ConocoPhillips

Canada Oil Sands

NON-CONDENSABLE GAS CO-INJECTION FOR THIEF ZONE MITIGATION NON-CONFIDENTIAL FINAL REPORT

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1.0 Executive Summary

Overlying top water (or thief) zones, common to many oil sands reservoirs in Alberta, act as thermal sink when in hydraulic communication with the steam chamber formed during in-situ steam assisted gravity drainage (SAGD) operations. Interactions with thief zones reduce reservoir pressure, thus requiring increased steam injection to maintain suitable pressures for oil production. This leads to higher steam to oil ratios (SORs) and higher greenhouse gas (GHG) emissions from natural gas combustion for steam generation.

ConocoPhillips Canada (CPC) developed a low-cost technology that leverages existing in-situ infrastructure at SAGD facilities to address energy-intensive thief zone interactions. Validated by extensive reservoir simulation work, the co-injection of a non-condensable gas (NCG) with steam was piloted at a well pad at the Surmont SAGD project to mitigate negative top water interactions. This pilot successfully demonstrated that NCG co-injection minimizes thermal losses to the thief zone and helps maintain reservoir pressure, resulting in reduced SORs and GHG emissions.

2.0 Background

The pilot Pad (Pad "A" for the purposes of this document) is located under a regional top water thief zone, with virgin pressures ranging from 1,000 kPa to 1,100 kPa. This top water caused significant steam losses and associated rise in SORs due to the pressure gradient between the steam chamber and the thief zone (Figure 1). While this could be partially mitigated through reduced pressures in the SAGD injector wells, the heat and steam losses were still significant. The reduced pressures also impacted rates because less steam was injected into the formation.

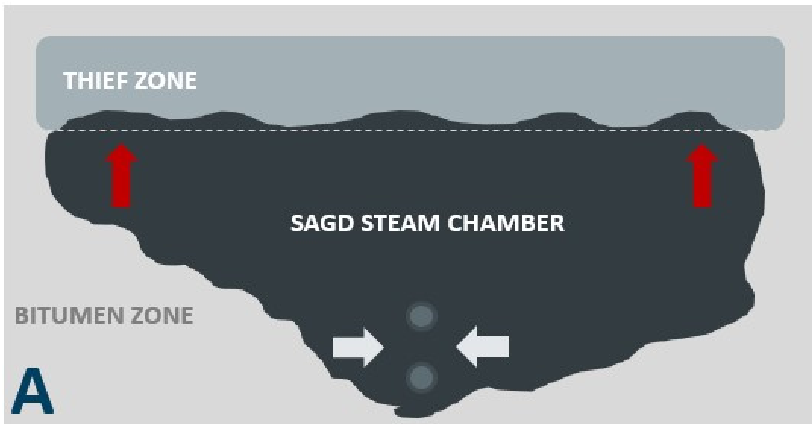

Figure 1: Thief zone interaction with a SAGD steam chamber

The losses to the top water led to the decision to pilot NCG co-injection on this pad. The goal for the pilot was to reduce the pad SOR by replacing the 'sacrificial' steam lost to the thief zone with NCG, which in turn would displace the top water to reduce heat and pressure losses (Figure 2).

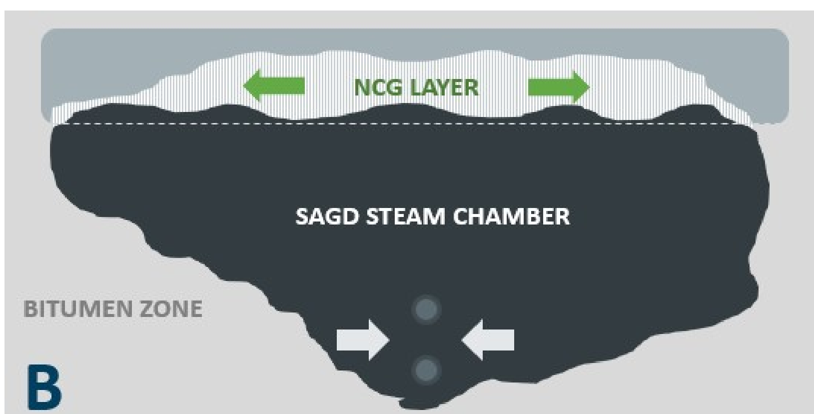

Figure 2: Mitigation of thief zone interaction with NCG co-injection

3.0 Pad Performance

3.1. **Pad History**

Pad "A" was put in operation in 2015 and had a typical SAGD circulation period. Following SAGD conversion, top water thief zone interaction began in late 2016. The severe steam losses to the top water forced a drop in the pad operating pressure. To support this lower pressure operation, the wells were converted from gas lift to ESP (electric submersible pump) production. A chart showing the pad performance and associated key events is shown in Figure 3 below.

