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SAGD and Geomechanics

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Highlights include handling large number of completions during the boom, the sale of Home Oil twice—a major evaluation, a significant award at SSI, large scale international reservoir simulations combined with securities reporting, and progressively more challenging technical projects, the most recent of which was the successful completion of an application in the Chard-Leismer Gas over Bitumen Hearing.

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Introduction

During the recent AEUB Chard Leismer Gas Over Bitumen Hearing, there was a considerable amount of technical evidence presented on a wide variety of SAGD technology. One aspect that was different from the last such hearing (Surmont) was the introduction of geomechanics related to the SAGD process. The purpose of this article is to outline the underlying concepts behind geomechanics and then to demonstrate that geomechanics are necessary for a consistent description of SAGD design and actual field performance.

Outline

The principles behind geomechanics were developed primarily in soil mechanics, which is widely used in civil engineering—in particular, the design of foundations and earth works. Soils are comprised of grains of mineral and/or rock that are not cemented or are weakly cemented. Unfortunately, the latter is often called "unconsolidated," although cementing and consolidation (volume reduction due to loading) are not directly linked.

The fundamental areas where geomechanics plays a critical role include:

1. Sampling procedures—in particular, coring;
2. Evaluating conventional formation properties such as porosity and bitumen, water, and gas saturations;
3. Determining in situ permeability;
4. Understanding the mechanisms within the formation during SAGD; and,
5. Determining operating conditions.

The above issues will be discussed in detail in the following, starting with a preliminary introduction to geomechanics.

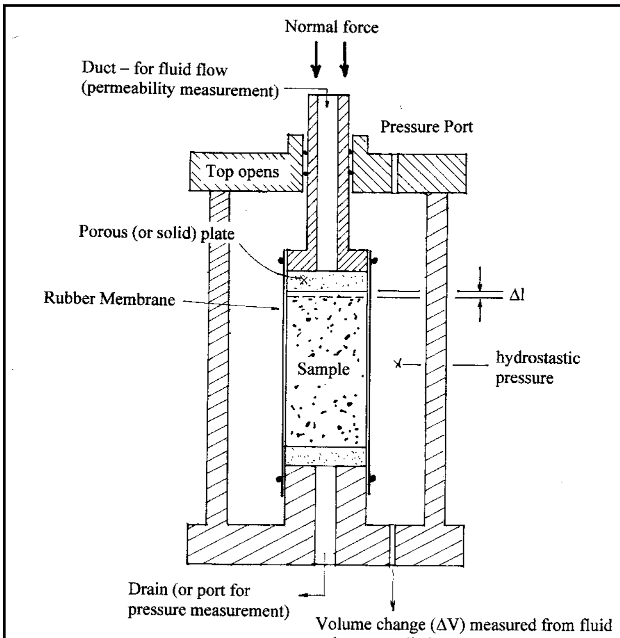


FIGURE 1

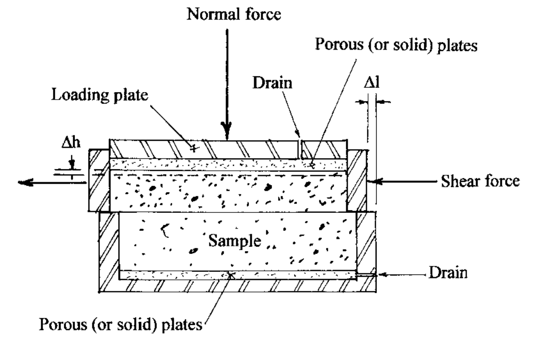


FIGURE 2

Soil Mechanics

Interlocked Structure

The fundamental control of physical properties of bitumen sands is the structure of the sand grains. In typical bitumen deposits, the sands are fine grained with the long axes of the grains lying horizontally. Deep burial in the past has resulted in a matrix structure of interlocked grains[1] (note that glaciation was not a major load compared to overburden in the Athabasca).

When subjected to loading, possible intergranular behaviour includes grain:

1. override
2. shearing
3. rotation (rolling)
4. translation (sliding)
5. elastic deformation
6. crushing.

Sands do not have any substantive tensile strength. Further, determining the bulk properties of granular material requires that the original structure of the grains not be disturbed. To date, no reliable methodology has been developed to reproduce the same sand grain structure once it has been disturbed. If great care is taken, it is possible that such effects can be minimized.

