

Aardwarmte Den Haag

Well testing report HAG GT-01 (Producer)

Opdrachtgever

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1 General

1.1 Introduction

For the geothermal project “Aardwarmte Den Haag” the producer (HAG GT-01) has been drilled and the screens have been installed (September 13th -17th). On September 18th an ESP has been installed in the producer and on Sunday 19th the first groundwater is produced.

The results of the tests are reported.

1.2 Installation of the screen

The screens have been installed in the Delft Sand. Screen sections of ca. 12 meters (8 metres of effective screen length) have been installed as good as possible over the sand sections of the reservoir. The interpretation of the gamma ray is mainly used defining the definitive installation depths of the screens and blanks (figure 1). The installation of the screens was delayed: because of hole problems (likely due to caving/swelling clays in the Rodenrijs and Ablasserdam formations) the hole was re-drilled during the running of the screen section.

After installation the mud in the screen section was replaced with clean brine (120 m³ NaCl). Then the port collar in the top blank has been opened and a screen wash with the running tool has been performed using clean NaCl brine. The screen has been washed top down and back again. The screen wash has been performed using an inflow of brine into a section tool of about 2 meters that is closed on top and bottom with swab cups. This created a flow of NaCl brine via the screens at the position of the section tool into the annular space and then flowing to the top of the screen section into the port collar. From this point it is circulated out of the well via the annulus between running string and casing.

After washing of the screens 5 m³ breaker fluid (see appendix 1 for specification) was spotted into the screen section and let soak for 40 hours before the well tests started.

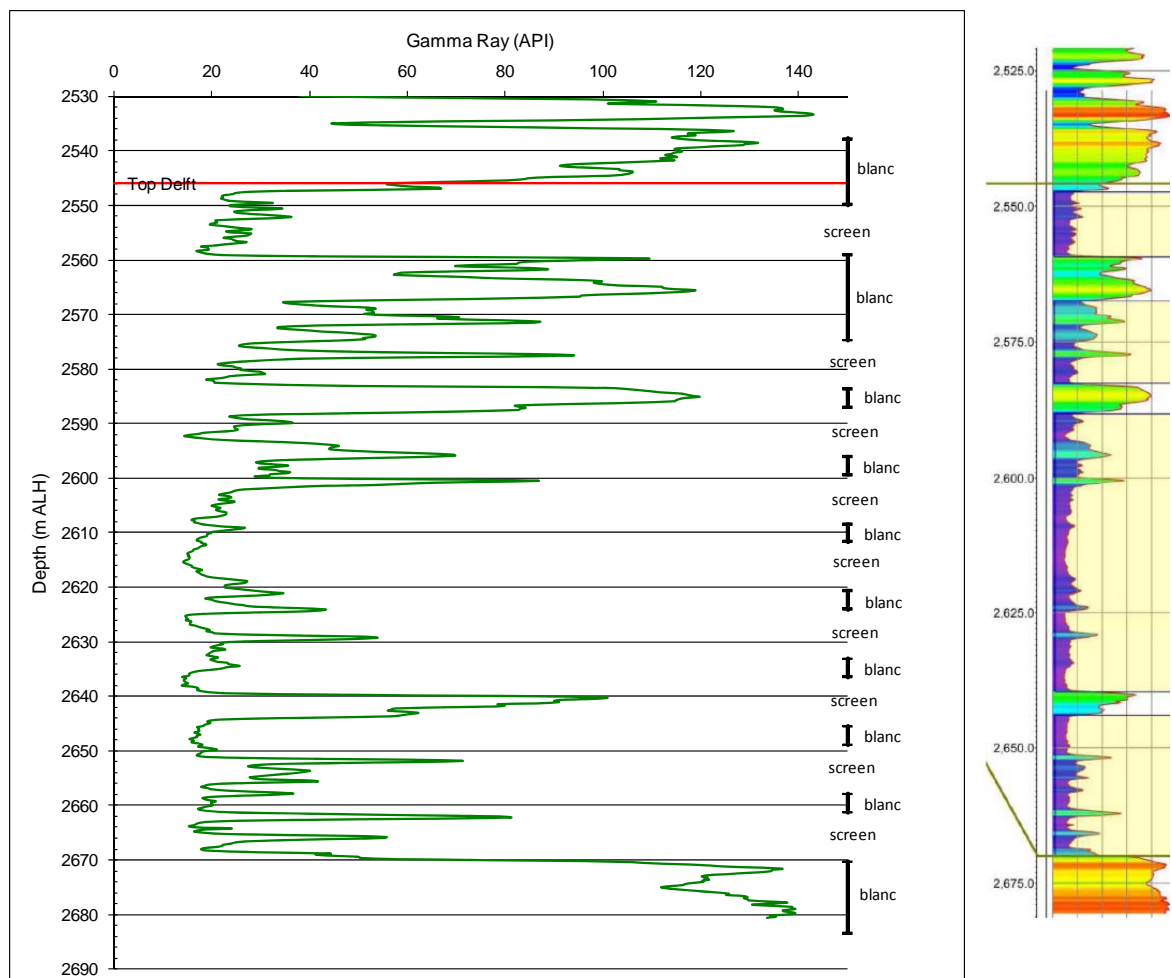


Figure 1.1 GR and installation depths screens

1.3 Well tests in general

After the installation of the screens, the well has been tested during three days using an ESP. Main goals were to have a positive indication of the well capacity and the produced water temperature, so a decision could be made to skid the drilling installation from the producer to the injector and start drilling the injector. Furthermore water samples could be taken to analyze the water quality.

During the well tests gas was detected. Because of this the plans of second and third day were changed and the focus was to get more information about the gas composition and amounts of gas.

2 Test procedures

2.1 Test plan

The test program of the producer (HAG GT-01) as used by WPMI is given in appendix 2. The duration of the test supposed to be two days. The first day the water would be produced in steps from low flow rates to higher flow rates. The second day the water would be produced constantly at high rate for about 8 hours.

Only the program for the first day has been carried out conform the plans. On the second day very small amounts of H₂S gas were measured and the test was stopped in the morning for safety reasons. After the installation H₂S detectors and other safety precautions on the third day only a short test has been performed, mainly to measure the H₂S concentration and other gas content.

2.2 Well capacity measurement

The well capacity can be expressed as the flow that can be generated by the pump per meter (or bar) draw down (DD) of the water level in the well. A high DD implicates much flow resistance in the filter or reservoir and pumping will take much energy in order to produce the required flow. In this report the capacity of the well is defined as specific capacity in m³/h per bar DD.

The water was pumped using an electrical submersible pump (ESP) of Baker Hughes. The ESP was installed at 488 m from RT (rotary table).

The DD is measured using a P/T sensor from Schulze which was installed at 468 m RT. The output of this sensor could be monitored directly on site. A back-up memory P/T sensor was installed near the pump that was read out after the test. Also the pump has logged the pressure at the intake. All measured pressures have been compared and showed the same fluctuation and pressures. The P/T sensor that has been monitored directly on site has been used to calculate the specific capacity.

During the tests the flow meter was not working properly. The flow meter was replaced by a new one on the second day, but still the measured flow did not match up with the physical measurement in the tanks. The fact that the flow meter did not work properly is probably caused by the two phase flow (gas+fluid) through the meter.

The physical flow measurement was carried out by measuring the time and the raising water level in the container in which the water was disposed. This was done frequently during the test on the first day. During the second and third day, this physical flow measurement was difficult to do, because the water was disposed into a different container.

Flows during these two days have been recalculated using the measured specific capacity in the first day (ca. 15 m³/h per bar draw down (DD)) and the DD that was measured by the P/T sensor.

2.3 Temperature measurements

Temperatures were measured at the pump intake and at the P/T sensor at about 470 m depth. During production the temperatures will raise slowly when the cooler water is refreshed by formation water and when the temperature losses during the transport from the formation to the surface will decrease, because of warming up the casings and cement and the soil around the casings.

2.4 Sand content

The sand content is measured by using a net (70 µm) that was directly held under the flow stream of the disposed formation water.

2.5 Water samples

During the end of the first day some samples of the formation water have been taken. It was planned to do the definitive sampling the next day. But as was mentioned above, the test plans changed and the second sampling was not carried out. On the third day all samples have been brought to the laboratory Alcontrol and have been analyzed.

2.6 Gas analysis

Several instruments have been used to detect gas:

- Handheld Dräger instruments from NDDC (H₂S and hydrocarbons)
- Handheld Dräger instruments from KCA-Deutag (H₂S and hydrocarbons)
- Chromatograph Petrolog: Petrolog collected gasses during a specific period of testing. The accumulated gas in this period was analyzed on composition. Using this method, samples could only be analyzed qualitative (composition) and not quantitative (amounts).
- Gas sampling and analyzing by Panterra: see report of Panterra in appendix 3.
- Personal H₂S sensors

3 Results

3.1 Well capacity

Only during the first day of testing the flow could be measured using the physical method as described in 2.2. Therefore the specific well capacity has been calculated using the results of this first day.

In figure 3.1 the measured sensor pressures are given. The sensor was 466 meters below surface and the natural water level was ca. 40 bars above the sensor. Taking into account the weight of the column of 1.09 kg/kg, the natural water level was ca. 100 m below surface.

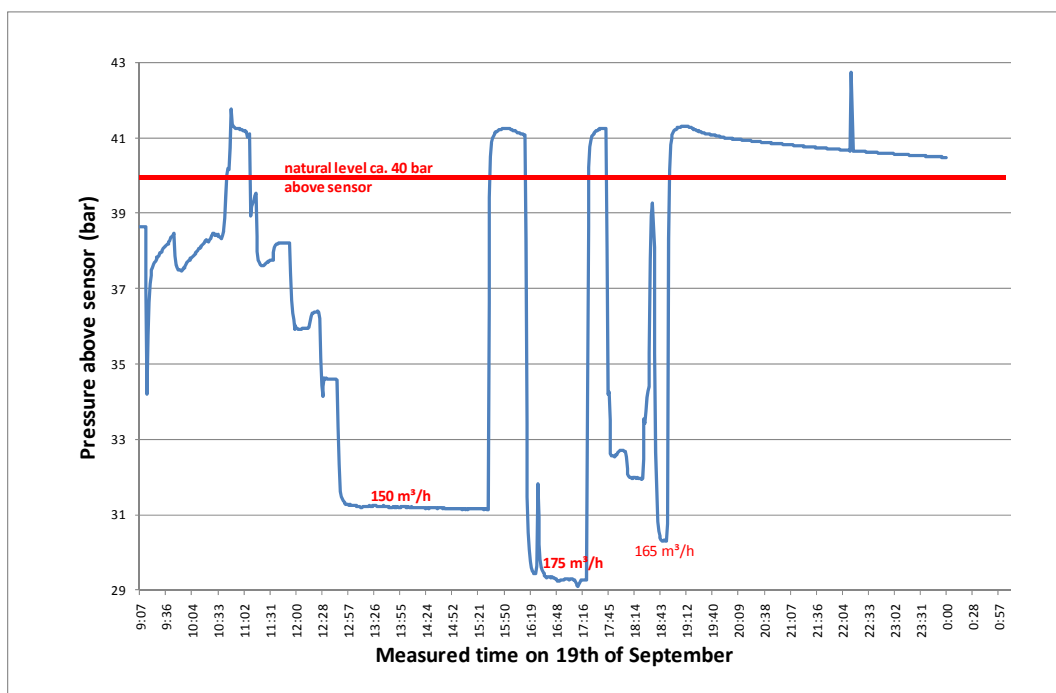


Figure 3.1 Measured sensor pressures (bar)

The draw down is calculated by subtracting the pressure during pumping at a specific flow from the natural pressure (Figure 2).

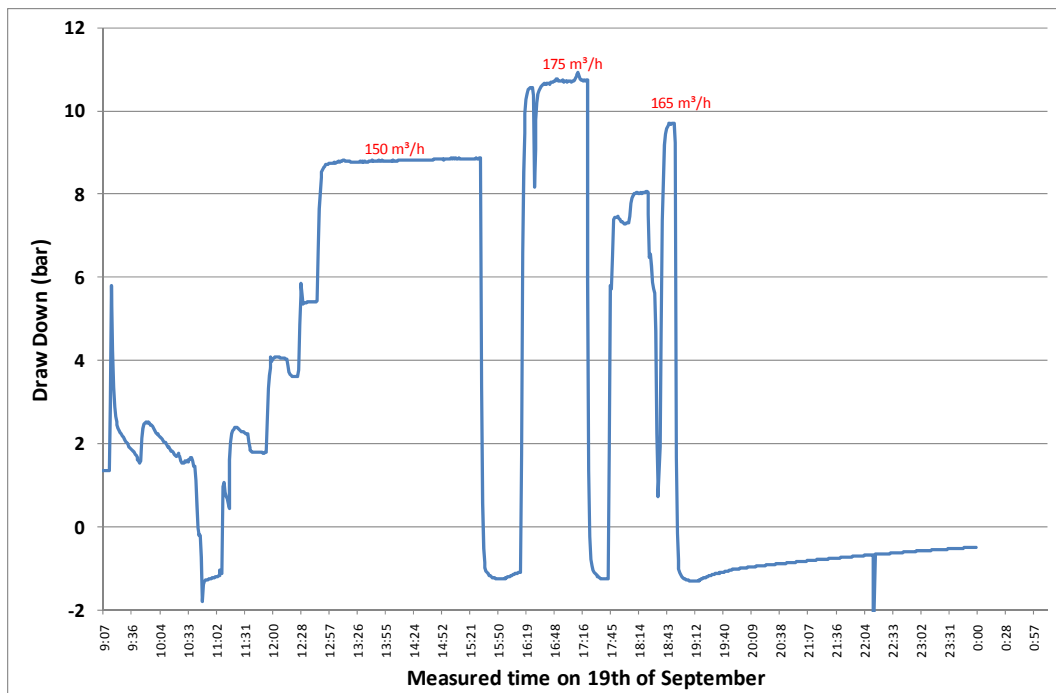


Figure 3.2 Draw down (bar)

For the project the reservoir transmissivity is calculated for 2 different cases:

- P50: average transmissivity to be expected;
- P95: worst case transmissivity to be expected.

The worse the transmissivity and the higher the flow, the higher the DD will be. In the figure below the expected DD is given for both P50 and P95 at different flows. It is assumed that filter and the formation around it are clean, so no drilling mud and fines are present anymore. Also three measured DD's during the test are given. Only these DD's are presented because the flow was only been measured at these times.

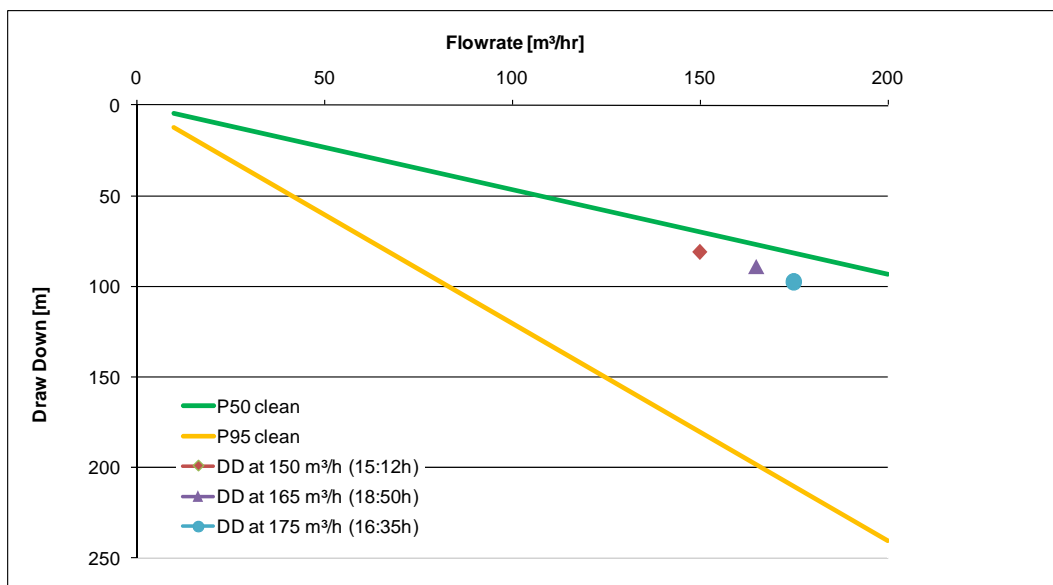


Figure 3.3 Draw down versus flow rate

It can be concluded that the measured DD's are close to the P50. This will probably improve when the wells are developed more intensively after installing the definitive pump. As the duration of the test has been very short and with many changes in the flow (no long term test has been done the second day), it was not very representative to calculate the skin factor. The skin factor will give an indication if the formation around the screen is developed good enough and that no drilling mud or fines are expected in the formation around the screen anymore. This can be worked out during the next development period, after the definitive pump is installed.

