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NAM

Nederlandse Aardolie Maatschappij

Technical evaluation of Twente water injection wells TUM1, TUM2, TUM3, ROW2, ROW3, ROW4 and ROW5 6 years after start of injection

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Nederlandse publiekssamenvatting

Sinds 2011 injecteert NAM productiewater, afkomstig van de oliewinning in Schoonebeek, in lege gasvelden in Twente. In dat jaar hervatte NAM de olieproductie in Schoonebeek, waar sinds medio jaren ’90 geen olie meer werd geproduceerd. Voor deze activiteiten zijn diverse vergunningen verleend door verschillende overheden. Voor de waterinjectielocaties in Twente zijn specifieke vergunningen verleend door de provincie Overijssel en het ministerie van Economische Zaken. In deze vergunningen is een voorschrift opgenomen dat NAM zes jaar na aanvang van de waterinjectie een uitgebreide evaluatie diende uit te voeren naar de waterinjectie-activiteiten en de effecten daarvan op de boven het reservoir gelegen afsluitende lagen. In dit rapport worden de resultaten gepresenteerd van deze evaluatie.

Het productiewater dat vrijkomt bij de oliewinning in Schoonebeek wordt geïnjecteerd in de diepe ondergrond in een drietal leeg geproduceerde gasvelden in Twente. De oude gasreservoirs waar op dit moment water in geïnjecteerd wordt bestaan uit kalksteenlagen waarin van nature schuren zitten die er voor zorgen dat de doorlaatbaarheid van dit gesteente hoog is. De kalksteenlagen worden aan de boven en onderkant begrensd door een laag anhydriet, een gesteentesoort dat geen gas of water doorlaat en niet in water oplosbaar is. Onder en boven deze anhydrietlaag zit een dikke niet doorlaatbare laag steenzout. De combinatie van een anhydriet en steenzoutlaag vormt een zeer goede afdichting die in het verleden ervoor gezorgd heeft dat het gas gedurende miljoenen jaren in de kalksteenlagen opgeslagen kon blijven en er nu voor zorgt dat het productiewater op een veilige manier in de diepe ondergrond opgesloten blijft.

Naar aanleiding van een uitgebreide Milieu Effect Rapportage (MER) zijn vergunningen afgegeven op basis van een verwachting dat al vrij snel na de start van de olieproductie in het Schoonebeek olieveld ongeveer 12,500 m^3/d productiewater geïnjecteerd zou gaan worden In werkelijkheid is de hoeveelheid water die is geïnjecteerd veel minder (4000-5000 m^3/d), omdat er minder olie is geproduceerd uit het Schoonebeek olieveld dan oorspronkelijk verwacht.

In de periode tussen 2011 en 2016 is slechts vierenenhalf jaar lang water geïnjecteerd. In januari 2011 is gestart met waterinjectie. In juni 2015 is de injectie gestopt, nadat door NAM werd vastgesteld dat een veilig en verantwoord transport van het injectiewater door de watertransportleiding naar Twente niet meer gegarandeerd kon worden. Als gevolg hiervan is begin 2016 deze bestaande transportleiding gerepareerd door een nieuwe 8 inch kunststofleiding door de bestaande 18 inch leiding te trekken. In augustus 2016 was de vernieuwde kunststofleiding gereed voor gebruik en is de oliewinning in Schoonebeek en de waterinjectie in het Rossum-Weerselo veld medio september weer opgestart.

Conform het Waterinjectie Management Plan, dat onderdeel uitmaakt van de verleende vergunning, is een uitgebreid inspectie- en controleprogramma uitgevoerd voor diverse waterinjectieputten. Conform de voorschriften uit deze vergunning zijn voor zeven (TUM1, TUM2, TUM3, ROW2. ROW3, ROW4 en ROW5) van de elf in gebruik genomen waterinjectieputten de resultaten geëvalueerd over de eerste zes jaar nadat is begonnen met waterinjectie. Dit rapport bevat een gedetailleerde evaluatie van deze inspecties en testen en dient beoordeeld te worden door het bevoegd gezag. Tijdens de evaluatie is gekeken naar het injectiegedrag (injectiedruk en injectiviteit; dat is de hoeveelheid water die per eenheid van druk wordt geïnjecteerd), de huidige reservoirdruk in vergelijking met het model, de integriteit van de stalen verbuizingen in de put en de integriteit van de injectiebuis.

Gedurende de periode dat water is geïnjecteerd tussen januari 2011 en juni 2015 zijn de injectiedrukken, als gemeten aan het oppervlak, voor alle putten nooit hoger geweest dan de in de vergunning opgenomen druklimieten (zie tabel 1 van het Waterinjectie Management Plan). Deze druklimieten zijn ingesteld met als doel de integriteit van de afsluitende lagen boven en onder de reservoirs te garanderen.

In de waterinjectieput ROW4 wordt een iets hogere, maar constante, reservoirdruk geconstateerd dan volgt uit het model en de verwachting. De reservoirdruk is echter nog steeds ruim binnen de gestelde veiligheidsmarges van de betreffende vergunning is. De reservoirdruk in putten TUM1, TUM2, TUM3, ROW2, ROW3 en ROW5 neemt sneller toe dan vooraf gemodelleerd, maar ook hier ligt de reservoirdruk in de diverse reservoirs voor alle putten nog steeds ruim onder de originele reservoirdruk en zijn er geen overschrijdingen geconstateerd van de drukken zoals in de vergunningen zijn vastgelegd. De metingen in put ROW3 lijken aan te tonen dat het gedeelte van het reservoir waarin nu water wordt geïnjecteerd veel kleiner is dan het gedeelte waaruit voorheen gas is geproduceerd. Echter, de hoeveelheid water die tot nu toe in de meeste putten (in het bijzonder voor putten TUM1, ROW2, ROW4 en ROW5) is geïnjecteerd, is nog steeds te gering om een betrouwbare voorspelling te maken van de uiteindelijke opslagcapaciteit op basis van de toename van de reservoirdruk. Daarom kunnen met de thans beschikbare gegevens de reservoirmodellen niet worden aangepast.

De injectiviteit in de reservoirs wordt bepaald door middel van een zogenaamde ‘step-rate’-test (SRT), een test waarbij op diepte van het reservoir de injectiedruk wordt gemeten terwijl de injectiesnelheid stapsgewijs wordt verhoogd. Deze testen tonen volgens de verwachtingen aan dat het water vooral wordt opgenomen in een bestaand

(natuurlijk) netwerk van scheuren in deze ondergrondse formatie. De waterinjectie in de putten ROW2, en ROW5 wordt beschouwd als erg goed (tot 2000 m^3 per dag), terwijl deze in put ROW4 (tot 1000 m^3 per dag) matig tot goed is. Putten TUM1, TUM2 en TUM3 hebben een geringe injectiviteit (minder dan 250 m^3 per dag). ROW3 is de enige put waar water in een zandsteenlaag wordt geïnjecteerd die op grotere diepte ligt dan de kalksteen en steenzoutlagen. In tegenstelling tot het Zechstein Carbonaat heeft dit oude gasreservoir geen natuurlijk netwerk van scheuren en heeft daarom een zodanig lage injectiviteit, dat waterinjectieput ROW3 slechts incidenteel gebruikt wordt.

In de MER en vergunningsaanvragen is destijds de nodige aandacht besteed aan het mogelijk oplossen van de afdekkende steenzoutlaag indien deze laag in aanraking zou komen met het injectiewater en het effect daarvan op bodemdaling. De MER concludeert dat deze zoutlagen niet of nauwelijks zullen oplossen in het injectiewater, echter om hierover aanvullende inzichten te verkrijgen is besloten uitgebreide modelleringen uit te voeren. Op basis van deze uitgebreide modelleringen is aangetoond dat de conclusie uit de MER juist is[1]. De conclusies van deze rapporten zijn beoordeeld door Staatstoezicht op de Mijnen en diverse buitenlandse instituten. Deze reviews wijzen uit dat er een groot aantal aanwijzingen zijn dat injectie van water niet zal leiden tot oplossen van zout of aardbevingen. In het theoretische geval dat injectiewater langs de buitenzijde van de stalen verbuizing van de waterinjectieput zou stromen, kan niet uitgesloten worden dat de zoutlaag dan plaatselijk aangetast wordt.

Ter voorkoming van zo'n situatie worden verschillende preventieve metingen in de injectieputten uitgevoerd om de status van de waterinjectieputten zeker te stellen:

1. Omdat de temperatuur van het injectiewater lager is dan de temperatuur in de diepe ondergrond zullen de zones waar water in geïnjecteerd wordt iets afkoelen. Met behulp van speciale apparatuur kan zowel in als buiten de put (dus achter de verbuizing) de temperatuur gemeten worden. Indien koude plekken worden gemeten achter de verbuizing kan dit erop wijzen dat daar injectiewater heeft gestroomd en zout heeft opgelost. In een dergelijk geval zal de waterinjectie stopgezet worden en zal nader onderzoek volgen. De waterinjectie wordt dan pas weer hervat als dit veilig plaats kan vinden, hetgeen inhoudt dat het risico op lekkage als zeer laag geklassificeerd wordt of als een reparatie uitgevoerd is.
2. De kwaliteit van de cementenwand die buitenom de gehele waterinjectieput zit, wordt gemeten met behulp van zogenaamde Cement Bond Logs (CBLs). Mocht blijken dat er kwaliteitsverschillen zijn in het cement, dan zou dit de mogelijkheid kunnen bieden voor stroming van injectiewater achter de verbuizing van een injectieput.Water wordt slechts daar geïnjecteerd waar geen aanleiding is om te vermoeden dat injectiewater achter de verbuizing in contact kan komen met zout.
3. De integriteit van de verbuizing wordt gecontroleerd door de wanddikte van de verbuizing te meten. Dit wordt gedaan door middel van een gedetailleerde diameter (of calliper) meting die afwijkingen in de wanddikte van de buis kan detecteren.

De temperatuurmetingen die in alle waterinjectieputten zijn uitgevoerd geven aan dat het water op de juiste plaats van het reservoir wordt geïnjecteerd en dat het steenzout niet aan het injectiewater is blootgesteld. Uit CBLs (zie punt 2) en calliper-metingen (zie punt 3) blijkt dat de waterinjectieput- en cementconditie goed zijn en dat het hierboven beschreven mogelijk risico van het oplossen van de zoutlaag verwaarloosbaar is.

Betreffende de integriteit van de waterinjectieputten kan worden vastgesteld dat alle gemeten drukken binnen de in de vergunningen opgenomen druklimieten zijn gebleven. In alle waterinjectieputten zijn de wanddiktes van de injectiebuizen meer dan voldoende om de maximale verwachte injectiedruk te weerstaan. In waterinjectieput ROW4 zijn zogenaamde putstimulaties uitgevoerd, die mogelijk invloed hebben gehad op de wanddikte. Echter de huidige wanddikte voldoet nog aan alle vereisten zodat de waterinjectie ook in deze putten veilig en verantwoord is.

Van alle uitgevoerde inspecties hebben alleen de "step-rate'-testen niet de gewenste informatie opgeleverd. Het rapport stelt dan ook voor om meer nadruk te leggen op het meten van de reservoirdruk via drukmetingen in de waterinjectieputten terwijl er niet gepompt wordt, in plaats van het uitvoeren van deze SRT's.

Geconcludeerd mag worden dat alle in de vergunning genoemde inspectie- en testprogramma's (beschreven in het Waterinjectie Management Plan) volgens plan zijn uitgevoerd. Hierbij is aangetoond dat de in de vergunning genoemde beheersmaatregelen van het waterinjectie-programma goed werken en dat alle waarborgen voor een veilig en verantwoord opereren van de waterinjectieputten aanwezig zijn.

[1] Nadat SodM, vanuit haar rol als toezichthouder, in 2011 om een risicoanalyse van het waterinjectie proces had gevraagd, heeft NAM in 2014 en 2015 vier technische rapporten geleverd over de risico's van het eventueel oplossen van zout bij het reservoir en naar de kans op het optreden van geïnduceerde aardbevingen.
SodM heeft deze rapporten voorgelegd aan onafhankelijke experts in Duitsland, Frankrijk en de Verenigde Staten, en hen om een review gevraagd. Deze reviews zijn in het voorjaar van 2016 ontvangen en wijzen uit dat de studies door NAM goed zijn uitgevoerd. Er is een groot aantal aanwijzingen dat de huidige injectie van het productiewater niet zal leiden tot oplossen van zout of aardbevingen.
(http://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

Management summary

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM1, TUM2, ROW2, ROW3, ROW5, ROW6 and TUB7) to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is required to evaluate and report the water injection process and activities and the effects on the confining cap rock every 6 years. In line with the requirements in the water injection permits, NAM will carry-out this evaluation 6 years after the start of injection. By then, sufficient data is collected to conduct a proper assessment and re-calibrate the models if necessary.

From an environmental point of view, the key concern is the mitigation of the risk for contamination of shallow aquifers due to loss of containment. The technical evaluation therefore will, in particular, focus on the effect of water injection on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir.

The water injection permits for the respective locations state that the 6-yearly evaluation should be carried-out on injection wells TUM1, TUM2, TUM3 and ROW2, ROW3, ROW4 and ROW5. In 2014, 3 years after start injection, a first technical evaluation was already carried-out for wells ROW3, ROW4, ROW7, ROW9, TUB7 and TUB10 that were expected to show faster pressure increase with respect to connected reservoir volume and planned injection rate.

In the period 2011-2016 actual injection only occurred during 4½ years. Injection started in January 2011 and stopped in June 2015 when it was discovered that the water export pipeline was no longer fit-for-purpose due to integrity issues.

Main conclusions from the 6-yearly technical evaluation are:

- All seven evaluated and hooked-up water injection wells in Twente are in good condition and can be used for future water disposal.
- The monitoring programs provide an appropriate early detection and protection framework to guarantee the integrity of both the wells and reservoirs and thus a safe and responsible operation.

More specific, conclusions are listed below.

From static pressure gradients (SPG's), surface injection pressures (THPi) and injection and fall-off tests the following is concluded, respectively:

- The actual average pressure in the various reservoirs is still significantly lower than the original reservoir pressure for all wells.
- During the entire injection period, the surface injection pressure remained well below the set injection pressure limit for the wells. Hence, for all wells the maximum bottom hole pressure during injection has never exceeded the minimum in-situ stress of the confining layers (ZeZ-Halite for the ROW and TUB wells and the shales in the Bunter Sandstein for the TUM wells).
- The amount of water injected so far for most wells is still too small to make an accurate prediction of the final storage capacity based on the pressure trends (in particular for wells TUM1, ROW2, ROW4 and ROW5). Therefore, the available data do not yet warrant an adjustment to the reservoir models.
- The step-rate test (SRT)-plots derived from the injectivity tests all show a linear trend indicating injection into existing natural fractures in the fractured Zechstein-Carbonate reservoir, which means that injection occurs below fracturing pressure.
- Apparent formation breakdown only occurred during a controlled injectivity test in well ROW3 where water was injected in the tight Carboniferous sandstone. The test data suggest that during normal prolonged injection, based on the poor injectivity, apparently the fracture was plugged-off.
- Since injection does not take place under fracturing conditions, determination of minimum horizontal stress from fall-off surveys cannot be done as intended, and fall-off tests for that purpose are no longer mandatory[2]. Pressure transient analysis suffers from large wellbore storage effects, and only indicative results for permeability (fracture spacing) are obtained.
- Conducted step-rate tests appear to yield poor quality data as in every test it takes progressively more time to achieve the required downhole pressure stabilization. Also in some wells the well bore does not completely fill up to surface, in which case it is not even possible to determine from the surface pressure whether stable downhole pressure was achieved.

Extensive studies have been carried-out regarding Halite dissolution when exposed to injection water and its effect on subsidence[3,4]. These studies have been independently reviewed by University experts under auspices of State

[2] Staatstoezicht op de Mijnen – Uw addendum op het evaluatierapport Twente waterinjectie, kenmerk 15137190. EP201510202648, oktober 2015

[3] Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal. EP201310203080, December 2014

[4] Subsidence caused by Halite dissolution due to water injection into depleted Carbonate gas reservoirs encased in Halite. EP201310204177, December 2014

Supervision of Mines[5]. From Halite dissolution modelling it was concluded that potentially this can only occur near the injection well. Hereto, a leak in the production casing in combination with a poor cement bond behind casing must occur simultaneously in order to allow injection water to directly flow past the Halite formation. Temperature surveys, cement bond logging and casing calliper surveys have been executed to check if injection water potentially exposes the ZeZ-Halite layers. From the logging the following is concluded:

- Downhole temperature surveys indicate that injection is restricted to the targeted Zechstein-Carbonate reservoirs.
- The risk for Halite dissolution is perceived negligible in all logged wells. Casing calliper surveys and cement bond logs show good cement and casing quality across the confining Halite seal layers. There is no indication for potential leak paths behind casing.

Evaluation of the well and tubing integrity shows that:

- Tubing strength calculations show that tubing integrity exceeds the minimum requirements for safe operations. All wells show enough wall thickness (degree of pitting < 60%) to withstand maximum injection pressures. No tubing leaks are detected.
- During the current injection period all A-, B- and C-annulus pressures have remained below their Maximum Allowable limit (MAASP).
- Pressure data demonstrate full pressure isolation between the tubing, A-annulus and B-annulus.

