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Evaluation of a Polymer Injection Pilot in Argentina

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Abstract

The present article is based on the enhaced recovery pilot in Argentina presented in SPE 160078 ("Desing and Execution of a Polymer Injection Pilot in Argentina").

A polymer injection pilot is being conducted since January 2012 in El Corcobo Norte field, in Neuquén Basin, Argentina. The project intends to evaluate the incremental volumetric efficiency for Lower Centenario formation, unconsolidated, strongly water-wet sandstone that has been under waterflood since the beginning of the field's production in 2006.

El Corcobo Norte field produces medium-heavy oil and, due to its unconsolidated nature, production strategy involves massive sand production all along the well's productive life. Although waterflooding efficiency has allowed achieving an important oil recovery, wormholing and chanelling issues represent a challenge to the field's development strategy of increased injection and fluid production. A polymer injection project would help increasing ultimate recovery factor, through enhacing injected fluid's efficiency to displace the oil. Along the past four years of experience operating this pilot, many lessons learnt regarding process, operational, logistic and chemical issues, became extremely valuable for the company's know how in operating this technology. Pilot surveillance has proven to be a key factor for understanding how the process is working in the reservoir.

This work will present the updated results of the polymer injection pilot, which is still under evaluation but already showing promising results that could lead to an attractive expansion project.

Introduction

A polymer injection pilot is being carried out since January 2012 in El Corcobo Norte field. Reservoir and fluid properties are detailed in Table 1. The pilot consists on six inverted 7-spot patterns of approximately 20 acres each. Same pattern design is used for most of the main zone of the field.

Since its beginning, the pilot has been operating continuously and is still under evaluation. In the past 4 years of operation, many important lessons were learnt in the process of pilot surveillance, plant operation, chemical supply, etc. Pilot evaluation tools were also enhanced over time, as new field information came along. The present article intends to share the preliminary evaluation of this technology in its application in El Corcobo Norte field.

Table 1—Reservoir and Fluid Properties

Reservoir	
Poiosity(%)	27-33
Permeability (abs. D)	0,5-4
Temperature (°C)	38
Depth (mbgl)	~650
Original Pressure (kPa)	3240
Thickness (m)	0,5–18
Fluid	
Oil density (°API)	18
Oil viscosity (live, mPa·s)	160-300
TAN(mg KOH/gr oil)	~4
Formation water salinity (ppm)	46000

Pilot Description

Polymer injection pilot was designed to inject 500 ppm active solution of a high molecular weight HPAM targeting a viscosity of 20-25 mPa.s (@ 38°C, 6 1/s) considering injection water salinity. Associated to the pilot there are 22 producer wells, 16 of them were active at the time of pilot start. Pilot zone is shown in Figure 1. Pilot is designed so that injectors operate at a desired constant injection rate (equal to initial injection rate), while fluid production is balanced in the producer wells to maintain a replacement ratio of 1. This same extraction strategy is used to manage the entire field waterflooding projects.

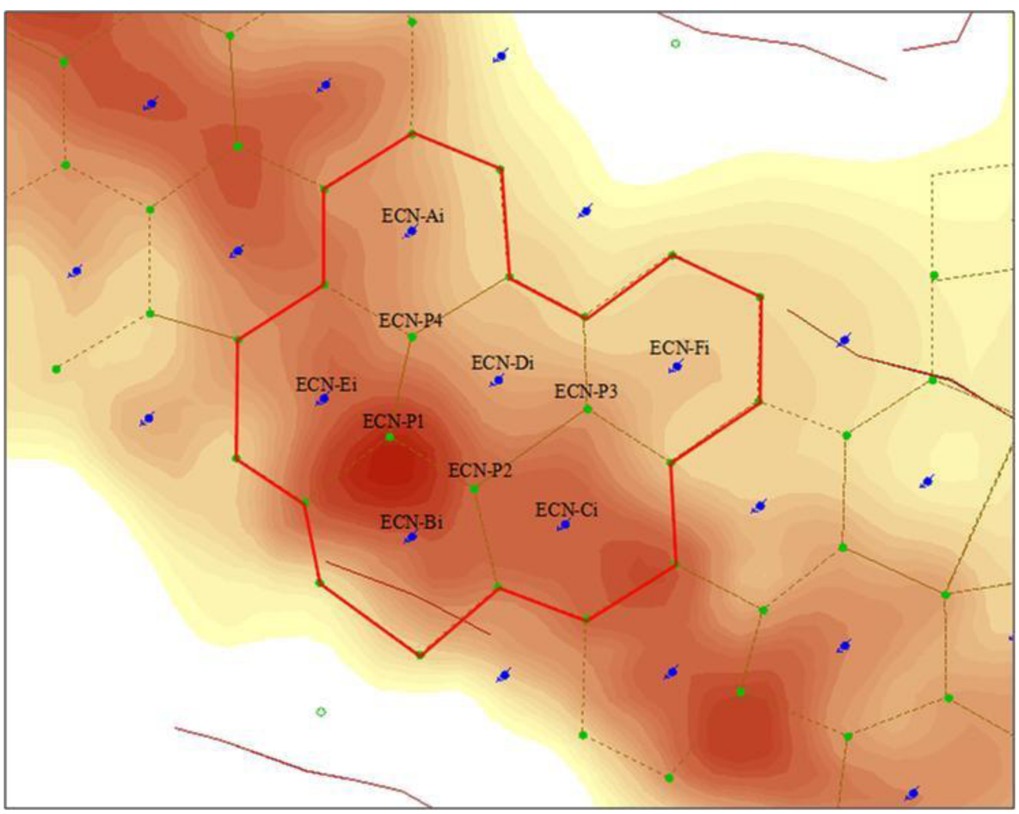

Figure 1—Pilot Zone

Wormholing, or injector-producer channeling due to sand production, does not behave differently in the pilot zone than in the rest of the field. Two of the central producer wells (Figure 1, see wells ECN-P3 and ECN-P4) of the pilot were shut off prior to pilot start because of channeling and remain closed during the evaluation.

According to pilot design simulation runs, production response was expected to show an oil pleateau, followed by an oil bank, representing an expected incremental over waterflooding baseline of 6-10% ultimate recovery factor.

Field Facilities Description

The injecting and producing facilities are located in the same area as the pilot zone. An isolated production facility was reactivated in order to separate the pilot production from the rest of the field's oil production. This would allow locally attending any water- oil separation issue caused by the presence of chemicals injected and produced in the pilot. Injection water is provided to the polymer plant from a water treatment plant that de-oxygenates and filtrates fresh water from a superficial source. Softening, and eventually water heating, occurs in the same injection facilities where polymer is hydrated. Injection is set up so that each injector well has a separate polymer pump. Mother solution hydrated in the tanks gets diluted on a well to well basis with a water stream that allows controlling each well's polymer concentration. Fresh water source provides with ~1000 ppm salinity water, that contains 200-400 ppm total hardness. Divalents get removed in an onsite softening plant that treats up to <5 ppm hardness content. Figure 2a and 2b show polymer plant process flow diagram and layout.