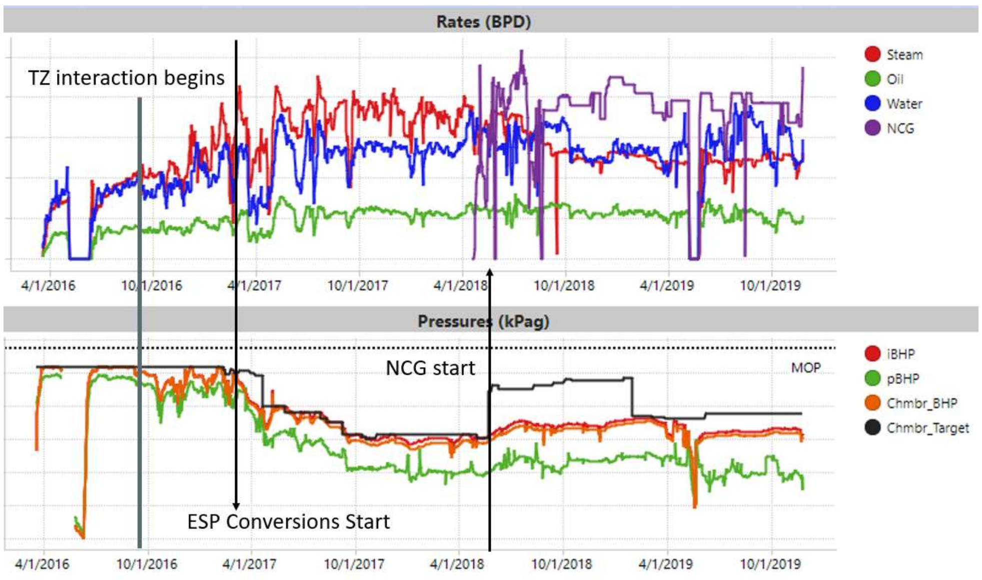

Figure 3: Pad "A" performance history and milestone dates

Reducing the pressure in the reservoir helped reduce the steam losses to the top water, but the pad SOR was still higher than average. At that point, the pad was selected for the NCG co-injection pilot. Pad injection and production rates were held steady from late 2017 to early 2018 to obtain a pre-NCG co-injection performance baseline. Then, the NCG co-injection pilot started in May 2018.

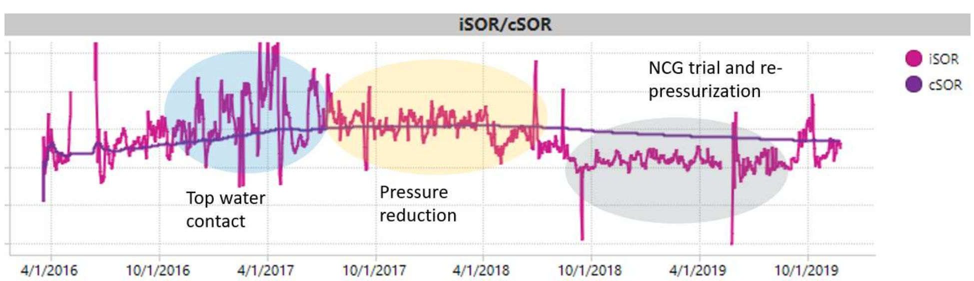

Figure 4: SOR history

3.1. **Pad Performance during NCG Pilot**

When NCG co-injection began, the pad injection pressure was allowed to increase in response to NCG co-injection, rather than maintaining a constant pressure target. Once the pressure had stabilized, steam injection was gradually reduced by about 30%.

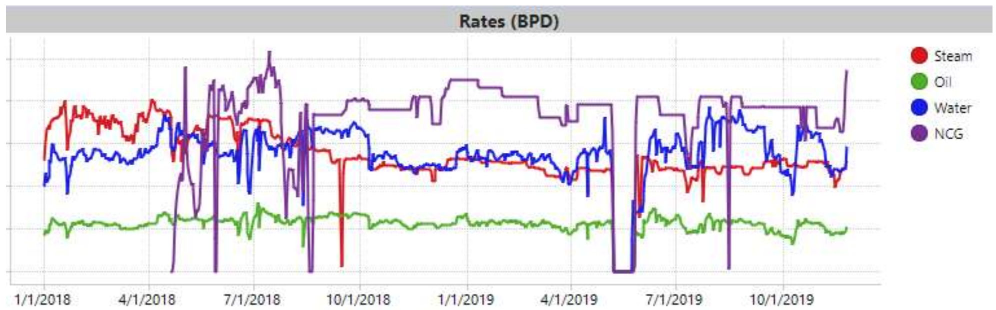

Figure 5: Timeframe showing the 2018 baseline data, NCG start and steam reductions

Despite the significant reduction in steam injection, the pad oil rate remained steady. The oil rate fluctuations throughout 2019 were related to well and pump repairs. As a result of lower steam injection rates and steady oil rates, the pad SOR decreased significantly.

