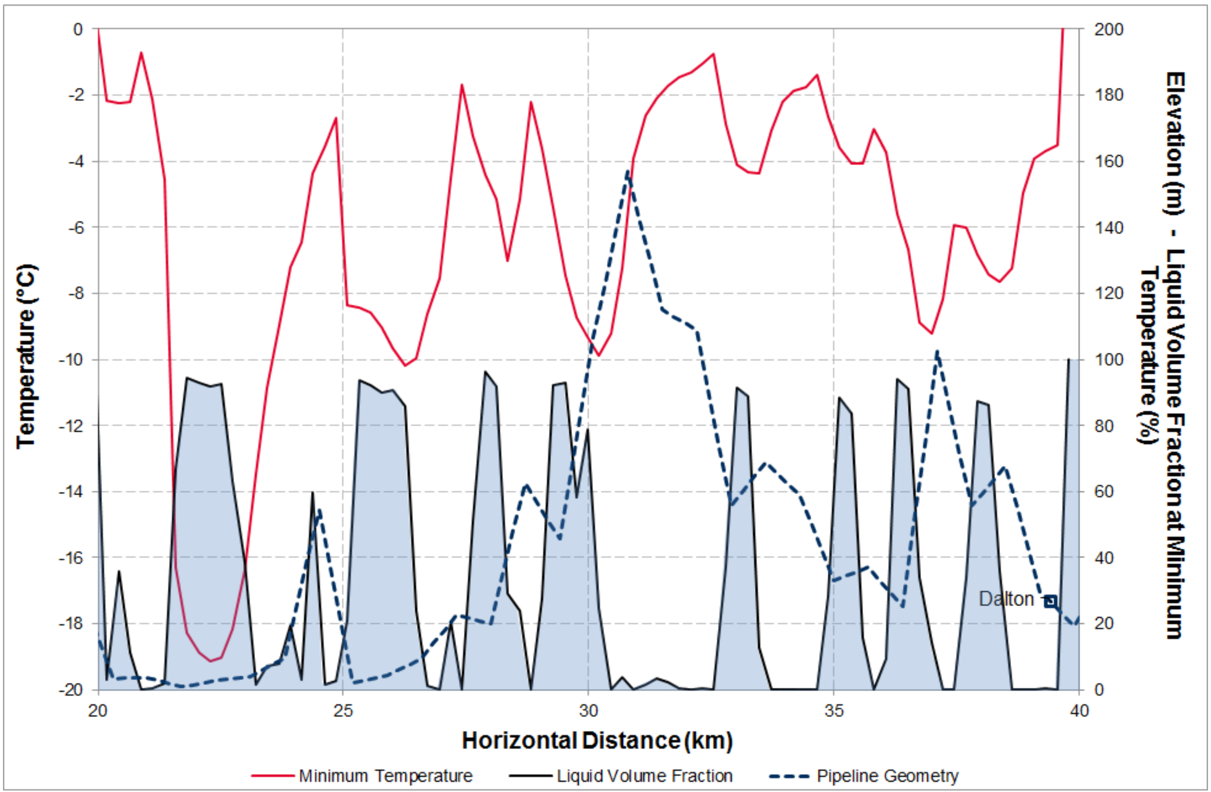
The fluid temperature in this case reaches -10°C on the upstream side of the peak elevation during depressurisation. The minimum temperature at each snapshot in time in Figure 7.43 moves further down the hill as increasing amounts of CO_2 is vaporised and the gas-liquid contact moves down the hill. Therefore, the minimum temperature does not occur at a single location (e.g. at the point of highest elevation).

7.7.5 Location of Minimum Temperature

Although the peak elevation was raised as an area for concern with regards to minimum temperatures during depressurisation, this is not where the lowest temperature occurs.

Figure 7.45 shows the minimum temperature in the Tollingham to Dalton pipeline section when depressurising through a 1 inch orifice.

Figure 7.45: Minimum Temperature during Depressurisation of Tollingham to Dalton through 1 inch Orifice



The minimum fluid temperature occurs at approximately 22.5 km (measured from Camblesforth), which is approximately 3 km from Tollingham, rather than the peak elevation point. This is because the CO_2 needs to take up the latent heat of vaporisation as the pressure reduces and the liquid CO_2 vaporises. Some of that heat is supplied by the pipeline wall (so the pipeline wall closely matches the fluid temperatures) and the surrounding soil; some of that heat is supplied by the remaining liquid CO_2. The liquid CO_2-filled section that is furthest away from the vent location cools the most because this section of liquid CO_2 is being expanded for longer (hence getting colder) than the sections of liquid CO_2 closer to the vent location (which vaporise earlier, so don't get as cold and they are heated by the surroundings due to the lower specific heat capacity of gas compared to liquid).

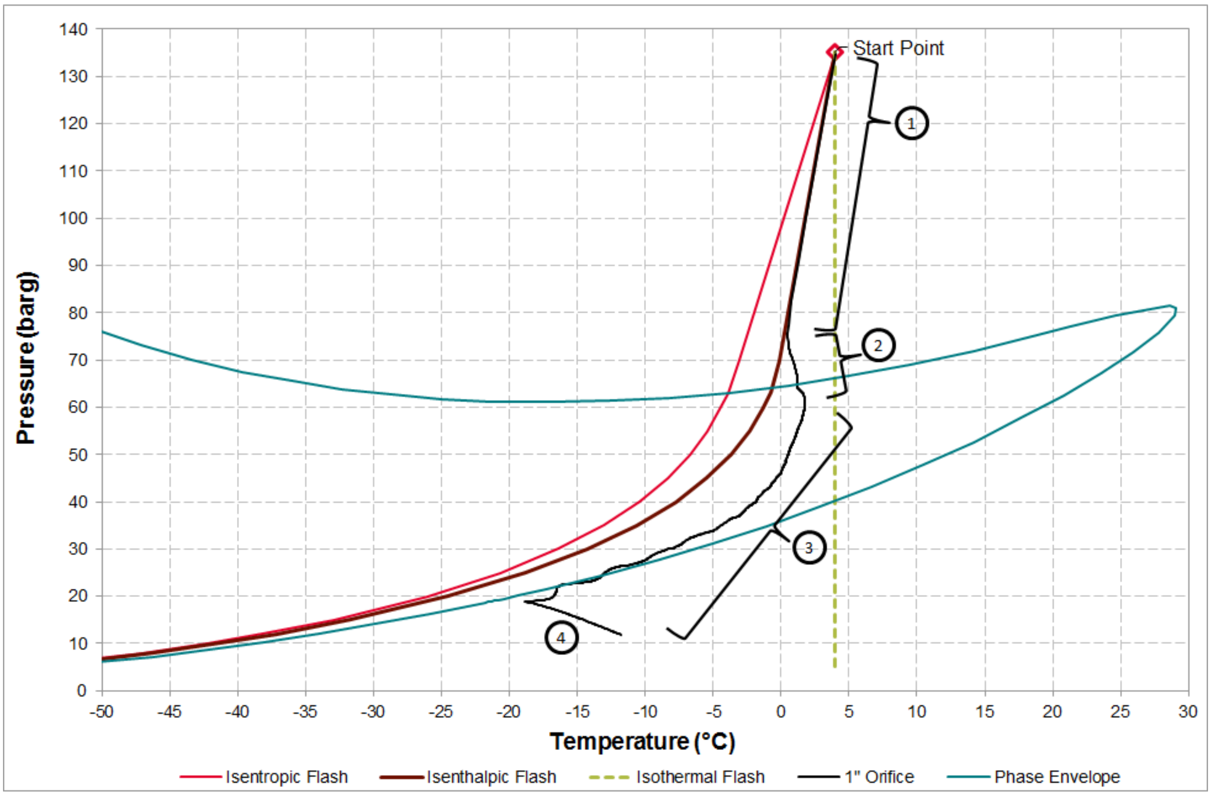
The trend of the minimum fluid temperature occurring at the opposite end to the vent in the section being depressurised is common throughout.

7.7.6 Do the Results from OLGA Make Physical Sense?

To ensure that the results predicted by OLGA are physically realistic, an assessment was carried out in Multiflash to determine the minimum theoretical fluid temperatures during depressurisation.

Figure 7.46 compares the pressure and temperature predictions from OLGA for the coldest part of the Tollingham to Dalton pipeline section when depressurising through a 1 inch orifice with an isentropic (adiabatic, no heat transfer to/from surroundings) and isenthalpic (constant enthalpy, similar to flashing across a valve) flash calculated in Multiflash. The isentropic flash is the minimum theoretical temperature that can be achieved when flashing a fixed composition and volume. The isothermal flash represents a constant temperature flash and would occur for an infinitely long depressurisation process, where the rate of pressure reduction (and subsequent temperature reduction) was sufficiently low for the heat supplied from the surroundings to be supplied faster than the fluid cools. A physically realistic scenario should lie between the isentropic and isothermal flash curves.

Figure 7.46: Comparison of Depressurisation with an Isentropic, Isenthalpic and Isothermal Flash during Depressurisation of Tollingham to Dalton through a 1 inch Orifice



The depressurisation process has four distinct areas:

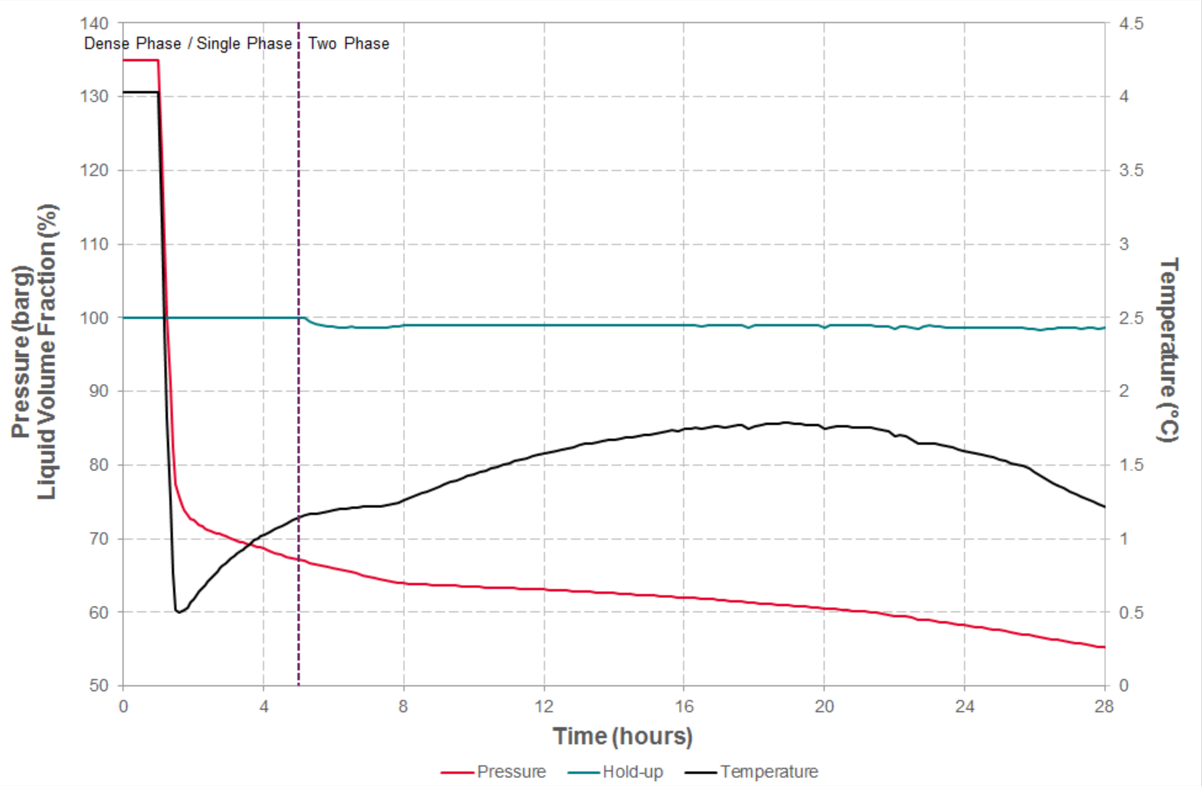
1. Rapid depressurisation of liquid follows isenthalpic behaviour. This process stops being isenthalpic when downstream sections of the pipeline (at lower pressure, downstream of the peak elevation) start to exhibit liquid vaporisation.
2. Liquid boiling phase. Temperature increases slightly (heat supplied by surroundings) as the light components are vaporised and the liquid becomes heavier. This process takes several hours. It appears that this process occurs (at least in the OLGA simulation) before the fluid has reached the phase envelope. However, because this process takes a long time some heat is supplied by the surroundings to the CO_2 in this section (thereby increasing the temperature slightly). This is explained further in Figure 7.51.
3. The fluid in this section enters the phase envelope at the bubble point. Heat loss through the reduction in pressure is compensated in part by heat supplied by the surroundings until reaching the phase envelope at the dew point.

4. The fluid has entered the vapour-only phase and absorbs heat from the surroundings. There is some variation in pressure-temperature predictions (a wobble in the depressurisation curve) due to how OLGA calculates the physical properties of the fluid – it is based on a data table and OLGA having to iterate between two data points across the phase boundary.

As the pressure-temperature behaviour stays within the two thermodynamic extremes, the OLGA predictions stay within the physics of the system.

Figure 7.47 shows the early stages of pressure, temperature and liquid volume fraction in the section of pipeline between Tollingham and Dalton that (ultimately) gets the coldest during depressurisation of this section.

Figure 7.47: Early Stages of Depressurisation of Coldest Section Far during Depressurisation of Tollingham to Dalton through a 1 inch Orifice



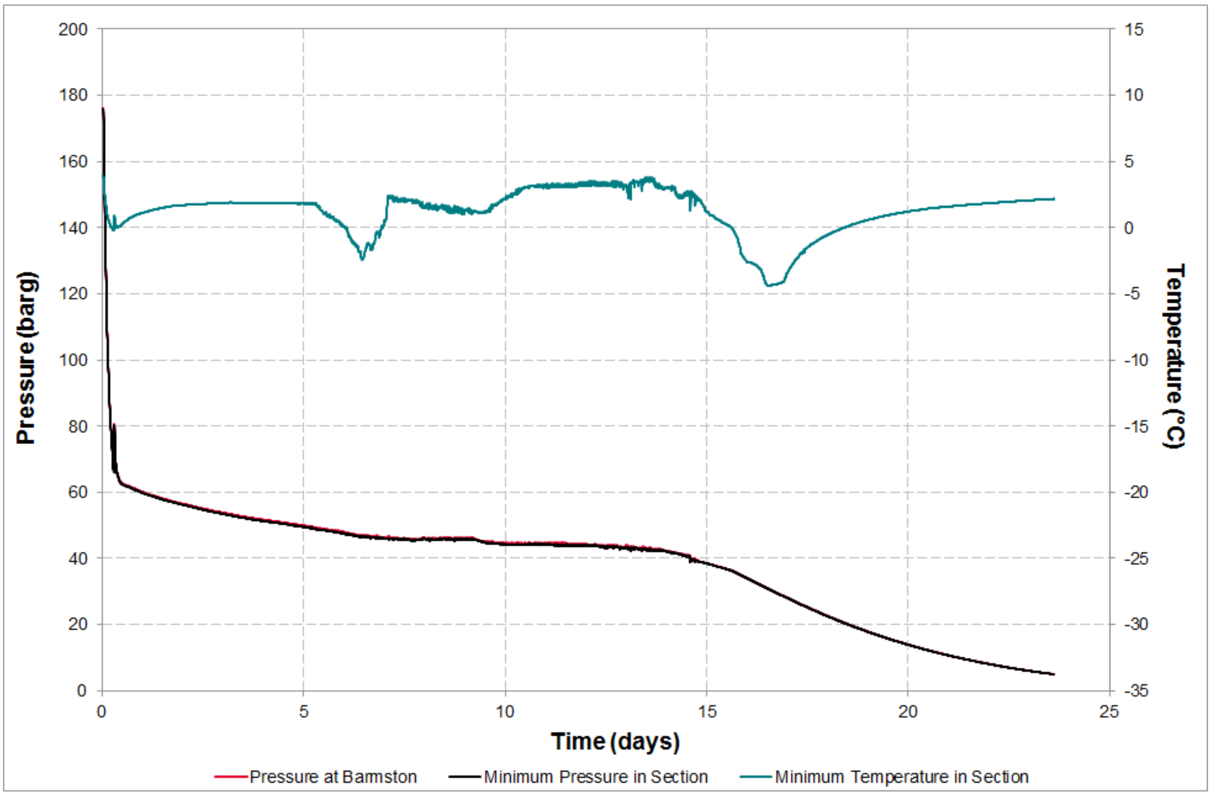
The pressure and temperature drop sharply in the first stage of depressurisation due to the dense phase / liquid phase having reasonably low compressibility (compared to gas). As the pressure downstream of this area (closer to the vent) is depressurised over the next 24 hours, the pressure in this section slowly depletes. However, as the pressure is depleting so slowly, the temperature increases as the heat supplied from the surroundings is supplied faster than the cooling effect due to J-T expansion of the CO_2 as the pressure drops.

7.7.7 Depressurisation of the Offshore Pipeline

The depressurisation of the offshore pipeline (from Barmston to the platform) is not subject to such low fluid temperatures during depressurisation compared to the onshore pipeline.

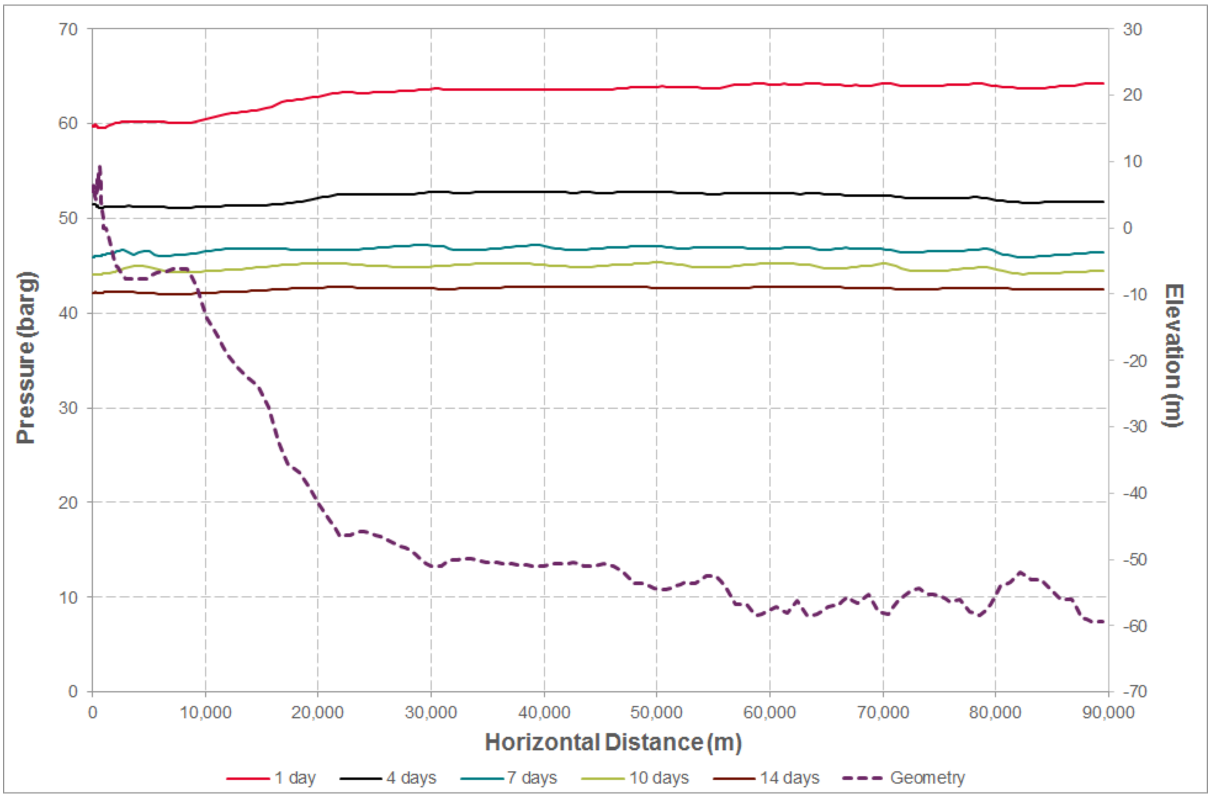
Figure 7.48 shows the minimum fluid temperature in the offshore pipeline when it is depressurised through a 1 inch orifice at the injection platform.

Figure 7.48: Minimum Temperature during Depressurisation of Offshore Pipeline though a 1 inch Orifice



The minimum fluid temperature is approximately -5°C, which is significantly warmer than the predictions for the onshore pipeline. Additionally, as the seabed bathymetry is generally sloping towards the platform, this prevents pockets of liquid CO_2 accumulating in the pipeline, allowing a smoother depressurisation and an improved sweep of liquids by the gas travelling along the pipeline. Figure 7.49 shows the pressure along the offshore pipeline as it is being depressurised.

Figure 7.49: Pressure Along Offshore Pipeline during Depressurisation of Offshore Pipeline though a 1 inch Orifice



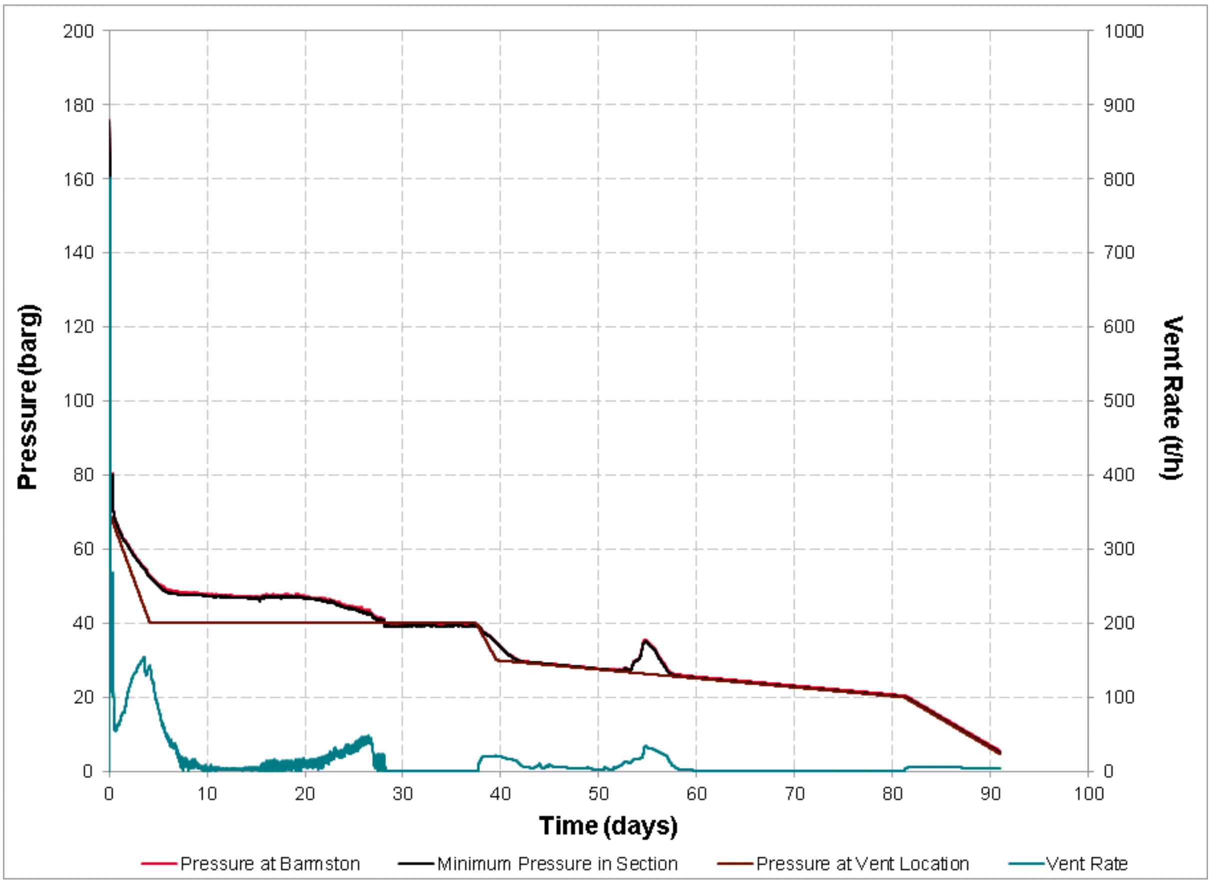
The pressure reduces almost uniformly along the pipeline, which is very different to the onshore pipeline. This is due to the seabed bathymetry being much flatter than the onshore topography and the seabed slopes towards the riser base. This means that liquids do not tend to get trapped in pockets and they drain from the furthest part of the pipeline from the vent location (i.e. at Barmston, which is close to sea level). The draining of liquid from the onshore end of the pipeline also helps the pipeline retain heat during depressurisation. The temperature in the pipeline does not get as low as for onshore depressurisation for the following reasons:

- depressurisation takes place over several days/weeks, increasing the amount of time available for heat from the surroundings to be supplied to the CO_2 in the pipeline; and
- the seabed bathymetry prevents liquid accumulation due to its relatively gentle profile and slope towards the riser. This means that liquids drain away from the furthest end of the pipeline from the vent location (where the temperature would get coldest if the liquid were trapped, because it is being expanded for longer (therefore gets colder) and because this area is buried, which would impede heat transfer from the seawater to the CO_2). As the liquid drains, it is replaced by gas, which is warmed up by the surrounding much easier.