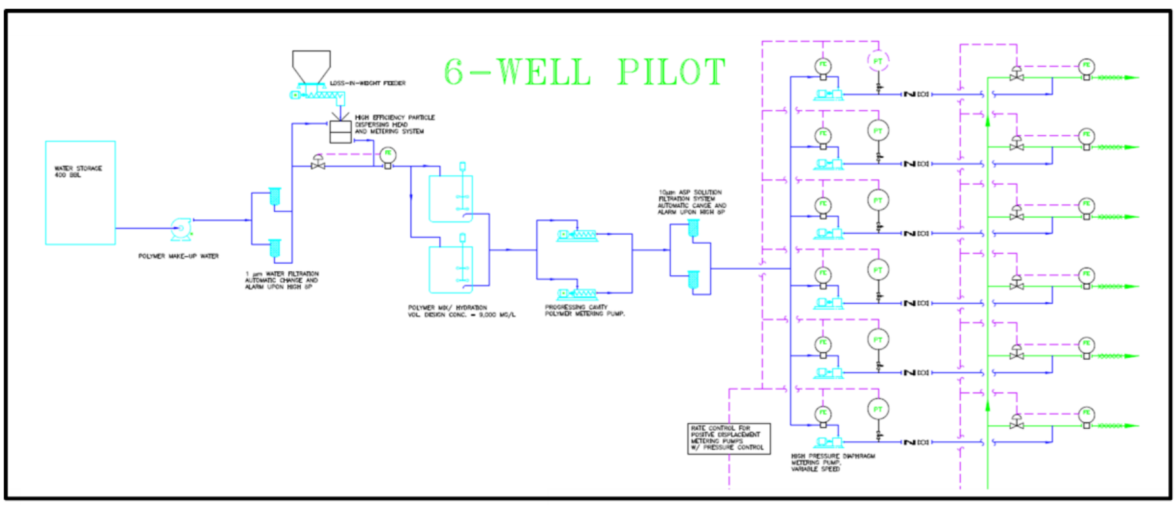

Figure 2a—Polymer Plant PFD

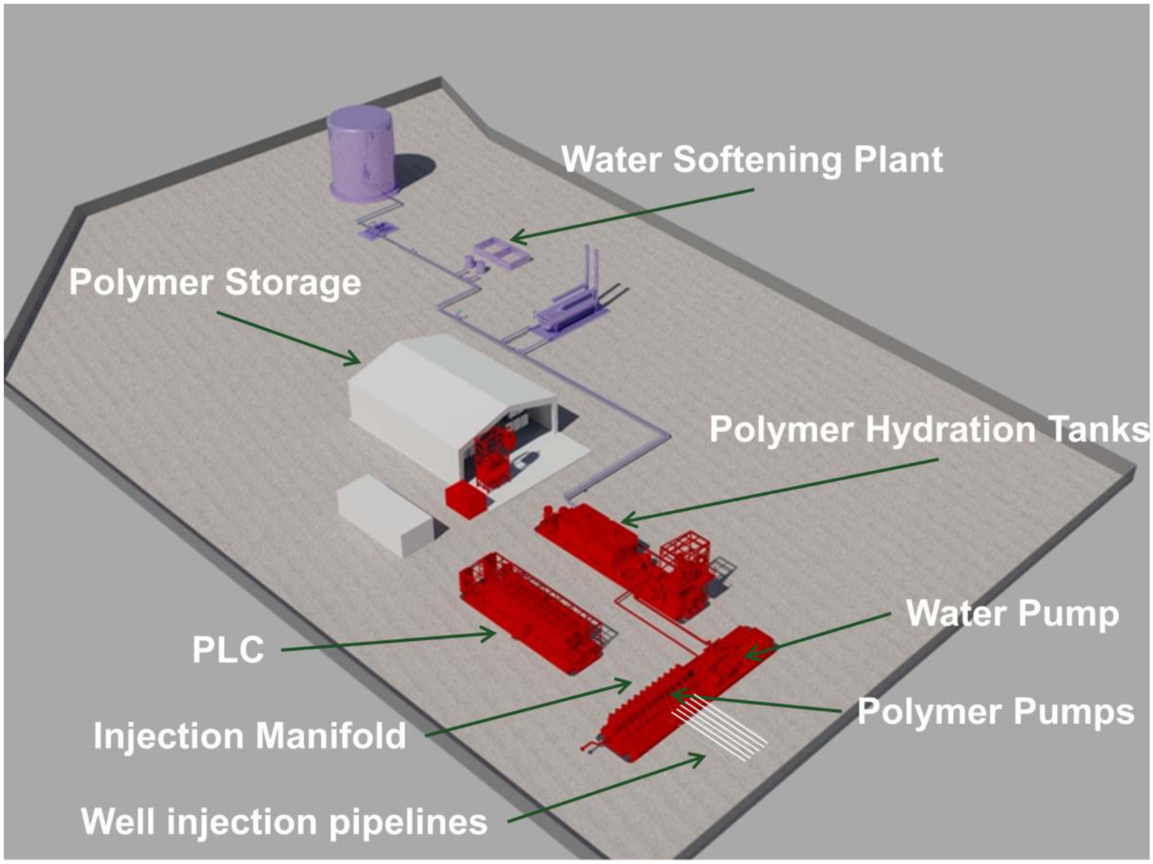

Figure 2b—Polymer Plant Layout

Pilot Operation

Plant operation has been running steady since pilot started in beginning 2012. Targeted viscosity has been achieved by the polymer hydrators without operational issues and viscosity checks continue to be measured daily on injector wellhead samples to guarantee injection to be within desired range. Polymer quality checked to be constant and according to specification in every single adquired lot. Due to Argentinean government policy changes regarding imported goods, polymer supply happened to be threatened in 2 ocations along the past 4 years of operation. To avoid this issue and guarantee the continuity of the pilot, the stock strategy was changed by increasing available stock on site and shortenning time between polymer orders. During polymer shortage, injection concentration was sometimes lowered to sustain a constant provision with remaining stock.

Critical plant operating parts, like polymer feeder, required replacement over the years due to their intensive use. Polymer feeder and stand-by piece were replaced by locally a built spares. Some minor plant modifications were performed to customize the plant operation.

Softening process has been providing water under specification since it started operating steadily in 2012. Water heaters are on service only during winter season periods, few months a year where fresh water supply can go below 5°C. Heat amount is delivered in order to take water to room temperature and facilitate polymer hydration process.

Aside from eventual power shut down or pump failure, no operational incidents were reported. No accident was registered on the polymer plant, onsite lab or the pilot- dedicated production facility.

