# ALTERNATE INJECTION OF STEAM AND HYDROCARBON VAPORS IN THE SAGD CHAMBER

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## 1. Introduction.

Only about 7% of Canada's oil sands can be mined, the majority has to be recovered using thermal in-situ recovery. When bitumen is too deep (>80 m) to economically mine, steam is injected, reducing the oil viscosity and allowing it to be pumped through surface wells.

Prior to the demonstration of the SAGD process, several other processes for the in situ recovery of tar were tested. These included cyclic steam stimulation, in situ combustion, electric heating, and other horizontal well processes. All of these approaches were disappointing and SAGD is the only process that shows economic potential.

SAGD is a simple technology in concept but complex in application: a well injects steam into the producing zone, creating a high-temperature steam chamber in the formation. The heat melts the thick crude which allows gravity to assist it to flow freely to the horizontal production well below. Although this technology works well in formations with good horizontal permeability, SAGD works better in deposits with good vertical permeability.

An important advancement in SAGD process came with the construction of the Alberta Oil Sands Technology and Research Authority's (AOSTRA's) Underground Test Facility (UTF) in which the first Athabasca test of SAGD was conducted starting in 1987. SAGD was invented by Roger Butler in 1978 and had been tested previously in Cold Lake in a much less elaborate facility.

The SAGD process is economic if the steam–oil ratio is not too high. The heat requirements, however, are large in thin reservoirs where heat losses are high and also in low porosity carbonates where the reservoir heat capacity per unit volume of initial oil is high. Big problems have occurred when the geology allows steam to escape, instead of it being contained in the oil sands reservoir. Lot of troubles are caused in water recycling efforts when greasy and dirty water can damage the steaming equipment. Perhaps the biggest concern is the reliance on natural gas to fuel the boilers that turn the water into steam. With the rising cost of gas, the race is on to find new technologies that are cheaper and lessens demand on gas.

The purpose of this project is to analyze alternatives or variations for SAGD process and overcome economic restrictions. It will be analyzed, first the basic theory which support this process and after that, several options developed by various researchers will be considered. Finally, conclusions will be mentioned.

## 2. SAGD Theory

The original recovery mechanism of the SAGD process was described by its inventor, Dr. Butler[1 2], who developed energy and oil flow equations associated with it. The energy flow by thermal conduction and drainage of the heated oil by gravity are the major components of this recovery concept. In summary, oil production rates vary directly with the square root of the height of steam chamber, permeability to oil, movable oil saturation, porosity and thermal diffusivity, and inversely with oil viscosity. Major assumptions are:

- Heat is transferred from the steam chamber to the cold oil zone by thermal conduction alone.
- The flow of steam condensate ahead of the steam chamber is ignored.

In the idealized SAGD process, a growing steam chamber forms around the horizontal injector and steam flows continuously to the perimeter of the chamber where it heats the surrounding oil. Effective initial heating of the cold oil is important for the formation of the steam chamber in gravity drainage processes. The heated oil drains to a horizontal production well located at the base of the reservoir just below the injection well. Butler derived the following equations:

$$q = L \cdot \sqrt{\frac{1.3 \cdot \phi \cdot \Delta S_o \cdot k \cdot g \cdot \alpha \cdot h}{m \cdot v_S}} \qquad \text{(Eq. 1)}$$

$$v = v_S \cdot \left( \frac{T_S - T_R}{T - T_R} \right)^m \qquad \text{(Eq. 2)}$$

Where the kinematic viscosity, $v$ ( = shear viscosity/ density), of oil as a function of temperature.

In (Eq. 1), $L$ is the length of the well, $\phi$ is porosity, $\Delta S_o$ is the initial oil saturation minus residual oil saturation, $k$ is the effective permeability for the flow of oil, $g$ is the acceleration constant of gravity, $\alpha$ is the thermal diffusivity, $h$ is the distance from the production well to the top of the reservoir, $m$ is a dimensionless viscosity exponent, $v_S$ is the kinematic viscosity of oil at steam temperature, $T_S$ and $T_R$ is the initial reservoir temperature. There are three major consequences of this theory:

- Steam chamber growth is necessary for oil production, and oil production occurs only as long as steam is injected
- Oil production rate increases as the steam temperature increases, and
- At a given steam temperature, the oil with the lowest viscosity exhibits the greatest production response.

