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Pseudo-Component, Thermal, Reservoir Simulation Study of a Proposed, Low Pressure, Steam-Assisted Gravity Drainage Pilot Project In Northeast Alberta

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Abstract

Bitumen production from the Athabasca Oil Sands in northeast Alberta, Canada typically uses steam-assisted gravity drainage (SAGD) techniques. For shallow bitumen resources, low pressure, SAGD (LP-SAGD) and expanding solvent, LP-SAGD (SLP-SAGD) techniques are viable options for such developments as these methods maximize bitumen production and control steam-oil ratios (SORs), while maintaining asset integrity throughout the life of the project.

In Alberta, applications requesting approval for pilot-scale, thermal exploitation of bitumen resources are submitted to the Energy Resources Conservation Board for review. As part of the application process, thermal reservoir simulation studies are often conducted, forecasting 10 years of asset development using SAGD.

The authors recently completed a 3D, pseudo-component, thermal, reservoir simulation study of the proposed Clearwater West, Phase 1 Pilot Project located southeast of Fort McMurray, Alberta. The simulation program, STARS™, was used for this investigation. Three potential development strategies for the Pilot Project were evaluated. These strategies included LP-SAGD, where 100% coldwater equivalent (CWE) steam is continuously injected into the reservoir for 10 years. The other cases were SLP-SAGD, where the injection stream consists of 75% CWE steam and 25% solvent is continuously injected into the reservoir for either 10 years or for 7 years, followed by wellpair blowdown and the termination of solvent injection. Comparisons of key modelling parameter results, such as steam chamber development, bitumen production and recovery, SORs and solvent loss, were completed for all development strategies. A sensitivity study was also conducted.

INTRODUCTION

Bitumen deposits from the Athabasca Oil Sands are typically produced via surface mining or *in situ*, thermal methods. About 20% of these deposits can be surface mined as the target reservoirs are shallow. The remaining deposits require *in situ* techniques, such as steam-assisted gravity drainage (SAGD) for bitumen production. Some of these shallow bitumen deposits, which are not mineable, have a relatively thin caprock rock and overburden. These assets are operated at low maximum operating pressures (MOPs), when compared to their deeper counterparts, in order to maintain caprock integrity during asset development. This has become a paramount issue in Alberta following the loss of caprock containment at the Total E&P Canada Ltd., Joslyn Creek SAGD project in May 2006 (Total, 2007; ERCB, 2010).

For *in situ* developments, constrained by low MOPs, incorporating expanding solvent, SAGD (ES-SAGD) presents a viable option for development. Co-injecting solvent with coldwater equivalent (CWE) steam provides the additional benefits of further reducing bitumen viscosity, improving fluid mobility and using less energy when compared to CWE steam only. As a result of these performance advantages, Alberta Oilsands Inc. (AOS) is considering using expanding solvent, low pressure, SAGD (SLP-SAGD) for developing the proposed, Clearwater West Phase 1 Pilot Project ("Pilot Project"). As a further result, a 3D, pseudo-component, thermal, reservoir simulation study forecasting the 10 year Pilot Project performance for a variety of development strategies was completed using the numerical code, STARS™. The results of this numerical study are documented in the application update submitted to the Energy Resources Conservation Board (ERCB) by AOS (2010).

A pseudo-component modelling approach was adopted for this investigation. Four components, consisting of water, solution gas and the heavy and light components of bitumen were used for the strategy consisting of CWE steam only (LP-SAGD). For the strategies involving co-injecting solvent (SLP-SAGD), five components were used with the additional components representing the solvent composition (C_3-C_7H). Key modelling parameters reviewed for this investigation were steam chamber development and temperature, bitumen production and recovery, steam-oil ratios (SORs) and solvent recovery.

CLEARWATER WEST PHASE 1 PILOT PROJECT

The Pilot Project is located in Sections 21 and 22, Township 88, Range 8, West of the 4th Meridian, about 8 km southeast of Fort McMurray, Alberta (Figure 1).

