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The False Lucre of Low-Pressure SAGD

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Abstract

The recent trend in SAGD is towards low-pressure steam injection. The intention is to be more thermally efficient: steam at lower pressures has a greater proportion of its heat as latent heat, which is the dominant source of heat released to the cold reservoir. The oil sand then warms up to the steam temperature, thus mobilizing the bitumen. The SAGD process must be thermally efficient for optimal economic viability.

However, a more rigorous examination of the SAGD process presented here, inclusive of surface processes, reveals that there are fewer thermal benefits in operating at lower pressures. In addition, SAGD will be hindered by low-pressure injection due to higher viscosities and the inhibited dilation of the unconsolidated sandstone reservoir. This paper demonstrates that a complete analysis of the SAGD process favours operation at high pressures, and that SAGD at low pressures will be less effective.

Introduction

Steam assisted gravity drainage (SAGD) has been successfully applied to the in situ thermal recovery of bitumen beginning with AOSTRA's Underground Test Facility laboratory-scale pilot project, Phase A (1987 – 1991)[1], and the subsequent commercial-scale pilot, Phase B (1991 – present)[2]. Since then, a large number of commercial SAGD projects have emulated their success.

The current trend in operating philosophy is towards low-pressure SAGD: LPSAGD. This is based on the fact that at lower pressures, a larger percentage of steam's total heat is latent heat.

Attractiveness of Low-Pressure SAGD

SAGD Process

In SAGD, most of the heat transferred to the cold oil sands formation is by the condensation of steam into the periphery of the steam chamber. The latent heat released from the steam is transferred to the colder formation mainly by conduction. Therefore, along the slopes of the steam chamber, the predominant flow of condensed steam (i.e. hot water) and mobilized hot bitumen is perpendicular to the direction of conductive heat flow.

Steam quality is the mass fraction of water converted from liquid to steam. In SAGD, the injection of less than 100% quality steam is counterproductive, since the injected liquid water fraction just falls from the injector well to the producer well under gravitational forces within the isobaric steam chamber. This adds to the water recycling costs while contributing neither to the release of energy to the formation nor to bitumen recovery.

Steam Properties

The energy in steam at constant pressure consists of sensible heat and latent heat. The sensible heat is the energy required to raise the temperature of the water from an initial source temperature to the steam temperature; the latent heat is the energy required for the phase change from that hot water to steam. It is this latent heat that provides the dominant source of heat for the SAGD process.

While the enthalpy of steam over the pressure range of 1,000 to 3,500 kPa is relatively uniform (see Figures 1 and 2), at lower pressures the proportion of heat as latent heat is higher. Since latent heat is the dominant form of heat transfer to the formation, one can see the attraction of low-pressure injection, solely from a steam energy viewpoint.

SAGD and Steam Injection Pressure

The trend towards LPSAGD began with Edmunds and Chhina (2001)[3]. The authors conducted four SAGD reservoir simulations assuming constant permeabilities of 3.5 D and 7 D, and reservoir thicknesses of 10 m and 25 m. They concluded that SAGD economics are more sensitive to the steam-oil ratio (SOR) than the oil rate, and that low injection pressures are favoured because of their low temperatures and low steam consumption. They postulated that pressures as low as 400 kPa might be optimal, based on a minimization of the SOR.

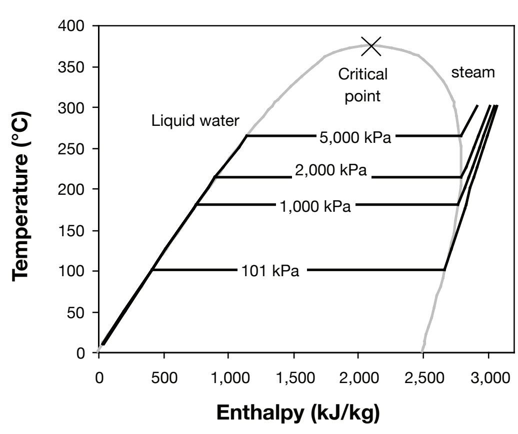

FIGURE 1: Temperature-enthalpy schematic for steam.

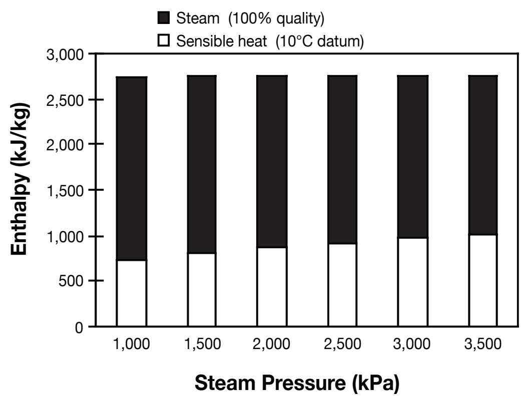

FIGURE 2: Enthalpy of steam vs. pressure.

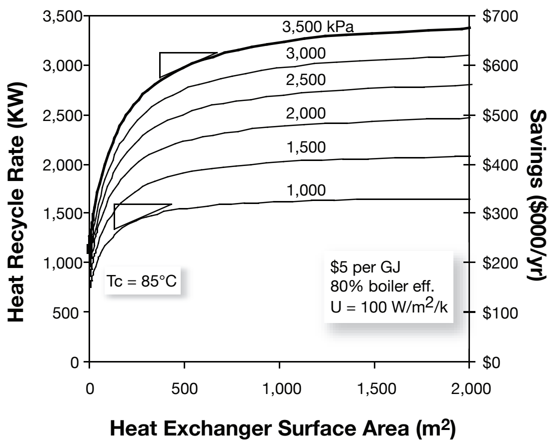

FIGURE 3: Value of recovered heat (CDOR = 100 m³/d).

