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Preliminary Review of IETP Projects Using Polymers

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This report and its contents, the project in respect of which it is submitted, and the conclusions and recommendations arising from it do not necessarily reflect the views of the Government of Alberta and industry.

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i. Nomenclature and Unit Measurements

°API	Degrees American Petroleum Institute (<i>Density</i>)
°C	Degrees celsius (<i>Temperature</i>)
ASP	Alkali surfactant polymer
BOPD	Barrels of oil per day
d	Day (<i>Time</i>)
Ha	Hectare (<i>Area</i>)
kg	Kilogram (<i>Mass</i>)
kg/m ³	Contextual – Density or kg of material per m ³ of incremental oil
L	Litre (<i>Volume</i>)
m	Metre (<i>Length</i>)
m ³	Cubic metre (<i>Volume</i>)
mg	Milligram (<i>Mass</i>)
mg/L	Milligrams per litre (<i>Concentration</i>)
mg/L·PV	Polymer mass (<i>Standardized Mass</i>)
mN/m	Millinewton per meter (<i>Interfacial Tension</i>)
mPa·s	Millipascal second (<i>Viscosity</i>)
OOIP	Oil originally in place
ppm	Parts per million (<i>Concentration</i>)
PV.....	Pore volume
SP	Surfactant polymer
V	Dykstra-Parsons coefficient of permeability (<i>0 – homogeneous, 1-heterogeneous</i>)

CHAPTER 1 EXECUTIVE SUMMARY

This project was initiated to provide a comparative evaluation of the five IETP funded projects that use polymer injection for enhancing oil recovery from medium/ heavy oil reservoirs in Alberta. This preliminary report summarizes observations based on annual reports available to the end of 2008. We will continue to closely monitor the progress of various IETP supported chemical floods on an ongoing basis and fine-tune our findings as they pertain to incremental recovery factors and associated costs including those required for the chemicals.

Four IETP supported projects for which performance data were available, were very well designed and executed. They indicated a promise that a secondary polymer flood in Brintnell in the Pelican Lake heavy oil reservoir in the North Central Alberta as well as, tertiary alkaline-surfactant-polymer (ASP) floods in Taber and Suffield medium oil reservoirs are technically and economically feasible and can potentially provide upwards of 10% incremental oil recoveries.

These projects encountered certain difficulties in maintaining injectivity at the injectors as well as, scale deposition in the well equipment at the producers. Most of scaling problems were being partially resolved by use of chemicals. Efforts at reusing the produced water for mixing chemicals were not as successful. These problems merit industry's continuing efforts before the potential of chemical flooding in Alberta's medium and heavy oil reservoirs could be fully realized. Other barriers to Province-wide application of chemical flooding include: aging facilities and wells; mature state of depletion (low oil-cut production) and, limited availability of fresh/ soft water for mixing with chemicals. Also, there is a general lack of awareness within the industry of the potential impact of this technology.

Results from these projects could be extended to many other analogous pools in Alberta. Medium and heavy oil resources of Saskatchewan are somewhat similar to those in Alberta and together, the two provinces provide potential for sizeable reserves additions and also, for development of associated infrastructure, service industry and chemical manufacturing.

A business assessment of plausible reserves additions by chemical flooding and development of ancillary businesses in Alberta is recommended based on encouraging results from these projects.

CHAPTER 2: INTRODUCTION

Polymer flooding technology for enhancing oil reserves has been subject of intense research and field-testing for over 40 years. Although early field tests did not live up to the expectations, significant progress has occurred in the last decade. Recent successful commercial scale projects in China have stimulated renewed interest in this technology. Helping the growing interest in field testing of this technology is a rapidly growing body of literature. There are several books with major chapters devoted to this technology¹⁻⁴. A search on the petroleum production related bibliographic website, “Onepetro” using the key word ‘polymer flooding’ yielded 1494 titles of various documents available in the public domain!

Canadian oil industry has been field-testing this technology for the last four decades (projects partially supported by the Provinces of Alberta and Saskatchewan). More recently, generous funding from the Province of Alberta via the IETP program contributed to further stimulation of industry’s efforts towards advancement of technology and operational methodology and, has led to initiation of five significant field pilots in the heavy and medium oil reservoirs of Alberta.

Premier Reservoir Engineering Services Ltd. was requested to prepare this assessment of these five projects by Alberta Energy (Research and Technology Branch) and, by Alberta Innovates-Energy and Environmental Solutions (AI-EES).

CHAPTER 3: BACKGROUND

Theory

The most common and economic method of exploitation of conventional oil resources beyond primary production is water flooding. Water flooding although field-proven suffers from low displacement efficiency (significant amount of residual oil saturation in the water contacted region due to interfacial tension between the oil and injected water) and/ or, low volumetric sweep between the oil and injected water due to viscous fingering. Out of 10,851 million m³ of conventional oil resources (in-place) discovered in Alberta as of the end of 2009, 5,080 million m³ have been subject to water flooding. For the water flooded reservoirs, NEB/ ERCB have projected a recovery efficiency of 30.9% of the oil-in-place⁵ (17.1% by primary and incremental 13.7% by water flooding). Obviously, cost-effective means of improving effectiveness of water flooding would make significant contributions to Alberta's conventional oil reserves and economy. This is the main motivation behind Province of Alberta's initiative of providing IETP's funding of innovative enhanced oil recovery field pilots.

Over the last several decades, water flooding enhanced by chemicals, has been developed and tested for reservoirs at depths less than 1200 m, mostly containing medium to light oil and, more recently in heavy oil reservoirs⁶⁻²³. Chemicals are added to water mainly for reducing interfacial tension between oil and water, thus improving displacement efficiency *and/or* for increasing viscosity of the injected water for reducing contrast between mobility of water and oil, thereby reducing viscous fingering and improving volumetric sweep. Usually, surfactants are added for the former objective and polymers for the latter objective. Sometimes alkali chemicals such as Sodium Hydroxide, Sodium Carbonate, Sodium Orthosilicate or Sodium Borate are also added to reduce adsorption losses of the more expensive chemicals or, for improving effectiveness of other chemicals by acting as 'co-solvent or co-surfactant' or, by altering wettability of the reservoir rock or, for generating surfactants insitu by reacting with naturally occurring acids in the oil.

Many field trials of chemicals in the past were not successful but the collective and cumulative learning led to better products and better screening of reservoirs & modes of chemical flooding applications. For instance, many polymers used until 1980's had a temperature limitation of 80°C, salinity toleration of 2500 ppm and hardness toleration of 20 ppm but modern polymers are claimed by vendors to be stable up to 100°C or more, salinities of 100,000 ppm or higher, and hardness of 2000 ppm or more.

Reasons for failures of the early projects include: high risks (requirements of small well spacing and delayed oil production response after most of the expenses have been incurred); incomplete understanding of interactions between the injected chemicals and reservoir systems and also; with the well equipment. The first aspect can be partially mitigated using horizontal injectors and producers which not only make small well spacing more cost-effective but also enable faster throughput of the chemical solutions and help reduce oil rate response time. Performance also sometimes suffered due to very high starting water-cuts.

