COMPUTER MODELLING GROUP LTD.

STARS

Successful Optimization of an ASP Injection Achieves Increased Oil Recovery

Benefits

- Intuitive wizards enable quick and easy simulation model set-up of an ASP process
- Accurate modelling of important phonomena: polymer degradation, component adsorption & IFT reduction
- History match & optimize field-wide cEOR processes to reduce risk and increase probability of success

Why Implement?

Recover oil, from a reservoir, that was trapped after applying primary and secondary recovery methods

Why Simulate?

Test viability of an ASP flood in the Little Bow; if viable, the goal will be to optimize for the highest possible recovery factor

Results

Optimizing the ASP flood resulted in a 27% increase in the oil recovery factor

Despite the recent North American focus on developing unconventional reservoirs, large volumes of unrecovered oil still remain in conventional reservoirs. These conventional reservoirs may be great candidates for an Alkali-Surfactant-Polymer (ASP) process because it can mobilize and push out the trapped oil left behind after primary and secondary recovery methods.

ASP involves the injection of aqueous chemicals — surfactant and alkali — into a reservoir to reduce interfacial tension and alter rock wettability. As a result, trapped oil can be mobilized and recovered. In addition, polymer is injected to improve the sweep efficiency by making the injected fluid's mobility ratio more favourable.

If the chemical injection scheme is designed specifically for the reservoir, keeping in mind rock and fluid, characteristics, and implemented correctly in the field, an ASP injection should lead to incremental oil recovery. STARS™, an advanced processes reservoir simulator, has a robust platform that can be used to develop a strategic ASP design in order to optimize incremental oil recovery and avoid unforeseen issues during field implementation and production.

Little Bow Upper Manville I: Background

The Little Bow Upper Manville I field, managed by Zargon Oil & Gas Ltd, is a high permeability Glauconitic Formation located in southern Alberta, Canada. The main goal of this study was to determine the viability of ASP injection in the Little Bow field by analyzing the incremental oil recovery after the ASP flood. If successful, an optimization would be performed to determine the optimal ASP strategy by altering parameters, including: concentration or mix of injected chemicals; pore volumes injected; and number of injection and producer wells.

History Match & ASP Optimization Workflow

STARS

History Match of Field Simulation Model and ASP Core Test

Field Scale Primary & Waterflood Simulation Model

Zargon created the field scale simulation model in IMEX using geological, PVT, and petrographic data analyzed over different areas of the reservoir, as well as, multiple water-oil (WOC) and gas-oil contacts (GOC). In IMEX, a black oil PVT was used to perform the history match for the primary depletion and waterflooding stages and then was converted to a compositional PVT model for the ASP forecasting portion in STARS.

Lab Model

The ASP process was tested in multiple core flood experiments to achieve confidence in the applicability of the process on the Little Bow reservoir. The experiment led to an incremental oil recovery of 19% after the ASP flood. Furthermore, ASP flood followed by polymer chase reduced the residual oil by 60%, thus increasing the oil cut. The experiment proved an ASP flood could be successful in this field.

Using STARS, the core flood results were matched to reduce uncertainty and determine critical ASP related simulation parameters that could be used in the full field simulation model. To obtain a proper match to the historical data, several main effects or phenomena were considered in the simulation model.

1. **IFT Reduction Effects –** The presence of surfactant and alkali cause significant IFT reduction between the oil and water phase which results in wettability change from oil-wet to water-wet and a decrease in the residual oil saturation.
2. **Polymer Viscosity –** Polymer acts as a mobility controlling agent; therefore its viscosity significantly affects the sweep of the injected fluid. Since viscosity of the injected fluid is dependent on the polymer concentration, shear, and degradation effects, the lab measured data was adjusted to match the coreflood behavior.
3. **Surfactant & Polymer Adsorption –** Chemicals and polymer in the injected fluid exhibit different levels of adsorption on the rock surface, depending on the component's concentration in the injection stream. The effectiveness of the ASP process is contingent on a good sweep of the chemicals through the flood area and chemical adsorption negatively impacts the performance of the ASP flood, thus should be modeled accurately. The lab measured surfactant and polymer adsorption data was used and adjusted to history match the chemical effluent production from the coreflood experiments.

After incorporating all the advanced mechanisms associated with the ASP flood simulation and fine tuning them against the experimental data, a successful history match of the oil recovery was obtained.

ASP Prediction

For the purpose of implementing an ASP flood into the simulation model, the history matched blackoil IMEX model was converted to a STARS multi-component model and the parameters obtained from the lab-scale and waterflooding history match were imported into the full-field model. Prior to the ASP prediction run, a base case waterflood was implemented until the year 2035 to estimate the oil recovery, without doing an ASP flood. The simulation results showed incremental oil recovery of 4.7% over 21 years, suggesting it is inefficient to continue waterflooding due to the high residual oil saturation of 30-40% and poor sweep efficiency.