Pilot Surveillance

On a daily basis a number of parameters are monitored to assure the quality of the water that is provided to polymer hydrators, such as ph, hardness, water temperature, conductivity and oxygen content.

Oxygen content is reduced from water stream in a vaccum stripping deaereation system (that lowers dissolved oxygen content from source to < 2 ppm). This equipment is located in the water plant that provides for the polymer plant. All water tanks upstream polymer hydration tanks have the possibility to use blanketing system in order to displace oxygen in these vessels. Although polymer tanks have sealing plastic lids, no inert atmosphere is used in the hydrators. In times of the pilot design there was no proof of presence of iron, H_2S or any other agent that, in the presence of dissolved oxygen, could degrade polymer solution. Being a fairly green field, El Corcobo Norte had shown no hints of souring up to 2011. However, the highly acid characteristic of the oil made this condition change over the past few years. H_2S count started showing in gas and liquid production in the different areas of the field, with no exception of the polymer pilot zone. Although on well basis biocides and other field chemicals started being dosed to mitigate the problem, souring on a reservoir level is subject of a different study. It has been verified that in surface facilities the presence of H_2S in blanketing gas, even in a few ppm of concentration, degrades polymer solution very quickly, achieving only 10 mPa.s (@ 38°C, 6 1/s), instead of the target of 20-25 mPa.s (@ 38°C, 6 1/s). However since polymer solution (with dissolved oxygen content of < 2 ppm) would first meet H_2S when entering the reservoir, the occurance of this degradation cannot be effectively proven. Polymer effectivity loss to propagate and displace the oil along the reservoir because of chemical degradation is not measurable as a separate effect and would eventually show in field data as well as any other undesired effect impacting pilot results. There have been a number of investigations to determine the potential degradation of injected polymer solution when containing dissolved oxygen, including some that state that oxygen gets very quickly reduced when entering the reservoir by the presence of iron minerals like pyrite and siderite (Manichand *et al.* 2013). The overall impact on oil production of the eventual polymer chemical degradation would be appreciated along with the other detrimental effects (such as mechanical degradation, lower effective viscosity, higher retention, etc.) when matching pilot results with the project's production expectations.

Pilot total production is measured online after water oil separation. Producer wells are measured according to a schedule that contemplates a higher frequency of samples in central wells (surrounded by 3 polymer injectors). Producer fluid rate is determined through control tanks, whereas watercut is estimated with wellhead samples.

Caolin test to determine polymer presence is performed on production water from the very beginning of the pilot. Also, since polymer presence is detected and confirmed on each producer well, systematic samples are taken every 3 months to quantify polymer content. These determinations, unlike all others, are not perfomed in the plant field lab, but in a local lab located in Universidad Nacional Del Comahue, Neuquén. Special protocols and determination techniques needed to be developed as a joint work from Pluspetrol S.A. with Universidad Nacional Del Comahue lab crew in order to quantify polymer presence in production water (containing oil and field chemical traces).

Polymer arrival time in producer wells was fairly well in accordance to numerical simulation estimations prior to pilot start. Central wells did receive polymer before the less affected wells, with 1 or 2 associated polymer injectors. Unfortunatelly, achieved polymer quantification technique is not able to provide with data resolution good enough to match with produced polymer curves from simulation output. Nevertheless, the trends are used for the analysis and they show good accordance to expected results.

In November 2015, radioactive tracers were injected in 3 of the 6 pilot injectors, in order to compare results with the tracer campaign performed prior to pilot start in 2011. So far no chemical detection was reported in 2015 campaign for the producers associated to traced wells. Sampling time for this test was set in 2 years, expecting a higher transit time in polymer injection than waterflooding stage.

In Table 2 injection water composition is shown. Since the original salinity is above 40000 ppm, injection water salinity is also usable as a natural tracer to monitor how mature displacement is in this zone. Water salinity is a cheap, easy -to - determine parameter that can be used to continuosly monitor the evolution of a flood, when a salinity gradient between original and injection water salinity is available. All along El Corcobo Norte field, with the exception of the polymer pilot zone, injection water salinity is around 36000 ppm, as it's composed by formation water and a minor volume of fresh water (used to compensate oil volume and sustain injection – production ratio).

Table 2—Injection Water Composition

Fresh Water Composition	
Component	Concentration (pprn)
TDS	1044
Cations	
Na^{+}	144
K^{+}	10
Ca^{2+}	142
Mg^{2+}	20
Anions	
Cl^{-}	179
HCO_3^{-}	278
SO_4^{2-}	271

Figure 3 shows the evolution of produced water salinity for all operating producer wells associated to 2 or 3 polymer injectors. In Figure 3 it is noticeable that even in the case of the 2 central wells (red curve) for most of the time displacement is far from recirculating injection fluid, which is consistent with polymer concentration determination for these wells. Salinity in these central wells should tend to injection water salinity, which is of approx. 1000 ppm. This is appreciated in one of the 2 central wells for February 2016, when this well was channeled with one of the 3 associated polymer injectors, dropping its salinity down to injection water salinity and circulating all of the injected polymer solution (Measured polymer concentration went up to 400 ppm). At this point this well was shut off and scheduled to be repaired as it will be described in a following section.

Some producers associated to 2 polymer injectors are shown with blue curves. In the case of these wells even estimating the amount of fresh water considering a complete displacement from polymer injectors, it is noticeable that salinity they produce is far from total fluid circulation.