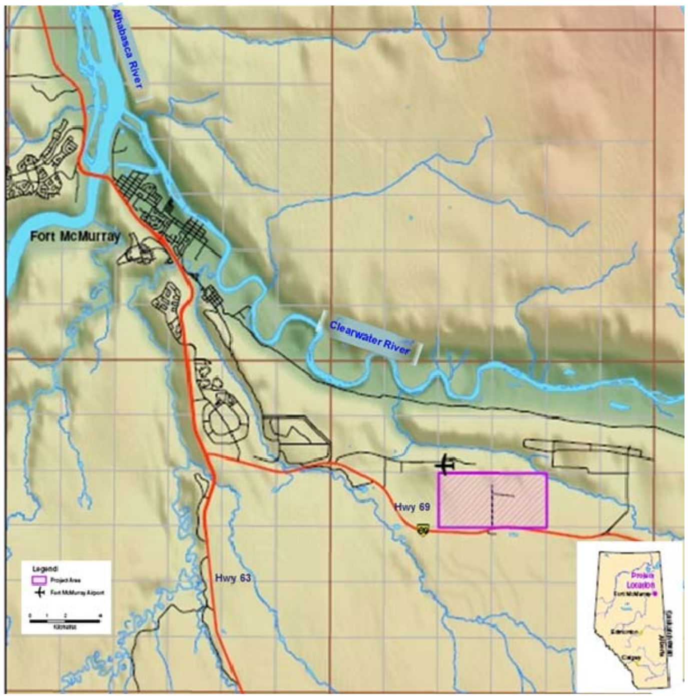

Figure 1 - Clearwater West Project Location

Phase 1 of the Pilot Project will consist of six parallel SAGD injector-producer wellpairs located about 110 m below ground surface within the thick estuarine channel sands of the McMurray Formation. Each wellpair is expected to be 600 m long, north-south orientated and operated at a MOP of 1,000 kPaa determined from a recent caprock integrity study (AOS, 2010). After a number of years of pilot operations, up to five “basement” wells will be completed in the basal McMurray Formation to assist with bitumen and solvent recovery. Electro-magnetic heating is also being considered in the Pilot Project development (Palmgren et al., 2011).

The Pilot Project will likely use SLP-SAGD to recover bitumen. Fluid injection will consist of CWE steam and solvent, injected at rates of 1,113 m^3/d and 183 m^3/d respectively, providing an injection stream consisting of 86% CWE steam and 14% solvent. Facilities will be designed to produce up to 695 m^3/d bitumen and 165 m^3/d solvent. Pilot Project start-up is expected in Year 2012 (AOS, 2010; Palmgren et al., 2011).

ES-SAGD PROCESS

AOS intends to utilize SLP-SAGD for developing the Pilot Project. This process incorporates the ES-SAGD technique, developed and patented by the Alberta Research Council (ARC; Nasr et al., 2003), and involves co-injecting a hydrocarbon additive (solvent) with CWE steam. Concentrations of the injected solvent are generally low and the type of solvent used depends on reservoir and fluid properties. When solvent and steam are injected into the reservoir, it condenses at the boundary of the SAGD steam chamber. This condensed fluid dilutes bitumen and in conjunction with heat, reduces bitumen viscosities to about 10 cP, a significant reduction from its *in situ* viscosity typically exceeding 2 million cP in the Athabasca Oil Sands (Gates and Chakrabarty, 2008). At the Pilot Project, *in situ* bitumen viscosities are >10 million cP (AOS, 2010).

Co-injecting solvent improves and accelerates bitumen production and recovery, reduces SORs, decreases water usage, lowers energy consumption, decreases greenhouse gas emissions, and reduces steam plant CAPEX when compared to conventional SAGD methods (Nasr et al., 2003). The ES-SAGD process has been successfully demonstrated in the laboratory, numerically, and in the field (Orr et al., 2010). Key factors contributing to its success are often associated with reservoir conditions, fluid properties, solvent composition and concentration and operational strategies. The main challenge of ES-SAGD method is economic viability and in particular, the high cost of solvent (Govind et al., 2008).

The MOP of ES-SAGD is an important design constraint as is impacts steam chamber growth, injection rates and production performance. Though publically available information about field applications of the SLP-SAGD method is limited, laboratory experiments conducted by the ARC indicate that when SLP-SAGD is implemented at optimal conditions, the resulting performances are generally competitive with higher pressure operations (Ayodele et al., 2009).

RESERVOIR MODEL

The reservoir simulation model was constructed from the P50 realization of the 3D, geostatistical model developed for the Pilot Project (AOS, 2010). A 2D, cross-sectional model was selected from the 3D geologic model and the unit thickness of the 2D model (j-plane) was increased to 600 m, equivalent to the length of the wellpair trajectories. The final 3D, reservoir model used for the simulation study contained uniform grid block dimensions of 20 m x 600 m x 1 m. The final descretization was 800 x 1 x 80 (i, j, k) providing a model grid consisting of 64,000 active cells to represent the Pilot Project.

Boundary Conditions

Boundary conditions assigned to the reservoir model were used to represent the groundwater flow system and fluid leak-off at the model edge. No-flow boundaries were assigned to the uppermost and lowermost grid faces in the vertical plane corresponding to the base of the Clearwater Formation shale (caprock) and a region within the Beaverhill Lake Group carbonates (underburden), respectively. Flux boundaries were assigned at the eastern and western model edges using pseudo discharge wells. A minimum threshold pressure of 148 kPaa was assigned to the top of the McMurray Formation and assumed hydrostatic thereafter, based on pressure measurements from a vibrating wire piezometer completed at the Pilot Project.

SAGD Wellpair Characteristics

Six SAGD wellpairs were modelled, with each wellpair having the following characteristics:

- 600 m well trajectory.
- Lateral spacing of 150 m.
- Vertical injector-producer spacing of 5 m.
- Drainage area extending 75 m from the well trajectory and along its entire length.
- No rate or pressure losses between along each well.

Limitations

The limitations of using a simplified 3D, cross-sectional model for this reservoir study are associated with characterizing:

- Geologic heterogeneity.
- Initial fluid saturations.
- Wellpair design and operation.

