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Reservoir design of a shallow LP-SAGD project for *in situ* extraction of Athabasca Bitumen

C. PALMGREN, I. WALKER; M. CARLSON, M. UWIERA; M. TORLAK
Alberta Oilsands Inc RPS Energy Siemens AG

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Abstract

The Clearwater project is located 8 km southeast of Fort McMurray, Alberta, Canada. The project intends to demonstrate safe in situ production from a shallow bitumen reservoir and evaluate the commercial viability of combining different subsurface technologies to optimize bitumen production while minimizing water use. The project may produce up to 4,500 bpd of bitumen with a maximum of 7,000 bpd of high quality steam injection.

The paper describes the reservoir design for the in situ recovery of oil sands bitumen by use of Steam-Assisted Gravity Drainage (SAGD) technology. The McMurray Formation in the project area comprises a high-quality bitumen deposit of some 35 metres underlain by a bitumen rich lower permeability layer of some 15 metres thick. Six SAGD well pairs will be placed at the bottom of the high-quality deposit and infill wells will be placed at the bottom of the McMurray Formation to effectively recover the bitumen. The reservoir simulation results based on reservoir models from the geological, petrophysical and geostatistical work provide a significant range of outcomes for steam injection and bitumen production rates.

The base of the cap rock is located at a depth of some 65 metres. The details of the geomechanical field measurements and special studies that were executed to describe the cap rock materials and determine the safe maximum steam injection pressure of 1,000 kPa are presented in the paper. The application of SAGD at the lower pressure of 1,000 kPa results in both lower bitumen production rates and lower cumulative steam oil ratios compared with more conventional SAGD applications.

The analysis performed shows that combining SAGD technology with "solvent co-injection" and "electro-magnetic heating" can lead to significant uplift in bitumen production rates while further reducing the steam oil ratio. An overview is provided of both "solvent co-injection" and "electro-magnetic heating" techniques.

We intend to start steam injection and bitumen production in 2012. The paper concludes with a description of the planned reservoir monitoring techniques, the predicted field behaviour of the six well pairs of the Clearwater project and the best estimate economics of the project.

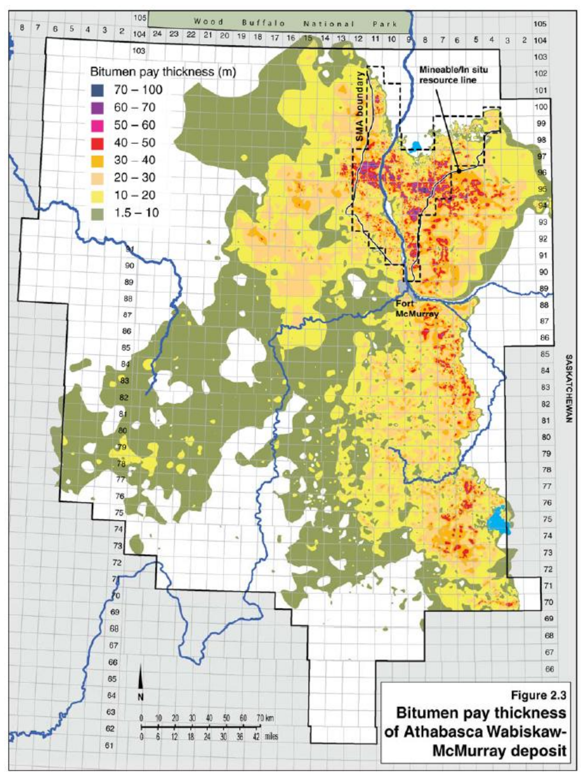

Figure 1. Athabasca Bitumen Pay Thickness

Introduction

The shallow Athabasca bitumen deposit in the Clearwater project area is known to contain some of the thickest sandstone bitumen pays in Alberta (Figure 1, Reference 1). The Clearwater project area contains some 351 million barrels Contingent Resources and Alberta Oilsands Inc (AOS) expects to produce 67.6 million barrels of Reserves (Reference 2) during Clearwater Phase I.

Clearwater Phase I will be located approximately 5 km southeast of Fort McMurray (Figure 2, Reference 3) and immediately north of Highway 69, which is the east-west highway that connects on to the main highway (Highway 63) from Edmonton to Fort McMurray.

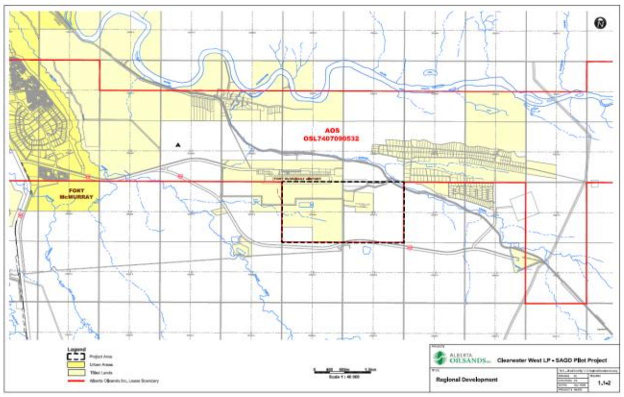

Figure 2. Location of Clearwater Phase I

Clearwater Phase I will consist of a Central Processing Facility and associated infrastructure complex including the oil production system, produced water handling, water treatment, steam generation, solvent generation, well pad site, storage tanks, storm water pond and flow lines. Access is readily available using an existing access road off Highway 69.

