Optimization of the Recovery Factor by Implementing a Continuous Steam Injection Pilot in the Huyaparí Field Located in the Orinoco Oil Belt. Venezuela.

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Abstract

The Orinoco Heavy Oil Belt (Faja) represents one of the largest accumulations of known Extra Heavy Crude Oil (EHCO), with estimates ranging in the 1.0 to 1.2 Trillion Barrels of Oil in place. Increasing the recovery from the reservoirs in the Faja is one of the key objectives of the new PDVSA.The application of a thermal recovery process, specifically steam injection, has been proven in other heavy oil reservoirs to be a successful way to increase production and recovery.

Even though not all the reservoirs in the area are amenable to the proposed thermal process, the average recovery could surpass the 20% target set by PDVSA for the Faja reservoirs. If the initial application is successful, production and recoveries in the Faja could experience the same increases already achieved by some fields and reservoirs impacted by steam. The objective of the proposed pilot project is to demonstrate technical and commercial feasibility of moving a large resource base to reserve by increasing ultimate recovery in the Orinoco Heavy Oil Belt (Faja) with a thermal Enhance Oil Recovery (EOR) process, specifically, steam injection

Introduction

The Faja (The Orinoco Heavy Oil Belt), as currently defined, covers approximately 54,000 square kilometers and extends for over 600 km in an east-west direction just north of the Orinoco River. It is the single largest oil accumulation in the world with an estimated 1.2 trillion barrels of heavy and extra-heavy crude oil in place. The presence of unconventional oil resources in the Orinoco oil belt has been known for many years, however, exploitation of these resources became economically feasible only recently by using a combination of advanced upstream and down-steam technologies.

Figure 1. Petropiar location in the Bolivarian Republic of Venezuela

Huyapari field, shown in figure 1, is located in the Ayacucho Block in the Orinnoco Heavy Oil Belt in eastern Venezuela, and operated by PDVSA Petropiar, a joint company between Chevron and PDVSA. Huyapari field is currently being produced under cold primary production with the expected recoveries in the order of 6 to 10%. To date, more than 390 horizontal producing wells have been drilled in the field, as shown in the figure 2.

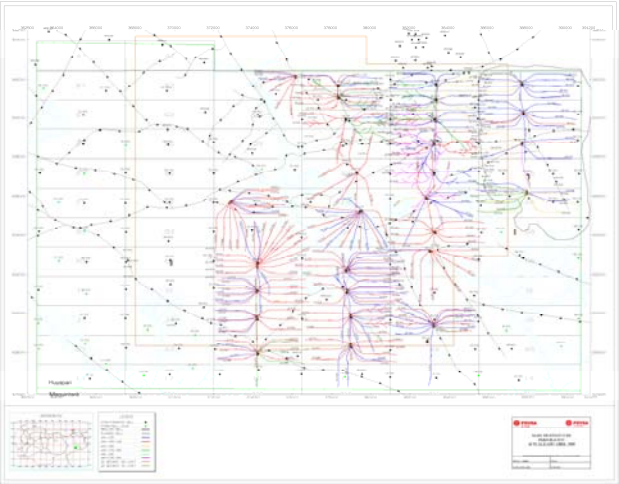


Figure 2. Drilled wells in Huyapari Field.

Cold production has its advantages from an economic point of view, but the levels of production and the recovery factor obtained are quite low. Therefore, increasing the recovery from the reservoirs in the Faja is one of the key objectives of the new PDVSA, it becomes imperative to implement enhanced recovery methods which are suitable for Faja reservoirs.

The application of a thermal recovery process, specifically steam injection, has been proven in other heavy oil reservoirs to be a successful way to increase production and recovery. However, the heavy and extra-heavy crude are not distributed uniformly in Huyapari. Oil gravity, viscosity and sulfur and metals content vary greatly in east-west and north-south directions as well as vertically within the fluvial dominated stratigraphic section. A thermally enhanced oil recovery pilot was proposed, and is under progress to address the challenges in such complex reservoir conditions for future expansion.

