An Innovative Waterflood Optimization Method for Unconsolidated Sandstone Reservoirs to Increase Oil Production, Lower Water-Cut, and Improve or Stabilize Base Oil Decline Rate

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ABSTRACT

In November 2011 Pan American Energy augmented three conventional well injectors in its Las Flores field in the Cerro Dragon asset in Southern Argentina with three fluid pulsing injection systems.[1] Potential problems associated with waterflood techniques include inefficient recovery due to variable permeability and early water breakthrough that may cause production and surface processing problems. The water/oil-mobility ratio is a key parameter in determining how much oil is displaced.

Fluid pulse technology has proved its ability to revive oil fields by recovering more barrels, stabilizing decline curves, and reducing production costs. The fluid pulses add acceleration and momentum to the injection stream, forcing it into the oil-bearing reservoir at speeds of up to 100 m/s. The result is a much better sweep of the oil toward the surrounding producing wells. This paper discusses various aspects of the waterflood fluid pulsing project implemented in 2011 and details the fundamental considerations involved when designing and operating a waterflood pulsing system.

The three injectors equipped with fluid pulsing systems were installed in a field with a reservoir of unconsolidated sandstone that has been on waterflood for 19 years. The heterogeneous nature of the reservoir gives rise to considerable channeling of the injected water to the surrounding production wells. To date the three pulsating water injection systems have increased production in the three injection patterns by an average of 5.84 m^3/d, which is approximately 24% above the base decline. The pulsating injection method, in particular when done with an electrically controlled downhole tool, is a successful method for increasing oil production, lowering water-cut, and improving or stabilizing the base oil decline rate. The ability to open new flow channels and increase oil production with the same amount of water injected is a game change in waterflooding technique.

INTRODUCTION

The patented pulsating injection system used in the Pan American Energy project generates pulsations of water, adding sufficient energy and momentum to produce a dilation of the pore spaces in the rock, permitting the passage of water and movement of oil through reservoirs that are otherwise difficult to mobilize with conventional injection approaches. In this way, an attempt is made to increase the recovery of oil by improving volumetric efficiency and reducing residual saturation following water filtration.

Currently, three pulsating injection tools have been installed. One of these was installed with wireline equipment and operates mechanically, adjusting its frequency of operation in accordance with the differential pressure applied to the bottom valve. The other two tools were installed with pulling equipment and operate electrically, connected via a cable to their controller at the wellhead. The electrical tools have the advantage of controlling the frequency of the pulses during operations from the surface by means of the control panel. Connection was made to the local SCADA System in order to achieve real-time monitoring of operating variables, as well as the ability to turn on and off the injector remotely and also to warn the operators of a power failure, as the controller has the ability to restart the tool automatically.

The objective of the project was to recover additional trapped oil, which was considered unmovable by waterflooding using conventional technology; the pulsing technology with its "waves" causes the coalescence of residual drops of oil, allowing these to be extracted.

The efficiency of the system was measured through the initial increase in the production of oil, the decrease in the percentage of water, and the improvement in the annual oil declination rate, which in its totality will result in an opportunity to increase productivity and recoverable reserves.

Reservoir properties

- Unconsolidated Sandstones
- Permeability: 250 mD
- Porosity: 24.0
- Temperature: 38° C
- Oil Density: 0.924 g/cm^3
- Oil Viscosity: 12 cP

Location of the oilfield

The Las Flores oilfield is located in southern Argentina, northwest of the Cerro Dragon asset, approximately 90 km west of Comodoro Rivadavia (Fig. A-1); it is a monocline elongated area with northeast-southeast orientation that is divided into two blocks by a direct fault, one located in the southern part, known as Block I; the other located in the northern part of the aforementioned area, identified as Northern Block (Block N) (Fig. A-2).

Figure A-1
Comodoro Rivadavia (A) to Cerro Dragon Asset (B)

Figure A-2
Cerro Dragon Asset (A) to Las Flores oilfield (B)

STATEMENT OF THEORY AND DEFINITIONS

The implementation of secondary and tertiary recovery systems has greater efficacy when the fluids are placed along the completed interval with both maximum distribution and depth of penetration. Conventional, steady-state injection methods are limited in their effectiveness to achieve these attributes because those approaches do not have the capacity to overcome difficult reservoir conditions such as low permeability streaks, high viscous oil, and sometimes even worse, the presence of fractures and thief zones. In addition, conventional steady-state injection and production establish primary pathways thereby reducing the effectiveness of the fluid injected, as the fluid merely follows the pre-established pathways.

As Spanos et al. (2003) demonstrate, the fluid pulsing methodology induces deep penetration and more uniform distribution of fluids used in EOR and IOR, through high-amplitude fluid pressure pulses. This form of fluid pulse creates a "dynamic flow" environment (Fig. B-1), which has been demonstrated to effectively

overcome the difficult reservoir conditions previously mentioned.

