

# **Novel Low GHG Heavy Oil Recovery Process**

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## Executive Summary

Expectations of sustained demand for petroleum products combined with the expected long term decline in the supply of light to medium crude oil have placed the spotlight on heavy oil and non-conventional resources. Commercial heavy oil technologies only achieve partial recovery and will leave a significant fraction of the resource in the ground. In a favourable pricing environment, the business as usual scenario is that the goal of increasing recovery is likely to be tackled by pushing commercial technologies to their limit with the unfortunate outcomes of higher costs, poorer energy efficiency, lower recovery factors, and increased greenhouse gas emissions and water intensities. The motivation for this project is to lay the groundwork for new technology directions to expand heavy oil recovery in ways that are economic and environmentally acceptable.

### Lloydminster Heavy Oil

While most of the interest is focused on Athabasca oil sands, there are good reasons to target Lloydminster heavy oil reservoirs for the development of new EOR technologies:

- Current commercial technologies will leave approximately 90% of the resource in the ground which is a sizable prize;
- The fact that 90% is not recovered implies that important volumes of the resource are still at or near original oil saturation;
- Lloydminster heavy oil is a higher quality product that commands a higher price than bitumen from oil sands;
- Heavy oil has been produced in Lloydminster for over 30 years and the area possesses a significant infrastructure dedicated to the oil and gas industry. Cost of development would therefore be expected to be lower than in undeveloped northern regions;
- Lloydminster heavy oil is mobile at reservoir conditions due to its viscosity and the relatively high permeability of the host unconsolidated sandstones. The fact that oil is mobile is a degree of freedom that does not exist in the oil sands;
- Until recently, there have been few technology development programs targeting heavy oil EOR in Western Canada. Many interesting ideas have simply not been tried in the field and the probability of success may be a higher than in a well studied area; and,
- The successful commercialization of a new heavy oil EOR technology could open the door for adaptation the same technology to oil sands.

The Lloydminster heavy oil region covers an area approximately 140 km by 90 km (12,600 km<sup>2</sup>), straddling the Alberta Saskatchewan border and centered on the town of Lloydminster (Township 49). Original light to heavy oil in place in the Lloydminster area is estimated at 12.7 billion m<sup>3</sup> (80 billion barrels). Remaining established reserves of light, medium and heavy crude oil are estimated at 43 million m<sup>3</sup> (270 million barrels). Adjacent oil areas with similar characteristics to Lloydminster are Frog Lake, Elk Point, Lindbergh and portions of Cold Lake and Primrose.

These unconsolidated sandstone formations are characterized as being relatively thin, clean, with high porosity, permeability and oil saturation. They are cohesionless sandstone structures with porosities of 30% to 36%. Oil saturation is high (75 to 90% of pore volume). Oil density ranges from 10° to 25° API. Dead oil viscosity is generally between 3,000 to 10,000 centipoises but may vary from 50 up to 50,000 centipoises. The original reservoir pressure is low, generally between 2,000 and 3,500 kPa. Core permeability ranges from 500 to 10,000 mD with an average value being 2,000 mD. Unfavourable aspects include high oil viscosity, low solution Gas Oil Ratio (GOR) and low initial reservoir pressures. Reservoir dips are low (less than 0.5°) and some areas are underlain by bottom water.

The reservoir thickness distribution has been estimated as follows (percent of original oil in place): 80% of reservoirs are between 2 and 5 m thick; 15% are between 5 and 8 m thick; and, 5% are between 8 and 12 m thick.

### **Existing Primary and Secondary Recovery**

A large number of reservoirs in Lloydminster are produced using cold primary production without associated sand production with relatively low productivities and recovery factors (5% to 7%). Waterfloods are also used to increase recovery by an additional 5% to 7%. Many heavy oil reservoirs in the Lloydminster area are susceptible to significant sand influx. These reservoirs are produced using Cold Heavy Oil Production with Sand (CHOPS). Allowing sand production dramatically increases production rates (by a factor of over 10 times) and results in recovery factors of 12% or better. Heavy oil, produced water, and sand are brought to the surface and sent to lease storage tanks where sand is separated from liquids. Sand is then trucked to central facilities where it is stockpiled temporarily and eventually disposed of into underground salt caverns. Liquids are further separated into heavy oil and water and each is trucked to central processing facilities. Some lease tanks are opened to the atmosphere and some of the produced gas, mostly composed of methane, may be vented to atmosphere where it will contribute to the overall greenhouse gas load.

The recovery mechanisms postulated for CHOPS are as follows:

- Production of sand increases the overall porosity and permeability of the formation and generates channels of greatly enhanced permeability;
- Sand mobility increases fluid mobility. The velocity of the sand, water and oil slurry with respect to the formation is higher than the velocity that oil alone could achieve with respect to an immobile sandstone formation;
- Evolution and containment of solution gas maintains pressure;
- A solution gas drive contributes to production. Low mobility bubbles of produced gas expand when pressure decreases as the slurry moves toward the surface;
- The presence of bubbles in the oil phase reduce its apparent viscosity;
- Sand movement eliminates fines blockages, gas blockages and asphaltene precipitation near the wellbore;
- Production of sand also removes any mechanical skin damage that might have developed near the producing well;

- Sand production increases the compressibility of the formation leading to easier formation compaction and expulsion of oil; and,
- Sand production results in vertical stress concentration, lateral stress reduction, shear dilation and continued formation destabilization which maintains the process.

Sand production removes sand from the formation. Sand cuts eventually stabilize at values between 0.75% and 3% for the less viscous heavy oil and levels ranging from 10% to 15% for the heavier crudes. However, it is important to consider that sand is not removed uniformly across reservoir volume but selectively from certain reservoir zones. CHOPS is thought to result in the formation of a higher porosity volume near the wellbore and of a network of high permeability channels where permeability is higher by three to five times the undisturbed matrix permeability. In other words, the application of CHOPS results in the creation of a dual porosity and dual permeability reservoir with high permeability channels (often named “wormholes”) spreading through the undisturbed formation. Flow of oil to the well is thought to be dominated by flow through these high permeability channels. These channels may extend far from the producing well and in some cases may establish communication with adjacent wells or water zones.

In tandem with sand production, CHOPS is sustained by a solution gas drive that maintains the oil rate through volume expansion and by keeping sand in suspension. Depressurization of gas saturated heavy oil causes bubbles to form but they are prevented from coalescing and forming an independent gas phase because of high oil viscosity, low diffusion rates and high pressure gradients. Solution gas remains trapped in the oil phase and is produced proportionately with the oil thereby maintaining reservoir pressure. Solution gas also drives production because bubbles expand the apparent volume of the oil phase. This expansion increases as the oil phase is driven by the pressure gradient toward the producing well. This continuous volume expansion is one of the mechanisms that support production. Another role postulated for gas bubbles is that they assist in destabilizing the sand formation. While small bubbles are able to flow through pore throats, large bubbles or gas slugs are unable to pass and may block pore throats. The local increase in stress from this blockage exerts pressure on sand grains, eventually destabilizing them and entraining them in the flow. Sand destabilization is an essential mechanism for CHOPS.

Subsidence, or formation compaction, is also thought to be an essential drive mechanism for CHOPS. Compaction of the formation from sand production supports the expulsion of sand and heavy oil toward the well. Water pressure from nearby aquifers may also provide some pressure support.

### **Production Decline and Post-CHOPS Reservoir conditions**

Typically, the oil rate gradually increases in early years. Afterwards, a long period of slow production decline sets in. Production is eventually stopped when the daily oil rate falls below an economic criterion. The cause for steadily falling oil production is generally the exhaustion and eventual depletion of the solution gas drive. Reservoir pressure is reduced and solution gas appears to have blown down.

A possible cause of production decline is a slowdown in sand production. Sand is destabilized at the farthest tip of the high permeability channel, where wormholes grow by

eroding the original sandstone matrix. As production progresses, the growth front is located further and further away from the wellbore and the pressure drawdown becomes extended. Eventually, the pressure gradient is not sufficient to support additional growth of the high permeability channel and sand movement slows down.

Another cause of cessation of primary production is excessive water influx. Aquifers with varying degrees of strengths may be present in the vicinity of a producing oil pool. Rapid oil production, particularly with vertical wells, may lead to water coning from an underlying aquifer.

One hypothesis for the fact that recovery with CHOPS is limited to approximately 10% is that CHOPS recovers oil only from the most favourable horizontal plane of the reservoir. The properties of the sand matrix and of the heavy oil vary with depth. It is possible that wormholes grow in a horizontal plane away from the well. Reservoir volumes below this plane, and possibly above it, could be simply bypassed.

Substantial quantities of heavy oil will remain in the Lloydminster area at the economic limit of cold production. It is therefore important to characterize and understand the state of the reservoir after CHOPS in order to properly design a suitable EOR process.

CHOPS is a production process that significantly alters reservoir properties from their original state, notably the creation of local high porosity zones caused by the extraction large volumes of sand. Oil was obviously produced from the zones from which sand was produced. These zones now have higher porosity and contain a higher proportion of liquids than the undisturbed matrix. However, the oil that was contained in these zones is insufficient to account for total production. Therefore, oil was also drained from the undisturbed matrix into the high permeability channels. It is likely that a proportion of the reservoir volume is still at the original porosity (no sand was removed) but at a reduced oil saturation.

The presence of high permeability zones where sand has been produced means that infill drilling becomes difficult because of lost mud circulation during drilling. In-fill drilling has been tried but found to be generally unsuccessful in Lloydminster.

A common view is that at the end of economic production, the reservoir only contains "dead oil" with no solution gas. The depletion of solution gas means that there is no longer a solution gas drive to destabilize the sand formation and move the oil. The oil remaining in the reservoir can only move slowly toward the wellbore, essentially under Darcy flow. Therefore, it cannot be pumped to the surface at economic rates.

However, while pressure can be transmitted hydraulically through the reservoir, gas bubbles are virtually immobile. Therefore, gas should still be present, likely in the form of bubbles a short distance beyond the permeability contrast of the high permeability channel and the undisturbed sand matrix. Dead oil would only be present in a cylindrical layer surrounding the high permeability channels. Live oil containing solution gas could be present beyond this layer. Immobilized by high oil viscosity, this gas cannot be produced unless the oil is produced.

## Lloydminster Strengths and Weaknesses

The opportunity for Lloydminster heavy oil EOR is the substantial quantity of oil that will be left in the ground after primary and secondary recovery. The threat for the oil industry in the region is that the end of activities based on existing commercial technologies is in sight. However, before investing in the development of a new EOR technology to exploit this opportunity and counter the threat, it is important to consider the strengths and weaknesses of the heavy oil region. The design of a new EOR method should build on the favourable factors and seek to reduce exposure to the unfavourable aspects. Strengths are listed as follows:

- Approximately 90% of the resource will be left in the ground which, being a sizable opportunity, should provide the economic justification for a commensurate research effort.
- Zones within exploited reservoirs are likely to still be at or near original oil saturation.
- The significant built infrastructure in the Lloydminster area should reduce costs of development.
- Lloydminster heavy oil is mobile at reservoir conditions because of its viscosity and the high permeability of the host sandstone formations.
- Heavy oil is a higher quality product that attracts a higher price than bitumen.

The weaknesses are given as follows:

- Most reservoirs are thin.
  - Gravity drainage will be weak; and,
  - The ability to support fixed capital investments will be limited.
- The unfavourable Mobility Ratio means that any displacement or drive process will be challenges by poor conformance and sweep efficiency.
- Reservoir pressures are relatively low due to shallow depths and prior cold production.
- Uncertainty over the extent and nature of reservoir disturbance resulting from primary production using CHOPS and from water communication promoted by waterfloods.

## Prospects for Enhanced Recovery

Two general situations exist with respect to EOR opportunities in Lloydminster:

### Post-CHOPS EOR

Most of Lloydminster production volumes come from CHOPS which will leave approximately 90% of original oil in place in significantly altered reservoirs at the end of the current commercial cycle. The primary challenges are the presence of wormholes and the apparent absence of solution gas.

One approach could be a workover methodology that could effectively erase existing wormholes near the wellbore and allow progressive cavity pumps (PCP) to initiate new wormholes upon restart. Thermal or solvent treatments have been shown to collapse

wormholes. For example, the injection of steam may disrupt existing wormholes. Portable steam generators could be used for the workover of CHPOS production wells.

The concept of a workover could be expanded into a cyclic process. Cyclic injection in a wormholed heavy oil reservoir of flue gas, with low-quality steam, would seem to address the challenges noted above. It is likely that high quality steam would prove to be uneconomic in the thin pay Lloydminster formations. The presence of pre-existing high permeability channels in the reservoir would preclude the choice of a drive configuration. In a cyclic process, the injected gas and steam mixture would preferentially flow through highly permeable channels and saturate them. Some channels would collapse under thermal effects but some may remain useable. Pressure is maintained during the soak time. Under the influence of the pressure gradient, water and gas flow from the high permeability channels into the bypassed lower permeability zones. This allows pressure and temperature to move toward equilibrium and reduces oil viscosity in the bypassed zones. During the production phase, the oil rate is increased because of the reduced oil viscosity and because of the back pressure provided by non-condensable nitrogen gas.

The most important benefit of flue gas is the contribution of thermal energy to the reservoir, thereby reducing oil viscosity. The presence of low-quality steam with flue gas would increase the amount of energy injected into the reservoir. The presence of water in low-quality steam would dilute the acidity from the presence of CO<sub>2</sub> in flue gas and may mitigate corrosion concerns. Low-quality steam would also reduce steam temperature and mitigate concerns about injecting steam into existing CHOPS wells that were not thermally completed. The cyclical nature of the process also mitigates concerns that may arise about the accumulation of scale in tubulars and possible plugging of the rock matrix by minerals present in the injected water. The reversal of flow from injection to production effectively back washes the well. This feature along with the choice of low-quality steam would allow the use of relatively untreated water for steam production, thereby avoiding the use of freshwater and reducing water treatment costs.

#### Post-Waterflood EOR

Non-CHOPS reservoirs are produced by cold production without sand followed by waterflooding. Here again, significant heavy oil volumes will be left behind. The challenges are the unfavourable mobility ratio between oil and water and the addition of important quantities of water to the reservoir.

While the mobility ratio could be improved by adding chemicals to water, this approach increases energy consumption and costs. The mobility of the oil phase could be increased by reducing its viscosity. Thermal energy and solvents are common approaches to reduce oil viscosity. Flue gas with low-quality steam could be a low-cost injectant that offers both thermal and solvent effects. Thermal energy heats the oil formation and reduces oil viscosity. CO<sub>2</sub> contained in flue gas dissolves in heavy oil and also reduces its viscosity.

In a reservoir under waterflood, flue gas and low-quality steam could be injected in an alternating manner with flood water. Flue gas and steam provide heat and solvent to the oil formation while water slows down injected gas and avoid premature gas

breakthrough. It is possible that the non-condensable gas in flue gas (nitrogen) will create new channels in the reservoir by the action of viscous fingering. This may allow chase water to enter previously bypassed zones. CO<sub>2</sub> is also known to reduce the interfacial tension between oil and water. This mild surfactant effect may cause emulsions with nitrogen and block existing water channels. This could force chase water into new reservoir zones and improved sweep efficiency.

### **Design of a Novel Lloydminster Heavy Oil EOR Technology**

The business concepts for the design of a new EOR technology in Lloydminster are as follows:

- The capital and operations costs must be kept low because the thin pay zones in the Lloydminster region will not justify high levels of investment;
- Equipment should be designed to be transportable for use at multiple locations to reduce costs but also to acknowledge that the working life of any particular well is likely to be short because of the thin pay zone;
- The new technology should require few new wells, if any, in order to take advantage of the existing built infrastructure and to minimize costs.

A review of existing thermal and solvent technologies led to the following points with respect to their potential adaptation to the characteristics of Lloydminster reservoirs after primary and secondary recovery:

- Most Lloydminster reservoirs are too thin for the effective application of CSS, SAGD or steam floods. Thermal energy losses would be too great and result in low energy efficiency and high costs and greenhouse gas emissions.
- CO<sub>2</sub> injection as an immiscible gas could be technically promising based on laboratory investigations. However, the total cost of capturing, treating, compressing and transporting CO<sub>2</sub> is likely to be prohibitive. On the other hand, flue gas, which contains 9% to 15% CO<sub>2</sub> and is less effective than pure CO<sub>2</sub>, could be locally available at a significantly lower cost.
- Steam has a heat capacity in the order of 100 times greater than air or flue gas on a volumetric basis. Therefore, adding steam to flue gas would dramatically improve the efficiency of injecting thermal energy into the reservoir.
- Keeping costs low is critical for thin reservoirs such as those found in Lloydminster. High quality steam may be too expensive. Production of low quality steam using portable generators would be a way to keep steam costs manageable.
- Co-injection of flue gas and steam is more energy efficient than the conventional approach of injecting steam only and venting hot exhaust gas to the atmosphere. Direct contact steam generation conserves all of the energy liberated by combustion and makes it available to the reservoir. This inherent efficiency improvement directly translates into less greenhouse gas emissions.
- Furthermore, CO<sub>2</sub> in flue gas dissolves in oil, reducing its viscosity and increasing its volume.
- Nitrogen in flue provides pressure support, in part compensating for pressure loss due to steam condensation.



- A hypothesis that needs further investigation is that the presence of CO<sub>2</sub> reduces interfacial tension between oil and water which allows nitrogen in flue gas to form emulsions. Chase water may then be diverted into unswept zones because emulsions block or slowdown water mobility in existing water channels. The result is improved sweep efficiency and higher oil recovery.
- Pressure cycling is thought to promote mixing and accelerate the dissolution of a solvent into heavy oil, increasing production rate.
- Injection of a cold gas (e.g. methane or propane) into a reservoir that had been produced by CHOPS is likely to result in only small increases in reservoir pressure, particularly in the reservoir is laterally extensive. It is likely that the high permeability channels created by CHOPS allow the injected gas to move great distances in the reservoir. Therefore, the prior or simultaneous application of heat is required to collapse or curtail some of the high permeability channels.

### **Proposed Gas and Steam Stimulation EOR Technology**

The core idea of the proposed EOR technology for Lloydminster heavy oil centers on the injection of flue gas with low quality steam into the heavy oil formation. The addition of steam would increase the efficiency of the process because steam carries a higher energy density than flue gas and the rate of thermal energy injection into the formation is higher. The injection of flue gas would stimulate the formation using four different mechanisms:

- Addition of thermal energy to heavy oil, reducing its viscosity and increasing its mobility;
- Injection of Non Condensable Gas (nitrogen) would re-pressurize the formation, generating a pressure drive to move oil to producing wells, in a cyclic configuration utilizing blowdown to mobilize oil;
- Addition of CO<sub>2</sub> as a solvent which would incrementally swell the oil phase and reduce its viscosity; and,
- The possibility that CO<sub>2</sub> would reduce interfacial tension and allow the nitrogen component of flue gas to form emulsions and divert condensate or chase water into unswept zones, thereby improving recovery.

### **Well Workover to Collapse Wormholes**

The technology could be deployed in a workover approach. This concept centers on the idea that most of the oil remaining in a reservoir after CHOPS production resides in bypassed zones. The initial application of CHOPS created wormholes that accessed certain reservoir zones. Erasing these wormholes and re-initiating the CHOPS process may create new wormholes that could access new zones and recover new oil. The work over could be reapplied on a periodic basis to continually initiate new wormholes into new reservoir volumes.

### **Cyclic Gas and Steam Stimulation**

This concept is designed as an EOR process after primary recovery by CHOPS. Cyclic Gas and Steam Stimulation (CGSS) is similar to heavy oil recovery method used by

downhole steam generators in the 1980s with the exception that the steam generator is located on the surface. Flue gas and low-quality steam are low-cost injectants that may be economically viable in the thin pay Lloydminster reservoirs. A Direct Contact Steam Generator (DCSG) is used to produce the mixture of flue gas and low quality steam that is injected into the heavy oil formation. The DCSG allows the use of low quality produced water. The preference would be to use existing CHOPS wells. The injection volume may be set by a reservoir pressure limit, a time period or by a specified steam volume. A soak period follows to allow thermal energy to penetrate unswept zones of the reservoir. Production is then initiated using the PCP. Once production falls below a certain criterion the cycle is repeated.

The main features of this process concept are:

- Flue gas would be less costly than pure CO<sub>2</sub>.
- Low-quality steam would be less costly than high-quality steam.
- The lower steam temperature would be more compatible with wells that were not thermally completed.
- The lower steam pressure would be below formation fracture pressure.
- The presence of water in low-quality steam would dilute any acidity resulting from the presence of CO<sub>2</sub> and mitigate corrosion concerns.
- Wormholes in the reservoir preclude the application of a drive process where an injectant displaces oil from an injector well to a producing well.
- Cyclical injection and production on a field level takes advantage of the existing wormholes network. Collapse of the wormholes would happen because of the injection of steam but this collapse may not be complete or widespread. The high permeability channels provide a distribution network for injectants and conduits for oil production.
- The combination of steam, condensate, CO<sub>2</sub> and nitrogen as a non-condensable gas results in a variety of interactions with the reservoir matrix and may result in improved sweep efficiency. Nitrogen, a non-condensable gas may penetrate different zones of the reservoir and open new paths for steam and condensate to follow.
- The presence of condensate would reduce the mobility of flue gas in a way that is analogous to the Water Alternating Gas (WAG) process.
- Some CO<sub>2</sub> would dissolve in heavy oil reducing its viscosity.
- The pressure cycle may create a blowdown solution gas drive effect. Reservoir pressure is increased during injection. This pressure is released during production and used to drive fluids to the well.
- The presence of nitrogen, methane and CO<sub>2</sub> gas in the blowdown fluids may disrupt the sand matrix and create sand production.
- The presence of injected water and condensate in produced fluids could drag additional oil and sand to the well.

- The cyclic nature of the process features a reversal of flow from injection to production in reservoir channels. The reversal of flow may further disrupt the rock matrix, causes additional sand production and may also improve sweep efficiency;
- The cyclic pattern also mitigates concerns about accumulation of scale in the well and possible plugging of the rock matrix by minerals present in injected water. The reversal of flow effectively back washes the wellbore and the well.
- CO<sub>2</sub> reduces the interfacial tension between oil and water and may contribute to the formation of emulsions in the presence of nitrogen. These emulsions may divert the flow of water and condensate into unswept reservoir zones thereby improving sweep efficiency and oil recovery.

In addition to determining recovery performance and determining optimum operating strategies by gaining experience through field trials, a number of infrastructure and surface facility issues would need to be resolved. These include:

- Non-thermal wells;
- PCP pump elastomers;
- Corrosion concerns;
- Handling and recycling large volumes of produced gas;
- Transferring produced gas and water from wells pads under production to well pads under injection; and,
- Caprock integrity.

### **CGSS with Horizontal Wells**

Horizontal wells offer a number of advantages as compared to vertical wells. In particular, their greater exposure to the reservoir matrix allows a more uniform distribution of injectants, access to more reservoir volume and generally improved sweep efficiency. In the thin but aerially extensive Lloydminster formations, horizontal wells would provide greater access to the reservoir, thereby reducing the number of wells and the extent of surface disturbance. Despite their higher initial cost, they result in a greater productivity and economic effectiveness.

Horizontal wells are not used for CHOPS because sand production is not possible with them. Therefore, the use of horizontal wells in CHOPS fields would imply the drilling of new wells as opposed to the utilization of existing wells. This would increase the cost of the EOR technology. However it would offer the opportunity to thermally complete these new wells thereby avoiding the challenges of injecting steam using non-thermal wells.

A clear challenge posed by horizontal wells is that they are unable to sustain sand production. If the EOR technology results in sand production, horizontal wells will not be suitable. However, thermal stimulation of the reservoir would reduce the viscosity of the heavy oil. One consequence is that production of hot and low viscosity heavy oil would not entrain as much sand. This could open the possibility that thermal stimulation could result in sand production levels low enough to allow the use of horizontal wells.

Drilling new horizontal wells in reservoirs that have been exploited with CHOPS is likely to be highly problematic. Upon encountering wormholes there will be loss of circulation.

Continuing to drill blind using water would be extremely difficult in thin pay. On the other hand, the use of drilling muds and lost circulation fluids is likely to damage the reservoir. This challenge indicates the opportunity for research and development to tackle the problem of drilling and completing horizontal wells in wormholed or extensively fractured formations where loss of circulation is a problem.

### **Flue Gas WAG**

Under this concept, waterfloods in Lloydminster would be modified by the periodic injection of flue gas, with or without low-quality steam. In laboratory experiments, flue gas injection prior to a waterflood significantly increased recovery by the waterflood. The mechanisms postulated for this effect were the presence of a free gas drive and viscosity reduction from CO<sub>2</sub> in flue gas.

Another idea supporting flue gas WAG is that the reduction of interfacial tension from CO<sub>2</sub> in flue gas could result in the formation of emulsions in the presence of nitrogen. These emulsions would further slow down the mobility of water and may block some water channels forcing water into unswept zones.

### **Next Steps**

The recommended path forward is a JIP with an order of magnitude scope of \$1 million per year over five years. The recommended technology program is data mining of past operational records and field testing of promising heavy oil EOR concepts, along the following principles:

- Industry participants open their confidential operating records to a team of investigators to extract patterns and suggestions for improved CHOPS methods and for EOR concepts.
- Industry participants contribute existing production wells that are approaching the end of their productive life.
- Funding is assembled to operate a portable well stimulation system with associated instrumentation. This would include a portable steam generator, possibly a DCSG, portable compressors and instruments to measure temperature, pressure, fluid rates and overall process performance.
- A structured program is developed and agreed that would list typical well configurations, typical reservoir horizons, typical reservoir histories and promising EOR concepts with a range of parameters that could be evaluated, such as gas ratios (N<sub>2</sub>, CO<sub>2</sub>, steam), temperature, pressure and cycle length.
- In addition, the JIP may include in its scope the drilling of new horizontal wells with thermal completion for piloting EOR approaches based on new infill wells.
- As a first step in developing a viable EOR recovery technology for heavy oil after CHOPS, it would be advisable to focus on thicker deposits because thermal technologies could be economic in deposits between 8 and 15 m thick. This would allow the commercialization of technologies and equipment that could then be adapted to deposits less than 8 m thick.

In order to organize and launch such a JIP, scoping and organizational work will need to be done as part of a scoping project which may cost \$200,000 over one year with support from industry and governments in Alberta, Saskatchewan and the Federal Government. The scope would include:

- Identification of the EOR concepts with the most industry support and the larger potential rewards in terms of environmental benefits and opportunities for cost reduction;
- Development of the technology program;
- Conceptual design engineering, high-level capital costs, operating costs and comparative economics with existing production methods;
- Identification quantification of environmental benefit with respect to greenhouse gas emissions, water conservation and land impact;
- Scope and budget for any laboratory and bench scale work;
- Scope and budget for field evaluation trials;
- Preparation of the list of required equipment and service contracts for measuring and monitoring heavy oil production performance;
- Identification of available portable commercial equipment to produce a mixture of flue gas and low-quality steam for reservoir stimulation;
- Process for information analysis and dissemination;
- Path to commercialization and broad utilization by industry;
- Recruitment of JIP partners; and,
- Budget and financial structure of the JIP, including funding and governance.

## Table of Contents

Executive Summary .....	2
Table of Contents.....	14
List of Tables.....	17
List of Figures.....	18
1. Preamble.....	19
1.1. Low Carbon Futures PTAC Project.....	19
1.1.1. Bitumen in Carbonate Formations.....	19
1.1.2. Salt Caverns for Oil Extraction .....	20
1.1.3. Novel Low GHG Heavy Oil Recovery Process.....	20
1.1.4. Direct Contact Steam Generator .....	21
1.2. Importance of Heavy Oil.....	21
1.2.1. Extra-Heavy Oil .....	22
1.2.2. Canadian Bitumen .....	22
1.2.3. Canadian Heavy Oil.....	23
1.3. Motivation for this Work.....	23
1.4. Reasons to Focus on Lloydminster .....	24
2. Lloydminster Resource Description.....	25
3. Current Production Technologies.....	29
3.1. Overview .....	29
3.2. Cold Production without Sand .....	30
3.3. Cold Heavy Oil Production with Sand (CHOPS) .....	32
3.3.1. High Permeability Channels .....	34
3.3.2. Solution Gas Drive.....	35
3.3.3. Other Drive Mechanisms .....	37
3.3.4. Production Decline .....	38
3.3.5. Post-CHOPS Reservoir Conditions .....	39
3.4. Waterfloods .....	40
3.4.1. Overview.....	40
3.4.2. Heavy Oil Waterfloods in Western Canada .....	42
3.4.3. Hot Waterfloods.....	44
3.4.4. Polymer Floods.....	45
3.4.5. Surfactant and Alkali Flooding.....	46
4. Lloydminster Strengths and Weaknesses.....	48
4.1. Overview .....	48
4.2. Existing Built Infrastructure and Established Operators .....	49
4.3. Mobile Oil at Reservoir Conditions .....	50
4.4. Higher Value Oil .....	50
4.5. Thin Reservoirs .....	50
4.6. Unfavourable Mobility Ratio .....	51
4.7. Low Reservoir Pressures .....	51
4.8. Poor Sweep Efficiency during Cold Production.....	52
5. Prospects for Enhanced Recovery.....	52
5.1. Post-CHOPS EOR .....	54
5.1.1. Workover Concept.....	54
5.1.2. Cyclic Process Concept.....	55
5.2. Post-Waterflood EOR.....	57
6. Review of Thermal Processes.....	59
6.1. Cyclic Steam Stimulation.....	59

6.1.1.	Overview.....	59
6.1.2.	Pikes Peak.....	60
6.2.	Steam Floods .....	60
6.3.	Steam Assisted Gravity Drainage .....	61
6.3.1.	Overview.....	61
6.3.2.	SAGD in Thin Formations.....	62
6.4.	Carbon Dioxide and Steam .....	63
6.5.	Non Condensable Gas and Steam.....	65
7.	Review of Solvent Processes.....	67
7.1.	Vapour Extraction.....	67
7.2.	Carbon Dioxide Enhanced Oil Recovery.....	69
7.2.1.	Overview.....	69
7.2.2.	Miscible CO <sub>2</sub> EOR .....	70
7.2.3.	Immiscible CO <sub>2</sub> EOR .....	71
7.2.4.	CO <sub>2</sub> Workover.....	80
8.	Review of Gas Injection Processes.....	81
8.1.	Inert Gas Injection .....	81
8.2.	Hydrocarbon Gas Injection.....	81
8.3.	Flue Gas Injection .....	82
8.3.1.	United States Experience .....	82
8.3.2.	Russian Experience.....	83
8.3.3.	Developments by the Saskatchewan Research Council .....	84
9.	Comparison of Viscosity Reduction by Heat and CO <sub>2</sub> .....	84
10.	Reservoir Sweep Considerations .....	91
11.	Design of a Novel Lloydminster Heavy Oil EOR Technology.....	92
11.1.	Key Learnings from Thermal and Solvent Technologies.....	93
11.2.	Key Uncertainties .....	94
11.3.	Flue Gas and Steam Stimulation EOR Technology .....	94
11.4.	Well Workover to Collapse Wormholes.....	95
11.5.	Cyclic Gas and Steam Stimulation .....	96
11.5.1.	Concept .....	96
11.5.2.	Features .....	96
11.5.3.	Challenges.....	97
11.6.	CGSS with Horizontal Wells.....	100
11.7.	Flue Gas WAG .....	100
12.	Supporting Technologies for Novel Low GHG Recovery .....	101
12.1.	Characterizing the “Depleted” Reservoirs .....	101
12.1.1.	Mapping Post-CHOPS Reservoir Interwell Connections.....	102
12.1.2.	Connecting Channels .....	102
12.1.3.	Locating “Undepleted” Areas.....	103
12.1.4.	Characteristics of “Undepleted” Areas.....	103
12.1.5.	Estimation of Produced Sand and Gas Volumes .....	103
12.2.	Assessing Well Integrity .....	105
12.2.1.	Casing Deformation.....	105
12.2.2.	Communication Behind Casing .....	105
12.2.3.	Sources of Water Inflow .....	106
12.3.	Assessing Site Assets .....	106
12.3.1.	Fuel.....	106
12.3.2.	Power Sources .....	107
12.3.3.	Water .....	108
12.3.4.	Delivery and Production Systems.....	108

12.3.5.	Gas Storage Zones .....	109
12.4.	Injectant Supplies and Properties.....	109
12.4.1.	Flue Gas Generation Methods .....	110
12.4.2.	Thermal Sources .....	111
12.4.3.	Hybrid Systems .....	113
12.5.	Injection and Production Methods .....	113
12.5.1.	Co-annular Injection .....	113
12.5.2.	PCP or Multi-Phase Pumps.....	114
12.5.3.	Annulus Separation .....	115
12.5.4.	Blocking Water Influx.....	116
12.6.	Production Facilities .....	118
12.6.1.	Pressurized Separation .....	118
12.6.2.	Low-cost Gas Treatment and Monitoring Modules.....	118
12.7.	Inter-well Issues.....	119
12.7.1.	Ownership of Wells in Clusters.....	119
12.7.2.	Gas Redistribution Lines .....	119
12.7.3.	Oil/Water Gathering.....	119
12.7.4.	Impacts of Pads vs. Single Wells .....	119
12.7.5.	Well Operations in Clusters for CGSS.....	120
13.	Sustainability Issues for Novel Low GHG Conventional Heavy Oil .....	120
13.1.	Economic.....	120
13.1.1.	Modular/Portable Equipment .....	120
13.1.2.	Opportunities to Reduce Capital Investment .....	121
13.1.3.	Maximize Use of Local Natural Gas and Energy Sources.....	121
13.1.4.	Maximize Use of Locally Available Injectants.....	121
13.1.5.	Small Scale to Avoid Unitization.....	122
13.1.6.	Use of Existing Wells.....	122
13.2.	Environment .....	122
13.2.1.	Net GHG Impacts .....	123
13.2.2.	Avoid Formation of Hydrogen Sulphide.....	125
13.2.3.	Water Impacts .....	126
13.2.4.	Land Impacts .....	126
13.3.	Security/Societal.....	127
13.3.1.	Continued Exploitation of a Known Resource .....	127
13.3.2.	Sustaining Local Businesses and Communities.....	127
13.3.3.	Importance to Saskatchewan .....	128
13.3.4.	Safety Risk Management .....	128
13.3.5.	Capital and Cash Flow Risk Management .....	129
13.3.6.	Regulatory Streamlining .....	129
13.3.7.	Application to Larger Oil Sands Resources.....	129
14.	Next Steps.....	130
14.1.	Overview.....	130
14.2.	Joint Industry Program for Steam and Gas Stimulation .....	130
14.2.1.	Data Mining .....	130
14.2.2.	Field Testing .....	131
14.2.3.	JIP Scope .....	131
14.3.	Scoping Project .....	132
14.4.	Immediate Next Steps .....	132
15.	References.....	134



# List of Tables

Table 1 –Typical Parameters for Lloydminster Reservoirs ..... 26  
Table 2 – Description of Heavy Oil Reservoirs in the Lloydminster Area..... 28  
Table 3 - 2006 Tertiary Enhanced Oil Recovery Production..... 69  
Table 4 – Flue Gas EOR in the United States ..... 83  
Table 5 - Static Insulation of Tubulars..... 99

## List of Figures

Figure 1 – Steam Assisted Gravity Drainage .....	62
Figure 2 – Steam and Gas Push.....	66
Figure 3 – Pressure and Recovery Profiles during Gas and Water Displacement of Heavy Oil.....	74
Figure 4 – Effective Oil and Water Relative Permeabilities during Water Displacement of Heavy Oil.....	75
Figure 5 – Effective Oil and Gas Relative Permeabilities during Gas Displacement of Heavy Oil.....	76
Figure 6 – Viscosity of Bitumen vs. Temperature .....	86
Figure 7 – Viscosity of Bitumen vs. CO <sub>2</sub> Solubility at Saturation.....	87
Figure 8 – Conceptual Comparison of Viscosity Reduction (Logarithmic Scale) .....	89
Figure 9 – Conceptual Comparison of Viscosity Reduction (Normal Scale) .....	90
Figure 10 – Heavy Oil Gas Oil Ratio (GOR) .....	104
Figure 11 – Cost of Fuel Options .....	107
Figure 12 – Flue Gas Generation.....	110
Figure 13 – Energy Content of Injectants.....	111
Figure 14 – Energy Content of Water Saturated Gases .....	112
Figure 15 – Co-Annular Injection .....	114
Figure 16 – Annulus Separation.....	116
Figure 17 – Sulphur Injection .....	117
Figure 18 – Greenhouse Gas Emissions .....	123
Figure 19 – Methane Venting.....	124

# Novel Low GHG Heavy Oil Recovery Process

## 1. Preamble

### 1.1. *Low Carbon Futures PTAC Project*

During fiscal year 2006-07, the Petroleum Technology Alliance Canada (PTAC) managed and completed the exploratory project Low Carbon Futures with support from Natural Resources Canada (NRCan), the Alberta Energy Research Institute (AERI) and industry. The project was concerned with the identification of technologies for the sustainable recovery of bitumen and heavy oil resources for which no commercial recovery technology currently exist. In particular, bitumen in carbonate formations in Alberta and un-recovered heavy oil after primary and secondary recovery were targeted. In addition, the project explored the potential economic and environmental benefits of warm water geothermal resources associated with existing oil and gas operations.

High-value outcomes from the 2006-07 project included the identification of the following technology opportunities:

- A technology development program for the sustainable recovery of bitumen in carbonate formations in Alberta;
- The concept of using salt caverns underneath Lloydminster heavy oil deposits in order to conduct part of the extraction process underground thereby avoiding methane emissions and minimizing land utilization;
- The development of a novel low GHG heavy oil recovery process by injection of immiscible CO<sub>2</sub> or flue gas; and,
- The Direct Contact Steam Generator technology concept which would allow the use of lower quality fuels and water resources for the production of steam thereby resulting in a lower environmental impact.

#### 1.1.1. **Bitumen in Carbonate Formations**

With respect to bitumen in carbonate formations, the 2006-07 project identified technical challenges and R&D needs for this resource and the effort was in part the catalyst for a multi-stakeholder research and development program that is currently being developed under the leadership of AERI and the Alberta Research Council (ARC). The volume of bitumen in carbonate formations is substantial and accounts for approximately 26% of all in place bitumen resources in Alberta. Three decades ago, the Alberta Oil Sands Technology and Research Authority (AOSTRA) attempted with limited success to develop technology to recover this resource, conducting research projects and field pilots. The current AERI/ARC/industry program is being scoped as a significant, long-term, high risk R&D investment composed of four integrated components: geology, recovery processes, production engineering, and field pilots. The breadth and complexity of the technology challenges has led to a collaborative strategy involving a number of different research organizations.

### **1.1.2. Salt Caverns for Oil Extraction**

The concept of using salt caverns was built on an initial idea by C-FER and developed in collaboration with this organization. The idea was named SuperSump and is now being actively promoted by C-FER who is looking for partners for engineering studies and demonstration pilots. Heavy oil in the Lloydminster region is currently produced by pumping oil, water and sand to the surface, separating these components near the well and subsequently trucking them to aggregation point for further processing. By contrast, the SuperSump would involve the solution mining of a small cavern underneath the oil deposit. Oil, water and sand would be conveyed down to the underground cavern where gravity would separate sand from the liquids. A well would pump the liquids to the surface, leaving the sand in the cavern. Conducting the separation process underground avoids the costs and environmental impact of processing and transporting sand on the surface. In addition, the production of a liquid stream would allow the use of pipelines instead of trucks and aggregate the oil and water separation operation at central batteries. The elimination of trucks and separation operations at each well site would significantly reduce costs and reduce environmental impact, particularly methane venting and land use.

### **1.1.3. Novel Low GHG Heavy Oil Recovery Process**

The remaining two high-value outcomes from the 2006-07 project, namely the novel low GHG heavy oil recovery process and the Direct Contact Steam Generator, were further advanced by PTAC as part of a new project for the 2007-08 fiscal year with continuing support from NRCan, AERI and industry. The purpose of the 2007-08 project was to further define the challenges and technology opportunities in these areas, to identify technology providers and potential users, and to facilitate a process for the development of an implementation program that would see these beneficial technologies utilized by industry

In Alberta and Saskatchewan, CO<sub>2</sub> Enhanced Oil Recovery (EOR) is applied to conventional light oil. The largest commercial CO<sub>2</sub> EOR project is located in Saskatchewan at Weyburn-Midale. While there are some very important differences between light oil and Lloydminster heavy oil, some of the relevant lessons learned could be of value if transferred to Lloydminster reservoirs.

In Lloydminster, CO<sub>2</sub> could be injected under immiscible conditions and distributed via the high permeability zones to re-pressure the reservoir. The CO<sub>2</sub> would also swell the oil and reduce its viscosity. Various drive and well configurations were explored and analyzed in order to develop recovery scenarios.

A variation on the use of CO<sub>2</sub> is flue gas injection. Flue gas depleted of oxygen contains approximately 10% CO<sub>2</sub> and 90% nitrogen. Based on work done at the Saskatchewan Research Council, enriched flue gas (30% CO<sub>2</sub> and 70% nitrogen) may offer a desirable balance of properties for an EOR process. CO<sub>2</sub> provides solvent related benefits while nitrogen provides pressure maintenance and possibly gas blocking effects that may enhance sweep efficiency.

The potential for designing a novel EOR process for Lloydminster heavy oil based on CO<sub>2</sub> or flue gas injection formed the starting point for this project. This report presents the findings of the 2007-08 project with respect to the novel low GHG heavy oil recovery process. The learnings from the investigation of the DCSG concept are the object of a companion report.

#### **1.1.4. Direct Contact Steam Generator**

The Direct Contact Steam Generator (DCSG) could be a key technology for improving energy efficiency, reducing cost, and reducing water and GHG intensities. Development programs for the precursor technology occurred some 20 years ago for the purpose of generating steam downhole in deep formations to avoid the considerable heat losses incurred when conveying steam from the surface to the formation. At that time, these programs were referred to as Downhole Steam Generator technology developments.

