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? **Technical Note**

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Attached documents	none

Summary - Conclusion

The polymer flood pilot production history has been matched up to end 2005, through a thorough search for the main uncertainties related to the reservoir description, namely relative permeability to oil and water, rock compressibility and absolute permeability. History matching could not be obtained by simply modifying relative permeability curves. On the contrary, it was obtained by fitting the rock compressibility (unconsolidated formation) and absolute permeability. A more precise matching of the relative permeability curves will be possible after water breakthrough, which is not yet the case. This note provides a detailed description of the matching procedure.

A predictive run using the matched parameters and the default relative permeability curves gives some indication that the maximum allowable WHP in the injectors (7600 kPa) could be reached at the end of 2006 and water breakthrough could occur at the beginning of 2006.

1. Background of the study

This document summarizes the work undertaken since the last meeting that took place between IFP and CNRL at the CNRL offices in Calgary (November 4, 2005).

The main purpose of the work was the matching of the WHP in injectors during the polymer injection in the polymer pilot. The observed WHP has a pseudo-linear increase ever since the polymer has been injected and could be attributed to:

1. A pure polymer effect, i.e. the reduction in permeability (Rk) and mobility (Rm) due the viscosity of the polymer flowing in the reservoir. However, it appears that the modification of the polymer concentration during the operations had no influence whatsoever on the WHP evolution.

2. A little bit overestimation of some permeability values used in the initial simulations as mentioned by CNRL,

3. A relative permeability (Kr) effect as evoked by CNRL,

4. A rock compressibility effect,

5. A clay swelling effect, the Grand Rapids water used for the injection of polymer having a relatively low salinity (3 g/L TDS). This could lead to clay swelling and fines mobilization which can damage the formation and induce the WHP increase at the injector,

6. A degradation/complexation of the polymer due to a reaction involving the iron of the completion with the oxygen contained in the injected solutions, which could result in an increasing skin effect at the injectors.

It was necessary to prioritize the hypotheses mentioned above and clarify the different options.
Concerning the mobility and permeability reductions (assumption 1), the input data for reservoir simulations are not modified and are the results of laboratory experiments conducted in 2004-2005.

Assumptions 5 and 6 were not investigated in the present study.
- Referring to the clay swelling effect (assumption 5), laboratory results (IFP Report 58650, May 2005) showed no significant clay de-stabilisation even with Fresh Water. The permeability was found to decrease by a maximum value of 6% at the end of the softest water injection (Tertiary Gravel).
- Concerning the integrity of the polymer injected (assumption 6), the similar evolution of the WHP in the two injecting wells does not suggest, *a priori*, a polymer degradation/complexation with iron/O_2. However, although we did not take this assumption 5 into account in this sensitivity study, this phenomenon should not be completely discarded.

In order to have a consistent approach, the main uncertain parameters (assumptions 2 and 3) have been reviewed and integrated into a history matching methodology. The principles and workflow are briefly explained in the next paragraphs before the presentation of the current results.

2. Uncertainty management

A few parameters have been identified as uncertain from the previous work and the general knowledge of the field. When there are many uncertain parameters which could lead to a high variability in the results, it is better to have a consistent approach for history matching, rather than just a trial and error method. Therefore, we used an assisted history matching tool (Condor, a software developed by IFP).

The method is based on the calculation of the gradients of the uncertain parameters, integrated into an objective function to be minimized. The objective function is typically the difference between the field production rates and the simulated rates.

These parameters are ordered by increasing degree of uncertainty, which means that the flexibility in modifying the value of the parameter increases:

- Absolute permeability of the layers (Top Bar Complex, Bar Complex Good Pay, Bar Margin)
- Relative permeability curves
- Rock compressibility. The rock compressibility used in the simulator is a global parameter taking into account the fluids which saturate the rock.

The rock compressibility is the most uncertain parameter for two reasons:
- The produced oil is a foamy oil, whose flow properties are not well known.
- The reservoir rock is unconsolidated. This introduces a high difficulty, hence uncertainty in the measurement of rock compressibility. According to IFP specialists, a ten fold variation is possible.

However, it is necessary to define a reasonable range of variation of the uncertain parameters that is permitted during the history matching process. If a matching is obtained by modifying a parameter to a value which is outside the reasonable range, it could be concluded that that parameter is not relevant for the matching and the solution lies elsewhere.

The parameters need to be continuous variables in order to modify their values. For the absolute permeability and rock compressibility, the values can be modified directly. For the relative permeability curves, they are approximated by an analytical function. This is done with a Corey function, which is a power function whose shape is entirely determined by the exponents Nw and No, as shown below.

$$Krw = \left(Sw_{normalized}\right)^{Nw} \qquad Kro = \left(1 - Sw_{normalized}\right)^{No} \qquad \text{with} \qquad Sw_{normalized} = \frac{S_w - S_{wi}}{1 - S_{orw} - S_{wi}}$$

The values that will be modified during the history matching are the exponents Nw and/or No. The larger the exponent, the more convex the curves are, as shown in the example (**Figure 1**). The linear curves correspond to Nw and No equal to 1.

