THESIS

Evaluation of Acid Stimulations

by

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Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Peter JANICZEK

Leoben, June 2008

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Abstract

The objective of this thesis was to identify critical parameters which influence acid stimulations and formation damage. This master thesis is based on the work of Chavez [1].

The first part of this thesis deals with technical analyses and economical considerations. It was tried to work out a heterogeneity index using gamma ray data and spontaneous potential logs. A simple approach to describe this value was developed by introducing the standard deviation.

Fluid losses, productivity indices and the production scenarios with a description of the workovers and pertinent information were plotted versus time in order to trace the origin of the formation damage and determine factors controlling the success of acid stimulations. In several cases, increasing the gross rate also resulted in an increase of sand production. In other cases high fluid losses during the workover caused a rising water cut. It was found out that in some wells the treatment pressures may have exceeded the fracture gradient of the formation. It was further noted that the documentation and nomenclature for the workover database is not standardized.

Additional stimulations, which were monitored online, were analyzed. The method for calculating the bottomhole pressure derived by Chavez [1] could be verified. The correlation could be improved by accounting for friction pressure losses in the surface line by using the equivalent length concept. An economical evaluation of the stimulation treatments was performed by calculating the pay out time. About half of the analyzed wells were economic successes.

The laboratory work comprises two series of experiments: The first one demonstrated that two polymeric mud components were equivalent in terms of formation damage.

The other showed that acidizing plugs from a shaly sandstone with 15 % hydrochloric acid resulted in most cases in a reduction of permeability or even in collapse of the plugs.

1. Introduction

Since this thesis is the referenced work of the master thesis of Chavez [1], this chapter will briefly introduce the reader in the well's inflow, the restriction and matrix acidizing. More details about the single acidizing additives and candidate selection can be found in Chavez' work [1].

The flow towards the well is caused by a pressure difference, described by inflow equations. If this optimal flow is hindered, we speak of skin which is basically an additional pressure drop.

Skin is affected by a series of conditions; the most common being due to perforation, partial penetration and slant, gravelpack, the so-called pseudo-skin (mainly the deviation from Darcy-flow) and the damage skin. The last one is the only one that can be reduced by a treatment –stimulation. Prior determination of the kind and the dimension of the skin is therefore crucial. The different types of damage skin, indications and treatment manifestations can be found in chapter 2.4.

Matrix acidizing is one of the three common stimulation techniques, next to hydraulic fracturing and acid fracturing. The basic principle of acidizing is to dissolve rock minerals and damaging particles in the near wellbore area by pumping acid with a pressure below the fracture pressure in the well in order to recover original permeability or create flow-paths.

The type of acid is dependent on the formation, which generally is divided into sandstone and carbonate rocks. Additionally, also components in the rock will influence the decision of the acid. Basically, carbonate rocks are stimulated with hydrochloric acid (HCl), formic (HCOOH) or acetic acid (CH_3COOH). Sandstones treatments are performed with hydrofluoric acid (HF) normally produced from ammonium bifluoride (NH_4HF_2). The basic reactions of limestone and dolomite with hydrochloric acid and sandstone with hydrofluoric acid are shown below.

$$\mathrm{CaCO_3 + 2HCl \longrightarrow CaCl_2 + CO_2 + H_2O}$$

Reaction of HCl with limestone

$$\mathrm{CaMg(CO_3)_2 + 4HCl \longrightarrow CaCl_2 + MgCl_2 + 2CO_2 + 2H_2O}$$

Reaction of HCL with dolomite

$$\mathrm{NH_4HF_2 + 2HCl \longrightarrow HCl + 2HF + NH_4Cl}$$
$$\mathrm{6HF + SiO_2 \longrightarrow H_2SiF_6 + 2H_2O}$$

Reaction of HF with sandstone

$$\mathrm{Al_2Si_4O_{10}(OH)_2 + 36HF \longrightarrow 4H_2SiF_6 + 12H_2O + 2H_3AlF_6}$$

Reaction of HF with clay

There are a series of side reactions of the acids with rock components, like carbonates in sandstones and some clay components (Na^+ and K^+ ions) with hydrofluoric acid. (see chapter 2.4). The result is precipitation, which causes an even more severe plugging.

The other mentioned acids are mainly used for retarded reaction, resulting in deeper penetration. Furthermore they are less corrosive. Also combinations of the acids are commonly used.

Additives have the task to assist the acid in doing its job. Briefly summarized, there are corrosion inhibitors, which slow down the reaction of the acid with iron from the production equipment. Furthermore there exists a variety of surfactants to prevent emulsions, decrease interfacial tensions and make the matrix more water wet. Suspending agents, which hold fines in suspensions, scale inhibitors, friction reducing agents, clay stabilizers, retarders, diverters and fluid loss control agents are some other important additives.

Typically an acidizing job consists of the following treatment sequence: It begins with the preflush, which displaces the brine from the wellbore and dissolves carbonate in sandstone reservoirs. The main treatment reacts with the damage or formation particles according to the chemical reactions above. The last step is the postflush to displace the main acid flush deeper in the formation.

2. Evaluation of Damage

2.1 Introduction:

Initially, one only recognizes a decrease in production rate in producing wells or an increase in injection pressure in injection wells. The reason for it might not always be formation damage. A normal production decline, shutting off a nearby injection well or turning one producing well into an injecting well may also be reasons for change in production data. Therefore it is crucial to determine if there are indications for a reversible formation damage to prevent wasting money and the formation of further damage by an improper stimulation job. Production tests, pressure buildup or drawdown tests, comparison with neighboring wells and a thorough inspection of the production trends will assist the identification of formation damage.

Also information about the reservoir rock is of crucial interest to design the proper stimulation and workover job. Mineralogical composition and the lithology of the formation are two very important parameters.

2.2 Formation Characterization

There are direct and indirect methods. The first ones allow a visual inspection or a direct measurement of properties, like coring, sidewall sampling, mudlogging, formation pressure testing and fluid sampling. The latter infer reservoir parameter from measurements, like logging on wireline or while drilling and seismic.

2.2.1 Coring and Core Analysis

Cores provide the most detailed view on the formation; next to description of depositional environment, sedimentary features and diagenetic history, they are used to measure physical rock properties in the laboratory.

There exist two methods of coring:

Conventional coring system:

> The cores are taken during drilling operation with a special assembly, which consists of a coring bit and a coring barrel. The bit is a hollow cylinder with an arrangement of cutters on the outside which cut circular grooves in the formation.

Sidewall coring system:

> Core samples can be taken after drilling and logging. It is very common to run the sidewall coring tool together with a gamma ray logging tool for example to make a correlation in the open hole section for a better depth control of the coring point.

As a standard procedure a depth correlation with a log from the formation with a log from the core is performed.

Additionally to the geological evaluation, plugs (smaller cylinders) are drilled from the core to perform the following tests:

The standard analysis of the plugs contains determination of porosity, horizontal air permeability and grain density. The special core analysis (SCAL) includes analysis of the vertical air permeability, the relative permeabilities, capillary pressure, cementation and saturation exponent and the wettability.

To determine the mineralogical composition, either thin sections or x-ray diffractometry (XRD) can be performed. A general division in the amount of the components and the cementation and matrix is very desirable. XRD allows a determination of the single crystalline components in mass-percent by measuring and correlating the intensities of the main peaks from the mineral phases [12] and thin plates allow a determination of the cement phases.

2.2.2 Logging

This method is usually applied during drilling (LWD – Logging While Drilling) or afterwards (wire line logging tools or conveyed). Due to the high pressure and high temperature environment in those depths, special requirements for the material are needed.

Logging allows a more accurate analysis of the lithology and also a better estimation on the kind of fluids in the formation. Therefore different logging techniques exist, which allow different types of application and measurements; also units can be combined to reduce the amount of runs in and out of the borehole. Since a vast variety of logging tools are available, this subchapter will only cover the techniques used in the project.

Spontaneous Potential (SP):

The SP-log is basically a record of the naturally occurring electrical fields. Electrochemical potentials are mainly caused by differences in concentration of ions in the fluid and membrane effect in clays. By measuring the difference of the potential to the electrode on the surface, this method is able to distinguish between shales and sands of the formation In other words in shale the potential difference is higher, therefore kicks to the right of the log. Spontaneous potential logs can only be used in boreholes filled with fresh drilling mud, they won’t work properly in salt muds or in air-filled holes.

Gamma Ray (GR):

The gamma ray tool measures the natural radioactivity of uranium (238U), thorium (232Th) and also potassium (40K). The GR-detector (e.g. Geiger-Müller tube) registers the incoming gamma rays as an electronic pulse.

New GR-tools allow determination of the elements which are responsible for the radioactivity.

The interpretation allows determination of the clay-content. The standard assumes that shales have abundant 40K in their composition. In general shales contain a higher amount of radioactive elements, like 238U and 232Th than sandstones. But certain clay minerals (e.g. glauconite, containing 40K) in sandstones can cause misinterpretation.

Gamma ray logging is only of limited use in carbonates, because of the presence of soluble impurities like uranium.

2.2.3 Cuttings

Fragments of rock, created by the crushing action of the bit are called cuttings. They allow a permanent visualization on the lithology during drilling. Thereafter, they are washed, dried and examined (lithology, texture, etc.) and also tests can be made on cuttings.

Once the cuttings are retrieved from the mud system, they are typically split into a bulk, unwashed wet-cut sample and a washed and sieved dry-cut sample. The first ones are packaged in closed bags, while the latter are immediately examined wet under binoculars for rock type, lithology, color, hardness, grain size and –shape, sorting, cementation, porosity and HC shows.

Although they allow a continuous visual record of the formation some problems, like powdering due to excessive weight on bit, falling back or accumulation, due to too low mud viscosity or annular velocity, can also occur. Therefore the question is whether the cuttings are truly representative or if only a part of the material arrives at the surface. A detailed documentation is required.

2.2.4 Bailer Sampling

Bailer samples are taken to sample any bottomhole solids and fluids accumulated in the wellbore through the application of a downhole bailer.

Basically, there exist two types of bailers, the hydrostatic bailer and the sand bailer. The first one is a sealed atmospheric chamber and a activation mechanism to allow communication with the wellbore. After activation the fluid is surged into the chamber by equalizing the pressure. Debris and sediments can either be captured or dislodged by a shroud device. The sand bailer is commonly used to remove sand from the well’s bottom or as a swabbing device. The procedure is similar to the hydrostatic bailer, but the basic aims are the sediments.

For cased-hole completions, these samples are the only physical samples available.

The fluids and sediments brought to surface can then be analyzed in a laboratory for the origin and composition (e.g. type of precipitation, bacteria, origin of water, and so on).

When a bailer is used to purge a well, it must be made of material that will not alter sample parameters. When sampling for organics, teflon is the recommended material of choice and stainless steel is the second choice. Polyvinylchloride (PVC) bailers are not recommended for sampling organic constituents.

2.3 Methods used for Formation Characterization

There are two important types of information: lithology and mineralogy. The basic differentiation criterion for the acid was, if the reservoir is sandstone or limestone, until now. But the whole lithological and mineralogical composition of the reservoir – especially in sandstone reservoirs – has to be observed. Also the heterogeneity has, according to appropriate literature [3], an important influence, i.e. the frequency of changes in shale and sand layers. The assumption is that more changes in layers, or higher lamination, result in a higher possible contact area with the acid, which can result in more precipitation products, or dislocation of more fine particles, which can also plug pores.

2.3.1 Mineralogical Specification

Thin-sections and XRD analyses were used for determinating the mineralogy. Since there were no data available for the pre-selected wells [1], it was necessary to control if data from other wells containing the same horizon could be used. This was carried out by checking the average data and calculating the standard deviation. If this resulted in a small deviation, the horizon values were assumed to represent the well.

It is important to mention, that the thin-section and XRD analyses were only performed from the sand layers of the horizons, meaning that shale or marl layers were not considered within the analyses. Therefore the amount and type of the occurring clays only refers to the sand layers.

The mineralogy was characterized the following way:

- The individual components (quartz, feldspar, etc.)
- Total amount of carbonates, defining the maximum soluble part of the formation, consisting of limestone ($CaCO_3$), dolomite ($CaMg(CO_3)_2$), siderite ($FeCO_3$)
- Amount and type of clays (Illite, Kaolinite, Chlorite, Smectite, mixed layers)
- Amount of cement

Well	Hor	PE	Field	Lithology	Horizon Interval	average horizon values in [%] Quartz	K-Fsp	Plag	Calcite	Dolo mite	Anke rite	Side rite	Pyrite	Clay Tot+Mica	Illite	Kaolinite	Chlorite	Smectite	Mixed-Layer	Carbonates Solubility	Cement	Info
Pir 15	107	10	A017	Sandstone	896-934	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
Pir 24	107	20	A017	Sandstone	958-986,5	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
Pir 79	107	20	A017	Sandstone	936-966	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
HL 13	111	10	A016	Sandstone	992-1016	65	2	-	26 (no differenciation)				1	1	-	-	-	-	-	26	31	DS
HL 31	111	10	A016	Sandstone	992-1087	65	2	-	26 (no differenciation)				1	1	-	-	-	-	-	26	31	DS
					992-1087																	
HL 25	205	10	A016	Sandstone	1228-1256	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	no data
HL 71	205	11	A016	Sandstone	1244-1350	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	no data
S 111	208	10	A015	Sandstone	1230-1268	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
S 133	208	10	A015	Sandstone	1224-1263	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
S 256	208	10	A015	Sandstone	1236-1264	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
MaC 2	209	91	A015	Sandstone	1286-1330	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
MaF 6	209	91	A015	Sandstone	1296-1336	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
S 28	209	91	A015	Sandstone	1279-1314	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
S 179	209	91	A015	Sandstone	1270-1329	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
Ma 56	216	10	A015	Sandstone	1601-1633	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
					1601-1633																	
Ma 84b	216	10	A015	Sandstone	1597-1627	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Ma 268	216	10	A015	Sandstone	1615-1674	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Bo 49	216	20	A015	Sandstone	1615-1664	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Bo 98	216	20	A015	Sandstone	1606-1656	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
ST 31	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 64	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 78	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 90a	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
PT 4	800	12	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general

Figure 1: Mineralogical composition of the horizons of the selected wells

2.3.2 Heterogeneity Description

The literature does not present a single number or formula for the description of the reservoir heterogeneity. Therefore several trials were necessary to explain this parameter in a simple and easy way.

Trial nr. 1:

The first trial was to use evaluated and interpreted logs. This interpretation was done decades ago as following. Different depth intervals were analyzed with a classification of gross and effective thickness and the clay content within this interval. The general determination of shale was done by using the gamma ray or spontaneous potential log. For a finer identification the resistivity log was additionally used. Shale peaks in the resistivity log with dimensions of 10 to 15 centimeters where usually counted as one interpretation interval and therefore subtracted from the gross thickness. If the supposed shale layer was larger than the attributed 10 to 15 centimeters a new interpretation interval was chosen with the same subdivision. The clay content was quantified using low, medium and high and describing parameters, meaning low for smaller 0.05, medium for 0.05 to 0.15 and high for values larger 0.3 (1 is indicating pure shale).

The main idea in using these evaluated logs for this project was to calculate something like a “relative shale number” (RSN) by dividing the difference between the gross and the net by 10 centimeter, which represents a pessimistic value for shale layers within the sand packages. This should show how heavy the lamination of the stimulated depth is.

$$RSN = \frac{\text{gross thickness} - \text{net thickness}}{0.1}$$

The amount of interpretation intervals determined the layers between the sand packages; also the total thickness of the thicker layers was calculated

The number of shale layers (SL) within the sand packages was calculated by dividing the difference between gross thickness and the combined length of the thicker layers plus the net length by ten centimeter

$$SL = \frac{\text{gross thickness} - \text{net thickness} - \sum(\text{shale layers})}{0.1}$$

The overall shale content was calculated and also the shale content neglecting layers thicker than ten centimeters.

One problem is that the derivation of the shale content from the evaluated logs is very subjective is also not available for every well (only around one third of the wells had such evaluations) and depends on the saturations and hydrocarbon content (due to the usage of the resistivity log). Furthermore this is not a fast and simple method, because a detailed analysis of the evaluations and counting of the single intervals is necessary (which is very time consuming). This is not a viable method.

Trial nr. 2:

The next try was to extract gamma ray and spontaneous potential data from the log database (logDB). CE-logs were chosen.

The .LAS files from the database did not contain any unit, therefore initially °API was assumed until some logs with a quite constant and low extinction were compared with the evaluated logs from trial nr 1, which showed high shale content. The header from the original log-sheets from the archive presented different units, like µR/h (micro roentgen per hour) or µg Ra-eq/to (microgram Radon equivalent per ton). There was no accurate conversion factor at hand due to the dependency of the logging device. But the general trend within the curve is constant.

The shale content was calculated using the following formulae:

For gamma ray logs: $I_{GR} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$

where GR is the ongoing extension

GRmin is the minimal extension for a certain interval

GRmax is the maximal extension for a certain interval

For spontaneous potential logs: $V_{cl} = 1 - \frac{PSP}{SSP}$

where PSP is the pseudostatic potential (the ongoing extension)

SSP is the static spontaneous potential (maximum extension)

The logged interval stretches over different horizons, which are not homogeneous; therefore the sandline and the shaleline for one log will not be representative for the whole interval. Only the stimulated horizon was considered and I_{GR} and V_{Cl} were calculated for the stimulated thickness, in other words a shaleline and a sandline were created for the particular horizon.

Normally, the I_{GR} value is not the shale content, because some corrections for the age and the consolidation have to be considered. Since there is a variety of possible formulae, which all lower the shale content, this parameter was neglected.

The calculated I_{GR} was assumed to be V_{clay} for the gamma ray log, a linear relationship. For the calculation of the spontaneous potential clay content no correction factors were developed; a linear relationship is widely accepted.

For describing the heterogeneity of the stimulated part of the horizon, the standard deviation was used. Mathematically it describes the spread of the values around the average value. Certainly, this is not the ideal solution in describing the heterogeneity.

For controlling of the calculated parameters shale content and heterogeneity, a subjective appreciation them was also performed. Therefore the stimulated region and some ten meters in both directions were observed. This categorization must not necessarily agree with the calculated values, because they are based on the design of the log curves. The shale content was divided into sand, shaly sand and sandy shale according to the gamma extension and into low, moderate and high for the heterogeneity according to the intensity of peak changes.

By comparing the spontaneous potential with the gamma ray data and also the calculated with the subjective data, one will recognize that they fit quite well together.

Conclusions and Results:

Hence, method two was adopted.

However, both methods can not really be applied in this way for dolomite. Here, the differentiation between dolomite and marl is very important, which is hard to determine from gamma ray logs. Furthermore no thin sections or XRD analyses have been made.

It further has to be mentioned that some stimulated intervals are small, therefore, the classification of heterogeneity and shale content may be inaccurate.

The tables with the mineralogical composition of the observed wells, the overall shale content and the heterogeneity can be found in figure 1 and 2 on the next pages and in appendix A.

						Gamma Ray				Spontaneous Potential			
Well	Hor	PE	Field	Lithology	Horizon Interval [m]	overall clay content [%]	Std. Dev. heterog.	Subjective Shale content	Subjective heterog.	overall clay content [%]	Std. Dev. heterog.	Subjective Shale content	Subjective heterog.
Pir 15	107	10	A017	Sandstone	896-934	55	6	sandy shale	low	52	7	sandy shale	low
Pir 24	107	20	A017	Sandstone	958-986,5	52	15	sandy shale	moderate	59	16	sandy shale	moderate
Pir 79	107	20	A017	Sandstone	936-966	33	24	shaly sand	high	29	22	shaly sand	high
HL 13	111	10	A016	Sandstone	992-1016	26	18	shaly sand	moderate	7	8	sand	low
HL 31	111	10	A016	Sandstone	992-1087	41	24	sandy shale	moderate	85	3	sandy shale	moderate
						28	20	sandy shale	moderate	80	7	sandy shale	moderate
HL 25	205	10	A016	Sandstone	1228-1256	49	18	shaly sand	high	54	28	shaly sand	moderate
HL 71	205	11	A016	Sandstone	1244-1350	13	5	sand	low	-	-	-	-
S 111	208	10	A015	Sandstone	1230-1268	66	19	shaly sand	moderate	71	16	shaly sand	moderate
S 133	208	10	A015	Sandstone	1224-1263	52	24	shaly sand	moderate	36	29	shaly sand	moderate
S 256	208	10	A015	Sandstone	1236-1264	41	25	shaly sand	high	34	11	shaly sand	moderate
MaC 2	209	91	A015	Sandstone	1286-1330	58	12	sandy shale	moderate	59	13	sandy shale	moderate
MaF 6	209	91	A015	Sandstone	1296-1336	16	10	shaly sand	low	26	6	shaly sand	low
S 28	209	91	A015	Sandstone	1279-1314	69	23	sandy shale	high	45	29	sandy shale	high
S 179	209	91	A015	Sandstone	1270-1329	43	13	sandy shale	high	44	25	sandy shale	high
Ma 56	216	10	A015	Sandstone	1601-1633	13	4	sand	low	4	2	sand	low
					1601-1633	15	4	sand	low	10	2	sand	low
Ma 84b	216	10	A015	Sandstone	1597-1627	6	4	sand	low	16	13	sand	low
Ma 268	216	10	A015	Sandstone	1615-1674	25	18	shaly sand	moderate	39	18	shaly sand	moderate
Bo 49	216	20	A015	Sandstone	1615-1664	-	-	-	-	13	3	shaly sand	low
Bo 98	216	20	A015	Sandstone	1606-1656	-	-	-	-	27	1	sandy shale	low

Figure 2: Overall shale content and heterogeneity of the selected wells

2.4 Theory about Formation Damage

2.4.1 Types of Formation Damage:

Formation damage can be categorized into:

Reduction of the absolute permeability

Most important here is swelling and migration of clay and also precipitation of reaction products and heavy oil components.

Clay swelling is basically caused by building water molecules into the lattice of the clays. A further reason can also be diffusion of ions and balancing with water molecules and ion exchange, if they are larger than the original ones. Smectites are most sensitive to this phenomenon. Dispersed clay and sand particles can plug pore throats. A pressure or temperature reduction of oils can result in a precipitation of asphaltenes and paraffines in the formation, likewise anorganic scales can form by a shift of thermodynamic equilibrium (for instance by degassing or mixing of incompatible brines).

Reduction of the relative permeability

This is the result of an increasing water saturation or change in wettability in the near wellbore zone, caused by invasion of any drilling- or treatment fluid, called water bloc.

Increase of viscosity of the reservoir fluid

This is caused by creation of emulsions with high viscous fluids, called emulsion block. The emulsions can be generated by shear forces with surface active agents and are stabilized by material adsorbed at the interface, such as polymers, clay minerals, iron sulfide, asphaltenes and other fines..

Following the most important causes, types and indicators for formation damage are listed, separated into drilling and completion damage, workover damage and production induced damage.

2.4.2 Damage during Drilling and Completion

Generally, overbalanced drilling causes invasion of drilling mud particles and filtrate in the formation. Negative factors are too small particles, which do not bridge the pore throats and long exposure time of the mud to the formation.

Indicators for this kind of damage are for example fluid loss to the formation, meaning that the size of bridging particles and lost-circulation agents were chosen incorrectly. A long exposure time in the particular interval causes a much deeper invasion of the filtrate in the formation, while solids normally stay very close to the wellbore. A higher overpressure to the formation is the result of high densities of the drilling mud, which is severe in depleted formations. Fractures or fissures in the wellbore also cause fluid loss, therefore a comparison to other neighbouring wells in the same horizon should be done.

The type of mud plays an important role. Modern polymer based muds can generally be removed easier by using hydrochloric acid, than clay based muds, like bentonite. The invasion of water from water based muds is not avoidable. Therefore it is possible that the saturation of water increases to an extent to reduce the relative permeability of oil. If there is a significant amount of carbonate (CO_3^{2-}) in the drilling fluid, it is possible, that in carbonate reservoirs, calcite ($CaCO_3$) precipitates and plugs the fractures' surface because of an oversaturation of Ca^{2+} ions in the brine.

This drilling damage might be partly overcome by a deep perforation afterwards. Moreover, if the well is produced for a long time and repeatedly stimulated, the possibility is quite high that this kind of damage becomes negligible, compared to the other types.

During cementing, the particles and fluid will also invade into the formation, settle there and plug the pores. The filtrate may even cause a wettability change or insoluble salt may be precipitated.

Perforating will crush the formation and debris will plug the pores. As mentioned, it is possible to overcome the drilling and also the cementing damage with deep perforations. Therefore an important factor is the depth of perforation and also the phasing.

2.4.3 Workover caused damage

If a well is shut in for a workover job, it is usually filled up with kill fluid to provide a pressure causing the reservoir not to produce.

Any kind of pumped fluid, which contains or induces particles, will cause a high risk of creating damage. Possible reasons are:

- poor quality of kill fluid
- bad quality of flooding fluid in injection wells. It can also be used to kill the well. Any dirt or particles should be filtered and the fluid has to be treated so that no precipitation can occur.
- While injecting fluid, grouting fluid or acidizing, particles from the tubing string can be dissolved and can access the pores, where they settle and plug the flow. This can be dirt, scales or rust.
- If the treatment (like scale removal) is performed from tubing to casing some deposits can stay at the bottom of the well, where they settle and plug the pores.

Of course, the higher the amount of performed workover jobs, the higher the risk in creating damage.

During installing a gravel pack, a treatment fluid is necessary. Most times this fluid is polymer based. It is important to know which kind of fluid was used, to determine how invading solids can be dissolved afterwards. Knowledge about the type of the viscous pill and the breaker is furthermore important for solvent selection. Usage of incorrect gravel size for the pack will result in an additional skin.

Knowledge about previous matrix acid stimulations combined with the mineralogy and lithology of the formation will also have an impact on the decision:

- Sandstone formations with certain amount of carbonates will create precipitations, if they are stimulated with hydrofluoric acid:

  $$2HF + CaCO_3 \longrightarrow CaF_2 \downarrow + H_2O + CO_2$$

  The critical carbonate value is varying in the literature, but around 15% have established over the years. Therefore the very first treatment should not be performed with hydrofluoric acid and the latter should include a preflush with only hydrochloric acid to dissolve the carbonates at first.
- Some clays swell when they get in contact with a waterbased fluid, for example mixed layers or smectite. If the amount of these clays is high, stabilizing agents should be used, else the occurring stresses may disintegrate parts of the formation.

- After reaction of hydrofluoric acid with sandstone or clays, silici- and aluminofluoric acid is generated, which will further react with K^+ and Na^+ ions from the brine or clays and precipitate as insoluble salts.

  $$H_2SiF_6 + 2Na^+ \longrightarrow Na_2SiF_6 \downarrow + 2H^+$$
  $$H_2SiF_6 + 2K^+ \longrightarrow K_2SiF_6 \downarrow + 2H^+$$
  $$H_2AlF_6 + 3Na^+ \longrightarrow Na_3SiF_6 \downarrow + 3H^+$$
  $$H_2AlF_6 + 3K^+ \longrightarrow K_3SiF_6 \downarrow + 3H^+$$

  There also exist clays which create precipitation products even with hydrochloric acid and also hydrofluoric acid, like chlorites with a high amount of iron or aluminum.
- A high number of shale or marl layers in sandstones increase the contact area of the acid and so the possibility to create fines. Also the amount of clay in the pore space has the same influence. An experiment (see chapter 5.2) has tested the acidizing response of such formations. The same can be assumed for carbonate or dolomite reservoirs containing marl layers. The acid may cause the surrounding formation to break down.
- Monitoring flow rates and pressures used during the treatment will provide conclusions, if the formation was fractured during the job and the acid moved in the fracture. A fracture gradient of 0.18 bar/m is assumed. The calculated bottomhole pressure should be less than the fracture pressure.

Cleaning of paraffin or asphalt from the tubulars with hot water or oil may plug the perforations, if the procedure is not done properly. The same can happen if these deposits are cut off with a knife.

2.4.4 Production caused damage:

During production damage may be caused by fines migration from outer reservoir regions to the near wellbore area, where they either settle and plug pores or are partly produced. The fines may consist of clays, marls or carbonates. Of course carbonate and partly marl fines can be removed easier than clay particles with hydrochloric acid. To get a better idea of the kind of fines bailer samples could be taken and analyzed.

There are several indicators and negative influencing factors:

- The older the well is, respectively the longer it has produced, the higher is the risk of fines migration, generally.
- High flow rates and a high pressure drop will also enhance the possibility of fine particle migration.
- Also jerky movements will give an impetus to small particles and force them to move into flowing direction. This is the fact for intermitting wells or wells, which were shut off frequently for some time.

- Furthermore multiphase flow has to be observed, because occurring turbulences will also force the fines to travel. For example a high water production rate is observed. To keep the amount of oil constant a stronger pump is installed, which also increases the amount of producing water and the pressure drop. The result is a more turbulent multiflow system, which may not only push the fines forward but also lead to gas coning or reaching the bubble point, resulting in a three phase flow.
- An excessive pressure drawdown decreases the pore pressure near the wellbore, resulting, that the effective stresses can exceed the comprehensive strength of the rock.
- An excessive pressure drawdown also may cause evolution of carbon dioxide (CO_2), resulting in a precipitation of calcite ($CaCO_3$) in the near wellbore area or in the gravel pack.

Gravelpacks and screens may become plugged with sand, silt, clay or other debris during production.

Of course the type of fines is dependent on the lithology and the grade of consolidation.

If inhibitors for corrosion, scale or paraffin get in contact with the formation, they also may decrease the permeability.

When the pressure builds up early after the treatments, one explanation is that fines in the near wellbore region were only displaced in the surrounding formation and move back during production. A further reason for a fast pressure increase (or even no decrease) can be that the formation or gravel pack was damaged during the treatment.

2.5 Methodology of Formation Damage Evaluation

As denoted in the introduction to this chapter, there are different possible approaches for evaluation of the formation damage. Most of the preselected wells [1] are quite old, production-, buildup and drawdown tests are seldom available. The selection was based on a comparison of acid stimulations; therefore it is crucial, that no other job was performed at the same workover.

A comparison with neighboring wells would have exceeded the scope of the work. Thus, this comparison was left aside.

Therefore the production scenarios of the wells were observed, beginning with the perforation in the current production interval, respectively the acidized interval. Every treatment and conspicuous point was marked. For identification of such points, trends, etc. following approaches were used:

- The monthly production data of gross rate, oil rate and water cut were plotted versus time. The gas-oil-ratio (GOR) was plotted versus time on a separate graph for a better visualization. These plots were used to identify the general production trends.

- Daily production data show remarks why a well was shut in and other minor repairs, where no workover rig was utilized.
- Workover reports were analysed for the general workflow with special respect to fluid losses and fluid types. Also, the analysis of the equipment is very important (visual and also laboratory inspections).
- Matrix Acid Stimulations:
  - For acidizing jobs, where pressures and flow rates were monitored, the maximum occurring pressure gradient was calculated (see appendix A) and compared.
  - The mineralogical composition and heterogeneity indicate if e.g. an acid stimulation with hydrofluoric acid was adequate, or if the reservoir tends to fines production and migration. Since gamma ray and spontaneous potential logs were used for deriving these values, the average of both is listed in the evaluations.
- Reports of change in production behavior will also give hints of what happened downhole.
- The trajectory has also been correlated with the frequency of sucker-rod pump changes.
- Also the gravel pack has been analyzed; installation time, gravel size, treatments with gravel pack inside, etc. are some important parameters.

The production scenarios are basically divided into two parts, the collection of facts, meaning any irregularity, and the assumptions, what might have happened, based on the facts. Furthermore they show, if the treatment was really necessary.

2.6 Evaluation of Formation Damage of Selected Wells and Stimulation Performance

All the charts can be found in appendix A. The following chapter will summarize the available data and failures and make assumptions and conclusions about what might have happened downhole.

It has to be mentioned that not all distinctive points in the charts can be explained, due to a lack in the documentation.

The chart below shows the results of Chavez´ work [1]. The table includes the comparisons of injectivity and productivity indices of the acid treatments. Furthermore it distinguishes between bullheaded or circulated out kill fluid and also, if ABF was used for the acid stimulation.

The first two columns show the ratio of the injectivity indices and the productivity indices before and after the acid treatment. The four next columns mark, if the IIs and the PIs have improved or deteriorated. The last three indicate, what happened with the kill fluid and if hydrofluoric acid was used for the job or not.

	II_E/II_I	PI_E/PI_I	II impr. / PI impr.	II impr. / PI deterior.	II deterior. / PI impr.	II deterior. / PI deterior.	KILL FLUID bull-headed	KILL FLUID circulated out	ABF used
no ICGP									
A015-208-S 111	64,7							x	x
A015-208-S 133	13,7	6,1	x					x	x
A015-208-S 256	1,8	3,8	x				x		x
A015-209-MA C 2	0,6	1,6			x		x		x
A015-209-MA F 6	3,6	319,2	x					x	x
A015-209-S 28	5,0						x		x
A015-216-Ma 268	1,8	1,6	x				x		
A015-800-P T 4	1,0							x	
A015-800-S T 64	927,0							x	
A015-800-S T 78	6,1	7,7	x					x	
A015-800-S T 90a	48,5							x	
A015-800-S T 31	81,2							x	
A017-107-PIR 15	2,1	0,5		x			x		x
A017-107-PIR 24	62,1	0,5		x			x		x
A017-107-PIR 79	1,2	3,9	x				x		x
ICGP									
A015-209-S 179	0,9	1,7			x			x	x
A015-216-BO 49	0,4	14,9			x		x		x
A015-216-BO 98	7,9	13,0	x					x	x
A015-216-MA 56 (96)	3,2						x		x
A015-216-MA 56 (02)	28,5	2,1	x					x	x
A015-216-MA 84b	1,1	2,7	x				x		x
A016-111-HL 13Y	1,1	11,0	x					x	x
A016-111-HL 13Y	0,8	0,5				x	x		x
A016-111-HL 13Y	0,8	11,0			x			x	
A016-111-HL 31	1,7	6,0	x					x	x
A016-111-HL 31	1,6	0,5		x			x		x
A016-205-HL 25	3,9	7,9	x					x	
A016-205-HL 71	1,8	69,5	x				x		x

Figure 3: Productivity and Injectivity Indices for acid treatments [1]

2.6.1 Pirawarth 015 (no ICGP):

Facts:

A017/107/10 shows an average carbonate amount of 15%, the well logs indicate an overall shale content of 53% and a low heterogeneity.

After perforating a higher interval the oil rate declined to a very low level. An acid stimulation of the ICGP improved the rate. A change of the gas lift valve, which was abraded and the demounting of the gravel pack resulted in zero oil production.

An acid stimulation afterwards with 4.5% ABF in the main treatment did not succeed. The maximum occurring pressure gradient was 0.17 bar/m.

Assumptions and Conclusions:

Though the problem must have obviously something to do with the change of the gas lift valves, it can not be declared, which kind of damage existed. The only sign, that sand might have been a problem is the abraded valve, but no further indications for this were listed in the reports.

2.6.2 Pirawarth 024 (no ICGP):

Facts:

A017/107/20 shows an average carbonate amount of 15%, the well logs show sandy shale (55% clay content) and a medium heterogeneity.

The lifting of the production interval resulted in a high initial oil and low water production; the oil rate decreased rapidly and an acid stimulation was executed with 4.5% ABF in the main treatment after a pressure build up measurement (indicating high skin). The result was more than a doubling of the water cut.

Assumptions and Conclusions:

Since after the acid treatment the production rate and the PI decreased and the water cut increased, the stimulation can not be handled as successful. The stimulation obviously was selective to the water strata.

2.6.3 Pirawarth 079 (ICGP):

Facts:

A017/107/20 shows an average carbonate amount of 15%, the well logs show shaly sand (31% total shale amount) and a high heterogeneity.

After increasing the flow rate of the intermittent gas lift well, the production declined very fast to zero. An acid stimulation with 4.5% ABF in the main treatment could put the well back on production. There, a maximal pressure gradient of 0.19 bar/m was reached. A further increase in flow rate again resulted in increase in GOR and rapid decrease of oil production.

An analysis of the gravel pack, which was removed during exchange to a different artificial lifting system, showed a deformed and tight pack.

Assumptions and Conclusions:

The increase in production caused an increased pressure drop downhole, which may have led to dissolution of CO_2 out of the reservoir fluid and therefore plugging of the gravel pack with calcite.

The compaction of the pack could have also been caused by fines from the formation, created by either that high pressure drop or by a previous treatment, e.g. the stimulation, where the pressure gradient was quite high.

No analysis of ICGP was performed for further details.

2.6.4 Hochleiten 013Y (ICGP):

Facts:

The sandstone (A016/111/10) has a relatively high amount of carbonates (26%); the total amount of shale (16%) and heterogeneity are moderate.

After installation of the gravel pack (filtered 2% KCl was used and 23m³ of it was lost to the formation) and the first acidizing of this interval (with 4.5% ABF in the main treatment, but without any incidents) the production rate declined normally.

It was tried to increase the rate several times and shortly afterwards, the pumping string needed to be replaced.

Right after the last pump change, the production rate declined rapidly and two more acid stimulations were performed, one again with 9.6% ABF in the main treatment, without success. During the first stimulation 15m³ of hot water were used to wash deposits in the annulus away.

The production rate normalized after changing the pump once more, where a high amount of sand was identified.

Assumptions and Conclusions:

The very frequent change of the string and the pump leads to the assumption that the gravel pack was not able to solve the sand problem. The second and the third acid stimulations were not necessarily useful, because the last workover showed sand accumulation in the downhole pump.

Besides the very first treatment, no indications of the quality of the used fluids were given, no composition and no filtration details. Also the hot water for the tubing cleaning job could be any, next, it is not very desired to wash deposits down to the perforations, because of secondary plugging.

2.6.5 Hochleiten 031 (ICGP):

Facts:

For the horizon A016/111/10 about 26% carbonates were identified. The well logs shows a sandy shale (total shale amount is 58%) and a moderate heterogeneity.

The first acid stimulation after perforation of the current production interval (and placement of an ICGP) was successfully executed with 4.5% ABF in the main treatment. A further steady production decline and slight increase in water cut and GOR followed, until a further acid stimulation was performed, again with 4.5% ABF. All the fluids were squeezed in the formation and the production was increased for some month, also the GOR increased more rapidly after the second acid stimulation.

Assumptions and Conclusions:

This well shows a normal plugging of the near wellbore zone with fines, and precipitations. Also the ICGP was in place for approximately ten years; during this time, it was stimulated twice, which may have impaired it.

2.6.6 Hochleiten 025 (OHGP):

Facts:

No mineralogical data are available for this horizon (A016/205/10), but the logs show a high amount of shale (51%) and a moderate heterogeneity.

The open hole gravel pack is inside the borehole since 1982.

Until January 1999 the production rate was increased twice, the second time was a four fold increase in GOR recognized and the productivity indices decreased. Afterwards the well shows a normal decline in oil production and the respective increase in water and gas production. Pump respectively pump string changes were necessary every two to three years on average. A matrix acid stimulation was performed together with one pump change, which resulted in an eight fold production and five fold PI increase for around one and a half year.

Assumptions and Conclusions:

Obviously the acid stimulation was successful. Aside from this it seems that a kind of multiphase flow, due to the steady increase of GOR, mobilized some fines from the reservoir in early in the observed interval.

It can be seen that a critical rate was exceeded with the second increase of the rate, because GOR increased extremely, the higher production declined and also the PIs.

2.6.7 Hochleiten 071 (ICGP):

Facts:

No mineralogical data are available for this horizon (A016/205/11), but the logs indicate nice sand (13% clay content) with low heterogeneity.

Due to increased occurrence of sediments while swabbing after initial perforation, a gravel pack was inserted in the casing. The typical production decrease after gravel packing was the trigger for an acidizing job, performed with 4.5% ABF in the main treatment, without any special events.

The production and the PIs stay nearly constant with a small increase in water cut, but an increase in the rate in August 2006 resulted in a high GOR increase and rate and PI decline.

Assumptions and Conclusions:

The acid stimulation resulted in a strong increase in PI and also in production rate; hence the stimulation should be handled as successful.

The gravel pack is downhole since 1999. With the strong increase in GOR, it is assumed, that the lower part is plugged and the upper one tends to gas coning. A cleaning of the pack with an acid stimulation should be tried.

2.6.8 Schoenkirchen 111 (ICGP):

Facts:

The sandstone horizon A015/208/10 shows a high amount of carbonate (29%) and the well logs identify a high amount of total shale (68%) with moderate heterogeneity.

The initial sand problem was eliminated with installation of an inside casing gravel (ICGP) pack during closing the lower part of the old production interval. It was tried to circulate out the sand with 35m³ hydroxyethylcellulose solution, but the HEC was lost to the formation.

The stimulation was performed with 3% ABF in the main treatment and a pressure gradient of 0.19bar/m was reached (the pressure, flow rate profile showed a 65 fold increase of the injectivity). On the well bottom plenty of sand was found and circulated out; afterwards an ICGP was installed with around 200m³ of 2%KCl losses (no sign for filtration).

The production was kept at a low, but constant level for years. Then the clay was tried to stabilize and after disappointment a further acidizing job with 3% HF was performed, which also didn't succeed. During liquidation operations, the gravel pack was visually analysed to be okay.

Assumptions and Conclusions:

The very high pressure gradient during the first treatment and the enormous increase of injectivity lead to the conclusion that a fracture possibly has been created during the workover. A further indicator is the high amount of sand recognized in the wellbore. The gravel pack may have prevented the formation from further collapse.

This acid stimulation can certainly not be compared with any other, because simultaneously some parts of the production interval were shut off, an ICGP was installed and the stimulation was performed.

But there is also no real sign for a formation damage afterwards, or what might have been the reason for the stabilizing treatment, which basically initiated the decrease in production.

2.6.9 Schoenkirchen 133 (no ICGP):

Facts:

The mineralogical analysis of this horizon (A015/208/10) shows a high carbonate (29%) and the logs a significant total shale (44%) amount and moderate heterogeneity.

The well did not show any extreme variations in production behaviour and also the workovers did not show any oddity (minor fluid losses) until the acid stimulation and the change of the pump. This caused the production to almost double for a short time then declining rapidly to nearly zero and the GOR to increase extremely. ABF was used in the main treatment and the pressure gradient was calculated to 0.17bar/m. Some acid was swabbed back afterwards.

Before liquidation of the well, two further pump changes were made, both showed very high amounts of sand in the pump and on the well's bottom.

Assumptions and Conclusions:

Since the problems started with the stimulation, it is assumed that the lower part of the perforation was plugged with either fines from the formation (heterogeneity), precipitation of calcium fluoride or collapse of the sandstone. Due to the occurrence of high amounts of sand at the well bottom and in the pump, the last one seems to be most realistic. It seems that the formation was not competent enough to withstand either the pumping pressure, swabbing or the acid recipe.

