Acorn CCS Project

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Document Title	Date Originally Issued	Document Title	Date Originally Issued
D02 Stakeholder Engagement and Communications Plan	31/08/2019	D12 Environmental Assessment (onshore)	
D24 Concept Options Report	08/11/2019	D13 Environmental Impact Assessment (offshore)	
D06 Permits & Consents Register	20/12/2019	D18 Risk Management Plan	
D11 Onshore Site Selection Report	28/02/2020	D21 Financing Plan	
D25 Concept Select Report	08/05/2020	D03 CO2 Capture Plant Design	
D10 Well Operating Guidelines	30/09/2020	D14 Economic Model & Report	
D08 Operations and Maintenance Philosophy	30/11/2020	D15 FEED Close-out Report	
D09 Well Design Report	30/11/2020	D16 FEED Lessons Learned Report	
D05 Storage Development Plan	31/03/2021	D17 Acorn CCS Development Plan & Budget	
D22 East Coast Deployment Report	31/03/2021	D19 Whole Chain Cost Estimate	
D04 Whole Chain BoD		D20 Project Schedule	
D07 Health, Safety and Environment Report		D23 Project Summary Report	

Signed by Storegga COO

Pale Blue Dot.

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1.0 Executive Summary

This document outlines the preliminary basis for operation of the proposed AS-01 subsea CO_2 injection well during Phase 1 of the Acorn CCS project. These guidelines will be updated if further wells are added during subsequent stages of the project.

The production of gas from the Goldeneye field, which is the proposed store for Phase 1 of the Acorn CCS project, was ceased in 2011 and the associated gas production wells were subsequently plugged as part of the Plug and Abandonment (P&A) program. Decommissioning activities will also result in the removal of the Goldeneye Platform and partial abandonment of the pipeline ends for the 20" production line and 4" service line to enable their re-use within this CO_2 injection project.

Phase 1 of the Acorn CCS project will be achieved by drilling a single subsea well into the Captain formation of the depleted Goldeneye reservoir. This first well (AS-01) will incorporate a dual string completion design which has been selected from flow assurance studies which allows both the pipeline and well to operate in dense phase whilst working within the operating pressure limit of 120 barg for the Goldeneye pipeline. The Goldeneye pipeline is planned to be operated within an 80 – 120 barg pressure range and a corresponding CO_2 injection rate range of 0.25 $MtCO_2/y$ – 0.80 $MtCO_2/y$ (29 t/h – 91 t/h).

These guidelines have been developed in conjunction with our industry partners and cover the following life cycle operations:

- Well completion installation operations,
- Well start-up operations,
- Steady state injection operations,
- Transient operations – planned and unplanned,
- Maintenance operations – incl. down hole safety valve testing,
- Repair operations – incl. well intervention & well kill,
- Well decommissioning operations.

One of the key conclusions derived from these guidelines is that the main constraint and differentiating factor working with CO_2, when compared to hydrocarbons, is the behaviour of CO_2 in the transition from dense phase to gas, whereby the rapid cooling associated with decompression of dense phase CO_2 may result in very low temperatures which if unconstrained could exceed the rated working temperature of various well construction components in addition to the tendency for hydrate formation under the appropriate conditions.

To ensure the above temperature constraint on equipment is enshrined within these guidelines clear diagrams are included which help to visualize the operating limits based on the rating of the components.

These preliminary operating guidelines show that the Acorn AS-01 well can be operated in all life cycle cases considered while respecting the rating of the equipment selected.

Note: The above guidelines are supported by early detailed engineering simulations using OLGA in both steady state and transient mode which will likely require further assurance before finalisation.

2.0 Project Summary

Acorn CCS project is a phased carbon capture and storage (CCS) development project in the north-east of Scotland as shown in Figure 2-1. Acorn CCS project is being designed to securely store captured CO_2 in the Acorn CO_2 Storage Site licenced area, as defined by an Oil and Gas Authority (OGA) Licence Agreement [1] and a Crown Estate Scotland (CES) Lease.

It is proposed that St Fergus gas terminal complex, located 55km north of Aberdeen, will be the onshore focus for Acorn CCS project and that existing, redundant, offshore gas pipelines will be re-purposed for transporting CO_2 to the Acorn CO_2 Storage Site licenced area.

This project will be led by PBDE with support from industry partners. The project is being partially funded by the EU as a Project of Common Interest (PCI) and partially by the UK Government, via the Department of Business, Energy and Industrial Strategy (BEIS) as part of the CCUS Innovation Fund and Industry.

The Acorn CCS project is nearing the completion of the Concept Select phase. The contents of this report, and other project deliverables from the Concept Select stage will be subject to assurance reviews by the industry partners before entering Define phase.

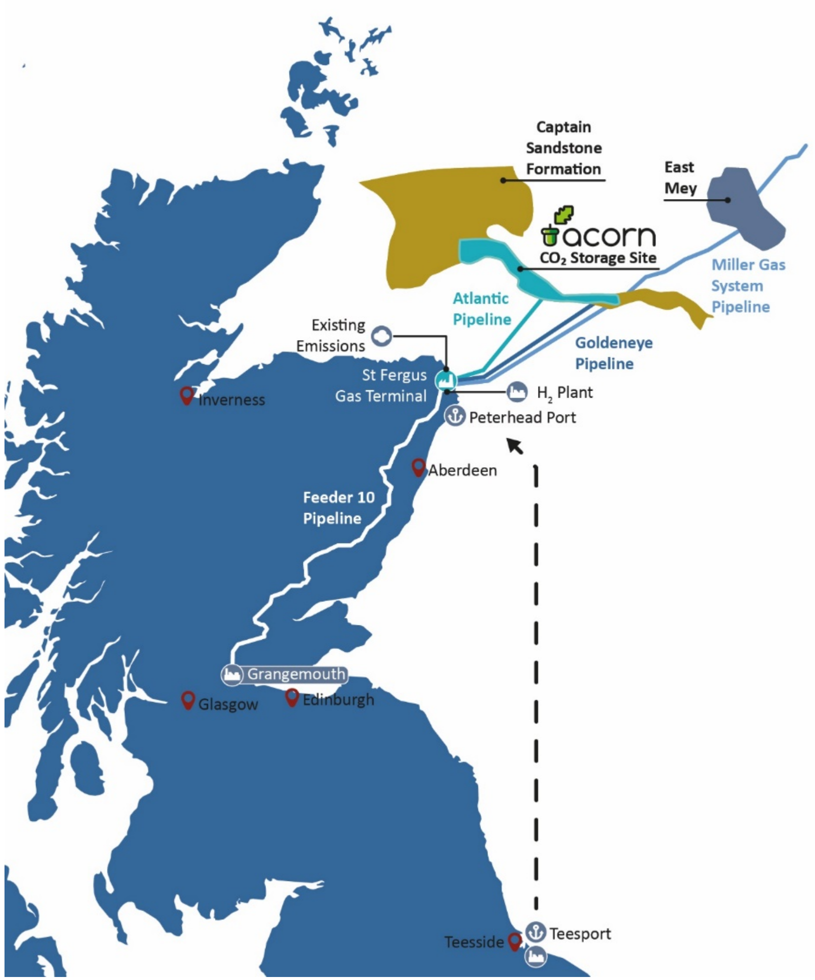


Figure 2-1: Acorn CCS Project map

As shown in Figure 2-2 the Phase 1 elements of the Acorn CCS Project include:

1. Flue gas collection from two existing St Fergus gas terminal complex industrial emitters and transport of the flue gases to the CO_2 capture plant.
2. Pre-conditioning of flue gas to remove SOx/NOx prior to entering the CO_2 capture plant (if required).
3. CO_2 capture plant using a liquid solvent.
4. Transport of the CO_2 from the CO_2 capture plant to the low pressure (LP) compression plant, conditioning of the CO_2 to remove oxygen and water, high pressure (HP) compression and cooling to meet the pipeline specification.
5. Onshore tie-in to the offshore pipeline (including pigging tie-ins/facilities if required).
6. Offshore infrastructure, including the re-use of the existing 20" Goldeneye pipeline and connection to one or more wells. Potential re-use of the Goldeneye 4" chemical injection line to provide methanol to the offshore well(s).
7. Drilling and completion of one CO_2 injection well, capable of injecting, as a minimum, the Phase 1 volumes of CO_2 (300ktCO_2/yr), complete with the subsea tree(s).
8. Subsurface work for the Acorn South CO_2 Storage Site and scoping work for the build-out.
9. Well control

The scope of the Acorn CCS project study also includes:

- Onshore health, safety and environment (HS&E) aspects to deliver a consentable, compliant design for Acorn Phase 1.
- Offshore HS&E aspects to deliver a consentable, compliant design for the Acorn South development and well control infrastructure (umbilical).

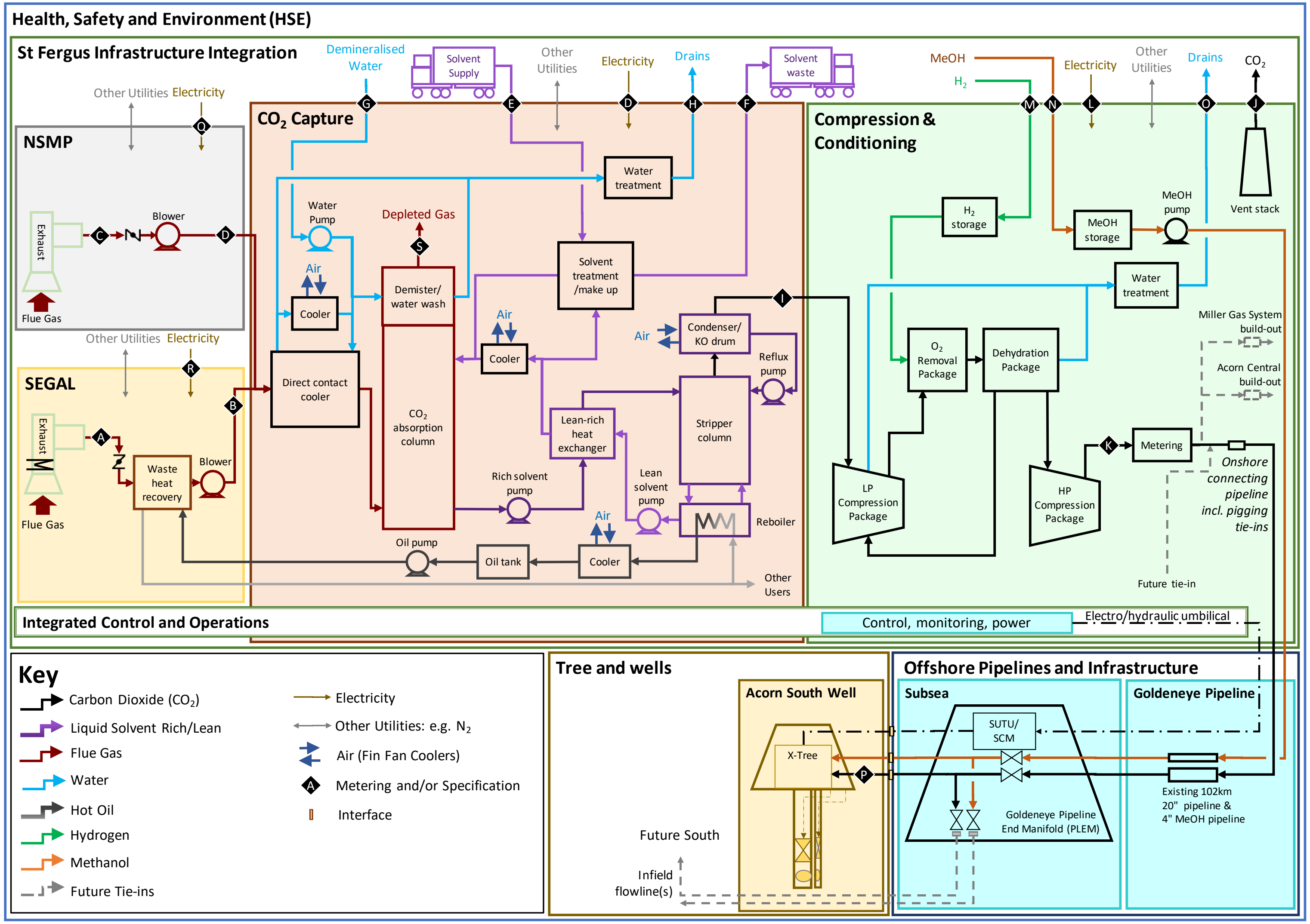


Figure 2-2: Preliminary Acorn CCS Phase 1 block diagram

Once the Phase 1 infrastructure has been established, Acorn CCS project could then be built-out via a number of potential Phase 2 options. These Phase 2 build-out options could include:

1. Carbon capture from a new hydrogen plant (reforming natural gas) at St Fergus known as Acorn Hydrogen and onwards transport of the CO_2 to the Acorn CO_2 Storage Site licenced area
2. Re-purposing of the National Grid Gas (NGG) Feeder 10 pipeline and infrastructure to transport CO_2 from the industrial centres around Grangemouth to St Fergus and onwards to the Acorn CO_2 Storage Site licenced area
3. Re-using the existing Peterhead Port infrastructure (where feasible) and installation of new infrastructure to support import of CO_2 to the St Fergus Acorn CCS facility and onwards transport to the Acorn CO_2 Storage Site licenced area
4. Using the Peterhead shipping infrastructure to support the export of CO_2
5. Drilling and completion of an additional well or wells capable of injecting, nominally 1.5–2.0MtCO_2/yr per well within Acorn South
6. Offshore infrastructure, including new in-field flowline to one or more Acorn South well(s)
7. Drilling and completion of further wells capable of injecting, nominally 1.5–2.0MtCO_2/yr each, at Acorn Central. The areas that represent Acorn South and Acorn Central are shown in Figure 2-3
8. Offshore infrastructure, including the re-purposing of the existing Atlantic pipeline, new in-field pipelines and manifold capable of expansion to further wells at Acorn Central
9. An international interconnection utilising the Miller Gas System pipeline

Development of the offshore infrastructure and drilling and completion of additional wells would be as and when needed (subject to looking at efficiencies of campaign mob/demob costs and weather windows) to match the timing of new sources of CO_2 becoming available.

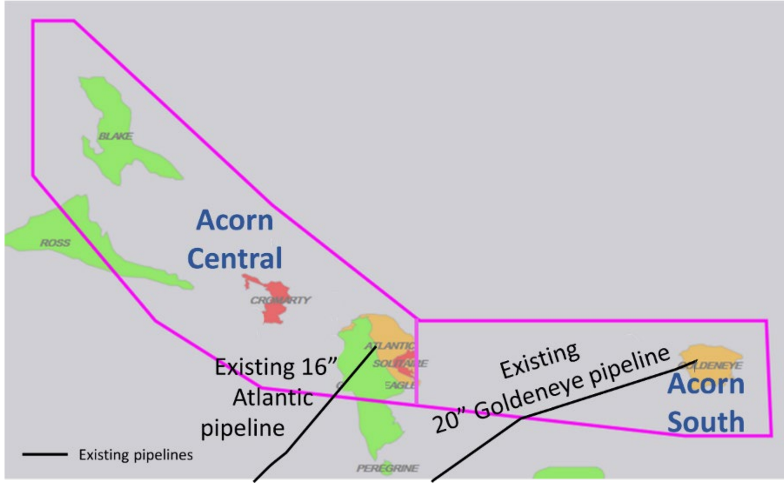


Figure 2-3 Acorn Central and Acorn South map

3.0 Introduction & Purpose

3.1 Introduction

The AS-01 or Acorn South 1 well will be the first well drilled as part of the Acorn CCS (Carbon Capture and Storage) project. The well will be completed with a dual string completion, the purpose of which is to create friction under dynamic conditions to allow CO_2 injection in dense phase while allowing a range of injection rates from 0.25 $MtCO_2/y$ – 0.8 $MtCO_2/y$ with reservoir pressure varying from initial conditions of around 205 bar (to confirm) to a pressure of around 270 bar.

The wellbore interface is cased and perforated [2], the risk of sanding is considered low, with around 90 m of sump within the proposed 5-1/2" liner available to collect any sand caused by the "CO_2 hammer" effect.

The dual bore completion design utilizes a 2-7/8" x 2-3/8" string which is referred to as string 1 or primary string and a 3-1/2" x 2-7/8" string referred to as string 2 or secondary string. The use of a tapered string for both string 1 and 2 is driven by the flow assurance requirements to create sufficient friction while injecting to maintain the CO_2 in dense phase and keep a surface pressure that is within the planned 80-120 bar operating pressure for the delivery pipeline. A 2-7/8" x 2-3/8" primary string allows for the use of existing completion equipment such as a 2-7/8" TRSCSSV (Tubing Retrievable Surface Controlled Sub-Surface safety valve) and tubulars in standard sizes. At the design stage, moving the depth of the X-over in the tapered string of the completion allows the completion tubing to generate more or less friction for a set injection rate. This will allow the Acorn South 1 completion design to meet the requirements of the properties of the CO_2 to be injected while operating within the defined pressure operating window for rates between 0.25 $MtCO_2/y$ – 0.8 $MtCO_2/y$ [3], as shown in Figure 3-1.

For the low rate in the proposed range, injection will be through the primary string (2-7/8" x 2-3/8"). As the rate is increased the injection can be changed from primary string to secondary string, by opening the injection wing valve on the subsea injection X-mas tree on the secondary string (3-1/2" x 2-7/8") and closing the injection valve on the primary string. The lower frictional losses through the larger bore will allow the rate to be increased until the limit at the wellhead is reached at which point the primary string can also be opened up to allow simultaneous injection through two strings.

The use of a dual bore completion in subsea is an unusual design, few dual bore subsea completions exist, the AS-01 well will make use of a dual bore vertical XT system installed on a tubing head spool (THS). Within the vertical X-mas tree system, what would traditionally be the annulus access bore will be utilized to access the primary string. The secondary conduit or larger string will be accessed through what would traditionally be the main bore.

As noted above access to the tubing x production casing annulus will be provided through the use of a tubing head spool (THS) system. Utilizing this design allows a standard subsea wellhead system to be used with a tubing head spool and vertical 5-1/8" x 2-1/16" dual bore XT system with relatively few modifications required to meet the requirements of the dual bore injection system. The design of the subsea system is not part of the scope of this study, however, to provide the user with an understanding of the AS-01 well and the access to the two injection bores plus the access to the tubing x production annulus it is necessary to provide a basic overview.

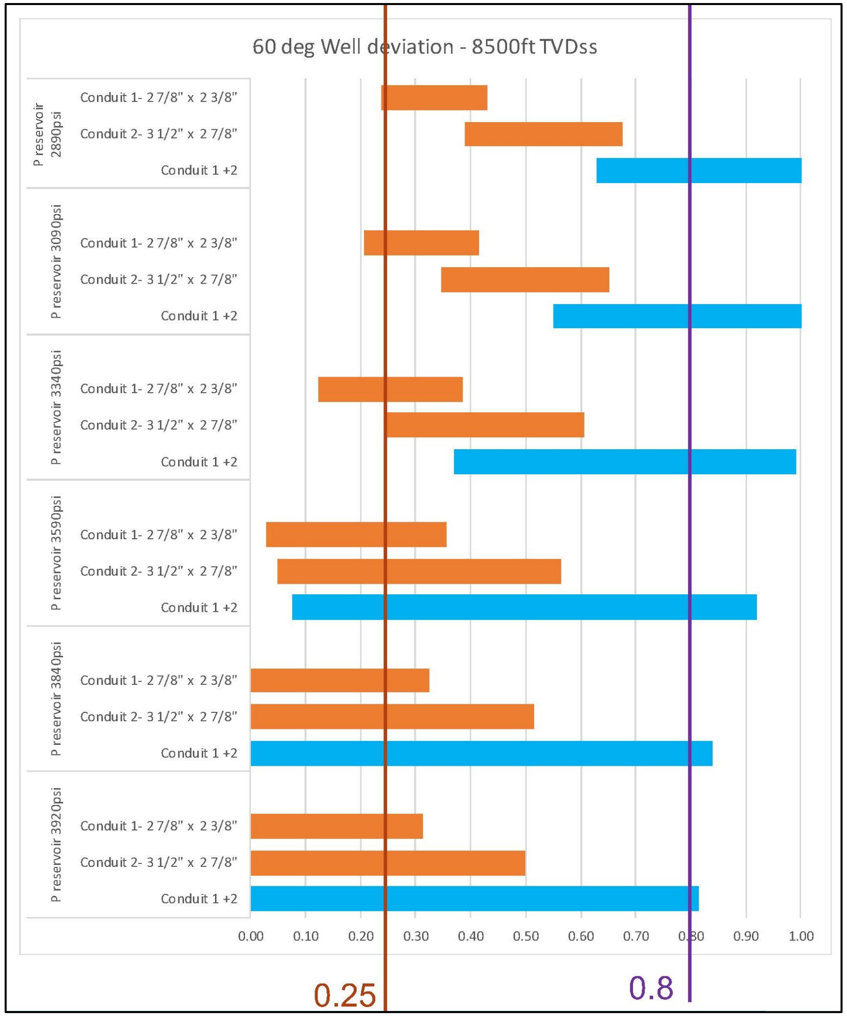


Figure 3-1:Simulation of injection rates through conduit 1, 2 & combined. (Simulation courtesy of Shell UK)

3.2 Purpose

The purpose of these preliminary well operating guidelines is to provide the reader with the key issues surrounding CO_2 well operations in a step-by-step manner. As new information becomes available these guidelines should be updated to ensure they continually improve throughout the life cycle of the project and subsequent operations.

Note: These operating guidelines have been prepared during the current early stage of detailed engineering and is based on information provided through the study partnership. All associated OLGA flow assurance modelling work will itself require assurance prior to finalising the operating details within these guidelines.

4.0 Well Design, Installation & Start-Up

4.1 Well Design

This document does not cover the completion basis of design, only a basic overview is provided, a well basis of design will be completed as part of a separate study, these Preliminary Well Operating guidelines have been created based on the draft completion design [3].

The completion design shown in Figure 4-1 utilizes the friction loss in the tubing to "choke" the injected dense phase CO_2, alternative designs such as the use of single or multiple downhole variable choke system were also considered, however, by removing actuated down hole chokes the risk of failure of active elements is removed. The basis of the dual bore subsea injection completion is a design that should not require through tubing intervention during the operating life of the well.

Access through the completion to the perforated interval is limited to access through the larger secondary string (3-1/2" x 2-7/8") due to the Y in the completion, there is no access to bottom hole considered through the smaller primary string (2-7/8" x 2-3/8).

Note: A more detailed overview of the proposed well completion is provided in the Appendix.

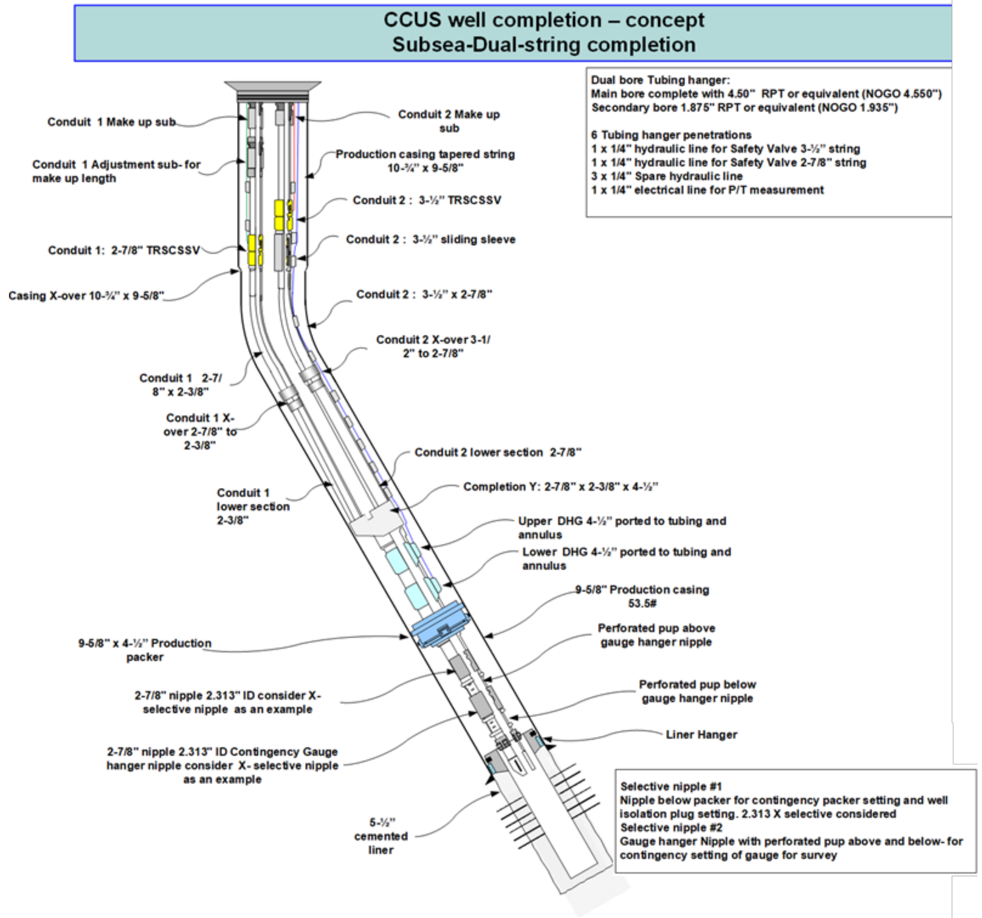


Figure 4-1: Basic outline of dual bore subsea completion

4.1.1 Basic Well Depths to Consider

Component	MD below mudline (473.7ft RKB to ML (ft md)	TVD MSL (ft TVD)	MD (80ft above MSL) (ft RKB)	TVD RKB (ft TVD)
Mudline	0	393.7	473.7	473.7
TRSCSSV conduit 1	2,126.28	2,463.4	2,600	2,543.4
TRSCSSV conduit 2	2,026.3	2,372.5	2,500	2,452.5
Completion Y (junction of 2 strings)	9,619.3	7,314	10,093	7,394
Top of Captain D	11,136.3	8,461.7 (pressure MLC 205 bara)	11,610	8,541.7

Table 4-1: Basic depths to consider - trajectory used reference 60/40° trajectory (4th August 2020)

4.1.2 Well-Bore Interface – Lower Completion System

The reservoir well bore interface will be achieved by perforation of the cemented 5-1/2" liner, the base case is: the well will be perforated after the upper completion is installed. The intervention will take place with the X-mas tree in place through an intervention pressure control rigid riser EDP/LRP (Emergency Disconnect/Lower Riser intervention Package) system.