As the flow rates and the DD's are known, the specific capacities can be calculated. These are given in table 3.1.

Table 3.1 Specific capacities

	specific capacity (m³/h per m DD)
P50	2,1
P95	0,8
At 150 m³/h (15:12h)	1,8
At 165 m³/h (18:50h)	1,9
At 175 m³/h (16:35h)	1,8

3.2 Temperature measurements

The measured temperatures are given in figure 3.4. It can be clearly seen that the temperature raises when the formation water is pumped and drops after the pump is stopped.

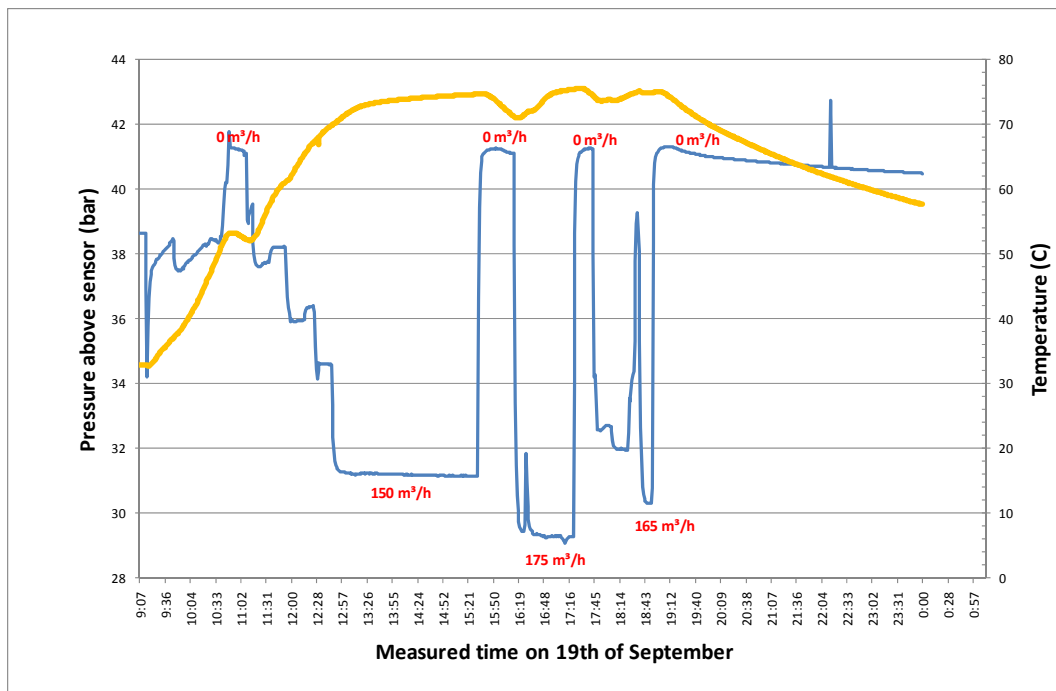


Figure 3.4 Measured temperature (orange line)

When the system has produced during some weeks, the cooling down will be slower after a stop and the warming up after a start will be quicker as the casing and the surrounding cement and formation from bottom to top have also warmed up.

The maximum temperature that was measured is 75°C, measured during the pump test at 175 m³/h. Had the test lasted longer, the temperature would have been higher still. In the future the system will always run at least at 50 m³/h with very limited stops and starts. Temperatures higher than 75°C are then expected.

3.3 Sand content

The sand content in the produced water was found to be very high. Three indicative measurements have been done at 13:30h, 15:10h and at 17:30h. The first measurement showed most sand: within 20 seconds of catching half the pumped flow, a large volume of sand had already been caught in the net (see photo 3.1).



Photo 3.1 Sand accumulation in the net after 20 seconds.

In the other two samples less sand was caught but still relatively high amounts. The sand is very fine ($<100\ \mu\text{m}$? nog nameten met microscoop), and smaller than the screen slots of 0.2 mm. The sand content will probably be reduced significantly after the well development next year. The results of these tests will make clear if filtration of the water is required before it is transported into the heat exchangers and other components. Besides causing accelerated wear of components the reservoir near the injection well may be blocked by the sand.

3.4 Water samples

The water samples have been analyzed by Alcontrol. The results are given in appendix 4. In the onsite lab of Scomi also some analyses have been performed.

Some results:

- The chloride content was some higher than expected: Alcontrol: 81 and 82 g/l, Scomi 78 g/l.
- Density was analyzed by Scomi: 1.09 kg/l.
- The pH: Alcontrol 6.3, Scomi 6.5 and 7.0

Barium and Sulfate content was analyzed: Barium=7,2 mg/l and Sulfate=95 mg/l. At these concentrations and the temperature of the sample (19°C) the solution was saturated with BaSO_4 . As the sample had cooled down before analysis some BaSO_4 may have precipitated before analysis and therefore the actual content of Barium and Sulfate in the water are probably higher. A representative sample has not been taken, because of the changed test program as was mentioned before.

For these measured Barium and Sulfate concentrations the saturation index at 40°C (infiltration temperature) is <0 (undersaturated) and therefore no precipitation would take place. Though as discussed the measured concentrations could be higher, which can easily lead to a saturation index >0 (supersaturated), which means that there might be a risk of precipitation of BaSO_4 . Inhibition may then be required to prevent blocking the infiltration well.

3.5 Gas analyses

3.5.1 Gas in the annulus around the production line of the ESP

During all tests the annulus was closed in by means of a pack-off sub. After the first day of testing and a night of recuperation the pressure in the annulus had reached 12 bars. This pressure was released by bleeding off the annulus. After the second day of testing the annulus pressure reached 8.5 bars. This gas was bled off to 4.0 bars. The next day the pressure in the annulus was found to be 3.7 bars.

The increase of annulus pressure after stopping the pump is attributed to the water level rising back to near its static level, thereby compressing the gas that has accumulated in the annulus during the test. From the fact that no significant increase in annulus pressure is noted after bleeding off the pressure it is concluded that it concerns only gas that is dissolved in the formation water. The mentioned pressure decrease from 4.0 to 3.7 bars is contributed to the decreasing temperature of the closed in gas, allowing the water level to rise.

3.5.2 Indicative gas detection

As soon as the pressurised annulus was detected on the second day, the handheld instruments were used by NDDC to monitor gas levels on site to ensure safe working conditions.

Petrolog also collected samples in the header box. It was found that mainly methane (up to 80-90% of the gas detected) was found in the accumulated gasses. Also slight amounts of up to 5 ppm H₂S were found. This forced a halt to the tests. H₂S detection instruments were ordered and installed the next day at different locations on site. Panterra was then asked to sample and analyze the water for H₂S and other gas components. During the sampling of Panterra the third day the H₂S concentration was also analysed by Petrolog again in the header box. Though handheld instruments of NDDC and the sampling procedure of Panterra did not measure any H₂S, Petrolog still detected concentrations of about 6 ppm (appendix .

3.5.3 Sampling by Panterra

Panterra was called out to collect pressurised fluid samples from the produced water flow. The sampling procedure is described in the Panterra report in appendix 3. The test was also reported by WEP:

This afternoon water and gas samples were taken by Panterra to evaluate bubble point, gas content and gas composition. First more than one well volume was produced to get fresh formation water at surface. The original approach was then to choke the production line at the highest possible pressure while still producing, produce the volume of the drill-pipe to get all separated gas out, and then take fluid samples which have all gas still dissolved. This turned out to be impossible with the available setup as at highest possible choking pressures of 250 psi / 17 bar only gas came out at the sample point (13m³/h production). It is suspected that gas accumulated in the highest point of the hose from the rigfloor down to the manifold as soon as the flow is reduced. At the manifold the gas occupies the top of the pipe.

At the sample line at the side of the manifold then only gas enters. Effectively the gate valve used as choke lets the fluid flow through but not the gas as the flow opening is at the bottom of the gate.

As an alternative samples were taken at higher flowrates and lower choke pressures. What is likely a two phase flow was sampled twice, with one well volume produced in between taking the samples. Additionally two gas samples were taken. One 20L sample was taken at 225 psi pressure in a steel bottle just after the second fluid sample had been taken, by increasing choke pressure until only gas came out. The other sample was taken at ambient pressure from the annulus in a plastic balloon.

During the first 1.5 produced well volumes no H₂S was detected, only hydrocarbons. Around the header box the concentration of these came above the LEL. From then on H₂S was detected by Petrolog in the header box in levels from 3 ppm rising to 6 ppm. Regular monitoring with a variety of handheld sniffers at the header box, water pit and sample point (even while expelling gas) did NOT show any readings.

Time breakdown:

12:30 H₂S sensors installed. Start pumping at approx 150 m³/h. Meanwhile rig up Panterra gear.

13:15 choked to 250 psi @ 13 m³/h

*13:30 tried to take sample > only gas
pump tripped due to overheating*

14:30 pump @ 150m³/h

14:45 take sample @ 100psi, 140 m³/h

15:00 continue pumping @ 140 m³/h

15:45 take sample @ 100psi, 140 m³/h

16:00 take 20L gas sample from same point at 225 psi

16:15 adjust choke pressures and observe gas/water production. At stalling pump water is produced again.

16:30 take gas sample at ambient pressure from annulus through choke manifold

16:45 finished

3.5.4 H₂S

From the lab results of Panterra and the in situ measurements it can be concluded that H₂S content of the formation water is nil to very low. It is not known where the detected quantities of H₂S in the header box originate. Small amounts of H₂S may have formed from reactions of the acid in the breaker fluid with sulphur present in thin coal seams in the Delft Sand, or the H₂S is present in low concentrations in the formation water and is partially absorbed by the steel in the well..Only sampling during prolonged production of the well will clarify this.

3.5.5 Other gasses

Results analysis Panterra

Panterra analyzed the water and gasses that were sampled (see appendix 3).

A summary of the results:

- From two liquid samples the bubble points of 1320 psig (91 bar) and 1100 psig (76 bar) at 75°C were measured.
- Gas Water Ratio's of 1.2 and 0.7 Nm³/m³ were found in these samples.
- 77-93 vol% of the gas is methane.

Panterra could not give any statements to the accuracy as the sample procedure may have influenced the results to a large degree. Despite these uncertainties it seems that a lot of methane is present in the extracted water.

Recalculation IF

IF has made a second opinion on the results of Panterra. Panterra tested the Bubble Points, using a physical method by reducing and raising the pressure of the water/gas sample. IF recalculated the bubble point in a geochemical model. For this recalculation the chemical composition of the gas-water sample and the measured Gas to Water Ratio were used. The bubble points that are calculated at Gas Water Ratios of 0.5, 1,0 and 1.5 Nm³/m³ are respectively 44, 97 and 169 bar. These results are in the same range as the results of the tests of Panterra.

This calculation is based on analysis of the sample by Panterra and therefore the results are also strongly influenced by the sample procedure.

Where do the gasses come from?

The dissolved gas is expected to stem from lower formations that contain(ed) these gases and leak(ed) to the Delft Sand formation. This has been an ongoing process of millions of years. It is very likely that most of the reservoir in the area of The Hague will be containing these gases and that production of these gases will not stop during the geothermal activities.

It is expected that all gasses are dissolved in the formation water at high pressures and temperatures. It is very unlikely that non-dissolved gasses are present that are trapped into the formation.

Information NAM

IFWEP informed the NAM about the high gas concentrations in the formation water. They were very interested in these results. NAM suggested that this information could fit into recent research on dissolved gasses that is being done at this moment. The contact with the NAM was only informative and needs to have a follow up in the further approach if gas will be produced and used.

A back of the envelope calculation shows that 5000hrs/y of 150 m³/h fluid production comes down to 750.000m³ of methane, at 15ct/m³ this represents a value of € 112.500 per year.

6 Conclusions and recommendations

6.1 Conclusions

Well capacity

The well capacity is as expected and close to the P50 value. Probably the capacity will improve during the future well development activities after installing the definitive pump.

Water temperature

The temperature during testing was already found to be 75°C. When the system is constantly producing, it is expected that this temperature will further rise some degrees.

Sand content

Sand content was very high. During the test sand content decreased slightly. The sand content is expected to decrease during the upcoming well development activities.

Water quality

BaSO₄ concentrations are a point of attention as the saturation index is close to 0 at injection temperature (40°C).

Gas

H₂S is possibly present at very low concentrations. Further testing needs to indicate if H₂S is continuously present or if its presence was related with the breaker fluid. At the witnessed concentrations no adverse consequences are expected for well and surface equipment.

Methane is found to be present in high amounts and bubble pressures are much higher than expected, with indications of 50 up to 150 bars. The Gas to Water Ratio in the two samples were about 0.7 up and 1.2m³ per m³ extracted formation water, mainly consisting of methane and partly other hydrocarbons.

Consideration must be given to health and safety issues relating to the presence of H₂S and hydrocarbons in the design of the surface system.

6.2 Recommendations

Well development

For improving the formation around the screen and decreasing the sand content it is recommended to adhere to the plans for intensive well development activities after installing the definitive pump.

Water sampling

During the above mentioned development activities it is recommended to take extra samples of the formation water to check the results of the single sample that has been analyzed now for mineral content (duplo-check). Furthermore some samples could be used to simulate the conditions in the geothermal system with cooling from 75°C to 40°C at specific system pressure for quantifying the precipitation.

The consequences of the gas content may be significant for the geothermal surface system. In order to get earlier results it may be advisable to take in-situ fluid samples with wireline techniques, or to advance the development phase by employing a rental pump.

Gas

The gas issue needs to be solved. The high gas pressures do not fit the current installation concept, which was designed for a maximum of 10 bar.

The following is recommended:

Work out the gas issue and the formulation of an action plan:

- Involvement of NAM: NAM should be involved to get permission to produce and use the gas. Secondly they have much experience which could be used for further plans;
- Involvement of SodM / EZ to inform and to work out the possibilities/consequences of producing and using the gas in the middle of The Hague.
- Find out if these bubble pressures and GW ratios are more common in this region (search in literature, information NAM);
- Find out if the high gas content could be a temporary issue, although this is not expected;
- Work out plans for more accurate measurements / analyses;
- Make some case scenario's with different solutions: technical solutions, profits/costs and permits.

Work out the plans:

- Measurements / analyses
- Engineering technical solutions for the installation.

Appendix 1

Specification Breaker Fluid

Breaker Placement Programme

Den Haag Geothermal Project

Norther Dutch Drilling Company

Rig: **No Limit 01**
Date: **August 2010**
Version: **DRAFT**

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1.0 Outline Displacement and spotting plan

Arcasolve™ well treatment fluid is prepared at the well site by mixing Arcasolve™ chemical concentrates as supplied with suitable make-up water or brine. Acidgen FG acid precursor is completely miscible with water or brine and is readily mixed by adding it to the water/brine in a mixing unit such as a paddle tank mixer or a homogeniser mixer that generates high shear (low shear mixing is also effective but may take longer). The Cellulose and Xanthan Breaker Enzyme should be mixed under low shear conditions. When all the chemicals have been mixed in to the water/brine, a sample should be taken and visually inspected to check the fluid is homogeneous before the fluid is pumped downhole.

