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Oil Exploration and Exploitation Project for the Capahuari Sur Extension Field of the Marañon Basin in the Peruvian Jungle

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Good Job

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Team I

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ABSTRACT

The present work involves the development of an integrated multidisciplinary project, which covers the main activities of the upstream stage of the hydrocarbon industry in which the development of the Capahuari Sur Extensión field is contemplated, a lead field located in block 192 of the Marañon basin.

Currently the oil industry in Peru is sustained by exploitation projects in mature fields, so the sector requires further studies that provide new opportunities for development in prospective fields, in order to ensure the country's energy security, which is why the following study is proposed from the university, showing the capabilities of the career of Petroleum Engineering and as future professionals to inherit this challenge for the country.

The project was based on a methodology of analysis of a field in exploration, supported by the various complementary specialties that encompasses the oil industry.

Through the present study it was demonstrated that the development of the field Capahuari Sur Extensión is viable, feasible and sustainable in time in a technical-economic and environmental way for the future operator of the block.

INTRODUCTION

The jungle is characterized as the area with the greatest number of reserves and resources in Peru, being the Marañon Basin the one with the greatest hydrocarbon potential with a long history of production since 1972.

Currently, the Marañon Basin has much to be explored and exploited; this is not happening due to various technical, economic, social, and environmental factors. In addition, Peru is an importer of crude oil due to the current low production of its fields, aggravated by the lack of investment projects in the sector.

In view of this problem, the present project shows the viability study of the exploration and exploitation project of the Capahuari Sur Extensión field, currently classified as Lead (exploratory), located in block 192 of the Marañon basin.

1. ABOUT THE PROJECT

1.1 Problem Statement

The production of hydrocarbons in the jungle represents around 50% of national production in 2019; and the Marañon basin has the most development oil fields since it has the largest accumulations of reserves since their discovery; however, oil production and new discoveries are in accelerated decline; moreover, by September 2020 all the lots in the northern jungle are paralyzed, due to different factors: political, environmental, social, technical and economic, which affects the economy of the region and the country. The situation is critical by the scarcity of oil investment in exploration and exploitation projects.

1.2 Project Objective

1.2.1 General Objective

The present project looks for the development of the viability of the exploration and exploitation of the Capahuari Sur Extensión of the Marañon Basin.

1.2.2 Specific Objectives

The specific objectives are:

- Demonstrate the technical feasibility of the project.
- Demonstrate the economic viability of the project.
- Analyze the environmental, social and legal feasibility of the project
- Promote the development of prospective fields located in the Marañon Basin.

1.3 Justification

In Peru, oil and gas represent more than 70% of the country's energy consumption. However, the national production of hydrocarbons is not sufficient to cover the country's internal demand, so more and more oil has to be imported. In economic terms, in the last 20 years, the production of hydrocarbons in the country has generated 21 billion dollars in royalties, more than 10 billion dollars in taxes and more than 17 billion dollars in investments (Perupetro, 2020). Given this situation, it is of vital importance to promote new areas with hydrocarbon potential.

For these reasons, the present project of development of Capahuari Sur Extensión Field, is justified to carry out a technical-economic, legal, environmental and social analysis of the field.

2. PROJECT LOCATION

2.1 Ubication

Block 192 (ex 1AB) - Capahuari Sur Extensión Field is located within the Marañon Basin, in the northern jungle of Peru. It is located between the provinces of Datem del Marañon and Loreto of the Loreto region, districts: El Tigre, Andoas and Trompeteros. See Figure 1.

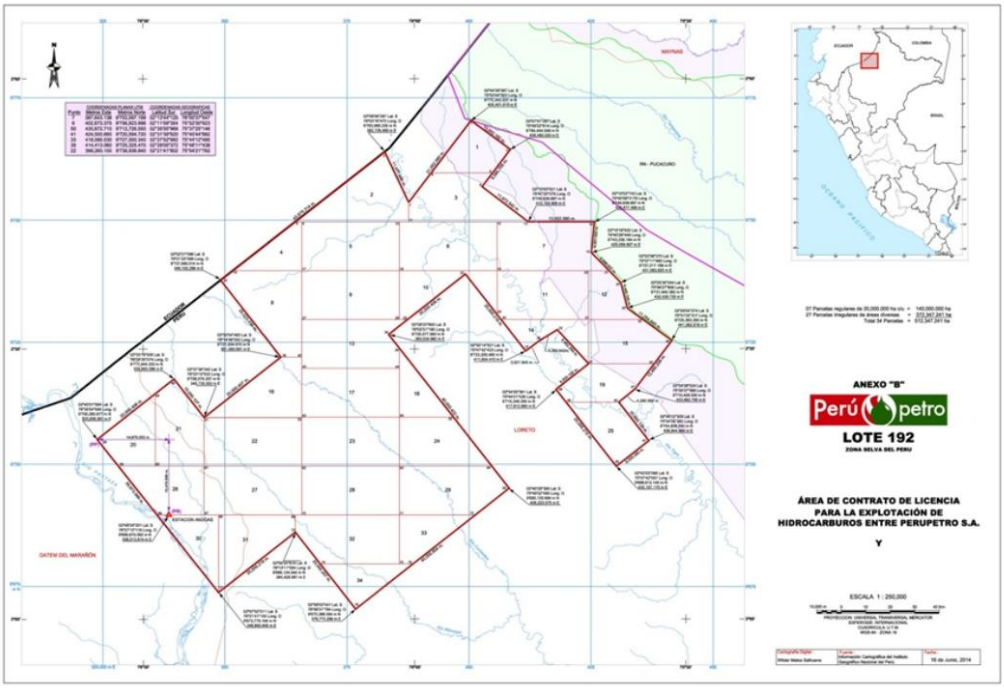

Figure 1. Location of Block 192 (source: Perupetro).

2.2 General Characteristics of Block 192

Block 192 has a current surface of 287,050.906 hectares. It is located in the department of Loreto, and in the province of Datem del Marañon.

In Block 192 the average crude oil gravity is 18° API, resulting from light crude oil deposits (30°- 40° API), heavy crude oil deposits (10.5°-16.5° API) and medium crude oil deposits (18°- 22.5° API).

In this area, 22 fields have been discovered and 13 of them were in production before the closure of the Oleoducto Nor-Peruano done by social problems in 2019. See Figure 2.

Studies done until December 2018 showed that Proven Reserves were estimated in 3480 MSTB, probable reserves were estimated in 78.9 MSTB and possible reserves in 65 MSTB (Perupetro, 2018).

2.3 Number of Current Wells

Yacimiento	N° de Pozos en Producción	N° de Pozos Productivos Cerrados	N° de Pozos (ATA)	N° de Pozos (APA)	N° de Pozos (DPA)	N° de Pozos Productivo-Inyector	N° de Pozos Inyectores	Total de Pozos
Bartra	0	15	0	1		0	0	16
Capahuari Norte	4	7	1	1		0	2	15
Capahuari Central	0	0	0	1		0	0	1
Capahuari Sur	11	13	2	8		0	2	36
Carmen	0	14	1	2		0	0	17
Carmen Central	0	0	0	0		0	0	0
Ceci	0	0	0	2		0	0	2
Dorissa	0	17	1	1		0	3	22
Forestal	0	12	3	0		0	2	17
Huayuri Norte	0	4	0	1		0	0	5
Huayuri Sur	0	12	0	1		0	2	15
Jibarito	0	15	1	0		0	1	17
Jibaro	0	6	0	0		0	2	8
Jibaro Extensión	0	0	0	0		0	1	1
Macusari	0	0	0	0		0	0	0
Pilar	0	1	0	0		0	0	1
San Jacinto	0	22	3	0		0	3	28
Shiviyacu	0	26	2	2		0	5	35
Shiviyacu Nor Este	5	0	0	0		0	0	5
Shiviyacu Sur Este	0	1	0	0		0	0	1
Tambo	2	0	1	1		0	0	4
Tigre	0	0	1	0		0	0	1
Total	**22**	**165**	**16**	**21**	**0**	**0**	**23**	**247**

Figure 2. Number of wells in Block 192 (source: Perupetro).

3. STRATEGIC ANALYSIS

The operator "ALFA ENERGY", will be in charge of development projects. It has a wide experience in the sector and has the necessary financial resources to face the present project.

3.1 Stakeholders

The main interest groups for the development of this project will be (See Figure 3):

- Investors.
- Workers and collaborators.
- Surrounding communities.
- National government, regional and local government.
- State regulatory and supervisor organisms
- Clients and suppliers.
- Financial institutions.
- Universities.

Figure 3. Outline of the interest groups (own elaboration).

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All referred to the activity of hydrocarbon exploitation, for which certain considerations will be had for the continuous communication depending on the case, due to the fact that a project of development of hydrocarbons according to the Peruvian constitution will last 40 years, for which it is necessary to generate synergy with the participants of the project for a coexistence and sustainability in favor of the project.

3.2 Internal Analysis

We will develop the strategic analysis for our operator "ALFA ENERGY" which will allow to establish and to execute the strategies that allow to create value by means of the generation of competitive advantages that are sustainable in the time.

We will analyze and understand the main activities of the company, considering the various resources such as: human talent, costs, structure and strategy of the company, among others. All this will allow us to evaluate the design of the value proposal, in order to enhance its effectiveness in the development of our operations.

Among the operations that our company, "ALFA ENERGY", plans to carry out are the tasks of searching for potential crude oil and natural gas reservoirs, the drilling of exploratory wells, and subsequently the development of the field

The value chain will be detailed in the main processes of the business units.

3.2.1 Value Chain

The oil industry value chain corresponds to the set of economic activities related to:

Upstream: It is known as the activities carried out in the hydrocarbon exploration and production (E&P) sector.
These activities include the search for potential crude oil and natural gas reservoirs, both subway and underwater, the drilling of exploratory wells, and subsequently the delimitation and exploitation of the wells that bring the crude oil or natural gas to the surface.

Midstream: The midstream is also known as the transport stage, whether by pipeline, ship, tanker, or truck, it also includes the storage of hydrocarbons. For example, this stage makes use of pipelines and other transportation systems that can be used to move crude oil from production sites to refineries in order to deliver the various refined products to downstream distributors.
Midstream is also involved in natural gas pipeline networks that collect gas from natural gas processing plants and transport it to downstream consumers.

Downstream: Downstream, the transformation stage, refers to the tasks of refining crude oil and processing and purification of natural gas, as well as marketing and distribution of crude oil products and natural gas.

This set of activities is also made up of the regulation and administration of these.

In Figure 4 The value chain of the oil industry is shown in a general way.

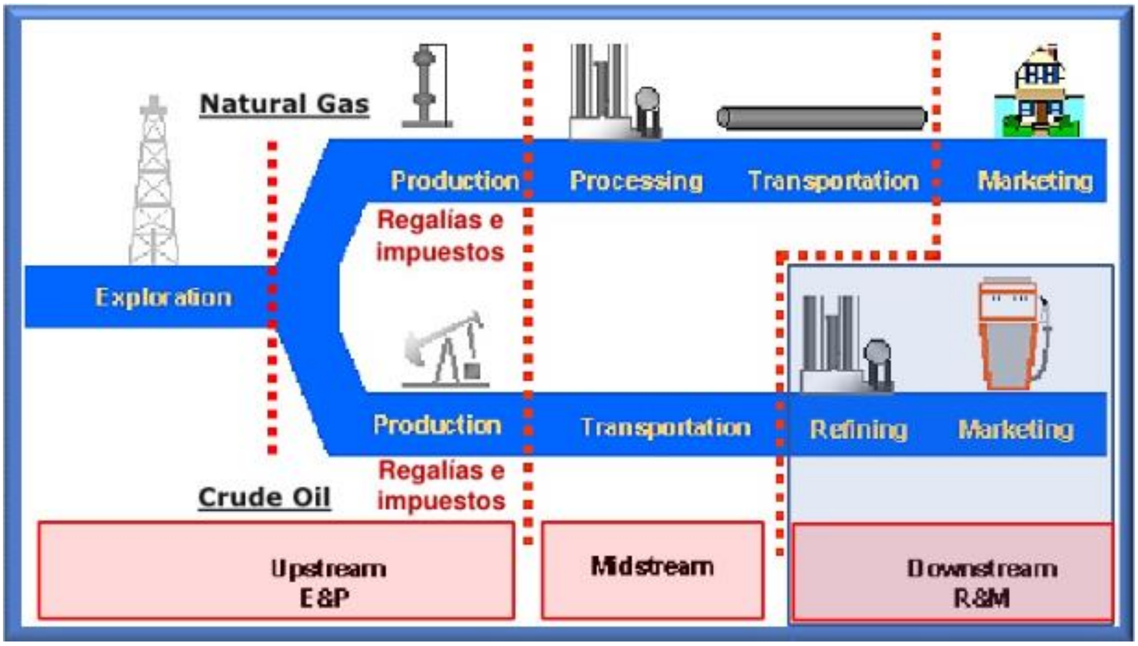

Figure 4. Oil and natural gas Value Chain (Roberto Dobles, IEEE, 2012).

Our operator "ALFA ENERGY" will concentrate on participate in the initial part of the value chain of the sector, covering certain activities from the exploration and exploitation of hydrocarbons until the sale of crude oil.

All of these essential activities for making a product or providing a value chain service fall into two groups:

Primary line activities

The main objective of these activities is to add value and create a competitive advantage. These are directly related to the production and commercialization of the product.

Supporting Activities

Its main role is to increase the effectiveness of primary activities. There are four of them and when you increase the level of any of them, you manage to benefit at least one of the primary activities.

They are essential, because they also add value to the product.

In the Figure 5shows the value chain of the operator "ALFA ENERGY" where it is specified all the activities and operations that will be carried out for the development and exploitation of the Capahuari Sur Extensión Field.

Support activities

Company Infrastructure
-Management of the equipment (separators, pumps, valves, etc.). Adequate environments for workers.
-Maintain the safety of the company's productive assets by carrying out maintenance activities on the equipment and installations.
-Management of the company's financial resources. Control of the income and expenses of our company.

General Management and Human Resources
-Selection of managers and heads of each area.
-Training courses for staff and support areas.
- Management of employee development and performance.

Technology development
- Modeling of the field using 3D seismic technology.
- Reservoir modeling by means of simulators.
- Measurement systems during drilling.

Shopping
Purchase and storage of equipment and materials:
-Safety system for wellheads, valves, flanges, electro-submersible pumps, etc.
-Casing, Tubing, Production shaft, chokes, etc.

Primary Activities

Inbound logistics	**Operations**	**Outbound logistics**	**Marketing y Ventas**	**After Sales Service**
Reception and storage of all materials, equipment and data that will make possible the production of hydrocarbons: -Interpretation of seismic data and reservoir data -Drill pipe, Tubing, ESP unit, etc.	- Hydrocarbon drilling and production activities. -Gathering systems. -Hydrocarbon separation process. -Maintenance and control of activities.	Transport to to the storage tanks, points of sale or inspection point where we will sell our crude.	- Visits and meetings with buyers or clients (Petroperu). -Commercial proposal.	Activities related to maintaining product value.

Figure 5. Alfa Energy value chain (own elaboration).

3.3 External Analysis

3.3.1 Porter´s Five Forces

➢ **New potential participants:**

Our company is dedicated to Upstream sector, we have a long history of discovering new successful areas of exploitation in other countries, which allows us to be qualified as a top company, a condition required for the bidding process. Besides, we add our huge capital injection for the investment in this project, guaranteeing the execution of all technical studies in the field. In this way We reduce interest of other operators for this Block.

➢ **Bargaining power of buyers:**

Petroperu is our only buyer and we will be its important supplier, so we will seek greater transparency in the negotiations with our client, for it we will use the strategy of concentration of Porter.

➢ **Bargaining power of suppliers:**

We have good relationships with international suppliers, so we ensure a reduction in costs and an optimal service, and we ensure their participation with us in future projects. Among these service companies we have:

- Schlumberger
- Petrex
- National Oilwell Varco
- Halliburton
- Baker Hughes

➢ **Threat of substitute products:**

Currently, national oil production does not supply the Talara refinery, so there would be no threat of a substitute; rather, we seek to cover the existing gap in national production that would provide energy security to the country. In addition, we seek to generate trust, good value for money and empathy with our consumers in order to provide the best added value to our product. Faced with the threat of renewable energy, we will ensure that the energy used in the production of one barrel be used as efficiently as possible.

- **Rivalry among competitors:**

As there is an internal gap in the production of crude oil for the refinery, there is no rivalry in the sale.

3.3.2 PESTEL

The analysis of the general environment gives us the tools, which, from the perspective of the economic and social system, affect the situation of the company. To carry out this analysis we will consider the political, economic, social, technological, environmental and legal variables (PESTEL). See Table 1.

Variable	Environmental Trends	Impact on Industry	Threats / Opportunity
Politics	High levels of corruption in public management	Investments come to a standstill.	Threats
	Modification of the Organic Law of Hydrocarbons	Attractive to investors.	Opportunity
Economics	Peru has a great constant growth in the GDP	Continuity in Project investment by the State.	Opportunity
	High oil price volatility in recent years	Cuts in project investments. Closing of operations.	Threats
Social	Hiring of local labor by law	Acceptance by the population due to job generation.	Opportunity
	Previous consultation	Slows down the process of awarding contracts for lots and creates uncertainty of approval.	Threats
Technologic	Promotion of technological development.	Increases process efficiency.	Opportunity
	New renewable energies.	Migration of oil companies to energy companies.	Threats
Environmental	North Peruvian Pipeline Leaks	Mistrust of industry in the face of possible contamination.	Threats
	Creation of new protected areas	Rejection of the exploitation of fields near protected areas.	Threats
Legal	Law 26221	Promotes the development of hydrocarbon activities.	Opportunity

Table 1. PESTEL analysis (own elaboration).

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3.4 SWOT Analysis

Figure 6. SWOT analysis of the project: strengths, opportunities, weaknesses and threats in order to establish strategies (own elaboration).

3.5 Strategies

In this section, the operator "ALFA ENERGY" knows perfectly the legal and social context that Block 192 addresses. The approval of the extension of the oil exploitation contract of Block 192 (Loreto) with Frontera Energy of Peru, leads us to carry out a series of future strategies for our area of interest. Establishing the appropriate strategies will allow us to achieve the objectives in the financial, customer, innovation and learning perspectives, as well as the internal perspectives of the company.

As a starting point, 2 viable options are handled for the strategic plan of exploration and exploitation of the block.

The first option is to form a strategic alliance with PETROPERU. We know that the state-owned company has begun the process of selecting a strategic partner for the transfer of a percentage share in the hydrocarbon exploitation license contract for Block 192. The first results of the economic balance do not guarantee the viability of the project, it shows us a scenario of limited income for the company ALFA ENERGY.

Therefore, the operating company will be the only one in charge of the lot, in all its competent value chain (Upstream & Midstream). Our company as a corporation, must work under a trajectory according to its Strategic Plan and thus improve or strengthen the development of its activities. Thus, one of the main topics in our portfolio is the creation of programs for the conservation of the environment and the due respect to the rights of the offset communities.

The stage of energy transition that we will go through is influenced by a more environmentally friendly action. Therefore, as a future operator, we propose a policy of continuous communication and dialogue with the nearby inhabitants and discuss the impact that may be being generated to their locality and how these are being remedied or avoided. ALFA ENERGY's effective strategy is to present reports every six months of the activities and measures taken by the company in the area of environmental protection (fauna and flora), as well as the projects for the environmental management of its water resources.

The technical and engineering strategies to carry out the development of the exploration and exploitation project of Block 192, is guaranteed as a leading company in the hydrocarbon sector, with great economic support and an operational presence in several countries.

The application of the above-mentioned strategies has the sole purpose of increasing the national production of hydrocarbons in Peru, as well as contributing with its energy development.

4. TECHNICAL STUDY

4.1 Geology

4.1.1 Location of the Field

Block 192 (ex 1AB) - Capahuari Sur Extensión Field is located within the Marañon oil basin, in the northern jungle of Peru. It is located between the provinces of Datem del Marañon and Loreto in the Loreto region, districts: El Tigre, Andoas and Trompeteros. See Figure 7.

Block 192 has been operated by Frontera Energy Company since 2015. In August 2015, Perupetro signed a service contract with Pacific Stratus Energy of Peru, the former name of the company in charge of the oil block.

It is worth mentioning that the Capahuari Sur Field, an already exploited oil field, maintains an analogy with our field of study. Therefore, the technical calculations will start from this base.

Figure 7. Location of Block 192 (source: Perupetro).

The Capahuari Sur field is the largest field in Block 192. It was discovered in 1972, commercial production began in February 1978 and reached a maximum production peak of 72,815 BOPD in May 1979 with all producing wells in natural flow. This field produces from the Vivian and Chonta reservoirs at depths of 3,597m and 3,819m, respectively.

4.1.2 General Geology of the Basin

The Marañon basin is a sub-Andean basin that extends north from the Ucayali basin, through Peru to Ecuador and Colombia, where it is known as the Oriente and Putumayo basins, respectively. The Basin evolution begins in the late Permian through the early Triassic with an important Extensional event that dissected the underlying Paleozoic platform and basement rocks into a series of roughly northwest-southeast grabens and half grabens. See Figure 8.

In the western extremes, deep rift basins were formed containing sequences of syn-rift continentally derived sediments that are overlain by Triassic to Jurassic age transitional marine unit (sabkha) dominated by carbonate and evaporite reservoirs. This, in turn, is covered by continental regressive red beds of the Jurassic age.

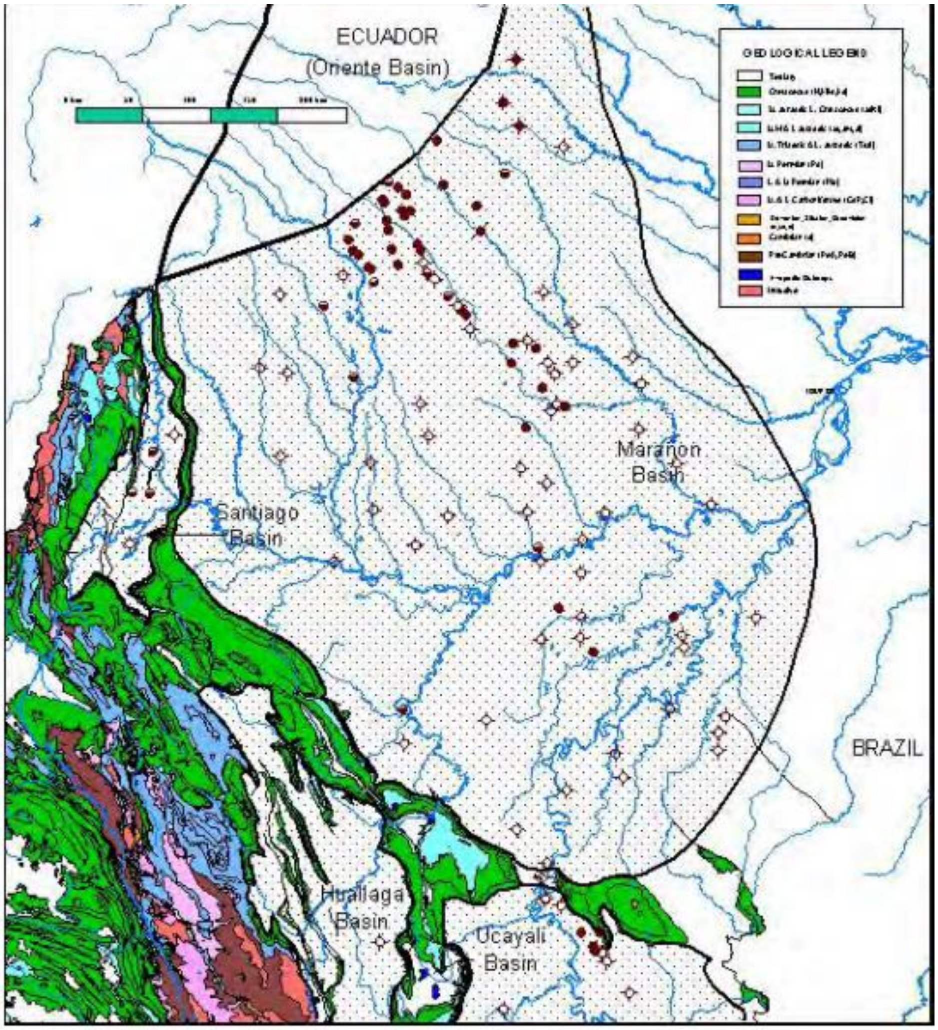


Figure 8. Geology of the area of Marañon / Santiago / Huallaga basin (source: Marañon Basin Technical Report PARSEP).

The eastern Marañon, on the other hand, is very different, as the remains of the Extensional event from the late Permian to the early Triassic were chased only as a series of half grabens (sloping fault blocks) containing a preserved section of Paleozoic rocks within the lows with the early Cretaceous Peneplanation removing the majority of the intermediate sediments. In eastern Marañon, the amount of preserved Paleozoic rocks below the Cretaceous decreases considerably from south to north to the point where the Cretaceous is seen over overlapping affinity rocks in the basement as it approaches the border with Ecuador.

