Technological Developments for Enhancing Extra Heavy Oil Productivity in Fields of the Faja Petrolifera del Orinoco (FPO), Venezuela*

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Abstract

The Faja Petrolífera del Orinoco (FPO) is located in the Eastern Venezuela Basin. The 55,000 sq. km. area currently has a recoverable oil estimate of 257 billion barrels and contains projects with a production totaling 1.1 million BOPD and upgrading facilities that convert the 8.5° crude into oils of 16° to 32° API at the "Jose Upgrading Complex". Twenty percent (20%) of this extensive area is being developed using cold production wells with 3,000-5,000 foot horizontal extensions; with six new joint venture projects in a startup phase. Cold recovery factors are on the order 8% to 12%, due to high viscosities of 2000-5000 Cp at reservoir conditions. To facilitate crude transport a 50° API naphtha diluent is injected downhole, decreasing viscosities and increasing the 8.5° API crude to 16°. At present there is a strong focus on increasing oil production rates from existing fields. Besides providing additional economic benefits, this increment allows for lowering reservoir pressures in a shorter time span to provide for an earlier initiation of proposed thermal enhanced recovery projects. These involve techniques such as SAGD, HASD and conventional SD.

This article presents an overview of the application of best practices involving the use of the following innovative technological developments and how they are currently enhancing the crude oil productivity in the area: Down Hole Diluent (Naphtha) Injection, Down Hole Electrical Heaters, Injection of Surfactants, Sealing Gels for water entry shut off, "Dewatering" techniques, use of Azimuthal Resistivity Tool (ADR) for geosteering in thin heterolithic reservoirs, and also various methods currently in a pilot phase of development such as Viscosity Reducing Polymers, Diluent Heating and Cold Heavy Oil Production with Sand, (CHOPS). It is clear that new developments in technology are making the Faja Petrolífera del Orinoco (FPO) one of the most important extra heavy oil producing areas in the world.

Introduction

The Faja constitutes the foundation for Venezuela's future economic and energy development. Currently, the corporation is promoting new developments which are based on growth at a technological level. These new developments will promote the corporation's medium and long term autonomy in generating and managing new products based on the experiences which have been obtained in the fields under development by existing joint ventures and in the traditional areas

Cold production wells with 3,000-6,000 foot horizontal extension with 50° API naphtha diluent injected downhole combined with the use of many innovative production technologies have made the projects in Venezuela's Orinoco Oil Belt very economically attractive. Today it is very apparent that new "mixed enterprise" investments and further development of existing technology will make this one of the most important oil producing areas in the world (Figure 1).

Location

The FPO is located along the southern margin of the Eastern Venezuela Basin, parallel to the Orinoco River, covering a geographic area on the order of 55,000 sq. km. The Belt is 600 km in length and 90 km in width (Figure 3). Within it lies one of the largest oil deposits in the world, roughly 1.3 trillion barrels of "oil in place". It is estimated that around 90% of the extra-heavy crude in the world is located in the Orinoco Oil Belt. Venezuela's 297 billion barrels of recoverable oil match the oil reserves of Saudi Arabia. Estimates, however, indicate that only about 8-10 billion barrels will have been produced over the 35 year life time of the joint venture projects currently being developed, this represents a mere 3% of the total oil reserves present.

Ongoing Projects in the Oil Belt

The FPO area is divided, from west to east, into four distinct production zones: Boyacá, Junín, Ayacucho and Carabobo. It includes five projects in operation between the state oil company PDVSA and foreign partners: Petrocedeño (PDVSA 60%, Total 30%, Statoil 10%), and Petroanzoategui (PDVSA 100%) both in Junín; Petropiar (PDVSA 70%, Chevron 30%) in Ayacucho; Petromonagas (PDVSA 83%, TNK-BP-17%), and PetroSinovensa (PDVSA 60%, CNPC 40%) both in Carabobo.

All five projects convert the extra-heavy 8-9° API crude to lighter sweeter synthetic crude of 22° to 32° API (Figure 2) at the Jose upgrading complex (delayed coking technology) located on the coast 200 km. to the north. After the oil reaches the upgraders, the naphtha diluent is extracted and returned to the fields via a smaller parallel line for recycling.

Six (6) new joint ventures have been created within the last couple of years: PetroMacareo (PDVSA 60%, Vietnam 40%), PetroUrica (PDVSA 60%, CNPC 40%), PetroJunin (PDVSA 60%, ENI 40%) and PetroMiranda (PDVSA 60%, Byelorussia 40% in the Junín Block, and PetroIndependencia (PDVSA 60%,Chevron 34%, Impex 5%, SueloPetrol 1%) and PetroCarabobo (PDVSA 60%, Repsol 11%, ONGC 18%, Petronas 11%) in the Carabobo Block (Figure 3).

General Geology

During Miocene times uplift and subsequent erosion of the ancient Guyana Shield produced a large abundance of clastic sediments. The general direction of sedimentation of these sandstones into the Orinoco Belt region was from south to north corresponding to various deltas fed by rivers flowing from the south. During this time the most important reservoir, the Oficina Formation, was deposited conformably overlying the Merecure Formation. The main top seal for these reservoirs consist of the thick shale sequences of the overlying Carapita Formation. Oficina has been split in two main intervals. The Lower Oficina consists mainly of stacked unconsolidated sands deposited in a braided, meandering fluvial system. The Upper Oficina corresponds to sands encased in a shaly sequence associated with a deltaic system (Figure 4).

The Middle Cretaceous sediments of the Querecual and San Antonio formations contain the vast majority of the organic matter that produced these huge oil deposits. Orogenic activity in the area raised the local temperatures and induced the "cooking" process of the organic rich marine source rocks. The oils migrated from north to south up dip a few hundred kilometers during the Late Middle Miocene and formed the Oil Belt (Talukdar, 1991). Important changes took place in the composition of these oils during this migration process. The lighter fractions evaporated and microbial activity, aided by oxygen-rich meteoric waters, converted the originally light oil into extra heavy oil.

Regional Geological Model

Since 1936, the FPO has been visualized as a complex area with a vast amount of hydrocarbons. In 1951, the first regional geological description was performed and by 1967, after a full geological review, four distinct areas of interest were defined. At the end of the 1980s a new regional study was done to understand processes like migration, entrapment, structural features, and stratigraphic characteristics. This allowed PDVSA to calculate an improved value of the OOIP. In 1980, the exploitation of the FPO was initiated. Today, PDVSA has carried out a major reserves quantification and certification study (Magna Reserves Project). One of the main objectives of this study is to review and establish a regional model. The study has permitted the identification of the geological characteristics of each principal area, defined from east to west as Carabobo, Ayacucho, Junín and Boyacá (Figure 5). This new geological model combines data from the existing joint ventures and new information. The challenge is to continuously integrate and update the regional model with new well and seismic data acquired by new joint venture projects. It will also establish a unique and uniform correlation, improving mapping of detailed zones, identifying fluid migration patterns and reservoir heterogeneities. This will allow screening of the suitable areas for future EOR projects and provide a guide for identifying future opportunities in new areas

Basic Reservoir Properties

The Orinoco Oil Belt area has a reservoir section depth range on the order of 800 to 4,000 feet with temperatures of 100 to 140 Deg. F. (Figure 6) and initial reservoir pressures of 450 to 1,200 psi. (Figure 7). The *in situ* oil viscosity ranges from 1,000 to 5,000 cp and oil gravity from 6.5° to 10.5° API. Net sand thickness values of 20 to 300 ft. are observed with porosity of 28% to 34% and permeability’s of 1-20+ Darcies. Cold production recovery factors are on the order of 8% to 12% (Figure 8) and thus it is imperative that Enhanced Oil Recovery (EOR) techniques be applied.

Oil Gravity

Gonzalez de Juana pointed out that “any zone located south of the Eastern Venezuelan Basin, where the oil gravity is lower than 15° API is on the fringe of the Faja. If it is less than 12° API it is definitely within the Faja. The Faja’s northern border is usually arbitrarily set south of the traditional fields.” In the Carabobo area, there is also an API vertical variation. The Pilón Formation is 10° API, while the Morichal Formation is 8° API (Figure 9 and Figure 10). Due to the extra heavy nature of the oil it requires several days to achieve an accurate API measurement.

Viscosity

The compound effect of oil gravity variation, pressure, temperature, and Rs is reflected on oil viscosity. The latter has a direct impact on oil rates (Figure 11) under cold production and on data acquisition and development plans. Oil viscosity increase is higher with reductions in temperature and depth (Figure 12). A present challenge is to have an aerial estimation of reservoir viscosity (Figure 13) that will allow the design of fluid sampling and testing programs. This key parameter controls the sequence for any development plan and answers questions like: primary production for how long, what level, well design, spacing, sequence of EOR, lifting method, etc.

Irregular Oil-Water Contacts (OWC)

The water in the Faja is a world in itself. Water salinity varies from brackish to salty, making water saturation calculations a complex task. The small differences between oil and water densities combined with zones of permeabilities less than 1 Darcy can create “soggy rocks,” inverted oil-water contacts (Figure 14) and large transition zones (Figure 15). Additional nuisances are inner aquifers called “poncheras” created by irregularities in basement topography. In the FPO a careful development strategy must be carried out to manage and optimize the production operations that deal with water issues.

Production Strategies - “Cold” and “Hot”

Current projects of this Phase 1 stage of development produce by “cold” production (Figure 16). This is possible due to the excellent reservoir properties and the “foamy oil” nature of the crudes. The initial development strategy has concentrated on drilling horizontal wells in sands thicker than 30-40 feet, independent of sedimentary environment. More recently the thinner sands are also being drilled. Recovery factors associated with this first phase are 8-12%, making the use of EOR techniques imperative. However, since steam processes are more efficient in low-pressure reservoirs and initial pressures in the FPO are relatively high this first phase will reduce these pressures to facilitate the later economical implementation of steam injection methods.

Phase 2 is focused on cold production aided with EOR. Today the main uncertainties related to thermal projects have been identified (inefficient steam diversion, coning of the aquifer, confinement of the steam chamber, unexpected geological barriers, etc.). These uncertainties justify a phased development approach to prove the applicability of the technologies that could increase recovery factors > 20-25%.

The main cluster patterns currently used in the Faja are the "pitchfork" configuration (Figure 17) with 600 m or 300 m spacing and 1000 to 2000 m length and the "star" shaped configuration with 25° spacing in order to maintain the 300 m spacing at the wells' toe. An important consideration for future wells is the reservoir vertical depth. Reservoir depths vary from 1300 m to 250 m. To drill horizontal sections at the shallow depths, higher doglegs will be required which can lead to rod or tubing failures. On clusters where up to five productive layers will be drilled, there may also be a risk of collision and the feasibility of using such patterns will have to be more deeply studied. The "pitchfork" pattern may be the ideal one for EOR reservoir drainage, but it is more complicated in drilling and completion because it requires 3D profiles. It is foreseen that slant rigs will be used in some areas to drill the 3D profiles and to reduce doglegs.

Well Productivity Enhancement

Diluent Injection in Horizontal Wells and Injection Point Location

As stated, the FPO's first development phase is primarily by "cold" production using diluent injection in horizontal wells. Some wells have sections up to 2000 m in horizontal length. Different injection points are being used (Figure 18): (a) at surface, (b) downhole at the Progressive Cavity Pump (PCP), and (c) at the "toe" of the horizontal section. Field tests indicate that diluent injection at the "toe" of the well increases productivity 28% vs. either of the two other injection points (Figure 19). However, operators that inject at the surface report a longer PCP pump life. A current challenge is to work with pump manufacturers in designing more resistant elastomers to offset these adverse effects. Another alternative possibly worth evaluating is to field test the metal-to-metal PCP under downhole injection conditions since these pumps do not have neoprene elastomers.

With the injection designs being employed it is guaranteed that the diluent reaches the well bottomhole, providing for a better crude-diluent mixing. Thus we minimize friction effects on tubing and significantly reduce operational problems such as high torques and high loads on rod strings, surface equipment and subsurface pumps. PCP well rod string torque reductions of 25% are being obtained.

Remedial Wellbore Cleanouts Using Surfactants

Poor productivity and abnormal declines have been observed in FPO horizontal wells completed with slotted liners and damage was suspected (Figure 20). Studies were performed which identified many of the possible causes, such as swelling of clay minerals, clogged pores and blockage from asphaltene precipitation. Diagnosis of the damage mechanisms permitted formulation of applicable treatment fluids. These have been used over the past few years with excellent results in mitigating formation damage and substantially increasing and maintaining well production rates (Figure 21 and Figure 22). A current challenge is to locally formulate and manufacture a similar surfactant. Currently, the product called InteSurf, has been designed and is being tested in conjunction with the Venezuelan research affiliate, INTEVEP.

Downhole Electrical Heating Devices

In horizontal wells most of the production contribution comes from the section of the well closest to the lift equipment (PCP pump), the "heel" of the horizontal zone, thus the remaining area contributes little or no production. The objective is to complete a producing horizontal well with a heat generating electric cable that applies moderate increases in temperatures (Figure 23 and Figure 24) reduces viscosity, improves mobility and increases the drawdown at the toe of the well thereby increasing productivity and extending the primary production life of the well. Some of the conclusions we have observed from our successful Downhole Heater pilots are the following:

- Pressure drops between the toe of the well and the PCP pump are reduced by ~ 30%.
- Increasing the inlet pressure at the pump (drawdown reduction) allows the well to be produced at higher RPM, maintaining Pwf.
- Torque was reduced by 20% to 30%.
- The drawdown at the toe increased, representing a major contribution from this area.
- With the heater we obtained a better distribution of drawdown along the well bore.
- The productivity index (PI) increased from 30% to 40% after heating (Figure 25).
- The power consumption of the system (motor + cable) is similar to the energy consumption of two (2) normal wells.

"Dewatering" Technique

This is a locally developed technique applied in the western Faja, whereby a 1,500 ft. horizontal length "dewatering" well, is drilled 15- 20 ft. below the OWC. This well extracts large volumes of water (30,000 BWPD) with the use of an electro submersible pump (ESP) thus reducing the water cut simultaneously being produced in the structurally up dip oil wells with a direct or lateral contact to the water source (Figure 26). The key element in this procedure is that the high volumes of produced aquifer water are clean and can be transported using an alternate route to the main diluted crude oil line. This water is then pumped into the water injection line without passing through a water treatment plant thus not affecting the possible saturation of existing surface installations. The goal is maintaining a high water handling capacity to enhance the water management potential at the main station, multiphase pumps, and surface pipeline system in areas with a strong aquifer influx. A philosophy of efficient water management practices is a challenge for optimizing future oil potential and for improving the oil recovery factor in the FPO.

Effective Water Management Practices

Implementing production policies that provide appropriate water management techniques are essential in the FPO. Despite small density differences and unfavorable mobility ratios, well performances indicate that oil production potential and reserves can be maximized by producing watered out wells at a maximum drawdown. A thorough monitoring strategy of the water production allows a critical improvement in the understanding of reservoir dynamics. Detailed pressure and production data help significantly in evaluating the local aquifer strength and in assessing the risks of local water encroachment. It has been shown that the risks posed by the existing regional aquifer have proven to be less severe than what was originally believed. During cold development, we have learned that, contrary to early assumptions, these wells accumulate large volumes of crude over long periods with high water cuts.

Drilling and Completion Strategies

Use of Azimuthal Resistivity Tool (ADR)

This section presents experiences gained with the latest generation ADR Halliburton azimuthal resistivity tool (Figure 27) for geosteering in thin heterolíthic Miocene reservoirs (C2 Sand). The use of this tool has provided help in a proactive decision making manner during navigation, resulting in a better net sand count and a better location within the reservoir sand, especially in these reservoirs of a complex stratigraphic nature. In the Junin area the Petrocedeno joint venture conducted a 17 well drilling campaign using the ADR tool starting in February of 2010. These results were compared with those obtained with the conventional resistivity tool (EWR-P4) used prior to 2010 which show much less sand contact and the need for drilling numerous planned and non-planned sidetracks due to the uncertainty inherent in these geological settings. The use of the new azimuthal resistivity tool (ADR) combined with real time modeling applications (Strasteer 3D) and the active participation of the geoscience and drilling engineers has proven that geosteering can be a very successful technique in well trajectory location within the reservoir as well as in reducing rig time under complex scenarios. Geological and well positioning uncertainty was significantly reduced, decreasing the amount of sidetracks. Of the 17 wells drilled in this campaign only 2 unplanned sidetracks were required.