Material Testing

Two methods were developed in civil engineering to quantify the strength of sands. They are: (1) the direct shear apparatus; and (2) the triaxial cell. Basic depictions of these are shown in Figures 1 and 2[2]. These tests can be run in two fundamentally different ways. In the first method, pore fluids are allowed to escape; this is termed a “drained test.” In th e second method, the pore fluids are not allowed to dissipate; this is termed an “undrained test.” This has a profound effect on the behavior of the tested materials. In an undrained test, pore pressures will initially support the majority of the incremental load. In a drained test, sufficient time is allowed for the pore pressures to dissipate during loading. The speed of drainage is a function of permeability.

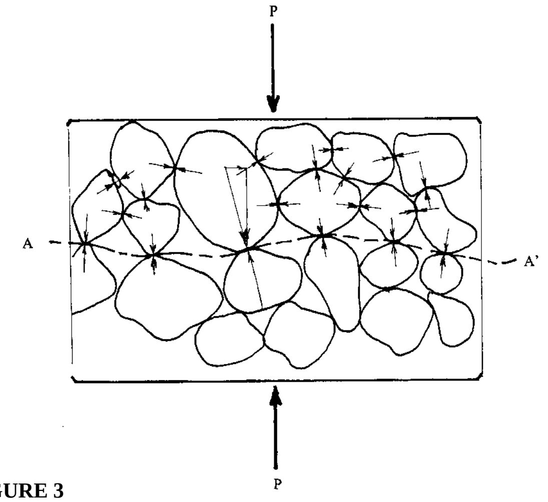


FIGURE 3

Effective Stress

In order to deal with the effects of pore pressure, the concept of effective stress was developed. Effective stress is the portion of the total stress in excess of the fluid pressure.

$\sigma' = \sigma - p$,

where:

σ' = effective stress
σ = total stress
p = fluid pressure.

The general concept is shown in Figure 3.

Typical Responses

The results from these types of tests are shown in Figure 4 on the upper left side. The test is strain controlled and the loads are read (otherwise, the testing machine may cause rogue sample destruction when the material softens and cannot hold more load). Note that Δl represents strain, which is vertical (axial) for the first apparatus and horizontal for the second apparatus. In a similar fashion, Δh represents either vertical or circumferential dilation. In the generalized figures, a clear distinction is made between loose and dense sands. The dense sands show a peak behaviour, after which their load-bearing capacity is reduced.

The McMurray formation in the Athabasca area is comprised of dense sands. Before complete shear failure can take place, the strength of the interlocking of sand grains in dense sand must be overcome in addition to the frictional resistance at the point of contact. A portion of the rock grains will physically break into smaller pieces. Therefore, the grain structure changes permanently and the process is not reversible. In the example shown, after a peak stress is reached, the load necessary to continue shear displacement is reduced. Note that if the slope of the stress strain curve reduces with strain, it is termed “strain softening.”

Dilation

The lower diagram on the left side of Figure 4 shows the

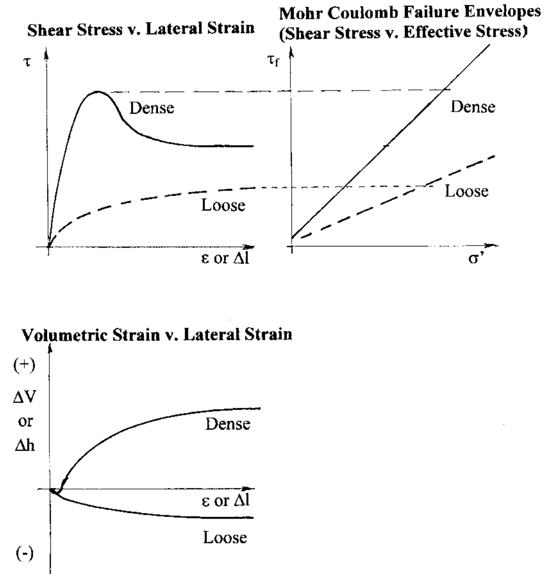


FIGURE 4

changes in volume which result from shearing and dilation. The structure of dense sands *expands*, which has the effect of *increasing* porosity and permeability. Note that loose sands *contract* with strain, which has the effect of *decreasing* porosity and permeability.

Failure Envelope

Multiple tests can be combined to determine a failure envelope, which is referred to as a "Mohr-Coulomb failure envelope." Mohr's circle can be used to define stress as a combination of shear and normal stresses for any plane. The construction of Mohr's circle and the failure criteria is shown in Figure 5.