4.1.3 Temporary Suspension – Install Tubing Head Spool (THS)

The temporary well suspension for installation of THS and prior to installation of upper completion will be carried out prior to perforation of the well and prior to the injection of any CO_2 into the formation, therefore, this will be covered by standard drilling and completion operational procedures. The considered barriers for the suspension of the well and the installation of the THS are the cemented and tested liner, and completion brine, an additional barrier element in the form of a retrievable bridge plug may or may not be required. This will be evaluated at the time of the preparation of the drilling program.

4.1.4 Well Intervention – Base Case

Through tubing intervention can be considered at the well construction phase for the cases mentioned below. These requirements will be reviewed as part of the completion basis of design, where possible, intervention free solutions shall be given preference. These operations during the construction phase will be carried out before the injection of CO_2 and therefore do not require specific equipment related to operation within a CO_2 environment. Through tubing operations after first injection of CO_2 will require specific equipment and procedures related to working in CO_2 storage well.

Construction phase means: Prior to first injection of CO_2.

Examples of through tubing well intervention operations are provided below:

4.1.4.1 Slick Line

The use of slickline is considered necessary for contingency interventions for the following operations:

- Tubing drift runs,
- Contingency packer setting operation.

4.1.4.2 E-Line

The use of E-line is considered necessary for the following operations:

- Correlation and perforation of the liner,
- Contingency tubing or packer cut to release,
- Logging as part of investigatory intervention.

4.1.4.3 Coiled tubing

No requirement for coiled tubing has been identified, the completion design with conduit 1 with 2-7/8” x 2-3/8” tubing and conduit 2 with 3-1/2” x 2-7/8” tubing, makes it unsuitable for standard coiled tubing operations. The base case considered for this well design is well construction and maintenance during the life cycle of the well without the use of coiled tubing. This could be updated during the operating life of the well and as such would be subject to a specific feasibility study and operational risk assessment.

4.1.4.4 Future intervention options

In the future well intervention may be carried out by operations from a moored rig with a rigid riser system or riserless with an intervention vessel.

A preference should be given to riserless intervention where possible since a riserless intervention system can take advantage of the ambient hydrostatic of seawater of around 12 barg (@ ~120 m), which will ensure at the point of intervention the minimum pressure does not go below this value. The benefit of this assured ambient condition is in the event of a CO_2 leakage a much lower degree of cooling will occur.

For future well interventions the requirements considered as a base case are:

- Setting of plugs for securing well,
- Bullheading of well for well kill,
    - Including contingency punch of tubing and circulation of annulus to kill weight brine.
- Intervention to the level of DHSV (Down Hole Safety Valve),
- To carry out contingency exercising of DHSV.

The specifics of these operations are not covered in detail in this document, however, the interfaces, feasibility and outline technical specification of the intervention pressure containing packages are included.

4.1.5 General Requirements of Completion and Subsea X-mas Tree Design

Figure 4-2 shows a simplified illustration of the AS-01 well with the tubing head spool, completion and X-mas tree in place. The general requirement of the system is to provide access to the wellbore interface with 2 well barriers for the operating life cycle of the well, including injection at predetermined injection rates, well intervention access and a system that allows well suspension while maintaining the 2 well barrier philosophy. Throughout these preliminary well operating guidelines, the schematic below will be utilized to show the arrangement of the installed equipment that is part of the permanent well and any equipment connected to the well as part of an intervention operation.

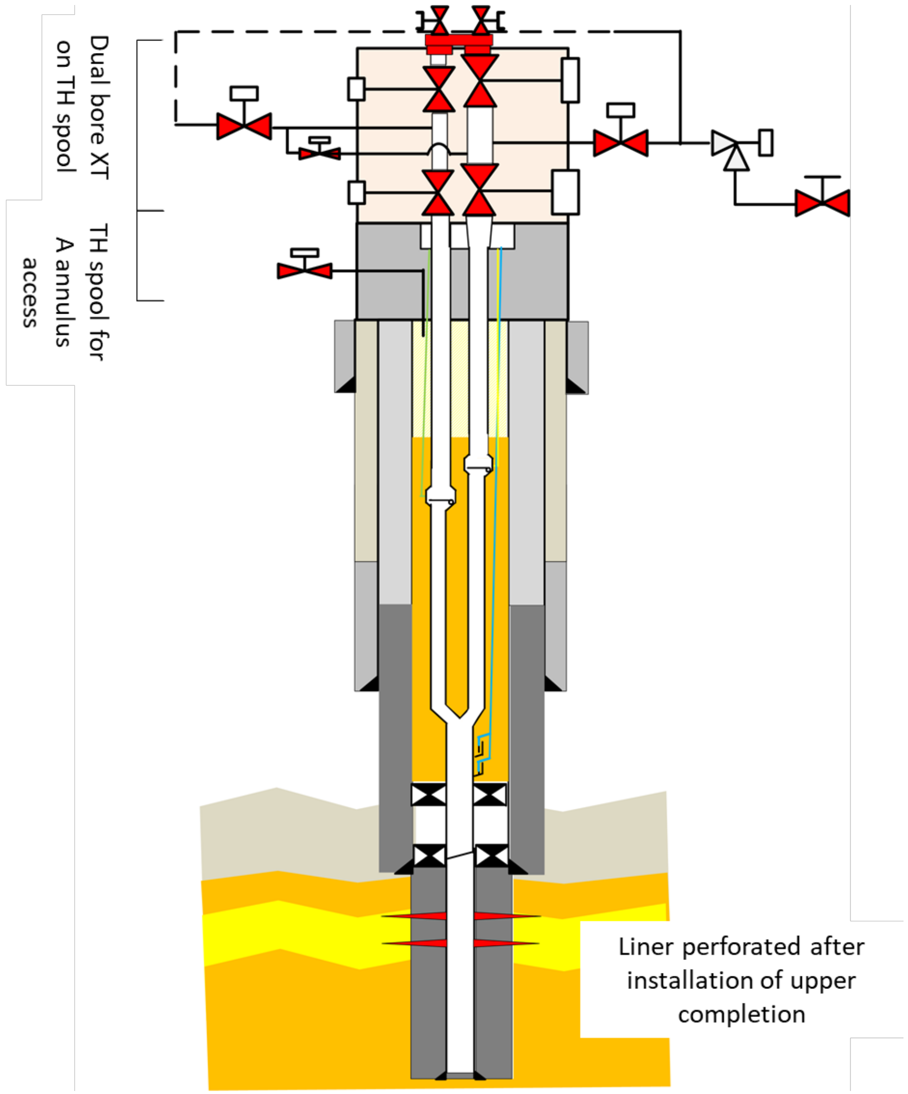


Figure 4-2: Well with dual dore completion, tubing head spool (THS) and dual bore vertical XT system.

The well design of X-mas tree on THS allows access to the tubing x production casing annulus. This access is required at the construction phase and for monitoring of pressure in the production by tubing or A annulus. Prior to the setting of the production packer, the annulus will be displaced to base oil and nitrogen during the construction phase, the depth of nitrogen in the A annulus will be around 305 m (1,000 ft) below the level of the wellhead. Having the interface of base oil and nitrogen in the production annulus with a 305 m nitrogen cushion will allow operation of the well with CO_2 through the completion into formation with cooling of the well from undisturbed temperature (geothermal) through cool down due to injection and cases of cool down due to expansion of CO_2 while maintaining a relatively stable annulus pressure. The annulus pressure behaviour is looked at in further detail in section 5.3 Annulus pressure management.

For the AS-01 well the pressure & temperature rating of the permanently & temporarily installed equipment will contribute to determining the conditions that must be maintained during the various operational steps in the well's life cycle.

The following component temperature ratings are considered.

Item	Pressure rating (°C)	Temperature rating (°C)	Temperature class
Subsea system			
X-mas Tree	5,000 psi	-46°C to +60°C	N
Tubing hanger system	5,000 psi	-46°C to +60°C	
Tubing head spool	5,000 psi	-18°C to +121°C	U

Water based inhibited Control fluid		-40°C considered	
Wellhead system	5,000 psi (Note typical systems offered may be 15KPSI)	-18°C to +121°C	U
Architecture			
Production casing	53.5# 80KSI-7,930psi To be finalized based on casing design modelling.	Material and connection considered -35°C subject to qualification.	
Completion system			
Production tubing- above and below level of TRSCSSV		Material and connection limit – considered -35°C subject to qualification.	
Completion assemblies			
Tubing hanger make up sub	5,000 psi	-35°C (requires qualification)	Requires qualification- current products limited to -29 °C
Tubing adjustment sub (2-7/8” string)	5,000 psi	-35°C (requires qualification)	
TRSCSSV **3-1/2” 9.3# & 2-7/8” 6.4#**	5,000 psi	Qualified for -7°C Material and connection considered -35°C subject to qualification.	No requirement to operate at -35°C. This applies to closed case only
Sliding sleeve **3-1/2” 9.3#** **5,000psi**	5,000 psi	-35°C (requires qualification)	Value of this sliding sleeve vs potential leak paths to be assessed
Downhole gauge system	5,000 psi	Qualified 0 to +100°C	
Packer system	5,000 psi	Qualified +4 to +100°C	

Table 4-2: Well equipment basic components temperature rating

4.1.6 Well Completion Requirements

The AS-01 completion requirements are, to allow injection at rates that will vary between 0.25 $MtCO_2$/y (685 t/d) – 0.80 $MtCO_2$/y (2,192 t/d) with a reservoir pressure varying from initial conditions of around 205 barg (to be confirmed) to a pressure of around 270 barg.

- During injection surface pressure at sea line shall be maintained in the range of 80 – 120 barg.
- The wellbore interface is cased and perforated; the risk of sanding is considered low.
    - Injection well: “CO2 hammer” effect has been considered - an allowance for some sanding shall be considered using the capacity in the sump below perforations.
    - The final capacity of this sump will be defined as part of the wellbore interface study.
- Withstand the operating pressure, temperature and mechanical loads throughout the lifecycle of operation of the well.

  - A specific WellCat™ tubing stress analysis has been completed for the well to define the operating limits associated with load cases throughout the life cycle of the well. These load cases are not reviewed within these preliminary well operating guidelines, however, for well construction, intervention and defining MAASP (Maximum Allowable Annulus Surface Pressure) and MAWOP (Maximum Allowable Well Operating Pressure) during routine injection the limits defined must be referred to and will be detailed for the construction and intervention phase as part of the well program. For the injection operational phase these will be defined within the well handover.
  - MAASP & MAWOP for A annulus- defined in well handover following construction phase.
- Comply with the project's barrier policy.
- Be protected against fluid corrosion without the need of corrosion inhibitor injection.
- Incorporate reservoir monitoring with a pressure and temperature gauge system.
  - Specific to the well design dual temperature and pressure gauge mandrels are included in the completion and provide the field operations and intervention team with pressure and temperature for tubing and annulus at two points in the completion spaced approximately 122 m (400 ft) TVD apart, this will allow fluid gradient calculations.
- Facilitate remedial interventions- the limits of which are provided in section 7 of this document.

4.1.7 Completion Fluids

For the well construction phase, the completion will be installed with the well in an overbalanced brine, to be defined as part of the drilling and completion program. The base case considered is a NaCl brine for the installation phase. This installation brine will be displaced to base oil after running the upper completion and before setting the production packer, the base oil in the production annulus will have a nitrogen cap of around 305 m (1,000 ft).

4.1.8 Wellhead And Xmas Tree System

The well will be constructed with a 30" conductor pipe, 13-5/8" technical casing and a 10-3/4" x 9-5/8" production casing. The high-pressure wellhead housing will be run as part of the installation of the 13-5/8" casing after the drilling of the 17-1/2" section.

The high-pressure housing will be based on a 1,035 barg (15,000 psig) 18-3/4" wellhead housing with H4 connection.

On completion of drilling activities and before the running of the completion, the well will be suspended to allow BOP disconnection and the installation of the tubing head spool (THS) on the wellhead housing. The function of the tubing head spool on the Acorn AS-01 well is to allow access to the A or production annulus bore. With the THS in place, the BOP will be reconnected on top of the THS and tested, thereafter access to the well will be re-established for completion operations.

The well will be displaced to clean fluids and the bore protectors removed. The dual string completion will be run and landed with orientation inside the tubing head spool. On successful completion of installation procedure, the well will be suspended with required barriers and the BOP disconnected to allow the installation of the dual bore X-mas tree. On completion of installation of the dual bore X-mas tree, suspension barriers will be removed and access to the well will be established through an EDP/LRP package.

All operations for completion of the well at the construction phase after the installation of the X-mas tree will be completed through an EDP/LRP system. For the purpose of these preliminary well operating guidelines, the X-mas tree and well head system will be shown in diagrammatic form to visualize the well barriers and well barrier elements for various phases and operations, as seen in Figure 4-3 below.

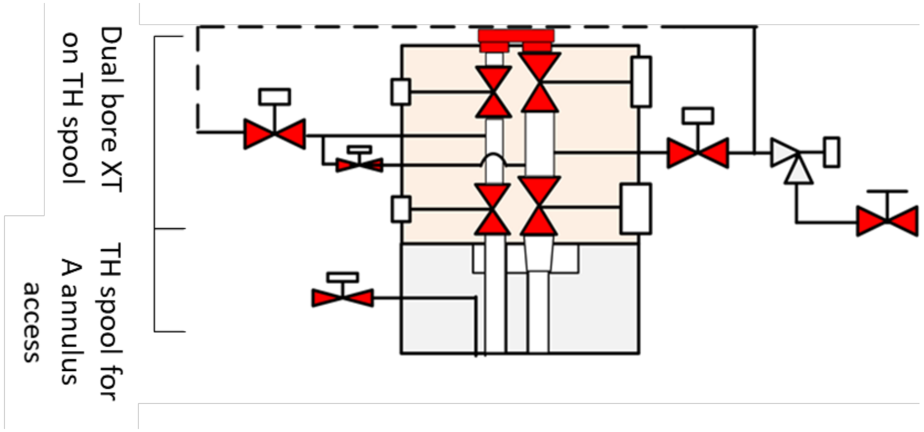


Figure 4-3 Diagrammatic representation of dual bore X-mas tree on tubing head spool.

4.1.9 Control Line Fluid

The final control fluid will refer to subsea production systems recommendation, the fluid utilized will be an environmentally friendly water-based fluid that is inhibited from hydrate risk and allows operation without freezing at the considered operating temperatures for the AS-01 well in all cases considered.

The design of the Acorn CCS well considers that the lowest temperature that can be achieved is -35°C at the level of the wellhead in the case of a CO_2 leak through the X-mas tree to the sea. As part of the specification of the X-mas tree system the control fluid for operation of X-mas tree and downhole valves should have a rating to -35°C or better. Selection of control fluid is outside of the scope of these preliminary well operating guidelines however as a minimum the operating range of the control fluid should be agreed between wells design team and the company subsea systems team.

- Base case type: Water based containing mono ethylene glycol.
- Pour Point: To be defined by subsea team – working temperature to be -35°C or better (lower).

It is recommended to carry out a compatibility test between completion brine and control fluid including test with and without any inhibitors that will be added to the completion brine. This test is required to ensure no precipitation/ blockage in TRSCSSV lines at the stage of well suspension disconnection of tubing hanger running tool prior to installation of X-mas tree and any future operation where control lines may be exposed to workover fluids.

4.2 Well – Completion Installation

4.2.1 Dual Bore CCS Completion Installation Basic Overview

These “Preliminary well operating guidelines” are not part of any completion installation program, the below sequence is given as a high-level overview and can be useful for the users to understand the first well start-up.

- 5-1/2” Liner in place and cemented.
- Well displaced to filtered brine.
- Well suspended with suspension plug.

- Wear bushing recovered.
    - Jet and clean wellhead.
- Disconnect BOP and install and test THS.
- Reconnect BOP and test.
- Recover suspension plug.
- Recover THS bore protector and jet profile.
- Run Upper Completion and land in THS with simplified landing string.
- Displace packer fluid and set production packer.
    - Test production packer and completion elements.
- Set suspension plugs in tubing hanger on primary and secondary bore.
- Recover drilling BOP and install and test X-mas tree.
    - X-mas tree run with EDP/LRP.
- Recover suspension plugs.
    - The secondary bore plug will be recovered on the first run with EDP/LRP.
    - The use of a single bore WOR (Work Over Riser) system will require the system to be recovered to reconfigure the LRP to X-mas tree adaptor for the plug from the primary bore and continuation of operations.
- Perforate well on wireline.
- Bullhead well with tubing contents to leave base oil plus nitrogen cushion in well.
    - Around 1,976 m TVD (6,483 ft TVD) of base oil plus a nitrogen cap will leave a wellhead pressure of around 45 barg in preparation for well start-up. These figures are provided for general information, final base oil and nitrogen values will be provided in the well completion and intervention program.
- The well will be suspended with X-mas tree in place in preparation for injection of CO_2.
- A X-mas tree, tree cap will be installed, this tree cap will provide a second barrier element on the vertical flow path above the 2 swab valves of the X-mas tree.

4.3 Well Start Up – First Injection CO_2

4.3.1 Well Conditions Prior to First CO_2 Injection

The well has been completed with a dual string completion, all valves on the X-mas tree are in the closed position. Injection flowline has been installed and commissioned (tested). The dewatering of the sea line is not covered within these well operating guidelines, it is assumed that the dewatering has been carried out and the sea line is in CO_2 at a static pressure at the Acorn CCS X-mas tree level of around 90 barg. The upper section of the Captain D reservoir unit has been perforated and injectivity confirmed during the well construction phase. The well was bullheaded to base oil plus a nitrogen cushion prior to suspension at the end of the construction phase. This base oil plus nitrogen cushion remains in place in both the primary and secondary bores as seen in Figure 4-4, illustrated as a single string for ease of identification.

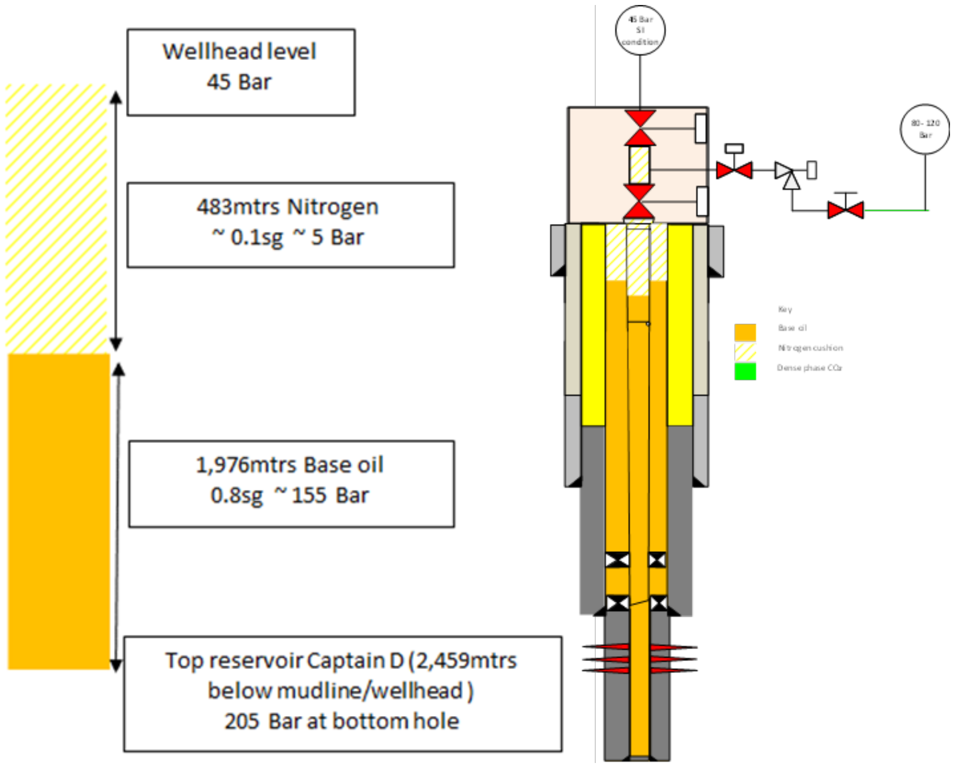


Figure 4-4: Fluids in suspended well after construction phase in preparation for start-up. Shown as a single string to show fluids in place.

Well start-up for first injection of CO_2 will be with 45 barg WHP (Well Head Pressure) for first introduction of CO_2, the use of the nitrogen cushion will help to provide a smooth displacement process, as dense phase CO_2 at seabed temperature of approximately 7°C and 90 barg WHP is injected into the well, the WHP will gradually decrease as the dense phase CO_2 displaces the nitrogen and the density of the column increases.

For the first introduction of CO_2 to the well, there are 3 options that can be considered.

- Injection into conduit 1: 2-7/8" x 2-3/8".
- Injection into conduit 2: 3-1/2" x 2-7/8".
- Injection into conduits 1&2 simultaneously.

From an operational perspective concurrent injection into both conduits could provide the simplest solution to have the completion and well displaced to CO_2, however, this may or may not be feasible at the time depending upon available CO_2 to maintain a relatively stable pipeline pressure.

With the dual bore completion Y tool placed at a measured depth RKB (Rotary Kelly Bushing) of 3,077 m (10,093 ft) measured depth or 2,254 m (7,394 ft) TVD RKB below wellhead, the Y is approximately 350 m (1,148 ft) vertical depth above the top of the Captain D and the open perforations. Displacing one string and the well below to CO_2 will result in dense phase CO_2 below the Y piece to the open perforations. This displacement (of the base oil that had been put in place for start-up) will have the net effect to reduce the pressure at the level of the completion Y and therefore the pressure in the un-displaced string will have reduced. The relatively short length of the string below Y piece to top perforations (349 m) should ensure the net reduction in pressure in the un-displaced string is relatively low and in the region of 7 bar. This will allow relatively smooth displacement of the second string when the available CO_2 injection rate allows.

The option to leave 1 string un-displaced until such time as the system demands the capacity of dual string injection can be also be considered. The use of a base oil and nitrogen cushion in each string should make such an approach feasible. However, it is assumed that during early injection with CO_2 there may be a test and performance program to confirm the performance of the full system prior to the continuous increase in system capacity.

4.3.2 First Injection of CO_2 After Well Construction Phase Summary

At the stage of well construction after well perforation the well will be bullheaded for confirmation of injectivity index, the well will then be displaced to base oil due to the low reservoir pressure this base oil column would have a relatively low pressure at wellhead (around 13 barg). As part of the displacement sequence after the pumping of base oil, nitrogen will be bullhead in each string. At the end of the bullheading, each conduit (1 & 2) will be left with a nitrogen cushion in the string to maintain a pressure at the wellhead level that will ease the first start-up of injection. The target WHP using the nitrogen cap is 45 barg. This value may be further refined during the detailed engineering phase. Having a pressure ~45 barg in each string will allow controlled dense phase injection as part of the start-up sequence.

4.3.3 First Injection of CO_2 Further Work to Consider

During the detailed engineering phase the well start-up sequence should be modelled to simulate the displacement from nitrogen & base oil in each string to CO_2. At this stage there is no requirement considered to detail this displacement, the key parameter to define is a minimum well shut-in pressure at end of well construction phase to allow remote start-up of the well.

5.0 Steady State Operation

5.1 Well Operating Envelope

The following well envelopes shown in Figure 5-1 and Figure 5-2, have been generated by Shell UK and should be considered as draft at this stage.

These well operating envelopes consider the well limitations and the planned conditions of the reservoir, injectivity rates and completion specific limitations. The well operating envelope is based on injection into the Captain D reservoir layer. The non-permissible operating areas are shown in pink with description.

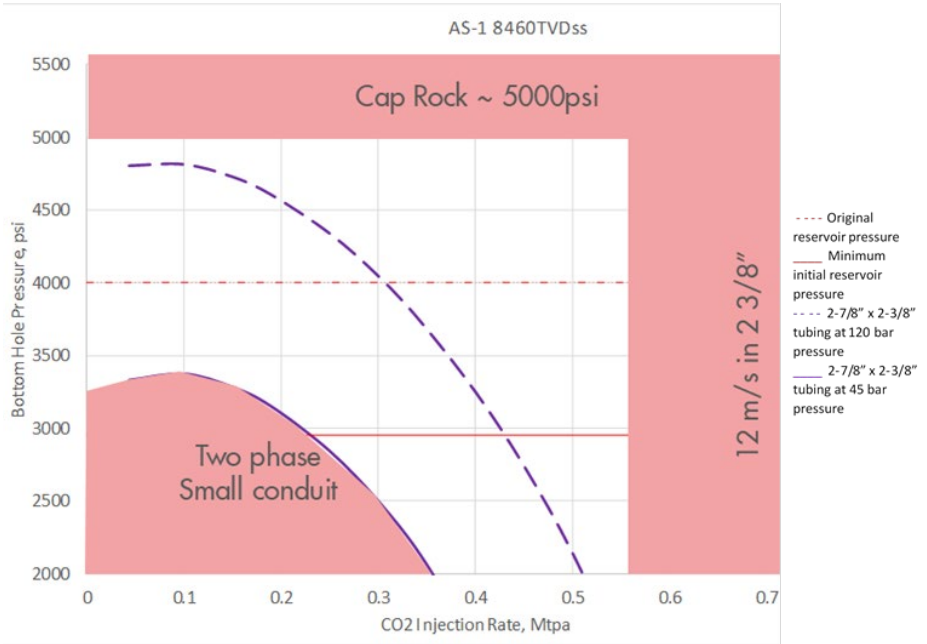


Figure 5-1: Draft well operating envelope for Acorn AS-01 subsea well small conduit injection showing operating limits. (Courtesy of Shell).