The basic requirements of chemical flooding are⁶⁻¹⁰:

- A. To propagate chemicals (polymers or surfactants) deep inside the reservoir
- B. To overcome chemical adsorption or consumption, and
- C. To improve sweep efficiency and/or to reduce interfacial tension between oil and water.

The underlying concepts and current application practices for polymer flooding and, for Alkaline-Surfactant-Polymer (ASP) flooding are briefly presented next.

Polymer Flooding

It is basically a technique of improving volumetric sweep efficiency of water floods. The applications discussed here do not include formation of polymer gels for profile modification. Needham and Poe⁶ in their 1987 review pointed out that due to improving mobility ratios, effective permeability to water can be significantly reduced in the swept zone. The reduced mobility ratio in turn, improves the rate of oil recovery by increasing fractional flow of oil. Polymer injection does not reduce the residual oil saturation *per se* but, enables us to reach it more quickly and economically by reducing water production. Reduced effluent handling helps extend economic oil production thereby providing increased oil recovery.

In a polymer flood, sweeping of additional reservoir volume occurs due to improved mobility ratio between the polymer and the reservoir fluids. This is in addition to the favourable changes in fractional flow to oil within the swept zone. This is reflected in rapid lowering of 'water-cut' and increases in oil rates.

It has also been suggested that polymer flooding would provide a better oil recovery performance if it is implemented in the secondary mode (after primary production) instead of in the tertiary mode (in maturing water floods). Under favourable conditions (horizontal wells, good injectivity), incremental oil recoveries of up to 20% OOIP have been projected. For this, one may consider various means of improving injection such as optimal use of horizontal injectors, small well spacing and well stimulation.

Intuitively, slower injection rate is relative more efficient in achieving incremental oil recovery. However, time value of money often dictates that the processing rate be as high as feasible, subject to injection pressure limitations.

Oil recovery increases with the amount of polymer injected. This amount, "polymer mass" is measured in mg/L-PV. Beyond certain polymer mass, its effectiveness starts diminishing (progressive mechanical degradation and the law of diminishing returns). Of course, one must minimize amount of polymer produced with the effluent as it is not only wasteful but may cause complications in processing of the oil. These days, amount of polymer solution injected (slug size) is generally in the range of 30 to 70% of the pore volume (PV).

The following physical phenomena affect polymer applications:

- a. Solution viscosity increases with increasing polymer concentration, often increasing disproportionately at high concentrations. Polymers with higher molecular weights (at the same concentrations) result in higher viscosities and also, higher oil recoveries. Higher viscosities may constrain injectivity, depending upon permeability. Similarly, for the same molecular weight, higher concentrations would cause higher viscosities and provide relatively higher recoveries. Apparent viscosity of polymers is usually much higher within the porous medium, than in the bulk (e.g. in viscometer in the laboratory or, in pumping equipment), due to various 'permeability reduction' phenomena.
- b. Many polymer solutions are non-Newtonian (often shear thinning) and their rheology within a porous medium plays an important role in their effectiveness during a flood as shear rates vary along the flow path^{2, 3}. Polymer solutions generally undergo progressive 'mechanical/shear degradation' as the shear rates increase. Laboratory studies indicate that oil recovery can be correlated with Trouton ratio (ratio of extensional viscosity to shear viscosity). This ratio depends upon polymer formulation (average molecular weight and distribution of molecular weights, hydration, etc)⁴.
- c. Many polymer solutions fail to attain high viscosities in presence of high salinity, divalent ions (Calcium or Magnesium), or high temperatures. To protect the polymer, in some cases the hardness needs to be significantly reduced by 'pre-flushing' with fresh water.
- d. Some polymer is adsorbed on the rock surface, causing decreases in solution viscosity. Some reduction in water phase relative permeability also occurs because of adsorption.
- e. Some finer pores become inaccessible to the polymer because of relatively large sizes of polymer molecules. This factor is borne in mind during deciding the average molecular weight for the polymer solution. Typically, accessible pores should constitute more than 70% of pore space.

Alkaline-Surfactant-Polymer (ASP) Flooding²⁴⁻⁴⁰

Surfactant flooding involves reducing interfacial tensions to sufficiently low values (~0.01 mN/m) to mobilize the residual oil by addition of surfactant to the injection water. Combination of alkali and surfactant injection helps in reducing interfacial tension while also lowering surfactant requirements by generating soaps insitu, by reducing adsorption losses and, by altering wettability. For example, in order to lower the interfacial tension between water and Daqing oil, it was determined that alkali (Na₂CO₃ in this specific case) needed to be between 0.75 and 1.6% by weight and surfactant between 0.5 and 3.5% by weight.

Use of alkalis is indicated when the oil contains sufficient naturally occurring saponifiable naphthenic acids components to generate soaps insitu. The combination of injected surfactant and soap created by interaction between the injected alkali and the oil can generate water-oil interfaces with ultra-low interfacial tensions (<0.01 mN/m)^{26, 47}. Acid numbers of such oils typically exceed 0.5 mg KOH/g of oil. Acid gases (CO₂, H₂S), if present in the oil in significant amounts, would react with the injected alkali and reduce its effectiveness.

The local soap/surfactant ratio determines the optimal salinity for minimum interfacial tension. High salinity of the water in the reservoir requires high concentrations of alkali to be effective. The reservoir rock may react with the injected alkali and thereby increase hydroxyl ion concentrations on it, making it negatively charged. This helps increase salinity and hardness tolerance, change wettability and reduce anionic surfactant's adsorption losses. For instance, use of Sodium Carbonate was found to significantly reduce adsorption of anionic surfactants on dolomites and calcite thus making the process applicable to carbonate reservoirs. At the same time, wettability could be significantly altered in some cases to preferentially water-wet. Consequently, surfactant requirements under some conditions might be reduced by an order of magnitude. However, at high pH created by the alkali, some rock dissolution and precipitation may also occur. The use of weaker alkalis such as Sodium Bicarbonate, Sodium Carbonate or buffered mixtures has been suggested as one way of mitigation. In other words, use of alkalis can be very beneficial in certain situations and troublesome in others. Hence, it is very critical to test compatibility of the chemicals to be injected with the reservoir system and also, with the well equipment.

ASP flooding involves initial injection of a combined alkaline-surfactant-polymer slug for improving displacement efficiency by mobilizing more of the residual oil in the pore spaces, followed by a straight polymer slug to improve volumetric sweep by improving mobility ratio and volumetric sweep. The goals are improved oil rates *and* reduced water production. Typical ASP formulations involve 0.2 PV of 1% surfactant and 0.5% alkali, chased by 0.3 PV or more of a solution containing 1000 ppm polymer. Here again, incremental oil recoveries of up to 25% or even more have been reported, depending upon specific geology, well spacing and injectivity.

Studies^{3,4} indicated that chains of some polymer molecules readily spread in the liquid phase without alkali, but they curl upon adding alkali. At high concentrations of alkali (~1%), some polymer chains curl tightly and the molecules do not fully spread. Oil recovery (displacement as well as, sweep efficiency) becomes more favourable at low alkali concentrations which result in better visco-elastic characteristics.