"Unconventional" Drilling Methods to Suit Particular Geologic Conditions

The use of "unconventional" drilling methods will have a significant positive impact on developing the huge oil resources located in "thin sands" (10 to 20 ft.) of the FPO. It is estimated that 30-40% of the oil is in sands of less than 20 feet thick. Thus, it is a challenge to evaluate the most suitable way to target these undeveloped thin beds. It is important to note that these "non-conventional" wells are only to be proposed in areas where traditional horizontal wells cannot be drilled. The objective of these is to produce economically thin sands of limited lateral extension. The lower limit is mainly associated with difficulties in reaching extremely thin beds and isolated sand bodies. The well design will depend on different possible geological scenarios considering future workover feasibility as a principal limitation. Examples of non-conventional well architectures are (Figure 28):

a) Highly deviated, which can be used in areas where several disconnected small sand bodies are superimposed; the inclination angle will depend on distribution of sand lenses.
b) "Stair" shaped which can be used when two or more disconnected sand bodies are distributed diagonally along the layers, they can be drained with one well that contacts all.
c) "U" shaped. This architecture can reach disconnected sand bodies dispersed in two or more sub-layers.
d) "Snake" shaped wells. This architecture is similar to having two or more connected "U" shaped wells.

Innovative Well Completion Methods

Areas for continuous improvements are well completion and well service techniques, particularly related to the lifting system, such as downhole location of the pump, testing new generation PCPs to handle gas, and testing high capacity PCP pumps. Other aspects being assessed are horizontal drain completions using 300 micron slotted liners in the fine-grained sands vs. the conventional 500 microns used in the coarsegrained fluvial environment. Also, using trapezoidal design liner slots vs. conventional parallel slots and designing with sand control equipment such as Wire Wrapped Screens or other innovations in this area.

Pilot Projects in Development Phase

Viscosity Reducing Polymers

Polymer injection is a modification of conventional water injection techniques. A crude oil bank is formed which pushes from injector well to producer well. The water is made more viscous by the addition a water soluble polymer, leading to an improvement in the water/oil mobility ratio and sweeping efficiency, thus obtaining a greater recovery factor.

The main objectives of this pilot are the following:

• Evaluate the feasibility of implementation of the technique in the FPO.
• Assess the increase in recovery factor in the pilot area.
• Check the increased production in neighboring wells.
• Provide rapid solutions to possible large-scale application of the technique.
• Evaluate the efficiency and reliability of the skid in preparing the polymerized water mix.
• Test the technology for possible treatment of production waters.

Recently numerous successful projects are under execution in Canada. Advanced Polymer Projects are: Pelican Lake Area with CNRL and Cenovus (ex EnCana) and in the Lloydminster Area East Bodo and Senlac. Other more recent Polymer Projects in the Lloydminster area are: Pelican Lake (Black Pearl, Daylight Energy), Wainwright (Harvest Energy, Enerplus, Cenovus), Suffield (Cenovus, Harvest Energy, CNRL), Seal Reservoir (Murphy, Pennwest, Shell).

Thermal Recovery Pilot Project

The Petrocedeño Joint Venture has engaged in an EOR (Enhance Oil Recovery) Thermal Recovery Pilot Project. The object of which is to design and build a steam generation plant, injection and producer wells as well as a gas and emulsion separation plant in order to test the performance of the three steam injection mechanisms selected: (i) Steam Assisted Gravity Drainage (SAGD), for 50 ft. clean, sands, (ii) Horizontal Alternate Steam Drive (HASD) for 15-30 ft. sands with no aquifer, and (iii) Controlled Steam Drive (CSD), where temperatures are kept below 120° C. providing applicability in areas originally completed for cold production (Figure 29). Also, monitoring of the steam chamber with the use of observation wells and 4D seismic. For each mechanism, relevant parameters such as recovery rate, produced H_2S and Steam Oil Ratio will be measured aimed at obtaining key information for the future design of the steam injection and production facilities required for full field project implementation. While the project goal is to evaluate technologies, it has been designed for an estimated peak production rate of 4000 BOPD.

Cold Heavy Oil Production with Sand (CHOPS)

Another pilot project under consideration is Cold Heavy Oil Production with Sand, (CHOPS) currently being successfully applied in Canada (Figure 30). There are similarities in reservoir rock and oil properties between the Canadian Lloydminster area and the FPO fields, so the technique should also be successful in the Faja. It has never been applied here, although it has a high probability of success and if so it could be a major breakthrough for the FPO. However, only a Pilot will tell us if the experiences from Canada are applicable here. Some objectives for this pilot project are: (a) Asses productivity profile over time, (b) Set initiation of sand production, development of wormholes and growth of channel network beyond the near well region, (c) Establish correlations for well productivity, flowing well pressure, GOR, etc., and (d) Determine how much sand will be produced and how it will decrease with time.

Preheating Diluent at Surface or Downhole Diluent Heating

Preheating the naphtha diluent at surface before injection is another idea under consideration. A second process involves heating the diluent within the horizontal producer by means of the use of an electrical resistance. In both cases we would obtain moderate increases in temperatures, reductions in crude oil viscosity and improvements in mobility with associated increases in oil recovery in the well drainage area. For evaluating the feasibility of these techniques, plans are being made to develop two B2 Sand deltaic environment pilot projects in the Junín Area.

Conclusions

The main technological challenge we have for developing the Faja Petrolífera del Orinoco (FPO) is to have an excellent understanding of the rock and fluid properties, since they will determine the best combination of production schemes and EOR methods to apply. Positive recent productivity developments experienced in the FPO with the use of many innovative technologies, such as those described here, provide strong support to the belief that this giant extra heavy oil area is extremely promising. The huge numbers of recoverable oil estimated to be present rival the reserves of the Kingdom of Saudi Arabia. Estimates, however, indicate that only a small portion of these will have been produced over the 35 year life time of the current joint venture projects. These facts leave little doubt that huge investment opportunities exist for those interested in participating in joint ventures in the FPO with the Venezuelan government.

Acknowledgement

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Figure 1. Location of Faja Petrolífera del Orinoco (FPO).

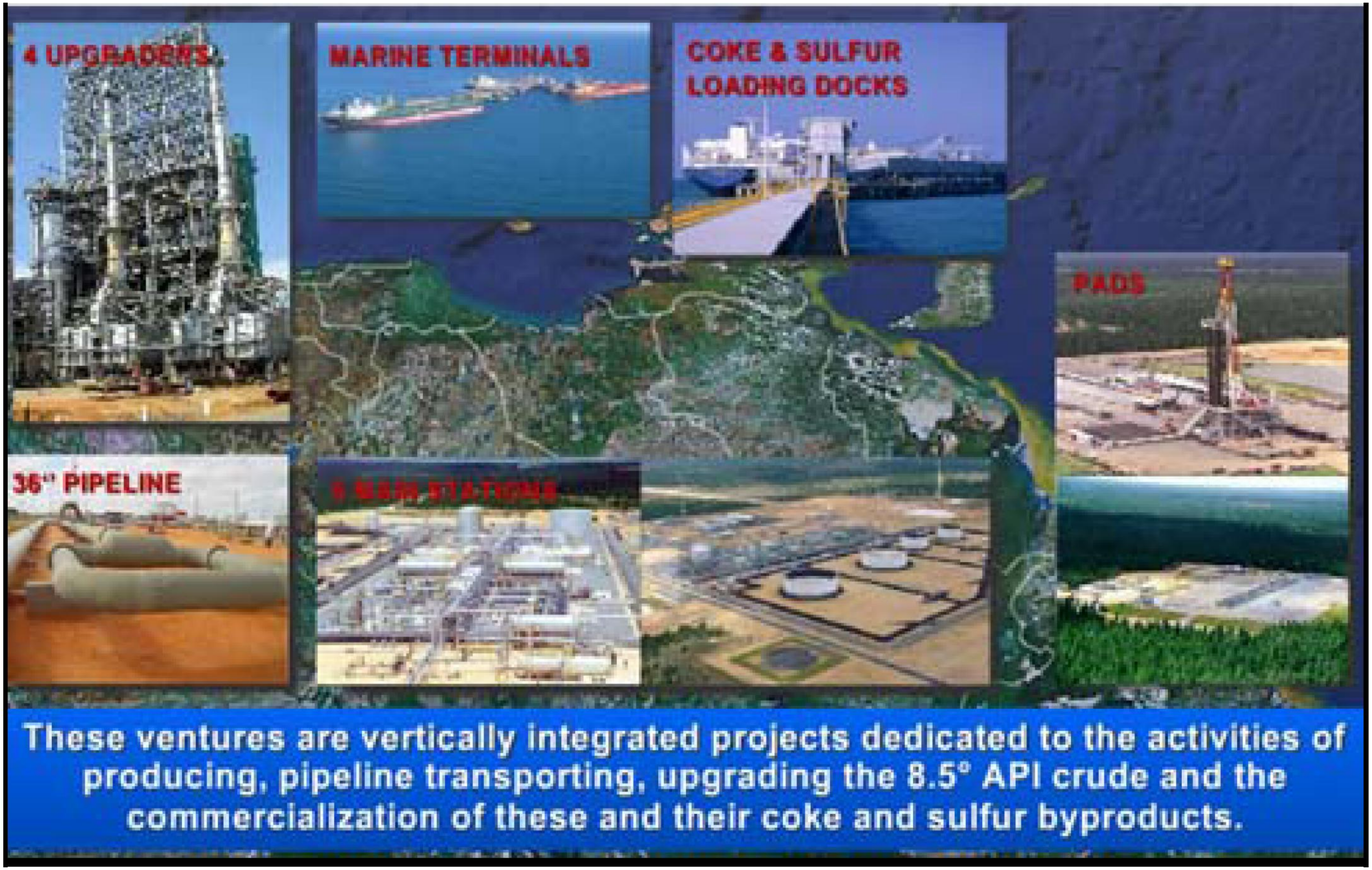


Figure 2. Overview of Orinoco projects.

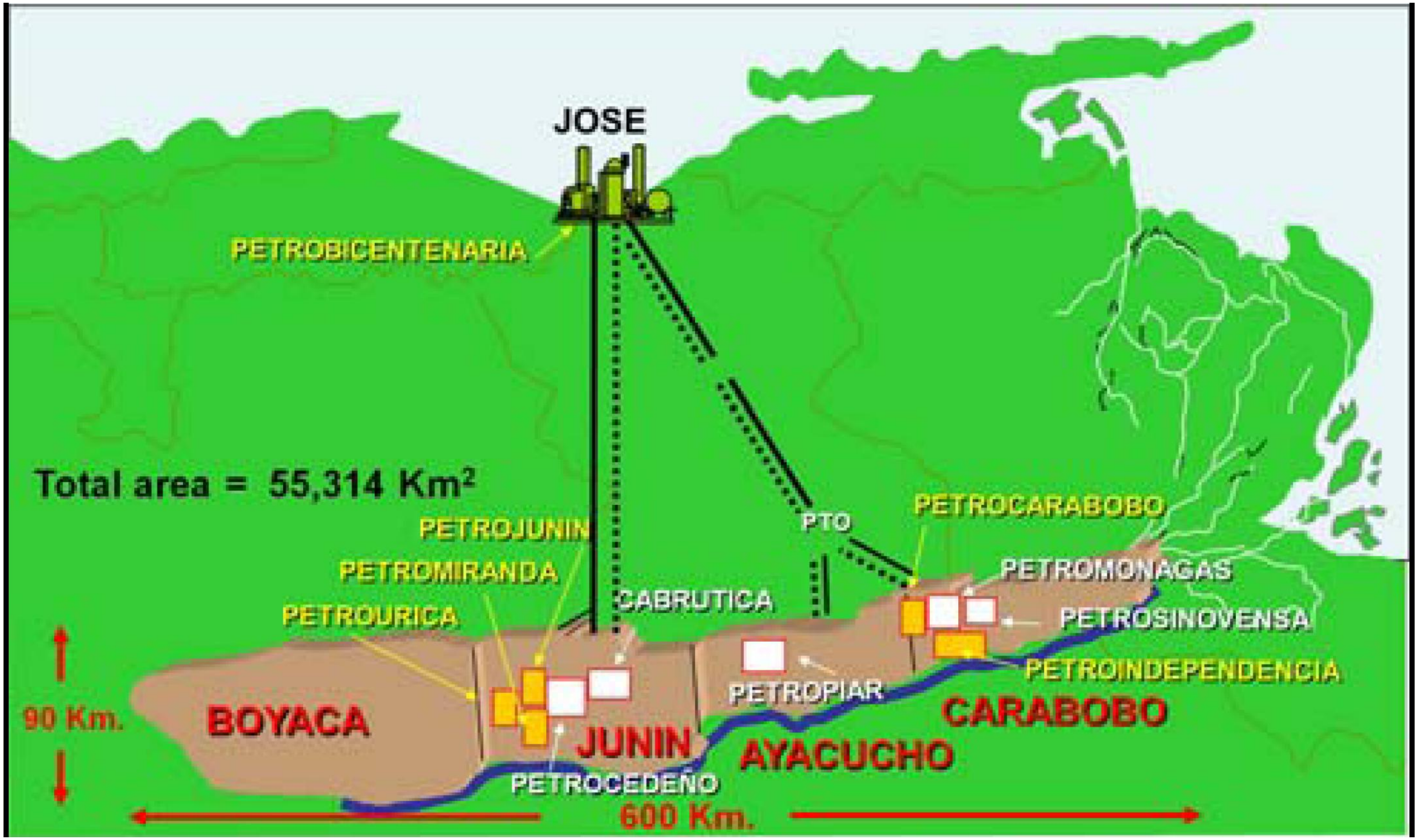


Figure 3. Existing facilities (white) and new projects (yellow).

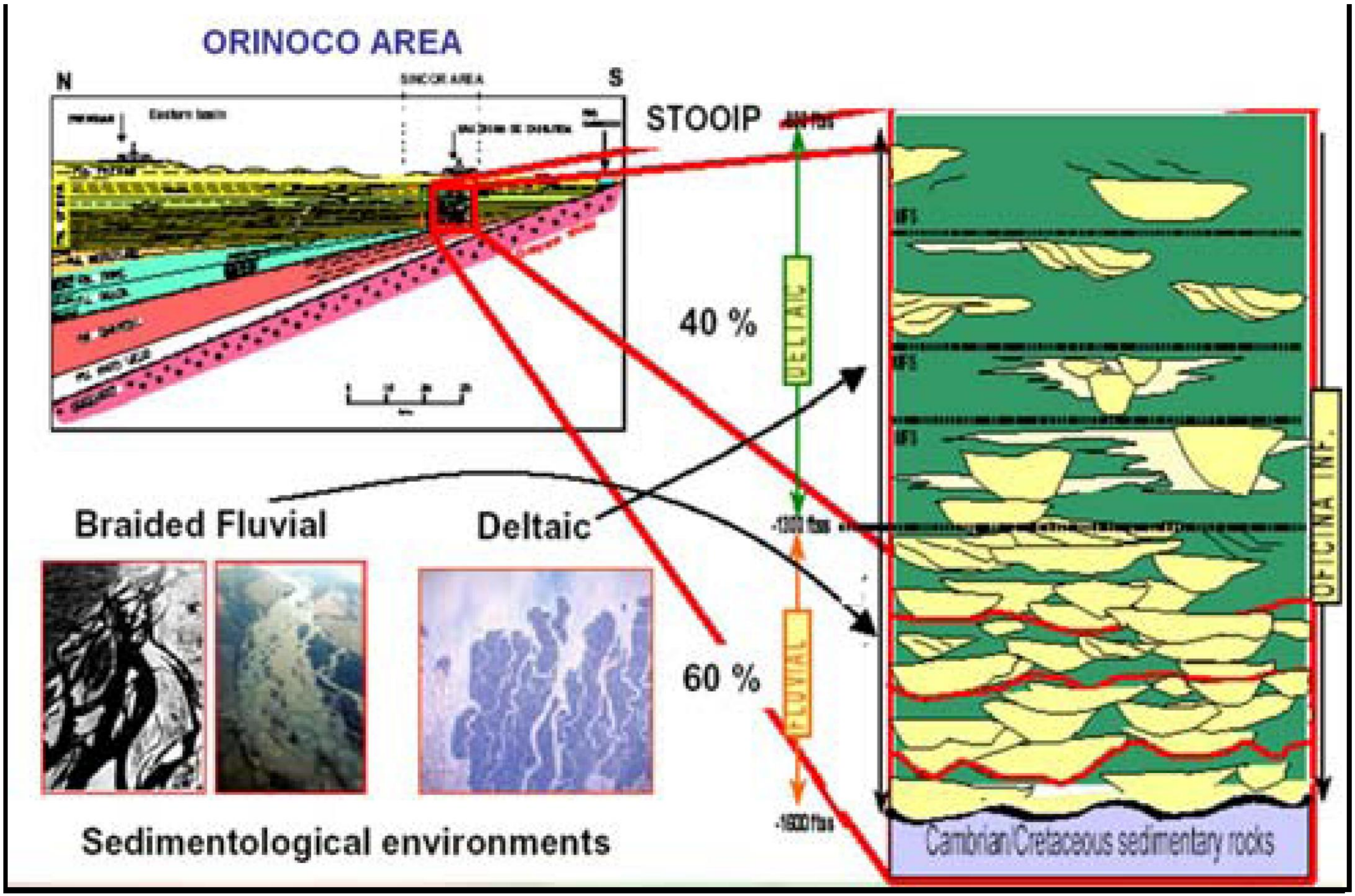


Figure 4. Stratigraphy of the Orinoco area.