Thermal Accounting: SOR vs. Net Energy

The current practice of using the SOR as the economic indicator for SAGD performance is flawed as it only considers the energy injected. An improved metric would be the energy consumed, which includes the energy recovered.

Historically, the SOR has been a fair indicator of the efficacy of steam recovery processes. Before SAGD, two successful steam recovery processes were steamfloods and cyclic steam stimulation (CSS). In steamflooding, steam is continuously injected into one well while warm water and oil are produced from another well. In CSS, steam is injected into one well for about a month, and then the well is shut-in for the "soak" period. Afterwards, that same well is put on production for three or four months, producing hot water and oil at progressively cooler temperatures until the lower production rates warrant another injection cycle. In both processes, all of the latent heat and much of the sensible heat have been lost to the formation. As such, the SOR is a good first-order indicator of energy consumption.

In contrast, SAGD produces fluids continuously at constant rates and just below the steam saturation temperature. This makes SAGD ideally suited for heat recovery. This energy is currently being recovered by SAGD operators and must be included in any rational thermoeconomic analysis.

Heat Recovery and Heat Exchangers

Heat exchangers provide the primary method of heat recovery from the produced fluids at steam injection thermal recovery projects. They are a known technology with proven performance.

Heat exchangers are classified according to their flow arrangement and construction, with the most effective design consisting of two concentric pipes with counterflow. The exchange of heat occurs as the hot and cold fluids flow past each other in opposite directions. Other flow arrangements are less efficient. However, sometimes efficiency is foregone in order to optimize the design of the heat exchanger in terms of other criteria such as volume, dimensions, differential thermal expansion, flow constriction and maintenance. Shell and tube exchangers with one shell pass and one tube pass through multiple tubes utilize counterflow.

Heat Exchanger Effectiveness

The effectiveness of a heat exchanger(4) is the ratio of its heat transfer rate to the maximum possible heat transfer rate and this is largely a function of the surface area of the exchanger, the ability of the exchanger to transfer heat for a given temperature difference, U, and the heat capacity rates of the hot and cold fluids(5).

The potential for heat recovery from the co-mingled produced fluids was examined using the injection pressures and resultant SORs provided by Edmunds and Chhina(3) for their simulation of a 25 m thick reservoir with a 7 D permeability. This analysis assumed a conservative overall heat transfer coefficient of U = 100 W/m²/K (17.6 BTU/ft²/h/°F) and a CDOR (calendar day oil rate) of 100 m³/d.

Figure 3 clearly shows that the amount of recoverable heat is much lower at low pressures. The heat recycle rate is plotted against the heat exchanger area. Curves are plotted at the heat capacity ratios corresponding to the SORs at six operating pressures from 1,000 to 3,500 kPa. The x-axis is the surface area; therefore, these curves include the effect of the minimum heat capacity rate for each pressure. All the curves intersect the y-axis at an assumed water recycle outlet temperature of 85°C. Relative to a make-up water temperature of 5° to 10°C, this is a continual savings in energy required to heat the recycled water to the boiling point, T_{sat}. All other heat recovery is from the heat exchanger.

The higher rates of energy recovery at higher operating pressures are a direct result of their higher operating temperatures and higher total fluid production rates. At higher operating pressures it is advantageous to have a larger surface area since the hot and cold flow rates are both higher; their heat capacity ratio is closer to unity and therefore a larger area is required for the same level of heat exchange effectiveness.

Assuming a price of $5 per GJ for the natural gas firing the boilers, at a boiler efficiency of 80%, the heat recovered can be converted to cost savings. These are based on a CDOR of 100 m³/d that is scalable to expected production rates. Savings of over $650K per annum are predicted for the highest operating pressure of 3,500 kPa.

The effect of SAGD heat recovery as a function of operating pressure is shown in Figure 4, assuming a constant heat exchanger area of 1,000 m². Higher heat recoveries are obtainable with larger areas or larger heat transfer coefficients. This thermal analysis demonstrates that, from a thermoeconomic standpoint only, the

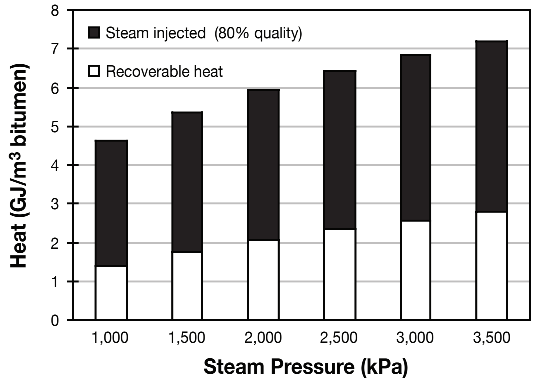

FIGURE 4: Net energy.

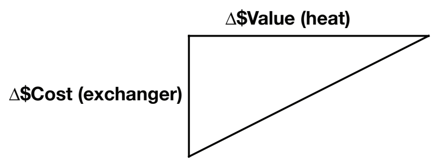

FIGURE 5: Marginal cost and benefit of incremental heat exchanger area.

