Successful Application of Hot-Water Circulation in the Pelican Lake Field: Results and Analyses of the E29 Hot-Water-Injection Pilot

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Summary

The Pelican Lake field in northern Alberta (Canada) is home to the first successful commercial application of polymer flooding in higher-viscosity oils (i.e., greater than 1,000 cp), which has opened up new opportunities for the development of heavy-oil resources.

The field produces from the Wabiskaw "A" reservoir, which has thin pay (2 to 6 m) and exhibits a significant viscosity gradient across the field, with oil viscosities as low as 600 cp in the existing waterflood and polymer-flood areas to more than 200,000 cp in the current undeveloped "immobile" area. This unique geological feature limits the application of chemical injection to the less-viscous areas of the field and calls for different methods for the heavier accumulations.

As a first step to develop alternative technologies capable of recovering oil from heavier areas of the field not ideal for polymer flooding, a Cenovus-designed hot-water-injection pilot began implementation in June 2011. The hot-water-injection scheme was applied to a transition area in which dead-oil viscosity ranges from 3,000 cp to approximately 15,000 cp. It consisted of one horizontal producer supported by two horizontal hot-water injectors, with an injector/producer distance of 50 m for both injectors, and three vertical observation wells equipped to monitor pressure and temperature between one injector and the producer.

The pilot was operated in three phases. The first phase consisted of a 6-month primary-production period to obtain a baseline of the pilot performance before hot-water injection. The second phase consisted of hot-water injection through the edge injectors. The third phase consisted of hot-water edge injection accompanied by hot-water circulation in the production well as a means to stimulate oil production. One of the features of this stage is the use of an insulated coiled tubing (ICT), which delivers hot water continuously to the toe of the producer and allows continuous stimulation and uninterrupted oil production.

This paper describes the mechanical components of the pilot and discusses the results obtained with an emphasis on the hot-water-circulation process, which has proved to be very effective. Oil production increased from approximately 6 m^3/d during the flood stage to more than 25 m^3/d during the hot-water-circulation stage and has held relatively steady for more than 2 years.

The data captured have been reconciled with analytical and reservoir-simulation models, and results suggest that the technology may help unlock some of the heavier oil accumulations in the field.

Introduction

The Pelican Lake Field is located approximately 250 km north of the city of Edmonton, Alberta, Canada **(Fig. 1).** It was discovered in 1978, and since then, it has had a remarkable production history, which is currently based on waterflooding and polymer flooding by use of horizontal wells (Delamaide et al. 2014).

The main challenge to the development of the field is associated to the thin nature of the reservoir (2 to 6 m) and the high oil viscosity (600 to 200,000 cp or greater). Despite the success of polymer flooding, it became evident that chemical injection was suited mostly to the lighter areas of the field (i.e., less than 5,000 cp), and alternative technologies had to be developed for the heavier areas **(Fig. 2).**

When it comes to producing from thin, heavy-oil reservoirs that are not amenable to chemical injection, different enhanced-oil-recovery (EOR) and stimulation technologies have been proposed and tested at both laboratory and field scale. These include cyclic steam injection, in-situ combustion, electromagnetic heating, cyclic gas/solvent injection, solvent injection, and pressure cycling, among others (Gutiérrez et al. 2013). However, to the best of our knowledge, there is not a single successful commercial EOR project in a reservoir similar to that in Pelican Lake (thin and relatively immobile at reservoir conditions).

When tackling this challenge, given the viscous nature of the reservoir, preference was given to thermal EOR methods. Steam was the first choice, and different development scenarios were evaluated using reservoir simulation, but results were not encouraging. In-situ combustion was also considered, but discarded as a primary EOR method because the oil is not mobile enough and its implementation would require the injection of significant volumes of steam, which hindered the economics of the project. Such high-temperature operation is a more-reasonable plan for later stages of the field development.

As with steam and air injection, different reservoir-simulation scenarios were evaluated by use of hot-water injection. This included the testing of hot-water circulation as an alternative to the thermal-oil-recovery (TOR) technology developed by MAJUS (MAJUS 2015a, 2015b; Blonz and Ollier 2009) or other wellbore-heating methods such as electrical heating (Ojeda and Parman 2013).

Results from the evaluation of hot-water injection were promising. Hence, as a first step to develop alternate technologies capable of recovering oil from the more viscous sections of the field (Fig. 2), a hot-water-injection and -circulation pilot was designed and implemented in June 2011, which represents the first successful application of hot-water circulation worldwide and is the main subject of this paper.

Overview of the E29 Hot-Water-Injection Pilot

When evaluating options for a new pilot at Pelican Lake, it was identified that horizontal, thermal-flooding-development schemes would be disadvantaged because of the thin nature of the formation. However, viscosity/temperature relationships from the less-viscous step-out areas indicated that relatively low temperatures (40 to 60 °C) could be enough to enhance oil mobility to levels similar to those in the polymer-flood area **(Fig. 3).** It was this unique desire to deploy (small amounts of) heat in such a way that

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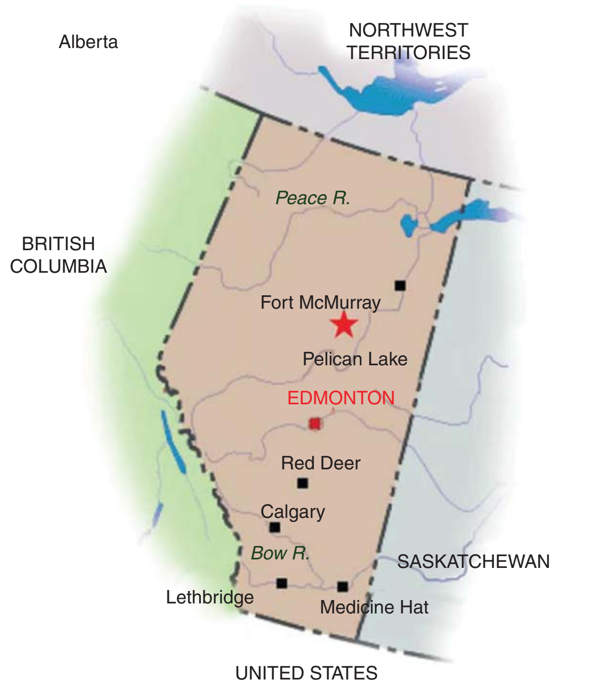

Fig. 1—Location of the Pelican Lake field (Delamaide et al. 2014).

minimized the disadvantage of the thin formation that led to the novel idea of a hot-water-circulation process. Reservoir-simulation studies indicated that the technology had potential over a conventional waterflood or hot-water injection, and it was decided to pilot it at the E29 field site.

The E29 hot-water-injection pilot was operated in three phases. The first phase consisted of a 6-month primary-production period to obtain a baseline of the pilot performance before hot-water injection. The second phase consisted of hot-water injection through the edge injectors. The third phase consisted of hot-water edge injection accompanied by hot-water circulation in the production well as a means to stimulate oil production **(Fig. 4).** One of the features of this stage was the use of an ICT (MAJUS 2015a) to deliver hot water continuously to the toe of the producer, which enables continuous stimulation and uninterrupted oil production. A historical summary of the main events of the pilot is presented in the following.

In 2000, as part of the development of the Pelican Lake Wabiskaw formation, two horizontal production wells (100/10-33-081-20W4 and 100/14-33-081-20W4) were drilled at an interwell distance of 400 m. The horizontal section of these wells was approximately 2500 m. They were put on primary production in early 2001, and both produced steadily until 2010, when 100/10-33 was shut-in as part of the first phase of the E29 hot-water-injection pilot. The baseline primary performance of these wells is shown on **Fig. 5.**

In 2010, two new horizontal wells were drilled, offsetting the existing 100/10-33 production well (Fig. 4), all at approximately the same depth. The first well, 102/11-33-081-20W4, was drilled at a 50-m offset to 100/10-33 and served as the central production/circulation well for the pilot. The second well, 103/11-33-081-20W4, was drilled at a 50-m offset to the new 102/11-33-081-20W4 well and was used as one of the hot-water injectors. The horizontal section of these wells was 2000 m. Concurrently, the existing 100/10-33 producer was converted into a second injector to create a horizontal injection-bounded production well. In March 2011, three vertical observation wells were drilled in support of this pilot, intersecting the flood plane between the newly drilled injector and the pilot production/circulation well (Fig. 4). These three wells were equipped with downhole pressure gauges and thermocouples to monitor the advancement of the flood front.

