SPE 129963

Simulation of Expanding Solvent – Steam Assisted Gravity Drainage in a Field Case Study of a Bitumen Oil Reservoir

John Akinboyewa, SPE, Colorado School of Mines, Swapan K. Das, SPE, Marathon Oil Company, Yu-Shu Wu, SPE, and Hossein Kazemi, SPE, Colorado School of Mines

Copyright 2010, Society of Petroleum Engineers

This paper was prepared for presentation at the 2010 SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, USA, 24–28 April 2010.

This paper was selected for presentation by an SPE program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of SPE copyright.

Abstract

With the increasing demand for energy around the world, more attention is directed to heavy oil and bitumen reservoirs for energy supply. Currently, these high viscosity heavy oil resources are produced primarily by steam. For instance, steam assisted gravity drainage (SAGD) is used widely for the exploitation of bitumen from relatively shallow reservoirs in Alberta, Canada. However, to increase the efficiency of SAGD operations and to improve economics, it has been proposed to add solvent to the injected steam.

With solvent injection, there is an increase in the production rate and a reduction in the required injected steam, resulting in a lower steam-bitumen ratio (SBR). Higher concentrations of injected solvent show additional enhancement in oil production rate including some of the solvents. Although simulation results show that the rates of solvent recovery vary depending on the concentration and the nature of solvent used. For optimal results, injection strategy needs to be adjusted depending on the geological conditions, solvent characteristics and reservoir properties.

The study presented in paper was motivated by observing promising results of a field test with solvent injection in a SAGD bitumen project. The study began with a compositional thermal simulator to quantify the benefits of solvent addition to the SAGD process (referred to as ES-SAGD) to produce bitumen more efficiently with lower energy requirements. A secondary objective was to determine the optimal and more cost-effective operational protocol for such solvent-steam injection projects.

The paper presents (1) the methodology used to model the ES-SAGD enhanced oil recovery process, and (2) reports the field and modeling results of the application of the ES-SAGD process to an oil sand project in Alberta, Canada.

Introduction

Heavy oil and bitumen reservoirs have higher viscosities, lower temperatures and higher permeabilities in contrast to conventional oil reservoirs. The viscosities, which range from thousands to millions of centipoise (cp) at reservoir conditions, can be reduced drastically by increasing the reservoir temperature. A thermal method called steam assisted gravity drainage (SAGD) has been used worldwide to produce bitumen and heavy oil from the subsurface that is too deep to mine.

The SAGD process involves the placement of a pair of horizontal wells, about 15ft apart vertically, in the bottom of the reservoir's oil saturation zone. Figure 1 is a simple illustration of the SAGD concept. Steam is injected into the upper well, and as the steam chamber forms, mobile oil with lower viscosity flows down the outside slopes by gravity, into the lower producing well. Figure 2 is a screenshot of a simulation of the SAGD process, showing the rise of the "steam chamber" as steam injection continues. The height of the reservoir is exaggerated in this view and only certain slices of the reservoir blocks are shown. Temperatures range from 46.4˚F (blue) to the temperature of the injected steam, 460˚F (red). With continuous steam injection, the reservoir temperature slowly approaches the temperature of the steam as more areas of the reservoir are contacted; however the temperature growth is affected by heat losses to produced oil, and to the overburden and under burden formations. Figure 3 illustrates the propagation of the steam chamber through the reservoir. The temperature

threshold in the figure ranges from 300˚F to 450˚F. The hollow region shown in the middle of the reservoir (inside the red) is close to the steam temperature of 460˚F, while the outer region (outside the green) is lower than 300˚F and approaches the reservoir temperature of about 46.4˚F.

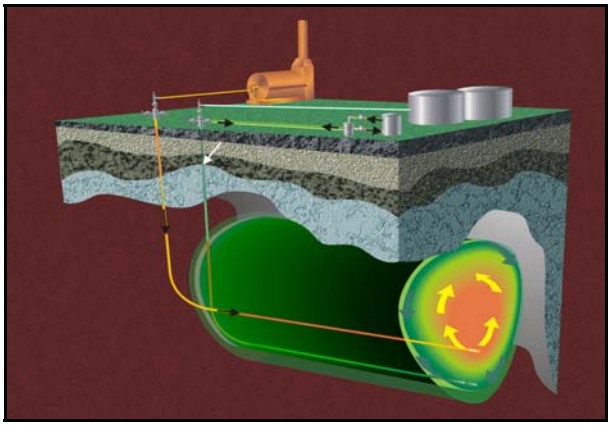

Figure 1 – Illustration of SAGD concept.

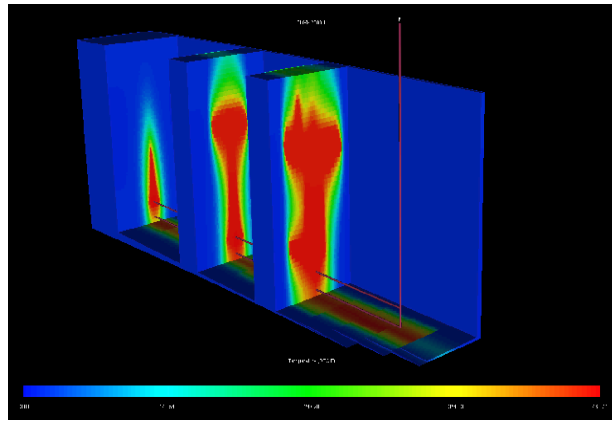

Figure 2 – Steam chamber growth in simulation of SAGD process. Reservoir height is exaggerated to show effect (46.4°F – blue; 460°F – red).

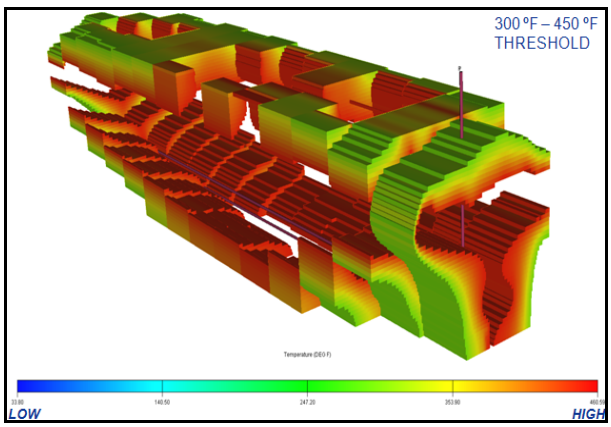

Figure 3 – Propagation of steam chamber through the reservoir using SAGD. Temperature threshold is from 300°F (outside the green) to 450°F (inside the red).

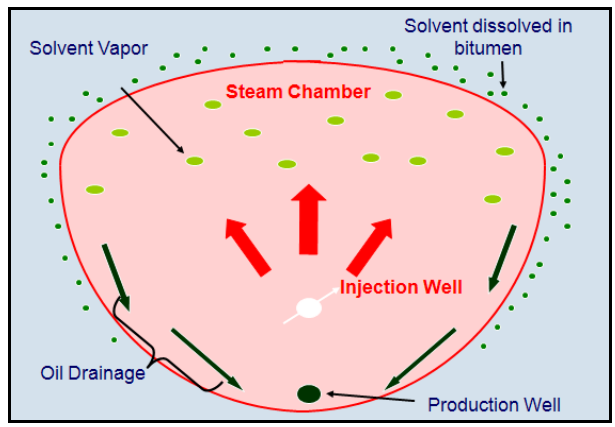

Figure 4 – Illustration of ES-SAGD concept.

Expanding Solvent – SAGD (ES-SAGD)

In SAGD operations, natural gas is burned to generated steam to be injected into the formation. To increase the efficiency of SAGD operations and improve economics, solvent may be added to the injected steam. Solvent injected into the formation mixes with the bitumen, essentially creating a diluted interface where the steam and bitumen meet, and enhances the efficiency of the steam to heat up the in-situ bitumen oil. The viscosity of the solvent injected is significantly lower than that of the in-situ bitumen by several orders of magnitude. When viscosity mixing occurs at the elevated temperatures, resultant viscosities at the interface of steam and bitumen is lowered. Figure 4 is an illustration of the effects of solvent addition. The process has been patented by Nasr et al (US Patents 6,230,814 and 6,591,908).

Addition of Solvent Reduces SOR

The cost structure of thermal recovery operations discourages investors and operating companies from venturing into heavy oil / bitumen resource projects. As with all oil and gas operations, energy is spent to produce more energy. In order to consider a project successful, the energy recovered from the system should be much higher than the energy input into the system. At times operations continue under marginal efficiencies to recover an alternative commodity that is more desirable. The efficiency of SAGD operations in the field is generally evaluated by the ratio of cold water equivalent (CWE) barrels of injected steam to the barrels of oil produced. The addition of a solvent gas (such as butane, naphtha, or a natural gas mixture) to the injected steam has been shown to positively enhance the steam-oil ratio (SOR) of the project.

Eclipse Model

The simulation was carried out using the Eclipse 300 Thermal Suite. Simulation of ES-SAGD processes involves solvent in a compositional model, in addition to the thermal aspect. A geological model was created from a bitumen asset in Canada. The reservoir depth is at 1,060ft, with an average thickness of about 314ft. Since SAGD operations target the highly oil saturated zone, it is important to note that only about 170ft of this reservoir has an oil saturation of 75% or greater. Depending on the simulation time desired, the upper and lower sections of the geological model may be quite irrelevant until sufficient heat is carried to those blocks and the reservoir fluids are mobile. Thus the highly water saturated section of the model was removed to reduce simulation time and complexity. The dimensions of the model used were about 490ft x 3280ft x 170ft (x-y-z). The grid blocks were divided into an average of 164-ft sections in the y-direction (direction of the horizontal well length), 3.28-ft sections in the x-direction, and 3.28-ft sections in the z-direction. Figure 5 shows the original reservoir model in terms of saturation (Dark blue: 100% water saturation; Dark Red: 100% oil saturation). Figure 6 shows the section of the reservoir with an oil saturation of at least 75%. The curvatures of the upper and lower horizons in the original model were preserved and super-imposed on the sectional model to be used in the simulation (Figure 7). For demonstration of concepts discussed within this paper, variations of the model were used to speed up calculation time. For each concept, the base case response is explained as well as factors contributing to differences from the base case.

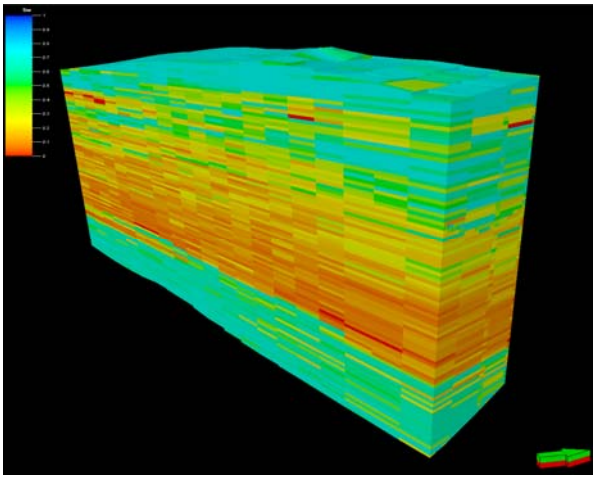

Figure 5 – Original reservoir model showing S_g. Dark blue is 100% water saturation; dark red is 100% oil saturation.