However, present needs in Western Canada are different because heavy oil and bitumen formations are relatively shallow and heat losses, while measurable, are not economically critical. Therefore, it would be possible to locate a DCSG on the surface rather than downhole and still benefit from the advantages that the DCSG could deliver in the areas of energy efficiency, cost reduction, and decreases in water and GHG intensities. Furthermore, the possibility of locating the DCSG on the surface would improve design flexibility and minimize cost, maintenance and reliability challenges associated with a downhole placement. Key areas for future research are corrosion resistance, operational reliability and impact on reservoir and the recovery processes.

The first steps in reenergizing research on DCSG are to document past developments, outline key design criteria for applications such as surface mining, thermal in situ recovery and Lloydminster heavy oil. Future steps would include laboratory work, testing of prototypes with improved design, and research to better understand thermal and chemical characteristics of an injectant composed of combustion gas and steam. Finally, technology demonstration at field locations will eventually be necessary.

As mentioned earlier, the findings from the investigation of the DCSG concept are covered in a companion report.

### **1.2. Importance of Heavy Oil**

Continued global growth in standards of living and industrialization underpins forecasts of increased energy demand over the next decades, particularly for electricity and automotive fuel. Sustained demand for liquid automotive fuels is likely to maintain crude oil's share of total primary energy supply at around 35% until 2030 (Sanjere and Lantz 2007). These demand expectations combined with the expected long term decline in the supply of light to medium crude oil have placed the spotlight on heavy oil and non-conventional resources such as extra heavy oil and oil sands. Technologies to recover heavy oil and oil sands in ways that are economic and environmentally acceptable are therefore important.

### **1.2.1. Extra-Heavy Oil**

Heavy oil is defined as having an API density between 10 and 22. Oil with an API density less than 10 is considered extra-heavy oil if it is able to flow at reservoir conditions or called bitumen if it cannot flow at reservoir conditions. Over 90% of the world's extra-heavy oil resources are found in Venezuela, with in place volumes of 190 billion m<sup>3</sup> (1.2 trillion barrels) and recoverable volumes estimated at 5.7 billion m<sup>3</sup> (36 billion barrels) based on a deposit-wide recovery factor of 3% for the currently applied primary recovery technologies (Saniere and Lantz 2007).

### **1.2.2. Canadian Bitumen**

Canada holds over 75% of world bitumen resources, the vast majority of which are present in Alberta with much smaller amounts in western Saskatchewan (Marsh 2007). Alberta's initial in place crude bitumen volumes are 270.3 billion m<sup>3</sup> (1.7 trillion barrels) (Alberta Energy and Utilities Board 2007). The ERCB reports that initial established bitumen reserves are 28.3 billion m<sup>3</sup> (179 billion barrels), based on an implied basin-wide average recovery factor of 10.5%. This reserves estimate was calculated by applying the following deposit-wide recovery factors for the following technologies: 82% for surface mining, 20% for in situ thermal recovery and 5% for in situ primary recovery. (For commercial in situ thermal projects, the ERCB applies the following area specific recovery factors: 40% in Peace River, 50% in Athabasca and 25% in Cold Lake.)

Surface accessible oil sands are already under active commercial exploitation. In 2006, two thirds of these 5.0 billion m<sup>3</sup> (31.5 billion barrels) of established reserves were under active development (Moritis 2007). While surface mineable oil sands represent 6% of the initial in place bitumen volume, they account for 18% of remaining established bitumen reserves and 88% of remaining reserves under active development (Alberta Energy and Utilities Board 2007). Surface accessible oil sands represent a larger proportion of industrial activity as compared to in situ oil sands because of their longer history and significantly higher recovery factor which quadruples their reserves impact. Surface mineable oil sands are not a stranded resource and are not in need of new recovery technologies to unlock their potential. Technology opportunities for surface mining include lower costs, improved energy efficiency and reduced environmental impact.

Therefore, technology development efforts aimed at improving and increasing recovery should be targeted at in situ oil sands and heavy oil resources. They present a significant opportunity for long term growth in petroleum reserves and production through the development of new appropriate recovery technologies. In situ in place volumes are not only over 16 times larger than mineable volumes, but their recovery factors are lower ranging from 50% for Steam Assisted Gravity Drainage (SAGD) in Athabasca to as low as 5% for primary recovery of oil sands and heavy oil. Existing in situ commercial technologies only recover a fraction of the oil in place and only from the higher quality deposits, leaving vast oil quantities labelled as un-recoverable.

In place volumes of in situ oil sands are by far larger than heavy oil volumes. For this reason, in situ oil sands have been the object of substantial research and technology development in the past twenty years, resulting in the development of SAGD and major

improvements to surface mining and Cyclic Steam Stimulation (CSS). The pace has quickened in the past few years with major field pilots currently in progress for new recovery processes such as low-pressure SAGD, SAGD hybrids with solvents and non-condensable gases, Vapour Extraction (VAPEX), Toe to Heel Air Injection (THAI) and electrical heating approaches.

By contrast, heavy oil has received far less attention from technology developers, despite a longer commercial history. This project and report therefore does not address oil sands because the area is well served but focuses instead on heavy oil due to the existing gap between opportunity and need, and commitment of technology development resources.

### **1.2.3. Canadian Heavy Oil**

In Canada, heavy oil is found in the Western Canada Sedimentary Basin (WCSB). The ultimate potential of heavy oil in place volumes was reported by the Canadian Geological Survey at 7.9 billion m<sup>3</sup> (50 billion barrels) (Osadetz and Chen 2007). Primary recovery varies between 5 and 10%. Secondary recovery such as waterflood projects, can add an incremental 4 to 10% recovery.

According to information provided by the AEUB, the initial volume in place of heavy oil in Alberta is 2.275 billion m<sup>3</sup> (14.3 billion barrels). Of this amount, 401 million m<sup>3</sup> (2.5 billion barrels) are considered to be initial established reserves, resulting in an implied basin wide recovery factor of 17.6%. Heavy oil initial established reserves can also be characterized by recovery mechanisms: 72% are attributable to primary production while 28% are associated with waterfloods. The basin wide historical recovery factor for heavy oil by primary production is 12.5%. Waterfloods add an incremental 17%. At the end of 2006, cumulative production of heavy oil from Alberta resources was 332.7 million m<sup>3</sup> (2.09 billion barrels), leaving 68.5 million m<sup>3</sup> (430 million barrels) as remaining established reserves. Production of heavy oil was estimated at 29,200 m<sup>3</sup> per day (184,000 barrels per day) in 2006, or an annual production of 11 million m<sup>3</sup> (69 million barrels). Therefore, the reserve index for Alberta heavy oil currently stands at approximately 6 years (Alberta Energy and Utilities Board 2007).

### **1.3. Motivation for this Work**

The critical challenge with oil sands heavy oil is not exploration. The deposits were found and mapped decades ago. The challenge is economic recovery without environmental impact. Commercial technologies exist today for higher quality deposits such as heavy oil, surface accessible oil sands, and in-situ oil sands that are thick, clean and contained. However, as stated above, commercial in situ technologies only achieve partial recovery and leave a significant fraction of the resource in the ground. Furthermore, commercial technologies do not yet exist for lower quality deposits such as, for example, bitumen in carbonates and thin in situ oil sands. All told, as indicated above, existing commercial technologies will only recover and add value to nominally 10% of in place heavy oil and bitumen resources. The 90% un-addressed by commercial technologies therefore represents an extremely attractive development target.

In a favourable pricing environment, the business as usual scenario for bitumen and heavy oil resources is that, in time, lower quality resources are likely to be tackled using existing commercial technologies with the unfortunate outcomes of higher costs, poorer energy efficiency, lower recovery factors, and increased greenhouse gas emissions and water intensities. The motivation for this project is to lay the groundwork for improvements to the business as usual scenario through the identification of new technology directions appropriate for these resources.

#### **1.4. Reasons to Focus on Lloydminster**

Straddling the Alberta-Saskatchewan border, Lloydminster is a prolific heavy oil region with a long and successful history. However, the end of this success is now in sight. Commercial recovery technologies have already been applied to the vast majority of oil formations and the onset of regional production decline is expected within the next decade. The opportunity resides in the fact that over 90% of the heavy oil will remain in the ground, un-recovered by commercial technologies. This oil represents a substantial opportunity for the development of a new appropriate recovery technology.

Specific reasons to target Lloydminster heavy oil reservoirs for the development of a new EOR technology are as follows:

- Current commercial technologies will leave approximately 90% of the resource in the ground which is a sizable prize;
- The fact that 90% is not recovered implies that important volumes of the resource are still at or near original oil saturation;
- Lloydminster heavy oil is a higher quality product that commands a higher price than bitumen from oil sands;
- Heavy oil has been produced in Lloydminster for over 30 years and the area possesses a significant infrastructure dedicated to the oil and gas industry. Cost of development would therefore be expected to be lower than in undeveloped northern regions;
- Lloydminster heavy oil is mobile at reservoir conditions due to its viscosity and the relatively high permeability of the host unconsolidated sandstones. The fact that oil is mobile is a degree of freedom that does not exist in the oil sands;
- Until recently, there have been few technology development programs targeting heavy oil EOR in Western Canada. Many interesting ideas have simply not been tried in the field and the probability of success may be a higher than in a well studied area; and,
- The successful commercialization of a new heavy oil EOR technology could open the door for adaptation the same technology to oil sands.

Therefore, this project specifically addresses heavy oil that will be left behind after primary and secondary recovery in the Lloydminster area. This target was chosen because primary and secondary recovery technologies will leave approximately 90% of the oil un-recovered. Factors such as the fact that the oil is mobile at reservoir conditions and that the area possesses a well developed petroleum recovery infrastructure would facilitate the implementation of a new technology. In time, the



technology could be adapted and transferred to the more difficult challenge of bitumen left behind in Cold Lake, Athabasca and Peace River after the application of thermal technologies such as SAGD and Cyclic Steam Stimulation (CSS).

## 2. Lloydminster Resource Description

Heavy oil and bitumen are found in the WCSB in a discontinuous trend which extends from the Peace River area in northwest Alberta, through Athabasca and Cold Lake, and to the Lloydminster region on the Alberta-Saskatchewan border. Most of these heavy oil and bitumen accumulations are found in Lower Cretaceous sand deposits.

The Lloydminster heavy oil region covers an area approximately 140 km by 90 km (12,600 km<sup>2</sup>), straddling the Alberta Saskatchewan border and centered on the town of Lloydminster (Township 49). Original light to heavy oil in place in the Lloydminster area is estimated at 12.7 billion m<sup>3</sup> (80 billion barrels) (Wong and Ogronick 1998). Remaining established reserves of light, medium and heavy crude oil are estimated at 43 million m<sup>3</sup> (270 million barrels), according to the ERCB. Adjacent oil areas with similar characteristics to Lloydminster are Frog Lake, Elk Point, Lindbergh and portions of Cold Lake and Primrose.

In the Lloydminster area, heavy oil is found in the Mannville group of the Lower Cretaceous, which is comprised of nine major formations, listed below in depositional order:

- Colony
- McLaren
- Waseca
- Sparky
- General Petroleum
- Rex
- Lloydminster
- Cummings
- Dina.

Most of the production from the region's heavy oil pools has been from the Sparky, Waseca and Cummings formations. Other formations that have seen oil production are the Clearwater, General Petroleum, Lloydminster and McLaren formations (Dusseault, Geilikman et al. 1995; Wong and Ogronick 1998).

These unconsolidated sandstone formations are characterized as being relatively thin, clean, with high porosity, permeability and oil saturation. They are cohesionless sandstone structures with porosities of 30% to 36%. Oil saturation is high (75 to 90% of pore volume). Oil density ranges from 10° to 25° API. Dead oil viscosity is generally between 3,000 to 10,000 centipoises but may vary from 50 up to 50,000 centipoises. Reservoir temperature varies from 20° to 30° C. The original reservoir pressure is low, generally between 2,000 and 3,500 kPa. Core permeability ranges from 500 to 10,000 mD with an average value being 2,000 mD. Unfavourable aspects include high oil viscosity, low solution Gas Oil Ratio (GOR) and low initial reservoir pressures. Reservoir dips are low (less than 0.5°) and some areas are underlain by bottom water. Typical reservoir parameters are summarized in Table 1.

**Table 1 – Typical Parameters for Lloydminster Reservoirs**

Reservoir Rock	Unconsolidated sandstone
Depth (m)	300 to 600 m
Thickness (m)	2 to 25 (mostly 2 to 5)
Porosity (%)	30 to 36
Oil Saturation (%)	75 to 90
Dead Oil Viscosity (centipoises)	3,000 to 10,000
Live Oil Viscosity (centipoises)	500 to 3,000
Solution Gas Ratio (m <sup>3</sup> gas per m <sup>3</sup> oil)	30 to 40
Original Reservoir Pressure (kPa)	2,000 to 3,500
Bubble Point Pressure (kPa)	3,500
Reservoir Temperature (° C)	20° to 30°
Permeability (mD)	500 to 10,000
Heavy Oil Density (° API)	10° to 25°
Source: (Adams 1982; Loughead and Saltuklaroglu 1992; Dusseault, Geilikman et al. 1995; Wong and Ogronick 1998)	

Lloydminster reservoirs are not uniform. Sand grains generally coarsen upward with depth. Oil properties also vary with depth with the heavier oil likely present near the bottom of the reservoir.

Lloydminster Mannville sands are mostly sheet-like regionally extensive blanket sands that are typically thin, usually less than 7 m. Permeability ranges from 500 up to 3,000 mD. Channel sands also exist but are limited in aerial extent. They can have up to 30 m of net pay and permeabilities up to 10,000 mD. Reservoirs are buried at depth from 300 to 600 m, are bound by silty clays and have relatively few cemented bands. Reservoir quality may vary considerably within an area.

The reservoir thickness distribution has been estimated as follows (percent of original oil in place):

- 80% of reservoirs are between 2 and 5 m thick;
- 15% are between 5 and 8 m thick; and,
- 5% are between 8 and 12 m thick (Miller, Moore et al. 2002).

From the above discussion, it can be appreciated that reservoir quality may vary considerably within the Lloydminster area. For example, thin blanket sands will be amenable to different recovery technologies than thick permeable channel sands. The

local presence of water zones will also be a significant consideration. For the purpose of matching reservoirs to available recovery technologies, heavy oil formations in the Lloydminster area can be divided into four categories:

- Thick Channel Sands: representing approximately 5 % to 10% of the resource, these reservoirs are on average 10 m thick. The recovery rate is 5-7% under cold primary production without sand. They have been and remain candidates for steam injection EOR processes.
- Sand Reservoirs with Active Bottom Water: The presence of an underlying active aquifer means that vertical wells are rapidly subject to water coning, resulting in uneconomic water production. However, these reservoirs are producible with horizontal wells and, with this configuration, the water zone can provide pressure support. The rate of recovery is approximately 5%. This category also accounts for approximately 5% to 10% of the resource.
- Thin Areal Sands: These reservoirs are 3 m thick on average but laterally extensive. They are prevalent and represent 40 to 50% of the resource. Typically they are not affected by bottom water but edge water may be present. Most of reservoirs produced by Cold Heavy Oil Production with Sand (CHOPS) come from this reservoir category. With CHOPS, the recovery factor is approximately 12%. Without sand influx, the rate of recovery would only be only 5 to 7% with a much slower production rate. Reservoirs that do not produce sand and with minimal water present are generally viewed as good candidates for water floods which may boost the extent of recovery by an additional 5%.
- Non-Active Bottom Water: This category represents the balance of the Lloydminster reservoirs. They are typically produced by cold production without sand with a recovery factor of 5%.

The description of heavy oil reservoirs in the Lloydminster area is summarized in Table 2.

**Table 2 – Description of Heavy Oil Reservoirs in the Lloydminster Area**

<b>Reservoir Type</b>	<b>Description</b>	<b>Percent of Total Heavy Oil In Place in Lloydminster (Alberta and Saskatchewan)</b>	<b>Typical Primary Recovery Technology</b>	<b>Extent of Recovery after Primary Recovery</b>	<b>Typical Secondary Recovery Technology</b>	<b>Extent of Recovery after Secondary Recovery</b>
Thick Channel Sands	Localized reservoirs with average thickness of 10 m.	~ 5% to 10%	Cold production without sand; some thermal	5-7%	None	N/A
Sand Reservoirs with Active Bottom Water	Reservoirs with active underlying aquifer that provides pressure support but may also lead to water coning	~ 5% to 10%	Cold production without sand with horizontal wells	5%	None	N/A
Thin Areal Sands	Laterally extensive but thin (2 m average) reservoirs; generally bottom water is not present.	40 to 50%	CHOPS	Up to 12%	None	N/A
			Cold production without sand	5-7%	Water flood	Up to 10-12%
Non-Active Bottom Water	Balance of Lloydminster reservoirs; bottom water may be present but not active.	~30% to 40%	Cold production without sand	5%	None	N/A

## 3. Current Production Technologies

### 3.1. Overview

In Lloydminster, primary recovery of heavy oil is currently done with or without associated sand production. Traditional cold production excludes sand and recovery factors can range between 2% and 8%. Allowing sand production is generally referred to as Cold Heavy Oil Production with Sands (CHOPS) and is a primary production process developed in the Lloydminster region during the 1980s. CHOPS dramatically increases production rates (by a factor of over 10 times) and results in recovery factors of 12% or better. CHOPS is responsible for most of the oil produced from the Lloydminster area.

While most heavy oil reservoirs are under primary production, waterfloods are increasingly used to enhance production in suitable reservoirs which generally excludes reservoirs under CHOPS. There are currently a number of waterflood projects in the Wabasca and Lloydminster bitumen and heavy oil fields in Alberta and Saskatchewan. Waterfloods are classified as secondary recovery processes and work by injecting water to maintain reservoir pressure and displace oil toward producing wells. Generally waterfloods inject brine or brackish water sourced from deep saline aquifers with a high rate of recycling.

New waterflood technologies such as polymer injection, which increases the viscosity of injected water and mitigates the unfavourable mobility ratio, are currently being piloted. One drawback of polymer injection and an opportunity for technology development is the need to use fresh water (as opposed to brackish water or brine) for current polymer formulations to be effective.

Tertiary recovery generally refers to Enhanced Oil Recovery (EOR) technologies that are applied after primary and secondary recovery methods and include such technologies as: steam injection (for example SAGD and CSS), solvent injection (for example ethane, propane, butane, acid gas and CO<sub>2</sub> injection) and in situ combustion. However, the application of tertiary recovery technologies in Lloydminster is limited. Lloydminster heavy formations are considered too thin for technologies that rely on gravity drainage as the primary drive mechanism, such as SAGD and classic VAPEX. During the 1960s, operators in Lloydminster trialed steam processes in thick channel sand reservoirs in an attempt to recover a higher percentage of the original oil in place. Due to the relatively shallow depth of these formations, steam often had to be injected at pressures exceeding the formation fracture pressure in order to achieve acceptable steam injection and heat transfer rates. Unfortunately, this resulted in rapid steam channelling to neighbouring wells. In thin pay zones steam injection resulted in significant heat losses which made thermal processes uneconomic.

However, as compared to bitumen found in Athabasca, heavy oil in Lloydminster is mobile at reservoir conditions. This fact combined with the relatively high permeability of the unconsolidated sand formations are factors that need to be exploited for the development of successful EOR processes. Work has started to adapt EOR technologies to the specific challenges posed by Lloydminster heavy oil. For example,

the JIVE project in Saskatchewan is attempting to develop and demonstrate vapour extraction approaches in Lloydminster heavy oil. In situ combustion is also being discussed.

In the following sections, current primary and secondary recovery technologies employed in Lloydminster are reviewed in more detail.

### **3.2. Cold Production without Sand**

As can be inferred from the resource description, a large number of reservoirs in Lloydminster are produced using cold primary production without associated sand production with relatively low productivities and recovery factors (5% to 7%). While there are a relatively large number of such wells, in aggregate they do not account for the largest share of production. The remaining reservoirs, colloquially referred to as “sanders”, are subject to matrix failure and massive sand influx and, as a result, are produced by CHOPS, which allows higher productivities and recovery factors. As a result, most of Lloydminster’s production by volume is from CHOPS. There is no apparent geographic pattern for the distribution of reservoirs subject to sand influx. They occur as clusters, sometime within the same pool.

With cold production without sand, after fairly high initial production rates, output falls rapidly and, eventually, recoveries are limited. The limitation with cold production is that fluids must become available to fill pore volume as it is vacated by the produced oil. Natural processes that allow this to happen can be slow or of limited scope. They include the following:

- Expansion of reservoir fluids as a result of decreasing reservoir pressure;
- Expansion of solution gas as a result of decreasing reservoir pressure;
- Water influx from an adjacent aquifer; and,
- Compaction of the reservoir matrix.

For Lloydminster cold production, the main production drive is assigned to a solution gas drive effect. Solution gas is near equilibrium at reservoir pressure. Upon production, gas bubble nucleation occurs with pressure drop. Because gas mobility in heavy oil is very low, bubble growth and coalescence is so slow that the gas remains as dispersed bubbles resulting in an apparent foamy oil phase. Gas bubbles do not coalesce and do not form a separate continuous phase until very high saturation levels of 25 to 35%. This fact means that gas is not produced as a separate phase. Rather, the presence of tiny gas bubbles swells the apparent volume of the foamy oil phase creating a very efficient solution gas drive (Loughead and Saltuklaroglu 1992; Dussault, Geilikman et al. 1995). In addition, the presence of a dispersed phase of tiny bubbles reduces the apparent viscosity of the oil (Lebel 1994).

Primary production without sand in Lloydminster uses vertical and horizontal wells. Early vertical wells were able to produce a steady but low oil rate of 3 to 5 m<sup>3</sup> per day with a conventional pump arrangement. Switching to high torque progressive cavity pumps increased production rates by a factor of almost 4. The implementation of horizontal wells with progressive cavity pumps further increased production 2 to 3 times (Wong and Ogronick 1998).

The advantages of vertical wells as compared to horizontal wells are reported as follows (Miller and Steiger 1999):

- Vertical wells are less complicated and quicker to drill. The result is that more wells are drilled without problems, and production occurs sooner resulting in earlier cash flow.
- For a similar reservoir exposure, the number of vertical wells exceeds the number of horizontal wells. This can provide more flexibility to adjust injection rates, pressures and sweep on a field the basis.
- Infill vertical wells are less costly and can be directed at smaller unswept reservoir pockets.
- Sand cleanout technology is less expensive and more mature.
- Undesirable inter-well communication can be controlled by shutting in or synchronizing wells, which is less costly and easier to do with vertical wells than horizontal wells.
- Fewer temperature observation wells and downhole data collection devices are required given the larger number of vertical wells.

In theory, given the same oil viscosity, horizontal wells with an 800 m horizontal section should produce at rates 100 times faster than vertical wells. Another way to consider the same calculation is to state that horizontal wells, given a minimum economic production rate, are able to produce oil 100 times more viscous than vertical wells (Butler and Yee 2002). The viscosity of heavy oil in the Lloydminster area is not too high and economic production is possible from both horizontal and vertical wells. In other areas, such as in the Athabasca and Peace River oil sands areas, cold production of heavy viscous oil is only economic with horizontal wells (Fontaine 1992; Yeung 1995).

In thin reservoirs, horizontal wells allow exposure to a large zone of the reservoir. Horizontal wells also permit the reduction of the near wellbore pressure drop that is characteristic of conventional vertical wells (Fontaine 1992). Reducing this pressure drop reduces the propensity for water or gas coning and facilitates the maintenance of a relatively stable interface at the oil-water contact (Butler 1993).

In Lloydminster, a vertical well with 2 m of perforation may produce 6 to 10 m<sup>3</sup> per day of heavy oil. By contrast a 1,000 m long horizontal well may produce up to 50 m<sup>3</sup> per day.

The cost of horizontal wells is reported to be between three and four times the cost of equivalent and vertical wells. However horizontal wells have the potential to increase production by up to 10 times thereby reducing the unit cost of production (Towson 1997). Surface facility costs are also reduced because the wells themselves replace some of the gathering system associated with vertical wells. Drilling from pads consolidates batteries and allows economies of scale.

This reduction in production costs allows longer production lives. The larger drainage volume of horizontal wells reduces geological risk by averaging exposure to reservoir heterogeneities. The reduced pressure drawdown of horizontal wells delays the onset of water breakthrough when water zones are present. These factors contribute to higher ultimate recovery factors for horizontal wells.

However, horizontal wells are vulnerable to sand influx because the cleaning workover process may be expensive and time-consuming. Therefore, the use of horizontal wells is generally limited to cold production without sand.

### **3.3. Cold Heavy Oil Production with Sand (CHOPS)**

Many heavy oil reservoirs in the Lloydminster area are susceptible to significant sand influx. In such reservoirs, excluding sand results in production rates that are usually too low to be economic and recovery factors that hardly reach 3%. CHOPS is therefore widely practiced in heavy oilfields in the Lloydminster area. It has been estimated that in 2002, CHOPS accounted for 95,400 m<sup>3</sup>/day (600,000 barrels/day) of production, or 20% of Canada's oil production (Han, Bruno et al. 2007).

The impetus behind the adoption of CHOPS was the development of advanced progressive cavity pumps during the late 1980s which enabled the handling of slurries containing large quantities of sand. Allowing sand production increased production by 10 to 20 times and made production economic. With CHOPS, small diameter vertical or inclined wells can maintain sustained production rates of 5 to 48 m<sup>3</sup> per day for many years with an ultimate recovery factor that can reach up to 20%. The production life of CHOPS wells may extend to 12 to 14 years (Han, Bruno et al. 2007).

A progressive cavity pump is a positive displacement pump. There are only two parts: a rotor and a stator. The rotor is a spiral or helical gear that meshes with the stator which is a fixed internal spiral gear. The rotor and the stator mesh in a way that forms cavities that spiral up the barrel of the pump when the rotor is turned. For oil production, the stator is fixed to the tubing and the rotor is attached to a sucker rod string which is driven by a motor. The positive displacement rate is not a function a pressure but is controlled by speed of rotation. The cavities are sealed by a layer of elastomer applied to the stator. If solids are caught between the rotor and the stator, they are pressed into the elastomer and expelled into the next cavity.

Progressive cavity pumps are excellent sludge pumps and they perform well in CHOPS service because they are able to pump fluids containing a large amount of sand. Progressive cavity pumps produce high pressure at low speeds and their cylindrical shape is a suitable for wellbore use. Other advantages include low capital cost, low power consumption, convenience of installation, little visual impact, low noise and reduced surface footprint. The presence of gas will not gas-lock the pump but will cause apparent pump inefficiency because gas will take up pump capacity.

A vulnerable element of progressive cavity pumps is the elastomer. Aromatics in crude oil can penetrate the rubber and cause it to soften and swell. Hydrogen sulphide and high concentrations of CO<sub>2</sub> can over-vulcanize the rubber and cause it to become brittle. Typical elastomers are also limited to temperatures below 170° C. Therefore, the use of steam injection, which would cause thermal stress and production of H<sub>2</sub>S, would likely require a special elastomer.

CHOPS production typically involves a high sand cut level upon starting production. Sand cuts of 15 to 40% by volume are typical during initial production. The high initial sand influx is generally explained because during early production pressure gradients



are at their highest point due to a small drainage area and short flow distances. Eventually, sand cuts decline to levels of 10 to 15% for lower API gravity crudes and levels of 0.75 to 3% for higher API gravity heavy oils. Conversely, fluid production starts at a low level but production rates steadily climb over a period of several months. The mixture of oil, water and sand is produced as a foamy mass which is separated by gravity in a stock tank at a surface location.

CHOPS cannot be produced with a horizontal well because sand will enter the horizontal section of the well and will not come out.

In Western Canada, CHOPS is practiced in unconsolidated sandstone formations where mobilization of sand can be easily triggered and maintained. The recovery mechanisms postulated for CHOPS are as follows (Loughead and Saltuklaroglu 1992; Lebel 1994; Dusseault, Geilikman et al. 1995; Wong and Ogronick 1998; Han, Bruno et al. 2007):

- Production of sand increases the overall porosity and permeability of the formation and generates channels of greatly enhanced permeability;
- Sand mobility increases fluid mobility. The velocity of the sand, water and oil slurry with respect to the formation is higher than the velocity that oil alone could achieve with respect to an immobile sandstone formation;
- Evolution of solution gas maintains pressure;
- A solution gas drive contributes to production. Low mobility bubbles of produced gas expand when pressure decreases as the slurry moves toward the surface;
- The presence of bubbles in the oil phase reduce its apparent viscosity;
- Sand movement eliminates fines blockages, gas blockages and asphaltene precipitation near the wellbore;
- Production of sand also removes any mechanical skin damage that might have developed near the producing well;
- Sand production increases the compressibility of the formation leading to easier formation compaction and expulsion of oil; and,
- Sand production results in vertical stress concentration, lateral stress reduction, sheer dilation and continued formation destabilization which maintains the process.

Heavy oil, produced water and sand are brought to the surface and sent to lease storage tanks where sand is separated from the liquids. Sand is then trucked to central facilities where it is stockpiled temporarily and eventually disposed of into underground salt caverns. Sand production from CHOPS wells can be as much as 5,000 m<sup>3</sup> per year. Sand disposal costs are estimated at \$100/m<sup>3</sup>, for annual expenses of \$0.5 million per year related to sand production. Major producers in the Lloydminster region may be handling up to 500,000 m<sup>3</sup> of sand per year (Wagg and Fang 2007).

Liquids are then further separated into heavy oil and water and each is trucked to central processing facilities. Lease tanks are often opened to the atmosphere and some of the produced gas, mostly composed of methane, may be vented to atmosphere where it will contribute to the overall greenhouse gas load.

### 3.3.1. High Permeability Channels

Sand production removes sand from the formation. During initial production, high sand cuts are reported - in the order of 15% to 40% by volume of the sum of solids and liquids. These high levels are likely due to the fact that oil production initially takes place near the wellbore resulting in high pressure gradients and high rates of sand destabilization. With time, the rate of sand production drops and the rate of fluid production increases. Sand cuts eventually stabilize at values between 0.75% and 3% for the less viscous heavy oil and levels ranging from 10% to 15% for the heavier crudes. Sand production may average up to 1,000 m<sup>3</sup> per well over its productive life. (Dusseault, Geilikman et al. 1995).

Does this relatively high level of sand removal significantly change the reservoir? Production parameters vary between reservoirs and individual wells. However, if what could be typical values are used to construct an example, the following could be representative: If 10% of the original oil in place is produced by CHOPS with average sand and oil cuts of 5% and 70%, then less than 0.2% of reservoir sand was removed.

However, it is important to consider that sand is not removed uniformly across reservoir volume but selectively from certain reservoir zones. CHOPS is thought to result in the formation of a higher porosity volume near the wellbore and of a network of high permeability channels where permeability is higher by three to five times the undisturbed matrix permeability. In other words, the application of CHOPS results in the creation of a dual porosity and dual permeability reservoir with high permeability channels (often named "wormholes") spreading through the undisturbed formation. Flow of oil to the well is thought to be dominated by linear flow through these high permeability channels. These channels may extend far from the producing well and in some cases may establish communication with adjacent wells.

Laboratory experiments were conducted at the Alberta Research Council to demonstrate the existence of wormholes (Tremblay, Sedgwick et al. 1996). A large sand core was packed with Burnt Lake sand. The sand was compacted at a pressure of 27 MPa to obtain a porosity of 32% which approximates field conditions. X-Ray Computed Tomography (CT) was performed on the sand pack before and after oil production. The CT images showed that a high porosity channel had developed within the pack. The channel was still full of sand but its 52% porosity was higher than the porosity of the undisturbed pack. The channel diameter was 15 mm to 33 mm. The channel had followed regions within the pack where porosity was already slightly higher. The authors concluded that wormholes will form within the weaker and more porous sands of an unconsolidated formation.

Other researchers have suggested that wormholes range in diameter from 10 cm to as much as 1 m in diameter. Half length of wormholes have been estimated at approximately 150 to 200 m, on the basis of calculations using production figures and bottom hole pressure data from CHOPS wells (Saltuklaroglu 2007).

Work on physical models done at the Georgia Institute of Technology resulted in different observations and suggested that sand removal resulted in an erosion front and the formation of a cavity structure (Gonzalez, Alvarellos et al. 2007).

Tests were conducted by PanCanadian in Lindbergh on wells that had produced 39,000 m<sup>3</sup> of fluids and 560 m<sup>3</sup> of sand (Metwally 1996). Comparison of post-production neutron and gamma ray logs to original open hole logs showed that after production there were only few zones with higher porosity than originally in the wellbore area. Injectivity tests conducted on this well showed that most of the fluids entered a few narrow zones. These tests indicated that there did not appear to be a large cavity formed near the well and that most of the sand production likely came from a small number of channels that originated at the well and extended into the formation.

The wormhole network appears to follow unpredictable and random paths. For example, a tracer test demonstrated communication with a well 500 m away but no communication with another well in between.

Seismic work on cold production wells at Burnt Lake support the suggestion that networks of high permeability channels are formed. The aerial extent in the zone of density change ruled out the formation of a big cavity surrounding the well bore. In addition, dye tests showed that communication occurs readily in a matter of hours between wells. This indicated that the dye had flowed through high permeability channels of limited size within the sand matrix (Yeung 1995).

It appears that the reservoir engineering visualization of high permeability channels or wormholes is that of empty pipes analogous to a network of horizontal wells. However, from a perspective of rock mechanics, there appears to be a view that a significant void space cannot exist in such high porosity rock at the depths of Lloydminster heavy oil deposits. A rock mechanics view on wormholes would be that they are zones of very high porosity with very low horizontal stress. Flow in the zones would be typical of Darcy flow through porous media.

### **3.3.2. Solution Gas Drive**

In tandem with sand production, CHOPS is sustained by a solution gas drive. Depressurization of gas saturated oil causes bubbles to form but bubbles are prevented from coalescing and forming an independent gas phase in heavy oil because of high viscosity, low diffusion rates and high pressure gradients (Alshmakhy and Maini 2007). The solution gas drive sustains the oil rate through volume expansion and by keeping sand in suspension.

Production of an oil reservoir decreases pressure eventually causing pressure to drop below the bubble point pressure. At this stage, solution gas starts to come out of solution creating bubbles in the oil phase. As pressure is further reduced, existing bubbles expand and new bubbles are nucleated. In a light oil reservoir, viscosity is low enough to allow bubble mobility. Bubbles move through the oil phase, eventually colliding and coalescing with each other. This process continues until a continuous gas phase is formed which is known as the critical gas saturation point and is identified by a significant increase in the Gas Oil Ratio (GOR) at the wellhead.

In heavy oil however, the oil viscosity is high enough to restrict bubble mobility and delay, if not prevent, the formation of a continuous gas phase. Because evolved solution gas remains trapped in the oil phase, this phenomenon is characterized by a constant

low GOR. Production records often show a constant GOR for many years. This indicates that the formation is not depleted of its solution gas during the early phase of production by the creation of a continuous gas phase but rather that solution gas remains trapped in the oil phase and is produced proportionately with the oil.

Solution gas drives production because bubbles expand the apparent volume of the oil phase. This expansion increases as the oil phase is driven by the pressure gradient toward the producing well. As pressure decreases along the pressure gradient, more bubbles are formed and the existing ones expand, further expanding the apparent volume of the oil phase. This continuous volume expansion is one of the mechanisms that support production. It is generally analogous to the mechanism that causes a shaken pop bottle to overflow.

Another role postulated for gas bubbles in the oil is that they assist in destabilizing the sand formation. While small bubbles are able to flow through pore throats, large bubbles or gas slugs are unable to pass and may block pore throats. The local increase in stress from this blockage exerts pressure on sand grains, eventually destabilizing them and entraining them in the flow. The presence of gas bubbles, or of a discontinuous gas phase, promotes additional sand destabilization and contributes to the maintenance of the sand production process. Sand destabilization is an essential mechanism for CHOPS.

Another factor that may explain the absence of a continuous gas phase is bubble break-up. While bubbles may collide and coalesce with each other, they may also undergo events that cause their break-up and reduction in size. The higher the break-up rate, the more likely bubbles will not coalesce into a continuous phase. A study conducted at the University of Calgary identified three processes for bubble break-up in porous media:

- A moving bubble may split into daughter bubbles when entering two adjoining pores; in other words, the rock tip between adjoining pores splits the bubble in two;
- A bubble may become elongated under the influence of the flow field reaching a point of instability where it disintegrates into several smaller bubbles; and,
- A process known as waist break-up when a bubble invades a new pore and a portion of the bubble separates from the rest of the bubble.

The study found that a higher pressure gradient would increase the rate of bubble break-up, providing an explanation for the fact that increasing drawdown pressure generally increases recovery in solution drive reservoirs. On the other hand, interfacial tension and the presence of asphaltenes may not play an important role in bubble break-up. Viscosity was shown to delay bubble break-up (Javadpour 2007).

One approach to analyzing a solution gas drive is to treat the combination of oil and bubbles as an apparent "foamy oil" phase. This term arises because of observations at the wellhead where oil samples appear to be in the form of an oil continuous foam containing a large volume of dispersed gas bubbles. The apparent density of produced heavy oil from the Henan oilfield in China was measured at 0.58 g/cm<sup>3</sup> while the density of the oil once all the gas had been removed was 0.95 g/cm<sup>3</sup> (Firoozabadi 2001).

The presence of gas bubbles in the oil phase not only reduces apparent density but is also reported to reduce apparent viscosity by up to one order of magnitude.

Experiments conducted at the University of Calgary confirmed that the injection of bubbles into heavy oil reduced apparent viscosity with higher reductions correlating with higher gas volume fractions (Islam and Chakma 1990).

Another study from University of Calgary indicated that the presence of asphaltenes in heavy oil appears to facilitate bubble nucleation, decrease critical super saturation and help in maintaining dispersed gas flow by suppressing bubble coalescence (Adil 2005).

The concept of foamy oil is therefore a pseudo single phase of heavy oil containing large amounts of small dispersed gas bubbles. Another analytical approach to solution gas drive is to describe the process as a two-phase flow model with two parameters (Firoozabadi 2001):

- Critical gas saturation; and,
- Oil and gas relative permeabilities.

The critical gas saturation is generally defined as the minimum gas saturation at which gas flow occurs in the two-phase gas-oil system. This parameter is highly dependent on the pressure gradient. At reservoir production conditions, values of 1 to 3% are generally cited for light oil, and 3 to 5% for heavy oil. The implication is that a larger volume gas phase may be dispersed in heavy oil than in light oil.

Gas and oil relative permeabilities are conventional concepts. Data produced at the Reservoir Engineering Research Institute in Palo Alto, California indicate that the relative permeability curve of heavy oil in a two-phase oil gas system is similar to that of light oil. However the gas relative permeability is very low in heavy oil systems. Values of  $10^{-6}$  to  $10^{-5}$  are quoted (Firoozabadi 2001). The implication is that the gas phase has very low mobility in heavy oil due to high oil viscosity.

In a two-phase flow model, the high efficiency of the solution gas drive is explained by high oil viscosity which essentially traps a discontinuous gas phase inside the oil phase. The point is not the description of the gas phase as microbubbles, as bubbles, as foam, or as disconnected gas slugs. It is possible that gas exists as bubbles in the initial phase of heavy oil production from a reservoir but as gas saturation increases, relative gas permeability also increases and gas may become increasingly a discontinuous segregated phase. The key point however is the very low mobility of the dispersed gas phase. The expansion of this gas phase supports the movement of oil towards the producing well.

### **3.3.3. Other Drive Mechanisms**

Subsidence, or formation compaction, is also thought to be an essential drive mechanism for CHOPS. In a virgin reservoir, unconsolidated sand is held in place by a balance of stresses in all directions. When a well is drilled and sand is removed from the near well bore area by the PCP, and unbalanced stress situation results. Sand is no longer constrained in the plane facing the well. Therefore, the stresses acting on the sand volume will cause to flow in the direction of the well. One of the important sources of stress is the weight applied by the overburden. Compaction of the formation from sand production supports the expulsion of sand and heavy oil toward the well. Formation compaction is generally thought to be of secondary importance but might play

a larger role toward the end of primary production after large volumes of sand have been removed and the solution gas drive approaches exhaustion.

Water pressure from nearby aquifers may provide some pressure support. However, the water to oil mobility ratio is in the order of several hundreds and highly unfavourable. Water would tend to finger from an aquifer toward producing wells rather than providing a uniform interface for oil displacement. Once water fingers breakthrough to producing wells, the water cut increases significantly, negatively affecting the economics of oil production. Wells are typically located at structurally high locations in the reservoir to delay the onset of water breakthrough (Loughead and Saltuklaroglu 1992).

### **3.3.4. Production Decline**

Typically, the oil rate gradually increases over a period of a few years, reaching a peak at a level around 20 m<sup>3</sup>/day. Afterwards, a long period of slow production decline sets in. Production is eventually stopped when the daily oil rate falls below an economic criterion. The cause for steadily falling oil production is generally the exhaustion and eventual depletion of the solution gas drive. Reservoir pressure is reduced and solution gas appears to have blown down.

It has proven very difficult to re-establish a solution gas drive once a well or a deposit appears to have been depleted of its solution gas. Attempts to inject methane into the reservoir have not been successful because the time required for methane to dissolve into heavy oil is extremely long.

One hypothesis for the fact that recovery with CHOPS is limited to approximately 10% is that CHOPS recovers oil only from the most favourable horizontal plane of the reservoir. The properties of the sand matrix and of the heavy oil vary with depth. It is possible that wormholes grow in a horizontal plane away from the well. Reservoir volumes below this plane and possibly above it are simply bypassed.

A possible cause of production decline is a slowdown in sand production. The movement of sand entrains oil with it to the well bore. However, sand is destabilized at the farthest tip of the high permeability channel or wormhole, where wormholes grow by eroding the original sandstone matrix. As production progresses, the growth front of the high permeability channel is located further and further away from the well bore and the pressure drawdown becomes extended. Eventually, the pressure drawdown is not sufficient to support additional growth of the high permeability channel and sand movement slows down.

