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Findings from a Solvent-Assisted SAGD Pilot at Cold Lake

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Abstract

ExxonMobil and Imperial Oil Resources (Imperial) are conducting a Solvent Assisted - Steam Assisted Gravity Drainage (SA-SAGD) experimental pilot at Cold Lake in the Clearwater formation where up to 20% by volume of hydrocarbon solvent (diluent) has been injected along with dry steam in a dual horizontal well SAGD configuration.

Experimental work performed by the Alberta Research Council (ARC) (Nasr, 2003) and Imperial indicated that addition of solvent to steam increases bitumen rates and decreases steam-oil ratios relative to the conventional SAGD process. The main objective of this pilot has been to produce high quality field data to definitively support these experimental conclusions.

The pilot scope includes two horizontal well pairs (four wells), six observation wells, associated steam and diluent injection facilities, artificial lift, as well as, dedicated production measurement and testing facilities. The SA-SAGD pilot uses existing steam generation, water treatment, bitumen separation and processing facilities at Imperial's Mahkeses plant and existing steam distribution and production gathering systems.

The main focus of this paper is to document the integrated approach taken to ensure that this multi-year pilot is successful and to provide information resulting from this multi-year pilot. Key surveillance products, such as, production/injection measurements, horizontal-well temperature logs, observation-well temperature and saturation logs, time-lapse 3D seismic, and the impact of a mid-pilot solvent switch will be discussed. In addition, this paper will review how these surveillance products are integrated with laboratory data and simulation efforts to improve our understanding of this process and increase confidence in go-forward predictions.

Given the emerging importance of solvent-assisted thermal heavy-oil processes and the accelerated conversion of this technology from laboratory-scale to field-scale, data from a field pilot provides invaluable information in the quest to deploy this emerging in-situ recovery technology.

Introduction

In-situ bitumen production in Alberta has increased over the past 10 years to more than 1 million barrels per day, of which approximately 50% is produced from Steam-Assisted Gravity-Drainage (SAGD) projects (Alberta Government ST-53 Report). However, ongoing challenges, primarily related to reservoir quality and environmental regulations, continue to encourage technology improvements to the conventional SAGD process.

Experimental work and computer modeling, both analytical and numerical at lab scale (performed by ARC and Imperial) indicate that addition of solvent to steam increases bitumen rates and decreases steam oil ratios relative to the conventional SAGD process. However, pilots are required to understand the incremental benefits at field scale. Prior to approving the significant expenditures for this effort, ExxonMobil and Imperial optimized the development and operating plan for this SA-SAGD pilot to reliably measure the uplift expected from the SA-SAGD process (Perlau, 2011), recognizing that the uplift could easily be masked by measurement errors, operational issues and impacts from geology.

Imperial Oil and ExxonMobil use a systematic, staged evaluation process for all new developments and pilot testing can play a key role in this process. Best practices from previous pilots (Leaute, 2005; Teletzke, 2008), and the successful LASER pilot in Cold Lake (Leaute, 2002), were adopted for the SA-SAGD pilot.

The pad was commissioned in late 2009 and the two well pairs successfully transitioned to SAGD operation in July 2010. Solvent injection commenced in late 2010 and continues to this date.

Pilot Location

The decision to pursue a dedicated pilot located within Imperial's existing Cold Lake operating area, approximately 300 km NE of Edmonton (Figure 1), was made early in the pilot planning process. This decision recognized the advantages of integration into a reliable facility with competent operational support. However, proposing a SA-SAGD pilot, to be operated at native reservoir pressure in the Clearwater formation, adjacent to an active, high pressure CSS operation presented challenges that needed to be addressed. Effective down hole spatial separation from existing CSS well bores, and between the pilot's two well pairs, was important to ensure isolation from any localized reservoir influences so that each well pair could operate independently and provide uncompromised data.

The prioritized pilot site selection criteria were: 1) minimum of 15 m of clean bitumen pay zone in the Clearwater formation, with effective standoff from bottom water; 2) low risk of encountering thermal or pressure influences from adjacent CSS wells in the Clearwater formation; and 3) surface pad location adjacent to existing steam and production pipelines and lease roads. After a detailed review of a large number of potential location, a site that best matched the selection criteria was chosen in the south-east corner of Imperial's Cold Lake development area (Figure 2) and is now known as Mahkeses T13 pad.

Wells and Facilities

The plan view of the T13 pilot area (Figure 3) shows the approximate scale of the pilot and proximity to the closest CSS wells drilled from T10 pad. Six vertical OB wells were drilled in the centre of the pilot area to better quantify the local reservoir description and bottom water standoff. The first four vertical OB wells were drilled, cored and a full suite of open hole logs run (including dipmeter) in late 2005. Two additional OB wells were similarly drilled, cored and logged in March 2007. To supplement the geology data set further, the entire T13 reservoir area was included in a regional 3D seismic program to provide the base line for future 4D seismic programs specific to the pilot area. All six OB wells were cased to surface (177.8 mm) so gyro surveys could be run before the installation of the coiled tubing thermocouple strings.

The four horizontal wells, originating from T13 pad, had to be drilled accurately along trajectory tracks over existing CSS wellbores prior to entering the Clearwater formation. Tight target constraints within the Clearwater reservoir also needed to be honored. The horizontal sections needed to avoid expected concretion units, maintain constant TVD elevations and provide variable lateral offset distances from the vertical OB wells. Coiled tubing strings containing thermocouples and bubble tubes were run during the completion of the horizontal wells to provide real time temperature and pressure monitoring during pilot operations. The eastern-most wellpair (T13-01 and T13-02), referred to as wellpair #1 (WP1) and the western-most wellpair (T13-03 and T13-04), referred to as wellpair #2 (WP2) were drilled in 2008.

One of the objectives of this pilot is to safely obtain high quality operating data to aid in the interpretation of pilot results. To accomplish this objective, dedicated production testing facilities were installed to accurately meter and sample the production. Onsite facilities for steam separation, production cooling, and solvent truck offloading and storage were also required. A schematic showing the basic process flow and surface facilities, including meters and sampling points, is presented in Figure 4. Figure 5 is a picture of the T13 surface facilities.

High pressure wet steam from the Mahkeses plant is let down at the inlet to the steam separator at T13 pad. Dry steam (99+% quality) off the top of the separator is metered (group and individual well heel and toe) and routed to the two injector well heads. Solvent (diluent) is pumped through a filter and metered prior to routing through a heat exchanger and into the heel and toe steam injection lines upstream of each injector wellhead. All steam rates are converted to Cold Water Equivalent units.