## 3. General Description of Steam Assisted Gravity Drainage (SAGD)

The SAGD process runs two directional wells approximately 5 meters apart. Steam is injected through the upper wellbore (Fig. 1[3]), the steam then permeates the oil sand, heating the oil and thus reducing the oil viscosity (Fig. 2). The heated oil and condensed steam then flow to the surface through the lower wellbore (Fig. 3). Over time, the steam chamber grows in size resulting in higher production rates. During the rise period the oil production rate increases steadily until the chamber reaches the top of the reservoir. This cross-section shows the steam chamber at a later stage, where reduced viscosity and a horizontal production well allow practical rates without steam production. Injected steam replaces produced oil allowing continuous heating of the reservoir and drainage of the heated oil together with condensed steam.

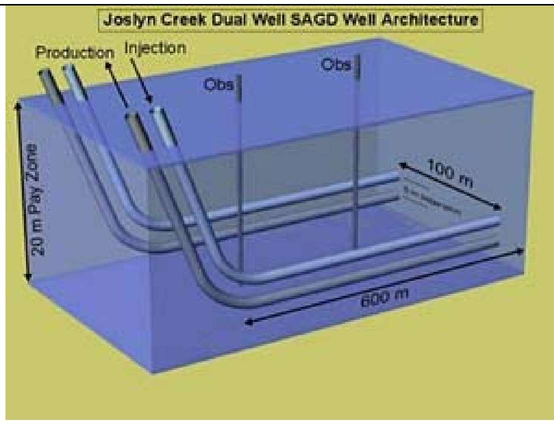


Fig. 1

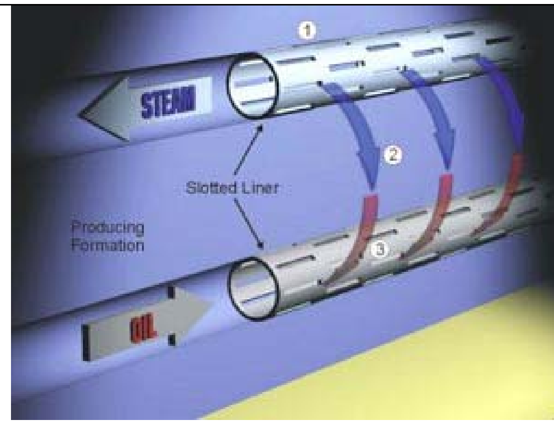


Fig. 2

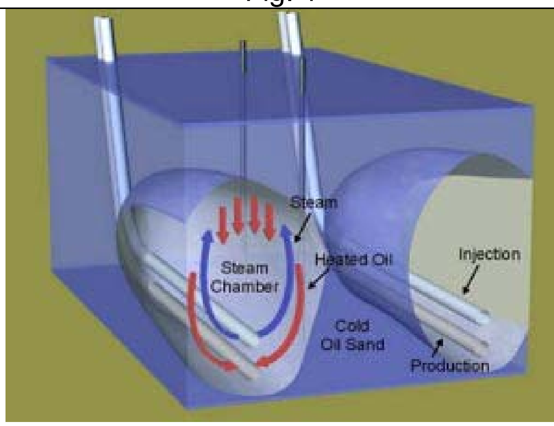


Fig. 3

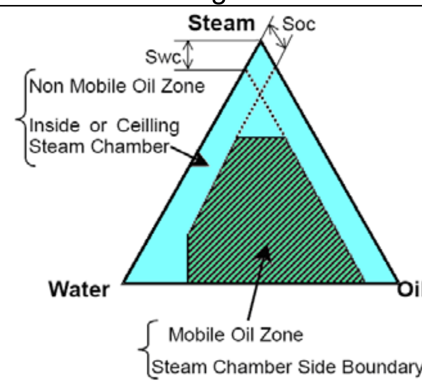


Fig. 4 Mobile and non-mobile zones in consideration of three phases in steam chamber

