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Phased Heating and Solvent Injection to Enhance Recovery of Heavy Oil and Bitumen

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Abstract

The main challenges faced by oil sands operators are the cost of operations and the environmental intensity of the recovery processes. The Athabasca oil sands deposit contains bitumen with viscosity typically over 1 million cP. To lower the viscosity of the bitumen so that it can be drained from these reservoirs, it is heated with injected steam by using Steam-Assisted Gravity Drainage (SAGD). This process is effective and enables recovery factors over 60%. The major cost in the recovery process is steam generation and associated water treatment and handling. The combustion of natural gas to generate steam is the main origin of the carbon dioxide emissions associated with SAGD. An alternative to steam injection is the use of solvents co-injected with steam. Solvents dilute bitumen leading to an oil phase with reduced viscosity. Also, there is potential to recycle solvent for re-injection. Thus, solvent added to steam can improve the steam-to-oil ratio and as a consequence can lower the carbon dioxide emissions per unit volume oil produced. In this extended abstract, we describe a phased solvent and heat process that yields improved performance beyond that of SAGD and current solvent-aided SAGD processes.

Introduction

Typically, in situ methods are used in heavy oil or bitumen deposits that are greater than about 70 m deep where it is no longer economic to recover the hydrocarbon by current surface mining technologies (Gates, 2013). For the Athabasca oil sands deposit located in Northeastern Alberta, Canada, the viscosity of the oil is of order of 1 million cP within sandstone with porosity typically of order of 0.3 and permeabilities often greater than 3 D. For in situ operations, the only commercial recovery process in the Athabasca deposit is Steam-Assisted Gravity Drainage (SAGD). Depending on the operating conditions of the in situ process and the geology of the heavy oil or bitumen reservoir, SAGD can recover between about 25 and 75% of the initial hydrocarbon in the reservoir. In this process, high pressure and high temperature steam is injected into the reservoir. The steam, on losing its latent heat in the reservoir heats the oil to over 200 °C (for most SAGD operations) which lowers the viscosity of the oil to less than 10 cP. Thus, the oil is mobile and drains under the action of gravity and is produced from the reservoir. One other option beyond that of steam is the use of solvents which is often added to steam and injected into the reservoir. The solvent also reduces the viscosity of the bitumen which enables greater drainage rates from the reservoir.

Steam-Assisted Gravity Drainage (SAGD)

The SAGD process consists of two horizontal wells, one above the other, where steam is injected into the top well and steam condensate and reservoir fluids are produced to the surface through the lower well. The well pair is typically placed at the base of the reservoir with inter well separation between the horizontal wells equal to about 5 m. The spacing between well pairs is typically between 80 and 120 m.

The key to a successful SAGD operation is heat transfer – it controls the temperature of the bitumen at the edge of the steam chamber and thus its viscosity (Gates and Chakrabarty, 2006). If heat transfer is poor, then the ability to heat the oil sand beyond the edge of the steam chamber is impaired and the thermal efficiency is less than ideal. Thus, at its most fundamental level, the success of SAGD (and other steam-based recovery processes) is strictly linked to heat transfer at the edge of the chamber. Thus, means to enhance heat transfer at the edge of the chamber will improve the thermal efficiency of the recovery process. As with all conductive heat transfer, it can be enhanced by increasing the thermal conductivity of the medium or by raising the heat transfer area or by raising the temperature gradient.

In typical practice, SAGD achieves steam-to-oil ratios (SORs) between 2 and 10 m³/m³ where steam is expressed as cold water equivalent (Akbilgic et al. 2015). This implies a carbon dioxide emissions intensity of between 300 and 2,000 kgCO₂ per m³ of bitumen produced (Gates and Larter 2014).