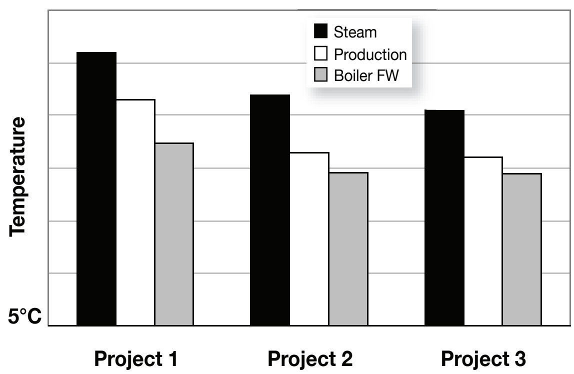

FIGURE 6: Temperatures of injected steam, produced fluids and boiler feedwater.

SAGD process is almost pressure independent if reasonable heat recovery is used.

Heat Exchanger Optimization

The optimal size of a heat exchange system will be one where the marginal cost of increasing the size of the heat exchanger equals the incremental benefit of the heat recovered. This requires realistic estimates of the exchanger effectiveness and the value of recovered heat. This ratio can be expressed graphically as a triangle, if the costs and benefits are expressed in equivalent annual prices (see Figure 5).

The optimal heat exchanger size is obtained when the triangle's hypotenuse is tangent to the curves in Figure 3, in which two triangles for the cases of high and low pressures are depicted. As the price of fuel gas increases, so does the value of the recovered heat and the triangle becomes flatter, increasing the optimal heat exchanger area. Conversely, an increase in the cost of heat exchangers will shift the optimal point towards smaller sizes.

The analysis in Figure 4 has been done assuming a uniform heat exchanger size of 1,000 m^2. However, the optimal size of a HPSAGD heat exchanger will be larger than for a LPSAGD heat exchanger since there is still considerable energy left in the produced fluids. This is shown schematically in Figure 3, where the triangle for high-pressure operation is to the right of the identical triangle at low pressure. As such, the net energies reported in Figure 4 are slightly biased in favour of LPSAGD. A more complete analysis should include a rigorous examination of heat exchanger sizes, costs and performance specifications.

Heat Recovery and Field Data

Figure 6 shows the temperatures of the injected steam, produced fluids and boiler feedwater for two SAGD projects and one CSS project. The datum temperature is 5°C, representing the make-up water. These heat recovery systems are fairly effective, with boiler feedwater temperatures at 80% of the produced fluid temperatures.

Boiler feedwater temperatures at the Dover Project (UTF), when operated by Devon Canada[6], ranged from 190° to 205°C. Given that SAGD steam has an enthalpy of approximately 2,800 kJ/kg, their recovery was 28% – 31% of the injected heat. In contrast, Edmunds and Chhina[3] assumed that only 10% of the injected heat would be recovered, which would equate to a boiler feedwater temperature of 80°C.

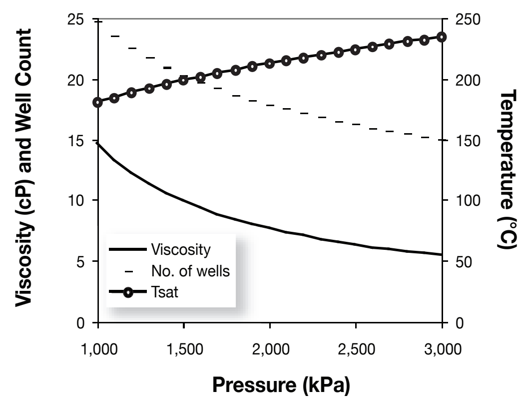

FIGURE 7: Temperature, viscosity and well count vs. operating pressure.

These field data demonstrate that the heat recovered can be considerable. Since this heat replaces fuel gas energy, it must be included in any economic analysis in a realistic manner. Once that is done, there is far less thermal benefit to LPSAGD. For colder reservoirs at 5°C to 10°C, heat recycle efficiency will be approximately 15% of the boiler feedwater temperature in °C (e.g. 200°C for 30% heat recovery).

SAGD Economics

The goal of all SAGD practitioners is to maximize benefits to our companies. This objective resulted in the pursuit of a lower SOR, which would reduce costs. However, the SOR is only one part of a complex equation and it cannot be used in isolation.

The use of the SOR as *the* economic indicator for any SAGD project is erroneous because the SOR only examines the heat injected without giving any value for the heat recovered. However, even net energy is not the best measure, since it is only one operating cost and does not address the capital expenditures.

CAPEX Dependence on SAGD Pressure

A major drawback of LPSAGD is the associated drop in temperature. Bitumen viscosity is exponentially proportional to temperature and the production rate is proportional to $(\text{viscosity})^{-0.5}$, so the production rate is strongly dependent upon temperature[7].

Figure 7 shows three curves plotted against the steam pressure: the saturated steam temperature, a typical Athabasca viscosity, and its inverse square-root, which indicate the relative number of wells required for a given CDOR at pseudo-steady-state conditions.