A gravel pack would certainly not have been wrong.

The PI displayed shortly after the stimulation cannot be seen as representative for the last production period, since the rate was declining rapidly to zero.

2.6.10 Schoenkirchen 256 (no ICGP):

Facts:

The mineralogical analysis of this horizon (A015/208/10) shows a high carbonate (29%) and the logs a total amount of shale of 37% and moderate heterogeneity.

Since perforation in the current production interval in 1994, sand has been a major problem. Therefore a series of pump and string changes were necessary, also sand needed to be removed from the well bottom, once even with hydroxyethylcellulose solution. Abraded protectors and corrosion holes were always recognized.

The acid stimulation was simultaneously performed with a further pump change with 3% ABF in the main treatment without any recorded problems. The result was a strong increase in production rate, also in PI, the GOR normalized and the watercut nearly doubled.

Assumptions and Conclusions:

It was necessary to replace the pump very often and sand at the bottom was noticed.

A gravel pack might have been an additional solution to the acidizing job, which obviously stimulated the water horizon in a high degree. It is assumed, that no damage in sense of this thesis occurred.

2.6.11 Matzen C 002 (no ICGP):

Facts:

A015/209/91 shows high content of carbonate (29%) and the logs indicate high amount of total shale (58%) with a moderate heterogeneity.

After perforation in the current interval the GOR peaked out and the PI reduced to a very low level. Therefore an acid stimulation was performed with ABF in the main treatment, resulting in slight increase of oil production and a lower, but still high level of GOR.

Afterwards the lifting system was changed to intermittent gas lift and a production increase was recognized, but the reports do not show anything else than the basic workflow.

Assumptions and Conclusions:

It seems that the acid treatment stabilized the gas production, but it seems not to have been successful, perhaps due to the high amount of carbonates in the reservoir rock.

The little information in the reports only told that abrasion was a problem, which may signify that sand from the formation was released.

2.6.12 Matzen F 006 (no ICGP):

Facts:

A015/209/91 shows a high amount of carbonate (29%) and the logs indicate 21% of total shale (shaly sand) and low heterogeneity.

After a long production time at very low oil rate (~30t/month) the pump was changed and an acid stimulation was done within the same workover. The stimulation was quite extensive, because a series of stages were pumped, one with 4.5% ABF. Around 10m³ of stimulation fluid were swabbed back; the rest was squeezed in the formation. The whole treatment resulted in a nearly four fold increase in injectivity without any oddities. Afterwards it was observed that the gross rate was initially nearly ten times higher, declining very fast, but with a water cut of almost 100%.

Assumptions and Conclusions:

Since only high fluid losses were observed in the one treatment, it is nearly impossible to determine the damage. It may be possible that the water horizon was stimulated or that the fluid loss caused a water bloc.

2.6.13 Schoenkirchen 028 (no ICGP):

Facts:

The amount of carbonate in the sandstone horizon A015/209/91 is high (29%). Logs furthermore show a high total shale concentration (57%) and a high heterogeneity.

Before the well was lowered from the 8.Th in the 9.Th the rate was increased, with the result of high GOR and shortly afterwards the well was killed. During this workover fluid losses were recognized (40m³). An acidizing job, performed directly after did not success, although no sign for problems was listed, but only water was produced.

A higher interval was perforated and the lower cemented, during that job 110m³ filtered 2% KCl was lost to the older interval and 10m³ to the newer one. Some pump changes later on indicated corrosion holes at the tubing and sand at the well bottom.

Assumptions and Conclusions:

Like a series of wells before, it seems that the increase in rate exceeded a critical value, which is confirmed by the fact, that the well was killed shortly afterwards and a high increase in GOR. This may have led to a total collapse of this interval, therefore this stimulation could have never have become successful.

2.6.14 Schoenkirchen 179 (ICGP):

Facts:

The amount of carbonate in the sandstone horizon A015/209/91 is high (29%). Logs furthermore show a high total shale concentration (43%) and a high heterogeneity.

The very first workover consisted of three treatments: installation of an ICGP, acid stimulation and changing the downhole pump. The acidizing job was performed with 4.5% ABF in the main treatment, the injectivity staid nearly constant and the pressure gradient was inconspicuous.

The production declined over the next four years in a normal way, also the PI did. Then the sucker rod was exchanged to a PCP and the gravel pack was dismounted. Major sand problems occurred and high fluid losses were noticed (50m³).

A production attempt and a stimulation did only result in fluid losses in the order of 75m³ to the formation.

Assumptions and Conclusions:

It seems possible that the acid stimulation disrupted the stability of the formation and the gravel pack hindered further invasion of sand in the borehole and pulling out the pump and the gravel pack caused the extreme sand inflow and collapse of the interval.

2.6.15 Matzen 056 (ICGP):

Facts:

The amount of carbonate in the sandstone horizon A015/216/10 is around 10%, the total amount of shale is low (10%) and the heterogeneity is also low.

Until perforation in the current production interval, a series of treatments (placement of ICGP, acid stimulations, etc.) showed very high losses to the formation and major sand problems (even after ICGP placement).

The first acidizing job in this interval, performed with 4.5% ABF resulted in a three fold injectivity increase and a higher production. A new ICGP with 20/40 mesh needed stimulation shortly after placement, again carried out with 4.5% ABF in the main treatment. Each treatment lost a high amount of fluid to the formation (in sum: around 350 m³) and during each treatment sand from the well bottom was circulated out.

Assumptions and Conclusions:

Both stimulations certainly performed well in cleaning the gravel pack, but since it plugged quite fast, it seems possible that a 20/40 mesh is not the best solution for this well.

Although a high fluid loss could once be observed, no signs for a water bloc were found.

Due to irregular production behaviour, caused by undescribed shut ins, it is difficult to identify any further formation problems.

2.6.16 Matzen 084b (ICGP):

Facts:

The amount of carbonate in the sandstone horizon A015/216/10 is around 10%, the total amount of shale is low (11%) and the heterogeneity is also low.

After deepening the sidetrack and installation of an ICGP (30/50 mesh), due to sand in the well bottom during the previous workovers, the production declined normally. An acid stimulation executed five years later with 4.5% ABF in the main treatment resulted in more than doubling of the production. The calculated pressure gradient was 0.27 bar/m, no problems were listed.

Assumptions and Conclusions:

It seems that the ICGP plugged over the time with fines and sand from the formation and the acid stimulation solved the problem, as it should. The very high maximum pressure gradient could also be the result of wrong recording of the data.

From the standpoint of this thesis, this acidizing job was a success.

2.6.17 Matzen 268:

Facts:

A015/216/10 shows quite a low amount of carbonate (10%), a total shale amount of 32% and a moderate heterogeneity.

Due to an extreme water cut of 98-99% it was tried to block the water influx. The acid stimulation before this treatment had the aim to increase the injectivity of sodium silicate.

Therefore this is not an acid stimulation in sense of the thesis.

2.6.18 Bockfliess 049 (ICGP):

Facts:

A015/216/20 shows an amount of carbonate of around 10%, the well logs indicate a total amount of shale of approximately 13% and a low heterogeneity.

Due to extreme water cut the production interval was lifted and an ICGP with 20/40 mesh gravel was placed. The production declined very fast. Therefore an acid stimulation with 4.5% ABF in the main treatment was performed. To wash the gravel pack, the acid was swabbed back without any problems.

The production rate is afterward declining with a normal trend and six years after the stimulation at a level like before.

Assumptions and Conclusions:

Obviously the stimulation was the correct treatment; the damage was therefore with a high certainty in the gravel pack, but the origin can only be assumed. Plugging would have been too fast to come from the formation, since afterwards it shows no sign for it.

2.6.19 Bockfliess 098:

Facts:

A015/216/20 shows an amount of carbonate around 10%, the well logs indicate a total amount of shale of approximately 27% and a low heterogeneity.

Similar to Bo 049, a higher interval was perforated and an ICGP (20/40 mesh) was inserted. During this treatment around 50m³ fluid were lost to the formation.

The production declined and an acid stimulation was executed with 4.5% ABF in the main treatment; half of the acid mixture was swabbed back. The oil production increased five times and the GOR was reduced.

Assumptions and Conclusions:

Like Bo 049 the damage was very probably in the gravel pack and could be reduced with this acidizing job. Also, it stabilized gas production. The stimulation was a success in terms of this thesis.

2.6.20 Schoenkirchen Tief 031 (no ICGP):

Facts:

S T 031 is in A015/800/10, which is a dolomite horizon.

Since both acid stimulations were performed together with raising of the production interval the performance of the acid treatments itself is unclear.

2.6.21 Schoenkirchen Tief 064 (no ICGP):

Facts:

S T 064 is in A015/800/10, which is a dolomite horizon.

The acid stimulation was executed simultaneously with the perforation in a higher interval, therefore no evidence of damage or performance of the acidizing job is evident.

2.6.22 Schoenkirchen Tief 078 (no ICGP):

Facts:

S T 078 is in A015/800/10, which is a dolomite horizon.

A sucker rod pump was installed after raising the current production interval. Shortly afterwards, an acid stimulation was performed with 15% HCl. While swabbing the acid out of the borehole, paraffin deposits in the string were observed. The acid stimulation resulted in an increase of oil production.

It was necessary to change the pump three times; each time hot water was used to clean the string. Each time the production decreased, the last time even severely.

Assumptions and Conclusions:

Paraffinic deposits were pumped down to the perforations over and over again, where they plugged the formation bit by bit. Although this assumed damage has nothing to do with the previous acid treatment, it is important to mention. The stimulation itself was certainly necessary.

2.6.23 Schoenkirchen Tief 090a (no ICGP):

Facts:

S T 090a is in A015/800/10, which is a dolomite horizon.

The perforation was done overbalanced to raise the production interval to the current one. No stimulation was performed afterwards.

The acid stimulation six years later resulted in an oil production increase, but also in quite a fast rise of the water cut from zero to significant values.

A further rising of the production interval resulted only in gas production.

Assumptions and Conclusions:

Apparently, the acid treatment stimulated mostly the water interval below, an oil sweeping additive, like musol, may have prevented this.

2.6.24 Prottes Tief 004 (no ICGP):

Facts:

P T 004 is in A015/800/12, which is a dolomite horizon.

After installation of a sucker rod pump, where paraffin deposits were recognized in the string, additional perforations were shot and an acid stimulation was performed within the same workover.

Therefore this acid stimulation is inconclusive.

Two pump changes showed some minor losses of fluid to the formation and after cleaning the string with hot water, the oil production was reduced ten fold and the water cut doubled.

Assumptions and Conclusions:

Although the acid treatment can not be analysed, the latest most probable damage is plugging of the perforations with organic deposits by washing them down from the tubing string. They also may accumulate in the tubing string.

2.7 Summary, Conclusion and Ideas for Improvement

- Basically, the documentation must be improved and standardized in some way. There are generally very little hints, which fluid quality was used for the treatments, if it was filtered or not, which concentrations or the type of viscous pill and the breaker were used.
- Some kind of quality control for the reports and consistent vocabulary are desired.
- A series of preselected wells do not meet the original requirements, that the stimulation has to be the only treatment to be able to compare the acidizing jobs. This fact again reduced the amount of possible evaluations.
- *Increasing the gross rate* resulted in the majority of cases in a strong increase in GOR and a complete killing of the well. They also had afterwards a high tendency to sand problems. For example Pirawarth 15 and 79, Hochleiten 25 and 71 and Schoenkirchen 28 showed this behaviour clearly.

  Two wells (namely Schoenkirchen 256 and Prottes Tief 4) only showed an increase in watercut after increasing the gross rate.

  Only one increase in gross rate (the first increase of Hochleiten 25) did not result in such an observation.

  Therefore it is assumed that some critical rate was reached or even exceeded.

- It is crucial to monitor the *pressure gradient* during treatments and compare it with the fracture pressure of the formation. Some treatments showed quite a high gradient. For example Pirawarth 79 and Schoenkirchen 111 and 133 had abrasion or sand problems afterwards.

  Only Matzen 84b showed a high maximum pressure gradient, but no such side actions.

- Washing *organic deposits*, like paraffin, down from the tubing string with hot water can plug the formation, this is the assumed damage for Schoenkirchen Tief 78.

- After some treatments, the *water cut or GOR increased* extremely, but the oil rate stayed constant. This was observed at Schoenkirchen 133, 256, Schoenkirchen Tief 31 and Matzen Flut 6 for example.

  It is recommended to sweep the oil away before acidizing, because the acids are water based and will tend to go where similar behaviour exists. The usage of diverters may also be a solution.

- It was observed that ABF in the main treatment in formations with a carbonate content of 10 to 15% resulted in success, like Matzen 84b, Bockfliess 49 and 98 showed for example.

  Although the literature proposes only to use hydrochloric acid for the very first treatment of a new production interval in formations with carbonate content of higher than 15%, it seems to have no influence, if the preflush is based on HCl and its volume is large enough.

- The reason for some acid stimulations can not be retraced, sometimes a *gravel pack* would have been a better solution, like for Schoenkirchen 28 or 133, which is of course also an economical question.

  Some showed sand problems even with gravel inserted, like Schoenkirchen 111, 179 or Matzen 56. The mesh size seems to be incorrect.

- No consistent correlation between *heterogeneity* or *overall shale content* and stimulation success could be read out, only some wells with higher heterogeneity, like Schoenkirchen 111, 133 or Hochleiten 13Y showed more sand problems afterwards.

  This analysis should be made more often, because only a few wells were available.

- High fluid losses could show an increase in watercut for the following wells: Matzen 56, 84b and Schoenkirchen 111. A water bloc, as reported in literature, could not been observed.

3. Real Time Evaluation of Treatments

3.1 Introduction

After deriving certain formulae for calculating the bottomhole pressure from the wellhead pressure (see below) as done by Chavez [1], a computer program was developed, which automatizes this process. It was only possible to check the usability of the formulae for one acid stimulation.

The aim of this chapter is to check the validity of the data calculated by the program by comparing it with results derived by hand calculation. Furthermore, these data are compared with memory gauge data recorded during the pumping job. Additionally, improvements for the methodology and for the program should be derived. Also some ideas how the observed acid stimulations performed should be figured out.

Basically, by adding the hydrostatic pressure to the pump pressure and subtracting the friction losses in the pipes, one can derive the bottomhole pressure during an acid injection job. The formulae therefore are:

$$p_{wf,inj} = p_{pump} + p_{hydr} - \Delta p_{friction}$$

where p_{pump} is the measured pump pressure in [bar]

p_{hydr} equals the hydrostatic pressure in [bar]

$\Delta p_{friction}$ is the total friction loss in the pipes [bar]

$$p_{hydr} = \rho \cdot g \cdot h$$

where ρ is the density of the liquid column in [kg/m³]

g is the gravitational force of the earth in [m/s²]

h is the height of the liquid column [m]

$$\Delta p_{friction} = \frac{C \cdot \rho^{0,75} \cdot q_{inj}^{1,75} \cdot \mu^{0,25} \cdot h}{d^{4,75}}$$

where C is the conversion factor from field units to metric units equals to $1.04875 \cdot 10^{-3}$, because this formula was originally derived for field units.

ρ is the density of the liquid column in [kg/m³]

q_{inj} is the injection rate of the fluids in [l/min]

μ is the viscosity of the injected liquids in [cP]

h is the height of the liquid column [m]

d is the pipe's diameter in [cm]

The complete derivation of the formulae and more details can be found in Chavez' Master Thesis [1].

3.2 Workflow for Formulae and Program Verification

A detailed workflow for the program will not be presented, because this tool is still under development, and inputs, choices, etc. may not be valid in a later version of it.

By the end of the last master thesis only two more stimulations had been performed with a memory gauge installed downhole. During one of these treatments the wellhead pressure was recorded with a pressure measurement and data unit (SPIDR). The validation is based on the evaluation of this available information.

A series of surface measurements, like online pressure and flow rate recordings for acid stimulations were performed, these are analyzed for success or failure.

3.2.1 Idea for Improvement

The current bottom hole calculation is based on the surface pump pressure, although the appropriate input for the correlation ought to be the well head flowing pressure. To account for the fact that there are friction pressure losses in the surface pipe lines, the calculation methodology may be extended to include also these surface lines. Usually they have a length of some ten to thirty meters including various knees and bends.

Since the friction formula has also to be valid for such lines, most critical conditions are high injection rates, high lengths and small pipe diameters. Further knees and bends can be calculated according to the equivalent length concept and simply increase the length parameter in the formula.

3.2.2 Bockfliess 082

General Information

Bo 082 initially was a producer, which should be converted to an injector for a better sweeping of the oil in the 16.Th. Therefore from 1614 to 1652.6 m the casing was milled away to a 9” open hole. To improve the injectivity of the 38.6m opened interval, an acid stimulation with 37.5m³ of 15% HCl, 2% citric acid, 0.5% Cronox and 0.3% Sapogenat T139 was performed. The memory gauge was installed at 1500m depth.

Before the treatment started, the well was completely filled half a day before.

The pump pressures and flow rates were recorded online and the newly developed program was used to represent the acid stimulation (figure 4 below). The results of this action, the manual calculation using excel and the memory gauge data were then plotted in a separate chart for comparison. (figure 5).

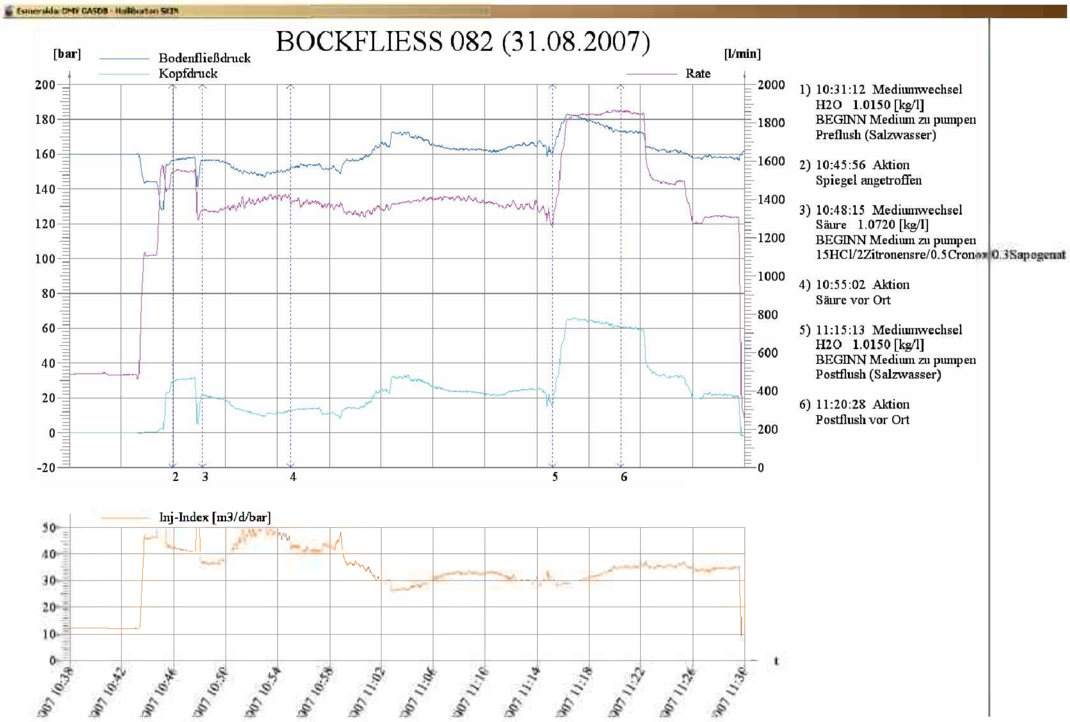

Figure 4: representation of the acid stimulation of Bo 082

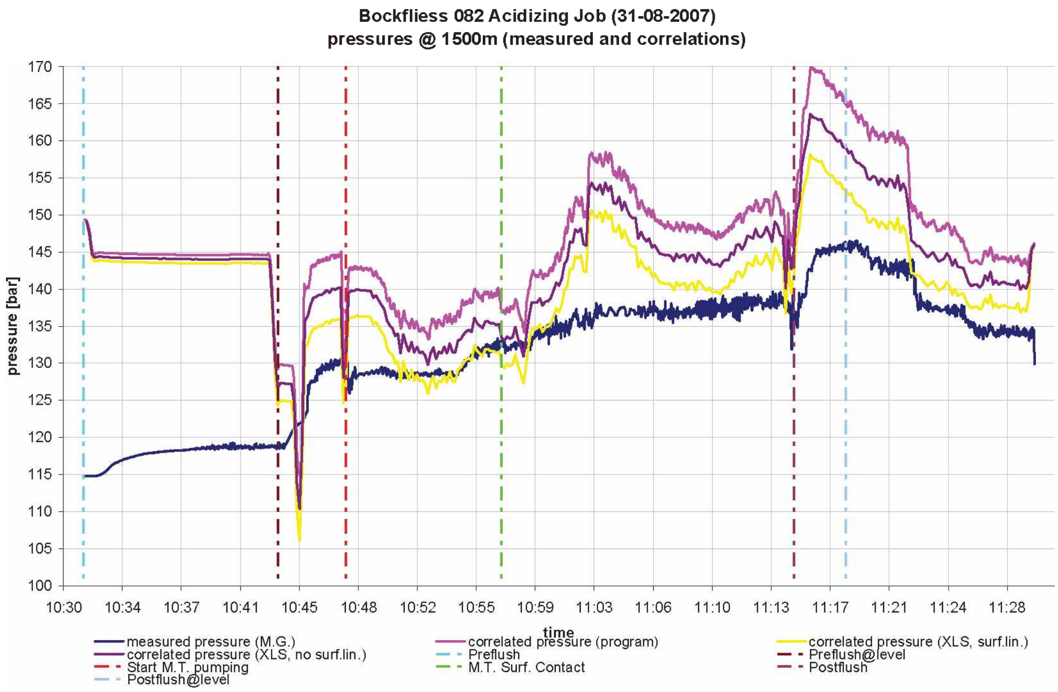

Figure 5: comparison of different calculations

Results and Conclusions

Given that a high amount of flooding water did not cause any pressure increase, the initial injectivity is high. During the treatment the injectivity index falls from nearly 50 m³/bar/day to 35 m³/bar/day, around 30%. This shows that the treatment did certainly not result in a success; the treatment caused more damage. As an assumption improper flooding water might have been one reason.

An injectivity test prior to the acid stimulation with pure, filtered flooding water might have shown that the injectivity is high enough and the acid treatment would not have been necessary at all.

The comparison of the single pressure data shows that the program's calculation and the manual calculation nearly match with a small shift, which is almost constant. This shift can be explained by the fact, that the program ignored the 9" under reamed open hole section, but in manual calculation it was considered A correlation between the pressures calculated by the program and by hand versus flowrate is shown on the figure 6 below, but although the differences are generally minor, no correlation can be read out (determination coefficient: $r^2=0.55$).

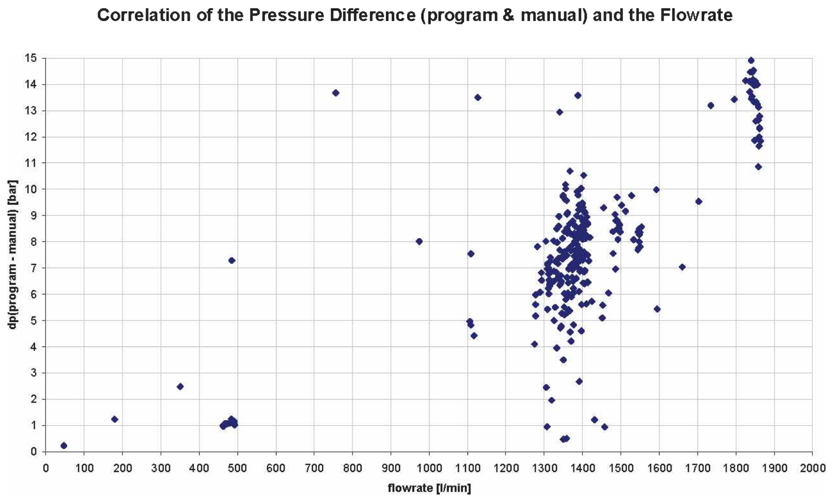

Figure 6: Correlation of pressure difference (calc.-MG) and flowrate of Bo82

The memory gauge data (blue line in the figure 5) do not show any similarity with any of the two lines. A test of the memory gauge performed later did not show any malfunction, but obviously, these data can not be used for verification. It was tried to find any correlation between the difference of the pressures recorded by the memory gauge and the ones calculated by the program and the flow rate (see figure 7 below), but none could be identified (coefficient of determination: $r^2=0.36$).

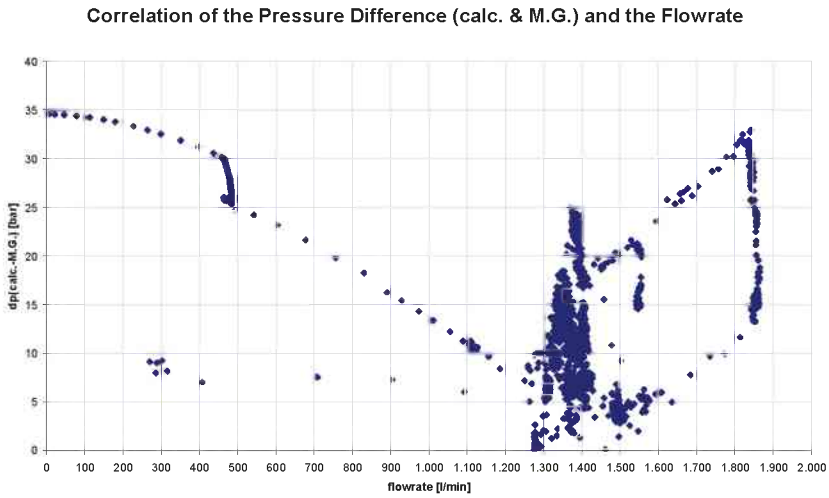

Figure 7: Correlation of pressure difference (calc.-MG) and flowrate of Bo82

One explanation for the small shift between the program's line and the manual calculation can be the pressure loss in the surface lines. During the treatment two ten meter lines with an inner diameter of 2" were used from the pump to the wellhead, which consisted of one 90° pipe elbows each.

Using the mentioned equivalent length concept with a multiplication factor for the 90° pipe elbows of 30 results in:

$$\frac{L_{equ}}{D} = 30 \quad \Rightarrow \quad L_{equ} = 30 \cdot (2'' \cdot 0.0254) \cdot 2 = 3.048 \approx 3m$$

additional pipe length for friction pressure loss calculation. Therefore the maximum additional pressure drop, which was neglected till now is:

$$\Delta p_{fric,surface} = \frac{C \cdot \rho^{0.75} \cdot q_{inj}^{1.75} \cdot \mu^{0.25} \cdot l}{d^{4.75}}$$

$$= \frac{0.00104875 \cdot 1.073^{0.75} \cdot 1800^{1.75} \cdot 1.258^{0.25} \cdot (20+3)}{(2 \cdot 2{,}54)^{4.75}} = 6 \quad bar$$

The most important factors for this concept can be found in the figure 8 below:

Globe valves, fully open	450	90" standard elbow	30
Angle valves, fully open	200	45" standard elbow	16
Gate valves, fully open	13	90" long-radius elbow	20
3/4 open	35	90" street elbow	50
1/2 open	160	45" street elbow	26
1/4 open	900	Standard tee:	
Swing check valves, fully open	135	Flow through run	20
In line, ball check valves, fully open	150	Flow through branch	60
Butterfly valves, 6 in. and larger, fully open	200		

Figure 8: Equivalent length to diameters coefficients for valves and fittings [4]

3.2.3 Schoenkirchen Tief 007

General Information

ST7 is located in the horizon 323 and the stimulated interval is between 2767 and 2805 m; in sum there are 16 m of open perforations.

The stimulation was performed with 17m³ of 15% HCl, 2% citric acid, 0.5% Cronox and 10% Musol. Afterwards, 8.2m³ flooding water were injected for displacement.

A memory gauge was installed at 2754 m depth and a SPIDR on the wellhead to validate the idea of friction pressure drop calculation in the surface lines.

The pump pressure and the flow rates were measured and recorded directly at the pump.

The resulting chart is printed below (figure 3), allowing identification of different interesting events during the treatment:

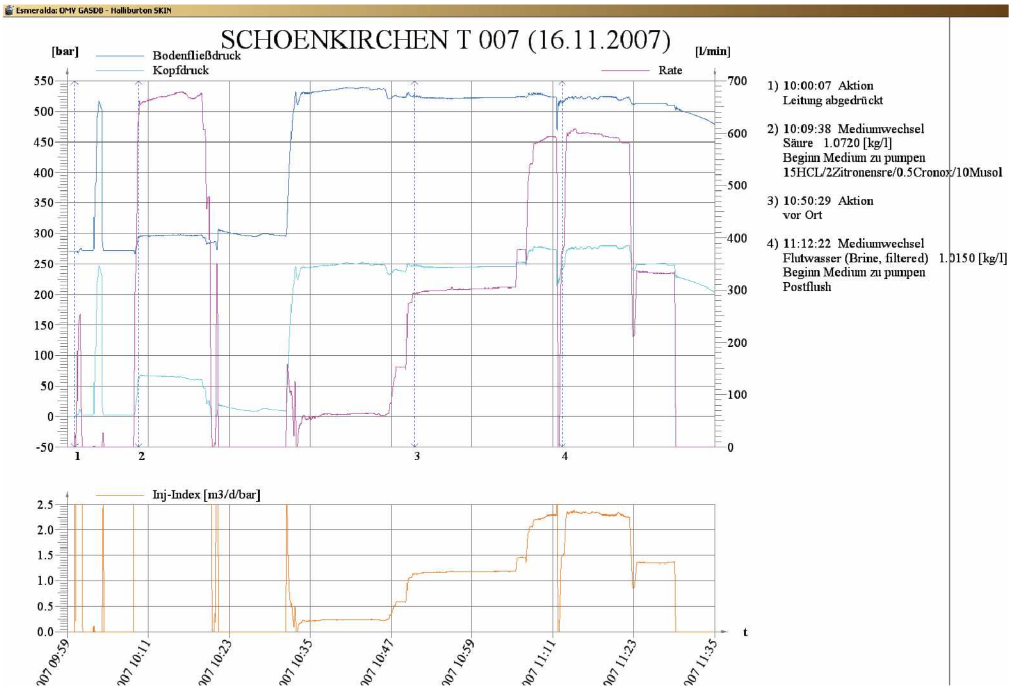

Figure 9: re-interpretation of acid stimulation of ST7

Interpretation of the Stimulation

Just when event 2 (change to main treatment) occurs, the flow rate increases rapidly, but the pressure remains low. This indicates that the well is not completely filled.

We know that the depth of the well is around 2750 meter. If we assume a conservative fracture pressure gradient of 0.18 bar/m, it will result in a fracture pressure of around 500 bars at this depth, which is exceeded during the treatment over a very long time.

The increasing flow rate and the constant pressure at the same time show us at event 3 (main treatment reservoir contact) either that the reaction takes place, or confirms the mentioned probability of fracture initiation.

A further confirmation for fracture creating is that the pressure did not fall off as smoothly as it should, when the reaction with the formation occurs.

If really a fracture was created, the acid did certainly not flow as initially assumed. Furthermore, the Injectivity Index calculation cannot be applied in a proper way.

Verification of the Formulae:

After plotting the pressures measured by the memory gauge and the computed ones, a time shift of 25 seconds was observed. A correction to the pump-clock was performed.

Comparison of memory gauge data with the correlations, computed by the program and calculated by hand with excel (see figure 4 below) shows only minor differences between the models.

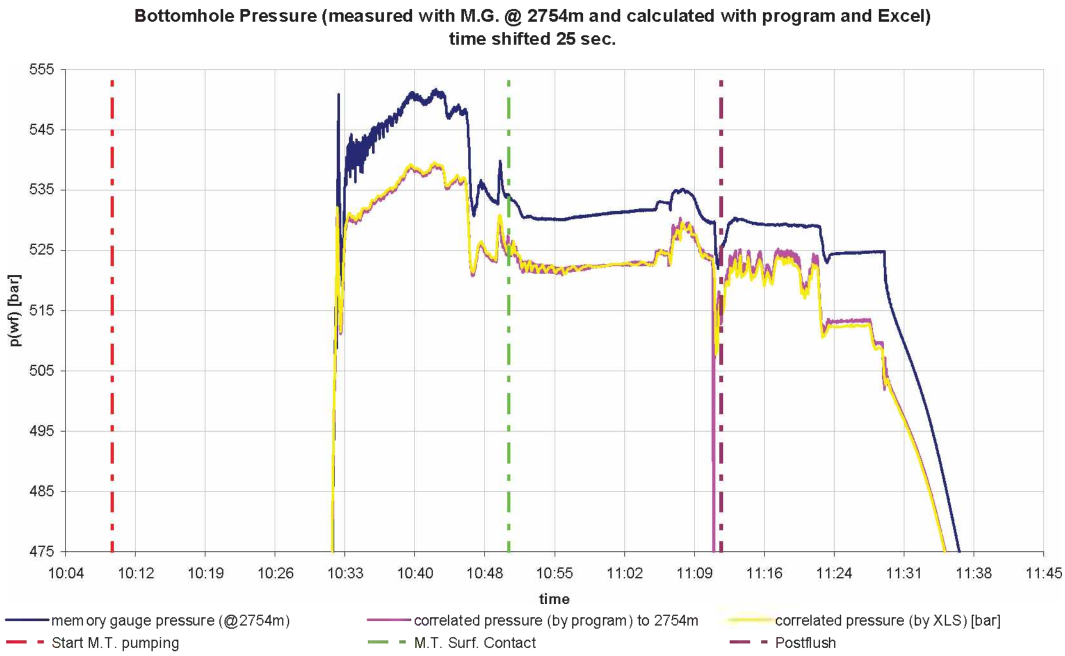

Figure 10: comparison of memory gauge data with correlations

The negligible differences between the program's correlation and the calculation by hand show that the program works correctly.

The shift of about ten bars to the memory gauge is also quite small and more or less constant over the treatment. This ensures that the formulae for the correlation are sufficiently accurate to define qualitative and quantitative success. Nevertheless it should be tried to explain this gap:

First it has to be mentioned that density and viscosity values for 20°C were used. Reservoir temperature is higher, in this case around 70°C. The graph below shows the influence of adapting the values to the higher temperature value.

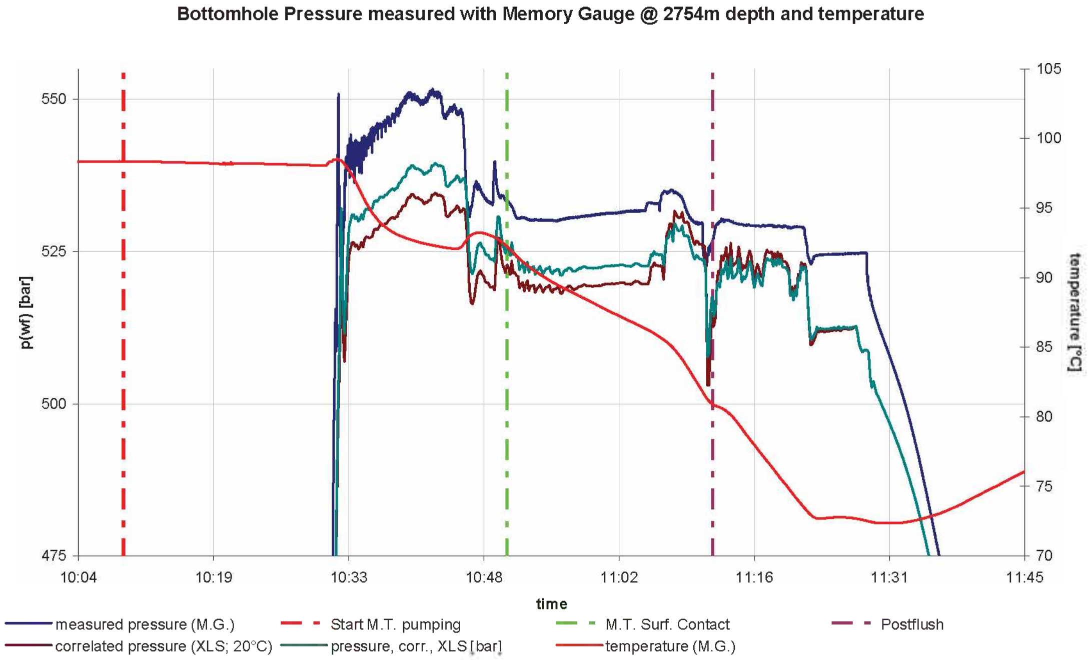

Figure 11: comparison of pressures with temperature effect

One recognizes that the temperature lowers the curve, which can be easily explained by looking at the formulae for friction pressure loss:

The value for density decreases only a little, but for viscosity exponentially with increasing temperature. If we multiply both factors with their respective exponents which are smaller than one, we see from the correlation, that the influence of friction becomes very small. The hydrostatic pressure on the other hand is calculated with a lower value for density.

Again, dependency of the pressure difference between the calculated values and the measured by the memory gauge to flowrate and temperature was tried to be proven with correlation charts (figures 12 and 13 below). No consistent correlation between any of the plots could be detected (best determination coefficient for flowrate: $r^2=0.03$ and for temperature: $r^2=0.065$)

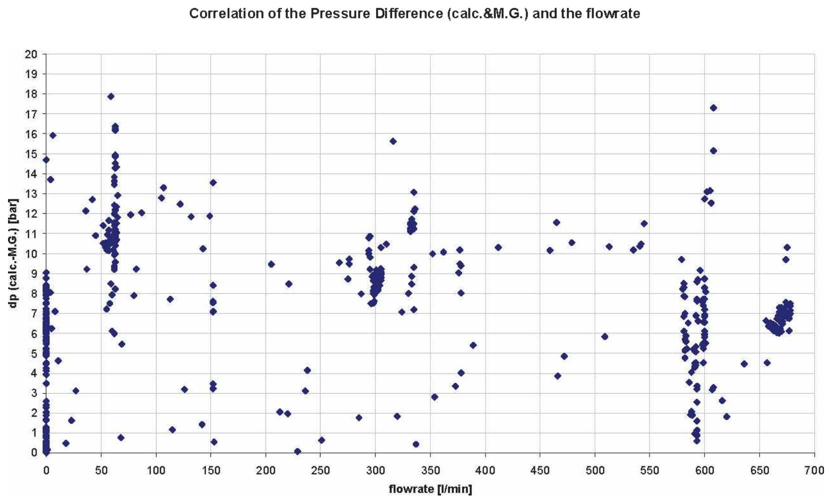

Figure 12: Correlation of pressure difference and flow rate of ST7

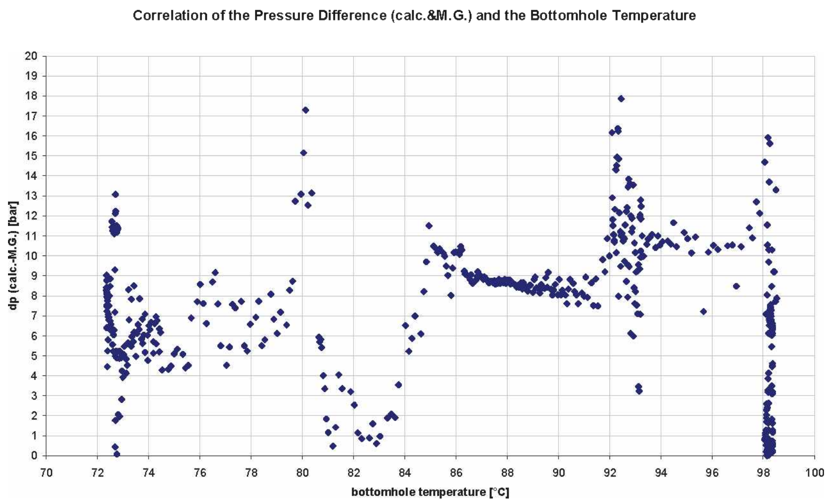

Figure 13: Correlation of pressure difference and temperature of ST7

Summing up assumptions to explain the discrepancies:

The friction pressure loss formula is only a simplified model

We assumed a uniform diameter for the tubing string and for the casing string, but in reality we have connections with a different diameter, rust, scales and so on inside the strings, which cause an unpredictable behavior.

The installed spider should show if the friction pressure loss in the surface lines is as high as the correlation tells. The surface lines normally consist of several meter lines and some 90° pipe elbows. The friction loss in the surface lines and the elbows is calculated with the equivalent length concept. During the acidizing job of the S T 7 one line was used from the pump to the wellhead, which consisted of four 90° pipe elbows and a sum of ten meter surface lines, with an inner diameter of 2”. The multiplication factor for the 30° pipe elbows is 30. Therefore the calculation for the maximum occurring pressure drop is the following:

$$\frac{L_{equ}}{D} = 30 \quad \Rightarrow \quad L_{equ} = 30 \cdot (2" \cdot 0.0254) \cdot 4 = 6.096 \approx 6m$$

additional pipe length for calculation

$$\Delta p_{fric,surface} = \frac{C \cdot \rho^{0.75} \cdot q_{inj}^{1.75} \cdot \mu^{0.25} \cdot l}{d^{4.75}}$$

$$= \frac{0{,}00104875 \cdot 1.073^{0.75} \cdot 600^{1.75} \cdot 1.258^{0.25} \cdot (10+6)}{(2 \cdot 2{,}54)^{4.75}} = 0.61 \quad \text{bar}$$

We see, that for this case, the influence of the surface pressure drop can be neglected, because of the resolution and the variance of the data of the SPIDR.

For proving the influence of the surface pressure loss, a shallower well, where higher pump rates can be applied and two surface lines should be used, because these two factors have the highest impact in the formulae, due to the exponents.

As can be seen on the next figure, the SPIDR had some measuring problems, because of the high differences between the pump and the wellhead pressure; there must be a malfunction of the tool.