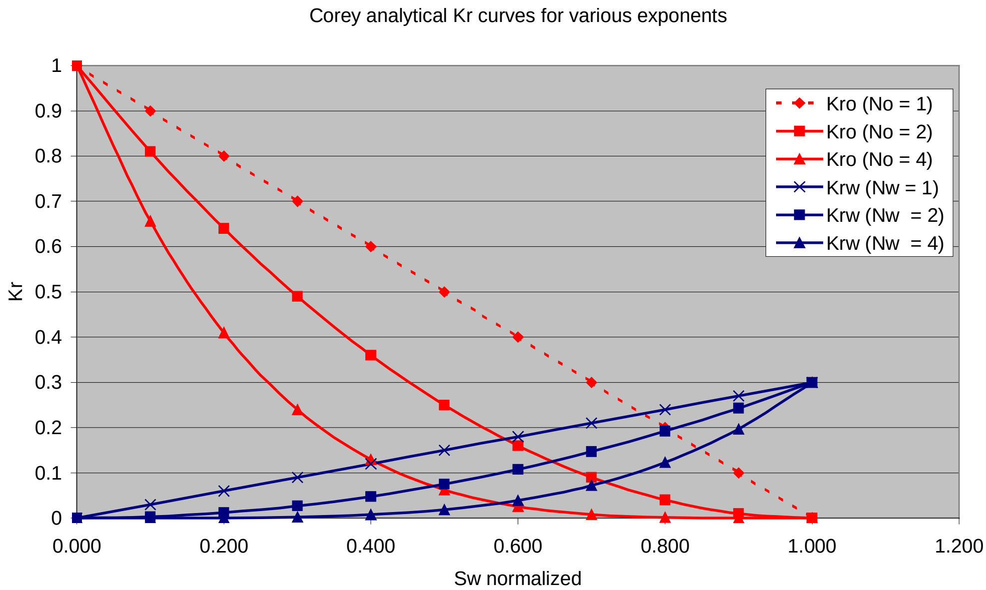

Figure 1: Parametrization of Kr curves by Corey functions

3. Polymer flood pilot

3.1 Presentation of the case

3.1.1 Geometry

The pilot simulation model is made of the 3 layers as shown in **Figure 2** with the petrophysical parameters in **Table 1**. The field is produced through 5 production wells during the primary production: 00-14, 00-15, 00-16, 02-15 and 02-16. During the polymer injection phase, two of them are transformed into injection wells: 02-15 and 02-16. The names used in the simulation have been simplified. The link with the actual official names is shown in **Table 2**.

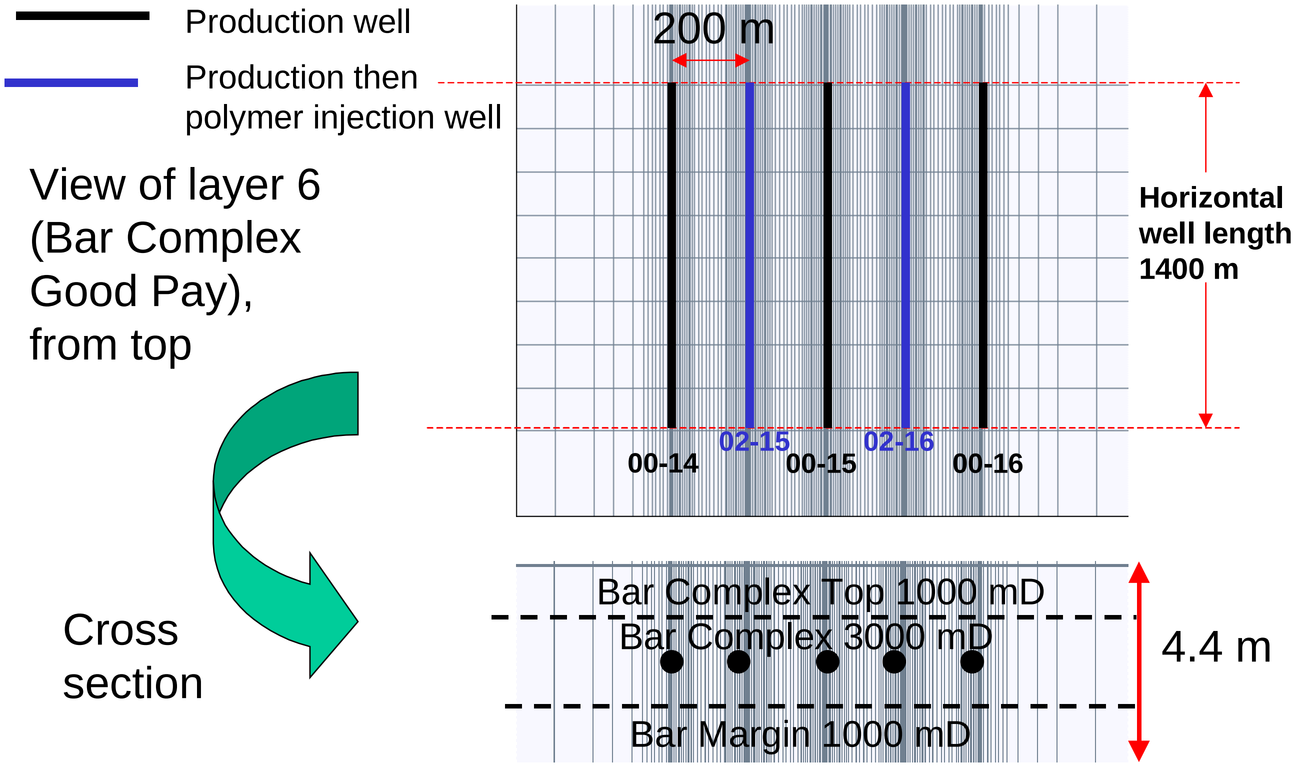

Figure 2: Polymer flood model

Table 1: Petrophysical properties of the formation

	Thickness (m)	Porosity	Permeability Kh (mD)	Permeability Kz (mD)
Bar Complex Top	0.8	0.28	1000	300
Bar Complex Good Pay	2.4	0.33	3000	1500
Bar Margin	1.2	0.34	1000	100

3.1.2 Wells and production history

Table 2: Well names used in the simulation

simplified well name	official name	status	well_name
00-14	00/14-34-081-22W4/0	Heavy oil prod	P6 14-34-81-22W4
02-15	02/15-34-081-22W4/0	Heavy oil prod then water injector	P6 15C-34-81-22W4
00-15	00/15-34-081-22W4/0	Heavy oil prod	P6 15-34-81-22W4
02-16	02/16-34-081-22W4/0	Heavy oil prod then water injector	P6 16C-34-81-22W4
00-16	00/16-34-081-22W4/0	Heavy oil prod	P6 16-34-81-22W4