A reduction in temperature increases the number of well pairs required to maintain a specified CDOR. At $3 million per well pair, this is a considerable capital expenditure (CAPEX) required at the onset of a project. This could increase the CAPEX beyond the hurdle cost for a project, increase the exposure to risk, make the project less economical, tie up capital that might be better spent elsewhere, and preclude any technical innovations that could be applied to a project with wells having a shorter life span. LPSAGD wells will also be on production for a considerably longer time, which is a commitment to continuing their operation for their longer life.

With low production rates, LPSAGD wells will reach their economic limit at lower recoverable reserves. While LPSAGD abandonment rates will likely be lower than for HPSAGD, the recovered reserves will also be lower. One solution is to reduce the well pair spacing, which would increase the number of well pairs drilled.

In contrast, HPSAGD operates at higher temperatures with lower viscosities. Production rates are higher so fewer well pairs are required for a given CDOR. Well lifespans are shorter, allowing more flexibility on the placement and number of subsequent well pairs. CAPEX is deferred to the future, since wells are only drilled when required.

Artificial Lift

A major benefit of HPSAGD is that the produced fluids flow to surface under reservoir pressure, as long as the pressure differential between the steam chamber and the wellhead exceeds the hydrostatic head of the production fluids. In contrast, LPSAGD requires artificial lift with its CAPEX and operating expenditure (OPEX). In addition, thermal operation pumps require frequent maintenance and replacement. Some artificial lift configurations require larger casing and therefore higher drilling costs.

Water Handling, Heat Exchange and Piping

HPSAGD's higher SOR requires larger volumes of water which must be recycled. Larger heat exchangers are required in order to optimize the heat recovery; however, this is offset by the value of the heat. All piping and vessels must be designed for the higher pressures.

Heat Loss

Although operating temperatures are lower with LPSAGD, the length of time that each well pair operates is considerably longer than for a HPSAGD well pair. The effect of more well pairs over a longer operating life supersedes the benefit of operating at a lower temperature. As a result, heat losses may be higher for a LPSAGD project at an equivalent CDOR.

Present Value: a Rational Approach

SAGD projects are large, complex, and cost hundreds of millions of dollars. Any sensible SAGD economic analysis must identify and quantify each and every cost and benefit, their interdependencies, and their variations with time, scale and operating pressure. A present value analysis should be done in order to bring all parameters into a common frame of reference in which to make fair and valid comparisons. Any assumptions made in this process should be explicit, so that they can be easily reassessed. Only when this is done can we truly optimize the SAGD process.

For each choice of operating strategy (e.g. LPSAGD vs. HPSAGD) a cost/benefit analysis should be done for the life of the project. For example:

- CAPEX: surface facilities, heat exchangers, well pairs, lift system, etc.
- OPEX: natural gas, electrical power, workovers, royalties, taxes, etc.
- Benefits: bitumen, produced gas, recovered heat, utility heat, power cogeneration, total recoverable reserves, etc.

The analysis should include cash flow forecasts, present value analyses and sensitivity analyses of predictions vs. controlling factors. A levellized cost presentation may provide some insight into the price sensitivity of individual components.

This facilitates the decision-making process, as it couches all costs and benefits in a common frame of reference so that valid comparisons can be made. This methodology does not differentiate between CAPEX and OPEX; however, CAPEX costs will be prominent if the selected discount rate is high.

For larger companies, the optimal choice of operating strategy may be the one with the largest net present value (NPV):

$$NPV = \sum_{i=1}^{m} PV_{Benefits}\left[C_{(t)}^{i} Q_{(t)}^{i}\right] - \sum_{j=1}^{n} PV_{Costs}\left[C_{(t)}^{j} Q_{(t)}^{j}\right] \quad \text{.............................. (1)}$$

where $C_{(t)}$ and $Q_{(t)}$ are the unit cost and quantity of each component over time. Companies may have different criteria, such as the rate of return, minimizing CAPEX, cash flow or ensuring a minimum bitumen rate.

With this approach to SAGD economics, the relative benefits of LPSAGD vs. HPSAGD become more apparent. This analysis would include the reservoir's response to low- or high-pressure operation in the forecast production profiles (including geomechanical effects), SORs, enthalpy profiles and recovered heat. Intuitively, this is an improved approach to assessing the value of differing operating strategies as compared to the simplistic approach of using the SOR. Once this analytical tool is created, it becomes a powerful means of optimizing the SAGD process to maximize benefit.

Our objective is to maximize benefit. Economic optimization differs from the optimization of the SAGD physical process, since drowning a production well is inefficient in terms of maximizing production. As an example, Birrell et al.[8] simulated a mature SAGD steam chamber to examine the effect of the seasonal fluctuation in the price differential between crude oil and bitumen, which falls during the summer paving season. By using the mature steam chamber for production storage by throttling production when prices were low, and flushing production when prices were higher, the projected economic benefit was increased.

Similarly, the operating pressure could be cycled, with an increase in steam injection and gas consumption in the summer months, and a reduced rate of steam injection in the winter when gas prices are predictably higher. Seasonal fluctuations in steam and fluid rates would add to the facilities cost. These would be included in a complete present value analysis.

SAGD Geomechanics

The debate on HPSAGD vs. LPSAGD has been devoid of geomechanics. This reflects a lack of understanding of geomechanics rather than its significance. Most reservoir engineers presume that the permeability of the oil sand reservoir is fixed and is independent of operating pressure. This is not true because the beneficial enhancement of porosity and permeability with shearing is maximized at high pressures. These effects can and should be substantial if the geomechanical aspects of the SAGD process are to be optimized. Without geomechanical enhancement, permeabilities may be as low as 10% of expected values, resulting in production rates being a third of expectations. The economics of most SAGD projects could not afford this.

