THESIS

EVALUATION AND OPTIMISATION OF MATRIX ACIDIZING IN OMV FIELDS

Mario-Luis RODRIGUEZ CHAVEZ

Submitted at the Department of Mineral Resources and Petroleum
Engineering at the Mining University of Leoben
Supervised by
Univ.-Prof. Bergrat h.c. Dipl.-Ing. Dr.mont. Gerhard Ruthammer
May 2007

To my parents

I declare that this thesis is my own work and has not been submitted in any form for another degree or diploma at any university or other institution of tertiary education. Information derived from the published or unpublished work of others has been acknowledged in the text and a list of references is given.

Mario-Luis RODRIGUEZ CHAVEZ

Leoben, May 2007

Acknowledgement

In the first place I would like to express my gratitude to **Univ.-Prof. Bergrat h.c. Dipl.-Ing. Dr.mont. Gerhard Ruthammer**, Head of Department of Petroleum Production Engineering at the Mining University of Leoben, for giving me the great opportunity to write this thesis provided by OMV Exploration & Production GmbH under his supervision.

I would like to thank **Dipl.-Ing. Dr. Markus Oberndorfer**, Head of the Laboratory for Exploration & Production at OMV Exploration & Production GmbH, for his support and encouragement during my work at OMV.

Furthermore I wish to record my gratitude to my advisor **Dr. Nikolaus Philippovich**, Senior Expert at the Laboratory for Exploration & Production at OMV Exploration & Production GmbH, for his help, valuable hints and his crucial contribution.

I am deeply indebted to my advisor **Dipl.-Ing. Markus Mostegel**, Reservoir Engineer at the Department for Reservoir Management, whose help, stimulating suggestions and constructive comments I benefited from during the elaboration of this thesis.

The whole team of the OMV E&P Laboratory and the Department of Reservoir Management gave me their overall support.

The OMV Exploration & Production GmbH granted a generous scholarship and other resources for the preparation of this thesis.

TABLE OF CONTENTS

LIST OF FIGURES

ABSTRACT

The aim of this thesis was to structurally approach matrix acid stimulation optimisation. In order to get a solid grounding in the various disciplines of matrix acidizing the first chapters are dedicated to the theoretical background.

Near-wellbore damage with its contributing mechanisms is focused on in the opening chapter culminating in the selection of a candidate well and the type of stimulation treatment. The main mechanisms and chemical reactions occurring during the etching process depending on the type of reservoir rock and the type and strength of the acid solution are presented along with their potential risks of creating further damage in sandstone formations. A sequence of the different injected batches is standard in matrix acidizing. Hence, their purpose is discussed. A matrix acid stimulation will always require acid solution additives depending on the treatment. The various types of additives are discussed in the closing chapter of the literature review. The different types of acids and additives currently used in OMV are listed.

The issue in optimising matrix acid stimulations is to make the treatments comparable. The prerequisites which must be valid have been defined and stimulated wells with the same set of conditions have been analysed. In order to evaluate the gross effectiveness of the treatments, the Productivity Index has been defined as a success criterion. The evaluation of the treatment progression has been done introducing the instantaneous Injectivity Index of a stage hitting the formation face. The pressure correlation, computed on the basis of a memory gauge recording downhole and a real-time measurement at the surface, mostly matched. Relative Injectivity and the Productivity Index change correlated qualitatively in the majority of the cases.

1. INTRODUCTION

The drilling and completion process of a well often influences the near-wellbore area in an unpredictable and unfavorable manner. Most of the wells, for instance, are drilled overbalanced which means higher pressure of the drilling mud in the borehole than in the formation and hence the forming of an internal and external mud filter cake on the borehole wall. Thus, for instance, natural fractures which initially could have been highly permeable can now be plugged due to the fluid losses.

All mechanical, hydraulic and chemical processes during drilling, completion and production of an oil or gas well that detain the fluid flow causes an additional pressure drop in the wellbore vicinity which is referred to as the near wellbore damage. Drilling fluids which migrated into the near wellbore area and caused reduction of the permeability can be removed.

Well stimulation can be categorized in fracturing and acidizing. Acidizing basically is increasing production by dissolving the rock, fines or mud particles in the near wellbore region and hence enlarging the channels through which oil, gas, or water flows towards the well.

2. DAMAGE

2.1 TYPES AND MECHANISMS OF SKIN

In general, stimulation is done in order to decrease the skin and as a result increase productivity. Skin is defined as an additional pressure drop in the near wellbore region. The total skin factor consists of several components [1]:

$$S = S_d + S_{perf} + S_{gp} + S_{pp/slant} + \sum S_{pseudo}$$

S_d is the skin due to drilling and production damage caused by drilling and completion fluids which migrate into the formation, fines which migrate from the formation to the borehole or precipitation products.

S_{perf} is the skin due to perforation, in other words the crushing and compaction of the casing, the cement and the formation.

S_{gp} is the skin due to the set gravel pack which in an open hole should be very small compared to the formation. Still, the pressure drop through the perforations in an inside casing gravel pack contributes significantly to the overall pressure drawdown.

$S_{pp/slant}$ is the skin due to partial penetration and slant which on the one hand occurs because the layer in most of the cases cannot be completed along the whole reservoir height and hence results in reduced reservoir exposure. As rule of thumb we can assume that a completed interval exceeding 75% of the reservoir height makes this skin negligible. On the other hand a deviation has the opposite effect which means that inclination results in a negative skin.

$\sum S_{pseudo}$ is the sum of the pseudo skins of all the other components. They are phase and rate dependent and contribute to the total skin factor in terms of turbulent flow.

Regarding Darcy's law[1] (assuming steady-state flow conditions and using outer boundary pressure instead of the average reservoir pressure) we will now see how the skin factor contributes to the overall pressure drop in a radial system:

$$q = \frac{2\pi hk\ (p_E - p_{WF})}{\mu B\left(\ln\left(r_e / r_w\right) + s\right)} \qquad [2.1]$$

whereas ***h*** is the height of the reservoir, in [m],

k is the undamaged permeability, in [m²],

p_E is the reservoir pressure at the outer boundary, in [Pa] ,

p_{WF} is the well flowing pressure, in [Pa],

μ is the viscosity of the crude oil, in [Pa.s],

B is the formation volume factor, [-],

r_e and ***r_w*** are the outer boundary and the well radius, respectively, in [m],

and ***s*** is the dimensionless skin factor.

Rearranging the equation will show very clearly the role of the skin factor as an additional pressure drop in the near wellbore region:

$$p_E - p_{WF} = \frac{q\mu B}{2\pi hk} * \ln\left(r_e / r_w\right) + \frac{q\mu B}{2\pi hk} * s \qquad [2.2]$$

$$p_{WF} = \Delta p + \Delta p_{skin}$$

whereas the first term refers to the expected pressure drop according to Darcy's law without any damage and the second one expresses the additional pressure drop due to the skin effect.

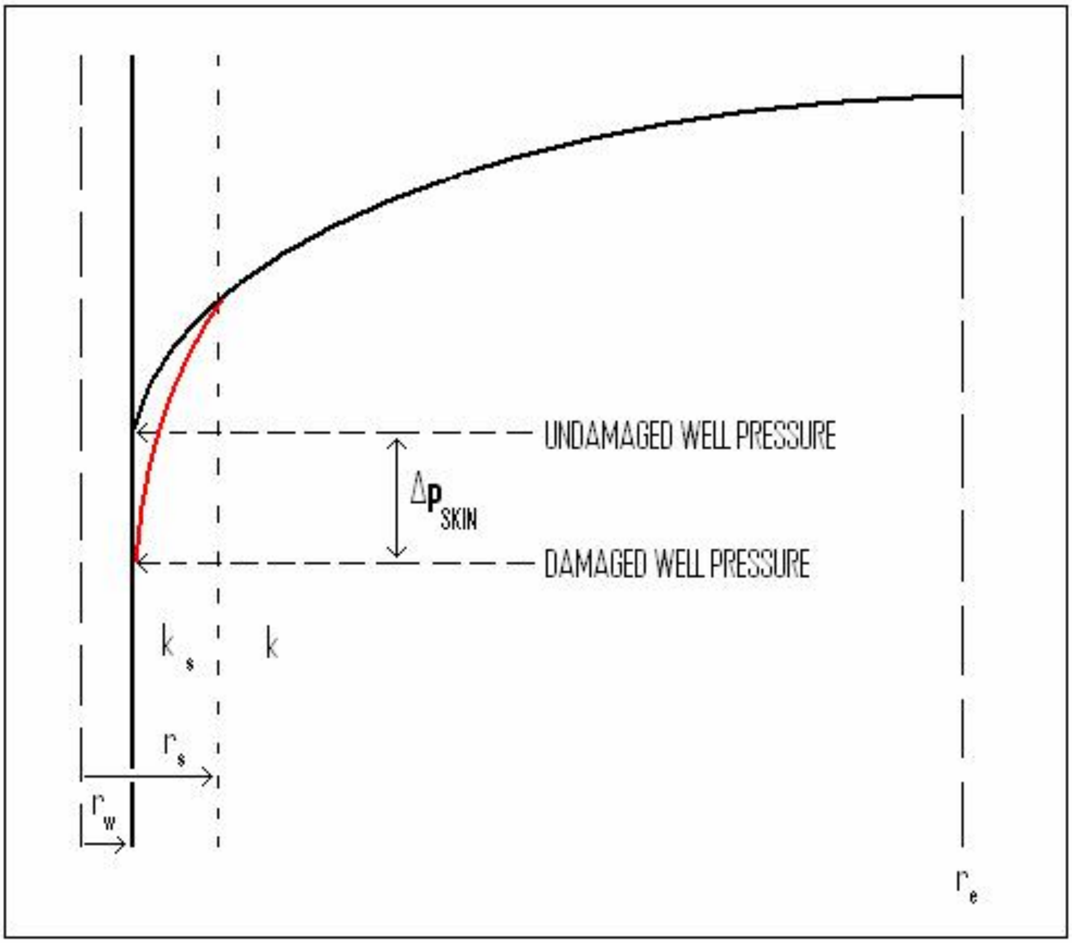


FIGURE 1: PRESSURE DRAWDOWN IN THE NEAR-WELLBORE REGION

Taking a look at Eq.[2.1], we can integrate the skin factor into the logarithmic expression in order to consider the skin factor when looking at the relationship of the radii. What we get is the so called apparent well radius:

$$\ln\left({r_e}/{r_w}\right) + s = \ln\left({r_e}/{r_{wa}}\right) \qquad [2.3]$$

whereas r_e is the outer bounder radius, r_w the well radius, and r_{wa} the apparent wellbore radius, in [m].

Solving the equation by applying the power of *e* leads to:

$$r_{wa} = r_w * \exp(-s) \tag{2.4}$$

Taking a look now at Eq.[2.2] and Eq.[2.4] we can easily see that a low or even a negative skin factor on the one hand reduces the pressure drawdown in the near wellbore region and on the other hand simultaneously results in a larger apparent wellbore radius which naturally increases the productivity index. In other words, the damage is being removed or overcome and this is generally achieved by stimulation.

2.2 TYPES OF DAMAGE

2.2.1 Damage due to the drilling process

The near wellbore effects occur as a result of different kinds of damage. The damage due to the drilling process is a big concern when drilling overbalanced. Even before an internal and external filter cake can be formed, we experience a so called spurt loss of the drilling fluid which is a sudden fluid invasion into the formation. Basically the drilling fluid filtrate can damage the formation by fines migration, precipitation, forming of emulsions and water blockage.

In terms of fines migration the drilling particles should be larger than the pores in order to keep the particle invasion small (less than 1 in. to 1 ft) and minimize this damage. A small depth of invasion of the damage can be overcome later on by perforating through the damaged region or acidizing treatment of the well.

Concerning the filtration chemistry, chemicals can react with reservoir fluids and form precipitations or emulsions. Gas, for instance, containing CO_2 reacts with Ca^{2+} of a calcium bentonite drilling mud and forms $CaCO_3$ which precipitates. Oil can contain organic acids which can form emulsion. If water blockage is a potential problem, water-based muds must be avoided. Water-based muds should also be avoided in case of large amounts of clay in the formation in order to prevent their swelling and/or migration. In case of water-sensitive formations oil-based mud should be used since it is inert but in this case we have to consider the change of wettability.

In old wells with a very long production history, the drilling damage may only contribute little compared to the overall damage.

2.2.2 Completion damage

The invasion of completion fluids into the formation will also cause reduced permeability. Casing cementing and perforation afterwards will also result in damage and in a so called compact zone permeability due to perforation. Well stimulation itself can also have the opposite effect on the skin. Reason could be the wrong selection of acid system, for instance.

2.2.3 Damage due to production

Fines migration from the formation to the borehole during the lifetime of a well can plug flow channels in the near wellbore zone. High velocities in the vicinity of the well are sufficient to mobilize fines which can plug the pore throats. Furthermore precipitation during production can cause additional troubles.

In addition, heavy hydrocarbons such as paraffines or asphaltenes can precipitate as organic deposits. They can form in the formation itself, in the perforations and in the tubings. The main cause for their formation is the change in pressure and temperature in the wellbore or in the near wellbore zone. Naturally, the injection of cold treating fluids will benefit the formation of organic deposits to a large extent.

2.2.4 Impact on production

All those kinds of damage lead to a reduced permeability k_s in the near wellbore zone which mainly defines the skin factor according to Hawkins [2]:

$$s = \left(k/k_s - 1 \right) * \ln\left(r_s/r_w \right) \qquad [2.5]$$

whereas ***k*** is the initial permeability, in [m²],

$\boldsymbol{k_s}$ is the reduced (damaged) permeability, in [m²],

$\boldsymbol{r_s}$ is the skin radius, in [m], (which is not equal to the depth of invasion: $\boldsymbol{r_w}$ + depth of invasion = $\boldsymbol{r_s}$)

and $\boldsymbol{r_w}$ is the radius of the well, in [m].

We can now easily see that a reduced permeability leads to a positive skin factor and a stimulated near wellbore zone can lead to a higher skin permeability compared to the formation permeability and hence result in a negative skin factor.

A quick check in an Excel-sheet, for instance, shows that the reduced permeability has more impact on the skin factor than the skin radius. Normally with stimulation, we try to restore initial permeability which would mean that the skin factor in Eq.[2.5] would become roughly zero and therefore we would only face the predicted pressure drop according to Darcy's law.

Theoretically, a negative skin after stimulation can be achieved. This would mean a larger apparent wellbore radius than the diameter of the well Eq.[2.4] and hence result in a smaller pressure drop across the invaded zone Eq.[2.2]. This will be referred to in the next chapter in connection with wormholes.

Throughout the entire lifetime of a well we experience different stages where different types of damage might occur like in the beginning the drilling process, followed by the completion of the well which includes all working steps in the transformation from the borehole to the producing well, and finally the production period which covers the largest time span. Therefore we need to find out what kind of damage it is we are dealing with – in other words – what causes the additional pressure drop in order to select the appropriate stimulation method.

If we were able to exactly define the situation in the near wellbore region we could for instance also stimulate a well that currently is a very good producer and enhance its already high production rate.

2.3 STIMULATION CANDIDATE SELECTION

The iterative enhancement process of the Inflow Performance Relationship, IPR *(inflow)*, and the Tubing Performance Relationship, TPR *(outflow)*, is called NODAL analysis and is one of the most powerful tools in production system optimization.

A NODAL systems analysis is performed in order to determine if the well is producing at its potential. The resulting curves, upstream curve and downstream curve, are analyzed in both directions.

The inflow performance, which is the ability of the reservoir to deliver oil or gas through the formation, the near wellbore zone and the completion into the wellbore, is described by the pressure and the corresponding rate of the reservoir. This is a function of the *geometrical and geological parameters of the reservoir* itself and reservoir fluid characteristics.

The outflow performance, which is the ability of the producing system to take the reservoir fluids, is described by the *tubing intake relationships and surface conditions* like the wellhead pressure, for instance, which is needed in order to keep the fluid under the required pressure.

At this point, specific factors restricting production and their location are determined. From this information, wells that have the potential for significantly enhanced production from a stimulation treatment can be identified.

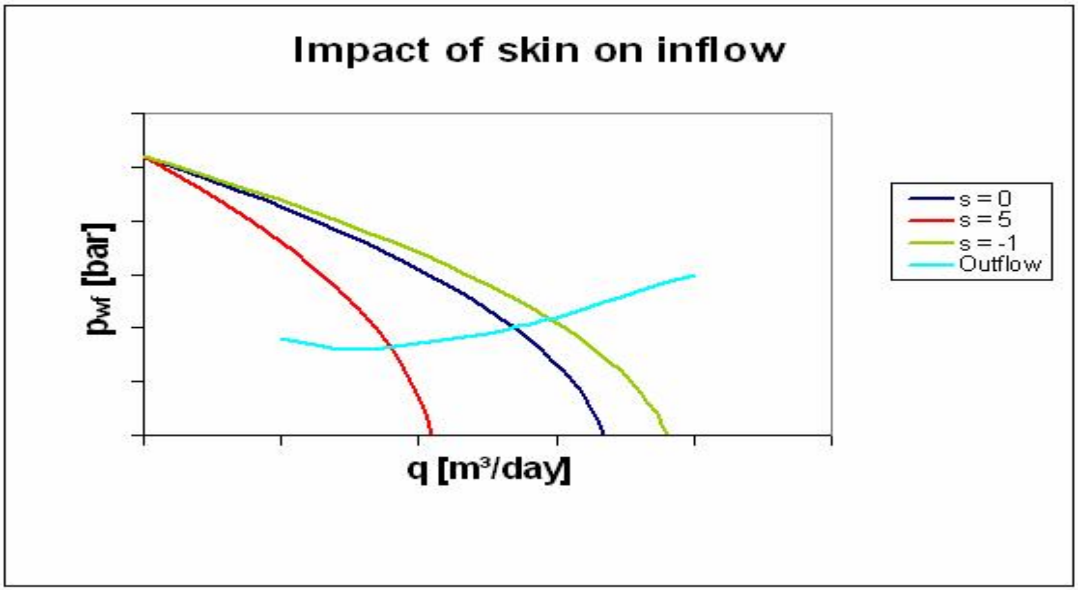


FIGURE 2: SKIN AFFECTED INFLOW

2.4 CRITERIA OF SELECTING STIMULATION METHOD

The two most common countermeasures are fracturing and acidizing. Each one has its purpose and applicability.

Fracturing basically is bypassing the near wellbore damage by creating highly conductive flow paths by injecting the pad slurry and the proppant slurry at pressures higher than formation breakdown pressure. Fracturing should primarily be done in low to moderate permeable reservoirs where the productivity index can not be increased by removing the damage around the well or in undamaged wells where acidizing would only lead to very little stimulation. When using the “tip-screenout” technique, which basically obstructs the fracture length propagation of the fracture by pumping the proppants shortly after the pad slurry in order to plug the tip and as a result get a width inflation, it can also be applied in highly permeable reservoirs.

In terms of acidizing, acid washing, acid fracturing and matrix acidizing must be distinguished. The aim of acid washing is to remove acid-soluble scales from the tubing, the perforations and the wellbore. The procedure of an acid fracturing job as the name already gives away is injecting acid into the formation while fracturing the formation. This is favoured in highly permeable formations whereas propped fractures are mostly favoured in low permeable carbonate reservoirs. Acid fracturing has no application in sandstone wells. Furthermore the mode of action of the etching process in sandstone rocks is not convenient for this type of stimulation. Why, will be mentioned in a later subchapter.

In matrix acidizing, the plugging material in the near wellbore region (which is about 1 ft in sandstones and can be 10 ft in carbonates) is tried to be removed by injecting acid into the wellbore below parting pressure to eventually remove the damage in the near-wellbore area. It is the most common stimulation method in Central Europe and will be the emphasis of this thesis.

3. THEORY OF MATRIX ACIDIZING

3.1 ACID SOLUTIONS

In general, all chemical compounds which increase the concentration of hydronium ions (H_3O^+) in a water solution below a pH of 7 can be considered acids. The pH is a measurement of the concentration of hydronium (H_3O^+) and hence a measure for the acidity of a solution. There are only of few kinds of acids that are commonly used in acidizing.

3.1.1 Most common types of acids in acid stimulations

We distinguish between inorganic (mineral) and organic acids.

Among inorganic acids, *hydrochloric acid, HCl*, is the most popular. It is very strong and the basis of almost every acidizing treatment, no matter what kind of formation. "Strong" means that it is totally dissociated into hydrogen and chloride ions when in solution.

Carbonic acid, H_2C0_3, is an example for a weak mineral acid.

Hydrofluoric acid, HF, which is not strong although inorganic, is used in sandstone formations. The objective of most HF acidizing treatments is to eliminate damage around the wellbore due to particle invasion from the mud solids after the drilling process and swelling, dispersion, movement or flocculation of formation clays.

In the presence of hydrochloric acid, hydrofluoric acid is poorly dissociated and behaves like a weak acid. This becomes important when doing sandstone acidizing in order to handle precipitations which we will see in the next chapter.

For operability purposes hydrofluoric acid (liquid) is handled and added in form of ammonium bifluoride, $(NH_4)HF_2$ (solid).

The only two organic acids that are frequently used are *acetic acid,* CH_3COOH, and *formic acid,* $HCOOH$, which in terms of strength is between hydrochloric and acetic acid. They are both used for dissolving carbonate formations. Since organic acids are weak, they do not totally dissociate and hence react incompletely with the reservoir rock. Taking acetic acid, CH_3COOH, as an example, it will partially dissociate by the reaction:

[Acetic acid]

CH_3COOH	<–>	H^+	+	CH_3COO^-
		[Hydrogen ion]		*[Acetic ion]*

Whenever the chemical activity, the driving force for a change, of the reaction products balances the activity of the reactants, the acid reaches equilibrium. At this point the dissolution of the formation material stops, even though acetic acid molecules may still be in solution.

The equilibrium of the acetic acid dissociation is described by the equilibrium constant:

$$K_D = \frac{\left[H^+\right]\left[COOH^-\right]}{\left[CH_3COOH\right]} \qquad [3.6]$$

In this case the equilibrium constant is also referred to as the *dissociation constant.* As can be seen in Eq.[3.6] K_D is small for weak acids as for acetic acid. At 150°F acetic acid has a K_D of 1.488×10^{-5} and formic acid of 1.486×10^{-4}. In general, the higher the concentration of organic acids, the lower the dissociation. Therefore organic acids are frequently used in retarded acidizing jobs.

3.2 PETROGRAPHY OF RESERVOIR FORMATIONS AND ACID SELECTION

Matrix acidizing is performed in two main types of formations:

- carbonates and
- sandstones.

Acidizing of both groups face different general requirements. Each formation composition within the two groups theoretically requires individual treatment and recipe in terms of acid type, acid concentration, injection rate, injection pressure (since we do not want to frac the formation) and additives. In order to find the adequate treatment for each formation, we first need to understand the rock.

The decisive factor in the effectiveness of a reaction between the rock and the acid is determined by the components of the rock which naturally cannot be changed. Hence the composition of the rock in the near wellbore region can be regarded as a given parameter for each well. The acid-rock combination, the mineral distribution and the morphology will result in different reaction rates and reaction products. We will see that when doing matrix acidizing the acid has not the same effect on the carbonate rock as on the sandstone rock. The mode of action in each case is a very different one.

3.2.1 Carbonates

When doing carbonate acidizing we mostly use hydrochloric acid, HCl. The ideal chemical reaction can be described as follows [3]:

[Limestone] *[Hydrochloric acid]*

$CaCO_3$ + $2HCl$ –>

$CaCl_2$ + H_2O + CO_2

[Calcium chloride] *[Water]* *[Carbon dioxide]*

The surface reaction rate of limestone with hydrochloric acid is very high which can cause wormholes even up to 10 feet long in the near wellbore region connected to the flow channels. Wormholes are caused by non-uniform dissolution of limestone, which basically means that larger pores grow faster than the smaller ones. The limiting factor in most of the cases is the mass transfer. If initially a well has no skin at all or the wormhole length after the acid treatment is larger than the skin radius, then the pressure drop across the wormholes is negligible which eventually means infinite permeability across this region. Taking a look now at Hawkins formula, Eq.[2.5]:

$$s = \left({}^{k}\!\diagup_{k_s} - 1 \right) * \ln \left({}^{r_s}\!\diagup_{r_w} \right)$$

we can see that assuming an infinite permeability ($\boldsymbol{k_s} = \infty$) and a wormhole radius which equals the skin radius ($\boldsymbol{r_{wh}} = \boldsymbol{r_s}$) the skin factor results in:

$$s = -\ln \left({}^{r_{wh}}\!\diagup_{r_w} \right) \qquad [3.7]$$

We know that a negative skin factor effectively means that the apparent radius of the well is being enlarged, Eq.[2.4].

Acetic and formic acid reacts on limestone as follows:

[Limestone] *[Acetic acid]*

$CaCO_3 + 2CH_3COOH \rightarrow$

$Ca\,(CH_3COO)_2 + H_2O + CO_2$

[Calcium acetate] *[Water]* *[Carbon dioxide]*

[Limestone] *[Formic acid]*

$CaCO_3 + 2CHOOH \rightarrow$

$Ca\,(CHOO)_2 + H_2O + CO_2$

[Calcium formate] *[Water]* *[Carbon dioxide]*

We can assume that at pressures above 70 bar carbon dioxide stays in solution after the reaction. In the reaction of dolomite with hydrochloric acid it must be considered that the ratio of calcium to magnesium is not constant. An idealized chemical reaction is shown below:

[Dolomite] *[Hydrochloric acid]*

$CaMg\,(CO_3)_2 + 4HCl \rightarrow$

$CaCl_2 + MgCl_2 + 2H_2O + 2CO_2$

[Calcium chloride] *[Magnesium chloride]* *[Water]* *[Carbon dioxide]*

3.2.2 Sandstones and clays

Most sandstone formations are composed of quartz particles, $Si0_2$, which are bonded together by various kinds of cementing materials, mainly carbonates, silica and clays. This diversity of materials in the composition makes it a lot more difficult to predict the outcome of a reaction. It is obvious that hydrochloric acid alone in most of the cases will not be enough to dissolve the rock. An idealized primary reaction of hydrofluoric acid on sand (silicon dioxide) and clay could look as follows[3]:

[Silicon dioxide] *[Hydrofluoric acid]*

$Si0_2$ + $6HF$ –>

H_2SiF_6 + $2H_20$

[Fluosilicic acid] *[Water]*

[Clay] *[Hydrofluoric acid]*

$Al_2Si_40_{10}(OH)_2$ + $36HF$ –>

$4H_2SiF_6$ + $12H_20$ + $2H_3AlF_6$

[Fluosilicic acid] *[Water]* *[Fluoaluminic acid]*

A big concern in terms of clays reacting with hydrofluoric and hydrochloric acid solutions is damage due to secondary reactions. The primary reaction results in complete dissolution of the aluminosilicate and is the only reaction leading to the removal of clay damage. Fluorides act to dissolve silicon and an excess of acid is required to dissolve non-silicon cations and keep them in solution.

The dominant silicon fluoride species among the silicon reaction products can best be described as $HSiF_5$. Experiments showed that when H_2SiF_6 is added to HCl, immediate decomposition to $HSiF_5$ and free HF occurs.

The secondary reaction of HF with aluminosilicate, in essence, is the reaction of fluosilicic acid with aluminosilicate. Now other cations are dissolved from the aluminosilicate which is connected with further acid consumption. The reaction, however, does not dissolve the silicon in the aluminosilicate. Rather, all portions of clay are removed except the silicon which eventually leads to an amorphous and chemically complex silica-gel residue or film. Furthermore silicon originally present as $HSiF_5$ is completely precipitated as a silica-gel film on the surfaces of the reacting aluminosilicates. This film contains a large amount of water which either comes from the reaction products or from the solution itself. The secondary reaction benefits the formation of sodium and potassium fluosilicate precipitates (Na_2SiF_6, K_2SiF_6) to a high extent. These insoluble fluoride precipitates are gelatinous type materials which occupy a large volume of pore space in the sand around the wellbore and are responsible for treatment failures especially in high permeable feldspar formations[4].

Therefore, in crucial cases (high amount of sensitive clays or high temperatures which accelerate reactions), a good advice is to reduce the concentration of hydrofluoric acid in order to limit the potential for detrimental secondary reactions.

We also have to consider that hydrofluoric acid is able to dissolve quartz and clay particles but will cause problems when reacting with calcium carbonate [3]:

$$\underset{\text{[Calcium]}}{Ca^{++}} + \underset{\text{[Fluoride]}}{2\,F^-} \rightarrow \underset{\text{[Calcium fluoride]}}{CaF_2}$$

Whenever free fluoride and calcium are present they will precipitate. Hydrofluoric acid should therefore among other reasons always be used together with a surplus of hydrochloric acid. The surplus of hydrogen ions will bond the free fluorides in order to bar them from reacting on calcium. Furthermore a combination of hydrochloric, HCl and hydrofluoric acid, HF, should be used due to the manifold composition of sandstone rocks. A preflush of hydrochloric acid is almost standard in order to remove the calcium and magnesium but this will be the focus of a later chapter. A rule of thumb states that a formation with about 15-20% HCl solubility should be treated by HCl alone.

3.2.3 Differences in the mode of action

When acidizing either limestones or dolomites, acid enters the formation through pores in the matrix of the rock or through naturally induced fractures. The intensity of the reaction depends due to mass transfer limitation on the injection rate, the contact area and the number and size of the fractures if present.

The reaction rates vary depending on the formation and the acid. Hydrochloric acid, for instance, reacts faster with limestone than with dolomites, and only very little with sandstone.

The fast reaction rate of carbonates and the potentially resulting wormholes might have a penetration into the formation of 10 ft whereas in sandstone formations it might probably only be 1 ft. The structures of wormholes depend on the flow geometry, the injection rate and the mass transfer rates. The wormholes propagate due to the unevenly progressing etching pattern of hydrochloric acid with carbonates. Naturally the acid will have more impact in flow channels with the largest exposed area, like a natural or induced fracture or an already etched wormhole, than in a very narrow path. Now it is also understood why acid fracturing treatments in sandstone formations are not applicable – the reaction rate of hydrochloric acid as well as of hydrofluoric acid on sandstones is to slow to create unevenly etched channels in terms of enlarging fractures or even creating wormholes

The big difference we have to consider in sandstones compared to carbonate acidizing is that we do not create any wormholes in order to get a connection to various flow channels but we basically remove the damage around the wellbore. Additionally, when using hydrofluoric acid in sandstones we usually dissolve clay particles or fines resulting either from the drilling or production process.

3.3 PROCEDURE DESIGN

In planning the stimulation treatment the sequence of the fluid patches and the exact timing is crucial. Each well has experienced a different kind of damage, therefore theoretically requires a unique treatment. The stages which a sequence normally consists of apart from the treatment itself are preflush and postflush[5].

First of all we want to know in what kind of formation the acid treatment is to be performed. In case of carbonate reservoirs the selection of the acid type becomes easier. Furthermore, in most of the cases no preflush is required. In sandstone acidizing a core analysis would give information on the amount of cement, clays, other pore filling minerals and the type and distribution of the components. However, in most of the cases cores of the desired formation are not available which turns the whole process into some kind of guess work which is very much dependent on experience with the particular petrography of the reservoir formation. A mixture of hydrochloric and hydrofluoric acid is commonly used as a main treatment. Why a preflush is therefore recommended will be discussed in the following subchapter.

The physical placement must be determined and consequently we can decide whether diverting or retarding agents should be added to the acid system.

3.3.1 Preflush

In many acid stimulation treatments preflushes are used ahead of an acid treating solution to prepare or condition the formation which is going to be stimulated so the formation will accept the acid in the most favourable sections.

The main purpose of the preflush is to displace the brine from the wellbore to avoid contact between the hydrofluoric acid and the formation brine containing potassium, sodium and calcium which leads to precipitations. In sandstone acidizing a hydrochloric acid preflush is required to dissolve carbonates in the formation so the hydrofluoric acid will not spend on those but rather remain active to dissolve the clays and silicates.

Aromatic Solvents, either with or without hydrochloric acid, can be used to remove paraffine and asphaltene components. Mutual solvents, such as ethylene glycol monobutyl ether (EGMBE), are also used in preflush (and also in postflush) fluids because of their ability to dissolve away the oil coating.

A kerosene or diesel oil preflush can be used in order to allow the formation to react with the acid in the oil-producing interval while restricting the invasion of acid into the water-producing strata.

3.3.2 Main treatment

The purpose of this stage is the removal of the damage of the well. The injection rate influences the placement of the live acid and thus the success of the treatment to a large extent. The type of the acidizing job – matrix acidizing or acid fracturing - determines the ideal injection rate. The acid system, depending on the formation, is injected with a rate which in terms of matrix acidizing must not correspond to pressures exceeding fracture pressure. In general, low injection rates which produce pressures below the breakdown pressure are recommended to repair skin or shallow formation damage as sometimes in sandstone wells. Low pump rates are also recommended when acidizing in proximity to high water saturation zones.

With injection rate kept constant the pressure at the pump can be observed. Whenever the pressure decreases the formation starts to take notice of the injected acid. A fast decline means a fast reaction of the acid with the formation. In carbonates wormhole velocities increase with injection rate which means for rapid wormhole propagation a high injection rate should be applied. On multizone treatments where different zones accept the acid solution at different pressures, a more complete acid coverage can be obtained also by applying high pumping rates. If the formation is able to sustain higher forces, the maximum allowable pressure for the tubing, the surface equipment and the pump, together with the maximum achievable pump rate, must be kept in mind since in such a case those parameters will define the pressure limit and not the reservoir rock parameters.

3.3.3 Postflush

The overflush is used to displace the main acid flush at least 4 feet away from the wellbore. The precipitation products are pushed as far away as possible from the critical region, the near wellbore.

Postflushes can also be used as an over-displacing medium. Retarded acids might help to obtain greater penetrations of the acid since the reaction time of the retarded acid on the formation is longer than its injection time.

Since a flow of the acid system back to the well immediately after the treatment is not beneficial for avoiding corrosion, water or brine could be an overflush which would help to minimize the contact time of the live acid on the tubing and the casing. Naturally, we try to avoid additional precipitation products. In acidizing sandstone formations with hydrofluoric acid a ammonium chloride, NH_4Cl, postflush is recommended instead of postflush consisting of potassium chloride, KCl.

3.3.4 Success evaluation, possible damage and general recommendations

Generally, the success can be measured in terms of Productivity Index (PI) improvement or skin reduction. An acid stimulation treatment can also cause further damage instead of damage removal. Precipitation products coming from the reaction itself or loose solids generated during the acidizing job might cause further plugging of flow channels. Dirt from the tank or tubulars, release of fines from carbonate rocks, precipitation of iron reaction products, plugging by colloidal sludge and chemical incompatibility of the acid system itself or with the formation might cause further problems. Some crude oils and strong inorganic acids can produce sludges such as organic deposits which cannot be dissolved.

State of the art nowadays is the *real-time-monitoring* of an acidizing job. The skin factor correlated, for instance, with Paccaloni's model (which will be focused on in subchapter 7.4.5) from the measured pressure changes is plotted versus the injected volume of acid solution during the acidizing job in order to determine the optimum point when to stop the injection. Continuation of the treatment would probably lead to an increasing skin factor again as can be seen in the graph.

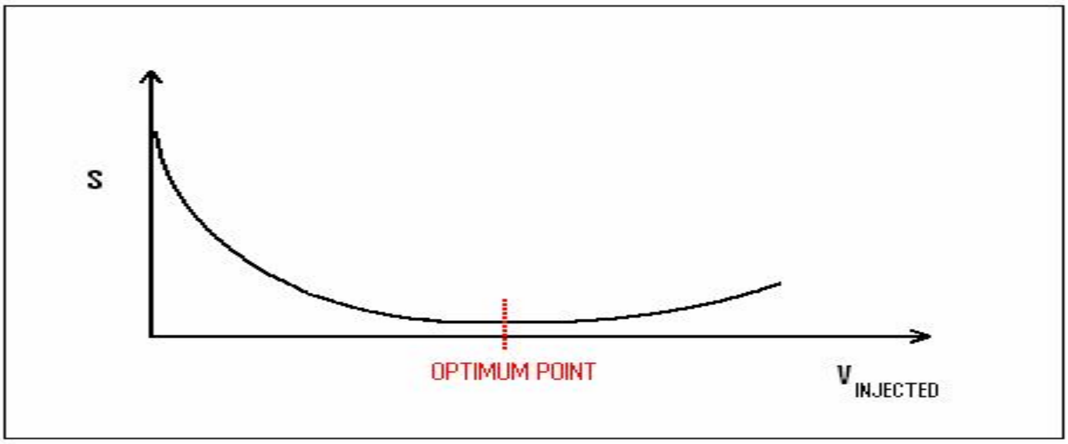


FIGURE 3: THE PRINCIPLE OF REAL-TIME MONITORING

Below, we can find a summary, in order to shortly review on some general operation recommendations before and after the treatment:

- During the preparation of the acid solution minimize open air time while mixing the fluid batches.
- Make sure the tanks and flowlines are clean.
- A corrosion inhibition measure is to not produce the spent acid into the flowline after the acidizing job, but in tank. We can never be sure that 100% of the live acid totally reacted on the formation rock.
- Oxide layers which may develop on the surface metallic components should be removed by pickling in order to avoid precipitations downhole.
- Depending on the acid solution pumped, be aware that damage can also occur during shut-in time and not only during pumping and the primary reaction.

4. APPLICABILITY OF ADDITIVES

4.1 SURFACTANTS

We experience different secondary actions and side effects during and due to acidizing treatments. Some of them can only be handled by the use of different *surface active agents* (surfactants). The emphasis of the surfactants' impact in oil production lies in the change of interfacial tension between:

- two liquids (oil and water),
- a liquid and a solid or
- a liquid and gas[3].

