PORTHOS
Basis of completion design

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2.0	8-8	Included comments IdV and updated to follow ISO specification

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1. INTRODUCTION

As part of the Porthos CCS project it is planned to inject CO2 in the depleted P18-2 and P18-4 Bunter gas reservoirs. A multidisciplinary well selection workshop* has been held on the 31st of January in the EBN office to select the candidate wells for injection based on reservoir properties and well integrity status. All planned injection wells are located on the normally unmanned P18/A platform and are currently producing gas that is evacuated through the P15/D platform. The below table lists all wells that were selected to serve as an injection well:

Well Name:	Well type	Well type
P18-2A1	P18-A platform	Injector
P18-2A3	P18-A platform	Injector
P18-2A5	P18-A platform	Injector
P18-4A2	P18-A platform	Injector
P18-2A6	P18-A platform	Optional injector*
P18-6A7	P18-A platform	Optional injector*

**The mother bore of P18-2A6 well and the P18-6A7 well have been added as optional injection candidates to the basis of completion design in a later phase because the flow assurance study indicated that there may be a benefit in using these wells as "start-up" wells and to increase the total storage capacity.*

The purpose of this document is to prepare a basis of design for re-completion of the wells to make them suitable for CO_2 injection based on current known requirements for the wells. The design will follow ISO standard 27914 "Carbon dioxide capture, transportation and geological storage - Geological storage".

2. DESIGN ASSUMPTIONS

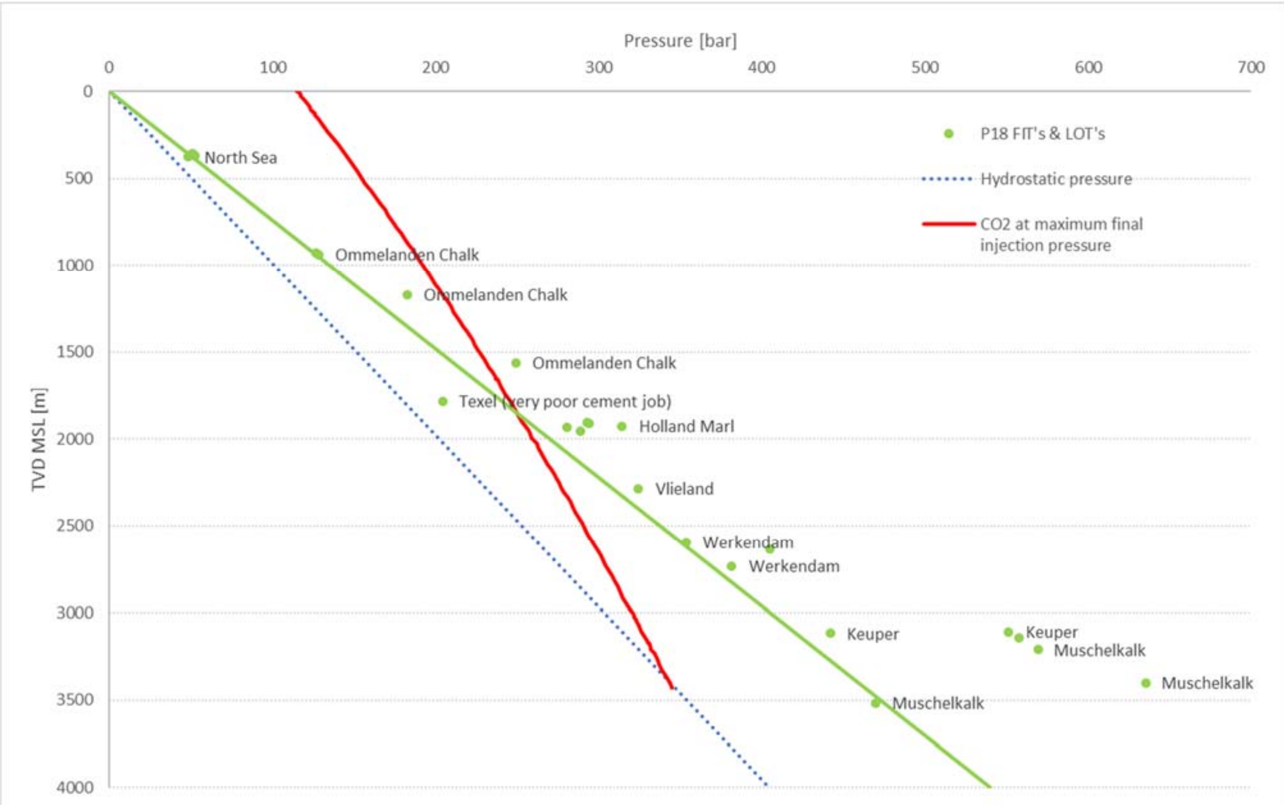
2.1. Reservoir

CO_2 is planned to be injected in the Bunter reservoir at a depth of around 3200 m TVD. The caprock consists of the Solling Claystone Member and an >500m TVD thick sequence consisting of the Rot, Muschelkalk, Keuper and various Altena shales. A generalised stratigraphy of the P18 wells can be found in appendix A.

2.2. Regional pore pressure and fracture gradient profiles

The pore pressures and formation fracture pressures are displayed in the figure below;

- The minimum fracture gradient is based on P18 limit and leak-off test results, indicated by a Green dot. The Green line connects these dots and is indicative of the formation strength.
- The Blue line shows the hydrostatic pressure line of the formations
- The Red line shows the pressure profile in case the well would be fully filled with CO_2 at the final planned reservoir pressure of 345 bar



2.3. CO_2 delivery specifications

Component	Concentration*	Based on
CO_2	$\geq$ 95%	ISO-27913
H_2O	$\leq$ 40 ppmv	OCAP $\leq$40ppmv / Technical Operation $\leq$50 ppmv[Note 1]
Sum [H_2+N_2+Ar+CH_4+CO+O_2]	$\leq$ 4%	ISO-27913[Note 2]
H_2	$\leq$ 0.75%	ISO-27913[Note 2]
N_2	$\leq$ 2%	ISO-27913
Ar	$\leq$ 1%	ISO-27913
CH_4	$\leq$ 1%	ISO-27913
CO	$\leq$ 750 ppmv [Note 3]	OCAP
O_2	$\leq$ 40 ppmv [Note 4]	Storage license P18-4
H_2S	$\leq$ 5 ppmv [Note 5]	OCAP
SO_x	$\leq$ 50 ppmv	ISO-27913
NO	$\leq$ 2.5 ppmv	OCAP (emitters do not require additional purification)
NO_2	$\leq$ 2.5 ppmv [Note 6]	OCAP (emitters do not require additional purification)
NO_x	$\leq$ 5 ppmv [Note 6]	OCAP NO+NO_2
C2+ (hydrocarbons)	$\leq$ 1200 ppmv [Note 7]	OCAP (emitters do not require additional purification)
Aromatic hydrocarbons (incl.BTEX[Note8])	$\leq$ 0.1 ppm	OCAP (emitters do not require additional purification)
Total volatile organic compounds[Note 9]	$\leq$ 350 ppm	Already being sent to OCAP [Note 10]
Ethylene (Etheen)(C_2H_4)	$\leq$ 1 ppmv	OCAP (emitters do not require additional purification)
H-cyanide (HCN)	$\leq$ 20 ppmv	OCAP (emitters do not require additional purification)
Carbonyl Sulfide	$\leq$ 0.1 ppmv	OCAP (emitters do not require additional purification)
Dimethyl Sulfide	$\leq$ 1.1 ppmv	OCAP (emitters do not require additional purification)

*All percentages are mole %. Note: 1 % (mole) = 10 000 ppmv

Note 1: A study of the phase diagram with CO_2 and H_2O vs. the Porthos operating regimes indicated that solids may form at 100ppm H_2O, but not at 50ppm. Optimization between these steps has not been done to determine the maximum amount of H_2O that could be allowed to prevent solid formation.

