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TNO report

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Porthos - CO2 injection

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Summary

This report presents the results of a flow assurance analysis of the first elements of an offshore CO_2 transport and storage network that is being designed by the Porthos consortium. The network is intended to transport CO_2 from industrial sources in the Rotterdam harbour to offshore depleted gas fields. The scope of the flow assurance study was the offshore pipeline from the compressor outlet, from the Maasvlakte to the P18-A platform, and up to four injection wells in the P18-2 and P18-4 fields. These activities are part of TNO project 060.33502.

The goal of the simulations is to evaluate the operating envelope within pre-described boundary conditions and restrictions. The goal of this project is to:

- Define the required compressor discharge conditions (pressure and temperature)
- Evaluate potential start-up and shut-in procedures and evaluate any showstoppers in these processes.

Evaluation of the sizing of the main pipeline was part of the phase-1 activities and as such is not covered in this report.

To obtain the goals the following activities have been done:

- Transient simulations to obtain steady state operating conditions. In the simulations, the effect on the steady state results were evaluated for:
    - Variation well diameter
    - Variation reservoir parameter (pressure and accompanying injectivity index)
    - Variation wellhead temperature (for single well models)
    - Variation compressor outlet temperature
    - Variation pipeline pressure control
- Start-up simulation
    - Different starting conditions (gas, two-phase, liquid) conditions in the pipeline.
    - Variation of the reservoir pressure.
- Shutin/turn-down simulations
    - Variation reservoir pressures.
    - Variation shutin valve closure time.

For steady state conditions the following conclusions are found:

- At low reservoir pressure (20-40 bar), no steady state solution is found which comply with both the topside and downhole temperature restrictions when the pipeline pressure is maintained in the liquid state. Therefore, at low reservoir pressure the pipeline must be operated in gas or two-phase conditions. This puts limitations on the maximum injection rates per well or for all four wells combined.
- At reservoir pressures (40-300 bar), the required flow rate (170 kg/s) is achieved using four wells.
- At close to the maximum reservoir pressures, the compressor outlet temperature needs to be reduced. Otherwise no injection is possible.

For depressurization the following conclusions are found:

- The heat ingress in the pipeline is limited. Therefore, during depressurization or emptying the pipeline the temperature follows the pressure via the phase line and low temperatures conditions can occur in the complete pipeline. Therefore, a pressure control of the pipeline is recommended.

For shutin simulations the following conclusions are found:

- During well shutin, low fluid temperatures will occur in the well downstream of the choke. The temperature will go down to the corresponding phase line temperature. At a reservoir pressure of 20 bar, this means a temperature of -37 °C. At lower reservoir pressures this will lower even further. At higher reservoir conditions, the temperature will increase. -17, -5 and +30 °C at reservoir pressures of 60, 100 and 340 bar.
- During ramp-down, low temperatures occur mainly in the top part of the well. These temperatures go well below -10 °C.
- During ramp-down also the temperature in the pipeline itself will drop down to values below -20 °C.
- The low temperatures during shutin/ramp-down are difficult to avoid and as such it is recommended that all piping should be able to withstand the low temperatures.

From the start-up simulations the following conclusions are found:

- For all reservoir conditions, at initial choke valve opening, a short period of low temperature will occur downstream of the control valves. For the start-up, a faster valve-opening is beneficial with respect to the temperatures.
- In the sequencing of well opening and compressor ramp-up, the flow rates from the pipe to the wells must not decrease too quickly to avoid too low pressures (and therefore temperatures in the well and pipeline). Therefore, the compressor ramp-up must be done relatively soon after the well opening. The compressor can be ramped-up before the well opening at higher reservoir pressures with the limit that the pipeline pressure must not be higher than 85 bar.
- At low reservoir pressure, the system could be started up from low pressure (10, 30 bar) or medium pressure (60 bar). In case of medium-pressure conditions, the downhole temperature is too low for a limited period of time (less than 500 minutes).
- At low reservoir pressure, starting from high pressure pipeline conditions leads to long periods of too low temperatures (longer than 2000 minutes).
- At medium and higher reservoir pressures start-up can be done from medium-pressure (two -phase conditions) conditions within the temperature restrictions.

The base recommended operations (based on the set restrictions) are:

- At low reservoir pressure, the pipeline is operated in the gas phase and all well chokes are kept open to avoid pressure drop. The compressor outlet temperature is set to 80 °C.

- At mid to high reservoir pressures, the compressor outlet temperature is set to 40 °C. The setting is an optimization between cooling power and compressor power.

- At very high reservoir pressures, compressor outlet temperature must be set to 40 °C, otherwise injection is not possible.

Reservoir pressure [bar]	Compressor outlet temperature [°C]	Pipeline control	Well operations
20 – 40 bar	80	30	Full open
40 – 300 bar	40 - 80	30	1 well on pressure control. Other wells on mass control
300 – 340 bar	40	30	1 well on pressure control. Other wells on mass control

During well shutin, a fast closure the choke valves leads to very low temperatures. At low reservoir pressures the shutin procedure should be leaving the wells open while shutting down the compressor.

The main recommendations include:

- All piping material should be de designed for extreme low temperatures (-40°C, based on expected wellhead pressures of 10 bar).

- Update simulation model to include full heat transfer (rather than U-value approach) at the time the well design and pipeline design is set.. This to get more detailed temperature information on pipe wall temperatures and annulus fluid temperatures.

- Considering the fact that fluid temperatures less than -10°C are probably not avoidable, the restriction of -10°C for the topside temperature should be reconsidered/re-evaluated.

- The criterion of 15°C downhole temperatures is restrictive. Alternatives for hydrate preventions should be evaluated.

- An operational guidebook should be set up which describes the number of wells and control settings for each mass flow rate.

This guidebook should also contain guidelines of start-up and shutin procedures

Contents

1 Introduction

1.1 Introduction

This report presents the results of a flow assurance analysis of the first elements of an offshore CO_2 transport and storage network that is being designed by the Porthos consortium. The network is intended to transport CO_2 from industrial sources in the Rotterdam harbour to offshore depleted gas fields. The scope of the flow assurance study was the offshore pipeline from the compressor outlet, from the Maasvlakte to the P18-A platform, and up to four injection wells in the P18-2 and P18-4 fields. These activities are part of TNO project 060.33502.

1.2 Project goals

The goal of the simulations is to evaluate the operating envelope within pre-described boundary conditions and restrictions (Chapter 2). The goal of this project is to:

- Define the required compressor discharge conditions (pressure and temperature)
- Evaluate potential start-up and shut-in procedures and evaluate any showstoppers in these processes.

Evaluating of the sizing of the main pipeline was part of the phase-1 activities and as such not covered in this report.

1.3 Project activities

To obtain the goals the following activities have been done:

- Transient simulations to obtain steady state operating conditions.
  In the simulations, the effect on the steady state results were evaluated for:
  - Variation well diameter
  - Variation reservoir parameter (reservoir pressure)
  - Variation wellhead temperature (for single well models)
  - Variation compressor outlet temperature
  - Variation pipeline pressure control
- Start-up simulation
  - Different start conditions (gas, two-phase, liquid) conditions in the pipeline.
  - Variation reservoir pressure.
- Shutin/turn-down simulations
  - Variation reservoir pressures.
  - Variation shutin valve closure time.

1.4 Report layout

Prior to discussing the simulation results an overview of the main trends in CO_2 injection are covered in Chapter 3. In Chapter 2, the boundary conditions and restrictions are presented with in Chapter 4 a discussion on the model used.

The results are presented in the Chapters 6 (steady state results), Chapter 7 (Start-up simulations), Chapter 8 (depressurization/venting) and Chapter 9 (Shutin/turn down). The Chapters 10 and 11 cover the main conclusions and discussion.

2 Boundary conditions and assumptions

2.1 Introduction

This section describes the boundary conditions and restrictions at the start of the project.

2.2 Boundary conditions

The following boundary conditions/assumptions are set in the project:

- Compressor outlet temperature 35 < T < 80 °C.
    - In the simulations a range of 40 to 80 °C is used as Gasunie had indicated that the last 5 °C required a huge investment.
- Desired flow total rates of 15 – 170 kg/s.
- A preferred mass flow rate of up to 70 kg/s per well.
- 4 wells available for injection (1 well in P18-4 compartment and 3 wells in the P18-2 compartment).
- Start reservoir pressure 20 bar; maximum Pres = 340 bar.
- Compressor control is based on suction pressure control.
    - This means that all CO_2 delivered to the low pressure network needs to be injected.
    - This means that not all the wells can be at mass flow control. This is important as from Chapter 2 it is clear that there are restrictions in mass flow rate.
- Pipeline Constraint
    - Preferred operation in single liquid phase condition.
    - Minimum discharge pressure compressor of 60 bar.
- Well Constraints
    - Downhole temperature T > 15 °C
    - Topside piping T > -10 °C
    - Erosion, Tubing vibrations, thermal/mass flow rate constraints for reservoir, thermal gradients in well (radial and axial)) are not considered at this stage

2.3 Simulation goals

The goal of the simulations are:

- Steady state results to obtain required compressor envelope
- Start-up scenarios
- Shut-in scenarios
- Discussion of cold vs warm start-up

3 General discussion

3.1 Introduction

In this chapter, some typical behaviour of CO_2 injection is discussed. This is done based on results for a simple pure vertical monobore geometry.

In section 3.2, results are presented for a free well. That means no pipeline is attached and no control choke is present at the wellhead. In section 3.3 results are presented with a control action at topside. This means for instance a pipeline pressure of pressure 85 bar and a mass controlled injection into the well.

3.2 CO_2 injection behaviour in wells free flow

3.2.1 Model description

The model used for this chapter is a simple monobore, pure vertical well of depth 3000m with a topside section of 100m horizontal (0.15m ID), with a heat transfer of 9.5 W/m2K with a vertical thermal gradient of 10 to 123 °C.

3.2.2 Base result

Some base results are given in Figure 1 with the downhole temperature and the wellhead pressure as function of mass flow rate. The behaviour can be divided into low and high reservoir pressures. Low reservoir pressure typically means up to a reservoir pressure of 50 bar. At that pressure, the accompanying phase line temperature is 15°C (for discussion on limitations and boundary conditions: Chapter 2).

At low reservoir pressure the important features are:

- The required wellhead pressure is strongly dependent on the wellhead temperature (higher temperatures require higher pressures).
- For a large range of mass flow rates, the required wellhead pressure is constant due to the fact that the wellhead is in two-phase conditions.
- The required wellhead pressure at low flow rates is (very) low.
- The downhole temperature decreases with increasing mass flow rate up to the point that two-phase conditions occur downhole. In that case the downhole temperature increases due to an increase in bottomhole pressure due to an increase reservoir pressure drop. When in two-phase conditions, the downhole temperature is independent of the wellhead temperature but only a function of the downhole pressure.
- The range of downhole temperatures higher than 15°C increases with increasing wellhead temperature.

At higher reservoir pressures the important features are:

- An almost constant wellhead pressure for all mass flow rates.
- The downhole temperature is almost always higher than 15°C and the remaining trend is that the bottomhole temperature decreases with increasing mass flow rate.

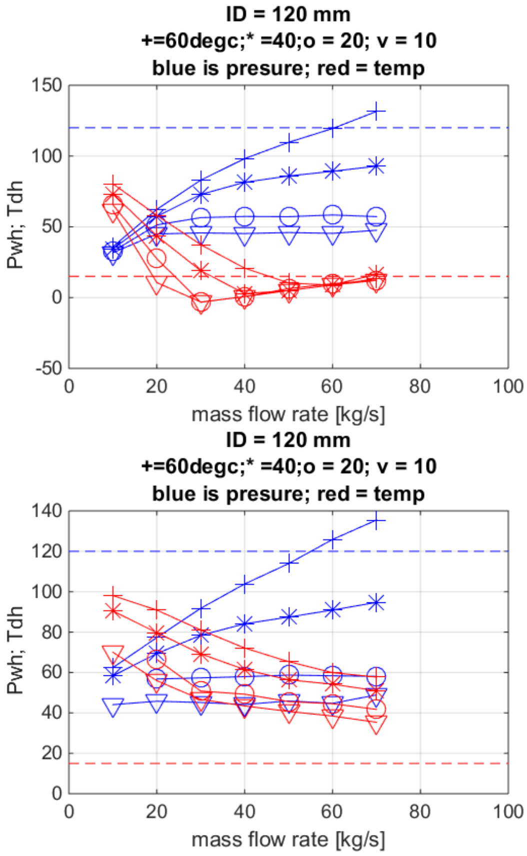


Figure 1: Wellhead pressures (blue) and downhole temperatures (red) as function of mass flow rate for a reservoir pressure of 20 bar (top) and 100 bar (bottom). Dashed lines indicate critical boundary conditions (120 bar and 15 °C). Each line is for a different wellhead temperature (10, 20, 40, 60 °C).

As example the pressure and temperature profiles in the well are plotted for:
Reservoir pressure 20 bar, Wellhead temperature 10 °C Figure 2
Reservoir pressure 20 bar, Wellhead temperature 40 °C Figure 3
Reservoir pressure 100 bar, Wellhead temperature 10 °C Figure 4
Reservoir pressure 100 bar, Wellhead temperature 40 °C Figure 5
Reservoir pressure 300 bar, Wellhead temperature 10 °C Figure 6
Reservoir pressure 300 bar, Wellhead temperature 40 °C Figure 7

The difference in behaviour between low and high pressures are directly clear. At low reservoir pressure, the well is mainly in the two-phase regime for the major part of the well. At high reservoir (300 bar), the complete well is in single phase supercritical conditions.

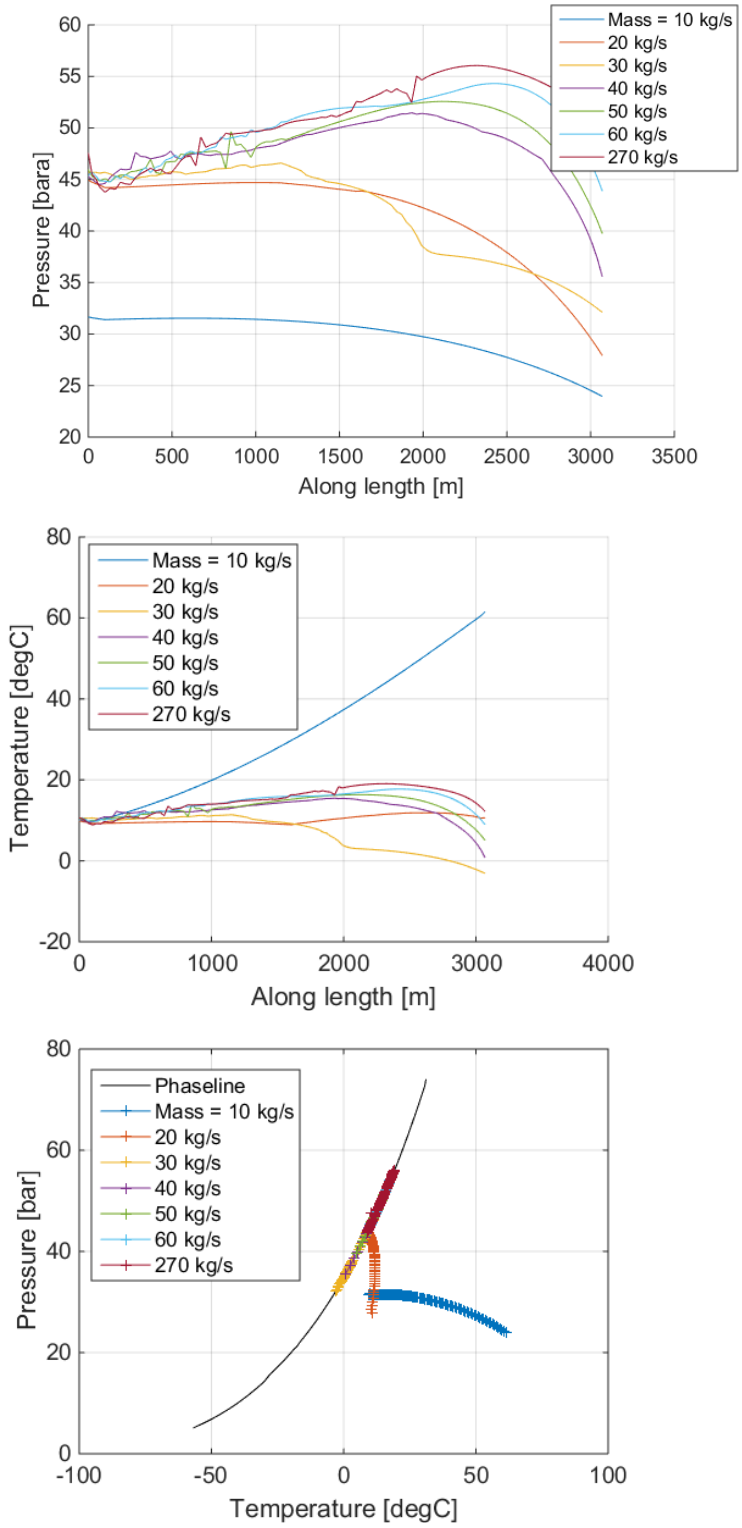


Figure 2: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 20 bar and a wellhead temperature of 10°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

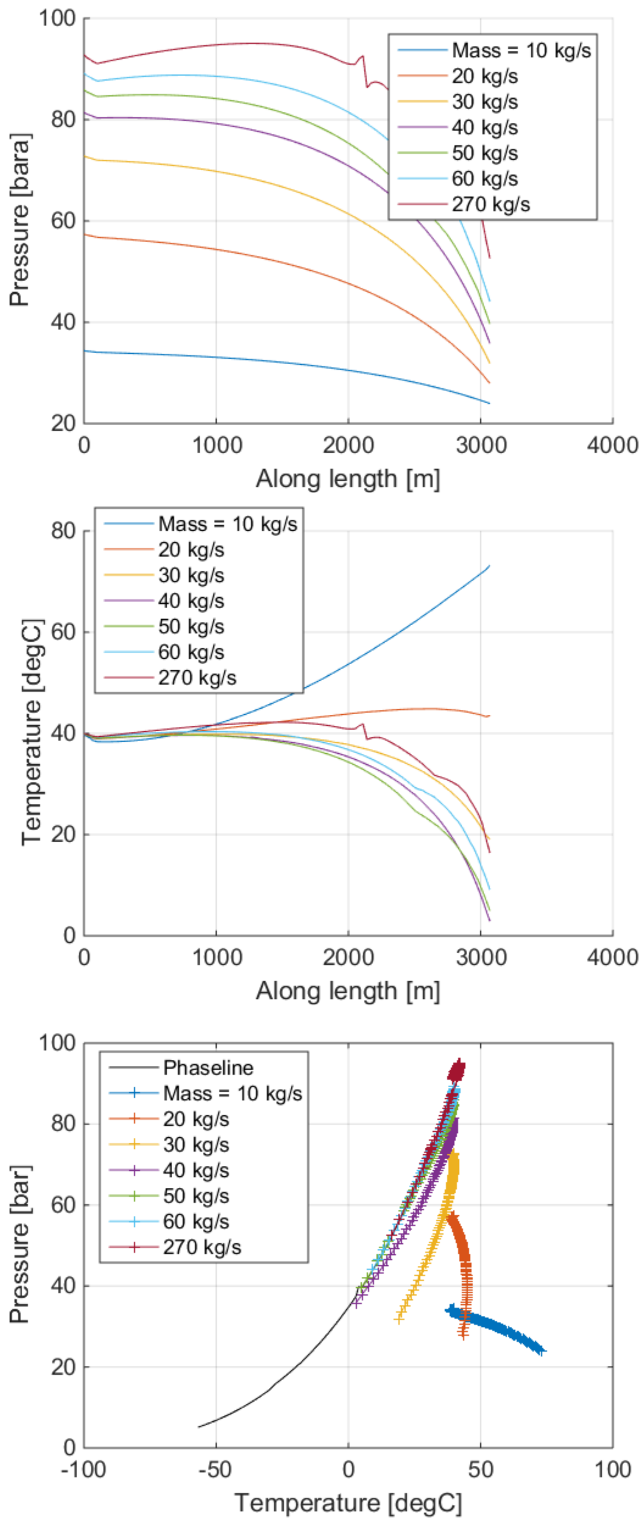


Figure 3: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 20 bar and a wellhead temperature of 40°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

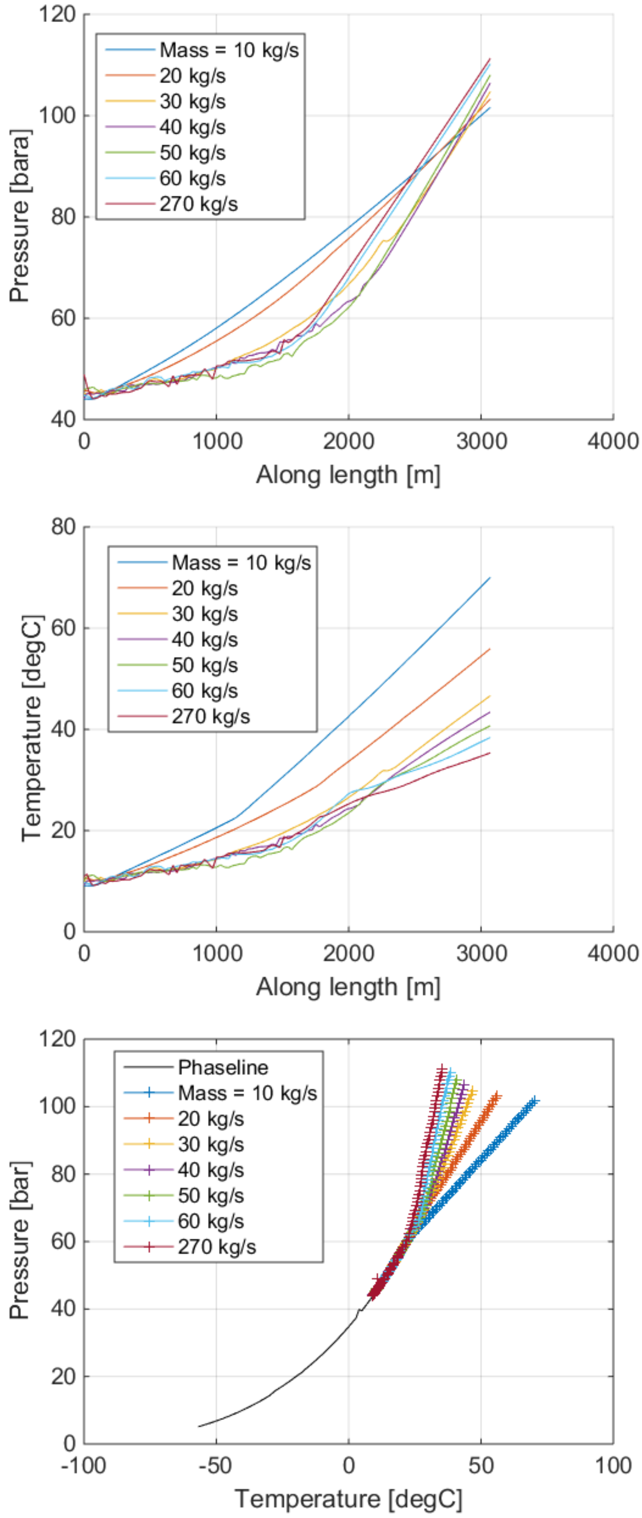


Figure 4: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 100 bar and a wellhead temperature of 10°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

