Pelican Lake Polymer Flood Success Story: A Significant Breakthrough in Heavy Oil Reservoir Exploitation

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Abstract

The Pelican Lake heavy oil field located in Northern Alberta (Canada) has had a remarkable history since its discovery in the late 1970s. The reservoir formation is thin (less than 5m) and as the oil is viscous (from 600 to over 80,000cp), initial production using vertical wells was low. Several methods were used in order to improve production and recovery, including an air injection scheme in the 1990’s. However it is only with the introduction of horizontal drilling that the field began to reach its full potential; indeed Pelican Lake was one of the first fields worldwide to be developed with horizontal then multi-lateral wells.

With primary recovery around 5-7% and several billion barrels OOIP, the prize for EOR is large; polymer flood had never been considered in such high viscosity oil until 1995, when the idea of combining polymer flood and horizontal wells gave way to a polymer flood pilot in 1997. This was the first step on the way, and today the field is in the process of being fully converted to polymer flood, with several hundred injection wells already in action. Polymer flooding has the potential to increase recovery to over 20% OOIP at relatively low cost.

This paper presents the history of the field then focuses on the polymer flooding aspects.

Introduction

The Pelican Lake field\(^1\) was discovered in 1978 by the well Gulf Wabasca 6-9-81-22W4M; located approximately 250km North of Edmonton, Alberta, Canada (Figure 1), the field started producing in 1980. It covers whole or part of 19 townships (177,000ha) from Townships 79 to 82 and Ranges 19 to 23W4M as part of the much larger Wabasca oil sand deposits. With over 6 billion barrels OOIP (4.1 billion barrels on CNRL lands (CNRL 2012) and 2.3 billion barrels on Cenovus lands (EnCana Corporation 2003)) and a primary recovery estimated at less than 7%, it presents a significant target for Enhanced Oil Recovery (EOR). But it is also a challenging reservoir with high viscosity oil in a thin formation.

Geology and reservoir characteristics

The reservoir formation is the Wabiskaw “A” sand, part of the Clearwater formation of the Upper Mannville Group of Lower Cretaceous age (Figure 2). It is a coarsening upward sheet sand interpreted as part of a prograding

\(^1\) The pool is also called Brintnell in some references. We will use “Pelican Lake” in this paper
shoreface (McPhee and Ranger 1988) deposited in a 35x60km NE-SW trending lobe and capped by the transgressive marine shale of the Clearwater formation. It thins to the North, East and South. 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 in Townships 81 to 83, Ranges 17 and 18 (Cenovus 2011).

The reservoir is composed of unconsolidated sands which consist mainly of quartz and chert. Grain size coarsens upward from very fine grained sands and shales (illite dominant) at the base of the reservoir, to fine grained massive sands at the top (kaolinite dominant). The reservoir can be further broken down into the lower “Bar Margin” and the upper “Bar Complex”. The “Bar Margin” is a lower quality interval with finer grained sand and shale breaks while the “Bar Complex” has the best reservoir properties and is a clean high energy sand unit (Fossey, Morgan and Hayes 1997).

The reservoir has generally excellent petrophysical properties with 28-32% porosity and a permeability that varies between 300 up to 3,000 md. The main reservoir characteristics are summarized in Table 1 and a type log is provided in Figure 3.

**Early history**

The reservoir depletion mechanism is solution gas drive, as there is no aquifer underneath most of the field. However the initial reservoir pressure is 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 relatively viscous (from 600 to 80,000 cp) primary recovery is low, approximately 5 to 10% OOIP. In addition the reservoir is thin (3 to 5 m) and as a result the first wells drilled in 1980-1981 in T81R22W4 were not economic: low rates (less than 30 bbl/d usually declining rapidly to less than 10 bbl/d) and low recoveries (an average of 28,000 bbl total per well). The operator Gulf Canada tried various methods such as steam injection and air injection to improve the recovery but those attempts met with little success. Amoco which was operating to the West of Gulf in T81R23W4 was no more successful and after drilling 45 wells in the pool in 1985 these two operators did not drill any well in 1987 (Figure 4).

At that point over 200 wells had been drilled in the pool, over C$100 million had been spent, production was 1,260 bbl/d from 87 wells and options appeared limited.

**Horizontal drilling**

**The beginning of horizontal drilling**

The property was revived in 1988 through the application of horizontal drilling by CS Resources, a junior company founded by Dennis Sharp in 1984.