7.7.8 Full System Depressurisation

A case looking at depressurising the entire CO_2 transportation system was analysed to determine the time required and the feasibility of this operation. Figure 7.50 shows the pressure in the offshore pipeline and vent rate during depressurisation of the entire CO_2 transportation system through a 2 inch orifice located at the injection platform.

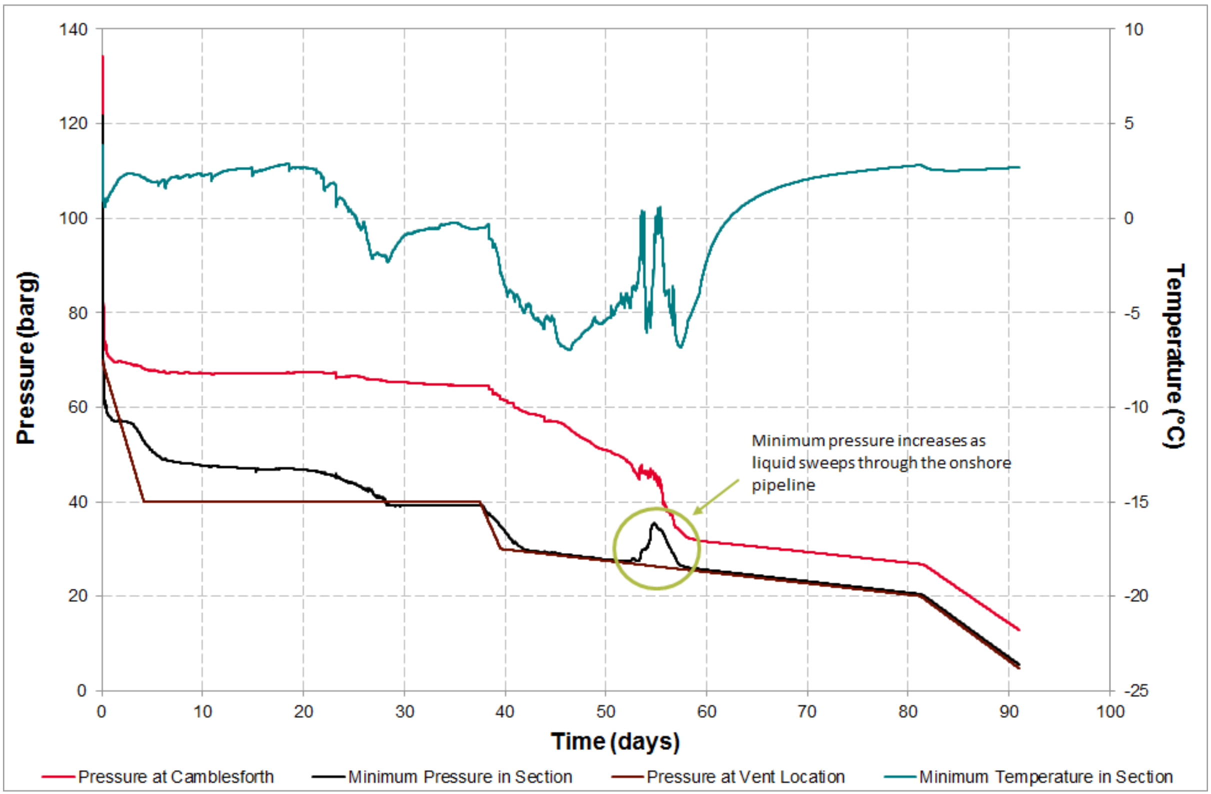
Figure 7.50: Offshore Pipeline Pressure and Vent Rate during Depressurisation of Entire System through a 2 inch Orifice



Full system depressurisation in this case takes approximately 3 months. The pressure at the vent location is carefully reduced in this case as the OLGA model is very sensitive to changes in pressure and the time to depressurise the transportation system is not optimised.

Figure 7.51 shows the minimum temperature in the Camblesforth to Barmston pipeline during depressurisation of the entire CO_2 transportation system through a 2 inch orifice located at the injection platform. This section exhibited the lowest minimum temperature in this case. As discussed in Section 7.7.7, the offshore pipeline does not get as cold as the onshore pipeline during depressurisation as the seawater is able to provide much more heat to the pipeline than the surrounding ambient air.

Figure 7.51: Pressure and Minimum Temperature in Camblesforth to Barmston Pipeline during Depressurisation of Entire System through a 2 inch Orifice



The fluid temperature does not drop below -7°C as the depressurisation takes such a long time and a significant amount of heat is supplied to the fluid over this time, preventing very low temperatures.

The bump in minimum pressure that occurs at approximately 55 days is caused by liquid being swept through the 600 mm nominal diameter onshore pipeline. This liquid, previously accumulated upstream of the peak elevation between Tollingham and Dalton, is swept through as the pressure differential across the liquid becomes high enough for gas to blow it over the high point.

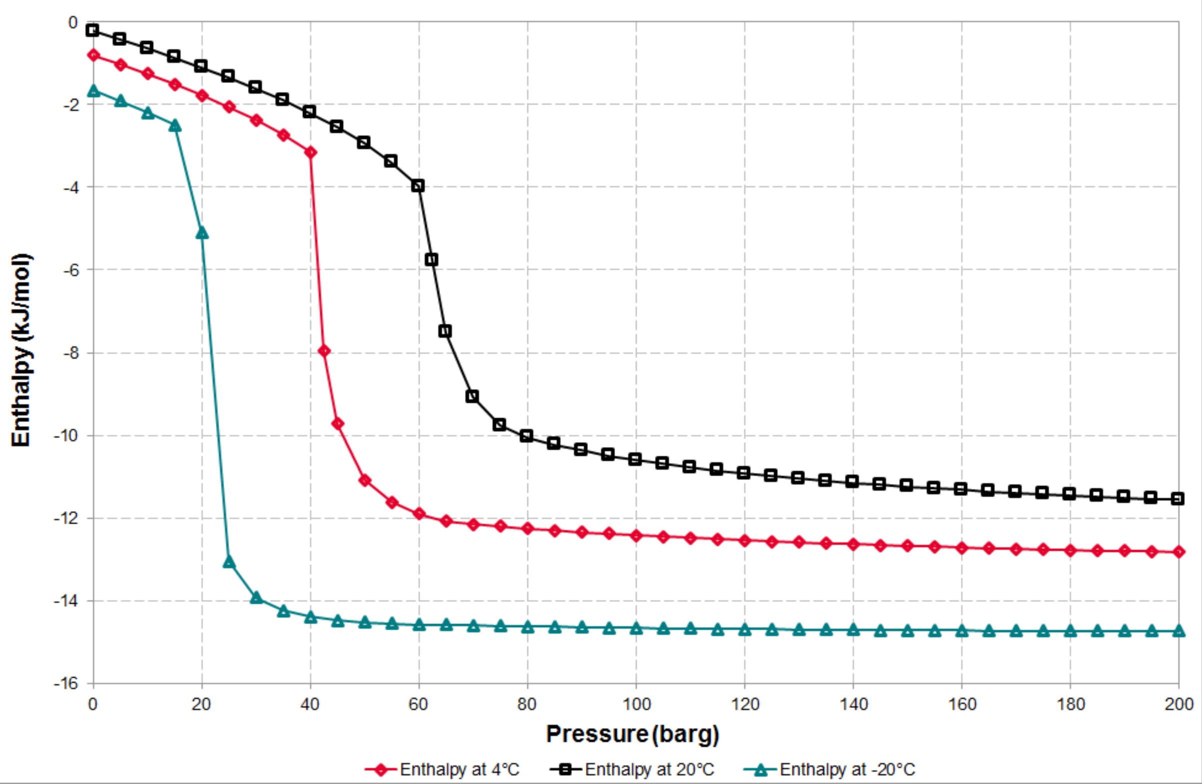
The above demonstrates that full system depressurisation can be performed without transgressing the minimum pipeline design temperature, although the time to do so (albeit not optimised) is significant (several weeks).

- The phase envelopes for CO_2-rich fluids are significantly narrower than hydrocarbon system.
  - OLGA uses pressure-temperature tables to interpolate the fluid properties. Due to the narrow nature of the phase envelopes is it difficult to obtain good discretisation around the phase boundaries and discontinuities can occur due to large difference in fluid properties across the phase boundary.
  - Compositional tracking, which would normally improve modelling of the transition across the phase boundary is not suitable as it uses the Peng-Robinson equation of state and is not applicable to this system (predicted phase boundaries are quite different to those predicted using GERG).
- A small change in pressure can result in a large change in enthalpy in CO_2.

- As shown in Figure 7.52 over certain pressure ranges (i.e. when inside the phase envelope), there is a steep change in enthalpy for a small change in pressure. This can lead to a relatively large change in temperature.

- CO_2 has a high J-T coefficient, which means that a reduction in pressure results in higher temperature reduction compared with hydrocarbon gases. This causes the cold temperature issues when depressurising the pipeline.

Figure 7.52: Pressure-Enthalpy Curves for Impurities Composition

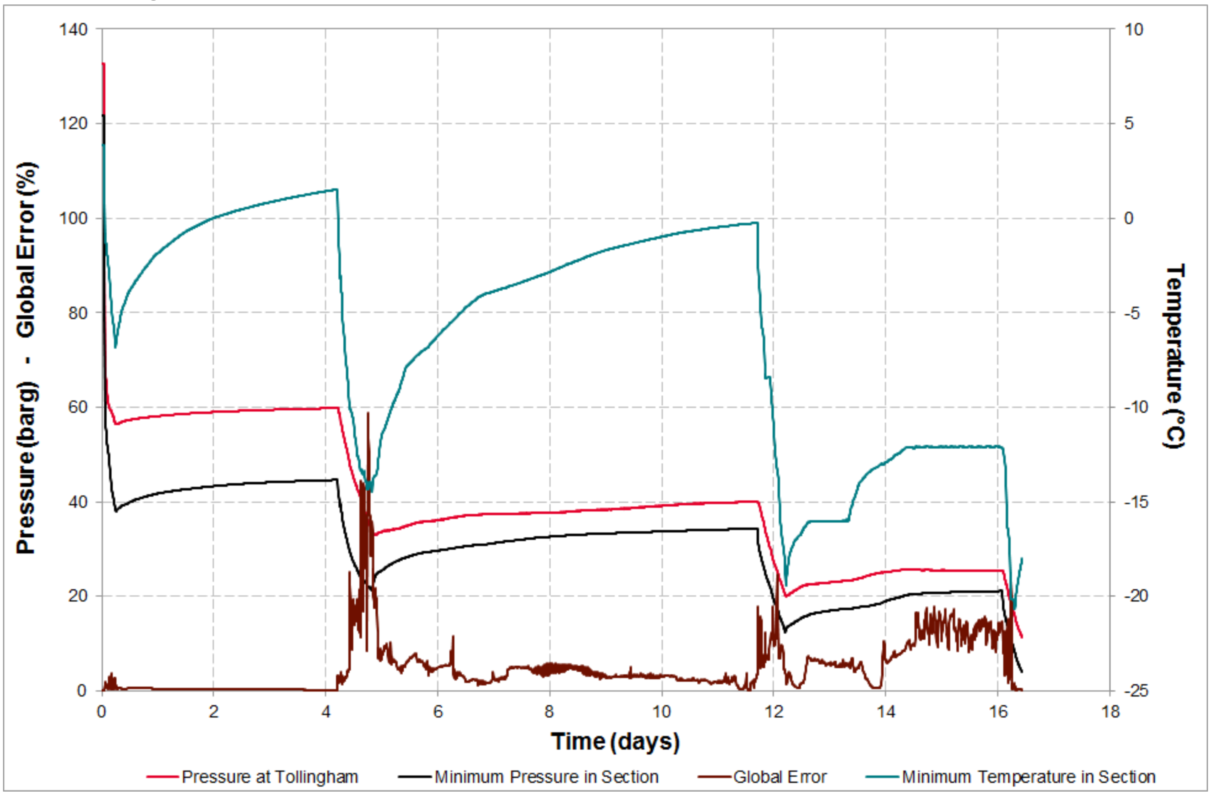


When modelling the depressurisation cases in OLGA, high maximum global volume errors (circa 50% to 60%) are observed when the pressure reduces quickly, as gas is vaporised and OLGA struggles to converge the volume calculations (see Figure 7.53); this tends to occur in all simulations where the phase boundaries are crossed. Global volume error is a calculated property in OLGA that compares a section volume (defined by the section length and the pipeline internal diameter) and the fluid volume back calculated from the predicted mass and density in that section. During steady state (stable) conditions there should be no difference between these two volumes (i.e. volume error is zero). However, under transient conditions there is often a difference between the two volumes caused by how OLGA solves the numerous mass and energy balances throughout the system (i.e. for a given section, OLGA can under or over-predict the fluid volume in that section compared with the physical volume of the pipe section). The larger the volume error, the more deviation there is between the physical pipe section volume and back-calculated fluid volume.

The global volume errors predicted for operation involving two-phase CO_2 are higher than typical for stable simulations and introduces uncertainty in the results that is difficult to quantify precisely in terms of how the pressure and temperature of the system should respond. Therefore conservative recommendations on vent sizes and holding times between depressurisation stages have been made.

Figure 7.53 shows the maximum global volume error recorded by OLGA for depressurisation of Tollingham to Dalton through a 2 inch Orifice. The global volume error is defined as the maximum error in calculation of gas and liquid volume (compared against the actual volume of the section) in each discrete section of the pipeline due to a failure of OLGA to converge in its calculations.

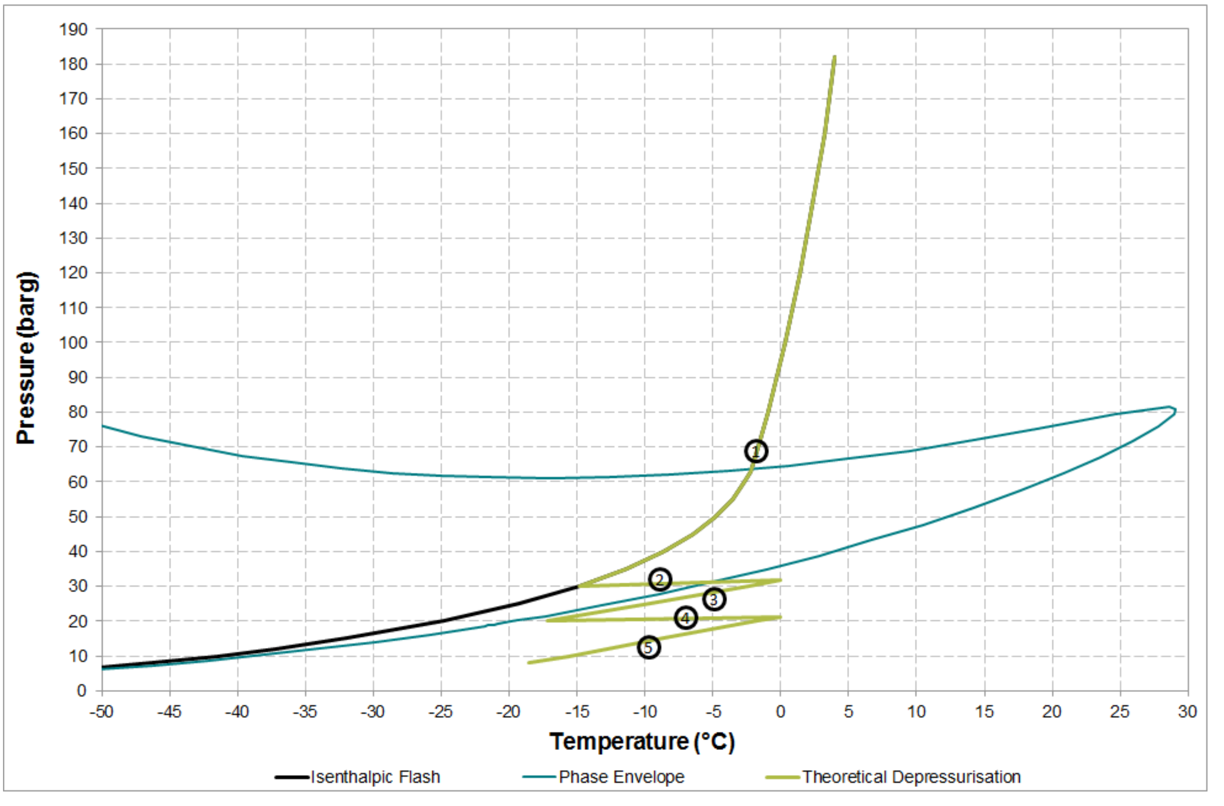
Figure 7.53: Maximum Global Volume Error Recorded in OLGA during Depressurisation of Tollingham to Dalton through a 2" Orifice



The maximum global volume error spikes when the pressure is reduced as vapour breaks out of the liquid CO_2 and the calculations struggle to converge.

Using a theoretical approach, whereby the fluid temperature is assumed to follow an isenthalpic path, the minimum possible temperatures for a given pressure can be predicted. Figure 7.54 shows a theoretical depressurisation process for the offshore pipeline from 182 barg and 4°C. Note that during the holding stages, it is assumed that the fluid heats up to 0°C rather than 4°C (minimum ambient) due to the additional time it would take to reach ambient. The increase in pressure as temperature increases is calculated based on the ideal gas law.

Figure 7.54: Depressurisation Steps based on Theoretical Minimum Temperatures



The recommended depressurisation process follows five distinct stages, which requires the depressurisation process to be held when certain pressures are reached to avoid the temperature falling below -20°C (these pressures are not optimised):

1. Depressurisation to 30 barg. The minimum theoretical temperature is -14.8°C. This is assumed to follow the isenthalpic flash curve, but as discussed in Section 7.7.6, heat supplied by the surroundings would result in temperatures greater than those predicted using this curve.
2. The first holding stage, where the pipeline inventory is held and allowed to warm up to 0°C.
3. The fluid is depressurised further to 20 barg. The minimum theoretical temperature that can be achieved, if the fluid was held at 30 barg for sufficient time to reach 0°C, is -17.2°C.
4. The second holding stage, where the pipeline inventory is held and allowed to warm up to 0°C.
5. The fluid is depressurised further to 8 barg. The minimum theoretical temperature that can be achieved, if the fluid was held at 20 barg for sufficient time to reach 0°C, is -18.6°C.

If a lower pressure were to be achieved, a further holding stage and subsequent depressurisation may be required from 8 barg. However, as the entire pipeline would likely be in the vapour-only region at this pressure, heat supplied by the surroundings may be sufficient to depressurise to 5 barg without the fluid temperature reaching -20°C (as seen in Figure 7.46).

It is interesting to note that using this approach moves the fluid outside the phase envelope during the first holding stage and stays in the vapour-only region through the remaining depressurisation steps. However, the pressure through the pipeline is not uniform (as shown in Figure 7.42), so the pressure at the holding stages must be considered as the minimum pipeline pressures (which are generally very close to the pressure measured upstream of the vent orifice). Therefore, it should not be expected that the entire section being depressurised be in the vapour-only phase after the first holding phase.

It is recognised that this approach is conservative and there may be an opportunity to optimise the depressurisation process later in the design / operation of the CO_2 transportation system. However, it has been demonstrated that depressurisation of the pipeline can be achieved.

Figure 7.41 shows that it takes approximately 1 week for the fluids to heat up from a temperature of -15°C to 0°C in the holding stage. It is recommended that each holding stage be for a minimum of 1 week.

Where this approach becomes more challenging is in the calculation of the time required for the pipeline to warm up at the different holding stages. Based on the time predicted for depressurisation of the section between Tollingham and Dalton through a 2 inch orifice (see Figure 7.40), a one to two week holding period should be sufficient to ensure the pipeline is within 1°C to 2°C of ambient temperature. Temperature sensors at the vent locations would help inform this, however it is unlikely there would be the means to measure temperature along the length of pipeline for the operators to know the absolute temperature of the fluid.

Options to minimise the risk of excessively low temperatures during depressurisation include:

- follow the step-wise depressurisation process described above to limit the minimum fluid temperatures to -20°C;
- Charpy testing the pipeline to ensure a minimum temperature of -45°C is acceptable, which is the minimum theoretical temperature that the CO_2 could reach when depressurising to 11 barg from 135 barg at 4°C (this pressure would be at the peak elevation point rather than upstream of the vent). The impact on vendor selection should be considered if selecting this option as the additional testing may preclude some vendors from bidding to supply the pipeline; and
- avoiding depressurisation of CO_2 by using a PIG/PIG rain to displace the CO_2 into the well using an inert fluid (e.g. air or water). If this option was selected, then it may be required for maintenance on the pipeline/equipment that sectional depressurisation would otherwise be used, requiring an air supply and the initial start-up process to be followed to bring the pipeline back into operation.

7.7.9 Depressurisation Summary

Table 7.12 shows the time to depressurise each section of the onshore and offshore system to 5 barg and the peak rates and total inventory of CO_2-rich fluid vented during the depressurisation process for the Impurities composition, based on winter conditions.

Table 7.12: Depressurisation Times and Mass of Vented CO_2-rich Fluid (Impurities Composition)

Pipeline Section	Orifice Size (in)	Time to Reach 5 barg from MAOP (days)	Mass of CO_2-rich Fluid Vented (t)	Peak CO_2-rich Fluid Vent Rate (t/h)

Pipeline Section	Orifice Size (in)	Time to Reach 5 barg from MAOP (days)	Mass of CO_2-rich Fluid Vented (t)	Peak CO_2-rich Fluid Vent Rate (t/h)
Drax to Camblesforth	0.5	1.1	262	61
Camblesforth to Tollingham	1	5.0	3,145	226
	2	6.7	3,440	762
Tollingham to Dalton	1	6.0	3,324	226
	2	16.4	3,595	771
Dalton to Skerne	1	5.9	2,771	224
	2	5.9	2,893	732
Skerne to Barmston	1	3.2	2,119	219
	2	4.8	2,270	676
Drax to Barmston	1	20.1	11,661	236
	2	6.2	12,538	896
Barmston to Platform	1	23.6	19,775	279
Drax to Platform	2	91(1)	31,242	802

The time to depressurise has not been optimised and there is scope to reduce this time significantly.

It can be seen that peak vent rates are clearly much higher for larger orifice sizes and the depressurisation times are, in general, shorter. However, for some cases, the depressurisation for the larger orifices takes longer because more blowdown-warmup cycles are required. This is because the higher rates induce greater or quicker pressure drop rates and, consequently, it is more difficult to control the associated J-T cooling. In addition, this effect is most pronounced in pipeline sections with very hilly terrain (i.e. the Tollingham to Dalton section).

