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Drilling and MCP department

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Theme

Study about the compositions of transcoil ESP completion in the well RERN-6

Discussed in :08/06/2023

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DEDICATION

I dedicate this project to God Almighty my creator, my source of inspiration, wisdom and knowledge.

I also dedicate this to my parents and my loving brothers and sister who encouraged me all the way and whose encouragement have made sure that I give it all it takes to finish that which I have started.

Alaeddine

إهداء

الحمد لله وكفى والصلاة على الحبيب المصطفى وأهله ومن وفى اما بعد:

الحمد لله الذي وفقنا لتثمين هذه الخطوة في مسيرتنا الدراسية بمذكرتنا

هذه ثمر الجهد والنجاح بفضله تعالى و الى الوالدين الكريمين حفظهما الله

وادامهما نورا لدربي

والى كل العائلة الكريمة والاسرة التربوية والى كل من نسيهم قلمي

ونسال الله ان يجعله نبراسا لكل طالب علم .

GRATITUDE

First of all we thank God the almighty who gave us the strength, the patience and the perseverance necessary to reach this stage and carry this modest work.

*We would thank our promoter and teacher **Mr. MECIBAH** for his advice, his guidance and valuable help.*

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Our warmest thanks go to our families and loved ones for their support, encouragement and help that nothing could have been possible without it.

We would like to thank all those who have contributed directly or indirectly to the development of this work.

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Nomenclature:

QO : Oil Flow

Qw : Water Flow

Pr: Reservoir Pressure

Pwf: Bottomhole flowing pressure

Pwh: wellhead Pressure

Ps: Separator Pressure

PI: Production Index

Abbreviation:

ESP: Electric Submersible Pump

BRN: Bir Rebaa Nord

GOR : Gas Oil Ratio

IPR: Inflow Performance Relationship

VLP: Vertical LIft Performance

WOC: Water Oil Contact

WC: Water Cut.

OPEC : Organization of the Petroleum Exporting Countries

MPFM: Multiphase Flow Meter

TAGI: Triassic Argyles griseous Inferior

BPD: Barrel Per Day

RPM : Rotation Per Minute

HAVA : High Angle Vane Auger

BOP: Blow Out Preventer

GVF: Gas Volume Fractions

BHA: Bottom Hole Assembly

Abstract :

In the beginning of exploitation phase, the reservoirs producing hydrocarbons have a pressure called "reservoir pressure." As production progresses, reservoirs begin to run out, experiencing a steady fall in this pressure, and a drop in eruptive energy. This fall may therefore, at a time, become insufficient to ensure production in a natural way. At this point, it is said that the well has become non-eruptive which requires the use of artificial ways of production. In this thesis, we have studied the various activation modes to improve the production of RERN by studying the best activation mode amoung them for well RERN-6 based on a techno-economic study.

We suggest a new technology that called Transcoil as a tool to optimize the production flow based on ESP

ملخص:

في بداية مرحلة الاستغلال، يكون للخزانات المنتجة للهيدروكربونات ضغط يسمى «ضغط الخزان». مع تقدم الإنتاج، تبدأ الخزانات في النفاد، وتعاني من انخفاض مطرد في هذا الضغط، وانخفاض في الطاقة الثورانية. لذلك قد يصبح هذا الانخفاض في ضغط، في وقت ما، غير كافٍ لضمان الإنتاج بطريقة طبيعية. في هذه المرحلة، يقال أن البئر أصبحت غير ثورانية مما يتطلب استخدام طرق صناعية للإنتاج. في هذه الأطروحة، درسنا أنماط التنشيط المختلفة لتحسين إنتاج **RERN** من خلال دراسة أفضل وضع تنشيط يكافئها **RERN-6** جيدًا بناءً على دراسة تقنية واقتصادية.

نقترح تقنية جديدة تسمى **Transcoil** كأداة لتحسين تدفق الإنتاج بناءً على **ESP**

Résumé

Au début de la phase d’exploitation, les réservoirs produisant des hydrocarbures ont une pression appelée "pression du réservoir." À mesure que la production progresse, les réservoirs commencent à s’épuiser, subissant une chute constante de cette pression et une baisse de l’énergie éruptive. Cette baisse peut donc, à un moment donné, devenir insuffisante pour assurer une production naturelle. À ce stade, il est dit que le puits est devenu non perturbateur qui nécessite l’utilisation de moyens de production artificiels. Dans cette thèse, nous avons étudié les différents modes d’activation pour améliorer la production de RERN en étudiant le meilleur mode d’activation en les utilisant pour bien RERN-6 basé sur une étude techno-économique.

Nous proposons une nouvelle technologie qui a appelé Transcoil comme un outil pour optimiser le flux de production basé sur ESP

ESP : electric submersible pump

Introduction

Any production well is drilled and completed to move the oil or gas from its original location in the tank to the stock tank or sales line. The movement or transport of these fluids requires energy to overcome friction losses in the system and to lift products to the surface. Fluids must flow through the tank and piping system and ultimately into a separator for the separation of gaseous liquids. The production system can be relatively simple. Or may include many components in which pressure or energy losses occur.

Wells are one of the main investments in the development of oil fields, so the goal is to have a maximum flow for as long as possible. However, this production may be reduced due to pressure drop or reduced permeability. The latter can be the result of minimum deposits in perforations such as salt deposits.

In recent years, the problem of increasing the water cut seems to be widespread almost over the Algerian oil fields especially in the BRN field (Bir Rebaa Nord) where many wells have seen their potential so reduced that some of them are closed. This problem is a real calamity, because they seriously affect the production of fluids.

From this moment, the objective of this work is based on three principles: analysis, investigation and solution. In order to improve the life of the wells and especially to increase their production, an analysis of the problems encountered in the wells will be carried out, subsequently an investigation on their origin will be conducted and finally possible solutions technically and economically will be proposed.

- Chapter I : Description of Bir Rebaa Nord field
- Chapter II : Overview on Nodal Analysis
- chapter III : Artificial Lift
- Chapter IV : Electric Submersible Pumps (ESP)
- Chapter V: Studied Case

Chapter I

Description of Bir Rebaa Nord field

I.1 introduction :

North Africa is a single depositional basin on the northern shelf of the African craton. The basin generally deepened northward where deposition and marine influence are greater.

There is a general conformity of structure throughout most of the Paleozoic until the Hercynian, which marks the collision between Laurasia and Gondwana and which caused regional uplift, folding, and erosion. Paleozoic basins, delineated by earlier tectonic events, were modified, resulting in the development of several intracratonic sag and foreland basins.

Algeria is subdivided into two major structural units, the northern Algerian Alpine and the southern Saharan Algerian Platform, separated by the south Atlas fault:

1-The northern Algerian: mainly affected by Alpine orogeny, was formed of young mountains during Tertiary times and consists of a number of structural sedimentary units. From north to south:

The Algerian off shore - The Tellian Atlas - The Hodna Basin - The High Plateaus - The Saharan Atlas.

2- The Algerian Saharan Platform : is located to the south of the Alpine domain and is part of the North African craton that yields most of Algeria's hydrocarbon resources. It has been a relatively stable area of low tectonic activity over the course of geologic time. The Paleozoic structural basins southwest of the Algerian Sahara comprise the following:

Tindouf Basin - Bechar Basin - Reggane and the Timmimoun Basins - The Illizi Basin [1]

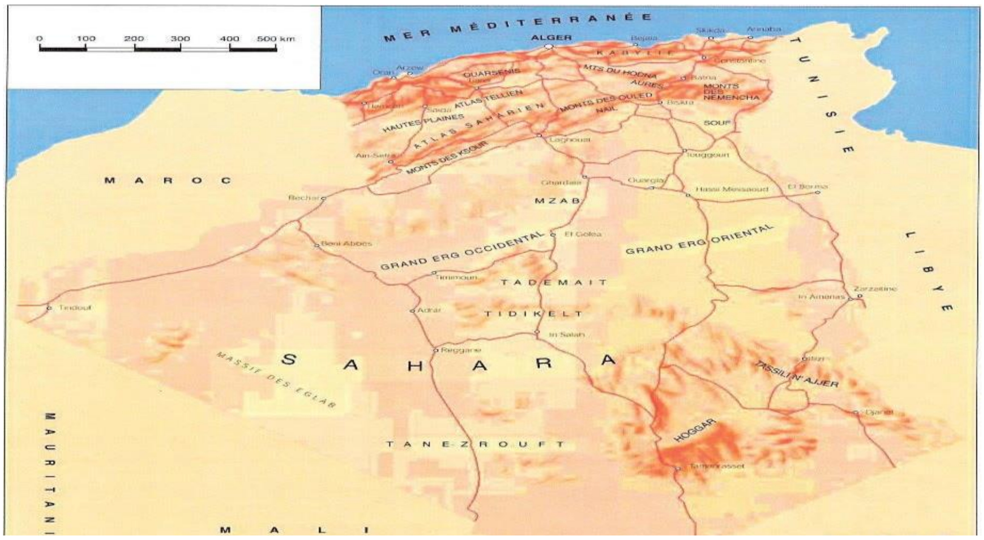


***FIGURE I. 1** : NATURAL BOUNDRIES OF ALGERIA AND MORPHOLOGICAL ZONES*[1]

I.2 Genral information :

The BRN (Bir Rebaa Nord) field is located in Exploration Permit 403, which represents a portion of the northern area of the Berkine/Ghadames basin

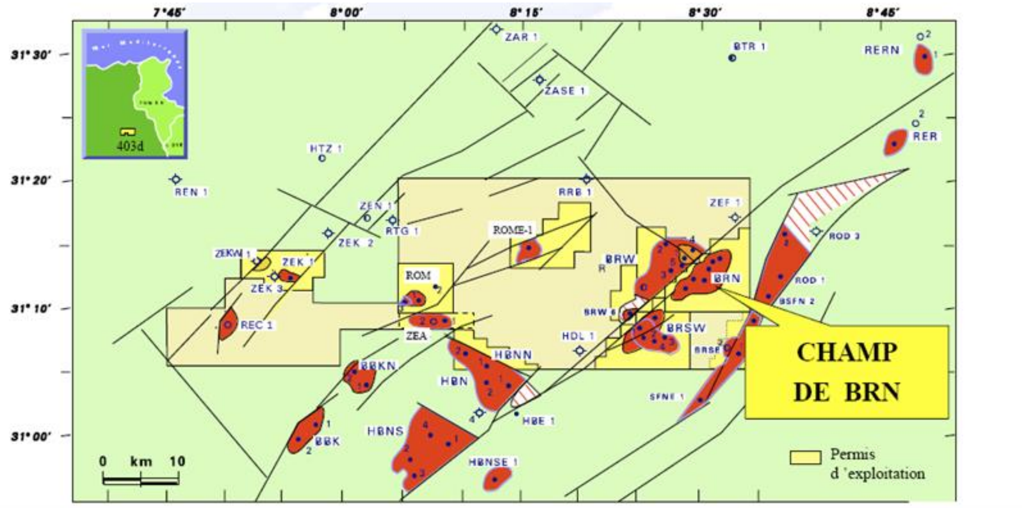


FIGURE I.2: *LOCATION OF THE BRN FEILD*[2]

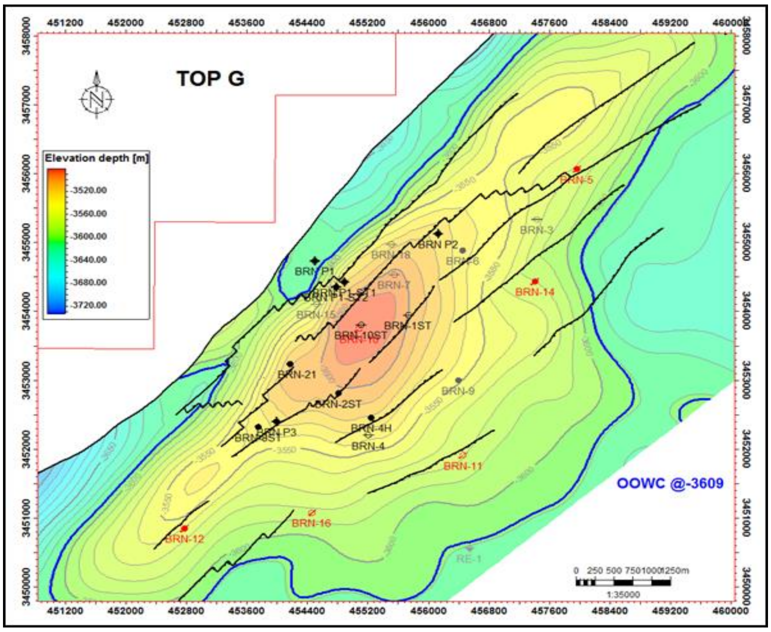


FIGURE I .3: *BRN FIELD*[2]

I.3 Geographical location of BRN fields:

So far, in the G+T reservoir, we have drilled a total of twenty-three wells, including the workover-sidetrack and the RE-1 well (abandoned), drilled by Esso Sahara in 1962. Sonatrach and ENI drilled 5 other wells for BRN Profonde from 2014 with objective the Silurian levels that crossed the Devonian reservoirs so they took into consideration in this study.

Well BRN-1 (October 1989 – January 1990) was the exploration well that led to the discovery of the field. Indeed, it crossed the Devonian series by highlighting the presence of liquid hydrocarbons in the “Tadrart” Formation and in the “Ouan Kasa” Formation (reservoir “B”+”G”), In addition, the field is delimited in the South by the RE-WELL1, drilled by Esso Sahara in the early 1960s and met all the above-mentioned water-saturated levels.

Between May and December 1990, we drilled the two exploration wells BRN-2 and BRN-3. These wells confirmed the trap produced by an elongated and faulty anticline in the NE-SO direction. The development phase took place from October 1992 to February 1994 with the drilling of five (5) producing wells and five (5) gas injection wells:

- October 1992: BRN-4 (oil producer),
- November 1992: BRN-5 (Gas Injector),
- February 1993: BRN-6 (oil producer),
- February 1993: BRN-7 (oil producer),
- May 1993: BRN-8 (oil producer),
- June 1993: BRN-9 (oil producer),
- November 1993: BRN-10 (Gas Injector),
- August 1993: BRN-11 (Gas Injector),
- November 1993: BRN-12 (Gas Injector),
- February 1994: BRN-14 (Gas Injector).

Wells BRN-4, BRN-6, BRN-7, BRN-8 and BRN-9 were completed with a double completion: ‘long string’ (to produce in the G+T reservoir) and ‘short string’ (to produce in the B reservoir). Production in the G+T reservoir began in July 1995.

Since start-up, four new wells and five sidetracks were drilled into this tank:

- January 1998: BRN-15 (Assessment),
- April 1998: BRN-16 (Gas Injector),
- November 1999: BRN-18 (oil producer),
- April 2004: BRN-4Hor (oil producer),
- December 2006: BRN-8ST (oil producer),
- June 2008: BRN-21 (oil producer),
- June 2008: BRN-1ST (oil producer),
- November 2008: BRN-2ST (oil producer),
- December 2011 BRN-10ST (oil producer).

The productive history of the field can be summarized as follows:

- Since the beginning of production (1995), wells have been opened in sub-levels G2, G3, G4, T1, T2 and T4; on the other hand, gas injection has been carried out through sub-levels G2, G3, G4, T1 and T2

- In various wells, we found an early and progressive increase in Water Cut values (related to the progressive rise of the water table). In addition to the flooding of the lower levels by water, we have also noticed increasing increases in GOR.

- In August 2001 we isolated the G+T tank (long string) by cement plug in well BRN-4. This insulation was made following the high values of GOR and Water Cut. At the beginning of 2004, because we had found it impossible to restore the production of the well even by the short string (dedicated to tank B), a horizontal sidetrack well (BRN-4Hor, April 2004) was drilled, with the objective of operating only level G.

- In September 2006, a workover intervention was necessary for the BRN-8 well after the rupture and the impossibility to recover the old completion installed in the well, a sidetrack was carried out. The BRN-8ST well was drilled in order to resume production in the G+T tank through a simple completion and perforation of the G1-G2-G3-G4 and T1-T2 sub-levels.

- In 2008 we did the workover at wells BRN-1 and BRN-2. The drilling of these sidetrack proved necessary following the requirement to secure both wells (substitution of completion).

The two workover also provided new data on the real water saturation conditions of the G+T tank. After analysing the petrophysical data, we decided to exploit the tank through the single T4 sub-level. Unfortunately, when both sidetrack were opened to production, they showed high GOR values (2000~ 4000 STm3/Stm3)

- In 2008, we also drilled the BRN-21 well, with the objective of producing G+T oil in the area west of the field. The well results showed weak petrophysical properties in the G level; at the same time the upper part of the Tadrart showed a high amount of gas. The interpretation of the logs also highlighted the rise of the aquifer from the original oil-water contact. Based on this information, the well was drilled in sub-level T4. The production parameters of the well were more or less aligned with those of the sidetrack BRN-1ST and BRN-2ST, essentially showing strong GOR values

- In December 2011 we drilled the sidetrack of the BRN-10 gas injector well. The BRN-10ST well was drilled in the top part of the field with the objective of exploiting the basal part of the Tadrart reservoir. It was perforated in the only T6 sub-level with the objective of moving away, as far as possible, from the rise of the water below and the area invaded by the gas above. The well was put into production in March 2012, showing a rapid increase in GOR values. The well is closed due to integrity issues on 01/03/2015.

- In recent years SH and ENI drilled 3 more wells (BRN Profonde) plus 2 sidetrack with objective the Silurian levels that crossed the Devonian reservoirs so they took into consideration in this study. [2]

I.4 GEOLOGY of RERN field

I .4.1 Oil System :

I .4.1.1 source rock:

The main source rocks of the region are:

- Silurian graptolite clays (main hydrocarbon generator),
- Frasnian clays under Hercynian discordance**.**

I .4.1.2 Rock reservoir :

The main reservoir in the study area is the Lower Sandstone Argilo Triassic. It is subdivided into four levels which are top to bottom:

- Upper TAGI,

- Middle TAGI,
- Lower TAGI,
- Basal TAGI.

The reservoir rock is of elongated anticlinal structure in a system of inverted faults.

I .4.1.3 Rock cover :

The cover of the TAGI reservoir is formed by clays and evaporatites from the carbonated trias.

I.5 Reservoir RERN

I.5.1 introduction

The reservoirs investigated in this study are part of the Triassic Argilo Griseous Inferior (TAGI),

subdivided into multiple depositional sequences . The target interval for this study is the Upper TAG-I. The Middle TAG-I was included in the model, although it is water bearing.

Subsequently, no uncertainty analysis was performed on it. TAG-I formation is characterized by fluvial sedimentological environment assuming the concept of anastomosed/braided channels.As such the reservoir is very heterogeneous.