2.0 Breaker Fluid Formulation and costs.

Formulation

PRODUCT	FUNCTION	CONCS	COMMENTS
NaCl brine (1.08 sg)	Base Fluid		Aqueous solution
Sodium Carbonate	Buffer	0.25 lb/bbl	adjust the pH of the fluid to close to neutral when it's first pumped
Cellulose Breaker	Break down cellulose polymers	0.74% v/v	
Xanthan Breaker	Breakdown xanthan polymers	0.74% v/v	
ACIDGEN FG	Filter cake breaker	7.7% v/v	generate formic acid in-situ to dissolve the carbonates
Cronox 281	Corrosion Inhibitor	1.0% v/v	

- The above chemicals would be mixed with NaCl brine at the wellsite to give a final breaker fluid s.g. of 1.08 or as required.
- Using this formulation at 70°C BHST - allow 24 hours for the breaker to have full effect.
- Incorporation of a corrosion inhibitor in the fluid is optional if concerns about metal lurgy

Estimated Costs

PRODUCT	CONCS / BBL	MATERIAL REQUIREMENTS	UNIT COST US\$	TOTAL COST US\$
Sodium Carbonate	0.25	1 x 25 kg sack	8.67	8.68
Cellulose Breaker	0.74 % w/v	1 x 20 kg pail	956.00	956.00
Xanthan Breaker	0.74 % w/v	1 x 20 kg pail	1,005.34	1,005.34
ACIDGEN FG	7.7 % w/v	1 x 210 kg drum	5,250.00	5,250.00
Corrosion Inhibitor	1 % v/v	1 x 210 kg drum	2032.06	2,032.06
			Total	9,253.08

3.0 Current Well Status

The well is assumed to be drilled to TD and the 10 3/4" x 7" casing and liner set with 5" wire wrapped screen in place.

CASING SHOE	MD (M) BRT	TVD (M) BRT	INCLINATION
7" liner lap	1200	1140	
10 3/4" casing shoe	1300	1200	
7" liner shoe	2215	1790	
5" wire wrapped screens	2215 to 2405	1790 to 1915	

- Actual depths to be entered once established

4.0 Mixing Procedures

Batch Mixing

Arcasolve™ is normally prepared by batch mixing. The required volume of clean, particulate free water/brine to make up the formulation is placed in a suitable container such as a clean mud tank or frac tank and a means of mixing and recirculating the fluid in the container is provided. Suitable mixing can be provided by use of a paddle blender and recirculation can be provided by the pump used to pump the fluid downhole. However, any mixing method which can adequately dissolve and mix the Arcasolve components in the water may be used.

Acidgen FG acid precursor may conveniently be mixed by addition to water/brine that is being re-circulated by a pump out/in to a clean tank. If a paddle blender or homogeniser unit is available, these have also been found to be highly effective for mixing Acidgen FG. Acidgen FG is denser than water and if added to water in a mixing tank with low agitation it may form a layer on the bottom of the tank. If water recirculation is used to mix the solution, the water feed to the recirculation pump should be taken from the lowest point in the tank. Ideally the tank should be inclined towards the pump feed to prevent undissolved Acidgen FG substrate lying in "dead spots" on the base of the tank and remaining undissolved. If Acidgen FG acid precursor is not fully mixed a sample taken from the mixing tank will have separate phases e.g. an Acidgen FG layer separate from the water/brine layer. When the Acidgen FG is fully mixed with the water/brine there will be no separate layers apparent.

When the Acidgen FG acid precursor has been fully mixed, the remaining chemical components required for the specific Arcasolve™ formulation are added by pouring the contents of the plastic containers into the recirculating water stream e.g. at the mixer unit. The enzyme preparations are all water based and are readily soluble in water and easily mixed into the Acidgen FG solution. Enzymes should be laid on the side until everything is ready for pumping the Arcasolve™ fluid. When ready the

enzymes should be mixed into the tank and the fluid pumped downhole with minimal delay.

Equipment requirements

- A clean vessel* large enough to hold the required amount of water and formulated fluid
- A means of safely handling 240 Kg drums
- A means of mixing and recirculating the fluid in the mixing tank (often the same pump used to pump the fluid downhole)
- A pump by which the formulated Arcasolve fluid can be pumped downhole, preferably within a 1-4 hour period.

**The container and pump lines should be free of residues of other chemicals, muds, soil, grass, etc. and should preferably be rinsed with clean water prior to the treatment. Particular care should be taken to avoid the presence of conventional acids or alkali material in the mixing tank/container and/or the pump lines. Very low or high pH in the fluid when mixing in the Arcasolve™ chemicals could adversely affect the activity of enzymes within the formulation or cause premature formation of the acid from the acid precursor. When the mixing tank has been filled with water or brine the pH of the fluid should be checked to ensure it is within the preferred range of pH 6 – 8 for water or at the planned pH for a brine based formulation. The pH of the make up fluid before adding the Arcasolve™ chemicals should not be below pH 4.5. If it is the pH of the fluid should be brought to above pH 4.5 e.g. by adding some sodium acetate or even some calcium carbonate to buffer any acid present and raise the pH.*

5.0 Product Requirements for 20 bbls of breaker fluid

The volume of Arcasolve fluid required for this type of treatment is based on the volume of the open hole being treated plus some extra fluid in case of any losses when placing the fluid or dead volumes in the mixing tank/lines, typical treatment volumes are equivalent to the volume of the open hole being treated plus 20%.

This would give a total treatment volume of 17 bbls which allows for the volume displacement of the screens plus any possible slight losses during pumping etc? (Should the open hole volume change then the volume usage will need to be re-calculated to ensure there is no additional acid generated that is not used in the dissolving of the carbonates)

PRODUCT	CONCS / BBL	UNITS	TOTAL MATERIAL REQUIREMENTS
Sodium Carbonate	0.25	lb/bbl	1 x 25 kg sack
Cellulose Breaker	0.74 %	w/v	1 x 20 kg pail
Xanthan Breaker	0.74 %	w/v	1 x 20 kg pail
ACIDGEN FG	7.7 %	w/v	1 x 210 kg drum
Corrosion Inhibitor	1 %	v/v	1 x 210 kg drum

6.0 Spotting Procedures

It is not necessary to pump Arcasolve™ fluid at high rate in order to get uniform acid placement. Once mixed Arcasolve™ fluid can be pumped at low, medium or high rates as required. For Arcasolve™ treatments on new wells a typical method for placing the Arcasolve™ fluid is through the drill string and BHA, through a work string or coiled tubing once drilling has reached T.D.

Procedure for Arcasolve™ Fluid Placement - new well completed with a liner and FIV, placing fluid using a stimulation string

Mix Sodium Chloride brine or suitable completion fluid in sufficient quantity to circulate and control the well while running in hole and displacing the Arcasolve™ treating fluid. Check the density with the mud engineer to control the well.

1. Clean all mixing tanks and pumping equipment used to mix and pump Arcasolve™ fluid. The mixing set up must be free of all mud residues, organic deposit, check the pH value of the fluid at the end of the tank washing, it should be around 7 (+ 1 pH) unit i.e. free from residual acidic or alkaline material.
2. When drilling operations are completed, circulate the well bottom up until returns are clean displacing whole mud with solids free mud.
3. Run slotted liner into hole in solids free mud.
4. Sting stimulation string into end of liner and circulate out solids free mud from liner/wellbore annulus with push pill followed by brine.
5. Start pulling stimulation string OOH and circulate solids free mud from inside liner with push pill followed by brine.

Tapered Push Pill – Preferred Method

- a) Displace liquid mud from hole using a solids free viscosified push pill made from xanthan dissolved in brine of same s.g. as the drilling mud.
N.B. low shear viscosity of push pill should be 3 x that of the mud in

the hole (e.g. if mud contains 1 ppb xanthan then push pill needs to contain c.a. 3 ppb xanthan).

- b) Volume of push pill should equal open hole volume plus perhaps a few bbls extra so that when the push pill is placed there's enough volume to displace the liquid mud and fill the open hole with the push pill.
- c) Once approximately half the total volume of push pill has been pumped, start pumping the clear brine (same s.g. as push pill) into the push pill tank at same rate as push pill is being pumped to dilute the 2nd part of the push pill. Continue pumping push pill and brine until the volume of brine added to push pill tank equals approximately 1 tank volume and when push pill tank runs out switch to pumping clear brine of same s.g. as mud system.

Push Pill – Simple Method

- a) Displace liquid mud from hole using a solids free viscosified push pill made from xanthan dissolved in brine of same s.g. as the drilling mud. N.B. low shear viscosity of push pill should be 3 x that of the mud in the hole (e.g. if mud contains 1 ppb xanthan then push pill needs to contain c.a. 3 ppb xanthan).
 - c) Volume of push pill should equal open hole volume plus perhaps a few bbls extra so that when the push pill is placed there's enough volume to displace the liquid mud and fill the open hole with the push pill.
 - d) Push pill is then flushed from the hole with clear brine of same density as used to make the pill
- 6. Start to mix Arcasolve™ fluid and set aside the enzymes until all the other Arcasolve™ chemicals have been mixed with water/brine and the solution is homogeneous and ready to pump.
 - 7. When ready to pump, mix the enzymes, check the solution is homogeneous and repeat steps 4 and 5 to displace brine from liner/wellbore annulus and inside liner with Arcasolve™ fluid.
 - 8. Leave the stimulation string at the liner heel, within the FIV, until displacing the Arcasolve™ fluid has been completed. Then POOH allowing FIV to close leaving Arcasolve™ fluid in place to soak.

Soak Period

Once Arcasolve™ fluid has been placed downhole and the FIV closed the fluid is left in place for the designated time, depending on downhole conditions, to allow acid to be produced in-situ.

7.0 Disposal of Spent Arcasolve™ Fluid

Arcasolve™ fluid constituents and reaction products are low hazard, non-toxic and readily biodegradable. Spent Arcasolve™ fluid contains organic calcium salts, such as calcium formate, and alcohols that present minimal disposal problems. It is

assumed that facilities exist for handling spent fluid such as Arcasolve[™] fluid. Proper disposal of spent fluid in accordance with local regulations is the responsibility of the well operator or its well service contractor. In general, the disposal method used for spent acidizing fluids from conventional acidizing with organic acids will be adequate.

8.0 On-Site Q.A./Q.C. during Arcasolve[™] treatments

The Acidgen FG, is stable under extreme ambient conditions such as in the Middle East. Arcasolve[™] enzymes are stable for over 6 months when stored below 25°C.

On site Q.A./Q.C. during Arcasolve[™] treatments is relatively simple:

1. Check that chemical containers are in good shape, not leaking, and have not been opened beforehand i.e. seals intact.
2. Check mixing tanks and pumps (especially previously used mud pits/pumps) have been well flushed and cleaned before being used to mix/hold Arcasolve[™] fluid.
3. Once mixing tank/pit has been filled with make up water or brine check its free from particulate material and check the pH (before adding the Arcasolve[™] chemicals) which should be between pH 6 and pH 8 for fresh water. When fresh completion brine is used as the base fluid for Arcasolve[™] check the brine pH matches the expected value in the brine specification.
4. Ensure any enzymes to be used in the fluid formulation are stored properly and only added just before the fluid is to be used and pumped downhole.
5. When all the Arcasolve[™] chemicals have been mixed in the water or brine recheck pH to ensure it is not below pH 4.5.

MEMO – there's no starch breaker in this formulation (no starch in the DIF) so this is irrelevant to this job.

9.0 Storage of Arcasolve[™] Chemicals

Drums or IBC's of Acidgen FG, should be stored out of direct sunlight and not opened until just before use to prevent ingress of moisture or possible contaminants from the environment.

Long term storage of Arcasolve[™] Cellulose or Xanthan Breaker Enzymes should be below 25°C where possible and cans should not be opened until just before use to prevent ingress of moisture or possible contaminants from the environment.

If stored as directed these Arcasolve™ chemicals should be stable for at least 6 months.

N.B. Short term storage (i.e. for a few days) of Arcasolve™ Cellulose or Xanthan Breaker Enzymes in the shade at the well site at high ambient temperatures will not impair enzyme activity.

10.0 Handling of Arcasolve™ Chemicals

All the Arcasolve™ chemicals listed in 2.0 above are low-hazard for handling and use. Please refer to the relevant MSDS sheets for further information.

Appendix 2

Test program WPMI



Geothermal Wells The Hague South West

Well test program HAG GT-01

Operator

Aardwarmte Den Haag VOF
Guntersteinweg 377
2531 KA DEN HAAG
Contactpersoon: F. Schoof

Prepared by

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E info@dutchdrilling.com

Contact: R. Woudstra
R. te Gussinklo Ohmann

Well test program Geothermal Production Well HAG GT-01

Version 03, 25th of August 2010

Prepared by:	WPMI
Approved:	
Publication date:	25 th of August

1. Test Design

This production test has two objectives:

1. Cleaning the well & screens to prevent scaling of the formation/screens in the near future.
2. Indication of production capacity of the well.

The well will be tested using a down hole pump (ESP) on 5" drill pipe. The drill pipe is run into hole until a depth of 450 m. Along side of the drill pipe wire line will be run with a sensor to register temperature and pressure.

The test is divided in two parts:

1. Step wise increasing production over a period of 8 hrs. increasing flow every 2 hrs. Pending on the production flow the following steps can be taken:
 - a. Pump test is continued
 - b. Production flow fluctuation by changing pump volume and flow.
 - c. Optional use of chemicals (RIH drill pipe to the reservoir)
2. When the production test of the first day results in higher specific capacity (Q_{spec}) then 0,8 m³/h per meter draw down (P95) at constant flows of about 100 to 150 m³/h, a production test with a constant flow between 100 and 150m³ will take place for 4 hours.

The production water will be gathered in a separate container to settle, from which the water will be pumped through a flow meter in to the temporary storage. From this storage the production water will be transported to the water treatment plant (Houtrust).

Please note: The mentioned production flows and time are depending on the maximum reachable transport volume from location to the water treatment location Houtrust.

2. Organisation

The drilling supervisor of WPMI is responsible for the testing operation. The testing will be executed by NDDC, lead by the toolpusher. The logistics will be coordinated by the logistic coordinator of WPMI.

3. Safety

Major safety hazards points will be (Include above points in pre job meeting as well with the rig crew as the logistic crew):

1. Pipe handling – handling Drill pipe with power cable and gauge cable.
2. Logistics, truck will be loaded near the temporary storage.
3. Handling highly saturated brines (KCl/NaCl) and produced fluids
4. Hot water (>70 degrees Celsius), constant temperature measurement, safety precautions and procedures to be conducted
5. Traffic
6. Offloading at Houtrust (hot saline water)
7. Well control

4. Well control

A "Pack Off Sub" (POS) will be installed on the last drill pipe to be run in the hole. This Pack Off Sub enables the wire line cable and electric cable to be run in the hole through the rubber packing element of the Sub. The POS will be aligned against the Annular preventer which, when activated, will compress the rubber on the POS resulting in a sealing of the annulus. After it is activated, by closing the annular, a pressure test will be conducted to assure that it can hold pressure. In Appendix 1 a concept pack-off sub is given.

5. Status

The status of the well is as follows:

1. In the 6" open hole section a wired wrapped screen is installed as part of the liner.

6. Preparation

1. Line up temporary piping and storage (240 m³)
2. Line up the tank trucks
3. Test pump on drillpipe
4. Check if water pits are clean and empty
5. R/U SchulzeTest P/T gauge before running in to hole
6. Prepare pump in sub in the lubricator.

7. Suppliers

Schulze will supply the wire line services and Centrlift Baker Hughes will deliver the test pump (ESP), and Reym will provide the necessary transportation means.