Table 7.13 shows the recommended orifice sizes for the onshore and offshore pipelines, based on a pipeline minimum design temperature of -20°C**.** It should be noted that these orifice sizes are preliminary, based on the uncertainties discussed in Section 7.7.2. It is also assumed for the vent orifice size recommendations that depressurisation through a single vent point (on the platform) would not be performed.

Table 7.13: Recommended Blowdown Orifice Sizes

Pipeline Section	Recommended Orifice Size
300 mm Onshore Pipeline	0.5 inch
600 mm Onshore Pipeline	1 inch
600 mm Offshore Pipeline	1 inch

Table 7.14 shows the recommended stages for depressurisation of the various pipeline sections to ensure a minimum operating temperature of -20°C is not transgressed. The time to depressurise each section to the required pressure is dependent on the section being depressurised (in terms of both volume and terrain).

Table 7.14: Recommended Depressurisation Stages

Stage	Pressure at Vent (barg)	Time (days)
Depressurisation	30	~0.5
Hold at Pressure	30	>7
Depressurisation	20	~1
Hold at Pressure	20	>7
Depressurisation	8[(1)]	~0.5

[(1)]A pressure of 5 barg may be achieved at this stage as the CO_2-rich fluid will be in the vapour-only region and therefore will be heated by the surroundings more than when in the two-phase region and a temperature of -20°C may not be reached.

7.8 Leak Detection

The purpose of this analysis is to determine the time required for a leak of 2.5% of the total flowrate to be detected by a reduction in operating pressure. For the purposes of this analysis, it is assumed that the leak results in a constant flow, and occurs at the pipeline entrance at Drax to obtain the maximum detection time. It is also assumed that the platform choke position is not changed in response to the decline in pressure as a result of the leak. For those cases with the Barmston pump in operation, the leak was still assumed to be detected at the platform.

Figure 7.55 shows the pressure decline at the platform (upstream of the injection trees) observed due to a 2.5% leak at the inlet of the Drax to Camblesforth onshore pipeline. This case is selected as it represents the longest detection time due to the low flowrate. The pressure at the platform steadily declines due to the leak in the onshore pipeline, with a 1 bar reduction in pressure occurring 3.5 hours after the leak appears.

Figure 7.55: Pressure Decline at Platform due to 2.5% Leak in Drax-Camblesforth Pipeline – First Load Composition, 2.68 MTPA

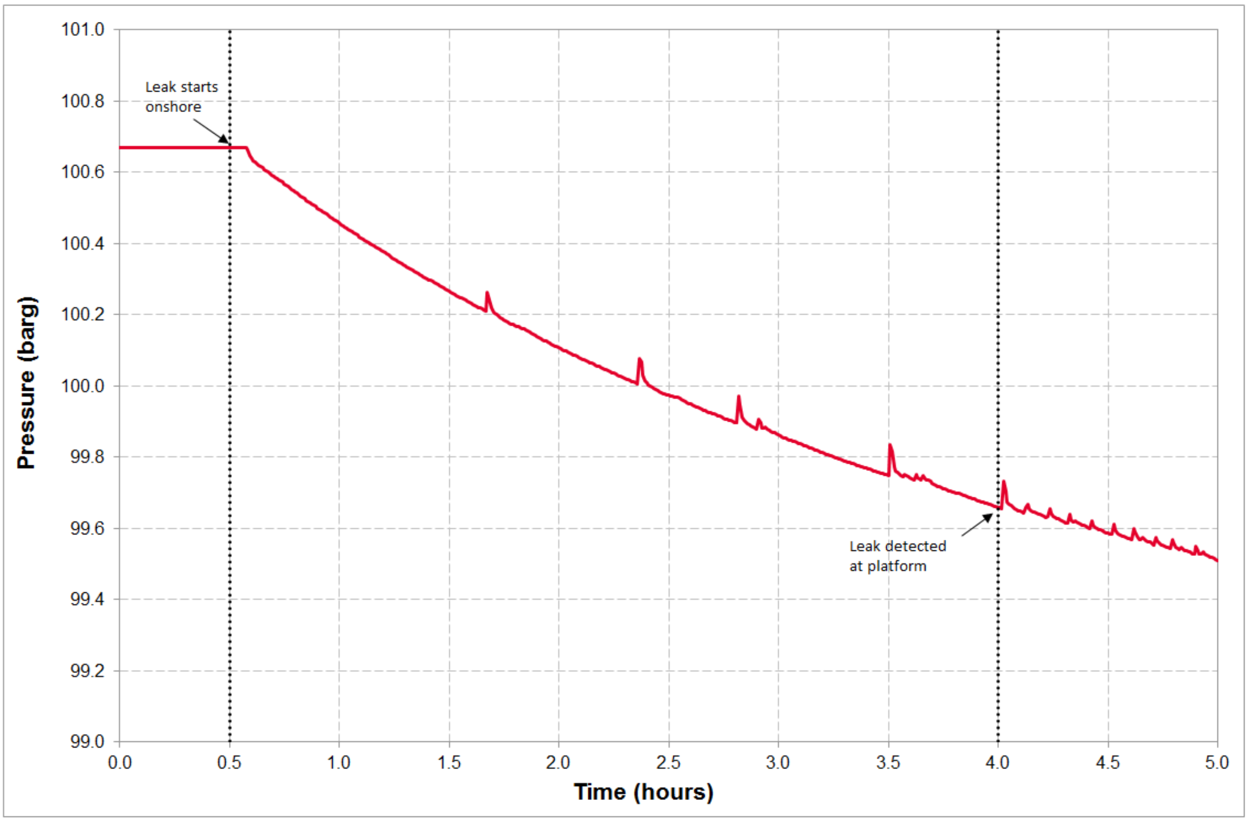


Table 7.15 shows the leak detection times and mass of CO_2 released prior to detection for a 1 bar reduction in pressure.

Table 7.15: Leak Detection Times and Leak Quantities for 1 bar Pressure Loss Detected

	Reservoir Pressure	Initial Flowrate	Detection Time	Mass Leaked Before Detection
Fluid	**(barg)**	**(MTPA)**	**(hours)**	**(te)**
First Load	150	2.68	3.5	26
Full Flow	171	10	0.7	19
	177	10	0.6	18
	178	17	0.5	23
	194	17	0.5	24
Impurities	171	10	0.7	21
	177	10	0.7	20
	178	17	0.5	25
	194	17	0.5	25

The reduction in pressure can be detected quicker at higher flowrates (in approximately 0.5 hour to 0.7 hour), but the total mass of CO_2 leaked into the atmosphere does not change significantly and remains between 18 tonnes to 25 tonnes.

7.8.1 Leak Detection Summary

- It is assumed for this analysis that a leak can be detected by a 1 bar reduction in pressure.
- The reduction in pressure due to a leak can be detected quicker at higher flowrates, but the resulting mass of CO_2 leaked to the atmosphere is not significantly different as the leak is based on 2.5% of the total flowrate.
- Leaks of 2.5% of the total flowrate could be detected within 0.5 hour to 3.5 hour.

7.9 Line Pack

If a section of the pipeline becomes shut in and CO_2 supply continues, pressure will rise and potentially exceed the MAOP. This analysis aims to estimate the time for this to occur. In addition, a series of cases were considered to demonstrate the available line pack when the system is subjected to swings in production rates or changes in injection wells availability.

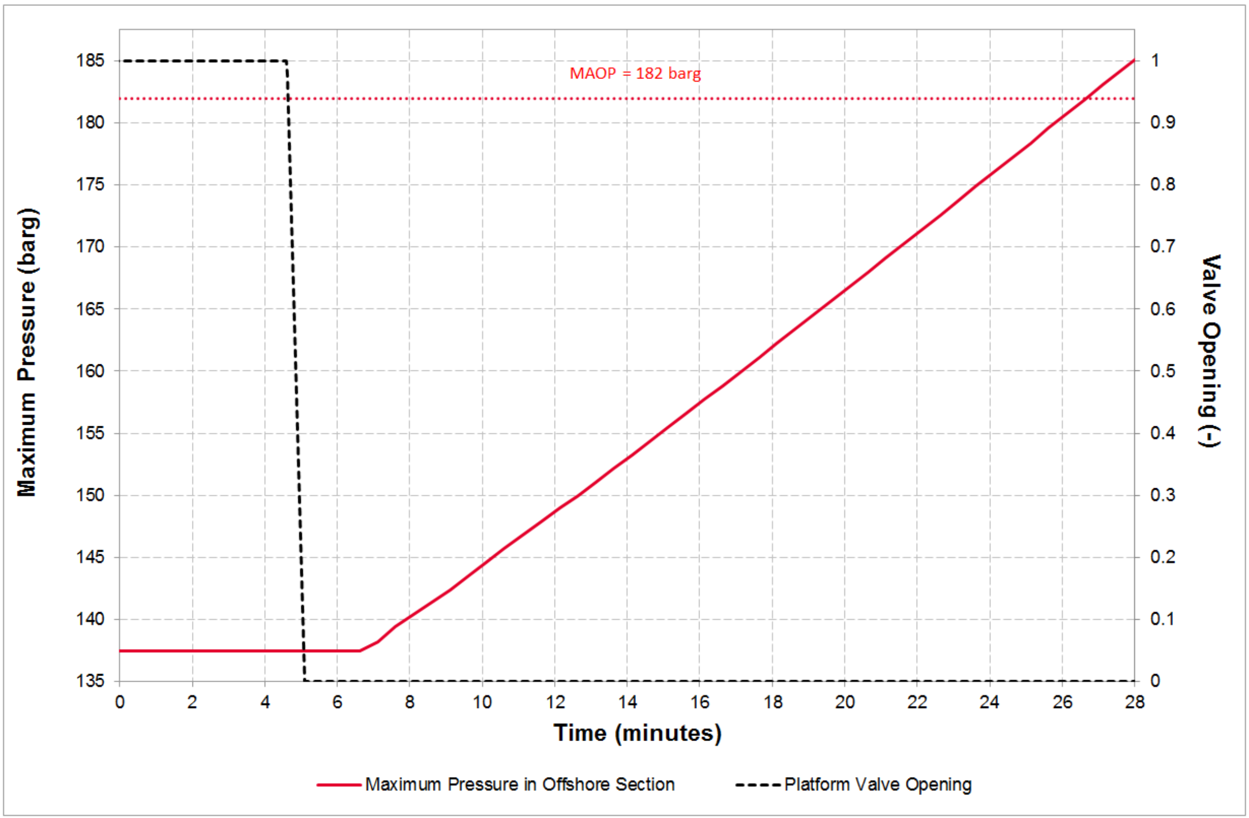
7.9.1 Pipeline Shut-in

The purpose of this analysis is to determine the time for the pipeline operating pressure to reach the MAOP where Drax and Camblesforth continue to supply CO_2 to the pipeline at the same flowrate for the following scenarios:

- Shut-in at the Platform;
- Shut-in at Barmston; and
- Shut-in at Camblesforth.

6 wells are assumed to be online during these scenarios when operating at ≥10 MTPA. Figure 7.56 shows how the pressure in the offshore section of the pipeline increases when flow is blocked at the platform with continued CO_2 supply from Drax and Camblesforth at a rate of 10 MTPA.

Figure 7.56: Maximum Pipeline Pressure when Flow is Blocked at the Platform, Full Flow, 10 MTPA, 177 barg Reservoir Pressure



In this case, the maximum pipeline pressure in the offshore pipeline reaches the MAOP of 182 barg within 24 minutes of shut-in at the platform. Pressure does not increase significantly in the onshore pipeline as the Barmston pump is suction pressure-controlled and, therefore, the pump speed adjusts to maintain the setpoint. However, this assessment should be carried out again in detailed design when the final selected pump characteristics and control system responses are known for a more accurate analysis.

Similar analysis has been carried out for ESDV closure at Barmston and Camblesforth, with the pressure following a similar trend to that shown above. Table 7.16 shows the packing times following shut-in at various locations for the main cases, including at Barmston and Camblesforth.

Table 7.16: Packing Times following Shut-in at Various Locations

	Reservoir Pressure	Initial Flowrate	Shut-in at Camblesforth	Shut-in at Barmston	Shut-in at Platform
Composition	(barg)	(MTPA)	Packing Time (minutes)		
First Load	150	0.58	5	249	737(1)
	150	2.68	1	45	119(1)
Full Flow	171	10	1	13	24
	177	10	1	13	22
	178	17	0	4	9
	194	17	0	0	0

Composition	Reservoir Pressure (barg)	Initial Flowrate (MTPA)	Shut-in at Camblesforth	Shut-in at Barmston	Shut-in at Platform
			Packing Time (minutes)		
Impurities	171	10	1	14	23
	177	10	1	14	20
	178	17	0	3	6
	194	17	0	0	0

[(1)]Onshore design pressure of 135barg is reached before the offshore design pressure.

The Drax to Camblesforth section reaches the MAOP of 135 barg in less than 1 minute (irrespective of which valve is closed) for maximum flowrates as the pipeline capacity is relatively small and the steady state pressure is close to MAOP at high flowrates. For shut-in at Barmston (upstream of the pump), the onshore pipeline reaches the MAOP within 14 minutes when flowing at 10 MTPA. This is due to the normal operating pressure at steady state being close to the MAOP at the higher flowrates.

Due to the very short packing time in the onshore pipeline following shut-in in the onshore facilities (at Camblesforth throughout operational life and at Barmston from Year 5), there is insufficient time for operators at Drax and Camblesforth to reroute CO_2 from the pipeline to the secondary disposal route; an automated response may be required.

A shut-in at the platform has a longer packing time than the offshore pipeline MAOP of 182 barg due to the larger pipeline diameter and the higher MAOP compared with the onshore pipeline from Drax to Camblesforth (the pipeline has a 300 mm nominal diameter) and is significantly longer. Note that for the low flow cases without the Barmston pump in operation, the design pressure is exceeded in the onshore section of the pipeline rather than the offshore section. The packing time ranges from 6 minutes to 24 minutes for the design and Full Flow flowrates of 17 and 10 MTPA respectively.

7.9.2 Changes in Flowrate and Well Availability

The purpose of this analysis was to look at the system behaviour during periods of varying flowrate and how it responds to wells being taken offline; specifically the time taken for the system to re-establish steady operation.

A series of cases were considered where the following sequence was implemented:

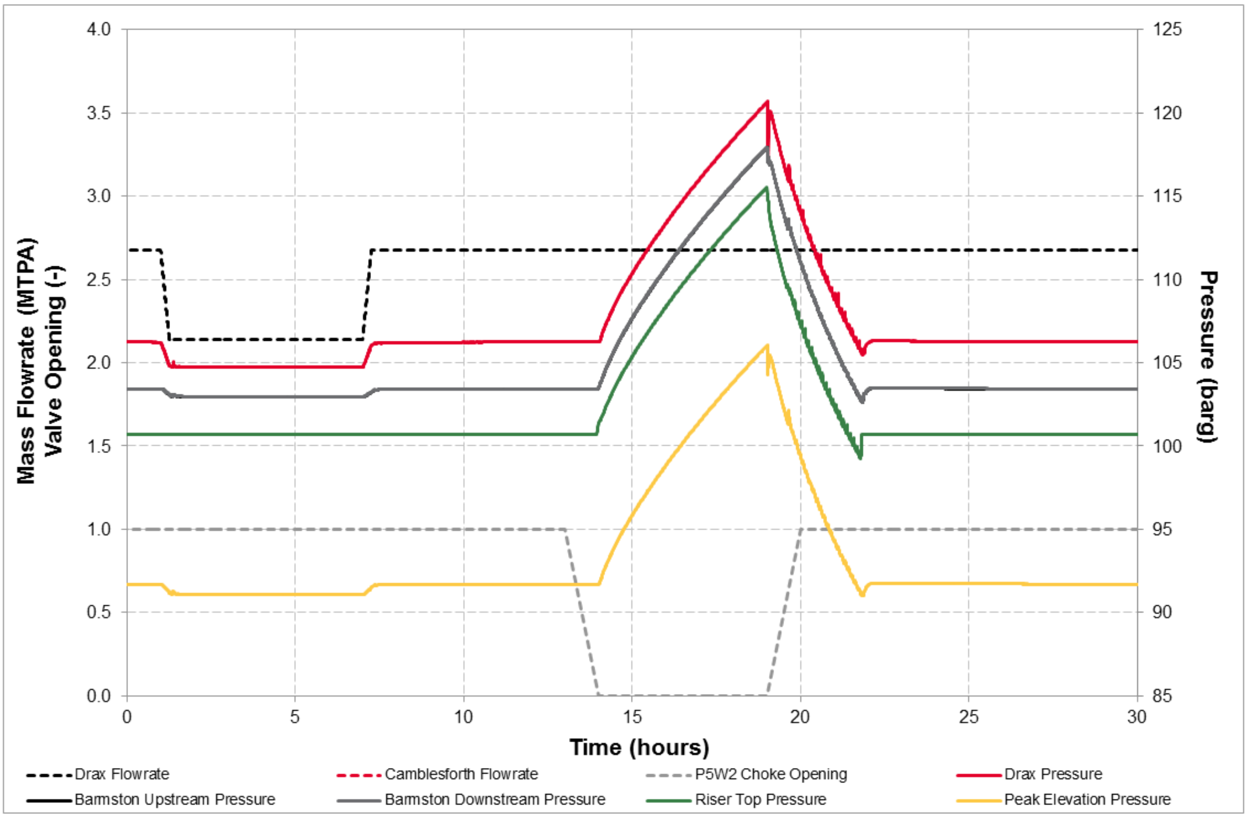
- t = 0; Simulation starts at steady state;
- t = 1 hr; Flowrate from Drax or Camblesforth is dropped by 20% in 15 min;
- t = 7 hrs; Flowrate from Drax or Camblesforth is increased by 20% in 15 min;
- t = 13 hrs; P5W2 well choke is closed in 1 hour; and
- t = 19 hrs; P5W2 well choke is opened in 1 hour.

Three steady state flowrates were considered; 2.68 MTPA, 10 MTPA and 17 MTPA.

Figure 7.57 shows the change in pressure and temperature at different locations in response to these changes for an initial flowrate of 2.68 MTPA. As the pressure at the platform end is fixed at 100 barg, the impact of flowrate fluctuation becomes more significant towards the pipeline inlet where a 20% flowrate reduction results in a 1.5 bar pressure drop.

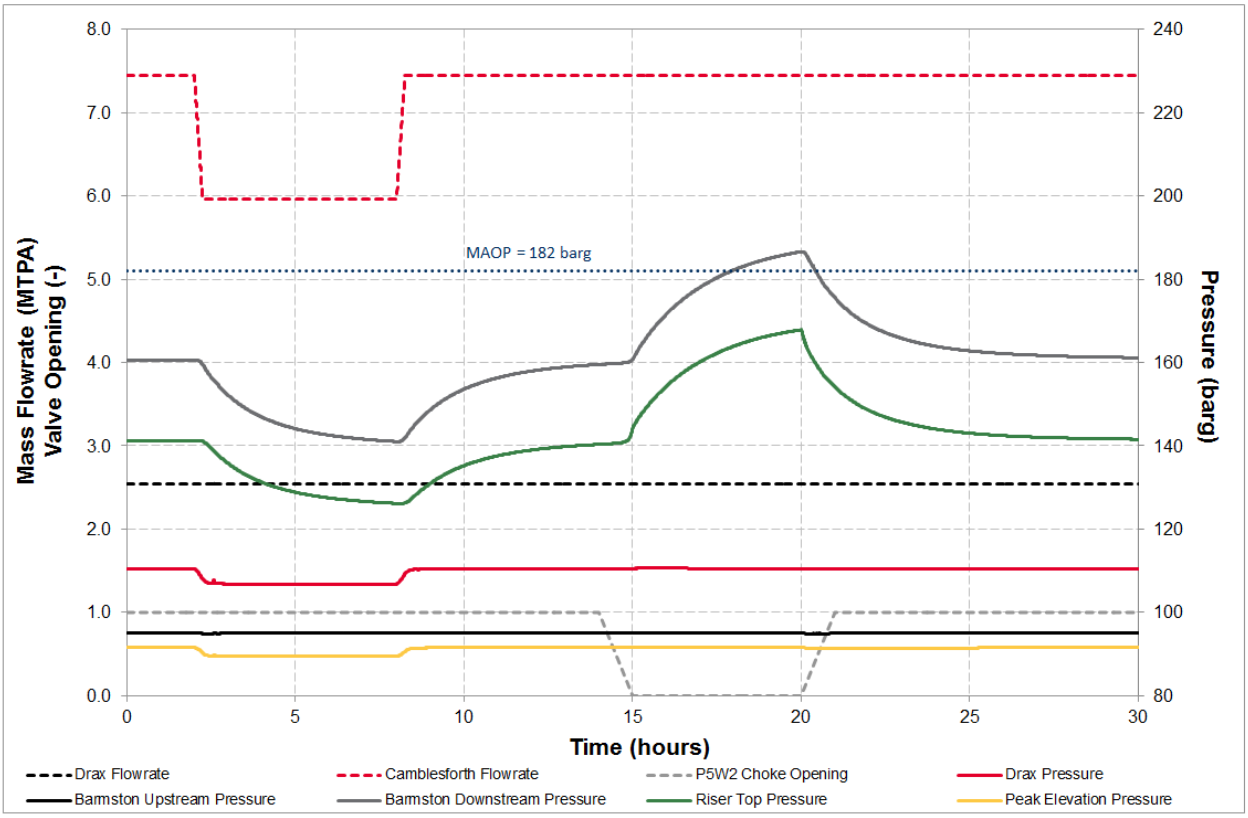
Taking P5W2 offline, and leaving 1 well on-line, causes a pressure rise at an approximate rate of 3 bar per hour across the length of the pipeline. If left to reach steady state, the pressure at Drax is expected to exceed 135 barg, as indicated in the Steady State Report. However, this will occur more than 9 hours after P5W2 has been taken offline and can be avoided by turning the Barmston pump on and increasing the platform pressure setpoint to ensure the pressure differential across the pump is above 20 bar to avoid cavitation. Opening the well choke again causes the pressure to drop at a quicker rate (≈ 5 bar per hour).

Figure 7.57: Pressure Response to Changes in Flowrate and Taking P5W2 Offline/Online with a Steady State flowrate of 2.68 MTPA and 2 Injection Wells, First Load Composition, Summer



A different response is observed when the pumps are in operation and the flowrate is 10 MTPA (see Figure 7.58). Upstream of Barmston, effective suction pressure control limits the impact of flowrate changes on pressure. However, a 20% reduction in flowrate would lead to a discharge pressure that is lower by about 20 bar. Taking P5W2 offline results in a similar response as observed earlier, but only downstream of Barmston, where pressure exceeds the MAOP within 3 hours. Since the platform chokes are fully open in this case, it takes longer for pressure to settle back to its steady state profile when P5W2 is brought back online.

Figure 7.58: Pressure Response to Changes in Flowrate and Taking P5W2 Offline/Online with a Steady State flowrate of 10 MTPA and 5 Injection Wells, Impurities Composition, Summer



Implementing the same changes while operating at 17 MTPA leads to similar trends as in the 10 MTPA case but with a more pronounced impact. This is shown in Figure 7.59. In this case, the pump discharge pressure decreases by 37 bar following flowrate reduction, and the higher operating pressures mean that it takes less time for the pressure to exceed the MAOP when P5W2 is taken offline, which occurs in less than an hour.

Due to the large changes in pressure, this case also leads to the largest changes in temperature, particularly in winter. Figure 7.60 shows that temperature drops by nearly 5°C over the six-hour period when Camblesforth flowrate is reduced by 20%.