Surface active agents can have a variety of applications depending on the phases at the interface. Using a surfactant as a demulsifier, the interfacial tension of a liquid-liquid interface can be reduced in order to break the emulsion which can create severe damage downhole and eventually reduce the viscosity. The different groups of interfaces and the corresponding surface active agents will be discussed in this chapter.

4.1.1 Types of surfactants

The vast majority of surfactants consist of two parts. One part is made up of a long hydrocarbon chain which is oil-soluble. The second part is a group that is water-soluble that keeps the molecules sufficiently water-soluble to be useful for the surfactant process.

Generally there are three different groups of surfactants. Those are anionic, cationic or nonionic[3].

Anionic type surfactants are organic chemicals whose molecules ionize upon contacting water. The positively charged particle of each ion goes into solution in the water and plays little role in the surface tension phenomenon. The negatively charged particle, though, consisting of an oil-soluble and a water-soluble end is surface active. The negatively charged active part orients itself at the surface of the liquid in case of a liquid-air interface or at the interface between water and oil in case of a liquid-liquid interface, naturally in both cases the water-soluble end of the negatively charged particle being in the water.

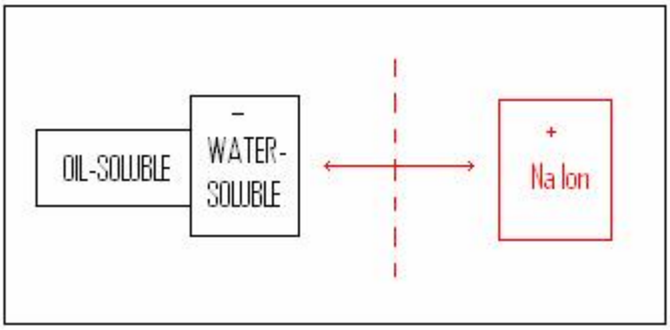


FIGURE 4: ANIONIC TYPE SURFACANT

Cationic type surfactants share the same principle, only vice versa. In this case the negatively charged particle goes into solution in the water and the positively charged particle, in this case consisting of and water-soluble and an oil-soluble end, contains the surface active portion of the molecule which orients itself at the liquid-air or liquid-liquid interfaces.

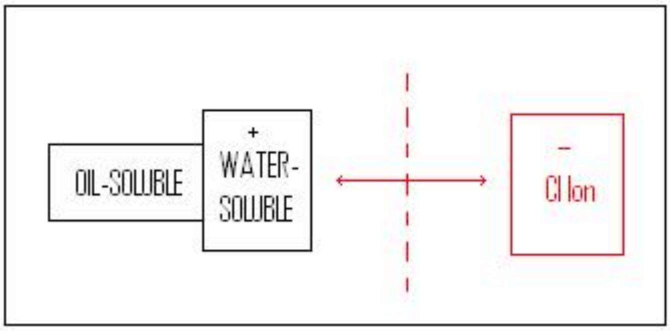


FIGURE 5: CATIONIC TYPE SURFACTANT

Nonionic type surfactants as their name already gives away do not ionize into charged particles. Nevertheless, these organic chemicals do also have water-soluble and oil-soluble ends.

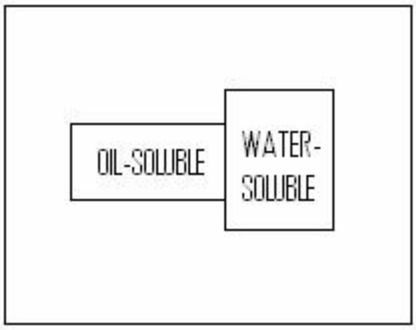


FIGURE 6: NONIONIC TYPE SURFACTANT

4.1.2 Wettability dependency at liquid-solid interfaces

How the solid surface of sand grains which like most surfaces in nature is negatively charged will be wet by the surfactant and the well fluid depends on the type of surfactant. Soil particles are negatively charged and, in case of cationic type surfactants, will attract and hold the positively charged chemicals, which results in an oil-wet surface. In case of anionic type surfactants the oil-soluble end of the surfactant molecule adsorbs to the formation and the negatively charged water-soluble end which is rejected by the grain sand will be exposed resulting in a water-wet surface[3].

Since oil flows more easily through water-wet sands, the important thing is that when there is a choice in selecting a surfactant for emulsion breaking or emulsion preventing in an acid treating solution it is better to choose the surfactant that is capable of water-wetting the formation. Why it is so crucial to control emulsions will be the topic of the next subchapter.

4.1.3 Action of demulsifiers and emulsifiers on liquid-liquid interfaces

Water and oil are not miscible like water and alcohol, for instance. They rather separate into two layers. A system having experienced a forced mixture of two immiscible liquids resulting in fine droplets of one fluid remaining suspended in the other is called an emulsion.

The surface between the two immiscible liquids as already mentioned is called interface. The interfacial tension of a crude oil and reservoir water system is affected by temperature, pressure, gas in solution, viscosity, specific gravity and, of course, the presence of surface active agents. An increase in temperature or pressure, for instance, decreases interfacial tension. The more gas in solution in oil and water above the bubble point pressure, the lower the interfacial tension, but vice-versa the more gas in solution below the bubble point. A decrease in the viscosity or specific gravity difference between the oil and water generally goes along with reduced interfacial tension.

Emulsions may be water-in-oil or oil-in-water. In a water-in-oil system oil is the continuous or external phase having fine water droplets dispersed through the oil. This is the most common type of emulsion found in oil reservoirs. The problem related to emulsions is the resulting higher viscosity. Emulsions always have higher viscosity than either of their components. Very viscous emulsions can act even quasi-solid and may plug pores of the treated matrix. An ideal emulsion's viscosity can described as follows [3]:

$$\mu = \mu_0 \left(1 + 2{,}5\Phi\right) \qquad [4.7]$$

whereas μ is the viscosity of the emulsion, in [Pa.s],

μ_0 is the viscosity of the external phase, in [Pa.s], and

Φ is the volume fraction of the dispersed phase, [-].

Now we can see that the viscosity of emulsions is determined by the relative amount of the internal, or dispersed, phase and the viscosity of the external phase. If either of these parameters increases the more viscous the emulsion becomes and hence the more difficult to produce through the formation, as can be seen regarding Darcy's law of steady state flow (Eq.[2.1]):

$$q = \frac{2\pi hk\ (p_E - p_{WF})}{\mu B\left(\ln\left(r_e/r_w\right) + s\right)}$$

An increase in viscosity, such as in emulsion blocking, results in a decrease in flow rate.

Demulsifying or non-emulsifying agents are designed to facilitate or prevent emulsions which form between live or spent acid and crude oil and hence to provide a more efficient clean up after the stimulation treatment. Their mode of action is to reduce the interfacial tension of a liquid-liquid or a liquid-gas system in order to force a segregation of the two phases. This results in two liquids, each one having a lower viscosity than their emulsion. What must be distinguished is that demulsifiers are surfactants that break and non-emulsifiers surfactants that prevent emulsions[6].

The figure below shows an example of a sandstone acidizing treatment. The first contact of the injected solution with the formation fluids is critical since emulsifying is most likely to occur. Using the right preflush precipitations can be minimized[5].

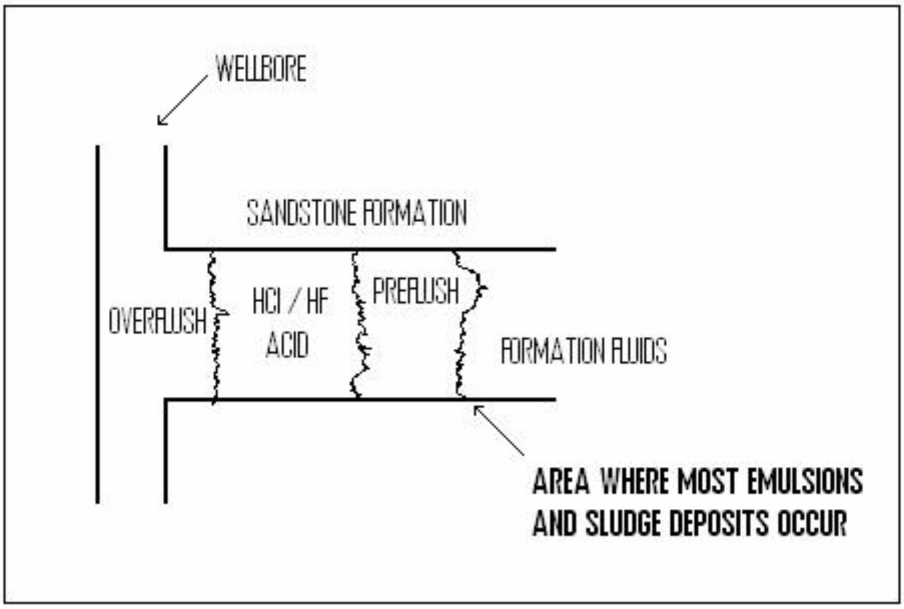


FIGURE 7: RISK OF EMULSIONS AND SLUDGE DEPOSITS

On the other hand, emulsifying agents are used to manufacture aqueous external emulsion stimulation fluids. Their main purpose is to provide a high viscosity stimulation fluid which makes it more efficient at carrying sand and controlling leak-off.

Mutual solvents, such as ethylene glycol mono butyl ether (EGMBE), are additives which are soluble in both aqueous based fluids, such as acid solutions, and hydrocarbon based fluids such as formation oils. Effectively, this means a decrease of the miscibility gap of the two fluids. Originally mutual solvents were designed to facilitate acid reaction on oil coated surfaces because of their ability of dissolving the oil coating and hence allow reaction of the acid on the formation rock. Mutual solvents, in the same manner as demulsifying agents, also help to lower the surface tension of the reactive acid which facilitates spent acid recovery and well cleanup after the treatment. However, the difference to demulsifying agents in the applicability is that mutual solvents are added in stoichiometric quantities. In order to be effective they must be added at concentrations of approximately 10% by volume of acid which substantially contributes to the costs of the treatment [7,8].

4.1.4 Action of wetting and penetrating agents on liquid-solid interfaces

Surfactants may also control the effectiveness of an acid treatment as well the ability of oil to flow through the formation. Surfactants that improve the spreading or the wetting ability of a fluid are known as wetting or penetrating agents. They are added to an acid solution so it provides spreading across and hence reacting more effectively with the limestone or dolomite formation. A formation initially covered by an oil film can be acidized using wetting agents which help the acid to spread and remove the oil layer, so the surface of the formation is exposed to the acid[3].

4.2 CORROSION INHIBITORS

When pumping stimulation acids through the tubing or casing into the formation we will experience different corrosion processes. The corrosiveness of an acid mainly depends on its concentration and temperature. The rate of corrosion is measured by actually weighing a small specimen of steel before and after exposure to the acid.

A counter measure is the use of corrosion inhibitors which retards the reaction rate of acid on steel by establishing a film that protects metal from corrosive fluids. In oilfield systems one class of chemicals is used as corrosion inhibitors:

- organic amine based.

In general, they work by interfering with the production of hydrogen at the cathode region. The majority of organic inhibitors are organic-film-forming inhibitors. These are organic chemicals with a polar, water loving, head and a long hydrocarbon, oil loving, tail. When applied, these compounds align with the polar head towards the metal and the tail towards the outside, effectively establishing an oil-wet film on the metal surface. This inhibitor film breaks the corrosion cell by separating the metal surface and the electrolyte containing water[3,7].

In inhibited hydrochloric acid the influence of temperature on corrosion rate follows the same pattern as in uninhibited acid [3].

If a surfactant is defined as being an agent acting on a surface then inhibitors can be considered surfactants as well.

4.3 SEQUESTRANTS AND SCALE INHIBITORS

A big concern in production as well as in injection wells are iron scale deposits which may precipitate from the acidizing treatment. Typical scale deposits are iron carbonate, $FeCO_3$, iron sulfide, FeS_2, and iron oxide, Fe_2O_3. These precipitates are water-insoluble and do not only restrict production or Injectivity, they can also influence the performance of an acidizing job significantly.

Hydrochloric acid, for instance, when injected through the tubing or casing dissolves part of existing iron scales and carries iron compounds put into solution as iron chloride, $FeCl_2$, into the formation. The iron in solution will undergo hydrolysis and reprecipitate as iron hydroxide, $Fe(OH)_2$. The worst case is when iron hydroxide once more reacts with oxygen resulting in the formation of $Fe(OH)_3$ which is much less soluble and hence a very strong plugging material. Formation of this insoluble plugging material in the near wellbore can reduce permeability and eventually cause permanent plugging of flow channels resulting in reduced oil and gas production in producing wells or higher required injection pressure and reduced injection volume in water-flood wells.

The control of reprecipitation of iron deposits from spent acid solutions can be achieved using sequestering agents. They act to complex ions of iron and other metallic salts to inhibit precipitation of iron cations in spent hydrochloric acid. Most sequestrants are organic acids such as acetic, citric or lactic acid, each one being differently effective in reducing the activities of iron. The effectiveness of the acid furthermore is influenced by its concentration, the pH of the system and the external temperature of the system[3,7].

Ethylenediaminetetraacetic acid (EDTA) is nowadays frequently used for complexing metal ions. It contains four carboxylic acid groups and two amine groups with lone electrons.

Sequestered acid has particular application in treating water injection or disposal wells where iron compounds are deposited on the formation face. Sequestrants should furthermore be used if rusty tubing or casing is to be contacted.

4.4 SUSPENDING AGENTS

Carbonate and sandstone formations may contain HCl-insolubles such as clays and silts which after the acidizing treatment can cause blocking in the formation pores or fractures if the fines released by the acid are allowed to settle and bridge. Suspending agents hold the fine undissolved clay and silt particles in suspension and thereby play an essential role in the effectiveness of their removal[3].

4.5 FRICTION REDUCING AGENTS

Friction reducers in general reduce the amount of turbulence of a fluid flowing through tubular goods and as a result reduce the friction pressure losses. They are long-chain natural or synthetic polymers. These polymers when being dry resemble tightly coiled springs. When adding water the springs uncoil and hence being in solution serve as a multitude of elastic layers dampening turbulence. High molecular weight synthetic polymers are most commonly used since they resist attack by acid at normal treating temperatures.

Friction reducers can be classified according to their base fluids. In general the two base fluids used in well stimulation are hydrocarbon such as kerosene, diesel fuel and crude oils, and aqueous such as water and brine. In hydrocarbons, for instance, friction can be reduced using synthetic polymers and in situ soap gels, whereas in aqueous systems natural gums and synthetic polymers are used[3].

4.6 ANTI-SLUDGE AGENTS

Acid contacted with heavy asphaltic crudes may form insoluble sludge. Sludge generally consists of asphaltenes and may also contain resins and paraffin waxes, high molecular weight hydrocarbons and formation fines or clays.

Some surfactants which usually also function as emulsion preventers might keep colloidal material dispersed. High strength acids, in general, tend to form severe sludges[3,7].

4.7 CLAY STABILIZERS

Clays are layered minerals of silicon and aluminum oxides and exist in the majority of sandstone formations. Some can lead to formation damage, either damage caused by:

- clay swelling or
- clay migration.

As soon as their chemical environment is changed in the formation like in acid treatments, clay particles may be released when the treating solution dissolves the surrounding material. The particles become entrained in the moving fluids. The *dispersion* and movement of fine clay particles in water sensitive formations eventually plugs flow channels causing a reduction in permeability.

The alteration of equilibrium between clays and formation waters which means change in salinity causing imbalances in the forces between clays. Ion exchange between the aqueous system and the formation can cause *swelling* clays which reduce permeability. The most common swelling clays are smectites and smectite mixtures. Clay stabilizers act to decrease the activity of ions in order to prevent ion exchange [3,6,7].

In this manner, they are effectively desensitized to swelling and migration or coated or fused, rendering them immobile

Ammonium chloride, NH_4Cl, is commonly used as a pre- and postflush brine or as a spacer when stimulating with hydrofluoric acid. The ammonium ion acts as a temporary stabilizer for migrating and swelling clays normally found in sandstone reservoirs. When performing acid stimulations using hydrofluoric acid the wrong spacer can cause precipitations. Potassium chloride, KCl, for instance, and hydrofluoric acid will form potassium fluosilicate precipitates, K_2SiF_6. Ammonium chloride as a spacer will not induce the formation of precipitations.

Fluoboric acid, HBF_4, also provides clay stabilization through reactions related to borate and fluoborate ions. The cation exchange capacity is strongly decreased and hence swellable clays are desensitized [9].

4.8 RETARDERS

Normally hydrofluoric acid reacts so rapidly with the siliceous formations that the acid tends to become spent before penetrating deeply into the formation.

Consequently an increase in porosity and permeability can only be achieved in zones very close to the wellbore. The damaged region, though, can very often reach much deeper into the formation than conventional hydrofluoric acid systems are able to penetrate.

In sandstone matrix acidizing improved penetration of hydrofluoric acid stimulations can be achieved retarding hydrofluoric acid by complexing fluoride ions with aluminum chloride, $AlCl_3$. The aluminum ions form aluminum fluoride complexes which retard the formation of the hydrofluoric acid itself. Retardation is accomplished by constantly controlling the amount of hydrofluoric acid actually available for the reaction. As a result the retarded acid system always has some free HF molecules which react quickly with clay minerals but very slowly with sand grains[10]. In this manner live acid is still available when the acid solution system is pumped deep into the formation.

4.9 FLUID LOSS CONTROL AGENTS

The acid solution itself is not prone to deep penetrations. This is due to two reasons:

- acids have a high reaction rate on most producing formations;
- acids have a low viscosity.

Deeper penetrations can be achieved using fluid loss additives which help to confine the live acid by temporarily sealing off the openings in the flow channels and in this manner reducing leak-off into the formation [3].

4.10 BLOCKING AND DIVERTING AGENTS

Diversion of matrix treatments can be accomplished by using *mechanical blocking agents* which temporarily seal a zone completely, *selective permeability reducing chemical solids* which basically function like fluid loss additives and *foam* which helps in acidizing different producing formations uniformly.

When pumping the acid into the well, it will always follow the path of least resistance which practically means the highest permeable zone. Since the aim of an acid treatment is to stimulate the damaged areas, namely the low permeable zones, the high permeable zones have to be isolated with the use of blocking agents. Among the *mechanical blocking methods* there is the use of packers, straddle packers, frac baffles and perforation ball sealers which provide selective stimulation treatment. Mechanical diverting methods have limitations. On the one hand using packers may take several hours which usually leads to concerns about the rig costs and on the other hand perforation ball sealers need to have sufficient rate/perforation to hold the balls on the perforations as the acid is placed[7].

Chemical diverting agents used for matrix diversion basically are designed to bridge at the formation pores and to function in a similar way as fluid loss additives. The diverting agent first enters the zone of greatest flow capacity and causes a decrease in flow rate into this zone. At this point the additive quantity reaches its optimum since further additive injection would result in a further equally reducing flow rate in each zone. Chemical solids include rock salt, solid organic acids, such as benzoic acid flakes, and oil-soluble resins. Most of the solids used for diversion are soluble in at least one the fluids they will be exposed to during the final stages of the acidizing treatment or at least during the early stages of well production. Solids, such as benzoic acid, should be exposed to the flowing stream in order to be effectively removed. Rock salt is soluble in spent acid and some formation fluids. A further damaging of the formation can be avoided, if the chemicals are used sparingly[6,7].

In sandstones and gravel packed completions a more complete exposure of different producing formations to acid can be achieved by the use of *foam*. This distribution over the entire production or injection interval can be achieved using a foaming solution which produces foam in-situ when activated by compressed carbon dioxide or nitrogen which is pumped after the first portion of acid and the foaming solution and followed by the next portion of acid. As soon as the foaming solution is activated and foam is being produced the pressure build-up diverts the next portion of acid into the next section of the injection interval[3].

A *technique using injection rate for treatment diversion* during matrix acidizing treatments is advocated by Paccaloni. This involves increasing the injection rate as soon as treating pressure decrease due to improved or restored permeability. Additional acid is pumped at ever increasing rates as skin is removed in order to deliver more treatment fluid to the clean zone than its restored permeability will allow and thus diverting the fluid flow to other portions of the zone in order to create another path of least resistance with the acid reaction. This method has its limitations since it may require large amounts of horsepower and volumes of acid when used in high permeability formations [6].

5. OMV FIELD OPERATIONS

5.1 ACIDS AND ADDITIVES CURRENTLY USED IN OMV

ACIDS used in OMV	
Name	*Formula*
Hydrochloric acid	HCl
Hydrofluoric acid	HF
Acetic acid	CH3COOH

FIGURE 8: ACIDS CURRENTLY USED IN OMV

Most common types of ADDITIVES used in OMV		
Additive type	*Name/Components*	*Commercial Product*
Surfactants	Tri butyl phenol ethoxylate	Sapogenat T 139 (nonionic) Dodicor 1946 Losurf 259
Corrosion Inhibitors		Cronox AK-12K HAI-85 M (Halliburton) LP-55
Sequestrants	Citric acid Acetic acid	
Mutual solvents	Ethylene gylcol mono - butyl ether	Musol (Halliburton)
Clay stabilizers		Cla Sta II
Spacers	Ammonium chloride Potassium chloride	
Diverters	Temblok 40 TLC-80 Gelsystem	
Breakers	Ammonium persulfate	APS (Halliburton)

FIGURE 9: ADDITIVES CURRENTLY USED IN OMV

6. FORMULATION OF PROBLEM IN ANALYSING STIMULATIONS

In general, a matrix acid stimulation treatment should remove the damage around the wellbore in order to achieve higher production rates and hence a faster delivery of hydrocarbons out of the reservoir. In theory, acidizing is an easy procedure compared to e.g. hydraulic fracturing. Also in field practice, acidizing usually has been a straight-forward procedure in the past. So, why do we want to evaluate acid stimulations?

Local OMV fields mainly consist of sandstone reservoirs. The potential problems in acidizing sandstone reservoirs using hydrofluoric acid have been discussed in chapter 3. This, however, out of many problems that can occur during field operations, is only one theoretical concern dealing with the chemistry of matrix acidizing. In addition, each horizon has its peculiarities in terms of mineralogical composition and anisotropies.

The quality and quantity of production we obtain as a result of the acid stimulation treatment is a unique response to the whole treatment of a well. All injected fluid stages, their sequence, their injection rate at each time step and the corresponding counter pressure of the formation result in one solution – the productivity of the well as a direct result of the performance of the acid solution. This leads us to the essential part: how can we optimise stimulation treatments and their procedures?

7. METHODOLOGY IN EVALUATING AND OPTIMISING

7.1 CRITERIA OF COMPARISON OF ACIDIZING TREATMENTS

If we want to state something about the effectiveness of matrix acid stimulation treatments we have to ask ourselves the following: how can we make stimulations comparable?

In this paper matrix acidizing of wells with production history will be regarded. Of course we could also compare the production of newly drilled, completed and perforated wells if they have been acidized. But how do you know the production increase or decrease is a direct result of the acidizing treatment? Also, acidized wells with an already existing production history cannot be evaluated if they have been re-perforated within the same work-over or shortly before the stimulation treatment. Naturally, wells with existing production history which have been perforated once more in an upper position within the same horizon or even within another horizon during the same work-over, will not be regarded.

In order to compare the effectiveness, also similar mineralogical conditions for the wells have to be valid. In fact, they will at best be similar. It is understood that carbonate and sandstone acidizing cannot be compared. Also, wells completed with an inside-casing-gravel-pack (ICGP) are not comparable to wells without. Some of the wells where ICGPs had been installed have been acidized by acid injection through the annulus and not through the tubing or washpipe. They will be compared to each other and at best to other wells completed with an ICGP.

Wells where the kill fluid has been circulated out before the acid hits the formation face in contrast to wells where the acid has been injected after bullheading the kill fluid into the formation, could also yield similarities during the operation itself and in later production performance.

Naturally, treatments performed in order to remove carbonate deposits from the tubing will not be among the selection of evaluation.

Summarizing criteria for comparison of matrix acid stimulation treatments:

- only wells with a long enough production history are evaluated.
- no re-perforations within the same work-over or shortly before.
- only carbonate matrix acid stimulation treatments can be compared amongst each other.
- only sandstone matrix acid stimulation treatments can be compared amongst each other, if at all.
- only wells with either an ICGP or without can be compared amongst each other.
- regard stimulations with injection through annulus separately.

Considering all the boundary conditions requires a large number of stimulated wells in order to define different groups, each one having the same conditions.

7.2 PROVIDED DATA QUANTITY AND QUALITY DEFINES SELECTION

318 matrix acid stimulation operations, mostly of oil producers but also of gas producers and injectors, in the fields Matzen (A015), Hochleiten (A016) and Pirawarth (A017) stretching over 58 horizons have been performed over the

last 10 years, whereas multiple stimulations of the same well are already included in that number. Stimulations of new or re-perforated wells have already been excluded. All the horizons together with the corresponding fields where matrix acid stimulations have been performed over the last 10 years can be found in Appendix A.

		TOTAL	
# STIMULATIONS		318	
(multiple stimulations of one well included)	**OIL WELLS**	GAS WELLS	INJECTORS
	205	14	99

FIGURE 10: NUMBER AND TYPE OF STIMULATED WELLS (1996-2006)

Few gas producers were stimulated. The stimulations of the injectors had already been analysed within OMV and therefore were not of the highest priority.

Taking a look at the completion history of all the stimulated oil wells already showed that the perforations of most of the wells had been altered in various ways, which cuts down the number of wells which can be analysed significantly.

In order to be able to compare the treatments, parameters like pressure, temperature and mineralogical composition should be as similar as possible within a group which leads to the conclusion that probably the best approach is defining groups of stimulations within the same horizon. Furthermore a certain number of stimulations within the same horizon must be available. As a rule, a randomly chosen horizon provides one or two stimulations having, if at all, poor data quality, which makes an evaluation difficult.

At this point in time, only oil well stimulations are regarded because they provide a minimum number of stimulation treatments according to predefined criteria. In the table below, we can see a summary of the outcomes of the selecting process. The concepts of the evaluation of Productivity and Injectivity Indices will be discussed in the following chapters.

		OVER THE LAST 10 YEARS	**FINALLY SELECTED ACCORDING TO CRITERIA**	
			only Injectivity Index evaluation	*PI evaluation possible*
# OIL WELL STIMULATIONS (multiple stimulations of one well included)	*IN TOTAL*	205	**28**	**21**
	IN THE FIELDS:			
	Matzen-A015	148	**18**	**11**
	Hochleiten-A016	31	**7**	**7**
	Pirawarth-A017	26	**3**	**3**
	# HORIZONS	58	**7**	**7**

FIGURE 11: STIMULATED OIL WELLS AND CORRESPONDING FIELDS

7.3 PEFORMANCE CRITERIA

It has been decided for this thesis that the success of a matrix acid stimulation treatment will be measured according to technical results and not according to economical analysis. Usually an increase in gross production rate would indicate technical success whereas economical success is defined as a function of net production rate and oil prize.

Still there are stimulations of wells with sucker rod pumps installed as an artificial lift method which fulfil the prior defined conditions and criteria but the pump setting depth has been changed in the same work-over after the stimulation treatment. A deeper pump setting depth, for instance, will relieve the bottom hole from a higher hydrostatic column. A reduction in well flowing pressure, as we know, yields a higher pressure drawdown and hence a higher production rate. So an increase in gross production rate after the treatment could also be only a result of the change in pump setting depth. What we want to find out, though, is whether the matrix acid stimulation treatment was successful or not. Gross production rate does not provide us with this information. We have to take the pressure drawdown into account by relating the gross production rate to the pressure drop. The best method to do so is calculating the *Productivity Index (PI)*:

$$PI = \frac{q}{p_{WS} - p_{WF}} \qquad [7.8]$$

whereas the ***PI*** is given in [m³/day.bar],

q is the production rate, in [m³/day],

p_{WS} is the well static pressure, in [bar],

and p_{WF} is the well flowing pressure, in [bar].

Furthermore the comparison of the gross production rate before and after the treatment does only give indirect information about the relative damage removal, but not about the repercussion of pressure drop in the near wellbore itself.

The change of the Productivity Index was chosen in order to evaluate the effectiveness of the whole acidizing treatment.

Eventually, 28 stimulations referring to 24 different wells in 7 main horizons were chosen, whereas 21 stimulations referring to 18 wells can directly be compared to the production performance. In other words 18 different PI histories of wells within the 7 horizons, ranging over the time span in which the stimulations were performed, could be calculated. The rest of the wells do not provide either Pressure-Buildup-Tests or enough measured static and dynamic levels which Productivity Indices can be estimated from. It must be noticed that three of the wells produce out of a dolomite formation where stimulation treatments usually perform very well.

7.3.1 Possibilities of estimating Productivity Indices

The effectiveness of an acid stimulation can sometimes not be determined by looking at only one PI value. A multitude of PIs and even more than one method of determining them, if possible, are required in order to decide about the repercussions of the treatment. Sometimes the calculated PIs cannot directly be taken as absolute values, but more as relative ones or even ranges which restrict the possible outcome.

Usually the best way in evaluating a Productivity Index is well testing. Well test analysis results in flow capacity, ***kh***, skin factor, ***s***, well static pressure, $\boldsymbol{p_{WS}}$, and well flowing pressure, $\boldsymbol{p_{WF}}$.

$$PI = \frac{q}{p_{WS} - p_{WF}} = \frac{2\pi hk}{\mu B\left(\ln\left(r_e / r_w\right) + s\right)} \qquad [7.9]$$

Taking a look at the very right hand side of Darcy's equation for steady state conditions shows that inserting the results gained from the well test analysis allows us to calculate a Productivity Index and furthermore to find out about the PI reduction as a direct result of the degree of formation damage. The fluid properties can be found in OMV's database GasDB. Setting the skin factor, ***s***, to zero gives information about the ideal Productivity Index.

$$PI = \frac{2\pi hk}{\mu B\left(\ln\left(r_e / r_w\right) + s\right)} \qquad [7.10]$$

Pressure-Buildup-Tests are rather rare, mostly because wells are not free-flowing after perforation. Hence the little number of actual and ideal PIs calculated will be more of an index for PIs calculated on a different basis discussed later in this chapter rather than the essential hint for the evaluation of the effectiveness of an acid stimulation treatment.

Another possibility of estimating typical PI ranges for the selected wells with the data provided lies in an alternative approach for calculating the flow capacity, ***kh***. Knowing the initial water saturation, S_{wi}, and the porosity, Φ, the permeability, ***k***, can be correlated. A variety of approaches are available which the permeability can be averaged of. Since this value for permeability will most likely not be very accurate, a definition of an upper and lower limit for the flow capacity can be made. Taking two boundary values for the height, ***h***, yields two flow capacities and hence two Productivity Indices. The upper PI limit is defined by estimating the net height, h_{net}, from well-log data. This can be done by reading off the pay zone from the log and then adding together all the table values available for the effective pay zone. Now a net-to-gross ratio can be estimated which then can be related to the entire interval in order to obtain the net height. The lower PI limit is simply defined by the perforation height, h_{perf}.

We have to notice that these two boundary values refer to undamaged conditions since the initial water saturation has been taken. We can compare the outcome to the Productivity Index calculated from the well test flow capacity setting the skin factor, ***s***, to zero.

In order to compare the Productivity of two wells, the specific Productivity Index, which is defined as the Productivity Index per unit of open interval thickness, can be taken as a criterion.

At this point enough information about the undamaged well conditions should be available. Unfortunately one well test does only yield one Productivity Index under damaged situation and the number of well tests would not allow to make a statement concerning the skin reduction of an acidizing treatment. Effectively, we want data before and after the acidizing treatment which allow us to compare the Productivity Index progression qualitatively. Still, we face the problem of wanting to have comparable data.

There is still the possibility of using static and dynamic fluid levels from Sonolog measurements to calculate well static and well flowing pressures. This has been taken into account while defining the selection of 18 stimulated wells in sandstone formations to be analysed.

Taking a look at the sketch below, which refers to dynamic conditions, we can define the pressure components acting on the bottom hole. We assume that under dynamic conditions oil accumulates in the annulus between the tubing and the casing. Below the end of the tubing a water-oil mixture is being produced, as shown in the sketch.

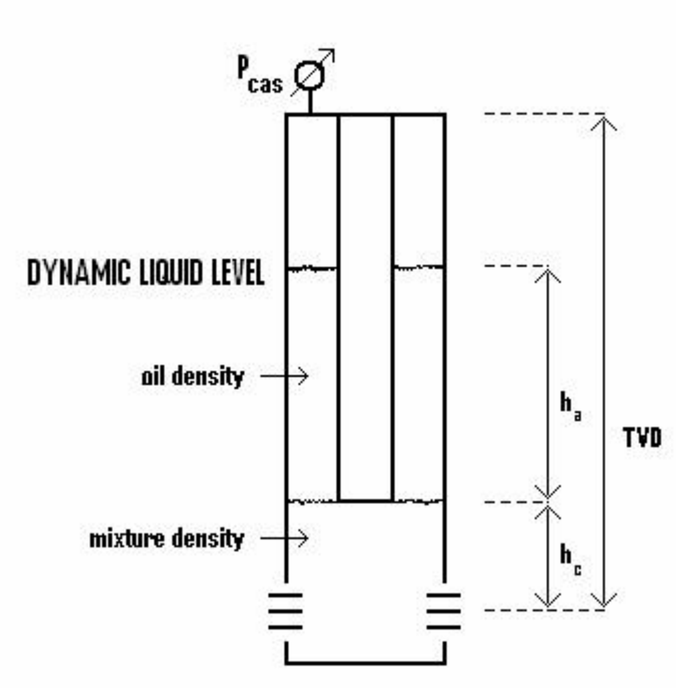


FIGURE 12: LIQUID COLUMN UNDER DYNAMIC CONDITIONS

Thus we can define two different hydrostatic liquid columns:

$$p_{HYD,OIL} = \rho_{OIL} g h_a \qquad [7.11]$$

$$p_{HYD,MIX} = \rho_{MIX} g h_c \qquad [7.12]$$

whereas $p_{HYD,OIL}$ is the hydrostatic pressure of the oil in the annulus

and $p_{HYD,MIX}$ is the hydrostatic pressure of the water-oil mixture which is being produced.

Notice that the oil density, ρ_{OIL}, does not need to be necessarily the same for two different wells especially if they are located in different fields. If the water cut of two wells is different, the mixture density, ρ_{MIX}, will for sure be different. Since most of the wells analysed show a rather high water cut the mixture density can be approximated somewhat below the brine density which is around 1,01 to 1,015 [kg/l].

Neglecting the hydrostatic pressure of the gas and taking into account the gas pressure measured at the casing head, we can calculate the total pressure acting on the well bottom, which under dynamic conditions is defined as the well flowing pressure, p_{WF}:

Together with the liquid level, the casing pressure, p_{CAS}, is measured. The well flowing pressure, p_{WF}, can be then calculated as:

$$p_{WF} = p_{HYD, OIL} + p_{HYD,MIX} + p_{CAS} \qquad [7.13]$$

The different heights always refer to TVD and not to the length of the tubulars.

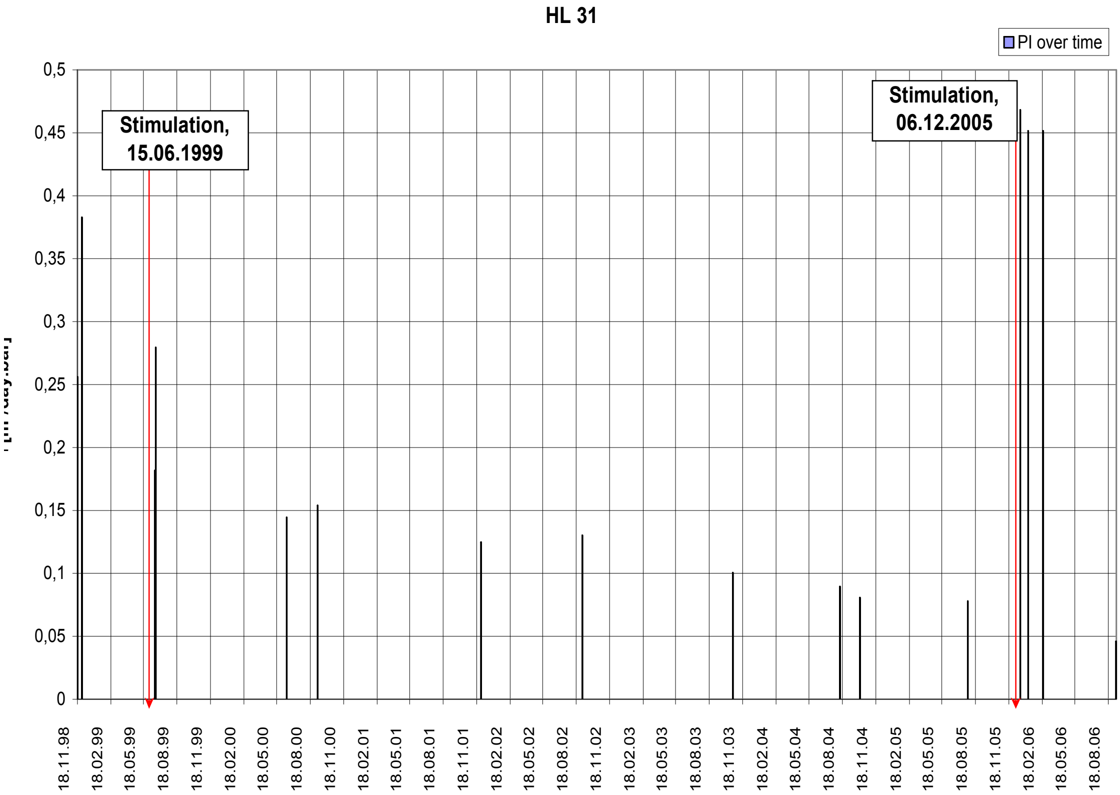
The bottom hole pressure under static conditions can be calculated similarly. We will now face the problem that we have different static well pressures. Sometimes the deviation lies within 30 bars. In OMV's database GDB the production days and the days of standstill can be determined. If we compare the days of standstill before the static liquid level has been measured, we may find out about the reliability of the one or the other measured liquid level since the pressure needs time to build up. This number of days can also be compared to the duration the memory gauge has been in hole during a Pressure-Buildup-Test. In this manner a representative well static pressure can be estimated in order to compute a pressure drawdown later on.