8. Test

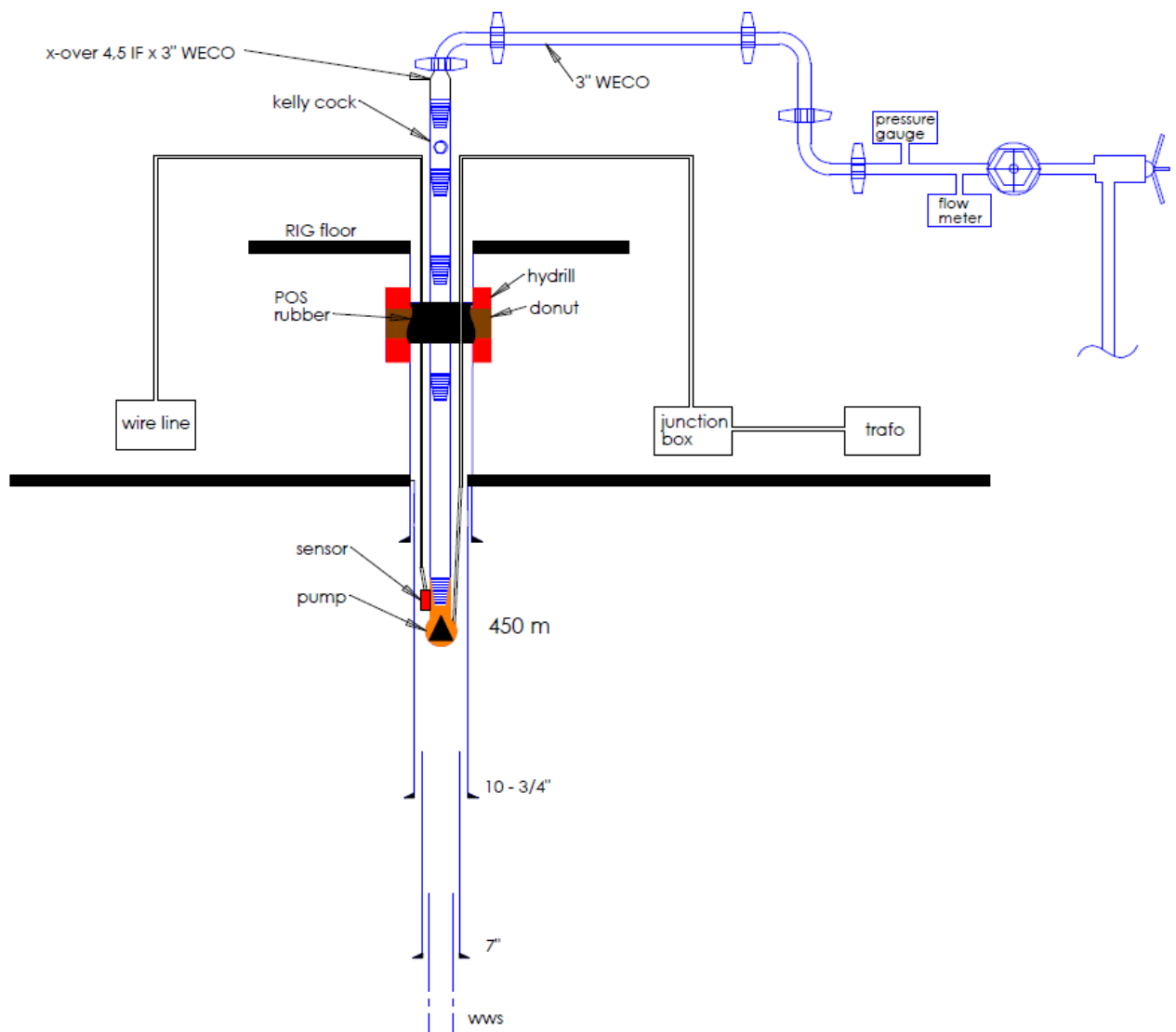
1. Install piping with flow meter towards the storage tanks.
2. Install ESP on drill pipe and function test pump.
3. RIH pump on 5 " dp together with e-line and power cable of the pump.
4. RIH to 450 m ALH.
5. Install PO Sub and RIH same and position towards Annular Donut.
6. Install Kelly cock
7. Close Annular and P/T POS.
8. Open Wellhead valves (prevent vacuum in Annulus)
9. Start pumping (expected pressure up to 50 bar)
10. Increase pump volume to that 60 m³/hr production is reached (ADH rep. to witness!)
11. Record pressure drop temperature and flow (ADH representative to witness)
12. Observe production for 2 hrs
13. Increase production with 20 m³ and start transport to Houtsrust.
14. Return to step 10. until a maximum production of 150 m³ is reached or the temporary storage is full.
15. Stop production and observe pressure response.
16. When all is stable close Wellhead valves.
17. Move production water to location Houtrust.

Next day

18. Observe pressures.

19. Install pump in sub.
20. Line up production lines
21. Open Well head valves
22. Start pumping and increase slowly to 150 m³/hr
23. Record pressure drop temperature and flow (ADH representative to witness!)
24. Observe production and pressure for about 4 hrs. (Production time can be limited by logistics)
25. Transport production water to Houtrust
26. After the test close the Well head valves and POOH and L/D pump.
27. Line up installation of well head.

9. Well schematic



10. Disposal of production water

The testing of the producer will be done in two days. In the table below the quantities of disposed water are given.

Table 1, Quantities disposed test water

Day 1					Day 2				
Hours	Production Volume	Transport capacity	Transport Cum.	Stored on location	Hours	Production Volume	Transport	Transport Cum.	Stored on location
Unit	m ³ (cum)	m ³	m ³	m ³	Unit	m ³	m ³	m ³	m ³
1	60	90	60		1	150	90	90	60
2	60 (120)	90	120		2	150 (300)	90	180	120
3	90 (210)	90	210		3	150 (450)	90	270	180
4	90 (300)	90	300		4	150 (600)	90	360	240
5	120 (420)	90	390	30	5	(600)	90	450	150
6	120 (540)	90	480	60	6	(600)	90	540	60
7	150 (690)	90	570	120	7	(600)	90	600	0
8	150 (840)	90	660	180					
9	(840)	90	750	90					
10	(840)	90	840	0					

The production water will be transported to water treatment plant Houtrust of Delfluent at the Houtrustweg. Aardwarmte Den Haag has arranged a permit (ARW/2010.5941) to dispose the water at the Houtrust plant. The maximum amount of water that can be disposed and transported per hours is about 90 m³. On the drilling site itself a maximum amount of 150 - 240 m³ can be stored. As a consequence only 8 hours of testing is possible, of which the last 2 hours 150 m³ per hour.

The second day this amount will increase during the test phase to 240 m³. This will take an other 4 hours after the test to truck this off. It is assumed it is possible to dispose 90 m³/hr from location. The testing of the wells will be executed during day time.

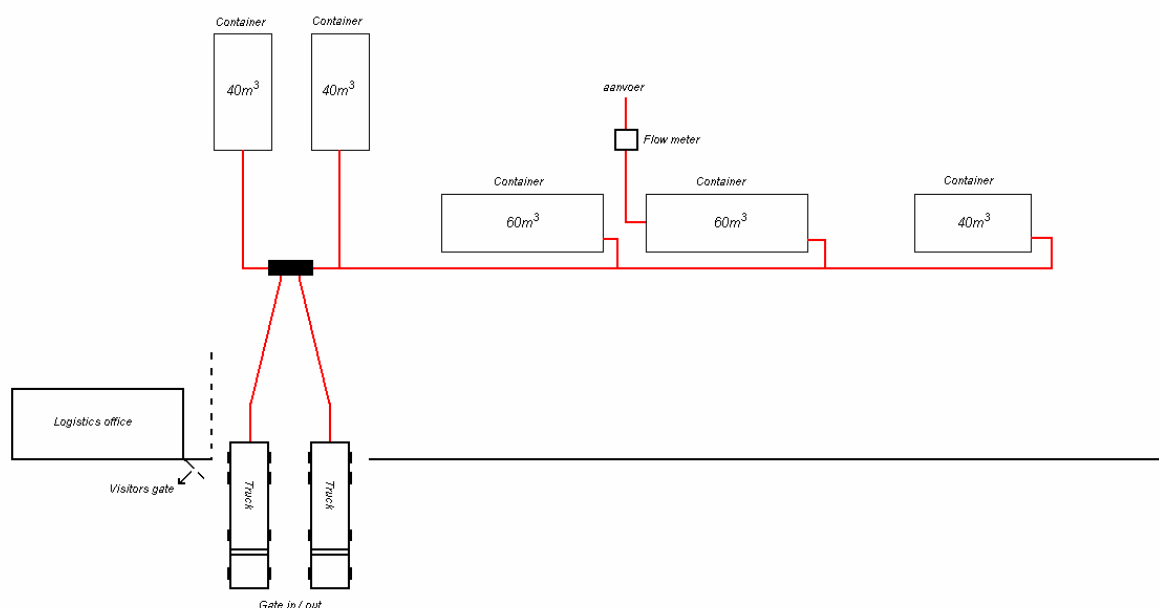
11. Logistics and equipment

The test water will be transported to the AWZI Houtrust of Delfluent, where it can be disposed in their water cellar. With the operators at Houtrust the following has been agreed upon:

- The testing of the first well will most likely happen between the 12 and the 19th of August and will take 2 days. The operators at Houtrust will be informed as soon as possible (at least 2 days before by logistic coordinator).
- On the first day about 10 hours of trucking is foreseen, on the second day 7 hours.
- If possible the transport of the brine will not take place in the weekend. The first day will start at 8.00 hours up to 18.00 hours. The second day will be within the operating hours of Houtrust (7.45 – 16.15 hours)
- WPMI / REYM will provide the connection equipment to discharge the brine on the Houtrust location. Two location next to each other have been identified, which makes it possible to discharge with two trucks.
- WPMI / REYM will make sure that the discharge locations are clearly marked.
- The operators at Houtrust will make sure that the discharge locations can be reached properly.
- WPMI / REYM will keep the discharge areas clean and will provide drip / collections bins for the brine if needed.
- Houtrust provides shower possibilities.

To be able to transport 90 m³ per hour from the drilling location to Houtrust, 8 trucks (storage of 20 - 25 m³ per truck) will be used and a tank storage of 240 m³. The trucks have 2 hours to ship the disposal to the Houtrust (including taking in and dumping). Due to traffic regulations it is prohibited that more than 2 trucks are waiting around the drilling location. In the figure below a schematic overview of the storage of the disposal water and the trucks is given. This system allows two trucks to be loaded at the same time. The water will be disposed through the choke manifold into the storage system, from where it will be loaded into the trucks.

Figure 1, Schematic overview drilling location



The transport equipment will be provided by WPMI and REYM. The following items are required on the drilling site:

- T-stuk ± 4 stuks
- Bochten 4 stuks
- 80 meter 4" slang-rubber-pijp
- Manifold
- Extra rubbers 4"
- 1x container 60 m3
- 2x container 40 m3

After leaving the drilling location a left turn on the Leyweg is made, after which the Thorbeckelaan is followed up to the crossing with the Sportlaan. A right turn on the Sportlaan is made. The Sportlaan becomes the Segbroeklaan and finally a left turn is made on the Houtrustweg, see Figure 2.

Figure 2, Routing from drilling location to Houtrust plant



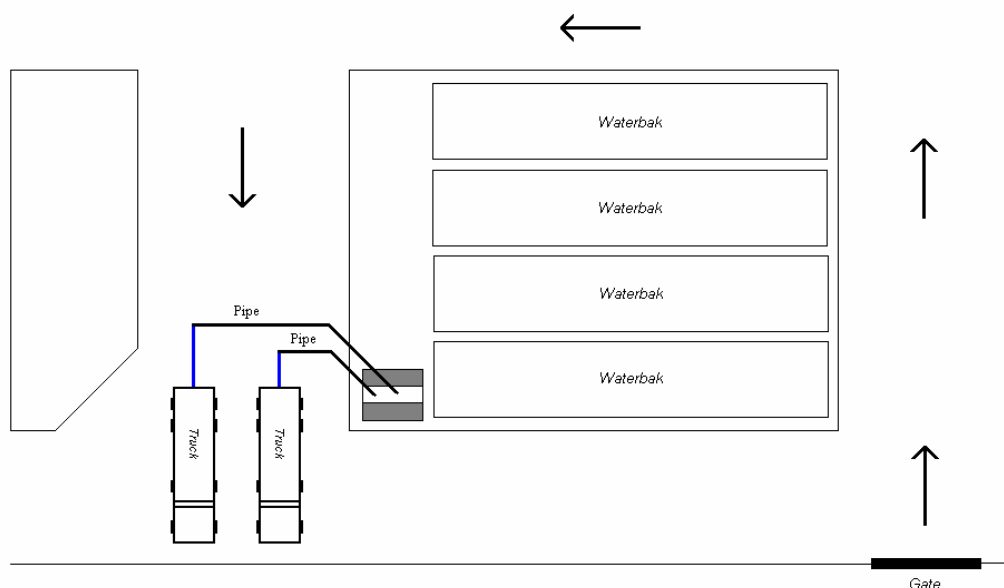
On the Houtrust location there is enough space for the trucks to move and turn, however at the entrance of the plant, the bicycle path should be noted! After the entrance the trucks drive straight ahead, whereas at the end two times a left turn is made. In Figure 3 the routing of the trucks on the Houtrust plant is given.

Figure 3, Disposal location Houtrust



Two trucks can discharge the test water parallel into the disposal of the Houtrust plant, see Figure 4.

Figure 4, Schematic overview Houtrust plant



About 50 meter 4" hoist / pipe and 2 drippans are required. These will be supplied by WPMI / REYM.

When the trucks have disposed their test water at Houtrust they call the logistic coordinator of WPMI for approval to come to the drilling location again. If not the truck will stay on the plant site.

12. Contact details

Name	Function	Organisation	Telephone number
Paul Weij	Technical advisor	Delfluent	0651074323
Controlekamer CCK Houtrust		Delfluent	0703625366
Dienstdoende operator		Delfluent	0654288614
Bas Pittens		IF-WEP	0653206926
Roel Woudstra	Project manager	WPMI	0610033821
Bas Hengeveld	Drilling supervisor	WPMI	0610000609
Lars Andersen			
Koop Eleveld			
Harry Knip	Logistic coördinator	WPMI	0610000608
Hans Kracht			
R. te Gussinklo Ohmann	Operational manager	NDDC	0610033812
Paul Basey	Rig manager	NDDC	0613120647
Erik de Bruine	Logistic coördinator	Reym	????

Address drilling location:

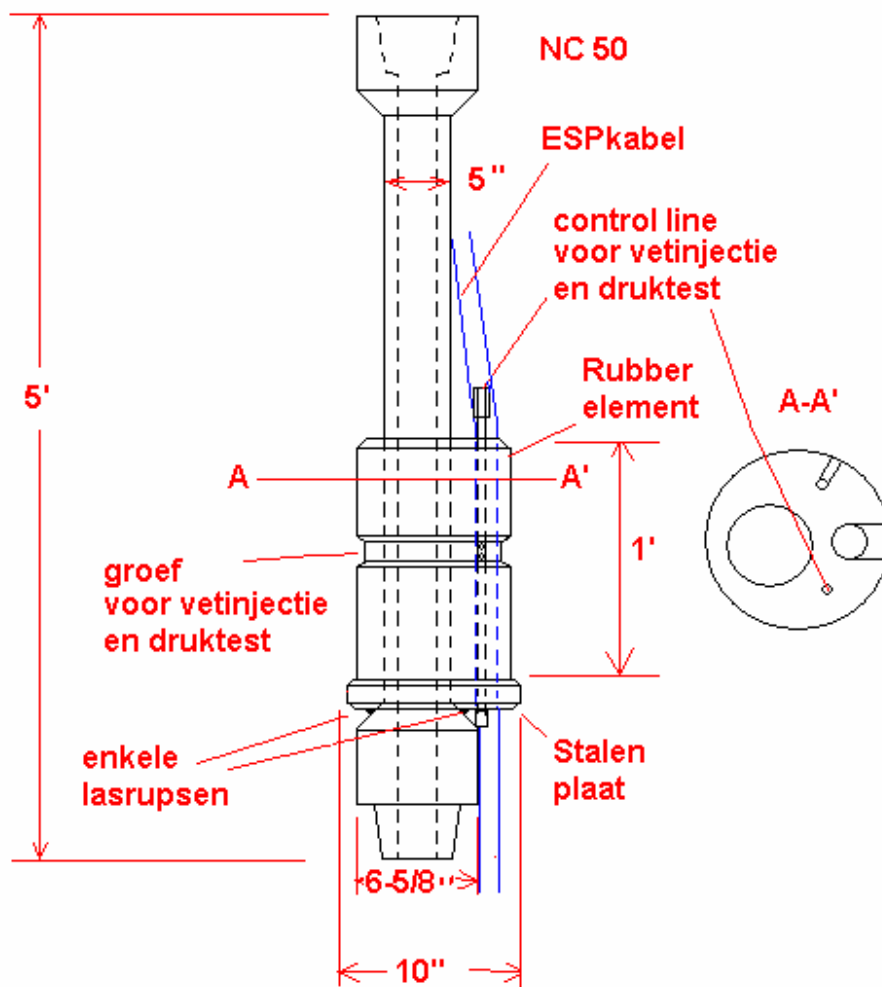
Leyweg 289
The Hague

Address AWZI Houtrust

Houtrustweg 120
2566 GJ Den Haag

Appendix 1, Concept pack-off sub

Concept pack-off sub



Appendix 3

Report Panterra: gas sampling and gas analyses



Analysis Report

Water/Gas Samples

HAG-GT1 Well

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ABN Amro Bank: 49.28.54.319
Stationsweg 31-33, Leiden
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SWIFT: ABNANL2A



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1. Procedures Description

1.1. Sampling Sequence

The sampling kit with a purging tee was connected to a branch manifold from the drillpipe. The water well was choked to 250 psi for 15 minutes. A purge was conducted to determine the nature of the sample, the sample collected at the purge tee was just gas with very little liquid.