Note 2: Components lighter than CO_2 shift the phase diagram upwards. This increases the operating costs for compression, but also increases the 2-phase zone which must be avoided in the offshore pipeline. Crossing the 2-phase zone from high pressure to low pressure causes significant temperature drops by the Joule Thompson effect. Hydrogen is the lightest of these components and should therefore be allowed with caution.

Note 3: Next limit: ISO-27913 CO < 0.2%.

Note 4: ISO-27913 stipulates O2 < 10 ppmv (Petroleum Industry Standard w.r.t. well integrity), although recommendation from material specialist to avoid corrosion is 100ppm. Also, for wells in stainless steel, low levels of O2 is actually required to form an oxidation layer. Therefore, the specification was slightly relaxed to OCAP composition.

Note 5: Next limit: ISO-27913 and specialist recommendation to avoid corrosion and: H_2S < 200ppmv.

Note 6: Next limit: ISO-27913 NO_2 < 50 ppmv

Note 7: Next limit: ISO-27913 C2+ < 2.5%

Note 8: BTEX = benzene, toluene, ethylbenzene, xylene

Note 9: Total volatile organic compounds = ethanol, acetaldehyde, ethyl acetaat, traces of n-propanol, isobutanol, acetone, dimethyl ether, propanal, 2-butanol, methanol, n-butanol and isoamyl acetaat

Note 10: OCAP specification on Total volatile organic compounds < 1.2 ppm

2.4. Normal operational parameters and input from the flow assurance study

For the flow assurance study (Flow assurance study presentation January 31th 2019, Stefan Belfroid, TNO) the following parameters have been taken into account for steady state injection:

Temperatures:

- Compressor outlet temperature 35 < T < 80 °C
- Downhole temperature T > 15 °C
- Topside piping T > -10 °C

Flowrates:

- Desired flow rates 15 – 170 kg/s, (through pipeline) with an objective of 70 kg/s per well
- 4 wells available for injection (1 well in P18-4; 3 wells in P18-2). The optional injection wells P18-2A6 and P18-6A7 were added in the final stage of this study, hence no detailed FAS modelling has been done for these two wells. Therefore, the generalized completion and well design have been applied for both the P18-2A6 and P18-6A7. The recommendation is to update the flow assurance study including these two additional wells to understand the impact on completion and well design due to differences in reservoir properties and injectivity.

Pressure:

- Reservoir pressure prior to start of CO2 injection: 20 bar (note: The P18-2 and P18-4 reservoir pressures are now around 22 bar and the P18-6 reservoir pressure is around 46 bar)
- Reservoir pressure end of CO2 injection: 340 bar
- Minimum pipeline pressure 60 bar (minimum discharge pressure compressor)
- Other constraints such as tubing vibrations; thermal/mass flow rate constraints for reservoir, thermal gradients in well (radial and axial)

In order to stay within the above operating boundaries, the flow assurance study has shown that a completion with primarily 5 1/2" tubing is the most optimal. When using a smaller diameter tubing it will be easier to meet the temperature constraints at the topside. On the other hand, it will lead to higher wellhead pressures which implicates that at the final reservoir pressure the desired injection rates cannot be met. When modelling the larger diameter tubing it became apparent that it will be very difficult to meet the temperature requirements at low reservoir temperatures. (Flow assurance study presentation January 31th 2019, Stefan Belfroid, TNO)

During start-up and shut-in, the temperatures of the CO_2 in the well can drop even further. The worst case that is modelled for the flow assurance study is an Emergency Shut Down (ESD) with 20 bar reservoir pressure, below is a graph with the resulting minimum temperature and lowest mean temperature of the CO_2. When the reservoir pressure increases with injection this temperature effect will reduce and the well will stay at higher temperatures.

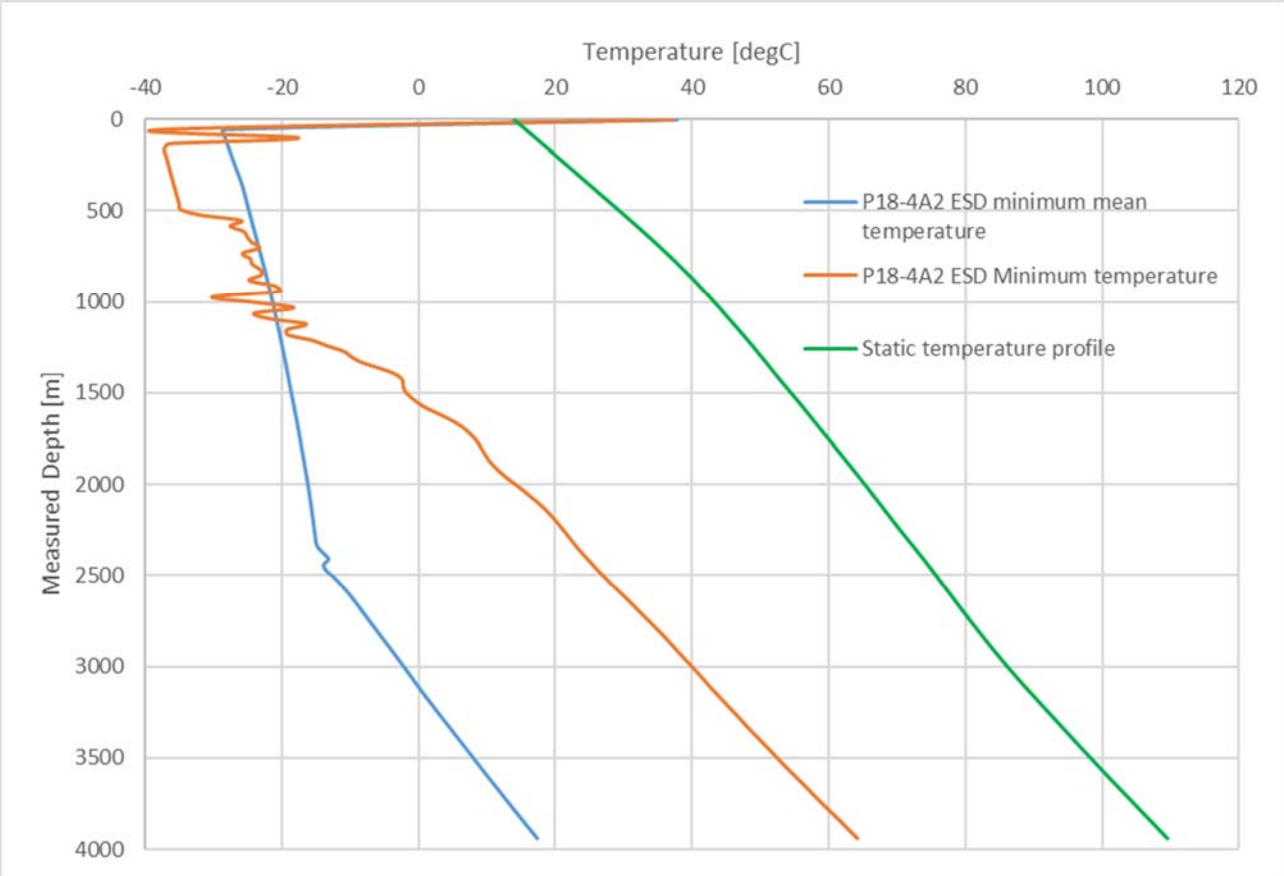


Figure 1 Static temperature and CO2 temperature profiles during an ESD

Downhole monitoring

The flow assurance modelling has shown that the wellhead pressure will vary very little with increasing reservoir pressure, refer to appendix B for a graph (Flow assurance study presentation January 31th 2019, Stefan Belfroid, TNO). It is therefore recommended to install a downhole pressure gauge to allow for accurate monitoring of the reservoir pressure. Given the large expected temperature variations and the big impact that this will have on the completion it is recommended to install a continuous array of temperature measurements over the tubing to confirm the results of modelling and aid in operating the well in the design envelope. The data gathered in the Porthos project may also be beneficial for future CO_2 storage projects.

