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Pulsed Water Injection during Waterflooding

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Abstract

During a half-year field test a novel method was applied for water injection during waterflooding in a weakly consolidated, heavy oil reservoir (90-120 cP). The injection has been combined with a hydraulic pulsing tool downhole in the injection well to provide additional dynamic pressure pulses on the order of 4-17 bar, with 5-6 pulses per minute. The technology, developed in Canada and applied successfully, especially as a well stimulation technique in order to initiate or stimulate oil production with sand co-production. The first objective was to see whether pulsing would be beneficial for the efficiency of the injection process. Furthermore, laboratory experiments and theoretical developments suggest that pulsing might improve the sweep efficiency of the flooding pattern. Hence, the promise of this technique would be potentially faster and higher oil recovery during waterflooding. In the design of the field test it was chosen to keep the total water injection rate on the same level as before pulsing was applied, on the order of 110 m^3/d. The rationale behind this decision was that previous experience in the field has shown that higher injection rates resulted in pressurization of the reservoir and increased fingering. In addition, the fixed injection rate allowed us to focus on improvements in sweep efficiency, without correcting production figures for the higher injection rate.

Pressure Pulse Technology (PPT) was applied without any significant operational problems for half a year although severe corrosion problems unrelated to the PPT project were uncovered after the trial. Injection and production performance has been monitored before, during and after the test. When pulsing started, injection pressure dropped, and even after the pulsing stopped a lower wellhead pressure has been measured. With constant injection rate this shows an improvement in injectivity. It also indicates a significant reduction in near wellbore skin factor or possible improved injection conformance. The injection water used is considered dirty and potentially deteriorates injectivity over the life of the well. Indications are that injection pressure is now slowly building up again following the trial.

Improvements in production have not been confirmed by this field trial. The accuracy and repeatability of the production measurements have not assisted in identifying the potential effect. However, the field trial results have enabled us to recognize the potential use of the technology for an efficient high-rate injection strategy, which would avoid injection under fracturing conditions. We outline situations where such applications would be desirable. Moreover, we believe the pulsing technique can be applied for efficient waste disposal. Higher injection rate and more efficient pulsed injection potentially lead to improved recovery, although actual improvements need to be assessed with further tests.

Introduction

During waterflooding, water is injected in order to sweep the remaining oil towards the producers. The volumetric sweep efficiency is influenced by factors such as the mobility ratio, gravitational and capillary forces, injection rate, and reservoir heterogeneity[1]. Higher injection rate promotes faster recovery and supress gravity dominated water underruns. High pressure resulting from high injection rates can induce fractures, which can cause early water breakthrough by creating a preferential flow path to the producing wells. Higher pressures can also lead to accelerated viscous instabilities leading to poor sweep efficiency. Slower injection promotes capillary crossflow beneficial for increasing sweep in lower permeability layers. Summarizing, the optimum injection/production strategy will depend on the particular reservoir.

Many technologies aim at improving the recovery of a flooding pattern, either by changing the physical properties of the injected fluid or by changing the injection and production strategy.

A relatively inexpensive technology that has been reported[2] to lead to improved recovery is the use of non-steady state waterflooding, or cyclic waterflooding based on using changes in injection rates over periods of days to months.

Laboratory research in Canada investigated the use of rapid pressure pulses on the flooding of core samples. In this case the water injection is combined with short period (order 1-5 seconds) pressure pulses, pulsing several times each minute. The results of these laboratory experiments have been published[3,4] and the related claims can be summarized as:

- Liquid pressure pulsing can enhance liquid injection and production, even in the absence of a change in the external head.
- Pulsing improves areal and vertical sweep efficiency.

For a detailed analysis of the claims the reader is referred to the original papers where the experimental observations have been linked to theoretical developments in poro-mechanics. The so called de la Cruz-Spanos model constitutes an adaption of Biot-Gassman theory, which is extended with porosity as a dynamic variable, i.e. it is a function of time and changes because of the fluid-solid coupling media model.

The laboratory experiments and the theoretical developments have resulted in the development of several applications in the oil industry. PPT has been applied for production well stimulation in a CHOPS (Cold Heavy Oil Production with Sand) strategy, where sand is intentionally co-produced together with the heavy oil. Without sand influx, production rates of vertical wells for 1000-10,000 cP oil are on the order of 1-20 bbl/day. If sand influx is initiated and maintained in vertical wells production rates potentially increase to 50-300 bbl/day[3]. Generally the CHOPS well design are standard cemented casing combined with big hole perforations (12shots/ft). The oil and sand is lifted using PC (Progresive Cavity) pumps. Application of PPT has shown that sand/fines can be mobilized from the near wellbore area. The process can be improved by combining the pulsing with chemical placement, with the intention to remove/dissolve asphaltenes and waxes. Succesful production improvements have been made using this treatment with good payback times despite the generally low rates of the CHOPS producers[4,5,6].

Pulsing has been applied in injector wells for improving the efficiency of waterflood patterns[7] and has shown indications of increased oil production and decreased water cut[7].

Another area where pressure pulsing has been applied is in the recovery of LNAPL (Light Non-aqueous Phase Liquids) for shallow soil cleaning. In this case PPT is applied using compressed air devices at a few meters depth and LNAPL is recovered at shallow extraction wells.

The tools

PPT uses a piston and cylinder tool in order to force fluid under high pressure into the formation. The pressure excerted by the piston on a downstroke originates from simply dropping the piston on its own weight. The tools are constructed in such a way that on an upstroke movement fluid is able to flow around the cylinder avoiding a negative pressure or surging effect.

Two separate tools have been developed; a workover tool for single well, one-day well stimulations and a EOR or semi-permanent tool integrated in the completion of an injection well for longer duration (several months) pulsing during waterflooding.

In case of the workover tool the piston is attached to the lower part of a string of production tubing providing substantial weight on the tool to create high-pressure pulses on the downstroke movement. The piston tool moves within the production casing. Lifting the tool and tubing string with a workover hoist achieve the upstroke movement. Figure 1 and 2 show an example of a recording of downhole pressure using a pressure gauge inside the tool during a workover simulation. These figures show that pressure pulses can have an amplitude of 40 bar peak-to-peak, and approximately three pulses per minute are achieved by lifting the tool and tubing with the service hoist. In Figure 1 the hydrostatic pressure has been estimated based on the fluid level, which was measured with an acoustic Echometer. The dropping fluid level during pumping indicates that fluid is injected into the formation. The second line drawn in Figure 1 indicates the pressure that would be excerted by the total weight of the tool and fluid above the perforations. This line shows that the maximum pressure during pressure pulsing is roughly determined by the weight of the tool. Almost 20 m^3 of fluid was injected over the whole pulsing interval. At the end of the treatment the fluid level is stabilising, indicating that less fluid is being injected into the formation. This is thought to be the result of having increased the reservoir pressure locally around the wellbore. The experience with workover pulsing in producer wells at Rühlermoor has showed that pulsing can mobilize fines and sand around the wellbore. Used in the right context, this shows the potential of the technology to improve the flow potential of the formation.

For the semi-permanent tool in the injection well, the piston is attached to the lower part of a string of lifting rods normally used for beam-pumps. The piston moves inside a special cylinder that makes it possible to inject water at the same time under static conditions alongside the pulsing tool. The upward stroke is achieved by using an automated hydraulically actuated lifting device for pulsing with the semi-permanent tool in an injector well. The duration of the downstroke movement ranges from 3-5 seconds and 5-6 pulses are applied each minute. Because of the lower weight of the lifting rods compared to the production tubing the amplitude of the pressure pulses are lower for the semi-permanent tool compared to the workover tool. The surface equipment for the semi-permanent tool can be seen in Figure 3.