After flowing the well for 1 hour at a rate of 150 m³/hour, the sample was collected using the displacement procedure from the branch manifold at 14:45. During the sampling, the well was flowing at a pressure of about 100 psi and a rate of 140m³/hour.

The second pressurized liquid sample was collected after an hour of well flowing, again at 140 m³/hour and 100 psi.

The pressurized gas sample was collected at 16:15 with the well flowing, with a backpressure of 250psi.

An additional atmospheric gas sample was collected in a balloon from the annulus.

1.2. Samples Preliminary Checks and Analysis

1.2.1. Visual Inspection upon Receiving the Samples

Upon receipt, the samples were visually inspected for any obvious faults, i.e. leaks, bent valves or any other mechanical problems. The sample cylinders were all found to be in good condition.

1.2.2. Opening Pressure Measurement

The pressurized sample cylinders at room temperature were connected at the water end to a high pressure pump, the opening pressure was read at the pump display.

For the gas cylinder, a pressure gauge was attached to the top valve at room temperature. The opening pressure was read directly at the gauge.

1.2.3. Gas Bottle Water Check

With the gas sample in a vertical position, a few cc's were purged from the bottom valve in order to check the water content. All the water found was drained.

1.2.4. Gas H₂S Presence Check

With the gas sample in a vertical position, a few cc's were purged on a paper strip imbibed with Lead Acetate. H₂S reacts specifically with lead acetate to form a lead sulfide brown stain. There was a very slight change in color indicating that there was some infinitesimal H₂S amount. During the purge, some H₂S smell could be vaguely perceived.

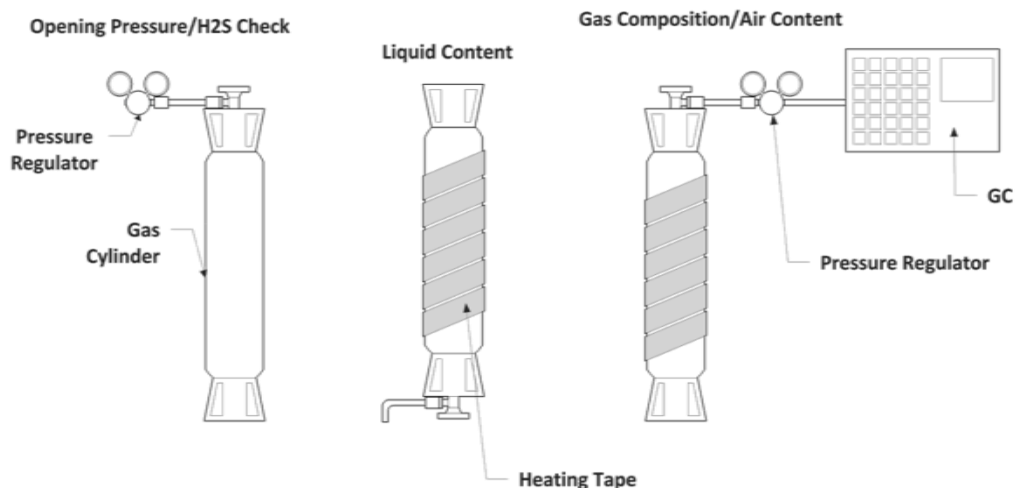


Figure 1-Gas Samples Quality Check

1.2.5. Samples Restoration

The liquid samples were pressurized to the working pressure and stabilized by shaking. While connected to a positive displacement pump, the samples were heated up to a temperature of 95°C and homogenized for 24 hours prior to any removal of samples.

1.2.6. Bubble Point Measurements

The liquid samples were subjected to pressures ranging from pressures higher than the reservoir pressure to much lower pressures at reservoir temperature.

The change in the slope of the PV curve indicates the bubble point pressure.

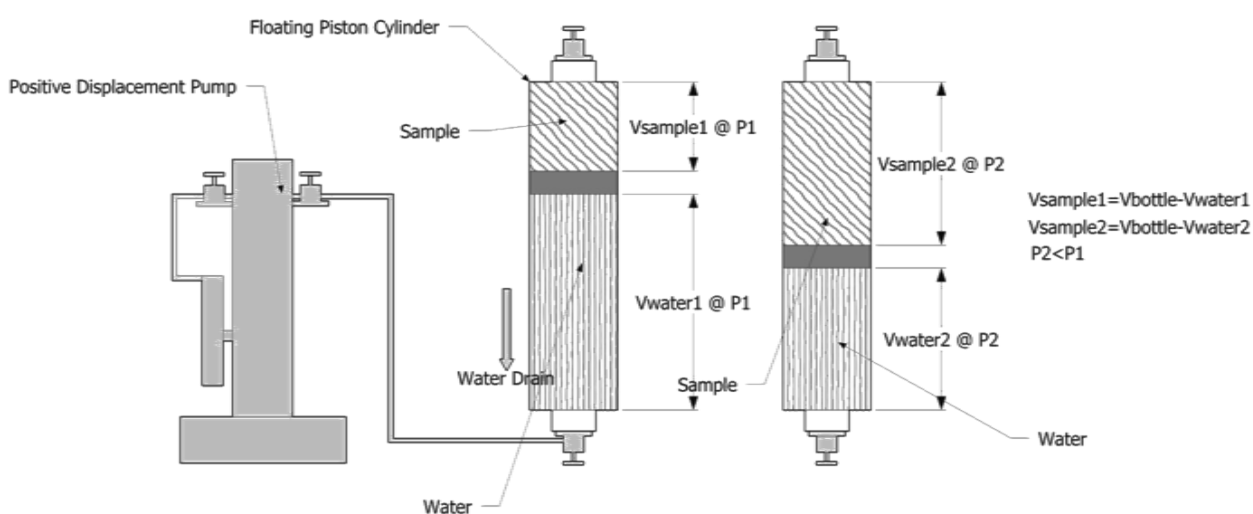


Figure 2-Bubble Point Measurement

1.2.7. Compositional Analysis

1.2.7.1. Flash Separation

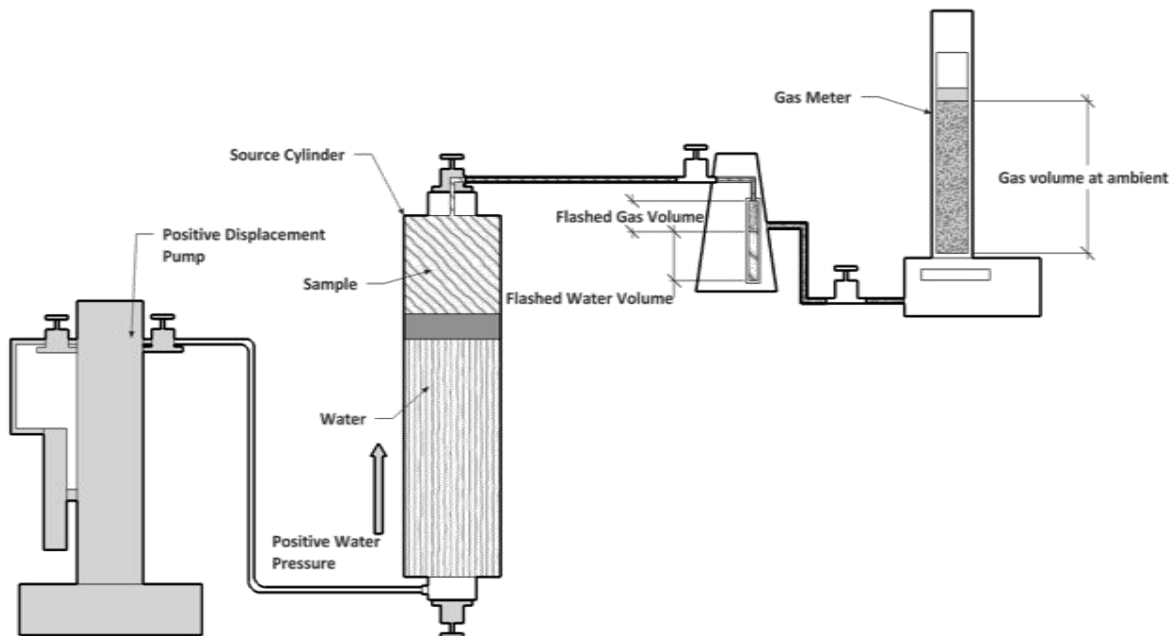


Figure 3-Flash Separation

A volume of a single-phase fluid was pumped from the sample cylinder into a trap connected to a gas meter at atmospheric conditions of pressure and temperature. The flashed water and gas volumes, separation temperatures and atmospheric pressures were accurately recorded.

The composition of gas was subsequently measured using the procedure described below. The flash GOR (gas oil ratio) was calculated as well as the ratio between the flashed liquid and the collected gas.

1.2.7.2. Sample Composition

The resulted gas fraction was analysed using the gas chromatography procedure.

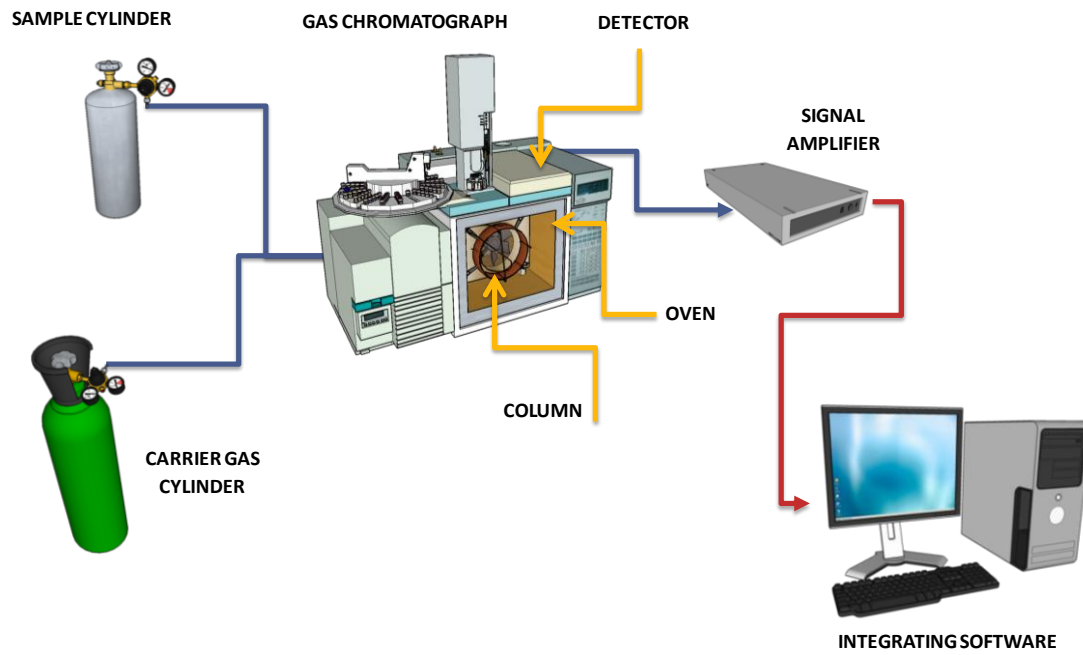


Figure 4-General Chromatographic Procedure Layout

Compositions up to C_{11+} were measured. Components: porous polymer and mole sieve columns, TCD detector (for C_1 - C_3 , permanent gases), capillary column and FID detector (for C_4 to C_{11+}).

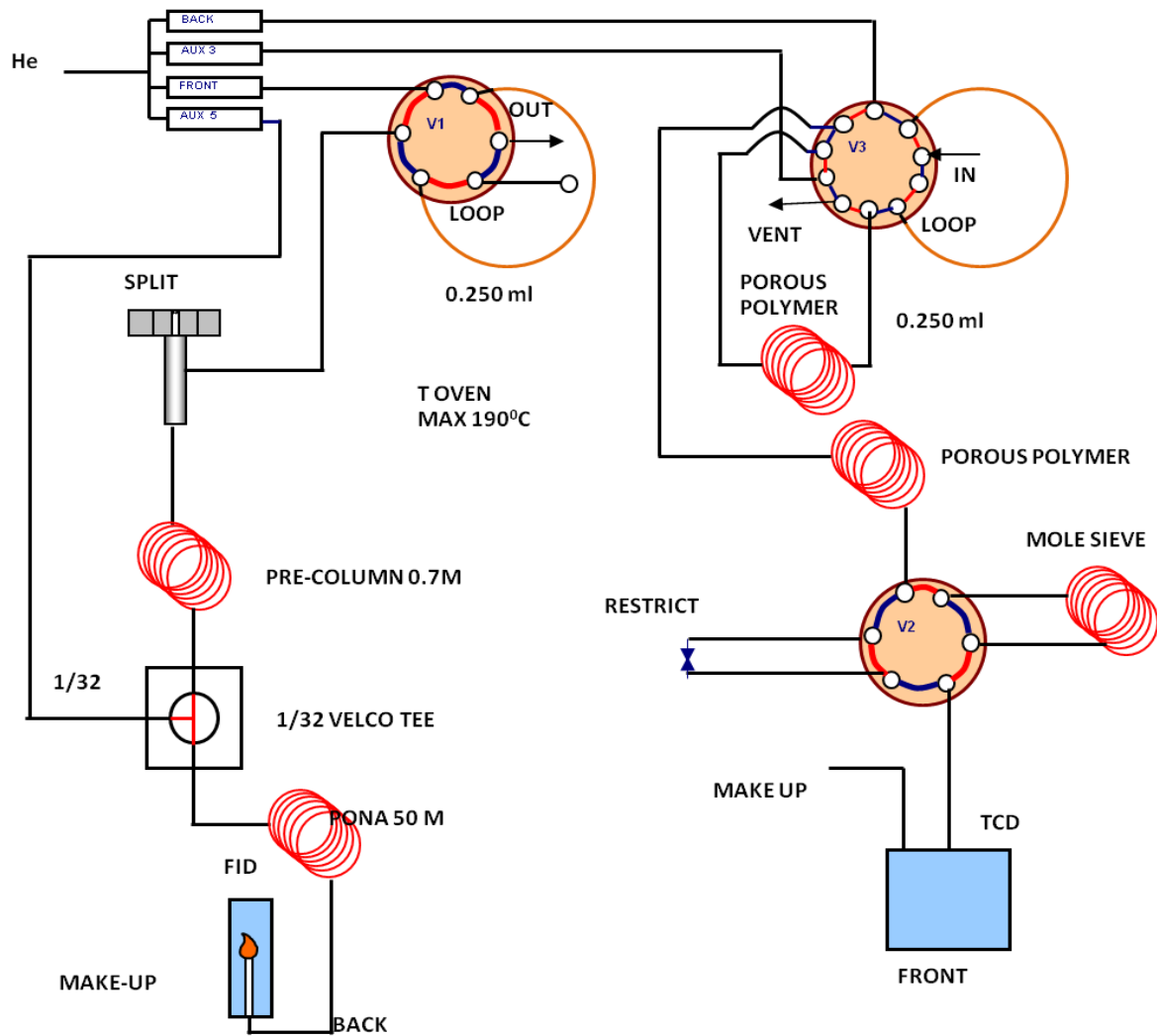


Figure 5-Gas Chromatography Layout

2. Provided Information

2.1.1. Summary of Well Data

Well: HAG-GT1

Reservoir Fluid: Water/Gas

Reservoir Pressure: 3300 psi

Reservoir temperature: 75°C

Vertical Depth: 2301 m

2.1.2. Summary of Sampling Data

Table 1-Summary of Sampling Data

Sample type	Well	Sampling Point	Original bottle no.	Date/Time Sampling	Surface Line Pressure (psi)
Pressurized Liquid	HAG-GT1	Surface – Drill Pipe Manifold	F80009/156	22-9-10/14:45	100
Pressurized Liquid	HAG-GT1	Surface – Drill Pipe Manifold	32138	22-9-10/15:45	100
Pressurized Gas	HAG-GT1	Surface – Drill Pipe Manifold	DW-7214	22-9-10/16:00	100
Atmospheric Gas	HAG-GT1	Surface - Annulus	Plastic Recipient	22-9-10/16:30	250 (back pressure)

