CATO-2 Deliverable WP3.4-D01

Progress report: Qualitative well integrity assessment of the P18 gas field (TAQA)

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1 Executive Summary (restricted)

CO_2 storage is being considered in TAQA's P18 gas field. In the context of the CATO-2 project the suitability of the existing wells in the field is being investigated for injection and long-term storage of CO_2. The well integrity assessment covers the operational phase of the injection project (decades) and the long-term post-abandonment phase. The study aims at the evaluation of the relevant well system barriers to identify potential showstoppers and recommendations on remedial actions and abandonment strategies. This report presents progress until September 2010, but does not describe the final conclusions of the well integrity assessment of the P18 field.

The P18 field comprises 3 reservoir blocks, penetrated by a total of 7 wells, some of which have been sidetracked. One of these sidetracks also penetrates the caprock and the reservoir.

One of the wells, P18-2, is plugged with several cement plugs. At this time the actual status of this well, i.e. abandoned or suspended, is not confirmed. The current layout of plugs in P18-2 is inadequate for long-term containment of CO_2, as it provides likely migration pathways from the reservoir to shallower levels, bypassing the caprock. In case the well proves to be permanently abandoned and remediation is not techno-economical feasible, this will be a showstopper for CO_2 storage in the largest P18-2 reservoir block.

There is uncertainty with respect to the sidetracked P18-2A6 well. From the limited available data on the sidetracking operation it is uncertain how the parent hole was abandoned and if this is satisfactory for CO_2 storage. This needs to be verified before final judgement can be passed on the suitability of the well for CO_2 storage.

All other wells are still accessible and therefore can be remediated. Most of these show questionable cement sheath quality at caprock level from CBL data (i.e. P18-2A1, P18-2A3, P18-2A6, P18-6A7) or lacked data to verify this (i.e. P18-2A6st, P18-4A2, P18-6A7). Inadequate primary cement imposes a risk to long-term integrity, but could also affect the operational phase. However, these wells can be accessed and, in order to prepare the accessible wells for CO_2 storage, it is recommended to re-evaluate and, if required, remediate the cement sheath quality at least over caprock level.

When considering wells that will be used for CO_2 injection it is recommended to check the packer operating envelope against CO_2 injection scenarios. Potential elastomers and wellhead configuration should also be verified and adapted where required. Moreover, it is suggested to adjust completion materials (tubing, tubing hanger and packer) to corrosive circumstances, where applicable. All operational wells will need abandonment in the future, either prior to or after the injection phase. For these wells abandonment can be designed specifically for CO_2 storage. At present, there are two general options to permanently seal a wellbore for CO_2 containment. If the quality of the primary cement sheath is ensured over critical intervals, traditional abandonment plugs can be positioned and tested at caprock level. Alternatively, and especially in the case of questionable cement sheaths, pancake plugs can be used at caprock level. This would involve milling out of the casing, annular cement and part of the formation, followed by placement of cement in the cavity. This operation may pose difficulty particularly in horizontal or strongly deviated wells. Both of these options should be accompanied by additional plugs higher up the well, according to common practice and as prescribed by governing abandonment regulations.

At present, the evaluation is ongoing and requires additional data on some of the wells to be able to draw final conclusions on the suitability of the P18 wells for CO_2 storage.

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Table of Content

2 Applicable/reference documents and abbreviations

2.1 Applicable documents

	Title	Doc nr	Version date
AD-01	Beschikking (Subsidieverlening CATO-2 programma verplichtingnummer 1-6843	ET/ED/9078040	2009.07.09
AD-02	Consortium Agreement	CATO-2-CA	2009.09.07
AD-03	Program Plan	CATO2-WP0.A-D.03	2009.09.29

2.2 Reference documents

	Title	Doc nr	Version/issue	Date

2.3 Abbreviations

CBL	Cement bond long
USI	Ultrasonic imaging log
A-annulus	Annular space between the innermost tubular in the well, typically the production tubing, and the production casing
B-annulus	Annular space between the production casing and the intermediate casing.
EOWR	End of well report
CBL-VDL	Cement bond log – Variable density log
CBL-CET	Cement bond log – cement evaluation tool
USIT-CBL	Ultra sonic imaging tool – cement bond log
SC-SSSV	Surface controlled sub surface safety valve
NLOG	Netherlands Oil & Gas portal (www.nlog.nl)
i.d.	Inner diameter
o.d.	Outer diameter
TOC	Top of cement
TOL	Top of liner

3 Introduction

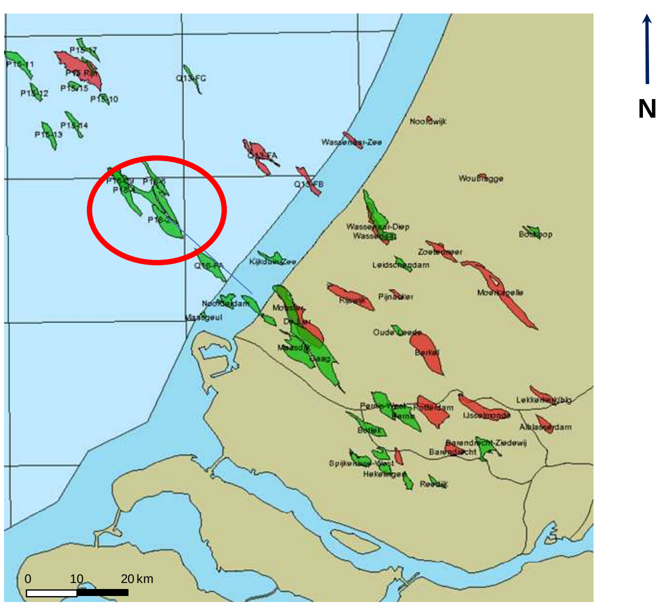
Potential migration from the reservoir along wells is generally considered as the major hazard associated with CO_2 storage (e.g. Gasda et al., 2004; Pruess, 2005, Carey et al., 2007). With respect to the evaluation of long-term integrity of the geological storage system, the quality of wells penetrating the storage reservoir therefore must be taken into account.

The well system forms a potential conduit for CO_2 migration because wellbore cement may be susceptible to chemical degradation under influence of aqueous CO_2 or to mechanical damage due to operational activities. Wet or dissolved CO_2 forms a corrosive fluid that could induce chemical degradation of the oil well cement (e.g. Bruckdorfer, 1986; Scherer et al., 2005; Barlet-Gouédard et al., 2006), potentially enhancing porosity and permeability. It could also stimulate corrosion of steel, which may lead to pathways through the casing steel (Cailly et al., 2005). Furthermore, operational activities (e.g. drilling, pressure and temperature cycles) or natural stresses can result in mechanical degradation through the development of tensile cracks or shear strain, enabling highly permeable pathways to develop (Shen and Pye, 1989; Ravi et al, 2002). Finally, poor cement placement jobs or cement shrinkage could cause the loss of bonding between different materials (debonding) and lead to annular pathways along the interfaces between cement and casing or host rock (Barclay et al., 2002).

CO_2 storage is being considered in TAQA's P18 gas field. In the context of the CATO-2 project we investigate the feasibility of injecting and storing CO_2 in the field with respect to the existing wells. The well integrity assessment aims to determine whether the existing wells are fit for CO_2 injection and long-term containment as currently planned, covering the operational phase of the injection project (decades) and the long-term post-abandonment phase. The study comprises the identification of potential showstoppers and recommendations on remedial actions and abandonment strategies.

3.1 History of the P18 field

Figure 1: Location of P18 fields



The Buntsandstein reservoir is primarily capped by the Solling and Röt Claystone Members (RNSOC and RNROC, respectively). These are overlain by a secondary caprock, the Muschelkalk and Keuper formations (RNMU and RNKP, respectively).

The P18 reservoirs are drained by seven wells. They are listed in Table 1.

Table 1: Reservoirs and wells in the P18 field

	Reservoir	*Well*	*NLOG-name*	*Drilled*	*Comments*	*Status*
1	**P18-2**	P18-2	P18-02	1989		Abandoned
2		P18-2A1	P18-A-01	1990	Previously P18-03	Producing
3		P18-2A3	P18-A-03	1993	Sidetracks –S1, –S2	Producing
4		P18-2A5	P18-A-05	1997		Producing
5		P18-2A6	P18-A-06	1997	Sidetrack –S1	Producing
6	**P18-4**	P18-4A2	P18-A-02	1991		Producing
7	**P18-6**	P18-6A7	P18-A-07	2003	Sidetrack –S1	Producing

3.2 Data availability

Table 2 shows the well data that TAQA provided to the study. This data forms the basis of the evaluation presented in this report.

Table 2: Data available for the P-18 wells

Wells/boreholes	P18-2A1	P18-2A3z	P18-2A5 (S1)	P18-2A6z	P18-6A7	P18-4A2	P18-2
Well status	Producing	Producing	Producing	Producing	Producing	Producing	Abandoned
Spud date	11-1993	14-5-1993	18-11-1993	17-11-1996	7-2003	4-6-1991	11-3-1989
Abandonment date							28-5-1989
Final Well Report	N/A	x	x	x	N/A	x	x
Well/completion diagrams	x	x	x	x	x	x	x
Casing and cementing reports		x		x		x	x
Drilling reports	x	x	x	x		x	x
Well tests	N/A	x	x	x			N/A
Cementing and corrosion logs (mentioned in EOWR)	CBL (7" L)	CBL-VDL (5" L)	USIT-CBL (5"L), CBL-CET (7"L)[1]	USIT-CBL (7" L)[2]	N/A	N/A	CBL (7", 9 5/8")
Openhole logs over reservoir section only	x		x	x	x	x	x
Stratigraphy along the well	x	x	x	x	N/A	x	x
Annulus pressure reports	N/A	N/A	N/A	N/A	N/A	N/A	
Production data	Dec 1993 - March 2010	Dec 1993 - March 2010	Dec 1993 - March 2010	June 1997 - April 2003	Dec 1993 - March 2010	Dec 1993 - March 2010	

[1] Cement bond log mentioned in EOWR, but data not physically available
[2] Cement bond log available for pilot hole (P18-2A6) only

We make the following assumptions in our analysis of well integrity (see Table 3).