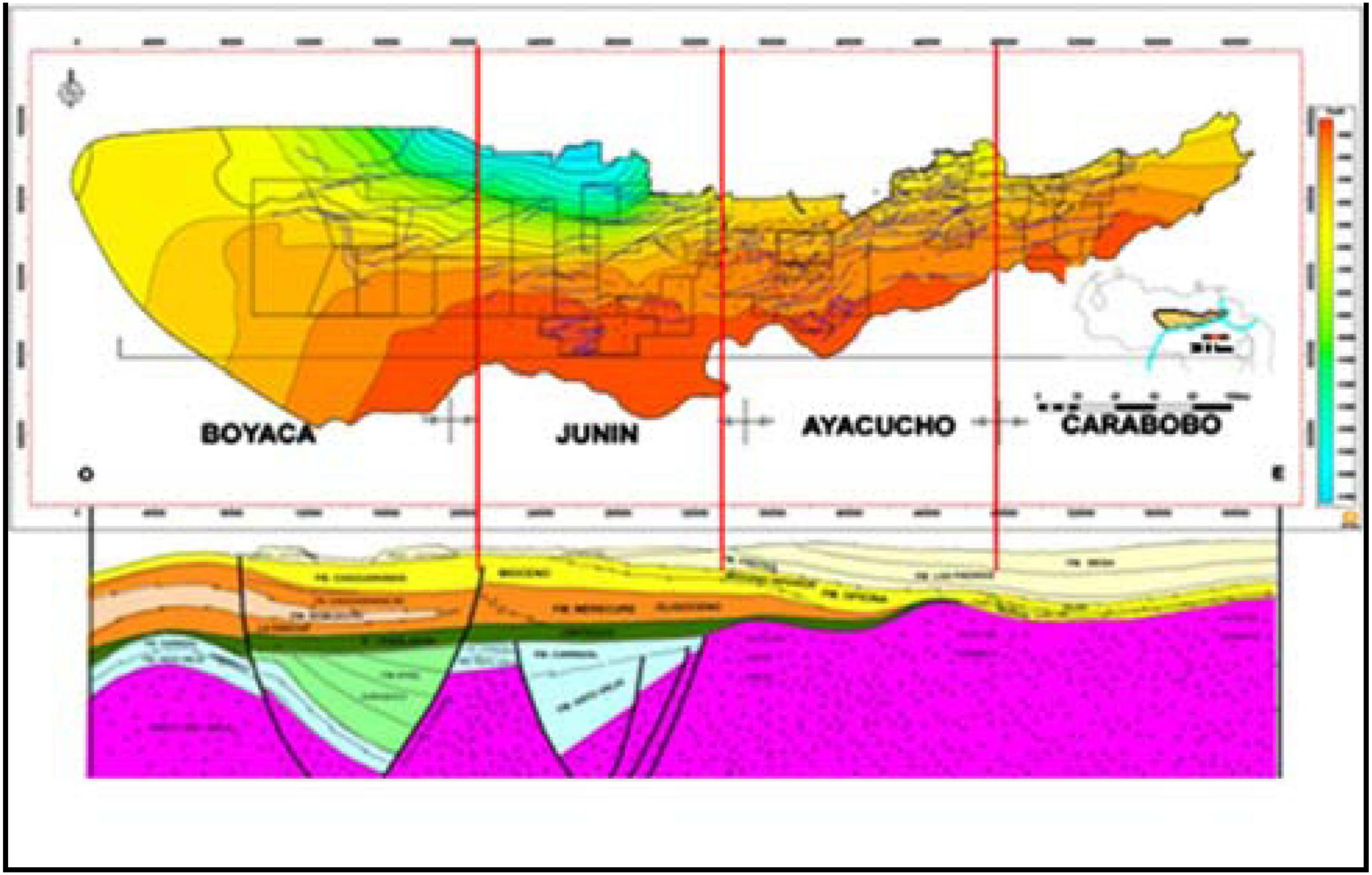


Figure 5. Regional geological model of Faja Petrolífera del Orinoco.

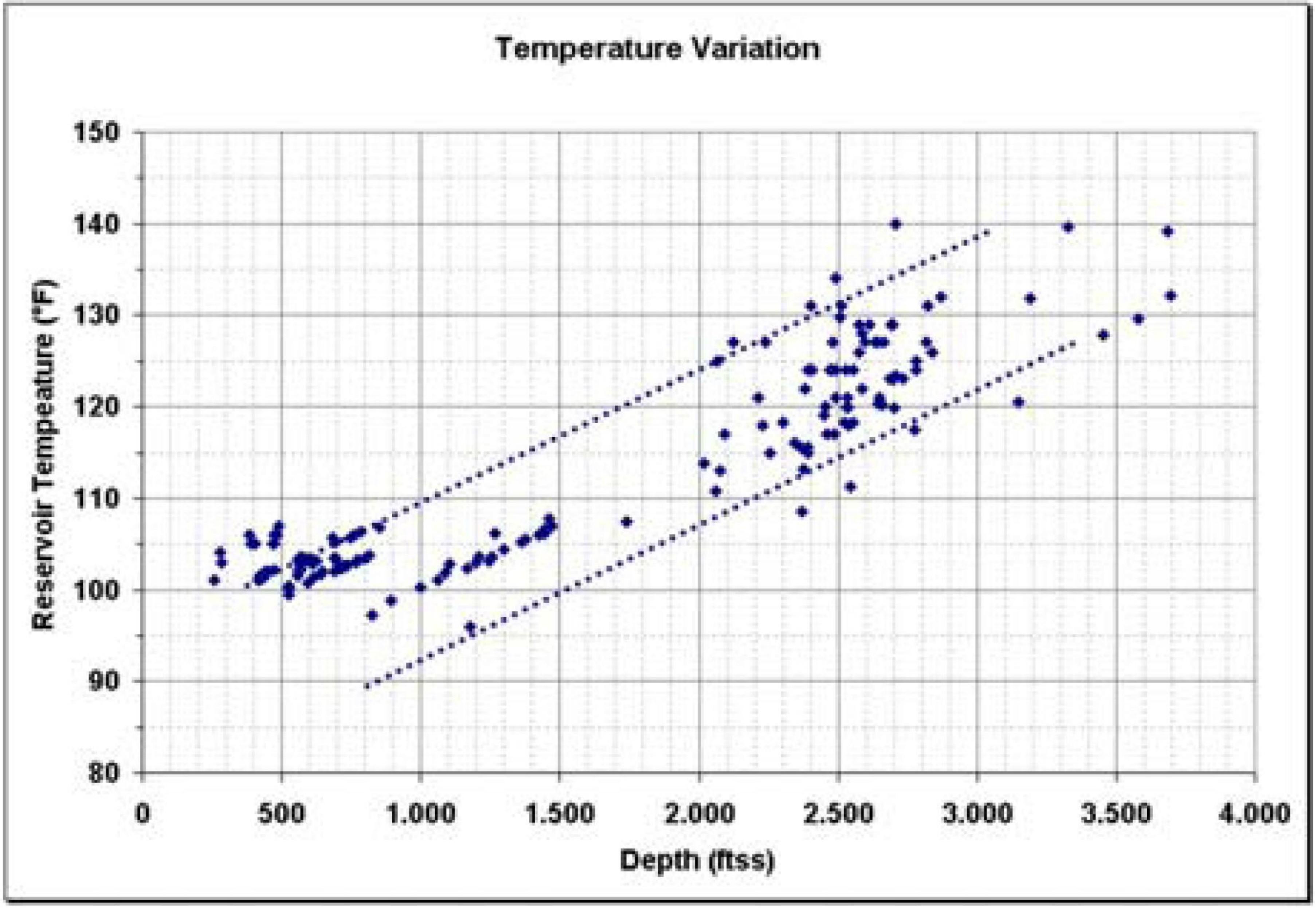


Figure 6. Reservoir temperature vs. depth.

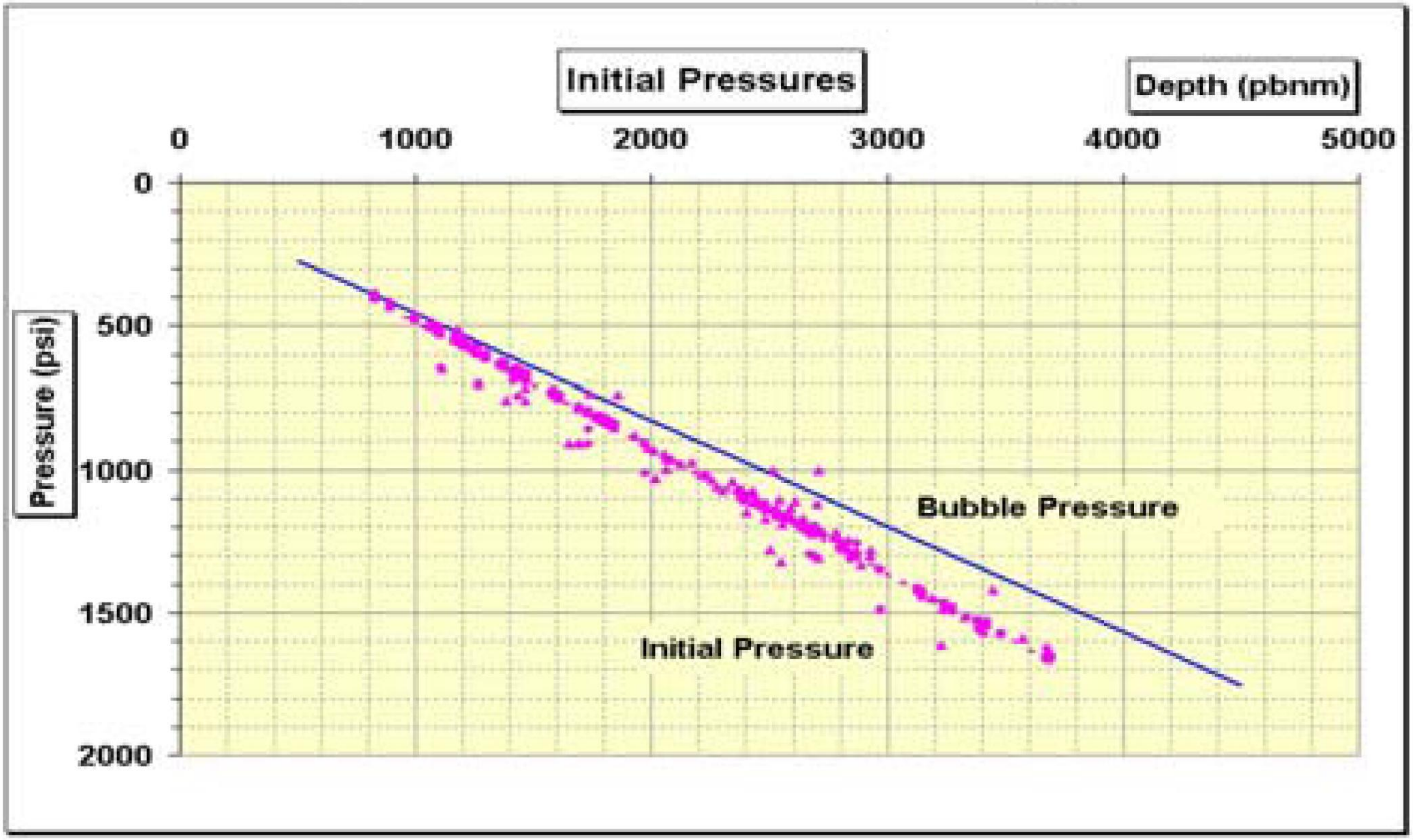
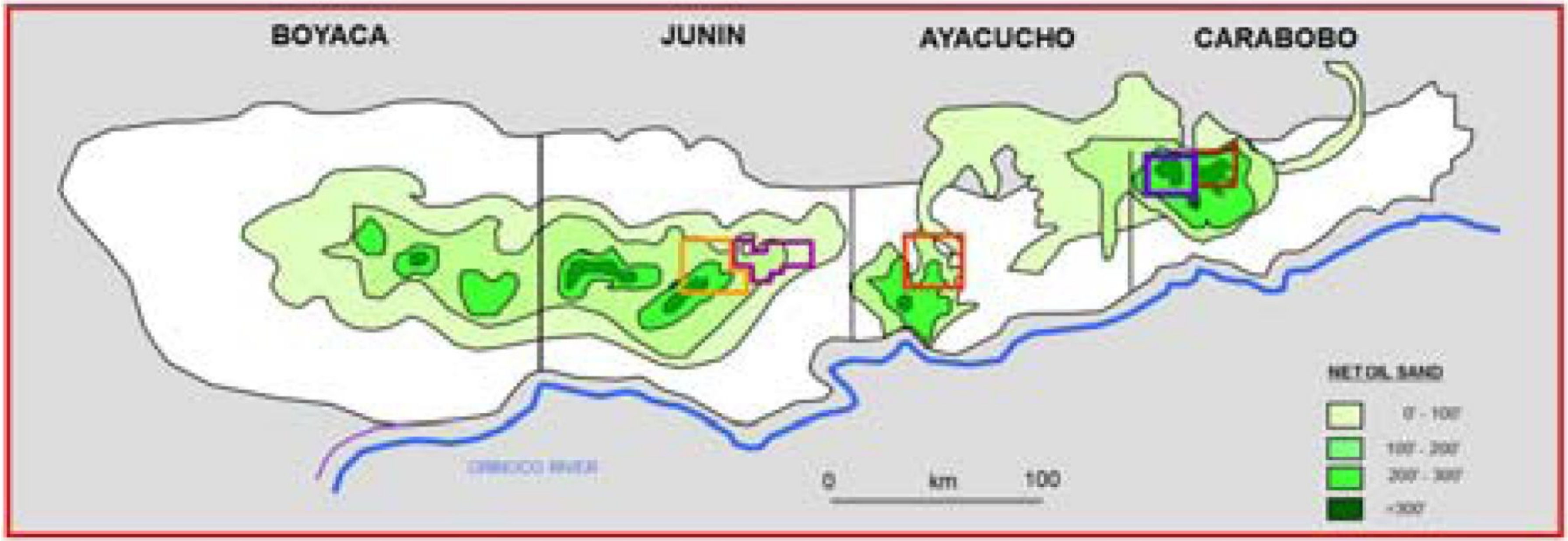


Figure 7. Initial reservoir pressure vs. depth.



• Depth Range	1600 - 4000 ft.	•Initial Res. Pres.	800 - 1000 psi
• Temperature Range	115 - 130 Deg. F.	•In Situ Viscosity	1000 - 5000 cp
• Gross Thickness	200 ' - 500'	•Porosity Range	28 - 34 %
• Net Thickness	50 ' - 300 '	•Permeability	1 - 20 + Darcies
• API Gravity	7.5 - 9.5	•Water Sat.	8 - 30 %
• Initial Gas Oil Ratio	60 - 70 scf /Bo	•Rec. Factor (Cold)	9 - 12.5 %

Figure 8. Faja Petrolífera del Orinoco basic reservoir properties.