**Advantages:**

- High bitumen recovery factor (typically >50%)
- High calendar day oil rates
- Continuous process

**Disadvantages:**

- Requires clean, continuous reservoirs
- Requires 2 wells (higher capital investment)

## 4. Intermittent Steam Injection on the Production Well

This modified process uses a well with both functions of intermittent steam injection and oil production similar to the single SAGD well, instead of the usual production well. Using the modified process by adding intermittent steam injection on the lower well while steam injects continuously from the upper well, the time to generate near break-through condition between two wells is shortened, and oil production rate and expanding rate of the chamber area are enhanced compared with that of ordinary SAGD process. The intermittent steam injection from lower well accelerated instability of the interface near the ceiling, then fingering area became larger compared with usual SAGD process.

The SAGD process with longer well spacing is better for production with higher production rate after break-through, however a problem with oilsands reservoirs is leading time to generate a rising steam chamber in near break-through condition From the reports about UTF projects, the period for pre-heating of oilsands was almost half a year for a well spacing of 5 m.

It was found that by using shorter vertical spacing between two wells, leading time is reduced while production rate after break-through becomes lower[4]. In this process, steam is injected from both of upper and lower wells. Then, the lower well has both functions of production and steam injection.

The break-through time, $t_{BT}$, is sensitive to pressure drive of oil. Fig. 5 shows the experimental results of $t_{BT}$ against $\Delta P$. The $t_{BT}$ increases with decreasing $\Delta P$, however it becomes quite large near $\Delta P$ = 20kPa. Furthermore, the shape of steam chamber at near break-through of both wells is affected by $\Delta P$.

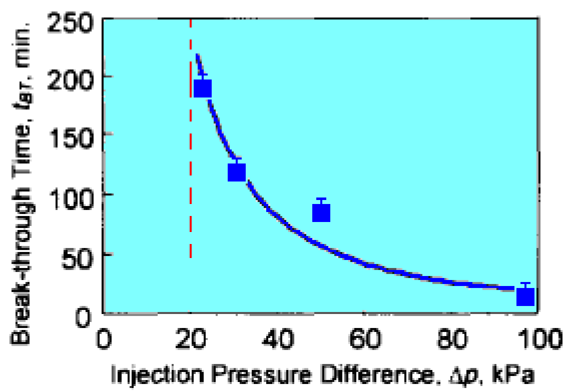


Fig. 5. Effect of steam injection pressure difference between two wells on break-through time

Fig. 6 shows comparisons of cumulative oil production and steam chamber area between both processes. The results show that the $t_{BT}$ becomes shorter and production rate increased compared with usual one by adding intermittent steam injection from production well. However, total amount of steam injection of the modified process increased 26 % to that of the usual SAGD process. The increase of steam consumption has yet to be completely clarified. It largely depends on increasing heat loss to the side walls and heat storage into the reservoir caused by the larger chamber area.

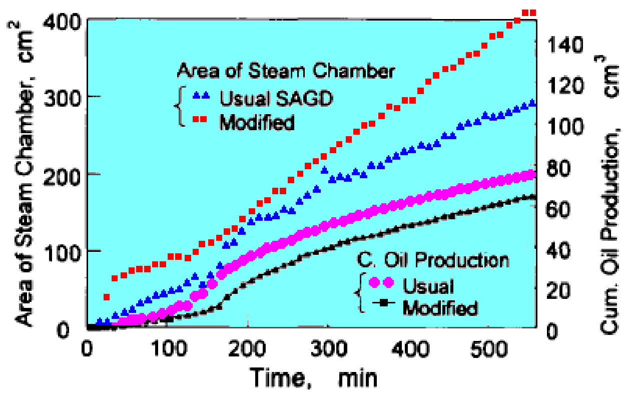


Fig. 6 Comparison area of steam chamber and cumulative oil production between usual and present modified SAGD processes