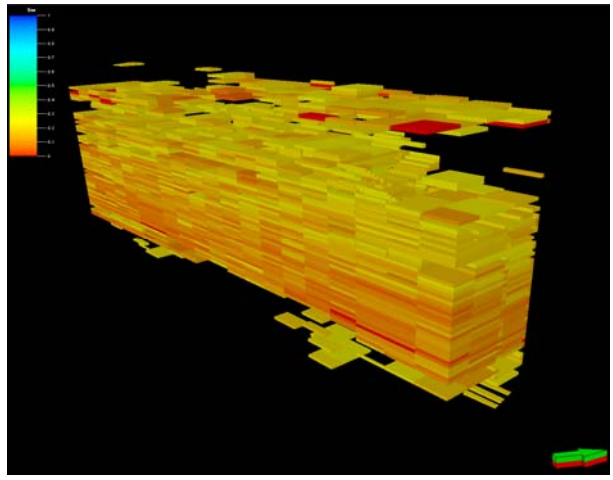

Figure 6 – Sectional of reservoir with $S_o \geq$ 0.75. Dark blue is 100% water saturation; dark red is 100% oil saturation.

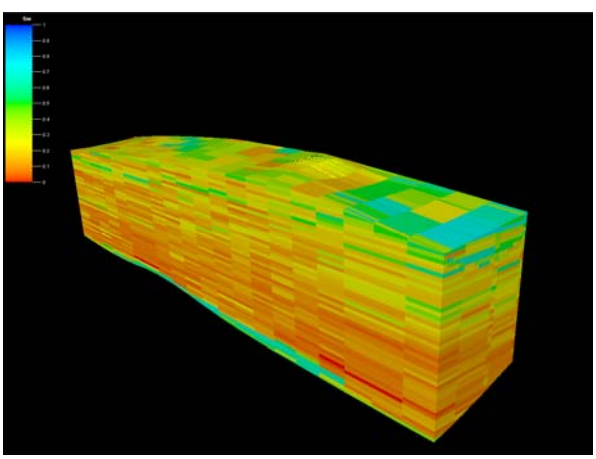

Figure 7 – Re-zoned reservoir model with original horizons. Dark blue is 100% water saturation; dark red is 100% oil saturation.

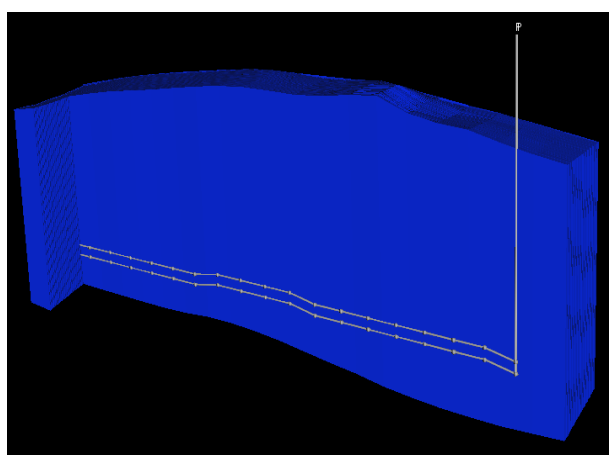

Figure 8 – Reservoir model showing well locations.

The fluid model was constructed with three hydrocarbon components plus water. These included:

- Bitumen (non-volatile oil phase)
- Methane (trace amounts – volatile hydrocarbon gas and oil phase)
- Butane (main component of injected solvent – volatile hydrocarbon gas and oil phase)
- Water (aqueous and steam phases)

The injected solvent composition is 98% butane and 2% methane. The initial average reservoir properties were:

- Pressure: 116 psia
- Temperature: 46.4˚F
- S_w: 18.4%
- S_g: 0%
- Porosity: 27.9%
- Horizontal permeability: 5,774 *md*
- Vertical permeability: 5,328 *md*

Correlations of pressure- and temperature-dependent K-values were used to flash the volatile components. The generic schedule for the solvent injection cases involved a heating period for about 100 days, a pure steam injection period for about 150 days, then commencement of the steam-solvent co-injection period. From this point forward, the produced hydrocarbon from the reservoir will be simply referred to as *"produced oil"* while the heavy hydrocarbon ***component*** will be referred to as *"bitumen"*. Thus the original reservoir oil is composed of bitumen and methane.

Steam Simulation Model

The resolution of the model in the z-direction was set to 3.28 ft (1 m). It is important to note that the base of the highly oil saturated zone may not be the region of highest permeability values within the model. This can present a difficult issue as the well must still be drilled towards the bottom of the oil zone to fully capture the "gravity" assisted production. Figure 8 shows the well placement in the model.

To effectively commence a SAGD simulation, the reservoir grid blocks containing the injection and producing well must be heated. This creates fluid communication through the grid blocks between both wells and ensures the possibility of steam injection to mobilize fluids towards the producing well. This is extremely important for uniform steam distribution, as improper heating will cause failure of the SAGD process and production will halt or never begin in most sections of the well pairs. For good injectivity, the grid blocks between the wells need to be between 150˚F and 250˚F and in good pressure communication before commencing steam injection (Figures 9 and 10). Series in the plot below indicate pressures of grid blocks for both wells.

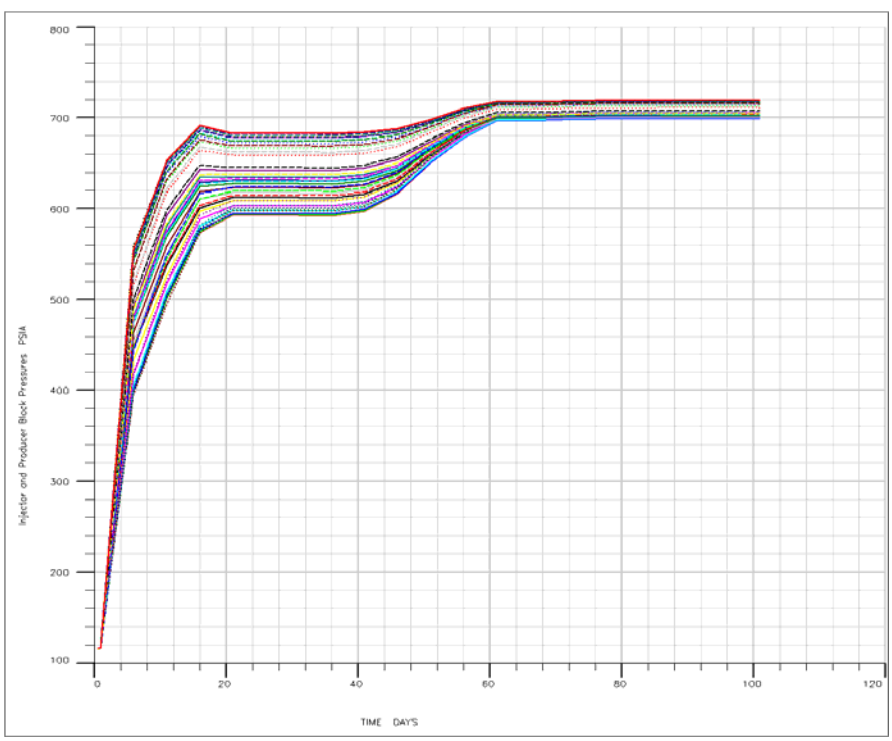

Figure 9 – Pressure plot showing pressures of injector and producer blocks approaching pressure communication during the heating period. The colors of each series in the plot are irrelevant.

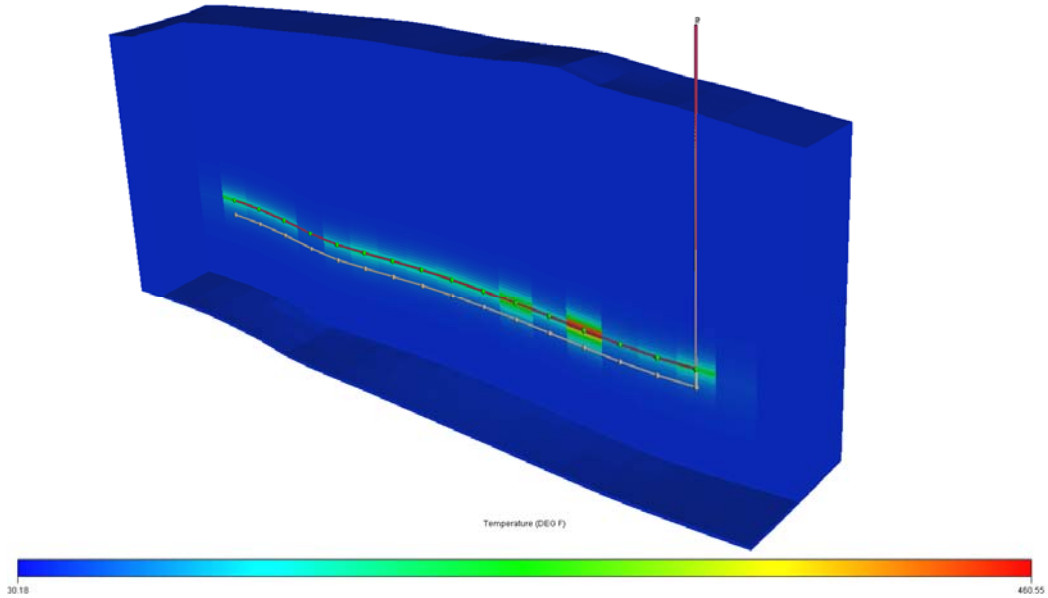

Figure 10 – Failure of SAGD effect due to lack of proper pre-heating (after 6.5 years).

To simulate the heating period in Eclipse, numerous iterations of the HEATER keyword were necessary to find the correct numeric combinations. Simply increasing the maximum heating rate did not proportionally generate a higher temperature in the grid blocks. In Figure 11, the value on the y-axis is the average heated temperatures for the grid blocks between the injector and the producer (˚F). These trends were generated by increasing the maximum heater rate from 3E6 Btu/day to 7E6 Btu/day. As shown, the optimal heating rate for this model with 164ft x 3.2808ft x 3.2808ft blocks was iteratively determined to be 4E6 Btu/day or 5E6 Btu/day. The numerical issue occurring with the 4.5E6 Btu/day was unknown and not further investigated. It was concluded that the size of the grid block determines the correct heating parameters to be used. The heaters should then be shut off once the steam injection period commences.

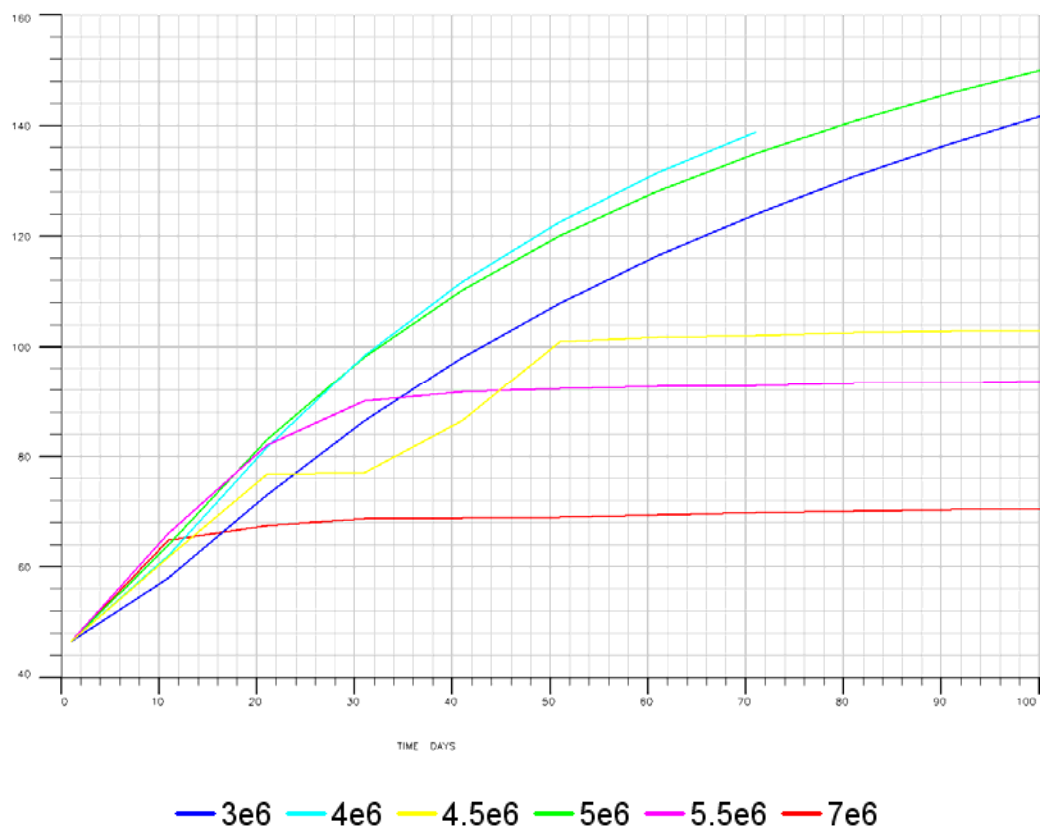

Figure 11 – Non-linearity in grid block temperatures and heating rates. Y-axis is the average heated temperatures for the grid blocks between the injector and the producer (˚F).