The production wells are equipped with conventional bottom-hole pump and rods while the casing flows are controlled with a back pressure regulator. The pump jacks are equipped with Corpac Variable Frequency Drive units to capture pump cards for calculating inferred tests. The two producer wells are cycled through the test facilities on a twenty-four hour rotational basis.

Produced fluids from the tubing string are cooled to approximately 130^{o}C prior to arriving at the test separator (V-8004) where chemicals are added to enhance separation. Fluids exit either the water leg or the oil leg on this vessel and are metered and sampled before being co-mingled and metered again on route to the group line. The combination of redundant metering, inferred testing and water cut data from manual samples increases confidence in the liquid production test results.

Casing gas is cooled in the vent gas cooler to approximately 40^{o}C to enhance liquids drop out in the dedicated vent gas separator (V-8003) and improve testing accuracy. Separate metering on the three outlet streams from this vessel is designed to increase confidence in the gas and entrained liquids test results.

There are a total of five outlet streams from the two test vessels. Each outlet is equipped with either a mass or flow meter and either a manual sampling point or a proportional sampler. A rigorous sampling program complements the data obtained from the testing facilities and provides the input data for the analysis of solvent recoveries. The process developed by Leaute (Reference 6), is used to quantify the solvent recovered during the pilot timeframe.

Operating and Surveillance Plan

The primary technical goals of the Cold Lake SA-SAGD pilot are to: determine a SAGD 'baseline' in the Clearwater Formation at 3600 kPa operating pressure, and determine the incremental effect(s) of solvent addition to the performance of SAGD. To accomplish these goals and minimize the impact of process variability on the analysis of the pilot results, some operating tactics were defined in advance of pilot start-up. These tactics consisted of only one wellpair on SA-SAGD operations at-a-time, at least one solvent switch during the duration of the pilot, injection rates controlled to meet a constant injection-pressure target, and production rates controlled to achieve both a constant sub-cool target and a relatively constant fluid level between the producer and the injector. The latter was achieved by monitoring temperatures along the well, the subcool at the heel of the well, water production up the annulus of the well, and casing temperatures at surface.

The pilot surveillance plan was developed using internal best-practices guidelines. Since the pilot goals deal primarily with maximizing technical learnings, as opposed to maximizing economic value, the surveillance objectives emphasize attaining high quality operating data and cost effective diagnostic data.

The pilot surveillance plan consists of two sections - operating data monitoring and reservoir performance monitoring, however, in reality these activities were occurring simultaneously. The operating-data monitoring encompassed the following areas:

- Process control
- Measurement
- Well testing
- Data integrity and quality control
- Performance data
- Sampling protocol
- Diluent sampling and quality control
- Well effluent sampling

The reservoir-performance monitoring encompassed the following areas:

- Horizontal well (injector and producer) pressure and temperature data
- OB well temperature data
- Sample analyses to determine diluent concentration
- 3D seismic (time-lapsed)
- Reservoir saturation monitoring using cased hole neutron logs

Operational Performance

Acquisition of high quality data from any pilot is highly dependent on reliable and repeatable measurements. For the T13 SA-SAGD pilot, several aspects of the facilities design and operating plan were instrumental in ensuring acquisition of high quality data. These considerations included:

- Solvent storage capacity must consider solvent delivery schedule and tank drawdown rates
- Accurate measurement of reproduced solvent volumes from all vapour and liquid streams is critical
- Redundant water-cut measurement is a useful QC tool
- Accurate estimates of variability in delivered steam quality is critical when designing steam separators
- Reproduced solvent in vent-gas system can substantially reduce and/or eliminate vent-gas separator free-gas volumes resulting in test-vessel measurement and operational complications
- Bitumen density a good measure of reproduced liquid-phase solvent concentration
- Rod pump inferred testing (dynamometer cards) provides an independent check on production rates
- Production and injection upsets can yield valuable surveillance data
- Steady-state behavior can take months to achieve especially in mid-life operations
- Injected solvent must yield volume uplift well in-excess of process variability and measurement uncertainty

- Mid-pilot solvent switch (switching solvent injection from one well-pair to the other) is the most definitive method to assess impact of solvent

Wellpair Performance

Both well pairs commenced SAGD operations in July 2010, and WP2 commenced SA-SAGD operations in October 2010. As shown in Figure 6, WP2 ramped up to 25-30 m3/d of diluent injection over the first few months (~ 20% of steam injection rates). Steam and solvent injection was suspended in the fourth quarter of 2011 for other field maintenance activities. Solvent injection ceased in May 2012 to switch solvent injection over to WP1 (aka "solvent-switch") and WP2 continued to operate in SAGD mode. Water production tracked steam injection during the pilot period indicating minimal water storage and/or connate-water mobilization. Figure 7 illustrates the WP1 injection rates and water production profile during the same time. This wellpair commenced solvent injection in June 2012 ("solvent-switch") and quickly ramped up to 25-30 m3/d of diluent injection (~ 20% of steam injection rates). Suspension of steam-and-solvent injection also occurred in the fourth quarter of 2011 for other field maintenance activities. Water production and water-steam-ratio (WSR) performance was similar to WP2.

Liquid hydrocarbon rates (bitumen + reproduced diluent), instantaneous steam-oil-ratio (iSOR) and cumulative steam-oil-ratio including warm-up steam (cSOR) for WP2 are shown in Figure 8. During SA-SAGD operations, the production rates progressively increased from 40 to 75 m3/d and the iSOR maintained a constant level of 3-4 m3/m3. Although not shown in the figures, the solvent recovery is in agreement with expectations. Solvent recovery for WP2 is greater than 75% to-date. After the solvent-switch, the rate and iSOR performance changed rapidly. Although this performance is consistent with our expectations, some of this degradation in performance is due to near-wellbore pressure drops ("skin") around T13-03. A review of this skin behavior is detailed below. The T13-03 producer continued to produce during the Q4 2011 injection shut-in resulting in the rate and iSOR variability observed during that time. The same performance parameters for WP1 are shown in Figure 9. This wellpair established a consistent SAGD performance baseline prior to the solvent-switch with production rates between 25-30 m3/d and an iSOR of 5.5 m3/m3 (during 2012). After the solvent-switch, the production rate and iSOR both showed clear evidence of a solvent response. As with WP2, the WP1 producer remained on-stream during the Q4 2011 injection shut-in resulting in the rate and iSOR variability observed during that time.

