2" CT VELOCITY STRING RIG LESS COMPLETION TECHNIQUE USING A SPECIALLY DESIGNED CT HANGER SYSTEM - A NEW WAY TO STABILIZE AND RECOVER GAS/OIL PRODUCTION IN DEPLETED WELLS

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Key Words

New way to stabilize and recovery gas/oil production, Velocity String, Rig Less, Specially Designed CT Hanger System

Abstract

The Aguada Pichana Gas field is located in the center of the prolific Neuquén Basin, in Argentina. It produces gas and condensate through monobore completions. Since 2006, an increase in liquid loading has become an issue in current wells conditions, resulting in the need of reducing production tubing size to enable stable gas production (for continuous liquid removal). After a specific study, the appropriate solution resulted in running a velocity string (VS) as an effective means for liquid removal at current and future production conditions. The challenge was to find a hanger system which would allow to hang a 2" CT VS, enabling to unloading of the well by circulating nitrogen and restore the production rate without fully recovering the VS if needed. A multidisciplinary team came out with a special design of VS CT Hanger. The whole process led to important benefits to be described in this paper:

- From the production point of view, this system stabilizes the gas and condensate production.
- From an operations stand point, this system allows us to set and unset rigless the VS as many times as required to optimize or restore the production
- Underbalance installation through X-tree, using Coiled Tubing was identified to be crucial in preventing formation damage.
- The use of this system prevents X-tree and surface line modification and represented a solution to keep surface safety barriers on the well-head versus the use of an additional conventional hanger.
- Logistical cost optimization through rigless intervention versus other work over alternatives.

During the first 4 months of the project, 20 VS were safely installed leading to a gas production increase of 400 Km3 /d. This paper shows the design, operational planning, deployment system and results of an original rigless application described.

Key Words

Nueva técnica para estabilizar y recuperar producción de gas/oil, Sartas de Velocidad, Operación sin equipo (Rig Less), Sistema especialmente diseñado para colgar la sarta de velocidad sin modificar el cabezal de pozo.

Resumen

En Argentina, el Yacimiento Aguada Pichana está localizado en el centro de la Cuenca Neuquina. En el mismo se produce gas y condensado a través de instalaciones de producción monobore. Desde 2006, el incremento en el corte de agua ha comenzado a afectar la producción de gas asociada a cada pozo. Esta problemática trajo aparejada la necesidad de reducir el diámetro de la tubería de producción con el fin de incrementar la velocidad en ella de los fluidos y poder permitir una extracción estable de gas mediante la remoción de la carga de líquido.
Un profundo estudio, arrojó que la solución apropiada para la remoción efectiva del líquido asociado a la producción de gas actual, era la instalación de sartas de velocidad.
Definida la solución, el mayor desafío era encontrar un sistema de instalación de tuberías de coiled tubing de 2”, que permita el colgado de la misma sin modificar el cabezal de pozo actual, y a su vez permita el levantamiento del pozo mediante circulación de nitrógeno para restaurar la producción sin la necesidad de recuperar la totalidad de la sarta de velocidad ya instalada.
Gracias a un equipo multidisciplinario de trabajo, finalmente se logró encontrar el sistema de colgado especial de sartas de velocidad que cumplía con todos los requisitos de seguridad, producción y operatividad deseada para la recuperación de producción.
Luego de la aplicación exitosa en campo, éste proceso ha dejado importantes beneficios que se describen en el paper:
- Desde el punto de vista de producción, el Sistema permitió estabilizar la producción de los pozos.
- Desde el punto de vista operacional, el Sistema permitió instalar y desinstalar las sarta de velocidad en varias oportunidad y de manera rigless permitiendo recuperar la producción requerida.
- La instalación sin ahogo de pozo, utilizando equipamiento de Coiled Tubing es crucial para prevenir el daño de la formación productiva.
- El uso del colgador especial sin modificación del cabezal de producción existente en el pozo, permitió una solución efectiva para mantener las barreras de seguridad, lo cual con los colgadores convencionales de tubería existentes no se podía lograr.
- Se logró la optimización de costo mediante operación rigless versus otras alternativas como workover rigs o snubbing units.