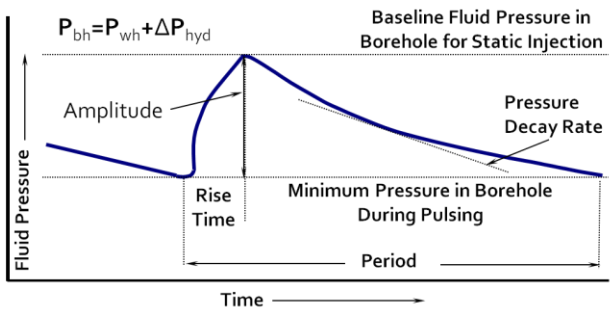

Figure B-1
The fluid pulsing technology forced injectivity

How does a fluid pressure pulse work? As Dusseault, Davidson, and Spanos (2000) explain, when a fluid pulse is applied, the pore space elastically responds causing the pre-determined pore networks momentarily to increase in volume and interconnectivity, as well as opening multiple, additional pathways to liquid flow (dynamic permeability) (Fig. B-2, adapted from p.17 in Dusseault, Davidson and Spanos (2000)).

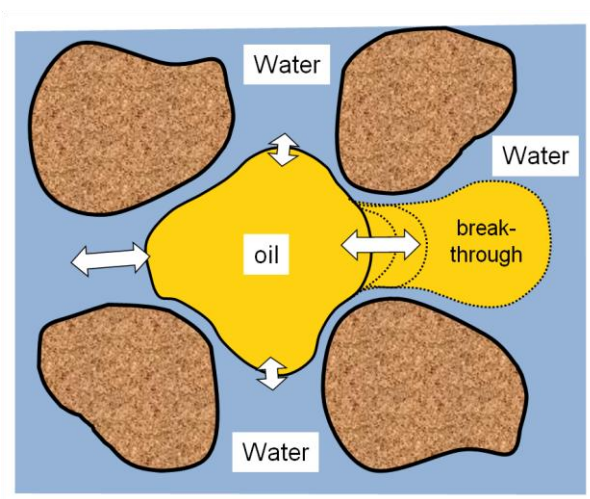

Figure B-2
Fluid pulses create a dynamic permeability

The result is greater dispersion of the injected fluid, maximizing the sweeping efficiency and bypassing the existing fingers and preferential channels. Overall, this represents greater productivity gains, increasing oil recovery.

HISTORICAL INFORMATION OF THE FIELD AND CONDITIONS OF INSTALLATION

Production and injection history

The block selected to implement the present pulsating injection project is Block N, which initiated its secondary recovery project in February of 1992 with 2 injectors and 4 producers, later eventually reaching the current 7 injectors influencing 11 producing wells.

The response time for a fluid pulsing projects with a history of injection is generally estimated to be between 2 and 6 months, counted from the beginning of the pulsations. (In a new project, with no history of injection, depending on formation conditions, response time typically will be 4-12 months). However, in the Las Flores project, an immediate improvement was detected in the declination of oil-cut.

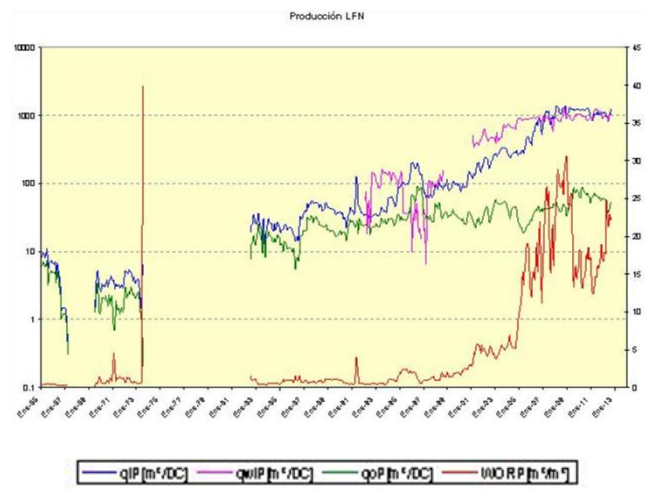

Figure C-1
Block N Production Curves

The production and injection histories of the block are shown in Fig. C-1; it may also be seen in this figure that beginning in 2007, the produced liquid exceeds the water injected, establishing a tendency to improve the balance of fluids from the block.

Additionally, production and injection from the original project and the variations produced by the 2 successive expansions are shown, including a period without injection that runs from August of 1998 to February of 2001.