As illustrated in Figure 10 and Figure 11, the injection pressures were maintained at a constant level except for the Q4 2011 injection shut-in. Producer casing pressures also remained relatively constant during this period but it should be noted that these pressures are equal to the surface separator back-pressures and are not the same as the flowing bottomhole pressures (FBHP). As stated previously, WP2 has experienced an increasing near-wellbore pressure drop in T13-03. For much of the pilot period, this pressure drop did not interfere with the operations of WP2 as the FBHP was higher than the surface separator pressure ensuring that a fluid column was maintained above the pump. However, during the latter part of 2012 the FBHP declined to the point where this fluid column could not be sustained and gas interference effects became apparent. These effects complicate interpretation of the post solvent-switch production decline for WP2.

Temperature, Saturation, and 4D Seismic Data

Thermocouple arrays in all six OB wells and the four horizontal wells were installed to monitor arrival and growth of steam chambers in the observation wells; and to assess conformance and subcool in the horizontal wells. Figures 12a and 12b are examples of the evolution of the steam chamber growth as observed in OB-B1. Figure 12a contains time-lapse snapshots of the vertical temperature profile (y-axis) versus time (x-axis) in this observation well referenced against a density log and the bitumen mass-fraction estimates derived from the core data. Figure 12b is a continuous depiction of the growth of the steam chamber in this well versus time.

Temperature profiles in the well pairs were also monitored to assess SAGD and SA-SAGD performance characteristics as well as wellbore conformance. An example of the wellbore temperature profiles for WP2 is shown in Figure 13. Both diagrams display color-shaded temperatures along the length of the well on the x-axis against time on the y-axis. All thermocouple measurements are shown including the measurements in the build section in the wellbore (as referenced at the top of the chart). The injection well temperatures (left hand plot) indicate a relatively consistent temperature profile along the length of the well with the Q4 2011 injection shut-in (and other minor injection shut-ins) showing up as cooling events. The impact of the solvent switch is expressed in this plot as a slight increase in injection temperature. This behavior is consistent with predicted behavior associated with a switch from SA-SAGD to SAGD operations.

All six OB wells had baseline cased-hole saturation logs run prior to the start-up of steaming operations at T13. Subsequent logs were run in 2012 to evaluate the development of the steam chambers in these wells and to assess the differential performance of SAGD versus SA-SAGD performance. Figure 14 contains an example of the results from this logging program for OB-B1. In general, the vapor saturated intervals in these repeat saturation logs were consistent with the thermocouple temperature profiles and showed low residual-bitumen saturations for both SAGD and SA-SAGD operations.

A baseline 3D seismic survey was also obtained prior to the start-up of steaming operations at T13 and the first repeat 3D survey was obtained in 2012. As illustrated in Figure 15, the steam chamber appears to be relatively well developed along the length of both wellpairs and the conformance was very consistent with the temperature measurements from the observation wells. There are no significant differences in the steam conformance patterns between the two well pairs.

Integration with Laboratory and Simulation Efforts

An integrated research program has been implemented in order to progress the SA-SAGD technology from the laboratory to the field and to better quantify the benefits of SA-SAGD over SAGD. This integrated research program includes fundamental laboratory work, advanced numerical simulation studies, scaled physical laboratory models, and the two well-pair field pilot referenced in this document. Each individual component of the research program is important and provides useful information concerning the SA-SAGD process. However, only by bringing the various pieces together are we able to assess the full recovery potential for SA-SAGD (Dickson, 2013a).

Scaled Physical Experiments

Over the past four decades, ExxonMobil and Imperial have utilized scaled physical models to test various heavy oil recovery processes, including SAGD (Butler, 1981) and LASER (Leaute, 2002). These models are invaluable and provide a tool with which a range of operating conditions can be tested in a timely and affordable manner. Currently, the physical models have been used to quantify the impact of such parameters as operating pressure, solvent concentration, and solvent composition on SA-SAGD performance. The experiments have been performed under typical Athabasca and Cold Lake oil sands reservoir conditions. A picture of the current physical model is shown in Figure 16. The rectangular box measures 100x60x20 cm and is filled with glass beads as the porous media (Khaledi, 2012).

Numerical Simulation

Using an in-house thermal simulator, both the scaled physical model and the pilot were history matched. The ultimate goal of the pilot history-match exercise was to calibrate the flow simulation model in order to: aid in interpreting the field data, improve the simulator predictive capabilities, and tie together the results from the field and laboratory. Figure 17 shows the history match results for the total hydrocarbon production rates and the instantaneous SORs for each well pair in the Cold Lake SA-SAGD pilot. A complete discussion of the pilot history match is provided elsewhere (Dickson, 2013b).

Summary

The following summary comments are offered:

1. All pre-defined operating tactics were used during the three year operation of the SA-SAGD pilot including only one wellpair on SA-SAGD operations at-a-time, at least one solvent switch during the duration of the pilot, injection rates controlled to meet a constant injection-pressure target, and production rates controlled to achieve both a constant sub-cool target and a relatively constant fluid level between the producer and the injector.
2. ExxonMobil and IOR’s first field trial for SA-SAGD has clearly shown the positive impact of solvent injection on bitumen production and SOR. The field results show an increase in bitumen rate and a decrease in SOR during SA-SAGD operation relative to SAGD.
3. Establishment of SAGD baseline performance characteristics are an essential step in determining the SA-SAGD uplift characteristics.
4. Rigorous attention to field surveillance data-gathering, and rigorous analysis of these data is essential to the development of a high-quality field database and provides real-time opportunities to enhance pilot performance.
5. Integration of field-pilot data with laboratory scale measurements and reservoir simulations is essential to the preparation of a high quality predictive SA-SAGD capability.

Acknowledgements

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Nomenclature

SAGD = *Steam-Assisted Gravity Drainage*
SA-SAGD = *Solvent-Assisted SAGD*
LASER = *Liquid Addition to Steam for Enhancing Recovery*
CSS = *Cyclic Steam Stimulation*
OB = *observation*
4D = *time lapse 3D*
CWE = *cold water equivalent*
VFD = *variable frequency drive*

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Figure 1-- Map of the major oil sands in Canada and the location of Cold Lake and the ongoing SA-SAGD pilot.