Another cause of cessation of primary production is excessive water influx. Aquifers with varying degrees of strengths may be present in the vicinity of a producing oil pool. Rapid oil production, particularly with vertical wells, may lead to water coning from an underlying aquifer. The use of careful production methods will delay the onset of water influx but is not sufficient to avoid it. Any water present near a producing oil reservoir will be drawn to fill the void left behind by the produced oil. Because water is more mobile than oil and because of permeability variations in the rock formation, water will not advance as a uniform front behind the oil but will show tendencies to finger through the oil zone and reach the lower pressure zone surrounding the wellbore.

Water breakthrough may also result in uneconomic water cuts even for wells distant from the original oil water contact. Because of the extensive development of high permeability channels, catastrophic water inflow can occur in wells that can be up to 800 m away from the oil and water contact.

A challenge that is sometimes encountered in CHOPS exploitations is that some reservoirs contain a certain type of interbedded shale that breaks down during production and plugs the area near the wellbore. Workovers have not been successful in cleaning up this type of shale accumulation and the well must be abandoned when this happens.

### **3.3.5. Post-CHOPS Reservoir Conditions**

Substantial quantities of heavy oil will remain in the Lloydminster area at the economic limit of cold production. It is therefore important to characterize and understand the state of the reservoir after CHOPS in order to properly design a suitable EOR process.

CHOPS is a production process that significantly alters reservoir properties from their original state, notably the creation of local high porosity zones caused by the extraction large volumes of sand. CHOPS extracts oil, water and sand from the reservoir and, in doing so, creates a network of high porosity channels. These channels are thought to extend far away from the producing well because of the observed rapid migration of edge water. Injected fluids and tracers are also observed to communicate between wells up to hundreds of meters in various directions. Tracer studies suggest that wormholes create multiwell networks.

Oil was obviously produced from the zones from which sand was produced. These zones now have higher porosity and contain a higher proportion of liquids than the undisturbed matrix. However, the oil that was contained in these zones is insufficient to account for total production. Therefore, oil was also drained from the undisturbed matrix into the high permeability channels. It is likely that a proportion of the reservoir volume is still at the original porosity (no sand was removed) but at a reduced oil saturation.

The presence of high permeability zones where sand has been produced means that infill drilling becomes difficult because of lost mud circulation during drilling. In-fill drilling has been tried but found to be generally unsuccessful in Lloydminster.

Wormholes can be interpreted as horizontal wells that developed as result of the recovery process and that could be used in a follow up EOR process for distribution of injectants or aggregation of production. However, these high permeability zones have not been found to be inherently stable. Injecting steam or solvent in wormholed reservoirs has resulted in the collapse of the high permeability channels.

Another consequence of sand production during primary production is alteration of the geomechanical characteristics of the sand formation. CHOPS would result in a reservoir with a compressibility of up to about two orders of magnitude greater than original reservoir conditions. This would not allow injection of fluids such as steam at pressures low enough to avoid fracturing. High compressibility and high susceptibility to fracturing would likely impair a follow-up process that would rely on injected fluids to displace oil in a drive configuration (Loughead and Saltuklaroglu 1992).

A common view is that at the end of economic production, the reservoir only contains “dead oil” with no solution gas. The depletion of solution gas means that there is no longer a solution gas drive to destabilize the sand formation and move the oil. The oil remaining in the reservoir can only move slowly toward the wellbore, essentially under Darcy flow. Therefore, it cannot be pumped to the surface at economic rates.

The amount of dead oil in the reservoir after cessation of cold production or CHOPS is uncertain. One school of thought is that the foamy oil zone may extend possibly 10 m from the wormhole center (Lines and Daley 2006). Gas could have diffused from bypassed zones to produced zones so that at the end of CHOPS sizeable volume of the reservoir is left with oil that is below its original gas content. Therefore, at the end of production, from a practical perspective, the reservoir could be depleted of solution gas.

However, while pressure can be transmitted hydraulically through the reservoir, gas bubbles are virtually immobile, as discussed earlier. Therefore, gas should still be present, likely in the form of bubbles a short distance beyond the permeability contrast of the high permeability channel and the undisturbed sand matrix. Dead oil would only be present in a cylindrical layer surrounding the high permeability channels. Live oil containing solution gas could be present beyond this layer. Immobilized by high oil viscosity, this gas cannot be produced unless the oil is produced. The resulting low gas flow rates create the appearance that the reservoir is depleted of solution gas.

There may be an opportunity after a number of years to revisit and retest abandoned CHOPS reservoirs after the formation has been given the time to re-equilibrate itself. With the passage of time and given the fact that a substantial quantity of oil is still present, it is possible that the oil column may have risen again and additional production may be possible.

### **3.4. Waterfloods**

#### **3.4.1. Overview**

While most Lloydminster reservoirs are under primary production, waterfloods are increasingly used to enhance production in suitable reservoirs. Water flooding is a well known secondary recovery production method that involves injecting water to displace oil toward producing wells. While waterflood theory is well established for conventional oil, the practice in Canadian heavy oil fields is not as well documented.

The inherent assumption in conventional oil waterflood is that plug flow displacement of oil by water occurs because the viscosities of water and oil are similar at reservoir conditions. At the end of a conventional oil waterflood, residual oil that is left in place is largely the result of reservoir heterogeneities and capillary trapping.

The Mobility Ratio (M) is defined as the ratio of the mobility of the displacing fluid (generally water) divided by the mobility of the displaced fluid (generally oil). The equation for M is generally given as:

$$\begin{aligned} & \text{(For water displacing oil)} \\ & M = (k_w/\mu_w) / (k_o/\mu_o), \text{ or} \\ & M = (k_w * \mu_o) / (\mu_w * k_o) \end{aligned}$$



where:

k is permeability

$\mu$  is viscosity

When M is greater than one, the displacement process will be inefficient. In theory, the stability of the displacement front depends on the balance of forces involved. If the combined forces of gravity and capillarity are greater than viscous forces, the displacement front will be stable. Viscous fingers will emerge when viscous forces overwhelm gravity and capillary forces (Mai and Kantzas 2007).

At the microscopic or pore level, more displacing fluid needs to flow in order to displace oil and reduce residual oil saturation in the pores. At the macroscopic or reservoir level, high values of M mean that the displacing fluid will tend to flow past and bypass the oil resulting in channelling, early breakthrough and poor sweep efficiency.

Given that permeability values generally range between zero and unity, for heavy oil the overwhelming parameter becomes oil viscosity which results in a very high value for M and inefficient displacement. The large viscosity difference between heavy oil and water results in an unstable displacement front and the formation of viscous fingers whereby water channels and breaks through prematurely to producing wells. The subsequent process is really a recirculation of water that entrains oil with it to the surface at a rate sufficient to justify the economics of the operation. This generally involves the movement of large quantities of water, at water cuts above 90% for long periods of time. Heavy oil waterfloods are generally characterized by higher water cuts and lower recoveries than their conventional oil counterparts and are usually viewed as having marginal economics. A large component of oil left behind is held in unswept zones.

General approaches to improving the mobility ratio in displacement floods are:

- To increase the viscosity of the displacing fluid; for water, this can be done by adding a suitable polymer that will make water more viscous. When gas is used as the displacing fluid, there are no practical approaches for increasing gas viscosity.
- To reduce the viscosity of oil; heating the oil will reduce its viscosity and this is one of the mechanism of steam floods and hot waterfloods. Oil viscosity can also be reduced by solvents in EOR approaches such as CO<sub>2</sub> and hydrocarbon miscible and immiscible floods.

The interfacial tension also affects the efficiency of a displacement process. Reducing interfacial tension will reduce residual oil saturation by decreasing the impact of capillary forces and, therefore, improve oil recovery.

Reduction in interfacial tension may also result in the formation of oil and water emulsions which may have a significant effect on the efficiency of the displacement process. Emulsions can lower the mobility of the displacing water phase thereby improving the mobility ratio. Emulsions may also block water channels forcing the displacing water into unswept zones and thereby improving sweep efficiency.

Laboratory experiments conducted at the Saskatchewan Research Council (SRC) compared the performance of a cold waterflood to that of a hot waterflood (Thomas,

Farouq Ali et al. 2001). The experiments were conducted on Senlac oil from the Saskatchewan heavy oil producing region with the following viscosity to temperature relationship:

- 25° C - 2,045 centipoises
- 35° C - 875 centipoises
- 55° C - 219 centipoises

In other words, heavy oil viscosity can be reduced by a factor of 10 by increasing temperature to 55° C.

Starting from un-produced sand packs, the cold waterflood recovered 37% of the original oil in place while the hot waterflood showed higher recovery at 48%. The hot waterflood recovered more oil during the initial stage of the displacement process. The cold waterflood maintained a 100% oil cut until approximately 0.18 Pore Volume (PV) produced while the hot waterflood maintained 100% oil cut until approximately 0.3 PV produced. For both floods, once water broke through the producing end, significant declines were experienced in oil cut and recovery. The waterflood process appears to exhibit efficient displacement until water breakthrough occurs. After this event, pressure, oil cut, oil production and oil recovery decline dramatically.

The key to achieving significantly higher recovery from waterfloods appears to lie in the development of approaches that will delay the onset of water breakthrough either by slowing water velocity or interrupting the water channelling process.

### **3.4.2. Heavy Oil Waterfloods in Western Canada**

Heavy oil waterfloods have been in operation for over 50 years in Alberta and Saskatchewan. With heavy oil, the mobility ratio between oil and water is highly unfavourable and water breakthrough between injectors and producers occurs very quickly.

Reservoirs that are not subject to sand influx are often good candidates for water flooding to enhance recovery, unless aquifers are present in the vicinity. Water flooding is not applicable to reservoirs susceptible to significant sand influx or where CHOPS has been applied. The high permeability channels are obvious conduit for early water breakthrough which would negate the value of a waterflood project.

Despite low expectations, waterflood projects have been undertaken in the Lloydminster area with results generally better than expected (Adams 1982). The typical pattern of heavy oil production under cold production without sand followed by waterflood is that the oil rate gradually declines over time from, for example, an initial rate of 800 m<sup>3</sup> per day per pad to a late life rate of 200 m<sup>3</sup> per day per pad after two to three years. During that same time, the water production rate increases rapidly in the early life of the project from an initial rate of, for example, 60 m<sup>3</sup> per day per pad and then stabilizes at rates as high as 1,100 m<sup>3</sup> per day per pad. The water cut therefore increases from initial levels of around 30% to levels of approximately 90% and higher in the late life of the project (Miller and Soroko 2005).

In the Lloydminster area, there are currently, on the Alberta side, 39 large waterfloods targeting 235 million m<sup>3</sup> of oil in place, representing approximately 11% of heavy oil resources. On the Saskatchewan side, 37 large waterflood projects are currently active, targeting 409 million m<sup>3</sup> of oil in place volume, or approximately 15 to 20% of the heavy oil resources. The success of waterfloods is variable, but can reach a total of 26% of recovery in the best cases. The Lloydminster area is the only area of the world where waterfloods are effective for heavy oil and SRC has undertaken an extensive parametric analysis to uncover the factors affecting successful recovery.

The SRC statistical study documented 207 waterfloods operating in Alberta and Saskatchewan with varying degrees of success. Some recover as much as seven times primary recovery while others have been abandoned. A specific study involved a data set of 83 waterfloods, 44 of which were heavy oil and 39 medium oil (Renouf 2007). The study attempted to correlate five measures of success with 42 reservoir and operating parameters. The measures of success with the highest correlation were:

- Success Index: the percentage of original oil in place produced by the waterflood divided by the number of years in operation.
- Success Index at Fill Up: the percentage of original oil in place recovered in the first year after 90% fill up of the voidage created by primary recovery. This measure compares waterflood at the same stage of maturity.

The reservoir and operating parameters that impacted success were different for medium oil and heavy oil reservoirs. The success of waterfloods in medium oil reservoirs depended mostly on:

- Injection volume and rate;
- Permeability; and,
- Reservoir heterogeneity.

By contrast, heavy oil reservoirs depended primarily on:

- Injection volume and rate; and,
- Factors related to the deployment of horizontal wells.

Injection volume and rate were by far the most dominant factors influencing the success of waterfloods in both medium and heavy oil reservoirs. Factors related to injection pressure had less significance. This observation may support the idea that recovery in heavy oil waterfloods is primarily the result of water dragging the oil rather than pushing it (Renouf 2007).

The fact that medium oil reservoirs were significantly impacted by permeability and heterogeneity validates conventional knowledge of water flooding. However these factors were not significant for heavy oil reservoirs. It is likely that in heavy oil applications, the severely unfavourable mobility ratio between water and heavy oil dominates permeability and heterogeneity considerations. This may explain why operating variables related to horizontal wells were found to have a significant impact on the success of heavy oil waterfloods. In general, increasing the ratio of horizontal to vertical wells (whether producers or injectors) positively impacted the outcome. On the

other hand, horizontal wells did not have a significant impact on the performance of medium oil waterfloods.

Another review of the performance of various waterfloods identified that increasing the volumetric sweep of waterfloods usually results in rising production. In other words, increasing the volume of water raises the probability of water sweeping into previously bypassed zones. By contrast, aggressive injection rates often lead to high water cuts (Singhal and Holowatuk 2007).

Within economic limits, the optimal approach for heavy oil waterfloods appears to be injecting large volumes of water using horizontal wells on relatively small well spacings to avoid high injection pressures.

Proposed recovery mechanisms for heavy oil waterfloods include pressure support, oil drag, oil emulsification, control of solution gas drive and gravity drainage. The operating guidelines for heavy oil waterflood in Canadian oilfields appear to be as follows (Miller 2006):

- Matching injection volumes to production volumes because over injection exacerbate water channelling;
- Maintain uniform conditions across the field under waterflood;
- Focus on improving aerial sweep efficiency;
- Emphasize operational efficiency;
- Overlying gas zones are generally a cause for water channelling;
- Injection of dirty water may plug the formation near the injector;
- Conversion of injectors and producers is helpful in addressing sweep issues; and,
- Line drive is often effective.

The fact that larger volumes of injected water increase the oil production rate is in part explained by the mechanism of inhibition. In a strong water wet system, water will invade smaller pores preferentially due to capillary forces and in doing so force oil out into the larger pores. If the injected volumes are sufficiently high, water can enter both large and small pores resulting in a more efficient displacement. Inhibition also provides a possible explanation for the fact that oil production continues in heavy oil waterfloods after water breakthrough and under conditions of high water cuts. Under these conditions, water does not provide a uniform displacement front but channels from injectors to producers. However, in a water wet system, capillary forces will induce water to enter smaller pores and displace oil into larger pores that had been previously flooded with water. This fluid redistribution moves oil from the smaller pores that are not being swept into the larger pores where water is moving and dragging oil with it to the producing well. Reduced pressures and water velocities not only minimize the extent of viscous fingering and water channelling, they also allow for the water inhibition mechanism to contribute more on a relative basis.

### **3.4.3. Hot Waterfloods**

Hot water flooding has been attempted with heavy oil, generally without major successes. When the purpose is to convey heat to the formation, steam has almost

three times the heat carrying capacity of hot water and is therefore vastly more efficient in carrying thermal energy. When the purpose is to gain incremental recovery as compared to a cold waterflood, it has been generally difficult to observe and measure significant improvements (Farouq Ali 1974; Miller 2006).

#### **3.4.4. Polymer Floods**

With heavy oil, waterfloods are generally considered uneconomic because of the relatively poor sweep efficiency and the short time to water breakthrough which results in high water cuts and high costs for handling large volumes of produced water. These disadvantages primarily arise from the unfavourable mobility ratio between water and heavy oil. Therefore, the efficiency of the waterflood could be improved by increasing the viscosity of injected water.

Polymer floods are a variation on waterfloods where polymer is added to water at relatively small concentrations. The purpose is to increase water viscosity, thereby decreasing the water to oil mobility ratio and enhancing efficiency. However, one of the issues with polymer injection is that fresh water needs to be used for the polymer to be effective.

Examples of polymer additives include: partially hydrolyzed polyacrylamides, polysaccharides, polyethylene oxides and hydroxyethyl cellulose. Polymer concentration may range from 20 to 2,000 ppm (Selby, Alikhan et al. 1989).

Increasing water viscosity reduces the mobility of water and therefore the water to oil mobility ratio. This improves sweep efficiency and increases recovery. The use of polymers is thought to have a significant impact at the front edge of the polymer slug. The relative permeability of water is significantly decreased because adsorbed polymer molecules enhance water wettability. It is also thought that a reduction in the mobility ratio increases oil relative permeability. Oil becomes relatively more active and its relative permeability is increased. The combined impact of decreased water relative permeability, increased oil relative permeability and improved mobility ratio results in enhanced oil recovery during laboratory experiments, reaching as high as a 30% improvement (Lu 2005).

Polymer flood evaluations were conducted at the University of Regina using uniform and channelled sand packs (Wang and Dong 2007). Polymer flooding was applied as a tertiary EOR process after primary recovery and water flooding of the sand packs. The effective viscosity of injected polymer solutions ranged from 2 to 76 centipoises. It was determined that the effectiveness of the polymer flood increased with higher viscosities of injected polymer solutions. However, diminishing returns applied and increasing viscosity beyond 40 centipoises yielded relatively small increases in recovery. Improvements also decreased when using a channelled sand pack as compared to a uniform sand pack.

Experiments conducted at the Alberta Research Council showed that polymer floods have the potential to increase recovery in Western Canada heavy oil fields (Wassmuth, Green et al. 2007). Polymer was added to injected water at concentrations between 1,000 and 1,500 ppm, increasing the viscosity of water from 1 up to 30 centipoises.

Core flood experiments demonstrated that recovery factors could be improved from 16 to 23%. Data from core flood experiments was used to conduct a field scale numerical simulation and economic analysis. While primary recovery recovered 6% of the original oil in-place after three years, a conventional waterflood on 200 m well spacing recovered 23% after 22 years. By contrast, a polymer flood on the same well spacing recovered 51% over 44 years. A polymer flood on a reduced well spacing of 100 m recovered 49% over 17 years. Polymer floods dramatically reduced water cut as compared to waterfloods thereby extending the economic life of the process. While the shorter well spacing resulted in a slightly lower recovery, the rate of recovery was greatly accelerated (17 years vs. 44 years), increasing the economic value of the approach. The Net Present Value (NPV), using a 15% discount rate, was calculated at \$5.5 million for primary recovery, doubling to \$10.7 million for a waterflood. The polymer floods returned NPV of \$12.6 million on a 200 m spacing and \$19.2 million on a 100 m spacing.

A polymer flood pilot is currently being conducted by Pengrowth at its heavy oil field straddling the Alberta Saskatchewan border (East Bodo and Cosine) (Wassmuth, Arnold et al. 2007). Difficulties were encountered with respect to achieving the water quality required for effective use of the polymer. The presence of dissolved iron and hardness in produced water and makeup brine from an underground aquifer lowered the viscosity increase attributable to the polymer. Fresh groundwater had to be used for the pilot. While the pilot is still in early stages, field scale simulations indicated that significant quantities of additional heavy oil could be recovered by implementing a polymer flood particularly using horizontal wells for polymer injection at a central location in the field.

Opportunities for polymer flood technology developments include the following:

- Cost effective water treatment technologies to reduce hardness and iron content in produced water; and,
- The development of new polymers that would be tolerant to produced water with high Total Dissolved Solids (TDS). In particular polymers that could increase the viscosity of saline brine from underground aquifers would be valuable.

### **3.4.5. Surfactant and Alkali Flooding**

Surfactant and alkali flooding are part of the general category of chemical floods whereby chemicals are added to enhance the performance of a waterflood.

Surfactant flooding is the addition of surfactants to injected water to reduce the oil-water interfacial tension. Surfactants are molecules that are both hydrophobic and hydrophilic. Part of the molecule is compatible with oil while another part of the same molecule is compatible with water. The most stable configuration for surfactants is at the interface between oil and water and their presence reduces the oil-water interfacial tension. Reducing interfacial tension reduces the intensity of capillary forces responsible for trapping oil inside pore spaces, thereby making more oil available to mobilization by flowing water. The presence of surfactants may also lead to the formation of emulsions which may become trapped by pore constrictions therefore blocking the flow of water and causing the waterflood to be diverted to unswept zones. This mechanism leads to improve sweep efficiency and increased oil recovery.

Alkali flooding is the addition of alkaline chemicals to injected water in order to effect in situ reactions that would enhance the efficiency of a waterflood. The principal oil recovery mechanism of alkali flooding is the formation of in situ surfactants which reduce interfacial tension and the final oil saturation level in water swept zones. They may also contribute to the formation of emulsion which may divert water to unswept zones and improve sweep efficiency. Examples of alkaline agents include sodium hydroxide, sodium phosphate, ammonium hydroxide and ammonium carbonate (Selby, Alikhan et al. 1989). Alkaline chemicals react with naturally occurring acids present in the crude oil to form surfactants which reduce the interfacial tension at the oil water interface. This reduction of interfacial tension enables a decrease of the final oil saturation achievable in rock pores swept by the waterflood. Alkali chemicals also react with multivalent cations present in reservoir brine, such as calcium and magnesium ions, and reduce their activity of by forming precipitates. This reduction in cation concentration leads to increased surfactant activity. Finally, alkali chemicals also react with reservoir rock. This latter set of reactions is detrimental to the performance of the alkali flood because it results in consumption of injected chemicals and increased costs.

Alkali Surfactant (AS) Flooding is a combination of surfactant and alkali flooding technologies. When added to injected water, alkalis react with organic acids present in the oil leading to the in situ generation of surfactants. However, alkalis are also adsorbed on porous media and it is difficult to control the amount of injected alkali that becomes available for the generation of in situ surfactants. Adding surfactants reduces the reliance on in situ reactions but increases costs. The purpose of AS flooding is to achieve an optimal performance to cost balance. AS flooding may also be optimized further by the addition of polymers.

One of the disadvantages of surfactant and alkali floods is the need to soften water which implies increased capital and operating costs when using produced water or brine.

The potential for AS flooding for heavy oil was studied at the University of Calgary (Bryan and Kantzas 2007). In core flood experiments, water flooding was compared to AS flooding. During waterflood experiments, water was injected at a constant rate. The pressure of the system increased because oil cannot be displaced at the same rate as the rate of water injection. Upon water breakthrough, pressure decreased and water cut increased. After breakthrough, oil continued to be produced at high water cuts. Waterfloods recovered between 3 and 4% of in place heavy oil. The pattern was similar with AS flooding. The differences with AS flooding were that:

- The time to water breakthrough was slightly longer;
- At breakthrough the pressure did not decline as quickly; and,
- Recovery was approximately 6%.

Experiments also involved first conducting a waterflood and following it up with an AS flood. Upon the switch from waterflood to AS flood, pressure rose considerably while the water cut decreased sharply. A significant volume of additional heavy oil was produced with total recoveries ranging from 9 to 14%. It is hypothesized that the injection of the alkali surfactant solution into an existing waterflood pattern resulted in water diversion. It is possible that oil droplets were emulsified, became trapped, and blocked existing water

channels. If the early water channels were being blocked or plugged by emulsified oil, then injected water was being diverted into previously unswept zones, resulting in a significant increase in heavy oil recovery.

An alkaline polymer flood was conducted in the David Pool in the Lloydminster region of Alberta (Pitts, Wyatt et al. 2004). The oil in this formation has a density of 22.6 degree API and a viscosity of 34 centipoises at the reservoir temperature of 30° C. The test area had produced 5.7% of the original oil in place by primary production and an additional 25.5% from a waterflood. When the alkaline polymer injection was initiated, the oil cut was 40%. This chemical flood slow down the decline of the oil cut and eventually recovered an additional 21.1% of the original oil in place.

The design of the chemical flood was as follows: 1% by weight of sodium carbonate was added to injected water to provide an alkaline solution that would create in situ surfactants by reacting with naphthenic acids from the oil. Measurements indicated that the initial interfacial tension between oil and water was 18 dyne/cm. The presence of the alkali reduced interfacial tension by 270 times which was deemed a sufficient reduction to overcome capillary forces and produce incremental oil. Therefore, the addition of a surfactant was not needed and its cost was avoided. The reduction in interfacial tension improves water permeability and incrementally increases water mobility thereby making the mobility ratio worse. Polymer was added to increase water viscosity to counterbalance this effect and improve the mobility ratio.

## **4. Lloydminster Strengths and Weaknesses**

### **4.1. Overview**

As discussed earlier, the opportunity for Lloydminster heavy oil EOR is the substantial quantity of oil that will be left in the ground after primary and secondary recovery. In the same vein, the threat for the oil industry in the region is that the end of activities based on existing commercial technologies is in sight, as illustrated by the 6 year reserve life index.

However, before investing in the development of a new EOR technology to exploit this opportunity and counter the threat, it is important to consider the strengths and weaknesses of the heavy oil region. The design of a new EOR method should build on the favourable factors and seek to reduce exposure to the unfavourable aspects. Strengths are as follows:

- Approximately 90% of the resource will be left in the ground which, being a sizable opportunity, should provide the economic justification for a commensurate research effort.
- Zones within exploited reservoirs are likely to still be at or near original oil saturation.
- The significant built infrastructure in the Lloydminster area should reduce costs of development.
- Lloydminster heavy oil is mobile at reservoir conditions because of its viscosity and the high permeability of the host sandstone formations.



- Heavy oil is a higher quality product that attracts a higher price than bitumen.

The weaknesses are as follows:

- Most reservoirs are thin.
  - Gravity drainage will be weak; and,
  - The ability to support fixed capital investments will be limited.
- The unfavourable Mobility Ratio means that any displacement or drive process will be challenges by poor conformance and sweep efficiency.
- Reservoir pressures are relatively low due to shallow depths and prior cold production.
- Uncertainty over the extent and nature of reservoir disturbance resulting from primary production using CHOPS and from water communication promoted by waterfloods.

Some of these points will be discussed further in the following sections.

## **4.2. Existing Built Infrastructure and Established Operators**

The Lloydminster area is home today to an active heavy oil sector. A large number of wells have been drilled including associated service roads. Central processing facilities for oil, water and sand dot the landscape as well as a web of pipelines connecting them to markets. There is local availability of experienced service companies and skilled workers.

A new EOR technology that could utilize existing infrastructure would certainly offer lower costs than a technology requiring investment in brand-new assets. Therefore the design of the new technology should seek to utilize existing wells, surface facilities and pipelines.

Between 5 and 10 major oil companies are active in the region. It is anecdotally reported that cooperative technology development has increased in recent years and that the level of collaboration exceeds that of past decades. Companies familiar with Lloydminster understand that the end is in sight, within one or two decades, for the profitable application of existing primary and secondary recovery technologies. Currently, maintaining annual oil production rates necessitates the drilling of new wells. Obviously, the regional extent of the Lloydminster deposit is limited and eventually, companies will simply run out of new drilling locations. A change in strategy from developing new lands and in-fill drilling to increased recovery from existing lands through the application of new technologies is required.

This understanding is starting to sink in and, in recent years, a number of Joint Industry Projects have appeared. Examples include:

- The JIVE project in Saskatchewan which is piloting the application of solvent injection technologies in shallow and thin Lloydminster heavy oil reservoirs (The partners in JIVE are Husky, Nexen, and CNRL);
- A multient waterflood statistical study managed by the Saskatchewan Research Council;

- A joint industry study group on the design of heavy oil and water pipelines, also managed by SRC; and,
- Discussion of an in situ combustion pilot.

### **4.3. Mobile Oil at Reservoir Conditions**

Two reasons explain the fact that Lloydminster heavy oil can flow at reservoir conditions:

- While heavy oil viscosity is high, it is not a solid at reservoir conditions as it is the case for bitumen in the oil sands; and,
- The Lloydminster unconsolidated sandstones offer relatively high permeabilities, or, in other words, less resistance to flow than other rocks that typically host petroleum deposits.

The fact that oil is mobile presents the following advantages in the design of an EOR process:

- Primary production is possible and indeed practiced. It is primary production that provided the justification for building the existing infrastructure in the region.
- When primary production is done using CHOPS, a substantial amount of sand is co-produced with heavy oil. High permeability areas and channels are created in the reservoir. The design of the EOR technology should seek to take advantage of the presence of these high permeability conduits either to distribute injectants or access oil in previously bypassed zones.
- Displacement to EOR processes can be considered. The success of waterfloods proves this point. If water is able to displace heavy oil toward producing wells, injectants that reduce oil viscosity such as steam, hot gases and solvents could also be technically successful. The issues are likely to be costs and economics.

### **4.4. Higher Value Oil**

Heavy oil is more valuable than bitumen because of its inherent properties but also because it generally can be pipelined to markets without diluent. It is also less vulnerable than bitumen to the heavy oil price differential. This higher value of heavy oil as compared to bitumen should imply that developments in Lloydminster should be able to attract an equivalent, if not incrementally higher, level of investment than what is currently being directed at the oil sands.

### **4.5. Thin Reservoirs**

From a recovery engineering point of view, the fact that most Lloydminster reservoirs are relatively thin means that gravity drainage processes will have limited effectiveness. A thin pay results in a short vertical head and a limited opportunity for gravity drainage. Recovery processes that principally rely on gravity drainage, for example SAGD and classic VAPEX, are therefore unsuitable for most Lloydminster reservoirs. In addition, gravity drainage is usually a mechanism that contributes to the overall production drive of other recovery processes. The fact that gravity drainage is of little significance would also reduce the efficiency of other recovery processes. Therefore, recovery processes that are designed to generate horizontal drive mechanisms should be favoured.

However, the more significant consequence is that thin pay reservoirs cannot support a high capital costs. The drainage volume of a well is generally determined by vertical and aerial parameters. With a given well spacing, wells completed in thin deposits will drain a smaller volume than in thick deposits. A smaller drainage volume generally implies a smaller total production and a shorter economic life for the well and associated surface facilities. Therefore, recovery processes that offer low capital and operating costs would be preferable, particularly if the capital assets are not permanently fixed but able to be transported and shared between multiple well locations.

Therefore any EOR process for Lloydminster would need to favour low capital cost approaches, avoid site-specific engineering and be focused on standard design portable or transportable assets. In other words, thin pay reservoirs will not support a large investment in fixed capital assets.

#### **4.6. Unfavourable Mobility Ratio**

Any injectant used to displace oil, whether water or gas, would be more mobile than high viscosity heavy oil. Approaches that would reduce the viscosity of heavy oil, such as the addition of thermal energy or of a solvent, would have a favourable impact. Heating heavy oil is a more practical approach to reducing its viscosity than adding a solvent. This is because heating occurs as a result of convection or conduction which is a faster process than the mass transfer or diffusion of solvent molecules into heavy oil. In addition, the extent of viscosity reductions that can be achieved by thermal means is greater than what can be achieved with solvents.

#### **4.7. Low Reservoir Pressures**

The original reservoir pressures are generally low because of the relatively shallow depths of the formations. This, in part, explains the relatively low recovery factors obtained by primary recovery. The original reservoir energy is rapidly depleted. Pressure maintenance strategies such as waterfloods become quickly useful to maintain production. However, waterfloods are only applicable to reservoirs without wormholes. EOR approaches must be designed to impart new energy inside the reservoir.

Production decline from CHOPS is directly related to continuously declining reservoir pressure. The solution gas drive declines when less solution gas is made available to the producing fronts. There may be significant un-accessed reservoir volumes where solution gas levels maybe near original values. Should this be the case, the obvious goal of an EOR process would be to establish pathways into these previously bypassed zones. Another possibility is that the entire reservoir has been mostly depleted of solution gas. In this case, the EOR process may need to inject a gas such as CO<sub>2</sub> or methane in order to re-establish a solution gas drive on a drive or cyclical basis.

Reservoir fracture pressures are also relatively low. This limits the pressure at which injectants such as steam, CO<sub>2</sub> or flue gas can be injected into the formation. Lower injection pressures will also mean lower injection rates which will reduce economic returns. Cyclic processes that in part rely on a pressure cycle to recover oil during a blowdown phase will also be penalized.

#### **4.8. Poor Sweep Efficiency during Cold Production**

When producing a reservoir with CHOPS, a large quantity of sand is produced. It is inferred that high permeability zones or wormholes are created. The location and distribution of these zones are not known with precision. This situation will present challenges for infill drilling and for any EOR process that relies on the injection of fluids for stimulation. It is likely that oil has already been recovered by CHOPS from the high permeability zones and their immediate surrounding areas. If injected fluids follow these high permeability zones they are likely to stimulate areas that have already been depleted of oil and bypass unswept zones. Therefore, it is likely that an optimal EOR process should attempt to collapse or block high permeability channels in order to direct injectants to previously bypassed zones.

CHOPS, has likely resulted in a dual porosity reservoir with a small volume of high permeability channels with relatively low oil saturation and a relatively large volume of undisturbed sandstone with oil saturation near original values. One unfortunate aspect of the high permeability channels is that they provide very rapid inter-well communication. This means that any injectant in a displacement drive configuration (waterflood, chemical floods, steam flood or gas displacement) would be channelled immediately from injection well to producing well. For a displacement process to be successful, the pre-existing high permeability channels would need to be collapsed or blocked. However, even if this was achieved, displacement processes are notably inefficient for heavy oil.

Major reservoir heterogeneities such as shale layers, clay zones, gas caps and water zones have a major impact on the ability of any recovery process to uniformly sweep through the reservoir. These issues are understood and are generally dealt with by judicious well placement and use of conformance technologies. However, even in clean unconsolidated sandstone layers, CHOPS does not result in a uniform recovery of reservoir volumes. High permeability zones and wormholes are created in specific places and oil is likely preferentially recovered from these places.

It would be useful to understand why wormholes occur here and not there. It would also be useful to control their location and growth. However, these may not be the key issues. Significantly increasing recovery using CHOPS would likely require ways to increase the absolute number and spatial density of wormholes. In other words, methods are required to continuously start new channels and wormholes accessing new unswept zones.

### **5. Prospects for Enhanced Recovery**

Increasing recovery after the exhaustion of primary and secondary technologies requires the application of tertiary recovery techniques also referred to as Enhanced Oil Recovery (EOR).

Oil recovery processes are generally classified as primary, secondary or tertiary. Primary recovery does not involve stimulation of the reservoir. Oil is produced either from natural flow or using artificial lift. Secondary recovery refers to pressure maintenance methods where water or gas is injected in order to maintain pressure in the

reservoir. Waterflooding, where water is injected to displace oil toward producing wells is considered a secondary recovery process.

Other oil recovery methods generally qualify as tertiary recovery or Enhanced Oil Recovery (EOR). They include the following:

- Thermal methods, such as SAGD, CSS, steamflood, in situ combustion, THAI, hot waterfloods, electromagnetic heating, etc;
- Gas and solvent injection, whether miscible or immiscible, including gases such as light hydrocarbons, CO<sub>2</sub>, nitrogen and flue gas., and including solvent processes such as VAPEX;
- Chemical injection, such as polymer, alkali and surfactant floods, and foam;
- Others, such as microbial or biological processes.

Steam injection is of course applied commercially to in situ oil sands as the first recovery method because conventional primary and secondary recovery technologies are not suitable for bitumen.

With the exception of oil sands, the extent of application of tertiary recovery technologies in the WCSB is limited. A small number of conventional oil CO<sub>2</sub> and acid gas EOR projects are currently commercial or under demonstration with a great deal of attention focused on the Weyburn and Midale CO<sub>2</sub> EOR projects in Saskatchewan which will result in the incremental production of 20.6 million m<sup>3</sup> of crude oil (130 million barrels) while permanently storing approximately 20 million tonnes of CO<sub>2</sub>.

Steam processes were trialed in thick Lloydminster channel sands. Due to the relatively shallow depth of these formations, steam often had to be injected at pressures exceeding the formation fracture pressure in order to achieve acceptable steam injection and heat transfer rates. Unfortunately, this resulted in rapid steam channelling to neighbouring wells. In thin formations thermal processes are considered uneconomic because they penalized by significant heat losses to the over and under burden. Anecdotal information is also reported about steam injection trials in reservoirs produced by CHOPS with results that apparently did not justify the continuation of the work.

Thin Lloydminster reservoirs do not offer enough vertical height for effective gravity drainage. Technologies that rely on gravity drainage as the primary drive mechanism, such as SAGD and classic VAPEX would not be effective.

However, as compared to bitumen found in Athabasca, heavy oil in Lloydminster is mobile at reservoir conditions. This fact combined with the relatively high permeability of the unconsolidated sand formations should form the foundation of a successful EOR process.

Within this scope there are numerous technology directions and opportunities. Some have already been taken up by others. Examples include major technology programs for in situ oil sands in Athabasca such as THAI and electric heating. The learnings could be ported to Lloydminster heavy oil. Furthermore, solvent injection technologies are being piloted by the Joint Implementation of Vapour Extraction (JIVE) project in Saskatchewan. In situ combustion approaches are being discussed by some companies. The purpose of this study is not to repeat valuable developments done elsewhere. In particular,

vapour extraction and in situ combustion (air injection) are not addressed in this work to avoid duplications of initiatives already underway.

As indicated earlier, one of the outcomes of the Low Carbon Futures project was the identification of the potential for a novel low GHG recovery technology for heavy oil based on CO<sub>2</sub> or flue gas injection with or without steam. This provided an opportunity and a launching point for a relevant project that would fill a gap. The focus of this study can therefore be described as the scoping of an EOR method that would be economic, environmentally appropriate and based on CO<sub>2</sub> or flue gas injection with or without steam. The goal is to increase the ultimate recovery factor for heavy oil while minimizing environmental impact on GHG, water, air and land.

Two general situations exist with respect to EOR opportunities in Lloyminster:

- **Post-CHOPS EOR:** Most of Lloyminster production volumes come from CHOPS which will leave approximately 90% of original oil in place in significantly altered reservoirs (wormholes and low solution gas) at the end of the current commercial cycle.
- **Post-Waterflood EOR:** Non-CHOPS reservoirs are produced by cold production without sand followed by waterflooding. Here again, significant heavy oil volumes will be left behind in reservoirs containing important quantities of water.

Each situation brings its own different set of challenges for an EOR technology and will be discussed in more details in the following sections.

## **5.1. Post-CHOPS EOR**

A heavy oil field that has been produced using CHOPS to the extent that the production drive has declined to the economic limit still contains approximately 90% of the original oil in place. It is likely that a significant fraction of the oil that was produced came from high permeability zones that represent a small volume fraction of the total reservoir volume. It is also likely that the remaining oil is held in zones that were mostly bypassed by CHOPS. An attractive concept to increase oil recovery from such a field would be to find a way to access unswept zones using the existing CHOPS wells. This would minimize capital investment, reduce environmental impact and benefit from high process efficiencies that come from accessing zones with high oil saturation.

### **5.1.1. Workover Concept**

One approach could be a workover methodology that could effectively erase existing wormholes near the wellbore and allow progressive cavity pumps (PCP) to initiate new wormholes upon restart. Thermal or solvent treatments have been shown to collapse wormholes. For example, the injection of steam may disrupt existing wormholes. Thermal energy could collapse wormholes by heating the oil and reducing its ability to provide structural stability to wormholes. Portable steam generators could be used for the workover of cold production wells.

Steam injection test conducted two decades ago at Amoco Clearwater into a wormholed CHOPS reservoir showed temperature communication within one day in a nearby observation well. However, soon after, the temperature in the observation well started to

decrease while the pressure in the injection well increased dramatically. It appeared that the permeability channel that initially allowed steam to communicate had collapsed. Steam was no longer able to flow along into high permeability channels and injection pressure increased. The temperature observation well was now isolated from the steam flow and its temperature decreased.

The oil rate tends to decline over time in part because of near wellbore zone blockage by asphaltenes and resinous substances. The injection of steam could be an efficient method for production improvement by blowing out asphaltenes and resins from the near wellbore area deeper into the reservoir essentially cleaning the rock matrix in the near wellbore area and restoring its original permeability.

### **5.1.2. Cyclic Process Concept**

The concept of a workover could be expanded into a cyclic process. Cyclic injection in a wormholed heavy oil reservoir of flue gas, with or without low-quality steam, would seem to address the challenges noted above.

The presence of pre-existing high permeability channels in the reservoir would preclude the choice of a drive configuration and almost mandate the selection of a cyclic process. In a cyclic process, the injected gas and steam mixture would preferentially flow through highly permeable channels and saturate them. Some channels would collapse under thermal effects but some may remain useable. Pressure is maintained during the soak time. Under the influence of the pressure gradient, water and gas flow from the high permeability channels into the bypassed lower permeability zones. This allows pressure and temperature to move toward equilibrium and reduces oil viscosity in the bypassed zones. During the production phase, the oil rate is increased because of the reduced oil viscosity and because of the back pressure provided by non-condensable nitrogen gas.

The most important benefit of flue gas is the contribution of thermal energy to the reservoir, thereby reducing oil viscosity. The presence of low-quality steam with flue gas would increase the amount of energy injected into the reservoir. While injecting 100% high quality steam would be technically more efficient, it is likely to be uneconomic because of the high fixed capital costs incurred for the production of high quality steam. By contrast, portable devices could be designed to produce flue gas and low-quality steam with minimal water treatment. The important requirement is low cost steam, which is likely to mean low quality steam.

The presence of water in low-quality steam would dilute the acidity from the presence of CO<sub>2</sub> in flue gas and may mitigate corrosion concerns. Low-quality steam would also reduce steam temperature and mitigate concerns about injecting steam into existing CHOPS wells that were not thermally completed. In the reservoir, steam condenses into hot water as it delivers its energy to the reservoir. The presence of water would reduce the mobility of flue gas in a way that is analogous to the Water Alternating Gas (WAG) process. The presence of CO<sub>2</sub> in the injectant stream would have a small but favourable solvent effect.

Cycling between injection and production may also disrupt wormholes by the effect of the pressure cycle. During the injection phase, CO<sub>2</sub> penetrates and dissolves into the

oil. During the production phase, pressure is substantially reduced causing CO<sub>2</sub> to evolve from the oil as gas bubbles. The presence of bubbles in the oil phase creates the equivalent of a solution gas drive and may apply localized pressure on sand grains to destabilize the unconsolidated sand formation allowing oil and sand to flow.