Vapour Extraction (VAPEX)

There are other examples of the processes that use combinations of steam and solvents to recover heavy oil. In an extension of SAGD, Palmgren et al. (1995) describes a process where high temperature naphtha replaces steam in the SAGD process. However, given the value of naphtha, a substantial amount of the injected naphtha is required to be recovered for the process to be economic and compete with SAGD. A similar extension of SAGD which uses 100% solvent, called Vapour Extraction (VAPEX), was proposed by Butler and Mokrys (1991, 1993, Das and Butler, 1995, Butler and Jiang, 2000) as a commercial alternative to SAGD. VAPEX, similar to SAGD, consists of two horizontal wells positioned in the reservoir. The top well is the injection well whereas the bottom well is the production well. In VAPEX, a gaseous solvent (for example ethane, propane, or butane) is injected into the reservoir instead of steam. The injected solvent condenses and mixes with the heavy oil or bitumen and reduces its viscosity. Under the action of gravity, the mixture of solvent and bitumen flow towards the production well and are produced to the surface. Due to absence of steam generation and water handling facilities, capital costs associated with VAPEX facilities are expected to be lower than that of SAGD. However, it is unclear how interwell communication is to be established and how the process is to be operated in order to make the process economic. Also there are unresolved issues on how to prevent significant solvent losses to the reservoir which will be vitally important for economic success of the process. Additionally, the operating pressure range of VAPEX is limited because of required condensation of the injected gaseous solvent at the edges of the vapour chamber.

In several papers, Butler and Mokrys (1991, 1993) documented a version of VAPEX which uses hot water and solvent vapour, for example propane, near its dew point in an experimental Hele-Shaw cell to recover heavy oil. The solvent vapour fills the vapour chamber and at the chamber edges, the solvent dissolves into the heavy oil lowering the oil phase viscosity. The reduced-viscosity oil flows at the chamber edges to the production well located at the bottom of the formation. Butler and Mokrys describe that the solvent is co-injected with hot water to raise the reservoir temperature by between 4 and 80 °C. The hot water also re-vaporizes some of the solvent from the heavy oil to create refluxing and additional utilization of the solvent.

Expanding Solvent SAGD (ES-SAGD)

U.S. Patent 6,230,814 (Nasr and Isaacs, 2001) describes the Expanding Solvent-SAGD (ES-SAGD) method that comprises continuously co-injecting steam and an additive (one or a combination of C₁ to C₂₅ hydrocarbons and carbon dioxide) into the reservoir. The additive is chosen so that its saturation

temperature is in the range of about 150 °C of the steam temperature at the operating pressure. After injection, a fraction of the additive changes from vapour to liquid phase in the reservoir. This patent teaches that the additive concentration in the injected stream is between about 0.1% and about 5% liquid volume. The benefit of this process is that the steam and the solvent both lower the viscosity of the bitumen which implies that less steam is required if a target bitumen viscosity is desired (Gates, 2007). This means that the amount of steam required to achieve a given bitumen mobility can be reduced and thus the SOR and carbon dioxide intensity drops. In practice, these processes have yielded reduced SORs and thus have been demonstrated to be more thermally efficient than SAGD (Gupta and Gittins, 2002, 2003). However, the key challenge of these processes is solvent recovery – since the cost of the solvent is greater than that of the produced bitumen, in general, solvent recovery must be greater than about 85% to ensure that the recovery process is economic (Gupta and Gittins, 2002, 2003).

Results from analytic theory, physical model experiments and reservoir simulation support that intermediate molecular weight solvents such as hexane provides the best performance for ES-SAGD (Nasr et al., 2003, Sharma and Gates, 2011, Li et al., 2011). This is because of its similar phase behavior to that of saturated steam.

An alternative to the traditional ES-SAGD operation is to change the composition of the solvent through time (Gupta and Gittins, 2007b; Gates and Gutek, 2008). In these recovery processes, the method transitions from heavier to lighter solvents as the operation proceeds. In the early stage of the process where the steam is injected at the highest pressure, heavy solvents are used since they are most effective at high temperatures. Later on, lighter solvents are used to help recover the more expensive heavier solvents. Furthermore, lighter solvents are easier to recover and less costly to leave behind (Gates and Gutek, 2008, Edmunds et al., 2010).

N-SolvTM

Nenniger (2008) described a warm solvent process, N-SolvTM which uses no steam in its operation. In N-SolvTM, warm solvent (such as propane or butane) is injected into the reservoir in vapour form. The solvent moves out to the edge of the depletion chamber and condenses there and then mixes with the bitumen at the edge of the chamber. The latent heat from the solvent lends some heat to the bitumen but the major agent for the reduction of the bitumen viscosity is via the action of mixing at the edge of the chamber. As described by Nenniger (2008), N-SolvTM is a pure solvent-based gravity drainage process that uses the same well configuration as that of SAGD. The key challenge faced by N-SolvTM is solvent recovery. As shown by Cao (2014), solvent losses can be greater than 50% and thus the process will need to be evaluated economically to determine its performance relative to SAGD (the solvent losses may be less than the costs of steam generation and water treatment and handling). One key benefit of N-SolvTM is that it does not require steam generation and thus has a very low carbon dioxide intensity compared to that of SAGD.