A probabilistic workflow was applied to address the uncertainty of the static parameters.

Multiple realizations of the field were created testing the uncertainty related to time-depth

conversion, channels geometry and channels fraction and porosity. The dynamic behaviour of the realizations was subsequently screened and compared to the historical well performance. Results from dynamic screening were integrated to adjust the uncertainty workflow

The following chapters discuss the geological evaluation, model construction, generation of the realizations and impact of the different uncertain parameters on the STOIIP. The geological modelling was performed using the Petrel 2010.2.2 Software from Schlumberger

TABLEAU I.1 **:** *OVERVIEW OF THE TAGI-6 SUBDIVISION*

TAG-I Triassic-argilo-Grèseux Inférieur (Lower triassic clay sandstone)	Upper TAG-I
	Middle Shales TAG-I
	Middle TAG-I
	Lower TAG-I
	Basal TAG-I

I.5.2GEOLOGICAL SETTING

I.5.2.1 STRUCTURAL GEOLOGY :

The RERN field is located in the intra-cratonic Berkine Basin in Algeria. The Berkine basin

developed during Middle-Late Triassic times on the Northern margin of the Sahara platform. It is bounded to the North by the Saharan flexure and the Saharan and Telling Atlas Mountains, to the west by the Hassi Messaoud Ridge (a North-South fracture zone) and to the South by the Illizi basin (Figure 4).The structure of the basin is controlled by the reactivation of Palaeozoic basement lineaments. Late Cretaceous/Early Tertiary compressional inversion accounts for several TAG-I reservoir oil fields including RERN.

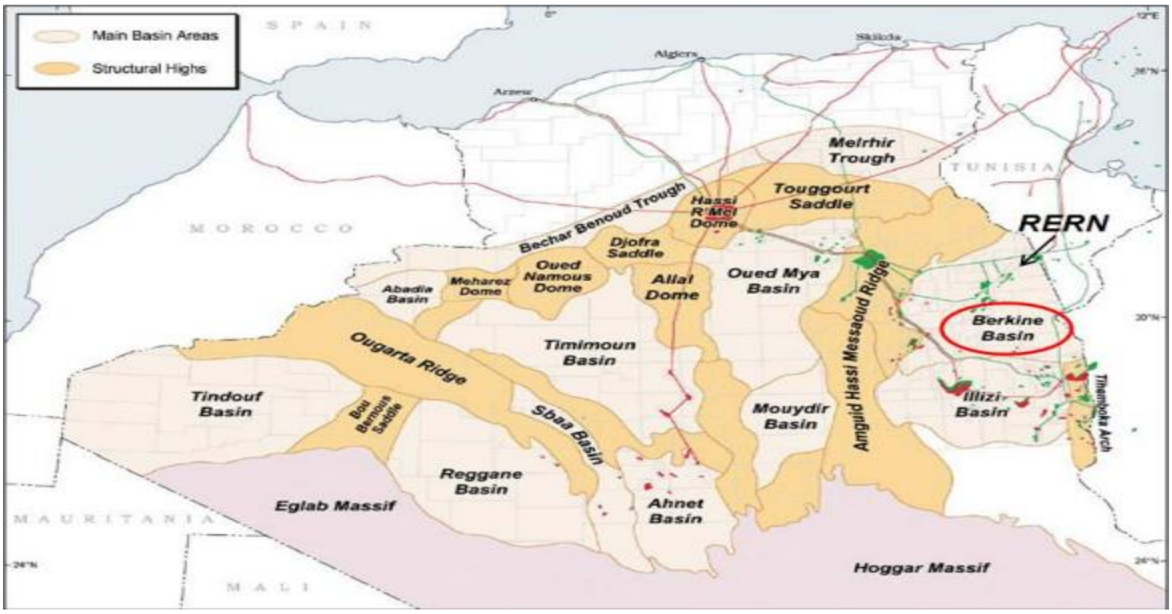


FIGURE I.4 : *REGIONAL STRUCTURAL ELEMENTS OF ALGERIA[2]*

I.6 Well RERN-6

I.6.1Well History :

RERN-6 is a Vertical Oil Producer well drilled in January 2016 as development producer in the Northern area of RERN field, close to RERN-1 Plugged & Abandoned well.

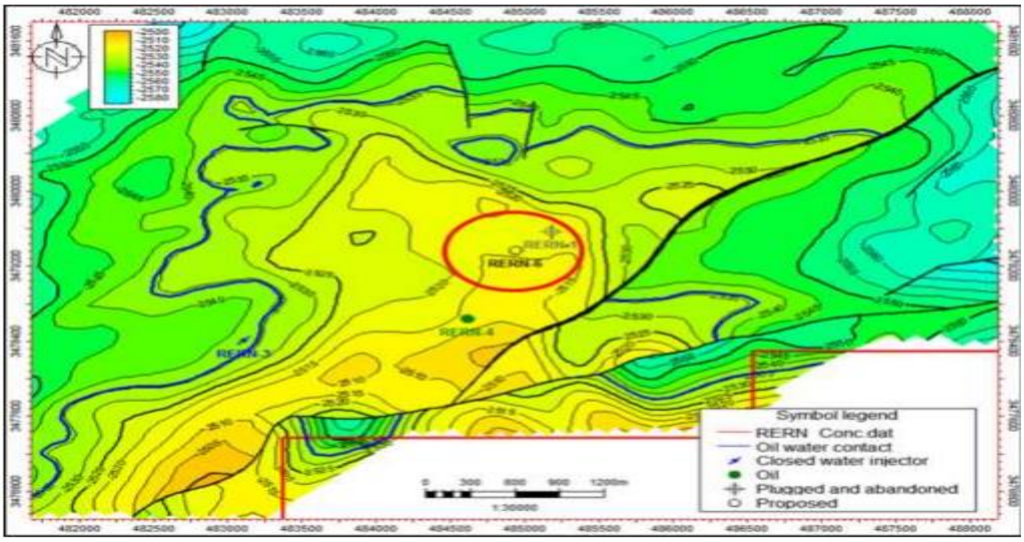


FIGURE I.5: *RERN-6 WELL LOCATION[2]*

Drilling operations started on December 13th, 2015, reached a total depth TD of 2887 mRT on January 28th, 2016. The well is perforated in Upper TAGI level as follows:

o 2764.0 – 2766.5 m MD Upper TAGI 2.5 m

o 2770.5 – 2776.5 m MD Upper TAGI 6.0 m

The well was equipped with ESP and production started up on March 30th 2016 with an average anhydrous oil rate about 1240 STBD at wellhead pressure of 65 Bars. On April 15th 2016, the well has been choked down in order to honor the field plateau rate approved by the authorities (1600 STBD), so the wellhead pressure has been adjusted from 65 to 86 Bars revealing an oil rate around 800 STBD. One month after startup, the water breakthrough was occurred and was taken an increasing trend passing within 15 days from null to 5%. The well was shut-in between 31/03/2017 to 28/01/2018 due to OPEC limitation. Well production was periodically monitored through MPFM tests; Figure 6 show the production tests with MPFM performed on RERN-6 since production start-up. On December 3 rd 2019, the well was shut-in due to ESP failure following an electrical issue.

I.6.2 RERN Reservoir pressure behavior :

The reservoir pressure in RERN TAGI is maintained thanks to the active aquifer, confirmed by the water breakthrough occurred in RERN-1 and RERN-4 wells, the rise in oil-water contact observed in the logs of the RERN-6 for the Middle TAG-I level (1.6 m higher compared to the original contact recognized in the RERN-4 well) is also a confirmation of the activity of the aquifer. Considering the aquifer activity and the poor communication between the water injector RERN-3 and the main area, the water injection has never started. The figure below shows the historical static pressures registered in RERN wells. [3]

Chapter II

Overview on Nodal Analysis

II.1 introduction:

In petroleum engineering, nodal analysis is a method used to analyze the flow of fluids through a well or a network of wells. It involves the application of conservation of mass, momentum, and energy equations at each node of the system to determine the pressure and flow rates at each point in the system.

The steps involved in nodal analysis in petroleum engineering are as follows:

Identify all the nodes in the system, including the production wells, injection wells, and reservoir.

Choose one or more nodes as the reference nodes, and assign a pressure of 0 psia to them.

Write down the mass, momentum, and energy conservation equations at each node in terms of the pressure and flow rates.

Solve the resulting system of equations to find the pressure and flow rates at each node relative to the reference nodes.

Use the nodal pressures and flow rates to calculate other important parameters, such as the well productivity, reservoir pressure, and recovery factor.

Nodal analysis is particularly useful for optimizing the production and recovery of hydrocarbons from a reservoir. By analyzing the pressure and flow rates at each point in the system, engineers can identify ways to increase production, improve recovery, and reduce costs.

Nodal analysis can also be used to optimize the design of well completion and production systems. By analyzing the pressure and flow rates at each node in a well completion system, engineers can identify ways to improve well productivity, reduce the risk of equipment failure, and minimize environmental impact. [4]

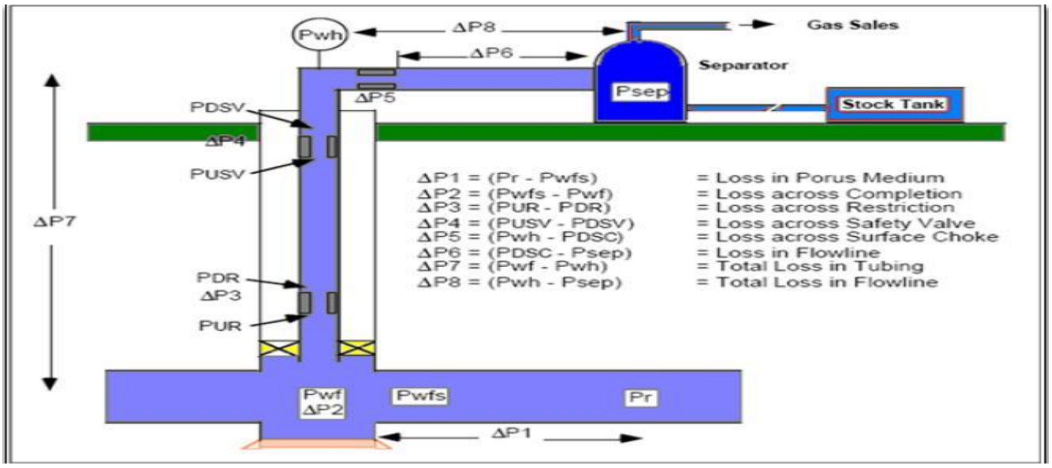


FIGURE II. 1:*POSSIBLE LOAD LOSSES IN A PRODUCTION SYSTEM*[4]

In this figure II.1 the load losses in the production system are classified as
Follows:

$\Delta P1 = Pr - Pwfs$: Loss in porous medium,

$\Delta P2 = Pwfs - Pwf$: Loss along completion,

$\Delta P3 = PUR - PDR$: Loss along restrictions,

$\Delta P4 = Pusv - Pdsv$: Loss in porous medium,

$\Delta P5 = Pwh - PDSC$: Loss in surface Duse,

$\Delta P6 = PDSC - Psep$: Loss in surface piping,

$\Delta P7 = Pwf - Pwh$: Total loss in tubing,

$\Delta P8 = Pwh - Psep$: Total loss in collections.

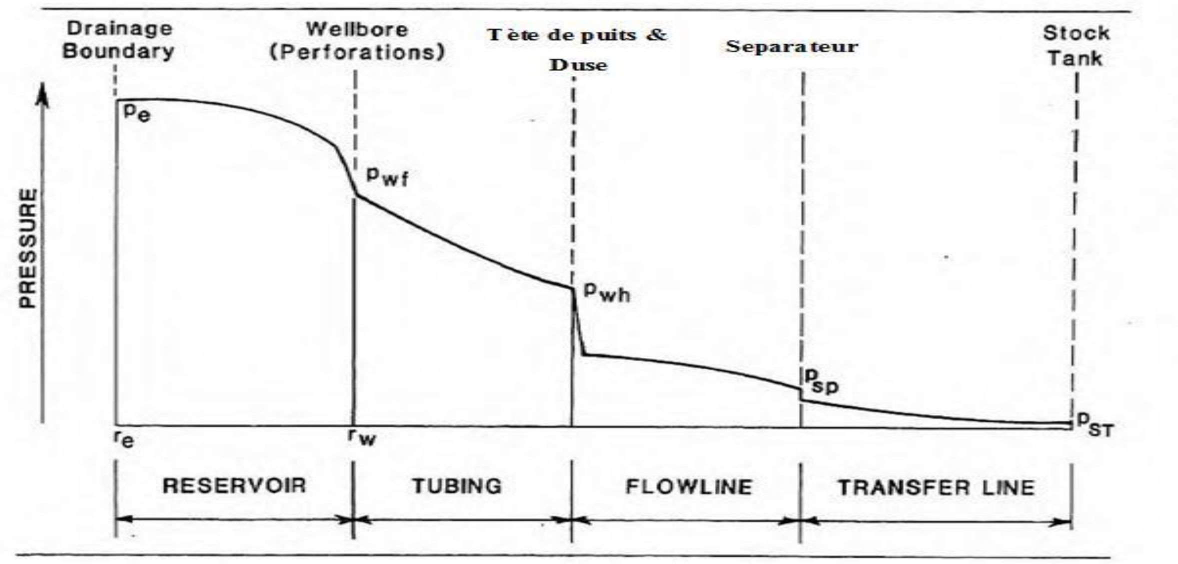


Figure II 2: *profile of production pressure[4]*

II.2 Concept of nodal analysis:

In order to solve all production system problems, nodes are placed inparts or segments that are defined by the different equations or correlations. The figure(II.3) shows the locations of the various nodes.

It should be noted that in the system there are two pressures which are not flow function: Pr and Psep if the well is controlled by a duse. The choice and dimensioning of the different components is very important, but due to the interaction between them, a change of fall pressure in one can change the pressure drop behavior in all other

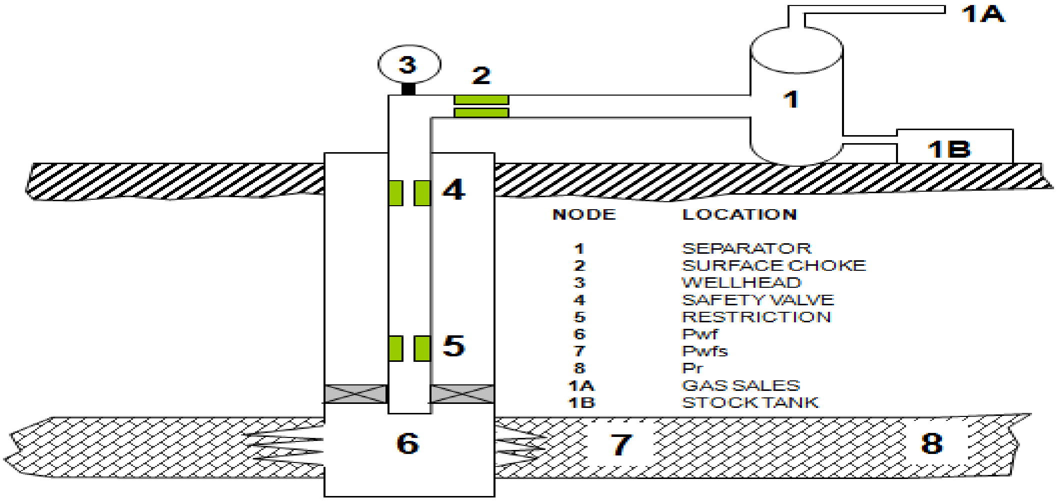


FIGURE II 3: *POSITION OF THE DIFFERENT NODES[4]*

II.3NodalAnalysis Application Procedure:

Nodal analysis is applied to analyze the performance of systems that consist of several elements acting on each other. The process involves selecting a node in the well and dividing the system at that node. The nodes used are shown in Figure II.4. All components upstream of the node make up the Inflow section, while the Outflow section is composed of all elements downstream of the node. A relationship between flow rate and pressure drop must be established for each element of the system. Figure II.: Position of the different nodes.

Once the nodel is selected, the pressure at the node is determined by:

- Inflow : Pnode = Pr − ΔP
- Outflow : Pnode = Psep + ΔP

The pressure drop in any component varies with the flow q, a representation pressure as a function of flow produces two curves whose intersection will give a point which checks the two conditions mentioned above; this is the point of operation of the system. (See figure II.5) The change effect in any component can be analyzed by recalculating the node pressure as a function of flow using the new characteristics of the component.

The procedure is as follows:

- Choose the components to optimize,
- Select the location of the node that will feel the effect of change in the component chosen,
- Develop expressions for inflow and outflow,

- Obtain the necessary data for the construction of the IPR,
- Determine the effect of changing the characteristics of the selected components by plotting the inflow and outflow. [5]

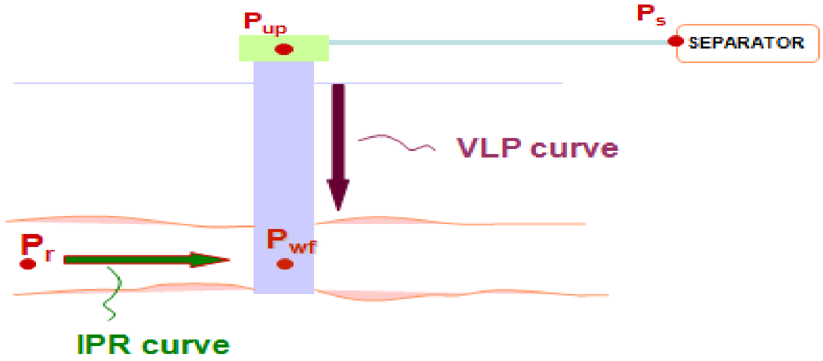


FIGURE II 4 : *CONNECTION BETWEEN DIFERENT NODES*[5]

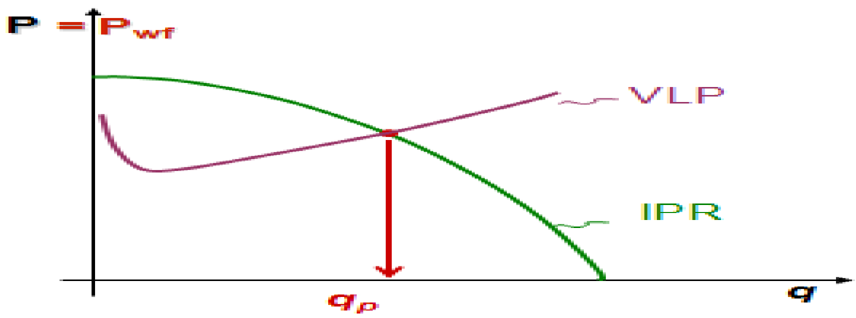


FIGURE II.5 :*POINT OF OPERATION[5]*

II.4 Objectives of Nodal Analysis:

The objectives of nodal analysis are:

- Determines the flow produced by an oil or gas well (initially by natural flow) given geometry constraints and well completion,
- Determine under what flow conditions (which may be time dependent) the well will flow or leak,
- Tune your system to produce at your planned throughput,
- Check the performance of each component in the system,
- Determine the most economical time to install an artificial facelift and help you choose a method,
- Tune the system to produce the desired flow rate,

- Enable managers and technical personnel to quickly identify opportunities to increase production rates.