Table 3Assumptions of feasibility study

Only existing producing well will be converted	TAQA can convert any of the six producing wells (see Table 1) into CO_2 injection wells. This is because we have no information on which wells—or number of wells—TAQA prefers to convert to injection. Our assumption implies that TAQA will not re-enter the abandoned well.
Initial reservoir pressure	The maximum reservoir pressure during the injection project will be the original reservoir pressure (ca. 350bar)
Cold injection	The temperature of the injected CO_2 will be much lower than ambient temperature in the well (the undisturbed geothermal gradient) i.e. injected CO_2 will not be pre-heated before injection. Therefore, injection will introduce additional thermal-induced stresses to the well tubulars.
Only existing wells	We investigate only the existing wells. We do not assess the (potential) integrity of any additional wells that may be drilled in the field.
Dry CO_2 injection	We assume that TAQA will inject dry CO_2.

3.3 Methodology

Our objective is to understand whether the wells in the P18 field are fit for CO_2 injection and long-term containment of the injected CO_2 as currently envisaged in the CATO-2 project. We assess the integrity of the wells in the operational and post-operational period using the methodology discussed in Table 4

Table 4: Methodology used in assessing the feasibility of injection using P18 wells

Identify well barriers	We identify the well barriers that keep the well fluids inside the wellbore and prevent uncontrolled discharge to the overburden—above the caprock—and to the atmosphere. These typically include the cement section outside the production casing adjacent to the caprock and the production casing itself.
Assess the evidence for failure	Delving into the well history, we assess whether there is evidence suggesting failure of the identified barriers.
Direct evidence	These include direct measurements of the quality of the barrier that show that the barrier was not installed properly (such as cement bond logs, pressure tests) or that the barrier may have been breached during the productive life of the well (annular pressure information).
Indirect evidence	When direct evidence of failure is unavailable, we look for indirect evidence that the barrier might be compromised. Such evidence includes drilling information on kicks, cement losses.
Define robustness criteria	In order to be fit-for-CO_2 storage, some barriers may need to be upgraded. For example, wetted areas of pipes. Where applicable, we state what barriers need to be ‘upgraded’ for CO_2 service by defining robustness criteria.
Gaps	If there is no data to guide our analysis of the condition of the barrier, we state clearly what the data gaps are and why closing the data gap will help reduce uncertainty in the analysis.

3.4 Report structure

This report is organised as follows:

1	**Executive summary**	Summary of the work performed, including main recommendations
2	**Introduction**	Background, the scope and the methodology of the study
3	**Definition of well barriers**	We define the well integrity barriers and the criteria that we use to assess the quality of the barriers.
4	**Assessment of well status**	We assess the well integrity barriers of the seven wells, based on the criteria defined in the previous section; we identify data gaps, where possible.
5	**Showstoppers – operations**	We summarise and rank any showstoppers identified for all the seven wells
6	**Abandonment strategy**	We develop preliminary designs for abandonment and make recommendations on the abandonment phase of the project.
7	**Conclusion**	We summarise the results and draw conclusions
8	**Recommendations**	We make recommendations on how to address the showstoppers and/or to remediate the integrity of the wells.

4 Definition of well integrity barriers

Consider a generic P18 well, based on the information provided by TAQA, as shown in Figure 2

Figure 2: Generic P18 well showing the well barriers

1. Primary cement across primary caprock
2. Production liner
3. Production casing
4. Wellhead
5. Production tubing (with completion elements like SC-SSSV)
6. Primary cement outside production casing
7. Production liner hanger
8. Production packer

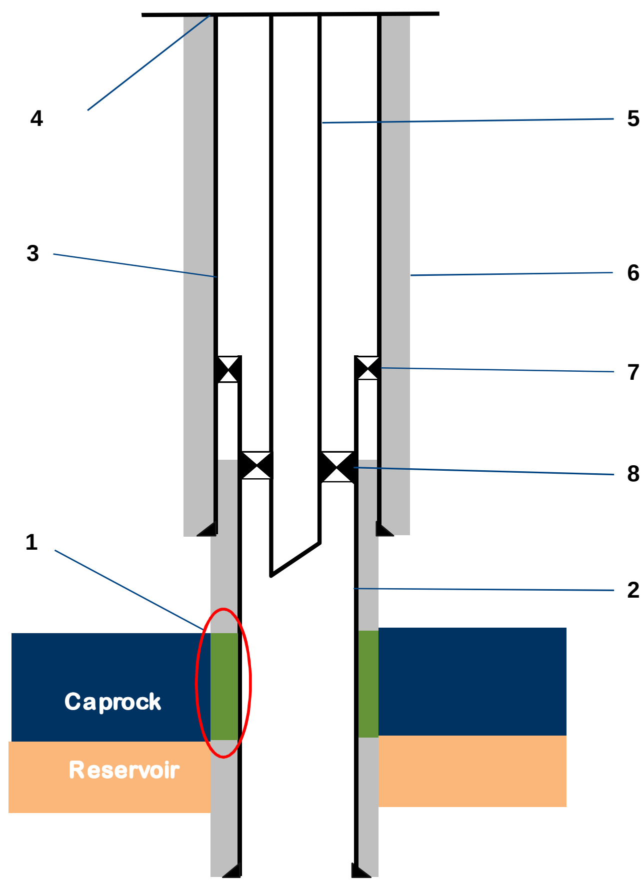


Figure not to scale

In the following sections, we define the failure and robustness criteria applied to the identified barriers in the field. We divide our robustness criteria into two types: mandatory criteria and recommended, "nice-to-have" criteria.

Well depths in this report are stated as in measured depth along hole (MDAH).

4.1 Primary cement across the caprock

The most obvious evidence that the cement across the primary caprock failed during production life is the confirmed presence of reservoir gas in the B-annulus after the production liner and wellhead are tested OK. We assess the robustness of the primary cement across the caprock using the criteria summarised in Table 5.

Table 5: Robustness criteria used in assessing quality of primary cement across caprock

		Mandatory	Recommended ("nice-to-have")
Direct evidence	Good (preferably recent) quality cement azimuthal log showing good cement quality across the caprock	×	
Indirect evidence	No serious defects such as microannuli and cracks are created in the cement due to injection of cold CO_2.	×	
	No large caving/hole washouts in the openhole across caprock		×
	No significant fluid/cement loss during placement		×
	Chemical resistance of the cement to CO_2 attack		×
	No 'high-pressure' well operation that could have compromised the cement across caprock		×
	Good centralisation i.e. if the pipe was well-centralised, then *all factors being equal,* we expect a better quality cement operations		×

Note. The cement bond log does not measure the absolute hydraulic isolation of the cement; it only gives an indication of the quality of the bond from which we infer hydraulic isolation. The industry rule of thumb is that hydraulic isolation is achieved if there is 3m of 'good' cement, which, in turn, is defined by a CBL reading of 1-2mV.

4.2 Production liner

A pressure test during setting of the liner could tell whether or not the liner itself failed. Failure below the liner hanger is not necessarily a showstopper because of the other barriers above the leak. In addition, we look out for failure due to plastic salts in the overburden during the production life of the well.

The recommended robustness criterion for the liner during CO_2 service is that the wetted area of the liner be made of corrosion-resistant alloy. However, this criterion can be relaxed if the amount of free water in the injected CO_2 stream is expected to be very low.

4.3 Production casing

Like the production liner, the production casing is usually tested when it is set. We investigate whether the casing failed this test. In addition, we investigate the impact (if applicable) of plastic salt layers that may impinge upon the intermediate casing. Direct evidence for failure of the production casing during producing life could include annular pressure communication between the A and B annuli, noise logging and pressure testing of the production casing.

4.4 Wellhead

The main barrier between the well and the atmosphere, the wellhead is tested during installation and periodically during operation. We investigate whether the wellhead passed these tests. In addition, we investigate the materials used to construct the metallic and non-metallic components of the wellhead to ensure that they are fit for CO_2 service.

4.5 Production tubing

The evidence for failure of the production tubing is almost always direct evidence. This includes (but is not necessarily limited to):

- failure of the tubing to hold pressure during initial installation;
- pressure communication between the A-annulus and the tubing;
- reservoir gas-cap on top the A-annulus; and
- depletion of annulus fluid

The production tubing provides the main wetted surface during CO_2 injection. Due to the corrosive nature of CO_2 (in the presence of free water), the main robustness criteria for the tubing are:

- the wetted areas (the i.d.) be made of CO_2-resistant material;
- tubing i.d. be sufficient to prevent erosion and high pressure losses; and
- the tubing be designed to withstand the thermal stresses (due to contraction) that injecting cold fluid will impose on the pipe.

4.6 Primary cement outside production casing

The evidence of failure of this cement sheath is more or less the same as that of the primary cement sheath across the caprock, as described in section 4.1.

4.7 Production liner hanger

The production liner hanger is an additional barrier between the reservoir and the production casing. Evidence of failure of the liner hanger could include the presence of reservoir fluids in the A-annulus and/or failure of hanger test during installation.

4.8 Production packer

The production packer isolates the corrosive reservoir fluids from the production casing, and ‘forces’ the fluids to enter the tubing. In addition, the packer may bear some of the tubing loads (depending on how the completion is set. Like the production tubing, evidence for failure of the packer is almost always directly observed. It includes:

- Failure of pressure test during initial installation;
- Loss of annulus fluid levels;
- Presence of reservoir fluids inside the production casing during production life; and
- Pressure communication between the production tubing and the production casing.

We do not have enough information to distinguish tubing failure from packer failure; therefore, for the remainder of this report, the tubing and production packer will be grouped as one barrier: tubing and completion barrier.

5 Assessment of the integrity of the wells

In this section of the report, we apply the failure modes and robustness criteria to the seven wells in order to form a picture of their suitability for injection. Where there is no information on a well integrity barrier, we do not mention the barrier.

5.1 Well P18-2A1 (P18-A-01)

This well was spudded in 1993 and has produced gas ever since. Available drilling and completion information suggests that no problems occurred during the drilling or completion phase of the well. Refer to the schematic of the well in Figure 3.