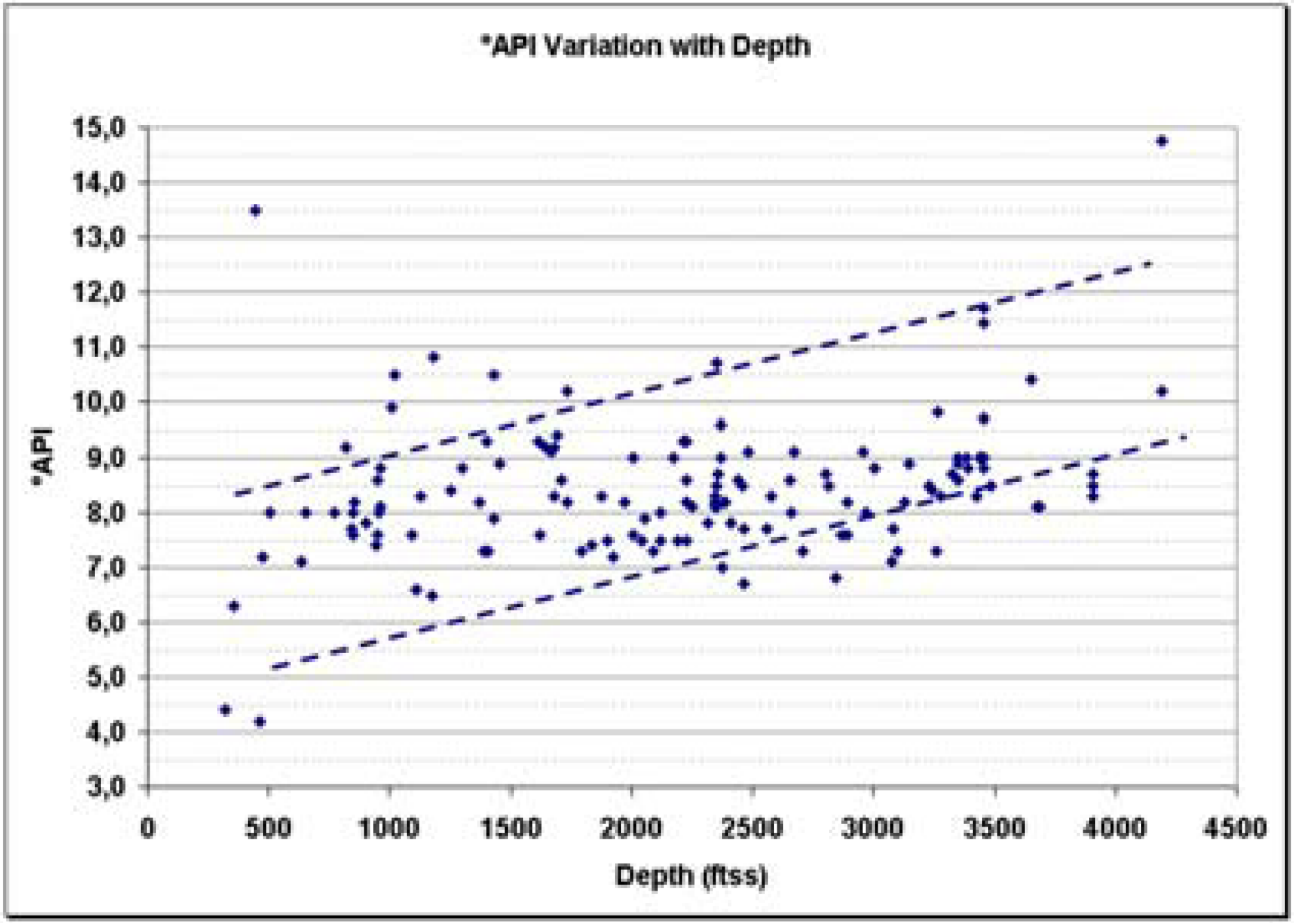


Figure 9. Variation of API with depth.

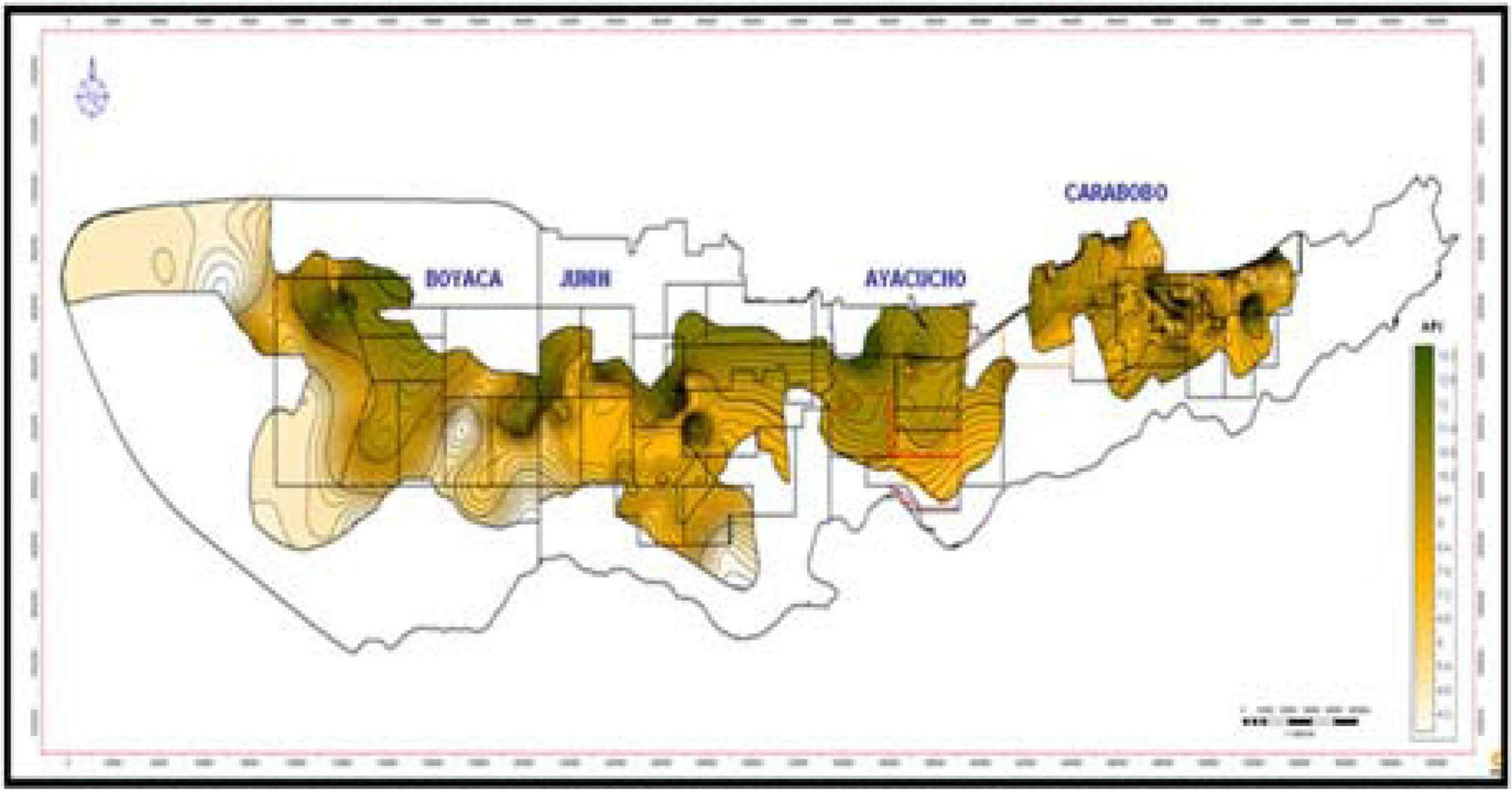


Figure 10. Distribution of crude oil API.

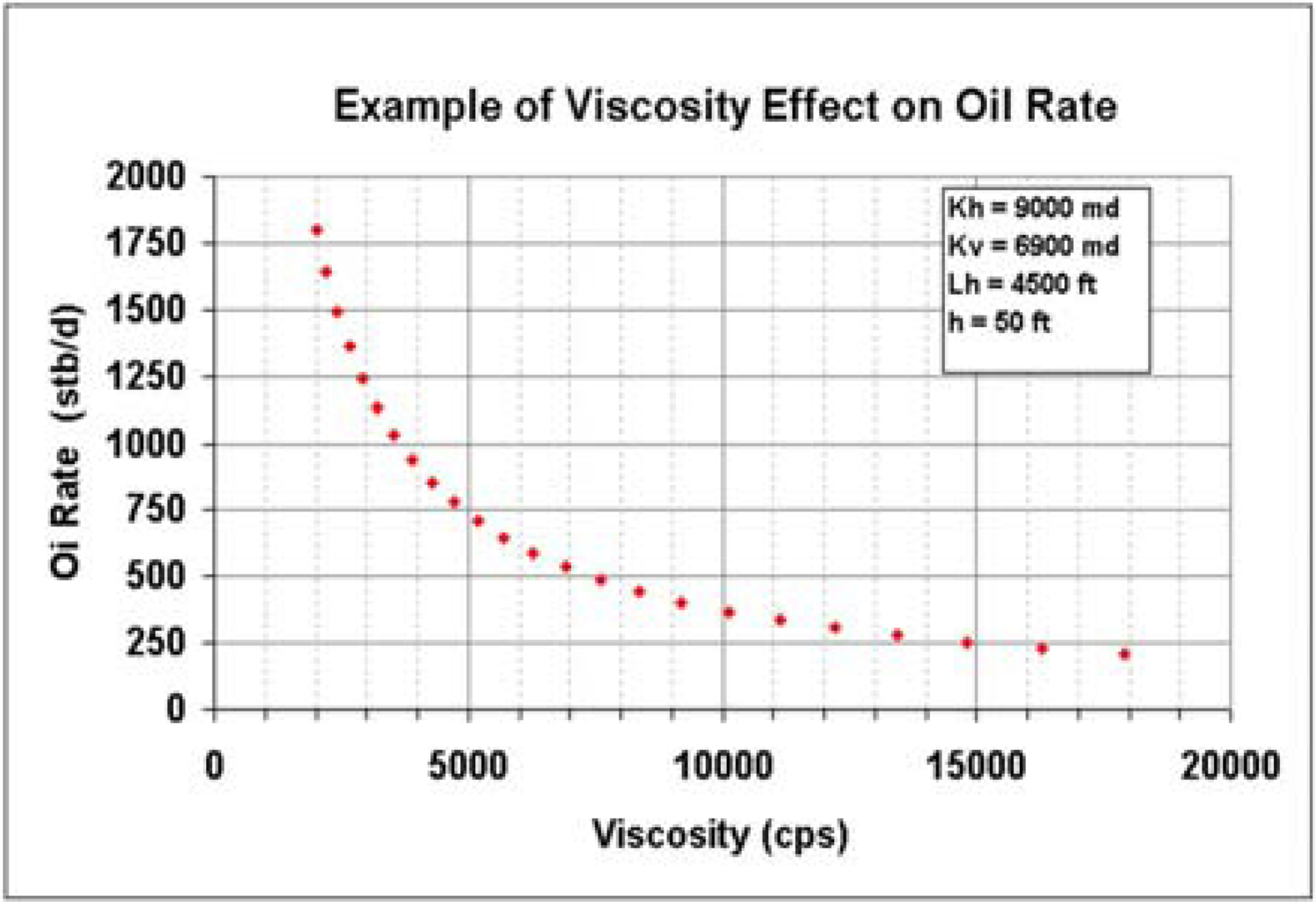


Figure 11. Faja Petrolífera del Orinoco viscosity effect on oil flow rate.

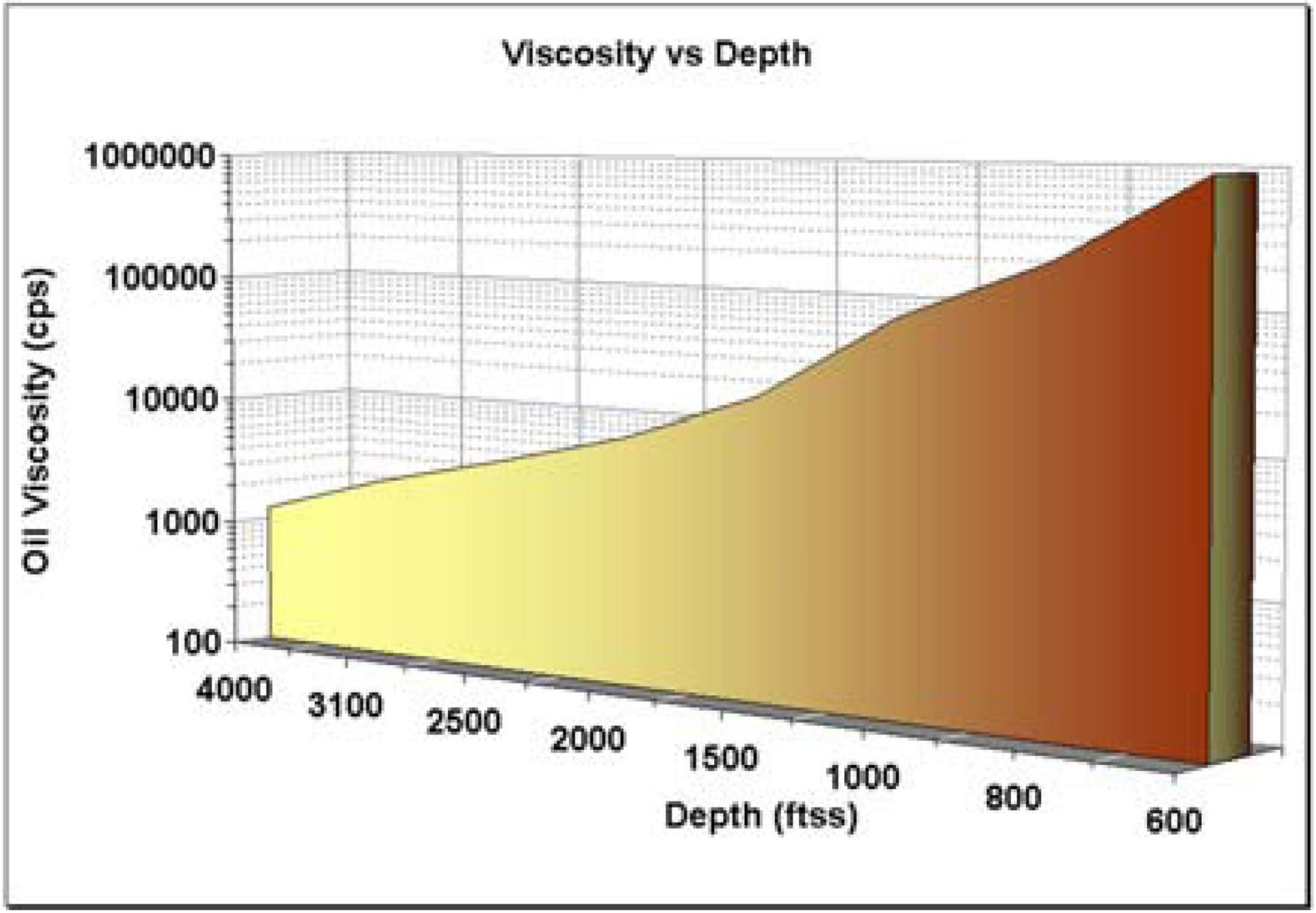


Figure 12. Faja Petrolífera del Orinoco oil viscosity vs. depth.