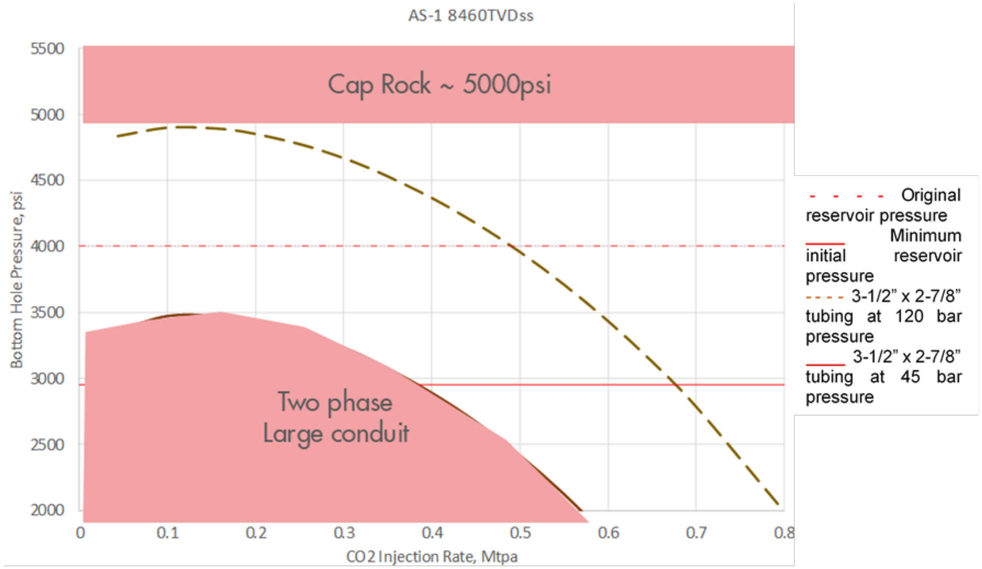


Figure 5-2: Draft well operating envelope for Acorn AS-01 subsea well large conduit injection showing operating limits.(Courtesy of Shell UK)

The operating envelopes for the dual string completion are displayed as two separate strings to show the limitations of:

- Initial reservoir pressure,
- Cap rock rating,
- Velocity limit in tubing,
- Two phase injection.

From these draft well operating envelopes it can be seen that the design of the AS-01 completion and the planned operating conditions fall within the limiting boundaries of the well operating envelope.

5.2 Well Monitoring Pressure & Temperature

For well monitoring, dual downhole pressure and temperature gauges are provided at a level below the completion Y (junction between the two completion strings). These quartz type high accuracy and resolution, low drift downhole gauges are installed on two separate downhole gauge mandrels. The gauges are ported to the tubing and annulus (separate gauges) at each position. The inclusion of dual downhole gauges provides a means to measure the tubing pressure and temperature at two stations downhole approximately 120 m apart, allowing the gradient of the CO_2 to be calculated. In addition, at the level of the X-mas tree, pressure and temperature gauges are provided on each bore. The location of pressure and temperature monitoring points is shown in the schematic provided in Figure 5-3.

In the case of a failure of the downhole gauges a nipple profile will be included that allows the option of installation of memory downhole gauges that may be installed in the well and the well returned to injection. The gauges can then be recovered after a set period of time and the data downloaded from these gauges to allow for continued monitoring of bottom hole conditions. The small tubing size requires that the installation of downhole memory gauges that allow injection in the well must be below a perforated section of tubing. The ID of any lock system that could allow the gauges to be hung in the well is too restrictive for a system that allows injection through the lock. The details will be provided in the well basis of design document.

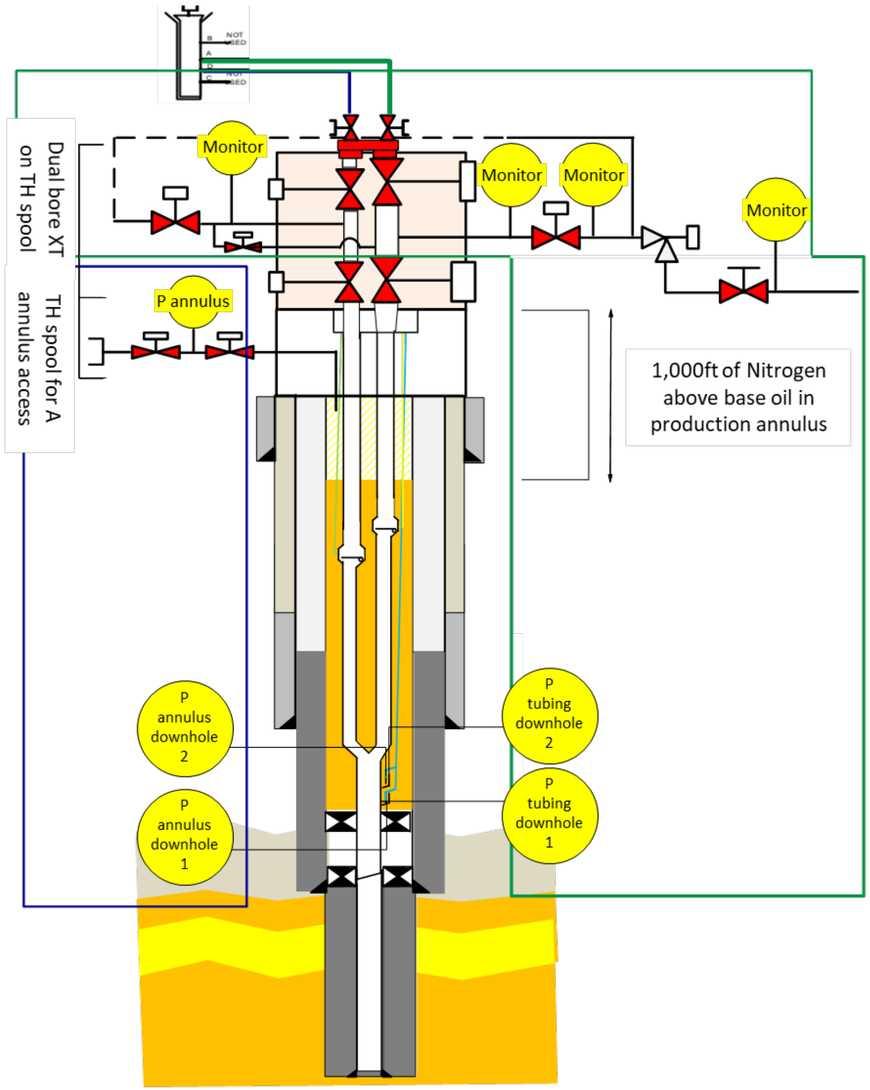


Figure 5-3: Basic well schematic showing the location of pressure and temperature monitoring points.

5.3 Annulus Pressure Management

5.3.1 Annulus Arrangement General

For the AS-01 well the general well arrangement is: X-mas tree installed on tubing head spool, this arrangement allows the dual completion design with access to the 2 strings through the dual bore X-mas tree and access to the 1st annulus (completion x production casing annulus) through the tubing head spool. At the construction phase of the well the drilling BOP will be installed on the THS and the completion will be run with the well in a filtered inhibited completion brine. After the landing and orientation of the completion in the tubing head spool the completion brine will be displaced from the annulus and replaced with base oil plus a nitrogen cushion. The displacement of base oil will be down to the level of the tail pipe. For the displacement of the nitrogen cushion this can be before or after setting of the production packer. The inclusion of a sliding sleeve in the major string can provide an option whereby the nitrogen can be displaced into the annulus after the setting of the production packer if this step was not already completed. The benefit of the sliding sleeve vs the additional potential leak paths that it presents between tubing and annulus shall be further assessed during detailed engineering.

The use of base oil below the nitrogen cushion will provide an annulus fluid that has good resistance to freezing and will not contribute to corrosion in the production annulus.

The base case is the nitrogen cushion in the annulus will be from wellhead to around 305 m (1,000 ft) below wellhead as shown in Figure 5-4.

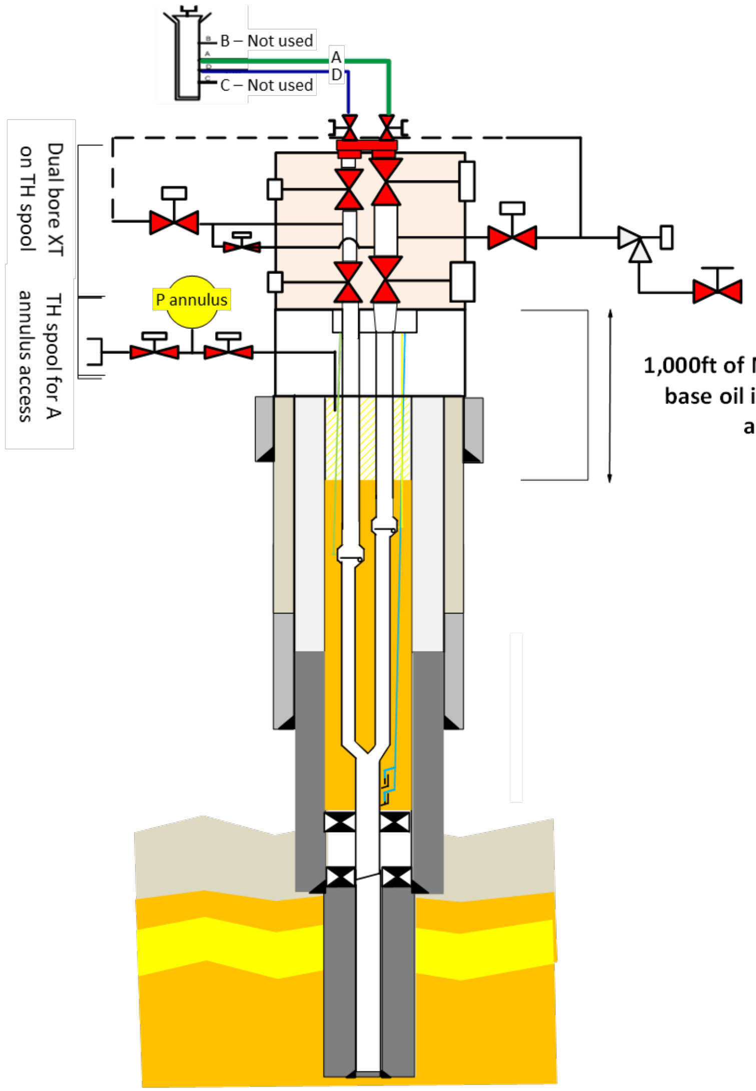


Figure 5-4: Well general arrangement showing dual bore completion with nitrogen cushion in annulus.

5.3.2 Annulus Pressure Management Close Up

At the construction phase with the well at the undisturbed geothermal temperature, the nitrogen blanket installed in the annulus will be at ~45 – 50 barg. The 45 – 50 barg shut-in pressure of nitrogen with a 305 m (1,000 ft) column of nitrogen has been calculated to allow for operation of the well while maintaining a positive pressure.

Under injection conditions with cooling of the well the base oil (simulated with EDC-99DW) will contract and the interface level of the base oil to nitrogen will drop. This interface level will drop by around 119 m (390 ft) as a result of cooling during injection based on calculation provided courtesy of Shell UK. A drop in interface level results in expansion of the nitrogen with the pressure dropping to around 30 – 35 barg.

The working window of 45 – 50 barg in geothermal conditions with 30 – 35 barg in injection conditions provides a working window for the production annulus pressure that allows pressure monitoring and manageable load cases. Figure 5-5 shows the variation in pressure in the A annulus with respect of depth for geothermal and injection conditions These pressures will be included in completion and casing stress analysis calculations.

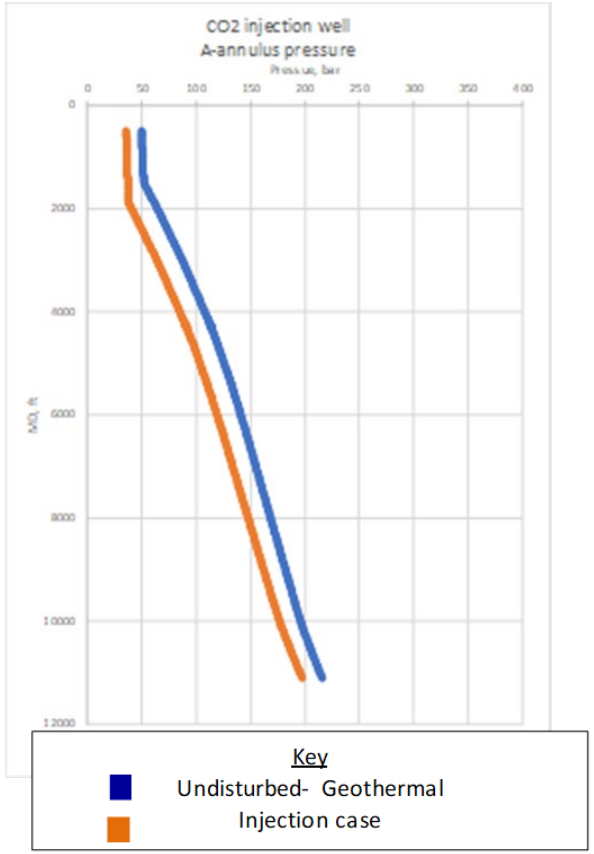


Figure 5-5: A annulus (production annulus) pressure vs depth for 2 cases undisturbed and injection.

With the 45 – 50 barg annulus cushion (pressure at wellhead level) in the geothermal case the A annulus pressure the fluid columns are represented in Figure 5-6 below.

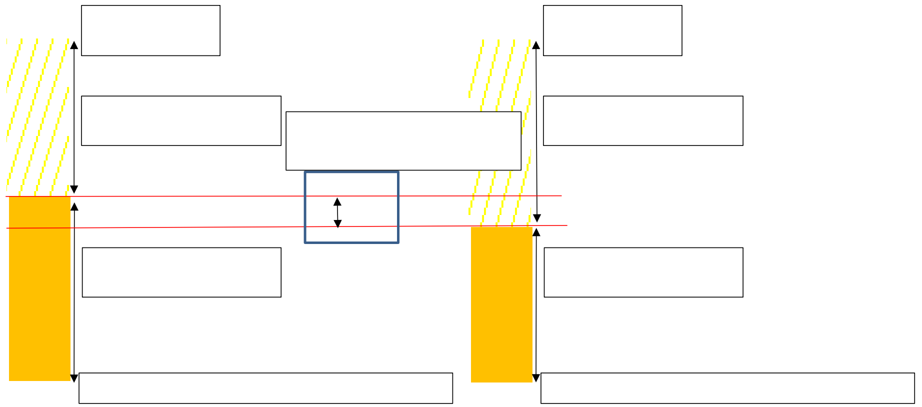


Figure 5-6: Operating window for annulus pressure between the shut-in geothermal and injection case

The annulus pressure can be monitored at the level of the wellhead and at the level of the downhole gauges. The two downhole gauges in the completion below the level of the completion Y piece are ported to allow pressure and temperature measurement in the completion string and in the annulus. Having annulus pressure measurement both down hole and at the level of the wellhead will allow interpretation of the expansion and contraction of the annulus fluids and the change in the level of the interface.

Access to the A annulus for pressure bleed off or re-pressurisation will be by intervention only. Figure 5-7 shows a close up of the annulus access through AAV (Annulus Access Valve 1 & 2) and an interface connection, the base case considered is 2” connection.

The pressure gauges shown THS Annulus PT (Pressure Transmitter) at wellhead level will indicate the nitrogen pressure and the downhole PT 1 & 2 will show the combined hydrostatic of base oil plus nitrogen + nitrogen applied pressure. With basic tables at the well operating stage the operator will be able to monitor the behaviour of the annulus actual vs modelled. The inclusion of downhole gauges ported to the annulus will also aid any trouble shooting in the event of any abnormal annulus pressure behaviour.

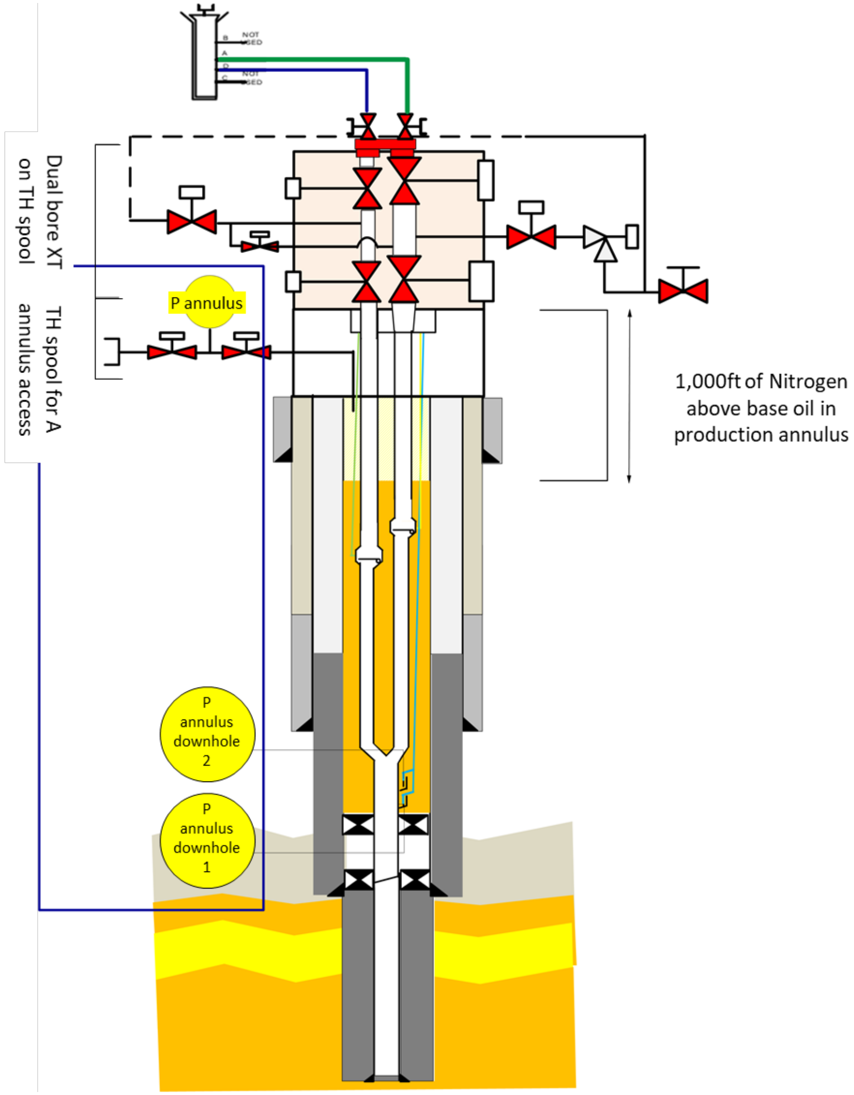


Figure 5-7: Highlighting annulus pressure monitoring at downhole and wellhead with access in intervention mode.

5.3.3 Annulus Pressure Monitoring Leak at Level of Production Packer

In the shut-in condition with base oil from a theoretical packer depth of 3,378 m (11,080 ft) BRT or 2,330 m (7,642.4 ft)TVD below wellhead with 305 m (1,000ft) nitrogen gas cap, the applied pressure above the production packer due to the column of base oil (158 bar) + nitrogen (2 bar)+ nitrogen pre-charge pressure (50 bar) results in a pressure above the production packer of around 210 bar. At the early stage based on Captain D reservoir pressure of 205 barg (at 2,459 m TVD below wellhead) the pressure above the packer will exceed the pressure below (estimated at 194 barg) by around 16 bar. In the shut-in condition a declining annulus pressure could be indicative of a loss of nitrogen pre-charge pressure or a possible communication past the production packer from annulus to the well.

During injection the pressure below the packer is similar, the pressure in the A annulus will fall due to the cooling effect and approximately 15 bar of nitrogen pressure will be lost due to the reduction of the level of base oil. In the injection case there will be almost no differential pressure across the production packer.

To simplify analysis of annulus pressure behaviour and to allow detection of a production packer leak, it could be useful to consider a higher nitrogen pre-charge pressure. Selecting a higher pre-charge pressure to maintain a positive pressure above the production packer during injection during the early life of the well could be beneficial. It is recommended that a sensitivity study be performed during detailed engineering to assess the optimum life cycle pre-charge pressure.

5.3.4 Annulus Pressure Management Summary

The AS-01 well tubing by production annulus will be displaced to base oil and nitrogen. The use of base oil as a packer fluid provides a relatively low sg (specific gravity) fluid that has good thermal insulating properties and will not contribute to corrosion in the tubing x production casing annulus. The use of a nitrogen cushion or cap above the base oil in the annulus provides a gas that will allow the base oil to expand and contract while maintaining a relatively low change in pressure. The work carried out by the Shell UK team has shown that based on a 305 m (1,000 ft) nitrogen gas cap above the base oil in the annulus, the well can be operated with temperatures from the highest considered being the geothermal undisturbed temperature to the lowest operational case injection of CO_2 with a relatively low change in pressure of around 15 bar. The proposed nitrogen pressure to be left in the A annulus at the end of construction phase, with the well ready for start-up is 45 – 50 barg. With 45 – 50 barg in the annulus at geothermal conditions the pressure will reduce to approximately 30 – 35 barg during injection due to cooling of the well and the annulus fluid.

The A annulus can therefore be monitored without the need for intervention during the planned injection and shut-in cases.

5.3.5 Annulus Pressure Management Further Work to Consider

For completion design TSA (Tubing Stress Analysis) and casing design load cases the use of a Nitrogen gas cap in the A annulus must be considered.

It could be useful to consider the benefit of a higher nitrogen pre-charge pressure to assist in detection of leak past the production packer. The value of a higher nitrogen pressure should be assessed.

6.0 Planned Transient Operations

6.1 Hydrate Prevention & Inhibition

The risks of hydrates in the AS-01 will be managed by controlling the water content in the injected CO_2 and the use of hydrate mitigation plans for well start-up and any well intervention operation that may be planned.

For first well start-up, the basis of the hydrate mitigation plan is to remove water-based fluid from the well by bullheading the tubing contents into the well with base oil followed by a nitrogen cushion. This process will remove the risk of hydrates originating from fluids introduced as part of the well construction phase. In addition to bullheading the tubing contents, the X-mas tree valves and X-overs will be flushed with a water free or inhibited fluid to remove water from voids and valve cavities. This procedure will be part of the well suspension and preservation sequence and will be detailed in a specific program. For the de-watering of the sea line and prevention of hydrates sea line and the well shall be managed by a specific procedure for well start-up.

For well intervention cases, a hydrate mitigation plan will form part of the well intervention program. The well will be displaced to base oil and nitrogen cushion as part of the intervention program, this will form the first part of the hydrate mitigation plan. For all pressure testing and equalization an inhibited fluid will be used.

As part of the Peterhead CCS project, Shell UK carried out extensive work on hydrate prevention for the surface wellhead scenario. The following guidelines make use of this work carried out by Shell UK.

Extract from Well Operation Guidelines [4] - where applicable references to the specifics of the Peterhead well completion and reservoir well bore interface have been updated to reflect the cased and perforated wellbore interface planned for the AS-01 well.

Hydrates will be managed during steady state injection primarily by dehydration of the injection fluids to remove the water to sufficiently inhibit the formation of hydrates. The specification of 20 ppm weight (50 ppm mol or 0.005 mol%) [5] of water into the export pipeline from St Fergus is based on the requirement that during normal injection and during start-up/shut-in hydrate formation is prevented. The final specification of the CO_2, water content and impurities may change as there may be opportunities to consider CO_2 from other sources. As the work already carried out is based on the composition of the CO_2 that was planned to be injected for the Peterhead project, the hydrate Inhibition guidelines will require to be updated when the specification of the CO_2 for Acorn CCS project is finalized. The requirement for an update of the hydrate Inhibition guidelines has been added to the section of risks and opportunities in this document.

During hydrocarbon production, water has encroached into the Goldeneye gas hydrocarbon section and at least part of the perforated liner will be surrounded by water when CO_2 injection commences. As such hydrocarbon gas and water will be present during the initial CO_2 injection. The trapped gas saturation is estimated to be 25%, so some methane will remain near the well. The methane is miscible with CO_2 and consequently will eventually be displaced by the injected CO_2. The initial injection of CO_2 will drive water away from the well and cool the reservoir. Exceeding the normal water specifications in the CO_2 will increase the hydrate risks considerably, especially during start-up and shut-in operations.

The following risks were identified for non-steady state operations with the above specification of the CO_2 stream:

- Start-up of the injection at an initial pressure below 20 bara at the wellhead level,
- Start-up after a well intervention,
- Testing of the Down hole safety valve (DHSV),
- Initial start-up of CO_2 injection.

6.1.1 Gas Hydrate Behaviour in the System CO_2 and Water

A mixture of carbon dioxide and water will form crystalline solids or gas hydrates under certain pressure and temperature conditions.

For a water concentration of 0.005 mol% the maximum is found at the intersection with the boiling curve of CO_2 at a temperature of -22.1°C and a pressure of 18.4 bara. The Hydrate Equilibrium Temperature (HET) is depending on the amount of water in the system, see Figure 6-1.

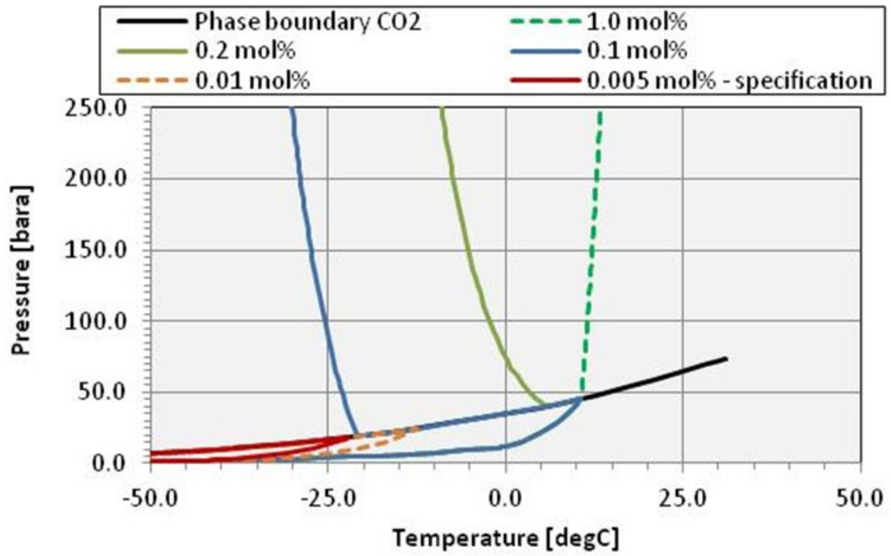


Figure 6-1: Gas hydrate phase boundaries for the CO_2+water system for different concentrations of water.

In addition to the hydrate equilibrium temperature the dew point line for water and the ice phase boundary was calculated for a water concentration of 0.005 mol%. The low concentration of water has a large impact on these phase boundaries. Figure 6-2 shows that the water dew point takes place at a lower temperature than the hydrate equilibrium temperature below the boiling curve of CO_2. The intersection of the phase boundary line with the boiling curve is at negative 28.2°C and 15.2 bara. Ice formation of water takes place below -43°C and 1.9 bara.