5.1.1 Cement barrier across primary caprock

The 222m thick Middle Bunter Sandstone (RBM) reservoir is topped by the primary caprock (25m thick), the Solling (RNSOC) and the Röt Claystone (RNROC) members. A cement bond log was run across the 7" liner, covering the reservoir, the primary caprock and the lower part (21m) of the secondary caprock, with top of cement (TOC) found at 3,477m. The CBL-VDL log shows poor casing-cement bond in the liner lap above the perforations, including the primary caprock section, and mainly good bonding below the perforations.

5.1.2 Cement barrier across secondary caprock

The Muschelkalk (RNMU) and Keuper (RNKP) formations (141m thick) are believed to act as the secondary caprock. As mentioned above, a cement bond log was run across the lower part of the secondary caprock, showing poor bonding. Across the 9⅝" casing string, which traverses most of the secondary caprock, no cement bond logs were run. However, there is indirect evidence suggesting that the casing bond:

- no problems such as loss of cement or mud were encountered during drilling or cementing; and
- the well is vertical and the production casing was centralised with at least six centralisers suggesting good centralisation.

There is no information about the condition of the hole, e.g. washouts, or sort of centralisers used.

5.1.3 Production liner and casing

Both the 7" and 9⅝" liner/casing strings were pressure tested OK to 5,000 psi for 20 min. The 7" liner consists of 29 lb/ft N-80 casing and the 9⅝" casing is 53.5 lb/ft HC-95 material. According to reports, neither of the two strings is made of Cr13. There is no data on annulus pressures; therefore, we have no information on possible communication between the completion and casing.

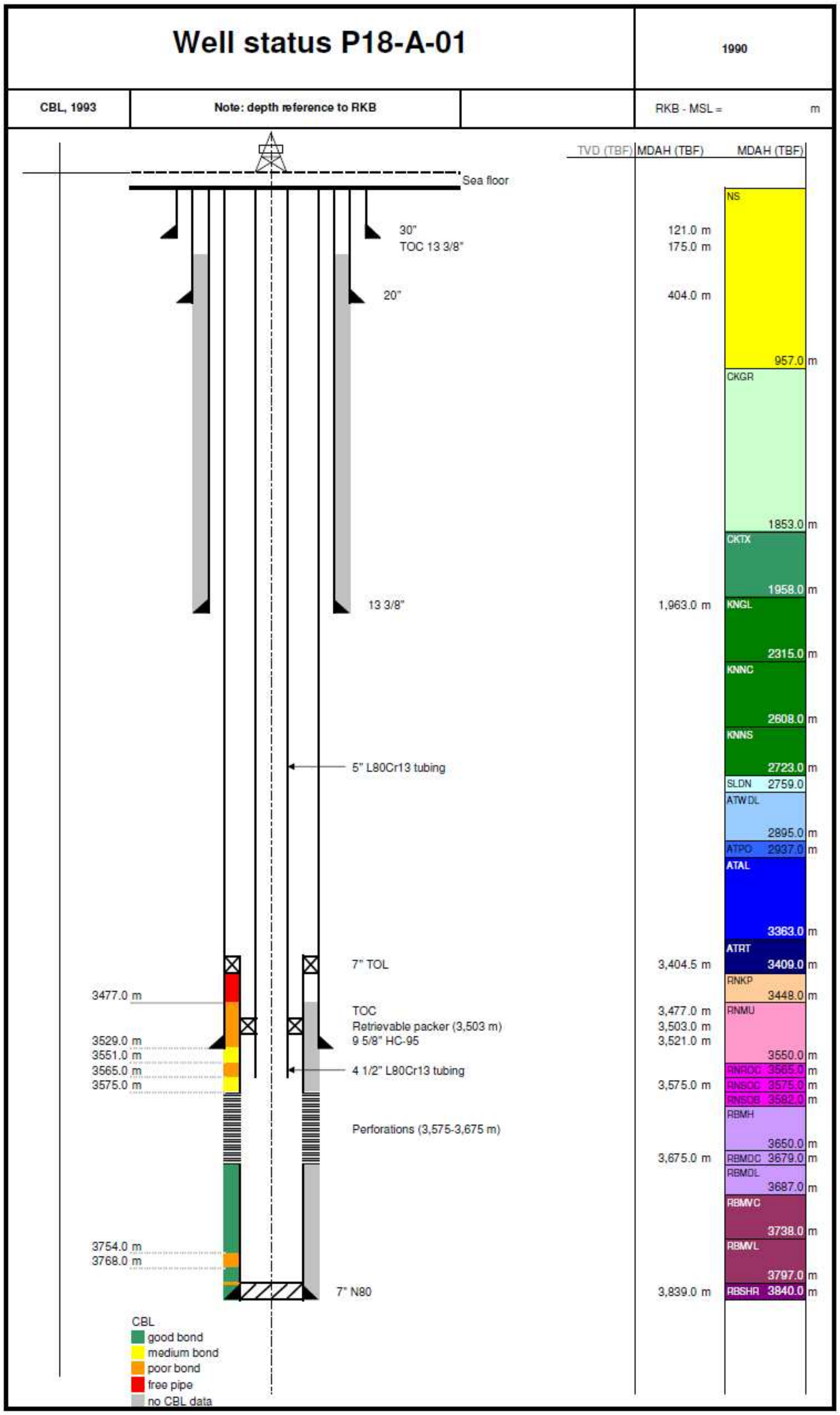
5.1.4 Production tubing and completion

The completion is 4½"/5" L80 Cr13 tubing. Since it is made of Cr13, it is fit for CO_2 injection. However, a retrievable packer is used. This packer could become unseated during CO_2 injection depending on the packer operating envelope[3].

We have no information on the wellhead and type of elastomers (if any). Therefore, we cannot assess whether the wetted areas of the wellhead or any elastomers are fit for CO_2 service.

[3] The packer operating envelope shows the tensile, compressional and burst loads that the packer is designed to handle. In essence, it shows the conditions under which the packer can operate. Operating the packer outside this envelope would result in failure of the packer – and loss of well integrity.

Figure 3: Well sketch of well P18-2A1 with adjacent reservoir and caprock stratigraphy



Note: figure not drawn to scale

5.1.5 Conclusion

Information from available cement bond logs suggest poor casing-cement bond across the upper part of 7” liner. This implies inadequate hydraulic isolation over the reservoir and the primary caprock and parts of the secondary caprock. No information is available for the 9⅝” casing cementation. However, successful casing tests, presence of casing centralisers and the absence of cementing and drilling problems provide favourable boundary conditions for a successful cementing job. We suggest that the cement sheath be re-evaluated before considering it for CO_2 injection by checking annulus pressures or running cement bond logs over the intervals in question. Although the casing strings themselves are not made of Cr13, the completion is and therefore would be fit for CO_2 injection. We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

5.2 Well P18-2A3z

Well P18-2A3 was spudded in May 1993 and sidetracked twice. The first sidetrack became necessary after the drill pipe got stuck at 590m MD. After backing off the string and setting a cement plug, the well was sidetracked at 426m. The second side-track occurred after a tight hole was experienced in the region around 3,496m in the Werkendam/Aalburg shales.

After washing out the hole, circulation losses occurred, a cement plug was set and a cement squeeze was performed at the 9⅝" casing shoe. The cement was drilled out and the hole sidetracked at 3,375m. While drilling the 8½" borehole, mud losses occurred. Refer to the schematic of the well in Figure 4 below.

5.2.1 Cement barrier across the primary caprock

The 210m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (45m thick), consisting of the Solling and Röt Claystone members (RNSOC and RNROC, respectively), separated by the Main Rot Evaporite Member (RNRO1).

A cement bond log was acquired across the 5" liner, covering the reservoir and both the primary and secondary caprocks. The log suggests poor casing-cement bond with CBL amplitudes around 70mV (good cement bond is usually about 1-2mV). The cementing report mentions that the liner had to be re-run due to loose casing centralizers. Moreover, a total of 240bbls of mud were lost during cementation and the cement plug at the end of the cement job did not bump. All of the above indicators support the poor cement bond seen on the cement bond log.

We notice an inconsistency in the top of liner and cement. According to information from TAQA, the top of the cement outside the 7" liner is at 2,65m whereas the top of the liner is at 2,

5.2.2 Cement barrier across the secondary caprock

The Muschelkalk (RNMU) and Keuper (RNKP) formations (118m thick) are believed to act as the secondary caprock (Figure 4).

No cement bond log was acquired across the 7" liner. The report mentions the loss of 66bbls of mud during the cement job, and also the cement plug bumped at the end. Since no information on casing centralization or borehole washouts is available, the quality of the casing cement bond cannot be inferred. However, a formation integrity test (FIT) was performed at the 7" liner shoe to about 15ppg (11.3ppg in the hole). This pressure increase could theoretically have compromised the integrity of the 7" liner cement sheath. Although, none of the caprocks or reservoir is located across this section, due to the poor casing-cement bond across the 5" liner, the 7" liner annulus could become a potential leak path for CO_2.

