USING HORIZONTAL WELLS FOR CHEMICAL EOR: FIELD CASES

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Primary production of heavy oil in general only achieves a recovery of less than 10% OOIP. Waterflooding has been applied for a number of years in heavy oil pools and can yield much higher recovery but the efficiency of the process diminishes when viscosity is above a few hundreds cp with high water-cuts and the need to recycle significant volumes of water; in addition, significant quantities of oil are still left behind. To increase recovery beyond that, Enhanced Oil Recovery methods are needed. Thermal methods such as steam injection or Steam-Assisted Gravity Drainage (SAGD) are not always applicable, in particular when the pay is thin and in that case chemical EOR can be an alternative.

The two main chemical EOR processes are polymer and Alkali-Surfactant-Polymer (ASP) flooding. The earlier records of field application of polymer injection in heavy oil fields date from the 1970's however; the process had seen very few applications until recently. ASP in heavy oil has seen even fewer applications. A major specificity of chemical EOR in heavy oil is that the highly viscous oil bank is difficult to displace and that injectivity with vertical wells can be limited, particularly in thin reservoirs which are the prime target for chemical EOR. This situation has changed with the development of horizontal drilling and as a result, several chemical floods in heavy oil have been implemented in the past 10 years, using horizontal wells. The goal of this paper is to present some of the best documented field cases.

The most successful and largest of these is the Pelican Lake polymer flood in Canada, operated by CNRL and Cenovus which is currently producing over 60,000 bbl/d. The Patos Marinza polymer flood by Bankers Petroleum in Albania and the Mooney project (polymer, ASP) by BlackPearl (again in Canada) are also worthy of discussion.

Keywords: Heavy oil, Enhanced Oil Recovery, EOR, chemical EOR, polymer, Alkali-Surfactant-Polymer (ASP), field cases, horizontal wells

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Introduction

Primary production of heavy oil in general only achieves a recovery of less than 10% OOIP. Waterflooding has been applied for a number of years in heavy oil pools (Beliveau, 2009) and can yield much higher recovery but the efficiency of the process diminishes when viscosity is above a few hundreds cp with high water-cuts and the need to recycle significant volumes of water; in addition, significant quantities of oil are still left behind. To increase recovery beyond that, Enhanced Oil Recovery methods are needed. Thermal methods such as steam injection or Steam-Assisted Gravity Drainage (SAGD) are not always applicable, in particular when the pay is thin (Delamaide, 2017) and in that case chemical EOR can be an alternative.

The two main chemical EOR processes are polymer and ASP flooding. The principle of polymer flooding is to increase the viscosity of the injection water, thereby improving the mobility ratio. Polymer can also improve horizontal and vertical sweep efficiency, for instance by increasing pressure drops in high permeability layers thus diverting flow to less permeable layers. The principle of ASP (Alkaline, Surfactant and Polymer) is to achieve a reduction of interfacial tension between the water and the oil, which allows to reduce the residual oil saturation. In some cases when the oil is reactive, the addition of an alkaline agent such as NaOH can promote the formation of in situ surfactants, which allows to reduce the quantity of surfactant required. Alkali also allows to decrease surfactant adsorption.

The earlier records of field application of polymer injection in heavy oil fields date from the 1970's (Delamaide, 2014); however the process had seen very few applications until recently and indeed, screening criteria used to limit the oil viscosity to 150 cp for polymer flood applications (Delamaide, 2017). A major specificity of chemical EOR in heavy oil is that the highly viscous oil bank is difficult to displace and that injectivity with vertical wells can be limited, particularly in thin reservoirs which are the prime target for chemical EOR. This situation has changed with the development of horizontal drilling and as a result, several chemical floods in heavy oil have been implemented in the past 10 years, using horizontal wells; Table 1 presents a list of these projects. As can be seen from the table, most of these projects have been implemented at a large scale. The goal of this paper is to present some of the best documented field cases.

The most successful and largest of these is the Pelican Lake polymer flood in Canada, operated by CNRL and Cenovus which is currently producing over 60,000 bbl/d. The Patos Marinza polymer flood by Bankers Petroleum in Albania and the Mooney project (polymer, ASP) by BlackPearl (again in Canada) are also worthy of discussion.

Company	Field	Formation	Country	Dead oil viscosity (cp)	Process	Status
CNRL, Cenovus	Pelican Lake	Wabiskaw	Canada	1,500-2,500	P	Full field
BlackPearl	Mooney	Bluesky	Canada	255-400	P, ASP	Successful polymer pilot, ASP appears successful
Murphy	Seal	Bluesky	Canada	5,000-12,000	P	Large scale expansion
Bankers Petroleum	Patos Marinza		Albania	1,500	P	Large scale expansion
Northern Blizzard	Cactus Lake	Basal Mannville-Bakken	Canada	>500	P	Full field
PDO	Nimr		Oman	500?	P	Pilot
Enerplus	Medicine Hat	Glauconitic	Canada	1,000-1,500?	P	Successful pilot

Table 1. Recent chemical EOR field cases using horizontal wells

Projects description

Pelican Lake (CNRL and Cenovus, Canada)

The Pelican Lake field (sometimes called Brintnell) located approximately 250 km north of Edmonton, Alberta, Canada (Fig. 1) was discovered in 1978 and started producing in 1980 (Cenovus Energy…, 2013). Original Oil In Place is approximately 6.5 billion barrels.

The reservoir formation is the Wabiskaw "A" sand, a coarsening upward sheet sand interpreted as part of a prograding shoreface within the Clearwater formation of the Upper Mannville Group of Lower Cretaceous age (Fig. 2). It is deposited in a 35x60 km^2 NE-SW trending lobe thinning to the North, East and South and capped by the transgressive marine shale of the Clearwater formation. A water leg is found down-dip to the SW and a gas cap is found up-dip to the NE. Locally, small isolated gas caps may also be found. Immobile (highly viscous) oil is also found to the North-East (Cenovus Energy…, 2013). The reservoir is composed of unconsolidated sands which consist mainly of quartz and chert. Reservoir petrophysical properties are generally excellent with 28-32% porosity and a permeability that varies between 300 up to over 5,000 md. The main reservoir characteristics are summarized in Table 2 and a type log is provided in Figure 3.

