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## A Case Study in Improving Capital Efficiency

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### Abstract

The initial phase of Venezuela's first large-scale horizontal development drilling program in the Faja del Orinoco will soon be completed. This project is known as the Venezuela Extra Heavy Oil Project (VEHOP) and is operated by Petrozuata, C.A., a strategic association between Petroleos de Venezuela, S.A. (PDVSA) and Conoco, Inc. The planning process began in 1994 with the evaluation of worldwide heavy oil operations. A test well was drilled which incorporated design changes to improve well productivity and allowed the operator to gain experience in Venezuelan operations.

The Petrozuata development program was based on drilling and completing 95 horizontal wells of identical design as efficiently as possible in order to maximize the project economics. To accomplish this goal, a minimum well design was established based on managed risk. Discrete operations were then analyzed to establish breakthrough targets for drilling performance. To ensure targets were met, a well manufacturing process, including fit-for-purpose drilling rigs, contracting strategy, procurement strategy, and detailed operational plans were developed.

Performance improved significantly from an initial 19.2 days to 5.4 days per well. The basis of design included 4000 foot lateral sections with actual lengths exceeding 6000 feet measured depth (MD). A capital efficiency improvement of 18% is projected based on current performance. This paper details how shared goals, teamwork, and continuous improvement initiatives between the contractors and operator resulted in world-class drilling performance, record setting horizontal completions, and a new standard for future Venezuelan operations.

### Introduction

The VEHOP Project is located in the Zuata region of the Faja del Orinoco (**Fig. 1**). The project scope includes the drilling of 95 horizontal wells and the installation of production facilities and pipelines. The extra heavy crude (8-11° API) is contained in massive, multi-storied, coalescing channel sands located at a depth of approximately 2000 feet true vertical depth (TVD).<sup>1</sup> VEHOP drilling operations began in August 1997, following 3½ years of project front-end loading and detailed engineering. The 13 month front-end loading cost for the drilling operations was 2.4MM USD and is anticipated to realize a 20.3MM USD reduction in development drilling costs, not including rig purchase costs, upon project completion. This equates to a capital efficiency improvement of 18% utilizing unescalated costs.

In 1996, the most dramatic breakthrough to the original basis of design occurred. The project evolved to horizontal wells and cold production from slant wells and steaming operations. The well count estimates were reduced significantly, to 1/5 of the initial well count and to roughly 1/2 of the total well count projected for the slant wells. This decision was based largely on the production results from a horizontal test well that was drilled in another area of the Faja del Orinoco. The VEHOP development plan was based on this well design which incorporated larger tubulars and a formation compatible drill-in fluid to increase well productivity.

During the front-end loading phase, the drilling operation was envisioned as a repetitive, fast-paced, low technical risk development drilling and completion program. Heavy oil operations in Canada, Alaska, and Venezuela were benchmarked in order to identify improvements to the development plan that would increase well productivity, reduce drilling costs, and reduce drilling and completion time. The benchmarking exercise showed that similar Canadian horizontal wells were being drilled in 7.9 days on average, a 68% improvement over wells in the Faja del Orinoco that were drilled prior to the start of the VEHOP development (**Fig. 2**). This indicated that a streamlined approach to the well design and drilling operations, along with project focused contracting and procurement strategies could improve operations significantly.

## Project Planning

In 1986, Brennan<sup>2</sup> outlined the procedure for optimizing cost performance through analysis of cost trends and discrete operational practices. This methodology is based on separating the time-related costs associated with the operational performance from the fixed costs associated with procurement items. He also detailed the well manufacturing process for optimizing repetitive, low risk operations. These basic concepts were utilized in the initial planning and operations optimization efforts.

**General Well Design.** The wells are drilled from pad locations, which vary from 4 to 8 wells each. The well design is composed of three hole sections. A vertical 16" surface hole is drilled to +/- 500 feet TVD where 13<sup>3</sup>/<sub>8</sub>" casing is run. The objective of this section is to cover the fresh water zones. The 12<sup>1</sup>/<sub>4</sub>" build section is drilled to +/- 3000 feet MD and terminates at 90 degrees in the target sand. The build begins at +/- 1000 feet TVD at a rate of 5 to 6 degrees per 100 feet. A 200 foot tangent section is constructed at 70 degrees to provide for placement of the Electric Submersible Pump (ESP). This section is cased with 9<sup>5</sup>/<sub>8</sub>" pipe. Finally, an 8<sup>1</sup>/<sub>2</sub>" horizontal section is drilled across the producing sands and a 5<sup>1</sup>/<sub>2</sub>" or 7" slotted liner is installed based on the reservoir quality (Fig. 3). The ESP is installed on 4 1/2" tubing with a diluent injection string.