A geological model was created of the bitumen bearing formation and the overburden and the underburden using core drilling and seismic data. This model was then used to identify the optimal location for the horizontal wells based on the quality of the reservoir and the continuity of the bitumen. The identification of a thick estuarine channel sand trending through the Middle McMurray facilitated the choice of an optimal location.

Clearwater Phase I will initially consist of six parallel well pairs landed at the base of the estuarine channel above the Devonian unconformity. The horizontal section of these wells will be nominal 600 m in length and the well pairs will be spaced 75 m apart giving a drainage area of approximately 35 ha. After a number of years of solvent-steam injection and bitumen production, up to five “basement” wells will be drilled between the well pairs but landed lower in the reservoir close to the Devonian unconformity to increase the recovery of the bitumen resource and assist with recovery of solvent. A schematic depiction of the thermal scheme is shown in Figure 3. This configuration was chosen after reservoir simulations were completed on a number of alternative development scenarios.

AOS proposes to establish the commercial viability of solvent-assisted low pressure steam-assisted gravity drainage (SLP-SAGD) to recover bitumen *in situ*. This technology uses a solvent injected into the reservoir in conjunction with steam injection to optimize bitumen production Clearwater Phase I is expected to produce up to 695 m3/d (4,350 bpd) of bitumen and 165 m3/d (1,040 bpd) of solvent with daily dilbit sales of 928 m3/d (5,830 bpd). To meet these production goals a maximum of 1,113 m3/d (7,000 bpd) of steam combined with 183 m3/d (1,150 bpd) of solvent will be injected into the reservoir. The daily source water volume is 1,239 m3/d (7,790 bpd) and the water disposal volume is 1,130 m3/d (7,105 bpd).

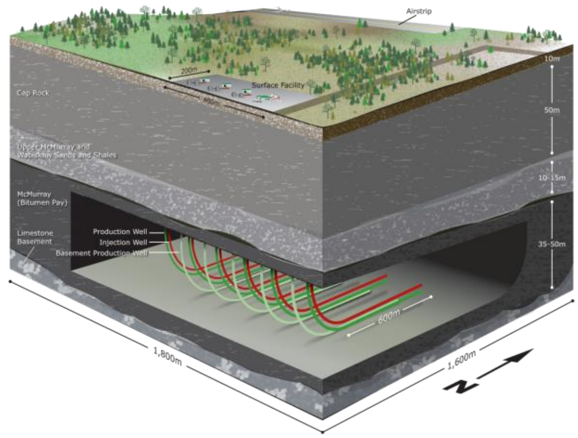

Figure 3. Artist view of Clearwater Phase I

A new technology termed electromagnetic low pressure SAGD (EMLP-SAGD) may also be tested on one of the well pairs. This technology is under evaluation and preliminary results are provided below. It is projected that the use of the SLP-SAGD recovery technology will lead to a reduction in water use, increased bitumen production, and reduced energy input compared to conventional SAGD projects.

Most of this paper and the technical work presented has been sourced from Reference 3.

Caprock integrity

The primary oil sands deposits in the Fort McMurray area lie within the McMurray Formation sandstones of Lower Mannville age. The McMurray Formation in this region consists of a number of fluvial and estuarine depositional environments, within a major incised-valley system. The overlying Wabiskaw Member represents a marine shore face system conformably overlying the McMurray Formation. The Wabiskaw Member may contain oil sands where it is present. Due to the poor quality of the Wabiskaw and the presence of a shale layer between it and the main McMurray bitumen pay, the Wabiskaw is not considered as net bitumen pay.

Based on extensive analysis of the caprock as described below, the Clearwater Phase I allowable safe operating pressure has been determined to be 1,000 kPa(a). All reservoir analyses and forecasts and the preliminary facility engineering work have been based on an operating pressure of 1,000 kPaa.

Caprock description

The Clearwater Formation is generally shale with interbedded silty to sandy mudstone. The caprock thickness ranges from 46 to 61 m and fracture sets forming a pervasive pathway system through the cap rock were not observed in the datasets evaluated (Reference 3). Core photos seem to indicate multiple horizontal fractures apparent in the caprock. The observed “horizontal fractures” are partings on the bedding planes of the mudstone that occur after bringing the core to surface where the overburden pressure is removed and the core becomes dehydrated.