The reservoir depletion mechanism is solution gas drive, but initial reservoir pressure was low and there is very little dissolved gas (Rs = 4-6 m^3/m^3) so there is little energy in the reservoir. As the oil is also viscous (from 800 to 80,000 cp) primary recovery is low, approximately 5 to 10% OOIP. In addition, the reservoir is thin (1 to 9 m, average 5 m) and as a result the first (vertical) wells drilled in 1980-1981 were not economic: low rates (less than 30 bbl/d usually declining rapidly to less than 10 bbl/d) and low cumulative productions (an average of 28,000 bbl total per well). This changed with the introduction of horizontal drilling in 1988; horizontal wells achieved much higher rates and improved the economics significantly, and as a result the whole pool was developed with horizontal wells (Delamaide et al., 2014a).

However, the recovery factor for primary production remained low even after the introduction of horizontal drilling. Thermal methods were tested but were not efficient due to the thin pay of the reservoir thus other methods were piloted. After a first – unsuccessful – polymer flood pilot in 1997, waterflood was also piloted. The waterflood managed to increase oil production but at the cost of high water-cut (Delamaide et al., 2014b).

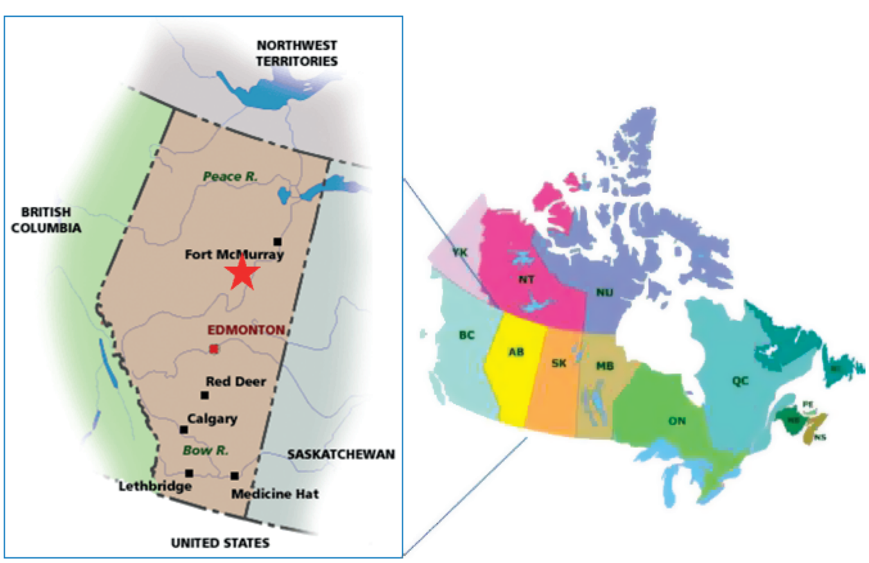

Fig. 1. Map showing location of Pelican Lake and Mooney pools (reproduced from (Delamaide et al., 2014b))

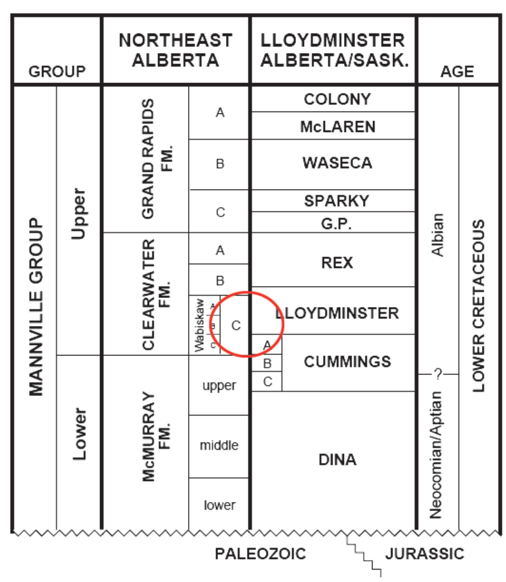

Fig. 2. Stratigraphic chart of the Mannville Group with Wabiskaw formation circled in red (reproduced from (Delamaide et al., 2014b))

Project	Country	Average depth (m)	Reservoir temperature (°C)	Average net pay (m)	Permeability (md)	API gravity	Live oil viscosity (cp)
Pelican Lake	Canada	300-450	12-17	1-9	300-5,000	12-14	800-10,000
Mooney	Canada	875-925	29	3-5	100-10,000+	12-19	100-250
Seal	Canada	610	20	8.5	300-5,800	10-12	3,000-7,000
Patos Marinza	Albania	1,200-1,300	40-42	4-12	100-2,500	8-10	600-1,600
Cactus Lake	Canada	850	27	6	500-1,500	15	500
Nimr	Oman		51	30-50	2,000-5,000	20	250-500
Medicine Hat	Canada	850	26	7	0-10,000		500-1,000?

Table 2. Main characteristics of selected projects

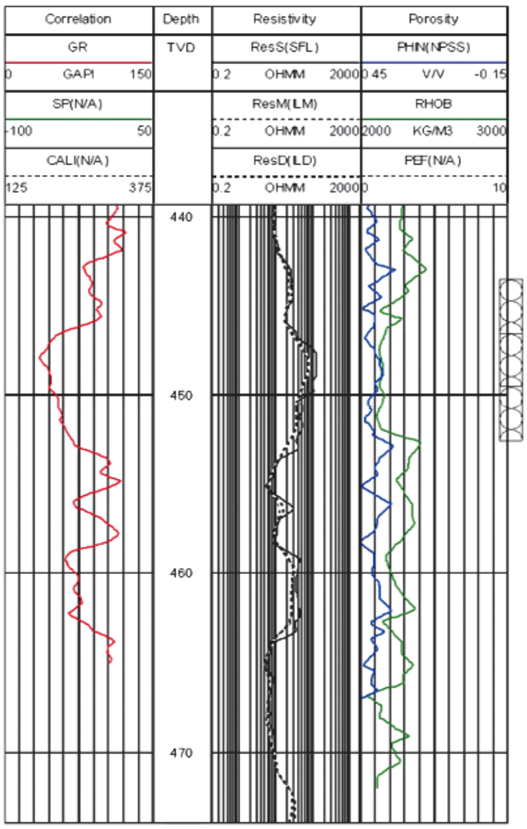

Fig. 3. Pelican Lake – Type log of well 1AD/11-09-081-22W4M (reproduced from (Delamaide et al., 2014b))

As a result, a second polymer pilot started in 2005.

This second pilot was composed of five 1400 m long horizontal wells (Delamaide et al., 2014a): three production wells (14-34, 15-34 and 16-34) and two injection wells in between (2/15-34 and 2/16-34), with a spacing of 175 m between the wells (Fig. 4). The wells had been drilled in 1997-1999. Viscosity in the pilot area ranges from 1,200 cp to 1,800 cp.