**Contracting Strategy.** The contracting strategy permitted a successful alliance between contractors and operator based on mutual goals, a well-defined process, and performance-based incentives<sup>4</sup>. It consisted of an integrated services contract, a drilling rig contract, and leveraged purchasing for the duration of the initial development phase or the anticipated 95 wells. The integrated services structure allowed a single services contractor to manage and coordinate all subcontractors. This approach minimized contract administration and improved team cohesiveness by emphasizing the contractor to contractor relationship, rather than the contractor to operator relationship. A separate drilling rig contract was required to address long term contracting issues, operator specifications, and allow the operator to take a decisive role in the rig delivery and start up schedule. Leveraged purchasing was critical to the overall cost savings by fixing costs over the contract duration.

The drilling rig contract included two drilling rigs that were purchased and refurbished by Petrozuata. The scope of work required fast moving rigs, quick rig up, and dedicated crews. The rig requirements were based on standards for heavy oil development drilling which were observed and evaluated in Canada. The contract term was for 10 years with a buy-back of the rigs by the drilling contractor after a specified number of operating days followed by a rig sharing relationship beyond the initial contract period. The first rig required minor modifications after a complete overhaul of the operating system and the second rig was a new build utilizing some of the existing rig components.

Fixed cost assets were leveraged based on 95 wells. Since fixed cost items were anticipated to be up to 55% of the total

well cost, it was critical that these costs be minimized while meeting quality and schedule requirements. Some items, such as wellheads and drilling fluid products, were found to be more cost effective if imported. Other products and services such as tubulars and liner slotting were purchased locally. Local suppliers were maximized based on quality, cost and schedule considerations.

**Organization and Teamwork.** After the contracts were awarded in May 1997, a week-long workshop was held with all dedicated contractor representatives and wellsite supervisors to review the development plan and brainstorm new ideas and approaches to the well design and operations. This meeting included breakout sessions to discuss detailed operational plans such as waste management processes, solids control and drilling fluid handling, and critical path items. Outstanding issues were identified and future work responsibilities assigned accordingly.

During this meeting, the drilling procedure was broken down into discrete operations, analyzed, and recombined to develop the initial program. This exercise was similar to establishing a technical limit<sup>3</sup> for each operation in that it determined the time performance that was possible. These time goals were developed in the workshop with full team participation, and were later used to benchmark the operation. This joint development was critical to achieving the goals, which are based on the Canadian benchmarking exercise. A learning curve was also established based on the target times. The first three wells were estimated to be drilled and completed in 17 days per well, rapidly improving to 8 days by well 15. The ultimate goal established was 6 days per well.

This process was important to overall success because it ensured that the goals were developed and agreed to by the team since these goals were later used in the contractor incentive plan. It also became apparent that, in order for the goals to be realized, a detailed operational plan was required. The plan was detailed in a Drilling Operations Manual (DOM) which was also generated by the entire team. The DOM described all the operations and included the equipment, materials, and time requirements for each operation along with cost estimates. It proved to be an excellent planning tool because constant cooperation and discussion was required between the operator's engineering and operations staff and the various contractors.

The group development of the plan and goals confirmed that in order to reach the objective, no time could be lost at the wellsite. Therefore, it was agreed that the field personnel would be given the authority and information to make critical decisions related to wellbore trajectory and even geological sidetracking, if necessary. Horizontal performance criteria were established to guide this decision making process which included minimum horizontal length and reservoir quality parameters.

**Well Manufacturing Process.** The batch drilling operation was one of the key breakthroughs to the drilling development plan. Each hole section, including the completion, is a

separate rig operation. This technique has proven to be efficient and has reduced the learning curve substantially. The enhanced learning curve is due to reducing the job to a series of short-lived, repetitive cycles. This reduces the time between tasks and greatly increases the speed at which the task becomes familiar. It has also provided the option to delay drilling the horizontal section and running the completions until the production is needed, thus minimizing the potential for formation damage.

The well manufacturing process efficiencies include the elimination of waiting time. This includes waiting on cement and having service personnel, such as directional drillers, waiting on location for the next operation. It also includes less tangible but still significant efficiencies such as reducing the number of actions and resources required to complete a cycle and having fewer people on location at any one time. This allows the onsite supervisors to devote more attention and energy to the operation and less to logistics. The extra attention and energy speeds the optimization process as inefficiencies are more obvious and can be quickly noticed. Discrete operations are evaluated and modified to improve the repetitive operations.

Each drilling rig has been specifically designed for the operation it performs and is modular to facilitate fast move and rig up operations. The small rig runs surface casing and completions and is a hydraulic slant rig equipped with a pipe handling arm and power swivel. The central mud system and mud pumps are removed for the completions to further reduce the moving times. The larger rig is a fit-for-purpose triple drilling rig equipped with a portable top drive. The skidding system allows well to well moves with the 5" drill pipe racked in the derrick. A specialized low-pressure wellhead and blowout preventer (BOP) connector system was designed which reduces nipple up time to less than 10 minutes per well.