Production and injection from the block under consideration for August of 2011 is indicated in the values shown in Table A-1:

Description	Production		Water Injection
	Oil	Water	
Daily Production (m^3/d)	57	973	1.139
Accumulated M^{m3}	386.3	2.740	3.281
Active Wells	9		7

Table A-1
Data from before the installation

Oil production has remained stable since this date, showing consistent behaviour with a good produced/injected balance in recent years.

Project Selection

The first producing wells of the N block of the Las Flores North field were drilled and put into production in January of 1965, the majority of which documented pressurized oil with high volumes of dry oil for the final tests of zone E-1, the injection zone targeted in this project. Gas tests were also performed on this zone in the uppermost area of the structure.

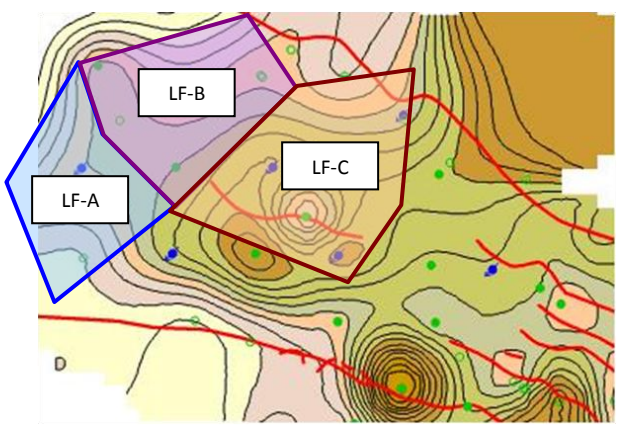

Figure C-2
Las Flores Oilfield

Up until August of 2011, block injectors were injecting a total of 1139 m3/day. In November 2011, for the pilot of the project, three injectors were selected on which to install the pulsing tools: LF-A, LF-B and LF-C, which are located in an area with fewer faults and therefore better connectivity between wells (Fig. C-2). That month, one electrical tool was installed on LF-A, and the mechanical tool was installed on LF-B. (Due to operational logistics, the second electrical tool's installation on LF-C was delayed until March 2012.)

The predominant natural production mechanisms prior to the start of water injection, deduced from the production history and pressures, were monophasic expansion and later expansion of the gas in solution.

Figure C-2 shows the isopachous map of zone E-1, with very good continuity and thickness in the area.

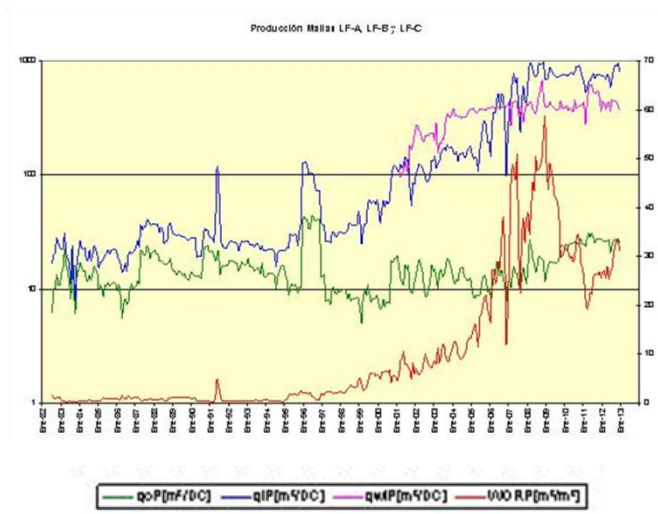

Figure C-3
Production in Area Implementing the Pilot

Although the field includes various injection zones, for this particular pilot of the project, injection zone E-1 was targeted to test the tools since that zone was recognized as that with the most potential to increase oil production. Zone E-1, highly permeable and accessible, found in a shallow area approximately 700 m down, was considered depleted through conventional modes of injection. It has good thickness and surface area. Additionally, important individual evidence of oil has been documented, without the need for fracking. The specific characteristics of E-1 are summarized in Table A-2.

Waterflood Started:	February 1992
Pilot Injectors	LF-A, LF-B and LF-C
Pilot Producers	LF-1, LF-2, LF-3, LF-4, LF-5 and LF-6
Liquid Production	665 m^3/day
Oil Production	24m^3/day
Injection Area (3 Injectors)	300 m^3/day
Original Average Reservoir pressure	63 kg/cm^2
Average Permeability	200-260 m/day
Injection Pressure	15 kg/cm^2 (213 psi)
Dead Oil Density	0.924 g/cm^2 (21.6 ºAPI)
Soa	57%
Current Primary Fr	4%
Current Secondary Fr	3.5%
(Prim+Sec. Fr.) 2047	17%
VP	1128 mm^3
Average Porousness	24%
Average Dist. Inj.-Prod.	460 m
Inj. VP	42%
Viscosity	12 cp@ res. temp. 38ºC
Layer E1 Average Thickness	6 m
Balance Qwiny/Qliq	1.1

Table A-2
Injection Zone E-1 Characteristics

Analyzing the most recent entries we can see that the injectors showed an injection pressure at the wellhead of between 4 and 30 kg/cm^2 for the month of August of 2011.