The production data history available is summarized in the **Table 3** and **Table 4** below:

Table 3: Primary production period

Well name	Simplified well name	Status	Item	Period covered
00/14-34-081-22W4/0	00-14	PROD	oil, gas, water of wells	1st March 1997 - 30 April 2004
02/15-34-081-22W4/0	00-15	PROD	oil, gas, water of wells	1st March 1997 - 30 April 2004
00/15-34-081-22W4/0	00-15	PROD	oil, gas, water of wells	1st March 1997 - 30 April 2004
02/16-34-081-22W4/0	02-15	PROD	oil, gas, water of wells	1st March 1997 - 30 April 2004
00/16-34-081-22W4/0	02-16	PROD	oil, gas, water of wells	1st March 1997 - 30 April 2004

Table 4: Polymer injection period

Well name	Simplified well name	Status	Item	Period covered
00/14-34-081-22W4/0	00-14	PROD	oil, gas, water of wells	30 June 2005- 8 Sep 2005
02/15-34-081-22W4/0	00-15	PROD	oil, gas, water of wells	30 June 2005- 8 Sep 2005
00/15-34-081-22W4/0	00-16	PROD	oil, gas, water of wells	30 June 2005- 8 Sep 2005
02/16-34-081-22W4/0	02-15	INJ	Injector WHP	3 May 2005- 23 Jan 2006
00/16-34-081-22W4/0	02-16	INJ	Injector WHP	3 May 2005 – 23 Jan 2006

3.2. Sensitivity tests for history matching

All case runs are summarized in **Table 5** below. As explained in paragraph 2, a sensitivity study has been carried out using the three uncertain parameters: relative permeability, absolute permeability and rock compressibility**.**

Table 5: List of cases performed for the history matching

<table>
<tr><th>Test number</th><th>Kr used</th><th>Rock compressibility</th><th>Absolute permeability</th></tr>
<tr><td>BASE CASE</td><td>Retailleau Kr curves (default)</td><td>0.064 kPa-1</td><td>Top Bar complex: 1000 mD
Bar Complex Pay: 3000 mD
Bar Margin: 1000 mD</td></tr>
<tr><td colspan="4">Sensitivity to Kr curves</td></tr>
<tr><td>TEST 1</td><td>High value of Corey exponent (No = 20) for oil</td><td rowspan="2">0.064 kPa-1</td><td rowspan="2">Top Bar complex: 1000 mD
Bar Complex Pay: 3000 mD
Bar Margin: 1000 mD</td></tr>
<tr><td>TEST 2</td><td>Low value of Corey exponent (No=1) for oil</td></tr>
<tr><td colspan="4">Sensitivity to rock compressibility</td></tr>
<tr><td>TEST 3</td><td rowspan="4">Retailleau Kr curves (default)</td><td>HIGH value (*10 times)
0.64 kPa-1</td><td rowspan="4">Top Bar complex: 1000 mD
Bar Complex Pay: 3000 mD
Bar Margin: 1000 mD</td></tr>
<tr><td>TEST 4</td><td>LOW value (/10times)
0.00643 kPa-1</td></tr>
<tr><td>TEST 5</td><td>LOW value (/20 times)
0.0032 kPa-1</td></tr>
<tr><td>TEST 6</td><td>LOW value (/100 times)
0.00064 kPa-1</td></tr>
<tr><td colspan="4">Final match</td></tr>
<tr><td>TEST 7</td><td>Retailleau Kr curves (default)</td><td>LOW value (20 times)
0.0032 kPa-1</td><td>-30% of the default values:
Top Bar Complex: 700 mD
Bar Complex Pay: 2100 mD
Bar Margin: 700 mD</td></tr>
</table>

3.2.1. BASE CASE

The **base case** was arbitrarily defined as the simulation of the primary production and polymer injection with default parameters and options:

- Retailleau Kr curves,
- default permeability values by layers (see Table 1),
- default rock compressibility input in IFP Athos simulator (0.064 kPa^{-1}).

Retailleau curves are shown in **Figure 3** below.

The oil (and water if any) rates of the producers and the WHP of the injectors are expected to be matched. The simulator calculates the BHP of the well instead of WHP, when the pressure loss tables are missing in the model. It has been considered that BHP (field) = WHP (field) + 4000 kPa, assuming a depth of 400 m for the reservoir and an hydrostatic pressure between the surface and the bottom. For all cases, the producer wells work at imposed rates (history rates) and a minimum limit BHP of 100 kPa.