Beyond SAGD and ES-SAGD

There is a need to improve recovery processes especially for operations that have already invested in steam generation and water handling and treatment plants. Here we describe a phased heating and solvent injection recovery process for oil sands reservoirs.

Phased Heating and Solvent Injection Process

In the process described here, the well configuration is the same as that of SAGD with a horizontal injection well and a horizontal production well. The process consists of a first phase operated at high-pressure in which steam and hydrocarbon solvent and non-condensable gases are injected into the reservoir and a second phase in which the injected fluids are transitioned to a high content of solvent and non-condensable gas and a reduced amount of steam to maintain a warm zone in the neighbourhood of the injection and production wells (Gates and Bunio, 2013). Steam injection is sufficient to promote

vapour transport of the solvent into the vapour depletion chamber and maintain the process at elevated temperatures to maintain low fluid viscosities in the production wellbore and to achieve preferred phase behaviour of the solvent hydrocarbon and the heavy oil or bitumen. The operating pressure of the process is controlled to prevent losses of the solvent hydrocarbon to the formation and to aid in solvent production to the production well for future re-cycling. The process operated as described has anticipated improved economic benefit with relatively high production at the start of the process, reduction of heat injection after the process starts to lose heat to the cap rock to improve thermal efficiency of the process after the cap rock is contacted, heated solvent injection to deliver diluted and possibly partially upgraded heavy oil or bitumen to the production wellbore, and high solvent re-cycling capability to improve the economics of the process.

The well completions of phased heating and solvent injection process we introduce in this paper is similar to SAGD and ES-SAGD. Steam, solvent, and non-condensable gas are injected through the injection well into the reservoir over time while reservoir fluids are produced through the production well. The injected fluids enter a vapour chamber that surrounds and extends above the injection well. The injection rates and injection pressure are controlled in order to minimize heat losses to the overburden and maximize the action of the solvent in reducing the viscosity of the heavy oil or bitumen. Additionally, the operating pressure is controlled together with the relative amounts of steam, solvent, and non-condensable gas to maximize the solvent recovery from the process. This means that the partial pressure of the solvent is controlled in the vapour chamber as the process is evolved. The solvent may be a hydrocarbon solvent that consists of one or a combination of the C3+ hydrocarbons or any of the components that may normally be found in gas condensates or diluent. The non-condensable gas may include nitrogen gas, natural gas, methane, carbon dioxide, or the flue gas that results from the combustion of a fuel. The recovery method may include the additional step of adjusting the injection pressure and relative amounts of steam, solvent, and non-condensable gas to control the vapour chamber temperature to enhance the solubility of solvents.

Figures 1 and displays a phased process with two stages 1 and 2. Figure 1 displays rates (steam is 4, solvent is 5, and non-condensable gas is 6) whereas Figure 2 shows the pressure profile, labelled as 3. Figure 1 displays typical injection and production profiles for steam 4, solvent 5, and non-condensable gas 6. In Stage 1, steam is the major injectant flowing into the reservoir from the injection well. In Stage 1, the vapour chamber is created in the reservoir. The injection pressure is maintained sufficiently high so that a vapour chamber is created in the reservoir.