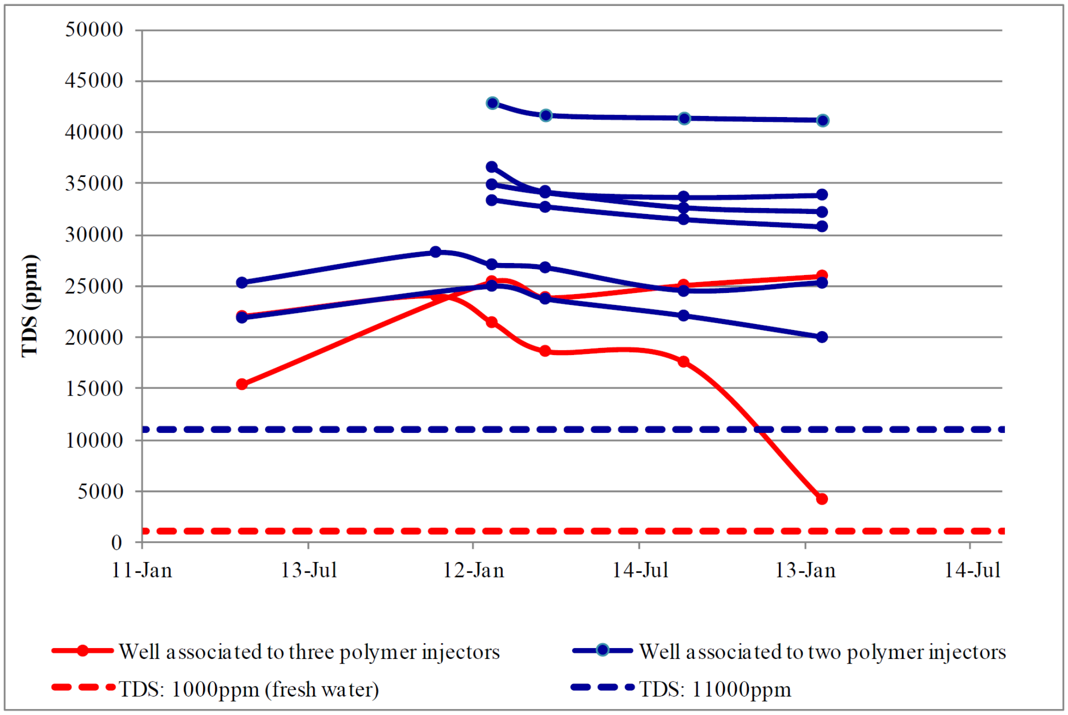

Figure 3—Producer Wells Salinity

Injector Well Response

Injection pressure response is one of the most interesting monitor parameters of this pilot. In El Corcobo Norte field, due to massive sand production and constant well stimulation, downhole pressure is rarely predictable. Simulation models, even history matched, sometimes fail to predict pressure evolution because sudden pressure changes occur regularly. For this reason, pressure evolution under the effect of polymer flooding was among the important information to be obtained from the field pilot experience. As exposed by Hryc *et al.* (SPE 160078), each of the 6 injectors belonging to this project has a shown different pressure response. Injection pressure evolution behaved as arbitrary in wells under polymer injection as in waterflooding. Wormholing occurred in the polymer pilot area just as often as in other parts of the field, with the same kind of pressure behavior.

At pilot start injector wells ECN-Ai and ECN-Bi had to be restricted in the surface line, since they showed zero injection wellhead pressure. However after a few days bottomhole pressure started increasing in all injector wells and it was possible to remove the surface restriction.

Figure 4a and Figure 4b show updated data for wellhead viscosity, pressure and injection rate evolution for the 6 injection wells. Pressure limit of 4700 kPa shown on figures corresponds to an operational limit imposed by surface lines. Once achieved, this limit forced injection rates to decrease, creating injectivity loss. This fact forced to eliminate surface restriction by changing to high pressure injection lines. This represented an important conclusion for the eventual massification of the project, since the need for replacement of currently available injection lines was unclear at the beginning of the pilot. Surface restriction was removed at beginning 2015, so for the first 3 years of pilot operation, injection rate was under design rate and total injected poral volumes were dimished. This had an effect on the timing of the oil response, prolonging the oil pleateau stage and therefore, pilot evaluation time. Before increasing injection pressure a caprock integrity study was carried out to find, if available, an upper limit to operating pressure to avoid integrity issues. The conclusion of this study was that it was still safe to work at 8800 Kpa in the injector wellhead, without jeopardizing caprock integrity. This upper limit is expected to be much higher that a plausible operating pressure.