The field test

The field test was performed in an oilfield in Germany. A number of the fields in this region contain relatively heavy oil, with a viscosity ranging from 100 to 1,000,000 cp. Numerous thermal projects have been implemented in this area, ranging from steam-soak treatments to hot-water and finally steam-drive projects[8].

The section of the oilfield where the PPT field trail was implemented has not been under steam-drive. This part of the reservoir experiences edge water drive and in addition waterflooding is implemented. The viscosity is lower, ranging from 90-120 cp at initial reservoir conditions with a stock tank API gravity of 24.5 (0.907 g/ml). The oil has a bubble point pressure of 55 bar and initial GOR of 20 sm^3/sm^3.

The reservoir is a weakly consolidated sandstone reservoir, faulted and slightly dipping towards the southeast with a top depth ranging between 560-885 meters. The thickness of the productive Bentheimer sandstone layers ranges between 20-35 meters, consisting of two layers, 10-20 meter gross each, separated by a shale layer. The sandstone has a porosity of 20-30% and permeability from 100-5000 mD. Initial reservoir pressure at 750 m was 80 bar, corresponding to a pressure gradient of 0.11 bar/m. Currently about 25% of the STOIIP of 104 million ton has been recovered, reducing the actual pressure gradient to 0.06-0.07 with 0.11 bar/m close to the aquifer.

The wells in this area produce between 5-20 m3/d. For many wells in this area production is reduced because of fines migration. In addition, the oil viscosifies due to degassing of the oil, especially around the wellbore. Most of the wells are completed with wire-wrapped sandscreens, reducing the sand/fines production to less than 0.5 g/l. The standard stimulation treatment that is being applied for these wells is to inject hot water with a small concentration of surfactants and demulsifiers.

PATTERN SUMMARY AND ANALYSIS

The pattern chosen for the injection pilot project is centred on the injector well 678. The six offset producers are well 86, 311, 677, 679, 688 and 689. The pattern configuration is shown below in Figure 4. Using a field map of the field, the pattern area was calculated to be around 95,900 m^2. Table 1 shows the reservoir parameters for the pattern wells.

The thickness of the different layers was obtained for the pattern in order to estimate a representative average value, to conduct volumetric calculations, and to enable creation of simple geological cross sections to visualize potential water flow paths from the injector to the producers. This data is shown in Table 2.

With an average injection rate of 108 m^3/d in well 678, and fluid off-take of roughly 173 m^3/d in the producers, the pattern voidage replacement is approximately 62%. Offtake data for the pattern is shown in Table 3. Pattern production has been allocated 100% to the well 678 pattern due to the fact that other injectors are a minimum distance of 500 m away and has at least one row of producers between the well 678 pattern production wells and the next injector. The areal pattern production conformance is presented in Figure 5.

Using an average aggregate reservoir thickness of 32.1 metres (upper and lower oil sand) for the pattern area, a connate water saturation of 20%, an irreducible oil saturation of 25% and 100% areal and vertical sweep efficiency, the flooding rate for the pattern can be calculated. Using these parameters a flooding rate of 4.3% TPV/year (TPV – Total Pore Volume) or 5.3% HCPV/year (HCPV – Hydro Carbon Pore Volume) was calculated. Another way of looking at the data is to see how long it takes to inject one pore volume into the pattern, which comes out as 23.4 years for one TPV and 18.7 years for one HCPV.

Figure 6 shows the front velocity and time for injected water to reach a given distance from the injector assuming 100% areal and vertical sweep efficiency.

PULSE STIMULATION

This section has been divided into three parts in order to discuss performance against each of the three elements of the original scope of the project.

Increasing Injectivity

To simplify analysis of pre and post PPT stimulation results, it was decided to keep the water injection into well 678 constant, limited to a maximum of 108 m^3/d during the pilot. The effect of constraining the water supply is discussed in more detail in the section below on production.

Water injection pressure was stable just under 30 barg prior to the PPT pilot project. Three weeks after the continuous pulse stimulation had started, the wellhead injection pressures had dropped to 11 barg. Over time, the injection pressure increased somewhat, but stayed well below the pre-stimulation injection pressure. The injection pressure following the trial stayed at around 20 barg or around 28% lower than the steady state injection pressure for around a month before slowly starting to rise again. As the injection rate was held constant, the injectivity index was calculated in order to evaluate the injectivity enhancement during the pulse stimulation. Figure 7 shows the water injection data.

Initially injectivity increased by 40%. This is a significant increase and corresponds to the lower injection pressures observed. The injectivity index then declined, possibly associated with a pressurization of the near wellbore region. The decline in injectivity also corresponds to an observed increase in annulus pressure, indicating the beginning of a tubing leak. The corrosive nature of the injected fluid and its effect on the tubing and PPT equipment were more severe than anticipated which caused the equipment to be heavily corroded at the end of the trial. The average injectivity enhancement for the trial was around 30% with maximum and minimum observed values of 40% and 15%, respectively.

Demonstrating this injectivity enhancement is seen as a very important indicator for pressure pulse stimulation, in that for a liquid filled system, oil production is directly proportional to water injection rates.

Effect on Production

The improvement in injectivity could be related to an improvement in injection conformance and hence could translate into increased production and ultimate oil recovery for a continuous PPT installation.

The production data from each of the wells in the pattern is detailed below. When analyzing the production test data for these six producers, it must be noted that there is significant measurement uncertainty in some of the measurements and there are often few data points with significant scatter, so interpretation could become subjective. Based on the data analyzed all of the wells with the exception of one, well 677, appear to have changed in fluid production trend (well 311 and 679), oil production trend (well 688) or both oil and fluid production trend (well 86 and 689).

Figure 8 and Figure 9 shows section A-A' in map view and cross section view, respectively.

Cross section A-A' shows production wells 677 and 679 in relation to the injector well 678. A partially offsetting fault can be seen between the injector and well 679. It is believed that this fault will at least act as a baffle to flow from the injector, but should not act to seal the connection between injector and producer due to sand on sand contact between each layer on both sides of the fault. Production data for well 677 can be seen in Figure 10 and in Figure 11 for well 679.

Well 677 is located up dip from the injector without any mapped faults between it and the injector, but does not seem to have experienced any enhancement to either the fluid or oil production.

Well 679 was experiencing a decreasing fluid production prior to the PPT pilot starting in July 2002 as can be seen on Figure 11. On the data from September onwards it can be seen that the fluid rate flattens out. The watercut measurements fluctuate between 50 and 80%. Oil production seems to remain stable before and during PPT stimulation.

Figure 12 show cross section B-B' in map view and Figure 13 shows it in cross section view.

Cross section B-B' shows production wells 688 and 86 in relation to the injection well. Two partially offsetting faults can be seen between the injector and 688. It can be seen from the cross section in Figure 13 that there is virtually no communication from the injector to the lower sand in well 688. Production data for well 688 can be seen in Figure 14 and in Figure 15 for well 86. The gross fluid production for well 688 exhibits a gently falling trend throughout the measurement period. The oil production on the other hand, seems to show a positive trend. A steep decline is seen prior to the start of PPT stimulation. After the start of PPT stimulation, the oil rate decline is reduced and an increase in production is observed towards the end of the trial. The water cut data varies quite a lot, with data from 30% to just over 80%. Discounting the point at 30% changes the initial oil decline, but a reduction in decline is still seen.

Well 86 is located down dip from the injector without any mapped faults between the two. This well was also experiencing a decline in fluid rate prior to PPT stimulation. Following the trial it could look like there was the start of an increase in fluid production, but no data is available to confirm this for December. The last oil production test seem to break trend and show an increase in rate, but the water cut for this point was also lower than the other values, so this could be a spurious data point as two later water cut samples gave higher values.