The Marañon basin began to assume its current configuration through a sequence of tectonic events that extends through the Tertiary and culminated in the Miocene until near Recent with the highly deforming Quechua I, II and III orogenies. The current western margin was formed through a complex combination of high-angle faults related to keys, basin inversions, and thin-skinned deformation fronts that now separate the Marañon basin from the Santiago basin to the northwest and the Huallaga basin. to the southwest.

4.1.2.1 Regional geology

The geological evolution of the greater area of the Marañon basin is controlled by two regional tectonic systems recognized in the sub-Andean basins of Peru. The first, the pre-Andean system, encompasses three cycles of Ordovician, Devonian, and Permo Carboniferous ages that cover the Precambrian basement of the Guyanese and Brazilian shields. The second, the Andean System, began with the start of subduction along the western margin of Peru. It encompasses several mega stratigraphic sequences and numerous minor sedimentary cycles, ranging from the late Permian to the present.

4.1.2.2 Andean system

The Andean System began simultaneously with the beginning of the Andean subduction. An important change in the tectonic regime along the northwestern boundary of the South American plate promoted isostatic rearrangements. On a global scale, the initial phase of the Andean System developed during the Pangea rupture (M. Barros and E. Carneiro, 1991). The development of the

Andean subduction zone during the late Permian period to the early Triassic is supported by geological information compiled by Audebaud, et. Alabama (1976) along the Eastern Cordillera of Peru, where they recognized a Permo-Triassic continental volcanic arc. The Lavasen volcanic formation, seen in nonconformist outcrops underlying the Mitu Group west of the Huallaga basin (Series A: National Geological Chart, INGEMMET Bulletin No. 56, 1995) could be a remnant of this arc. The Lavasen Formation is also found intruding into older rocks such as the Ambo Formation. Its lower limb is a volcanic-sedimentary sequence with interspersed red clastics. The upper limb is composed of thick lava flows and gaps.

4.1.3 Petroleum System

A Petroleum System includes all the geological elements and processes that are essential for an accumulation of oil and gas to exist. (See Figure 9).

The essential elements of a petroleum system include:

- Source rock.
- Reservoir rock.
- Seal rock.
- Overburden rock.
- Trap formation
- Generation-migration-accumulation of hydrocarbons.

These essential elements and processes must be placed correctly in time and space so that the organic matter in a source rock can become an accumulation of oil. A petroleum system exists wherever all these essential elements and processes are known to occur or are thought to have a reasonable chance or probability of occurring (Magoon and Beaumont, 1999).

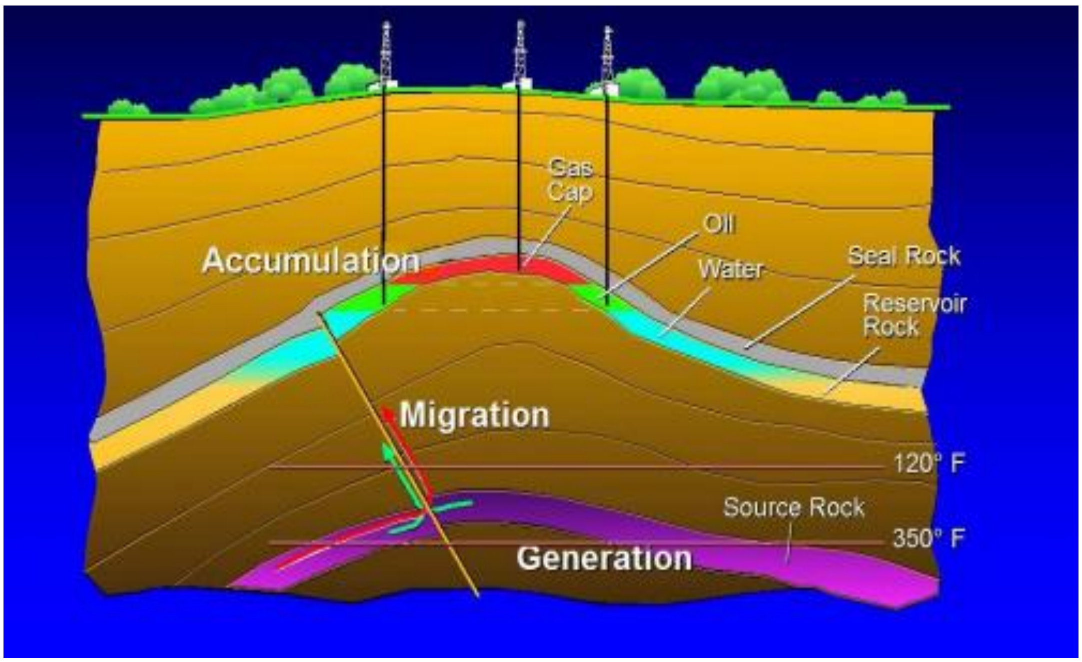


Figure 9. Elements and processes of the petroleum system.

4.1.3.1 Petroleum system - Capahuari Sur Extensión area - Block 192- Marañon basin

With previous studies of surface and subsoil geology, biostratigraphy studies and with the help of experts in descriptions of geological units of the Marañón Basin, the Petroleum System for the Capahuari Sur Extensión area was elaborated, making an analogy with the data that is they have of the Capahuari Sur field and the Marañón Basin.

The accumulations of oil and associated gas in the Capahuari Sur Extensión field are related to two known petroleum systems. These are the Pucará Petroleum System and the Chonta Petroleum System.

The Pucará oil system encompasses oil accumulations in the Chonta reservoir. The Chonta Petroleum System involves the Late Cretaceous Chonta source rock and the resulting oil accumulations in the Vivian and Chonta reservoirs.

Next, we describe the essential elements and processes of each of the petroleum systems.

4.1.3.1.1 Pucará petroleum system

For the Pucará Petroleum System, the following interpretation is presented (which is summarized in Figure 10).

- The Pucará formation of the Triassic-Jurassic is an oil-source rock for the Cretaceous sandstones of Chonta. However, there are several other potential reservoirs for Pucará oil such as the Vivian Cretaceous, Cushabatay and Agua Caliente sandstones and the Sarayaquillo Jurassic sandstones.
- The Chonta formation is the reservoir rock for the Pucará oil. Although the Cushabatay, Agua Caliente and Vivian sandstones are known to show good to excellent reservoir quality.
- The shales of the Raya Formation form the seal rock for the Cushabatay reservoirs and the shales of the Chonta Formation form the seal rock for the Agua Caliente reservoirs. Some clayey levels of Chonta form the seal rock of the Chonta sands (since there is presence of clays between sand and sand of the Chonta Formation).
- The trap styles for oil accumulations of Pucará origin are structural, stratigraphic or structural stratigraphic.
- It is presumed that the oil migration took place during the Paleocene-Middle Miocene (65-12 Ma).

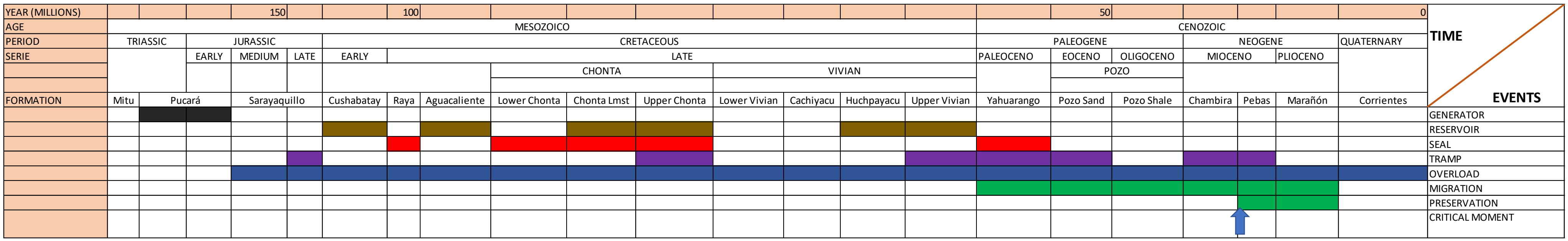


Figure 10. Pucará-Chonta petroleum system for the Capahuari Sur Extensión area (own elaboration).

4.1.3.1.2 Chonta petroleum system

Its main characteristics are:

- The Chonta Formation of the Late Cretaceous is the source rock unit for the Chonta oil system. The upper Chonta shales and the Chonta limestone unit contain the source rocks.
- Oil from Chonta is mainly known from the Chonta and Vivian Cretaceous sandstone reservoirs.
- The Lower Tertiary Yahuarango shales form the seal of the upper Vivian sandstones.
- Trap styles for accumulations in the Chonta and Vivian Cretaceous reservoirs are structural, stratigraphic, or structural stratigraphic. Structural traps are smooth anticline shapes with subtle closures.
- The generation, migration and accumulation of hydrocarbons began in the late Oligocene and continues to the present (30-0 Ma).

Figure 11 shows the Chonta-Vivian petroleum system for the Capahuari Sur Extensión Field.

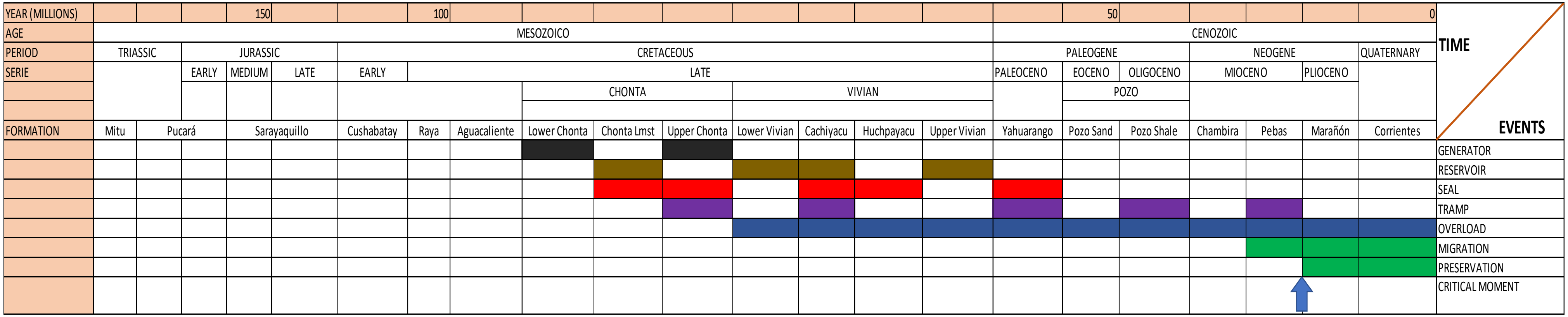


Figure 11. Chonta-Vivian petroleum system for the Capahuari Sur Extensión area (own elaboration).

4.1.4 Structural Map of the Capahuari Sur Extensión Field

The structural model is the definition of the geological structure that describes a reservoir, which is characterized by the relationship with the stresses and deformations that determine the type and orientations of the structure that forms it; trap, faults, and limits that the reservoir presents, in other words, a structural model is the architecture or skeleton that makes up a reservoir.

Defining the reservoir structure corresponds to the initial stage of geological modeling, for which we were provided with a structural map of the Capahuari Sur Extensión (CSE) field for each formation, we describe them below.

4.1.5 Structural Model

The objective reservoirs are Vivian and Chonta, so each body will have its own structural map observed in Figure 12 (Structural map of the Vivian Formation) and in Figure 13 (Structural map of the Chonta Formation).

Structurally, we define the Vivian reservoir as an anticline with a longitudinal axis in a northwesterly direction and of greater proportion to the transverse axis, the closure is observed on its 4 sides of the structure, that is, the filling area is limited by a water level and is given by a level curve at -3405.8 masl.

Structurally, we define the Chonta reservoir as an anticline with a longitudinal axis closer in size to the transverse axis, unlike the Vivian formation structure, similar to a dome structure without being completely one, the structure also presents the closure on its 4 sides limited by a water level and is given by a level curve at -3654.5 masl.

Figure 12. Structural map of the Vivian formation - Capahuari Sur Extensión (source: Perupetro).

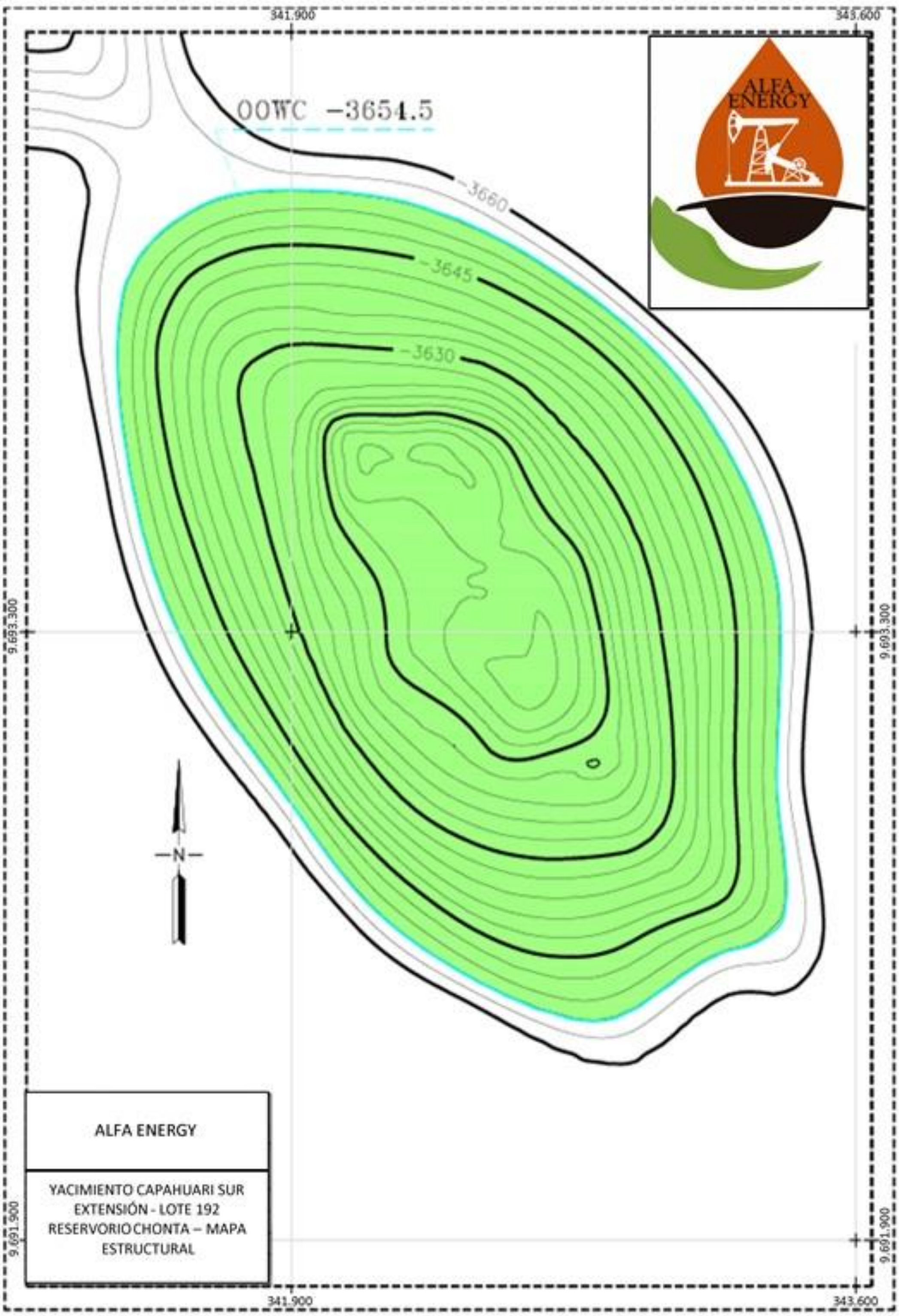


Figure 13. Structural map of the Chonta formation - Capahuari Sur Extensión (source: Perupetro).

4.1.6 Net Sand Map of the Capahuari Sur Extensión Field

In the net sand map of the Vivian formation, we observe that at the top of the anticline, the net oil sand has its greatest thickness, which is 27 meters, as shown in Figure 14.

Figure 14. Net Sand map of the Vivian formation - Capahuari Sur Extensión (source: Perupetro).

In the net sand map of the Chonta formation, we observe that at the top of the anticline, the net oil sand has its greatest thickness, which is 12 meters, as shown in Figure 15.

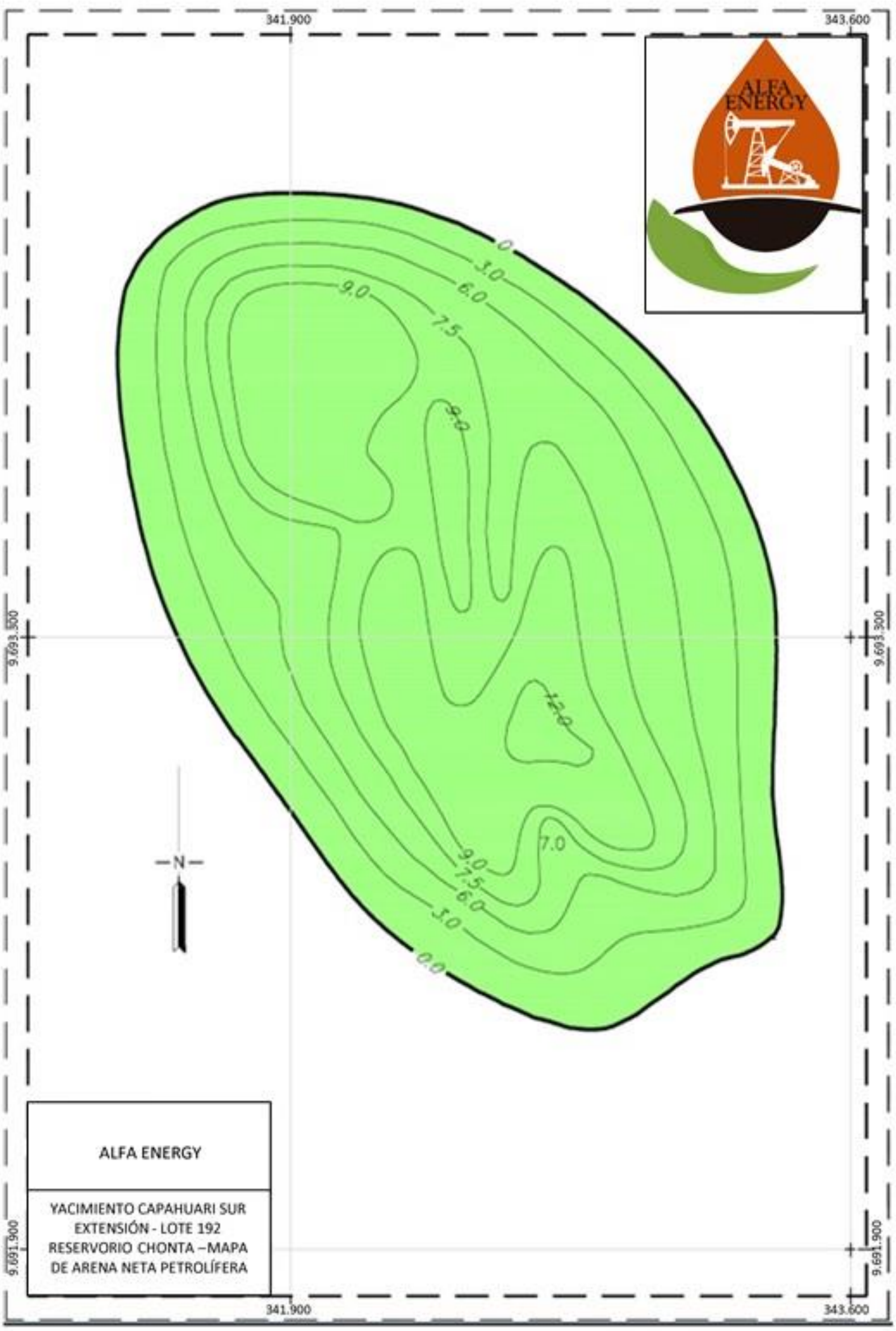


Figure 15. Net Sand map of Chonta formation - Capahuari Sur Extensión (source: Perupetro).

4.1.7 Stratigraphic Column Present in Block 192

The stratigraphy is distributed within the following era: Mesozoic: These sequences are represented by two important periods: the Triassic-Jurassic and the Lower-Upper Cretaceous. We will focus in the Cretaceous period because it has Vivian and Chonta formations which are our cases of study to develop this project. See Figure 16 and Figure 17.

- **Chonta Formation:**

In the Marañon basin, the lower chonta formation is made up of sandstones, limestones and shales associated with a nearby deltaic system on a carbonate platform (Jaillard, 1995); middle Chonta is characterized by a sequence of limestone and gray to black shales of carbonate platform (Gil, 2002); Upper chonta made up of marine shales (Jaillard, 1995). This formation is the objective of most of the wells in the Marañon Basin.

- **Vivian Formation:**

In the Marañon basin, it is made up of somewhat carbonaceous quartz sandstones, and to a lesser extent by siltstones and gray to black shales.

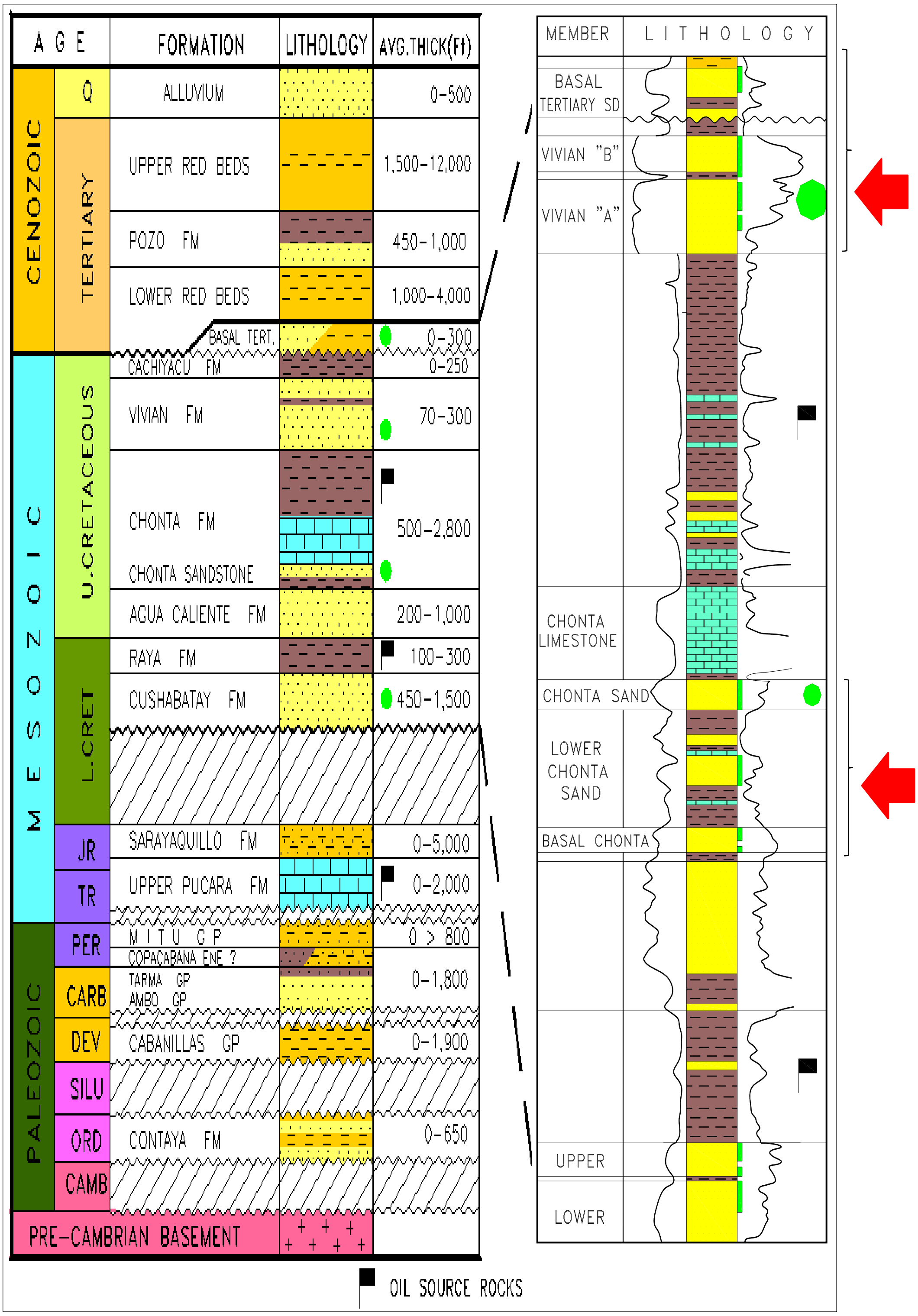


Figure 16. Lithological column of the Marañon basin (source: Technical report of the Marañon basin, PARSEP).