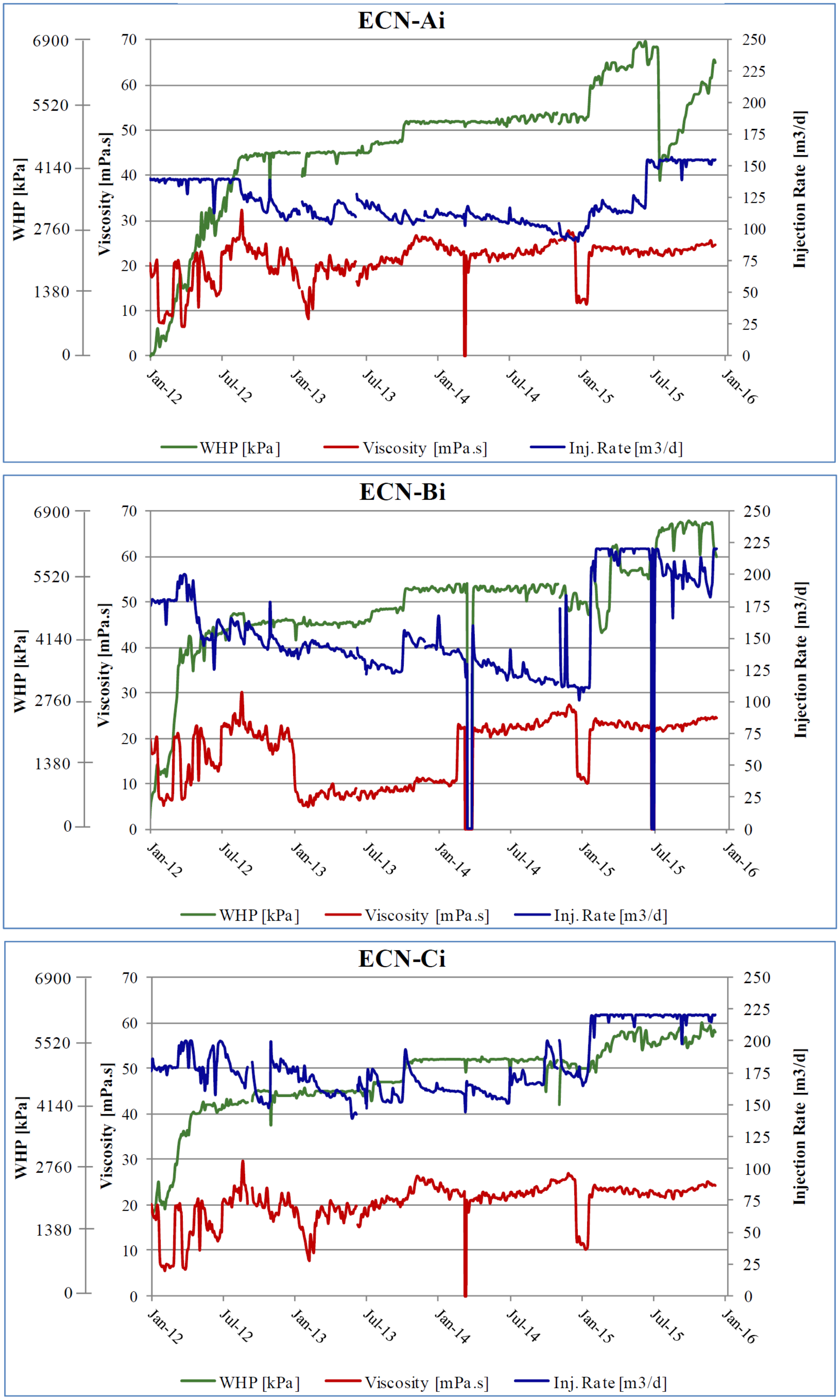

Figure 4a—Injector Well Response

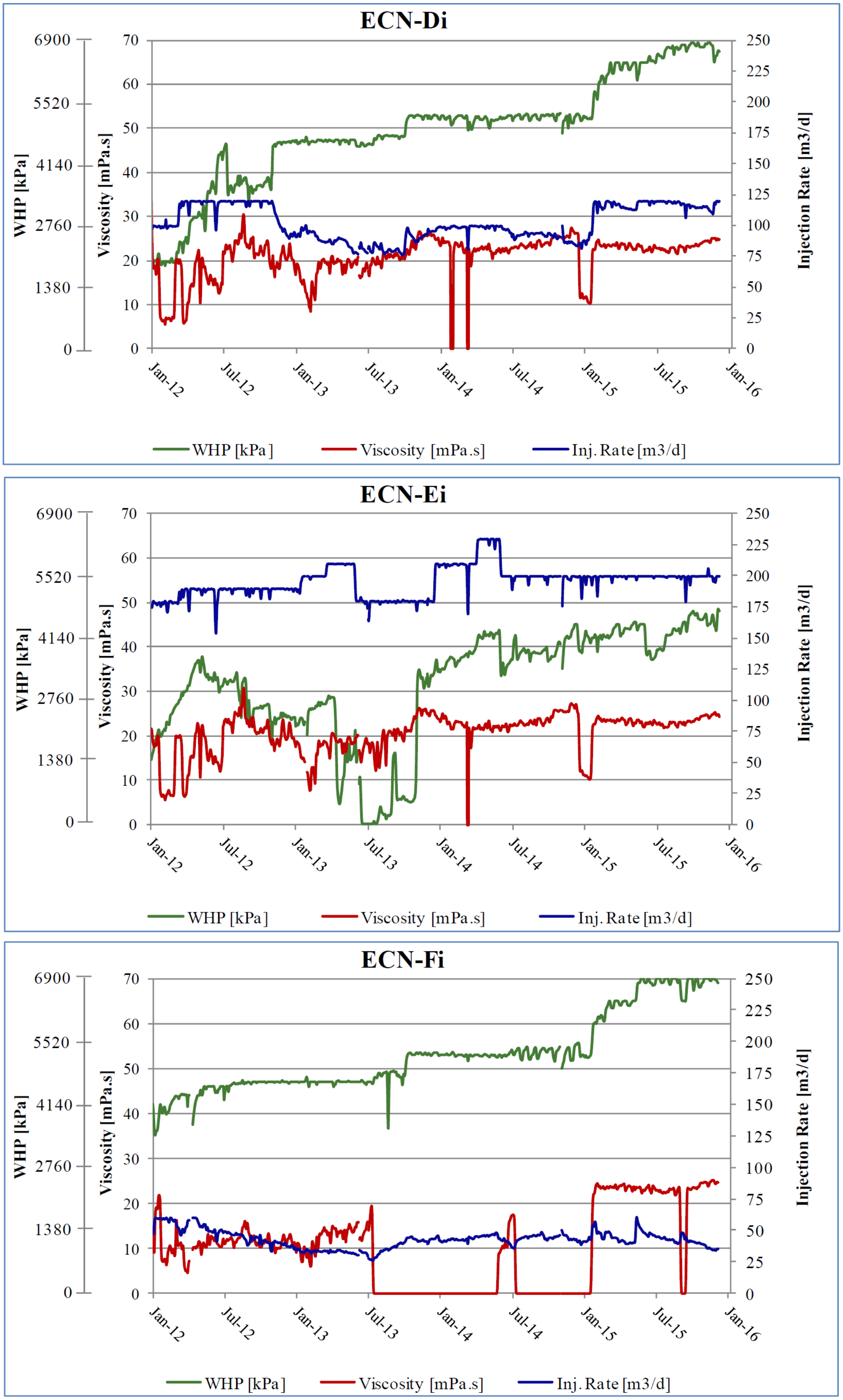

Figure 4b—Injector Well Response

Production Response

As mentioned above, when elaborating pilot design simulation runs, production was expected to show an oil plateau followed by an oil bank. Total magnitude of the incremental response was estimated according to sensitivity analysis.

As a result of the pilot operation, the response curve did behave with the expected trend, although the oil plateau stage lasted longer than the initial prognosis. This was mainly attributed to injectivity loss resulting from surface line restriction described previously. Figure 5 shows pilot oil response and liquid production. Dashed blue line corresponds to what was defined as project evaluation baseline. Oil decline showed by the baseline curve is the expected oil production if no polymer pilot had been implemented in this zone, and waterflooding surveillance strategy had been carried out as in the rest of the field. Red line points pilot start. WOR vs Np trend can be appreciated in Figure 6, where blue dots represent the stage prior to pilot start, and red dots mark WOR behavior after polymer injection. Exposing pilot production results through this method makes it even clearer that after pilot start a change in WOR trend is noticeable, modifying and even inverting the slope of the WOR curve once oil production started increasing.