In this paper, we will present an overview of the project and discuss the general aspects of project design, uncertainty management, and optimization plan, then end with a forward plan.

The project

The proposed Huyapari thermal pilot project is intended to demonstrate the technical and commercial feasibility of increasing recovery in the Faja with a thermal Enhance Oil Recovery (EOR) process, specifically, with continuous steam injection.

By demonstrating the applicability of continuous steam injection in the Faja, future expansion to additional areas amenable to thermal EOR will be supported and increases in the overall recovery in the Faja to above 20% could be achieved. The success of a thermal EOR process in the Faja could have a significant impact on the value of current operations. Production in the current developed areas could increase in the range of 300 to 600%, and recoveries could go as high as 60% in the areas impacted by the steam. These results could be achieved if the response of the Faja reservoirs to continuous steam injection is similar to the ones seen in other heavy oil reservoirs.

The key pilot objectives

- Prove that commercial rates of oil production and that the incremental recovery is achievable by the continuous injection of steam;
- Obtain information from capital investment and operating costs (including the steam / oil) to support the mass of the thermal process;
- Assess the potential of several thermal zones and / or different configurations of the producing wells and injectors;
- Evaluate the best method of artificial lift and completion strategies;
  Provide information needed to develop robust plans for managing risks and uncertainties of surface, subsurface and operational;
- Optimize the operation of the reservoir to increase the availability of financial resources for national development.

Key Uncertainties and Challenges

The Faja accumulations are vast and contain unconventional crude oils. These create a series of specific pilot uncertainties and technical challenges. Among these are:

- Reservoir quality (continuity and thickness) and fluid properties in the pilot area
- Time required to lower reservoir pressure to optimize thermal efficiency
- Optimum injection and production well configuration
- Artificial lift constraints for thermal production, currently around 1800 BFPD
- Diluent requirement for transport of produced hot crude

The Project Scope

The pilot will test sufficient area and achieve sufficient levels of production in order to provide a sound base upon which a decision for field expansion can be made. The pilot design includes:

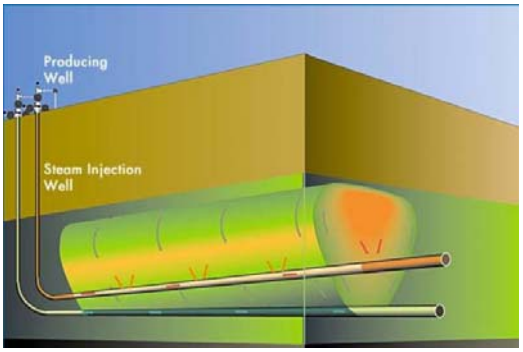
- +/- 300-acre project area
- +/- 20000 BOPD peak oil production
- +/- 60000 BSPD, cold water equivalent steam injection
- Primary production to lower reservoir pressure and get the thermal infrastructure in place before beginning continuous steam injection
- Production, steam injection, and observations wells as required by the optimum configuration
- Use of cyclic steam stimulation to optimize production
- Test artificial lift strategies to maximize production

Several well configurations will be tested in the pilot. Some of the most promising are:

Horizontal injector and horizontal (HIHP):

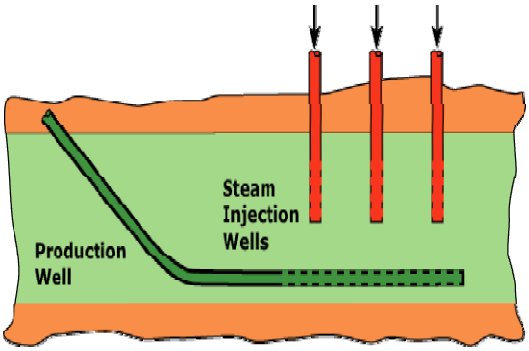
This well configuration consists of parallel horizontal wells separated vertically with or without off-set. The lower well is the producer while the top well is the steam injector. The horizontal well length will be based on artificial lift limitations. Vertical separation and injector off-set can also be optimized. The Steam Assisted Gravity Drainage (SAGD) experience of

15-feet could be used as a starting point. A schematic of the configuration is shown below.