4.1.8 Stratigraphic Column of the Marañón Basin

AGE	PARSEP NE Peru		Marañon Oxy	Marañon Petroperu	Huallaga	Ucayali	Santiago	
Q		Corrientes		Corrientes				
TERTIARY		Marañon	Upper Red Beds	Marañon	Capas Rojas Superiores	Ipururo		Nieva
		Pebas		Pebas				Upper Puca
		Chambira		Chambira		Chambira		
	Pozo	Pozo Shale	Pozo Shale	Pozo Shale	Pozo	Pozo Shale	Pozo	Pozo Shale
		Pozo Sand	Pozo Sand	Pozo Sand		Pozo Sand		Pozo Sand
		Yahuarango	Lower Red Beds	Yahuarango	Capas Rojas Inferiores	Yahuarango	Lower Puca	Santiago SS
CRETACEOUS	Vivian	Upper Vivian	Basal Tertiary	Upper Vivian	Cachiyacu	Casa Blanca		Cachiyacu
		Huchpayacu	Cachiyacu	Huchpayacu		Huchpayacu		
		Cachiyacu		Cachiyacu		Cachiyacu		
		Lower Vivian	Vivian	Lower Vivian	Vivian	Vivian		Vivian
	Chonta	Upper Chonta	Chonta shale	Pona	Chonta	Chonta		Chonta
				Lupuna				
				Upper Cetico				
		Chonta Lmst	Chonta Lmst	Caliza				
			Chonta Sand					
		Lower Chonta	LowerChontaSand	Lower Cetico				
			BasalChontaSand					
		Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente		
		Raya	Raya	Raya	Raya	Raya		
		Cushabatay	Cushabatay	Cushabatay	Cushabatay	Cushabatay		Cushabatay
JURAS	Sarayaquillo	Red Beds	Sarayaquillo	Sarayaquillo	Sarayaquillo	Sarayaquillo	Sarayaquillo	Red Beds
		Evaporitic Unit						Evaporitic Unit
	Pucará	Condorsinga	Pucará	Pucará	Pucará	Pucará	Pucará	Condorsinga
		Aramachay						Aramachay
TRIAS		Chambara						Chambara
		Mitu	Mitu	Mitu	Mitu	Mitu		Mitu
PERM		Ene	Ene	Ene	Ene	Ene		Ene
		Copacabana	Copacabana	Copacabana	Copacabana	Copacabana		Copacabana
CARB		Tarma	Tarma	Tarma		/Tarma		?
		Ambo	Ambo	Ambo	Ambo	Ambo		
DEV		Cabanillas	Cabanillas	Cabanillas		Cabanillas		
ORD		Contaya	Contaya	Contaya	Contaya	Contaya		
Basement								

Figure 17. Stratigraphic column of the Marañon basin (source: Technical report of the Marañon basin, PARSEP).

4.1.9 Sedimentary Model of the Basin

In the case of the sedimentary model, we refer to the way in which the basin was formed, to describe the sedimentary environment, to describe the type of lithology of the formation strata, mainly of the formations that contain traces of hydrocarbon formation (Kerogen type I, II or III, mainly).

In order to be more certain about the sedimentary environment, information on the lithology, geometry of the sedimentary body, sedimentary structures, network of paleocurrents and fossil content must be obtained. Being the lithology of great importance not only for its composition but also for its texture because their information on the transport of the strata is obtained.

Next, Figure 18 shows the migration of oil from Chonta and Pucará from the Santiago Basin to the Marañón Basin, which gives us some idea of the sedimentary medium of formation.

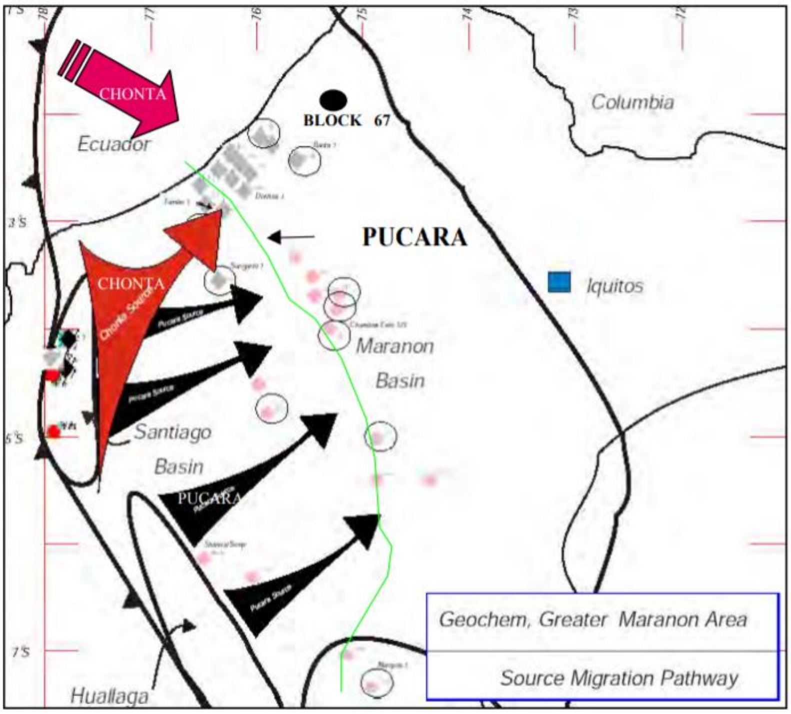


Figure 18. Chonta and Pucara oil migration (source: PARSEP).

In Figure 19 we can see the stratigraphic chart of the Marañón Basin and its limits to the NE with the Guyano Shield and to the SW with the Santiago Basin (Campanquiz Mountains), the sub-Andean trend of hydrocarbons is observed. Basin. We observe that the deepest area is to the SW side, this is due to the presence of the Andes Mountains and what was previously a marine environment of sedimentation and that with the passage of time it was eroding.

In this project, there are some information obtained from Perupetro which helped us to develop this project, taking that into consideration and base on TOC and Rock Evaluation data, nine formations from the Ordovician to the Tertiary age can be identified as potential source rocks in the Marañn basin, whose lithology is as follows:

Tertiary

Oil shale formation with Kerogen type II, which becomes locally a Kerogen type I, this source rock may be restricted to the Santiago and Huallaga basins, as low TOC has been recorded in most of the Marañon basin.

Cretaceous

The Chonta formation contains Kerogen type II and type II-III in the north and northwest areas of the Marañón basin.

The Raya, Agua Caliente and, Cushabatay formations also have characteristics of origin, but are mainly of Kerogen type III and III-II.

Triassic / Jurassic

The Pucará Group is a bituminous carbonate with rich organic shale interspersed in sections, found in the westernmost areas of the Marañón and Huallaga Basin.

Paleozoic

The Contaya and Cabanillas formations are generally extremely mature, but still have moderate TOC values in the SE of the Marañón Basin.

Ambo / Tarma-Copacabana formations consisting of shales and marine carbonates, located in the southern part of the basin.

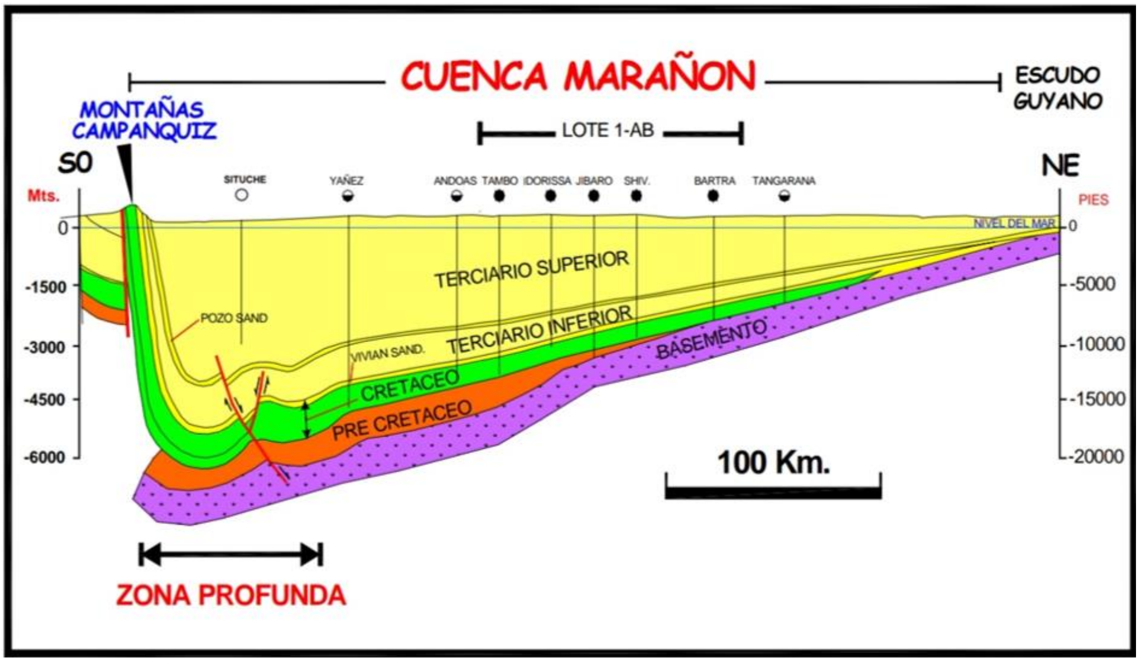
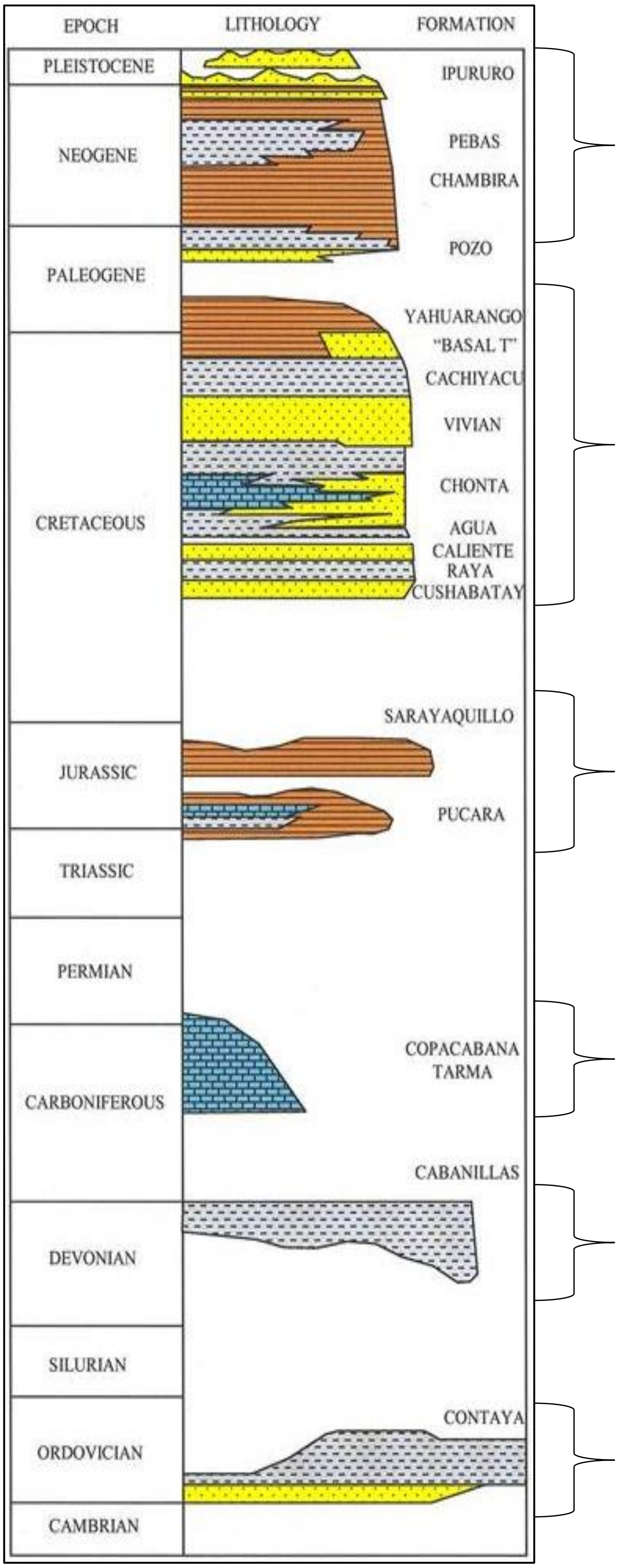


Figure 19. Generalized stratigraphic chart of the Marañón basin.

4.1.10 Sedimentary Cycles

Now we will see the formation of the sedimentary cycles and the lithology that composes it, being the Vivian and Chonta formations the most relevant and of greatest importance due to be the reservoirs of this project. See Figure 20.



Paleogene and Eocene to recent.

Shallow marine transgressive clastics (Pozo Fm).

Fluvio-estuarine clastics (Vivian and Cachiyacu Fms).

Clastics and transgressive marine carbonates (Chonta Fm).

Volcanic compounds, carbonates from marine platforms, continental evaporites and clastics (Pucara Gp and Sarayaquillo Fm).

Marine classics and carbonates (Tarma-Copacabana GPS).

Middle to late Devonian marine clastics (Cabanillas Gp), fluviodeltaic clastics (Ambo Gp).

Marine classics of the Ordovician middle, (Contaya Fm).

Figure 20. Sedimentary cycles of the Marañon basin (source: PARSEP).

- **Vivian Formation:**

The Vivian formation is made up of 2 reservoirs: Vivian B and Vivian Principal or Vivian Inferior. The size of the grains varies from medium to coarse. The clasts present from regular to good selection, with a good degree of sphericity.

Environment: Regarding the deposition environment, it is an environment close to the coastline, and this is supported by the presence of terrigens and fossilized plant material within sediments.

In addition to the characteristics considered and the high porosity values, as well as the size of the pores and their permeability, they make it a good prospect for an oil reservoir.

- **Chonta Formation:**

The Chonta formation is made up of three reservoirs: Basal Chonta, Lower Chonta and Main Chonta. These 3 reservoirs were deposited in a marine environment and are interspersed with marine shales and limestone. From a lithological point of view, these are medium to exceptionally coarse-grained sandstones.

The Chonta formation configures a transgressive marine face that represents the maximum entry of the Cretaceous Sea on the continent, giving rise to the deposition of sediments.

The Chonta sandstones present productivity problems in some wells in certain fields, which is why in certain cases stimulation and even fracturing are necessary.

4.2 Reservoir Engineering

A basic study of reservoirs will be carried out, starting with the petrophysical characterization of the field, then the construction of a PVT fluid model based on correlations and adjusting with values from offset fields, then a model of decline curves analysis and a model for the behavior of the aquifer for each reservoir, Finally, a productive behavior of the fluids in the reservoirs is predicted, identifying the type of dominant fluid flow present in each case, thus determining the final recovery (Np) per formation and of the field; and with it, locating the wells that will allow the maximum recovery of the commercial oil volumes in the 20 years of the contract.

For the present project we will use the data from offset fields such as Capahuari Sur, Capahuari Norte and Dorisa; based on the principle of analogy applied when studying a new field, due to their proximity to the study field, Capahuari Sur Extensión (CSE).

4.2.1 Petrophysics Evaluation

The first stage to characterize the reservoir will be to evaluate the petrophysical properties based on representative well logs from a offset field.

Since the Capahuari Sur Extensión (CSE) reservoir does not have any well because it is an area under exploration, a representative well log from the Capahuari Sur field will be used, to interpretate the petrophysical of Vivian reservoir.

Using IP v3.5 ® software, we conveniently plotted the well loggings of a representative offset field (see Figure 21). We relied on the structural map and punching reports to ensure that the sand identified in the logs is Vivian's formation.

The reservoir was characterized using the following methodology:

- It is zoned in 6 bodies in an interval of <12093'-12070'>, based on the GR and SP logs, trying to identify sand and shale.
- Based on the properties of each zone, a Shale Volume curve is generated through the GR and SP curves.

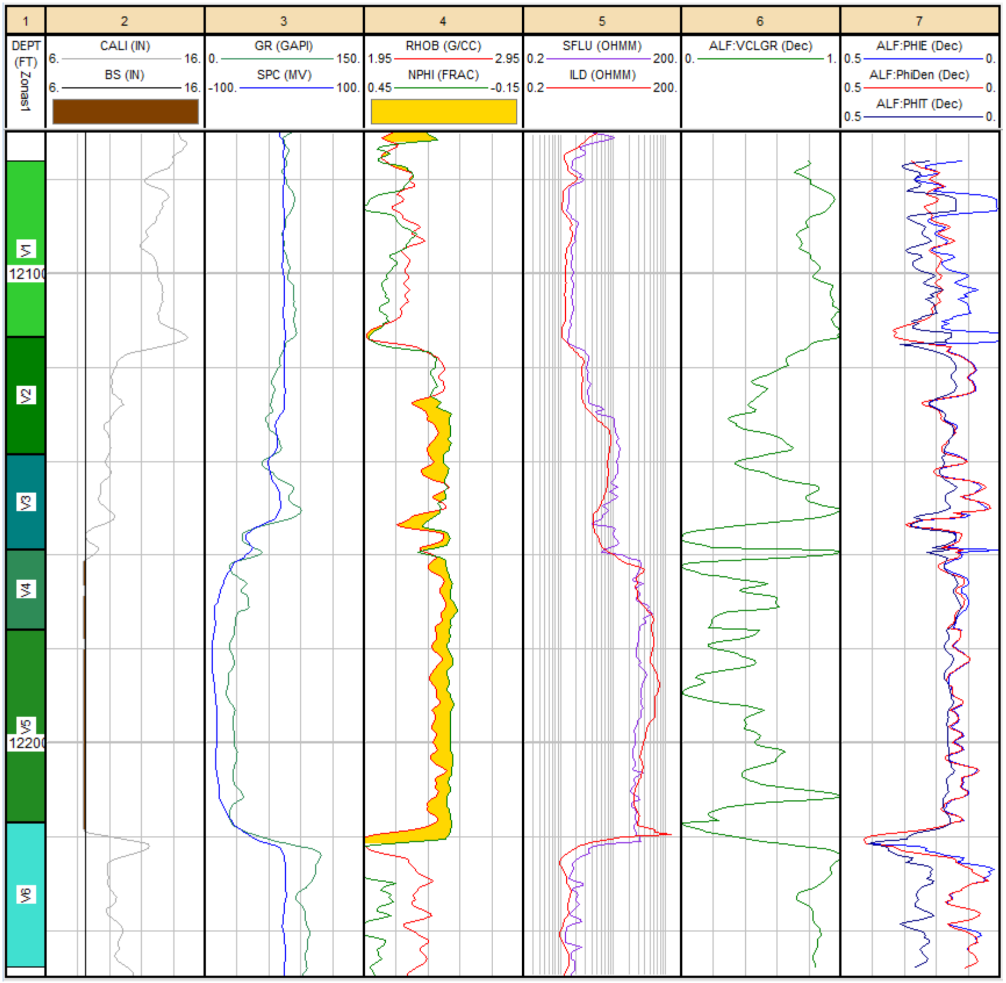


Figure 21. Shale zoning and volume 1A 42-1.

- The IP tool was used to calculate the Water Saturation and Effective Porosity, based on these results, we can generate a representative synthetic lithological curve of the zones. See Figure 22.

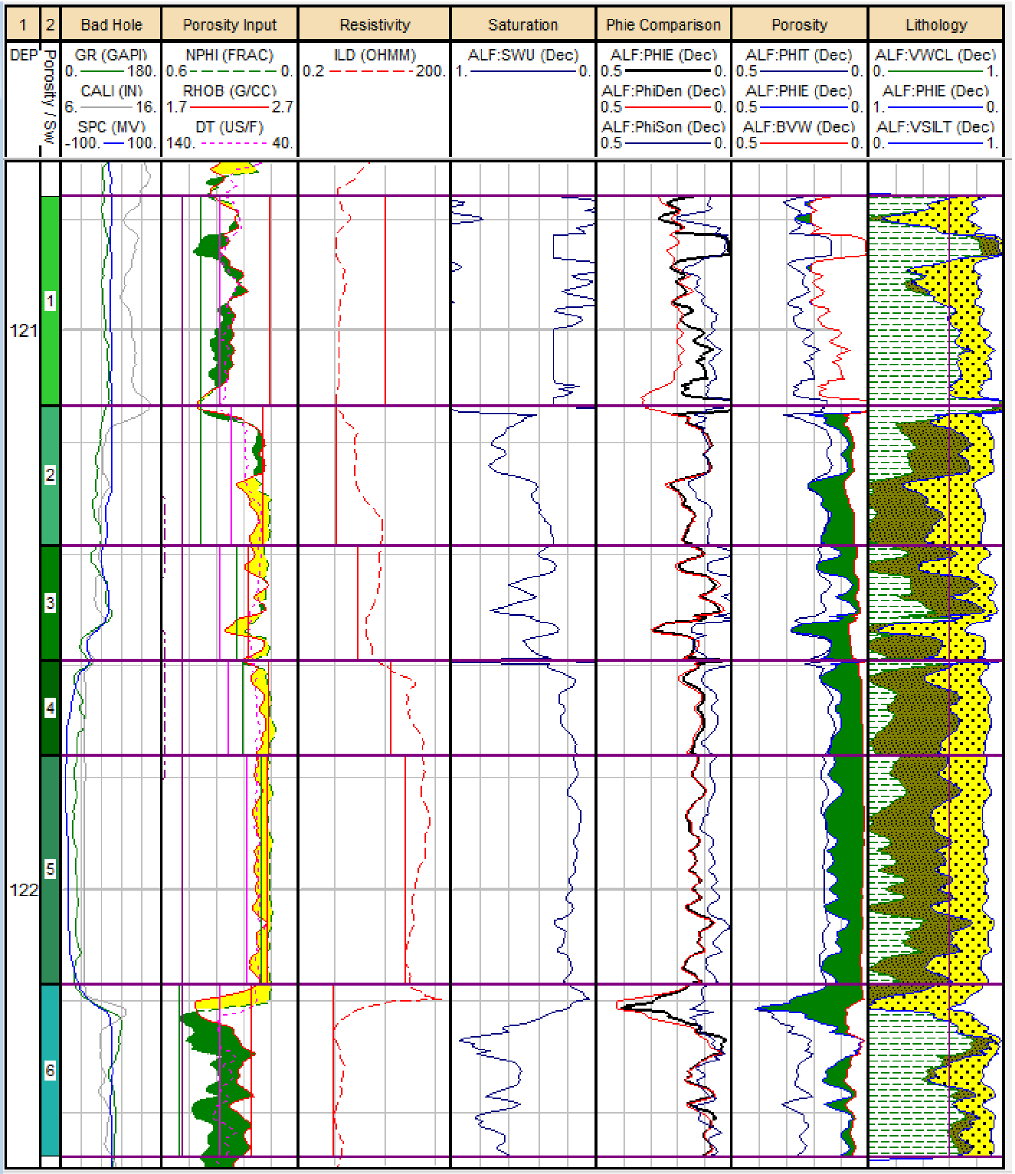
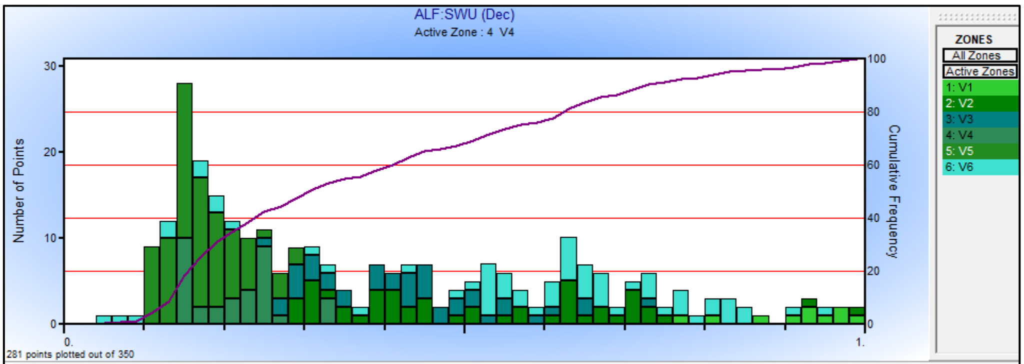


Figure 22. Porosity curves, water saturation and synthetic lithology log.

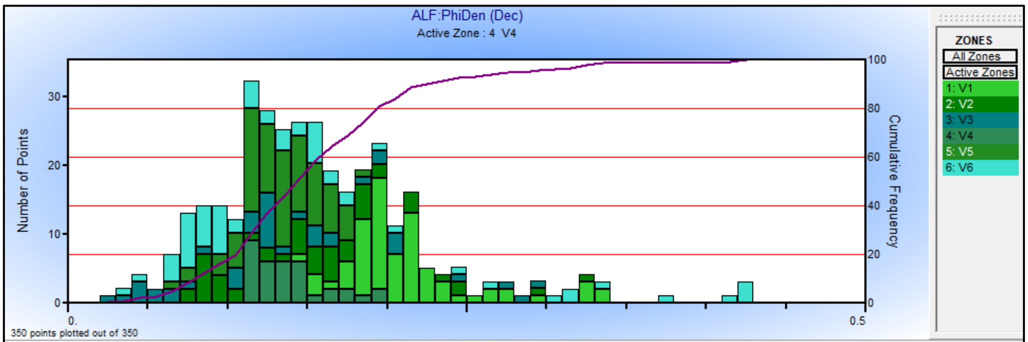
- Synthetic porosity curves are built through the 3 logs that allow calculating porosity (Neutron, density and sonic), we choose the porosity curve from the density log because the well has no washout.