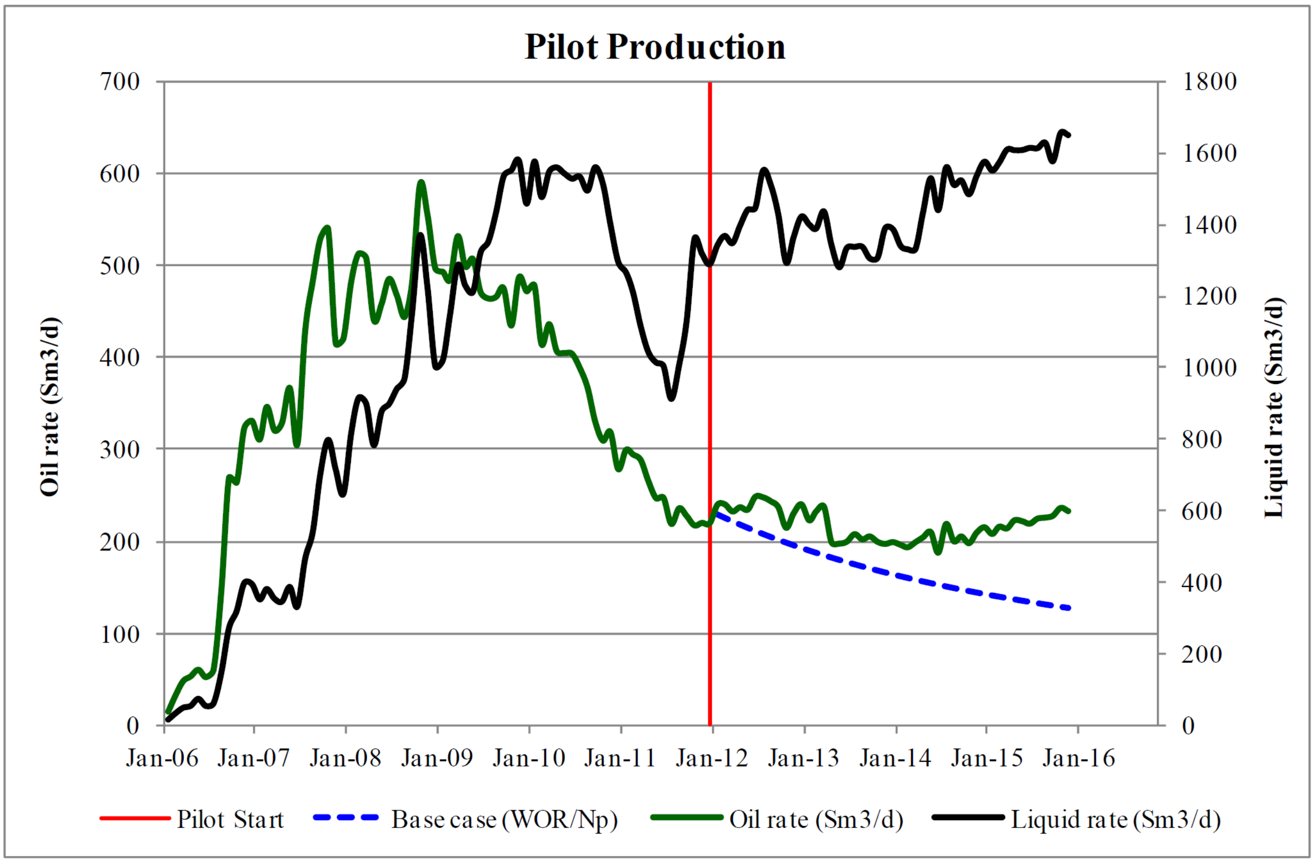

Figure 5—Production Response

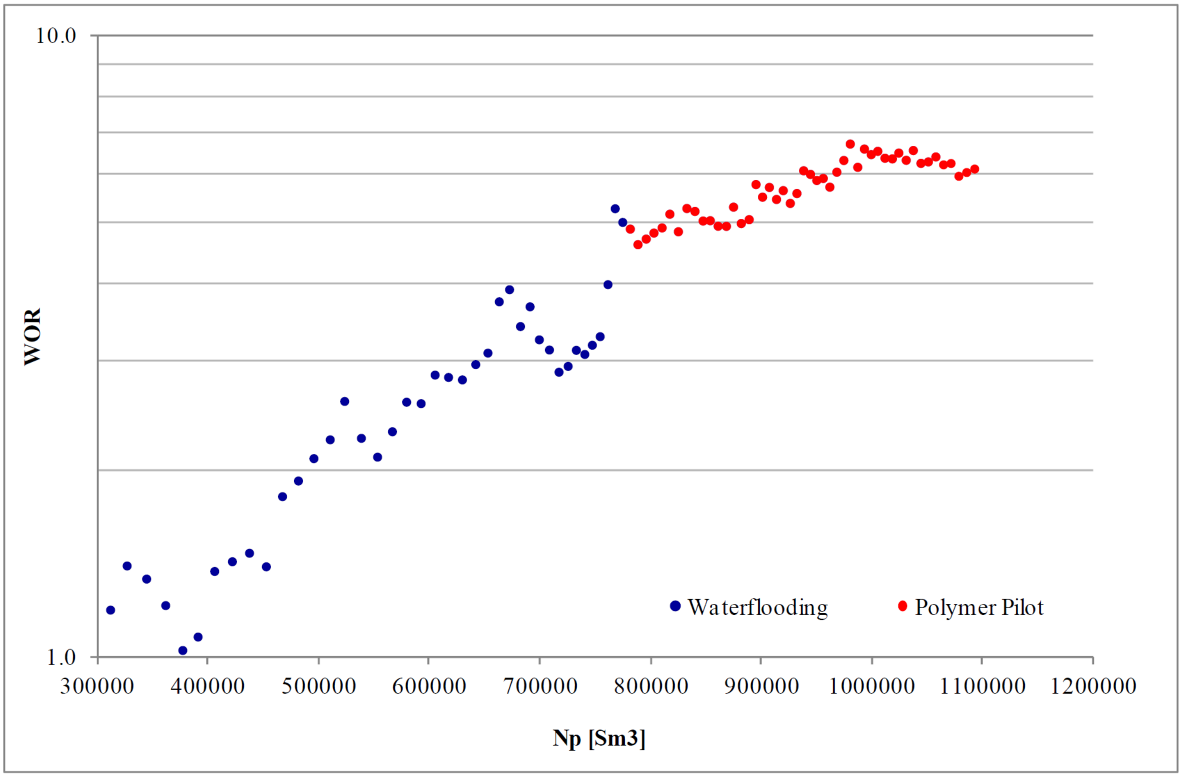

Figure 6—WOR vs Np

On a well to well basis, the response shows sometimes noisy to analyze, considering the margin of error of wellhead sample watercut determination. For this reason, even when producer wells production is monitored and compared periodically to simulation forecasts, all the efforts are focused on matching the pilot production as a whole.

In May 2013 central producer well ECN-P1 (see Figure 1) was chanelled with injector ECN-Ei. Aside from being one of the 2 producing central wells of the project, this producer had been identified as one of the wells with more connection with its injectors from early waterflooding stage, and was also the first well to receive polymer after 14 months of polymer injection.

Pluspetrol S.A. has done extensive work investigating and testing methodologies to repair channeled wells over the past few years. Different approach and technologies have been used from injectors and from producer wells to attend the so called type I chanelling (Saez, *et al*. 2012), which is described as an injector-producer hydraulic communication. This type of connection between wells has been only repaired 100% effectively by a poral matrix reconstitution treatment, using the injection of sand and resin from the producer well side. This technique with certain design adjustments has also been applied for the completion of infill wells, in order to try an alternative completion methodology that avoids well stimulation by sand production. In the articles published by Kruse *et al*. in 2014 and 2015 a detailed description of these treatment design and execution is described. It's interesting to remark that producers repaired with sand and resin treatments have recovered up to one third of their oil production prior to injector channeling. This represents an economic limit in the candidate selection for this kind of treatments.

In December 2015 central producer ECN-P2 was channeled with injector ECN-Ci, completing a total of 4 channeled producer wells in the pilot zone (considering the 2 producers that were shut off before the pilot). This well was also repaired using the mentioned remediation technique and is currently on production. In the case of repaired producers affected by polymer injection, recovered production proved to be higher than the one third limit, since these wells continue the trend of reducing watercut, even at a lower extraction regime. Figure 7a and 7b show producers ECN-P1 and ECN-P2 watercut, liquid and oil production, before and after channeling event.