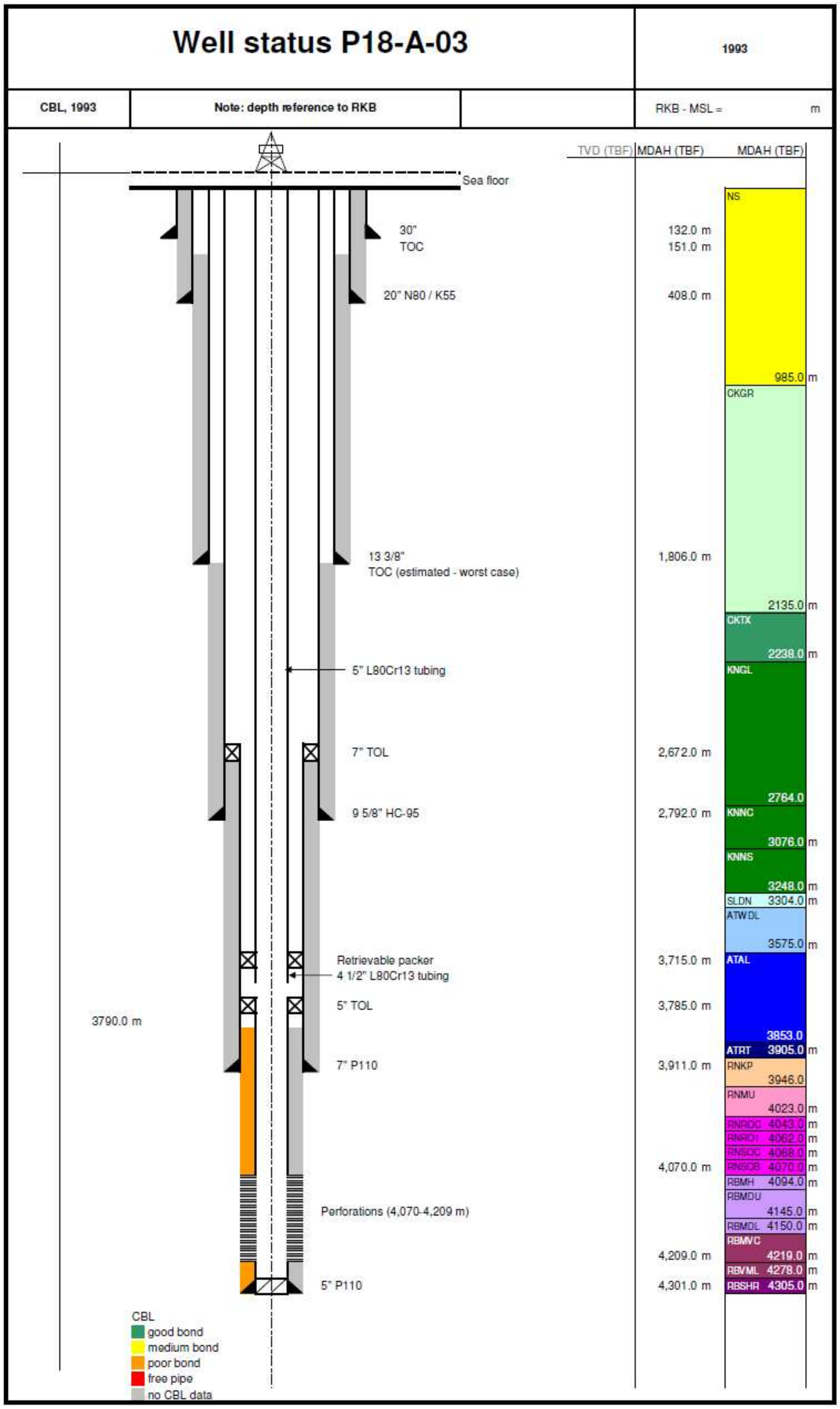
5.2.3 Production and intermediate liner

Both the 5" and 7" liner strings were pressure tested OK to 4,000 psi for 20 min. The 5" liner is 18lb/ft P110 and the 7" liner 32 lb/ft P110 casing. According to reports neither of the two strings is made of Cr13.

5.2.4 Tubing and completion barrier

The well has been in production since December 1993. The tubing is 4½"/ 5" L80Cr13, which is fit for CO_2 injection. Due to the use of a retrievable packer, it is suggested that its operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover be performed. Elastomers and wellhead information was not available but should also be checked.

Figure 4: Schematic of well P18-2A3z with adjacent reservoir and caprock stratigraphy



Note: figure not drawn to scale

5.2.5 Other criteria

The mother bore hole and the first sidetrack do not traverse the caprock or the reservoir and therefore should not act as additional leakage pathways for CO_2. No information is available about annulus pressures or the cement quality across intermediate aquifer zones.

5.2.6 Conclusion

The available cement bond log suggests poor casing-cement bond across the 5" liner, which covers both the reservoir and the two caprocks. Although not much information exists for the 7" liner cementing job, the FIT performed at the 7" liner shoe could have compromised the integrity of the cement sheath. As a result, we suggest that the cement sheath be re-evaluated before considering it for CO_2 injection by checking annulus pressures or running cement bond logs over the intervals in question. Although the casing strings themselves are not Cr13, the completion is and therefore would be fit for CO_2 injection.

We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

5.3 Well P18-2A5

Well P18-2A5 was spudded in November 1996. The well was sidetracked once because of wellbore instability problems across the Aalburg (ATAL) shales (4,058m). A cement plug was set from 3,830m to inside the 9⅝" casing and the 8½" sidetracked drilled below the 9⅝" casing shoe. After successfully sidetracking the well, a 7⅝" casing was run without success. The hole was cleaned and a 7" liner run and cemented in place. While drilling the 6" openhole section, mud losses occurred until the mud weight was lowered to 9.1ppg. The well schematic is shown in Figure 5 below.

5.3.1 Cement barrier across the primary and secondary caprocks

The 327m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (69m thick), consisting of the Solling Claystone (RNSOC), the Main Röt Evaporite (RNRO1) and Röt Claystone (RNROC) members. The overlying Muschelkalk (RNMU) and Keuper (RNKP) formations (174m thick) are believed to act as the secondary caprock (see Figure 5).

Conditions for cementing were good. Although mud losses occurred during drilling, no problems were mentioned during the cementing job. The casing string was centralized well by placing 1 centralizer on each joint and 3m of cement were drilled above the liner top. A cement bond log is available across the 5" liner; it covers the reservoir and the caprocks. The log confirms overall good bonding across the caprocks, represented by low CBL amplitude and good formation arrivals from the variable density log (VDL). Incidentally, short poor-quality zones can be distinguished. The calculated top of cement is at 4,398 m (approximately top of the 5" liner).

The end of well report suggests that also a cement bond log was acquired across the 7" liner suggesting good casing-cement bond and top of cement (TOC) 50 m below the 9⅝" casing shoe. However, the log was not available for analysis. No problems occurred during drilling and cementing operations and the casing was centralized using solid spiral centralizers, providing good cementing conditions and supporting the reported result of the cement bond evaluation.

5.3.2 Production liner

The 7" liner was pressure tested OK to 4,000psi for 15min; there. The 5" liner is 18 lb/ft N-80 and the 7" liner 29 lb/ft N-80 casing. According to reports, neither of the two strings is made of Cr13.

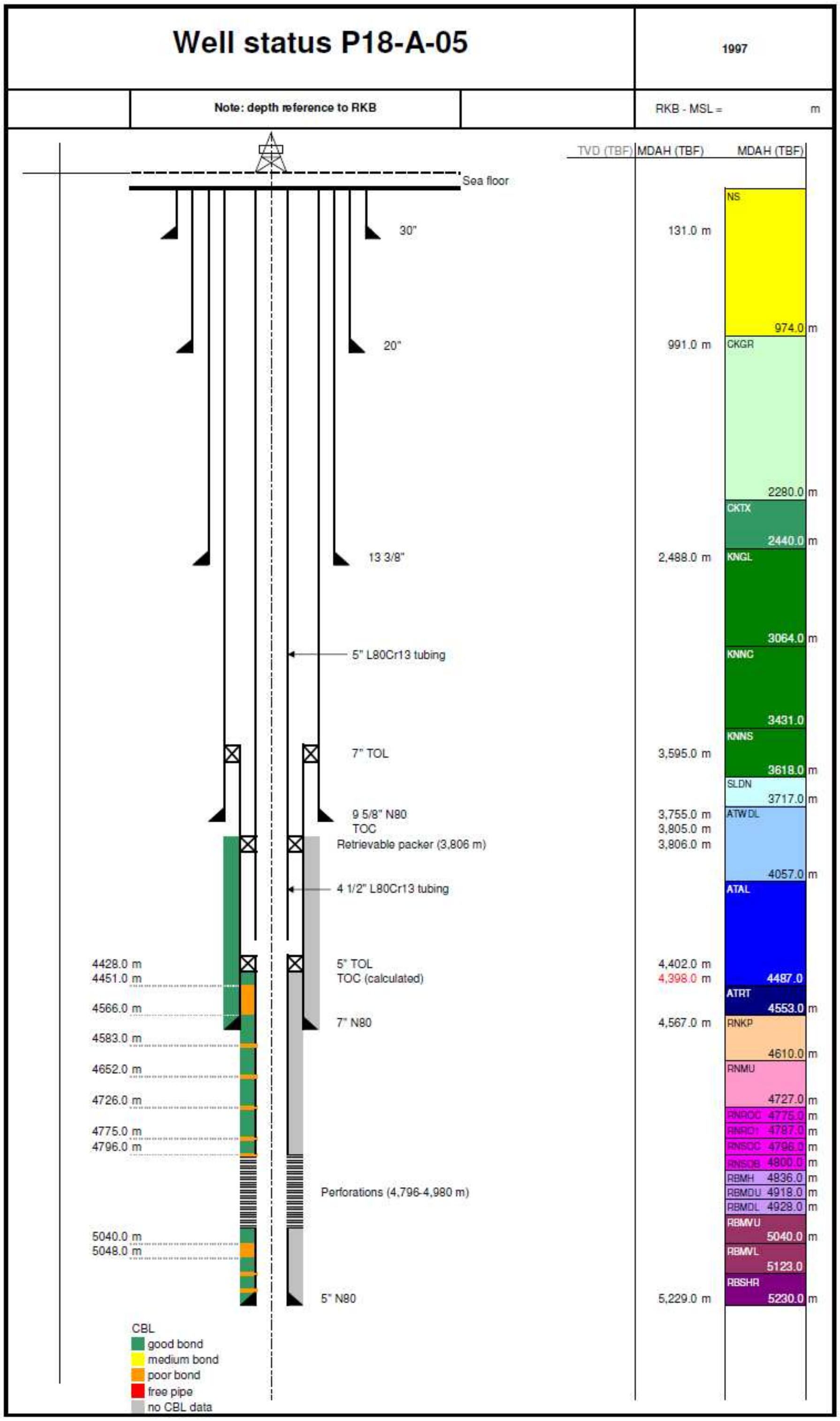
5.3.3 Tubing and completion

The well has been in production since Nov 1996. The tubing is 4½"/ 5½" L80Cr13 tubing, which is fit for CO_2 service. Due to the use of a retrievable packer, it is suggested that its operating envelope be checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Elastomers and wellhead information was not available but should also be checked.

5.3.4 Other criteria

The pilot hole does not truncate the caprock or the reservoir and therefore should not act as additional leakage pathways for CO_2. No information is available about annulus pressures or the cement quality across intermediate aquifer zones.