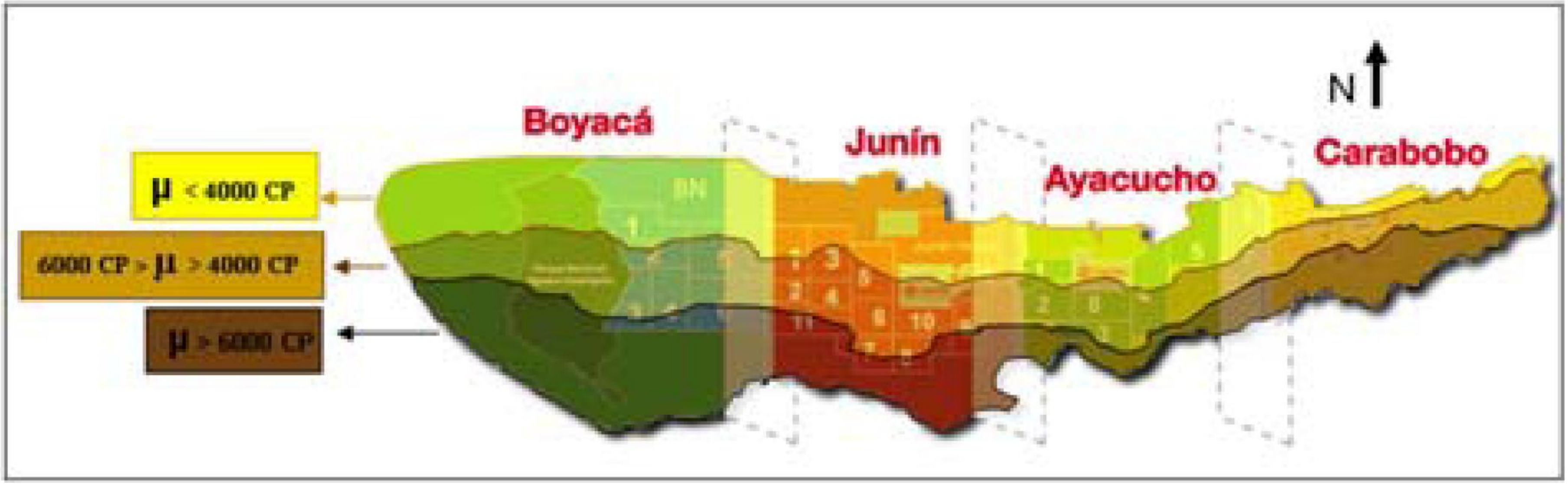


Figure 13. Faja Petrolífera del Orinoco regional viscosity variation.

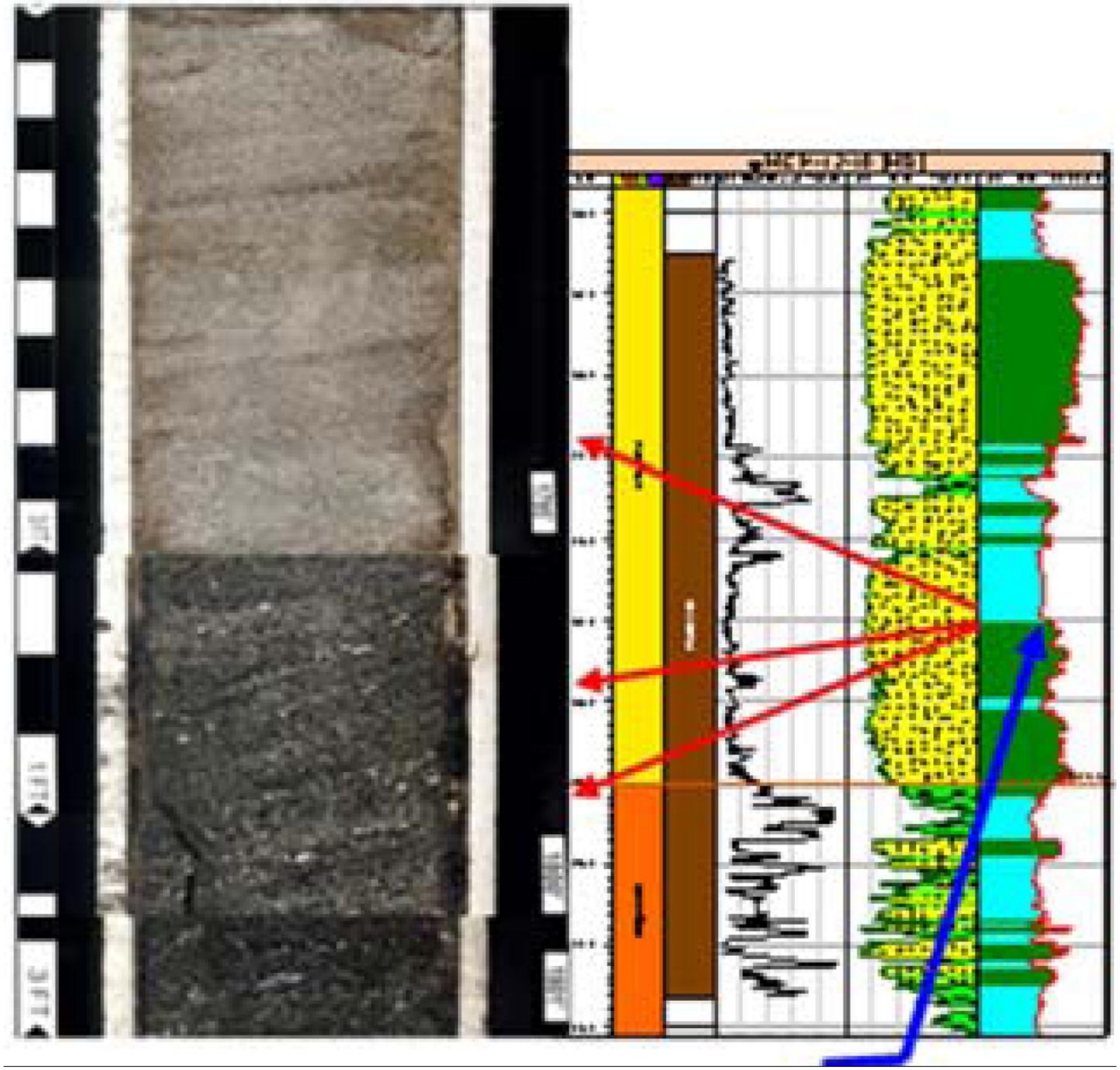


Figure 14. Example of inverted oil-water contact from well in Faja Petrolífera del Orinoco.

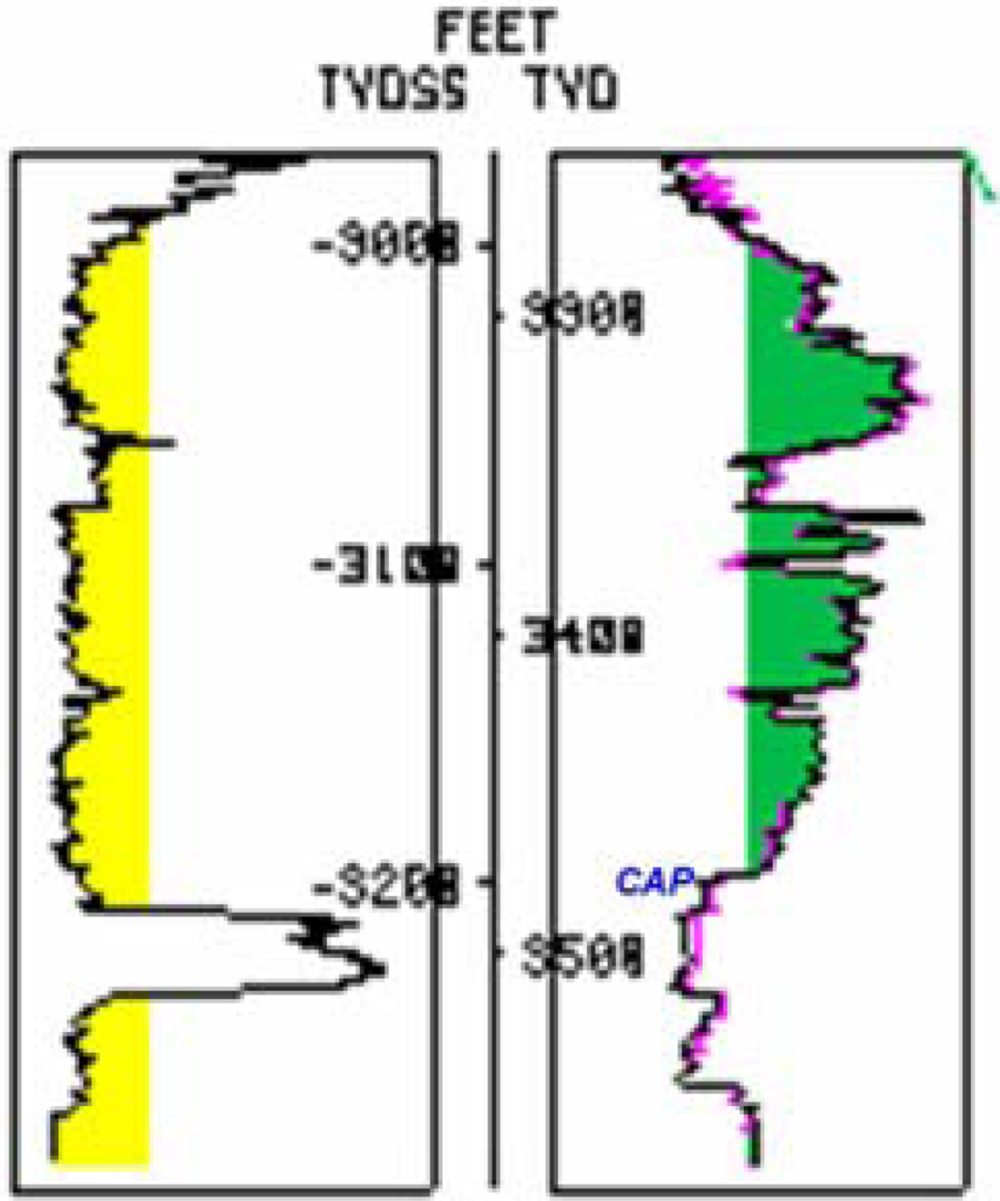


Figure 15. Example of very long transition zone from well in Faja Petrolífera del Orinoco.

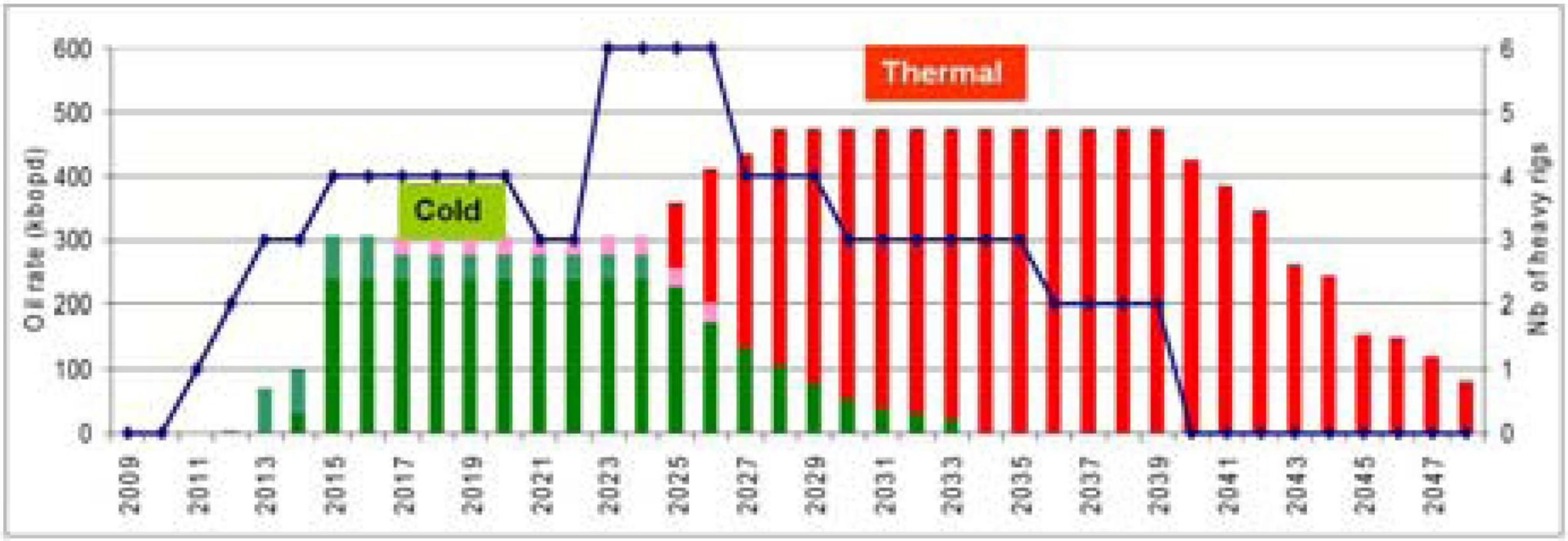


Figure 16. Results of “Cold” and “Hot” production strategies (Phases 1 & 2).

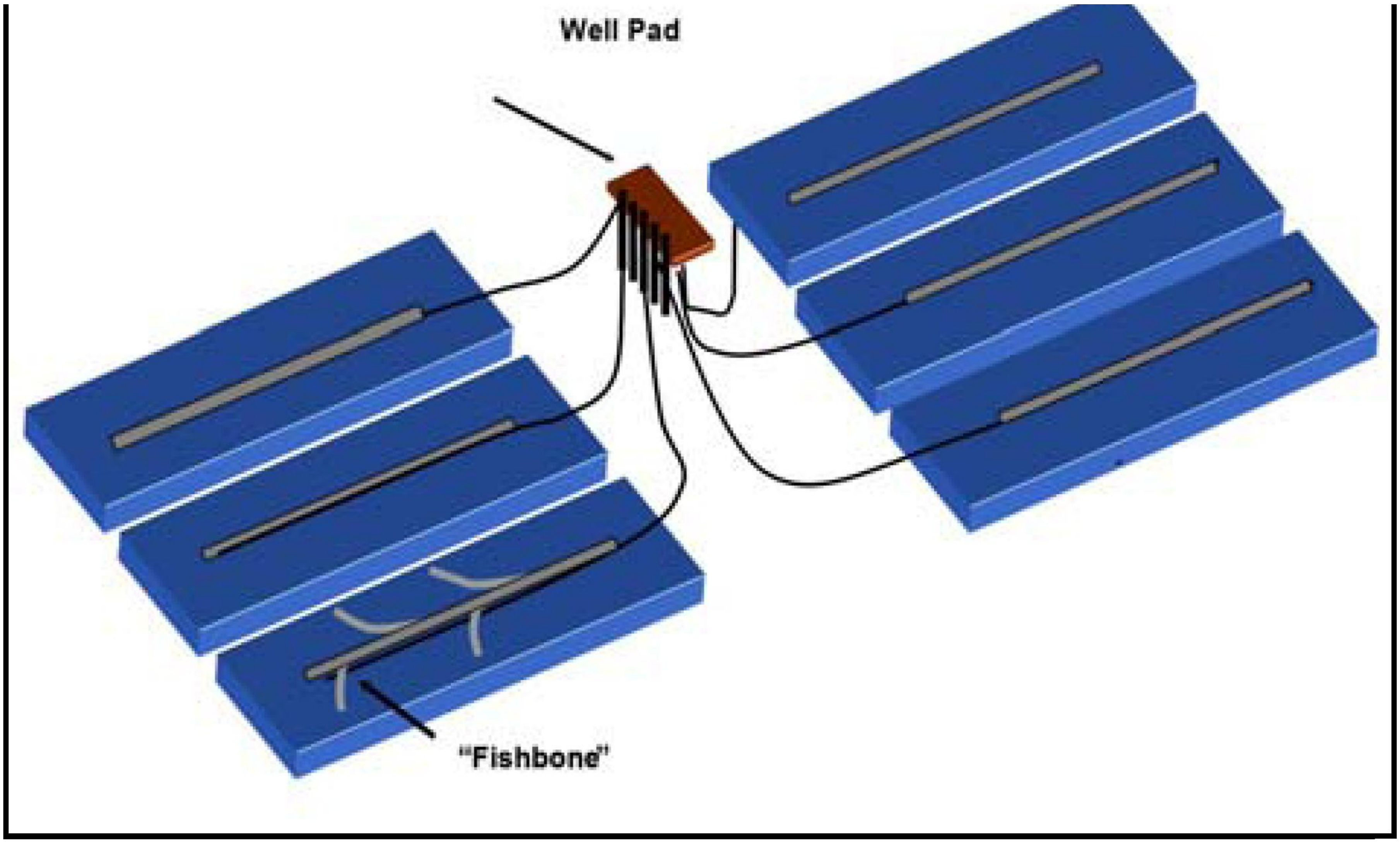


Figure 17. "Pitch Fork" pattern of horizontal wells drilled from a central pad.