Durante los primeros 4 meses del proyecto se instalaron de manera segura y eficiente, 20 sartas de velocidad, con un incremento de producción de 400 Km3 /d.

Introduction

The Aguada Pichana field is located in the center of the Neuquén Basin (Fig. 1). It produces gas and condensate through 225 drilled and completed wells using 4.5”, 3.5” monobore completions.
The gas is produced from sandstones (mainly fractured) of the Mulichinco formation.
Mulichinco Formation, at +/- 1650 meters is characterized by a relatively thick sedimentary column, ranging from 150 to 250 meters, with 30 to 80 meters of pay zone, from South to North. *et al* D. Coulon- R.Sentinelli *et al* (2007)

Since 2006, unstable gas production as a result of liquid loading was observed, and had become an issue in current production wells condition (at the production line pressure of 288 psi and critical rate for 4.5” completions 60000 m3/day, for 3.5” completions 40000 m3/day, wells turned to intermittently production), resulting to a need of reducing production tubing ID size to enable stable gas production.
With the objectives to stabilize the wells intermittent production and produce additional gas volumes, three different options were studied, (well head compressor installations, capillary tubing installations and surfactant injection and VS installations), after study, Velocity string (VS) with an special VS CT Hanger resulted as the most appropriate solution to this problem.
Once the VS was selected as the best solution, the specific CT hanger was designed in order to comply with the company rules, since a conventional CT hanger (Fig.2) did not meet the safety standards.

Introducing a conventional CT hanger over bottom master valve, would result in the elimination of the required double safety barriers. In order to avoid surface facilities modifications, perform VS installations without killing the well, comply with safety standards, with the possibility to unload the liquids from the wellbore, a special VS CT Hanger was designed.

The whole process led to important benefits described in this paper:

- From the production point of view, this system stabilizes the gas and condensate production.
- From an operations stand point, this system allows us to set and unset rigless the VS as many times as required to optimize or restore the production
- Underbalance installation through X-tree, using Coiled Tubing was identified to be crucial in preventing formation damage.
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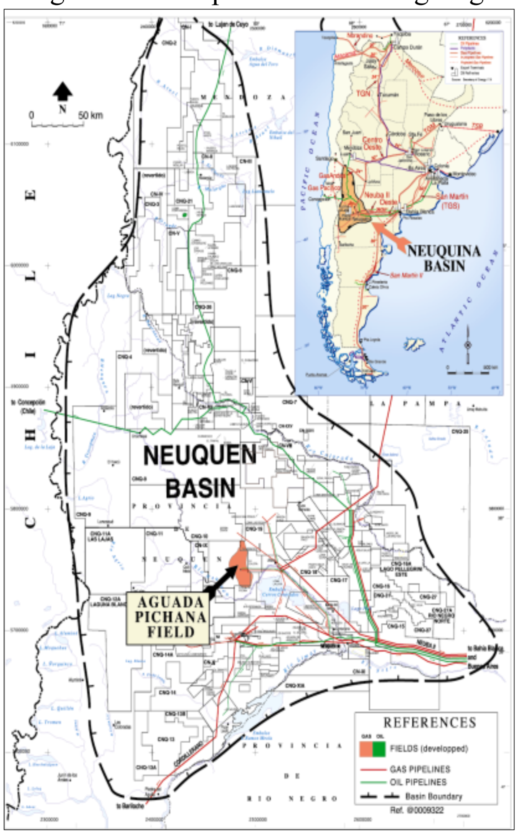


Fig. 1 – Neuquen Basin (*Aguada Pichana Field*)