Figure 5: Schematic of well P18-2A5 showing stratigraphy



Note: figure not drawn to scale

5.3.5 Conclusion

The available information shows that good casing-cement bond exists across the majority of reservoir and caprock formations. Although the casing strings themselves are not Cr13, the completion is and therefore would be fit for CO_2 injection. We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

5.4 Well P18-2A6 and P18-2A6-ST1

Well P18-2A6 was spudded in November 1996. Mud losses occurred during drilling of the pilot hole. The bottomhole assembly got stuck at the bottom of the 12¼" openhole section in the Triassic Muschelkalk and needed to be fished. After the 9⅝" liner was set and cemented (TOC = 3,000m), a 13⅜" casing wear log indicated 25% wear on the casing, so a 9⅝" tie back casing string was run and cemented (TOC = 1,613m). See Figure6.

While drilling the 8½" openhole section no problems occurred. The 7" liner was cemented successfully. Both the 9⅝" casing and the 7" liner were pressure tested OK to 5,000psi and the well displaced to filtered completion brine.

The well was sidetracked in 2003 (P18-2A6-ST1). The sidetrack's geometry is presented in Figure 7. Unfortunately, the reports on the sidetracked borehole were not available.

5.4.1 Cement barrier across the caprocks

The 256 m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (33 m thick), the Röt Claystone member (RNROC). The above Muschelkalk (RNMU) and Keuper (RNKP) formations (188 m thick) are believed to act as the secondary caprock (Figure 6).

A cement bond log is available across the 7" liner of the pilot hole from 4,755 to 4,255m, which covers reservoir and both caprocks. The log suggests good casing-cement bond (CBL amplitude < 2mV) across the reservoir section in the following intervals: 4,755-4,743, 4,721-4,700 and 4,695-4,675m. The rule of thumb of the oil and gas industry suggests that in a 7" casing hydraulic isolation is achieved when the good bond interval is at least 3m, which is the case for the above intervals. However, cement bond is moderate to poor across the caprock with CBL amplitudes ranging between 10 and 30mV.

No cement bond logs are available across the 9⅝" casing string of the pilot hole. End of well reports mention that mud losses occurred during drilling and while running the 9⅝" casing string in hole. This suggests non-ideal cement placement conditions.

Since no end of well report is available for the sidetracked borehole, information about the cementing and casing-cement bond across the 7" and 4½" liner could not be obtained.

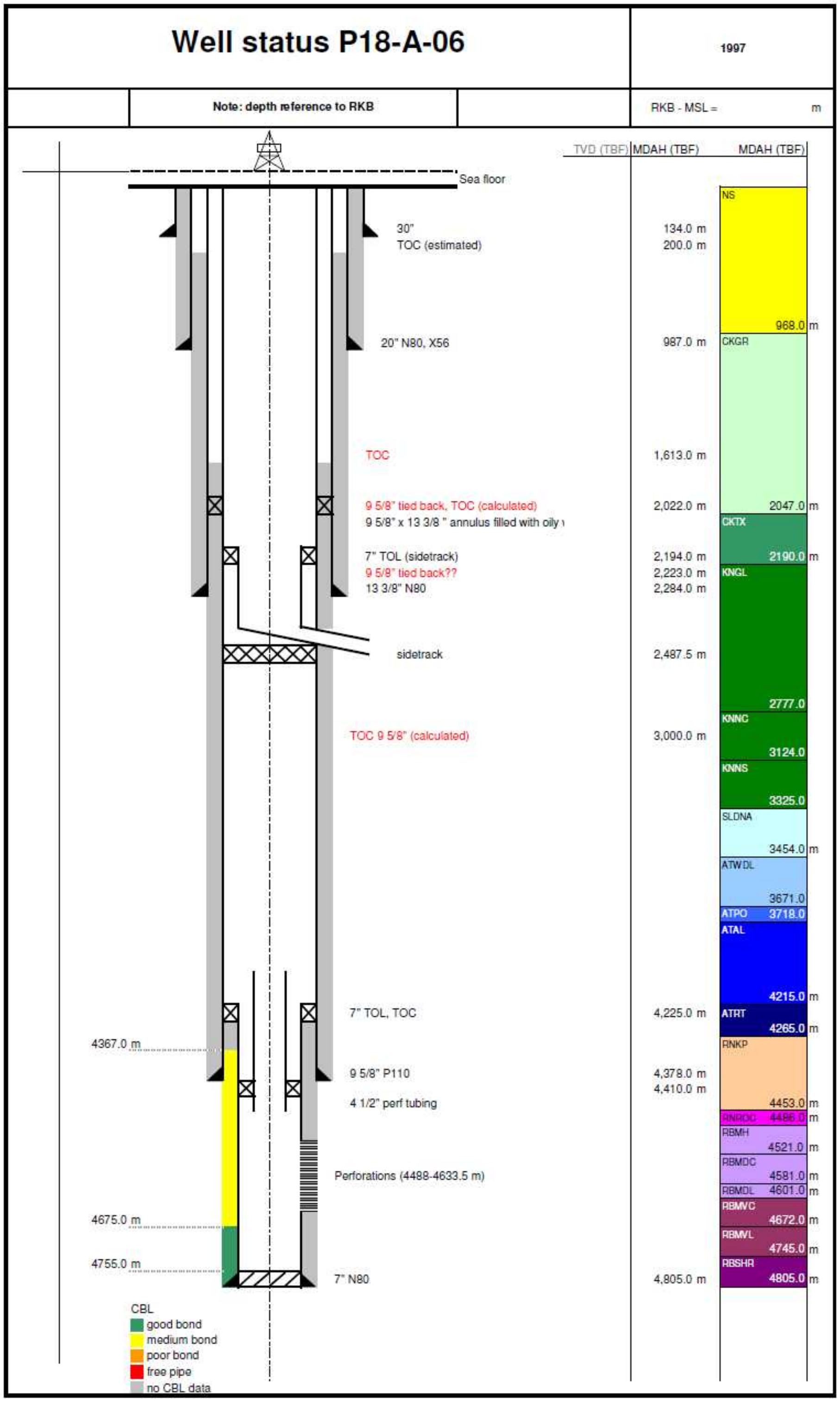
5.4.2 Production casing

Both the 9⅝" casing and the 7" liner of the pilot hole were pressure tested ok to 5000 psi. The 7" liner consists of 29 lb/ft N-80 and the 9⅝" casing of 53.5 lb/ft N-80 casing. According to reports neither of the two strings are Cr13. No information on pressure tests of the 7" and 4½" liner of the sidetracked borehole is available. The sidetrack's 7" liner consists of L80 Cr13 steel.

5.4.3 Tubing and completion barrier

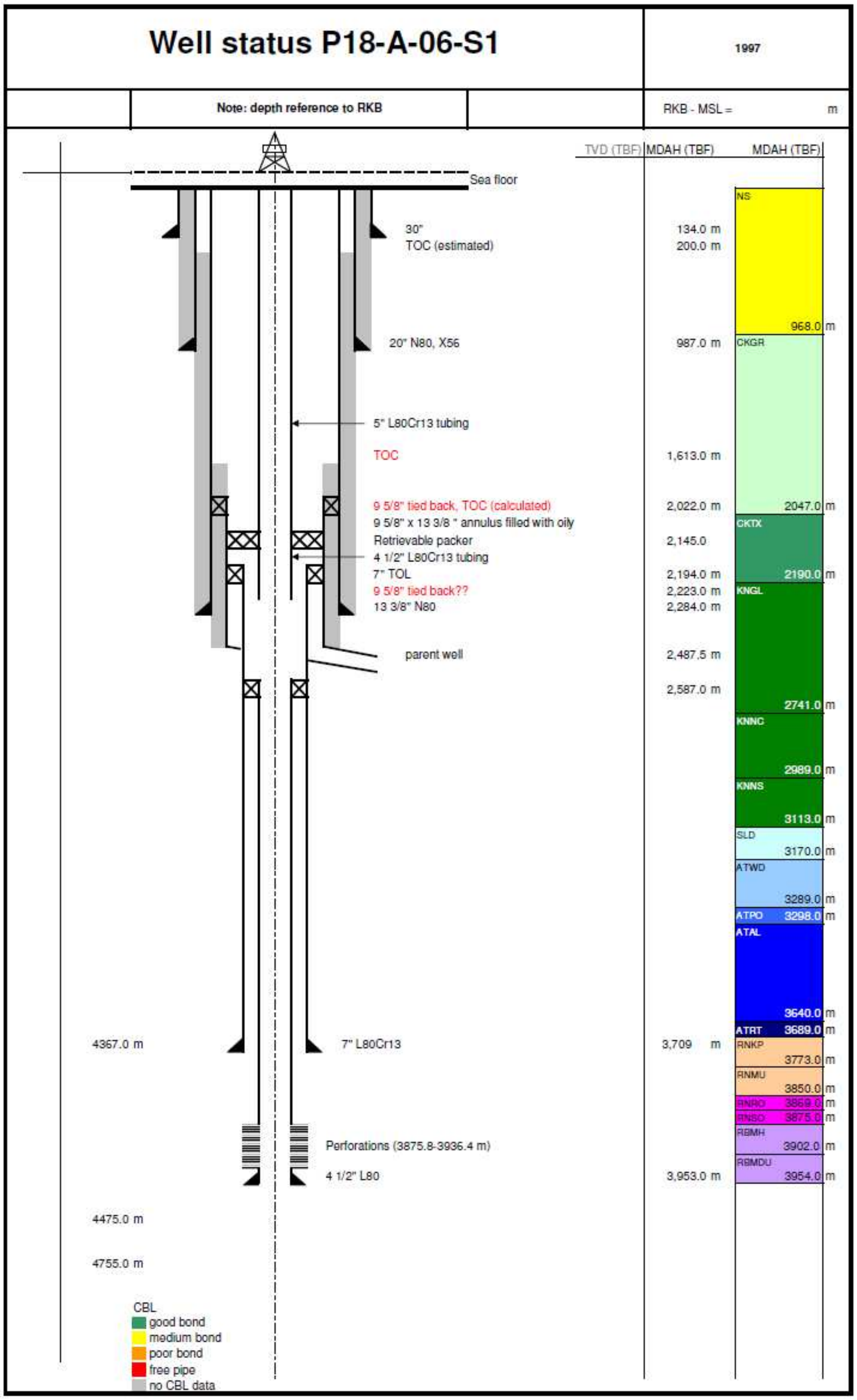
The pilot well was in production from June 1997 to April 2003, whereas the sidetracked well produced since June 2003. The sidetrack's tubing is 4½"/ 5½" L80Cr13 tubing, which is fit for CO_2 service. A retrievable packer is used in the well; therefore, it is suggested that the packer operating envelope be checked against CO_2 injection scenarios by performing a tubing stress analysis and - if needed - workover to be performed. Elastomers and wellhead information was not available, but should also be checked.