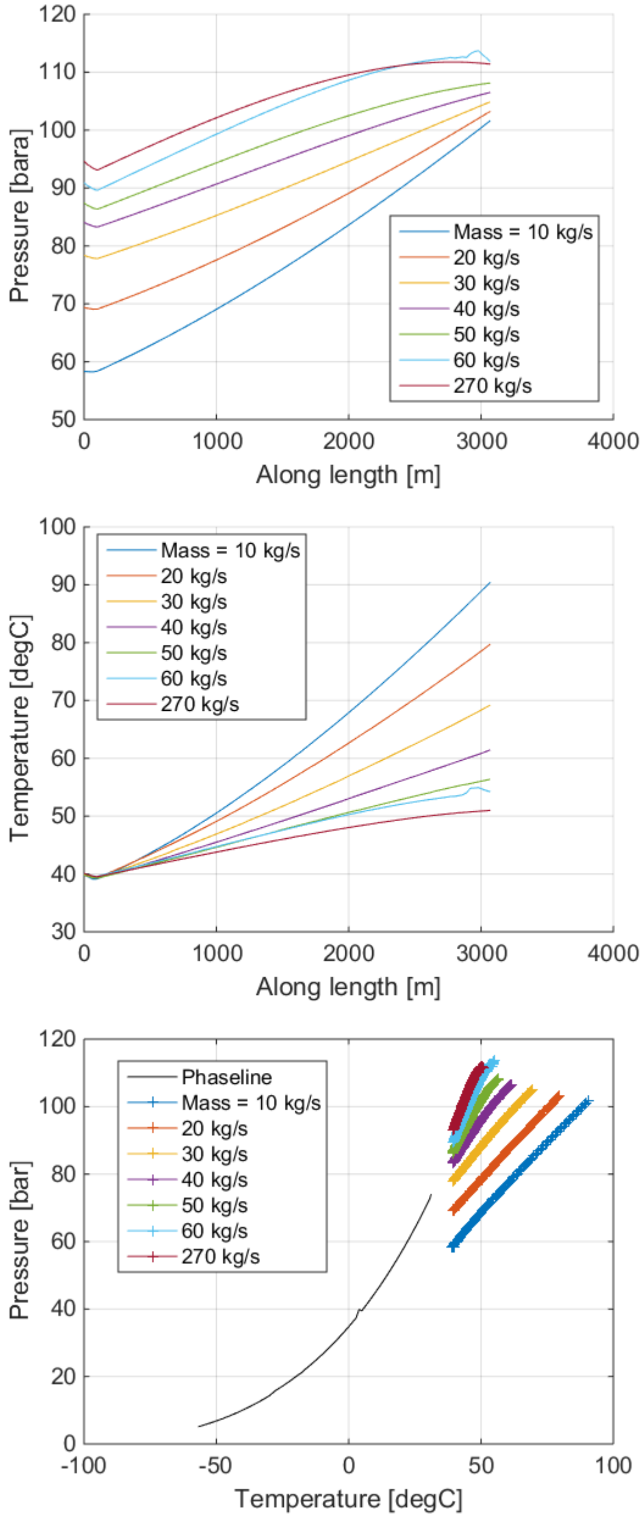


Figure 5: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 100 bar and a wellhead temperature of 40°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

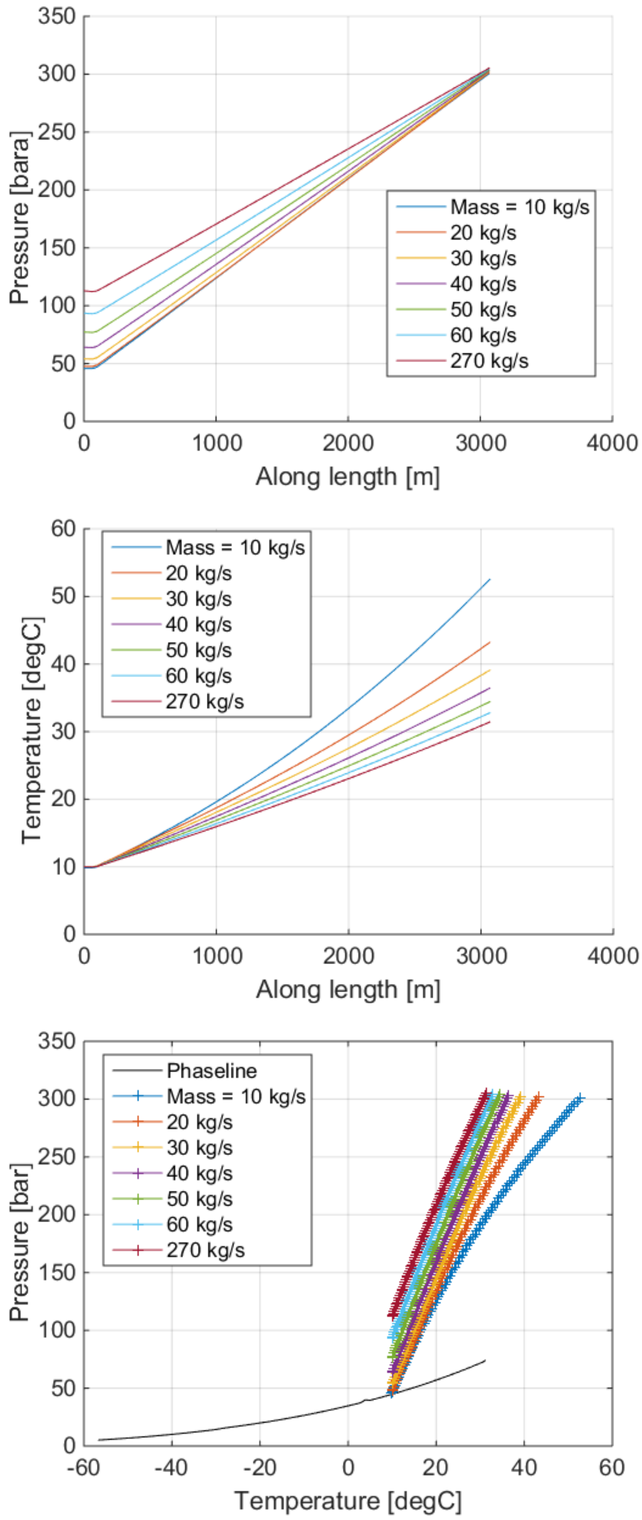


Figure 6: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 300 bar and a wellhead temperature of 10°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

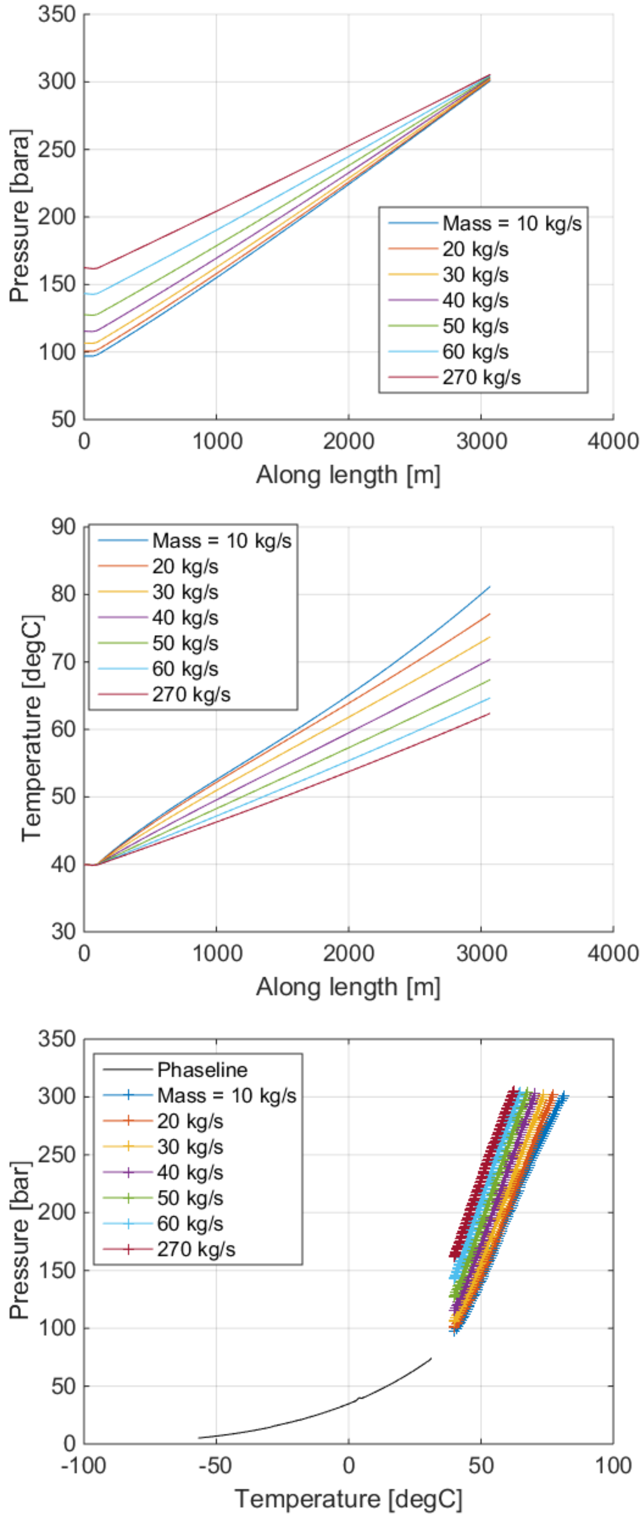


Figure 7: Pressure profile (top), temperature profile (middle) and P,T profile for a reservoir pressure of 300 bar and a wellhead temperature of 10°C. The mass flow ranges from 10 to 70 kg/s (edit one caption is wrong to be changed).

3.2.3 *Results influence reservoir pressure & influence well ID*

The influence of the well ID is plotted in Figure 8 in which the wellhead and downhole temperature are plotted as function of mass flow rate for a well with 50, 70, 90, 120 an d 150 mm. These diameters are chosen based on 2 3/8”, 3½ “, 4 ½ “ , 5½ “ and 7” tubing (approximate mid strength class).

At low reservoir pressure it is found that:

- The range of allowed flow rates with respect to the bottomhole temperature increases for increasing diameter.
- At larger diameters, the required wellhead pressure decreases.
- At temperatures lower than the critical temperature, the required wellhead pressure is constant for a range of mass flow rates. The minimum mass flow rate for when the required wellhead pressure becomes constant, increases for larger diameters..
- At smaller diameters, the required wellhead pressure is severely limiting. At a diameter of 70mm, the maximum flow rate is just 30 kg/s (at 10°C).

At mid reservoir pressures it is found:

- For diameters larger than (and including) 90 mm, there are basically no downhole temperature restrictions.
- For diameters smaller than (and including) 90 mm, the wellhead pressure is limiting to the mass flow rates for al temperatures.

At higher reservoir pressures it is found:

- For diameters smaller than (and including) 120 mm, the wellhead pressure is severely limiting for the allowed injection rate at higher temperatures.

Based on this set, a number of aspects can be concluded:

- At low reservoir pressure, a high temperature and large diameter is better with respect to the downhole temperature.
- At high reservoir pressures, a smaller diameter is rapidly restricting with respect to the mass flow rate. In other words, at smaller diameters, the required mass flow rates cannot be injected within the available wellhead pressure envelope.

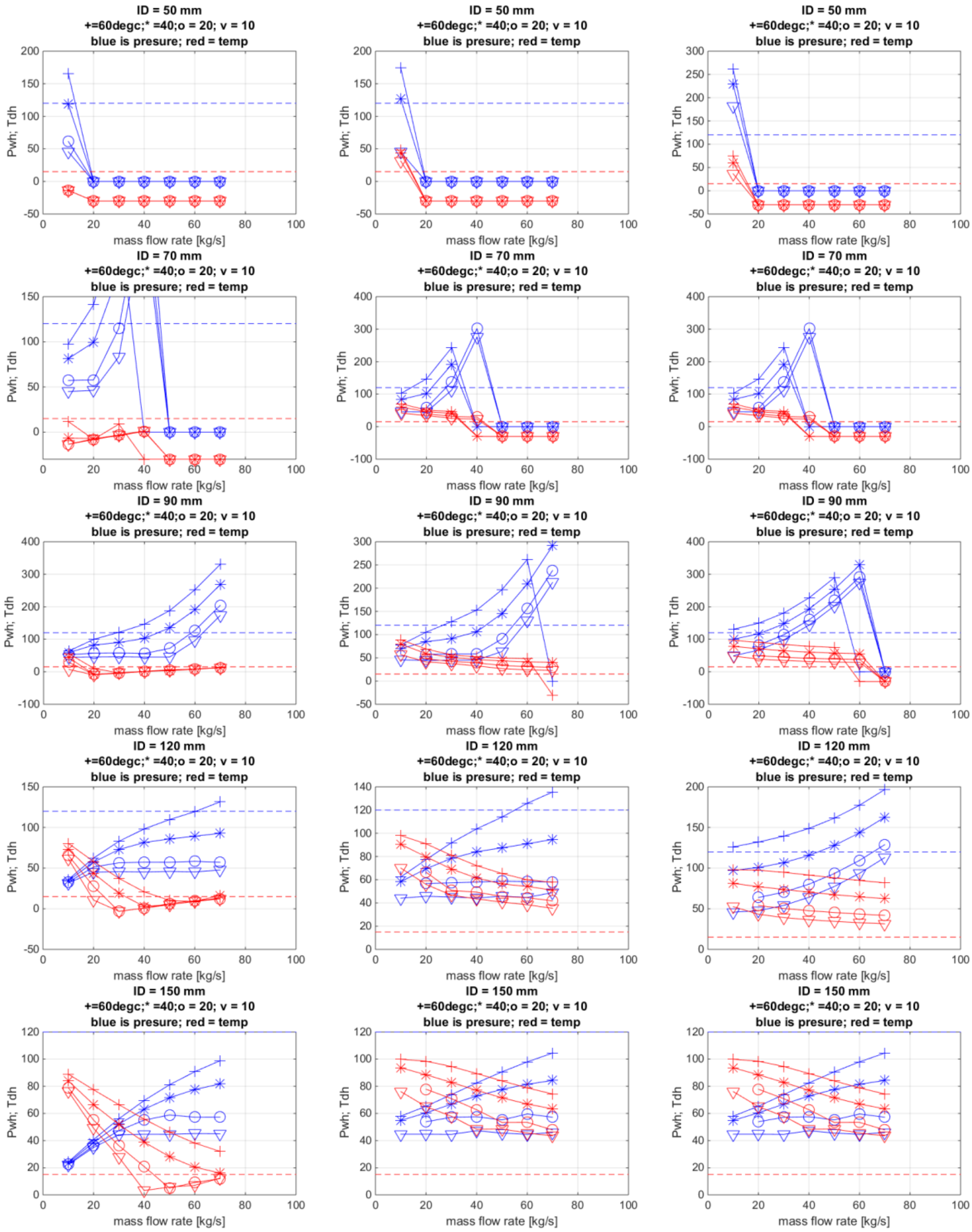


Figure 8: Influence well diameter (top to bottom rows) for a reservoir pressure of 20 bar (left), 100 bar (middle) and 300 bar (right). The simulations are limited to 350 bar. All cases with conditions higher than 350 bar are plotted as a pressure of 0 bar and a temperature of -30 °C.

3.3 CO_2 injection with controlled pipeline pressure

The results in the previous section are with a ‘free’ wellhead pressure. That is, there is no control choke at the wellhead. In this section a control valve is added. This control valve will keep the upstream pressure to a set value (or higher). It must be remarked that a section of 400m horizontal is used on the topside. This length was not set to very short as this would lead to numerical problems (with opening and closing of the choke the mass flow rate from the upstream side increases/decreases rapidly. This can lead to fast pressure variations in small volumes). Unfortunately that also meant some heat transfer was allowed in that section (for future cases, the heat transfer could be set to zero at those sections). This means the temperature arriving at the choke was not always similar to the ‘inlet’ temperature. This is especially true for low flow rates.

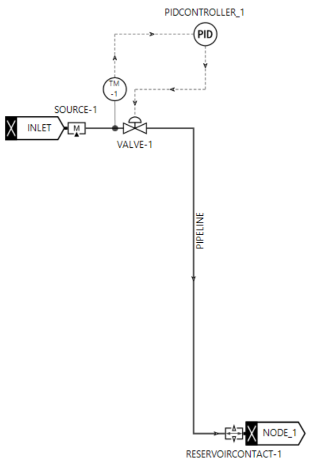


Figure 9: Model with control.

In this section results are given for:

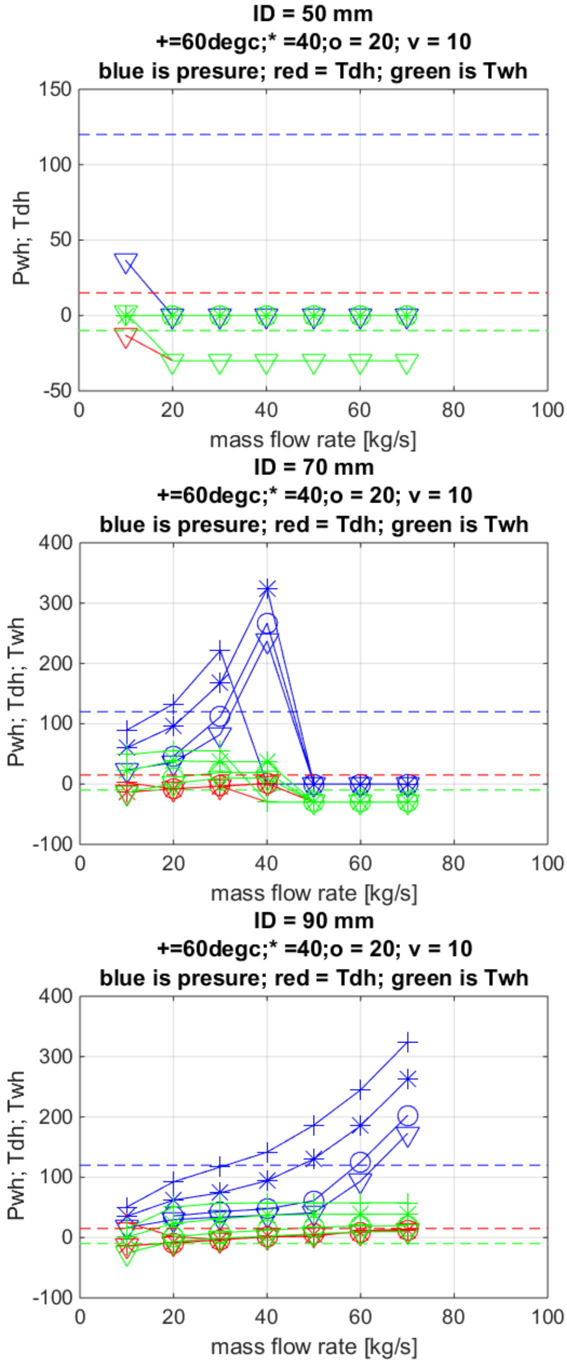
- Reservoir pressure 20 bar
- Pipeline pressure is minimally 85 bar

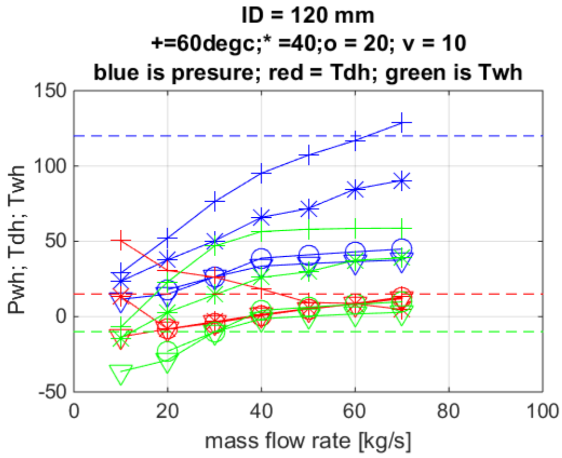
This condition is chosen as the low reservoir pressure is a strong limiting conditions as was shown in section 3.2.3.

The results are given in Figure 10. The figures are complex but the important conclusions are:

- At larger diameters, due to the low required wellhead pressures, a large pressure drop and therefore temperature drop occurs across the choke.
- The range of possible flow rates due to the downhole restriction (see Chapter 2) is limited due to this pressure drop across the control chokes.

This means that at low reservoir pressure, either the downhole temperature restriction is not achieved or the wellhead restriction. Only for the highest temperatures there is a margin of operation up to a flow rate of 40 kg/s in case of a ID = 120mm well. A side issue is that a low flow rates the cooling in the pipeline is such that 60 °C is difficult to achieve. This is only possible for high flow rates.


ID = 50 mm
+=60degc;* =40;o = 20; v = 10
blue is presure; red = Tdh; green is Twh
Pwh; Tdh
150
100
50
0
-50
0
20
40
60
80
100
mass flow rate [kg/s]
ID = 70 mm
+=60degc;* =40;o = 20; v = 10
blue is presure; red = Tdh; green is Twh
Pwh; Tdh; Twh
400
300
200
100
0
-100
0
20
40
60
80
100
mass flow rate [kg/s]
ID = 90 mm
+=60degc;* =40;o = 20; v = 10
blue is presure; red = Tdh; green is Twh
Pwh; Tdh; Twh
400
300
200
100
0
-100
0
20
40
60
80
100
mass flow rate [kg/s]



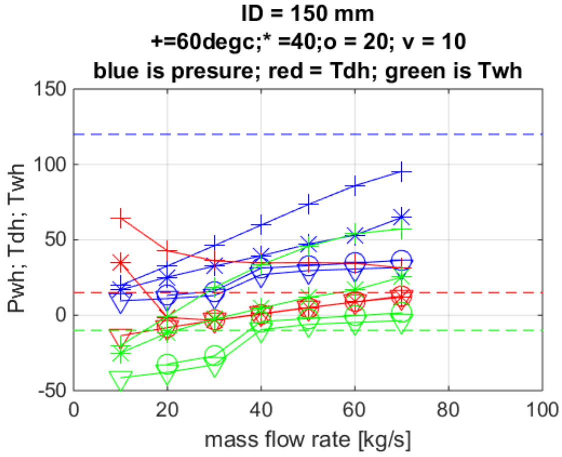


Figure 10: Wellhead pressures (downstream choke), wellhead temperatures (downstream choke) and downhole temperatures. The simulations are limited to 350 bar. All cases with conditions higher than 350 bar are plotted as a pressure of 0 bar and a temperature of -30 °C.

4 Simulation model(s)

4.1 Introduction

The simulations as presented have been done using OLGA 2017.1.0 with the single component CO_2 module using the P-H methodology. All simulations are done in transient mode simulating long enough to reach steady conditions (if any).

4.2 Basic model

The basic model is given in Figure 11. It consists of:
- Pipeline.
- 4 wells.
- A control valve at the pipeline inlet (to maintain a minimum discharge pressure of 60 bar).
- A control valve at the pipeline outlet to maintain the pipeline pressure at a minimum pressure.
- Each well has a control valve which is used in either mass flow or pressure control mode.

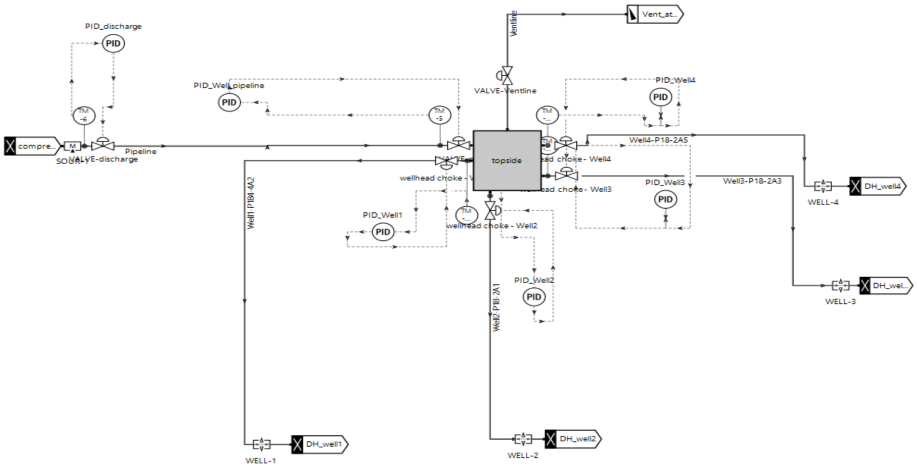


Figure 11: Olga model.

The controllers are all PID controllers with settings for the pressure controllers of:
Amplification: 2e-8
Bias: 0
Derivativeconst: 0 s
Error: 0
Integralconst: 5 [s]
The maximum change: 0.2

The mass flow controllers are set to:
Amplification: -0.0005
Bias: 0
Derivativeconst: 0 s
Error: 0

Integralconst: 5 [s]
The maximum change: 0.2

The control settings are not varied between cases and are relatively ‘soft’. That is the gain could be put higher (and still avoid unstable control). However, these settings seemed to work for almost all conditions and as such it was chosen to keep the settings more or less constant.