Figures 16 and 17 show cross section C-C' in map view and cross section view, respectively.

Cross section C-C' shows production wells 689 and 311 in relation to the injection well. Two partially offsetting faults can be seen between the injector and well 689 and it can be seen from the cross section in Figure 17 that there is little communication from the injector to the lower sand in well 689.

Production data for well 689 can be seen in Figure 18 and in Figure 19 for well 311. The most stable data for well 689 is the water cut measurements with one outlying point. The fluid rate seems to decline and recover during the trial, but there are few data points with significant scatter, so interpretation can become subjective. Oil production seems to reverse trend between September and November, but again one cannot rely on a statistically valid data sample.

Well 311 is located slightly up dip from the injector without any mapped faults between the two. The well experienced an early water breakthrough after drilling. It is believed to be communicating with an injector further to the North East through a fault running close to well 311 and the injector. well 311 was seeing an increasing fluid rate trend prior to PPT stimulation, which seems to drop somewhat and stabilize during the PPT pilot. No significant movement could be seen in the oil production data.

Three factors play a part in making the effect on production difficult to determine. These are:

1. Impact of limited water supply.

Pressure Pulse Technology is an injection process. To achieve optimum economic results it is important that fluid injection is maximized at all times. To explain this, it is important to explain the factors impacting the propagation of the porosity dilation wave during pressure pulsing and a little on the process that takes place.

A porosity dilation wave has much higher attenuation than a normal first arrival P-wave and travel at a fraction of the velocity, typically 100 m/s vs. 3500 m/s. As it dissipates, the local reservoir pressure increases. This pressure increase allows subsequent dilation waves to travel further and ultimately cause production enhancement in a reasonable timeframe.

The reservoir quality in the two sands is such that the upper sand permeability is approximately twice that of the lower sand.

Assuming permeability values at the mid-point for the stated ranges i.e. 1.5D for the upper layer (1 – 2 range) and 0.75D for the lower layer (0.5 – 1 range), the average permeability for the layers was calculated to be 1.33D for the upper oil sand and 0.67D for the lower oil sand. This corresponds to a permeability thickness of 85,800 mDft for the upper sand and 27,300 mDft for the lower sand. Assuming both sands have been perforated and that one zone has not been stimulated or damaged differently than the other, it follows that injection would split roughly 75% into the upper oil sand and 25% into the lower.

One of the strengths of pressure pulsing that is claimed is that it can improve injection conformance (vertical sweep efficiency) and areal sweep efficiency. This could also be a possible explanation for the improved injectivity. Improved injection conformance will result in an increase in oil recovery at some time in the future. The timing of this increase affects the economics of the project, and the sooner the production increase can be achieved, the better the economics will be. In order to accelerate the production increase it is important to inject such that the voidage is maintained in the high permeability layers as well as creating improved sweep in the lower permeability layers. This will aid create a "pressure bulge" and allow it to spread in the reservoir and help the porosity dilation wave to propagate further into the res ervoir.

By limiting the injection rate to pre PPT levels an improvement in injection conformance could, in the short term, result in a temporary decrease in oil production as the voidage into the layers dominating production drop. With limited injection, when the system has reached a new equilibrium, it would be expected that the oil cut go up, as the less mature zone is likely to produce with lower water cut. Again, the timing of the oil production increase would be linked to the water injection rate.

Not to limit water injection rate for other than containment issues is, therefore, one of the main lessons from this pilot project. Note that water injection rates were also limited by the pump specifications at the start of the project.

2. Measurement uncertainty

The uncertainty in the measurements is such that no firm conclusions can be drawn as to whether an oil production increase was seen or not during the pilot project. The fluid rate accuracy estimate is ±5%. The water cut measurement accuracy is given as ±5% for water shakeout data and ±20% for Coriolis measurements due to the uncertainty in fluid density. The accuracy of these types of water cut measurements are, however, also reliant on the placement of the sample point and the flow regime at that point.

3. Corrosion

The wellbore environment was much more corrosive than anticipated at the start of the trial and it is believed that this had a significant impact towards the end of the trial and ultimately led to the failure of the downhole pulse equipment. The effect of corrosion can not be quantified, but for future projects it will be important to ensure proper material selection for the well conditions.

CONCLUSIONS

During the PPT field trial two of the three objectives for the trial were met, namely equipment operability and increased injectivity.

The equipment outperformed the project scope of operating remotely for a period of five months compared to the target three months. The equipment achieved this even though operating in harsh wellbore condition in a more corrosive environment than anticipated.

An average increase in injectivity of 30% was recorded during the trial with a plateau injectivity enhancement of 40% during the first two months. The maximum injectivity corresponded with injection pressure at 40% of the historical values. Injection pressure remained low even after the trial was completed at around 70% of the steady state injection pressure for about one month. After that time the injection pressure started to increase.

It is important to note the significance of the injection pressure remaining low after the PPT pilot was terminated. .

Increased injection rates are not only significant for existing developments. By increasing the injection rate per well, the capital expenditure for new projects can be reduced, resulting in increased profits and improved economics for the project.

The injection water contained 50 mg/l hydrocarbons with viscosity of around 150 cP and 15 mg/l fines. PPT maintained improved injectivity throughout the stimulation period regardless of the poor water quality. This indicates that another use of the PPT technology would be waste water disposal.

The third objective – to increase oil production, is difficult to evaluate due to the absence of high quality data. The most important factors are believed to be the low pattern voidage, the water injection rat e limitations imposed due to water availability during the field trial and the corrosive downhole environment. With the assumptions outlined in the paper, it would take around 18 years to inject one hydrocarbon pore volume of water in this pattern. Even accounting for non-ideal factors it would be very difficult to get results in five months if the porosity dilation waves could not be made to propagate from the injector to the producer. Overall, with the limitations imposed, the project is viewed as a technical success.

RECOMMENDATIONS

For future projects it is recommended that:

1. Increase in injection rate is achieved, hence maximizing the benefit from the increased injectivity. This can improve the recovery rate of the waterfoold pattern.
2. Adequate tool and tubing material selection for the downhole conditions.
3. The injector well is equipped with a calibrated continuous water meter at surface.
4. The injector well has continuous pressure monitoring at surface and downhole.
5. Data is made available for the injection history of the well including ideally daily injection volume and injection pressure.
6. The well spacing is as close as possible such that production impacts can be seen in a timely manner and that pulse parameters can be adjusted if required.
7. Several offset wells are equipped with downhole pressure transducers.

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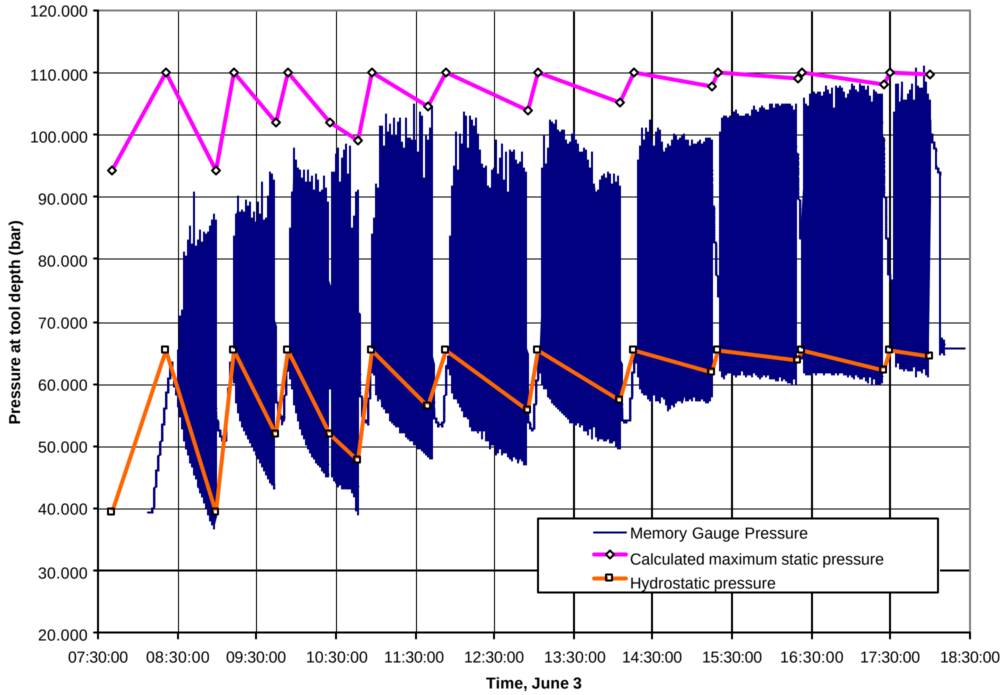