3. Analysis Results

3.1. Preliminary Check Results

Table 2-Preliminary Check Results

Sample Type	Cylinder no.	Opening Pressure (psig)	Opening Temperature (°C)	Sample Volume (cc)	Bubble Point (psig) at 75°C
Pressurized Liquid	F80009/156	80	22	700	1320
Pressurized Liquid	32138	84	22	700	1100
Pressurized Gas	DW-7214	380	50	20000	N/A

* Sample volume at opening pressure

3.2. Compositional Analysis

Table 3-Gas Composition Sample no. DW-7214

	Component	Mole%	Weight%
H ₂	Hydrogen	0.000	0.000
H ₂ S	Hydrogen Sulphide	0.000	0.000
CO ₂	Carbon Dioxide	1.697	4.267
N ₂	Nitrogen	2.424	3.879
C1	Methane	93.074	85.286
C2	Ethane	2.066	3.548
C3	Propane	0.428	1.077
C4	i-Butane	0.039	0.130
C4	n-Butane	0.051	0.168
C5	i-Pentane	0.008	0.033
C5	n-Pentane	0.004	0.018
C6	Hexanes	0.009	0.044
C7	Heptanes	0.003	0.015
C8	Octanes	0.001	0.005
C9	Nonanes	0.000	0.001
C10	Decanes	0.156	1.192
C11+	Undecanes Plus	0.040	0.337
	Total	100.000	100.000
Calculated Gas Properties			
Gas Density (kg m ⁻³ @ 15°C)		0.740	
Gas Mole Weight (g mol ⁻¹)		17.508	
Real Relative (to air) Density of Gas		0.604	
Mole weight of Heptanes Plus (g mol ⁻¹)		135.569	
Density of Heptanes plus (g cm ⁻³ at 60°F)		0.781	
Mole Weight of Undecanes plus (g mol ⁻¹)		147.000	
Density of Undecanes plus (g cm ⁻³ at 60°F)		0.789	
Calorific Value (MJ m ⁻³)		37.545	

Table 4-Flashed Gas Composition Sample no. F80009/156

	Component	Mole%	Weight%
H ₂	Hydrogen	0.000	0.000
H ₂ S	Hydrogen Sulphide	0.000	0.000
CO ₂	Carbon Dioxide	3.371	5.147
N ₂	Nitrogen	1.521	1.478
C1	Methane	77.860	43.337
C2	Ethane	1.802	1.880
C3	Propane	2.082	3.186
C4	i-Butane	0.499	1.006
C4	n-Butane	2.827	5.700
C5	i-Pentane	0.907	2.271
C5	n-Pentane	2.515	6.296
C6	Hexanes	1.007	2.934
C7	Heptanes	0.344	1.084
C8	Octanes	0.626	2.034
C9	Nonanes	0.009	0.037
C10	Decanes	0.001	0.005
C11+	Undecanes Plus	4.628	23.604
	Total	100.000	100.000
Calculated Gas Properties			
Gas Density (kg m ⁻³ @ 15°C)		0.935	
Gas Mole Weight (g mol ⁻¹)		28.823	
Real Relative (to air) Density of Gas		0.763	
Mole weight of Heptanes Plus (g mol ⁻¹)		137.548	
Density of Heptanes plus (g cm ⁻³ at 60°F)		0.792	
Mole Weight of Undecanes plus (g mol ⁻¹)		147.000	
Density of Undecanes plus (g cm ⁻³ at 60°F)		0.789	
Calorific Value (MJ m ⁻³)		45.407	

Flash Gas Water Ratio: 1.235 Nm³/m³

Table 5-Flashed Gas Composition Sample no. 32138

	Component	Mole%	Weight%
H ₂	Hydrogen	0.000	0.000
H ₂ S	Hydrogen Sulphide	0.000	0.000
CO ₂	Carbon Dioxide	5.292	12.080
N ₂	Nitrogen	2.037	2.959
C1	Methane	88.521	73.661
C2	Ethane	1.827	2.849
C3	Propane	0.485	1.109
C4	i-Butane	0.064	0.194
C4	n-Butane	0.363	1.095
C5	i-Pentane	0.137	0.513
C5	n-Pentane	0.407	1.522
C6	Hexanes	0.412	1.795
C7	Heptanes	0.180	0.852
C8	Octanes	0.265	1.307
C9	Nonanes	0.009	0.056
C10	Decanes	0.001	0.008
C11+	Undecanes Plus	0.000	0.001
	Total	100.000	100.000
Calculated Gas Properties			
Gas Density (kg m ⁻³ @ 15°C)		0.818	
Gas Mole Weight (g mol ⁻¹)		19.279	
Real Relative (to air) Density of Gas		0.667	
Mole weight of Heptanes Plus (g mol ⁻¹)		94.041	
Density of Heptanes plus (g cm ⁻³ at 60°F)		0.797	
Mole Weight of Undecanes plus (g mol ⁻¹)		147.000	
Density of Undecanes plus (g cm ⁻³ at 60°F)		0.789	
Calorific Value (MJ m ⁻³)		38.049	

Flash Gas Water Ratio: 0.701 Nm³/m³

Table 6-Gas Composition Sample Plastic Balloon

	Component	Mole%	Weight%
H ₂	Hydrogen	0.000	0.000
H ₂ S	Hydrogen Sulphide	0.000	0.000
CO ₂	Carbon Dioxide	0.038	0.099
N ₂	Nitrogen	1.653	2.760
C1	Methane	95.455	91.250
C2	Ethane	2.183	3.912
C3	Propane	0.497	1.307
C4	i-Butane	0.051	0.176
C4	n-Butane	0.061	0.210
C5	i-Pentane	0.011	0.046
C5	n-Pentane	0.021	0.089
C6	Hexanes	0.028	0.138
C7	Heptanes	0.002	0.010
C8	Octanes	0.001	0.003
C9	Nonanes	0.000	0.000
C10	Decanes	0.000	0.000
C11+	Undecanes Plus	0.000	0.000
	Total	100.000	100.000
Calculated Gas Properties			
Gas Density (kg m ⁻³ @ 15°C)		0.711	
Gas Mole Weight (g mol ⁻¹)		16.782	
Real Relative (to air) Density of Gas		0.580	
Mole weight of Heptanes Plus (g mol ⁻¹)		88.446	
Density of Heptanes plus (g cm ⁻³ at 60°F)		0.783	
Mole Weight of Undecanes plus (g mol ⁻¹)		147.000	
Density of Undecanes plus (g cm ⁻³ at 60°F)		0.789	
Calorific Value (MJ m ⁻³)		38.219	