Since, at this point in time, we have determined a reasonable quantity of well flowing pressures, the only thing still required for each dynamic liquid level is the corresponding daily production rate, which can be found in the GDB of OMV's databases.

The unit of the Productivity Index defined in this thesis is [m^3/(day.bar)].

In order to check upon the reliability of the PI calculation we can compare a PI calculated from a Pressure-Buildup-Test to PIs calculated on the basis of liquid levels. This matching of Productivity Indices also allows us to check if the hydrostatic liquid columns computed are based on correct mixture densities. The PIs calculated on the basis of liquid levels can be chosen in time one before and one after the well test, for instance.

Below, the PI performance over time of a multiple stimulated well is shown. We can clearly see the decline of the Productivity Index over time and also the impact of the matrix acid stimulation treatment on the Productivity of the well. The first stimulation treatment resulted in a PI decline whereas the second treatment enhanced the Productivity Index. All the computed PI-histories can be found enlarged in Appendix B. The first PI-history of Appendix B shows the effect of a successful acidizing treatment and the second one the effect of an unsuccessful treatment on the Productivity Index. A screenshot of a sample of the calculation can be found in Appendix E.



Stimulation, 15.06.1999

Stimulation, 06.12.2005

FIGURE 13: IMPACT OF STIMULATION ON PRODUCTIVITY INDEX

7.4 POSSIBILITIES OF EVALUATING THE PROGRESSION OF THE TREATMENT

The comparison of Productivity Indices before and after the treatment defines the gross effectiveness of the overall treatment. But how can you evaluate the progression of the treatment itself with existing data? What is even possible with given data quality?

A matrix acid simulation is normally plotted on a Two-Pen-Chart. Below an example of a matrix acidizing job using hydrofluoric acid in a sandstone formation is shown.

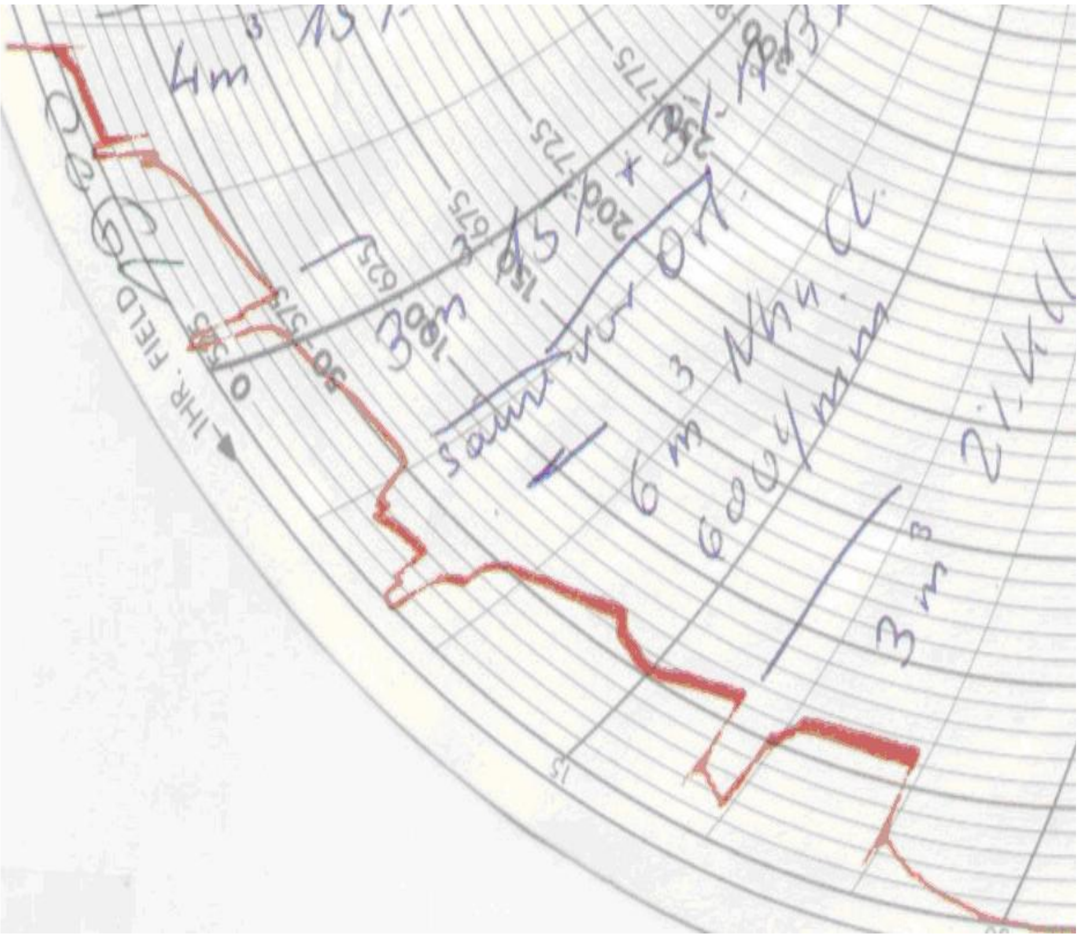


FIGURE 14: TWO-PEN-CHART

Basically, what can be read off from a Two-Pen-Chart is the pump pressure, p_{PUMP}, over time. In most of the cases the injection rate, q_{INJ}, is written at the beginning and at the end of each tank volume injected. Taking a look at the injection rate at the start and at the end of the treatment together with the corresponding pressure which can be read off from the chart, we already can get a rough idea about the relative effect on the injection performance of the whole treatment. A low injection rate at the beginning of the procedure corresponding to a high pressure response of the formation and a high injection rate at the end of the treatment corresponding to a relatively lower pressure indicates at least that the acid has dissolved part of the rock without having caused too much precipitation.

7.4.1 Problems with inaccuracies of Two-Pen-Charts

A matrix acid stimulation treatment typically consists of more than one stage, as we know. Especially acid stimulations performed in sandstone reservoirs usually require a variety of stages. So the first step in procedure optimisation is to evaluate the impact of every single stage and change in injection performance from stage to stage. From a Two-Pen-Chart we only can read off the time point when a certain stage enters the tubulars, but it does not directly show the exact time point when the stage hits the formation face.

A problem which we will always face when working with Two-Pen-Charts is the fact that the exact value of the injection rate at the moment a fluid stage hits the formation face which creates a certain pressure response is unknown in almost one hundred percent of the cases. Thus, the only possibility lies in calculating back the fluid-hits-formation-face time point from the time span the pressure is drawn on the chart and hence estimating the average injection rate from the boundary values available around the time when the fluid stage most likely will have reached the bottom hole.

Once we know the moment the fluid stage reaches the bottom of the well we can also analyse the pressure conditions at this time point.

7.4.2 Determination of the well flowing injection pressure

At the time point any given fluid stage reaches the bottom hole a certain flow rate, q_{INJ}, is pumped which results in a certain wellhead pressure, p_{WH}. This wellhead pressure corresponds to a well flowing injection pressure, $p_{WF,INJ}$, which can be estimated as follows:

$$p_{WF,\ INJ} = p_{WH} + p_{HYD} - \Delta p_{FRICTION} \qquad [7.14]$$

whereas p_{HYD} is the hydrostatic fluid column acting on the bottom hole,

and $\Delta p_{FRICTION}$ are the friction pressure losses which depend on the fluid properties, the tubulars and the rate.

Since the stages in the acid stimulation jobs analysed do not contain any gelling agents the liquid solutions should follow a Newtonian behaviour.

The flow regime during injection in the analysed stimulation is always turbulent since laminar flow would require a flow rate far below 10 [l/min] in order to get a Reynolds number, ***Re***, smaller than 2100 (=$Re_{CRITICAL}$) which practically does not happen. Of course when starting pumping we will at some point have to pass the critical Reynolds number but once have achieved that we never fall back to a Reynolds number below the critical one. The Reynolds number can be calculated as follows:

$$\mathrm{Re} = \frac{928 \rho v d}{\mu} \qquad [7.15]$$

whereas ρ is the density of the fluid ,in [lbm/gal],

v is the fluid velocity, in [ft/sec],

d is the internal diameter of the tubular, in [in],

and μ is the fluid viscosity, in [cp].

The friction pressure losses in Field units or [psi], respectively, assuming a Newtonian fluid model in a pipe can be calculated according to the formula:

$$\Delta p_{FRICTION} = \frac{\rho^{0,75} v^{1,75} \mu^{0,25} L}{1800 d^{1,25}} \qquad [7.16]$$

whereas **ρ** is the density of the fluid, in [lbm/gal],

v is the fluid velocity, in [ft/sec],

μ is the fluid viscosity, in [cp],

L is the assumed length the fluid is flowing, in [ft],

(notice that the length here refers to MD und not TVD)

and ***d*** is the internal diameter of the tubular, in [in] [11].

Inserting $\left(\frac{q_{INJ}}{2{,}448 d^2}\right)$ for the fluid velocity, ***v***, and transforming the formula to the units given in the OMV Two-Pen-Charts results in:

$$\Delta p_{FRICTION,PIPE} = \frac{C * \rho^{0,75} {q_{INJ}}^{1,75} \mu^{0,25} L}{d^{4,75}} \qquad [7.17]$$

whereas ***C*** equals 1,04875*10^{-3} which is the conversion factor to [bar] allowing to insert the following units into the latter equation:

[kg/l] for **ρ**,

[l/min] for q_{INJ},

[cp] for **μ**,

[m] for ***L***,

and [cm] for ***d***.

The friction pressure losses across an annular volume using a Newtonian fluid model can be calculated as follows:

$$\Delta p_{FRICTION,ANNULUS} = \frac{C * \rho^{0,75} q_{INJ}^{1,75} \mu^{0,25} L}{\left((d_2 - d_1)^{1,25}\left(d_2^{\,2} - d_1^{\,2}\right)^{1,75}\right)} \qquad [7.18]$$

whereas in this case a value of 1,03523*10^{-3} for the constant ***C*** was computed in order to get the pressure losses in [bar].

Naturally, in case of a changing pipe diameter or a changing annular capacity the total friction pressure loss calculation has to be subdivided into as many segments as there are changes in diameter. The partial pressure losses have to be added up.

Eventually we can compute the well flowing injection pressure, $p_{WF,INJ}$, by adding the hydrostatic pressure, p_{HYD}, to the pump pressure, p_{WH}, and finally subtracting the friction pressure losses, $\Delta p_{FRICTION}$, according to Eq.[7.16]. Note that the hydrostatic pressure is a function of the fluid density, ρ, and the friction pressure losses are a function of the fluid density and the fluid viscosity, μ. Those two fluid properties are pressure and temperature dependent. Since pressure and temperature change with increasing depth, the accuracy of the computed hydrostatic pressure and the friction pressure losses will suffer. The temperature dependency and hence the transient temperature increase of the injected stage while being pumped through the tubulars, will be neglected in this thesis.

7.4.3 Comparing correlation with memory gauge recordings

The stages pumped should normally behave like a Newtonian fluid model. Assuming the fluid properties of the pumped stages being at room temperature during the whole operation, how can we be sure the correlation of the fluid model chosen is accurate enough?

At the end of August 2006, a matrix acid stimulation treatment was performed in a local dolomite formation. The well was perforated from 2716 [m] to a depth of 2724 [m] in measured depth. Hence, the mid-perforation was at a measured depth of 2720 [m] and a value of almost 2700 [m] for the true vertical depth of the mid-perforation was computed.

The treatment operation itself was rather simple. 4 [m³] of 15 [%] hydrochloric acid (ρ = 1,0726 [kg/l], μ = 1,258 [cp]) including 0,7 [%] corrosion inhibitor, 2 [%] citric acid and 10 [%] of a mutual solvent, was pumped downhole to the end of the tubing while circulating out the kill fluid via annulus. Then the tubing-seal-divider was connected to the packer and the 4 [m³] of acid solution system were then displaced into the perforations by pumping 5 [m³] of brine (ρ = 1,015 [kg/l], μ = 1,04 [cp]) downhole.

The speciality of this stimulation within OMV was not the treatment itself, but rather the manner the data acquisition was performed. Already shortly before this treatment, pump pressure, $\boldsymbol{p_{WH}}$, and injection rate, $\boldsymbol{q_{INJ}}$, had been recorded online in other well stimulations. This time, however, a memory gauge was installed during the stimulation treatment which recorded the downhole pressure and temperature at the mid-perforation. In this manner the two relevant pressures, wellhead pressure, $\boldsymbol{p_{WH}}$, and well flowing injection pressure, $\boldsymbol{p_{WF,INJ}}$, were recorded digitally every 10 seconds and every 3 to 4 seconds, respectively.

In addition, the usual recording on a Two-Pen-Chart was done.

The curves below show the downhole pressure and temperature recorded by the memory gauge every 3 seconds during the acidizing treatment. Note that the pressure increase indicates the arrival of the acid solution at the formation face. The kill fluid had been circulated out which is indicated by the pressure peaks and declines before. What can be observed as well is the temperature decrease (in red) as soon as the "cold" acid solution hits the memory gauge and the temperature increase after the pressure drop due to the exothermal reaction of the hydrochloric acid and the dolomite rock.

The pressure and temperature increase and decrease at the beginning and the end of the recordings refer to the tripping actions (installing and pulling out the memory gauge at the beginning and the end of the work-over, respectively).

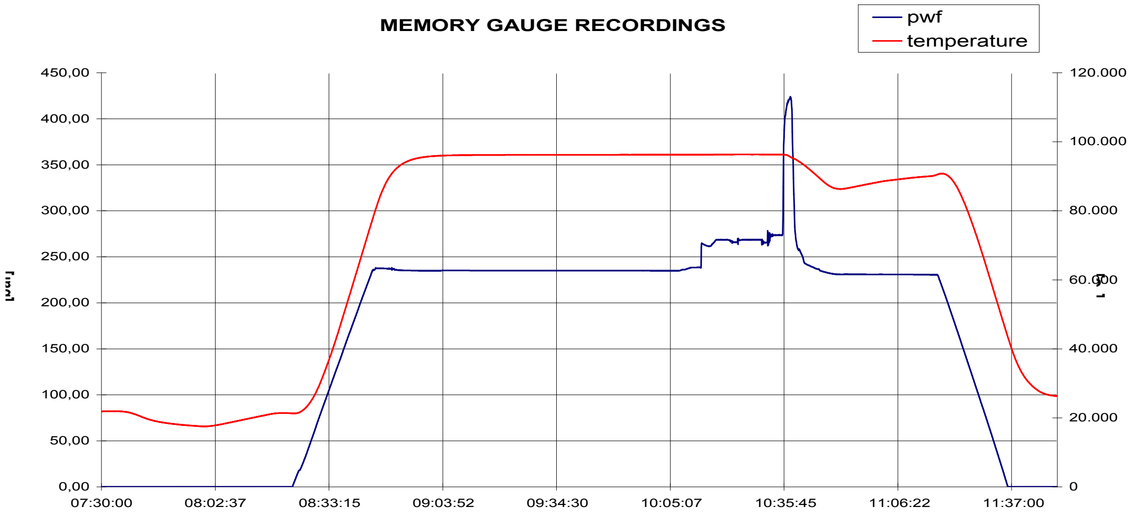


FIGURE 15: MEMORY GAUGE RECORDINGS

The graph below shows the two measured pressures, pump pressure at the surface and the well flowing injection pressure at the mid-perforation, over time.

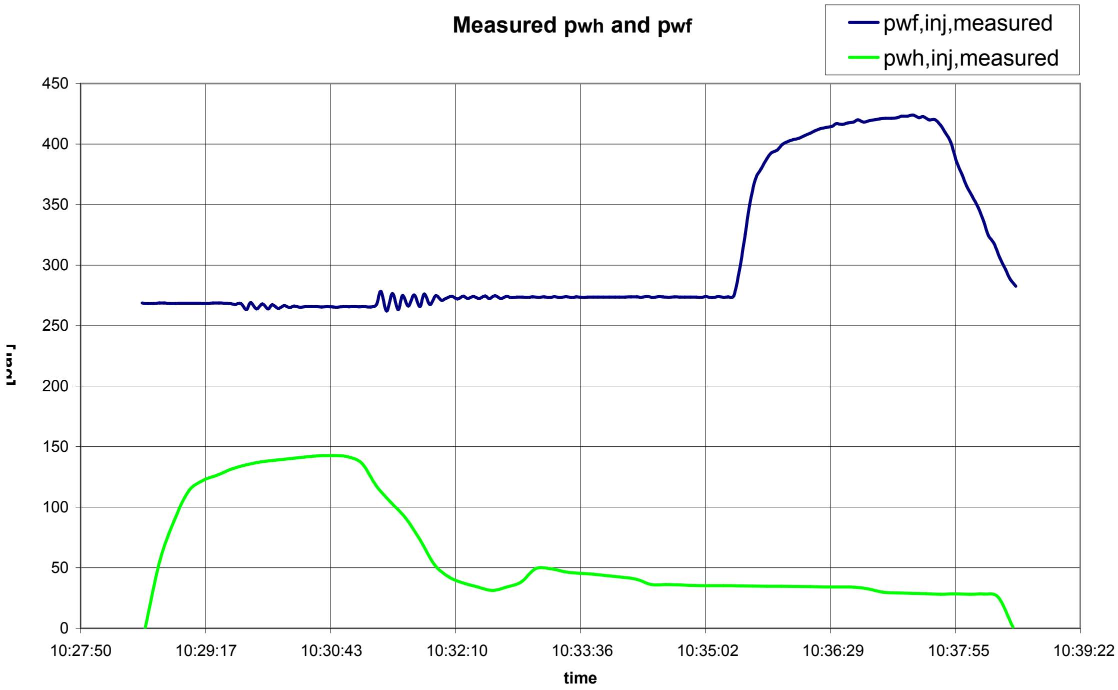


FIGURE 16: ONLINE MEASURED AND MEMORY GAUGE RECORDED PRESSURE

We can see that the two recorded pressures deviate roughly six and a half minutes from each other. The two clocks, one at the surface and one downhole, have been programmed independently of each other. So the clocks themselves are potential error sources. Even at a depth of about 2700 [m] the transient effects concerning a pressure build-up will not result in a difference of six and half minutes. Furthermore the injected medium, a water based solution, is almost incompressible which leads to the conclusion that the two major pressure peaks do not necessarily have to deviate that severely from each other.

Below, the online wellhead pressure and the correlated well flowing injection pressure are plotted over treatment time as recorded at the surface. The curve of the well flowing pressure injection (orange in the graph below) assumes an instantaneous pressure build-up at the perforations, as soon as the pressure rises at the surface.

Since for this particular stimulation treatment values for injection rate and pump pressure are available for time steps of ten seconds it is possible to calculate the constantly changing hydrostatic columns of fluid stages while they are being injected. Since the length of the hydrochloric acid column is decreasing every ten seconds and the column of the postflush is increasing, not only the hydrostatic pressure acting on the bottom of the hole is changing, but also the friction pressure losses which also are directly proportional to the measured depth of a certain fluid stage. How fast the heads of the different stages change, is a function of the injection rate which, naturally, is not a constant value.

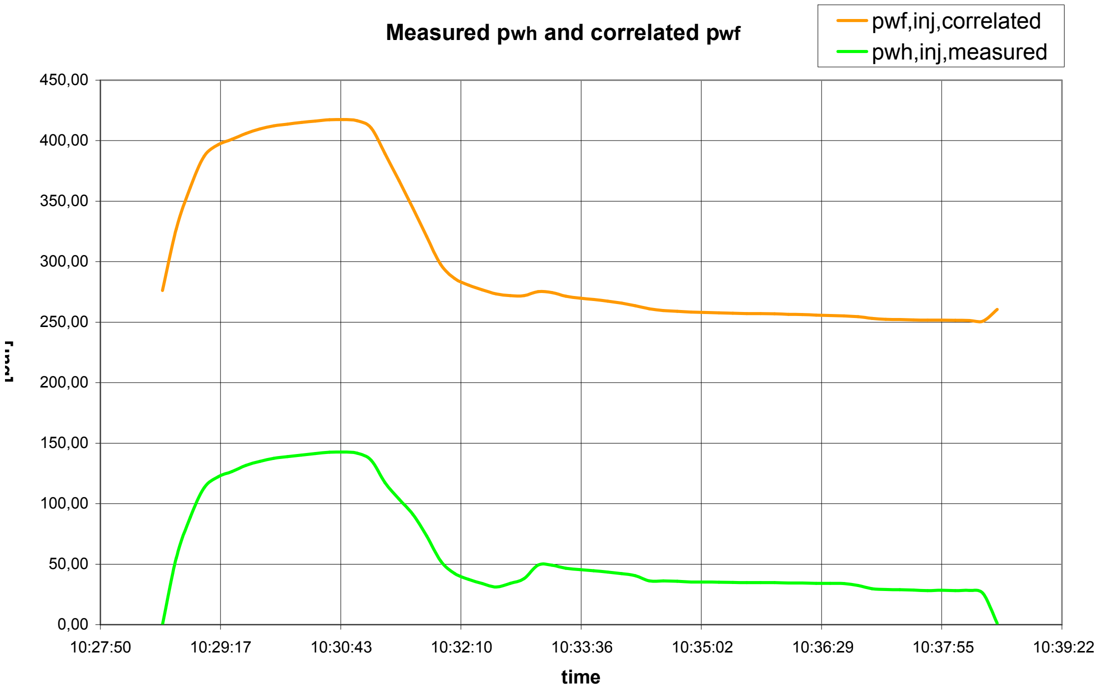


FIGURE 17: ONLINE MEASURED PRESSURE CORRELATED PRESSURE

The deviation in time of the measured and correlated well flowing injection pressure can be seen below, again. If we could trust both programmed watches, this would mean that at the time point we stop pumping the postflush downhole we experience the pressure build-up at the mid-perforation which certainly is not the case.

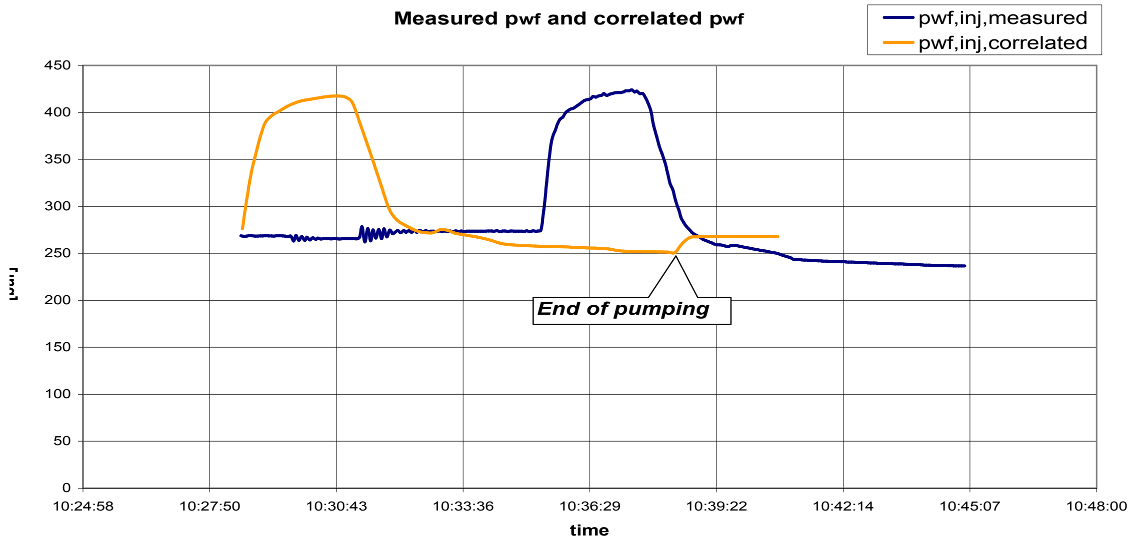


FIGURE 18: MEMORY GAUGE RECORDED AND CORRELATED PRESSURE

Overlaying the two curves, as shown below, by shifting either the measured or the correlated well flowing injection pressure curve by six minutes and forty seconds, shows when the curves start deviating from each other.

FIGURE 19: RECORDED AND CORRELATED PRESSURE OVERLAY

We see that the curves match nearly perfectly during the initial stage of the treatment. Also, shortly after the acid solution hits the dolomite formation the correlated and the measured pressure result in almost the same pressure values.

The graph below basically shows the same overlay of the two pressure curves on a different scale with the only difference that the injection rate has been included. Note that the scale on the left hand side refers to [bar] in terms of pressure and to [l/min] in terms of injection rate. All the graphs related to the stimulation of the well S T 31 can be found enlarged in Appendix C.

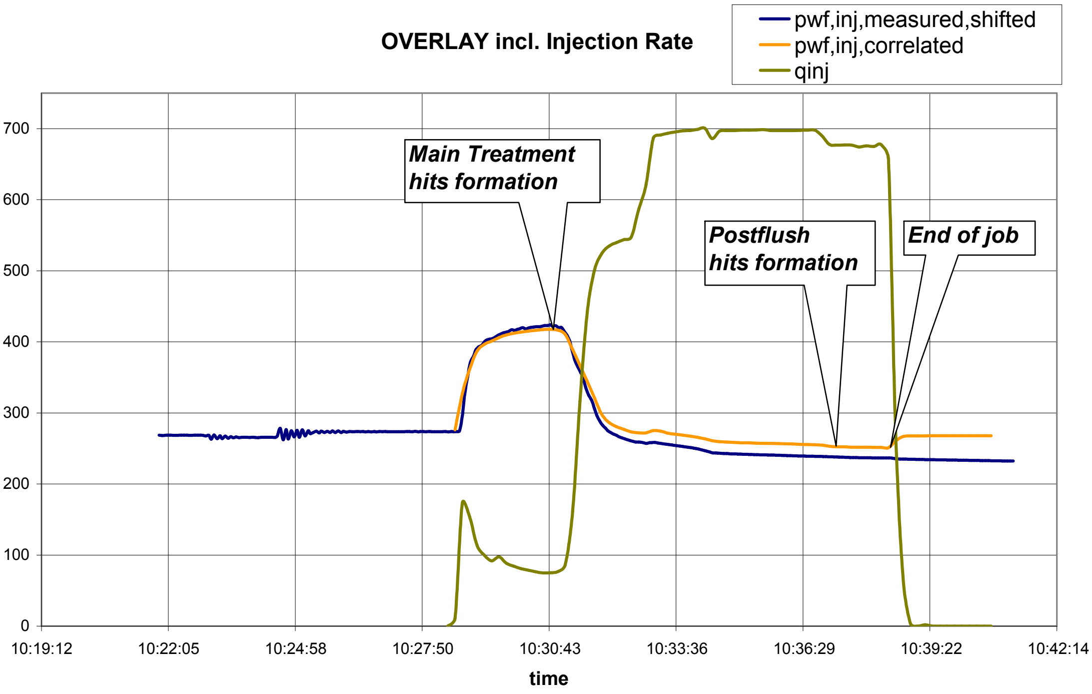


FIGURE 20: OVERLAY INCLUDING INJECTION RATE

We can see now that the two pressure curves start deviating from each other as soon as the injection rate increases which usually happens after the acid has reacted on the formation rock. Higher rates result in higher friction pressure losses. According to the equations valid for the Newtonian fluid model (Eq.[7.19], Eq.[7.20]), the exponent for the injection rate, $\boldsymbol{q_{INJ}}$, is 1,75 which almost corresponds to a quadratic increase. Higher friction pressure losses should normally result in a lower well flowing injection pressure. The calculated well flowing pressure, however, is higher than the measured one which could lead to the conclusion that the correlated exponent of $\boldsymbol{q}$ for this example could be different.

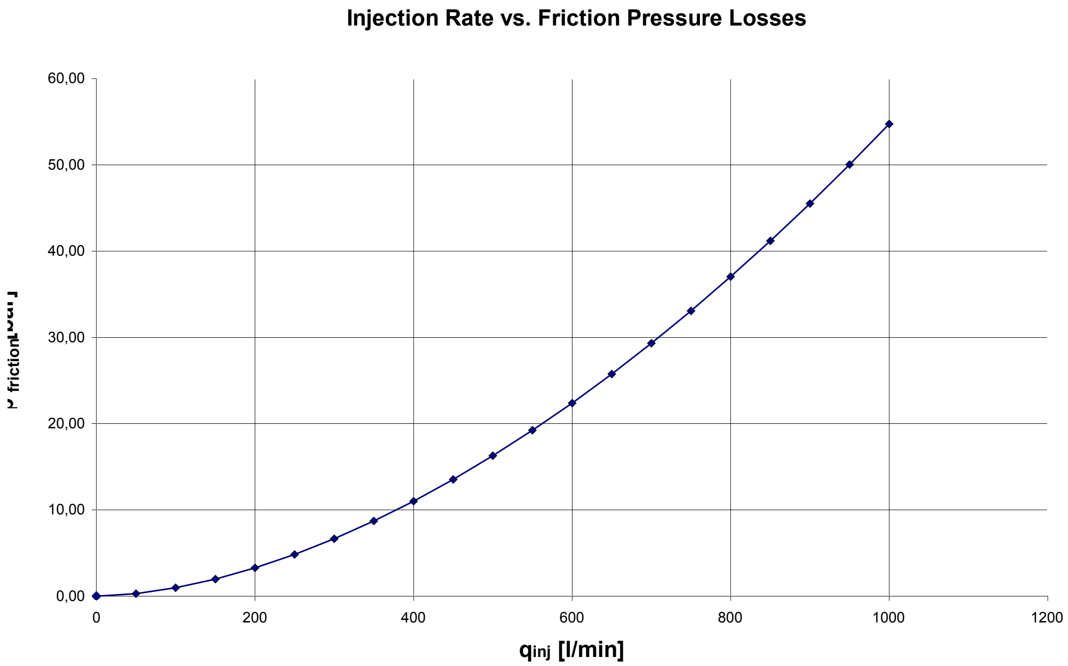


FIGURE 21: DEPENDENCE OF FRICTION PRESSURE LOSSES ON RATE

Another potential error source, which is even more likely, is the temperature dependence of the changing fluid properties. Lower injection rates, which occur during the initial stage of the treatment, mean that the acid stays at greater depths much longer before it reacts. From the memory gauge recordings we can see that the temperature at 2700 [m] is 96,3 [°C] which will definitely have a great impact on the acid's temperature. Also, we can see that the temperature drop occurs after the first live acid reacted on the formation rock which indicates that "fresh" and colder acid pumped reaches the memory gauge. Since the access to the formation has already been etched, subsequent acid is not that highly influenced anymore and thus could have higher densities and viscosities when it hits the formation. This could result in higher friction pressures losses and hence lower well flowing pressures. On the other hand, the warmed up acid which reacts during the initial stage of the treatment results in lower friction pressure losses and hence higher well flowing pressures.

After the treatment the memory gauge shows a continuously decreasing pressure which goes even below the original value. This might be the result of not having airtight conditions at the surface. If the system formed an absolute pressure integrity, a vacuum, which would never allow a pressure drop in the wellbore, would be the result. Taking a look at the correlated pressure curve, we observe a pressure increase after pumping stopped. This results in an even higher deviation from the downhole measured data which indicates that the hydrostatic pressure calculated is not based on the correct height of the liquid column.

Taking a look at the overlay, again, we also observe that the initial hydrostatic pressure of the two pressure curves is not exactly equal. It is possible to match density of hydrochloric acid (ρ = 1,0726 [kg/l]) in order to get a lower initial hydrostatic pressure. A lower density would also correspond to higher temperatures. Consequently, the whole curve would be shifted to a lower position.

Also, we have to notice that this stimulated well, completed at 2700 [m] in a dolomite formation is an extreme example. The discussed potential deviation sources might have a greater impact under such circumstances. Almost all of the wells analysed are far above this horizon and situated in sandstone formations where neither the temperature is as high not the reaction rate of the acid solution on the rock is as fast.

A recommendation for further fluid model analysis could be to install memory gauge in a well completed sandstone formation of not more than 1500 [m] true vertical depth. In this manner, the matching could be compared for a different set of conditions.

If we consider the same relative error in all the stimulated wells regarded, the resulting estimate will still be useful, since we want to qualitatively state something about the effectiveness of the treatment. Eventually, we want to relatively compare different treatments. In order to do so we do not need to know the exact value of the friction pressure losses or the hydrostatic pressure at each time point. Much more we need to know whether the relation of pressure and injection rate during the operation is changing or not.

7.4.4 Method of expressing changing injection performance

The well flowing injection pressure, $\boldsymbol{p_{WF,INJ}}$, defines the pressure difference, $\Delta \boldsymbol{p_{WF,INJ}}$, during injection.

$$\Delta p_{WF,\,INJ} = p_{WF\,,INJ} - p_{WS} \qquad [7.19]$$

Dividing the injection rate by the temporarily corresponding pressure difference, Eq.[7.15], results in an index which basically can be described as an “inverse Productivity Index”. This index describes the injection performance at a certain time point and will from now on be referred to as the Injectivity or *Injectivity Index (II)*.

$$II = \frac{q_{INJ}}{\Delta p_{WF\,,INJ}} \qquad [7.20]$$

The Injectivity Indices can now be determined at the time points the different stages hit the formation face and hence a separate evaluation of the impact of each stage is possible.

In order to get a reasonable value for the Injectivity Indices, the units have been converted to [m³/(day.bar)]. In this manner they can be compared to the Productivity Indices.

An example of the progression of Injectivities for analysed wells in a sandstone formation without inside-casing-gravel-pack (ICGP) located in the 9th Tortonian is shown below.

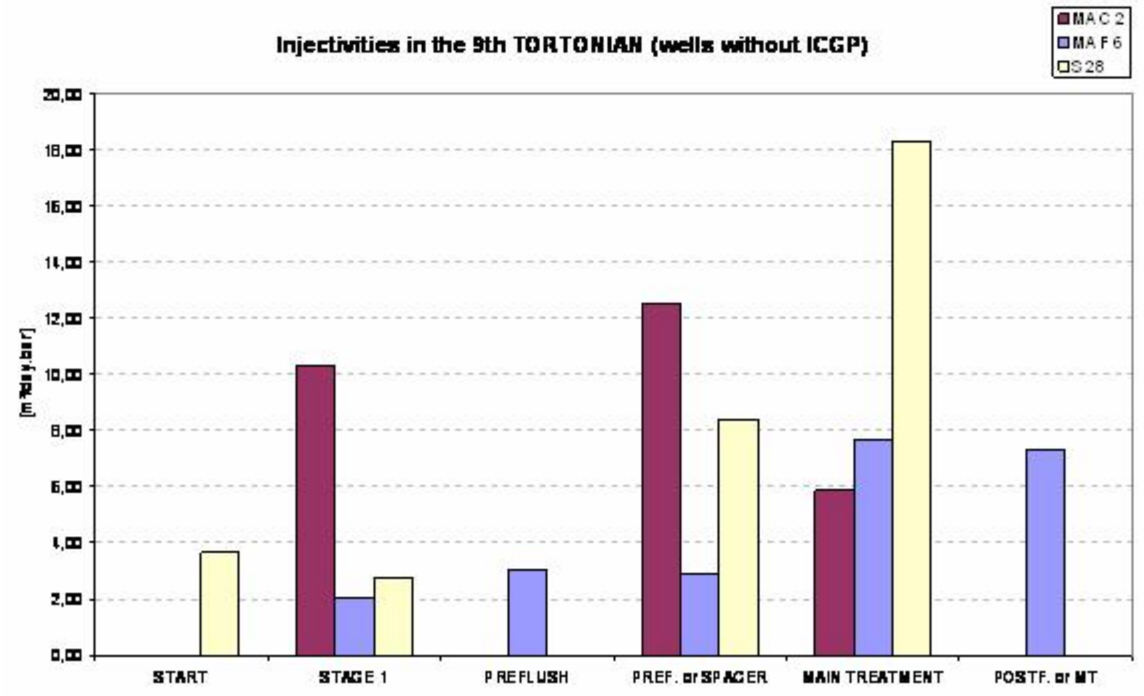


FIGURE 22: PROGRESSION OF INJECTIVITY DURING TREATMENT

An Injectivity increase of the stimulated well MA C 2 from roughly 10 [m³/(day.bar)] to 12 [m³/(day.bar)] (bars in violet) effectively means that pumping the preflush into the formation, resulted in an increase of Injectivity of 2 [m³/(day.bar)]. The 12 [m³/(day.bar)] refer to the time point when the preflush has been completely displaced into the formation, in other words: the time point just before the main treatment first hits the formation face. Bar graphs summarizing the change in Injectivity of all the analysed stimulations can be found in Appendix D. The graphs compare the progression of the different stimulations performed in the same horizon. Appendix E shows s screenshot of the Injectivity calculation for one stage (main treatment) of a few wells in the field A015.