4.3 Pipeline geometry

The pipeline is modelled as:
- 22km, horizontal, (Inner) diameter = 0.4318m
- 25m, vertical, (Inner) diameter = 0.4318m
- 50m, horizontal, (Inner) diameter = 0.254m

The vertical diameter has been kept large as that is worst case for instabilities (in case we have two phase flow) but a 10” section was added for pressure drop.

Two controllers are added to the pipeline:
- Compressor outlet valve at a pressure control of 60 bar.
- Pressure controller at the horizontal section at ‘the platform’ .

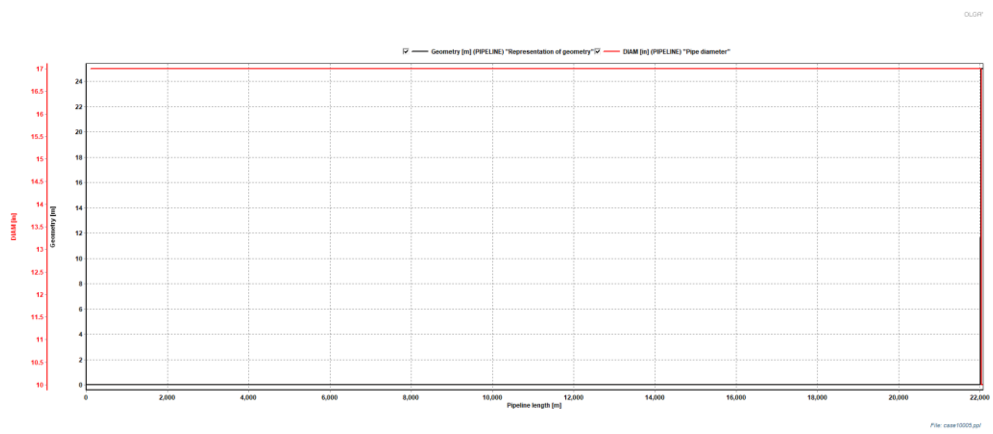


Figure 12: Pipeline geometry.

4.4 Well geometry

For the base model, the well inclination profiles of the wells P18-4A2, P18-2A1, P18-2A3 and P18-2A5 are used. For the base case, a tubing of 5.5” (0.12m ID) is used. The tubing diameter is used up to the point it could fit the casing/liner (as not for all a 5.5” tubing would fit down to the perforations). The detailed geometry used is given in Figure 13.

Well1 = P18-4A2 ID = 0.12m (5.5”)
Well2 = P18-2A1 ID = 0.12m (5.5”)
Well3 = P18-2A3 ID = 0.12m (5.5”)
Well4 = P18-2A5 ID = 0.12m (5.5”)

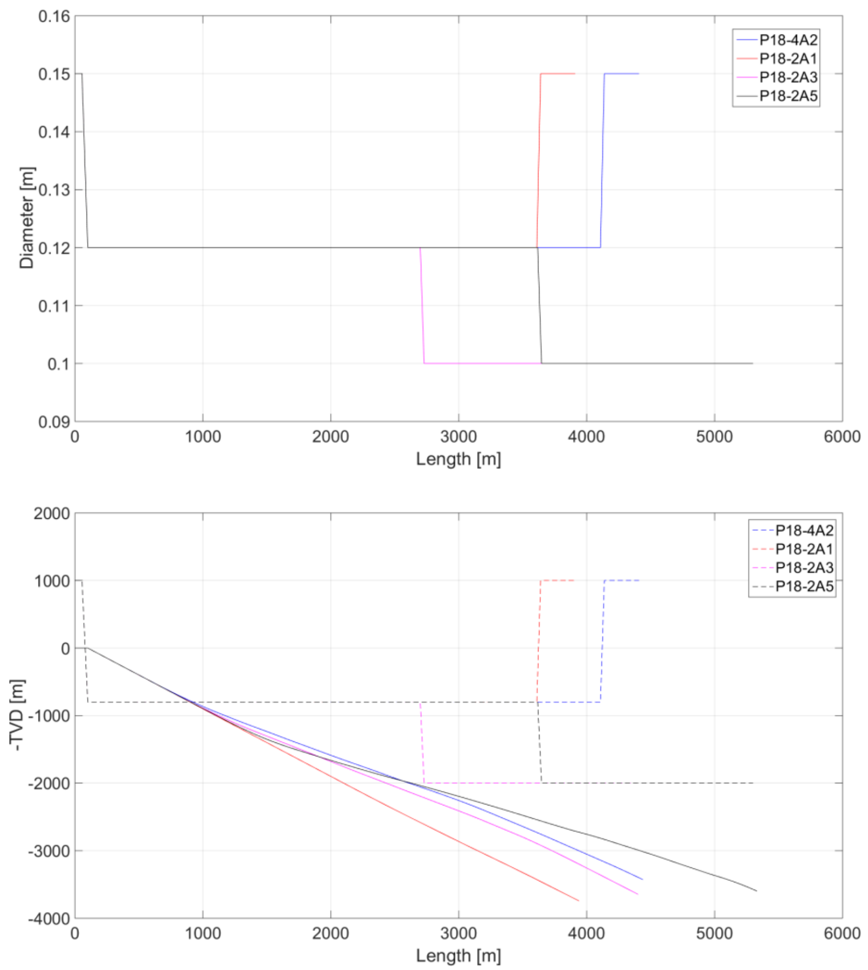


Figure 13: Well geometries used for the four wells. Diameter in bottom figures are scaled for visualisation.

The choice of diameters is based on :
- A larger diameter is 'better' for the downhole temperature (higher temperatures up to higher flow rates)
- A larger diameter is 'better' at high reservoir pressure
- A smaller diameter is 'better' with respect to topside temperature considerations (a smaller diameter builds up pressure faster with respect to mass flow rate and as such the pressure drop is less across control chokes at the wellheads.

A more detailed 'optimization' was done for 10°C injection cases. These are not reported in this report.

4.5 Reservoir

For the reservoir injectivity, a reservoir pressure dependent value is used. For all four wells the same injectivity (PI) index is used (based on P18-4 data). The injectivity is defined according:

$$m\ [kg/s] = \ PI \ \cdot \Delta p\ [Pa]$$

Table 1: Injectivity index used. * For 340 bar no data was available and the same value as for 300 bar was used.

Reservoir pressure [bara]	Injectivity index [(kg/s)/Pa]
20	2.53e-5
60	4.04e-5
100	6.14e-5
200	0.000109
300	0.000129
340	0.000129*

4.6 Heat transfer

For the heat transfer, at this stage an overall U value methodology is used. That is basically a steady state approach and less appropriate for dynamic simulations as the heat capacity of the walls are not included. However, as details on pipeline construction (insulation materials, burial depth, soil properties) and well selection (well used, annuli fluids) are not known the choice was made to use a U value methodology.

The pipeline is calculated using:
Ambient temperature: 10 °C
U value: 1.5/ m2-K (based on ID)
This includes the ‘riser’ and ‘topside’ part of the platform.

The wells are calculated using:
Vertical thermal gradient from 10 to 123 °C
U value: 9.5/ m2-K (based on ID)

5 Shutin-wellhead conditions

The shutin pressure for well P18-4A2 was calculated by ramping up the reservoir pressure after shutin. In Figure 14, the wellhead pressure is plotted as function of the reservoir pressure. This figure is obtained for a simulation in which the reservoir pressure was (linearly) increased slowly from 20 to 340 bar in 500000s (5.8 days). As the details of the results are determined by heat transfer, deviations might occur in case the details of the heat transfer and outer temperature will be different.

There are three regimes:

- At low reservoir pressure, the wellhead conditions are closely to single phase gas. In this region, the shutin wellhead pressure increases with the reservoir pressure (as the static head is in that case purely density and therefore pressure dependent).
- In the mid region, the wellhead is at two-phase conditions and all is dominated by heat transfer details (Figure 15). The wellhead pressure will be more or less constant as function of reservoir pressure and will be determined by the temperature.
- At high reservoir pressures, the wellhead is at liquid (supercritical) conditions and the wellhead pressure will increase with the reservoir pressure.

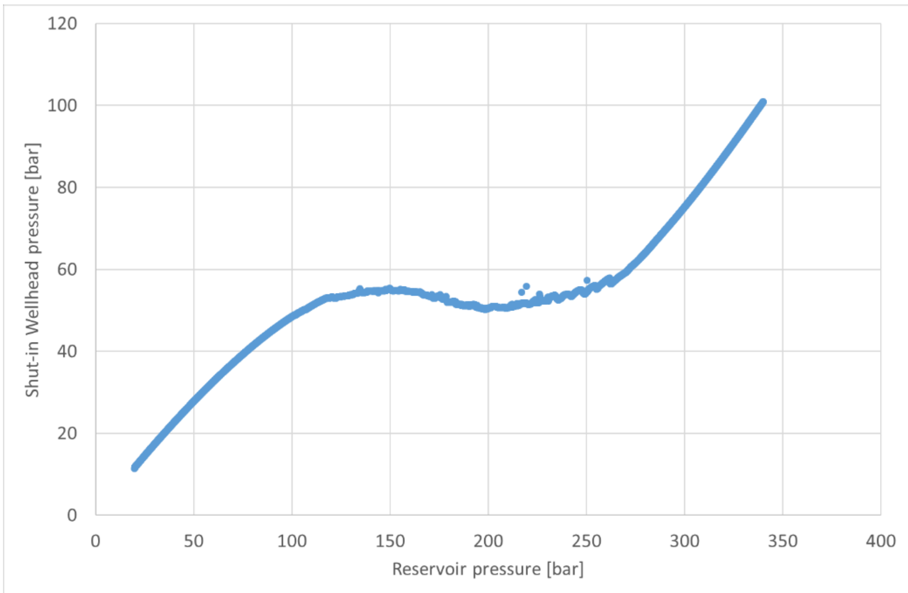


Figure 14: Shutin wellhead pressure for well P18-4A2. The reservoir pressure was increased from 20 to 340 bar in 500000s (5.8 days). For long term shutin case results of 12, 45, 45, 70 bar were obtained for 20, 100, 200, 300 bar reservoir pressure. The difference is due to the time allowed to reach steady state.

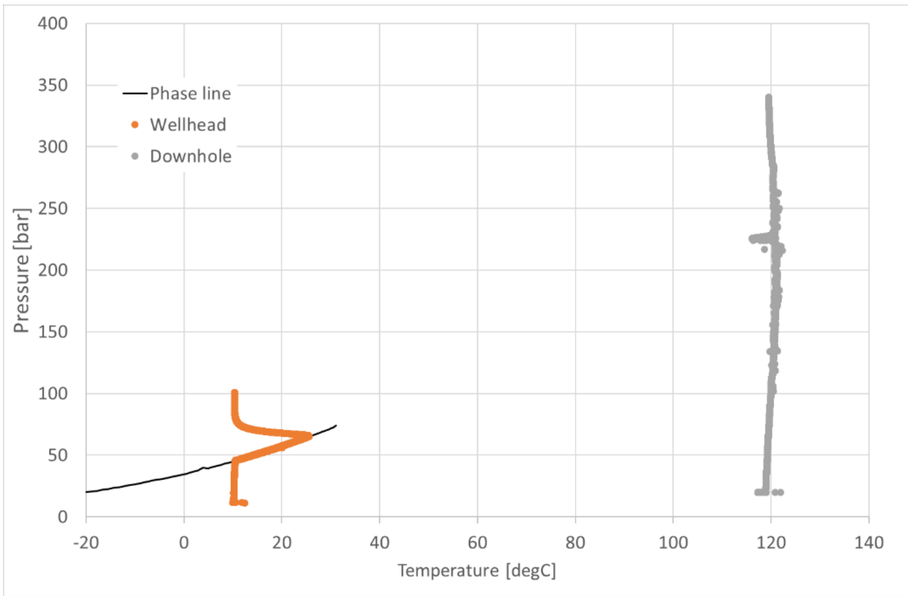


Figure 15: Wellhead and downhole condition for simulation with reservoir pressure increase.

6 Steady state

6.1 Introduction

In this chapter, the steady state results (final results of transient simulations) are discussed. These steady state simulations were done for a large range of models, flow rates and conditions. In this report only those results are presented with the model as described in Chapter 4. Previous models had no pipeline, a single well, no pipeline control valve or no compressor outlet control valve. When one well is used this is typically well-1 (P18-4A2).

In Section 6.2, an overview is given of the cases which have been simulated. The results of these cases are given in Annex A. In Section 6.3 a summary is given of the results.

6.2 Simulation cases

Case	***Pres***	***Tcompr***	***Wells***	***control***	***Mass flow***
4000	300	40	1 open	Platform (85 bar)	15
4001	300	40	1 open	Platform (85 bar)	30
4002	300	40	1 open	Platform (85 bar)	60
4002_45	300	40	1 open	Platform (85 bar)	45
4003	300	40	1 + 2 open	Platform (85 bar)	60
4004	300	40	All wells open	Platform (85 bar)	170
4119	300	80	All wells open	Platform (85 bar)	60
4120	300	80	All wells open	Platform (85 bar)	50
4005	340	40	All wells open	Platform (85 bar)	170
4006	340	40	All wells open	Platform (85 bar)	140
4110	340	80	All wells open	Platform (85 bar)	140
4111	340	80	All wells open	Platform (85 bar)	100
4113	340	80	All wells open	Platform (85 bar)	40
4114	340	80	All wells open	Platform (85 bar)	5
4130	340	40	1	Platform (85 bar)	30
4131	340	40	1	Platform (85 bar)	45
4132	340	40	1	Platform (85 bar)	38
4078^	100	40	All wells open	Platform (85 bar)	170
4079	200	40	All wells open	Platform (85 bar)	170
4080	100	40	1 open	Platform (85 bar)	60
4081	200	40	1 open	Platform (85 bar)	60
4082	100	40	1 open	Platform (85 bar)	30
4083	100	40	1 open	Platform (85 bar)	15
4084	200	80	1 open	Platform (85 bar)	30
4085	200	80	1 open	Platform (85 bar)	15
4118	200	80	All wells open	Platform (85 bar)	100
4127	100	80	All wells open	Platform (85 bar)	100
4124	100	80	1	Well (85)	15
4125	100	80	1	Well (85)	30

4127	100	80	1	Well (85)	60
4007	60	40	1 open	Platform (85 bar)	15
4008	60	40	1 open	Platform (85 bar)	30
4009	60	40	1 open	Platform (85 bar)	60
4010	60	40	1 open	Platform (85 bar)	100
4011	60	40	1 + 2 open	Platform (85 bar)	100
4012	60	40	All wells open	Platform (85 bar)	170
4013	60	40	All wells open	3 * mass; 1 P (85 bar)	170
4115	60	80	All wells open	3 * mass; 1 P (85 bar)	170
4116	60	80	All wells open	3 * mass; 1 P (85 bar)	100
4117	60	80	All wells open	3 * mass; 1 P (85 bar)	110
4121	60	80	1	Well 85	
4122	60	80	1	Well 85	
4123	60	80	1	Well 85	
4014	20	40	1 open	Platform (85 bar)	15
4015	20	40	1 open	Platform (85 bar)	30
4016	20	40	1 open	Platform (85 bar)	60
4017	20	80	1 open	P control at well (85)	15
4018	20	80	1 open	P control at well (60)	15
4019	20	80	1 open	P control at well (60)	60
4020	20	80	All open	3 * mass; 1 P (60 bar)	170
4021	20	80	All open	3 * mass; 1 P (60 bar)	120
4022	20	80	1 open	P control at well (60)	45
4023	20	80	1 open	P control at well (60)	30
4024	20	80	1 open	No control	15
4025	20	80	1 open	No control	30
4026	20	80	1 open	No control	45
4027	20	80	All wells open	No control	170
4028	20	80	All wells open	No control	140
4128	20	80	All wells open	No control	100
4129	20	80	All wells open	No control	90

6.2.1 *Results overview*

An overview of the results is given in Table 2 to Table 5. In these tables the main pressures and temperatures are given.

Pcomp: Compressor discharge pressure
Tcomp: Compressor discharge temperature
Pplatform: Pressure upstream of well control valves
Tdownstream: Temperature downstream of well control valves
Tdownhole: Downhole temperature at injection position

For a reservoir pressure of the 20bar, no case, with a liquid filled pipeline, adheres to both the wellhead and downhole temperature restriction (see Annex A). Therefore, only cases in which the pipeline pressure was not controlled are presented.

In general results have been calculated with for a single well starting at low flow rate and determining the maximum flow rates with respect to the temperature restriction (either wellhead or downhole), and for scenarios with all wells open, determining the maximum allowed flow rate with respect to the compressor pressure.

Table 2: Examples of results for a reservoir pressure of 20 bar. * The minimum wellhead temperature (Tdownstream) and downhole temperature are given if more than one well is used.

Reservoir pressure [bar]	Case	# wells	Mass flow rate [kg/s]	P comp [bar]	Tcomp [°C]	Control	P Platform [bar]	T* Down stream [°C]	T down hole* [°C]
20	4024	1	15	60	80	None	46	17	47
20	4025	1	30	80	80	None	80	42	17
20	4028	4	140	115	80	None	103	64	19
20	4128	4	100	90	80	None	81	58	35
20	4129	4	90	83	80	None	75	56	40

Table 3: Examples of results for a reservoir pressure of 60 bar. * The minimum wellhead temperature (Tdownstream) and downhole temperature are given if more than one well is used.

Reservoir pressure [bar]	Case	# wells	Mass flow rate [kg/s]	P comp [bar]	T comp [°C]	Control	P Plat form [bar]	T* Down stream [°C]	T down hole* [°C]
60	4007	1	15	85	40	Pipe: 85	30	-6	25
60	4008	1	30	85	40	Pipe: 85	56	18	27
60	4009	1	60	89	40	Pipe: 85	87	37	32
60	4011	2	100	89	40	Pipe: 85	75	31	31
60	4013	4	170	95	40	Well: 85	85	19	29
60	4121	1	15	86	80	Well: 85	85	-5	41
60	4122	1	30	87	80	Well: 85	85	39	46
60	4123	1	60	138	80	Well: 85	136	65	38
60	4115	4	170	155	80	3*well; P(85)	143	41	38
60	4116	4	100	100	80	3*well; P(85)	93	46	57
60	4117	4	110	119	80	3*well; P(85)	111	33	47

Table 4: Examples of results for a reservoir pressure of 100 bar. * The minimum wellhead temperature (Tdownstream) and downhole temperature are given if more than one well is used.

Reservoir pressure [bar]	Case	# wells	Mass flow rate [kg/s]	P comp [bar]	T comp [°C]	Control	P Plat form [bar]	T* Down stream [°C]	T down hole* [°C]
100	4083	1	15	85	40	Pipe 85	33	-2	50
100	4082	1	30	85	40	Pipe 85	52	15	53
100	4080	1	60	90	40	Pipe 85	87	37	51
100	4078	4	170	93	40	Pipe 85	76	32	50
100	4126	4	100	98	80	Pipe 85	90	60	82
100	4124	1	15	86	80	Well 85	85	9	60
100	4125	1	30	87	80	Well 85	85	45	71
100	4127	1	60	142	80	Well 85	139	64	60

Table 5: Examples of results for a reservoir pressure of 300 and 340 bar. * The minimum wellhead temperature (Tdownstream) and downhole temperature are given if more than one well is used.

Reservoir pressure [bar]	Case	# wells	Mass flow rate [kg/s]	P comp [bar]	T comp [°C]	Control	P Plat form [bar]	T* Down stream [°C]	T down hole* [°C]
300	4000	1	15	85	40	Pipe 85	58	21	64
300	4001	1	30	92	40	Pipe 85	90	35	73
300	4002_45	1	45	108	40	Pipe 85	105	33	62
300	4002	1	60	136	40	Pipe 85	133	32	58
300	4003	2	60	94	40	Pipe 85	91	37	77
300	4004	4	170	116	40	Pipe 85	108	36	68
340	4006	4	140	123	40	Pipe 85	116	36	68
340	4005	4	170	138	40	Pipe 85	130	36	66

6.3 Overview conclusions

For the different reservoir pressures the following is concluded:

- Reservoir pressure = 20 bar

Cases calculated with Tcompressor = 40 °C and 80 °C
Cases with T = 40 °C have a too low bottomhole pressure
With a pipeline at a pressure control of 85 bar, the minimum flow rate leads to a too low bottomhole temperature.
With a pipeline at a pressure control of 60 bar, the maximum flow rate is 30 kg/s.
At a pressure control of 60 bar, the maximum flow rate for all wells open is 120 kg/s

At open flow, the maximum flow rate for Well 1 is ~ 40 kg/s
At open flow, the maximum flow rate for all wells is ~ 140 kg/s

- Reservoir pressure = 60 bar

The cases are calculated with a compressor discharge temperature of Tcompressor = 40 °C. At those conditions, there are no limitations in mass flow rate due to the wellhead temperatures or downhole temperatures.
Due the compressor limit of P = 120 bar, the maximum mass flow rate is between 60 and 100 kg/s for a single well and higher than 170 k/s in case all wells are open.

With platform control, downstream of the choke control, two phase flow occurs
Recommended to use individual control (1 pressure control, rest mass flow control)

- Reservoir pressure = 300 bar

The cases are calculated with a compressor discharge temperature of Tcompressor = 40 °C. At those conditions, there are no limitations in mass flow rate due to the wellhead temperatures or downhole temperatures.
Due the compressor limit of P = 120 bar, the maximum mass flow rate is 45 kg/s for a single well and higher than 170 k/s in case all wells are open.

- Reservoir pressure = 340 bar

The cases are calculated with a compressor discharge temperature of Tcompressor = 40 °C. At those conditions, there are no limitations in mass flow rate due to the wellhead temperatures or downhole temperatures.
Due the compressor limit of P = 120 bar, the maximum mass flow rate is 140 kg/s in case all wells are open.

A summary of these conclusions is given in Table 6.

Table 6: Overview maximum flow rates.

Reservoir pressure	Maximum flow 1 well	Maximum flow 4 wells
20 bar - Tcomp = 80 °C	30 kg/s	140 kg/s
60 bar - Tcomp = 40 °C	60 kg/s	> 170 kg/s
300 bar - Tcomp = 40 °C	45 kg/s	> 170 kg/s
340 bar - Tcomp = 40 °C		140 kg/s
60 bar - Tcomp = 80 °C		110 kg/s
200 bar - Tcomp = 80 °C		100 kg/s
300 bar - Tcomp = 80 °C		45 kg/s
340 bar - Tcomp = 80 °C		0 kg/s

7 Start-up simulations

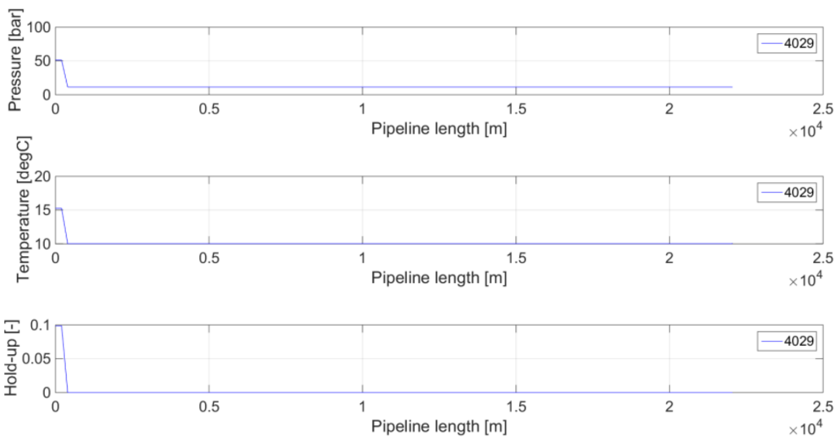
7.1 Introduction

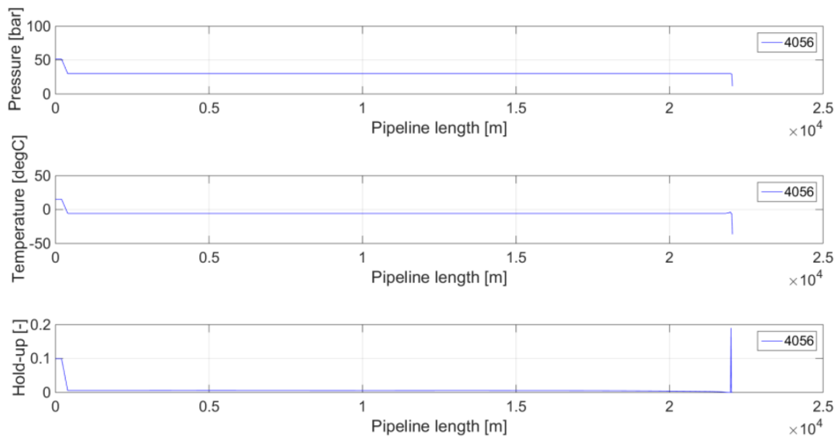
In this Chapter an overview of start-up simulation are presented. In principle only low temperature start-up cases have been simulated as these are almost always worst cases.