At the time horizontal drilling was in its infancy. Even though the first horizontal wells had been drilled in the 1930s in the US and USSR then later again in the 1950s and 1960s in the USSR and China, they did not produce more than vertical wells and thus the technique had been abandoned (JPT 1999).

It reappeared almost at the same time in North America and Europe in the late 1970s – early 1980s. In the US the first horizontal well of that period was drilled in the Empire Abo Pool in New Mexico (Stramp 1980). In Canada the
first horizontal well was drilled by Esso at Cold Lake in 1978 (Bezaire and Markiw 1979) but surprisingly 10 of the first 30 horizontal wells drilled in Canada were drilled not by a major but by CS Resources (Sharp 1989) (Fossey, Morgan and Hayes 1997) (Springer, et al. 1993) (Sharp, Coffin, et al. 1991) with the technical support of two European companies.

Indeed in Europe horizontal drilling had also taken off, following a joint research project initiated by Elf Aquitaine and Institut Français du Pétrole (IFP) in 1978 (Reiss, Jourdan, et al. 1984). The first horizontal wells were drilled in the South of France in the Lacq gas field in 1980 and 1981. But it is the 3rd well drilled in 1982 in the Adriatic Sea offshore Italy in the Rospo Mare field that proved the potential of the method by producing at a rate 20 times higher than the vertical wells in the same reservoir (Reiss 1987). Rospo Mare became the first field to be developed entirely with horizontal wells.

In 1987 CS Resources entered into an agreement with Elf Aquitaine and IFP (Sharp 1989) to get access to the know-how and technologies developed by those two companies in horizontal drilling and to apply those in Canada.

**Horizontal drilling in Pelican Lake**

CS Resources drilled its first horizontal wells in the Winter pool in Saskatchewan (Sharp 1989) then turned to Pelican Lake after farming in on Gulf in 1987. Horizontal drilling is well adapted to Pelican Lake – provided that the well can be maintained in the pay zone – because the reservoir is so thin, a horizontal well can increase the reservoir exposure tremendously. CS Resources drilled 23 horizontal wells in Pelican Lake between 1988 and 1993 (Fontaine, Hayes and Reese 1993); the wells produced by primary depletion using PCP pumps located close to the heel of the well.

The production performances of the horizontal wells were better than those of the verticals (Figure 5) and seemed to correlate reasonably well with the length of the horizontal drain in the reservoir (Fossey, Morgan and Hayes 1997). Although other parameters such as reservoir quality and viscosity affect these performances, the trend is generally correct (Figure 6). As the cost to drill a horizontal well kept decreasing, horizontal drilling became highly attractive.

In 1991 CS Resources drilled a first open hole lateral arm (Fossey, Morgan and Hayes 1997) from a main horizontal drain (11-16-81-22W4). Then in 1993 they went one step further and drilled two multilateral wells (Smith, Hayes and Wilkin 1994) using a newly developed tool, the Lateral Tie Back System (LTBS). The use of multilaterals would greatly expand in the years to come, with wells such as 13D-24-80-21 drilled in 1999 by PanCanadian with 8 laterals and totalling 10,833m of drain in the reservoir (Figure 7).

However even though horizontal or multilateral wells improved recovery and economics, it was clear that recovery would be limited to 5 to 10%OOIP unless other methods were applied.

**EOR methods screening for Pelican Lake**

As discussed in some relatively recent papers (Miller 2005) (Beliveau 2009), a number of heavy oil pools had been waterflooded in Canada in the mid-1990s, in particular in the Lloydminster area, but there were very few definite
conclusions drawn from those except that viscosity was a limitation and 1,000 to 2,000cp dead oil viscosity was often cited as “the limit” (Miller, State of the Art of Western Canadian Heavy Oil Water Flood Technology 2005). Due to the unfavorable mobility ratio water channels rapidly through the oil and significant volumes of water have to be injected in order to significantly increase the recovery. It is not surprising then that very little thought was given to waterflooding Pelican Lake, at least at the time.

Pelican Lake is not well adapted to steam injection methods because of its thickness, which causes severe heat losses to the over and under burden. Thermal methods were tested very early by Gulf to increase the recovery but attempts were unsuccessful. The viscosity of the oil is also too high for gas injection.

In 1993 Amoco tested a new EOR method – cyclic air injection – in the field (Township 81 Range 23W4M) using one horizontal injection well and two horizontal producers drilled on either side (Thornton, Hassan and Eubank 1996). The results were good, with the rates more than doubling, but the process was abandoned, apparently because of low oil prices.