II.4.1 Application of Nodal Analysis:

Nodal Analysis can be used to analyze several problems of oil wells and gas. The procedure can be applied for naturally flowing wells and gas lift. The procedure can also be applied to the well performance analysis injectors by the appropriate modification of the inflow and outflow expressions.

Nodal analysis is often used to optimize the following parameters: the skin of the well[6]

chapter III

Artificial Lift

III.1 Introduction :

Production of oil requires energy to lift the fluids from the reservoir to the surface. In the early phase of their production lifetime, the majorities of oil wells flow naturally and are referred to as flowing wells. In a naturally flowing well there is enough energy stored in the reservoir to flow the produced fluid to the surface. Reservoir pressure and formation gas provide this energy in the flowing well. When reservoir energy is too low for natural flow, or when the desired production rate is greater than actual production rate then it becomes necessary to use artificial lift to get
desired production.

Artificial lift uses to increase the flow of liquids to the surface of a production oil well and this is usually achieved by :

- A mechanical device inside the well, such as a pump;
- Decreasing the weight of the liquid/gas mixture via high pressure gas;
- Improving the lift efficiency of the well via velocity strings. [7]

III.2 Activation methods :

III.2.1 Gas Lift :

Among the different activation methods, it is the processes closest to the natural flow. This is an activated production technique for wells not or insufficiently eruptive. It consists of injecting the most compressed gas possible in the production column. Essentially, liquids are lightened by the gas that allows the tank pressure to force fluids on the surface. The clean installation and compatibility of material, on the surface or in well bottom, are essential to any system gas lift.

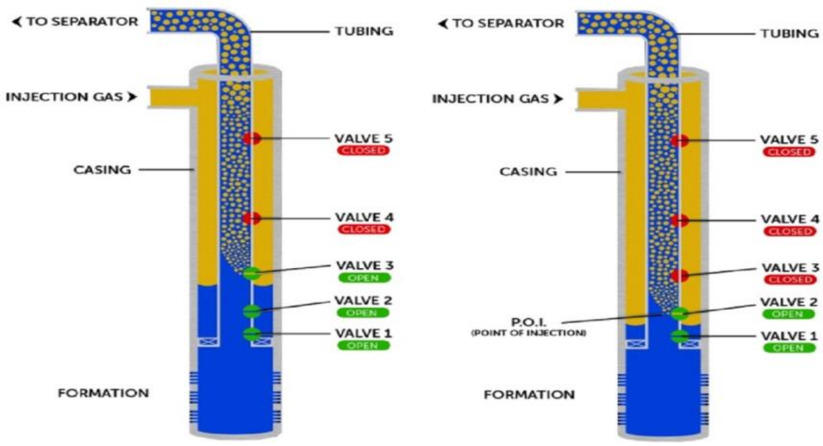


FIGURE III 1: *GAS LIFT*[7]

III.2.1.1 Gas Lift Types :

a) Gas lift continues :

A continuous injection of natural gas, at a determined pressure and flow rate, at the base of the production column lightens the volume of fluid in the column and allows the mixture thus constituted to rise to the surface, the well thus becoming eruptive again.

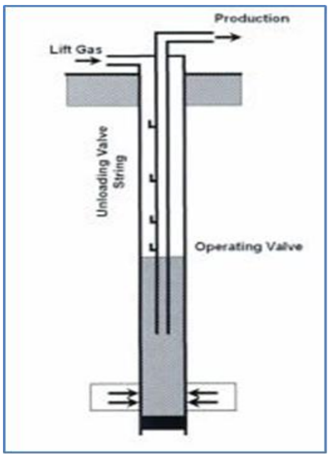
b) Gas lift intermittent:

Intermittent injection has a high flow rate of a determined volume of pressurized gas in the lower part of the production column so as to drive up the volume of liquid it contains. As the pressure on the layer decreases, the layer begins to restart and the liquid that accumulates below the injection point will be expelled in the same way and so on.

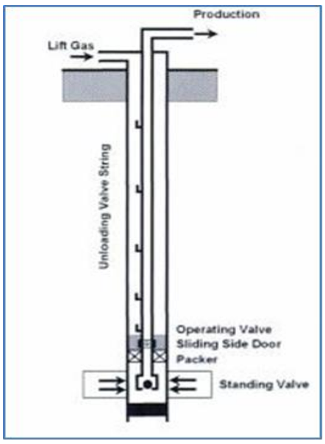
Selection of Gas Lift Type:

Table III.1:*gas lift type[7]*

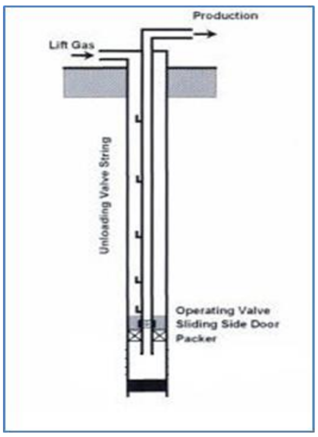
Bottom hole pressure	Productivity index	Type
Low	Low	Closed Intermittent
Low	High	Closed Intermittent
High	Low	Semi Closed Intermittent
High	High	Open/Closed Continuous



Open Installation



Closed Installation



Semi Closed Installation

III.2.1.2 Advantages:

- If a high pressure gas source is available, the initial investment cost may be inexpensive.
- The gas lift adjusts to all well profiles.
- Gas lift is extremely adaptable: gas flow may be simply adjusted from the surface.

The gas-lift valves can be recovered using low-cost cable.

- There are no production concerns due to the presence of sand or water.
- The ability to inject an additive.

III. 2.1.3 Limitations:

- High Fluid Viscosity
- Availability of Gas
- Needs High-Pressure Gas Well or Compressor
- Bottom hole Pressure[8]

III.2.2 Suker rod pump :

This is currently the oldest and most common type of pumping. This method is primarily used in shallow wells of moderate depth (elevation < 10,000 feet (3048 m)). The pump pumps the liquid in the pipe to the surface. In its simplest form, it consists of a pump body (or cylinder) suspended from a pipeline, with a ball valve "foot valve" (or fixed valve) at its base, and a second ball valve "movable valve". " is placed. Located inside the piston The piston is reciprocated from top to bottom within the pump body by a series of pump rods consisting of steel rods bolted together at both ends and fixed to the surface after passing through the polished rods. The wellhead, pumping unit, surface, and pumping unit provide reciprocating motion for the sucker rod train and pump thanks to the motor and connecting rod system. [9]

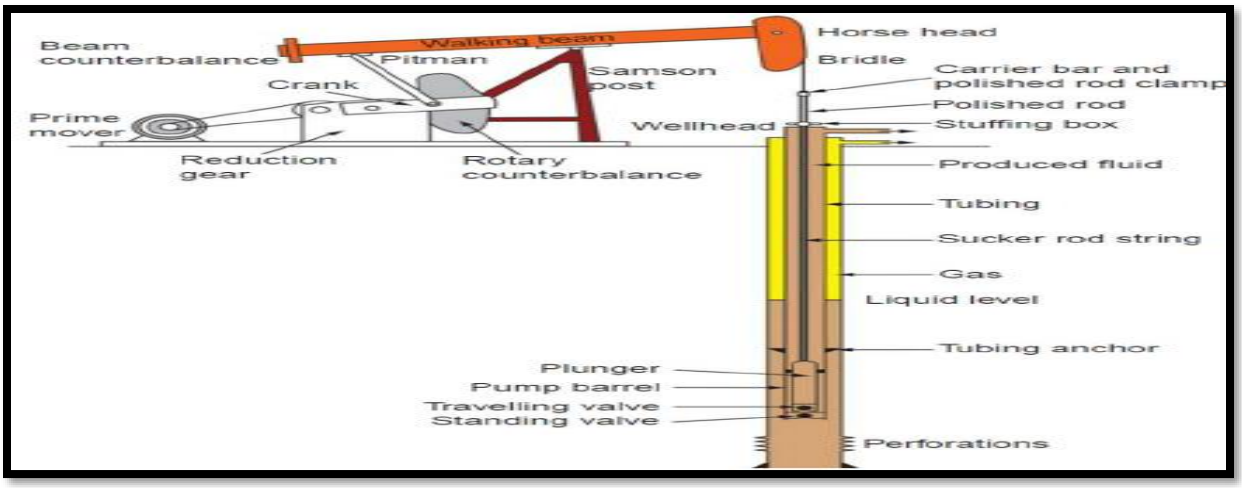


FIGURE III. 2: *SUCKER ROD[9]*

III.2.2.1 Advantages:

- Used for about 80% of land drilling.
- Economic method.
- No gas influence on the pump.
- Best for heavy oils.

III.2.2.2 Limitations :

- Potential for Tubing and Rod Wear
- Gas-Oil Ratios
- Most Systems Limited to Ability of
- Rods to Handle Loads

(Volume Decreases As Depth Increases) [8]

III.2.3Progressive cavity pumps (PCP):

Progressing Cavity Pumps (PCP) are widely used highly viscous fluids and are frequently applied in the oil industry. They are positive displacement pumps and consist of a rotor and a stator. Using a top side or a bottom hole motor, the rotor is rotated which creates sequential cavities to push the oil to the surface. Progressive cavity pumps as artificial life solutions provide a wide range of flexibility in terms of variable rate and depth. The simple design of PCPs has a low operating and capital cost as compared to other artificial lift systems. Their efficient performance of the artificial lift method is highly effective as they offer outstanding resistance to abrasives and solids. They also have superior sand lifting capacity but are restricted to setting depths and temperatures.

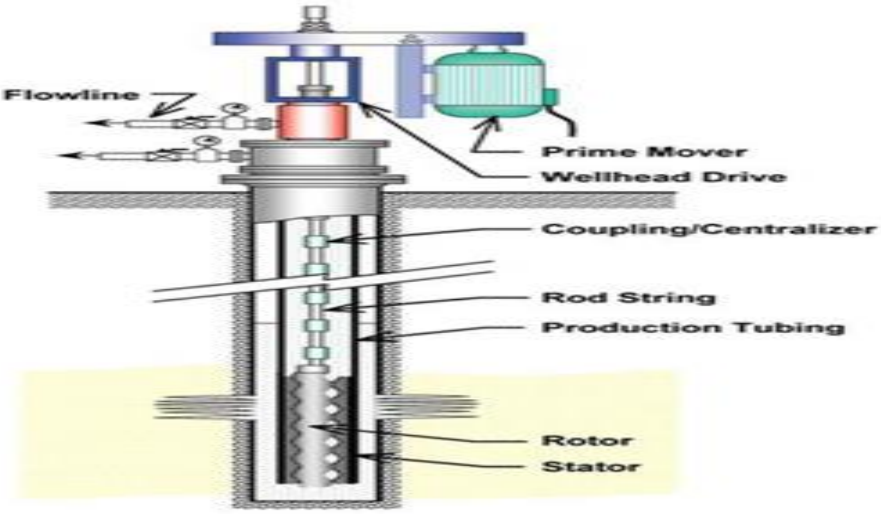


FIGURE III. 3: *PROGRESSIVE CAVITY PUMPS*[9]

In recent times advanced fully automatic progressive cavity pumps provide better artificial lift services by monitoring torque, flow rates, and pump speed. Such automatic types of artificial lift systems can be accessed remotely to control any parameter.

III.2.3.1 Advantages:

- Suited to high and low viscosity applications.
- Can handle air entrained, multiple phase and abrasive fluids.
- Allows continuous, gentle and low-pulsation flow.

III.2.3.2 Limitations :

- The volumetric efficiency of the pump can be affected when viscous fluid doesn't flow quickly enough into the pump.

Progressive cavity pumps are slower moving and don't produce large amounts of flow. ... [8]

III.2.4 Hydraulic Pump :

Hydraulic pumping activation first appeared in 1930 in the United States. Especially used in this country and others around the world.Schematically, the hydraulic pump has two solid pistons mounted on the same axis and moving each in a pump body.The upper piston serves as engine piston. It is activated by the power fluid brought from the surface by a supply tubing. A drawer dispenser allows the fluid to be sent alternately to the lower or upper chamber of the engine cylinder.

The piston pump, attached to the engine piston, draws the effluent from the well and pushes it to the surface. [10]

III.2.4.1Advantages:

- Suitable for large depths and deviated wells.
- Ease of changing pump size and rate to fit well conditions.
- Motor fluid for use as carrier fluid for injection of an additive

III.2.4.2 Limitations :

- Initial investment in equipment and maintenance of the latter is quite costly [8]

III.2.5 Plunger lift :

Plunger lift is an artificially listed method of liquefying a natural gas well. Pistons are used to remove contaminants such as water, sand, oil and wax from productive natural gas wells. The basic principle of the piston is to open and close the gate valve of the well at the optimal time to bring the piston and contaminants to the top and maximize the natural gas production. A well without dewatering technology will stop flowing or slow down and become a non-producing well long before it becomes a properly draining well.

The plunger lift have low energy costs, low environmental impact, low capital investment and low maintenance costs. Modern wellhead controls offer a variety of standards for controlling

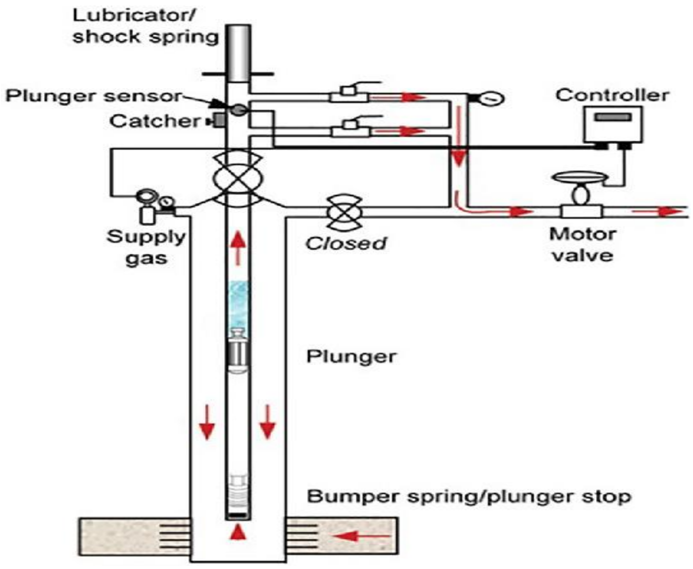


FIGURE III. 4: *SCHEMATIC OF A PLUNGER LIFT INSTALLATION*[11]

the piston. The original controllers were just timers with fixed on and off cycles. Measuring different pressures in the system enables intelligent reaction control. Commonly used measurement pressures are shell pressure, pipe pressure, pipe pressure and differential pressure. Other measured times are plunger arrival time, flow, temperature and status of various auxiliary equipment: tank level, compressor status. [11]

III.2.5.1Advantages:

- Marginal flow characteristics result from the liquid fallback.
- Clears liquid from well bore.
- Returns well to full production.

III.2.5.2 Limitations :

- Danger exists in plunger reaching too high velocity and causing surface damage.

- Communication between tubing and casing is required for good operation unless used in conjunction with gas lift. [8]

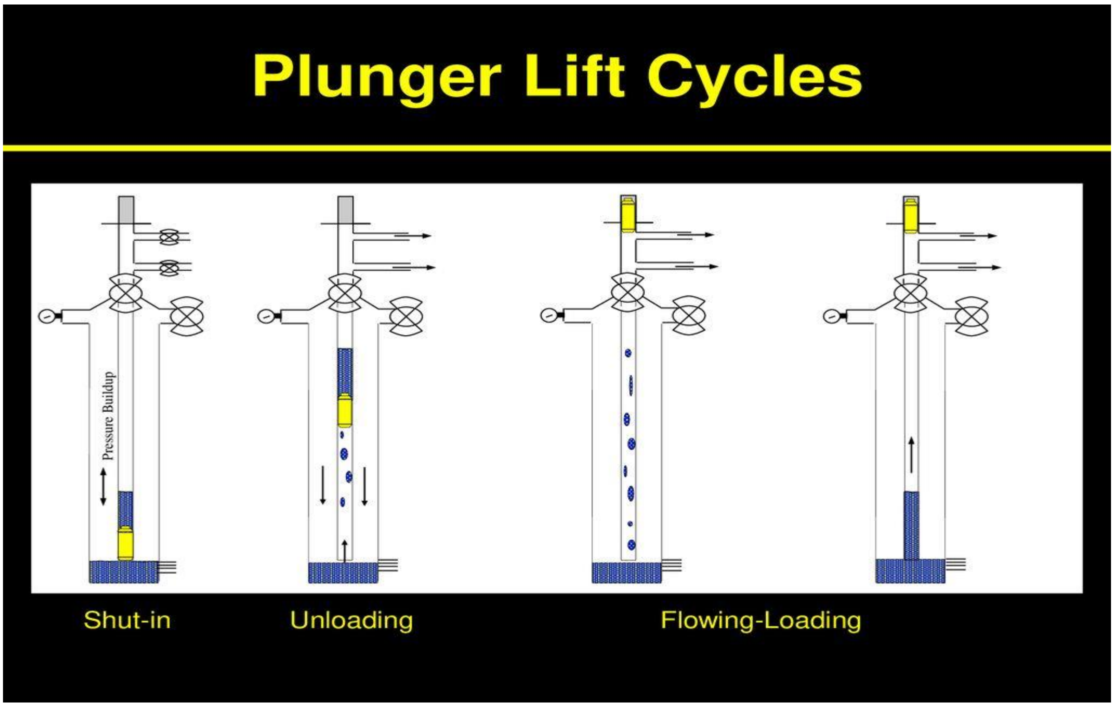


FIGURE III 5: *PLUNGER LIFT CYCLES*[8]

III2.6 Electrical submersible pump:

About 15% to 20% of the world's nearly 1 million wells use electric submersible pumps to pump water in some form of artificial buoyancy. Additionally, ESP systems are the fastest growing form of artificial lift pump technology. In oilfield jacking systems, they are often considered the champions for high volume and depth. ESPs can be found in operating environments around the world and are used in a variety of ways.