[5] These studies have been independently reviewed by independent University experts under auspices of the Dutch Mining Regulator (State Supervision of Mines). All the conclusions and findings of the studies were supported by both the experts and the regulator. (https://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

1 Introduction

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM1, TUM2, ROW2, ROW3, ROW5, ROW6 and TUB7) to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is requested to evaluate and report the water injection process and activities every 6 years. From an environmental point of view, the key concern is the mitigation of the risk for contamination due to loss of containment. The technical evaluation therefore will, in particular, focus on the effect of water injection on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir.

Because of the high injection rates (from the Schoonebeek FDP in 2003[6], a plateau rate as high as 12,500 m^3/d was expected with up to 2000 m^3/d for some wells) and volumes, it was decided by the regulator (State Supervision of Mines (SodM)) to execute this evaluation 6 years after start injection, because sufficient data should have been collected then to calibrate the models and conduct a proper assessment. The water injection permits for the respective locations state that the 6-yearly evaluation should only be carried-out on injection wells TUM1, TUM2, TUM3 and ROW2, ROW3, ROW4 and ROW5. As specified in the permit, a first technical evaluation was carried-out in 2014, 3 years after start injection, for a number of wells (ROW-3, -4, -7 and -9 and TUB-7, -10) that were expected to show faster pressure increase with respect to connected reservoir volume and planned injection rate. The evaluation report for these wells was shared with the regulator (Ministry of Economic Affairs/SodM) in January 2015[7].

In the years 2011-2016 actual injection only occurred during 4½ years, rather than 6 years (Figure 1). Injection started in January 2011 and stopped in June 2015 when it was discovered that the water export pipeline was no longer fit-for-purpose due to integrity issues. As a result, the Schoonebeek field has been closed in since June 6 2015.

Installation of a smaller 8” diameter flexible composite pipe (FCP) inside the existing 18” water transport pipeline was completed in August 2016. With the FCP installed, water transport capacity to Twente is constrained. Currently injection is focussed on locations ROW2, ROW3 and ROW5, which are connected with corrosion resistant cladded pipelines. The injection wells on these locations (wells ROW2, ROW4, ROW5 and ROW7) have a total potential injection capacity of 5500 m^3/d.

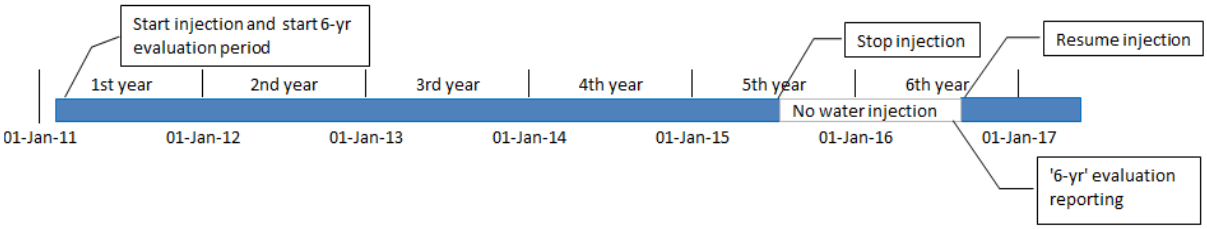


Figure 1 – Schoonebeek production water injection timeline in Twente

As mentioned, to abide by the water injection permit, the evaluation focusses on the effect of water injection on the integrity of the sealing cap rock, to ensure containment of injected water in the target reservoir and avoid migration of injected water to surface. The integrity of the cap rock will be maintained when:

- the downhole injection pressure at the depth of the cap rock does not exceed its fracturing pressure
- no significant near-wellbore Halite dissolution occurs

Here to, relevant parameters such as the surface injection pressure and rate, actual injection pressure at top reservoir and injection tubing and casing wall thickness have been closely monitored and measured in accordance with the Water Injection Management Plan[8,9]. The results of the extensive monitoring plan and conclusions are shared in this report. In addition, overall well integrity status of the various injectors is addressed.

[6] Schoonebeek Oilfield Redevelopment - VAR 3 Field Development Plan. Final Version. EPE200401201716, October 2003

[7] Technical evaluation of Twente water injection wells ROW3, ROW4, ROW7, ROW9, TUB7 and TUB10 3 years after start of injection. EP201410210164, January 2015

[8] Water injection Management Plan. EP201308203212 (2009)

[9] Concept Addendum Waterinjectie Management Plan - Voorstel om het surveillance programma voor waterinjectie en de tabel voor jaarlijkse rapportage aantepassen . EP201504208558, april 2015

2 Description of water injection system

2.1 Injection system

In the Schoonebeek Oilfield production system produced water is re-injected into depleted gas fields in Twente. These fields are the Tubbergen-Mander (TUM), Tubbergen (TUB) and Rossum-Weerselo (ROW) fields. Significant gas volumes were produced from these fields in the past providing a significant water storage capacity.

The produced water is separated from the Schoonebeek Oilfield production stream at the Central Treatment facilities (CTF). Once separated, the water is cooled to 40 °C. Subsequently, corrosion inhibitor is added after which the water exits the CTF at a flowrate of first 3,000 m^3/d up to a peak rate of 8,000 m^3/d in a few years and at a pressure of about 20-35 bars. The initial produced water composition was similar to that of the Schoonebeek formation water. However, with time, the ion content is decreasing due to dilution by the condensed 'sweet' water that originates from the steam injected into the Schoonebeek reservoir. The produced water contains <100 ppm oil and <100 mg/l suspended solids (>5 µm).

Figure 2 shows that the produced water is transported from the CTF to the Den Hulte scraper station via a 17 km, 14" GRE pipeline. This new pipeline has a maximum capacity of 15,500 m^3/d and a maximum design pressure of 40 bars. At Den Hulte the new 14" GRE pipeline is connected to the 45 km, 18" Twente trunk line, which was previously used to evacuate the sour wet gas from the Twente wells. This trunk line was used to transport the injection water to depleted gas fields in Twente. Due to integrity issues of this pipeline, water injection was stopped in June 2015 and, consequently, oil production and steam injection had to be stopped too. The trunk line is repaired by installing an 8" flexible composite pipe (FCP) inside the existing 18" pipe. The installation was completed in August 2016.

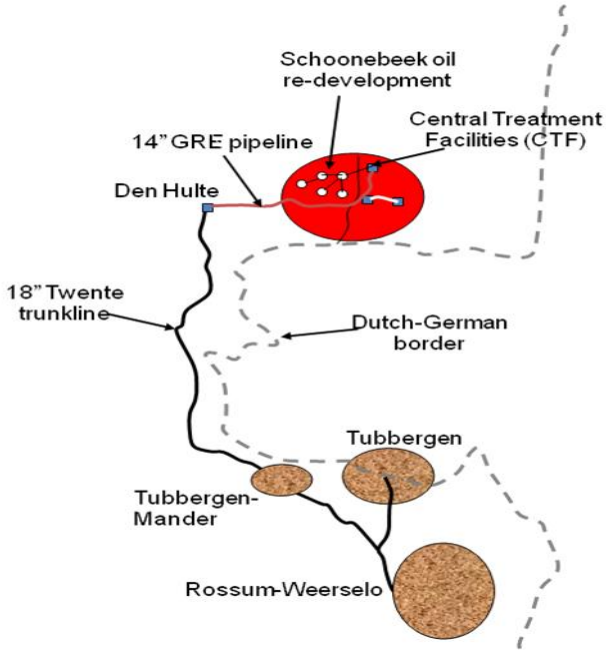


Figure 2 - Schematic representation of water injection system within Schoonebeek Oilfield production system

The transported water arrives at the Twente well sites at a pressure of approximately 5 bars and a maximum temperature of 30 °C. At every injection well a skid with a horizontal multistage centrifugal pump (MCP) is installed. This MCP contains a variable speed drive, which allows the pump to be operated at the required rates and pressures.

2.2 Injection reservoirs

Water is injected into 2 types of reservoirs: the naturally fractured Zechstein Carbonate formation and the Carboniferous (DC, Carboniferous) sandstone formation. The Zechstein Carbonate formation is sealed off by Zechstein salt (Halite) layers (in case of the ROW fields) or the Claystone layer in the Buntersandstone formation (in case of the TUM field). The carbonate injection reservoirs are separated at both the top and base from the salt by laterally continuous Anhydrite layers. These Anhydrite layers are several meters thick (2-10 mTV), impermeable and essentially insoluble (the solubility of Anhydrite in water at reservoir conditions is a factor 1000 less than that of Halite). The Carboniferous sandstone formation is basically sealed-off by the thick ZeZ1-Anhydrite (76mTV) and ZeZ1-Halite (290 mTV) layers.

All wells, except ROW3, are connected to Zechstein Carbonate reservoirs, namely the ZeZ2C and ZeZ3C. ROW3 is connected to the Carboniferous sandstone reservoir.

3 Injection performance - Actual versus Plan

In this chapter the actual water injection, which was performed in Twente over the first 5 years of operation (2011-2015), is being discussed and compared to the plan as it was presented in the water injection FDP[10]

In the Schoonebeek FDP the assumption was that during the first 3 years of operations the water injection would be at a plateau rate as high as 12,500 m^3/d. In reality, the actual total injection rate has only been 4,000-5,000 m^3/d, which is significantly less than what was assumed in the FDP (Figure 3). The difference between actual and expected injection rates in the FDP is due to lower production rates of Schoonebeek Oilfield production wells.

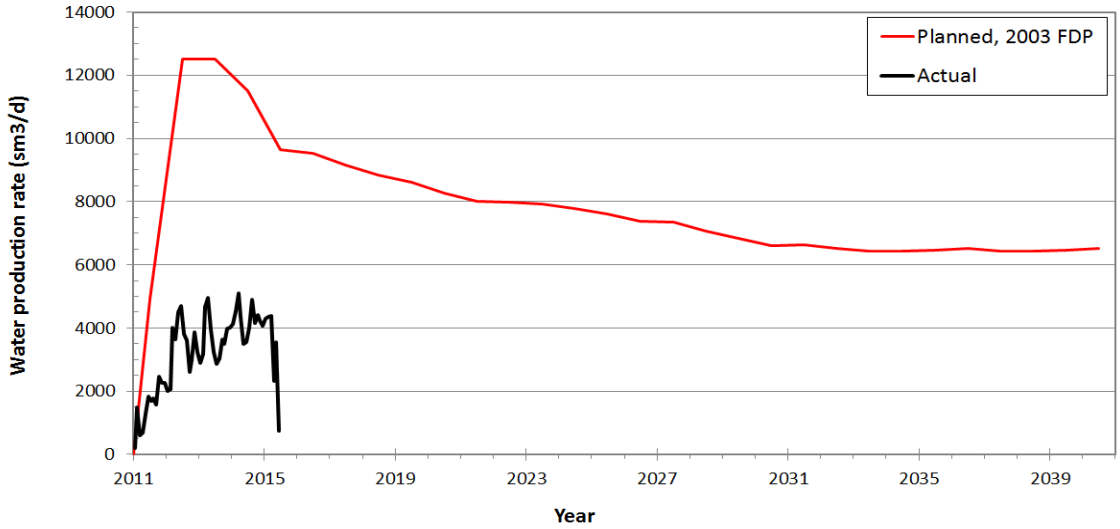


Figure 3 – Actual water injection rates compared to planned in FDP

Figure 4 shows the cumulative volume of water that has been injected in the 11 available water injection wells from start of injection in 2011 until June 2015. This figure shows that, for the wells evaluated in this report, water has mainly been injected into well ROW2. Wells TUM1, TUM2 and TUM3 show poor to moderate injection performance (<20 m^3/d/bar) in combination with a reservoir pressure that increases faster compared to the reservoir model (Chapter 4.3). Therefore, injection into these wells has been limited. Well ROW3 has been shut-in most of the time, because the injection pressure required to inject at the minimum pump rate rapidly reached the THP limit and, consequently, water injection was stopped. The data point to a very low reservoir injectivity.

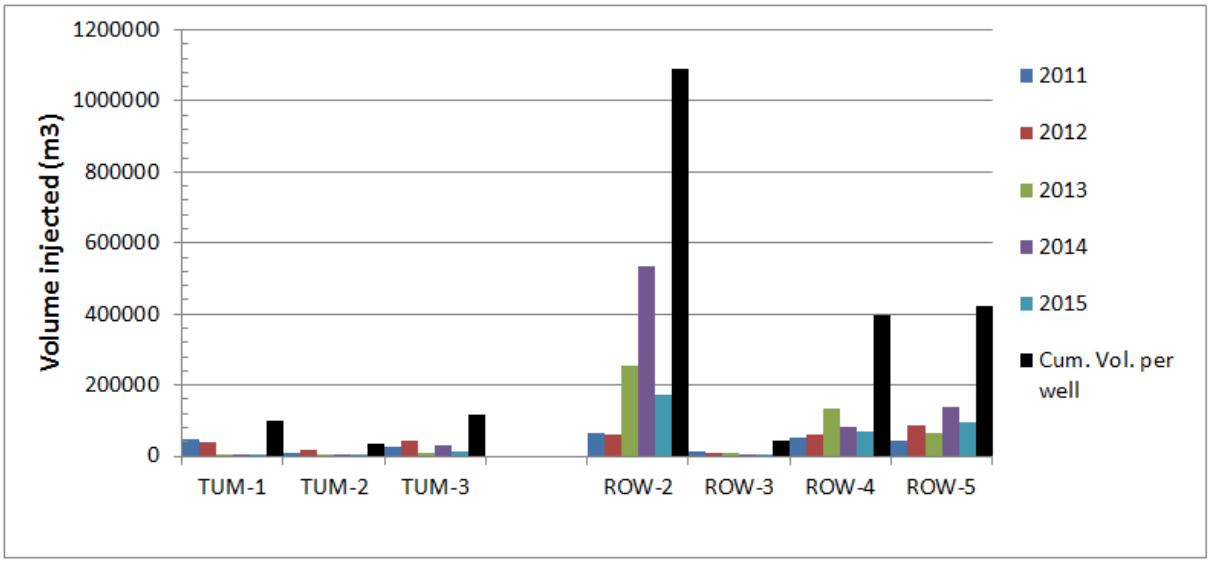


Figure 4 - Cumulative injective volume per year for the evaluated water injection wells

Table 1 lists the total cumulative water volume that has been injected per location from the start of injection in Q1 2011 until June 2015. Because of the lower than expected water injection rate, the total injected volume at all locations is still much lower than the volumes allowed according to the water injection permit for each location.

[10] Schoonebeek Oilfield Redevelopment - VAR 3 Field Development Plan. Final Version. EPE200401201716, October 2003

Table 1 – Cumulative injected water volume per location until June 2015 in comparison with the allowed volume according to the water injection permit for each location

Location	Injection well	2011 [m3]	2012 [m3]	2013 [m3]	2014 [m3]	2015 [m3]	Cumulative per well [m3]	Cumulative per location [m3]	Total permitted cumulative volume [m3]
Tubbergen Mander 1	TUM-1	46,557	40,532	5,373	315	4,909	97,686	97,686	1,570,000
Tubbergen Mander 2	TUM-2	9,845	18,495	1,597	1,322	2,624	33,883	152,062	2,200,000
	TUM-3	26,603	41,234	6,916	29,262	14,164	118,179		
Rossum-Weerselo 2	ROW-2	65,318	61,786	254,802	536,105	173,711	1,091,722	1,091,722	19,100,000
Rossum-Weerselo 3	ROW-3	14,798	9,440	10,241	5,499	4,144	44,122	440,972	7,800,000
	ROW-4	50,785	59,786	135,107	83,593	67,579	396,850		
Rossum-Weerselo 5	ROW-5	41,327	86,908	63,247	137,119	94,091	422,692	422,692	6,590,000

4 Water injection and integrity of reservoir confining seals

4.1 Introduction

During produced water reinjection, it is important that the water is injected and contained within the targeted injection reservoir and that any possible upward migration that could result in exposure and contamination of shallow aquifers is prevented. It is essential therefore that the containment layers directly above and below the injection reservoir and the confinement layers surrounding the containment layers are not affected by the injection process. Especially, fracture propagation and/or migration of injected water into the confining layers must be prevented. The depleted gas reservoirs in Twente, in which water is injected, are mainly Zechstein Carbonate reservoirs (ZeZ2C and ZeZ3C) with an existing natural fracture network. The containment layer is formed by a water insoluble Anhydrite layer that is surrounded by Halite, which then is the sealing confinement layer. Well ROW-3 is injecting into the tight Carboniferous Sandstone formation, for which the ZeZ1-Anhydrite and ZeZ1-Halite layers above the Carboniferous form the containment and confining layer, respectively. For the Tubbergen-Mander reservoirs the confinement layer is the Bunter sandstone formation which includes sealing shales.