In June 2011, a 9 million Btu/hr boiler was commissioned and started as part of the hot-water-generation facilities, which distributed hot water to the three wells for injection and circulation, as required. The injection water is low-salinity water produced from the Grand Rapids formation.

Oil-production performance during each one of the phases of the pilot is illustrated in **Fig. 6,** and will be discussed in detail later.

Phase 1. Before beginning the hot-water pilot, time was invested to gather the necessary baseline data to investigate the possibility that the newly drilled (pilot) producer (102/11-33) had a higher production capability than the pre-existing producers. Between December 2010 and June 2011, there was no injection into the injectors. The primary production data (Fig. 5) was collected from the pilot producer. When compared to the 10 years of history on the 100/10-33 and 100/14-33 production wells, it was concluded that production capability (under primary depletion) of the new

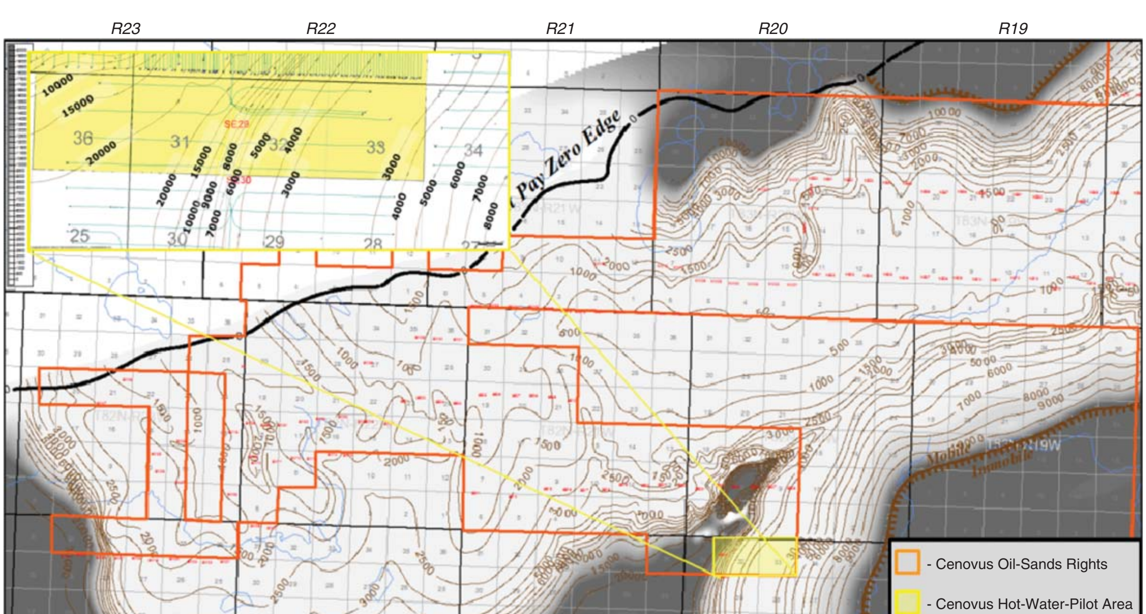

Fig. 2—Cenovus Pelican Lake field produced-wellhead-viscosity map.

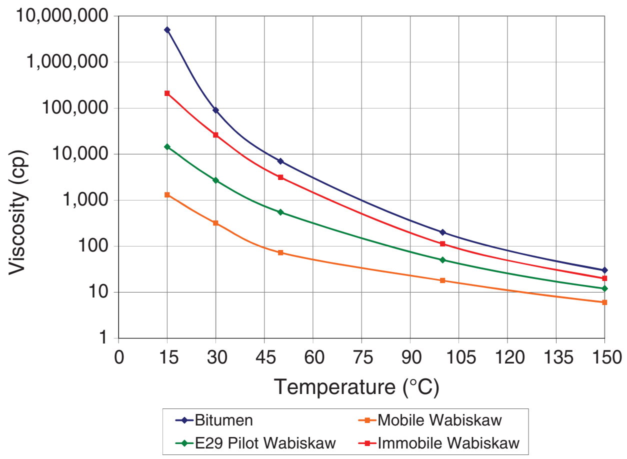

Fig. 3—Pelican Lake Wabiskaw oil viscosities.

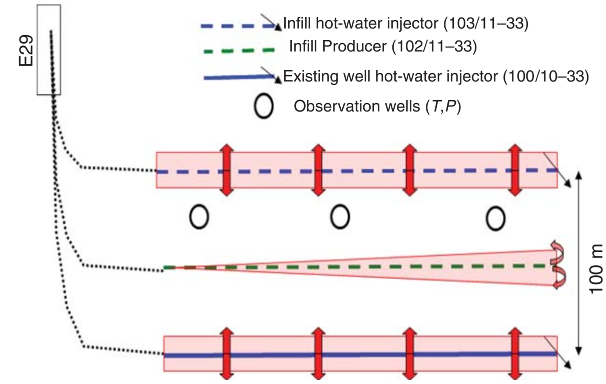

Fig. 4—Phase 3: hot-water injection and circulation.

pilot producer was similar to the pre-existing wells, justifying the continuation to the next phase of the pilot.

Phase 2. In June 2011, hot-water injection began in the two pilot injector wells. During this time, the central well produced as it had during the first phase of the pilot. The injection well (100/10-33) was limited to a maximum injection temperature of 60 °C because it was originally drilled in 2000 and, at that time, no consideration of thermal operation went into the design of the wells. The initial injection temperature of the newly drilled injector (103/11-33) was 60 °C and was ramped up to 90 °C over time. The lower initial temperatures were necessary to avoid steam because the edge injectors were initially on a small vacuum at the surface.

Phase 3. In 2012, hot-water circulation by means of an ICT (MAJUS 2015a) in the pilot producer (102/11-33) began while simultaneously producing from the well. A wellbore schematic of this well is illustrated in **Fig. 7.** During the beginning of this phase, there were a number of months of poor uptime performance because learnings from the operation of the complex well were being obtained. Stabilized injection/circulation performance of the pilot was achieved in mid-2012.

During this phase, once stable operation was achieved, significant increases in the oil rate in the 102/11-33 producer were observed. As time went on, various changes in target rates and temperatures were executed, reasoned by the corresponding learnings that will be discussed in the sections that follow. The highest heat-discharge configuration that was achieved during this time was a circulation temperature of 180 °C at a water-injection rate of 100 m^3/d (Fig. 6).

Reservoir Properties

Geology and Reservoir Characteristics. The E29 hot-water-injection pilot was conducted in the Wabiskaw "A" sand-reservoir unit, at a depth of approximately 370 m. The Wabiskaw Member is Lower Cretaceous, Albion, and is part of the Mannville Group.

The Wabiskaw "A" sand in the Pelican Lake area is a prograding shoreface sand comprised of both lower shoreface and middle shoreface sediments. In general, the unit coarsens upward from very fine upper sand in the lower shoreface to fine lower sand in the middle shoreface, and cleans upward from an average of 25% mud content in the lower shoreface to less than 10% mud in the middle shoreface. Therefore, the reservoir quality is best near the top of the unit.