**Drilling Rig Design and Specifications.** The drilling rig specifications are listed in Table 1. Rig 731 is a carrier mounted single with a hydraulic top drive and a pipe handling system working in conjunction with an Iron Roughneck. Pipe handling is virtually hands free. The rig is suitable for drilling, completions and workovers and can work with the mast as much as 45 degrees from vertical. During completions or workovers the central mud system is not used and is not moved with the rig. This rig was used to drill the surface and build sections of the wells.

Rig 732 is a more conventional triple rig design with a 600 HP electric top drive and a system for self skidding which allows well to well moves with the drill string racked in the derrick. This rig was designed to drill both the build and horizontal sections on a single pad in batch mode.

The moving system utilizes hydraulic rams to lift the substructure/mast/drillstring combination. During the skidding process the rig is lifted by vertical hydraulic rams. The weight of the rig is carried on beams, which rest on matting. The beams are mounted to both the horizontal and vertical rams. This feature eliminates the need to handle the beams as part of the rig move.

The rig is skidded by the horizontal hydraulic rams. At the end of the ram travel, the rig is set back down onto the matting, the beams are lifted with the vertical rams and moved ahead with the horizontal rams and the cycle repeated until the rig is positioned over the next well. Actual time from well to well has been as short as 15 minutes with this configuration.

### Drilling Operations and Efficiency Improvements

The team goal was to aggressively test the plan and to identify and make necessary changes as quickly as possible. To assist this process and evaluate operational efficiency, average vs. fastest time was compared for each discrete operation<sup>2</sup>. Using this methodology, drilling practices on both rigs evolved quickly.

**Drilling Fluids.** The most substantial optimizations occurred early in the drilling program. The drilling fluid plan and specifications changed significantly for each well section as did the hydraulic design.

The surface hole fluid evolved from a bentonite system to freshwater within nine surface holes or approximately one week. The native clays encountered built sufficient fluid viscosity to clean the hole for running casing without the need for wiper or clean-out trips. Within the same time frame the pump rate was increased from 300 GPM to 800 GPM. The total drilling time for the surface hole sections decreased from the initial 33 hours to 8.5 hours over the first 20 wells (**Fig. 4**).

The drilling fluid for the 12¼" build section evolved from a design basis of a polymer system to a lignite/bentonite system to the present freshwater. Light polymer treatment assists in cuttings transport and fluid loss control near total depth. A thinner is added to reduce the rapid reaction of native clays while tripping out and running the 9<sup>5</sup>/<sub>8</sub>" casing.

Reducing the Brookfield viscosity from the initial 50,000 cp to less than 20,000 cp optimized the solids-free polymer drill-in fluid utilized for the horizontal section. This is estimated to save approximately 20,000 USD per well. Operational improvements have been realized in changing over to the drill-in fluid after drilling out the cement and float shoe.

**Running Casing.** The trip out to run 9<sup>5</sup>/<sub>8</sub>" casing now includes backreaming for precautionary purposes. It was determined that two hours of backreaming usually saves three to four hours of casing running time.

The 13<sup>3</sup>/<sub>8</sub>" and 9<sup>5</sup>/<sub>8</sub>" casing is run on Rig 731 using the hydraulic top drive to make up the casing. To resolve the thread damage encountered on the first several jobs, the drillers developed a "feel" for the hydraulic pressure required for initial thread engagement. It was also learned that rig alignment to hole center and rig leveling was important to ensure proper makeup.

All casing jobs on Rig 732 are run conventionally with power tongs. Monitoring of drag forces while running the slotted liners revealed that a 50/50 combination of rigid and bow type centralizers run one per joint afforded the lowest drag forces. Drag measurements and three incidents of stuck

7" liners in 9<sup>5</sup>/<sub>8</sub>" casing showed that backreaming from final total depth to 20 degrees inclination was necessary to predictably run 7" liners. A less extensive backreaming program was found to be effective for the 5 1/2" liners.

**Torque and Drag.** With only 1000 feet of vertical section, it is impossible to run sufficient heavy weight drill pipe (HWDP) required to supply weight on the bit. The objective of drilling the horizontal section to total depth without having to trip out of the hole to rearrange the drill string was achieved by drilling as much as the first 2000 feet of horizontal hole with drillpipe to surface prior to picking up HWDP. Weight transfer to the bit became a problem toward the end of the horizontal section in some of the longer wells and in wells with a high percentage of silts/shales. This problem was alleviated using 5 stands composed of 2 drill collars and one heavy weight as the upper most drillstring component<sup>1</sup>. This provided an additional 3000 lbs per stand of available weight at surface. Trips to rearrange the drillstring configuration are still required on some of the longer wells and are made at the discretion of the onsite supervisor in consultation with the directional driller and geologist.

While drilling in sliding mode, practically the entire string is in compression. While drilling the last 1000 feet of lateral, 3000 feet of 5" drill pipe is working under compression in the open hole. The tolerance between the 8 1/2" hole and 6<sup>3</sup>/<sub>4</sub>" OD tool joints work to prevent the drillpipe from buckling severely. Buckling occurs when drilling in sliding mode, which is normally less than 40 % of the time. To date, there have been no failures due to pipe buckling.