2.5. Well integrity

A well integrity review has been performed by TNO (Well integrity study presentation January 31th 2019, Paul Hopmans, TNO NB: This review did not consider the P18-6A7 well as a potential injector). The currently installed completions have a retrievable packer which is not deemed suitable for the expected temperature variations and will therefore need to be replaced. The main conclusion of this review, on the well materials that will stay in the well, were:

- No major operational issues during cementing of the production casings and liners which are located at the proposed packer setting area.
- Most of the cement bond logs that were run over the production liners showed poor bonding.
- No annular pressures have been observed during the productive life of the wells except for the P18-2A5 well where there is a sustained pressure slowly building on the A-annulus.
- The formation integrity tests done after cementing show competent casing shoes whereby all casing shoes from the 13 3/8” down can cope with the anticipated maximum CO_2 pressure.

- The P18-2A6 well is a multilateral well, consisting of a lateral which will need to be decommissioned and a mother bore which could be considered as an injection candidate, this will involve retrieving a whipstock and isolation of the lateral section.

A Taqa quick scan of the P18-6A7 well integrity has revealed the following:

- The completion has a permanent packer, in the define phase it could be considered to perform a detailed assessment including a flow assurance study to check whether the completion could be used as is including potential temperature limitations.
- FIT's of the 9 5/8" casing (Holland Marl) down are of sufficient strength to cope with anticipated maximum CO_2 pressure.
- There are no abnormal annular pressures recorded.
- No CBL's were run, the 13 3/8" primary cement job failed due to a blocked bottom plug / float collar, the result of subsequent squeeze jobs was poor.
- Losses were observed during the 9 5/8" casing cement job, the calculated top of cement is inside the 13 3/8" shoe.
- Losses were observed during the 7" liner cement job, the theoretical top of cement was estimated at 118 m below the TOL (spacer returns observed), the liner was rotated during the first part of the displacement.
- During the 5" liner cement job the top wiper plug was bumped 2.2 m3 early, it was thought that cement had bypassed the wiper plug, therefore only spacer and no cement was observed above the TOL, rotation not reported.

When the annular cement of a production liner is deemed inadequate it could be considered to place the packer above the liner across a caprock in an area with good annulus cement. It is therefore not expected that the current cement status will be an issue for CO_2 injection. However, the prognosed quite extreme temperature cycles may influence the cement bond quality during the well life. A study is being performed by TNO on the effect of the temperature cycles on the cement bond quality, it is advised to take the study results along in the define phase. Remediation for a poor annulus cement is discussed in the design requirements section (section 3.4).

3. DESIGN REQUIREMENTS

3.1. Completion configuration

The Flow assurance study shows that 5 1/2" is the optimal tubing size for the injection wells. This will fit in the top part of all injection wells since the top part of the wells consist of 9 5/8" casing. Three of the wells have a 7" liner above the reservoir, 2 wells have a 5" liner over the reservoir and the P18-6A7 has a predrilled 3 1/2" liner over the reservoir. The P18-2A6 well will require decommissioning of the lateral and isolation of the lateral from the motherbore. Various solutions exist which could be used, this is not expected to lead to a reduction in ID smaller than that of the ID of a 7" liner. In the define phase the benefits of using a system with a larger ID which could enable using a larger tubing to deeper in the well could be weighed against potential downsides of such a solution including potential extra cost. Below is a table with the depth of the Top Of Liners (TOL) and the top of the perforations.

	P18-2A1	P18-2A3	P18-2A5	P18-4A2	P18-2A6	P18-6A7
7" TOL [m]	3405	2672	3594	3924	*2200	2435
5" TOL [m]	N/A	3785	4402	N/A	N/A	3761
4 1/2" TOL [m]	N/A	N/A	N/A	N/A	N/A	N/A
Top of perforations [m]	3575	4070	4796	4083	4488	**4953

* Estimated top of a to be installed scab liner over the window, this could be 7" scab liner or a different size scab liner/patch, this will be decided on in the define phase

** Predrilled holes in 3 1/2" liner

For the wells with a 7" liner over the reservoir there is an opportunity to install the packer across the caprock just above the perforations in case the annulus cement at that level is deemed competent (refer to appendix C for an example completion diagram). This will reduce the amount of liner and casing that is in contact with CO_2. It will also facilitate the final decommissioning of the well as the packer with a plug installed can be used to isolate the upper part of the well from the reservoir and it can serve as a base for the cement plug. This will reduce decommissioning risks and cost whilst still allowing to set a full-bore cement plug against the caprock (for more details on the decommissioning please refer to the Porthos basis of decommissioning design). The maximum tubing size that will fit in a 7" liner is 4 1/2" when a pressure/temperature monitoring cable is run with the tubing.

For the wells with a 5" liner the packer will need to be installed as deep as possible in the 7" liner across a suitable caprock (refer to appendix D for an example completion diagram). For the P18-6A7 well this means that the packer will be installed just above the caprock (Altena shales). This is not the preferred place since it could allow leakage above the caprock without a possibility to monitor it. However, it could be considered to stab the tailpipe of the completion into the 5" TOL to add an additional barrier to the 7" liner and to monitor the condition of the barrier by regular risk based corrosion logs. Installing a packer in the 5" liner will result in a too small tubing size to allow for the required injection rates. This means that the 5" liners will be exposed to CO_2. For the P18-6A7 well it may be preferred to install a deeper packer and to accept a reduced injection capacity. In the define phase, it should be confirmed with Flow Assurance calculations that the depth of the packers will not form a too big restriction for injection, this will be an iterative process. Next to pressure and temperature effects, the maximum allowed velocity in the well components to avoid erosion should be considered.

An example of the proposed configurations with a 7" liner and with a 7" & 5" liner can be found in appendix C and D.

Packer

It is preferred to install a completion whereby the tubing is fixated to a packer. Given the relatively large impact of pressure fluctuations on well temperatures in CO_2 injection wells it is advised to perform flow assurance calculations based on the final injection parameters for the operating envelope of each specific well. The outcome from the flow assurance study can be used as input to calculate the

loads on the packer and as such to validate the final packer design. For the wells where the packer can be placed just above the perforations permanent packers may be used since these can be left downhole during decommissioning of the wells. However, in case of an unexpected workover due to issues with the new completion this would lead to extra workover cost compared to a retrievable packer.
For wells where the packers cannot be set close enough to the caprock for instance due to poor casing quality, poor annulus cement or unsuitable production liner size it is advised to source retrievable packers with a cut to retrieve option for ease of later decommissioning. In case no retrievable packers of sufficient strength can be sourced, a permanent packer can be installed but this will lead to extra time spend on milling of the packer during the final decommissioning of the wells.
The extreme temperature variations that are modelled in the Flow Assurance study will lead to very high loads on the tubing and packer and will lead to strict specifications for the packer and tubing.