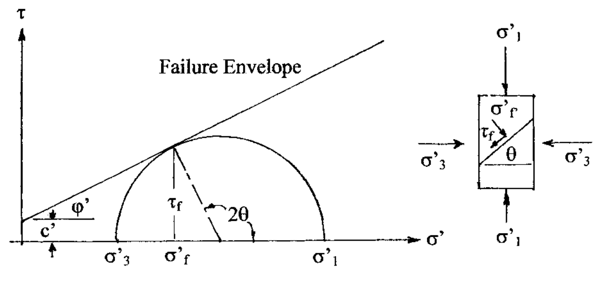


FIGURE 5

Note that these methods concentrate on bulk deformation of the sand and how much load can be carried. However, for reservoir engineering purposes, we are interested in a little more. How do the loads and the changing effective stresses influence porosity and permeability? It is possible to conduct the tests previously described under different stress paths by varying the confining pressure through the use of computers. In this manner, the stress history of an element in a heavy oil reservoir can be approximated.

Sampling Procedure—Coring

Core from unconsolidated sands containing bitumen causes a number of unique difficulties. This has been well documented since 1984 when Dusseault described the difficulties in obtaining core with the in situ grain structure intact from oil sands reservoirs[3]:

- Since the sands are not cemented, they are prone to mechanical deformation. In this case, the core is subjected to rotational friction, which will cause shear dilation. The sand grains ride up on each other.
- Solution gas ex-solution will cause significant deformation. The solution gas content of bitumen is quite low, normally under 4 m^3/m^3. However, in relation to the sample volume, this is potentially a large expansion. Note that this corresponds to an oil shrinkage of only 1 – 2%.
- Like conventional core, the oil sands core is subject to mud filtrate invasion due to the circulation of drilling mud while coring. However, because the uncemented sands expand and "create" more pore space, a much higher degree of invasion occurs than in conventional core.
- Stress is released from the core during the coring process. This causes outward expansion.
- The bitumen is sufficiently viscous that one would not expect significant bitumen displacement.

The expansion of bitumen sands normally results in core extruding from the core barrel at surface. It is also common for oil sands recovery to exceed 100% due to linear expansion. Most tar sands core barrels use white PVC pipe to maintain the physical integrity of the samples since they can be remolded or broken by hand. For this reason, core is normally frozen immediately upon extraction.

There are a number of implications:

- Core porosities (measured) are greater than in situ porosities;
- The water saturations from oil sands cores are too high; and,
- The alteration of the grain structure causes measured permeabilities to be too high.

Some apparent contradictions exist in the literature on this topic. The geotechnical literature has concentrated on gas ex-solution; there are passing references to the imbibition of drilling mud filtrate. There is passing reference to solution gas ex-solution in the petroleum literature, which is regarded as insignificant since heavy oils have low solution gas oil ratios. In the conventional oil industry, it is well known that water is imbibed into conventional oil cores despite solution gas that is expelled. Geotechnical engineers do all their sample preparation for laboratory analysis on cores frozen up to -18º Celsius to prevent mechanical rearrangement of the sand grains.

Physical Testing

There are serious implications of core sample damage due to physical testing. As indicated, it is virtually impossible to obtain a sample with the original grain structure intact or no disturbance. As a consequence, the samples that are tested will always be skewed towards the performance of a loose sand. *This means that data screening should more heavily emphasize those samples demonstrating dense sand behaviour.*

Heavy Oil Sands Analysis

Due to these unique problems, core is analyzed differently for heavy oils. Summation of fluids is used. The process involves putting small samples of the oil sands in a Dean Stark apparatus. The volume and weight of the total sample is measured first. This can be done by a variety of methods. The oil and water are extracted by using toluene as a solvent as well as heat. This is done with an electric heater for fire and safety reasons. The water is condensed and measured in a graduated container. Note that this measurement is made at a specific temperature. At high temperatures, water is driven off from clays and other minerals. Since the specific gravity of water and the bitumen are known, the volume of oil can be calculated by subtraction.

For additional cost, the volume of oil can also be measured directly. Common sense indicates that this should result in a tarry mess left in the sample and that the volume of oil recovered from the condenser will be less than the volume of bitumen originally in the sample. This is, in fact, the case. By "cooking" known volumes of bitumen and toluene, a volume correction factor can be calculated.

Adding the known volumes of gas, bitumen, and grain volume will not match the measured volume. This shortfall represents the gas-filled portion of samples. This last step is rarely done. For samples, which are permeability-tested, porosity will be calculated using a Boyle's Law porosimeter—the latter values will generally be higher than most summation of fluid calculations. It may also be concluded that permeability porosities and general summation of fluid porosities will not be equivalent.