The actual torque and drag values obtained have been similar to those predicted. The drilling torque towards the end of the horizontal sections was typically in the range of 12,000 to 14,000 ft-lbs, but in a few wells increased close to the operating limit of the top drive. On laterals with higher doglegs, directional changes, or a high percentage of silt, drag has increased to the point of losing the ability to slide. The difference in hookload between rotating off bottom and pick up without rotation normally ranged between 40,000 and 50,000 lbs, but in a few wells this difference would be as high as 80,000 to 90,000 lbs.

**Stuck Pipe.** When drilling across high permeability sands at high rates of penetration (ROPs), greater than 1000 feet per hour instantaneous, there is a high probability of differential sticking as soon as drill pipe motion is ceased. The practice of reciprocating the entire stand prior to stopping to pump up a survey was implemented and additional stabilization was added to the bottom hole assembly (BHA). This has eliminated significant stuck pipe incidents in the last 40 wells.

In the event of differential sticking, the string has been "freed" by applying torque with the string in compression and reducing wellbore pressure by stopping the pump. If the first attempt failed, the well was circulated clean and the process repeated. If still unsuccessful, the well was circulated to water and the process repeated again. No BHAs have been lost in the hole and all fishing operations have been successful.

**Bits.** Initially tricone bits IADC Type 1-1-7 were used to drill the lateral portion of the well. The entire section could be drilled with a single bit but ROP through the shale sections was low. Polycrystalline Diamond Compact (PDC) bits demonstrated a significant increase in the ROP across the shale sections. The design of the PDC bits has been improved by studying their performance and wear characteristics. The preferred bit is a short PDC with 6 blades and 19mm cutters. The flow is directed at the bottom of the hole utilizing three nozzles. Flow diverted to the walls of the borehole causes erosion and makes the BHA more difficult to control, thus increasing the amount of sliding required.

The most successful bit used for the 12<sup>1</sup>/<sub>4</sub>" build sections was an IADC 1-1-7 with enhanced gage protection and diamond enhanced cutters. This bit design has drilled as many as 4 build sections or up to 11,000 feet of hole per bit and many have been retipped locally and rerun.

**Solids Control and Fluid Handling.** The heavy oil characteristics have created challenges in fluid handling and drill solids removal. With a specific gravity equivalent to water, the heavy oil does not float on the surface of the tanks for easy removal but instead is incorporated into the drilling fluid. The heavy oil also contains dissolved gas which evolves slowly once the oil is at surface conditions. This creates a foaming effect, making fluid transfer difficult.

The initial solids control system utilized three cascading shakers at a scalping station near the rig floor. A mud cleaner and high speed centrifuge were mounted on the central mud system. The cascading shakers have been run with screens as fine as 84 mesh on the lower shakers when drilling the oil sand and pumping fluid at 500 GPM. These parameters and screen size require that the shakers be monitored continuously. The mud cleaner was generally ineffective due to what appeared to be screen blinding but could possibly have been compaction and adhesion of the sand to itself and to the screens caused by the asphalt content of the heavy oil.

The mud cleaner was replaced by two low speed centrifuges. This system worked well but the abrasive nature of the sand and the high sand content associated with extremely high drilling rates quickly eroded the centrifuges and further use of this system was deemed to be uneconomic. A desilter was then added to the system ahead of the centrifuges in an effort to remove some of the sand. A high level of wear on the centrifuges was still experienced.

The present system replaces the two low speed centrifuges and the desilter with a single two-cone enhanced hydrocyclone<sup>5</sup> that is fed by two 100 HP pumps. Since the discharge from this unit is sufficiently dry, no further processing is required. It makes a fine cut, possibly as low as 20 microns, greatly reducing wear on the remaining high speed centrifuge which is performing well. Experience indicates that this hydrocyclone works best when very coarse, 38 mesh screens are used on the primary shakers. This also eliminates constant cleaning of the shakers.

Transferring the drilling fluid from the well to the central mud system poses a challenge once the oil content goes above

the range of 4 to 5%, which it often does when drilling long sections of productive sand. Several changes to the centrifugal transfer pump suctions have been made to date, without significant improvements.

**Motivation of Rig Crews.** Sixty percent (60%) of all crew personnel are supplied by labor unions. Regular meetings with these unions and a screening process were necessary to ensure that high quality, trainable people were chosen to make up the drilling crews. The drilling contractor performed the selection and training through PDVSA institutions responsible for all oil industry training. Hands-on training was also used to emphasize teamwork among the crew personnel. The drilling crews at this time are able to perform efficiently and with a great deal of motivation. An environment of trust has been created which also improves working relations. To date, there have been no significant labor issues that have adversely affected the operations.

**Incentive Program.** All crew members registered with the union participate in an incentive program that is designed to improve operational efficiency and to reduce absenteeism and work related accidents. The crew is rewarded through fixed value service checks that are exchangeable at local stores.