Figure 6: Schematic of well P18-2A6 with stratigraphy



Note: figure not drawn to scale

Figure 7: Schematic of well P18-2A6st with stratigraphy



Note: figure not drawn to scale

5.4.4 Other criteria

The pilot hole traverses both the caprock and the reservoir and the available cement-bond log does suggest poor casing-cement bond across the caprock and parts of the reservoir. Due to the missing end of well report for the sidetrack (P18-2A6-St1), it is not clear how the pilot hole was abandoned. Therefore, there is uncertainty on whether a leak path exists from into the original hole. No information is available about annulus pressures or the cement quality across intermediate aquifer zones.

5.4.5 Conclusion

Due to the missing information about the sidetracked well, we cannot conclude on the suitability of the well for CO_2 storage. Specifically, no information is available on the location and bonding quality of the cement in the sidetrack. However the cement bond log across the 7" liner of the pilot hole suggests poor casing-cement bond across the caprock with only a few good intervals across the reservoirs. As this poses a potential threat to long-term CO_2 containment, the abandonment of the pilot hole is crucial for well integrity. However, it is unclear how the pilot hole was abandoned and if the current layout is suitable for CO_2 storage. This issue needs to be clarified before CO_2 injection begins. Without the appropriate data available, there is some likelihood that a leakage pathway exists at least along the 7" liner.

In addition, information about the sidetracked wellbore is crucial to decide on its suitability for conversion into a CO_2 injector or for long-term containment of CO_2. Although the casing strings across the reservoir and caprocks, are not Cr13, the completion is and therefore would be fit for CO_2 injection.

We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

5.5 Well P18-4A2

Well P18-4A2 was spudded in April 1991 and was temporarily suspended with three cement plugs. Subsequently, it was completed and brought on stream in June 2003. The end of well report suggests that no problems occurred during the drilling and cementing operations, except in the 9⅝" casing string, where mud losses were experienced. Refer to the schematic of the well in Figure 8.

5.5.1 Cement barrier across the caprocks

The 225 m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (24 m thick), the Solling (RNSOC) and Röt Claystone (RNROC) members, and the secondary caprock, the Muschelkalk (RNMU) and Keuper (RNKP) formations (120 m thick).

No cement bond logs are available for the 7" liner and the 9⅝" casing strings. The 7" liner was set across the reservoir, the primary and the secondary caprock. The end of well report reports that no mud losses occurred during the drilling of the openhole section and no other problems occurred during the cement job itself. In combination with the in-gauge borehole and evenly spaced casing centralisers this provides adequate conditions for proper cement placement across the formations of interest. The calculated top of cement is at the top of the 7" liner: 3,924 m.

The 9⅝" casing string covers most of the secondary caprock. According to the end of well report 709bbls of mud were lost while setting the casing; moreover only four casing centralizers were used. Top of cement is estimated to be at around 2,000m. This suggests, *all other factors equal*, the quality of the cement bond across the 9⅝" casing string to be worse than that across the 7" liner. However, as stated earlier, we do not have the data to verify either of the cement bonds.

5.5.2 Production casing and liner

No information about pressure testing the 9⅝" casing and the 7" liner was available. The 7" liner consists is 32 lb/ft P-110 and the 9⅝" casing of 53.5 lb/ft N-80 casing. Neither string is Cr13. Mud across 9⅝" casing interval showed CO_2/$CaCO_3$ contaminations and low to medium corrosion. Corrosion control is reported.

5.5.3 Tubing and completion barrier

The well has been in production since December 1993. The tubing is 4½"/ 5½" L80Cr13 tubing, which is fit for CO_2 service. Since the production packer is a retrievable one, we suggest that the packer operating envelope be checked (by tubing stress analysis) that it is indeed fit for 'cold' CO_2 service. If needed, thereafter, a workover could be performed.

There was no information on packer/wellhead elastomers; we recommend that this information be checked before start injection to confirm applicability for CO_2 service.

5.5.4 Other criteria

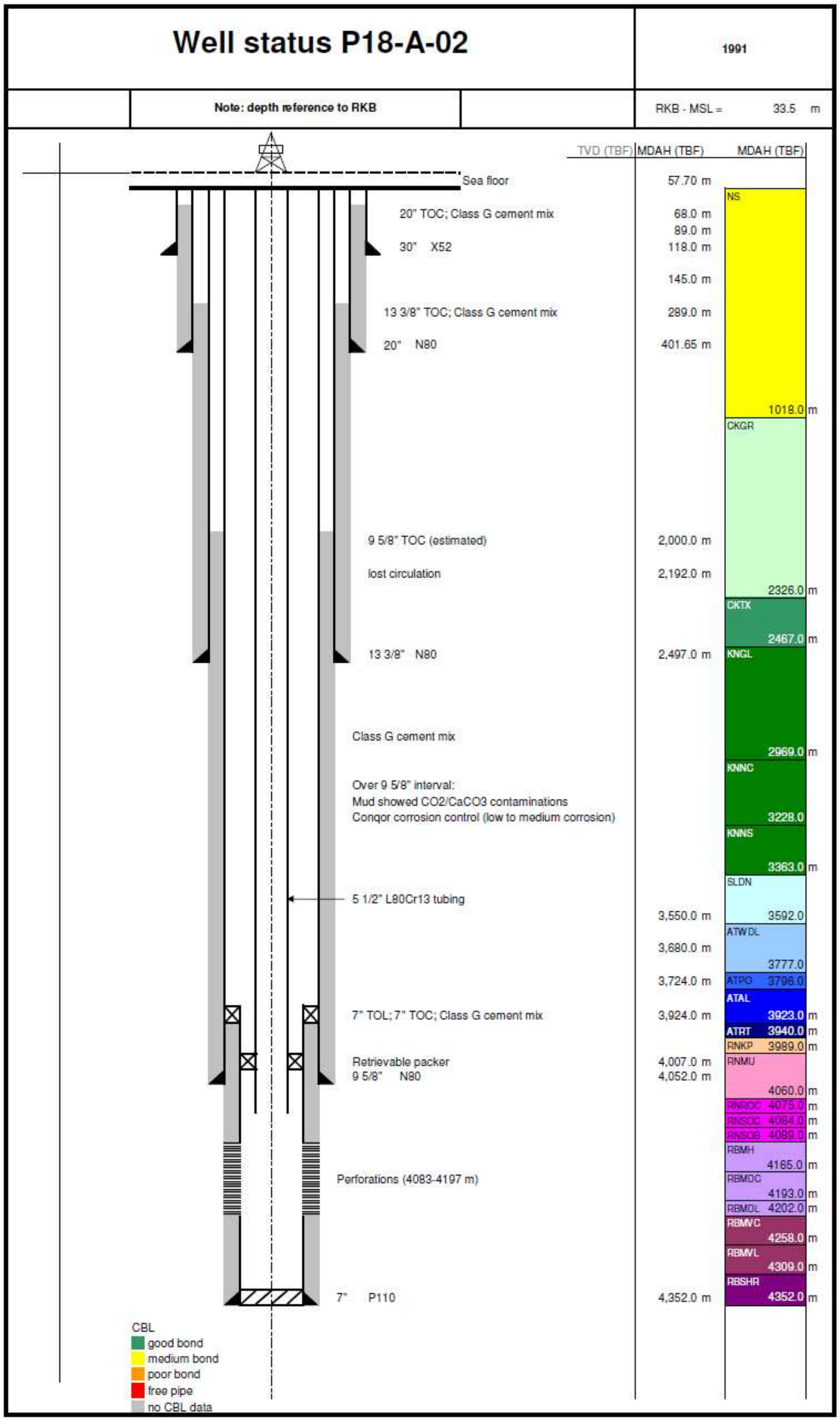
There is no information about annulus pressures or the cement quality across intermediate aquifer zones.

5.5.5 Conclusion

Reports indicate overall good cement placement conditions across the 7" liner, suggesting that good hydraulic isolation over the reservoir and the primary caprock and parts of the secondary caprock might exist.

Mud losses, which occurred while running, circulating and cementing the 9⅝" casing, and the limited number of centralisers, suggest that cement placement might not have been optimal.

Figure 8: Well sketch of well P18-4A2 with stratigraphy



Note: figure not drawn to scale

However, these observations are only an indirect inference of cement quality made in the absence of direct measured information; therefore, they need to be verified with the actual data.

Although the casing strings themselves are not made of Cr13, the reported corrosion in the 9⅝" casing should be verified before converting the well to CO_2 service. The completion is and therefore would be fit for CO_2 injection. We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

5.6 Well P18-6A7

Well P18-6A7 was spudded February 2003. The pilot well was sidetracked in the Ommelanden Formation (CKGR). The end of well report indicates that the first cementing stage on the 13⅜" casing did not enter the annulus due to plug problems and that only the second cementing stage was successful. The 3½" liner is not cemented. Refer to the schematic shown in Figure 9.

5.6.1 Cement barrier across the caprocks

The 95m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (27m thick), the Solling (RNSOC) and Röt Claystone (RNROC) members; the overlying Muschelkalk (RNMU) and Keuper (RNKP) formations (161m thick) are believed to act as the secondary caprock (see Figure 9).

The 3½" liner covers the reservoir and the primary caprock, whereas the lower section of the 5½" liner is set across the secondary caprock. Casing-cement bond information is not available for the 5" liner and therefore, we cannot make any statement on its cement quality. The 3½" liner, positioned across the primary caprock, is reported to be uncemented.

5.6.2 Production liner and casing

No information about pressure testing the 3½" and 5½" liners was available. The 3½" liner consists is 9.5 lb/ft L-80Cr13 and the 5½" liner 18 lb/ft L-80Cr13 material.