In case the detailed modelling shows that the use of a standard packer completion is not an option it could be considered to select a system where the tubing is allowed to slide in a sealbore. The downside of this option is that given the frequent movement past the seals this is more susceptible to leakages.

Subsurface safety valve
The use of a Surface Controlled SubSurface Safety Valve (TRSCSSSV) is mandatory for self-flowing wells. This safetyvalve should be suitable for the low anticipated temperatures in the well, it is however expected to be difficult to find a standard safetyvalve in the market that fulfils this requirement, especially in the top section which is expected to cool down the most, it could be considered to place the safteyvalve deep in the well where the temperatures will be higher. Next to that the control line fluid may be susceptible to freezing which will hamper the functionality of the TRSCSSSV. Therefore, it could be considered to use an injection valve rather than a TRSCSSSV or a combination of both. An injection valve will always close directly in case of an uncontrolled release whereas a TRSCSSSV closes after a sequence of valves is closed or hydraulic pressure is lost. A downside of injection valves is that they may be more susceptible to erosion and that they are not controllable from surface. A dispensation will need to be requested from the regulator for not installing a TRSCSSSV. The pro’s and cons of both options and the effect of the low CO_2 temperature on the control line fluid needs to be investigated in the define phase. A deep-set injection valve which gives backpressure to the system may aid in reducing the ESD loads on the well, this should be investigated in the Flow Assurance study.

Downhole monitoring
In order to get the full temperature profile of the wells a fibre optic Distributed Temperature Sensor (DTS) system could be installed in combination with a downhole pressure gauge. This will lead to restrictions on the tubing size at the bottom of the wells compared to a design where no downhole monitoring is required.

3.2. Materials

Tubulars
For the flow wet tubulars Cr13 material will be required to cope with the proposed CO_2 specification, higher quality super Cr13 variants could be required to cope with the very low temperature requirements. In the define phase this should be discussed with OCTG (tubing) suppliers in order to prepare the material specification.

Casing & Liners
The casing designs of the injector wells will need to be checked against the CO2 injection load cases. As part of this wellhead movement should be assessed and checked for interference with the platform structure and facilities.

Wellhead & X-tree
The existing wellhead and tree have not been designed (Temperature class PU -20°C to 121 °C) to cope

with the very low expected temperatures. The flow wet components such as the tubing hanger and the X-tree can be changed out, the new equipment will need to be ordered to artic specification (API temperature class KU -60°C to 121 °C). It will be very difficult to change out the wellhead equipment of the casings, it should however be checked what the temperature effect will be on this equipment and whether the equipment is suitable for this. Also the use of heat tracing could be considered. Refer to Appendix E for wellhead and tree setup for the P18-A wells. Please note that the wellhead & tree of the P18-6A7 well is different than that of the other P18 wellhead and trees.

Elastomers
If elastomers are used in the packer, wellhead or subsurface safety valve these need to be checked against compatibility with the CO_2 specification

3.3. Annulus fluids

Standard oil and gas wells in the Netherlands are completed with a completion brine in the A-annulus, however in these wells the expected low temperatures may lead to freezing of the brine. Also, the outer annuli could be exposed to freezing conditions. In the define phase, the temperature effects on the annulus fluids should be modelled. In case it is apparent that the A-annulus will freeze it should be considered to add anti-freezing agents, use an oil-based annulus fluid and/or nitrogen blanket in the annulus. The use of a nitrogen blanket in the annulus may have the additional benefit of insulation to the outer casing strings and will lead to a continuous overpressure which will allow continuously verification of the barrier envelope. This could be an option in case modelling shows that the outer annuli will be susceptible to freezing conditions since it is not possible to change-out the fluids that are present in the outer annuli. Alternatively, the operating envelope would need to be reduced in order to keep the temperatures of the annuli within acceptable boundaries. Introducing a nitrogen blanket will however make the completion installation a bit more complex and may introduce a potential leak path in the completion.

3.4. Production Liner & Casing cement

The preferred setting depth of the production packer is as close to the perforations as possible where the well geometry allows this. This means that the production liners and the annulus cement will be part of the primary barrier envelope. The CBL's that were done on the production liners just after installation showed poor bonding for most of the wells. However, the isolation of the liner cement is believed to be sufficient for CO_2 injection when the cement job parameters were good and no annulus pressures have been observed during the producing life of the wells. It could be considered to reinterpret the existing CBL's to gain extra confidence in the cement bond logs.
Alternatively the production packer could be installed in the production casing when the cement job parameters were good, a FIT/LOT showed that the shoe is of sufficient strength to cope with the maximum anticipated pressure and no annulus pressures have been observed during the producing life of the wells.
In case that no isolation is present remedial actions could be considered. The best way to remediate a poor cement job would be to decommission the existing production liner with a Full-bore Formation Plug against the caprock and sidetrack back into the reservoir to install a new production liner, this will be an expensive solution.

3.5. Logging requirements

Several logs could be run before running the new completion to verify the condition of the well. During the injection phase production logging may be required to assess the well and the injection performance. As per ISO 27914:2017 standard prior to conversion for CO2 storage, the long-string casing shall be inspected and tested for integrity over its full length by obtaining and evaluating cement integrity logs and running and evaluating a casing inspection log for casing corrosion or damage.

Cement bond logs
A cement bond is typically used during the construction of a new well when there were operational issues with the cementation to check if there is a cement bond behind the casing. Please note however that it is the experience of Taqa that CBL results can be misleading, we have had examples of well sections with poor CBL's and good isolation and well sections with good CBL's where there was an obvious leak path. It is therefore of importance to ensure that the planned cement evaluation tool is suitable for the specific cement/casing situation and that prior to running the tool the evaluation and decision criteria are established.

Corrosion logs
Corrosion logs will be run as per the ISO standard. It is important to ensure that the minimum required wall thickness is known prior to running the tools and that the evaluation and decision criteria are established. Special focus areas of the corrosion logs are the proposed packer setting area in the production liner since in cases where this area was exposed to well fluids containing a minor amount of CO_2 during the production life and the P18-2A5 well where irregular A-annulus behaviour has been observed during its productive life.

Production logs
When for some wells there are doubts on reservoir performance (injectivity) a production log like an (M)PLT could be considered. The CCS ISO standards also mentions that a baseline saturation log should be obtained to establish gas saturations near the wellbore, the benefits of such a log should be discussed with the subsurface team in the define phase.

3.6. Clean-out

Before running a new completion and potentially some logs it is advised to perform a clean-out run with casing scrapers to remove scales, debris and plugging material from the well kill from the casing walls.