**5. Steam and Gas Push (SAGP)[5]**

Butler contended that it is not necessary to heat the entire reservoir to the steam temperature but only the region close to and above the production well. In the vapor chamber the gas would become enriched as steam condenses. This gas accumulation gradually increases in the upper parts of the chamber. This would result in a lower average chamber temperature and, particularly much lower heat loss to the overburden, resulting in a low steam oil ratio. Lab results confirmed that the addition of a non-condensable gas to steam injection reduces the temperature in the upper portions of the upper chamber. The non-condensable gas accumulated in the leading lateral edge of the vapor is believed to be able to resaturate to the middle of the steam chamber. During the laboratory experiment, most of the injected gas was produced (80%) back from the production well.

Steam not only mobilizes the oil by heating, but also equalizes the pressure vertically. Steam must be injected continuously at relatively high rate, otherwise the steam condenses and the vapor chamber collapses. This limitation is overcome in the SAGP process. Even though steam may condense, gas remains in the reservoir, prevents collapse of the heated zone, and maintains pressure. In SAGP, fingers of gas rise warming the reservoir and maintaining pressure. The literature suggests it is not necessary to carry the latent heat to the top of the reservoir in the SAGP process. The chamber temperatures required to achieve production at rates comparable to conventional SAGD are obtained from the following equations:

$$T_{SZ} = T_R + (T_S - T_R) \cdot \left[ \frac{h - z}{(h - h_i / 2)^2} \cdot \frac{m}{k \cdot g \cdot \alpha \cdot \phi \cdot \Delta S_o} \cdot \left( \frac{q}{L} \right) 2 \right]^{\frac{1}{m}} \quad \text{(Eq. 3)}$$

Where $T_{SZ}$ is chamber temperature at height $z$, $T_S$ is steam temperature, and $h_i$ is injector height above the bottom of the reservoir. The unknown flow rate, $q$ $(m3/s)$ is obtained from (Eq. 1) by substituting $h$ with $h_L$ (height of a SAGD reservoir with the same rate):

$$h_L = \sqrt{(2h - h_i) \cdot h_i} \quad \text{(Eq. 4)}$$

## 6. Naphtha Assisted Gravity Drainage (NAGD)[6]

In the SAGD process it is necessary to heat the formation to a temperature well above initial reservoir temperature to ensure sufficient oil mobility. This operation mode is subjected to heat losses to surrounding formations. In order to reduce the heat losses, Butler and co-workers have proposed the VAPEX process. Here, light hydrocarbons vapor, such as ethane or propane are injected into the oil bearing formation instead of steam. Oil mobility is no longer assured by heat transfer, but is due to viscosity reduction by solvent dilution into the oil. Oil viscosity reduction by the dilution mechanism is much slower than by heat diffusion as the mass diffusion coefficient is orders of magnitude smaller than the thermal diffusion.

Previous work on solvent injection has shown that the important considerations for solvent to compete with steam are:

- the solvent to use is determined by the operating conditions,
- it must be readily available at location,
- it should not be too expensive,
- it is fully miscible with the oil in place (or produced), and hence does not lead to asphaltene precipitation.

The injection, as a vapor, of a heavier hydrocarbon with a boiling point well above reservoir temperature would combine the heat effect obtained with steam injection and the dilution effect obtained with lower weight hydrocarbons. Injecting a naphtha slug prior to steam injection seems the best alternative to recover oil from a homogeneous tar sand pack. There is an optimum combination of solvent and steam slug sizes. Only 2 per cent of the oil needs to precipitate before permeability damage becomes significant.