Start-up simulations are done starting from three conditions (Figure 16):
- Low pressure (12 or 30 bar, 10°C; gas phase)
- Mid pressure (60 bar, 21°C; two-phase)
- High pressure (115 bar, 14°C; liquid phase)

The mid pressure conditions were obtained by closing in the pipeline at approximate 85 bar, 40 °C. When cooling down the conditions shift to the two-phase line conditions such that the total mass remains constant.

The high pressure conditions are assumed to be a near critical cases.





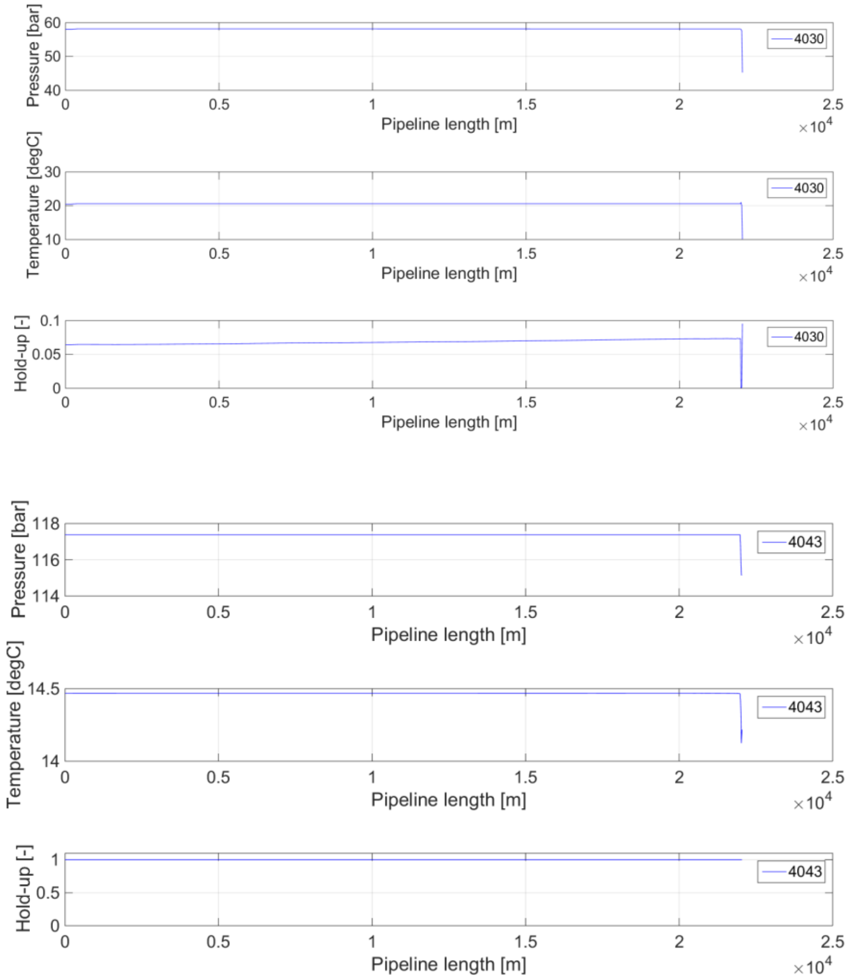


Figure 16: Pressure, temperature and hold-up profile for low (top 2 figures), middle and high pressures.

An overview of simulations ran is given in Section 7.2, with in Section 7.4, Section 7.5 and Section 7.6 start-up simulations at low reservoir pressure. In Section 7.9 and 7.10 the start-up cases for higher reservoir pressures are presented. Section 7.7 and Section 7.8 give a discussion on alternatives for low reservoir pressure start-up.

7.2 Simulations overview

In Table 7 an overview is given of the simulations ran. The different heading indicate:

Case:	Simulation case number
Pres:	Reservoir pressure [bar]
Tcmp:	Compressor outlet temperature [°C]
Wells:	Number of wells open or case number from which is restarted
Control:	Indication on how control is done None means the control settings are such that valves are full open (except discharge pressure control valve)

	Pipe N indicates that the pipeline pressure control valve is set to N bar
Mass flow	Compressor discharge mass flow rate [kg/s]

Table 7: Overview of simulations.

Case	*Pres [bar]*	*Tcmp [°C]*	*Wells*	*Control/ number of wells open*	*Mass flow [kg/s]*
4029	20	80	All wells open	Initialization at T = 10°C	
4030	20	80	All wells closed	Initialization at P ~85 bar (leading to a pipeline pressure of ~60 bar)	
4031	20	80		Shutin wells from 4028 (lading to a pipeline pressure of ~115 bar)	
Low pipeline pressure start-up with no control					
4032	20	80	Start from 4029	none	15
4033	20	80	Start from 4029	None	30
4034	20	80	Start from 4029	2 wells	60
4054	20	80	Start from 4029	4 wells	60
4055	20	80	Start from 4029	4 wells	170
Mid pipeline pressure start-up					
4035	20	80	Start from 4030		0
4036	20	80	Start from 4030	1 well full open	15 at t = 5000s
4037	20	80	Start from 4030	1 well full open	15 at t = 0s
4038	20	80	Start from 4030	2 wells Full open	60 at t = 5000s
4039	20	80	Start from 4038	3 wells Full open	90 at t = 1000s
4065	20	80	Start from 4030	Pipeline = 30 bar	0
4066	20	80	Start from 4030	Pipeline = 30 bar 1 well full open	15 at t = 5000s
4067	20	80	Start from 4030	Pipeline = 30 bar 1 well full open	Opening valve 10, 100, 300, 1000s
High pipeline pressure start-up					
4043	20	80		Initialization at t=10, 120 bar	
4044	20	80	Start 4043	Full open	15 at t = 5000s
4045*	20	80	Start 4043	Well 2 Control on 30 kg/s	15 at t = 5000s
4047*	20	80	Start 4043	Well 2 Control on 10 kg/s	15 at t = 5000s
4048	20	80	Start 4043	Well 2	15 at t = 5000s

				Control on 60 kg/s	
4046**	20	80	Start 4043	Full open @ t = 5000	15 at t = 0
4049	20	80	Crashes	Pipe 85 bar Well 60	
4050	20	80	Crashes	Pipe 0.05 Well 0.05	
Venting solution					
4051	20	80	Start 4043	Temporary vent	
4052	20	80	Start 4043	venting Well 1 open at 14000	15 at t = 10000
4053	20	80	Start 4043	Start at full open Well 1 + well 2	
4068	20	80	Start 4043	vent	
4069	20	80	Start 4068	Well 1 full open	15 at 5000s Well open at 1000
4071	20	80	Start 4068		Valve opening times
4072	20	80	Start 4068		15 at 1000 Well open at 5000
4074	20	80	Start 4068	Well 2 control	Control 15, 30, 45, 60 kg/s (60 *)
4075	20	80	Start 4068		15 at 1000 Well open at 6000
4076^	20	80	Start 4068	30 bar 4 wells open	15 at 10000s Well open at 1000
Low Pipeline pressure startup with pressure control					
4056	20	80	Pipe 30 bar	Initialization at T = 10°C	
4057	20	80	Start 4056	Pipe 30 bar (1 well full open)	30
4058+	20	80	Start 4056	None (1 well open)	30
4059++	20	80	Start 4056	None (1 well open)	30
4060	20	80	Start 4057	Open well 2	
4061	20	80	Start 4056	None (2 wells open)	60
4062	20	80	Start 4061	Open well 3	
4063	20	80	Start 4061	Open well 3 Variation opening time	topen = 10s, 100s 300s, 1000s
4064	20	80	Start 4060	Open well 2 Variation opening time	topen = 10s, 100s 300s, 1000s
4070	20	80	Start 4056	Pipe 30 bar (1 well full open)	15

High pipeline pressure start-up with Well ID = 0.09m					
5000	20	80		Vent	Well 1 0.09
5001	20	80	Start 5000		15 kg/s
High pipeline pressure start-up with choke in well (variation ID and position)					
6000	Initialization DHC position 4000m				
6001	20	80		Start 6000	15

6002	Initialization DHC position 3700m				
6003	20	80		Start 6002	15
6004	Initialization DHC position 3200m				
6005	20	80		Start 6004	15
6006	Initialization DHC position 2200m				
6007	20	80		Start 6006	15
6008	Initialization DHC position 1200m				
6009	20	80		Start 6008	15 kg/s
6010	20	80		Start 6000	Pressure control DHC

* Hydrodynamic slugging is turned -off; otherwise no convergence.
** This scenario is not useful as the pipeline pressure will rise too fast.
+ The maximum time step is limited
++ Hydrodynamic slugging is turned -off; otherwise no convergence.
^ Slip is turned-off otherwise no convergence

Case	***Pres***	***Tcmp***	***Wells***	***control***	***Mass flow***
4100	All 60	80	All wells closed	Pipe 85	For initialisation
4101	1*60 3*20	80	All wells closed	Pipe 85	For initialisation
4102	All 60	80	Start 4100	Pipe 85	15
4103	60; 3*20	80	Start 4101	Well 85	30
4104	60; 3*20	80	Start 4103	Well 85 Mass 15	30
4105	All 60	80	Start 4101	Well 1 open Pipe 30	15
4106	All 60	80	Start 4100	Well 1 open Pipe 30	30
4107	All 60	80	Start 4100	Well 1 open Pipe 30	60
4108	All 60	80	Start 4106	Opening well 2	60

Case	***Pres***	***Tcmp***	***Wells***	***control***	***Mass flow***
4200	All 100	40	All wells closed	Pipe 85	For initialisation
4201	All 100	40	*Start 4200- 1 well*	Pipe 85	15
4202	All 100	40	*Start 4200- 1 well*	Pipe 85	30
4203	All 100	40	*Start 4200- 1 well*	Pipe 85	60

Case	***Pres***	***Tcmp***	***Wells***	***control***	***Mass flow***
4300	All 200	40	All wells closed	Pipe 85	For initialisation
4301	All 200	40	*Start 4300- 1 well*	Pipe 85	15
4302	All 200	40	*Start 4300- 1 well*	Pipe 85	30
4303	All 200	40	*Start 4300- 1 well*	Pipe 85	60

Case	***Pres***	***Tcmp***	***Wells***	***control***	***Mass flow***
4400	All 300	40	All wells closed	Pipe 85	For initialisation
4401	All 300	40	Start 4400- 1 well	Pipe 85	15
4402	All 300	40	Start 4400- 1 well	Pipe 85	30

4403	All 300	40	Start 4400- 1 well	Pipe 85	60

Case	***Pres***	***Tcmp***	***Wells***	***control***	***Mass flow***
4500	All 340	40	All wells closed	Pipe 85	For initialisation
4501	All 340	40	Start 4500 – 1 well	Pipe 85	15
4502	All 340	40	Start 4500 – 1 well	Pipe 85	30
4503	All 340	40	Start 4500 – 1 well	Pipe 85	60
4504	All 340	40	Start 4500 – 2 wells	Well 1:85 Well 2:30 kg/s	60

7.3 Remarks valve openings

Before the general start-up behaviour is discussed, the detailed temperature behaviour around valves is discussed. As example, in Figure 18, the fluid temperature is plotted as function of time of well-2. This well is opened while well-1 is running at 30 kg/s (Figure 17). The opening time of the valve is varied from 10s to 1000s.

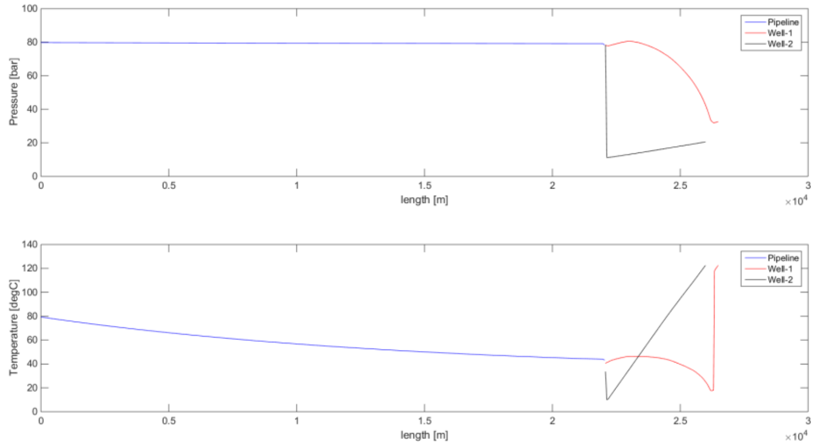


Figure 17: Initial conditions for case 4064.

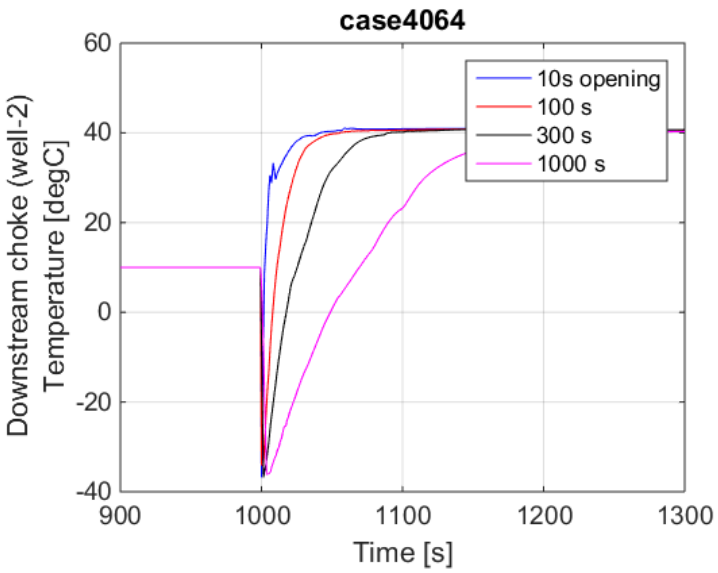


Figure 18: Temperature downstream choke of well-2 with different valve openings speeds (10s means the valve is opened from fully opened to fully closed in 10s).

As the conditions at the valve opening downstream of the valve are approximately 12 bar, when the CO_2 is expanded over the valve, the downstream conditions are for a short period at low temperature corresponding to the wellhead pressure and phase line temperature of approx. -38 °C. With a faster opening of the valve, the mass flow rate increases more rapidly through the valve resulting in

- A higher back pressure and therefore higher temperature
- A faster higher temperature arriving at the valve.

This will basically always occur when a new well is opened. A faster opening of the valves limits the period of low temperatures.

It must be remarked that the temperatures are fluid temperatures and not wall temperatures. When piping arrangements are known, a more detailed simulation can be done to determine actual wall temperatures when pipe thermal capacity is included.

7.4 Discussion start-up reservoir pressure 20 bar– low pipeline pressure

The start-up simulations are run from a low pressure pipeline conditions (Figure 19).

The sequence for the start-up are (Figure 20):

- The compressor mass flow rate is ramped up from 0 to a given flow rate from t = 1000s to 1600s.
- The pipeline pressure control valve is at p = 10 bar at t= 0s.
- For case 4032 and case4033, the well control was set to 10 bar at t= 0s (meaning full open).
- For case4033, the well 2 control was set to 1000 kg/s at t= 0s (meaning full open).

The sequence is setup such that the wells are first opened but that the pipeline pressure has not reduced too far down before the compressor is started up. However, the compressor is not started up too soon such that the pipeline is pressurized before the wells are opened.

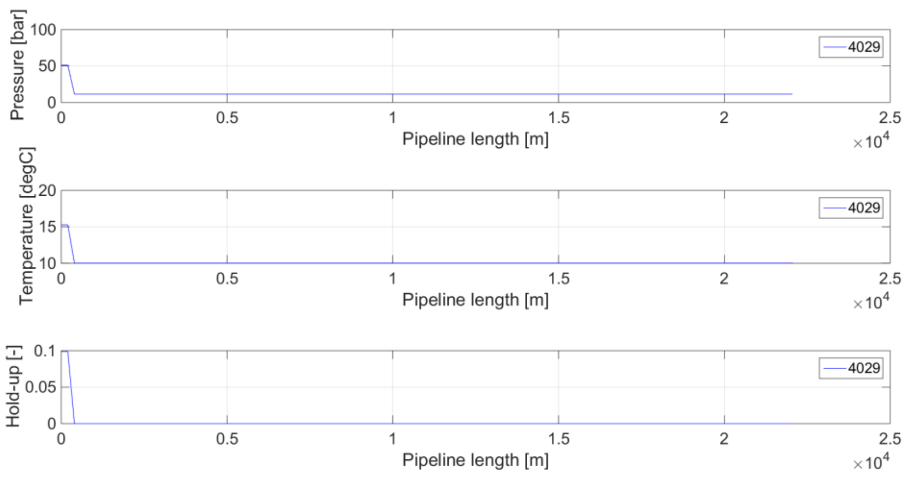


Figure 19: Initial conditions for start-up.

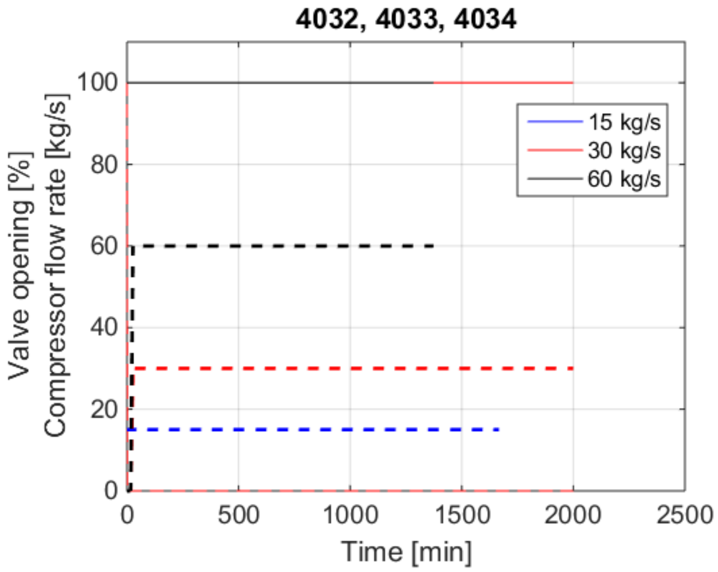


Figure 20: Compressor and valve openings.

The main parameters such as pipeline inlet pressure, the temperatures downstream of the choke valves and the downhole temperature are plotted as function of time in Figure 21. All pressures and temperatures comply with the restrictions. When the high temperatures have arrived at the platform other wells might be opened.

It must be remarked that the stabilization time before steady conditions are reached is nearly 500 – 1000 minutes (8-17 hrs).

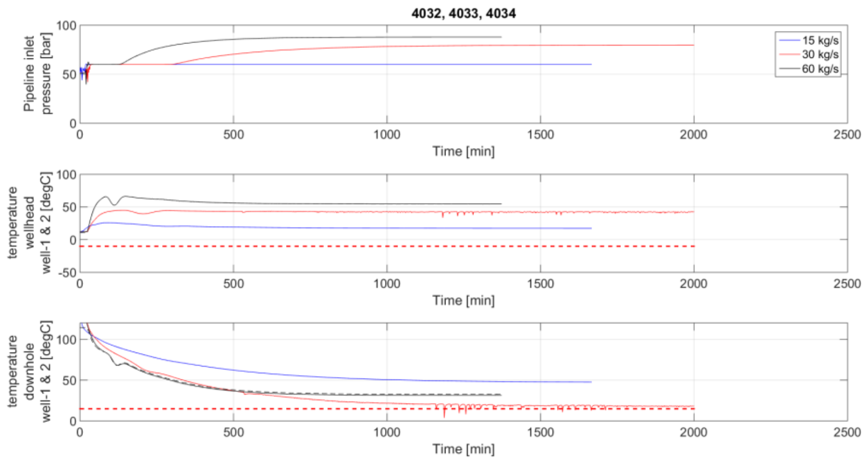


Figure 21:Pipeline inlet pressure, wellhead temperature (downstream choke valve) and downhole temperatures.

7.5 Discussion start-up reservoir pressure 20 bar– mid pipeline pressure

If the pipeline is at mid pressures (Figure 22), two potential start-up scenarios could be done:

- One in which the pipeline inventory is first emptied in the well by opening the well chokes prior to compressor start-up.
- Start-up the compressor while the pipeline is still flowing.

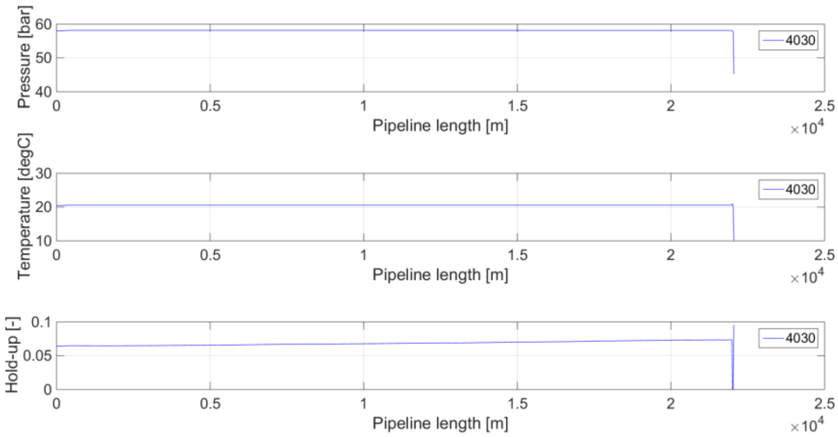


Figure 22: Initial conditions for start-up.

7.5.1 Empty pipeline (no pipeline pressure control) (case4035)

For case4035 the sequence is (Figure 23):

- The pipeline pressure control valve is set to p = 10 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.

The resulting temperatures are plotted in Figure 24.The wellhead temperatures are for a prolonged period too low (700 min).

Therefore, this scenario is not advised.

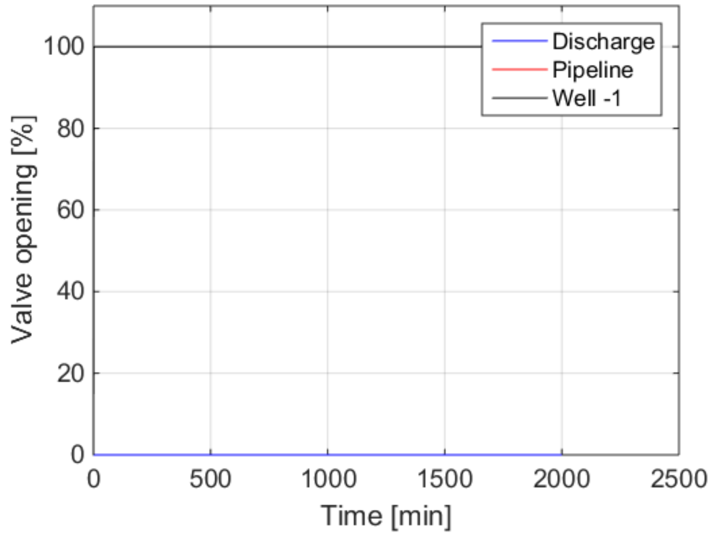


Figure 23: valve openings as function of time.

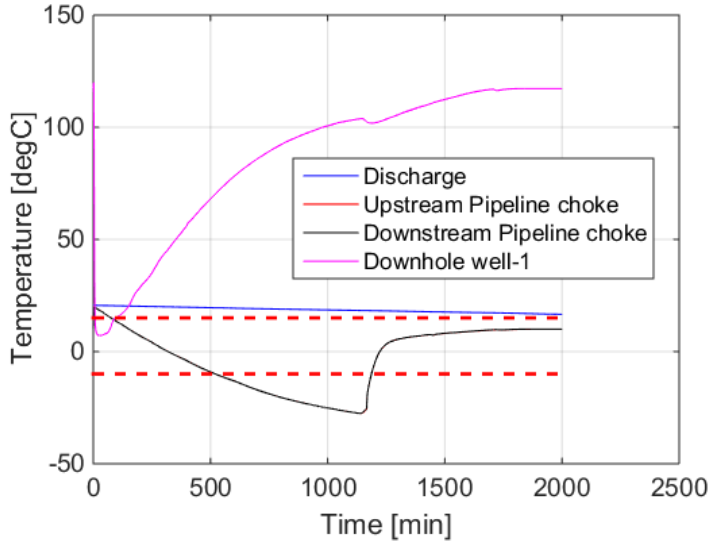


Figure 24: Resulting temperatures.