Figure 1: Downhole pressure measurements during pressure pulsing for workover stimulation job.

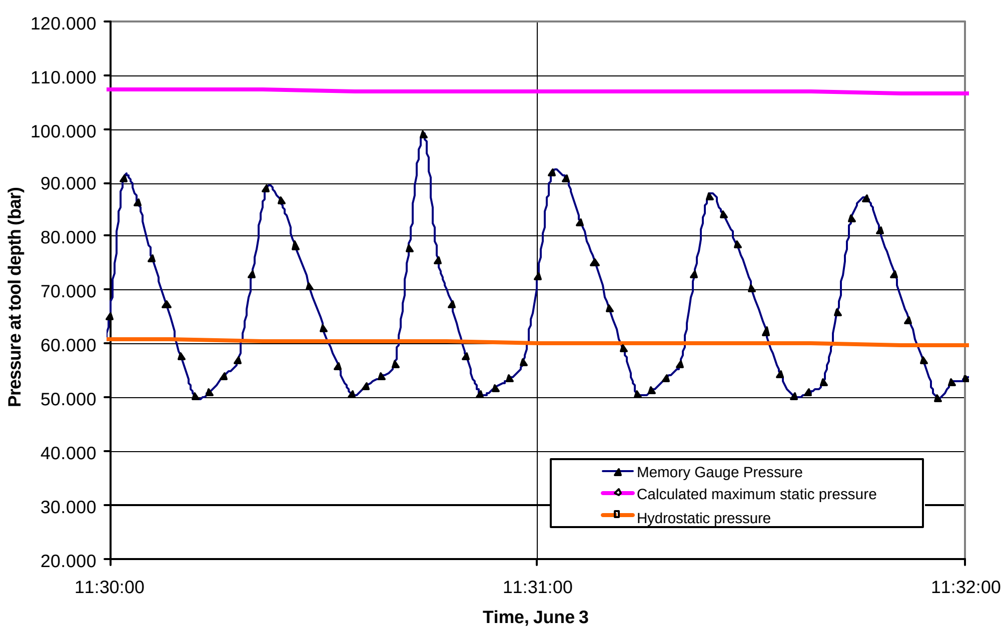

Figure 2: Detail of pressure recordings. Note that pressure pulse amplitudes are approximately 40 bar peak-to-peak.

Figure 3: The mast of the pulsing tool with the hydraulic unit in the background.

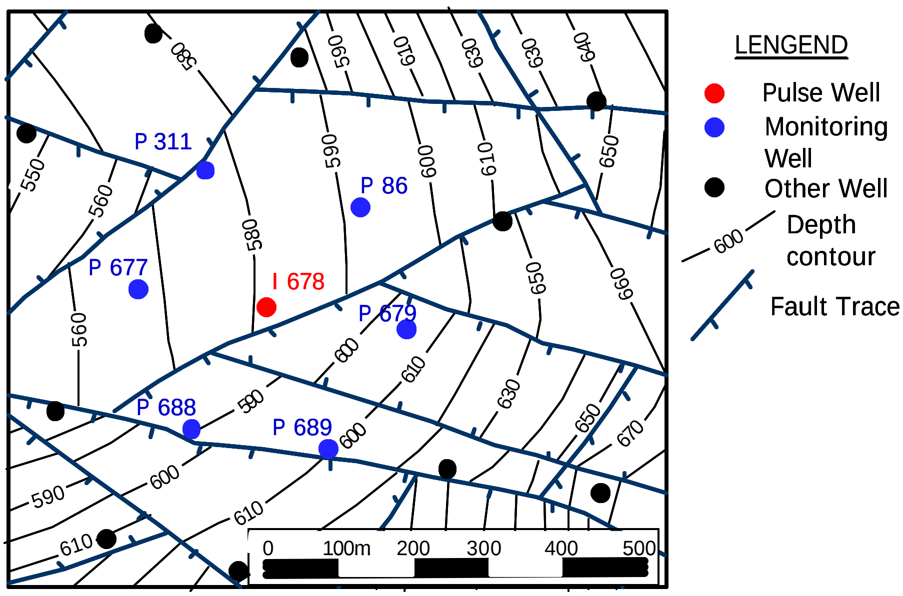

Figure 4 Injection well 678 Pattern Configuration.

Well Name	Bentheim sandstone (m)	Upper Oil Sand (m)	"Tonmittel" (m)	LowerOil Sand (m)
Well 678	20	21	3	13
Well 86	no data	18	No data	14
Well 311	no data	no data	No data	no data
Well 677	no data	21	No data	12
Well 679	no data	21	No data	13
Well 688	no data	19	No data	10.5
Well 689	no data	18	No data	12
Average	20.0	19.7	3.0	12.4

Table 2 Injection well 678 Pattern Layer Thickness Data

Well Name	Distance from Injector (m)	Fluid Production (m^3/d)
P 86	180	45
P 311	205	42
P 677	180	48
P 679	190	22
P 688	190	10
P 689	205	6
Average	192	29
Total	n/a	173

Table 3 Injection well 678 Pattern, Additional Data

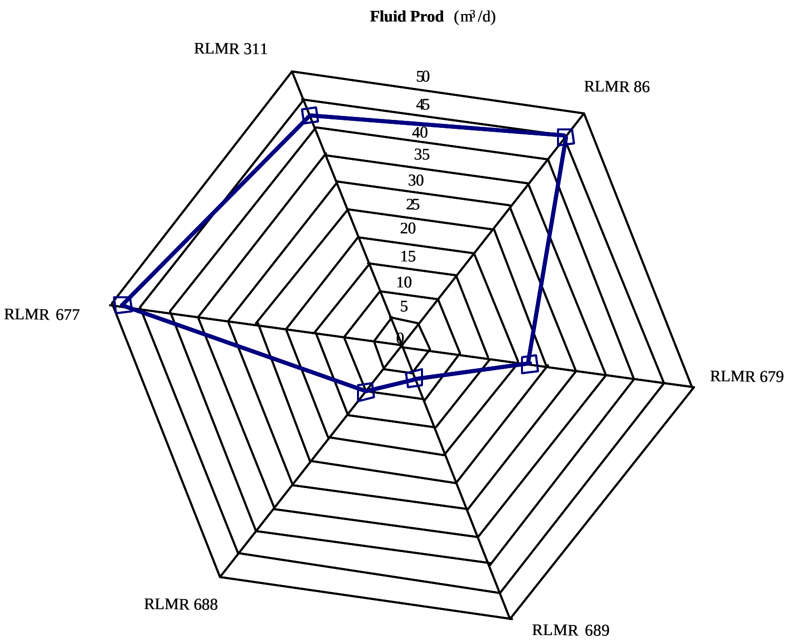

Figure 5 Areal Pattern Conformance.