Determining Correct Saturations From Logs and Calibrating to Core

Woodhouse describes the correct method of calibrating logs and core[4]. The basic assumptions are simple. First, relatively little bitumen is displaced from the core due to its high viscosity. Second, the in situ density measured from geophysical logs has the least disturbance. The log calculations are therefore tuned to weight percent bitumen. The errors in core analysis saturations do not affect the correct calculation of original oil in place. The increased porosity compensates for the filtrate invasion in cores. *This is significant in thermal recovery calculations—i.e., simulations where the extra connate water must be heated as part of the process.*

Uncemented formations typically have lower values of *m*, the cementation exponent in the Archie equation. It is also known that *n*, the saturation exponent, normally follows *m*. Actual core tests obtained from the Hangingstone McMurray formation conducted at overburden pressure indicate values of *m* and *n* of 1.40 and 1.77, respectively. Since these cores do not fully recover from grain restructuring with net overburden (NOB) loading, the lower water zones from the adjoining oil sands leases were checked using a Pickett plot. An in situ value of 1.35 was determined for *m* for this area. Pickett plots cannot be used to verify *n*. If $m = n = 2$ were incorrectly assumed, then the *Sw* would have been calculated as 30% instead of the correct value of 17.1%. *Using the correct values of m and n will significantly lower the calculated connate water saturations.*

Air Permeabilities

The standard design process for SAGD was developed on the UTF project. The predictions of performance were based on core permeabilities derived directly from air permeabilities on dilated cores. As a conventional reservoir and simulation engineer knows, this approach is not the generally accepted methodology. Air permeabilities must by adjusted for "slippage" and connate water saturations.

There is experimental data available which shows the difference between liquid and air permeabilities for oil sands. Again, this data is from Hangingstone and included permeability for cleaned and uncleaned samples. There are two factors to consider in evaluating the effects of NOB:

1. Normally, a horizontally drilled plug is placed vertically in a triaxial apparatus. The effective pressure applied surrounds the entire sample, even in what would be the vertical sides of the core plug. As a result, NOB tests typically provide stresses that are higher than those which actually exist in the ground. Consequently, NOB tests tend to systematically indicate permeabilities that may be lower than actual in situ values.
2. Most unconsolidated samples do not behave elastically. Hence, not all of the unloading effects are replicated by reloading the sample. Typically, the grains do not return to a compact form as they would have been in situ.

To some degree, these two factors may cancel out. However, it is not easy to estimate which factor dominates. The experimental results are shown in Figure 6. In total, 25 plugs were tested for liquid permeability. On average, the NOB liquid permeability is 0.249 times the air permeability. This is a useful indicator of how much correction should be applied to core air permeabilities to derive in situ reservoir permeabilities.

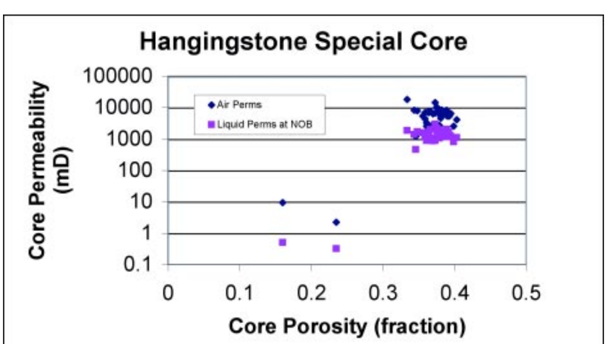


FIGURE 6

Method of Donnelly

Donnelly, in his description of Hilda Lake design[5] and during the Chard Leismer hearing, adjusts permeabilities to correct for the lower in situ porosities. He uses the core air permeability versus core porosity relation derived from many cores and then uses a permeability that corresponds to actual in situ (log-derived) porosity. This is clearly more realistic and is a significant improvement. The limitation of this method is that it does not account for air-liquid adjustments and that the core data is still optimistic by virtue of sand grain expansion from sampling.

Documented history matches (UTF Phases A and B) did not utilize any such corrections. *It may be concluded that there must be some significant mechanism occurring in the reservoir that causes air permeabilities to be representative in SAGD modelling*[6].

Clearly, a more careful analysis of permeability is warranted. Two situations will be examined: (1) one for *cold* oil sands; and, (2) another for *hot* oil sands conditions.