Initial conditions

Prior to beginning the pilot project, the stability of production and injection of the area was assured through an increase in production controls and daily monitoring of injection volumes. In this way, a referential base line of production was guaranteed, upon which the variations in production as a result of the pulsating injection system could be estimated safely.

Water Quality

Water quality is monitored through daily testing of parameters such as ppm of oil in water, total suspended solids (mg/l) and oxygen content (ppb) and bacterial count (col/ml). In the figures below (C4, C5 & C6) it can be seen that said parameters are within good quality ranges set principally not to lose injectivity as a result of clogging in the secondary layers.

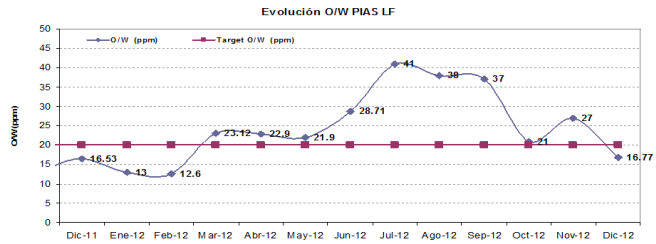

Figure C-4
Oil in Water (ppm)

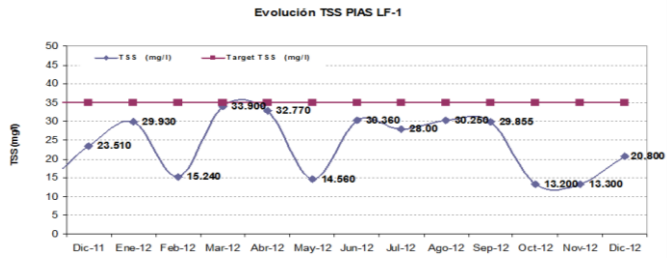

Figure C-5
Total Suspended Solids (mgl)

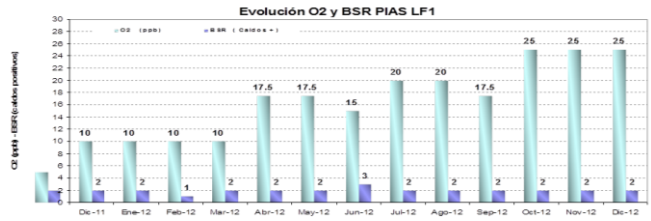

Figure C-6
Oxygen and Bacteria Content within the Water

Surface Equipment

Injector well LF-A has an aqueduct 620 m in length and 2” in diameter, which connects it to the manifold. Injector well LF-B has an aqueduct 600 m in length and 2” in diameter. Injector well LF-C has an aqueduct 890 m in length and 2” in diameter.

The injection pumps used in the PIAS are quintuplets with a manifold pressure of 1450 psi. The distance from the PIA to the manifold is 16 km.

Currently the injection parameters are obtained with surface measurements through calibrated digital flow metres located in the injection manifold. Said data (volume and injection pressure) are sent to the SCADA system for better monitoring of same.

Length of Pilot

The project at this point of analyzing the results has a duration of 24 months (and 20 months for the third tool with a delayed installation).

Electrical Tool Installation: LF-A and LF-C

LF-A began injection in Jan. 2001 with 2 associated producers (LF-1 and LF-2) and LF-C in Sept. 2001 with 3 front-line producers (LF-2, LF-5 and LF-6). Added to these in 2009 were LF-3 (a well with a production history, but zone E-1 had not been penetrated until that time) and in 2011 LF-4 (the final well to be drilled in the network).

Wells LF-A and LF-B were selected to install the first electrical tool (Fig. C-7) and the mechanical tool in November since they were the only candidates available for the pilot that had just zone E-1 penetrated, and as a result only 1 packer above the targeted zone was used.

Since well LF-C had three injection zones and zone E-1 was the bottom one, to install the second electrical tool in March, two packers were required above E-1. The bottom packer, right above the zone has to be a mechanical packer because the electrical tool must be able to remain open in its resting mode during installation, and the pressure required to activate a hydraulic packer would be lost through the tool. A hydraulic packer was installed at the top, using a rupture-disc between the two packers in order to activate the upper packer and test the completion.