To ensure integrity of the confining layers, the following monitoring and controls are in place:

- Average reservoir pressure should not exceed the original pressure, i.e. the reservoir pressure prior to gas production.
  At the original reservoir pressure, the confining layers have sealed the gas bearing reservoirs for millions of years. Hence, it is not realistic that at lower reservoir pressure injected water (which is much heavier than gas) will migrate upwards through these layers. The pressure at reservoir depth has been measured every year during the injection period so far.
- The injection pressure at surface is constrained to avoid that the injection pressure downhole exceeds the minimum in-situ stress of the sealing confinement layer. The maximum tubing head injection pressures are, therefore, calculated based on the fracture pressure gradient of the reservoir seal:

$$THPi_{max} = F.G._{seal} \times TVD_{bottom\ seal} - P_{hyd}$$

  In which:
  - $THPi_{max}$ = the surface injection pressure limit (bar)
  - $F.G._{seal}$ = the fracture gradient of the disposal reservoir confining layer (bar/m)
  - $TVD_{bottom\ seal}$ = the true vertical depth at the bottom of the reservoir seal, i.e. at top disposal reservoir
  - P_{hyd} = hydrostatic pressure (assuming water density of 1.05 sg)

  To apply conservative $THPi_{max}$, note that the frictional pressure drop in the tubing is ignored. This friction can be as much as 45 bars (at 2000 m^3/d flowing through a 3.5“(OD) 1200 m long injection tubing). In addition, it is assumed that the entire wellbore is filled with water.
- Propagation of the existing natural fracture network in the Zechstein Carbonate reservoir or propagation of (an) induced fracture(s) in the Carboniferous Sandstone was surveyed by the execution of injection step-rate tests (SRT’s) and pressure fall-off (FO) tests. Plotting stabilized bottomhole pressure (FBHPi) as function of increasing injection rate gives information on the injectivity. In non-fractured reservoirs, such as the Carboniferous Sandstone reservoir, it will be evident from the change in the slope of the step-rate curve that formation breakdown has occurred and/or that fracture propagation has occurred. In the naturally fractured Carbonate, a slope-change would indicate extension of the fracture network which would result in an increased injectivity.

The static reservoir pressures determined from static pressure and temperature gradients (SPTG’s), the actual surface injection pressures (THPi) and the injectivity and step-rate/fall-off tests are discussed below in Chapters 4.2, 4.3 and 4.4, respectively.

4.2 Static pressure gradient surveys

To determine the local pressure for each well at reservoir depth, a pressure/temperature gauge is run-in hole on wireline down to reservoir level. Subsequently, it’s pulled upward to measure the pressure (and temperature) at various depths. As the well is shut-in sufficiently long prior and during the survey, static pressure and temperature gradients (SPTG) can be determined along the wellbore. Often, liquid levels in the wellbore can also be observed. Because the near-wellbore pressure (FBHPi) during injection is higher than the average reservoir pressure, the pressure that is measured with the survey is usually higher than the actual (far field) reservoir pressure. It is, therefore, important that the well is shut-in sufficiently long prior to the pressure survey to allow the pressure to equalize and approach the far-field reservoir pressure. In case the injectivity is moderate or poor and the shut-in period is too short, the derived pressure at the wellbore can be significantly higher than the average reservoir pressure. Regarding the injectivity in relation to shut-in time, injection modelling performed by Horizon Energy

Partners explains that the injectivity is expected to drop in time due to gas/water displacement effects[11]. In initial stages only a small ring of water is present around the water injection well. As the injection water is much more viscous than the gas, present in the reservoir, this means that initially only a relatively small overbalance is required to achieve the desired injection rate. During the injection period this water ring will grow requiring a higher overbalance. Hence, the injectivity is expected to decrease over time requiring longer shut-in period, as well. Step-rate tests and fall-off tests in the Twente water injectors over time have shown that it takes longer time each year, up to months even, before pressures stabilize.

The pressures at top perforations derived from the SPTG-surveys and the corresponding shut-in times from start of injection are listed in Table 2. Pressures from build-up and fall-off tests are included. With the latter, a memory pressure gauge is installed as close as possible above top perforations and left in-hole during the test period.

Table 2 - Pressure (at top perforations) development per well

Well	Original reservoir pressure (bar)	Pressure @ top perforation (bar)	Pressure @ top perforation (bar)	Shut-in time (days)	Pressure @ top perforation (bar)	Shut-in time (days)	Pressure @ top perforation (bar)	Shut-in time (days)	Pressure @ top perforation (bar)	Shut-in time (days)	Pressure @ top perforation (bar)	Shut-in time (days)
TUM1	190	2009	Nov-11		Nov-12		Nov-13				Nov-15	
		37	90	<<1	143	2	89	260			77	172
			Nov-11									
			79	3								
TUM2	190	2009	Nov-11		Nov-12		Nov-13				Nov-15	
		60	133	<1	124	14	96	262			98	172
TUM3	190	2009	Nov-11		Nov-12				Mar-14		Feb-16[1]	
		63	68	3	75	3			76	242	88	263
									Sep-14			
									85	7		
ROW2	150	2009	Nov-11		Nov-12		Jan-13		Apr-14		Sep-15	
		7	10	<1	11	160	10	9	32	4	23	95
ROW3	199	2009	Nov-11		Mar-12		Feb-13				Feb-16[2]	
		71	119	13	106	28	119	22			117	270
							Nov-13					
							139	5				
ROW4	150	2009	Nov-11		Dec-12				Apr-14		Sep-15	
		8	45	3.7	39	6			37	13	39	81
									Sep-14			
									60	14		
ROW5	150	2009	Nov-11		Nov-12		Dec-13		Oct-14		Sep-15	
		6	8	2	9	14	9	37	10	1	13	103

[1] Initial attempt on 24th of August 2015 to execute SPTG failed, due to tool hold-up at 500 mAH

[2] Postponed from 2015 to 2016 because of lower priority and no injection in the mean time

mmm-yy Pressure derived from static pressure gradient measurement

mmm-yy Pressure derived from pressure build-up and pressure fall-off tests

From the table it is clear that the actual pressure in the various reservoirs is significantly lower than the original reservoir pressure. The last pressure measurements in 2015 were all carried-out after the wells were shut-in for a long period. This period is assumed long enough, at least for the wells that show good injection performance (ROW2 and ROW5,) to let the near-wellbore pressure decline sufficiently to achieve a good estimate of the actual average reservoir pressure.

The expected development of reservoir pressure as a function of injected water volume was predicted prior actual injection for each well. Hereto, the water storage capacity was determined for each well by dividing the total amount of gas produced with the original gas formation volume factor[12,13]. The reservoir pressure prediction as a function of injected volume is presented per well in Attachment 8. The actual downhole pressures, reported in Table 2, have been included in these graphs. The attachment shows that the measured local pressure (ref: top perforations) in wells TUM1, TUM2, TUM3 and ROW3 is increasing faster than the predicted pressure according the model. This is also the case for ROW2 and ROW5, but here the increase is small compared to the original pressure. The faster pressure increase can be explained by the fact that apparently the reservoir is less accessible to water than to gas, because of poorer connection to the fracture network or to a network with a lower fracture density, and that not all pores (certainly those that are in the tight carbonate matrix and contained gas) will be re-filled with water resulting in a lower effective storage capacity than assumed in the prediction. For ROW3 it is

[11] P.J. Weijermans - Schoonebeek Produced Water Disposal Study, Dynamic Modelling of Water Injection in Depleted Naturally Fractured Zechstein Carbonates. EP201405202187, June 2004.

[12] P.J. Weijermans and G. Warren – Dynamic Modelling of Produced Water Reinjection in Depleted Naturally Fractured Gas Fields. SPE99242, June 2006.

[13] T. Vandeweyer - Technische beschrijving Water Injectie Schoonebeek Project. EP200907328363, Juli 2009.

believed that the well is connected to a smaller reservoir compartment in comparison to the produced gas volume. The Carboniferous (DC) map of the Rossum-Weerselo field shows that only a small corridor exists from this small reservoir compartment to the remainder of the ROW Carboniferous. During the gas production phase this corridor was apparently big enough for significant amounts of gas to flow through. However, during the water injection phase this corridor forms a significant blockage to water flow.

For ROW4, when the first local pressure measurement, after injection started in 2011, is compared to the pressure at the start of the injectivity test in 2009, there is a pressure offset. However, apparently, the pressure remains more or less constant during the injection period thereby still following the model.

This pressure offset is also present with wells TUM1, TUM2, TUM3 and ROW3. Upon further data analysis it was discovered that the offset can be explained due to pumping a large volume (>30 m^3) of hot boiler feed water one day before the execution of the pressure survey to prevent the tools to stand-up while run-in-hole. Basically, the disadvantage of this is that for wells that show a low to moderate injectivity (0-30 m^3/d/bar, from injectivity tests, ref. Chapter 4.4.1, Table 5 the shut-in time is not sufficient, consequently. Typically, the injectivity of wells TUM1, TUM2, TUM3, ROW3 and ROW4 is in this range.

The injected volume of water thus far is listed in Table 3 for each well. The relatively small amounts, compared to the expected storage capacity for each well, have resulted in an actual pressure that is significantly below the original reservoir pressure. This, in combination with the unclear pressure trends in wells such as TUM1, ROW2, ROW4 and ROW5, would lead to a highly arbitrarily and inaccurate readjustment of the modelled storage capacity. For that reason, it is proposed to not yet adjust the model, but keep monitoring pressure trends each year according the Water Injection Management Plan until it is more obvious how the pressure develops.

Table 3 – Injected volume of water compared to modelled and permitted capacity

Location	Well	Injected volume mln m^3	Modelled capacity[1] mln m^3	Degree of filling %	Permitted capacity[2] (per location) mln m^3	Capacity used (per location %
TUM-1	TUM-1	0.098	2.6	3.7	1.57	6.2
TUM-2	TUM-2	0.034	1.8	1.9	2.2	6.9
	TUM-3	0.118	1.2	10.2		
ROW-2	ROW-2	1.092	13.2	8.3	19.1	10.3
ROW-3	ROW-3	0.044	2.2	2.0	7.8	5.7
	ROW-4	0.397	4.0	9.9		
ROW-5	ROW-5	0.423	5.3	8.0	6.59	6.4

[1] Assuming an initial gas saturation of 80%

[2] According 'Vooschriften Wel Milieubeheer' in granted Waterinjection Permit

4.3 Injection pressures

Occasionally, increasing THPi was observed during shut-in periods. This is due to gas migrating from the gas reservoir into the well, building up a gas pressure at surface, when the hydrostatic pressure in the well is lower than the static reservoir pressure. Because it is not likely that the wellbore is completely water-filled during shut-in (resulting in a significantly lower hydrostatic pressure than listed in Table 4), fracturing the confining cap rock is not possible at this THP. For that reason, shut-in pressures are not reported.

Table 4Table 4 presents the maximum injection pressure for all water injection wells observed at surface (THPi) during the entire injection period. It is clear that the injection pressure remained well below the set THPi-limits for the wells. For the wells TUM1, TUM2, ROW3 and ROW4 the maximum THPi has been closer to the set THPi-limits. This is due to a combination of a high local reservoir pressure and poor to moderate injectivity. For well ROW4 the THPi is high most of the time (>1000 m^3/d). This is believed to be due to poor connection to the low density fractured network given the 0 degrees phasing of the perforations (Chapter 4.4.2). To improve the connectivity to the fractures, 60 degrees phased, 6 spf perforations were added in May 2015. Unfortunately, because injection was stopped shortly thereafter, the benefit of additional perforating could not be shown, yet.

Occasionally, increasing THPi was observed during shut-in periods. This is due to gas migrating from the gas reservoir into the well, building up a gas pressure at surface, when the hydrostatic pressure in the well is lower than the static reservoir pressure. Because it is not likely that the wellbore is completely water-filled during shut-in (resulting in a significantly lower hydrostatic pressure than listed in Table 4), fracturing the confining cap rock is not possible at this THP. For that reason, shut-in pressures are not reported.

Table 4 – Surface injection pressure (THPi) over the entire injection period compared to the THPi limit

Location	Well	THPi, range (during injection period) bar	THPi, max bar	Injection rate (@THPi, max) m^3/d	THPi, limit bar	Hydrostatic pressure (with fluid column to surface) bar	BHPi,max (calc. excl. ΔPfriction) bar	BHPi,max (calc. incl. ΔPfriction) bar	Injection rate (@BHPi, max) m^3/d	σ_h,min (confining cap rock) bar
TUM-1	TUM-1	44 ⇨ 2	44	210	59 (-20%)	164	208	205	210	246 - 287
TUM-2	TUM-2	48 ⇨ 4	48	100	62 (-20%)	169	217	212	100	256 - 296
	TUM-3	11 ⇨ 2	11	90	61 (-20%)	168	180	179	90	254 - 295
ROW-2	ROW-2	6 ⇨ 11	11	2050	115 (-10%)	113	124	118	650	245
ROW-3	ROW-3(DC)	155 ⇨ 168	168	600	180 (-10%)	174	342	335	600	382
	ROW-4	94 ⇨ 116	116	>1000	131 (-10%)	127	243	215	1050	278
ROW-5	ROW-5	7 ⇨ 4	10	680	124 (-10%)	120	130	127	680	262

From the table it is also clear that for all wells the maximum bottom hole pressure ($BHPi_{max}$) has never exceeded the minimum in-situ stress (σ_h,min) of the confining ZeZ-Halite (for the ROW- wells) and Buntersandstein (for the TUM-wells) layers, not even when pressure friction loss is ignored.

As explained, a conservative THPi-limit was calculated assuming a liquid column to surface without taking into account friction losses during injection. To assess the true risk of exceeding the σ_h,min of the confining layer, the $BHPi_{max}$ including friction loss is listed in Table 4, as well.

The $BHPi_{max}$ during the entire injection period was determined retrieving THPi and injection rate from field data (PI). The pressure friction loss ($\Delta P_{friction}$) over the entire tubing length was calculated at each rate for the respective tubing ID. The $BHPi_{max}$ was then calculated via the following equation:

$$BHPi_{max} = THPi_{max} + P_{hyd} - \Delta P_{friction}$$

Because the exact liquid level in the wellbore during injection is unknown, for the hydrostatic pressure (P_{hyd}) a liquid column to surface is assumed. However, for those wells that show excellent injectivity (mostly indicated by a low THPi) the liquid column is much smaller. It is known from injectivity tests that for some wells (such as ROW-5, for instance) the liquid level remained even below the depth at which the downhole pressure gauge was installed, even at very high injection rates.

As a typical example, Figure 5 shows the BHPi with the $\Delta P_{friction}$ taken into account as function of the injection rate for well ROW-4 during the entire injection period. Note that the THPi is increasing with increasing injection rate, but that the BHPi decreases due to pressure friction loss in the tubing, when it is assumed that the tubing is always completely water-filled. As obvious from Figure 5 the pressure friction loss is significant at high injection rates and should not be ignored. The highest BHPi is achieved at low injection rates and low THPi. This results from the incorrect assumption that the wellbore always contains fluid to surface. It is likely that liquid levels are lower at low injection rates, such that the hydrostatic head is over-estimated. In well ROW4 the impact of pressure friction loss is large because of the high injection rate in combination with the small 3½" (OD) tubing (2.922" ID).

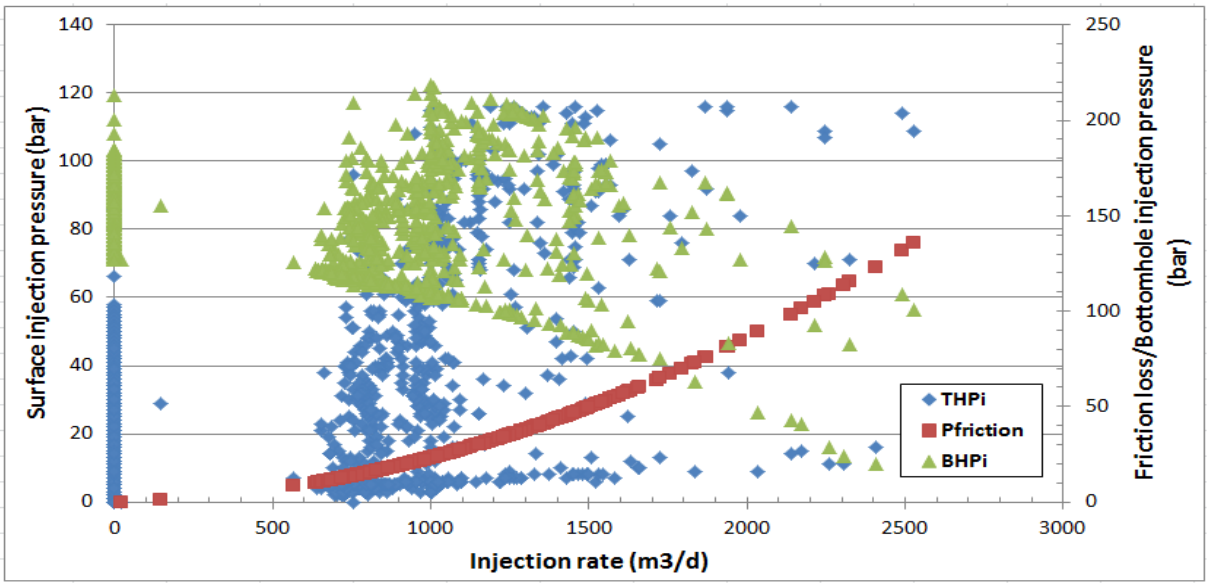


Figure 5 – Relation between THPi and BHPi for injection well ROW-4 taking into account tubing friction loss as function of the injection rate during the entire injection period.

Despite the good injectivity of wells ROW2 and ROW5, the difference in BHPi due to friction loss are only a few bars because of the large(r) tubing (5" OD). All other wells have a poor or moderate injectivity at which, consequently, injection rates and friction losses are lower. For these wells the BHPi's with and without friction loss are almost similar and so is the injection rate at which $THPi_{max}$ and $BHPi_{max}$ occur.

The injection pumps have been equipped with alarms and trip settings to avoid that the THPi limit is exceeded. In case the alarms are missed in the system, as a second barrier, a Pressure Safety Valve will open. In addition, a safety margin of 10% for the Halite and 20% for the Buntersandstein is applied to the calculated THPi limit to arrive at a maximum THPi applied in practice.