The classification of the stages 1 to 6 has been done according to their chemical composition. If a stage does not show any value for an Injectivity, this stage has not been pumped during the treatment. The 6 stages are defined as:

- *St.1* - either Musol (mutual solvent – EGMBE), diesel-oil or ligroin.
- *St.2/Preflush* - 15% hydrochloric acid (HCl) (in one case 10%), dependent on horizon: 2%-5% citric acid, 3%-5% acetic acid, inhibitors, in some cases 10% Musol.
- *St.3/Spacer* - 2% ammonium chloride (NH_4Cl) or 5% hydrochloric acid (HCl) and inhibitor.
- *St.4/Main treatment*- in15% hydrochloric acid (HCl), 4,5% ammonium bifluoride (ABF) (in exceptional cases 2%,3% or 9,6%, in some cases 5% citric acid, inhibitor; in carbonates: without ABF.
- *St.5/Postflush* - 2% ammonium chloride (NH_4Cl), in one case 15% hydrochloric acid (HCl) and 3% Musol; in carbonates: saltwater.
- *St.6* - 2% potassium chloride (KCl), in two cases 0,5% calcium chloride ($CaCl_2$)

Since a sandstone acidizing treatment using ammonium bifluoride for compatibility purposes requires ammonium chloride instead of potassium chloride as postflush or spacer, stage 5 usually refers to a sandstone acidizing job.

It must be noticed that if the same preflush and main treatment acid solution recipes had not been pumped for years, a definition of comparable groups would probably not have been possible. The recipes of the acid solutions will be discussed in a later chapter. Details concerning the solution recipes of the stimulations analysed can be found in the next chapter (Figures 25 and 26).

7.4.5 Real-time-monitoring

Naturally, online measurements of the injection rate and the pump pressure allow computing a skin factor which also can be plotted in real time. The advantage of this method is that you can directly see the degree of formation damage and shut off the pumps in case the skin factor increases while pumping the acid solution. At this point in time OMV only records pump pressure and injection rate. Plotting an online-skin is only a matter of adding the formula to the software program which records online. The skin factor based on Darcy's law for radial flow according to Paccaloni [12] can be described as:

$$s = \frac{2\pi hk\left(p_{WF,INJ} - p_{WS}\right)}{q_{INJ}\,\mu B} - \ln\left(r_b / r_w\right) \qquad [7.21]$$

whereas **h** is the height of the reservoir, in [m],

k is the undamaged permeability, in [m²],

$p_{WF,INJ}$ is the well flowing injections pressure, in [Pa] ,

p_{WS} is the well static pressure, in [Pa],

q_{INJ} is the injection rate, [m³/s],

μ is the viscosity of the crude oil, in [Pa.s],

B is the formation volume factor, [-],

r_b is the radius affected by acid injection, in [m],

and r_w the well radius, in [m].

The example of the stimulated well below is the same on the basis of which the comparison of the measured and correlated well flowing injection pressure has been discussed in subchapter 7.3.4. The skin factor, s, as well as the well flowing injection pressure, $p_{WF,INJ}$, have been calculated after the treatment and then added to the graph. The last few values of the skin factor which refer to the end of pumping have been taken out of the graph since a pumping rate converging towards zero will naturally result in an infinite increase of the skin factor. Plotting this increase of the skin factor could misguide us, making us believe that we caused damage during the treatment. The Paccaloni-skin resulted in roughly 8 and later well test analysis confirmed the calculation.

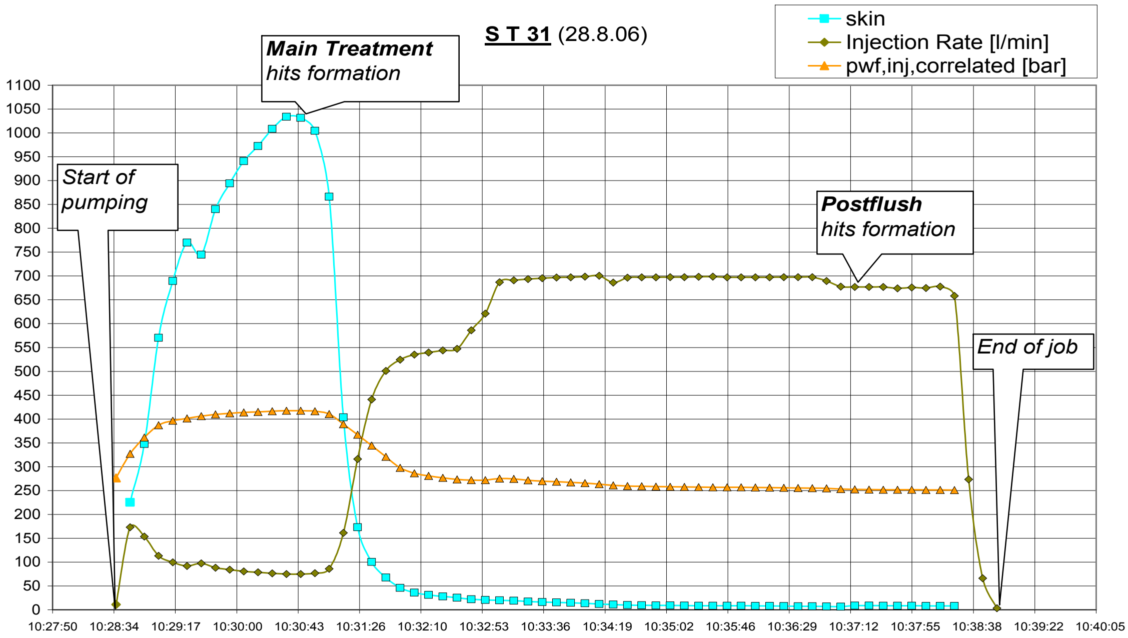


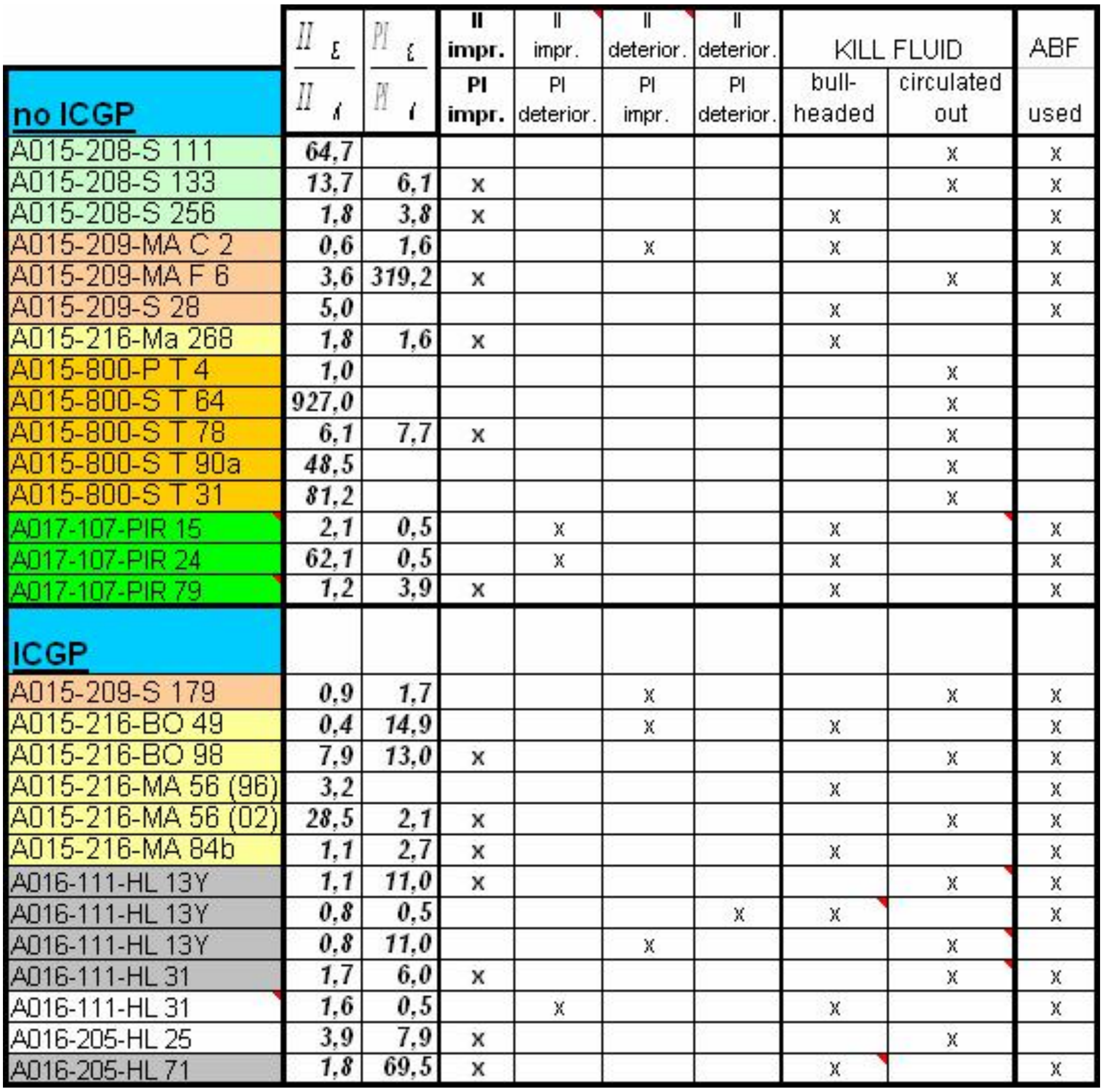
FIGURE 23: SKIN PROGRESSION DURING TREATMENT

The reason why Injectivity Indices were calculated instead of a skin factor for the comparison of the stages' impact as discussed in the last subchapter, is that the skin factor is dependent on the constantly changing fluid properties, which can be seen from the Paccaloni-skin. It is difficult to express the skin factor in a reasonable manner at a time point when half of the tubulars are filled with fluid A and the other half with fluid B. Since we already face an uncertainty with the changing fluid properties in estimating the friction pressure losses, Injectivity Indices were chosen as criteria for performance evaluation.

8. ANALYSIS

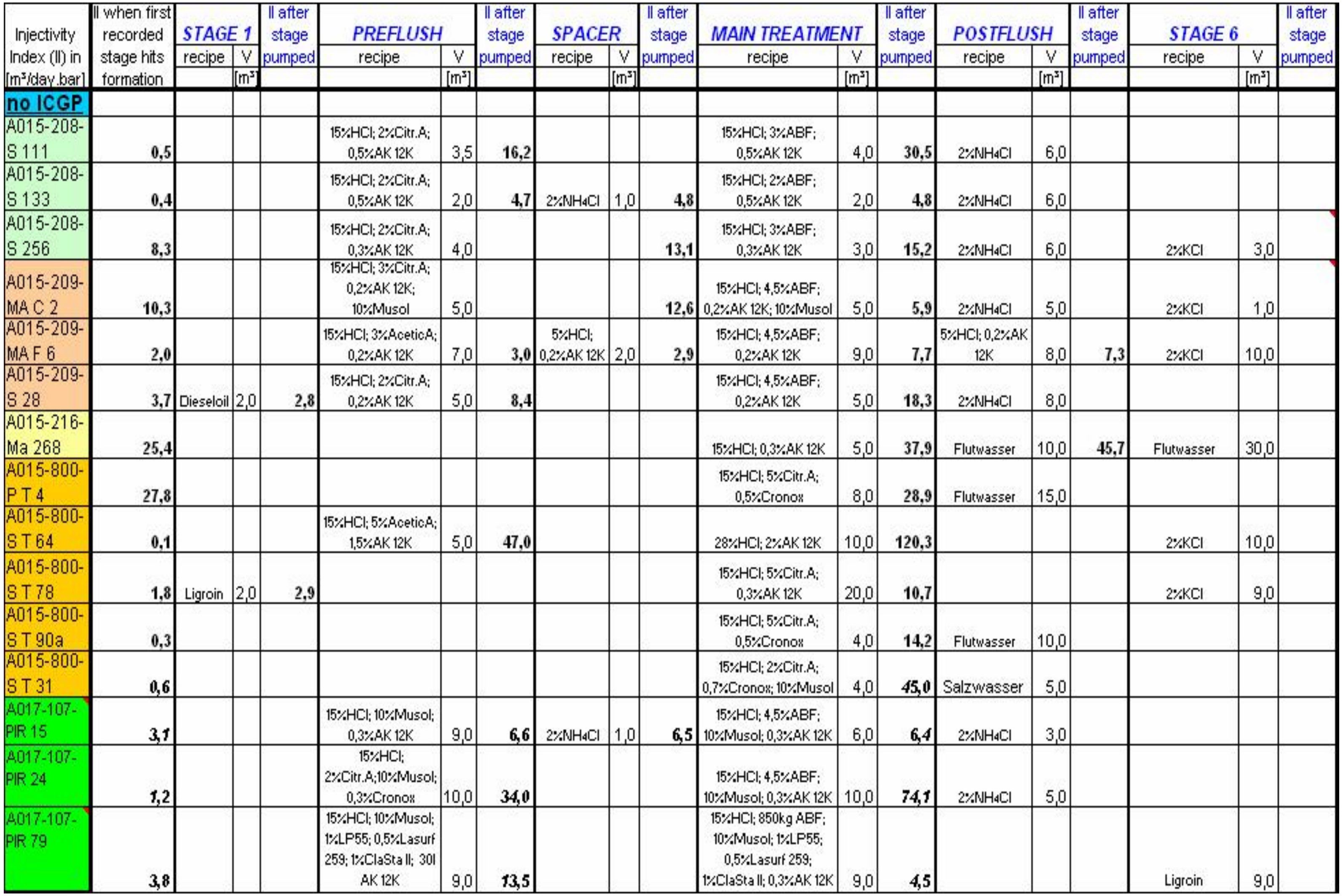
8.1 REPERCUSSION OF STIMULATION TREATMENTS

The following tables sum up the impact of the 28 matrix acid stimulations. The different colours refer to the different groups. Note that the grey background colour in field A016 refers to stimulations where the acid solution was pumped via annulus. Not all of the 28 stimulation provided data to analyse production behaviour after the treatment.



	$\frac{II_{\varepsilon}}{II_{i}}$	$\frac{PI_{\varepsilon}}{PI_{i}}$	**II impr.**	II impr.	II deterior.	II deterior.	KILL FLUID		ABF
no ICGP			**PI impr.**	PI deterior.	PI impr.	PI deterior.	bull-headed	circulated out	used
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 24: PRODUCTIVITY AND INJECTIVITY INDICES



Injectivity Index (II) in [m³/day.bar]	II when first recorded stage hits formation	STAGE 1		II after stage pumped	PREFLUSH		II after stage pumped	SPACER		II after stage pumped	MAIN TREATMENT		II after stage pumped	POSTFLUSH		II after stage pumped	STAGE 6		II after stage pumped
		recipe	V [m³]		recipe	V [m³]		recipe	V [m³]		recipe	V [m³]		recipe	V [m³]		recipe	V [m³]	
no ICGP																			
A015-208-S 111	**0,5**				15%HCl; 2%Citr.A; 0,5%AK 12K	3,5	**16,2**				15%HCl; 3%ABF; 0,5%AK 12K	4,0	**30,5**	2%NH_4Cl	6,0				
A015-208-S 133	**0,4**				15%HCl; 2%Citr.A; 0,5%AK 12K	2,0	**4,7**	2%NH_4Cl	1,0	**4,8**	15%HCl; 2%ABF; 0,5%AK 12K	2,0	**4,8**	2%NH_4Cl	6,0				
A015-208-S 256	**8,3**				15%HCl; 2%Citr.A; 0,3%AK 12K	4,0				**13,1**	15%HCl; 3%ABF; 0,3%AK 12K	3,0	**15,2**	2%NH_4Cl	6,0		2%KCl	3,0	
A015-209-MA C 2	**10,3**				15%HCl; 3%Citr.A; 0,2%AK 12K; 10%Musol	5,0				**12,6**	15%HCl; 4,5%ABF; 0,2%AK 12K; 10%Musol	5,0	**5,9**	2%NH_4Cl	5,0		2%KCl	1,0	
A015-209-MA F 6	**2,0**				15%HCl; 3%AceticA; 0,2%AK 12K	7,0	**3,0**	5%HCl; 0,2%AK 12K	2,0	**2,9**	15%HCl; 4,5%ABF; 0,2%AK 12K	9,0	**7,7**	5%HCl; 0,2%AK 12K	8,0	**7,3**	2%KCl	10,0	
A015-209-S 28	**3,7**	Dieseloil	2,0	**2,8**	15%HCl; 2%Citr.A; 0,2%AK 12K	5,0	**8,4**				15%HCl; 4,5%ABF; 0,2%AK 12K	5,0	**18,3**	2%NH_4Cl	8,0				
A015-216-Ma 268	**25,4**										15%HCl; 0,3%AK 12K	5,0	**37,9**	Flutwasser	10,0	**45,7**	Flutwasser	30,0	
A015-800-P T 4	**27,8**										15%HCl; 5%Citr.A; 0,5%Cronox	8,0	**28,9**	Flutwasser	15,0				
A015-800-S T 64	**0,1**				15%HCl; 5%AceticA; 1,5%AK 12K	5,0	**47,0**				28%HCl; 2%AK 12K	10,0	**120,3**				2%KCl	10,0	
A015-800-S T 78	**1,8**	Ligroin	2,0	**2,9**							15%HCl; 5%Citr.A; 0,3%AK 12K	20,0	**10,7**				2%KCl	9,0	
A015-800-S T 90a	**0,3**										15%HCl; 5%Citr.A; 0,5%Cronox	4,0	**14,2**	Flutwasser	10,0				
A015-800-S T 31	**0,6**										15%HCl; 2%Citr.A; 0,7%Cronox; 10%Musol	4,0	**45,0**	Salzwasser	5,0				
A017-107-PIR 15	**3,1**				15%HCl; 10%Musol; 0,3%AK 12K	9,0	**6,6**	2%NH_4Cl	1,0	**6,5**	15%HCl; 4,5%ABF; 10%Musol; 0,3%AK 12K	6,0	**6,4**	2%NH_4Cl	3,0				
A017-107-PIR 24	**1,2**				15%HCl; 2%Citr.A;10%Musol; 0,3%Cronox	10,0	**34,0**				15%HCl; 4,5%ABF; 10%Musol; 0,3%AK 12K	10,0	**74,1**	2%NH_4Cl	5,0				
A017-107-PIR 79	**3,8**				15%HCl; 10%Musol; 1%LP55; 0,5%Lasurf 259; 1%ClaSta II; 30l AK 12K	9,0	**13,5**				15%HCl; 850kg ABF; 10%Musol; 1%LP55; 0,5%Lasurf 259; 1%ClaSta II; 0,3%AK 12K	9,0	**4,5**				Ligroin	9,0	

FIGURE 25: INJECTIVITY CHANGE INCLUDING RECIPES (wells without ICGP)

Injectivity Index (II) in [m^3/day.bar]	II when first recorded stage hits formation	STAGE 1		II after stage pumped	PREFLUSH		II after stage pumped	SPACER		II after stage pumped	MAIN TREATMENT		II after stage pumped	POSTFLUSH		II after stage pumped	STAGE 6		II after stage pumped
		recipe	V [m^3]		recipe	V [m^3]		recipe	V [m^3]		recipe	V [m^3]		recipe	V [m^3]		recipe	V [m^3]	
ICGP																			
A015-209-S 179	**4,8**	Ligroin	3,0	**2,9**	15%HCl; 3%AceticA; 0,2%AK 12K	7,0	**3,0**	5%HCl; 0,2%AK 12K	2,0	**3,6**	15%HCl; 4,5%ABF; 0,2%AK 12K	9,0	**4,7**	5%HCl; 0,2%AK 12K	8,0	**4,3**	2%KCl	8,0	
A015-216-BO 49	**8,7**				15%HCl; 5%Citr.A; 0,3%AK 12K	5,0	**5,1**				15%HCl; 4,5%ABF; 0,3%AK 12K	5,0	**6,5**	2%NH_4Cl	6,0	**3,7**	2%KCl; 0,5%$CaCl_2$	6,0	
A015-216-BO 98	**0,8**	Musol	3,2	**3,1**	15%HCl; 2%Citr.A; 0,3%Cronox242ES; 0,6%SapogenatT139	8,6	**1,9**	2%NH_4Cl	1,4	**1,7**	15%HCl; 4,5%ABF	8,8	**5,9**	2%NH_4Cl	7,3				
A015-216-MA 56 (96)	**2,4**				10%HCl; 2%Citr.A; 0,3%AK 12K	3,0	**8,6**				15%HCl; 4,5%ABF; 0,3%AK 12K	5,0	**7,8**	2%NH_4Cl	5,0		2%KCl	3,0	
A015-216-MA 56 (02)	**0,5**				15%HCl; 5%Citr.A; 0,3%Cronox	5,0	**3,0**				15%HCl; 4,5%ABF; 0,3%Cronox	5,0	**17,1**	2%NH_4Cl	6,0	**13,7**	2%KCl; 0,5%$CaCl_2$	5,0	
A015-216-MA 84b	**1,0**				10%HCl; 0,3%AK 12K	5,0	**1,1**				15%HCl; 4,5%ABF; 0,3%AK 12K	5,0	**1,1**	2%NH_4Cl	5,0				
A016-111-HL 13Y	**8,7**				15%HCl; 10%Musol; 0,5%AK 12K	9,0	**8,7**				15%HCl; 4,5%ABF; 10%Musol; 0,5%AK 12K	9,0	**9,5**	2%NH_4Cl	4,0		2%KCl; 0,5%$CaCl_2$	16,0	
A016-111-HL 13Y	***15,0***				15%HCl; 10%Musol; 0,6%Sapogenat; 0,3%Cronox	10,0	***12,5***				15%HCl; 9,6%ABF; 10%Musol, 0,3%Cronox	10,0		2%NH_4Cl	10,0		2%KCl; 0,5%$CaCl_2$	15,0	
A016-111-HL 13Y	**14,3**	Musol	5,0	**10,9**							15%HCl; 2%Citr.A; 0,3%Cronox	10,0	**12,0**				Salzwasser	17,0	
A016-111-HL 31	***4,1***				15%HCl; 10%Musol; 0,5%AK 12K	7,5	***6,4***				15%HCl; 4,5%ABF; 10%Musol; 0,5%AK 12K	3,0	***7,0***	15%HCl; 3%Musol; 0,3%AK 12K	4,0				
A016-111-HL 31	**3,3**				15%HCl; 2%Citr.A;20%Musol; 0,5%Cronox	5,0	**5,9**	2%NH_4Cl	1,0	**5,9**	15%HCl; 4,5%ABF; 10%Musol, 0,5%Cronox	5,0	***8,4***	2%NH_4Cl	6,0	**5,5**	Flutwasser	5,0	
A016-205-HL 25	**7,5**	Musol	2,0	**5,7**							15%HCl; 2%Citr.A; 0,3%Cronox	6,0	**28,9**				Salzwasser	5,7	
A016-205-HL 71	**6,5**				15%HCl; 10%Musol; 0,3%AK 12K	9,0	**9,7**				15%HCl; 4,5%ABF; 10%Musol; 0,3%AK 12K	9,0	***11,8***	2%NH_4Cl	6,0				

FIGURE 26: INJECTIVITY CHANGE INCLUDING RECIPES (wells with ICGP)

The II-ratio in the first table refers to the first and the last Injectivity value available during the treatment. So, for instance, if an acid stimulation treatment allowed evaluations of the Injectivity Indices at the time point the preflush hit the formation face and the postflush has been displaced completely into the formation, then those two values form the II-ratio. The PI-ratio is computed by taking the two Productivity Indices which are the closest to the date of the stimulation treatment. In some cases, even through the Productivity Indices were calculated using dynamic liquid levels, the time spans between the two PI-values were quite long, which can make a determination of the effectiveness of the treatment doubtful. The table also lists in which treatments the kill fluid had been bullheaded and in which it had been circulated out before the treatment hit the formation face.

The second table presents the progression of the Injectivity Index of the stages including the pumped volumes and the solution recipes.

8.2.1 Analysis of characteristic features

If we agree on the previously discussed success criteria, we first notice that most of the stimulations were technically successful. 16 out of 21 stimulations showed an increase in PI even though if we trusted the progression of the Injectivities some stimulations must have led to a PI decrease. We will shortly discuss these symptoms. Furthermore, in the majority of successful stimulations (10), the kill fluid has been circulated out instead of bullheaded while pumping the acid solution downhole.

Bullheading the kill fluid is a quite crucial procedure. Normally, the kill fluid rests downhole for a certain amount of time. Since, we cannot monitor the chemical reactions taking place during the preparation of the stimulation treatment, we cannot be sure if bullheading the perhaps altered kill fluid might cause troubles.

The fact that Injectivity and Productivity Index do not always correlate, has been mentioned. Three cases have been observed, where on the one hand

Injectivity improved relatively and on the other hand Productivity Index deteriorated. Conspicuous is that in those three cases the kill fluid was bullheaded before the treatment hit the formation face. Note that a deteriorating II refers to a relative decrease in Injectivity from the first to the last stage observed. This could mean that, the first observed stage hitting the formation face, which corresponds to the time point when the kill fluid has been completely displaced into the formation, results in a bad Injectivity which, compared to the last stage, improves throughout the treatment. This improvement of the Injectivity, however, does not result in an increase of the Productivity Index. The Injectivity only improves relatively compared to the first and, as a result of the bullheaded kill fluid, bad absolute value of Injectivity, but the formation (and hence Productivity Index) does not forget the fact the kill fluid has been displaced into the near-wellbore area. A higher pressure drop across this area might be the result.

We have to mention that calculating an Injectivity for the first stage faces different conditions than calculating one for the last stage. Naturally, a pressure buildup might occur during the injection of various stages but since the pressure difference during injection is computed with the same reservoir pressure throughout the treatment, the Injectivity of the last stage observed is rather conservative. Consequently, a small increase in Injectivity might in fact represent a significant improvement. This might also be the reason why in 4 of the cases observed, the Injectivity deteriorated but the Productivity Index increased.

No significant symptoms could be recognized about matrix acid stimulations via annulus, except that the only example observed which resulted in a decrease in both in Injectivity and Productivity Index was among those. On the other hand, the rest of the stimulations performed within this group resulted in a PI-increase.

Obviously, all acid stimulations performed in the dolomite formation (orange colour in the table) showed a significant increase in Injectivity. However, only one out of the 5 stimulations performed in this horizon allowed a determination of the Productivity Index. Since this one improved significantly and in all the stimulations performed the kill fluid was circulated out, we might be able to predict that the other 4 stimulations could have resulted in a PI-increase as well. Furthermore, the relative improvement of the Injectivity Index (factor 6,08) and Productivity Index (factor 7,72) almost correlate linearly.

Neglecting the stimulations in the dolomite formation, the number of cases where the preflush or the main treatment caused an increase or a decrease of Injectivity Index, are listed below. In none of the cases did both preflush and main treatment cause an II-reduction.

	PREFLUSH	MAIN TREATMENT
# wells where the stage caused an INJECTIVITY -		
INCREASE	16	17
DECREASE	3	5

FIGURE 27: INFLUENCE OF PREFLUSH AND MAIN TREATMENT ON INJECTIVITY

In general, the most successful matrix acid stimulations in sandstone formations, in terms of an increase in PI as well as in II, apart from those in the dolomite formation, were performed in the 5th, the 8th and the 16th Tortonian. Taking a look at the Injectivities of the two most influential stages, preflush and main treatment, we can see, that in the 5th and the 8th Tortonian, each stage pumped results in an increase of Injectivity. Hence, the acid solutions must have had reacted without causing significant precipitations. The 16 th Tortonian, however, showed a different behaviour. Both Bockfliess wells Bo 49 and Bo 98 surprisingly showed an Injectivity decrease while the preflush was pumped whereas in the first case the kill fluid was bullheaded and in the second circulated out. So the problem must be somewhat connected with the preflush acid solution, which in both cases was 15% hydrochloric acid. Ma 56(96) and

Ma 84b, both located in the 16th Tortonian as well, showed slight Injectivity decreases while pumping the main treatment. Hence, we can, on the one hand, assume that the hydrofluoric acid reaction on the rock was not significant, but, on the other hand, the hydrofluoric acid might have caused precipitations. In both cases the main treatment recipe, which for both was 15% hydrochloric acid together with 4,5% ammonium bifluoride, was not successful. The preflush which was 10% hydrochloric acid for both cases resulted in an Injectivity increase.

Another horizon where hydrochloric and hydrofluoric acid were not successful as a main treatment is the 7th Sarmatian. 2 out of 3 stimulations did not respond well to the main treatment. The well Pir 79 even showed a decrease in Injectivity by a factor of 3. Also in the 9th Tortonian, we can find an example were the main treatment results in an Injectivity reduction of more than 50%. We can now see that, even though at this point in time we are only talking about sandstone formations, the same acid solution recipe does not have the same impact on each of the formations. The diversity of materials in the composition of sandstone rocks has already been discussed. However, the solution recipe of the main treatment in most of the cases was exactly the same.

8.2 EQUAL ACID SOLUTION RECIPE

Generally, the different matrix acid stimulation treatments had different impacts on the progression of the Injectivities during the treatment and Productivity Indices afterwards. The fact that in sandstone acidizing, in most of the cases, equal acid solution recipes have been used first of all emphasises that matrix acidizing is more of a straight-forward procedure rather than a detailed planned operation, but in fact is one of very few parameters which stay constant and hence allow a comparison of the different treatments.

The use of ammonium bifluoride, which dissociates to hydrofluoric acid, has become standard in designing solution recipes for sandstone acidizing jobs. Its widespread use might have historical reasons. Bentonite which basically consists of clay particles was frequently used as a drilling mud in the past and, since hydrofluoric acid is able to dissolve clays, the use of ammonium bifluoride was, from a chemical point of view, justified. Nowadays, since different drilling muds are used, the use of ammonium bifluoride should only be advocated in cases where the composition of the rock is well known and, then, only in low concentrations. In order to optimize the solution recipes we would require a certain number of cores of the focus areas to perform laboratory tests. Also, we have to keep in mind that the majority of the stages pumped resulted in an increase of Injectivity which clearly shows that the ability to perform a matrix acid stimulation within the company is given.

8.3 PRODUCTIVITY INDEX CAN BE EVALUATED QUALITATIVELY

We have seen that relative Injectivity and Productivity Index change do correlate qualitatively in 14 out of 21 cases, which corresponds to 67%. However, the distribution showed no linear or any other kind of correlation. The potential reasons why in the rest of the cases the dependence of II-ratios and PI-ratios behaved differently have been elaborated.

Since the axes in the graph below are on a logarithmic scale, the two lower quadrants, characterized by a PI-ratio smaller than 1, indicate a relative decrease in PI. Hence, the graph cuts the outcome of all stimulations, where PIs were available, into four areas, as already shown in figure 24.

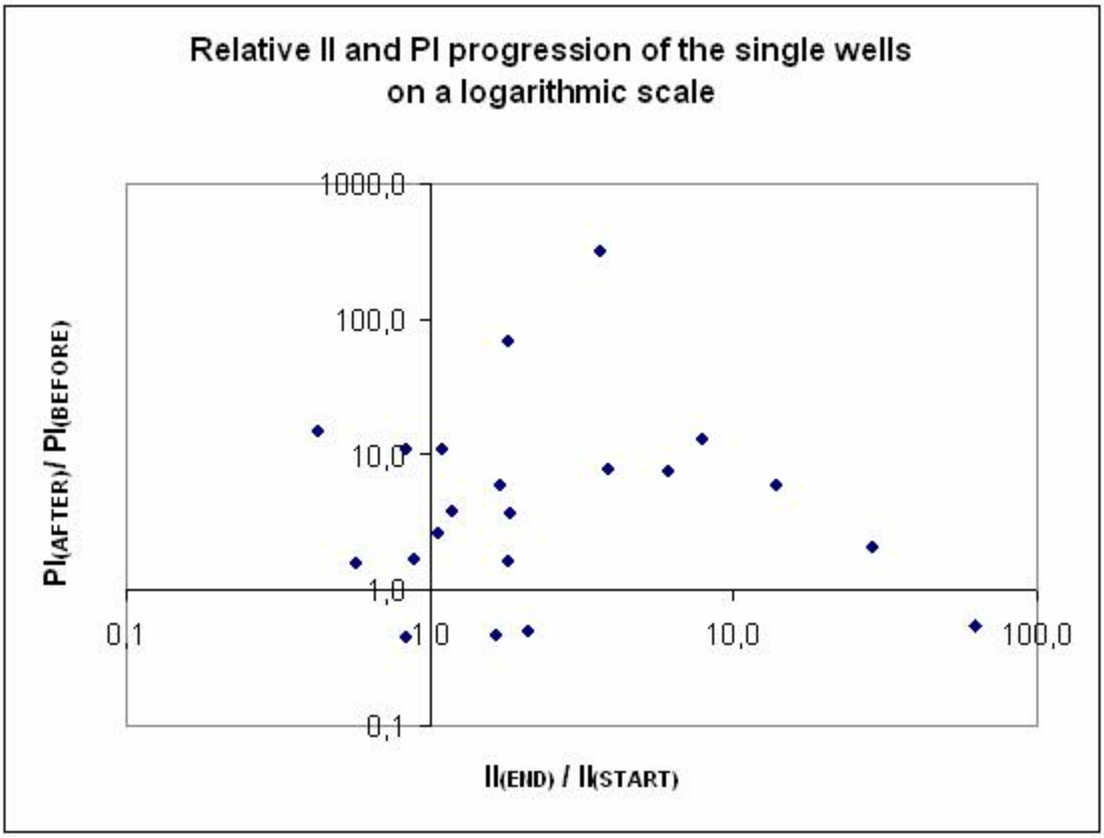


FIGURE 28: INJECTIVITY AND PRODUCTIVITY INDEX RATIO

We also have seen that the correlation between wellhead and well flowing pressure during injection match in a manner which makes it possible to state something accurately enough about the pressure-rate conditions downhole. The fact that in some examples we face a decline in Injectivity together with an increase in Productivity Index might be the result of the very conservative pressure difference calculation during the late stage of the treatment. So, we might be allowed to make analysis, based on the progression of the treatment, even when no Productivity Index has been determined. This emphasises the need to do further online monitoring of stimulations treatments since computing the progression of the treatment will be easier and more accurate compared to the work with Two-Pen-Charts.

9. FINDINGS AND CONCLUSIONS

Summary of evaluation:

- 28 stimulations have been analysed. 20 stimulations were performed using ABF, 8 stimulations were performed using HCl alone as a main treatment.
- All the stimulations performed with HCl showed an increase in PI and in cases where a PI-evaluation was not possible, an increase in Injectivity.
- All stimulations resulting in a decrease in PI were performed using ABF.

The success criteria have been defined as:

- Productivity Index instead of gross production rate as a measure for the overall effectiveness of the acidizing treatment.
- Injectivity Index at the time point a certain stage hits the formation face as a measure for the progression of the treatment.
- Paccaloni-skin for real-time monitoring confirmed from well test data for S T 31.

The success criteria showed a correlation:

- Relative improvement of Injectivity Index and Productivity Index do correlate qualitatively.
- Correlation between Injectivity and Productivity Index fluctuates due to conservative pressure difference calculation during injection of the last stages.

Determining the well flowing injection pressure:

- Correlation between wellhead and well flowing pressure during injection.

Repercussion of success parameters:

- Correlation between Injectivity and Productivity Index not valid if kill fluid has been bullheaded.
- Hydrochloric acid showed a relative Injectivity improvement in nearly all of the cases.
- Hydrofluoric acid as a main treatment did only harm Injectivity progression of a few wells. Both Bockfliess wells showed an Injectivity decrease.

10. RECOMMENDATIONS

After analysing matrix acid stimulations within OMV performed over the last 10 years, the following can be recommended.

Recommendations in performing the treatment on site:

- While performing sandstone acidizing, in crucial cases, reduce concentration of hydrofluoric acid. The risk of precipitations during the treatment is being reduced. If possible, perform an acidizing job without hydrofluoric acid, since in most of the cases we do not know the exact mineralogical composition of the rock.
- Circulate out the kill or completion fluid instead of bullheading, since analysis of the stimulations has shown better performance of Injectivity Indices.

Recommendations to improve data quality for better analysis in matrix acid stimulation treatments:

- Install memory gauges in a well not deeper than 1500 [m]. The well should be located in a sandstone formation. In this manner it is possible to ensure the well flowing pressure correlation is also valid for a different set of conditions. Remember that S T 31 is located in 2700 [m] depth in a dolomite formation where matrix acid stimulation treatments usually perform very well. The not-instantaneous reaction of acid on a sandstone rock or even a bad progression of the treatment could lead to an unstable well flowing pressure correlation.
- Proceed with further online monitoring of matrix acid stimulations. Up to now about 15 matrix acid stimulation jobs have been

recorded in real-time. Those, however, did only record wellhead pressure and injection rate, therefore:

- Add online-skin-factor and Injectivity Index to software program.

Recommendations for further research in optimising matrix acid stimulations:

- Definition of success criteria of the overall performance of a matrix acid stimulation treatment as well as of its progression, was one of the main objectives in the elaboration of this thesis. As a next step, we should approach the question: How do we best perform an acidizing job? This requires a detailed analysis of further success parameters, like injection pressure and rate and their repercussions on the treatment. Their analysis, together with the elaborated success criteria, might help in further understanding of how to optimise matrix acid stimulations.
- Performing core tests would give information about the effectiveness of the acid on the rock.
- Investigation and analysis of skin due to damage may help us making future decisions about when and why matrix acid stimulation was or was not successful and when a matrix treatment should or should not be performed. We might get further understanding in stimulation candidate selection.