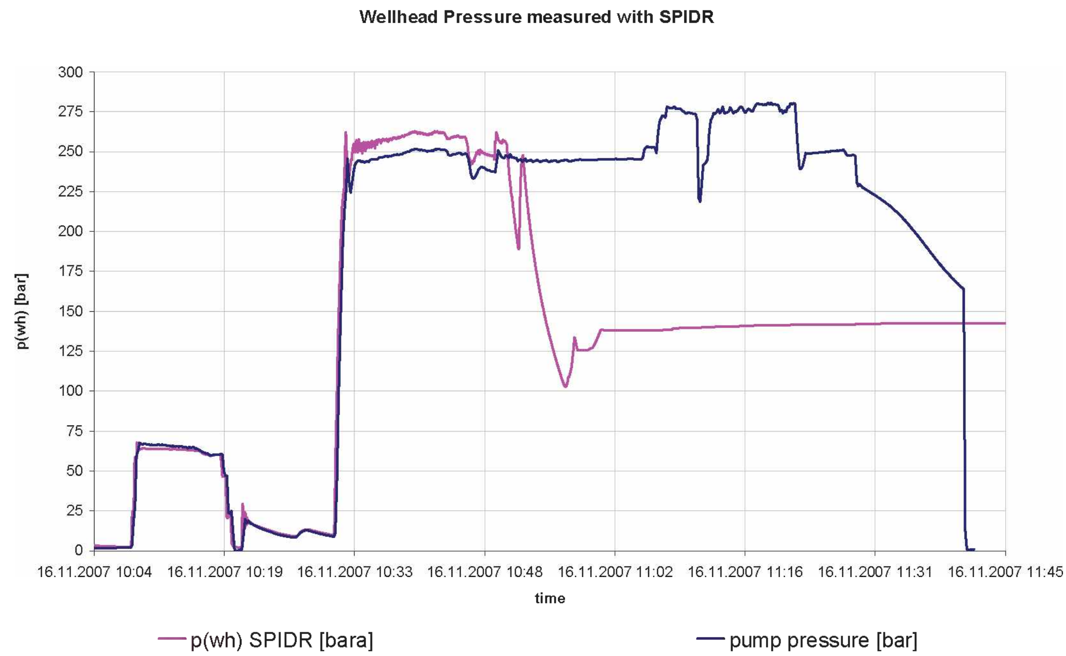

Figure 14: SPIDR data – measuring problems

Even if we neglect the data, where the gap between the pump pressure data and the SPIDR data was too large, the SPIDR showed earlier a higher pressure than the pump. Physically it is not possible that during an injection operation the wellhead pressure is higher than the pump pressure. Moreover, the small differences at the very first pressure increase cannot really be separated, because of the resolutions of the tools.

Summary, Conclusions and Recommendations:

- A variety of indications show that probably a fracture was created during the treatment due to high depth and pumping rates. Therefore it would not make sense to analyze the injectivity index, because the result would be inaccurate.
- Comparison of the correlations with the program and manually showed that the program works correctly.
- Comparison of the calculated bottom pressure with the memory gauge recordings shows that the used correlation is sufficiently accurate enough for this problem. It might look different for other wells.
- Comparison of the pump pressure with the wellhead pressure recorded by the SPIDR was not satisfactory. For further work, wells where high pump rates can be achieved should be used to better analyse the friction losses.

3.3 Analysis of further Stimulations Recorded Online

There were six more acid stimulations were the flow rate and the pump pressures were recorded online. All the corresponding charts, evaluated with the software, showing the bottomhole-, the wellhead pressure and the flow rate as well as the injectivity index are shown in the appendix B.

The table below shows a summary of how the single stages performed for the wells analyzed in this subchapter.

	Gravel Pack	Prod. / Inject.	II (first stage)	Stage 1					Stage 2				
				recipe	volume [m³]	p(pump) [bar]	flowrate [l/min]	II [m³/day/bar]	recipe	volume [m³]	p(pump) [bar]	flowrate [l/min]	II [m³/day/bar]
Schoenkirchen 249	none	Injector	5	15%HCl + 4% Citric Acid + 0.5%Cronox	8.8	109 --> 50	340 --> 500	10.2	flooding water	7.7	49 --> 57	500 --> 500	10 - 4 - 2
Matzen 174	none	Injector	12	15%HCl + 2% Citric Acid + 0.5%Cronox	36	60 --> 13	680 --> 950	17	flooding water	27	13 --> 50	950 --> 1200	16
Matzen 254	none	Injector	12	15%HCl + 2% Citric Acid + 0.5%Cronox	36	56 --> 51	1000 --> 1400	20	flooding water	27	51 --> 30	1400 --> 1000	20 - 17
Bockfliess 040	none	Injector	15	15%HCl + 2% Citric Acid + 0.5%Cronox	36	60 --> 10	1000 --> 1000	24	flooding water	27	100 --> 20	1150 --> 1150	30
Schoenkirchen Tief 041	none	Injector	25	flooding water	50	80 --> 0	1900 --> 870	32	15%HCl + 0.2% Acetic Acid + 0.5%Cronox + 0.3% Sapogenat	48	100 --> 60	1900 --> 1900	36 - 30
Matzen 473	OHGP	Producer	3.5	15%HCl + 10% Musol + 2% Citric Acid + 0.5%Cronox	9	70 --> 5.5	520 --> 340	3.8	flooding water	4.3	5.5 --> -1	340 --> 340	4.5

Figure 15: Injectivity changes with stages and recipes

II(first stage) means the injectivity, when the first stages enters the formation. The injectivity indices presented for stage one and two mean the maximum achieved value, except it falls significantly, there the steps are noted.

3.3.1 Schoenkirchen 249 (no ICGP)

Facts:

The stimulation was performed with nearly 9m³ 15% HCl, 4% citric acid and 0.5% Cronox and a postflush of further 9m³ flooding water. The perforations are from 1328m to 1332m depth in the 9th Tortonian and the aim of the stimulation was to increase the injectivity after re-completing the well to an injector.

The II-chart indicates an increase, corresponding to an increase in rate, but already during the main treatment, the II starts falling. The postflush shows a further decrease in injectivity.

Also the initial pump pressure is quite high at 100 bar, so that a bottomhole pressure of around 230 bars occur.

Assumptions and Conclusions:

Since this well was previously a producer, some oil will be left in the near wellbore region. Since no preflush with a surfactant, like musol, was used, the contact area of the acid is reduced.

It is also possible,that a fracture was created during the treatment, the pump pressure for this depth seems to be quite high, the maximum pressure gradient was 0.18 bar/m.

3.3.2 Matzen 174 (no ICGP)

Facts:

Ma174 is an injector and was stimulated in the 16th Tortonian to increase the intake of the well. The perforations between 1650m and 1660m depth were stimulated with 36m³ 15%HCl, 2% citric acid and 0.5% Cronox. 27m³ flooding water were used as a postflush.

The injectivity plot shows a steady increase from 7m³/bar/day to 17 m³/bar/day. The maximum pressure gradient was around 0.13 bar/m.

No other incident occurred.

Assumptions and Conclusions:

The treatment seems to be successful, because of strong increase of the injectivity index.

3.3.3 Matzen 254 (no ICGP)

Facts:

Ma254 is an injector and was stimulated in the 16th Tortonian to increase the injectivity of the well. 36m³ of 15% HCl, 2% citric acid and 0.5% Cronox were used to stimulate this horizon between 1661m and 1663m depth. Some 27m³ of flooding water were used for displacement.

The ratio between the initial injectivity index of 12 m³/bar/day and the final one of 16 m³/bar/day shows an increase of around 30%. Also the maximum pressure gradient is rather low, 0.12 bar/m.

Assumptions and Conclusions:

The treatment seems to be successful, because of increase of the injectivity index.

3.3.4 Bockfliess 040 (no ICGP)

Facts:

Bo40 is an injector and was stimulated in the 16th Tortonian to increase the injectivity. The perforations are between 1660m to 1674m depth and the stimulation was performed with 36m³ of 15% HCl, 2% citric acid and 0.5% Cronox. 27m³ flodding water as a postflush were used. The maximum occurring pressure gradient was 0.15 bar/m.

It was recognized, that the program cannot handle different tubing diameter, like in this well. Therefore one weighted diameter was calculated.

This stimulation shows a doubling in injectivity, namely from 15 m³/bar/day to 30 m³/bar/day.

Assumptions and Conclusions:

The treatment seems to be successful, because of increase of the injectivity index.

3.3.5 Schoenkirchen Tief 041 (no ICGP)

Facts:

The perforations in the Aderklaaer Conglomerate are between 1845m to 1865m. 50m³ flooding water were used as a preflush and 48m³ 15%HCl, 0.2% acetic acid, 0.5% Cronox and 0,3% Sapogenat were used to stimulate the horizon. Flooding medium was also used for final displacement.

The injectivity increases from initial 12 m³/bar/day to 36 m³/bar/day after the main treatment but falls to around 30 m³/bar/day after the postflush.

The maximum pressure gradient was 0.12 bar/m.

Assumptions and Conclusions:

It seems that the treatment was successful, although the II decreased afterwards slightly.

3.3.6 Matzen 473 (OHGP)

Facts:

The aim of the acidizing job of Ma473 was to stimulate the OHGP, because no flow at all was observed. Ma473 is perforated in the 11th Tortonian between 1418m and 1426m depth. The stimulation was performed with 9m³ 15% HCl, 10% Musol, 2% citric acid and 0.5% Cronox. 4.3m³ flooding water were finally pumped as a postflush.

The only observation is an increase in II from 3 m³/bar/day to 4.5 m³/bar/day.

Assumptions and Conclusions:

Although if the effect of injectivity increase is not outstanding, it is existing and the treatment should be handled as successful. But it has also to be mentioned that an increase in injectivity not necessarily results in an increase of productivity.

3.4 Conclusions and Recommendations

Concerning the program:

- The program does not consider friction pressure losses in surface lines, which can be quite high, if the pump rate is high, the diameter is small and a certain amount of knees are installed.
- The density and viscosity parameter used are for surface temperature. As the temperature in the wellbore is usually higher, an error is preassigned. However, values for higher temperature would only shift the correlation and a stepwise adjustment to higher temperatures would be too complex.
- The resulting chart should also show a critical fracture pressure, with a warning area. This will allow reducing the pump rate and therefore the bottomhole pressure, when recognizing, that this area is reached.
- Although it is still under development, it should be more flexible. In example, only one well type can be entered (constant tubing diameter, perforations and packer).

Concerning the validation of the formulae:

- The transient reservoir pressure behavior during injection for the II calculation should be included, because without this option the injectivity decline is always predicted by the formulae.
- It is shown that the program does a correct job in calculating the bottomhole pressure. The friction pressure formula can be applied also for pressure loss in surface lines.
- Nevertheless, some more validations with installed memory gauge and SPIDR should be performed at different types of wells (high/low flowrate, depth, etc.)

Concerning the evaluated acid treatments:

- It was recognized that a mutual solvent for sweeping the oil coating away is not often used. At least, if recompleting a producer to an injector this should be used.
- If a too high bottomhole pressure is chosen, the expectation in creating a fracture is increased.

4. Economics of Selected Treatments

4.1 Introduction

It is obvious that an acid stimulation should result in a production benefit to cover the costs for the treatment. Only a technical success can result in an economical success.

For comparing the economics of the preselected acid stimulations[1], the parameter “payout-time” was chosen, which is basically the time, when the additional oil production covers the expenditures of the stimulation treatment. Of course, the shorter the time, the more successful the treatment is.

Hence:

$$(q_{after} - q_{before}) \cdot t \cdot price_{oil} - costs_{treatment} = 0$$

Converting to t yields in:

$$t = \frac{costs_{treatment}}{(q_{after} - q_{before}) \cdot price_{oil}}$$

where $costs_{treatment}$ are the costs of the acid stimulation in [EUR]

q_{after} is the oil production rate averaged over the half year of production after the acid stimulation in [t/day]

q_{before} is the oil production rate averaged over the last half year of production before the acid stimulation in [t/day]

$price_{oil}$ is the average oil price for the year, when the treatment was performed in [EUR]

t is the payout time in [days]

4.2 Assumptions

For the economic calculations the additional oil production but no gas production is considered. This has been done to focus on the main issue of the stimulation job, which is to increase oil production.

The flow rates inserted in the formula for payout are calculated by taking the average of the daily flowrates of the six months before the acid stimulation was performed.

Only cases where the acid stimulation was a stand-alone treatment are evaluated, whenever other treatments are concerned, this is noted.

The time value of money (NPV concept) was neglected because payout in most cases is achieved within one year.

4.3 Evaluation

28 stimulations were analyzed according to their economical feasibility. The table below shows the results. The table including comments can be found in the appendix.

The comment "not successful" means, that the rate decreased after the treatment.

Grey values indicate that the acid stimulation was not the only workover and / or no itemization of the costs was available, but the calculations were done to examine the whole workover treatment.

Well	Stim.Date	q_{before} [t/day]	q_{after} [t/day]	Oilprice [EUR/t]	Costs [EUR]	$time_{payout}$ [days]
Pir 15	26.03.2002	0.3	0.0	152.8	10,090	not successful
Pir 24	26.04.2001	2.7	0.7	149.4	10,673	not successful
Pir 79	21.01.1999	0.9	3.1	134.7	18,787	62
HL 13	27.05.1999					
	01.07.2004	4.1	0.6	147.8	16,274	not successful
	20.04.2005	0.5	0.0	177.9	16,071	not successful
HL 31	15.06.1999	6.1	7.3	104.9	10,632	84
	06.12.2005	0.7	2.1	177.9	78,696	305
HL 25	25.11.2004	1.5	5.5	147.8	18,767	32
HL 71	30.11.1999	4.3	6.3	104.9	11,686	55
S 111	27.03.1998	0.1	1.5	101.0	89,958	629
S 133	03.08.1998	1.0	0.1	101.0	5,414	not successful
S 256	22.04.1998	1.3	1.0	101.0	32,065	not successful
MaC 2	25.08.1999	0.5	1.3	104.9	8,610	103
MaF 6	10.09.1996	0.4	0.0	128.6	15,308	not successful
S 179	02.05.1999	0.0	3.4	104.9	9,120	26
S 28	11.08.1997	0.0	0.0	134.7	7,769	not successful
Ma 268	24.04.2001	0.3	0.0	149.4	116,833	not successful
Ma 56	28.10.1996	0.4	2.2	128.6	3,566	15
	15.05.2002	16.6	15.6	152.8	50,307	not successful
Ma 84b	24.10.1996	2.7	7.3	128.6	34,865	59
Bo 49	08.08.2001	3.3	4.6	149.4	50,507	266
Bo 98	30.06.2006	0.4	2.5	256.0	76,566	143
ST 31	28.08.2006	5.2	16.2	256.0	302,416	107
ST 64	20.05.1997	6.5	31.3	134.7	280,101	84
ST 78	23.11.1999	4.5	13.5	104.9	49,142	52
ST 90a	03.10.2002	6.5	13.6	152.8	147,468	135
PT 4	10.06.2002	4.4	7.3	152.8	173,543	386

Table 1: Results of economical evaluation

4.4 Results

Please note that 12 of the 28 stimulations can not really be analyzed for the economical stimulation effect, because some other jobs were performed within the same workover and sometimes the costs include the overall workover costs and not the stimulation costs itself. The other workover(s) can be seen in the complete table in the appendix.

Furthermore it can be seen that ten of the stimulations resulted in a production rate decrease, therefore these wells never can pay out.

There are 17 wells which pay out, but only ten of them can be recognized as successful only due to the acidizing job.

5. Laboratory Work

5.1 Polymer Mud Component

5.1.1 Introduction

The aim of this experiment series was to check the feasibility of replacing one viscosifier of a polymer mud by another; in that case DuoVIS should be exchanged with FlowZAN, to have an alternative viscosifier.

Since any new component of fluids for drilling, workover and so on must run through a laboratory test, core flooding experiments to determine the damage potential of both viscosifiers were performed.

Both products, DuoVIS and FlowZAN, are basically biopolymers, more precisely xanthan gums, with the general chemical formula $(C_{35}H_{49}O_{29})_n$. Xanthan gums are created by bacteria out of sugary substrates. Therefore by using different microbial strains for the single batches the quality can significantly differ by variation of the length of the main- and side chains of the molecules.

Naturally these xanthan gums exist in helical configuration and can experience a transition to a random coil at higher temperature.

5.1.2 Methodology

There are generally two effects which cause the degradation of the polymer, which are the reaction with hydrochloric acid and the thermal decomposition. The two effects were observed separately, because it is easier and also safer to do core experiments at room temperature.

Calculating the permeability of the plugs at any time, Darcy’s formula was used in a modified way, meaning that other dimensions can be inserted.

$$k = \frac{q \cdot \mu \cdot l \cdot}{d^2 \cdot \Delta p} \cdot 21.5$$

where k is the permeability in [mD]

q is the flow rate in [ml/min]

μ is the viscosity in [mPa.s]

l is the length of the plug in [cm]

d is the diameter of the plug in [cm]

Δp is the measured pressure difference in [bar]

21.5 is the constant appearing due to unit conversion

5.1.2.1 Samples

Since alone the damage from the polymer mud has to be observed and not any influences from the formation, the plug material should be as inert as possible against hydrochloric acid. Therefore Bentheim sandstone plugs were chosen, which are free of carbonates. The more or less clean sandstone furthermore has quite a high permeability in the range of one to two Darcy.

5.1.2.2 Apparatus

To pump the fluids a Shimadzu LC-81 pump was used.

A ten bar pressure sensor was used for measuring the input pressure. Because no backpressure was used, the pressure after the plug was the atmospheric pressure.

The data acquisition was performed with the program Agilent VEE pro, which used the inputs of the pressure sensors and from a balance to display and calculate the pressure behaviour and the actual flowrate.

5.1.2.3 Fluids

Brine

The aqueous reservoir medium is represented by a 3% potassium chloride (KCl) dilution, which was stabilized by adding some sodium azide (NaN_3). To cause no damage to the plugs by this fluid it was sucked through a 0.45 µm filter.

Damaging Media

A 5 g/l solution of the viscosifier (DuoVIS and FlowZAN) was prepared by mixing the 3 % potassium chloride solution (for FlowZAN) resp. fresh water (for DuoVIS) at 500 rpm with a blender and very slowly adding the biopolymer (see subchapter “observations during experiments and results” for the reason). Afterwards the dispersion was further mixed at this revolution speed for an hour and finally the viscosity was measured in a Fann Viscosimeter at 600 rpm and 300 rpm.

Acidizing fluid

A 15 vol% hydrochloric acid (HCl) was pre-mixed out of concentrated one (37 vol%). To minimize risk of corrosion, even on highly alloyed material 0.5 vol% corrosion inhibitor (Cronox) and 1 vol% citric acid ($C_6H_8O_7$) for complexation of possibly generated iron were added.

5.1.2.4 Workflow

At first, the plugs were weighted; the permeability was measured with nitrogen and then saturated in 3% KCl solution by using a vacuum pump.

The plugs were mounted between end plates and the assembly was thoroughly degassed, so that no air bubbles remained in the lines or anywhere between the plates and the plug.

The initial permeability in 3% KCl solution was measured at different flow rates to identify possible microfracs. A maximum of eight pore volumes of 0.5% xanthan solution was displaced into the plug by a nitrogen overpressure of five bars.

Next, the plug was reversed and the damaging medium was flushed back in the initial measuring direction with 3% KCl solution at flow rates of one, five and twenty ml/min. Of course, the permeabilities at measured constant pressure were calculated.

After a further flipping of the plug ten pore volumes of acid were pumped in original direction at a flow rate of one ml/min by using a compensation tank and displacing the acid with 3% KCl solution.

Finally the plug was flushed again in counter direction with 3% KCl solution at a rate of one, five and twenty ml/min.

The effect of degradation of the biopolymer due to temperature was observed separately as following:

Eight samples were prepared with the two xanthan gums with either 15% hydrochloric acid or 3% potassium chloride at either room temperature or 60°C.

After an initial mixing, the viscosity was measured immediately afterwards, after four, twenty and twenty six hours by using an Ubbelohde viscosimeter.

5.1.2.5 Simplifications

An initial oil or gas saturation was not established for simplification.

No real drilling mud was prepared, because the experiment should only determine the damaging potential of this single component, hence it is some kind of intensified test.

The calculation of the viscosity during the observations of the temperature effect with an Ubbelohde viscosimeter results in “pseudo” kinematic viscosity, because such a viscosimeter can only be used with Newtonian fluids. The Fann viscosimeter was too insensitive.

5.1.3 Observations during Experiments and Results

While preparing the xanthan suspensions, more than once it was observed, that DuoVIS did not suspend properly in 3% KCl solution. Therefore fresh water was used instead, where these problems did not occur. Although the salinity of fresh water is much lower, this was the only and fasted possibility to keep the experiment running without any further suspension trials.

The permeability measurements and the damaging action did not cause any problems; they followed the basic workflow described above.

The initial conditions and measurements of the single plugs are shown in table 3 below:

Plug #	length [cm]	diam. [cm]	m_{dry} [g]	$m_{sat.}$ [g]	PV [cm³]	Φ [%]	$k_{init,N2}$ [mD]	$k_{init,\ KCl}$ [mD]
NH14/21	8.2	3.0	201.2	214.3	13	22	2185	1900
NH13/190	7.3	3.0	230.2	240.6	10	20	1222	1058
NH052	6.6	3.0	157.9	168.0	10	21	1717	1522
NH14/13	8.0	3.0	198.3	210.6	12	21	2015	1335
NH13/050	8.0	3.0	254.3	256.2	11	19	1102	855

Table 2: initial conditions of plugs

The first three plugs (NH14/21, NH13/190 and NH052) were damaged using the 0.5% FlowZAN suspension and the latter two (NH14/13 and NH13/050) using the 0.5% DuoVIS suspension.

Basically, the two xanthan gums behaved similarly. After the first brine flush, so before acidizing, the regained permeability was between 15 to 20 % and after acidizing around 45 to 50 %.

To illustrate this tendency, the permeability itself before and after the treatment and also the regained permeability versus flow rate were plotted. As an example NH13/050 is shown below (see the others in appendix D)

Plug #	Damaging Medium	$k_{init,\ KCl}$ [mD]	k_{washup} @20ml/min [mD]	k_{acid} @20ml/min [mD]	$k_{init,\ KCl}$/ $k_{acid@20ml/min}$ [%]
NH14/21	FlowZAN	1900	261	832	43,8
NH13/190	FlowZAN	1058	182	568	53,7
NH052	FlowZAN	1522	338	698	45,9
NH14/13	DuoVIS	1335	300	579	43,4
NH13/050	DuoVIS	855	117	411	48,1

Table 3: permeabilities of the plugs before and after damaging

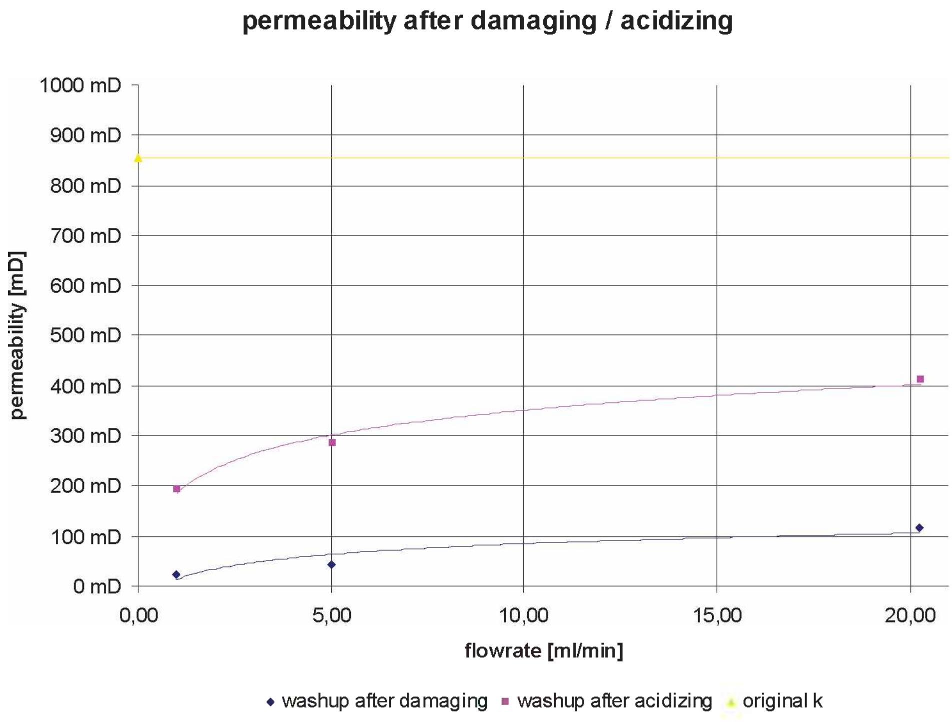

Figure 16: NH13/50 results of permeability

The planned workflow included also temperature effects.

The following run times through the Ubbelohde viscosimeter were measured and "pseudo" viscosities were calculated:

#	Mixture		T [°C]	Running time [s] after 0 h	4 h	20 h	26 h	Ubbel. const.	„pseudo" visc. [cSt] after 0 h	4 h	20 h	26 h
1	FZ	HCl	20	48	34,5	31	31	0,318	15,3	11,0	9,9	9,9
2	FZ	KCl	20	45	44,5	44	44	0,318	14,3	14,2	14,0	14,0
3	FZ	HCl	60	179	124	50	41	0,0513	2,3	1,6	1,5	1,5
4	FZ	KCl	60	239	237	228	232	0,0513	2,2	2,1	2,2	2,1
5	DV	HCl	20	44	31	30	30	0,318	56,9	39,4	15,9	13,0
6	DV	KCl	20	42	41	42	41	0,318	76,0	75,4	72,5	73,8
7	DV	HCl	60	203	163	82	71	0,0513	10,4	8,4	4,2	3,6
8	DV	KCl	60	290	284	289	286	0,0513	14,9	14,6	14,8	14,7

Table 4: running times and calculated "pseudo" viscosities

The figure 17 below shows the results of the experiment as graph.

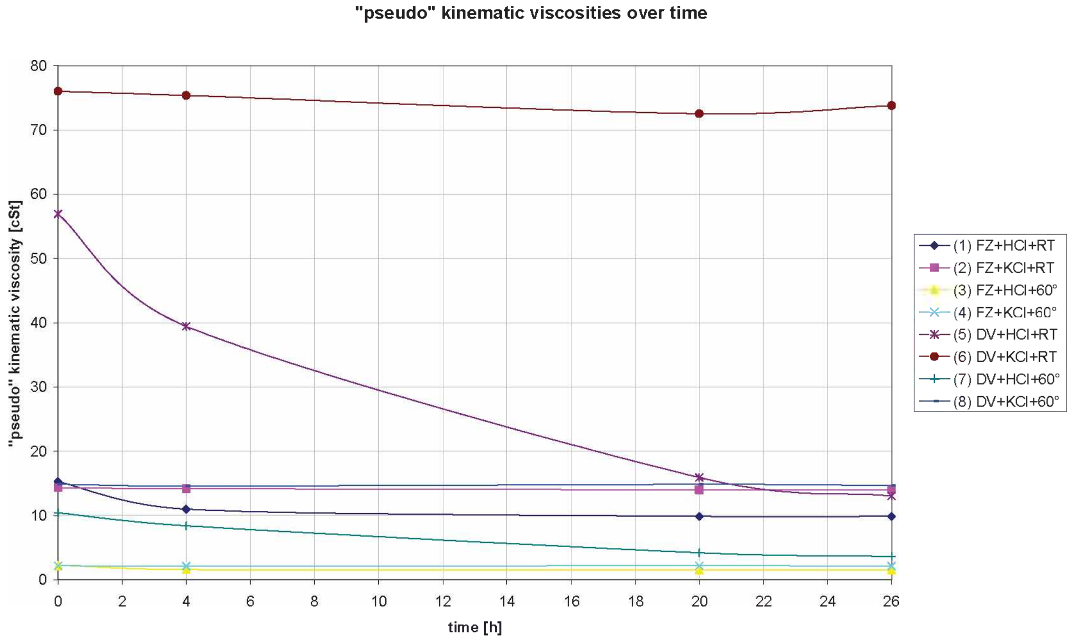

Figure 17: Plot of the “pseudo” kinematic viscosites

One recognizes that the viscosity of FlowZAN always is below the viscosities of DuoVIS at any time. Furthermore it can be seen, that DuoVIS needs more time to be degraded by the acid at room temperature. A very high viscosity can be reached with DuoVIS, but not with FlowZAN at the same concentrations.

5.1.4 Conclusions and Recommendations

Since only the damaging potential was to be determined and not the performance in drilling behaviour, we can conclude that both have nearly the same impact for formation damage.

At normal temperature it was also possible to flush the same amount of the polymer out of the plugs, with and without hydrochloric acid. The maximum regained permeability was around 50% of the original one.

But hydrochloric acid only nibbles a little on the highly branched molecule. Some kind of peroxides, like hydrogen peroxide (H_2O_2) would lead to better degrading results, but will also cause more side effects.

At higher temperature (60°C) FlowZAN decomposes very fast to a lower viscosity, while DuoVIS stays a little longer. At room temperature FlowZAN also reaches a low viscosity level very fast, but DuoVIS remains at a high level without the acid.

5.2 Influences of Mineralogy and Lithology

5.2.1 Introduction

As explained in the chapter dealing with damage identification (chapter 2.4), the formation will always be affected by production and remedial workover jobs. A variety of factors can cause the formation to create problems, like fines and their migration or even a complete collapse of the reservoir rock.

Formations with a clayey matrix or fine shale layers are sensitive to acid. Additional risk occurs when a moderate to high amount of carbonate is present or when the shale layers exhibit high carbonate content. Not only clays from the matrix may plug pores, but also released particles, if the carbonates in the matrix are dissolved.

The aim of the experiments is to show what can happen during an acidizing job with the formation and that such a treatment might not always result in a success, meaning that it can also cause damage itself. Reasonably, if the formation's carbonates are dissolved, fine particles from the clayey matrix are released and can move, until they settle in the pore throats and plug them. The same problem is true for sandstone formations, interbedded with shale and possibly exaggerated due to the large contact area between the reservoir rock and the layers.

If the pore throats are plugged, the permeability will be reduced.

To determine a damage the permeabilities before and after the treatment are measured.

5.2.2 Methodology

5.2.2.1 Samples

As a basis for these experiments proper formation material with shale lamination or clayey matrix is necessary. Thin section analysis was chosen to identify potential rock samples and the plugs were observed visually for consistency. A plug has a diameter of around three centimetres and a length of around six to seven centimetres.

Matzen F 209 plugs showed a very good condition and six plugs with a clayey groundmass were chosen after checking them with thin section analyses and macroscopic observation.

5.2.2.2 Apparatus

The experiments were performed at a constant rate; therefore a special high quality pump was necessary to be also able to pump hydrochloric acid: the Quizix SP-5200, which allows pumping a constant rate up to four digits behind the comma in ml/min.

Furthermore pressure sensors and backpressure valves were needed. The backpressure valves, set to 50 bars, minimize the gas generation in the plug, which would falsify the measurement. Thus the pressure sensors must be suitable for high pressures; 200 bars sensors were chosen.

Three way valves are useful to be able to easily switch between different fluids and to clean the system with the new fluid, because the pumping cylinders are still filled with the previous one and there is also some dead volume. Further, they are necessary to direct the fluids from top to bottom of the plug and vice versa. Shut off valves are required to shut off one outlet completely.

Figure 9 shows the general assembly, this figure can also be found enlarged in appendix E.

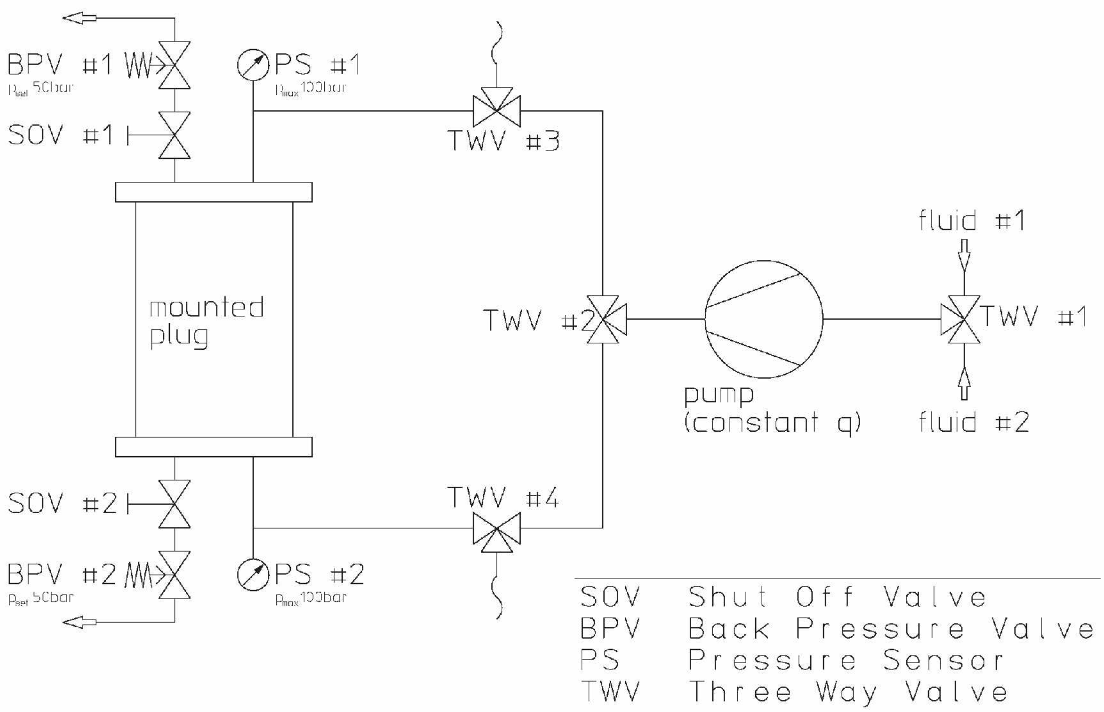

Figure 18: sketch of the assembly for core flooding experiments

For example, if the fluid #1 is directed from bottom to top, TWV #1, #2 and #4 must be set for flow in this direction, SOV #2 must be closed and SOV #1 open. TWV #3 must also be closed; else the fluid would not only leave the plug through BPV #1. If all five valves are operated again, the fluid will move from top to bottom.

The option of switching between two directions is necessary to represent a producer's acidification, where the generated fines are not washed away in acidizing direction, but in producing direction.

5.2.2.3 Fluids

Brine

The aqueous reservoir medium is represented by a 3% potassium chloride (KCl) dilution, which was stabilized by adding some sodium azide (NaN_3). To cause no damage to the plugs by this fluid it was filtered through a 0.45 µm membrane.

Acidizing fluid

A 15 vol% hydrochloric acid (HCl) was pre-mixed out of concentrated one (37 vol%). To minimize risk of corrosion, even on highly alloyed material 0.5 vol% corrosion inhibitor (Cronox) and 1 vol% citric acid ($C_6H_8O_7$) for complexation of possibly generated iron were added.

Final displacing fluid

To be able to dry the plug afterwards without crystallisation of KCl or clay-swelling, methanol (CH_3OH) was finally pumped through the plug.

5.2.2.4 Workflow

The selected plugs were mounted in epoxy sleeves. Afterwards, the permeability in nitrogen was measured to have a basic idea of the permeability in potassium chloride solution The measured permeability in nitrogen has to be corrected for different readings from the pressure sensors to calibrated ones and increased pressure losses with increased flow rate of gas.

Before saturating them in brine, their dimensions were measured and weight was recorded, to calculate the porosity and check the carbonate reaction with acid. After saturation, they were again weighted.

After putting one plug between the end-plates and filling the system with KCl dilution to displace the whole air, all parameters for the pump and backpressure valve were set. The pump rate was adjusted to 5 ml/min and the backpressure valve to 50 bars. The initial pressure difference between the two plug-ends was measured at 5ml/min, 10ml/min and 20ml/min. Due to the result (see subchapter results) of the first two experiments, the pump rate was reduced to constantly 5 ml/min for later plugs.

Next, the flow direction was reversed and the system filled with the hydrochloric acid dilution. Ten pore volumes of 15 vol% HCl were pumped through the plug with a constant rate of 5 ml/min to dissolve the amount of carbonate completely. The pressure was also recorded.

The first plug (#8) was simply flooded with KCl and HCl in the same direction to get a feeling for the workflow. This represents in principle the acidizing job of an injector.

Afterwards the hydrochloric acid was displaced from the system with the potassium chloride solution. The flowing direction was again switched and the acid displaced out of the plug. The pressure difference was again measured at the previously used flow rates (only for plug #8, #10 and #14).

Finally, the plug was flooded by methanol, dried at 60°C over night constantly weighted to calculate the amount of carbonate, that reacted and observe the surface of the plugs.

If any sediment was washed out of the plug, it was collected in a beaker with the fluids. The fines, which accumulated in the backpressure valve, were added to the beaker and filtered as completely as possible. After drying, the filter was weighed to calculate the amount of carbonates reacted with hydrochloric acid. For this the filtrated amount of fines was added to the mass of the plug after the treatment.

Any conspicuous behaviour of the plug, the fluid and pressure were noted and can be found in the results subchapter.

5.2.2.5 Simplifications

Normally, the formation has some oil saturation (residual oil saturation at least), which was neglected.

The flow rate per unit of contact area was kept well below the real one during an acidizing job to reduce the necessary amount of fluids. Furthermore the pump was limited to a flow rate of 30 ml/min. To avoid cracking of the plugs a lower pump rate was chosen.

5.2.3 Experiments and Discussion

As mentioned, the gas permeability, dimensions and weights were initially measured to get an idea of the fluid's permeability and to be able to calculate the pore volume. The next table summarizes the results of the plugs (the permeability is already corrected as explained before).

plug number	length [cm]	diameter [cm]	$k_{gas,av.}$ [mD]	$mass_{dry}$ [g]	$mass_{sat.}$ [g]	porosity []	PV [cm³]
#8	6.71	2.93	78	173.80	185.55	26	12
#10	6.68	2.90	177	172.15	183.47	25	11
#12	5.79	2.92	16	154.11	162.82	22	9
#14	6.24	2.86	28	169.27	176.78	19	8
#15	6.78	2.96	395	177.36	188.19	23	11
#17	6.69	2.93	7	180.14	186.98	15	6.5

Table 5: results of "dry" measurements of the MaF209 plugs

The pressures before and behind the plug, the pressure difference and the flow rate (only for plug #8, #10 and #14) were plotted into one chart. After the pressure values have stabilized for each single treatment, for example the different flushes, the permeability was calculated out of the pressure difference. Furthermore any event has been marked in the chart, like:

- Start of a new flush (KCl, HCl, CH_3OH)
- Emissions out of the plug:
  - generated bubbles and sediments
  - Turbidity
- Sudden pressure irregularities (increase, drop, etc.)
- Visual observation at the plug (cracks, holes, etc.)

It must be mentioned that a pressure jump before and after in the chart of all experiments except number 8 , 10 and 14 during the acidizing treatments is no error. This is the result from reversing the flowing direction. The pressure sensors were not reprogrammed and the sensor which measured the pressure after the plug had the function to measure the pressure before the plug, which is higher.

The following table summarizes the results of the single plugs:

plug number	$k_{gas, init}$ [mD]	$k_{KCl, init}$ [mD]	$k_{KCL, after}$ [mD]	comments
#8	78	10	4	after rate increasing the plug collapsed
#10				already initially crack observed
#12	16	6	(21)	notches on plug ends, collapse
#14	177	4	(2)	circular crack near resin cement
#15	395	38	19	fine cracks on plug ends
#17	7	3	9	sucessfully stimulated

Table 6: Summary of performance and results of experiment

As an example the chart of plug number 8 is presented below, the others are in the appendix E.

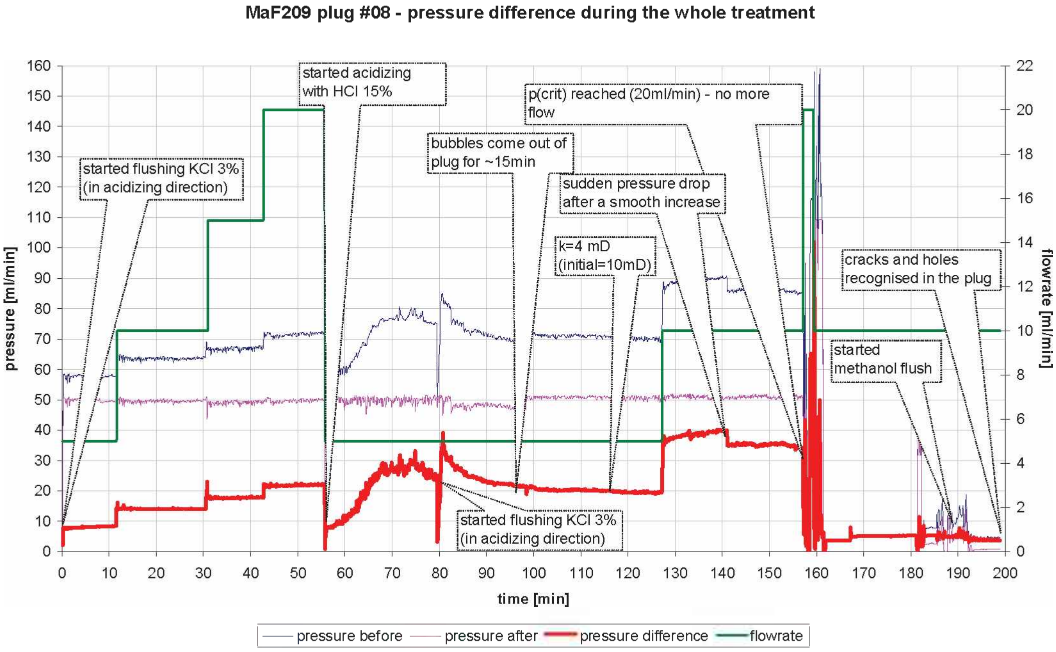

Figure 19: evaluation chart of the whole treatment of plug MaF209 #8

5.2.3.1 Plug #8:

This plug was flooded and acidized in the same direction as mentioned a few pages before.

The first treated plug (number eight) showed a strong non linear dependency of the flow rate from the pressure difference. Due to the age of the plugs, it is quite probable that some fine fissures were generated during storage, but in field scale it is also very probable that such micro fractures exist in the formation. The calculated permeability in KCl was 10mD. One recognises the quite large difference to the permeability in gas (nearly 80mD), which could be explained by the clay content, which swelled, even in saline wells.

With the start of acid pumping at constantly 5 ml/min, the pressure increased, partly due the viscosity difference, but one may identify also beginning plugging of pores.

The following KCl flood showed a higher pressure level than the initial one. The calculated permeability was 4mD. A further increase in flow rate for validation resulted in a complete collapse: The maximum allowed pressure of the pump, which switched off, was reached. A release of the backpressure showed, that sediments plugged the valve, which could no longer operate. All sediments were washed out without the backpressure and the plug was flooded with methanol finally.

A visual observation of the plug ends showed some holes and cracks in it.

The flooding medium, which came out of the plug was filtered and dried. Also the plug was dried. Both were weighted to constancy. A calculation, how much of the carbonate reacted with the hydrochloric acid showed that only 7% of the initially present carbonate were dissolved.

The data shows that it is very likely, that fines were released from the matrix, which plugged pore throats (permeability decrease from 10 to 4 mD). The collapse of the plug shows that either the consistency of the plug was not sufficient, or that acidizing such formations has even more impact than originally assumed.

5.2.3.2 Plug #10:

This plug was the first to be treated in different flowing directions.