4.4 Well injectivity

4.4.1 Step-rate tests

In all cases, because of the low reservoir pressure and, consequently, low fracturing pressure (i.e. σ_h,min) of the reservoir, in the FDP water injection was expected to occur at fracturing conditions[14]. However, in most of the wells, apart from well ROW3, the water is injected into depleted Zechstein Carbonate reservoirs containing an extensive fracture network already. Here, the existing fractures are filled with the injected water without creating new fractures or propagating existing fractures. Still, during water injection, injectivity tests were executed to verify that fractures have not propagated into the confining Halite layer.

Initially in 2009 and during the first 3 years (2011, 2012 and 2013) injectivity/step-rate tests (SRT) have been carried-out in each water injection well. The test is carried-out with a memory pressure gauge installed in the tailpipe nipple of the completion close to the injection reservoir. Subsequently, injection is started and the injection rate (Q) is increased in steps. During each step the injection pressure is expected to stabilise. Plotting stabilised bottomhole pressure (BHPi) versus injection rate then gives information on the injectivity. In non-fractured reservoirs, such as the Carboniferous (DC) sandstone reservoir (for ROW3), it is evident from the change in the slope of the step-rate curve that formation breakdown has occurred and that a fracture is propagated in case injection is continued (Attachment 8.2). For the ZeZ2C and ZeZ3C formations, however, injection water merely fills the existing fracture network. For that reason, a change in the slope of the step-rate curve is not observed.

The SRT-plots are shown for each well in Attachment 8.2. From the plots, showing the BHPi (at top perforations) vs. Qinj, it is obvious from the slope change that formation breakdown occurred during the injectivity test in ROW3 in 2009. Consequently, the injectivity (expressed in m^3/d/bar) increases.

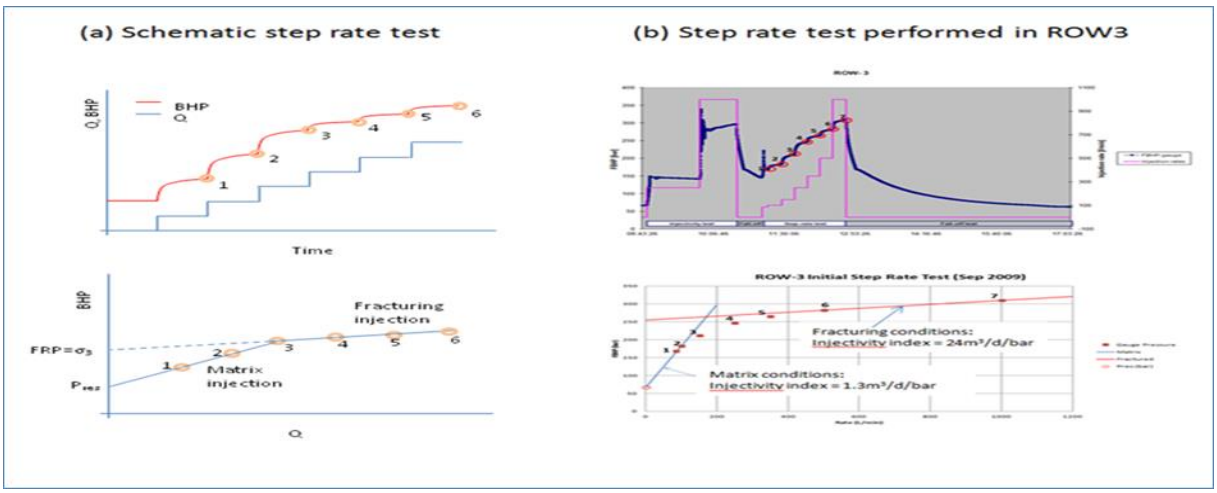


Figure 6 – Step-rate test principle applied in well ROW3

For the other wells, where water is injected into the fractured Zechstein Carbonate reservoir, most SRT-plots show a linear trend. As expected, in most wells only a low BHPi (<σ_h,min) is required to inject the planned water volumes. The curve intersects the y-axis at approximately the local near-wellbore pressure. Note that the SRT in TUM1 in June 2009 does seem to indicate formation breakdown. However, in TUM1 the formation breakdown pressure only matches with a Poisson's Ratio of 0.11, which is far too low (range 0.25 – 0.4, depending on porosity).

Table 5 lists the injectivity derived from the SRT's carried-out in the first five years. In the table it is indicated whether the pressures had properly stabilised during the various steps and the duration per step, as well. The time required to achieve stable BHPi was determined from the injection pressure reading at surface (THPi). For that

[14] Schoonebeek Oilfield Redevelopment - VAR 3 Field Development Plan. Final Version. EPE200401201716, October 2003

reason, it could only be verified that BHPi had really stabilized from the gauge read-out once they were retrieved. In case pressure stability is indicated as poor or very poor, the outcome of the SRT must be used with care.

Table 5 shows very good initial injectivity for wells ROW2, ROW4 and ROW5. In those wells the injectivity could not be measured as the fluid level did not reach the installed BHP-gauge or BHPi more or less remained constant with increasing injection rate. Currently, the injectivity in wells ROW2 and ROW5 is still considered high, whereas in wells TUM3 and ROW4 it appears to be moderate, but constant. The injectivity performance in TUM1, TUM2 and ROW3 is poor. The injectivity of TUM3 is better than the injectivity of the other two injection wells (TUM1 and TUM2) in the Tubbergen-Mander field, because TUM3 is an open hole completed, horizontal well that, therefore, intersects more effectively with the existing fracture network. For ROW3, to operate within the operational envelope of the injection pump, injection cannot be sustained as the THPi-limit is reached within a day at the minimum pump rate. For that reason, minimum amounts of water have been injected. In the last 2 years, wells TUM1 and TUM2 have been largely shut-in. Water was injected occasionally to control wellhead pressure build-up due to reservoir gas ingress.

The low injectivity in ROW3 is due to the fact that the Carboniferous sandstone reservoir for this well does not contain a natural fracture network. Formation breakdown was achieved, in a controlled way, during the injection test in 2009, but the resulting fracture(s) is (are) too small to achieve a good injectivity, or have closed again since It is known that formation breakdown and fracture propagation must occur at very high rate, especially when water is injected, to create a single fracture, rather than multiple small fractures. From the SRT-plot it is clear that formation breakdown occurred at a pump rate of 150-200 l/min. For comparison, in hydraulic fracturing, with viscosified brine, the injection rate applied for formation breakdown and fracture propagation is typically 2500-3500 l/min to ensure that a single fracture is generated. Hence, it is likely that multiple small fractures were created in ROW3 that have not propagated sufficiently. In case these small fractures get plugged with debris and/or waxy oil, they even will not propagate further or re-open, which then explains the poor injectivity.

Acid stimulations have been carried out to improve the injectivity in ROW4 in May 2012 and June 2013. However, the acid stimulation in ROW4 did not improve injectivity. Main difference between the two stimulations is that in May 2012 30 m^3 15% HCl was pumped, preceded by a solvent preflush, whereas in June 2013 100 m^3 28% HCl was used.

An essential observation from Table 5 is that every subsequent year the required stabilisation time becomes longer. Before start of water injection it appears that the injection pressures stabilised within hours whereas after 3 years of injection rate steps need to last for weeks to ensure stabilisation. This is attributed to the increasing volume, and hence radius, of water build-up around the well and associated gas/water mobility. In practice, because of required available injection capacity, scheduling SRT's becomes increasingly difficult with a risk of poorer data quality.

In 2014 and 2015 no more injectivity tests have been carried-out. On request of SodM, in 2015, NAM made an update of the Waterinjection Management Plan. In this update it is proposed to remove the injectivity- and fall-off tests from the mandatory annual surveillance activities as listed in the Water Injection Management Plan[15]. Instead, injectivity is surveyed more by daily monitoring of the surface injection pressure (THPi) at actual injection rate in combination with static reservoir pressure. In case, unexpected changes in the injectivity are noticed that cannot be explained, the well will be shut-in and an investigation will be carried-out for which an adhoc injectivity test could be necessary. SodM has agreed with this proposal, but mentions that based on advice of external experts, the decision might be revisited if required[16].

[15] Concept Addendum Waterinjectie Management Plan - Voorstel om het surveillance programma voor waterinjectie en de tabel voor jaarlijkse rapportage aantepassen . EP201504208558, april 2015

[16] Staatstoezicht op de Mijnen – Uw addendum op het evaluatierapport Twente waterinjectie, kenmerk 15137190. EP201510202648 (oktober 2015)

Table 5 – Step-rate test overview per well during entire the entire water injection period

Year	Well / Parameter	TUM1	TUM2	TUM3	ROW2	ROW3	ROW4	ROW5
2009	**Injectivity, m3/d/bar**	7 (matrix) 195 (fractured)	21	8	733	1 (matrix) 26 (fractured)	-	-
	Pressure stability	Poor	Poor	Poor	Poor	Very good	-	-
	Duration per step	15 min	15 min	15 min	15 min	15 min	15 min	15 min
	Remark	Fracture re-opening/ re-connection			BHP almost independent of inj. rate	Formation breakdown	No data, BHP independent of injection rate	High injectivity, no fluid at BHP gauge depth
2011	**Injectivity, m3/d/bar**	12	-	9	324	-	6	-
	Pressure stability	Reasonable		Good	Very poor	-	Very poor	
	Duration per step	1 day		1 day	1 day	-	1 day	
	Remark		Only one rate was tested	Limited rates: 100 to 120 m3/d		No sustained injection		High injectivity, no fluid at BHP gauge depth
2012	**Injectivity, m3/d/bar**	5	-	11	79	-	7	-
	Pressure stability	Reasonable	Very poor	Good	Very poor	-	Very poor	
	Duration per step	7 days	7 days	7 days	5-7 days	-	5 days	
	Remark		Not possible to derive injectivity	Limited rates:100 to 150 m3/d	Test extended until Jan 2013	No sustained injection	Acid stim. in May prior SRT	High injectivity, no fluid at BHP gauge depth
2013	**Injectivity, m3/d/bar**					-	6	-
	Pressure stability					-	Very poor	
	Duration per step					-	5-7 days	
	Remark	Well is shut-in long term	Well is shut-in long term	Well is shut-in long term		Well is shut-in long term	Acid stim. in June prior SRT	High injectivity, no fluid at BHP gauge depth
2014	**Remark**	No injectivity tests carried-out						
2015	**Remark**	No injectivity tests carried-out						

4.4.2 Pressure fall-off tests

Multiple pressure fall-off surveys have been conducted, mostly in conjunction and after the injectivity tests. The original objective of these pressure fall-off tests was to determine the fracture closure pressure or minimum horizontal stress (σ_h,min). However, as explained in Chapter 4.4.1, for all wells except ROW3 water injection occurs in the existing network of natural fractures in the Zechstein Carbonates at a lower pressure than the σ_h,min. Consequently, it is not possible to determine the minimum horizontal stresses from the pressure fall-off curves.

For a number of fall-off tests it was possible to derive permeability estimates from pressure transient analysis. This permeability should be interpreted as the effective permeability of the combined matrix and natural fracture system. The result of the pressure transient analysis in ROW4 is presented in Table 6. Dual porosity models were applied, in an attempt to obtain characteristic parameters of the natural fracture system. All fall-offs are highly affected by large wellbore storage effects resulting from falling liquid levels and fluid redistribution effects. As a result, the pressure response misses the true characteristics of a dual porosity system. Therefore, the fracture spacing values listed in Table 6 are merely indicative.

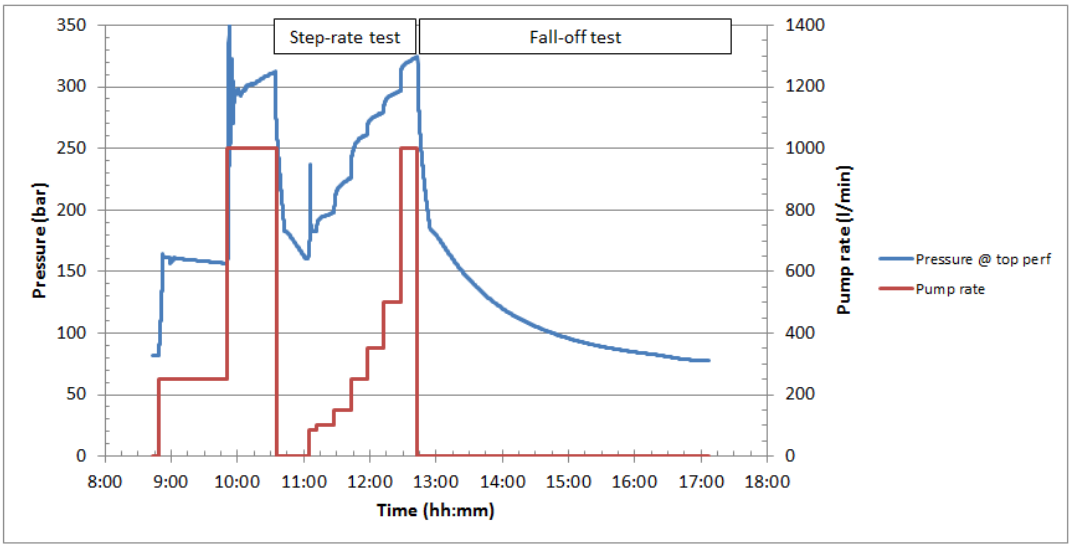
The results suggest that ROW4 has a low fracture density (i.e. larger fracture spacing) resulting in a lower effective permeability. ROW4 also had a lower productivity during the gas production phase (Q_{50} in ROW4 was only 125,000 Nm^3/d).

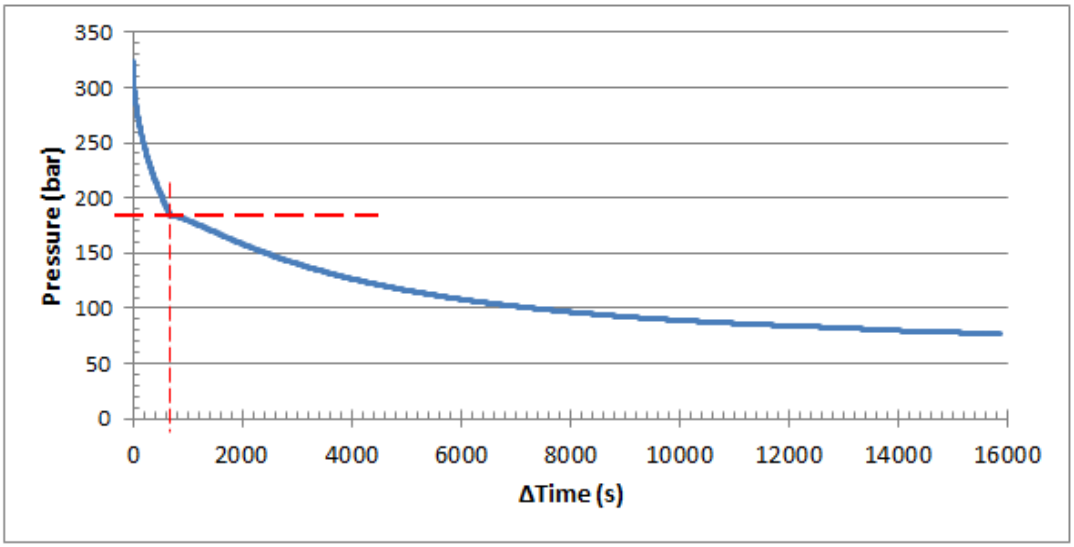
Table 6 – Results of the pressure transient analysis of the fall-off tests

Well	Fracture spacing, m	Permeability, mD	Skin	Quality of fall-off test data
ROW4	1	4		poor

In ROW3 it was clear that a fracture was created as explained in Chapter 4.4.1. Figure 7 shows the ROW3 pressure curves during injection and fall-off. The pressure during the fall-off test is presented both as function of the shut-in time (i.e. the time since the pump is stopped) and as function of the square-root shut-in time. The slope change indicating fracture closure can be clearly observed. The fracture closure pressure at about 185 bars is similar to the step-rate pressure where the injection pressure starts to deviate from the matrix injectivity. At this pressure (small) fractures are initiated in the formation resulting in increasing injectivity when the fractures are extended. Using Eaton's equation to calculate the σ_h,min, a closure pressure of 185 bars matches with a Poisson's ratio of 0.26, which is typical for sandstone formations. Because fractures that are initiated by water only (instead of a viscous fluid) do have a narrow width usually, the closure time of almost 9 minutes is surprisingly long. This indicates the tight character of the Carboniferous sandstone.
Still, because the fracture closure slope change does not feature as smooth as normal in pressure fall-off curves, the FO-test was closely investigated in September 2014. From this analysis, using the primary pressure derivative of the FO-data, it was concluded that the 'kink' could not be due to fracture closure[17].