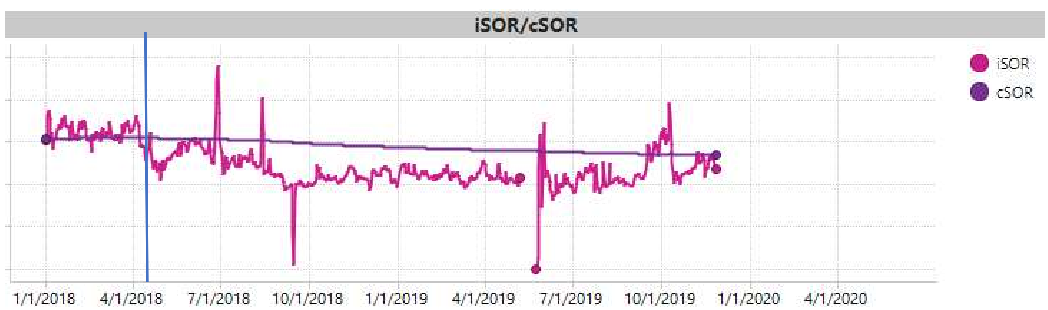

Figure 6: SOR reduction during NCG co-injection

3.2. **Water Production**

About a year into the pilot, pad water production began to increase. Most wells started to produce more water than there was steam injected. The subsurface team confirmed that this water was not coming from adjacent pads. When reviewing well specific data, it could be seen that wells with additional water production also had cold inflow at the toes. This, combined with the knowledge that the water was not coming from neighboring pads, supported that it was top water inflow. As discussed in the simulation section, simulation also predicts top water inflow.

3.3. **Pressure Behavior**

When NCG co-injection was started, both steam chamber and top water pressures increased. However, the top water pressure increased at a faster rate than the chamber pressure, which decreased the pressure differential between the top water and the chamber. Figure 7 shows the convergence of the top water and steam chamber pressures, where some observation wells show pressure equalization.

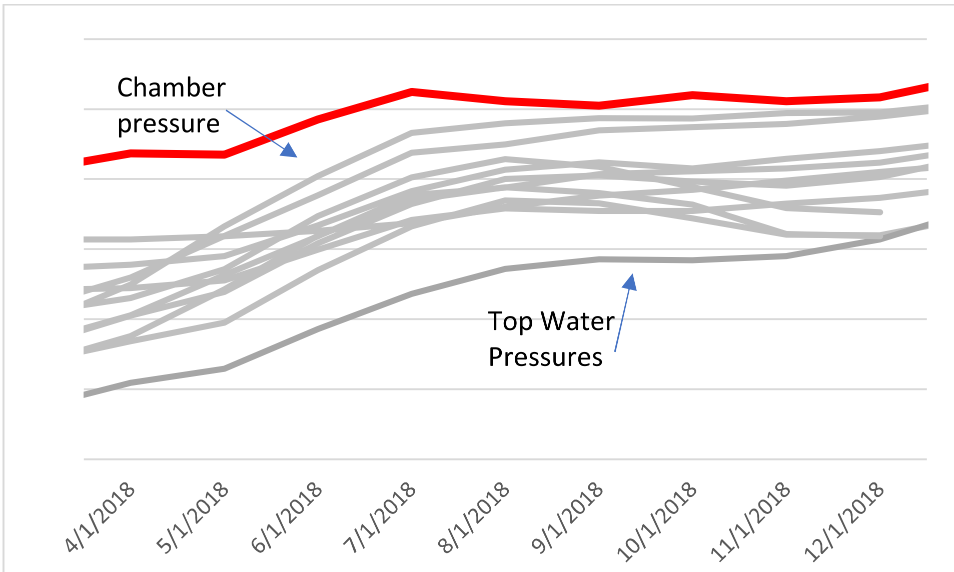

Figure 7: Observation well pressures for top water and steam chamber

4.0 Geosciences

4.1. **Residual Saturation Tool (RST) Monitoring Program**

ConocoPhillips conducted a baseline RST logging program in 2018 Q1 at 4 observation wells over Pad "A". This baseline logging program provided an understanding of the steam chamber sweeping efficiency prior to commencing the NCG co-injection pilot. A second RST logging program took place approximately 9 months after NCG co-injection started. The RST monitoring program was designed to help map NCG accumulation in both the steam chambers and top water thief zone.

<u>RST Program Results</u>

Pre-NCG RST baselines were acquired at 4 observation wells in February 2018, followed by the first monitor in February 2019. Observations and results from the pre-NCG baseline and subsequent monitor for each of the observation wells include:

<u>Well #1</u>

Pre-NCG RST: Limited vertical steam chamber development approximately 10mTVD above producer. Potentially stalled growth due to abundant mud-clast breccia over this location.

RST Monitor 1: Significant vertical steam chamber development 9 months after NCG deployment and 1 year after pre-NCG baseline. Approximately 20mTVD vertical growth between monitors. This rapid growth may be attributed to NCG helping penetrate low permeability mud clast breccia. However, this hypothesis is yet to be demonstrated due to dipping architecture of the McMurray formation and potential chamber growth from adjacent well pairs. Increased oil saturation above the top of the continuous bitumen suggests mobilization of bitumen from poorer reservoir above the defined pay.

<u>Well #2</u>

Pre-NCG RST: Extensive vertical steam chamber development sweeping most of the continuous bitumen interval, including steam across most of the top water thief zone.

RST Monitor 1: Similar saturation profile compared to the pre-NCG baseline with improved sweeping near the well pair level and gas accumulation within the inclined heterolithic strata (IHS) near the top of the McMurray. Differentiating between NCG and steam cannot be resolved using RST alone and will require detailed 4D seismic analysis.

<u>Well #3</u>

Pre-NCG RST: No steam chamber development due to lack of injector and unlined producer at location of observation well. Inflection in temperature and presence of some gas within top water thief zone suggests migration of chamber from adjacent well pair.