Convergence and time-stepping criterion may need to be adjusted, sometimes iteratively, to arrive at factors generating a stable run. These factors may be critical to the success of the simulation. From a series of tests, the conclusion was that a combination of finer and coarser tuning is necessary for the simulation. During the heating period, no injection or production is incident thus finer tuning may be used. However, at the beginning of steam injection, coarser tuning is suggested to accommodate for the larger unstable changes in temperature and saturation, occurring in the grid blocks around the wells. It is observed that the magnitude of water saturation in the model has significant influence on the simulation. A facetious test of a model with no original water saturation ran to completion too quickly showing that initial water present in the model adds an important factor to the computational complexity.

The control limits for steam injection and production affect the stability of the production rate as well as the presence of oscillations and instability with the simulation. It is normal in field operations to observe varying surges of produced oil volume from SAGD reservoirs, as the rate at which the bitumen oil is mobilized from certain zones of the reservoir may be different than the ongoing production rate. The daily injection rate should not be limited as this reduces the efficiency of the system and oil production declines (Figure 12). This rate is dependent on the injection pressure. This "limitless" steam approach helps to reduce condensation of the injected steam. In field operations, this is obtained by injecting steam at pressures at or slightly higher than the saturation pressure, and ensuring constant supply of sufficient steam at the desired operational settings.

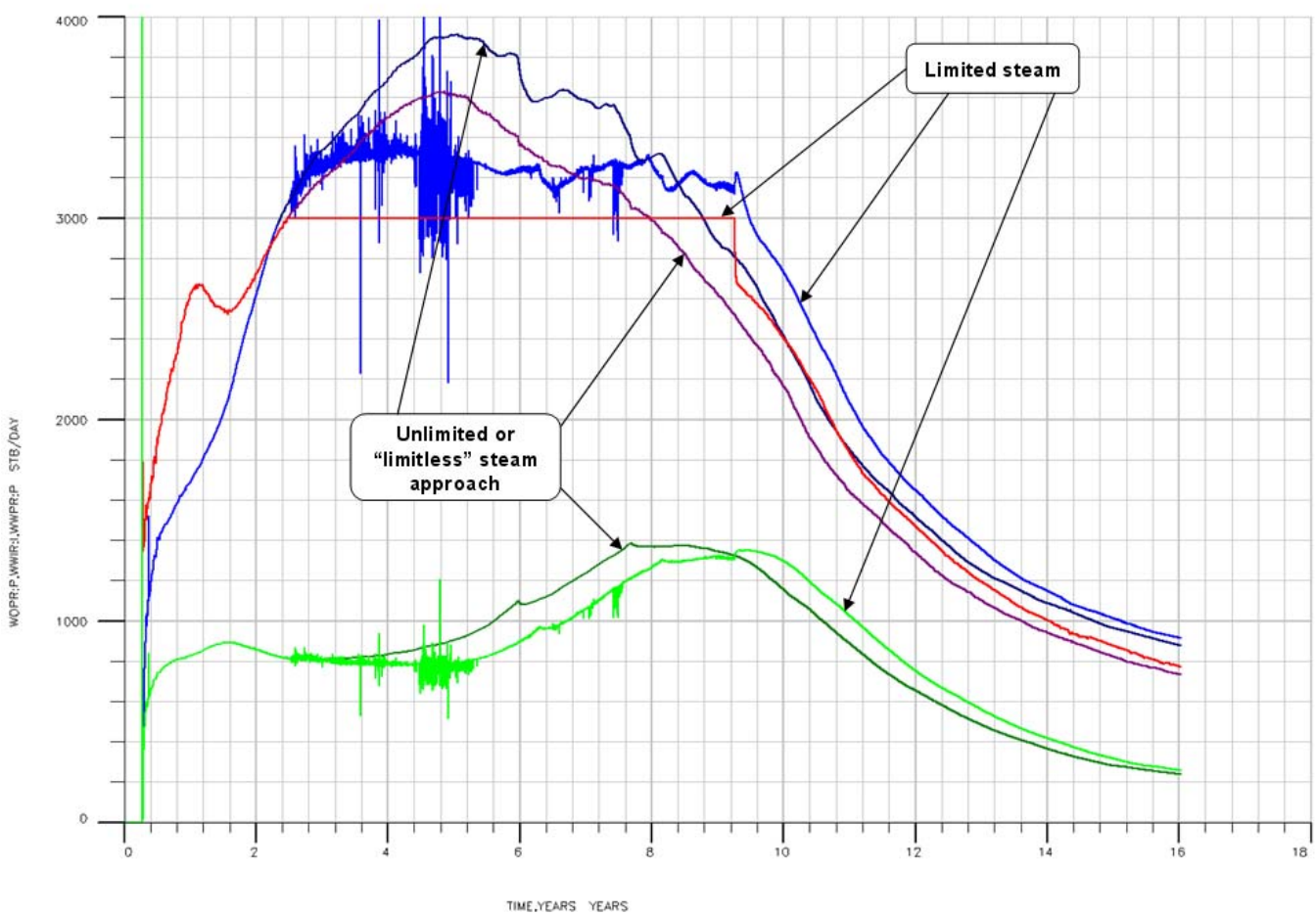

Figure 12 – Declining oil production with limited steam injection rate. Red lines are steam injection, green lines are oil production and blue lines are water production. Darker trends represent the unlimited steam case while the lighter trends represent the limited steam injection case. Limitless steam approach advances production.

In the plots above, the red lines are steam injection, the blue lines are water production, and the green lines are oil production. The darker color trends represent the unlimited steam case. As shown in the plot, the unlimited steam case generates less oscillation in the solution. With unlimited steam, the oil production volume is also advanced, although cumulative oil production quantities approach the same value (Figure 12).

The production constraints are governed by a production volume limit (guided by well completions / artificial lift capacity), a desired operating (bottom-hole) pressure, and a steam trap concept. In field operations the injection and production wells approach similar pressures. This is due to the proximity of the two wells. If the producer bottom-hole pressure is lowered, live steam will breakthrough into the producer causing serious damage to the liner and sand control problems. Field operations may adjust the steam trap and production volume constraints to ensure that no live steam is produced; this will minimize operational challenges. The combination of adjusting the constraints may be used to ensure a sufficient liquid level above the producing well for continuous, stabilized production rates, yet lower than the injection well. This facilitates constant and efficient steam injection and heat propagation to the rest of the reservoir, rather than heating up the fluids waiting on imminent production (Figures 13 and 14). In the beginning of the steam injection phase, the bottom-hole pressure of the production well may be set to a much lower value than reasonable (e.g. 75 psia). Though the pressure will not get as low as this value, it is suggested to help stabilize the simulation. A realistic bottom-hole pressure that is close to the steam injection pressure may actually cause iteration / solution issues with the simulation due to repeated closing and re-opening of the well. A reasonable steam strap constraint will ensure that the bottom-hole pressure of the producer does not drop below reasonable values.

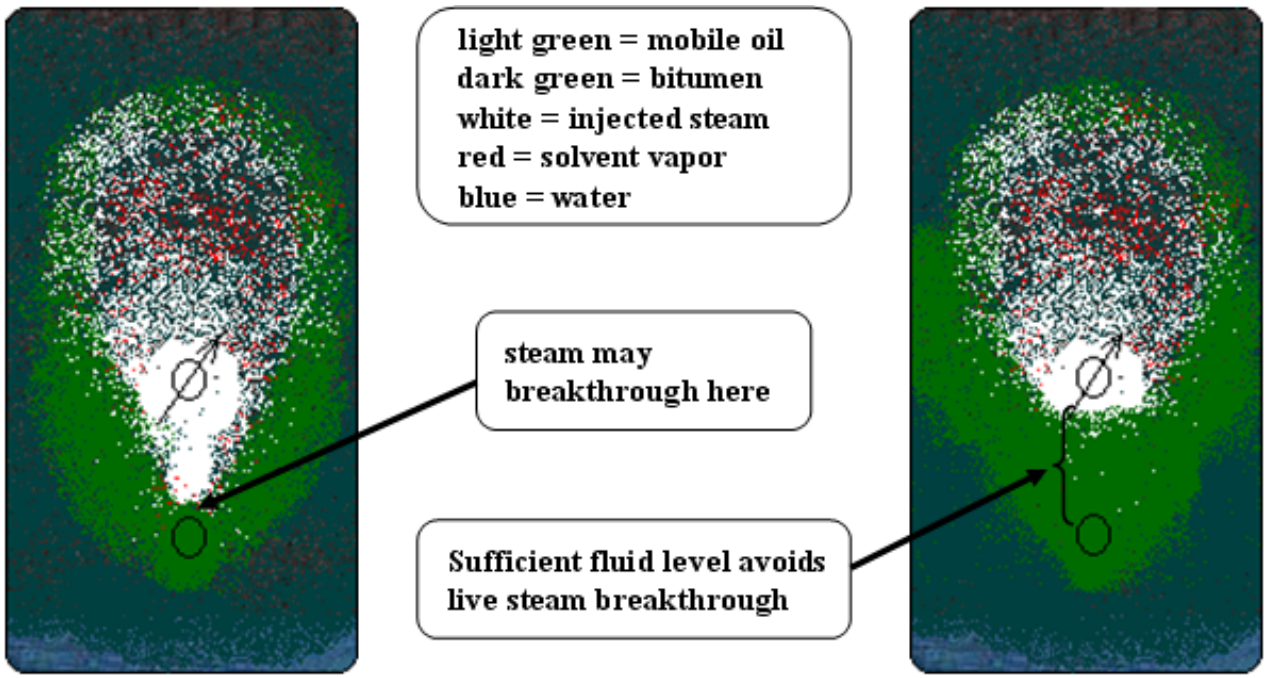

Figure 13 – Bad fluid level control. **Figure 14 – Good fluid level control.**

Furthermore, the John Appleyard linear solver (JALS) in Eclipse was the effective solver in the numerical simulation. Memory configurations must be taken into account when designating parameters for this solver. An adaptive implicit solver was attempted but was not successful. Due to the nature of the SAGD simulation process, a fully implicit solver must be implemented. Using a fully implicit method helps generate reasonable solutions for saturations, pressure, and temperature at the end of each iteration. The simulation of these processes can grow increasingly complex and resource demanding.

The presence of solvent in the system causes computational difficulty during solvent and steam flashing. Boundary effects of the steam chamber also affect the computational speed of the simulation. Refined vs. variable gridding scenarios were also investigated. Though a variable grid approach may be plausible in delivering comparable results as with refined gridding (Figure 15 and 16), variable gridding does not enhance the speed of the simulation by a remarkable amount, unless the number of cells are significantly reduced. Furthermore, variable gridding reduces the effect of the steam chamber seen in the reservoir (see oil saturation and temperature profiles in Figures 17 through 20). For the re-gridding comparison, a homogeneous model was developed for easier computation and analysis (grid sizes shown per zone in Figures 21 and 22).