The efficiency of a steam injection process can be expressed in the cumulative steam oil ratio (CSOR), or, how many tones of steam does one need to produce one tone of oil. The volumetric CSOR can be written as:

$$CSOR = \frac{M_R \cdot \Delta T_s}{\phi \cdot \Delta S_s \cdot \rho_w \cdot (c_w + f_s \cdot L_{v,s})} \cdot \left( 1 + \frac{t_p}{2 \cdot a} + \frac{4}{3} \cdot \sqrt{\frac{t_p}{\pi}} \right) \qquad \text{(Eq. 5)}$$

$$t_p = \frac{4 \cdot \alpha \cdot t}{h^2} \qquad \text{(Eq. 6)}$$

Where: $M_R$ : effective matrix heat capacity; $\Delta T_S$ : temperature difference SAGD; $\phi$ : porosity; $\Delta S_S$ : Movable oil saturation SAGD; $\rho_w$ : water density; $c_w$ : water specific heat capacity; $f_S$ : steam quality; $L_{V,S}$ : heat of vaporization of water; $a$ : empirical constant ($\approx$ 0.4); $\alpha$ : effective thermal diffusivity; $t$ : time; $h$ : effective process thickness

In order to compare the oil production during the NAGD process with respect to the one obtained during SAGD, the following equation is used (densities and the dynamic viscosities are determined at vapor chamber temperature):

$$\frac{q_{o,n}}{q_{o,s}} = \sqrt{\frac{\mu_o \cdot T_s}{\Delta S_s \cdot (\rho_o \cdot T_s - \rho_s \cdot T_s)}} \times \sqrt{\frac{\Delta S_n \cdot (\rho_o \cdot T_n - \rho_{n,g} \cdot T_n)}{\mu_o \cdot T_n}} \tag{Eq. 7}$$

$$\frac{CNOR}{CSOR} = \frac{\Delta T_n}{\Delta S_n \cdot \rho_{n,l} \cdot L_{v,n}} \times \frac{\Delta S_n \cdot \rho_w \cdot L_{v,s}}{\Delta T_s} \tag{Eq. 8}$$

Where: $q_{o,n}$: oil production rate during NAGD; $q_{o,s}$: oil production rate during SAGD; $\mu_o$: dynamic oil viscosity; $T_S$: steam chamber temperature; $T_n$: naphtha vapor chamber temperature; $\Delta S_S$: movable oil saturation SAGD; $\Delta S_n$: movable oil saturation SAGD; $\Delta T_n$: Temperature difference NAGD; $\Delta T_S$: Temperature difference SAGD; $\rho_o$: oil density; $\rho_w$: water density; $\rho_s$: steam density; $\rho_{n,g}$: naphtha vapor density; $\rho_{n,l}$: naphtha liquid density; $L_{v,n}$: heat of vaporization of naphtha; $L_{v,s}$: heat of vaporization of water.

The volume of oil produced at a certain time by NAGD is between one and a half to two and a half times higher than the oil produced by SAGD within the same period of time. At the same pressure, the temperature of the naphtha chamber is higher than the steam chamber temperature (Fig 7). A higher temperature induces a lower oil viscosity, which is the main reason behind the higher oil production rate determined for the NAGD process.

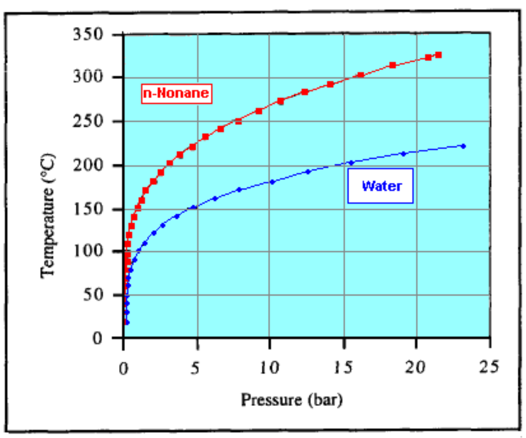

Fig. 7. Saturated vapor curves

Water has a latent heat of vaporization one order of magnitude above the values for the naphtha. That is, each tone, or cubic meter cold liquid equivalent, injected naphtha carries less heat than a tone of water injected.

## 7. Steam Alternating Solvent (SAS)[7, 8]

The process is intended to combine the advantages of the SAGD and VAPEX process to minimize the energy input per unit oil recovered. The SAS process involves injecting steam and solvent alternately, and the basic well configurations are the same as those in the SAGD process.