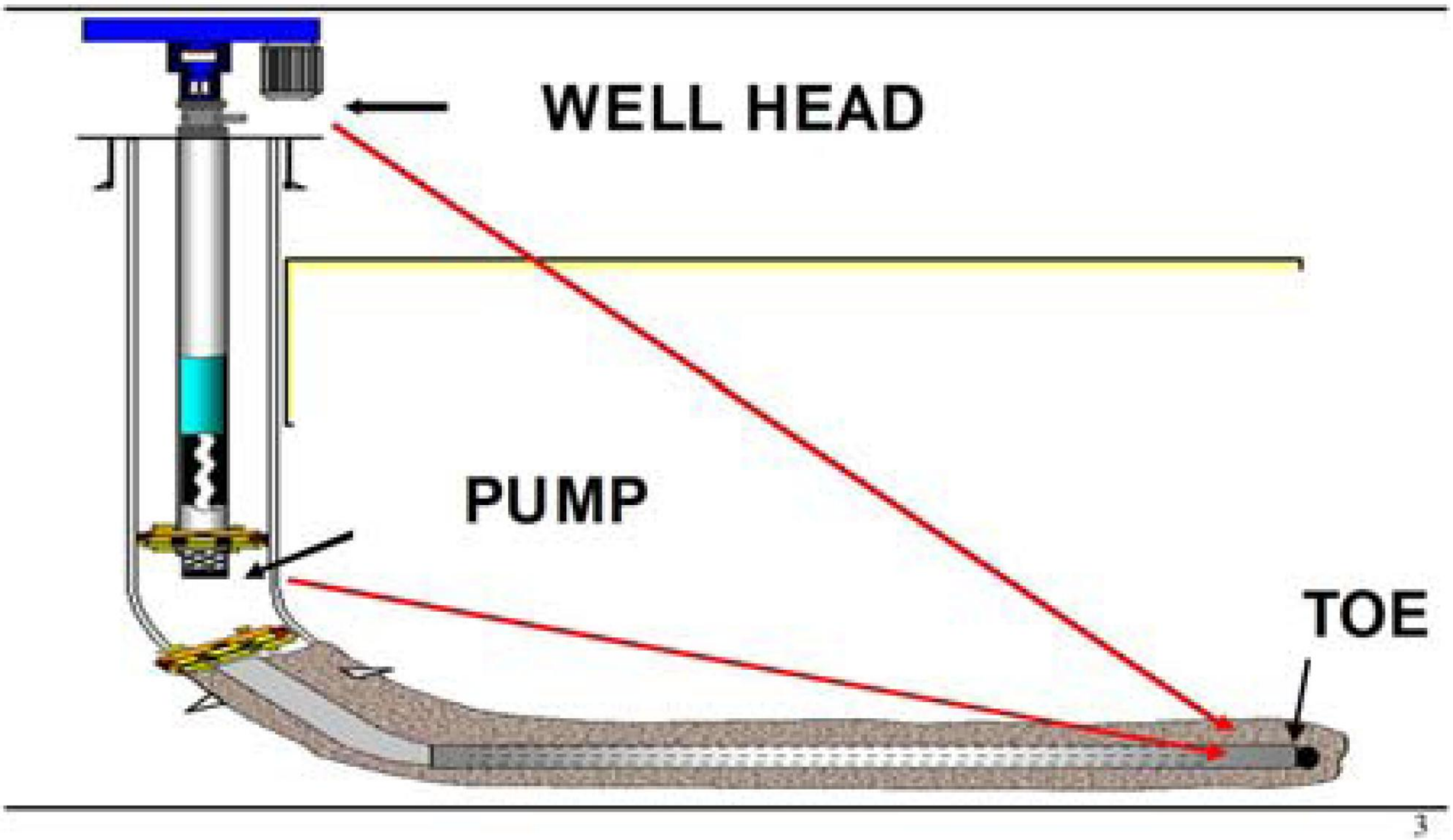


Figure 18. Three existing injection points.

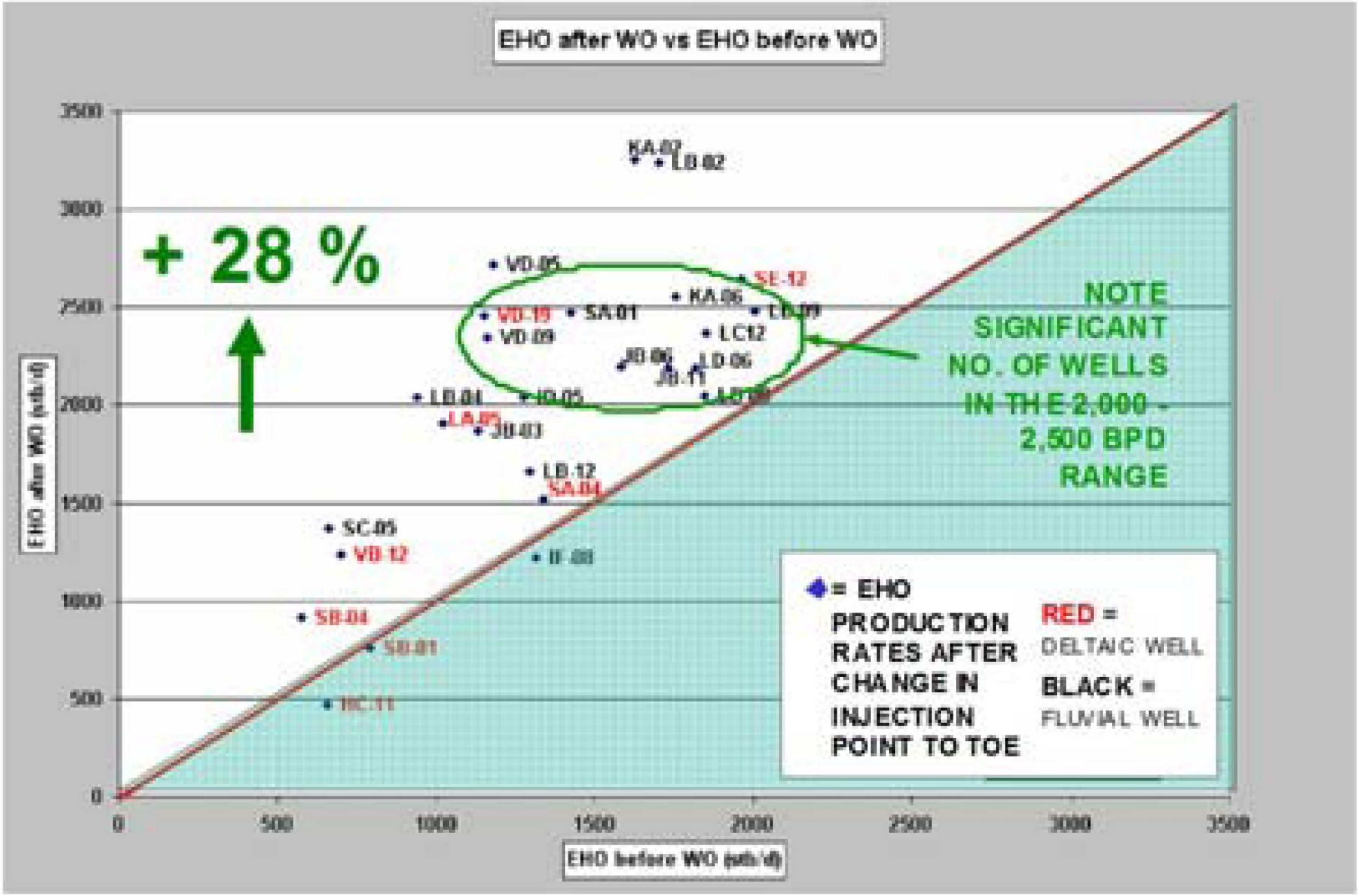


Figure 19. Productivity increase vs. injection point at “toe”.

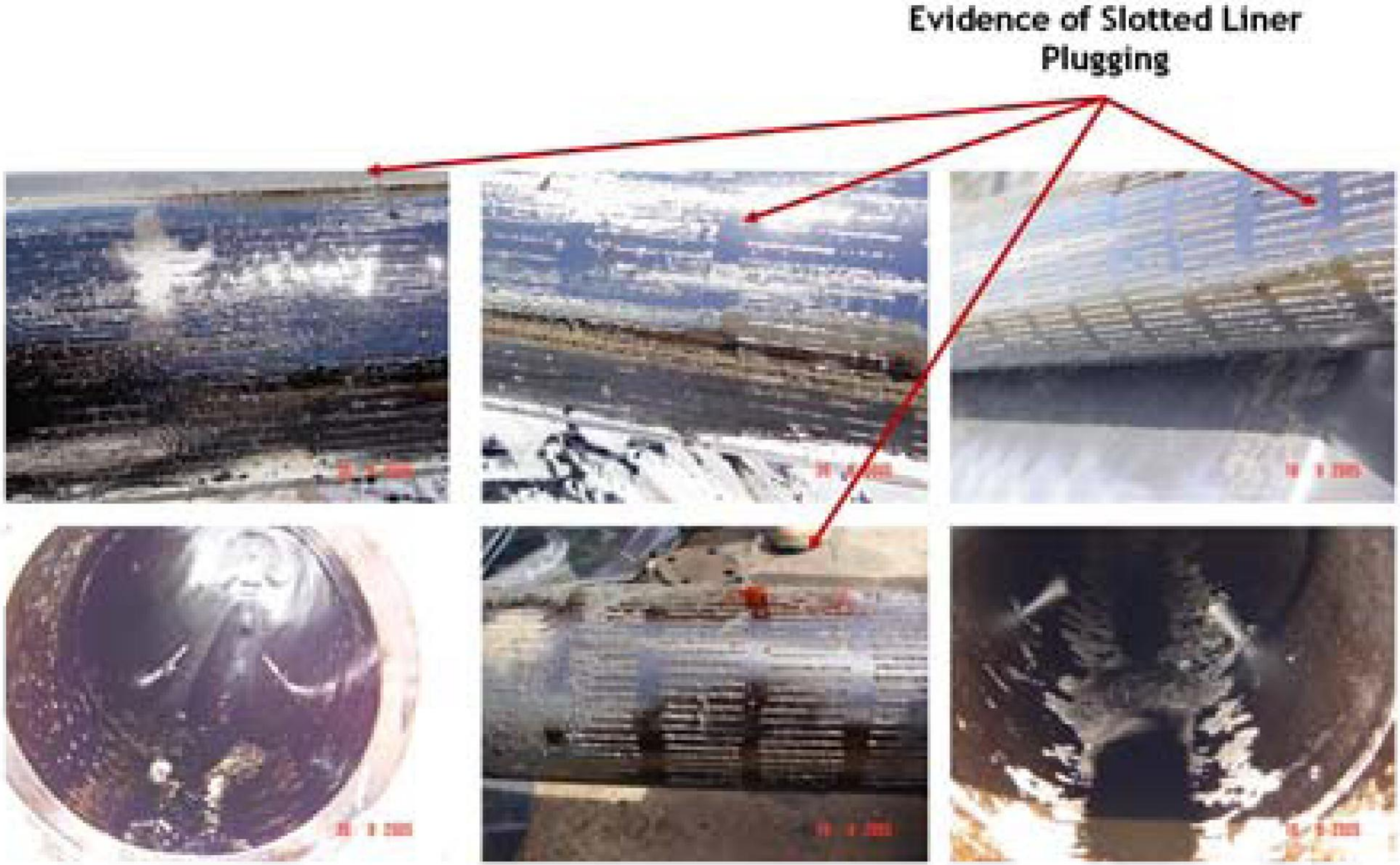


Figure 20. Evidence of plugging of slotted liner.

pozo	ULTIMA PRUEBA ANTES TRATAMIENTO				PRIMERA PRUEBA DESPUES TRATAMIENTO				
	Fecha prueba	Tipo prueba	IP B/D/lpc	EHO B/D	Fecha prueba	Tipo prueba	IP B/D/lpc	EHO B/D	Delta EHO
YC01	05-Oct-2009	Medicion	0.9	496	21-Feb-10	Medicion	4.5	1095	599
JD03	11-Mar-10	Medicion	1.3	450	[illegible]	[illegible]	[illegible]	520	70
JD12	5-Apr-10	Medicion	1.8	650	[illegible]	[illegible]	[illegible]	1100	450
WB01	25-Oct-09	Medicion	0.3	84	[illegible]	[illegible]	[illegible]	559	475
WB08	15-Apr-10	Dummy	0.2	106	[illegible]	[illegible]	[illegible]	193	87
YA11	5-Jun-10	Dummy	0.8	297	20-Jul-10	Medicion	3.0	855	558
YA01	31-May-10	Dummy	0.5	258	10-Jul-10	Medicion	1.9	836	578
YA05	3-Jun-10	Dummy	0.2	86	17-Jul-10	Medicion	2.0	566	480
YA02	1-Jun-10	Medicion	0.5	183	26-Jul-10	Dummy		303	120
VB04	9-Jun-10	Dummy	1.0	534	13-Aug-10	Medicion	2.9	980	446
VC07	13-Jul-10	Medicion	0.4	227	19-Aug-10	Medicion	2.2	988	761
KA09	20-Apr-10	Medicion	2.0	733	20-Aug-10	Medicion	2.8	875	142
VB05	26-Jun-10	Dummy	1.0	330	8-Sep-10	Medicion	3.5	1187	857
VC04	1-Jul-10	Dummy	0.8	285	12-Sep-10	Medicion	0.6	220	-65
KA10	20-Aug-10	Medicion	0.7	285	8-Sep-10	Medicion	0.8	313	28
VB18	13-Aug-10	Medicion	0.8	287	22-Sep-10	Dummy	0.6	172	-115
YB07	[illegible]	[illegible]	[illegible]	111	[illegible]	[illegible]	[illegible]	658	548
HC13	[illegible]	[illegible]	[illegible]	198	[illegible]	[illegible]	[illegible]	445	247
YC10	[illegible]	[illegible]	[illegible]	334	[illegible]	[illegible]	[illegible]	776	442
XA26	[illegible]	[illegible]	[illegible]	236	[illegible]	[illegible]	[illegible]	[illegible]	-236
YA04	2-Oct-10	Medicion	0.6	319	18-Jan-11	Medicion	1.3	678	359
WB03	4-Nov-10	Dummy	0.2	110	18-Jan-11	Medicion	4.5	1085	975
VC02	12-Jan-11	Medicion	0.8	356	23-Feb-11	Medicion	1.7	815	459
YC09	5-Dec-10	Medicion	0.5	[illegible]	2-Mar-11	Medicion	1.2	[illegible]	412
				7196				15872	8676

Increase of 8,676 bopd.
Per Well = 377 bopd

Before the Treatment = 7,196 bopd

After the Treatment = 15,872 bopd

Figure 21. Summary of 24 wells treated with surfactant.

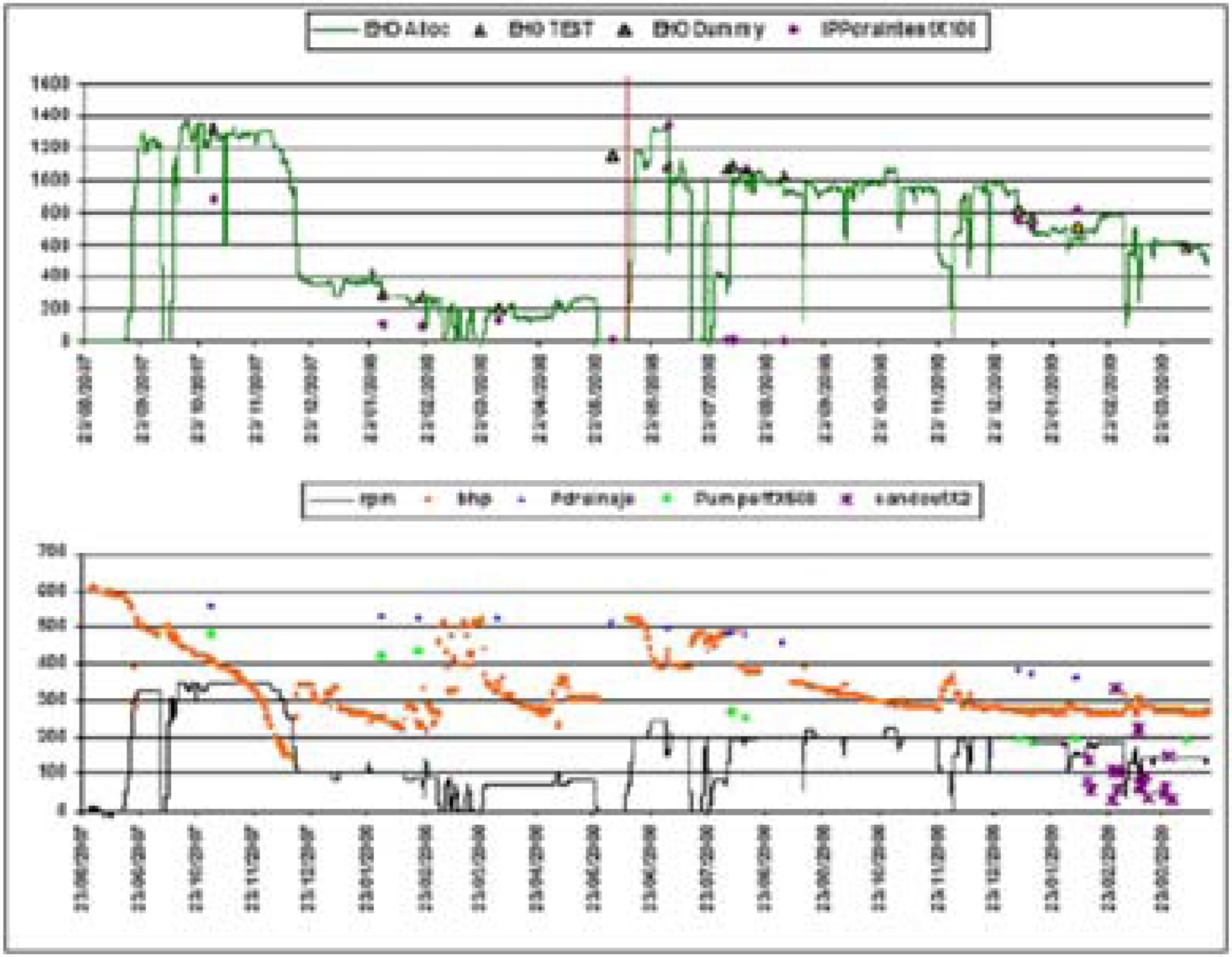


Figure 22. Simulation with use of surfactants.