Mini-frac tests on AA/05-22 and AB/09-21

The purpose of the mini-frac tests on multiple intervals in the AA/05-22 and AB/09-21 wells was to assess the rock stresses in the oilsand reservoir and above in the caprock. A stress analysis was done on minifrac (microfracture) data in the reservoir and its caprock in order to quantify the driving forces that exist *in situ* before the SAGD process begins. Oilsands and its adjacent formations are affected by the compressional tectonic strains resulting from the formation of the Rocky Mountains.

The analysis of the AA/05-22 mini-frac tests (see Figure 4) showed that the stresses in this well were anomalously low which was attributed to the proximity of down cutting erosion by the Clearwater River. This has resulted in very low reservoir pressures and stress relief. The analysis of the minifrac tests determined that the lowest principal stress was a horizontal stress (Reference 3). This means that any induced hydraulic fractures would be vertical or sub-vertical, and that the fracture gradient would be less than the overburden gradient. The magnitude of the overburden stress was measured to be higher than the fracture gradient, with the maximum horizontal stress appearing to be the largest stress in the caprock, but the intermediate stress in the underlying oilsands.

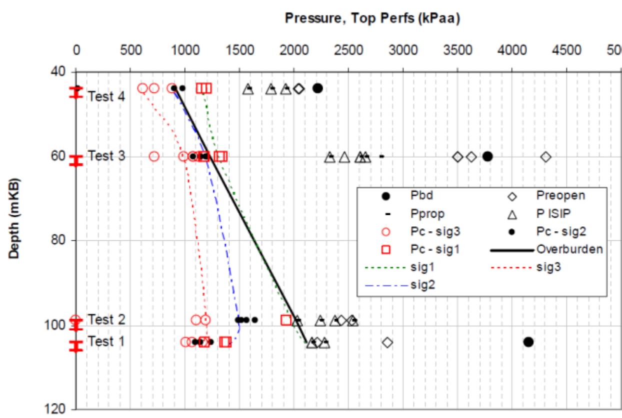

Figure 4. Mini-frac results for the 05-22 well

The AB/09-21 mini-fracs employ a mini-/micro-hydraulic fracturing stress test protocol that has been successfully audited by world-leading experts from global companies. The testing procedure contains modifications tailored specifically for use in the oil sands and heavy oil development. Before commencing testing, the target interval is perforated. Water is then injected directly down into the casing. Testing began at the lowest depth and a packer is set between two adjacent perforation intervals. Multiple injection and shut-in cycles are used during each test. The injection pressures were monitored on-site via two surface pressure sensors: one close to the pumps and the other at the wellhead. The current mini-/micro-hydraulic fracturing tests are the most reliable method to assess the in situ minimum stress. Via controlled well injection, it creates a fracture and propagates it to a sufficient distance from the injection well and into the formation. This ensures the fracture senses the far-field stress condition. Multiple cycles are run to verify the data consistency. The pressure data is analyzed to estimate the fracture closure pressure. The fracture closure pressure can then be equated to the in-situ minimum stress acting perpendicular to the fracture.

A flow-back procedure is also used during each test. For the flow-back, a certain volume of water is manually withdrawn from the injection system (wellbore plus the fracture) during the shut-in period. The fracture is thus able to close quickly and properly due to the manually reduced pressure drop.

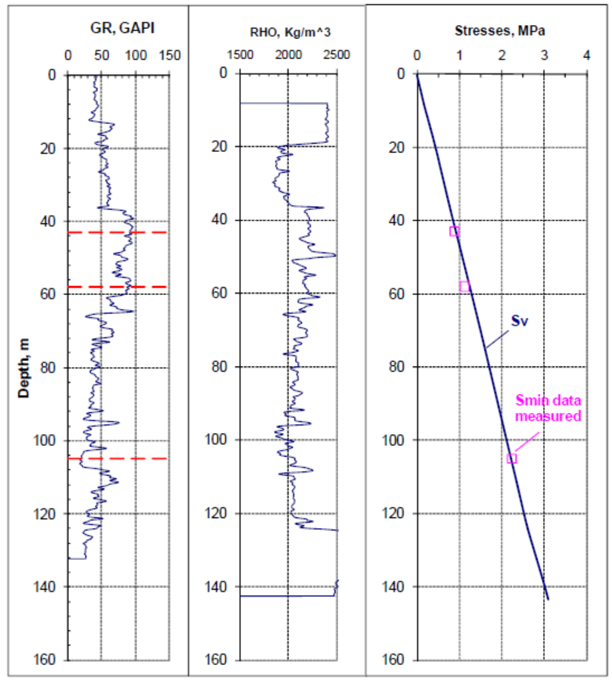

Figure 5. Mini-frac results for the 09-21 well

The mini-frac tests conducted at well 9-21 suggest that the tested depths, including the reservoir and its overburden shale, are all in the horizontal fracture stress regime. In general, such horizontal fracture stress regime is beneficial for maintaining the hydraulic integrity of the caprock. It means that in the unlikely worst-case scenario, if a hydraulically-driven fracture is inadvertently formed due to high injection pressures, the fracture would be horizontal and stay within the reservoir. Such a horizontal fracture would not create a channel extending to the surface or connecting the reservoir with shallower formations.