Cold Oil Sands Permeability

Oldakowski performed tests on cold bituminous cores subjected to shear forces[7]. The results are shown in Figure 7. This data is comprehensive in that different stress paths were used and these tests were performed at in situ cold reservoir conditions. Cold bitumen has a very high viscosity and it would be surprising if the bitumen moved during a short duration test. *Clearly, the increase in water permeability is substantive with shearing.*

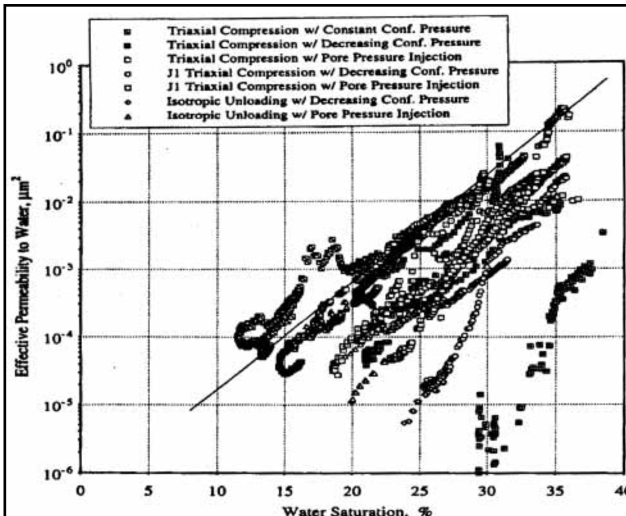
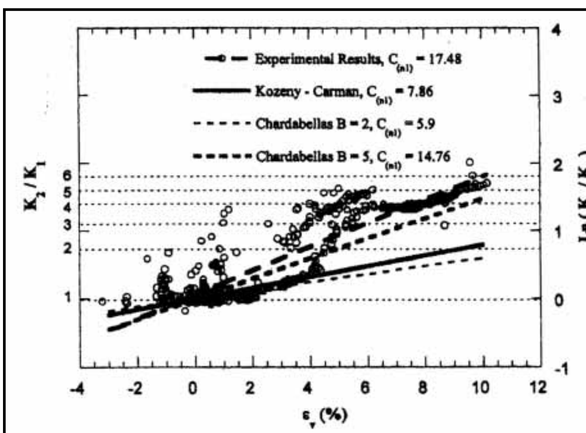


FIGURE 7

Hot Oil Sands Conditions (Absolute Permeability)

Touhidi-Baghini (1998) and Scott (1997) studied the change in absolute permeability of oil sands while specimens were undergoing shearing. They tested a sample of non-bituminous McMurray formation sands excavated from a natural river outcrop. This step was required to eliminate the effects of solution gas expansion. Specimens were obtained parallel and perpendicular to bedding.



Variation of absolute permeability in dilation
Vertical core specimens, average porosity = 33.9%
(Dilation is assumed positive)

FIGURE 8

Due to the unique sampling process used, this is probably the most accurate data available on how absolute permeability varies with shearing.

The absolute permeability increase, relative to the initial value,

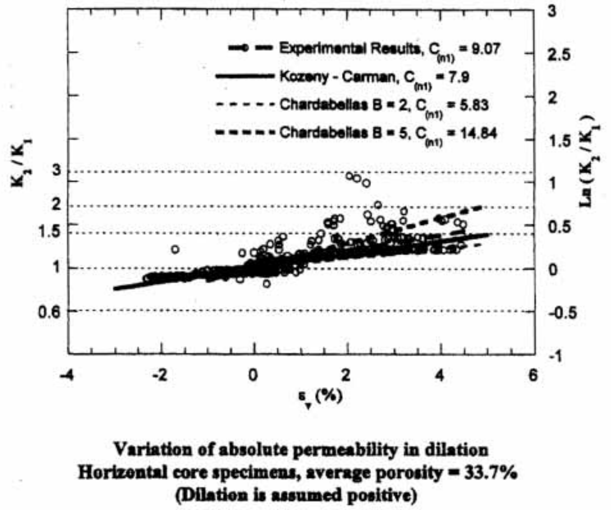


FIGURE 9

is given in Figures 8[8] and 9[9]. At volumetric strains of 4%, roughly corresponding to the peak strengths of the samples, the vertical permeabilities increased by 100%. Some specimens had an increase in absolute permeability of one order of magnitude during the test. Permeability increases were attributed to dilation and shearing. Restated, pore volume increase and widened flow paths increased pore connectivity.

Note that this lab data shows that substantial increases in vertical permeability occur, with smaller increases in horizontal permeability.

Convection

In the strictest sense, convection means the transfer of heat by the motion of fluids that have heat capacity. This was clearly envisaged by Butler, who in his theoretical developments shows material moving down the interior of the SAGD steam chamber along the sides. This process was observed in reservoir simulation by Ito et al[10]. They showed a series of diagrams in their papers that illustrate a progressive change in the saturations and depth of the mobile material at the SAGD steam chamber front.