Meanwhile CS Resources had decided to explore another avenue using chemical EOR (polymer flooding) in partnership with IFP. At the time IFP had developed a significant expertise on polymer flooding based to a large extent on its work on the first polymer pilots in the Daqing oil field in China (Chauveteau, Combe and Han 1988) (Corlay, et al. 1992) (Wang, et al. 1993) (Delamaide, Corlay and Demin 1994) and the continuing collaboration with CS Resources led in 1993 to the idea of testing polymer flooding in Pelican Lake. Except for the oil viscosity, Pelican Lake’s reservoir conditions are ideal for polymer applications: low temperature, low water salinity (6-10g/L TDS), no bottom aquifer below most of the pool and high permeability which is favorable for injectivity. The most significant issue was thus the oil viscosity.

**Polymer flooding of viscous oil**

In the early 1990s, there had been very little thoughts towards using polymer flooding to improve the recovery of heavy oil.

An early paper published in 1977 (Knight and Rhudy 1977) had studied polymer injection in corefloods performed in sandpacks with high viscosity oil (210 and 1,140cp) but had not addressed injectivity issues and was not followed by any significant research.

A few polymer pilots had been performed in high-viscosity oil but those were poorly documented at best and apparently unsuccessful. A polymer flood pilot had been implemented in the Langsdale field in Mississippi (Manning, Pope and Lake 1983) but conflicting viscosity values are reported for the field, one at 1,494cp and another one at 120cp (NIPER 2004). An early paper reviewing 61 polymer flood projects (Jewett and Schurz 1970) lists two with viscosities over 1,000cp but neither of these projects is documented and both appear to have been failures.

On the other hand a test at West Cat Canyon in California in the early 1960s had been declared successful with an oil viscosity at reservoir conditions of 110cp (Sandiford 1964).
Thus the “conventional wisdom” at the time was that polymer flooding was limited to viscosities below 200cp (Selby, Alikhan and Farouq Ali 1989) and that was also the criteria proposed in the most widely used EOR screening guide (Taber, Martin and Seright 1997).

This was not only the result from practical field experience; the thinking was that the higher the oil viscosity, the more viscous a polymer solution had to be in order to make a meaningful contribution to recovery. But higher viscosity polymer would result in lower injectivity thus there were some practical limitations to injecting viscous polymer – at least with vertical wells. As Taber and Seright had probably been the first to point out (Taber and Seright 1992), the advances in horizontal drilling had changed things: by using horizontal injection wells injectivity could be improved significantly in certain cases.

Given CS Resources expertise with horizontal drilling, the idea of a polymer flood in Pelican Lake was thus judged worthy of further investigations.

**CS Resources polymer flood pilot**

**Preliminary studies**

An evaluation using reservoir simulation was first performed to verify that polymer flooding had the potential to increase the recovery in the field (Zaitoun, Tabary, et al. 1998) in order to justify initiating more costly laboratory studies. The evaluation was performed with a simplified reservoir model and standard polymer properties and confirmed the potential interest of the process.

The next step was the laboratory measurements of polymer properties in cores. Given the mild reservoir conditions a hydrolyzed polyacrylamide (HPAM) with a molecular weight of 13.6 $10^6$ Daltons was selected. Corefloods were performed using an injection brine from a shallow Quaternary aquifer after confirming the compatibility with reservoir brine. Due to the low salinity of both brines polymer viscosity was similar in both. Measured adsorption was low (10$\mu$g/g) and Permeability Reduction (Rk) and Mobility Reductions (Rm) were measured as a function of polymer concentration.

Further reservoir simulation work was performed using the laboratory data to evaluate the influence of various parameters such as polymer concentration and well spacing. The reservoir simulation and laboratory work took place over 1994-1996 and the decision to proceed with a pilot was finally taken in 1996.

**Pilot description and operations**

The pilot consisted (Figure 8) in three 1250m-long horizontal wells, two production wells (00/01-05-081-22W4M and 02/01-05-081-22W4M) drilled in 1996 and one injection well (03/01-05-081-22W4M) drilled in 1997 in between. The distance between production and injection wells was 150m. All three wells were put on production until the pilot start-up in July 1997 in order to improve injectivity. Injection lines as well as the liner of the injection well were coated with epoxy to prevent polymer contamination by iron.