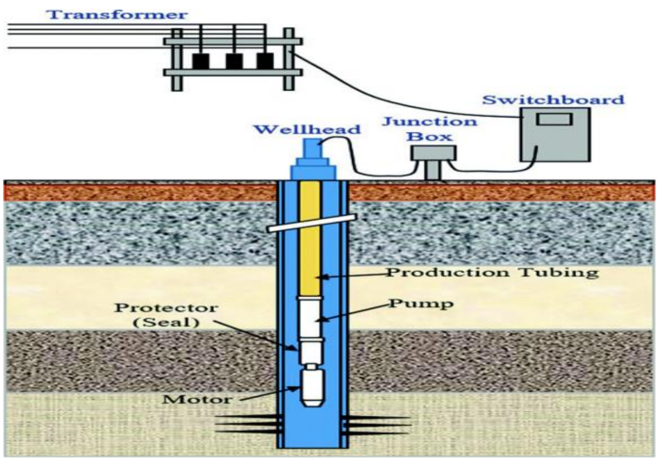


FIGURE III 6: *ELECTRICAL SUBMERSIBLE PUMP*[8]

The centrifugal pump is suspended at the end of the production tubing after being lowered to its side in the casing. An unbound cable transports electrical energy to the motor and is clamped to the tubing as it lowers.A unique tubing head with a gasket allows the cable to be carried out to a control cabinet on the surface.By varying the back pressure on the pump, an adjustable drop makes it possible to change the flow. If the bottom unit fails, the tubing pump system should be disassembled and reassembled for repair.

III.2.6.1Advantages :

- High Efficiency Over 1,000 BPD
- High Volume and Depth Capability
- Minor Surface Equipment Needs
- Low maintenance
- Good in Deviated Wells[8]

III.2.6.2Limitations:

- Available Electric Power
- Higher Pulling Costs
- Free Gas and/or Abrasives [8]

III.3Lift System Selection – How to Approach :

III.3.1Project scoop :

1– General Field Requirements

2– Data Collection

Well Information

Production & Fluid Information

Desired Production Rate

System Details

3– Data Confirmation

III.3.2Elimination process :

Table III 2: *Elimination process[11]*

	Gas Lift	Plunger	Rod Lift	PCP	ESP	Hyd pump
Max depth	18000 ft	19000 ft	16000ft	8600 ft	15000ft	17000ft
Max volume	75000bpd	200bpd	6000bpd	5000bpd	60000bpd	9000bpd
Max Temp	450F	550F	550F	250F	482F	550F
Corrosion Handling	Good to Excellent	Excellent	Good to Excellent	Fair	Good	Good
Gas Handling	Excellent	Excellent	Fair to Good	Good	Faire	Faire
Solid Handling	Good	Fair	Fair to Good	Excellent	Sand<40ppm	Faire
Servicing	Wireline or Workover rig	Well head catcher or Wireline	Workover or pulling rig	Wireline or Workover rig	Wireline or Workover rig	Hyd or Wireline
Prime mover	Compressor	Well natural energy	Gas or Electric	Gas or Electric	Electric	Gas or Electtric
Offshore applications	Exellent	N/A	45 to 60	50 to 75	35 to 60	45 to 55

TABLE III 3: *PERFORMANCE COMPARISON[11]*

Performance Comparison					
Characteristic	**SRP**	**PCP**	**ESP**	**Gas Lift**	**Jet**
Rates	Poor	Fair	Good	Excellent	Good
Gas Production	Fair	Poor	Poor	Excellent	Good
Viscous Fluids	Good	Excellent	Fair	Fair	Excellent
Emulsions	Good	Excellent	Fair	Fair	Excellent
Solid Handling	Fair	Fair	Poor	Excellent	Excellent
Wax Mitigation	Fair	Fair	Fair	Good	Excellent
Corrosion	Good	Good	Fair	Good	Excellent
Reliability	Excellent	Good	Varies	Excellent	Good
Efficiency	Good	Good	Fair	Poor	Poor
Capital Costs	Moderate	Low	Moderate	Moderate	Moderate
Operating Costs	Low	Low	High	Low	Moderate

III.3.3Final Selection:

Proposal for Viable Forms of Lift

Economic Evaluation Model

- Capital Expenditure
- Operating Expenses
- Comprehensive Analysis

ESP : electrical submersible Pump

RRP : sucker Rod Pump

PCP : progressive cavity pump

GL : gas lift

PL : plunger lift

HL : hydraulic lift

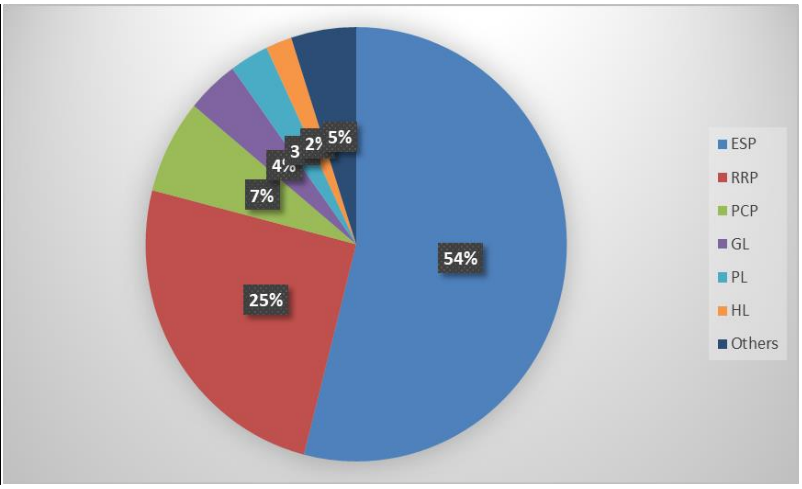


FIGURE III.6: *ARTIFICIAL LIFT MARKET SHARE BY TYPE BASED ON DOLLARS SPENT*

Chapter IV

Electric Submersible Pumps (ESP)

IV.1 Introduction:

Electric Submersible Pumps (ESP) are widely used in the oil and gas industry for the efficient extraction of liquids, particularly oil, from wells. They are designed to operate in various conditions, including deepwater drilling, subsea oil wells, and onshore oil wells.

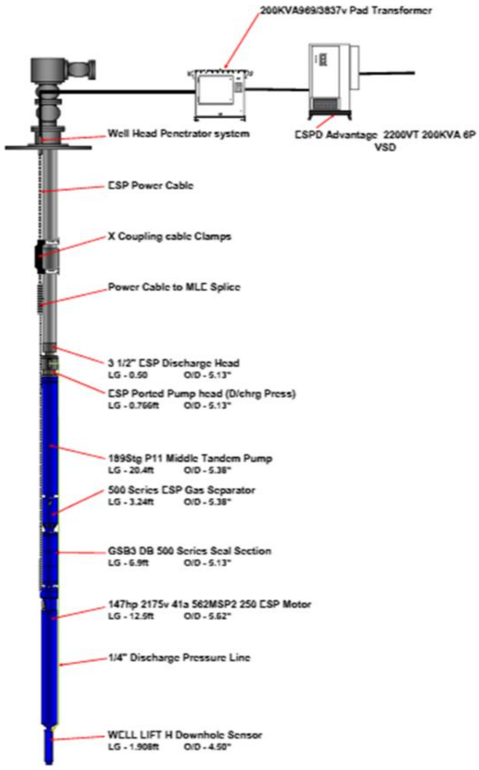


FIGURE IV 1: *ESP SYSTEM[12]*

The ESP system consists of a submerged electric motor and a pump assembly. The electric motor is positioned downhole and is powered by electrical cables that run from the surface. The pump assembly, which includes an impeller, is also located downhole and is responsible for generating the necessary pressure to lift the fluids to the surface.

ESP systems offer several advantages over other pumping methods. They can provide high flow rates and maintain consistent pressure, enabling efficient production. Additionally, ESP systems are compact and require less surface space compared to other pumping systems. Their downhole configuration also allows for easy installation and maintenance.

These pumps are commonly employed in scenarios where natural reservoir pressure is insufficient to lift the fluids to the surface. ESPs can provide the additional energy required to overcome the well's backpressure and optimize production rates. [12]

IV.2 principle of operation:

The principle of operation of Electric Submersible Pumps (ESP) involves converting electrical energy into mechanical energy to lift fluids from a well to the surface. Here is an explanation of the principle, along with a suggested source for further information:

The ESP system consists of three main components: the electric motor, the pump, and the seal section. The electric motor is a hermetically sealed unit, designed to be submerged in the well fluid. It is powered by electricity transmitted through the power cable from the surface. The motor converts electrical energy into mechanical energy, driving the pump assembly.

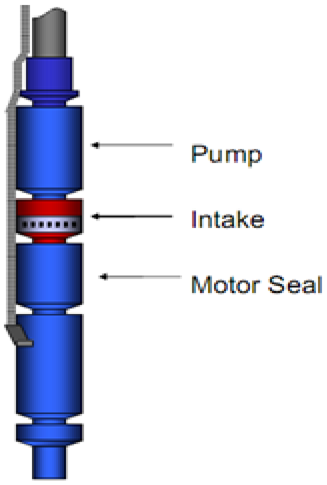


FIGURE IV 2: *COMPOSITION OF AN ESP SYSTEM[12]*

The pump assembly consists of a series of stages, each containing an impeller and a diffuser. As the motor rotates the impeller, it imparts kinetic energy to the fluid, which is then converted into pressure energy by the diffuser. This pressure energy allows the fluid to be lifted to the surface.

The seal section is located above the pump and is responsible for preventing well fluid from entering the motor. It contains mechanical seals and other sealing mechanisms to ensure the integrity of the system. [13]

IV.3 Composition of an ESP system

The composition of an Electric Submersible Pump (ESP) system typically includes several key components that work together to efficiently lift fluids from a well. Here is an overview of the common components found in an ESP system, along with a suggested source for further information:

Electric Motor: The electric motor is a hermetically sealed unit designed to be submerged in the well fluid. It converts electrical energy from the surface into mechanical energy to drive the pump.

Pump: The pump assembly consists of multiple stages, each containing an impeller and a diffuser. The impeller imparts kinetic energy to the fluid, while the diffuser converts this kinetic energy into pressure energy, enabling the fluid to be lifted to the surface.

Seal Section: Located above the pump, the seal section prevents well fluid from entering the motor. It includes mechanical seals and other sealing mechanisms to maintain the integrity of the system

Power Cable: The power cable connects the electric motor to the surface power source, supplying electricity to the motor for operation.

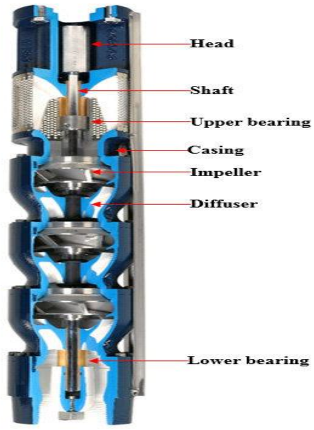


FIGURE IV 3 :*COMPONENTS ESP PUMP[12]*

Intake: The intake, also known as the intake or suction assembly, is responsible for drawing the well fluid into the pump. It typically includes a series of screens or filters to prevent the entry of solids or debris that could damage the pump.

Discharge: The discharge section is where the fluid exits the pump and is directed towards the surface through production tubing or casing. Title: "Electric Submersible Pumps: Design and Operations[13]

IV.3.1ESP pump:

The heart of the ESP system is the submersible pump, for understand how the entire ESP unit works, it is important to understand the operation of the pump. This is

why the system component description must be started with a thorough analysis of the construction and operation of the pump. ESP uses submersible centrifugal pumps driven by electric motors that transform the power of the rotary shaft into centrifugal forces that lift the fluids to the surface.Main features of centrifugal pumps in ESP systems:

- multi-stage pumps

- they have radial or mixed flow configurations

- Operates in vertical position

IV.3.1.1Components :

ESP Pumps are made up of the

following basic components:

• Shaft,

• Impeller,

• Diffuser,

• Housing.

IV.3.1.1.1 Impeller :

The impeller is keyed to the shaft and rotates at the motor RPM. As the impeller rotates it imparts centrifugal force on the production fluid. is an illustration of an impeller keyed to a shaft, and identifies key sub-components of the impeller. Figure is a cutaway illustration of a pump impeller identifying various sub components

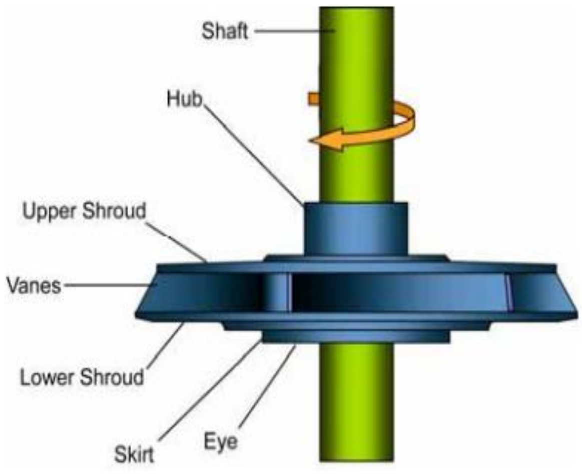


FIGURE IV 4 :*ILLUSTRATION OF IMPELLER AND SUB COMPONENTS*[12]

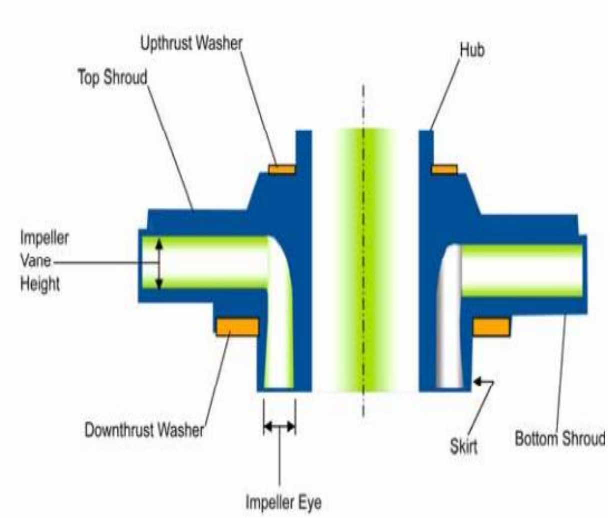


FIGURE IV 5 : *CUTAWAY ILLUSTRATION OF IMPELLER AND SUB COMPONENTS*[12]

IV.3.1.1.2Diffuser :

The diffuser turns the fluid into the next impeller and does not rotate.

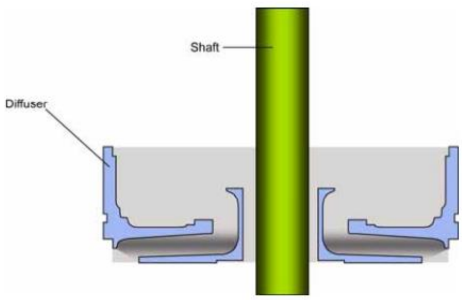


FIGURE IV 6 :*ILLUSTRATION CUT AWAY OF A DIFFUSER*[12]

IV.3.1.1.3Pump Stage :

A pump stage is formed by combining an impeller and a diffuser. Figure IV 7 is an illustration of a pump stage cut-away, showing the impeller mated to the diffuser, the fluid flow path, and shaft rotation.

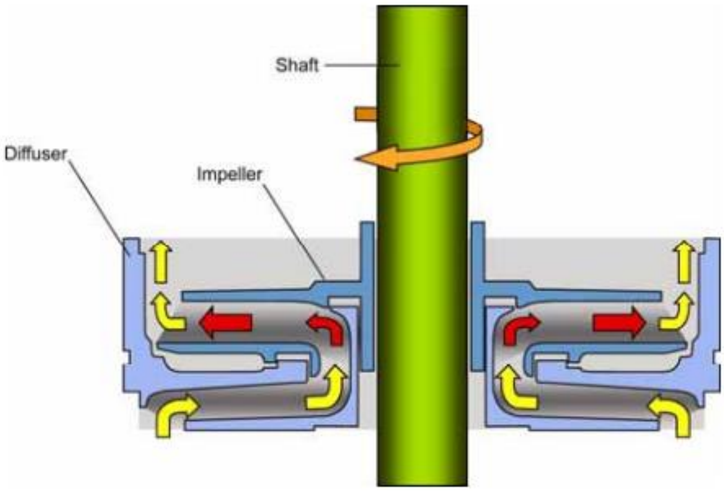


FIGURE IV .7: *ILLUSTRATION OF A PUMP STAGE (IMPELLER AND DIFFUSER*[12]

IV.3.1.1.4Shaft:

The pump shaft is connected to the motor (through the gas separator and seal section), and spins with the RPM of the motor. Figure IV 8 is a cutaway of an assembled Centrilift Pump Stage with the shaft and optional Abrasive Resistant Bearings.

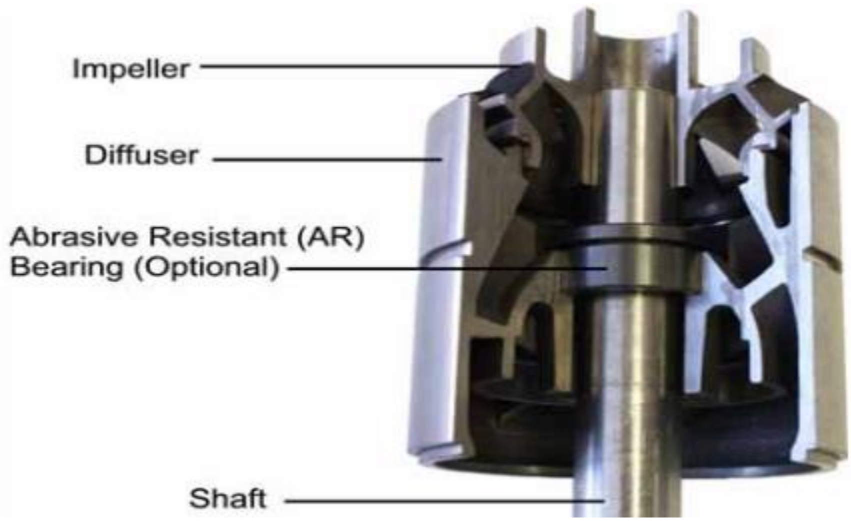


FIGURE IV 8 : *SHAFT AND PUMP STAGE CUTAWAY*

IV.4 Theory of Operation:

Centrilift produces ESP pumps with multiple stages. These stages consist of a rotating part called an impeller and a stationary part called a diffuser. When the impeller spins, it pushes the fluid outward and increases its speed. This can be seen in Figure 9 with the red arrows. The diffuser then guides the fluid into the impeller above it, as shown by the yellow arrows, and converts the kinetic energy of the fluid into pressure energy or "lift".