Polymer injection started in May 2005 with a target viscosity of 20 cp (corresponding to a concentration of 600 ppm initially), which was reduced to 13 cp at the end of August 2005 and later increased to 25 cp (Delamaide et al., 2014a). Initial injection rate was 930 bbl/d/well but it was later reduced as pressure increased in the pattern.

The response occurred in February 2006 in the central production well, and in April 2006 and September respectively in the two other producers (Fig. 5-7). As can be seen from the figures, the responses were excellent with oil rates increasing more than ten fold. On the contrary, the water-cut increased slowly and moderately in all three wells, especially compared to what was experienced in the waterflood pilot nearby, and after 10 years of constant polymer injection, is still in the 60-70% range.

Following that success, polymer flooding has been extended to significant portions of the field, with hundreds of wells under polymer injection (Fig. 8).

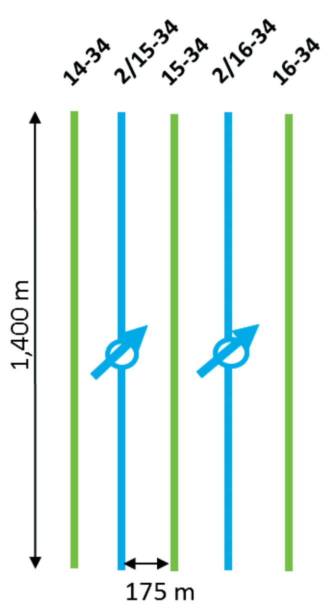

Fig. 4. CNRL HTLP 6 polymer flood pilot map (reproduced from (Delamaide et al., 2014b))

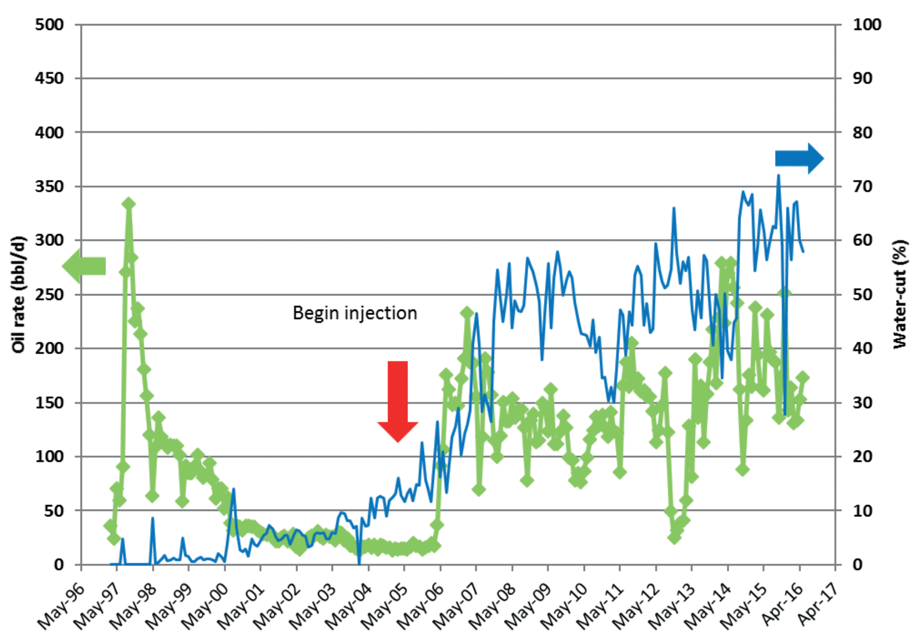

Fig. 5. HTLP 6 polymer flood pilot – Well 00/14-34-081-22W4 rate and water-cut (modified from (Delamaide et al., 2014b))

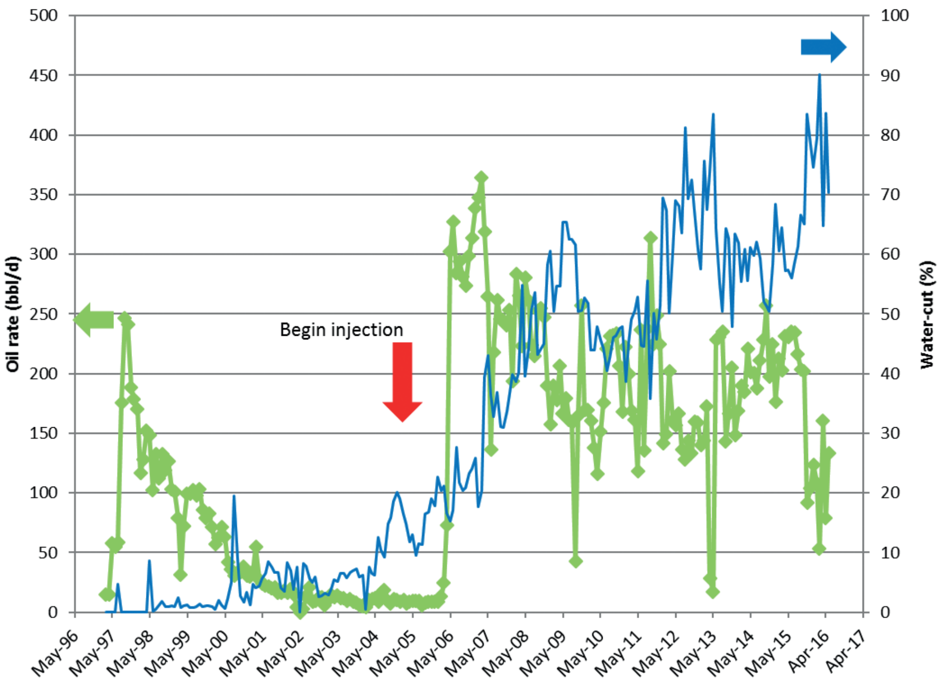

Fig. 6. HTLP 6 polymer flood pilot – Well 00/15-34-081-22W4 rate and water-cut (modified from (Delamaide et al., 2014b))