The start-up operations did not go as planned, as it was observed that the viscosity target for the polymer solution (100-200cp) could not be achieved (Zaitoun n.d.); further analysis revealed that the Quaternary aquifer water contained a significant quantity of dissolved iron (Fe II); that had not been observed in the lab because the water...
sample bottle provided had not been sealed hermetically and thus iron had precipitated into Fe(OH)$_3$. The oxidation reaction of Fe II into Fe III induced some polymer degradation. In order to get around the issue it was decided on the spot to precipitate the Fe II into Fe(OH)$_3$ by aeration of the make-up water before preparing the polymer solution, as Fe(OH)$_3$ has no detrimental effect on polymer properties.

In spite of that, injectivity in the pilot dropped rapidly from September 1997, suggesting formation damage around the wellbore; this was later attributed to plugging by iron particles through a filter improperly installed (Tabary, Behot and Zaitoun 2005). Polymer concentration was progressively reduced in order to try and maintain the injection rate but that failed to stem the injectivity decline.

Before the issue could be investigated further, CS Resources was taken over by PanCanadian in July 1997 and the project became dormant (the pilot was suspended in 1998).

**Lessons from CS Resources polymer flood pilot**

The first pilot was very disappointing but still brought some important information. When PanCanadian decided in 2000 to evaluate the possibility of starting a new polymer pilot the behavior of the first pilot was analyzed using reservoir simulations (Tabary, Behot and Zaitoun 2005). A good history match was obtained by using an increased skin in the injection well and low water relative permeability at residual oil saturation (Krwm); further corefloods under CT scan were performed and confirmed that hypothesis.

Relative permeabilities for viscous oil are notoriously difficult to measure (Maini 1998); in addition, if the influence of oil viscosity on relative permeability has long been debated (Nejad, Berg and Ringen 2011), it seems now accepted that viscosity does indeed have an influence on relative permeability measurements. Water relative permeability at residual oil saturation has been shown to decrease with increasing oil viscosity (Nejad, Berg and Ringen 2011) (Wang, Dong and Asghari 2006). Given the uncertainty in the measurements of heavy oil viscosity, (Miller, Nelson and Almond, Should You Trust Your Heavy Oil Viscosity Measurement? 2006) reducing the relative permeability to obtain a match does not seem unreasonable.

The important practical consequence was thus that polymer viscosity did not need to be as high as originally thought to improve the oil/water Mobility Ratio.

The other important conclusion was that the whole concept of polymer flood for Pelican Lake was still valid – the problems had been due to operational issues.

The new pilot never took place. Two new horizontal wells were drilled in the first pilot between the injection and production wells in September 2000; the plan was to turn them into injectors and restart the pilot sometime in 2001. However before that could happen PanCanadian sold its interest in the field to Canadian Natural Resources (CNRL) which already had a major land position in the pool and the project was once again halted.

**Waterflood pilots**

Ironically, shortly after the sale PanCanadian merged with Alberta Energy Company (AEC) which was at the time the other large operator of Pelican Lake to form EnCana; AEC had initiated several waterflood pilots on its lands at the end of 2000 to test the process in various reservoir contexts. The waterflood pilots successfully increased the
even if the water-cut also increased sharply.

**Figure 9** shows the results from one of the best pilots (two production wells, one injector) in 1,400-1,600cp oil (EnCana 2004). EnCana decided to extend the waterflood to other parts of the field (EnCana 2002). Estimated incremental recovery for EnCana’s portion of the pool was 6%OOIP initially but that number was later revised to 12%OOIP (EnCana 2009) then to 9%OOIP.

CNRL initiated its own waterflood pilot in 2003. The CNRL North Horsetail waterflood pilot composed of 12 horizontal injection wells (Figure 10) started injection in June 2003 (CNRL 2006) in 1,000 to 2,000cp oil. The response occurred within 3 months in some of the wells; in particular water breakthrough occurred very rapidly in section 12-82-22W4M. In spite of that, the oil rate increased from a minimum of 366bbl/d (for the whole pilot area) up to a maximum of 2,677bbl/d in September 2005 (**Figure 11**).

CNRL estimated an incremental recovery factor of 7.5 to 10%OOIP for the pilot and went to the commercial phase of the waterflood in 2004 (CNRL 2006).

Both EnCana’s and CNRL’s recovery numbers seem to be in line with those of other fields discussed in a recent paper (Beliveau 2009).