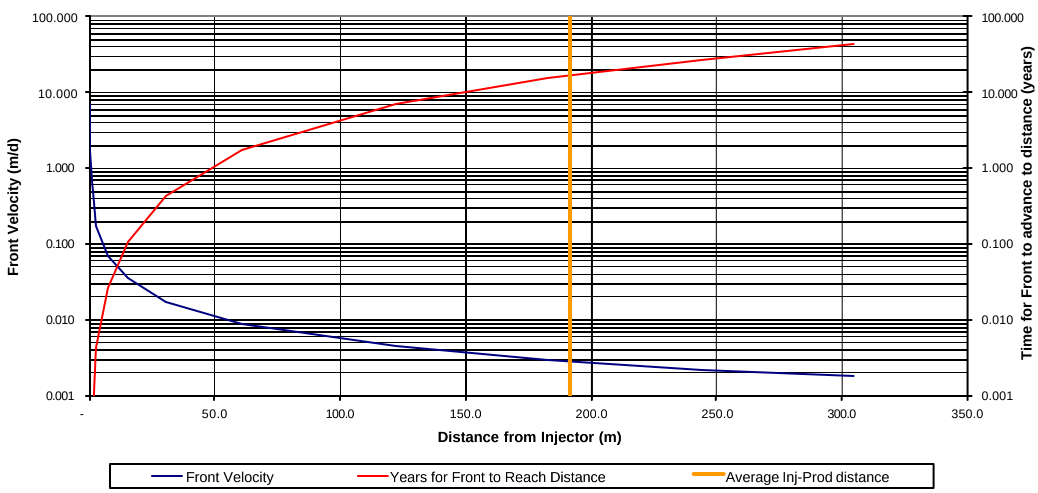

Figure 6 Injected water front velocity and time for water to move a given distance away from the injector.

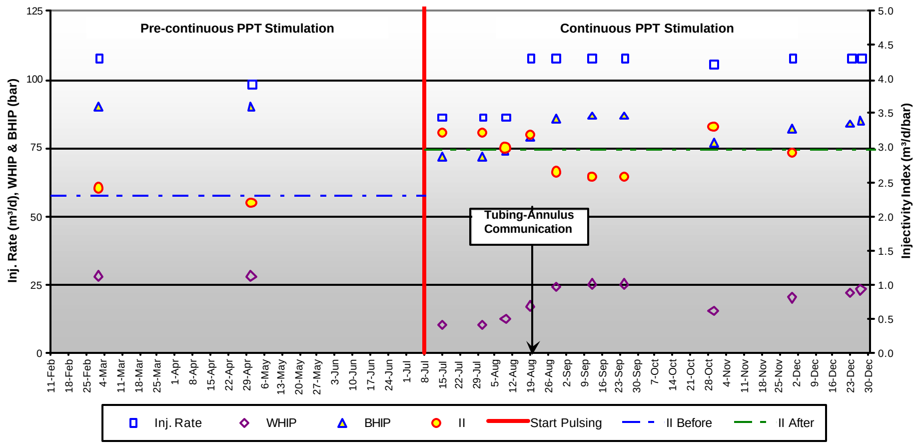

Figure 7 Well I 678 Injectivity data.

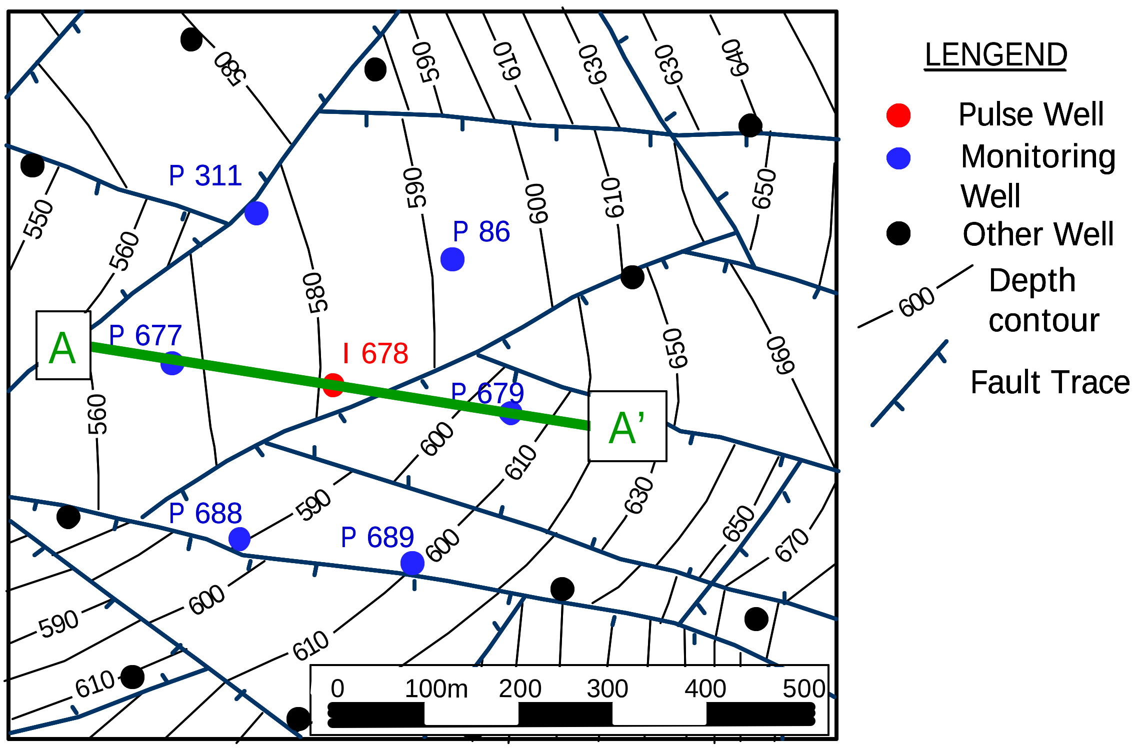

Figure 8 Map view of cross section A-A'.

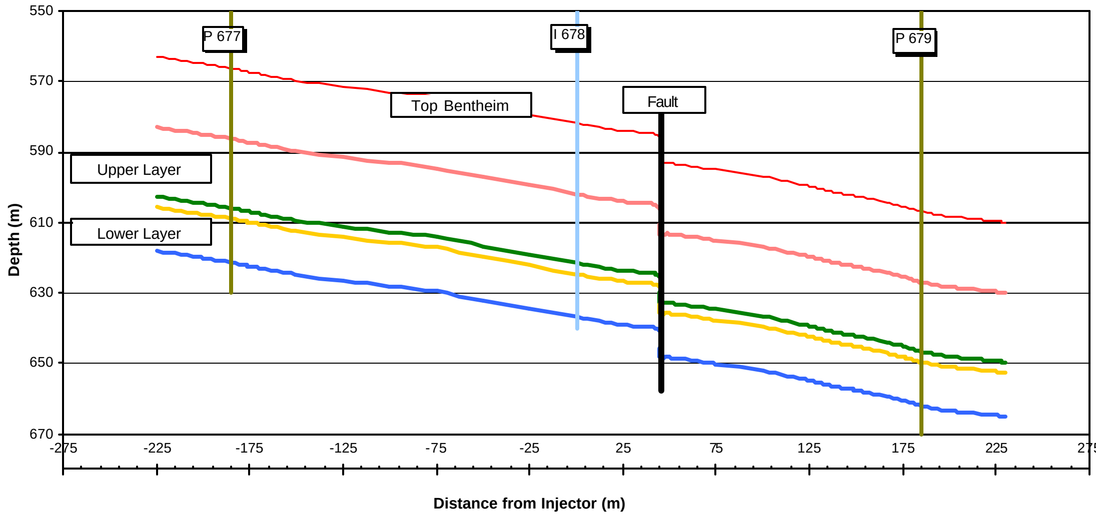

Figure 9 Cross section A-A'.