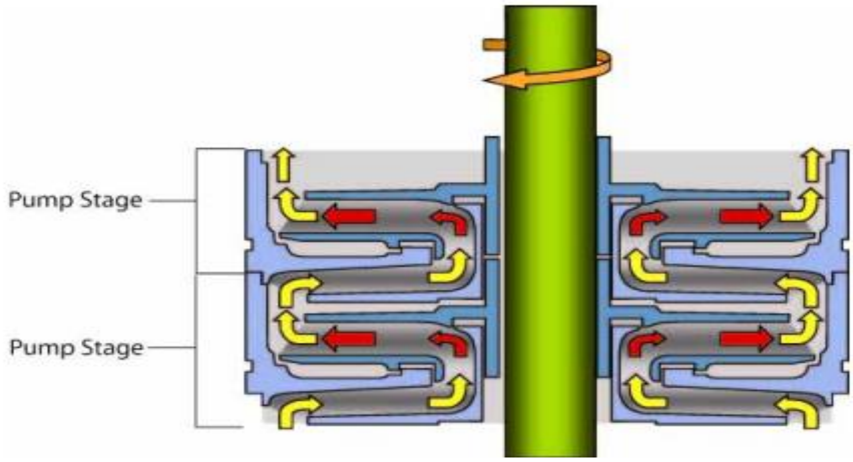


FIGURE IV 9 : *DIRECTION OF FLOW THROUGH STAGES*[12]

IV.5Gas Separator:

IV 5.1 Purpose:

To enhance pump performance in wells with high gas-oil ratio, Gas Separators are employed as replacements for standard pump intakes. These separators play a vital role in improving pump efficiency by segregating a portion of the free gas before it enters the initial stage. This process aids in the prevention of gas locking and extends the operational capabilities of ESP systems.

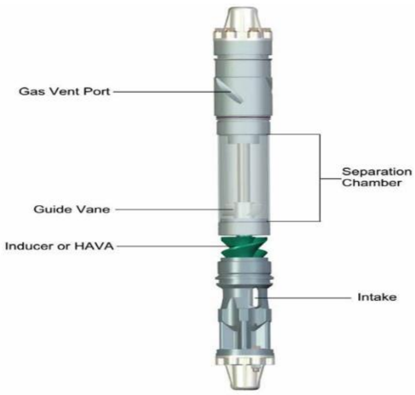


FIGURE IV 10 : *ROTARY GAS SEPARATOR*[13]

Centrilift, as a prominent industry leader in electric submersible pumping (ESP) systems, has made significant strides in effectively managing gas-related challenges. In fact, Centrilift introduced the pioneering rotary gas separator specifically designed for oilfield applications back in 1978. These gas separators from Centrilift serve as the ideal complement to down-hole pumps when confronted with substantial gas volumes at the pump intake.

IV 5.2 Components:

ESP Rotary Gas Separator are made up of the following major

components:

• Gas Vent Port

• Guide Vane

• Inducer or High Angle Vane Auger (Patented)

• Separation Chamber

• Intake

• Shaft

Rotary Gas Separator

IV.5.3 Theory of Operation:

The fluid enters the system through the intake and then proceeds through the rotating component known as the inducer or high-angle vane auger (HAVA). The HAVA effectively transfers the fluid to the separation chamber, where the higher specific gravity fluid is directed towards the outer wall, while the lighter gas accumulates in the center. This separation process is facilitated by the centrifugal force generated by either a separator rotor or an induced vortex stage.

FIGURE IV 11 : *GAS SEPARATOR[13]*

To remove the gas from the fluid stream, a diverter located at the top of the separation chamber is employed. The gas is vented through designated gas ports and produced up the annulus. The fluid, on the other hand, continues its journey into the lower part of the pump, where the stages lift the separated liquid towards the surface.

Gas separators typically achieve efficiencies of 80% or higher. The efficiency of the separation process is influenced by factors such as fluid flow rates, liquid viscosity, and the proportion of free gas in relation to the total volume produced. In situations with extremely high gas conditions, tandem gas separator assemblies are installed to further enhance pump performance.

There are two main technologies used to generate centrifugal force for the separation process. The first technology employs a separator rotor (rotary). In this design, the rotor acts as an enclosed centrifuge, compelling the higher-density fluid towards its outer diameter, leaving the lighter gas at the center. This configuration yields the most effective separation force and is particularly advantageous when high separating efficiency is required, especially with highly viscous fluids.

The second technology utilizes an induced vortex stage. A modified impeller induces a vortex in the fluid, providing the centrifugal force necessary for separating the two phases of a gassy fluid. Although the rotational speed of the fluid is slower compared to the rotary design, the separation and venting of the fluid occur in a similar manner as previously described. The slower rotation and reduced rotating mass make this design more suitable for abrasive applications. The vortex technology is recommended for a broader range of flow rates compared to the rotary separator[13]

Chapter V

Studied Case

V.1 Problem and objective:

The BRN field is one of the most important fields in Algeria, Among the wells of BRN is found RERN-6 which has a remarkable decrease in oil production flow, a increase in Water Cut and a problem of salt deposits, understanding and detection of the origin of these problems is necessary to improve the efficiency and increase the life of this well.

TABLE V.1 : *RERN-6 WELL TEST HISTORY[17]*

date	Whp (bar)	LP (bar)	Q (Stp)	Qw (total)	Salinity ((g/l)	Qw(dilution)	Wctotal (sm³/d)	Wcres	Og (kscm/d)	GOR Sm3/Sm3
31/03/16	65	59	1239	0	N/A	0	0	0	21	109
05/04/16	64	56	1271	1	N/A	0	0	0	22	107
08/04/16	73	57	1003	2	N/A	0	1	1	17	107
15/04/16	86	62	785	6	N/A	0	5	5	13	107
01/06/16	83	67	666	7	N/A	0	6	6	11	104
27/06/16	84	71	560	11	300	0	11	11	10	107
01/08/16	84	70	518	11	290	0	12	12	9	106
03/09/16	73	70	642	13	332	0	11	11	11	107
03/02/18	82	71	887	23	280	0	14	14	15	109
30/08/18	78	71	420	12	300	0	15	15	7	107
06/11/18	88	74	689	14	280	0	11	11	11	104
03/12/18	89	72	633	14	260	0	12	12	10	102
07/02/19	86	73	606	13	250	0	12	12	10	107
20/05/19	84	68	583	15	328	0	14	14	10	107
12/08/19	77	71	617	15	340	0	13	13	10	100
12/11/19	82	71	531	12	300	0	12	12	9	106

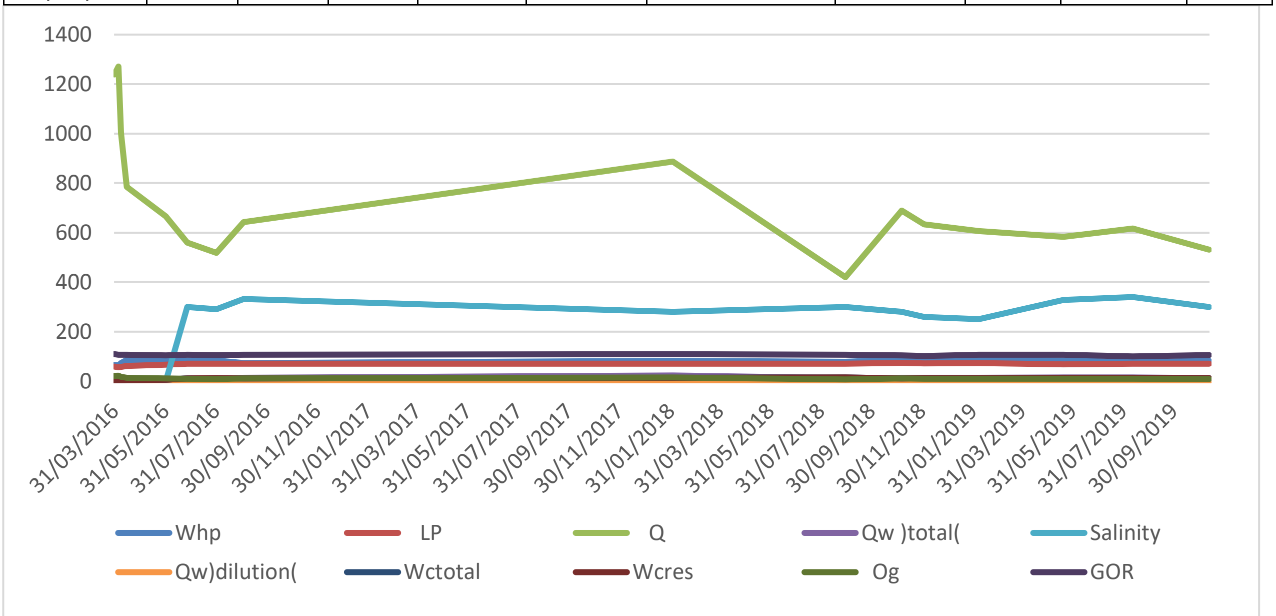


Figure V. 1 : *RERN-6 Tests History March 2016 – November 2019[17]*

Notice:

We note in short duration the increased water flow rate which causes the pressure to decrease

V.2 Well Operations Problems RERN-6:

V.2.1 Water inlet:

The well RERN-6 has a water inlet, which is directly inferred from evolution

Close the water in that well.

- The production of this well appeared at the beginning of March 31/03/2016
- During 08/04/2016 well, we noticed an increase in water cutting Causes low head pressure so we lose well (pressure equation head pressure and flow line).
- Measurements are made by PLT (logging production tool)
- OWC 2542 TVDSS
- Botm perf 2540

V.2.2 Consequences of water inflows :

The problem of water breakthrough is a problem that cannot be ignored and it may have Different consequences for the well and its production, we quote

a. Deposits

The salt in the produced water will crystallize and settle to form deposits during

the flow of effluent into the tubing as a result of the drop in pressure and temperature

lead to a decrease in salt solubility in water. Different deposits can reduce the flow section until the production column and the well and collection facilities, and therefore decrease well production.

b. corrosion of production equipment

Corrosion refers to the phenomenon by which metals tend to return to the state under which they are found in nature (oxide, carbonate, sulphates, etc.), that is, their most stable state, water produced is generally very salty and can therefore be the cause of aggravation of this phenomenon.

c. Heaving of the hydrostatic column

Water production causes the production column to become heavier as a result of increase in the average density of the water/oil mixture. This results in a increased bottom pressure and a total flow drop.

d. Decrease in relative oil permeability

The productivity of oil wells is strongly related to the relative permeability of oil at well vicinity. The well is impaired by the simultaneous presence of water.

e. Sand production:

Water can weaken cement materials that hold grain and formation in place, thus allowing the production of sand.

V.3 Well Performance Analysis :

RERN-6 throughout its production history a productivity index of 2 Sm3/d/bar. The anticipated reservoir pressure is roughly 260 bar 2400 m MD. while the anticipated WC is 12% and GOR 107 Sm3/Sm3 (as per last MPFMs). The following plot illustrates the inflow performance of the well.

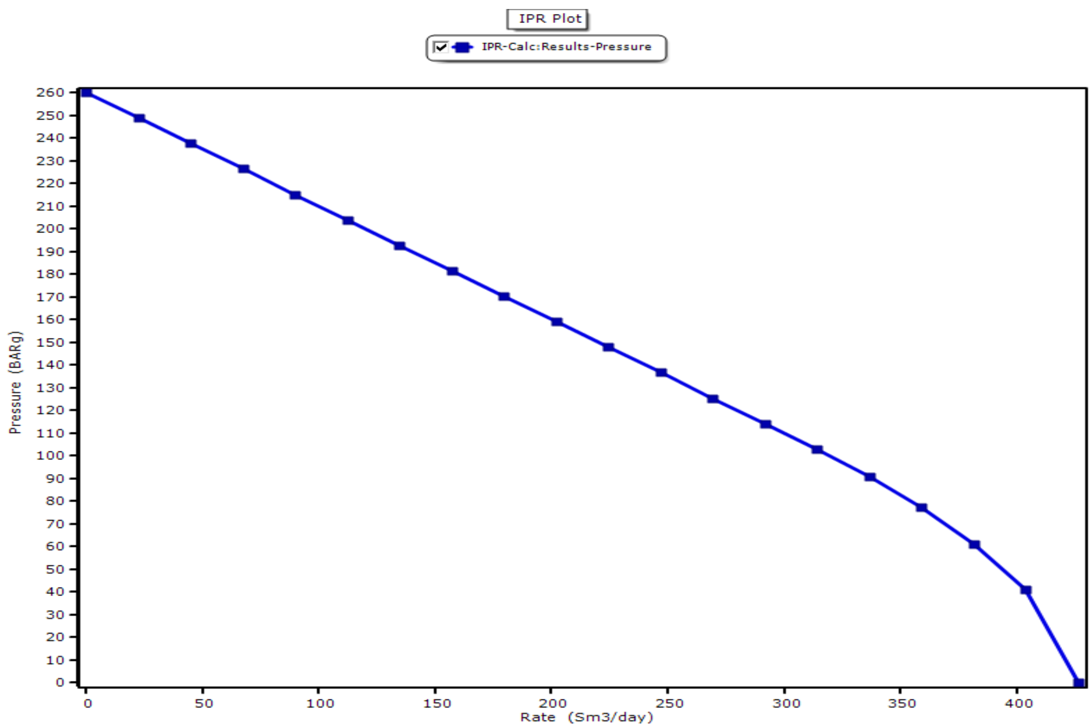


FIGURE V. 2 : *RERN-6 IPR[17]*

On the basis of the log and MDT data, a Prosper Darcy model was made to estimate the parameters of RERN-6 production.

The parameters considered are:

Static pressure = 260 bar

Average permeability (K) = 30 mD

H = 6 m (U.TAGI)

Skin = 2

After commissioning the pump, the Model Prosper PI was calibrated with the following parameters:

PI = 2.38 Sm^3/day/bar (as expected)

WC = 15%

GOR = 100 Sm^3/Sm3

Q Liquid = 1000 Sbopd

WHP = 45 bar

After well commissioning, a production test will be performed to optimize pump and well parameters.

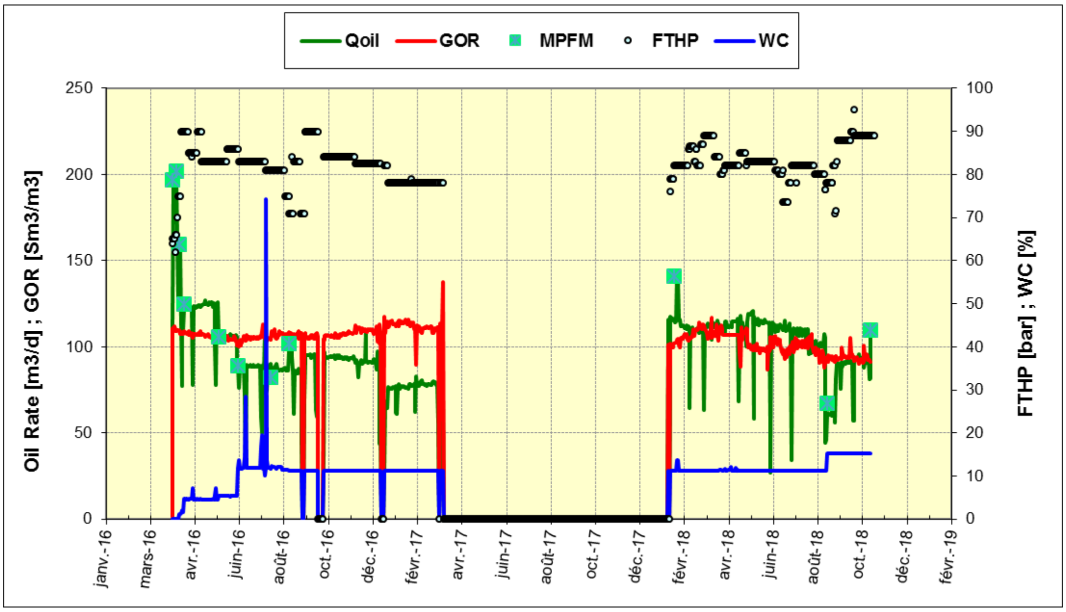


FIGURE V. 3 : *RERN-6 PRODUCTION AND MPFM TESES[17]*

V.4 Scope of work :

Scope of the Workover intervention is to replace the existing failed ESP system in RERN-6 after declared electrical failure on the 3rd December 2019, in order to restore the oil production with Trasncoil ESP (Rigless ESP)

FIGURE V.4 : *RIGGING UP EXAMPLE*

V.4.1 OPERATION SUMMARY :

V.4.1.1Rig moving/Mobilization

- Move in location CT tower

V.4.1.2 Completion

- Rig up and prepare for PCE stack press test
- Retrieve BOP plug (if fitted)
- Prep transcoil for Torus Valve & install Torus valve to Transcoil
- Pick up and make up Transcoil adaptor to transcoil below Torus valve.
- Pick up and make up Seal Stack assy and Intake assyMake up ESP assy
- Connect Adaptor assy to Top of sensor
- RIH
- Set Torus Valve
- Continue to bottom
- Space out & Cut Transcoil
- Make up Coil Tubing Hanger

- Land off hanger
- Remove BOP stack & M/U Wellhead
- Make up surface electrical connections
- Start Pump

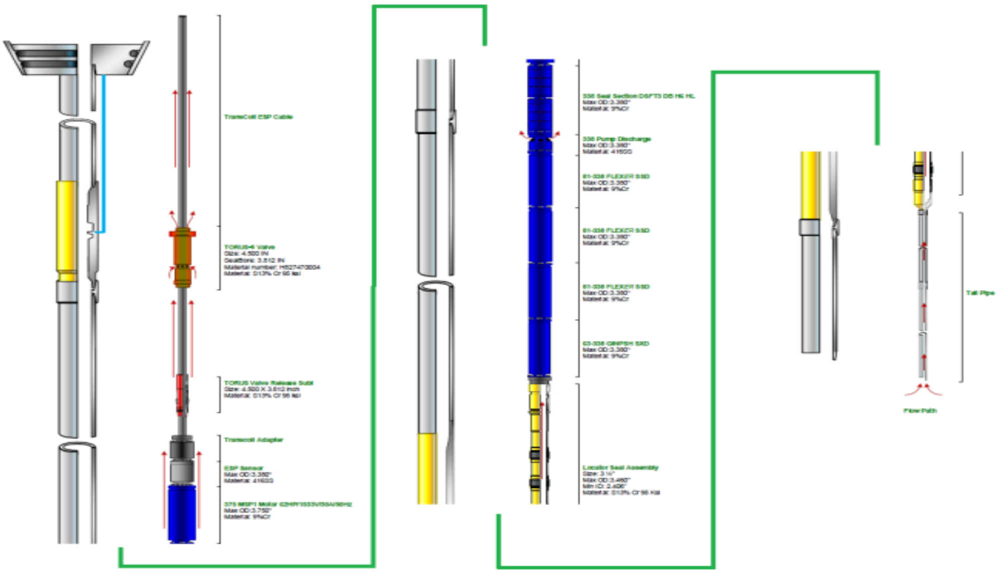


FIGURE V.5 : *INSTALLATION TRANSCOIL*[17]

V.4.1.3Instalation :

V.4.1.3.1Prep Transcoil for Torus valve :

- Straighten transcoil coil for Torrus make up

Well barrier

-premary barrier: kill fluid.