RST Monitor 1: No indication of steam chamber development. Increased temperature within IHS in top water thief zone and increased gas saturation compared to baseline. Potential NCG migration and accumulation over this area.

<u>Well #4</u>

Pre-NCG RST: Significant vertical steam chamber development sweeping the entire net continuous bitumen interval. Indication of steam near base of top water thief zone within Sandy-IHS.

RST Monitor 1: Little to no change in saturation profile between monitors. It appears that gas is stalling within Sandy-IHS at the base of the top water thief zone. Further analysis using 4D seismic may help differentiate NCG from steam.

<u>Future RST Monitoring</u>

RST monitoring has been planned for 2020 Q1 in 3 of the 4 observation wells that had previously run RST in support of the pilot. The timing of this RST program aligns with recent 4D seismic acquisition. This data can be integrated with the RST interpretation to better understand NCG gas accumalation and migration within the upper section of the reservoir, including the top water thief zone. In addition, 2 observation wells located on an adjacent drainage area have also been selected for RST monitoring in 2020 Q1 to help understand potential NCG migration off the pilot area. Continuous monitoring will improve our understanding of NCG accumulation and migration, allowing for better decision-making with respect to NCG deployment and operational efficiencies.

4.2. Reflection Seismic Data Acquisition Program

Reflection seismic data is an effective reservoir monitoring tool that ConocoPhillips utilizes for monitoring the conformance and development of thermal chambers over the Surmont SAGD asset. The seismic baseline survey on Pad “A” was acquired in 2011, approximately 4 years prior to first circulation of steam. After SAGD start, Pad “A” has had 3 time-lapse seismic monitoring surveys acquired.

Time-lapse Seismic Results - Baseline up first monitoring survey

Thermal chamber development, both lateral and vertical growth, can be observed since the first 4D time-lapse monitoring survey, approximately 11 months after the pad was converted into SAGD operation. The vertical growth was in the range of 5-10 meters above the injectors and it is growing as expected.

Time-lapse Seismic Results – Cumulative up to Fall 2019 monitoring survey

At the time of this report, the interpreted incremental 4D seismic anomalies from the Fall 2019 survey (first monitoring survey post NCG co-injection) show a combination of thermal growth and/or presence of NCG. Thermal chambers continue to grow where there is high vertical permeability connecting the reservoir to producers, with incremental growth between 10 to 20 meters. Excellent thermal chamber conformance can also be observed in Pad “A”.

AVO Seismic Analysis – In Progress

AVO seismic analysis is a technique that has been widely utilized in the oil and gas industry for exploration of natural gas in conventional reservoirs. Results from this AVO analysis are expected to show NCG anomalies accumulated in the reservoir.

ConocoPhillips will conduct an AVO analysis to differentiate anomalies from thermal response and presence of NCG in Pad “A” for continued monitoring/evaluation of NCG impact.

5.0 Reservoir Modelling

As the field trial of NCG co-injection for top water mitigation commenced on Pad “A”, a concurrent reservoir modeling project was kicked off in Q2 2018. The ultimate objective of the project was to achieve a history-matched model of the NCG field pilot once at least one year of field data was available. This allowed for validation of the NCG mechanisms and pilot performance, which increased the confidence level for the technology and supported the case for commercialization of the technology. The model was also be able to assist with demonstrating NCG benefits, both qualitatively and quantitatively, and provided insights for field strategy and planning. The reservoir modelling project was split into successive phases. Each phase and its key objectives are summarized here:

1. Mechanistic Study and Flexible Grid Modelling (FGM) Testing
    - Establish ideal top-water modeling methodology
    - Preliminary analysis of effect of shutdown on top water DA (drainage area)
    - Comparison of FGM vs. GR (gamma ray) geomodels
    - FGM geomodelling iteration
    - Geomodel upscaling validation
    - Comparison and selection of simulation software for the project

2. Global DA-Level SAGD History Match
    - Realization selection
    - Global modifications to achieve DA-level history match (pre-NCG)
    - Update shutdown analysis to assist with 2019 turnaround preparation
3. Refined Wellpair-Level SAGD History Match
    - Local modifications to achieve wellpair-level history match (pre-NCG)
4. NCG History Match
    - Achieve model with 16-month NCG history match
    - Establish scenarios for “dynamic baseline” to benchmark field performance
    - Provide theory for physical subsurface NCG mechanisms and demonstrate NCG value

5.1. Mechanistic Study and FGM Testing

The project began with a mechanistic study to set a solid foundation and ensure the best model, methods, and software were used for the history match. This part of the study involved evaluation of ideal methods for extensive top water simulation, an assessment of the new FGM model, selection of simulation software, and validation of model upscaling methodology.

5.1.1. Extensive Top Water Simulation Methodology

Pad “A” drainage area (DA) is under an extensive top water zone that encompasses an area much larger than the single DA. This has implications on DA performance by causing more fluid and pressure leak-off than if the top water was constrained. This leak-off has been observed in the field performance, thus to achieve a history-match of the DA, the extensive top water phenomenon needs to be captured in the simulation. A mechanistic study was conducted to determine the most suitable method to model an extensive top water on the basis of runtime, adaptability, ease-of-use, and how well it captures field-observed leak-off. The four methods examined were virtual wells, volume modifiers, semi-analytical aquifers, and a physically extensive top water grid.