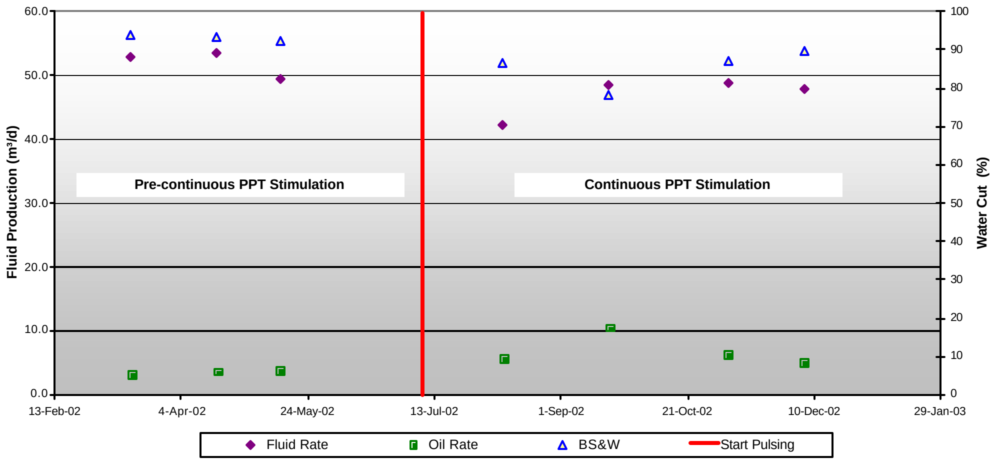

Figure 10Well 677 Production Data.

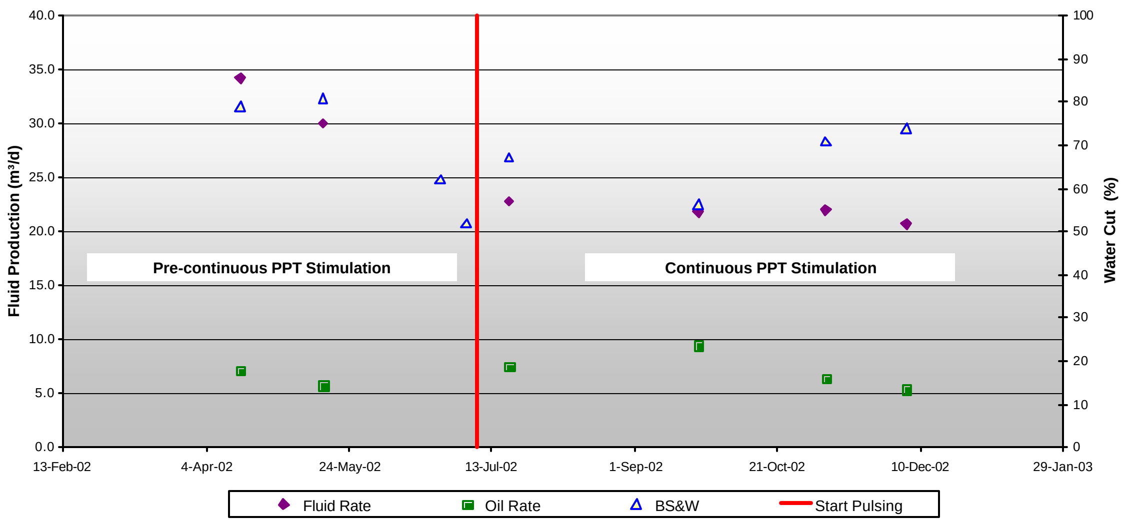

Figure 11Well 679 Production Data.

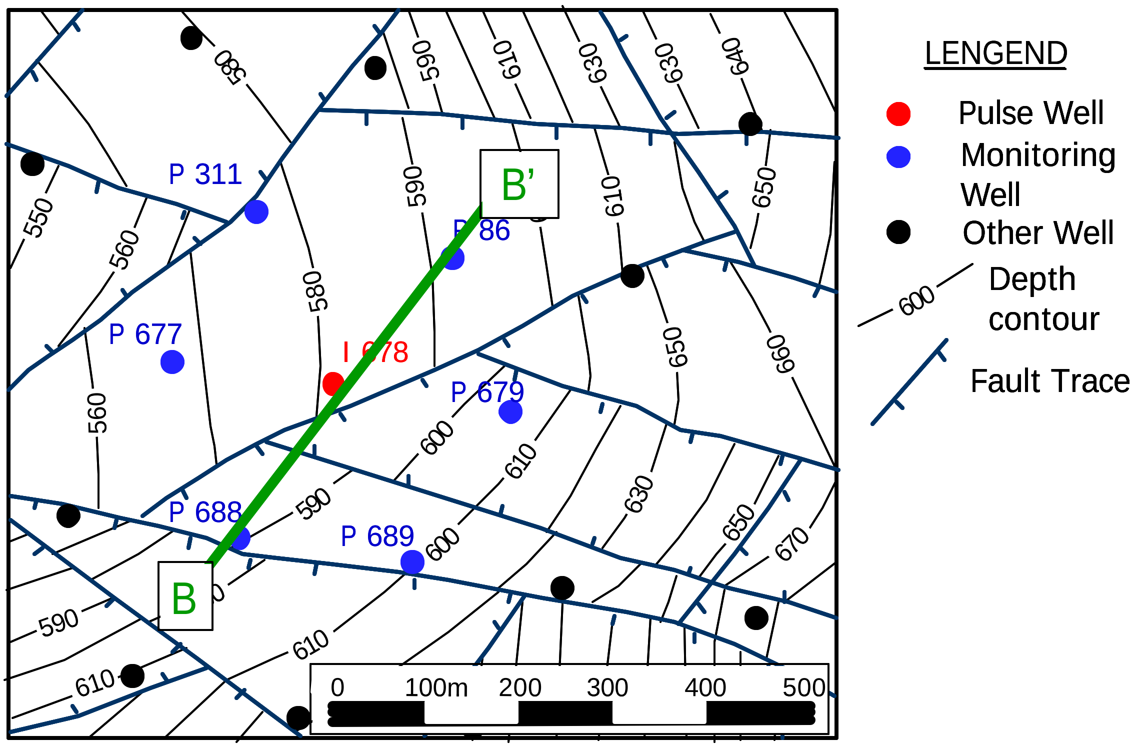

Figure 12Map view of cross section BB'.