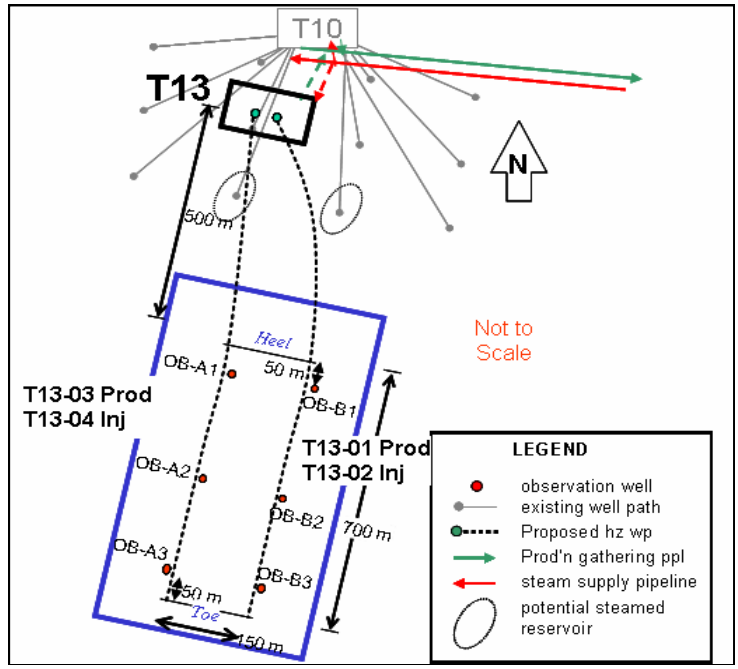


Figure 3 -- T13 pilot schematic.

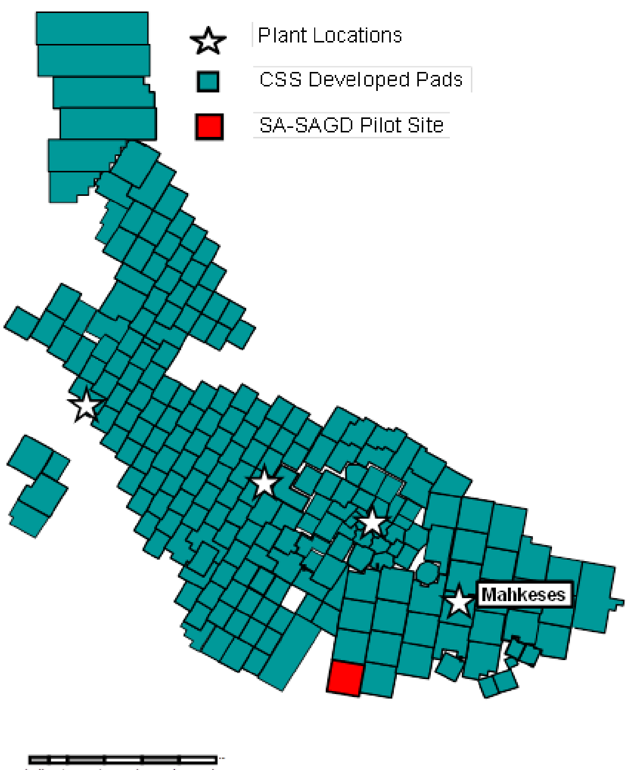


Figure 2 -- Cold Lake field layout.

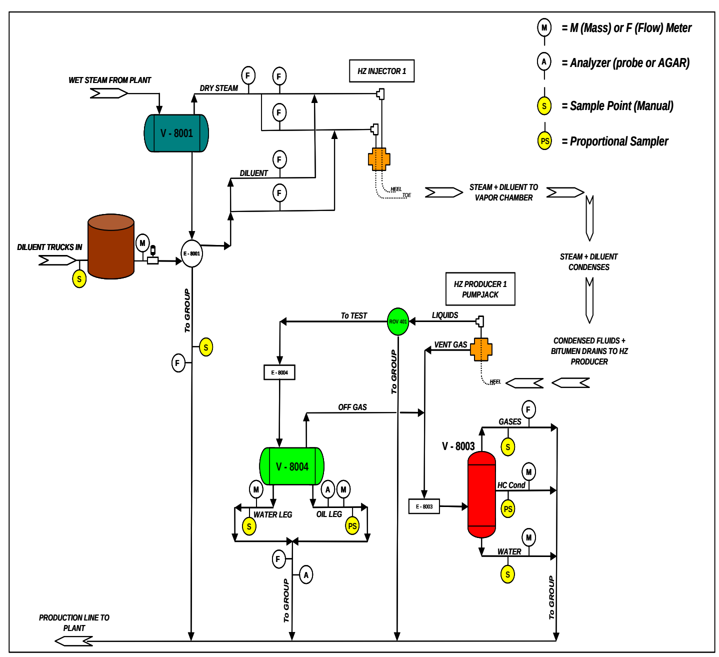


Figure 4 – Process-flow and metering schematic.

Figure 5 – T13 surface facilities.

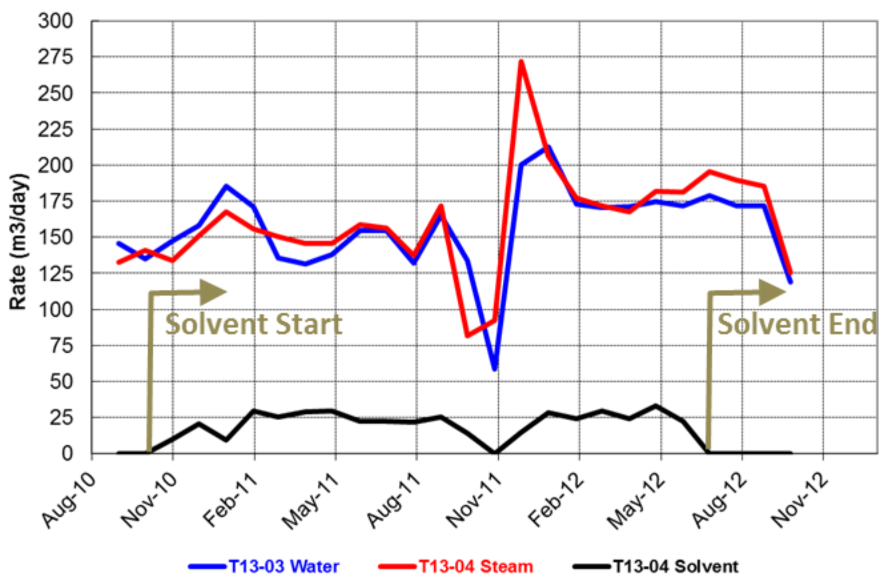


Figure 6 – WP2 injection rates and water production profile.