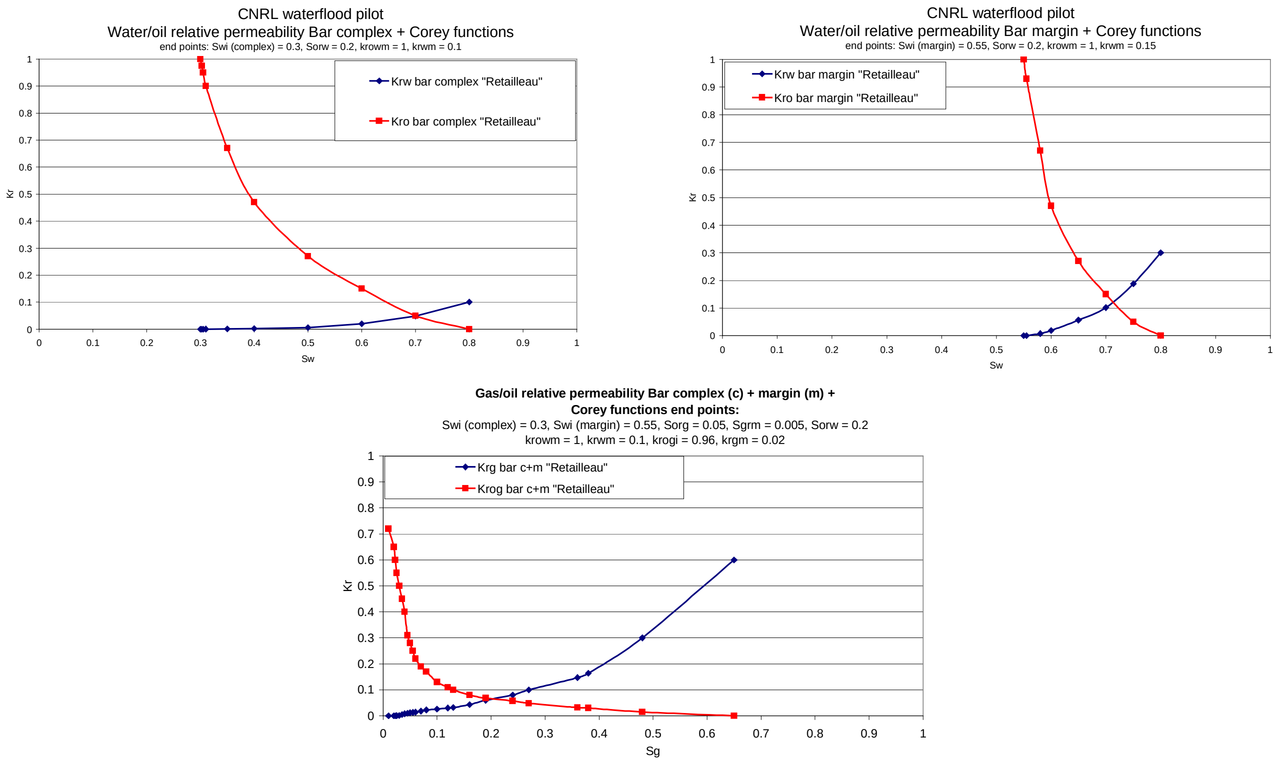

Figure 3: Retailleau water/oil Kr curves for the Bar Complex and Bar Margin layers

The base case matches the primary production (**Figures 5 and 6**). However, during polymer injection, the simulated BHP in injectors is low compared to the actual field value (**Figure 7**). After identifying the uncertain parameters, several sensitivity tests were performed to optimize the match.

3.2.2. TESTS 1 and 2: Sensitivity to Kr

As water breakthrough has not yet occurred in producers 00-15, 00-16 and 00-14, a good match of the primary production does not mean that a particular set of curves will be valid after water breakthrough has occurred. Since there may be a strong Kr effect related to the foamy texture of the oil, as CNRL mentioned, two extreme cases have been run in order to evaluate the sensitivity of the oil production to these curves. An exponent of No = 20 makes the relative permeability to oil to be pseudo-vertical for low water saturation as shown in **Figure 4**. At the opposite, No = 1 corresponds to the most favorable condition for the oil to flow. The shape of the relative permeability to water has not been modified.