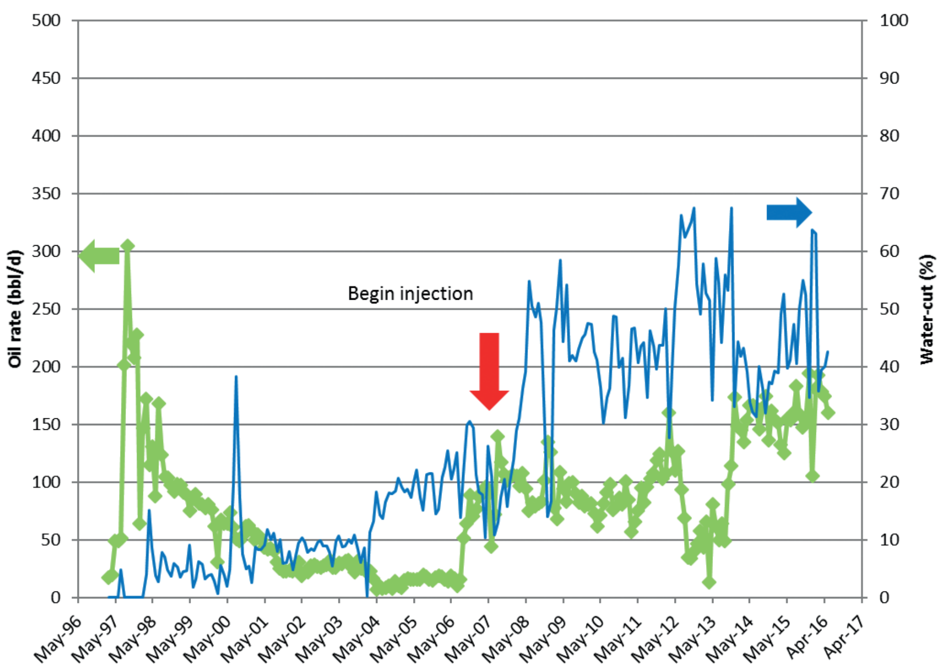

Fig. 7. HTLP 6 polymer flood pilot – Well 00/16-34-081-22W4 rate and water-cut (modified from (Delamaide et al., 2014b))

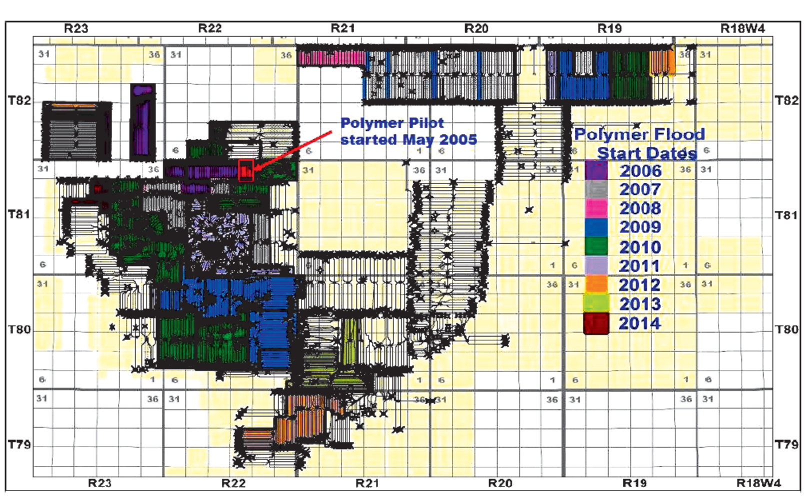

Fig. 8. Map of CNRL Pelican Lake pool with pilot location (in red) and polymer flood deployment (modified from (Delamaide et al., 2014b))

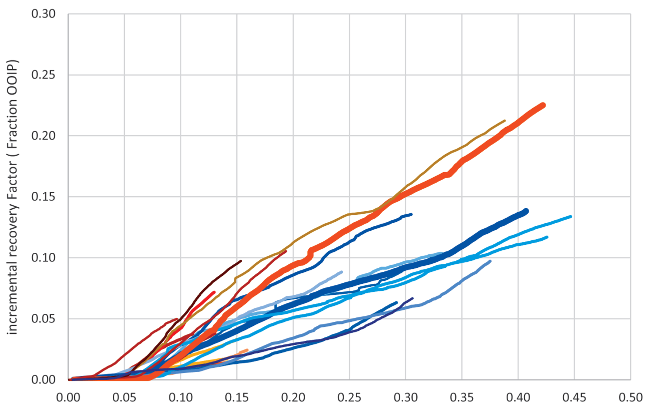

Fig. 9. Plot of Recovery vs. Cumulative injection for various wells in Pelican Lake. Each curve corresponds to a production well. Yellow-orange-brown colors correspond to secondary polymer flood while blue colors correspond to tertiary polymer flood (reproduced from (Delamaide, 2016))

The operators estimate that polymer flooding will increase the recovery factor to 20% OOIP to 30% OOIP, with the best pads achieving 38% OOIP.

A recent paper (Delamaide, 2016) reviewed the performances of primary, secondary and tertiary polymer flood in Pelican Lake. Figure 9 presents some of the results; they suggest that polymer flood is more efficient when applied in secondary conditions at least in Pelican Lake: recovery is accelerated and increased compared to waterflood, while water-cut is reduced. This first success allowed to demonstrate the potential for polymer flood in oil viscosities much higher than the ones recommended by the screening criteria, and opened the door for other field applications of the process.

Patos Marinza (Bankers Petroleum, Albania)

The Patos Marinza field is the largest onshore field in Western Europe and has been producing since 1928 (Hernandez et al., 2015). The reservoir is composed of several zones that consist in multiple stacked sands deposited during the Upper Miocene in a shallow marine environment at depth between 1,000 to 1,800 m. The main reservoir is the Lower Driza formation. Net pay is 4-12 m, and the petrophysical properties of the reservoir are good with a porosity of 21-26% and a permeability of up to 2,000 mD. The Lower Driza formation contains a heavy oil of 8-10 API with a live oil viscosity of 600 to 1,600 cp in reservoir conditions. OOIP is 5 billion bbl (Jacobs, 2015). A map of the field location is presented in Figure 10 and a type log in Figure 11.

The field was initially developed with vertical wells of which approximately 2,400 were drilled and produced by primary depletion (Weatherhill et al., 2005) with partial aquifer support but primary production only achieved a recovery of 6-10% OOIP. CHOPS (Cold Heavy Oil Production with Sand) was also tested in the field and horizontal wells were introduced since 2008: approximately 600 have been drilled so far. However, as in Pelican Lake, recovery remains limited even with horizontal wells and as a result EOR methods are required to increase recovery further.