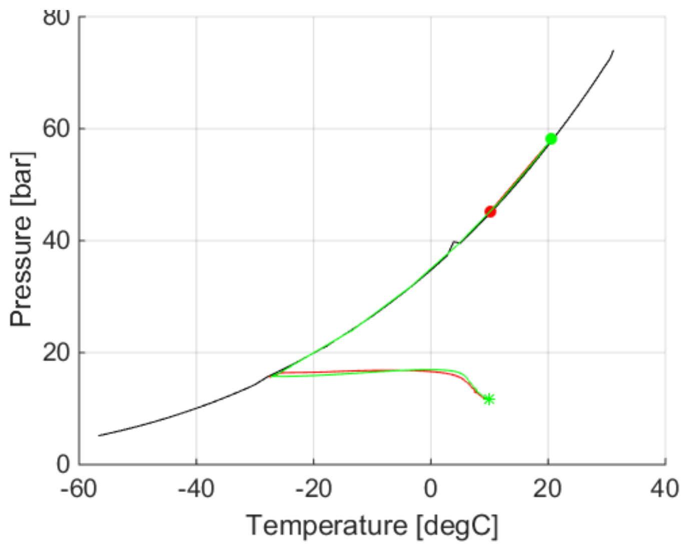


Figure 25: Pressure/temperature profile in the phase envelope. Black is the phase line. Green is downstream of the pipeline pressure control valve. Red at the pipeline inlet.

7.5.2 *Start-up without pipeline control (case 4036, 4037) (1 well)*

The second scenario is that the compressor is started up while the pipeline is emptied.

For case4036 the sequence is (Figure 26):

- The pipeline pressure control valve is set to p = 10 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.
- The compressor is ramped up from t = 5000 to 5600s.

For case4037 the sequence is (Figure 26):

- The pipeline pressure control valve is set to p = 10 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.
- The compressor is ramped up from t = 1 to 601s.

The resulting pressures & temperatures are given in Figure 27. Only for a short time (500 min) the downhole temperature criterion is just not met.

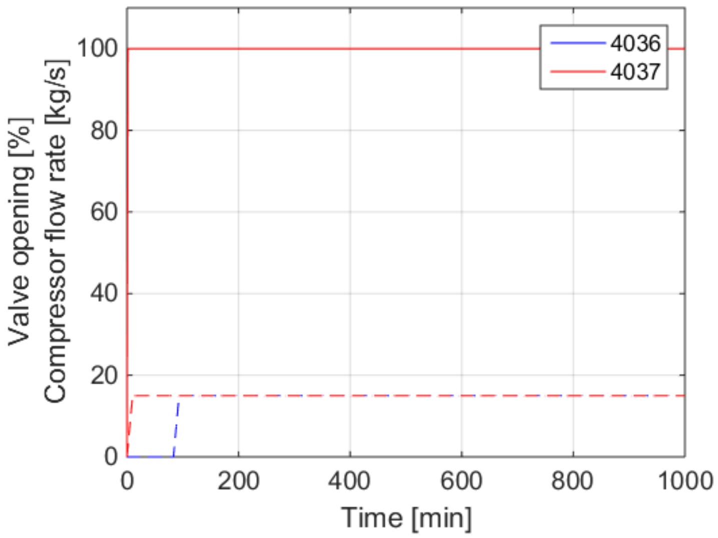


Figure 26: Valve (solid lines) and mass flow rates (dashed lines).

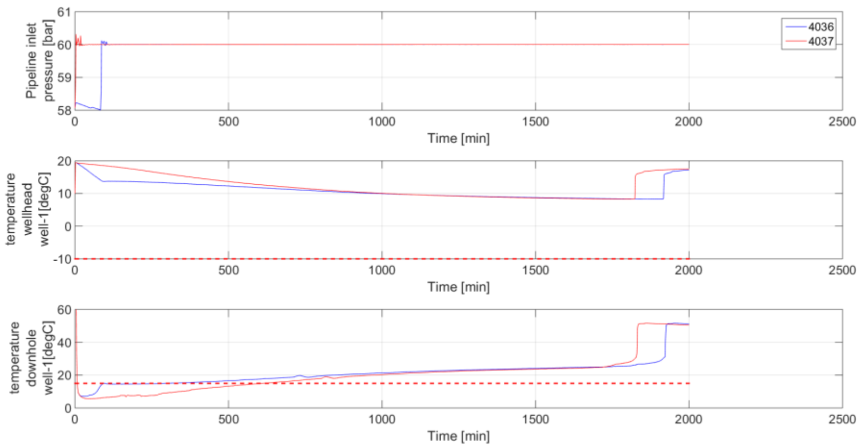


Figure 27: Resulting pressures and temperatures.

7.5.3 *Start-up without pipeline control (case4038) (2 wells)*

Case4038, is a start-up at higher mass flow rates with two wells open.

For case4038 the sequence is (Figure 28):

- The pipeline pressure control valve is set to p = 10 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.
- The control valve of well-2 is set to 1000 kg/s at t = 0s.
- The compressor is ramped up from t = 5000 to 5600s.

As with the previous start-up (Figure 27), for a short period, the downhole temperature criterion is not met but again this is for a shorter period (~200 minutes).

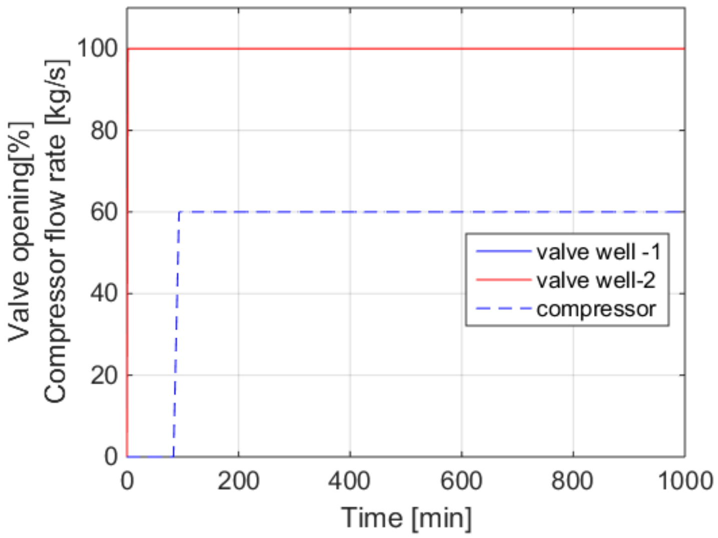


Figure 28: Valve opening (solid lines) and mass flow rate (dashed line).

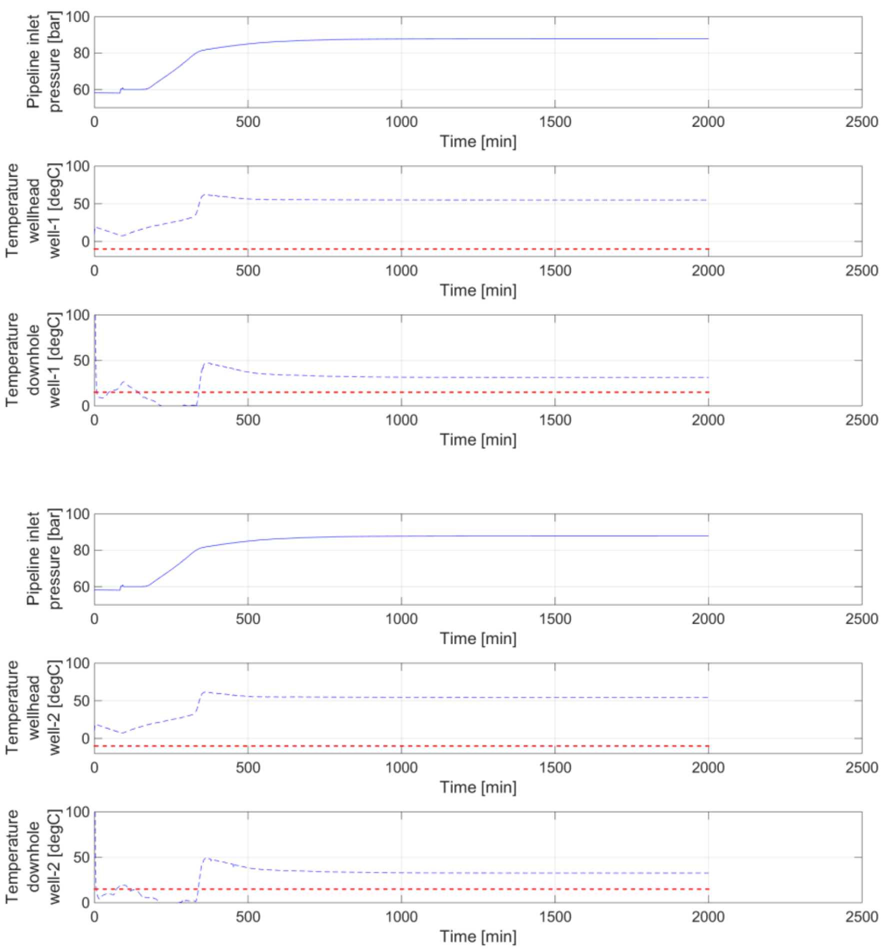


Figure 29: Pressures and temperatures for well-1 (top) and well-2 (bottom).

7.5.4 Start-up without pipeline control (case4039) (3 wells)

Finally, a large mass flow start-up with three wells is calculated.

For case4039 the sequence is:

- The pipeline pressure control valve is set to p = 10 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.
- The control valve of well-2 is set to 1000 kg/s at t = 0s.
- The control valve of well-3 is set to an opening 0, 0.05, 0.1, 0.2, 0.5 and 1 at t= 0, 100, 200, 300, 600, 700 s. (This sequence was chosen to open the well-3 in a controlled way. No variations for other sequences have been tried).
- The compressor is ramped up from t = 1000 to 1600s (from 60 to 90 kg/s).

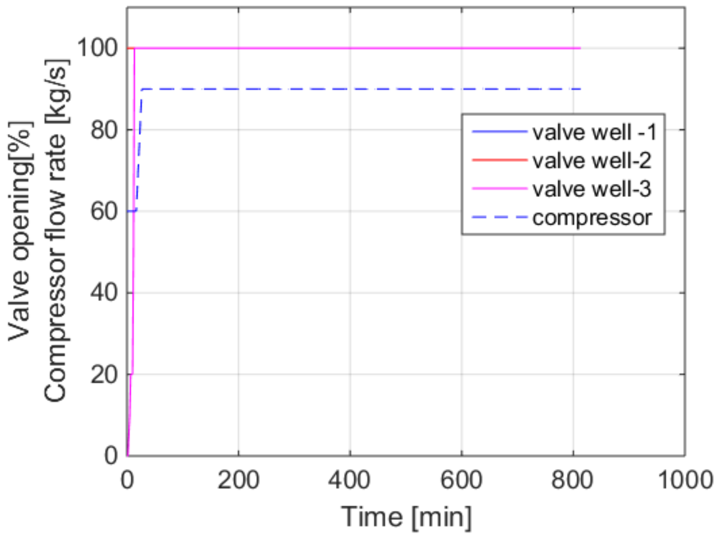
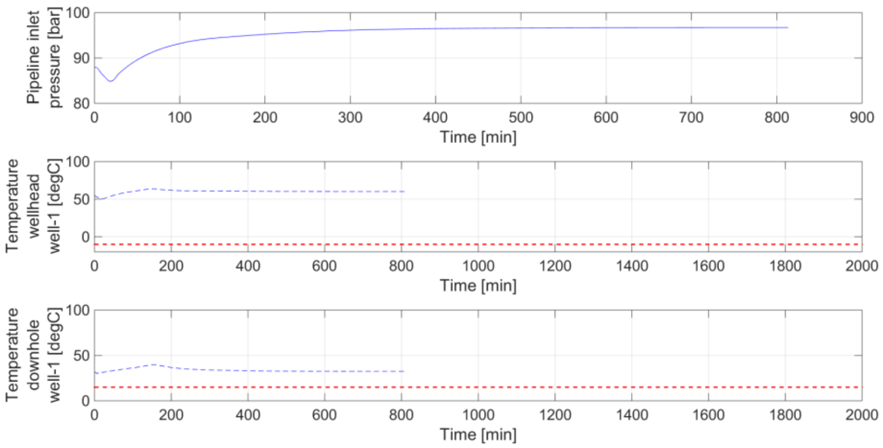


Figure 30: Valves (solid lines) and mass flow rate (dashed line).

The pressures and temperatures for the three wells are given in Figure 31. All conditions are met.



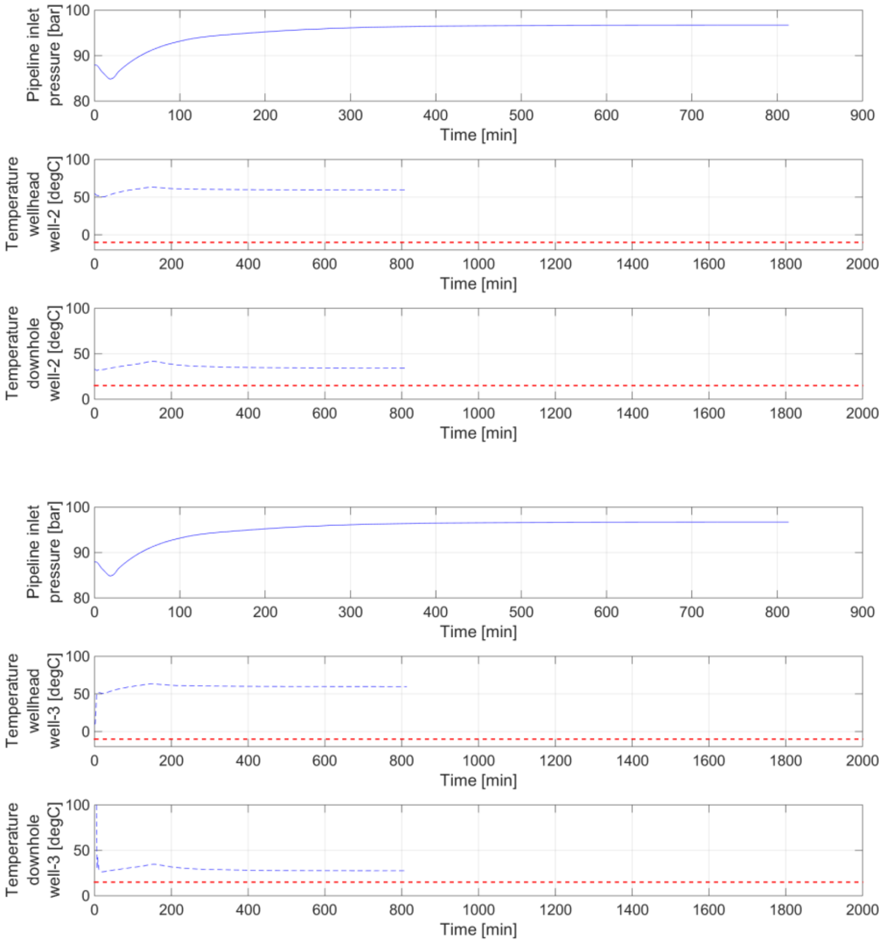


Figure 31: Pressures and temperatures for well-1, 2 and 3.

7.5.5 *Empty pipeline (with pipeline pressure control) (case4065)*

The previous start-up cases were without a pipeline pressure control. Case4065 is a case in which the pipe is emptied while there is a pressure control of 30 bar.

For case4065 the sequence is (Figure 32):

- The pipeline pressure control valve is set to p = 30 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.

As with the full pipeline emptying, the pressure and temperature drop (Figure 33, Figure 34). At a time of 440 min, the pressure control valves starts to close. Downstream of the valve the flow expands further down to 12 bar. This results again to temperatures of -38 °C before the heat transfer starts to kick-in.

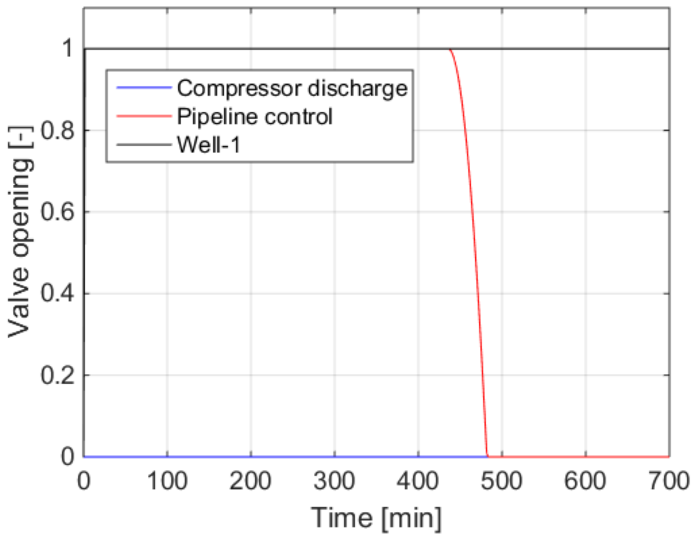


Figure 32: Valves as function of time.

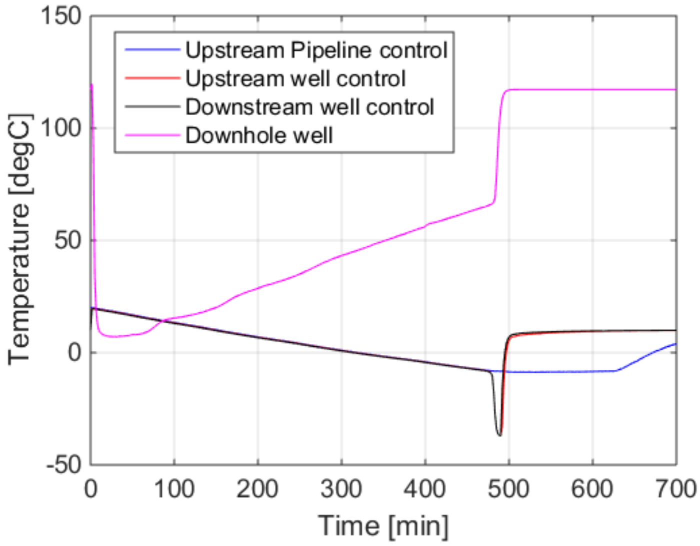


Figure 33: Temperatures as function of time.

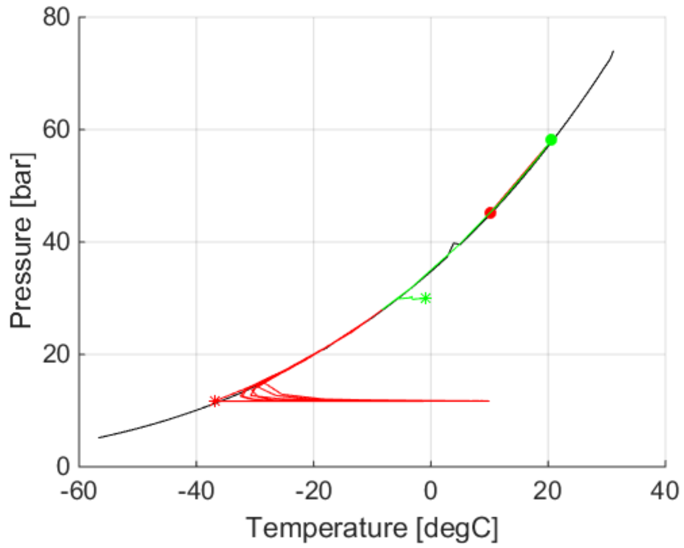


Figure 34: Pressure/temperature conditions in the phase envelope. Red indicated the conditions downstream of the pressure control valve. Green the conditions at the pipeline inlet.

7.5.6 *Start-up without pipeline control (case 4066) (1 well)*

For case4066 the sequence is (Figure 35):

- The pipeline pressure control valve is set to p = 30 bar at t= 0s.
- The control valve of well-1 is set to 10 bar at t = 1000s.
- The compressor is ramped up from t = 5000 to 5600s. (This means the pipeline pressure if emptied partly before the compressor is ramped up).

The resulting temperatures are given in Figure 36. Only a very short time the downhole temperature is too low.

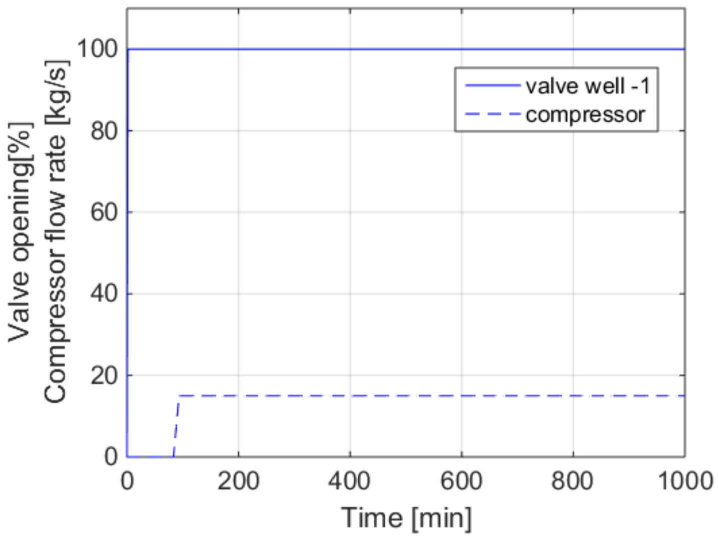


Figure 35: Valves (solid lines) and flow rates (dashed lines).

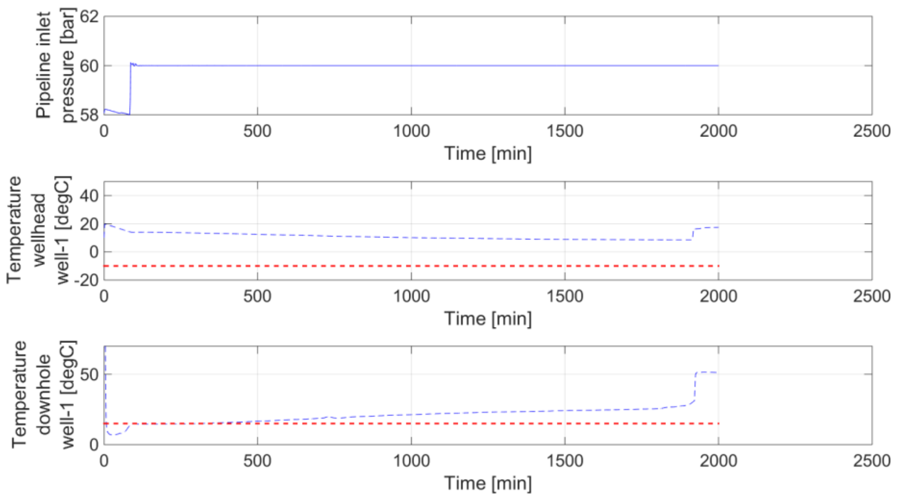


Figure 36: Pressures and temperatures as function of time.

7.6 Discussion start-up reservoir pressure 20 bar– high pipeline pressure

For the high pressure initial conditions (Figure 37), different strategies have been tried:

- First emptying the pipeline (case4044).
- Start up with the well (well2) the mass flow was limited (4045, 4047, 4048).
- A double pressure control (the pipeline at 85 bar and the well at 60 bar) (4049). (This case did not converge).
- Both the pipeline and well are at a limited opening (0.05) .