Core Disturbance

In no other area of petroleum engineering is the core cut at one porosity, and tested at a much higher porosity, with the core results directly applied to reservoir conditions. The increase in porosity due to core disturbance has a profound effect on the resultant porosity, saturations, absolute permeability and fluid mobility.

Oil sand core is susceptible to disturbance due to its unconsolidated structure. These sands are dense interlocked sediments of near-uniform grainsize[9]. The only difference between these unconsolidated formations and indurated sandstones is their lack of cementation. Without cementation, oil sand's strength depends upon the confining stress. If an isotropic confining stress is maintained, thus preserving the dense interlocking structure developed over geologic time, the oil sands have strength characteristics far greater than if reconstituted at overburden stress.

Gas exsolution is a major cause of oil sand core disturbance. The cold bitumen in the oil sand core is immobile, but it is often saturated at the reservoir pressure and temperature. Once the pressure is relieved with coring, gas will begin to nucleate and expand. Since the bitumen is immobile, and the gas phase is non-continuous, the growing gas bubbles force the pores to expand. The core slowly blows itself apart. This results in permanent and irrecoverable disruption of the sand structure.

Coring

In the past, oil sands were cored with conventional drillrigs with one or two stands (9 to 18 m) per core run. Trip times were considerable since the entire drillstring had to be retrieved to obtain the core. Now, wireline rigs are used with triple-tube coring. The faster retrieval of the core makes shorter core runs of 2 to 3 m practical. Shorter core runs put less vertical load on the core, since the core is self-supporting within the inner core tube, particularly once the core barrel is extracted from the well.

Gas bubble nucleation and growth is a time-dependent phenomenon. With the rapid core recovery, bituminous core can be frozen at the surface before gas bubbles initiate. Freezing temperatures must be sufficiently low to prevent gas exsolution, not just to freeze the pore water. Otherwise, gas bubbles will grow until the core completely fills the core tube. More gas exsolution will cause axial core extrusion[10]. For this reason, core recoveries of more than 100% have been reported. Slotted inner core tubes allow the gas to escape but do not eliminate the disturbance as the core expands to fill the inner core tube. Using "zero clearance"[11] (1.27 mm clearance) inner core tubes is highly recommended, as this minimizes the capacity of the core to expand as it fills the core tube. The potential for higher frictional resistance to the core entering the core tube is minimized with the shorter, faster wireline core runs.

Specimen Preparation

Without specialized coring, most core expands to fill the core tube. For conventional core, this is a 15% increase in bulk volume, not including any longitudinal expansion. Next, the tube is sawed lengthwise, which removes all confining stress. Lastly, the core is semi-thawed to permit a sharpened tube to be forced into the exposed side of the core to obtain a cylindrical specimen, although the option of nitrogen coring is available. This plug is extruded into a flexible sleeve for permeability and porosity testing. The specimen disturbance at this point is considerable, and there are numerous reports of the ubiquitous discrepancy between core and log porosities[12].

In contrast, oil sand for geomechanical testing is cored with zero-clearance core tubes. The core is frozen with dry ice to ensure that the core fluid is kept undersaturated at atmospheric pressure. The core is stored at –40°C. Sample preparation is done in a cold room at –20°C by technicians in parkas in order to preserve the structural integrity of the core. Specimens are placed in a lathe and machined to the testing diameter; the ends are sawed and trimmed to create a cylinder. Several times during this procedure, each specimen is sealed and immersed in a cold bath to preclude gas exsolution. Otherwise, even core at –20°C has been observed to exsolve gas. Each specimen is mounted in a triaxial testing frame under overburden pressure before thawing is allowed. The improvement in core quality justifies this procedure, but only if the core arrives at the laboratory with minimal disturbance.

Quantifying Core Disturbance

Dusseault and van Domselaar[13] defined their "Index of Disturbance" as the percentage increase from the initial porosity, ϕ_0, to the current porosity, ϕ:

$$I_D = \frac{\phi - \phi_0}{\phi_0} \qquad (2)$$

As an example, oil sands cored from a formation with a porosity of 30% but with a core porosity of 36% would have an $I_D = 20\%$, which is not uncommon. Any core with $I_D > 10\%$ was generally accepted to be of little use for geomechanical strength testing; its effect on permeability is equally as profound. Although reapplying the in situ confining stress can reduce core porosity by re-seating grains, any grain rotation will be permanent, and the core's mechanical and hydraulic properties cannot be restored.

Routinely reporting the I_D for all specimens is highly recommended in order to quantify core quality.

Core Disturbance and Absolute Permeability

The best absolute permeabilities of undisturbed Athabasca oil sand were from specimens cored in the laboratory from block samples of McMurray Formation outcrop taken from an area uninvaded by bitumen[14, 15]. This precluded gas exsolution. Specimens cored vertically and horizontally were tested under triaxial loading conditions, with permeability continuously measured in the direction of loading.