A contractor incentive program was developed to reward improved operational performance by sharing the cost savings on a monthly basis. This is a tiered system of target, challenge, and superior levels of performance that are based on the original workshop goals. Since no bonus is paid for plateau performance, the performance level must continuously be increasing. Both programs have a minimum safety performance that must be met before any incentives are in effect.

**Safety and Environmental.** Safety, health, and environmental issues are given high priority at all levels of the operation. To accomplish this, the basic philosophy that safety is the responsibility of all employees was implemented. This program supports the education of all wellsite personnel and office staff in safety awareness, fire fighting, well control, spill response and emergency response training. Safety audits are performed and followed up on a regular basis and safety meetings are conducted every tour change. The safety performance continues to be a challenge, one, which relies on a change in culture in order to create a real conscience for safety.

The Ministry of Environment and Natural Resources (MARNR) regulates environmental affairs and gives final approval to waste management strategies. Complying with these regulations was another challenge for this project. Prior to the commencement of drilling operations and supported with the results of the analysis of numerous samples obtained from the first stratigraphic well drilled, an elaborate waste management plan was prepared and submitted for approval. The plan included the handling, treatment, and disposal of all wastes resulting from the drilling operation. Through contractors, all water base drilling fluids are processed to meet

specifications and the solids are mixed, buried and covered upon analysis presented to the MARNR.

### Project Results

The learning curve and continuous improvement initiatives have reduced the drilling and completion time from 19.2 days on the initial well to 6.7 days on well number 10 (**Fig. 5**), a 65% improvement. The best performance to date is 5.4 days, a 72% learning curve improvement.

The overall time savings is 25% which results in a 17.9MM USD reduction in development drilling costs. This equates to a capital efficiency improvement of 18%.

Non-productive time (NPT) has been reduced from 7.7 days or 40% on the initial well. The average NPT for wells 11 thru 15 was 9% (**Fig. 6**).

Included in these savings are 17 geological sidetracks that were not planned and an average horizontal length that is 4600 feet compared to the 4000 feet planned. Well length is based on reservoir quality sand available, the longest lateral drilled, as of December 1998, is currently 6619 feet MD.

### Conclusions

The most influential factor on the success of the VEHOP drilling program has been the tremendous level of teamwork, the aggressive challenging of traditional work methods, and the front-end loading of the planning and engineering efforts. These resulted in the well manufacturing process, a rapid learning curve, and continuous improvement of the drilling operation.

The week-long workshop was successful in securing ownership of the project by all team members. This was critical to setting the stage and achieving the time and performance goals.

The numerous challenges encountered included the additional effort associated with being "first". Petrozuata is a startup operation, the first Venezuelan strategic association, and the first large-scale heavy oil development program in Venezuela. Local conditions, labor, safety and environmental issues also presented challenges that required constant attention.

Critical path reviews and optimization efforts are a continuous process that must be directed at discrete operations.

Just-in-time purchases to minimize cash flow did not prove useful and were labor intensive due to the fast-paced, repetitive operations.

The handling of fluids in heavy oil operations remains a significant challenge in terms of solids control and drilling waste management. Teamwork and organizational structure allowed rapid adjustments of the plan to meet changes in regulations and actual results.

As a result of this project, numerous Venezuelan and 4 world records have been achieved, including the longest horizontal completion at 6584 feet.

## Acknowledgments

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Table 1 – Drilling Rig Specifications

### Rig 731

Depth Capacity	5000 ft with 4.5" DP
Drawworks	Single drum, 600 HP input power
Mast	Clear working height 73.5 feet
Substructure	Incorporated in semi trailer, 250,000 lbs hookload capacity
Table	Load capacity of 250,000 lbs
Top Drive	Hydraulic Swivel. 500,000 lbs static load cap., max speed 120RPM w/ 9700 ft-lbs. Max make up torque 96,000 ft-lb, Max clamping force 75,000 ft-lbs with pipe handling arm
Mud Pumps	2 F800 Triplex, 9" stroke, with 765 HP engines
Mud Tank System	3 mud tank system consisting of 1 shaker transfer, 1 reserve, and 1 active. Total active system is 700 bbls.

### Rig 732

Depth Capacity	9750 ft with 5" DP
Drawworks	700 hp
Mast	Triple Mast (Cap 364,000 lbs – 10 lines)
Substructure	Max rotary capacity: 300,000 lbs. Max setback capacity: 300,000 lbs. Self-skidding system with max setback
Rotary Table	Max capacity: 900,000 lbs.
Top Drive	Max static capacity: 551,000 lbs. Continuous torque rating: 20,100 ft-lbs, Max break out torque 60,000 ft-lbs, Max RPM 233, Max circulating press. 5000 psi.
Mud Pumps	2 F1000. Triplex 10" stroke. 1000 hp rated.
Mud Tank System	3 mud tank system consisting of 1-65 bbl transfer, 1-455 bbl mud treatment, and 1-277 bbl suction tank.