3.3. Graphs

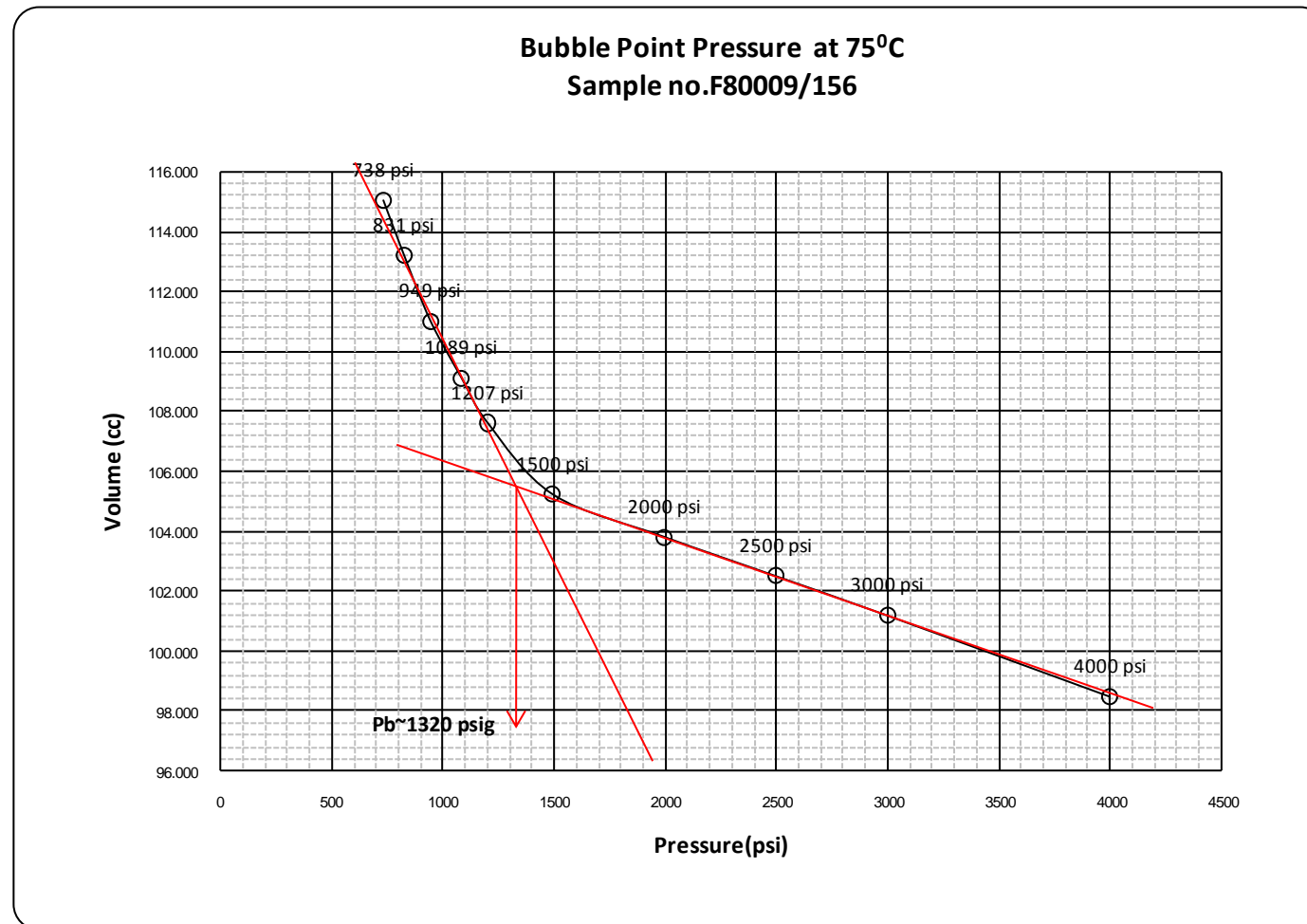


Figure 6-Bubble Point Measurement – Sample no. F8009/156

Bubble Point Pressure at 75°C
Sample no.32138

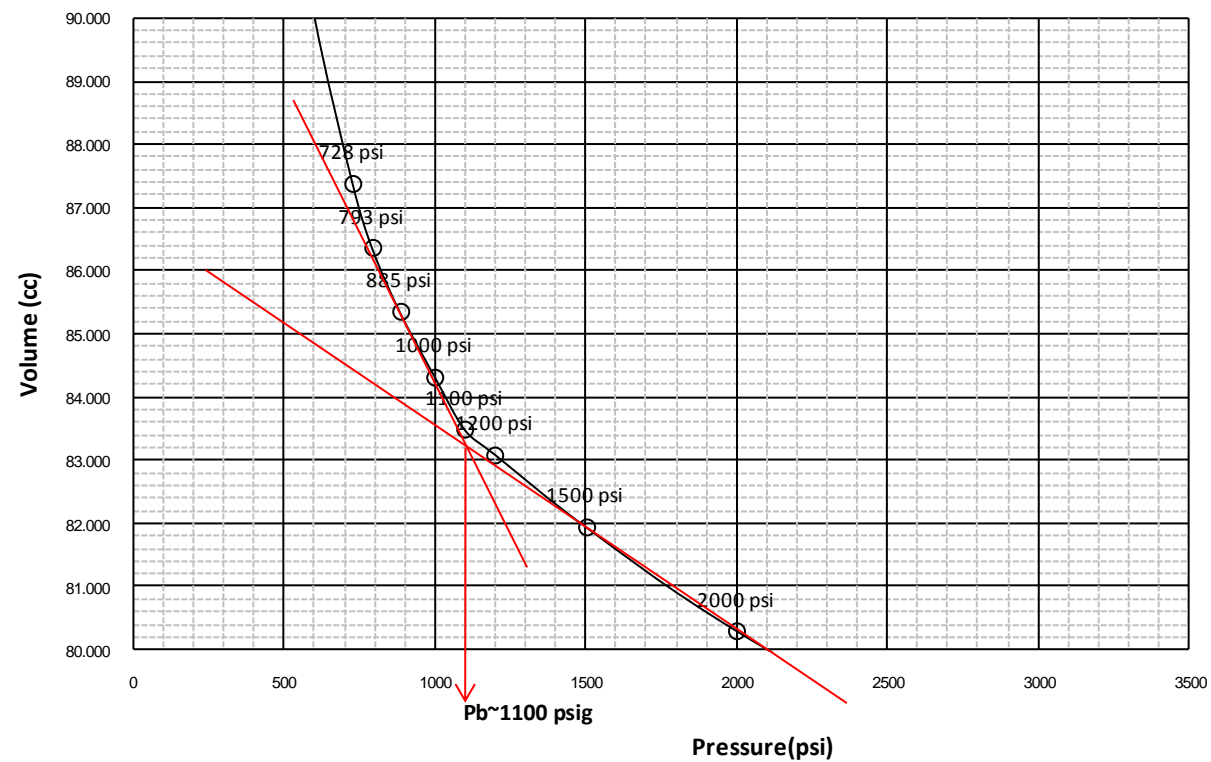


Figure 7-Bubble Point Measurement – Sample no. 32138

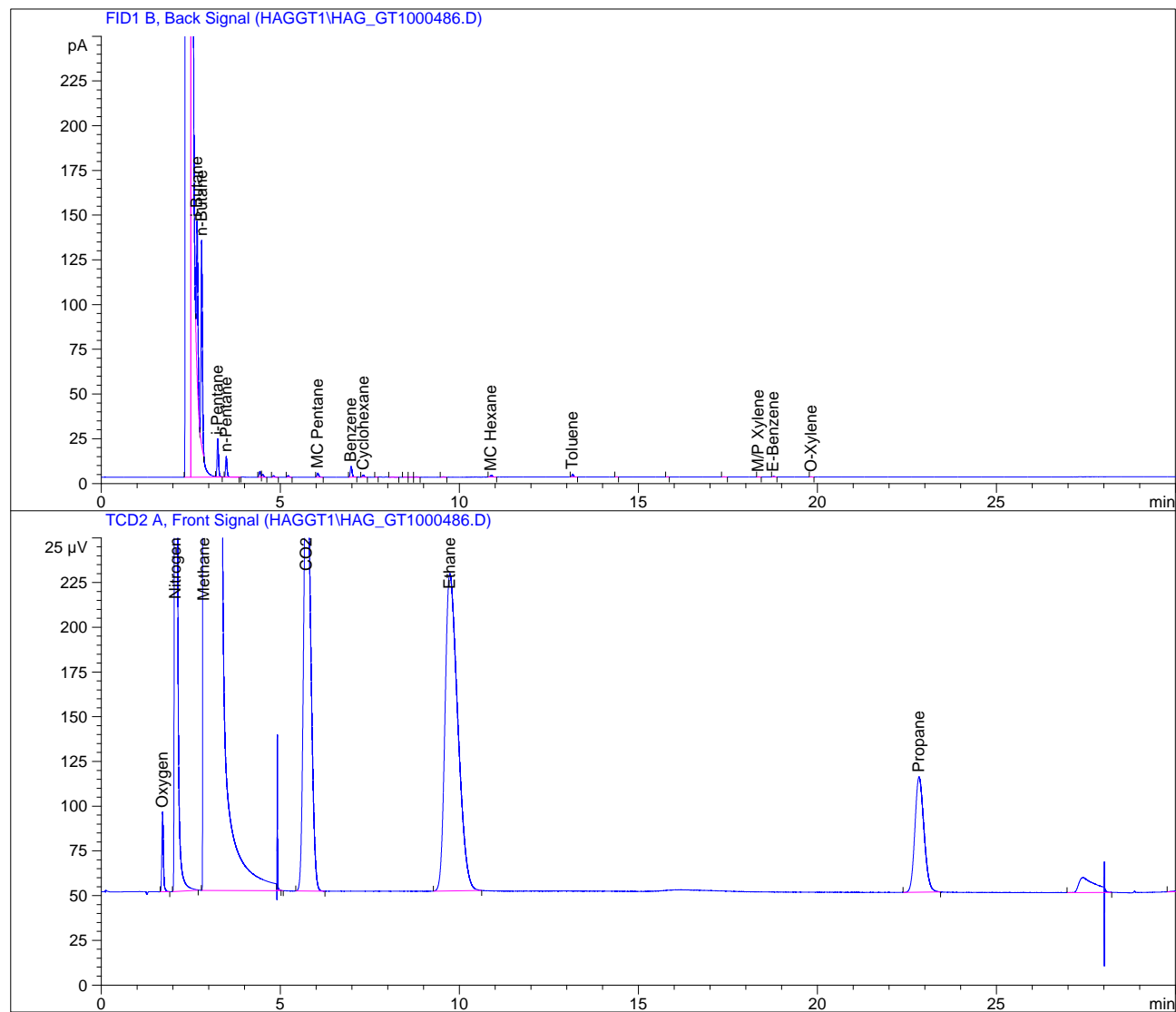


Figure 8-Gas Chromatogram Sample no. DW-7214

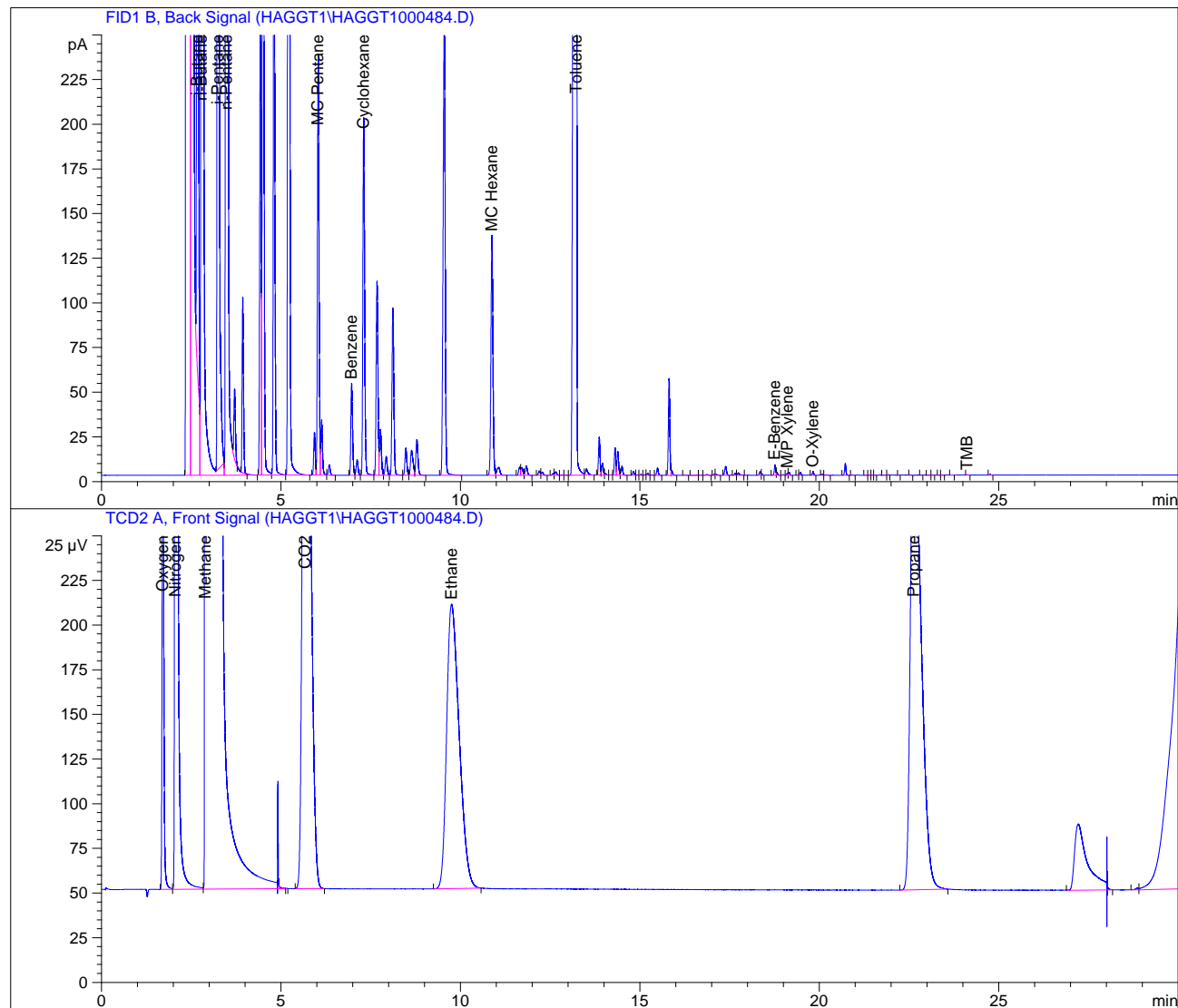


Figure 9-Flashed Gas Chromatogram Sample no. F8009/156

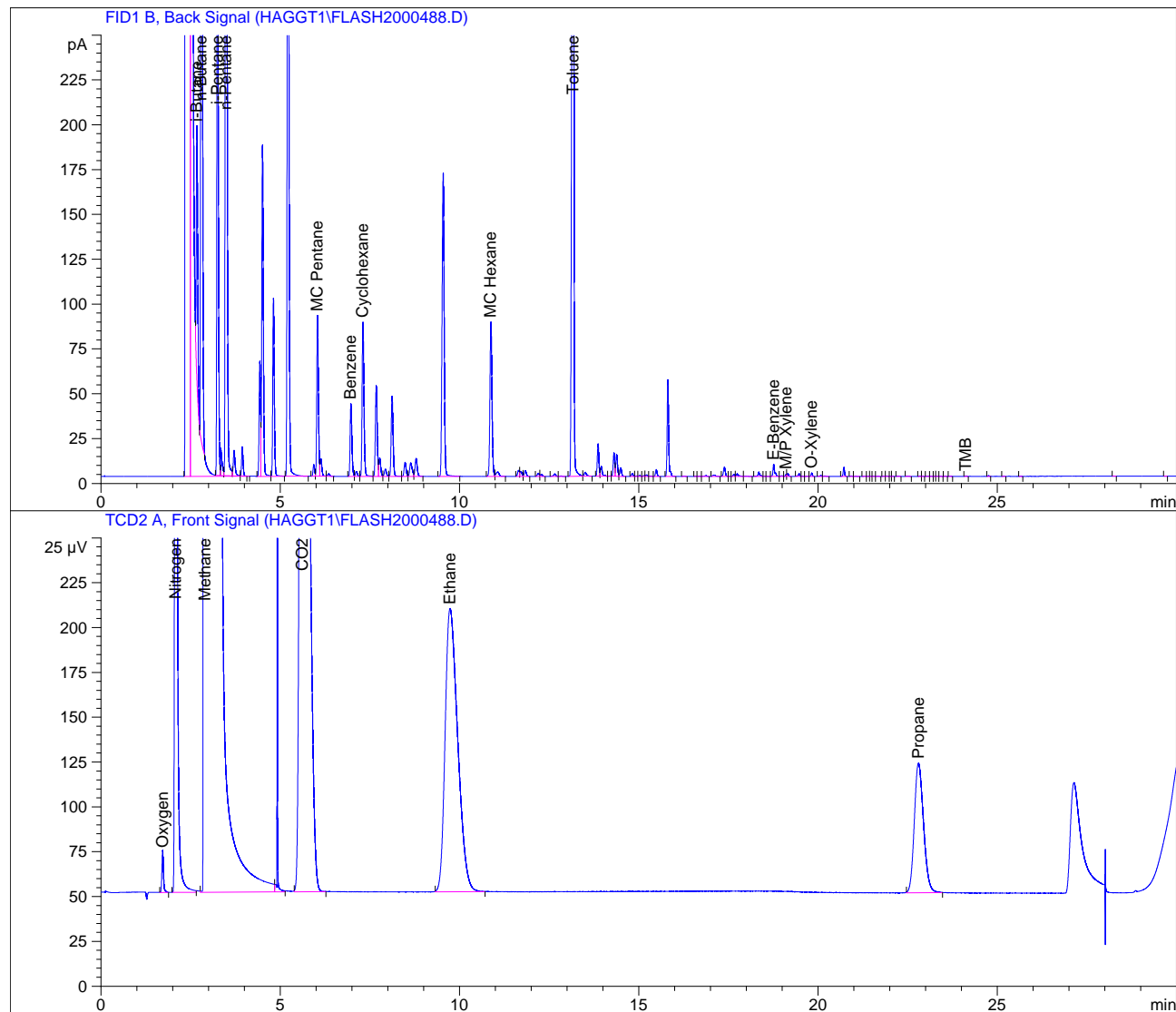


Figure 10-Flashed Gas Chromatogram Sample no. 32138

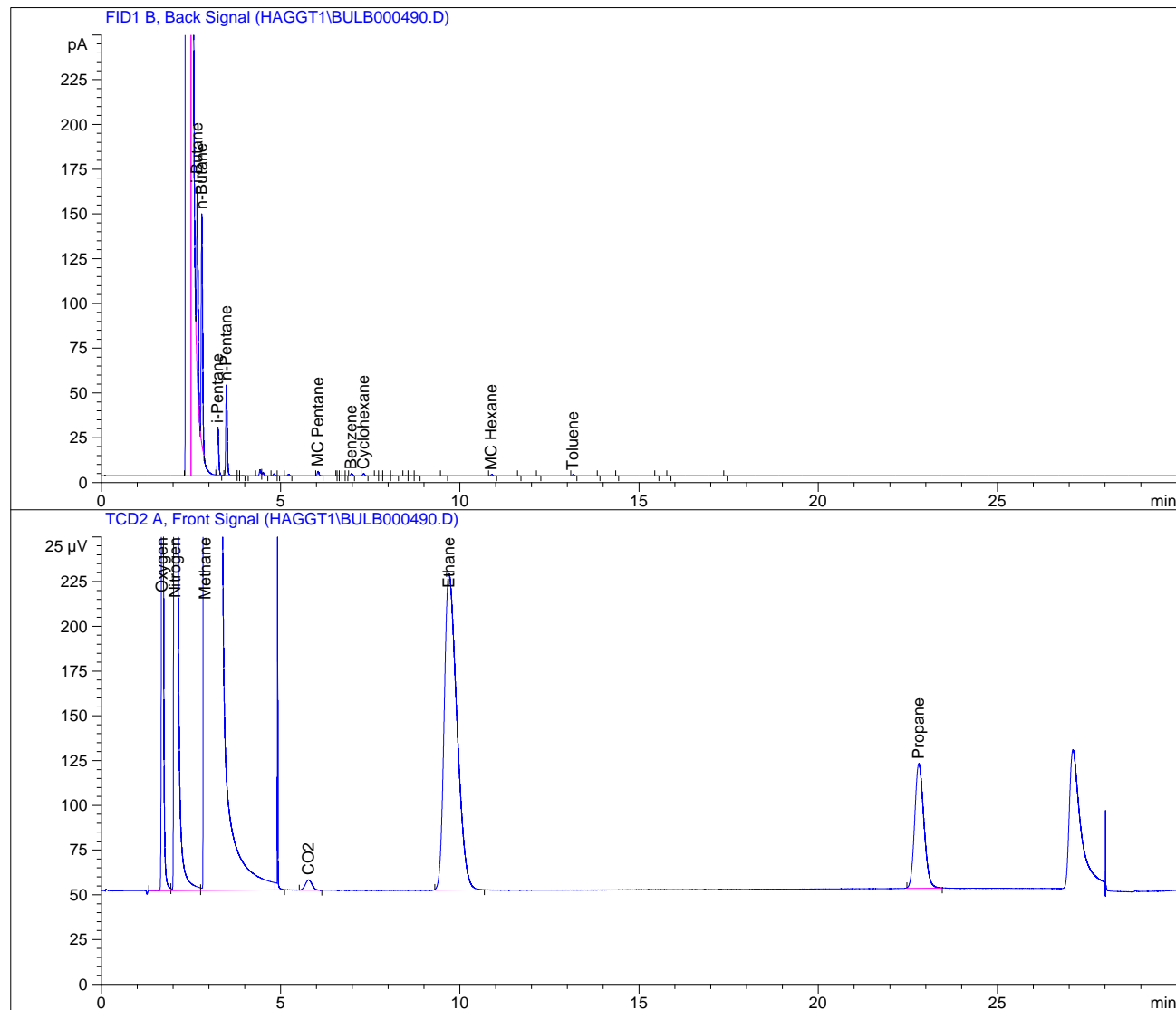


Figure 11-Gas Chromatogram, Plastic Balloon sample

4. Conclusions

In order to obtain a representative sample, the recommended method of sampling is bottomhole sampling, which gives the possibility of collecting a single phase sample from the formation level thus preventing the subsequent change in composition (flash). Surface sampling is recommended where there is a separator at surface and the flow rates of both separated fluids (liquid and gas) can be accurately measured.

In the case of the well Hag-GT1 neither of the two scenarios above were possible, therefore the samples were collected without the certainty that the fluid was flowing in single phase. Depending on the degree of choking, various types of fluids (gas, wet gas, water with bursts of gas etc) were encountered during purging process.

Bubble points were lower than the reservoir pressure at reservoir temperature, but different from each other. The gas water ratios were different from each other, i.e. different fluids were flowing through the manifold at the sampling times. Moreover, the gases flashed from the two pressurized samples, the 20l gas sample and the gas sample collected in a plastic balloon were all compositionally different (the 20 l gas sample and the gas balloon appear closer to each other and probably to the real gas composition).

Consequently, there is no way of guaranteeing the representativity of the samples. If the well was flowing with more gas than it actually contains dissolved in the water in the reservoir, then the sample bubble point would be artificially high and the opposite is true for a flow of degassed water.

Although the H₂S presence was detected by Lead Acetate Strip Paper and by smell, there was no H₂S peak during the compositional analysis due to the following:

- extremely low concentration, close to the lower limit of the GC equipment (5 ppm)
- possible absorption of part of the already infinitesimal amount into the metal parts of the sampling equipment (sampling hose, lines, cylinder).
- the sampling flowing in two phases and thus releasing the gas fraction leading to the above absorption in all metal parts.

Sampling during unstable (two phase) flow is not recommended for very accurate H₂S determination. A wellsite portable measurement equipment could provide much more accurate results (i.e. Draeger tubes with Accuro Pumps) with an accuracy of 0.2-5 ppm H₂S.