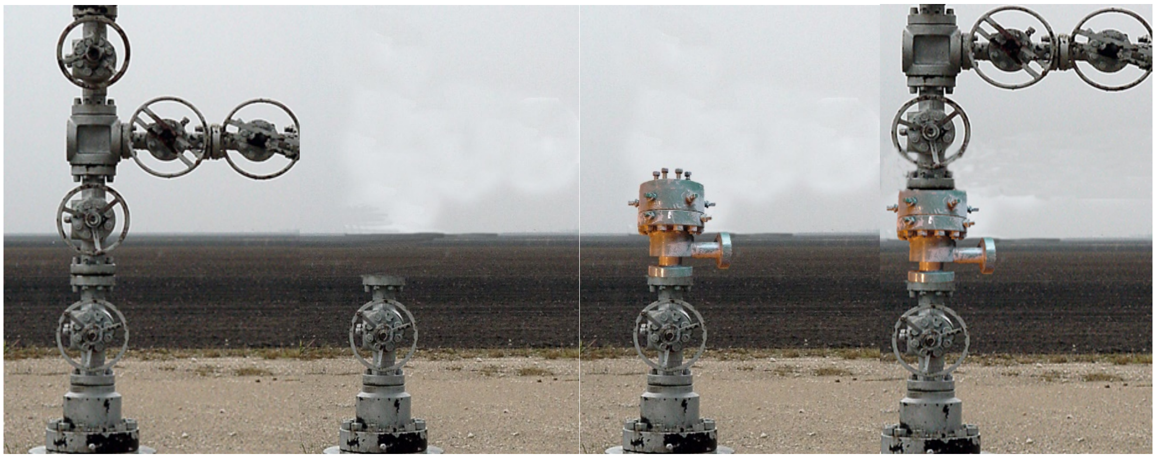


Fig. 2 – Conventional CT Hanger – X-mas tree modifications

VS String Candidate

VS string well candidates were defined accordance intermittently production. At the production line pressure of 288 psi the critical rate for 4.5” completions is 60000 m3/day, and for 3.5” completions 40000 m3/day. When gas well get mentioned critical rate intermittently production appears, resulting to a need of reducing production tubing ID size to enable stable gas production.

Fig. 3 show that 76% of total wells need VS string installations because they have liquid load and your production is 50% of initial gas rate production.