When ASP solution is injected in a maturing water flood, residual oil is mobilized due to lowering of interfacial tensions and sometimes via emulsification. Injected water with reduced mobility due to polymer addition, may contact some of the previously bypassed oil. This is reflected in rapid and significant lowering of 'water-cut' and sustained increase in oil rates within relatively short periods. As the ASP flood matures, water-cuts gradually begin rising as within the contacted region, progressively less oil is available for mobilization. Eventually, ASP injection becomes uneconomic and is discontinued. The water-cuts stabilize at usually high values. Nature of oil rate and water-cut profiles for the project area determines its economic success/ failure and hence, needs to be properly designed and managed.

Blending of Chemicals

Chemicals are usually transported to the oilfield as solids (powders) and blended on site with water. The success of the solution to be injected depends to some extent on the blending process. For example, the quality of the water used can sometimes lead to degeneration of the resulting solutions. Produced water or other available water may need to be softened and rigorously treated as they may contain

hardness that may cause precipitation or degeneration, particulates, or entrained oil droplets. All these may play havoc with maintaining the desired injectivity or injectant quality within the reservoir. Quality control during blending of chemicals is very critical⁴¹ Consequently; the standards of cleanliness and degree of sampling and monitoring for some of the ASP projects are more like those seen in speciality chemicals or food processing plants⁴².

For polymer injection, typically a solution of a polymer in water with a concentration of 5000 ppm is prepared at the surface (mother solution) that is further diluted to the desired injection concentration (typically, 1000 ppm) near the injection facilities. It is then injected into the injection well with the intent of increasing viscosity of the injected water under reservoir conditions to a 'design' value in the range of 15 to 400 mPa·s. This reduces mobility contrast between the oil and the injected polymer solution and helps improve volumetric sweep. To reduce requirements of fresh or softened water for diluting the mother solution, a new technique of 'Post Eductor Polymer Slicing' for powdered HPAM (pre-wetted) polymer using Rapid Dissolution Unit (RDU) can be used in conjunction with Polymer Make-Down Unit, as described by Cenovus in their application to IETP for funding their Suffield UU pilot project. This method enables a highly concentrated mother solution (9000 ppm) to be prepared, helped by 'slicing'. This solution can be then be further diluted using the normal injection water.

Water Treatment

ASP flooding usually requires blending of chemicals with soft water to be effective. With low hardness, Sodium Carbonate may be an effective alkali but at high hardness, novel alkalis such as Sodium Meta-borates can provide equivalent results. Hard water containing high amounts of Calcium and Magnesium ions can be treated by Strong Acid Cation (SAC) resins or, by Weak Acid Cation (WAC) resins. This method requires the feed water to contain very small amount of oil/ grease (<50 ppm). Alternate treatment could be by Select Ion Sequestration (SIS) method that can tolerate relatively more oil carryover (up to 500 ppm).

Scaling Issues during Chemical Flooding⁴³⁻⁴⁴

Scaling of the wellbore equipment is caused by reaction between the alkali and divalent metal cations such as Calcium and Magnesium that result in excessive alkali consumption and surfactant precipitation. The precipitated material under certain conditions of pH, temperature and pressure deposits on the well equipment as a 'scale', thereby 'fouling' it. In the process, calcium as well as, silicate scales form that may play havoc with the well bore equipment.

Scaling problems have been reported from ASP projects in China (Daqing) and elsewhere³⁷⁻⁴⁰. In Daqing, it was surmised that scaling is aggravated as the residence time within the reservoir increases⁴⁰. This would imply that the problem would be less severe when well spacing is small and injection rates, large. They report solving the scaling problem by fracturing injection and production wells with ceramic proppants, and by using 'low carbon mixed organic acid' for heavily scaled producers.

Cenovus in their reports on the IETP project at Suffield UU stated that there were two types of scales generated during ASP projects-initially calcium carbonate based and later, amorphous silica based. Increasing pH due to injection of alkali plays a role in the deposition of the two kinds of scales. The first kind occurs when the pH increases between 8.3 and 9 whereas, the second kind is aggravated by Calcium and Magnesium acting as 'glue' to bridge colloidal silica. Similarly, Husky in their reports on Taber projects stated that scale becomes evident when the pH of the produced water is between 9 and 11. Outside this range, scales are not deposited in the well equipment.

The key to chemical intervention is to minimize duration when the pH of effluent is in this range and, to retard growth of these phenomena once they occur. Injection of scale inhibitors in the producing wells has been attempted to protect the well tubular and near well-bore reservoir rocks.

Intuitively, use of small well spacing may reduce residence time for reactions to be completed but would cause effluents from more wells to have pH in the vulnerable range to form scale in the well equipment. Hence, there is a clear need for developing appropriate mitigation strategy.

Most of these problems will plausibly be resolved in the next few years by further research and development including, field testing of various new chemicals supplied by different service companies.

Non-Petroleum Based Chemicals

The commonly used EOR chemicals are mostly petroleum based. Prices of polymer/ surfactant costs are generally indexed to the price of oil or, the price of the kerosene/ aviation fuel.

These days, many non petroleum based chemicals have also become available for EOR use. These include 'bio-based' or 'plant-based' chemicals including those based on by-products of paper & pulp, and food processing. Plant based chemicals and bio-polymers/bio-surfactants have been claimed to provide salinity tolerance over a much larger range than the sulphonate surfactants. Similarly, some of these could be applied at higher temperatures than polyacrylamides. Besides, their costs would be at least theoretically independent of the oil prices. In many instances, they are claimed to be 'green' chemicals that help reduce the overall environmental foot-print of EOR operations. For these reasons, they have been receiving serious attention.

Emerging Trends

Over the years, many aspects of polymer applications have been clarified. For example, there was some controversy in the past about optimal approaches to polymer flooding. The debate was between small slugs with high chemical concentrations or large slugs with low concentrations. There was a concern of dispersion negating benefits of the former approach and adsorption negating benefits of the latter approach. The consensus seems to be towards a hybrid approach, i.e., use large slugs of relatively concentrated solutions of polymers/ surfactants. The industry practice of using large "polymer mass" has moved from values of 125 mg/L·PV in 1970's towards 240 mg/L·PV in 1980's, towards 600 mg/L·PV currently.

Most polymer and ASP floods have been implemented in sandstone reservoirs but efforts are underway to extend these techniques to carbonate reservoirs. Similarly, issues of compatibility testing or, formation's sensitivity are being handled more effectively these days. The limitations of polyacrylamide temperatures (< 80°C) and of salinity/hardness tolerance are being relaxed by superior formulations.

Similarly, on the application front, there is a better appreciation of blending of polymers/ surfactants in the emulsified state to obtain the desired viscosity/ interfacial tension insitu, and also of optimal concentrations, slug sizes and chemical flood operations in the field, including those of coping with the anticipated problems such as scaling or corrosion using various sequestration approaches.

There is also an increasing trend of the polymer usage in the 'blocking and diverting' mode whereby gels are created insitu, often involving 'cross-linking'. These gels significantly modify the 'profile' of injection⁷, either near the injector or, deep in the reservoir by reducing permeability of already swept regions and forcing the injected water to go around them, thereby sweeping incremental volumes within the reservoir.

CHAPTER 4: PAST CHEMICAL FLOODING PROJECTS IN CANADA AND ELSEWHERE

USA

In 1980, Phillips Petroleum conducted a 1440 acre freshwater polymer project in the North Burbank Unit in Osage County, Oklahoma¹¹. They injected 4.2 million lbs of polyacrylamide and 4 million lbs of 2.9% aluminum citrate cross-linking solution and projected an incremental oil recovery of 2.5 million barrels (utilization of about 5 kg polymer/m³ incremental oil).