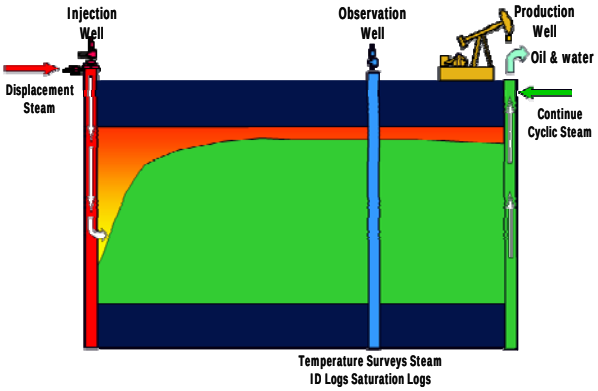
Vertical Injectors with Horizontal Producers (VIHP):

This well configuration consists of horizontal producers with vertical steam injectors. Injector well location and number can be optimized. As for the previous case, the horizontal well length will be based on artificial lift limitations.



Vertical Injectors with Vertical Producers (VIVP):

This well configuration consists of vertical producers and steam injectors. Injector well location and number can be optimized using standard steamflood patterns already in use in other thermal operations.



Project Development

Rock and Fluid Property Challenges

The pilot uncertainty management plan (UMP) was based on Petropiar uncertainty management plan for primary production, and broadened by thermal recovery experts to include additional parameters from analog fields.

Initial feasibility studies studied possible pilot well configurations and identified important Huyapari geologic, reservoir, and fluid parameters that effect oil production performance independent of the site. The study screened out a number of uncertainties through the folded Plackett-Burman experimental design.

However, nine variables were found to be significant for all pattern configurations and recommended to be carried forward in the future site specific work

1. Sand proportion (LOCAL)
2. Sand continuity / correlation length of sand (X direction – A1-S)
3. Sand continuity / correlation length of sand (Z direction – A3-S)
4. Ratio vertical permeability to horizontal permeability (KVKHC for sand and / or (shale)mud's)
5. Ratio vertical permeability to horizontal permeability (KVKHSI for silt)
6. Residual oil saturation to gas (SORG)
7. Oil viscosity (OVIS)
8. Relative permeability to gas (KRG)
9. Vertical permeability (ZPERM)

Site Selection

The main objective was to identify the best site for the thermal pilot in the Huyupari field. This was a critical phase for the pilot and one of the most important to be developed.

The intent of the site selection study was to identify the most favorable site for an approximately 300 Acre thermal pilot with the possibility of running multiple well configurations including at least one pattern with horizontal producers and one pattern with vertical producers. This mix of configurations could be accommodated by an area where there are two separate pay zones.

The following criteria were developed for selecting a pilot site:

- maximize hydrocarbon thickness (weighted PHIE in pay * weighted So in pay * interval thickness*NTG)
- must be outside of morichales' catchment areas
- must be penetrated by a well
- minimize initial pressure

Desirability mapping was conducted by querying the full field earth model to generate maps of the following criteria:

1. Pay thickness (hydrocarbon column thickness)
2. Potential thickness of perched water (wet pay)
3. Initial pressure (depth of reservoir combined with amount of potential production-drawdown)
4. Distance to fault zone
5. Vertical continuity of pay zone

The L5 site (see figure 6A) was selected for the pilot. The drawback of this site, which has a total of three vertical stratigraphic wells and no 3D seismic, is the lack of data. The initial work plan for the pilot includes four additional stratigraphic wells and 3D seismic acquisition.