These simplifications affect pressure communication between the injector and producer wellpairs, steam chamber development and Pilot Project performance. By constructing the grid in this fashion, computational time and effort were significantly reduced while still obtaining representative performance forecasts of the Pilot Project.

RESEVOIR PROPERTIES - ROCK

The reservoir properties assigned to the dynamic model were obtained from geostatistical models, laboratory investigations, core evaluations, geophysical log assessments, analytical work and equation of state (EOS) modelling. The vertical permeability in the model grid is shown in Figure 2. It should be noted that this permeability distribution simulated adequate pressure and fluid communication between the SAGD wellpairs throughout the model forecast.

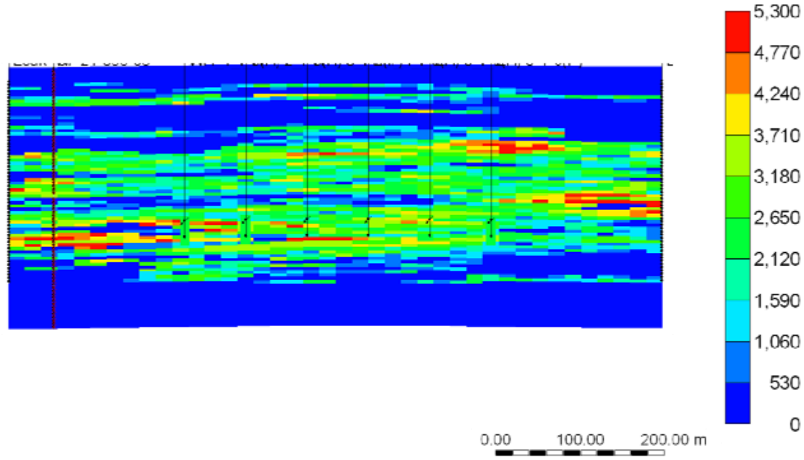

Figure 2 - Vertical Permeability in the Reservoir Model

Relative Permeability

Oil-water and gas-oil relative permeabilities, temperature dependency for critical fluid saturations and endpoint values were adopted from a previous simulation study of the Pilot Project (AOS, 2010). The oil-water relative permeability curve was subsequently modified so that fluid losses simulated during the 6-month, wellpair heating and circulation stage were between 20% and 30% of the maximum CWE steam injection rate, typical of fluid losses observed at other SAGD operations in Alberta. The irreducible water saturation for all rock types was assigned at 15% providing a CWE steam injection rate of about 260 m^3/d, or 23% of its maximum. The gas-oil relative permeability was not modified.

RESERVOIR PROPERTIES - FLUID

The reservoir fluids were represented by either four pseudo components (LP-SAGD) or five pseudo components (SLP-SAGD). The characteristics of these pseudo components were provided to the authors for the numerical study. Water, solution gas and solvent (C_3-C_7H) were each represented by one pseudo component. Bitumen was represented by two pseudo components, one heavy and one light, determined from laboratory testing and EOS modelling. The fluid PVT and viscosity properties are documented by AOS (2010).

Initial fluid saturations of the dynamic model show a gassy zone in the Upper McMurray Formation, with increased accumulations in the western region of the model grid (Figure 3).

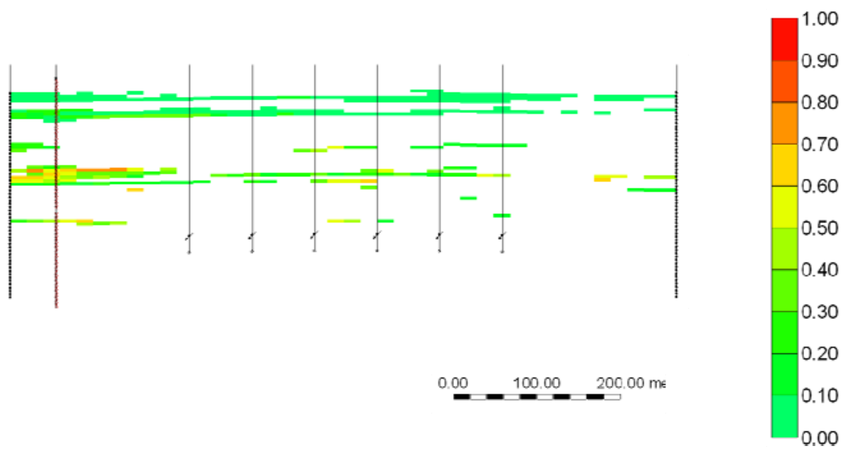

Figure 3 - Initial Solution Gas Saturation in the Reservoir Model

DEVELOPMENT STRATEGIES

Three development strategies were evaluated for the Pilot Project:

- LP-SAGD.
- SLP-SAGD.
- SLP-SAGD with wellpair blowdown commencing in Year 7.

MODEL CONSTRAINTS

Modelling constraints were assigned at the pilot-scale (Table 1) and wellpair-scale (Table 2).

Table 1 – Pilot-Scale Model Constraints

Case	Injection			Production
	CWE (m^3/d)	Solvent (m^3/d)	Stream (CWE-Solvent) (%-%)	Bitumen (m^3/d)
LP-SAGD	1,113	-	100-0	NA
SLP-SAGD	1,113	371	75-25	NA
SLP-SAGD w/bd	1,113	371	75-25	NA

Notes: NA - not applicable.