Figure 7.59: : Pressure Response to Changes in Flowrate and Taking P5W2 Offline/Online with a Steady State flowrate of 17 MTPA and 6 Injection Wells, Impurities Composition, Summer

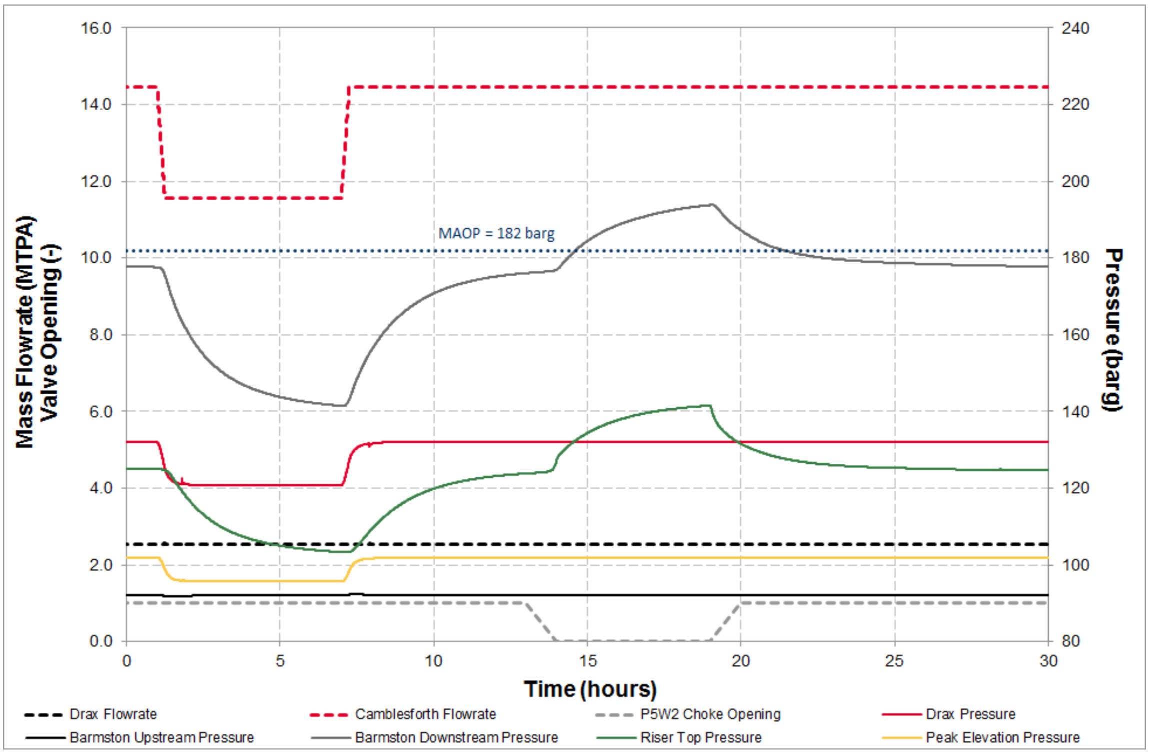
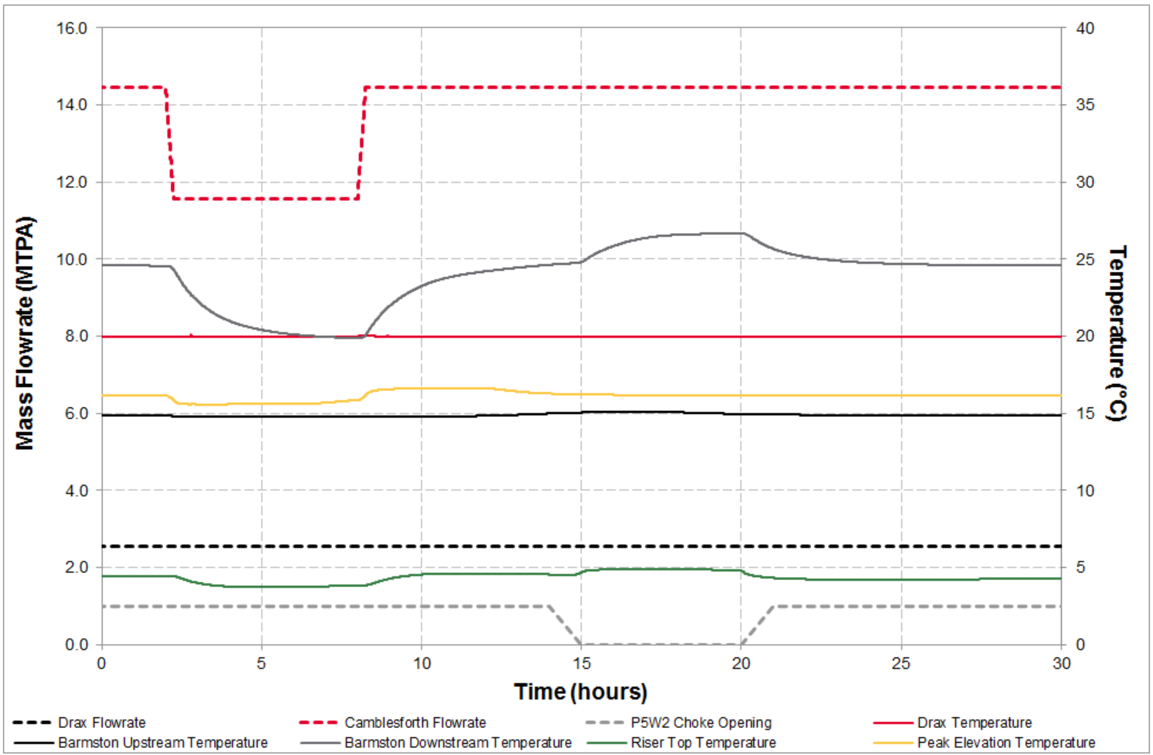


Figure 7.60: Temperature Response to Changes in Flowrate and Taking P5W2 Offline/Online with a Steady State flowrate of 17 MTPA and 6 Injection Wells, Impurities Composition, Winter



7.9.3 Linepack Summary

- Due to the short packing time (0 to 9 minutes), an automated response may be required to avoid exceeding the MAOP in the onshore pipeline as a result of 1) a valve shut-in at Camblesforth at any stage of operational life or 2) a valve shut-in at any location while operating at 17 MTPA.
- Pressure control at the platform (Years 1 to 5) and the pump suction (after Year 5) limit the impact of flowrate changes on upstream sections. The pipeline downstream of Barmston will be susceptible to notable pressure changes when the pump speed is adjusted based on the flowrate.
- Taking a well offline without changing production rates could lead to exceeding the MAOP within hours. The time available to avoid this outcome decreases from around 9 hours in years 1 to 5 down to less than an hour after year 10.

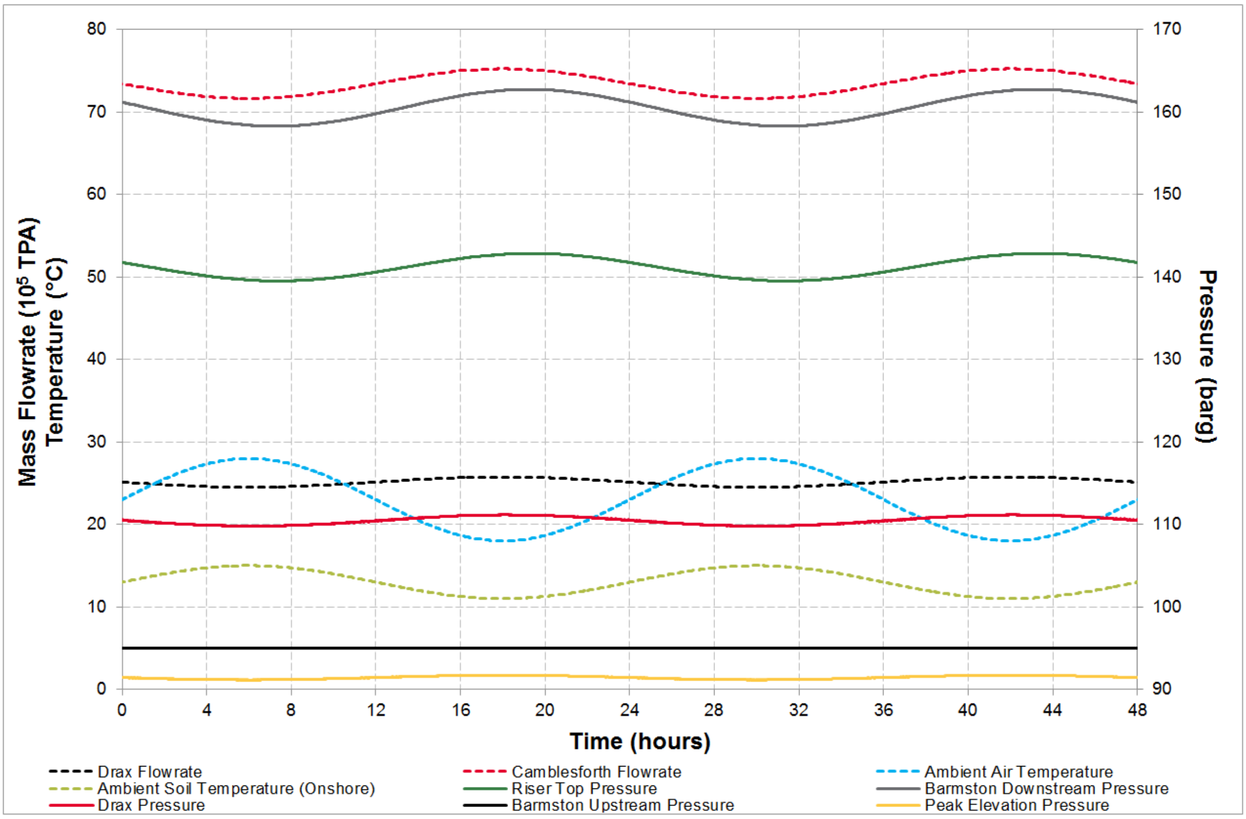
7.10 Daily Swing

The day-to-day temperature swing could impact on the temperature and pressure profiles in the pipeline. In addition, changes in air temperature may cause variations in the CO_2 production rate by affecting compression efficiency at the emitter's site. This section demonstrates the operation of the system over a 24-hour temperature swing period. As the exact system response to pressure and flowrate changes would be governed by the controller settings and the compressors at the emitter's site, the results should only be used as an indication of how the system could behave in reality when subjected to such temperature swings.

The ambient air temperature was assumed to exhibit sinusoidal variation with amplitude of 5°C summer conditions. At the pipeline burial depth, the ambient soil temperature is expected to show a smaller degree of variation, hence ±2°C was assumed. For both temperatures, the upper limit was kept at the maximum values used for all other simulations under summer conditions (28°C and 15°C respectively). The day-to-day sea temperature variation is expected to be negligible and be limited to the surface layers. To account for the impact of air temperature on compression efficiency, CO_2 production rates at Drax and Camblesforth were varied by ±2.5% of their base values.

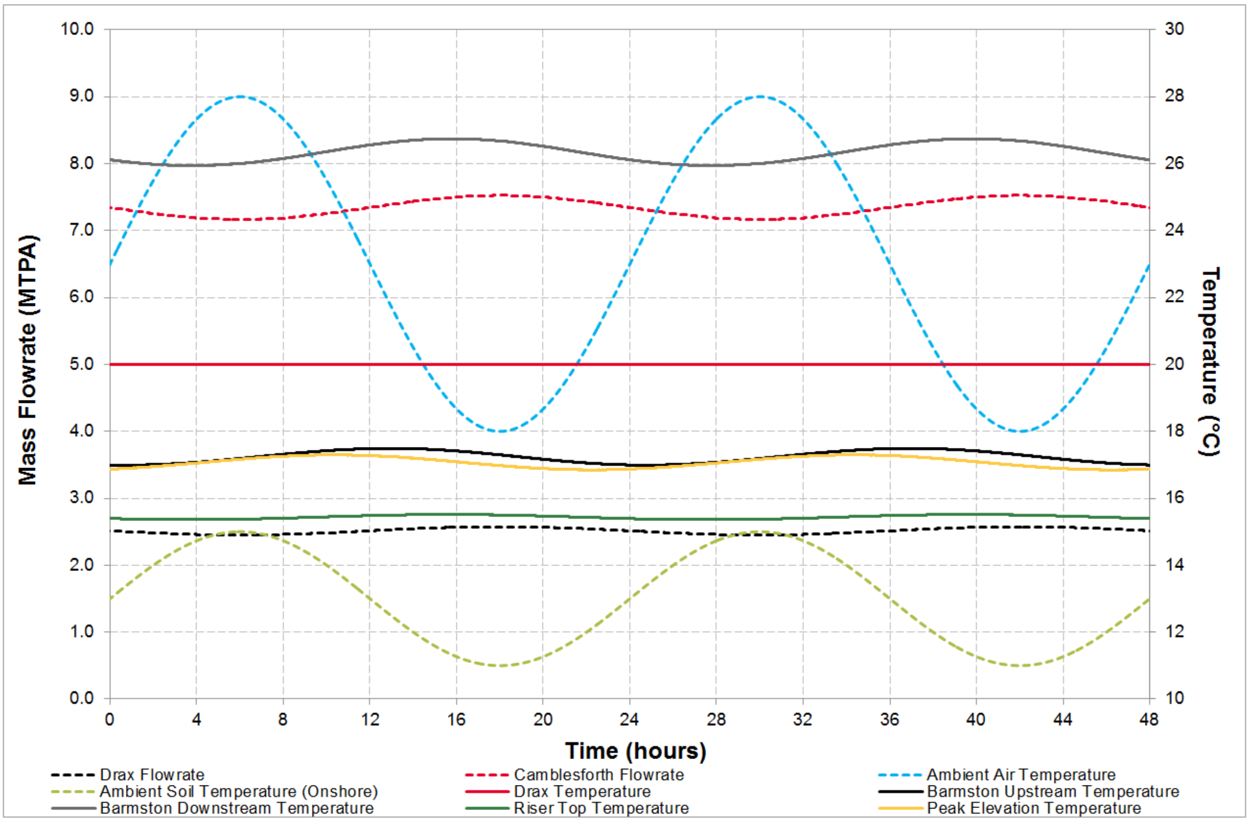
Figure 7.61 shows the resulting changes in pressure at different locations for a case where the total CO_2 production is 10 MTPA with 5 injection wells online. Pressure changes follow the oscillations in flowrate, but are limited to a narrow range; the largest changes occur downstream of Barmston (±2.5 bar) as the pump speed is adjusted in response to flowrate changes.

Figure 7.61: Pressure Changes at Different Locations along the Pipeline Resulting from Daily Temperature Swing with Impurities Composition, 10 MTPA, 177 barg Reservoir Pressure



The resulting changes in temperature for the same case are presented in Figure 7.62. The figure shows that temperature changes are minimal; the difference between maximum and minimum daily temperatures at any one location does not exceed 1°C.

Figure 7.62: Temperature Changes at Different Locations along the Pipeline Resulting from Daily Temperature Swing with Impurities Composition, 10 MTPA, 177 barg Reservoir Pressure



7.10.1 Daily Swing Summary

- Daily ambient temperature swing is unlikely to have a significant impact on the stability of the system during operation.

7.11 Maximum Pipeline Inventory

The pipeline will contain the maximum inventory when operated at the minimum flowrate and highest pressure profile. Based on this, one of two cases could potentially lead to the maximum inventory:

1. operating at the minimum flowrate during Years 1 to 5 with a maximum pipeline pressure of 135 barg (First Load composition); or
2. operating at the minimum flowrate during Years 5 to 10 with a maximum pipeline pressure of 182 barg downstream of Barmston (Full Flow composition).

The second case is highly unlikely to take place during normal operation since the pumps will be operating at a low speed at minimum turndown. Assuming it does occur, simulations with a flowrate of 7.9 MTPA (turndown flowrate – see Section 7.3) have shown that the inventory in the section downstream of Barmston will still be lower than in the first case with a flowrate of 0.58 MTPA, which is shown in Table 7.17.

The maximum inventory in the whole pipeline was found to be 39.1 kT and occurs in winter, as indicated in Table 7.18. The corresponding pressure and temperature profiles for the summer and winter cases are shown in Figure 7.63 and Figure 7.64 respectively.

Table 7.17: Maximum Pipeline Inventory Downstream of Barmston

Flowrate (MTPA)	Ambient Conditions	Maximum Inventory Downstream of Barmston (kT)
0.58	Winter	22.0
0.58	Summer	20.6
7.9	Winter	21.0
7.9	Summer	20.2

Table 7.18: Maximum Pipeline Inventory

Flowrate (MTPA)	Ambient Conditions	Maximum Pipeline Inventory (kT)
0.58	Winter	39.1
0.58	Summer	36.9

Figure 7.63: Pressure Profile from Drax to Platform for the Maximum Pipeline Inventory Case in Summer and Winter at 0.58 MTPA

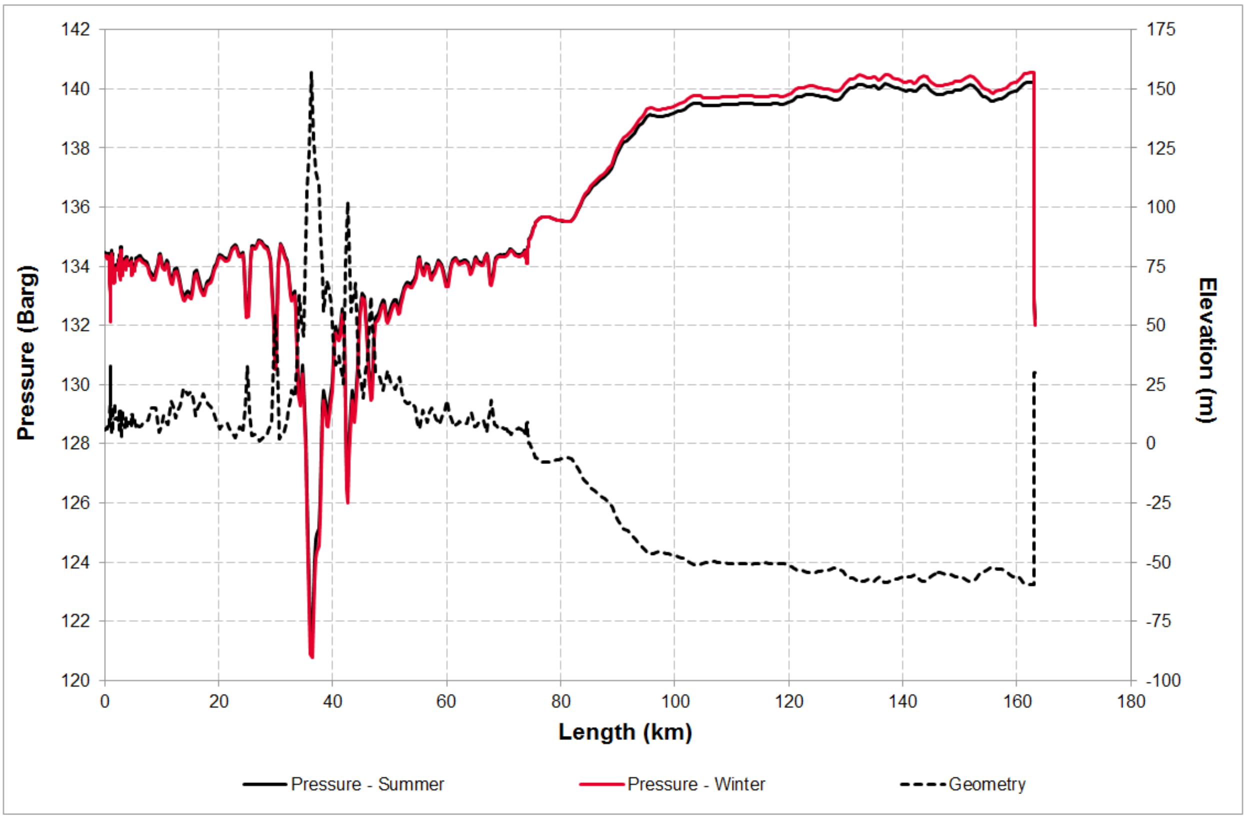
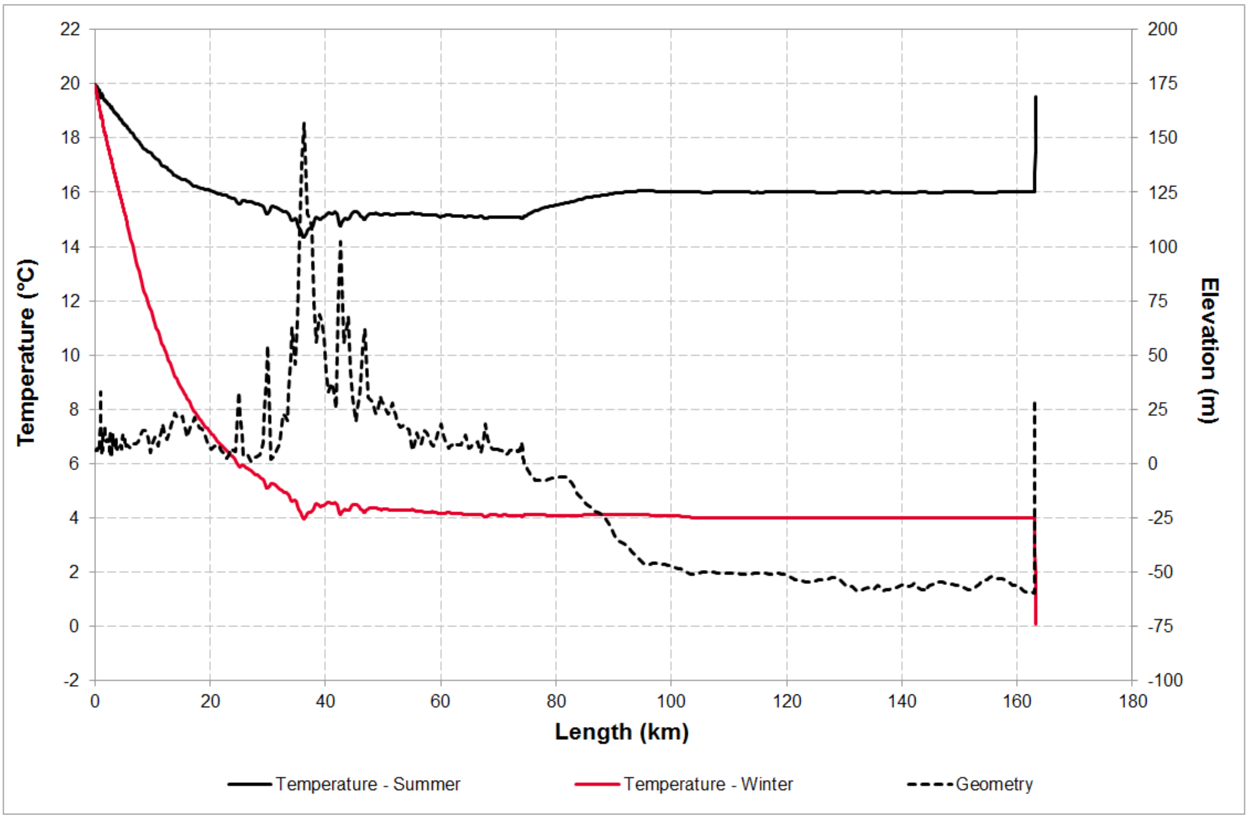


Figure 7.64: Temperature Profile from Drax to Platform for the Maximum Pipeline Inventory Case in Summer and Winter



7.11.1 Maximum Pipeline Inventory Summary

- The maximum pipeline inventory under steady state conditions is about 39.1 kT.

7.12 Pipeline Unpacking

The purpose of this analysis is to determine the time that injection can continue at the wells when the supply of CO_2 from Drax and Camblesforth is shut-off. In the simulations performed, the wells were not shut-in as the intention was to determine how long injection into the wells could continue (therefore, some pressures below 90 barg are reported), whereas in practice the pressure control system would prevent this occurring.

Note that in this scenario, unpacking is from normal operating conditions – the system has not been packed in anticipation of an unpacking operation. It is also assumed that the control system responds to maintain the suction pressure at Barmston and selective shut-in of wells to maximise unpacking time has not been performed. A sensitivity case where the control response is disabled is also presented for comparison.