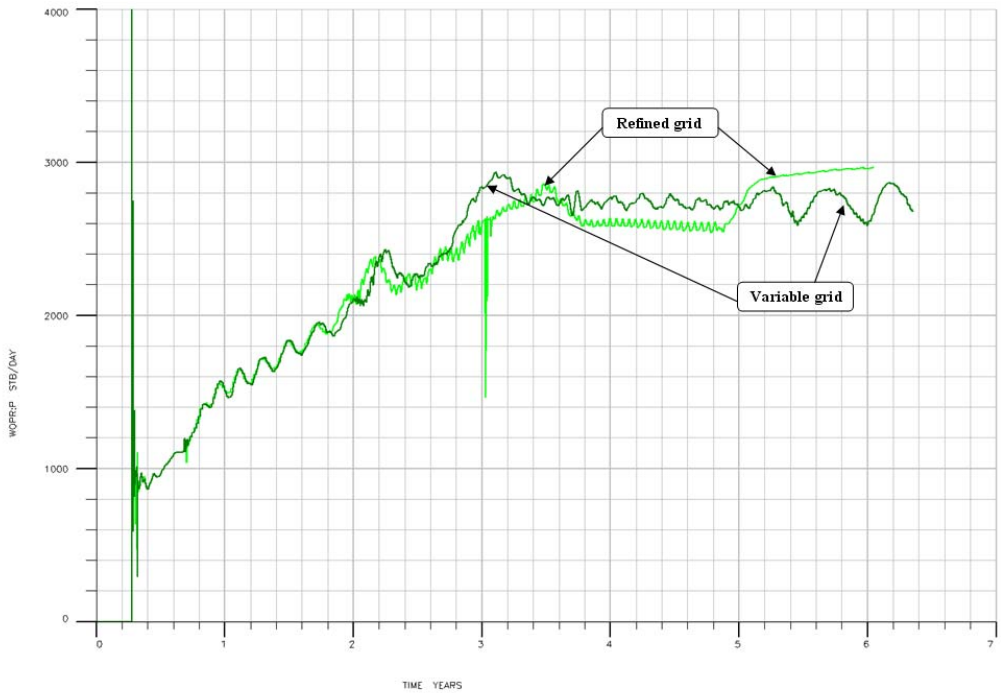

Figure 15 – Cumulative oil production with refined and variable gridding (light green: refined, dark green: variable).

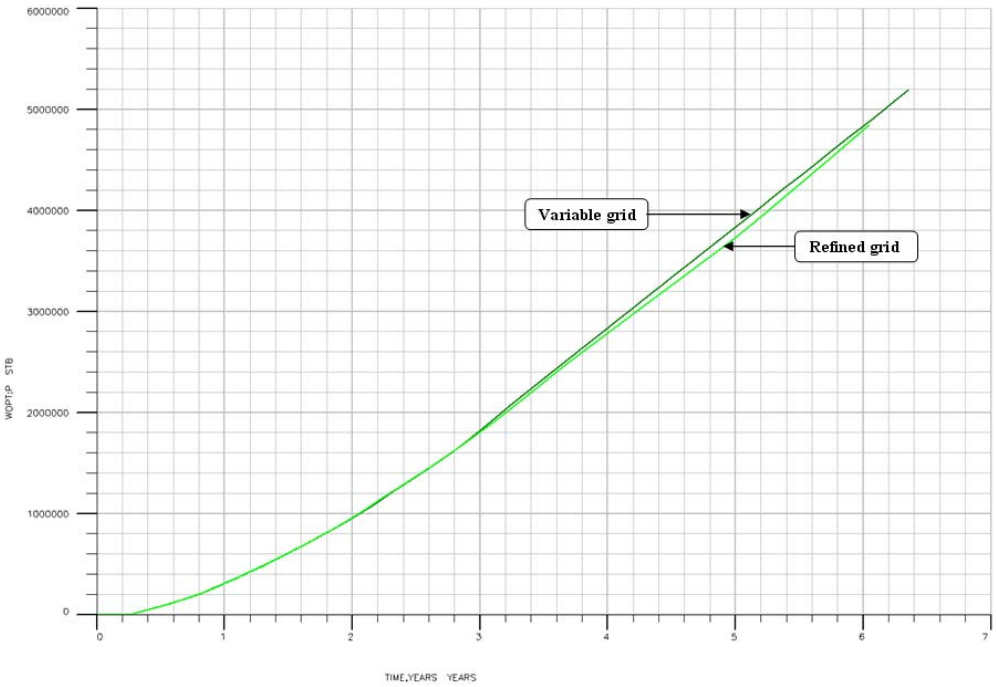

Figure 16 – Cumulative oil production with refined and variable gridding (light green: refined, dark green: variable).

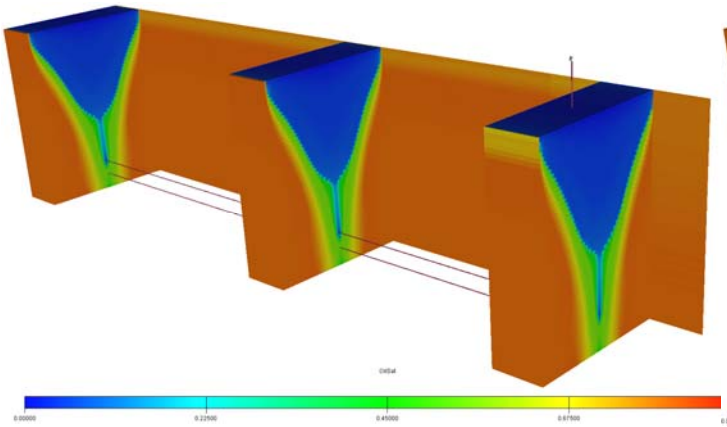

Figure 17 – Oil saturation shown at 1751 days – about 4.8 yrs (REFINED GRID).

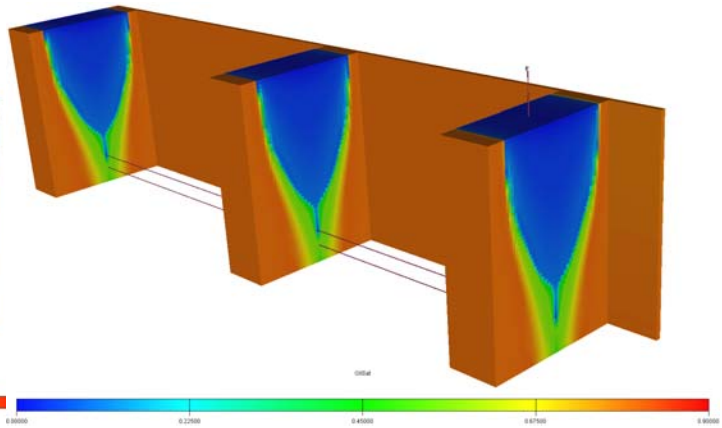

Figure 18 – Oil saturation shown at 1751 days – about 4.8 yrs (VARIABLE GRID).

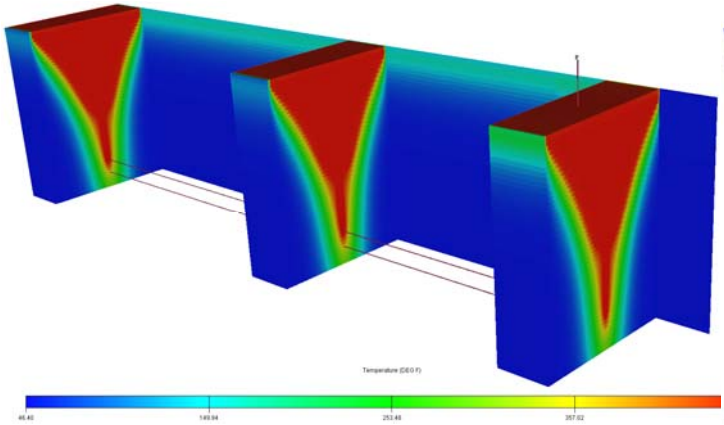

Figure 19 – Temperature shown at 1751 days – about 4.8 yrs (REFINED GRID).

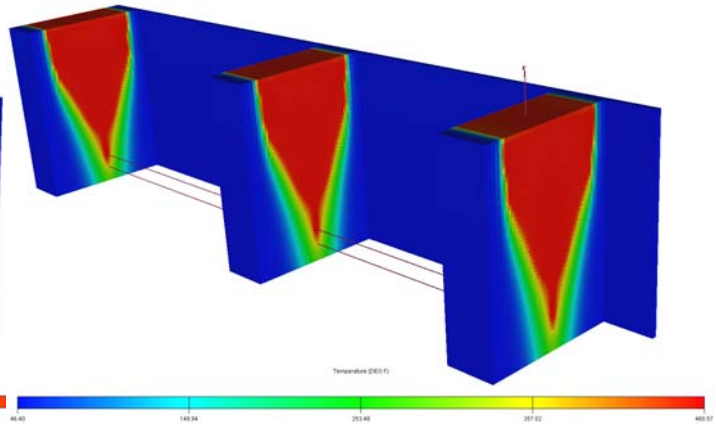

Figure 20 –Temperature shown at 1751 days – about 4.8 yrs (VARIABLE GRID).

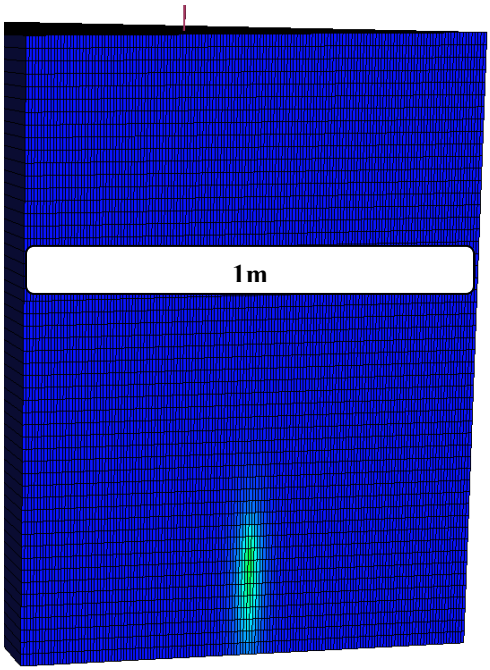

Figure 21 – Homogenous model (REFINED GRID).

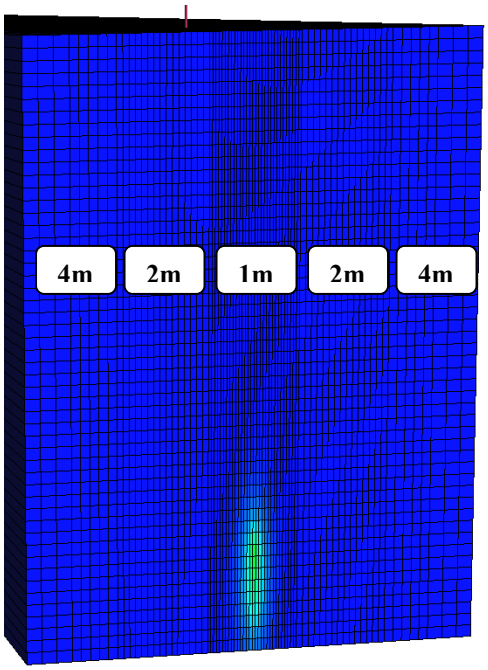

Figure 22 – Homogenous model (VARIABLE GRID).

Results

Field Test

Figures 23 and 24 are results of a field test utilizing a solvent aided process with steam injection. About five months after steam injection, co-injection begins and the production rate is shown to increase. Instrument malfunction may slightly skew the reported data but the general trend shown is a 20% to 40% increase in production. The reported SOR of the operation also shows improvement once the steam-solvent co-injection period begins. V820 represents the solvent used.