Touhidi-Baghini[14] fit the increase in permeability to the volumetric strain in a semi-logarithmic relationship [Equation (3)] where k is the current absolute permeability, k_0 is the original absolute permeability, $C_{\phi o}$ is a porosity-dependent proportionality constant, and ε_v is the volumetric strain. This relationship can also be re-stated in terms of the initial porosity and B, a proportionality constant [Equation (4)].

$$\ln\frac{k}{k_0} = C_{\phi_o}\varepsilon_v \qquad (3)$$

$$\ln\frac{k}{k_0} = \frac{B}{\phi_0}\varepsilon_v \qquad (4)$$

Touhidi-Baghini and Scott[15] found that $C_{\phi o} = 17.48$ for vertical Athabasca specimens and $C_{\phi o} = 9.07$ for horizontal specimens. Alternatively, $B = 5$ for vertical specimens and $B = 2$ for horizontal specimens, although site-specific values obtained from low-disturbance core would have been preferred. The permeability factor is inversely proportional to the initial porosity, signifying that volumetric strains will have more of an effect on the core with lower porosity. Re-written in terms of porosity:

$$\ln\frac{k}{k_0} = \frac{B}{\phi_0}\frac{\phi - \phi_0}{1-\phi} \qquad (5)$$

If the log porosity is assumed to be the undisturbed porosity, then the measured core permeability can be back-corrected to its in situ value. Equation (6) becomes a useful tool for estimating the undisturbed in situ permeability from core data.

$$\ln\frac{k_{core}}{k_{\log}} = \frac{B}{1-\phi_{core}}\frac{\phi_{core} - \phi_{\log}}{\phi_{\log}} = \frac{B}{1-\phi_{core}} I_D \qquad (6)$$

Initial vertical and horizontal permeabilities of these clean undisturbed Athabasca oil sand specimens were 1 D and 1.5 D[18]. This is a marked difference from the typical laboratory results that are in the order of 10 D.

These specimens will have enhanced permeability if disturbed, as predicted using Equation (6) for initial porosities of 33% and 35% (Figure 8). Vertical permeabilities are close to 10 D for a 15%

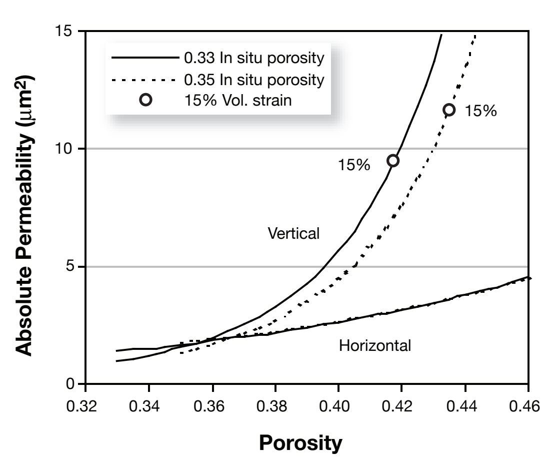

FIGURE 8: Predicted absolute permeability resulting from disturbance.

volumetric strain, which corresponds to the typical condition of conventional core upon arrival at the laboratory.

Disturbed oil sand core permeabilities are 5 to 10 times larger than undisturbed in situ permeabilities. The fact that history matches of existing SAGD projects require permeabilities in the range of 5 to 10 D is indicative that this is the effective permeability in the reservoir under current SAGD operating pressures, which are generally high. SAGD operation at lower pressures will maintain the oil sand's frictional strength, which will reduce shearing and its associated dilation and enhancement of porosity and permeability. Lower oil rates should be expected.

Core Disturbance and Fluid Mobility

The increase in porosity results in an influx of fluid to occupy the induced voidage. At colder temperatures, the bitumen is effectively a solid and is immobile. Gas exsolution is similarly retarded, particularly if SAGD increases ambient pressures, which undersaturates the bitumen. At colder temperatures, water is the only mobile fluid.

Oldakowski[(16)] conducted geomechanical triaxial tests on high-quality Athabasca oil sands core at the 8°C reservoir temperature. Shear-induced dilation increased core porosity, which increased the water saturation and resulted in the commensurate increase in effective fluid mobility by three orders of magnitude[(17)].

The implications for SAGD are significant. The increase in porosity ahead of the steam chamber will propagate the pressure front ahead of the steam chamber and accelerate the gravity drainage of the heated bitumen. Furthermore, the increase in fluid pressure reduces the effective stresses in the rock, which promotes further shearing, dilation, increased porosity and fluid mobility ahead of the steam chamber.

Application to SAGD

The initial stress state in the oil sands is a function of its geological history. The overburden applies the vertical load. The horizontal stresses are due to the elastic response of the formation to the overburden, and to tectonics. As such, in most Alberta reservoirs the highest stress is the major horizontal stress, with the minor horizontal stress magnitude often being comparable to the vertical stress.

The injection of pressurized steam reduces the effective stresses on the oil sands. This unloads the reservoir matrix, which then expands vertically, as measured in cold oil sands ahead of the steam chamber[(18)]. The resultant volumetric strain over seven months was small (0.25% for Dover UTF Phase B) but the additional porosity created gradually fills with water originating in the steam chamber. This creates a finite demand for several thousand cubic metres of water per well pair at the onset of steaming. Significantly, the additional water saturation increases the total mobility and pressure communication ahead of the steam chamber. The Dover UTF project reported the SAGD pressure front arriving 5 m to 12 m ahead of expectations within the cold oil sand[(19)].