4. CONCLUSIONS AND RECOMMENDATIONS

- The 4 initially proposed P18-2 and P18-4 gas wells are suitable to convert to CO_2 injection wells.
- The P18-2A6 well is a multilateral well, consisting of a lateral which will need to be decommissioned and a mother bore which could be considered as an injection candidate, this will involve retrieving a whipstock and isolation of the lateral section.
- The P18-6A7 well could be considered as an injection candidate, it does have a different well architecture and wellhead system than the other P18-A wells which will lead to variations in the design.
- For P18-2A6 and P18-6A7 a flow assurance study needs to be done to understand the impact on completion and well design due to differences in reservoir properties and injectivity.
- The large variation in modelled injection temperature profiles will lead to large loads on the tubing and packer and will require strict specifications and lead to extra cost and longer lead times
- The expected extreme low temperatures will lead to strict specifications for materials and lead to extra cost and longer lead times
- The cyclic temperature loading on the existing cement should be taken into account in the detailed design.
- It is recommended to review options to reduce the temperature loads in order to be able to use a more cost-effective design.
- It is recommended to prepare a flow assurance model for the detailed completion of each well and to update this model with the actual planned start and end reservoir pressures.
- The completions should cater for production logging during the operational stage
- The casing designs of the injector wells will need to be checked against the CO2 injection load cases.
- Temperature limitations of well elements that cannot be changed-out during a workover such as annulus fluids and wellhead seals must be evaluated as they might impact the operational boundary conditions.
- Wellhead movement should be assessed and checked for interference with the platform structure and facilities.
- In the define phase start engaging equipment vendors for completion items & wellhead / xmas tree to share the project requirements and issue statement of requirements allowing for expert input on dedicated equipment specifications.
- For time and cost estimates please refer to the separate “Porthos CCS P18-2 well options cost estimates” document (ECM#198432)

5. APPENDICES

5.1. Appendix A: generalized stratigraphy of the P18 area

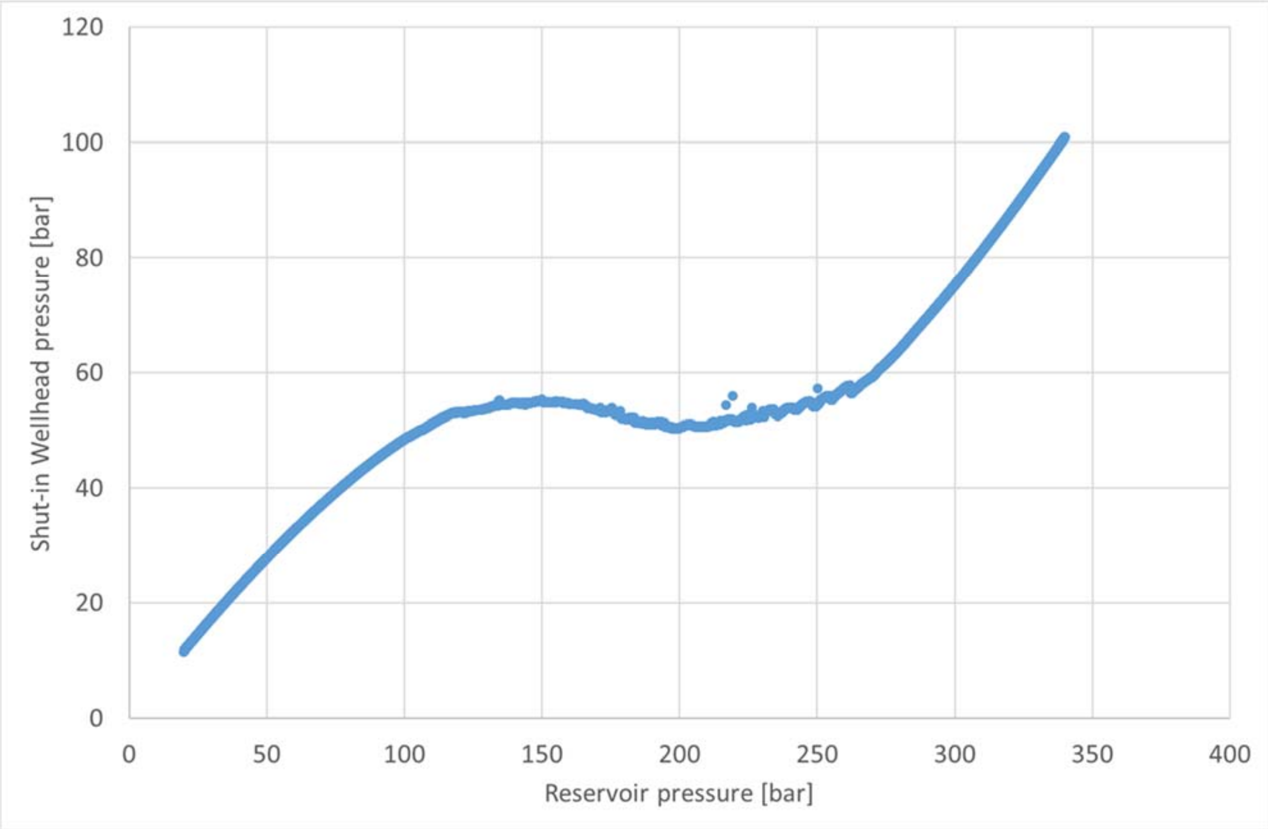
The Mainbuntsandstein formation “Bunter” in Taqa nomenclature is the only stratigraphic interval in the P18a,c area that has producing gas fields. In the nearby P15 production license, the Rijswijk member “Rijn” in Taqa nomenclature and Delft sandstone member “Delfland” in Taqa nomenclature may contain oil.

Generalised Stratigraphy of the P18 wells (based on the vertical P18-2 well):

				M TVDSS (+-)	
Tertiary	Upper North Sea		Undifferentiated	0	The North Sea Group, which consists of siliciclastic sediments. Three major aquifers cam be distinguish; the Dongen sand, a basal transgressive sandstone, and the marine Brussels sand and the Berg sand
	Middle North Sea		Boom Clay	417	
			Berg Sand	456	
	Lower North Sea		Asse Clay	465	
			Brussel sand	489	
			Ieper Clay	530	
			Dongen sand	637	
			Landen Clay	870	
Upper Cretaceous	Chalk		Ommelanden Formation	920	Upper Cretaceous Chalk Group, which consist at the base of the formation of sands and marls and a thick layer (900 m) of limestones (Chalk). The distribution of the basal Texel Greensand is limited to the southern basin margin.
			Texel Marlstone Member	1785	
			Texel Greensand Member	1828	
Lower Cretaceous	Rijnland	Holland	Upper Holland Marl Member	1876	Lower Cretaceous Rijnland Group, which consist of marine sandstones, shales and marls. At the base of the Rijnland Group, the Rijn / Rijswijk sandstone is present. This sandstone is widely distributed in the P18 area. It is also known for its oil (P15) and gas (onshore) accumulations within the West Netherlands Basin. The Rijnland sandstones are interpreted as transgressive sheet sands, with good lateral continuity. The Berkel and IJsselmonde are interpreted as coastal barriers with less lateral continuity. It must be assumed that the Berkel Sand is in connection with the Rijswijk/Rijn member. The IJsselmonde, Berkel and Rijswijk/ Rijn share the same seal which is the Vlieland Claystone and Lower Holland Marl Member. In the upper part of the Rijnland succession, the Holland Greensand is present. It consists of argillaceous sands and silts. The distribution is limited to the southern margin of the West Netherlands Basin. Although the Holland Greensand has good lateral continuity, permeability is in general low
			Middle Holland Claystone Member	1996	
			Holland Greensand Member	2056	
			Lower Holland Marl Member	2078	
		Vlieland	Vlieland Claystone Formation	2190	
			IJsselmonde Sandstone Member	2416	
			IJsselmonde Claystone Member	2436	
			Berkel Sandstone Member	2486	
			Berkel Sand-Claystone Member	2496	
			Rijswijk Sandstone Member (Rijn in TAQA Nomenclature)	2529	
Jurassic	Schieland	Delfland	Rodenrijs Claystone Member	2544	The Schieland Group, which consists of shales and (stacked) channel sands of the Nieuwekerk Fm. (Delft sandstone equivalent). The lateral continuity of the individual sandbodies (thickness 2-5m) is probably very limited.
			Delft Sandstone Member (“Delfland” in Taqa nomenclature)	2562	
	Altena		Alblasserdam Member	2567	Directly above the primary seal, a thick succession of marine claystones, siltstones and marls is present. These sediments have excellent sealing quality and belong the Altena Group (Jurassic age).
			Lower Werkendam Member	2573	