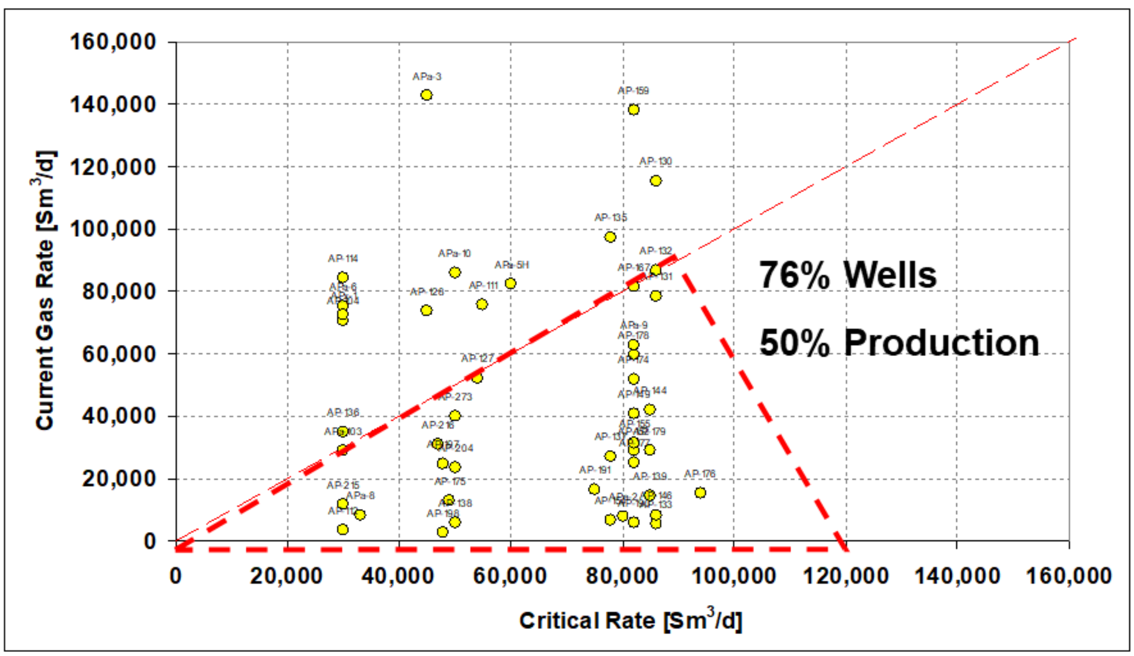


Fig. 3 Maps of well current gas well production versus critical rate

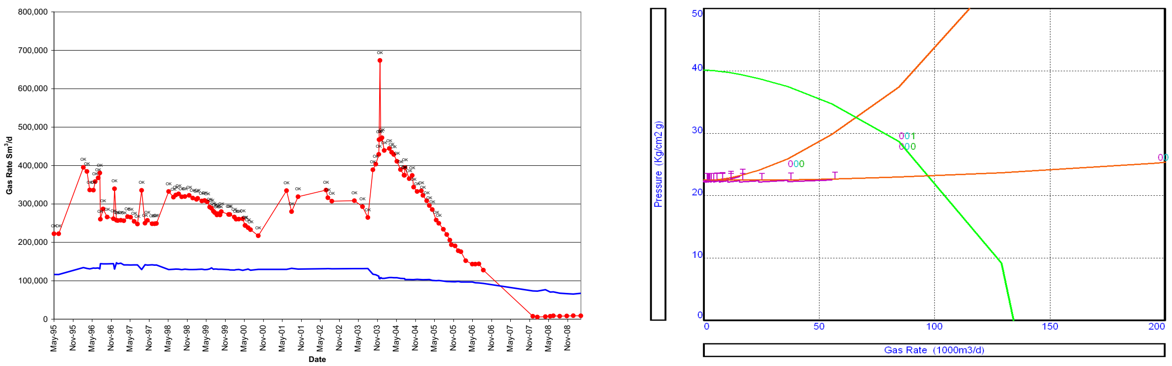


Fig. 4 Production History and Index Production Rate curve versus Tubing Production Rate

The figure above shows the production history of a well, the blue line represent the Turner critical rate at current production conditions. Once the production rate approaches the blue line, the well loses its ability to lift liquids, and hence production is severely impaired. The plot on the right shows the difference in production conditions from a 4½” tubingless completion and a 2” Velocity string. The velocity string has higher pressure losses, but at the same time stabilizes production enabling liquids removal.

VS String size selection and characteristics

The CT string size selection was optimized taking into account several points of view. First, Operator Company Production Engineers defined that required diameter of the Velocity string has to fit with future production conditions: The optimum tubing ID would be the one that minimizes flowing restrictions, in this case larger diameters are preferred, but at the same time would extend the life of the well in stabilized conditions, in this case smaller sizes are preferred.

A too small tubing diameter (e.g. 1.5”) has the advantage of significantly lowering critical rate, but may penalize day by day production profit.

A too large diameter (e.g. 2-7/8”) may have more instantaneous production but will reach quickly at instable regime.

Fig 5 shows the index production rate versus different output CT size production rate that helped to define the 2” OD size selected coiled tubing from productions point of view.

Second, Coiled Tubing Engineers performed tubing force analysis (Fig.6) and collapse pressure simulations to define the minimum thickness wall required to support operational force and stresses, but maintained a balance between production rates versus operational needs during VS CT string installations.

After above-mentioned analysis and taking in consideration that designed CT string need to be run in 4-1/2” and 3½” completions, Coiled tubing equipment market availability, bottom hole intervention possibilities with 1-1/4” slickline (CT drifted at 1.5”), old coiled tubing string available on the local market permit to get small price ; finally, 2” external diameter CT size , 70000 psi grade and the 0.1090” minimum thickness wall were the material selected