In 1985, Amoco conducted a polymer (emulsion polyacrylamide) injection project at Sleepy Hollow, Nebraska¹² in a maturely water flooded project area containing 10 injectors and 45 producers on 40-acre spacing. Target oil had a viscosity of 24 mPa·s and polymer formulation, a viscosity of 10 mPa·s. They used strict quality control on the polymer solution and conducted close surveillance to ensure that injectivity losses and shear degradation at the sand-face were not excessive. Water-oil ratios declined from 45 to 17. They reported increased corrosion and partial plugging of producers after polymer breakthrough. For injecting 48% PV slug containing 750 ppm polymer, they had projected an incremental recovery of 8% OOIP. They actually used a 1000 ppm solution but curtailed injection rates and polymer concentrations due to low oil prices since 1986. From the published data, it appears that they injected about 8 kg of polymer for every incremental m³ of oil recovered.

The earliest field testing of ASP flooding was implemented at West Kiehl, Wyoming^{29, 30} beginning in December 1987. The incremental oil recovery over the next 2.5 years had reached 26% OOIP. At West Kiehl they used soda ash (Na₂CO₃) as the alkali.

Another ASP project was conducted beginning in 1998 at Sho-Vel-Tum oil field³¹. The chemical mix was reported as 1000 ppm polymer, 1.6% Na₂CO₃, 0.3% STPP (for sequestration) and 0.5% surfactant.

Canada

The earliest polymer flood in Alberta was conducted at Taber South Mannville B, beginning in February 1967^{13, 14}. Polymer was injected for 5 years but the amount of incremental oil could not be quantified.

At Rapdan in southwest Saskatchewan, Talisman conducted a polymer flooding project¹⁵ from January 1986 (13 producers and 5 injectors). By December 1994, 43% PV of a 21 mPa·s solution had been injected in confined patterns and oil-cut increased by 8% (stable). During the same time, oil rate from the pattern increased from 8 to 28 m³/d.

At David (now called Black Creek), a portion of the field was subjected to an alkaline-polymer flood beginning in June 1987³³, when that area was producing oil with an oil-cut of 40%. The area contained 7 injectors and 18 producers on 20 acre spacing. By 2004, 21.1% incremental oil had been produced and the oil-cut had declined to 1.5%.

Husky's ASP projects in the Taber area have been briefly described in company announcements, interviews, their and vendor's websites, etc^{34, 35}.

Likewise, Pengrowth's earlier polymer project in East Bodo¹⁶ and CNRL's earlier and current projects in the Taber area of Alberta have been described in some detail in the open literature³².

In a recent article in New Technology Magazine³², current and planned polymer flooding activities are summarized. The article informed that at Pelican Lake, Cenovus was injecting polymers via 125 injectors. Also, at Wainwright, Harvest Operations are conducting a polymer flood.

It also reported that at Suffield, Cenovus determined ASP flooding to be successful and are moving towards commercialization.

As of December 2010, nine ASP projects had been approved by EUB.

The article also lists many projects under active development in Alberta, Saskatchewan and British Columbia.

In Alberta, the following polymer or ASP projects were active or planned during 2011¹⁹:

Approval #	Company	Formation	Field Name	Injection Type
11488A	Blackpearl Resources Ltd.	Bluesky A	Mooney	ASP Flood
11485	Harvest Operations Corp.	Upper Mannville U	Suffield	Polymer Flood
11292B	Cenovus Energy	Sparky JJ	Viking-Kinsella	Polymer Flood
11250B	Cenovus Energy	Upper Mannville H	Countess	Chemical Flood
11249B	Cenovus Energy	Upper Mannville UU	Suffield	ASP Flood
11195A	Harvest Operations Corp.	Wainwright B	Viking-Kinsella	Polymer Flood
10860E	Husky Oil Operations	Glauconitic K	Taber	ASP Flood
10529F	Penngrowth Energy	Lloydminster SS	Provost	Not Specified
10418E	Husky Oil Operations	Mannville B	Taber South	Polymer Flood
10245D	CNRL	Glauconitic SS	Grand Forks	Not Specified
9300D	Cenovus Energy	Upper Mannville YYY	Suffield	ASP Flood
10787	CNRL	Athabasca Oil Sands Area	Oil Sands Area	Polymer Flood
11320	Murphy Oil Company Ltd.	Peace River Oil Sands Area	Oil Sands Area	Polymer Flood
9336F	Enermark Inc.	Lloydminster A, Sparky E	Wildmere	Polymer Flood

Elsewhere

France

Putz et al.²⁰ describe a polymer flood project at the Courtney in the Chateaufrenard Field, France with an oil viscosity of 40 mPa·s at 30°C. One pore volume of 900 ppm polyacrylamide solution in field water was

injected via 4 injectors (380 m³/d) followed by water injection at a rate of 420 m³/d. 14 of the 18 producers responded and the produced polymer showed no signs of degradation. (OOIP for the project area was 640,000 m³, or one pore volume can be injected in about 5 years). Strong oil bank was reflected in the resulting oil rate increases. The incremental oil recovery was reported to be as per the 'original expectations'.

Argentina

Marcit gels (about 150,000 bbls of cross-linking formulation) were injected in two layers of the Comodoro Rivadavia formation in the Golfo San Jorge basin (YPF and TecPetrol). Seven months later, this was followed by placement of 18% HCPV CDG in the target intervals, for the purposes of in-depth profile improvement⁷.

Malaysia

To overcome problems of precipitation while blending ASP components with seawater on the offshore platform applications, specifically at the Angsi reservoir offshore Malaysia, an acid-alkali-surfactant (AAP) using Sodium Carbonate and a new polymeric surfactant derived from Jathhropha oil has been reported³⁶. The seawater contains a large quantity of divalent metal cations. For their formulations, optimal alkali and surfactant concentrations were determined to be 0.6 wt% each and optimal slug size was 0.5 PV or, a chemical strength of 3000 ppm.PV. In the laboratory tests, most of the incremental oil recovery (18.8%) was obtained during the chase water injection after placement of the chemical slug.

Successful Chemical Floods at Daqing, China (References 21-24, 37-40, 43)

The world's largest polymer flood for enhancing oil recovery by improving mobility ratio was implemented at Daqing beginning in 1996. In Daqing alone in 2004, there were 31 commercial scale projects involving 2,427 injection wells and 2,916 production wells over areas encompassing 67,759 acres. For polymer flood in Daqing and Shengli fields³⁸, incremental oil recoveries of 6 to 12% OOIP have been reported in good quality reservoirs. These two fields contributed approximately 250,000 BOPD in 2004 (73.5 million barrels for the whole year). To 2006, more than 70 million m³ of oil had been recovered and the fresh water requirements were reduced by 193 million m³. Consequently, water consumption per m³ oil was reduced by 21.8 m³. At the same time, water-cut was reduced by about a quarter resulting in significant savings.