Facility constraint of 693 m^3/d bitumen not assigned to model.

Table 2 – Wellpair-Scale Model Constraints

Stage	Case	Time Period	Injection					Production		
			Total Fluid (m^3/d)	CWE Steam (m^3/d)	Solvent (m^3/d)	Stream (CWE-Solvent) (%-%)	MOP (kPa)	Bitumen (m^3/d)	wBHP (kPa)	Steam Production (m^3/d)
Heating and Circulation	All Cases	0-6m	20-30 %*	220-335	0	100-0	1,000	-	-	-
Production	LP-SAGD	6m-10 yr	200**	200**	0	100-0	1,000	NA	600	3
	SLP-SAGD		250***	187.5***	62.5***	75-25	1,000	NA	600	3
	SLP-SAGD w/bd	7yr-10yr	250***	187.5***	0	100-0	1,000	NA	600	3

Notes: *- During heating and circulation all wells are injecting to 20-30 % of maximum CWE injection rate.

** Maximum injection rate set at 200 m^3/d to limit some well pairs injecting more than others

*** Maximum injection rate of 250 m^3/d (75 % CWE 187.5 m^3/d and 25 % solvent 62.5 m^3/d).

NA - Bitumen production rate constraints not assigned to producing wells.

Pilot Project operation will likely undergo six months of wellpair heating and circulation prior to the onset of SAGD production. During this heating and circulation stage, 100% CWE steam is injected into the reservoir at a rate between 20% and 30% of its maximum and at the MOP of 1,000 kPaa. After this stage, the following injection constraints are assigned for the remainder of the 10-year forecast depending on the development strategy evaluated:

- LP-SAGD – 100% CWE steam (1,113 m^3/d).
- SLP-SAGD - 75% CWE steam (1,113 m^3/d) and 25% solvent (371 m^3/d).
- SLP-SAGD - 75% CWE steam (1,113 m^3/d) and 25% solvent (371 m^3/d) until Year 7. At this time, solvent injection is terminated.

Bitumen and solvent production are unconstrained.

Key Assessment Parameters

The key assessment parameters for evaluating and comparing the development strategies and model sensitivity study results were:

- Steam chamber development and temperature.
- CWE steam and solvent injection performances.
- Bitumen production rates, volumes and recovery.
- Instantaneous and cumulative SORs (ISORs and CSORs, respectively).
- Solvent recovery and loss.

FORECAST RESULTS

Fluid Injection

Fluid injection forecasts of the three development strategies are shown in Figure 4. The volumes of CWE steam injected into the reservoir were predicted at 3,943 x10^3 m^3 (LP-SAGD) and 3,981 x 10^3 m^3 (SLP-SAGD cases). After six months of wellpair heating and circulation, the injection rates for CWE steam and solvent remained constant for the duration of the model forecast. The total volume of solvent injected was 1,299 x 10^3 m^3 for SLP-SAGD and 892 x 10^3 m^3 for SLP-SAGD with wellpair blowdown commencing in Year 7.

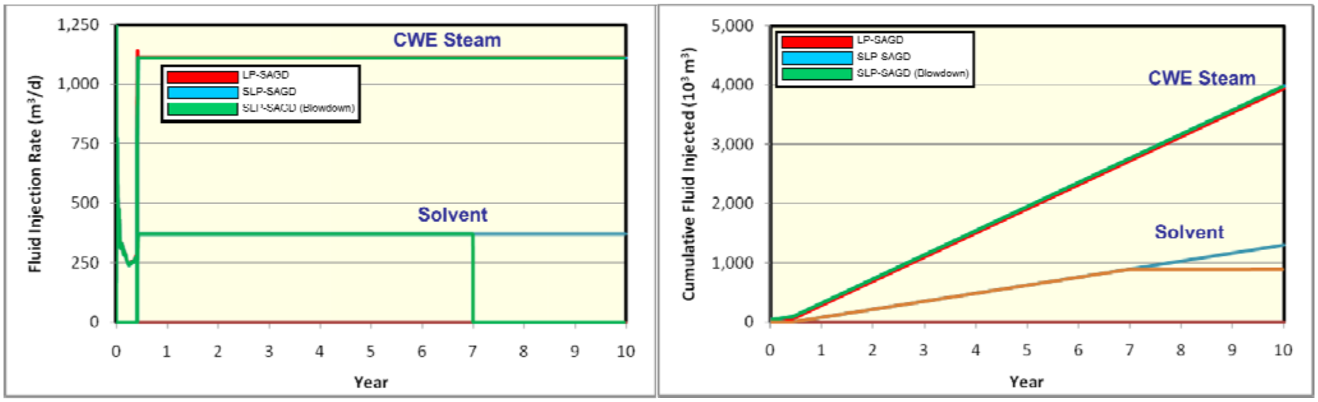

Figure 4 - Pilot-Scale, Fluid Injection

The simulated MOP for all injectors was equal to or less than, 1,000 kPaa. For all development strategies, the injection pressures were constant at 1,000 kPaa during the heating and circulation stage and afterwards reduced to between 580 kPaa and 620 kPaa for the remainder of the forecast period.