The results obtained through this methodology are presented by making Histogram WOR of the petrophysical properties for each zone, reporting the average value for each zone: (See Figure 23, Figure 24, Figure 25)



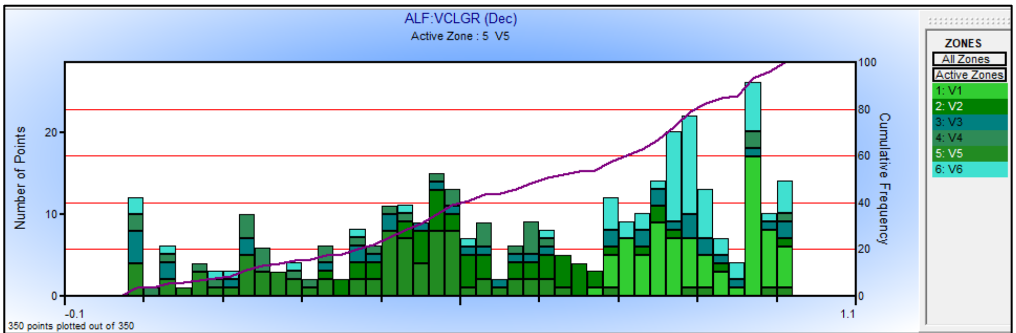
Curve	Well	Zone	Top	Bottom	Min	Max	Std Dev	Mean	Mode	P10	P50	P90
ALF:SWU	1A_42-1	V1	12076 FT	12113.5 FT	0.77821	0.9803	0.069539	0.91071		0.81151	0.9257	0.97907
ALF:SWU	1A_42-1	V2	12113.5 FT	12138.5 FT	0.29902	0.99639	0.17287	0.51791		0.3154	0.44557	0.71961
ALF:SWU	1A_42-1	V3	12138.5 FT	12159 FT	0.25869	0.72812	0.11798	0.42826		0.28381	0.42052	0.59363
ALF:SWU	1A_42-1	V4	12159 FT	12176 FT	0.14038	0.33593	0.056164	0.21335	0.15	0.14382	0.21974	0.26323
ALF:SWU	1A_42-1	V5	12176 FT	12217 FT	0.10669	0.29203	0.042994	0.17251	0.15	0.11946	0.16596	0.2255
ALF:SWU	1A_42-1	V6	12217 FT	12248 FT	0.048361	0.94057	0.22699	0.56769	0.53	0.17097	0.62978	0.8233
Overall					0.048361	0.99639	0.23964	0.3911	0.15	0.14204	0.31557	0.7338

Figure 23. Histogram of the water saturation calculation for the 6 zones.



Curve	Well	Zone	Top	Bottom	Min	Max	Std Dev	Mean	Mode	P10	P50	P90
ALF:PhiDen	1A_42-1	V1	12076 FT	12113.5 FT	0.14173	0.33533	0.041249	0.21354	0.195	0.17865	0.20438	0.27402
ALF:PhiDen	1A_42-1	V2	12113.5 FT	12138.5 FT	0.074893	0.32946	0.057871	0.15426	0.085	0.082867	0.15521	0.21943
ALF:PhiDen	1A_42-1	V3	12138.5 FT	12159 FT	0.027622	0.29704	0.067624	0.1338	0.125	0.049308	0.12306	0.20719
ALF:PhiDen	1A_42-1	V4	12159 FT	12176 FT	0.11085	0.1946	0.024417	0.13872	0.115	0.11291	0.13539	0.1795
ALF:PhiDen	1A_42-1	V5	12176 FT	12217 FT	0.066207	0.18444	0.024312	0.134	0.115	0.10313	0.1326	0.16459
ALF:PhiDen	1A_42-1	V6	12217 FT	12248 FT	0.037632	0.42717	0.10199	0.15212	0.075	0.071039	0.117	0.31936
Overall					0.027622	0.42717	0.065973	0.15793	0.115	0.084514	0.14847	0.22891

Figure 24. Histogram of the porosity calculation for the 6 zones.



Curve	Well	Zone	Top	Bottom	Min	Max	Std Dev	Mean	Mode	P10	P50	P90
ALF:VCLGR	1A_42-1	V1	12076 FT	12113.5 FT	0.71136	1.0013	0.086438	0.86484	0.944	0.75093	0.85772	0.96926
ALF:VCLGR	1A_42-1	V2	12113.5 FT	12138.5 FT	0.29375	1.0011	0.15856	0.56401	0.464	0.37175	0.53702	0.77827
ALF:VCLGR	1A_42-1	V3	12138.5 FT	12159 FT	0.0002826	1	0.31975	0.54877	0.008	0.056448	0.55616	0.92828
ALF:VCLGR	1A_42-1	V4	12159 FT	12176 FT	0.0012251	1.0016	0.26231	0.38911	0.608	0.060629	0.36702	0.62728
ALF:VCLGR	1A_42-1	V5	12176 FT	12217 FT	0.0003558	1.0001	0.21066	0.38679		0.1135	0.40662	0.61382
ALF:VCLGR	1A_42-1	V6	12217 FT	12248 FT	0.0003558	1.0031	0.24724	0.76136	0.848	0.33379	0.83867	0.94594
Overall					0.0002826	1.0031	0.28451	0.60351	0.944	0.17267	0.64194	0.94451

Figure 25. Histogram of shale volume calculation for the 6 zones.

The results of this interpretation are presented in the following table for each zone: See Table 2.

Zona	SW	Porosity (RHOB)	VCL-GR
V-1	0.911	0.214	0.751
V-2	0.518	0.154	0.372
V-3	0.428	0.134	0.056
V-4	0.213	0.139	0.061
V-5	0.173	0.134	0.114
V-6	0.568	0.152	0.334

Table 2. Petrophysical interpretation results.

Based on the petrophysical analysis already made (Table 2) to a well analogous to the field of study; this section is complemented with the average permeability values extracted from offset fields, as well as the values for the petrophysical properties of Chonta Reservoir. See Figure 26.

Yacimiento (CAPAHUARI NORTE)	A	Tope	Base	Ht	Hn	Ø	GOR	K	Sw
	(Acres)	(ft)	(ft)	(ft)	(ft)	(%)	(SCF/Bls)	(mD)	(%)
VIVIAN	3550.9	11911.0	11995.0	84.0	23.7	14.5	41	300	40.59
CHONTA	4152.9	12868.0	12905.5	37.5	13.6	12.8	640	40	33.6

Yacimiento (CAPAHUARI SUR)	A	Tope	Base	Ht	Hn	Ø	GOR	K	Sw
	(Acres)	(ft)	(ft)	(ft)	(ft)	(%)	(SCF/Bls)	(mD)	(%)
VIVIAN	6000	11795.0	11900.0	105.0	54.2	16.5	41	1500	16
CHONTA	6189	12636.0	12690.0	54.0	21.9	12.0	690	100	24

Yacimiento (DORISSA)	A	Tope	Base	Ht	Hn	Ø	GOR	K	Sw
	(Acres)	(ft)	(ft)	(ft)	(ft)	(%)	(SCF/Bls)	(mD)	(%)
VIVIAN	4493	10639.0	10746.0	107.0	31.0	18.2	98	1000	31.2
CHONTA	3977	11401.0	11436.0	35.0	15.3	12.8	485	200	33.63

Figure 26. Properties of offset fields (Source: Perupetro).

We can show a representative value of the petrophysical properties that we will find in the Vivian reservoir based on the petrophysical analysis already done, the results are summarized in Table 3, taking the value of the V-5 layer for water saturation and based on the analogy we propose the petrophysical properties for Chonta; the permeability value is proposed from the information of offset fields for each reservoir. See Table 3.

	Hn (ft)	φ (frac)	Sw (frac)	K (mD)
Vivian	54.2	0.15	0.16	1500
Chonta	21.9	0.12	0.24	100

Table 3. Summary of petrophysical properties by formation of the Capahuari Sur Extensión field.

4.2.2 Fluid Model

The fluid model in the reservoirs of Capahuari Sur Extensión, was developed based on correlations of the literature of Reservoir Engineering, and then adjusted by the known properties of the fluids given for our field for each formation, these analogies will be necessary for the determination of a static and dynamic model of the reservoir in order to infer more accurately the initial behavior of the flow of the reservoirs.

A representative PVT was constructed by correlations (see Equation 1) for each reservoir based on the basic properties of the reservoirs (Ahmed, 2016):

- Solubility Ratio, Standing Correlation:

$$R_s = \gamma_g \left[\left(\frac{p}{18.2} + 1.4 \right) 10^x \right]^{1.2048}$$

$$x = 0.0125\text{API} - 0.00091(T - 460)$$

Equation 1. Standing correlation for solubility ratio calculation.

- Volumetric Formation Factor, Standing Correlation: (See Equation 2)

$$B_o = 0.9759 + 0.000120\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25(T-460)\right]^{1.2}$$

Equation 2. Standing correlation for the calculation of the volumetric formation factor.

- Isothermal Compressibility of Crude: (See Equation 3)

  Petrosky-Farshad Correlation, for P > Pb:

$$c_o = 1.705 \times 10^{-7} R_{sb}^{0.69357} \gamma_g^{0.1885} \mathrm{API}^{0.3272} (T-460)^{0.6729} p^{-0.5906}$$

Equation 3. Petrosky-Farshad correlation for the calculation of the compressibility of supersaturated crude.

  - McCain Correlation, for P < Pb: (See Equation 4)

$$c_o = \exp(A)$$

$$A = -7.633 - 1.497\ \ln(p) + 1.115\ \ln(T) + 0.533\ \ln(\mathrm{API}) + 0.184\ \ln(R_{sp})$$

Equation 4. McCain correlation for the calculation of the compressibility of low-saturated crude.

- Dead Viscosity, Glass Correlation: (See Equation 5)

$$\mu_{od} = \left[3.141\left(10^{10}\right)\right](T-460)^{-3.444}[\log(\mathrm{API})]^A$$

$$A = 10.313[\log(T-460)] - 36.447$$

Equation 5. Glass correlation for dead viscosity calculation.

- Viscosity at saturation point: (See Equation 6)

$$\mu_{ob} = (10^{a})(\mu_{od})^{b}$$

$$a = R_s\left[2.2\left(10^{-7}\right)R_s - 7.4\left(10^{-4}\right)\right]$$

$$b = 0.68(10)^{c} + 0.25(10)^{d} + 0.062(10)^{e}$$

$$c = -0.0000862R_s$$

$$d = -0.0011R_s$$

$$e = -0.00374R_s$$

Equation 6. Glass correlation for calculating viscosity to Pb.

Based on the data from reservoirs and basic petrophysics, the mentioned correlations were used for the construction of the PVT of the field at each pressure at the same reservoir temperature. Finally, values such as Isothermal Compressibility, dead viscosity and compressibility factor were adjusted so that the PVT has a more representative value. (See Figure 27 and Figure 28).

Vivian PVT:

petrophysics	
Porosity	16.5%
Inicial Water Sat	16.00%
Actual Oil Sat	84.00%
Actual Gas Sat	0.00%
Reservoir	
API	34
Ggas	0.65
Rsi (scf/bbl)	41
Tr (°F)	282
Inicial Pr (psi)	5130
Reser Grad (psi/ft)	0.57
Espec. Oil Grav.	0.85
Oil Dens. lb/ft3	53
PVT	
Pb (psi)	349
Rs act (scf/stb)	41
Bob (bbl/stb)	1.1068
Boi	1.0969
Boact (bbl/stb)	1.0969
Uo dead oil (cp)	0.98
Uob (cp)	0.91
Cf (psi-1)	3.9E-06
Coi (psi-1)	1.9E-06
Cgi (psi-1)	1.9E-04
Cw (psi-1)	3.7E-06
Init Oil Dens. (lb/ft3)	49
bub Oil Dens. (lb/ft3)	49
Ctinicial(psi-1)	9.2E-06

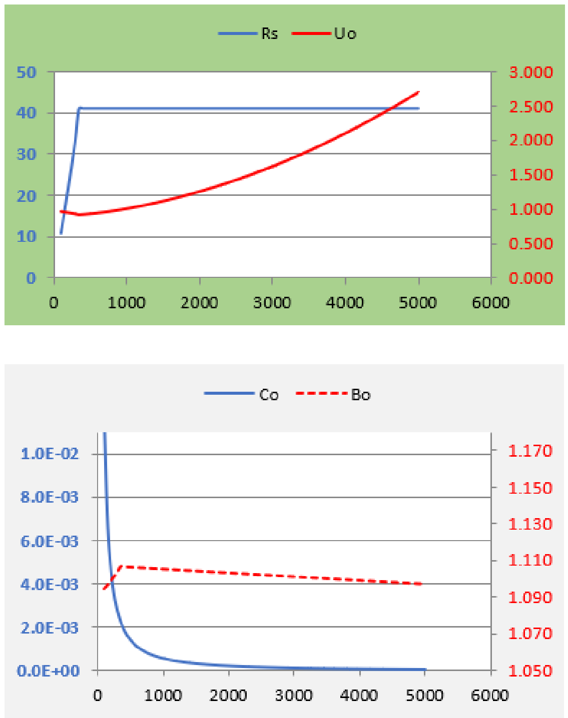


Figure 27. PVT model for Vivian formation.

Chonta PVT:

petrophysics	
Porosity	12.0%
Inicial Water Sat	24.00%
Actual Oil Sat	76.00%
Actual Gas Sat	0.00%
Reservoir	
API	35.50
Ggas	0.80
Rsi (scf/bbl)	690
Tr (°F)	292
Inicial Pr (psi)	5600
Reser Grad (psi/ft)	0.56
Espec. Oil Grav.	0.85
Oil Dens. lb/ft3	53
PVT	
Pb (psi)	2877
Rs act (scf/stb)	690
Bob (bbl/stb)	1.4740
Boi	1.4203
Uo dead oil (cp)	0.93
Uob (cp)	0.38
Uo act (cp)	0.50
Cf (psi-1)	4.5E-06
Coi (psi-1)	1.4E-05
Cgi (psi-1)	1.8E-04
Cw (psi-1)	3.7E-06
Ctact (psi-1)	3.8E-05
Init Oil Dens. (lb/ft3)	43
bub Oil Dens. (lb/ft3)	41
Ctinicial(psi-1)	2.0E-05

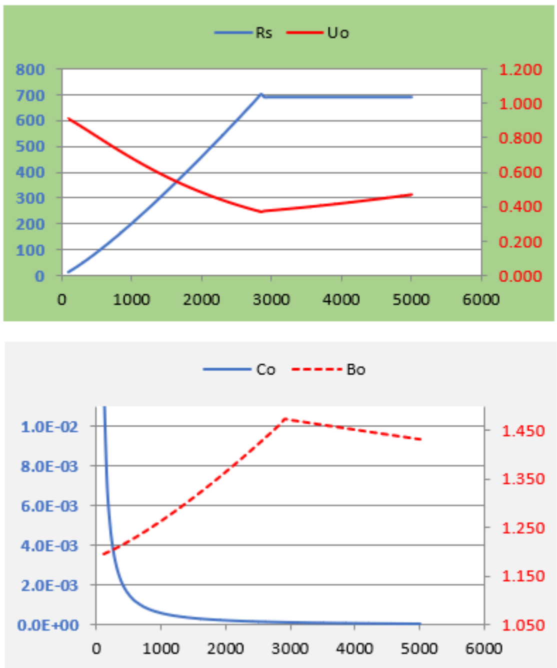


Figure 28. PVT model for Chonta formation.

With the correlations of the fluid´s properties, we can plot the values of Solubility Ratio (Rs), Crude Viscosity (Uo), Crude Isothermal Compressibility (Co) and the Volumetric Factor (Bo); these values will allow us to determine an initial flow rate for each formation and infer its future behavior with the field pressure drop.

4.2.3 In Situ Volume Estimation

4.2.3.1 Use of analogy

By using the information of offset fields, we can infer analogous properties like the Water Saturation, Volumetric Petroleum Factor and Net Thickness, for the calculation of volume in situ in our case. See Figure 29.

Yacimiento (CAPAHUARI NORTE)	A	Tope	Base	Ht	FR	POES
	(Acres)	(ft)	(ft)	(ft)	(%)	(MMSTB)
VIVIAN	3550.9	11911.0	11995.0	84.0	39.2	51.9
CHONTA	4152.9	12868.0	12905.5	37.5	3.9	26.3
Yacimiento (CAPAHUARI SUR)	A	Tope	Base	Ht	FR	POES
	(Acres)	(ft)	(ft)	(ft)	(%)	(MMSTB)
VIVIAN	6000	11795.0	11900.0	105.0	45.5	328.4
CHONTA	6189	12636.0	12690.0	54.0	30.8	65.3

Figure 29. Information on nearby fields (source: Perupetro).

4.2.3.2 Volumetric method

The calculation of the in situ volume of the Capahuari Sur Extensión field, was made in two ways, through a deterministic method and a probabilistic method, the procedure and the results for each reservoir are presented below.

4.2.3.2.1 Deterministic volumetric

Using the petrophysical properties already defined, a fluid model characteristic of the field of study and a twin static model from a nearby reservoir, we proceed to calculate the in-situ volumes of the reservoirs. See Equation 7.

$$N = \frac{7758 * A * h * \phi * (1 - Swi)}{Boi}$$

Equation 7. Calculation of the original in situ oil.

Where:

$\phi: Effective\ porosity\ of\ the\ formation\ (fraction)$

A: Area (acres)

h: Net oil thickness (feet)

Swi: Initial water saturation (fraction)

Boi: Volumetric factor of oil at initial conditions

- **OOIP calculation for Vivian:**

The areas of each plane of the anticlinal structure that defines the Vivian reservoir are calculated using AutoCAD 2019 ® software, and grouped at the corresponding depths for the calculation of the gross volume: (See Table 4)

Planes	Area (acres)	Depth (ft)	Ht. (ft)	Hnet (ft)	Method	Volume (acre*ft)
1	49.4	11011.0	6.0	6	Spheric	261.260
2	186.3	11020.8	9.8	8	pyramidal	1326.477
3	564.3	11030.6	9.8	8	pyramidal	4299.352
4	697.0	11040.5	9.8	8	Trapezoidal	5045.096
5	1010.4	11050.3	9.8	8	Pyramidal	10186.062
6	1353.8	11060.2	9.8	8	Trapezoidal	9456.844
7	1796.8	11070.0	9.8	8	Trapezoidal	12602.517
8	2252.7	11079.8	9.8	8	Trapezoidal	16197.885
9	2586.6	11089.7	9.8	8	Trapezoidal	19356.999
10	2914.8	11099.5	9.8	8	Trapezoidal	22005.573
11	3275.2	11109.4	9.8	8	Trapezoidal	24760.023
12	4086.6	11119.2	9.8	8	pyramidal	44080.635
13	5047.5	11129.0	9.8	8	Trapezoidal	36536.184
14	5567.4	11138.9	9.8	8	Trapezoidal	42459.691
15	6167.3	11148.7	9.8	8	Trapezoidal	46938.774

Table 4. Calculation of the gross volumes, structure of the Vivian.

Using Equation 7, the volume of Vivian formation is calculated using the deterministic method: (See Table 5)

Volume (acre*ft)	295600
PHI	0.15
Swi	0.16
Boi	1.065
OOIP (MMbls)	**325**

Table 5. OOIP Vivian, deterministic method.

- **OOIP calculation for Chonta:**

The areas of each plane of the anticlinal structure that defines the Chonta reservoir are calculated. (See Table 6)

Planes	Area (acres)	Depth (ft)	Ht (ft)	Hnet (ft)	Method	Volume (acre*ft)
1	97.8	11827.7	6.0	1	Spheric	162.017
2	544.8	11837.5	9.8	2.2	pyramidal	960.874
3	921.0	11847.4	9.8	2.2	Trapezoidal	1612.424
4	1168.9	11857.2	9.8	2.2	Trapezoidal	2298.916
5	1469.4	11867.0	9.8	2.2	Trapezoidal	2902.150
6	1777.1	11876.9	9.8	2.2	Trapezoidal	3571.162
7	2098.3	11886.7	9.8	2.2	Trapezoidal	4262.915
8	2503.8	11896.6	9.8	2.2	Trapezoidal	5062.325
9	3348.6	11906.4	9.8	2.2	pyramidal	9622.741
10	3826.7	11916.2	9.8	2.2	Trapezoidal	7892.815
11	4346.8	11926.1	9.8	2.2	Trapezoidal	8990.865
12	4875.3	11935.9	9.8	2.2	Trapezoidal	10144.304
13	5419.6	11945.8	9.8	2.2	Trapezoidal	11324.413
14	5976.6	11955.6	9.8	2.2	Trapezoidal	12535.807
15	6558.4	11965.4	9.8	2.2	Trapezoidal	13788.512
16	7188.4	11975.3	9.8	2.2	Trapezoidal	15121.504
17	8017.1	11985.1	9.8	2.2	Trapezoidal	16726.070
18	8847.2	11995.0	9.8	2.2	Trapezoidal	18550.806

Table 6. Calculation of the gross volumes, structure of the Chonta formation.

Using Equation 7, the in-situ volume of the Chonta formation is calculated by the deterministic method: (See Table 7)

Volume (acre*ft)	145500
PHI	0.12
Swi	0.24
Boi	1.475
OOIP (MMbls)	**67**

Table 7. OOIP Chonta, deterministic method.

4.2.3.2.2 Probabilistic volumetric

By using the Crystal Ball ® tool, a probabilistic distribution is generated for each property, and 10,000 tests are simulated for the probabilistic calculation of the OOIP for each reservoir, obtaining the P10, P50 and P90 percentiles of the OOIP, thus inferring with greater precision the in-situ volume of the CSE field (See Table 8 and Table 10).

Calculation of the OOIP for Vivian:

	Min	Best estimate	Max	Distribution
Volume (acre*ft)	236410.7	295513.4	354616.0	Triangular
PHI	0.17	0.18	0.19	Normal
Swi	0.14	0.16	0.18	Normal
Boi (BR/STB)	1.065	1.065	1.065	Uniform
OOIP (MMSTB)		325.484		

Table 8. Field properties for OOIP calculation - Vivian

A distribution of the 10000 simulations for the calculation of the OOIP can be generated in a range of assumed uncertainty, proposing a sensitivity for each factor in order to obtain the best result: (See Figure 30 and Figure 31)

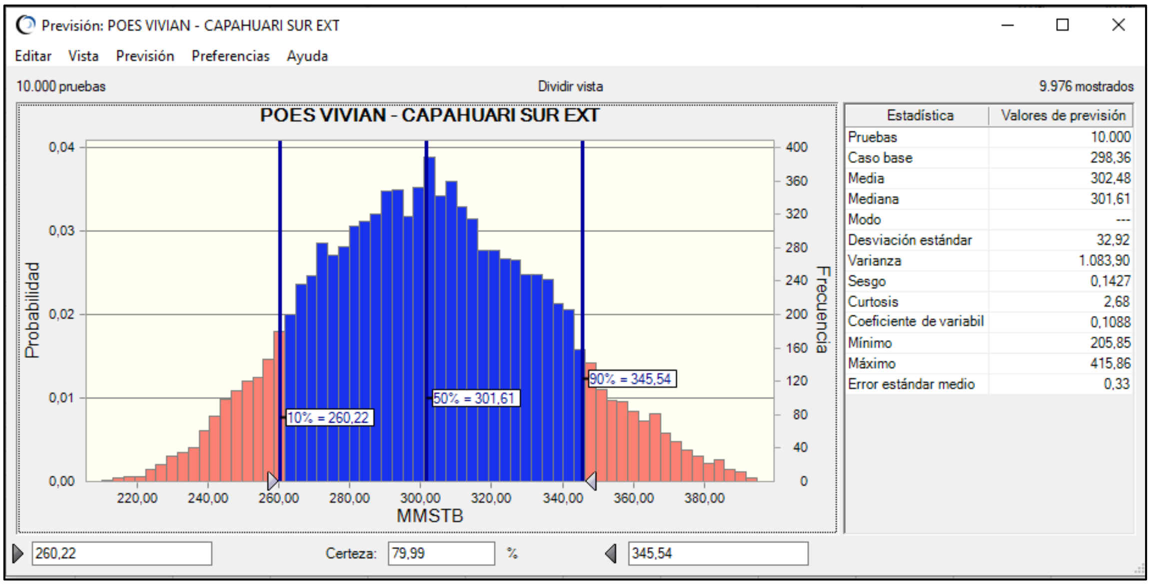


Figure 30. Distribution of results, OOIP Vivian.