		Posidonia Shale Formation		2747	In the P18-02 well, the Altena Group has a thickness of approx. 500 m.
		Aalburg Formation		2778	
		Sleen Formation		3036	
Upper Triassic	Upper Germanic Triassic	Upper Keuper Claystone Member		3077	The primary seal to the P18 reservoirs is formed by siltstones, claystones, evaporites and dolostones of the Solling Claystone Member, the Röt Formation, the Muschelkalk Formation, and the Keuper Formation that discomformably overlie the reservoir. The Solling Claystone Member consists of red, green and locally grey claystones that where deposited in a lacustrine setting just after the tectonic movements of Hardegsen phase during a major transgression (Geluk et al., 1996). It is the first laterally extensive claystone above the reservoir rocks of the Main Buntsandstein. In well P18-02, it has a thickness of approx. 5 m (Fig. 11). The Röt Formation consists of thin-bedded claystones, and is approx. 40 m thick. The Muschelkalk Formation consists of claystones, dolomites, and evaporates, and is approx. 70 m thick. All these rocks contain variable amounts of nodular anhydrite cementation (Spain and Conrad, 1997). The Keuper Formation consists of claystones intercalated with zones of anhydrite and gypsum, and is approx. 40 m thick. In total, the thickness of the primary seal in well P18-02 is approx. 155 m.
		Dolomitic Keuper Member		3086	
		Red Keuper Claystone Member		3111	
		Upper Muschelkalk Member		3123	
		Middle Muschelkalk Marl Member		3145	
		Muschelkalk Evaporite Member		3158	
		Lower Muschelkalk Member		3165	
		Röt Claystone Member		3208	
		Solling Claystone Member		3228	
		Rot Sandstone / Basal Solling Sandstone		3226	Sandstone
Lower Triassic	Lower Germanic Triassic	Main Buntsandstein “Bunter”	Hardegsen Formation	3239	Dominated by reservoir-quality **sandstones, depleted gas accumulation**
			Detfurth Claystone Member	3308	
			Lower Detfurth Sandstone Member	3338	
			Volpriehausen Clay-Siltstone Member	3349	
			Lower Volpriehausen Sandstone Member	3404	
		Rogenstein Member		3454	
		Main Claystone Member		3547	
Permian	Zechstein	Zechstein Upper Claystone Formation		3595	
		Z1 Fringe Sandstone Member		3605	
		Z1 Middle Claystone Member		3618	
	Rotliegend	Slochteren Formation		3622	
	Caboniferous	Ruurlo Formation		3645	

5.2. Appendix B: Static wellhead and reservoir pressures for CO2 injection well



Source Flow assurance study presentation January 31th 2019, Stefan Belfroid, TNO

5.3. Appendix C: Example CO_2 injection completion P18-4A2 well

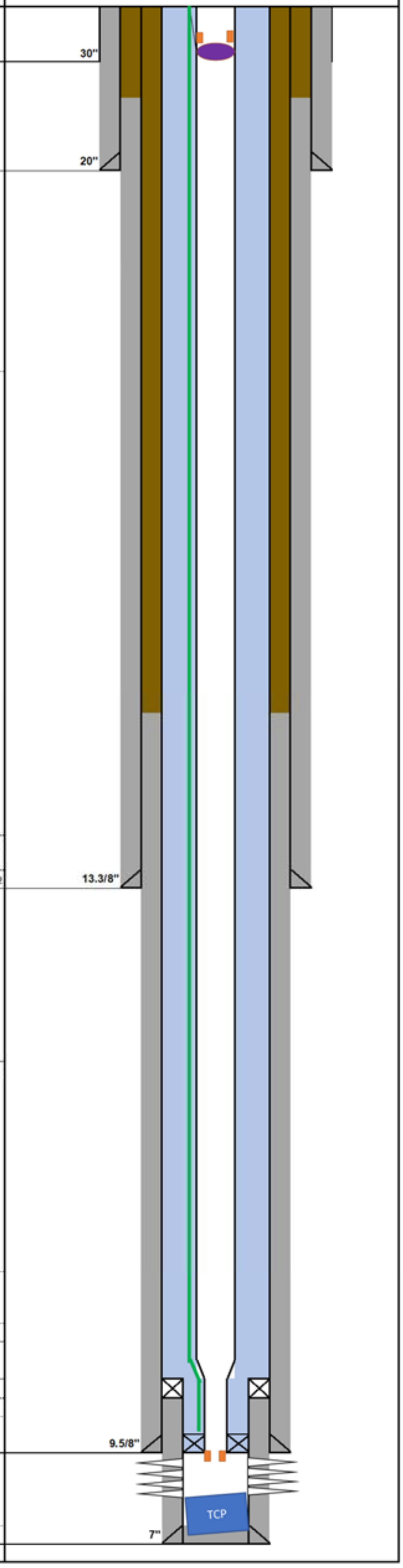
TAQA ENERGY BV

well name:	P18-4A2
well type:	Gas / CO2 storage
revision:	draft
based on trajectory:	original trajectory

Penrod 81		
RKB - MSL	**33,53**	[m]
RKB - seabed	**57,72**	[m]

Hole Size / Dev	Shoe Depth mTVD MSL	Shoe Depth m MD RKB	CASING	LITHOLOGY (not to scale)	Formations		Depth mTVD MSL	Depth mAHD RKB
	81	115	SCTRSSSV		**North Sea**			
Driven	84	**118**	**30", 310#, X52, RL-4**					
incl 0.7° @118m	141	175	13 3/8" TOC (calculated)					
	255	**289**	13 3/8" TOC (calculated)					
	368	**402**	**20", 133#, N80, Big Omega**			**North Sea**		
26" incl 5° @402m								
					Ommelanden Chalk		926	1 018
	1 623	2 000	9 5/8" TOC (calculated)					
					Texel Chalk / Greensand	**Cretaceous**	1 842	2 326
17 1/2"	1 957	**2 497**	13-3/8", 68/72#, N80, BTC		**Upper/Lower Holland marl**		1894	2402
incl 49° @2497m								
					Vlieland Claystone		2 273	2 969
			5 1/2", L80Cr13, tubing					
					Sandstones?			
					Werkendam		2 763	3 592
					Posidonia	**Jurassic**	2 917	3 777
					Aalburg		2 932	3 796
	3 007	3 886	X-over to 4 1/2", L80Cr13 tubing					
	3 038	3 924	7" TOL & TOC		**Sleen**		3 038	3 923
					Keuper		3 052	3 940
	3 108	4 008	Packer		**Muschelkalk**		3 064	3 955
	3 144	**4 052**	**9 5/8", 53.5#, N80 vam**		**Rot/Solling**		3 151	4 060
12 1/4"	3 170	4 083	Top perfs (4083)		**Main Bundsantstein**	**Triassic**	3 175	4 089
incl 34°	3 268	4 197	Bottom perfs (4197)					
@4050m	3 270	4 200	Wireline HUD 2006 / Top of fish 4199m calc					
	3 407	**4 352**	**7", 32#, P110, VAM**		**Rogenstein**		3 368	4 309
8 1/2"	3 407	4 352	TD					