Geomechanical modelling

The objectives of this modelling investigation (Reference 3) are to determine a maximum operating pressure for the proposed pilot project that would maintain the integrity of the AOS asset throughout the duration of the LP-SAGD operation. In May 2006, the *in situ*, oil sands development industry experienced an unexpected and catastrophic failure at the Total Canada E&P (Total) operated, Joslyn Creek SAGD project. In light of this unexpected event, determinations of maximum operating pressures and caprock performances for proposed *in situ* projects are critical. Furthermore, detailed assessments the behaviour and deformation response of the reservoir and cap rock as well as estimates the potential surface heave that could result from SAGD operation are paramount for determining the maximum operating pressure for the development.

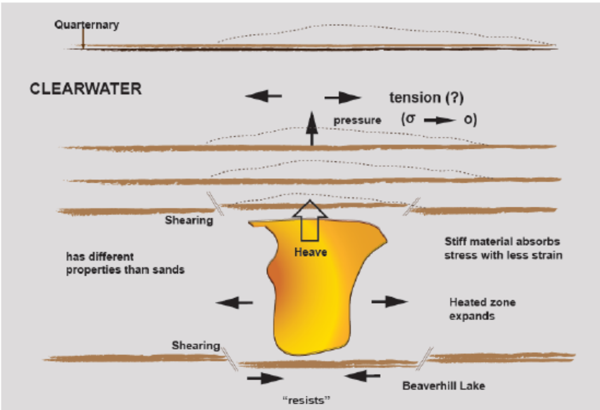

Figure 6. Main geomechanical mechanisms

The characteristics of the base case model and its results are summarized below. Further modelling studies may be required once the pilot project commences and performance data has been collected. The results of this conservative, geomechanical simulation study conducted indicate that an operating pressure of 1,000 kPaa should maintain the integrity of the AOS' asset throughout the life of the pilot project. Cap rock shear stress levels for the 1,000 kPaa operating pressure are 0.8, a 20 % margin, and corresponding factor of safety of 1.25. These values were determined using residual strength properties (with some cohesion added). If peak rock strength properties were used, the factor of safety would likely exceed 2.0.

The maximum surface heave over the drainage pattern is determined at 43 cm after 10 years of pilot operation. This is consistent with that measured at Suncor's MacKay River SAGD project. The base case model contains uniform geology and the real steam chamber likely would not be as well developed if geological variations were incorporated geostatistically. In reality, the amount of heave would likely be lower for the Clearwater Phase I SLP-SAGD project. The maximum surface heave reported at MacKay River, is based on the operation of 4 mature complete patterns, which is a higher level of development than that of Clearwater Phase I. Surface heave gradually decreases, radially outwards from its maximum values located above the well pairs. Surface heave is not predicted to extend to the Fort McMurray airport.

Diagnostic strain monitoring

Monitoring combines microdeformation diagnostics modeling with real time highly sensitive tiltmeter measurements (References 4, 5, 6 and 7) and space-based InSAR spatial coverage. The monitoring program serves to monitor shallow fluid migrations in real time to ensure cap rock integrity while operating the SAGD steam chamber and to provide precise surface heave measurements over a large area. This microdeformation technique for reservoir monitoring has been successfully utilized over the past 15 years in numerous worldwide applications where caprock integrity was a concern. Figure 7 provides a picture of the region of interest with an indication of the proposed monitoring instrumentation. Complete monitoring of the Clearwater Phase I horizontal wells is expected to require some 155 tiltmeter installations. GPS sites serve to monitor potential surface deformation and to anchor the tiltmeter array and provide long-term stability to the tilt-based measurements. One GPS station, shown to the southwest in Figure 7, is a reference station.

Tiltmeter density is determined as a function of the minimum mapping depth. Tiltmeter patterns spread out as a function of distance from the source so the surface deformation pattern from a shallow source tends to be confined to a smaller area. Between 6 to 10 tiltmeters are required to accurately identify and characterize a shallow fracture network. The confining caprock in this case is located at a very shallow depth of 65 meters, thereby requiring that the real-time tiltmeter density the instrument density must be particularly dense so as to adequately detect, characterize and mitigate potential events.