During determination of the initial permeability loss, release of sediments was recognised. Furthermore the pressure drops in the two directions were not even near equal. Therefore the plug was observed visually and fissures and cracks were observed. This might mean, that either the plug was disrupted before the treatment and the fissures were overlooked or that the formation has damaging potential by itself, without any exterior influence.

Hence, the plug was not acidized and no chart is provided.

5.2.3.3 Plug #14:

During the initial KCl flush, it was recognised that doubling the flow rate does not result in a twofold pressure drop. Because the same phenomenon did occur in counter direction and no fines were generated, the experiment was continued. A permeability around 3 mD was calculated (compared to the gas permeability of around 30 mD).

Pumping the acid solution did not show any significant increase in pressure drop, but immediately after pumping KCl in counter acidizing direction the second time, the pressure drop decreased by 40% and a cloudy fluid was displaced out of the plug.

Increasing the flow rate did not result in an equivalent increase in pressure drop, like before.

Finally a circular crack reaching from one end to the other near the resin coating was observed.

The muddy outflow was filtrated and calculation led to the conclusion that only a seventh of the carbonates had reacted with hydrochloric acid. This might originate from an early creation of the circular crack during acidizing.

5.2.3.4 Plug #15:

This plug was treated in two flow directions but with a constant flow rate of 5ml/min. It showed the highest gas permeability (nearly 400 mD), but the permeability determined in KCl was only one tenth of this.

When pumping the acid through the plug, a very strong gas production was observed. The second potassium chloride flush was not very homogeneous in terms of pressure behaviour and the registered permeability was around 22 mD. After a further pressure irregularity happened, sediment generation was recognized and the permeability levelled to 19 mD.

During pumping methanol fines were registered and finally fine cracks on top and on bottom were observed. This plug showed that nearly half of the carbonate amount had reacted with hydrochloric acid.

5.2.3.5 Plug #12:

This plug was dealt with in the same way as the previous one (#15). It showed an initial permeability of 6 mD (compared to 16 mD in nitrogen).

The acid treatment showed a strong and sharp increase in pressure which finally levelled. Pressure fluctuations were observed after starting to pump the KCl, which developed to a pressure peak, followed by a sharp decrease in pressure to a very low level (21 mD). During the fluctuations sediment particles were recognized coming out of the plug.

Just after starting to pump the methanol, the pump reached a critical pressure and turned off. The backpressure valve was again filled with fines, which were rinsed out. Afterwards a notch was seen on the top of the plug and some fine cracks on bottom.

5.2.3.6 Plug #17:

Plug number 17 was treated like the others before, it showed the lowest initial permeability in 3% KCl solution, namely 3 mD (in nitrogen 7mD were determined).

No sediments were flushed out during any treatment. After acidizing, the permeability increased to 9 mD.

After drying and weighting of the plug it was calculated that the carbonate content had been decreased by only five percent.

5.2.4 Conclusions and Recommendations

- It was observed that every plug behaves differently:
  - Two showed a reduction of permeability (plugged pores) after acid treatment before they collapsed.
  - Two showed a collapse quite after pumping the acid dilution.
  - One showed multiple cracks already before acidizing, so in KCl dilution.
  - The one with the lowest permeability showed an increase in permeability after acidizing that can be explained with a link between permeability and consolidation.
  - It was recognized that an increase in flow rate causes an instantaneous collapse of the plug, therefore some certain critical flow rate must exist. This will not only be true in these laboratory experiments, but also in the field.
- The experiment series showed that formation with high shale content tends to generate fines and one should therefore be very carefully in designing acid treatments.
- Hence, while designing an acid stimulation in the field proper investigation to the detailed mineralogy and shale content is suggested.
- This series of plugs was quite small. For getting a better idea of the mechanism and the damaging potential more experiments with other acids (for example more diluted ones, or retarded ones) should be performed. Also different kinds of formations should be tested.
- No standard, norm or working procedure could be found in the literature for this experiment, therefore an approach to a suitable workflow was necessary and certainly is not definitive.

The following picture shows four of the plugs, from severely damaged to successfully stimulated:

Figure 20: picture of selected plugs

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Appendix A (Damage Evaluation)

Trial #1 for determination of heterogeneity

Well	gross	net	rel. shale nr.	Shale layers betw. sand	thickness	Shale layers within Sand	Shale Content	Shale Cont. w/o layers
Pir 15	4,5 m	2,5 m	20	1	0,1 m	19	23 %	18 %
Pir 24	5,0 m							
Pir 79	2,0 m							
HL 13	6,0 m	4,9 m	11	2	0,8 m	3	19 %	
HL 25	14,5 m	4,5 m	100	6	9,5 m	5	70 %	12 %
S 133	1,0 m							
S 256	2,0 m	1,5 m	5	1	0,3 m	2	26 %	6 %
MaC 2	2,5 m	2,1 m	4	1	0,3 m	1	28 %	18 %
MaF 6	4,0 m	3,2 m	8					
S 111	2,0 m							
S 28	4,0 m							
Ma 268	4,0 m							
Ma 56	3,0 m							
Ma 84b	3,0 m	2,8 m	2	0	0,0 m	2	5 %	5 %
Bo 49	3,0 m							
Bo 98	3,0 m							

Mineralogical Composition of the selected wells:

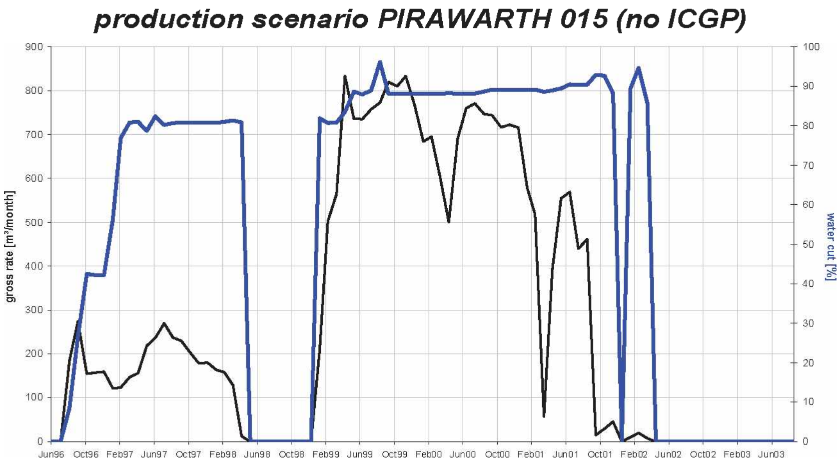
						average horizon values in [%]																
Well	Hor	PE	Field	Lithology	Horizon Interval	Quartz	K-Fsp	Plag	Calcite	Dolo mite	Anke rite	Side rite	Pyrite	Clay Tot+Mica	Illite	Kaolinite	Chlorite	Smectite	Mixed-Layer	Carbonates Solubility	Cement	Info
Pir 15	107	10	A017	Sandstone	896-934	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
Pir 24	107	20	A017	Sandstone	958-986,5	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
Pir 79	107	20	A017	Sandstone	936-966	67	2	1	15 (no differenciation)				< 1	2	-	-	-	-	-	15	< Data	DS
HL 13	111	10	A016	Sandstone	992-1016	65	2	-	26 (no differenciation)				1	1	-	-	-	-	-	26	31	DS
HL 31	111	10	A016	Sandstone	992-1087	65	2	-	26 (no differenciation)				1	1	-	-	-	-	-	26	31	DS
					992-1087																	
HL 25	205	10	A016	Sandstone	1228-1256	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	no data
HL 71	205	11	A016	Sandstone	1244-1350	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	no data
S 111	208	10	A015	Sandstone	1230-1268	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
S 133	208	10	A015	Sandstone	1224-1263	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
S 256	208	10	A015	Sandstone	1236-1264	57	2	4	5	17	5	2	1	9	51	18	10	23	3	29		XRD
MaC 2	209	91	A015	Sandstone	1286-1330	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
MaF 6	209	91	A015	Sandstone	1296-1336	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
S 28	209	91	A015	Sandstone	1279-1314	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
S 179	209	91	A015	Sandstone	1270-1329	59	2	2	4	21	4	0	0	8	38	32	12	10	12	29		XRD
Ma 56	216	10	A015	Sandstone	1601-1633	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
					1601-1633																	
Ma 84b	216	10	A015	Sandstone	1597-1627	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Ma 268	216	10	A015	Sandstone	1615-1674	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Bo 49	216	20	A015	Sandstone	1615-1664	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
Bo 98	216	20	A015	Sandstone	1606-1656	81	2	2	5	2	2	1	1	5	27	49	12	3	15	10		XRD
ST 31	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 64	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 78	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
ST 90a	800	10	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general
PT 4	800	12	A015	Dolomite		dolomite: 80-90 % clay: 5-10 % quatz: <5% (important are marl-layers)																general

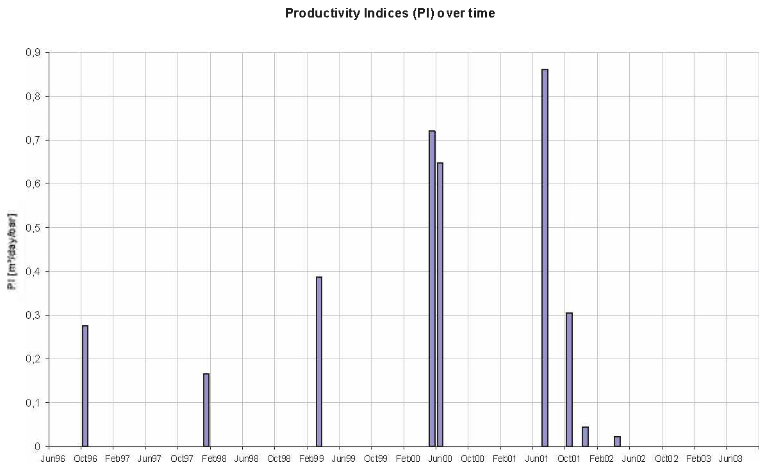
Overall Shale Content and Heterogeneity of the selected wells:

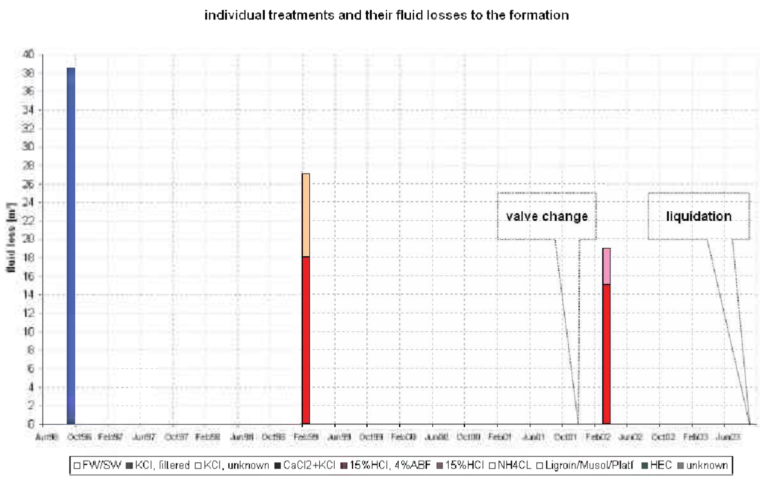
						Gamma Ray				Spontaneous Potential			
Well	Hor	PE	Field	Lithology	Horizon Interval [m]	overall clay content [%]	Std. Dev. heterog.	Subjective Shale content	Subjective heterog.	overall clay content [%]	Std. Dev. heterog.	Subjective Shale content	Subjective heterog.
Pir 15	107	10	A017	Sandstone	896-934	55	6	sandy shale	low	52	7	sandy shale	low
Pir 24	107	20	A017	Sandstone	958-966,5	52	15	sandy shale	moderate	59	16	sandy shale	moderate
Pir 79	107	20	A017	Sandstone	936-966	33	24	shaly sand	high	29	22	shaly sand	high
HL 13	111	10	A016	Sandstone	992-1016	26	18	shaly sand	moderate	7	8	sand	low
HL 31	111	10	A016	Sandstone	992-1087	41	24	sandy shale	moderate	85	3	sandy shale	moderate
						28	20	sandy shale	moderate	80	7	sandy shale	moderate
HL 25	205	10	A016	Sandstone	1228-1256	49	18	shaly sand	high	54	28	shaly sand	moderate
HL 71	205	11	A016	Sandstone	1244-1350	13	5	sand	low	-	-	-	-
S 111	208	10	A015	Sandstone	1230-1268	66	19	shaly sand	moderate	71	16	shaly sand	moderate
S 133	208	10	A015	Sandstone	1224-1263	52	24	shaly sand	moderate	36	29	shaly sand	moderate
S 256	208	10	A015	Sandstone	1236-1264	41	25	shaly sand	high	34	11	shaly sand	moderate
MaC 2	209	91	A015	Sandstone	1286-1330	58	12	sandy shale	moderate	59	13	sandy shale	moderate
MaF 6	209	91	A015	Sandstone	1296-1336	16	10	shaly sand	low	26	6	shaly sand	low
S 28	209	91	A015	Sandstone	1279-1314	69	23	sandy shale	high	45	29	sandy shale	high
S 179	209	91	A015	Sandstone	1270-1329	43	13	sandy shale	high	44	25	sandy shale	high
Ma 56	216	10	A015	Sandstone	1601-1633	13	4	sand	low	4	2	sand	low
					1601-1633	15	4	sand	low	10	2	sand	low
Ma 64b	216	10	A015	Sandstone	1597-1627	6	4	sand	low	16	13	sand	low
Ma 268	216	10	A015	Sandstone	1615-1674	25	18	shaly sand	moderate	39	18	shaly sand	moderate
Bo 49	216	20	A015	Sandstone	1615-1664	-	-	-	-	13	3	shaly sand	low
Bo 96	216	20	A015	Sandstone	1606-1656	-	-	-	-	27	1	sandy shale	low

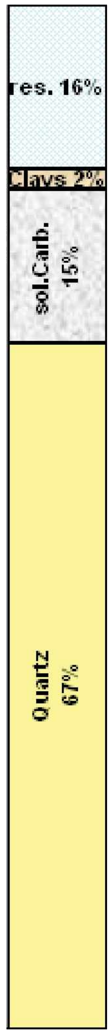
Maximum Pressure Gradient during treatments

Well	Hor	PE	Field	II(end)/ II(bef.)	PI(end)/ PI(bef.)	Perf.Mitte TVD [m]	Stufe 1 qinj [l/min]	pwf,inj [bar]	Stufe 2 qinj [l/min]	pwf,inj [bar]	Stufe 3 qinj [l/min]	pwf,inj [bar]	Stufe 4 qinj [l/min]	pwf,inj [bar]	Stufe 5 qinj [l/min]	pwf,inj [bar]	Stufe 6 qinj [l/min]	pwf,inj [bar]	max. gradient [bar/m]
Pir 15	107	10	A017	2,1	0,5	898,63		94,56	100	128,99	300	147,27	300	148,72	200	126,86		94,56	0,17
Pir 24	107	20	A017	62,1	0,5	969,48		102,01	70	163,68		102,01	400	96,12	450	87,95		102,01	0,17
Pir 79	107	20	A017	1,2	3,9	939,13		98,82	300	176,64		98,82	500	116,61		92,54	250	143,38	0,19
HL 13	111	10	A016	1,1	11	1009,96		106,27	500	150,76		106,27	500	150,76	500	144,07		106,27	0,15
				0,8	0,5	1009,96		106,27	700	135,40		106,27	600	137,60		99,52		106,27	0,14
				0,8	11	1009,96	550	123,42		106,27		106,27	600	147,60		100,56	600	139,85	0,15
HL 31	111	10	A016	1,6	7,9	1001,94		105,43	250	155,27		105,43	350	147,15	350	140,28		105,43	0,15
				1,6	0,5	997,74		104,98	200	154,16	300	141,82	300	141,32	450	145,28	300	146,82	0,15
HL 25	205	10	A016	3,9	7,9	1236,18	300	147,25		130,07		121,81	300	164,84		121,81	500	114,38	0,13
HL 71	205	11	A016	1,8	69,5	1234,65		129,91	300	169,66		121,66	500	177,30	500	164,11		129,91	0,14
S 111	208	10	A015	64,7		1237,58		99,55	50,00	239,98		121,95	500,00	131,86	700,00	120,37		122,74	0,19
S 133	208	10	A015	13,7	6,1	1234,34		99,29	30,00	206,78	300,00	176,76	300,00	174,44	300,00	173,76		122,42	0,17
S 256	208	10	A015	1,8	3,8	1242,79		99,97	350,00	174,80		122,47	600,00	180,43	600,00	171,21		123,26	0,15
MaC 2	209	91	A015	0,6	1,6	1303,71		104,87	350,00	154,68		128,47	500,00	163,18	350,00	191,74		129,30	0,15
MaF 6	209	91	A015	3,6	319,2	1318,48		106,06	150,00	212,05	200,00	199,71	200,00	203,95	350,00	170,43	350,00	174,09	0,16
S 179	209	91	A015	0,9	1,7	1324,92	250	149,19	250	200,49	250	195,30	300	194,01	375	190,54	350	193,02	0,15
S 28	209	91	A015	5		1311,67	200,00	189,60	200,00	215,17		129,25	300,00	162,23	470,00	147,86		130,09	0,16
Ma 268	216	10	A015	1,8	1,6	1627,18		171,22		171,22		171,22	600,00	155,16	600,00	144,02	800,00	146,42	0,11
Ma 56	216	10	A015	3,2		1623,31		130,58	150,00	214,81		159,96	500,00	208,57	400,00	199,51		161,00	0,13
				28,5	2,1	1617,81		130,14	40,00	245,02		159,42	250,00	245,11	400,00	158,98	450,00	172,54	0,15
Ma 84b	216	10	A015	1,1	2,7	1618,17		130,17	200,00	431,24		159,46	200,00	422,24	200,00	416,12		160,49	0,27
Bo 49	216	20	A015	0,4	14,9	1638,81		131,83	600,00	219,67		161,49	330,00	214,05	330,00	193,97	300,00	236,13	0,14
Bo 98	216	20	A015	7,9	13	1631,24	40,00	198,75	210,00	219,86	127,00	219,34	131,00	228,99	180,00	167,30		161,78	0,14
ST 31	800	10	A015	81,2		2699,19	670,00	265,09		284,01		284,01	75,00	425,55	677,00	252,28			0,16
ST 64	800	10	A015	927		2731,63		219,74	20,00	482,32		269,18	900,00	288,00		271,99	900,00	271,17	0,18
ST 78	800	10	A015	6,1	7,7	2764,30	200,00	384,15		290,87		272,40	400,00	420,73		275,25	800,00	328,02	0,15
ST 90a	800	10	A015	48,5		2758,78		221,92		290,28		271,85	50,00	482,76	800,00	318,01		273,61	0,17
PT 4	800	12	A015	1		2704,11		217,52		284,53		266,47	1000,00	281,70	1000,00	279,75		268,19	0,11









Overall clay content:

53%

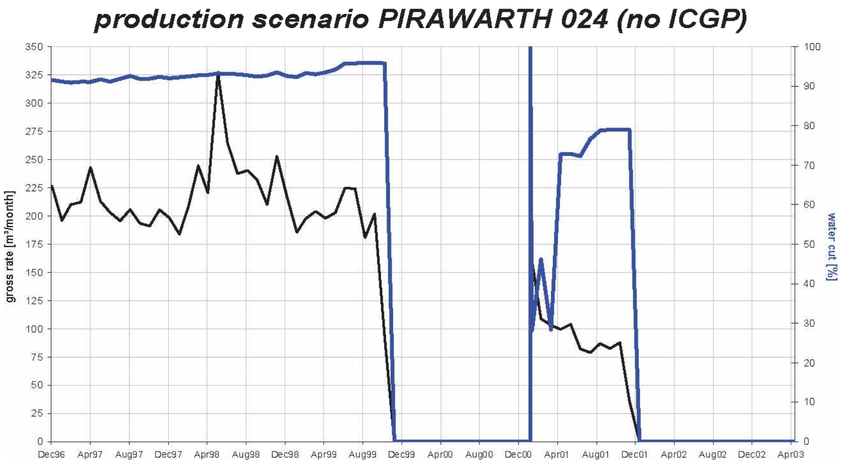
(sandy shale)

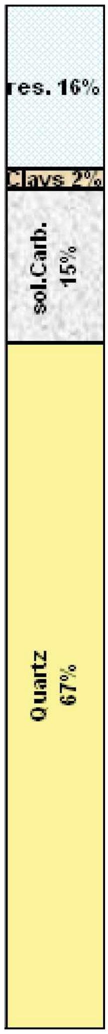
Heterogeneity:

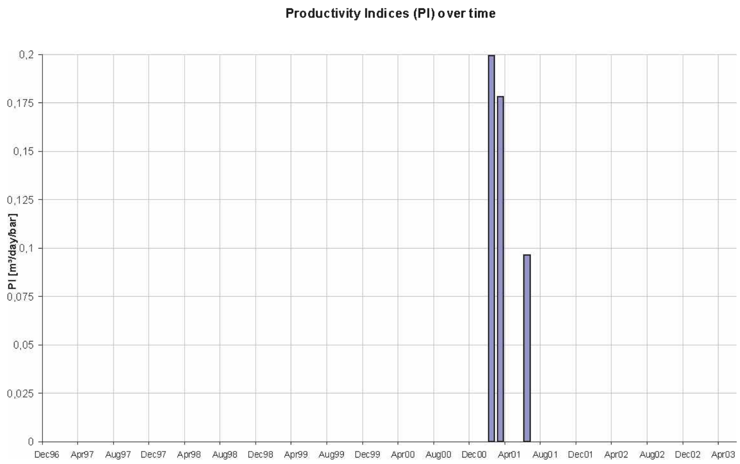
6

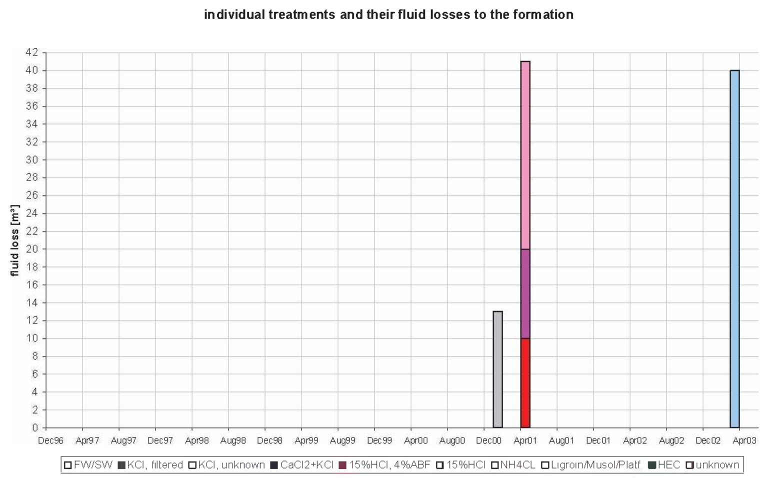
(low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Sep96	perf. of upper interval	39 m³	14 days	
Feb99	acid stimulation	27 m³	1 days	
Nov01	valve change	0 m³	2 days	GLV abraded
Mar02	acid stimulation	19 m³	1 days	γ_{max}=0.17 bar/m
Sep03	liquidation	0 m³	6 days	







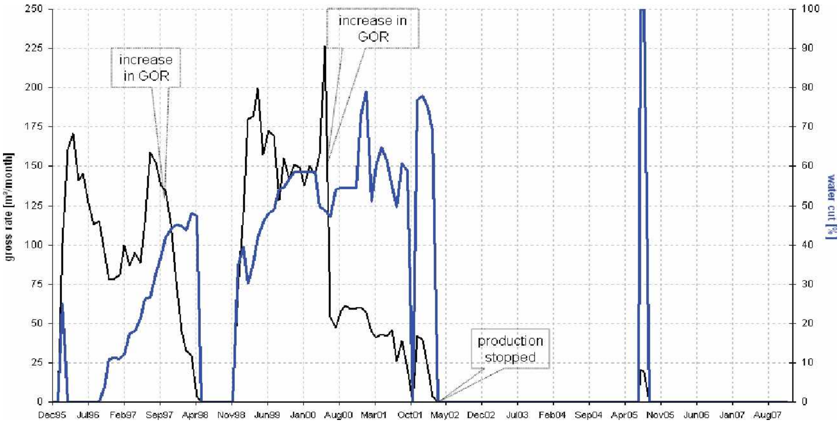


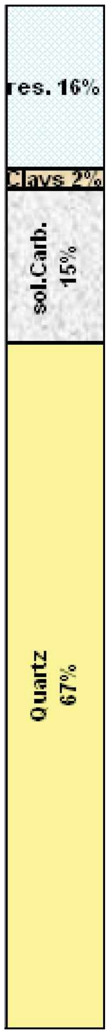
Overall clay content: 55% (sandy shale)

Heterogeneity: 15 (moderate)

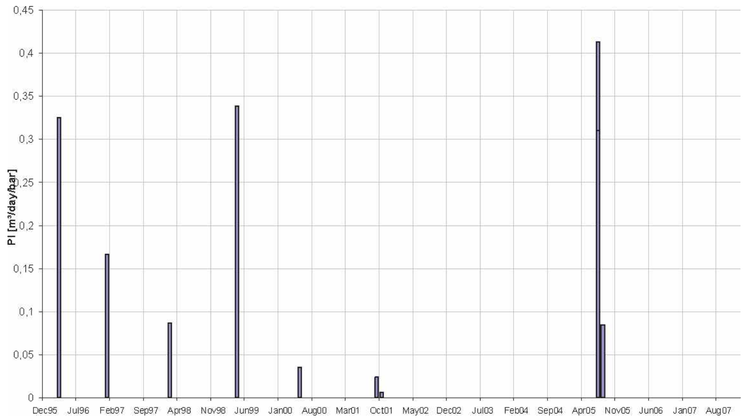
Date	Type of Workover	Σ(losses)	t(open)	Observations
Jan01	perf. of upper interval	13 m³	5 days	
Apr01	acid stimulation	41 m³	1 days	γ_{max}=0.17 bar/m
Mar03	liquidation	40 m³	155 days	

production scenario PIRAWARTH 079 (ICGP since Mar 96)

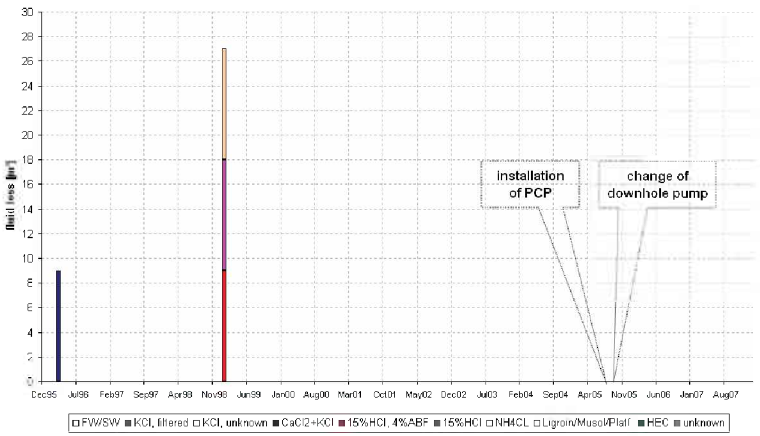




Productivity Indices (PI) over time



individual treatments and their fluid losses to the formation

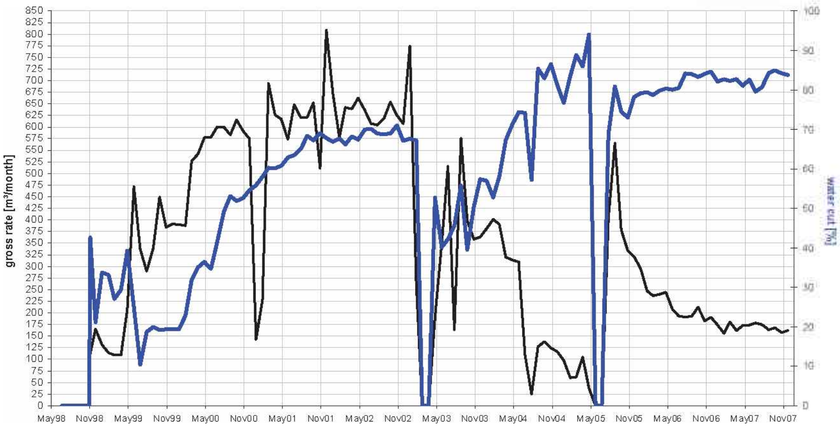


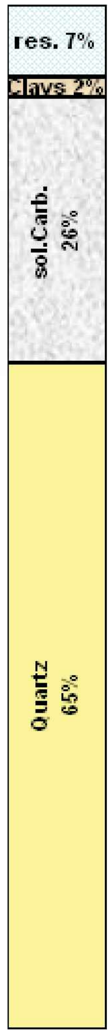
Overall clay content: 31% (shaly sand)

Heterogeneity: 23 (high)

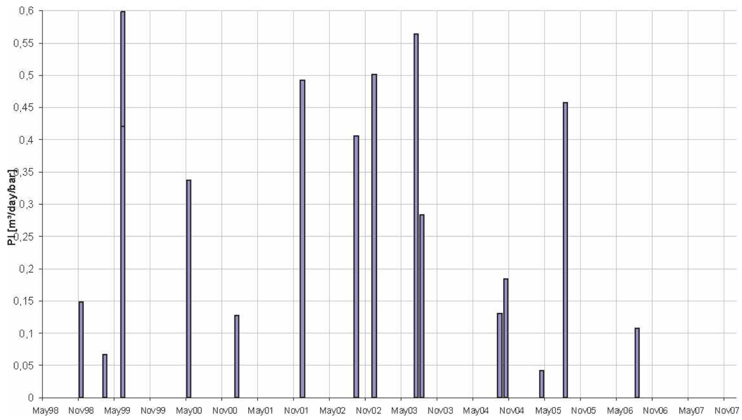
Date	Type of Workover	Σ(losses)	t(open)	Observations
Mar96	perf. of upper interval, ICGP installation	9 m³	13 days	
Jan99	acid stimulation	27 m³	1 days	γ_{max}=0.19 bar/m
Jun05	installation of PCP	0 m³	8 days	Deformed and tight GP
Jul05	change of downhole pump	0 m³	6 days	

production scenario HOCHLEITEN 013 Y (ICGP since Oct 98)

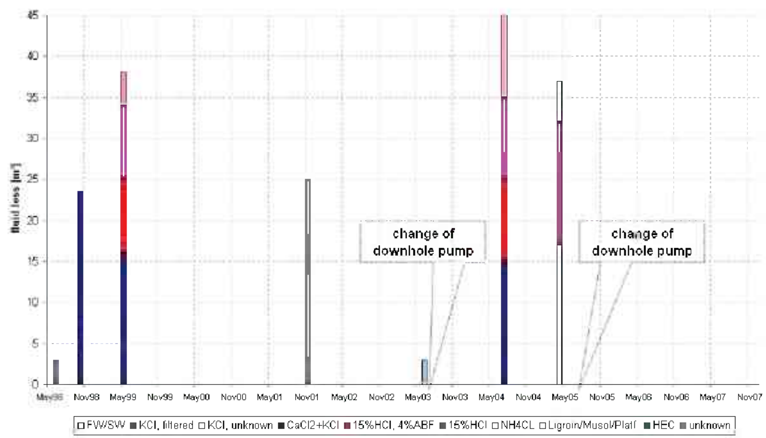




Productivity Indices (PI) over time



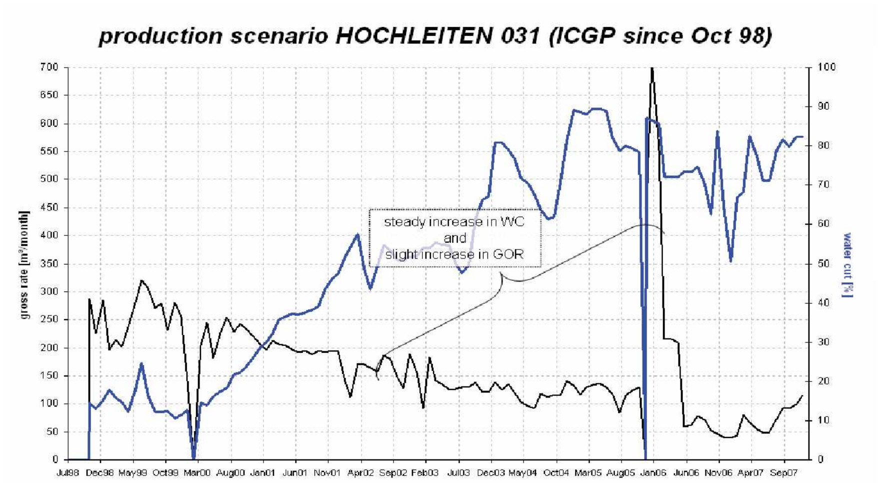
individual treatments and their fluid losses to the formation

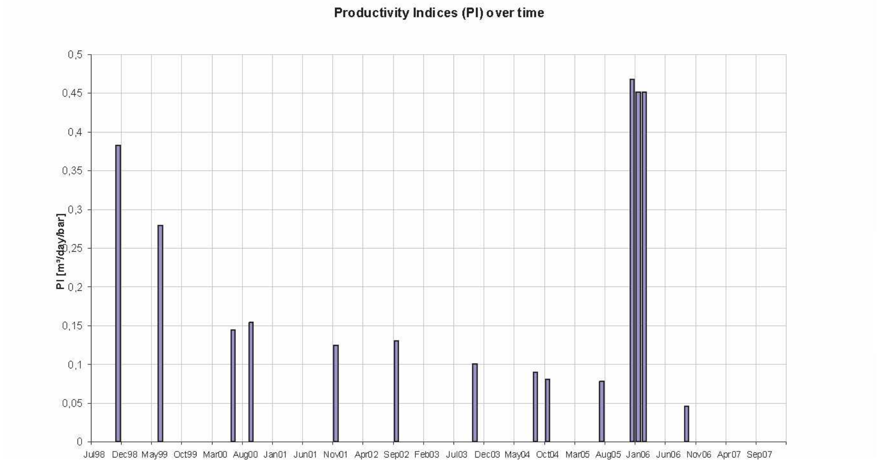


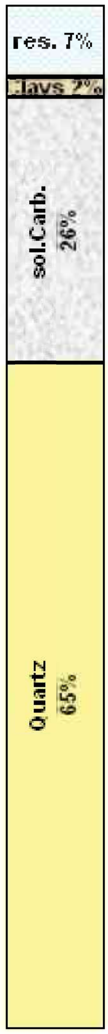
Overall clay content: 16% (sand)

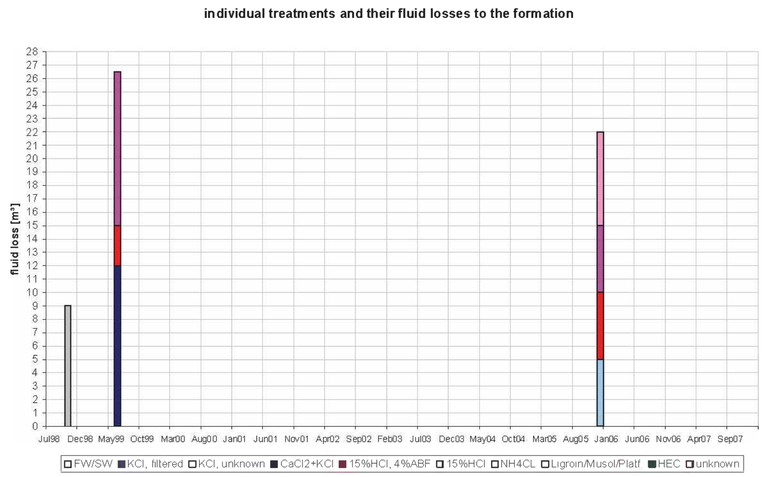
Heterogeneity: 13 (low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Jun98	perf. of upper interval	3 m³	5 days	
Oct98	ICGP installation	24 m³	9 days	
May99	acid stimulation	38 m³	1 days	γ_{max}=0.15 bar/m
Nov01	change of downhole pump	25 m³	1 days	
Jun03	change of downhole pump	3 m³	1 days	
Aug03	change of downhole pump	0 m³	2 days	
Jul04	acid stimulation	45 m³	1 days	γ_{max}=0.14 bar/m
Apr05	acid stimulation	37 m³	1 days	γ_{max}=0.15 bar/m
Aug05	change of downhole pump	0 m³	2 days	Sand at well bottom





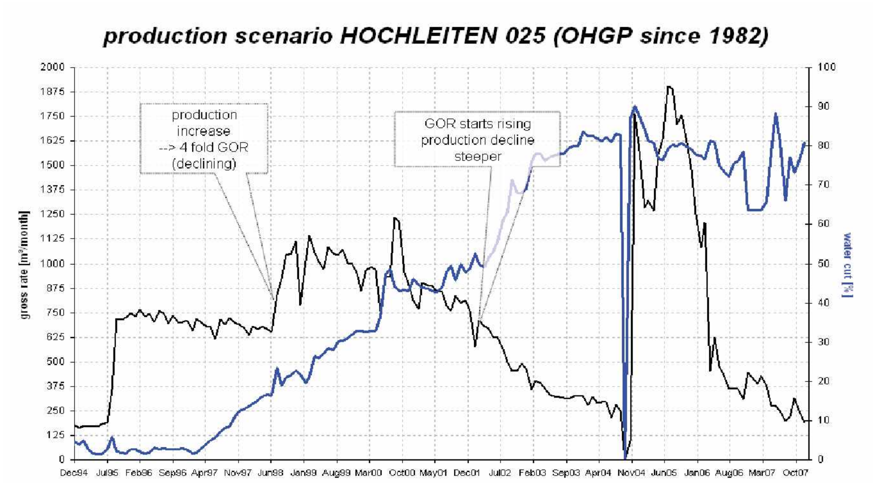


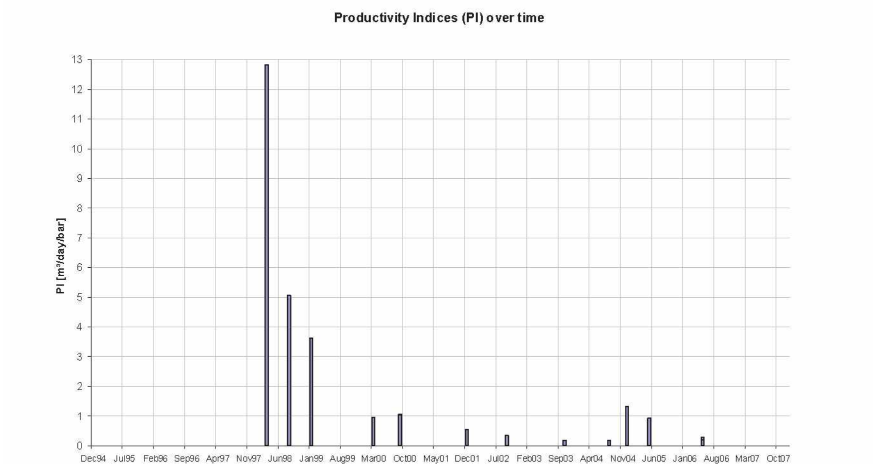


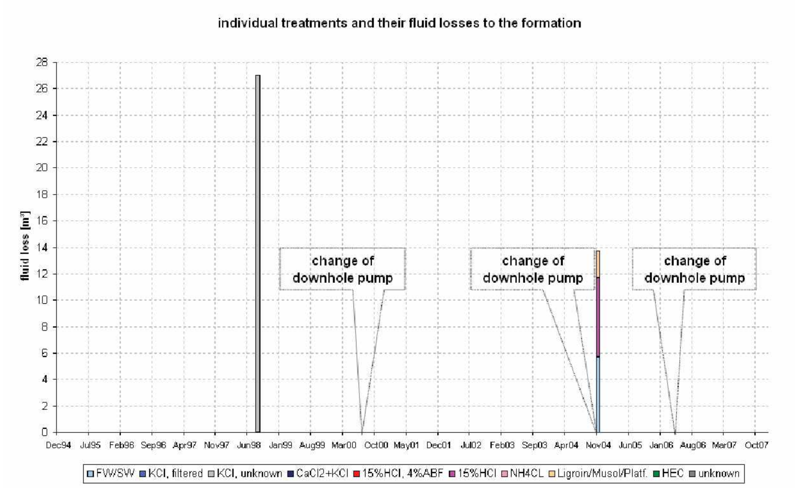
Overall clay content: 58% (sandy shale)

Heterogeneity: 13 (moderate)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Oct98	perf. of upper interval & installation of ICGP	9 m³	15 days	
Jun99	acid stimulation	27 m³	1 days	γ_{max}=0.15 bar/m
Dec05	acid stimulation	22 m³	11 days	γ_{max}=0.15 bar/m





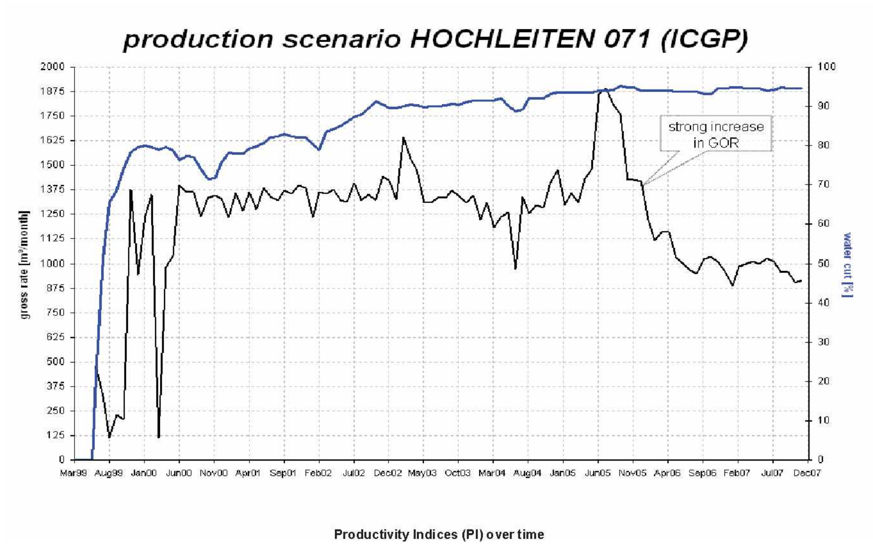


Overall clay content: 51% (shaly sand)

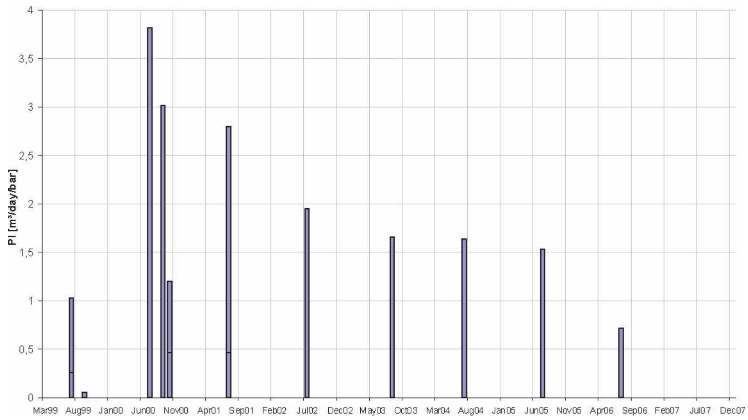
Heterogeneity: 23 (moderate)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Aug98	**change of downhole pump**	**27 m³**	**4 days**	
Aug00	**change of downhole pump**	**0 m³**	**2 days**	
Nov04	**change of downhole pump**	**0 m³**	**6 days**	
Nov04	**acid stimulation**	**14 m³**	**2 days**	γ_{max}**=0.13 bar/m**
Apr06	**change of downhole pump**	**0 m³**	**3 days**	

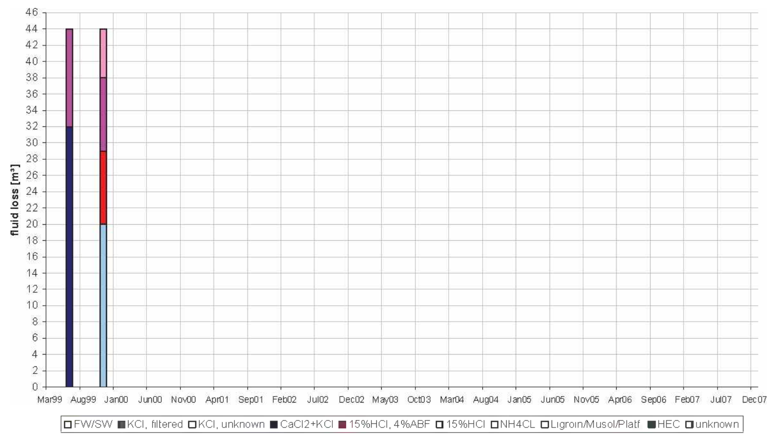
Open Hole Gravel Pack was inserted in 1982!