In spite of the relatively high oil viscosities, the waterflood proved capable of increasing oil production significantly, however the high water-cut made it necessary to look at some options to reduce water production. Polymer flood was an obvious one.

**Polymer pilots**

Starting in 2003, EnCana did some workovers using polymer to improve conformance; conformance control consists in injecting a polymer or gel to solve water channeling problems by plugging off high permeability
intervals or thief zones. The treatments seem to have been successful and were extended to a number of injection wells (EnCana 2004).

The longest polymer flood history for EnCana is in pattern NE 5 around injection well 00/04-06-83-19W4M and polymer injection there started in January 2005 (EnCana 2009).

**CNRL Polymer flood pilot**

CNRL initiated a polymer flood pilot in the field in 2004; the work consisted first in a review of the CS Resources pilot, then laboratory and reservoir simulation work (CNRL 2004). Only the laboratory work will be described here.

*Laboratory work*

This section is mostly a summary of a more complete public document (Tabary, Behot and Zaitoun 2005).

The laboratory work consisted in the selection of the polymer, the determination of its bulk properties and the corefloods to measure the adsorption as well as determine rheological parameters for reservoir simulations.

As mentioned earlier the reservoir conditions for a polymer flood in Pelican Lake are mild, however the experience of the CS Resources polymer pilot stressed the importance of the injection water quality.

*Water sources*

There were 4 potential sources of water for the pilot:

- the Grosmont formation (Upper Devonian)
- the Grand Rapids formation (Lower Cretaceous)
- the Quaternary gravels used in the CS Resources pilot
- the Wabiskaw reservoir brine

The Quaternary water was abandoned because of their iron Fe II content and their low salinity, which could have caused issues with clay migration and swelling. The water analyses for the three remaining brines are presented in Table 2.

The Grosmont water has the highest salinity (26g/L TDS) which means that it will require more polymer to develop the same viscosity. It also contains H₂S which can degrade the polymer but on the other hand it is available in large quantities.

The Grand Rapids water has a lower salinity but as such its use is limited by the regulators; the production brine has no iron but needs to be filtered to remove the hydrocarbon residues it contains.

It was finally decided to perform the coreflood experiments both with the Grosmont water and a 50/50 mix of Grand Rapids and Wabiskaw reservoir brine.

The oil used in the corefloods was from the North Horse Tail waterflood pilot. Its viscosity was approximately 2,020cp at 16°C (Figure 12).
Polymer selection and bulk properties

Given the high reservoir permeability, polymer FP (Flopaam) 3630S from SNF with a molecular weight of 18. 10^6 Daltons was selected.

During the tests with the Grosmont water it became apparent that the presence of H₂S induced a severe degradation of the polymer because of its reducing properties in the presence of oxygen; this remained true even at low H₂S concentrations (1 ppm). As a result it was decided to have the rest of the work proceed with a synthetic Grosmont water without H₂S but this degradation would have to be taken into account for the field implementation.

The relative viscosity \( \eta_r \) (i.e. the viscosity of the polymer solution divided by the water viscosity) of polymer at various concentrations in synthetic Grosmont water is shown in Figure 13 and the relative viscosity of polymer at a concentration of 1500ppm is shown for the three brines in Figure 14.

Corefloods

Two plugs were cut from a full size core from Well 00/09-18-80-22W4M and packed in series in a Viton sleeve under an overburden pressure of 1400kPa then mounted in a Hassler cell. The measured porosity was 33.6%.

The experimental set up is shown in Figure 15.

Experimental procedure

The procedure used was the following:

1. Oil injection (several pore volumes at various rates) to obtain the permeability at Swi
2. Injection of Grosmont water followed by Wabiskaw/Grand Rapids mix then again Grosmont water to measure permeability at Sor in each case
3. Polymer injection at 500ppm in Grosmont water at constant rate to measure adsorption (Zaitoun and Kohler 1987)
4. Injection of Grosmont water to measure the Permeability Reduction Rk
5. Injection of polymer at 1000, 1500 and 2000ppm in Grosmont water at various rates to measure the Mobility Reduction curve Rm at various concentrations and various shear rates; Grosmont water without polymer is also injected between each step to check the Permeability Reduction
6. Steps 3, 4 and 5 are repeated with the Wabiskaw/Grand Rapids mix

At the end of the procedure the core was cleaned with solvents to remove adsorbed polymer and oil, flushed with water and the absolute permeability of the core to water (3480md) was measured.