During the completion of the electrical tool, there were no difficulties in the lowering of the tool, even though the completion required an electrical cable from the tool all the way to the computer at the surface (Fig. C-8) that governs the function of the tool downhole. Due to the long shut-in of the injector, the reservoir was depressurized and when injection resumed the pressure at the wellhead was 2 kg/cm2 (previously it had been 30 kg/cm2) (Fig. C-9).

In spite of this, once the power was turned on in the well, calibration of the tool went ahead (from the computer); it was set to 12 pulses/min, with the tool set at 1.5 seconds open and 2.5 seconds closed, the longer closed period temporarily set to increase injection pressure. At the end of the second day following the installation of the tool, it was noted above-ground that the pressure had returned to normal, that is to say, 30 kg/cm^2. (A typical set in the computer, once the pressure in the well is regularized, would be 1.5 seconds open and 1.5 seconds closed, unless variables and reservoir conditions require a different setting.)

Figure C-7
Electrical pulsing tool at the end of the injection BHA

Figure C-8
Computer at Surface (Control Panel/Controller)

Figure C-9
Electrical Tool, typical wellhead completion

Mechanical Tool Installation: LF-B

LF-B started injection in Feb. 2009 with 2 associated producers (LF-1 and LF-2). Added to these were LF-3 in 2009 (well with a production history, but layer E-l had not been penetrated until that time), and LF-4 in 2011 (the last well to be drilled in the network).

For the installation of the mechanical tool (Fig. C-10) in well LF-B, the completion was simple as the installation required only wireline equipment, to set the mechanical tool downhole with a lock to seat it in the landing nipple at the end of the injection string (Fig. C-11). To position the mechanical tool at the right depth, extension tubing of 1" was required between the landing nipple and the tool.

As with well LF-A, the reservoir was depressurized. When injection was resumed, the pressure at the wellhead (Fig. C-13) was 0.0 kg/cm^2, while the pressure had previously been 1.5 kg/cm^2 (20 psi). In this instance, it required 7 days for the reservoir to begin pressurize, reaching its original pressure (20 psi) 14 days following the re-establishment of injection.

Figure C-10
Mechanical pulsing tool at the end of the injection BHA

Figure C-11
Typical lock and landing nipple used

Figure C-13
Mechanical Tool, typical wellhead completion

Monitoring Schedule

A monitoring schedule was implemented in accordance with the expected results in the estimated times, with the objective of determining if a response was produced in the volumes of the affected producing wells in the Pilot. The producing wells of the networks involved were tested at least 2 times per month, for the first 12 months.

The submersion depth of the pumps was tested more frequently, in order to quickly correct any variation and maintain them at optimal performance.

Any required work on the producers was made before the installation. Production and injection was stabilized and tested in order to reach a base oil decline curve that was stable at least a month before the installation of the tool.

Measurements of injected volume are taken at the surface with calibrated flow metres. Surface pressure and temperature is also recorded for the injectors on which the electrical tool is installed.

On the affected injectors, the accumulation of pulses and the surface pressure is being monitored as shown in the following table A-3:

Day	Pulses Accumulated	Bottom Temp.	Wellhead Pressure
30/11/2014	1,909 K	77° C	280/460

Table A-3
Data from the affected injectors

In the case of the mechanical tool, the pressure observed at the wellhead is that reached at the time of closure, this being its maximum value, later to decrease to 0 psi when it is open; these are instantaneous measurements, in which the cycle lasts approximately 8 seconds, as a result of installing the accumulator at the wellhead; it does not affect the equipment at the surface.

SCADA and the pulsing tools

Wells LF-A and LF-C include SCADA technology. SCADA means: *Supervisory Control And Data Acquisition*. By definition, SCADA is a system operating with coded signals over communication channels so as to provide control of remote equipment. Typically, SCADA would be used to monitor parameters from well producers; however, Pan American Energy requested the electrical pulsing tool with the SCADA system, as the computer has the capacity also to collect data on the functionality of the electrical tool downhole. Besides monitoring parameters from the electrical tool, one of the several advantages that the electrical tool with SCADA offers real-time problem identification that occurs with the pulsing tool, and can be fixed remotely from the control room.

The SCADA system added to the electrical pulsing tool is called a MODBUS Unit, and it is designed to work with the client's existing SCADA system via Modbus RTU slave communication. The MODBUS unit is interfaced with the computer of the electrical pulsing tool, and needs to be connected to the client's SCADA system upon site installation.

For interfacing with the client's existing SCADA system, the MODBUS addition has:

1. a 4-wire RS485 interface running at 9600 baud, 8 bit, no parity, one stop bit.
2. Or a 2-wire RS232 interface running at 9600 baud, 8 bit, no parity, one stop bit.

It will also have an 8 bit dip switch to send the slave address with.