The results are summarised in Table 7.19. Due to the minimum steady state pressure in the onshore section being very close to 90 barg in most cases (occurs at the peak elevation), pressure falls below 90 barg almost immediately after CO_2 flow is stopped.

In the offshore section, with the exception of the case where the CO_2 flowrate is 2.68 MTPA, the unpacking time increases marginally when the flowrate is increased and steady state pressure profile is elevated, but remains between 10 to 20 minutes in most cases.

If the suction pressure control is disabled and pump speed is fixed when CO_2 flow is stopped, a longer offshore unpacking time is expected, as illustrated in Figure 7.65. This is because the differential pressure (ΔP) across the pumps would no longer be reduced as the flowrate drops. This, however, would result in a more rapid decrease in pressure onshore. This also explains why bypassing the pumps in years 1 to 5 (with a flowrate of 2.68 MTPA) gives a longer unpacking time.

Figure 7.65: Pipeline Unpacking following Shut-off of Supply from Drax and Camblesforth, Full Flow composition, 10 MTPA, 171 barg Reservoir Pressure

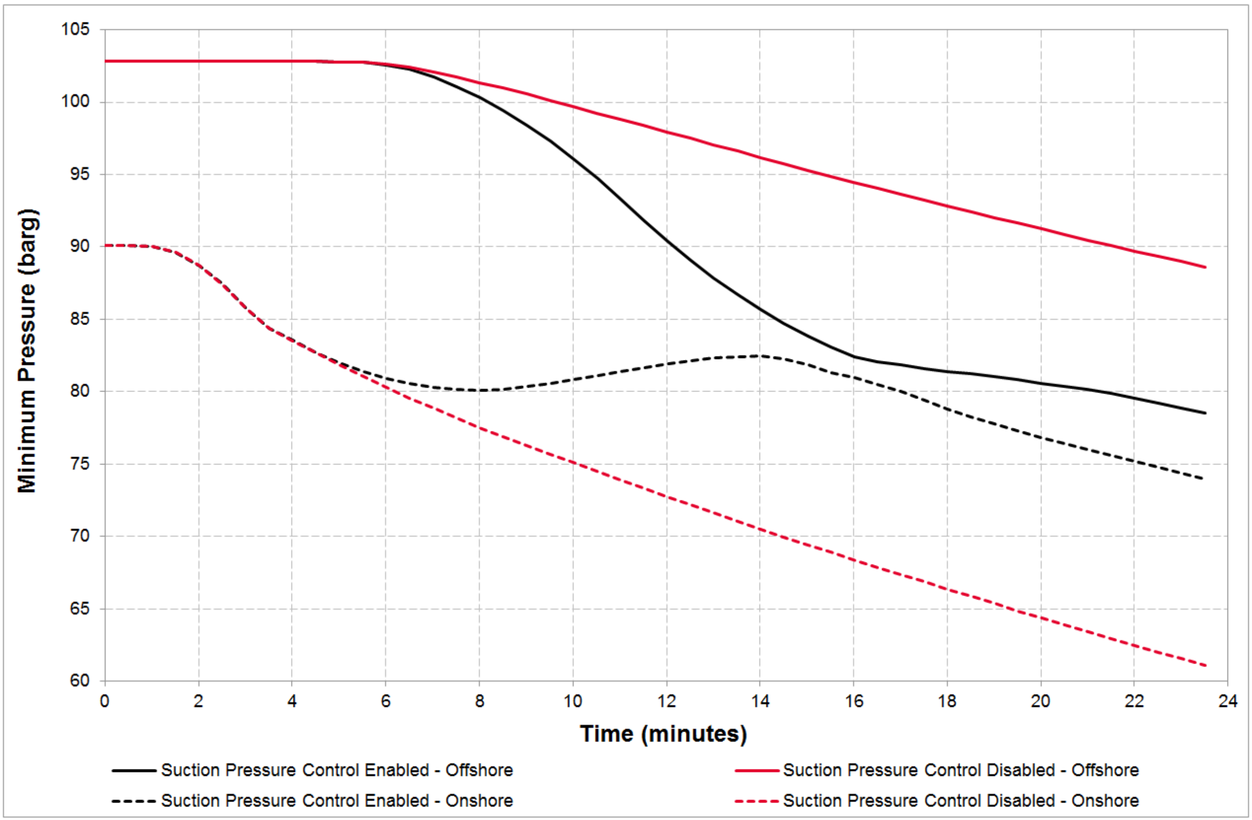


Table 7.19: Onshore and Offshore Pipeline Unpacking Times following Shut-off of CO_2 Supply from Drax and Camblesforth

Composition	Initial Flowrate (MTPA)	Reservoir Pressure (barg)	Onshore Pipeline Unpacking Time (minutes)	Offshore Pipeline Unpacking Time (minutes)
First Load	2.68	150	0	27
Full Flow	10	171	0	10
	10	177	0	12
	17	178	2	13
	17	194	4	21

Composition	Initial Flowrate (MTPA)	Reservoir Pressure (barg)	Onshore Pipeline Unpacking Time (minutes)	Offshore Pipeline Unpacking Time (minutes)
Impurities	10	171	0	14
	10	177	0	17
	17	178	2	16
	17	194	6	21

Operating with a higher pump suction pressure would not provide much additional unpacking time before the pressure in the onshore pipeline falls below 90 barg, as the pressure drops approximately 10 bar within 5 minutes of the loss of supply from Drax and Camblesforth. Additionally, the MAOP of 135 barg limits the pressure at which the onshore pipeline can operate.

7.12.1 Pipeline Unpacking Summary

When the supply of CO_2 from Drax and Camblesforth is shut-off, the pressure at the peak elevation falls below 90 barg almost immediately provided that the CO_2 injection into the wells is not stopped. A marginally longer unpacking time (2 to 6 minutes) would be expected when the initial flowrate is 17 MTPA.

7.13 Pressure Surge Due to ESD Valve Closure

The purpose of this analysis is to determine whether the pressure surge associated with the sudden closure of an ESD valve causes the pipeline operating pressure to exceed the maximum incidental pressure of 148.5 barg in the onshore pipeline and 200 barg in the offshore pipeline. For this analysis, the design flowrate of 17 MTPA was selected as it presented the highest operating pressure case and therefore it is most likely to result in the maximum incidental pressure being exceeded.

There is a degree of uncertainty as to how the control logic around the valves, pumps, and CO_2 sources will be configured. Therefore various assumptions have been made which should represent a realistic worst case. Three scenarios were considered, a spurious valve closure at the platform, a spurious closure of the valve upstream of the Barmston pump station and a spurious valve closure at the inlet to the pipeline at Drax. The valve at Drax is fast-closing (closes in 3 seconds). The valves at Barmston and at the platform were closed over 24 seconds (assuming 1 sec per inch). The analysis of the impact of sudden valve closure at Drax is limited to the CO_2 pipeline (i.e. downstream of the valve) – pressure surges that may occur within the Drax AGI piping are not considered as part of this scope.

Following the valve closure, it is assumed that, because this is a spurious valve closure, the control system is unaware of the closure until some other high or low pressure trip is initiated. Therefore the pump at Barmston will continue to operate and CO_2 will continue to enter the system from Drax and Camblesforth (with the exception of the spurious valve closure at Drax, where supply from Drax will stop).

In the case of the valve closure at the platform, the pumps are allowed to continue running until the pressure on the discharge side reaches 182 barg. This is assumed to be the High-High trip setting. Once this has occurred then a pipeline shutdown is initiated with the pumps being stopped and ramping the source flowrates to zero.

For the valve closure upstream of the pumps, a Low-Low trip of 90 barg is assumed on the suction side of the pump to initiate a pump shutdown, with the source flowrates not shut off until the pressure at Drax had reached the MAOP of 135 barg.

It should be noted that for simplicity, and knowing that it is conservative, all the surge analysis was carried out with rigid pipes, and no credit was taken for the elasticity of the pipe wall.

The compressibility of the fluid is calculated from the PVT table used by OLGA. However, off line calculations confirmed the bulk modulus of the dense phase fluid to be ~0.27 GPa, which compares to ~0.19 GPa for the liquid fluid. This suggests that dense phase CO_2 is relatively compressible when compared to a typical liquid hydrocarbon with a bulk modulus of ~1.1 GPa, and water with a value of 2.15 GPa.

Figure 7.66 shows the pressure behaviour upstream of the platform valve and downstream of the Barmston pump, following a spurious closure of the platform valve. The valve closes over 24 seconds and the initial pressure rise is small (approximately 10 bar) due to the high compressibility of the dense phase CO_2. However due to this compressibility it takes approximately 7 minutes for the pressure to increase 5 bar up to a pressure of 182 barg at the pump discharge, which initiates the pipeline shutdown.

Figure 7.66: Pressure Behaviour following Sudden Closure of the Platform ESDV

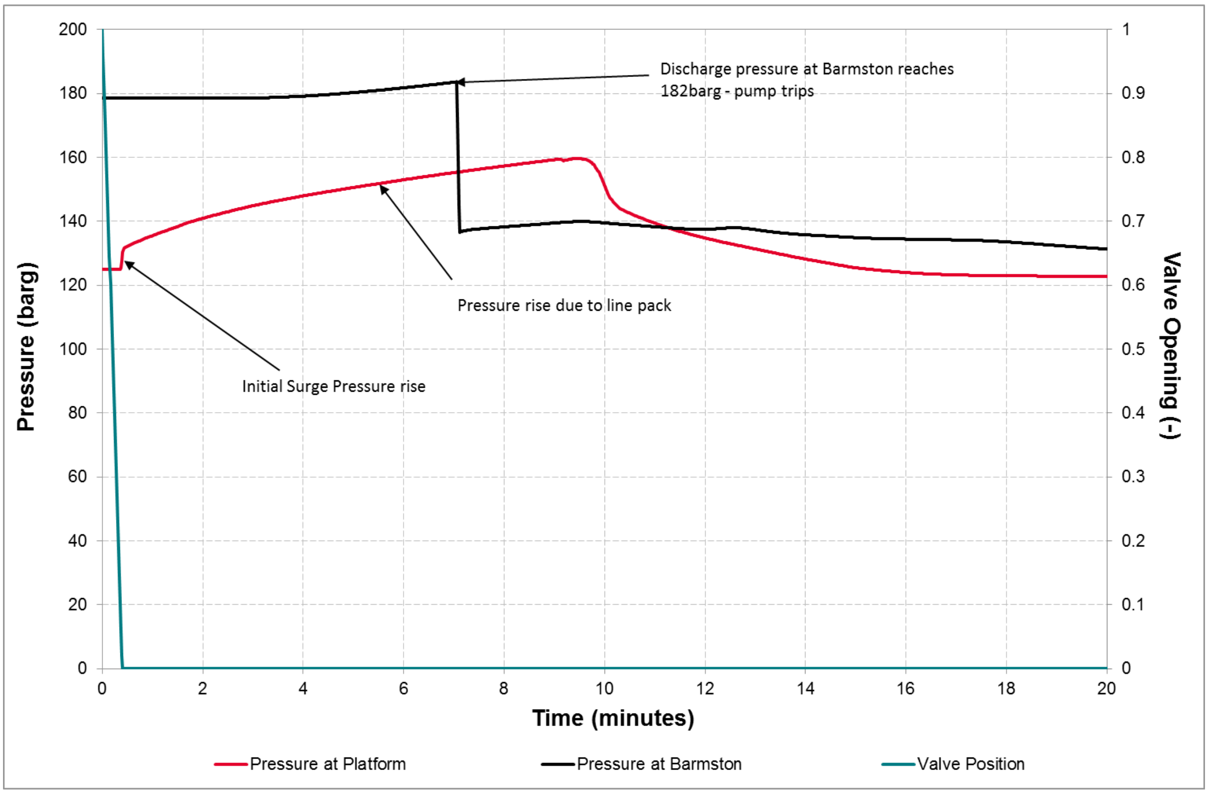
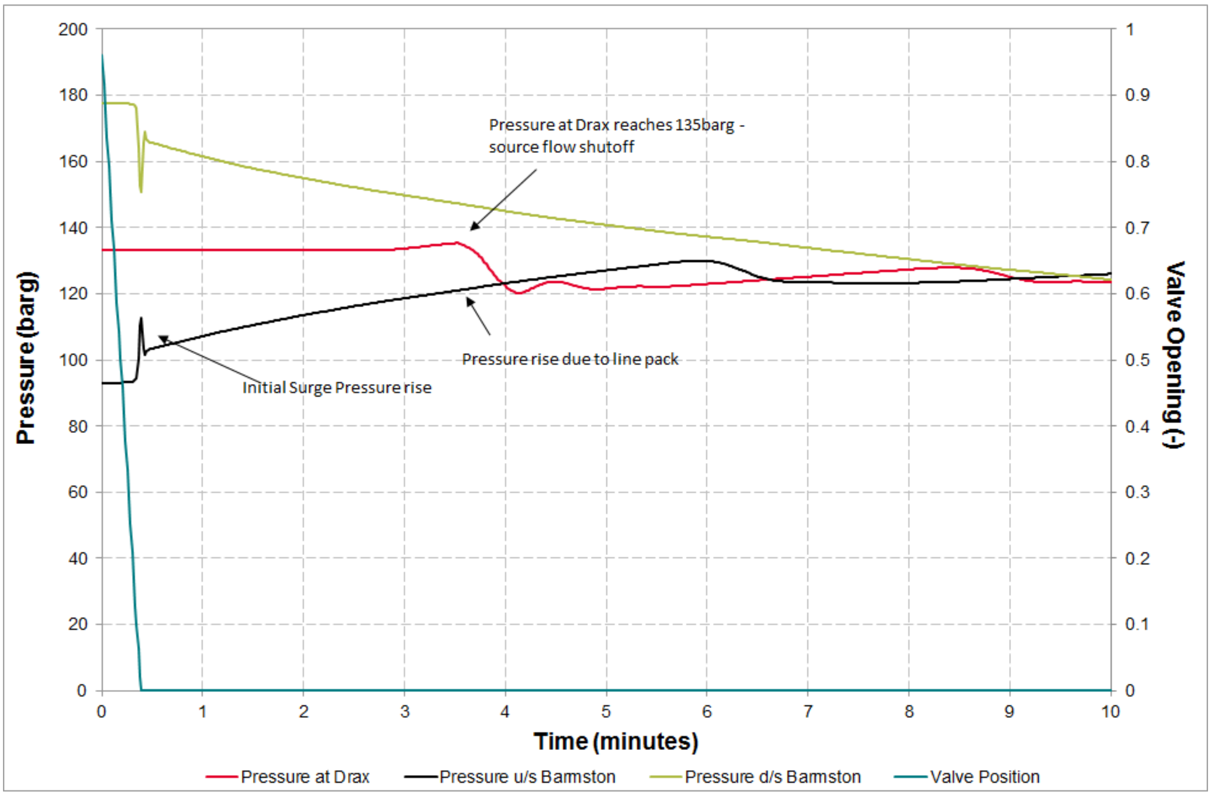


Figure 7.67 shows the pressure upstream of the ESD valve at the Barmston pump station following a spurious valve closure at the station inlet. The initial pressure rise associated with the valve closure is approximately 20 bar. Although not shown in the figure, the pressure downstream of the valve drops rapidly to the assumed 90 barg Low-Low trip resulting in the pumps tripping almost immediately. The

upstream pressure continues to rise gradually as the pipeline packs with CO_2. After approximately 3.5 minutes the pressure at Drax rises to 135 barg initiating a shutdown of the flow sources.

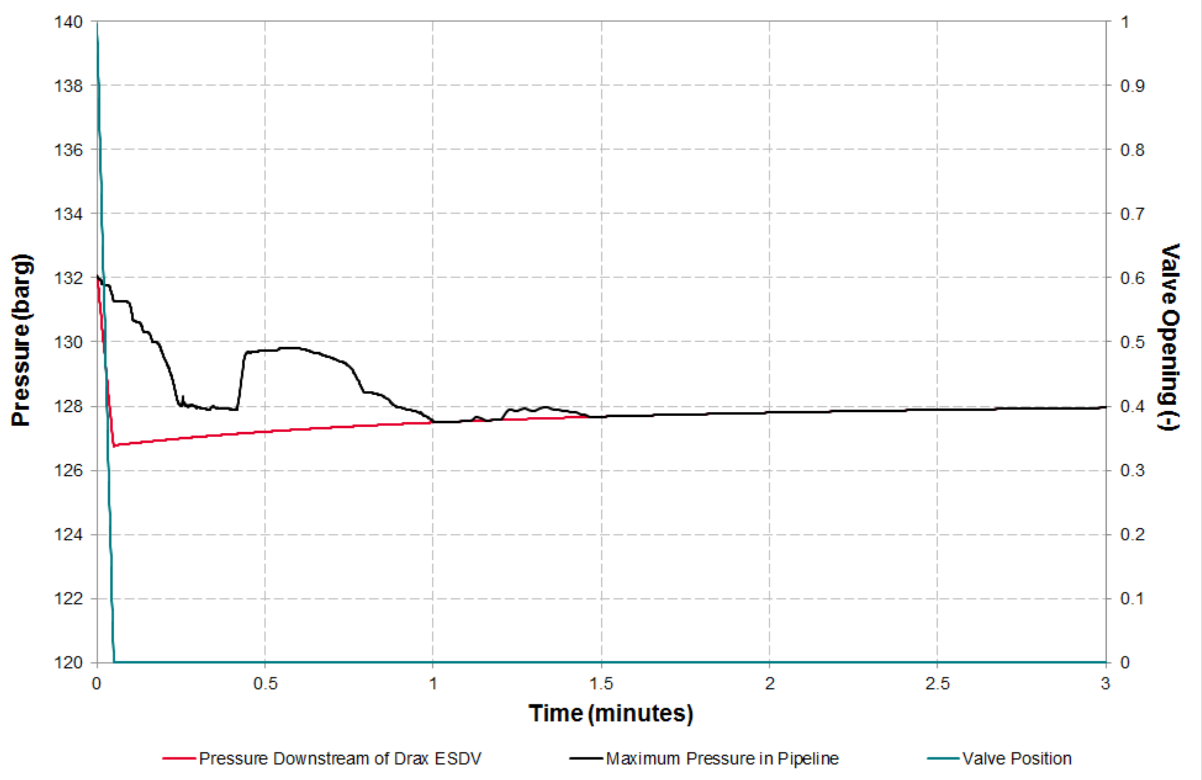
Figure 7.67: Pressure Behaviour following Sudden Closure of the Barmston ESDV



The maximum pipeline pressure is below the maximum incidental pressure in the onshore and offshore pipelines, therefore the pressure surge following sudden ESD valve closure does not cause a pipeline integrity issue. The lack of an appreciable pressure surge compared with liquid export pipelines is due to the relatively high compressibility of dense phase CO_2 compared with a liquid. Pressure downstream of the pump suffers a short dip when the valve closes, partially recovers and then steadily declines.

Figure 7.68 shows the maximum pressure in the onshore pipeline between Drax and Camblesforth following sudden valve closure at Drax. Valve closure time = 3 seconds.

Figure 7.68: Pressure Behaviour following Sudden Closure of the Drax ESDV



Sudden closure of the valve at the pipeline inlet at the Drax AGI does not result in the pressure in the pipeline exceeding the MAOP of 135 barg. The pressure wave that travels through the CO_2 in the pipeline when the valve closes is dampened by the relative compressibility of the dense-phase CO_2 (relative to liquid hydrocarbon or water) and the pressure spike at approximately 0.4 hour is lower than the initial pressure in the pipeline.

7.13.1 Pressure Surge Summary

- The maximum pipeline pressure is below the maximum incidental pressure in the onshore and offshore pipelines, therefore pressure surge following sudden ESD valve closure (hammer) does not cause a pipeline integrity issue. The lack of appreciable pressure surge is due to the compressibility of the dense phase CO_2, which is significantly higher than say liquid water.

7.14 Water Wash

This section aims to examine the water wash operation for removing halites from injection wells, as well as the subsequent restart of water-washed wells. The proposed water wash operation (which has not been optimised) to be examined consists of the following steps:

- 57 wt% MEG/seawater solution is injected into the well at a rate of 7,071 kg/h for 4 hours;
- Wash Water is injected into the well at a rate of 42,743 kg/h for 7 days; and then
- 57 wt% MEG/seawater solution is injected into the well at a rate of 7,071 kg/h for 4 hours.

Simulations were performed to confirm the operating pressure upstream of the wellhead, which is subject to a MAOP limit of 182 barg. It should be noted that a key variable in these simulations is the reservoir injectivity. The following section describes the approach taken in modelling this behaviour.

7.14.1 Reservoir Injectivity (for Water Wash Operation)

The reservoir injectivity dictates the pressure driving force required to inject a particular fluid into the reservoir at a specific rate; it is a function of both reservoir and fluid properties. Specifically, mass injectivity of the reservoir is inversely proportional to the kinematic viscosity (ratio of dynamic viscosity over density) of the fluid at the bottom hole conditions, as illustrated in the equation below:

$$I_{mass} = \frac{q\rho}{p_{bh} - p_e} = \frac{4\pi kh\rho}{\mu f(r_w, l)}$$

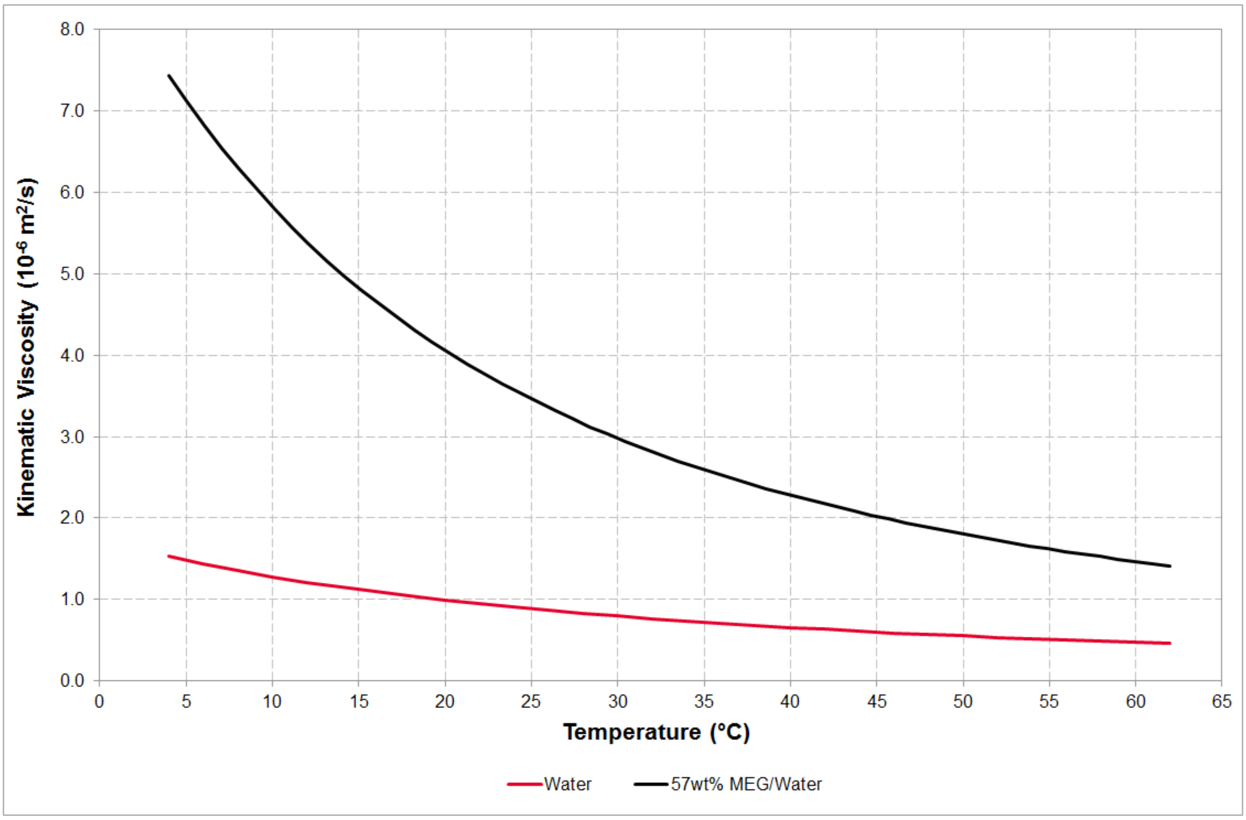
Where I_{mass} is mass injectivity of the reservoir, q is fluid volumetric flowrate, ρ is mass density, p_{bh} is bottom hole pressure, p_e is reservoir equilibrium pressure, k is reservoir permeability, h is reservoir thickness, μ is fluid dynamic viscosity and $f(r_w, l)$ is a function of wellbore radius r_w and the length l over which the pressure drop occurs.