At the site of the E29 hot-water-injection pilot, the reservoir properties are very good, uniform, and consistent along the length of the horizontal wells, with an average porosity of 29%, average resistivity of 50 Ω, average water saturation of 27%, and a net pay of 5 m **(Fig. 8).**

Oil Viscosity. The oil viscosity in the Pelican Lake field ranges from 600 to more than 200 000 cp at 15 °C. In the location at which the pool is currently being produced, the viscosity ranges between 600 and 20 000 cp. The oil is considered immobile after 20 000 cp and would currently require thermal methods to access it (Fig. 2). At the site of the hot-water pilot, the produced-oil viscosity ranges from 3000 to 15 000 cp and is the only reservoir

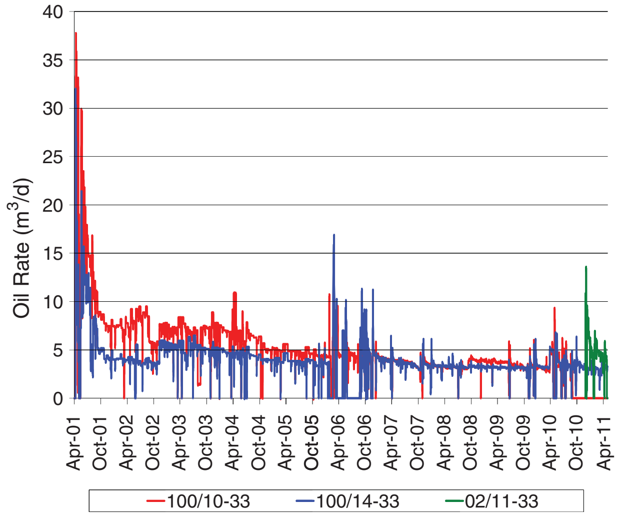

Fig. 5—Primary-production baseline.

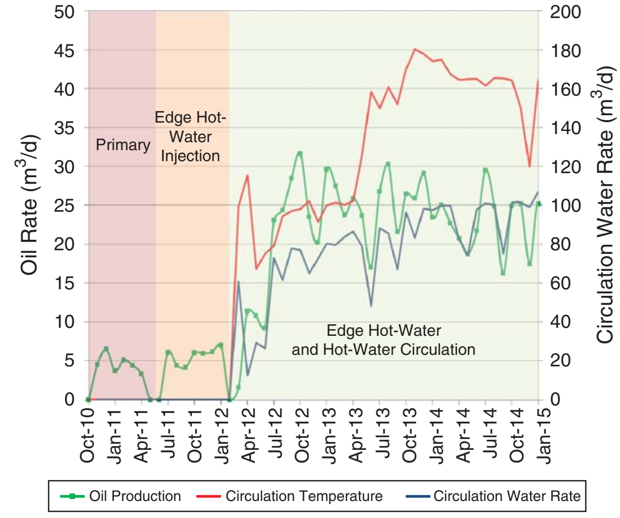

Fig. 6—Hot-water-circulation performance.

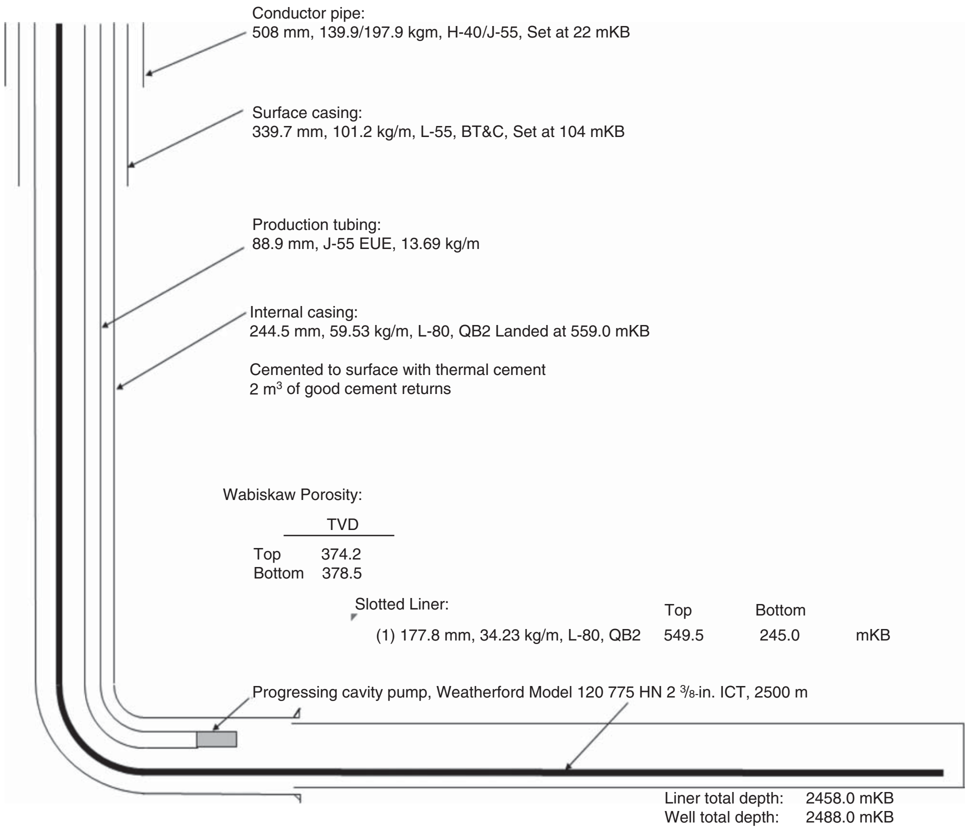

Fig. 7—Wellbore schematic of hot-water-circulation well. TVD = true vertical depth.

characteristic that varies along the length of the wellbores. The viscosity decreases from west to east (Fig. 2, inset). This trend is seen in the produced wellhead viscosities of the surrounding horizontal wells, in the produced viscosities of the three observation wells (**Table 1**), and even in the chip-sample oil viscosities taken at different points along the well paths of the producer and thermal injector while drilling the wells **(Fig. 9).**

Mechanics of Hot-Water Circulation

In thermal operations, the usual fluid to convey energy from the surface to the reservoir entails amounts of water converted into steam. The steam is injected into the reservoir to heat the formation by convection. Here, the objective is not to inject any fluid into the formation, but is to circulate hot water to heat the wellbore and heat the reservoir by conduction. This new technology requires very-high-performance insulating materials to avoid thermal losses between the heat source above ground and the downhole production zone. The temperature differential between the hot source and the reservoir is essential because the efficiency of conductive heating is driven by it.

Heating the oil reduces its viscosity, consequently reducing the pressure losses in the formation. Therefore, increased productivity can be achieved for the same pressure drop if a sufficient temperature increment is maintained at the wellbore. The aim is to provide an efficient way of heating reservoirs by conduction to decrease heavy-oil viscosity.

The vertical section of the well is completed with a conventional production tubing and a downhole pump. The fluid produced goes to the production facilities. At the surface, a pump

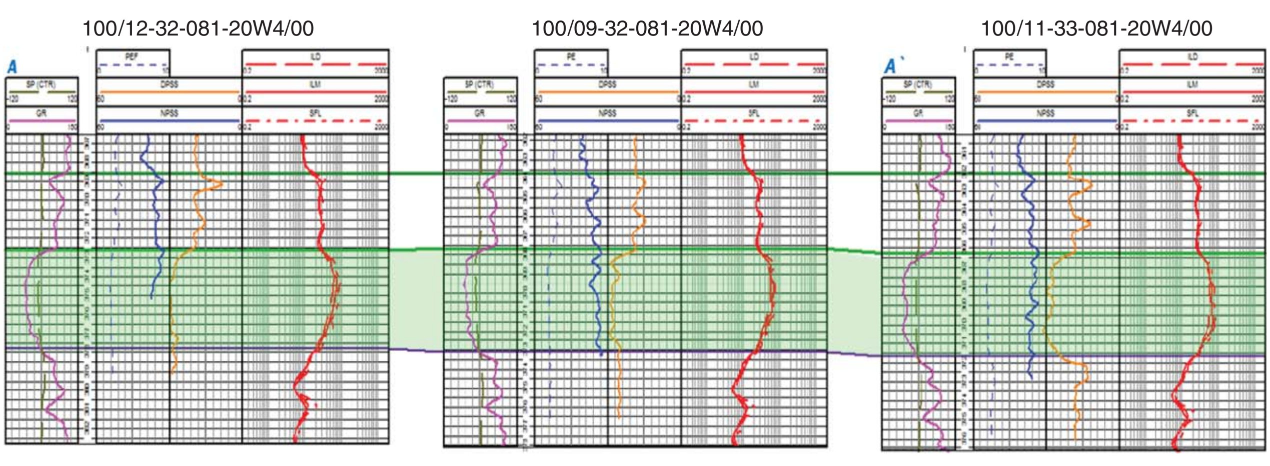

Fig. 8—Stratigraphic cross section of observation wells over hot-water-injection pilot.