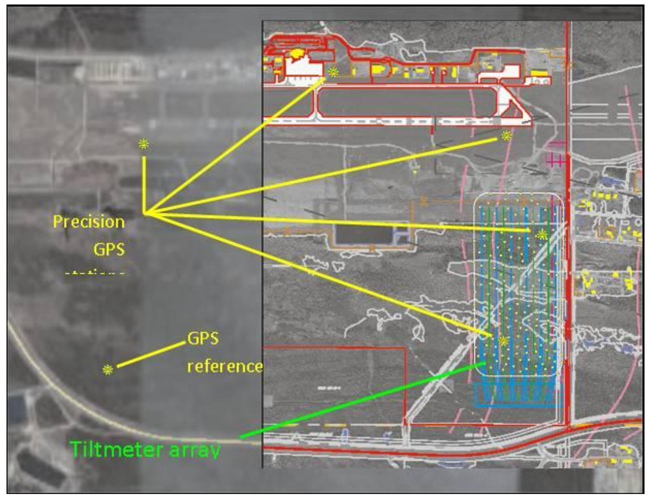

Figure 7. Area for diagnostic heave monitoring

The tremendous spatial capability of InSAR allows coverage of the entire pilot well area as well as the airport and surrounding areas. The entire area shown in Figure 7 may be covered. Radar reflectivity in areas with vegetation or other conditions may be augmented with corner reflectors, passive devices anchored to the ground that focus and redirect radar energy to the satellite.

Production Scheme

The commercially established *in situ* recovery method for the Athabasca oil sands is SAGD. AOS proposes to establish the commercial viability of SLP-SAGD as a modified approach to *in situ* bitumen recovery technology to optimize Clearwater bitumen production while reducing water and energy use. This method was selected due to the shallow nature of the McMurray reservoir in this region that requires a relatively low allowable operating pressure. In SAGD operations, a pair of stacked horizontal wells are drilled and landed within the reservoir to optimize the resource recovery. The top well in the horizontal well pair is a steam injection well located 4 to 5 m above the lower horizontal production well. The horizontal sections of both wells landed in the reservoir have a liner installed to eliminate hole collapse and sand intrusion from the unconsolidated sand reservoir. In the SLP-SAGD variant of *in situ* recovery, a solvent is added to the injection stream. The addition of solvent to the relatively low pressure steam injection is expected to further decrease the viscosity of the bitumen enabling economic production rates.

Reservoir geologic model

Statios Software and Services Inc. updated the Clearwater static geological model using all 23 core well data (logs, core analysis, ERT), Spectrum 2000 Mindware provided the petrophysical analysis. The geological model provides a probability based 3-D description of the interval between the bottom of the Clearwater Formation shale (considered the main caprock) and the top of the Beaverhill Lake Group. The 23 wells within the modelling area penetrate the entire reservoir interval. Basic information such as well location (X and Y co-ordinates), Kelly-Bushing elevation, and bottom depth (BD) is available for all the wells. Most wells have a complete suite of logs that include gamma ray, caliper, neutron porosity, bulk density, and resistivity. In addition, some wells have spontaneous potential (SP) and photoelectric factor (PEF) logs as well as conductivity and compressional sonic logs. FMI logs were also recorded and interpreted in five wells.

Cores were taken for all wells and conventional core analyses were performed. The core-testing program was comprehensive and the heterogeneities within the reservoir interval were well represented within the cores. These core analyses were used to calibrate the petrophysical log interpretation. Combined interpretation of FMI and core photographs resulted in the development of a representative set of sedimentological facies. These facies were further compared to the petrophysical interpretation to define their rock property characteristics

The facies categories take into account not only the descriptive aspect (texture and internal structure) of the facies and their association and localization within the interpreted depositional environment, but also their rock quality characteristics (shale content, porosity and permeability). Regional knowledge of the depositional environment was applied to constrain the lateral extension of the genetic facies within the model.

The variable thickness of the shales in the Upper McMurray over the study area formed the main reason to consider them as secondary potential cap rock and not as the primary seal for steam containment. The shale of the Clearwater Formation constitutes the primary cap rock.

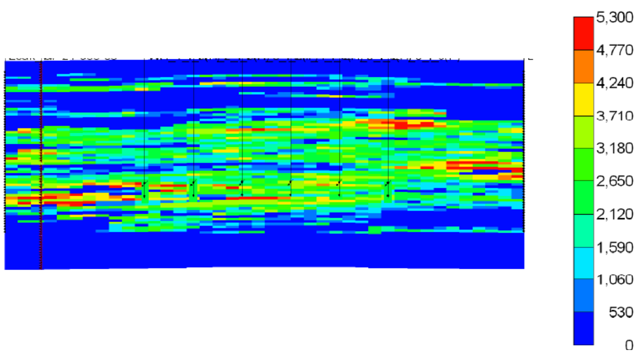

Figure 8. Vertical permeability across the well pairs

The rock property distribution was carried out by applying the facies model as a basis for control. The vertical permeability distribution depicted in Figure 8 is provided as an example (Reference 3). Each property distribution was studied for individual facies, and populated independently within the different facies. Rock properties were distributed in a consistent manner relative to one another.

Gassy zones are prevalent throughout the McMurray Formation in Sections 21 and 22. The gassy zones contain up to 50% bitumen saturation and appear to be non-correlatable between wells. Special care was exercised when distributing and validating the gassy zone distribution in the 3-D static geological model.