Coreflood results

The Swi was measured at 23% and the permeability to oil at Swi was 1420md. The krmw at Sor was determined to be 0.06. It was checked by flushing the core with several pore volumes of Wabiskaw/Quaternary water mix that there was no clay swelling effect.
The adsorption of polymer was 12μg/g.

The rheological properties of polymer solutions at 500ppm and 1000ppm are shown in Figure 16 and Figure 17.

The Permeability Reduction was determined to be 1.9 in Grosmont water and 2.0 in the Wabiskaw/Grand Rapids brine.

The final core tests consisted in flushing the core with brines of decreasing salinity to check whether there was any sign of clay swelling or destabilization; none was found, even at low salinity.

**Pilot operations and results**

CNRL selected an area just South of the North Horse Tail waterflood pilot, in pad HTLP 6 (sometimes also noted HP 6) in section 34 Township 81 Range 21W4M (Figure 18). The pilot is composed of five 1400m long horizontal wells: three production wells (14-34, 15-34 and 16-34) and two injection wells in between (2/15-34 and 2/15-34), with a spacing of 175m between the wells (Figure 19). The wells had been drilled in 1997-1999.

Polymer injection started in May 2005, with a target viscosity of 20cp corresponding to a concentration of 600ppm (CNRL 2007) initially, which was reduced to 13cp at the end of August 2005. Initial injection rate was 930bbl/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 (Figure 20, Figure 21 and Figure 22). As can be seen from the figures, the responses were excellent with rates going from 18bopd to 232bopd in the first well, 9bopd to 364bopd in the central well and 16bopd to (only) 139bopd at the maximum in the last well.

The second striking feature is the slow and relatively moderate increase in the water-cut for all three wells, especially compared to what was experienced in the waterflood pilot nearby.

It must also be noted that the rates have remained high for almost six years now.

Wellhead injection pressure (Figure 23) increased more rapidly than predicted by reservoir simulations, which could have been caused by a number of factors such as incorrect assumptions on the permeability, rock compressibility or relative permeability – all relatively benign – to the more severe formation damage by clay swelling or degradation of the polymer (Institut Francais du Petrole 2006).

In order to clarify the situation actual field injection pressure data were input in the model and a history match was performed. A good match was obtained by modifying the rock compressibility and the reservoir permeability (Institut Francais du Petrole 2006).

As a precaution against plugging, polymer was switched to one with lower molecular weight (SNF FP 34305, 12.5 \(10^6\) Daltons). The polymer concentration was increased accordingly to maintain the same viscosity.

Injection pressure later leveled off and then decreased as the producing wells started to respond.

**Extension of polymer flood**
Given the results of the polymer pilot, it is hardly surprising that CNRL decided to extend the polymer flood to larger portions of the field. As early as 2006 CNRL started installing polymer injection skids (Figure 24) and converting wells into polymer injectors (CNRL 2006). The extension has progressed in stages as illustrated in Figure 25 (CNRL 2012). Cenovus the corporate successor of EnCana has also converted a large portion of its lands to polymer flood (Figure 26).

The wells are mostly drilled on a 200m spacing (between injection and production wells) although Cenovus has started testing reduced spacing (50m and 100m) to improve the recovery. In the old Gulf/CS Resources development area where wells have not been drilled in a pattern CNRL had to adapt to the existing geometry of the wells.

Due to the H₂S content of the Grosmont water, the Grand Rapids formation which contains a low salinity water had initially been supplying most of the injection water. Significant efforts have been made by CNRL and EnCana to reduce the use of low salinity water by using some produced water as well as some of the Grosmont saline water.

**Polymer flood and multilateral wells**

CNRL has been testing the polymer flood with multi-lateral producers in at least two patterns, with the first pilot located South-West of the HTLP 6 polymer pilot (Figure 18). The multi-lateral well (00/12/-28-081-22W4M) is drilled in a comb shape with a main drain and five lateral arms varying in length from approximately 900m to 1200m (Figure 27). Distances between the arms are approximately 350-375m. A final injection well to the South was added recently.

The three westernmost injection wells were put on injection in December 2007 and the two easternmost in December 2010. The southern injection well was put on injection in April 2011. The production data is presented in Figure 28. The response to polymer injection occurred in October 2008 and was excellent, oil rate climbing from 70bopd to 700bopd. Following the start of the second injection (eastern injectors), production increased towards 800bopd before jumping again to 900bopd once the last (southern) injection well was put on injection.