REFERENCES

1. Economides, M. J. and Nolte, K. G. 1989. Reservoir Stimulation. New Jersey, 2nd Edition, 12, p. 1-8 and 1, p. 1.
2. Hawkins Jr., M. R.: “A Note on the Skin Effect,” in: JPT. December 1956, SPE paper 732, p. 65-72.
3. Byron Jackson Inc. (Ed.). 1972. Applied Engineered Stimulation. Long Beach, California. Previous Edition 1970.
4. Gdanski, R. D. and Shuchart, C. E.: “Newly discovered Equilibrium Controls HF Stoichiometry,” in: JPT. February 1996, p. 145-149.
5. Allen, Th. O. and Roberts, A. P. Production Operations Vol.2. 1978. Tulsa, Oklahoma, 3rd printing, p.137-138.
6. Rae, P. and di Lullo, G.: “Matrix Acid Stimulation – A Review of the State-Of-The-Art,” SPE paper 82260. Presented at the European Formation Damage Conference, 13-14 May, 2003, The Hague, Netherlands.
7. Coulter, G. R. and Jennings Jr., A. R.: “A Contemporary Approach To Matrix Acidizing,” SPE paper 38594. Presented at the SPE Annual Technical Conference and Exhibition, 5-8 October, 1997, San Antonio, Texas.
8. Williams, B. B., Gidley, J. L. and Schechter, R. S. 1979. Acidizing Fundamentals. New York – Dallas, p.96-97.
9. Kunze, K. R. and Shaughnessy, C. M.: ”Acidizing Sandstone Formations with Fluoboric Acid,” in: SPE Journal. February 1983, SPE paper 9387, p.65-72.
10. Gdanski, R. D.: “$AlCl_3$ retards HF acid for more effective stimulations,” in: Technology. Oil & Gas Journal. Oct 28, 1985, p. 111-115.

11. Bourgoyne Jr., A. T., Millheim K. M., Chenevert, M. E. and Young Jr., F. S. 1986. Applied Drilling Engineering. United States of America. SPE Textbook Series, Vol. 2, p.144-155.

12. Paccaloni, G. and Tambini, M.: “Advances in Matrix Stimulation Technology,” SPE paper 20623. Presented at the SPE Annual Technical Conference and Exhibition, 23-26 September, 1990, New Orleans, Texas.

APPENDIX A (FIELDS AND HORIZONS)

A005 NORDFELD
A015 MATZEN
A016 HOCHLEITEN
A017 PIRAWARTH
A046 ROSELDORF
A053 STOCKERAU-OST

SARMATIAN	
105	5. SARMATIAN
107	7. SARMATIAN
109B	9B. SARMATIAN
110	10. SARMATIAN
111	11. SARMATIAN
111	11. SARMATIAN
111B	11B. SARMATIAN
112	12. SARMATIAN
112	12. SARMATIAN
112B	12B. SARMATIAN
113	13. SARMATIAN
113	13. SARMATIAN
113B	13B. SARMATIAN
113C	13C. SARMATIAN
114	14. SARMATIAN

TORTONIAN	
201	1. TORTONIAN
202	2. TORTONIAN
203	3. TORTONIAN
205	5. TORTONIAN
205	5. TORTONIAN
205N	5N. TORTONIAN
206	6. TORTONIAN
207	7. TORTONIAN
208	8. TORTONIAN
209	9. TORTONIAN
209N	9N. TORTONIAN
210	10. TORTONIAN
210B	10B. TORTONIAN
211	11. TORTONIAN
212	12. TORTONIAN
212	12B. TORTONIAN
213	13. TORTONIAN
213B.	13. TORTONIAN
214	14. TORTONIAN
215	15. TORTONIAN
215Z	15Z. TORTONIAN
216	16. TORTONIAN

ADERKL.KONGL.

300K	ADERKL.KONGL.

KARPATIAN

300	KARPATIAN

GAENSERND.SCH.

323	GAENSERND.BEDS
324	GAENSERND.BEDS

OTTNANG

404	4. OTTNANG
408B	8B. OTTNANG
409	9. OTTNANG
409B	9B. OTTNANG
409C	9C. OTTNANG
410	10. OTTNANG
411	11. OTTNANG
411	11B. OTTNANG
412	12. OTTNANG
432	32. OTTNANG
433	33. OTTNANG

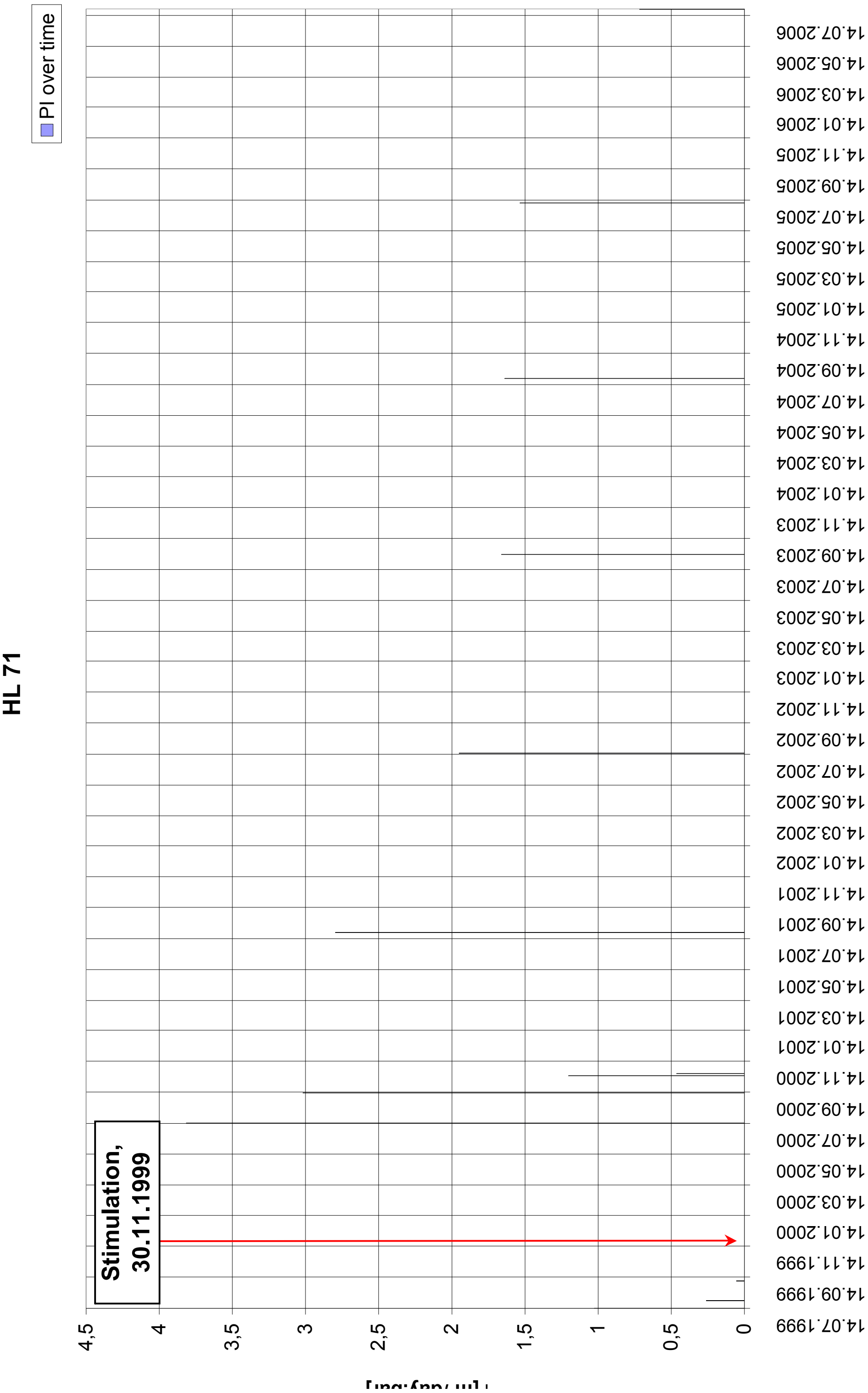
PALAEOGEN

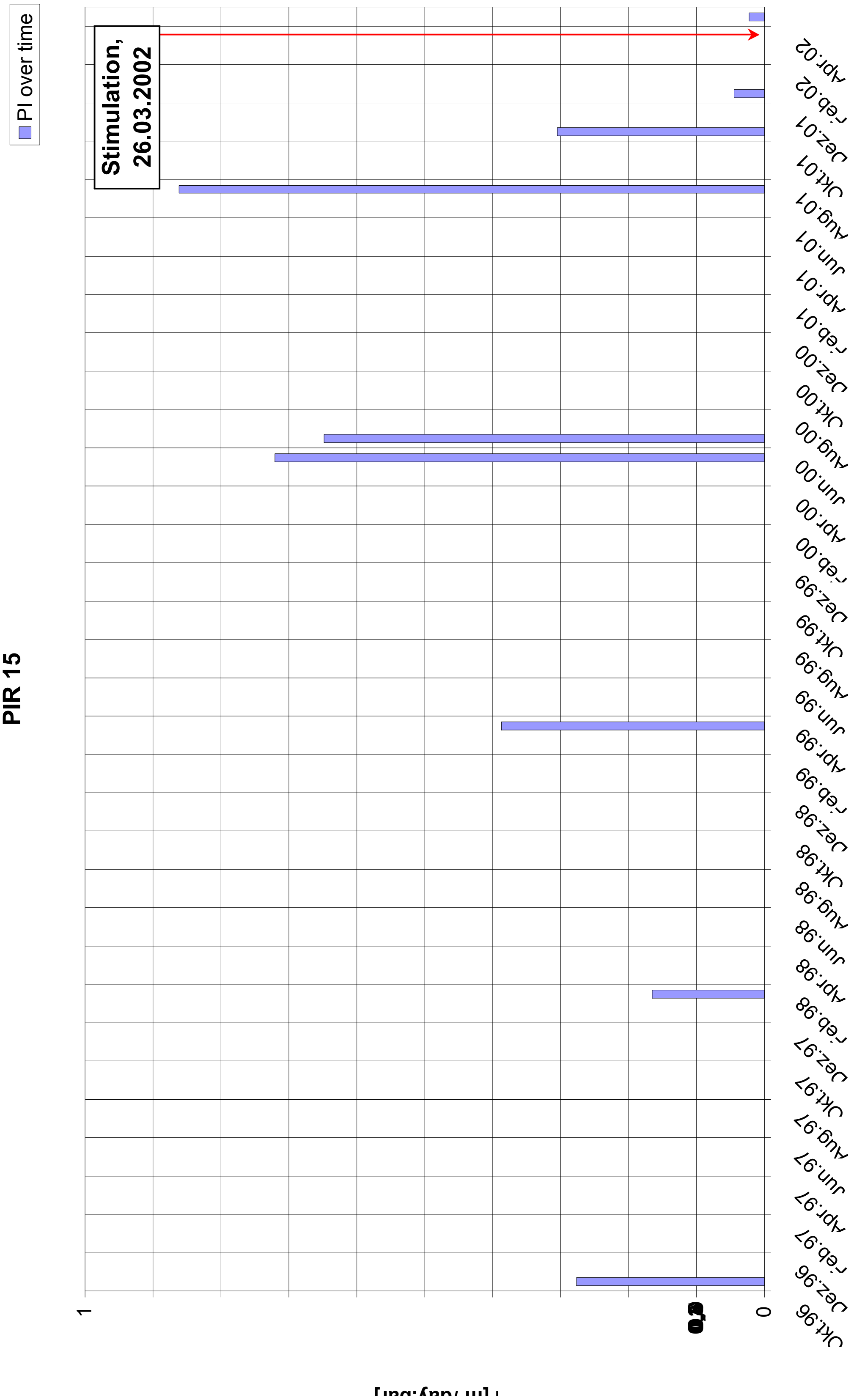
501	PALAEOGEN
550	PALAEOGEN

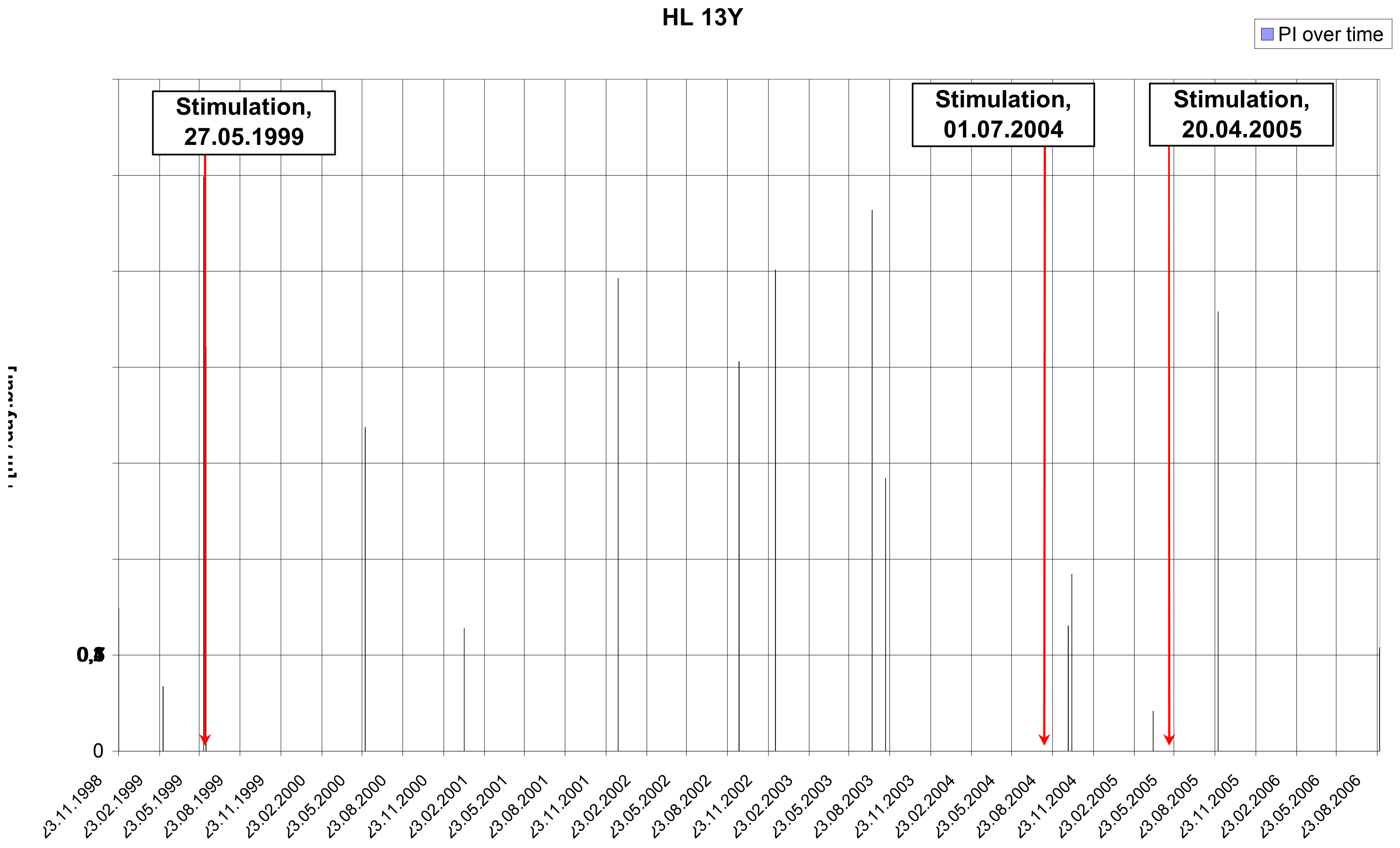
TRIAS

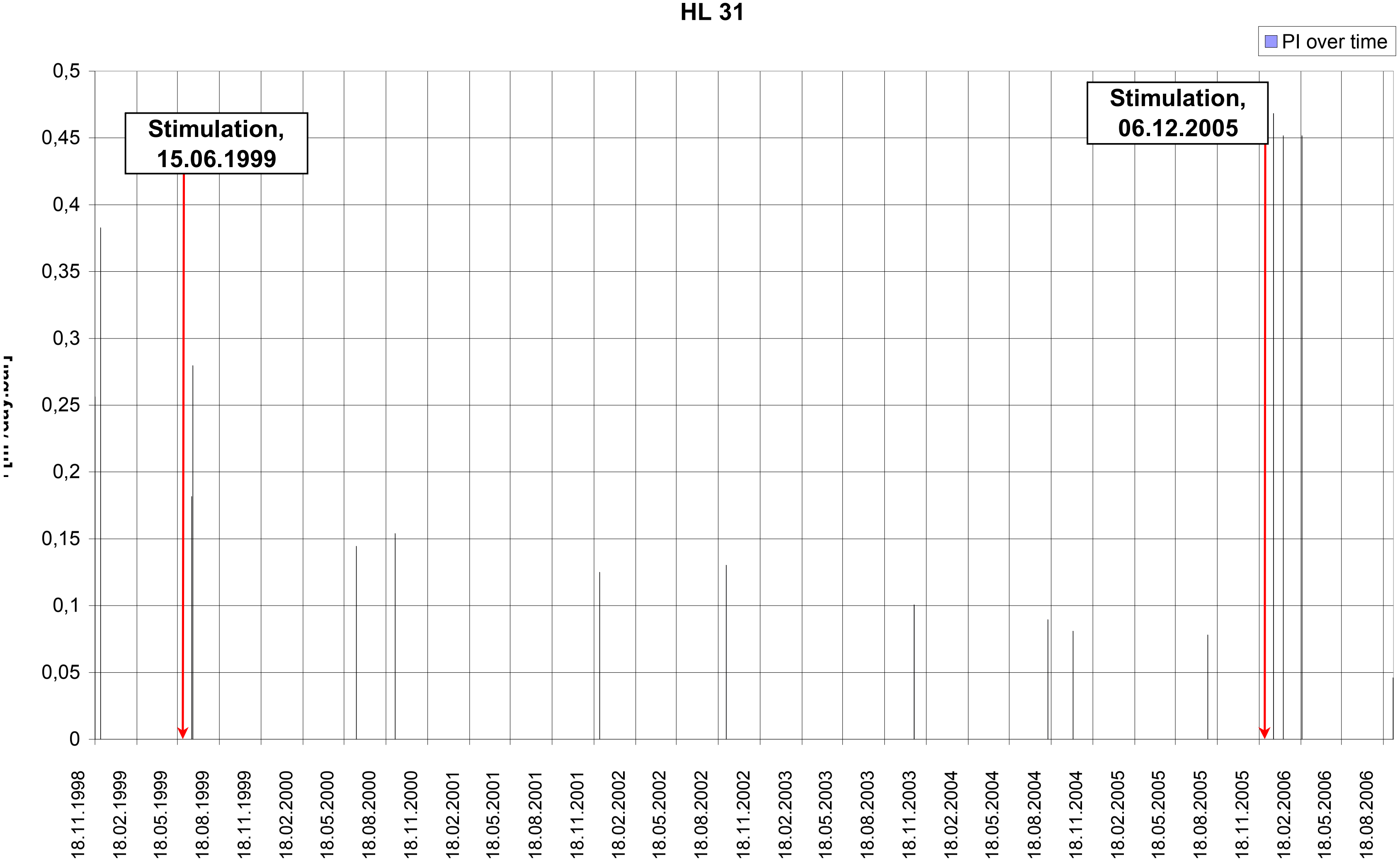
800	TRIAS
848	

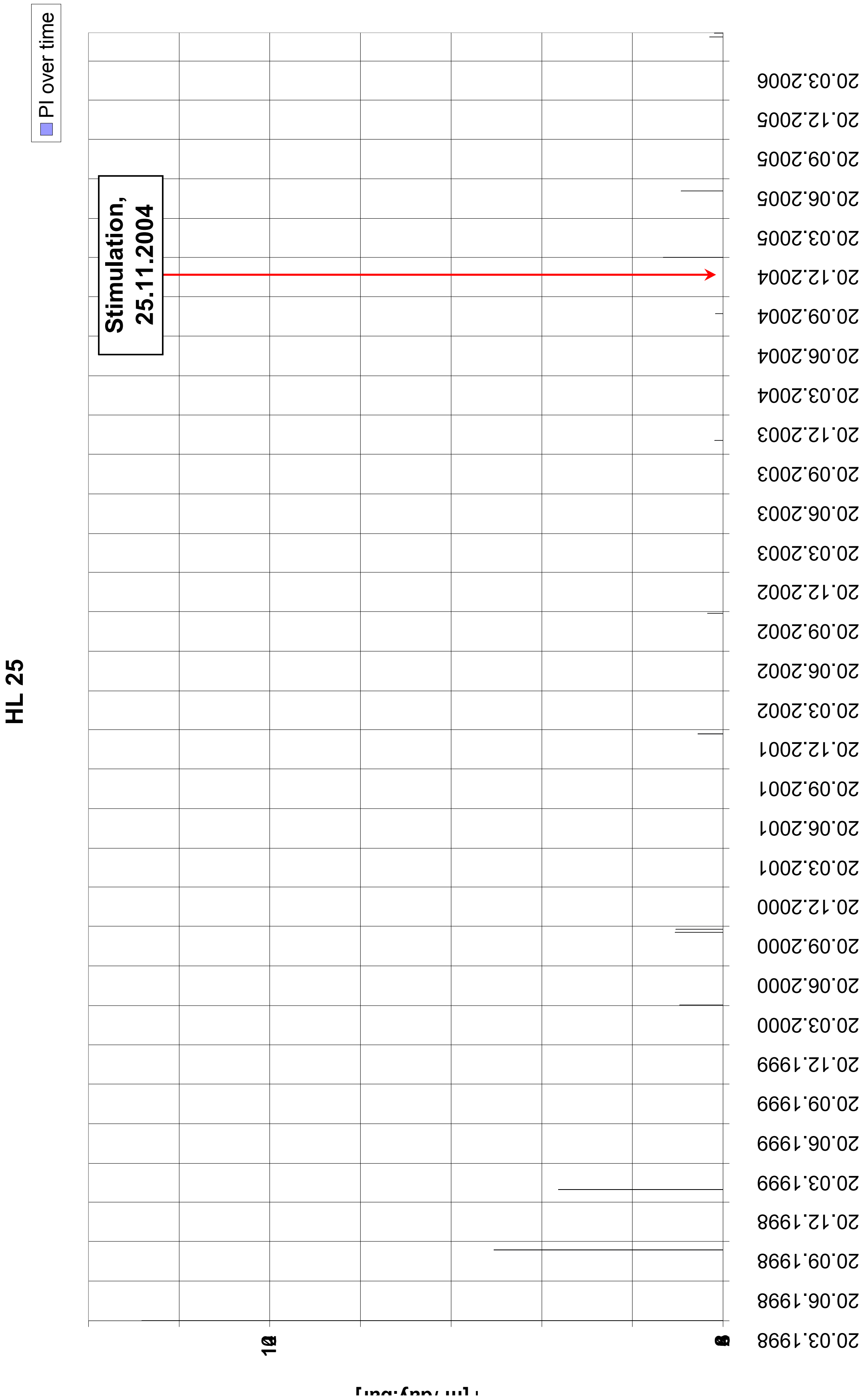
APPENDIX B (PI-HISTORIES)

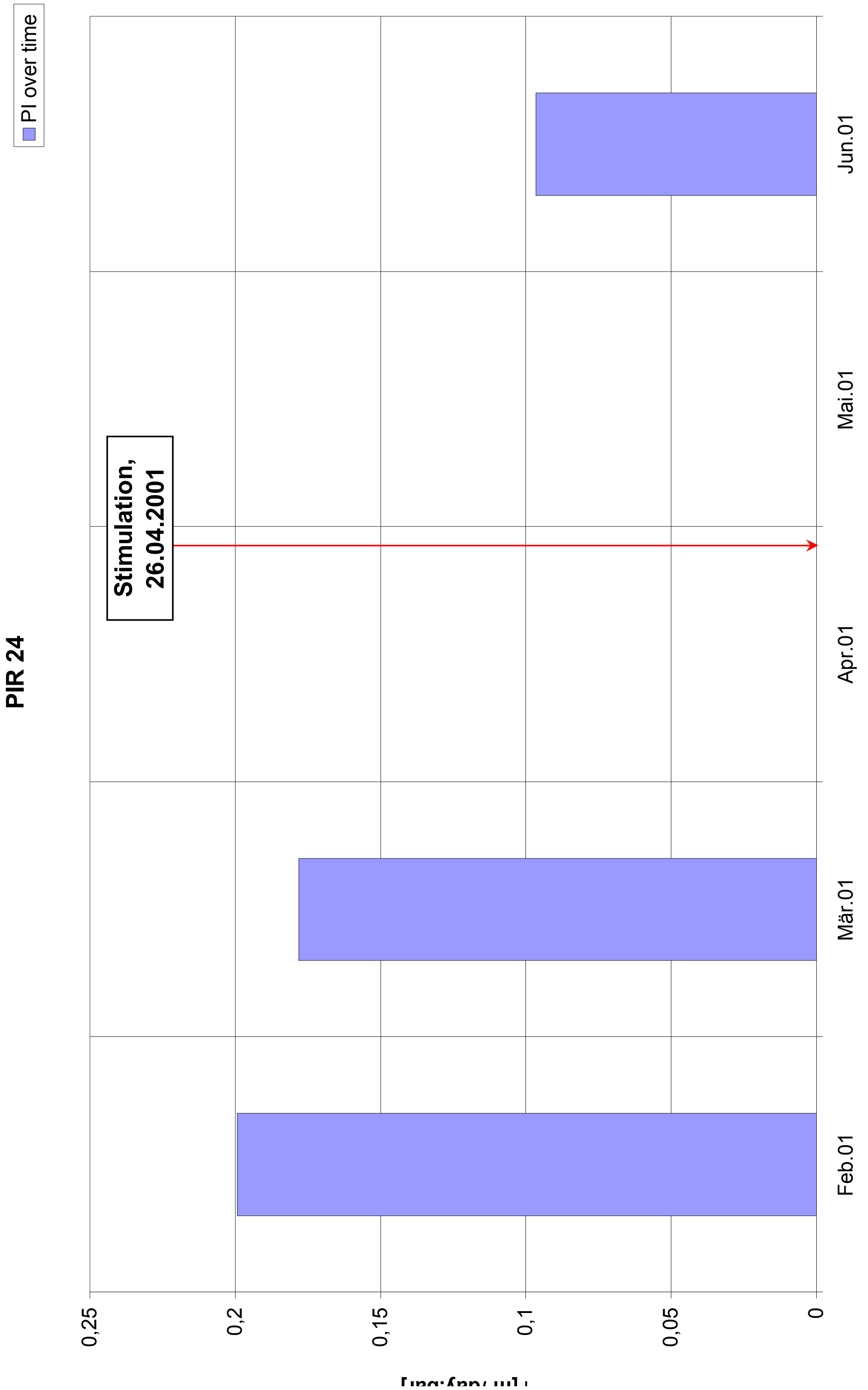


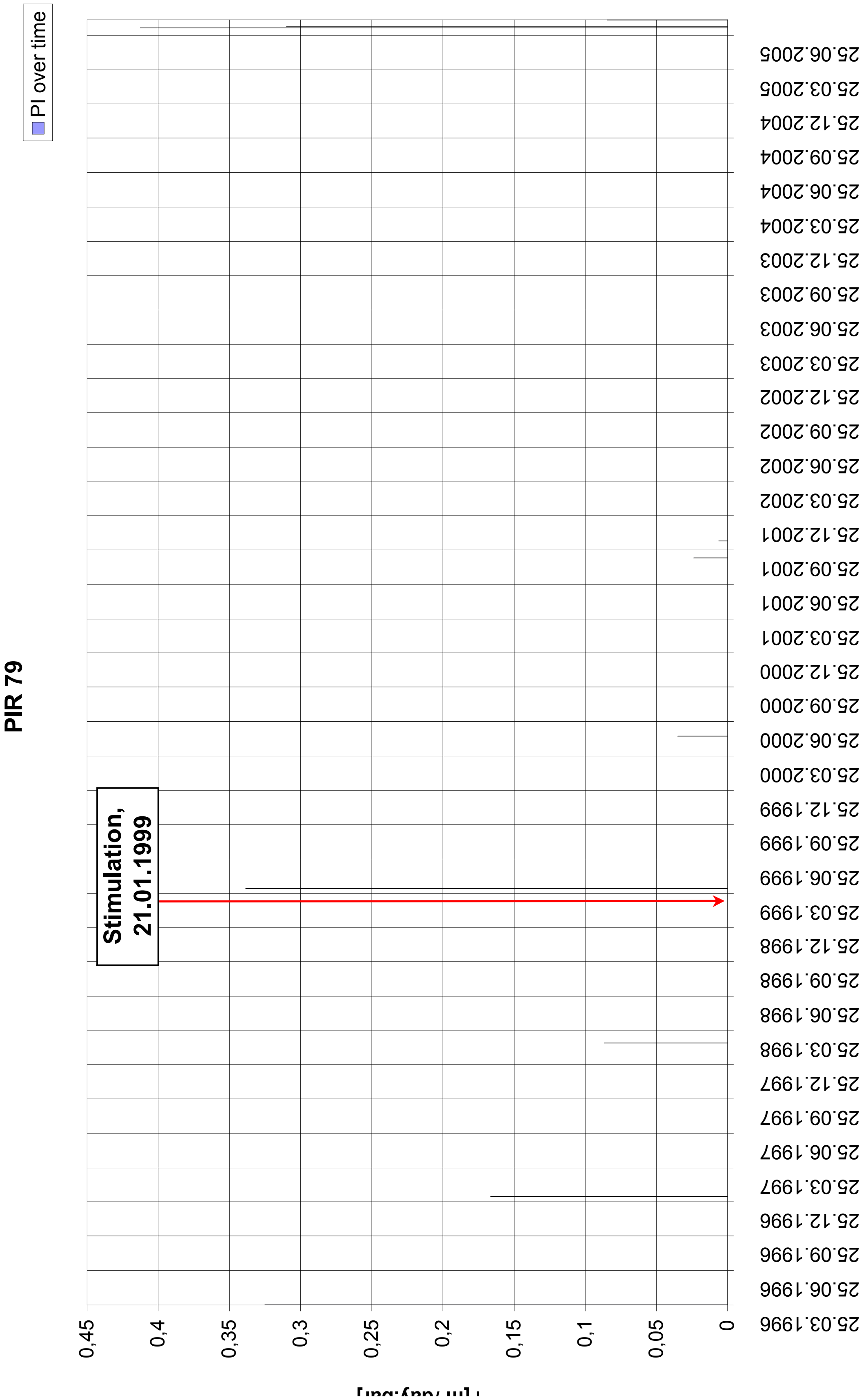

PIR 15
PI over time
Stimulation, 26.03.2002
1
0
Okt.96
Dez.96
Feb.97
Apr.97
Jun.97
Aug.97
Okt.97
Dez.97
Feb.98
Apr.98
Jun.98
Aug.98
Okt.98
Dez.98
Feb.99
Apr.99
Jun.99
Aug.99
Okt.99
Dez.99
Feb.00
Apr.00
Jun.00
Aug.00
Okt.00
Dez.00
Feb.01
Apr.01
Jun.01
Aug.01
Okt.01
Dez.01
Feb.02
Apr.02

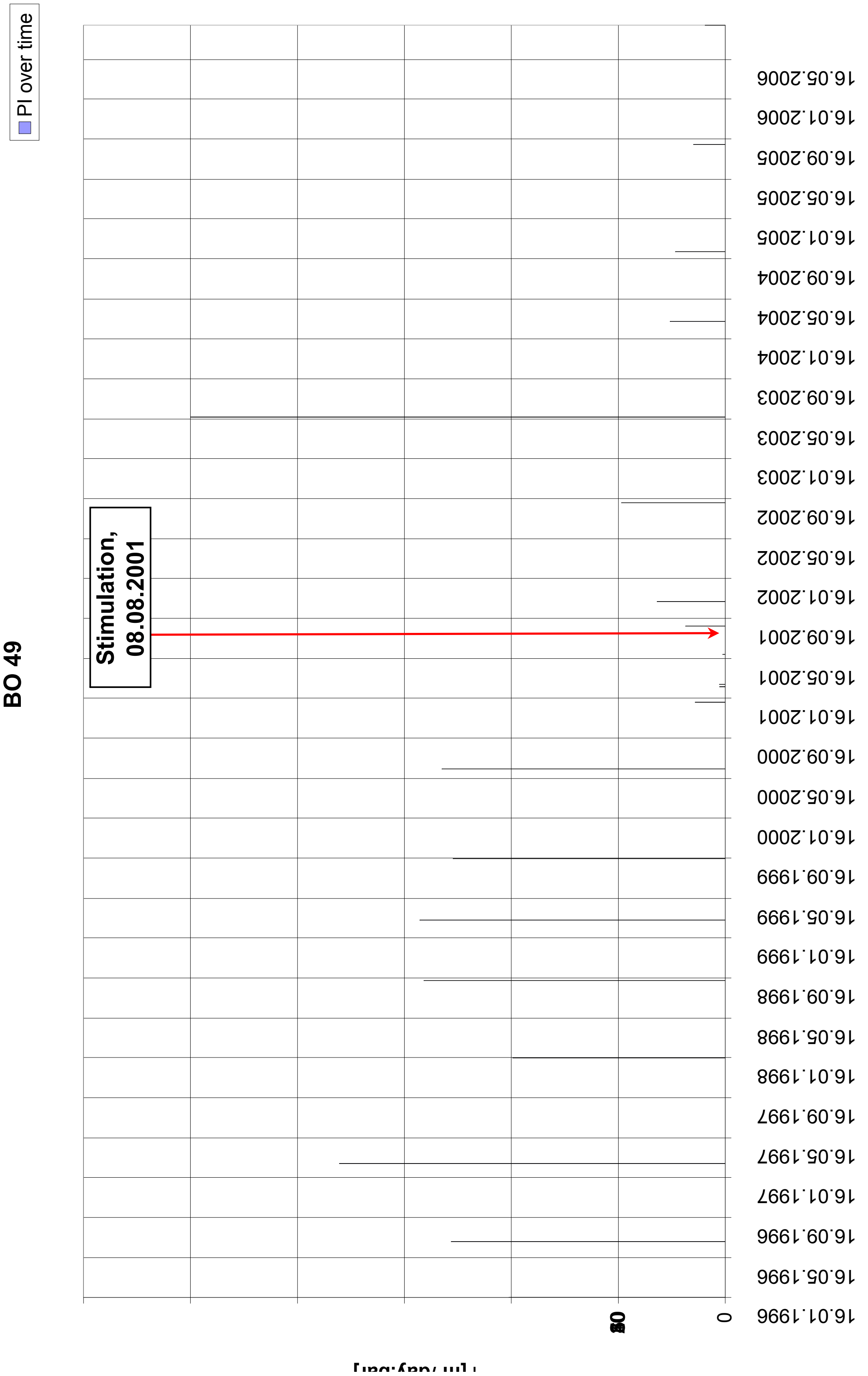

HL 13Y
PI over time
Stimulation, 27.05.1999
Stimulation, 01.07.2004
Stimulation, 20.04.2005
0
0,5
23.11.1998
23.02.1999
23.05.1999
23.08.1999
23.11.1999
23.02.2000
23.05.2000
23.08.2000
23.11.2000
23.02.2001
23.05.2001
23.08.2001
23.11.2001
23.02.2002
23.05.2002
23.08.2002
23.11.2002
23.02.2003
23.05.2003
23.08.2003
23.11.2003
23.02.2004
23.05.2004
23.08.2004
23.11.2004
23.02.2005
23.05.2005
23.08.2005
23.11.2005
23.02.2006
23.05.2006
23.08.2006

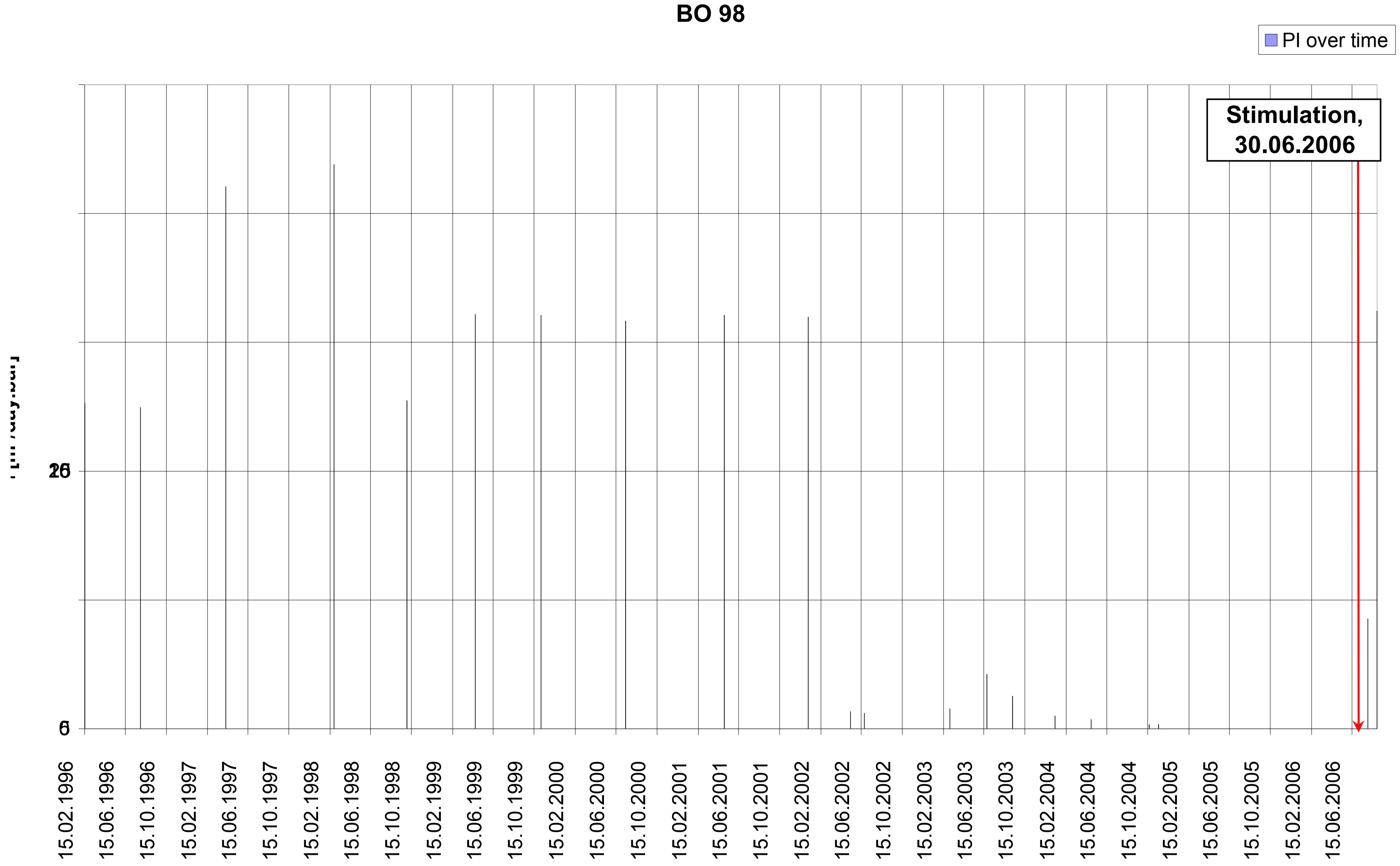

HL 31
PI over time
Stimulation, 15.06.1999
Stimulation, 06.12.2005
0,5
0,45
0,4
0,35
0,3
0,25
0,2
0,15
0,1
0,05
0
18.11.1998
18.02.1999
18.05.1999
18.08.1999
18.11.1999
18.02.2000
18.05.2000
18.08.2000
18.11.2000
18.02.2001
18.05.2001
18.08.2001
18.11.2001
18.02.2002
18.05.2002
18.08.2002
18.11.2002
18.02.2003
18.05.2003
18.08.2003
18.11.2003
18.02.2004
18.05.2004
18.08.2004
18.11.2004
18.02.2005
18.05.2005
18.08.2005
18.11.2005
18.02.2006
18.05.2006
18.08.2006