Well	Test Date	°API at 15°C	Oil Viscosity at 15°C (cp)
Heel Observation Well 100/12-32	9 December 2011	13.4	9,166
	12 April 2012	13.2	8,218
	12 April 2014	13.2	8,462
Middle Observation Well 100/09-32	9 December 2011	14.8	4,316
	12 April 2012	15.4	2,446
	12 April 2014	16.6	1,233
Toe Observation Well 100/11-33	9 December 2011	15.5	2,517
	12 April 2012	15.6	1,977
	12 April 2014	15.8	1,832

Table 1—Observation-well produced-oil viscosity.

sends water to a heater, and then farther into an ICT run to the toe of the horizontal section (Fig. 7). This coiled tubing is pipe-in-pipe form, with the insulating material in the space between the pipes **(Figs. 10 and 11).** During hot-water-circulation operation, the fluids exchange heat with the formation by conduction. There is no intention of liquid injection within the formation because it would imply less fluid coming from the formation.

Hot-Water-Circulation Results

Because the reservoir is thin, heat losses to the overburden and underburden tend to dominate the performance of the hot waterflood, which basically defaults to that of a cold waterflood, at least during the first few years, as confirmed by reservoir simulations. Hence, most of the positive production response is a result of the heat delivered through the hot-water-circulation process, which is the main topic of this discussion.

The oil-production rate of the pilot responded positively to the circulation of hot water in the central production well (Fig. 6). After an initial flush production, the oil-production rate of the pilot producer settled out at less than 4 m^3/d under primary production. Once hot-water edge injection began, the pilot ramped up to an observed oil-production rate of more than 7 m^3/d, and simulation indicated that had this phase continued without interruption, the pilot would have peaked at 18 m^3/d. Once hot-water circulation began in the production well (initially at 80 to 100 °C), oil rates ramped up to a peak of 32 m^3/d. After that peak, the pilot oil rate was on decline for a number of months until a hot-water-circulation temperature change was implemented in May 2013 (increasing from 100 to 180 °C over 6 months), which caused the pilot to have a secondary peak of 30 m^3/d.

It is recognized that many different factors may be contributing to the improved performance of the production well during the time it was circulating hot water. However, our analyses indicate that the behaviour can be explained by a simple model on the basis of the conductive heating that is achieved during circulation, which reduces the oil viscosity in the near-wellbore region.

The steepest pressure gradient along the horizontal well is from the outlet of the ICT to the inlet of the production pump (Fig. 7), which limits the amount of hot water that can enter the formation and makes heat conduction the main mechanism of reservoir heating. Hence, the effect of hot-water circulation on reservoir temperature is limited to a radius of influence of a few metres (as dictated by conduction), which causes a viscosity reduction in

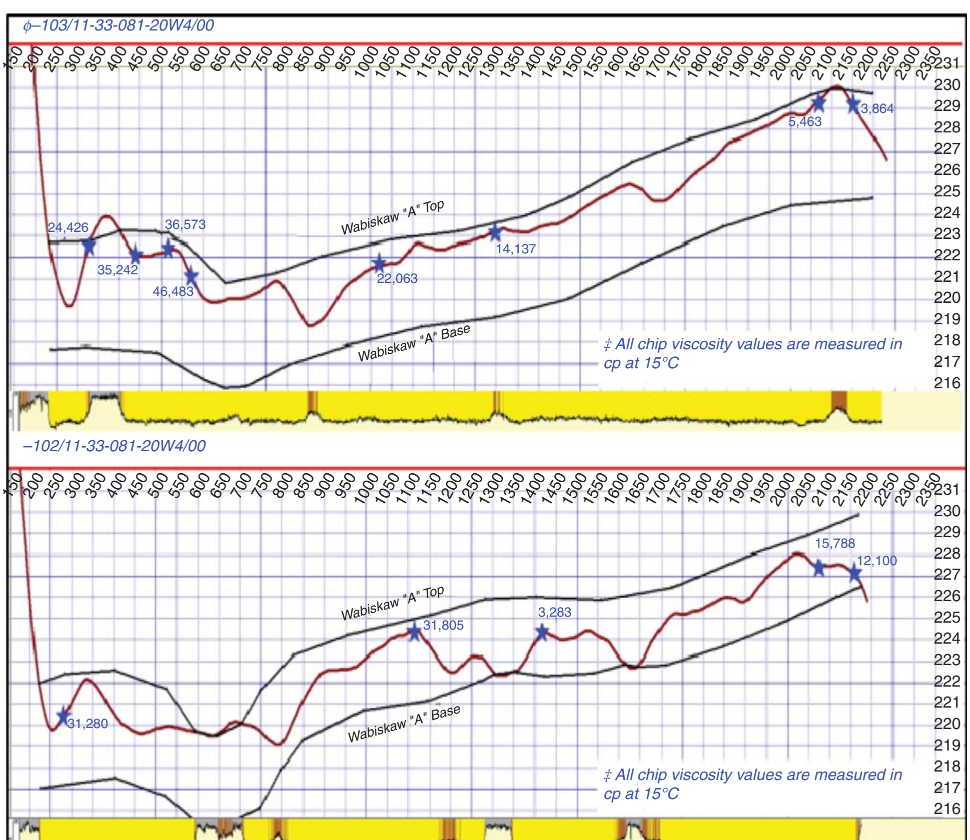

Fig. 9—Chip-sample viscosities along well paths.

Fig. 10—Typical microporous insulation blanket.

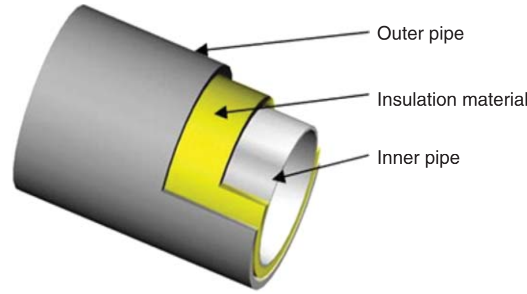

Fig. 11—Pipe-in-pipe coiled-tubing configuration.

that area and, thus, improved well productivity. This mental model is supported by the following analysis.

Between the middle of August and September 2013, there was a period of extended water injection and circulation downtime caused by a packer failure on the thermal injector. During this time, all water injection and circulation at the E29 hot-water-injection pilot ceased; however, the central producer remained on production **(Fig. 12).**

During the 10-day water-injection and -circulation outage, the produced water cut increased from 85 to 90%, which is a more significant result than it would first appear **(Fig. 13).** Before the outage, the pilot was producing a total of 205 m^3/d of water and 35 m^3/d of oil, and the water-circulation injection rate was 90 m^3/d. As a result, the effective inflow water cut from the reservoir before the outage was 77% (115 m^3/d of reservoir-supplied water and 35 m^3/d of reservoir-supplied oil). During the water outage, there was no circulation water, so the observed 90% water cut is also the reservoir inflow water cut, which clearly illustrates the benefit of hot-water circulation.

Other data available during the outage included oil-viscosity measurements **(Fig. 14)** from a collected oil sample and a wellbore model that had been created previously and tuned to previous circulation data (i.e., measured surface rates, temperatures, and pressures) by use of Neotec's WELLFLO™ software. This model was used to provide estimates for values (i.e., pressure and temperature) at each point in the system that could not be measured directly (e.g., downhole temperature at the outlet of the ICT). In August, when hot water was being circulated at 160 °C, the producing temperature of the well was 55 °C, and the wellbore model indicated that the effective downhole temperature would be 41 °C. In September, when there was no hot-water circulation, the production temperature of the circulation well was 28 °C, and the model indicated that the effective downhole temperature had declined to 31 °C.

Using the oil-viscosity measurements collected and the associated Andrade equation (Evans 1937) (Fig. 14), it was estimated that the effective oil viscosity flowing into the wellbore (downhole) on 27 August was approximately 400 cp and was 1,200 cp on 5 September.

These data were then used to reconcile the performance differences observed before and after the water injection and circulation outage or, in other words, the benefit of hot-water circulation.