In order to recover heavy oil and bitumen deposits, there are generally two types of methods for the reduction of oil viscosity. The first is to increase oil temperature by injecting a hot fluid, such as steam, into the formation, or by combustion through injecting oxygen-containing gases. The second method is to dilute the viscous petroleum by low viscosity hydrocarbon solvent. This method involves injecting a hydrocarbon solvent such as propane or butane, or a mixture of solvents, into the reservoir. The solvent dissolves and mixes with the viscous oil. The viscosity of the mixture becomes much lower than the original viscosity of the heavy oil.

The main difference between SAS and SAGD is that the first one involves a different injection pattern or operating strategy (Fig. 8):

- inject pure steam as that in the SAGD process to start up the operation;
- stop steam injection and start solvent injection as steam chamber has established, and when heat loss to overburden becomes significant;
- stop solvent injection and start steam injection when the chamber temperature is reduced;
- repeat the steam injection and solvent injection cycle until it is no longer economic to do so;
- recover the solvent still in place by a blowdown phase at the end of the operation.

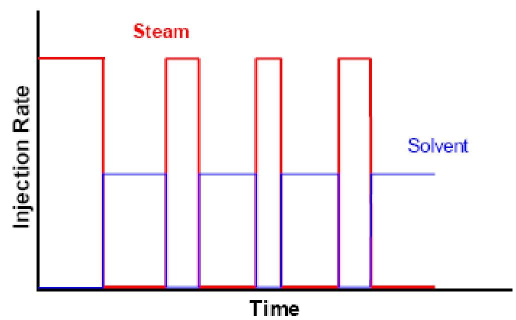

Fig. 8 SAS process injection pattern

The basic idea in the SAS process is to replace a large amount of steam injection in the SAGD process by solvent injection, and furthermore, this solvent is recycled. The operating temperature in the SAS process is lower than in the SAGD process due to reduced steam injection.

The gradual spreading of the temperature in the chamber was probably due to both conduction and convection. The temperature ahead of the vapor chamber in SAS process was higher than the original temperature, but lower than the steam temperature. The viscosity reduction at the chamber boundary in the SAS process is due to both dissolution of gas in oil and increase in temperature. The viscosity of the oil/solvent mixture at the chamber boundary is higher, usually one order of magnitude or more, than the oil viscosity at steam temperature. The following equation describes this last state:

$$Q \propto \sqrt{\frac{k \cdot k_{ro}}{\mu}} \qquad \text{(Eq. 9)}$$

Where $Q$ is oil drainage rate, $k$ is absolute permeability, $k_{ro}$ is oil phase relative permeability, and $\mu$ is oil viscosity.

The reason for the high oil recovery rate in the SAS process is that, the usually higher viscosity of the oil along the chamber boundary in the SAS process was largely compensated by higher relative oil phase permeability resulting from higher oil phase saturation. Results obtained from field scale simulation suggested that the oil production rate of SAS process could be higher than that as a SAGD process. Preliminary economic analysis indicated that comparing to the SAGD process, the SAS process might save 18% of the energy input for the same oil production.

## 8. Economic analysis

There is no consistent approach used by industry to define "bitumen in place" and therefore recovery factor for in-situ projects. Imperial Oil calculates the "original bitumen in place", or OBIT, based on the quantity of bitumen present in the gross reservoir thickness with a bitumen content ≥ 6 wt%. No other consideration is applied. Others define an "exploitable bitumen in place", or EBIP. Although in some cases EBIP can equal OBIP, in most cases the EBIP will typically represent only a portion of OBIP.

A common measure of thermal efficiency of the SAGD process is Steam Oil Ratio (SOR) – the ratio between the volume of steam injected and the volume of bitumen ultimately recovered ($m^3$ dry steam/$m^3$ bitumen). There is also an economic limit SOR – above which the value of the bitumen recovered fails to provide adequate return for the capital investment and operating expense incurred in generating the steam to extract an incremental $m^3$ of bitumen. It would appear that the average economic limit SOR in for SAGD projects examined is about 4.