A CO_2 injectivity of 1.4 x 10^{-5} kg/s/Pa had been inferred from the available data, as explained in the simulation basis. To calculate the water and MEG solution injectivities for the same reservoir properties, this value was adjusted based on the kinematic viscosity of the fluid at bottom hole conditions, assuming a kinematic viscosity of 0.077 x 10^{-6} m^2/s for CO_2 (as predicted at 160 barg and 62°C).

The kinematic viscosity, and hence the injectivity, is a strong function of temperature; between 62°C (approximate reservoir temperature) and 4°C (water injection temperature in winter), the kinematic viscosity of the MEG solution and pure water increase by five-fold and three-fold respectively. This is illustrated in Figure 7.69. Simulations were performed using an injection temperature of 4°C (at the wellhead) to obtain the highest operating pressures.

Note that the impact of halites on the injectivity is not considered here – halites will impede injectivity but the degree to which this occurs is dependent on the amount of deposition, which is unknown.

Figure 7.69: Relationship between Water Temperature and Kinematic Viscosity at 160 barg



The strong temperature influence introduces uncertainty in the simulation results; a single injectivity value in each OLGA run. To address this issue, additional simulations were performed for cases where heat transfer can have significant impact on the results. The injectivity values used for each case are presented in Table 7.20, along with the basis of these values. A reservoir pressure of 150 barg was assumed for all runs.

Table 7.20: Injectivity Values Used for Water Wash Simulations

Stage	Reservoir Injectivity (kg/s/Pa)		Viscosity Basis
	Base Case	Low Injectivity Case	
Prewash MEG Flush	7.7×10^{-7} (1)	N.A	Viscosity calculated at reservoir temperature (62°C); bottom hole temperature drop during MEG flush was found to be insignificant.
Water Wash	8.7×10^{-7}	7.1×10^{-7}	Base Case: viscosity calculated at the minimum bottom hole temperature observed in simulations (11°C). Low Injectivity Case: viscosity calculated at injection temperature (4°C)
Postwash MEG Flush	1.9×10^{-7}	1.5×10^{-7}	Base Case: viscosity calculated at the minimum bottom hole temperature observed in simulations (11°C).(2) Low Injectivity Case: viscosity calculated at injection temperature (4°C)

(1)Water injectivity was used as it is more conservative than using CO_2 injectivity in this case.
(2)It is assumed that the time interval between the end of water wash and the beginning of MEG flush is too short to allow water remaining in the tubing to warm up.

7.14.2 Prewash MEG Flush

The changes in pressure and temperature in the tubing are shown in Figure 7.70. The wellhead pressure increases gradually to 47 barg, while the temperature at the bottom of the tubing drops by less than 3°C. The results can be used to predict the wellhead pressure required when the reservoir pressure increases later in field life. This is shown in Table 7.21. The pressure remains significantly lower than the MAOP upstream of the wellhead (182 barg).

Figure 7.70: Pressure and Temperature Profiles during Prewash MEG Flush with an Injectivity of 7.7 x 10-7 kg/s/Pa, 150 barg Reservoir Pressure, Winter Conditions

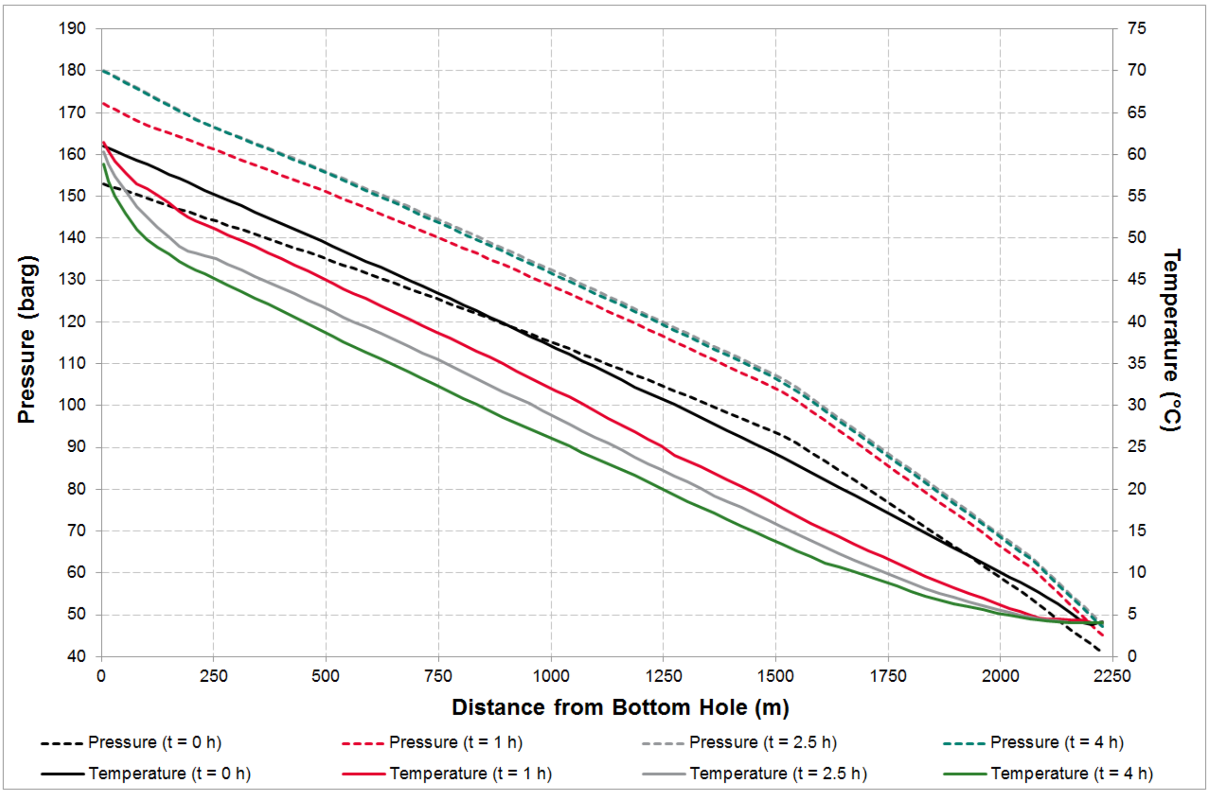


Table 7.21: Wellhead Pressure during Prewash MEG Flush for Different Reservoir Pressures

Reservoir Pressure (barg)	Wellhead Pressure during Prewash MEG Flush (barg)
150	47
194	91

7.14.3 Water Wash

The water fraction, pressure and temperature profiles in the well tubing during water wash are shown in Figure 7.71. The figure shows that water occupies the full volume of the tubing. The temperature of the injected water increases as it flows down the tubing, but the bottom hole water temperature decreases from 16°C at the end of day 1 to about 11°C at the end of day 7 as the surrounding rock approaches thermal equilibrium with the cold water. The pressure at the wellhead reaches 146 barg for the base case, increasing to 177 barg if water warming in the tubing is not accounted for. In either case, the MAOP upstream of the wellhead is likely to be exceeded if the same operation is to be performed with a reservoir pressure of 194 barg, as outlined in Table 7.22.

Figure 7.71: Pressure, Temperature and Water Fraction Profiles during Water Wash, 150 barg Reservoir Pressure, Winter Conditions

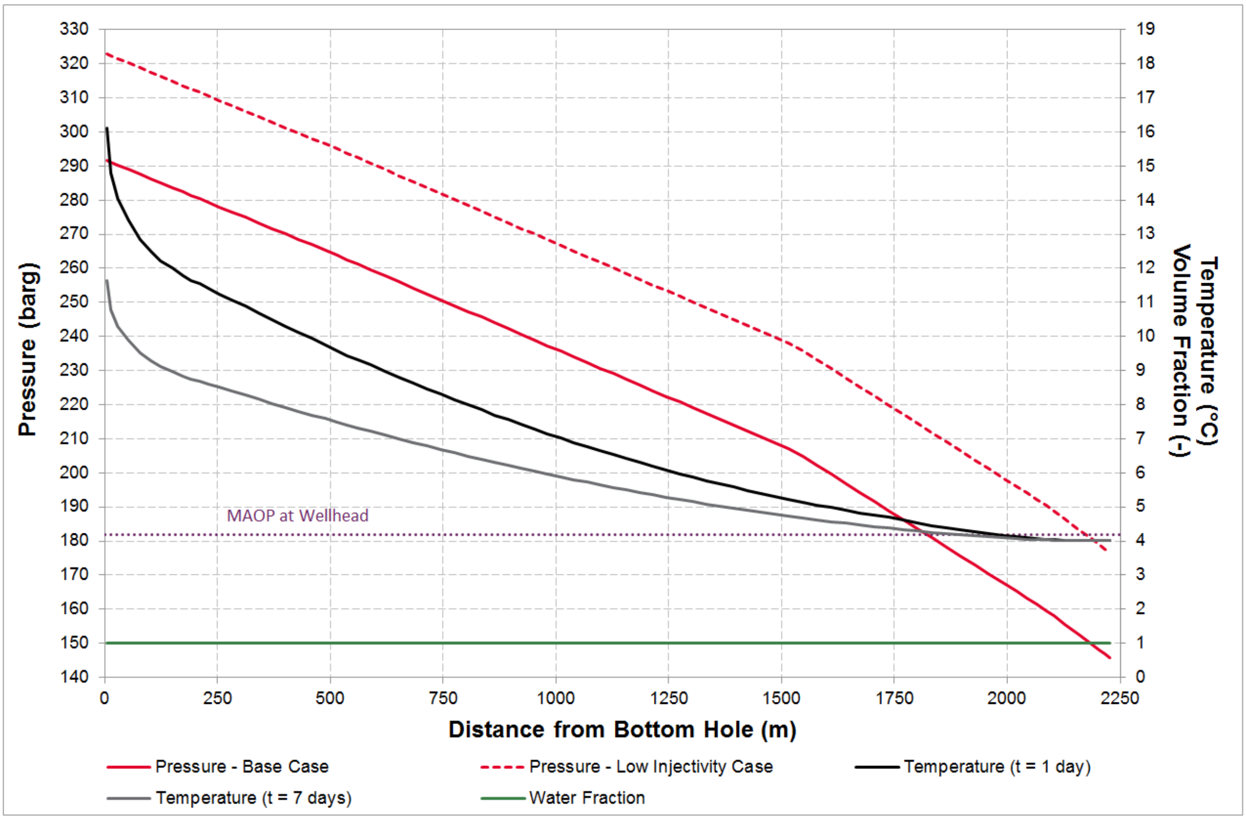


Table 7.22: Wellhead Pressure during Water Wash for Different Reservoir Pressures

Reservoir Pressure (barg)	Wellhead Pressure during Water Wash (barg)	
	Base Case	Low Injectivity
150	146	177
194	190	221

One way to avoid exceeding the MAOP at any scenario is to adjust the water flowrate such that the pressure is 182 barg when the reservoir pressure is 194 barg. Table 7.23 shows the wash water flowrates that satisfy this condition. If the total volume of water used is kept constant, the operation may need to be extended by 2 days in the worst case.

Table 7.23: Maximum Wash Water Flowrates Subject to MAOP of 182 barg at the Wellhead

Reservoir Pressure (barg)	Case	Maximum Wash Water Flowrate (kg/h)	Duration (days)
194	Base Case	41,400	7.2
194	Low Injectivity	32,940	9.1

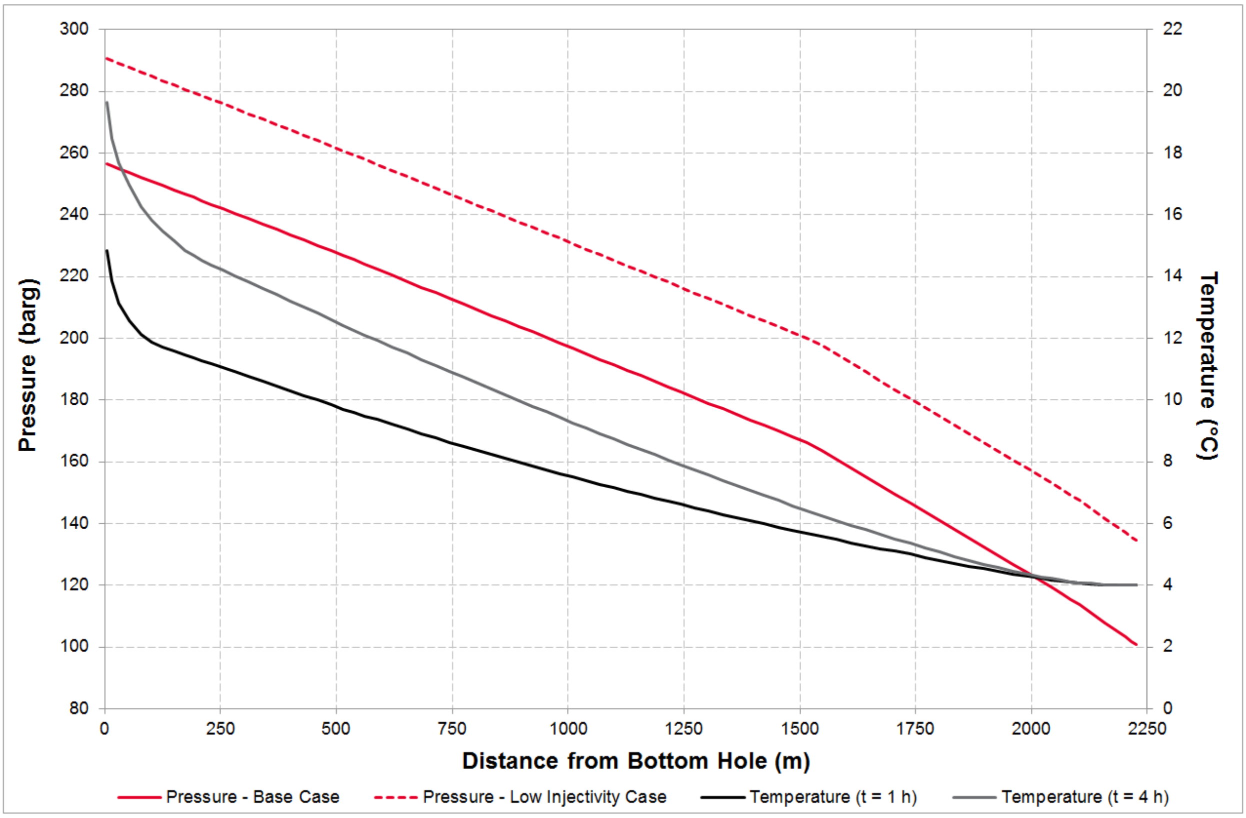
Note that the presence of halites will reduce injectivity and therefore reduce the maximum water flowrate achievable within the MAOP, but as they are removed the injectivity will start to increase and the pressure at the wellhead will reduce for a constant flowrate (how much the flowrate reduces by depends on how much halite has been deposited). This can be used to indicate the success of the wash operation.

7.14.4 Postwash MEG Flush

The pressure profile during postwash MEG flush is largely dependent on the fluid temperature at the bottom of the tubing as this will determine the reservoir injectivity. If this stage is started immediately after water wash then the initial bottom hole temperature could be as low as 11°C; it is assumed that this is the case for the purpose of this study as this would give the maximum pressure upstream of the wellhead.

Figure 7.72 shows the pressure and temperature profiles in the tubing during this stage. The results show that the operating pressure at the wellhead is about 100 barg for the base case and 135 barg for the low injectivity case. The bottom hole temperature continues to increase throughout the 4 hours of flushing, rising by approximately 9°C from its initial value.

Figure 7.72: Pressure, Temperature and Water Fraction Profiles during Postwash MEG Flush with an injectivity of 1.9 x 10-7 kg/s/Pa, 150 barg Reservoir Pressure, Winter Conditions



Based on these findings, the pressure at the wellhead, when the reservoir pressure increases to 194 barg, would not exceed the MAOP upstream of the wellhead of 182 barg, even with the low injectivity assumption. This is illustrated in Table 7.24. This is because of the lower flowrate associated with the MEG flush compared to the water wash operation.

Table 7.24: Wellhead Pressure during Postwash MEG Flush for Different Cases

	Wellhead Pressure during Postwash MEG Flush (barg)	
Reservoir Pressure (barg)	Base Case	Low Injectivity
150	101	135
194	145	179

7.14.5 Start-up Post Water Wash

Following the water wash operation, and the subsequent MEG flushing, the well is ready to receive CO_2 from the pipeline. It should be noted that because each well is water washed individually, the pipeline would still be operating.

The main aim of this analysis is to determine the operating pressures and temperatures during the well restart, and assess the likelihood of hydrate formation.

The simulations were carried out on a single well, with a pressure source set at the platform pressure corresponding to the case being considered. A low reservoir pressure was used (150 barg) as this will give the lowest shut-in pressure at the wellhead and therefore the greatest pressure drop across the choke and hence the greatest J-T cooling. It should be noted that there would be the facility to inject nitrogen into the wellhead to increase the wellhead pressure and therefore reduce the J-T cooling. This has not been considered as a worst case because the resulting CITHP would be higher (due to lower density of nitrogen) and therefore resulting temperatures downstream of the choke valve would be warmer (and less conservative).

The model was restarted from the post-water wash MEG flushing. During the water wash operation the CO_2 present in the well tubing is fully displaced down into the reservoir. It is assumed that following the water wash operation, and MEG flush, there is sufficient water/MEG around the near bore that no CO_2 is produced back into the tubing. Therefore prior to the restart with CO_2 the well tubing is completely liquid filled.

Figure 7.73 shows the pressure and temperature upstream and downstream of the wellhead choke during a restart post water wash. The initial pressure downstream of the choke is 11 barg, but this quickly increases to approximately 39 barg as the valve is opened at time = 5 minutes. The temperature downstream of the choke drops to -13°C due to the J-T cooling before recovering to a steady state value of -1.7°C.

Figure 7.73: Pressure and Temperature at Wellhead During Post Water Wash Start-up

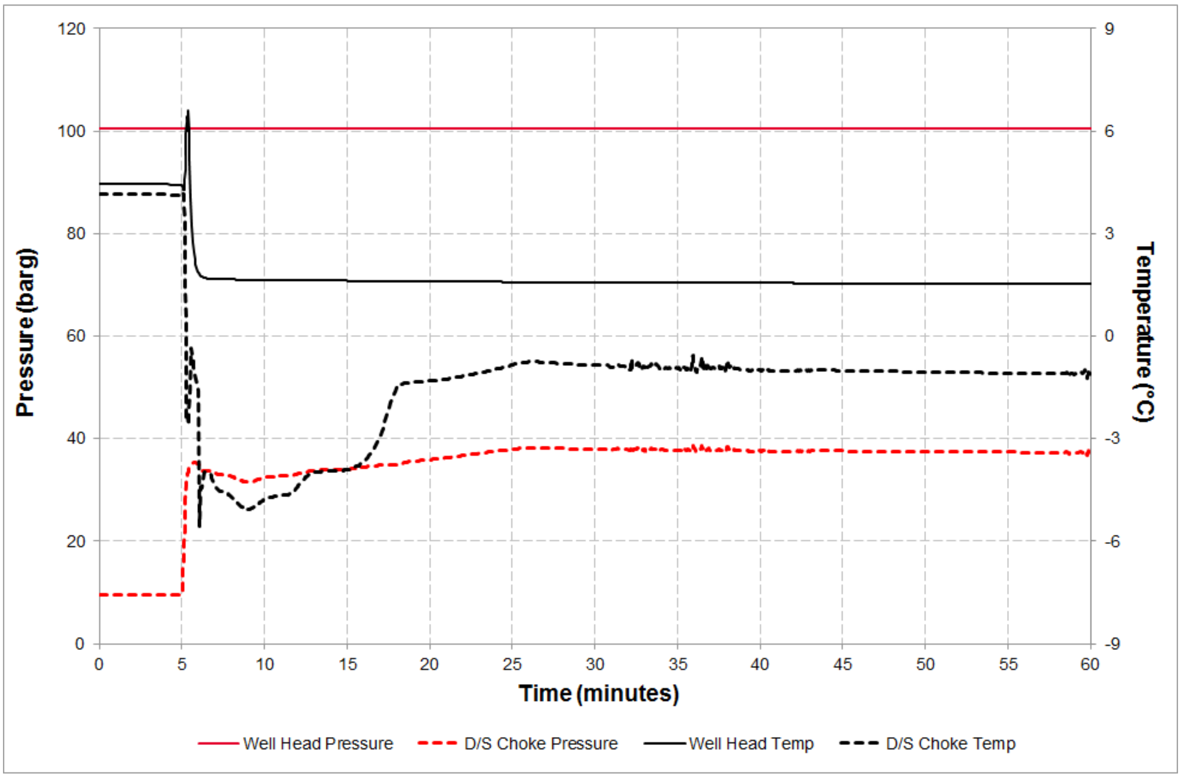
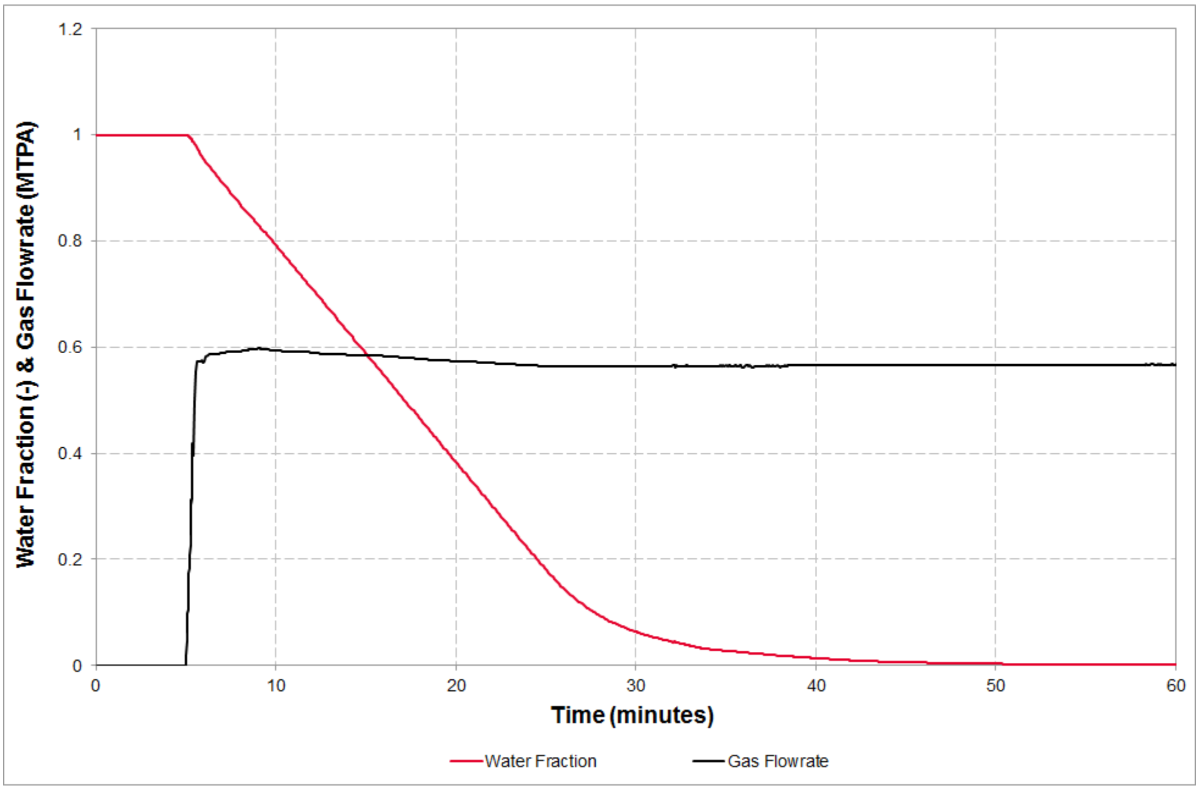


Figure 7.74: Water Fraction in Tubing and Gas Flowrate During Post Water Wash Start-up



During the restart of the wells the CO_2 entering the wells pushes the liquid (57wt% MEG) down into the reservoir. This is illustrated in Figure 7.74, where the water fraction decreases steadily before reaching zero after ~50 minutes.