5.6.3 Tubing and completion

The well has been in production since July 2003. The tubing is 4½" L80Cr13 tubing, which is fit for CO_2 injection. Unlike the other production packer in the other wells, the production packer in well P18-6A7 is not retrievable. However, we still recommend confirming that the packer's operating envelope is appropriate for the anticipated CO_2 injection service.

Elastomers and wellhead information was not available and should be checked also.

5.6.4 Other criteria

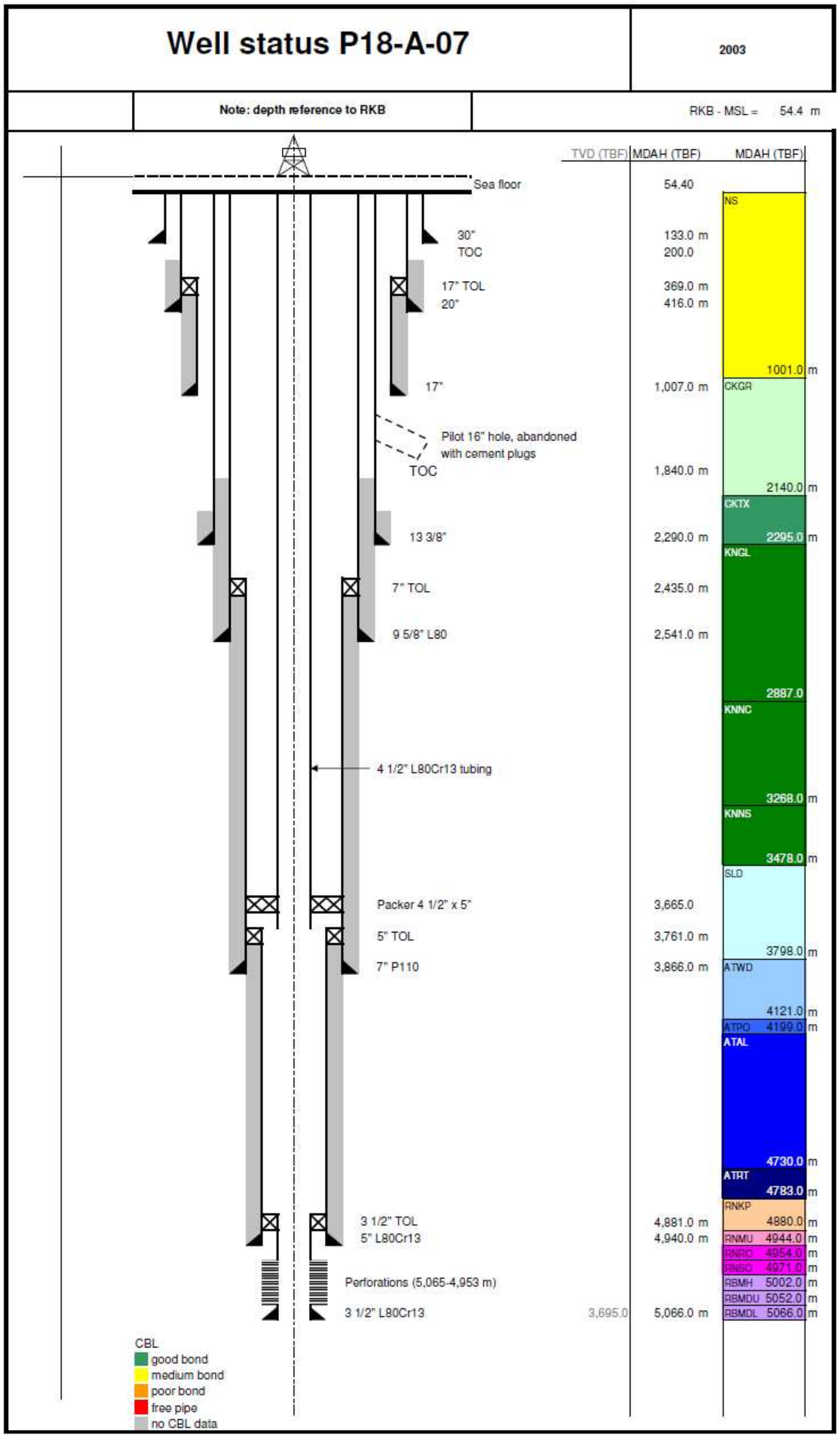
There is no information on about annulus pressures or the cement quality across intermediate aquifer zones. The well is not located in the immediate vicinity of other boreholes, which truncate the caprock and could provide additional leakage pathways for CO_2.

5.6.5 Conclusion

There was limited data available for the P18-6A7 well. Due to missing cementing reports and cement bond logs across the 5½" liner, the casing-cement bond quality across the secondary caprock is highly uncertain. We recommend it to be checked before start of injection. The 3½" liner, positioned across the primary caprock, is uncemented.

In addition, both liners and the completion are made out of Cr13 and are therefore fit for CO_2 injection. We suggest that the packer operating envelope is checked against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, elastomers and wellhead information should also be checked.

Figure 9: Schematic well P18-6A7 with stratigraphy



Note: figure not drawn to scale

5.7 Well P18-2

This well was spudded in March 1989 and suspended with four cement plugs after a DST test was performed in the Bunter Sandstone Formation. The end of well report does not mention any particular problems during drilling or cementing operations of the 7” liner. The current well configuration is shown in Figure 10

5.7.1 Cement barrier across the caprocks

The 213 m thick Middle Bunter Sandstone (RBM) reservoir is topped by its primary caprock (33 m thick), the Solling (RNSOC) and Röt Claystone (RNROC) members; the overlying Muschelkalk (RNMU) and Keuper (RNKP) formations (131m thick) are believed to act as the secondary caprock. Refer to Figure 10.

The 7” liner covers the reservoir and both the primary and secondary caprocks. It was centralized with 47 centralisers within an in-gauge borehole. After running the cement bond log under pressure (1,000 psi), overall poor bonding was recorded with moderate to well bonded sections from 3,664-3,597m and 3,276-3,247 m, with top of cement at around 3,005m MD, inside the 9⅝” casing. See Figure 10.

The 9⅝” casing string was centralized with 32 centralisers. A cement bond log was acquired from 2,960 to 100 m, showing overall poor bonding. The top of cement was found at 1,932m and at 1,525 m, separated by a free pipe section on top of a multi-stage PKR at 1,893 m.

5.7.2 Abandonment plugs

The deepest of the four cement plugs is located across the upper part of the reservoir section (Figure 10), directly above the perforations, but below the caprocks. The cement that was placed on a (presumably) mechanical plug extends only 1.5 m. The remaining cement plugs are located above the caprock intervals. The next plug is positioned at 3,006-2,896 m across the Aalburg Formation (ATAL) at the 7” liner hanger, with a length of 110 m – of which 60 m is situated above the liner hanger. At 1,915-1,846 m a cement plug is placed at the 13⅜” casing shoe and 9⅝” multi stage PKR, across the Texel Chalk Formation (CKTX). The uppermost plug extends from 154-85 m, covering the base of the 30” conductor pipe. Each of the cement plugs were pressure tested OK to 2,000 psi.

5.7.3 Production liner and casing

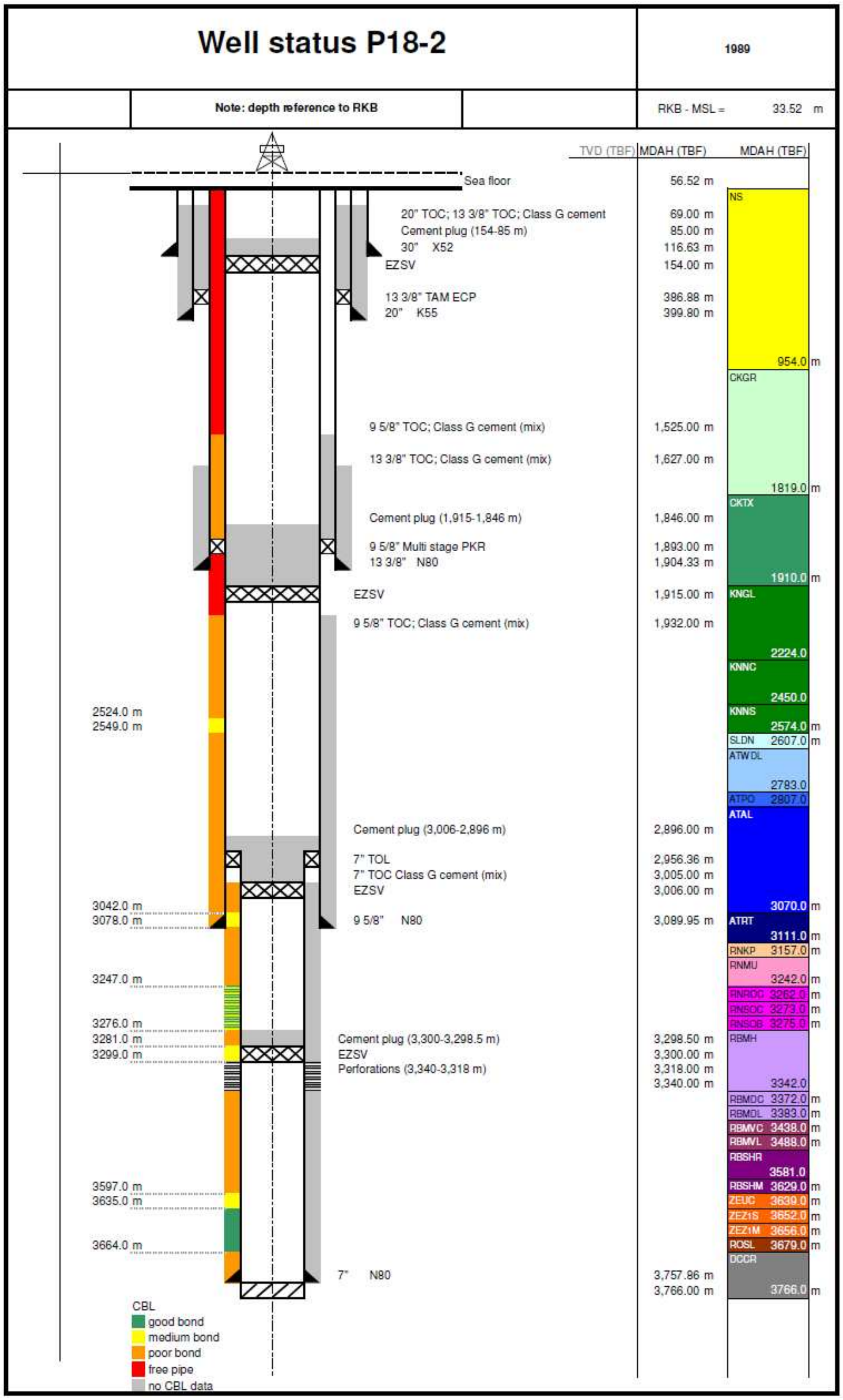
The 7” liner and 9⅝” casing string were pressure tested OK to 4,000 psi and 5,000 psi respectively. The 7” liner consists is 29 lb/ft N-80 and the 9⅝” casing of 47 lb/ft N-80 casing; neither of them made of Cr13 material.