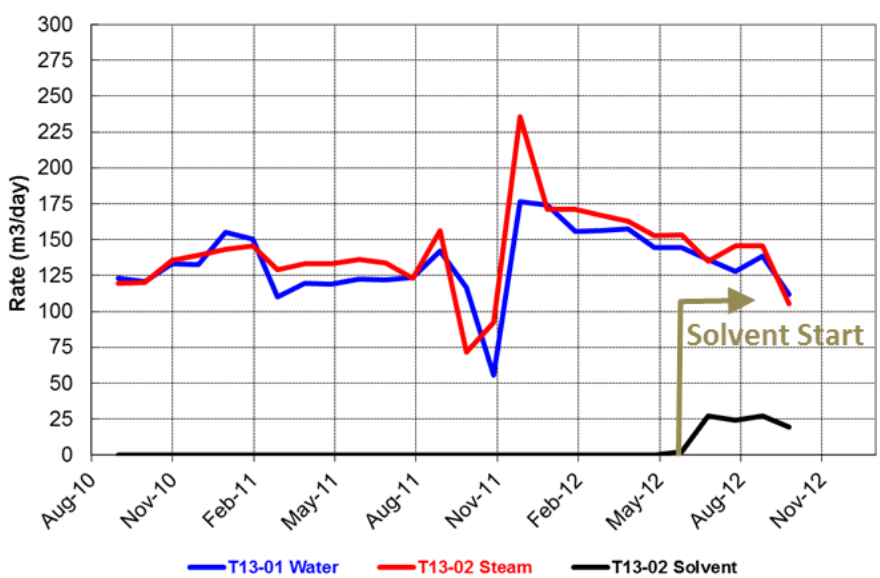


Figure 7 – WP1 injection rates and water production profile.

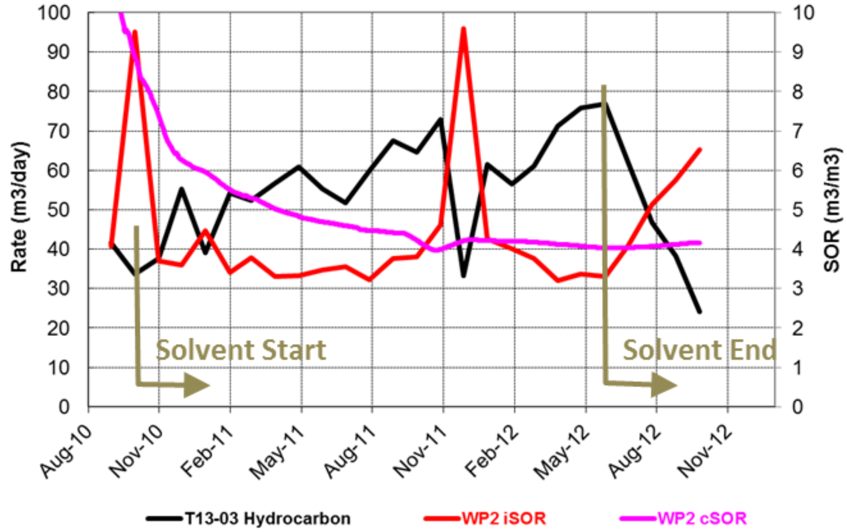


Figure 8 – WP2 liquid hydrocarbon rates and instantaneous SOR.

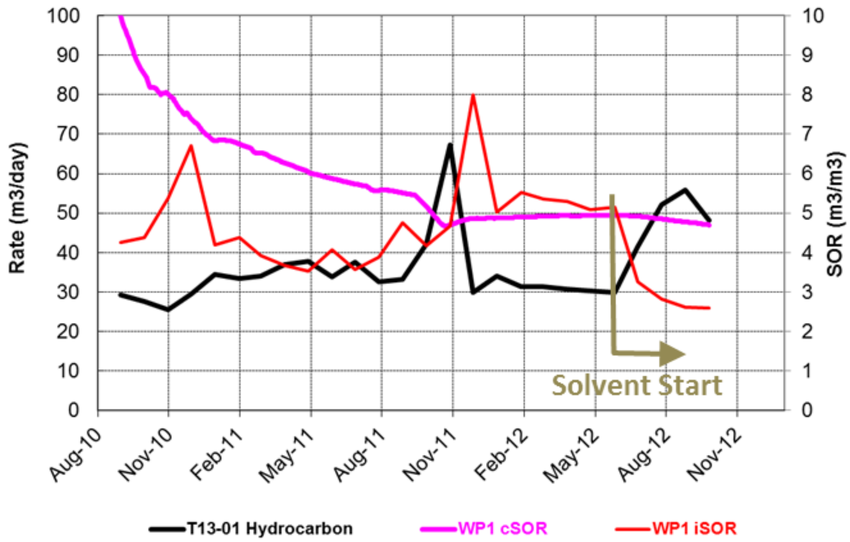


Figure 9 – WP1 liquid hydrocarbon rates and instantaneous SOR.

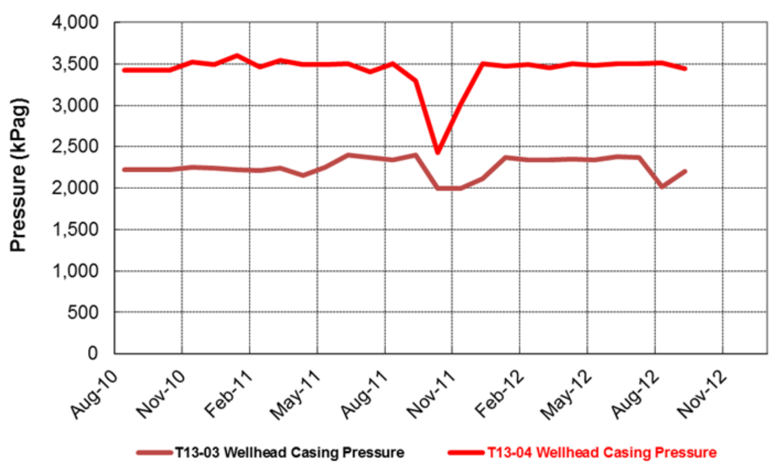


Figure 10 – Wellhead pressures for WP2 injector and producer.

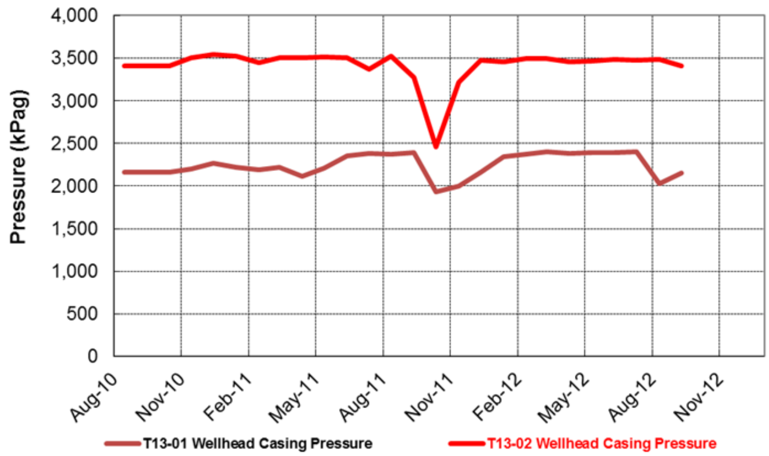


Figure 11 – Wellhead pressures for WP1 injector and producer.