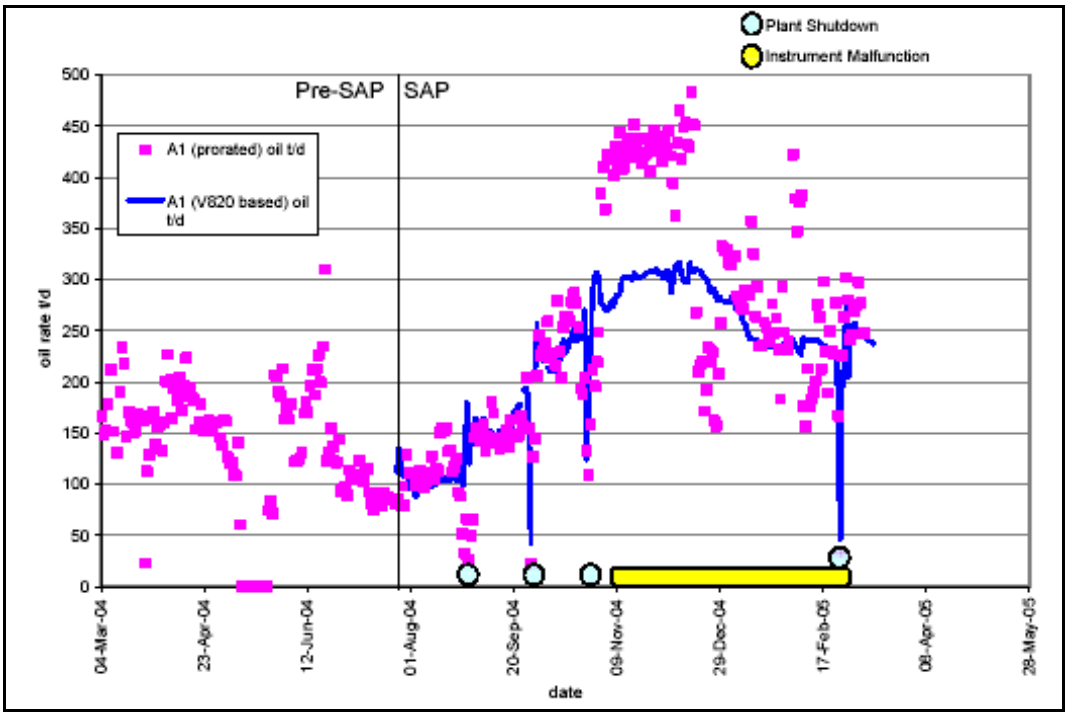

Figure 23 – Production from pilot test of ES-SAGD well pair. V820 represents the solvent used.

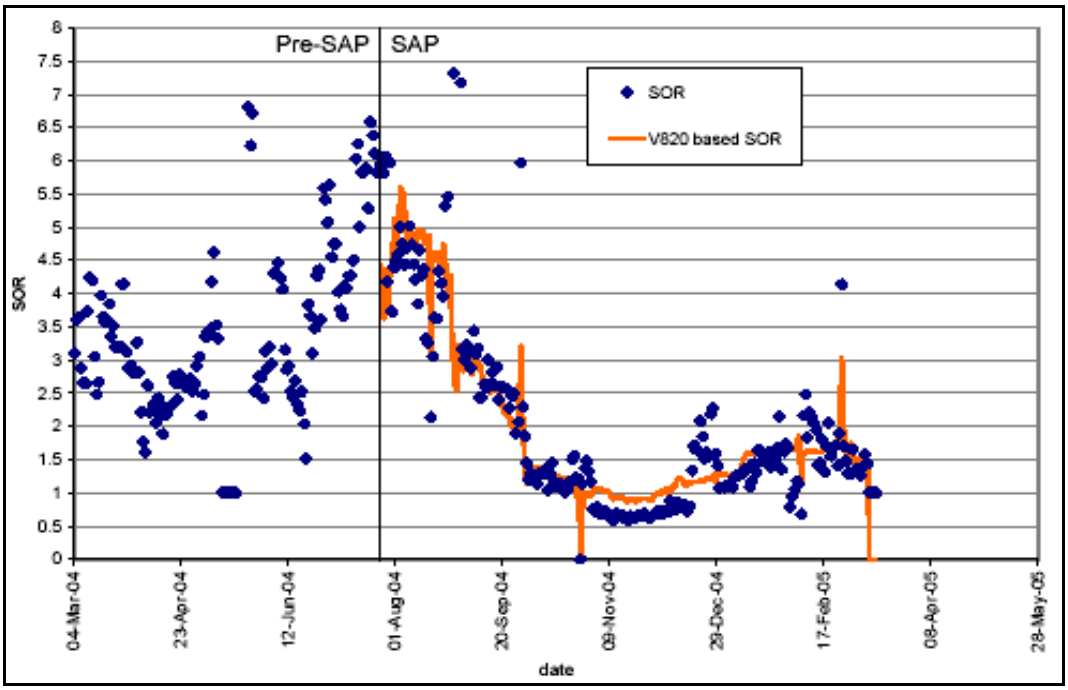

Figure 24 – Steam-oil ratio from pilot test of ES-SAGD well pair. V820 represents the solvent used.

A base case of steam injection was set to be the benchmark to compare to the co-injection cases. Figures 25 through 28 show the comparison of the produced oil and water, and steam injection rates. It shows the results from the base case SAGD process with no solvent injection and the cases with solvent injection with varying concentrations. These concentrations were determined as a percentage of the CWE of injected steam, thus at 3000 bpd of CWE injected steam a 10% solvent case would represent 300 bpd of solvent added to the injection steam. Higher solvent concentrations generated higher oil production rates. This increase in production is comparable to that of the field tests. An alternate model developed also showed similar results (Figures 33 and 34).

Reduced Steam Injection

It is essential to note that the produced oil in the solvent injection cases contains some amount of the injected solvent. Therefore, the efficiency of the solvent injection process can be determined more precisely by subtracting the volume of the produced solvent from the total volume of produced oil. This theory suggests that the efficiency of ES-SAGD operations should be evaluated on a basis of steam-bitumen ratio (SBR) rather than the generic SOR. This method accounts for the effects of solvent present in the system that is used to enhance the production of bitumen, without accounting for skewed volumes of produced oil. The SBR is improved with the use of solvent injection (Figures 29 and 30). Though not directly proportional over time, increasing concentration of solvent further lowers the SBR. Further improved efficiency occurs as increased oil production rates actually require reduced steam injection rates. An in-depth economic analysis is difficult due to the varying cost of solvent depending on composition, and nature of the solvent used. Figure 31 and 32 show the fractional recovery of the injected solvent. Though simulation results show that the solvent is eventually recovered with production (e.g. over 40% recovery after 8.5 years with 2% solvent injection – Figure 34), the rates of solvent recovery vary depending on the concentration of solvent used in the model.

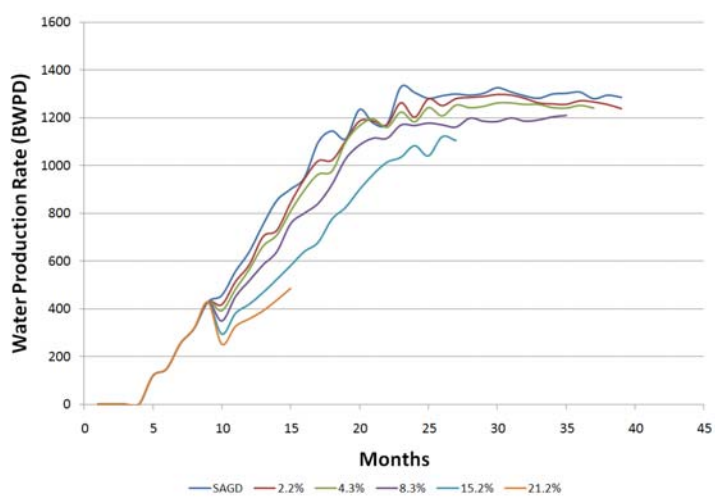

Figure 25 – Water production rate comparisons for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

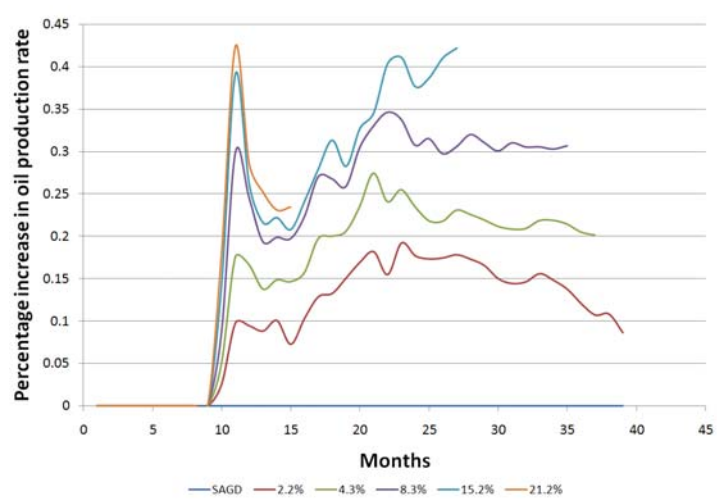

Figure 26 – Percentage increase in oil production for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

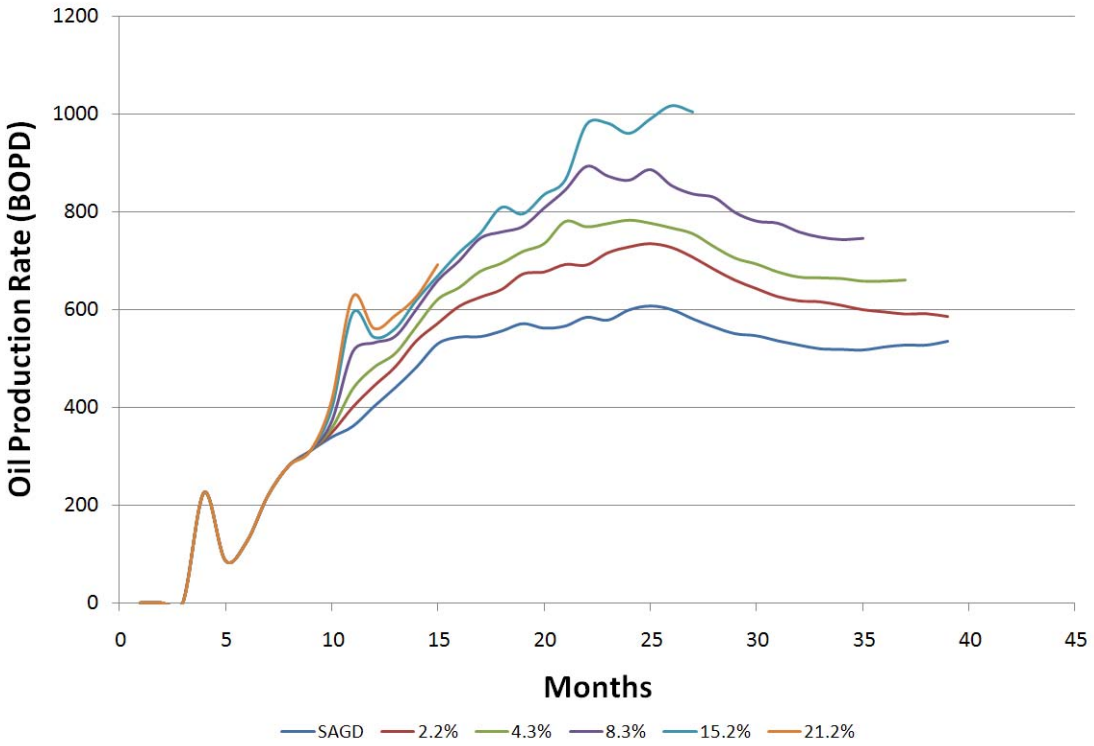

Figure 27 – Oil production rate comparisons for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