The recommendation was to use virtual wells in the top water as a proxy for an extensive thief zone due to the fast runtime, ease of implementation, and ability to fine-tune the magnitude, timing, and persistence of the leak-off.

5.1.2. FGM Model

Near the start of this project, Flexible Grid Modelling (FGM), a new method of geologic modelling, became an alternative to the standard hybrid modelling method. The unique functionality of flex grid modelling was ideal for adjusting the framework of the ESMM (early stage McMurray), and then better reflect the stratigraphy without the need for onerous framework building.

5.2. SAGD (Pre-NCG) Global History Match

The history match approach was to first apply global model modifications to improve the DA history match, primarily on fluid rates and well pressures. 4D seismic was used qualitatively to compare against the areas of steam chamber growth in the simulation model. Local modifications for individual wellpairs followed the global history-matching exercise to ensure that the wellpairs performance was captured. The

NCG simulation was then performed on the refined wellpair-level SAGD history-matched model. The SAGD history match period goes until the NCG pilot start.

5.2.1. Global History Match Summary and Results

The DA-level results of the global history match compared to the base cases and the field are shown in Figure 8. Overall rate trends show a good match to field actuals and significant improvement over the base models. The cumulative volume errors for the global history match model are 5%, 6%, and 10%, for liquid production, oil production, and steam injection volumes, respectively. A key mismatch is the low steam injection rate in the model in 2017. This coincides with the historical strong thief zone interaction. One of the goals of the next phase of refined history matching is to increase the leak-off during this period while attempting to maintain a close match on production rates.

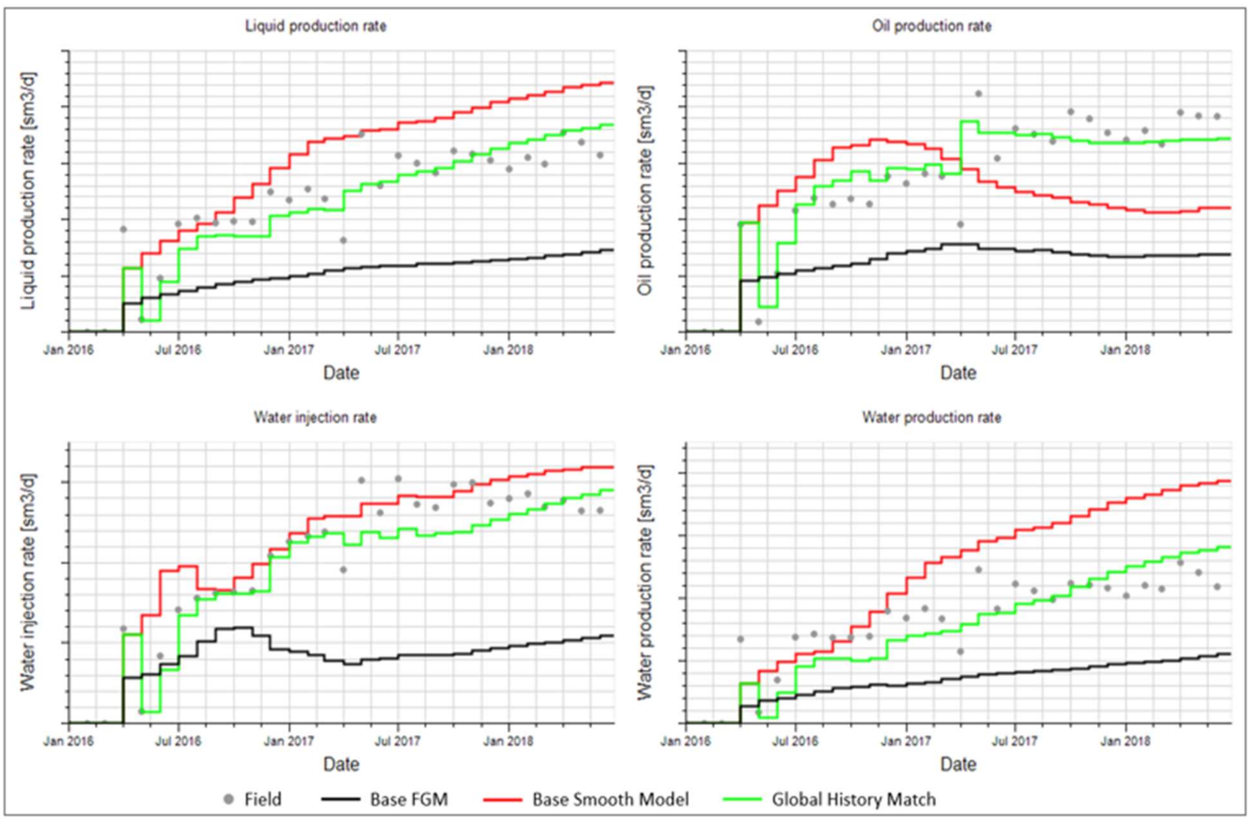

Figure 8: Simulation fluid rates compared to field actual (global HM and base models)

5.3. SAGD (Pre-NCG) Refined History Match

The global modifications described above resulted in a close match of pre-NCG DA cumulative volumes of oil, water, and steam. The wellpair-level match, however, varied significantly and the average cumulative volume errors for each wellpair were almost 20% for total liquid production and steam injection volumes, and almost 35% for oil production. Thus, the goal of the refined history match was to improve this wellpair-level match, primarily to increase the chance of success of the NCG history match, which was the ultimate goal of the project.