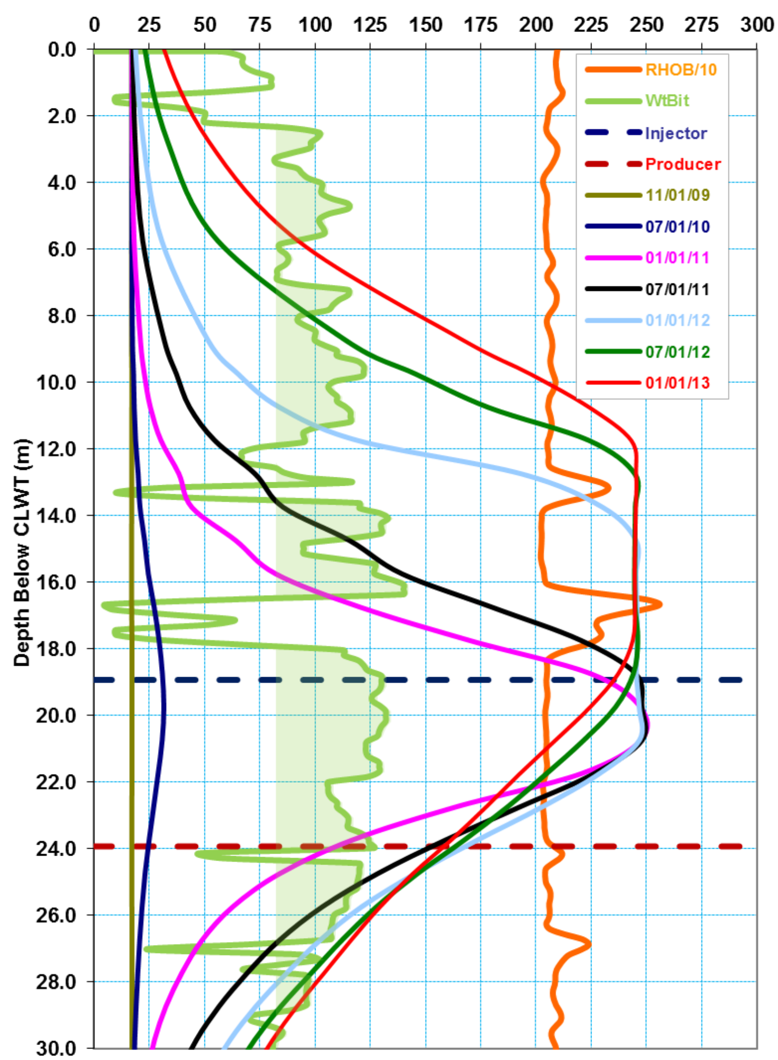


Figure 12a – Time-lapse OB-B1 temperatures overlain on open-hole density and bitumen mass fraction data.

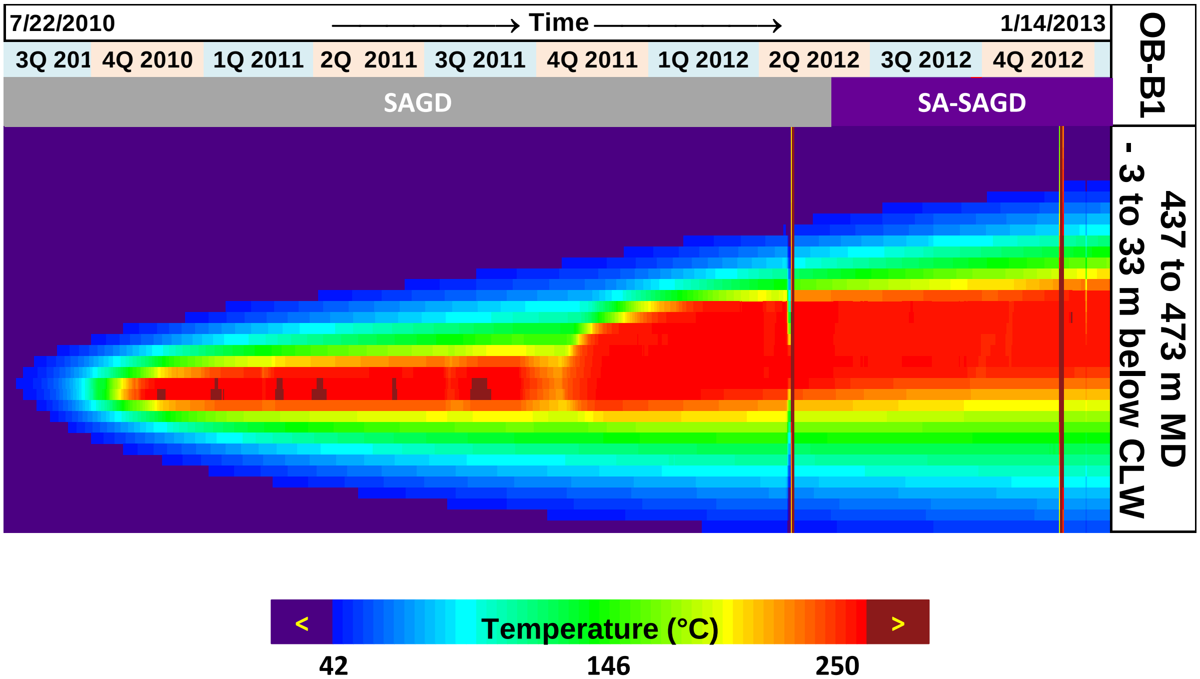


Figure 12b – Time-lapse wellbore temperature profiles OB-B1.