For instance, during the pilot, in October 2013, the SCADA system identified a malfunction of the 2 electrical tools in the pilot due to a power failure. Pan American Energy's operator in the control room received the 2 alarms on their screen (Fig. C-14). The operator was then able to identify the problem, as each injector was showing the problem from a power failure (Figs. C-15 and C-16).

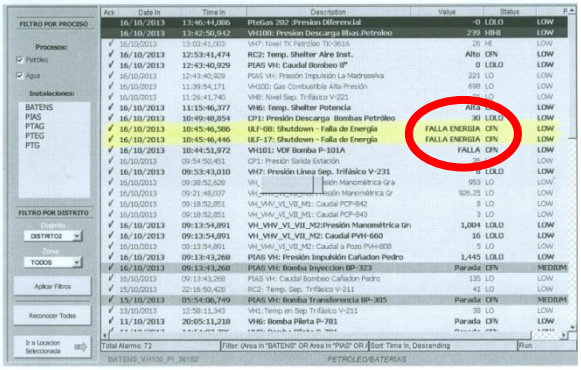

Figure C-14
SCADA screen from Pan American's system

Figure C-15
SCADA Screen Alarm for the injector LF-A

Figure C-16
SCADA Screen alarm for the injector LF-C

Once the problem was identified and confirmed, Pan American Energy's operator (in Argentina) informed Wavefront's technician (in Canada) via email about the it; and, in less than an hour, with instructions from Wavefront's technician, the injectors were back to normal, pulsing the water injected in the wells LF-A and LF-C. It is important to mention that the power failure only caused the tool to stop pulsing; the injector,

however, continued to inject the required volume of water during the period of power failure until the tool resumed pulsing. The tool design ensures that it will never fail closed, so that there is no risk of affecting the injection rate or the flow lines integrity.

The "Register 2" of the Registry Map of the electrical pulsing tool's SCADA, contains a bit mask of the various statuses of the tool. The following shows the meaning of each status bit.

1. Tool Running – Automatic Mode
2. Tool Running – Manual Mode
3. Tool Shutdown – Low Pressure
4. Tool Shutdown – High Pressure
5. Tool Shutdown – Over Temperature
6. Tool Shutdown – Local Operator
7. Tool Shutdown – Power Fail
8. Tool Shutdown – Load Too Hot
9. Tool Shutdown – Cabinet Too Hot
10. Tool Shutdown – Solenoid Resistance to Low
11. Tool Shutdown – No Load
12. Tool Shutdown – Remote Operator
13. Tool Reset to Default Settings

The Registry Map includes also other Registers such as:

a) Register 1: The software version
b) Register 3: Tool temperature
c) Register 4: Pulses per minute
d) Register 5: Flow meter per minute
e) Register 6: Surface pressure reading, and
f) Register 100: Run Control Register

The use of SCADA technology in an injector positioned the electrical pulsing tool at the cutting edge of technology of its type, adding a superior benefit to what the downhold pulsing tool have offered up to this point.

Pan American Energy is the first company in the world to install a pulsing injector with a SCADA system.

DATA AND OBSERVATIONS

On a quarterly basis, an "ABC"—or "After-Before-Compare"— approach was used to evaluate the gathered information for each oil producer. ABC plots (Fig. D-1) were created to visually demonstrate well response on a before-and-after oil rate and water rate basis. The average WOR (water and oil rate) for the corresponding study area is plotted and appears as a diagonal through the axes. The top-right quadrant represents an increased WOR, the bottom-right is an increased oil and decreased water rate response (the most preferred scenario), the bottom-left is decreased oil and decreased water, and the top-left is a decreased oil rate and increased water rate (the worst case scenario). The top-right and bottom-left quadrants are somewhat interpretive as to whether or not they are positive or negative responses. Thus, adding the average WOR slope line helps with the analysis. In the top-right where both oil and water have increased, the points below the WOR slope line indicate better responses, as the oil rate has increased with a lower (and thus more desired) ratio of water increase. Likewise, for the bottom-left quadrant, where both oil and water rate decrease, the points below the WOR slope line are better responses as the water rate has decreased more than the oil rate to a WOR lower than the area average. A schematic plot highlighting the quadrants for the ABC plots is shown in Figure D-1.