5.7.4 Conclusion

Cement bond across the reservoir and caprocks generally shows poor results. The abandonment plugs are situated such that the first plug above the reservoir is located considerably higher than the primary and secondary caprock. This combination does not provide adequate conditions for CO_2 storage. Aqueous CO_2 could affect the lowermost (1.5m thick) seal or associated poor bonded cement or penetrate the carbon steel casing above the plug, and as a result could easily bypass the primary and secondary caprock.

Although the abandonment plugs were pressure tested OK, it is reasonable to expect that, in the long term, CO_2 could bypass the lowermost abandonment plug and migrate through the wellbore to levels above the primary and secondary caprock. Furthermore, we cannot exclude the possibility of subsequent upward migration of the CO_2 given the poor quality of the cement bond adjacent to the 7” liner and the 9⅝” casing.

Figure 10: Schematic of well P18-2 with stratigraphy



Note: figure not drawn to scale

6 Summary of integrity assessment of the P18 wells

In this section, we summarise our assessment of the integrity of the seven studied wells. As discussed in section 5, we infer the integrity of the well barriers using available direct and indirect evidence.

Refer to Figure 11 for a summary of our assessment.

Figure 11: Summary of integrity of P18 wells

	Well	*P18-2A1*	*P18-2A3*	*P18-2A5*	*P18-2A6*	*P18-2A6st*	*P18-4A2*	*P18-6A7*	*P18-2*
Barriers	*Cement sheath across primary caprock*	✗	✗	✓	✗	?	✓	✗	✗
	Cement sheath across secondary caprock	✗	✗	✓	✗	?	✗	?	✗
	Production casing and liner	✓	✓	✓	✓	?	?	✓	✓
	Tested OK?	Y	Y	Y	Y	?	?	?	Y
	Cr13?	N	N	N	Y	Y	N	Y	N
	Production tubing and completion	✓	✓	✓	N/A	✓	✓	✓	N/A
	Production packer	?	?	?	N/A	?	?	?	N/A
	Wellhead	?	?	?	?	?	?	?	?
	Abandonment plugs	N/A	N/A	N/A	?	N/A	N/A	N/A	✗
Comments (see below)		2, 3, 4	2, 3, 4	2, 3, 4	2, 3, 4	1, 2, 3, 4	2, 3, 4	1, 2, 3, 4	

✓ Direct evidence suggesting that barrier is of good quality or robust for CO_2 service

✓ Indirect evidence suggesting that barrier might be of good quality of robust for CO_2 service

✗ Direct evidence suggesting that barrier is not of good quality or robust for CO_2 service

✗ Indirect evidence suggesting that barrier might not be of good quality or robust for CO_2 service

? No data to suggest quality of barrier or robustness

1 No end-of-well report available

2 No information on annulus pressure during production life

3 Applicability of (retrievable) packer for cold CO_2 injection needs to be confirmed by tubing stress analysis

4 Applicability of wellhead and any potential elastomers to CO_2 service unknown

7 Long-term well integrity

7.1 Material degradation

Long-term containment is one of the specific aspects of geological storage of CO_2. Under certain conditions aqueous CO_2 can chemically interact with well materials. Especially taking into account time spans of thousands of years, these processes may play a crucial role in the integrity of wells and therefore of storage reservoirs.

A review of laboratory experimental studies indicates that diffusion-based chemical degradation rates of cement are relatively low. Extrapolation of the general results shows a maximum of up to a few meters of cement that may be affected in 10,000 years. Even under very high temperatures, extrapolated degradation rates would result in a maximum of 12.4 m of cement plug degradation after 10,000 years of exposure to CO_2, assuming that diffusion processes define the degradation mechanism. In order to translate the experimental results to field situations, several limiting factors apply. Whereas cement samples in the laboratory in certain cases were immersed in a bath of supercritical CO_2, well material in reality will be partially surrounded by reservoir rock, limiting the available reaction surface, the supply of CO_2 and the transportation of reaction products. Furthermore, in specific field cases, especially in depleted gas fields, the availability of water necessary for degradation may be far more limited compared to the experiments. Moreover, injected CO_2 will push back the brine present in the storage formation. As dissolution will take place slowly, many wells may not come across the CO_2-water contact at or near critical levels, such as the cap rock. The presence of only connate water would significantly limit the chemical reactivity of CO_2, although CO_2 is expected to favourably dissolve water. Finally, higher salinity of formation water will likely decrease the solubility of CO_2 and reaction products, thus reducing cement degradation rates. Especially relative high concentrations of calcium and magnesium in the brine may limit the degradation of wellbore cement. Steel corrosion is much faster than cement degradation with rates up to mm's per year. However, also corrosion rates will be seriously reduced by the limited availability of water. A more detailed discussion is presented in IEA GHG (2009).

As a result of the above, the mechanical integrity and quality of placement of primary cement and cement plug probably is of more significance than the chemical degradation of properly placed abandonment plugs. The presence or development of fractures or annular pathways in the cement or along material interfaces will strongly affect the cement's bulk permeability. These phenomena, which may be associated with either operational activities or degradation, will play an important role in leakage mechanisms and may significantly reduce the sealing capacity of the cement. Moreover, degradation in lateral direction, affecting the primary cement sheath and casing steel, is likely to compromise integrity in decades. As previously abandoned wells generally cannot easily be remediated, these wells form an element of especial attention in any prospective CO_2 storage project.

7.2 P18 well integrity

In the scope of the present study P18-2 is the only abandoned well. The lowermost abandonment plug is very thin and actually positioned below the primary caprock. In case the CO_2 in the reservoir will dissolve present (connate) water, the aqueous CO_2 is likely to interact with the cement sheath and carbon steel casing above this plug. In conceivable times the lateral barrier may be compromised, providing a pathway into the interior casing leading to higher levels, bypassing both the primary and secondary caprock. Given the poor quality of the annular cement sheath along the entire well, leakage pathways through the annulus cannot be excluded.

As described in sections 5 and 6, except P18-2A5, the accessible wells present inadequate barriers or lack data to assess these. Even if CBL showed good bonding, the evaluated CBL data was acquired prior to production and bonding could have deteriorated as a result of induced temperature or pressure loading cycles during the production stage. Moreover, CBLs are unable to see thin channels along the material interface and, therefore, even good signal response does not necessarily imply full isolation. In order to prepare the accessible wells for CO_2 storage, cement sheaths should be verified with adequate techniques and if required remediated.

8 Conclusions and recommendations

From the perspective of well integrity, the feasibility of CO_2 storage in nearly depleted gas fields, is primarily determined by the suitability of inaccessible wells for containment of CO_2. In the P18 reservoirs, only the P18-2 well was previously abandoned and practically inaccessible.

The lack of a cement abandonment plug at caprock level and the poor quality of the annular cement, cause the P18-2 well in its current state to be unsuitable for CO_2 storage application. An abandonment plug of sufficient length positioned across the primary and/or secondary caprock, accompanied by a good cement-to-casing bond at this interval, is required for zonal isolation.

All other wells are still accessible and therefore can be remediated. Most of these show questionable cement sheath quality at caprock level from CBL data (i.e. P18-2A1, P18-2A3, P18-2A6, P18-6A7) or lacked data to verify this (i.e. P18-2A6st, P18-4A2, P18-6A7). Inadequate primary cement imposes a risk to long-term integrity, but could also affect the operational phase. A special case is the sidetracked p18-2A6 well. From the limited available data it is uncertain how the parent hole was abandoned and if this is satisfactory for CO_2 storage.

8.1 Remediation and mitigation

When considering wells for CO_2 injection it is recommended to check the packer operating envelope against CO_2 injection scenarios by performing a tubing stress analysis and if needed workover to be performed. Furthermore, potential elastomers and wellhead configuration should also be verified and adapted where required. Moreover, it is suggested to adjust completion materials (tubing, tubing hanger and packer) to corrosive circumstances, where applicable.

With respect to CO_2 injection and especially long-term containment, it is recommended to re-evaluate the cement sheath quality at least over caprock level by checking annular pressures or running cement bond logs over the intervals in question. Even when subsequent logging showed good bonding, temperature and pressure loading during production could have adversely affected the cement quality. If verification gives cause for remediation, e.g. cement squeezing should be considered.

8.2 Abandonment

Except for the P18-2 well, all wells are still operational and will need abandonment in the future. For these wells abandonment can be designed specifically for CO_2 storage. After the most optimal injection well would be selected, the objectives for the other wells also need to be defined. Although forming a potential conduit to the surface, wells also form an invaluable source of information from the reservoirs. Serious thought should be directed at using specific wells for monitoring purposes, equipped with measurement devices.

At present, there are two general options to permanently seal a wellbore for CO_2 containment. If the quality of the primary cement sheath is ensured over critical intervals, traditional abandonment plugs can be positioned and tested at caprock level. Alternatively, and especially in the case of questionable cement sheaths, pancake plugs can be used at caprock level. This would involve milling out of the casing, annular cement and part of the formation, followed by placement of cement in the cavity. This operation may pose difficulty particularly in horizontal or strongly deviated wells. Both of these options should be accompanied by additional plugs higher up the well, according to common practice and as prescribed by governing abandonment regulations.

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