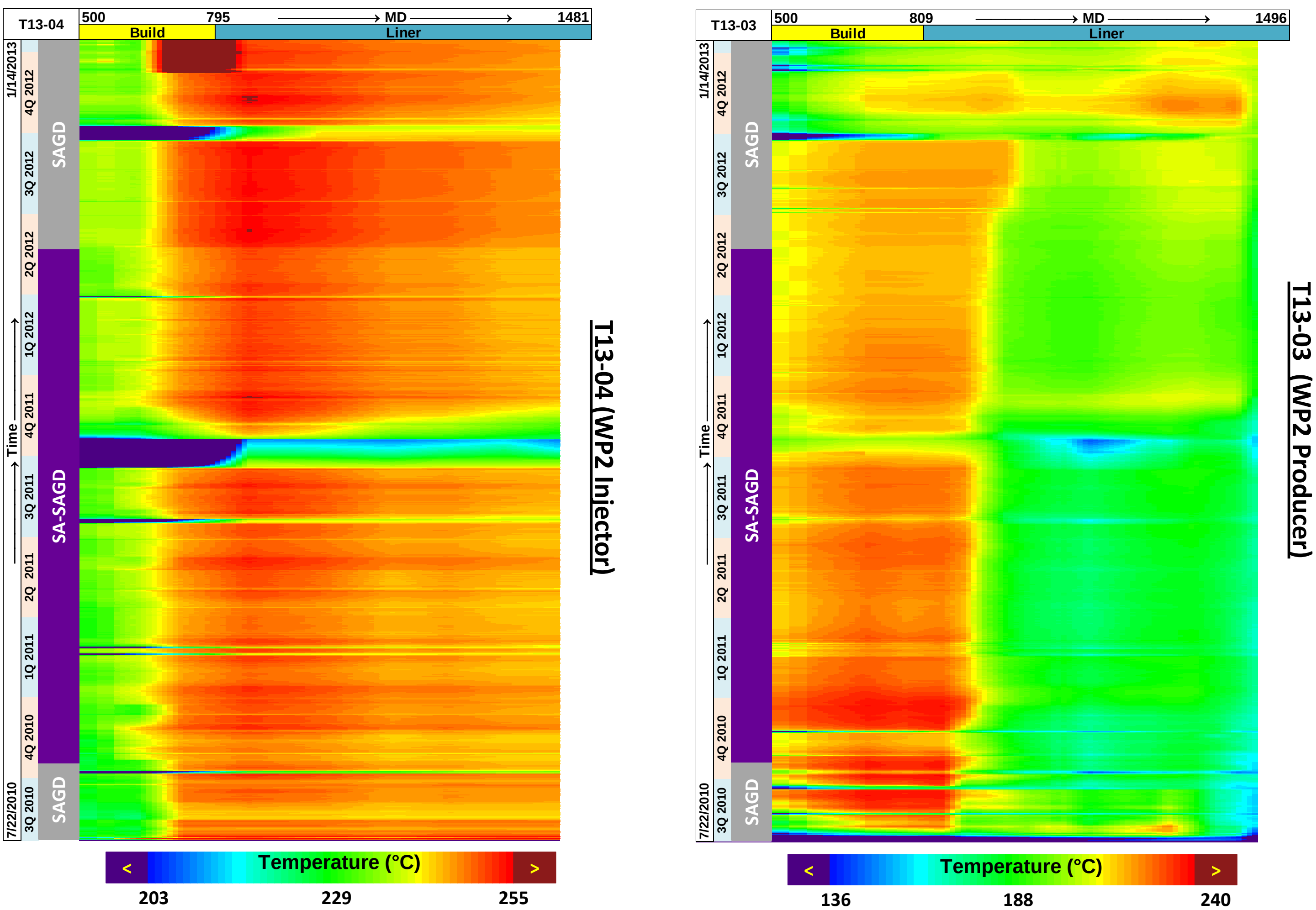


Figure 13 – Time-lapse wellbore temperature profiles for WP2 injector and producer.

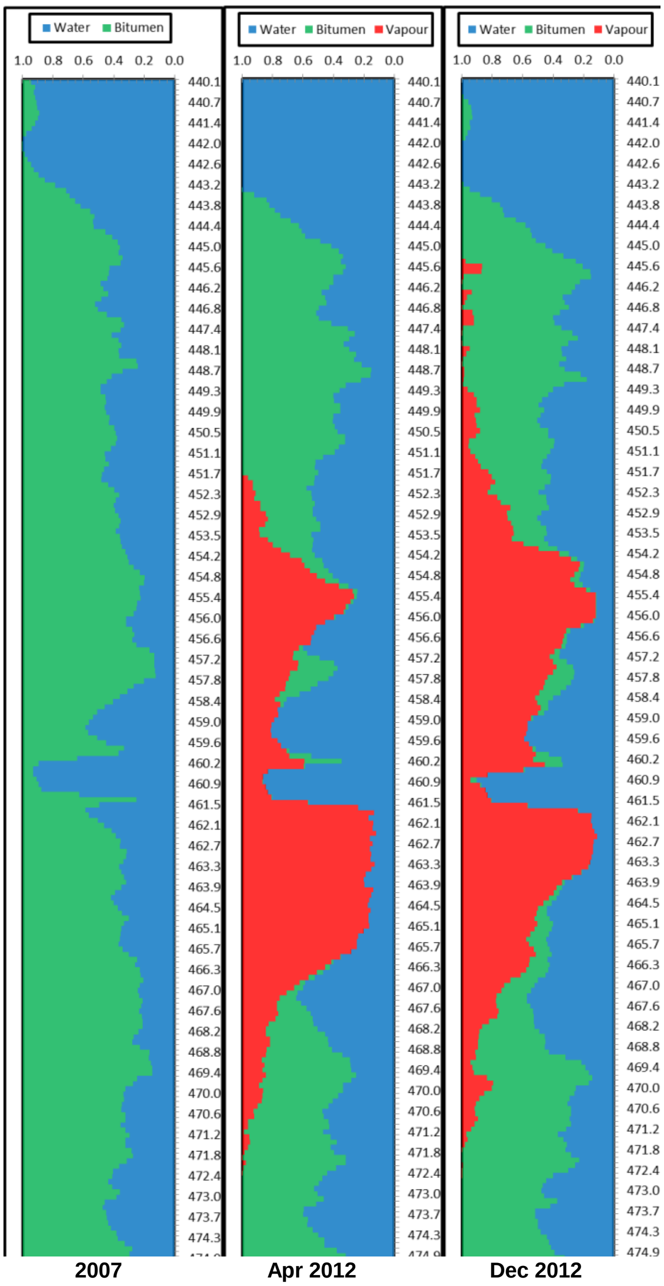


Figure 14 – Fluid saturation estimates determined from pulsed neutron logs run prior to the start of SAGD operations and twice in 2012.