Productivity Indices (PI) over time



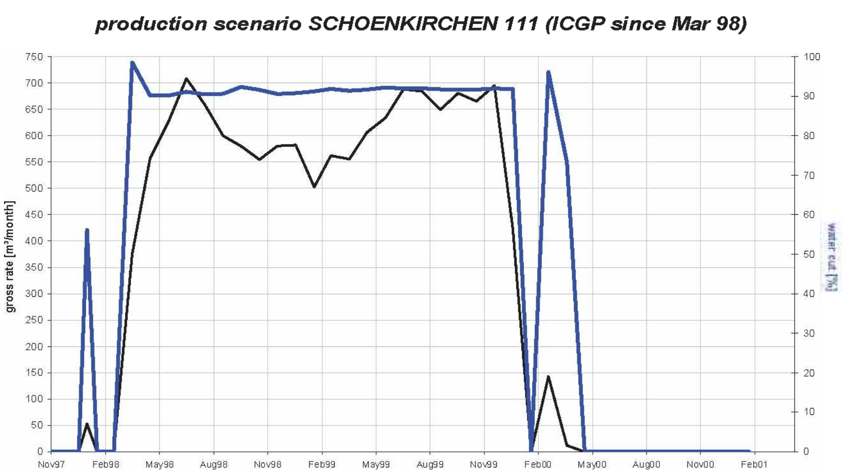
individual treatments and their fluid losses to the formation

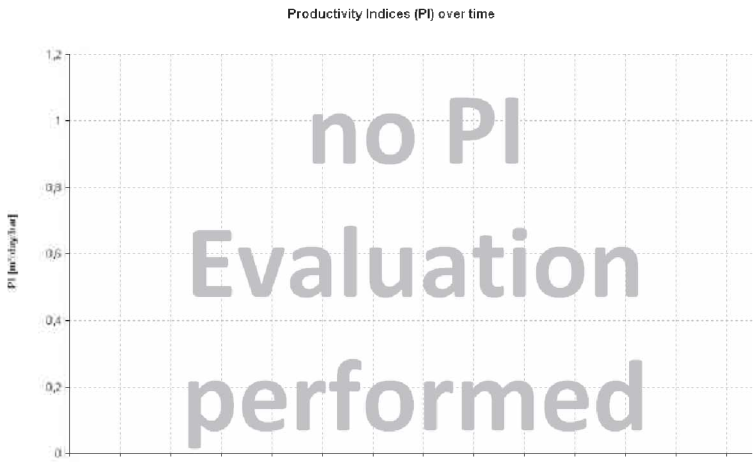


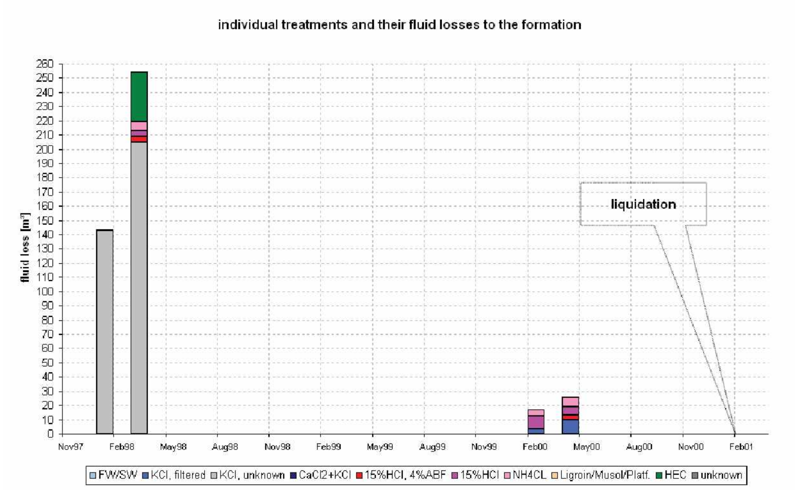
Overall clay content: 13% (sand)

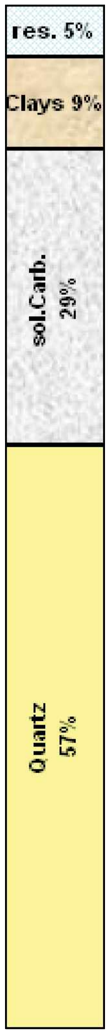
Heterogeneity: 5 (low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Jun99	**perf. of current interval**	**44 m³**	**8 days**	**During swabbing, sediments observed**
Nov99	**acid stimulation**	**44 m³**	**2 days**	**γ_{max}=0.14 bar/m**







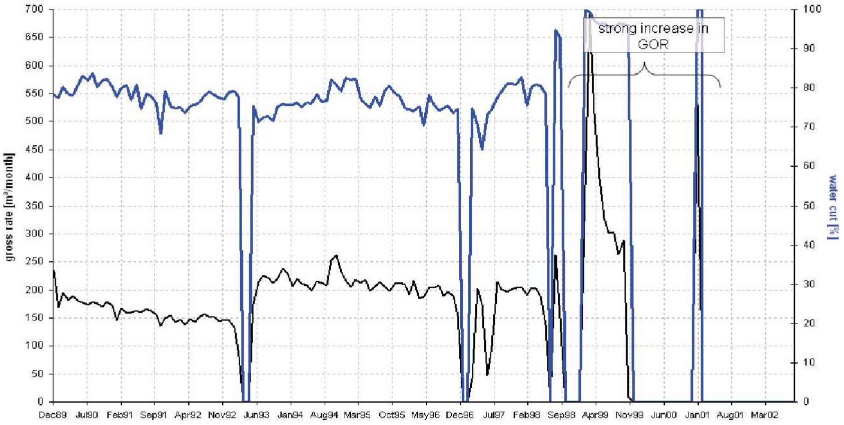


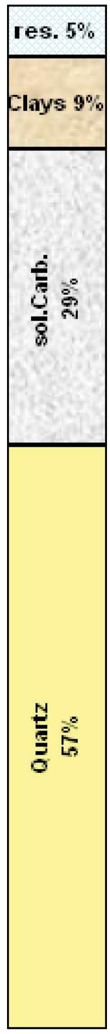
Overall clay content: 68% (shaly sand)

Heterogeneity: 17 (moderate)

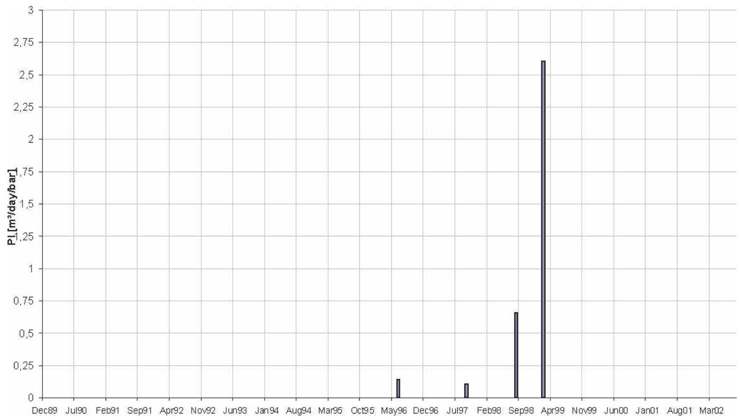
Date	Type of Workover	Σ(losses)	t(open)	Observations
Jan98	perf. of current interval	144 m³	8 days	Strong sand problems
Mar98	partial closure of perforation, acid stimulation and installation of ICGP	254 m³	12 days	γ_{max}=0.19 bar/m, Sand at well bottom
Feb00	acid stimulation	18 m³	2 days	Clay stabilizing treatment
Apr00	acid stimulation	26 m³	1 days	Sand at well bottom
Feb01	liquidation	0 m³	5 days	

production scenario SCHOENKIRCHEN 133 (no ICGP)

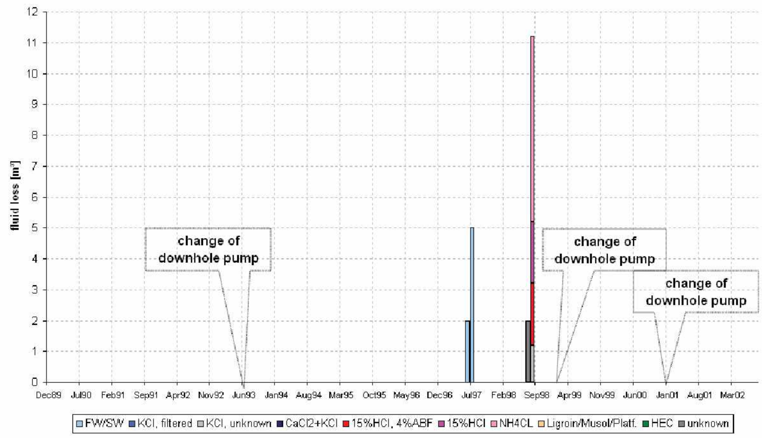




Productivity Indices (PI) over time



individual treatments and their fluid losses to the formation



Overall clay content:

44%

(shaly sand)

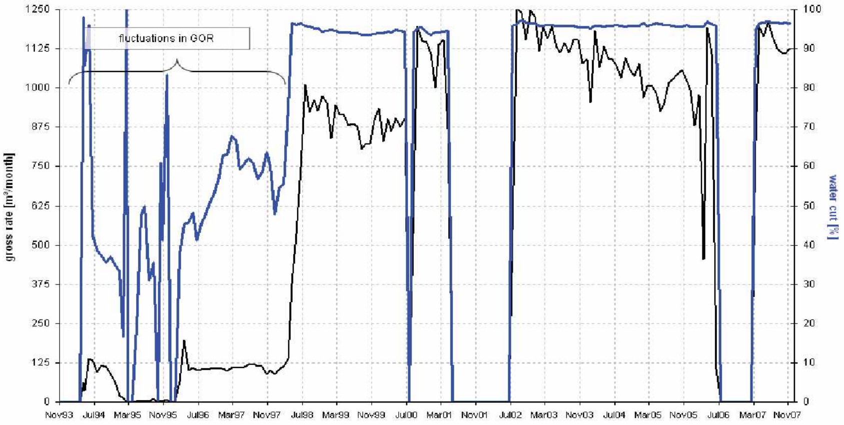
Heterogeneity:

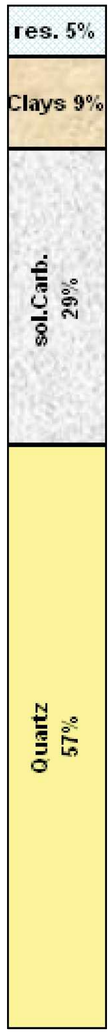
26

(moderate)

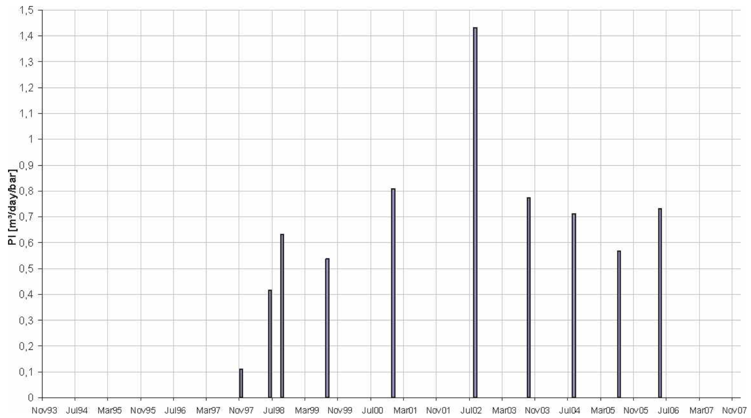
Date	Type of Workover	Σ(losses)	t(open)	Observations
May93	change of downhole pump	0 m³	5 days	
Jun97	change of downhole pump	2 m³	3 days	
Jul97	change of downhole pump	5 m³	2 days	
Jul98	change of downhole pump	2 m³	9 days	
Aug98	acid stimulation	11 m³	2 days	γ_{max}=0.17 bar/m
Jan99	change of downhole pump	0 m³	5 days	Protectors abraded
Jan01	change of downhole pump	0 m³	7 days	Tubing abraded

production scenario SCHOENKIRCHEN 256 (no ICGP)

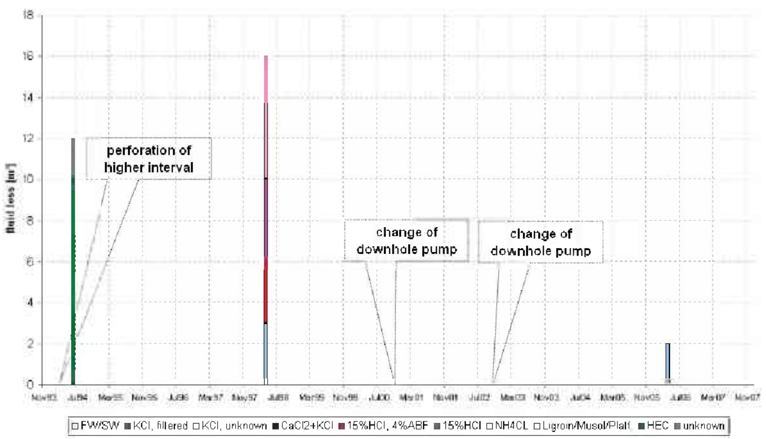




Productivity Indices (PI) over time



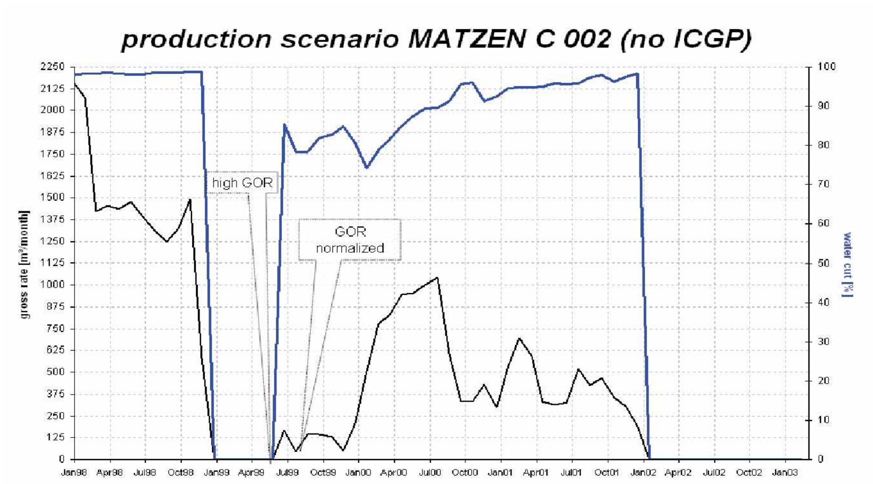
individual treatments and their fluid losses to the formation

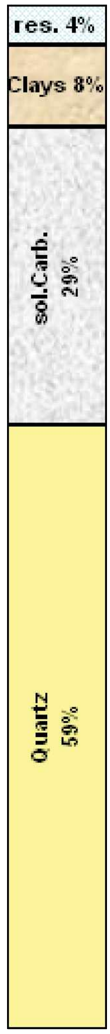


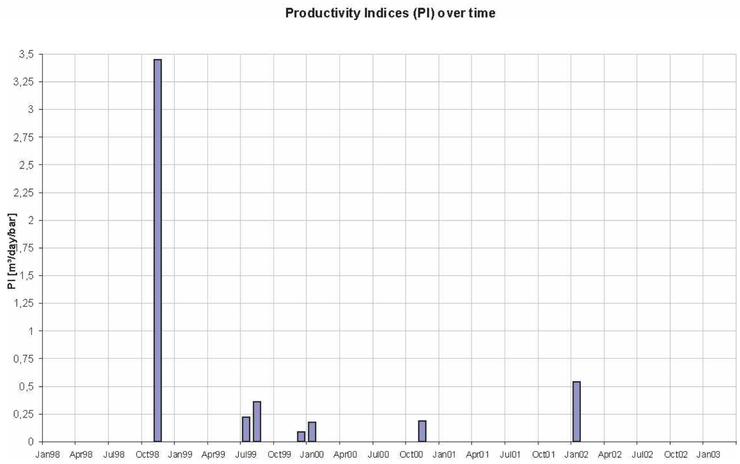
Overall clay content: 37% (shaly sand)

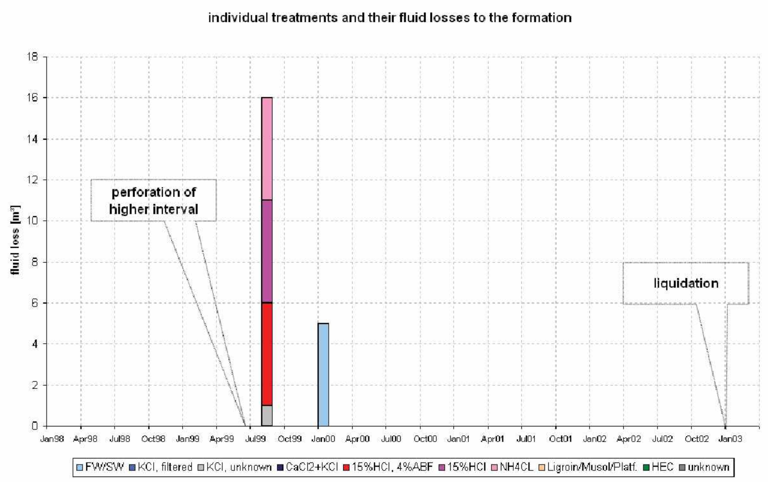
Heterogeneity: 18 (moderate)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Apr94	perf. of upper interval	0 m³	7 days	Corrosion hole in tubing, sand at well bottom
Jun94	change of downhole pump	12 m³	4 days	
Apr98	change of downhole pump / acid stimulation	16 m³	3 days	γ_{max}=0.15 bar/m
Sep00	change of downhole pump	0 m³	2 days	
Aug02	change of downhole pump	0 m³	5 days	Corrosion holes in tubing string
Apr06	change of downhole pump	2 m³	2 days	Corrosion holes in tubing string





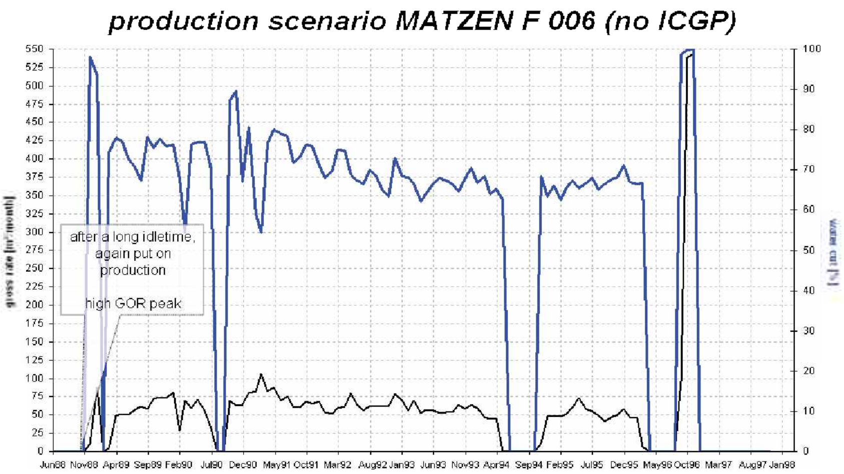


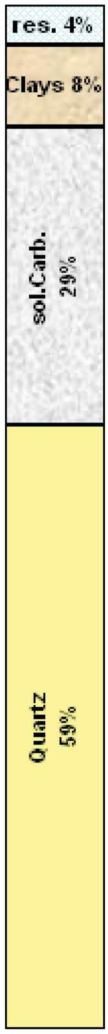


Overall clay content: 58% (sandy shale)

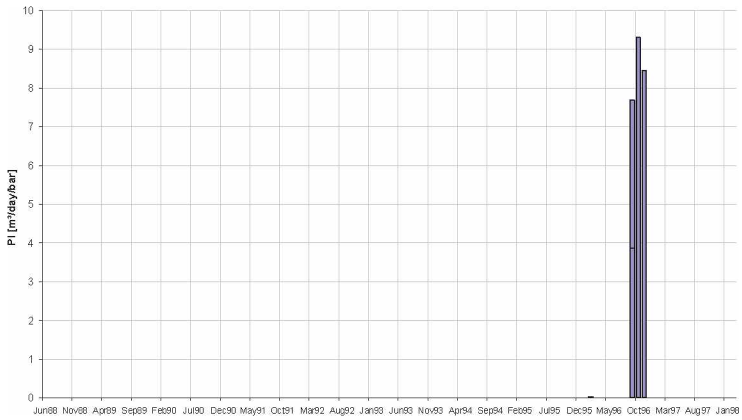
Heterogeneity: 12 (moderate)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Jun99	perf. of upper interval	0 m³	6 days	~25 corrosion holes in tubing string
Aug99	acid stimulation	16 m³	1 days	γ_{max}=0.15 bar/m
Jan00	change to gaslift installation	5 m³	3 days	
Mar03	liquidation	0 m³	3 days	

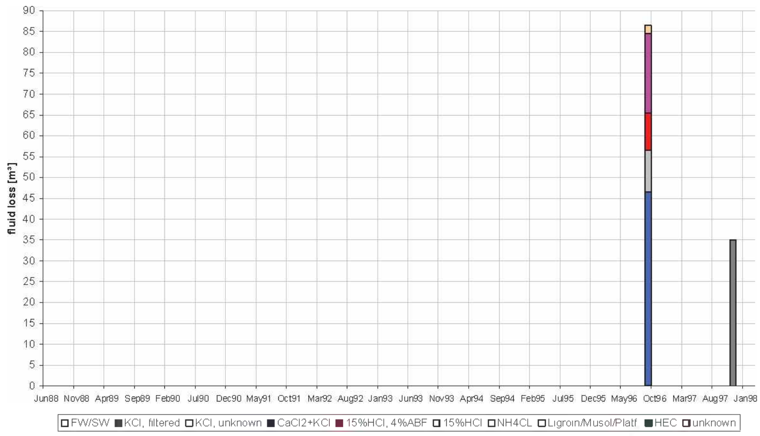




Productivity Indices (PI) over time



individual treatments and their fluid losses to the formation



Overall clay content:

21%

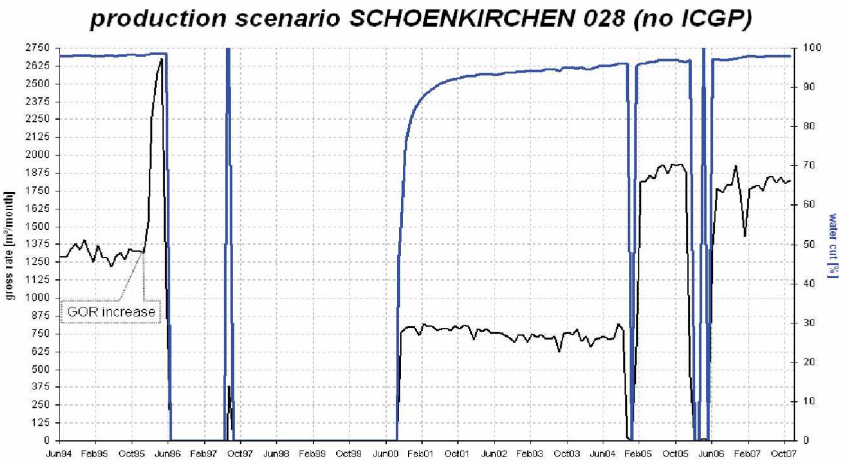
(shaly sand)

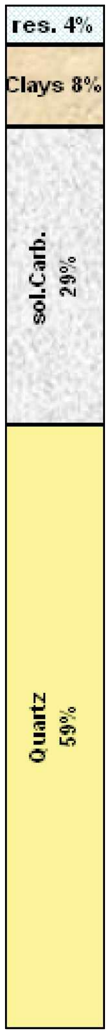
Heterogeneity:

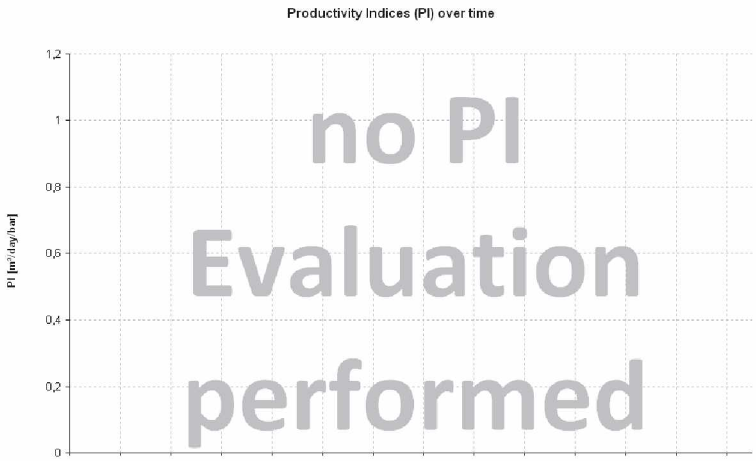
8

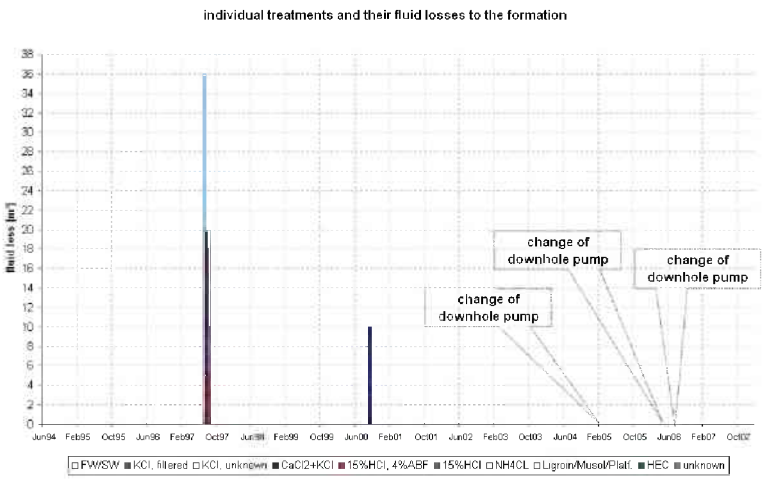
(low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Sep96	change of downhole pump / acid stimulation	87 m³	8 days	γ_{max}=0.16 bar/m
Nov97	liquidation	35 m³	2 days	









Overall clay content:

57%

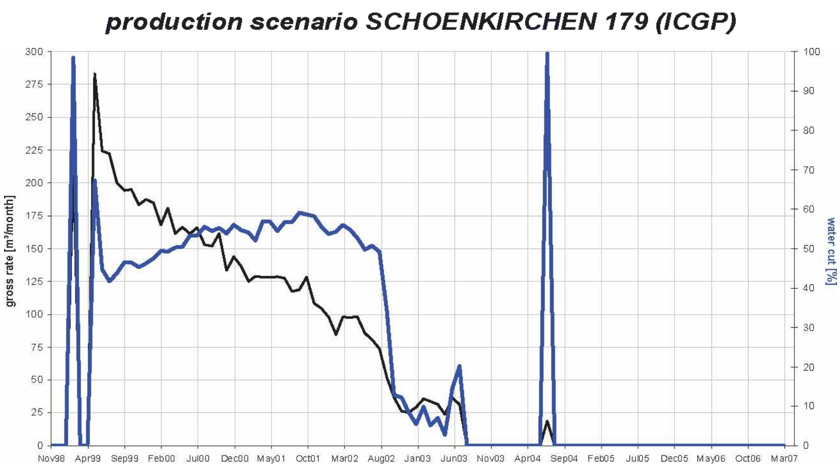
(sandy shale)

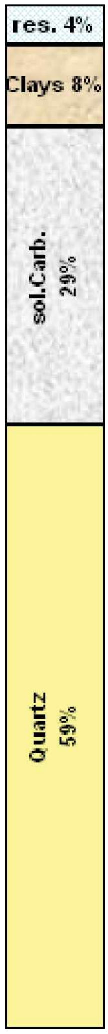
Heterogeneity:

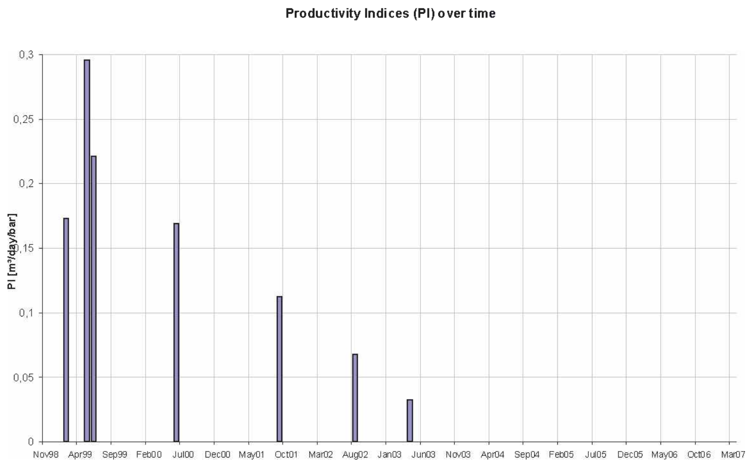
26

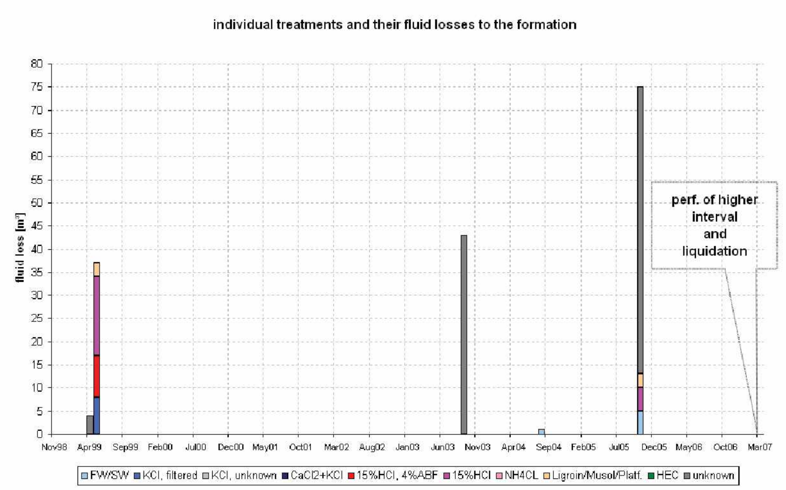
(high)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Jul97	perf. of lower interval	36 m³	9 days	Sand at well bottom
Aug97	acid stimulation	20 m³	1 days	γ_{max}=0.16 bar/m
Sep00	perf. of upper interval	10 m³	10 days	
Feb05	change of downhole pump	0 m³	6 days	
May06	change of downhole pump	0 m³	2 days	Corrosion holes in tubing string
Jul06	change of downhole pump	0 m³	2 days	





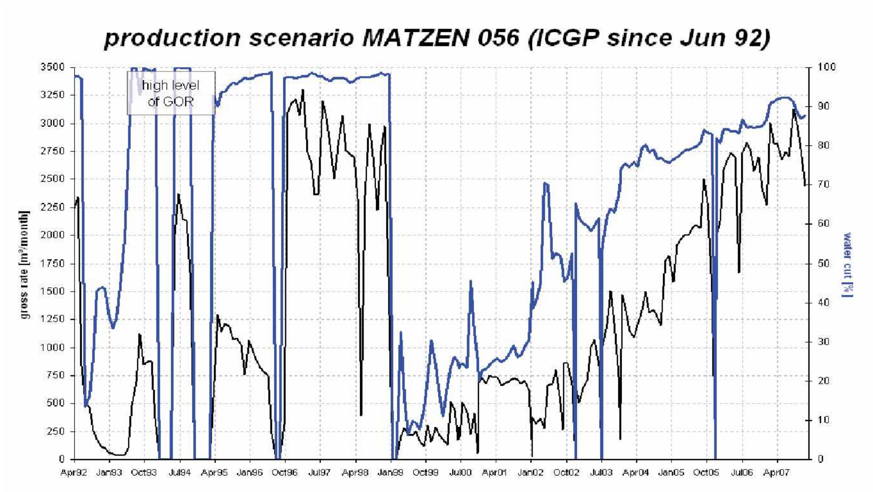


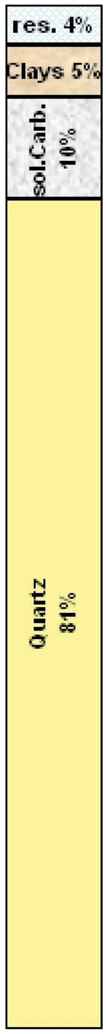


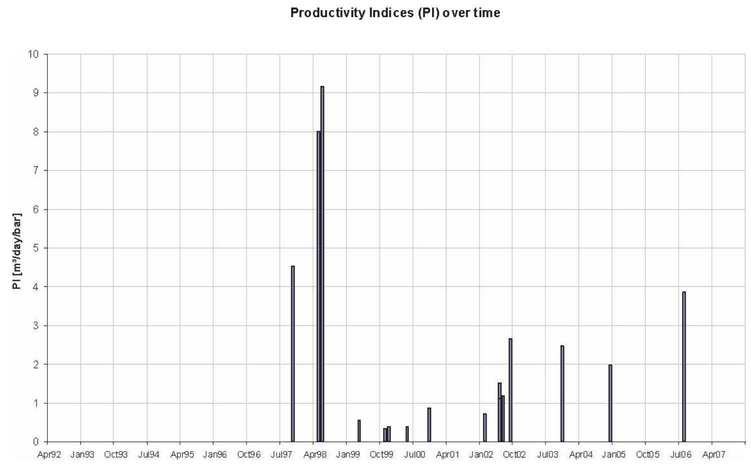
Overall clay content: 43% (sandy shale)

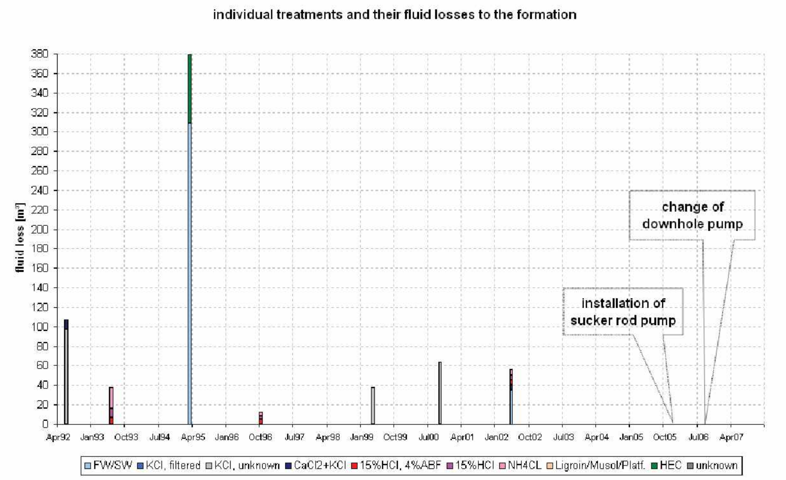
Heterogeneity: 19 (high)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Apr99	change of downhole pump	4 m³	4 days	
May99	acid stimulation	37 m³	1 days	γ_{max}=0.15 bar/m
Sep03	change to PCP	43 m³	6 days	Sand at well bottom, sediments recorded
Aug04	controlling of PCP	1 m³	7 days	Sand at well bottom
Oct05	production attempt and stimulation	75 m³	6 days	
Mar07	perf. of upper interval and liquidation	0 m³	12 days	





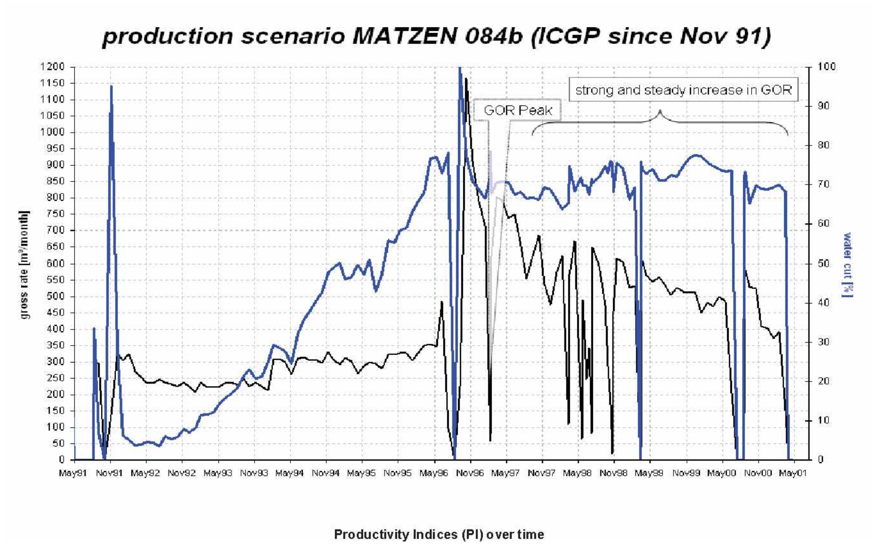


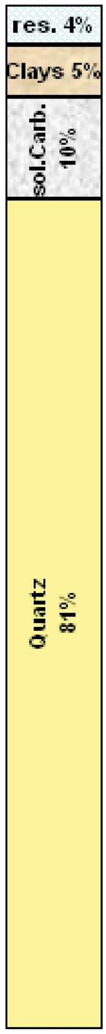


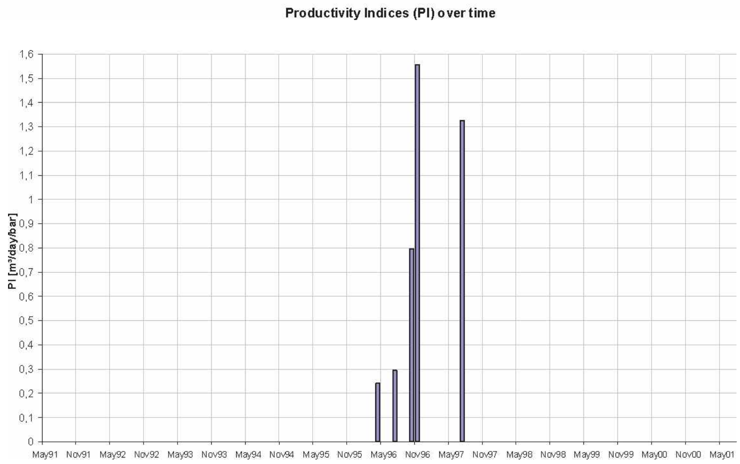
Overall clay content: 10% (sand)

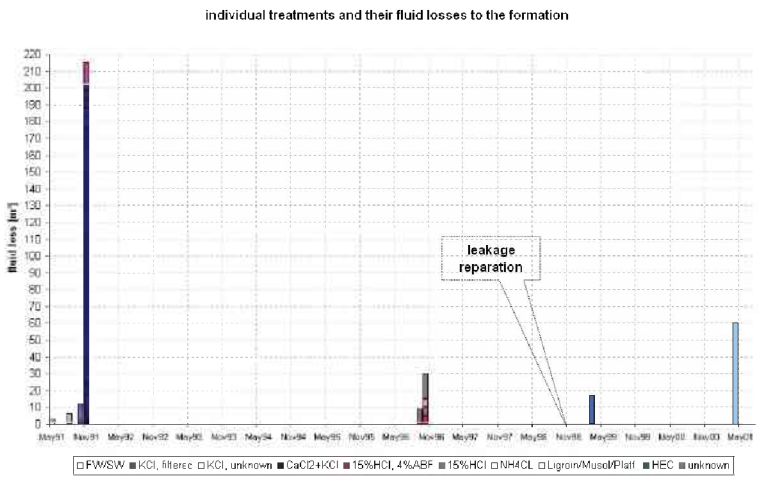
Heterogeneity: 3 (low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Jun92	additional perforation / ICGP installation	107 m³	32 days	Sand at well bottom
Jun93	acid stimulation	38 m³	1 days	γ_{max}=0.13 bar/m
Mar95	perf. of higher interval	379 m³	20 days	Lot of sand swabbed
Oct96	acid stimulation	13 m³	1 days	γ_{max}=0.15 bar/m
Apr99	perf. of higher interval	38 m³	8 days	
Oct00	ICGP installation	64 m³	9 days	Sand at well bottom
May02	swabbing and acid stimulation	56 m³	4 days	
Dec05	installation of sucker rod pump	0 m³	3 days	
Aug06	change of downhole pump	0 m³	2 days	