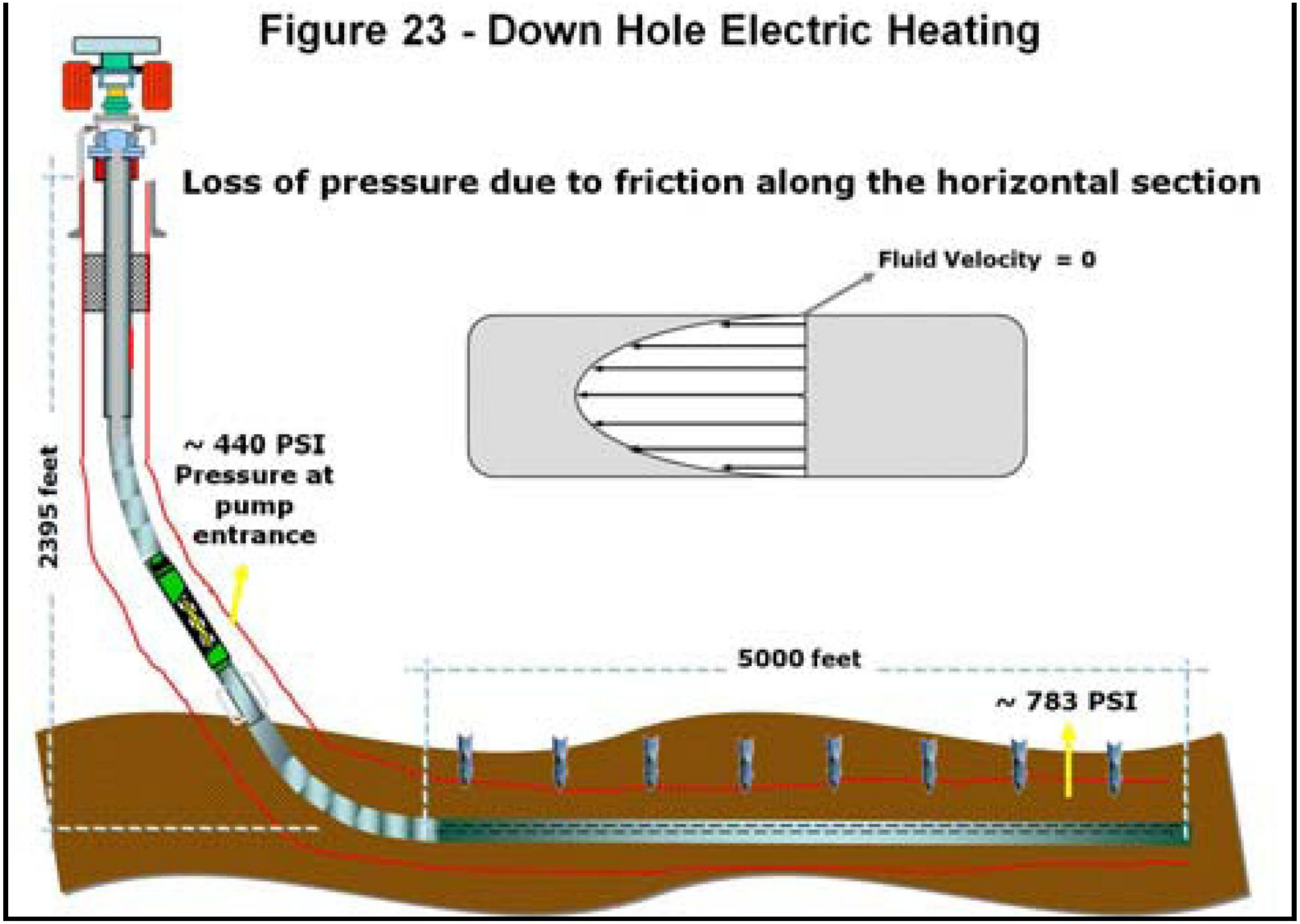


Figure 23. Downhole electric heating.

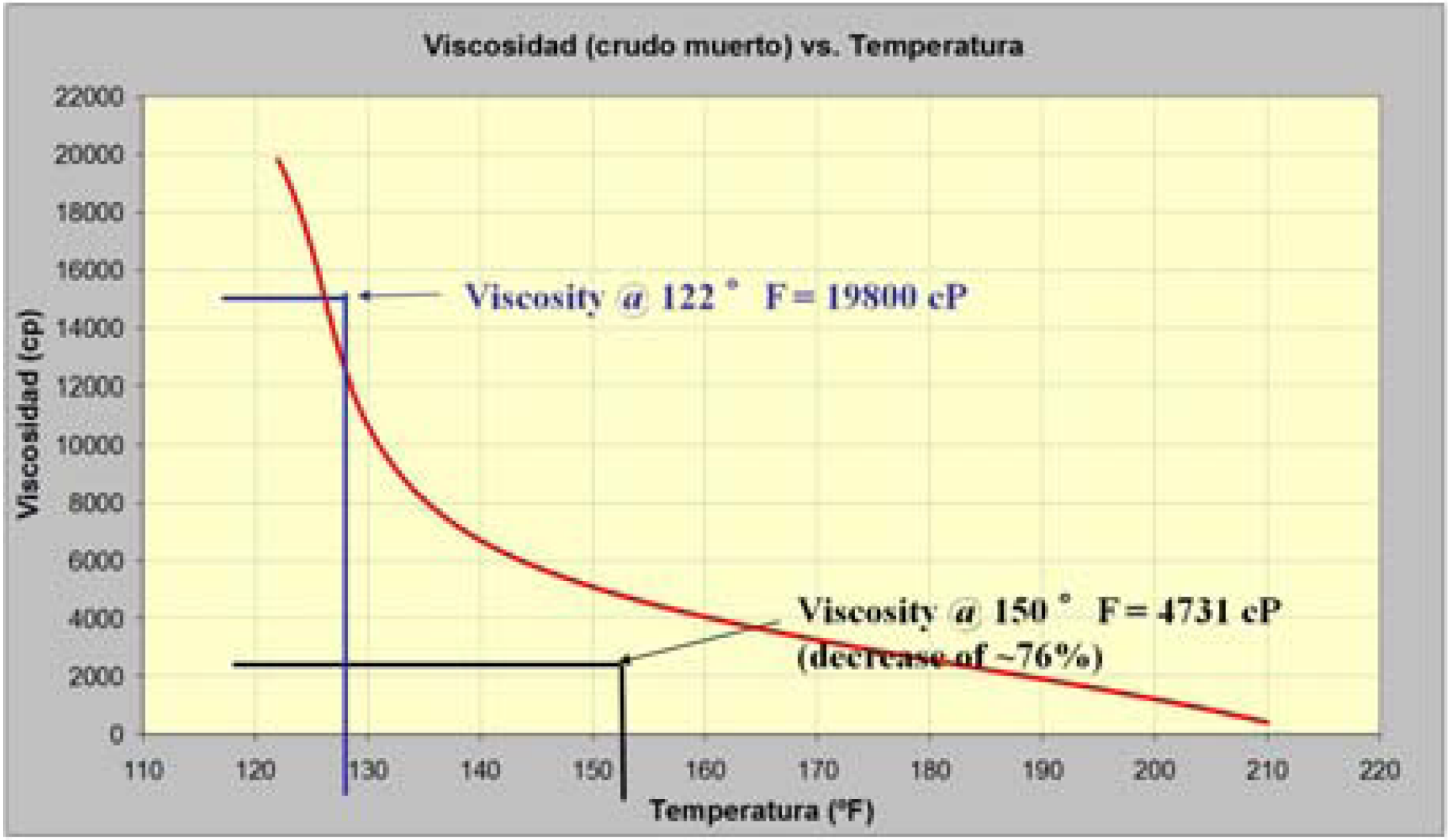


Figure 24. Dead oil viscosity vs. temperature.

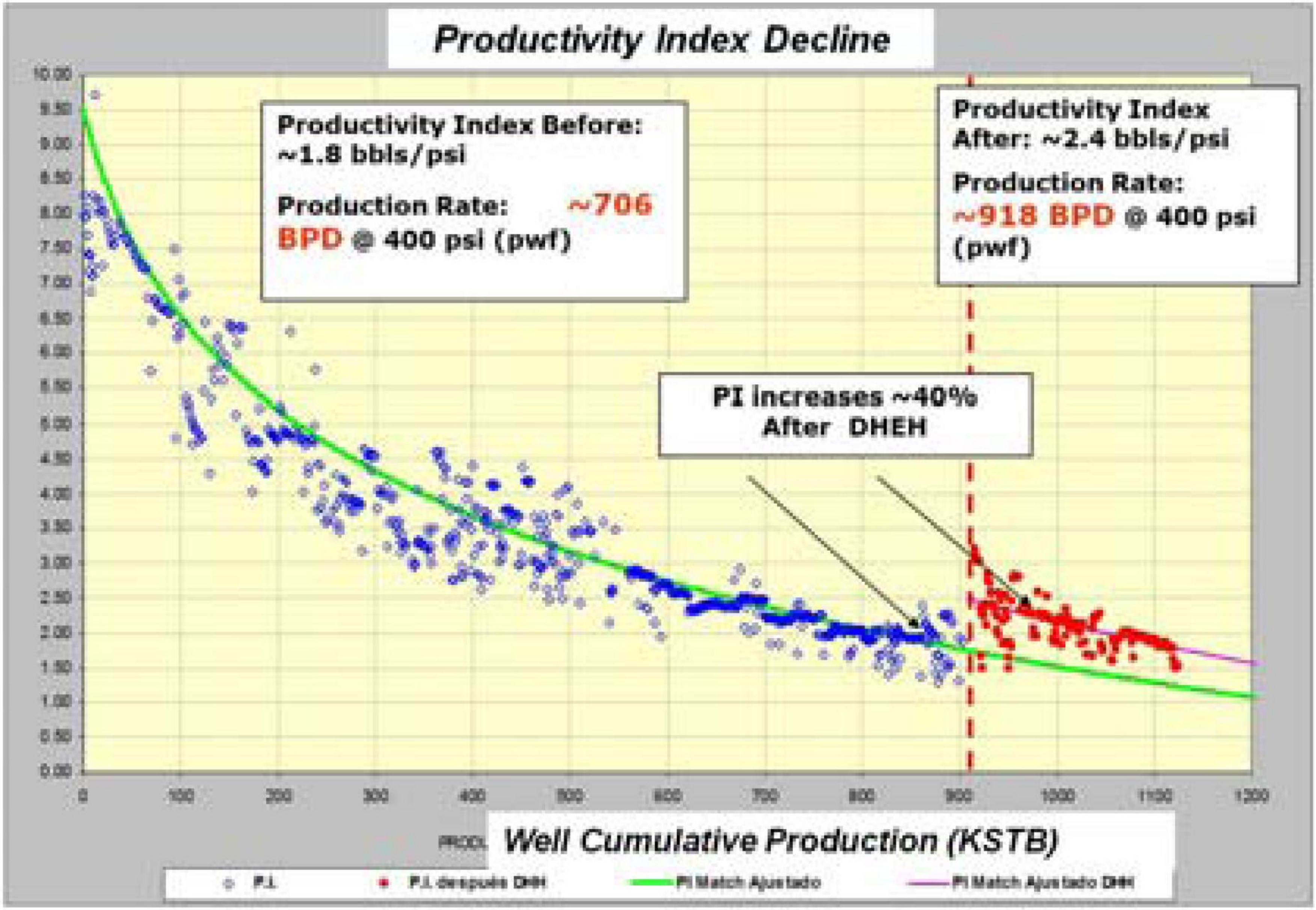


Figure 25. Productivity increase with electric heater.

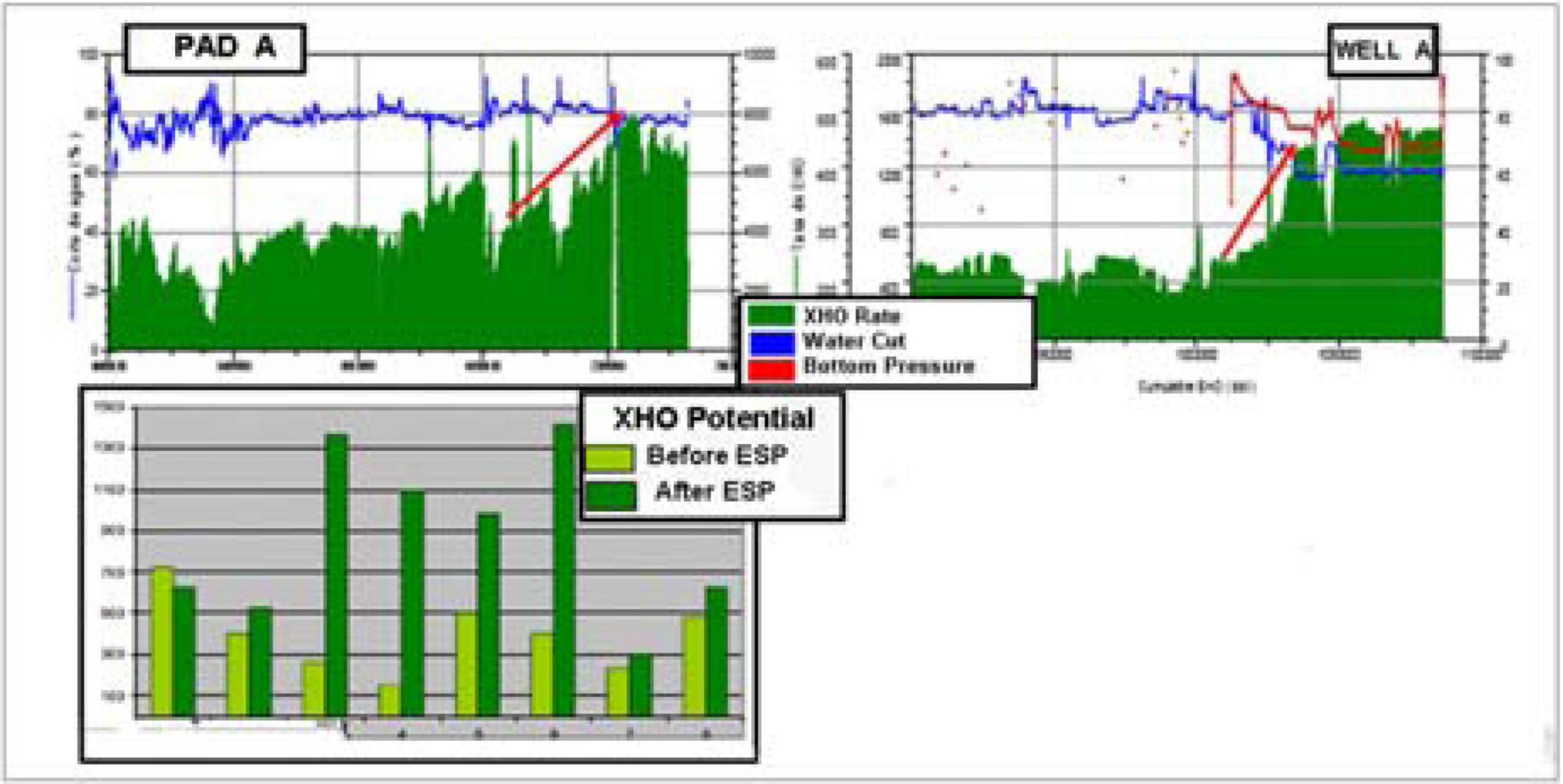


Figure 26. Successful application of dewatering technique.