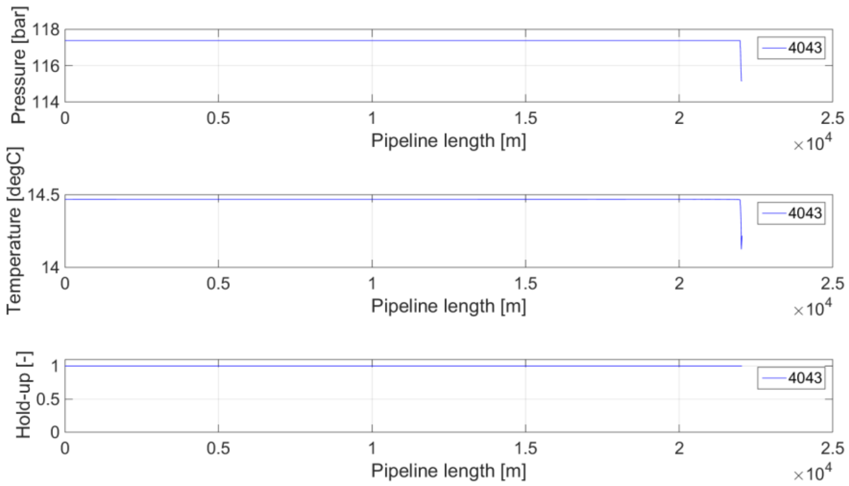


Figure 37: Initial conditions for high pressure start-up.

7.6.1 *Results case4044*

In case4044, the pipeline is emptied in to well-1 trying to release pressure (Figure 38 and Figure 39). However, this procedure leads to long periods of low downhole temperatures.

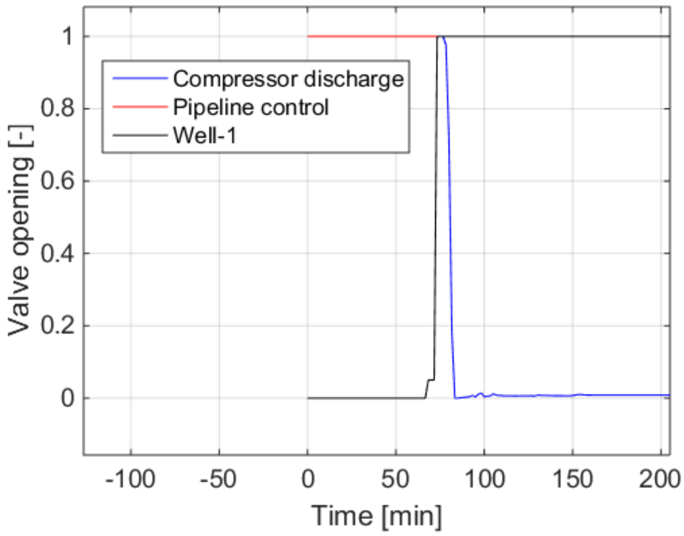


Figure 38: Valves as function of times.

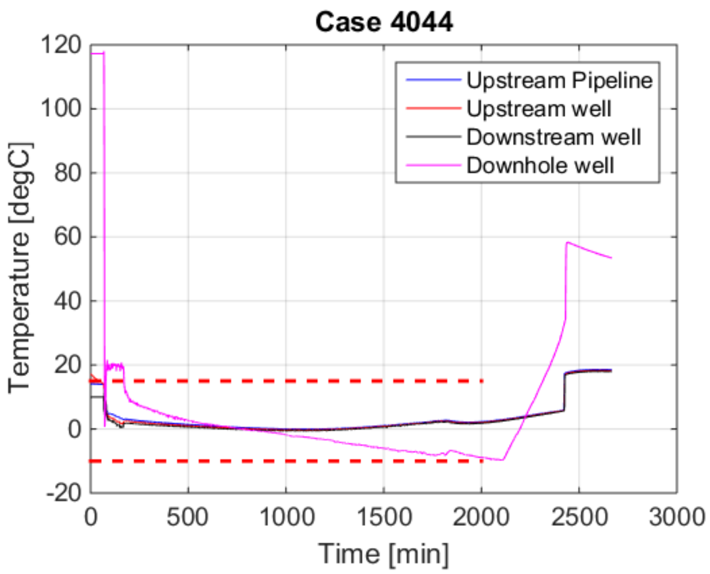


Figure 39: Resulting temperatures as function of time.

7.6.2 *Results case4045*

In case 4045, well-2 is used for injection and to limit the downhole temperature, the mass flow rate was constraint to 30 kg/s. However, both the topside wellhead temperature becomes too low as well as the downhole temperature.

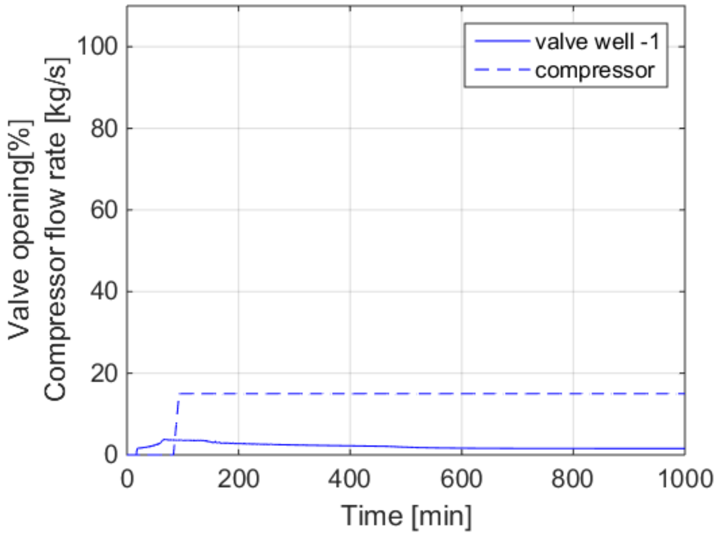


Figure 40: Valves and mass flow rates (dashed line).

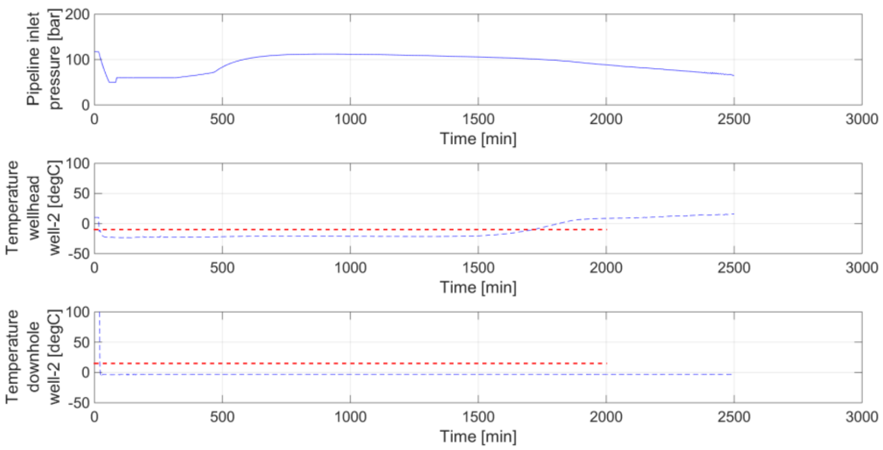


Figure 41: Temperatures and pressures as function of time.

7.6.3 *Results case4047 & 4048*

For completeness, the results of case4047 and case4049 are plotted in Figure 42 and Figure 43. In all these cases the temperatures are too low.

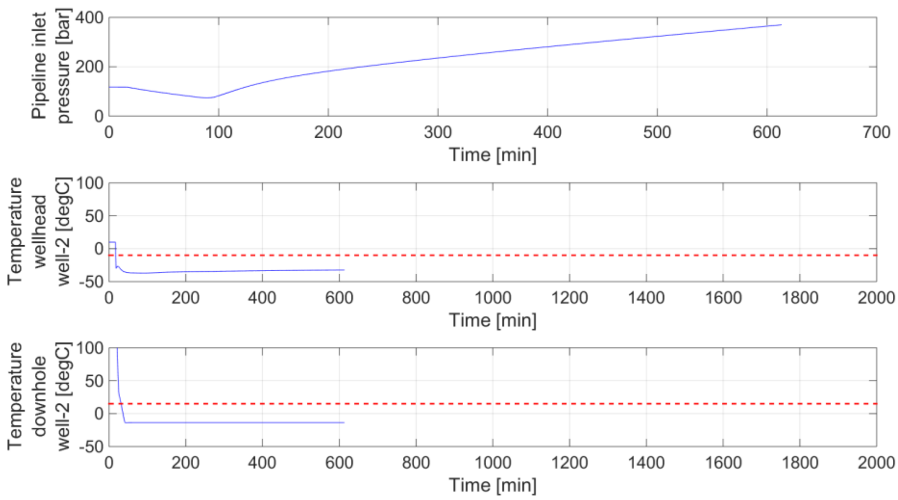


Figure 42: Results case4047.

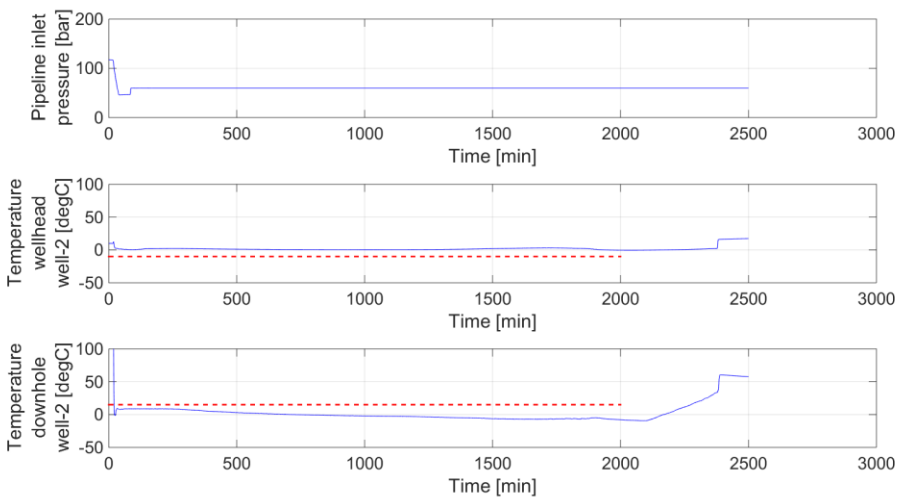


Figure 43: Results case4048.

7.7 Discussion venting

The high pressure start-up leads to long periods of too low temperatures. Therefore a set of venting solutions have been tried. The pipeline is vented down to a given pressure from which the system is started up again. (cases4051-4076).

If vented down to approximately 40 bar, the temperature in the pipeline is approximately 5 °C (for instance case4052). Different start-up scenarios, starting from this conditions were evaluated:

- First opening the wells
- First pressurizing the pipeline
- Mass flow control on the wells

Venting down to 40 bar, did lead to long periods of too low temperatures (Figure 44).
Venting down to 60 bar should lead to similar start-up sequences as discussed previously.

An alternative is that instead of venting, the pipeline pressure is slowly released into the well and that the topside piping is protected from the cold temperatures by local heating. As the bleed rate is low, the total heat capacity should be low. This scenario has not been calculated yet.

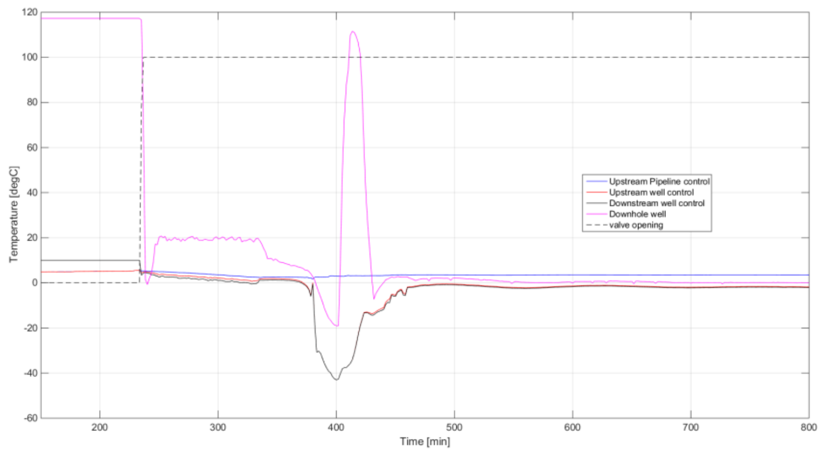


Figure 44: sharp peak is due to control action on the pipeline pressure control valve.

7.8 Discussions alternatives

Instead of venting a number of alternatives have been evaluated:

- Use of a very small ID well (0.09m). This increases the topside pressure at lower flow rates and keeps the flow rates at a given pipeline pressure limited.
- Adding N2 (5% mole fraction) in the hope that the temperature effects are reduced.
- Adding downhole chokes (different sizes and different depts).

These were trial simulations and more scenarios could potentially be simulated. However, the cases tried did not pass the temperature boundary condition limitations.

7.9 Discussion start-up reservoir pressure 60 bar – mid pipeline pressure

For the start-up with a reservoir pressure of 60 bar two sets of cases are analysed. The first set is that all wells are at a reservoir pressure of 60 bar (cases 4105, 4106, 4107). In addition to the basic start-up, the effect of opening a 2nd well is evaluated (4108).

7.9.1 Results 4105 – 4107

The initial pipeline conditions at a pipeline pressure of approximately 63 bar, 24°C with a liquid hold-up of approximately 0.26 (Figure 47).

For all cases a sequence of events has been used defined by:
- The chokes of wells 2, 3, and 4 (P18-2 wells) are closed.
- The choke valve of well-1 is set to a pressure control of 85 bar at t= 0s.
- The pipeline control valve is set to a pressure control of 1 bar at t= 0s (this is already open in the initialisation cases).
-The compressor is ramped from t= 1000s to t = 1300s from a flow rate of 0 kg/s to the desired flow rate.

The results are given in
Figure 45. For all three start-up scenarios, the calculated temperatures are higher than the temperatures limitations.

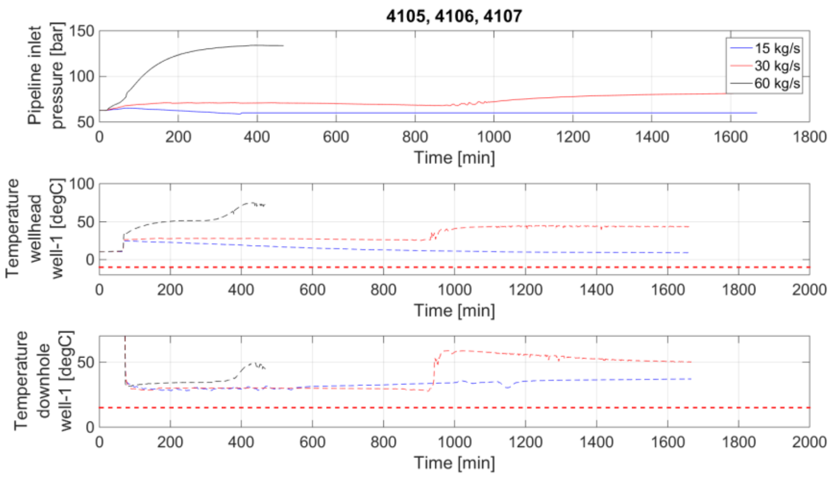


Figure 45: Resulting pressure and temperatures.

7.9.2 Results 4108 (opening 2nd well)

Case4108 is started from case4106 (with a reached steady conditions with a total mass flow rate of 30 kg/s).

The sequence of events is:
- The mass flow rate is increased to 60 kg/s at t = 0s.
- The choke at the second well well-2 is opened from 0 to 1 at t = 1000s.

Except for a very short period directly at opening of the choke valve (Figure 46) all temperatures meet the requirements.

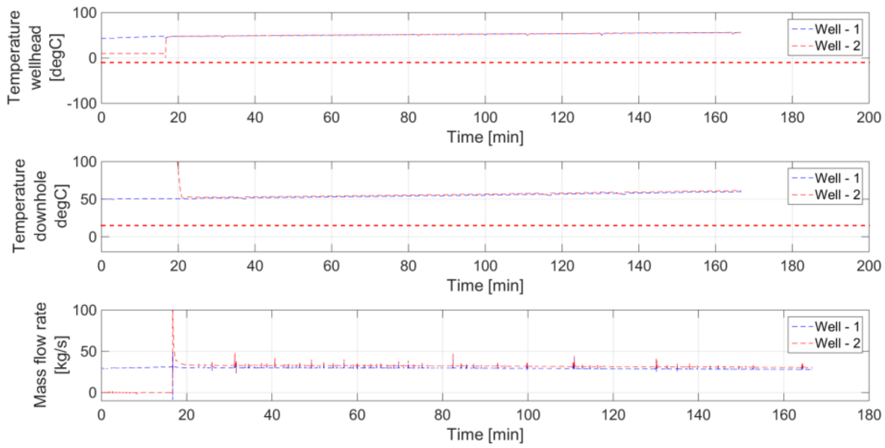


Figure 46: Resulting pressure and temperatures.

7.10 Discussion start-up reservoir pressure 100 – 340 bar – mid pipeline pressure

The higher pressure start-up cases have been done with pipeline conditions at a pipeline of approximately 63 bar, 24°C with a hold-up of approximately 0.26 (Figure 47).

For all cases a sequence of events has been used defined by (Figure 48):
- The chokes of wells 2, 3, and 4 (P18-2 wells) are closed
- The choke valve of well-1 is set to a pressure control of 85 bar at t= 0s.
- The pipeline control valve is set to a pressure control of 1 bar at t= 0s (this is already open in the initialisation cases).
- The compressor is ramped from t= 1000s to t = 1300s from a flow rate of 0 kg/s to the desired flow rate.

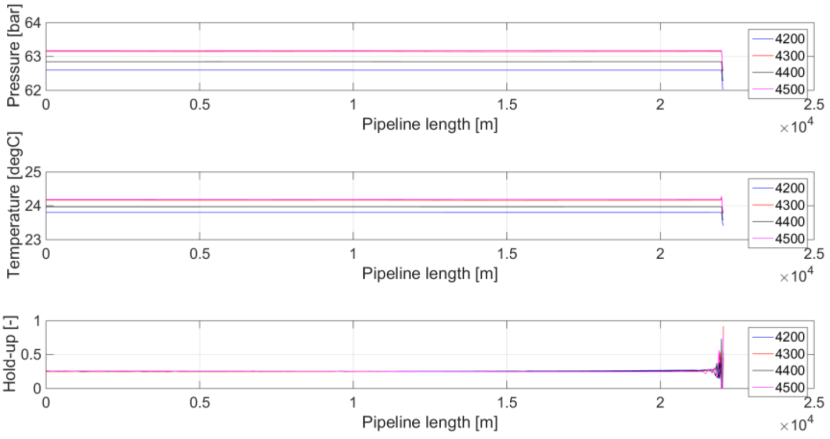


Figure 47: Pressure, temperature and hold-up profile at the start of the start-up sequence.

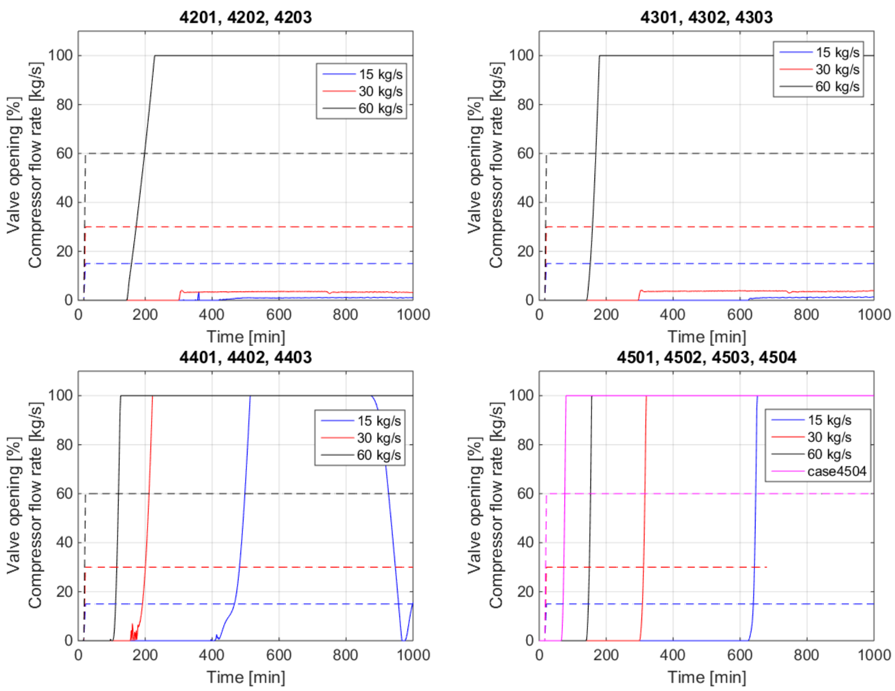


Figure 48: Compressor flow rates and valve openings at well 1 for the 4200, 4300, 4400 and 4500 series. Solid lines the valve opening [%]. Dashed lines indicate the compressor flow rates.

7.10.1 *Results reservoir pressure 100 bar*

For a reservoir pressure of 100 bar, the resulting pressures and temperatures are given in Figure 49. For all times, the temperatures are high enough both topside as well as downhole.

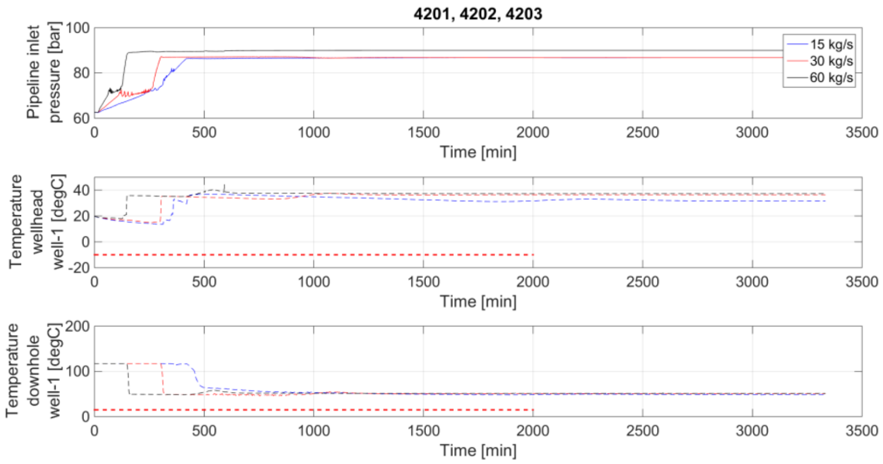


Figure 49: Pressures and temperatures as function of time.

7.10.2 Results reservoir pressure 200 bar

For a reservoir pressure of 200 bar, the resulting pressures and temperatures are given in Figure 50. For all times, the temperatures are high enough both topside as well as downhole.

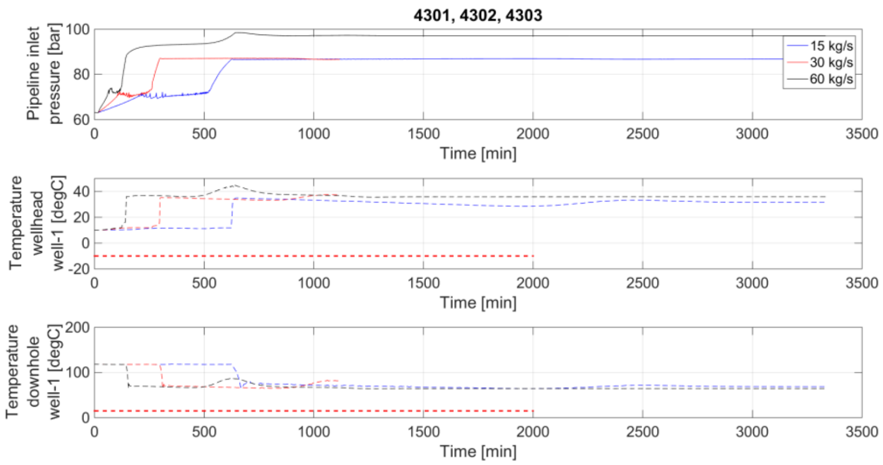


Figure 50: Pressures and temperatures as function of time.

7.10.3 Results reservoir pressure 300 bar

For a reservoir pressure of 300 bar, the resulting pressures and temperatures are given in Figure 51. For all times, the temperatures are high enough both topside as well as downhole. The high mass flow rate start-up might take longer than calculated as the maximum calculated compressor pressure is nearly 150 bar. Therefore, this start-up rate must be done with more than one well open.