By use of fractional-flow theory (Buckley and Leverett 1942), it was assumed that the viscosity change in water and the ratio of relative permeability of oil and water is negligible between 31 and 41 °C. These terms were collapsed into a single variable C, which is kept constant when writing the fractional-flow equation for this application.

$$f_w = \frac{1}{1+\dfrac{K_{ro}}{K_{rw}}\dfrac{\mu_w}{\mu_o}} = \frac{1}{1+\dfrac{C}{\mu_0}}. \quad (1)$$

Writing the fractional-flow equation for the time period when there is no circulation (no circ) and assuming that the change in water viscosity and the change in ratio of relative permeability of oil to water are negligible between 31 and 41 °C give

$$\begin{aligned} f_w(\text{no circ}) &= \frac{1}{1+\dfrac{C}{\mu_o(\text{no circ})}} \\ \rightarrow C &= \mu_o(\text{no circ})\left[\frac{1}{f_w(\text{no circ})}-1\right] \\ &= 1,200\left(\frac{1}{90\%}-1\right) = 133. \end{aligned} \quad (2)$$

Writing the same expression for the time period when hot water was being circulated gives

$$f_w(\text{circ}) = \frac{1}{1+\dfrac{C}{\mu_o(\text{circ})}} = \frac{1}{1+\dfrac{133}{400}} = 75\%(\text{vs. } 77\%). \quad (3)$$

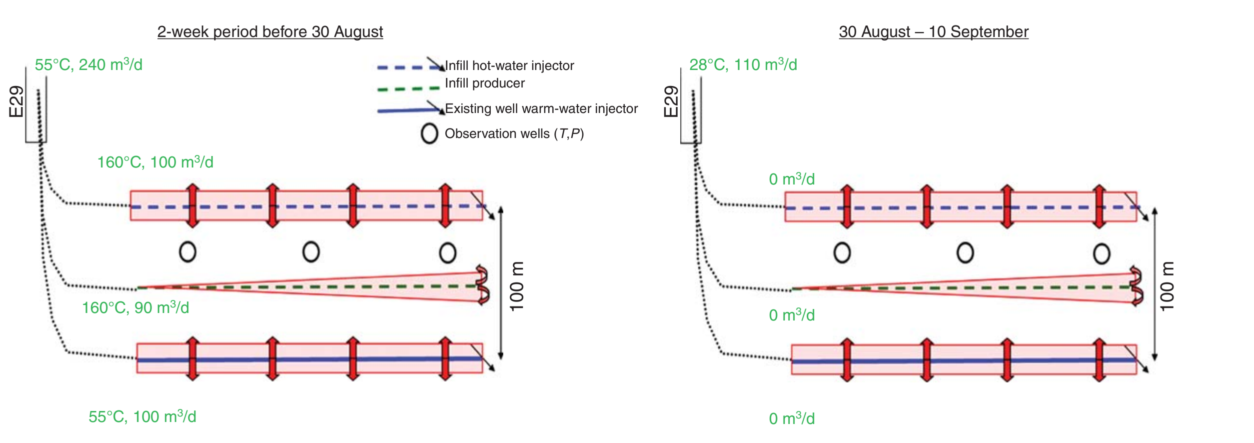

Fig. 12—Hot-water-circulation well conditions during downtime.

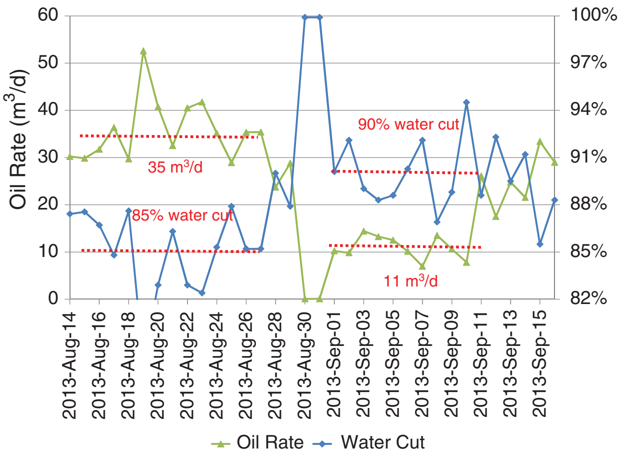

Fig. 13—Pilot oil rates and water cuts during outage.

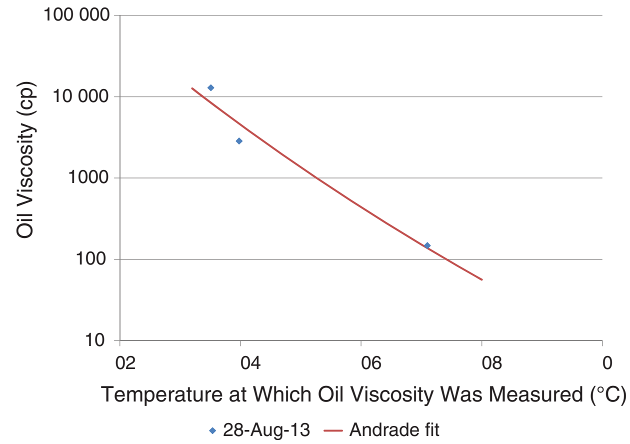

Fig. 14—E29 produced-oil viscosity of sample taken during outage.

This illustrates that the overall performance of the pilot observed during this period can be explained by viscosity reduction of the oil in the near-wellbore region, caused by the hot-water circulation. Nevertheless, some other possible explanations exist and are presented, as follows:

- Circulating water in the production well provides the benefit of continuous sand removal from the well that otherwise accumulates and hinders performance (so even cold-water circulation would show an uplift).
- Heat transfer to the formation is more efficient than would be implied by conductive heating because some of the hot water exiting the ICT at the toe does penetrate the formation and transfers heat (convectively) before being produced.

It is not disputed that these (or other factors) may exist and that they could contribute to the pilot performance observed during hot-water circulation. However, it is important to consider that the majority of the observed difference in production could be reconciled with the model described in the preceding (viscosity reduction of oil because of the conductive heating of the near-wellbore reservoir region) and that has been confirmed with reservoir simulations.

Reservoir Simulation

Given the relatively uniform nature of the reservoir in the pilot area (Fig. 8), a simple box model was used to perform the reservoir simulations. The model was centered to the 100/10-33 primary producer, which later became an injector, and its petrophysical properties were homogeneous but anisotropic (i.e., permeability was lower in the vertical direction). The main challenge of this work was modelling the viscosity variation observed along the newly drilled horizontal wells (Fig. 9) and from the observation wells (Table 1), which was also reflected in the pressures recorded by the observation wells before noticing the impact of injection and production in the pilot area **(Fig. 15).** If the reservoir were completely homogeneous, the three pressure profiles should have been similar. Also, the viscosity of the produced oil is not representative of the viscosity inside the reservoir, and hence the conventional method of modelling viscosity is not applicable. During production, lighter fractions of the oil are produced first, leaving the heavier ends behind, making it difficult to obtain a representative oil sample of the area.

To account for the viscosity variation of the oil, two oil components were used. For simplicity, the pressure/volume/temperature model used was the same for the two components and was based on a differential-liberation test performed on an oil sample from the lighter area of the field. However, their oil viscosities were different. Oil viscosity/temperature relationships for the two components **(Fig. 16)** were derived from data measured on two different oil samples, which represented the two ends of the spectrum of viscosities encountered in the pilot area (i.e., 1,350 and 30,000 cp at 15 °C, respectively).

The Models. At the time this work was performed, a viscosity map of the area, which included the recent pilot viscosity data, was not available. To generate a viscosity distribution for the

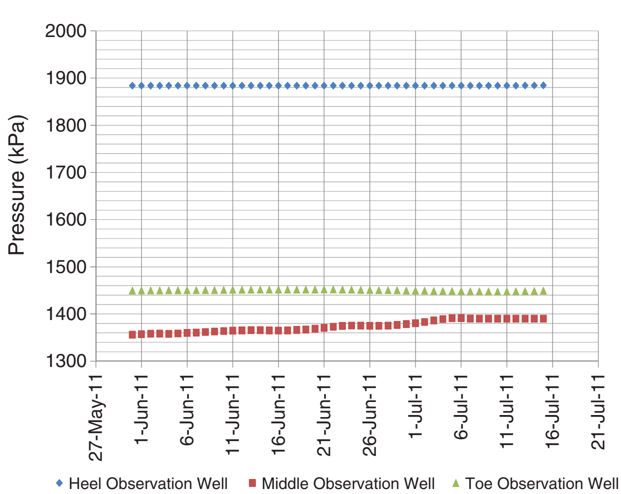

Fig. 15—Pressure at observation wells before recording response to injection.