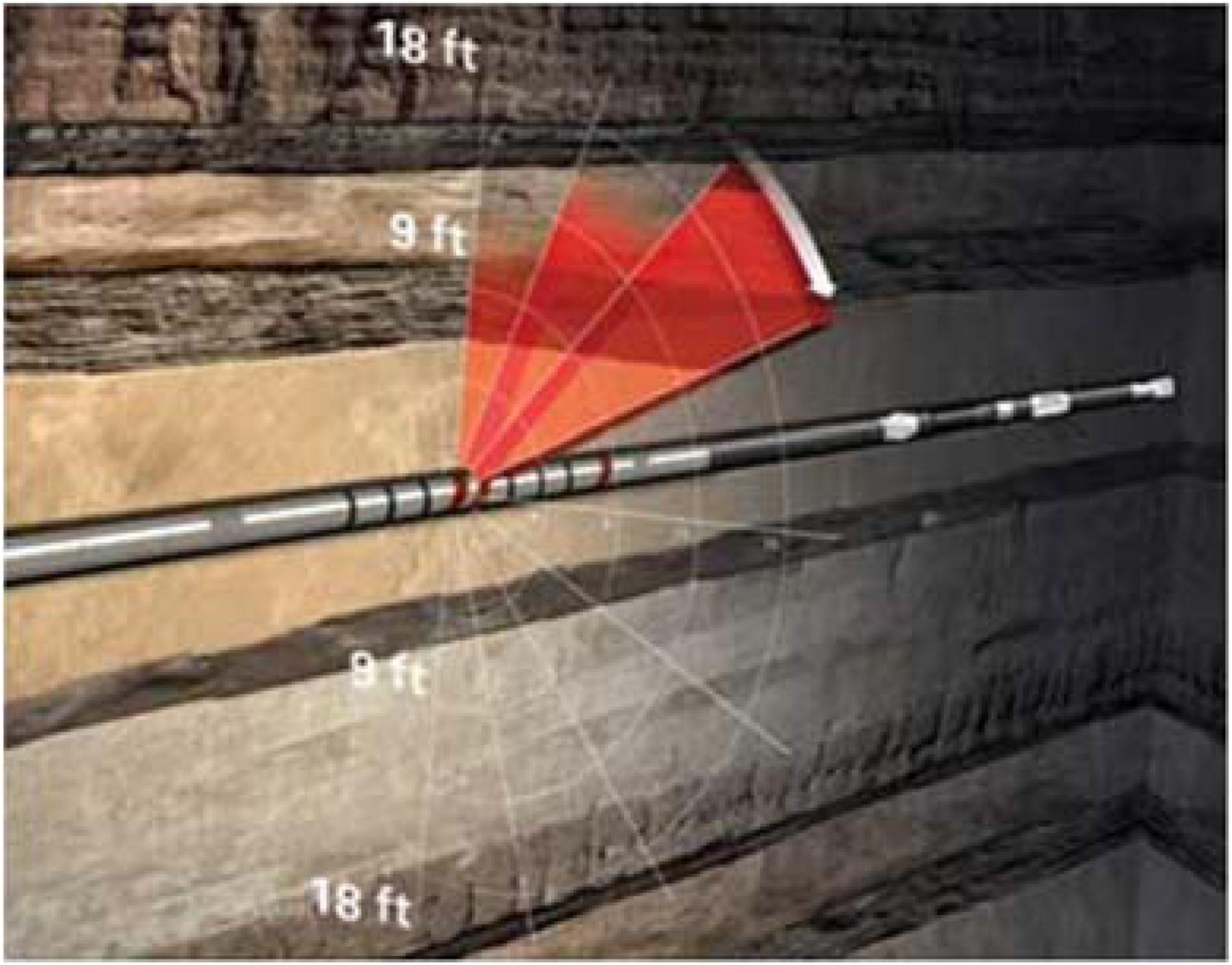


Figure 27. Thin sand development – Azimuthal Resitivity Tool (ADR)

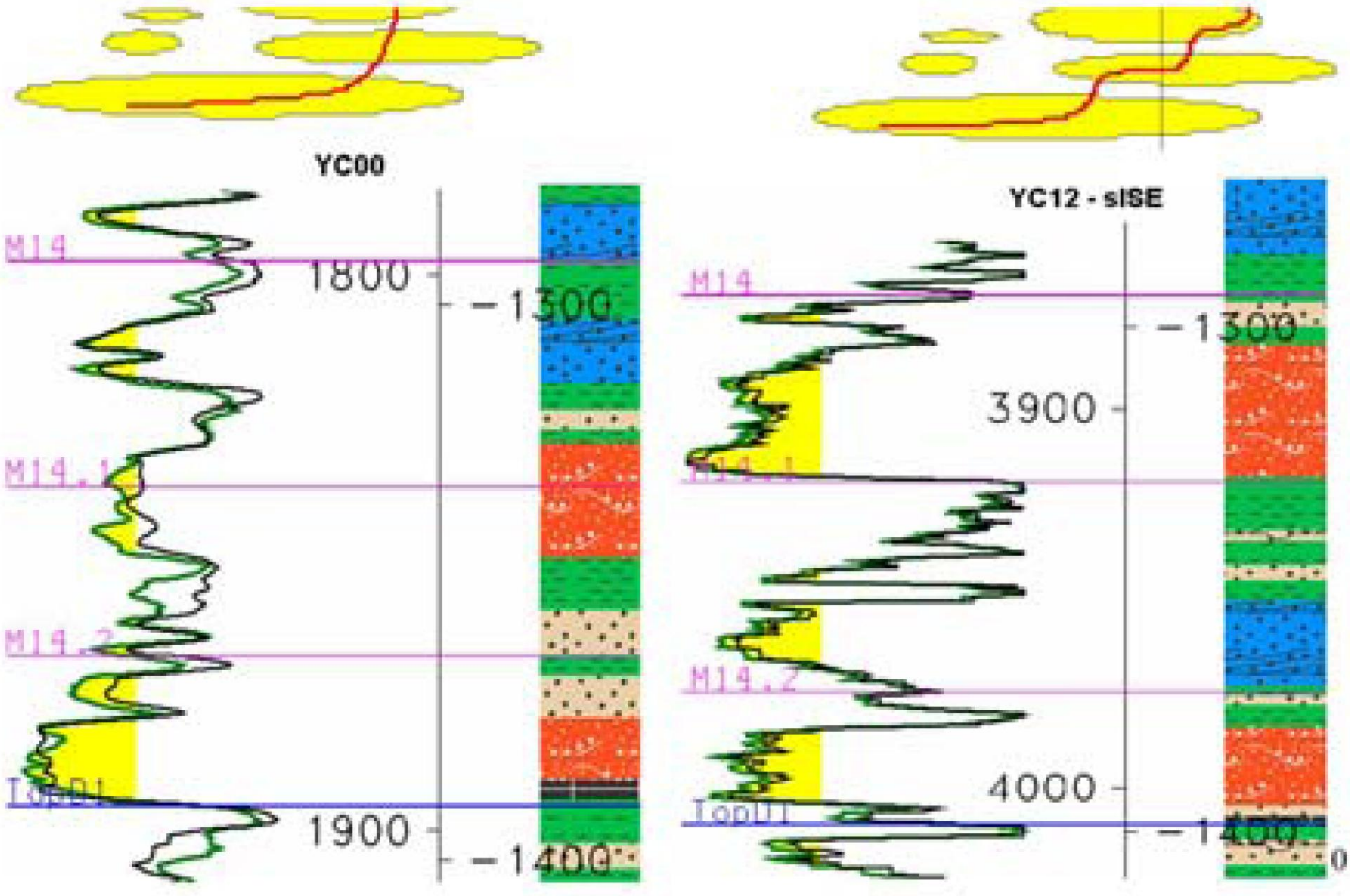


Figure 28. “Non-conventional” wells.

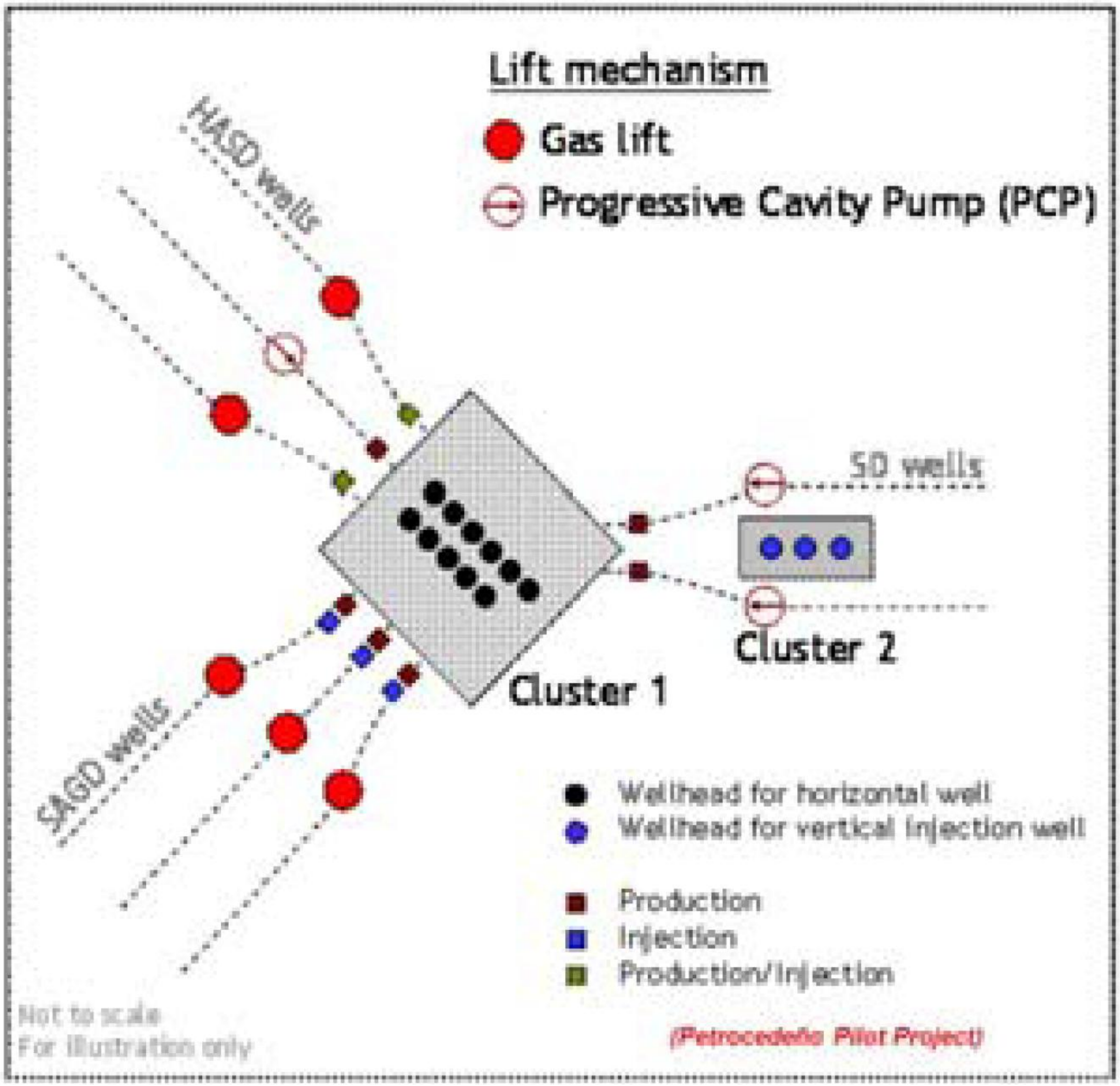


Figure 29. EOR thermal techniques to be applied.

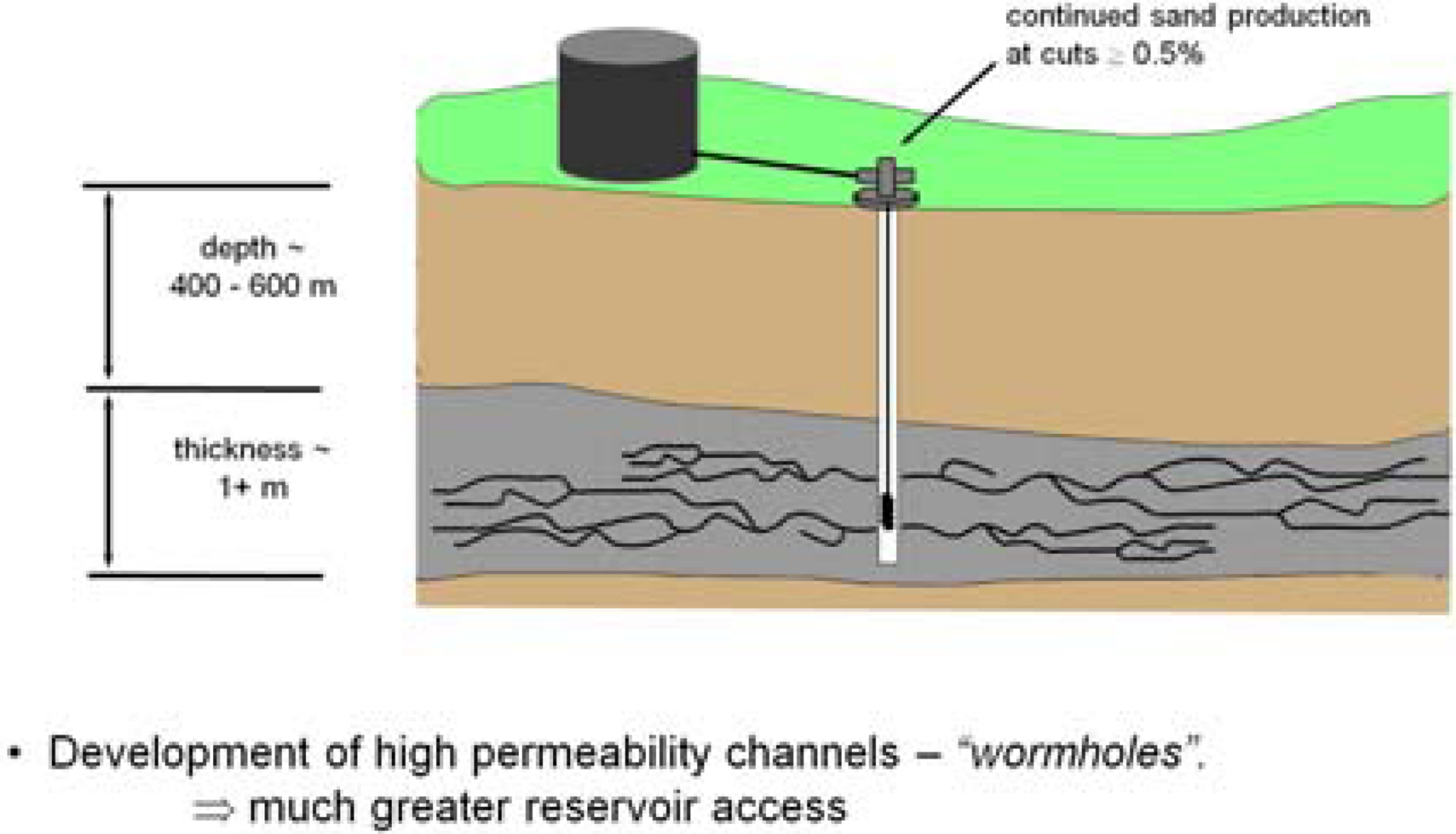


Figure 30. Cold heavy oil production with sand (CHOPS).