The focus of the refined history match was to achieve a good match to field data on cumulative volumes, rates and pressures for each wellpair. Additionally, a qualitative steam chamber growth area match to 4D seismic and observation well data was pursued. For all match parameters, particular emphasis was placed on the match quality in later time since this was very important for progression to the NCG phase. There is also more transience in early time, which makes simulation matching more challenging and less valid.

The high-level workflow used for the refined history match is shown in Figure 9. There were three key opportunities identified to improve the wellpair history match; local geological/petrophysical reservoir property edits, local thief zone severity reduction via permeability and water saturation multipliers, and fine-tuning of virtual and injector well pressure strategies.

Some local reservoir properties and top water modifications were initially trialed on individual wellpair sector models for quick turnaround with low runtime. However, most iterations needed to be run on the full DA model since the inter-wellpair effects and the open boundary effects can be significant factors for some well performance. The combination of the different modifications was an iterative process and careful attention was paid to the analysis of well performance since the correct balance and combination of different modifications was needed to achieve a successful history match.

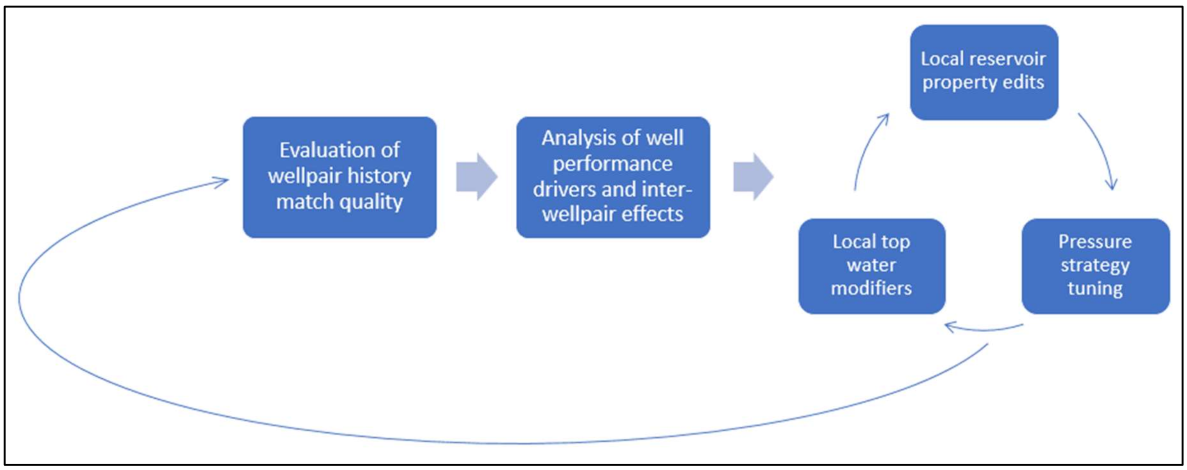

Figure 9: Refined history matching workflow for each well-pair

5.3.1. Refined History Match Results

While the global history match significantly improved the DA-level history match, there was still significant variations at the individual wellpair level. The refined history match did not significantly change results at the DA-level but drastically improved the wellpair-level history match. A comparison of the average wellpair-level error for cumulative volumes in simulation compared to field actuals right before the start of NCG is shown in Figure 10.

The refined history match also slightly improved the qualitative match to the 4D seismic anomalies (a strong correlation already existed in the base model). A qualitative evaluation of the simulation match to observation well temperature readings was also performed and there was full agreement of which wells were seeing steam temperature versus which were not.

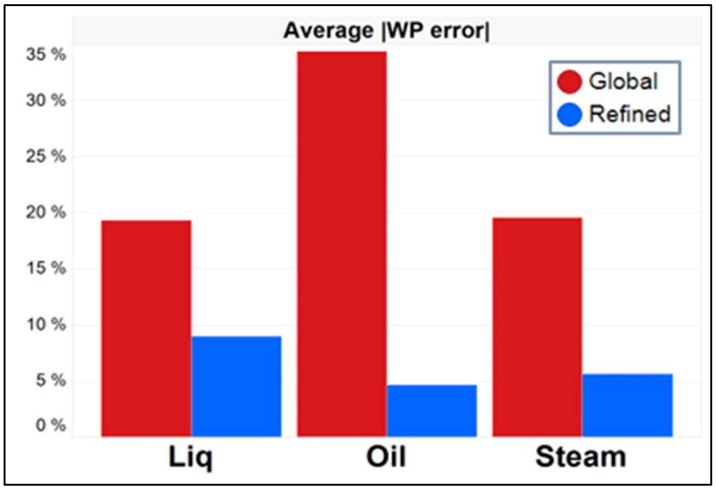

Figure 10: Average wellpair simulation error - Global vs Refined History Match

The refined history match also slightly improved the qualitative match to the 4D seismic anomalies (a strong correlation already existed in the base model). A qualitative evaluation of the simulation match to observation well temperature readings was also performed, and there was full agreement of which wells were seeing steam temperature versus which were not.