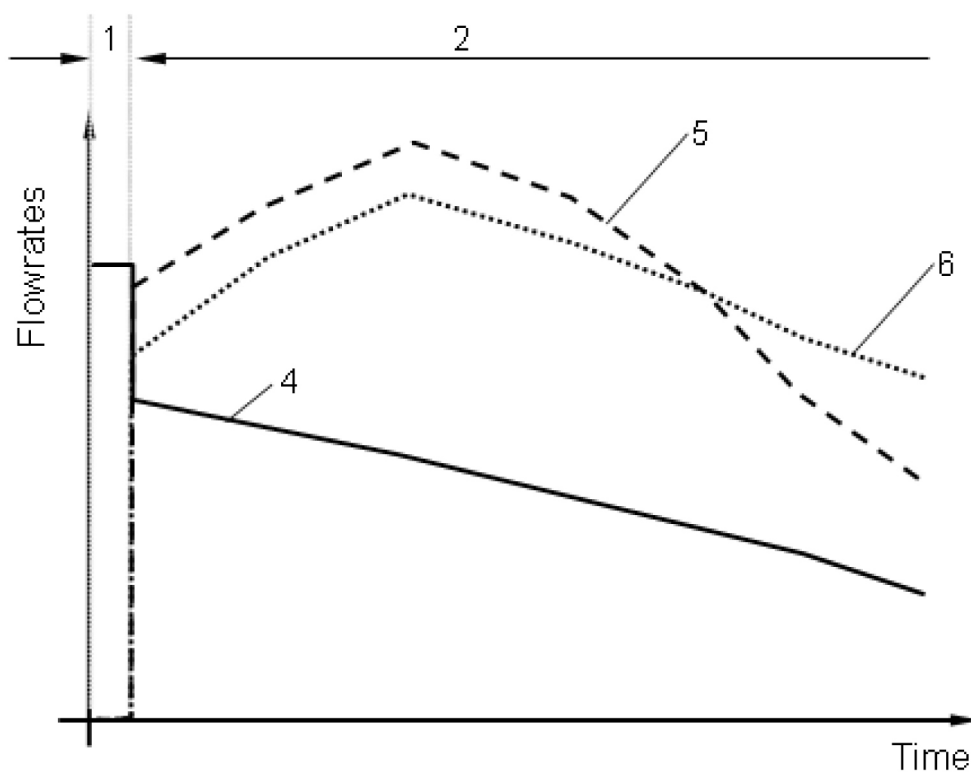


Figure 1—A sample injection profile conforming to the phased process with Stages 1 and 2 (steam = 4, solvent = 5, and non-condensable gas = 6).

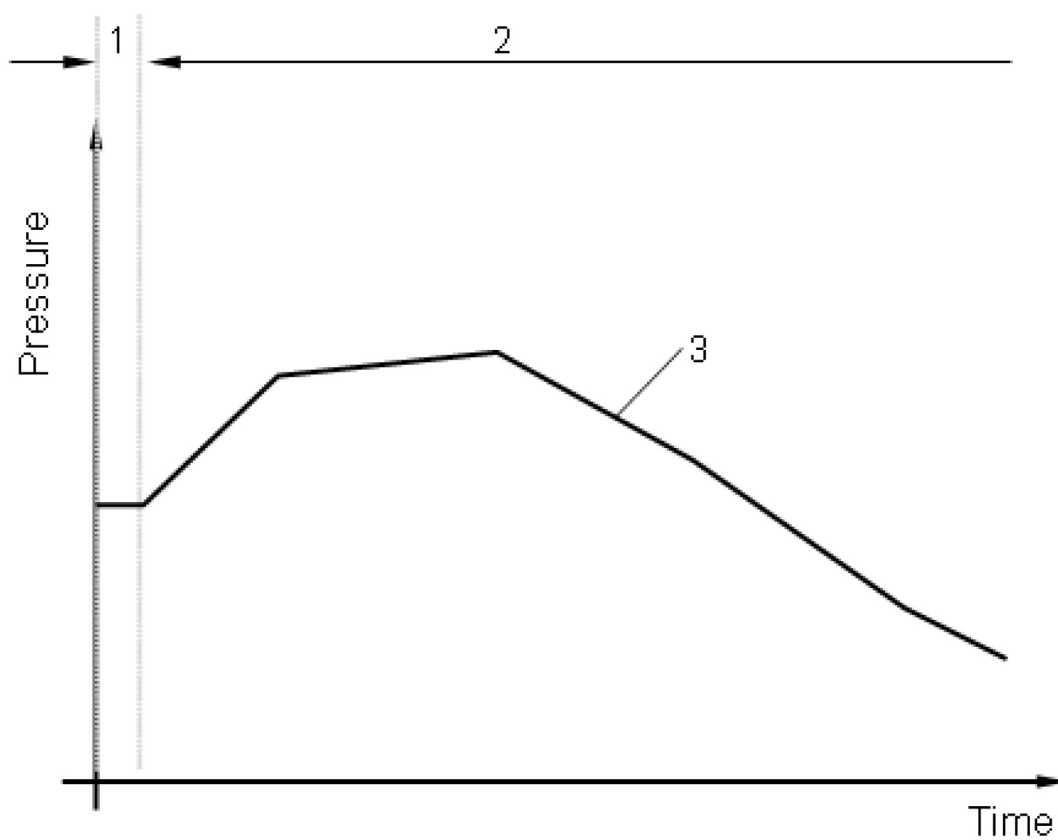


Figure 2—A sample injection pressure (3) profile conforming to the phased process with Stages 1 and 2.