The following approaches integrating reservoir engineering approaches and technology are credited for the success of polymer floods in China:

1. Incorporation of permeability contrast and continuity during selection of target intervals and well patterns; wherever appropriate, they injected polymers into separate individual layers.
2. They generally use high polymer concentrations and high molecular weights as well as, wide molecular weight distribution formulations. At Daqing, they used a large polymer slug with a combined strength much greater than 240 mg/L·PV. In December 2002, the average polymer injection was 725.7 mg/L·PV, and polymer concentration was 1027.1 mg/ L.

3. They have evolved effective techniques for surface mixing, injection facilities, oil production and effluent treatment
4. They closely track the progress of polymer floods by characterizing into 5 stages according to behaviour of water-cuts^{22, 23}.
5. For dynamic flood monitoring, they are using well logging, testing, and inter-well tracers.

Polymer utilization for Daqing is in the range of 11 kg/m³ incremental oil.

They also report that Colloidal Dispersed Gel (CDG) process for in-depth profile modifications is more cost-effective than straight polymer flooding.

In the five ASP pilots conducted in the Daqing oil field to the end of 2009, incremental oil recoveries of up to 25% OOIP (over and above water flooding) have been reported. They state that “ASP flooding can form oil banks, greatly lower water cut, increase the oil production as well as oil recovery”. They had three pilots where inter-well spacing was between 200 and 250 m. In some areas this spacing was as low as 125 m.

They have expressed a concern that high amounts of chemicals required are hurting economics of ASP projects. Hence one of their challenges is to reduce the amount of chemical injection as effluents from their projects usually contain significant amounts of chemicals. Another reported problem was production of hard-to-break emulsions because of the use of ‘hard alkali’.

CHAPTER 5: MEASURING SUCCESS OF POLYMER FLOODS

General Features of Polymer Floods (partly based on Ref. 22-23, 45-47)

The main operational requirements are:

- A. Ability to prepare polymer solution of the desired viscosity (available for injection at wellhead)
- B. Ability to inject the polymer solution into the reservoir under safe conditions at adequate injection rates (wellhead pressure and fracture pressure limitations)
- C. Ensuring stability of the polymer solution in the reservoir (temperature, degradation) and in handling facilities
- D. Safe handling of injectant and effluent
- E. Ensuring equipments' compatibility with the injectant and effluent

Failure to meet any of the above requirements could result in a failed, or a partially successful project.

Factors Governing Performance

1. Adequate injection / reservoir processing rates (ability to 'process' or 'throughput' one hydrocarbon pore volume [HCPV] in 10 years would be much more preferable compared to say, 20 years).
2. Ability to completely replace voidage (voidage replacement ratio of one or slightly larger) so that reduced reservoir pressure *and* presence of a third phase do not reduce oil rates.
3. Adequate reservoir contact by the polymer and capture of the mobilized oil (well layout; horizontal injectors/ producers, appropriately vertically placed, would obviously be more advantageous than use of vertical wells only). It is appreciated that if the reservoir is fully developed with vertical wells, available choices for modified well configurations would be very limited.

4. Adequate amount of polymer injection (please recall that the industry practice has moved from 125 mg/L·PV in 1980's towards 600 mg/L·PV or larger amounts currently).
5. High oil saturations at the start of polymer injection would be preferable compared to low oil saturations). Parametric studies based on simulation have revealed that starting oil saturation and residual oil saturations are the most significant variables impacting on ultimate recovery whereas, these combined with heterogeneity influence time to chemical breakthrough the most⁴⁶. It follows that a secondary polymer flood would be much more efficient than a tertiary flood due to a high starting oil saturation (and low water saturation). Likewise, a completely watered out reservoir would most likely result in marginal or negative economics for chemical flooding.
6. Polymers, to be effective, should not react with the reservoir rock or fluids, nor be excessively adsorbed on the reservoir surface. In a lithologically heterogeneous reservoir, certain regions may have large amounts of reactive clays and others, high water saturation. Together, these may lead to a relatively poor performance.

Performance Characterization

- a. As a consequence of the above, effectiveness of chemical floods in different projects may vary widely.
- b. Operating conditions and procedures would also need to be adjusted for individual projects.
- c. The nature and timing of response in different projects would also vary.
- d. Within any given project, we would expect some polymer flood patterns to perform much better than the others.
- e. In the absence of complete reservoir description (distribution of shaliness, grain sizes, certain reactive minerals such as anhydrites, etc) and sufficient knowledge on polymer-reservoir interactions, it may not be possible to identify a priori the patterns which would behave poorly. Once conclusively known, patterns with poor performance can be excluded from the polymer injection projects for improving their cost-effectiveness.
- f. To manage and optimize these projects, we need a common metric for polymer flood effectiveness and evolve appropriate 'benchmarks'.

Metric to Quantify Effectiveness

- I. One simple metric⁴⁵ would be 'effectiveness factor' or polymer required per incremental volume of oil in terms of kg/m³. It may be pointed out that the cost of polymer/surfactant accounts for a major portion of expenses and incremental oil is a direct indicator of revenues. This factor would be very high in the early stages of a chemical flood as it takes several months/ years for the incremental oil to become apparent. As the sweep expands and mobilized oil is captured, this factor would decrease. Finally, beyond a certain point, the effectiveness of polymer injection will begin diminishing; the oil contributed by sweep expansion and scavenging of oil from the already swept regions becomes uneconomic to produce and indicates termination of chemical injection.
- II. In a large chemical flooding project with multiple injectors and producers, it would be desirable to identify poorly performing regions early. The use of a 'stream line' modeling approach can be combined with the above metric to obtain a flood management tool⁴⁵.
- III. It is realized that there may be many other factors determining cost-effectiveness of a chemical flood, including polymer and ASP floods. These include operational problems such as scales, corrosion, additional effluent treating costs due to presence of chemicals, etc. An overall economic evaluation and subsequent analyses would provide the final metric but the above method may be useful in identifying critical areas for detailed analyses.

CHAPTER 6: DISCUSSION OF KEY FINDINGS AND SIGNIFICANT ADVANCES IN INDIVIDUAL PROJECTS

Brintnell Polymer Pilot

This project demonstrated that secondary polymer flooding of conventional heavy oil with oil viscosity up to 2000 mPa-s using horizontal injectors/ producers is superior to the option of water flooding.

Some of the issues needing resolution are:

- a. What is the optimal well spacing? The well spacing used in the pilot is perhaps a bit large.
- b. How can we predict the timing and extent of polymer production in the effluent in order to cope with the problem?
- c. Can such projects be optimized based on data from occasional production logs, or via planned interventions?

If we deduct about 5 to 7% incremental oil recovery anticipated from an optimized water flood, the net incremental oil recovery due to polymer over water injection would be in 4 to 6% range. Thus polymer injection has a net effect of doubling incremental oil recovery (due to water injection) over the primary production. Another way to look at it is that polymer requirements for the truly incremental oil over water flood would be double those computed here, or in the range of 10 kg/m³ incremental oil. This is consistent with experience with tertiary polymer floods elsewhere.

Taber South ASP Pilot

This project demonstrates feasibility of tertiary application of ASP flood in a mature water flood in a medium gravity oil pool.

Severe problems of equipment scaling and injectivity loss were encountered; these were solved using treating chemicals with varying degrees of success.