[17] A.J. Landman - Analysis of Step-Rate-Injection and Fall-Off tests in ROW-3. EP201409211258 (September 2014)





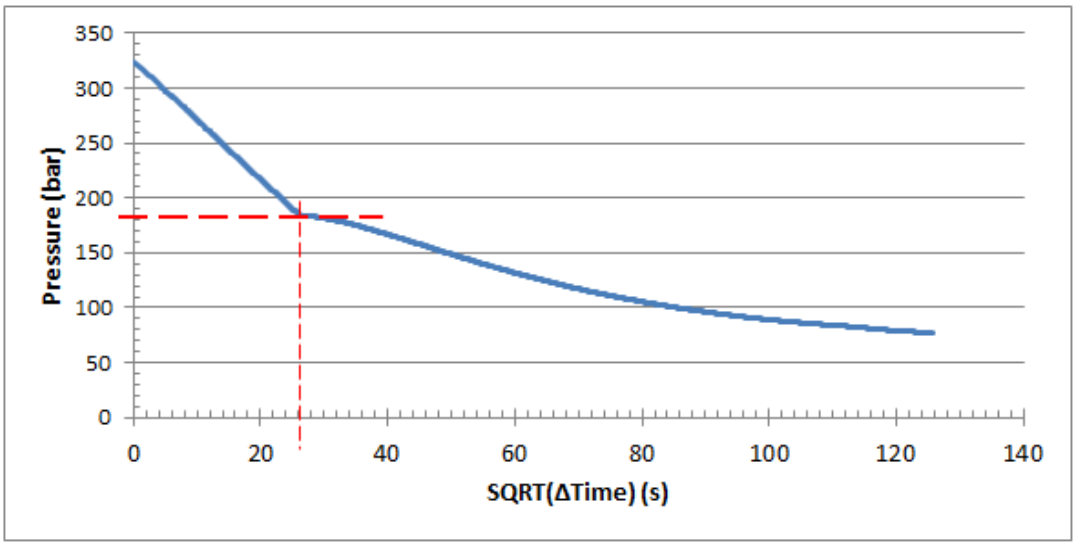


Figure 7 – Step-rate and fall-off pressure curves during the ROW3 injectivity test (figure at the top) that are used to determine the fracture closure pressure by pressure fall-off (decline) analysis (bottom two figures).

5 Management of Halite dissolution risk

5.1 Introduction

The injection water is under-saturated with salt and the salinity will decrease further as time progresses due to condensed steam breaking through from the Schoonebeek steam injection wells to the Schoonebeek production wells. This means that the injection water has a significant capacity to dissolve salt.

Figure 8, which shows a typical water injector well schematic where the production packer is set above Halite layers present in the Zechstein formation. To assess the Halite dissolution risk, modelling was performed by Shell P&T in Rijswijk[18]. The results of the modelling indicate that significant Halite dissolution can only take place near the injection well in case two specific conditions are simultaneously met. Only in case the production casing is leaking and its cement bond has also degraded, there is a path for water to flow directly past the Halite formation[19] potentially leading to Halite dissolution. If only one of these two conditions is met, the injection water can come into contact with the Halite, but due to lack of flow it cannot dissolve significant amounts of Halite. The confining Halites under and above the target reservoirs in ROW are shielded by the containing Anhydite layers, which implies that further away from the well, injected water cannot contact the Halite.

In order to mitigate the risk of Halite dissolution, a monitoring scheme, consisting of temperature logging, casing calliper surveys and cement bond logging (CBLs), was therefore applied to verify the status of the production casing and cement at the level of these Halite sections. The monitoring results for each survey are discussed in the next sections.

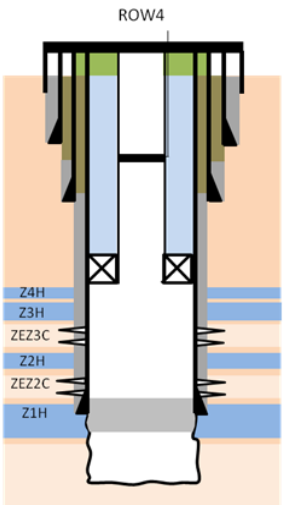


Figure 8 - Typical water injector well schematic showing Halite sections behind production casing (ZnH represents salt layers, ZeZnC represents carbonate layers where the water is injected into. Between the salt and carbonate layers is a thin Anhydrite layer)

5.2 Temperature logging

Temperature logging has been performed to check whether injection occurs into the injection reservoirs only or also into Halite sections. For this a temperature log was run several days after injection had been stopped. Herewith the layers that received most injection are expected to warm back much slower than layers where no injection occurred. This is based on the fact that the injection water is much cooler than the injection reservoirs and surrounding reservoir seals.

The temperature survey results have been summarised in Table 7. Injected volume during a representative period and shut-in time prior logging are specified. It must be mentioned that water in case it was injected intermittently in that period, short shut-in periods were ignored. Observations and comments on the temperature logging result are listed in the table for each well. The temperature surveys are shown in Attachment 8.3. The red curve represents the undisturbed geothermal gradient that is generally applied for the underground in The Netherlands (i.e. undisturbed temp. = 10.1°C + 0.031°C/mTV).

For all wells it is clear that warm-back is slower in the target injection reservoir compared to that of the overlying and underlying layers. Unambiguous verification of injection into the Carbonate formations only is masked by the varying (i.e. volume injected and shut-in period prior to logging) at which the temperature surveys are executed. In those wells where very large volumes of water were injected, the layers above the injection reservoir were

[18] C.P. Pentland - Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal. EP201310203080, September 2013

[19] Overkoepelende analyse ondergrondse risico's waterinjectie Twente. EP201503228132 (revision 1), november 2016

significantly cooled-off. This is clear from the temperature logs in well ROW2 (35000 m^3) where the measured temperature above the perforations significantly deviates from the undisturbed temperature.

Table 7 - Temperature survey results

Well	Date of survey	Injection volume (injection period)	Shut-in period	Injection into injection reservoir	Clear injection points identified within ZeZC	Comments
	dd-mon-yy	m3		yes/no /unclear	yes/no /unclear	
TUM1	08-Nov-12	4,000 (27 d)	14 d	yes	yes	(Slight) temperature minima at perforations in ZeZ3C. Confining cap rock heats-up faster than inj.reservoir ZeZ2C is plugged-off.
TUM2	23-Oct-12	1,500 (21 d)	4 d	yes	yes	Clear minima observed at perforations
TUM3	05-Nov-12	400 (4 d)	5 h	yes	unclear	Interpretation is masked by the fact that the well is highly deviated and completed open hole. Slower warm back is clear from middle of horizontal section, as well as the reservoir temperature deviates more fom the undisturbed temperature up to top reservoir.
ROW2	28-Nov-12	35,000 (63 d)	160 d	yes	unclear	Well is openhole completed across ZeZ2C, whereas there's no injection in the ZeZ3C possible. Injection into ZeZ2C is clear from slower warm-back, but large amount of injected water has resulted in clear cooling of fromation above ZeZ3C.
ROW3	11-Dec-12	600 (1 d)	1 d	yes	yes	Injection point aligns with perforations into highest porosity streak. No apparent injection at top perforation intervals.
ROW4	12-Dec-12	1,200 (20 d)	18 h	yes	yes	Slow warm back clearly aligned with injection reservoirs and perforation intervals
ROW5	30-Nov-12	1,000 (18 d)	1 d	yes	yes	Temperature survey not run passed separation packer down to ZeZ2C. Injection point aligned with bottom perforated interval.

Notice that in wells TUM2 and ROW4 (e.g.), warm back between the Carbonate reservoirs and the ZeZ2H layer is very clear. In those wells the shut-in time is long enough relative to the small volume of water injected.

For future temperature surveys it is recommended to apply a longer shut-in period prior to a temperature survey to allow the ZeZ2H to sufficiently warm back. However, it should be realised that at all times sufficient injection capacity is available to dispose the water. With only 4 wells available (ROW2, ROW4, ROW5 and ROW7), with the 'pipe-in-pipe'-scenario, this implies that required long shut-in times are not practical in relation to the large volume of water that will be injected in these wells.

5.3 Casing calliper survey and cement bond logging

Temperature surveys cannot be fully conclusive with respect to Halite contact. As clearly shown by the temperature logs water is injected into the perforated Carbonate formations or Carboniferous formation (for well ROW3). There is no evidence that injected water has come into contact with Halite layers. But in some cases it cannot be entirely excluded from the observed warm-back of the Halite and Anhydrite layers in between the ZeZ2C and ZeZ3C and above the ZeZ3C. Large injected volumes have cooled-off the reservoir so much that warm-back effects are masked. A relatively small volume leaking-off to the Halite via a potential casing leak may not be large enough to cause sufficient cooling to be detected by temperature logging. For that reason, in addition to temperature surveys, also cement bond logs (CBLs) and production casing callipers[20] were run to verify whether any injection water contacts Halite formations.

Only in case the calliper detects a leak in combination with poor cement bond across a Halite formation, there is a path for water to flow directly past the Halite formation, potentially leading to Halite dissolution.

Regarding the evaluated wells, CBL's and casing callipers were carried-out in 2013 in wells ROW2, ROW4 and ROW5. The results of these logs have been summarized in Table 8. The actual logs are shown in Attachment 8.4. The table shows that the risk that Halite is exposed to injected water is perceived low in all logged wells.

The injection wells in the Tubbergen-Mander field were not logged, because there is no Halite present. ROW3 was not logged for the following reason:

- In ROW3 the injection packer is set below the ZeZ2H, ZeZ3H and ZeZ4H Halite formations at the depth of ZeZ1H. Exposure of the ZeZ1H with injection water is highly unlikely as it is not only shielded off from the injection water by the 9⅝" injection casing but also by a cemented 7" scab liner, which has been installed in February 1987 to shut-off gas production from the ZEZ3C. In addition, ROW3 was mainly shut-in due to a very poor injectivity.

[20] Casing calliper surveys were explicitly executed to establish the casing integrity/wall thickness to detect weak spots in time and to avoid that salt layers might be directly exposed to the injected water. The objective is, therefore, fundamentally different from the tubing calliper surveys (ref. Chapter 6.1) that were carried-out to verify the injection tubing integrity status. Weak spots in the tubing, most often due to corrosion and/or erosion causing reduction of the wall thickness, can lead to tubing-annulus communication and, hence, loss of the primary well barrier. It is important to note that calliper tools are multi-finger imaging tools measuring inside, and not behind, the tubing/casing.

Table 8 - Overview of CBLs and callipers run in production casing underneath injection packer (2013)

Well	Calliper Tool	Max Metal loss %	Depth mAHbfd	Casing condition	Cement quality	Halite exposure risk level
ROW-2	PMIT	8	1165	No corrosion visible	Cement bond is very good, suggesting squeezing salt.	Low
ROW-4	PMIT	20	1375	Minor corrosion	Mainly good cement bond	Low
ROW-5	PMIT	13	1180	No corrosion	Good to fair cement bond, 3C-3H transition interval cement bond masked by fast formation. Poor cement bond at 2C does not expose 2H because of good cement bond across it.	Low

Calliper surveys were repeated in Q4 2015 in wells ROW2, ROW4 and ROW5. The Tubbergen-Mander injectors and well ROW3 were not surveyed for the same reasons as in 2013 (absence or no possible exposure of the Halite seal and little injection, respectively). The results are listed in Table 9. In contrast to the casing calliper surveys executed in 2013 maximum penetration depth and metal loss were quantified in more detail. It is important to stress that the maximum penetration depth and metal loss do represent the worst single spot measured in the casing wall. It does not reflect the overall condition of the casing, which is much better.

In none of the surveys were any leaks detected and, hence, there's no possibility that Halites have been exposed to the injection water. Maximum metal losses in 2015 are similar to those measured in 2013 for ROW2, ROW4, and ROW5.

In summary, from a Halite dissolution point of view, all evaluated wells were found to be appropriate for continued water injection provided regular monitoring and evaluation is executed.

Table 9 – Overview casing callipers surveys carried-out in 2015

Well	Calliper Tool	Max penetration %	Max Metal loss %	Depth mAHbfd	Casing condition	Halite exposure risk level
ROW-2	PMIT	7.6	6.5	1164.9	Overall logged casing appears to be in good condition with light wall penetration less than 10%.	Low
ROW-4	Sondex	19.6	10.4	1365.7	The 7" casing appears to be in good to fair condition, with overall metal loss <10%	Low
ROW-5	PMIT	18	12.1	1182.5	Overall logged casing appears to be in good condition with light wall penetration less than 10%.	Low

6 Well integrity surveillance and management

6.1 Tubing calliper surveys

Weak spots in the tubing, most often due to corrosion and/or erosion causing reduction of the wall thickness, can lead to tubing-A-annulus communication and, hence, loss of the primary well barrier. To verify the integrity state of the tubing, calliper surveys have been regularly carried-out in all water injectors. Similar to the casing callipers, a multi-finger tool is used to circumferentially measure the inner tubing radius. The surveyed data is then processed to provide a maximum wall penetration depth and maximum percentage metal loss for each tubing joint. Callipers do not measure wall thickness, i.e. the condition of the outside of the pipe is assumed to be at nominal condition. Note, however, that the outside is not in direct contact with potentially corrosive fluids. If the loss of wall thickness of the tubing reaches the maximum acceptable limit it will be replaced.

The maximum wall penetration depth measured in each well since start of injection is presented as degree of pitting in Figure 9. The red dashed line indicates the pitting degree limit of 60%, at which NAM's practice is to seriously consider change-out the tubing[21]. Wellcat modelling shows that with 60% corrosion (i.e. assuming worst case scenario that 60% pitting exists uniformly along the entire tubing) the axial and tri-axial loads are approaching the design factors[22].

Table 10 describes the actual integrity state of the tubing based on latest calliper survey and its interpretation. Note that for those wells in which a calliper survey was not carried-out in 2015, the data of previous calliper surveys is used.

Figure 9 shows that the measured degree of pitting, based on the maximum recorded pitting depth (considered the weakest point in the tubing) for all wells is still below the pitting degree limit of 60%. In wells TUM2, and ROW4 significantly deeper pits were detected in 2013-2014 compared to pitting depths recorded end of 2011. It is not clear what causes the increased pitting depth in TUM2, but the overall tubing integrity is still classified as good to fair. TUM2 will not be used for water injection in the short term anymore. The well will most likely remain shut-in long term, since with the FCP-pipe installed in the existing water transport line ('pipe-in-pipe'), the location is not accessible for further water injection. In ROW4 increased degree of pitting is believed to be due to the acid stimulations that have been carried-out in these wells in 2012 and 2013. However, the mechanism is not well understood. During the stimulation, even when the tubing has been exposed to 28% HCl for 5 h, the acid mixture was designed such that sufficient corrosion inhibitor was added to provide protection for typically 16 h.

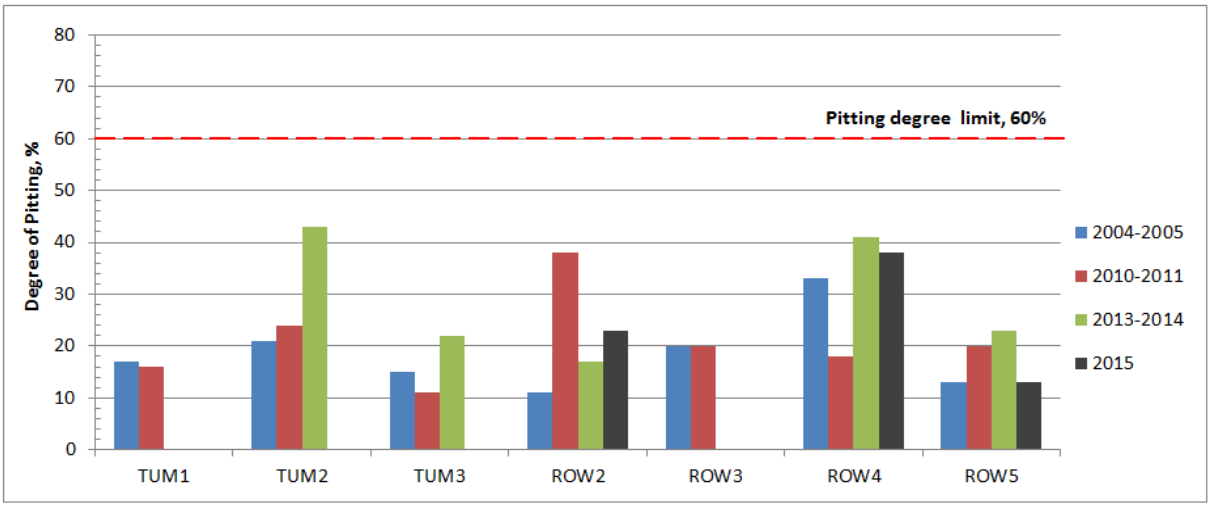


Figure 9 – Maximum wall penetration for each injection well derived from calliper surveys since start of injection

[21] W.J. Kolthof and D. van der Wal – The use of digitised tubing calliper data for workover planning. SPE23134 (September 1991)

[22] A. Ciufu – Twente water disposal wells – tubing integrity review. EP201603224863 (March 2016)

Table 10 – Overview of actual tubing condition based on latest calliper surveys

Well	Calliper Tool	Date last calliper survey	Max Penetration depth %	Depth mAHbdf	Max Metal loss %	Tubing condition
TUM1	Kinley	18/11/2010	16	293.7*	<7	Good
TUM2	Kinley	23/10/2012	43	1344.5*	<13	Good to fair, with 1 isolated pit showing poor condition, but no apparent leaks
TUM3	PMIT	25/03/2014	23	1330.1	<15	Good
ROW2	PMIT	15/09/2015	23	1111.2	<7	Good
ROW3	Kinley	10/11/2010	20	1029.3	<7	Good
ROW4	Kinley	02/09/2015	38	1097.6	<11	Good to fair, with 2 isolated pits showing moderate condition
ROW5	PMIT	23/09/2015	13	796.4	<7	Good

Furthermore, the (spent) acid is not produced back, which usually leads to exposure longer than 1 day, but over-displaced into the reservoir with injection water directly after the treatment. From the calliper survey interpretation, only scattered isolated pits are identified in ROW4. The pitting might be caused by oxygen corrosion on 'cleaned' tubing due to the acid stimulation, as well. The injection wells are all protected against oxygen ingress by a back pressure valve (BPV) that is installed in the tubing hanger nipple. However, BPV's will not provide a proper seal in case dirt (e.g. solids, precipitated wax,..) is present on the seal area. Consequently, oxygen ingress can occur when injection is stopped creating a vacuum.