Steam Chamber Position and Reservoir Temperature

The steam chamber position and temperature distribution after 10 years of LP-SAGD and SLP-SAGD are presented in Figures 5 and 6, respectively. Evaluations show more lateral spreading of the heated zone towards the model boundaries when solvent was injected. Moreover, the temperatures of the heated zone between the SAGD wellpairs were slightly lower, and less continuous, for the SLP-SAGD case than for the LP-SAGD case. These temperature differences were primarily due to the differences in the mobility of the steam front in the bitumen phase and the increased lateral migration of solvent along the gassy zones.

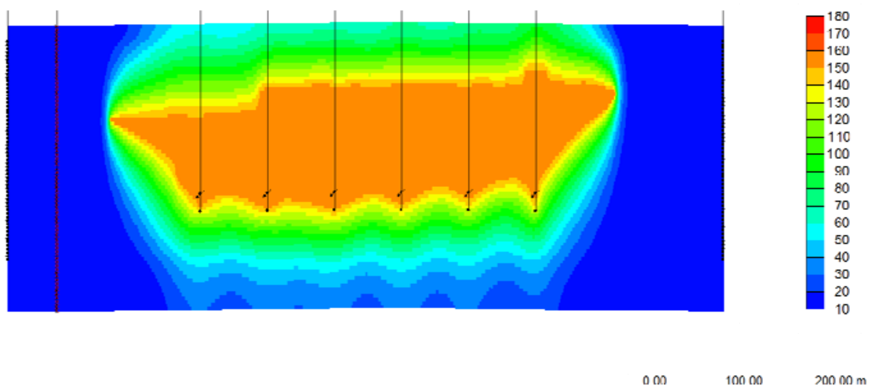

Figure 5 – Steam Chamber Position and Temperature after 10 years (LP-SAGD)

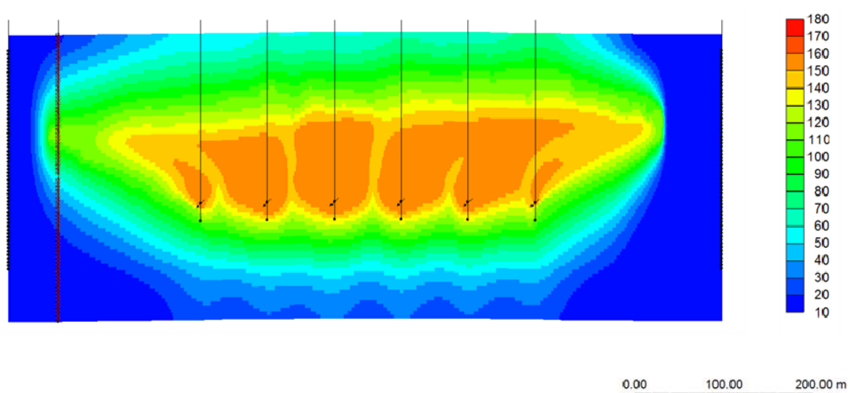

Figure 6 – Steam Chamber Position and Temperature after 10 years (SLP-SAGD)

Bitumen Production and Recovery

Simulated bitumen production and recovery are shown in Figure 7. For the LP-SAGD case, production rates gradually increased during the forecast period, attaining peak rates of about 550 m^3/d in Year 8. The SLP-SAGD cases indicated higher rates and accelerated oil production, especially during the first 5 years of Pilot Project operation. During this time the simulator calculated production rates between 2 to 4 times greater when solvent was injected. Peak oil production rates were attained in Year 4 (~1,200 m^3/d) and reduced thereafter, coinciding with increased fluid losses at the model boundaries. Initiating wellpair blowdown in Year 7 significantly decreased bitumen production for the remainder of the forecast period.