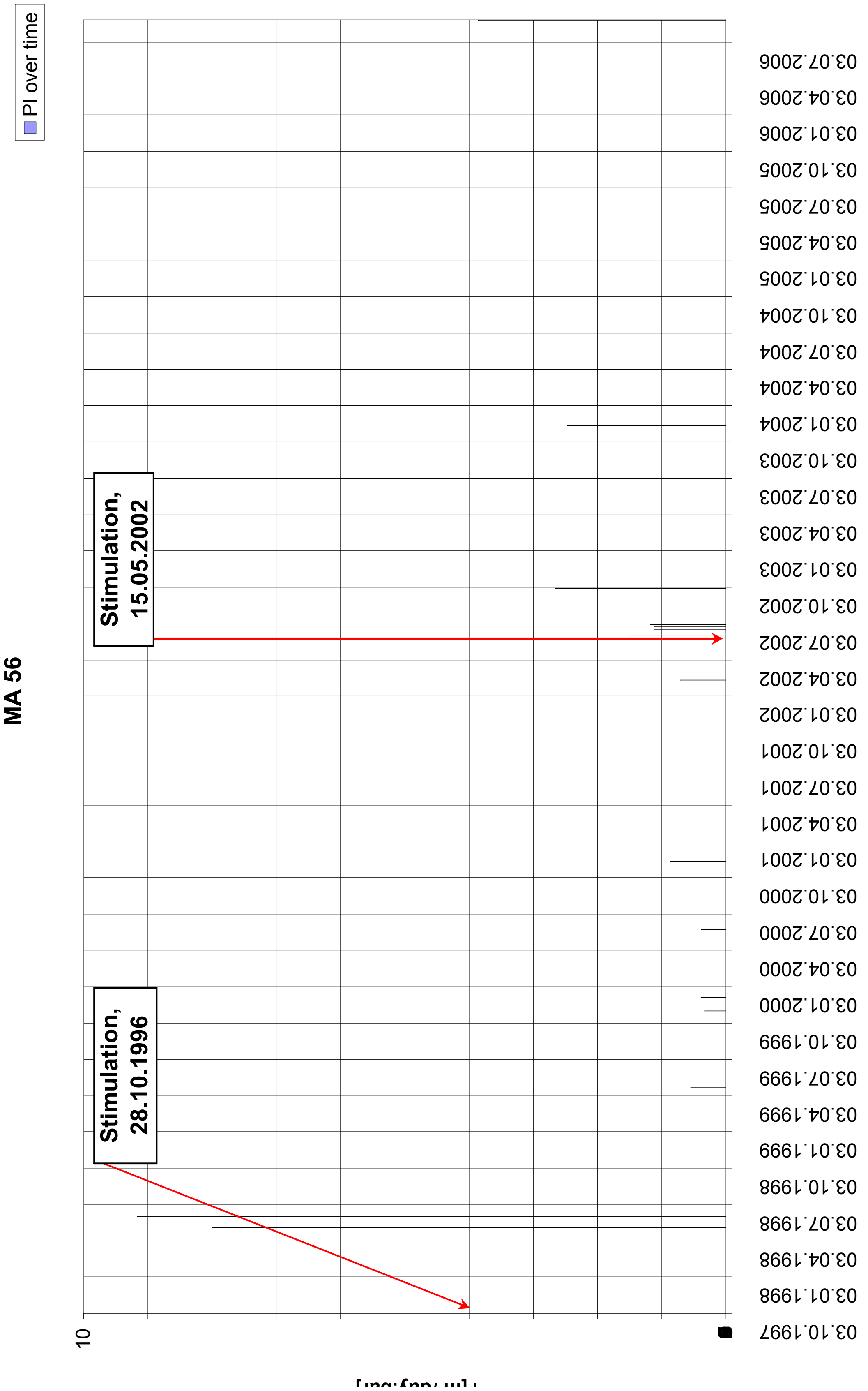

HL 25
PI over time
Stimulation, 25.11.2004
20.03.1998
20.06.1998
20.09.1998
20.12.1998
20.03.1999
20.06.1999
20.09.1999
20.12.1999
20.03.2000
20.06.2000
20.09.2000
20.12.2000
20.03.2001
20.06.2001
20.09.2001
20.12.2001
20.03.2002
20.06.2002
20.09.2002
20.12.2002
20.03.2003
20.06.2003
20.09.2003
20.12.2003
20.03.2004
20.06.2004
20.09.2004
20.12.2004
20.03.2005
20.06.2005
20.09.2005
20.12.2005
20.03.2006

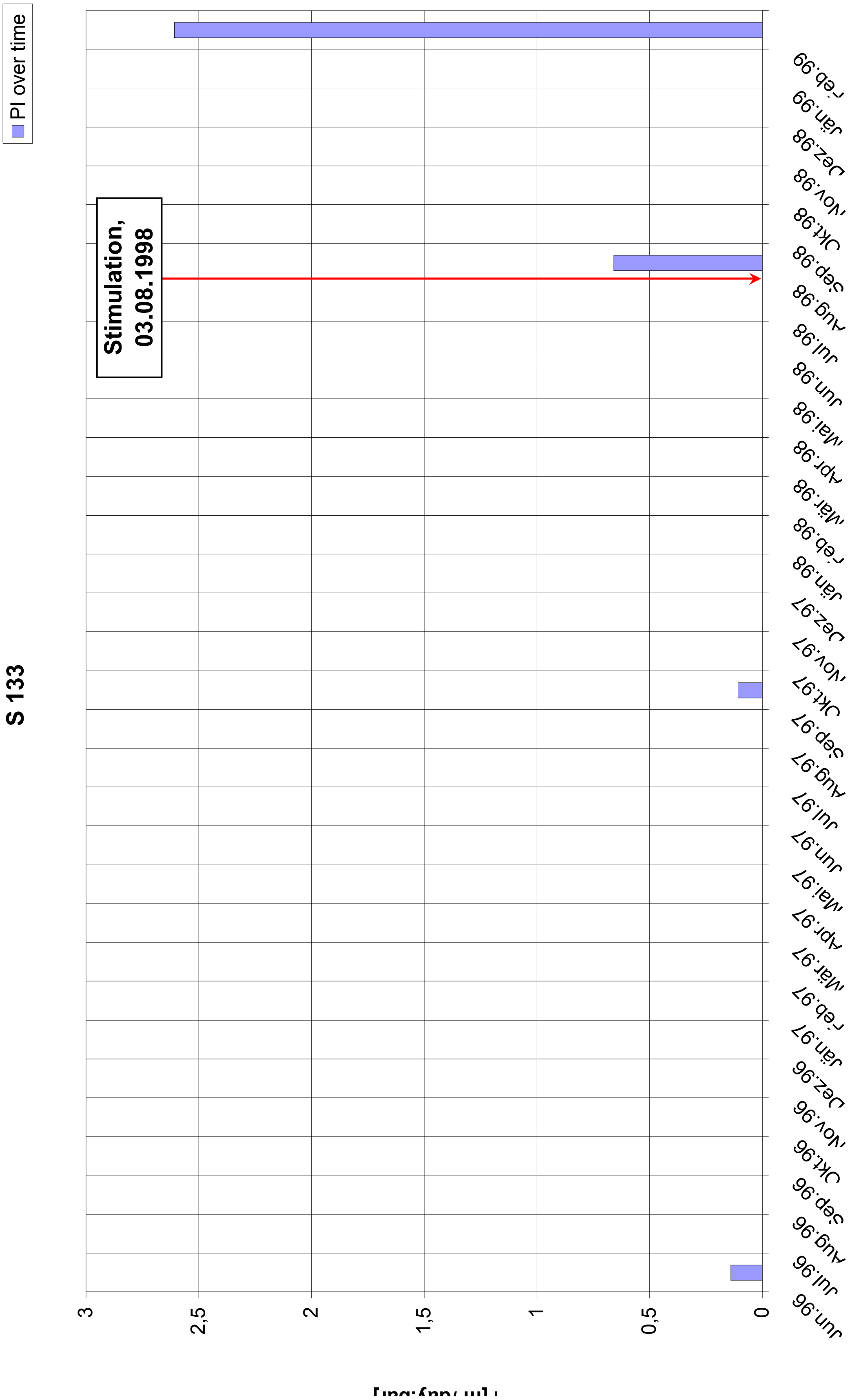

PIR 24
PI over time
Stimulation, 26.04.2001
0,25
0,2
0,15
0,1
0,05
0
Feb.01
Mär.01
Apr.01
Mai.01
Jun.01

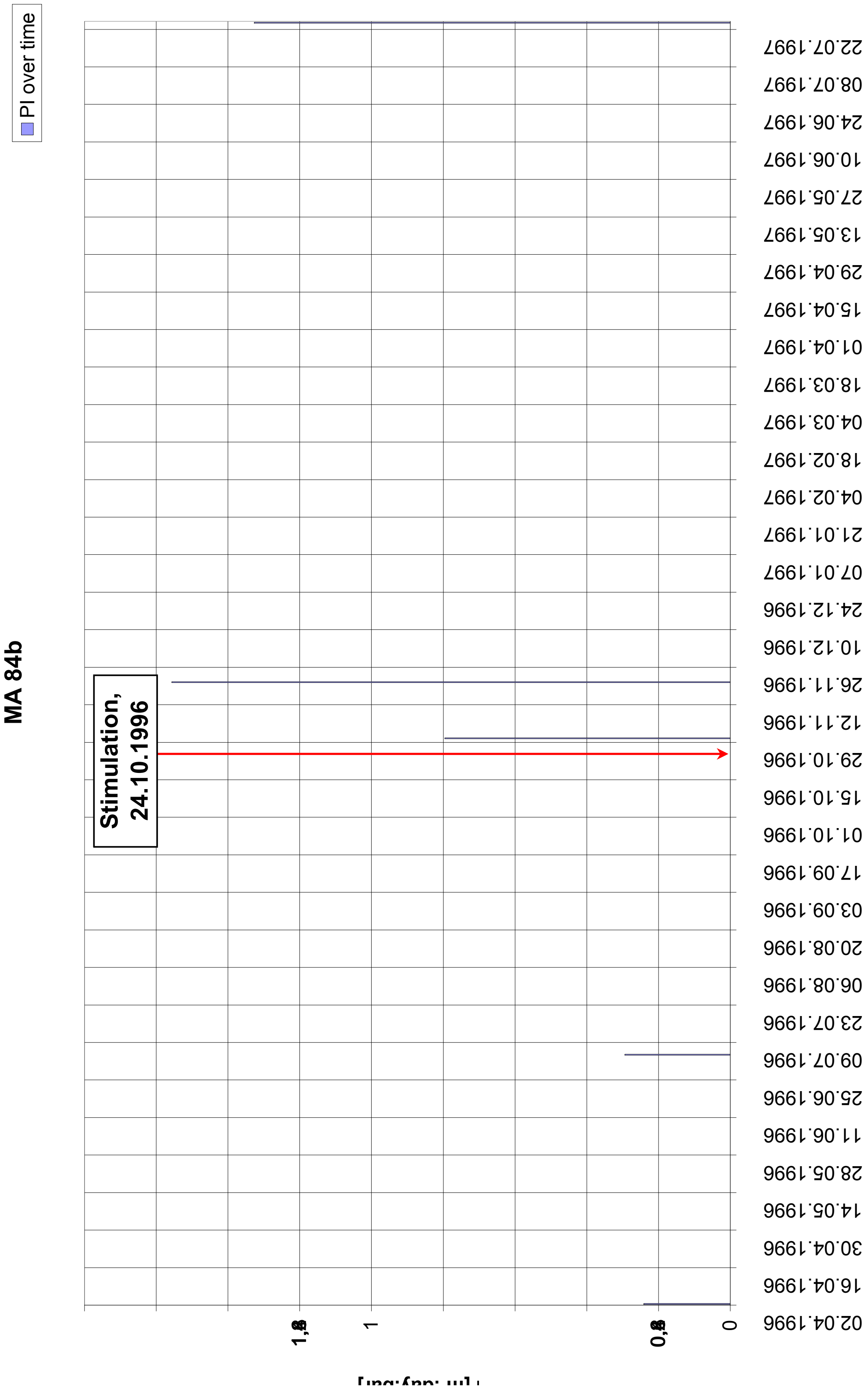

PIR 79
PI over time
Stimulation, 21.01.1999
0,45
0,4
0,35
0,3
0,25
0,2
0,15
0,1
0,05
0
25.03.1996
25.06.1996
25.09.1996
25.12.1996
25.03.1997
25.06.1997
25.09.1997
25.12.1997
25.03.1998
25.06.1998
25.09.1998
25.12.1998
25.03.1999
25.06.1999
25.09.1999
25.12.1999
25.03.2000
25.06.2000
25.09.2000
25.12.2000
25.03.2001
25.06.2001
25.09.2001
25.12.2001
25.03.2002
25.06.2002
25.09.2002
25.12.2002
25.03.2003
25.06.2003
25.09.2003
25.12.2003
25.03.2004
25.06.2004
25.09.2004
25.12.2004
25.03.2005
25.06.2005

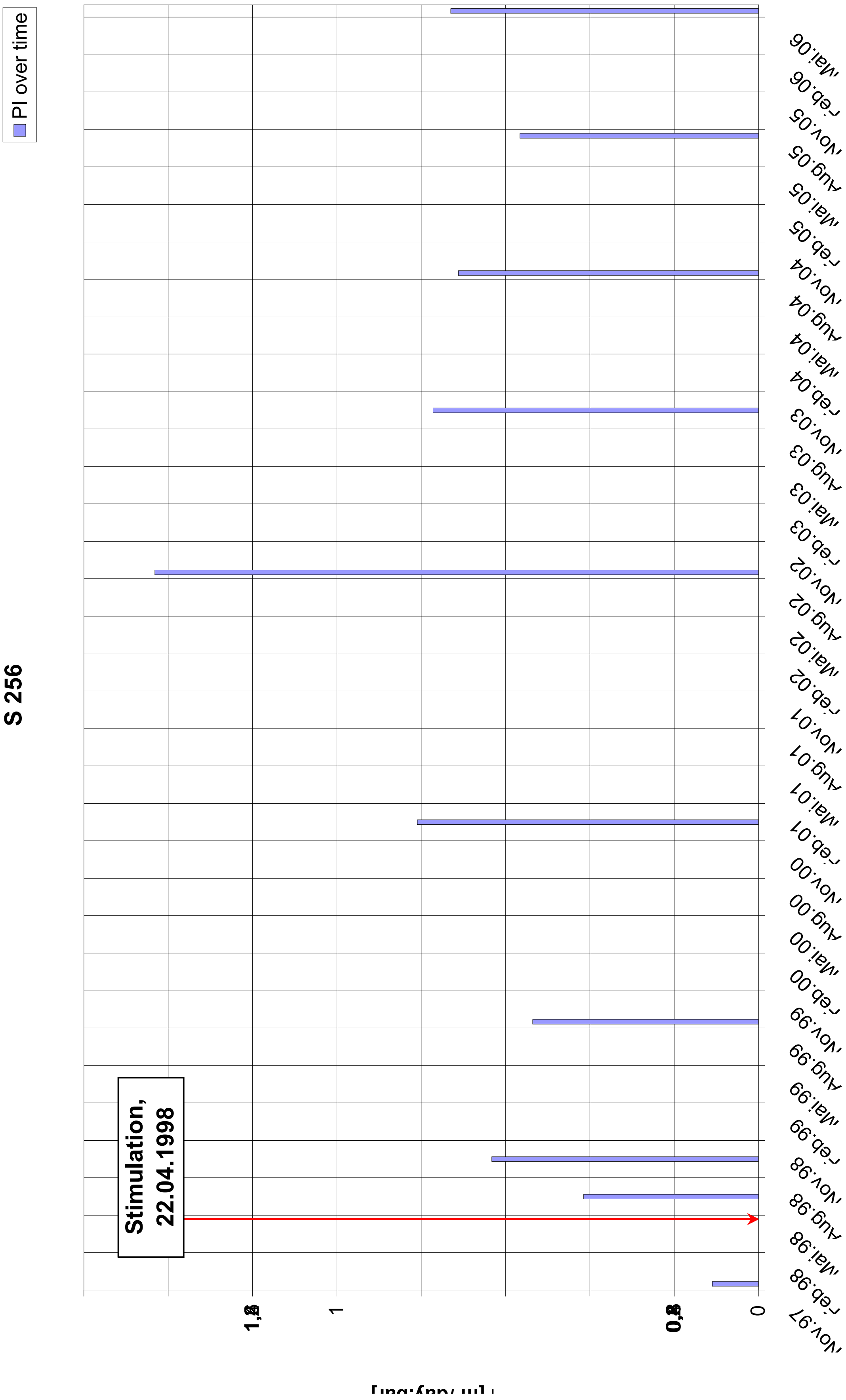

BO 49
PI over time
Stimulation, 08.08.2001
0
16.01.1996
16.05.1996
16.09.1996
16.01.1997
16.05.1997
16.09.1997
16.01.1998
16.05.1998
16.09.1998
16.01.1999
16.05.1999
16.09.1999
16.01.2000
16.05.2000
16.09.2000
16.01.2001
16.05.2001
16.09.2001
16.01.2002
16.05.2002
16.09.2002
16.01.2003
16.05.2003
16.09.2003
16.01.2004
16.05.2004
16.09.2004
16.01.2005
16.05.2005
16.09.2005
16.01.2006
16.05.2006

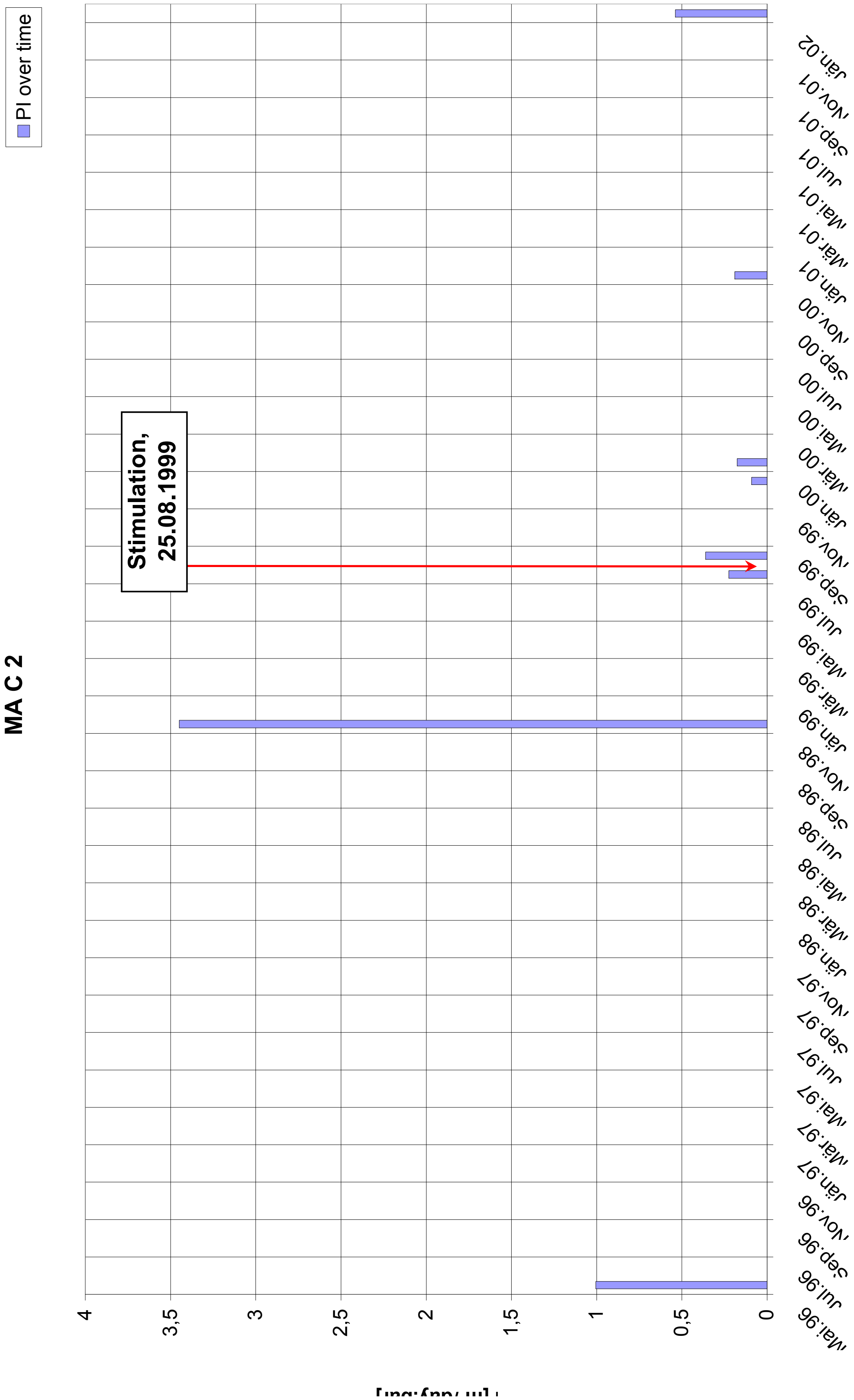

BO 98
PI over time
Stimulation,
30.06.2006
20
0
15.02.1996
15.06.1996
15.10.1996
15.02.1997
15.06.1997
15.10.1997
15.02.1998
15.06.1998
15.10.1998
15.02.1999
15.06.1999
15.10.1999
15.02.2000
15.06.2000
15.10.2000
15.02.2001
15.06.2001
15.10.2001
15.02.2002
15.06.2002
15.10.2002
15.02.2003
15.06.2003
15.10.2003
15.02.2004
15.06.2004
15.10.2004
15.02.2005
15.06.2005
15.10.2005
15.02.2006
15.06.2006

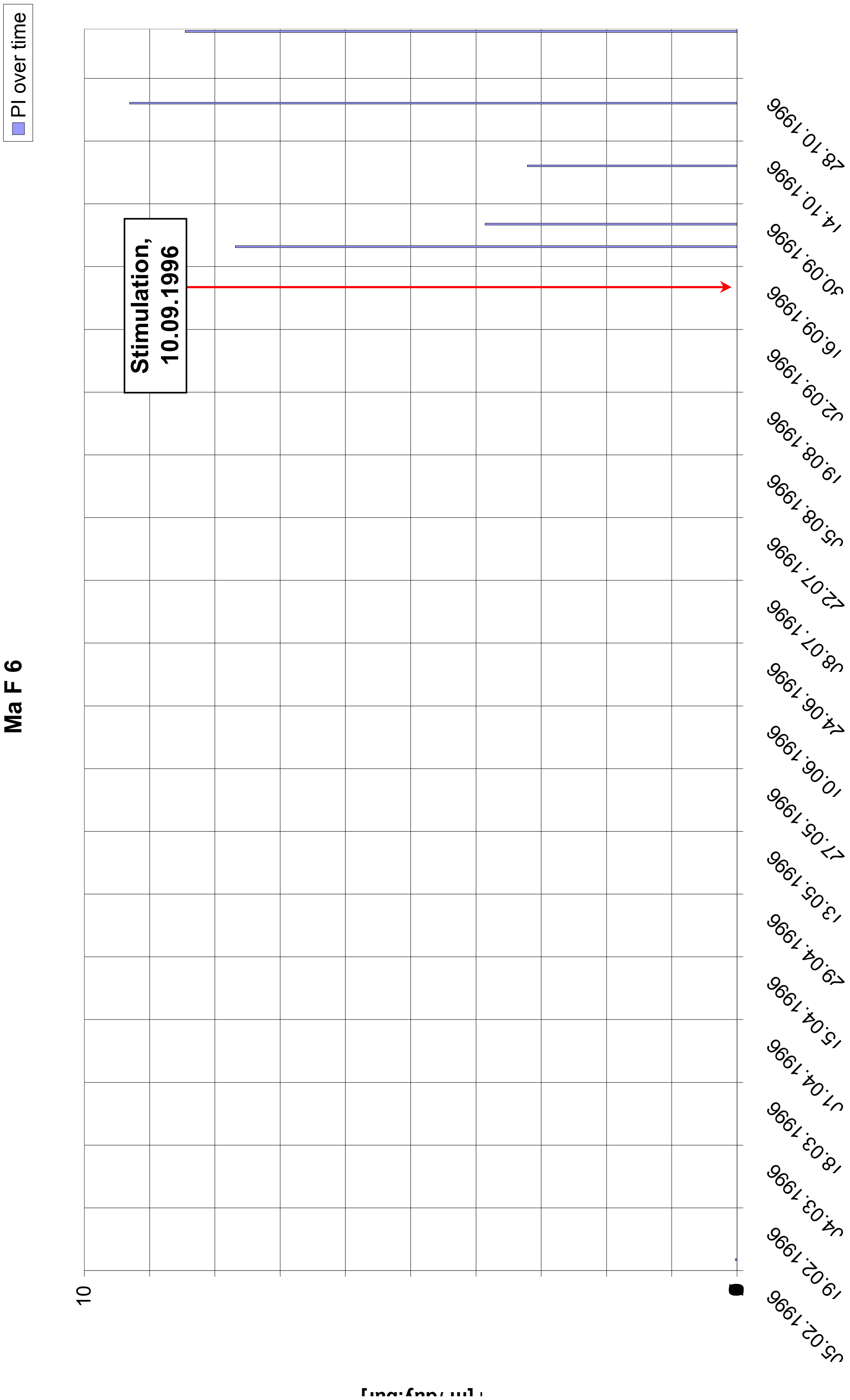

MA 56
PI over time
Stimulation,
15.05.2002
Stimulation,
28.10.1996
10
03.10.1997
03.01.1998
03.04.1998
03.07.1998
03.10.1998
03.01.1999
03.04.1999
03.07.1999
03.10.1999
03.01.2000
03.04.2000
03.07.2000
03.10.2000
03.01.2001
03.04.2001
03.07.2001
03.10.2001
03.01.2002
03.04.2002
03.07.2002
03.10.2002
03.01.2003
03.04.2003
03.07.2003
03.10.2003
03.01.2004
03.04.2004
03.07.2004
03.10.2004
03.01.2005
03.04.2005
03.07.2005
03.10.2005
03.01.2006
03.04.2006
03.07.2006

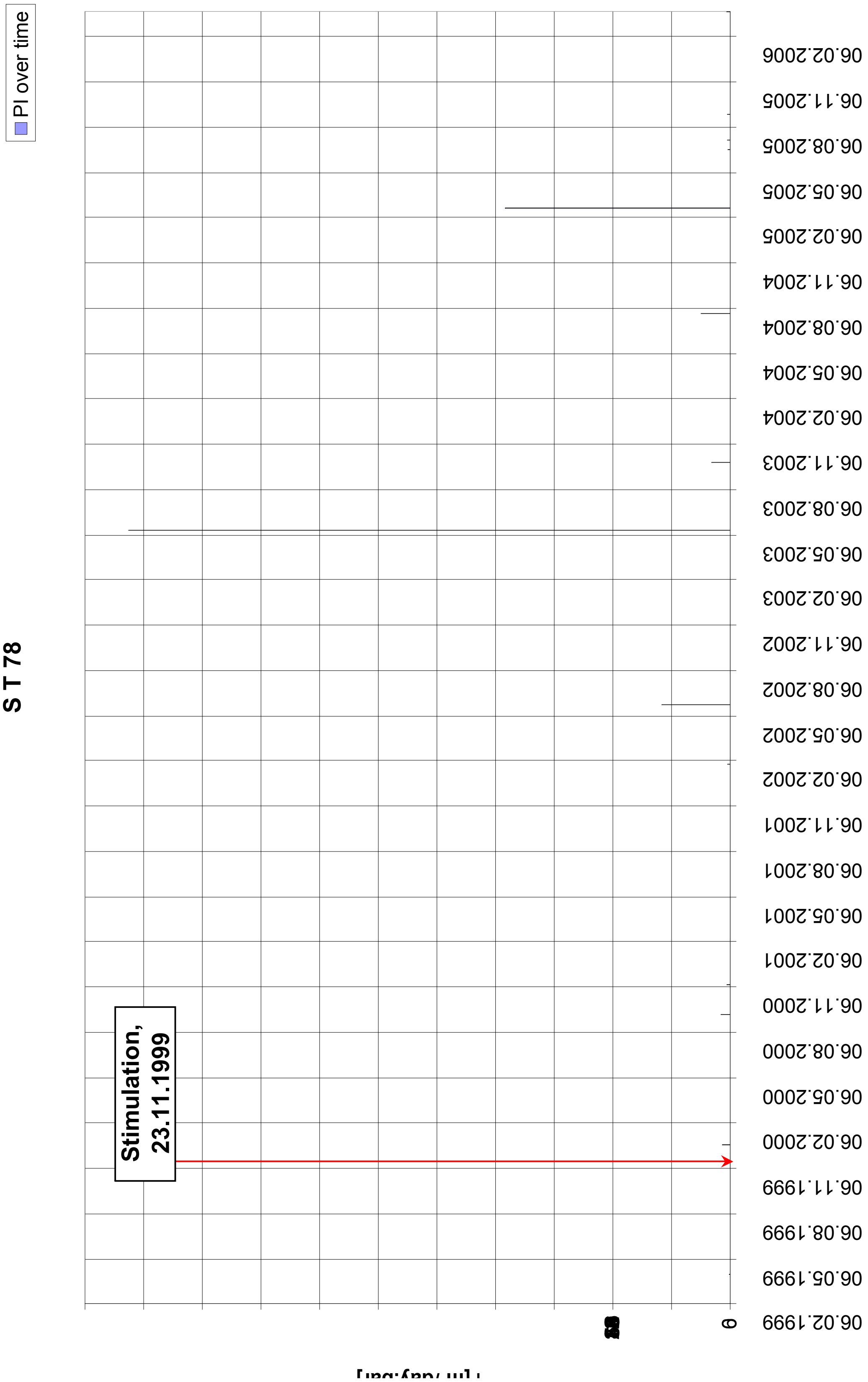

S 133
PI over time
Stimulation,
03.08.1998
0
0,5
1
1,5
2
2,5
3
Jun.96
Jul.96
Aug.96
Sep.96
Okt.96
Nov.96
Dez.96
Jän.97
Feb.97
Mär.97
Apr.97
Mai.97
Jun.97
Jul.97
Aug.97
Sep.97
Okt.97
Nov.97
Dez.97
Jän.98
Feb.98
Mär.98
Apr.98
Mai.98
Jun.98
Jul.98
Aug.98
Sep.98
Okt.98
Nov.98
Dez.98
Jän.99
Feb.99

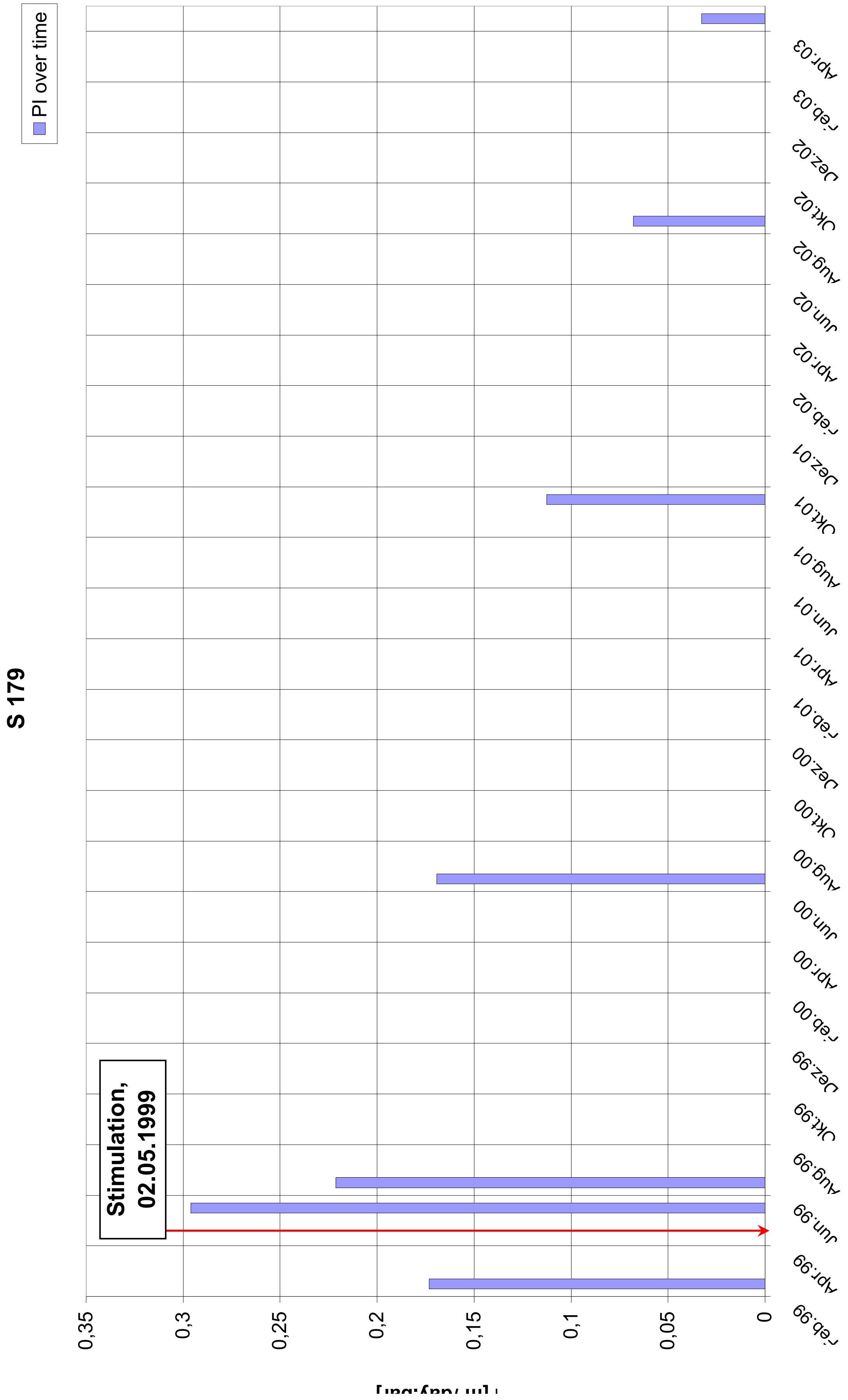

MA 84b
PI over time
Stimulation,
24.10.1996
0
0,8
1
1,8
02.04.1996
16.04.1996
30.04.1996
14.05.1996
28.05.1996
11.06.1996
25.06.1996
09.07.1996
23.07.1996
06.08.1996
20.08.1996
03.09.1996
17.09.1996
01.10.1996
15.10.1996
29.10.1996
12.11.1996
26.11.1996
10.12.1996
24.12.1996
07.01.1997
21.01.1997
04.02.1997
18.02.1997
04.03.1997
18.03.1997
01.04.1997
15.04.1997
29.04.1997
13.05.1997
27.05.1997
10.06.1997
24.06.1997
08.07.1997
22.07.1997