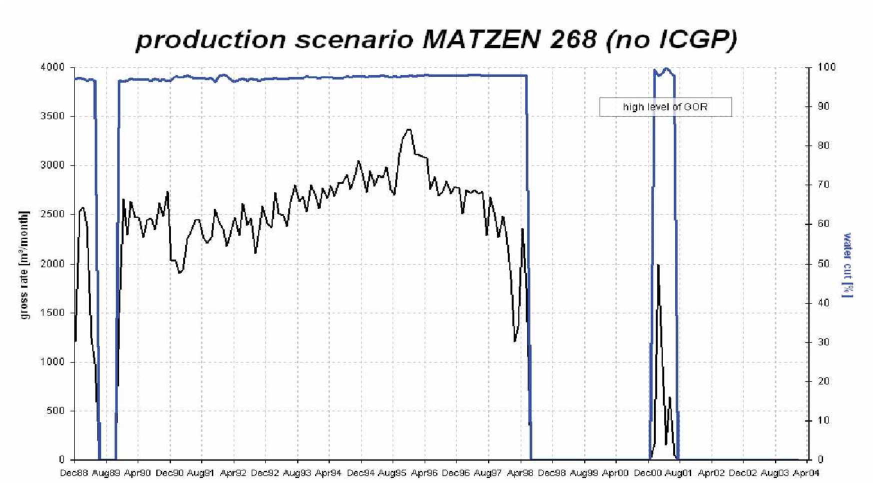


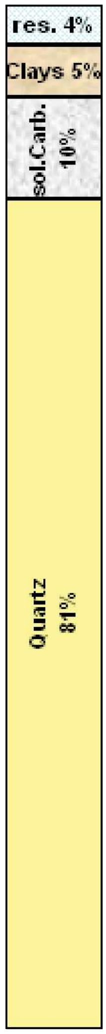


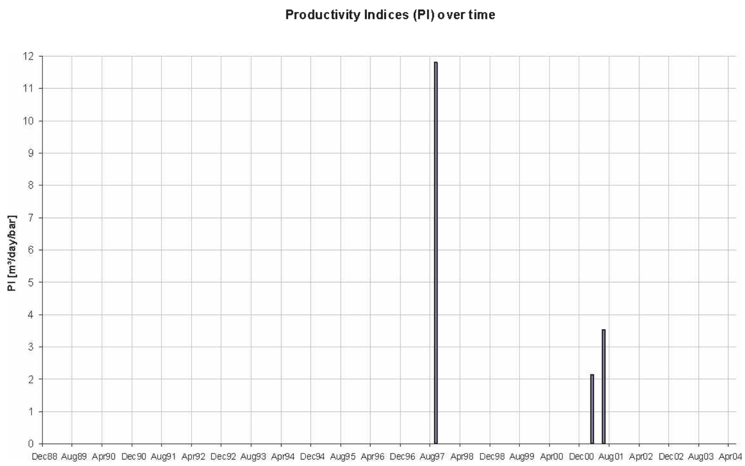
Overall clay content: 11% (sand)

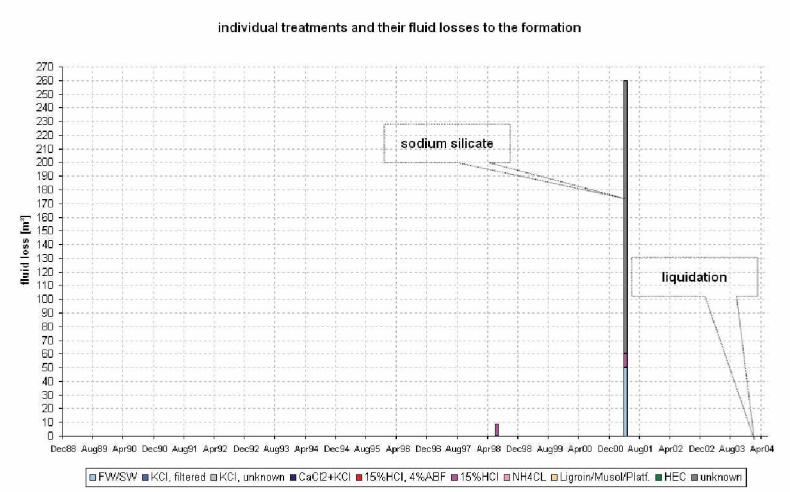
Heterogeneity: 8 (low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
May91	sidetrack drilling	3 m³	22 days	
Aug91	first perforation	6 m³	9 days	
Oct91	change of downhole pump	12 m³	4 days	
Nov91	ICGP installation	215 m³	41 days	Pack sand circulated back 1st time
Sep96	casing leackage reparation	9 m³	16 days	
Oct96	acid stimulation	30 m³	3 days	γ_{max}=0.27 bar/m
Nov98	leakage reparation	0 m³	3 days	
Mar99	change of downhole pump	17 m³	3 days	
Apr01	liquidation	60 m³	28 days	









Overall clay content:

32%

(shaly sand)

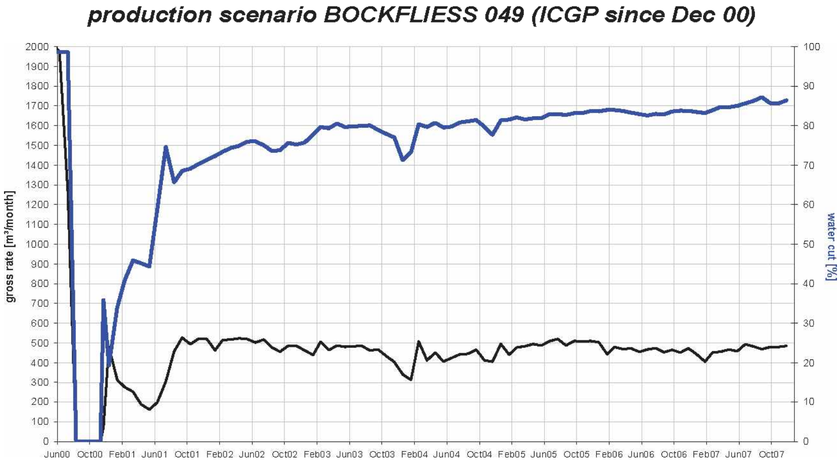
Heterogeneity:

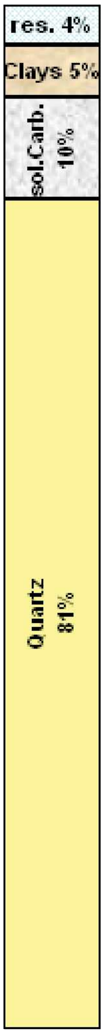
18

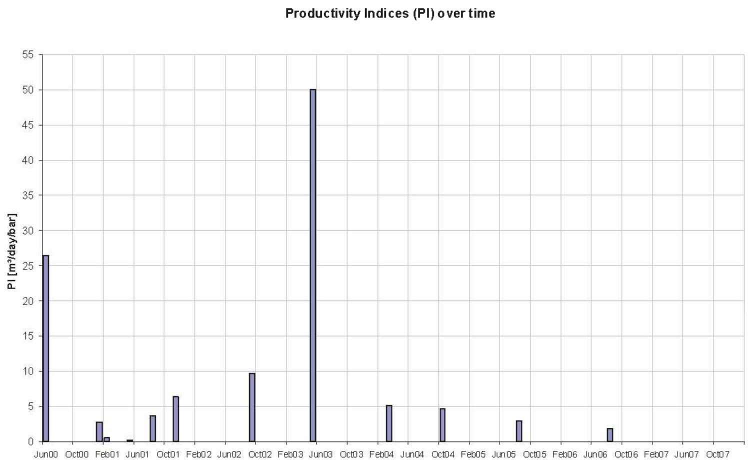
(moderate)

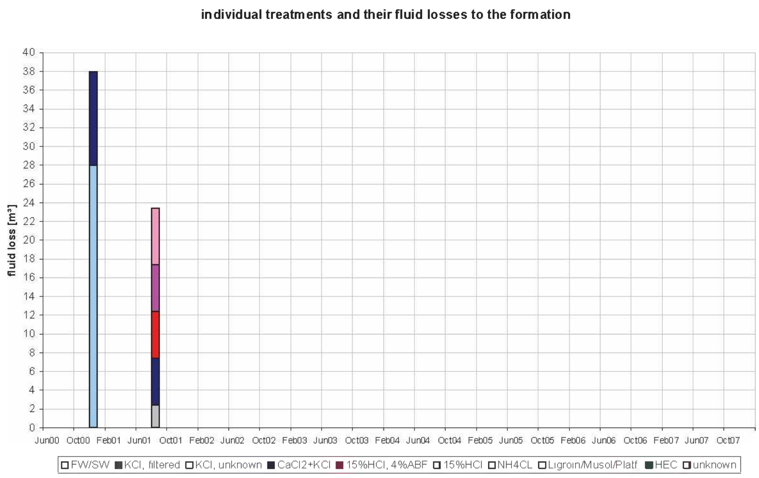
Date	Type of Workover	Σ(losses)	t(open)	Observations
Jun98	acid stimulation	9 m³	1 days	
Apr01	waterblock and acidizing	260 m³	25 days	γ_{max}=0.11 bar/m
Feb04	liquidation	0 m³	3 days	

Stimulation was performed for a better injectivity of sodium silicate, therefore no stimulation in sence of this master thesis.





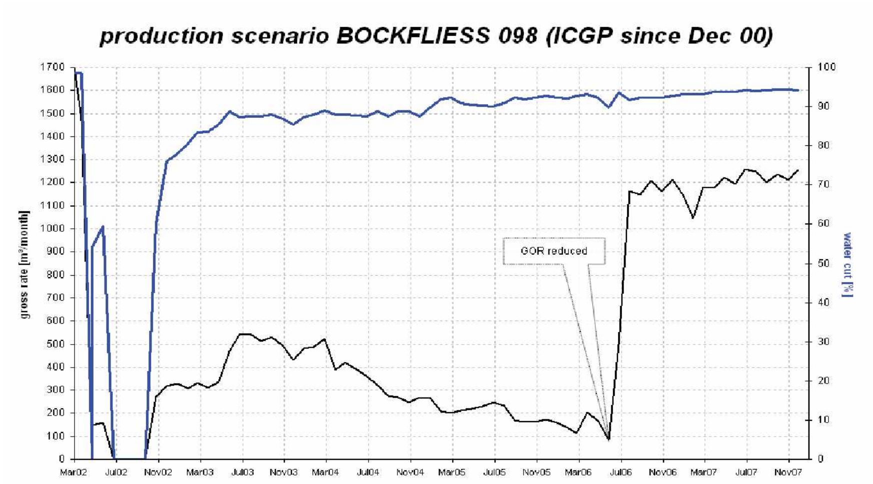


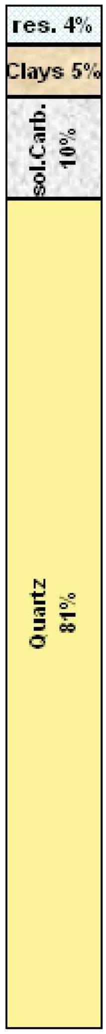


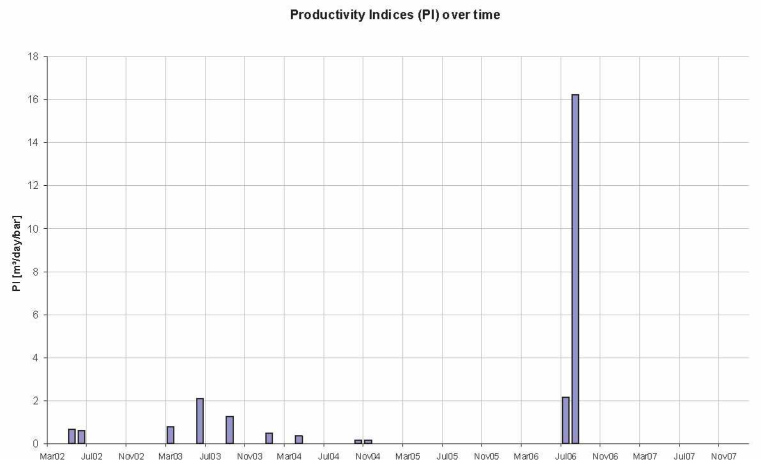
Overall clay content: 13% (shaly sand)

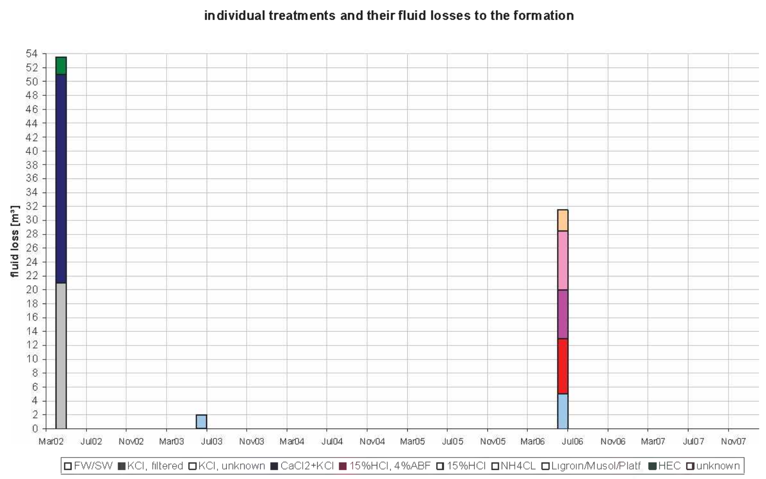
Heterogeneity: 3 (low)

Date	Type of Workover	Σ(losses)	t(open)	Observations
Dec00	perf. of upper interval / ICGP installation	38 m³	14 days	
Aug01	acid stimulation	23 m³	3 days	γ_{max}=0.14 bar/m





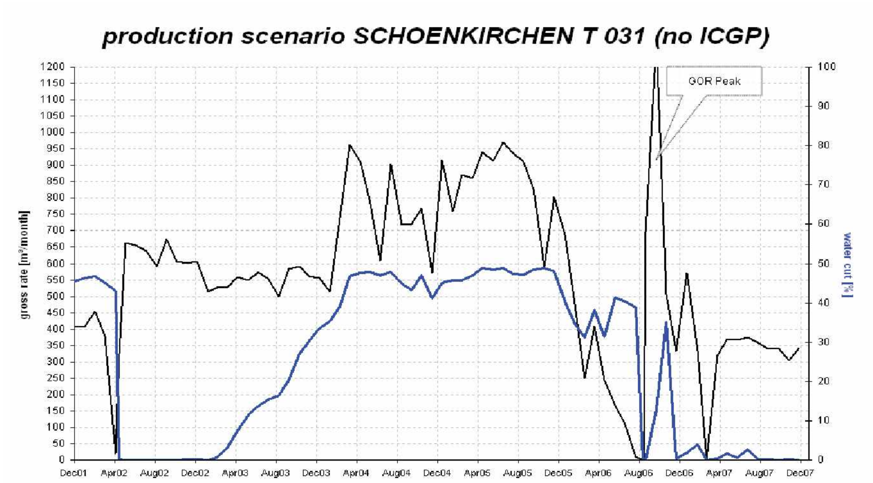


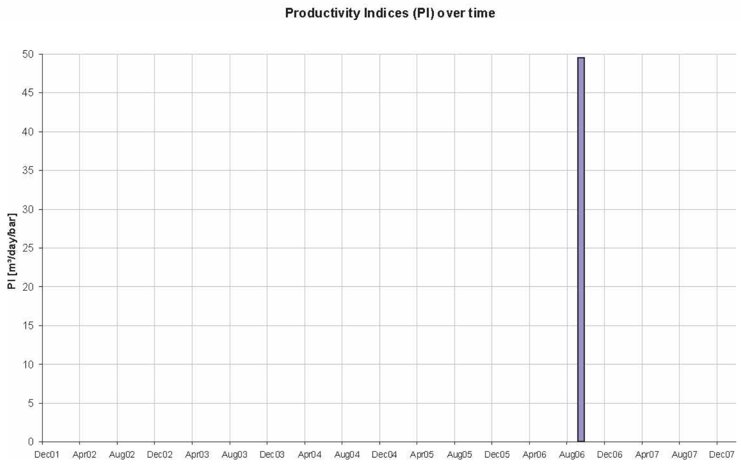


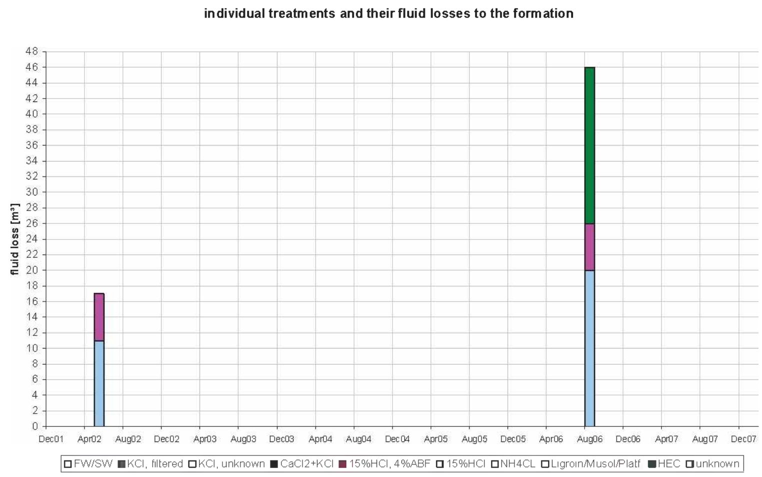
Overall clay content: 27% (sandy shale)

Heterogeneity: 1 (low)

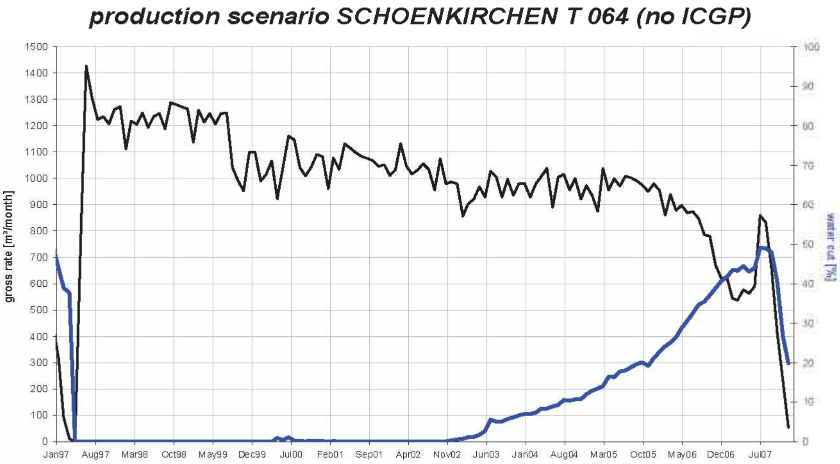
Date	Type of Workover	Σ(losses)	t(open)	Observations
Dec00	perf. of upper interval / ICGP installation	38 m³	14 days	
Aug01	acid stimulation	23 m³	3 days	γ_{max}=0.14 bar/m

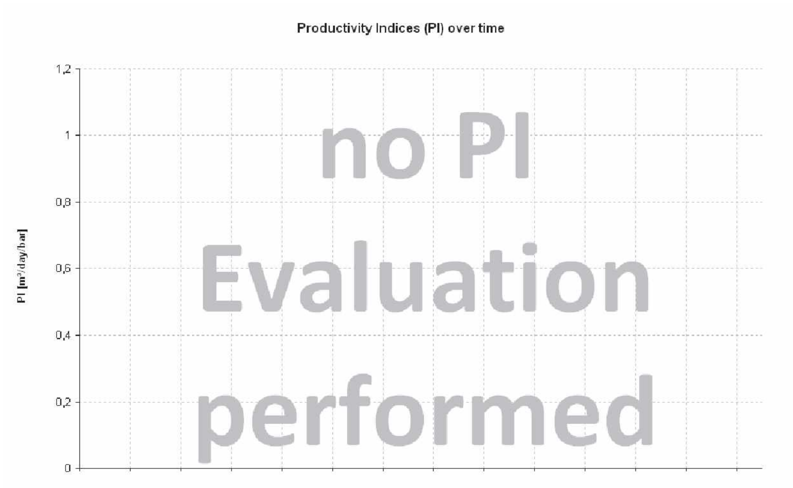


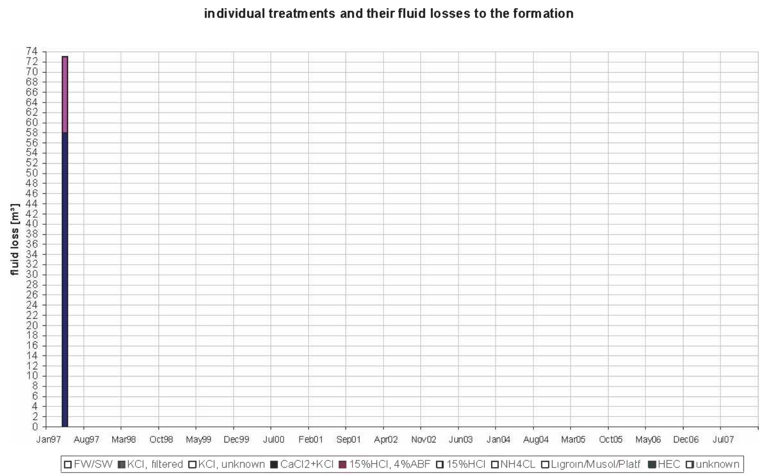




Date	Type of Workover	Σ(losses)	t(open)	Observations
May02	perf. of upper interval / acid stimulation	17 m³	14 days	
Aug06	perf. of upper interval / acid stimulation	46 m³	28 days	γ_{max}=0.16 bar/m

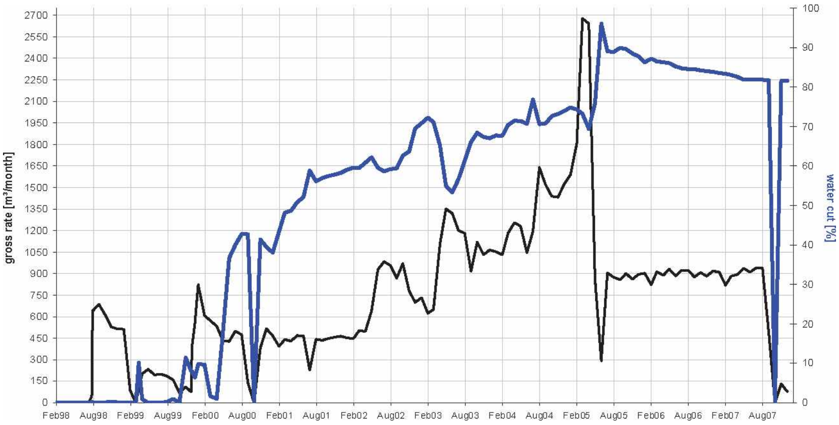




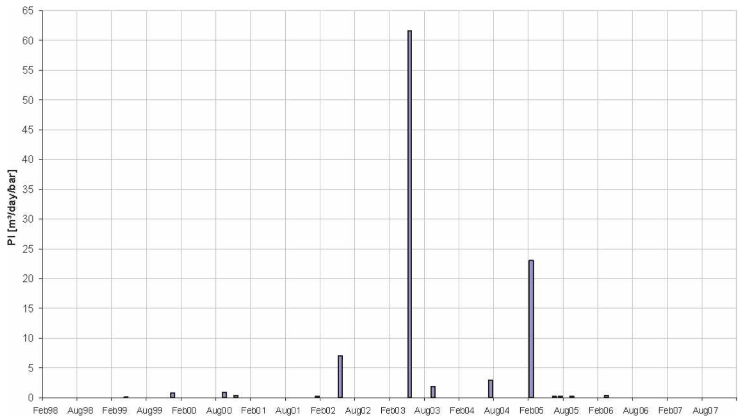


Date	Type of Workover	Σ(losses)	t(open)	Observations
Apr97	**perf. of upper interval / acid stimulation**	**73 m³**	**49 days**	**γ_{max}=0.18 bar/m**

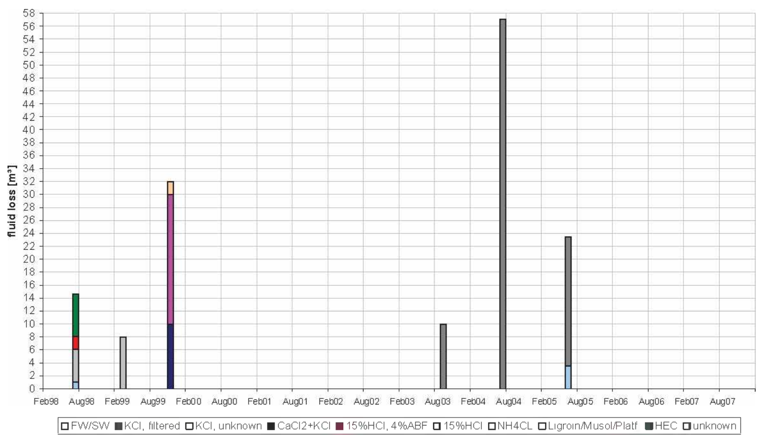
production scenario SCHOENKIRCHEN T 078 (no ICGP)



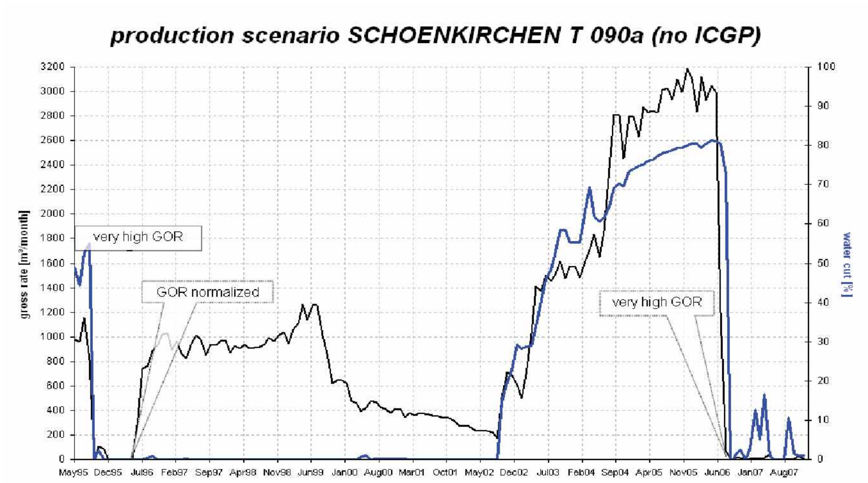
Productivity Indices (PI) over time

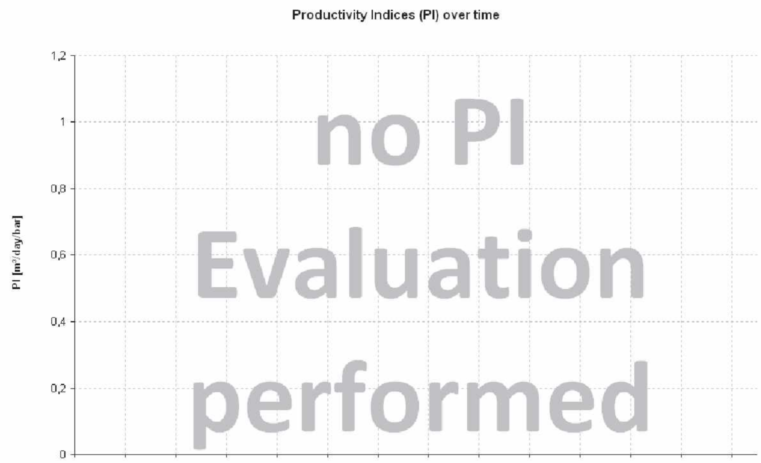


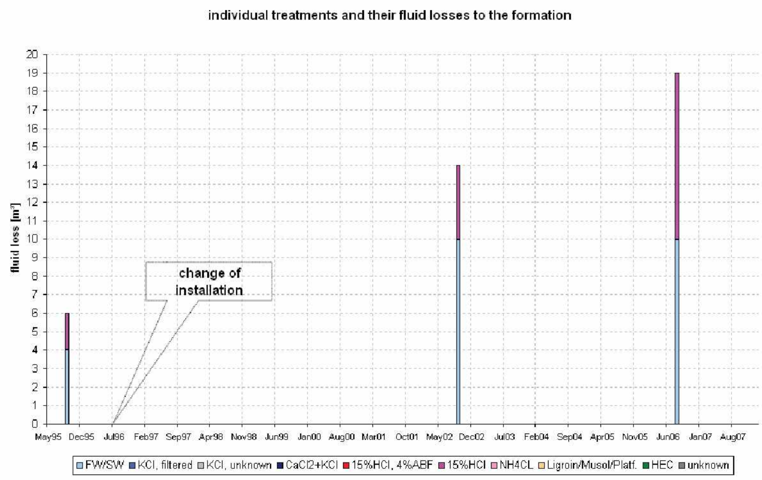
individual treatments and their fluid losses to the formation



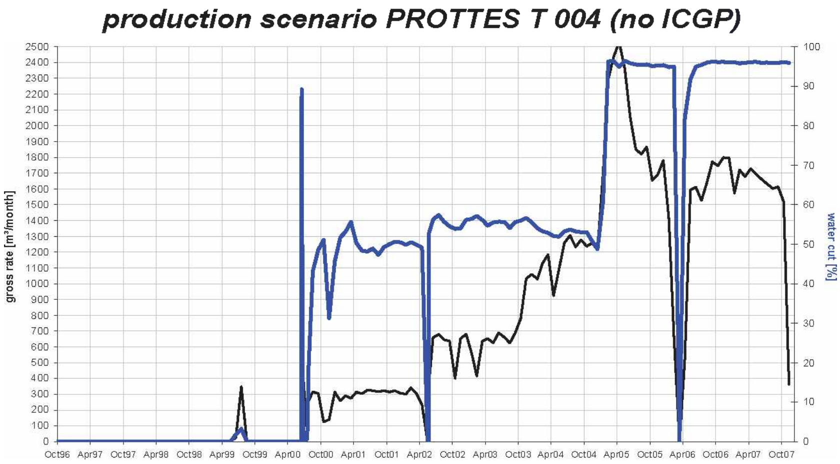
Date	Type of Workover	Σ(losses)	t(open)	Observations
Jul98	perf. of upper interval	15 m³	19 days	
Mar99	installation of sucker rod pump	8 m³	5 days	
Nov99	acid stimulation	32 m³	6 days	γ_{max}=0.15 bar/m
Sep03	change of downhole pump	10 m³	2 days	
Jul04	change of downhole pump	57 m³	5 days	Tubing with hot water cleaned
Jun05	change of downhole pump	24 m³	12 days	Tubing with hot water cleaned

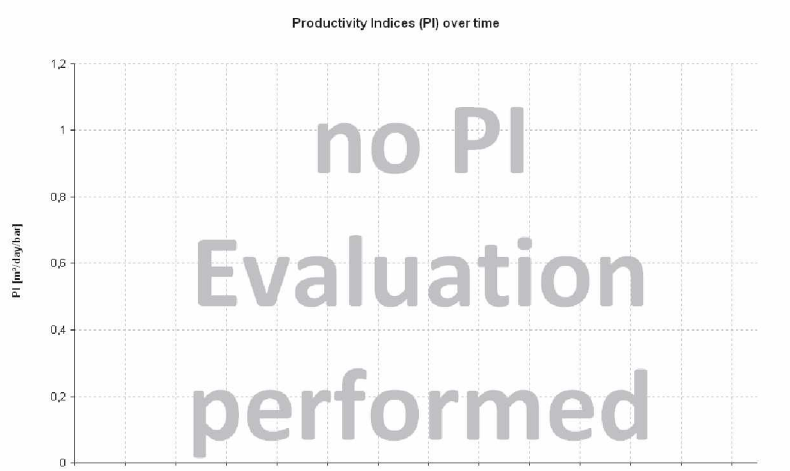


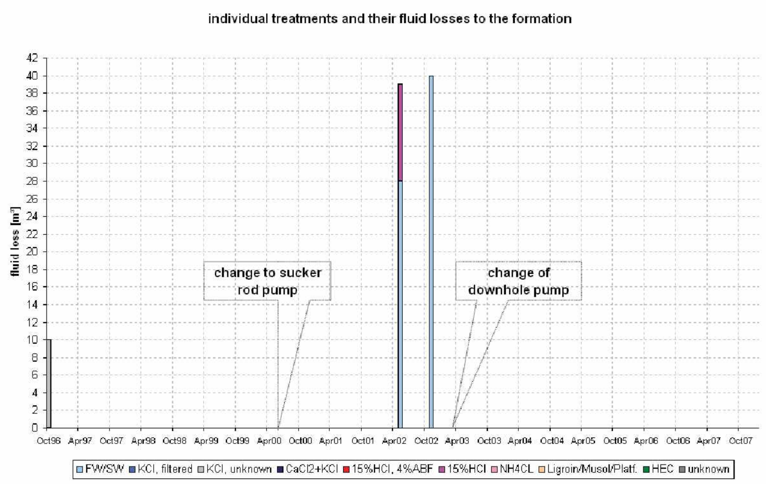




Date	Type of Workover	Σ(losses)	t(open)	Observations
Sep95	perf. of upper interval / acid stimulation	6 m³	39 days	
Jul96	change of installation	0 m³	6 days	
Sep02	acid stimulation	14 m³	9 days	γ_{max}=0.17 bar/m
Aug06	perf. of upper interval / acid stimulation	19 m³	19 days	

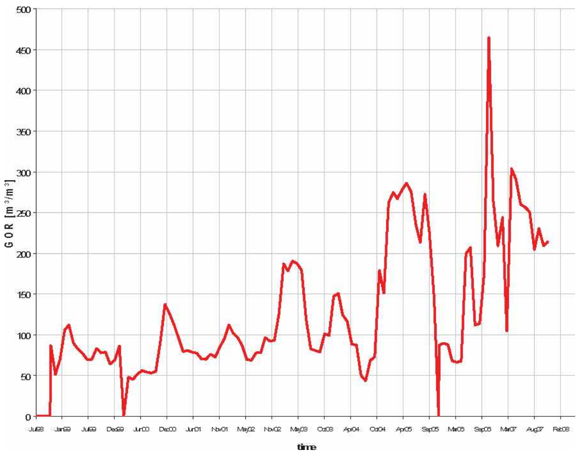




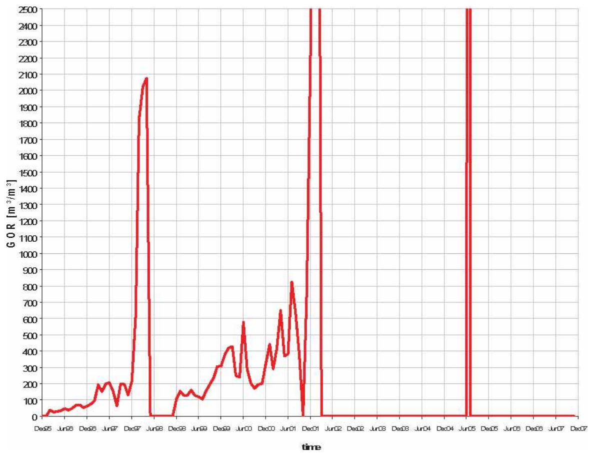


Date	Type of Workover	Σ(losses)	t(open)	Observations
Oct96	perf. of lower interval	10 m³	40 days	
Jun00	change to sucker rod pump	0 m³	15 days	
May02	additional perforation and acid stimulation	39 m³	19 days	γ_{max}=0.11 bar/m
Nov02	change of downhole pump	40 m³	4 days	Tubing with hot water cleaned
Mar03	change of downhole pump	0 m³	3 days	