For the ASP flood prediction, the strategy involved injecting the Alkaline-Surfactant slug first, followed by polymer injection, and lastly a chase waterflood.

The goal for the initial Alkaline-Surfactant slug is to reduce the residual oil saturation and displace oil from the surface of the rock. Next, the polymer injection provides mobility control, improved sweep efficiency and sweeps the mobilized oil towards the producer.

The subsequent chase water injection provides pressure support and pushes any remaining oil and chemicals towards the producer. The ASP flood simulation in the Little Bow reservoir led to an incremental oil recovery of 18.5%, compared to 4.7% with the waterflood therefore validating the applicability of this process for this reservoir.

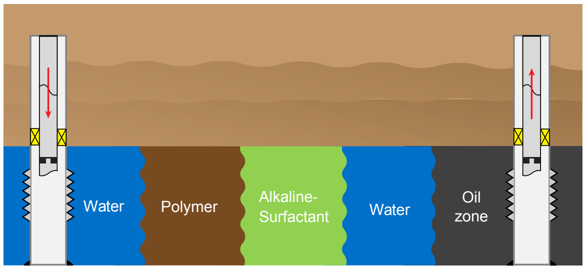

Figure 1 - Alkali is injected to react with the organic acid in the oil to produce in-situ surfactant to reduce S_{orw}. Synthetic surfactant and Polymer flood are also injected to further reduce S_{orw} and improve mobility control.

STARS

ASP Optimization

The large number of variables in the ASP process presented a good opportunity to conduct an optimization of the ASP injection scheme. The main optimization parameters that were considered are below:

- **Chemical Concentration & Slug Size –** Optimal chemical concentration and slug size for injected chemicals (i.e. Alkaline ,Surfactant and Polymer) is critical for economic and technical success of the process/project.
- **Polymer Slug Injection Strategy & PV –** To determine the effectiveness of the tapered polymer chase, the polymer slug is split into two segments. The second polymer slug has a lower viscosity than the first to improve reservoir sweep. The concentration and PV of both polymer slugs were also optimized.
- **Injector-Producer Location Optimization –** The study used six potential injectors and one producer well as optimization parameters. Note, the drilling and completion cost of the well was also included in the economic analysis of the process.

Due to the large number of variables, CMOST™, an integrated analysis and optimization engineering tool, was used to determine the optimal combination of all the parameters. CMOST used the Designed Exploration and Controlled Evolution (DECE) optimization algorithm to focus on the parameters that had the greatest effect on the results; therefore CMOST was able to converge on an optimal solution, without running too many cases. The goal of the optimization study was to identify the strategy that yields the optimal net present value (NPV). CMOST converged on an optimal case with a $200MM NPV and a 27.2% incremental oil production.

Field Implementation and Validation

Over the past few years, the ASP process was implemented in the field and once the simulation model was updated with the field injection data, it closely matched the field production *(figure 2)*. STARS' advanced ASP features enabled Zargon to attain a predictive simulation model that replicated the field behavior, and proved the value of simulation and optimization prior to field implementation.

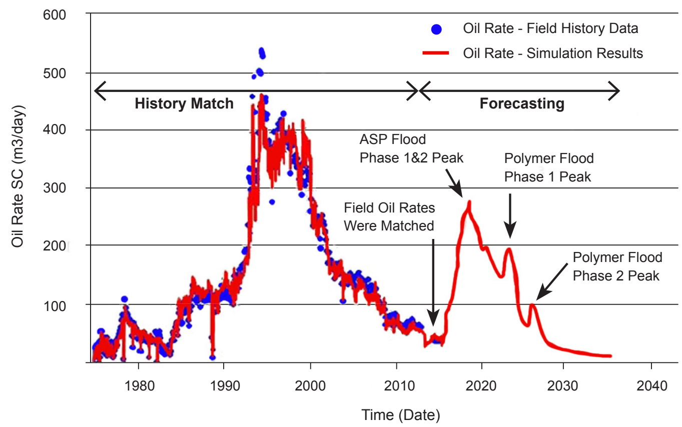

Figure 2 - ASP field implementation in comparison to simulation results

This case study is based upon SPE 183112-MS "Full Field Chemical EOR in a Mature Southern Alberta Water Flooded Reservoir - The Little Bow Case Study" †. To read the full technical paper, please visit www.onepetro.org.

Contact
For more information please contact **sales@cmgl.ca**

R&D Investment
CMG reinvests 20% annual revenue back into R&D, to further innovation and drive technology forward

Superior Software
CMG delivers easy to use software that provides the most accurate results

Dedicated Support
Experienced technical sales & support personnel, deliver high-quality, timely and personalized customer support

Relevant Training
CMG's industry renowned reservoir software training provides the skills to improve productivity and efficiency