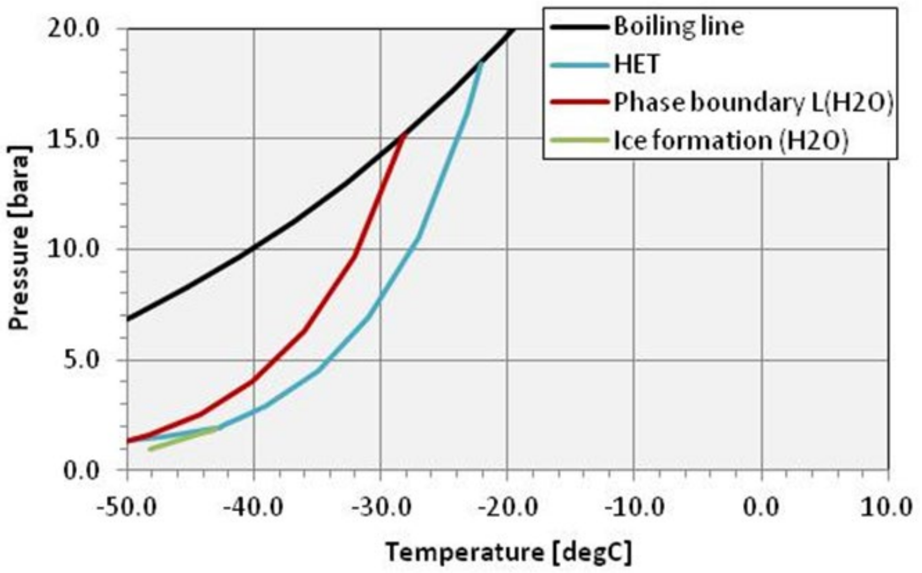


Figure 6-2: Hydrate equilibrium temperature (HET) and the water dew point line for 0.005 mol% of water in CO_2 below the boiling curve for CO_2

In the presence of free water, it is possible to form hydrates when the temperature is below 13.4°C at high pressures. Under injection conditions this corresponds to a depth in the well of approximately 1,200 m below the wellhead (updated for AS-01 well utilizing steady state conditions injection at 0.5 $MtCO_2/y$). In theory, injecting a hydrate inhibitor above this depth will solve all the issues related to hydrate. However, hydrostatic pressure considerations are required to avoid excessive JT (Joule Thomson) cooling in the top of the well when the tubing head pressure is relatively low.

The well will warm up during the closed-in operation. The 13.4°C will be encountered at a depth of approximately 330 m (updated for AS-01 well). Any hydrate plug formed below this depth will be melted by the heat of the formation.

6.1.2 Hydrate Formation Risks

6.1.2.1 *Injection conditions*

Meeting the specification of less than 20 ppm weight (50 ppm mol or 0.005 mol%) of water in the export from the compressor at the carbon capturing plant is sufficient to ensure that hydrates do not form during normal steady-state and shut-in operations. Even during short excursions into the hydrate formation conditions, a water content of 20 ppmw will result in very little gas hydrates. The injection well will develop cold conditions, the bottom hole injection temperature during normal injection is expected to be between 23°C to 35°C as such there is not an issue of hydrate deposition in terms of injectivity.

6.1.2.2 *Closing-in operation*

The well is still injecting CO_2 during the closing-in operation as such there is no aquifer influx yet. The bottom part of the well is not in the region to form hydrates, from the simulations in injection conditions the BHT will be between ~ 23°C and 35°C.

During the closing-in operation the well is still injecting CO_2 at the specification. Under controlled well shut-in following the recommended time to carry out the closing-in operation there is not risk of hydrate deposition.

Even entering the hydrate formation conditions for short periods will not lead to any issues at the top of the well because of the low amounts of water in the CO_2 stream. Before shut-in, the available and fully distributed water in the whole well tubing will be less than 400 g (calculation based on Peterhead project well completion this shall be updated). A sensitivity shall be carried out based on a revised calculation of the amount of water, at this stage it is considered that there will not be enough water to form a complete blockage as a full blockage requires at least 700 g of water (figure from Peterhead well completion simulations).

6.1.2.3 Closed-in period

In the closed in condition, the well will be warming up during this time and will tend to go into the geothermal conditions. The bottom part of the well will be at temperatures above the hydrate equilibrium temperature even assuming the presence of free water.

The top part of the well will be warming up, but the pressure and temperature conditions will stay in the hydrate curve assuming free water.

The main uncertainty during this period is the presence of free water in the well. For the Peterhead project water was observed in the existing closed-in wells. However, with increased injection of CO_2, water from the aquifer is pushed away by the CO_2. The time where the water is not coming back into the well will require to be updated based on the AS-01 well injection rates, for the Peterhead well and the associated injection rates this was estimated to be between six months to one year of continuous injection. After this continuous time of injection, the water will tend to stay away from the wellbore. However, in case that the well has been injecting for a short time then it is possible that water may enter the wellbore.

6.1.2.4 Starting-up operation

For the start-up of the CO_2 injection, one should be aware that hydrate formation may occur. This also means that the history of events after shut-in is important.

In order to reduce the initial risk of hydrate formation during the first years of injection, (aquifer water has not been fully displaced from the wellbore) it is considered prudent to introduce batch hydrate inhibition prior to operational opening of a well for injection.

When starting the injection after a normal shut-in during which (without intervention or changing the content of the well tubing) the wellhead pressure may decrease below 20 bara. It is advised to inject a hydrate inhibitor during start up because the well may operate at temperatures below -22°C (inside the hydrate formation condition for the water specification of 0.005 mol%). Hydrates, when formed may accumulate as continuously small amounts of water are injected into the well. No hydrate formation risks are foreseen if the wellhead pressure is higher than 20 bara before start-up.

In all other cases, it is advised to inject a hydrate inhibitor during start-up, as the content of the tubing may contain more water than the specifications given for the project and accordingly an increased risk of a hydrate blockage may exist.

6.1.2.5 Testing of the SSSV

Low temperatures can be encountered during the de-pressurisation period. In case that the testing is done immediately after closing the well from injection then it is not required to inject methanol into the well as the CO_2 will be under specification conditions and the lowest observed temperature is -7°C outside if the hydrate deposition window.

Methanol is required to equalize the pressures across the valve to be able to open it once the test has been completed.

6.1.2.6 Initial start-up of injection

Before the initial start-up of the CO_2 injection, the well tubing will contain large amounts of water from the reservoir or from the well intervention. This amount of water may cause an issue when cold CO_2 enters the tubing during the initial start-up. This will be addressed as part of the well first start-up program and any subsequent well intervention program. The base case considered is that the well will be bullheaded with base oil or an inhibited fluid plus nitrogen. The bullheading will displace water into the reservoir and the column of nitrogen will be adjusted to a pressure of around 45 bar for well start-up both for initial start-up and following any intervention.

6.1.2.7 *Starting up after a well intervention*

The fluids after a well intervention may have changed considerably and may contain large amounts of water. When starting the injection of CO_2 with a low tubing head pressure, the interface of the fluids in the well tube may become in direct contact with a cold stream of CO_2.

The base case considered is that the well will be bullheaded with base oil or an inhibited fluid plus nitrogen. The bullheading will displace water into the reservoir and the column of nitrogen will be adjusted to a pressure of around 45 bar for well start-up both for initial start-up and following any intervention.

6.1.3 Hydrate Avoidance Guideline

6.1.3.1 *Preferred inhibitor*

Guideline: Methanol

Part of the remediation will consist of injecting a hydrate inhibitor. In this case, a thermodynamic hydrate inhibitor like methanol or MEG/water, needs to be used. Methanol is the recommended inhibitor to be used, because of the low temperatures it may become exposed to with CO_2 (e.g. during a depressurisation). The freezing point of MEG/water depends on the percentage of MEG. The minimum freezing temperature is about -50°C. For the Acorn CCS well, in the subsea context the inhibitor will be supplied via the 4" MeOH line, for any well intervention the practicality of the use of MeOH will have to be considered. MEG/water mix may be considered, in addition, the minimum pressure and minimum temperature that can be reached will also be taken into account. For the subsea case without bleed off to atmospheric pressure the lowest pressure considered is 12 bar.

6.1.3.2 *(Steady state) Injection conditions*

Guideline: **See section 6.1.2.1**

6.1.3.3 *Closing-in operation*

Guideline: **See section 6.1.2.2**

6.1.3.4 *Closed-in period*

Guideline: Inject methanol in the well during this period when the following conditions are met:

- Injection time in the well of less than 2 years,
- Closed-in period of more than 24 hours,
- Volume of MeOH to inject 4.9 m^3 (approximate volume to TRSCSSV for both strings).

The well is closed-in and it is warming up during this time. The bottom part of the well is warm even after injection and hydrates are not expected. There is uncertainty in the presence of water in the top part of the well where it is cold, and temperatures are below the HET for the free water case.

The well needs to be prepared for the re-introduction of CO_2 and avoid potential hydrate deposition.

The introduction of methanol is required considering the following cases:

- During the initial stages of injection where the CO_2 plume is not developed and water from the aquifer might be in contact with the well. It can take after 2 years of injection for the water not to come back into the well.

- Even with the presence of the water in the well it is possible that the water does not reach the top of the well. Temperature below 15°C (HET temperature for high pressures) can be encountered above ~1,372 m (4,500 ft) TVD in the well. It is unlikely that under short term closed-in periods the water will be able to travel from the reservoir to 1,372 m TVD in the well. Diffusion and convection process are slow.

It is proposed to displace methanol during a normal start-up if the well is closed-in for more than 24 hours. This is considered a very conservative time duration.

In case of having injected in a well for a long time where a CO_2 plume is formed then methanol is not required to be injected into the well. One might argue that is better to standardise the starting up operation for all the cases and methanol is required. This can be decided during the operational phase of the project where more experience will exist in the management of the wells.

6.1.3.5 Starting-up operation

Guideline: Methanol has been injected into the well during the closed-in period as such hydrates are not expected into the well.

6.1.3.6 Normal testing of the DHSV

Guideline:

- Inject 4.9 m^3 of methanol after the SSSV test (approximate volume to TRSCSSV for both strings).
- Evaluate displacement pressures
- Depending on displacement pressure it is possible that more methanol pumping is required to equalise the pressures across the valve (valid for a well full at geothermal conditions)
- Apply control line pressure
- Re-commence injection after SSSV test is complete.

6.1.3.7 Remediation in case of a hydrate plug

Symptoms may indicate that a hydrate plug is being formed. An example of such an indication can be the erratic behaviour of the wellhead pressure or pressure drop over the wellhead choke (flow fluctuations) during CO_2 injection. In case of a blockage, the pressure will show an increase in the pressure in the pipeline when injecting. During a depressurisation, this erratic behaviour may be observed in the form of pressure drop fluctuations over the vent valve (case considered DHSV testing).

In general, when hydrates are likely to be formed and symptoms indicate a hydrate plug, the best way forward is to immediately stop the CO_2 injection or stop the depressurisation (case considered DHSV testing) and assess the situation.

During the assessment, one should try to determine the location of the blockage, as the location of the plug may limit the remediation options. Common method to determine the location of a blockage is to do a partial depressurisation, in the context of the subsea well the options are limited. From the initial and final pressures and an estimate of the amount of gas released the location of the blockage can be estimated.

As the CO_2 stream contains a very small amount of water, hydrates might be formed at a very low temperature, a period of shut-in may already melt the blockage. If not, two-sided depressurisation is generally recommended for conduits that are completely blocked, as it is safer because there is less (not zero) risk that large pressure differences will be created over a hydrate plug. Although in principle straightforward, care must be taken that depressurisation does not worsen the problem or threaten the integrity of the system. The following general guidelines apply to depressurisation:

1. The approximate hydrate dissociation pressure must be known before starting the depressurisation, such that the operator knows the conditions when hydrates start to melt.
2. The system is de-pressurised in steps of not more than a few bar each.
3. It must be possible to immediately close-in the system if pressure surges are observed.

A two-sided depressurisation is not possible for a blockage in the well tubing. Given the fact that hydrates can only be obtained at very low temperatures for normal operational conditions, a shut-in period would already melt the plug as heat will be transferred from the environment to the blockage. Care should be taken that the pressure stays within the limits of the system.

If the blockage occurs as part of an operational upset, e.g. more water may have entered the well tubing, the remediation actions may become a time-consuming process. If the hydrate plug does not melt after a period of shut-in, which may occur for depths ranging between 200 – 1,200 m below the seabed (depending on the soil/rock temperature around the well tubing and the water content of the fluid), an alternative method may be required. Injecting a batch of methanol may not affect the hydrate melting process as the density of methanol is well below the density of the dense CO_2 fluid and, therefore, the methanol may not reach the hydrate blockage or, when in contact with the blockage, melting of the plug would cause a layer of water on top of the plug that separates the methanol from the plug. In the case of normal operations only methanol will be available, through the 4” service line. In the case of an intervention operation injection of a MEG solution into the well tubing would provide a better solution. Based on the density, the MEG solution would become in contact with the plug and the process of melting would take place.

In normal operations without the option of MEG injection, one may require a stepwise depressurisation, which involves much more operational risks. Pressure drop may have been build-up over the plug and a sudden release of the plug may cause a pressure surge through the system and the hydrate plug may be released with the potential to cause damage. If this approach is taken, care should be taken to analyse the possible impact of a sudden pressure release, the control options (pressure/flow sensors and control valve) required to counteract the surge and the safety risks involved for the equipment.

6.2 Well Start-Up After Long Shut-In (> 24hrs)

Extract from Well Operation Guidelines [4] - where applicable references to the specifics of the Peterhead well completion have been updated to reflect the dual bore subsea completion of the planned for the Acorn AS-01 well.

Guideline: “Open the well over 30 minutes to obtain minimum flow in 30 minutes. Use the actuated subsea choke in multiple stages of proportionally increasing CO_2 rate. Increase injection pressure to 50 bara.”

This section describes the starting-up of the well when it is filled with CO_2 and the well has been closed for a long time, as such the well is at geothermal conditions.

When starting up from geothermal conditions the lowest fluid temperatures in the well are reached during a low reservoir pressure start-up. The low temperatures are confined to the top of the well only.

For the well start-up operations, the top of the well will contain gaseous CO_2 phase depending on the reservoir pressure. Rapid ‘bean up’ of the well is required to avoid cooling due to continuous CO_2 JT effect. 30 minutes start-up is considered the reference case for normal start-up operations.

Modelling has shown that the temperature at the wellhead does not drop below -10°C during well start-up.

6.3 Well Start-Up After Short Shut-In (< 24hrs)

Extract from Well Operation Guidelines [4]**-** where applicable references to the specifics of the Peterhead well completion have been updated to reflect the dual bore subsea completion of the planned for the AS-01 well.

Guideline: Open the well over 30 minutes to obtain minimum flow in 30 minutes (injection pressure of 50 bara) Use the actuated subsea choke in multiple stages of proportionally increasing CO_2 rate. Increase injection pressure to 50 bara."

The CO_2 conditions during start-up after short shut-in period will be influenced by the series of events before the start-up operation. Nevertheless, due to the short time shut-in, the well will not be able to warm up and it is expected to have cold temperature conditions.

During start of injection there will be a pressure drop seen at the tubing head due to differences in CO_2 density. Later, the pressure will increase, as frictional pressure drop comes into play.

For the well start-up operations, the top of the well will contain gaseous CO_2 phase. Rapid 'bean up' of the well is required to avoid cooling due to the CO_2 JT effect. This needs to be balanced with the limitation imposed by the lower completion with respect to maximum velocity across the screen / gravel pack.

The sequence of steady state injection, close-in operation (30 minutes), shut-in time (30 minutes) and start-up operation (30 minutes) was simulated for low reservoir pressure of ~200 bara (2,890 psia) and it is shown in Figure 6-3 and Figure 6-4 below for early life and late life conditions respectively.

From the simulation for short shut-in it can be seen that the minimum wellhead temperature reached is -10°C.

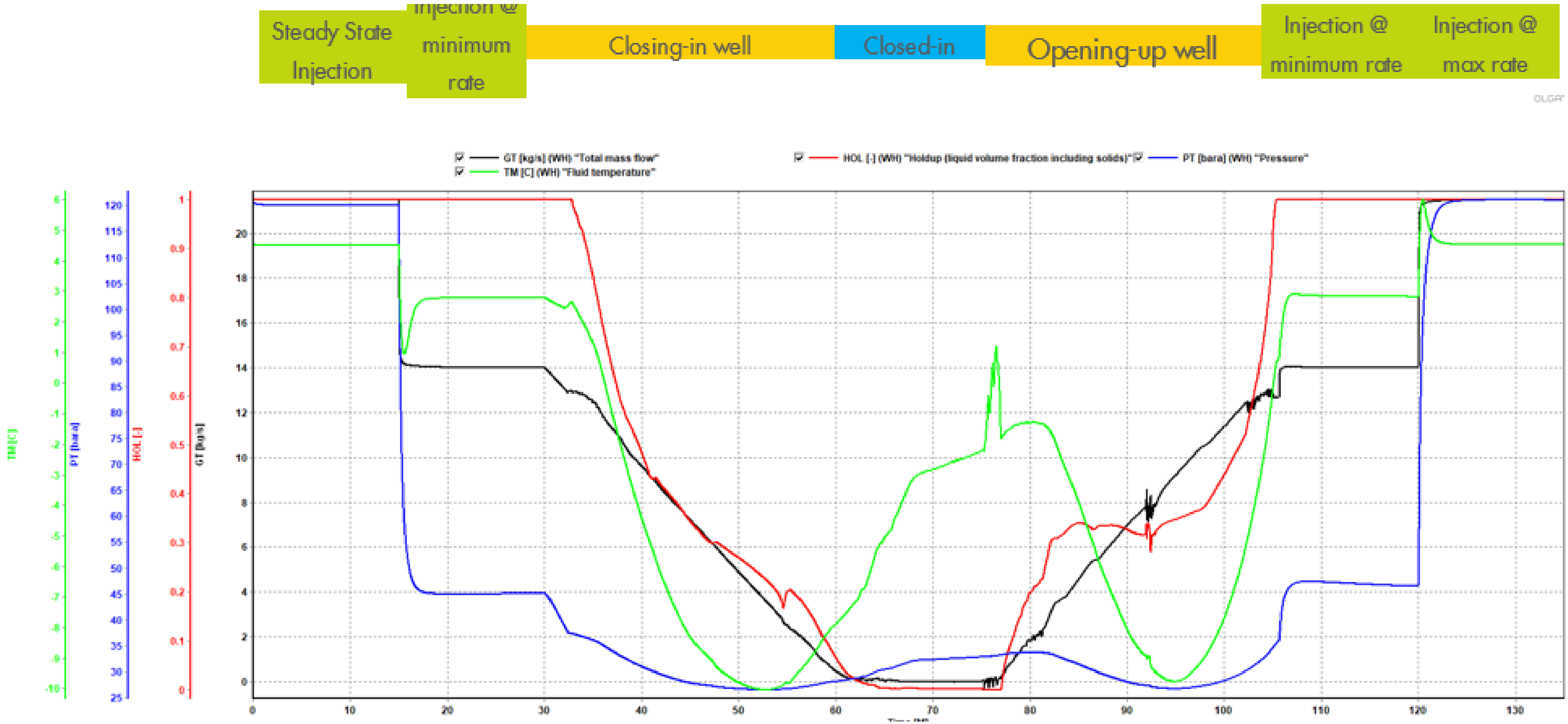


Figure 6-3: Early life short term well closure, WHT WHP, injection rate and liquid hold up (HOL) well restart after short shut-in.

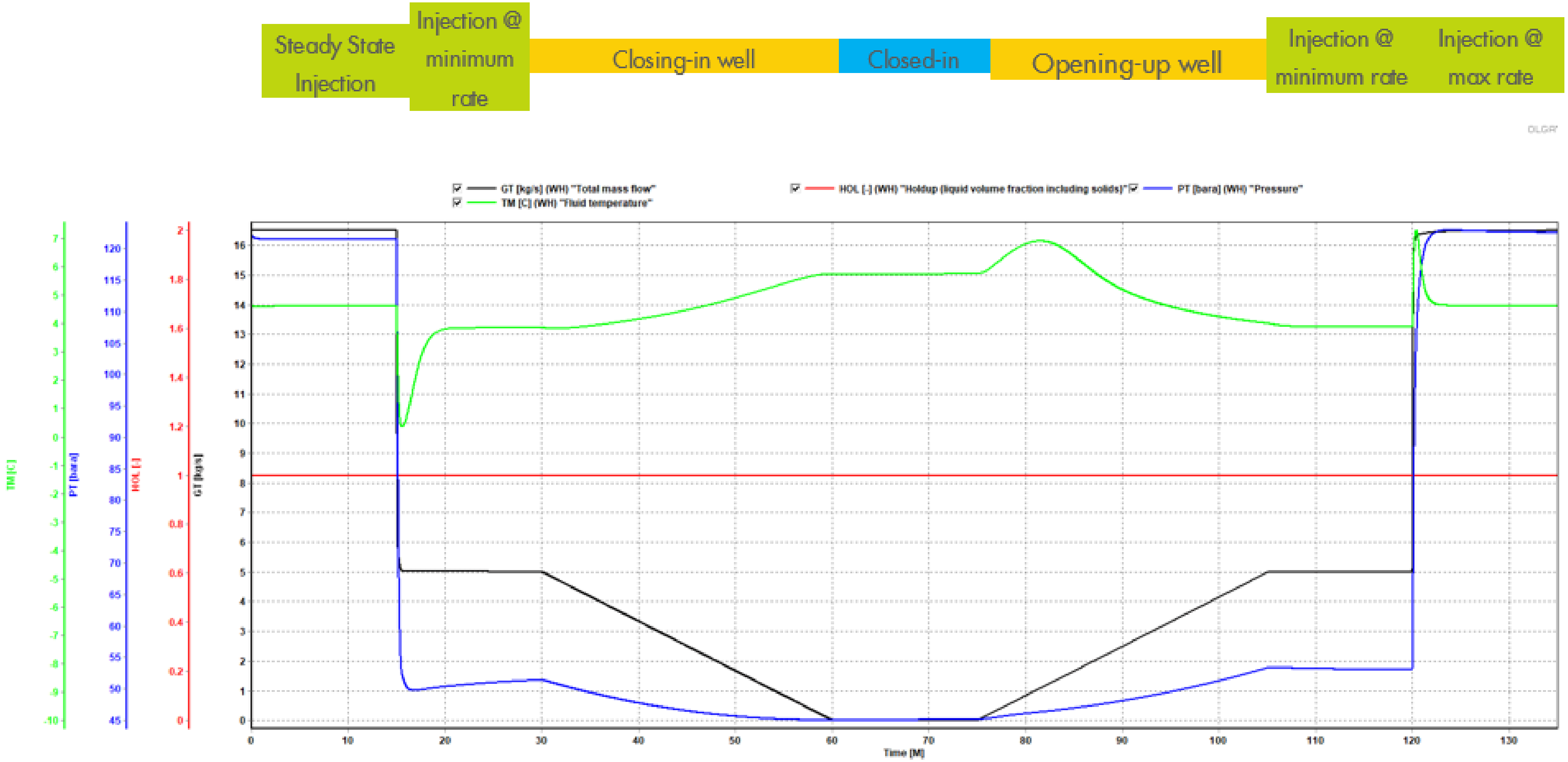


Figure 6-4: Late life, short term well shut-in. WHT WHP, injection rate and liquid hold up (HOL) well restart after short shut-in.

6.4 Closed-In Well After Long Injection

Extract from Well Operation Guidelines [4]- where applicable references to the specifics of the Peterhead well completion have been updated to reflect the dual bore subsea completion of the planned for the Acorn AS-01 well.

Guideline: "Bean back the well. Reduce injection pressure to 50 bara. Close the well or bring the flow to zero in stages – 30 minutes."

This scenario is for a well that needs to be closed after a long period of injection, the well is under cold conditions with bottom hole temperatures in the order of 25 – 28°C.

During closed-in operations the frictional pressure drop over the well is reduced, resulting in a lower injection tubing head pressure. This results in JT cooling as long as CO_2 is still supplied by the pipeline. At the end of the closed- in operation the CO_2 in the top of the tubing will be in form of gaseous state due to the depleted reservoir condition. The gas-liquid interface will be shallower with increasing reservoir pressure. The lower the reservoir pressure, the more cooling is expected in the well.

During normal well operations the well needs to be closed-in in 30 minutes. This is a balance between closing the well rapidly to avoid cooling of different well elements and 'hammer' effects induced by closing the wells too rapidly.

The recommended guideline is to:

- Bean back the choke,
- Reduce injection pressure to 50 bara,
- Close the well or bring the flow to zero – over a 30-minute period,
- Alternatively, close the well in 30 minutes by reducing the injection rate in 5 proportional stages of approximately 6 minutes each.

There is no requirement to inject methanol during this operation as CO_2 at the specification level is still injected into the well and there is no water in the well.

The minimum temperature observed from OLGA simulations performed by Shell U.K. does not drop below -10°C at the wellhead.

7.0 Unplanned Transient Operations

7.1 Rapid Closure of The Well

Guideline: Tree valves to be closed as soon as possible.

This situation might be valid during emergency shutdowns (ESD).

Simulations have been carried out for well ESD in early life and late life based on rapid closure of tree valves in case of emergency. Figure 7-1 and Figure 7-2 show the case for early and late life reservoir conditions. The CO_2 temperatures generated under this scenario do not pose any integrity concerns to the well.

Rapid closure summary: Simulations have been carried out by Shell U.K. for well ESD in early life and late life based on rapid closure of tree valves in case of emergency. The CO_2 temperatures generated under this scenario do not pose any integrity concerns to the well.