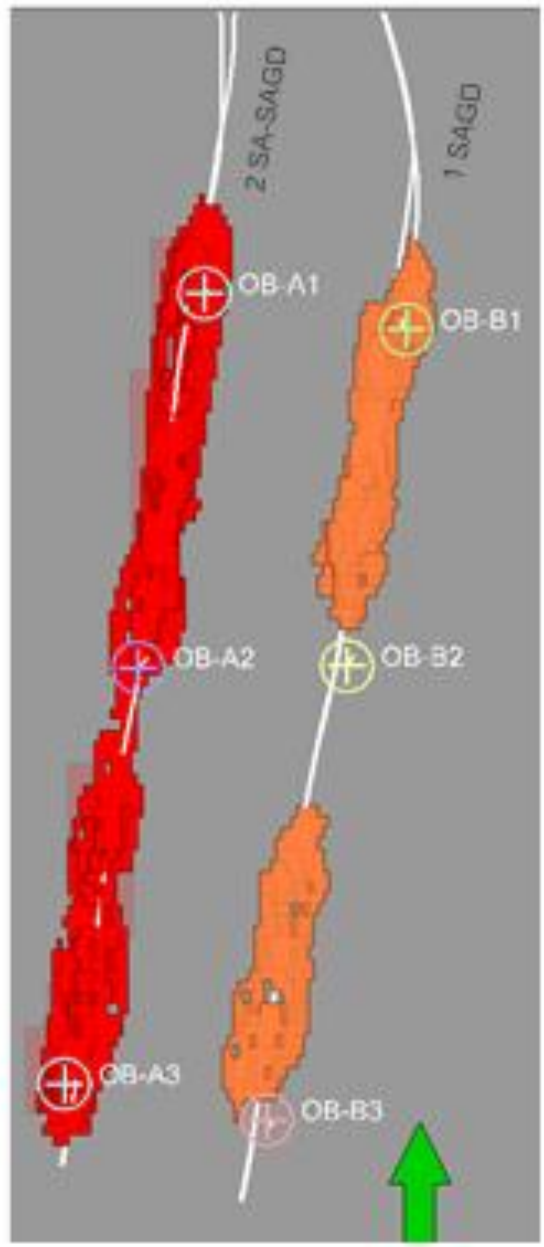


Figure 15 – Extraction from the 2012 repeat 3D seismic survey indicating the extent of the steam chamber for WP1 (eastern well pair) and WP2 (western well pair).

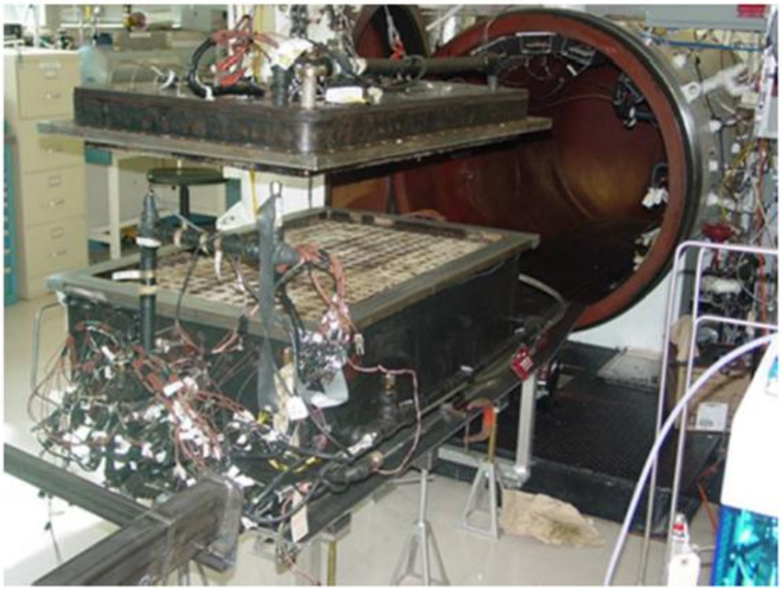
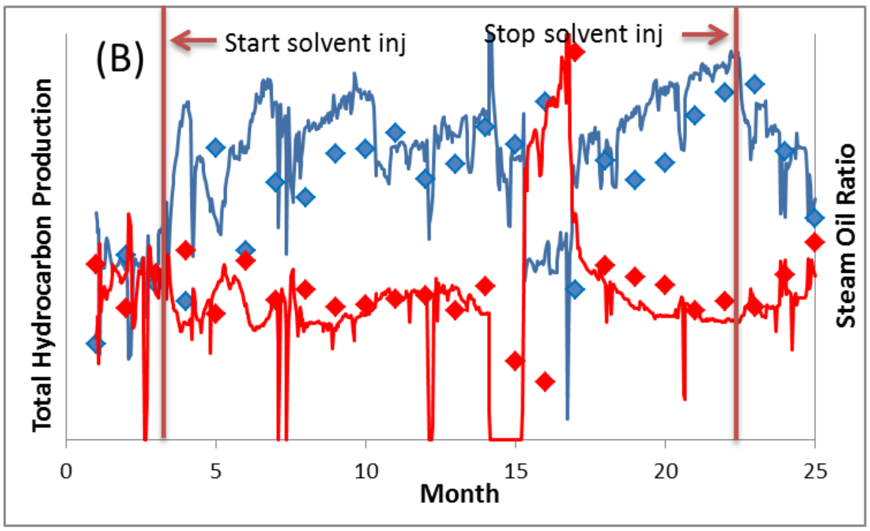


Figure 16 – Picture of the scaled physical model used for SA-SAGD testing.



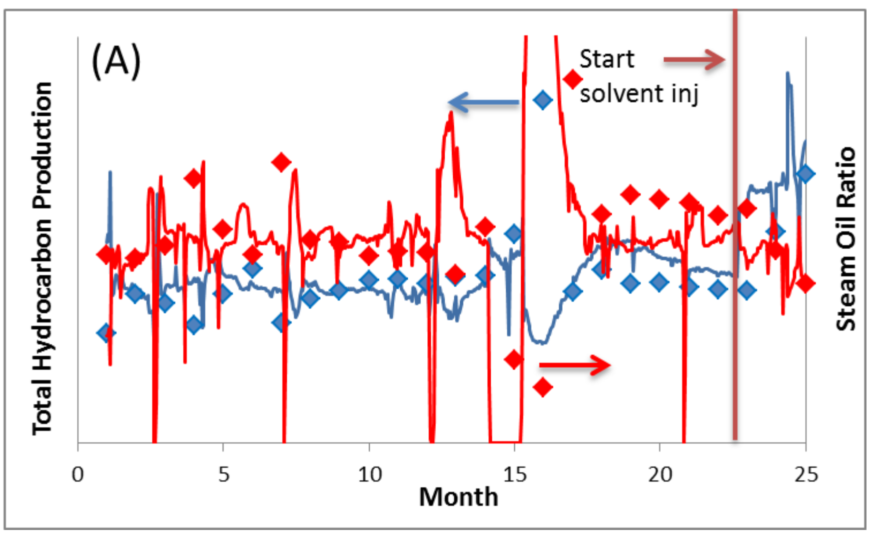


Figure 17 – History match of the total hydrocarbon production rate (blue curve) and instantaneous SOR (red curve) for well pair 1 (A) and well pair 2 (B). The points represent the field data and the solid line represents the simulation results.