Appendix 4

Report Alcontrol: Analyses of formation water



Analyserapport

IF Technology
Dhr. U. Sobering
Postbus 605
6800 AP ARNHEM

Blad 1 van 4

Uw projectnaam : Aardwarmte Den Haag
Uw projectnummer : 56193/BP
ALcontrol rapportnummer : 11599619, versie nummer: 1

Rotterdam, 27-09-2010

Geachte heer/mevrouw,

Hierbij ontvangt u de analyse resultaten van het laboratoriumonderzoek ten behoeve van uw project 56193/BP. Het onderzoek werd uitgevoerd conform uw opdracht. De gerapporteerde resultaten hebben uitsluitend betrekking op de geteste monsters. De door u aangegeven omschrijvingen voor de monsters en het project zijn overgenomen in dit analyserapport.

Het onderzoek is, met uitzondering van eventueel door derden uitgevoerd onderzoek, uitgevoerd door ALcontrol Laboratories, gevestigd aan de Steenhouwerstraat 15 in Rotterdam (NL).

Dit analyserapport bestaat inclusief bijlagen uit 4 pagina's. In geval van een versienummer van '2' of hoger vervallen de voorgaande versies. Alle bijlagen maken onlosmakelijk onderdeel uit van het rapport. Alleen vermenigvuldiging van het hele rapport is toegestaan.

Uitgebreide informatie over de door ons gehanteerde analysemethoden kunt u terugvinden in onze informatiegids.

Mocht u vragen en/of opmerkingen hebben naar aanleiding van dit rapport, bijvoorbeeld als u nadere informatie nodig heeft over de meetonzekerheid van de analyseresultaten in dit rapport, dan verzoeken wij u vriendelijk contact op te nemen met de afdeling Customer Support.

Wij vertrouwen er op u met deze informatie van dienst te zijn.

Hoogachtend,



R. van Duin
Laboratory Manager



IF Technology
Dhr. U. Sobering

Analyserapport

Blad 2 van 4

Projectnaam Aardwarmte Den Haag
Projectnummer 56193/BP
Rapportnummer 11599619 - 1

Orderdatum 21-09-2010
Startdatum 21-09-2010
Rapportagedatum 27-09-2010

Analyse	Eenheid	Q	001
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DOC	mg/l		74
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pH		Q	6.3
geleidingsvermogen (EC)	µS/cm	Q	14000
temperatuur t.b.v. pH	°C		19.7

METALEN

aluminium	µg/l		<1300 ¹⁾
barium	µg/l	Q	7200
cadmium	µg/l	Q	<10 ¹⁾
calcium	µg/l	Q	3900000
kalium	µg/l	Q	970000
koper	µg/l	Q	<130 ¹⁾
lood	µg/l	Q	<250 ¹⁾
magnesium	µg/l	Q	1000000
mangaan	µg/l	Q	2000
natrium	µg/l	Q	34000000
nikkel	µg/l	Q	<250 ¹⁾
silicium	µg/l		8300
strontium	µg/l	Q	250000
ijzer	µg/l	Q	33000
zink	µg/l	Q	<500 ¹⁾

ANORGANISCHE VERBINDINGEN

ammonium	mgN/l	Q	55
sulfide (vrij)	mg/l	Q	<0.1
fosfaat (tot.)	mgP/l	Q	0.1
bicarbonaat	mg/l	Q	170 ²⁾
silicaat	mg/l	Q	23

DIVERSE NATCHEMISCHE BEPALINGEN

chloride	mg/l	Q	81000
nitriet	mg/l	Q	<0.3
nitraat	mg/l	Q	<2.0 ¹⁾
zwavel (totaal)	µg/l	Q	62000 ³⁾
sulfaat	mg/l	Q	95

De met S gemerkte analyses zijn geaccrediteerd en vallen onder de AS3000 erkenning door de ministeries VROM en V&W. Overige accreditaties zijn gemerkt met een Q.

Nummer	Monstersoort	Monsterspecificatie
001	Grondwater	Onttrekkingswater 20-9-2010



IF Technology
Dhr. U. Sobering

Analysrapport

Blad 3 van 4

Projectnaam Aardwarmte Den Haag
Projectnummer 56193/BP
Rapportnummer 11599619 - 1

Orderdatum 21-09-2010
Startdatum 21-09-2010
Rapportagedatum 27-09-2010

Voetnoten

- 1 Verhoogde rapportagegrens i.v.m. noodzakelijke verdunning.
- 2 Het monster is aangeleverd met een luchtlaag.
- 3 Het monster is niet of verkeerd geconserveerd aangeleverd, derhalve zijn de resultaten indicatief.



Projectnaam Aardwarmte Den Haag
 Projectnummer 56193/BP
 Rapportnummer 11599619 - 1

Orderdatum 21-09-2010
 Startdatum 21-09-2010
 Rapportagedatum 27-09-2010

Analyse	Monstersoort	Relatie tot norm
DOC	Grondwater	Conform NEN-EN 1484
pH	Grondwater	Conform NEN 6411 (1981)
geleidingsvermogen (EC)	Grondwater	Conform NEN-ISO 7888 en CMA/2//A.2
aluminium	Grondwater	Conform NEN 6966 en conform NEN-EN-ISO 11885
barium	Grondwater	Idem
cadmium	Grondwater	Idem
calcium	Grondwater	Idem
kalium	Grondwater	Idem
koper	Grondwater	Idem
lood	Grondwater	Idem
magnesium	Grondwater	Idem
mangaan	Grondwater	Idem
natrium	Grondwater	Idem
nikkel	Grondwater	Idem
silicium	Grondwater	Eigen methode
strontium	Grondwater	Conform NEN 6966 en conform NEN-EN-ISO 11885
ijzer	Grondwater	Idem
zink	Grondwater	Idem
ammonium	Grondwater	Conform NEN 6604
sulfide (vrij)	Grondwater	Conform NEN 6608
fosfaat (tot.)	Grondwater	Ontsluiting volgens eigen methode, meting met CFA, conform NEN-EN-ISO 15681-2
bicarbonaat	Grondwater	eigen methode, titrimetrische methode
silicaat	Grondwater	Conform NEN 6471
chloride	Grondwater	Conform NEN 6604
nitriet	Grondwater	Idem
nitraat	Grondwater	Conform NEN-EN-ISO 10304-1
zwavel (totaal)	Grondwater	Conform NEN 6966 en conform NEN-EN-ISO 11885
sulfaat	Grondwater	Conform NEN 6604

Monster	Barcode	Aanlevering	Monstername	Verpakking
001	B0963787	22-09-2010	22-09-2010	ALC204 Theoretische monsternamedatum
001	B0963791	22-09-2010	22-09-2010	ALC204 Theoretische monsternamedatum
001	B5358547	22-09-2010	22-09-2010	ALC207 Theoretische monsternamedatum
001	B5358548	22-09-2010	22-09-2010	ALC207 Theoretische monsternamedatum
001	B5358554	22-09-2010	22-09-2010	ALC207 Theoretische monsternamedatum
001	B5358579	22-09-2010	22-09-2010	ALC207 Theoretische monsternamedatum
001	B5358585	22-09-2010	22-09-2010	ALC207 Theoretische monsternamedatum
001	D3026990	22-09-2010	22-09-2010	ALC284 Theoretische monsternamedatum
001	D3026993	22-09-2010	22-09-2010	ALC284 Theoretische monsternamedatum
001	F5539372	21-09-2010	21-09-2010	ALC227 Theoretische monsternamedatum
001	H7262249	21-09-2010	21-09-2010	ALC281 Theoretische monsternamedatum
001	Q0086770	22-09-2010	22-09-2010	ALC230 Theoretische monsternamedatum
001	T0098614	22-09-2010	22-09-2010	ALC244 Theoretische monsternamedatum

Paraaf :

Appendix 5

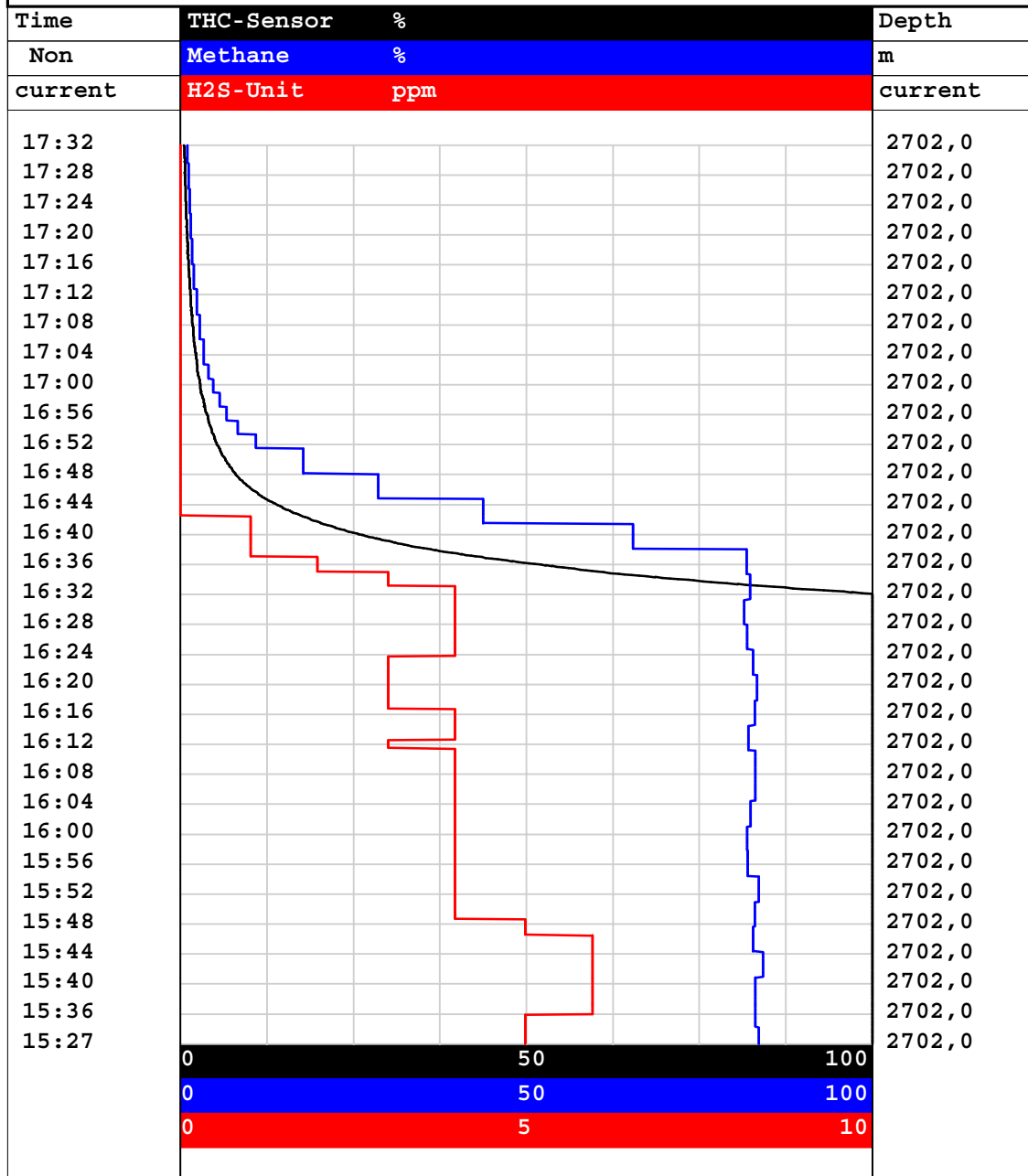
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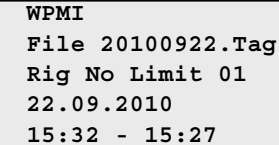


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Page 1/ 4 Time 17:34:52 Date 22.09.2010



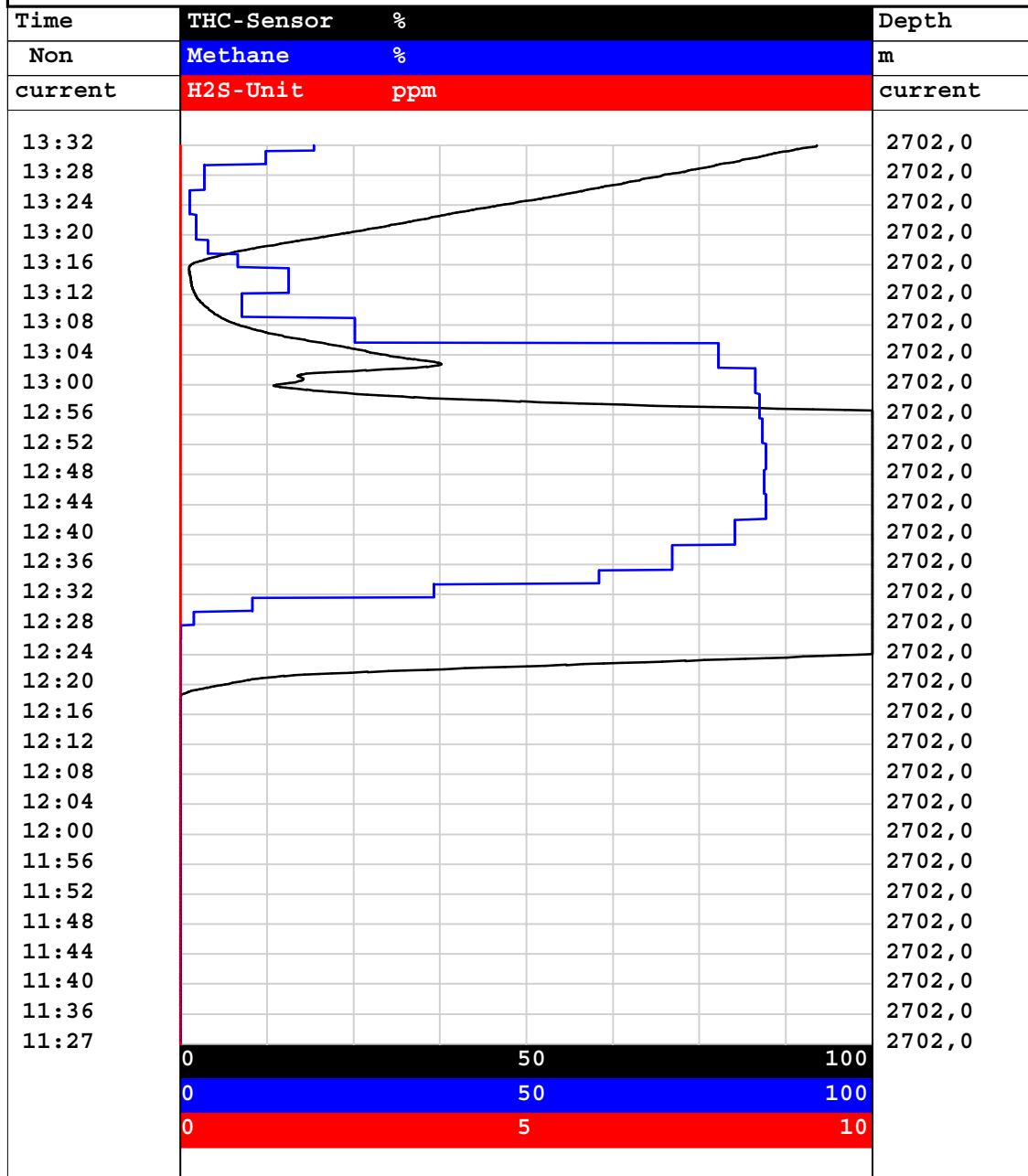




HAG GT-01

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Page 3/ 4 Time 17:34:57 Date 22.09.2010





HAG GT-01

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Rig No Limit 01
22.09.2010
11:32 - 11:27

Page 4/ 4 Time 17:35:00 Date 22.09.2010

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Non	Methane %							m
current	H2S-Unit ppm							current
11:32								2702,0
11:28								2702,0
11:24								2702,0
11:20								2702,0
11:16								2702,0
11:12								2702,0
11:08								2702,0
11:04								2702,0
11:00								2702,0
10:56								2702,0
10:52								2702,0
10:48								2702,0
10:44								2702,0
10:40								2702,0
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	0			50				100
	0			5				10

Appendix 6

Photos