The injection of high-pressure steam reduces the confining stress on the sand grains. If differential stress is applied to the oil sand, as is naturally in place with the varying vertical and horizontal stress, it makes it easier for the individual grains to slide over one another, rotate and displace. The net result of this shearing is dilation: an increase in the porosity. With higher injection pressures, the effective stresses are lower, the oil sand has less strength, and the shearing and dilation are more prominent. Along with the dilation comes the increase in fluid mobility and absolute permeability, as discussed. However, shearing and enhancement is not uniform within the reservoir. Instead, it occurs along induced shear planes, which then become transmissibility conduits for mobile fluids. Field evidence of discrete thermal intrusions ahead of the steam chamber supports this[(20)]. The Dover UTF project also reported significant heat convection in the cold reservoir[(21)] which was comparable in magnitude to heat conduction at the perimeter of the steam chamber.

From a facilities and reservoir engineering standpoint, pressures are an absolute. For geomechanics, pressures are relative, being either "high" or "low" depending upon the depth. For example, 4,000 kPa would be high at a depth of 200 m, but low at a depth of 400 m. This difference in terminology is central to an understanding of the geomechanical effects of injection pressures.

The thermal gradient ahead of the steam chamber also imposes differential thermal stresses on the oil sand, in the order of 1,000 kPa[(22)]. Depending on the orientation of the steam chamber boundary with respect to the in situ stresses, this can either help or hinder shearing by adding to or diminishing the differential stresses due to the original rock stresses. In general, thermal stresses tend to increase the anisotropic growth of the chamber.

Lastly, the growth of the steam chambers themselves will alter the original stress field. Steam chambers pushing upwards and outwards will increase the horizontal stresses and reduce the vertical stresses in the cold oil sand between well pairs[(23)]. This thermal "jacking" will accentuate differential stresses. Depending on the existing stress state, this can encourage shearing and the lateral growth of the chambers culminating in steam chamber coalescence.

Once shearing and dilation have occurred, the beneficial effects of enhanced porosity and permeability will be permanent. Reducing the steam chamber pressure afterwards will have little effect on the induced permeability.

Field Evidence of LPSAGD Geomechanics

Field evidence of SAGD operating at low pressures is scarce, largely because the continuous operation of SAGD at low pressures remains unproven. However, there are indications that reservoir performance at low pressures will be less successful than at high pressures (pressure being relative to depth).

Shell Peace River

Shell Canada's Peace River SAGD process[(24)] was less successful than anticipated, with reported SORs ranging from 5 to 10. The SAGD process was attempted twice, with some wells in bottomwater and some not, with no difference in performance. After switching to cyclic steam stimulation (CSS) with "soak radial" and multi-lateral side reach ("haybob") well layouts, they achieved acceptable SORs at injection pressures of 11,000 kPa, which exceeds the fracture pressure at that depth.

In explanation, Shell stated that they "forgot the lesson of pressure-enhanced vertical conformance"[(25)]. The SAGD injection pressure was 2,700 kPa, identical to that of UTF Phase A. However, the UTF wells were at 155 – 160 m depths whereas the Peace River wells were at a 600 m depth. The UTF wells were operated within 700 kPa of the fracture pressure, whereas the Peace River wells were several MPa below theirs.

JACOS Hangingstone

A poignant example of the effects of operating pressure on SAGD performance is documented by Ito et al.[(26)] The operating pressures used at the Hangingstone project are intentionally high, explicitly to achieve geomechanical enhancement within the reservoir, with injection pressures, P_{inj}, at 4,800 – 5,300 kPa at a well depth of 300 m. However, with additional wells coming on production, steam capacity was diverted to them which resulted in a drop in P_{inj} to 4,600 kPa. The growth of the steam chamber was inhibited as a result, with no vertical growth observed. Once additional steam capacity was added, P_{inj} increased and the steam chamber growth resumed.

The cause of the inhibition could not be correlated with any geological feature, and was attributed to diminished effective permeability due to poor counter-current flow. However, their back-calculated effective "thermal conductivity" of 2.9 W/m/°C while the chamber was growing is in stark contrast to the values of 0.87 – 1.16 W/m/°C back-calculated when the chamber was stagnant. In comparison, controlled laboratory values from Chalaturnyk[(23)] were 1.5 W/m/°C at 225°C. It would appear that the higher value included some convective heat transfer, which indicates that the higher P_{inj} is accelerating the growth of the steam chamber. The authors also specifically recognize the benefit of geomechanical effects in their reservoir.

TABLE 1: Comparison of low vs. high pressure SAGD.

	LPSAGD	HPSAGD
Lift	Artificial lift	Free-flowing
Heat exchange	Lower pressure system	Larger high-pressure system
Water treatment	Lower rates	Higher rates
Viscosity	Higher oil viscosity, lower rates	Low viscosity, higher rates
Wells	Higher initial CAPEX; narrower well pair spacing, more wells	Fewer initial wells; wider well pair spacing, flexibility, deferred CAPEX
Heat losses	Longer exposure	Higher temperature for much shorter period
Geomechanical enhancement	Limited	Ample
Residual oil		Slightly lower

An Argument for Low-Pressure SAGD

LPSAGD is the only option where the steam chamber is in communication with a thief zone at low pressures. Mobile fluids in a geological unit at a lower pressure, which is in communication with a steam chamber, will necessarily be displaced by steam from the steam chamber. Since the thief zone is colder, steam will continue to condense within it until either the thief zone is pressured to steam chamber conditions, or the steam chamber pressure falls and is balanced with the pressure in the thief zone. If the thief zone is extensive, the thermal costs of continuing at a pressure above balance are uneconomic.