This pilot also highlighted that due to variability of reservoir properties, some parts of the pool may not effectively respond to ASP injection. The challenge is to identify such areas early in the life of an ASP flooding project to optimize cost-effectiveness of chemicals.

Taber Glaucconitic ASP Pilot

This project demonstrates feasibility of tertiary application of a non-petroleum based “green” ASP flood in a mature water flood in a medium gravity oil pool. One of the objectives of using the “green” chemicals was to determine if the produced water could be reused and this objective was not successfully met during this pilot.

Severe problems of equipment scaling and injectivity loss were encountered that were solved with partial success.

Suffield ASP Pilot

This project demonstrates feasibility of tertiary application of a “green” ASP flood in a mature water flood in a medium gravity oil pool but with a high oil viscosity (181 mPa·s) approaching that for heavy oils. One of the objectives was to determine if fresh water requirements could be minimized during preparation of chemical solutions for injection. This objective was successfully met (though with several problems which were successfully resolved). Another objective was to determine if the produced water could be reused and this objective was not successfully met during this pilot.

Scaling Issues during ASP Flooding

Scaling issues were noted in all the three IETP ASP projects reviewed in this report. The operators coped with them using various inhibitors and also, by mechanical scraping of scales from the well equipment. Inhibition with the recent generation of chemicals supplied by service companies showed promise but clearly there is need for further studies and trials.

In summary, these projects demonstrated potentials of chemical flooding but also helped identify some operating problems, especially of injectivity and scales, and reuse of the produced water which need to be resolved in order for this technology to fully contribute to Alberta’s economy.

Injectivity and Productivity Issues

There was evidence of impairment of injectivity and/or productivity in the three ASP flood projects and these kinds of problems might potentially also occur in the polymer flood. A procedure of interpreting Hall plots for the injectors has been developed⁴⁸. While interpreting Hall plots, it must be borne in mind that Hall plots are strictly for “steady state” operations and chemical floods are by no means, so. Also, it would not be possible from an analysis of a Hall plot to determine if the impairment was due to loss in transmissibility or, due to build-up of skin (due to scales or other near well bore phenomena). It would therefore be desirable to also conduct injection fall-off (IFO) tests for the latter, in addition to capture data for a Hall plot for the injectors. For producers, it would be desirable to occasionally conduct pressure build-up (PBU) tests to detect any changes in skin or near well bore region permeability.

CHAPTER 7: KEY INFERENCES ON SCREENING AND DESIGN OF CHEMICAL FLOODING PROJECTS

The performance of all IETP projects under chemical flooding was very encouraging. These projects had the following common features which plausibly contributed to the success of these projects:

- Fairly strong injectivity/ processing rates (which enabled fast fluid throughput and short project life).
- Good quality reservoirs with relatively high recovery factors under primary and water flood for the three ASP projects.
- Existence of many wells leading to a small inter-well spacing (10 Ha/well or less, except in Brintnell); existence of horizontal wells in two of the projects helped. (Together, these enabled enhanced reservoir contact and efficient capturing of the mobilized oil).
- Relatively soft (clean and fresh) formation water and availability of suitable 'source' water
- Existence of wells and facilities which were in very good mechanical shape and did not require expensive replacements or repairs during operation of these pilots.
- Economic operations prior to initiation of chemical flooding
- Trained manpower which enabled safe, prudent and efficient operations in the field.

Success of these projects establishes the first necessary step towards wider application of this technology that is to prove that it can be gainfully applied to Alberta's medium and heavy oil resources. It is very plausible that these reservoirs constitute the 'cream of the crop' amongst our medium and heavy oil reservoirs.

Recently, a screening methodology for SP and ASP flooding has been proposed based on known performance results of ASP floods⁴⁷. The authors conducted in-depth statistical analyses of several hundred simulation results (incremental oil production at breakthrough and as a function of different amounts of chemical throughput) and 18 different variables. They concluded that the chemical flood performance is most sensitive to mobile oil saturation at start of chemical flood, residual oil saturation to water flood, mobility ratios, reservoir heterogeneity, nature of stratification and, permeability anisotropy.

Since most of the reservoir parameters for Canadian heavy oil reservoirs are known, one can utilize a similar approach to screen them for feasibility of ASP application. The results of these pilots, and of other relevant projects can help in calibrating the projections.

Based on performance of the projects reviewed, the following screening criteria are proposed, specifically for Canadian medium and heavy oil pools that are almost all sandstones:

Parameter	Tertiary ASP Flooding	Secondary Polymer Flooding
Oil Density (kg/m ³)	890 to 940	>890
Oil Viscosity (mPa·s)	10-200	>35, up to 1000
Depth (m)	<2500	<3000
Permeability (md)	>50	>200
Dykstra-Parson (V)	<0.7	<0.75
Net Thickness (m)	>3m	>5 m
OOIP (e3m ³)	>500	>1000
Recovery factor (Primary)	>5%	>5%
Recovery Factor (Water Flood)	>7%	--
Mobility Ratio	<20	<50
Connate/ Source Water Hardness (mg/L)	<1000	<1000
Well Density (Ha/Well)	<10 Ha/well	<16 Ha/well
Anticipated Chemical Injection Rate (Pool) (m ³ /d)	>200	>600/section area
Oil-cut at start of the flood	>0.05	>0.2
Excluded reservoirs containing bottom water or gas caps	Yes	Yes
Anticipated incremental Recovery Factors	10%	8%
Anticipated polymer utilization (kg/m ³ incremental oil)	9	5

These criteria are still arbitrary and intentionally a bit on the optimistic side. These can be further adjusted based on performance of floods in specific areas. It must be pointed out that these are only based on known reservoir parameters. Practical considerations would further narrow down the list of prospects. These considerations include:

1. Wells and facilities need to be in sound mechanical condition as these projects may not afford costly replacements/ repairs.
2. Project life may be extended and recovery factor curtailed due to problems such as injectivity impairment and scales deposition on the well equipment.
3. Larger the current water-cut in the effluent, weaker and more delayed would be the response
4. Greater the pressure depletion in a reservoir, the longer will be the response time.
5. Not all parts of a reservoir will respond adequately to a chemical flood and hence some non-performing parts may need to be excluded during early stages of the flood. Consequently, anticipated recovery factors would be somewhat lower than anticipated.

CHAPTER 8: IMPLICATIONS TO ALBERTA'S RESOURCE BASE AND CHEMICAL REQUIREMENTS

Performance of IETP supported successful ASP pilot projects operated by Husky Oil between October 2005 and September 2009 encourages us to presume that this kind of performance can be replicated and improved upon in a number of medium heavy oil pools in the Lloydminster region, Southeast Alberta (PSAC 3) and Southwest Saskatchewan (Area IIIM). This presumption merits verification by further piloting/ analyses.

We speculate that requirements of formation water containing low salinity and hardness are best met at geological horizons deposited during transition between transgression and regression of the sea. During the Cretaceous period in Alberta, these phases occurred during transition from Lower and Upper Cretaceous periods. Also, conditions favouring low salinity were created by hydro-geological invasion of relatively fresh water into reservoirs subsequent to their deposition.