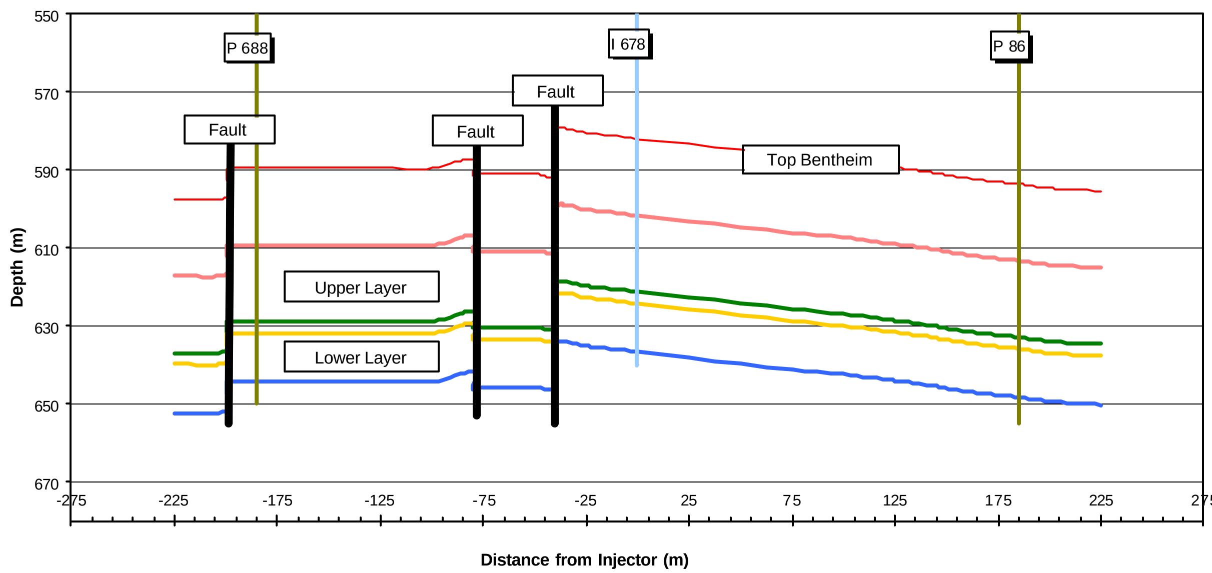

Figure 13Cross section B-B'.

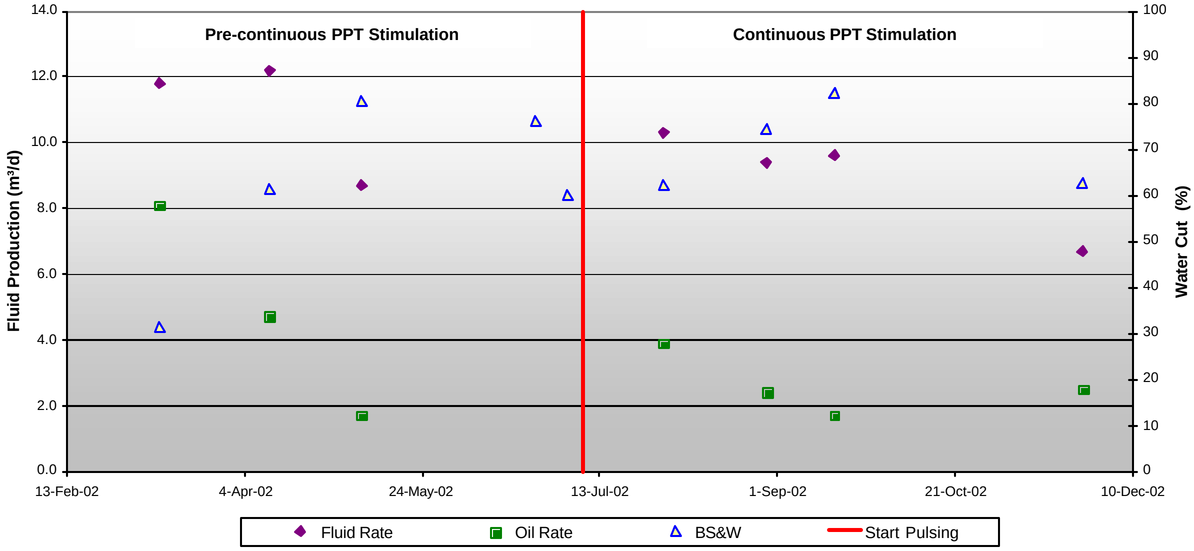

Figure 14Well 688 Production Data.

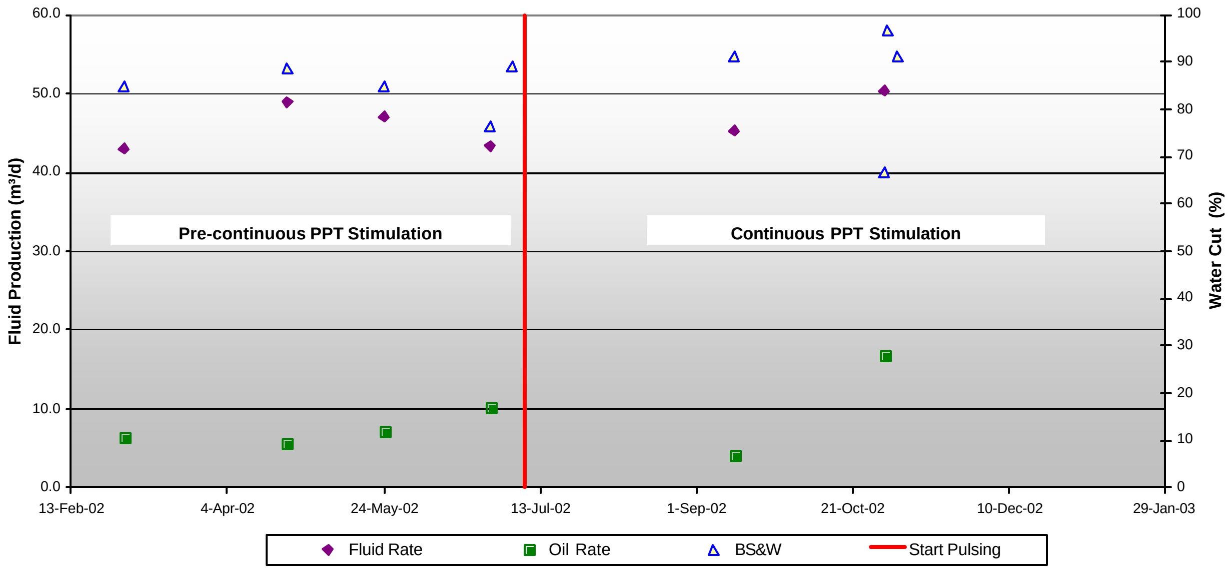

Figure 15Well 86 Production Data.

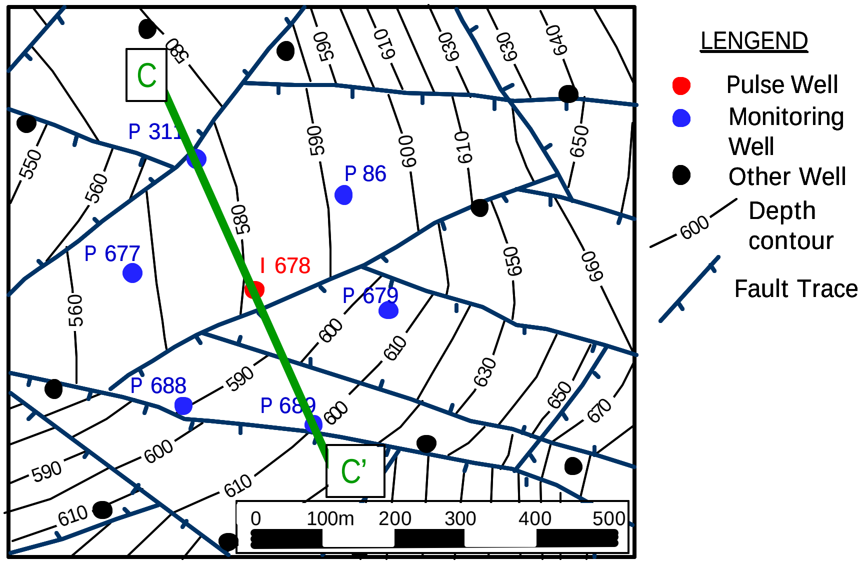

Figure 16Map view of cross section GC'.