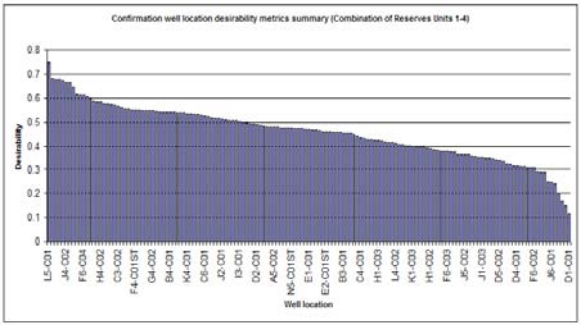


Figure 3: Summary of the Site Selection metrics

Site Specific Subsurface Modeling

For the L5 modeling, the drivers are to test the feasibility of secondary recovery on the targeted interval sands using steam flood and test well configurations decided in the earlier feasibility study at an appropriate scale.

Given these drivers, the modeling strategy for the thermal pilot is:

- Model a deterministic "base case" geologic realization and conduct studies for optimization of the different well configurations and constraints.
- Conduct Experimental Design changing both static & dynamic properties while keeping the "best" well configuration from the ¨base case¨ static model.

The initial deterministic "base case" model was constructed utilizing the all the available vertical stratigraphic well data, full field net sand maps, structural interpretation, scaled permeability models from the core.

The key interval of interest modeled is shown in Figure 4 below.

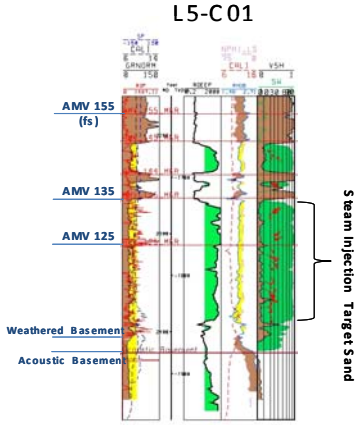


Figure 4 Steam Injection Target

The overall deterministic static model workflow is illustrated below:

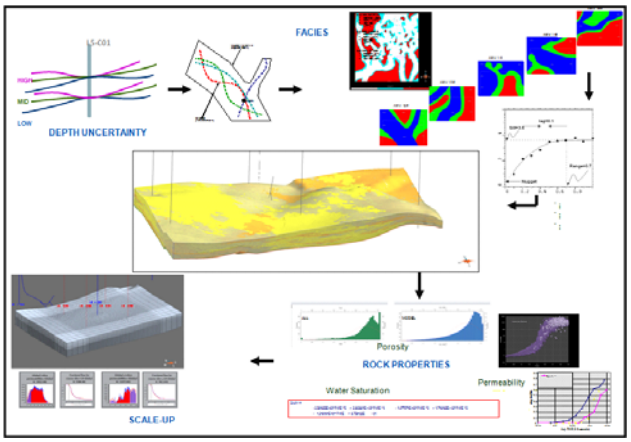


Figure 5, the overall deterministic static model workflow

Optimization of well configurations and well constraints

Optimization of wells were performed by thermal simulation subject to three well configurations, shown in Figure 8A:

- Horizontal Injectors and Horizontal Producers (HIHP)
- Vertical Injectors and Horizontal Producers (VIHP)
- Vertical Injectors and Vertical Producers (VIVP)

A series of sensitivity studies were performed to differentiate the effects of well length, spacing, orientation, and injection production constraints on thermal recovery factor, which are categorized as follows:

For Horizontal Injectors and Horizontal Producers (HIHP):

- Different HIHP well lateral spacing of 80, 120, 160 meters;
- Different HIHP well vertical separations of 40, 60, 80 and 100 feett;
- Different HIHP well lengths of 1000, 2000, 3000, and 4000 feet;
- Different HIHP well injection temperature and pressure constraints of 200, 300, 400, 500, 600 Psi;
- Different HIHP production steam controls subject to subcool constraints of 10, 20, 30, 40, 50, and 60 deg. F and maximum steam production rates of 1, 10, 20, 30, 40, and 50 cold water equivalent, bbls/day.
- HIHP well dipping impact (one task for perfectly horizontal wells and the wells that follow stratigraphy, another is to use a discretized well bore model for updip and down dip wells) in the dipping formation;
- HIHP well placement orientation along the channel axis;
- Cross HIHP and Shifted HIHP well configurations

For Vertical Injectors and Horizontal Producers (VIHP):

- The intensity of vertical injectors along the producers with lateral spacings of 60, 120, and 240 meters.
- The sapcing of vertical injectors between the producers with 80, 120, and 160 meters;
- Different horizontal well lengths of 1000, 2000, and 4000 feett.