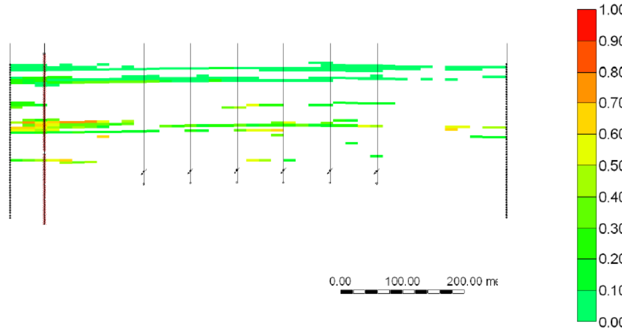

Figure 9. Gassy zone distribution across the well pairs

Production predictions for SLP-SAGD

The static geological model was imported into CMG's pre-processor Builder and a sub model of the area of interest was extracted in order to reduce the number of blocks and hence the simulation time. During construction of the reservoir simulation model it was thought that relevant geological heterogeneities would be preserved if the grid blocks perpendicular to the direction of the horizontal wells are refined into 1 m blocks. This was also deemed appropriate to capture the conductive and convective heat transfer that affects a typical SAGD process.

Calculations were performed for the combined pilot well pad. This combined PAD comprised six low pressure SLP-SAGD well pairs located some 75 m apart and oriented from the south to the north with nominal well lengths of 600 m. The simulation model assumed continuity of the gassy zones outside of the pad drainage area. Sufficient off-set and leak-off wells at the outer boundaries were used to capture the effect of extended gassy zones on the *in situ* bitumen recovery process. If the gassy zones prove to be of lesser extent it is expected that pilot results in terms of bitumen produced and solvent lost will improve compared to the model predictions. AOS is planning to use AVO analysis of the seismic data and to attempt a gas injectivity test into a gas zone in a well to be drilled this winter. The purpose of these activities is to determine the size, continuity, and flow characteristics of these gassy zones.

The current plan is to place the six well pairs near the bottom of the estuarine channel to ensure that the well pairs can be started up successfully. Start up is successful if the effective well length coincides with the full length of the well pair and the steam chamber is allowed to grow upwards and sideways into the reservoir in the near wellbore region without many impediments. The bottom of the estuarine channel is located several meters above the Devonian unconformity. The placement of future "basement" production wells between the well pairs ensures that a large part of the resource located between the bottom of the estuarine channel and the Devonian unconformity is captured. Pilot recovery factors are calculated using the Middle McMurray resource from the SLP-SAGD production wells and up.

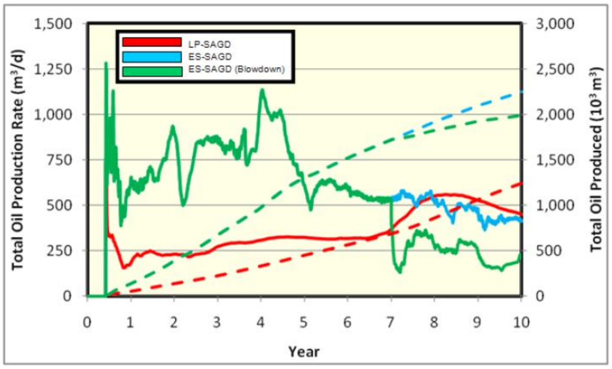

Figure 10. Predicted oil production rate

The illustrated simulation results represent the application of SLP-SAGD in all six well pairs but do not include recoveries from the basement wells. The volume of oil produced after 10 years of pilot operation using LP-SAGD is 1,243x103 m3, equivalent to a 48% oil recovery. The total volume of CWE steam injected is 3,943x103 m3, resulting in a cumulative SOR (CSOR) of 3.2 sm3/sm3.

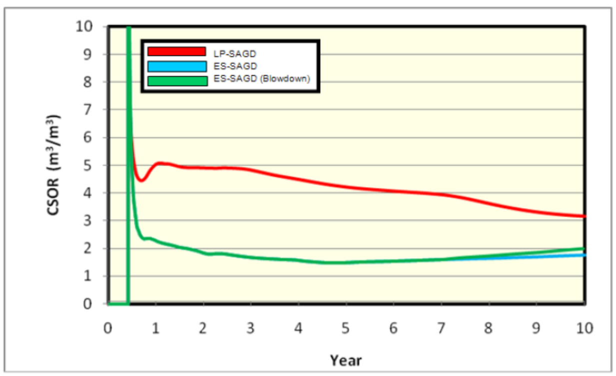

Figure 11. Calculated SLP-SAGD CSOR

For the solvent-assisted SAGD development, the total volume of oil produced after 10 years of pilot operation is 2,249x103 m3, equivalent to an 87 % oil recovery. The total volume of CWE steam and expanding solvent injected into the reservoir are 3,981x 103 m3 and 1,299x103 m3, respectively. The CSOR predicted after 10 years is 1.8 sm3/sm3.