ESD. Early Life. Wellhead conditions

Figure 7-1: Well closure on ESD early life. WHT WHP, injection rate and liquid hold up (HOL)

ESD. Late Life. Wellhead conditions

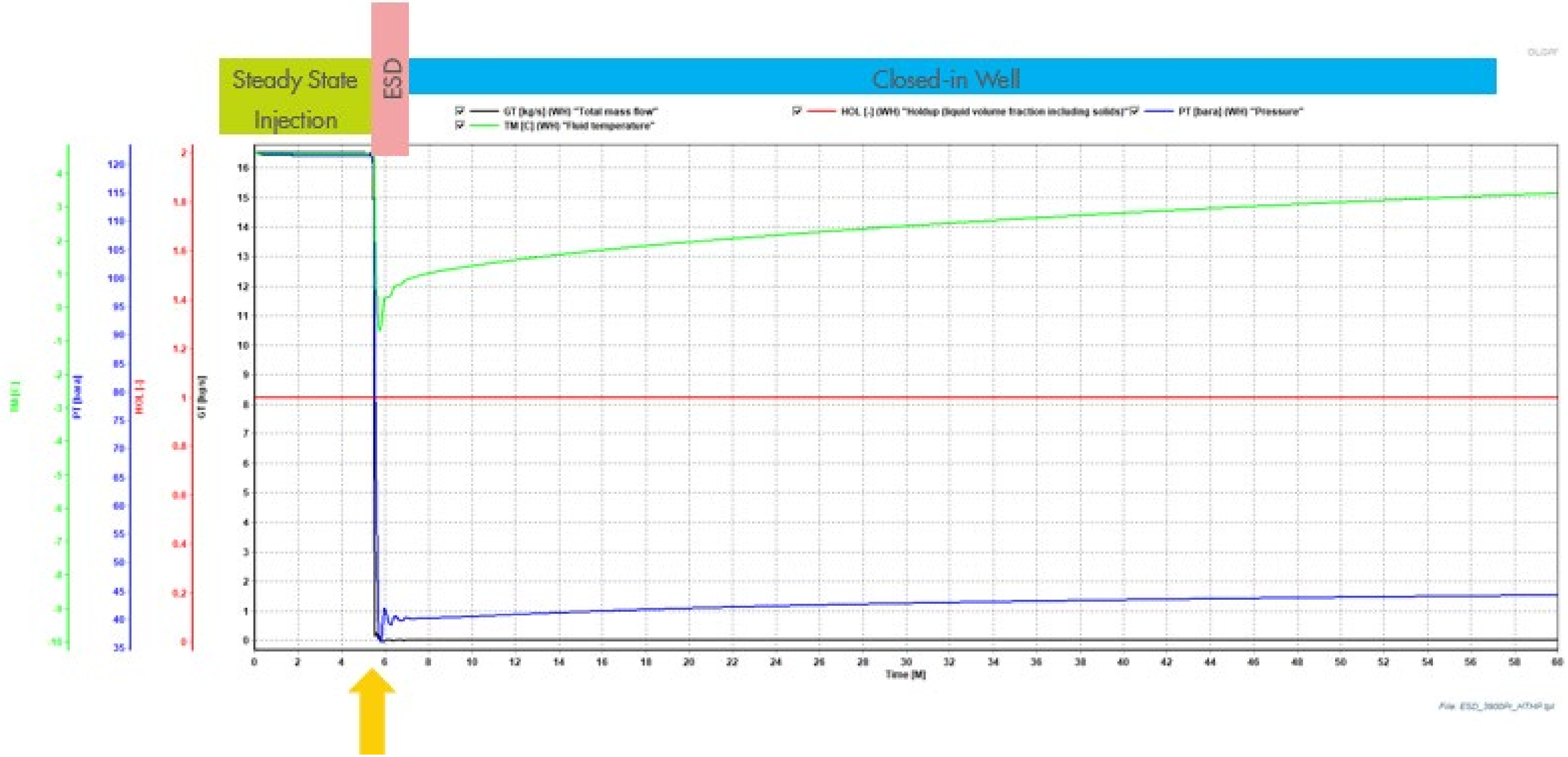


Figure 7-2: Well closure on ESD late life. WHT WHP, injection rate and liquid hold up (HOL)

7.2 Malfunction of the injection choke

Guideline: Identification by direct reading of CO_2 tubing head temperature. Once the problem has been identified then rapidly close the tree valves

Two-hour window of injection under two-phase has been calculated not to have any issues for well integrity.

The case of a stuck choke with a reduction in injection rate from around 77 t/h to around 18 t/h was simulated over a 2 hours period in early well life conditions (lowest reservoir pressure). The simulation shows that over a 2-hour period the integrity of the well is not compromised. The lowest temperature modelled with stuck choke condition is -10°C at the wellhead. The temperature falls to around -11°C at the time well shut-in is initiated by X-mas tree valve closure or ESD.

Well stuck choke summary: Only the case of early life with stuck choke has been simulated as this represents the worst-case condition (lowest WH pressure). A simulated stuck choke during a shut-in sequence with a reduction in rate by approximately 75%, with the stuck choke position maintained for 2 hours resulted in a wellhead temperature of ~-10°C this does not pose any threat to the integrity of the wellhead.

Stuck choke. Early life. Wellhead conditions

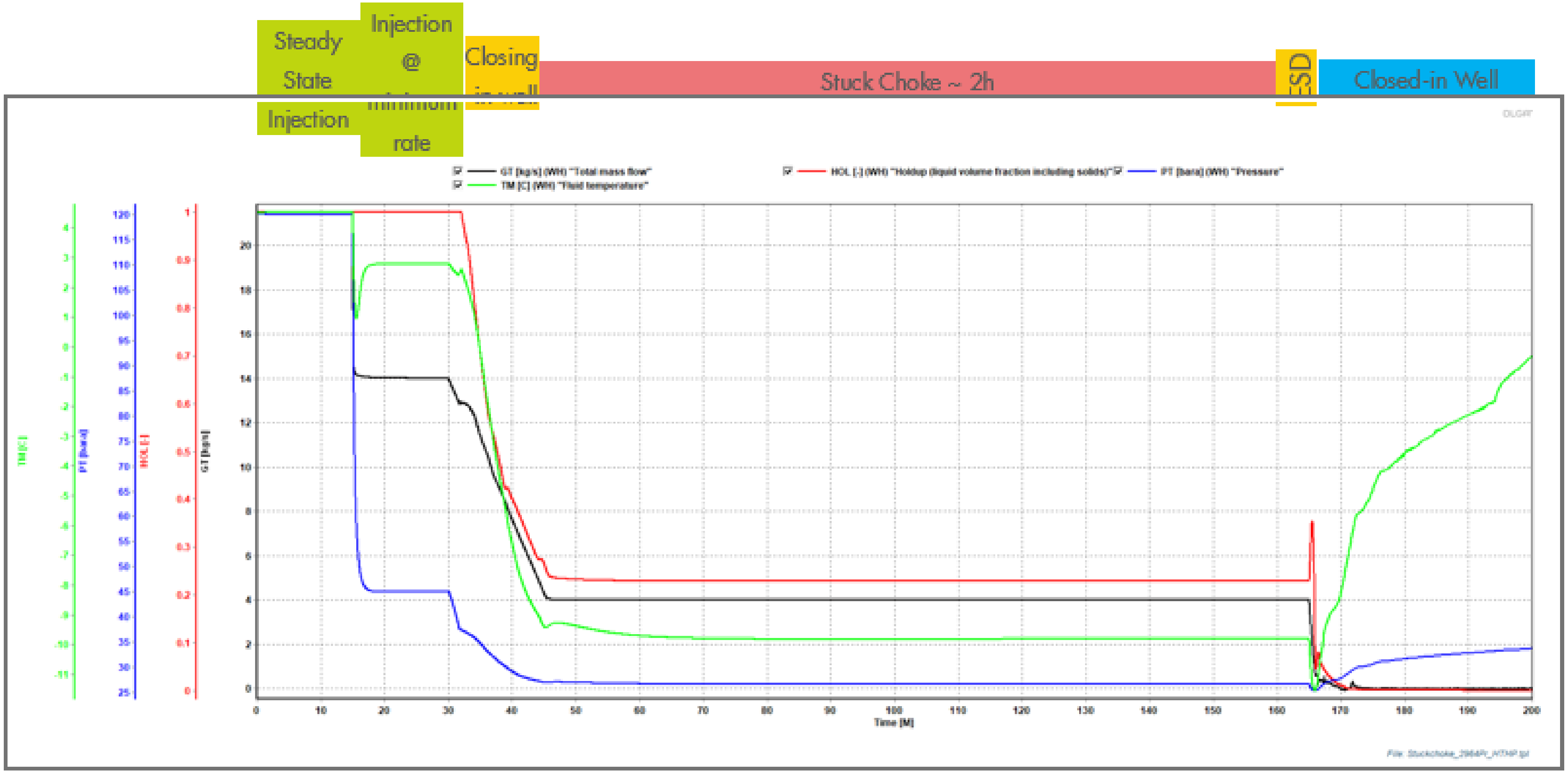


Figure 7-3: Stuck choke- early life (worst case condition) . WHT WHP, injection rate and liquid hold up (HOL)

7.3 Restart of Well With THP > 120 barg

Guideline: The case of well restart with THP close to or above 120 barg requires specific attention due to the limitation in the CO_2 supply pressure. In case of THP higher than 120 barg it will be necessary to lower the THP by pumping MeOH to the well to establish a fluid column that will lower the CITHP. The density of MeOH is around 0.79 sg, (maximum pipeline pressure will be limited to CO_2 available pressure at the tubing head)

Tubing size	Capacity L/M	Approximate reduction in THP per m^3 pumped (consider vertical height)
3-1/2" 9.2#	4.536	17.15 bar
2-7/8" 6.4#	3.019	25.6 bar
2-3/8" 4.6#	2.016	48.6 bar

Table 7-1: Guideline, reduction in THP based on 1m^3 of methanol pumped – for guidance.

At this time, the capacity of the MeOH pumps that will supply the 4" methanol line is not known. The working pressure of the 4" MeOH line has not been specified. It is assumed that the working pressure of the line will allow a reasonable injection rate to allow efficient pumping of MeOH for purposes of hydrate prevention and for pumping of MeOH to the well for the purposes of increasing the height of the liquid column and lowering the THP.

- Pump methanol into the well using the service line and dedicated injection point – note that a specific procedure will be required to ensure the supply of methanol from St Fergus and the monitoring of pumps rates and pressure.
- Introduce the CO_2 into the well once the tubing head pressure is around 80 bara.

7.4 Restart of Well With THP < 25 barg

Extract from Well Operation Guidelines [4]- where applicable references to the specifics of the Peterhead well completion have been updated to reflect the dual bore subsea completion of the planned for the Acorn AS-01 well.

Guideline: The THP will be around 25 bara after the test and the DHSV is closed. This is lower than the THP during normal closed-in condition, and hence upon CO_2 injection higher JT cooling is expected in the top of the well.

The valve is holding pressure from below which depends on the reservoir pressure assumed.

To open the valve, pressure from below and above the valve need to be equal (pressure equalisation). This will have an impact in the minimum temperatures to be observed above the SSSV.

For the case of the Peterhead well, the procedure to open the valve was modelled in OLGA using a check valve to take into account that the SSSV is opened by fluid pressure from the surface. The wellhead choke was opened in 30 minutes in the simulation. For the case of the Peterhead well (surface wellhead) the simulation showed that the minimum temperature reached was -18°C for the case of the low reservoir pressures and -14°C for higher reservoir pressures.

This guideline (equalization of DHSV by injection of CO_2) is not ideal as the pressure equalisation across the valve is not followed by the pressurisation of the control line. However, in the context of a subsea well this is not such an unusual case as control line trends are difficult to follow (due to the capacity of control line Umbilicals acting as an accumulator). This might lead to damage to the SSSV seal face over a prolonged period of injection. It is better to equalise the valve using methanol and then to re-commence injection. This procedure can be used as a back-up and indicates the worst-case condition in terms of JT cooling.

8.0 Maintenance & Repair Operations

8.1 TRSCSSV Testing Operations

Two scenarios can be considered for TRSCSSV inflow testing. The first is post intervention testing of TRSCSSV as part of exit barrier testing. The exit barrier testing will be integrated into the well intervention program, as part of the program the well will have been partially displaced to nitrogen, this nitrogen cushion will allow testing of both TRSCSSSV and facilitate well start-up post intervention with a wellhead pressure above 45 bar. The second scenario is routine TRSCSSV testing without intervention. The detailed procedures for TRSCSSV testing will be provided as part of Acorn CCS project detailed well operating procedures. In this section of the Preliminary well operating guidelines the general arrangement is outlined.

8.1.1 TRSCSSV Inflow testing – routine testing

For the case of routine TRSCSSV testing the base case considered is to bleed well pressure above the closed TRSCSSV to sea, in the context of a CO_2 injection well the controlled bleed off does not represent any environmental concern. Utilizing the dedicated bleed-off line complete with pressure regulator and low-pressure break pressure check valve will allow the wellhead pressure above the TRSCSSV to be bled down to no lower than 25 bar. This value has been selected specifically to ensure the temperature does not fall below – 7 °C this being the current technical limit for TRSCSSV. This value could be revised should the TRSCSSV be qualified to a lower temperature. A simplified sketch of the possible arrangement is shown below in Figure 7-1. At the time of writing the details of the bleed off arrangements to allow CO_2 to be bled to sea have not been finalized. The essential elements for safe operation are a backpressure controller to ensure the pressure does not fall below 25 bar and accurate pressure and temperature measurement.

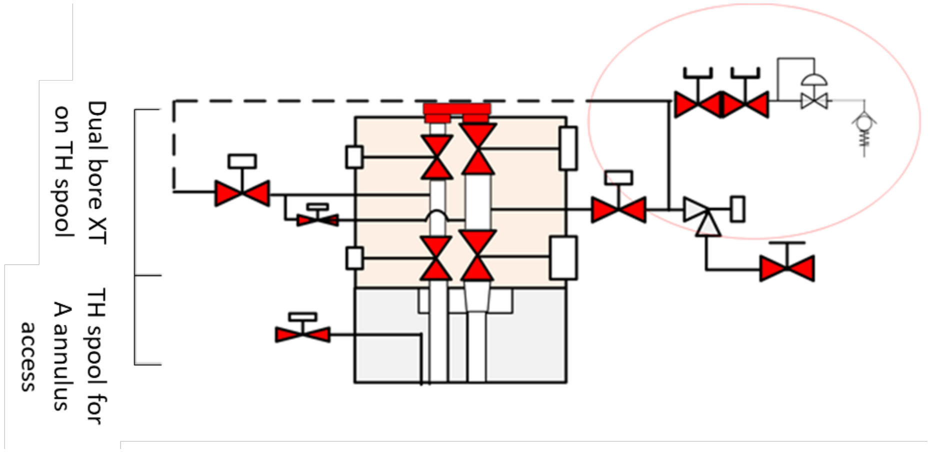


Figure 8-1: Possible route for CO_2 bleed off to sea through additional depressurization line on X-mas tree

With the well shut in and pressure allowed to stabilize, both TRSCSSV closed in, pressure will be bled off above the TRSCSSV through the back-pressure controller to sea. It is envisaged that this testing of TRSCSSV would be carried out at the time of ROV routine wellhead inspection, this will allow observation of the sequence and monitoring for hydrates at the area of vent to sea and PCV (production control valve). The high-level sequence will be as follows:

1. Stop injecting into the well. Wait for the CO_2 interface to stabilize.
2. Close the DHSV in each string .
3. Bleed off THP in both strings to 25 bar, the pressure will be controlled by back pressure controller.

4. The 25 bar limit is dictated by the current qualification level of the TRSCSSV being -7°C.
5. The bleed down requires to be carried out in a controlled manner, boil off will continue until boil off of CO_2 at the level of the DHSV.
6. The use of a self-regulating PCV is a requirement to make this operation feasible.
7. Pressure downstream of PCV will be 12 bar (ambient hydrostatic pressure of seawater), -35°C CO_2 temperature.
8. Once stable closed-in X-mas tree wing valves and monitor pressure build up on X-mas tree pressure transmitter.
9. In the case of a leaking valve, pressure increase would be seen on X-mas tree PT.

In the case of a failed TRSCSSV the option shall exist for a contingency control line operated wireline installed insert safety valve. For the major string (3-1/2") tubing, the work completed to date shows that this should be feasible. The impact on injection rates has not been studied. For the minor string 2-7/8" x 2-3/8" string, the access through the tubing hanger nipple profile creates a restriction, at this stage the restriction in ID is considered to be 1.85" ID however further work is required to determine if this can be increased. It is recommended that further work is undertaken to determine the feasibility of a contingency insert valve solution for the minor string.

For routine TRSCSSV testing there may be the possibility to have a fully standalone system with actuated isolation valves and adjustable PCV. The feasibility of standalone TRSCSSV testing should be studied, in the first instance the subsea system provider should be consulted to determine if developing an automated solution is viable or if the solution should remain as a manually operated system with ROV in attendance. In any case for the first such testing it is recommended that an ROV is in place to observe the bleed off and operate valves as required. For the duration to consider for TRSCSSV testing around 12 hours should be considered to allow for boil off and to reach stable conditions.

8.1.2 TRSCSSV Inflow Testing Summary

The water depth at the Acorn CCS well location and the context of CO_2 injection make the inflow testing of the TRSCSSV by CO_2 bleed off to sea feasible. The solution of a PCV (pressure control valve) to control the back pressure at the wellhead at the predetermined pressure of 25 bar provides a viable solution for TRSCSSV testing with no requirement to bleed down sea line.

The base case for routine TRSCSSV testing without well intervention is to carry out these tests in conjunction with routine wellhead monitoring and inspection. The testing will be carried out with the bleed the off, of CO_2 to sea with a ROV (remotely operated vehicle) in place to monitor the bleed off and manipulate valves as required.

The line diagram shows an NRV (Non-Return Valve) on the bleed off line downstream of the PCV, this may or may not be required, the inclusion of the NRV at this stage has been considered to remove the risk of water ingress into the system for any case where the pressure in the bleed off line was allowed to equalize with the ambient hydrostatic of seawater. This may not be considered necessary and could be removed. The risk of hydrates at this NRV has not been studied.

8.1.3 TRSCSSV Inflow Testing Further Work to Consider

The use of the PCV and the reliability of this PCV should be further studied to assess the pros and cons of a removable PCV that will be installed by ROV as and when required vs a permanently installed PCV system.

The TRSCSSV testing has been studied at level of feasibility, modelling of CO_2 boil off was carried out by Shell UK for the surface well scenario but not the subsea well scenario. Detailed modelling should be carried out for the subsea well case to determine boil off times and detailed TRSCSSV testing procedures should be developed during detailed engineering phase.

Feasibility of a fully actuated bleed-off line with PCV for TRSCSSV testing should be studied with subsea system provider.

For the bleed off, of CO_2 it is expected that with water depth and current, there will be rapid dispersion of CO_2 with minimal or no trace at surface however some work should be undertaken to determine this.

8.2 Well Control

For all well operations of the AS-01 well, well control procedures will be part of the well program.

For well intervention the basis is a 2-barrier policy with a primary and secondary well barrier for the intervention operation. In line with internationally recognised standards the cemented casing to the production packer plus tubing above to the level of the TRSCSSV represents the primary well barrier. The secondary well barrier is provided by the casing plus X-mas tree as shown in Figure 8-2. During intervention operations where the TRSCSSV cannot be operated due to the presence of the intervention strings in place, procedures must be in place to restore this barrier element when required by removal of the intervention string.

In the case where elements of a primary or secondary well barrier are compromised the well barrier is compromised and the impact must be assessed.

For well intervention operations contingency procedures shall be in place to account for failure of well barrier elements. The means to kill the well will form one of the basic requirements of any well intervention.

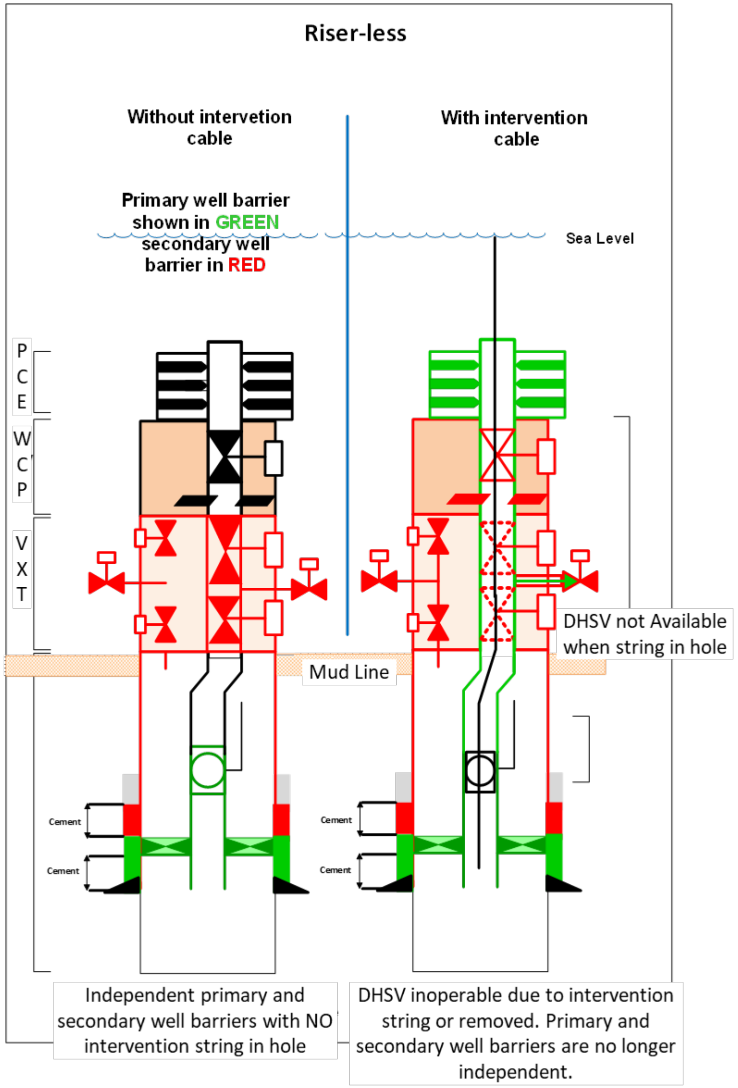


Figure 8-2: Intervention package in place (well shown as single string for simplicity) primary (Green) and secondary (Red) well barriers highlighted.

For any well intervention that requires access for intervention string or pumping operations the means to kill the well shall be part of the intervention program and the intervention system. Interventions will be based on a 2 well barrier policy. As part of any well intervention the dispersion of any release of well fluid (CO_2) should be modelled to determine the impact.

8.3 Well Kill Operations

For the case of well kill, the access to the well will be gained in the same manner in common with similar VXT (Vertical X-mas tree systems). For the well kill operations, connection with the well will be either through a riserless system or through a full EDP/LRP rigid riser system.

For the pumping sequence for well killing, the procedure will be similar to that used for a well kill for an oil well with free gas, where gas will be compressed into solution as pressure is increased. A bullheading well kill procedure will be prepared as part of the well construction and well intervention programs.

The main considerations for the well kill operations are the kill fluid, pumping pressure limits and downhole pressure limits. For the kill fluid for planned well kill for well intervention and workover, an oil-based fluid is considered as a push pill to reduce the risk of hydrate formation. Prior to pumping a kill weight fluid the well contents will be bullheaded with base oil. After bullheading to base oil, the well will be bullheaded with a kill weight brine including required blocking pills to allow a static fluid column to be maintained.

For fluid loss pills to allow a static fluid column to be maintained specific work is required to determine a suitable blocking pill that can also be removed when required for return to well injection. Well fluids & cementing department will work on fluid loss pills as part of the drilling and completion engineering with testing of pills based on reservoir permeability and requirements to remove pills when no longer required.

For the well kill operations the isolation of the intervention system from the pipeline must be ensured, the pipeline has a lower rating than the X-mas tree. Isolation is required due to specification break and to remove the risk of dense phase CO_2 from pipeline → intervention system. At this stage in the preparation of the well operating guidelines it is recommended that the flowline isolation valve is closed as well as IWV on X-mas tree and the integrity of these valves confirmed as part of the intervention procedure.

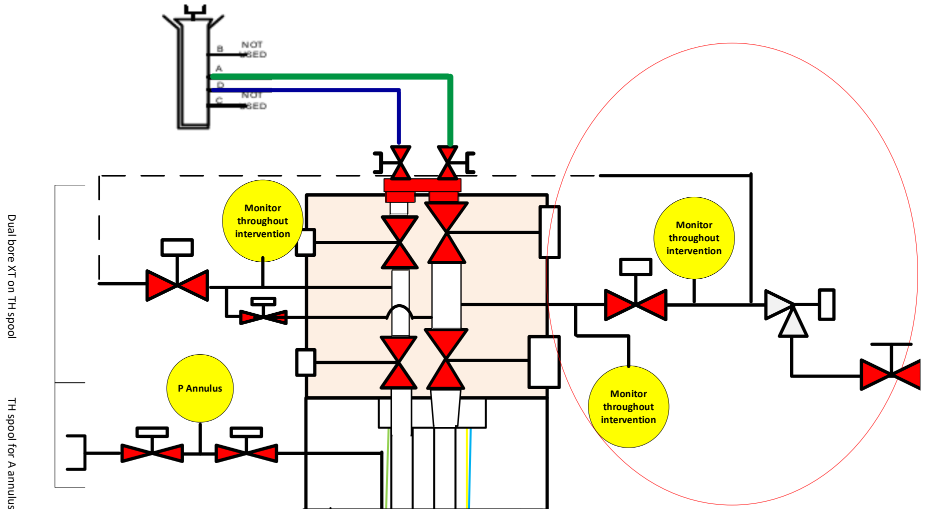


Figure 8-3: X-mas tree showing isolation from sea line to be monitored throughout intervention (P&T)

Specifics for corrosion risk to down hole completion and well architecture in CO_2 plus H_2O should be reviewed with the fluid's provider and company corrosion specialists. Testing of fluids and completion metallurgy may be considered. Corrosion subject matter expert shall be requested to review proposed brines from fluids providers.

8.3.1 Well Kill Summary

As part of the well kill procedures hydrate mitigation, fluid compatibility and means to remove any fluid loss or blocking pill must be studied during detailed engineering stage and any required testing to verify the suitability of kill fluids and pills scheduled with the providers.

Specifics for corrosion risk to down hole completion and well architecture in CO_2 plus H_2O should be reviewed with the fluid's provider and company corrosion specialists.

As part of the general recommendation for well interventions the isolation of CO_2 pipeline/sea line must be taken into account to remove the risk of contamination of choke spool with water based fluids that could create a hydrate risk on well restart and also prevent the risk of leakage of CO_2 from pipeline to well during the intervention operation. Pressure and temperature monitoring at the level of the flowline isolation valve → choke and IWV should be maintained throughout the intervention and should be part of the intervention procedures.

8.3.2 Well Kill Further Work to Consider

It shall be ensured that as part of the fluids selected for AS-01 well completion and intervention that kill fluids are checked for compatibility for formation, CO_2 base oil, blocking pills and hydrate prevention and any fluids that may be utilized for hydrate mitigation plan.