Injected gases (steam, flue gas, or solution gas) would likely penetrate the formation differently than wormholes, likely towards the top of the formation, and could access unswept zones. Low-quality steam with non-condensable gases could be useful here as well. Non-condensable gases establish paths into the formation by viscous fingering, assuming that many existing wormholes have collapsed. These new paths are likely into the top of the reservoir because gas tends to rise. The point is that they would access different zones than CHOPS. Steam would contribute thermal energy to collapse pre-existing wormholes and follow the new paths created by non-condensable gases. As steam condenses into hot water, production could be from hot water entraining oil and sand as a result of the drawing action of the PCP during the production phase of the cycle.

One of the features of a cyclic injection process is that compressibility of the reservoir causes the reservoir to inflate during the injection step. During the production step, this same compressibility allows the reservoir to deflate and the pressure exerted by the overburden squeezes some oil out of rock pores.

A cyclic process would need to be considered on a field basis. The presence of pre-existing high permeability channels would allow high injectivity and rapidly distribute injectants into the reservoir as long as all wells are injecting simultaneously. When switching to the production phase, the high permeability channels now act as conduits for producing oil. In addition, the cycling of pressure and the reversal of fluid movement in the reservoir may disrupt and cause blockage of previously swept zones, thereby forcing fluids into unswept zones. It would be necessary for this latter effect to happen because the cyclic process would otherwise be sweeping and re-sweeping zones previously swept by CHOPS and could be limited to recovering marginal amounts of oil.

Simultaneous injection by all existing CHOPS well in an oil field would provide thermal energy and pressure to the reservoir. Heat may destabilize existing wormholes and create the opportunity for injectant to be forced into unswept zones. The switch from injection to production on a field basis would create a rapid decrease in pressure causing release of any dissolved CO<sub>2</sub> and solution gas exposed to this pressure swing. This could create some reestablishment of a solution gas drive. The reversal of flow movement in the reservoir would further destabilize the interface between high permeability zones and undisturbed sandstone. Injected low-quality steam becomes hot water in the reservoir which is produced during the production phase and which entrains with it any oil or sand that was destabilized. Simultaneous injection and production on a field basis has the benefit of utilizing wormholes, including disrupted wormholes, in a productive way, as paths for injectant and as conduits for oil production.

The cyclical nature of the process also mitigates concerns that may arise about the accumulation of scale in tubulars and possible plugging of the rock matrix by minerals present in the injected water. The reversal of flow from injection to production effectively back washes the well. This feature along with the choice of low-quality steam would



allow the use of relatively untreated water for steam production, thereby avoiding the use of freshwater and reducing water treatment costs. Injected heat is retained by the reservoir matrix and the repetition of cycles increases overall reservoir temperature which in turn further reduces oil viscosity on a reservoir basis.

The injection of CO<sub>2</sub> or flue gas may create an effect similar to that of an alkali flood. CO<sub>2</sub> is known to reduce interfacial tension and may assist in the formation of oil and water emulsions. These emulsions may inhibit the free-flowing of water in high permeability channels by creating local blockages, thereby improving sweep efficiency. Similarly, a non-condensable gas (for example nitrogen) may also create local gas blocking and force injected steam and condensate into unswept zones. While the cost of injecting pure CO<sub>2</sub> is obviously high because CO<sub>2</sub> needs to be acquired, treated and transported to the well site, the cost of injecting flue gas or flue gas with low-quality steam would be lower and may be acceptable.

A key uncertainty is the level of oil saturation in wormholes. On the one hand, oil saturation could be low because the original oil in place has been produced from high permeability zones. On the other hand, wormholes could be full of oil drained from other reservoir zones and in the process of being transported to the producing well. The decline of the solution drive has slowed down the flow rate of oil in the wormholes. Under this hypothesis, wormholes are full of oil, but oil moving at a rate too slow to be economic.

## **5.2. *Post-Waterflood EOR***

The mobility ratio is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluids. High mobility ratios result in unfavourable displacement efficiency because the mobility of the displacing fluid is greater than that of the displaced fluid. Most of the energy is utilized for moving the more mobile displacing fluid and little energy is utilized in moving the displaced fluid. In the case of a heavy oil waterflood, this means that most of the energy is spent re-circulating water in and out the reservoir while a relatively small fraction of the energy is spent producing oil.

Generically, there are two approaches to improving the mobility ratio. The first approach is to increase the viscosity of the displacing fluid. This is done with polymer floods where polymer molecules are added to water in order to increase the viscosity of water. In general, increasing the viscosity of the displacing fluid, while it improves the mobility ratio, result in higher energy consumption because more energy is required to inject and pump the higher viscosity displacing fluid. The second approach is to reduce the viscosity of the displaced fluid. For heavy oil production this is generally done by reducing oil viscosity through the addition of heat or the addition of a solvent. Less energy is expended for the displacement process. However the thermal or chemical energy spent to reduce oil viscosity must be added to the total energy balance.

With heavy oil, waterfloods appear to provide an efficient displacement drive during the initial stage of the process. Before the occurrence of water breakthrough between injector well and producing well, the water slug displaces oil towards the producing well. After breakthrough, pressure is significantly reduced because water has an open channel between injector well and producing well. Nevertheless, a small quantity of oil is

evacuated from unswept rock pores by water inhibition and dragged by the water flow to the producing well. High quantities of water must be injected and re-circulated after water breakthrough for producing relatively small quantities of oil at a relatively high water cuts. While this process is technically inefficient, it is still economic at current oil and electricity prices.

Adding chemicals to waterfloods in order to improve their technical efficiency is possible. Polymers can be added to water to increase water viscosity and reduce the unfavourable mobility ratio. While this may provide for a more technically efficient displacement drive, it increases energy consumption because more work needs to be expended to pump and inject higher viscosity water. In addition, higher cost considerations are not insignificant. Polymer additives may be expensive and injected water needs to be treated. Alkalis and surfactants can also be added to injected water in order to reduce interfacial tension which would reduce final oil saturation in swept zones and which could create emulsions and improve sweep efficiency. The same cost considerations apply to alkalis and surfactants which must be purchased and transported, and require water treatment.

In general, chemical floods are less economically attractive for heavy oil than for light oil. With heavy oil, water breakthrough occurs early and subsequently large quantities of water need to be treated, injected and re-circulated. Large volumes of injected water also imply relatively large volumes of expensive chemical additives to maintain the required concentration. The cost of adding chemical additives (the cost of chemicals and water treatment) is directly proportional to the water cut. On the other hand, oil production and economic revenues are proportional to the inverse of the water cut. Therefore, the high water cuts experienced with heavy oil doubly reduces the economics of chemical floods.

Instead of improving the mobility ratio by adding chemicals to injected water, the mobility of the oil phase could be increased by reducing its viscosity. Thermal energy and solvents are common approaches to reduce oil viscosity. Flue gas with or without low-quality steam could be a low-cost injectant that offers both thermal and solvent effects. Thermal energy from flue gas and steam heat the oil formation and reduce oil viscosity. CO<sub>2</sub> contained in flue gas dissolves in heavy oil and also reduces its viscosity.

In a reservoir under waterflood, flue gas and low-quality steam could be injected in an alternating manner with flood water. Flue gas and steam provide heat and solvent to the oil formation while water slugs slow down injected gas and avoid premature gas breakthrough. It is possible that the non-condensable gas in flue gas (nitrogen) will create new channels in the reservoir by the action of viscous fingering. This may allow chase water to enter previously bypassed zones. CO<sub>2</sub> is also known to reduce the interfacial tension between oil and water. This mild surfactant effect may cause emulsions with nitrogen and block existing water channels. This could force chase water into new reservoir zones and improved sweep efficiency.

One possible downside of waterfloods is that they may damage the reservoir for future steam stimulation. Waterfloods increase the amount of cold water contained in the reservoir which will then increase the amount of steam required in a follow-up EOR process, possibly making it uneconomic.

## 6. Review of Thermal Processes

Thermal and solvent effects are likely to take center stage in the design of a novel EOR process for Lloydminster heavy oil after the economic limit of current primary and secondary recovery. Adding thermal energy to the reservoir would reduce oil viscosity and increase its mobility. The same is true of the addition of solvents such as propane, other hydrocarbons and CO<sub>2</sub> which dilute heavy oil and also reduce its viscosity. In addition, the release of dissolved gaseous solvents during a blowdown phase may create a solution gas drive which would move sand and fluids to the producing well.

In the next sections, thermal and solvent technologies that may be applicable to Lloydminster heavy oil will be reviewed in order to extract information that may be relevant to the design of a new EOR process for Lloydminster heavy oil based on flue gas injection, with or without low quality steam.

In past decades, some of these technologies were tried in Lloydminster but with uneven success. It is important to learn the lessons from these trials. More recently, the development of a new recovery process based on propane and other solvents is being developed and piloted by the JIVE project in Saskatchewan under the leadership of the Petroleum Technology Research Center. The purpose of this review is not to document the history of technology development in Lloydminster but to learn from experiences in the region and elsewhere technical information that would guide the development of a novel process based on flue gas injection with or without low-quality steam.

### 6.1. *Cyclic Steam Stimulation*

#### 6.1.1. Overview

The Cyclic Steam Stimulation (CSS) process is a three-step process that is generally repeated for a number of cycles. The first step involves injection of steam at relatively high pressure into a heavy oil formation deep enough to accept high pressure steam. During the initial cycles, steam is generally injected at pressures above the formation parting pressure to increase the speed at which the formation is heated and to reach large volumes of the reservoir. Steam injection may last for two to four weeks. The second step is a soak period during which the well is shut-in for a few days to allow the transfer of heat to the cold zones of the formation. During the third step, the well is put back into production, generally with a significant increase in the oil production rate. The oil rate declines with time but the production step may last from several weeks to several months. Once the oil rate has declined to a set criterion, the steam stimulation cycle is repeated.

The oil recovery mechanisms that occur during CSS are several and the interaction between them complex. The primary mechanism is the addition of heat to the formation by steam injection which lowers the viscosity of heavy oil and enhances its mobility. High pressure steam dilates the formation which then compacts during the production step providing a mechanism for expulsion of oil towards the producing well. The blowdown of steam towards the producing well is also responsible for entraining some of

the oil with it. Gravity drainage and solution gas drives are also thought to play a role. Because steam is injected at relatively high pressures, CSS is less susceptible than other thermal processes to permeability variations and other reservoir heterogeneities (Farouq Ali 1974).

### **6.1.2. Pikes Peak**

Steam processes were commercially implemented in the Lloydminster region in thicker reservoirs. The success of CSS and steam drive at Pikes Peak in Saskatchewan is well known (Miller, Stevens et al. 1991; Miller and Steiger 1999). CSS was applied first and resulted in the recovery of 20% of the original oil in place. Inter-well communication was observed but the cyclic nature of the process was thought to have altered or dissipated some of the communication paths.

Patterns within the field were then converted to a steam drive process. A non uniform steam front was found to have developed with ample communication with some wells in the patterns and almost no communication with others. This uneven aerial sweep efficiency was attributed to the pressure regime that had been established in the reservoir by CSS. Vertical conformance was evaluated by the drilling of a core hole after eight month of steam drive.

Core analysis indicated that oil saturation had been reduced to 12% in the top 9 m of the formation, but that the bottom 11 m still exhibited in oil saturation of 72%. Significant steam override through the top of the formation was still occurring despite the prior heating of the reservoir by CSS. It is possible that the steam drive process swept previously bypassed zone at the top of the formation, thereby improving overall oil recovery. At the field level, the steam drive process accounted for 30 to 40% of daily oil production.

The performance of CSS at Pikes Peak is described as excellent with recoveries of up to 40% of original oil in place and early cycle Steam to Oil Ratio (SOR) between 1 and 3. Following conversion to a steam drive process, ultimate recoveries approaching 70% are thought to be possible.

## **6.2. Steam Floods**

Steam floods are generally not effective for heavy oil as an initial process or immediately after cold production or water flooding. The low mobility of heavy oil at reservoir temperature means that steam cannot be injected at significant rates without fracturing the formation which means disperse steam far away from the pattern or even cause a breach into a water zone. This would reduce the effectiveness of the process (Hong 1999).

However, as mentioned above, at Pikes Peak in Saskatchewan, a steam flood was found to be successful after CSS because the CSS process had effectively heated the remaining heavy oil and improve its mobility.

Most Lloydminster reservoirs are too thin for the effective application of the CSS and steam flood processes.

## **6.3. Steam Assisted Gravity Drainage**

### **6.3.1. Overview**

Steam Assisted Gravity Drainage (SAGD) is a thermal in situ heavy oil and bitumen recovery process. The concept was introduced by Roger Butler in the late 1970s at the University of Calgary. It was further developed, piloted and demonstrated by AOSTRA at its Underground Tests Facility (UTF) in Athabasca. The SAGD process is schematically represented in Figure 1.

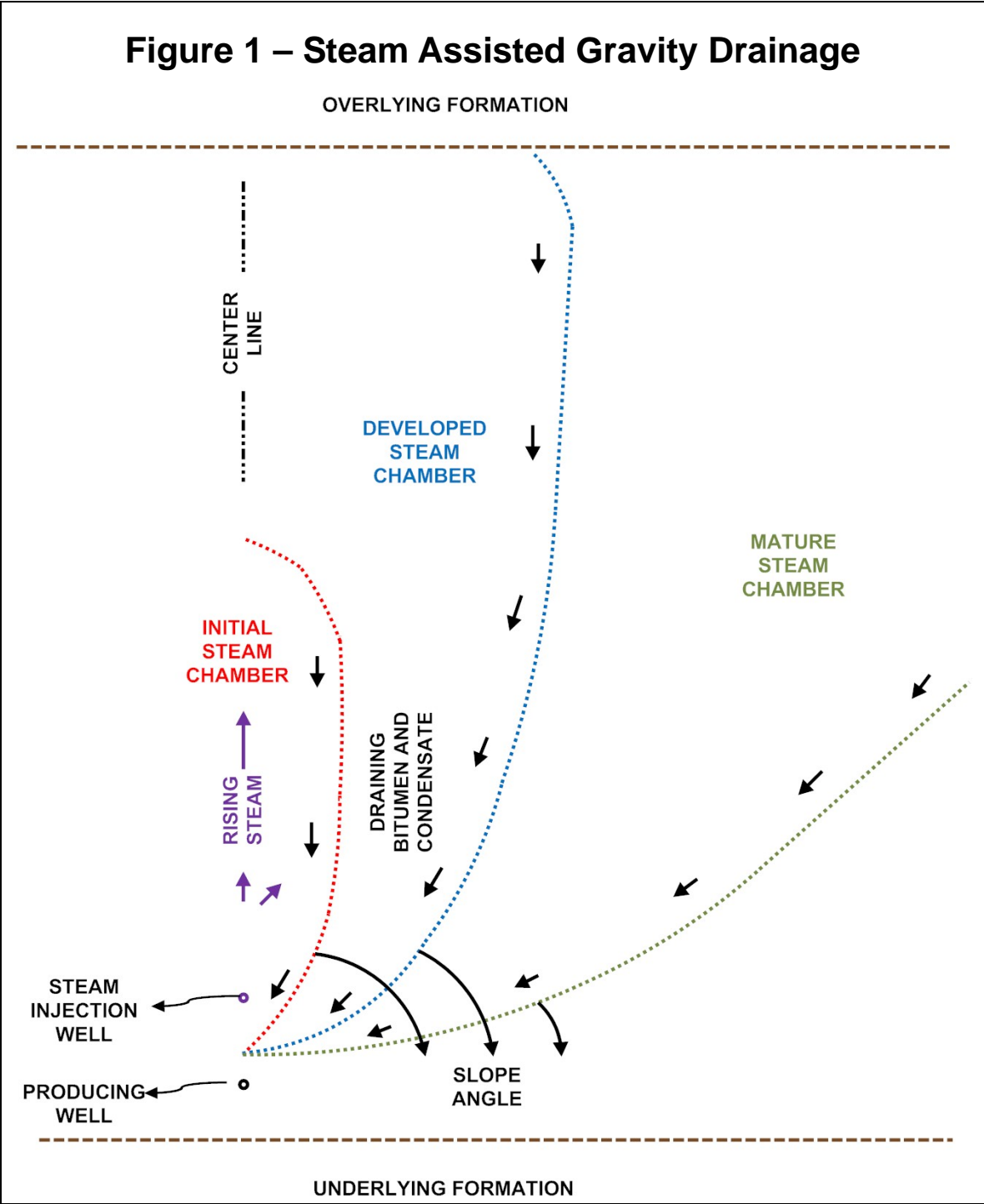
In SAGD, two horizontal wells are drilled parallel and vertically aligned, and operated as a well pair. Typical well length is 800 m, varying from 500 to 1000 m depending on reservoir characteristics and project planning considerations. Lateral spacing between well pair is typically 80 m but can range from 70 to 150 m. Increased reservoir heterogeneity dictates shorter spacing distances. The vertical distance between the two wells varies between 3 and 7 m with a target of 5 m. The bottom well is typically located 1 to 5 m from the bottom of the bitumen saturated zone but this distance is usually determined by the presence and thickness of water zones underneath the bitumen formation.

During the start up period, 100% quality steam is injected and circulated into both horizontal wells at a pressure which will depend on the depth of the formation but can be in the order of 4,500 kPa. This steam soak period that can take from six weeks to several months. During this time, steam is injected and circulated into both horizontal wells in order to heat the reservoir volume between the wells. The purpose is to soften bitumen in the vertical distance between the two wells, making it mobile enough to flow down to the bottom well. Once communication is established, steam injection into the bottom well is stopped and the function of this well is switched to bitumen production.

A steam trap control approach is used to prevent live steam from flowing downward and being produced by the lower horizontal well. The production rate is set to control the bottom hole pressure to a level generally equal to the steam saturation pressure corresponding to a temperature 5° C. higher than produced water. This ensures that only steam condensate is produced.

While actual experience will vary depending on depth and geological considerations, it is generally expected that the steam chamber will rise to the top of the formation in approximately one year after which time the steam chamber spreads horizontally. In the steam chamber, steam rises and is met by the descending counter current flow of steam condensate and oil which are falling to the bottom of the chamber where the lower horizontal well will produce them to the surface. The lateral expansion of the steam chamber will last most of the 8 to 10 year useful life of a SAGD well pair. During this period, oil and condensate drain along the slope of the steam chamber. As a steam chamber widens, the slope angle decreases and the oil production rate declines.

The SAGD production phase is expected to recover 50% of in-place bitumen. At the end of the production phase, a blowdown phase may increase total recovery to approximately 65%.



### 6.3.2. SAGD in Thin Formations

Using data from an in-house database containing information about several Canadian SAGD projects, Norwest conducted a number of numerical reservoir simulations to

identify reservoir properties that may affect the success of SAGD projects (Manrique and Pereira 2007). The exercise determined that in Athabasca, reservoir properties such as net pay thickness, top water and top gas are highly variable and more likely to affect the project's outcome. By contrast, conventional reservoir parameters such as porosity, permeability, depth, pressure and temperature had less influence. The work also explored the impact of reservoir thickness on ultimate recovery. Reservoirs 50 m thick and 30 m thick could be expected to have recovery factors 60% and 80% higher than a 15 m thick reservoir. SAGD being a vertical, gravity driven process, it should not be expected to perform well in thin reservoirs such as most of those encountered in the Lloydminster region.

A conceptual variation on SAGD has been proposed and named Cross-SAGD (XSAGD) (Stalder 2005). In this concept, the injection wells are perpendicular to the producing wells. This approach is of course only applicable on a field basis, for example, 8 injection wells at right angle to 8 producing wells. The purpose of this design is to induce lateral expansion of the steam chamber at an earlier stage. The fact that injectors and producers are offset forces steam to move horizontally as well as vertically. Numerical simulations indicated that XSAGD offered advantages over SAGD in thin formations where low formation heights limit the extent of vertical gravity drainage. In XSAGD, the lateral drive component compensates for the weak vertical head. In 30 m pay and at a pressure of 1,500 kPa, XSAGD reached 70% recovery after 10 years as compared to 15 years for SAGD. This resulted in a relative economic advantage for XSAGD. When conducting the simulations in 15 m pay, the economic advantage of XSAGD increased further (Stalder 2007).

Another interesting variation on SAGD is the concept of Bottom Up Solvent Aided Process (SAP) which involves spacing injection and production wells laterally as opposed to vertically (Gupta and Gittins 2007). The purpose is to promote lateral growth of the steam chamber. Injected steam will naturally rise but also be drawn laterally by the pressure gradient between injector and producer wells.

#### **6.4. Carbon Dioxide and Steam**

The performance of mixtures of steam with carbon dioxide and/or non condensable gases has received attention. Most of the effort has been on gaseous additives to steam that could improve the performance of steam processes such as CSS, steam flood and SAGD.

Laboratory studies on the addition of CO<sub>2</sub> to steam have been reviewed previously (Hornbrook, Dehghani et al. 1991):

- Adding CO<sub>2</sub> and ethane to steam was found to improve the recovery of Athabasca oil sands as compared to other additives. The improved recovery was attributed to improved sweep efficiency, solution gas drive, oil phase swelling and viscosity reduction (Redford 1982).
- Co-injection of CO<sub>2</sub> and steam was found to increase the ultimate recovery of Athabasca oil sands (Stone and Malcolm 1985).

- The simultaneous injection of nitrogen and CO<sub>2</sub> gases with steam resulted in a significant improvement in the ultimate recovery of crude oil in a steam flooding experiment (Harding, Farouq Ali et al. 1983).
- The addition of CO<sub>2</sub> to steam in a cyclic stimulation process improved recovery by providing additional drive energy during the final depletion cycles (Briggs, Redford et al. 1982).
- Co-injection of CO<sub>2</sub> and steam into heavy oil depleted of its solution gas improved recovery as compared to steam alone. However co-injection of CO<sub>2</sub> did not increase recovery of heavy oil saturated with methane (Frauenfeld, Ridley et al. 1988).

Test conducted at the Alberta Research Council indicated that the addition of CO<sub>2</sub> to steam accelerated production during the early stage of the recovery process. However, this effect tapered off and ultimate production rate and recovery were similar to steam alone (Singh, Malcolm et al. 1985).

There is an optimum amount of CO<sub>2</sub> that can be added to steam as an additive. Only a finite amount of CO<sub>2</sub> will dissolve in heavy oil. After the oil has become saturated with CO<sub>2</sub>, excess CO<sub>2</sub> gas will crowd out steam in the injection well resulting in lower heat input and decreased viscosity reduction. In other words, excess CO<sub>2</sub> becomes another non condensable gas. A sand pack laboratory test using Alaska heavy oil investigated the benefits of adding CO<sub>2</sub> to steam. The addition of 20% by volume of CO<sub>2</sub> to steam was found to increase oil recovery by 15% and to reduce Steam to Oil Ratio (SOR) by 50% (Hornbrook, Dehghani et al. 1991).

PanCanadian investigated the addition of CO<sub>2</sub> and methane to steam in the CSS process (Metwally 1990). Based on laboratory evaluations and numerical simulations, it was determined that the presence of a non condensable gas improved steam injectivity but did not improve overall oil recovery in CSS or steam flood.

Injection of CO<sub>2</sub>, either with steam or as a slug prior to steam, improved steam injectivity. The author suggested that CO<sub>2</sub> displaced solution gas in the oil and that the gas liberated from the oil was likely to move ahead of the steam front, creating viscous fingers or highly saturated gas channels that would enable steam to move more easily and penetrate more deeply into the reservoir.

Injection of methane with steam was found to reduce oil recovery during the initial stage of the process. The presence of methane in the injection flow diluted steam and reduced the rate of energy injected into the reservoir because methane has a significantly lower heat capacity than steam. A lower rate of energy injection is likely to result in a lower rate of oil production.

Another study was conducted by the Alberta Research Council involving numerical simulation of the SAGD process in order to investigate the potential benefit of injecting CO<sub>2</sub> or flue gas during the wind down phase of the process (Law 2004). For classic SAGD, the simulation indicated that the oil production rate increased while the steam chamber expanded vertically because the head for gravity drainage increased. However, once the chamber reached the top of the formation, oil production started to decline because the lateral expansion of the chamber reduced the slope angle of the



lateral walls. In this simulation, the average oil production rate during the first three years was 185 m<sup>3</sup> per day. However the oil production rate in years 4, 5 and 8 were 107, 58 and 3 m<sup>3</sup> per day respectively. Even though the rate of steam injection was also reduced in the later stage of the SAGD process, the Steam to Oil Ratio (SOR) continued to increase. Eventually, production became uneconomic and was terminated.

The numerical simulation explored the injection of CO<sub>2</sub> or flue gas instead of steam during the later stage of the process, evaluating three timing options: replacement of steam by CO<sub>2</sub> or flue gas after 3 years, after 4 years or after 5 years. The switch from steam to CO<sub>2</sub> or flue gas did not affect the ability to maintain sufficient pressure inside the steam chamber. However this approach reduced the temperature of the steam chamber and decreased oil production. Earlier starts to CO<sub>2</sub> injection caused greater reductions in production and in total oil recovery because of cooling effects from injected CO<sub>2</sub> or flue gas. However, the switch to CO<sub>2</sub> or flue gas injection in year 5 resulted in only a 1% reduction in total recovery as compared to the base case of continuing steam injection for the eight-year life of the SAGD well pair. The benefit was a 20% reduction in the total amount of steam injected which resulted in lower energy and water utilization, and possibly reduced costs.

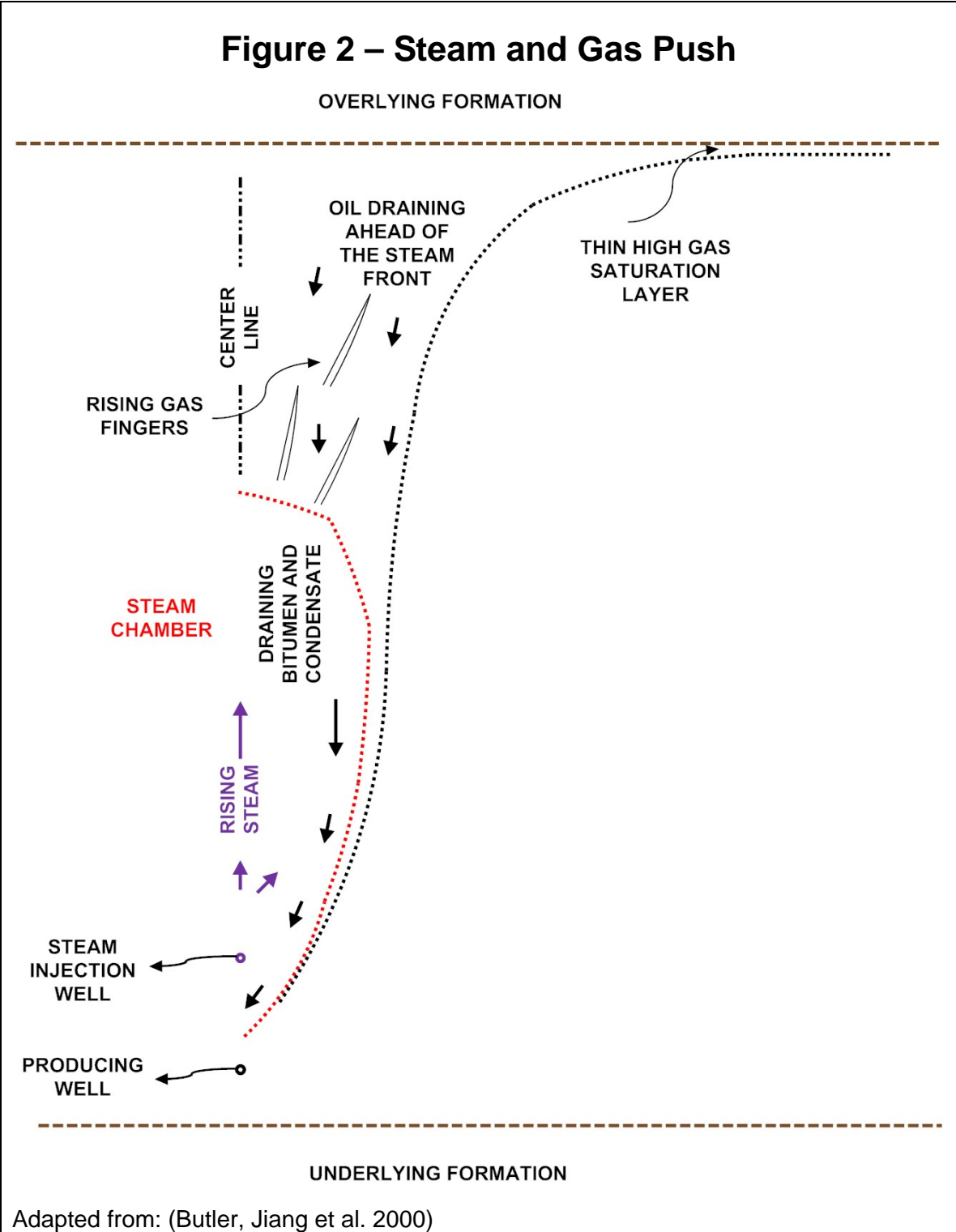
### **6.5. Non Condensable Gas and Steam**

An alternative to CO<sub>2</sub> or flue gas injection during the final years of SAGD production is injection of a Non-Condensable Gas (NCG) such as methane or solution gas. For example, EnCana in Athabasca adds NCG to curtail steam injection while maintaining pressure. The benefits are reduced steam requirements, improved energy efficiency and a lower SOR.

By contrast, adding NCG to steam during the initial stages of SAGD is thought to promote the vertical growth of the steam chamber because NCG rises more quickly than steam in the form of viscous fingers.

It is also thought that injected NCG will accumulate at the top of the steam chamber and insulate steam from the overlying shales. Injected NCG does not condense into a liquid in the steam chamber but remains as a gas which migrates by buoyancy to the top of the reservoir where it acts as an insulating layer over the steam region. Injection of NCG is thought to be particularly valuable once the vertical growth of the steam chamber has reached the top of the formation and its insulation role mitigates heat losses to the overburden.

The Steam and Gas Push (SAGP) process is similar to SAGD with the difference that a small amount of NCG such as nitrogen or methane is added to steam (Butler, Jiang et al. 2000). The principles of the SAGP process are illustrated in Figure 2.



The improved mechanisms sought from the addition of NCG are:

- NCG forms viscous fingers beyond the steam front and transport heat and carry pressure to bitumen zones yet untouched by the steam chamber;
- In SAGP, NCG accumulates as a thin layer at the top of the reservoir. This insulates steam from the overburden and reduces heat losses;
- Heating bitumen beyond the steam chamber initiates drainage and production from the zones earlier;
- Carrying pressure beyond the steam chamber reduces the pressure gradient in the reservoir. This effect can be interpreted as NCG pushing bitumen down to the producing well; and,
- NCG fills the pore space vacated by the draining oil.

In numerical modeling and physical scale experiments conducted at the University of Calgary it was determined that SAGP resulted in lower steam consumption and a lower Steam to Oil Ratio (SOR) than SAGD. For Lloydminster heavy oil, oil production rates were similar for SAGD and SAGP. However, for higher viscosity Athabasca and Cold Lake bitumen, SAGP exhibited lower production rates than SAGD.

Potential improvements to the SAGD process also include the Solvent Aided Process (SAP) which is being piloted by EnCana (Gupta, Gittins et al. 2005). SAP involves the addition of small amounts of hydrocarbon solvents, such as propane, butane or natural gas condensate, to injected steam in order to effect some measure of viscosity reduction and reduce the amount of steam injection. However, the improved SOR is obtained at the cost of solvent retained by the formation.

Air was added to steam in a CSS pilot in the Edison field near Bakersfield California. The production rate was higher than with conventional CSS. Improvements in oil recovery were explained by an increase in reservoir energy caused by the expansion of injected gases during the depletion phase (Rintoul 1979; Meldau 1981).

## **7. Review of Solvent Processes**

### **7.1. Vapour Extraction**

The injection of gaseous solvents to recover bitumen and heavy oil was proposed by Roger Butler of the University of Calgary using a well geometry analogous to SAGD with the exception that the upper horizontal well injects a solvent as opposed to steam. This process is referred to as VAPEX.

The solvent maybe heated or unheated. It may be injected into a cold reservoir or one that was previously heated by the application of SAGD or CSS. Upon entering the reservoir, the gaseous solvent moves upward. It contacts and dissolves into the bitumen. The dilution of bitumen by the solvent reduces its viscosity and it is now able to drain downward under the influence of gravity to the lower producing horizontal well.

Many variations and hybrids have since been proposed and some are being piloted at the JIVE and DOVAP projects. Solvents and solvent mixtures that have been tested include ethane, propane, butane with gases such as methane and CO<sub>2</sub>. Alternatives to

"classic" VAPEX geometry include laterally offsetting the injection and production wells, and single well cyclic designs.

A laboratory evaluation, simulation and economic study of various approaches to solvent injection was conducted by the Alberta Research Council (Frauenfeld, Lillico et al. 1998). Laboratory tests were conducted using Burnt Lake bitumen (40,000 centipoises) and Lloydminster heavy oil. A variety of solvent mixtures and well configurations were evaluated. These experiments were followed by numerically scaling results to the field level. A molar mixture of 18% methane, 70% ethane and 12% propane gave best results for Burnt Lake bitumen. Acceptable economics were obtained for a 15 m thick reservoir with laterally offset horizontal wells and a well pair spacing of 60 m. In the case of Lloydminster reservoirs, a molar mixture of 90% ethane and 10% CO<sub>2</sub> was selected. However, a well pair process was found to be economic only for reservoir thicknesses above 15 m, which are not prevalent in Lloydminster. To minimize capital costs, a single well cyclic solvent injection process was simulated and was found economic in an 8 m thick reservoir.

The numerical study underscored the economic importance of obtaining high sustainable production rates of bitumen or heavy oil soon after start-up. Solvents that existed in the two-phase region at reservoir conditions were more aggressive and dissolved more rapidly. Solvents which precipitated asphaltenes were also thought to be helpful because the partially de-asphalted heavy oil had a lower viscosity and may be able to capture a higher market value. The most important factor in lowering solvent costs was to keep solvent inventory low, particularly by selecting solvents which would exist mostly in the gas phase at reservoir conditions. The highest cost element was the cost of the horizontal wells. Single well cyclic strategies offered an opportunity for cost reduction because only one well needs to be drilled.

One of the potential benefits of tertiary recovery processes that use solvents is that the oil produced by the process may have been partially upgraded in situ. In effect, the solvent fractionates heavy oil in situ and the lower viscosity solvent rich phase is produced leaving in the reservoir the heavier components of the original heavy oil.

Laboratory research on the VAPEX process using propane as a solvent was conducted at the University of Calgary. Results indicated that in situ heavy oil upgrading may be an outcome of the VAPEX process (Mokrys and Butler 1993). The viscosity of Lloydminster heavy oil was found to be lower by a factor as high as 50 when recovered by the VAPEX process. Pressure cycling was also investigated. It was determined that pressure cycling of propane may increase drainage rates by up to 40% as compared to steady-state operations. However, cumulative oil recovery was 10% less with pressure cycling. Pressure cycling is thought to promote mixing and the formation of asphaltenes free flow paths for the diluted bitumen.

In situ partial upgrading by solvent injection was also demonstrated by recent experiments conducted at the Petroleum Technology Research Center and the University of Regina. Heavy oil from the Lloydminster area was placed in contact with propane in a one-to-one volume ratio at 23.9° C. and rotated vigorously for five days to ensure good mixing. Experiments were conducted at pressures of 1,900 kPa, 2,900 kPa and 5,000 kPa. At these pressures, the heavy oil propane system is heterogeneous and

can be roughly divided into three different layers. The top layer is a solvent rich oil phase where propane has extracted some of the light component of the heavy oil. The middle layer is deasphalted heavy oil with dissolved solvent. Asphaltenes and other heavy components have precipitated to the bottom layer. The bottom layer is composed of heavy components and generally represents 40% of the volume. The volume percentage split between the top and the middle layer varies with pressure, with the percentage occupied by the top layer increasing with increasing pressure (Luo, Yang et al. 2007; Luo, Yang et al. 2007).

## **7.2. Carbon Dioxide Enhanced Oil Recovery**

### **7.2.1. Overview**

CO<sub>2</sub> flooding is an EOR process that was first applied in the 1930s. It appeared to reach a peak of popularity during the 1970s. It is currently a leading EOR technology for recovery of light oil. It is an established technology for increasing production from conventional crude oil fields after the decline of primary and secondary recovery mechanisms. It may recover up to 15 and 20% of the original oil in place. (Dong, Huang et al. 2000; Jeschke, Schoeling et al. 2000; Hao, Wu et al. 2004).

As shown in Table 3, in 2006, CO<sub>2</sub> flooding was the second ranked tertiary recovery technology in the United States and the third ranked in Canada.

<b>Table 3 - 2006 Tertiary Enhanced Oil Recovery Production</b>		
(barrels per day)	<b>United States</b>	<b>Canada</b>
Steam Injection (including oil sands)	286,668	278,250
CO <sub>2</sub> Injection (including acid gas)	237,118	15,770
Hydrocarbon Injection	95,800	35,914
Nitrogen Injection	14,700	
In Situ Combustion	13,260	6,250
Hot Water	1,776	
Chemical	0	
<b>Total</b>	<b>649,322</b>	<b>336,184</b>
Source: (Moritis 2006)		

In 2006, 82 CO<sub>2</sub> EOR projects were active in the United States, an increase of 11 as compared to 2004. Production from these projects was 237,118 barrels per day, an increase of 14% from 2004. CO<sub>2</sub> EOR was the second largest EOR technology

practiced in the United States after steam injection. All but two projects injected CO<sub>2</sub> under miscible conditions, targeting light or medium crude oil with API gravity ranging from 29 to 44. The remaining two projects injected CO<sub>2</sub> under immiscible conditions. One project was a 100-barrel per day pilot operated by Chaparral Energy since 1998. The more notable of the two has been operated by Kinder Morgan since 2004 at the Yates oilfield in Texas, recovering an additional 2,600 barrels per day of API 30 crude oil at a depth of approximately 400 m from a total field production of 24,200 barrels per day (Moritis 2006).

In Canada, six miscible CO<sub>2</sub> EOR projects were active in 2006 all targeting light to medium crude oil with API gravity ranging from 28 to 42. The largest was operated by EnCana at Weyburn, Saskatchewan with an incremental production of 20,000 barrels per day (from 11,000 bpd on waterflood to 32,000 bpd after CO<sub>2</sub> EOR), followed by Apache Canada at Midale, Saskatchewan producing 5,900 barrels per day. The other projects were operated by Anadarko Canada (Enchant), Devon Canada (Swan Hills), and Penn West Energy (Joffre and Pembina). In addition, Apache Canada operated a 1000-barrel per day acid gas injection EOR project at Zama-Keg River.

### **7.2.2. Miscible CO<sub>2</sub> EOR**

The vast majority of CO<sub>2</sub> floods are carried out under miscible conditions, usually in light oil reservoirs that are more than 800 m deep. These depths are required in order to be able to inject CO<sub>2</sub> above the minimum miscibility pressure. Generally, oil density must be better than 30° API for miscibility conditions to be reached even at these depths.

In Alberta and Saskatchewan, CO<sub>2</sub> EOR and acid gas EOR (CO<sub>2</sub> and H<sub>2</sub>S) are being piloted and, in some cases, commercially applied to conventional light oil. In most cases, these projects are built on the local availability of low cost CO<sub>2</sub> or acid gas. The notable exception, and the largest commercial CO<sub>2</sub> EOR project, is located in Saskatchewan where 5,000 tonnes of CO<sub>2</sub> per day are purchased from a coal gasification plant in North Dakota and delivered via a 320 km pipeline. CO<sub>2</sub> is then injected into the conventional oil carbonate formations in Weyburn and Midale.

There are good reasons to focus on CO<sub>2</sub>. It offers solvent properties that, while not as strong as propane, have measurable effects. CO<sub>2</sub> can also be less expensive than propane and, in some cases, locally available. As CO<sub>2</sub> becomes more available, possibilities will open up for using it at pressures and quantities large enough for an EOR project. Miscible CO<sub>2</sub> EOR may present an important opportunity for light and medium oil fields in Alberta and Saskatchewan.

Characteristics of miscible CO<sub>2</sub> EOR are as follows:

- Up to an additional 8 to 16% of the original oil in place can be recovered;
- Most CO<sub>2</sub> floods follow waterfloods and incremental recovery can be 20 to 30% of the cumulative primary and secondary recovery; and,
- Homogeneous light oil reservoirs at depths greater than approximately 800 m are ideal candidates for CO<sub>2</sub> miscible flooding (Jeschke, Schoeling et al. 2000).

The mechanisms of CO<sub>2</sub> EOR are reported as follows:

- Swelling of the oil phase
- Reduction of viscosity
- Reduction of interfacial tension
- Establishment of a solution gas drive, particularly during the final blowdown phase.

### 7.2.3. Immiscible CO<sub>2</sub> EOR

#### Overview

For heavy oil, the minimum miscibility pressure is much higher than reservoir fracture pressure and only immiscible CO<sub>2</sub> EOR approaches are possible. For Lloydminster heavy oil, miscibility conditions can not be reached because the oil is too heavy and the reservoirs are too shallow. Therefore, immiscible CO<sub>2</sub> EOR needs to be considered.

Miscible and immiscible CO<sub>2</sub> flooding relies on similar drive mechanisms. In general, CO<sub>2</sub> miscible flooding of light oil is driven primarily by extraction of light ends into the CO<sub>2</sub> phase and displacement of oil by the advancing CO<sub>2</sub> phase. The viscosity reduction benefit of CO<sub>2</sub> is usually not meaningful for light oil from a recovery engineering point of view because the viscosity of light oil is already close to the viscosity of water. CO<sub>2</sub> will reduce the viscosity of light oil by 20 to 40% but not by factors of up to 10 times as for heavy oil.