Thermal Expansion

Thermal expansion occurs when the oil sands are heated. There are a number of implications to this. The fluids have a higher coefficient of thermal expansion than the solids (sand grains). To some extent, the sand will disaggregate. Butler analyzed expected pore pressure increases and dissipation time[11]. In effect, the differential expansion of oil sands fluids and solids will reduce the effective stress or reduce sand grain contact pressures. This will increase permeability and enhance the tendency of the oil sands to shear.

Of course, the amount of pressure that builds up and the rate at which pressure dissipates is strongly controlled by permeability. If one assumes that there is very limited permeability in cold bitumen due to the very high viscosity, this pressure will not be able to quickly dissipate laterally and vertically. Under these conditions, the sand will be very susceptible to physical rearrangement.

Extent of Permeability Changes

Based on the early UTF modelling, it would seem that very high permeabilities are required throughout the reservoir. However, if one considers a steam chamber, reservoir permeability has the most effect in the immediate vicinity of the well where there is a flow concentration. The author has done sensitivities to this. The concept was simple—compare the traditional air permeability assumption with a reservoir model based on localized permeability increases.

Pressure transient analysis (gas zones in channels) indicates the undisturbed permeability of good quality channels to be about 2,995 mD. Alternatively, a correction factor of 0.25 applied to core air permeabilities indicates an in situ original permeability of 1,875 mD. An increase in permeability by a factor of two over the well test permeability, near the wellbore, was required to obtain the correct cumulative productions of bitumen and water. This placed the near well permeability at about 5,850 mD. This is within 22% of the average air permeability (7,500 mD) derived from (disturbed) core. Away from the wellbore, a 30% increase in permeability was required. The modelling showed that no reasonable near wellbore alteration in permeability could completely account for the cumulative production required. From this, the author concluded that geomechanical effects must have occurred at, or ahead of, the steam chamber interface. In this context, the previous history match permeabilities (using air perms) are logical. Figure 10 shows the approximate permeability distribution required.

It is also appropriate to consider the effects of drilling and com-

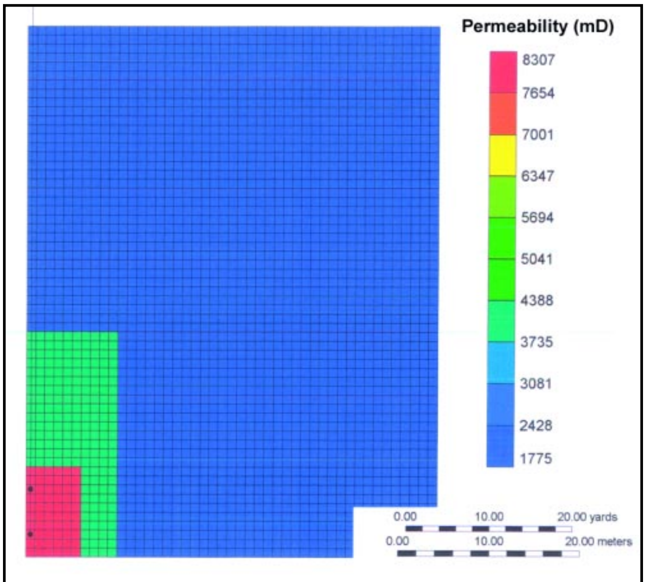


FIGURE 10

pletion. The well is drilled to a larger diameter than the liner. Most projects use either slots or a screen to prevent sand production. Therefore, the sand falls onto the slots or screens. In this case, not all of the dilation comes from imposed reservoir process effects. This occurs directly adjacent to the well where it will have the most impact.

Geomechanics and Operating Conditions

The experimental data shown previously indicates that dilation occurs with axial strain. Note that the dilation also changes with effective confining stress. This is shown in Figure 11. The maximum amount of dilation occurs near failure and with low confining stresses. So how can one create these conditions? Referring to Mohr's circle with the Mohr-Coulomb failure criteria, we can shift the entire circle to the left and towards the failure envelope by increasing pore pressure and thereby decreasing effective stress. *In operating terms, this means higher SAGD steam chamber or injection pressures.*

One can also increase the diameter of the circle, getting closer to the failure envelope by maximizing the difference between σ'_3 and σ'_1, which are the major and minor principal stresses, respectively. There are two main controls on the latter: (1) the initial stress conditions; and (2) how much stress is induced by either