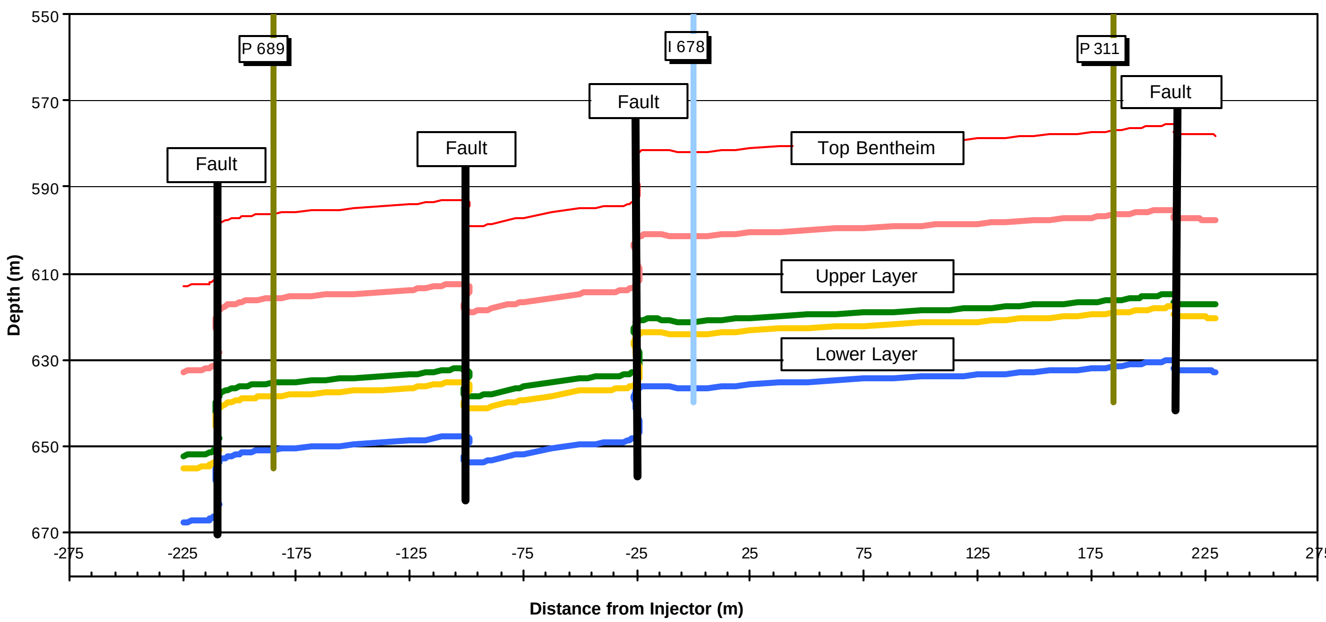

Figure 17Cross section C-C'.

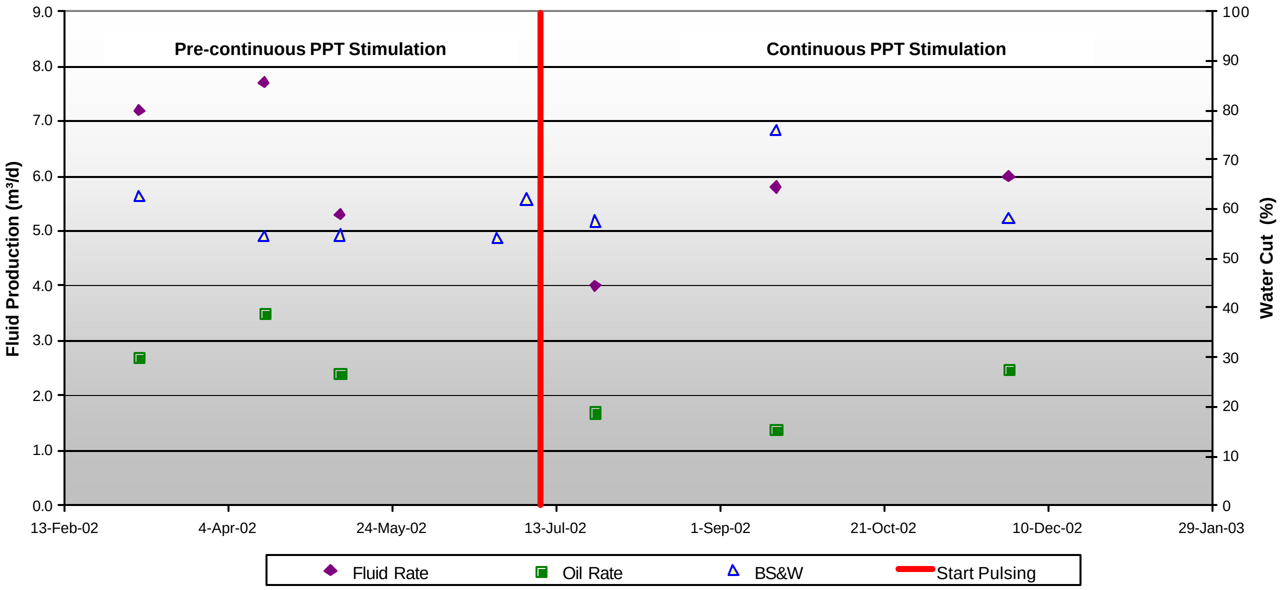

Figure 18Well 689 Production Data.

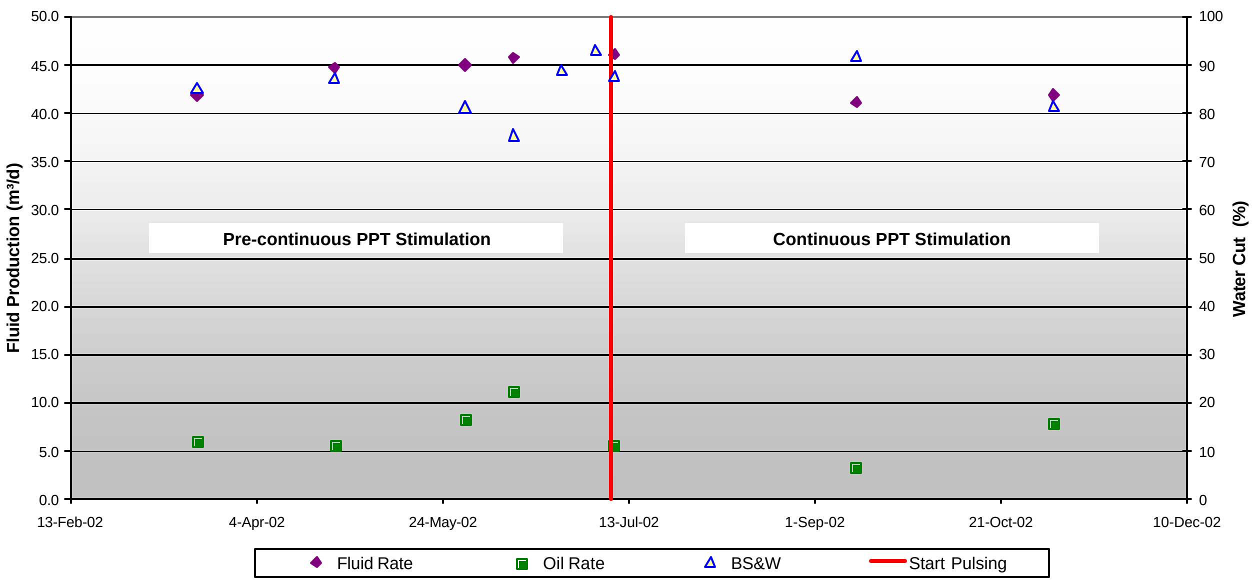

Figure 19Well 311 Production Data.