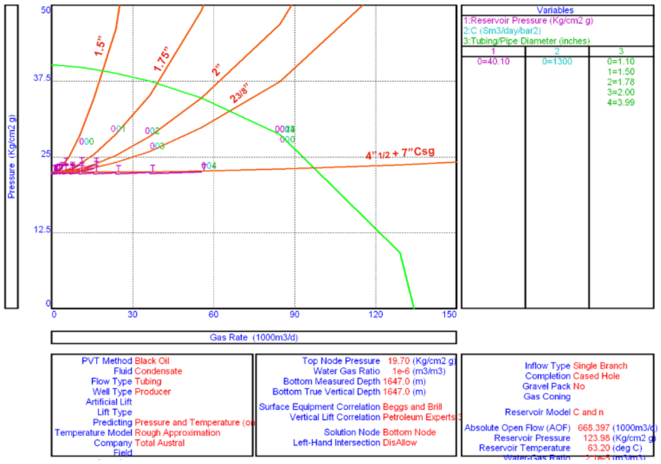


Fig. 5 Index Production Rate curve versus Tubing Production Rate

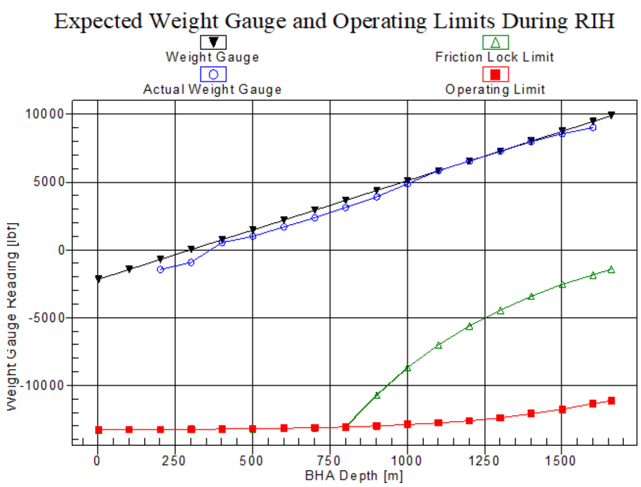


Fig. 6 TFA during real operations versus TFA during design

Special Velocity String CT Hanger

The Special Velocity String CT hanger system is comprising in two separated parts: Part A:

- **Metal Metal casing patch with seal bore ➔** to be set with Wire Line at 10 meter under x-mas tree

Part B:

- **GS internal profile ➔** for running with hydraulic setting tool
- **X nipple ➔** to ensure setting tool / locator sealing while running
- **No go locator with seals ➔** to work like a packer
- **XN nipple ➔** to isolate well (plug) as a first barrier
- **2 inches" coiled tubing ➔** velocity string
- **Pump out plug ➔** allows to run the CT empty and acts as a CT internal barrier

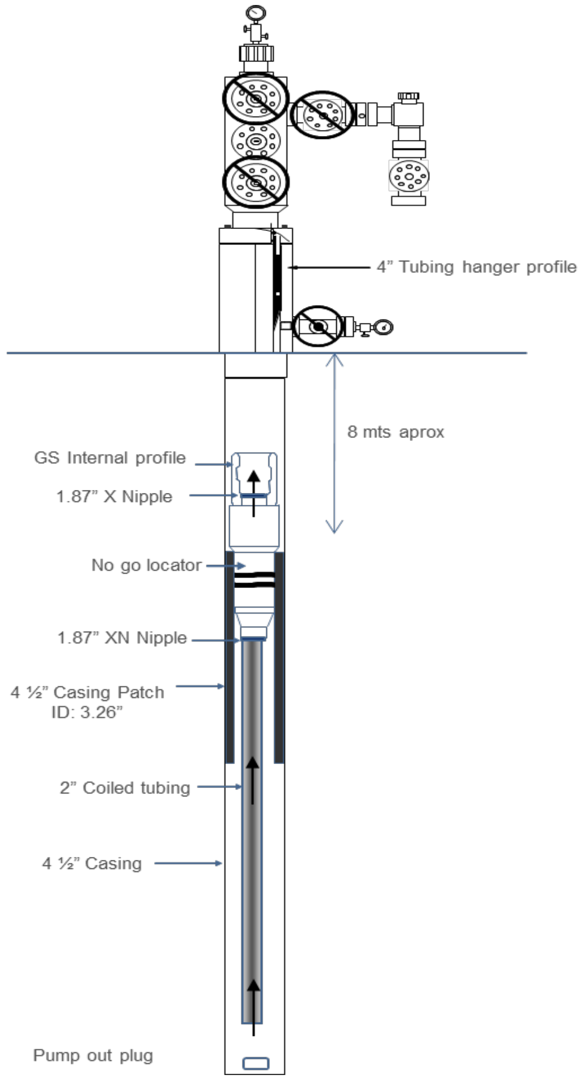


Fig. 7 4 ½” Casing Patch and No go locator - Completion schematic after VS installation