Concept CO2 completion
(not to scale)

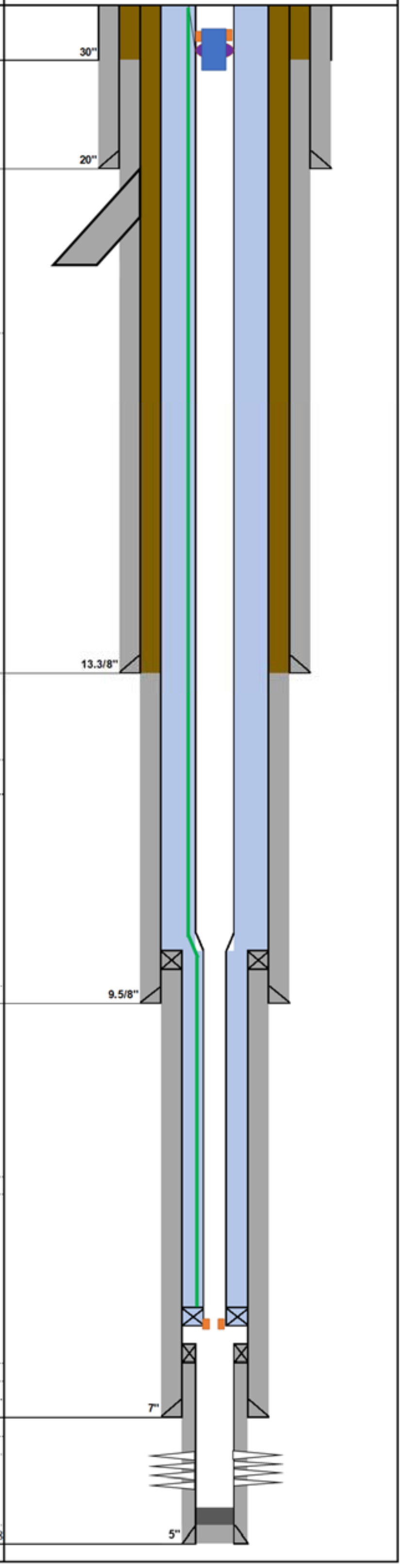


5.4. Appendix D: Example CO_2 injection completion P18-2A3 well

TAQA ENERGY BV		Global Marine adriatic III		
well name:	P18-2A3z	RKB - MSL	**47,72**	[m]
well type:	Gas / CO2 storage	RKB - seabed	**71,72**	[m]
revision:	draft			
based on trajectory:	original trajectory			

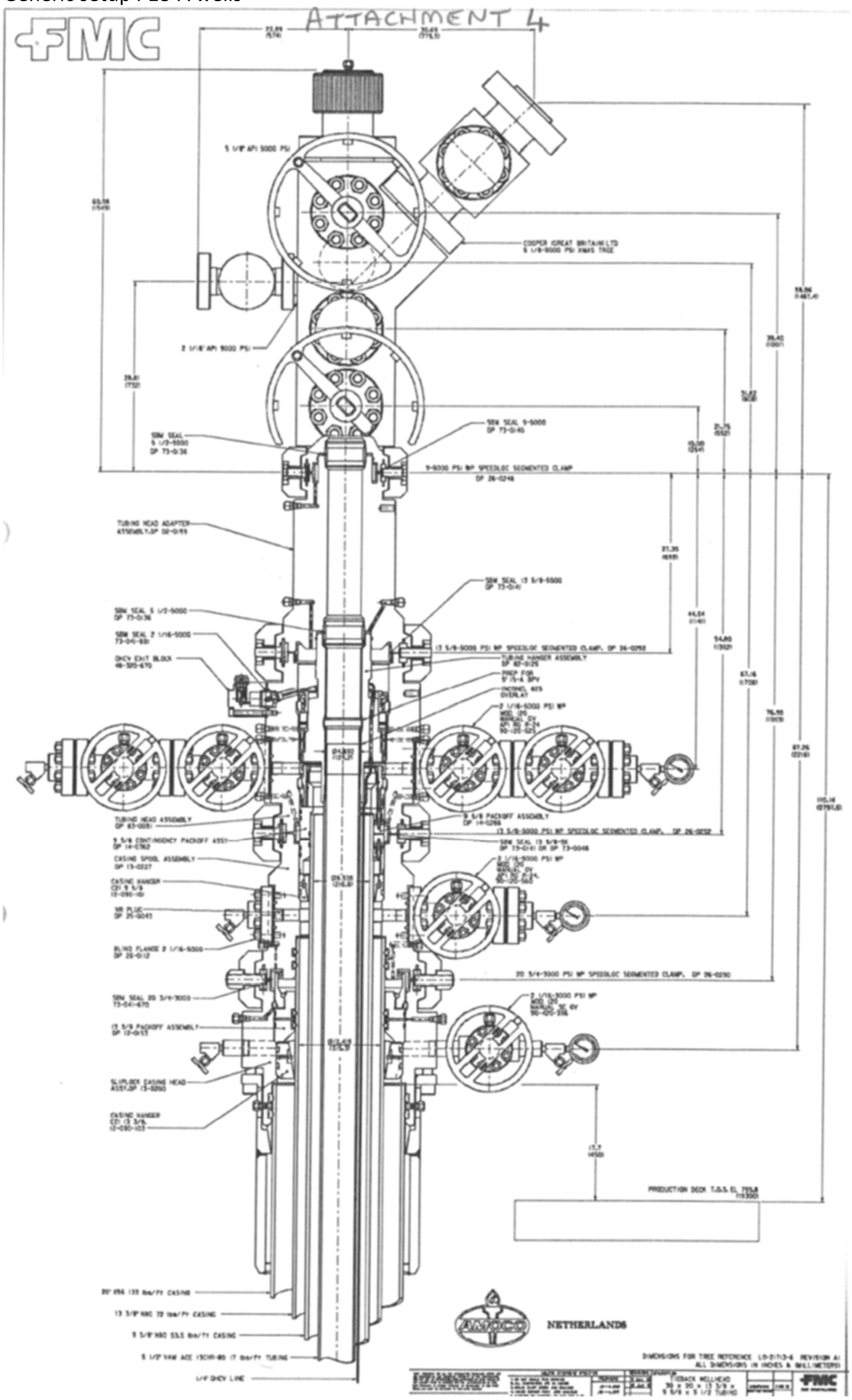
Hole Size / Dev	Shoe Depth mTVD MSL	Shoe Depth m MD RKB	CASING	LITHOLOGY (not to scale)	Formations		Depth mTVD MSL	Depth mAHD RKB
					North Sea			
	82	130	TRSCSSSV					
Driven	**84**	**132**	**30", 310#, X52**					
incl 0.5° @132m	103	151	13 3/8" TOC (calculated)					
	360	**408**	**20", 94 / 133#, X56 / K55 / N80, Big Omega**			**North Sea**		
26"	378	426	Sidetrack 16" hole					
incl 2.3° @408m								
					Ommelanden Chalk			985
			5 1/2", L80Cr13, tubing					
	1 560	1 806	9 5/8" TOC (calculated)					
	1 560	**1 806**	**13-3/8", 72#, N80, BOSS**					
17 1/2"								
incl 41° @1806m								
					Texel Chalk / Greensand	**Cretaceous**		2 135
					Upper/Lower Holland marl			2 238
	2 130	2 632	X-over to 4 1/2", L80Cr13, ubing					
	2 198	**2 672**	**7" TOL / TOC at 3475 m CBL**					
	2 285	**2 792**	**9 5/8", 53.5#, HC95/L80, New VAM**		**Vlieland Claystone**			2 759
12 1/4"								
incl 44° @2792m								
					Sandstones?			
					Werkendam			3 304
					Aalburg	**Jurassic**		3 375
	3 033	3 714	Packer					
	3 100	**3 785**	**5" TOL / TOC**					
					Sleen			3 853
					Keuper			3 905
	3 211	**3 911**	**7", 32#, P110, New VAM**		**Muschelkalk**			3 946
8 1/2"								
incl 38° @3211m					**Rot/Solling**			4 023
		4 070	Top perfs		**Main Bundsantstein**	**Triassic**		4 070
		4 209	Bottom perfs					
		4 215	HUD, wireline 2014, sample contained salt					
		4 301	**5", 18#, P110, HFJP**		**Rogenstein**			4278
6"		4 302	TD					