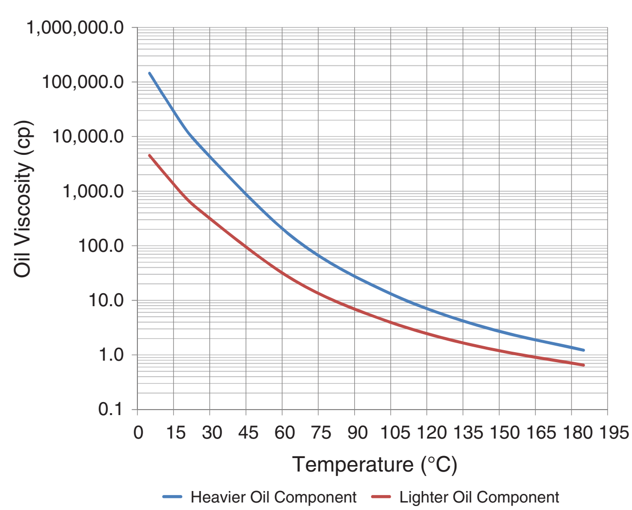

Fig. 16—Viscosity of oil components used in reservoir-simulation models.

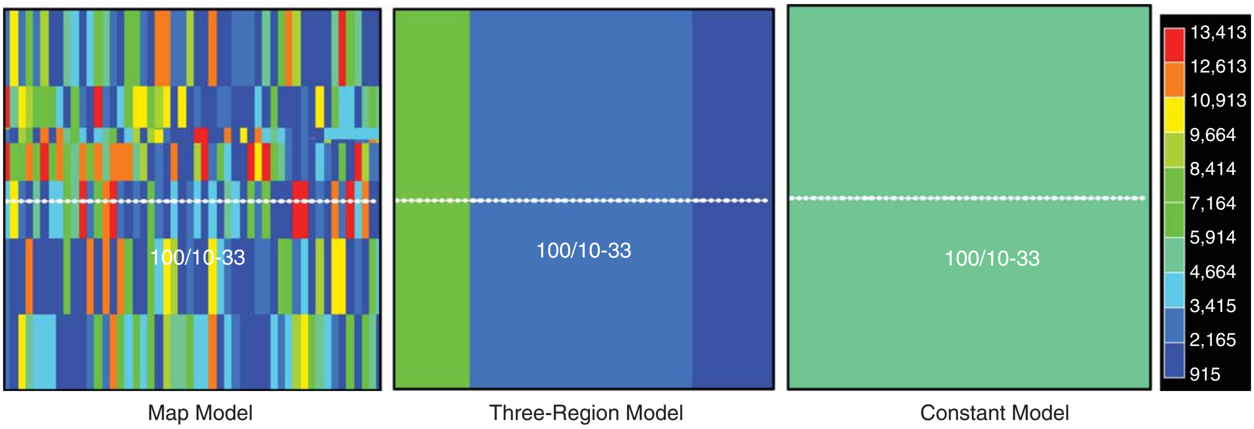

Fig. 17—Plan view of different oil-viscosity models (live-oil viscosity).

reservoir, a history-matching exercise was carried out with the Computer Modelling Group's (CMG) assisted-history-matching tool, CMOST™. The idea of the exercise was to history match the primary-production performance to assist in generating a suitable oil-viscosity distribution. The parameters that were matched were

1. Primary production from the 100/10-33 well
2. Pressures at the observation wells before pilot operation.
3. Produced-oil viscosity from the 100/10-33 well.

Fortunately, gas and water production were low during this period (i.e., solution gas is approximately 8 std m^3/m^3, and water saturation was below critical), which minimized the impact of relative permeability curves and made it easy to history match the production rates and allowed focusing on the modelling of oil viscosity. So, most of the efforts were on matching the observation-well pressures and produced-oil viscosity, which required a variable viscosity distribution.

It is acknowledged that there are other ways to history match the data (e.g., using heterogeneity on petrophysical data); however, the lack of well control in the area did not make it ideal to generate geostatistical realizations. Also, there is a vast amount of oil-viscosity data (with time) both at surface and reservoir conditions that illustrate areal viscosity variations, and make it more suitable to generate reservoir models.

Two approaches were followed to generate the viscosity distributions. In one, because there were three observation wells available that illustrated different pressure and produced-oil-viscosity responses, a model with three viscosity regions was assumed **(Fig. 17).** Hence, the main history-matching parameters were the composition of the oil within each region and the location of the viscosity boundaries.

In the second viscosity-modelling approach, a more random viscosity distribution was assumed (Fig. 17). In this model, the reservoir was divided into viscosity regions that contained a number of gridblocks. Each of those regions has a fixed oil composition, which would be the product of the history-matching exercise. Regions in which more viscosity data were available were made smaller, and areas with fewer viscosity data were grouped in coarser regions. Also, gridblocks of locations in which viscosity data were available (i.e., observation wells and horizontal wells) were constrained so that the oil composition always honoured the measured viscosity data.

The result of this exercise is presented in Fig. 17. Both the three-region model and the map model were carried forward to perform history matches of the pilot history. A constant-viscosity model (Figure 17) was also used to determine if a simpler model could be used to reconcile the pilot performance, which would make it simpler to export the learnings of the pilots to other areas of the field.

It is acknowledged that none of these geological representations resembles reality. For instance, it is clear that oil viscosity is not constant in the pilot area; viscosity changes are gradual and not sharp, as implied by the three-region model; and viscosity distribution is not random, as illustrated by the map model. Moreover, having high viscosities next to low viscosities in the map model is unrealistic; however, the purpose is to try to capture some heterogeneity in the modelling, and in that regard, the map can be thought of as a mobility (i.e., permeability/viscosity ratio) map.

The main purpose of using these three approaches was to generate fundamentally different history matches that can capture the overall pilot performance, which would then allow accounting for uncertainty in the forecasts.

History Matching. These models (Fig. 17) were all used to match the pilot performance, which included injection and production rates and pressures, and observation-well pressures. Observation-well temperatures were not used because none of the observation wells had recorded any significant temperature increase at the time the history match was performed. CMG's Flexwell option was used successfully to model the hot-water-circulation process and the hot-water injectors.

The history match was performed in two stages with data available up to November 2012. First, the historical data were matched until the end of August 2012 by use of an oil-rate constraint for the producers. In the second stage, the model was run in "forecasting" mode for the next 3 months, during which injection temperatures and rates were the input, and the producer was controlled on bottomhole pressure (BHP), assuming pumped-off conditions. This was performed simply to validate the history match and assess the forecasting capability of the models and provide more confidence for future predictions. A higher weight was given to this step over the previous history match; if the models were not able to forecast those 3 months of history, then they had to be revised and changed accordingly, regardless of the relative quality of the match achieved in the first step. A third stage consisted of performing forecasts on the basis of the anticipated injection conditions and the evaluation of possible operational changes that would maximize the learnings from the pilot.

Some of the results of the history matches are presented in **Figs. 18 through 26.** Clearly, none of the matches are perfect, but they seem to capture the most important features of the pilot. An important aspect of the work is the match of the liquids produced (Fig. 24). Modelling the first 4 months of circulation was challenging because of the operational difficulties experienced, which are hard to capture in the reservoir simulator. This caused a mismatch in the water cut (Fig. 25) and overall cumulative liquid production during that time (Fig. 24). Nevertheless, once steady operation was achieved in July 2012, the model was capturing the water-cut behaviour properly (Fig. 25).

Forecasting. The three history-matched models were used to perform pilot forecasts, but, most importantly, to identify ways to optimize the pilot operation and maximize the learnings from it.