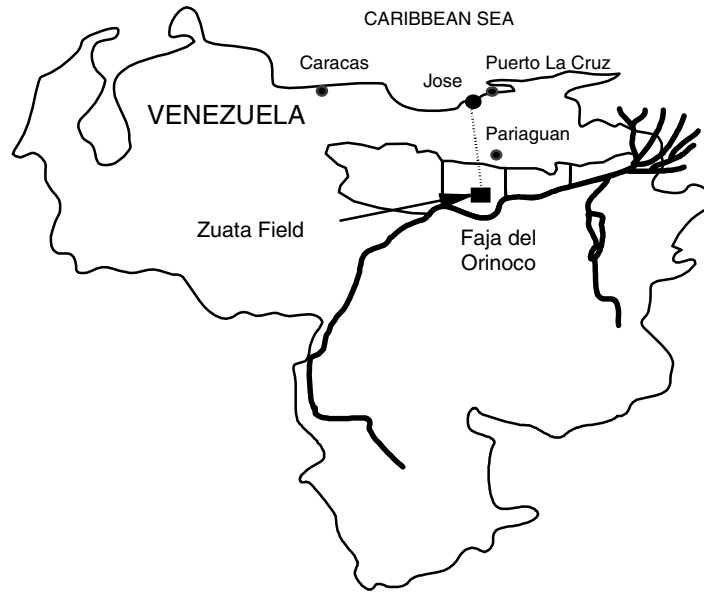


Figure 1 - VEHOP Project Location

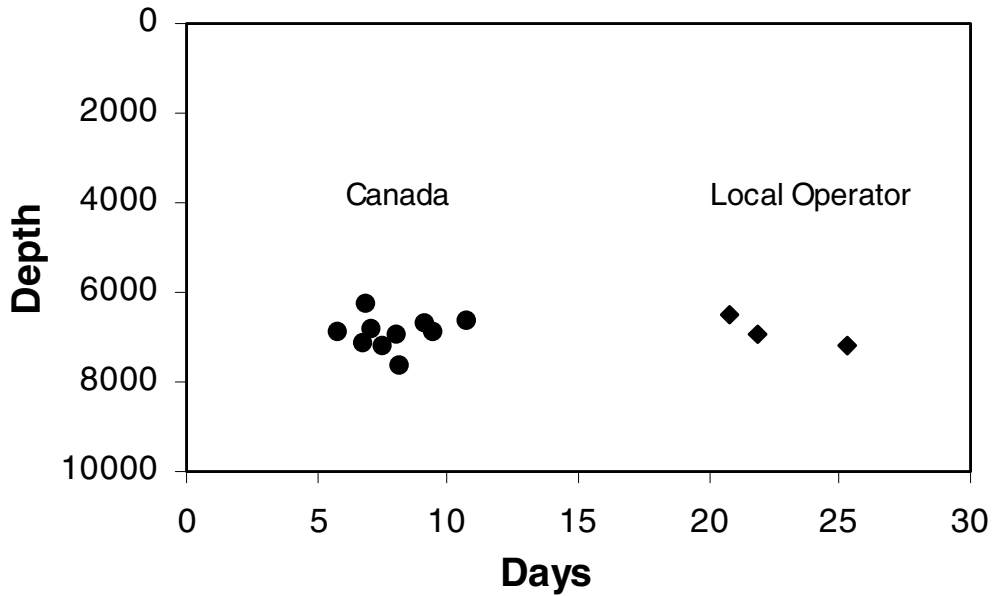


Figure 2 - Benchmark Wells in Canada and Venezuela

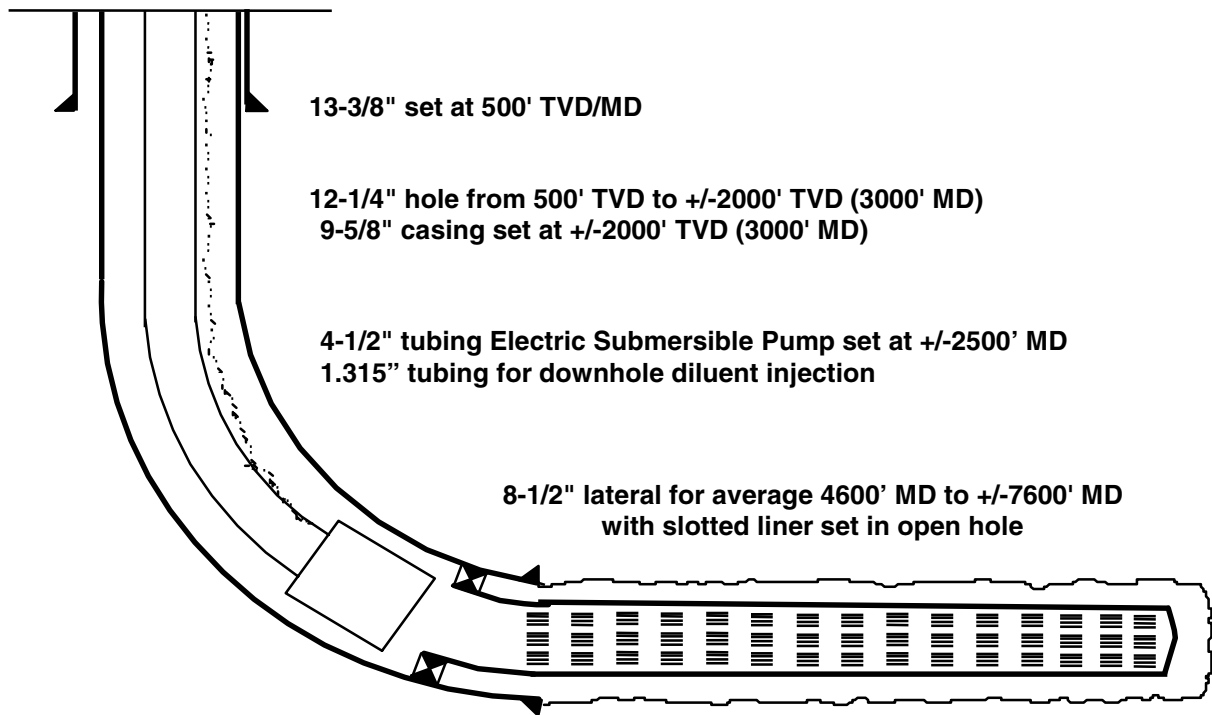