The water-cut decreased when the oil bank reached the production well then increased again but remains very low to this date (less than 40%).

This well has now reached a cumulative production of 1,645,000bbl; comparing this with the average 28,000bbl produced by the first wells drilled by Gulf, one can clearly see what impact the right technology can have in a pool.

A second multilateral well just to the East of 12-28-81-22W4 has also been started on polymer injection and is responding in a similar way.

**Higher viscosity areas**

EnCana tested polymer flood in a higher viscosity area starting in 2007 (Pads E19 to E23). We will show here the result of Pad E20 (Figure 29 and Figure 30) where the viscosity at 15°C is between 1200cp to 7000cp (average 3600cp) and where polymer flood started in October 2007. These plots show how different the response is
compared to the lower viscosity area. The oil rate increases but nowhere near as much as in the CNRL pilot for instance nor as much as in the good waterflood patterns. Also the rate increase does not last as long, for instance in Wells 02/06-7 or 02/08-10.

Some of the wells also exhibit early water breakthrough (02/02-02 and 02/15-14) while the water-cut diminishes in other wells (02/16-14).

Thus it appears that polymer flood is not as efficient in higher viscosity oil around 3000-7000cp and its efficiency should probably diminish again as the oil viscosity increases.

**Recovery estimation**

The estimations of recovery have of course varied with time and also depending on the area of the field. The most recent ones for CNRL are an Estimated Ultimate Recovery of between 15% to 21% OOIP (CNRL 2012) for most of their lands and between 27% to 31% OOIP for a small portion; Cenovus estimates recoveries of 3% OOIP to 32% OOIP at 1 Pore Volume injection (Cenovus 2012).

**Increasing recovery beyond polymer flood**

Even though the use of polymer allows increasing the recovery in the pool significantly, there will still remain vast volumes of Oil In Place at the end of the polymer flood. Thus both CNRL and EnCana are looking at the next options.

In 2008 EnCana applied to the ERCB to test the injection of emulsion in a pilot area using surfactant/emulsifier (EnCana 2008). The initial idea was to perform an emulsion flood i.e. to displace the viscous oil with emulsion.

Since EnCana and then Cenovus extended the injection of surfactant to other wells (Cenovus 2012) the process seems to have worked somewhat, however there is no mention of a successful displacement by the emulsion and the first pilot does not show conclusive sign of the formation of an oil bank. The only mention found on the surfactant injection in EnCana’s documents is that “surfactant can be effective at improving injectivity on high pressure injectors” (Cenovus 2010).

CNRL is also looking at a surfactant pilot (CNRL 2012) but no detail is available.

Finally, Cenovus is also looking at hot water injection to reduce the oil viscosity (Cenovus 2012); a pilot consisting of two horizontal injection wells and a single horizontal producer (02/11-33-081-20W4) in between at a distance of 50m was launched in 2011. Public production data suggest that there is some improvement over the baseline but it is too early to conclude.

**Conclusions**

The history of Pelican Lake reflects the progresses in heavy-oil production technology during the past decades and opens new perspectives for the future in conditions where thermal recovery is inefficient.
From the discovery up to 1987, the field was produced by vertical wells. The combination of thin reservoir, high oil viscosity and no pressure support rapidly showed that vertical well production was inefficient and uneconomical. Horizontal well technology was the first main breakthrough and the development from the late 1980s until today has been through long horizontal wells, sometimes with multilaterals.

Waterflood was implemented in the early 2000s and showed a substantial gain in Recovery Factor (from 5% to 10%). However, the adverse mobility ratio between the viscous oil (600 to 7000cp) and the water induced high water-cut production and poor sweep efficiency in some patterns because of water channeling.

By the mid 2000s, polymer flood has been implemented and proved highly successful, bringing the Recovery Factor up to 25% and higher while maintaining relatively low water-cuts. This second breakthrough in Pelican Lake exploitation is now implemented at the field scale. The important lessons from this experience are 1) for heavy oil in particular polymer flood does not need to target a Mobility Ratio of 1 to be efficient, but should be a compromise between Mobility Ratio and injectivity to optimize economics and 2) water quality is a key parameter.

Other technologies are now needed to take the recovery in Pelican Lake to the next step; it may come as polymer injection in hot water, or as surfactant, or as a new technology as yet untested. But the large volumes of remaining oil in place – in Pelican Lake and in other similar pools worldwide – make it a worthwhile target to pursue.