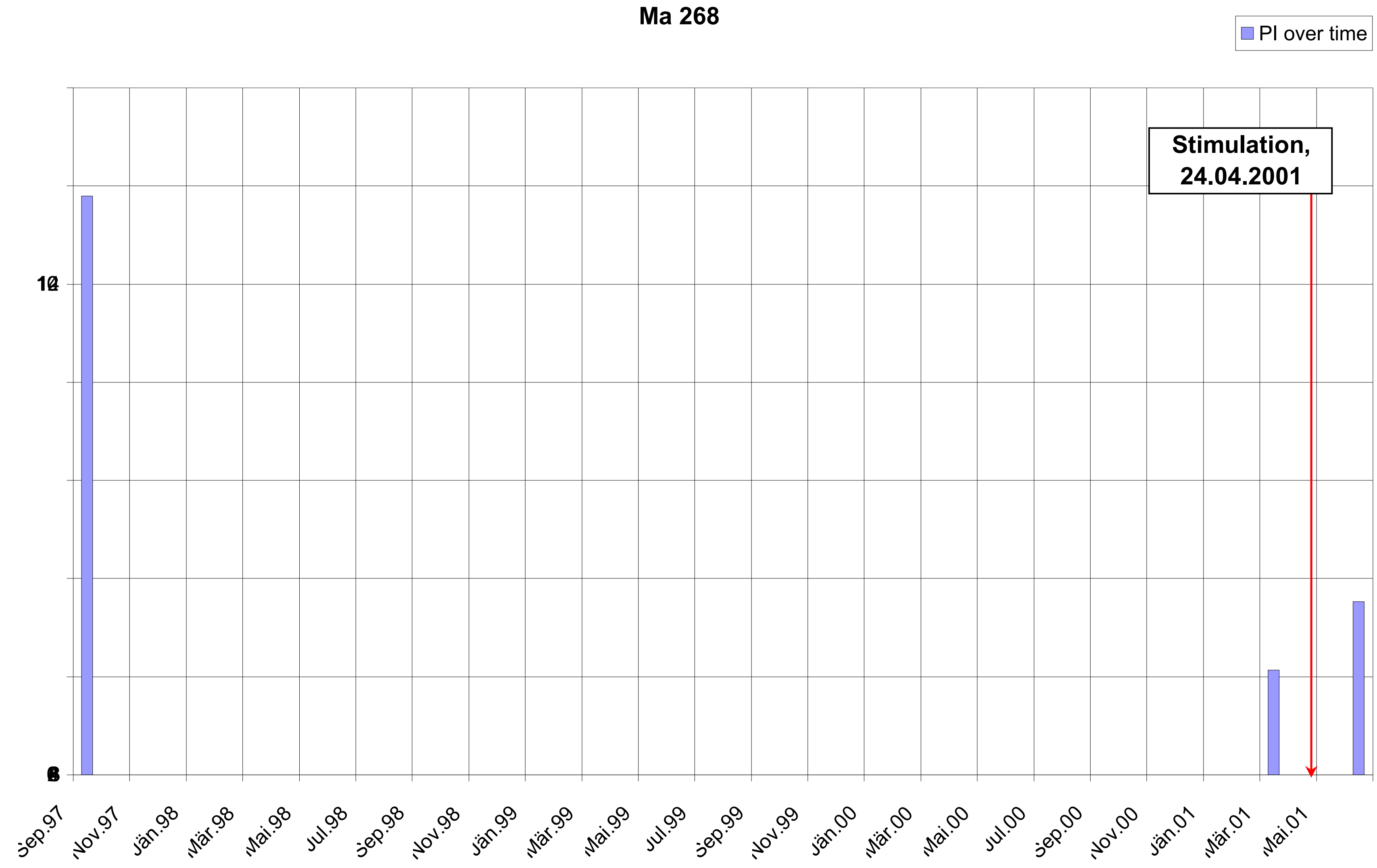

S 256
PI over time
Stimulation, 22.04.1998
1,2
1
0,8
0
Nov.97
Feb.98
Mai.98
Aug.98
Nov.98
Feb.99
Mai.99
Aug.99
Nov.99
Feb.00
Mai.00
Aug.00
Nov.00
Feb.01
Mai.01
Aug.01
Nov.01
Feb.02
Mai.02
Aug.02
Nov.02
Feb.03
Mai.03
Aug.03
Nov.03
Feb.04
Mai.04
Aug.04
Nov.04
Feb.05
Mai.05
Aug.05
Nov.05
Feb.06
Mai.06


MA C 2
PI over time
Stimulation, 25.08.1999
0
0,5
1
1,5
2
2,5
3
3,5
4
Mai.96
Jul.96
Sep.96
Nov.96
Jan.97
Mär.97
Mai.97
Jul.97
Sep.97
Nov.97
Jan.98
Mär.98
Mai.98
Jul.98
Sep.98
Nov.98
Jan.99
Mär.99
Mai.99
Jul.99
Sep.99
Nov.99
Jan.00
Mär.00
Mai.00
Jul.00
Sep.00
Nov.00
Jan.01
Mär.01
Mai.01
Jul.01
Sep.01
Nov.01
Jan.02

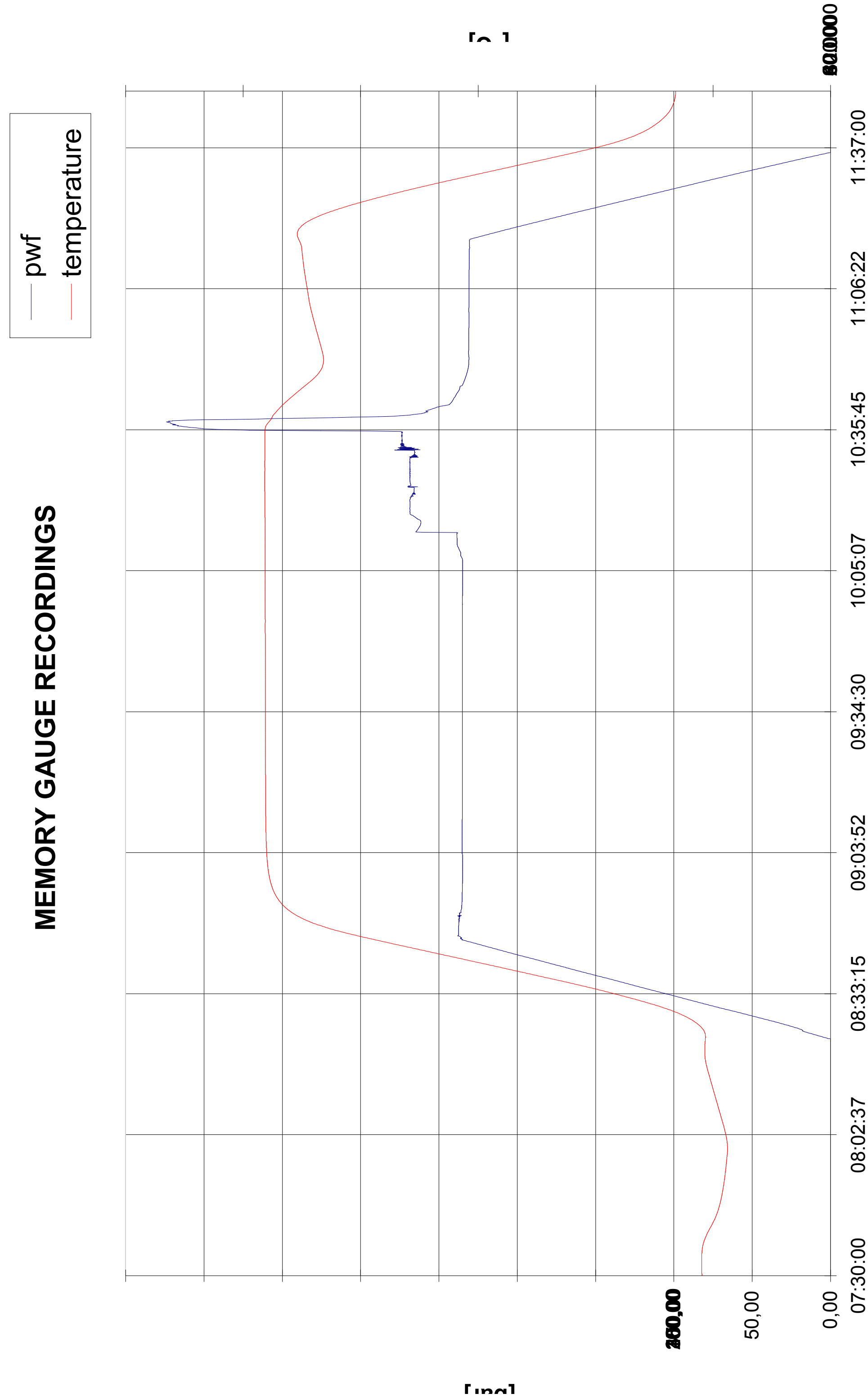

Ma F 6
PI over time
Stimulation,
10.09.1996
10
0
05.02.1996
19.02.1996
04.03.1996
18.03.1996
01.04.1996
15.04.1996
29.04.1996
13.05.1996
27.05.1996
10.06.1996
24.06.1996
08.07.1996
22.07.1996
05.08.1996
19.08.1996
02.09.1996
16.09.1996
30.09.1996
14.10.1996
28.10.1996

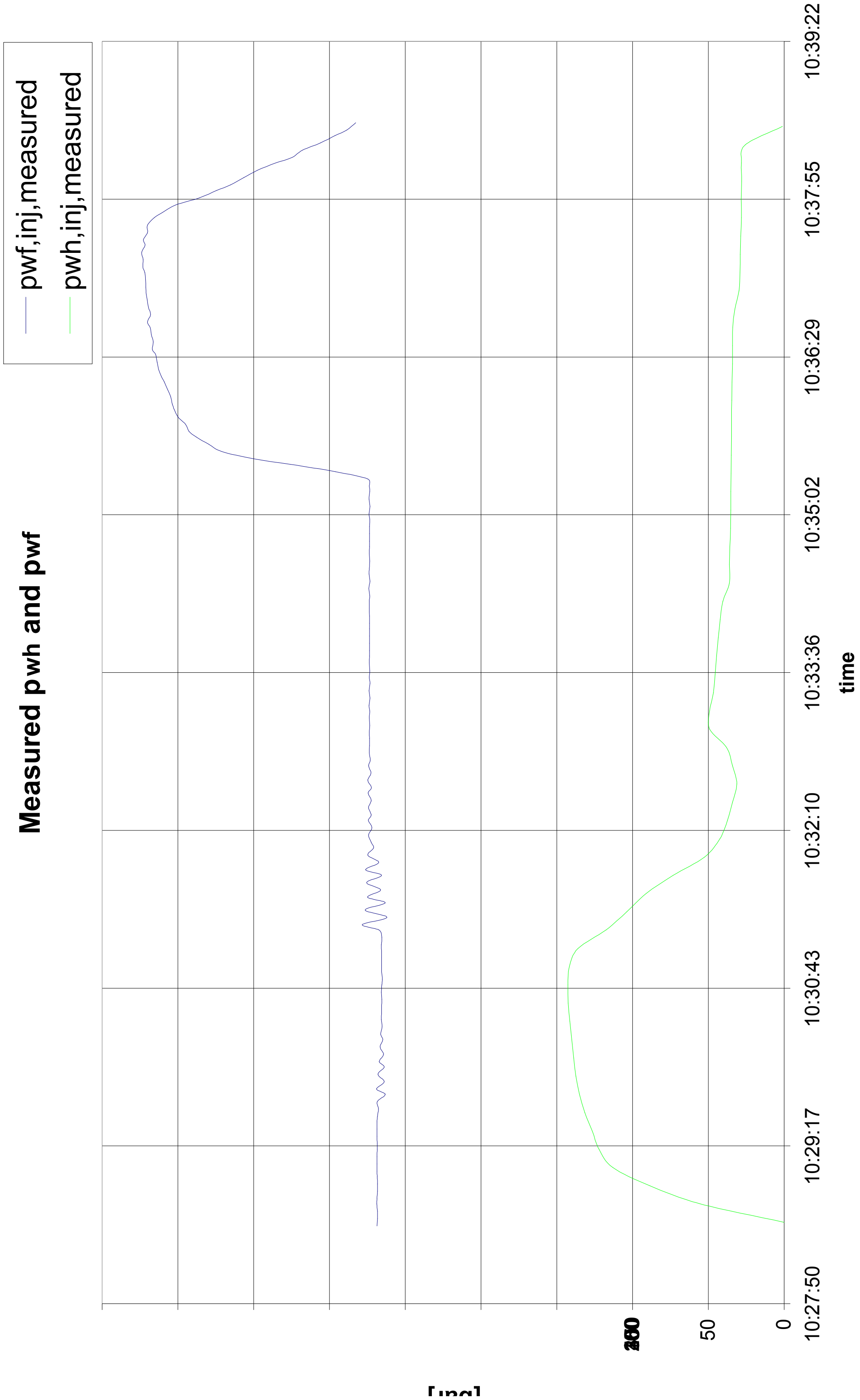

S T 78
PI over time
Stimulation, 23.11.1999
0
06.02.1999
06.05.1999
06.08.1999
06.11.1999
06.02.2000
06.05.2000
06.08.2000
06.11.2000
06.02.2001
06.05.2001
06.08.2001
06.11.2001
06.02.2002
06.05.2002
06.08.2002
06.11.2002
06.02.2003
06.05.2003
06.08.2003
06.11.2003
06.02.2004
06.05.2004
06.08.2004
06.11.2004
06.02.2005
06.05.2005
06.08.2005
06.11.2005
06.02.2006

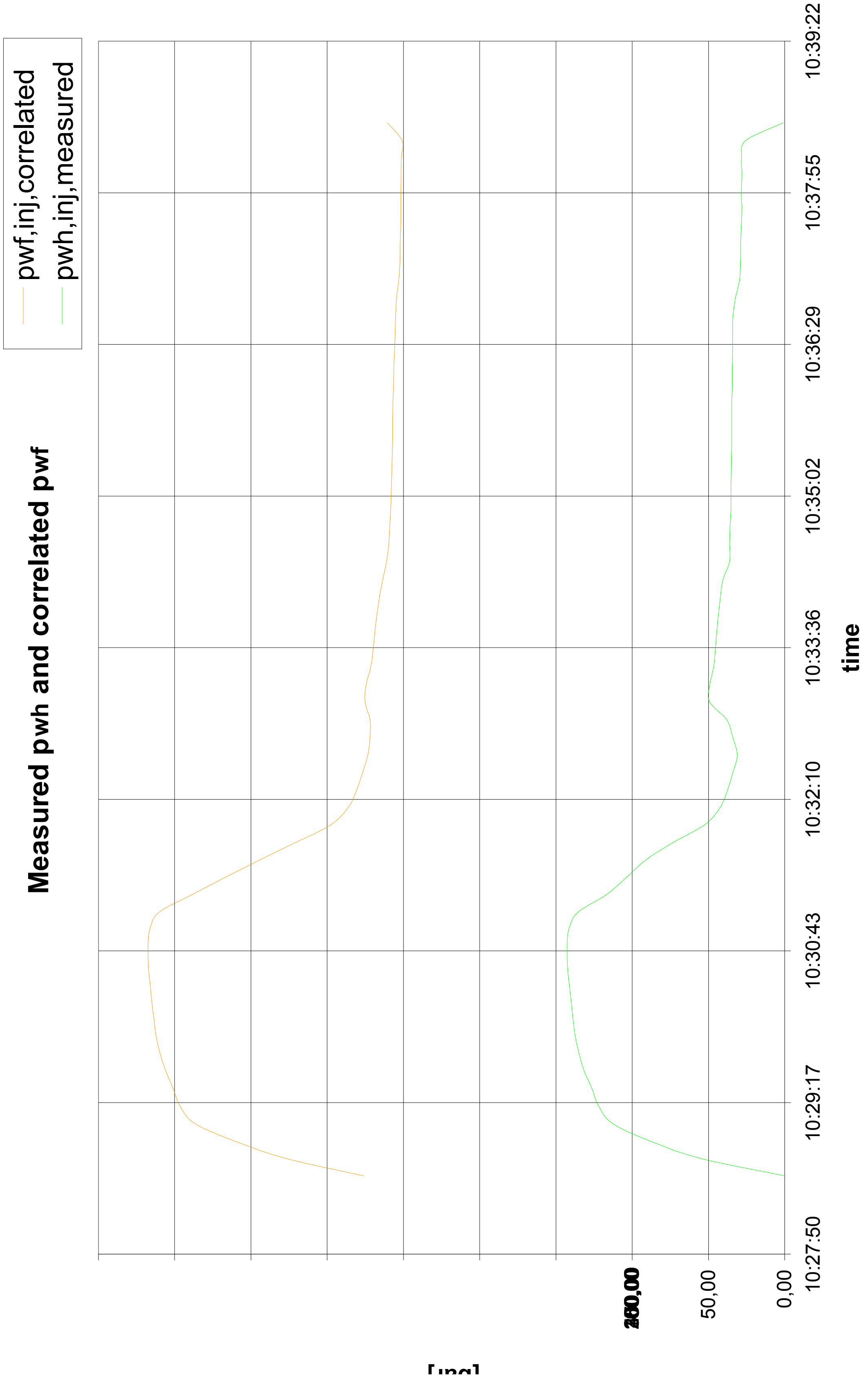

S 179
PI over time
Stimulation,
02.05.1999
0,35
0,3
0,25
0,2
0,15
0,1
0,05
0
Feb.99
Apr.99
Jun.99
Aug.99
Okt.99
Dez.99
Feb.00
Apr.00
Jun.00
Aug.00
Okt.00
Dez.00
Feb.01
Apr.01
Jun.01
Aug.01
Okt.01
Dez.01
Feb.02
Apr.02
Jun.02
Aug.02
Okt.02
Dez.02
Feb.03
Apr.03

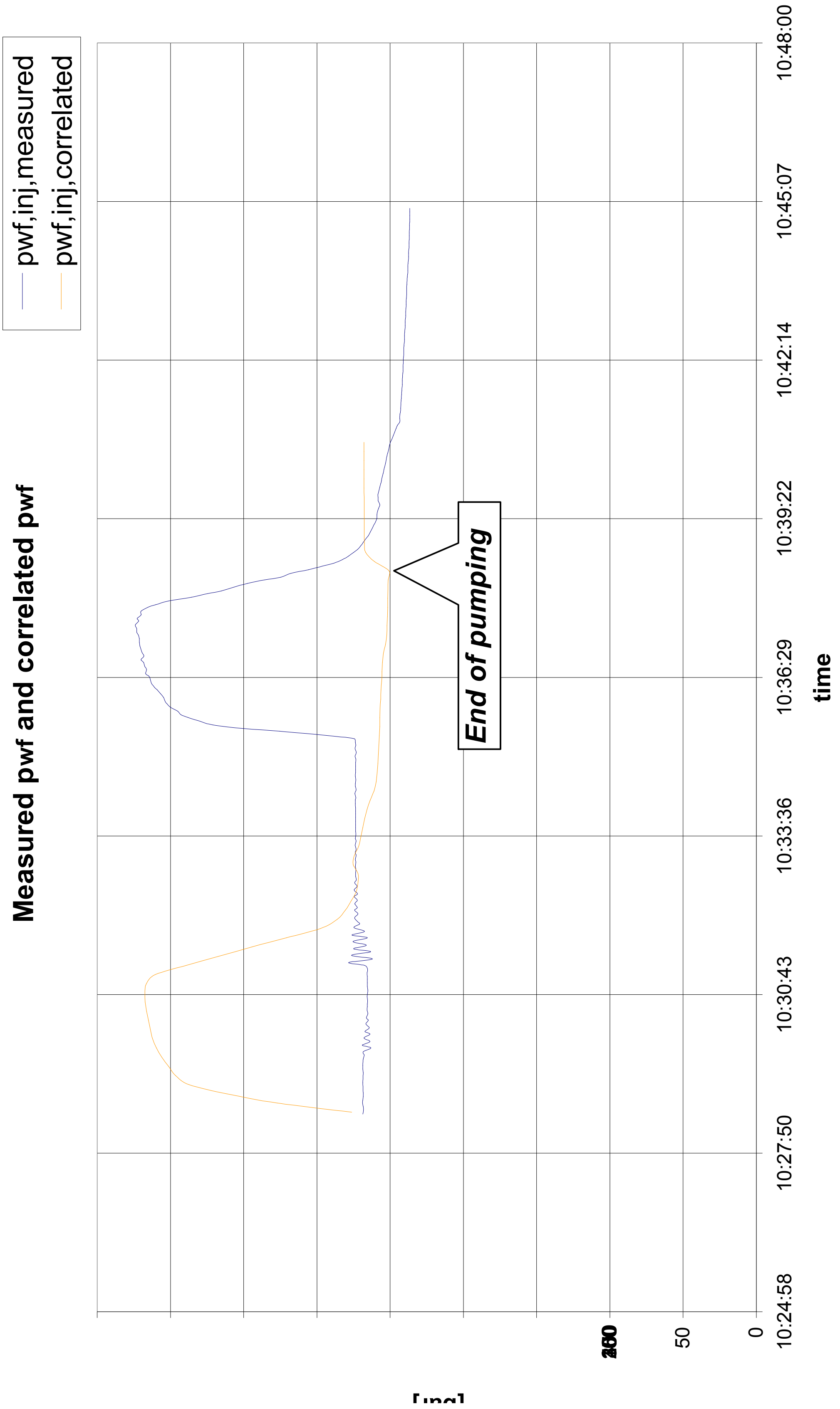

Ma 268
PI over time
Stimulation,
24.04.2001
12
0
Sep.97
Nov.97
Jän.98
Mär.98
Mai.98
Jul.98
Sep.98
Nov.98
Jän.99
Mär.99
Mai.99
Jul.99
Sep.99
Nov.99
Jän.00
Mär.00
Mai.00
Jul.00
Sep.00
Nov.00
Jän.01
Mär.01
Mai.01

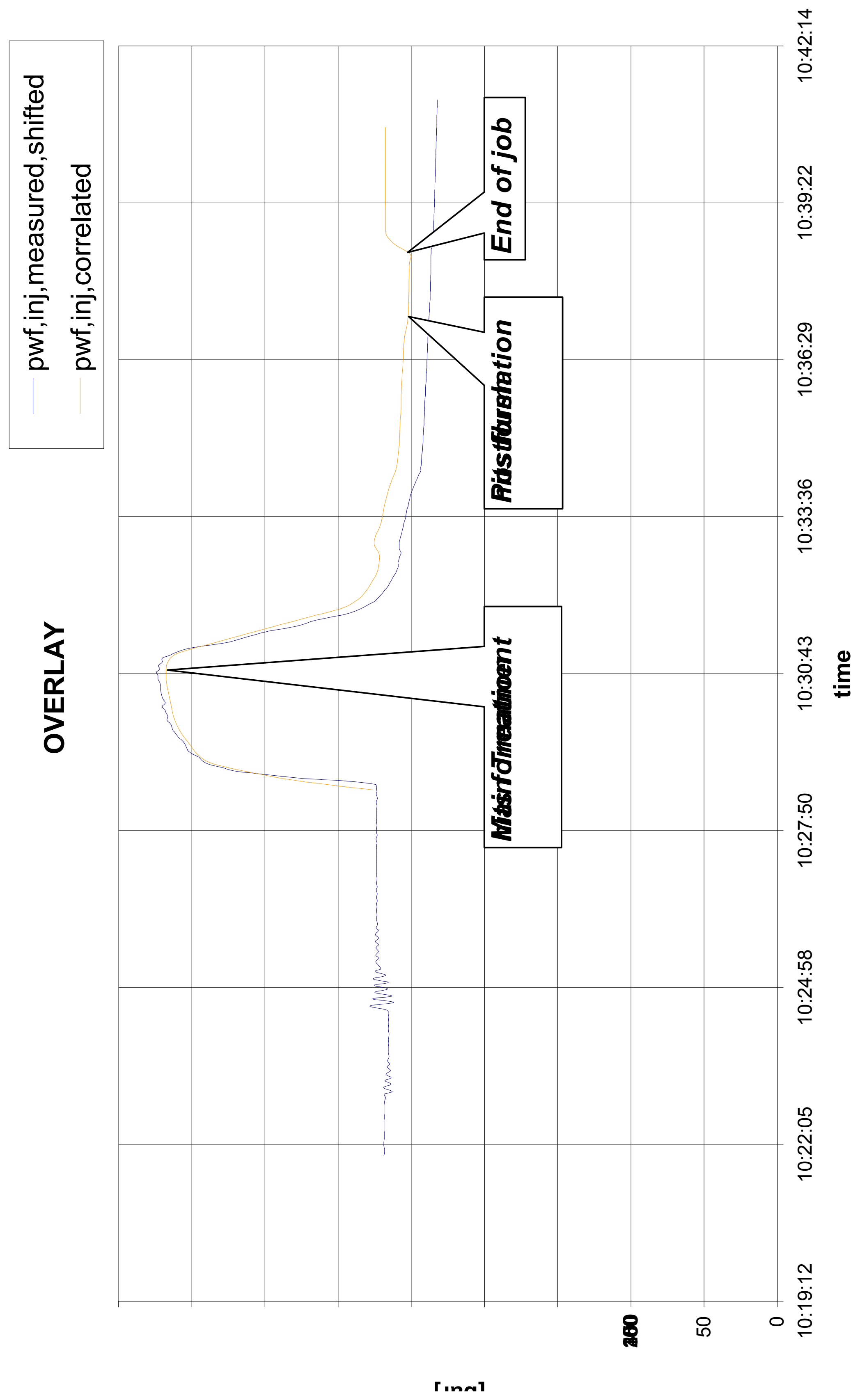
APPENDIX C (EXAMPLE S T 31)

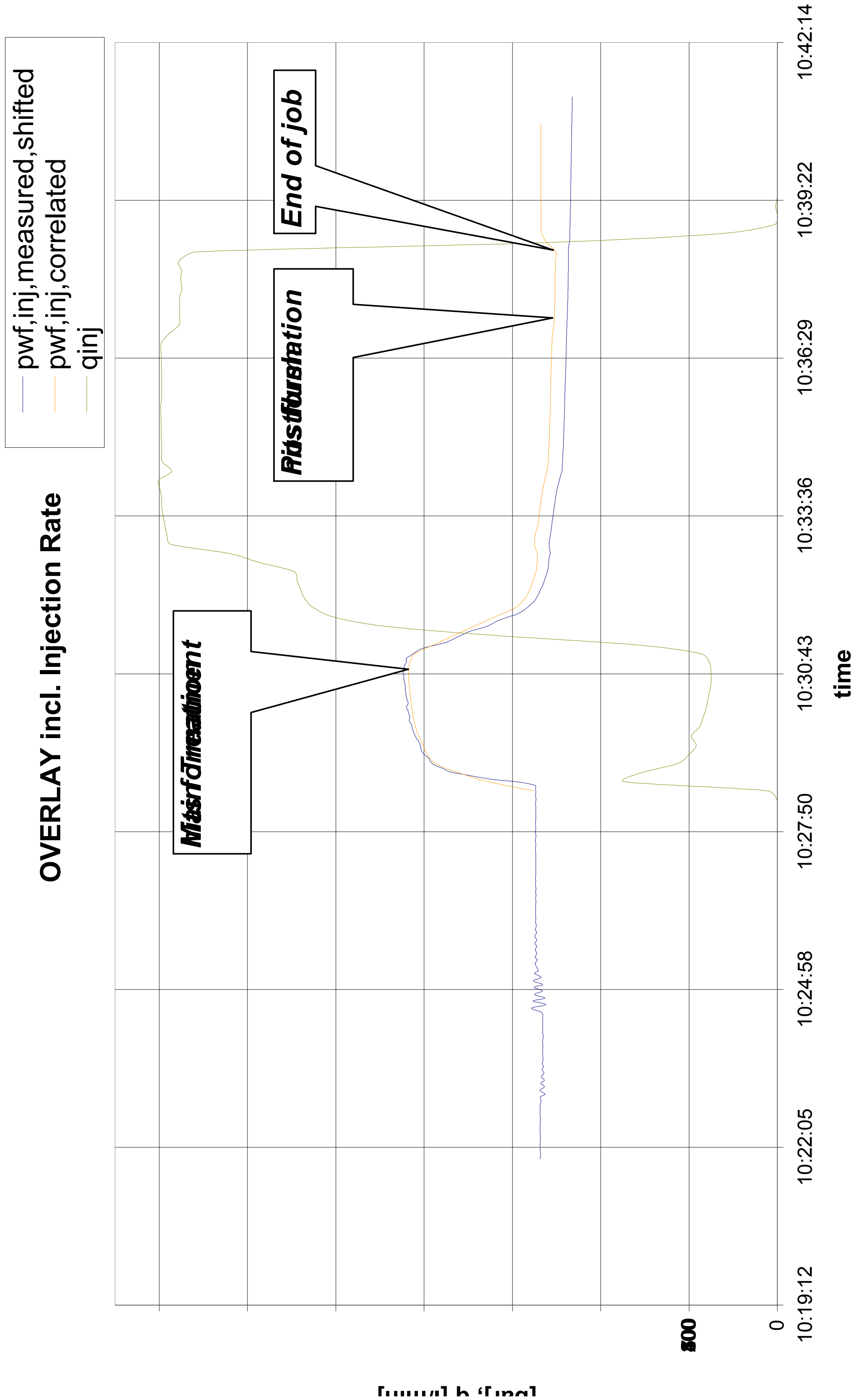


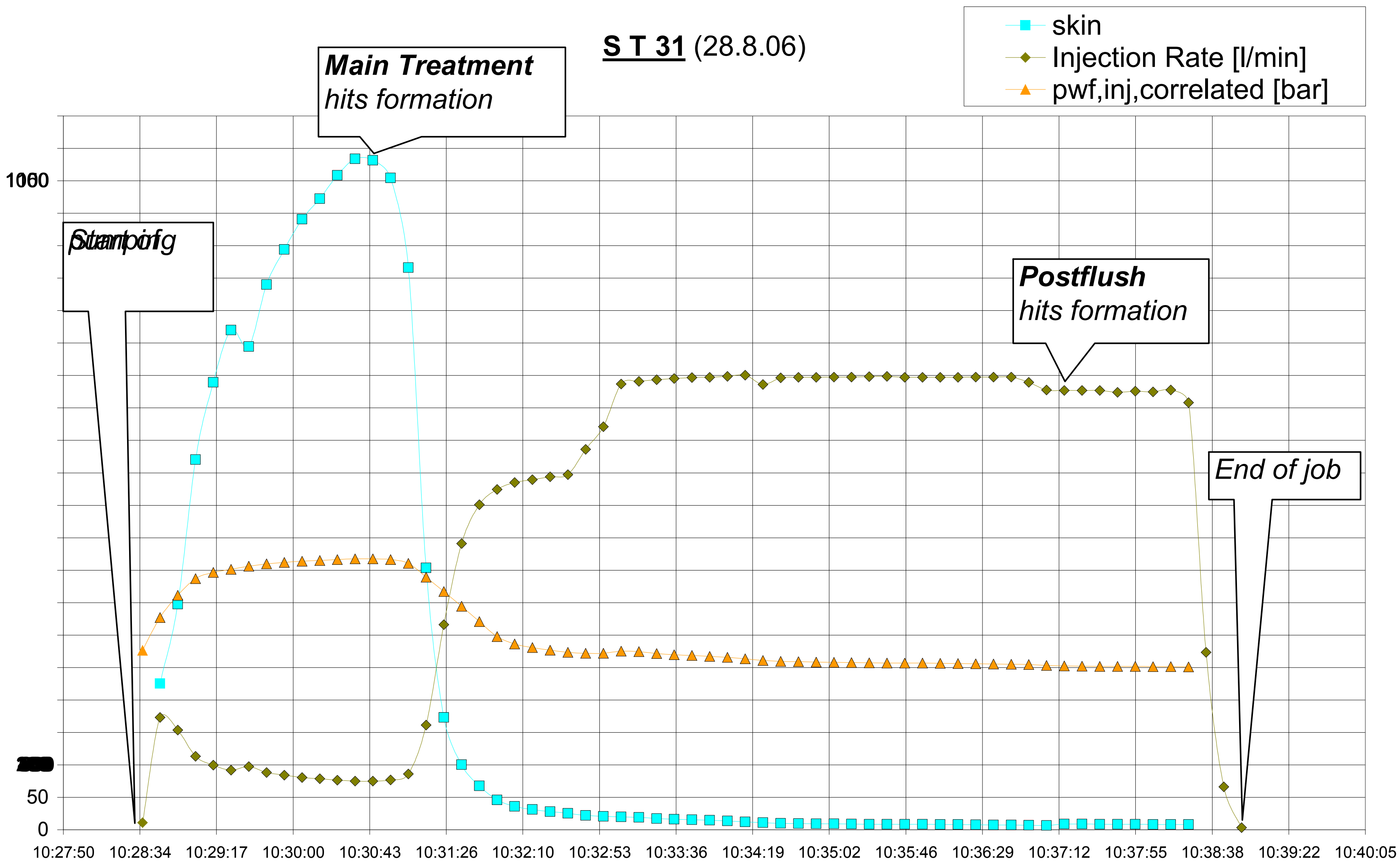

Measured pwh and pwf
pwf,inj,measured
pwh,inj,measured
0
50
time
10:27:50
10:29:17
10:30:43
10:32:10
10:33:36
10:35:02
10:36:29
10:37:55
10:39:22


Measured pwh and correlated pwf
pwf,inj,correlated
pwh,inj,measured
50,00
0,00
10:27:50
10:29:17
10:30:43
10:32:10
10:33:36
10:35:02
10:36:29
10:37:55
10:39:22
time

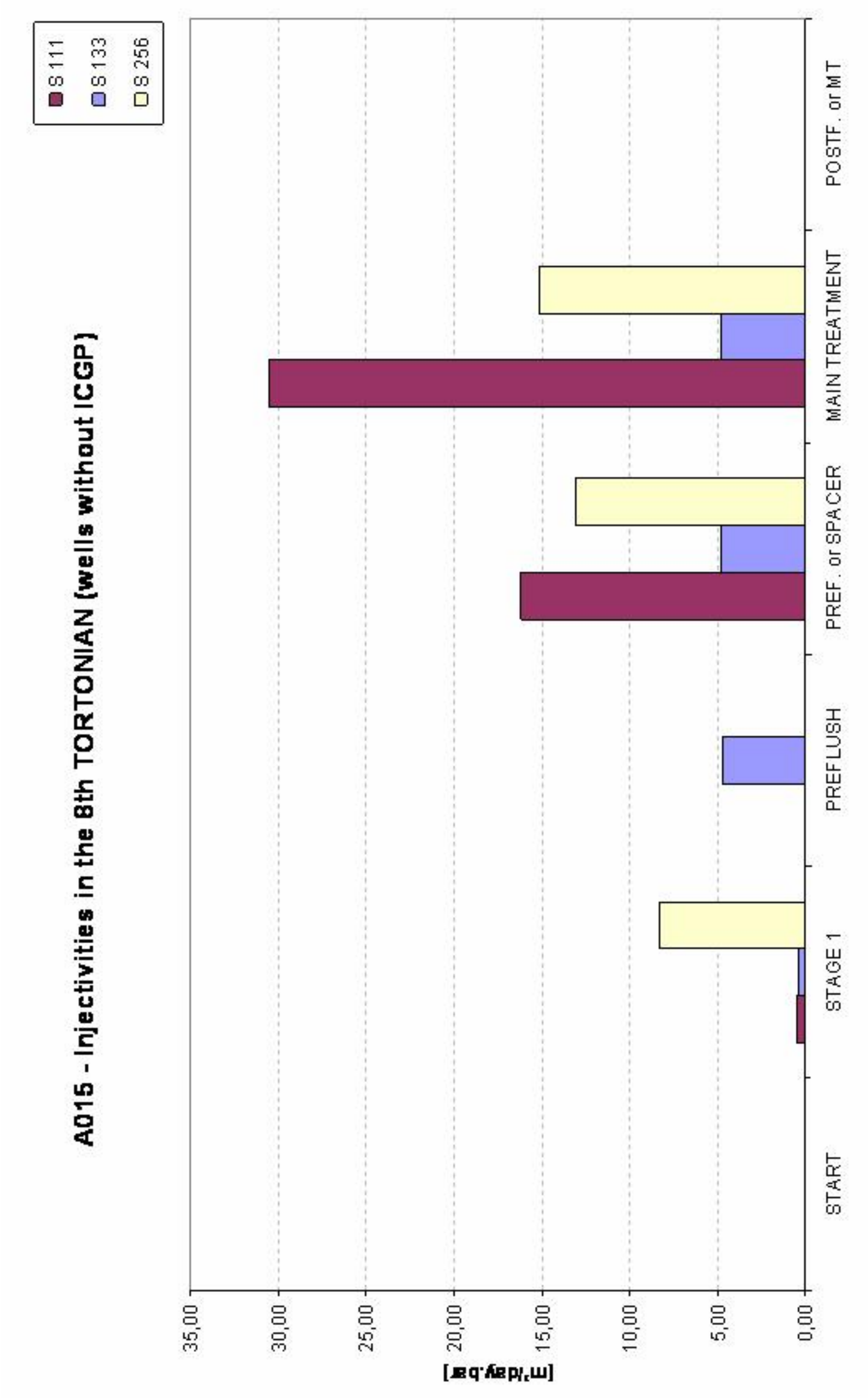

Measured pwf and correlated pwf
pwf,inj,measured
pwf,inj,correlated
End of pumping
time
0
50
10:24:58
10:27:50
10:30:43
10:33:36
10:36:29
10:39:22
10:42:14
10:45:07
10:48:00