The gas rate is also shown in Figure 7.74. For this simulation the valve was opened to achieve a steady state gas flow of 0.58 MTPA. Additional simulations were performed to look at the sensitivity on temperature with gas flowrate. The results are shown in Table 7.25.

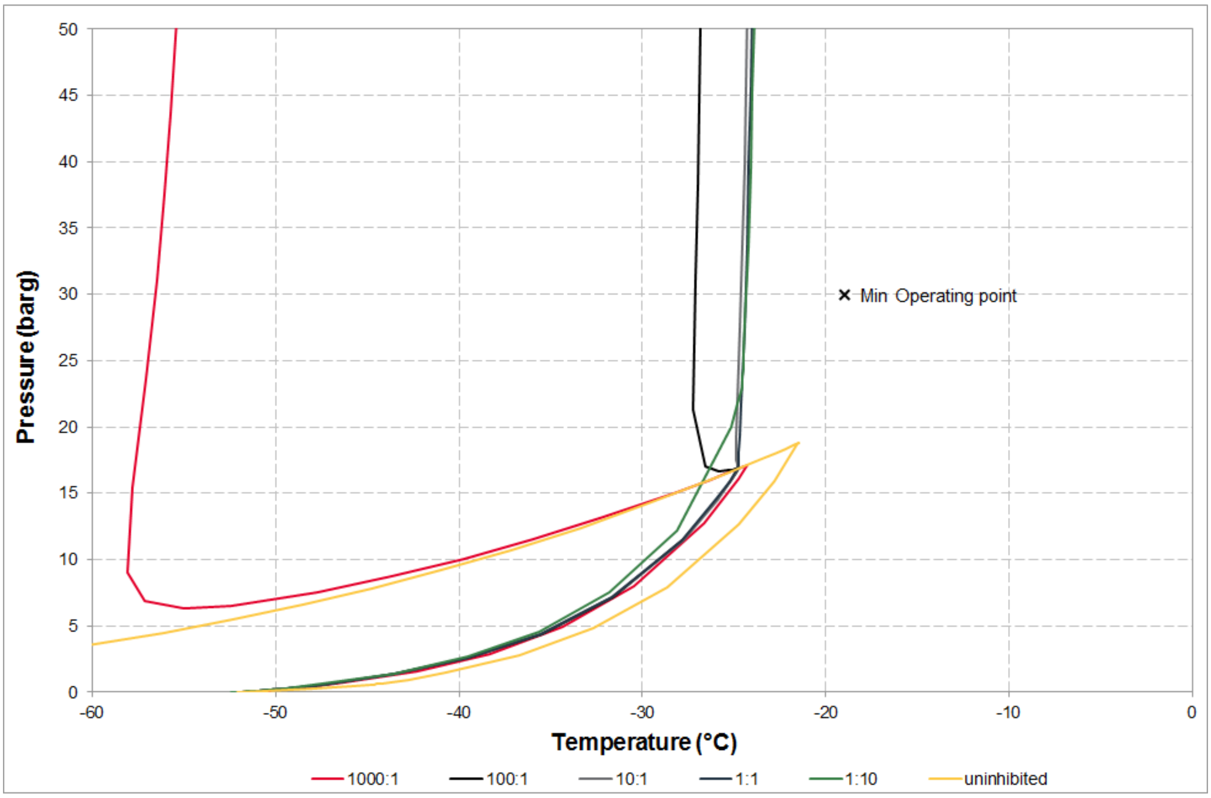
Table 7.25: Minimum Temperatures Predicted During Post Water Wash Restart

Steady State Gas Flowrate (MTPA)	Peak Initial Gas Flowrate (MTPA)	Minimum Temperature D/S Choke (C)
0.66	0.68	-16
0.58	0.61	-14
0.49	0.51	-15
0.49	0.49	-19

The low temperatures associated with this operation presents a risk of hydrate formation given the presence of water in the system. The CO_2 is flowing into the tubing, which has already been filled with 57wt% MEG. As the CO_2 flows into the well there will be a degree of mixing at the interface, however the mixing characteristics are very difficult to predict with any certainty. Therefore a range of CO_2 impurities composition and MEG solution blends were considered and the hydrate formation curves associated with them were plotted. These are shown in Figure 7.75, with the blended ratios for CO_2 impurities composition to 57wt% MEG, on a weight basis. It can be seen that the highest hydrate formation temperature predicted at the pressures we are operating at (~30 barg at the wellhead), occurs with the higher MEG concentrations, and that these temperatures are well below the minimum temperatures being predicted during start-up. Note that the ‘Uninhibited’ formation curve is for the undersaturated composition water concentration, not a CO_2 water-saturated composition.

It is acknowledged that in later life operation the pressure upstream of the choke could be higher due to the higher flowrates to the other wells. However during later life the reservoir pressure is also predicted to be higher also resulting in a pressure drop across the choke during start-up of the well, and the subsequent J-T effect, similar. It has already been shown in Table 7.11 that even with an upstream pressure of 182 barg the minimum theoretical temperature downstream of the choke was only -20°C, which is still above the hydrate formation temperature.

Figure 7.75: Hydrate Curves for Varying CO2 Impurities Composition to 57wt% MEG Ratios



The hydrate equilibrium curve exhibits behaviour that does not follow the "usual" behaviour when increasing the MEG concentration. In hydrocarbon systems, typically increasing the MEG content moves the hydrate curve to the left (i.e. for a given pressure, the hydrate equilibrium temperature is lower for increasing MEG content, i.e. hydrates are harder to form). However, for CO_2, as the water content is so low when there is no MEG present, the hydrate curve is extremely narrow, with hydrates only able to form within the yellow curve shown above (i.e. hydrates cannot form at pressures above 20 barg at any temperature). As the MEG content increases, so does the water content, so hydrates are more readily formed as there is more water available, despite the presence of MEG (hydrates still require very cold temperatures to form – for the 1000:1 blend the temperature must be below -50°C). As the MEG concentration (and hence water concentration) continues to increase, the hydrate equilibrium curve continues to shift to the right (easier to form hydrates) until a certain MEG and water concentration is reached. Thereafter, MEG starts to suppress hydrate equilibrium (starts to move the curve to the left again).

7.14.6 Water Wash Summary

Prewash MEG flush with a flowrate of 7,071 kg/h results in the pressure upstream of the wellhead remaining below the MAOP of 182 barg.

With a reservoir pressure of 150 barg, performing water wash in winter could result in wellhead pressures of around 146 barg, increasing up to 177 barg if water temperature does not rise as modelled while flowing down the tubing. The MAOP at the wellhead could be exceeded if the operation is not changed when the reservoir pressure increases later in field life. Injecting the same total volume of wash water over 9 days instead of 7 should prevent this from happening under the most conservative scenario considered.

The operating pressure at the wellhead during postwash MEG flush is not expected to exceed the MAOP in any case. The highest pressure would occur if MEG flush is started immediately after water wash, reaching 179 barg in the worst case.

Start-up following the water wash operation is not predicted to result in hydrate formation due to the MEG flushing prior to start-up, despite temperatures down to -19°C being predicted. Low temperatures can also be further mitigated by making use of the facility to inject nitrogen into the well prior to start-up to reduce J-T cooling.

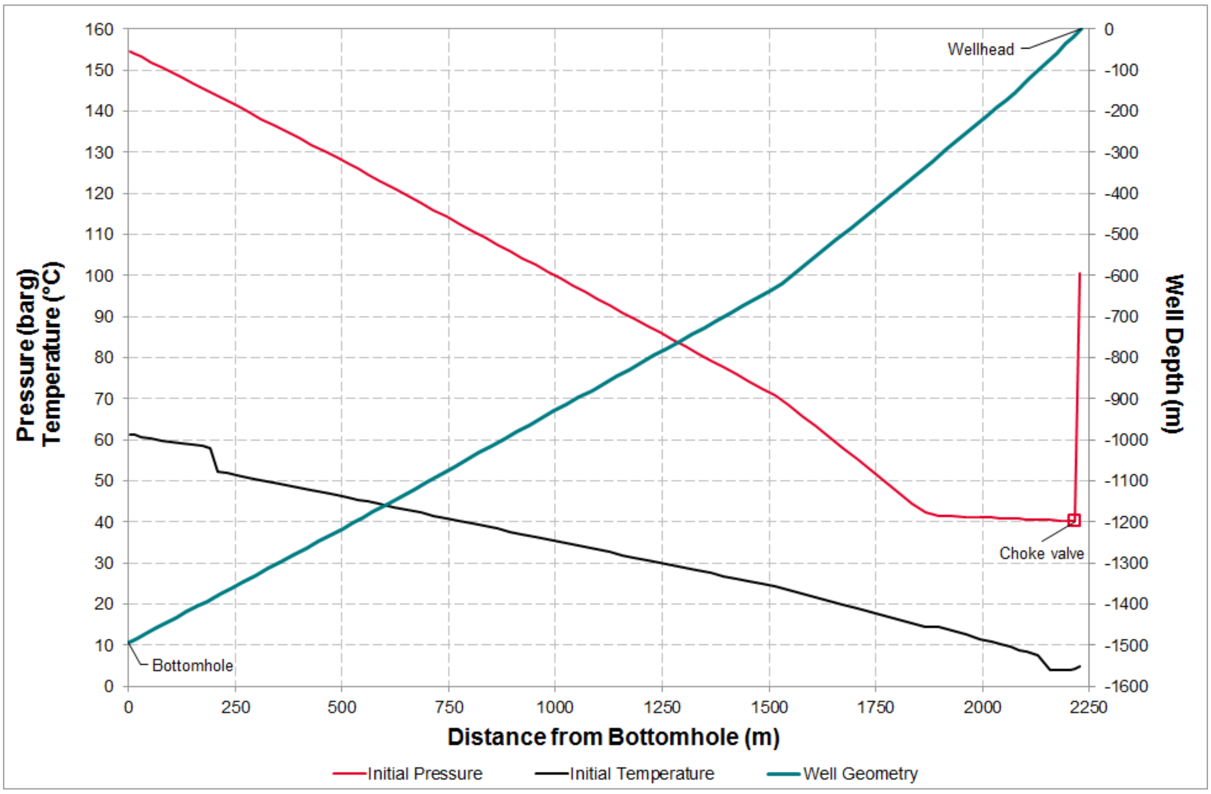
7.15 Initial Wells Inventory

This analysis is concerned with the pressurisation of the wells with CO_2 during first start-up. It is assumed that as part of the commissioning procedures, the wells have been cleaned out with inhibited brine and left full of inhibited brine by the drilling contractor. After pressurising the platform with dense phase CO_2, the following steps are implemented to start-up the wells:

- before opening the choke, a MEG plug (90% MEG solution) will be injected into the wellhead for mitigation of hydrate formation at the CO_2 / reservoir water interface;
- the wellheads (downstream of the choke valves) will then be pressurised up to 40 barg by the injection of nitrogen at each of the wellheads. The selection of 40 barg has been selected in order to limit the pressure drop across the choke during opening, keeping temperatures to within acceptable limits for the materials;
- the choke may then be opened while observing upstream and downstream pressures and temperatures, and the flow from Barmston / Drax commenced; and
- establish automatic choke control through the pressure controller on the injection manifold.

Based on these steps, the initial pressure, temperature and composition profiles obtained for well P5W2 are presented in Figure 7.76 and Figure 7.62. Note that the distance on the x-axis is measured starting from the bottom of the tubing. The MEG plug is not included as it is not required for the purpose of this analysis.

Figure 7.76: Pressure and Temperature Profiles along the P5W2 Tubing before Well Start-up with 150 barg Reservoir Pressure, Winter Conditions



After 10 minutes from the beginning of the simulation, the well choke is opened at a linear rate over 30 seconds up to the opening that leads to a steady state CO_2 flowrate of 0.58 MTPA. Since water will be displaced into the reservoir first, a low reservoir injectivity (estimated as 2.3 x 10^{-6} kg/s/Pa) will preside until full displacement is achieved, and hence the required choke opening during this period would be larger for the same CO_2 flowrate (see Section 7.14.1 for detailed discussion on injectivity adjustment). As observed from the composition profiles in Figure 7.78, this takes place approximately 50 minutes after the choke has been opened, at which point the choke opening is reduced to maintain a CO_2 flowrate of 0.58 MTPA.

Figure 7.77: Composition Profile along the Tubing before Well Start-up with 150 barg Reservoir Pressure, Winter Conditions

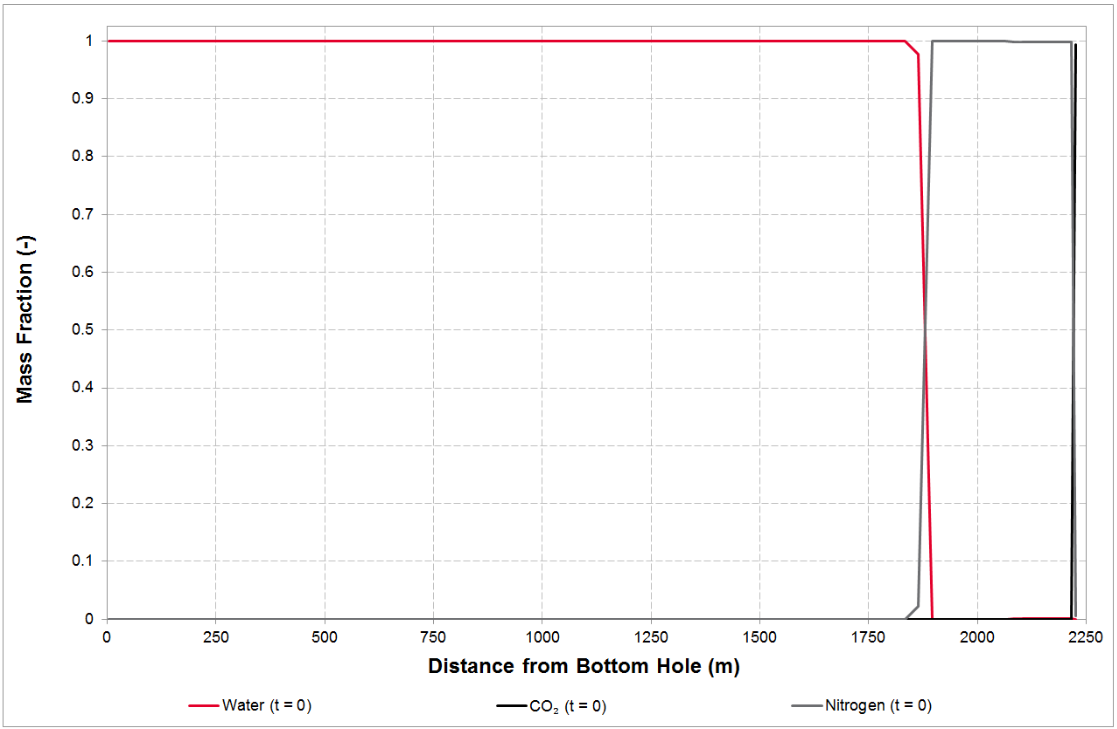
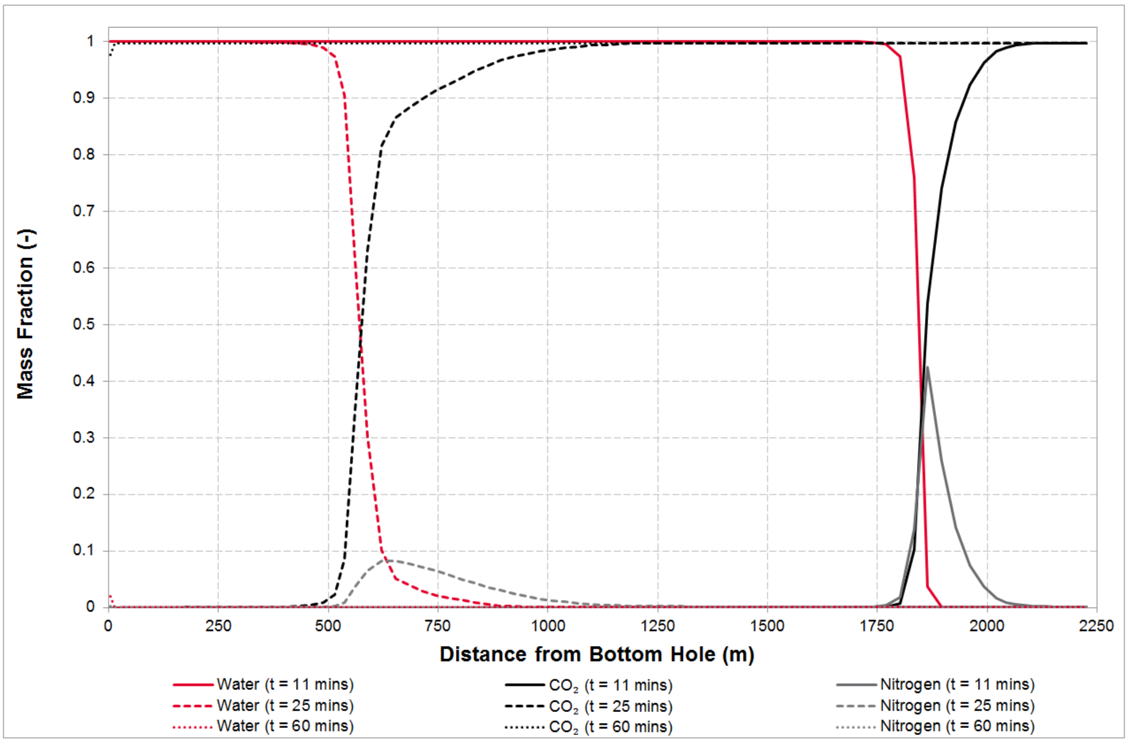


Figure 7.78: Composition Profile along the Tubing during Well Start-up with 150 barg Reservoir Pressure, Winter Conditions



The changes in CO_2 flowrate and water fraction with time are shown in Figure 7.79. When the choke is opened, the CO_2 surge into the well results in a peak flowrate of 3.3 MTPA. The flowrate then declines and fluctuates for a couple of minutes as a result of the pressure wave, before attaining a steady value downstream of the choke valve approximately 25 minutes after start-up. The surge is not seen at the bottomhole location as the volume of the well tubing dampens the CO_2 spike downstream of the choke. Fluctuation in CO_2 flowrate downstream of the choke is exacerbated by numerical instabilities in OLGA caused by two-phase operation.

Figure 7.79: Changes in CO2 Flowrate and Water Fraction in the Tubing during Well Start-up with 150 barg Reservoir Pressure, Winter Conditions

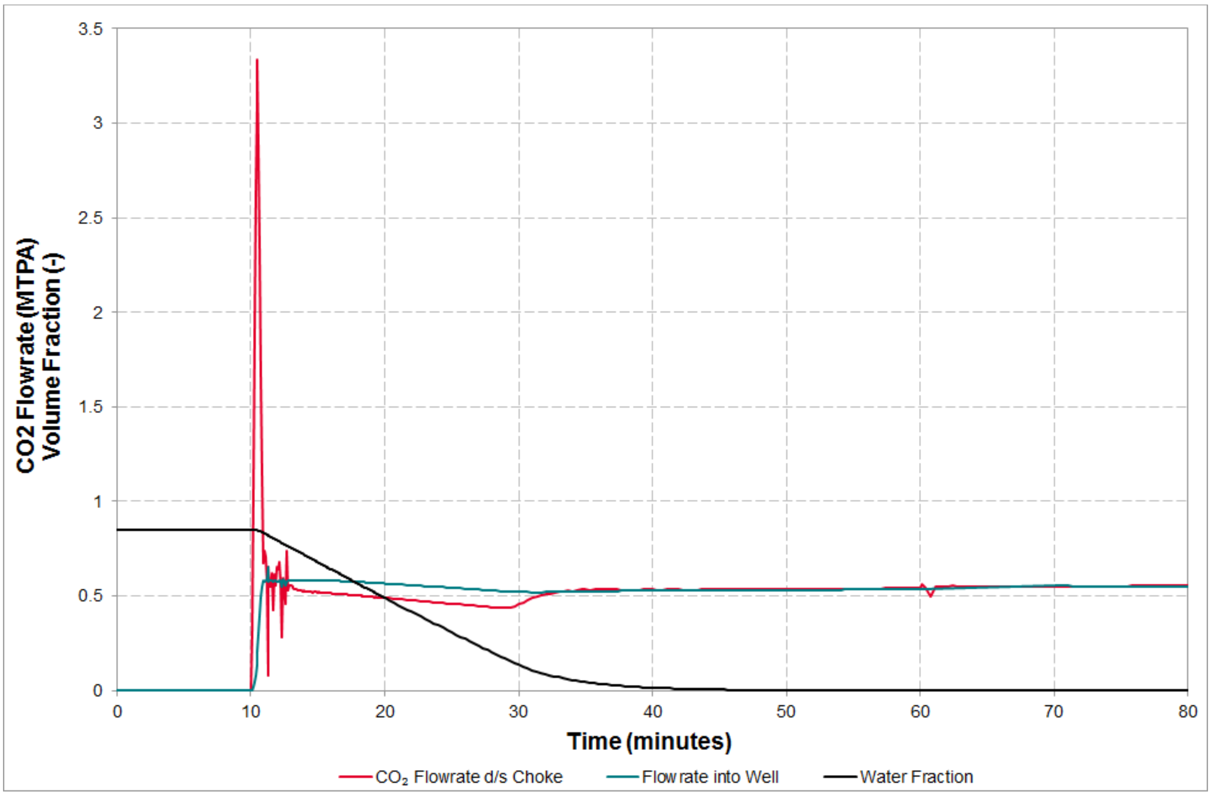
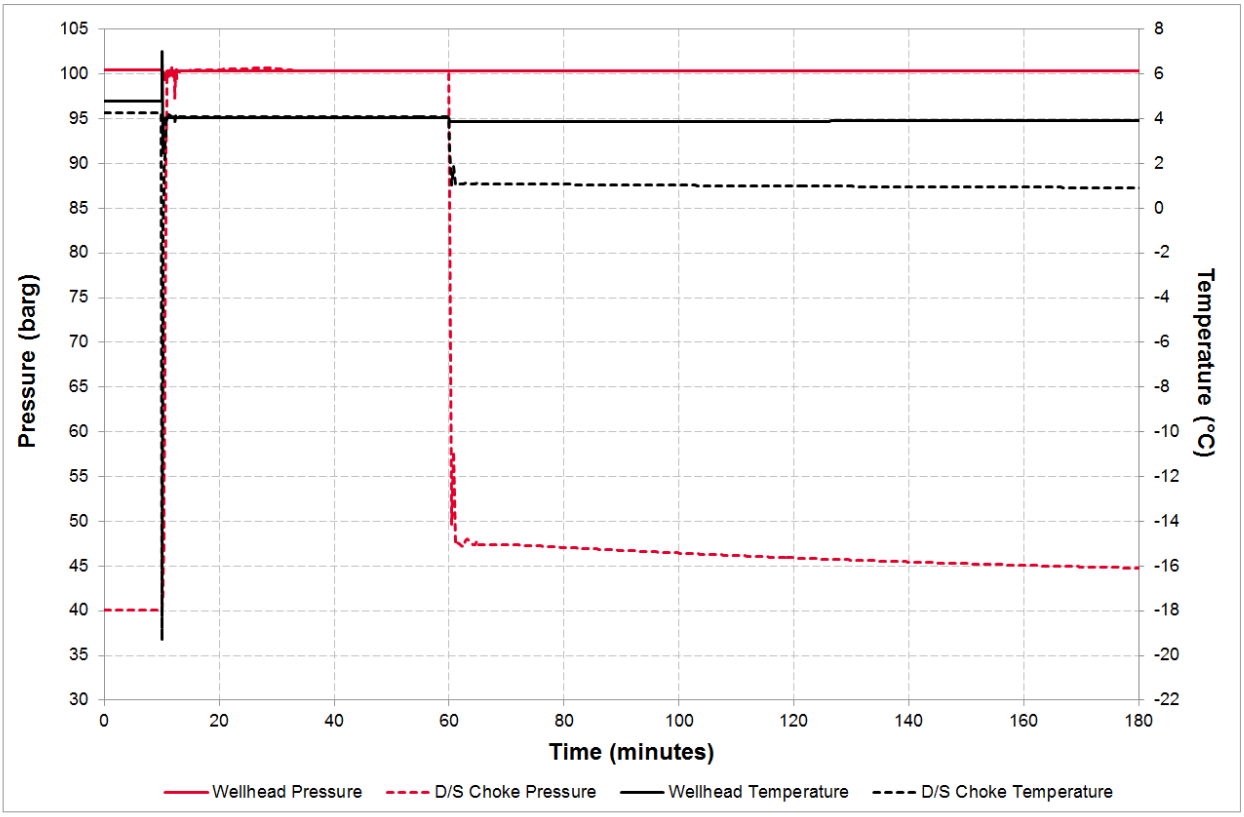


Figure 7.80 shows the pressure and temperature changes in the tubing during start-up. The J-T cooling effect results in a temperature drop to -19.3°C downstream of the choke. The pressure drop at t = 60 minutes results from reducing the choke opening to maintain a fixed flowrate when injectivity increases. In reality, this will depend on the rate of change of injectivity and its impact on CO_2 flowrate, as well as the flow controller/operator response.