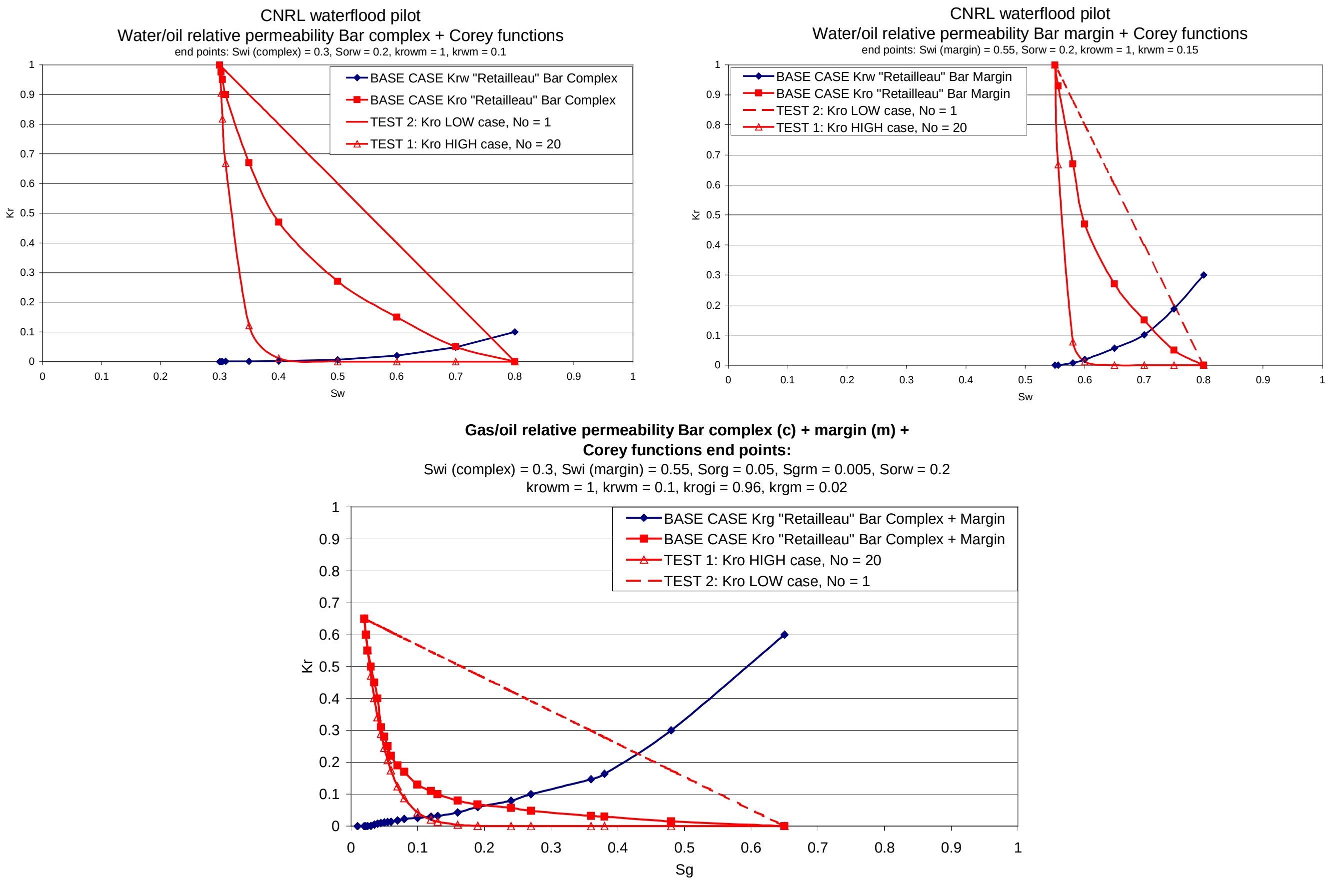

Figure 4: Low case and high case of the Kr curves for TEST1 and TEST2

The results presented are: oil production for the 5 wells and BHP of the injector 02-15 during the polymer injection (**Figure 5, Figure 6, Figure 7**). The match of oil production using Retailleau Kr curves is good and better than those using Kr with modified Corey exponent for oil (N_0=1 or N_0=20). Nevertheless, it cannot be concluded that Retailleau Kr curves are fully optimized and further adjustments may be needed to match the history later on, after water breakthrough.

In the subsequent tests, we decided to use Retailleau curves, assuming that they will need to be validated after water breakthrough.

3.2.3. TESTS 3, 4, 5 and 6: Sensitivity to rock compressibility

Based on the definition of the rock compressibility, it is expectable that the lower the rock compressibility, the higher the pressure at the injector will be for a same volume of polymer injected. The base case value is 0.064 kPa^{-1}.
As the rock compressibility is an uncertain parameter, four compressibility values were tested (0.064 kPa^{-1}, 0.0064 kPa-1, 0.0032 kPa^{-1}, 0.00064 kPa^{-1}), the other parameters remaining unchanged.
Decreasing the compressibility increases the WHP. However, an asymptotic behavior was observed at very low values (Figure 7).
There is virtually no difference between the WHP responses obtained with a rock compressibility reduced 10 times or 100 times, all other parameters being equal. Therefore, reducing the rock compressibility alone was not enough to match the BHP.

3.2.4. TEST 7: Optimized match – Adjustment of the absolute permeability

Tests 3, 4, 5 and 6 showed that the reduction of rock compressibility was not sufficient to obtain the match. It was necessary to associate the rock compressibility reduction to a slight decrease of absolute permeability of the 3 layers.

Taking into account CNRL knowledge and considering initial permeability used in our model (Table 1) should be a little bit overestimated, we decided to reduce permeability remaining in a coherent range of permeability. The values have been reduced by 30%.

A satisfactory history matching was obtained as shown in **Figure 5**, **Figure 6** and **Figure 7** using a rock compressibility of 0.0064 kPa^{-1} (10 times lower than the default value) and initial permeability of the three layers reduced of 30%.

All the simulations using the Retailleau Kr curves do not show any influence of a variation of polymer concentration on the WHP in the injectors. This result is consistent with field observation.