6.2 Annulus pressure monitoring

In addition to tubing calliper surveys, which are only carried-out once per year to identify weak spots in the tubing wall in time, daily annulus pressure monitoring (in particular for the A-annulus) is another way to detect whether the tubing and/or casing integrity is breached. In case sudden changes in the annulus pressure are observed, which could indicate a leak path between the tubing and the A-annulus or between the A-annulus and the B-annulus, the well will be shut-in and an investigation will be started.

In all water injection wells in Twente, the A-annulus is filled with KCl-brine (1.03 sg), which was circulated into the A-annulus when the wells were converted into water injectors. The side-pocket mandrels were equipped with dummy valves after placing the brine. The B- and C-annuli (only present in wells TUM1, TUM2, ROW4 and ROW5) contain water based drilling fluid of varying densities ranging from 1.25 to 1.4 sg.

For all water injection wells in Twente, integrity tests (WIT's and SIT's[23]) have been carried out each year. The tests do show that no pressure communication is present between the tubing and the A-annulus, nor between the A- and B-annulus. This is also in accordance with the observation that the pressures at the tubinghead, the A-annulus and the B-annulus are different and do not follow the same trend. This implies that all barriers between the tubing and the A-annulus, as well as between the A-annulus and the B-annulus are intact for all injection wells. In addition, from the WIT's and SIT's, no leaks to the environment were observed.

Since the start of water injection the A-, B- and C-annulus pressures have not exceeded the MAASP. For the B-annuli also a LAASP (Lowest Acceptable Annulus Surface Pressure) was defined. Several B-annuli had to be filled up ('top-ups') occasionally with nitrogen during the injection period to maintain the pressure above the LAASP. The B-annulus pressure loss can be explained by:

- The fact that the wellhead seals and casing head connections are not gas tight, enabling nitrogen to leak-off
- Nitrogen and/or annulus fluid leaking-off into permeable formations exposed to the B-annulus above top of cement
- Nitrogen and/or annulus fluid leaking-off to deeper formations via cracks in the B-annulus cement

[23] WIT (wellhead integrity test) is the routine scheduled preventive maintenance task for flow-wetted components of the well, which implies that the integrity of the sub-surface safety valve and Xmas-tree valves is tested.
SIT (subsurface integrity test) is the routine scheduled preventive maintenance task for non-flow-wetted components of the well, i.e. seals between the tubing and annuli are pressure tested.

- Warm water washes preceding well entries. Due to these washes the B-annulus pressure increased requiring a pressure bleed-down to maintain the pressure below the MAASP. Consequently, when injection was restarted, the cooler water caused a pressure drop below the LAASP making a nitrogen top-up necessary.

7 Conclusions

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM1, TUM2, ROW2, ROW3, ROW5, ROW6 and TUB7) to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is requested to evaluate and report the water injection process and activities every 6 years. In line with the requirements in the water injection permits, NAM will carry-out this evaluation 6 years after the start of injection.

From an environmental point of view, the key concern is the mitigation of the risk for contamination of shallow aquifers due to loss of containment. The technical evaluation therefore, has in particular, focussed on the effect of water injection on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir.

The water injection permits for the respective locations state that the 6-yearly evaluation should only be carried-out on injection wells TUM1, TUM2, TUM3 and ROW2, ROW3, ROW4 and ROW5. In 2014, 3 years after start injection, a first technical evaluation was already carried-out for wells ROW3, ROW4, ROW7, ROW9, TUB7 and TUB10 that were expected to show faster pressure increase with respect to connected reservoir volume and planned injection rate.

This evaluation actually covers the first 4½ years from the start of water injection in Q1 2011 until June 2015, when water injection was stopped, because of the poor state of the water transport line to Twente.

The main conclusions from the technical evaluation carried out are:

- All seven evaluated water injection wells in Twente are in good condition and can be used for future water disposal.
- The monitoring programs provide an appropriate early detection and protection framework to guarantee the integrity of both the wells and reservoirs and thus a safe and responsible operation.

More specific, conclusions are summarised below.

Regarding the water injection volumes, the following is concluded:

- The actual total injection rate has only been 4,000-5,000 m^3/d, which is due to lower performance of Schoonebeek Oilfield production wells.
- Thus far, 41% of the total injected volume has been injected into wells TUM1, TUM2, TUM3, ROW2, ROW3, ROW4 and ROW5. From these, approximately 20% of the total injected volume was injected into well ROW2.

From static pressure gradients (SPG's), the actual surface injection pressures (THPi) and the injectivity and step-rate/fall-off tests the following is concluded, respectively:

- The actual pressure in the various reservoirs is still significantly lower than the original reservoir pressure.
- The measured local pressure (ref: top perforations) is increasing faster than expected in wells TUM1, TUM2, TUM3 and ROW3. The same is true for ROW2 and ROW5, but here the increase is small compared to the initial pressure.
- The amounts of water injected so far for most wells are still too small to make an accurate prediction of the final storage capacity based on the pressure trends.
- A pressure offset is observed with ROW4, when comparing the first pressure measurement in 2011 with the pressure at the start of the injectivity test in 2009. However, the pressure has remained more or less constant during the injection period thereby still following the model.
- This pressure offset also is present with wells TUM1, TUM2, TUM3 and ROW3. Upon further data analysis it was discovered that the offset can be explained due to pumping a large volume (>30 m^3) of hot boiler feed water 1 day ahead of the pressure survey to prevent the tools to stand-up while run-in-hole. For wells that show a low to moderate injectivity (0-30 m^3/d/bar) the consequent shut-in time is not sufficient to restore the fluid level prior to the BFW flush.
- During the entire injection period, the surface injection pressure remained well below the set THPi-limits for the wells. Hence, for all wells the maximum bottom hole pressure ($BHPi_{max}$) has never exceeded the minimum in-situ stress (σ_h,min) of the confining layer (ZeZ-Halite and Bunter Sandstein), not even when pressure friction loss is ignored.
- The effect of tubing friction loss is largest in wells with a 3½"(OD) tubing and a high injection rate. For wells with a 5"(OD) tubing (ROW2 and ROW5) and/or a poor injectivity (TUM1, TUM2, TUM3 and ROW3) the difference is minor (<5%).
- The SRT-plots derived from the injectivity tests all show a linear trend indicating injection into existing fractures in the naturally fractured Zechstein-Carbonate reservoir, which means that injection occurs below fracturing pressure.
- Apparent formation breakdown only occurred during a controlled injectivity test in ROW3 where water is injected in the tight Carboniferous sandstone.
- Wells ROW2, ROW4 and ROW5 have a high injectivity. In those wells the fluid level did not reach the depth of the installed BHP-gauge or BHPi more or less remained constant with increasing injection rate.

The injectivity in wells TUM3 and ROW4 appears to be moderate, but constant. The injectivity performance in TUM1, TUM2 and ROW3 is poor.

- It was not possible to determine the minimum in-situ stress in the Zechstein-Carbonate reservoir from pressure fall-off curves, because injection does not occur above fracturing conditions.
- Since injection does not take place under fracturing conditions, determination of minimum horizontal stress from fall-off surveys cannot be done as intended, and fall-off tests for that purpose are no longer required. Pressure transient analysis suffers from large wellbore storage effects, and only indicative results for permeability can be obtained. Tracking well injectivity through step-rate test analysis is considered a more useful and straightforward approach. However, the long time required for pressures to stabilize for each injection step leads to inaccurate results and makes step-rate testing more and more impractical in the future.

Extensive studies have been carried-out regarding Halite dissolution when exposed to injection water and its potential effect on subsidence. These studies have been independently reviewed by University experts under auspices of State Supervision of Mines[24]. From Halite dissolution modelling it was concluded that potentially this can only occur near the injection well. Hereto, a leak in the production casing in combination with a poor cement bond behind casing must occur simultaneously in order to allow injection water to directly flow past the Halite formation. Temperature surveys, cement bond logging and casing calliper surveys were executed to detect if Halite is exposed to injection water. From the logging the following is concluded:

- Downhole temperature surveys indicate that injection occurs into the targeted Zechstein-Carbonate reservoirs and not in the Halite formations.
- For all wells it is clear that warm-back is slower in the target injection reservoir compared to that of the overlying-underlying layers.
- Warm back is masked in case very large volumes of water were injected and the shut-in period prior to logging was too short. Also the layers above the injection reservoir were significantly cooled-off in those wells.
- The risk to dissolve Halite is perceived negligible in all logged wells based on the condition of casing/liner from positive interpretation of calliper surveys and cement bond logs.

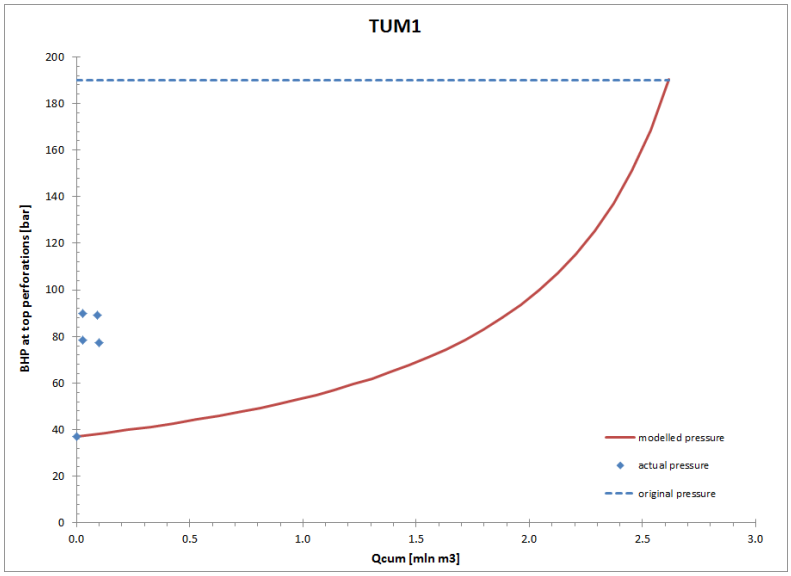
Evaluation of the well and tubing integrity show that:

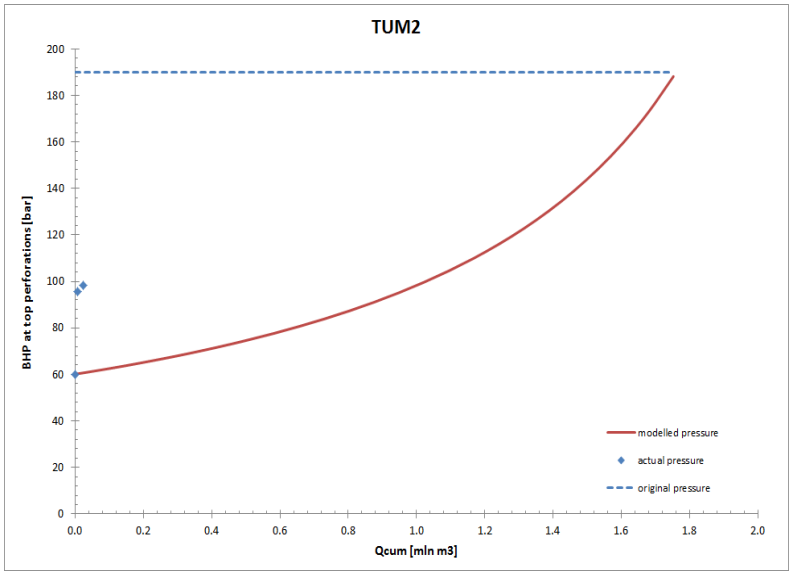
- Tubing strength calculations show that all the tubings still have enough wall thickness (degree of pitting < 60%) to withstand maximum injection pressures. No tubing leaks are present.
- During the first 3 years of operation all A-, B- and C-annulus pressures have remained below their MAASP.
- For all injection wells, no communication appeared to be present between the tubing, A-annulus and B-annulus.

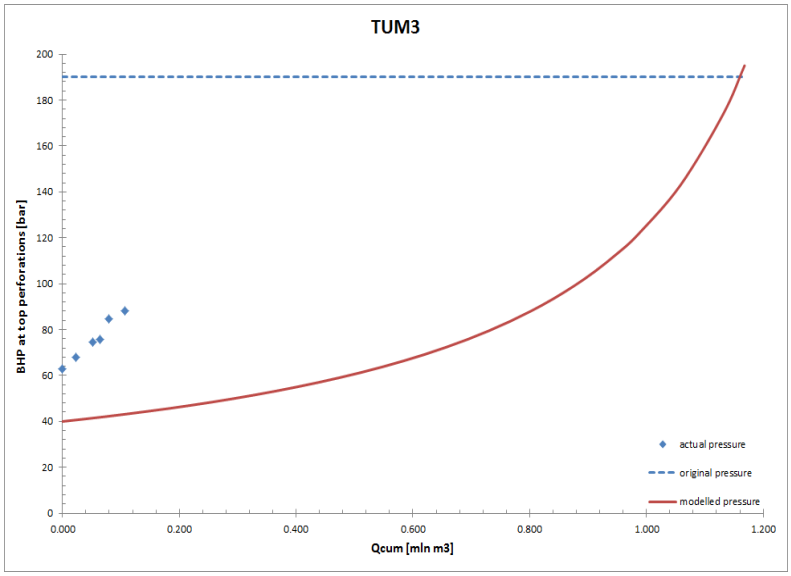
[24] These studies have been independently reviewed by independent University experts under auspices of the Dutch Mining Regulator (State Supervision of Mines). All the conclusions and findings of the studies were supported by both the experts and the regulator. (https://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

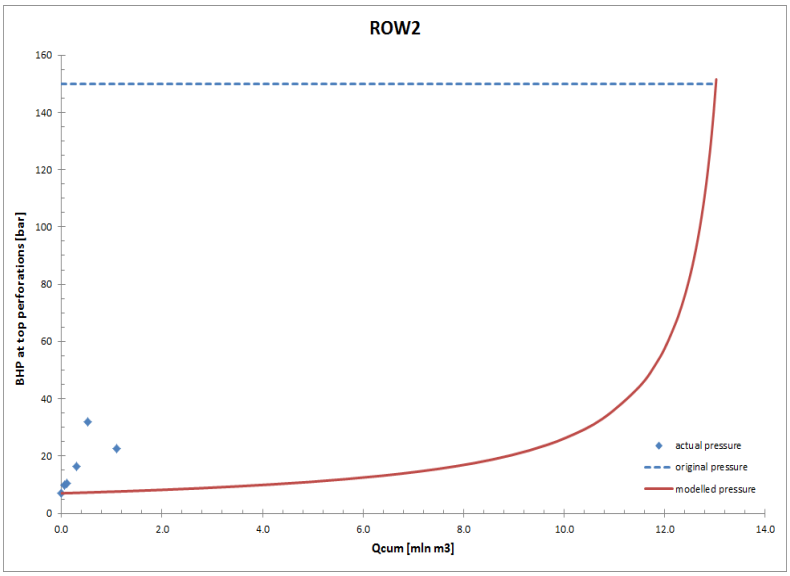
8 Attachments

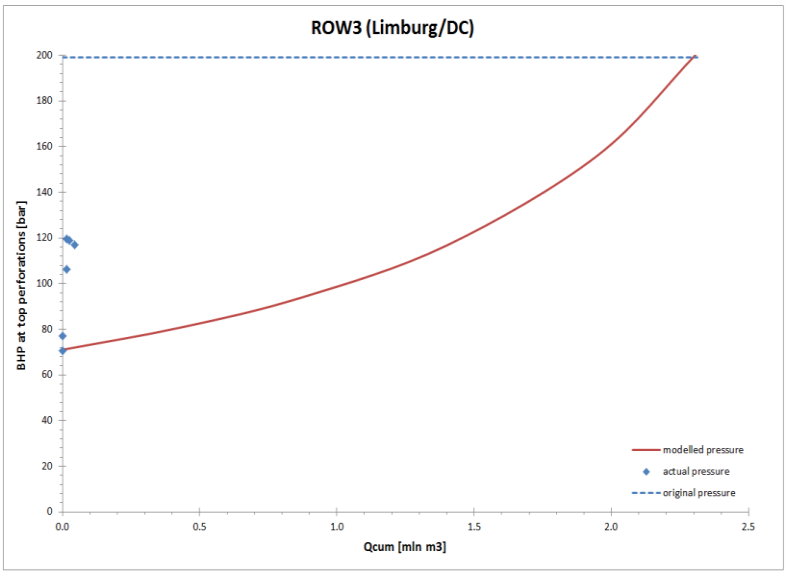
8.1 Reservoir pressure development during injection