Figure 3 - Horizontal Well Schematic

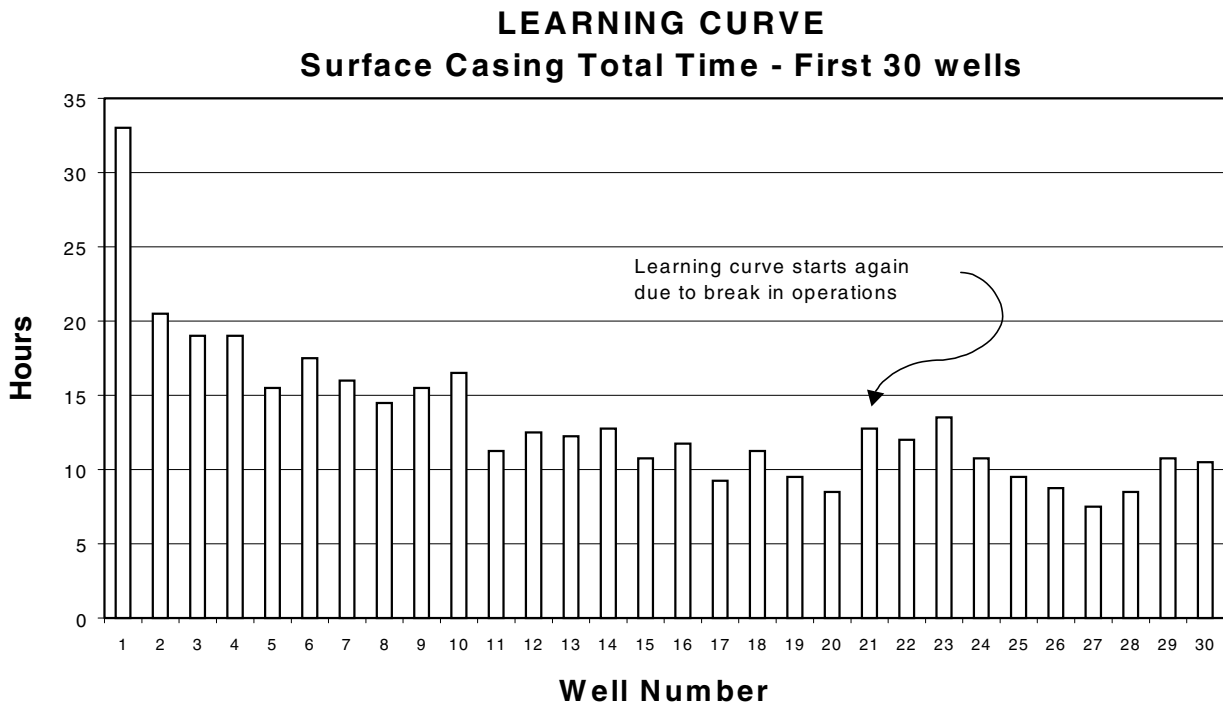


Figure 4 - Surface Casing Learning Curve

### Total Well Time- First 20 Wells

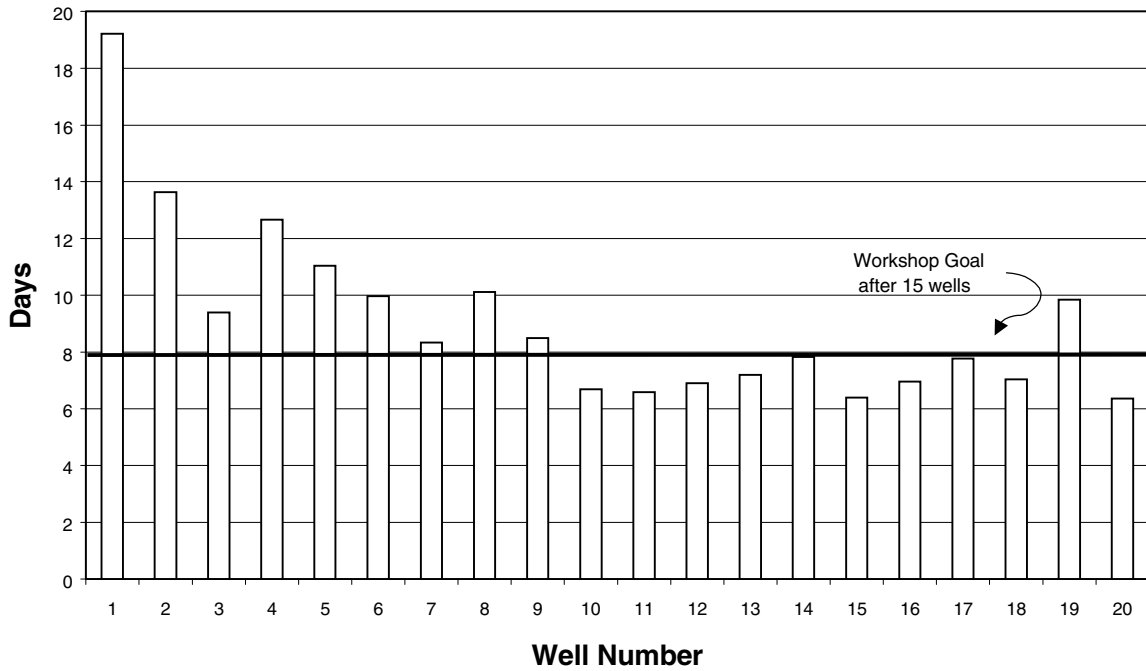