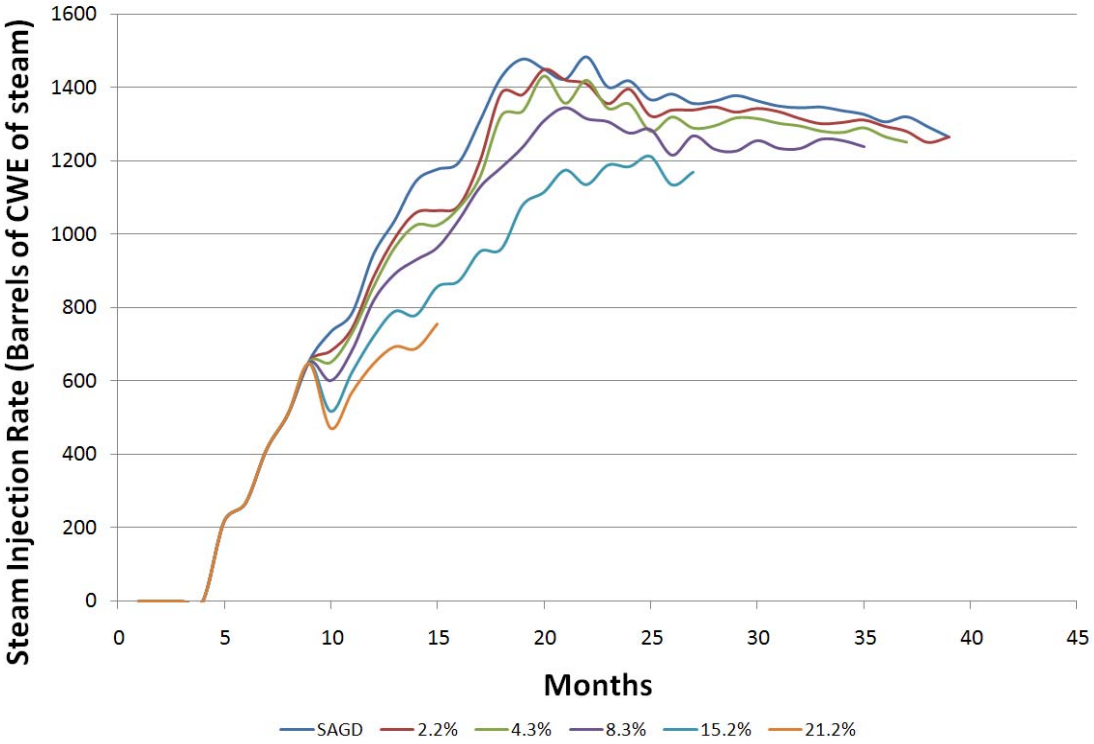

Figure 28 – Steam injection rate comparisons for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

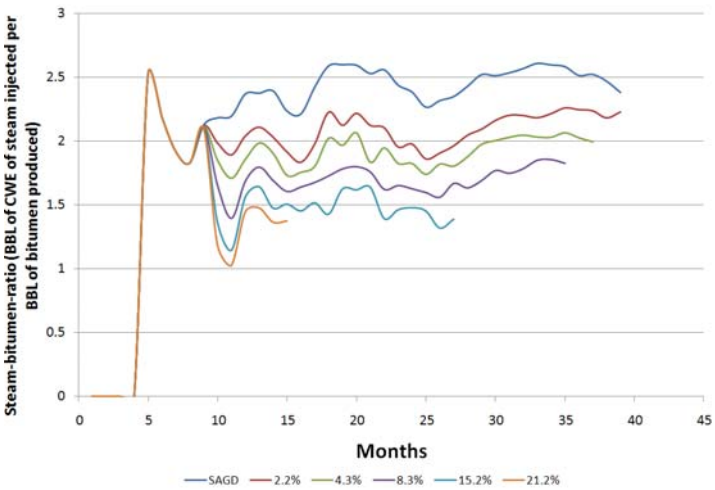

Figure 29 – Instantaneous steam-bitumen ratio for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

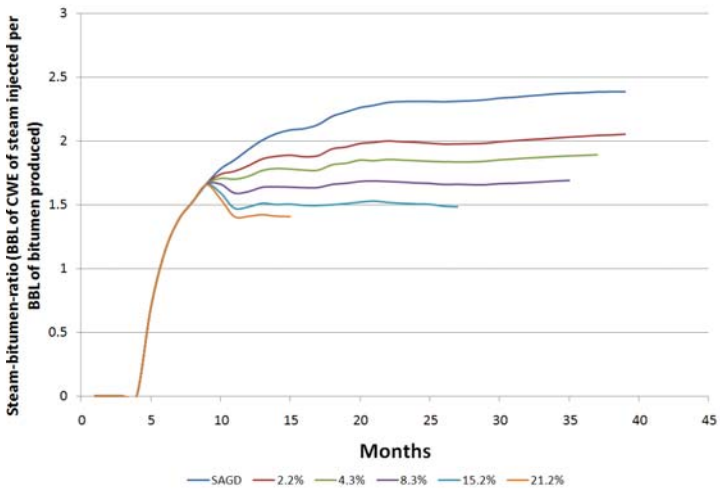

Figure 30 – Cumulative steam-bitumen ratio for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

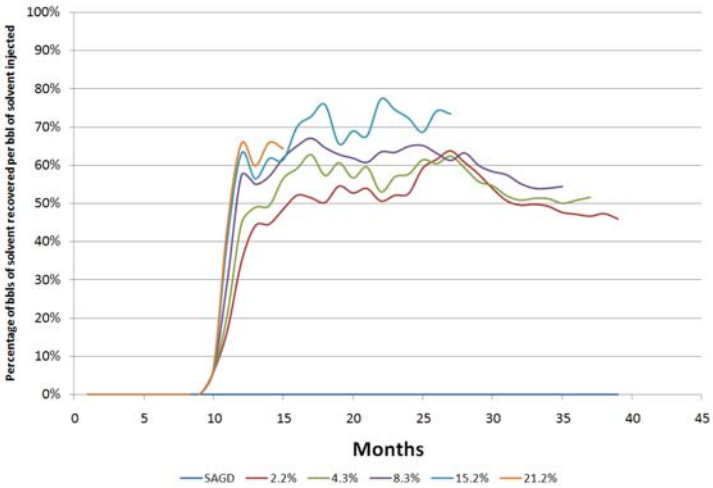

Figure 31 – Instantaneous solvent recovery fractions for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

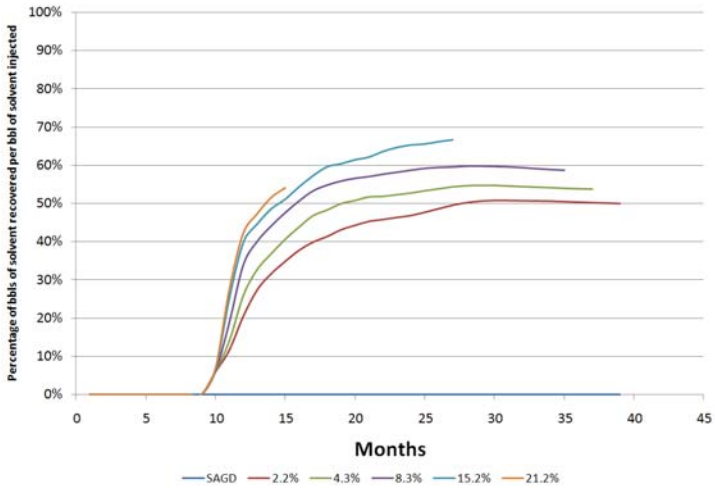

Figure 32 – Cumulative solvent recovery fractions for SAGD and ES-SAGD cases. Percentages are concentration of solvent as a fraction of injected CWE.

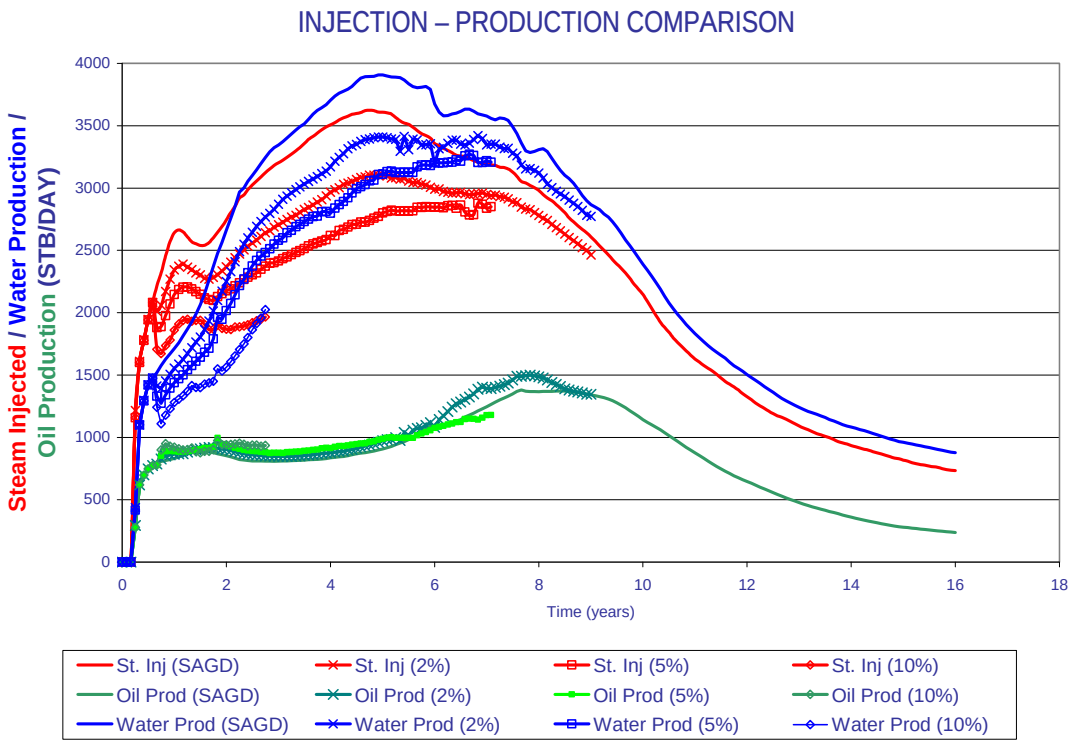

Figure 33 – Injection / Production summary for SAGD and ES-SAGD cases (alternate model scenario). Percentages are concentration of solvent as a fraction of injected CWE.