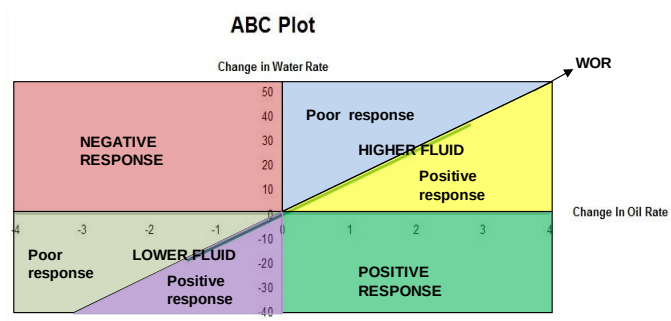

Figure D-1
After-Before-Compare (ABC) Rate Plot

The ABC-Plot for the six oil producers associated with the three patterns is shown below indicates four wells in the positive response quadrants and two wells which had only poor response, namely LF-01 & LF-03. It is to be noted that none of the wells had a negative response to the installation of the tools (Fig. D-2).

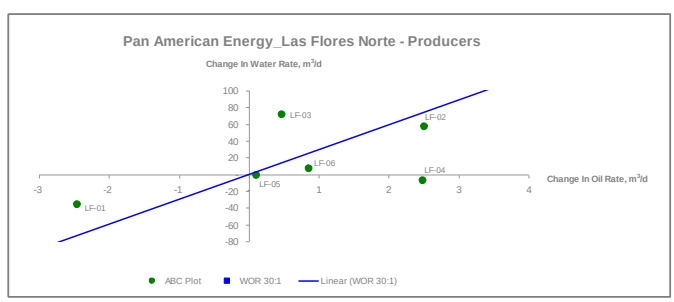

Figure D-2
ABC-Plot for the 6 producers associated

In the ABC-Plot, well LF-01 showed a drop in both water and oil rates, indicating that not much water is reaching this particular well through injection, while well LF-03 shows the opposite, as both water and oil rates have increased, which indicates that much of the water injected is reaching this well, and the effect is not entirely negative, as the oil production too has increased.

The other four wells, however, all showed a positive response, with well LF-05 showing a slight positive response, and the other three are showing significant improvement in oil rate along with a decrease in water rate. The variation in results to the different producing wells results from the differing influence of the paths from injector to producer, as each one communicates differently with its injector. Therefore, only when the results from all the wells are considered together the full impact of the project can be fully understood and the great benefit from the pulsing tool over the conventional system be seen, as illustrated in the Results section below.

RESULTS

The overall three patterns' oil decline rate was improved from 0.62% per month to 0.39% per month (Fig. E-1), representing an improvement of 36%. The vertical lines in Figure E-1 and E-2 represent the dates of installation of the tools in November 2012 and March 2013.

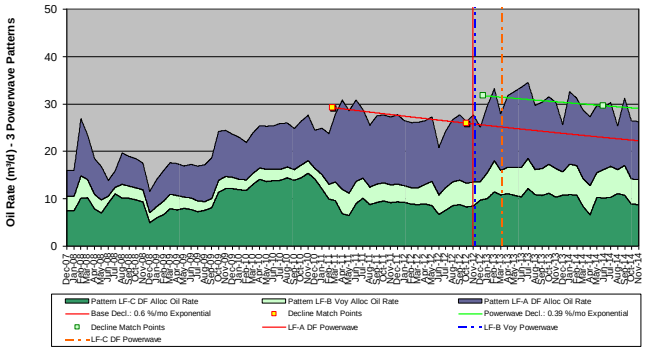

Figure E-1
Declination Curve Comparison, Before-After

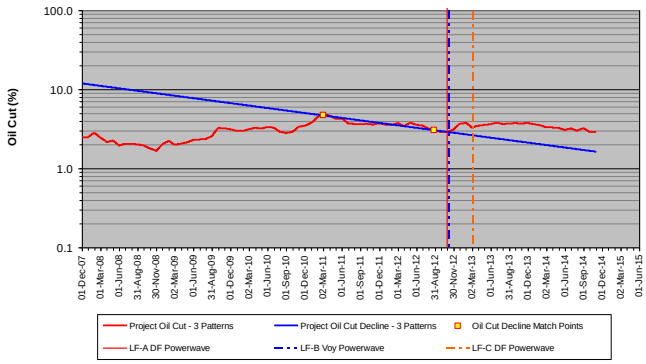

Figure E-2
Project Oil-Cut

The oil-cut (Fig. E-2) for the three patterns was monitored and graphically presented to calculate the trend.

As seen below (Fig. B-1), the overall project showed a 36% decrease in oil decline rate, a 24% increase in oil production, and a 55% increase in oil cut. Figure B-1 summarizes the three patterns' final results and the benefits of converting conventional injectors that inject in a steady-state way to the pulsating injectors, adding acceleration to the water when it is injected.