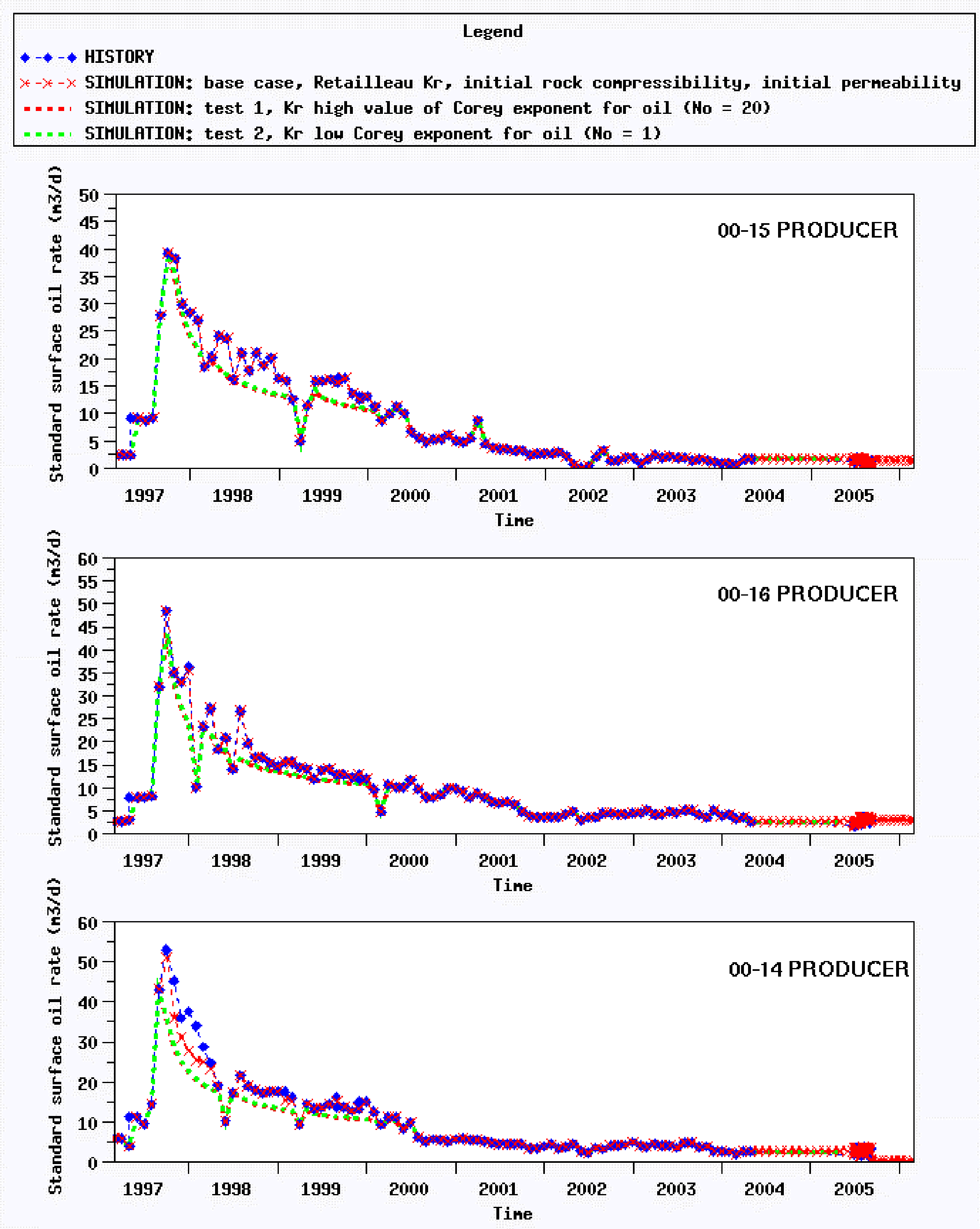

Figure 5: Oil production matching for production wells 00-14, 00-15 and 00-16

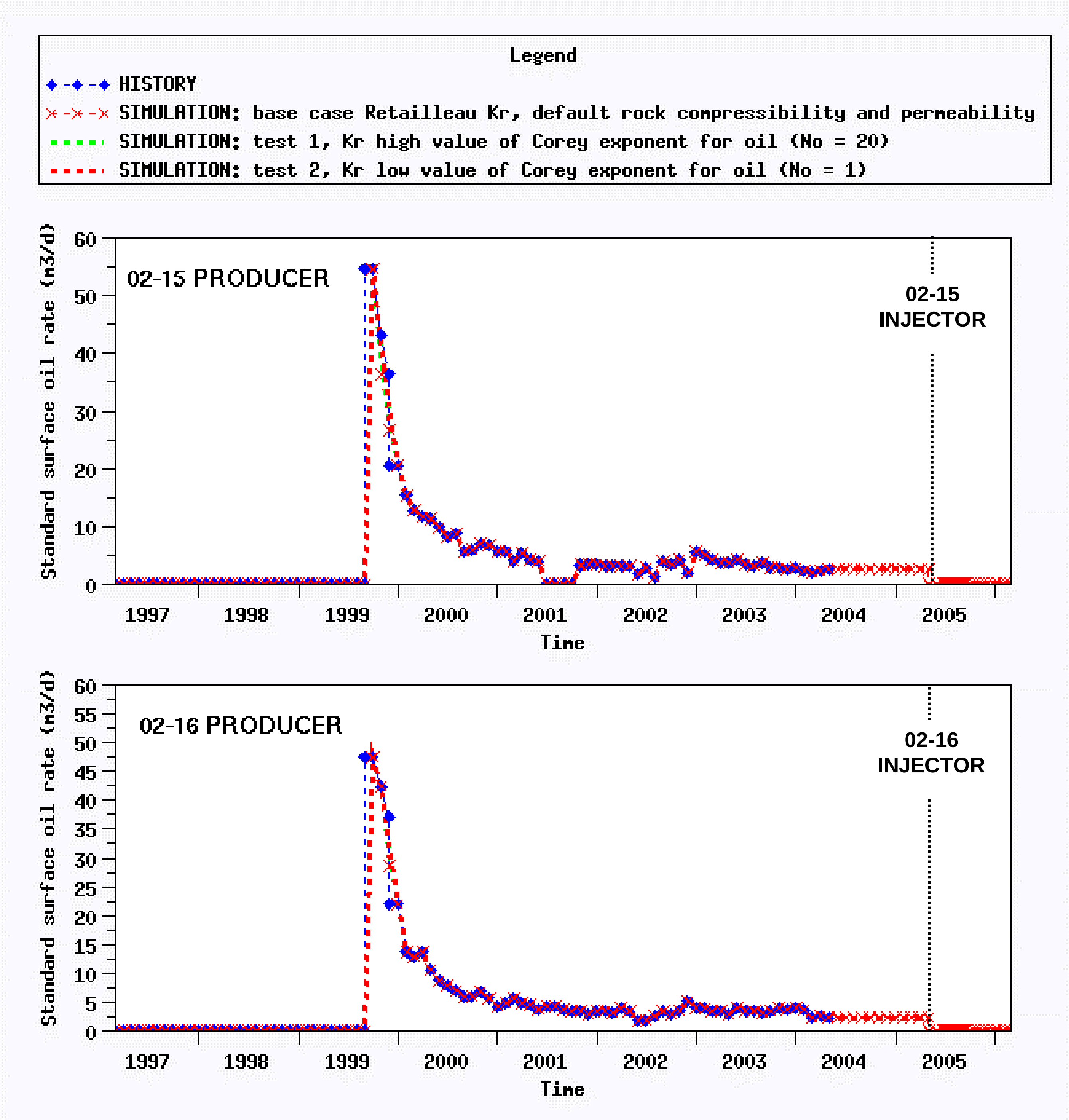

Figure 6: Oil production matching for production wells 02-15 and 02-16

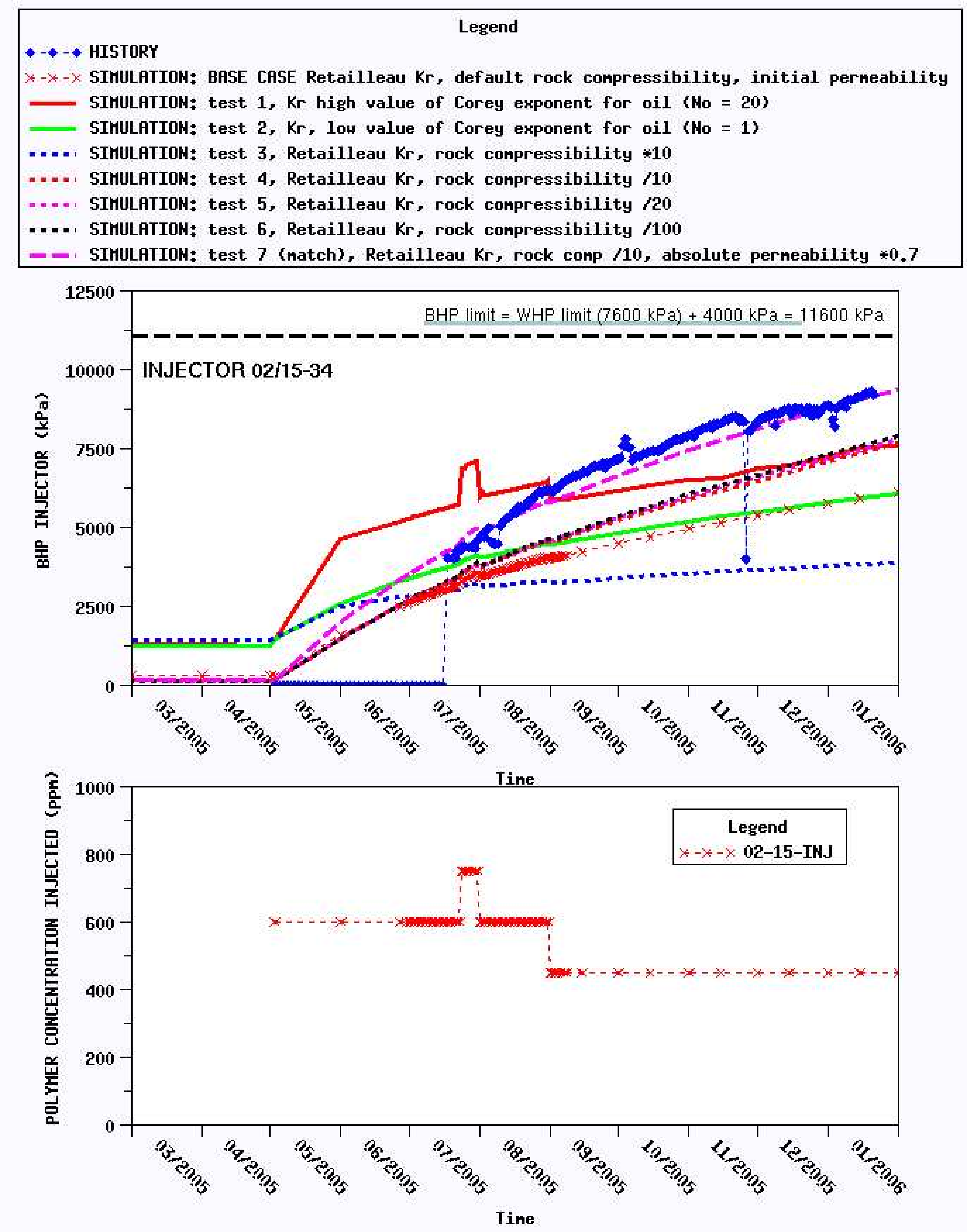

Figure 7: Influence of rock compressibility reduction (from 6.4e-4 bar-1 to 3.2e-5 bar-1) and permeability reduction (*0.7)

4. Predictive run with matched parameters

A run has been performed with the optimized parameters drawn from the previous history match to evaluate the profile of WHP in the injectors for the next few months and the water breakthrough time in the producers. This run is only indicative since uncertainty remains on the parameters used until now, mainly on relative permeability curves that will have to be adjusted more precisely when water breakthrough occurs in the field.

The BHP profile in the 02-15 injector shows that the allowable maximum pressure of 11600 kPa (WHP = 7600 kPa) is reached in the end of 2006, then the well is operated at this pressure with a corresponding decreasing well rate for 2 or 3 months. The BHP then decreases slightly to maintain the injection rate at 150 m3/day (**Figure 8**). The producers are operated with a rate constraint as long as history rates are available. The last date is 9 September 2005. After this date, the well is operated with a minimum BHP constraint whose values are those at the date of 9 September 2005. Based on our model, water breakthrough in producers is forecasted at the beginning 2006 (**Figure 9**).