The review of several polymer flood pilots in heavy oil – including Pelican Lake – led to the decision of piloting polymer injection in the field (Hernandez et al., 2015). A polymer flood pilot composed of 3 injection and 4 production wells, all horizontal, was initiated in 2013 (Fig. 12). The injection patterns consist of alternating injection and production wells. Following an initial success, the polymer flood was later expanded

Fig. 10. Location map of Patos Marinza field (reproduced from (Hernandez, 2016))

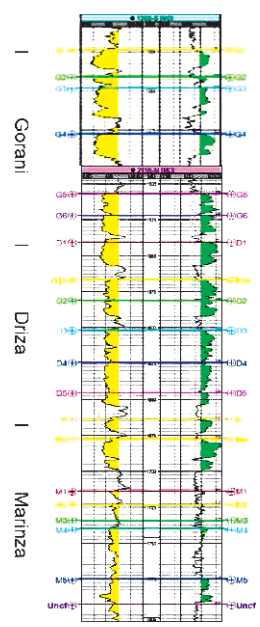

Fig. 11. Patos-Marinza type log (reproduced from (Hernandez, 2016))

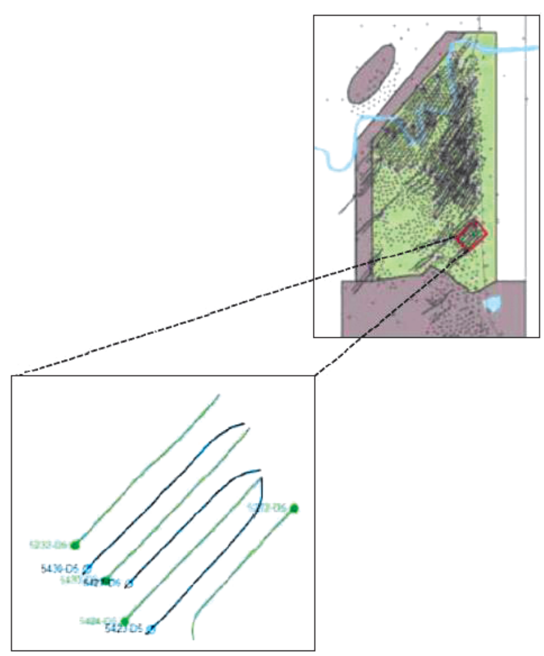

Fig. 12. Patos Marinza polymer flood pilot location and map (reproduced from (Hernandez, 2015))

to over 59 patterns in total (Hernandez, 2016). The performances of the polymer flood are presented in Figure 13 and Figure 14. As in Pelican Lake, the increase in production is mainly due to the increase in reservoir pressure, but without polymer water-cuts would increase very rapidly.

Mooney Bluesky polymer flood and ASP (BlackPearl, Canada)

The Mooney field is located in north-western Alberta in Canada (Fig. 1). The reservoir formation is the shallow marine Bluesky (early Cretaceous), located at a depth of approximately 930 m.

The thin reservoir (up to 5 m thick, average thickness 2.5 m) is composed of semi-consolidated shoreface sandstone with excellent characteristics: average porosity of 26% (varying between 23% and 31%), average permeability of 3 darcies with a maximum of 10 darcies (BlackPearl Resources…, 2009). A type log is provided in Figure 15. The oil is heavy (12-19 API) and its viscosity at reservoir temperature (29^0C) varies between 300 to 1,500 cp. The main reservoir and PVT characteristics of the pool are summarized in Table 2.

The pool was discovered in 1986 and put on production with vertical wells in 1987 but due to the limited thickness and high oil viscosity productivity was low; in addition water was produced initially even though no fluid contact was visible on the logs. The initial production mechanism was solution gas drive. The pool was abandoned in 1997 due to low rates and high water-cut.

It was revived in 2005 through the use of horizontal wells (Fig. 16) but even though production rates were better than with vertical wells, the wells again produced water from the beginning (this has been attributed to the presence of mobile water in the reservoir (BlackPearl Resources…, 2009)). The lack of natural drive in the reservoir lead the operator to the conclusion that primary recovery would be very low (around 4% OOIP). Thus a waterflood pilot – one injection and two

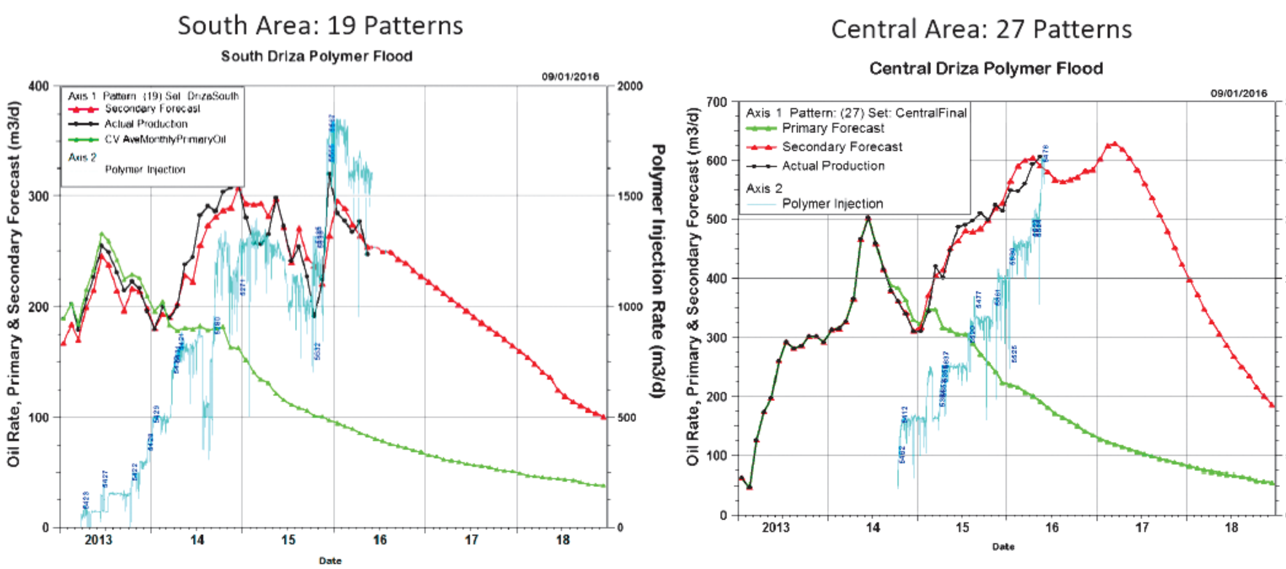

Fig. 13. Injection and production performances of polymer flood in Patos Marinza (reproduced from (Hernandez, 2016))