Figure 7.80: Changes in Pressure and Temperature in the Tubing during Well Start-up with 150 barg Reservoir Pressure, Winter Conditions



7.15.1 Initial Well Inventory Summary

The minimum temperature during initial well start-up is approximately -19.3°C.

With a target CO_2 injection rate of 0.58 MTPA, it takes about 25 minutes for a constant flowrate to be established. Full brine displacement from the tubing requires approximately 50 minutes, at which point choke adjustment will be required to maintain a constant flowrate.

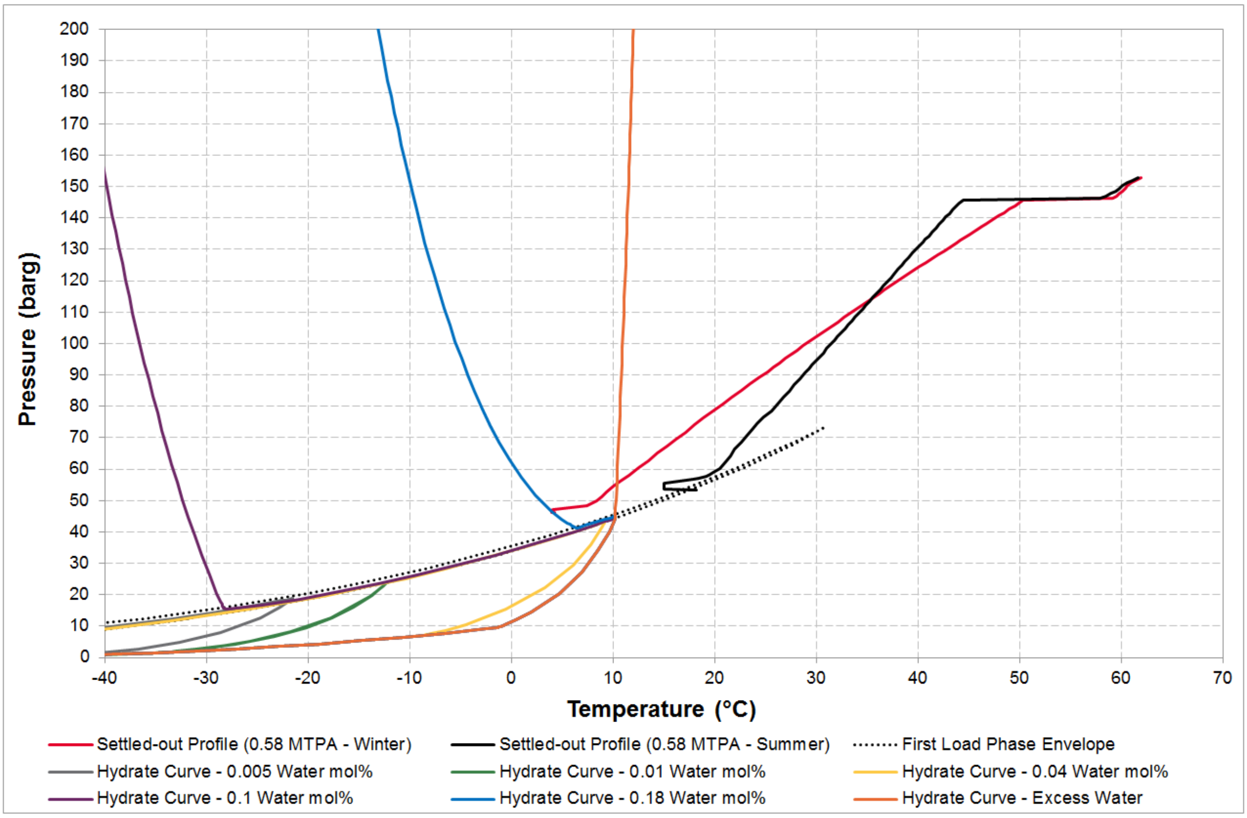
7.16 Low Pressure Well Settle-out

This section examines the settle-out conditions in wells during prolonged shutdown periods to assess impact of water content on hydrate formation risk.

The settle-out pressure and temperature profiles for two cases are plotted alongside different hydrate formation curves in Figure 7.81. The figure shows that the settle-out conditions are well outside the hydrate formation region with normal water content (0.005 mol%). As the water content is increased, the hydrate formation region continues to expand in the gas phase up to a water content of 0.1 mol%. Adding more water shifts the liquid/dense phase hydrate formation boundary to the right until there is an excess of water.

While the settle-out temperature is governed by the ambient conditions, the settle-out pressure hinges primarily on the reservoir pressure. Based on the observed shape of the hydrate phase boundary, the risk of hydrate formation increases with lower settle-out pressures; hence the worst case is associated with the lowest reservoir pressure (150 barg) in winter conditions. It can be seen that a water content of 0.18 mol% would cause the hydrate formation curve to intersect with the settled-out profile in this case. The intersection occurs at the seabed where the minimum ambient temperature exists and the fluid in the tubing is in the liquid phase. In summer conditions, vapour break-out takes place at the top of the liquid CO_2 column, but the settle-out conditions remain outside the hydrate formation region irrespective of the water content.

Figure 7.81: Settle-out Pressure and Temperature Profiles in P5W2 Well with Hydrate Formation Curves for Different Water Contents

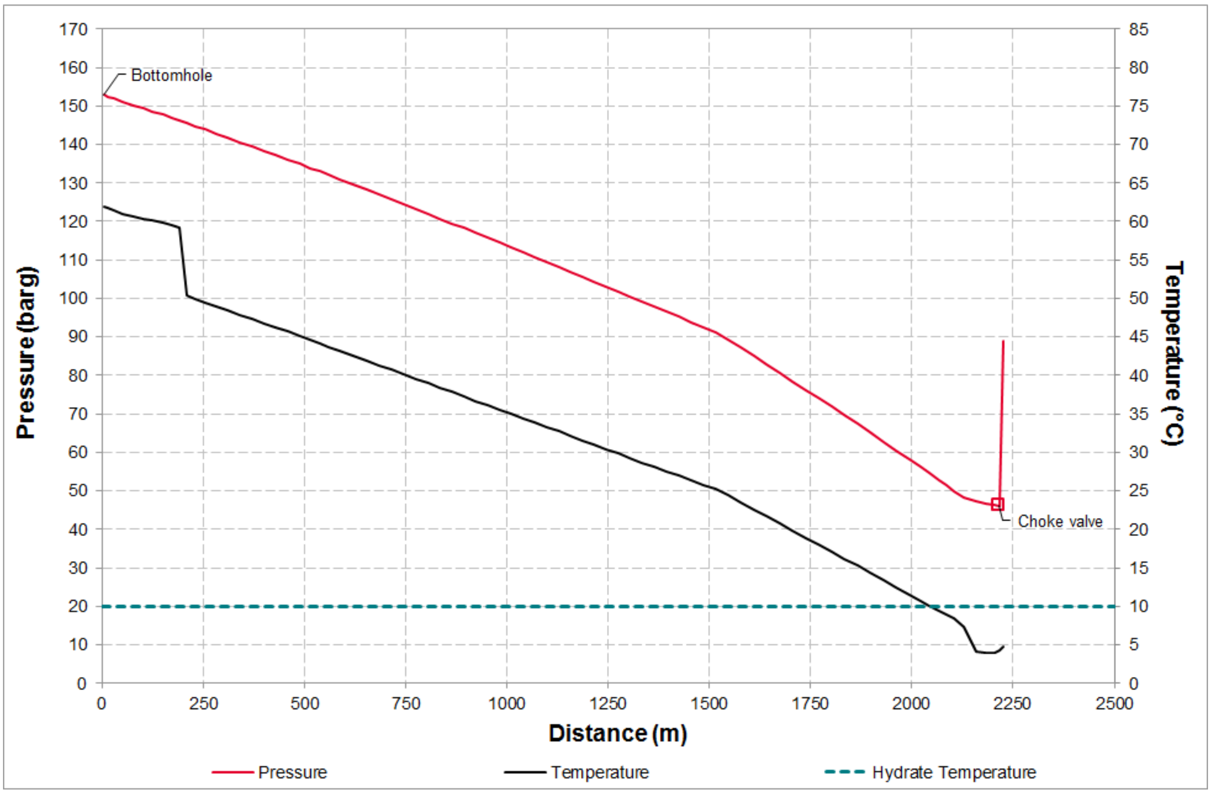


There are two things to note regarding settle-out conditions in winter however:

1. Aquifer water would have to ingress a long way up the tubing to cause a hydrate risk during low pressure well settle-out. Figure 7.82 shows that where the hydrate region is entered (at 10°C), it is more than 2,000 m from the bottom of the well tubing and water would need to be present here to form hydrates. Due to the geothermal gradient in the well, water ingress to depths below this would not cause hydrates in this settle-out condition.
2. The salinity of the aquifer has not been taken into account in calculating the hydrate curves. The salinity would suppress hydrate formation, moving the hydrate curves to the left. Although dependent on the salinity of the aquifer, suppression of more than 5°C would mean that conditions at the top of

the tubing would be outside the hydrate region. This would need to be confirmed when the aquifer saline composition is known.

Figure 7.82: Settle-out Pressure and Temperature Profiles in P5W2 Well – Winter Conditions



7.16.1 Low Pressure Well Settle-out Summary

The highest risk of hydrate formation during well settle-out is associated with the lowest reservoir pressure (150 barg) in winter. If the water content in CO_2 increases to 0.18 mol%, the settle-out conditions cross into the hydrate formation region at the seabed. Pipeline entry specifications should prevent this.

Water would have to ingress 2,000m up the well tubing to reach CO_2 at the hydrate temperature. Due to the geothermal gradient, water below this would be in contact with CO_2 at temperatures outside the hydrate region.

Aquifer salinity, not accounted for in this calculation, would suppress the hydrate curve, further reducing the risk of hydrate blockage in low pressure settle-out conditions.

8 Conclusions from Transient Analysis

8.1 General

- Modelling two-phase impure CO_2 presents a unique challenge due to the narrow phase envelopes and large changes in fluid properties for small changes in operating conditions (compared with hydrocarbon systems).
- These challenges, however, can be overcome by combining simulation results with a theoretical approach for two-phase operations.

8.2 Initial Start-up

- CO_2 arrives at the platform after approximately 4 days, with all the air displaced after ~5.25 days (at a flowrate of 2.68 MTPA).
- It takes approximately 4 weeks to displace air fully from the pipeline at a flowrate of 0.58 MTPA.

8.3 PIG Operations

- The average PIG velocity at First Load (2.68 MTPA) is within the acceptable range in the Drax to Camblesforth (300 mm nominal diameter) onshore pipeline section only; Camblesforth supply would need to be online, supplying a total of ≥3.8 MTPA (Drax plus Camblesforth) to achieve an average PIG velocity of 0.5 m/s in the 600 mm nominal diameter onshore and offshore pipelines.
- PIG operations at the design flowrate of 17 MTPA results in a PIG velocity below the 3 m/s maximum pig velocity limit, therefore CO_2 supply from Drax and Camblesforth do not need to be turned down for PIG operations, however PIG velocities might need to be controlled for in-line inspection depending on the optimum speeds.
- Confirmation of acceptable PIG velocity range (assumed to be 0.5 m/s to 3 m/s) with PIG vendors is required.
- The pipeline pressure does not transgress the minimum and maximum operating pressure constraints during PIG operations.

8.4 Turndown

- When bypassing the pumping station at Barmston in Years 1 to 5, pressure settles within 2 hours following turndown from 2.68 MTPA.
- The pressure settles within 2 hours in the onshore pipeline and within 15 hours in the offshore pipeline following turndown from 10 MTPA.
- At higher flowrates, when the Barmston pump is operating, the pressure control settings need to be adjusted to the target conditions prior to turndown being carried out to ensure the pressure in the pipeline does not fall below 90 barg and to ensure there is sufficient pressure differential across the pump to prevent cavitation.

- The temperatures through the pipeline (particularly at low flowrates in winter conditions) can take several days to reach steady state.
- Settle-out time in the offshore pipeline is highly dependent on the pump characteristics and control system settings.

8.5 Ramp-up

- When bypassing the pumping station at Barmston in Years 1 to 5, pressure settles within 2 hours following ramp-up to 2.68 MTPA.
- The pressure and temperature settle within approximately 1 hour in the onshore and offshore pipelines following ramp-up to 10 MTPA from turndown operation.
- Settle-out time in the offshore pipeline is highly dependent on the pump characteristics and control system settings.
- The pump suction and platform arrival pressure setpoints should not be changed to the final desired values until after ramp-up has been completed to avoid the risk of the pressure in the pipeline falling below 90 barg.
- Bringing a new well online before ramp-up results in a drop in pressure downstream of Barmston, but this is not expected to cause any concerns with effective suction pressure control in place.

8.6 Cooldown

- Cooldown durations are between 15 and 21 hours for the onshore sections during summer ambient conditions, but fluid at the platform end of the offshore section reaches ambient within 1 hour.
- Cooldown during winter ambient conditions takes ~40 days due to the higher initial difference in operating and ambient temperatures.
- During cooldown to winter ambient temperatures, with the impurities composition, the lower temperatures results in operating pressures and temperatures entering the two-phase region. Pressures as low as 65 barg are predicted for the high point between Camblesforth and Barmston.

8.7 Restart

- Restart simulations from a warm start-up reached thermal steady state after approximately 10 hours, with the pressure reaching steady state in a similar time.
- Cold restart simulations (starting from a pipeline at minimum ambient temperature) took in excess of 5 days to reach thermal steady state due to the time required to heat the soil surrounding the onshore (and part of the offshore) pipeline, but reached a steady pressure within approximately 10 hours.

8.8 Depressurisation

- A pipeline minimum design temperature of 0°C is not practical as depressurisation causes excessively low fluid (and pipeline inner wall) temperatures as the gas expands (J-T cooling) and due to the pipe wall supplying the heat of vaporisation to the fluid as it starts to vaporise/boil.

- The lower the minimum design temperature of the pipeline the quicker that depressurisation can take place as the reduction in pressure whilst maintaining the temperature above the minimum design is greater.

- Peak CO_2 vent rates deplete as pipeline pressure reduces and should be considered for dispersion analysis.

8.9 Leak Detection

- The reduction in pressure due to a leak can be detected quicker at higher flowrates, but the resulting mass of CO_2 leaked to the atmosphere is not significantly different as the leak is based on 2.5% of the total flowrate.

- Leaks of 2.5% of the total flowrate could be detected within 0.5 to 3.5 hours.

8.10 Line Pack

- Due to the short packing time (0 to 9 minutes), an automated response may be required to avoid exceeding the MAOP in the onshore pipeline as a result of:
  1. a valve shut-in at Camblesforth at any stage of operational life; or
  2. a valve shut-in at any location while operating at 17 MTPA.

- Pressure control at the platform (Years 1 to 5) and the pump suction (after Year 5) limit the impact of flowrate changes on upstream sections. The pipeline downstream of Barmston will be susceptible to notable pressure changes when the pump speed is adjusted based on the flowrate.

- Taking a well offline without changing production rates could lead to exceeding the MAOP within hours. The time available to avoid this outcome decreases from around 9 hours in Years 1 to 5 to less than an hour after Year 10.

8.11 Daily Swing

- Daily ambient temperature swing is unlikely to have a significant impact on the stability of the system during operation.

8.12 Maximum Pipeline Inventory

- The maximum pipeline inventory under steady state conditions is about 39.1 kT.

8.13 Pipeline Unpacking

- When the supply of CO_2 from Drax and Camblesforth is shut-off, the pressure at the peak elevation falls below 90 barg almost immediately if CO_2 injection into the wells is not stopped. A marginally longer unpacking time (2 to 6 minutes) is expected when the initial flowrate is 17 MTPA.

8.14 Pressure Surge Due to ESD Valve Closure

- The maximum pipeline pressure is below the maximum incidental pressure in the onshore and offshore pipelines; therefore pressure surge following sudden ESD valve closure (hammer) does not cause a pipeline integrity issue.

- The lack of appreciable pressure surge is due to the compressibility of the dense phase CO_2, which is significantly higher than a liquid (e.g. liquid water), and the ESD valve closure time.

8.15 Water Wash

- Prewash MEG flush with a flowrate of 7,071 kg/h results in the pressure upstream of the wellhead remaining below the MAOP of 182 barg.

- With a reservoir pressure of 150 barg, performing water wash in winter could result in wellhead pressures of around 146 barg, increasing up to 177 barg if water temperature does not rise as modelled while flowing down the tubing. The MAOP at the wellhead could be exceeded if the operation is not changed when the reservoir pressure increases later in field life. Injecting the same total volume of wash water over 9 days instead of 7 should prevent this from happening under the most conservative scenario considered.

- The operating pressure at the wellhead during postwash MEG flush is not expected to exceed the MAOP in any case. The highest pressure would occur if MEG flush is started immediately after water wash, reaching 179 barg in the worst case.

- Start-up following the water wash operation is not predicted to result in hydrate formation due to the MEG flushing prior to start-up, despite temperatures down to -19°C being predicted. Low temperatures can also be further mitigated by making use of the facility to inject nitrogen into the well prior to start-up to reduce J-T cooling.

8.16 Initial Well Inventory

- The minimum temperature during initial well start-up is approximately -19.3°C.

- With a target CO_2 injection rate of 0.58 MTPA, it takes about 25 minutes for a constant flowrate to be established. Full brine displacement from the tubing requires approximately 50 minutes, at which point choke adjustment will be required to maintain a constant flowrate.

8.17 Low Pressure Well Settle-out

- The highest risk of hydrate formation during well settle-out is associated with the lowest reservoir pressure (150 barg) in winter due to the potential for water ingress from the aquifer. If the water content in CO_2 increases to 0.18 mol%, the settle-out conditions cross into the hydrate formation region at the seabed.

- Water ingress would have to be substantial (approximately 2,000 m up the tubing) to be in contact with CO_2 at a pressure and temperature within the hydrate region, therefore risk of hydrates in this scenario is low.

9 Recommendations Derived from Transient Analysis

- PIG operations on the larger diameter pipelines should be minimised for velocities below 0.5 m/s, pending feedback from PIG vendors.

- The following orifice sizes are recommended for blowdown:

Pipeline Section	Recommended Orifice Size
300 mm Onshore Pipeline	0.5 inch
600 mm Onshore Pipeline	1 inch
600 mm Offshore Pipeline	1 inch

- MEG injection system design needs to be re-visited once reservoir injectivity with MEG/water is finalised and MEG injection calculations redone.

- Consider performing thermal load analysis during depressurisation during detailed design.

10 Glossary

Abbreviations	Meaning or Explanation
AG	above ground
AGI	Above Ground Installations
barg	Bar Gauge
BFD	Block Flow Diagram
°C	Degrees Celsius
CCP	Carbon Capture Plant
CCS	Carbon Capture and Storage
Charpy test	A standardized high strain-rate test which determines the amount of energy absorbed by a material during fracture.
CITHP	Closed in Tubing Head Pressure
CO_2	Carbon Dioxide
CPL	Capture Power Limited
DECC	The UK Government's Department of Energy and Climate Change
Dense Phase	Fluid state that has a viscosity close to a gas while having a density closer to a liquid. Achieved by maintaining the temperature of a gas within a particular range and compressing it above its critical pressure.
EBD	National Grid's European Business Development group.
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
FEED	Front End Engineering Design
FEED Contract	Contract made between DECC and CPL pursuant to which WR Project FEED (as defined) will be performed.
GPa	Giga Pascal
GPU	Gas Processing Unit – processes the flue gases to provide the dense phase carbon dioxide
h	hour
in.	inch
JT cooling	Joule Thompson cooling occurs when a non-ideal gas (such CO_2) expands from high to low pressure at constant enthalpy (theoretically with no heat exchange with the environment).
KKD	Key Knowledge Deliverable
km	Kilometre
KSC	Key Sub-Contract
kT	Kilo Tonne
mm	Millimetres
MAOP	Maximum Allowable Operating Pressure
MEG	Monoethylene Glycol
Mol%	Percentage by molar weight
MTPA	Million Tonnes Per Annum
MW	Mega Watt
NC	normally closed
ND	Nominal Diameter
NGCL	National Grid Carbon Limited
NGCL EPC Sub-contractors	Contractors providing an offer to develop a part of the WR T&S Assets in pursuance of the WR Development Project.
NGCL FEED Sub-contractors	Contractors entering into a contract with NGCL to carry out a part of the obligations under the KSC.
NGCL KSC	Contract made between CPL and NGCL pursuant to which that part of the WR Project FEED

Abbreviations	Meaning or Explanation
	(as defined) which appertains to the WR T&S assets will be performed.
NGCL KSC Deliverables	A number of documents and services, the delivery of which is a contractual obligation under the KSC.
NGCL Technical Assurance Team	EBD team responsible for providing independent technical auditing and peer review services to the WR T&S FEED Project.
NGCL WR Team	The NGCL team established to meet the obligations in the KSC.
NNF	normally no flow
NUI	Normally Unmanned Installation. A term usually applied to an offshore installation.
OPP	Oxy Power Plant
PFD	Process Flow Diagram
PIG	Pipeline Inspection Gauge: a unit, which is inserted into the pipeline, to clean and/or monitor the inner bore surface of the pipe.
t	tonne
T&S	Transportation and Storage
UG	underground
UK	United Kingdom
VSD	Variable Speed Drive
WR	White Rose
WR Assets	All those assets that would be developed pursuant to the WR Project
WR Development Project	A project to develop, operate and decommission the WR Assets which may transpire following the completion of the WR FEED Project.
WR FEED Project	Project to carry out a FEED (as defined in the FEED Contract) with regard to the WR Assets.
WR Project	White Rose CCS Project
WR T&S Assets	That part of the WR Assets which would carry out the carbon dioxide transportation and storage functions of the WR Project and to which the KSC Contract relates.
WR T&S FEED Project	The project to be pursued by NGCL in order to meet its obligations under the NGCL KSC.
wt%	Percentage by weight