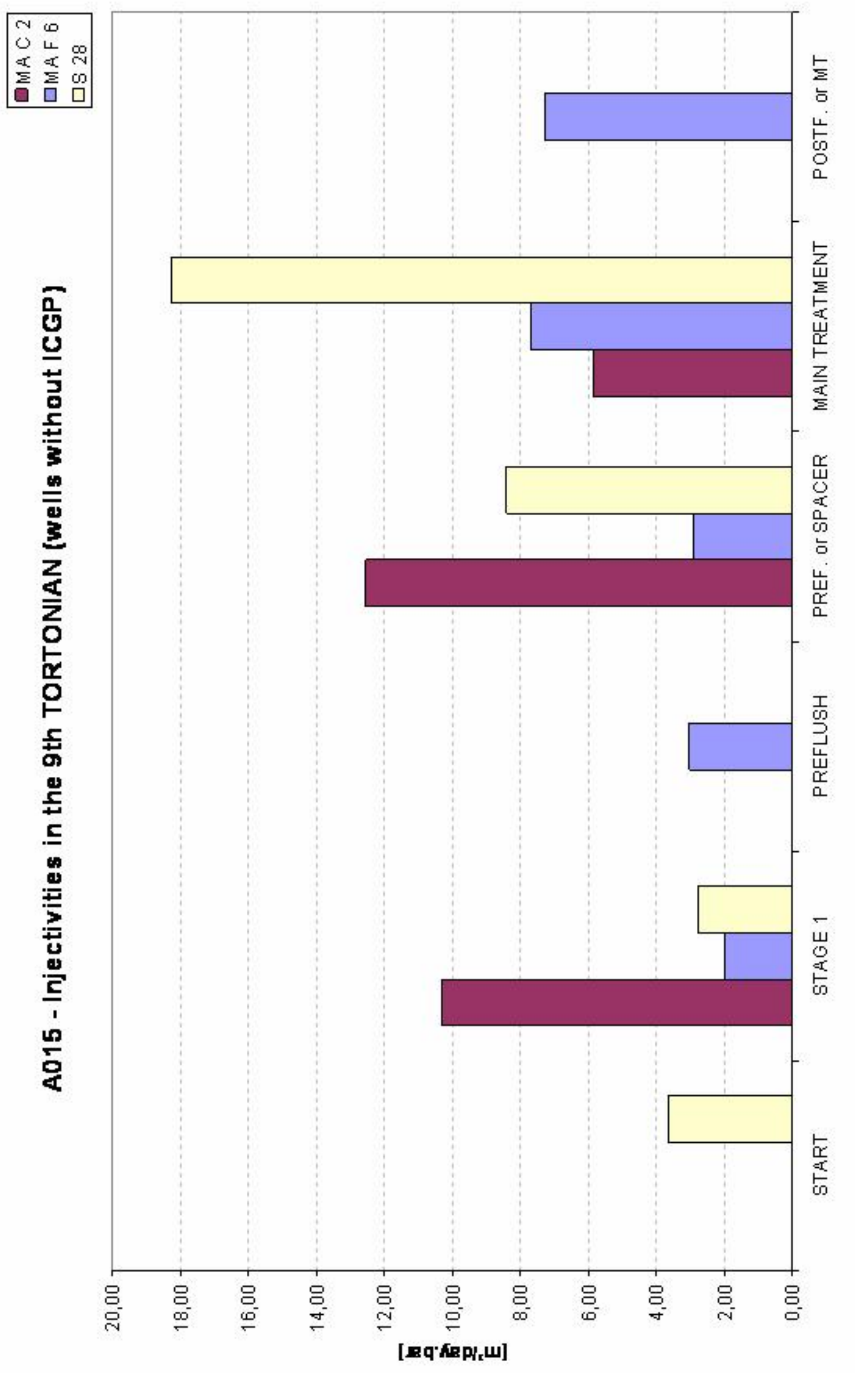

OVERLAY
pwf,inj,measured,shifted
pwf,inj,correlated
End of job
0
50
time
10:19:12
10:22:05
10:24:58
10:27:50
10:30:43
10:33:36
10:36:29
10:39:22
10:42:14

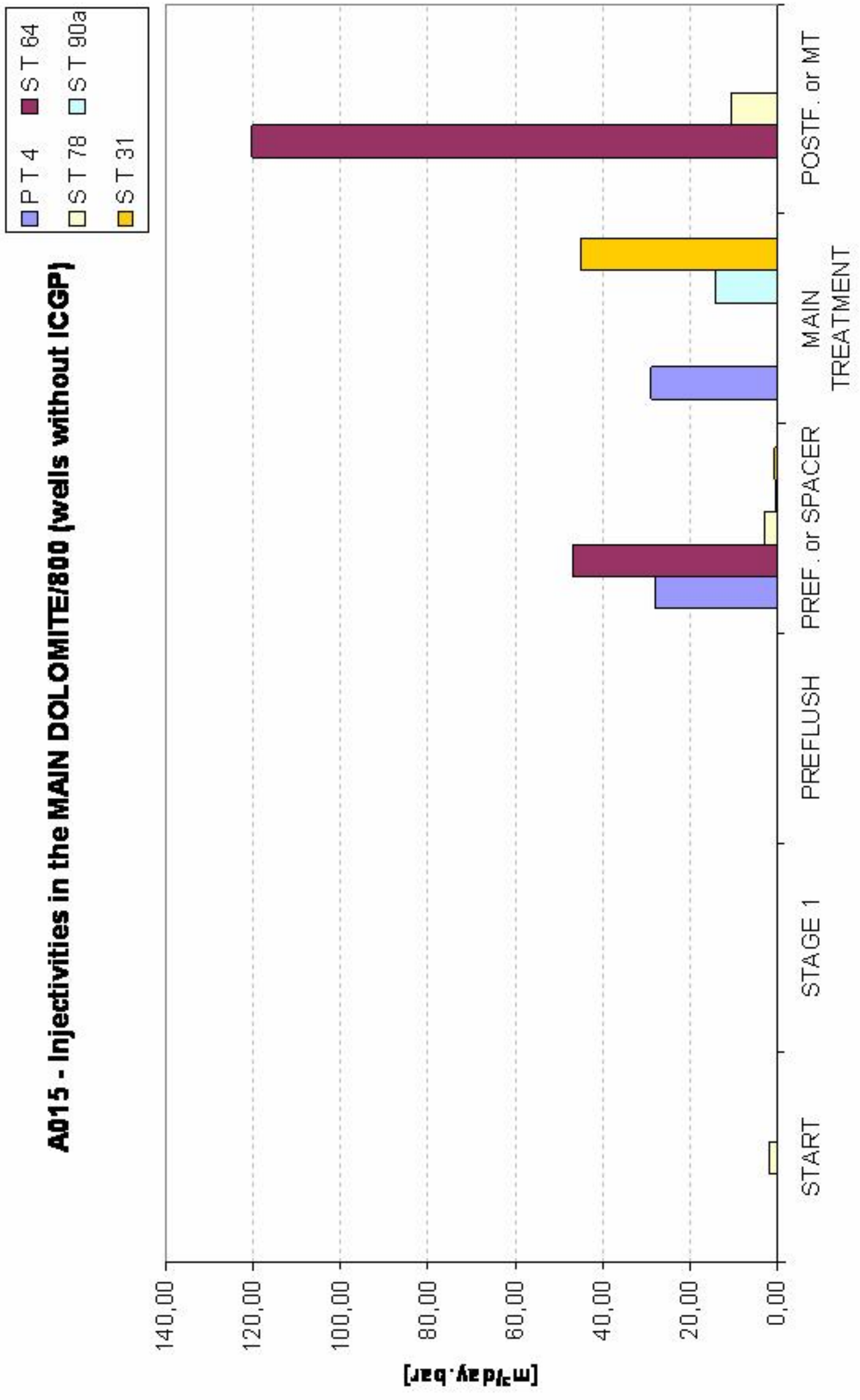

OVERLAY incl. Injection Rate
pwf,inj,measured,shifted
pwf,inj,correlated
qinj
End of job
0
10:19:12
10:22:05
10:24:58
10:27:50
10:30:43
10:33:36
10:36:29
10:39:22
10:42:14
time

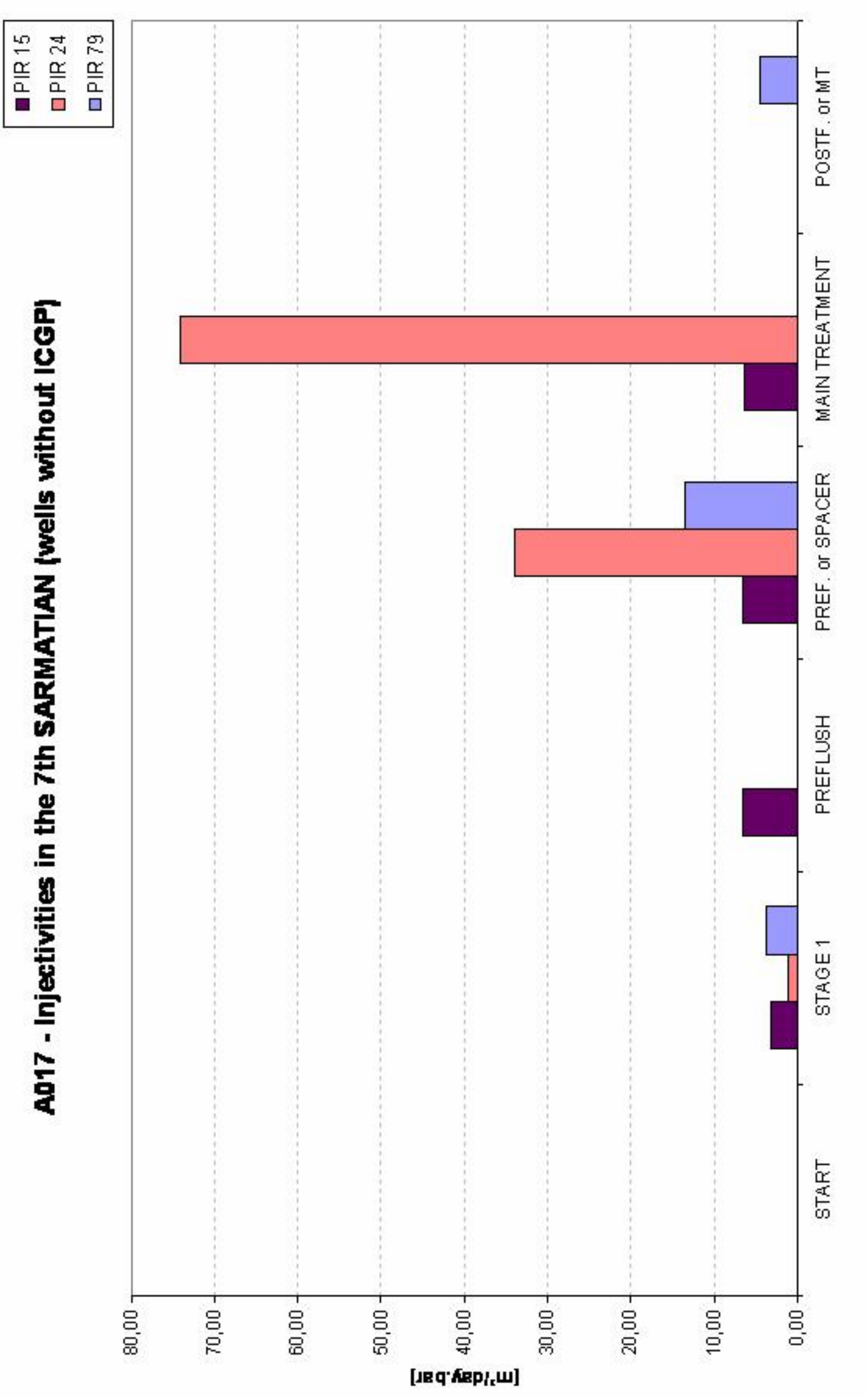

S T 31 (28.8.06)
skin
Injection Rate [l/min]
pwf,inj,correlated [bar]
Main Treatment
hits formation
Start of pumping
Postflush
hits formation
End of job
1060
50
0
10:27:50
10:28:34
10:29:17
10:30:00
10:30:43
10:31:26
10:32:10
10:32:53
10:33:36
10:34:19
10:35:02
10:35:46
10:36:29
10:37:12
10:37:55
10:38:38
10:39:22
10:40:05

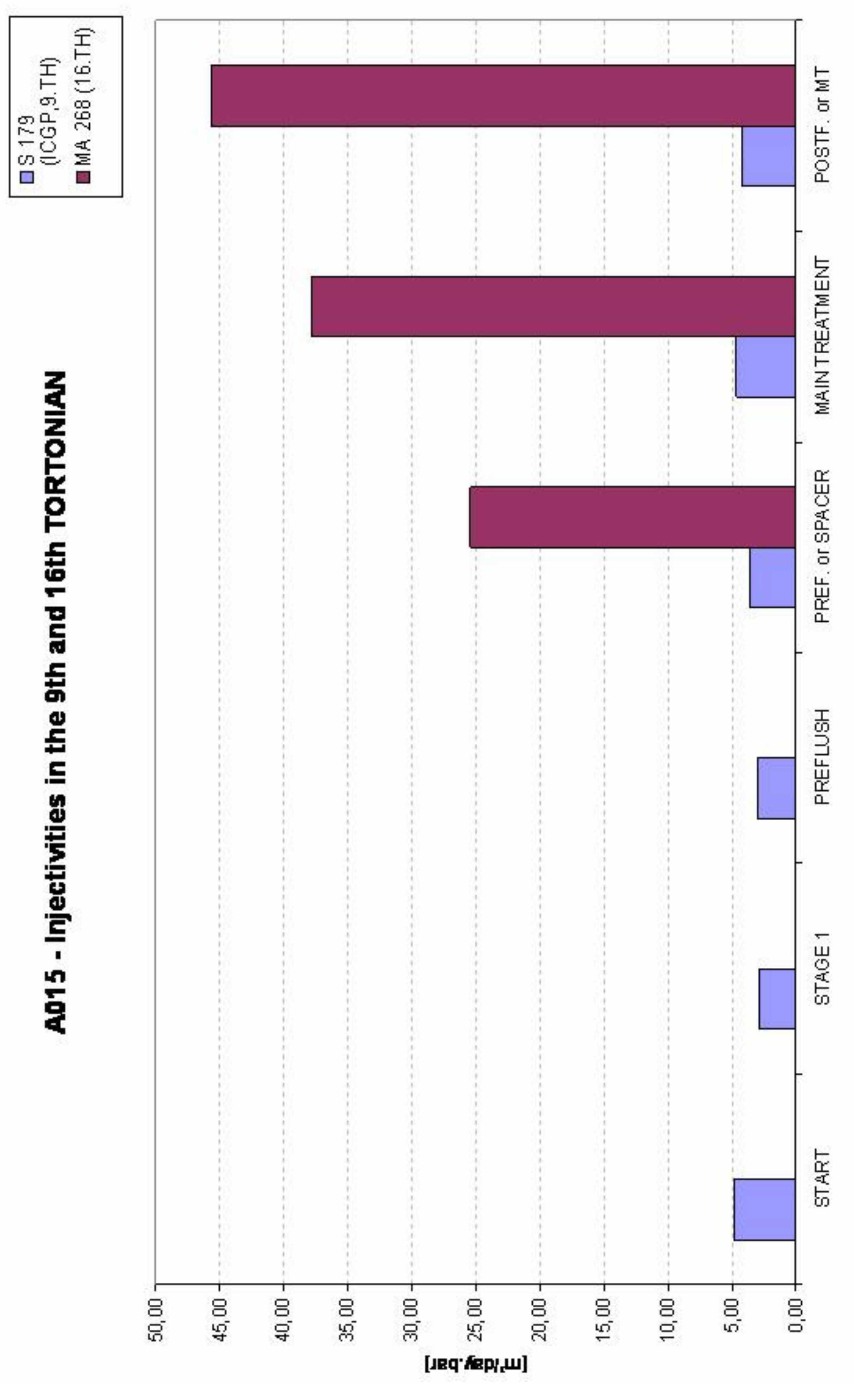
APPENDIX D (INJECTIVITY PROGRESSION)



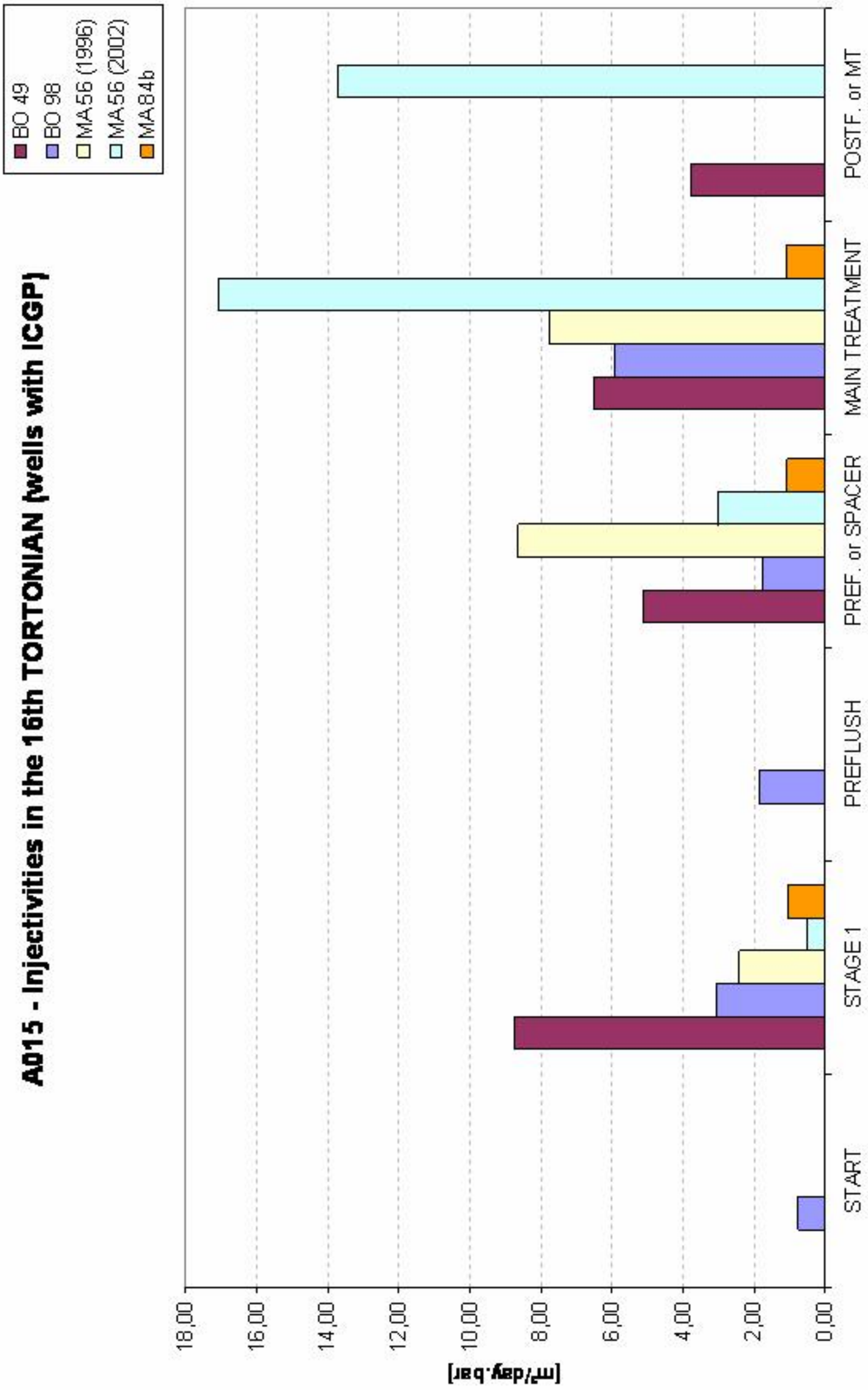

A015 - Injectivities in the 9th TORTONIAN (wells without ICGP)
■ M A C 2
■ M A F 6
□ S 28
[m³/day.bar]
20,00
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
START
STAGE 1
PREFLUSH
PREF. or SPACER
MAIN TREATMENT
POSTF. or MT


A015 - Injectivities in the MAIN DOLOMITE/800 (wells without ICGP)
P T 4
S T 64
S T 78
S T 90a
S T 31
[m³/day.bar]
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
START
STAGE 1
PREFLUSH
PREF. or SPACER
MAIN TREATMENT
POSTF. or MT

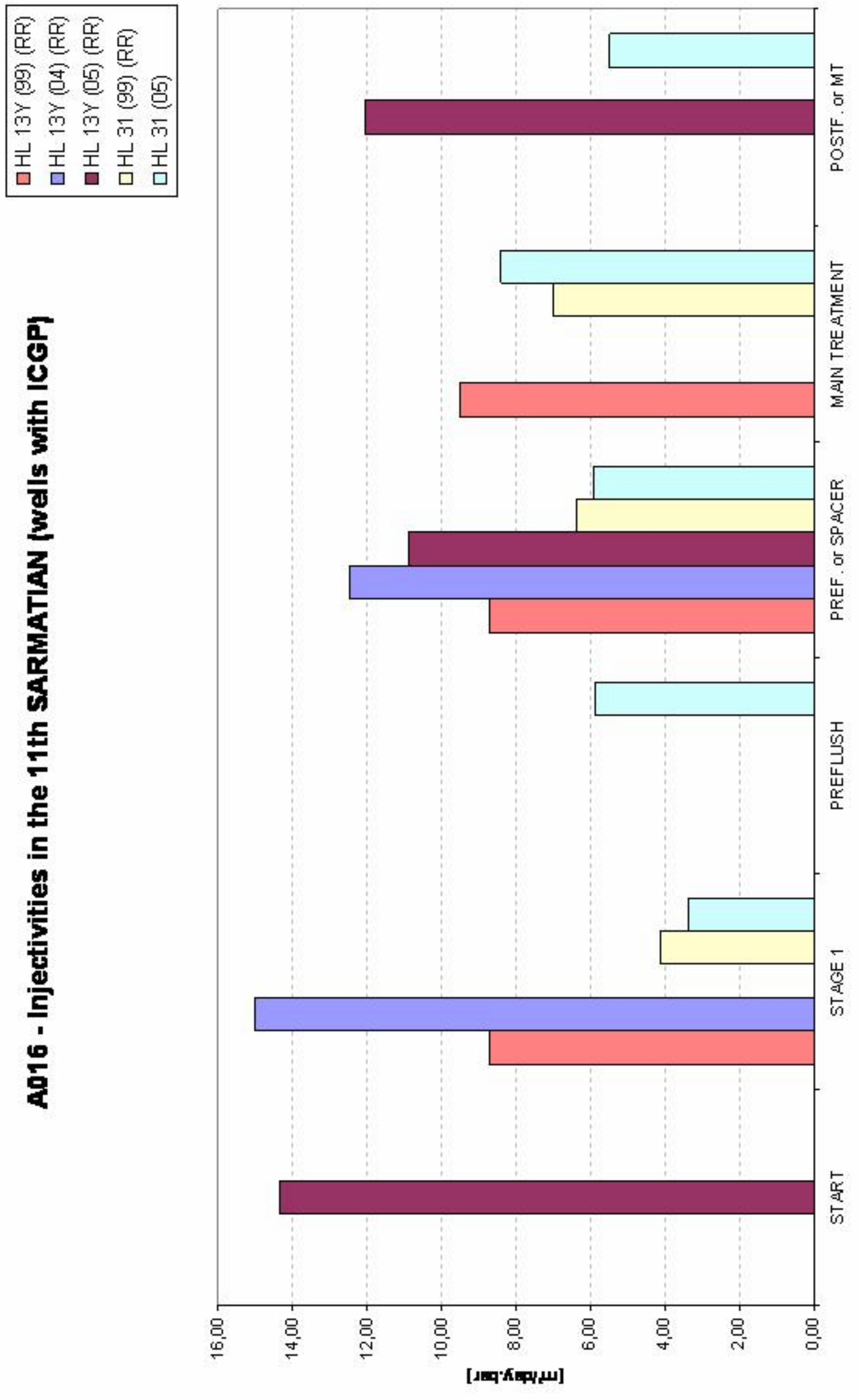

A017 - Injectivities in the 7th SARMATIAN (wells without ICGP)
PIR 15
PIR 24
PIR 79
[m³/day.bar]
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
START
STAGE 1
PREFLUSH
PREF. or SPACER
MAIN TREATMENT
POSTF. or MT

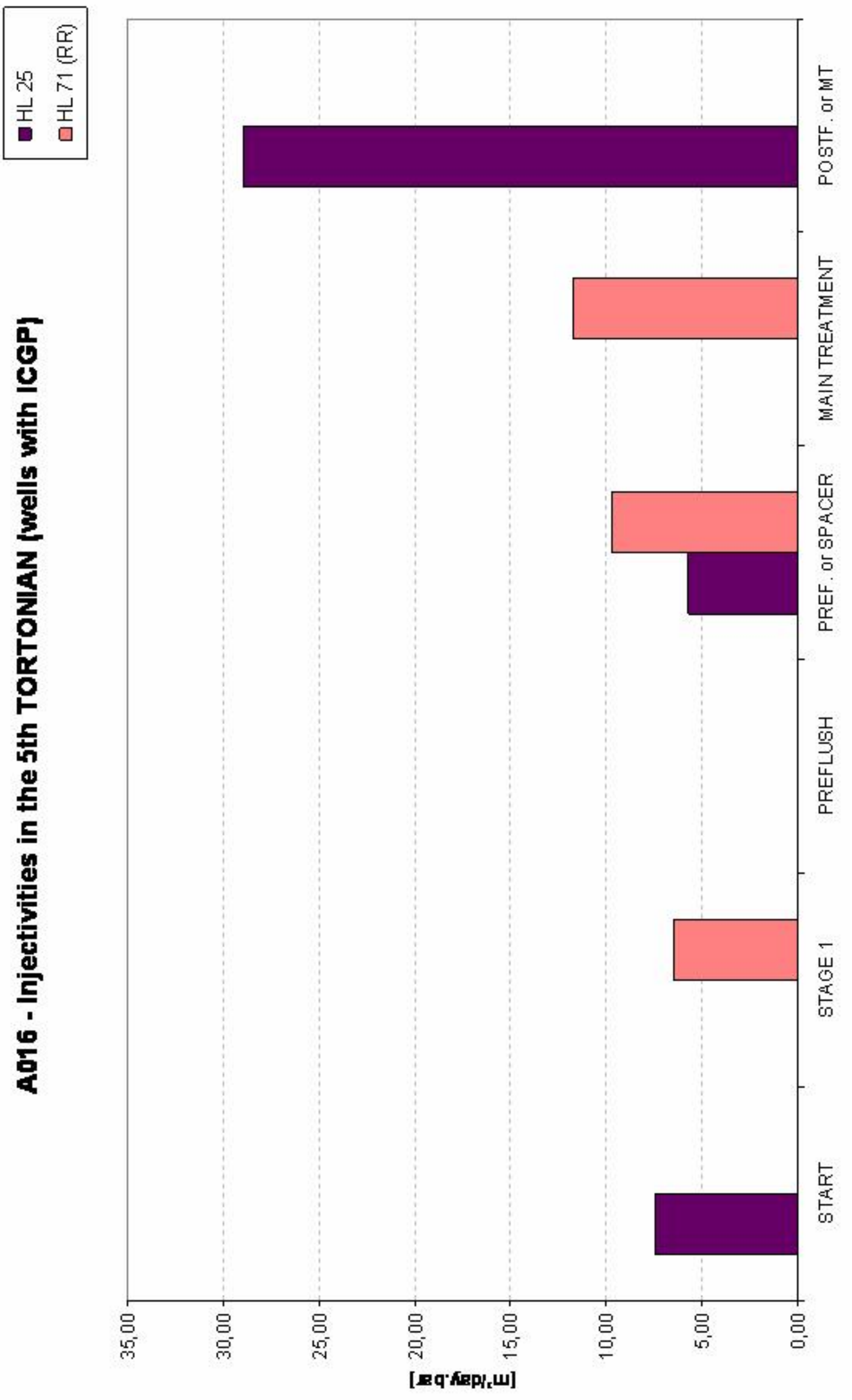


A015 - Injectivities in the 9th and 16th TORTONIAN



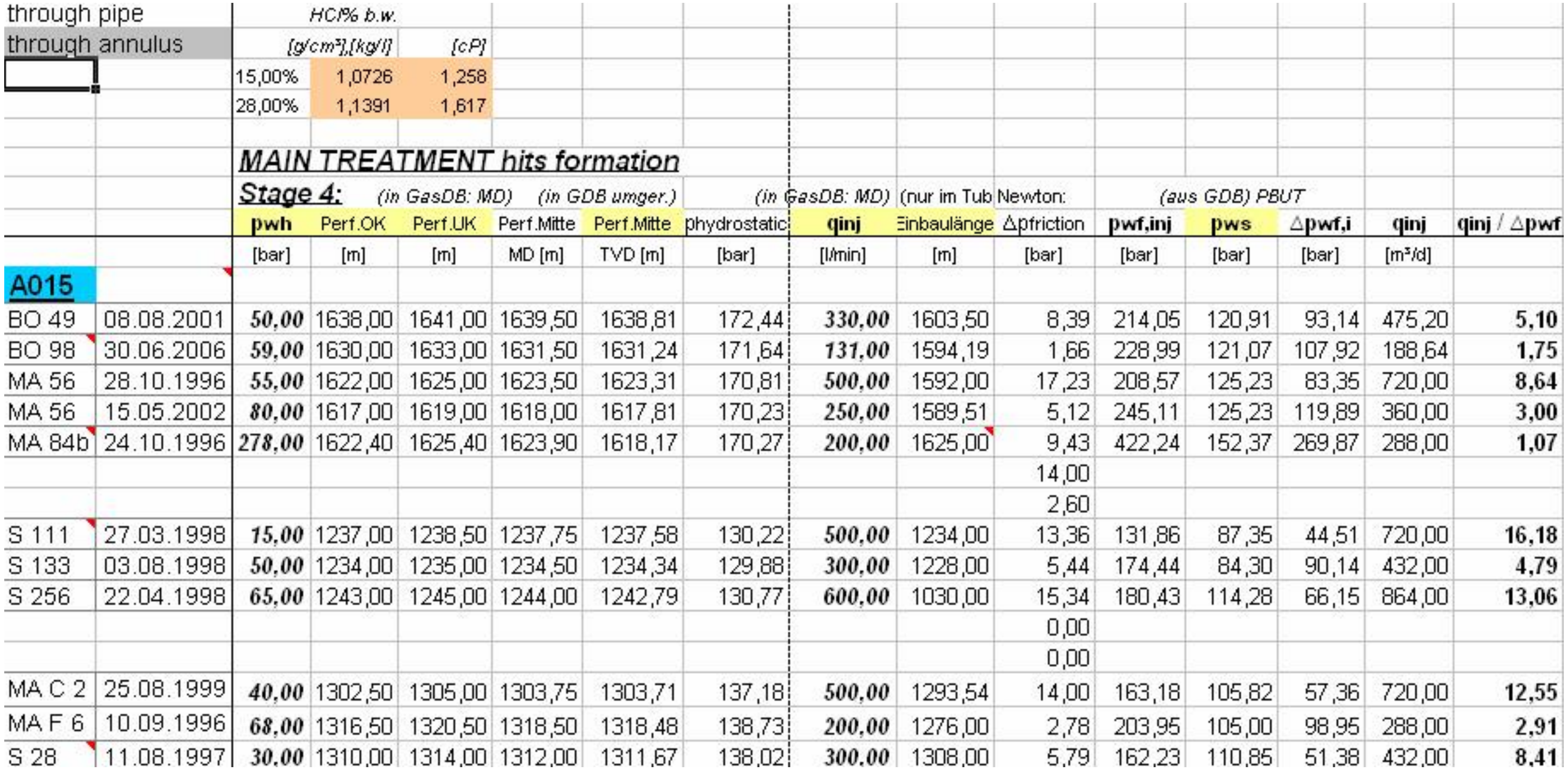
A015 - Injectivities in the 16th TORTONIAN (wells with ICGP)


A016 - Injectivities in the 11th SARMATIAN (wells with ICGP)
HL 13Y (99) (RR)
HL 13Y (04) (RR)
HL 13Y (05) (RR)
HL 31 (99) (RR)
HL 31 (05)
[m³/day.bar]
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
START
STAGE 1
PREFLUSH
PREF. or SPACER
MAIN TREATMENT
POSTF. or MT


A016 - Injectivities in the 5th TORTONIAN (wells with ICGP)
■ HL 25
■ HL 71 (RR)
[m³/day.bar]
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
START
STAGE 1
PREFLUSH
PREF. or SPACER
MAIN TREATMENT
POSTF. or MT

APPENDIX E (CALCULATION SAMPLES)

									Dichte	aus TAPRO										
									[kg/l]											
		WELL TESTS				SPIEGELMESSUNGEN			0,99	0,921	0,836	0,92	0,906	0,905	0,871					
		pws	pwf	q	PI	DATUM	DYNSP	BRUTTO	STATSP	CASINGD	TUBSPI	TUBD	TVD	L,tub	p,hyd,an	p,hyd,cas	Pwf	p,hydr	p,ws	PI
A016	Säuerung am				[m³/day.bar]															
HL 13Y	27.05.1999	67,6	12,8	2,9	0,05	28.08.2006	951	6,46		2		3	1009,96	960	0,81	4,856921	7,67			0,11
HL 13Y	01.07.2004	65,4	7,6	7,3	0,13	30.08.2005	812	20,29		5		4			13,37	4,856921	23,22			0,46
HL 13Y	20.04.2005	50,79	4,9	23	0,50	09.08.2005		0	347	1		3						64,386	65,39	
		63,5	9,3	10	0,18	03.06.2005		0	335	2		2						65,551	67,55	
						06.04.2005	914	2,32		3		4			4,15	4,856921	12,01			0,04
						20.10.2004		12	472	10		9						52,246	62,25	
						27.09.2004	953	7,66		3		12			0,63	4,856921	8,48			0,13
						27.09.2004	960	7,66		4		5			0,00	4,856921	8,85			0,13
						12.07.2004		0	820	10		12						18,449	28,45	
						09.07.2004		0	879	7		13						12,719	19,72	
						07.07.2004		0	933	4		11						7,4743	11,47	
						06.07.2004	960	0		2		2			0,00	4,856921	6,85			
						13.08.2003	951	16,73		3		5			0,81	4,856921	8,67			0,28
						14.07.2003	792	25,1		3		3			15,17	4,856921	23,03			0,56
						10.12.2002	966	0		5		3				4,269351	9,27			
						18.09.2002	949	23,42		4					0,99	4,856921	9,85			0,41
						20.12.2001	854	24,19		4					9,57	4,856921	18,43			0,49
						08.01.2001	968	7,34		6						4,075113	10,08			0,13
						30.05.2000	967	19,71		5						4,172232	9,17			0,34
						07.06.1999	967	19,1		18						4,172232	22,17			0,42
						02.06.1999	876	24,6		14					7,58	4,856921	26,44			0,60
						03.03.1999	967	4,2		1						4,172232	5,17			0,07
						23.11.1998	967	7,8		11						4,172232	15,17			0,15



through pipe		HCl% b.w.													
through annulus			[g/cm³],[kg/l]	[cP]											
		15,00%	1,0726	1,258											
		28,00%	1,1391	1,617											
		MAIN TREATMENT hits formation													
		Stage 4:	*(in GasDB: MD)*		*(in GDB umger.)*		*(in GasDB: MD)*		(nur im Tub	Newton:		*(aus GDB) PBUT*			
		pwh	Perf.OK	Perf.UK	Perf.Mitte	Perf.Mitte	phydrostatic	**qinj**	Einbaulänge	Δpfriction	**pwf,inj**	**pws**	**Δpwf,i**	**qinj**	**qinj / Δpwf**
		[bar]	[m]	[m]	MD [m]	TVD [m]	[bar]	[l/min]	[m]	[bar]	[bar]	[bar]	[bar]	[m³/d]	
A015															
BO 49	08.08.2001	***50,00***	1638,00	1641,00	1639,50	1638,81	172,44	***330,00***	1603,50	8,39	214,05	120,91	93,14	475,20	**5,10**
BO 98	30.06.2006	***59,00***	1630,00	1633,00	1631,50	1631,24	171,64	***131,00***	1594,19	1,66	228,99	121,07	107,92	188,64	**1,75**
MA 56	28.10.1996	***55,00***	1622,00	1625,00	1623,50	1623,31	170,81	***500,00***	1592,00	17,23	208,57	125,23	83,35	720,00	**8,64**
MA 56	15.05.2002	***80,00***	1617,00	1619,00	1618,00	1617,81	170,23	***250,00***	1589,51	5,12	245,11	125,23	119,89	360,00	**3,00**
MA 84b	24.10.1996	***278,00***	1622,40	1625,40	1623,90	1618,17	170,27	***200,00***	1625,00	9,43	422,24	152,37	269,87	288,00	**1,07**
										14,00					
										2,60					
S 111	27.03.1998	***15,00***	1237,00	1238,50	1237,75	1237,58	130,22	***500,00***	1234,00	13,36	131,86	87,35	44,51	720,00	**16,18**
S 133	03.08.1998	***50,00***	1234,00	1235,00	1234,50	1234,34	129,88	***300,00***	1228,00	5,44	174,44	84,30	90,14	432,00	**4,79**
S 256	22.04.1998	***65,00***	1243,00	1245,00	1244,00	1242,79	130,77	***600,00***	1030,00	15,34	180,43	114,28	66,15	864,00	**13,06**
										0,00					
										0,00					
MA C 2	25.08.1999	***40,00***	1302,50	1305,00	1303,75	1303,71	137,18	***500,00***	1293,54	14,00	163,18	105,82	57,36	720,00	**12,55**
MA F 6	10.09.1996	***68,00***	1316,50	1320,50	1318,50	1318,48	138,73	***200,00***	1276,00	2,78	203,95	105,00	98,95	288,00	**2,91**
S 28	11.08.1997	***30,00***	1310,00	1314,00	1312,00	1311,67	138,02	***300,00***	1308,00	5,79	162,23	110,85	51,38	432,00	**8,41**