5.4. **NCG History Match**

The final phase of the project was to simulate the NCG pilot and achieve a history match to the field. Other key goals of this phase were to determine a confidence level of NCG simulation, particularly with top thief zones, establish NCG modelling best practices, provide insights on the reservoir mechanisms of NCG in top water applications, and set a “dynamic baseline” to benchmark the pilot.

The KPI plots comparing the simulation to the field are shown in Figure 11 and overall cumulative volume errors for the model summarized in Figure 12.

During the NCG period, steam and NCG rates are essentially an exact match since the simulation is controlled on historical injection rate actuals. At the DA-level, the simulation oil production rate is a close match to the field actuals. The average injection BHP in simulation follows the same trend as the field with slight deviation between simulation and field beginning in 2019.

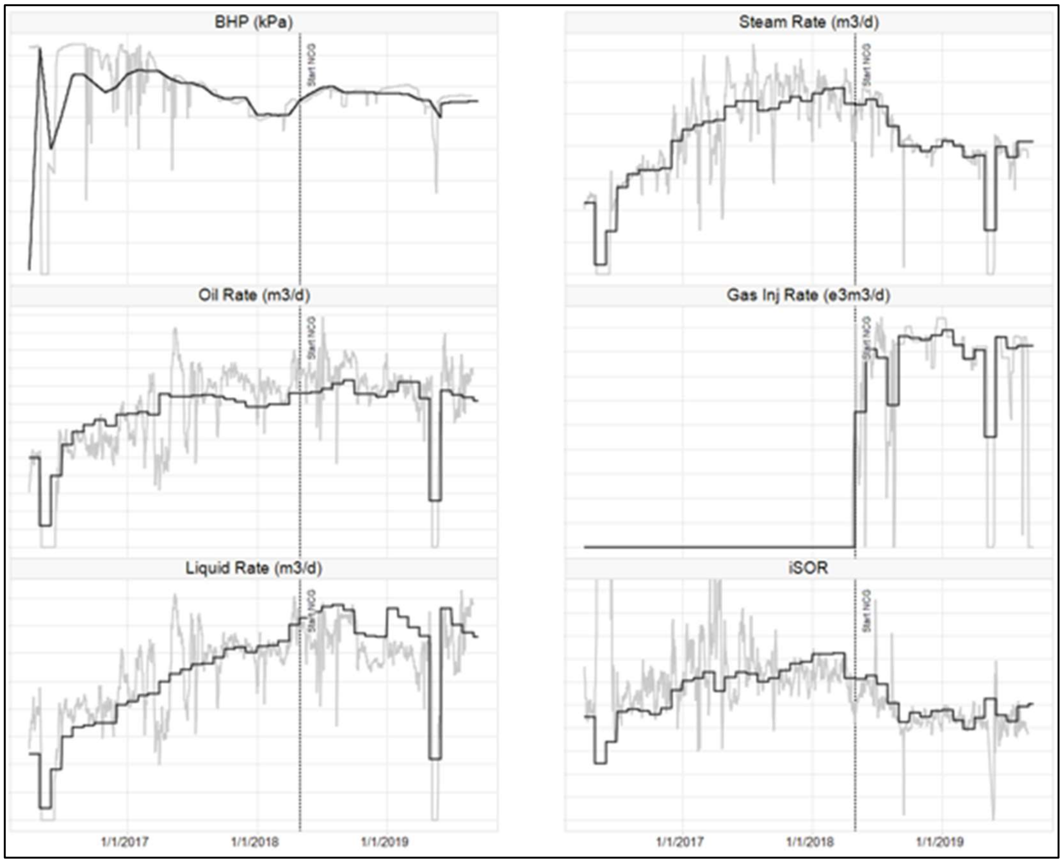

Figure 11: Comparison of NCG simulation (black) to field data (grey)

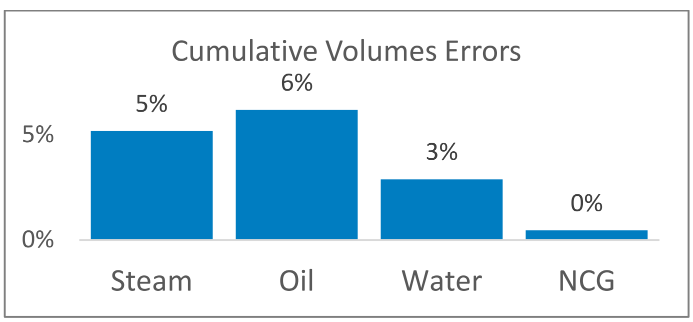

Figure 12: Simulation cumulative volume errors

5.4.1. Dynamic Baselines & NCG Benefits

Quantification of the SOR benefits of the NCG pilot has been generally achieved by comparison to a static historical baseline (i.e. the performance of Pad "A" prior to NCG). This baseline may not adequately account for the dynamic nature of the DA performance over time. Simulation can provide a dynamic baseline as an additional benchmark for pilot evaluation. Two non-NCG scenarios in simulation were used to achieve this:

1. A ***pressure baseline*** benchmarks NCG pilot performance against operating at a similar pressure strategy but without NCG. For the period of the NCG pilot, the simulation is operated with only steam and no NCG at a constant injection pressure close to the field operating pressure.
2. A ***steam baseline*** benchmarks NCG performance against the same steam rates but without NCG. For the period of the NCG pilot, the simulation is operated with the historical actuals for steam injection rate and without any NCG.