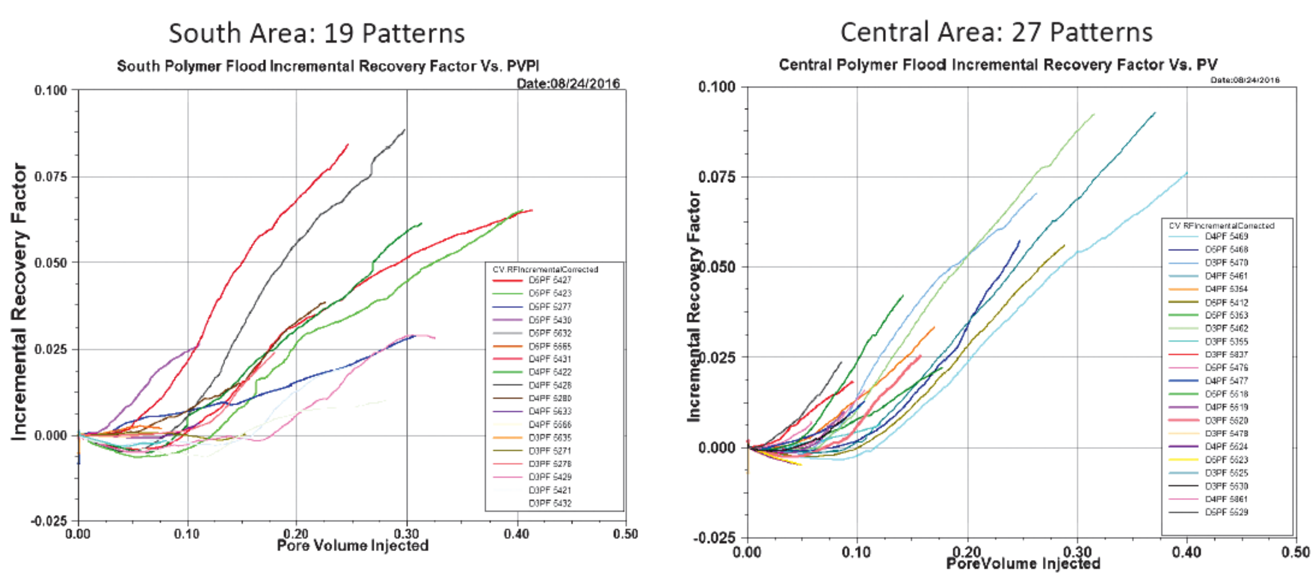

Fig. 14. Incremental recovery in Patos Marinza polymer flood (reproduced from (Hernandez, 2016))

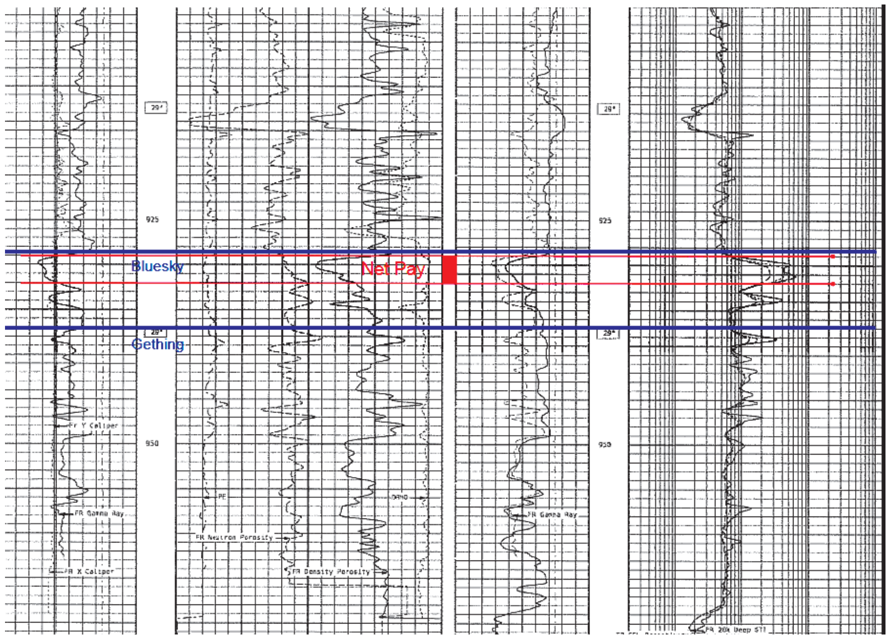

Fig. 15. Mooney – Type log of well 103/16-18-072-07W5

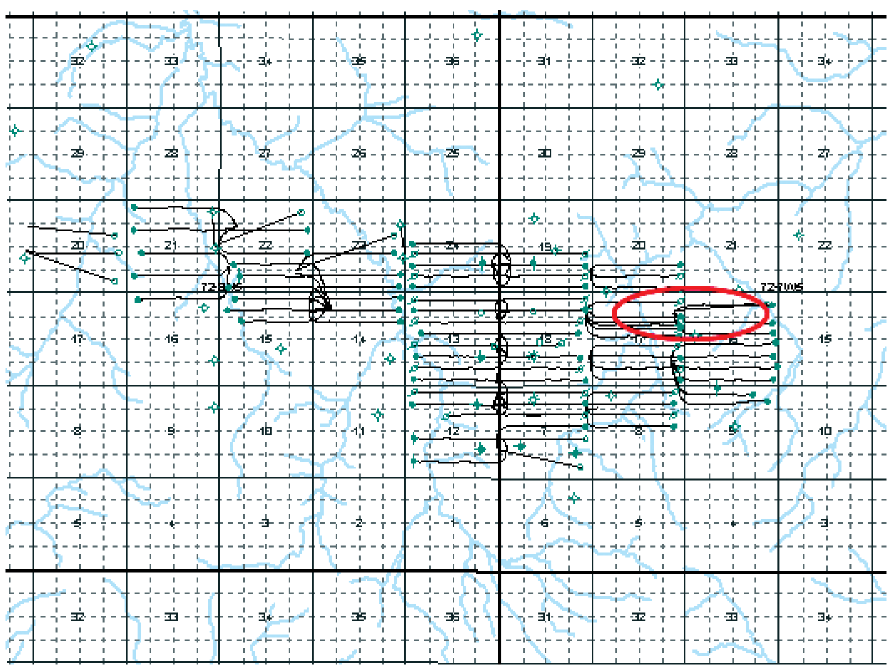

Fig. 16. Map of Mooney pool with pilot location (in red)

production wells, all horizontal – was implemented in 2006 but water breakthrough was quick and the oil rates dropped rapidly (BlackPearl Resources…, 2009). This quick breakthrough could be due to the presence of initial mobile water or to severe heterogeneity – or a combination of both.