Figure 5 – Total Well Learning Curve

### Total Well Non-Productive Time - First 20 Wells

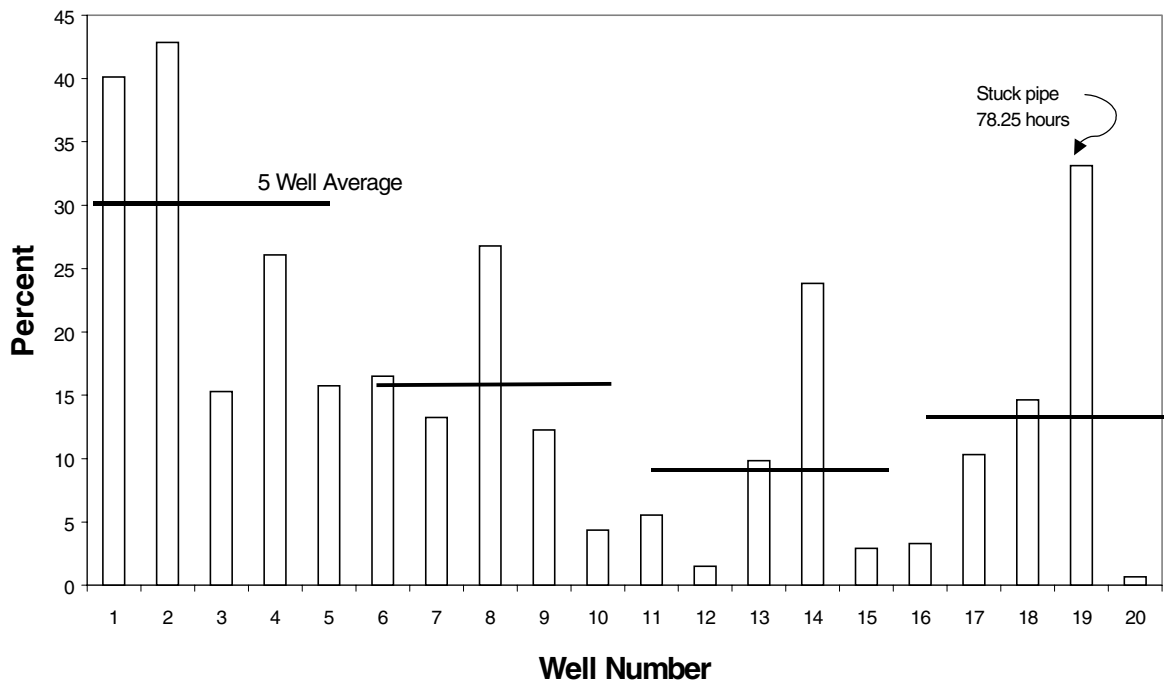


Figure 6 – Non-productive Time Reduction