Concept CO2 completion
(not to scale)



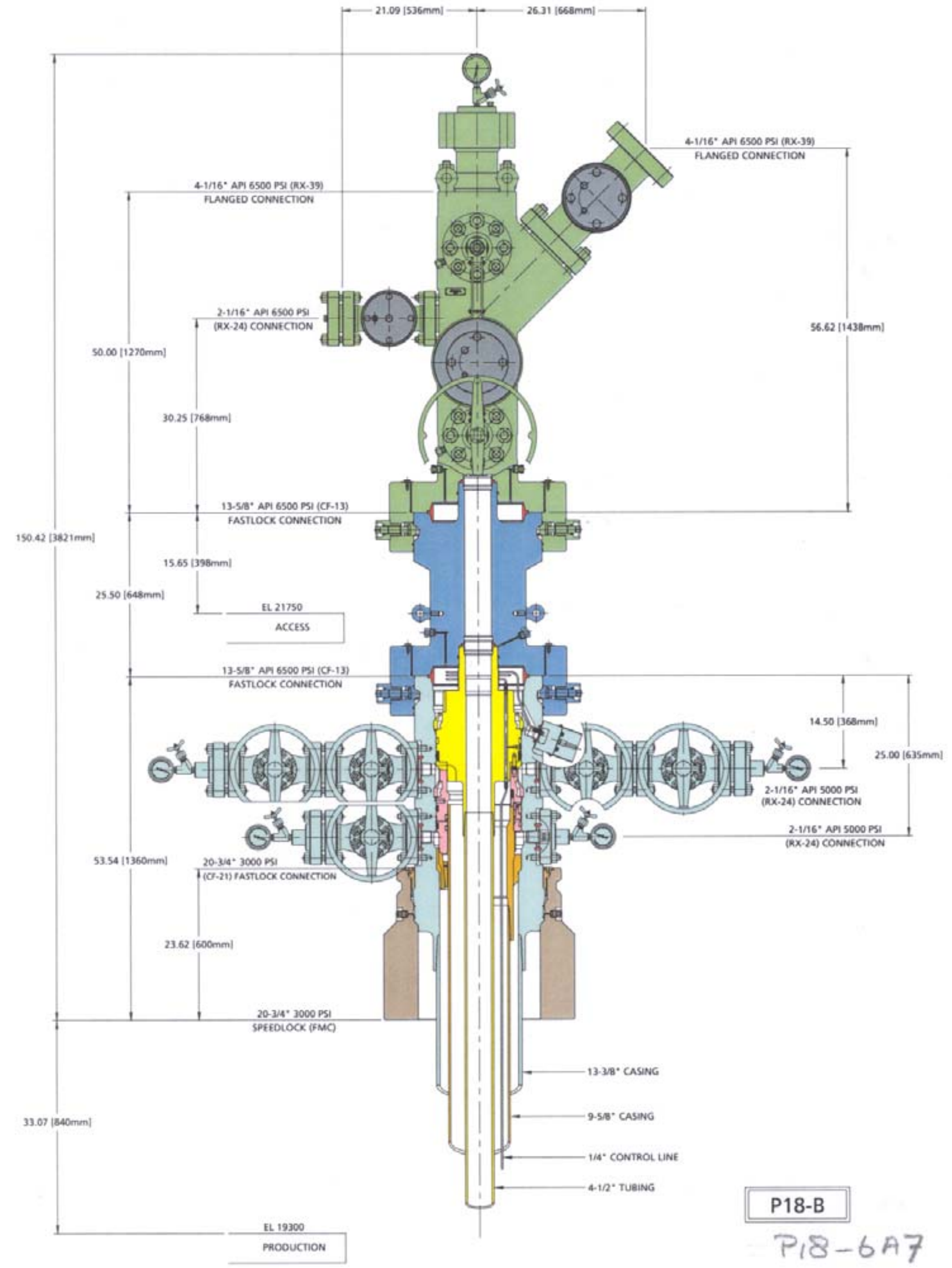
5.5. Appendix E: Wellhead and Tree

Generic setup P18-A wells



Part	Connection	Rating (psi)
Cameron 5 1/8” 5000psi Production tree with manual swab upper and lower master valves and hydraulically actuated wing valve	9” FMC Speedloc	5000
FMC Spacer Spool	13 5/8 FMC Speedloc x 9” FMC Speedloc	5000
FMC 13 5/8” x 13 5/8” Tubing Head Spool	13 5/8” FMC Speedloc x 13 5/8” FMC Speedloc	5000
FMC 20 ¾” x 13 5/8” Intermediate Casing Head Housing	20 ¾” FMC Speedloc x 13 5/8” FMC Speedloc	5000
FMC Sliploc type casing head	20 ¾” FMC Speedloc	3000

P18-6A7 wellhead and tree



BP - NETHERLANDS

CUSTOMER ASSEMBLY DETAILS: 13-5/8" 5000 PSI SSMC 2 STAGE COMPACT HOUSING. 13-5/8" 6500 PSI SPACER SPOOL. 4-1/8" 6500 PSI XMAS TREE. 30" CONDUCTOR x 20" x 13-3/8" x 9-5/8" CASING x 4-1/2" TUBING. ONE CONTROL LINE

SK-118853-01

Part	**Connection**	**Rating (psi)**
Cameron 4 1/16” 6500psi production tree with manual swab upper and lower master valves and hydraulically actuated wing valve	13 5/8” Cameron Fastlock	6500
Cameron Spacer Spool	13 5/8” Fastlock x 13 5/8” Fastlock	6500
Cameron 13 5/8” x 13 5/8” SSMC dual stage wellhead	13 5/8” Cameron Fastlock x 20 3/4” Cameron Fastlock	5000
X-over from Cameron to FMC	20 ¾” FMC Speedloc x 20 3/4” FMC Speedloc	3000
FMC Sliploc type casing head	20 ¾” FMC Speedloc	3000