This lead the operator to consider polymer flooding as a way to improve the sweep efficiency and reduce water production. A pilot composed of two injection wells and three production wells, all horizontal (Fig. 17) started in November 2008. Oil viscosity in the pilot area was approximately 300 cp. One of the specificities of this pilot is that it tested 3 different spacings between injection and production wells. Injected polymer concentration was approximately 1,500 ppm and

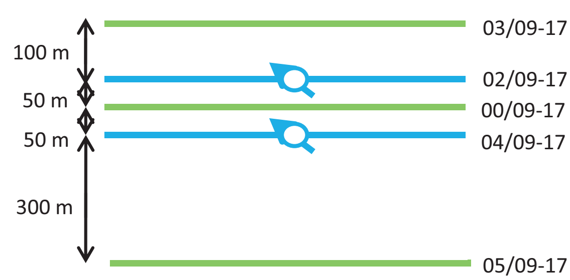

Fig. 17. Mooney polymer pilot map

viscosity ranged from 20 to 30 cp (Watson et al., 2014).

The polymer flood was able to increase production and maintain some kind of plateau for a few months in the two wells closest to the injection wells – a significant improvement over waterflood. However, water breakthrough still occurred within 4 months in the confined well and 6 months in the other well, and the water-cut increase was very sharp (Fig. 18, 19).

According to the operator, the polymer pilot ultimate recovery was estimated to be 18% OOIP (Watson et al., 2014).

In order to further increase recovery, the operator initiated an ASP flood in another part of the pool (Watson et al., 2014). The selected chemical formulation consisted of Na_2CO_3 at a concentration of 1.5% wt, a surfactant at a concentration of 0.15% wt and 2,200 ppm of associative polymer. Due to the hardness of the formation and injection water, water softening was required. This was done using a Weak Acid Cation exchanges unit.

ASP injection started in September 2011 in 23 injection wells. The production data is plotted in Figure 20; the response to the beginning of injection is clear. The response is first due to reservoir fill-up, as suggested by the increase in fluid production. The effect of the chemicals is difficult to discern; there was only a slight reduction in water-cut towards the end of 2013 then water-cut increased again while oil rate started to decrease. In cases such as this when ASP is injected in secondary conditions, it is difficult to differentiate

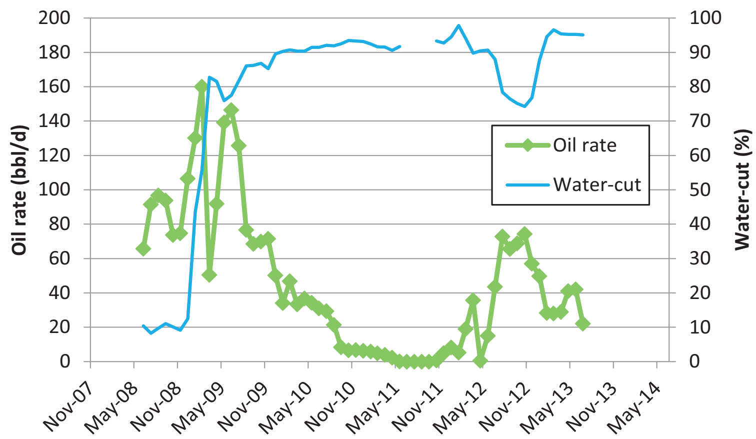

Fig. 18. Mooney polymer flood pilot – Well 09-17-072-07W5 rate and water-cut

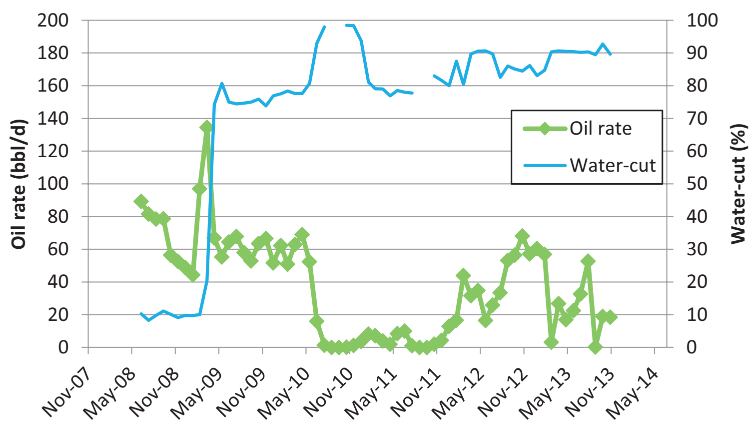

Fig. 19. Mooney polymer flood pilot – Well 03/09-17-072-07W5 rate and water-cut

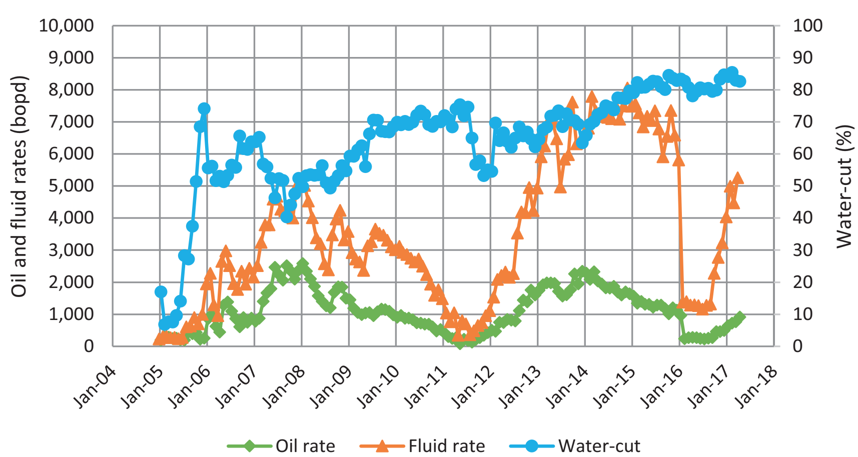

Fig. 20. Production data for Mooney ASP area

between the effect of the polymer and of the alkali and surfactant.

In 2016, the operator decided to suspend the injection in Mooney, citing high operating costs (BlackPearl…, 2012). At the end of 2016, cumulative oil production from the area was 5.2 MMbbl, which corresponds approximately to less than 9% OOIP; at that time approximately 15% PV of the ASP formulation had been injected. Clearly, these results are far below what was expected for the ASP flood, which targeted a recovery of 25% OOIP (BlackPearl press release, 2017) and even from the sole polymer flood which was expected to recover 18% OOIP. In early 2017 the company decided to reactivate the project, citing improved oil prices (Delamaide, 2017).