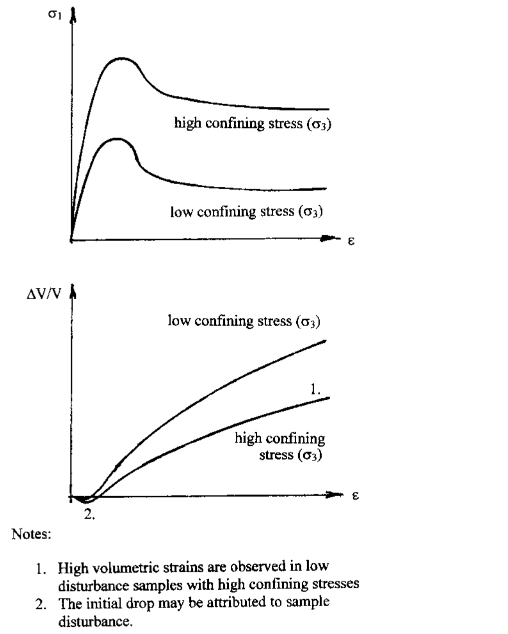


FIGURE 11

thermal expansion of the sands in the reservoir or by pressure in the steam chamber. Both will be discussed in the following.

Initial stress conditions are controlled by depth and tectonics. The forces that caused the Rocky Mountains still exist and there is a lateral stress component from large-scale tectonic events. For practical SAGD application depths, this means that at least one of the horizontal forces is larger than the vertical forces. As depth increases, lateral stresses also increase to support the overburden. The minimum principal stresses can be calculated from minifrac tests on existing projects. Horizontal stresses can be determined using the method of Eaton, then corrected for tectonic strains. An expected stress profile is shown in Figure 12[12].

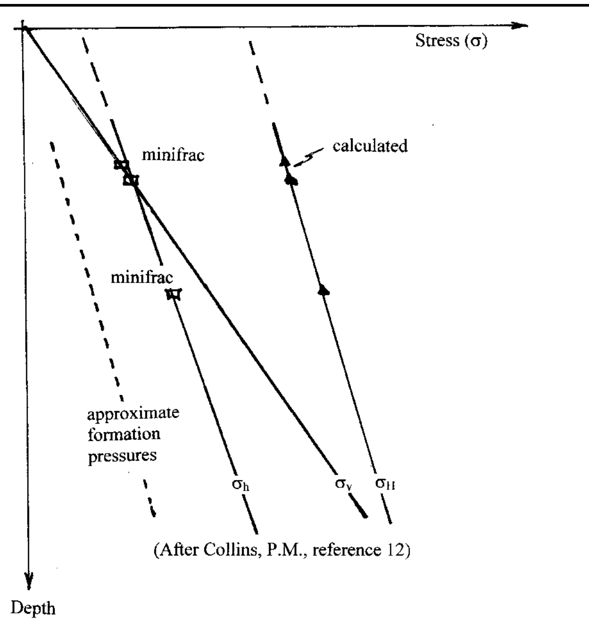


FIGURE 12

Effects of SAGD Steam Chamber Thermal and Pressure Expansion

If the SAGD steam chamber expands, the expansion and stresses must be absorbed vertically and laterally. This is depicted in Figure 13. Thus, the cold sand between and adjacent to chambers will be "squeezed horizontally." At the same time, the vertical expansion of the steam chamber will cause the overburden to be "jacked up," which will decrease vertical stresses in the cold areas surrounding the steam chambers. During the early periods of heating, there will be concentric expansion surrounding the injection and production wells for a SAGD pattern. Also, differential expansion will exist where cold and hot areas adjoin. Recall that the effects of dilation are non-reversible and are permanent.

Do these forces actually occur? Extensive instrumentation at the UTF project shows that this is the case. Inclinometers show lateral movements, and extensometers show the formation being "jacked up." Measurable heave occurs on the surface, although this is attenuated in the formations between the steam chamber and surface. There are also other significant indications.

If the formation is sheared there will be an increase in volume and, simultaneously, permeability. The formation in these areas is still cold, so bitumen cannot flow quickly. With increased porosity the pore pressure will drop, which will create a potential gradient for water to flow. How would this be detected? The pore pressures would have to drop if there is no fluid mobility. Alternatively, if water can move, the pore pressure would increase if water is available as condensate from the SAGD steam chamber. Extensive data shows that pressure increases in the cold bitumen, well ahead of the heated zone. This has been observed at the UTF[13]. At Hangingstone, episodic temperature increases are noted from thermocouples during the early SAGD process[14].