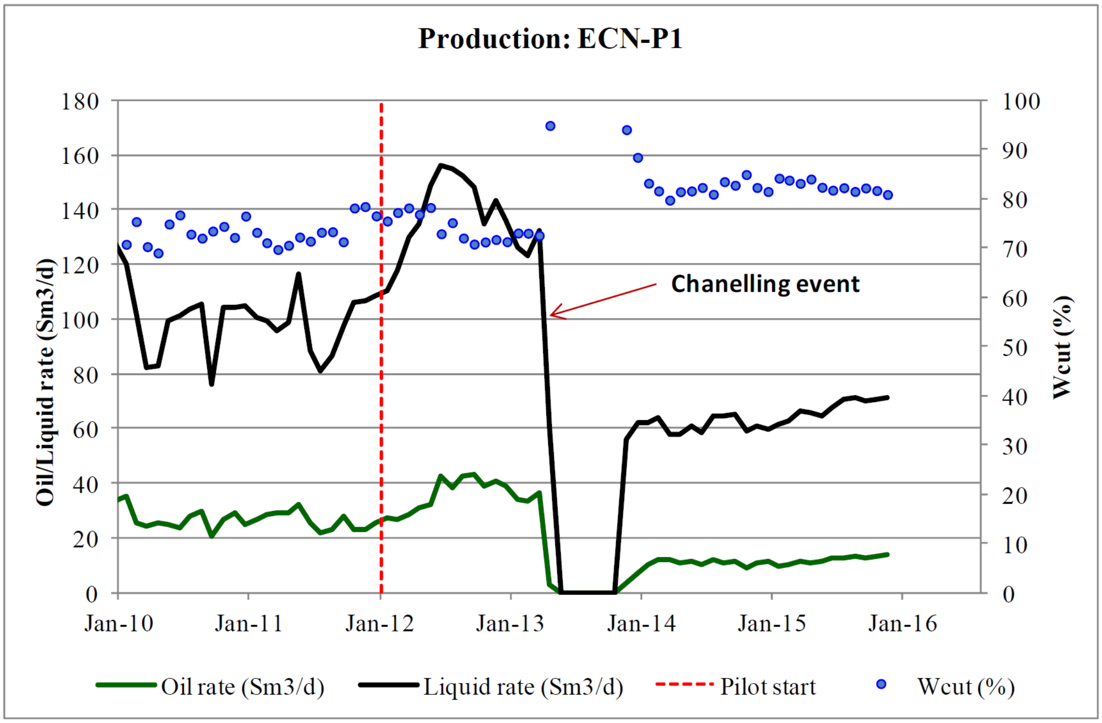

Figure 7a—ECN-P1 Production

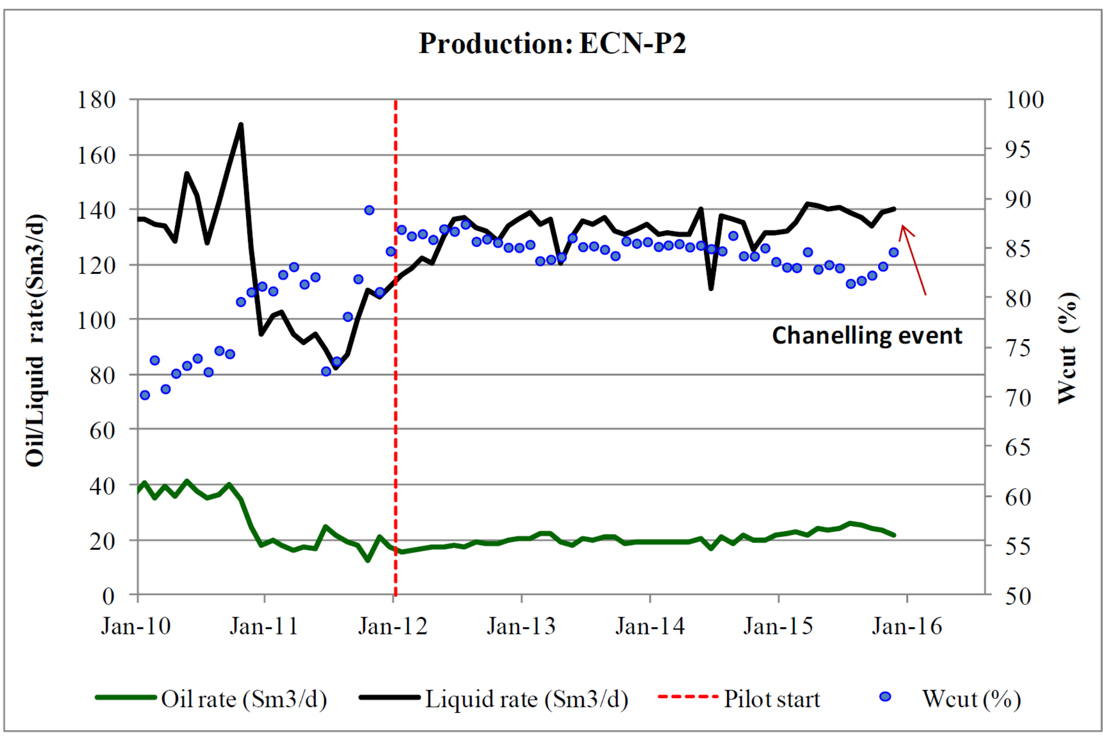

Figure 7b—ECN-P2 Production

Updated Simulation Results

Field simulation and sensitivity analysis performed during the pilot design stage was used as base for studying how field data compared to expected results. Predictive and history match runs were made by imputing the model field data such as oil, liquid and water injection. Simulation tool was used to understand the roleplay of each polymer process parameter (effective polymer viscosity, polymer adsorption/retention, residual resistant factor, etc.)

Figure 8 shows updated simulation results. Green dots correspond to pilot field's production, whereas full black line is the oil rate curve from the history matched run. Once injection rate and viscosity schedule was imput, the parameter that needed adjustment to be able to match pilot production was polymer adsorption. Initial prediction had been done asumming an adsorption level that was a mean value from the adsorption interval observed in the lab studies and coreflood history match. In order to match oil field production and still honour the pilot response, it was necessary to modify polymer adorption to a value of approximately 30% higher than initial estimation. It is important to remark that other recovery detrimental effects like polymer mechanical or chemical degradation can be overcompensated when assuming a higher polymer adsorption level. Although it is possible to include reactions to represent effects like polymer degradation, there is not enough information to simulate them separately.