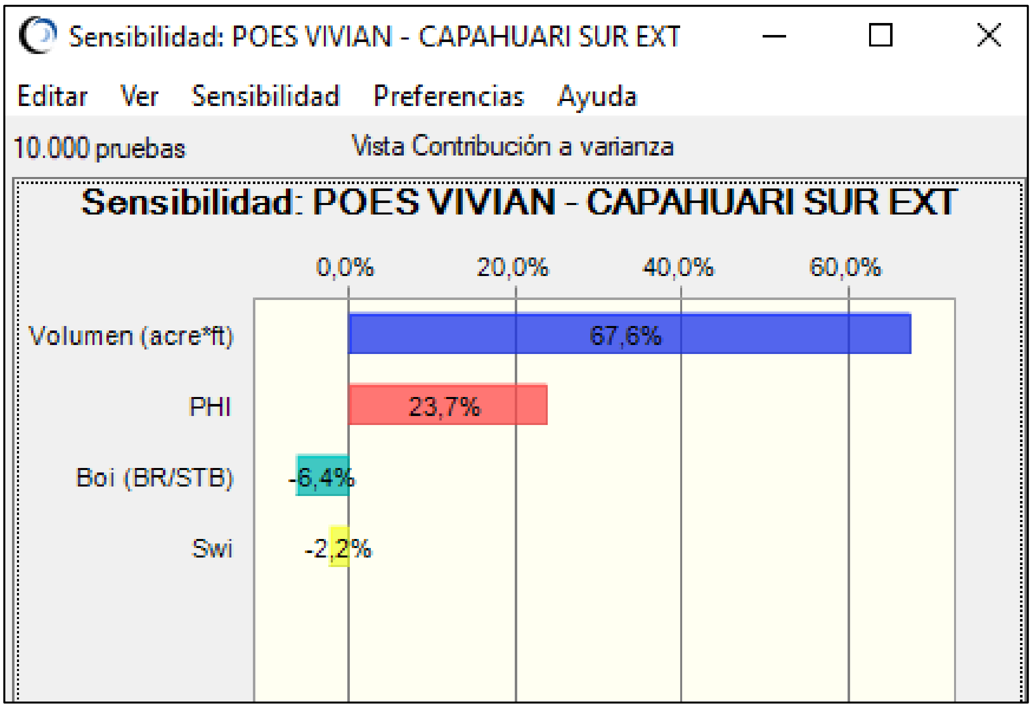


Figure 31. Sensitivity of the probabilistic method, OOIP Vivian.

The results of the in-situ volume for Vivian are presented below (see Table 9), we will take the P90 result as the most accurate for the OOIP calculation and for future field calculations:

OOIP VIVIAN (MMSTB)	
P 90 (1P)	**287**
P 50 (2P)	**329**
P 10 (3P)	**373**

Table 9. Results of the calculation, OOIP Vivian.

Calculation of the OOIP for Chonta:

	Min	Best estimate	Max	Distribution
Volume (acre*ft)	116424.5	145530.6	174636.7	triangular
PHI	0.1	0.115	0.13	Normal
Swi	0.22	0.24	0.26	Normal
Boi	1.475	1.475	1.475	Uniform
OOIP (MMSTB)		66.900		

Table 10. Field properties for OOIP calculation - Chonta.

A distribution of the 10000 simulations that are generated from the OOIP calculation can be generated with the range of values given, and the sensitivity that each factor represents in the determination of this result: (See Figure 32 and Figure 33)

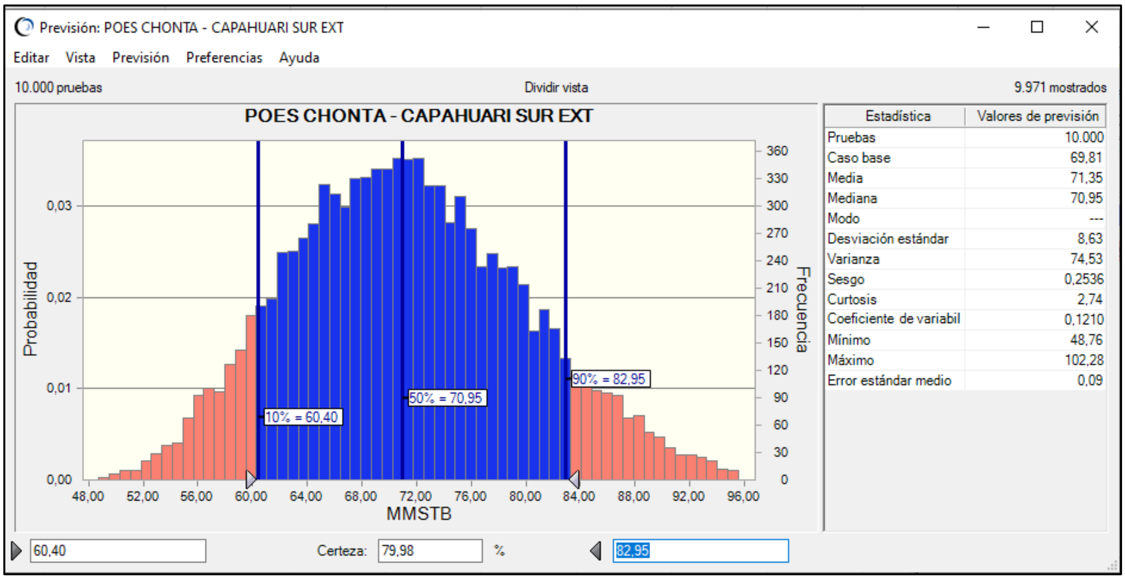


Figure 32. Distribution of Results, OOIP Chonta.

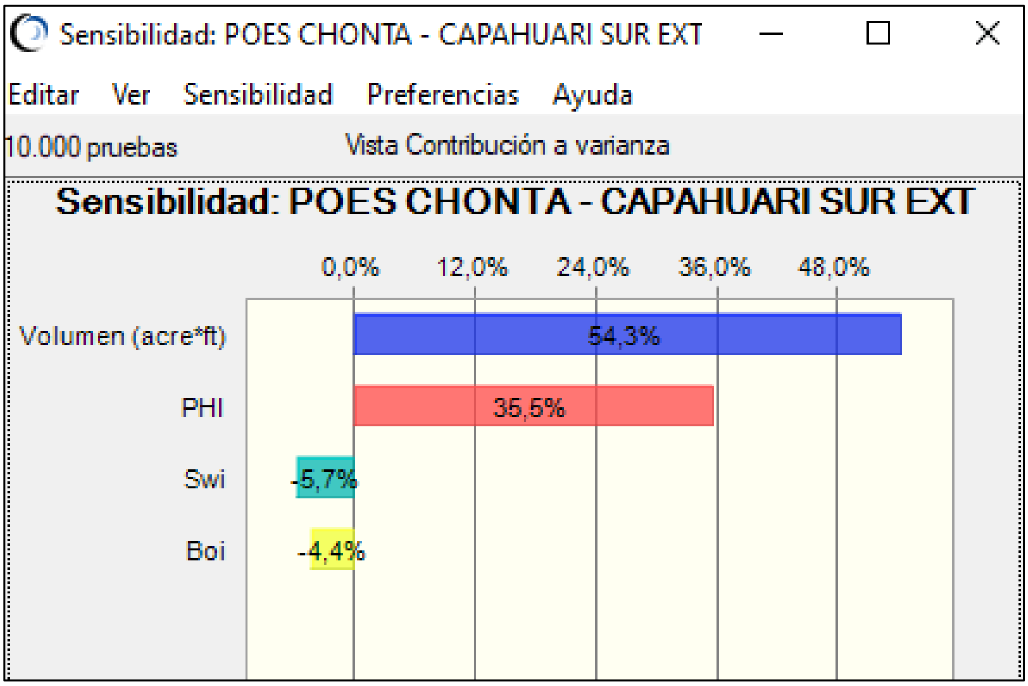


Figure 33. Sensitivity of the probabilistic method, OOIP Chonta.

The results of the in-situ volume for Chonta are presented below (See Table 11), we will take the P90 result as the most accurate for the OOIP calculation and for future field calculations:

OOIP CHONTA (MMSTB)	
P 90 (1P)	67
P 50 (2P)	73
P 10 (3P)	78

Table 11. Results of the calculation, OOIP Chonta

4.2.3.3 Declination and forecast model

4.2.3.3.1 Type curve by formation

Based on the historical production of offset fields, the production segregation for each formation is used to collect the production curves of a group of representative wells, in order to build a declination model by normalizing the production of the formations and determining the parameters that define them.

➢ **Vivian's type curve:**

9 Vivian segregated production curves were collected from Capahuari Sur field at the same drilling campaign. (See Figure 34)

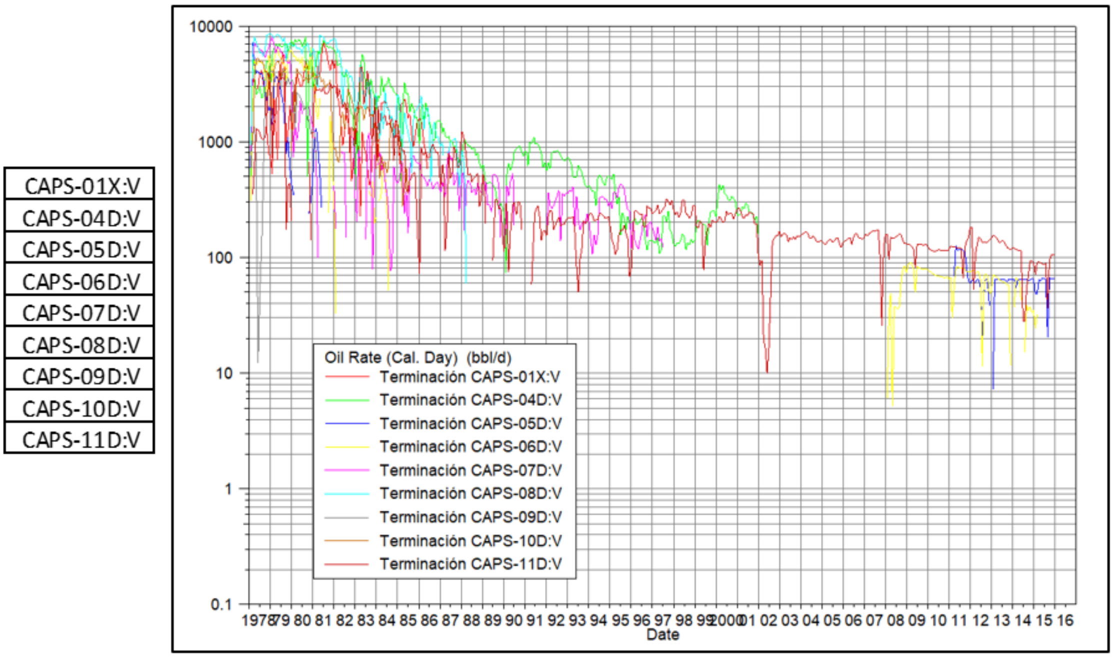


Figure 34. History Vivian production in Capahuari Sur field.

The production was normalized taking everything to a zero time and having a maximum flow equal to 1 for each well: (See Figure 35)

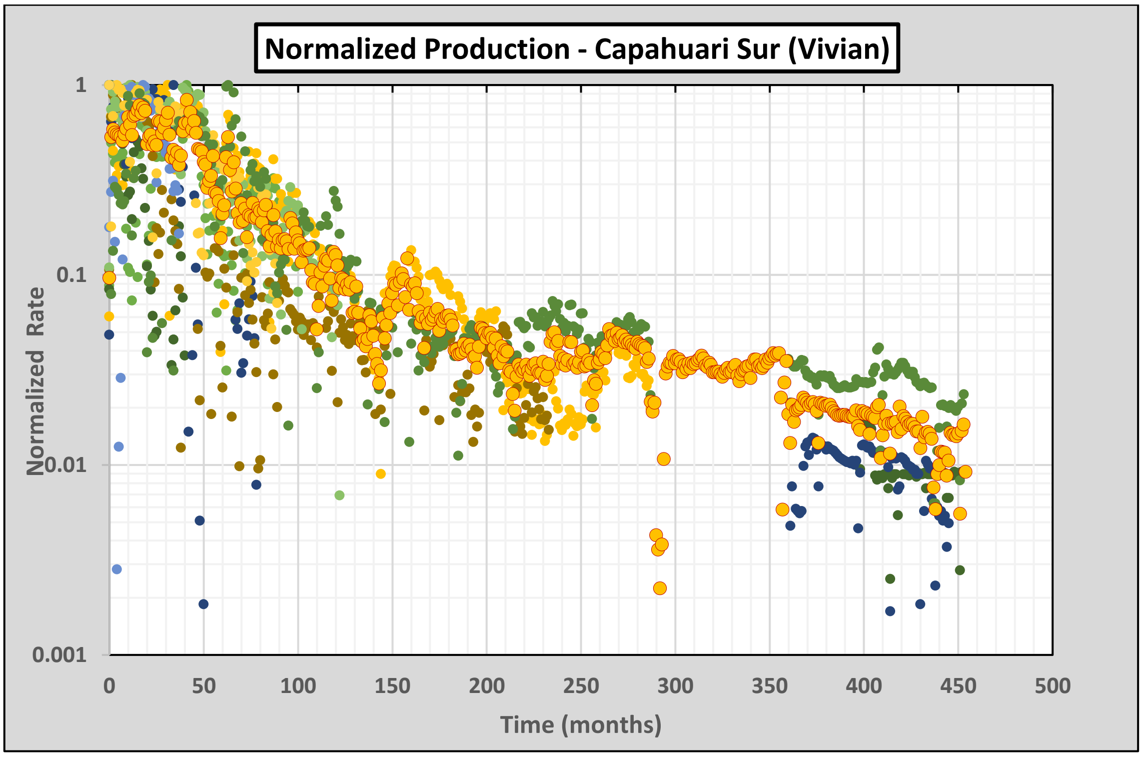


Figure 35. Standardized production Vivian.

Based on the average of these curves, a declination model was built to predict the behavior of any well producing from this formation: (See Figure 36)

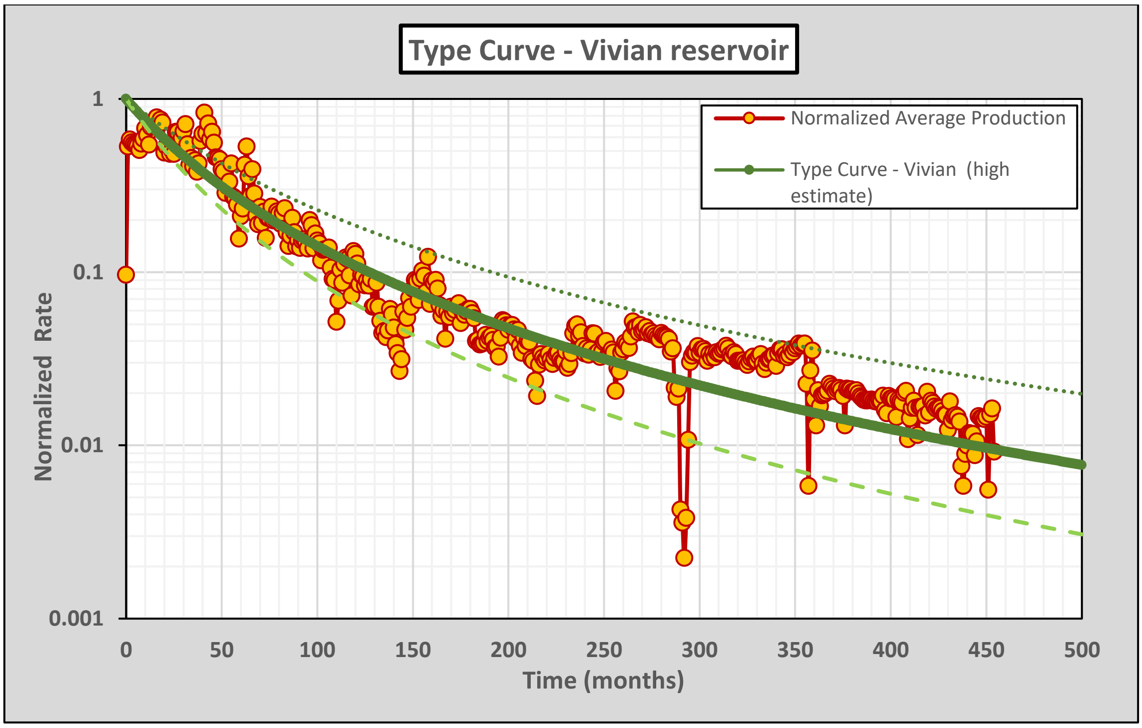


Figure 36. Vivian reservoir type curve.

We see that there is a good History Match with the model, the declination parameters that define this type curve are presented below: (See Table 12)

DCA VIVIAN			
	High estimate	**Best estimate**	**Low estimate**
Qi	1	1	1
Di	0.0384	0.0295	0.0206
b	0.355	0.395	0.434

Table 12. Declination parameters for Vivian.

- **Chonta type curve:**

6 Chonta segregated production curves were collected from Capahuari Sur field at the same drilling campaign. (See Figure 37)

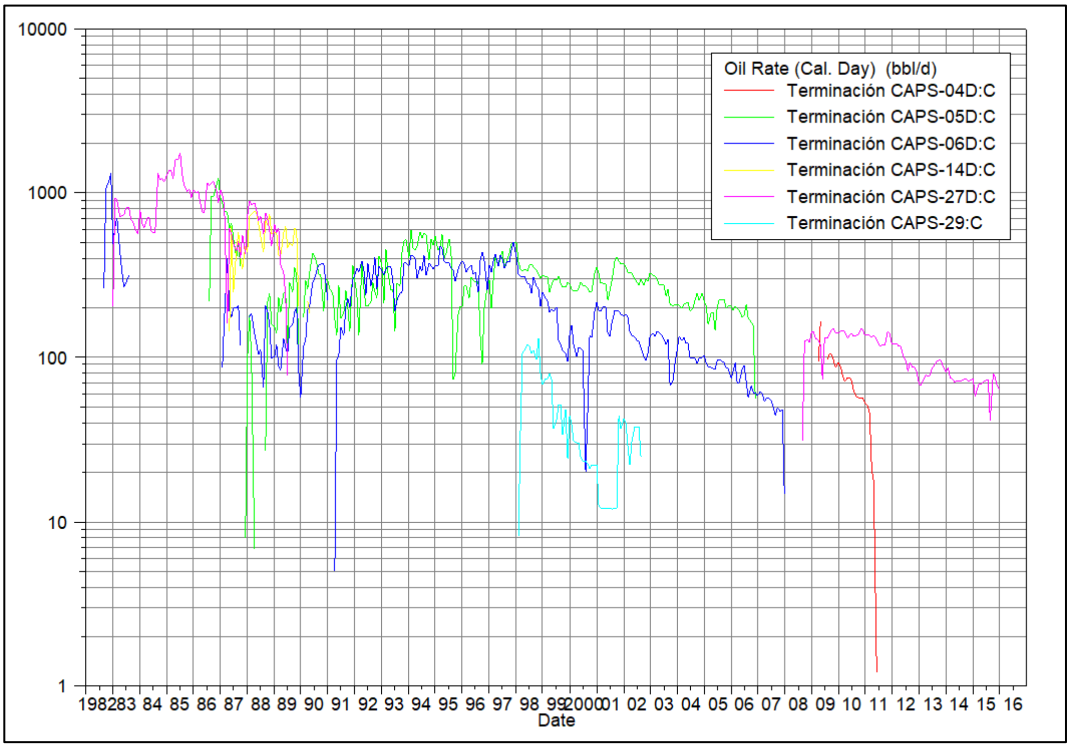


Figure 37. History Chonta production in Capahuari Sur field.

The production was normalized taking everything to a zero time and having a maximum flow equal to 1 for each well: (See Figure 38)

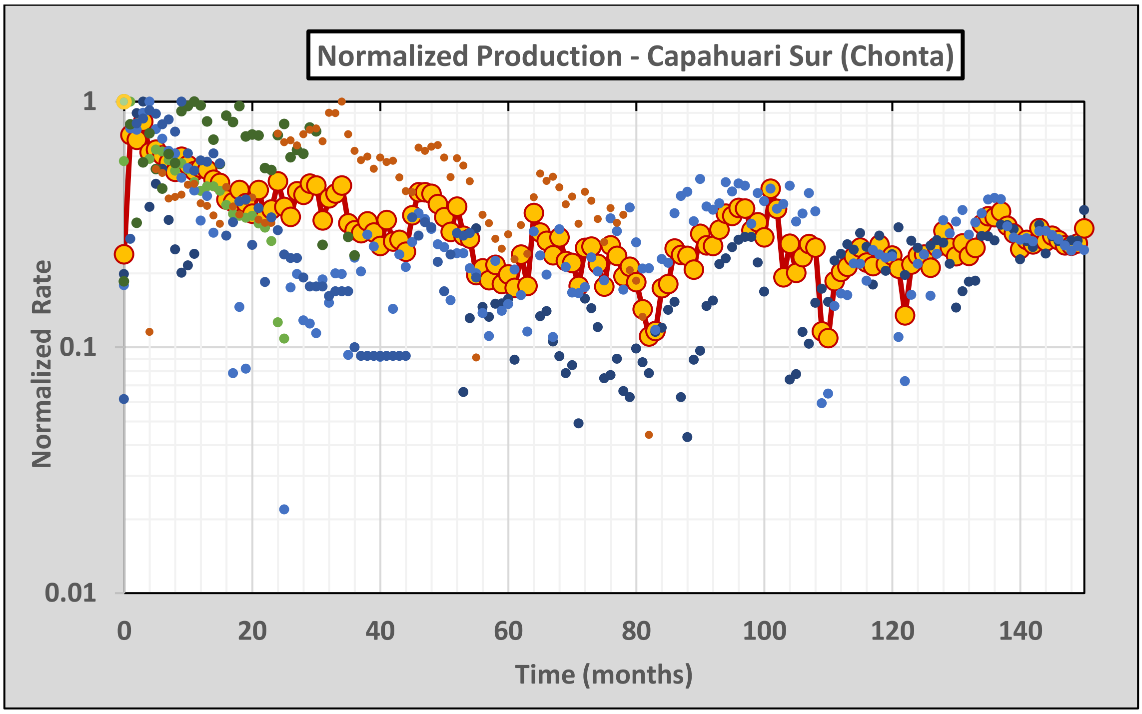


Figure 38. Standardized production of Chonta.

Based on the average of these curves, a declination model is built to predict the behavior of any well producing from this formation: (See Figure 39)

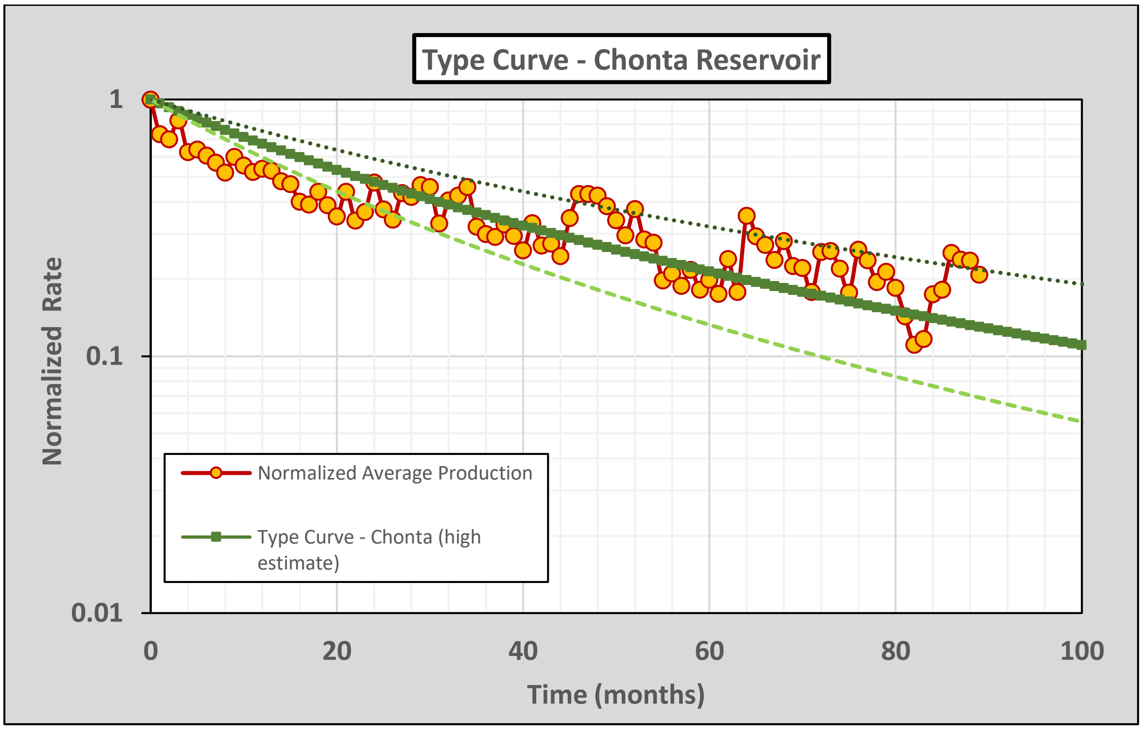


Figure 39. Chonta reservoir type curve.