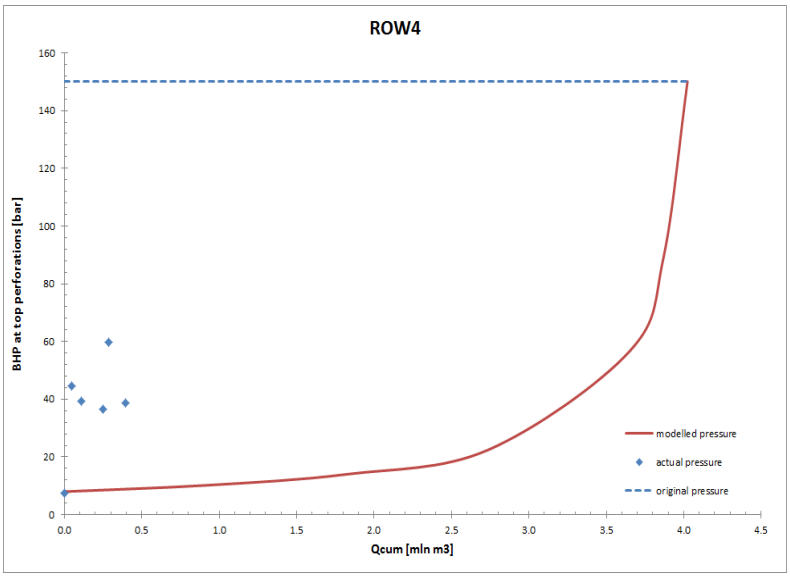


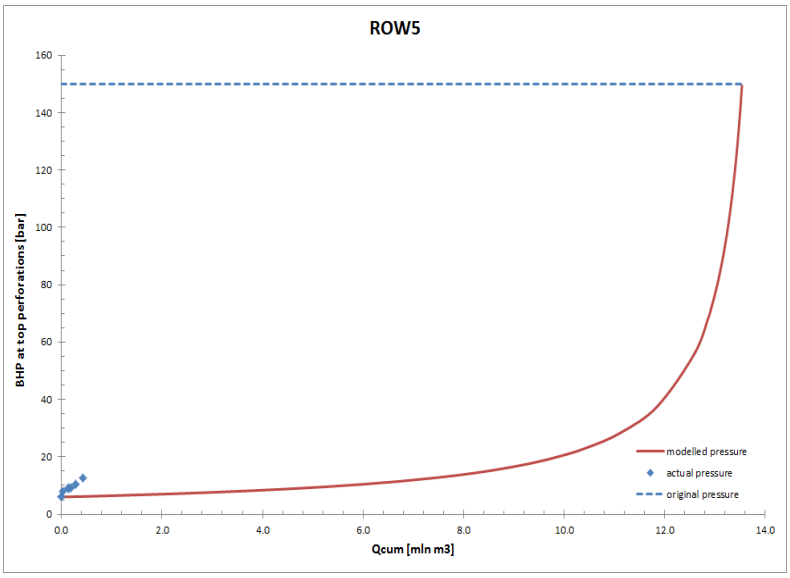





ROW2
BHP at top perforations [bar]
Qcum [mln m3]
actual pressure
original pressure
modelled pressure

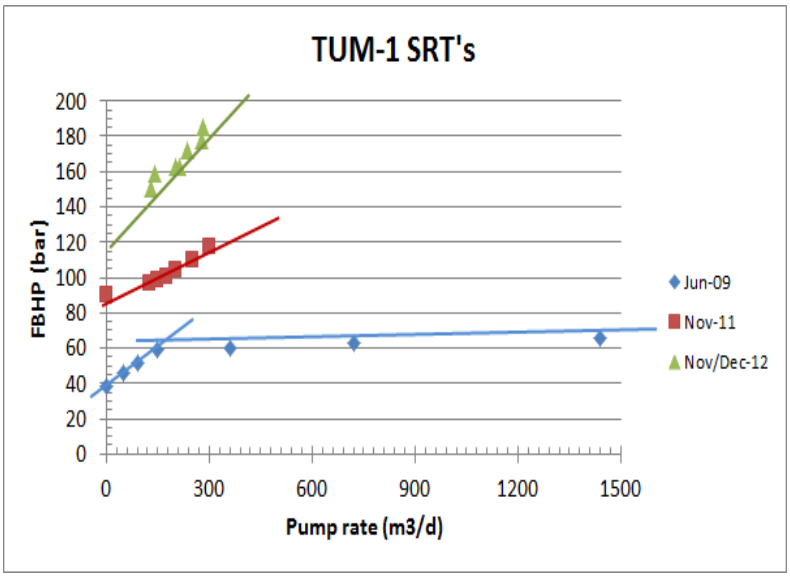

ROW3 (Limburg/DC)
BHP at top perforations [bar]
Qcum [mln m3]
modelled pressure
actual pressure
original pressure

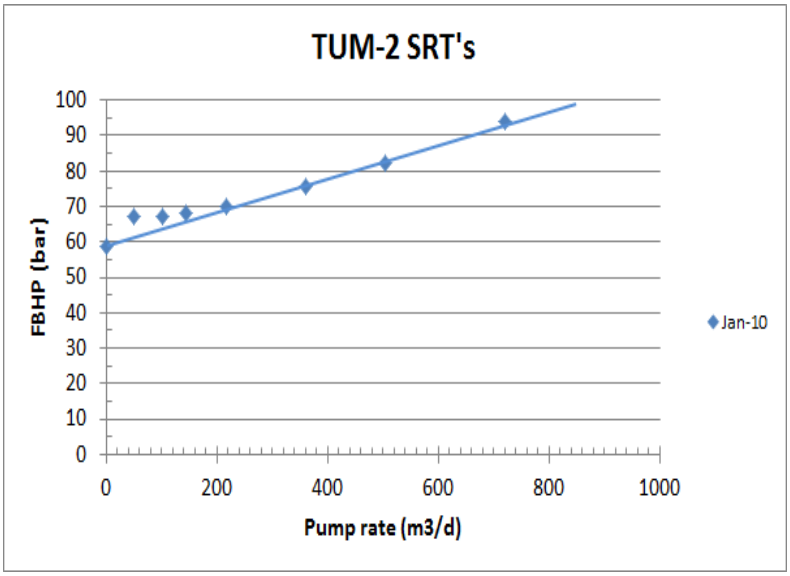

ROW4
BHP at top perforations [bar]
Qcum [mln m3]
modelled pressure
actual pressure
original pressure

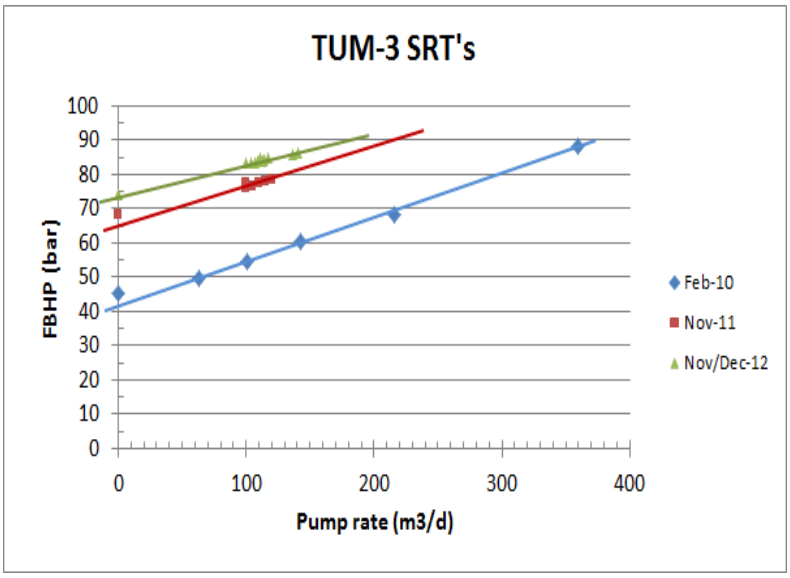

ROW5
BHP at top perforations [bar]
Qcum [mln m3]
modelled pressure
actual pressure
original pressure
0
20
40
60
80
100
120
140
160
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0

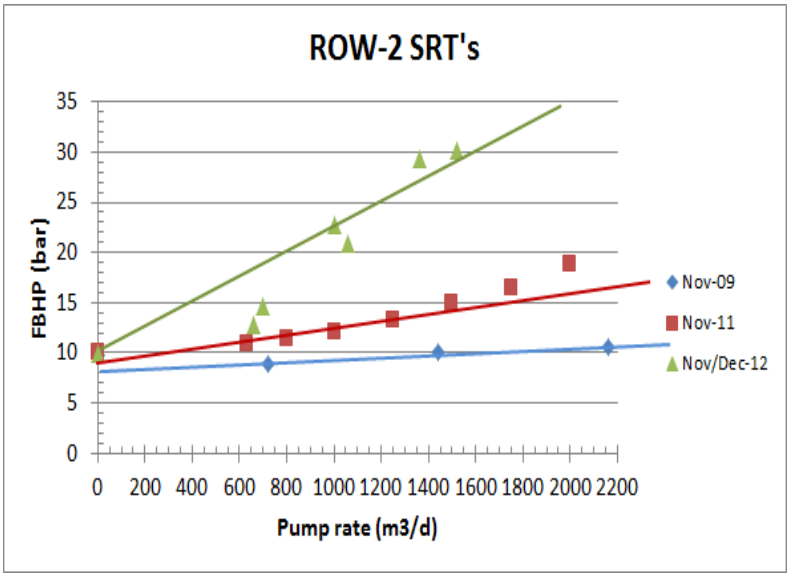
8.2 Step-rate test results

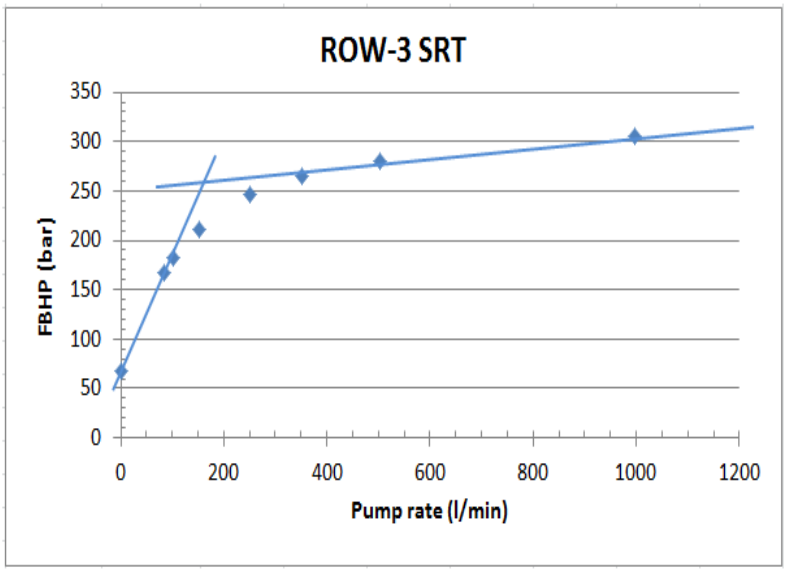
Note: all measured flowing bottomhole pressures (FBHP) at gauge depth have been recalculated to top reservoir.

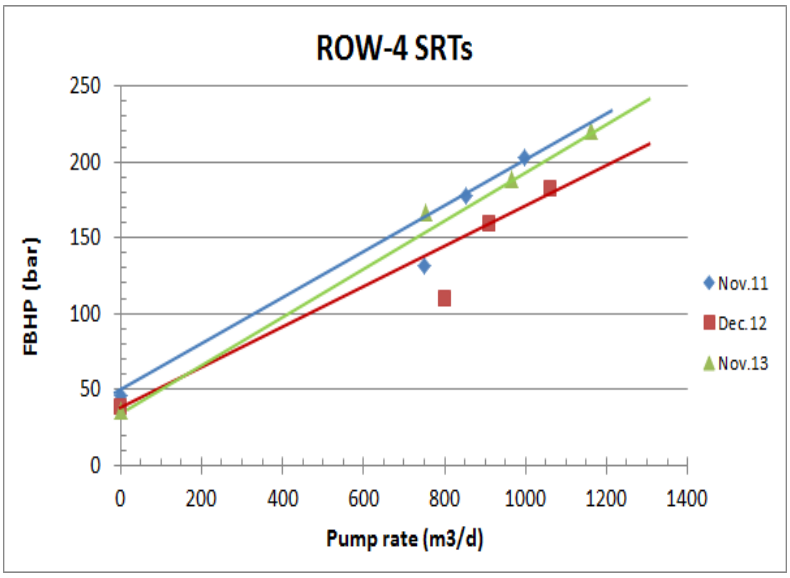




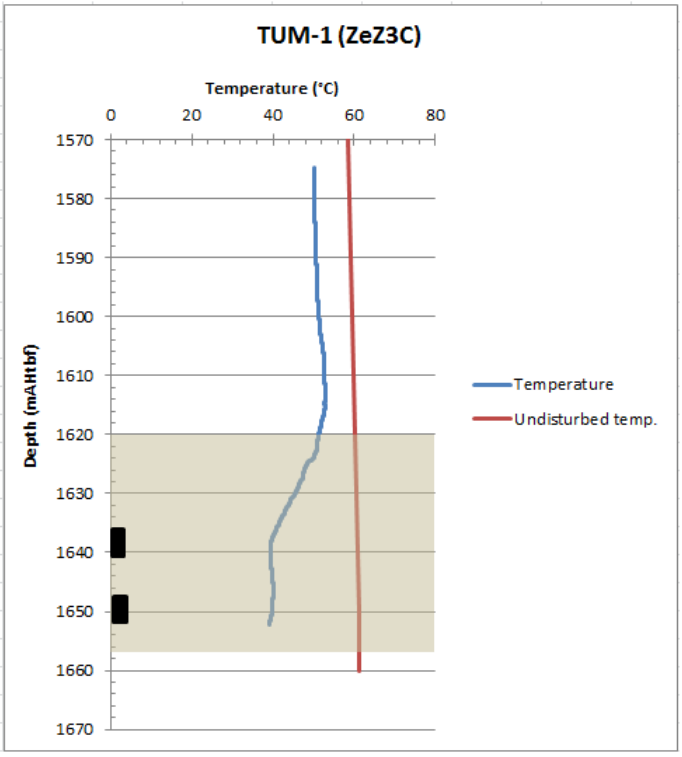

TUM-3 SRT's
FBHP (bar)
100
90
80
70
60
50
40
30
20
10
0
0
100
200
300
400
Pump rate (m3/d)
Feb-10
Nov-11
Nov/Dec-12

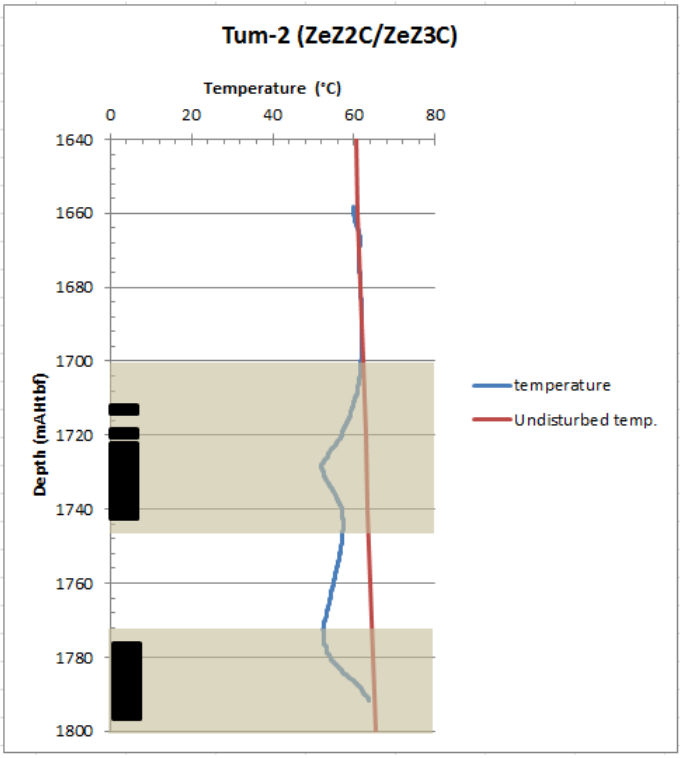

ROW-2 SRT's
FBHP (bar)
35
30
25
20
15
10
5
0
0 200 400 600 800 1000 1200 1400 1600 1800 2000 2200
Pump rate (m3/d)
Nov-09
Nov-11
Nov/Dec-12

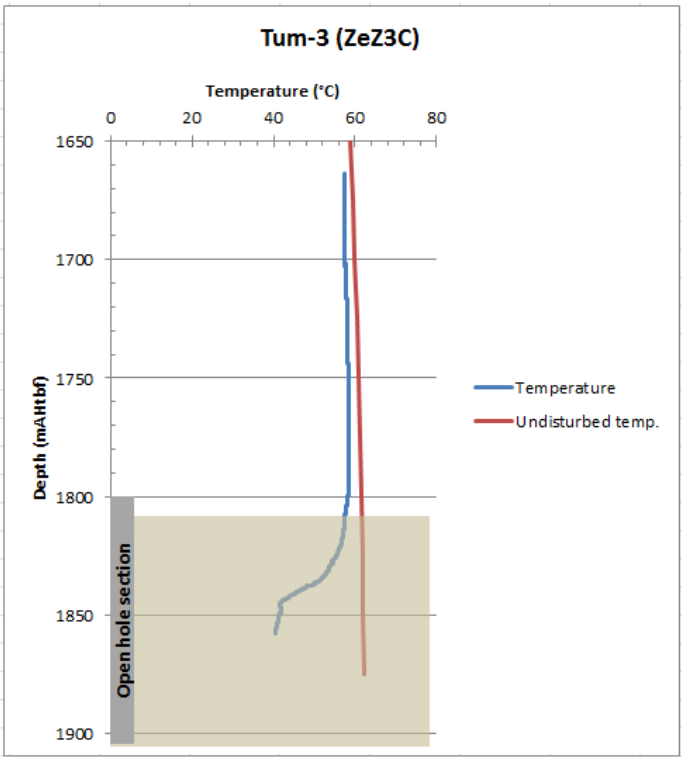

ROW-3 SRT
FBHP (bar)
350
300
250
200
150
100
50
0
0
200
400
600
800
1000
1200
Pump rate (l/min)