By contrast, immiscible CO<sub>2</sub> recovery of heavy oil relies mostly on viscosity reduction. Following are the principal recovery mechanisms for immiscible CO<sub>2</sub> EOR:

- Reduction of heavy oil viscosity;
- Swelling of oil and increasing apparent oil phase saturation in the pore space; and,
- Reduction of interfacial tension; and,
- A solution gas drive effect.

For example, the viscosity of Lloydminster heavy oil with a density of 14° API was reduced from 1,160 centipoises to 40 centipoises at room temperature by saturating it with CO<sub>2</sub> at a pressure of approximately 4,600 kPa (Mangalsingh and Jagai 1996).

The swelling of the oil phase increases its volume. Oil is always left behind by any recovery process. With CO<sub>2</sub>, this oil will be diluted with CO<sub>2</sub> and will contain less oil by mass for the same volume. Furthermore, volume expansion will force fluids out of rock pores and into the drainage flow.

CO<sub>2</sub> has been shown to reduce interfacial tension and enhance the mobility of oil. A 30% reduction of interfacial tension was obtained for heavy oil containing 50 to 100 m<sup>3</sup>/m<sup>3</sup> of CO<sub>2</sub> (Mangalsingh and Jagai 1996). This reduction of interfacial tension reduces capillary forces and final oil saturation in zones swept by the recovery process.

Solution gas drive and blowdown recovery during immiscible CO<sub>2</sub> EOR refers to the fact that some CO<sub>2</sub> dissolves into oil under the influence of injection pressure. In a drive configuration, CO<sub>2</sub> is driven by the positive pressure gradient between reservoir pressure and the lower pressure of the production well. In a cyclic approach, or at the end of an EOR project, once CO<sub>2</sub> injection is terminated and while production continues, CO<sub>2</sub> is also driven to producing wells by a positive pressure gradient. As pressure drops along

the gradient, CO<sub>2</sub> evolves as gas bubbles. Because of the extremely low mobility of gas bubbles in heavy oil, CO<sub>2</sub> entrains heavy oil with it as it is driven to the surface by the pressure gradient. Several researchers have reported that blowdown recovery following an immiscible CO<sub>2</sub> flood is a very effective mechanism that can recover significant amounts of the original oil in place.

Under immiscible conditions, CO<sub>2</sub> is typically able to increase the volume of heavy oil by 10% and reduce its viscosity by a factor of 4 to 10 (Rojas, Zhu et al. 1991). CO<sub>2</sub> may also contribute a solution gas drive effect and a reduction of interfacial tension. In addition, in carbonate formations, CO<sub>2</sub> may affect the carbonate bicarbonate equilibrium in formation waters which may result in a possible increase in pore volume and permeability.

### **CO<sub>2</sub> Solubility and Heavy Oil Viscosity**

The solubility of CO<sub>2</sub> in heavy oil is dependent on temperature and pressure. Generally CO<sub>2</sub> EOR does not involve thermal stimulation and the EOR process is conducted isothermally at reservoir temperature. Pressure is, therefore, the only variable that can be adjusted to enhance CO<sub>2</sub> EOR efficiency. CO<sub>2</sub> solubility and its uptake into heavy oil increase with increasing pressure. However, this relationship is limited by boundary conditions that are reservoir specific. Pressure should not exceed reservoir fracture pressure.

The solubility of solvent gases in heavy oil from Lloydminster and Cold Lake was measured in experiments conducted at the Alberta Research Council. Propane was found to have the highest solubility of the gases tested, followed by ethane, CO<sub>2</sub> and methane. The solubility of CO<sub>2</sub> in Lloydminster heavy oil was 0.2 mole percent at 1,179 kPa and 0.33% at 2,090 kPa. The measurements were conducted at 19°C (Frauenfeld, Kissel et al. 2002). While not as powerful a solvent as propane, CO<sub>2</sub> has a meaningful solvent potential for heavy oil.

When comparing immiscible CO<sub>2</sub> flooding with methane gas flooding, in a laboratory environment, highest recoveries were obtained from CO<sub>2</sub> flooding. The higher efficiency of immiscible CO<sub>2</sub> flooding as compared to methane was due to the fourfold reduction in oil viscosity, to a 35% swelling of the oil phase and to a delayed gas breakthrough (Mungan 1991).

CO<sub>2</sub> is more soluble in hydrocarbons as a gas than as a liquid. CO<sub>2</sub> is soluble in water to a lesser extent than in crude oil (Mangalsingh and Jagai 1996).

When CO<sub>2</sub> is made to contact heavy oil under pressure, some of the CO<sub>2</sub> dissolves into the heavy oil. However the converse is not true, which is to say that the CO<sub>2</sub> rich phase is generally found to remain to be almost pure CO<sub>2</sub> because heavy oil only contains extremely small amounts of light hydrocarbons that could be extracted into the CO<sub>2</sub> rich phase (Kokal and Sayegh 1990).

When solution gas is present in the heavy oil, CO<sub>2</sub> does not displace all of the methane (Holm and Josendal 1974). As a result, less CO<sub>2</sub> will go into solution into live oil than into dead oil. Consequently, oil phase swelling and viscosity reduction will happen to a lesser extent in oil containing solution gas. However, if the oil left behind in a reservoir



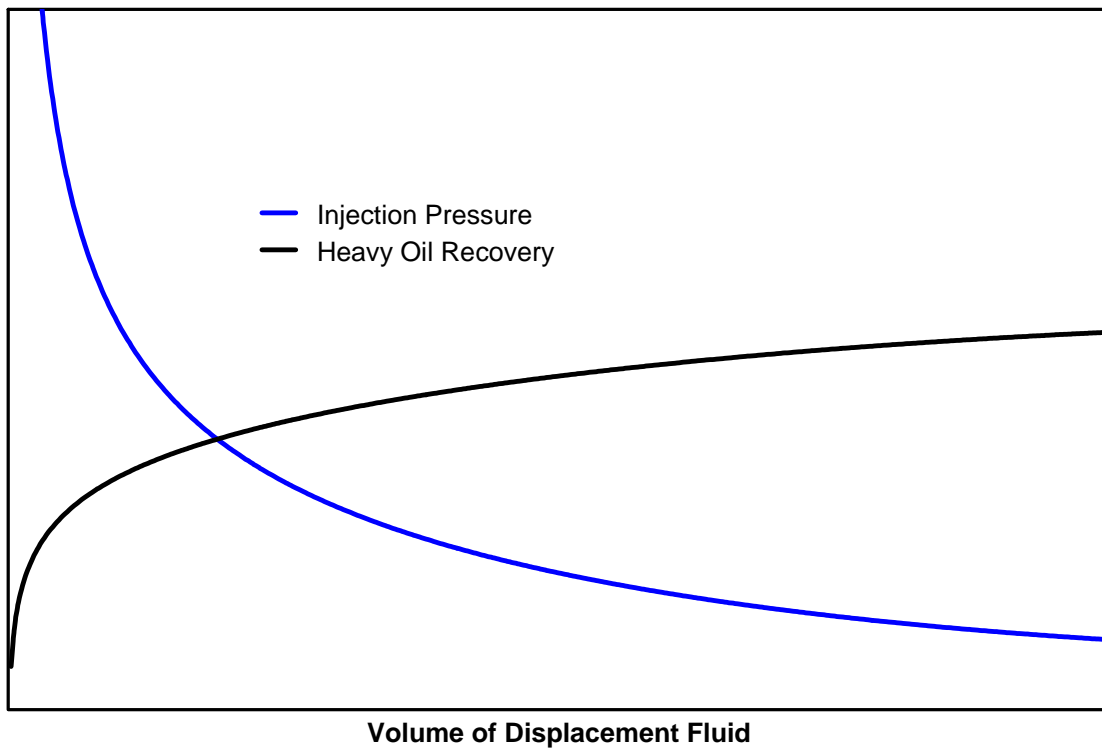
after the application of primary and secondary recovery processes is depleted of its solution gas, it should be able to accept significant quantities of CO<sub>2</sub>. Therefore, CO<sub>2</sub> injection is applicable to reservoirs that have been depleted of solution gas.

The Petroleum Recovery Institute (PRI) measured the solubility of CO<sub>2</sub> into heavy oil using a PVT cell (Sayegh and Maini 1984). The heavy oil under study had an estimated molecular weight of 325 and a physical density of 0.978 kg/m<sup>3</sup>. Its dead oil viscosity at 21° C was 10,500 centipoises. The bubble point pressure was 3,240 kPa. The viscosity of reconstituted live oil was 6,800 centipoises with a methane content of 11.4 mole %, or 0.6 weight %, or a Gas to Oil Ratio of 9.4 m<sup>3</sup>/m<sup>3</sup>. The reconstituted live oil was exposed to CO<sub>2</sub> in a PVT cell and it accepted 18 mole % of CO<sub>2</sub>, or 2.8 weight % at 4,000 kPa and 20° C. Viscosity was reduced by a factor of approximately 4 to 1,600 centipoises. Swelling of the oil phase was relatively low, less than 8%, due to the fact that dissolved methane was already present. Upon releasing pressure, methane was preferentially liberated from the oil. Consequently, the oil phase remained rich in CO<sub>2</sub> and its viscosity remained low.

During the same study, core displacement studies were also conducted with water and nitrogen in order to establish relative permeabilities. The irreducible water content was 12.9%. The general displacement profile for both water and nitrogen gas are shown on Figure 3.

The displacement of oil by injected gas was particularly inefficient. Gas broke through the production end after only 4% pore volume injection, resulting in a rapid pressure drop across the apparatus. The pressure and recovery profiles seem to indicate that, prior to breakthrough of the displacing fluid, oil was being displaced and produced relatively efficiently. However, upon breakthrough, the recovery process became inefficient, likely transitioning from displacement to entrainment of the marginal quantities of oil that are forced into the flow paths by capillary forces and water inhibition. This general profile would match field experience with waterfloods. A displacement process using only flue gas or CO<sub>2</sub> gas would likely also be inefficient for the same reasons.

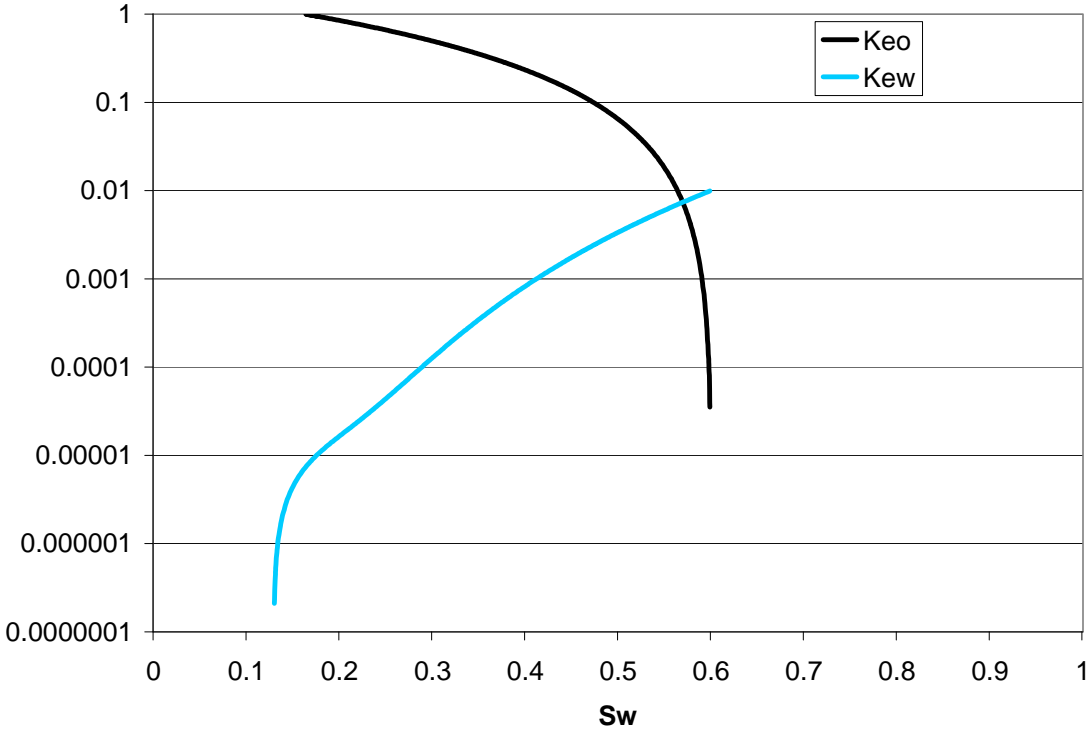
**Figure 3 – Pressure and Recovery Profiles during Gas and Water Displacement of Heavy Oil**



Adapted from (Sayegh and Maini 1984)

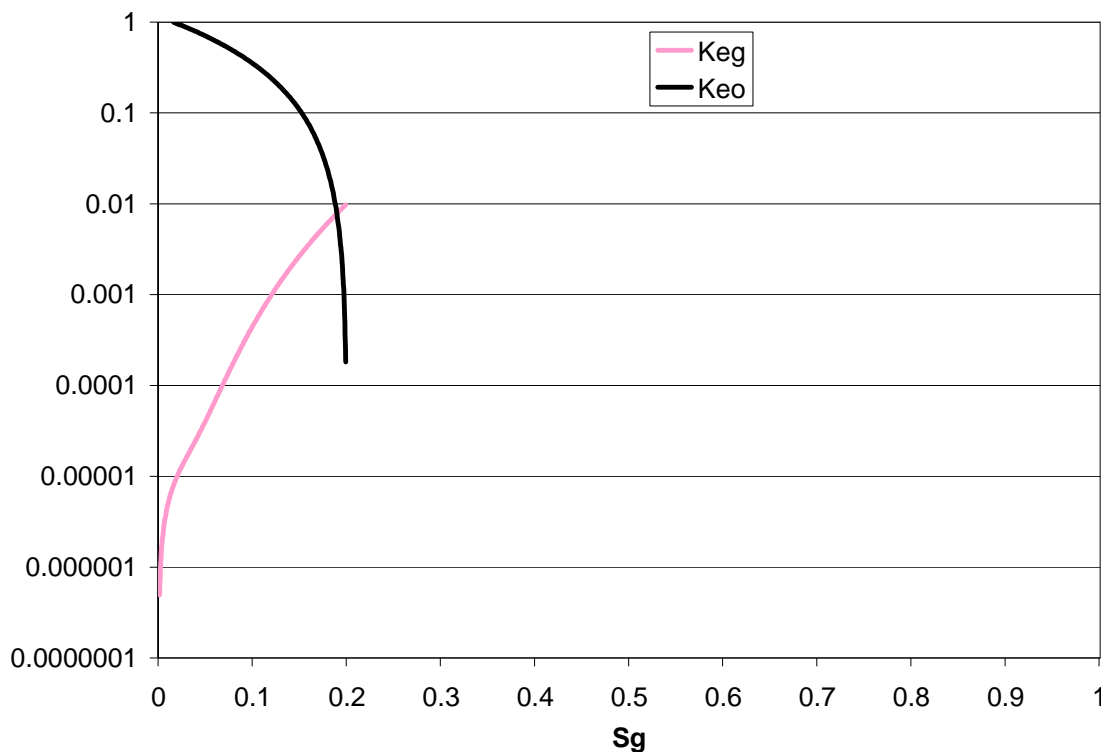
The results were computer matched by PRI and empirical formulas derived for effective relative permeabilities across the core. Figures 4 and 5 graphically represents relative permeabilities of oil, water and gas with respect to water and gas saturation.

**Figure 4 – Effective Oil and Water Relative Permeabilities during Water Displacement of Heavy Oil**



Graphed using equations from (Sayegh and Maini 1984)

**Figure 5 – Effective Oil and Gas Relative Permeabilities during Gas Displacement of Heavy Oil**



Graphed using equations from (Sayegh and Maini 1984)

The following observations can be made:

- The displacing fluids were unable to recover substantial amount of oil due to the presence of viscous fingers and breakthrough of displacement fluids to the production end. Gas breaks through faster than water.
- As a result, oil relative permeability is effectively truncated by the unfavourable mobility ratio. Essentially, oil ceases to flow from the core because the displacing fluid bypasses a significant proportion of the core volume.
- The relative permeabilities of water and gas are extremely low at high to moderate levels of oil saturation. As discussed elsewhere, it is the extremely low mobility of gas in heavy oil that enables a solution gas drive. Gas bubbles are essentially immobile in heavy oil and unable to coalesce as a free gas phase.

Similar results were obtained by PRI when  $CO_2$  was used as the displacement gas. Rapid gas breakthrough led to inefficient recovery. In heavy oil,  $CO_2$  gas is likely to finger and travel through the formation without causing significant oil displacement, other than the displacement required to establish communication channels for breakthrough.

A five-day soak period was attempted in order to determine if CO<sub>2</sub> would dissolve in heavy oil, thereby reducing the size of the viscous fingers and improving the mobility ratio from lower oil viscosity. However, this period was not sufficient to allow CO<sub>2</sub> to dissolve uniformly within the core, or a distance of less than 40 cm. These experiments by PRI indicate that CO<sub>2</sub> is indeed a solvent for heavy oil that is effective in reducing viscosity. However, a substantial amount of time and mixing action is required for significant dissolution to take place. Furthermore, only using gaseous CO<sub>2</sub> as a displacement fluid for heavy oil produces an extremely unfavourable mobility ratio and poor recovery effectiveness.

### **Sweep Efficiency**

Due to the high mobility of CO<sub>2</sub>, distribution of CO<sub>2</sub> into the reservoir and the delay of gas breakthrough are challenges.

Physical scale experiments conducted at the Institute of Petroleum Engineering in Scotland determined that the injection of immiscible CO<sub>2</sub> gas alone is unable to efficiently recover viscous oil. Gas breakthrough occurs very early because of the extremely unfavourable mobility ratio. The result is an inefficient process. Therefore, alternating water slugs must be injected to delay the onset of gas breakthrough and provide some efficiency improvements (Baggi 2007).

Immiscible CO<sub>2</sub> gas injection alone generally results in early CO<sub>2</sub> breakthrough and poor aerial sweep efficiency of the reservoir. Therefore, immiscible CO<sub>2</sub> flooding is generally combined with water injection in a Water Alternating Gas (WAG) injection scheme. This approach increases the CO<sub>2</sub> and oil contact time by slowing down CO<sub>2</sub> mobility. The immiscible CO<sub>2</sub> WAG process will generally recover more oil than continuous immiscible CO<sub>2</sub> injection and more than continuous water flooding (Mangalsingh and Jagai 1996).

The possibility of using immiscible CO<sub>2</sub> injection to recover heavy oil in Alberta and Saskatchewan was originally investigated by Farouq Ali in 1991 and subsequently by the Saskatchewan Research Council (Rojas, Zhu et al. 1991). Experiments were conducted with CO<sub>2</sub> but also with nitrogen in various injection configurations with water. The CO<sub>2</sub> WAG process was found more efficient than injection of CO<sub>2</sub> alone. The optimum WAG ratio was determined to be 4:1. Nitrogen WAG injection was found to recover the same amount of oil as a waterflood plus a final blowdown recovery that ranged between 2.4 and 4.1%.

In practice, immiscible CO<sub>2</sub> EOR involves the alternating injection of CO<sub>2</sub> and water. Water injection alternates with gas injection in order to reduce CO<sub>2</sub> mobility and improve sweep efficiency. In effect, the role of CO<sub>2</sub> is to swell the oil and reduce its viscosity. The role of water is equivalent to its role in a waterflood which is to displace the oil towards producing wells.

### **United States Field Experience**

Immiscible carbon dioxide flooding was extensively studied during the 1970s and 1980s. A number of laboratory studies and 25 field pilots were documented (Selby, Alikhan et al. 1989). The vast majority of these tests were deemed successful and incremental oil

recovery attributed to immiscible carbon dioxide EOR was up to 12% of the original oil in place.

Several immiscible CO<sub>2</sub> EOR projects have been implemented in the U.S. in the last 30 years. While immiscible CO<sub>2</sub> EOR of heavy oil is not as efficient as miscible CO<sub>2</sub> EOR of light oil, it remains attractive because of the fact that heavy oil reservoirs have high oil saturation at the onset of the EOR process. While primary and secondary recovery may recover 30 to 40% of conventional light oil, recovery factors are much lower for heavy oil. Therefore, the starting oil saturation at the beginning of the EOR process is generally higher for heavy oil.

An example of an immiscible CO<sub>2</sub> flood is the Lick Creek Meakin project. This sand formation was a 3 m thin heavy oil zone at a depth of approximately 850 m. Oil viscosity at reservoir conditions was 160 centipoises. The first phase of an immiscible CO<sub>2</sub> flood project started in February 1976 and lasted one year and consisted of a cyclic CO<sub>2</sub> stimulation of all wells in order to raise reservoir pressure, reduce oil viscosity and initiate a solution gas drive. The second phase was injection of CO<sub>2</sub> for several months into the injection wells. During the third phase, water injection was alternated with CO<sub>2</sub> injection. The fourth and final phase discontinued CO<sub>2</sub> injection. Only water was injected to maintain pressure and drive oil production. During the first four years of this 15 year project, approximately 3.2% additional oil recovery was obtained. The target incremental recovery for this immiscible CO<sub>2</sub> flood at the end of the 15 year lifespan is 13% of the original oil in place (Mungan 1991).

When CO<sub>2</sub> goes into solution into oil by the application of pressure, gas will come out of solution as pressure is decreased. In heavy oil, this will result in a solution gas drive because the gas phase will not be able to coalesce in a separate phase. Solution gas drives have been experienced at the end of CO<sub>2</sub> floods during a blowdown phase. Laboratory experiments conducted by Union Oil injected CO<sub>2</sub> at 6,000 kPa into a core containing heavy oil. Afterward, 14% of the oil in place was recovered simply by reducing pressure to 2,600 kPa followed by another 4.5% by reducing pressure to 1,300 kPa. The production mechanism was solution gas drive from the injected CO<sub>2</sub>. The authors of the study also reported that when the Mead-Strawn CO<sub>2</sub> and waterflood project was stopped, oil was produced for five additional years by a solution gas drive from the CO<sub>2</sub> remaining in the reservoir (Holm and Josendal 1974).

An immiscible CO<sub>2</sub> pilot was conducted in the heavy oil zone of the Wilmington field in California. Heavy oil with a density of 14° API had its original viscosity of 283 centipoises reduced to 18 centipoises by injection of CO<sub>2</sub> at a pressure of approximately 13,300 kPa. The incremental oil recovery was expected to be 10% of the original oil in place or approximately 20% of the waterflood residual (Mungan 1991).

Immiscible CO<sub>2</sub> EOR was extensively studied by the US Department of Energy and pilot testing was conducted in the Wilmington Field, one of the major oilfields that make up the Los Angeles Basin. Oil gravity is 14° API with a viscosity of approximately 200 centipoises.

Laboratory work and computer simulations concluded that the injection of CO<sub>2</sub> or of CO<sub>2</sub> and nitrogen mixtures (flue gas) essentially stripped methane from the oil and formed a

methane bank ahead of the injected gas. As a result, during pilot testing methane gas first broke through ahead of CO<sub>2</sub> gas. For both pure CO<sub>2</sub> and flue gas, the CO<sub>2</sub> content in heavy oil approached a limiting value in the vicinity of the injection well. For flue gas a limiting value was about 38 mole percent CO<sub>2</sub> in the oil phase while it was 46 mole percent for pure CO<sub>2</sub>. Viscosity was reduced from 200 centipoises originally to 51 centipoises with flue gas and 36 centipoises with pure CO<sub>2</sub> respectively (Miller and Jones 1981; Spivak and Chima 1984).

The production pilot was conducted between 1981 and 1985 after 30% of the oil in place had been recovered by 20 years of cold production and water flooding. Oil saturation at the beginning of the pilot had been reduced to 51% of the pore volume. The pilot was a partial five spot pattern. CO<sub>2</sub> was injected to alter the flow properties of crude oil in the reservoirs (viscosity reduction and swelling). Alternating water injection provided the driving force to mobilize and displace oil towards the producing well. Water also reduced excessive gas channelling and improved sweep efficiency.

In the pilot, pure CO<sub>2</sub> was used. Methane and CO<sub>2</sub> produced by the pilot were separated and CO<sub>2</sub> was compressed and re-injected.

The pilot involved 4 months of CO<sub>2</sub> injection during which only minor amounts of gas broke through. A large amount of methane gas was also produced. Methane content was about 30% in the first few months and thereafter declined to about 5%. Oil production was increased. Starting from a level of 4.5 m<sup>3</sup> per day, production steadily increased to a peak rate of 32 m<sup>3</sup> per day. Thereafter oil production rate assumed an exponential decline of 22% per year. At the end of the pilot 25,000 m<sup>3</sup> of additional oil had been produced. Water production fell dramatically from an initial high of about 191 m<sup>3</sup> per day to only slightly over 64 m<sup>3</sup> per day. The ultimate CO<sub>2</sub> efficiency extrapolated to between 1,100 and 1,780 m<sup>3</sup> CO<sub>2</sub> per m<sup>3</sup> of oil produced.

There were no failures of equipment because of corrosion. No problems were encountered with asphaltene precipitation (Saner and Patton 1986; Sankur, Creek et al. 1986; Spivak, Garrison et al. 1990)

### **Bati Raman (Turkey)**

The Bati Raman oil field in Turkey is estimated to contain 1.85 billion barrels of heavy oil reserves. The reservoir rock is a heterogeneous, fractured limestone. Production started in 1961 and by 1986 primary recovery processes had produced 1.5% of the oil in place. During this time, reservoir pressure decreased from approximately 12,000 kPa to as low as 2,600 kPa and production declined from a high of 9,000 barrels per day to 1,600 barrels per day. In 1986, the immiscible CO<sub>2</sub> injection EOR project was initiated. The initial cyclic approach led to uneven results and was replaced by a flood approach in 1988. Three separate phases have been identified for this recovery project. The first phase lasted between 1986 and 1993 and is described as the fill up period when injected CO<sub>2</sub> filled fractures and vugs. This phase is characterized by stable injection pressures on a field wide basis. The second phase was three years of increased production. The daily rate reached a peak of 13,000 barrels per day in 1993. The third phase started in 1997 and is identified by declining production to a low of 5,500 barrels per day. The major reason for declining production has been assigned to gas

breakthrough resulting from the very adverse mobility ratio between CO<sub>2</sub> gas and heavy oil. Gas had succeeded in establishing low resistance pathways between injection and producing wells. At the end of 2003, 5% of the original oil in place had been recovered.

A polymer gel pilot was implemented in three wells in an attempt to improve reservoir conformance. All test wells showed a gradual increase in injection pressure during treatment, indicating evidence of plugging of communication channels by the gel treatment technology. The application of WAG, polymer gel treatments and horizontal wells has gradually re-established production to the current level of 7,000 barrels per day and expectations are for the potential recovery of up to 10% of original oil in place. (Karaoguz, Topguder et al. 2004; Sahin, Kalfa et al. 2007)

The concept of hot CO<sub>2</sub> flooding was proposed by Reliance Industries of India for the Bati Raman oilfield. It would involve injecting CO<sub>2</sub> at a pressure of approximately 20,000 kPa and a temperature of 150° C. Under these conditions, heavy oil viscosity is calculated to be reduced from 592 centipoises to 65 centipoises by combining thermal and solvent effects (Picha 2007).

### **CO<sub>2</sub> Storage**

The possibility of storing CO<sub>2</sub> in depleted Lloydminster heavy oil reservoirs was investigated by numerical simulations conducted at the University of Alberta (Canbolat 2005). Reservoir conditions at the end of oil recovery are expected to be 21° C. and 6,500 kPa. Under these conditions, CO<sub>2</sub> solubility was calculated at 33 m<sup>3</sup>/m<sup>3</sup> in water and 71.5 m<sup>3</sup>/m<sup>3</sup> in heavy oil. Reservoir fluids are expected to be composed of 60% remaining oil and 40% water. Calculations indicated that approximately 8% by weight of CO<sub>2</sub> could therefore be dissolved in reservoir fluids resulting in storage of 72,000 tonnes of CO<sub>2</sub> in the drainage volume of a 500 m long horizontal well in a 25 m thick formation. While this amount of stored CO<sub>2</sub> may not be a very large it is also not insignificant given the large number of wells in the Lloydminster region.

#### **7.2.4. CO<sub>2</sub> Workover**

CO<sub>2</sub> injection has also been used as a well workover method. CO<sub>2</sub> is delivered to the well site as a liquid at approximately -20° C. and 2,000 kPa. It is injected into the water-based workover fluid where it goes into solution until the fluid is gas saturated. The addition of CO<sub>2</sub> causes the temperature of the workover fluid to decrease by approximately 5° C. No damage to the surface or downhole equipment was reported. Upon dispersing into the formation, CO<sub>2</sub> gas is released by the injected fluid. This action imparts a solution gas drive to the treating fluids which is utilized to backflow fluids, silts, muds, and aids in removing emulsion and water blocks (Crawford, Neill et al. 1963).

CO<sub>2</sub> is also used as a well of stimulants during fracturing and acidizing and as an additive to steam injection.



## 8. Review of Gas Injection Processes

### 8.1. *Inert Gas Injection*

Inert gas injection is used for EOR recovery of light oil. The advantages of gas injection as compared to a waterflood are thought to be as follows (Baggi 2007):

- Inert gases such as nitrogen do not react with reservoir rock;
- Gas injectivity is higher than water; and,
- Handling produced gas after breakthrough is not as costly as handling large volumes of produced water.

However a gas breakthrough occurs very early. Therefore, stabilization methods such as gravity stabilization or Water Alternating Gas (WAG) injection are required to achieve reasonable efficiencies. In thick or dipping light oil reservoirs, gas injection at the top of the formation is an established practice. The influence of gravity stabilizes the gas-oil interface and allows gas pressure to push oil to a producing well located at the bottom of the formation without premature breakthrough.

### 8.2. *Hydrocarbon Gas Injection*

Hydrocarbon injection and miscible floods are established recovery technologies for light oil. Their application to heavy oil is encountered infrequently.

During the mid-1990s, PanCanadian Petroleum proposed a pressure cycling process applicable to heavy oil deposits in Alberta and Saskatchewan that had already been produced by cold primary production (Metwally 1996). The process consisted of the following elements:

- A mixture of natural gas and propane is injected in order to pressurize the reservoir. The gas would be distributed through the formation via the high permeability channels created by cold production. Gas would also penetrate unswept zones by the formation of viscous fingers. The role of natural gas is to carry propane and to provide pressure support.
- Injection rates and pressure are kept relatively low.
- Vaporized propane dissolves into heavy oil, reducing its viscosity and causing some asphaltene precipitation.
- After reaching a specified injection target, the blowdown phase is started and all wells are placed on production. The cycle is repeated for a number of times.
- Gas and solvents are co-produced with the oil, recovered and recycled.

The process was expected to require three complete cycles over a three-year period. It was estimated to recover from 6 to 10% of the original oil in place.

Petrovera evaluated solvent gas injection at Frog Lake (Miller, Carlson et al. 2003). The test section had been produced by cold primary production to the extent of 9.5% of the original oil in place. High water cuts had resulted in shutting-in 22 of the 36 wells. The source of the water had not been established. The original reservoir pressure of 5,000 kPa had been reduced to 500 to 1,500 kPa by cold production. The injected gas was

composed of one third propane and two thirds methane. One of the objectives was to increase reservoir pressure to approximately 3,500 kPa. Injection was started in September 1997 and lasted approximately six months. Injection pressures increased only to a maximum of 1,750 kPa. Pressure response at neighbouring wells was below these values. Increases in pressure also dissipated quickly. The authors concluded that re-pressurization of a depleted heavy oil reservoir will not be an easy task, particularly if the reservoir is laterally extensive. After soak periods between 40 and 90 days, injection wells were placed on production. Production response following gas injection was disappointing. Injector wells placed on production rapidly watered out. It appeared that the presence of nearby water zones complicated the outcome of this pilot. This test also indicated that a soak period of up to 90 days is likely too short for propane to have a meaningful effect on heavy oil at reservoir conditions.

Test conducted by Imperial Oil at Cold Lake indicated that unconsolidated reservoir sands could be expanded by injecting gas followed by rapid depressurization. Sands surrounding drilled horizontal sections were expanded in this manner to fill the well bore to liner annulus (Miller, Carlson et al. 2003). This data indicates that it may be possible to destabilize wormholes by gas injection followed by rapid depressurization.

### **8.3. Flue Gas Injection**

#### **8.3.1. United States Experience**

Flue gas injection pilots were conducted in the United States during the 1980s with uneven success. Past flue gas pilot projects include the following (Hornbrook, Dehghani et al. 1991):

- A single well pilot involved the injection of combustion exhaust gases into a viscous oil reservoir. Increased production rates were attributed to oil viscosity reduction and increased reservoir energy from the injected gases (Clark, Roberts et al. 1964).
- Improved recovery was seen in three separate field tests with oil viscosity ranging from 80 to 300 centipoises when injecting gases from a generator producing a mixture of superheated steam, nitrogen and CO<sub>2</sub> (Sperry, Young et al. 1980).

Steam has a heat capacity approximately 100 times than air on a volumetric basis at 3,500 kPa (Farouq Ali 1974). Steam is therefore a much more efficient carrier for thermal energy than flue gas resulting in greater process efficiency and economic returns. If the EOR objective was thermal stimulation, steam injection would be preferred, assuming acceptable economics. If the purpose was gas injection, pure CO<sub>2</sub> would provide a more effective solvent effect than flue gas while nitrogen would operationally simpler because it is an inert gas. However, CO<sub>2</sub> and nitrogen are not usually available at good cost in an oilfield.

Nevertheless, miscible and immiscible flue gas EOR was conducted in the United States during the 1980s and 1990s. Table 4 shows production for flue gas EOR. The technology was used for eight years between 1984 and 1992.

**Table 4 – Flue Gas EOR in the United States**

<b>Year</b>	<b>Production (Barrels per day)</b>
1980	0
1982	0
1984	29,400
1986	26,150
1988	21,400
1990	17,300
1992	11,000
1994	0

Source:(Moritis 1990; Moritis 1992; Moritis 1994)

Most of the production was attributable to the two following projects:

- Arco in Crane, Texas: This project recovered 6,300 barrels per day by miscible flue gas injection using 98 injection wells from a 46° API oil reservoir. The project was converted in 1989 to a nitrogen and hydrocarbon immiscible flood.
- Exxon in Hawkins, Texas: This project had two components. Miscible flue gas injection recovered 11,000 barrels per day using 41 injection wells while immiscible flue gas injection recovered 1,500 barrels per day with 6 injection wells. The oil was slightly heavy with an API density of 24. In 1992, the Hawkins field was converted to immiscible nitrogen injection.

### **8.3.2. Russian Experience**

Russian oil companies have had experience with co-injection of steam and flue gas particularly in the Tatarstan oil fields. The simultaneous injection of hot exhaust gases and steam is viewed as more energy efficient than the conventional approach of injecting steam and venting hot exhaust gas to the atmosphere. Furthermore, the exhaust gases are primarily composed of nitrogen and CO<sub>2</sub> both of which can assist oil recovery. CO<sub>2</sub> dissolves in oil, reducing its viscosity and increasing its volume. Nitrogen provides pressure support, in part compensating for pressure loss due to steam condensation. Co-injection of flue gas and steam is considered particularly useful for small reservoirs being developed by a single well or a small number of wells (Moussine and Ibragimov 2007).

Two thermal cyclic thermal EOR processes involving injection of steam and flue gas were trialed in the Zybza-Glubokiy Yar field in Russia during the period 2000 to 2004. One of the processes involved the injection of gas and steam while the other injected only a hot gas. During the period, 37 wells were stimulated, 75% of which responded

with oil rate increases. The average ratio of injected fluids to oil production was 0.63 on a weight basis (Stashok and Antoniadis 2006).

### **8.3.3. Developments by the Saskatchewan Research Council**

The possibility of using immiscible CO<sub>2</sub> gas or flue gas as an EOR process for Lloydminster heavy oil was investigated by the Saskatchewan Research Council (SRC).

Physical model experiments using Senlac heavy oil showed that flue gas injection had the potential to increase oil recovery. Pure CO<sub>2</sub> was found to be more effective than flue gas, but the high cost of pure CO<sub>2</sub> precluded its use. Tertiary flue gas injection could recover an additional 5% of original oil in place. The mechanisms proposed were the existence of a free gas drive contributed by nitrogen and a viscosity reduction effect attributed to CO<sub>2</sub>. An extended waterflood was necessary after flue gas injection to achieve increased oil recovery (Dong and Huang 2002)

Another series of experiments were conducted at SRC on heavy oil with a dead oil viscosity of 2,140 centipoises. Reconstituted live oil, with a Gas Oil Ratio (GOR) of 6 m<sup>3</sup>/m<sup>3</sup>, had a viscosity of 1,498 centipoises. Tests were conducted using nitrogen, 100% CO<sub>2</sub> gas, flue gas with 15% CO<sub>2</sub> and enriched flue gas with 30% CO<sub>2</sub> (Zhang, Sayegh et al. 2006).

CO<sub>2</sub> saturated live oil at a pressure of 5,500 kPa had a total GOR of 32 m<sup>3</sup>/m<sup>3</sup> and a viscosity reduced to 274 centipoises. By contrast, saturation with nitrogen at 8,000 kPa only resulted in a total GOR of 9.8 m<sup>3</sup>/m<sup>3</sup> and a relatively unchanged viscosity of 1,456 centipoises. Flue gas gave intermediate results.

Core displacement experiments were conducted in a 4:1 WAG configuration at a back pressure of 2,500 kPa and a temperature of 29° C, after 34% to 36% of original oil in place had been recovered from the cores by water flooding. Nitrogen injection recovered an additional 3.1% while CO<sub>2</sub> improved recovery by 3.7%. Surprisingly, higher recoveries of 5.2% and 5.6% were obtained by flue gas injection.

It is likely that, at the low pressures representative of Lloydminster reservoirs and in the absence of extended soak times and mixing, limited amounts of CO<sub>2</sub> actually dissolved in heavy oil and that viscosity reduction and swelling effects were limited. This may explain the outcome that oil recovery for CO<sub>2</sub> gas was only slightly better than with nitrogen. A working hypothesis for the improved results obtained with flue gas is that nitrogen gas in the presence of CO<sub>2</sub> improved sweep efficiency and thereby recovery. The SRC researchers ran additional displacement tests with foam surfactant solutions which also yielded improved oil recovery. A possibility therefore is that the presence of CO<sub>2</sub> reduces interfacial tension which allows nitrogen gas to form emulsions that diverts the flow of chase water into unswept zones.

## **9. Comparison of Viscosity Reduction by Heat and CO<sub>2</sub>**

The viscosity of bitumen saturated with pure gases CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub> were measured in laboratory experiments at the University of Calgary for temperatures ranging from 25° C to 100° C. and pressures from 1,600 kPa to 9,600 kPa (Mehrotra and Svrcek 1982).

This work resulted in the following numerical correlation being estimated for gas solubility and viscosity of bitumen.