- Secondary barrier: CT PCE (ABOP**).**

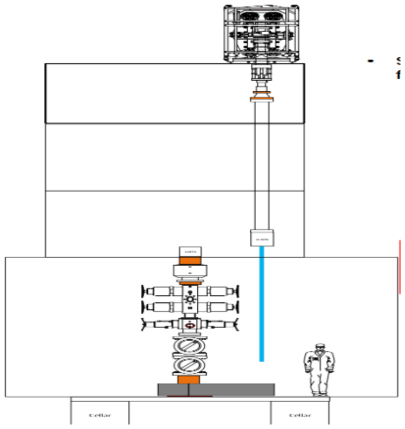


FIGURE V.6 : *PREP TRANSCOIL FOR TORUS VALVE*[16]

V.4.1.3.2 Make up transcoil connector :

- Complete the pressure test of Annular BOP
- Perform Final Pipe Straightener Setup
- Install the Torus Valve
- Install the TransCoil Adapter.

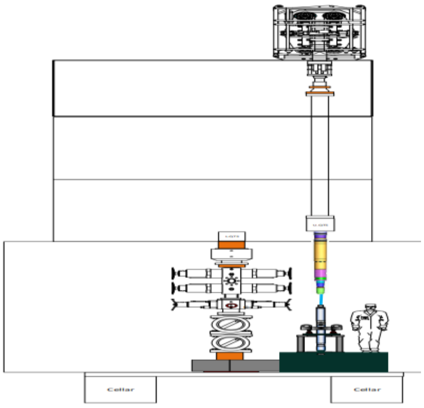
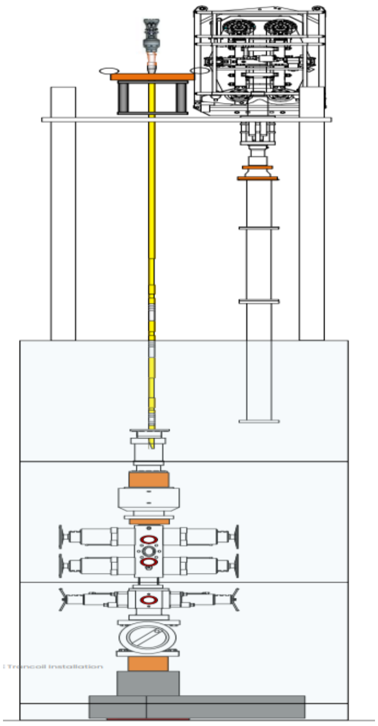


FIGURE V.7 *: MAKE UP TRANSCOIL CONNECTOR[16]*

V.4.1.3.3 P/U and M/U Seal Stack assembly :

- Seal Stack assembly to be loaded out in sub assemblies



FIGUREV.8 :*P/U AND M/U SEAL STACK ASSEMBLY[16]*

V.4.1.3.4 P/U and M/U pump section :

- Pick up 1st (Gas handler) Pump with lifting clamp and crane.
- Position above intake .
- Lower pump, Connect intake and pump using jacks.
- Pick up assy and remove Seal stack lifting clamp.
- Lower assy into well, rest pump lifting clamp on table.

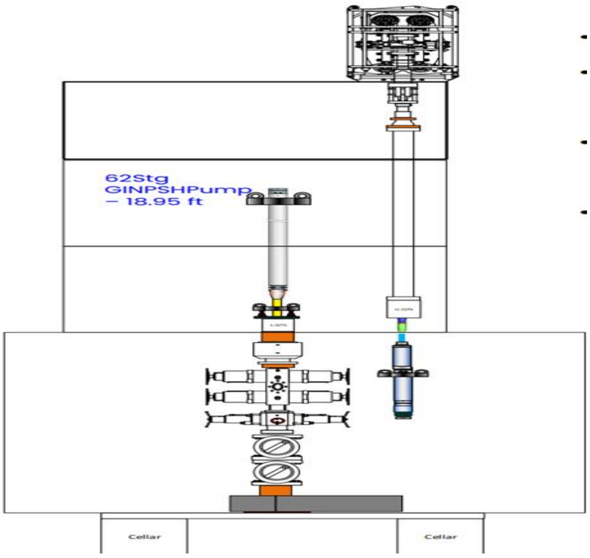


FIGURE V.9 : *P/U AND M/U PUMP SECTION[16]*

V.4.1.3.5 P/U and M/U 2nd & 3rd pump section :

- Pick up 2nd Pump with lifting clamp and crane.
- Position above LT pump.
- Lower pump, Connect intake and pump using jacks.
- Repeat for 3rd & 4th pump section.

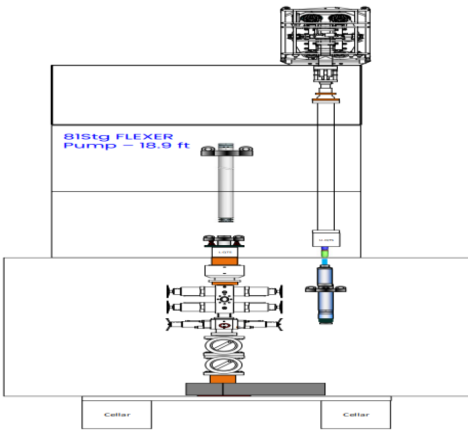


FIGURE V.10 : *P/U AND M/U 2ND & 3RD PUMP SECTION[16]*

V.4.1.3.6 P/U, M/U, and RIH motor section :

- Bring up motor section using lifting clamps.
- Connect motor to seal section by raising seal on jacks.
- Pick up BHA and remove seal lifting clamp.
- Lower BHA using motor lifting clamp and rest on jacks

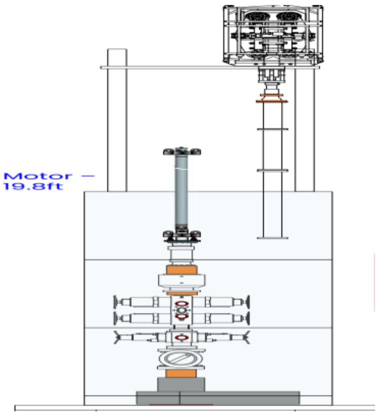


FIGURE V. 11 :*P/U M/U AND RIH MOTOR SECTION[16]*

V.4.1.3.7 P/U, M/U and RIH sensor section :

- Bring up sensor section over using lifting clamps.
- Connect sensor to motor section by raising motor on jacks.
- Pick up BHA and remove motor clamp and jacks.
- Service sensor
- Lower sensor to table.

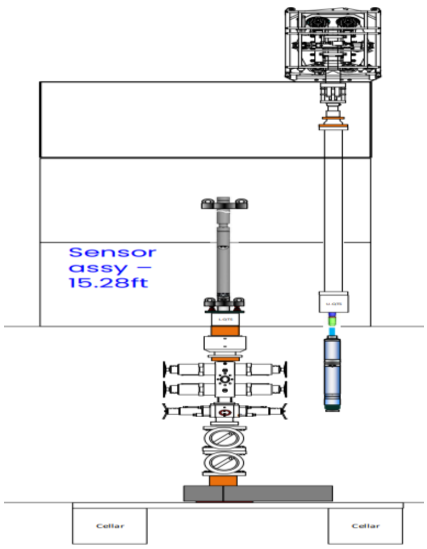


FIGURE V.12 : *P/U M/U AND RIH SENSOR SECTION[16]*

V.4.1.3.8 P/U and M/U Transcoil Adaptor :

- Make up Adaptor assy to top of sensor. (Flange to flange)
- Pick up and Remove Jacks and C plate
- Service Adaptor assy
- RIH retrievable completion

V.4.1.3.9.Set and P/T Torus valve :

- As the Torus valve nears the ported nipple in tie back string, begin pumping down control line.
- The Self-Set Lock will land off in the ported nipple no-go; there should be an increase in the C/L indicating seal stacks are in the Nipple Sealbore – stop pumping and then bleed-off C/L pressure.
- Increase tubing pressure to 1,000 psi to set the Self-Set Lock.
- Apply overpull to string to lift the Lock off the No-Go and to ensure keys are fully expanded in lock profile.
- Apply C/L pressure to cycle test Torus. Perform integrity test
- Continue RIH retrievable completion

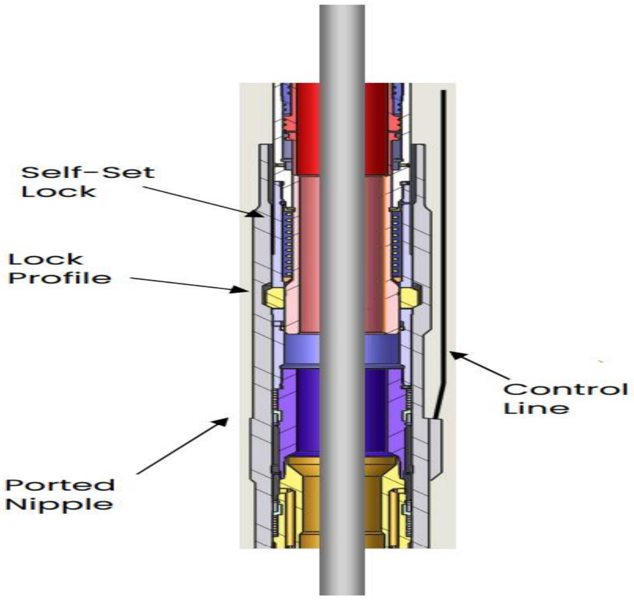


FIGURE V.12 : *SET TORUS VALVE*[16]

V.4.1.3.10 Space out retrievable completion :

- Tag top of No go at PBR
- Pull back 4.5m (15ft) to sit mid way in PBR (Hanger Set point Mark)

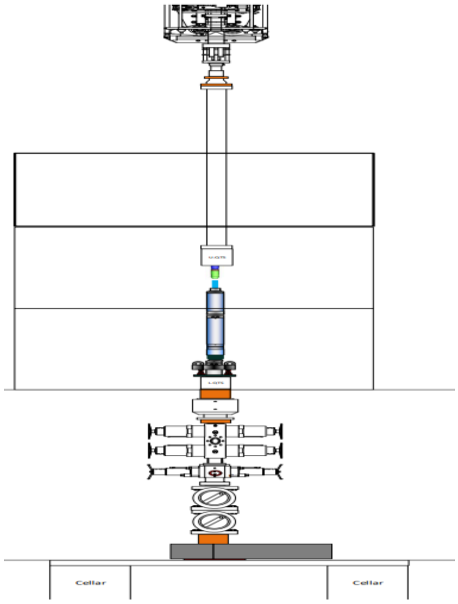


FIGURE V.13 : *SPACE OUT RETRIEVABLE COMPLETION*[16]

V.4.1.3.11 Cut Transcoil :

- Raise injector to expose transcoil and mark hanger set point. This is the datum.
- Lower transcoil until hanger set point mark is inline with top of assy table.
- Set transcoil in pneumatic spider slips.
- Cut transcoil at approx. 1.5m (60”) above Bot hanger set point. (This ensures enough cable for penetrator make up.)

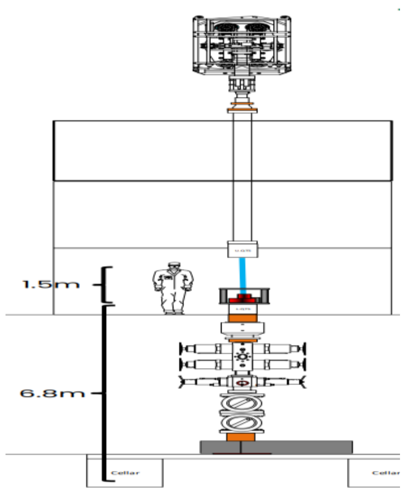


FIGURE V.14 : *CUT TRANSCOIL*[16]

V.4.1.3.12.M/U CT Hanger :

• M/U CT hanger.

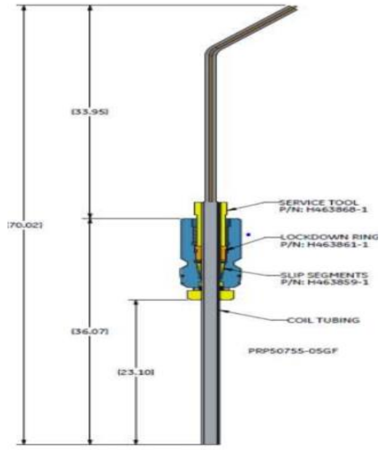


FIGURE V.15 : *M/U CT HANGER[16]*

V.5 Well performance study with pump :

The following figure shows the characteristic curve of the selected pump and the maximum and minimum network with network frequency sensitivity

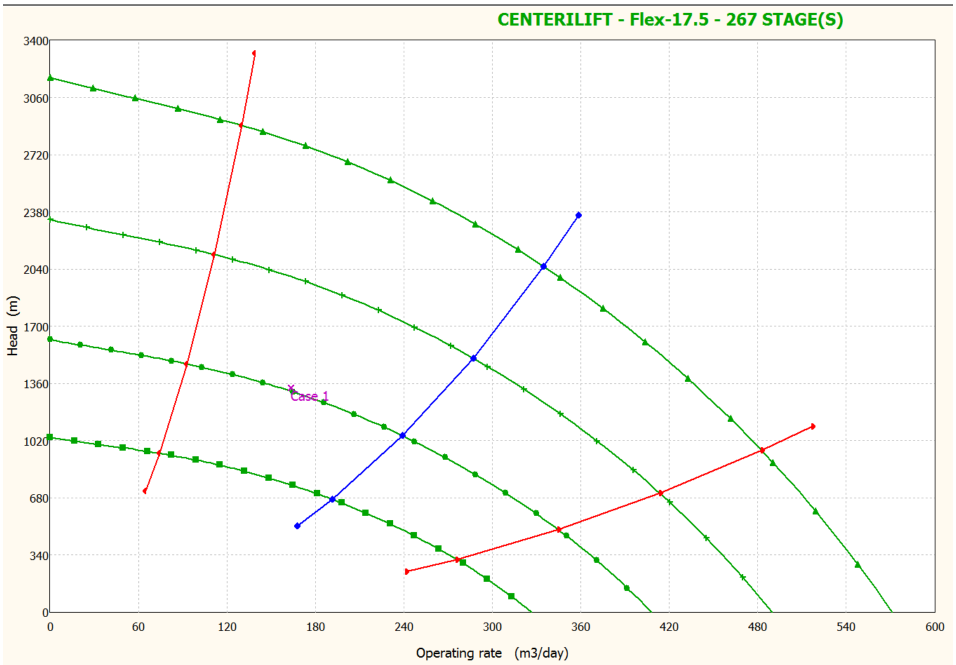


FIGURE V.16 : *PUMP CHARACTERISTIC CURVE[17]*

ESP is currently operating inside the ROR (recommended operative range),

Current estimated drawdown is 67 bar (26%)

V.6 IPR/VLP curve :

Th figure shown here shows the tubing and tank after installation of pump

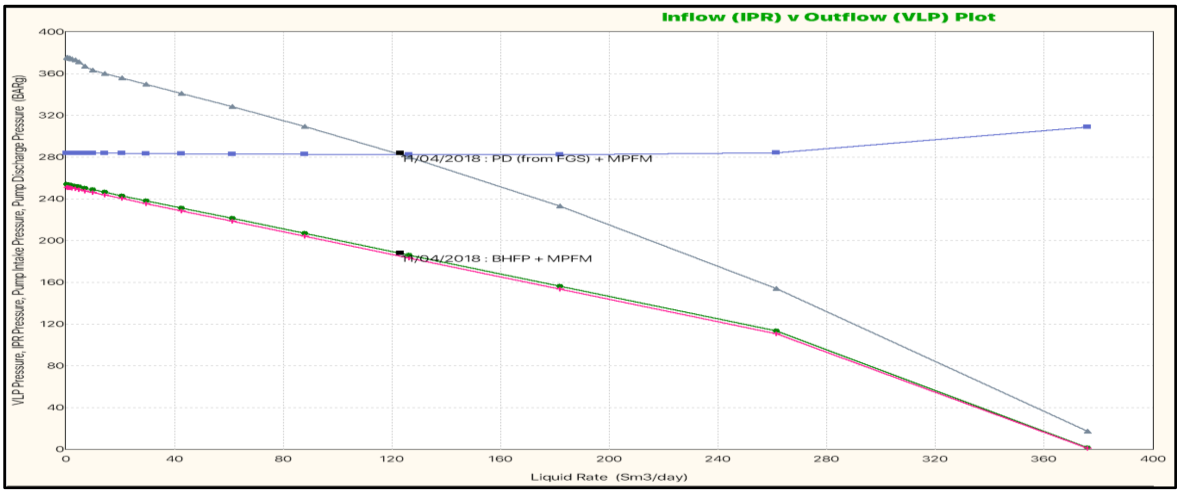


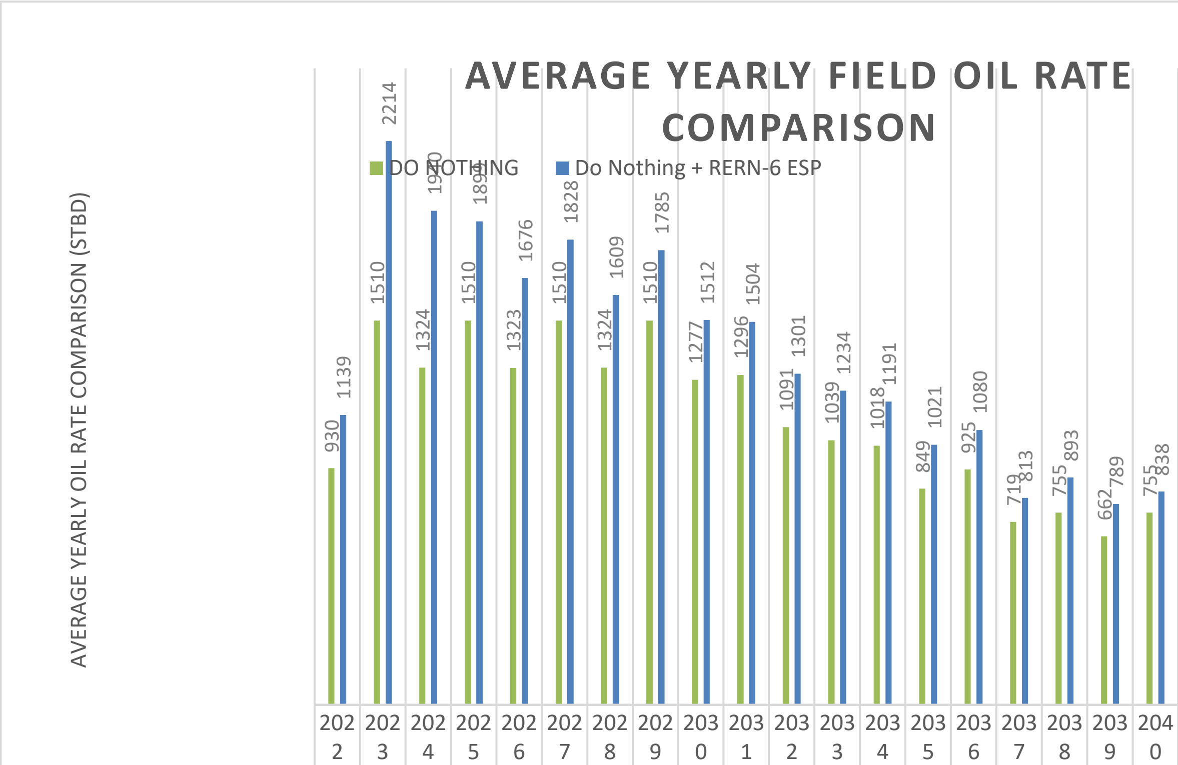
FIGURE V.17 : *IPR & VLP[17]*

V.7Equonomic study :