High-pressure operation is possible until the steam chamber comes into close proximity to the thief zone. This would maximize the geomechanical benefits within the limitations imposed by the thief zone and accelerate steam chamber growth at early times.

Where there is a high probability of communication with a thief zone, or where the impermeable barrier between the steam chamber and thief zone is inadequate, it is preferable to maintain a potential thief zone at as high a pressure as possible in order to allow the greatest flexibility in options for the recovery of the bitumen. Furthermore, should the thief zone be water-bearing, there is the possibility of that water gravity-draining into the steam chamber, even at balanced pressure. This would quench the steam chamber and impose a high thermal load on the process. Lowering the pressure in the thief zone may precipitate the influx of water from a downleg source.

Lastly, bottomwater may prevent operation above balance to prevent the egress of heated bitumen and production water. Unless the thief zone can be isolated, or the fluid losses are acceptable, balanced pressure operation is likely the only option.

Conclusions

A realistic thermo-economic analysis of SAGD, including the heat recovered from the produced fluids, demonstrates that there is far less benefit obtained by operating at lower pressures.

SAGD economics are improved by including the recovered heat, which is approximately 30% of the heat injected. This is a considerable savings in operating costs since this heat will displace projections of natural gas consumption for steam generation. This benefit will be larger for projects operating at higher pressures. Facilities engineers are already recovering much of this heat, so it is unlikely that there will be any immediate increases in revenue. However, recognizing the importance and value of heat recovered from the produced fluids identifies a specific area for optimization. Since the recovered heat reduces the steam generation OPEX considerably, thinner reservoirs become more economically viable: economically recoverable reserves will increase.

The steam-oil ratio is only a measure of the heat injected and neglects all of the heat produced. As such, it is an incomplete indicator of the true thermal balance of any SAGD operation, and should not be used as the metric by which the thermo-economics of SAGD are evaluated. While the SOR is useful for evaluating the physical processes within the reservoir and for mass balance calculations, as an economic indicator it is misleading and heavily biased. Using the SOR as the economic indicator will necessarily result in the false conclusion that low-pressure SAGD is thermo-economically optimal. LPSAGD, therefore, is the right answer to the wrong question, “How do we reduce the amount of steam needed to produce bitumen?” A better question would be, “How do we reduce the energy required to produce bitumen?” The appropriate indicator is net energy, which includes the heat recovered from the produced fluids, and the efficiencies of the various components associated with heat generation, transportation and recovery.

However, the energy balance does not encompass any CAPEX or other OPEX. The best question becomes, “How do we maximize the benefit to our companies?” For most operators, the net present value will be the determining criterion, although other constraints may dominate instead, such as threshold capital costs or minimum production profiles. For SAGD, the physical optimum is not necessarily the economic optimum.

Lastly, the geomechanics of SAGD dictate that the permeabilities and performance anticipated by reservoir engineers can only be achieved when operating at high pressures. When injection pressures are within 500 kPa of the fracture pressure, full geomechanical enhancement should occur[22]. At lower pressures this will either not occur or be inhibited. As such, injection pressures should start high and decline with the rise in the steam chamber, as has since been examined in more detail[27].

Without geomechanical enhancement, interwell start-up and the subsequent steam chamber growth will be much slower; oil rates will be lower and much less economical. The spectre of impermeable barriers and baffles are real at low pressures, whereas at high pressures they have been demonstrated to be inconsequential as SAGD inhibitors.

SAGD thermo-economics are highly dependent upon the operating pressure. Given SAGD’s high costs, there are potential savings in the millions in properly optimizing the operating pressure and the process. Table 1 compares some effects of operating pressure on SAGD.

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NOMENCLATURE

B	=	proportionality constant
$C^i_{(t)}$	=	unit cost of item “i,” varying with time
C_{ϕ^o}	=	proportionality constant, porosity-dependent
CAPEX	=	capital expenditure
CDOR	=	calendar day oil rate
CSS	=	cyclic steam stimulation, a.k.a. huff and puff
D	=	Darcy (1 μm^2 = 1.01325 Darcy)
HPSAGD	=	high-pressure SAGD
I_D	=	Index of Disturbance
k	=	permeability
k_0	=	permeability, initial
k_{core}	=	permeability, core
k_{log}	=	permeability, log
kPaa	=	kilopascals, absolute
LPSAGD	=	low-pressure SAGD

NPV	=	net present value
OPEX	=	operating expenditure
P_{inj}	=	injection pressure
PV	=	present value
$Q^{i}_{(t)}$	=	unit cost of item "i," varying with time
SAGD	=	steam assisted gravity drainage
SOR	=	steam-oil ratio, m^3/m^3, cold water equivalent
T_{sat}	=	temperature, saturated steam
UTF	=	Underground Test Facility, a.k.a. Dover Project
U	=	heat transfer coefficient
ε_v	=	volumetric strain
ϕ	=	porosity
ϕ_0	=	porosity, initial
ϕ_{core}	=	porosity, core
ϕ_{log}	=	porosity, log

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