As can be seen in Figure 13, the thermal stresses and chamber pressure act to increase the difference in major and minor principal stresses. Of course, the changes in stress caused by the thermal expansion of the steam chamber will increase with higher temperatures. Note that the additional heating requirements are not linear with temperature. Although this may not be intuitive, examination of a steam table will show that additional temperature and pressure increases come with smaller increments in required heat. *For saturated steam, the use of higher temperature and higher injection pressures throughout most of the life of the SAGD project is advantageous.* It should be noted that this is not totally absolute. For instance, thief zones and blow down strategies may favour lower pressures late in the life of injection. Note also that the analyses of low pressure SAGD reviewed by the author do not include the

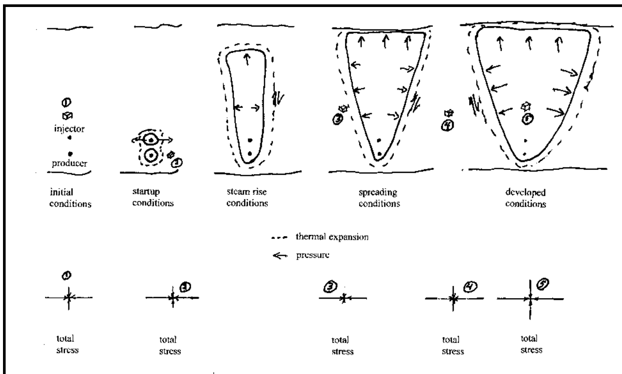


FIGURE 13

effects of geomechanics.

Can these observations be supported in the field? Interestingly, most successful projects in the McMurray formation have utilized relatively high injection pressures and are at relatively shallow depths. These include the UTF, Hangingstone, and McKay River projects. Detailed results have not yet been evaluated from Christina Lake. There have been some SAGD failures, the most dramatic of which appears to be the low pressure SAGD project described by Shell in the Peace River area. Coincidentally, Shell has been very successful with high-pressure injection using CSS and multi-laterals in the same reservoir. The author believes a high-pressure SAGD approach, designed on geomechanical principles, might have been successful. A few select quotes from other sources are outlined below.

Ito and Suzuki of JACOS state with respect to Hangingstone[15]:

"Geomechanical changes of the formation during the SAGD process in an oil sand reservoir seems to have a very important role in determining the operational conditions. A large amount of oil drains through the steam chamber when the geomechanical changes occur in the reservoir."

Chalaturnyk and Scott of the University of Alberta state with respect to the UTF[16]:

"Experimental, numerical, and field observations have been analyzed to assess the occurrence of geomechanical processes within the reservoir during the UTF Phase A SAGD test. It has been shown that formation displacements within the reservoir capable of significantly influencing reservoir properties, specifically absolute permeability, have occurred during the Phase A SAGD test. Vertical extensional strains of 2.5% and 30% increase in absolute permeability developed within the geotechnical cross section as a result of the steam assisted gravity drainage process."*

Geomechanical and Thermal Modelling

At present, there are a number of different models that can be used to model both geomechanical and thermal effects[17]. Successful reservoir simulations have been completed using this technology. Some areas, such as the inclusion of gas caps, remain difficult to evaluate.

Summary

The principles behind geomechanics developed from soil mechanics are briefly outlined. The key idea is to consider bitumen sands as aggregates of mineral and/or rock particles. This leads to the concepts of effective stress, rearrangement of sand grains with load, and the Mohr-Coulomb failure criteria, in which strength varies with confining stress. When the rock is stressed or fails, the rock grains re-arrange and this causes changes in permeability and bulk volume (porosity). The fundamental areas where this affects the SAGD process include:

1. Sampling procedures—in particular, coring;
2. Evaluating conventional formation properties such as porosity and bitumen, water, and gas saturations;
3. Determining in situ permeability;
4. Understanding that the mechanism within the formation is more complex than initial analysis may indicate and therefore should include the effects of geomechanics. Shearing and dilation occur during SAGD processes and these effects are significant. The most important mechanism is near wellbore permeability enhancement; and,
5. Changing operating conditions to maximize the positive effects of geomechanics in SAGD.

The explanation outlined is not detailed. To date, the effects of geomechanics are not widely accepted. There was also a wide range of differing conclusions and interpretations during the AEUB Chard Leismer Gas Over Bitumen Hearing. Therefore, the comments in this article should be taken as opinions.

One of the aims of the Petroleum Society of CIM is to encourage active debate on leading-edge technical matters. The purpose of this article is, in part, to encourage such professional discussion.

Acknowledgements

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* This value is dependent on the assumed initial absolute permeability. The author believes the original permeability based on air permeabilities from dilated core is overstated. Therefore the permeability increases are understated.

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