### Gas Solubility Correlation

$$\text{Solubility} = b_1 + b_2 * P + b_3 * P/T + b_4 * (P/T)^2$$

where,

Solubility = solubility of gas in bitumen, cm<sup>3</sup>/cm<sup>3</sup>

T = temperature, K (273.16 + ° C)

P = pressure, MPa

b<sub>1</sub>, b<sub>2</sub>, b<sub>3</sub>, and b<sub>4</sub> are correlation constants

### Viscosity Correlation

$$\log \log(\mu) = a_1 + a_2 * T + a_3 * P + a_4 * P/(273.16 + T)$$

where,

μ = viscosity of bitumen, mPa\*s

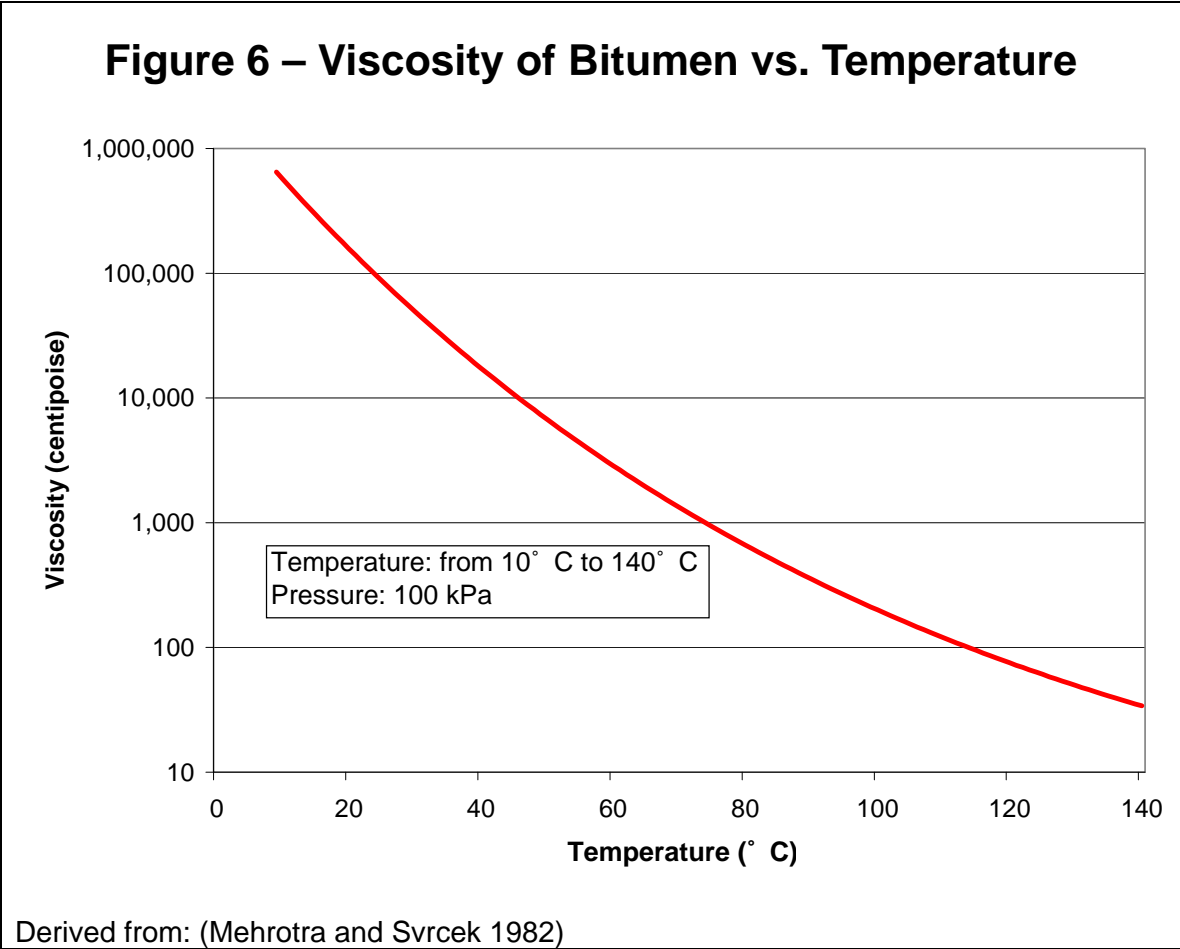
T = temperature, ° C

P = pressure, MPa

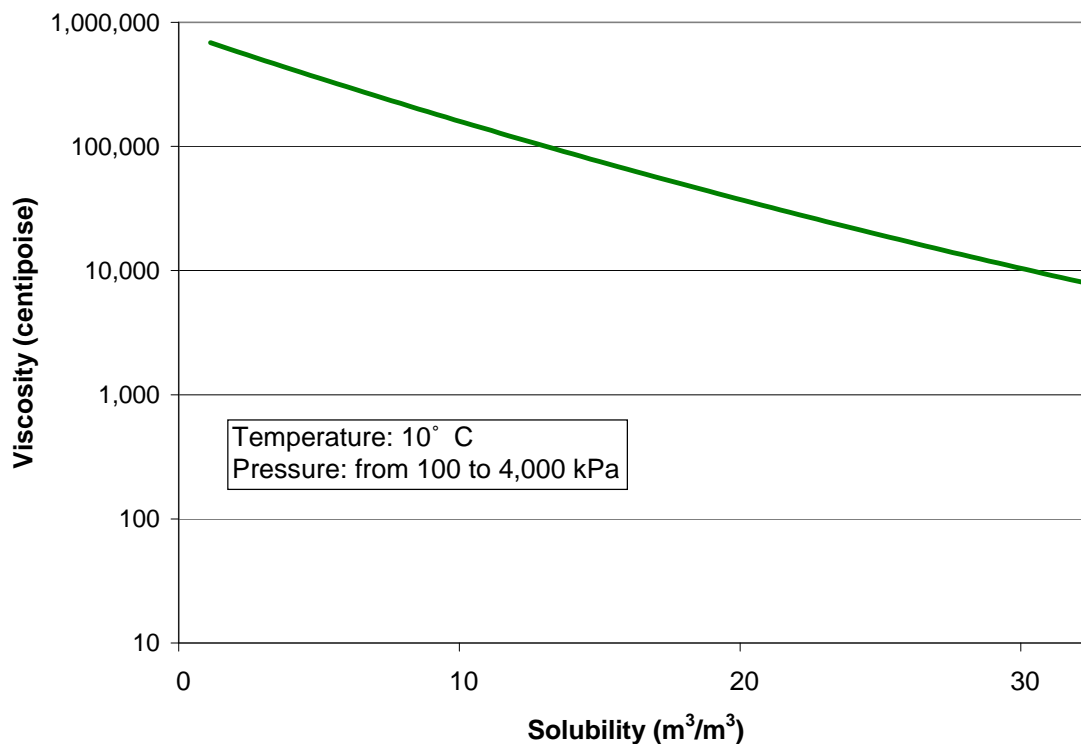
a<sub>1</sub>, a<sub>2</sub>, a<sub>3</sub>, and a<sub>4</sub> are correlation constants

These correlations are graphically represented in Figures 6 and 7. The dramatic reduction in viscosity obtained by increasing temperature (over three orders of magnitude) was also found by other researchers and is well established (Butler, Jiang et al. 2000).

Dissolving CO<sub>2</sub> into bitumen will also reduce its viscosity. The maximum amount of CO<sub>2</sub> that can be dissolved into bitumen depends on temperature and the applied pressure. The amount of CO<sub>2</sub> in saturated bitumen decreases with temperature but increases with pressure. By increasing pressure to 4,000 kPa, a maximum of 30 m<sup>3</sup>/m<sup>3</sup> of CO<sub>2</sub> can be dissolved in bitumen. Figure X shows the viscosity reduction achievable by dissolving up to 30 m<sup>3</sup>/m<sup>3</sup> of CO<sub>2</sub> by increasing pressure from 100 kPa to 4,000 kPa at a constant temperature of 10° C. The reduction in viscosity achieved is significant, approximately two orders of magnitude, but it is less than what is achievable by thermal means.



**Figure 7 – Viscosity of Bitumen vs. CO<sub>2</sub> Solubility at Saturation**



Derived from: (Mehrotra and Svrcek 1982)

The correlations developed by Mehrotra and Svrcek were adapted to Lloydminster heavy oil for the purpose of understanding the potential for viscosity reduction offered by thermal and CO<sub>2</sub> approaches. The options analyzed were:

- Injection of low-cost thermal energy from low-quality steam: As discussed earlier, it is unlikely that thin pay reservoirs in Lloydminster will be economic with high-quality, high pressure steam. A practical temperature increase achievable from low-cost thermal energy was deemed to be 50° C, for example from 20° C to 70° C.
- Injection of pure CO<sub>2</sub> gas at a pressure up to 4,000 kPa: This is deemed to be below formation fracture pressure for most Lloydminster reservoirs.
- Injection of hot flue gas with or without low-quality steam: Flue gas is composed of approximately 10% CO<sub>2</sub>. This approach combines the thermal effect with a partial CO<sub>2</sub> solvent effect.

- Injection of cold flue gas: This option would likely be the case if flue gas is dried of combustion water to avoid corrosion problems. It would only offer a partial CO<sub>2</sub> solvent effect.

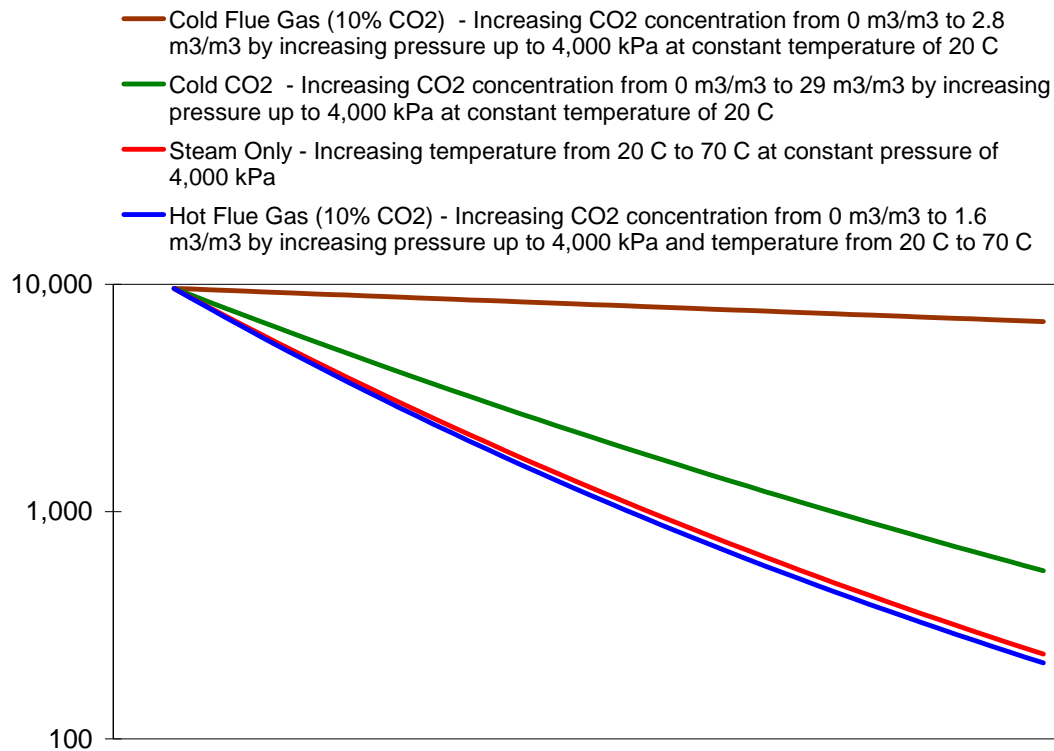
The viscosity reduction produced for these four conceptual options is shown on Figure 8. The comparison is only of a conceptual nature because the following simplifications were made:

- It was assumed that CO<sub>2</sub> would dissolve up to the saturation level at each given pressure. This likely overstates the amount of CO<sub>2</sub> in solution in heavy oil because of the likely presence of solution gas in reservoir oil and because of the long length of time for the solution process to occur in the absence of mixing. While CO<sub>2</sub> will displace some of the solution gas, it does not deplete it completely. As noted experimentally, the presence of a gas dissolved in heavy oil reduces the potential for dissolution of another gas (Mehrotra and Svrcek 1982).
- The amount of CO<sub>2</sub> from flue gas that would dissolve into heavy oil was assumed to be related to its partial pressure in flue gas. While this is a reasonable first approximation, the reality is likely more complex.

In Figure 8, the top line represents the viscosity reduction potential of cold flue gas at 20° C. The only viscosity reduction mechanism from cold flue gas comes from its 10% CO<sub>2</sub> component. Even assuming that full saturation level is achieved, the small amount of CO<sub>2</sub> in flue gas can only deliver in a limited viscosity reduction. The second line represents the potential offered by cold CO<sub>2</sub> gas. In effect, as compared to cold flue gas, this option contains approximately 10 times the amount of CO<sub>2</sub> and results in approximately 10 times the viscosity reduction potential under the same assumption of dissolution to the full saturation level. The third line indicates the potential offered by thermal energy in the absence of any solvent effect. The viscosity reduction achievable by a 50° C temperature increase is greater than that offered by 100% CO<sub>2</sub> gas at 4,000 kPa assuming optimal dissolution conditions. Finally, the fourth line shows the potential of hot flue gas which combines the thermal effect with the partial solvent effect offered by the 10% CO<sub>2</sub> component of flue gas. The line mirrors the viscosity reduction provided by thermal energy with a small increment attributable to the small CO<sub>2</sub> partial pressure.



## Figure 8 – Conceptual Comparison of Viscosity Reduction (Logarithmic Scale) Thermal vs. CO<sub>2</sub>

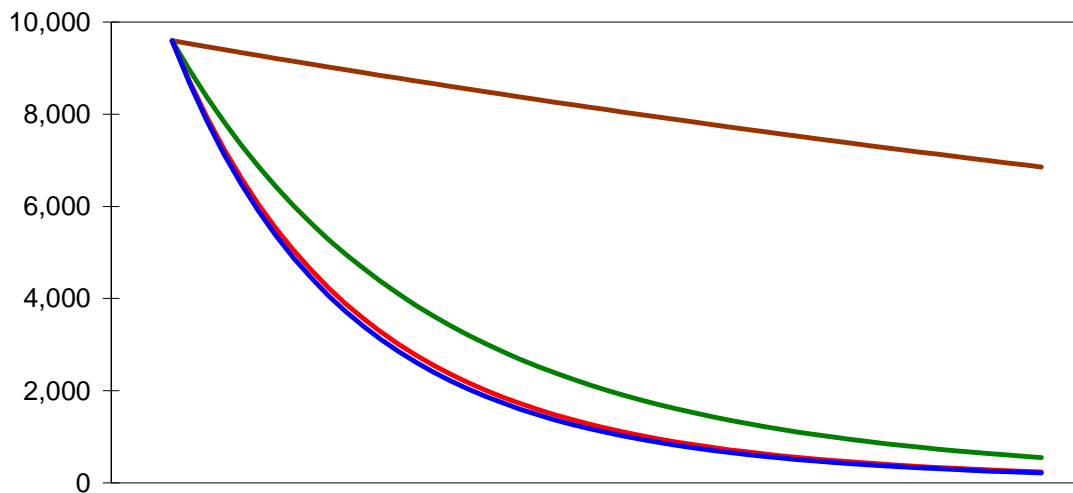


Prepared using information from: (Mehrotra and Svrcek 1982)

The same information is shown in Figure 9 with a normal scale instead of a logarithmic scale. While these scientific processes are properly described using a logarithmic scale, their impact on energy efficiency and economics is better assessed using a conventional representation. It can be appreciated that the application of even small temperature or solvent concentration increases has a significant impact on viscosity. Diminishing returns apply with the application of additional increments resulting in smaller viscosity reduction benefits. The importance of this observation is that the potential value of low-quality thermal energy should not be discounted without complete engineering and economic analysis. Increasing heavy oil temperature by as low as 10° C could reduce its viscosity in excess of 60% and this effect would have a major beneficial impact on energy efficiency, greenhouse gas emissions and production costs.

**Figure 9 – Conceptual Comparison of Viscosity Reduction (Normal Scale) (Thermal vs. CO<sub>2</sub>)**

- Cold Flue Gas (10% CO<sub>2</sub>) - Increasing CO<sub>2</sub> concentration from 0 m<sup>3</sup>/m<sup>3</sup> to 2.8 m<sup>3</sup>/m<sup>3</sup> by increasing pressure up to 4,000 kPa at constant temperature of 20 C
- Cold CO<sub>2</sub> - Increasing CO<sub>2</sub> concentration from 0 m<sup>3</sup>/m<sup>3</sup> to 29 m<sup>3</sup>/m<sup>3</sup> by increasing pressure up to 4,000 kPa at constant temperature of 20 C
- Steam Only - Increasing temperature from 20 C to 70 C at constant pressure of 4,000 kPa
- Hot Flue Gas (10% CO<sub>2</sub>) - Increasing CO<sub>2</sub> concentration from 0 m<sup>3</sup>/m<sup>3</sup> to 1.6 m<sup>3</sup>/m<sup>3</sup> by increasing pressure up to 4,000 kPa and temperature from 20 C to 70 C



Prepared using information from: (Mehrotra and Svrcek 1982)

## 10. Reservoir Sweep Considerations

Oil reservoirs are not homogeneous structures. Small-scale reservoir heterogeneities distribute injectants (steam, CO<sub>2</sub> and others) along higher permeability channels. Injectants bypass or contact to a limited extent other reservoir zones. This lowers the ability of the process to affect all of the zones in the reservoir. The oil in these low permeability zones has less opportunity to be heated, swelled and to become mobile from the action of heat or CO<sub>2</sub>. Reservoir heterogeneities will negatively impact the sweep efficiency any EOR process.

Viscous fingering is a separate but nonetheless important factor affecting sweep efficiency. Viscous fingering occurs in homogeneous situations such as laboratory core displacement experiments. The largely unfavourable mobility ratio of gas to heavy oil will promote viscous fingering and further challenge sweep efficiency.

If two similar zones in a heavy oil reservoir are taken, each with, for example, 85% oil saturation, it is possible that the application of a recovery process, whether cold production or waterflood, succeeds in recovering oil from one of the two zones and reduces its oil saturation to, for example, 50%. The second zone, however, was simply bypassed by the process.

One approach to increasing oil recovery could be to try to understand how the process recovered approximately 35% from the first zone and why it did not recover more from that zone. This could lead to incrementally higher recoveries from swept zones.

Another approach could be to ask: Why did the process sweep the first zone and not the second? Why was the second zone bypassed? Could it be possible to modify the process in a way that it would reach both zones, thereby doubling recovery from the reservoir?

This second approach is the one that appears to offer the highest opportunity for heavy oil. For example, in Lloydminster reservoirs, commercial primary and secondary technologies recover approximately 10% of the oil in place. If an assumption is made that commercial processes recover all of the oil in swept zones, then only 10% of the reservoir was swept. If the assumption is that 50% of the oil is recovered in swept zones, then only 20% of the reservoir was swept. In general, laboratory experiments, using cores or physical scale models, sweep most of the volume under study and yield recovery factors that are far above field results. It is therefore possible that recovery processes indeed recover high amounts from swept zones but return low overall recovery factors due to poor sweep efficiency.

Therefore, it is likely that the greater opportunity rests with designing technologies to improve sweep efficiency rather than improving the intrinsic performance of the process.

In the WAG process, gas and water are injected alternatively to improve aerial and vertical sweep efficiencies. Because water is more viscous and less mobile than gas, it slows the flow of gaseous fluids in high permeability layers and helps achieve a more efficient use of the injectants. In theory, based on laboratory data, waterfloods should be of limited value for heavy oil. Yet, some are very successful in Lloydminster. Viscous

fingering is less of a problem and sweep efficiency is better in practice than predicted by laboratory data. Laboratory experiments are conducted under accelerated conditions and may not accurately represent the relative permeabilities experienced inside the reservoir. Heavy oil is not a Newtonian fluid and its viscosity is dependent on the rate of shear. In other words, viscosity is dependent on the speed of flow. On the other hand, water is a Newtonian fluid. Its viscosity is independent of the flow rate. As a result, measurements conducted at different flow rates will yield different viscosity ratios for oil and water. The field success of waterfloods in Lloydminster could indicate that WAG EOR could also perform better in Lloydminster reservoir conditions than in laboratory conditions.

In practice, reservoir heterogeneity plays a more important role than and possibly overwhelms viscous fingering in determining sweep efficiency. In the field, while some of the reservoir volume is contacted by injectants under conditions similar to laboratory conditions, other reservoir volumes are contacted by less CO<sub>2</sub> and some of the reservoir is completely bypassed. Understanding and characterizing geological reservoir heterogeneities and those imparted by primary and secondary production are critical factors. Processes that maximize reservoir exposure to injectants are likely to be more successful. For example, it is believed that CSS is more successful than SAGD in Cold Lake because the higher steam injection pressures during the early cycles break shales and clay barriers, allowing steam to more completely penetrate the reservoir. In Lloydminster, high injection pressures are not possible, periodic workover approaches and cyclic processes may help in maximizing reservoir access.

This notion also implies that significant value may be gained from better reservoir characterization through seismic and tracer studies. These methods will allow mapping the network of high permeability channels present in the reservoir which in turn will permit more precise placement of original and infill wells in order to maximize sweep efficiency and the volume of heavy oil that is contacted by injectants and eventually produced. Significant progress has been made in using seismic techniques to better understand steam fronts in Lloydminster (Watson, Lines et al. 2002; Lines, Zou et al. 2005)..

## **11. Design of a Novel Lloydminster Heavy Oil EOR Technology**

In previous sections of this report, the opportunity presented by Lloydminster heavy oil was identified: substantial quantities of heavy oil will be left in the ground at the end of the primary and secondary recovery. Challenges facing the design of a tertiary or Enhanced Oil Recovery (EOR) technology were also outlined. Some arise from the specific characteristics of Lloydminster reservoirs such as thin pay, low pressures and potential presence of water zones. Others are the direct result of the application of existing commercial technologies. CHOPS will leave a reservoir with wormholes and apparently no solution gas. Waterfloods will add important volumes of water to the reservoir. This project aims at designing an EOR technology based on injection of CO<sub>2</sub> or flue gas with or without steam. Existing thermal and solvent technologies were

therefore reviewed in order to capture information that would be relevant to EOR in Lloydminster.

In this section, the information gathered is analyzed and used to articulate design technology concepts for potential EOR approaches that could be used fully field tested in Lloydminster.

The business concepts for the design of a new EOR technology in Lloydminster are as follows:

- The capital and operations costs must be kept low because the thin pay zones in the Lloydminster region will not justify high levels of investment;
- Equipment should be designed to be transportable for use at multiple locations to reduce costs but also to acknowledge that the working life of any particular well is likely to be short because of the thin pay zone;
- The new technology should require few new wells, if any, in order to take advantage of the existing built infrastructure and to minimize costs.

### ***11.1. Key Learnings from Thermal and Solvent Technologies***

The review of existing thermal and solvent technologies led to the following points with respect to their potential adaptation to the characteristics of Lloydminster reservoirs after primary and secondary recovery:

- Most Lloydminster reservoirs are too thin for the effective application of CSS, SAGD or steam floods. Thermal energy losses would be too great and result in low energy efficiency and high costs and greenhouse gas emissions.
- CO<sub>2</sub> injection as an immiscible gas could be technically promising based on laboratory investigations. However, the total cost of capturing, treating, compressing and transporting CO<sub>2</sub> is likely to be prohibitive. On the other hand, flue gas, which contains 8% to 15% CO<sub>2</sub> and is less effective than pure CO<sub>2</sub>, could be locally available at a significantly lower cost.
- Steam has a heat capacity in the order of 100 times greater than air or flue gas on a volumetric basis. Therefore, adding steam to flue gas would dramatically improve the efficiency of injecting thermal energy into the reservoir.
- Keeping costs low is critical for thin reservoirs such as those found in Lloydminster. High quality steam may be too expensive. Production of low quality steam using portable generators would be a way to keep steam costs manageable.
- Injection of CO<sub>2</sub>, either as an additive to steam or as a slug prior to steam injection, improves steam injectivity. It is likely that CO<sub>2</sub> dissolves into heavy oil and displaces solution gas which then advances as a front ahead of the steam front, creating viscous fingers or highly saturated gas channels that enable steam to move more easily and penetrate more deeply into the formation. Co-injection of flue gas and steam may be more effective than either fluid alone.
- Co-injection of flue gas and steam is more energy efficient than the conventional approach of injecting steam only and venting hot exhaust gas to the atmosphere. Direct contact steam generation conserves all of the energy liberated by

combustion and makes it available to the reservoir. This inherent efficiency improvement directly translates into less greenhouse gas emissions.

- Furthermore, CO<sub>2</sub> in flue gas dissolves in oil, reducing its viscosity and increasing its volume.
- Nitrogen in flue provides pressure support, in part compensating for pressure loss due to steam condensation.
- A hypothesis that needs further investigation is that the presence of CO<sub>2</sub> reduces interfacial tension between oil and water which allows nitrogen in flue gas to form emulsions. Chase water may then be diverted into unswept zones because emulsions block or slowdown water mobility in existing water channels. The result is improved sweep efficiency and higher oil recovery.
- Pressure cycling is thought to promote mixing and accelerate the dissolution of a solvent into heavy oil, increasing production rate.
- Injection of a cold gas (e.g. methane or propane) into a reservoir that had been produced by CHOPS is likely to result in only small increases in reservoir pressure, particularly in the reservoir is laterally extensive. It is likely that the high permeability channels created by CHOPS allow the injected gas to move great distances in the reservoir. Therefore, the prior or simultaneous application of heat is required to collapse or curtail some of the high permeability channels.

## **11.2. Key Uncertainties**

There are nevertheless a number of key uncertainties that will need to be investigated though additional field trials. These include:

- Distribution of porosity in a reservoir after CHOPS, in other words mapping the high permeability zones and channels;
- Fraction of the oil reservoir that was unswept by CHOPS or a waterflood;
- Oil saturation in high permeability zones and channels created by CHOPS and oil saturation in undisturbed reservoir matrix;
- Oil saturation in zones swept by a waterflood and in bypassed zones.

## **11.3. Flue Gas and Steam Stimulation EOR Technology**

The core idea of this potential EOR technology for Lloydminster heavy oil centers on the injection of flue gas with low quality steam into the heavy oil formation. The addition of steam would increase the efficiency of the process because steam carries a higher energy density than flue gas and the rate of thermal energy injection into the formation would be higher. The injection of flue gas would stimulate the formation using four different mechanisms:

- Addition of thermal energy to heavy oil, reducing its viscosity and increasing its mobility;
- Injection of Non Condensable Gas (NCG) which would re-pressurize the formation, generating a pressure drive to move oil to producing wells, either in a drive configuration from injector to producer or in a cyclic configuration utilizing blowdown to mobilize oil;

- Addition of CO<sub>2</sub> as a solvent which would incrementally swell the oil phase and reduce its viscosity; and,
- The possibility that CO<sub>2</sub> would reduce interfacial tension and allow the nitrogen component of flue gas to form emulsions and divert condensate or chase water into unswept zones, thereby improving recovery.

The new technology should be directed at accessing oil from unswept zones as opposed to be focused on extracting more oil from zones in which oil saturation has already been reduced by the application of primary and secondary recovery technologies. It is expected that most of the remaining oil resides in the zones that have been bypassed by CHOPS or by waterfloods. It is likely that the steady application of a recovery technology over several years has caused the reservoir to reconfigure itself according to the steady pressure gradient and flow is imparted by primary and secondary recovery technologies. There is opportunity in disturbing the reservoir because it might create access points to unswept zones. For example, injecting steam into a wormholed reservoir would likely cause the collapse of the wormholes thereby disturbing the established order. Resuming production after the collapse of the wormholes might create new wormholes into previously bypassed zones. Similarly, injecting hot NCG and CO<sub>2</sub> at pressure followed by a blowdown phase might further destabilize sand areas at the permeability contrast between wormholes and undisturbed sandstone, thereby creating access points into unswept zones.

An EOR recovery process based flue gas and low quality steam may provide an additional 6% recovery based on related laboratory studies. In Lloydminster, cold production without sand currently yields 5 to 7 % recovery. Waterfloods may recover an additional 5% from these reservoirs. CHOPS recovers up to 12%. Therefore, the prize is substantial for an EOR recovery process based on flue gas and low quality steam: increasing total recovery from the current 5 to 12% by an additional 6%, or up to doubling current recovery.

#### ***11.4. Well Workover to Collapse Wormholes***

This concept centers on the idea that most of the oil remaining in a reservoir after CHOPS production resides in bypassed zones. The initial application of CHOPS created wormholes that accessed certain reservoir zones. Erasing these wormholes and re-initiating the CHOPS process may create new wormholes that could access new zones and recover new oil. The work over could be reapplied on a periodic basis to continually initiate new wormholes into new reservoir volumes.

The most practical approach for this work over would be the injection of low-quality steam for the following reasons:

- Low-quality steam would be less costly than high-quality steam but may have the same effect of disrupting wormholes;
- The lower steam temperature would be more compatible with wells that were not thermally completed;
- The lower steam pressure would be below formation fracture pressure; and,
- Low-quality steam can be easily produced from a portable steam generator.

However, it is possible that even after erasing existing wormholes near the wellbore, and upon restarting the PCP, there would be no significant sand or oil production. Collapsing the wormholes would result in the creation of a volume near the well bore with poor consistency. The stress environment that led to the earlier initiation of wormholes would not exist. The environment of a friable solid placed in an unbalanced stress situation would not be present. Instead what might be present near the wellbore would be a plastic mass that would have the ability to dissipate any strain created by the PCP without localized failure.

There are reports that some operators have tried to re-establish CHOPS after steaming a reservoir that had already been exploited with CHOPS. One steam pilot had failed to deliver expected results. The operator decided to see if production could be re-established with CHOPS. However it appears that CHOPS cannot be restarted after steaming a reservoir. The proposed explanation for this situation was that steam would have driven away any remnant of solution gas and made reestablishment of a solution gas drive mechanism impossible.

## ***11.5. Cyclic Gas and Steam Stimulation***

### **11.5.1. Concept**

This concept is designed as an EOR process after primary recovery by CHOPS. Cyclic Gas and Steam Stimulation (CGSS) is similar to heavy oil recovery method used by downhole steam generators in the 1980s with the exception that the steam generator is located on the surface. Flue gas and low-quality steam are low-cost injectants that may be economically viable in the thin pay Lloydminster reservoirs. A Direct Contact Steam Generator (DCSG) is used to produce the mixture of flue gas and low quality steam that is injected into the heavy oil formation. The DCSG allows the use of low quality produced water. The preference would be to use existing CHOPS wells. The injection volume may be set by a reservoir pressure limit, a time period or by a specified steam volume. A soak period follows to allow thermal energy to penetrate unswept zones of the reservoir. Production is then initiated using the PCP. Once production falls below a certain criteria the cycle is repeated.

### **11.5.2. Features**

The main features of this process concept are:

- Flue gas would be less costly than pure CO<sub>2</sub>.
- Low-quality steam would be less costly than high-quality steam.
- The lower steam temperature would be more compatible with wells that were not thermally completed.
- The lower steam pressure would be below formation fracture pressure.
- The presence of water in low-quality steam would dilute any acidity resulting from the presence of CO<sub>2</sub> and mitigate corrosion concerns.
- Wormholes in the reservoir preclude the application of a drive process where an injectant displaces oil from an injector well to a producing well.



- Cyclical injection and production on a field level takes advantage of the existing wormholes network. Collapse of the wormholes would happen because of the injection of steam but this collapse may not be complete or widespread. The high permeability channels provide a distribution network for injectants and conduits for oil production.
- The combination of steam, condensate, CO<sub>2</sub> and nitrogen as a non-condensable gas results in a variety of interactions with the reservoir matrix and may result in improved sweep efficiency. Nitrogen, a non-condensable gas may penetrate different zones of the reservoir and open new paths for steam and condensate to follow.
- The presence of condensate would reduce the mobility of flue gas in a way that is analogous to the Water Alternating Gas (WAG) process.
- Some CO<sub>2</sub> would dissolve in heavy oil reducing its viscosity.
- The pressure cycle may create a blowdown solution gas drive effect. Reservoir pressure is increased during injection. This pressure is released and used to drive fluids to the well.
- The presence of nitrogen, methane and CO<sub>2</sub> gas in the blowdown fluids may disrupt the sand matrix and create sand production.
- The presence of injected water and condensate in produced fluids could drag additional oil and sand to the well.
- The cyclic nature of the process features a reversal of flow from injection to production in reservoir channels. The reversal of flow may further disrupt the rock matrix, causes additional sand production and may also improve sweep efficiency;
- The cyclic pattern also mitigates concerns about accumulation of scale in the well and possible plugging of the rock matrix by minerals present in injected water. The reversal of flow effectively back washes the wellbore in the well.
- CO<sub>2</sub> reduces the interfacial tension between oil and water and may contribute to the formation of emulsions in the presence of nitrogen. These emulsions may divert the flow of water and condensate into unswept reservoir zones thereby improving sweep efficiency and oil recovery.

### 11.5.3. Challenges

In addition to determining recovery performance and determining optimum operating strategies by gaining experience through field trials, a number of infrastructure and surface facility issues would need to be resolved. These include:

- Non-thermal wells;
- PCP pump elastomers;
- Corrosion concerns;
- Handling and recycling large volumes of produced gas;
- Transferring produced gas and water from wells pads under production to well pads under injection; and,
- Caprock integrity.

## Non-Thermal Wells

Five cases could exist for the application of CGSS in Lloydminster heavy oil. The same process technology would be utilized but the size of the equipment may differ. The five application cases are as follows:

- Existing single vertical or deviated well not thermally completed;
- Existing pad of vertical or deviated wells not thermally completed;
- Existing horizontal wells not thermally completed;
- New pad of thermally completed vertical or deviated wells; and,
- New pad of thermally completed horizontal wells.

For existing vertical and deviated wells that are not thermally completed the casing temperature limitation is understood to be a differential of 100° C or, in other words, a maximum of 120° C, assuming a ground temperature of 20° C. They generally have a non-thermal casing and non-thermal cement. At temperatures above 100° C, their integrity would start to be compromised. Heating would cause buckling of the casing and leaks could occur. In order to inject steam in these wells, an assessment of the risk factors would need to be conducted.

At 120° C, the pressure of saturated steam is of the order of 270 kPa which would be too low to insure efficient injection into the reservoir. Steam could be diluted with inert gases in order to raise injection pressure while ensuring that the partial pressure of steam does not cause temperature to be higher than the limitation imposed by non-thermally completed wells. While this approach would allow higher injection pressures, it would not result in substantially more thermal energy being injected into the reservoir because steam is the dominant carrier of thermal energy. Limiting the temperature of the DCSG effluent to less than 120° C at the wellhead is likely to severely limit the production efficiency of the process when applying it to existing non-thermally completed wells.

Static and dynamic insulation techniques exist to protect non-thermal well casing from the heat form a thermal injection tubular. Table 5 lists some potential static insulation approaches that could allow the use of existing CHOPS wells in thermal EOR.

Dynamic insulation would involve the injection of the flue gas and steam mixture down the well tubing and co-currently injecting cold produced gas down in the annulus space between this tubing and the casing.

The gas injection rate would be set to ensure that the casing temperature does not exceed 120° C. The pressure would be such that steam is kept out of the annulus. The gas would then be injected with the flue gas and steam mixture into the reservoir. The annulus gas would simply augment the quantity of non-condensable gas already injected by the DCSG. The gas would be recovered during the production cycle. Since the gas is flowing downward, the thermal energy it acquires from the tubing would be transferred to the reservoir. The well casing would be protected from an excessive temperature increase. Heat losses to the overburden would be reduced.

Using one of the approaches outlined above, or any other equivalent method, could allow the pressure of the flue gas and steam mixture to reach 4,000 kPa at which point,

the temperature of saturated steam at the expected partial pressure would be approximately 220° C.

<b>Table 5 - Static Insulation of Tubulars</b>		
<b>Insulation Provided</b>	<b>Heat Losses (%)</b>	<b>Casing Temp (°C)</b>
No Insulation	24%	290
Gas Pack	20%	230
Vented Annulus	17%	200
Crude Oil Gel	10%	140
Solid Insulation	6%	90
Source: (Peachey 2002)		

### **PCP Pump Elastomers**

An additional challenge is that existing PCP in Lloydminster are likely to become damaged by exposure to CO<sub>2</sub> or even flue gas because the existing elastomer was not designed for challenging chemical environments. This concern would require further investigation and possibly the utilization of different elastomers.

### **Corrosion**

The injection of hot gas containing CO<sub>2</sub> raises concerns with corrosion of tubulars, PCP and other equipment. As mentioned previously, the presence of water in low quality steam would dilute any acid present. Nevertheless, the subject will need to be examined in greater detail.

### **Surface Facilities**

Surface facilities need to be designed for the handling and treatment of large volumes of produced gas. The operation of PCP in the presence of large volumes of gas will also need to be reviewed.

A characteristic of a cyclic process is that gas and water produced by a set of well under production duty cannot be used immediately by these wells. Production fluids must be stored or, preferably transferred to another set of well under injection duty. Surface transfer lines need to be provided.

### **Caprock Integrity**

The injection of gas, whether flue gas, solution gas or steam, into Lloydminster reservoirs that have been produced may create risks of leakage to the surface. These reservoirs have been punctured over the past decades by a large number of wells that may or may not have been properly abandoned. These old well bores may create paths

for gas leakage to overlying formations and even to the surface. In other words, an assessment of caprock integrity would need to be conducted.

### **11.6. CGSS with Horizontal Wells**

Horizontal wells offer a number of advantages as compared to vertical wells. In particular, their greater exposure to the reservoir matrix allows a more uniform distribution of injectants, access to more reservoir volume and generally improved sweep efficiency. In the thin but aerially extensive Lloydminster formations, horizontal wells would provide greater access to the reservoir, thereby reducing the number of wells and the extent of surface disturbance. Despite their higher initial cost, they result in a greater productivity and economic effectiveness.

Horizontal wells are not used for CHOPS because sand production is not possible with them. Therefore, the use of horizontal wells in CHOPS fields would imply the drilling of new wells as opposed to the utilization of existing wells. This would increase the cost of the EOR technology. However it would offer the opportunity to thermally complete these new wells thereby avoiding the challenges of injecting steam using non-thermal wells. This fact combined with the inherent higher productivity of horizontal wells may make their utilization economic despite their higher initial cost

A clear challenge posed by horizontal wells is that they are unable to sustain sand production. If the EOR technology results in sand production, horizontal wells will not be suitable. However, thermal stimulation of the reservoir would reduce the viscosity of the heavy oil. One consequence is that production of hot and low viscosity heavy oil would not entrain as much sand. This could open the possibility that thermal stimulation could result in sand production levels low enough to allow the use of horizontal wells.

Infill drilling has generally not been successful in reservoirs exploited by CHOPS. The network of high permeability channels that results from CHOPS is an obstacle to infill drilling. During drilling of new wells, loss of circulation happens when encountering high permeability zones. Drilling new horizontal wells in reservoirs that have been exploited with CHOPS is therefore likely to be highly problematic. Upon encountering wormholes there will be loss of circulation. Continuing to drill blind using water would be extremely difficult in thin pay. On the other hand, the use of drilling muds and lost circulation fluids is likely to damage the reservoir. This challenge indicates the opportunity for research and development to tackle the problem of drilling and completing horizontal wells in wormholed or extensively fractured formations where loss of circulation is a problem.

### **11.7. Flue Gas WAG**

Under this concept, waterfloods in Lloydminster would be modified by the periodic injection of flue gas, with or without low-quality steam. As discussed earlier, laboratory work done at the Saskatchewan Research Council indicated that flue gas injection prior to a waterflood significantly increased recovery by the waterflood. The mechanisms postulated for this effect were the presence of a free gas drive and viscosity reduction from CO<sub>2</sub> in flue gas (Dong and Huang 2002).

Another idea supporting flue gas WAG is that the reduction of interfacial tension from CO<sub>2</sub> in flue gas could result in that formation of emulsions in the presence of nitrogen. These emulsions would further slowdown the mobility of water and may block some water channels forcing water into unswept zones.

While flue gas would be more mobile and more prone to breakthrough than water, it may channel into different areas of the reservoir than water and create a path for water to later access these unswept zones.

In addition, flue gas would contribute thermal energy to the reservoir reducing oil viscosity and improving the mobility ratio. While it may be possible to simply inject flue gas, this may not be thermally efficient because flue gas would need to be cooled before reaching the wellhead to meet the temperature limitations imposed by the casing. Using a DCSG would convert some of the thermal energy in flue gas into heat of vaporization. While the same amount of energy is present in the fluids, the fluids are now at a lower temperature. In other words, contacting hot flue gas with produced water would create steam thereby moderating and regulating the temperature of injection fluids.

The combination of these factors could result in an improved sweep efficiency and increased oil recovery. A field trial of the Flue Gas WAG concept could validate the concept and explore the influence of factors such as:

- Gas to water ratio;
- Gas temperature; and,
- Injection pressure.

## **12. Supporting Technologies for Novel Low GHG Recovery**

Previous sections of this report have highlighted the heavy oil resources to be accessed and the options that are being proposed for accessing the resources. There are other potential processes, such as vapour extraction (currently investigated by JIVE), THAI (Toe-Heel Air Injection), or other process which might also be suitable for these reservoirs and are being considered and addressed by others.

In support of whichever process is selected there are some basic research, engineering and geological sciences activities which should be carried out as part of the next steps towards assessing their use in post-CHOPS or post-waterflood reservoirs. This section outlines some of these support investigations and offers some suggestions, where appropriate.

### **12.1. Characterizing the “Depleted” Reservoirs**

The first step that needs to be addressed in assessing a follow-up recovery process is to assess the state of the “depleted” reservoir. As indicated in this report, it is likely that only 10-15% of the oil in place may have been produced, as well as sand, gas and water. In unconsolidated reservoirs, like those found in the Lloydminster region, the production of sand as well as the highly viscous heavy oil makes significant changes in the properties of the reservoir. These changes could have a significant impact on follow-

up processes. Therefore, characterizing the altered state of the reservoir will require some effort and thought.

### 12.1.1. Mapping Post-CHOPS Reservoir Interwell Connections

In many cases, the end of CHOPS production is accompanied by signs of significant interwell communication. Field tests of various types using tracers, changes in gas venting, or various injectants have shown that the materials injected will show up at adjacent wells in a matter of days or even hours. Depending on the recovery process(es) being considered, these connections can either be a benefit or a hindrance. However, in either case, communication paths need to be mapped and assessed as best as possible to allow realistic planning of trials and analysis of results. Potential mapping methods might include:

- **Gas Production Monitoring** – If the wells are still in operation, and venting gas, much might be learned from installing vent gas metering equipment on all wells in an area and observing changes in flows over time as production, venting backpressures, and pump speeds are varied during normal operations, or by intentionally manipulating operations to cause perturbations in vent gas flows. This is relatively low-cost and may only require the rental, leasing or provision of a large number of digital meters and data-loggers. New Paradigm Engineering Ltd. Vent Gas Quantification project obtained a number of examples of well vent behaviour that seem likely to be linked to operation of other wells in that area (Peachey 2002).
- **Tracer Gas Injection** – A more expensive method would be to inject a tracer gas, not normally found in the reservoir, but easily detected and measured at surrounding producers. Analysis of various trials under different production patterns might be used to indicate if gas connections are high or low in the reservoir.
- **Tracer Liquid Injection** – Similarly liquid tracers could be injected with water to determine which wells are connected through lower channels. Monitoring of volumes of water injected with time to breakthrough and pressure responses might provide additional information on the interconnections.
- **Passive or 4-D Seismic** – A growing range of passive, 4-D and comparative seismic methods have been developed in recent years which may be applied to areas of the reservoir while the above tests are being undertaken and might be able to detect variations in seismic signals as flow rates, directions, and compositions change.

### 12.1.2. Connecting Channels

Similar to CHOPS most waterfloods will develop at pattern of interconnections between injectors and producers which represent areas preferentially swept by the water.

- **Water Rate Changes** - Varying water injection rates while monitoring producing well flows, fluid levels and pressures, or use of tracers may indicate these connecting channels. Passive or 4-D seismic might be applied in these situations as well.

### 12.1.3. Locating “Undepleted” Areas

The mapping of reservoir connections may give a first approximation of where are the undepleted areas of the reservoir which have not seen extensive production.

- **Comparative seismic** - Ideally, comparative seismic of the reservoir before and after initial depletion would potentially show this but this type of information may not be available in all areas.
- **“Pressure Pulsing”** – Generating some type of pressure pulse at producing wells may generate signals that passive seismic methods may be able to detect and allow for detection of depleted areas which are not connected to other wells.
- **Infill Drilling** – A more expensive method of assessing undepleted areas would be to drill infill wells where other testing indicates low activity or connections. A common problem in infill drilling is loss of well circulation which indicates the presence of wormholes. Recently some techniques have been proposed that may allow drilling without risk of lost circulation. For example, RC Energy proposed such a system at the March 6th, 2008 Workshop for this project, that utilizes a sleeve to allow drilling with the advantage that lost circulation can be avoided and mud and cement can be prevented from being lost to adjacent well through wormholes.