In Stage 1, a small amount of solvent or non-condensable gas can be co-injected with the steam but if desired, steam can be injected alone into the reservoir as is done in the SAGD process. After the steam chamber has formed, in Stage 2, steam, solvent, and non-condensable gas are injected together into the reservoir. The amounts of the steam, solvent, and non-condensable gas and the injection pressure are chosen so that the solubility of the solvent in the heavy oil and bitumen is maximized. The addition of the solvent improves heavy oil or bitumen mobilization beyond that only due to heating alone because it dissolves in the heavy oil or bitumen, dilutes the hydrocarbon phase, and reduces its viscosity so that it can readily flow to the production well.

As the process evolves, the chamber reaches the top of the reservoir and thereafter spreads laterally. As the chamber grows, heat losses to the overburden increase because the greater exposed area of the heated vapour chamber to the colder overburden. To enhance the thermal efficiency of the recovery process, in Stage 2, the steam injection rate is lowered and the solvent and non-condensable gas injection rates are raised. The solvent content in the injected fluids is between 1 and 80 volume percent, preferably between 10 and 30 volume percent. The extent of the vapour chamber is maintained by the increasing volume of solvent and non-condensable gas injected into the reservoir.

Because the steam injection rate is reduced, the partial pressure of the steam in the vapour chamber falls and as a result, the corresponding saturation temperature of the steam drops and heat losses from the vapour chamber, in turn, are reduced because the temperature difference between the vapour chamber and the overburden is lowered. If the overburden temperature is higher than the vapour chamber, then heat previously lost to the overburden is harvested back to the vapour chamber. This improves the overall efficiency of the process. Furthermore, as the temperature of the vapour chamber falls, the solubility of the solvent increases in the heavy oil or bitumen. This leads to reduced viscosity of the heavy oil or bitumen that would not have been possible without the solvent. Also, the addition of the non-condensable gas helps to maintain or raise the operating pressure which also enhances the solubility of solvent into the heavy oil or bitumen. The relative amounts of the solvent and non-condensable gas are chosen to maximize the effectiveness of the solvent to reduce the viscosity of the heavy oil or bitumen and can be chosen from thermodynamic pressure-volume-temperature and viscosity calculations.

The amount of injected solvent is such that only sufficient solvent is provided that is needed by the produced bitumen. This minimizes the build-up and storage of solvent in the reservoir which enhances the economic performance of the recovery process. As the process further evolves, the amount of solvent and non-condensable gas are reduced and concurrently, the injection pressure is reduced. This helps to promote production of the solvent which enhances the economics of the process. At the end of the process, a blowdown stage can be done to recover additional solvent and heavy oil or bitumen from the reservoir. Heavy oil or bitumen production from the production well is initiated during Stage 1 and continues throughout the rest of the process.

The solvent preferentially consists of one or a combination of C3+ hydrocarbons, for example propane, butane, pentane, hexane, heptane, octane, nonane, and decane or any one or more components normally present in gas condensates or diluent. Preferably, the solvent is hexane or heptane, or is a combination of C5 to C8 hydrocarbons including any of the components that may normally be present in gas condensates or diluent. The non-condensable gas preferentially consists of C1 to C3 hydrocarbons, for example methane, ethane, and propane, natural gas, or other gases such as carbon dioxide or any one or more of the components normally present in the flue gas that results from combustion of a fuel to produce steam. The solvent, non-condensable gas, and injection pressure are chosen so that the solvent exist in substantially the vapour state at the conditions of the reservoir but so that the solubility of the solvent is maximized in the heavy oil or bitumen at the edges of the chamber.