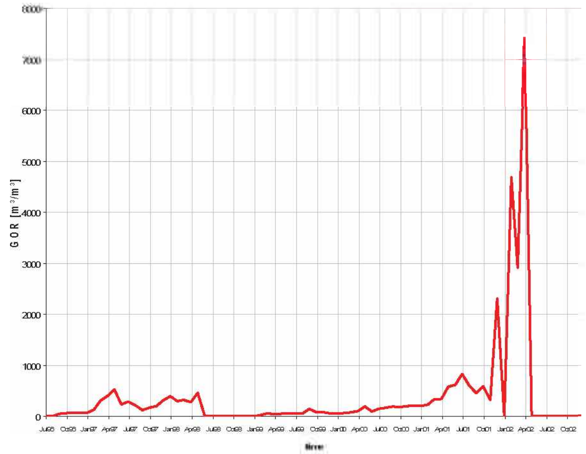
HOCHLEITHEN 031



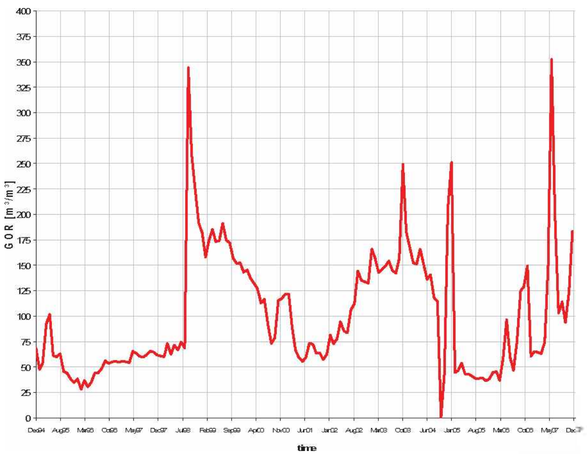
PIRAWARTH 079



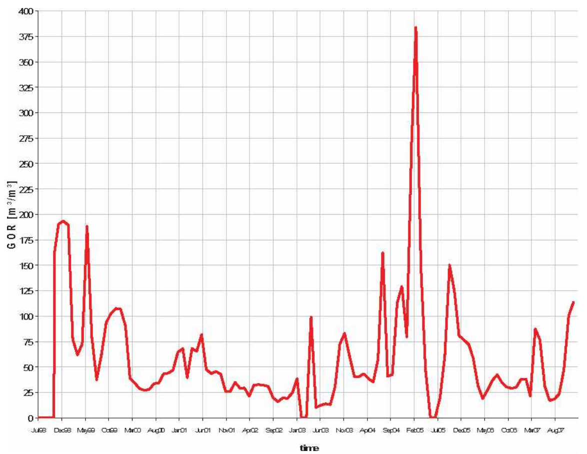
PIRAWARTH 015



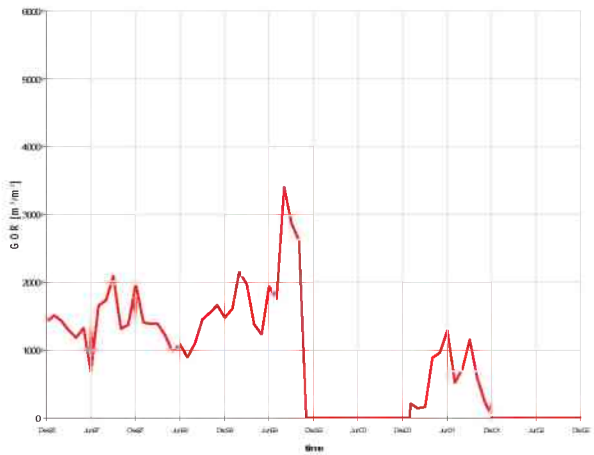
HOCHLEITEN 025

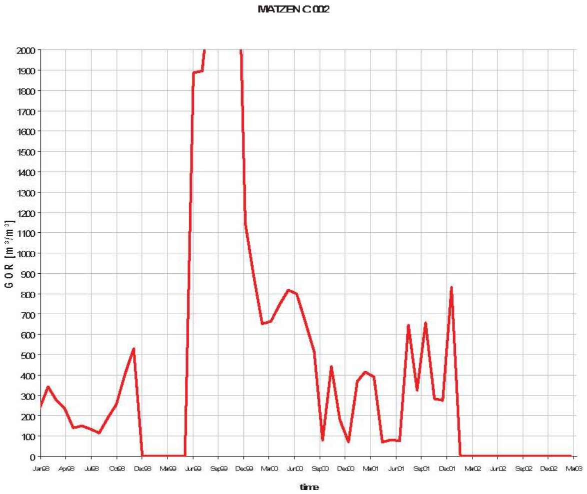


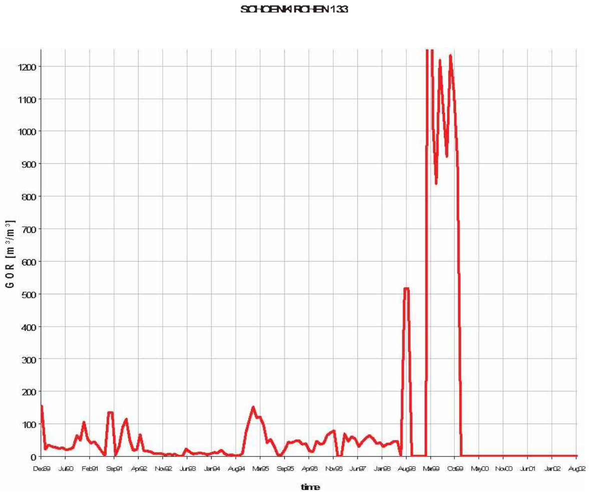
HOCHLEITEN 013Y

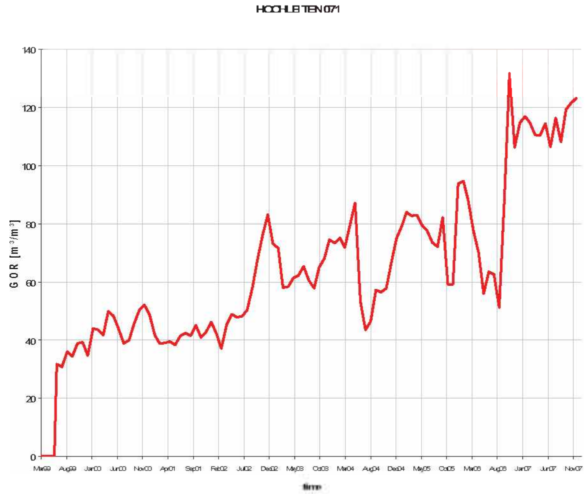


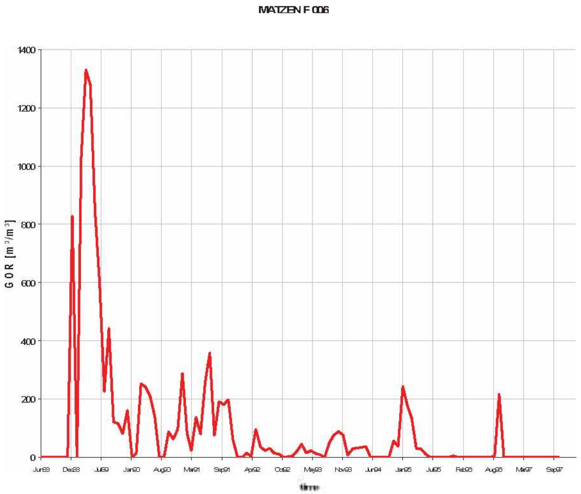
PIRAWARTH 024

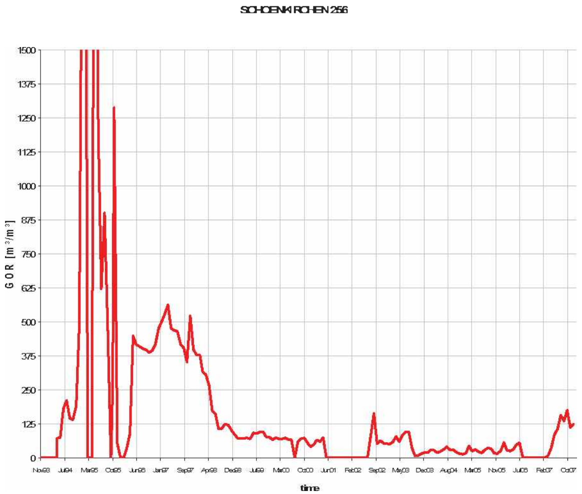


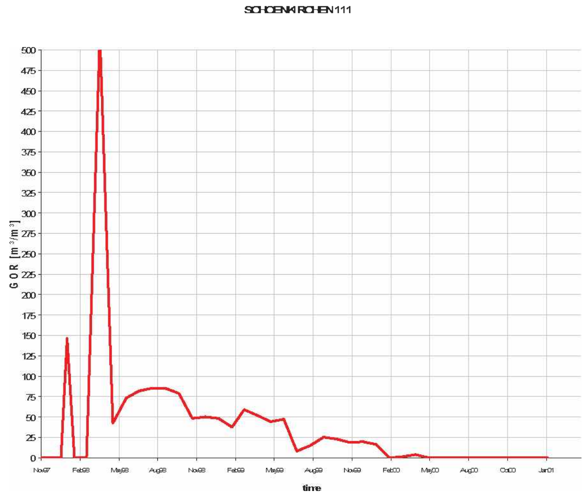

MATZEN C 002
G O R [m³/m³]
time


SCHOENKIRCHEN 133
G O R [m³/m³]
time

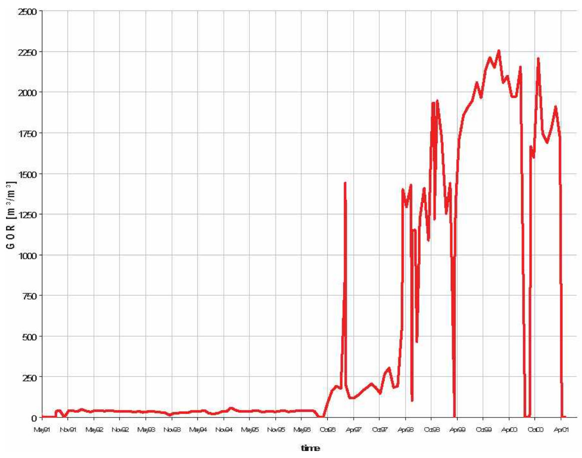

HOCHLEITEN 071
G O R [m³/m³]
time


MATZEN F 006
G O R [m³/m³]
time

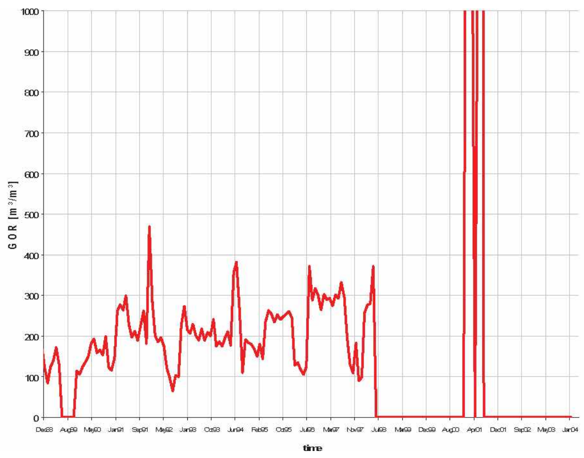

SCHOENKIRCHEN 256
G O R [m³/m³]
time


SCHOENKIRCHEN 111
G O R [m³/m³]
time

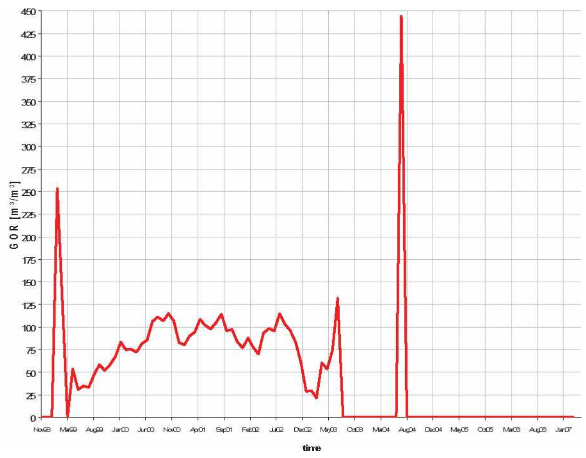
MATZEN 084b



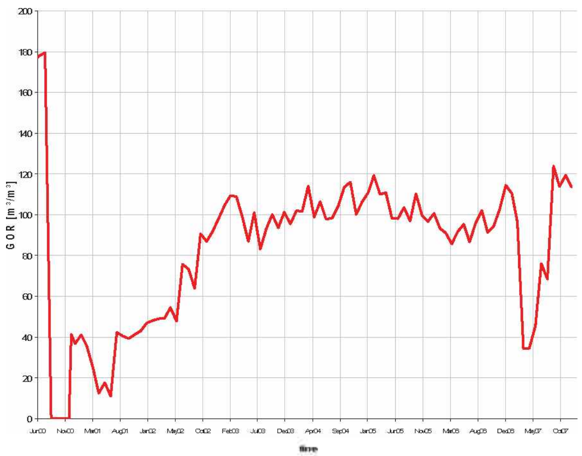
MATZEN 288



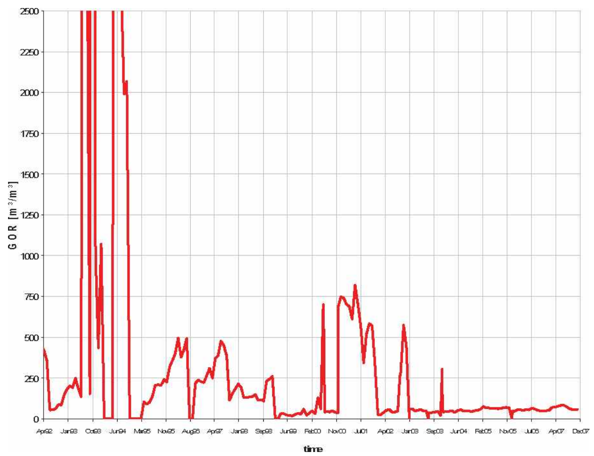
SCHOENKIRCHEN 179



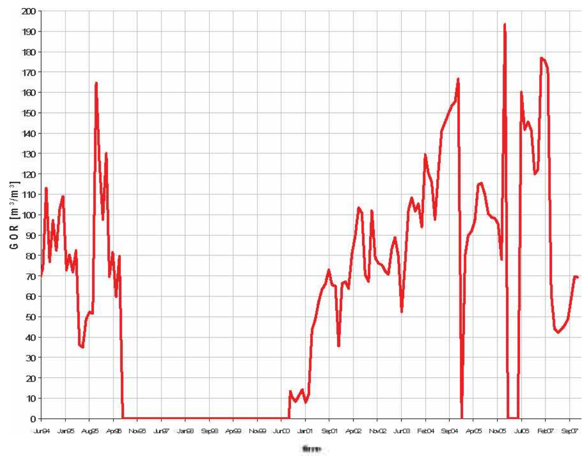
BOCKFLIESS 049

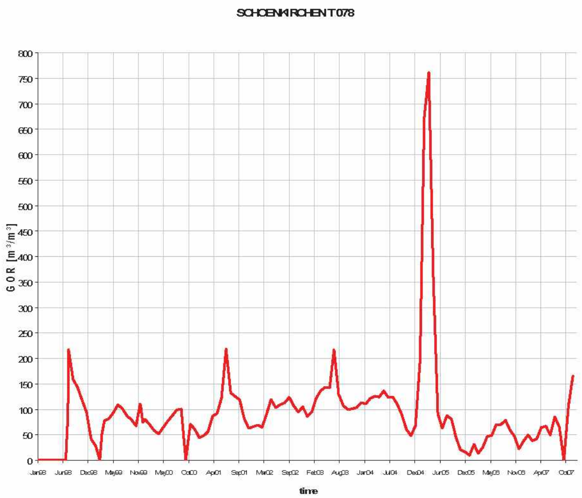


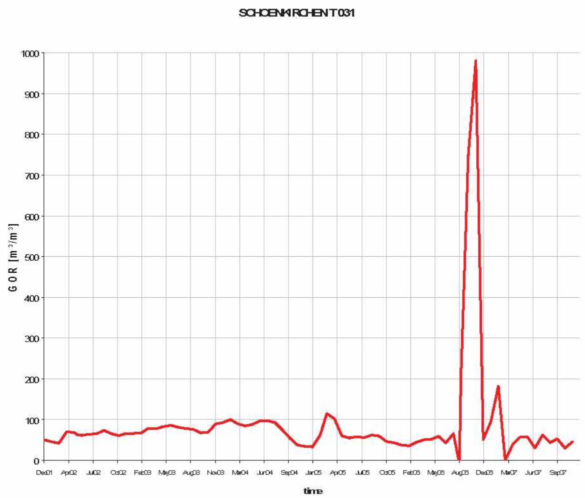
MATZEN 056

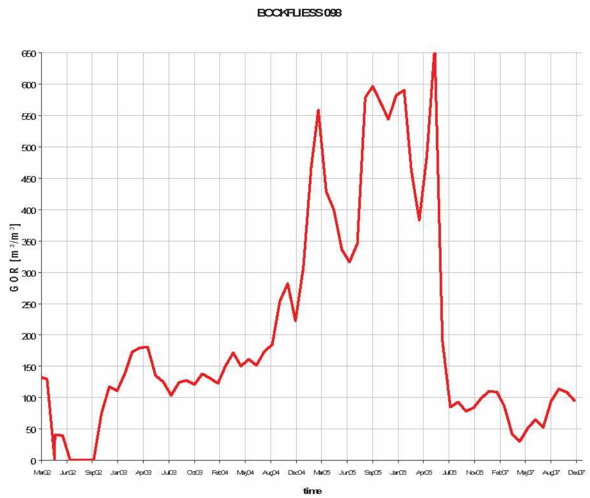


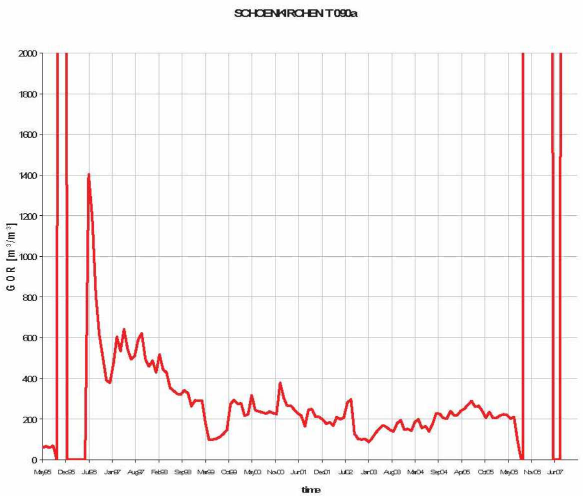
SCHOENKIRCHEN 028

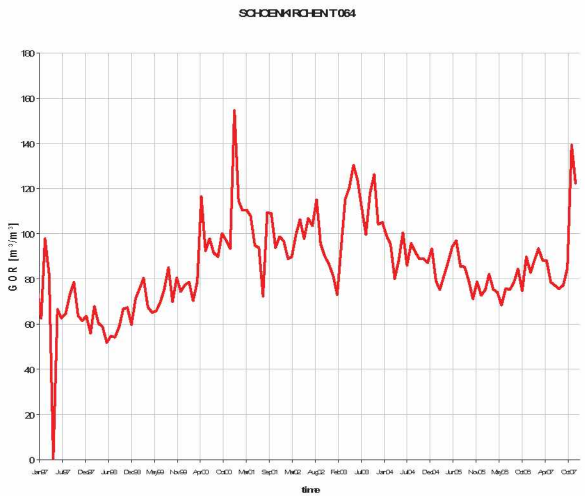


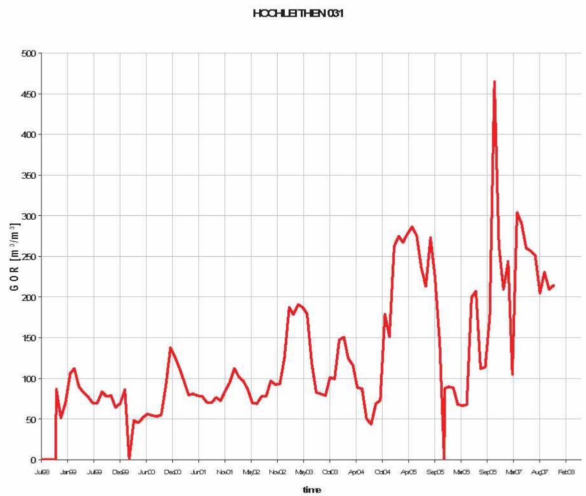

SCHOENKIRCHEN T078
G O R [m³/m³]
time

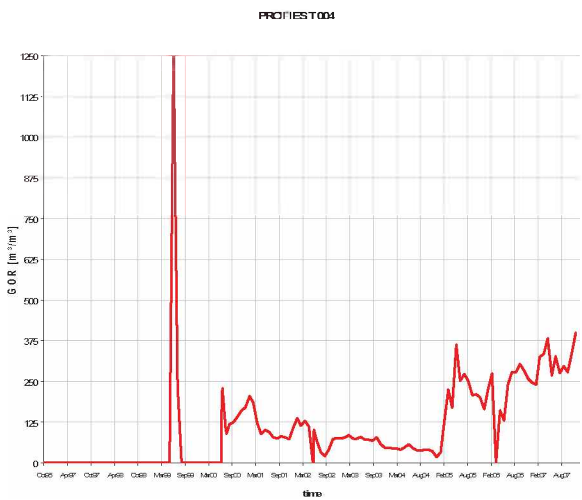

SCHOENKIRCHEN T031
G O R [m³/m³]
time


BOCKFLIESS 098
G O R [m³/m³]
time

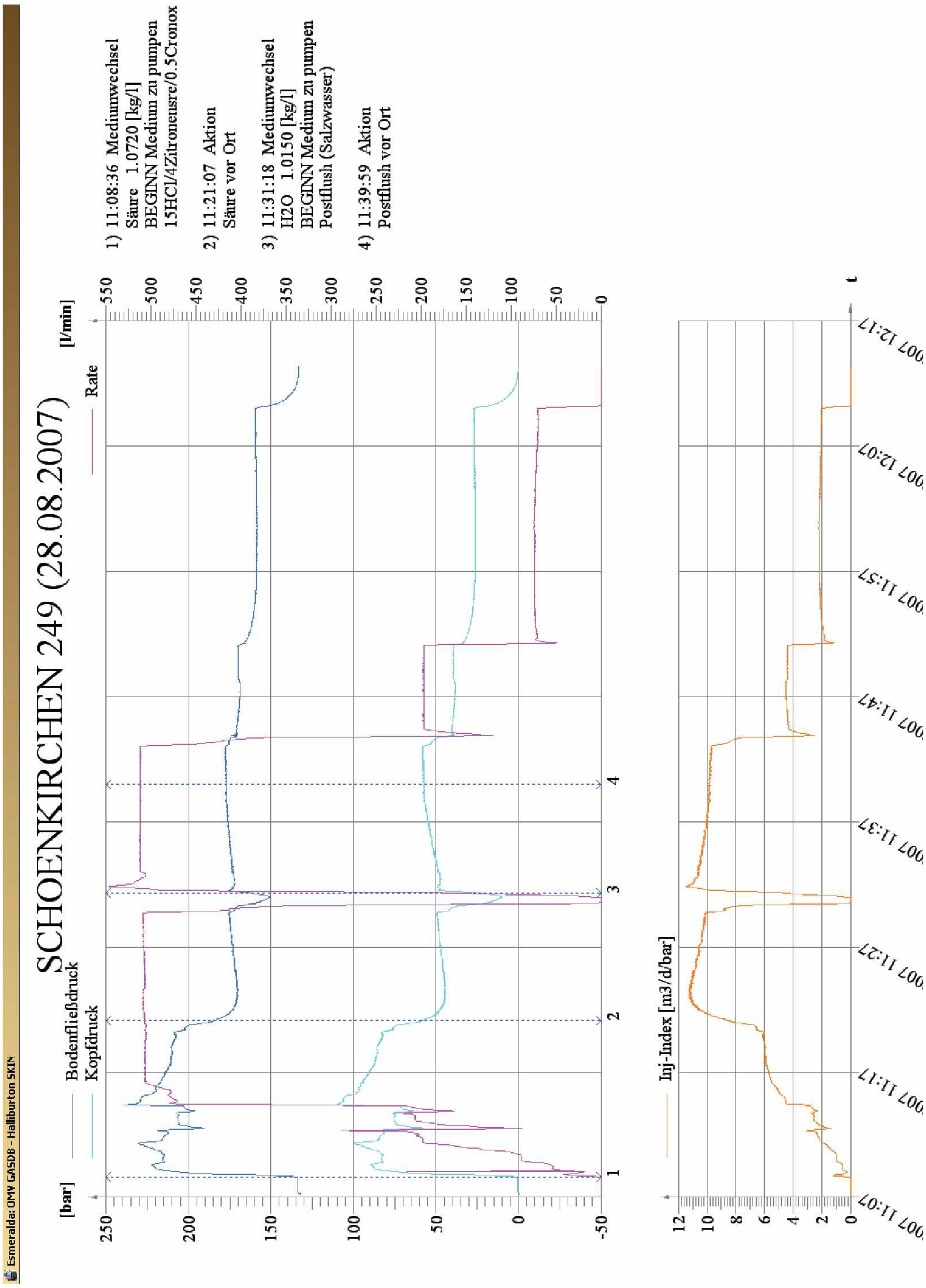

SCHOENKIRCHEN T090a
G O R [m³/m³]
time

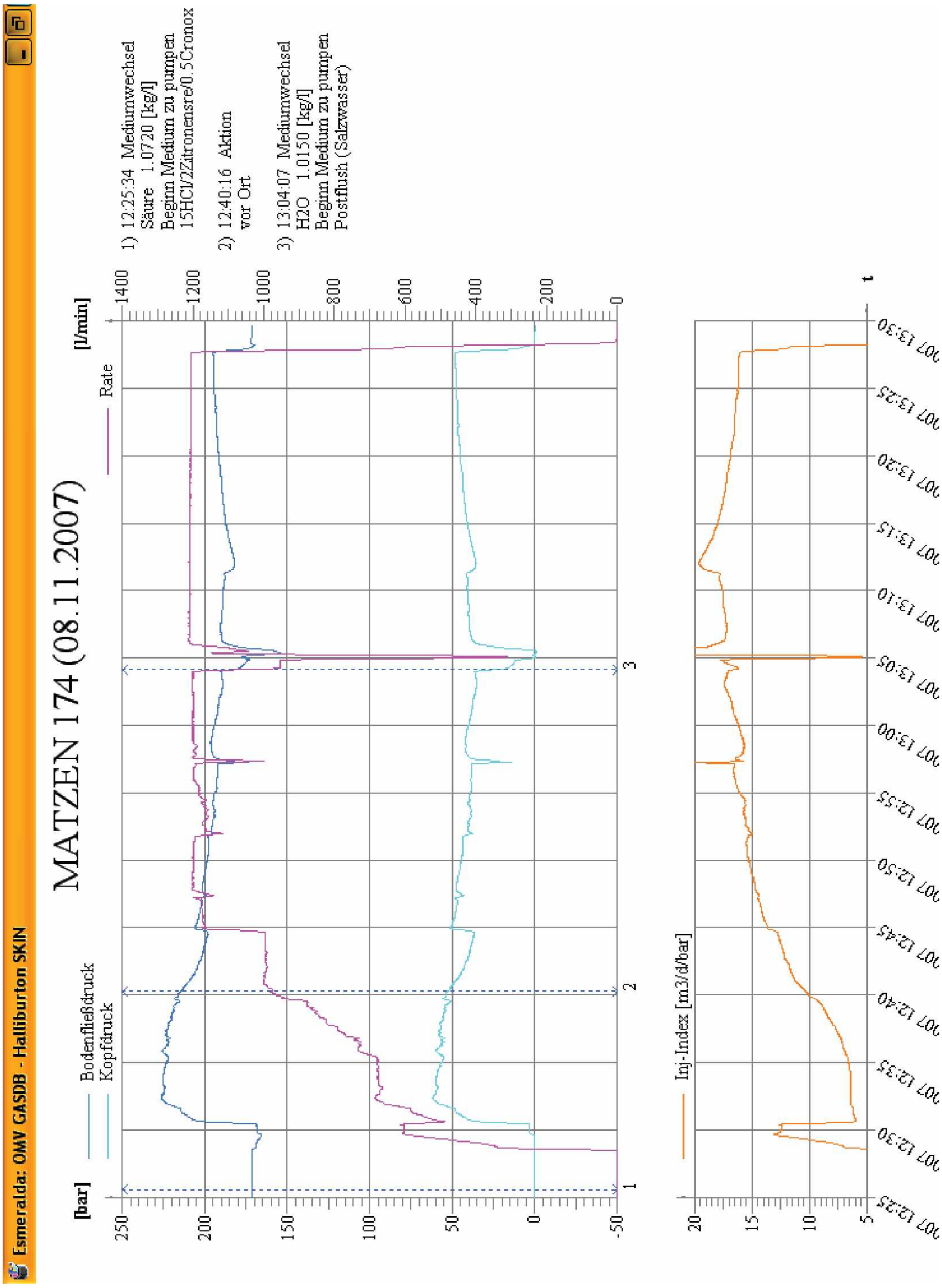

SCHOENKIRCHEN T064
G O R [m³/m³]
time

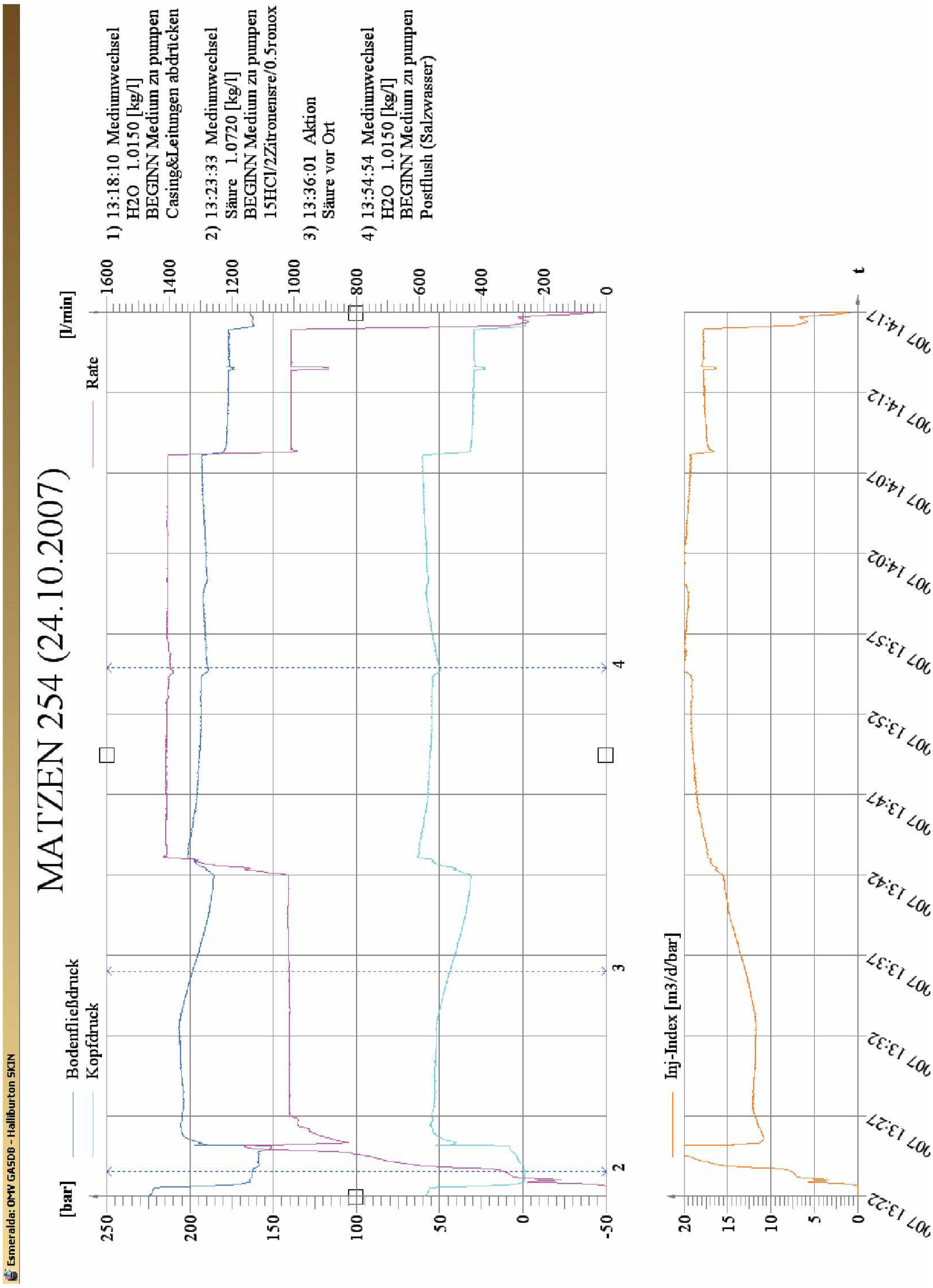

HOCHLEITHEN 031
G O R [m³/m³]
time

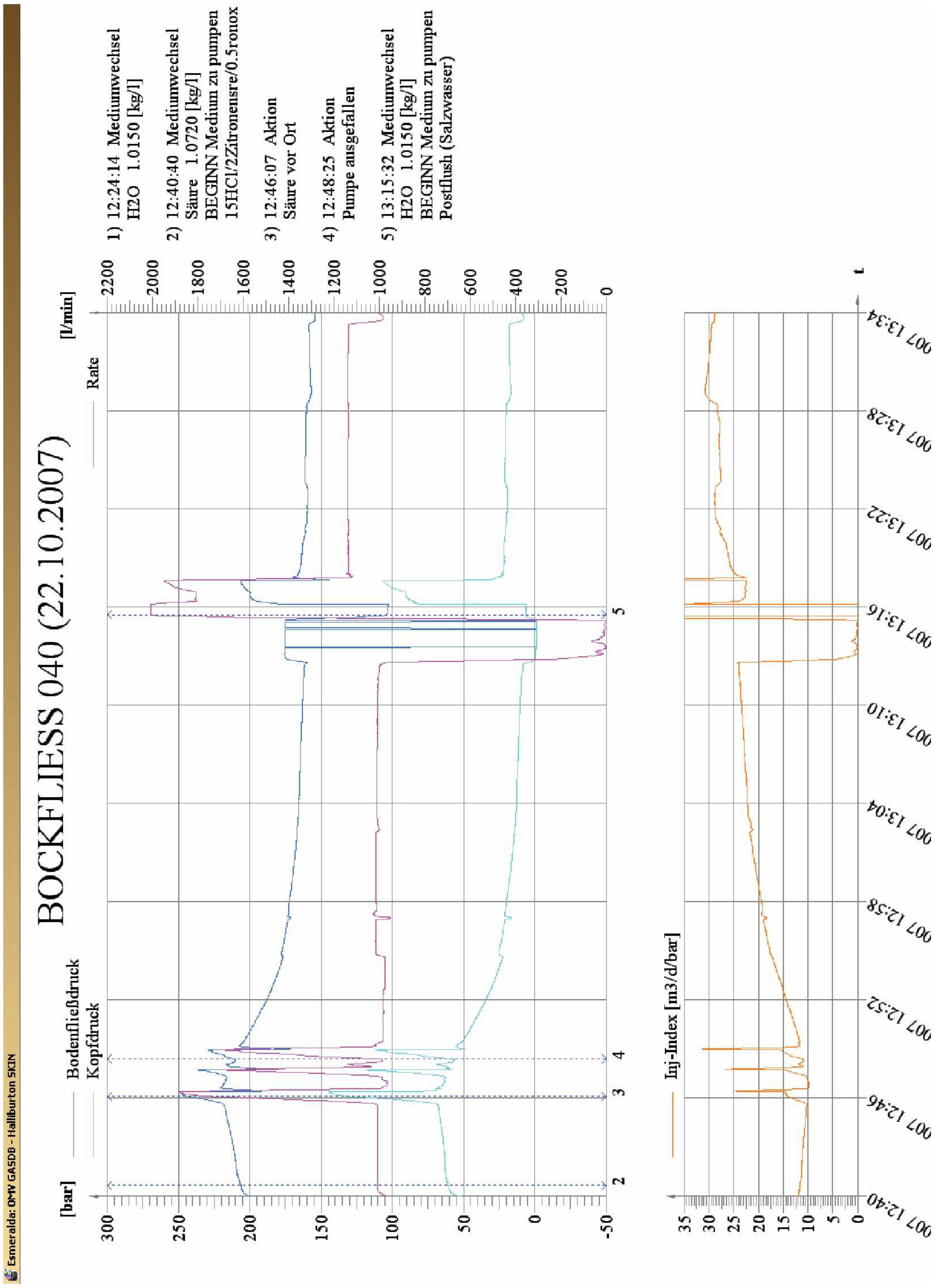

PROTTEST 004
GOR [m³/m³]
0
125
250
375
500
625
750
875
1000
1125
1250
Oct96 Apr97 Oct97 Apr98 Oct98 Mar99 Sep99 Mar00 Sep00 Mar01 Sep01 Mar02 Sep02 Mar03 Sep03 Mar04 Aug04 Feb05 Aug05 Feb06 Aug06 Feb07 Aug07
time

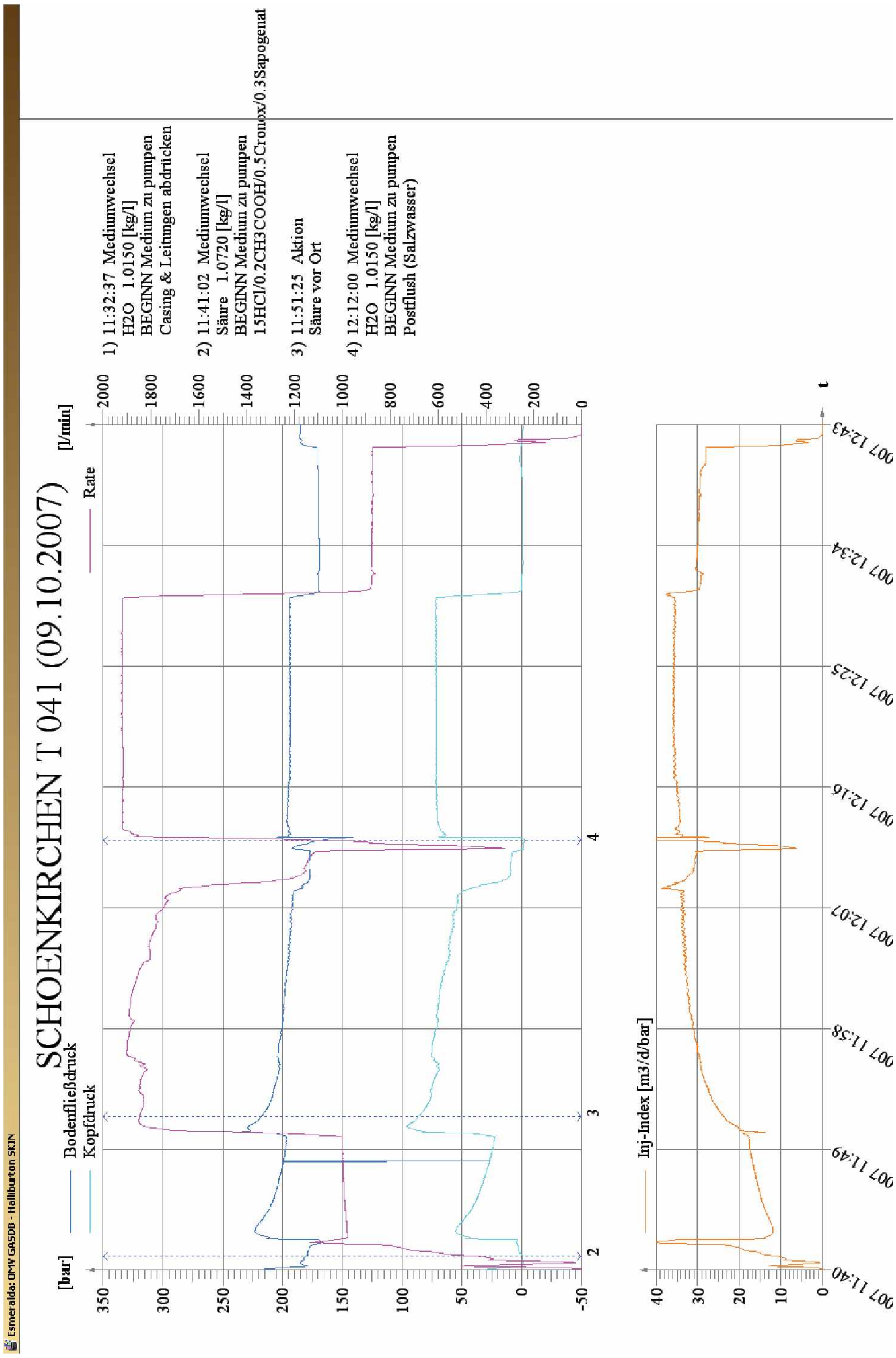
Appendix B (Real Time Evaluations)

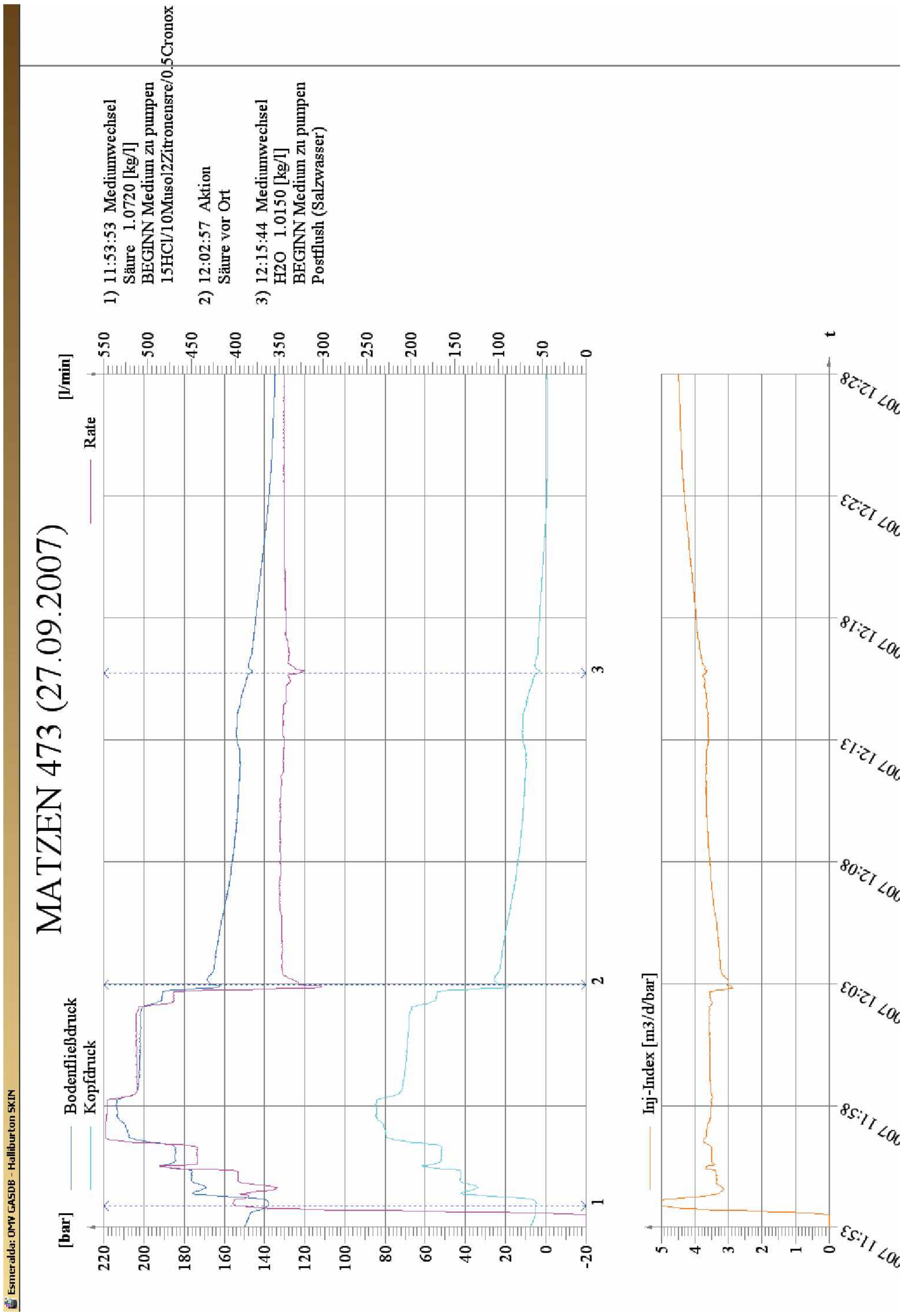



Esmeralda: OMV GASDB - Halliburton SKIN
MATZEN 174 (08.11.2007)
[bar]
Bodenfließdruck
Kopfdruck
Rate
[l/min]
1) 12:25:34 Mediumwechsel
Säure 1.0720 [kg/l]
Beginn Medium zu pumpen
15HCl/2Zitronensre/0.5Cronox
2) 12:40:16 Aktion
vor Ort
3) 13:04:07 Mediumwechsel
H2O 1.0150 [kg/l]
Beginn Medium zu pumpen
Postflush (Salzwasser)
Inj-Index [m3/d/bar]
t


Esmeralda: OMV GASDB - Halliburton SKIN
MATZEN 254 (24.10.2007)
[bar]
Bodenfließdruck
Kopfdruck
Rate
[l/min]
1) 13:18:10 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Casing&Leitungen abdrücken
2) 13:23:33 Mediumwechsel
Säure 1.0720 [kg/l]
BEGINN Medium zu pumpen
15HCl/2Zitronensre/0.5ronox
3) 13:36:01 Aktion
Säure vor Ort
4) 13:54:54 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Postflush (Salzwasser)
Inj-Index [m3/d/bar]
t


Esmeralda: OMV GASDB - Halliburton SKIN
BOCKFLIESS 040 (22.10.2007)
Bodenfließdruck
Kopfdruck
Rate
[bar]
[l/min]
1) 12:24:14 Mediumwechsel
H2O 1.0150 [kg/l]
2) 12:40:40 Mediumwechsel
Säure 1.0720 [kg/l]
BEGINN Medium zu pumpen
15HCl/2Zitronensre/0.5ronox
3) 12:46:07 Aktion
Säure vor Ort
4) 12:48:25 Aktion
Pumpe ausgefallen
5) 13:15:32 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Postflush (Salzwasser)
Inj-Index [m3/d/bar]
007 12:40
007 12:46
007 12:52
007 12:58
007 13:04
007 13:10
007 13:16
007 13:22
007 13:28
007 13:34
t


Esmeralda: OMV GASDB - Halliburton SKN
SCHOENKIRCHEN T 041 (09.10.2007)
[bar]
Bodenfließdruck
Kopfdruck
Rate
[l/min]
1) 11:32:37 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Casing & Leitungen abdrücken
2) 11:41:02 Mediumwechsel
Säure 1.0720 [kg/l]
BEGINN Medium zu pumpen
15HCl/0.2CH3COOH/0.5Cronox/0.3Sapogenat
3) 11:51:25 Aktion
Säure vor Ort
4) 12:12:00 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Postflush (Salzwasser)
Inj-Index [m3/d/bar]
007 11:40
007 11:49
007 11:58
007 12:07
007 12:16
007 12:25
007 12:34
007 12:43
t

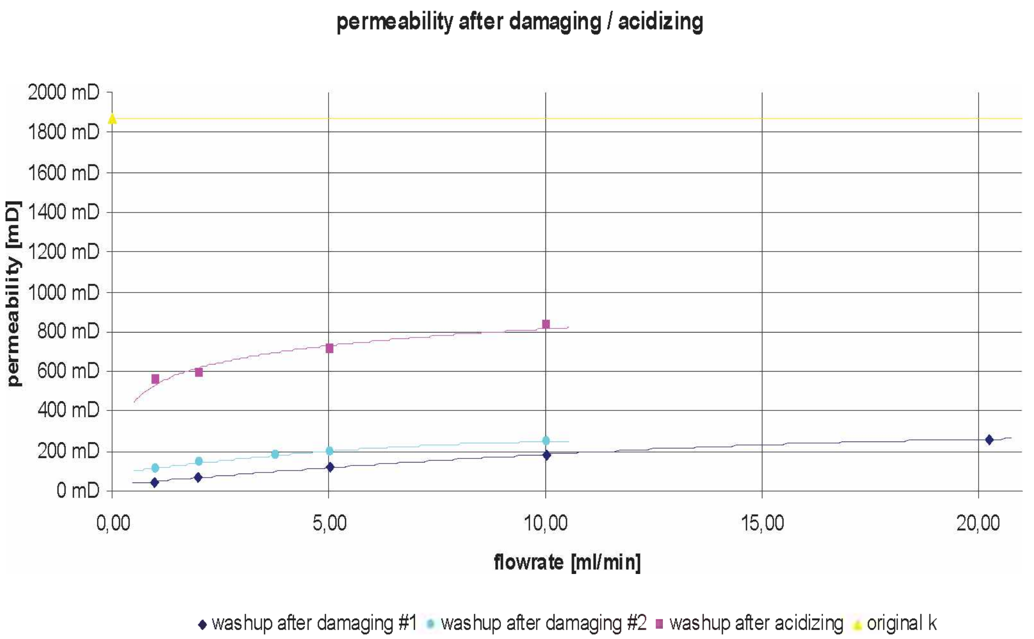

Esmeralda: OMV GASDB - Halliburton SKIN
MATZEN 473 (27.09.2007)
[bar]
Bodenfließdruck
Kopfdruck
Rate
[l/min]
1) 11:53:53 Mediumwechsel
Säure 1.0720 [kg/l]
BEGINN Medium zu pumpen
15HCl/10Musol2Zitronensre/0,5Cronox
2) 12:02:57 Aktion
Säure vor Ort
3) 12:15:44 Mediumwechsel
H2O 1.0150 [kg/l]
BEGINN Medium zu pumpen
Postflush (Salzwasser)
Inj-Index [m3/d/bar]
t
007 11:53
007 11:58
007 12:03
007 12:08
007 12:13
007 12:18
007 12:23
007 12:28