The declination parameters that define this type curve are presented below: (See Table 13)

DCA CHONTA			
	High estimate	**Best estimate**	**Low estimate**
Qi	1	1	1
Di	0.0469	0.0361	0.0252
b	0.312	0.416	0.479

Table 13. Declination parameters for Chonta.

4.2.3.4 Aquifer model

The early characterization of the field allows inferring that the Vivian reservoir is under a mechanism of water drive production, while the Chonta reservoir is presented as solution gas drive. It will be important to characterize the model of the aquifer present in the reservoirs (mainly Vivian) in such a way that we can infer the water flow that will be produced and treated at the surface.

Vivian's aquifer model:

We make use of the diagnostic plot Semilog Crude Cut vs. Accumulated Crude and we observe an average aquifer break point for the entire field. (See Figure 40)

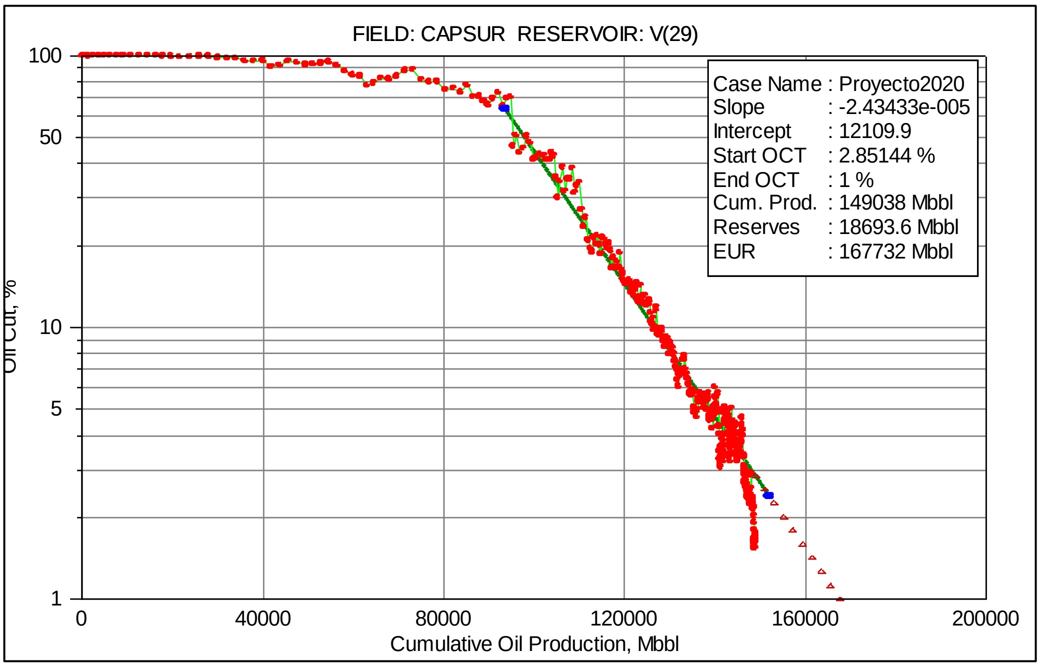


Figure 40. Oil cut vs cumulative oil by Vivian, Capahuari Sur field.

We observe an almost constant crude cutting behavior up to an accumulated of 40 MMbls, then a gradual decrease up to 80 MMbls, where the trend changes, this is due to the aquifer breaks in the drilled holes and generates another curve that represents it, so the customized analysis must be done depending on the location of each well in the structure.

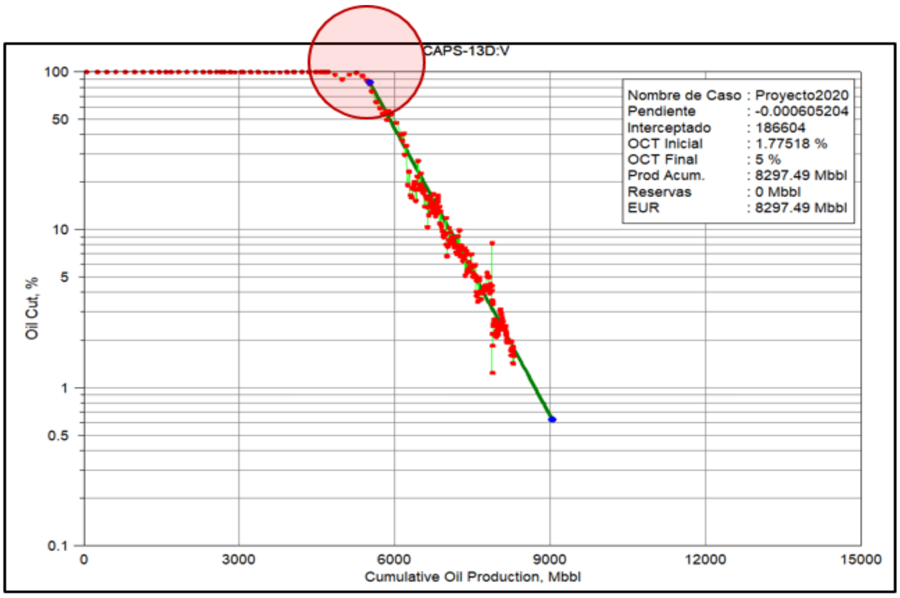


Figure 41. Oil cut vs cumulative oil, CAPS 13D Vivian.

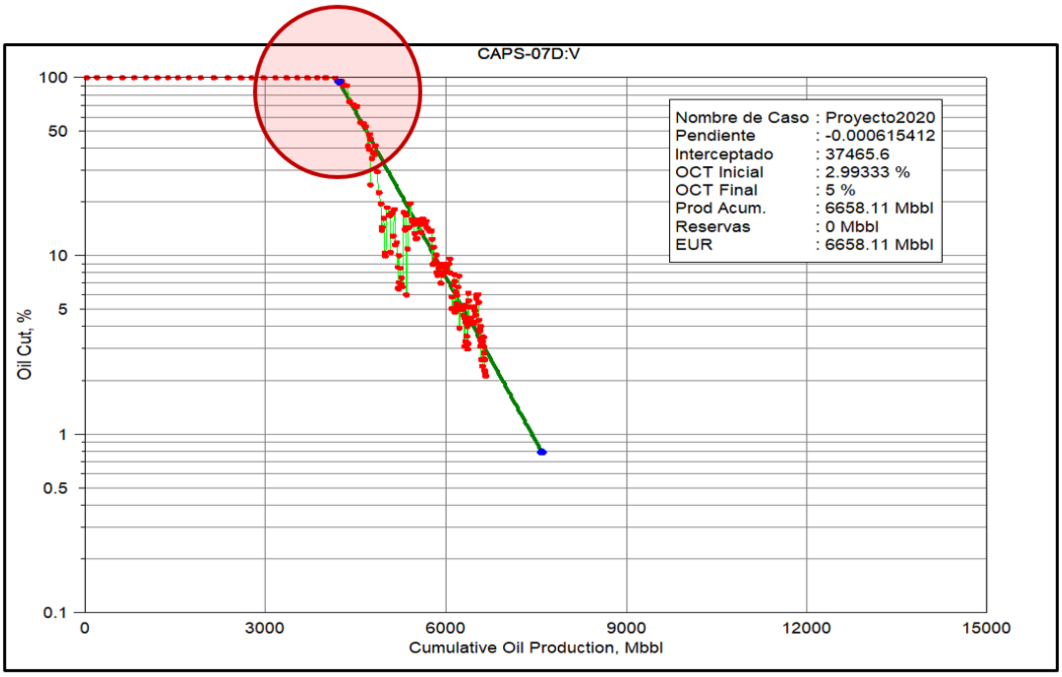


Figure 42. Oil Cut vs cumulative oil, CAPS 07D Vivian.

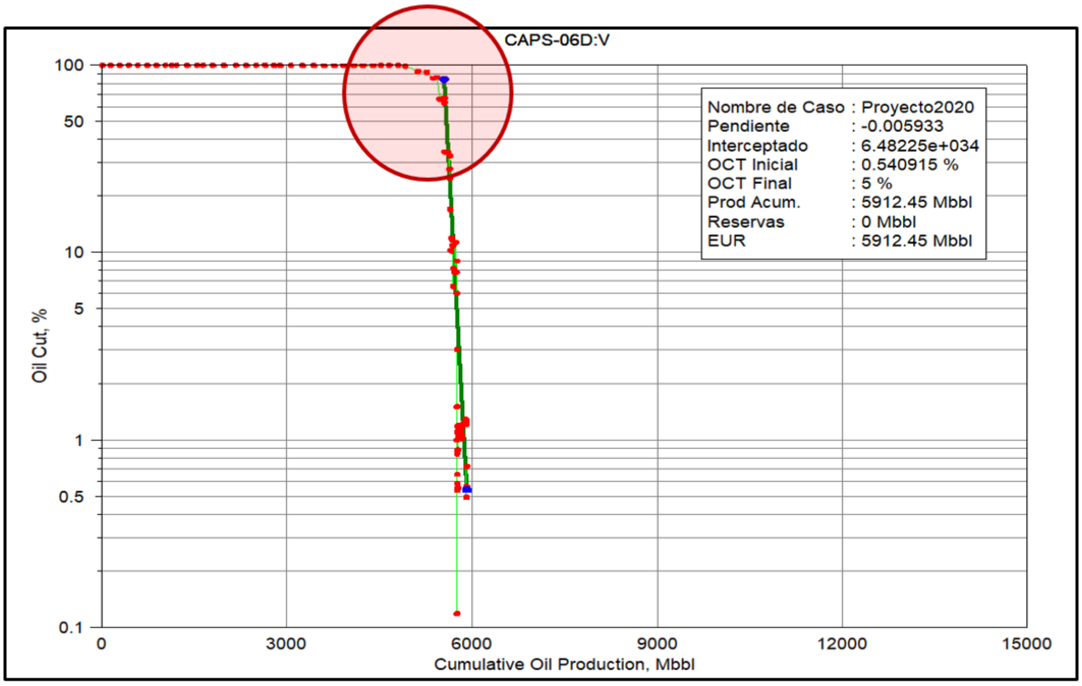


Figure 43. Oil Cut vs cumulative oil, CAPS 06D Vivian.

We observed that the aquifer breaks to different accumulated for each well located in the structure, a forecast of rupture of the aquifer is made depending on the expected final recovery (Np) of each well to raise in Capahuari Sur Extensión field. (See Figure 41, Figure 42 and Figure 43)

Based on the analysis, the following function of the accumulated crude oil is presented to predict the cut of crude oil at field level, and thus model the aquifer present in Vivian. (See Equation 8 and Equation 9)

Before the rupture of the aquifer:

$$\log(Oil.Cut) = -3.60743e\text{-}006 \ {}^*Oil.Cum + 1.99667$$

Equation 8. Vivian Reservoir Aquifer Model.

After the rupture of the aquifer:

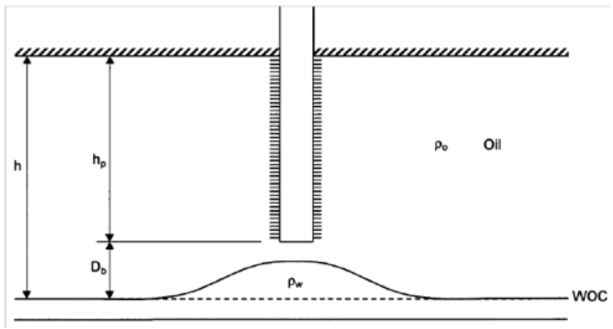
$$\log(Oil.Cut) = -0.000605204 \ {}^* \ Oil.Cum + 5.27092$$

Equation 9. Vivian reservoir aquifer model.

It will be important to analyze how long the aquifer breaks and what flow generates this effect faster; so then, we calculate the critical flow, which the aquifer breaks in the holes and verify if it is profitable to produce at this value.

The well to be analyzed will be the well located at the top of the structure, called ALFA 1X, determine the time in which this will break in the perforated and what would be the flow rate for this to happen: (See Figure 44)

ALFA 1X:V		
kh	1288	mD
PHI	0.165	
uo	2.79	cp
uw	0.80	cp
Bo	1.097	BR/STB
re	1000	ft
rw	0.35	ft
Qoc	382	bpd
Q proposed	8000	bpd
Z	0.555	
Krw)sor	0.4	
Kro)swc	1	
M	1.39	
a	0.5	
TDbt	0.4	
Tbt	673	dias
Tbt	22	meses
Tbt	1.9	años



maximum flow at which the aquifer is not present:

$$q_{oc} = \frac{1.5351 * 10^{-3}(\rho_w - \rho_o)(h^2 - {h_p}^2)\,k}{\mu_o \beta_o \ln\left(\frac{r_e}{r_w}\right)}$$

time at a given flow, so that the aquifer reaches to the perforations:

$$t_{BT} = \frac{\mu_o \, \emptyset \, h \, (t_D)_{BT}}{0.00137(\rho_w - \rho_o)k_v(1 + M^{\alpha})}$$

$$M = \left[\frac{(K_{rw})_{sor}}{(K_{ro})_{swc}}\right]\left(\frac{\mu_o}{\mu_w}\right)$$

Figure 44. Calculation of critical flow and break time.

Using Vivian's fluid data, we calculated the maximum flow rate at which the aquifer does not reach the perforated, knowing that the TD of the well is 120' from contact, we determined that at 2958 bopd, the aquifer still does not affect this well, however this initial flow rate and with a decline already determined, the project would not be paid, therefore we calculated how long it would take the aquifer to reach the perforated to the flow we propose to produce (at the begging 8250 bopd), resulting in 53 months from the start of production, through this analysis we can infer the break times of each proposed well to be drilled and thus have a better planning of water control systems and injection wells to be drilled.

- **Chonta aquifer model:**

By the same analysis, the diagnostic plot Semilog Crude Cutting vs Accumulated production is presented: (See Figure 45 and Figure 46)

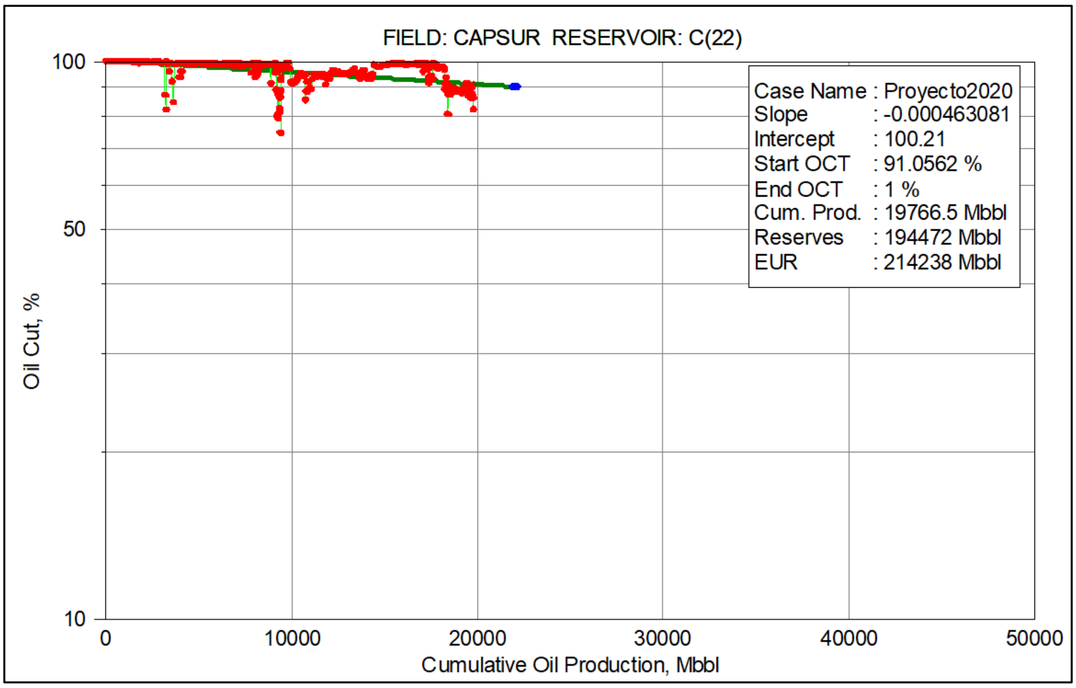


Figure 45. Oil Cut Chonta vs cumulative oil, Capahuari Sur field.

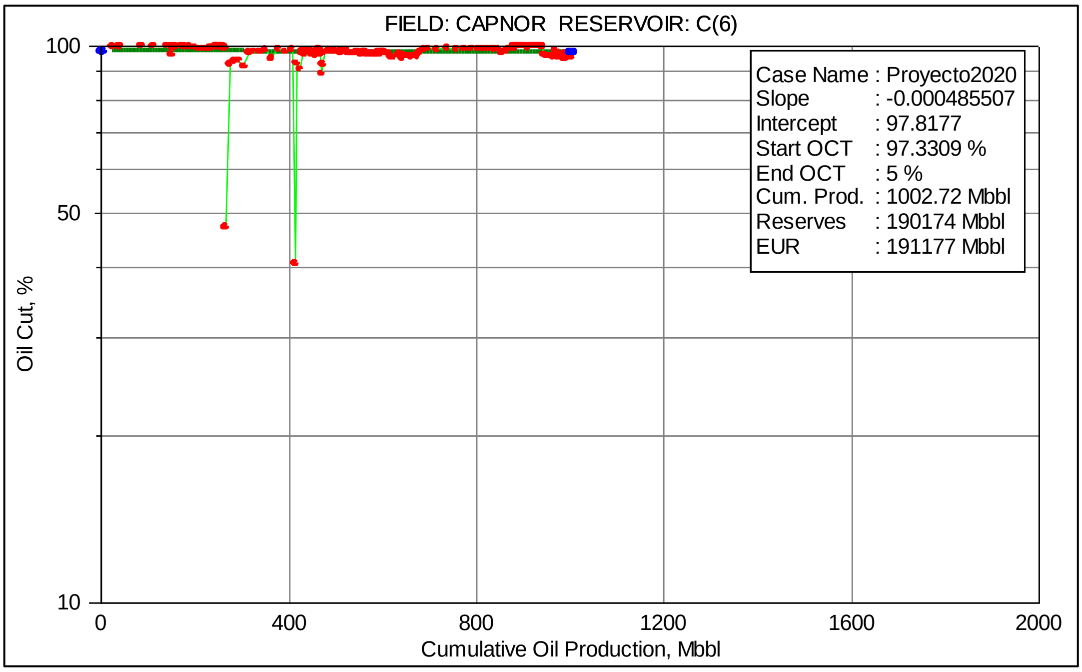


Figure 46. Oil Cut Chonta vs cumulative oil, Capahuari Norte field.

Based on the real behavior of the Chonta reservoir's oil cut in the 2 analogous fields, it is concluded that Chonta does not present aquifer as a reservoir drive mechanism. The water cut will be considered in a flat way in an interval of 2 to 10% of water cut along the productive life of Chonta reservoir.

4.2.3.5 Diagnostic charts

This section complements the characterization of the aquifer present in Vivian from an offset field, through Chan's Diagnostic plots (Chan, 1995), transferring the results we obtain to our field, because the aquifer must behave in a similar way in our field due to the proximity.

The use of the present methodology has helped to understand and identify quickly and safely the behavior of the present aquifer. The methodology is very simple and only requires production data. We proceed to plot the WOR (water-oil ratio) and the derivative of WOR versus time in a log-log graph; depending on the behavior of these curves, we can characterize the aquifer.

The productive history of wells from offset fields was taken and considered that the behavior of the Vivian aquifer will behave in the same way in Capahuari Sur Extensión field.

For the first part, we used the information from the CAPS 26D:V well, analyzing only the behavior of Vivian's segregated production, the results are compared with the models presented by Chan; therefore, for this well we can describe the aquifer as a bottom aquifer. (See Figure 47 and Figure 48)

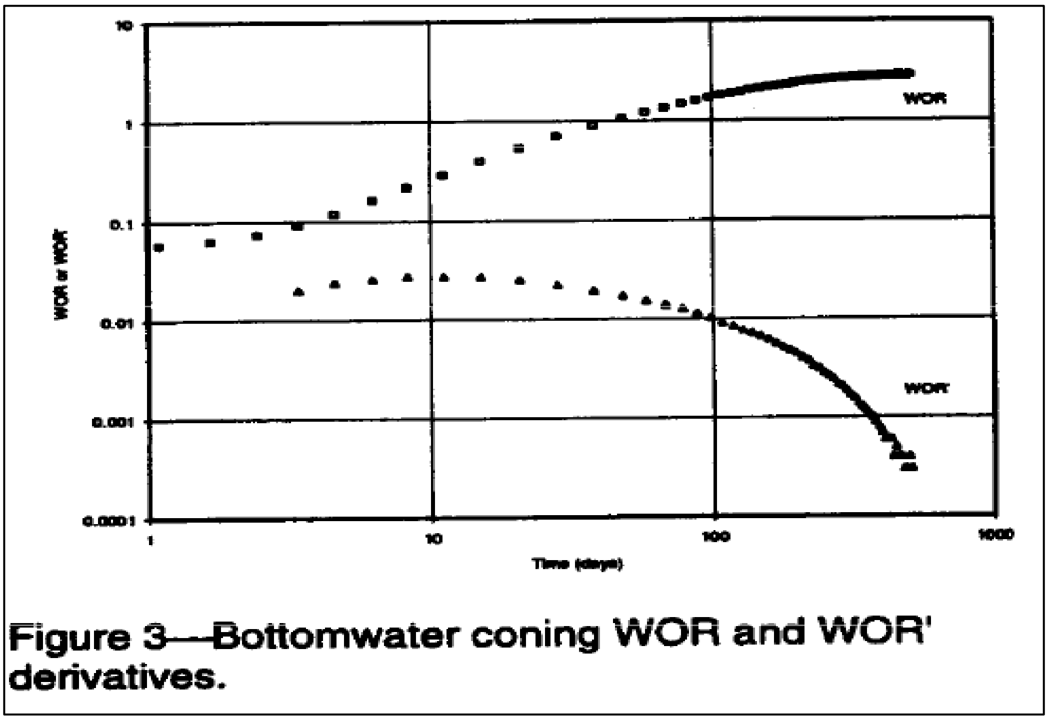


Figure 47. Chan curve to identify bottom aquifer.

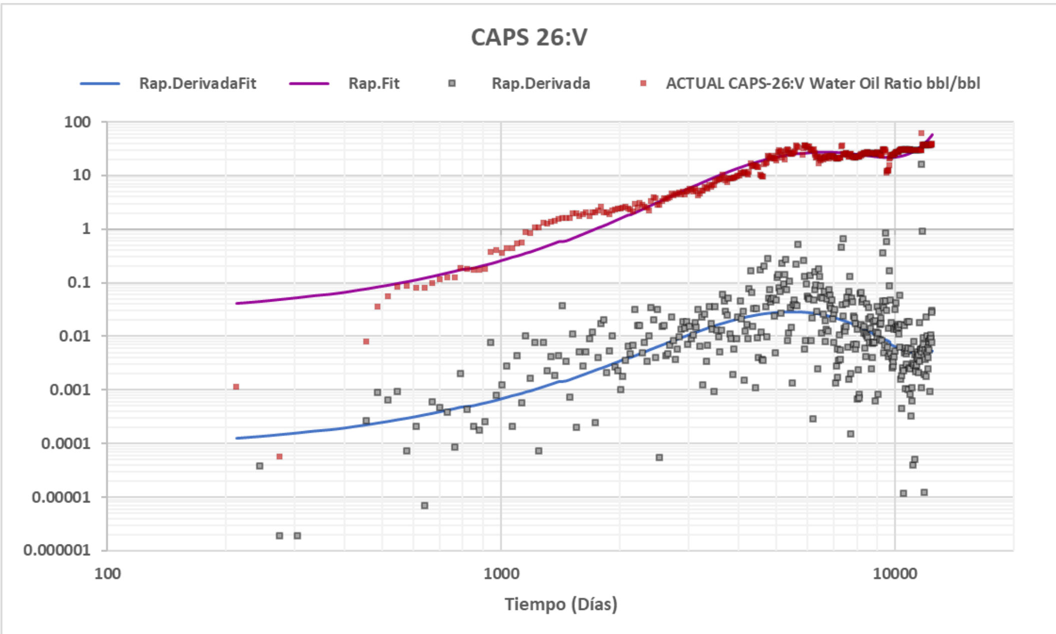


Figure 48. WOR vs WOR' results to identify aquifer behavior at CAPS 26:V.