Discussion

The use of horizontal wells in conjunction with polymer has allowed to increase recovery and production in heavy oil fields where oil viscosity had long been deemed out of range. As showed in Table 1 there are now several ongoing large scale projects, with more in the works.

A recent paper (Delamaide, 2017) presents an analysis of the performances of polymer flooding in heavy oil, mostly using horizontal wells. The 3 examples from this paper are included in that study. Figure 21 reproduced from that paper presents the performances of a number of wells from 6 heavy oil fields (all of them horizontal except for 3) and shows the expected recovery vs. cumulative fluid injected. As can be seen from the figure, the range is relatively large which is not surprising given the variations in reservoir properties investigated, but there is a clear trend. Figure 22 from the same paper compares the performances of primary, secondary and tertiary polymer injection; as can be seen from the figure, primary and secondary polymer injection appear more efficient than tertiary polymer injection. This is confirmed by Figure 23 from the same paper, which compares the Water Oil Ratios for the 3 methods.

These results confirm the potential for polymer injection in heavy oil fields using horizontal wells. On the other hand, ASP has not yet been field proven for high viscosity oil; given the volumes of oil that cannot be recovered even with polymer, this represents a very significant – albeit challenging – target.

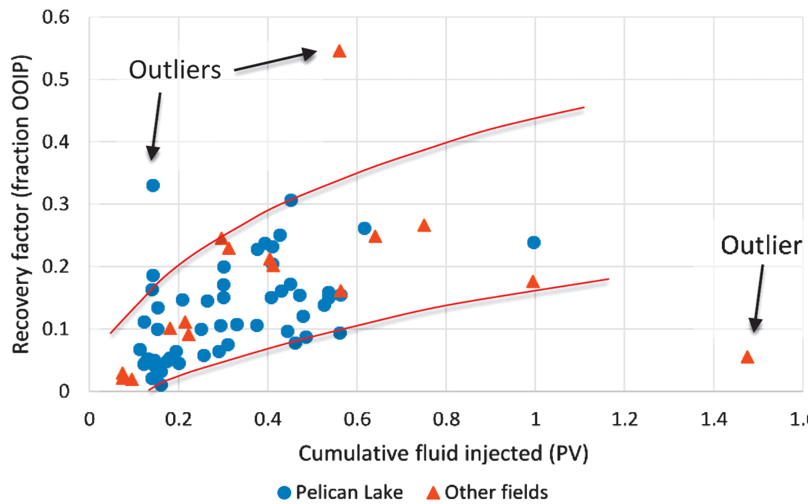

Fig. 21. Recovery factor vs. cumulative fluid injected (reproduced from (BlackPearl press release, 2016)). Each point represents a different well.

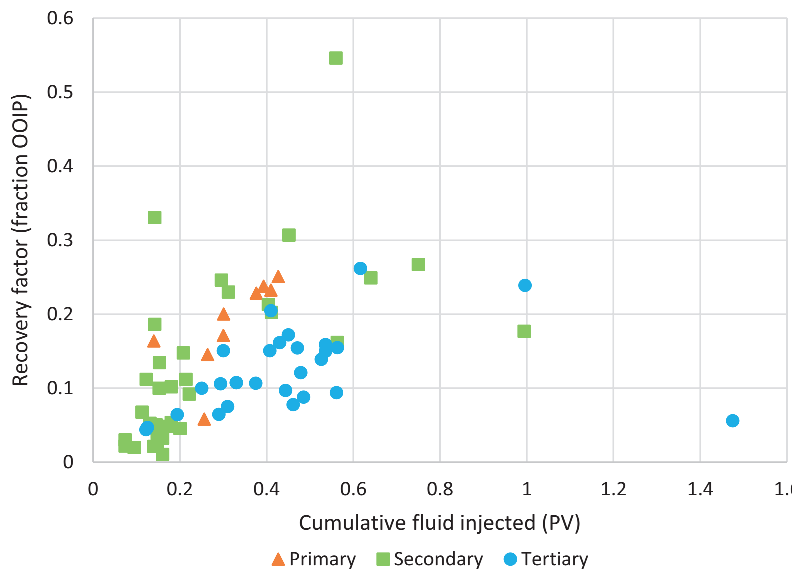

Fig. 22. Recovery factor vs. cumulative fluid injected for primary, secondary and tertiary polymer injection (reproduced from (BlackPearl press release, 2016)). Each point represents a different well.

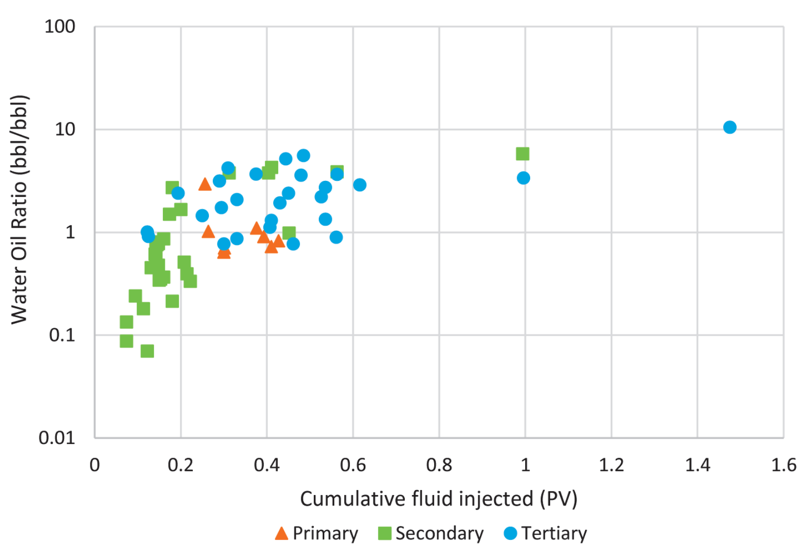

Fig. 23. Water Oil Ratio as a function of Cumulative fluid injected (reproduced from (BlackPearl press release, 2016)). Each point represents a different well.

Conclusions

The review of three chemical EOR projects in heavy oil which use horizontal wells – two polymer floods and one ASP floods – has led to the following conclusions:

• Polymer flooding is a viable solution to increase production and recovery in heavy oil. The process has been field tested for oil viscosity up to 7,000-10,000 cp and proven commercial for viscosity up to 5,000 cp.

• The Mooney case has showed that the process is still sensitive to factors such as heterogeneities and presence of initial mobile water, which can lead to early breakthrough;

• The ASP flooding process has not yet been tested at these high viscosities and its efficiency remains to be confirmed in the field.

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