Reservoir Model

The simulation model is based on a typical Athabasca oil sands reservoir and is fully described in [Gates et al. \(2007\)](#) and is not repeated here. In brief, the model consists of eight facies (shoreface sand, muddy marine sand, mudstone, mud-dominated heterolithic strata, sand-dominated heterolithic strata, sandstone, breccia, and mudstone filled). A single well pair is modelled in this research – the production well is positioned 2 m above the base of the oil column and the injection well is placed 5 m above the production well. The viscosity of the bitumen follows the Walther equation ([Gates, 2013](#)) and has viscosity equal to 5,000,000 cP at 10 °C and 9.96 cP at 200 °C. The solvent used in this research is hexane. The solvent properties used for the simulation can be found in [Gates \(2013\)](#).

Well Constraints

For the SAGD operation, steam injection occurs at 4,000 kPa pressure with steam quality equal to 0.95. At the production well, a maximum steam rate is imposed which mimics steam trap control ([Gates and Leskiw, 2010](#)). For the ES-SAGD operation, 5% by volume hexane is co-injected with steam into the reservoir at total injection pressure of 4,000 kPa with the steam quality equal to 0.95. The production well constraint is the same as that of the SAGD operation. For the phased heating and solvent process, at the start of the process, over the first 6 months, steam is injected into the formation at 4,000 kPa and 0.95 quality. Thereafter, solvent and non-condensable gas is injected and their proportion in the injection stream rises to 20% by volume after 2 years of production. Solvent injection is lowered to 1% after 8 years of operation and the non-condensable gas rises to more than 50% injection after 8 years of operation. Steam is progressively declined throughout the operation until it is less than 50% of the injectant stream after 8 years of operation.

RESULTS

[Figures 3 and 4](#) display the results of the SAGD, ES-SAGD, and phased heating and solvent processes. The results show that the SAGD operation achieves a cumulative steam-to-oil ratio (cSOR) that ranges from a peak value of about 2.7 m³/m³ which declines to about 2.3 m³/m³ by the end of the operation. The ES-SAGD operation achieves a lower result throughout the operation with a peak value equal to about 2.55 m³/m³ which declines to about 2.0 m³/m³ by the end of the operation. The SOR profiles for the SAGD operation has results that are typical of that of results in the field for a good quality Athabasca oil sands reservoir, for example, such as that found in Cenovus' Christina Lake SAGD operation or Suncor's Firebag operation. The reduction of the cSOR that is achieved from the ES-SAGD operation below that of SAGD is typical of that obtained in field pilots ([Gupta and Gittins, 2003](#)). The phased heating and solvent process reaches a peak value early in the process, the highest of the three processes, equal to about 2.7 m³/m³ which then declines to about 1.7 m³/m³ by the end of the operation. The results show that the phased process yields an overall performance that is better than the other two processes. [Figure 4](#) displays the cumulative oil recovered from the operations – the results show that the phased process yields significantly greater oil volume from the reservoir than that of the other operations. Given that the model is a single well pair model, the extent of the depletion chambers is greater than that expected from a pad of well pairs. Thus, the depletion chamber created by the phased process is substantially larger than that of the SAGD and ES-SAGD operations.