For Vertical Injectors and Vetical Producers (VIVP):

- 3 pattern sizes of 6, 7.5, and 12 acres.

Further work from the site specific team supported the earlier feasibility studies. A total of eight uncertainty variables were chosen to carry out simulation for all pattern configurations in the Experimental Design.

1. Net to Gross
2. Reservoir Architecture
3. Channel complex width
4. Horizontal permeability
5. Ratio KvKh
6. Residual oil saturation to gas (SORG)
7. Oil viscosity
8. Relative permeability

These uncertainty variables are part of experimental design study, which is currently underway.

Artificial Lift Challenges

Artificial Lift is a key part of the thermal pilot as it is important to install an artificial lift system that works efficiently under conditions of steam injection (high temperature). The team evaluated the following:

Researched about choices in the market on artificial lift with temperatures above 400 ° F.

• Assess gap in technology relating to:
- High temperature (> 400 degrees F)
- High rate of oil
- Levels of reliability existing options

• Evaluated the possible vision and technological progress in the next five years.

• Model possible rates of artificial lift

• Develop and provide the basis for developing probabilistic production forecasts.

Conclusion

The project is well under development; here we use a path forward to serve our conlusion of this paper.

Future work or next steps for the Huyapari EOR pilot are:

- Drill four pilot stratigraphic / future observation wells (see figure. 7A)
- Acquire 3D Seismic over the pilot area
- Update simulation models based on confirmation wells data, analogs and relevant project experience
- Perform appropriate DOE study of revised simulation models to further refine and improve oil production forecasts
- Perform decision analysis of all the alternatives
- Start cold production to lower reservoir pressure in the pilot site
- Implement the surveillance and monitoring plan

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Annex:

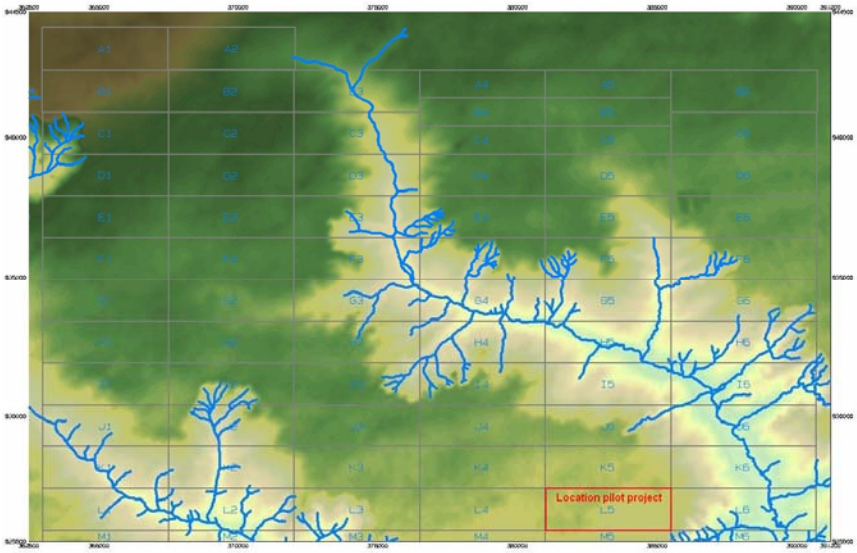

Figure. 6A.- Location of the pilot project "L5 area"