Description	Pre Powerwave	Post Powerwave	Change	
Project Basis Oil Decline Rate Oil Production (avg.) Oil Cut (avg.) Incremental Oil (Project) Incremental Oil (ΣPatterns)	0.62 %/month 23.92 m³/d 2.21%	0.39 %/month 29.76 m³/d 3.43% 4,275 m³ 5,577 m³	-0.22 %/month 5.84 m³/d 1.22%	(36% decrease) (24% increase) (55% increase)
Pattern 1 - LF-A DF				
Oil Decline Rate Oil Production (avg.) Oil Cut (avg.) Incremental Oil	0.9 %/month 11.34 m³/d 1.88%	13.75 m³/d 3.03% 1,770 m³	2.42 m³/d 1.14%	(21% increase) (61% increase)
Pattern 2 - LF-B Voy				
Oil Decline Rate Oil Production (avg.) Oil Cut (avg.) Incremental Oil	1.0 %/month 3.51 m³/d 2.46%	5.72 m³/d 4.74% 1,612 m³	2.22 m³/d 2.29%	(63% increase) (93% increase)
Pattern 3 - LF-C DF				
Oil Decline Rate Oil Production (avg.) Oil Cut (avg.) Incremental Oil	1.1 %/month 7.12 m³/d 2.11%	10.31 m³/d 3.53% 2,196 m³	3.19 m³/d 1.43%	(45% increase) (68% increase)

NOTE: The data in the table above has been calculated for the period 31-Oct-2012 to 31-Oct-14.

Table B-1
Overall Project Results

Figure B-2 shows well-by-well results during the project duration. It is worth highlighting that some oil producers are associated to more than one pattern with the assumption of equal interference between wells (i.e. equal sharing of benefits).

Pan American Energy Las Flores Norte Well Benefit Summary — Evaluation Period 31-Oct-12 to 31-Oct-14

Pattern	Well	Last Test Date	Last Test Oil Rate (m^3/d)	Avg.Base Decline Oil Rate (m^3/d)	Avg.Base Decline Oil Cut (%)	Avg.Post Powerwave Oil Rate (m^3/d)	Avg.Post Powerwave Oil Cut (%)	Avg.Powerwave Oil Rate Benefit (m^3/d)	Avg.Powerwave Oil Rate Benefit (bopd)	Avg.Powerwave Oil Cut Benefit (%)
		C	G	AK	BF	AP	AI			
LF-A DF	LF-01	31-Oct-14	6.60	5.81	3.03	6.76	3.95	0.94	5.94	0.92
	LF-02	31-Oct-14	5.51	1.99	1.39	7.11	3.42	5.12	32.21	2.03
	LF-03	31-Oct-14	6.35	3.26	1.48	6.34	1.85	3.09	19.42	0.37
LF-B Voy	LF-01	31-Oct-14	6.60	5.81	3.03	6.76	3.95	0.95	5.95	0.92
	LF-02	31-Oct-14	5.51	1.99	1.39	7.11	3.42	5.12	32.21	2.03
	LF-04	31-Oct-14	4.50	2.18	2.97	4.46	7.75	2.28	14.33	4.78
LF-C DF	LF-03	31-Oct-14	6.35	3.26	1.48	6.34	1.85	3.09	19.42	0.37
	LF-04	31-Oct-14	4.50	2.18	2.97	4.46	7.75	2.28	14.33	4.78
	LF-05	31-Oct-14	-	1.07	2.16	1.23	1.81	0.17	1.04	-
	LF-06	31-Oct-14	3.36	2.02	10.55	3.49	10.94	1.47	9.26	0.39
Sub Total				**16.32**		**29.39**		**13.07**	**82.19**	
Powerwave Benefit (Σ Post Powerwave - Σ Base Decline)								**13.07**	**80.1%**	
Powerwave Benefit (Σ benefit > 0)								**13.07**	**80.1%**	

Table B-2
Well-by-well Results

CONCLUSION

As a conclusion of the 2-year project monitoring and tracking well performance, it is clearly evidenced that pulsating water injection is more effective than conventional steady-state injection. Even though the field had been on injection since 1992 and preferential channels had been established between injectors and producers, the pulsing injection technology has demonstrated its ability to overcome and bypass these existing preferential channels and sweep new zones in the reservoir, which translates into an increase in oil recovery and often even—as in this project—a lowering in water cut.

Using pulsating technology in new wells is strongly recommended for new water-flooding projects in order to maximize the benefits from the start instead of using them only at a later stage when viscous fingering has already been created due to permeability variation and adverse mobility ratio.

In response to the results presented here, the current project in the Las Flores Field is now planned to expand with four more pulsing electrical tools in 2015.

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NOTES

1. A poster with preliminary information on this project was presented earlier on in the project in Spanish by Pan American Energy and Wavefront Reservoir Technologies at the Conference, "Congreso de Produccion y desarrollo de Reservas de Hidrocarburos" in Rosario, Argentina, May 21-24, 2013.

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