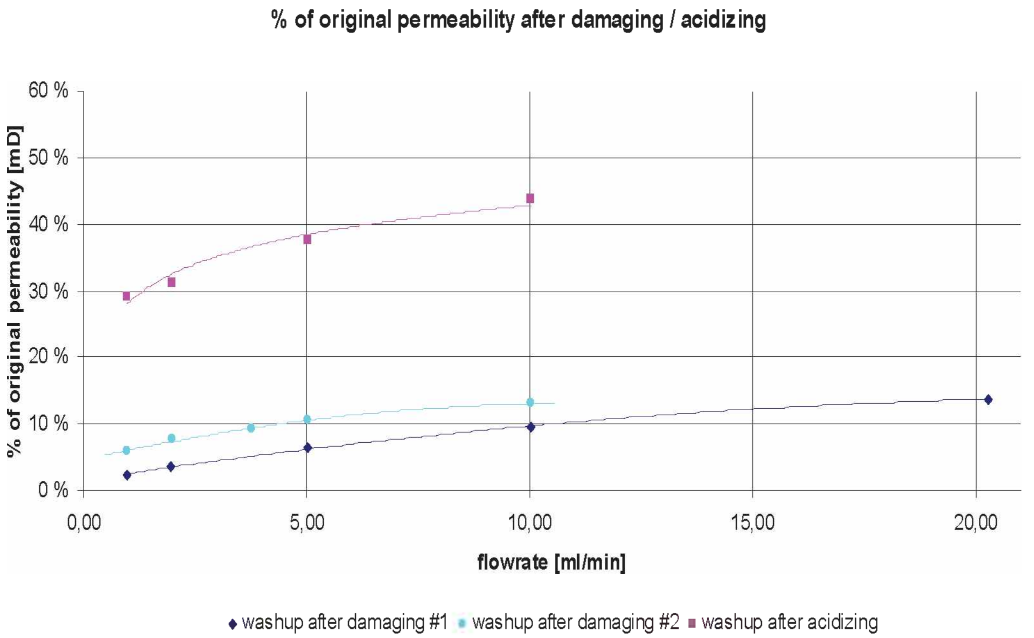
Appendix C (Economical Evaluation)

Well	Stim.Date	flowrate before	flowrate after	Oilprice [EUR/t]	costs [EUR]	payout time [days]	remarks
Pir 15	26.03.2002	0.3	0.0	152.8	10,090	not successful	
Pir 24	26.04.2001	2.7	0.7	149.4	10,673	not successful	
Pir 79	21.01.1999	0.9	3.1	134.7	18,787	62	
HL 13	27.05.1999						(no costs data)
	01.07.2004	4.1	0.6	147.8	16,274	not successful	
	20.04.2005	0.5	0.0	177.9	16,071	not successful	
HL 31	15.06.1999	6.1	7.3	104.9	10,632	84	
	06.12.2005	0.7	2.1	177.9	78,696	305	(some perforations plugged at same workover)
HL 25	25.11.2004	1.5	5.5	147.8	18,767	32	(change of pump at the same time)
HL 71	30.11.1999	4.3	6.3	104.9	11,686	55	
S 111	27.03.1998	0.1	1.5	101.0	89,958	632	(closure of perforation and installation of ICGP)
S 133	03.08.1998	1.0	0.1	101.0	5,414	not successful	(change of pump at the same time)
S 256	22.04.1998	1.3	1.0	101.0	32,065	not successful	(change of pump at the same time)
MaC 2	25.08.1999	0.5	1.3	104.9	8,610	103	
MaF 6	10.09.1996	0.4	0.0	128.6	15,308	not successful	(change of pump at the same time)
S 179	02.05.1999	0.0	3.4	104.9	9,120	26	(change of pump at the same time)
S 28	11.08.1997	0.0	0.0	134.7	7,769	not successful	
Ma 268	24.04.2001	0.3	0.0	149.4	116,833	not successful	(blocking water horizon)
Ma 56	28.10.1996	0.4	2.2	128.6	3,566	15	
	15.05.2002	16.6	15.6	152.8	50,307	not successful	(swabb-pv)
Ma 84b	24.10.1996	2.7	7.3	128.6	34,865	59	
Bo 49	08.08.2001	3.3	4.6	149.4	50,507	266	
Bo 98	30.06.2006	0.4	2.5	256.0	76,566	142	
ST 31	28.08.2006	5.2	16.2	256.0	302,416	107	(perforation at the same time)
ST 64	20.05.1997	6.5	31.3	134.7	280,101	84	(perforation at the same time)
ST 78	23.11.1999	4.5	13.5	104.9	49,142	52	
ST 90a	03.10.2002	6.5	13.6	152.8	147,468	135	
PT 4	10.06.2002	4.4	7.3	152.8	173,543	385	(perforation at the same time)

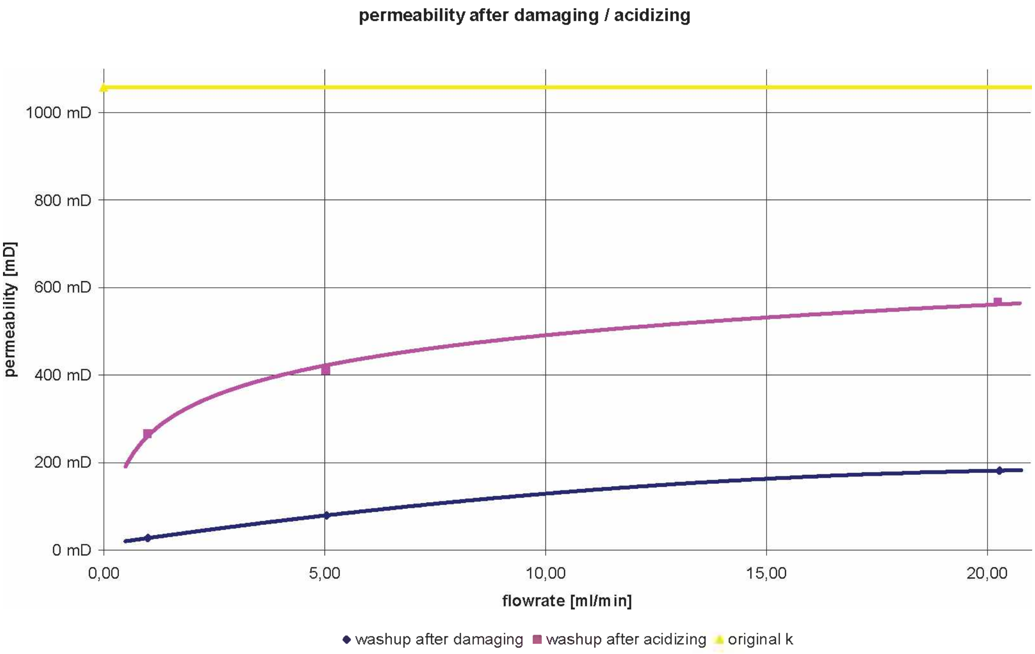
Appendix D (Core Flooding Experiments – Polymer Mud Component)

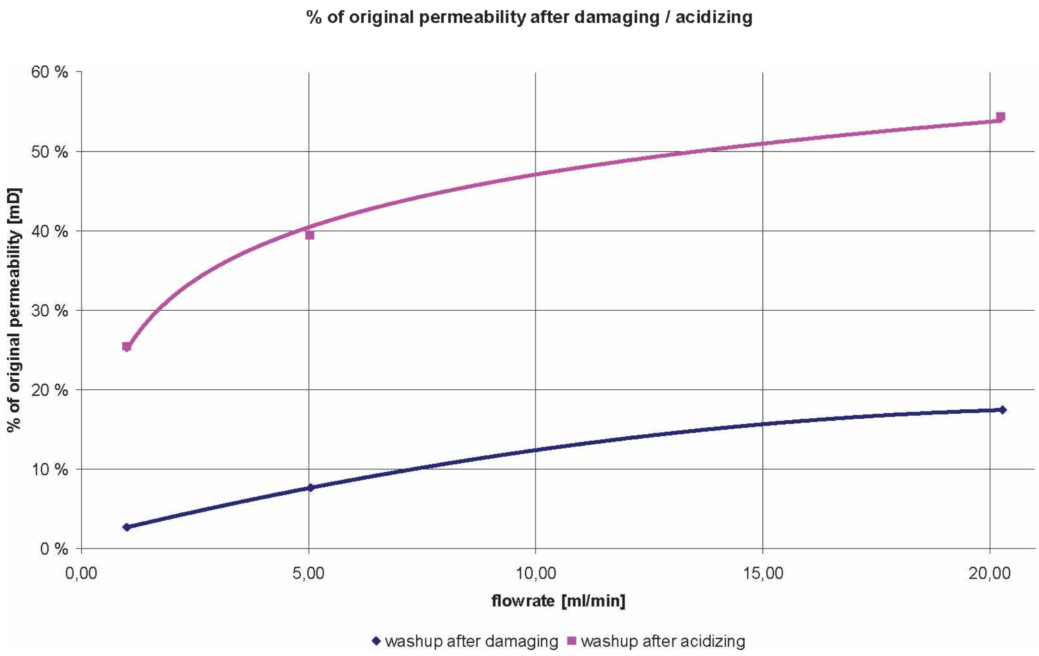
NH 14/21 (damaged with 0.5% FlowZAN)



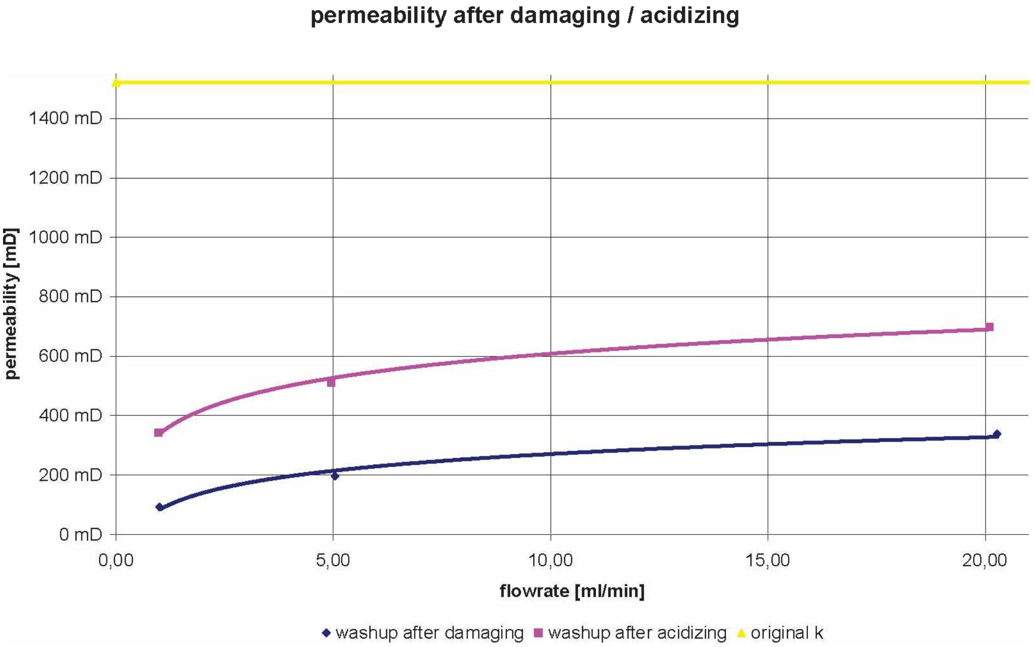


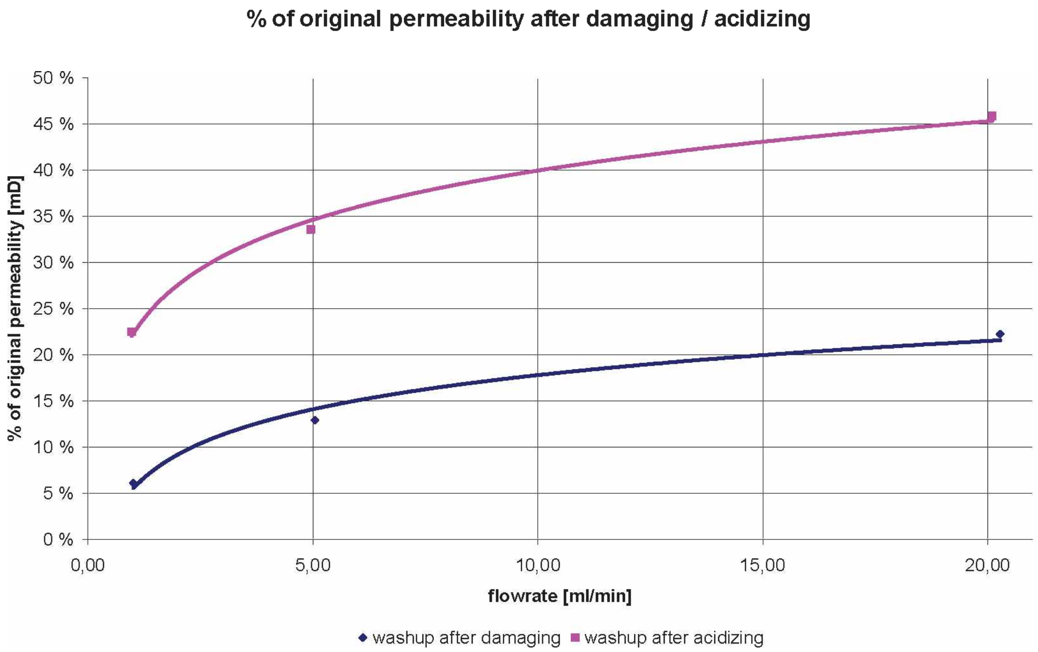
NH 13/190 (damaged with 0.5% FlowZAN)



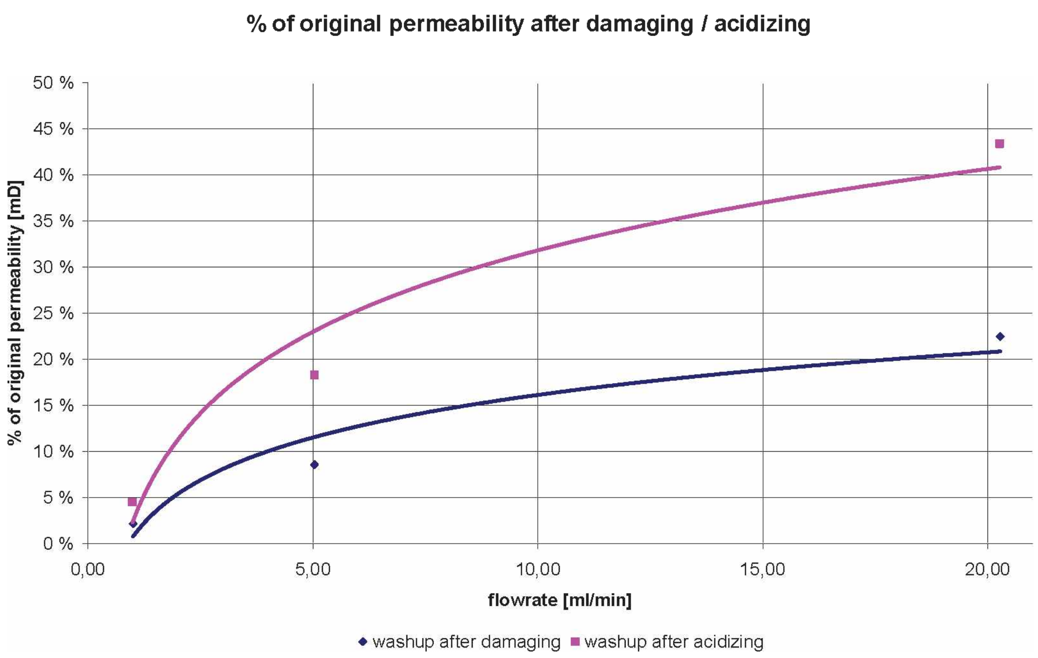


NH 052 (damaged with 0.5% FlowZAN)

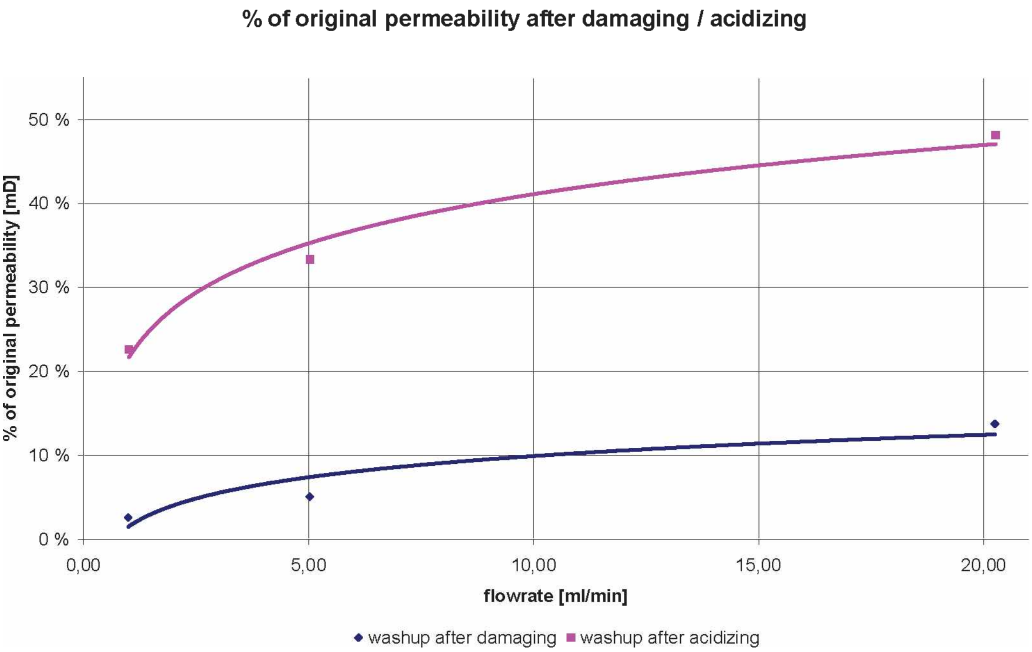




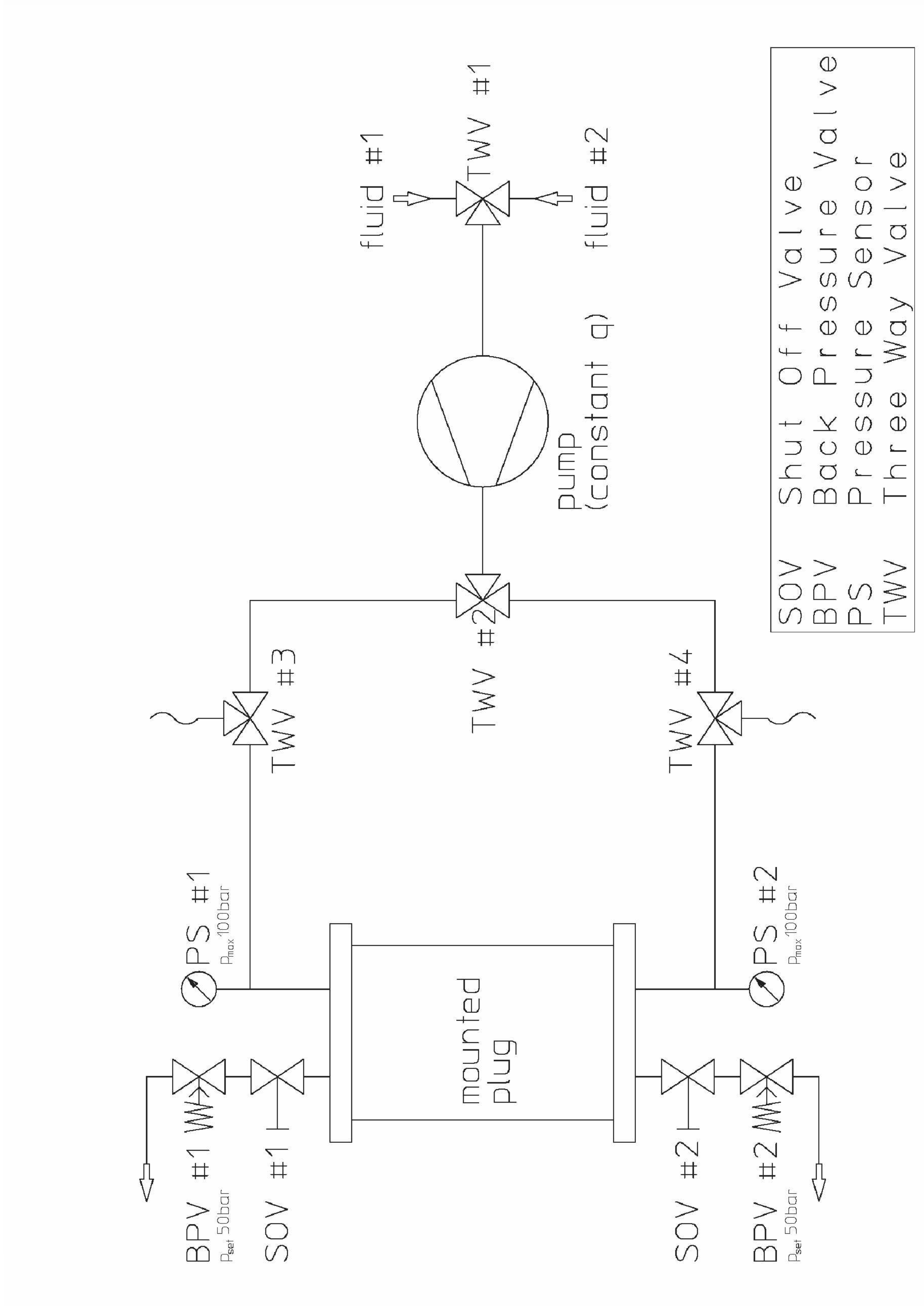
NH 14/13 (damaged with 0.5% DuoVIS)



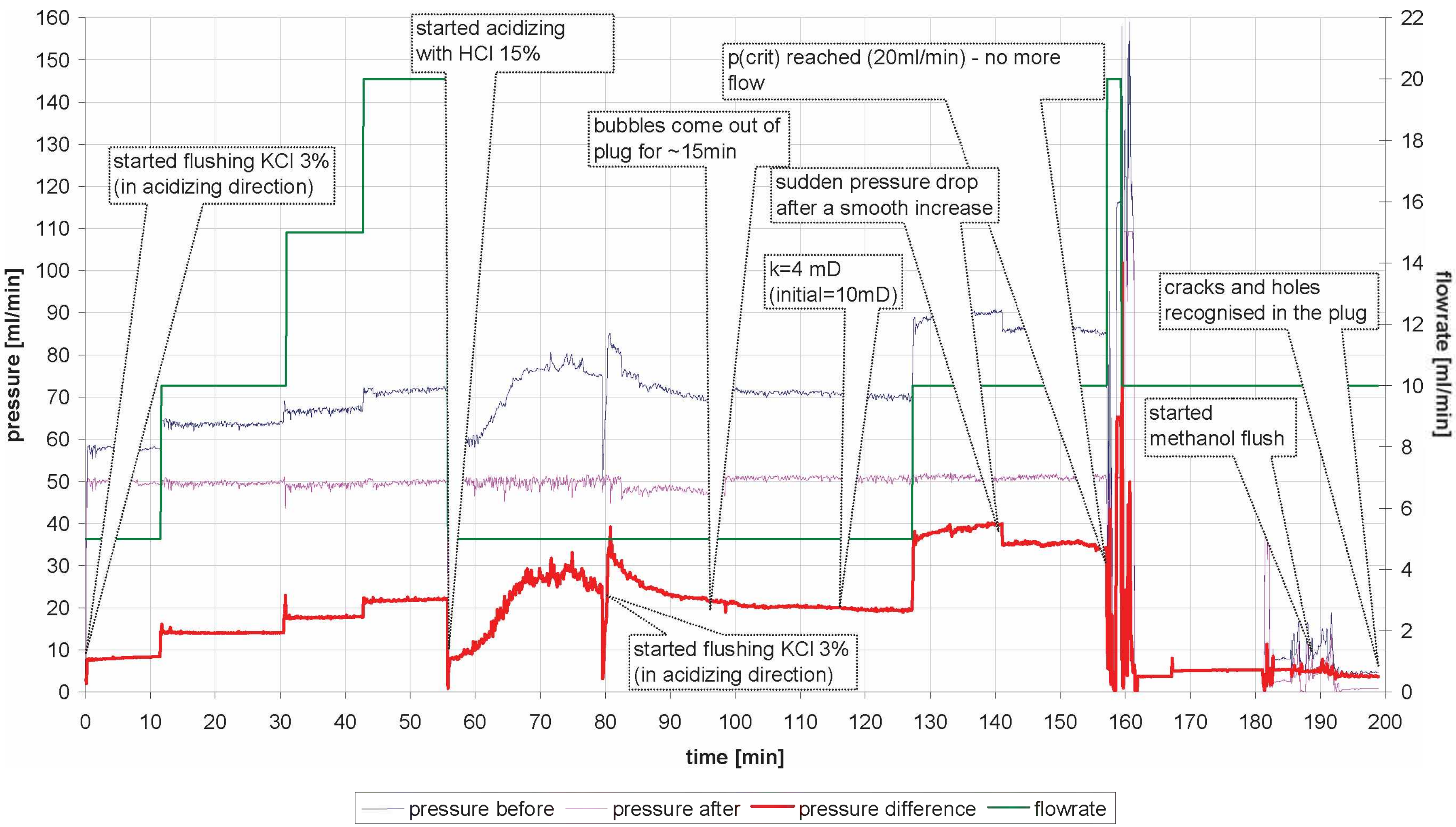
NH 13/050 (damaged with 0.5% DuoVIS)



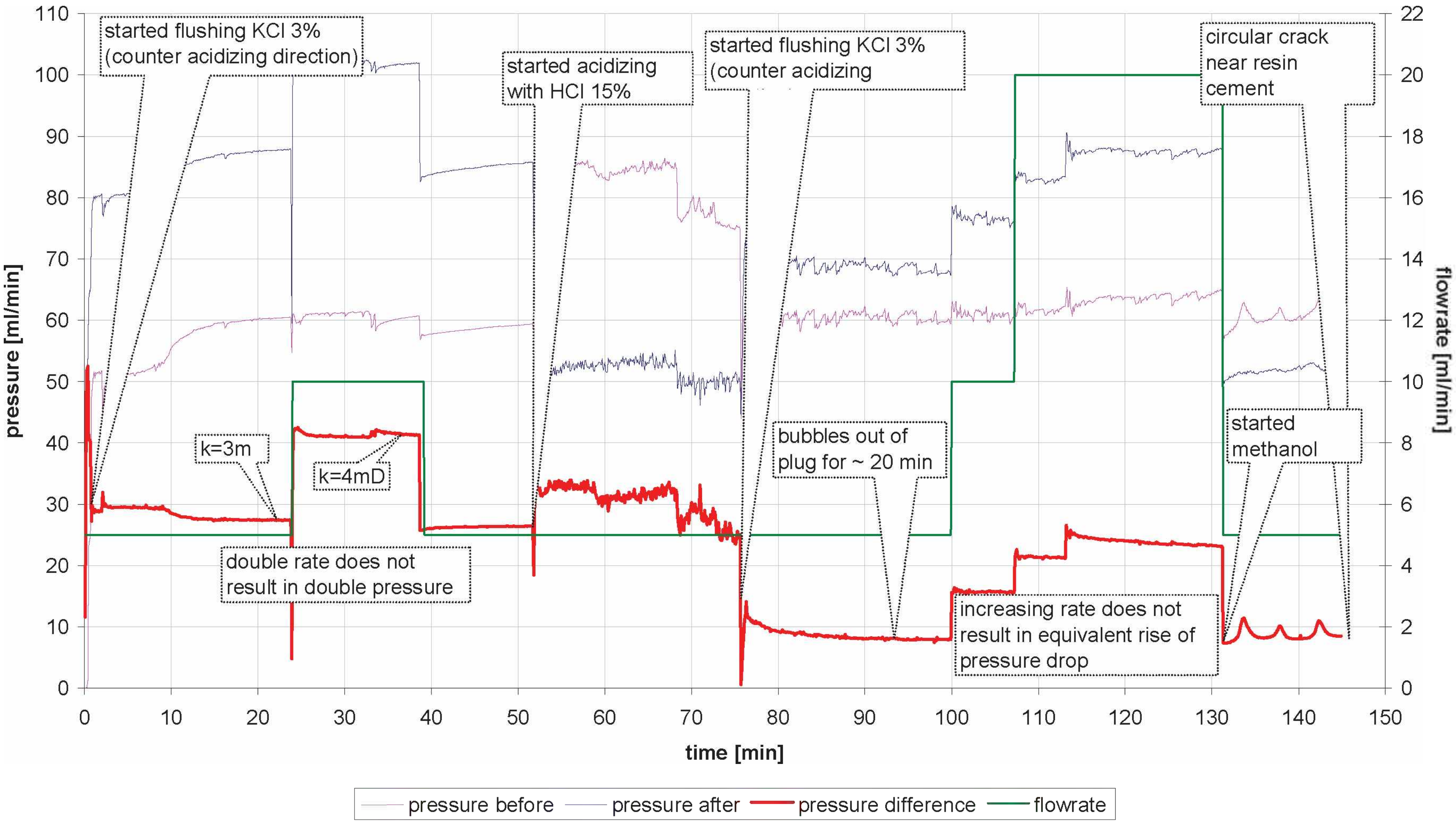
Appendix E (Core Flooding Experiments – Influences)

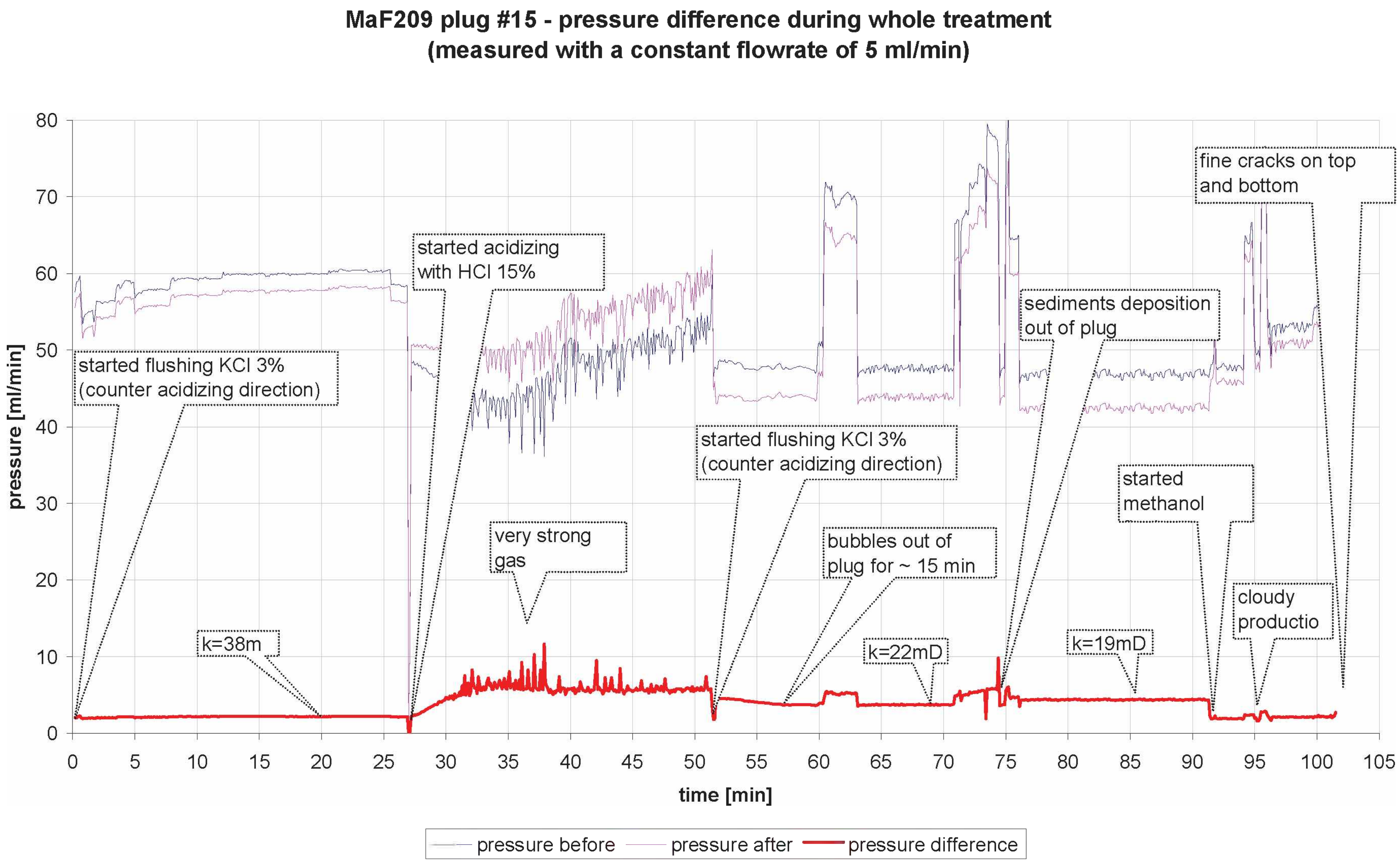


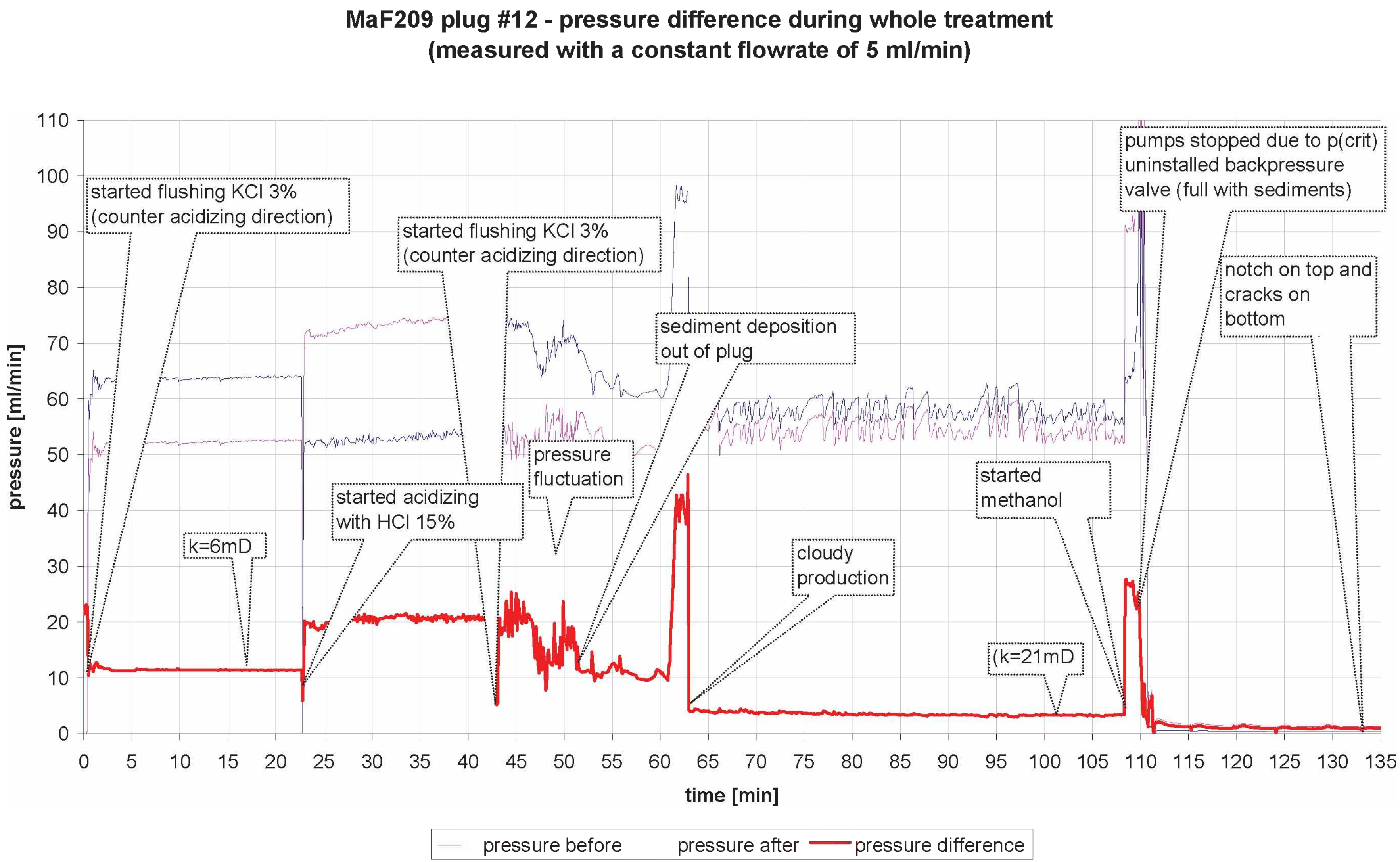
MaF209 plug #08 - pressure difference during the whole treatment



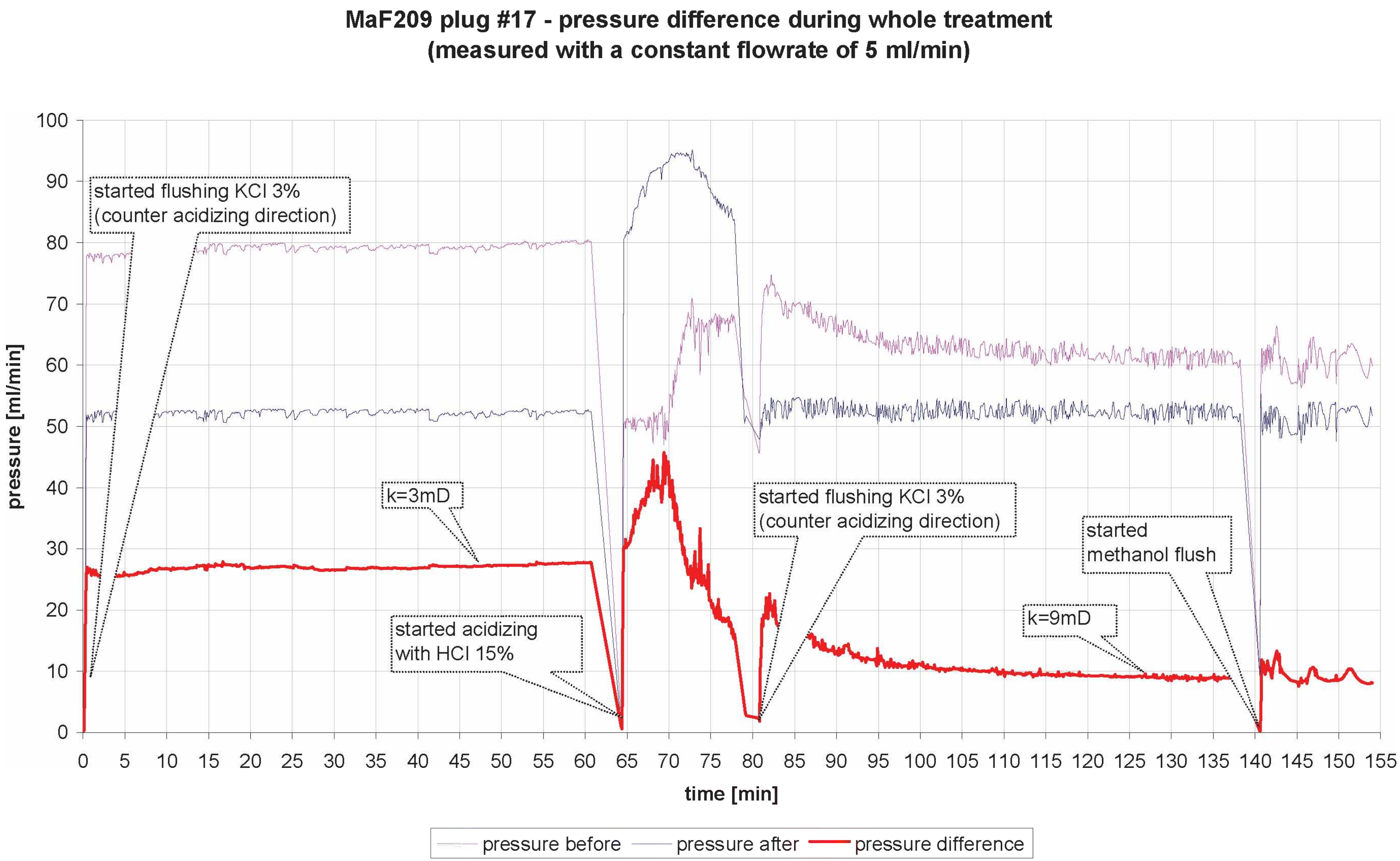
MaF209 plug #14 - pressure difference during the whole treatment




MaF209 plug #15 - pressure difference during whole treatment
(measured with a constant flowrate of 5 ml/min)
pressure [ml/min]
time [min]
0
10
20
30
40
50
60
70
80
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
95
100
105
started flushing KCl 3% (counter acidizing direction)
started acidizing with HCl 15%
k=38m
very strong gas
started flushing KCl 3% (counter acidizing direction)
bubbles out of plug for ~ 15 min
k=22mD
sediments deposition out of plug
k=19mD
started methanol
fine cracks on top and bottom
cloudy productio
pressure before
pressure after
pressure difference



MaF209 plug #12 - pressure difference during whole treatment
(measured with a constant flowrate of 5 ml/min)
pressure [ml/min]
time [min]
started flushing KCl 3% (counter acidizing direction)
started flushing KCl 3% (counter acidizing direction)
k=6mD
started acidizing with HCl 15%
pressure fluctuation
sediment deposition out of plug
cloudy production
started methanol
(k=21mD
pumps stopped due to p(crit) uninstalled backpressure valve (full with sediments)
notch on top and cracks on bottom
pressure before
pressure after
pressure difference


MaF209 plug #17 - pressure difference during whole treatment
(measured with a constant flowrate of 5 ml/min)
pressure [ml/min]
time [min]
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
95
100
105
110
115
120
125
130
135
140
145
150
155
started flushing KCl 3%
(counter acidizing direction)
k=3mD
started acidizing
with HCl 15%
started flushing KCl 3%
(counter acidizing direction)
started
methanol flush
k=9mD
pressure before
pressure after
pressure difference