O the other hand, there is also possible to measure the thermal efficiency using the ratio between $m^3$ of gas per $m^3$ of dry steam. SAGD projects typically require 77 $m^3$ of gas per $m^3$ of dry steam sent to the field. Combining the economic limit SOR and the gas required per $m^3$ of steam, suggest an economic limit for gas consumption of 300 $m^3$ gas/$m^3$ bitumen recovered. The assumption is that when the quantity of gas required to produce one $m^3$ of bitumen exceeds 300 $m^3$ the economic limit has been reached. If this does not occur, the initial project investment would not be economic as the bitumen revenue would not be sufficient to recover the project's capital and operating costs.

The economics of the SAS process, like any other heavy oil recovery process, is determined by the oil production rate and the energy intensity. These are affected by the temperature profiles and solvent concentration distribution in the vapor chamber. For an easy comparison of the economics between SAS and SAGD, energy input in GJ per unit oil recovered in $m^3$ are shown in the Fig 9. The energy intensity was 8.73 GJ/$m^3$ for SAGD, and 7.19 GJ/$m^3$ for SAS process, an 18% reduction.

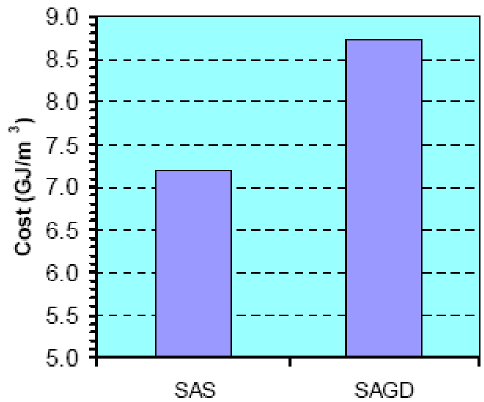

Fig. 9. Comparison of energy cost per unit produced oil from SAGD and SAS process

## 9. Environmental Concerns[9]

There are three main problems associated with the development of thermally produced extra heavy oil resources:

- The low value of the produced oil
- The high fuel cost associated with thermal production
- The need for diluents to transport the produced oil to markets

Regarding to the fuel cost for steam injection, this is currently attributed to the generation of steam which demands huge amounts of water. In the future, more stringent environmental regulation might further prohibit the use of water for the recovery of heavy oils. Also air emissions should be considered by plant design, energy efficient operations and use of clean-burning fuels.

For VAPEX, water and energy are conserved. In addition, the solvent is recovered and the casing gas is not vented. This technology contributes largely to the avoidance of greenhouse gas production during oil recovery.

There is an interesting example regarding of air emissions in the Long Lake Project[10]. According to studies, it will meet all current regulations and standards for $SO_2$, and $NO_x$, particulates and other regulated emissions. $CO_2$ emission is expected to be approximately 0.15 tonnes per bbl of upgrader product delivered to the market.

## 10. Other Alternatives

### Surfactant – SAGD

A new process named Surfactant-SAGD, injecting a surfactant before starting steam injection to enhance the communication between two wells and mobility of the production fluids, was tested[11]. It was used a new surfactant called CHEM-X which is inorganic monomer compounded with silicon and hydrogen (modified sodium silicate, pH = 13.1) It is stable and environmental safe, and works as an agent of wetting, surface active and separating oil. The surfactant was diluted with steam condensate in the reservoir and any concentration control was not done.

The injection of the surfactant from injector were attractive for mobile heavy oil by strong foaming and flooding functions at the initial stage when pre heating effects were not enough, then communication time during the tow wells was shortened by 38% compared to the conventional SAGD process. It was expected that the steam could be injected earlier due to quicker generation of the steam chamber between the two wells; thus, pre-heating of the reservoir around the wells can be shortened. Consequently, setting larger vertical spacing between the two wells can be possible for increasing production rate.