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Nomenclature

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\begin{align*}
    krwm &= \text{Relative permeability to water @ Sor} \\
    Rk &= \text{Permeability reduction factor} \\
    Rm &= \text{Mobility reduction factor} \\
    Swi &= \text{Initial water saturation} \\
    Sor &= \text{Residual oil saturation} \\
    \eta_r &= \text{Relative viscosity}
\end{align*}
\]

References


Cenovus. "Performance Review of In Situ Oil Sands Scheme Approval 9404K." *ERCB website*. March 9, 2011.

—. "Performance Review of In Situ Oil Sands Scheme Approval 9404P." *ERCB website*. 2012.


—. "Canadian Natural Resources In-Situ Performance Presentation." ERCB website. 2006.


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Depth 300-450m
Thickness 1-9m
Porosity 28-32%
Permeability 300-3000md
Oil Saturation 60-70%
Temperature 12-17°C
Initial pressure 1,800-2,600kPa
Oil gravity 11.5-16.5API
Dead oil Viscosity 800-80,000cp

Table 1: Reservoir characteristics

<table>
<thead>
<tr>
<th>Ion (mg/L)</th>
<th>Grosmont</th>
<th>Grand Rapids</th>
<th>Wabiskaw</th>
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<tbody>
<tr>
<td>Na</td>
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<td>K</td>
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<tr>
<td>Ca</td>
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<tr>
<td>Mg</td>
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<td>18</td>
<td>65</td>
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<td>Element</td>
<td>CNRL polymer pilot</td>
<td>CNRL polymer pilot</td>
<td>CNRL polymer pilot</td>
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</tr>
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<td>Ba</td>
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<tr>
<td>Sr</td>
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<tr>
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<td>H2S (ppm)</td>
<td>22</td>
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</table>

Table 2: Source water analyses for CNRL polymer pilot

Figure 1: Location of Pelican Lake field
Figure 2: Stratigraphic chart of the Mannville Group  
(from McPhee and Ranger 1988)

Bar complex
Bar margin

Figure 3: Type log of well 1AD/11-09-081-22W4M
Figure 4: Early drilling in Pelican Lake
Figure 5: Vertical - horizontal wells performance comparison

Figure 6: Cumulative oil production as a function of length in reservoir
Figure 7: Multilateral well 13D-24-80-21W4M wellpath plan view

Figure 8: Schematic view of first polymer flood pilot in Township 81 Range 22 W4M
Figure 9: EnCana waterflood pilot production plot

Figure 10: CNRL North Horsetail waterflood pilot map
(Note that the two injectors in the oval did not exist when the pilot was implemented)
Figure 11: CNRL North Horsetail waterflood pilot production plot

Figure 12: Crude oil viscosity vs temperature for corefloods
Figure 13: Viscosity of polymer in synthetic Grosmont water

Figure 14: Viscosity of polymer at 1500pppm in various brines
Figure 15: Core flood set-up

Figure 16: Rheological characteristics of polymer solution at 500ppm in Wabiskaw/Grand Rapids brine
Figure 17: Rheological characteristics of polymer solution at 1000ppm in Wabiskaw/GR brine

Figure 18: CNRL HTLP 6 polymer flood pilot location
(Note that the Westernmost injector did not exist at the time of the pilot)
Figure 19: CNRL HTLP 6 polymer flood pilot map
(Modified from (CNRL 2006))

Figure 20: HTLP 6 polymer flood pilot - Well 00/14-34-081-22W4 rate and water-cut
Figure 21: HTLP 6 polymer flood pilot - Well 00/15-34-081-22W4 rate and water-cut

Figure 22: HTLP 6 polymer flood pilot - Well 00/16-34-081-22W4 rate and water-cut
Figure 23: Injection rate and pressure for one of the two polymer injection wells in HTLP 6
(From (CNRL 2010))

Figure 24: 3D artist view of polymer injection skid
(Courtesy ABB)
Figure 25: Polymer flood development on CNRL lands

Figure 26: Cenovus polymer flood extension map
Figure 27: Polymer injection with on-injection dates and multi-lateral producer

Figure 28: Well 12-28-81-22W4 (multi-lateral) polymer pilot production data
Figure 29: Oil rate in Cenovus high oil viscosity area (pad E20)

Figure 30: Water-cut in Cenovus high oil viscosity area (pad E20)