Although, this specific case is not representative for the real life situations, no difficulties are expected as there are no temperatures limits downhole and the temperature effects topside are limited as the fluid is in the liquid state.

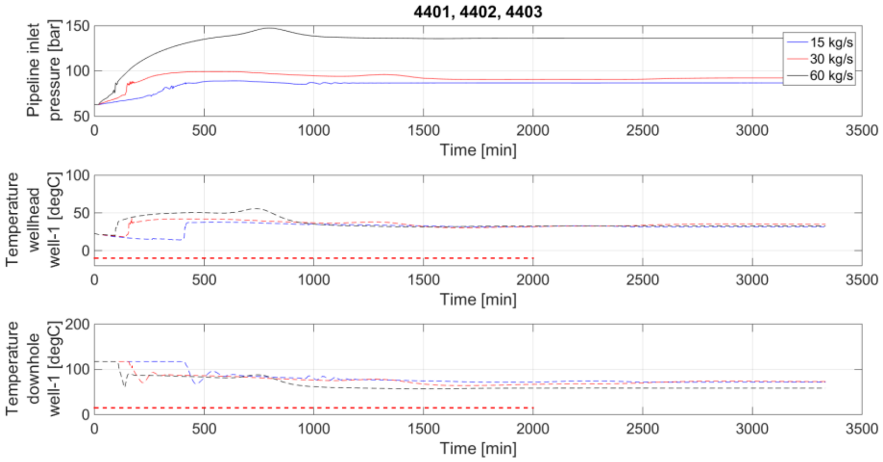


Figure 51: Pressures and temperatures as function of time.

7.10.4 *Results reservoir 340 bar*

For a reservoir pressure of 300 bar, the resulting pressures and temperatures are given in Figure 52 and Figure 53 For all times, the temperatures are high enough both topside as well as downhole. The high mass flow rate start-up might take longer than calculated as the maximum calculated compressor pressure is higher than 120 bar. Therefore, this start-up rate must be done with more than one well open.

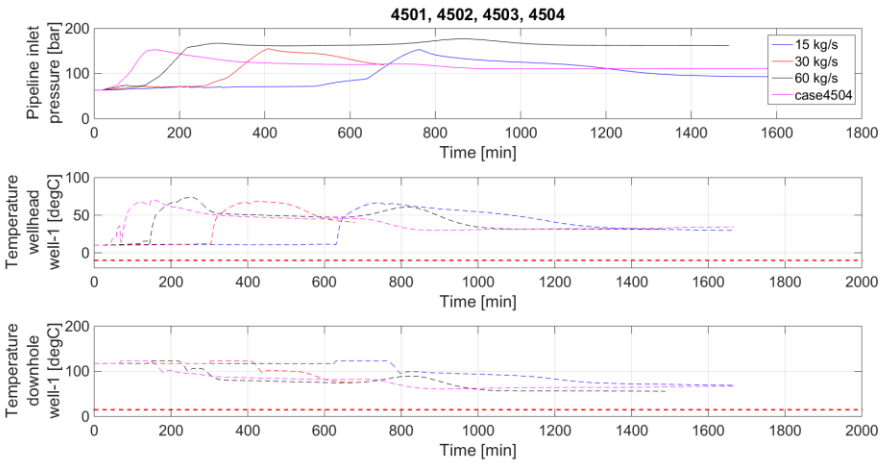


Figure 52: Pressures and temperatures as function of time.

8 Depressurization

An important event is venting or depressurizing the system. As most of the pipes are well insulated, there is no to little heat ingress. That means that the fluid temperature is almost adiabatic.

As an example, the pipeline is vented with initial conditions at the liquid state (115 bar, 15°C) (Figure 53). As soon as the venting starts, the pressure decreases rapidly as the pipeline is in liquid state. With the venting, the pipeline comes into two-phase conditions. With a continuation of the venting, the pipeline pressure decreases and the resulting temperature decreases fast.

This means that of venting continuous to atmospheric conditions, solid CO_2 will be formed and the temperature will drop down to extreme low temperatures. To avoid this it is recommended to keep venting/depressurization limited down to 30 bar. This 30 bar is chosen based on the fact that the phase line temperature for 30 bar is -5 °C. Even with some pressure undershoot this will limit fluid temperatures.

It must be remarked that this effect will occur with all venting or depressurization event. All sections which must be able to be depressurized fast will need to designed for extreme low temperatures.

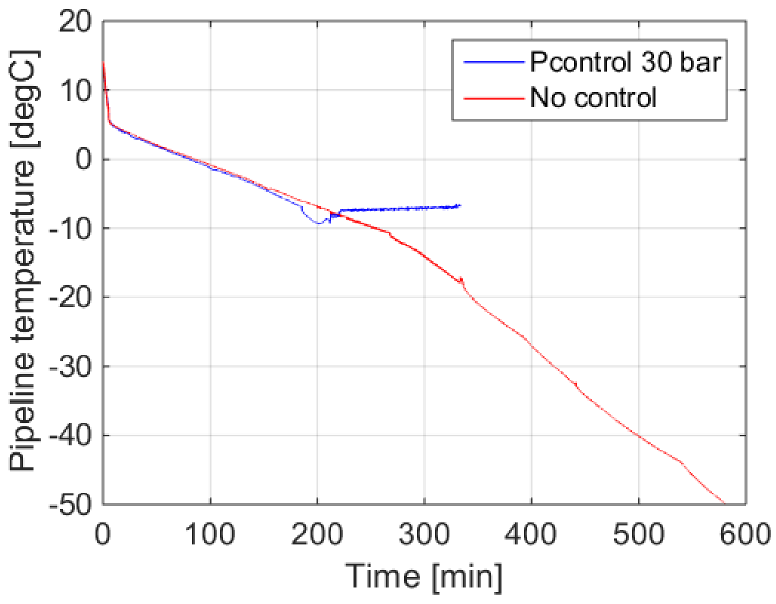


Figure 53: Pipeline temperature as function of time during a venting action with no pipeline control (red) or with the pipeline pressure control at 30 bar.

9 Shut-in/turn-down

9.1 Introduction

In this chapter two sets of simulations are presented. In the first set there are scenarios in which the mass flow is ramped down. The second set is a set in which the wells are shutin.

9.2 Simulation cases

Shutin at Pres = 20 bar

Case	*Pres*	*Tcmp*	*Wells*	*control*	*Mass flow*	*Start from*
7000	20	80	1	30	15->0; dt=300	4024
7001	20	80	1	30	30->0; dt = 300	4025
7002	20	80	4	30	140->0; dt = 300	4028
7005	20	80	1	no	15->0; dt=300	4024
7006	20	80	1	no	30->0; dt = 300	4025
7009	20	80	1	No	Well shutin	4025
7016	20	80	1	No	Well shutin 100	4025
7017	20	80	1	No	Well shutin 300	4025
7018	20	80	1	No	1000s	4025

Shutin at Pres = 60 bar

Case	*Pres*	*Tcmp*	*Wells*	*control*	*Mass flow*	*Start from*
7015	60	40	1	1 well	Well shutin	4009

The cases 7012-7014 have been wrongly initialised and are not reported

Shutin at Pres = 100 bar

Case	*Pres*	*Tcmp*	*Wells*	*control*	*Mass flow*	*Start from*
7008	100	40	4	Pipe (85)	170 -> 0	4078
7011	100	40	1	1 well	Well shutin	4078

Shutin at Pres = 340 bar

Case	*Pres*	*Tcmp*	*Wells*	*control*	*Mass flow*	*Start from*
7007	340	40	4	Pipe (85)	140->0	4006
7010	340	40	1	1 well	Well shutin	4006

9.3 Results well shutin for different reservoir pressures.

Well shutin simulations are done at different reservoir pressures. For a reservoir of 20 bar, the speed with which the valve was shutin was varied between 20 – 1000s (7009, 7016-7018). For reservoir pressures of 60, 100 and 340 bar only fast shutin cases were simulated.

For the shutin cases 7009, 7016-7018, the following sequences are calculated (Figure 54):

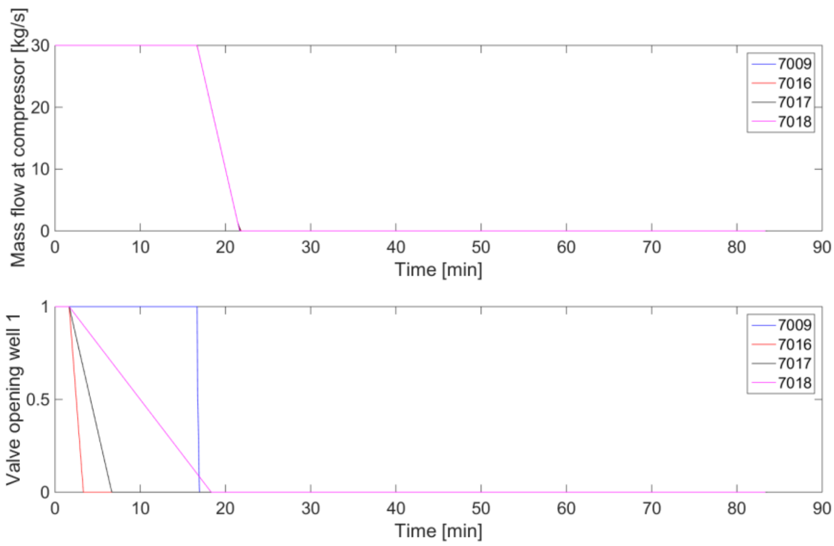
- Initial conditions are simulations at fixed mass flow ran long enough to obtain steady conditions.
- The mass flow is ramped down from t=1000s to t= 1100s
- The choke at well-1 is shutin at t = 1000s (7009) and at t = 100s (7016-7018).
- Similar sequences are done for the higher pressure cases.

During shut-in/depressurization low temperatures in the well will occur due to expansion. This occurs typically in the top region (top 1000 m) but at fast shut-in of the wellhead choke, the complete well can go down in temperature (basically following pressure gradient and following phase line). The well control valve shut-in-time does practically not matter (Figure 55).

At higher reservoir pressures, the minimum temperatures increase

- Reservoir pressure 20 bar -37 °C
- Reservoir pressure 60 bar -17 °C
- Reservoir pressure 100 bar -5 °C
- Reservoir pressure 340 bar +30 °C

For the higher pressures, the wellhead temperature is plotted in Figure 57. From this figure, it is more clear that the low temperature period can be in the order of 30 minutes. It must be remarked again, that for the current simulation model uses Uvalue methodology and therefore no heat-capacity of the walls and annulus fluids are included. This means that the heating up also occurs faster then will be in real-life but that the wall temperatures will be higher than the calculated temperatures.



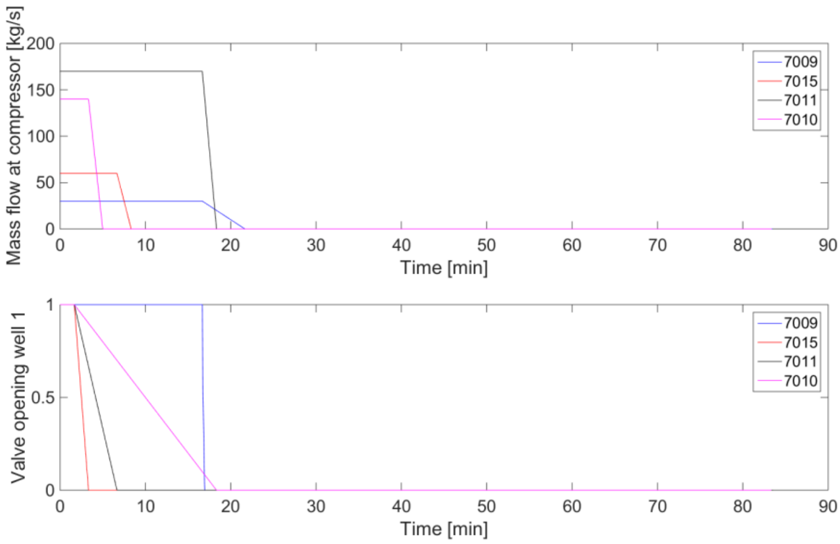


Figure 54: Sequences of flow rates and valves.

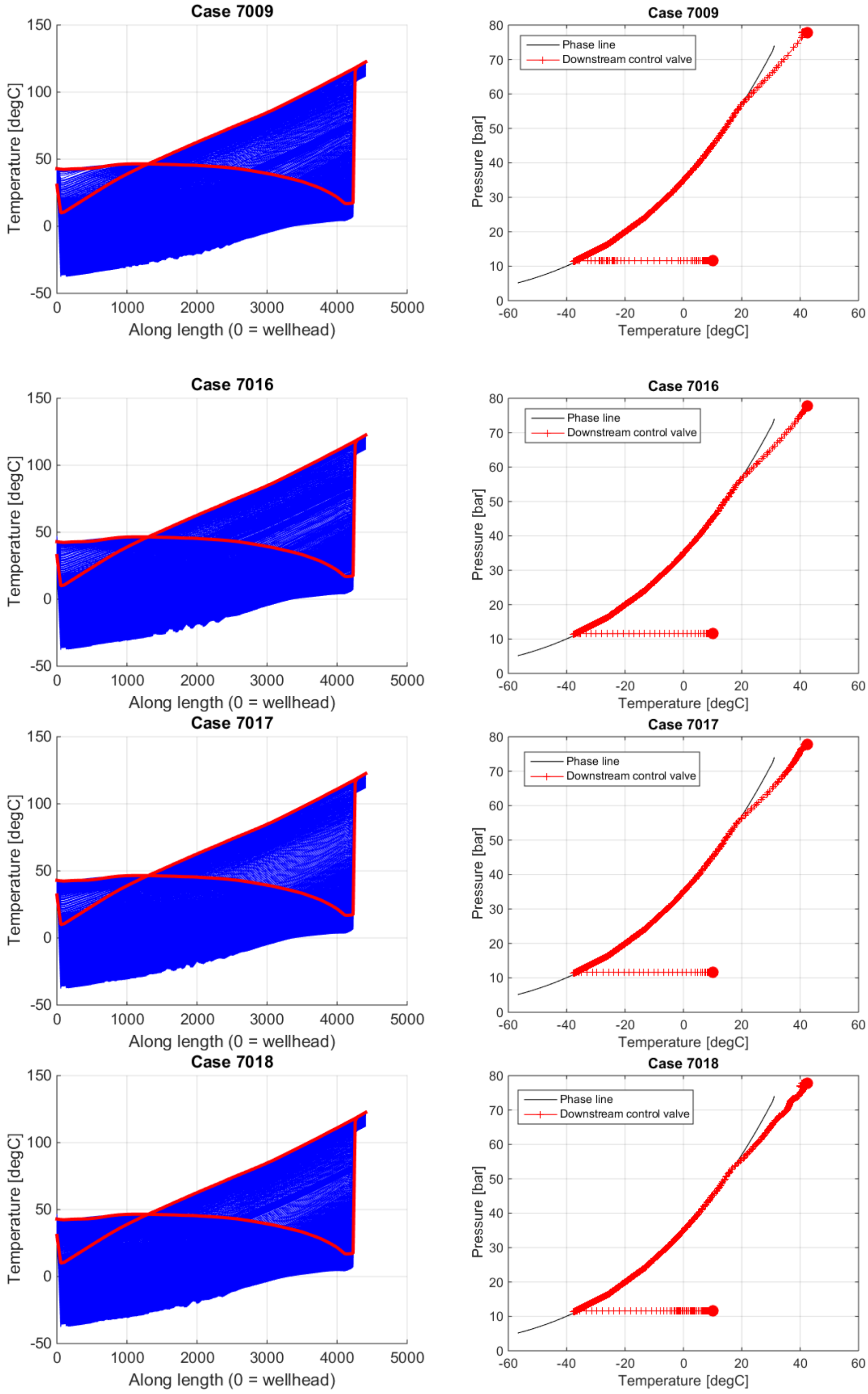


Figure 55: Temperature profile in the wells during ramp-down. The red lines indicate the initial and final profile. Each blue line is at a time step of 1 s. Right figures give pressure/temperature as function of time downstream of the choke at well-1. Cases 7009, 7016, 7017, 7018 are for cases without pipeline pressure control.

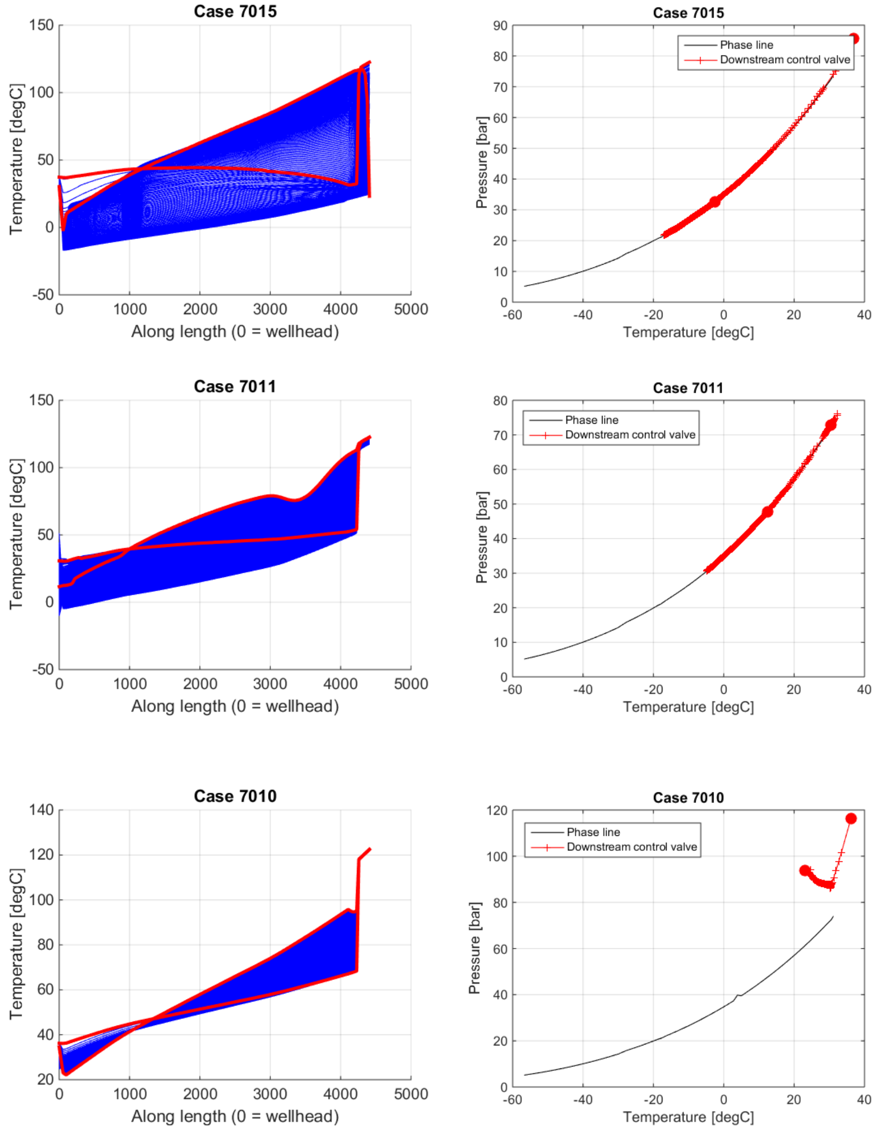


Figure 56: Temperature profile in the wells during ramp-down. The red lines indicate the initial and final profile. Each blue line is at a time step of 1 s. Right figures give pressure/temperature as function of time downstream of the choke at well-1.Cases 7015, 7011 and 7010 are for a reservoir pressure of 60, 100 and 340 bar.

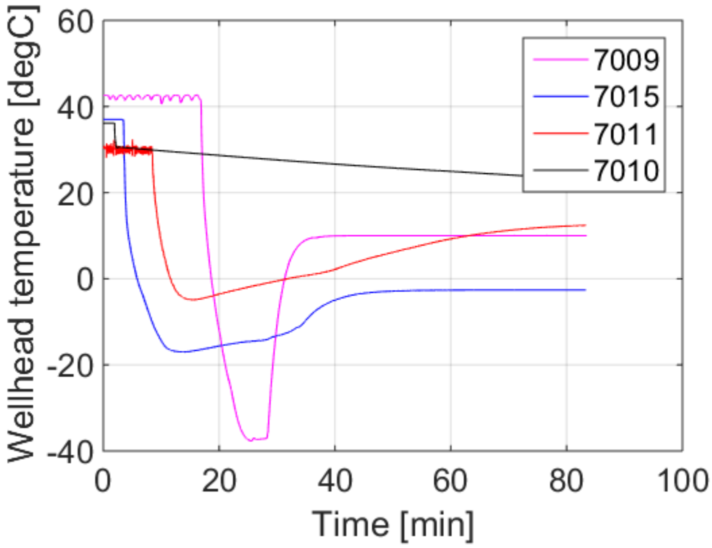


Figure 57: Wellhead temperature as function of time for the cases 7009 (20 bar), 7015 (60 bar), 7011 (100 bar), 7016 (340 bar).

9.4 Results turn-down reservoir pressure 20 bar

The cases with a reservoir pressure of 20 bar and including a pipeline control valve, the turn-down cases 7000, 7001, 7002, 7005 and 7006 are done. The sequences is mainly for (Figure 58):

- Mass flow rate is ramped down in 300s at t = 1000s.
- The well valves are kept open.

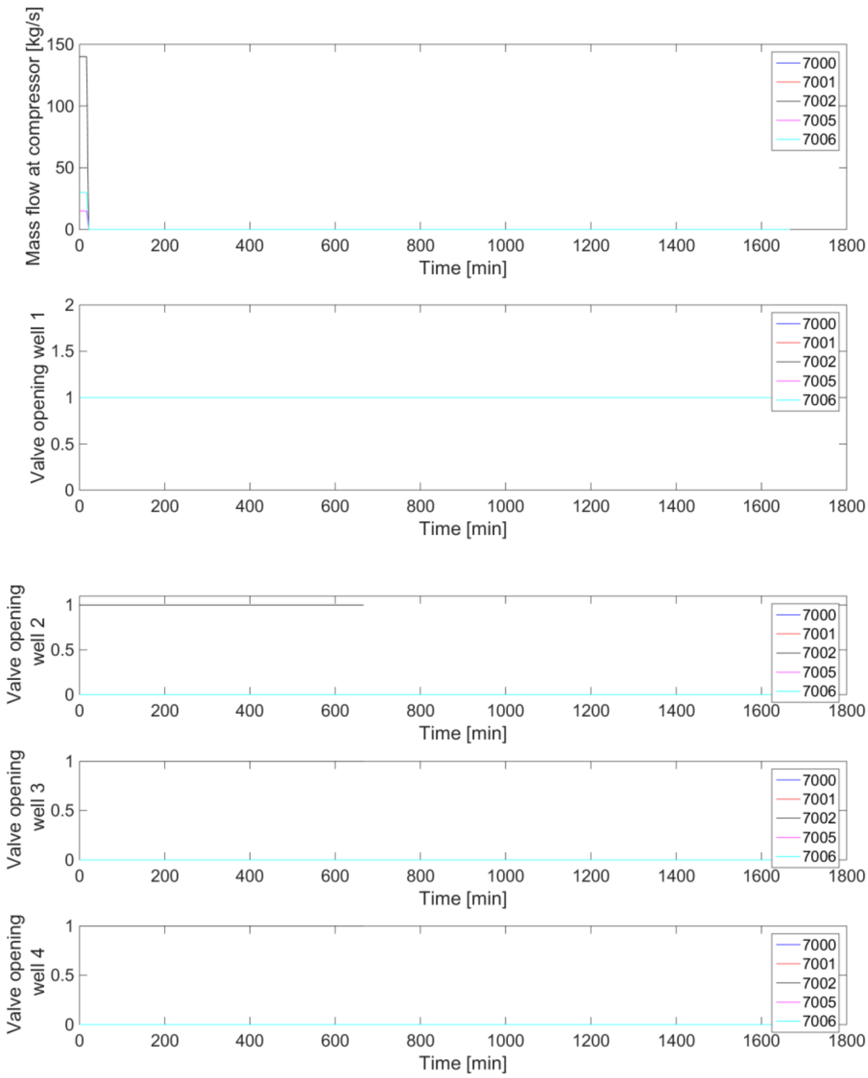


Figure 58: Mass flow rates and valve opening as function of time.