8.4 Well Intervention - Downhole Tools

At this stage intervention providers have been contacted to establish experience in well intervention qualification of downhole tools for service in CO_2 environment. The first feedback from service providers based in the UK is that there is experience in wells with a high CO_2 content but no experience in intervention in CO_2 injection and storage wells.

Service providers consider it preferable to bullhead the well prior to intervention with nitrogen this is in line with the basis planned for intervention on the AS-01 well. For the downhole tools including locks and plugs, the providers have noted a requirement for identification of suitable material and a possible requirement for testing of elastomers and sealing systems.

This work should be followed up during detailed engineering to ensure that intervention providers means both surface and downhole match the requirements of anticipated interventions.

8.5 Well Intervention - Riserless

8.5.1 Well Conditions Prior to Intervention

The well has been on injection with the well fully displaced to CO_2 as shown in Figure 8-4. The well is shut-in and isolated at the X-mas tree level to facilitate a well intervention operation utilizing a subsea riserless intervention package.

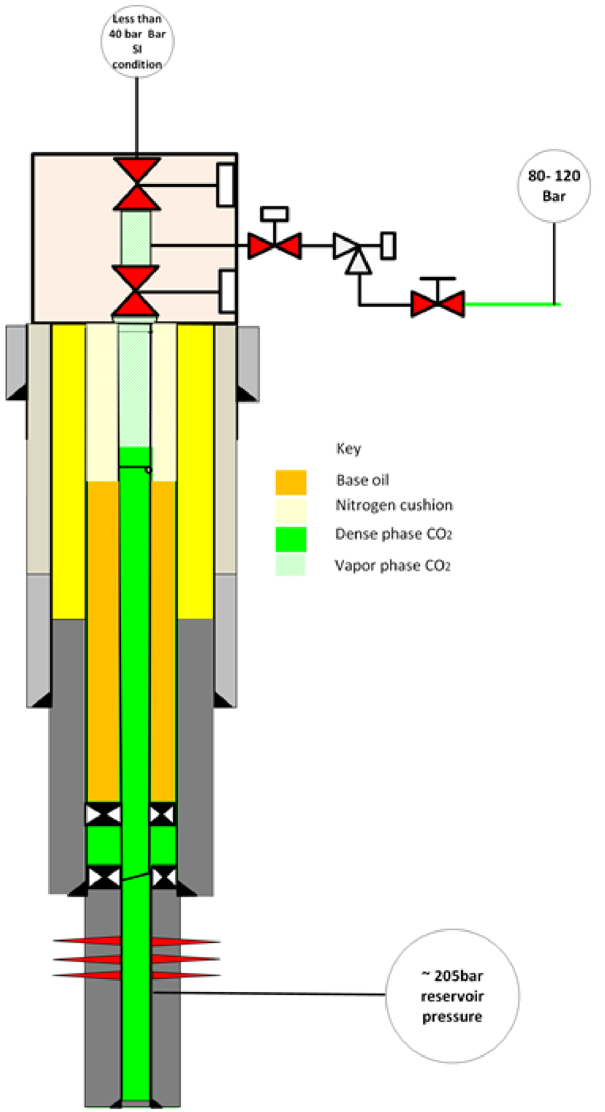


Figure 8-4: Well shut-in conditions prior to intervention, well already displaced to CO_2 shown as a single string for ease of illustration

8.5.2 Riserless Well Intervention

The intervention will be from a riserless DP3 (Dynamically positioned class 3) intervention vessel.

The intervention package will require a specific X-mas tree adaptor, specific to the selected dual bore X-mas tree system. The base case considered for the intervention package is an WCP or well control package, as there is no rigid riser between the X-mas tree and the intervention vessel there is no requirement for an EDP/LRP package. The well control package provides pressure control and containment to allow an intervention tool string to be deployed into the well on slickline, E-line or braided cable to perform intervention operations as required. In addition, it provides an interface for pumping and well kill as required. This is better illustrated in Figure 8-5 below.

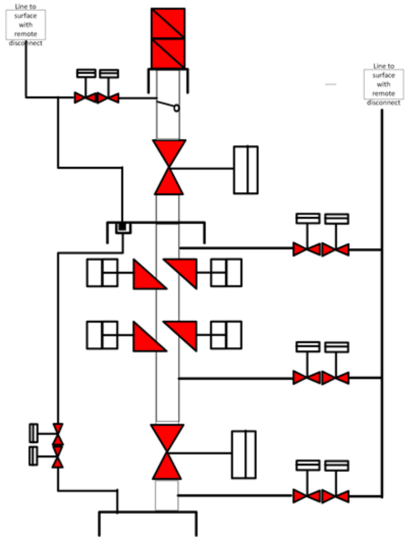


Figure 8-5: Shows the basic line drawing of a WCP for riserless intervention

For well intervention with a subsea riserless well control package plus pressure control head, the operations will take place with the surrounding environment being the hydrostatic of seawater. At the Acorn CCS well location with a water depth of around 120 m the hydrostatic is around 12 bar. The 12 bar hydrostatic of seawater will ensure that the minimum temperature at the level of the X-mas tree and well intervention package as a consequence of a leak and the expansion of the CO_2 leaking to sea, cannot drop below -35°C, as illustrated in Figure 8-6 below.

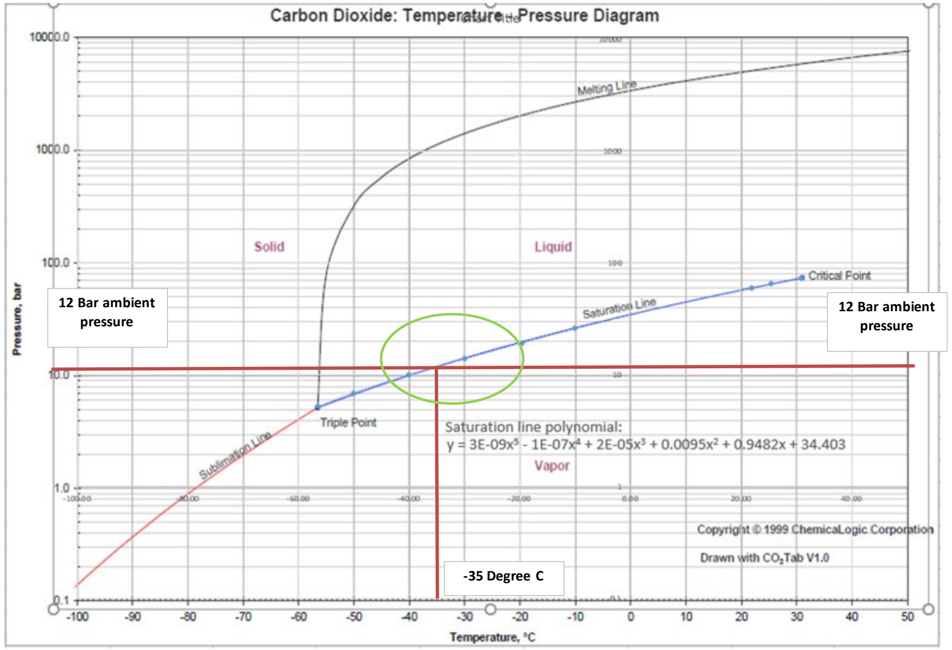


Figure 8-6: CO_2 pressure and temperature phase diagram – with 12 bar line drawn for illustration

The AS-01 well will utilize a class N X-mas tree, the temperature rating of the class N X-mas tree is -46°C to + 60°C. This rating makes the X-mas tree capable of withstanding any leak to sea and the resultant cooling. For riserless intervention operations the X-mas tree is fully rated.

For the intervention packages, currently there are no known subsea intervention packages that are based on the Class N temperature rating. The known intervention packages are Class U -18°C to +121°C.

For the context of a well intervention we need to consider that at the time of well intervention the well would be shut-in and the well temperature would be close to geothermal temperature. The contents of the tubing will be dense phase CO_2 in the well with some boil off, of CO_2 having occurred due to the low pressure and the temperature of the dense phase CO_2. In early life where low charging of the reservoir has occurred this liquid gas CO_2 interface will exist.

For the equipment rating for the intervention operation, the -18°C to 121°C temperature rating of a typical class U intervention package should not cause concern with the following constraints to be implemented.

Constraints for basic well intervention with class U riserless well intervention package:

- Through tubing intervention on static well only- no injection of dense phase CO_2 during well intervention.
    - Well at geothermal or close to geothermal temperature.
- For the setting of plugs where well shall be bled off above any plug that is set the following should apply.
    - For deep-set plugs, the well and CO_2 shall not be bled off above deep-set plugs. In the case where a deep-set plug is installed the requirements to bleed off tubing contents above the plug must first be considered. Where the plug must be bled off above to zero pressure, the well will be displaced to base oil and nitrogen in both conduit 1 & 2 before the deep-set plug is installed. The procedure for well displacement to base oil and nitrogen as followed for preparation for first injection will be followed. There will be adjustment as required (based on reservoir pressure at that time) to depth of nitrogen by base oil interface.
- For drift runs to confirm well access, there is no specific requirement to bullhead the well with base oil however displacement with nitrogen is considered a beneficial step to simplify bleed off operations and subsequent well restart post intervention.
- For operations to exercise TRSCSSV in the case of TRSCSSV mal function displacement with nitrogen is considered a beneficial step to simplify bleed off operations and subsequent well restart post intervention.
- For shallow set plugs at the level of the tubing hanger where contents of tubing and X-mas tree are CO_2 vapor, the intervention can be carried out and any required depressurization can be carried out using a rated circulation line as part of the well intervention and pressure control package.
    - In the case of dense phase CO_2 at the level of the X-mas tree tubing hanger profile in which the plugs will be installed, the well will be displaced with base oil or nitrogen to + 200 m below the required plug setting depth.
    - Note for the setting of shallow set plugs in the tubing hanger, as wireline tool strings shall be across the X-mas tree and intervention package at that time (i.e. non-shearable) this

should be considered and assessed. It is recommended that the plug profiles in the tubing hanger be NO-GO profiles to simplify the operational steps and to remove any risk that plugs can be dropped in hole. In such instances the operation can be undertaken with the TRSCSSV in each string closed.

- Intervention packages have tubing access through 1 bore, to gain access to the second bore the intervention package is recovered to surface and the alignment of intervention package to X-mas tree adapter is reconfigured to gain access to the send bore.

Emergency scenario:

- Leak through well intervention package- liquid temperature CO_2 worst case scenario depressurization from dense phase to vapor, fluid temperature of -35°C. The temperature remains within the rating of the X-mas tree (-46°C to +60°C) but exceeds the low temperature working limit of the intervention package WCP + PCH. (Well control package + Pressure control head).
    - Shut-in the well using the WCP (2 x blind shear rams).
    - Secure the well on the X-mas tree, function of X-mas tree valves should remain available i.e. not locked out.

Typical riserless intervention package shut down levels, 3 levels:

1. RLWI (ESD level 1): Closure of all side bore valves; main bore remains open.
2. RLWI ESD (ESD level 2): Level 1 plus closure of Safety Head and main bore lower gate valve, all barriers within 30 seconds.
3. RLWI EQD (ESD level 3): Level 2 plus disconnection of umbilical and disconnection of any hose connected to 2" well kill access.

As part of the general recommendation for well interventions the isolation of CO_2 pipeline/sea line must be considered to remove the risk of contamination of choke spool with water-based fluids that could create a hydrate risk on well restart. Also, to prevent the risk of leakage of CO_2 from pipeline to well during the intervention operation. Pressure and temperature monitoring at the level of the flowline isolation valve- choke and IWV should be maintained throughout the intervention and should be part of the intervention procedures.

8.5.3 Riserless Well Intervention Summary

For the Acorn AS-01 well riserless well intervention operations can safely be executed using systems currently available. With the 120 m water depth the column of seawater results in an ambient hydrostatic of around 12 bar. This 12 bar hydrostatic ensures that the Acorn CCS X-mas tree can withstand the minimum temperature to which it can be subjected assuming a leak to the surrounding sea. For the intervention package, the lowest temperature rating of packages that have been identified as part of an RFI (Request for information) are rated class U. (-18 to +121°C).

For intervention in a shut-in well on top of the fully rated X-mas tree the class U intervention package is suitable for all intervention scenarios considered such as the setting of shallow set and deep set plugs, intervention for drifts to confirm access, exercise of safety valve and well killing by pumping. In the case of setting of plugs where well contents must be bled off above the plug, 3 approaches are considered.

1. The option to first bullhead the well to base oil plus nitrogen prior to setting of deep-set plug.
2. Bullheading with nitrogen to ~200 m below the plug depth (shallow set).

3. CO_2 in vapour phase (gas) at ambient temperature- circulation and bleed off through intervention system with rated line.

It is considered that for post intervention barrier testing and well restart, partial displacement (bullheading) of the well to nitrogen to raise the wellhead pressure above 45 bar will lead to the smoothest option for well start-up. Therefore, it is a logical step that this displacement can be carried out as a pre well intervention step allowing the well entry without CO_2 at the level of the intervention package.

8.5.4 Riserless Intervention Further Work to Consider

The pros and cons of displacing nitrogen into the well for through tubing intervention should be further assessed and feedback requested from intervention providers and operators.

Compatibility test for non-metallic sealing systems, O-rings, seal assemblies and elements from the seals of BOP ram systems should be tested for compatibility with CO_2 and any impurities.

8.6 Well Intervention - Rigid Riser

8.6.1 Well Conditions Prior to Intervention

The AS-01 well has been under injection with the well fully displaced to CO_2 as shown in Figure 8-7. The well is shut-in and isolated at the X-mas tree level to facilitate a well intervention operation utilizing a rigid riser intervention package, the base case considered is intervention from an anchored semi-submersible rig with a single rigid riser EDP/LRP system.

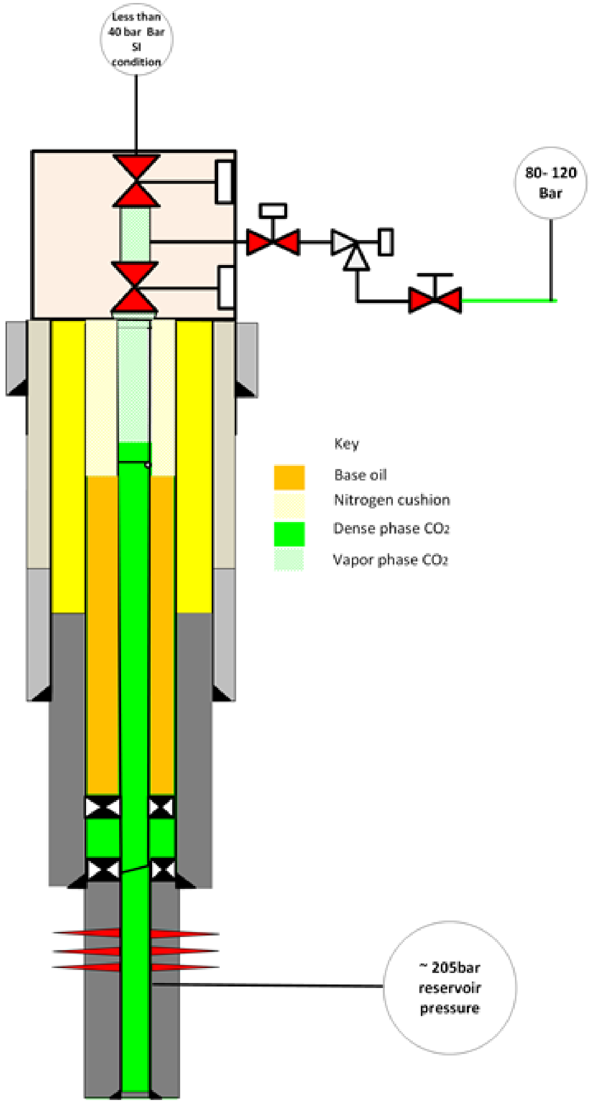


Figure 8-7: Well shut-in conditions prior to intervention, well already displaced to CO_2. (Shown as a single string for wase of illustration)

8.6.2 Rigid Riser Well Intervention

The rigid riser intervention operation when required would be carried out from an anchored semi-submersible rig. The relatively shallow 120 m water depth makes it unsuitable for rigid riser operations from a dynamically positioned vessel. The intervention package will be based on an EDP/ LRP system that allows securing of the well at the level of the LRP and disconnection at the level of the EDP. This EDP/LRP system will require an adaptor specific to the interface of the Acorn CCS X-mas tree system. The riser will be a single string WOR or system with a surface flowhead at the level of the rig floor to allow access for intervention with slickline, wireline and pumping operations. The surface flowhead will be suspended in compensated mode with a CTLF or coiled tubing lift frame. No coiled tubing intervention operations are planned, the CTLF will allow a safe working access for slickline and E-line operations through the surface flowhead. In the case where only pumping operations are required the rig up can be optimized. Surface flowhead's from well test providers are available compliant with API-6A and with a temperature qualification equivalent to -29°C + 121°C. (Class P- U).

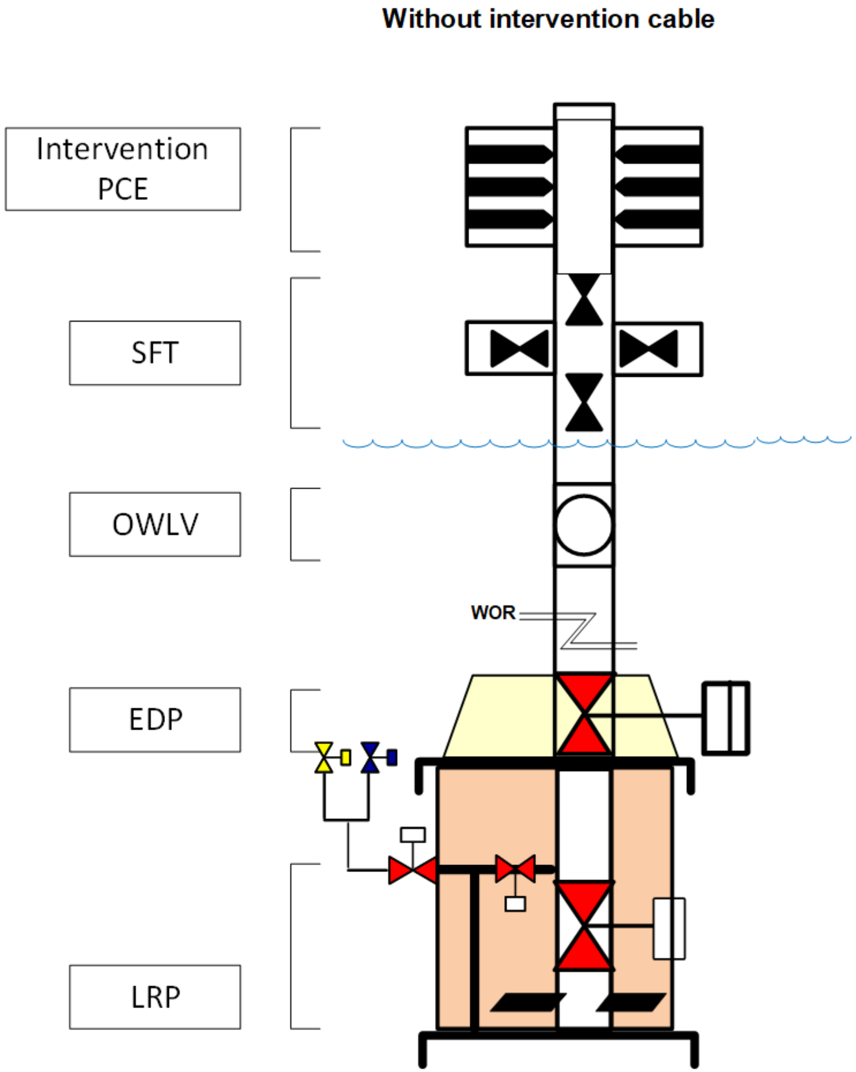


Figure 8-8: Shows the basic line drawing of a class U EDP/LRP system for rigid riser intervention

For well intervention with a rigid riser system the subsea intervention package is rated class U, the same temperature rating as the riserless intervention system. As per the philosophy for riserless intervention the same applies for rigid riser intervention. The X-mas tree is rated to -46°C and the intervention package at subsea level to -18°C and at surface to -29°C. In the case of leaks at the level of the X-mas tree the minimum pressure that will be realized is 12 bar and the fluid temperature should not go below -35°C, therefore the X-mas tree is fully rated for the case of a loss of pressure to sea at the X-mas tree level. For a loss of containment and venting to atmosphere the low temperature rating of the X-mas tree and intervention package could be exceeded, therefore for rigid riser-based intervention the well should be bullheaded to base oil and nitrogen. As detailed in the riserless intervention operation section, bullheading of the completion contents to place base oil and nitrogen in the conduit 1 & 2 will serve to place the well in the status for start-up post well intervention. Having base oil and nitrogen with a positive wellhead pressure will remove any risk of exceeding temperature limitation of intervention equipment.

There may be specific intervention operations where bullheading is not necessary, these should be considered on a case-by-case basis.

Similar constraints shall be imposed for rigid riser well intervention as those imposed for riserless intervention:

Constraints for basic well intervention with class U rigid riser EDP/LRP system.

- Through tubing intervention on static well only- no injection of dense phase CO_2 during well intervention.
    - Well at geothermal or close to geothermal temperature.
- For the setting of plugs where well shall be bled off above any plug that is set the following should apply.
    - For deep-set plugs, the well and CO_2 shall not be bled off above deep-set plugs. In the case where a deep-set plug is installed the requirements to bleed off tubing contents above the plug must first be considered. Where the plug must be bled off above to zero pressure, the well will be displaced to base oil and nitrogen in both conduit 1 & 2 before the deep-set plug is installed. The procedure for well displacement to base oil and nitrogen as followed for preparation for first injection will be followed. Adjustment as required will be made (based on reservoir pressure at that time) to depth of nitrogen by base oil interface.
- For drift runs to confirm well access, there is no specific requirement to bullhead the well with base oil however displacement with nitrogen is considered a beneficial step to simplify bleed off operations and subsequent well restart post intervention.
- For operations to exercise TRSCSSV in the case of TRSCSSV mal function displacement with nitrogen is considered a beneficial step to simplify bleed off operations and subsequent well restart post intervention and any function test that may be required.
- For shallow set plugs at the level of the tubing hanger where contents of tubing and X-mas tree are CO_2 vapor, the intervention can be carried out and any required depressurization can be carried out using a rated circulation line as part of the well intervention and pressure control package.
    - In the case of dense phase CO_2 at the level of the X-mas tree tubing hanger profile in which the plugs will be installed, the well will be displaced with base oil or nitrogen to + 200 m below the required plug setting depth.

  - Note for the setting of shallow set plugs in the tubing hanger as wireline tool strings shall be across the X-mas tree and intervention package at that time (i.e. non-shearable) this should be considered and assessed. It is recommended that the plug profiles in the tubing hanger be NO-GO profiles to simplify the operational steps and to remove any risk that plugs can be dropped in hole. In such instances the operation can be undertaken with the TRSCSSV in each string closed.
- Intervention packages have through tubing access through 1 bore, to gain access to the second bore the intervention package is recovered to surface and the alignment of intervention package to X-mas tree adapter is reconfigured to gain access to the send bore.

Emergency scenario:

- Leak at the level of the X-mas tree worst case scenario depressurization from dense phase CO_2 to vapor, fluid temperature of -35°C. The temperature remains within the rating of the X-mas tree (-46°C to +60°C) but exceeds the low temperature working limit of the intervention package EDP/LRP.
  - Shut-in the well using the LRP (1 x blind shear ram) 1 x isolation valve.
  - Secure the well on the X-mas tree, function of X-mas tree valves should remain available i.e. not locked out.
- Leak at surface to atmospheric conditions through rigid riser. For full release to atmosphere worst case scenario depressurization from dense phase CO_2 to vapor, fluid temperature of -78.5°C. The temperature would exceed the rating of the X-mas tree (-46°C to +60°C) and the intervention package EDP/LRP.
  - Well has been displaced to nitrogen as part of pre intervention displacement procedure, leak is nitrogen only.
- On detection of any leak:
  - Shut-in the well using the LRP (1 x blind shear ram) 1 x isolation valve.
  - Secure the well on the X-mas tree, function of X-mas tree valves should remain available i.e. not locked out.

Typical rigid riser EDP/LRP package shut down levels, 3 levels:

1. PSD level 1: Closure of surface valves- in SFH.
2. ESD 2: Level 1 & 2 Closed-in valves in intervention package, all barriers within 30 seconds.
3. EQD: Level 2 plus disconnection at connector between EDP and LRP.

As part of the general recommendation for well interventions the isolation of CO_2 pipeline/sea line must be considered to remove the risk of contamination of choke spool with water-based fluids that could create a hydrate risk on well restart. Also, to prevent the risk of leakage of CO_2 from pipeline to well during the intervention operation. Pressure and temperature monitoring at the level of the flowline isolation valve- choke and IWV should be maintained throughout the intervention and should be part of the intervention procedures.

8.6.3 Rigid Riser Well Intervention Summary

For the Acorn AS-01 well rigid riser well intervention operations can safely be executed using systems currently available. The class U intervention package with -18°C lower temperature limit can be utilized by controlling operations by procedures. The riser system should not be utilized for CO_2 bleed off while open to the well. Interventions will be carried out after first displacing the well to base oil and nitrogen, the use of a nitrogen cushion will allow all depressurizations to be carried out without risk to the subsea and surface intervention equipment.

For intervention in a shut-in well on top of the fully rated X-mas tree the class U intervention package is suitable for all intervention scenarios considered such as the setting of shallow set and deep-set plugs, intervention for drifts to confirm access, exercise of safety valve and well killing by pumping.

It is considered that for post intervention barrier testing and well restart, partial displacement (bullheading) of the well to nitrogen to raise the wellhead pressure above 45 bar will lead to the smoothest option for well start-up. Therefore, it is a logical step that this displacement can be carried out as a pre well intervention step allowing the well entry without CO_2 at the level of the intervention package.

8.6.4 Rigid Riser Intervention Further Work to Consider

Compatibility test for non-metallic sealing systems, O rings, seal assemblies and elements from the seals of BOP ram systems should be tested for compatibility with CO_2 and any impurities.

9.0 Well Decommissioning Operations

The Acorn AS-01 well construction will be reviewed in detail as part of the well detailed design endorsement. The well detailed design endorsement will cover the full well life cycle from the practicality of the construction considering the subsea context and the operations from a moored semi-submersible, through well first start-up, injection, work over cases and final cessation of injection well suspension and P&A.