Special Velocity String CT Hanger features

Once the Operator decided to install a velocity string as a liquid loading solution, during brainstorming design process some features were considered for described special CT Hanger .The system had to be able to be set for production and had to be able to set and unset easily , for the following reasons:

In case that liquid level should kill the well or intermittently production rate is reached, the system have to be able to easy lift with coiled tubing unit or a special designed jack system (tree saver design extension) until the seal assembly is out of seal bore, to circulate a water foot out with nitrogen if needed. (Fig 8 Production and Dewatering System way), additionally it should permit to be used to abandon the well at end of production and permit an easy and cheap recovery of all the tools for another well application.

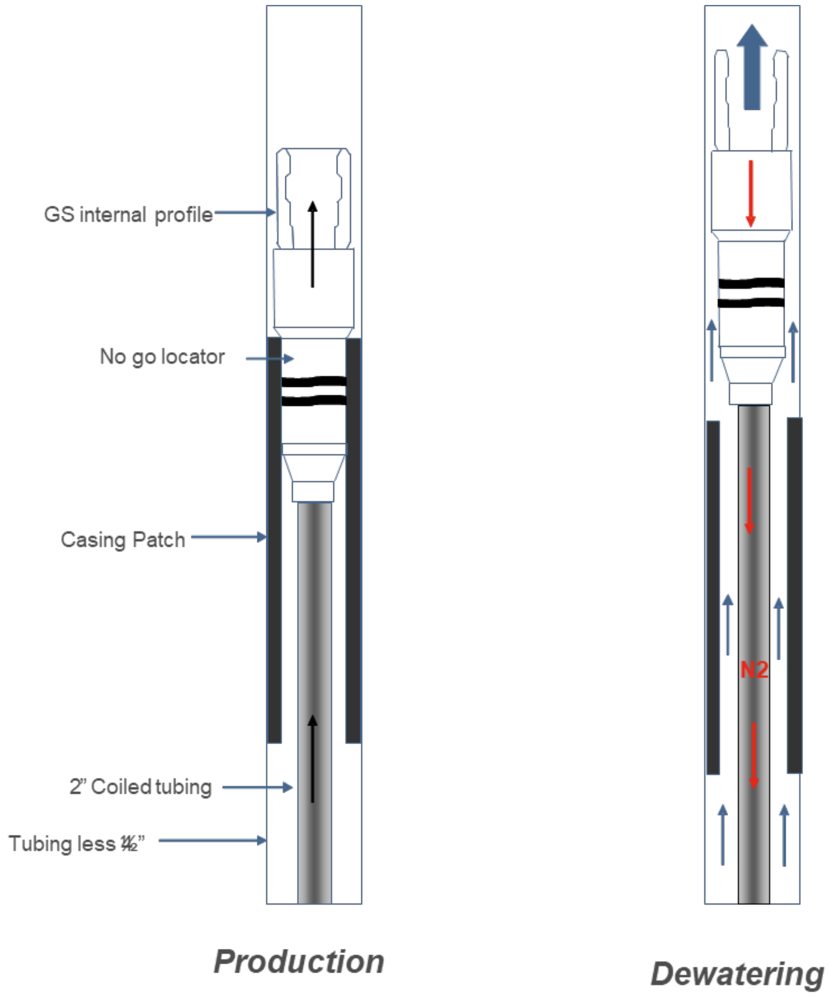


Fig.8 4 ½" Casing Patch and No go locator – while producing and Dewatering option

Special Velocity CT Hanger Safety Issues

Special features of CT Hanger system are the Safety Issues while production time and during installation:

While producing

- The design permits to keep integrity of X-tree valves and back pressure valve profile access
- Set a plug in nipple fit in VS hanger as 2nd barrier if need to repair X-tree valves

During installation

- Work permit including Job Risk Analysis
- While cutting coiled tubing, the 2 annulus barriers are the 2 sets of BOP pipe rams and the 2 tubing barriers (2" CT is empty) are bottom pump out sub + 2 BOP shear rams

Velocity String System Hanger installations - Operation

The operation program for velocity string installations consider two separated phases.