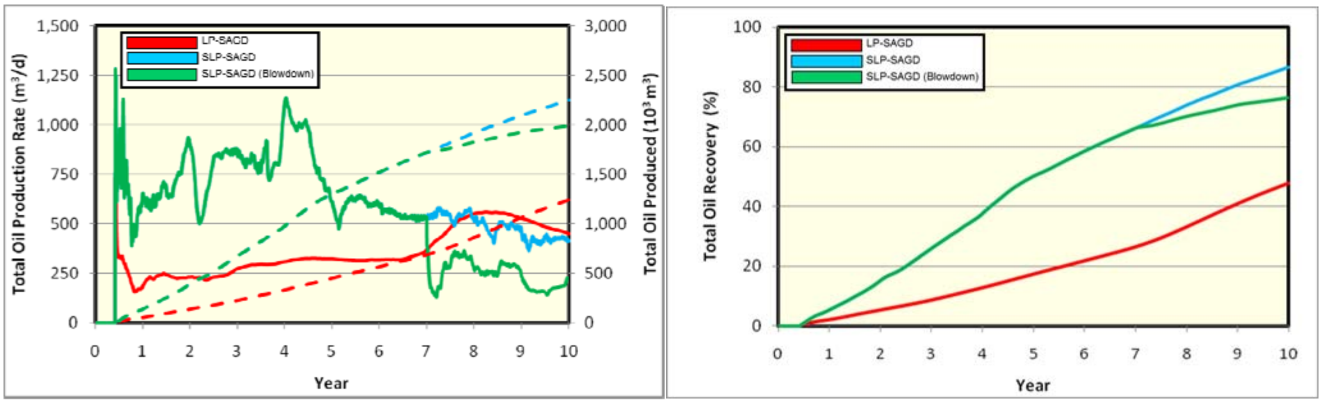

Figure 7 - Pilot-Scale, Oil Production and Recovery

The total volume of bitumen produced from the LP-SAGD development was 1,243x10^3 m^3, equivalent to 48% recovery. For the SLP-SAGD development, bitumen production was increased to 2,249x10^3 m^3, equivalent to 87% recovery. Incorporating wellpair blowdown at Year 7 reduced bitumen production and recovery to 1,986x10^3 m^3 and 77%, respectively.

SORs

The ISOR and CSOR forecasts are shown in Figure 8. Comparisons of SORs indicated that solvent injection significantly reduced ISORs and CSORs throughout the forecast period when compared to injecting CWE steam only.

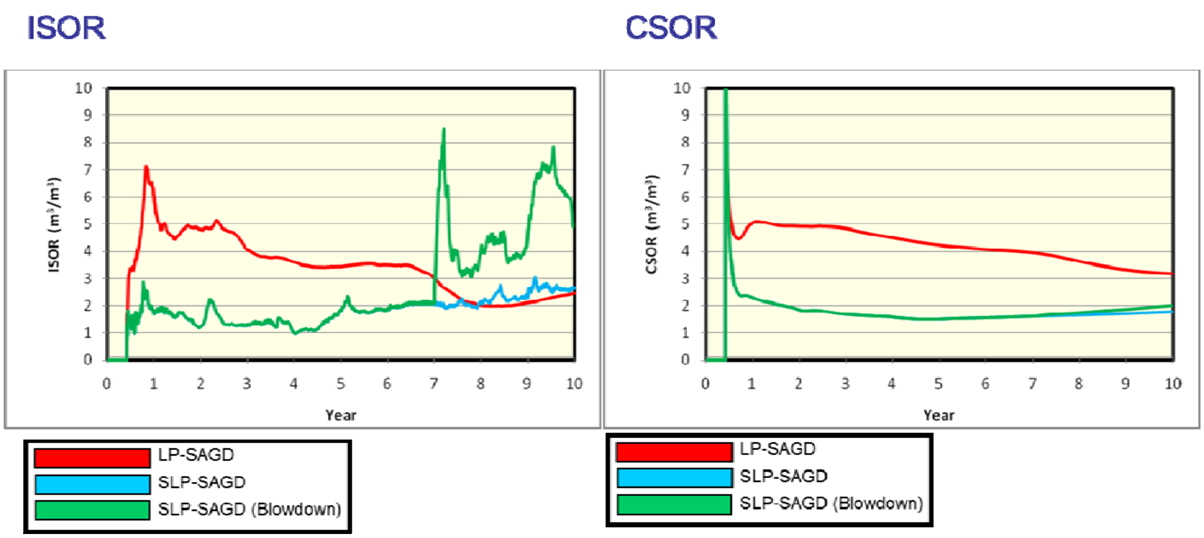

Figure 8 - ISOR and CSOR Performances

When only CWE steam was injected into the reservoir, the ISORs increased rapidly to 7 m^3/m^3 and after the first year gradually decreased thereafter to about 2.5 m^3/m^3 by the end of the model forecast. A similar trend was simulated in CSORs with values of about 5 m^3/m^3 during the first 3 years of Pilot Project operations and decreased thereafter to 3.2 m^3/m^3 by Year 10.

When solvent was co-injected with CWE steam, the ISORs fluctuated and gradually increased to nearly 3.0 m^3/m^3 by the end of the forecast period. The corresponding CSORs dropped after Year 1 to 1.8 m^3/m^3 by Year 10. Initiating wellpair blowdown at Year 7 flucuated and increased in ISORs from 3.0 m^3/m^3 to 8.0 m^3/m^3, with this trending continuing for the remainder of the forecast period. The corresponding CSORs gradually increased to 2.0 m^3/m^3 by Year 10.

Solvent Recovery and Loss

The predicted solvent recovery and loss are shown in Figure 9. As of Year 7, nearly 70% of the solvent injected in the reservoir was recovered. After 10 years, 77% of the solvent injected was recovered using SLP-SAGD. Incorporating wellpair blowdown at Year 7 marginally increased this recovery to 79%.