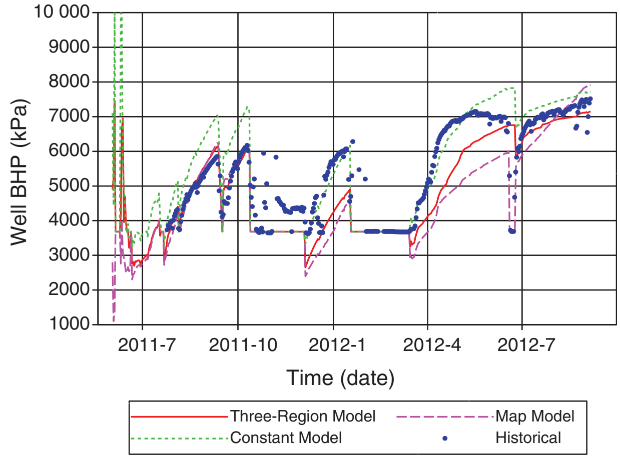

Fig. 18—BHP of thermal injector.

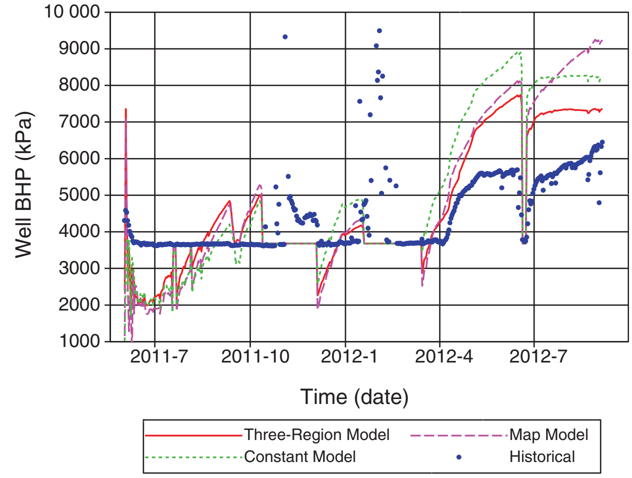

Fig. 19—BHP of warm injector.

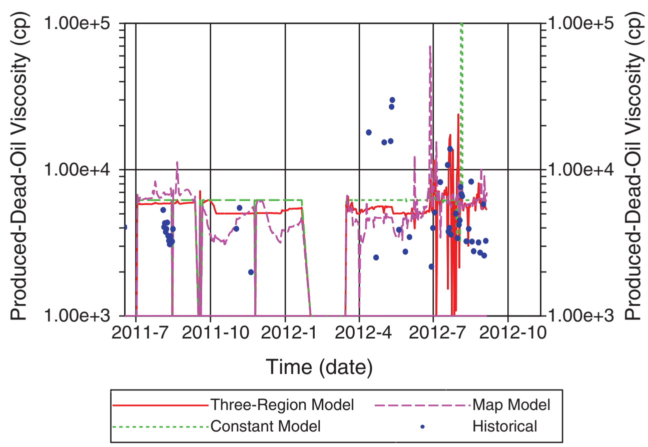

Fig. 20—Produced-oil viscosity.

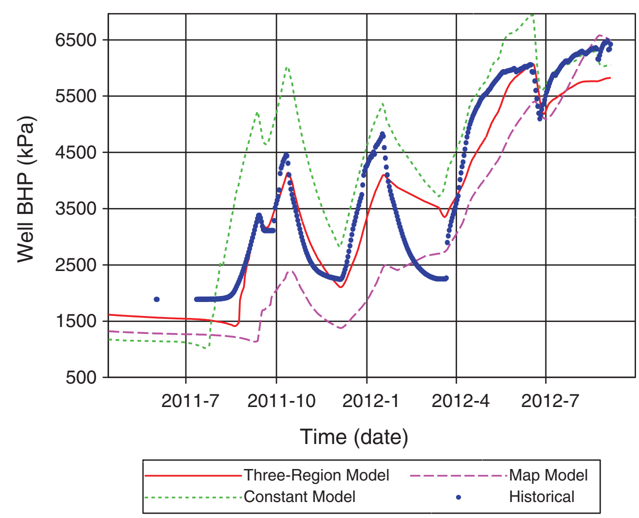

Fig. 21—Heel-observation-well pressure.

As a way to further validate the simulation models and enhance the learnings from the pilot, a sensitivity analysis to different operational parameters was performed to try to determine the most appropriate change that would allow both testing the forecasting capability of the model and maximizing oil production. It was then decided to increase the circulation temperature from 100 to 180 °C, which was executed in July 2013. As shown in Fig. 26, the pilot did respond as expected, thus validating the simulation models.

On the other hand, Fig. 26 illustrates the different oil-production forecasts from the three models, which exhibit a reasonably narrow band of uncertainty and provide confidence in the results. Moreover, the figure shows that the pilot results were within the range indicated by the simulation models for more than a year,

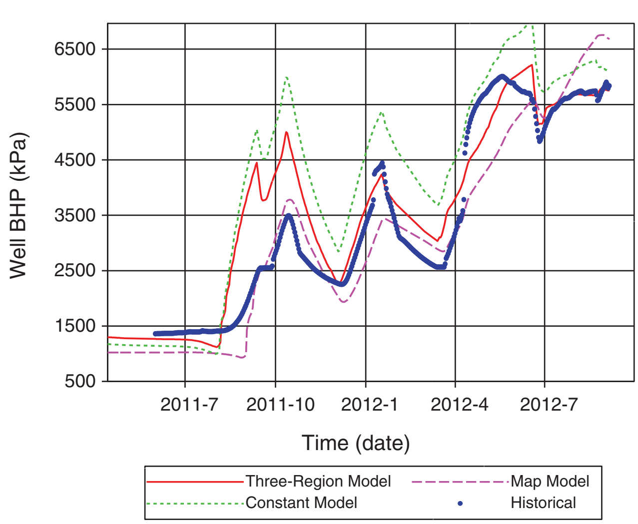

Fig. 22—Middle-observation-well pressure.

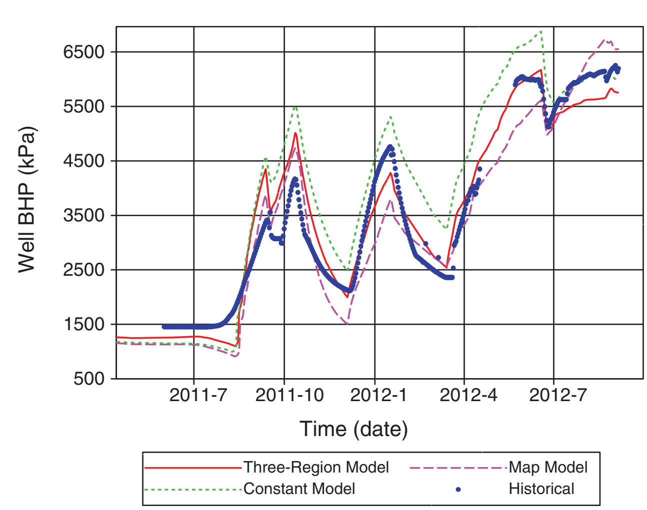

Fig. 23—Toe-observation-well pressure.

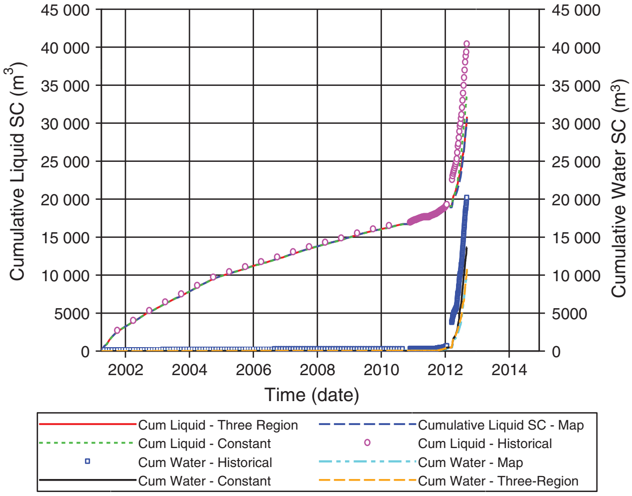

Fig. 24—Cumulative liquid production.