A comparison of the NCG simulation and field performance to the two dynamic baselines is shown in Figure 13. In order to maintain the pressure, the baseline case needs to inject much more steam than the field actuals or NCG simulation. This results in a significantly higher SOR since there is only a minor effect on oil rate from all this additional steam. The steam baseline case sees a significant drop in pressure since the field steam rate cuts are applied without any NCG to compensate. There is initially a negligible effect on oil rate compared to the NCG case, but after the first few months, the oil rate begins to deteriorate and SOR increases.

Overall, the NCG pilot field results demonstrate a 30-35% SOR reduction compared to the dynamic baselines as of September 2019. This corroborates the SOR benefits claimed from benchmarking against the static baseline. In addition to the SOR benefit, there is also a pressure benefit over the steam dynamic baseline.

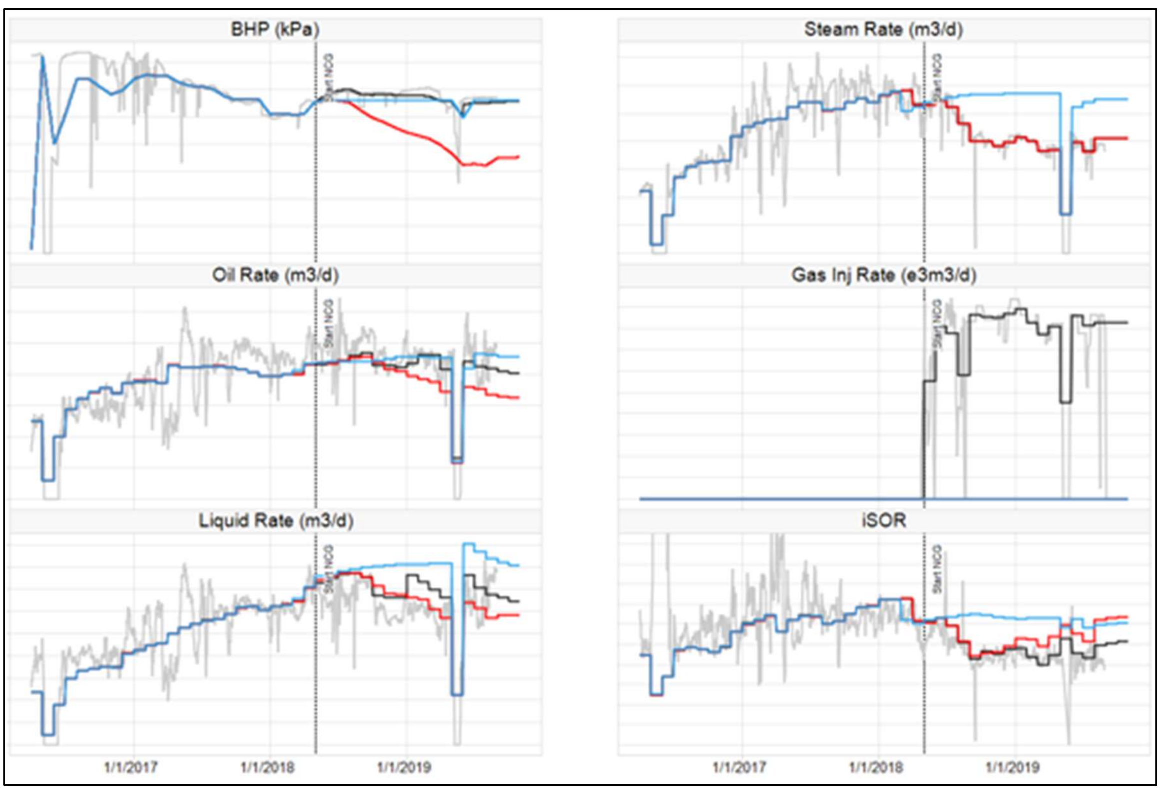

Figure 13: Comparison of field performance (grey), NCG simulation (black), steam baseline simulation (red), and pressure baseline simulation (blue)

6.0 Conclusions

The pilot clearly exceeded the expectations and metrics set in the beginning of the project. Steam-oil ratio (SOR) reductions were very strong with no impact to oil production rates. The pilot results are summarized in Table 1.

Table 1: Summary of Pilot Results

SOR Reduction	Total Steam Savings	Total NCG Co-Injected	Avoided GHG Emissions
35%	~6.2MM bbl	~22MM m^3	~110M tonnes

Building upon the success of this pilot, NCG co-injection will be expanded into adjacent pads that surround Pad "A" to mitigate the impact of the top water thief zone as a block. The expansion will start in Q1 2020, and the implementation sequence will be dictated by thief zone interaction severity.