First phase of operation, (previous to coiled tubing intervention), a wire line equipment calibrate the well to check that wells is clean to be sure that low production is caused by liquid loading not for scale or top of sand over the perforations. After caliper runs a metal-metal sealed casing patch prepared is set at +/- 10 meters under x-mas tree. The casing patch has a seal bore that hold and acts as a receptacle of No go locator seal assembly that permit to hang the velocity string and isolate annular gas production (Fig.8)

Second phase of operation, consider the CT operational procedure to set the Part B of the system:

Part B:

- **GS internal profile** ➔ for running with hydraulic setting tool
- **X nipple** ➔ to ensure setting tool / locator sealing while running
- **No go locator with seals** ➔ to work like a packer
- **XN nipple** ➔ to isolate well (plug) as a first barrier
- **2 inches" coiled tubing** ➔ velocity string
- **Pump out plug** ➔ allows to run the CT empty and acts as a CT internal barrier

Operational sequence:

- Rig Up Coiled Tubing Set and test the CT integrity with fluid and displace the string with N2.
- Install double Blow out Preventer over X tree.(Fig.9 - Fig 10 double barrier)
- Niple Up bottom hole assembly 2" CT Connector, Pump out plug with 4 shear pins.
- Run in hole 2" CT to 1661 meters
- Close pipe and slip BOP RAMs,
- With 0 psi at stack up over BOP Instal extra CT clamps.
- Cut the 2" CT 2" Lentgh; 100 cm from BOP.
- Assembly bellow mentioned BHA.
- 2" Connector coiled tubing + Quick connector from carrier CT side
- Install required part B and special setting tool (CT Quick Connector, 1.87" XN Niple , Pup joint 2 3/8", Locator seal assembly 2 3/8", Slick joint with internal GS fishing neck, niple X, GS Running/retrieving tool (with 1,25" ball inside of GS, Motorhead assembly, Stiff joint. 2"CT Connector.
- Perform Pull test to CT connector Pull Force: 15000 lbs higher than BHA and VS string weight
- Perform BHA pressure test with1500 psi

• Assembly setting tool with Quick connector
• Niple down extra CT clamp
• Pressurize stack up over the BOP and Open Slip and Pipe BOP
• Run in hole CT (8 meters) tagging the Casing Patch
• Set weigth (2000 lbs) to set the locator into a Patch.
• Aplly 1000 psi using N2 for GS releasing.
• Pull out of hole to recovery the setting tool.
• Eject Pump out plug and Open the well and test production.

Fig.11 show all the operational sequence during first applications AP-137

Fig. 9 Double BOP (double safety barriers) and Extra Clamp

Fig. 10 Operators installing BHA using Double BOP (double safety barriers) and Extra Clamp and safety platform