The production forecast for the SLP-SAGD development with asset blowdown commencing Year 7 produces 1,986x103 m3 of oil, about a 77 % recovery after 10 years of pilot operation. The corresponding CWE steam and solvent injected into the reservoir are 3,981x103 m3 and 892x103 m3, respectively. The CSOR predicted after 10 years is 2.0 sm3/sm3. This increase in CSOR, when compared to ES-SAGD without asset blowdown, is attributed to the termination of solvent injection.

Steam chamber expansion

Detailed reservoir monitoring using diagnostic techniques described above and conventional vertical well multi-point pressure and temperature observations as well as fully instrumented horizontal wells is expected to provide relevant and sufficient insight on scheme progress. Predictions indicate that about 80% of the solvent injected will be recovered prior to well blowdown. The solvent is located in the bitumen remaining between the well pairs and solvent is also located close to the edges of the steam chamber. The predicted steam chamber expansion after 10 years of continuous SLP-SAGD operations is provided in Figure 12. The gassy zones serve to distribute the steam preferentially laterally between wells and steam injection pressure, steam injection rate, fluid withdrawal rates and production well subcool need to be balanced continuously to ensure efficient and effective operations. Detailed simulation work is currently underway to identify an optimum operating strategy.

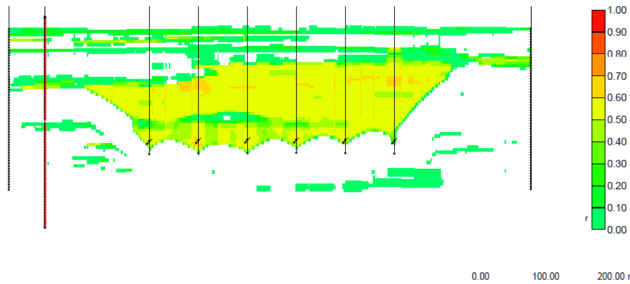

Figure 12. Predicted gas/steam saturation after 10 years

Predicted improvement using EM-SAGD

The newly developed of the EM-SAGD technology by SIEMENS AG (Reference 8) is to provide additional heating process for the reservoir with less steam consumption. The EM-SAGD heating process requires an inductor loop placed in the reservoir, typically around a well pair as shown in Figure 13.

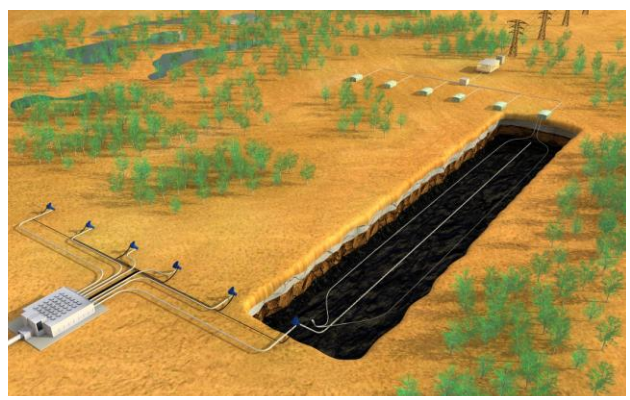

Figure 13. Artist impression of EM loop with on the left hand the well pad and the right hand top the induction loops power feed

Alternate current in the inductor loop, with a typical frequency of 50-100 kHz, generates electromagnetic field in the reservoir due to electric conductivity of the water in the reservoir. The arising eddy currents convert the energy into the heat.

During the process development stage, electromagnetic heating has been sucessfully tested in two experimental facilities (References 8 and 9). In parallel to that, computer simulations have been developed for optimization of the performance in the reservoir conditions. Simulations are done using two-way coupling between the reservoir simulator CMG STARS and a solver for electro-magnetic field propagation. The coupling is performed in adopted time periods, providing the updated data exchange between the two programs.

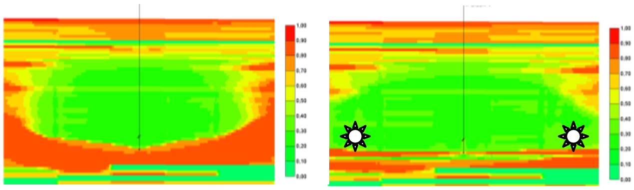

Figure 14 Oil saturation after 10 years: SAGD (left) and EM-SAGD (right). White symbols indicate the positions of the inductors.

Preliminary simulations of the Clearwater reservoir have shown superior performance of EM-SAGD over the typical SAGD process, both from the economical and the environmental point of view. Two operational modes of EM-SAGD were simulated: with and without solvent. The predicted oil production from one single well-pair (as this is supposed to be used in a possible pilot test) for EM-SAGD without solvent is about 350,000 m^3 and with solvent about 400,000 m^3 after 10 years, while a typical SAGD process delivers about 290,000 m^3 of oil for the same period. EM-SAGD allows oil recovery from the lower reservoir layers which are not typically captured by the steam chamber with SAGD as shown in Figure 14.