### 12.1.4. Characteristics of “Undepleted” Areas

Once “undepleted” areas have been detected and accessed the first question to assess is whether or not the undepleted reservoir can be produced as a primary producer through CHOPS, without sand or by waterflood. If it can, then initial depletion by those methods should proceed as long as it is economic. Meanwhile, core and other data should be collected to attempt to determine why the original depletion mechanism did not penetrate further, or if it had any impact on the undepleted zones, such as loss of solution gas, changes in in-situ stresses etc.

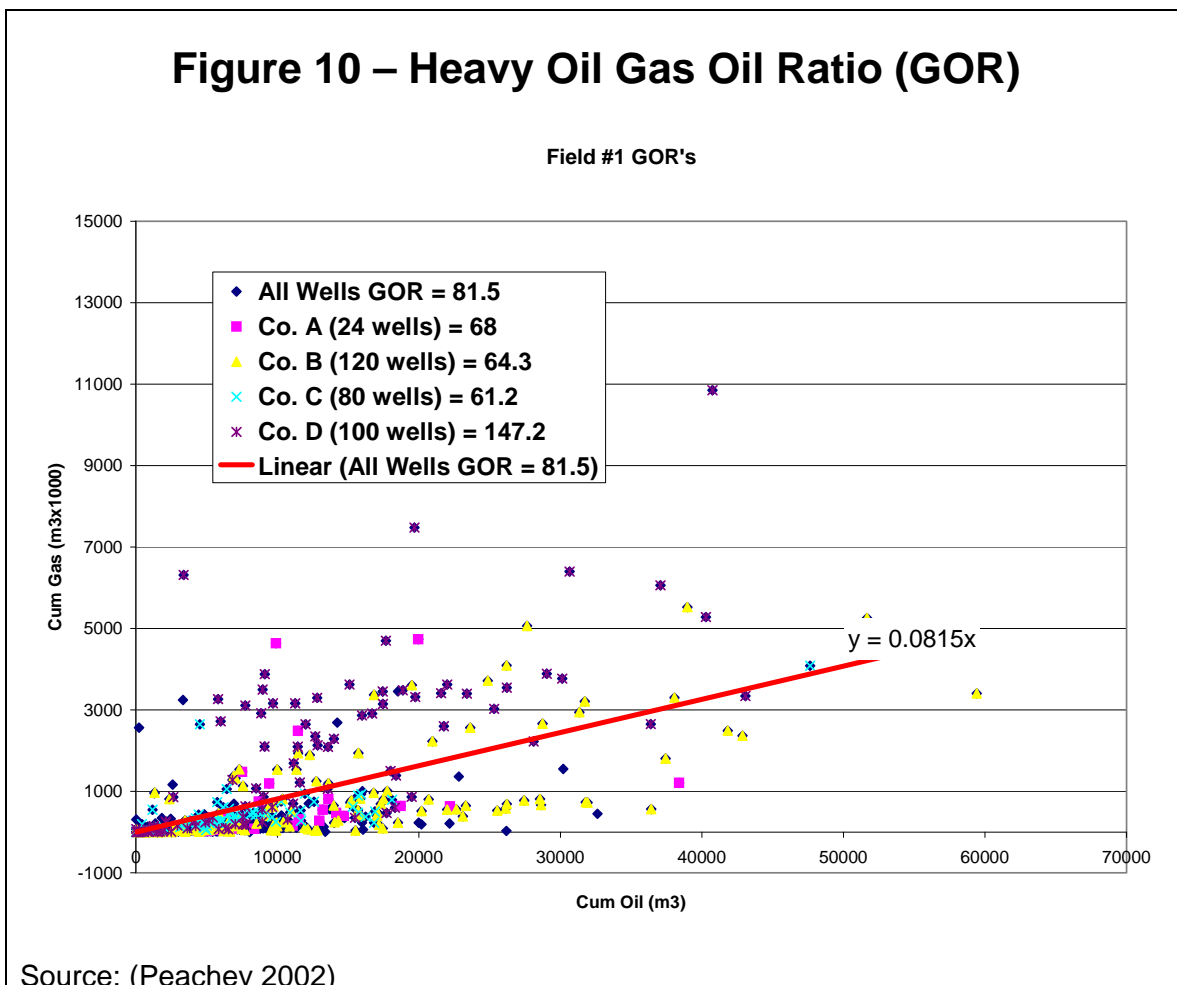
### 12.1.5. Estimation of Produced Sand and Gas Volumes

Past production practices did not put a strong emphasis on measurement and reporting of sand and gas production volumes, even though these were key impacts of recovery driven by sand production and foamy flow. In order to assess the current status of depleted reservoirs some estimate is needed to assess whether the remaining resource has been degassed (either from solution gas of overlying gas caps or coal seams) and the potential volume of sand removed to assess incremental porosity and/or chamber development in the reservoir around the wells.

- **Sand Volumes** – Sand is generally not measured and reported to the provincial regulators, but can be important in assessing the size and extent of wormholes in a given CHOPS well. Operators may, however, have information on the number of tank clean-outs required for each well. Some attempt should be made by companies to work together to develop a consistent methodology for estimating sand volumes produced from a given type of well in pools with similar sand clean-out methods and compare these estimations to other wells where sand volumes have been more accurately tracked.

- Gas Volumes** – Produced gas volumes reported for heavy oil pools, especially from wells producing before 2000 (Alberta) and 2003 (Saskatchewan) when the provinces began to require more complete and consistent measurement of gas volumes, can be of questionable quality. Most reported volumes are based on GORs obtained from annual short duration 24-hour tests using a range of measurement methods, which are then combined with trucked oil production volumes, and then normally adjusted further with estimates of on-site fuel use and venting. The GORs obtained from the testing and estimation are then applied to oil production numbers through the year to estimate total gas production.

Figure 10 compares the cumulative GORs reported for wells in a heavy oil pool in Alberta. The information was taken from New Paradigm Engineering’s Vent Gas Quantification Study (Peachey 2002) and only includes wells put into production after 1995 and is based on the cumulative gas and oil produced to 2003. While it would normally be expected that a given pool would have a consistent GOR, the data on this pool shows inconsistent results from the four main producers in the pool. Three companies (224 wells) appear to report GORs in the range of 61-68 m<sup>3</sup> of gas/m<sup>3</sup> of oil, while a fourth operator, likely using different measurement and estimation methods, is reporting much higher gas rates, averaging 147 m<sup>3</sup>/m<sup>3</sup> from 100 wells.





The above Figure, and similar ones for other heavy oil pools, show that some operators have a bias to reporting higher or lower numbers in some fields. Pool by pool analyses should be undertaken to try and assess reported GORs vs. measurement and estimation methods used so that a more reliable GOR can be determined for each pool. Pool data should also be assessed to look for wells that appear to have high GORs, which may indicate gas cap production. Based on an analysis of over 5,000 heavy oil wells, which began production after 1995, over 90% of the wells show a GOR of less than 150 m<sup>3</sup>/m<sup>3</sup> and most are less than 100 m<sup>3</sup>/m<sup>3</sup> (Peachey 2002).

## **12.2. Assessing Well Integrity**

During the March 6th workshop, C-FER Technologies discussed the issues related to well integrity, particularly in areas of high volume sand production. Three key areas will be particularly important to assess before a well can be considered for use for post-CHOPS EOR processes.

### **12.2.1. Casing Deformation**

In areas of massive sand production there are a range of potential deformation mechanisms that could impair access to a well or which could make a well a much higher risk of early failure when subjected to more energetic recovery methods. A key need before implementing new EOR should be to assess casing deformation which has already occurred so that the condition can be assessed and monitored in later production stages. Development of lower cost methods of assessing and analyzing deformation would greatly assist producers in gathering more information on the current state of the wells and also to allow on-going assessments during field tests to determine what degree or types of deformation are most at risk in EOR operations of various types. Due to the wide range of variables involved, this would best be undertaken as a Joint Industry Project with third party collection and analysis of data collected to allow for early identification of trends and development of casing failure mitigation strategies for low temperature thermal types of recovery.

### **12.2.2. Communication Behind Casing**

While wormholes are considered to be the main source of sand production through the CHOPS mechanism, there are also many cases where it appears that there is little or no barrier to flow behind the casing indicating at least some type of “chamber” or “cavity” may be formed in the near wellbore area. Defining the degree and extent of behind casing communication may help identify both additional concerns with lack of support for casing and how any injected fluids and gases may interact in the near well area. For example, a large cavity may result in rapid separation of injected gases and liquids which will impact flow behaviour and vertical sweep patterns in the reservoir. New methods of assessing communication behind casing should be assessed. This might include either physical removal of the casing to assess what is behind it or development of logging and analysis methods which might indicate the competency of the formation behind the casing.

### 12.2.3. Sources of Water Inflow

While not all CHOPS wells end their lives through watering out, it has been observed to occur in many wells, even after only a few days or weeks in production. Maurice Dusseault, also indicated, in his presentation at the March 6th workshop, that there are cases documented when water influx has increased for a short period and then stopped on its own. In any thermal or gas/solvent injection process, communication with a water zone usually has a major impact of recovery performance. Therefore, gaining a solid assessment of the volumes and sources of water which might be produced by heavy oil wells will likely be a key factor in the EOR success and minimizing energy and injectant losses. Methods of assessing water inflow might be:

- **Fingerprinting** – Gathering more extensive water compositions from producing, underlying and overlying water zones, and gathering this data into a central database may assist in determining water sources.
- **Water Production Profiles** – Gathering and analyzing more data on water production profiles for a wide range of wells may indicate characteristic inflow profiles for water from different sources or which enter the producing wells through different mechanisms. Data mining tools can often distinguish and predict trends even where the underlying processes are only poorly understood.
- **Tracer Studies** – Where water communication between zones is suspected some additional effort to conduct tracer studies on specific wells, may assist in determining the most likely sources of water influx on a pool wide basis, and will at least gather basic information required to assess potential mitigation methods to stop the inflow.

## 12.3. Assessing Site Assets

This effort is mainly directed at characterizing the resources or assets available at each potential target area. In any EOR process, the main assets needed for enhanced production are usually related to low cost energy sources, followed by water for thermal operations and systems to transport, store and dispose of surplus volumes of produced gases.

### 12.3.1. Fuel

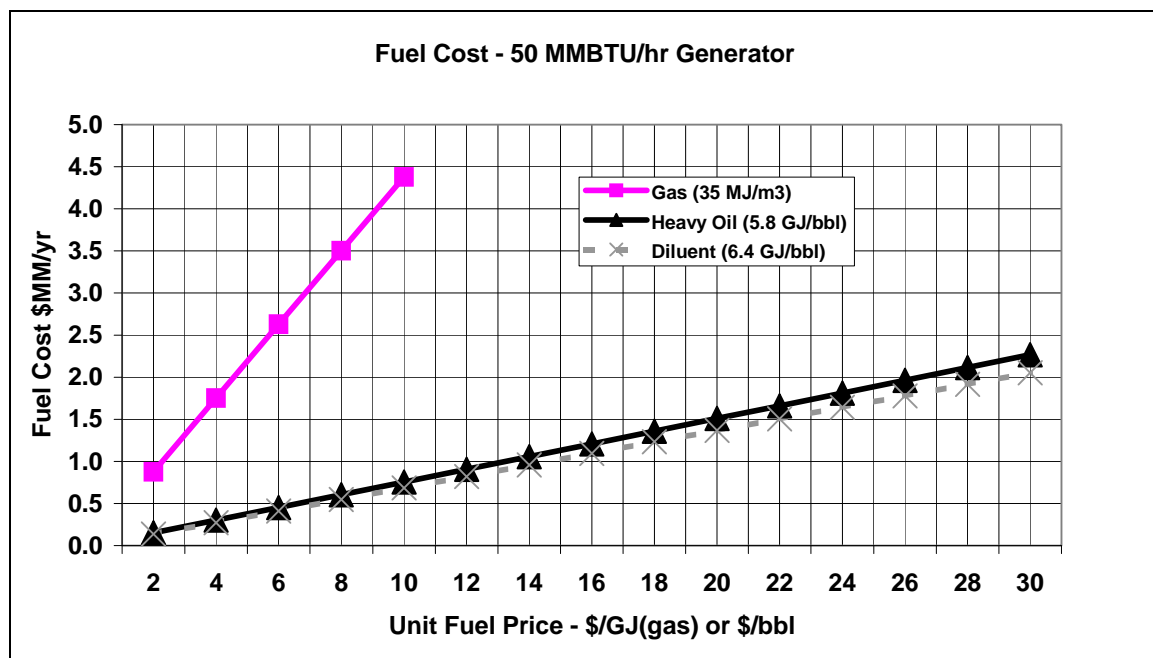
In most heavy oil operations methane is generally co-produced with heavy oil in volumes sufficient to provide energy for operating on-site equipment and heating. Current operations produce enough methane to operate engines to drive artificial lift systems and to heat production tanks for on-site separation, often with fuel to spare to export to other leases or for sale. Many heavy oil areas also contain shallow gas pools and may also contain shale and coal bed methane, which may serve as potential local sources of natural gas to avoid purchasing natural gas from pipelines or rural gas systems. A key factor will be to try and conserve local gas reserves for EOR and protect them from being contaminated with other injectants to the point where they cannot be used as fuel.

Sweet liquid hydrocarbon streams (e.g. low quality streams from an upgrader) might also be used for fuel where natural gas volumes are insufficient to meet the on-site needs.

Upgraders often generate streams that are low sulphur but have lower value as fuel demands change over the year, the lowest cost fuel option would be preferred. With liquid fuels currently at \$100 per barrel, it is unlikely liquid fuel would be lower cost than natural gas, even with the additional costs of pipelining gas. However, conversion between these two streams is relatively easy to do.

Heavy oil could also be burned as it is generally much lower in value than light sweet hydrocarbon liquids (average 30-40% lower in value), and may also not attract any royalties. An illustration of potential benefits is shown in Figure 11. The downside is that the heavy oil contains sulphur and emissions of sulphur dioxide will be a concern. Therefore, heavy oil as fuel is not a desirable option unless flue gases can be contained, as they potentially might be with Direct Contact Steam Generation.

**Figure 11 – Cost of Fuel Options**



Source: (Peachey 2002)

### 12.3.2. Power Sources

Many existing heavy oil well sites are not electrified as the cost of bringing in expensive electrical power is prohibitive. Often sites for water treatment and disposal, and for oil collection for treatment to sale specifications, are tied into the grid. Potentially power for these sites could be generated using surplus vent gas through the use of natural gas fired reciprocating engine gensets where power distribution systems are deregulated. With the processes proposed in this report, energy will potentially be required for compression of fuel, flue gas, and/or air, pumping of water and produced fluids, as well

as instrumentation for monitoring. With the use of clusters of single well batteries, alternating as injectors and producers, avoiding electrical power use on the sites is likely preferred.

### 12.3.3. Water

Sources of surface water are rare in the Lloydminster region except for the North Saskatchewan River and a few minor tributaries. However, saline/brackish produced water is available everywhere in the Western Canadian Sedimentary Basin and can be sourced from a number of zones that should be accessible from existing wells that prove to be unsuitable for injection or production. Using untreated brines is suitable as long as high quality steam is not generated and as long as heat fluxes are kept relatively low in the heating equipment, as they are in tank heaters, oil treaters and systems with indirect heating through use of heat pipes or other intermediate clean fluids.

If any combustion gases are being captured for injection, the exhaust gases will also contain water vapour which may be condensed and conserved if it is done in a way which will avoid the formation of concentrated acids in contact with carbon steel pipe or where more exotic metallurgy is used. Examples of these types of systems are given in the Direct Contact Steam Generator Report.

### 12.3.4. Delivery and Production Systems

Current operations have limited pipeline systems, mainly low pressure plastic piping for intersite transfer of vent/fuel gas, and steel lines for heavy oil and water gathering where there is high watercut production. The majority of the produced fluids and sand are usually produced into on-site tanks and trucked to centralized batteries for treating for oil sales and water disposal. This system has developed in order to maintain low capital costs and to reduce risks if a well fails early in its life. Options for future delivery and production systems include the following:

- **Dry Methane, Fuel or Flue Gas** – Ploughed in plastic lines operating at pressures below 2,800 kPa and 60 degrees C will likely be the best option, as they are in current operations. Costs are relatively low ranging from \$7,000/km for 2" lines to \$15,000/km for 6" lines. These lines are installed so they can be reclaimed and reused.
- **Heavy Oil** – Heavy oil is difficult to pipeline unless it is mixed with a larger volume of water, heated or diluted. Gathering from individual wells is difficult as lines may have to be purged in winter if the producing well goes down to prevent the oil from setting up in the line. However, trucking of oil may still be feasible. Heavy oil producers are working with the Saskatchewan Research Council's Pipeline Research centre to define the limits of application of gathering lines for heavy oil.
- **Produced Water** – Produced water lines can be buried deep enough to be used for transporting water between sites as long as heavy oil contents and solids are controlled. Using steel lines, potentially ploughed-in coiled tubing, would them allow for collection of heavy oil by pipeline when there is adequate produced water to keep the oil moving. Lines should be designed with no short radius elbows so that they can be easily cleaned out or pigged.

- **Sand** – Sand is currently cleaned out of the production tanks and trucked to sites where it is disposed of in salt caverns. This will likely continue to be the practice as sand volumes in the EOR process should be reduced from the levels seen in CHOPS and the presence of sand puts the gathering lines at greater risk. C-FER Technologies in Edmonton, is working on an alternate concept, called “Super-Sump” where smaller salt caverns are created for a group of drain wells, or potentially a cluster of conventional wells, to be used for local separation and disposal to reduce trucking and handling costs.
- **Imported or Manufactured Injectants** – If pure injectants, such as pure CO<sub>2</sub>, propane, oxygen or other “manufactured” injectants are to be used, the thin nature of most of the resource area will likely make bringing injectants in by pipeline too expensive. Therefore, these materials will likely be trucked in unless there is a thick channel zone that can be reliably developed and operate over a relatively long period of time.

### 12.3.5. Gas Storage Zones

Many of the producing areas have gas pools in the local area, which may or may not be connected to the heavy oil producing zones. Most of these zones may already be depleted or partially depleted by the time EOR activities commence. However, they could prove useful for cyclic gas injection operations. Potential uses might be:

- **Storage of Gases** – A key challenge, for a process based on periodic injection and production, is that injection may not be possible while production is underway if the wells are widely interconnected. In this case, it may be useful to collect the produced gases from production operations and store them in depleted gas zones until the next injection cycle begins. Preferably the main gases stored would be methane and/or CO<sub>2</sub>, with nitrogen vented as it is produced.
- **Enhanced Gas Production** – Gases surplus to the needs of the EOR operation could be injected into partially depleted gas zones to enhance gas production from those zones at low cost. Often gas zones still contain 30-40% of the Original Gas in Place and this incremental gas could be used in the EOR operations.
- **Gas Separation** – It may be possible to use depleted gas zones to help separate produced gases into methane, CO<sub>2</sub> and nitrogen if there is sufficient time for the gases to gravity separate in the highly permeable gas zones. If coals, shales or water are present in the gas zones these may absorb CO<sub>2</sub> and provide some sequestration benefits while enriching the remaining methane gas.

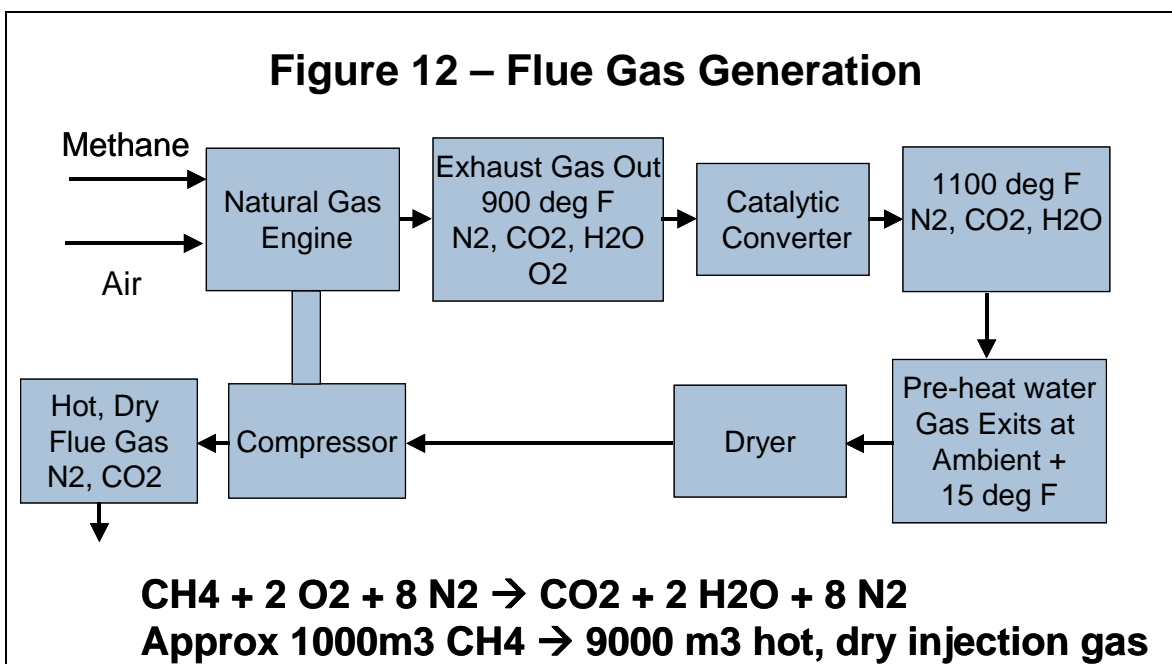
### 12.4. Injectant Supplies and Properties

As indicated earlier in this report, for the EOR process to be economic the injectants used must be available at low cost. Traditionally, reservoir engineers have only considered the use of high quality steam, high purity CO<sub>2</sub> or other solvents. The high quality and high purities come at a price in higher supply costs and more capital intensity and large scale processing equipment. While these high purity injectants may be preferred for thick rich deposits, supplying these types of materials to a wide-spread low

quality resource like most of the conventional heavy oil fields is likely unrealistic, especially since heavy oil is considerably lower in value than light or medium crudes.

### 12.4.1. Flue Gas Generation Methods

Flue gases from combustion sources are primarily made up of nitrogen, carbon dioxide and water vapour. Flue gas can be generated at any site with a suitable fuel supply, combustion equipment and some method of capturing the flue gas and pressurizing it for use. Some flue gas is already being generated from tank heaters and natural gas engines used to drive the existing artificial lift equipment. Potentially this equipment could be adapted to generate flue gas for injection. However, during injection this type of equipment is not likely to be operating on the injection site and collection, it may be cost prohibitive to collect this from remote production sites unless it can be stored in some fashion.

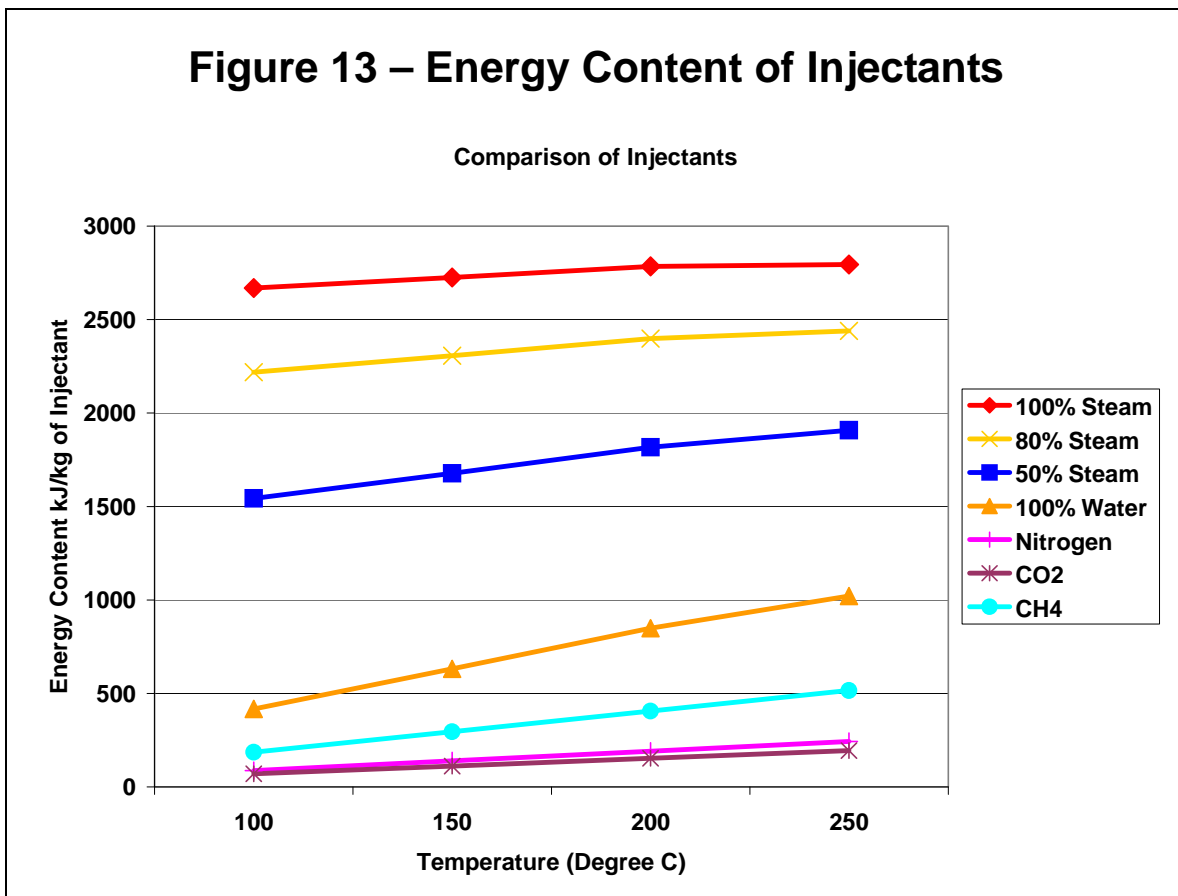


The above flue gas generation and compression process was originally developed for generating inert gas for underbalanced drilling, but has been adapted for generating nitrogen/carbon dioxide streams for re-pressuring gas-over-bitumen zones, and could be used for portable flue gas generation for conventional light to heavy oil recovery. The engine could also drive a power generator, and the heat generated by combustion and compression could be recovered to provide on-site heating and/or heating of other injectants.

Streams richer in some components might be desirable. Therefore, provision could be made to add other gases upstream of the compression such as methane from vent sources, pure or enriched CO<sub>2</sub> streams, or to the gases available.

### 12.4.2. Thermal Sources

For thermal operations in existing wells, the heat energy must be provided at a relatively low temperature 100-200° C (depending on in-well insulation scheme used as discussed in the next section). The product could be hot water, low-pressure steam, hot dry gases, water saturated gases or heated solvents. The chart below shows the relative energy content of various pure streams that might be injected. While 100% steam provides greater energy input per kg, the same energy could be input with larger amounts of the other materials e.g. 3 kg of 250° C water can deliver as much energy as 1 kg of 250° C steam, but can be provided at a much lower cost.

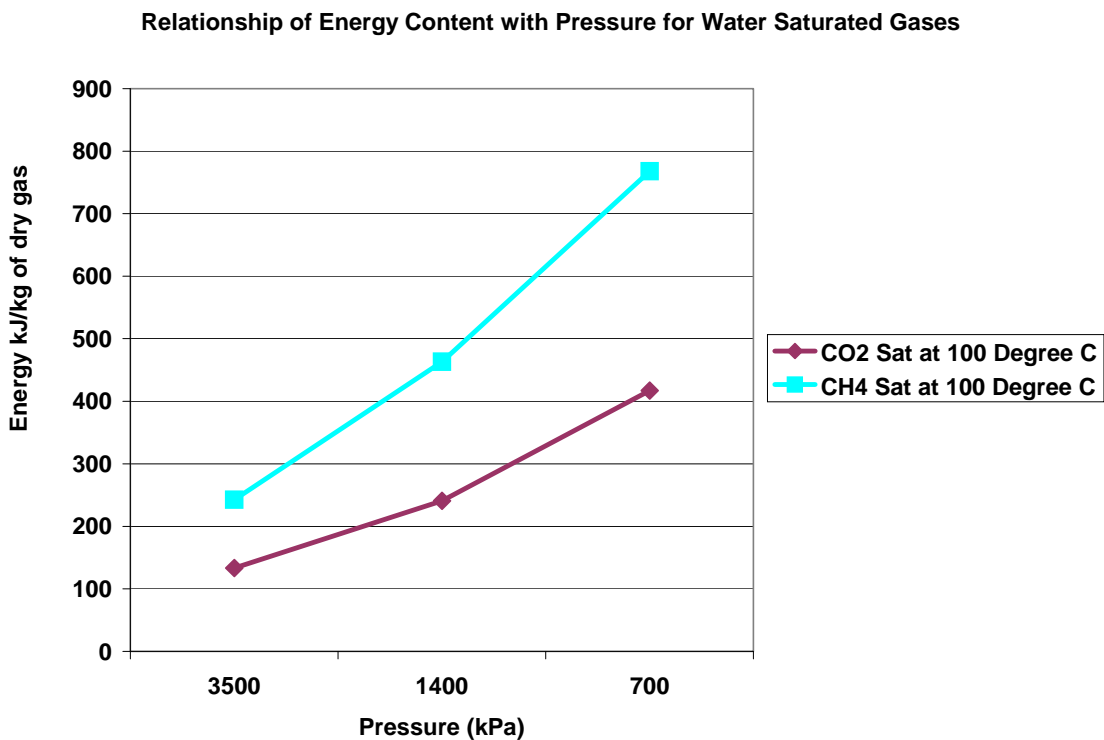


- Water Based Thermal Options** - To avoid the cost of water treatment it will be preferred to use heating methods with relatively low heat flux and to avoid boiling which might lead to heater fouling through hardness deposition. 100% steam requires demineralized water, which leaves behind minerals which must then be disposed of. Therefore, it is not very amenable to a small-scale, low cost or portable operation. 80% quality steam can be generated while retaining much of the salts and oil in the water phase but would likely still need water softening. As the quality of the steam generated drops the quality of the water needed for generation also drops to some point where some steam can be generated without

anything except basic produced water clean-up. The optimum steam quality will depend on the types of water sources and compositions available at a given site and the amount of capital, which can be invested to treat it, vs. the incremental costs of pumping more water back with the oil production.

- Gas Based Thermal Options** – Hot gases can be generated just from compression systems, as most available gases will be low pressure to start with, and heat is generated during compression, both from the engines and from the gas compression itself. Natural gas engine exhaust is often in the range of 450-500° C, and compressed gas may be at 200-300 ° C, which will likely be too hot for non-thermally cased wells. Potentially these hot gases could be “quenched” or cooled by using the hot gases to heat a co-injected water stream or to vaporize and heat any imported solvents such as liquid CO<sub>2</sub>, nitrogen or propane.
- Saturating the injected gases with water vapour** will increase the amount of energy transferred, especially at low pressures. This might be desirable to reduce the amount of compression required and if there is open communication between two wells. The water vapour energy in the gas stream will be given up as the stream cools and the water condenses. Since it is a mixture the water vapour does not have a fixed pressure/temperature saturation curve as is the case with steam so the energy should come out over a larger area of the reservoir and more gradually.

**Figure 14 – Energy Content of Water Saturated Gases**





### **12.4.3. Hybrid Systems**

The various forms of the Direct Contact Steam Generator provide hybrid systems which provide the advantages of both flue gas and thermal systems, while reducing the equipment required on site, thus lowering the costs. Compression is still required for the injected air and for any lower pressure natural gas used as fuel, or pumping for liquid fuels, however, it is believed that problems experienced in handling flue gases and water treatment for stand alone steam generation will be mitigated in DCSG and overall energy efficiencies will be greatly improved, while water is generated, and equipment costs are minimized. See companion report on Direct Contact Steam Generation (DCSG) systems.

## **12.5. Injection and Production Methods**

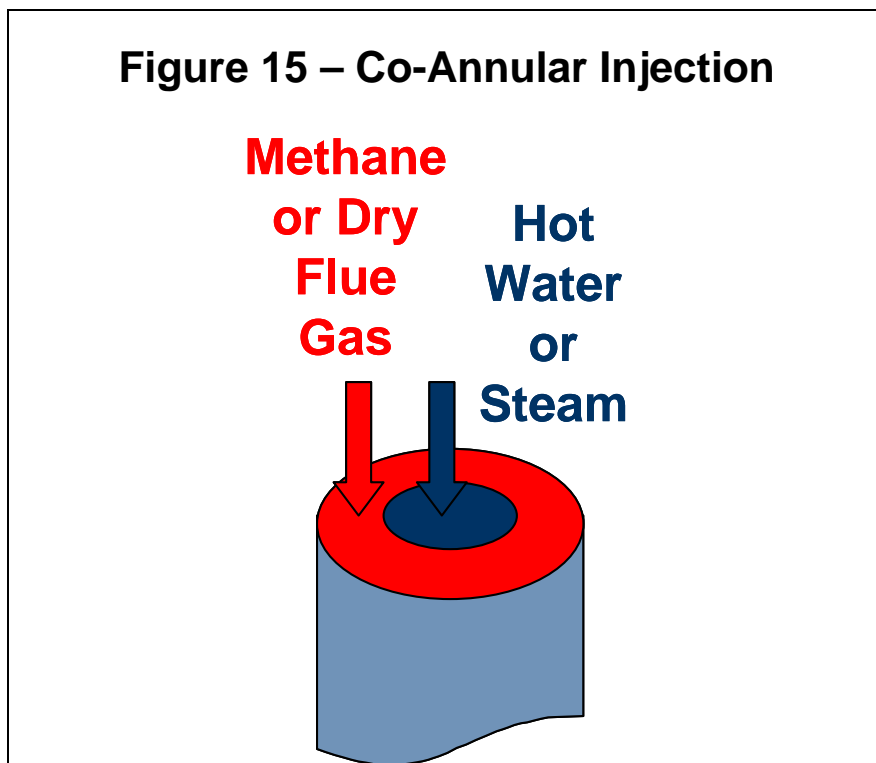
As has been mentioned a number of times, the conversion of existing cold production and water flooding operations to some type of thermal, CO<sub>2</sub> injection and/or solvent process will be faced by limitations imposed by the existing well infrastructure and incremental challenges as a result of injecting hot and potentially corrosive materials. Options need to be assessed to deal with these new environments, and each option will have to be adjusted, based on the recovery methods used in any given area.

### **12.5.1. Co-annular Injection**

One of the most critical requirements of any EOR process to enhance its profitability will be to make best use of the existing well infrastructure. As almost all of the existing wells were not thermally completed they would be likely to fail if casing temperatures were to rise above about 100-120° C. Also with the proposed injection of flue gases or CO<sub>2</sub>, it will be necessary to protect the production casing from corrosive attack. Conventionally, the well casing would be insulated from the tubing by putting some type of material in the annulus, with a downhole packer to maintain isolation.

A proposed alternate method of insulating the annulus and protecting the casing is to utilize a co-annular injection scheme, as illustrated in Figure 15. In this method, some type of dry gas is continuously injected down the annulus, with the wet or more corrosive streams contained in the tubing. This method has the advantages that:

- The dry gas in the annulus insulates the casing from the hot tubing and carries any energy given off to injection.
- Dry gas flowing downwards will stop wet gases from entering the annulus and condensing to acids.
- Rates can be adjusted from high-rates during injection to low rates during hot production and no gas once the well cools off to allow venting of cool gas from the annulus at low pressures when condensation is unlikely.
- Avoids the need to install a downhole packer to isolate the annulus from the injected fluids as is required with most other methods of insulating the tubing.



### 12.5.2. PCP or Multi-Phase Pumps

The main methods currently used for pumping cold production wells are Progressing Cavity Pumps (PCP), in high rate and high sand wells, or beam pumps in low rate, low sand wells. As all the pumps used are positive displacement they will likely have to be pulled or at least “unseated” during the injection cycles, preferably without having to pull the tubing which would increase costs.

While some adaptation of pump materials and methods are anticipated with the implementation of EOR schemes, the basic equipment should remain relatively unchanged, or new pumping systems could be adopted.

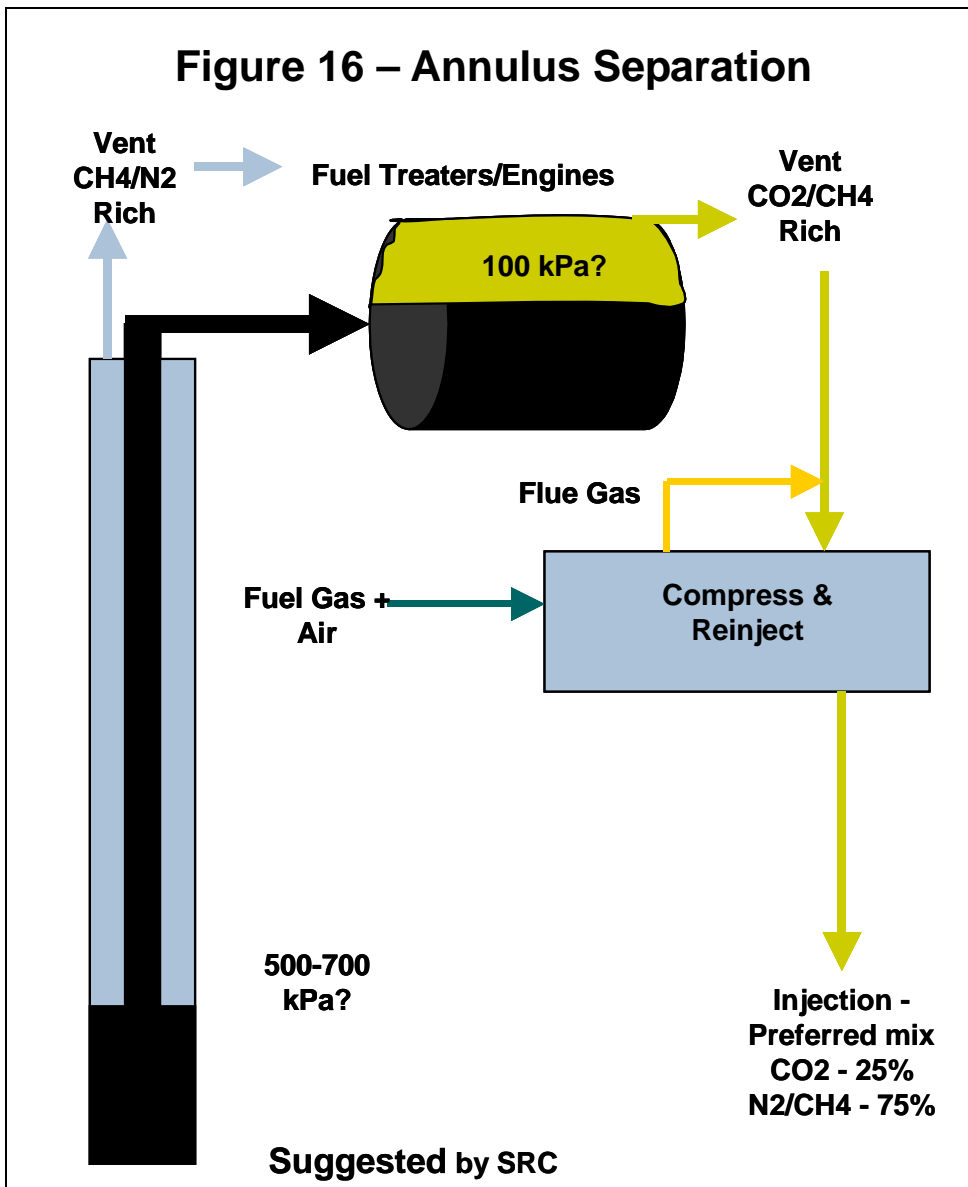
- PCP Adaptations** – PCPs are positive displacement and are driven by rotating rods from surface. They can already handle a considerable amount of free gas, although with decreased efficiency, and can handle sand. The main impacts of moving to some type of heated, solvent or gas based recovery will be in selecting the best elastomer for the pump stator and to protect the pump rotor and rod string from corrosion. If the oil content of the produced stream is high, corrosion may not be a major problem. However, the elastomers will tend to swell in the presence of high concentrations of solvents, soften at higher temperatures, and potentially experience damage from “decompression” if pressures fluctuations do not allow any absorbed gases or solvents to migrate out of the elastomer. PCPs are being developed for higher temperatures (metal on metal seals) and lighter oils so it is anticipated that most of these problems can be overcome once the pumping conditions have been determined.

- **Beam Pump Adaptations** – Reciprocating rod beam pumps are already used in a wide range of applications, but are best suited to situations where gas and sand volumes are low. Production rates may be limited to avoid gas production through the pumps, or gases will have to be vented through the annulus which may be a problem with any wet CO<sub>2</sub> gas production where condensation might occur in the well annulus.
- **Multi-Phase Pumps** – Other multi-phase pumps are coming on the market for downhole applications which can operate with high gas flows. Generally these machines have metal to metal seals so should be less impacted by the composition of produced fluids or gases, and should be able to handle 100 to 150° C temperature changes.

### 12.5.3. Annulus Separation

In the previous PTAC study, Low Carbon Futures, the Saskatchewan Research Council had suggested that the optimum injection gas for heavy oil might be a mixture containing around 25% CO<sub>2</sub>. They also suggested a potential method of obtaining enriched gas for re-injection through a two-stage separation of the produced gases.