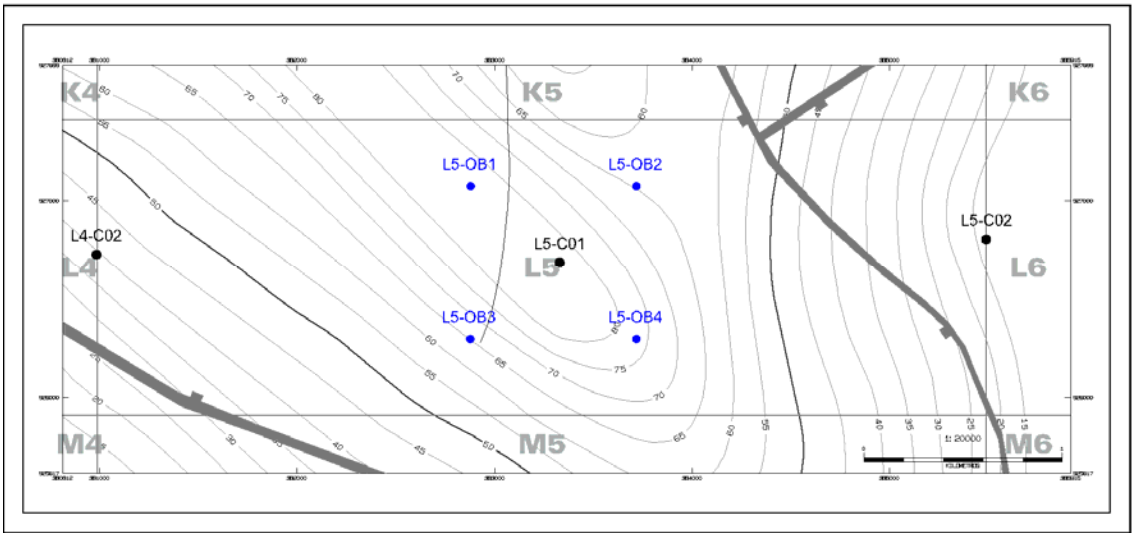

Figure. 7A.- Location the 4 stratigraphic / observation wells (Blue) in L5 area.

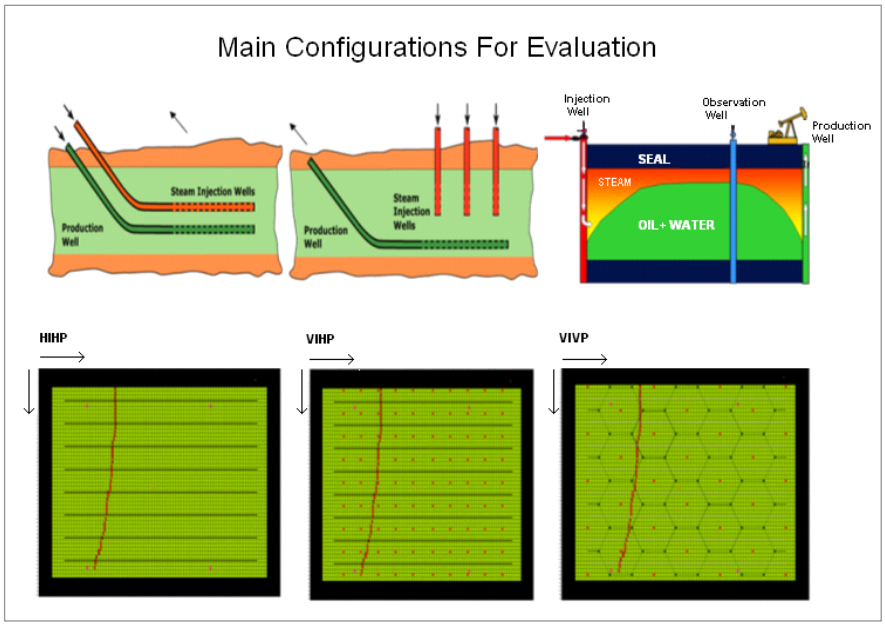

Figure 8A. Different configurations for project evaluation.