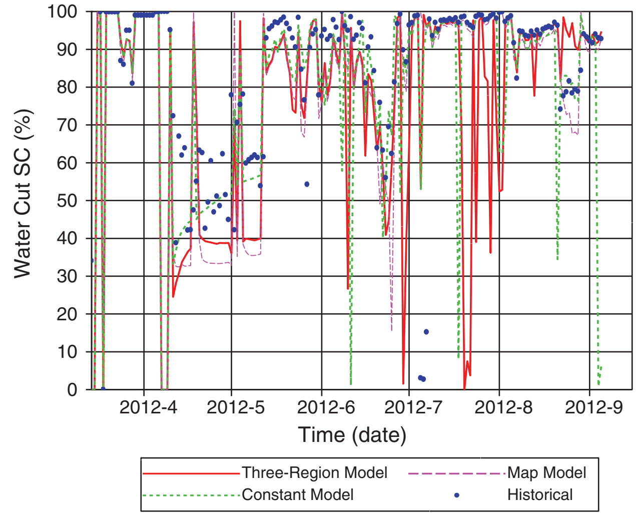

Fig. 25—Water cut in circulation well.

and it was only until recently that the results began to deviate from the simulation results. The interesting aspect of it is that actual pilot performance has been at the high end of (or exceeding) the simulation forecasts, which provided confidence that the models could be used to support further development plans by use of this technology. Nevertheless, the model is being updated to use a more realistic viscosity map (Fig. 2) and the learnings from the modelling work performed in the other areas of the field.

Another exercise that was performed was evaluating the net benefit of hot-water circulation as compared with hot waterflooding alone. **Fig. 27** shows a comparison of the actual pilot operation (i.e., with circulation) with a case in which circulation is stopped and the pilot continues as a hot waterflood. The benefit of hot-water circulation is evident—without hot-water circulation, the peak oil rate would have been 18 m^3/d as compared with 32 m^3/d with hot-water circulation.

Other Potential Benefits of Hot-Water Circulation

Apart from the beneficial effect of reducing the heavy-oil viscosity by means of heat conduction, hot-water circulation can potentially assist in improving the areal sweep efficiency (i.e., conformance) of a flood by increasing the effective length of the producer. Keeping the production well hot is equivalent to a continuous stimulation job in which the heat promotes cleaning of the wellbore and, more importantly, the liner slots, which could otherwise be plugged or obstructed by a mixture of sand and heavy oil. This enhancement in effective length would result in a longer and more-uniform pressure sink, which would promote a positive effect on the injection end and enhance sweep efficiency.

For the case of this hot-waterflood pilot, hot-water circulation would have the impact that is illustrated in **Fig. 28.** During injection through the hot-edge injector, the injected hot water cools down along the length of the well, and fluids are injected preferentially in the sections near the heel of the injector, which reduces the sweep efficiency of the flood.

Having hot-water circulation assists in mobilizing fluids from nearly the entire length of the producer, which in turn helps to increase the effective length of the injector and improve injectivity and sweep efficiency.

Conclusions

Results from the Pelican Lake hot-water-injection pilot indicate that hot-water circulation can be an effective way to develop thin-pay, heavy-oil reservoirs. Oil production in the pilot increased from approximately 6 m^3/d during the flood stage to more than 25 m^3/d during the hot-water-circulation stage, and has held relatively steady for more than 2 years. The process relies mostly on heat conduction and the corresponding reduction in oil viscosity around the producer, which makes it relatively simple to model and forecast with analytical and numerical techniques. Moreover, additional benefits can arise from having a continuously stimulated (i.e., hot) production well, which provides a self-cleaning

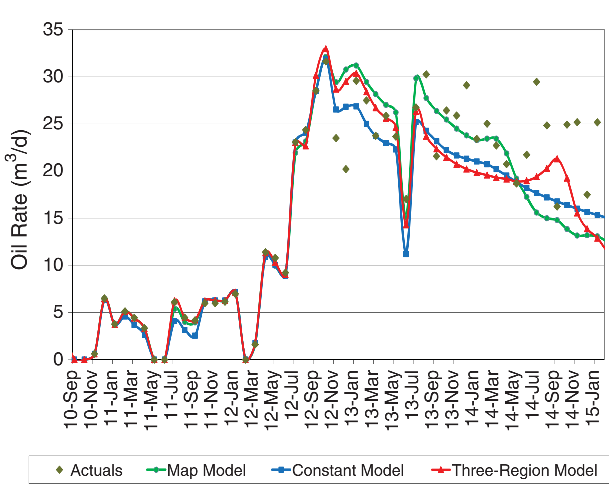

Fig. 26—Oil-production forecasts.

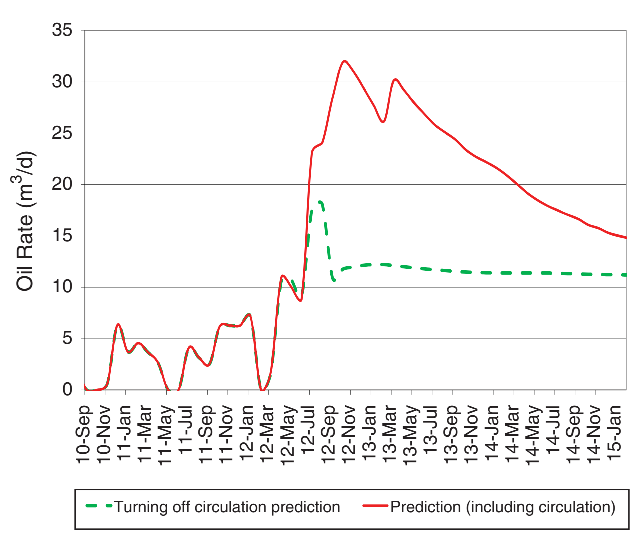

Fig. 27—Impact of circulation on oil rate: constant-viscosity model.

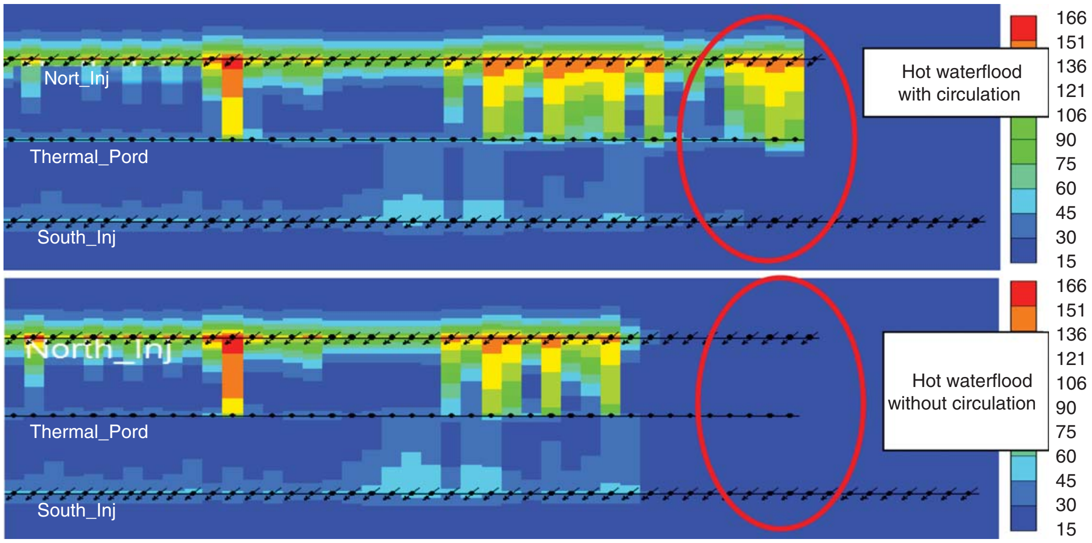

Fig. 28—Sample areal temperature distribution during hot-water injection: hot-water circulation vs. no circulation.

mechanism of the wellbore and also increases its effective length, promoting a better sweep efficiency of the supporting hot waterflood.

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