V.7.1 DN and DN+RERN-6 new well production profiles comparison :

Table V. 2 : *do nothing & do nothing ESP*

Date	DO NOTHING			Do Nothing + RERN-6ESP			
	Field Oil Rate	Yearly Oil Volumes	CUM	Field Oil Rate	Yearly Oil Volumes	CUM	**DELTA**
	(STB/D)	(MMSTB)	MMSTB	(STB/D)	(MMSTB)	MMSTB	MMSTB
2023	1466	0.53	0.91	2156	0.79	1.38	0.48
2024	1285	0.47	1.38	1741	0.64	2.02	0.64
2025	1466	0.53	1.91	1830	0.67	2.69	0.78
2026	**1285**	**0.47**	**2.38**	**1622**	**0.59**	**3.28**	**0.90**
2027	1466	0.53	2.92	1776	0.65	3.93	1.01
2028	1305	0.48	3.39	1590	0.58	4.51	1.12
2029	1446	0.53	3.92	1715	0.63	5.14	1.22
2030	1366	0.50	4.42	1615	0.59	5.73	1.31
2031	1375	0.50	4.92	1595	0.58	6.31	1.39
2032	1248	0.46	5.38	1443	0.53	6.84	1.46
2033	1157	0.42	5.80	1344	0.49	7.33	1.53
2034	1108	0.40	6.21	1239	0.45	7.78	1.57



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
DO NOTHING	930	1510	1324	1510	1323	1510	1324	1510	1277	1296	1091	1039	1018	849	925	719	755	662	755
Do Nothing + RERN-6 ESP	1139	2214	1940	1899	1676	1828	1609	1785	1512	1504	1301	1234	1191	1021	1080	813	893	789	838

FIGURE V.18 : *AVERAGE YEARLY FIELD OIL RATE COMPARISON*[17]

Notice:

- Table and curve represent the flow change in the well with and without a TRANSCOIL in the coming years
- Increased flow with TRANSCOIL
- The comparison results between the cases with and without RERN-6 ESP replacement is shown in Figure and 16 as well as in Table , respectively in terms of average yearly field oil rate and field oil cumulative over the period 2022-2040

V.7.2 Economic approach :

As the productivity of the RERN-6 well fell we proposed to install a pump

immersed. In the economic side the life of the pump is considerably long (3 years via).

The installation of a submerged pump requires a rigless. The purchase and trucking pumps is $550,000. rigless expenses are $400,000 for 7 days transcoil installation expenses: $5,850,000

V.7.3 Appraisal :

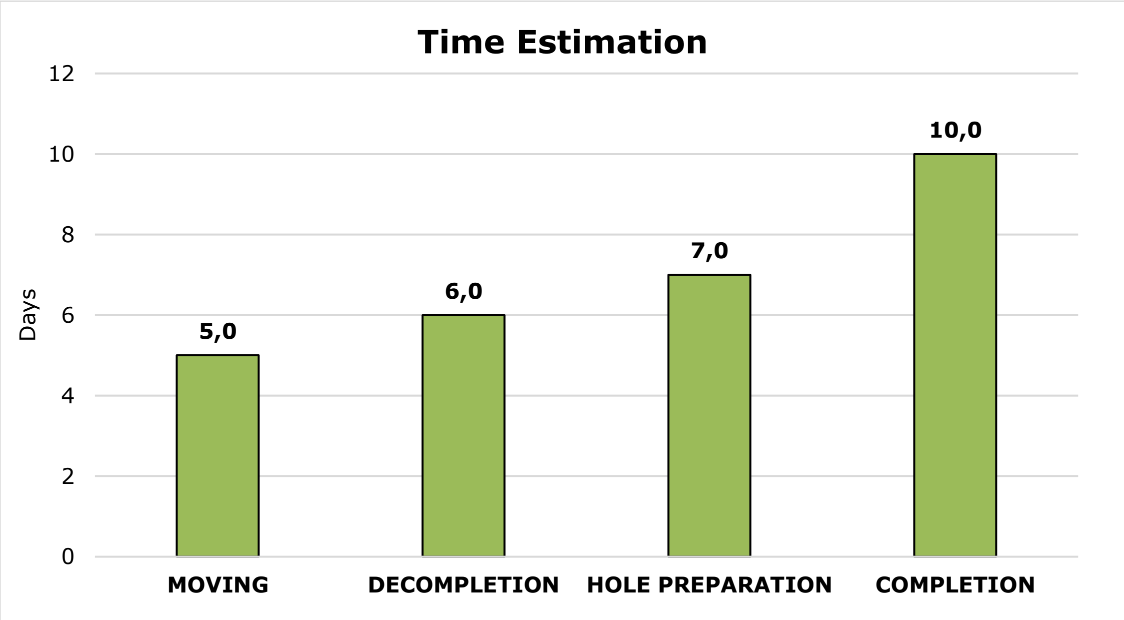
Comparing the production of wells studied in their current state and with the installation of

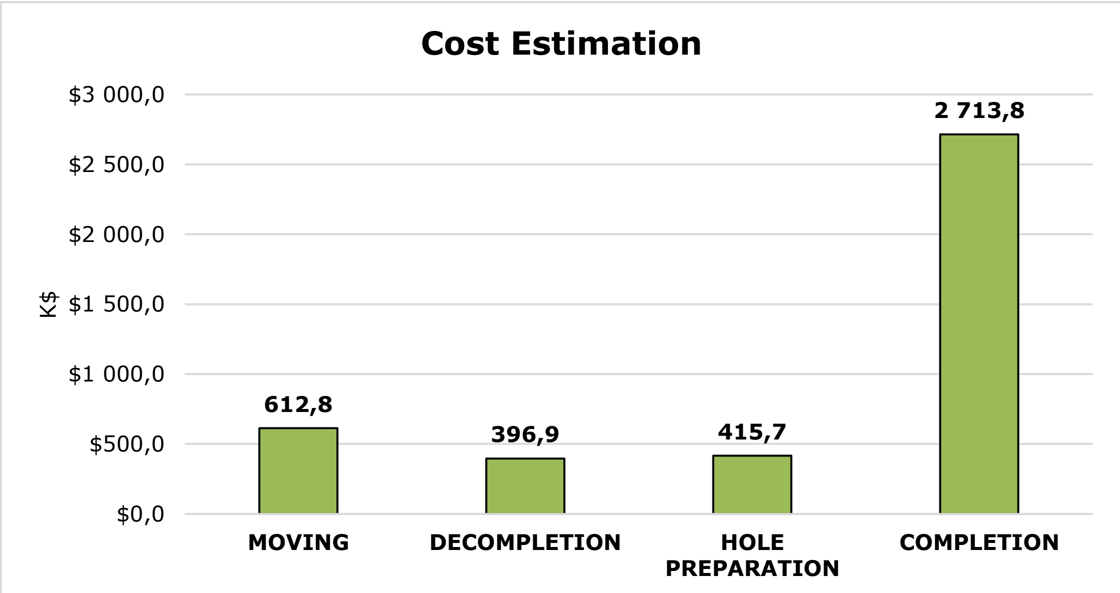
Submerged pump production improved by 6 m^3/h.

Average flow before pump installation is 14 m^3/h

Flow after pump installation is 20 m^3/h

V.7.4 TIME AND COST FORECAST Transcoil :





V.8 Result obtained：

The RERN-6 well starts to make profits from 50 days.

So economically the ESP transcoil installation project is feasible.

V.9 Conclusions and recommendations :

RERN-6 is a vertical oil producer well drilled in January 2016 as development producer in the Northern area of RERN field. The well was perforated in Upper TAGI and equipped with ESP, production started up on March 30th 2016 with an average oil rate about 1240 STBD. One month after startup, the water breakthrough was occurred and was taken an increasing trend.The well was shut-in between 31/03/2017 to 28/01/2018 due to OPEC limitation. On December 3rd 2019, the well was shut-in due to ESP failure following an electrical issue. The well is planned for workover in next July in order to replace the failed ESP and to be equipped with Transcoil ESP (Rigless ESP).

- As per ESP design, the target well oil rate is around 700 STBD. The ESP setting depth is 2400 m MD. Dilution water injection lines will be required.
- The incremental field oil reserves associated to the scenario with RERN-6 ESP replacement amount respectively to **0.83 MMSTB** at 01/2027 and to **1.80 MMSTB** at 01/2041 with respect to the Do-nothing case.

Recommendations:

➢ Although Transcoil is a new technology that has many benefits in improving and upgrading oil production, we have few precautions around it:

- It’s crucial to ensure that the pump is compatible with the fluid being pumped. Some fluids may contain corrosive or abrasive properties that can damage the pump components or effect its performance.
- ESPs are primarily used for deep well applications, but they have limitations regarding the maximum depth they can effectively operate. Factors like cable length, pump design and motor power rating may impact the depth capability of an ESP system.

- Depending on the application, ESPs can be prone the clogging due to the presence of solids or debris in the fluid. Proper filtration and maintenance practices are necessary to prevent blockages and maintain optimal pump performance.
- The coiled tubing cable can also be cutted during the pump retrieval process because of the probability of the cable being unable to withstand the tensile strength of the completion.
- The Torrus valve can also not well positioned on the right place on the ported nipples under 70m of surface.
- The operation of production through the annular will prevent us from Salt Dissolution Proces(Washover) which gatheres above the pump.

➢ Through our study and scientific research we offer some suggestions that we see may improve or develop this technology :

- We should monitor Gauges to see both the temperature and the pressure of the fluid in the pump to avoid the bubble point that can damage the pump because of gas.
- Completion components should be selected according to reservoir parameters such as : fluid viscosity, Permeability, porosity and reservoir pressure.
- Torus valve must be tested several times before and after entering it into the well also we have to do more research about it to develop it to correspond with permanent completion needs.
- It’s important to consult the manufacturer’s guidelines and recommendation specific to the Transcoil ESP or any other ESP system you are working with, as the limitations and considerations can vary depending on the specific product and application.

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[7] (Saurabh Goswami1, Dr. Tej Singh Chouhan2 1Research Scholar, 2Research Supervisor, Mechanical Engineering JJT University, Vidyanagari, Jhunjhunu–Churu Road, Jhunjhunu, Rajasthan, India)

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Author: Adam Hafiizhoh, Society of Petroleum Engineers (SPE)

Publication Year: 2019

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Publication Year: 2012

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[17] Transcoil Permanent Completion Installation WO Program sonatrach 2019

ANNEX

Annex 01: permanent completion

Baker Hughes

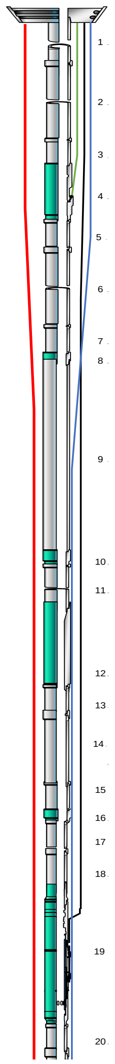
RERN-6 Permanent Completion
CWI

Customer: GSE
Field: RERN
Workstring/Tubing Size: 4-1/2" & 3-1/2"
Revision: 4
Country: Algeria
Serv. Sup:
Customer Rep: Derek Munro

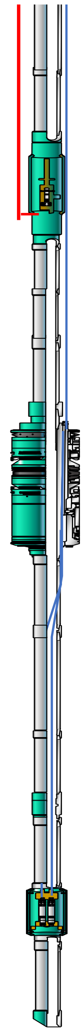
Job Type: Completion
Lease/Well: RERN-6
Casing Size: 9 5/8"
State:
SST#/Opp. ID:
Cust. Phone:

Project: Transcoil
Rig:
Casing/Liner Size: 7"
County/Parish:
District/District Phone:
Cust. Email:

(Permanent Completion - Tanscoil Project)



Proposed BHA	Equipment & Service	OD (inches)	ID (inches)	Drift (inches)	Quantity (Each)	Serial (Material) No.	Length (Meters)	Total Length (Feet / Meters)
	[1]. Tubing Hanger Assembly 4-1/2" 12.6# Vam Top Box	13.625	3.910	3.785	1.00	FMC	10.42	
	[2]. Tubing Joint 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	3.00	GSE	58.00	68.42
	[3]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	3.00	71.42
	[4]. Ported Nipple For TORUS Valve (4-1/2" 12.6# VT Box x Pin) 4.500 IN SAFETY VALVE LANDING NIPPLE BA W/BYPASS SLOTS TECH UNIT: B165-4S W/BA PROFILE 4.500 IN 12.60 LB/FT VAM TOP BOX UP RIGHT HAND THREAD UP 4.500 IN 12.60 LB/FT VAM TOP PIN DOWN RIGHT HAND THREAD DOWN 7.250 IN OD 3.812 IN ID 32.000 IN LG 3.812 IN SEAL BORE BMS-S229 SUPER 13 CR 95 MYS 29 HRC MAX BCS-A099 SURFACE TREATMENT API 14A & API 14L VALIDATION GRADE: V2 VALIDATION DATE: 15DEC98 REGULATED TRACEABLE 1,5 PSIA 20-300 DEGF WK TEMPERATURE TESTF SEE EBOM 6,000 PSI WP ABOVE 364,000 LBS CALCULATED TENSILE BAKER Q2 QUAL LVL C1 CRITICAL TO HSE (PN H827500008).	7.250	3.812	3.687	1.00	H827500008	1.00	72.42
	[5]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	1.00	73.42
	[6]. Tubing Joint 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	194.00	GSE	2288.00	2361.42
	[7]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	3.00	2364.42
	[8]. Crossover 4-1/2" 12.6# VT Box TO 5" 18# VFJL Pin CROSSOVER BUSHING 4.500 IN 12.60 LB/FT VAM TOP BOX UP 5.000 IN 18.00 LB/FT VAM FJL PIN DOWN 5.050 IN OD 3.858 IN ID 18.000 IN LG SUPER 13CR, 110 KSI MYS BMS-S229 SUPER 13 CR 110 MYS	5.050	3.858	3.733	1.00	H299896077	0.50	2364.92
	[9]. 3 x Flush Joint 5" 18# 13Cr 80Ksi VFJL Box x Pin 9m each	5.000	4.408	4.283	3.00	ALS	27.00	2391.92
	[10]. Crossover 5" 18# VFJL Pin Box TO 4-1/2" 12.6# VT Pin CROSSOVER BUSHING 5.000 IN 18.00 LB/FT VAM FJL BOX UP 4.500 IN 12.60 LB/FT VAM TOP PIN DOWN 5.050 IN OD 3.858 IN ID 18.000 IN LG SUPER 13CR, 110 KSI MYS BMS-S229 SUPER 13 CR 110 MYS	5.050	3.858	3.733	1.00	H299896081	0.50	2392.42
	[11]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	3.00	2395.42
	[12]. 30ft Seal Bore Extension, 4"-1/2" 12.6# VT Box x Pin SEAL BORE EXTENSION 80-32 4.500 IN 12.60 LB/FT VAM TOP BOX UP 4.500 IN 12.60 LB/FT VAM TOP PIN DOWN 5.000 IN OD 3.250 IN ID 382.000 IN LG BMS-S229 SUPER 13 CR 95 MYS	5.000	3.250	3.125	1.00	H499400090	9.00	2404.42
	[13]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	1.00	2405.42
	[14]. Tubing Joint 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	10.00	GSE	90.00	2495.42
	[15]. Tubing Pup 4-1/2" 12.6" S13Cr 95Ksi VT Box x Pin	4.500	3.958	3.833	1.00	GSE	3.00	2498.42
	[16]. Crossover 4-1/2" 12.6# VT Box TO 3-1/2" 9.2# VT Pin CROSSOVER BUSHING 4.500 IN 12.60 LB/FT VAM TOP BOX UP 3.500 IN 9.20 LB/FT VAM TOP PIN DOWN 4.967 IN OD 2.892 IN ID 18.000 IN LG SUPER 13CR, 95 KSI MYS BMS-S229 SUPER 13 CR 95 MYS	4.967	2.892	2.767	1.00	H299896052	0.50	2498.92
	[17]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	1.00	2499.92
	[18]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2502.92
	[19]. HCM-Plus Surface Controlled Hydrolic Sliding Sleeve HYDRAULIC CM SLIDING SLEEVE HCM-PLUS OIL BASED CONTROL LINE FLUID 3.500 IN 9.20 LB/FT VAM TOP PIN UP 3.500 IN 9.20 LB/FT VAM TOP PIN DOWN 2.812 AF PROFILE 5.250 IN OD 2.812 IN ID BMS-S229 SUPER 13 CR 95 MYS 40-325 DEGF WK TEMPERATURE 140,000 LB CALCULATED TENSILE 7,500 PSI WP ANNULUS & TUBING 10,000 PSI WP HYD CHMBR CM PKG UNITS & MSE SEAL ASSY 7,500 PSI RATING 1,500 PSI DIFF OPNG 2,250 FT-LBS TORQUE RATING 2.812 IN SEAL BORE (PN H810300083). **Return Volume**: 315ml	5.250	2.812	2.687	1.00	H810300083	3.00	2505.92