For the cessation of injection of CO_2, two cases can be considered early life, this case may arise due to an integrity issue that cannot be resolved by work over, or late life due to charging of the reservoir to the defined limit ~270 bar.

The dual bore completion creates some restrictions for through tubing access due to the small tubing size. To be noted no access through the completion Y piece is available through conduit 1 the minor string. Access below the level of the completion Y is only available through the major string 3-1/2" x 2-7/8". For the abandonment of the full well a specific study will be undertaken, and the P&A schematic will have been defined as part of the workflow for the approval of the well basis of design. The key points that are considered as part of these Preliminary Well Operating guidelines are as follows.

- The well will be perforated and target a single zone, at the stage of P&A of the well there should be no requirement to install additional plugs in the 5-1/2" liner to isolate identified zones to be individually isolated (IZI).
- The production packer will be a cut to release packer.
    - Pull to release packer systems have been considered however in the operating loads in CO_2 injection the loads created are primarily tensile loads due to the cooling of the completion therefore a pull to release packer system was considered not applicable.
    - The basis for the production packer is a 4-1/2" mandrel, cutting of the mandrel is considered feasible with through tubing mechanical (such as BH MPC) or explosive cutters.
    - In the case where it should be found that cutting of the packer or the pipe above is challenging a 3-1/2" cut sub or 3-1/2" packer will be utilized.
        - The impact of additional friction created has not been simulated however provisional review has concluded that the additional friction created by a short section of 3-1/2" can be taken into account. The details of the production packer and the basis for cut to release will be provided in the well detailed design.
- The position of the production packer will take into account the TOC and the validity of the bond of the cement behind casing. The packer will be positioned such that a minimum of around 50 m of validated cement→ casing exists below the production packer. For the TOC above the production packer the option shall be explored to have possibility to P&A the well without the requirement to recover the production packer. The base case to consider should be sufficient length of validated cement above the production packer to allow for a combination cement barrier plug to be installed above the production packer.

- A nipple is included in the completion below the production packer to allow isolation from reservoir and simplify execution of both work over and final P&A of the well.
- The P&A schematic will be drawn based on local regulations with the option to adjust the packer setting depth as required. For simplicity and efficiency of operations the P&A schematic should allow for P&A with and without the production packer left in place.

The design of the well and the completion shall be such that for P&A the following basic steps can be considered.

- Well bullheading.
- Installation of plug below production packer.
- Punch above production packer and circulation of homogenous brine.
- Cut tubing above production packer (a system that does not require string in tension will be considered).
- Plugs installed at tubing hanger level.
  - Requirements for plugs to be reviewed.
  - DHSV lock out to be assessed.
- Xmas tree recovery.
- BOP installation and testing.
- Completion recovery.
  - Recovery of tubing hanger plugs if applicable.
- Installation and testing of cement plugs for isolation of reservoir.
- Additional cement plugs and casing cut as required.
- BOP recovery.
- Wellhead removal and restoration of seabed.

The sequence will be optimized as part of the work on P&A schematic and procedure.

9.1 Well Decommissioning Operations Summary

The details of the well plug and abandonment will be provided as part of a separate study, the proposed high-level P&A schematic will be agreed at the time of the validation of the well architecture. As part of the Preliminary well operating guidelines a review has been carried out of the well life cycle from construction of the well from the steps of installation of the dual string completion, the operation of the well in injection, intervention, isolation by plug, well killing and suitability of the completion to allow access to P&A the well. The completion is considered suitable presenting no specific challenges to final P&A with the following points to be taken into account as part of the completion design.

- Access through the completion to cut production packer and tubing must be taken into account with cutting means identified.
- Validation off cement behind casing and the height of validated TOC behind casing must be considered for production packer setting depth.
- TOC should allow for the option of P&A with production packer left in place.

10.0 Risks & Opportunities

10.1 Risks

The following list of risks and uncertainties should not be considered as exhaustive. Where further work has been identified, this work should be assessed and if considered relevant it shall be added to the scope in detailed engineering phase.

- Modelling of well conditions is assumed to be accurate.
- The use of class U equipment for tubing head spool and wellhead system does not meet the requirements of minimum temperature of CO_2 in the case of a release to sea. Work carried out as part of the Peterhead project shows that for a surface wellhead installation in the cases modelled the wellhead system did not reach the temperature of the fluid (CO_2). For the Acorn CCS well it is recommended to complete similar work to demonstrate that in all cases the rating of the wellhead would not be compromised.
- For the TRSCSSV, the basis considered is a valve rated to -7°C operating and -35°C in shut-in conditions, to date suppliers are confident to deliver such product but some gaps exist specifically the -35°C has not yet been proven in the shut-in condition.
- For tubing and casing connection qualification, existing connection qualification standards are based on hot cycles, there are no known standards for testing under cold cycling. Some discussion has been launched on this subject but there remains some uncertainty in the type of qualification that would be undertaken and the value from such qualification. As part of these operating guidelines it is assumed that the work to conclude any additional connection qualification testing would be undertaken.
- For well intervention the base case is to bullhead the well with base oil plus a nitrogen cushion the impact of base oil injected into reservoir has not been studied. It is considered this should be non-damaging however work must be undertaken to confirm that damaging emulsions are not created. There may be opportunity to optimize the bullheading for specific interventions with reduction in volume and possible option to displace below the level of intervention to nitrogen only (while respecting pressure limitations). These options should be further reviewed in detailed engineering stage.
- For TRSCSSV testing the venting of CO_2 to sea in a controlled manner is considered to create minimal impact however this should be further studied to determine rate and dispersion.
- For an uncontrolled leak at the level of wellhead during well intervention the volume, rate and dispersion has not been studied. Although the risk and impact are considered to be low, the dispersion and rates should be assessed.
- The feasibility of an insert wireline set contingency safety valve for the minor string has not been assessed, it is anticipated that the restriction in ID through the tubing hanger on the minor bore may have an impact. Further work should be carried out in detailed engineering stage to assess feasibility and impact if any.
- Kill fluids and the compatibility of kill fluids with CO_2 has not been studied, the suitability of blocking pills and the means to remove

blocking pills has not been studied but should be undertaken with a fluid's provider in detailed engineering phase.

- Compatibility test with CO_2 any impurities, for non-metallic sealing systems, O-rings, seal assemblies and elements from the seals of BOP ram systems has not been carried out and should be captured as part of detailed engineering phase.
- The corrosion risk from kill brine has not been assessed and should be captured as part of detailed engineering phase.
- The benefit of the sliding sleeve in the 3-1/2" string as a means to displace nitrogen into the production tubing x production casing annulus should be further assessed during detailed engineering phase.
    - The alternative is to displace the nitrogen into the production annulus before setting of the packer. The potential leak paths that this sliding sleeve presents between tubing and annulus shall be further assessed.
- The PRV setting and capacity of the MeOH pumps that will supply the 4" pipe line with MeOH that will be utilized for hydrate prevention, remediation and filling of tubing to lower wellhead pressure is not defined at this stage . The rating of the pipeline and the pumps that supply MeOH should allow for injection at above 120 barg to allow for the case of a wellhead pressure that is close to or above the pressure in the CO_2, in such case MeOH will be pumped into the well to lower the THP.
    - This should be confirmed.
- The hydrate Inhibition guidelines will require to be updated when the specification of the CO_2 for Acorn CCS project is finalized.
    - As the work already carried out is based on the composition of the CO_2 that was planned to be injected for the Peterhead project.

10.2 Opportunities

The step of completing the Acorn CCS well as a subsea well as opposed to a surface wellhead installation, brings enhanced HSE by removing the risk of any contact to personnel from any released fluids during normal operations.

For intervention cases the use of riserless subsea intervention also brings with it the separation of well fluids under pressure from intervention team. Therefore, riserless intervention solutions can be considered in many aspects to simplify and enhance HSE, however rigid riser intervention solutions should remain an acceptable solution with appropriate control measures.

For the personnel involved in all intervention operations where these personnel have a responsibility for well control or have direct access to the well intervention operation, it is strongly recommended that these intervention personnel have specific training in the intervention on a CO_2 storage well and have as a minimum an appreciation of the principal of "boil off" and the temperature changes associated with a change of phase.

It is recommended that well programs should be specific to intervention on a CO_2 well and should not use procedures taken from work on producer wells unless these have been checked to confirm they remain relevant.

At the stage of well construction the specifics of a dual string completion and the requirement to run tubing hanger plugs in the tubing hanger as barriers for well suspension prior to install the X-mas tree results in a requirement for 2 runs with the EDP/LRP. The alternative to 2 runs of EDP/LRP is the option to run a dual bore workover riser system with dual bore surface intervention tree. This second option may be feasible, however at the time of discussion with subsea intervention system providers the feedback is that dual bore riser systems are not widely utilized and the sequenced considered is to recover plugs through a single bore riser system, recovering and re-orientating the intervention package to connect to the second bore when required. For the Acorn CCS well with a cased and unperforated reservoir section there may be an opportunity to evaluate the barriers for well suspension and remove the requirement for installation and subsequent recovery of the tubing hanger plugs. It is recommended to explore and assess this option.

11.0 Conclusions & Recommendations

11.1 Conclusions

A summary of conclusions derived from the above preliminary "Well Operations Guidelines" documentation is provided below:

- The Acorn AS-01 well will be constructed with a well architecture, well completion and subsea X-mas tree system designed to allow the well to inject dense phase CO_2 into the Captain D reservoir layer.
- The specific design of dual string completion is driven by flow assurance requirements where the use of two separate strings will allow the completion to create sufficient friction when injecting CO_2 to maintain the CO_2 in dense phase while accommodating a range of injection rates from 0.25 $MtCO_2/y$ – 0.8 $MtCO_2/y$ with reservoir pressure varying from initial conditions of around 205 bara to a final pressure of around 270 bar.
- The Acorn CO_2 injection pipeline installed on the seabed will operate at pressures between around 80 bar and 120 bar.
- These preliminary well operating guidelines have reviewed the following key stages of well life cycle:
  - Well installation.
  - Well start-up.
  - Steady state operations – incl. annuus pressure management.
  - Planned transient operations – incl. hydrate prevention.
  - Unplanned transient operations.
  - Maintenance operations – incl. SSSV testing.
  - Repair operations - incl. well interventions & well kill.
  - Well decommissioning operations.
- Simulations using Olga software were carried out by Shell UK to cover the cases of steady injection, transient cases, injection, shut-in and restart, and well blow out cases. These simulations have been reviewed to confirm the design limits of the completed well are not exceeded.
- Further cases have also been studied which consider the depressurization of the completed well above a fixed point to determine the required working temperature of downhole equipment or alternatively the requirements to control low temperature because of CO_2 boil off by management of minimum pressure.
- For the Peterhead project the Shell UK team studied the heat transfer from Xmas -Tree and tubing hanger system to the wellhead system. CFD simulations were undertaken for the Peterhead CCS well including continuous injection of CO_2 with stuck choke condition to create low pressure and a low temperature of -23°C. The results of the CFD showed that the limitation of the wellhead due to the -18°C temperature rating could not be reached.
- During detailed engineering it is recommended that further work is carried out to demonstrate for the AS-01 well, wellhead tubing head spool and X-mas tree system that the temperature rating of the class U equipment (wellhead and tubing head spool) are sufficient.
- For TRSCSSV leak testing, the tests shall be conducted by bleed off, of tubing pressure and CO_2 to sea. This solution is technically possible but must be recognized as non-conventional. The base case

considered is that such testing would be carried out with ROV in water to observe bleed off and operate valves. This is the proposed base case, there may be an opportunity to have a standalone solution with actuated valves allowing release to sea.

- Further work is required to determine dispersion of CO_2, and rate of boil off to determine if the standalone option should be pursued. In any case the recommendation will be to undertake the first such bleed offs with ROV in place to monitor even in the case of a fully automated standalone system.
- In the case of a failed TRSCSSV the option shall exist for a contingency control line operated wireline installed insert safety valve. For the major string (3-1/2") tubing, the work completed to date shows that this should be feasible. The impact on injection rates has not been studied. For the minor string 2-7/8" x 2-3/8" string, the access through the tubing hanger nipple profile creates a restriction, at this stage the restriction in ID is considered to be 1.85" ID however further work is required to determine if this can be increased. It is recommended that further work is undertaken to determine the feasibility of a contingency insert valve solution for the minor string.
- For well intervention operations two cases are considered, riserless and rigid riser well intervention. In each case the recommendation is to first bullhead the well to base oil and nitrogen, allowing the intervention to be undertaken with pressure maintained in the well with a nitrogen gas cap of around 45 bar at the level of the subsea X-mas tree. Undertaking the intervention with this nitrogen gas cap simplifies the operation, removing any considerations for the management of bleed off, of CO_2.
- Both rigid riser and riserless operations are possible, it is considered that a preference would be given to riserless intervention operations as all cases for through tubing slickline, e-line and pumping operations can be managed by a riserless system.
- In addition, the use of a riserless system brings with it some advantages when controlling the minimum wellhead pressure due to the ambient hydrostatic of sea water. However, if the base case is selected where all interventions are carried out after first bullheading a column of base oil and nitrogen then this point is no longer relevant.
- For downhole interventions the surface and subsea equipment has been reviewed and current subsea packages found to be limited to class U (-18 to 121°C), surface equipment such as temporary surface flowheads are available with ratings of -29°C.
- The approach taken for well interventions within these preliminary operating guidelines is to use existing proven intervention and pressure control packages while adapting the intervention to suit.
- For well kill operations the interface will be provided as part of an intervention package. The well can be killed when required with an oil-based push pill followed by an overbalanced brine. The injectivity with an overbalanced fluid will make it difficult to maintain a fluid column without the use of some form of blocking pill.
- In the context of the completion design with restrictive ID through the completion string it may be difficult to access perforations in the future for any remedial operation for removal of blocking pills. A preference will be given to using a mechanical isolation plug in the completion below the production packer as a means of providing positive isolation from reservoir with an overbalanced fluid circulated above.

- At this stage the possible impact of reservoir near well bore damage due to bullheading of base oil has not been studied and should be looked at during detailed engineering.
- For the intervention downhole tooling, no specific work has been undertaken at this stage. Intervention providers have been consulted and no challenge is foreseen, however, it must be recognized that this work has not been completed.
- For annulus management the use of a nitrogen column above a base oil annulus fluid provides a solution for an annulus where there should be no requirement to intervene on the well for annulus pressure management.
- In planned operating conditions only pressure monitoring should be required, the use of annulus pressure gauge at tubing head spool and at 2 positions downhole will allow the operator to follow the annulus pressure behaviour with the combination of the bottom hole and surface gauges assisting in the interpretation of any abnormal behaviour.
- For well monitoring for injection performance and BHP management dual pressure and temperature gauges are installed in the tubing below the completion Y piece. The lowest of the gauge positions will be around 12 m above the production packer, the second gauge position will be approximately 120 m above.
- The X-mas tree will also have pressure and temperature gauges allowing measurement of tubing pressure and temperature for each string. In the case where there should be a failure of the bottom hole pressure gauges, the contingency will be the installation of memory gauges.
- For the prevention of hydrates each well case will be covered by a hydrate mitigation procedure. For the first start-up the Acorn AS-01 well the water from the construction phase will have been displaced by preparing the well for start-up by displacing both tubing strings to base oil plus a nitrogen cushion.
- Care shall be taken to ensure all X-mas tree valves and x-over lines are flushed in a water free or inhibited fluid. For well intervention cases the well will be displaced to have base oil and nitrogen in the tubing and X-mas tree.
- For injection, the low water content of the injected CO_2 will prevent the accumulation of hydrates. Where a hydrate risk is identified MeOH shall be available to inject at the X-mas tree level, with MeOH supplied from the 4” service line or via the umbilical depending on final tie-back solution.

11.2 Recommendations

A summary of recommendations derived from the above preliminary “Well Operations Guidelines” documentation is provided below:

- Based on the work completed to date the Acorn AS-01 well can be operated in conditions of start-up, injection, shut down intervention and suspension while respecting the limitations of the tubulars, wellhead systems, X-mas tree and down hole completion equipment planned to be utilized in its construction.
- For the blow out case, the temperatures and pressures modelled are within the rating of the X-mas tree system but exceed the rating of the wellhead system. Shell UK modelled the example of a surface wellhead system under the Peterhead project where CFD showed that the rating

of the wellhead system was not compromised under specific conditions. For the Acorn CCS well it is recommended to complete similar CFD simulations or to determine the feasibility of a lower temperature rating for the wellhead and tubing head spool.

- The work to determine if the class U wellhead system and tubing head spool is suitable in all cases including blowout of CO_2 should be concluded as soon as possible.
- For the downhole equipment within the AS-01 completion, it is anticipated that sourcing these components will not present any specific challenge. The lead time for equipment should be adjusted based on the feedback from suppliers which will be available at a later date.
- For the TRSCSSV the basis considered is a valve qualified for a lower temperature limit of -7°C, with the option for additional testing in the closed position at -35°C to represent a closed valve with minimal leak rate and boil off, of CO_2 at 12 bar. Suppliers have stated that they do not see any challenges to meet these requirements.
- A list of further work to be considered is provided in the section “Risks and Opportunities”. It is recommended that the work outlined in this section is undertaken.
- These preliminary well operating guidelines have been prepared based on information provided by Shell UK and Costain Group PLC. At this stage it is assessed that all operational conditions identified can be managed with the completion and X-mas tree system proposed for the Acorn AS-01 well.

12.0 References

Explanatory note: Reference has been made to the Shell Peterhead project and in particular the document "Well Operation Guidelines PCCS-05-PT-ZR-7180-00003" which were based on a surface well head configuration.

The team have made use of this document where considered relevant for the Acorn subsea project. In the majority of cases the conditions in the context of the subsea well for conditions of injection, including well shut-in and well restart are considered to be similar to those for the surface well head configuration.

For the surface wellhead configuration lower pressures and resultant lower temperatures would be reached when compared to those encountered in the Acorn subsea well due to the ~120m head of water from the sea, except in the possible conditions of well intervention with a rigid riser.

Where references have been made to material based on a surface well head configuration edits will have been made to reflect the subsea conditions.

[1] OGA, "Carbon Dioxide Appraisal and Storage Licence CS003," 2018.

[2] Pale Blue Dot Energy, "Lower Completion Decision Note (ACCS-S-30-PB-YY-DN-0011)," Pale Blue Dot, 2020.

[3] Pale Blue Dot Energy, "Well Functional Specification (ACCS-S-30-SH-WE-RP-0008)," Pale Blue dot, 2020.

[4] Shell U.K. Limited, "Well Operation Guidelines - PCCS-05-PT-ZR-7180-00003," 2015.

[5] Pale Blue Dot Energy, "Export Composition Decision Note (ACCS-S-00-PB-YY-DN-0005)," 2020.

13.0 Glossary

Abbreviation duplication may exist in the list here below, the appropriate definition being subject to the related discipline, this is a generic list and not specific to this report:

A

AAV	Annulus Access Valve
AMV	Annulus Master Valve
API	American Petroleum Institute
ASV	Annulus Swab Valve
AWV	Annulus Wing Valve

B

BOP	Blow Out Preventer
BPV	Back Pressure Valve

C

CCUS	Carbon Capture Use and Storage
CCS	Carbon Capture and Storage
CFD	Computational Fluid Dynamics
CFT	Call For Tender
CI	Chemical Injection
CITV	Chemical Injection Throttle Valve
CIV	Chemical Injection Valve
CP	Conductor Pipe
CRA	Corrosion Resistance Alloy
CS	Carbon Steel
CTLF	Coiled Tubing Lift Frame
CT	Coiled Tubing
CTU	Coil Tubing Unit

D

DHIV	Down Hole Injection Valve
DHPG	Down Hole Pressure Gauge
DHPT	Down Hole Pressure Transmitter
DHPTG	Downhole Pressure & Temperature Gauge
DHSV	Down Hole Safety Valve
DIU	DHPTG Interface Unit
DP	Dynamic Positioning
DP	Differential Pressure
DSC	Down Stream Choke

E

ECS	Electrical Control System
EDP	Emergency Disconnect Package
EFAT	Extended Factory Acceptance Test
EFL	Electric Flying Lead
EH	Electro-Hydraulic
EPCI	Engineering Purchase Construction and Installation
EPU	Electrical Power Unit
EQD	Emergency Quick Disconnect
EQDP	Emergency Quick Disconnect Package
ESD	Emergency Shut-Down
F	
FAI	Fail As-Is
FAT	Factory Acceptance Test
FC	Fail Closed
FIV	Trade name for Formation Isolation Valve (see RIV)
FLET	Flow-Line End Termination
FMECA	Failure Mode Effects and Criticality Analysis
FO	Fail Open
FSC	Fail Safe Closed
FSO	Fail Safe Open
G	
GA	General Arrangement
GLR	Gas Liquid Ratio
GS	General Specification
H	
HA	Heavy Architecture
HAZ	Heat Affected Zone
HCLS	Heave Compensated Landing System
HCR	High Collapse Resistance
HCV	Hydraulic Control Valve
HFL	Hydraulic Flying Lead
HMI	Human Machine Interface
HOS	Hold Open Sleeve
HP	High Pressure
HPU	Hydraulic Power Unit
HSE	Health Safety and Environment
I	
ICSS	Information Control and Safety System
ID	Internal Diameter
ILT	Inline Tee

IMV	Injection Master Valve
IRCD	Injection Rate Control Device
ISO	International Standard Organization
ISV	Injection Swab Valve
IWOCS	Installation Work-Over Control System
IWV	Injection Wing Valve
J	
JM	Jumper Module
K	
KOP	Kick Off Point
L	
LP	Low Pressure
LRP	Lower Riser Package
LWIV	Light Well Intervention Vessel
M	
MAASP	Maximum Allowable Annulus Surface Pressure
MAWOP	Maximum Allowable Well Operating Pressure
MCS	Master Control Station
MeOH	Methanol
MFM	Multiphase Flow Meter
MIV	Methanol Injection Valve
MMI	Man Machine Interface
MODU	Mobil Offshore Drilling Unit
MPFM	MultiPhase Flow Meter
MQC	Multi-Quick Connect
MSDS	Material Safety Data Sheet
MSV	Maintenance Supply Vessel
MU	Make Up
N	
NACE	National Association of Corrosion Engineers
NDE	Non Destructive Examination
NDT	Non Destructive Testing
NO	Normally Open
NPT	Non Productive Time
NRV	Non Return Valve
O	
OD	Outside Diameter
P	
P&A	Plug and Abandonment
PBR	Polish Bore Receptacle

PCS	Process Control System
PCV	Pressure Control Valve
PGB	Production Guide Base
PLT	Production Logging Tool
PMV	Production Master Valve
PPE	Personnel Protective Equipment
PRV	Pressure Relief Valve
PSI	Pounds per Square Inch
PSV	Production Swab Valve
PT	Pressure / Temperature (gauge)
PTT	Pressure & Temperature Transducer
PWV	Production Wing Valve
Q	
QA	Quality Assurance
QC	Quality Control
R	
R/T	Running Tool
RBP	Retrievable Bridge Plug
RCACV	Remote Controlled Adjustable Choke Valve
RFI	Request
RIH	Running In Hole
RLWI	Riserless Light Well Intervention
ROT	Remote Operated Tool
ROV	Remotely Operated Vehicle
S	
SAT	Site Acceptance Test
SCM	Subsea Control Module
SD	Shut Down
SDV	Shut Down Valve
SFT	Surface Flow Tree
SHE	Safety Health Environment
SIT	System Integration Test
SITP	(Wellhead) Shut In Tubing Pressure
SIV	Subsea Intervention Vessel
SLV	Service Line Valve
STT	Surface Test Tree
T	
TBC	To be confirmed
TBD	To be developed
TH	Tubing Hanger

THP	Tubing Head Pressure
THRT	Tubing Hanger Running Tool
THS	Tubing Head Spool
TMGB	Template Mounted Guide Base
TRSCSSV	Tubing Retrievable Surface Controlled Subsurface Safety Valve
TSA	Tubing Stress Analysis
TVD-BML	Total Vertical Depth - Bellow Mud Line

U

USC	Up Stream Choke

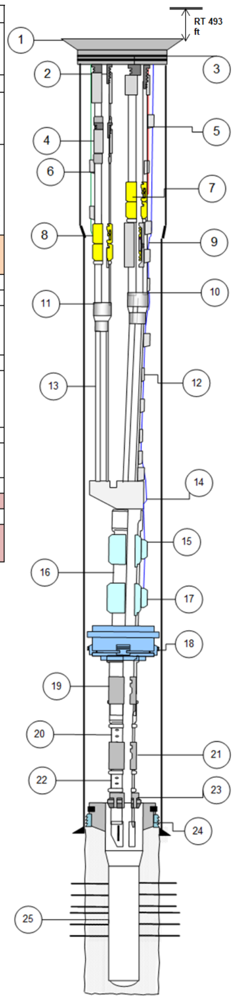
W

WH	Wellhead
WHO	Wellhead Pressure
WL	Wire Line
WLEG	Wire Line Entry Guide
WOR	Work Over Riser
WR	Wire Line Retrievable (WLR)
WLR-SCSSV	Wire Line Retrievable Subsurface Controlled Subsurface Safety Valve
WOCS	Work Over Control System