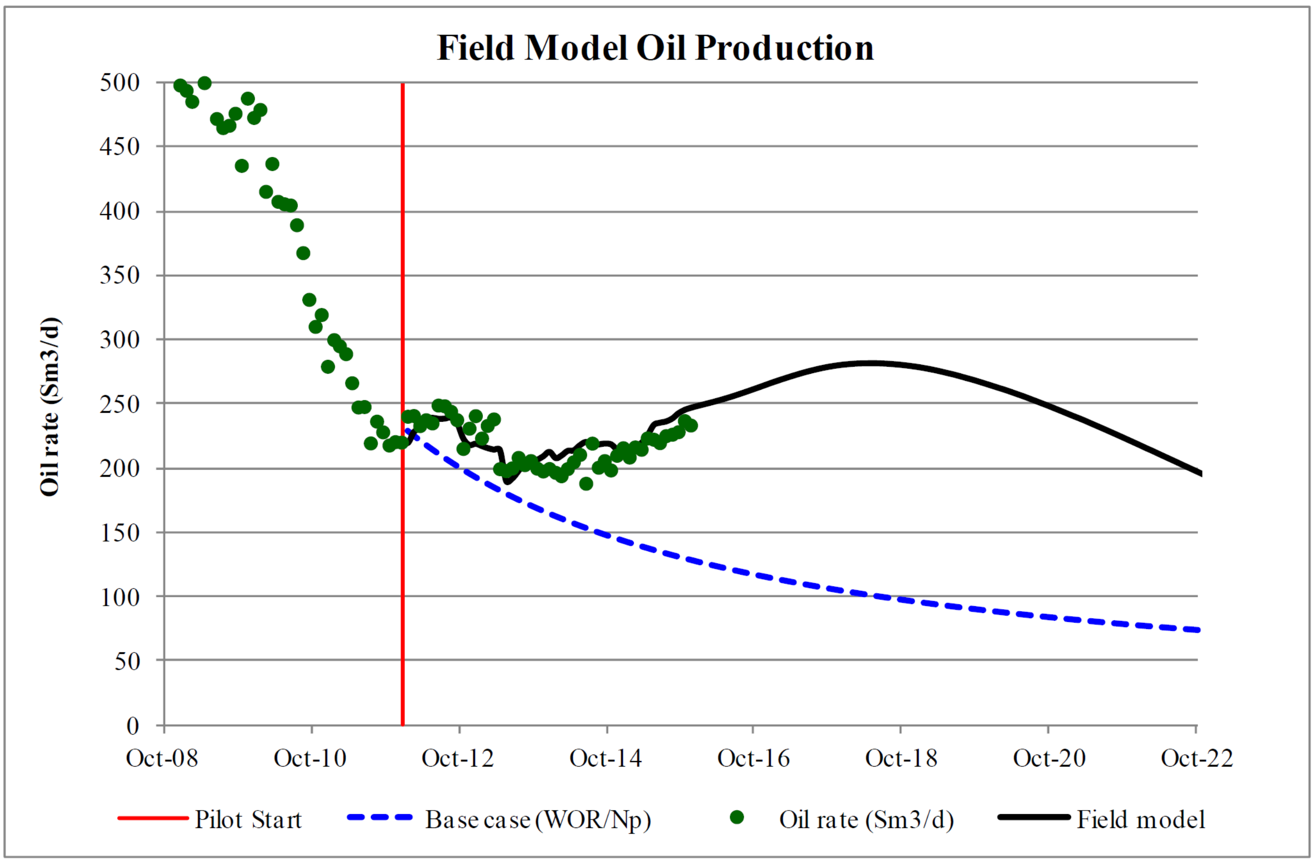

Figure 8—History Matched Simulation Results

As showed by Figure 8, production is expected to go on increasing, reaching an oil peak after October 2018. The pilot production will continue to be monitored and simulation updated in order to confirm the hypothesis of the matched case.

Preliminar Evaluation & Learnt Lessons

Pilot has responded so far, showing interesting incremental production over waterflooding expected oil curve. The production profile of the increment oil is strictly affected by the possibility to inject polymer at design rate. For this reason it's clear that injectivity needs to be guaranteed in order to expect a sooner oil bank. Resistant factor, among other parameters, used for pilor design runs were verified to be similar than expected. Production detrimental effects such as polymer degradation or polymer adsorption/retention were simulated using an adsorption level about 30% higher than the initial estimation. This matched adsorption still lies within the range of what was observed in lab tests and coreflood history match. Although this may be strictly not what is actually happening in the reservoir, it is the chosen approach to mimic the results in the absence of information that allows simulating envolved effects separately. Polymer concentration modifications in the pilot were studied but dismissed, since incremental effect would not be impacting at this point. However, considering matched adsorption/retention levels, project upscaling to new zones could be designed at a higher concentration to mitigate this effect and enhance incremental production profile.

Used also for pilot surveillance, numerical simulation proved to be a very used tool for more applications apart from project design. For the case of El Corcobo Norte project, injection pressure behavior, as expected, was not predictable with any available tool. Aside for specific pressure events in time, downhole pressure eventually started building up in all 6 injector wells due to polymer injection effect. Achieving injectivity control through modifications in polymer concentration was proven uneffective, and system pressure needed to be risen in order to mitigate injection rate drop. To assure injection solution quality, several parameters are monitored daily on water stream and wellhead samples. Viscosity target has been achieved with no major operational issue. Product quality was stable over the years of supply. Injector- producer channeling occurred in the pilot area as frequent as in the rest of the main zone of the reservoir. Attending channeled wells with poral matrix remediation technique allowed putting these wells back on production. Special criteria needed to be applied to correctly analyze the results on these producers. After recovering production, polymer effect still shows on these wells by alowering watercut trend. Polymer arrival started showing up in traces in 2013. More connected wells were the ones that received polymer first, and after some time of operation, caolin test showed polymer was arriving over detection limit in produced water from other wells. Produced polymer amount is measured periodically in a nearby lab, although polymer concentration determination technique needed to be adapted to make it applyable in produced water, considering the presence of field chemicals traces. Polymer presence in surface separation facilities has not created any operational issue. H_2S appearance made the company analyze again the requirement to displace oxygen from the complete polymer injecting system. Although studies are being carried out to deeper investigate this effect, it's unclear at this point if low dissolved oxygen levels like < 2 ppm could be responsible for reservoir polymer solution degradation.

The polymer pilot is still under evaluation and more field information needs to be adquired and considered in the analysis in order to confirm this process total incremental recovery.

Summary and Conclusions

A polymer injection pilot is operating in El Corcobo Norte field, Argentina, since January 2012. Detailed description of pilot design and execution has been covered by Hryc *et al.* (SPE 160078).

After 4 years operating the pilot, polymer injection has proven positive production results, showing increment over defined oil baseline. Field simulation was updated imputing pilot data and the model was history matched assuming a higher polymer adsorption level (about 30% higher) than initially expected. Injector-producer channeling was attended in the pilot area with a technique also used in other zones of the field. This allowed putting those wells back on production to continue pilot evaluation. Polymer plant operation and water-oil separation has not presented any major problem. Field experience has so far given very valuable information regarding project surveillance, production management, and onsite chemicals handling. Although preliminary results are encouraging some more evaluation time is needed to fully asses the value of the technology, and assure its potential for full field upscaling.

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