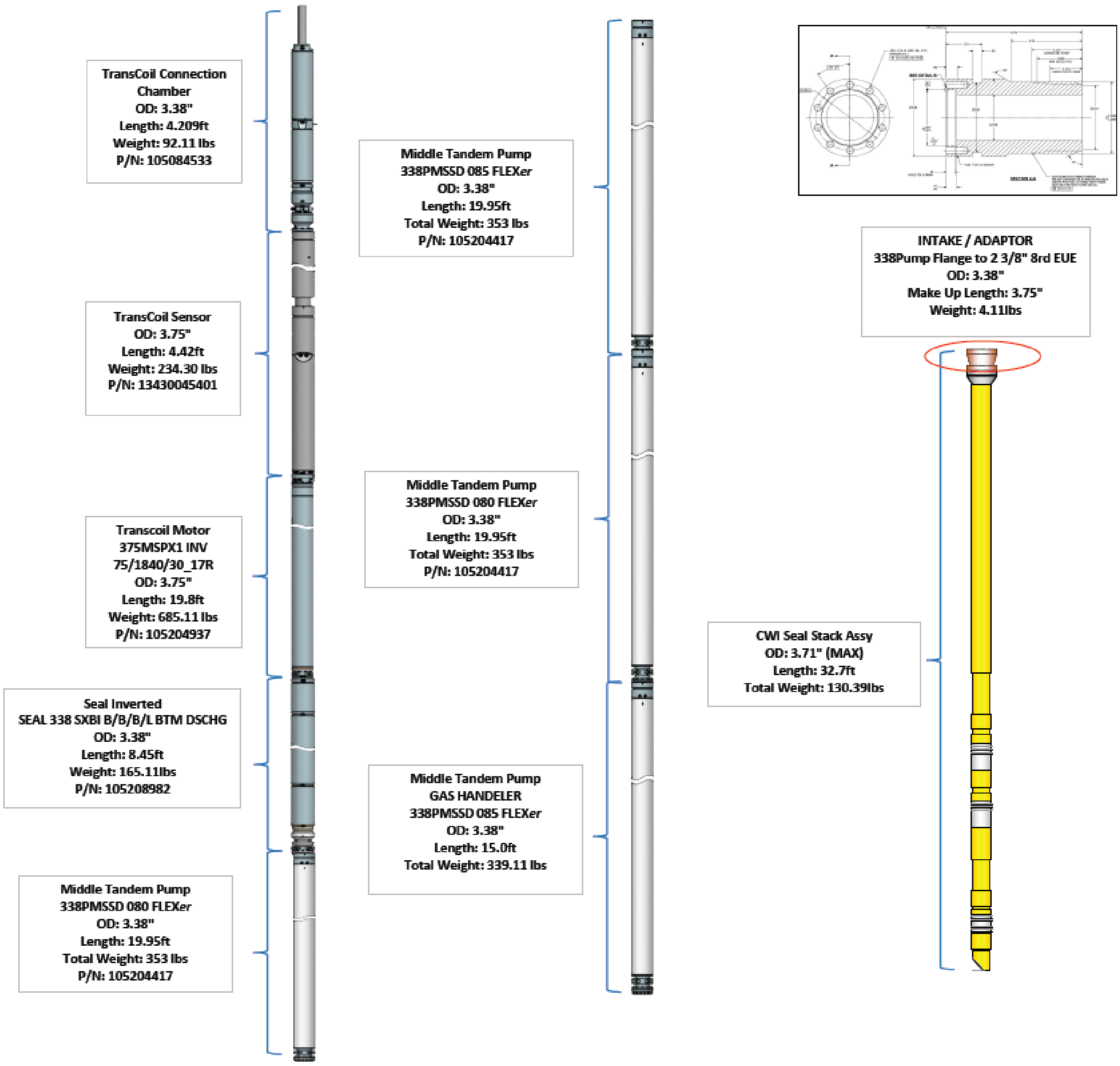
[20]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	1.00	2506.92
[21]. Tubing Joint 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	23.00	GSE	202.00	2708.92
[22]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2711.92
[23]. Suresens QPT Elite Gauge Carrier SINGLE/DUAL/TRIPLE QPT 3.500 IN PIPE 9.20 LB/FT PIPE 1.500 IN BYPASS SLOT WIDTH 0.600 IN BYPASS SLOT DEPTH 1.500 IN BYPASS SLOT WIDTH 0.600 IN BYPASS SLOT DEPTH 2 BYPASS SLOTS BMS-S230 SUPER 13 CR 110 MYS 32 HRC MAX NO BCS NO BCS DESCRIPTION VAM TOP BOX UP VAM TOP PIN DOWN TUBING PRESSURE SOURCE 1 GAUGE DEFINED PRESS SRC 2 GAUGE DEFINED PRESS SRC 3 RETAINER 2.900 IN ID 5.415 IN OD 5.415 IN RUN-IN OD 65.800 IN LG NO LOCKING NO BUMPER BAR 13,970 PSI BURST RATING 13,530 PSI COLLAPSE RATING 285,000 LBS TENSILE RATING 10,000 PSI TEST PRESSURE 3.363 IN TBG CENTERLINE TO OD PMM (PN H308090070)	5.415	2.900	2.775	1.00	H308090070	2.00	2713.92
[24]. Suresens QPT Elite Downhole PT Gauge-Single SURESENS 150 SINGLE MANIFOLD .750 IN DIA 150 DEGC CLBD TEMP 10K PSI MANIFOLD 1 CBLHD TUBING PRESSURE SOURCE 1 NO PRESSURE SOURCE 2 NO PRESSURE SOURCE 3 10390804 10390803 300 DEG F (150 DEG C)	N/A	N/A	N/A	1.00	H307030022	0.00	2713.92
[25]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	1.00	2714.92
[26]. Tubing Joint 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	9.00	2723.92
[26]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2726.92
[27]. Premier Packer Hydraulic Set w 5 Feed Through Port PREMIER PRODUCTION PACKER W/FEED THRU CUT RELEASE 598-293 07.000 IN 26.0-29.0 LB/FT CSG BMS-S229 SUPER 13 CR 95 MYS BPS-D202 (AP900) PE 90 HD PERMANENT AFLAS PE 3.500 IN 9.20 LB/FT VAM TOP BOX UP 3.500 IN 9.20 LB/FT VAM TOP PIN DOWN 5.983 IN OD 2.930 IN ID 91.800 IN LG BCS-A098 BH CWI PAINT/PROT COAT YFG REQ BPS-B201 (A40) O-RING BPS-F101 (T20) BACK-UP RINGS 7,500 PSI WP ABOVE 7,500 PSI WP BELOW 100-275 DEGF WK TEMPERATURE 7,500 PSI TEST PRESSURE W/5 X .250 IN CONTROL LINE FEEDTHROUGHS (PN H784690073)	5.983	2.930	2.805	1.00	H784690073	2.50	2729.42
[28]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2732.42
[29]. Tubing Joint 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	9.00	2741.42
[30]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2744.42
[31]. AF Top No-Go Seating Nipple SUR SET AF 2.750 AF PROFILE 2.750 IN SEAL BORE 3.500 IN 9.20 LB/FT VAM TOP BOX UP 3.500 IN 9.20 LB/FT VAM TOP PIN DOWN 3.940 IN OD 2.750 IN ID 28.000 IN LG BMS-S229 SUPER 13 CR 95 MYS (PN H835070091)	3.940	2.750	2.625	1.00	H835070091	0.60	2745.02
[32]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	1.00	2746.02
[33]. Chemical Injection Sub Ext Testable Dual Inline CHEMICAL INJECTION SUB W/NPT PORT DUAL INLINE VALVES 3.500 IN PIPE 9.20 LB/FT PIPE BMS-S229 SUPER 13 CR 95 MYS 3.500 IN VAM TOP BOX UP 3.500 IN VAM TOP PIN DOWN TUBING PORT (MUST DRIFT 2.867) 2.900 IN ID 5.565 IN OD 5.565 IN RUN-IN OD 3.512 IN TBG CNTRLINE TO OD 36.300 IN LG BCS-A098 BH CWI PAINT/PROT COAT YFG REQ NO LOCKING 12,070 PSI BURST RATING 12,080 PSI COLLAPSE RATING 246,000 LBS TENSILE RATING 10,000 PSI TEST PRESSURE NOT RETAINER 1.500 IN BYPASS SLOT WIDTH .700 IN BYPASS SLOT DEPTH 1.500 IN BYPASS SLOT WIDTH .700 IN BYPASS SLOT DEPTH 2 BYPASS SLOTS (PN H308380027).	5.565	2.933	2.808	1.00	H308380027	1.00	2747.02
[34]. Tubing Pup 3-1/2" 9.2" S13Cr 95Ksi VT Box x Pin	3.500	2.992	2.867	1.00	GSE	3.00	2750.02
[35]. Half Muleshoe Guide WIRELINE ENTRY GUIDE 3.500 IN 9.20 LB/FT VAM TOP BOX UP 1/2 MULESHOE BLANK DOWN 3.937 IN OD 2.950 IN ID 8.000 IN LG BMS-S229 SUPER 13 CR 95 MYS (PN H469210388)	3.937	2.992	2.867	1.00	H469210388	0.20	2750.22

Control Line Type and Size :

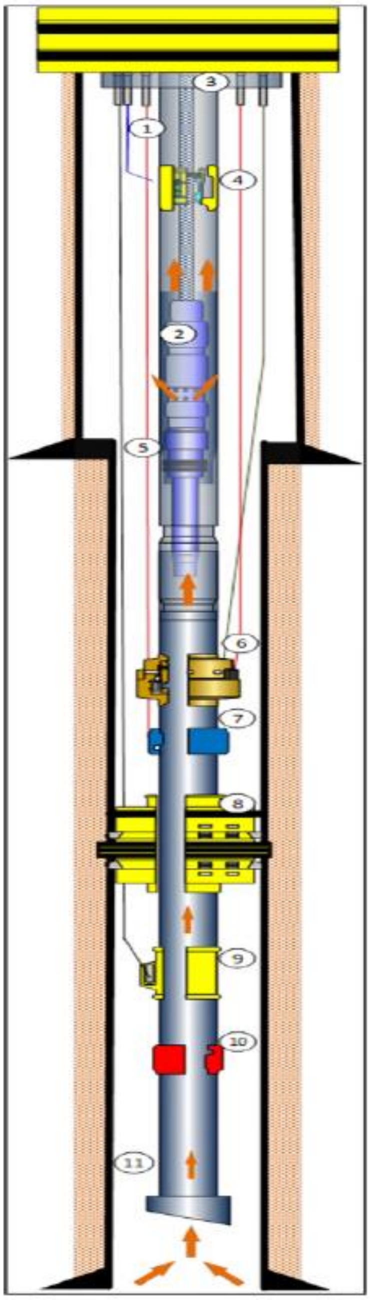
1 x ¼ ʺ Control Line for Safety Valve Ported Nipple Reel: 100m	H307960070
2 x ¼ ʺ Control Line for HCM Plus Sliding Sleeve (Flatpack) Reel: 2687m	H905210253
1 x ¼ ʺ TEC Line for Permanent Down Hole Gauge Reel: 2935m	H307980013
1 x ½ ʺ Injection Line for Chemical Injection Valve Reel: 2987m	H307960069

BHA DRAWING PREPARED BY:	*Salah Balahouane*	**TOTAL LENGTH:**	**2750.22**

Annex 02: Transcoil ESP Pump



Annex 03 : Well schematic after completion of the transcoil



1. 1.5" TransCoil with ESP Cable
2. ESP System
3. Tubing Hanger Assembly 4-1/2" 12.6# Vam Top Box x Pin
4. Ported Nipple For TORUS Valve (4-1/2" 12.6# VT Box x Pin)
5. 30ft Seal Bore for ESP Seal Assembly, 5" 15# VT Box x Pin
6. HCM-Plus Surface Controlled Hydraulic Sliding Sleeve (3-1/2" 9.2# VT Box x Pin)
7. Sure SENS QTP Gauge 3-1/2" 9.2# VT Box x Pin
8. 7" Premier Production Packer 1/4" feedthrough VT Box xPin (3-1/2" 9.2# VT Box x Pin)
9. Sure TREAT FLX Mandrel Sub C/W Check Valve (3-1/2" 9.2# VT Box x Pin)
10. AOF Ported Nipple (3-1/2" 9.2# VT Box x Pin)
11. Half Mule Shoe (3.5" 9.2# VT Box x Pin)

Baker Hughes

Annex 04 : WORKOVER COST ESTIMATE

GROUPEMENT
SONATRACH-ENI

	ADES #3	€/$= 1.4	30-Dec	4-Jan	10-Jan	17-Jan	27-Jan
CLASSES DE COUT GSE	RERN-6 - 3 1/2" Carbon Steel - OP ESP - 2868 [m]	OPERATION DAYS	MOVING	DECOMPLETION	HOLE PREPARATION	COMPLETION	TOTAL DAYS
	Full bore - Vertical	23.0	5.0	6.0	7.0	10.0	28.0
	DESCRIPTION						
6151411000	ENTRETIEN DES PISTES ET ROUTES	11,200	2,000	2,400	2,800	4,000	
6120100000	TRAVAUX DE TOPOGRAPHIE	0	0	0	0	0	
6120000000	TRAVAUX DE GENIE CIVIL	100,000	100,000	0	0	0	
6120030000	REALISATION PLATE-FORME PUITS	60,000	60,000	0	0	0	
	TOTAL GENIE CIVIL	**171,200**	**162,000**	**2,400**	**2,800**	**4,000**	
6139000000	AUTRES LOCATIONS	46,000	0	12,000	14,000	20,000	
6121300000	DEMENAGEMENTS DES SONDES DTM	375,000	375,000	0	0	0	
6121400000	MOB AND DEMOB	0	0	0	0	0	
6121000000	WORKOVER EN REGIE	547,400	0	142,800	166,600	238,000	
6112610300	INTENDANCE RESTAURATION ET HEBERGEMENT PERSONNEL TIERS	32,200	0	8,400	9,800	14,000	
	TOTAL DE TARIF RIG PAR JOUR	**1,000,600**	**375,000**	**163,200**	**190,400**	**272,000**	
6026120000	CARBURANTS ET COMBUSTIBLES FONCTIONN	0	0	0	0	0	
6026080000	CIMENT FORAGE	0	0	0	0	0	
6026070000	PRODUITS A BOUE DE FORAGE	30,000	0	20,000	5,000	5,000	
6026000000	OUTILS DE FORAGE	0	0	0	0	0	
6026060000	CASING ET TUBING	656,929	0	0	0	656,929	
6026060000	CASING ET TUBING ACCESSORIES	0	0	0	0	0	
6026065000	MATERIEL DE COMPLETION	1,065,000	0	0	0	1,065,000	
6026063000	TETE DE PUITS ACCESSOIRES	223,000	0	0	0	223,000	
6026063000	TETE DE PUITS	15,000	0	0	0	15,000	
6026690000	MATERIEL PERDU OU ENDOMMAGE	0	0	0	0	0	
	TOTAL DE MATERIEL	**1,989,929**	**0**	**20,000**	**5,000**	**1,964,929**	
6260000000	TELEPHONE ET DATA TRANSMISSION	7,000	1,250	1,500	1,750	2,500	
6122300000	SERVICES DE CIMENTATIONS	32,480	5,800	6,960	8,120	11,600	
6121210000	TRAITEMENT DEBRIS	0	0	0	0	0	
6121210000	SERVICE BOUE DE FORAGE	5,740	1,140	1,200	1,400	2,000	
6121500000	SURVEILLANCE GEOLOGIQUE DES PUITS	22,085	5,985	4,200	4,900	7,000	
6134300000	LOCATIONS DU MATERIEL ET OUTILLAGES	0	0	0	0	0	
6122064000	LOGGING ELECTRIQUE OPEN HOLE	0	0	0	0	0	
6122064000	LOGGING ELECTRIQUE CASED HOLE	50,000	0	0	50,000	0	
6134310000	LOCATION DES EQUIPEMENTS DE FORAGE DIRIGE	0	0	0	0	0	
6121620000	CLES AUTOMATIQUES	18,786	0	4,357	0	14,429	
6121200000	PRESTATIONS ANNEXES AUX FORAGES	0	0	0	0	0	
6134320000	LOCATION DES EQUIPEMENTS DE CARROTAGE	0	0	0	0	0	
6122160000	REPECHAGE D OUTILS	30,000	0	10,000	20,000	0	
6122000000	OPERATIONS ELECTRIQUES	40,000	0	40,000	0	0	
6122200000	TESTS ET ESSAIS DE PRODUCTION	15,000	0	0	0	15,000	
6122910000	OPERATIONS WIRE-LINE	22,505	0	6,287	6,678	9,540	
6122410000	COILED TUBING	55,000	0	30,000	0	25,000	
6122410000	STIMULATION AVEC COILED TUBING	0	0	0	0	0	
6175110000	ACTIVITE HSE	25,000	0	0	0	25,000	
6122800000	TRAVAUX DE COMPLETION	308,926	0	32,892	38,374	237,660	
6112610900	INTENDANCE RESTAURATION ET HEBERGEMENT DES MILITAIRES	35,532	6,345	7,614	8,883	12,690	
8906330020	REPARTITION COST DIR TECHNICQUE	98,000	17,500	21,000	24,500	35,000	
8906530002	REPARTITION COST DPT FORAGE	98,000	17,500	21,000	24,500	35,000	
8906530004	REPARTITION COST SCE GEOLOGIE	42,000	7,500	9,000	10,500	15,000	
8968340901	REPARTITION COST AUTRES PERSONNEL ET AUXILIAIRES BRN	42,000	7,500	9,000	10,500	15,000	
	TOTAL DES SERVICES	**948,054**	**70,520**	**205,010**	**210,105**	**462,419**	
6133500000	LOCATIONS DU MATERIEL DE TRANSPORT TERRESTRE	7,000	1,250	1,500	1,750	2,500	
6133510000	LOCATIONS DU MATERIEL DE TRANSPORT AERIEN	8,400	1,500	1,800	2,100	3,000	
6133500000	LOCATIONS DU MATERIEL DE TRANSPORT TERRESTRE POUR GSA	7,000	1,250	1,500	1,750	2,500	
6133500000	LOCATIONS DU MATERIEL DE TRANSPORT TERRESTRE POUR MILITAIRES	7,000	1,250	1,500	1,750	2,500	
	TOTAL DES TRANSPORTS	**29,400**	**5,250**	**6,300**	**7,350**	**10,500**	
	TOT	4,139,183	612,770	396,910	415,655	2,713,848	
	TOT APPROXIMATED	**4,200,000**	612,770	1,009,680	1,425,335	4,139,183	

Préparé par	**E.P. Ferraro / P. Angeletti**		**Date:**	**18/11/2022**	
Approbation Service	**G. Franco/ I. Soltani**		**Date:**	**18/11/2022**	

Annex 05 : General Information