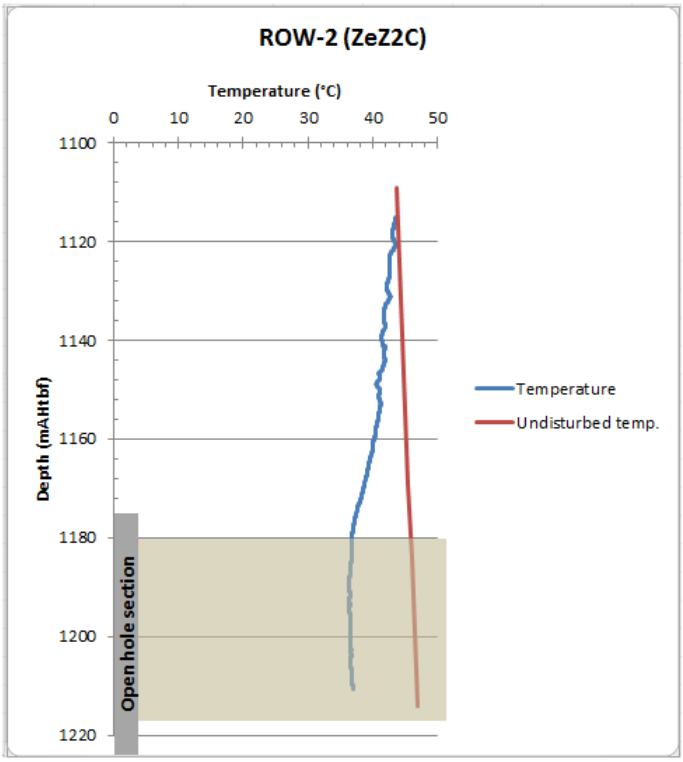

ROW-4 SRTs
FBHP (bar)
250
200
150
100
50
0
0
200
400
600
800
1000
1200
1400
Pump rate (m3/d)
Nov.11
Dec.12
Nov.13

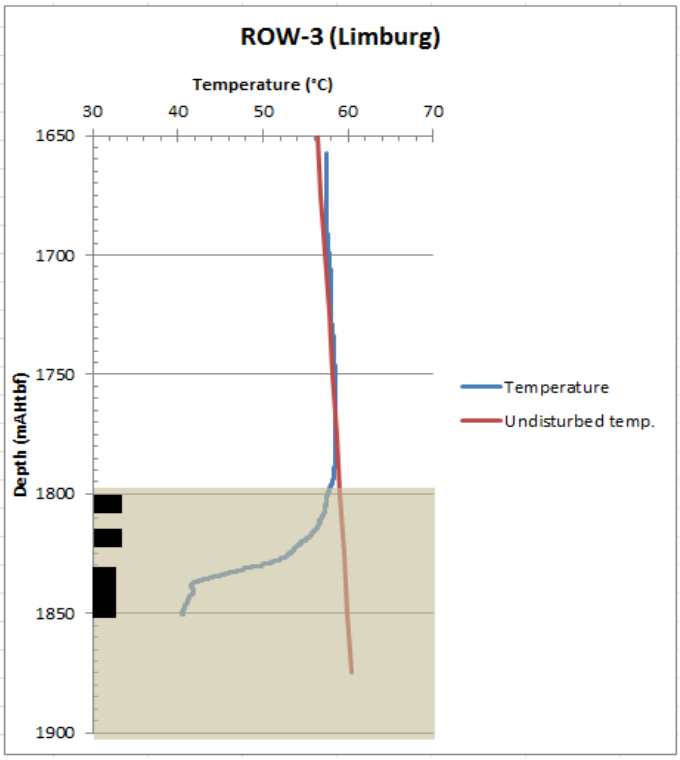
8.3 Temperature logging results

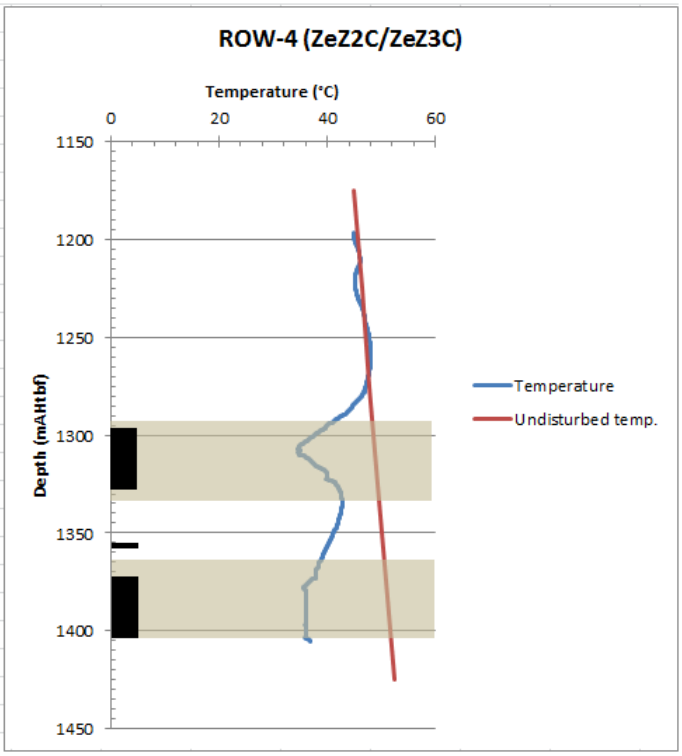


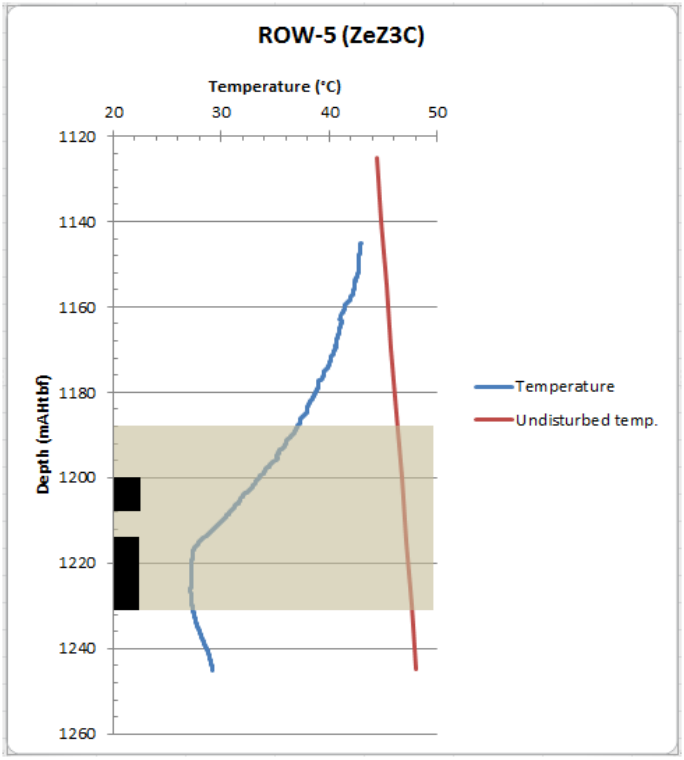



Tum-3 (ZeZ3C)
Temperature (°C)
0
20
40
60
80
1650
1700
1750
1800
1850
1900
Depth (mAHtbf)
Open hole section
Temperature
Undisturbed temp.


ROW-2 (ZeZ2C)
Temperature (°C)
0
10
20
30
40
50
1100
1120
1140
1160
1180
1200
1220
Depth (mAHtbf)
Open hole section
Temperature
Undisturbed temp.

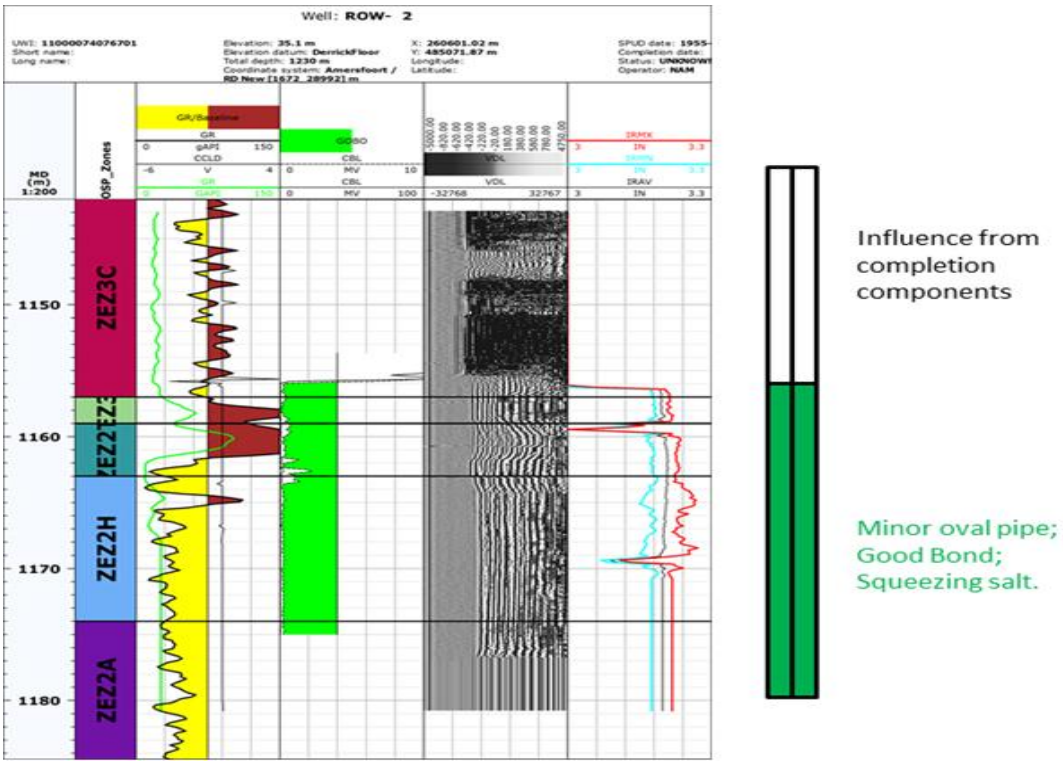

ROW-3 (Limburg)
Temperature (°C)
30
40
50
60
70
1650
1700
1750
1800
1850
1900
Depth (mAHtbf)
Temperature
Undisturbed temp.


ROW-4 (ZeZ2C/ZeZ3C)
Temperature (°C)
0
20
40
60
1150
1200
1250
1300
1350
1400
1450
Depth (mAHtbf)
Temperature
Undisturbed temp.

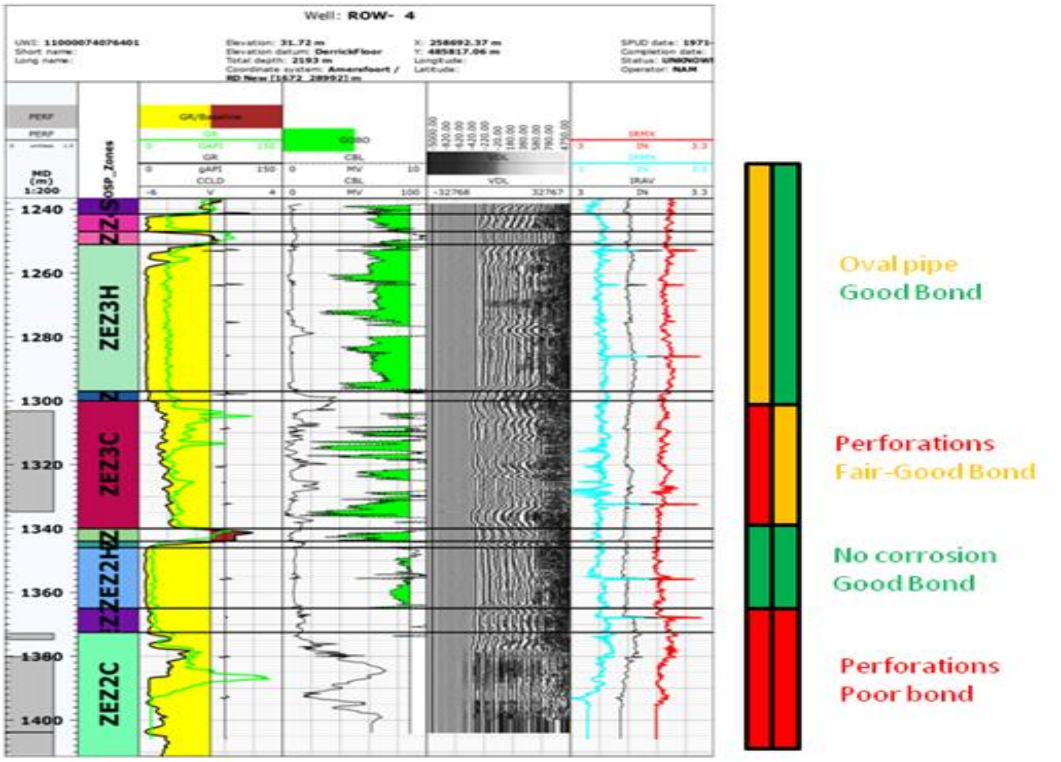

ROW-5 (ZeZ3C)
Temperature (°C)
20
30
40
50
1120
1140
1160
1180
1200
1220
1240
1260
Depth (mAHtbf)
Temperature
Undisturbed temp.

8.4 Calliper surveys and Cement Bond Logging

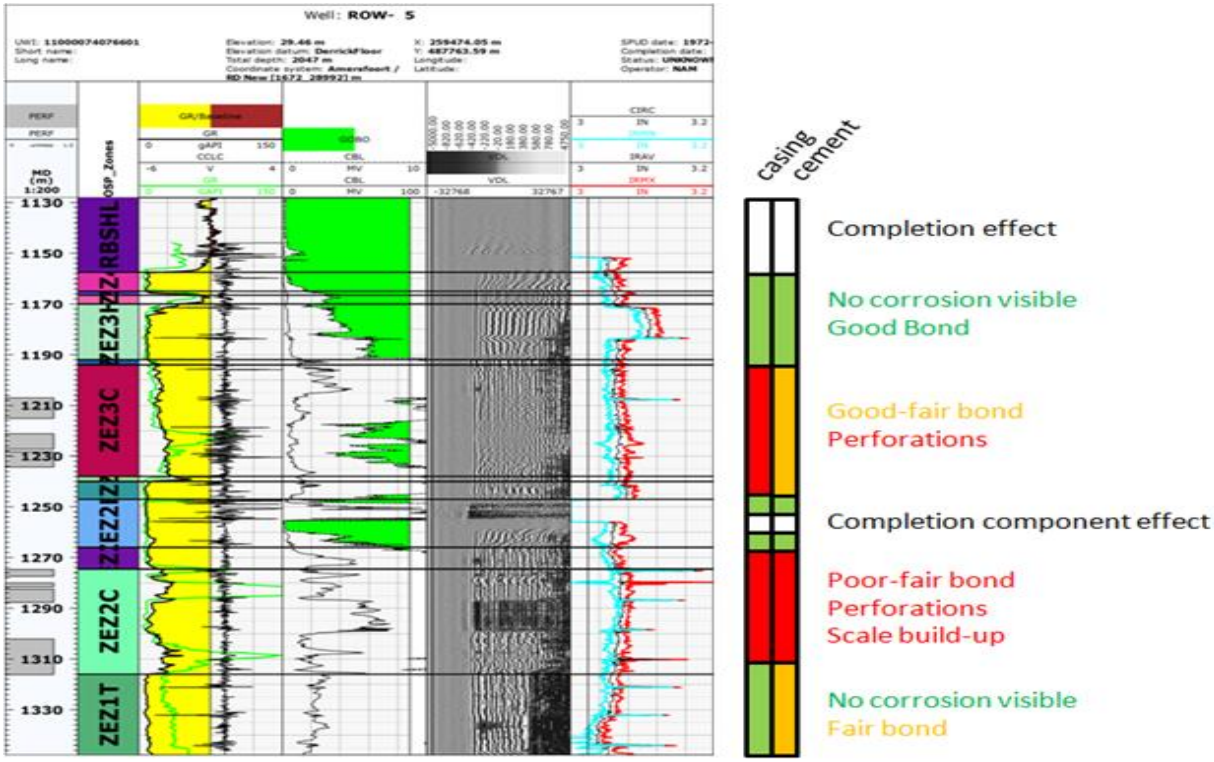
ROW2



ROW4



ROW5


Well: ROW- 5
ZEZ3C
ZEZ2C
ZEZ1T
casing
cement
Completion effect
No corrosion visible
Good Bond
Good-fair bond
Perforations
Completion component effect
Poor-fair bond
Perforations
Scale build-up
No corrosion visible
Fair bond