One more well is taken to verify the behavior of the aquifer, in this case the CAPS 4D:V well, analyzing only the behavior of Vivian's segregated production, the results are compared with the models presented by Chan; so for these wells we can describe the aquifer as a flank aquifer. (See Figure 49 and Figure 50)

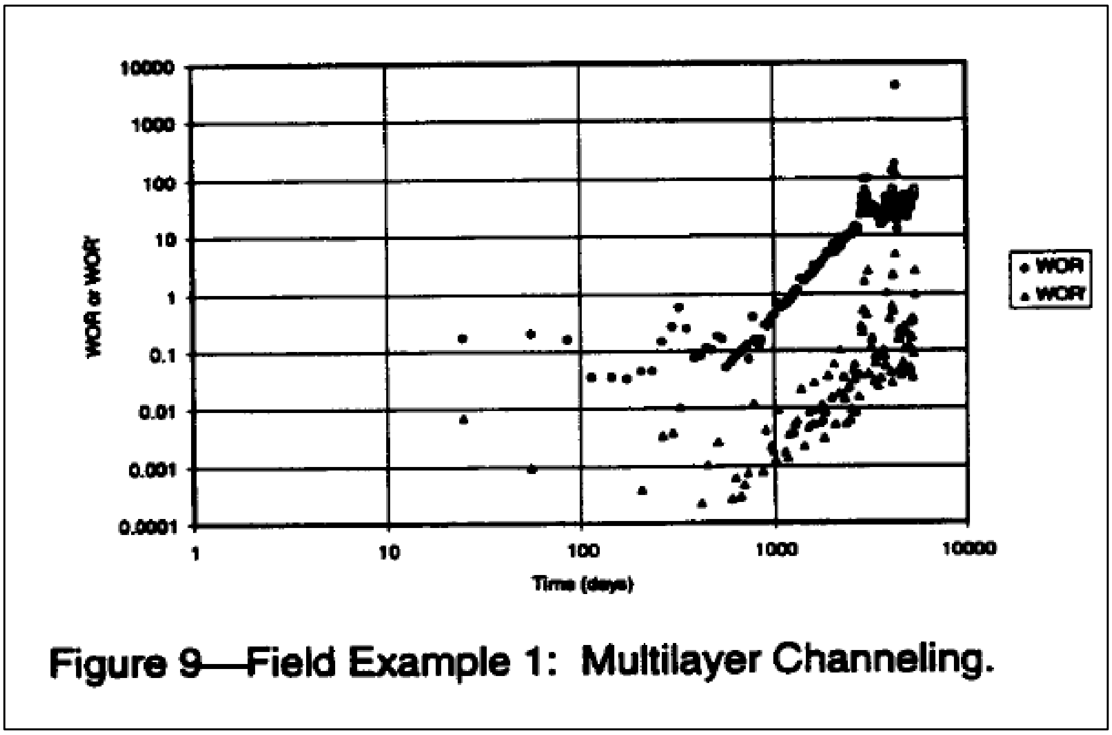


Figure 49. Chan curve to identify channeling by flanks.

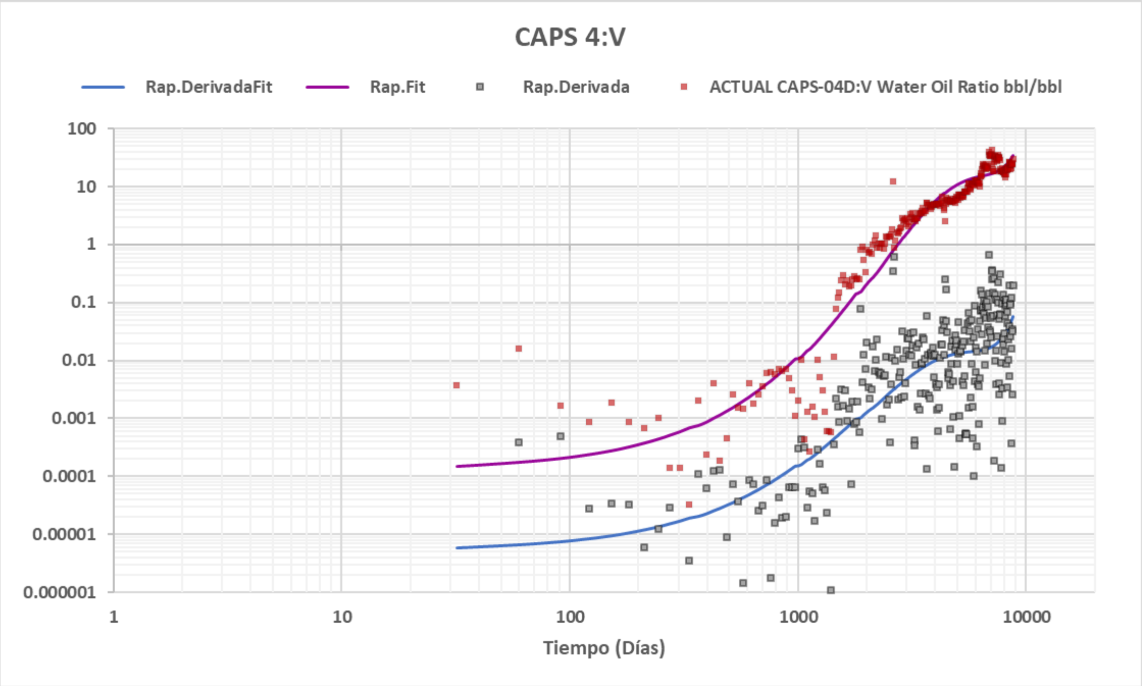


Figure 50. WOR vs WOR' results to identify aquifer behavior at CAPS 4:V.

The different result for each well allows us to conclude that the behavior of the aquifer will behave differently depending on the location of the well in the structure.

In the case of wells that are centered in the structure, as is the case of well CAPS 26, they are characterized by having a bottom aquifer, since the structure is less deep in the center; In the case of wells that are farther from the center of the structure, as is the case of well CAPS 4, they are characterized by having a flank aquifer, since the aquifer is presented surrounding the structure this will be better seen in the wells located on the edges.

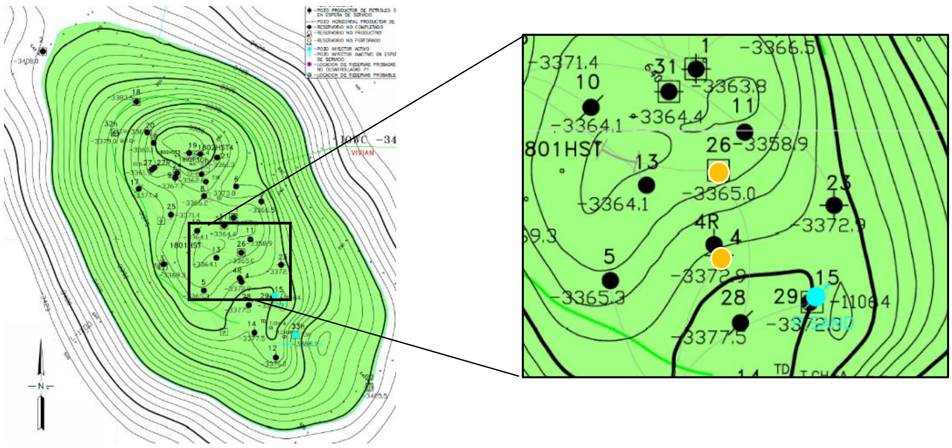


Figure 51. CAPS 26 y CAPS 4 ubication.

The present results (See Figure 51) allow a better understanding of the aquifer, also presents the diagnosis of Chan for the future operator to monitor during the productive life of the wells, trying to avoid, in its measure, the presence of water.

4.2.3.6 Reserves and selection of the number of wells

Knowing the type of drive mechanism of each reservoir, we can determine the Theoretical Recovery Factor of the reservoirs based on correlations.

- **Vivian's theoretical recovery factor:**

Using Guthrie's correlation for water-powered reservoirs. (See Equation 10)

$$E_R = 0.272 \log_{10} k + 0.256\, S_{wi} - 0.136 \log_{10} \mu_o - 1.538\, \phi - 0.0003\, h + 0.114$$

Equation 10. Guthrie correlation for RF calculation.

Using the basic reservoir data that we have detailed above, we determined a theoretical RF for Vivian, having the OOIP value calculated at the beginning for P90, we obtained the volume of recoverable hydrocarbons and taking as a reference the accumulated wells in Vivian from offset fields (see Figure 29) and assuming continuous oil production, it is estimated to recover in final Np 9 MMbls of oil per well to determine the number of wells to be drilled. (See Table 14)

Theory RF (%)	**59.3%**
P10 OOIP (MMbls)	287
theoretical reserves (MMbls)	170
Np average por Well	9
# Wells	**19**

Table 14. Results of the calculation of the theoretical reserves in Vivian.

- **Chonta's theoretical recovery factor:**

Using API correlation for Solution Gas reservoirs. (See Equation 11)

$$E_R = 41.8\left[\left(\frac{\phi(1-S_{wi})}{B_{ob}}\right)^{0.1611}\left(\frac{k}{\mu_{ob}}\right)^{0.0979}(S_{wi})^{0.3722}\left(\frac{p_b}{p_a}\right)^{0.1741}\right]$$

Equation 11. API correlation for RF calculation.

Using the basic reservoir data detailed above, we determined a theoretical RF for Chonta, having the OOIP value calculated at the beginning for P90, we obtained the volume of recoverable hydrocarbons and taking as reference the accumulations of wells in Chonta from offset fields (see Figure 29) and assuming continuous oil production, it is estimated to recover in final Np 2 MMbls of oil per well to determine the number of wells to be drilled. (See Table 15)

Theory RF (%)	**29.3%**
P10 OOIP (MMbls)	67
theoretical reserves (MMbls)	20
Np average por Well	2
# Wells	**10**

Table 15. Results of the calculation of the theoretical reserves in Chonta.

4.2.3.7 Location of wells

A radius of drainage was calculated based on the accumulated real production of the wells of Capahuari Sur in such a way that we avoid the superposition to the production moment and locate them in a better way.

Based on the following equation (See Equation 12) we calculated a drainage radius for the 8 best wells that best drained the reservoirs in the Capahuari Sur field.

$$Rd(ft) = \sqrt{\frac{Acum * Bo}{\pi * So * PHI * h}}$$

Equation 12. Drainage radius calculation.

Wells	Last production date	Np at 01/01/2016 (Mbbl)	Drainage radius (ft)	Drainage radius (km)
CAPS_04D	1/1/2002	15359.6	850.987	0.259
CAPS_08D	1/12/1988	14535.4	827.840	0.252
CAPS_26	1/1/2016	11768.5	744.892	0.227
CAPS_19D	1/2/2001	9426.2	666.655	0.203
CAPS_13D	1/1/2016	8297.5	625.470	0.191
CAPS_15D	1/12/1982	7987.0	613.655	0.187
CAPS_16DST	1/12/2014	7606.1	598.844	0.183

Table 16. Drainage radius of the 8 best wells of the Capahuari Sur field.

Based on the results (See Table 16), an average value of 780 feet is taken as the drainage radius for both reservoirs, based on this, the wells are located ensuring that there is no interference between them, taking into account the least number of platforms, the highest net thickness and the best petrophysical properties.

For the first scenario (vertical wells), we propose to drill 19 wells that go to Vivian and 10 wells that go to Chonta, using the following schedule for the drilling campaigns, thus proposing the best development of the field with vertical wells and the locations of the most convenient wells. (See Table 17).

Nº	Wells	COMPLETION DAY
1	ALFA 1X-D	1/01/2030
2	ALFA 2D	1/02/2030
3	ALFA 3D	1/04/2030
4	ALFA 4D	1/04/2031
5	ALFA 5D	1/04/2031
6	ALFA 6D	1/06/2031
7	ALFA 7D	1/08/2031
8	ALFA 8D	1/04/2032
9	ALFA 9D	1/06/2032
10	ALFA 10D	1/08/2032
11	ALFA 11D	1/10/2032
12	ALFA 12D	1/02/2033
13	ALFA 13D	1/04/2033
14	ALFA 14D	1/06/2033
15	ALFA 15D	1/08/2033
16	ALFA 16D	1/10/2033
17	ALFA 17D	1/08/2034
18	ALFA 18D	1/10/2034
19	ALFA 19D	1/12/2034

Table 17. Development schedule of the Capahuari Sur Extensión field.

4.2.3.8 Production forecast

Based on the proposed development plan we obtain the following production forecast and the results of the first scenario (static scenario) of the development of Capahuari Sur Extensión field. (See Figure 52)

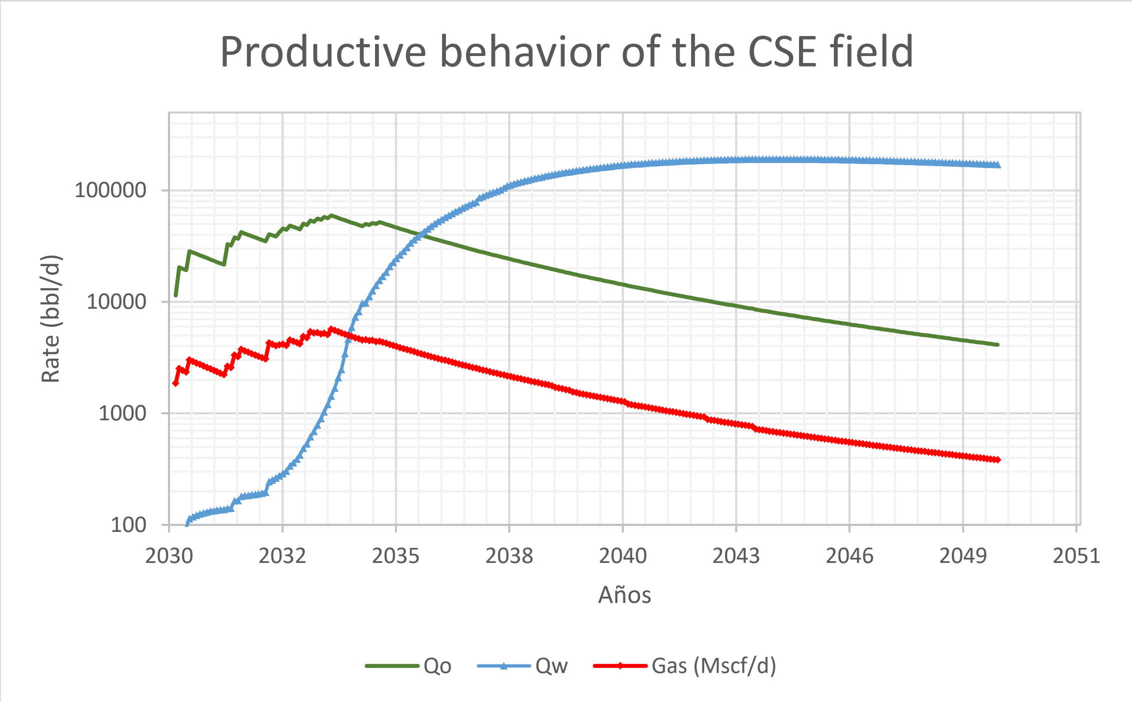


Figure 52. Productive behavior of the CSE field.

The first results obtained in the characterization by means of an analytical model, can be measured by the final recovery (RF) per reservoir; Vivian's RF is obtained in 49%, and Chonta's is only 12. 6%, values below the theoretical recovery factor calculated by correlations; mainly attributed these first results to the lack of a modeling of the artificial lifting systems (Electric Submersible Pump, Gas Lift, etc) in the wells and the behavior of the reservoirs through these methods; which makes us indicate that we must model these behaviors and propose another type of development of the field to guarantee the maximum recovery of hydrocarbons.

In such a way that we can present a better development plan, we propose to drill horizontal wells and model the development by means of numerical simulation, making use of the CMG ® simulator, so that we can introduce dynamic parameters that were not considered in the first scenario (fractional flow, relative permeabilities, solution of the diffusivity equation at each pressure, ESP, GL, etc) and be able to predict more precisely the behavior of the reservoirs.

4.2.4 Reservoir Simulation

The results of the studies carried out up to this part will allow us to better adjust our simulation model.

Based on the analytical model, a Numerical Black Oil model is built (Msc. Antonio Sepulveda, 2006): (See Equation 13 and Equation 14)

- Oil:

$$\sum_{l\in\psi_n}\left\{T^*_{ol,n}\left[\left(p^{n+1}_{o,l}-p^{n+1}_{o,n}\right)-\gamma^*_{ol,n}\left(Z_l-Z_n\right)\right]\right\}+q^*_{osc,n}=\frac{V_b}{\Delta t}\left[\left(\phi S_o b_o\right)^{n+1}-\left(\phi S_o b_o\right)^n\right]_n$$

Equation 13. Numerical black oil model equation for oil.

- Water:

$$\sum_{l\in\psi_n}\left\{T^*_{wl,n}\left[\left(p^{n+1}_{w,l}-p^{n+1}_{w,n}\right)-\gamma^*_{wl,n}\left(Z_l-Z_n\right)\right]\right\}+q^*_{wsc,n}=\frac{V_b}{\Delta t}\left[\left(\phi S_w b_w\right)^{n+1}-\left(\phi S_w b_w\right)^n\right]_n$$

Equation 14. Numerical black oil model equation for water

Aquifer model (Carter - Tracy):

$$(W_e)_n=(W_e)_{n-1}+[(t_D)_n-(t_D)_{n-1}]\left[\frac{B\,\Delta p_n-(W_e)_{n-1}(p'_D)_n}{(p_D)_n-(t_D)_{n-1}(p'_D)_n}\right]$$

Equation 15. Aquifer model (Carter - Tracy)

where B = the van Everdingen-Hurst water influx constant as defined by Equation 10-23
t_D = the dimensionless time as defined by Equation 10-17
n = refers to the *current* time step
$n - 1$ = refers to the *previous* time step
Δp_n = total pressure drop, $p_i - p_n$, psi
p_D = dimensionless pressure
p'_D = dimensionless pressure derivative

The simulation scenarios that will be presented below are the results of a sensitivity analysis for a scenario with directional wells and another scenario with horizontal wells. In both cases, have been considered the optimal locations for the wells, layers to be completed, BHP constraints, water cutoff, and maximum allowable flow rates.

The scenarios have been carried out considering the following types of wells:

- 1 exploratory well
- 2 confirmatory well
- 3 water injection wells
- Producer wells will be variable to the scenarios.

4.2.4.1 Scenario 1

The proposed scenario 1 (See Table 18) consists of drilling 19 producing wells that vertically cross the target formation. They are distributed as follows:

- 19 wells targeting the Vivian formation.
- 10 wells targeting the Chonta formation.

In some wells, it has been considered to start with production in the Chonta formation and later, after a few years of production, to produce in the Vivian formation.

STAGE 1 - VERTICAL WELLS					PROD. FORMATION		
Nº	**PLATF.**	**WELLS**	**OBJECTIVE**	**SECONDARY OBJ.**	**CHONTA OIL ACUM**	**VIVIAN OIL ACUM**	**DRILLING DAY**
1	A	ALFA 1X-D	VIVIAN	CHONTA	X	X	2029-10-01
2	B	ALFA 2C	VIVIAN	CHONTA	X	X	2030-01-01
3	C	ALFA 3C	VIVIAN	CHONTA	X	X	2030-03-01
4	A	ALFA 4D	VIVIAN	-	-	X	2031-01-01
5	C	ALFA 5D	VIVIAN	-	-	X	2031-07-01
6	B	ALFA 6D	VIVIAN	CHONTA	X	X	2031-04-01
7	B	ALFA 7D	CHONTA	-	X	-	2031-10-01
8	B	ALFA 8D	VIVIAN	CHONTA	X	X	2032-01-01
9	B	ALFA 6D	VIVIAN	-	-	X	2032-03-01
10	A	ALFA 7D	VIVIAN	-	-	X	2032-07-01
11	A	ALFA 8D	CHONTA	-	X	-	2032-10-01
12	A	ALFA 6D	VIVIAN	CHONTA	X	X	2033-01-01
13	A	ALFA 7D	CHONTA	-	X	-	2033-03-01
14	B	ALFA 8D	VIVIAN	-	-	X	2033-05-01
15	C	ALFA 6D	VIVIAN	-	-	X	2033-07-01
16	C	ALFA 7D	CHONTA	-	X	-	2034-04-01
17	B	ALFA 8D	VIVIAN	-	-	X	2034-06-01
18	C	ALFA 6D	VIVIAN	-	-	X	2034-08-01
19	C	ALFA 7D	VIVIAN	-	-	X	2034-10-01

Table 18. Well schedule – scenario 1

Vivian simulation model

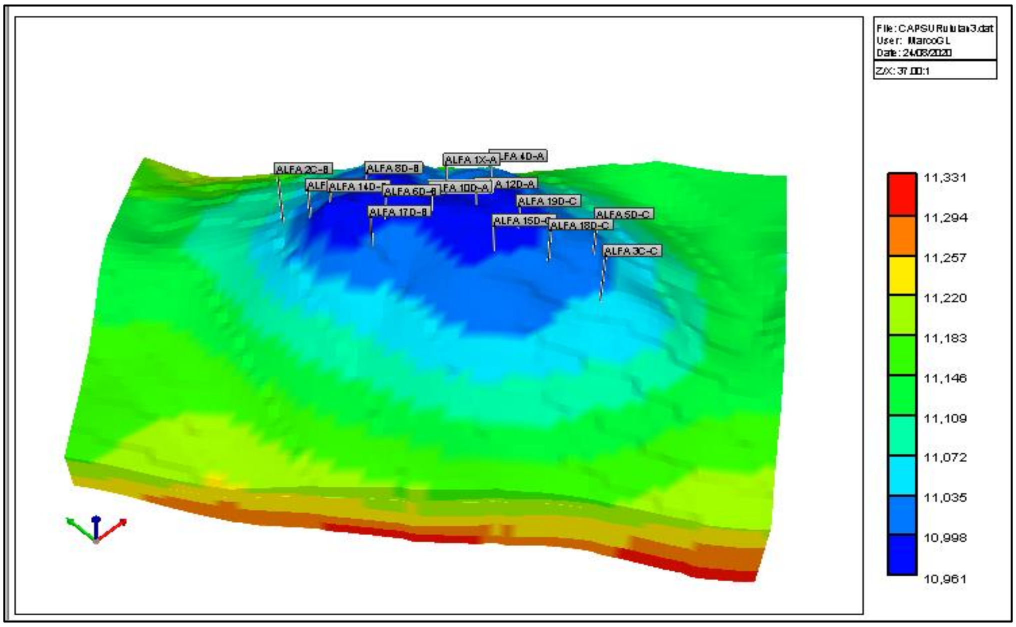


Figure 53. Vivian simulation model.

Productive performance of Vivian

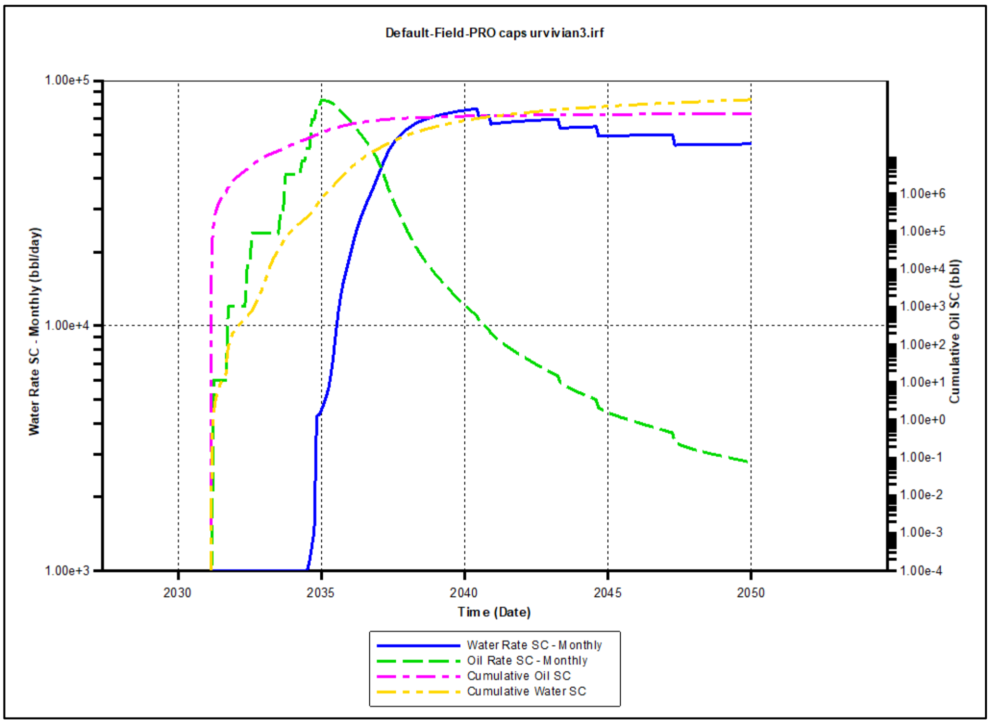


Figure 54. Productive performance of Vivian.