Potential Reserves Additions due to Polymer Flooding in Canada and Polymer Requirements

In Canada, polymer flooding will be applied to increase recovery from pools under water flooding, containing medium oil (18 to 30°API, generally with an insitu oil viscosity of less than 200 mPa·s) and heavy oil (<18°API gravity) of Alberta and Saskatchewan. In order to determine potential reserves additions to Canada's oil reserves, first we need to estimate the oil-in-place that is amenable to polymer flooding. In Alberta, PSAC Area 3 (southern Alberta) largely contains medium oil reservoirs, Area 4 (Lloydminster) contains heavy oil reservoirs and Area 6 contains Athabasca oil sands including the Pelican Lake heavy oil deposits. Some reserves data are available in the ERCB website for 2009-end (but not the OOIP for individual PSAC Areas).

In Saskatchewan, Areas I and II contain heavy oil and Area IIIM contains medium oil. Medium oil resources of Southwest Saskatchewan (Area 3M) were recently reported to be amenable to ASP flooding⁵⁰⁻⁵¹. These deposits are characterized by thin pay (2 to 8m, shaly sands at moderate depths (1200-1500 m) with insitu oil viscosities in the range of 10 to 80 mPa·s. Most of major reservoirs are in mature stages of water flooding. Saskatchewan Energy Resources website contains reserves and OOIP for these individual areas. NEB website contains a report published in 2001 on conventional heavy oil resources by geological horizons but not by individual areas or provinces. ERCB, NEB and SER use slightly different definitions and detailed breakdowns. The NEB report has assessed data for both the provinces on a consistent basis. These data are summarized below:

Area	Source/ Date	OOIP (E6m ³)	Initial Established Reserves (E6m ³)	Comments
Alberta PSAC 3 (medium oil)	ERCB (2009)		263	OOIP & reserves for water floods are not readily available
Alberta PSAC 4 (heavy oil)	ERCB (2009)		424	OOIP of 659 e6m ³ under flood
Alberta PSAC 6 (heavy oil)	ERCB (2009)	289	29	<i>Water flooded portion only</i>
Saskatchewan I (heavy oil)	SER (2008)	2,869	254	Figures for water flooded areas not readily available
Saskatchewan II (heavy oil)	SER (2008)	768	76	Figures for water flooded areas not readily available
Saskatchewan III (medium oil)	SER (2008)	638	153	Figures for water flooded areas not readily available
Canada (heavy and medium oil)	NEB (2001)	7,927	1,665	Figures for water flooded areas not readily available

In order to identify the target resources for polymer flooding in Canada, certain assumptions need to be made, in addition to using the screening criteria mentioned earlier. The reservoir must have been successfully water flooded but it should not be in a very mature stage with the current water-cuts preferably less than 95%. The existing water flood infrastructure must be adequate for use during polymer flood. The well spacing needs to be small (less than 10 Ha/well) preferably containing several horizontal producers/ injectors. Most importantly, wells and their completions should be in sound mechanical shape as most polymer floods would not be able to afford many infill/ replacement wells or new infrastructure. All these conditions restrict the amenable candidate reservoirs to oil pools under water flood of a more recent vintage (<20 years). Most likely, only the operators of successful water flood projects in large reservoirs are likely to be enthusiastic about a technology such as polymer flooding. The main exception would be Pelican Lake (e.g. CNRL) that has many horizontal wells and where water flooding has not matured to high water-cuts. Current pilot activity in the region is also expected to stimulate interest.

It is assumed here that reserves additions due to polymer/ chemical flooding would be 1% for large (>1 million m³ OOIP) medium and heavy oil reservoirs (10% incremental oil recovery from 10% OOIP targeted) and 5% OOIP from the Pelican Lake area (50% of water flood amenable OOIP targeted).

Area/ Horizon	# Pools (NEB 2001)	OOIP (E6 m³)	# Pools>E6m³ (NEB 2001)	Target OOIP (E6 m³)	Estimated Reserves Additions¹ (E6 m³)
<i>S. Alberta Lower Mannville</i>	716	238	47	161	2
<i>S. Alberta Upper Mannville</i>	373	316	58	266	5
<i>Lloydminster Dina & Cummings</i>	910	455	47	392	4
<i>Lloydminster Colony to Lloydminster</i>	2,770	2,474	233	2,233	22
<i>Saskatchewan/ Alberta Jurassic</i>	517	549	83	477	5
Total (NEB 2001 Base)	5,286	4,032	468	3,529	38
Revision to 2011 ²					46
Pelican Lake Area ³		670		OIP being flooded ³ 289	34
Total (2011)					80

Notes

1. It is assumed that 5% OOIP reserves addition for Pelican Lake and 1% for large medium and heavy oil reservoirs due to polymer/ chemical flooding (10% incremental oil recovery from 10% OOIP targeted). This conservative value of targeted OOIP is because of most candidate pools being at very mature stage with aging wells/ facilities, reducing well counts due to abandonments, limited freshwater availability and prevailing high salinities in the reservoir.
2. It is assumed that there has been a 20% appreciation in discovered resources (OOIP) between NEB data presented in their 2001 Report and now (2011).
3. ERCB (2009) ST98-2010, reference 5.

NEB (2001) had estimated 89 million m³ reserves additions due to 'improved oil recovery' for the Lloydminster (Colony to Lloydminster horizons) area. However, this figure most likely also included future water floods.

These potential reserves additions would be staggered over the next 20 or more years and it is assumed here that they would occur at a steady pace of 4 million m³/year.

It appears that Alberta would benefit relatively more from chemical flooding although Saskatchewan potentially might have larger target resource. The reasons for this are relatively newer water flood operations in the Pelican Lake area and maturing water floods in the Lloydminster heavy oil reservoirs.

Surfactant and Polymer Chemical Requirements

From the foregoing, reserves additions due to chemical flooding are estimated at 4 million m³/year. It is further assumed that half of this addition would be due to ASP and the other half due to polymers alone.

Assuming a 0.5% surfactant slug of 15% PV and 10% incremental oil recovery, surfactant requirements are about 10 kg/m³ incremental oil. Similarly, assuming a polymer concentration of 900 ppm and a buffer of 0.75 PV and 10% incremental oil recovery, polymer requirements would be 9 kg/m³ incremental oil.

Thus Canada might need up to 18,000 tonnes of polymer and 40,000 tonnes of surfactant/year for ASP flooding over the next 20 years. New generation of efficient surfactant could potentially reduce the total surfactant requirements.

Scale Inhibitor Requirements

Assuming inhibitor consumption of 1 kg/m³ for ASP projects, Canada might need 2,000 tonnes of inhibitor chemical/year.

Risks

Although most of the polymers used were polyacrylamides supplied by SNF and surfactants supplied by OilChem (these products and suppliers have survived in the market place for a long time), there is a great risk of obsolescence of these products as new or improved products enter the market. For example, non-petroleum based "green" chemicals, if successful, could change the market for acrylamides. Similarly, surfactants could also be vulnerable to the competition from new products. This business is like 'speciality chemicals' where continual efforts are required towards research and development to improve the quality and cost-effectiveness of products. At the same time, adequate amount of field testing of the products is critical for establishing and maintaining credibility of the vendor and the products. The vendors therefore tend to collaborate with manufacturers/ other service providers and offer chemicals as a part of larger business deals.