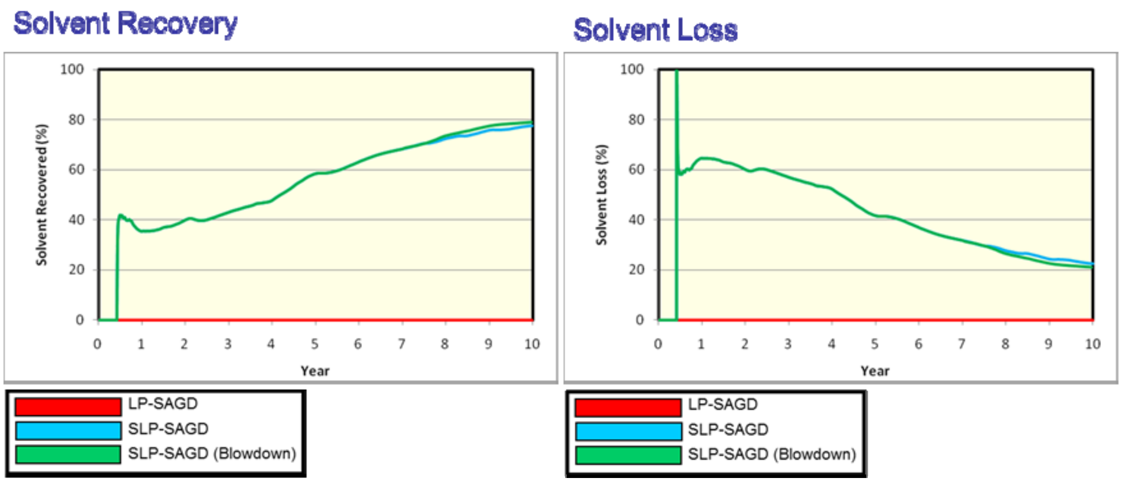

Figure 9 - Solvent Recovery and Loss (SLP-SAGD Cases)

Solvent remaining in the model grid after 10 years for the SLP-SAGD development is shown in Figure 10. Results indicate that most of the solvent was located along the perimeter of the steam chamber and in the gassy zones. These zones increased the laterally spreading of the steam chamber front towards the model boundaries. Continued migration of the solvent front and steam chamber eventually extended beyond the region of influence of the SAGD producers, thereby impeding solvent recovery.

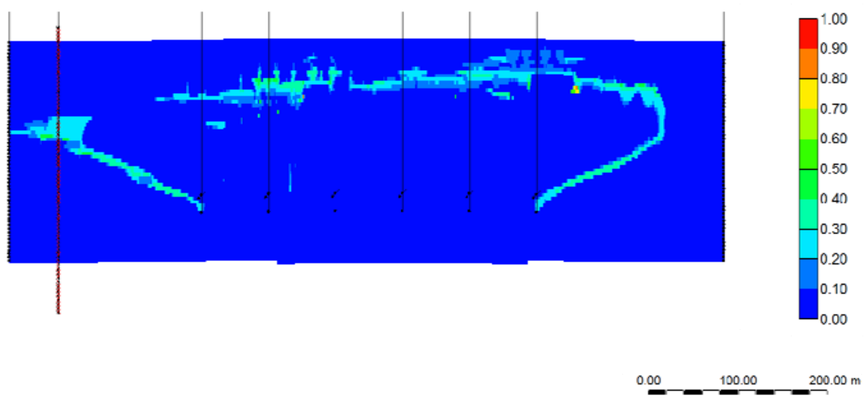

Figure 10 - Solvent Mole Fraction after 10 years (SLP-SAGD)

MODEL SENSITIVITY

The model parameters most influential to the Pilot Project performances were solvent injection, the occurrence of a gassy zone in the Upper McMurray Formation and the vertical permeability between the injector-producer wellpairs. Additional simulation studies were completed to determine the influence of other model parameters, which are listed below, on steam chamber development, oil recovery and solvent loss (Figure 11). The CSORs of these simulations were similar with Year 10 values predicted between 2.0 m^3/m^3 and 2.2 m^3/m^3 (AOS, 2010).

- Modified relative permeability to water.
- Increased threshold pressure at the model boundaries.
- Infill producer in the western region of the model grid.