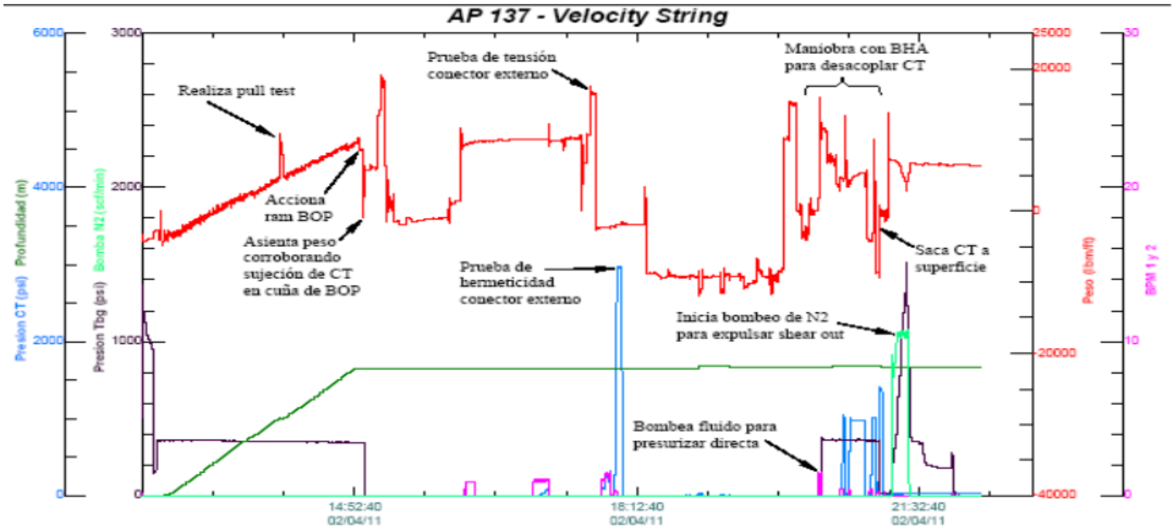
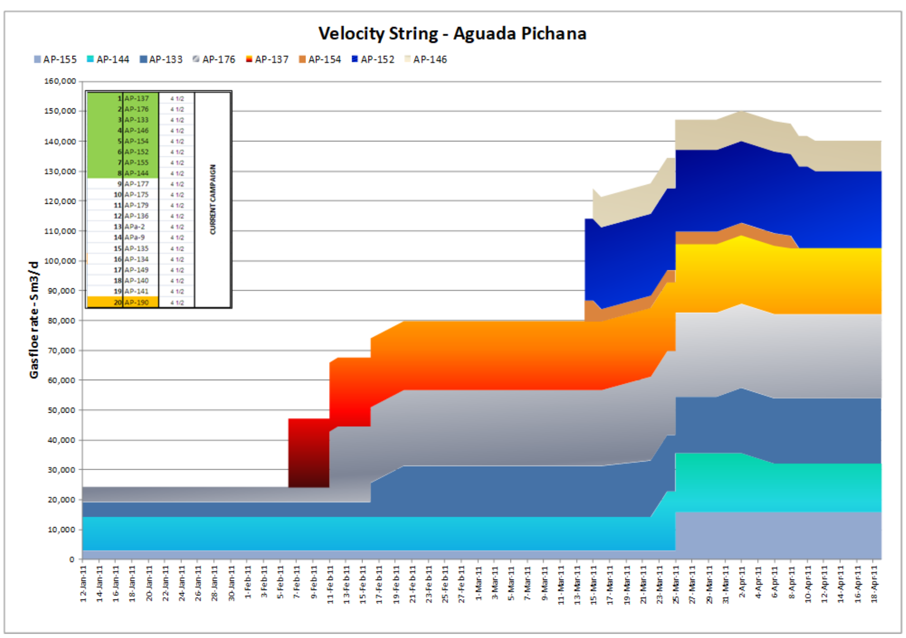


Fig. 11 Operational sequence Chart during first applications at AP-137 well.

Results:

During the first 4 months of the project, 20 VS were safely installed corresponding to a gas production increase of 400 Km3 /d. Average gas increase per well was +/- 20,000 sm^3/d with an estimated pay out of 60 days.

This solution was so successful that more than 100 wells were installed in the following years.



Economics

During technical study three different solutions were discussed, well head compressor installations, capillary tubing with surfactant injection and reduction of ID production tubing
Defined that reduction of ID production tubing will be the accepted solution, two alternatives were economically analized.

1) installation of 2 3/8" production tubing using workover rigs
2) installation of 2" CT Velocity Strings.(Tabla.1)

Tabla 1 – Economical Analysis	
2 3/8 inches Production Tubing installation	
Description	**Price (USD/well)**
Rig (Mov and De Mov and Operation)	xx
Services (Slick Line, Coiled Tubing)	xx
Materials(2 3/8" Tibing, Niples, Packers, Well head)	xx
Total Cost per Well	**600000**
2 inches Velocity String installation	
Description	**Price (USD/well)**
Coiled Tubing Unit operation	xx
Services (Slick Line, Wire Line)	xx
Materials(2" HS 70 string, Casing Patch, Niples,)	xx
Total Cost per Well	**155000**

Conclusions

The whole process led to important benefits:
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Nomenclatures

CT Coiled Tubing
VS Velocity String
ID: Internal Diameter of Coiled Tubing
OD: External Diameter
TFA: Tubing Force Analysis
IPR: Inflow Performance Rate
TPR:Tubing Performance Rate
BOP: Blow Out Preventer
BHA: Bottom Hole Assemby
RAM:

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