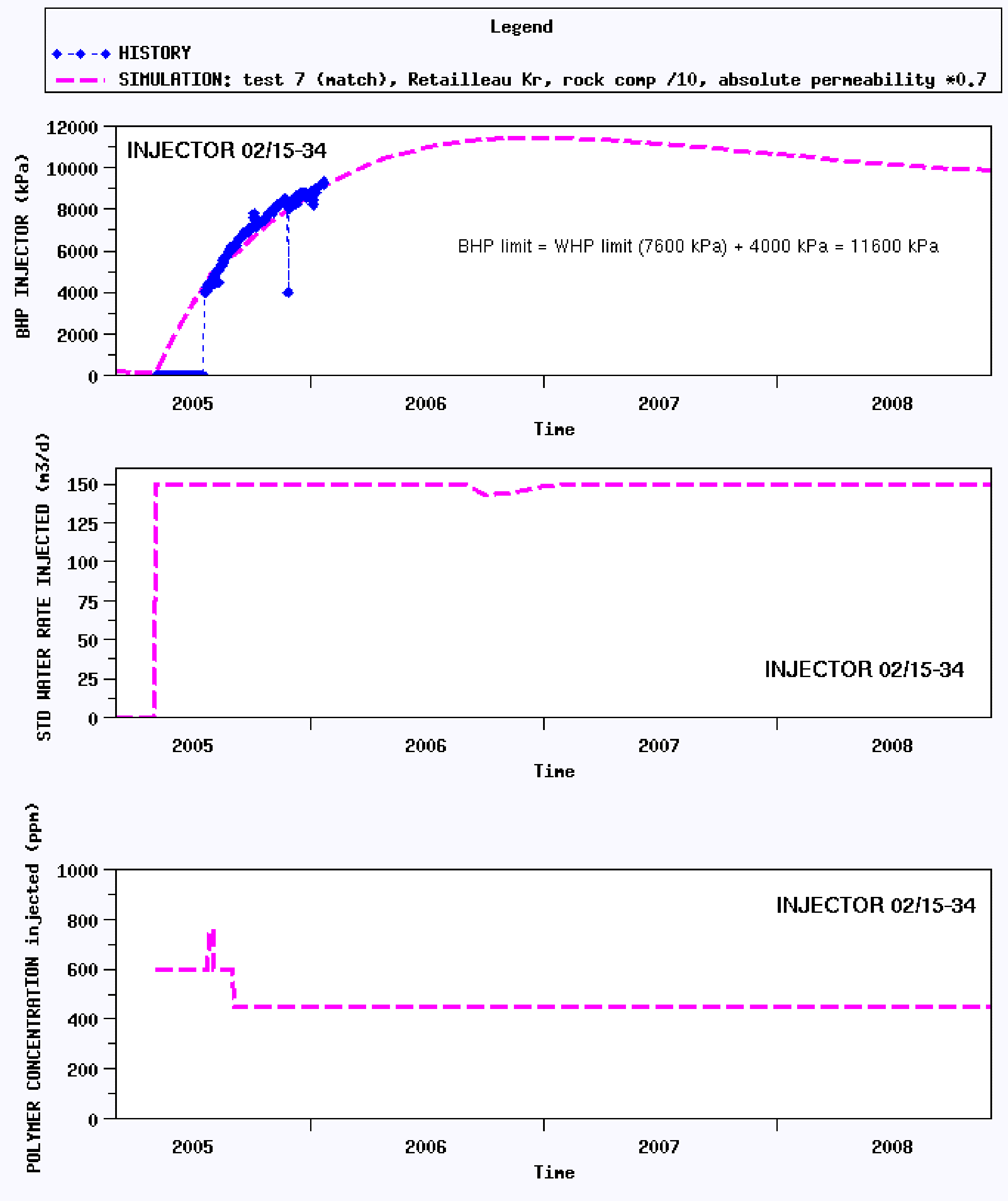

Figure 8: simulation of polymer injection up to 2008 with the matching parameters (test 7) – results at the injector 02-15

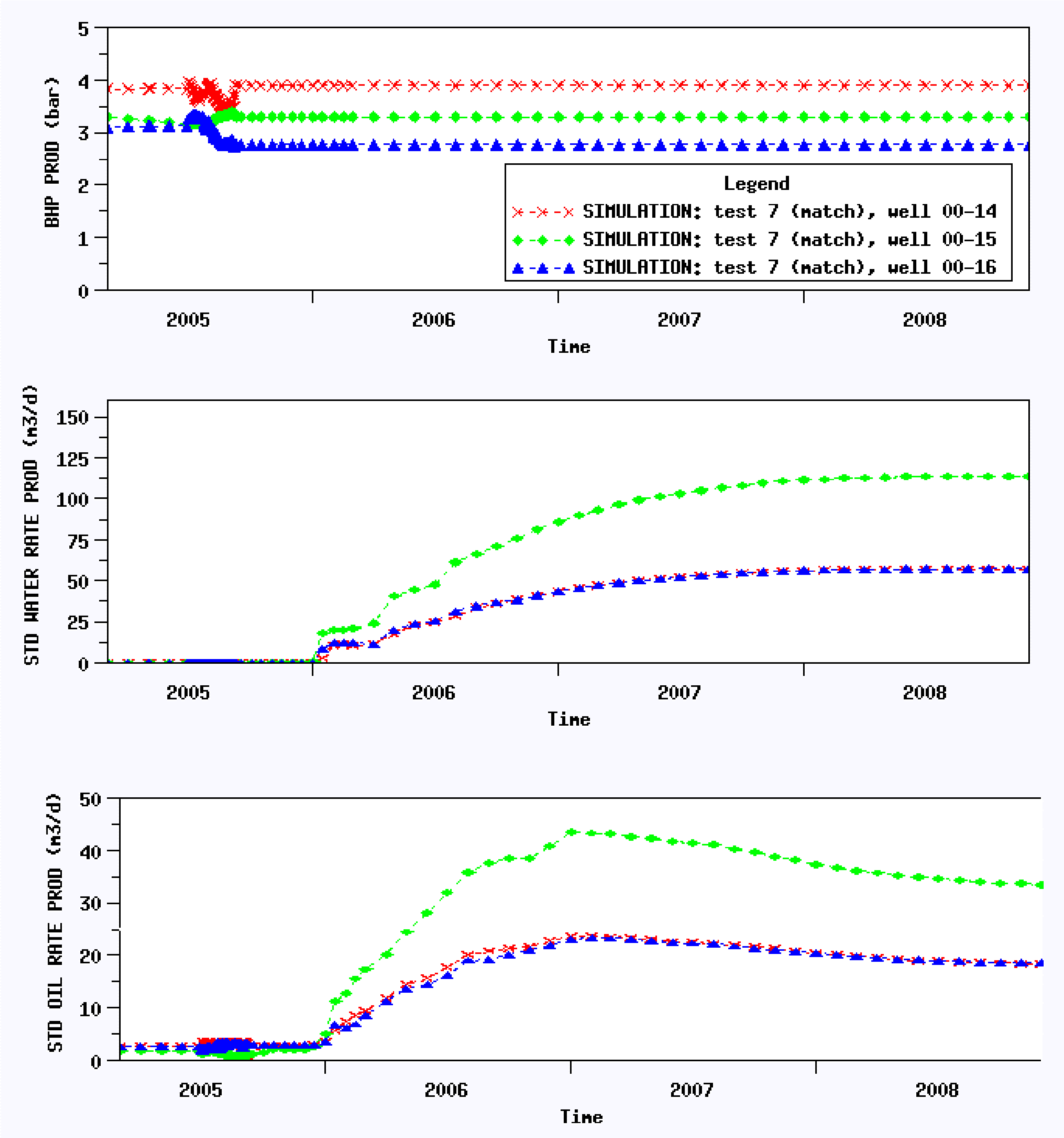

Figure 9: simulation polymer injection up to 2008 with the matching parameters (test 7) – results at the producer wells 00-14, 00-15 and 00-16