CHAPTER 9: CRITICAL UNCERTAINTIES AND DIRECTIONS FOR THE FUTURE

We need further understanding of the chemistry involved (understanding process performance in regions where it is currently very poor) in addition to that of the problems encountered in these projects for coping with scales, injectivity loss, reuse of produced water & corrosion. As the matters stand now, we may *not only* have to lower our expectations on incremental recovery factors from various projects *but also*, exclude some of the apparently poor (or non-performing regions based on these projects) parts of our medium/ heavy oil resources from potential application of this technology.

Scales

Issues of scales in wellbore equipment were reported and partially addressed by Cenovus as well as, Husky in their reports. Although inhibitor treatment appears promising for both silicate and carbonate scales, a more fundamental understanding of conditions in Canadian operations leading to these is needed so that appropriate practices for mitigation could be devised.

Injectivity Loss

Injectivity losses are known to occur in polymer and ASP flooding and require specific responses for relevant conditions in Canadian operations. To begin with, Hall plots can indicate progression of injectivity impairment which most likely would be slow. However, as mentioned earlier, Hall plots alone would not identify whether the problem is essentially a near wellbore one or, is caused deep within the reservoir or, a combination of the two. We would require time lapsed data, i.e. data for the same wells taken some months apart.

Also, having determined the locations of significant impairment, next we would want a systematic search for respective mitigation strategies (mechanical scraping, mini-fracturing, solvent/ acid washing, etc). In addition, we also need to explore the “Best Practices” for coping with the problem. For example, would it be a good idea to over-inject while the injectivity is good to make up for any potential future under-injection (assuming the producers wells are always ‘pumped off’)?

Reuse of Produced Water

In various IETP projects, the objective of reuse of produced water remained unfulfilled due to various difficulties. In view of potentially impaired injectivity, there is an imperative to minimize the amount of

entrained oil droplets in the injected water. The approaches of the operators had obvious limitations but it is not clear whether feasible cost-effective solutions exist for target oilfields of Alberta, at the present. If they do not, then the *potential of polymer flooding in Alberta would be seriously curtailed due to limited amount of fresh water available for this type of projects at different target oilfields.* Alternately, search must continue for cost-effective chemical floods that do not require fresh water for blending chemicals for injection.

If reuse of the produced water becomes feasible, we would need to identify 'Best Practices' such as optimal temperature of reinjection so as to minimize problems caused by sharp changes in solubility of certain components (e.g. CaCl₂) with changes in temperature upon mixing with warm reservoir water.

Corrosion

Other than the Pelican Lake area where wells are relatively new and several new infill wells can be added, other amenable reservoirs of Alberta have been fully developed by mostly vertical and sometimes horizontal wells. Hence coping with potential corrosion issues by proper selection of tubulars/ well equipment is not a viable solution for many of the mature oil pools of Alberta. The obvious choice would be to seek proper anti-corrosion coatings/ treatment. Since a number of service companies are already on this trail, this does not threaten to become a critical issue at this point in time. However, it must be flagged as a potential (though less likely) "show stopper".

Suggestions Regarding Annual Reports to IETP

Although discussed to some extent in various reports, inclusion of further details on the following would help a reader to better understand performance of various projects reviewed:

- Hall Plots to help examine injectivity changes during the project
- Economic analyses on cost-benefits of individual constituents of the chemical injection mix and synergistic effects in their specific projects
- Description of optimization efforts to make the chemical utilization more effective
- Plausible explanations on why certain areas/ regions responded poorly to chemical injection
- Operator's inferences on critical screening and design considerations for similar future projects
- Operator's ideas on what can be done to further reduce requirements of fresh/ softened water in their projects

CHAPTER 10: CONCLUSIONS

All of the five IETP projects for which performance data were available, were well planned and executed and provided encouraging results on application potential of the technology to Alberta's light and medium oil resource. For instance, in the prospects of similar quality as the current IETP polymer aided EOR projects, we can expect upwards of 10% OOIP incremental reserves at a consumption of about 10 kg/m³ incremental oil for tertiary ASP flood projects and about half as much polymer would be required for secondary polymer flood projects, especially in the Pelican Lake area.

It was determined that these technologies could potentially add 80 million m³ reserves to Alberta and Saskatchewan's reserves in the next 20 years. Alberta would probably add 60% of these, mainly due to potential of polymer flooding in the relatively new Pelican Lake oilfield.

In order to support this scale of operations, huge quantities of polymer, surfactant and other speciality oilfield chemicals such as corrosion and scale inhibitors would be required. Polymer requirements for Alberta alone might build-up to 10,000 tonnes/year.

Barriers

Most of the current opportunities in Alberta, other than in the Pelican Lake area are in watering out medium/ heavy oil pools. In these pools, wells and oil field equipment/ facilities are aging (> 25 years old), current oil-cut are typically in 5% range and water, relatively hard. The economics of a chemical flood will likely be marginal. Due to their relatively long payout (> 5years) and, low (<10%) rates of return (ROR), they may not meet the 'hurdle' criteria for many oil companies for investment. Many of these projects may also not be able to afford major capital expenditures such as replacement of wells, lines, etc.

The biggest barrier to a widespread use of this technology in Alberta is the limited availability of fresh water as the current IETP projects have not succeeded in reusing the produced water.

Another obstacle to chemical flooding is the presence of significant hardness (calcium and magnesium) in various oilfield waters of heavy/ medium oilfields of Alberta.

Yet another barrier is a lack of awareness of the current status and potential of this technology. This can be addressed by encouraging dissemination of results by IETP participants.

Although the four IETP projects (for which performance data were available) provided encouraging results, together they cover a limited range of medium oil/ heavy oil prospects. Further activities should stimulate interest within the industry.

CHAPTER 11: GENERAL SUGGESTIONS

It is recommended that further encouragement be provided to extend application of this technology to more reservoirs:

- With heavier oils (viscosity in 200 mPa·s or more), including secondary chemical floods in non-water flooded areas.
- Poorer quality reservoirs (with ultimate oil recovery inclusive of water flooding, of 7 to 12% OOIP).
- There might be selected horizons/ regions where salinity and hardness are relatively low. This occurrence (low hardness) would make respective reservoirs amenable to polymer aided floods. This merits further evaluation.
- Application to areas where the source water contains more hardness.
- Application of this technology focussing on reuse of produced water. It follows that efforts continue to identify cost-effective chemicals that could use 'hard' or 'waste' water. Also, efforts should continue to find ways of reusing produced water for blending chemicals for injection.
- More mature floods, namely, can one target watered out (<2% oil-cut) medium/ heavy oil reservoirs for economically viable tertiary chemical floods?
- IETP participants be encouraged to disseminate results by way of presentations and publications to increase awareness amongst the industry-at-large.
- A business assessment of plausible reserves additions by chemical flooding and development of ancillary businesses in Alberta is recommended based on encouraging results from these projects.
- Infrastructure for chemical flooding for EOR (provision of required goods and services) would also include active Research and Development capabilities in Alberta to continually develop and field test new products and technical solutions to cope with various current and emerging problems.
- Various comments/ inferences made in this document are based on reviews of a limited number of projects for relatively short durations. They are essentially preliminary and need to be refined on an ongoing basis as further performance data become available. Continual reviews of performance data for various chemical flooding projects could help in a better understanding of the factors affecting oil production and associated costs.

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