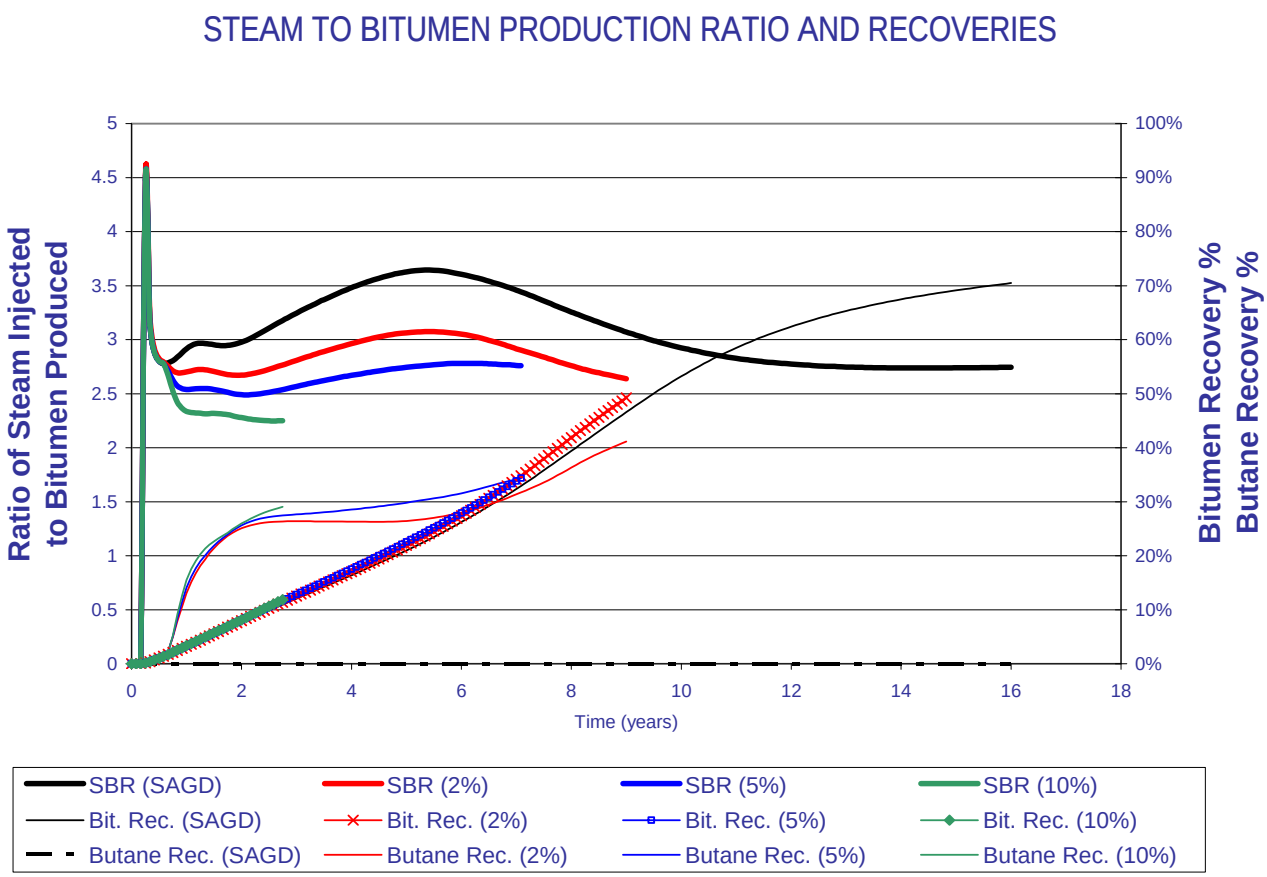

Figure 34 – SBR and solvent recovery summary for SAGD and ES-SAGD cases (alternate model scenario). Percentages are concentration of solvent as a fraction of injected CWE.

In-situ Upgrading

Due to solvent deasphalting of bitumen in the reservoir, there could be potential in-situ upgrading in this process. However, the simulation model did not account for this mechanism. The presence of solvent in the produced oil improves its composition and API (Figure 35). The increase in API depends on the concentration of the injected solvent. The API is calculated based on the composition of the produced oil. In field operations involving ordinary SAGD, some solvent is often added to the produced oil (bitumen) to reduce the viscosity of the oil and ensure stable flow to downstream operations through pipelines. The ES-SAGD method simply utilizes the addition of solvent early in the operation to enhance production and reduce the amount of "flow assurance" solvent that's added to the oil post-production. Comparing the solvent recovery, SBR, and excessive increase in the API shows that concentrations of more than about 5% to 10% of solvent in injected steam is not optimal, as the solvent injected is quickly produced with the oil. For this particular model, an 8.3% solvent concentration seems to be optimal in delivering improved production results with the ES-SAGD process, yet optimal to the co-injection cost structure. Considering all factors mentioned, most ES-SAGD cases may receive optimal enhancement to production when using just a 5% to 10% solvent concentration.

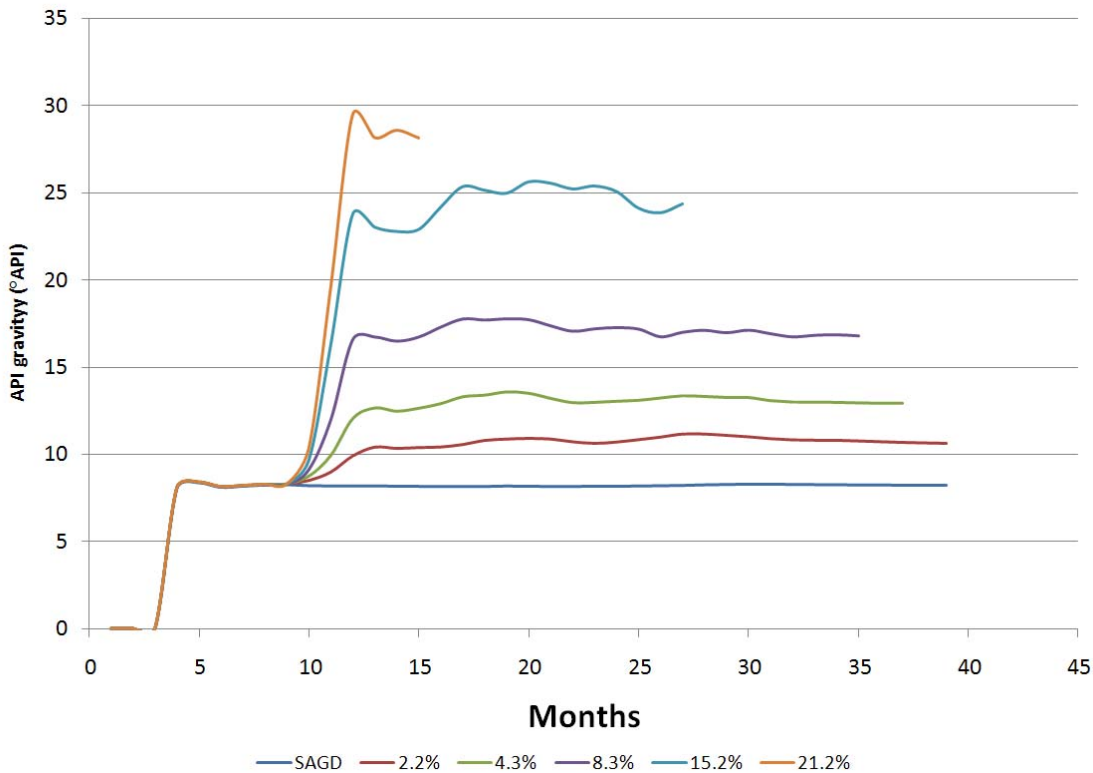

Figure 35 – Increased API or produced oil varying with solvent concentration. Percentages are concentration of solvent as a fraction of injected CWE.

Steam Chamber Growth and Viscosity Reduction

The presence of solvent in ES-SAGD slows the vertical growth of the steam chamber thus avoiding early loss of the steam's heat to the overburden. The steam chamber is able to grow a bit more laterally, thus increasing the efficiency of the operation. This is advantageous to assist the steam to overcome zones of permeability barriers. Figurer 36 and 37 show part of the reservoir with high permeability values ($k \geq 1{,}000$ *md*). With only 5% solvent injection, a wider zone of higher temperature is seen through the reservoir and around the wells as compared to an ordinary SAGD case.

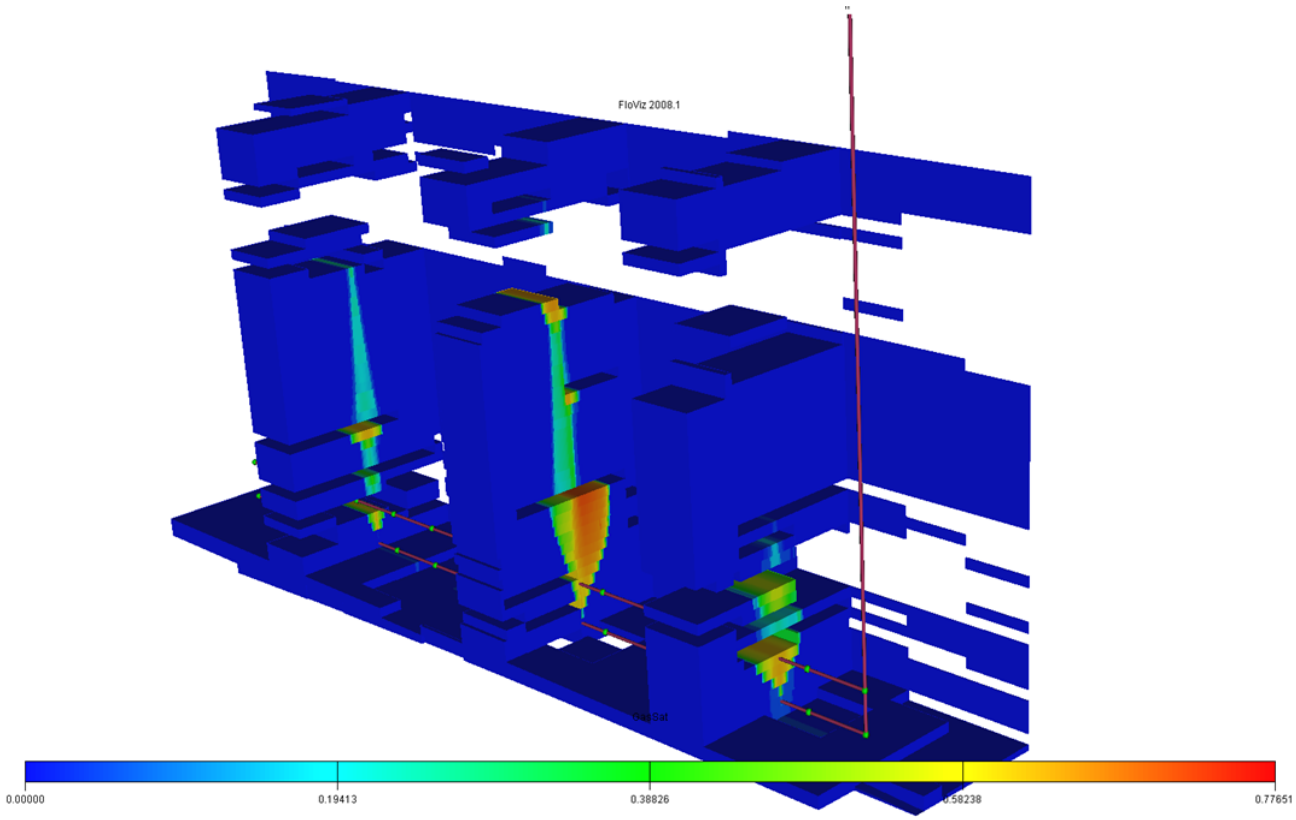

Figure 36 – Steam chamber with base case SAGD - no solvent.