14.0 Appendix

14.1 AS-01 Dual subsea completion schematic - DRAFT

Xmas-Tree	Vertical Xmas-Tree assembly					RIG Reference depth Semi : RT/MSL = 80 ft Water depth msl= 413ft Revised: 11th September 2020- G. SUTHERLAND					
Item	**Bottom hole equipment Primary string**	**ID Inch**	**OD Inch**	**Length ft**	**Top Depth ft MD/RT**	**Item**	**Bottom hole equipment Secondary string**	**ID Inch**	**OD Inch**	**Length ft**	**Top Depth ft MD/RT**
	Rotary Table Reference:										
1	**Tubing Hanger Dual bore complete with plug profile 4.50"RPT & 1.875" RPT**	**4.5**	**18-3/4"**	**10.00**	**493.00**	**1**		**1.875**	**18-3/4"**	**10.00**	**493.00**
3	Tubing hanger make up sub 3-1/2" 9.3# 25%Cr	2.992	4.650	10.00	503.00	2	Tubing hanger make up sub 2-7/8" 6.4# 25%Cr	2.441	3.940	30.00	503.00
5	Tubing 3"1/2 Vam Top 9.3# 25%Cr	2.992	3.500	1987.00	513.00		Tubing 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	33.00	533.00
						4	2-7/8" Tubing (6.4#) adjustment sub Alloy 925 or similar. Details estimated- awaiting specification	2.441	5.500	15.00	566.00
						6	Tubing 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	2019.00	581.00
7	3"1/2 TR-SCSSV Vam Top 9.3# Dimensions taken from Weatherford Optimax CW flow couplings	2.813	5.17	25.00	2500.00	8	2"7/8 TR-SCSSV Vam Top 6.4# Dimensions taken from Weatherford Optimax complete with flow couplings	2.313	4.610	100.00	2600.00
	Pup joint 3"1/2 Vam Top 9.3# 25%Cr	2.992	3.500	40.00	2525.00		Pup joint 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	40.00	2700.00
9	3"1/2 TR-Sliding sleeve - Connections Vam Top 9.3# (Based on OptiSliding Sleeve)	2.812	4.500	12.00	2565.00		Tubing 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	30.00	2740.00
	Tubing 3"1/2 Vam Top 9.3# 25%Cr	2.992	3.500	1716.00	2577.00		Tubing 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	3423.00	2770.00
10	XO 3"1/2 9.2# Vam Top x 2"7/8 6.4#	2.441	3.500	10.00	**4293.00**	11	XO 2"7/8 6.4# x 2"3/8 4.7# Vam Top	1.995	2.375	10.00	**6193.00**
12	Tubing 2-7/8" Vam Top 6.4# 25%Cr	2.441	2.875	5790.00	4303.00	13	Tubing 2-3/8" Vam Top 4.7# 25%Cr	1.995	2.375	3890.00	6203.00
14	Y tool 2"3/8 & 2"7/8 to 4"1/2 12.6# Vam Top 25%Cr with Hydro packer 9"5/6	2.441	8.350	12.00	**10093.00**	14	Y tool 2"3/8 & 2"7/8 to 4"1/2 11.6# Vam Top 25%Cr with Hydro packer 9"5/6	1.995	8.350	12.00	**10093.00**
	Pup joint 4-1/2" 12.6# Vam Top 25%Cr	3.913	4.500	10.00	10105.00						
	Tubing 4-1/2" 12.6# Vam Top 25%Cr	3.913	4.500	350.00	10115.00						
15	Upper Downhole gauge 4"1/2 Vam Top 25%Cr 12.6#	3.913	7.500	15.00	10465.00						
16	Tubing 4-1/2" 12.6# Vam Top 25%Cr	3.913	4.500	550.00	10480.00						
17	Lower Downhole gauge 4"1/2 Vam Top 25%Cr 12.6#	3.913	7.500	15.00	11030.00						
	Tubing 4-1/2" 12.6# Vam Top 25%Cr	3.913	4.500	35.00	11045.00						
18	**9"5/8 packer 4"1/2 Vam Top 25%Cr**	3.913	8.400	15.00	11080.00						
	Pup jointTubing 4-1/2" 12.6# Vam Top 25%Cr	3.913	4.5	10.00	11095.00						
19	Nipple profile X Selective nipple profile - nipple with 4" connections 12.6# above and below. Nipple example taken X with 2.313" seal bore	2.313	4.5	10.00	11105.00						
20	Perforated pup joint above gauge nipple	3.913	4.5	5.00	11115.00						
21	Nipple profile X Selective nipple profile - nipple with 4" connections 12.6# above and below. Nipple example taken X with 2.313" seal bore - for memory gauge	2.313	4.5	10.00	11120.00						
22	Perforated pup joint above gauge nipple	3.913	4.5	5.00	11130.00						
	4-1/2" Flush jointed pipe 11.6# Vam FJL 25%Cr	3.952	4.5	30.00	11135.00						
23	Locator with shearable centralizer	3.952	8.300	2.00	11165.00						
	Mule shoe	3.952	5.000	3.00	11167.00						
	End of string				11170.00						

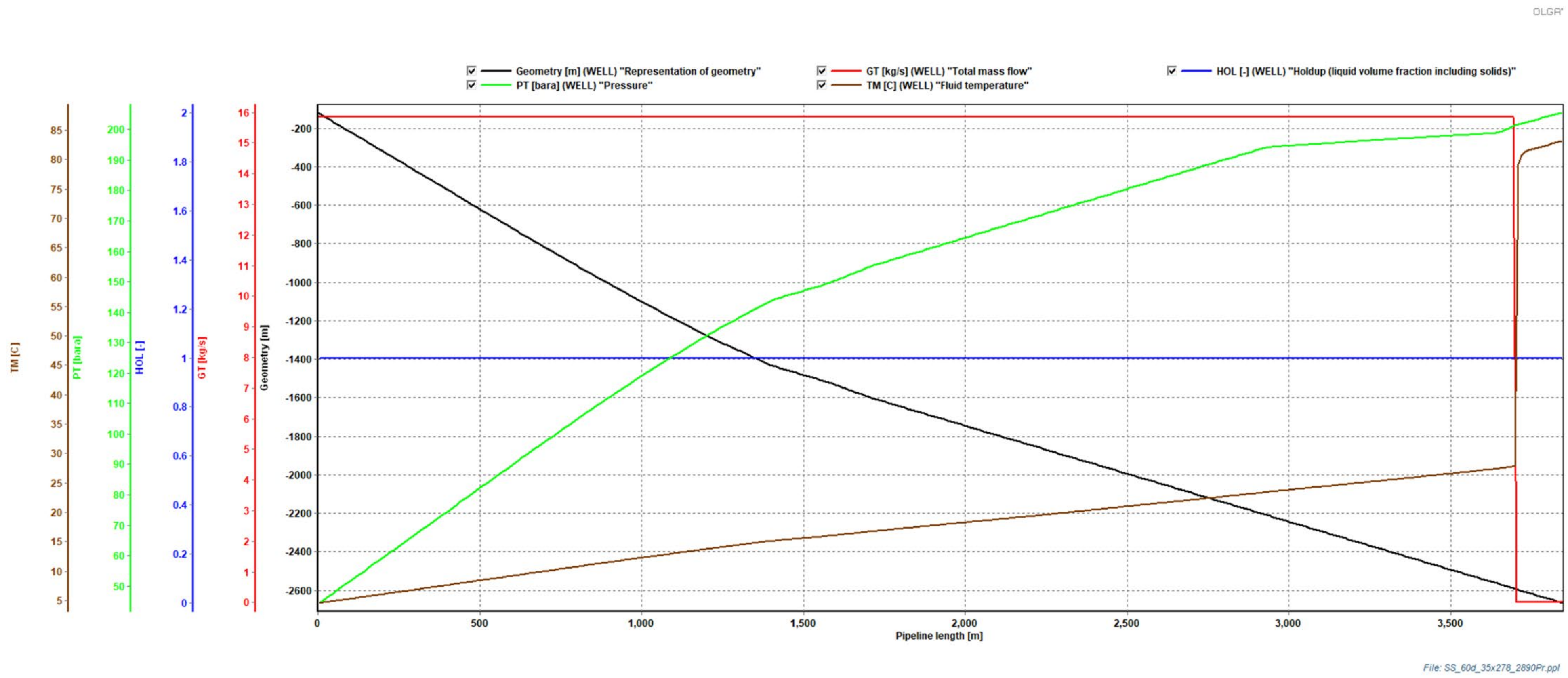


	5-1/2" liner				
Item	**Description**	**ID**	**OD**	**Length**	**Top Depth ft MD/RT**
24	9"5/8 Versa Treive liner hanger system or equivalent. 6" ID	6.000	8.450	10	11150.00
	Bottom Sub 7" 26# x 5"1/2 15.5# Vam Top Box	6.000	7.565	10	11160.00
	Pup joint 5"1/2 15.5# Vam Top 25%Cr	4.895	5.500	10	11170.00
	5"1/2 tubing 15.5# 25%Cr	4.895	5.500	633	11180.00
	Halliburton Double Valve Float Shoe 5"1/2 15.5# Vam Top	0	6.112	3	11813.00
	End of liner				11816.00

Casing & Liner			**Lbs/ft**	**Top Depth**	**Top TVD**	**Btm Depth**	**Btm TVD**
30" CP - 1" WT X52 HD/HT-90/QS	TBC		350	493.00	493.00	730.00	730.00
20" 129.29# X65 THM-90/MT	TBC		129.29	493.00	493.00	550.00	550.00
Casing 13"5/8 88.2# P110 Vam Top	TBC		88.2	550.00	550.00	4297.20	3980.00
Casing 9"5/8 Vam 21 P110 53.5#	TBC		53.5	493.00	493.00	10000.00	7331.80
Casing 9"5/8 Vam 21 25%Cr 53.5#	TBC		53.5	10000.00	7331.80	11500.00	8457.00
5"1/2 liner 15.5# 25%Cr VAM TOP or similar	TBC		15.5	11150.00			

Maximum inclination	60°			
Réservoir inclination		**Cross Couplings**		
Weight (without block) ↗ **Weight** (without block) ↘		**3-1/2"TR-SCSSV**		Single 1/4" CL 0.049" WT encapsuled inconel 11mmx11mm, Pop = XXpsi, Pcl = XXpsi, Vop = XXI
		2-7/8" TR-SCSSV		Single 1/4" CL 0.049" WT encapsuled inconel 11mmx11mm, Pop = XXpsi, Pcl = XXpsi, Vop = XXI
Completion Fluid	TBC	**1/4" TEC line**		Single TEC line 0.035" WT

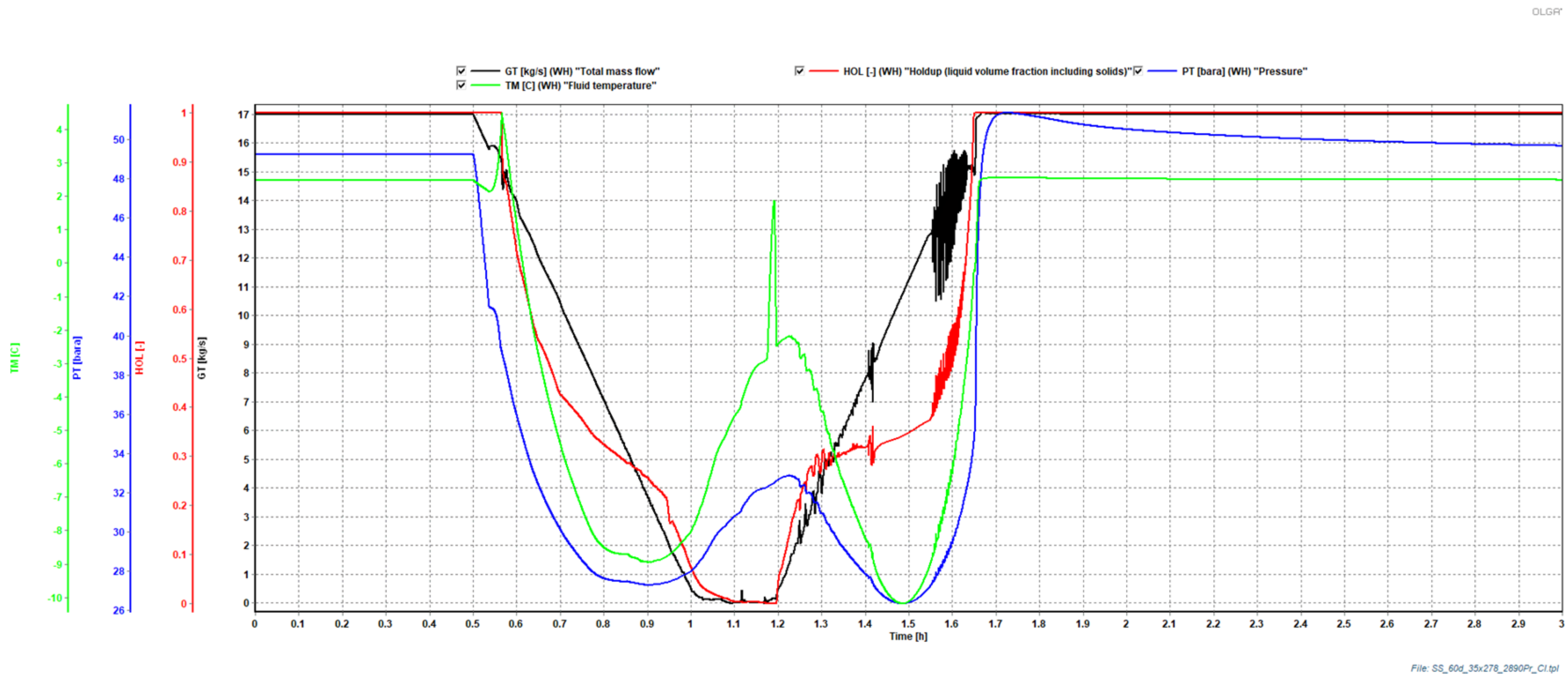
14.2 Simulations- injection Olga simulation steady state injection 0.5 $MtCO_2$/y - large string (3-1/2” x 2-7/8”)



Olga simulation courtesy of Shell UK, condition shown low reservoir pressure case 2,890psia, Pipe line temp 7°C, 120 bar injection rate 0.5 $MtCO_2$/y

Key consideration temperature minimum 5°C. (within the rated working temperature of the X-mas tree)

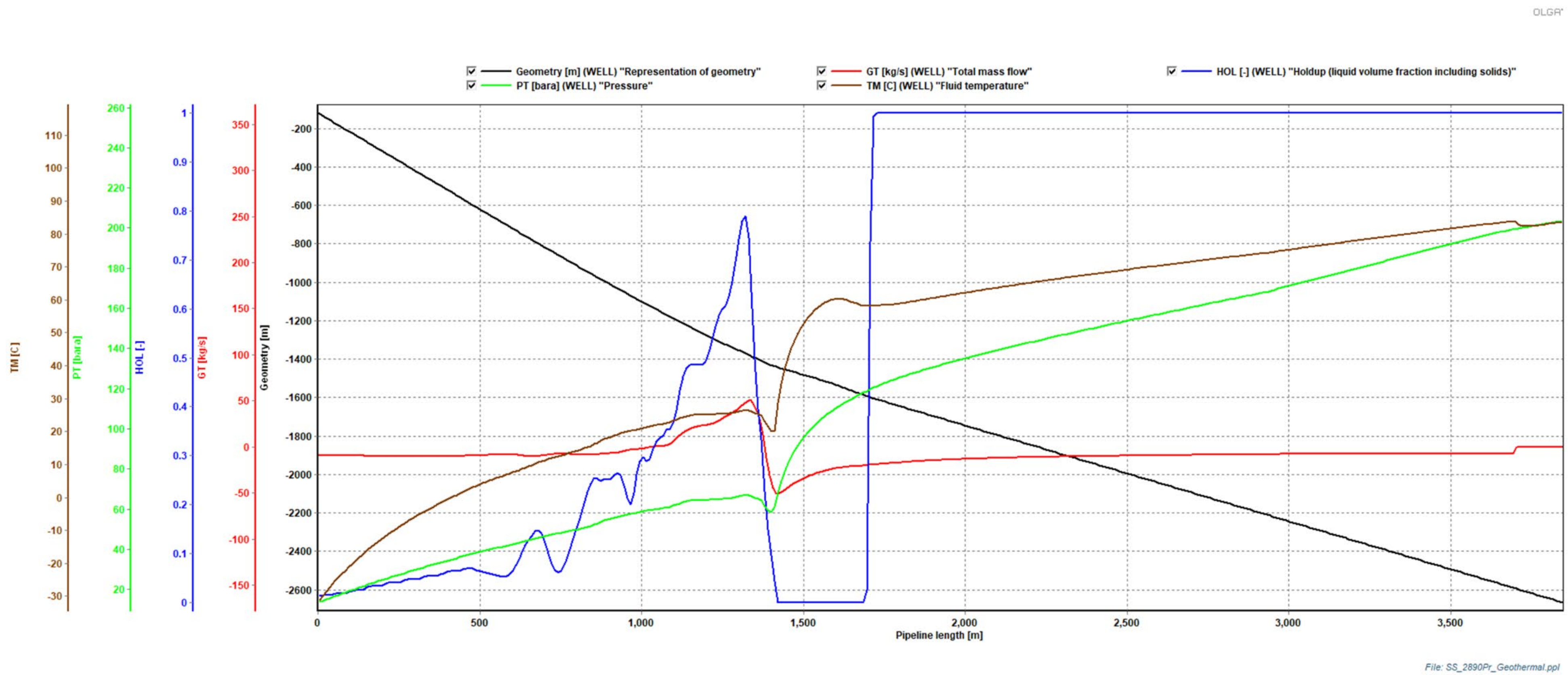
14.3 Simulations- Transient injection case Olga simulation- large string (3-1/2” x 2-7/8”)



Olga simulation courtesy of Shell UK, condition shown low reservoir pressure case 2,890psia, Pipe line temp 7°C, 120 bar transient condition, closed-in well over 30 minutes, well shut in duration 10 minutes, restart over 30 minutes.

Key consideration temperature minimum minus 10.2°C. at level of X-mas tree (within the rated working temperature of the X-mas tree)

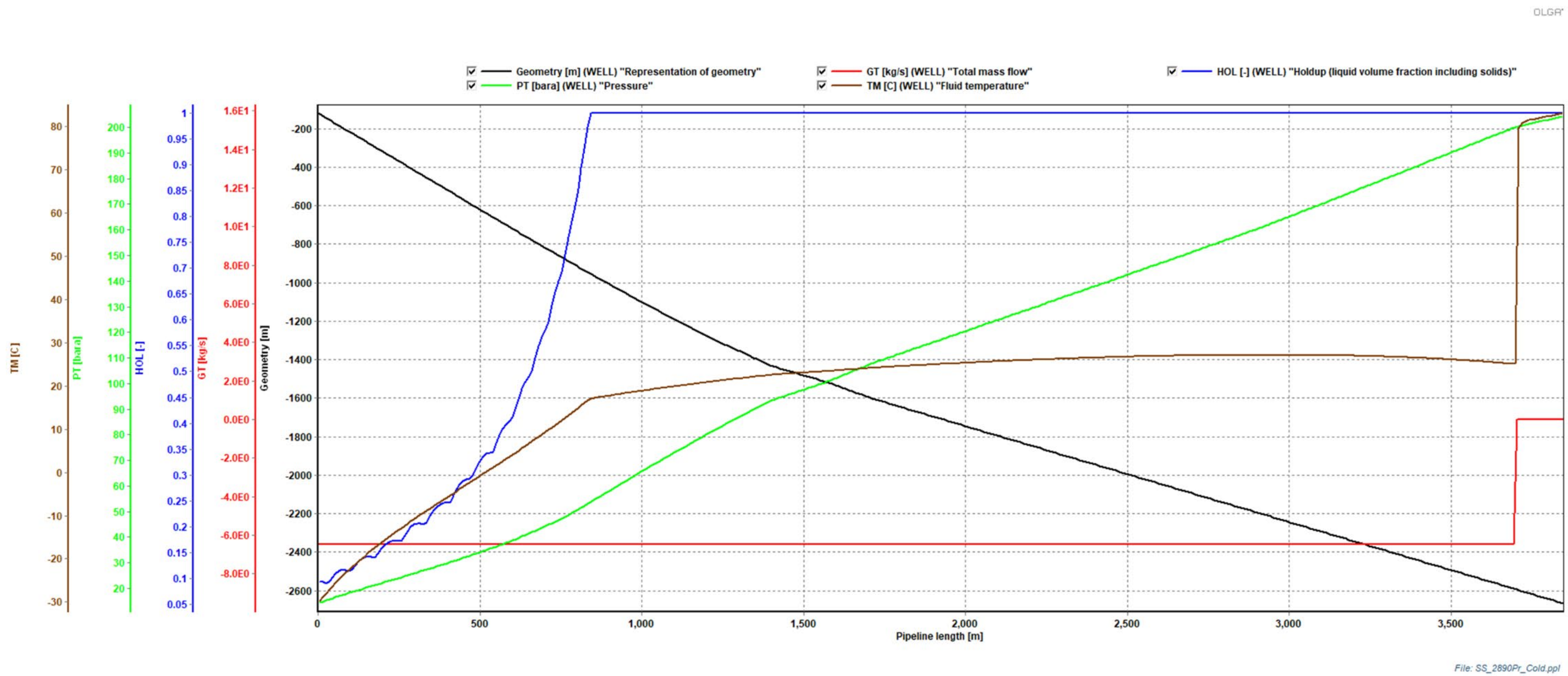
14.4 Simulations- Blow out case geothermal conditions- Olga simulation- large string (3-1/2" x 2-7/8")



Olga simulation courtesy of Shell UK, condition shown low reservoir pressure case 2,890psia, blowout release to sea through large string well in geothermal conditions.

Key consideration temperature minimum minus 31.2°C. at level of X-mas tree (within the rated working temperature of the X-mas tree)

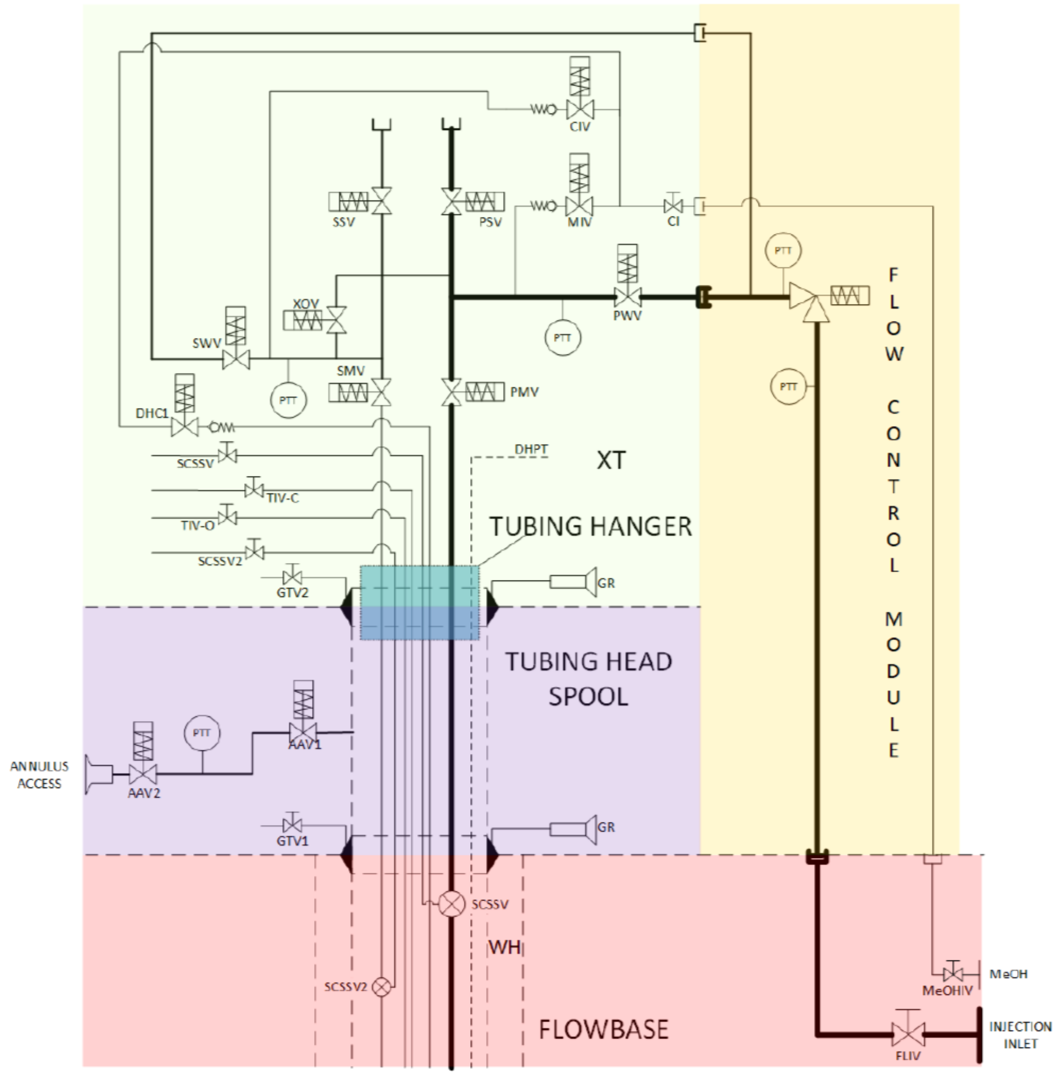
14.5 Simulations- Blow out case cold well conditions- Olga simulation- large string (3-1/2” x 2-7/8”)



Olga simulation courtesy of Shell UK, condition shown low reservoir pressure case 2,890 psia, blowout release to sea through large string well in cold condition after injection.

Key consideration temperature minimum minus 29.7°C. at level of X-mas tree (within the rated working temperature of the X-mas tree)

14.6 X-mas tree on tubing head spool example



Line diagram showing dual bore 5-1/8"x 2-1/16" X-mas tree on tubing head spool with instrumentation

Diagram courtesy of Costain extracted from overview of X-mas tree solutions for dual string completion.

14.7 CO_2 boil off at 12 bar

Property	Value	Unit
Medium :	**carbon dioxide**	
state of aggregation :	**boiling curve**	
Pressure :	12	[bar]
Temperature :	-35.071428571429	[Celsius]
Density fluid :	1096.8214285714	[kg / m^3]
Density gas :	31.156785714286	[kg / m^3]
Specific Enthalpy fluid :	122.95714285714	[kJ / kg]
Specific Enthalpy gas :	436.23928571429	[kJ / kg]
Specific Entropy fluid :	0.7075	[kJ / kg K]
Specific Entropy gas :	2.0233571428571	[kJ / kg K]
Specific isobar heat capacity : fluid cp'	2.0391071428571	[kJ / kg K]
Specific isobar heat capacity : gas cp''	1.0932142857143	[kJ / kg K]
Specific isochor heat capacity : fluid cv'	0.94763214285714	[kJ / kg K]

Data source online tables Peace Software

14.8 CO_2 boil off at 29 bar

Property	Value	Unit
Medium :	**carbon dioxide**	
state of aggregation :	**boiling curve**	
Pressure :	29	[bar]
Temperature :	-6.7875	[Celsius]
Density fluid :	965.913125	[kg / m³]
Density gas :	78.824875	[kg / m³]
Specific Enthalpy fluid :	183.88875	[kJ / kg]
Specific Enthalpy gas :	434.075625	[kJ / kg]
Specific Entropy fluid :	0.942585	[kJ / kg K]
Specific Entropy gas :	1.8819375	[kJ / kg K]
Specific isobar heat capacity : fluid cp'	2.3684625	[kJ / kg K]
Specific isobar heat capacity : gas cp''	1.61419375	[kJ / kg K]
Specific isochor heat capacity : fluid cv'	0.93406375	[kJ / kg K]

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