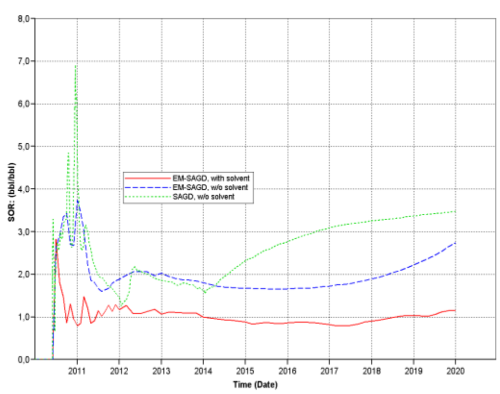

Figure 15. Comparison of steam-oil ratio (SOR) for EM-SAGD and SAGD process

The steam-oil ratio (SOR) of EM-SAGD with solvent is about 1 on average, without solvent about 2, while SOR of SAGD is between 2 and 3 (see Figure 15).

In conclusion, the newly developed in-situ production technology of Siemens supports the opportunities and chances of profitable oil sand bitumen production, dealing with the key operational challenges

1) Cost effective production;
2) Energy efficiency;
3) Environmental footprint.

The technology is based on inductive heating, which enables thermal production. The electric power can be controlled between 0% and 100%, allowing temperature or/and pressure controlled operation. The goal is to heat up bulk volume in-situ up to the point of sufficient mobilization, depending on viscosity of bitumen, i.e. up to 150°C. This allows significant heat loss reduction to overburden and underburden, compared to SAGD, where temperature - in the range above 250°C - cannot be controlled.

Clearwater Phase I benefits

Clearwater Phase I is expected to demonstrate that AOS can safely operate an *in situ* bitumen development scheme on the Clearwater Lease. The Project is also expected to confirm the economic viability of the SLP-SAGD recovery method in this shallow Athabasca bitumen reservoir. An initial indication of the commercial success of the Project lies in the results obtained during the one to two year ramp up stage. The ramp up of the bitumen production rate after the circulation phase together with detailed analysis of comprehensive reservoir monitoring will provide indications of SLP-SAGD performance. Any technical or operational learnings in the early period of the Project will be incorporated into calibrated simulations.

Using the Project performance information and calibrated simulations, AOS would apply to construct Phase II of this project to increase the capacity to produce between 2,400 to 4,000 m3/d (15,000 to 25,000 bpd). In addition, AOS expects to continue the evaluation of more cost-effective and environmentally enhanced surface and subsurface production technology or combination of technologies during Phase II. An optimum placement of the Phase II central processing facility is based on an optimum use of existing infrastructure in combination with buried pipelines and minimum surface disturbance for well pads, steam generation and emulsion collection satellites.

According to conceptual timelines for Clearwater Phase II, first production from the Phase II central processing facility can occur as early as 2016. Decommissioning of the Phase I Project plant is then possible as early as 2018. If Phase II does not proceed, AOS expects to operate the Phase I Project for approximately 10 years.

Using an estimated capital of $100 million until first steam and an estimated working capital of some $20 million to positive cash flow, the expected Net Present Value of Clearwater Phase I using SAGD only is $148 million and using SLP-SAGD is $219 million for a 10% rate of return.

Conclusion

Reservoir design requires the combined industry knowledge and oil sands experience of numerous experts in a variety of subsurface disciplines. Some aspects of the technical work behind the Clearwater Phase I reservoir design has been summarized in this paper. Several appendices of Reference 3 provide all the technical details.

In conclusion, Clearwater Phase I presents an excellent reservoir that requires special attention in the area of caprock integrity and steam chamber confinement. The reservoir model captures relevant subsurface characteristics to predict the SAGD and SLP-SAGD recovery processes in terms of injection and production rates and steam chamber expansion. Caprock integrity demands comprehensive field measurements, detailed laboratory measurements and collation of all information in a geomechanical modeling exercise to determine the safe maximum operating pressure. The 05-22 mini-fracs combined with detailed geomechanical modeling showed that an operating pressure of 1,000 kPaa should maintain the integrity of the AOS' asset throughout the life of Clearwater Phase I. The 09-21 mini-fracs corroborated the initial results for the safe maximum operating pressure. A reservoir monitoring scheme has been developed to enable direct and continuous feedback to ensure safe operations. The measurements can be used to align predictions with field behavior.

The simulation analysis shows that solvent co-injection is capable of significantly increase the injection rate and the recovery in the drainage area while at the same time reducing the CSOR from 3.2 for SAGD to 1.8 for SLP-SAGD which is shown to significantly improve project economics.

The EM-SAGD process needs field testing but initial analysis indicates a further reduction of the CSOR to 1.

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NOMENCLATURE

CWE	=	Cold Water Equivalent
CSOR	=	Cumulative Steam Oil Ratio
EM	=	Electro-Magnetic
SAGD	=	Steam-Assisted Gravity Drainage
SLP	=	Solvent-assisted Low Pressure

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