The resulting temperature profiles in well-1 are plotted in Figure 59 and the pipeline in Figure 60. The low temperature zone is mainly restricted to the topside in the well but the pipeline can get very cold with low temperatures down to -20 °C in the whole pipeline and very low temperatures downstream of the pipeline control valve.

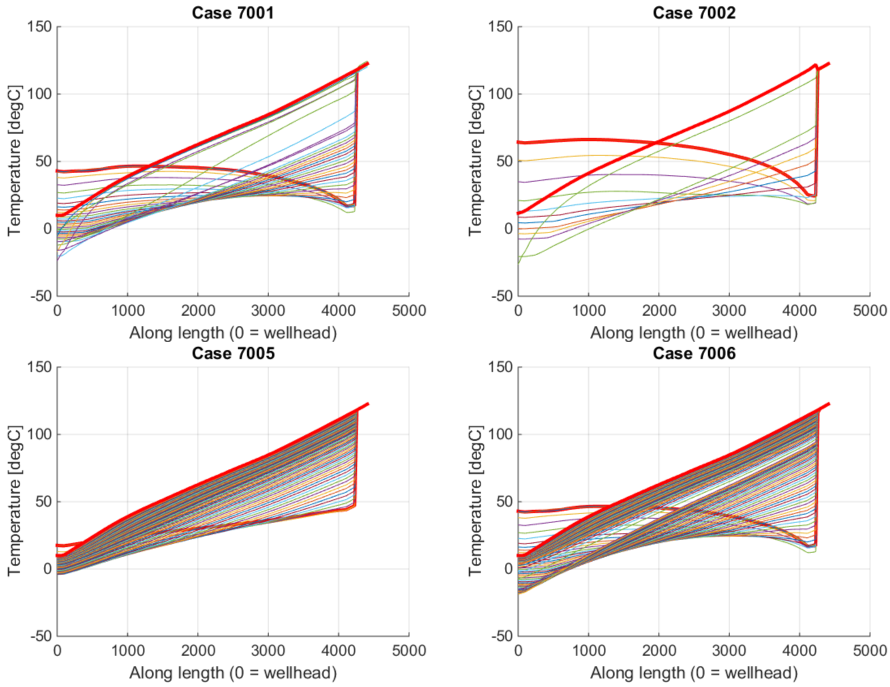


Figure 59: Temperature profile in the wells during ramp-down. The red lines indicate the initial and final profile. Each blue line is at a time step of 1000 s.

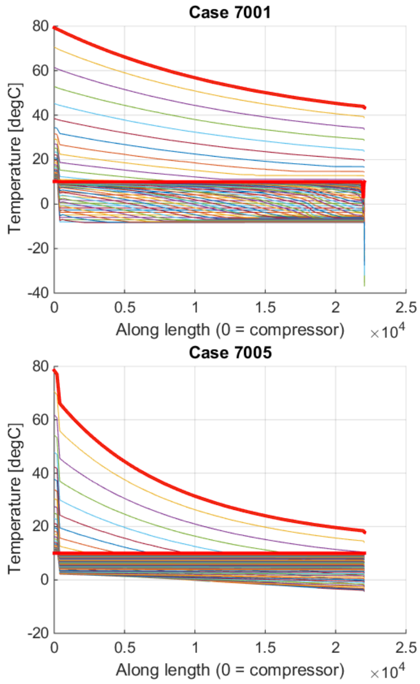


Figure 60: Temperature profile in the pipeline during ramp-down. The red lines indicate the initial and final profile. Each color line is at a time step of 1000 s. Cases 7001 and 7002 have a pipeline control of 30 bar. This means that downstream the valve, the expansion is deeper. This explains the sharp decrease observed in 7001 and 7002 results.

9.5 Results turn-down reservoir pressure 100 bar

For the case7008 with a reservoir pressure of 100 bar, the sequence of events simulated are (Figure 61):

- The mass flow rate is ramped down from t=0 to 100s
- The pipeline pressure controller is set to 85 bar
- Well-1 is at a pressure control of 10 bar (meaning full open)
- Well-2, 3, 4 is at a mass flow control at 1000 kg/s (meaning full open)

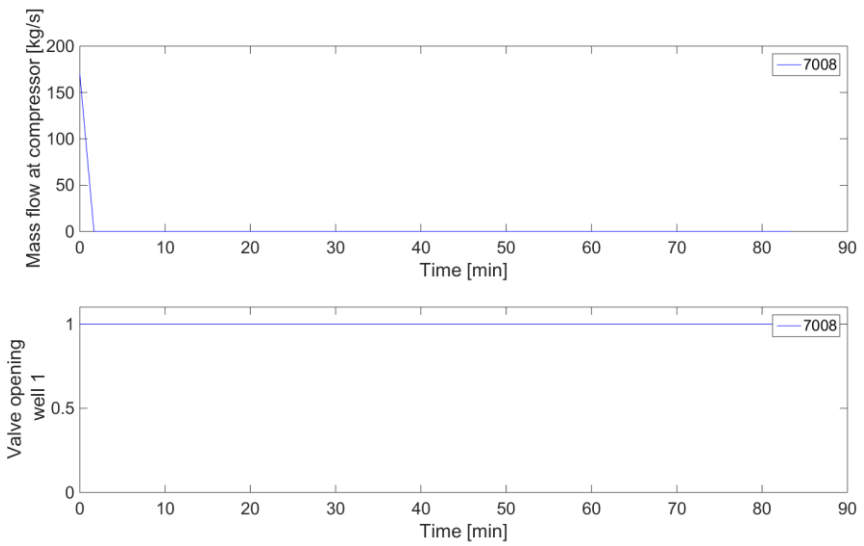


Figure 61: Mass flow rates and valve opening as function of time.

The resulting temperatures in all four wells and the pipeline is given in Figure 62 and in Figure 63. The minimum temperatures only just drop below 0 °C.

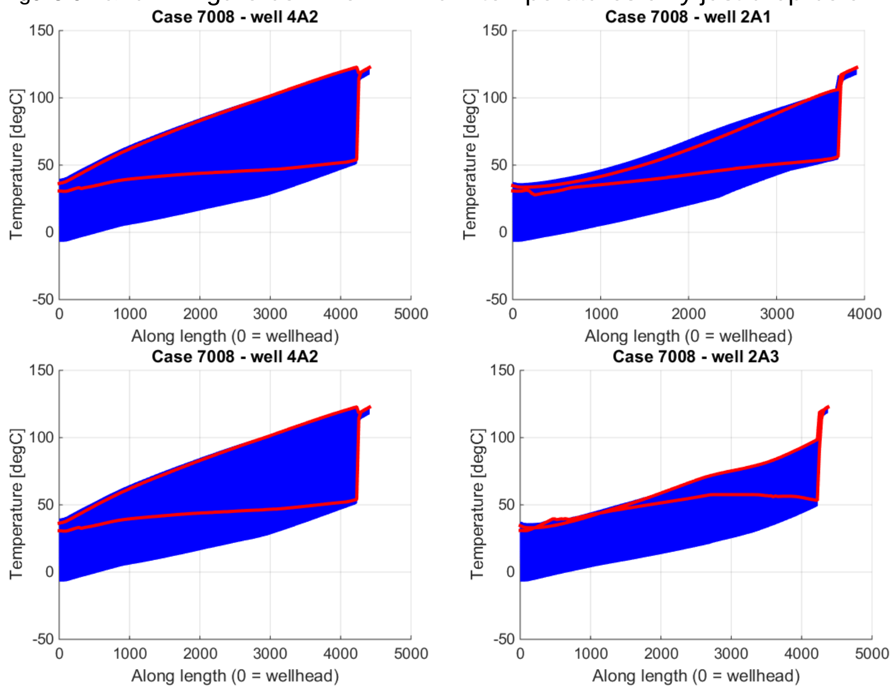


Figure 62: Temperature profile in the wells during ramp-down. The red lines indicate the initial and final profile. Each blue line is at a time step of 1 s.

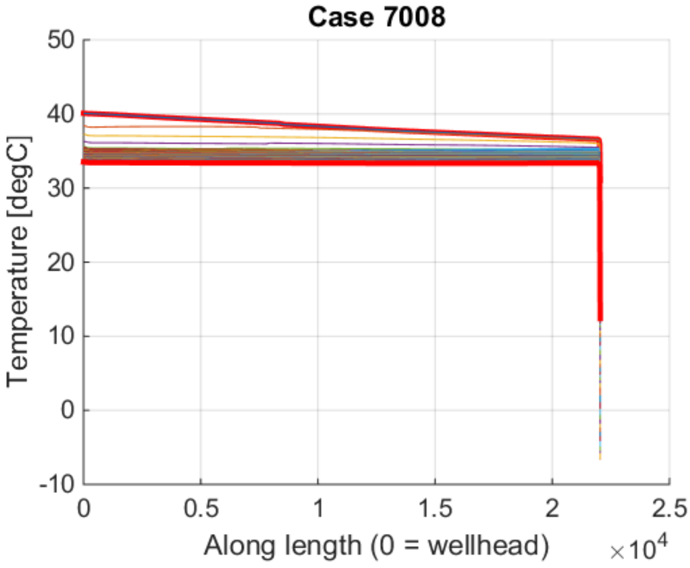


Figure 63: temperature profile in the pipeline. The red lines indicate the initial and final profile. Each coloured line is at a time step of 100 s

9.6 Results turn-down reservoir pressure 340 bar

Finally, for the case7007 with a reservoir pressure of 340 bar, the sequence of events simulated are (Figure 64):

- The mass flow rate is ramped down from t=0 to 100s
- The pipeline pressure controller is set to 85 bar
- Well-1 is at a pressure control of 10 bar (meaning full open)
- Well-2, 3, 4 is at a mass flow control at 1000 kg/s (meaning full open)

The resulting temperatures (Figure 65) all remain high.

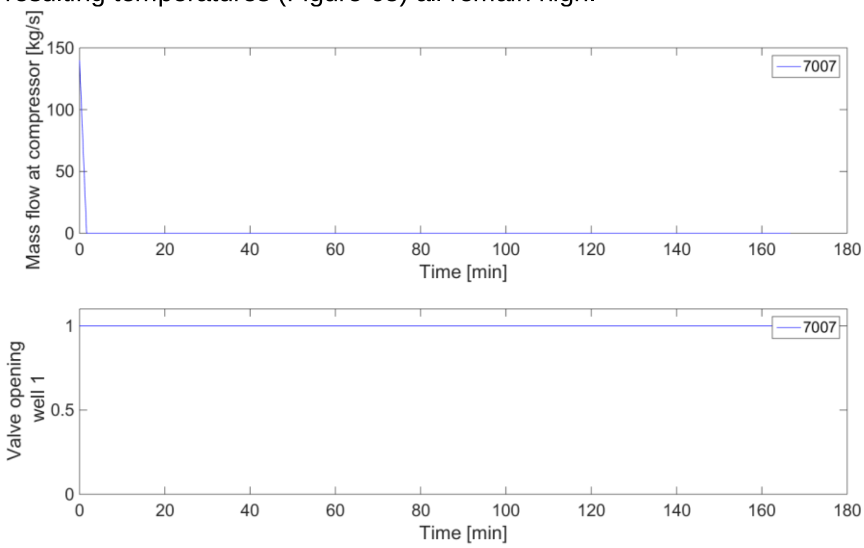


Figure 64: Mass flow rate and valve openings as function of time.

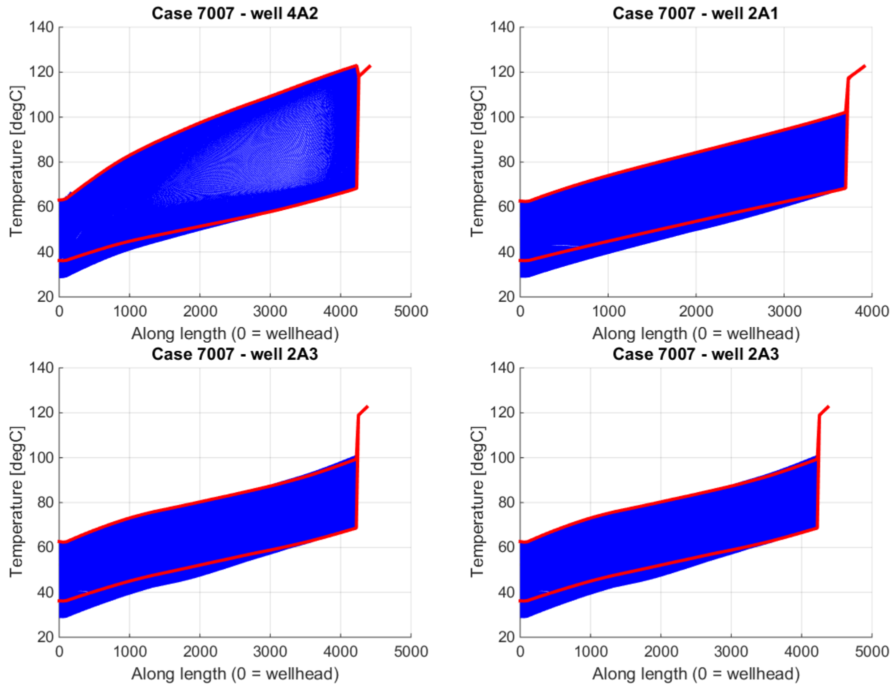


Figure 65: Temperature profile in the wells during rap-down. The red lines indicate the initial and final profile. Each blue line is at a time step of 1 s.

10 Discussion/ general remarks

This chapter summarises the conclusions and key results from the previous chapters.

The main concepts which determine injection:

- Phase line conditions link the temperature and pressure.
- The critical bottomhole pressure is 50 bar as this corresponds to a phase line temperature of 15 °C (which is the set downhole temperature limit).
- Keeping the mass flow rate and keeping the wellhead pressure high avoids low temperatures during steady operations. Smaller ID wells keep the wellhead pressure high already at low flow rates. However, small ID well limit the injection rate at low reservoir pressure due to too low downhole temperatures and at high reservoir pressures the rates are limited due to too high compressor pressures (too high friction).

- Scenario's in which the tubing diameter is changed after a period of operation have not been included in this report.

- Only a limited set of runs with more complicated well designs are done. Downhole valves, ICD's tuneable orifices etc are not included as this complicated the well design significantly and might risk of local freezing of components.

- The compressor discharge control valve is now set downstream of the compressor after-cooler. This as this is worst case for the simulations as we lose temperature across the valve. In reality this valve might be installed upstream of the cooler if so desired.
- In the simulations a dedicated pipeline pressure control valve is used. Downstream of the valve there is often two-phase flow.
    - The pipeline pressure control might also be done via a control on one of the wells. The other wells must be set on mass flow control.
    - The benefit of this is that upstream of the well control valves, there is single phase flow. This might be beneficial for metering.

- The flowing wellhead pressure is for a large range of conditions constant and not a function of mass flow rate but is mainly a function of temperature.
- The shutin wellhead pressure is for a large range of reservoir pressures constant.
    - Both conditions mean that the wellhead pressure is not a good control parameter and that his parameter cannot be used for flow allocation. Therefore, downhole gauges (pressure and temperature) are strongly recommended.

- The temperature downstream of valves is determined by a number of aspects:
    - Pressure drop and therefore temperature drop (mainly for a pressure drop across a valve with both upstream and downstream gas phase)

  - Phase line temperature (mainly for expansion across a valve from liquid to low pressure resulting in two phase conditions downstream of the valve)
  - Back pressure at the valve. At high flow rates, the well provides back pressure to the valves resulting is less temperature drop.

- A critical temperature of 15°C is used for downhole conditions. It has not been taken into account that the CO_2 expands in the reservoir resulting in lower temperatures in the near-well zone.
- The injectivity index is based on single phase assumption at reservoir temperature. Therefore it is likely that the pressure drop in the reservoir will be higher than calculated.

- In this report, no alternatives for hydrate prevention are evaluated.
- As low fluid temperatures might be unavoidable and piping (manifold, valves etc) needs to be designed for low temperatures, the topside low temperature restriction might be re-evaluated.

- The depressurization of the pipeline at high shutin pressure conditions is done via venting in this report. It might be evaluated whether slowly depressurizing and local heating of the pipe materials might work.

11 General conclusions & recommendations

11.1 General conclusions

For steady state conditions the following conclusions are found:

- At low reservoir pressure (20-40 bar), no steady state solution is found which comply with both the topside and downhole temperature restrictions when the pipeline pressure is maintained in the liquid state. Therefore, at low reservoir pressure the pipeline must be operated in gas or two-phase conditions.
- This puts limitations on the maximum injection rates per well or for all four wells combined.
- At reservoir pressures (40-300 bar), the required flow rate (170 kg/s) is achieved using four wells.
- At close to the maximum reservoir pressures, the compressor outlet temperature needs to be reduced. Otherwise no injection is possible.

For depressurization the following conclusions are found:

- The heat ingress in the pipeline is limited. Therefore, during depressurization or emptying the pipeline the temperature follows the pressure via the phase line and low temperatures conditions can occur in the complete pipeline. Therefore, a pressure control of the pipeline is recommended.

For shutin simulations the following conclusions are found:

- During well shutin, low fluid temperatures will occur in the well downstream of the choke. The temperature will go down to the corresponding phase line temperature. At a reservoir pressure of 20 bar, this means a temperature of -37 °C. At lower reservoir pressures this will lower even further. At higher reservoir conditions, the temperature will increase. -17, -5 and +30 °C at reservoir pressures of 60, 100 and 340 bar.
- During ramp-down, low temperatures occur mainly in the top part of the well. These temperatures go well below -10 °C.
- During ramp-down also the temperature in the pipeline itself will drop down to values below -20 °C.
- The low temperatures during shutin/ramp-down are difficult to avoid and as such it is recommended that all piping should be able to withstand the low temperatures.

From the start-up simulations the following conclusions are found:

- For all reservoir conditions, at initial choke valve opening, a short period of low temperature will occur downstream of the control valves. For the start-up, a faster valve-opening is beneficial with respect to the temperatures.
- In the sequencing of well opening and compressor ramp-up, the flow rates from the pipe to the wells must not decrease too quickly to avoid too low pressures (and therefore temperatures in the well and pipeline). Therefore, the compressor ramp-up must be done relatively soon after the well opening.

The compressor can be ramped-up before the well opening at higher reservoir pressures with the limit that the pipeline pressure must not be higher than 85 bar.
- At low reservoir pressure, the system could be started up from low pressure (10, 30 bar) or medium pressure (60 bar). In case of medium-pressure conditions, the downhole temperature is too low for a limited period of time (less than 500 minutes).
- At low reservoir pressure, starting from high pressure pipeline conditions leads to long periods of too low temperatures (longer than 2000 minutes).
- At medium and higher reservoir pressures start-up can be done from medium-pressure (two -phase conditions) conditions within the temperature restrictions.

11.1.1 Base operation

The base recommended operations (based on the set restrictions) are:

- At low reservoir pressure, the pipeline is operated in the gas phase and all well chokes are kept open to avoid pressure drop. The compressor outlet temperature is set to 80 °C.

- At mid to high reservoir pressures, the compressor outlet temperature is set to 40 °C. The setting is an optimization between cooling power and compressor power.

- At very high reservoir pressures, compressor outlet temperature must be set to 40 °C, otherwise injection is not possible.

Reservoir pressure [bar]	Compressor outlet temperature [°C]	Pipeline control	Well operations
20 – 40 bar	80	30	Full open
40 – 300 bar	40 - 80	30	1 well on pressure control. Other wells on mass control
300 – 340 bar	40	30	1 well on pressure control. Other wells on mass control

During well shutin, a fast closure the choke valves leads to very low temperatures. At low reservoir pressures the shutin procedure should be leaving the wells open while shutting down the compressor.

11.1.2 Shutin philosphy

During well shutin, a fast closure of the choke valves lead to very low temperatures. At low reservoir pressures the shutin procedure should be to leave the wells open while shutting down the compressor.

11.2 Recommedations

The main recommendations include:

- All piping material should be de designed for extreme low temperatures (-40°C, based on expected wellhead pressures of 10 bar).

- Update simulation model to include full heat transfer (rather than U-value approach) at the time the well design and pipeline design is set. This to get more detailed temperature information on pipe wall temperatures and annulus fluid temperatures.

- Considering the fact that fluid temperatures less than -10°C are probably not avoidable, the restriction of -10°C for the topside temperature should be reconsidered/re-evaluated.

- The criterion of 15°C downhole temperatures is restrictive. Alternatives for hydrate preventions should be evaluated.

- An operational guidebook should be set up which describes the number of wells and control settings for each mass flow rate.
- This guidebook should also contain guidelines of start-up and shutin procedures.

12 Signature

Delft, April 2019 TNO

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Heat Transfer and Fluid Dynamics

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A Steady state results

In this annex, the results for the steady state results are added.

Case	***Twh***	***Tdh***	***Pplatform***	***Pcomp***	***Mass flow***
Reservoir pressure = 300 bar					
4000	21 10 10 10	64 116 118 116	58	85	18 0 0 0
4001	35 10 10 10	73 117 118 115	90	92	28 0 0 0
4002	32 10 10 10	58 117 118 115	113	136	60 0 0 0
4002_45	33	62	105	108	45
4003	37 37 10 10	77 78 118 115	91	94	24 36 0 0
4004	36 36 36 36	68 69 69 70	108	116	42 53 39 36
Reservoir pressure = 340 bar					
4005	36 36 36 36	66 66 66 67	130	138	42 53 40 35
4006	36 36 36 36	68 68 69 69	116	123	33 45 33 29
Reservoir pressure = 200 bar					
4079	33 33 33 33	75 74 74 74	79	93	43 50 39 37
4081	36 13 13 12	62 118 119 116	95	97	60 0 0 0
Reservoir pressure = 100 bar					
4078^	32 32	55 54	76	93	40 38

	32 32	51 51			40 45
4080	37 11 11 12	51 117 118 115	87	90	60 0 0 0
4082*	15 11 11 12	52 117 118 115	52	85	30 0 0 0
4083	-2 11 11 11	50 116 118 115	33	85	15 0 0 0
Reservoir pressure = 60 bar					
4007	-6 10 10 10	25 116 118 115	30	85	15 0 0 0
4008	18 10 10 10	27 116 118 115	56	85	28 0 0 0
4009	37 10 10 10	32 116 118 115	87	89	60 0 0 0
4010	35 10 10 10	35 116 118 115	143	147	100 0 0 0
4011	31 31 8 8	31 32 118 115	75	89	48 53 0 0
4012	30 30 30 30	31 33 30 29	72	93	59 56 44 41
4013	20 19 20 29	29 29 29 30	85	95	40 40 40 50
Reservoir pressure 20bar – control 85 bar					
4014	-10 10 10 10	-11 116 118 115	27	85.1	15 0 0 0
4015	17	-3	53	85.3	30

	10 10 10	116 118 115			0 0 0
4016	37 10 10 10	9 116 118 115	86	89	60 0 0 0
4017*	0.4 10 10 10	4.9 116 118 115	85	86	15 0 0 0
Reservoir pressure 20bar – control 60 bar					
4018	7 10 10 10	36 116 118 115	61	61	15 0 0 0
4019	64 10 10 10	9 116 118 115	134	137	60 0 0 0
4020	77 47 61 63	12 11 6 5	126	140	50 40 40 40
4021	62 52 62 62	29 32 25 24	96	106	33 30 29 28
4022	57 10 10 10	7 116 118 115	109	111	46 0 0 0
4023	43 10 10 10	18 116 118 115	79	81	30 0 0 0
Reservoir pressure 20 bar – no control					
4024**	17 10 10 10	47 116 118 1115	46	60	15 0 0 0
4025	42 10 10 10	17 116 118 115	78	80	30 0 0 0
4026***	58	8.3 116 118 115	107	109	43 0 0 0

4027	67 66 66 67	16 19 12 11	116	131	44 48 39 38
4028	64 64 64 64	24 27 20 19	103	115	37 40 32 31

* No hydrodynamic slugging used
** single phase
*** not 100% converged
^ crashes

Case	***Twh***	***Tdh***	***Pplatform***	***Pcomp***	***Mass flow***
4128	*58* *58* *58* *58*	*40* *42* *35* *35*	*81*	*90*	*26* *28* *23* *22*
4129	*56* *56* *56* *56*	*45* *46* *40* *40*	*75*	*83*	*24* *25* *21* *20*