**Cyclic Steam Stimulation (CSS)[12]**

CSS process involves a single well with three stages and can use vertical, deviated, and horizontal wells. In stage 1, steam is injected at formation parting, or fracture pressure to heat the bitumen. In stage 2, the wells are shut-in soak. In stage 3, the wells are put on production. During a typical cycle, 10% of the calendar days are for steam injection, 10% are for soak, and 80% are for production operations.

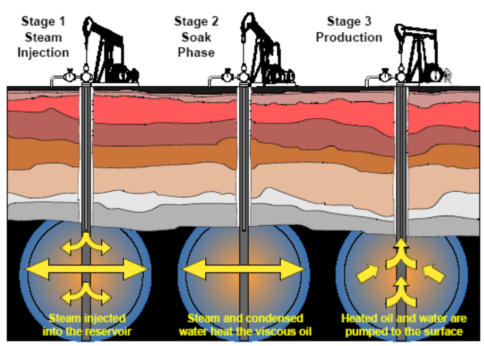


Fig. 10 Stages of the CSS process

Unlike SAGD, where the sensible heat of any condensate injected has no value in the recovery process, the heat from injected condensate does enhance recovery in CSS operations. As a result, CSS SOR is typically indicated on a wet steam basis. Over the first 20-years of operation, wet steam SOR for Nabiye is predicted to average 3.3

Using data for the last CSS cycle in the Nabiye application, the economic limit SOR is 5. The material balance provided in the Nabiye application has a requirement of 59 $m^3$ external gas per $m^3$ wet steam sent to the fiel.

**SAGD-Induced Stress and Permeability Changes**

The injection of hot, high pressured steam into the oil sands induces stress changes, and these cause increase in permeability. Permeability is a physical property of a rock and is largely a function of the connected porosity, and the connectivity. For almost all rocks, this physical attribute remains constant. However, oil sands can undergo large increases in porosity, both in situ and in the laboratory. As consequence, the permeability for any given core plug is also a function of its varying porosity.

Conventional reservoir simulations of thermal recovery processes in heavy oil and bituminous oil sands do not explicitly incorporate geomechanics[13]. When geomechanics are considered, absolute permeability in oil sands reservoir is far from being a fixed property. Thus the effects of the changing reservoir pressures and temperatures on the geomechanical behavior of the reservoir are calculated, and in turn, these were used to modify the reservoir parameter. Geomechanical enhancement of the SAGD process was found to be a significant beneficial effect, and would be increased by operating the SAGD process at higher injection pressures.

## 11. Conclusions

- The advantage of the SAGD process is its high recovery and oil production rate. However the high production rate is associated with excessive energy consumption, $CO_2$ generation, and post-production water treatment.
- The SAGD process has the potential to produce several damage scenarios including carbonate and/or silicate scales, asphaltene deposition or formation fines migration.
- There has been much written about the damaging mechanisms that occur in the steam injector wells. But there is very little written as to the damage mechanisms that can exist in the producing wells or the type of stimulation treatments that have been performed in them.
- The SAGP process' steam consumption is expected to decrease by approximately 70 percent
- In the Intermittent Steam Injection on the Production Well, total amount of steam injection increased 26 % to that of the usual SAGD process
- The injection of naphtha vapor instead of water vapor combines an effective thermal process with the diluents mechanism of the naphtha.
- Analytical calculations considering only thermal effects indicate that naphtha can produce more oil than steam within a certain amount of time.
- In Lab experiments, naphtha recovered 100 per cent of the bitumen in place, against only 80 per cent for steam.
- A preliminary economic evaluation indicates the necessity for naphtha recovery at the end, in order for the NAGD process to compete with SAGD.
- Results obtained from field scale simulation suggested that the oil production rate of SAS process could be higher than that as a SAGD process.
- Preliminary economic analysis indicated that comparing to the SAGD process, the SAS process might save 18% of the energy input for the same oil production.
- When a small amount of noncondensable gas is injected simultaneously with steam, the gas fingers quickly to the top of the model and displaces oil downwards.

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