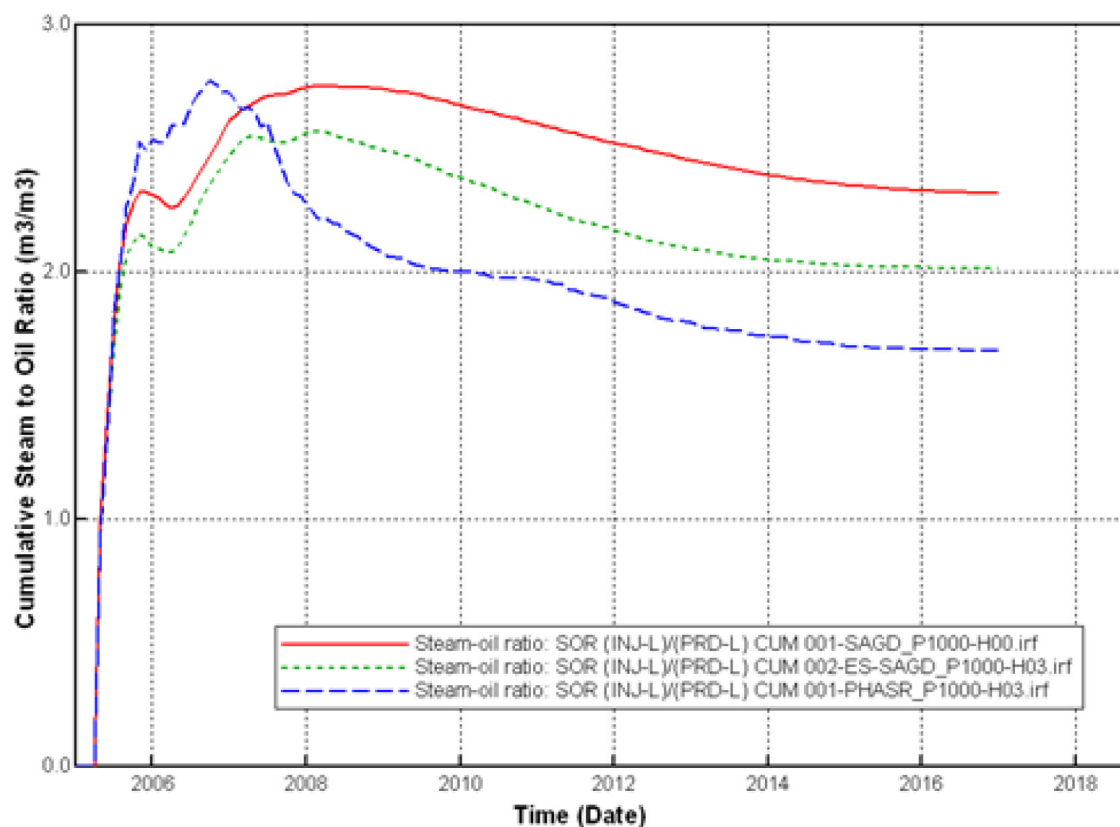


Figure 3—Energy efficiency of the SAGD, ES-SAGD, and phased heating and solvent processes as indicated by the cumulative steam to oil ratio over the time of production. The steam is expressed as cold water equivalent.

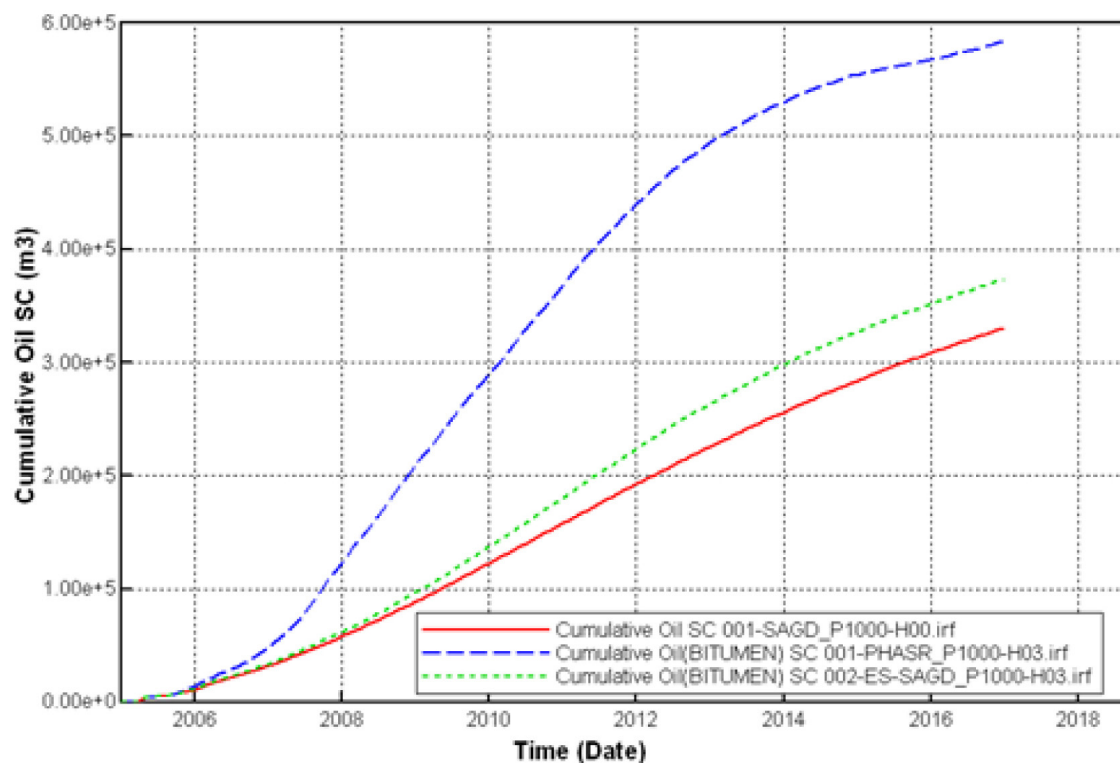


Figure 4—Bitumen recovery of the SAGD, ES-SAGD, and phased heating and solvent processes as a function of time.