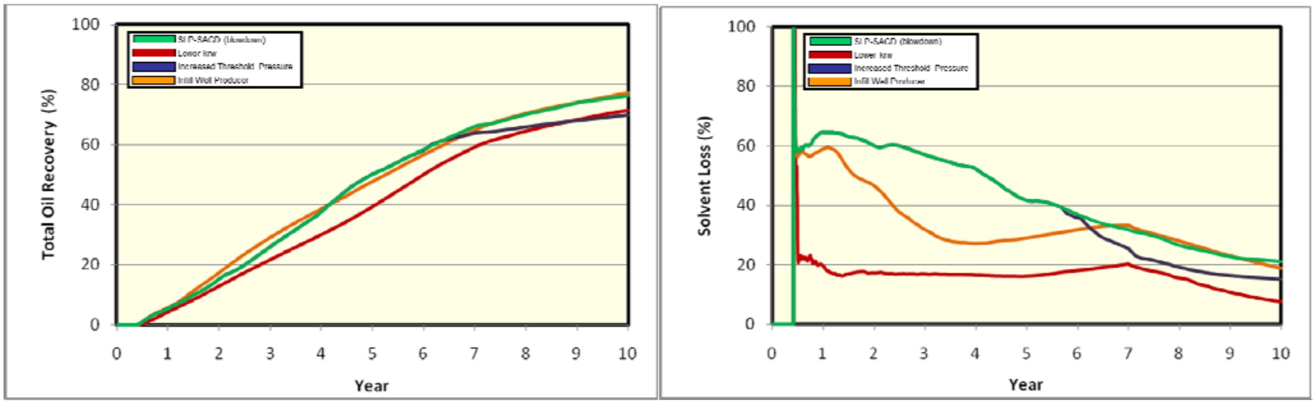

Figure 11 - Model Sensitivity Results for Oil Recovery and Solvent Loss

Modifying the oil-water relative permeability of the reservoir rock, notably impacted oil recovery and solvent loss. Increasing the irreducible water saturation to 25% improved solvent loss (8%), however decreased oil recovery (72%). The improvement in solvent recovery forecast is attributed to less solvent intercepting the gassy zones. The decrease in oil recovery is due to reduced steam chamber spread and region swept.

Increasing the minimum threshold pressure to about 744 kPa at the model boundaries was investigated even though this was not representative of *in situ* conditions at the Pilot Project. Simulation results show that increased threshold pressures and hence, reduced fluid leak-off at the model boundaries, simulates a more uniform steam chamber (less lateral migration and dispersion), when compared to lower threshold pressures (Figure 12). The predicted oil recovery and solvent loss were lower due to a smaller swept region and less solvent migration in the gassy zone.

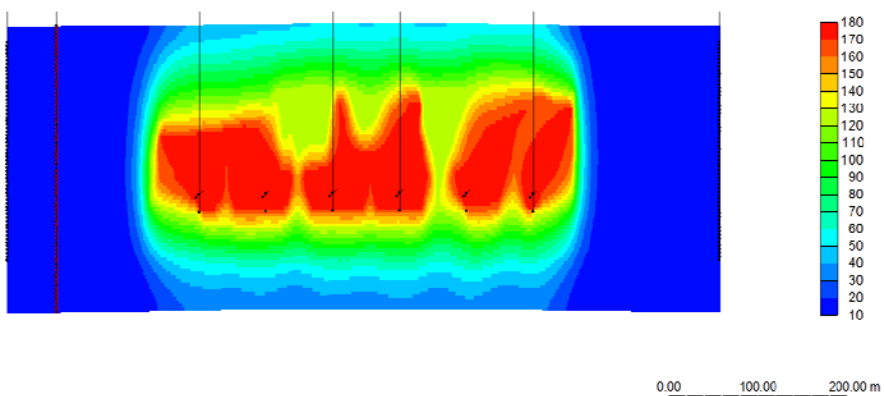

Figure 12 – Steam Chamber Temperature after 10 years - Increase Threshold Pressure (SLP-SAGD with Wellpair Blowdown)

Adding an infill well producer to the SLP-SAGD strategy, near the gassy zone of the western region of the model grid, improved solvent recovery; however, at the expense of bitumen recovered. It should be noted that the optimal location of the infill well producer performance was not determined and variations of this scenario would change forecast results.

SUMMARY AND CONCULSIONS

A 3D, pseudo-component, thermal, reservoir simulation study forecasting the 10 year performance for the proposed, Clearwater West Phase 1 Pilot Project was completed for a variety of development strategies using the simulation software, STARS™. The strategies investigated were LP-SAGD, SLP-SAGD and SLP-SAGD with wellpair blowdown starting in Year 7. The MOP for wellpair injection was 1,000 kPaa.

Forecast results demonstrate the advantages of co-injecting solvent with CWE steam at the Pilot Project. Injecting solvent improved sweep, increased oil recovery and reduced the CSORs during the 10 year forecast period, when compared to CWE steam only. Furthermore, co-injecting solvent nearly doubled bitumen recovery (87%) after 10 years of Pilot Project operation when compared to CWE steam only (48%). Solvent injection also successfully controlled CSORs, predicting a value of 1.8 m^3/m^3 after 10 years, notably lower than the corresponding CSOR of 3.2 m^3/m^3 determined from LP-SAGD. Incorporating wellpair blowdown after 7 years of SLP-SAGD operations reduced oil recovery to 77% and slightly increased CSOR to 2.0 m^3/m^3.

Solvent loss predicted for the SLP-SAGD strategy was 23% and when wellpair blowdown was implemented at Year 7, the corresponding value was slightly lower at 21%. These high solvent losses were attributed to solvent intercepting a gassy zone in the Upper McMurray Formation and migrating laterally towards the model boundaries outside of the region of influence of the well producers.

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NOMECLATURE

AOS	=	Alberta Oilsands Inc.
ARC	=	Alberta Research Council
CSOR	=	Cumulative steam-oil-ratio
CWE	=	Coldwater equivalent
ERCB	=	Energy Resources Conservation Board
EOS	=	Equation of state
ES-SAGD	=	Expanding solvent, steam-assisted gravity drainage
ISOR	=	Instantaneous steam-oil-ratio
LP-SAGD	=	Low pressure, steam-assisted gravity drainage
MOP	=	Maximum operating pressure
SAGD	=	Steam-assisted gravity drainage
SLP-SAGD	=	Expanding solvent, low pressure, steam-assisted gravity drainage

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