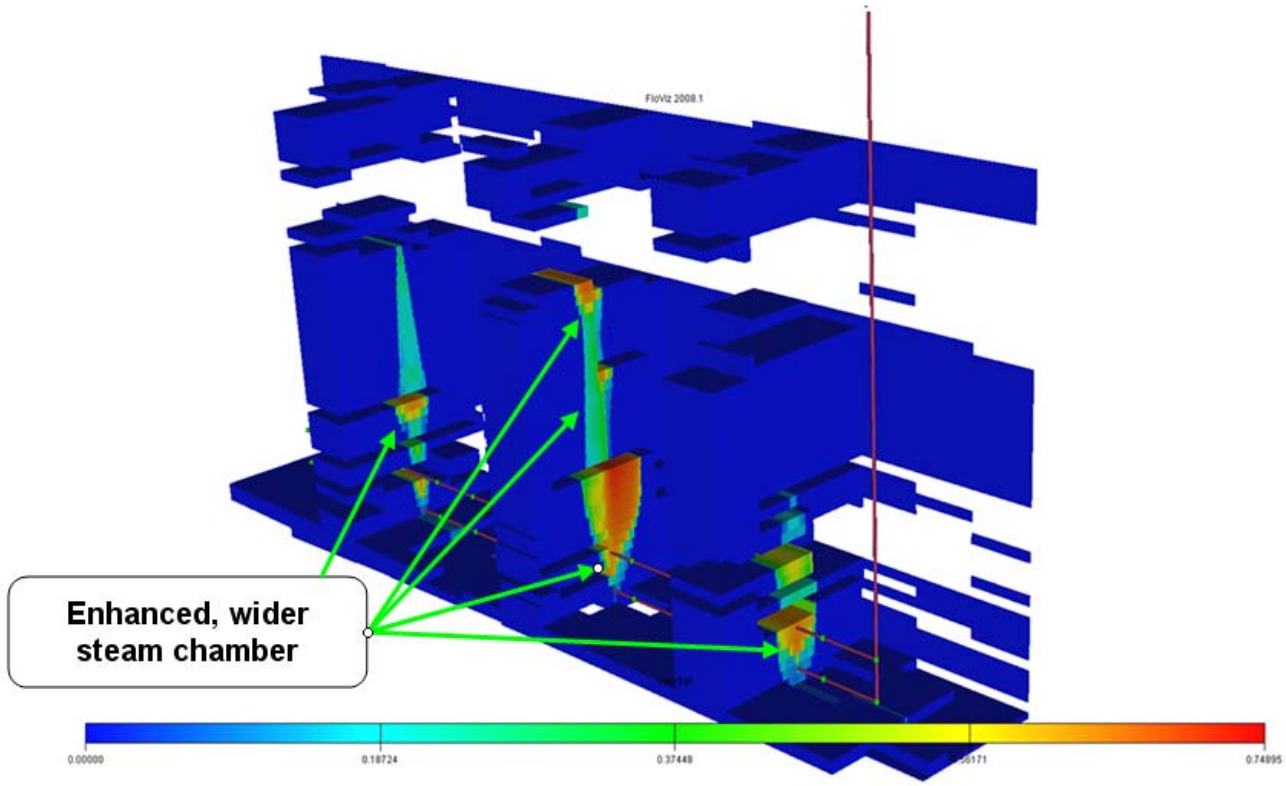

Figure 37 – Steam chamber with 5% solvent injection.

The viscosity of the oil at the drainage zone is also reduced due to viscosity mixing of the solvent and the bitumen. As gravity is a key factor in flow potential for SAGD, the increased presence of mixed solvent and bitumen in the gravity drainage zone increases the mobility of the oil when the mixing occurs. This assists the heat from the steam to reach further into the reservoir oil and increases mobility of the lower viscosity oil towards the well bore (Figures 38 and 39).

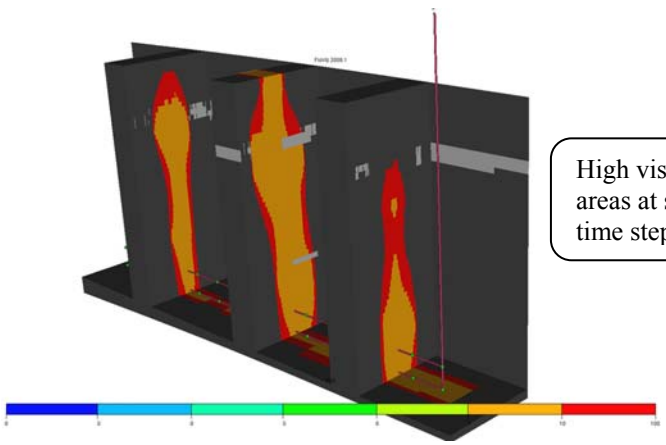

Figure 38 – Zone of lower viscosity in red (base case SAGD).

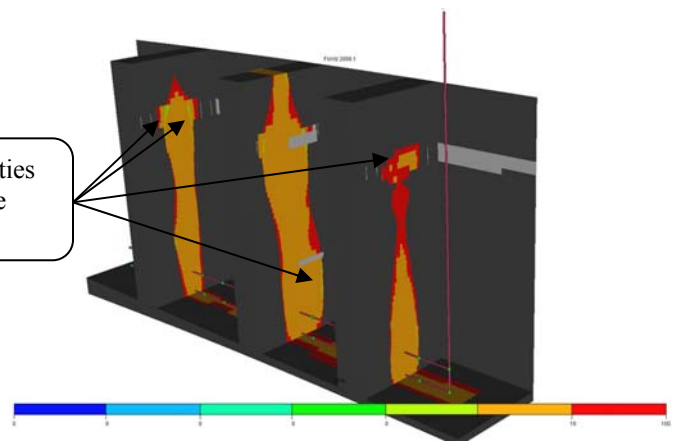

Figure 39 – Zone of lower viscosity in red and green (base case SAGD).

Mixed co-injection schedules

An unlimited amount of permutations exist when considering steam injection start and stop times. This also occurs with solvent injection. Due to the low temperature conditions in which these reservoirs exist, pauses in steam injection reflect almost immediately on the oil and water production rates. As co-injection continues, any stop to the solvent injection causes for the incremental oil production to decline and for the production rate to slowly approach a generic steam injection case (Figure 40). In summary, solvent injection should be continuous once commenced. Operator discretion may determine the varying concentration and periods of co-injection, based on upgrading of produced oil and solvent injection cost-structure. However, it is advisable that steam injection is not halted through the operation to maintain a steam chamber and mobilize more oil to the production well. Ultimately, injection strategy needs to be adjusted depending on the geological model to determine the optimal periods of solvent co-injection.

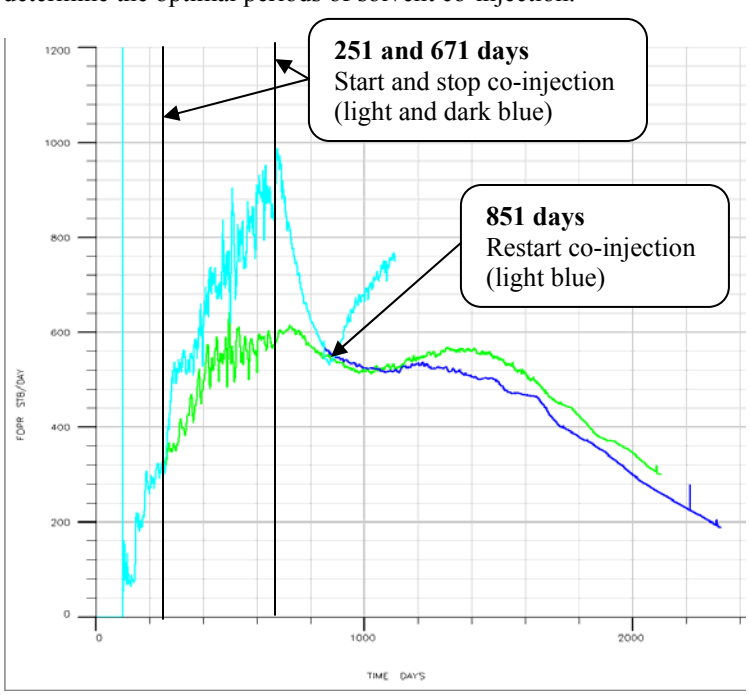

Figure 40 – Oil production using multiple schedules showing drop in production when co-injection stops (light and dark blue).

Green – Base Case SAGD
- Heating until 100 days
- Steam injection until 251 days
- Continue steam injection > 2000 days

Light Blue – 8.3% Solvent Injection
- Heating until 100 days
- Steam injection until 251 days
- Steam-solvent co-injection until 671 days
- Continue steam injection until 851 days
- Re-commence steam-solvent co-injection at 851 days until about 1120 days

Dark Blue – 8.3% Solvent Injection
- Heating until 100 days
- Steam injection until 251 days
- Steam-solvent co-injection until 671 days
- Continue steam injection > 2000 days

Conclusions

The following conclusions were made from the results of the simulation.

- With higher concentration of solvent in steam, the required steam volume reduces. This also leads to lower cost of steam and a reduction in carbon dioxide emission.
- The gravity drainage resulting from steam injection becomes more efficient and produces more oil in the presence of solvent. Any stop to solvent co-injection period reduces oil production rate to normal SAGD performance.
- The injected solvent dissolves into bitumen, enhancing oil viscosity reduction and possibly a lowering of interfacial tension.
- Steam-bitumen ratio (SBR) is a critical metric to evaluate the performance and efficacy of the ES-SAGD process in addition to the conventional steam-oil ratio (SOR).
- A solvent volume of five to ten percent of steam's cold water equivalent (CWE) is sufficient to produce more oil and to reduce operating costs. Higher concentrations of injected solvent would be uneconomical.
- Injected solvent is generally recovered in increasing amounts throughout the life of the project.
- Using uniform one-meter fine grid in the cross-section generates similar cumulative production results over time as compared to a spatially varying grid from one meter near the well bore to 4 meters at the drainage boundary; however, fine gridding is required around the well bore region only.

Acknowledgements

We express our appreciation to Marathon Oil Company and Marathon Center of Excellence for Reservoir Studies (MCERS) at Colorado School of Mines (CSM) for financial and technical support of this project. Also, we thank Schlumberger for their technical support in use of Eclipse simulator and Najeeb Alharthy, PhD student at CSM, for technical advice on this project.

References

1. Akram, F., Effects of Well Placement using Multi-Segmented Wells in a Full Field Thermal Model for SAGD: Athabasca Oil Sands, World Heavy Oil Congress, (March 2008)
2. Butler, R. M., Mokrys, I. J., Das, S. K., The Solvent Requirements for Vapex Recovery, SPE, (June 1995)
3. Butler, R. M.: Steam-Assisted Gravity Drainage: Concept, Development, Performance and Future, JCPT (February 1994) 44-50
4. Ferguson, M. A., Mamora, D. D., Goite, J. G., Steam-Propane Injection for Production Enhancement of Heavy Morichal Oil, SPE (March 2001)
5. Das, S., Steam Solvent Field Experiences, SPE, (September 2005)
6. Deng, X., Huang, H., History Match of an ES-SAGD Pilot, AERI/ARC Core Industry Research Program, (March 2009)
7. Fassihi, M., Brigham, W., Ramey Jr., H., Reaction Kinetics of In-Situ Combustion: Part 2 – Modeling, SPE Journal, (August 1984 – pg 408-416)
8. Govind, P. A., Das, S., Srinivasan, S., Wheeler, TJ, Expanding Solvent SAGD in Heavy Oil Reservoirs, SPE, CHOA, (October 2008)
9. Greaves, M., Xia, T. X., Underground Upgrading of Heavy Oil Using THAI – Toe-to-Heel Air Injection, SPE, CHOA, (November 2005)
10. Kisman, K. E., Yeung, K. C., Numerical Study of the SAGD Process in the Burnt Lake Oil Sands Lease, SPE, (June 1995)
11. Nasr, T. N., Process for enhancing hydrocarbon mobility using a steam additive, US Patent 6,230,814, (October 1999)
12. Nasr, T. N., Hydrocarbon production process with decreasing steam and/or water/solvent ratio, US Patent 6,591,908 (August 2001)
13. Prats, M., *Thermal Recovery,* Monograph Volume 7, Henry L. Doherty Series, SPE, (1986)
14. Nasr, T. N., Beaulieu, G. , Golbeck, H., Heck, G., Alberta Research Council, Novel Expanding Solvent-SAGD Process "ES-SAGD", Journal of Canadian Petroleum Technology Volume 42 Number 1, Petroleum Society of Canada, (January 2003)
15. Schlumberger Eclipse Simulation Software, Version 2009.1