Figure 5 displays the solvent recovery from the ES-SAGD and phased heating and solvent process. The ES-SAGD result achieves a recovery for a short period of time but in the long term as the chamber grows large, solvent recovery factor suffers. This result may appear to be inconsistent with field data e.g. Connacher's SAGD-solvent operation, but there are no ES-SAGD operations that have lasted more than 3 years as yet (nearly all pilots have been for less time) and thus it remains unclear how ES-SAGD will perform for longer term operations. The results show that the phased process exhibits greater solvent recovery than that of the ES-SAGD operation.

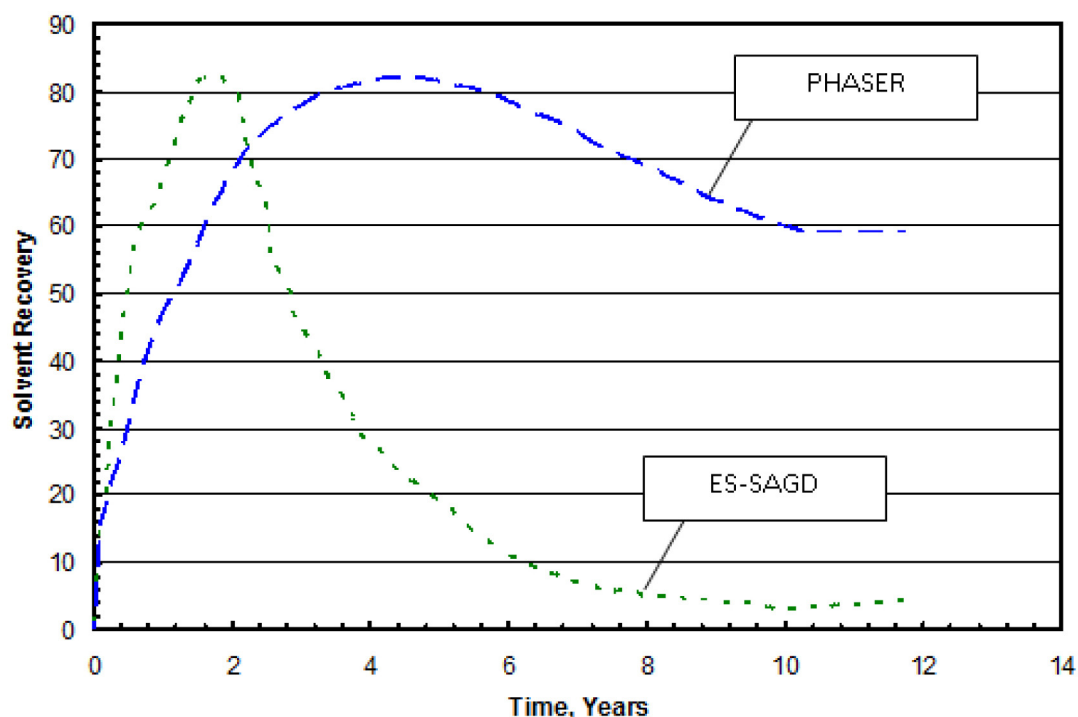


Figure 5—Cumulative solvent recovery of the ES-SAGD and phased heating and solvent processes as a function of time.

CONCLUSIONS

In this paper, we present a method to recovery heavy oil and bitumen by injecting steam, hydrocarbon solvent and a non-condensable gas into the injection well and producing hydrocarbon from the production well. During this process, the injection strategy is transitioned from the majority of steam to majority solvent and non-condensable gas to lower the temperature but raise the pressure of the steam chamber. The heat losses are reduced and the solvent solubility gets maximized by adjusting the steam injection pressure. The simulation results show that the cumulative steam to oil ratio of this process is lower than that of SAGD and ES-SAGD while the oil volume produced is higher than that of SAGD and ES-SAGD. Compared to ES-SAGD, the solvent recovery rate of this process is greater than that of ES-SAGD.

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