As shown in Figure 16, the proposed process would vent the less oil soluble gases, mainly methane and nitrogen, from the well annulus, while maintaining a relatively high downhole pressure and a low temperature. This stream could be used for fuel, although additional methane might have to be added to stabilize the gas heating value. A second stage of gas separation at a lower pressure and higher temperature in a pressurized separator would produce a gas stream enriched with CO<sub>2</sub>, which could then be preferentially sent for re-injection. Implementing this type of process would require better tools for predicting gas solubilities in heavy oil, and would require some means of transporting the CO<sub>2</sub> rich gas to injector wells, but may considerably enhance the recovery process. While the impact of CO<sub>2</sub> on heavy oil is small, this process might also be used for light and medium density oils at higher pressures.

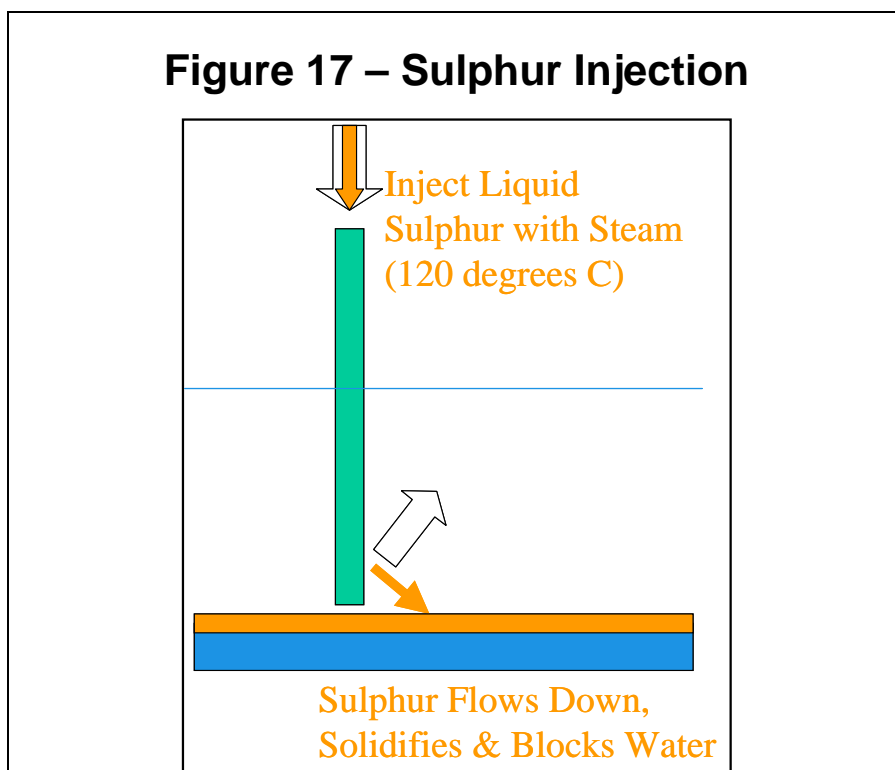


#### 12.5.4. Blocking Water Influx

Unwanted water influx will tend to reduce the efficiency and control of any enhanced recovery process. As with any downhole water management process, the key need is to determine where the water is coming from. Potential sources have been described earlier in this section. The mitigation method will generally depend on the source of the water influx.

- **Bottom Water** – If the water is coming in from a lower part of the reservoir, then, generally, the objective is to inject something that will block or hinder water flow in the well. In some cases dumping in cement will shut off the water. However, this generates a static slab, which may be bypassed over time. Another option is to

inject wax, which will distribute itself in the water wet area and block channels and make it more difficult for water to enter. Another suggested option is to inject molten sulphur which is liquid at 120° C, but will flow downwards and solidify once it contacts and is quenched by the water. The advantage of wax and sulphur in a low temperature thermal operation is that if steam leaks through them on the next injection cycle they will remobilize and can re-block any new channels which may form.



- **Top Water** – Top water may be caused by leakage from overlying water layers through channels outside of the casing, or through the formation of small fractures in overlying shales due to subsidence from CHOPS compaction drive or other causes. In these cases, remedial cement squeezes above the top of the formation may resolve the problem, or flows can be minimized, as they are in low pressure SAGD, by attempting to maintain the producing zone at a higher pressure which will still allow drawdown to the well, while minimizing water inflow. A concern with top water would be that pressure cycling may make the situation worse. Therefore, areas with top water might be considered for trials of VAPEX or some other process which operates at a relatively constant reservoir pressure.
- **Side Water** – Side water is water that comes in from the edges or pockets in the producing formation. Once an edge well waters out there are indications that water may quickly flow through to other central wells through wormholes. Options might be to use horizontal wells to de-pressure the aquifers at the pool edge, by pumping water into other zones or for use as a thermal injectant to thermally flood

from the center of the pool outwards. As in the case of top water, the EOR process selected might be one with a higher average pressure. Or some method such as steam or foam injection might be used to try and close the wormhole channels connecting to edge wells.

## **12.6. Production Facilities**

With aerially extensive and thin reservoirs, a characteristic of cold heavy oil production has been the use of small scale and highly portable production equipment such as truck loadable tanks, truck engine drives for pumping equipment and recoverable PVC piping for inter-site gas transfer. The same factors will drive the design of production facilities for enhanced heavy oil recovery, but will require some changes in the equipment required.

### **12.6.1. Pressurized Separation**

Currently production is sent from the well to an atmospheric tank for separation of oil and water, and for heating to allow oil transportation by truck. In most heavy oil areas, the only environmental impact of atmospheric treating is the need for more tanks to handle production from foamy wells, methane GHG emissions from the tank and well vents, and combustion gas emissions from the tank heaters. For enhanced recovery methods, which use injected gases or solvents, atmospheric tank separation will no longer be practical. The solvents and gases must be collected when they are produced back so they can be re-injected and/or the solvents may cause odour or other issues that are not present in current operations. Local vendors have already been working to develop pressurized separators for heavy oil and heated/pressurized separation is common in most light and medium oil operations, so the technology should be readily migrated to conventional heavy oil. Units can still be modular and portable to allow flexibility and optimize the use of capacity as production rates and separation needs change.

### **12.6.2. Low-cost Gas Treatment and Monitoring Modules**

The other main change in production facilities is related to the capture, treatment and recycling of the various gases. Capture of methane in a form that allows its use as fuel, and avoids venting will be key to low-cost and low GHG emission operations. Nitrogen from flue gas injection must be purged from the system as it is the least valuable gas, innocuous from an environmental perspective, but can hinder the recovery process if it is allowed to build up. Carbon dioxide can contribute as a solvent to reduce viscosity for both reservoir recovery, production separation and potentially for pipelining of heavy oil. If possible, it would be an advantage for any surplus CO<sub>2</sub> to be re-injected into other zones or sequestered by some process. For all gases removal of water vapour on surface will be necessary to allow transfer of gases between sites. Potential processes include:

- **Salt Dryers** – Salt desiccant dryers are often used in current options to dry vent gas in winter to prevent fuel gas freeze-off. They tend to be low cost from a capital perspective but salt usage will be much higher as produced gases increase in temperature and become more water saturated.

- **Membranes** – Membranes could be used for concentrating the various gases, as long as there is sufficient pressure and the membranes must be protected from oil contamination.
- **Gas Monitoring** – With the increased variability in gas flows and compositions in an EOR operation, it will be necessary to greatly enhance the ability to monitor well operations, especially the flow of gases which indicate in-situ performance of the recovery process. Low cost methods of measuring gas flow rates, assessing the compositions and communicating that information on a real-time basis will likely be a key factor in successful EOR operations.

## **12.7. Inter-well Issues**

Given that prior production of the reservoirs using CHOPS, or waterflooding may have enhanced interwell connections, it is necessary to consider how those interconnections will impact operations. As has been suggested, operating the wells in clusters helps to minimize the negative impacts of the interconnections. Operating cyclic clusters must still address interwell issues that result from this type of process.

### **12.7.1. Ownership of Wells in Clusters**

A key non-technical issue is that some of the well connected to each other may have different ownership. Ideally one company should control or operate all the wells in a cluster operation. If not the owners of the non-operated wells will either benefit from injection at no cost or may feel the operations are adversely affecting their own operations. Forming a unit or some other type of joint operating agreement is the best way to resolve this. Otherwise, methods may have to be developed to try and close down interwell communications channels without adversely affecting the overall EOR performance.

### **12.7.2. Gas Redistribution Lines**

A key challenge with cluster well operations is that wells undergoing injection (huffing) will not be producing gas. This requires that gas redistribution lines in an area be designed and sized to allow free transfer of gases between clusters in producing and injecting stages. Ideally these would be the same lines currently installed for vent gas collection but some additional lines may be required to more directly link sections of the system or to increase gas flow capacity.

### **12.7.3. Oil/Water Gathering**

Ideally oil and/or water gathering lines should also be designed for bi-directional flow of fluids so that they could be used during the production phases and potentially reversed to deliver water to the injection sites in the injection phase.

### **12.7.4. Impacts of Pads vs. Single Wells**

Economies of scale tend to drive pad well development as the complexity of the processes and the investment in processing equipment, pipelines or lease development become more significant than the incremental cost of drilling and operating directional

wells. Only a few conventional heavy oil or cold bitumen production areas have been developed with pad wells, so the majority of the leases are single well. If additional wells are needed for EOR consideration should be given to directionally drilling them from existing single well leases to increase operational flexibility.

### **12.7.5. Well Operations in Clusters for CGSS**

Operating clusters will create new challenges for reservoir managers and field engineering and technical staff to plan injection and production patterns within the constraints of interwell connections both in the reservoir and on the surface. These plans will have to be dynamic as thermal or other methods may cause wormholes or communication channels to open up or close off over time, and field operations will have to adjust to these changes rather than sticking to a fixed long-term injection and production plan. While injection and production planning will become more complex, operating wells in clusters may allow the development of operators who can specialize in either production or injection equipment to maximize knowledge gathering and to recognize changes or differences in operations between well clusters or pools.

## **13. Sustainability Issues for Novel Low GHG Conventional Heavy Oil**

While most of this report focuses on production and injection practices for heavy oil development using novel processes, those processes were mainly developed through consideration of their impacts on the three key sustainability criteria of: economics, environment and security. This section considers how the proposed processes can positively impact sustainability in comparison to current operations, other potential EOR methods and the “do nothing” case.

### **13.1. Economic**

While all three legs of sustainability are critical, economic criteria tend to be the main drivers for changes that require environmental and security issues to be addressed. In other words, if the proposed processes are not economic then the default is to do nothing, which tends to make assessment of the environmental and security impacts much more predictable in the near-term.

#### **13.1.1. Modular/Portable Equipment**

Modularized and portable equipment will be a key factor in making production of heavy oil by EOR methods feasible from thin and aerially extensive conventional heavy oil resources. As the oil is already mobile it should not require continuous injection to maintain production if cyclic injection can re-energize the reservoir. By utilizing the same capital equipment for multiple well clusters, the capital costs are spread out over a much wider asset base and are not at risk if a particular well or group of wells fails to perform. As will be discussed later, modularization opens up other business models for providing the required equipment and operational services.



### **13.1.2. Opportunities to Reduce Capital Investment**

Traditionally progression from primary or secondary recovery to EOR results in a significant increase in capital investment for new wells, fixed facilities and long distance transportation of injectants, and usually is implemented as a major field conversion. By modularizing and operating in clusters, as CHOPS or waterflooding become less economic, the investment in new EOR facilities can be done in small increments using a small project management and construction team. Avoiding major multi-year, multi-million dollar capital projects, and developing assets with small modular units, makes it possible to take advantage of short-term downturns in major oilsands projects or utilize workers outside of the over-heated Alberta construction industry. All of these factors, and others would present opportunities to reduce capital investment.

The use of modularized and portable equipment also raises the possibility that much of the required equipment could be built and leased to producers by local vendors, rather than being purchased. This reduces capital requirements for producers who generally have greater expectations for return on capital than would be the case for a local equipment vendor or service company. Sharing the equipment spreads the cost of design and fabrication over all users and helps to ensure that equipment utilization is high as vendors will be motivated to market the use of any equipment that is available but under utilized.

### **13.1.3. Maximize Use of Local Natural Gas and Energy Sources**

With highly variable energy commodity prices there is a significant advantage to maximizing locally available energy sources, many of which can be used on a royalty free basis. There is already a surplus of vent gas available in the region and low rate gas resources, not commercially viable for stand alone production might be utilized to provide energy for the EOR production. In most of the target area, rural gas distribution networks are already in place and may be sufficient to supply any make-up gas needed to fuel operations.

Other local opportunities may exist to use local natural gas to generate power, or to substitute low value fuels for natural gas if liquid hydrocarbon commodity prices drop below the value of natural gas. Generally it is more certain that natural gas prices will increase over time, as production moves to unconventional low pressure, remote Arctic, or offshore LNG sources. Heavy and light oil markets are more likely to be driven by international politics and security issues, at least in the near-term, rather than true supply shortages.

### **13.1.4. Maximize Use of Locally Available Injectants**

The other major supply issue for EOR is in having access to supplies of low-cost injectants, mainly flue gas and water, for the processes discussed in this report. For low quality, low value, thin and aerially extensive assets, any process that requires construction of large injectant supply networks, will tend to significantly drive up costs. As these imported injectants are high cost to purchase, there is a parallel need to install more sophisticated equipment and monitoring to recover and recycle the injectants to prevent losses. The other aspect of imported injectants is that they are subject to

demands from other, more lucrative, or critical needs, which can quickly dry up supplies for less economic developments heavy oil production. For example, propane/butane supplies are dropping as production of rich deep gas is displaced by lean gas from shallow or unconventional sources, and as light oil production, with rich solution gases declines, and is replaced by heavy crude and bitumen which has methane in solution. Another factor to consider is that any process that is economic for conventional heavy oil (usually valued at well below light oil prices), will tend to be even more economic for light and medium oil. Competition for a declining supply of pure injectants will soon put heavy oil EOR developments out of economic reach.

### **13.1.5. Small Scale to Avoid Unitization**

Another major cost that might be avoided by the implementation of the low-cost novel EOR processes discussed in this report, is in avoiding the costs and manpower required for pool unitization. In light to medium oil reservoirs, unitization of the pool would be a normal first step before being able to proceed with an expensive EOR scheme. In conventional heavy oil and cold bitumen areas, the fact that a relatively small number (5 or 6) of operators control most of the production, and have already strategically developed play-based land positions will help them to avoid unitization issues. This is even further supported by the nature of the resource in that cold heavy oil already forms a relatively good interlease barrier to flow of injectants, and small scale development can focus initially on areas of a pool where there are no third party leases involved. If objections or issues do arise between adjacent properties, the equipment can be moved elsewhere until some type of joint development agreement is reached.

### **13.1.6. Use of Existing Wells**

Finally a major factor to increase economic performance will be to make as much use as possible of existing wells. Not only does this reduce the capital cost of an EOR development, it also saves the time and effort of learning about a new well's unique characteristics. Knowledge of existing well's past performance, condition and interactions with other wells is a more intangible but very valuable asset for design and operation of an EOR process. Drilling new wells brings an automatic delay in EOR implementation of a few years as the impacts of the new wells are assessed. New technologies are being developed to potentially avoid high infill drilling costs due to lost circulation, but indications are that infills, especially those drilled late in CHOPS production in an area, will not develop in the same way as the original wells and will have a hard time paying for themselves, unless they can enhance recovery from other existing wells.

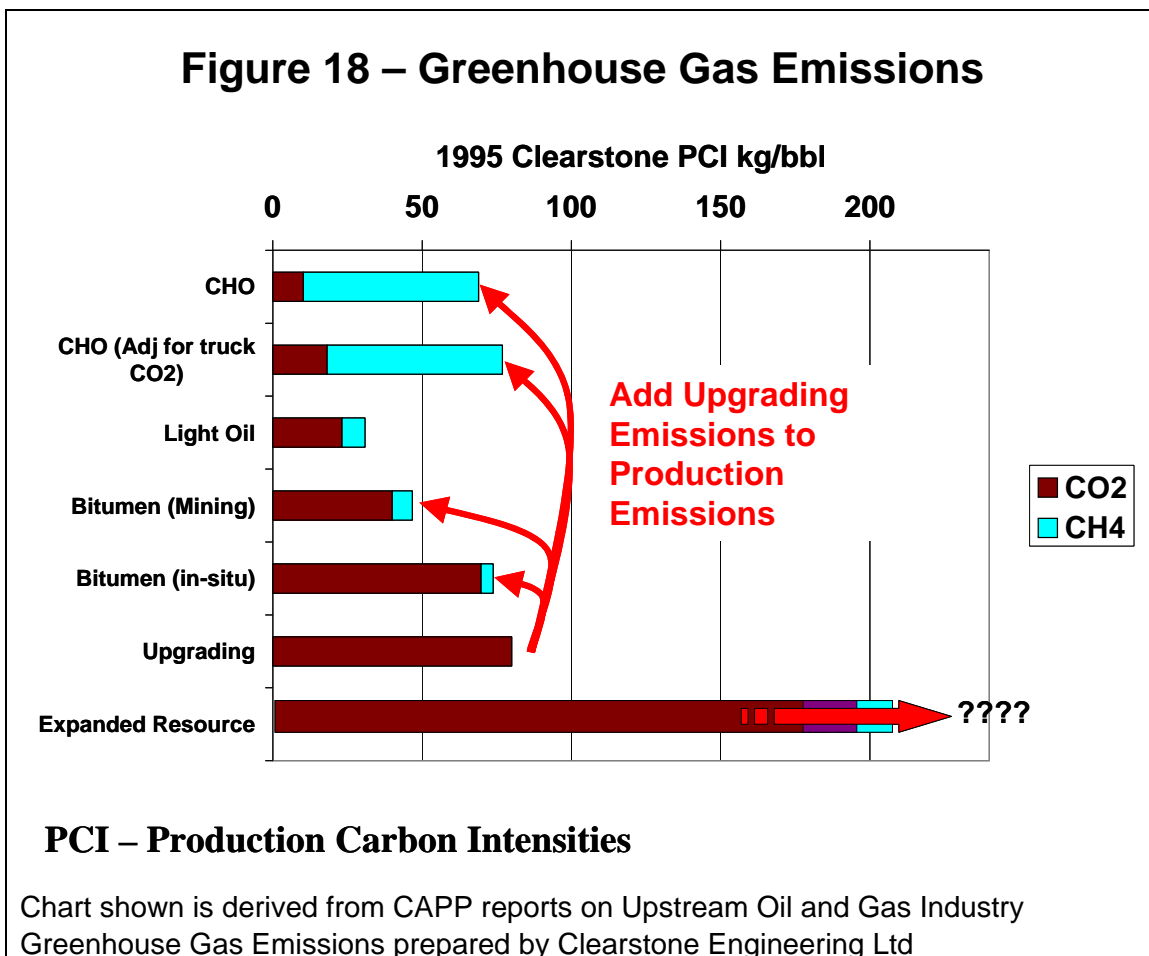
## **13.2. Environment**

Since the current study was developed to look for low emission and low GHG recovery, in an area already short of easy to access fresh water sources and highly developed as an agriculture production region, environmental impacts of potentially recovery processes are a key factor requiring comment, assessment and further investigation. In the "Low Carbon Futures" project Portfire Associates developed a simple spreadsheet model to assess the relative sustainability impacts of various recovery schemes and

processes for the target “inaccessible” resource assets. The intent of the current project is to continue to build on this assessment tool.

### 13.2.1. Net GHG Impacts

GHG impacts are becoming a key issue in all hydrocarbon resource developments and are a major challenge for EOR processes, which often require increased energy consumption for their development. In the case of conventional cold heavy oil and bitumen production, GHG emissions have traditionally been a major problem, mainly due to the practice of venting produced methane that, while small in volume, has a much higher global warming potential than CO<sub>2</sub>. Based on data and estimates from 1995, CHO emissions were almost equivalent on a carbon intensity basis as much more energy intensive thermal bitumen production and may have represented as much as 10-20% of the conventional upstream oil and gas industries total GHG emissions.



- Vent Gas Collection and Local Use** – While methane emissions have historically been high, the technology to conserve the methane gas has been available, and is being applied to these operations, motivated by both pressure to reduce GHG emissions and the increased value of natural gas which makes conservation more

economic. Since 2000, these emissions have been significantly reduced, in both Alberta and Saskatchewan, through the growing use of the vent gas to displace expensive imported fuel (mainly propane), and through increase collection, dehydration, compression and sale of the produced vent gas made possible due to high natural gas prices. The results in Alberta to voluntary measures have resulted in the significant reductions as shown in Figure 19, which have already resulted in an estimated 5 MtCO<sub>2</sub>eq annual reduction in GHG emissions. To further promote reductions, in 2007 Alberta implemented Directive 60 which should result in further reductions, and Saskatchewan is currently working to implement similar legislation on their side of the border. Collecting this low pressure gas for sale to pipelines requires considerable expenditures of capital and energy for compression to enter high pressure transmission pipelines. Using the methane locally for fuelling EOR would reduce equipment costs, still avoid venting and make more efficient use of the energy in the vent gas. Using vent gas for generating flue gas, as an injectant or for local power generation will further reduce methane GHG emissions and conserve energy in the EOR operations.

## Figure 19 – Methane Venting

Alberta Crude Bitumen Battery Venting 10<sup>6</sup> m<sup>3</sup>/yr  
(AEUB 2006 - Venting and Flaring Report)

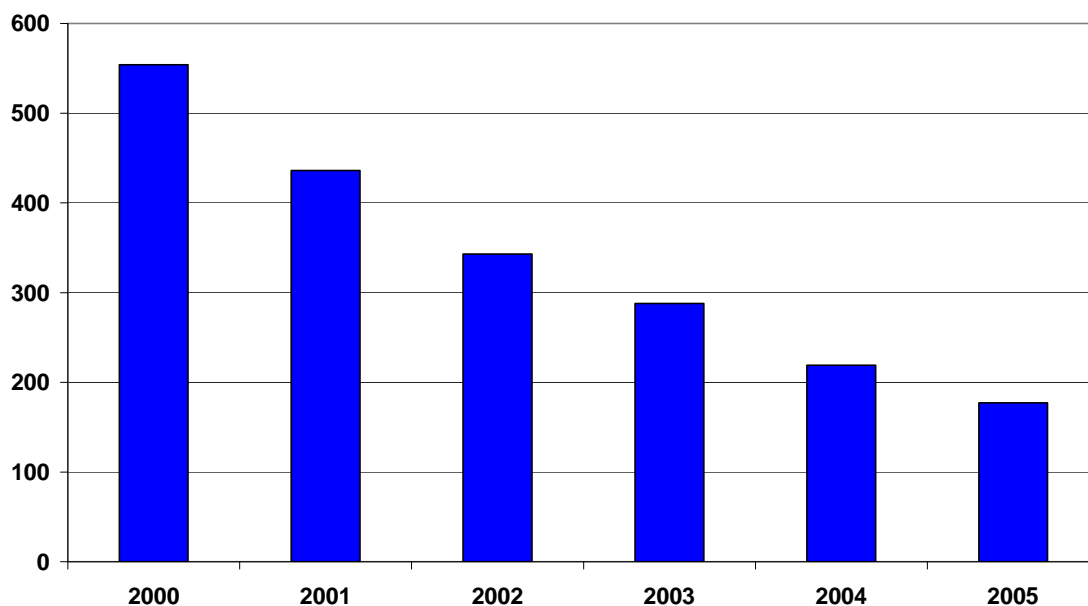


Chart shown is derived from CAPP reports on Upstream Oil and Gas Industry Greenhouse Gas Emissions prepared by Clearstone Engineering Ltd

- **Installing Gathering Lines to Avoid Trucking Emissions** – Currently short-term CHOPS production, does not lend itself to the economic use of gathering lines for transportation of water and heavy oil. As a result, trucks are used for transport of most of the production, and contribute significant GHG emissions even though these emissions are normally included in the transportation sector. As water volumes increase, trucking costs and emissions of GHG's, CAC's and particulates will increase. With implementation of EOR, pressurized treating and the need to keep produced gases in solution, gathering systems will begin to be more attractive, thus reducing emissions from trucks.
- **Water and Mineral Contacting for CO<sub>2</sub> Sequestration** – While heavy oil reservoirs are considered too shallow and low pressure for high volume storage of pure CO<sub>2</sub>, some of the injected CO<sub>2</sub> from flue gases should be sequestered through going into solution in produced water and/or reacting with minerals in the formations and being chemically sequestered. Research on actual field operations will be needed to assess the extent of sequestration which is highly dependent on water, reservoir rock and injectant compositions and properties. Potentially surplus CO<sub>2</sub> sequestration might be enhanced, by contacting CO<sub>2</sub> enriched steams with any available produced water being sent to a disposal zone. Contactors could be located at water disposal satellites with surplus high CO<sub>2</sub> content gas. By ensuring the CO<sub>2</sub> is tied up in the water there is little risk that it will be produced back so there may be opportunities for GHG credits or offsets.

### 13.2.2. Avoid Formation of Hydrogen Sulphide

The main Criteria Air Contaminant (CAC) that is likely to be of concern in heavy oil operations is hydrogen sulphide (H<sub>2</sub>S). In some existing primary or secondary operations there are already trace amounts of H<sub>2</sub>S present in ppb levels which tend to be more of an odour issue for local residents rather than a major safety risk. However, the introduction of thermal processes tends to cause some upgrading of the heavy oil and bitumen, which can contain 3-5% sulphur, and result in H<sub>2</sub>S generation. Most high-pressure thermal heavy oil operations, like Husky's Pikes Peak, begin producing larger amounts of H<sub>2</sub>S, which increases environmental emissions issues due to odours and SO<sub>2</sub> emissions when the produced gas is burned. H<sub>2</sub>S also tends to limit the use of some equipment, which may not be designed for sour service, so can increase costs dramatically. Therefore controlling recovery process temperatures and pressures to limit problems with non-thermal casing, should also help to reduce formation of H<sub>2</sub>S. Exactly how H<sub>2</sub>S generations varies with the low energy, low temperature and low pressure scenarios proposed in this report, will need to be investigated early on. As with most aspects of this type of recovery field testing will likely be required to determine conditions which will avoid H<sub>2</sub>S generation as many in-situ mineral could act as catalysts for the reaction and these conditions will be difficult to duplicate in the lab. Potential mitigation methods to avoid or cope with increased H<sub>2</sub>S formation include:

- **Maintain Low Reservoir Temperatures** – Even if new thermally cased well are drilled low temperature processes may be an advantage if H<sub>2</sub>S generation can be avoided. This will be especially important in operations near residences or community facilities.

- **High Water Flux Processes** – H<sub>2</sub>S is highly soluble in water, so processes that circulate high volumes of relatively low temperature water will tend to lead to more of the H<sub>2</sub>S going into solution in the water and hopefully being re-injected into disposal formations.
- **Dry EOR Methods** – If water is excluded from high temperature systems upgrading of the bitumen should be inhibited to reduce H<sub>2</sub>S generation.
- **Trace H<sub>2</sub>S Removal** – Low cost methods of scrubbing small amounts of H<sub>2</sub>S are available commercially, but need to be selective to H<sub>2</sub>S without absorbing CO<sub>2</sub>. Options might include contacting with iron sponge, activated carbon or liquid absorbents that can be collected and centrally regenerated.

### 13.2.3. Water Impacts

As fresh water sources are limited throughout much of the target producing areas, it is expected that the main water sources used would be either subsurface brine or combustion water vapour collection. While there will be a net water demand for replacing produced oil, in most producing areas there are very strong water aquifers in the region so make-up water should not be a major concern.

The main environmental impacts of the use of brine are in minimizing spills from tanks, trucks, dehydration systems (desiccant, salt or glycol) and gathering lines. Since salt contamination of soils is generally a greater threat than contamination with biodegradable oils or inert heavy asphalt material, monitoring, containment and spill clean-up processes will be the main requirements and these should already be in place for current operations.

With the potential addition of CO<sub>2</sub> to the produced water and conversion from water trucking to pipeline gathering there will be an increasing requirement for corrosion monitoring and prevention.

### 13.2.4. Land Impacts

Most of the areas currently producing conventional heavy oil are in agricultural areas focused on either grain production or livestock operations. The widespread use of single well batteries has already resulted in a relatively large footprint through the loss of farmland to roads and well leases. This will result in considerable pressure to minimize any additional increases in footprint with the introduction of EOR methods. Key technologies required will focus on mitigating impacts from:

- **Use of Existing Leases and Roads** – By use of directional drilling for any infill wells and upgrading roads and leases to better support the more facilities intensive and long-term EOR operations.
- **Greater Use of Gathering and Distribution Lines** – Improvements in ploughing in and recovering plastic and metal lines will help to reduce incremental surface disturbances and should be seen as a benefit to local residence if truck traffic can be reduced. However, farmers will want assurances that land disturbed by line installations can be returned to production as quickly as possible. As municipal gas systems may be used and impacted by other pipeline operations, engaging

the municipal utilities as contractors to install and operate lines may reduce net impacts through improve planning and coordination of efforts.

### **13.3. Security/Societal**

A major realization driving the current study and other efforts, such as PTRC's JIVE project, is that current CHOPS production operations, that in the past have constituted a major portion (up to 20% of total Canadian oil production at before the recent increases in bitumen production occurred) of Western Canadian oil production will soon begin to wind down as new drilling locations become more difficult to find. Lloydminster and surrounding regions have been experiencing a significant economic boom in the last two to three decades of growing and sustained heavy oil production, even with only 5-10% of the resource being recovered with relatively low technology production methods. Moving to EOR methods to continue heavy oil operations will have major impacts for securing development.

#### **13.3.1. Continued Exploitation of a Known Resource**

The most obvious impact is in EOR providing a means to continue the development and exploitation of a known resource. If heavy oil production stops, more energy intensive oil sands production will be required to replace current production volumes. Even if production activities are reduced for a few years, waiting for an EOR process to be implemented, considerable oil resources will ultimately be lost through early abandonment of wells and other producing infrastructure, perceptions of shareholder that the resource is "depleted", and most importantly the likely loss of the data, information, knowledge and people with experience operating in these formations. Once current operations are abandoned coming back will be made that much more difficult, expensive and inefficient.

#### **13.3.2. Sustaining Local Businesses and Communities**

Along with the impact on industry operations, suspension of oil and gas operations in the region will also result in the loss of the local business and population infrastructure, which has been established through the thirty year boom. If production is not sustained with early implementation of EOR, then house prices will drop, bankruptcies of businesses will increase and people will rapidly leave the area looking for work. As in the case of most boom-bust economies, once an initial bust occurs it is much more difficult to tempt people and businesses back to resume production operations. By pursuing a number of potential EOR methods such as JIVE (vapour extraction), SAGD (in thick reservoirs), air injection and small scale thermal/gas injection as proposed in this study, the likelihood of continued oil and gas production is greatly increased. Development and field demonstration of new methods and processes takes many years and it is much too early to pick a winner, and the impacts of not picking the right process are too great to risk putting all the development eggs in one basket.

### 13.3.3. Importance to Saskatchewan

For the province of Saskatchewan, continued production and recovery of heavy oil is critical for the provincial economy. While Saskatchewan does have conventional light and medium oil resources in the southern region of the province, and has already implemented some CO<sub>2</sub> EOR in Weyburn and Midale areas, over 50% of the oil in the province is heavy oil contained in Lower Cretaceous age deposits. Saskatchewan does appear to have some oil sand resources. However, these will be much lower in volume and average quality than deposits found in Alberta. So overall the conventional heavy oil assets are still considered to be “Saskatchewan’s Oil Sands” and on-going production from these resources will be needed to help maintain the health of the provincial economy in coming decades.

### 13.3.4. Safety Risk Management

The main hazards that may develop with new EOR processes must be considered in light of the hazards currently encountered in conventional heavy oil operations. Potential changes in existing hazards or new hazards may be related to:

- **High Rig Activity** in drilling, completions and well maintenance that are of primary concern to oilfield workers on the sites. Finding, training and maintaining skilled rigs workers has been a chronic challenge in this area where production levels are sustained through the drill bit. Inexperienced workers will generally have a greater chance of being injured during round the clock, year-round development activities. Moving to EOR using existing wells should reduce well drilling and completion efforts on a per unit of production basis, and convert many of the rig jobs to more secure and longer-term operations jobs so that there is a better chance of retaining trained and experienced personnel.
- **Road Safety** is a major public issue in the region with the high volumes of trucks hauling rigs, equipment, tanks and production in continually changing traffic patterns as the target developments shift into new locations and older production areas decline. Road construction and maintenance is a major concern for municipalities as they have little opportunity to plan for new oil development, and struggle to maintain roads in a safe condition for all the users. Moving more production to pipelines and stabilizing production through long-term EOR would help companies and municipalities to more appropriately manage road safety issues, even if the traffic will continue over a longer period of time with EOR.
- **Heavier than Air Gases** such as CO<sub>2</sub> and H<sub>2</sub>S generate a hazard, which isn’t normally encountered in current operations where the main gas produced is methane. Even though methane is flammable and can be a hazard when contained in a building with oxygen, in most heavy oil operations it is easily contained within hoses or pipes, and if it does leak it rapidly rises and dissipates into the atmosphere. With potentially greater volumes of CO<sub>2</sub> and H<sub>2</sub>S greater caution will be needed in cases where workers or others might be entering low lying or confined spaces such as tank, tank containment dykes, or low lying area adjacent to oil production leases. H<sub>2</sub>S is highly toxic, but can be readily detected at low concentrations, and most operating areas already equip personnel with H<sub>2</sub>S



detection and exposure monitors. CO<sub>2</sub> can be an asphyxiation hazard, if it leaks without H<sub>2</sub>S being present to give a warning, and is able to become concentrated in a low lying or enclosed area. Since the gases being used will not be highly concentrated in the processes proposed the presence of lighter than air gases in the streams and normal air circulation around warm production equipment should generally be able to dissipate the heavier than air gases.

- **Hot and Fired Equipment** are already found on most heavy oil leases in the form of natural gas fired engines for driving pumping or compression systems, and flame-arrested direct contact heaters for tankage. The proposed flue/gas and thermal methods proposed in this study should not greatly change the risks on any given site as injection and production activities will likely not be in operation at the same time so the amount of equipment operating on a given site at any point in time may not be greatly different from the current situation. The large size and complexity of the injection or thermal generation equipment will be compensated for by the fact that they will be more closely monitored and controlled and inspected than current equipment.

### **13.3.5. Capital and Cash Flow Risk Management**

As covered previously, past experience with conventional heavy oil CHOPS operations is that wells can water out or just stop producing for a number of reasons, so that companies have been concerned about investing too much capital on fixed installations at individual well sites. The concept of using portable, small-scale equipment for EOR helps to continue this capital risk mitigation strategy while allow greater recovery from known operational assets. The small scale modular development, especially if equipment can be leased, also helps managers to better manage their cash flow with varying commodity prices and adjust the pace of development to keep costs in line.

### **13.3.6. Regulatory Streamlining**

Given the temporary, well-based, and non-continuous nature of the proposed recovery methods, it may be possible to streamline regulatory approvals by treating the method as “stimulation” rather than an “enhanced recovery project”. Enhanced recovery projects usually require pool wide agreements, large facilities changes and require multi-year commitments to a given recovery method in a given pool. Reducing the regulatory hurdles will help to make the processes and methods used much more flexible and allow for continuous adaptation and incorporation of enhancements as the resource depletion proceeds. Avoiding the need for large scale diversion of water or other injectants should increase the willingness of regulators to consider non-standard review and approval processes while still support their objectives of protecting the safety and interests of the public.

### **13.3.7. Application to Larger Oil Sands Resources**

The primary reason for focusing on the conventional heavy oil producing areas is that the oil already has some mobility, and has already been partially depleted. However, if the methods tested in conventional oil have merit, they could potentially be applied as follow-up processes for oil sands operations where SAGD, CSS or some other method

has partially depleted and mobilized of the solid bitumen. Flue gas, solvent and other gas injection methods are already being piloted in oil sands, while portable low cost generation may prove useful as the need for continuous steaming declines to avoid expansion of centralized steam plants.

## **14. Next Steps**

### **14.1. Overview**

Consultation with oil producers in the Lloydminster region indicated concerns with the pace of production decline curves. New drilling is required to simply maintain production levels. If drilling programs were to be reduced due to high costs or low prices, it is expected that overall production of heavy oil would decline significantly over the next five to ten years. Longer term, the industry realizes that the end is in sight for oil production using existing commercial primary and secondary recovery technologies.

New technologies need to be developed and piloted in order to unlock remaining resources through EOR after CHOPS and waterfloods. Land positions in the Lloydminster region are well established. This is not an exploration play. Producers are starting to realize that keeping proprietary technology developments confidential has less value than cooperating and participating in multiple technology developments through Joint Industry Programs (JIP). Anecdotally, it is reported that there has been more cooperation between the 5 to 7 major heavy oil producers in the Lloydminster region in the past two years than in past decades. Example of such collaboration include the JIVE project to develop a new vapour extraction process, discussions on an in situ combustion project and joint development with SRC concerning waterfloods and the design of oil and water pipelines.

This project is in keeping with the industry trend noted above and is an effort by PTAC to articulate the conceptual design of a new Low GHG EOR process for Lloydminster and pursue it to implementation.

### **14.2. Joint Industry Program for Steam and Gas Stimulation**

In general, filling the gaps in knowledge and resolving key uncertainties around CHOPS and reservoir conditions after CHOPS do not involve studies and investigations conducted in the laboratory. There does not appear to be reliable laboratory methods to model CHOPS performance parameters.

#### **14.2.1. Data Mining**

However given the two or three decades of field operations, there is a wealth of operational data that could be mined and investigated. There has never been a systematic study of production factors associated with CHOPS. It is apparent that the industry has conducted a large number of trials that have not been publicly documented. It appears however that this information is known anecdotally. An opportunity for the identification of patterns and directions for improving CHOPS and for identifying EOR options would be data mining of the considerable number of trials and operational strategies conducted over the past 20 years by heavy oil operators. The vast majority of

this information has not been published. For example, data could be acquired with respect to heavy oil production rates, volumes and wells spacings. This information could be analyzed to determine if there is a relationship between production and well density.

Such a project could take the form of a JIP where operators give access to their historical records to a team of investigators that would mine this data in order to extract patterns and information about directions for technology improvements. Information developed could be useful immediately because it could identify methods to improve the current practice of CHOPS.

### **14.2.2. Field Testing**

While past records should be reviewed to capture learnings and new ideas could be evaluated in the laboratory, pilot testing of the better EOR candidates will eventually be necessary. Meaningful field testing will only be possible in a reservoir near to the end of its economic life after primary and secondary production. A structured program of field pilots using CHOPS wells near the end of their productive life would be needed in order to try a prioritized list of process improvement ideas. These trials would need to be fully instrumented for the learning to be captured and used in the design of additional tests or larger scale production pilots.

One approach could be a JIP where Lloydminster operators contribute a number of declining wells for the evaluations of EOR concepts with all JIP participants benefiting from the information generated by individual well tests.

The JIP could evaluate the ideas and concepts proposed in this report but should not be limited to them because new ideas for thermal and solvent stimulation of heavy oil reservoirs may be forthcoming from industry and other sources.

In particular, the project should focus on the environmental benefits of the proposed processes in terms of reduced greenhouse gas emissions and reductions in water intensity.

### **14.2.3. JIP Scope**

The recommended path forward is a JIP with an order of magnitude scope of \$1 million per year over five years. The recommended technology program is data mining of past operational records and field testing of promising heavy oil EOR concepts, along the following principles:

- Industry participants open their confidential operating records to a team of investigators to extract patterns and suggestions for improved CHOPS methods and for EOR concepts.
- Industry participants contribute existing production wells that are approaching the end of their productive life.
- Funding is assembled to operate a portable well stimulation system with associated instrumentation. This would include a portable steam generator, possibly a DCSG, portable compressors and instruments to measure temperature, pressure, fluid rates and overall process performance.

- A structured program is developed and agreed that would list typical well configurations, typical reservoir horizons, typical reservoir histories and promising EOR concepts with a range of parameters that could be evaluated, such as gas ratios (N<sub>2</sub>, CO<sub>2</sub>, steam), temperature, pressure and cycle length.
- In addition, the JIP may include in its scope the drilling of new horizontal wells with thermal completion for piloting EOR approaches based on new infill wells.
- As a first step in developing a viable EOR recovery technology for heavy oil after CHOPS, it would be advisable to focus on thicker deposits because thermal technologies could be economic in deposits between 8 and 15 m thick. This would allow the commercialization of technologies and equipment that could then be adapted to deposits less than 8 m thick.

### **14.3. Scoping Project**

In order to organize and launch such a JIP, scoping and organizational work will need to be done as part of a scoping project which may cost \$200,000 over one year with support from industry and governments in Alberta, Saskatchewan and the Federal Government. The scope would include:

- Identification of the EOR concepts with the most industry support and the larger potential rewards in terms of environmental benefits and opportunities for cost reduction;
- Development of the technology program;
- Conceptual design engineering, high-level capital costs, operating costs and comparative economics with existing production methods;
- Identification quantification of environmental benefit with respect to greenhouse gas emissions, water conservation and land impact;
- Scope and budget for any laboratory and bench scale work;
- Scope and budget for field evaluation trials;
- Preparation of the list of required equipment and service contracts for measuring and monitoring heavy oil production performance;
- Identification of available portable commercial equipment to produce a mixture of flue gas and low-quality steam for reservoir stimulation;
- Process for information analysis and dissemination;
- Path to commercialization and broad utilization by industry;
- Recruitment of JIP partners; and,
- Budget and financial structure of the JIP, including funding and governance.

### **14.4. Immediate Next Steps**

In order to gauge interest, it is recommended that PTAC issues an Expression of Interest (EOI) to determine specific and practical options for progressing the development of EOR technologies for Lloyminster heavy oil.

Near term next steps include:

- Continued discussion of how to progress this work to the next level at PTAC VORSC and TERE industry committees, at equivalent committees in Saskatchewan, and with government partners in Alberta, Saskatchewan and the Federal Government;
- Continuing presentation of the information developed in the present study at industry meetings in Edmonton, Fort McMurray and locations in Saskatchewan as well as at the Global Oil Conference in Calgary in 2008; and,
- A PTAC issued Expression of Interest for participation in a JIP and a Scoping Project by contributing information, access to equipment, facilities, oil fields, and funding resources.

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