Chonta simulation model

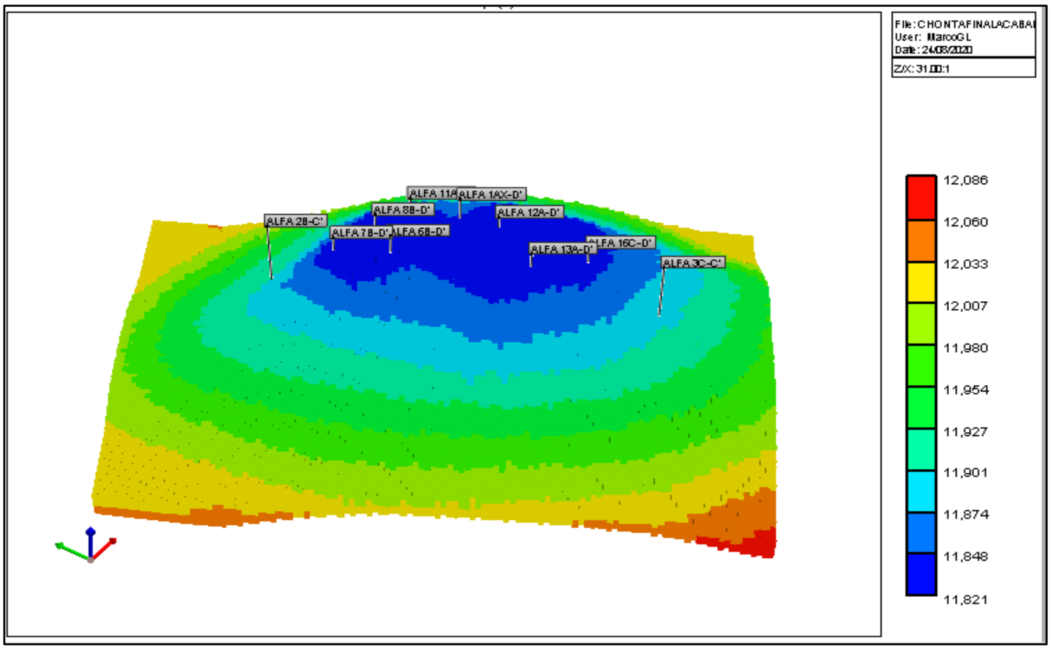


Figure 55. Chonta simulation model.

Productive performance of Chonta

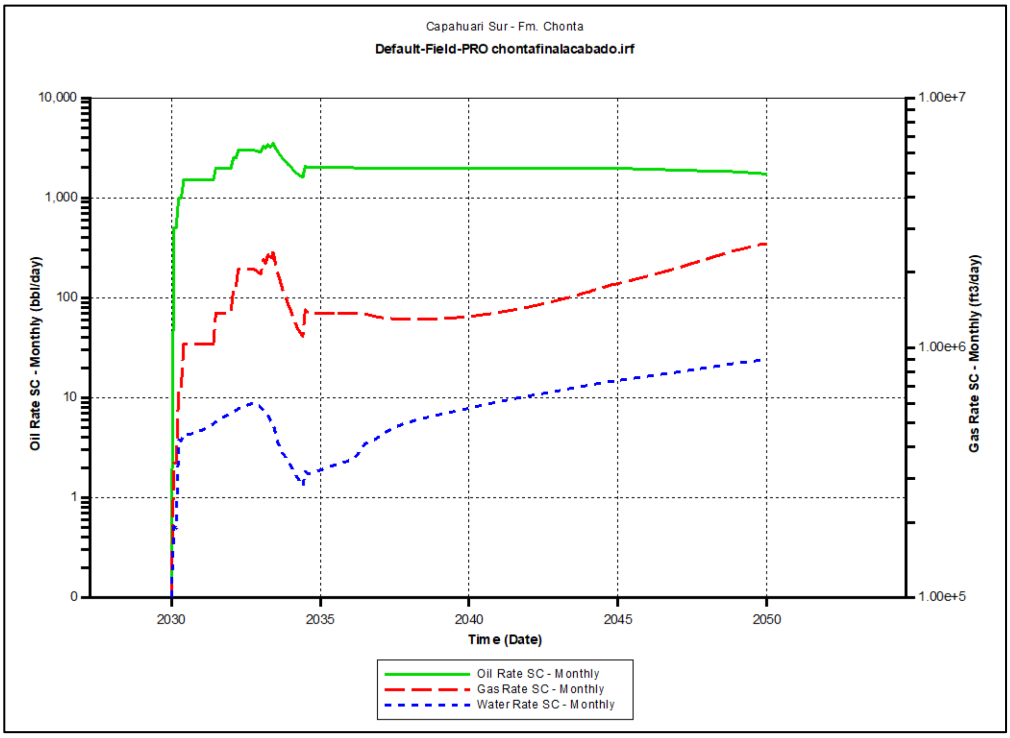


Figure 56. Productive performance of Chonta.

Productive performance of Vivian and Chonta – Scenario 1

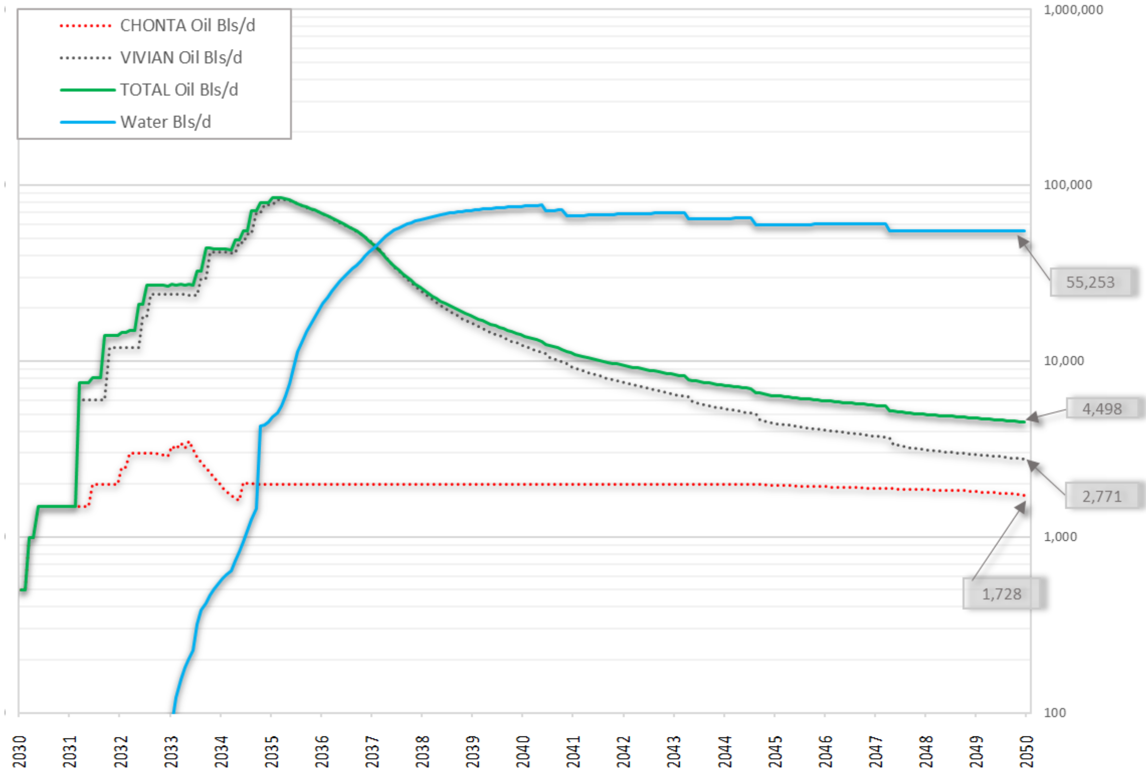


Figure 57. Productive performance of scenario 1.

Production in Chonta remains sustained due to the production of 4 wells until the end of the contract term. Also, the Figure 57 shows a decrease in oil production from Vivian, this due to the gradual closure of some wells that presented water cut of 97%.

4.2.4.2 Scenario 2

Scenario 2 (See Table 19) is presented in order to make a comparison between the results of considering horizontal wells and vertical wells, both for Vivian and Chonta.

- 5 Producing horizontal wells in the Vivian formation
- 3 Producing horizontal wells in the Chonta formation
- 7 Directional producing wells in Vivian and Chonta formation
- 1 Producing directional well in Vivian

STAGE 2 - HORIZONTAL WELLS					PROD. FORMATION		
Nº	PLATF.	WELLS	OBJECTIVE	SECONDARY OBJ.	CHONTA OIL ACUM	VIVIAN OIL ACUM	DRILLING DAY
1	A	ALFA 1X-D	CHONTA	VIVIAN	X	X	2029-11-01
2	B	ALFA 2C	CHONTA	VIVIAN	X	X	2030-01-01
3	C	ALFA 3C	CHONTA	VIVIAN	X	X	2030-03-01
4	A	ALFA 4H	VIVIAN	-	-	X	2030-11-01
5	A	ALFA 5H	VIVIAN	-	-	X	2031-01-01
6	B	ALFA 6H	CHONTA	-	X	-	2031-04-01
7	B	ALFA 7D	CHONTA	VIVIAN	X	X	2031-11-01
8	B	ALFA 8D	CHONTA	VIVIAN	X	X	2032-01-01
9	C	ALFA 9H	VIVIAN	-	-	X	2032-05-01
10	C	ALFA 10H	VIVIAN	-	-	X	2032-07-01
11	A	ALFA 11H	CHONTA	-	X	-	2032-11-01
12	A	ALFA 12D	CHONTA	VIVIAN	X	X	2033-01-01
13	A	ALFA 13D	CHONTA	VIVIAN	X	X	2033-03-01
14	B	ALFA 14H	VIVIAN	-	-	X	2033-11-01
15	B	ALFA 15H	VIVIAN	-	-	X	2034-01-01
16	C	ALFA 16H	CHONTA	-	X	-	2034-04-01

Table 19. Well schedule – scenario 2

Chonta simulation model

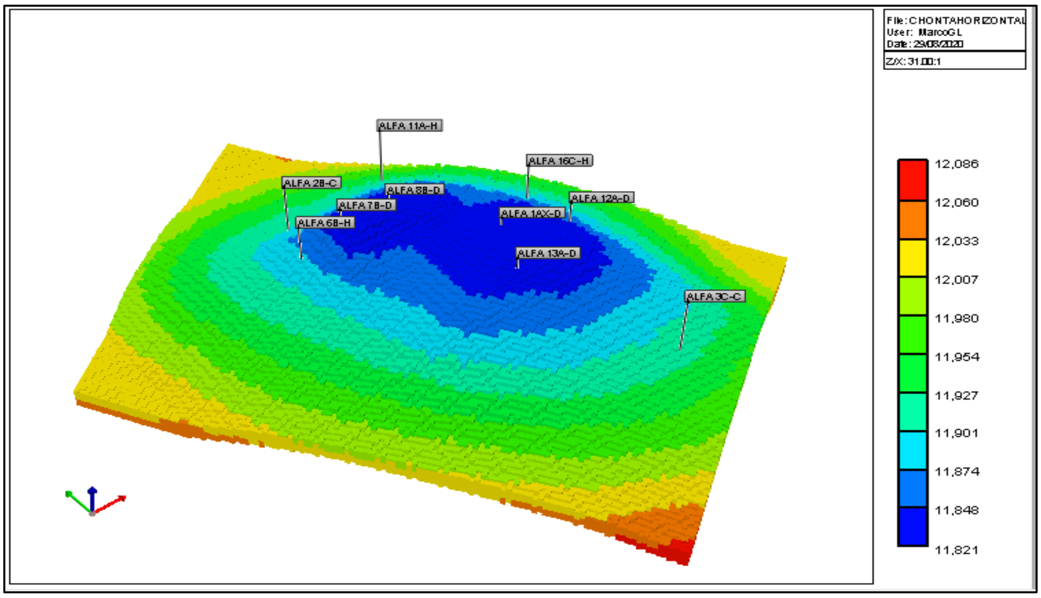


Figure 58. Chonta simulation model.

Productive performance of Chonta

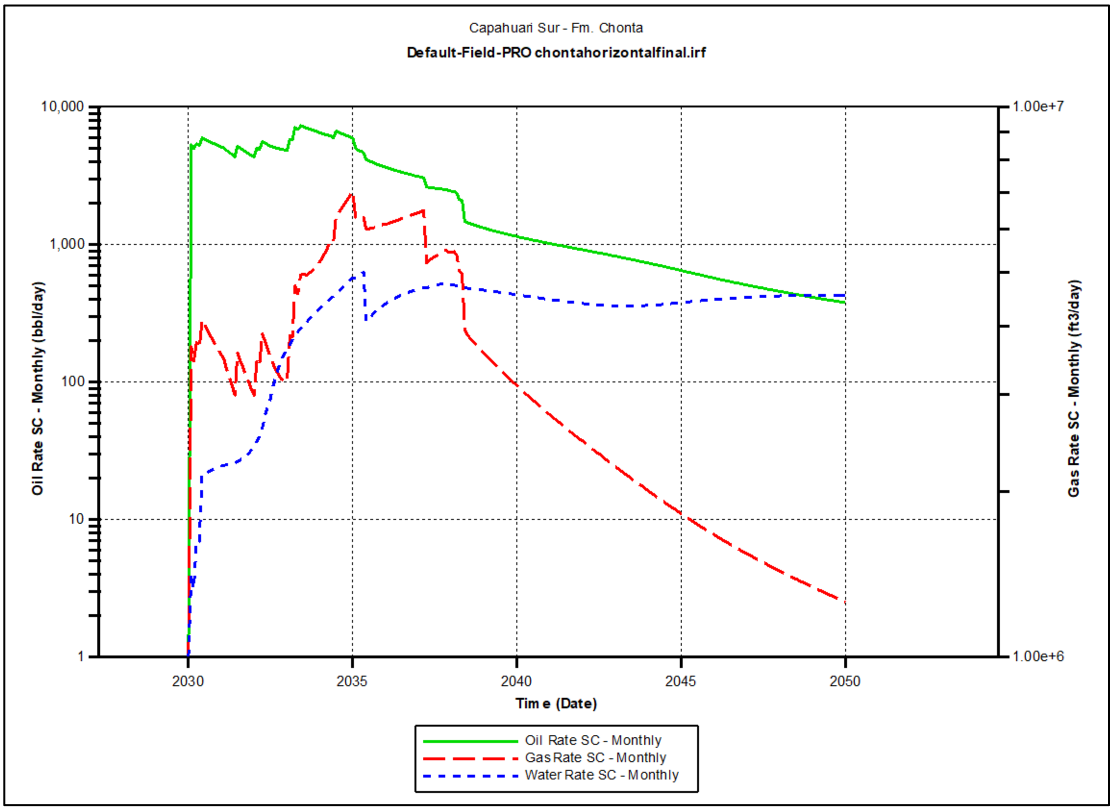


Figure 59. Comportamiento productivo de Chonta.

Vivian simulation model

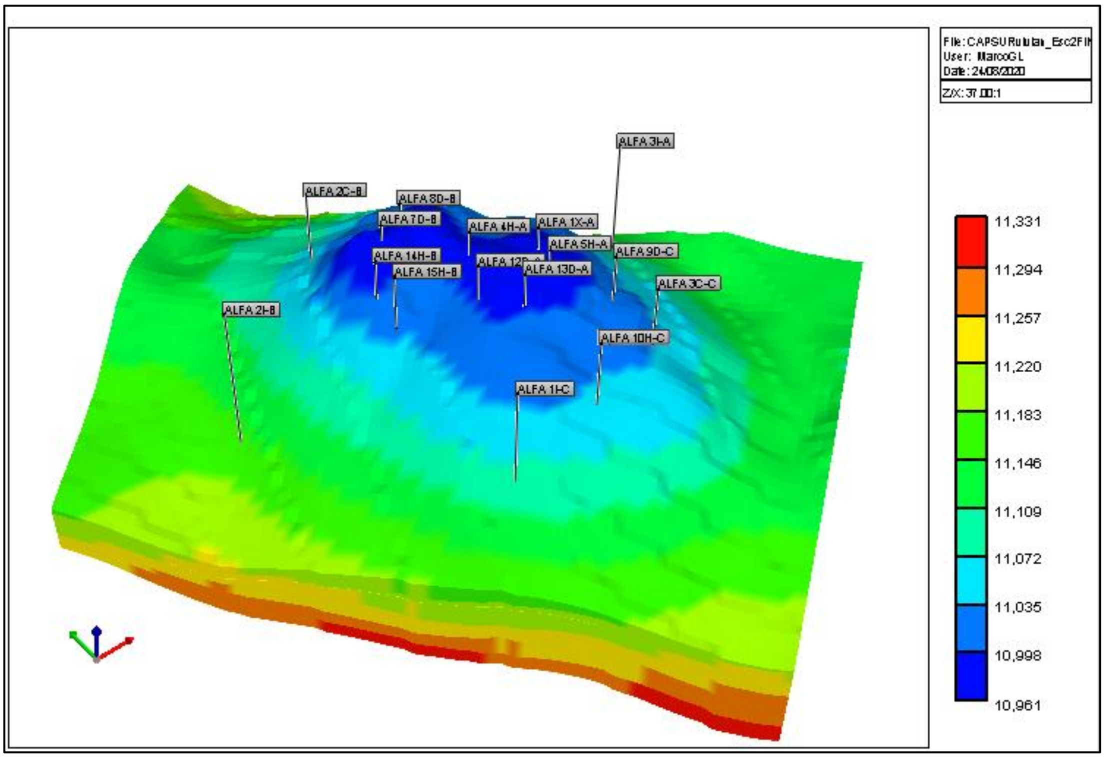


Figure 60. Vivian simulation model.

Productive performance of Vivian

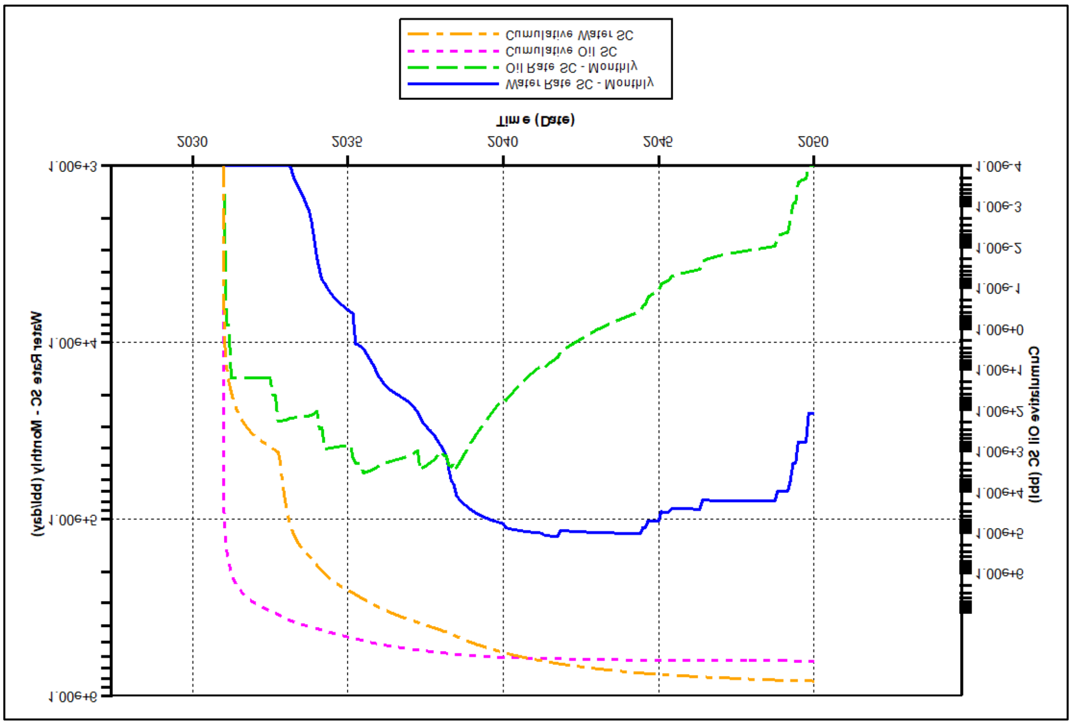


Figure 61. Productive performance of Vivian.

The BHP is plotted (See Figure 62) for the representative well ALFA 8D-B, showing the Vivian formation behavior.

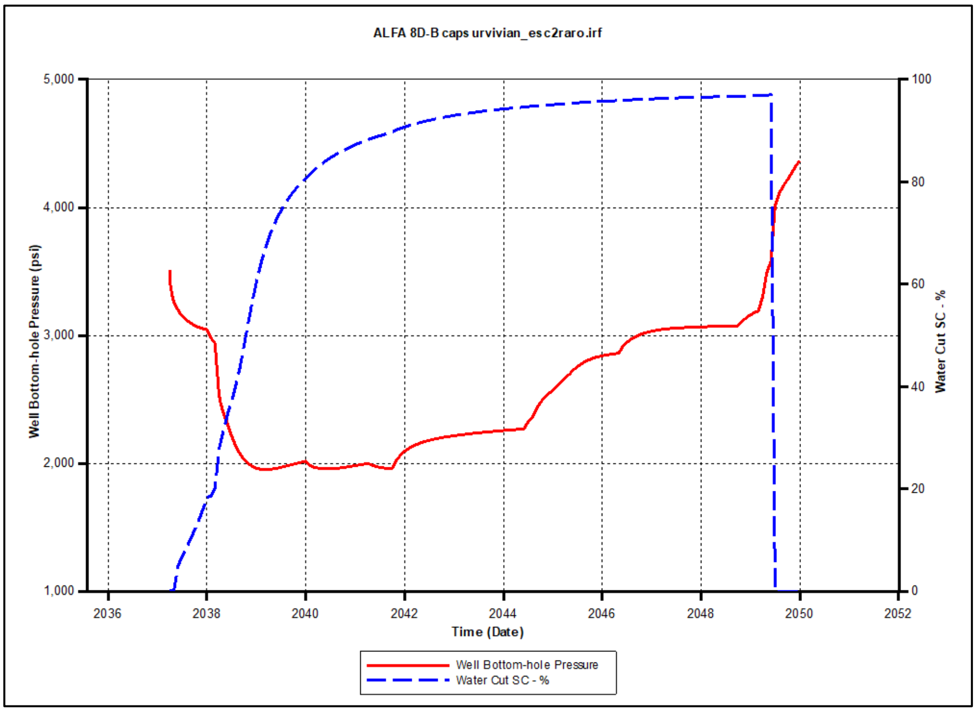


Figure 62. Behavior of BHP and watercut.

Productive performance of Vivian and Chonta – Scenario 2

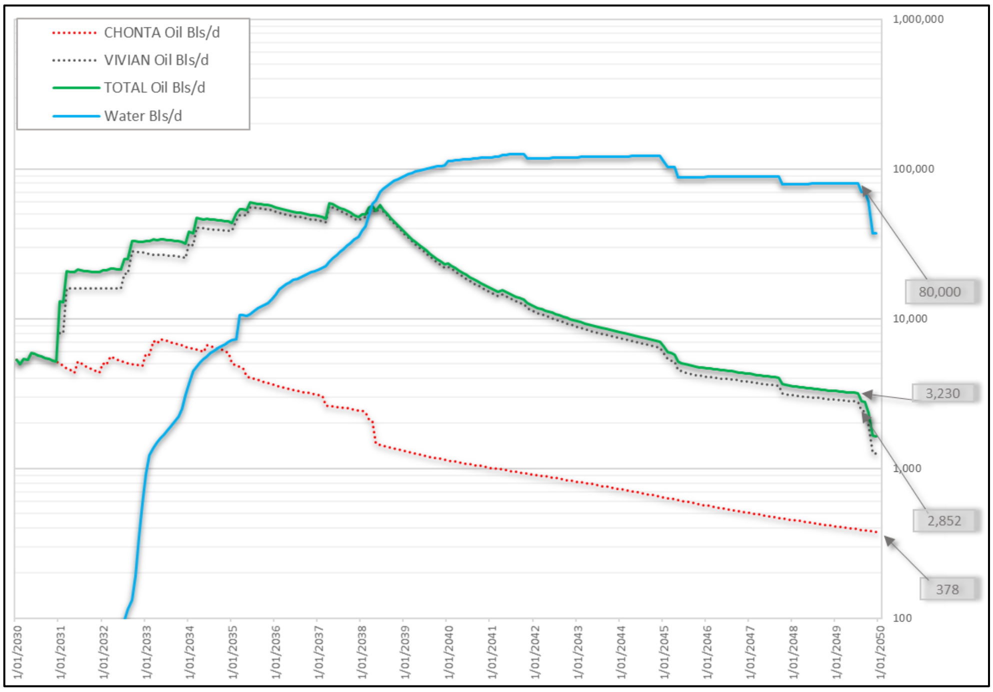


Figure 63. Productive performance of scenario 2

Results:

- The production of a horizontal well was twice that of a vertical well, considering a horizontal extension of 1300ft of the producing zone. (See Figure 64)

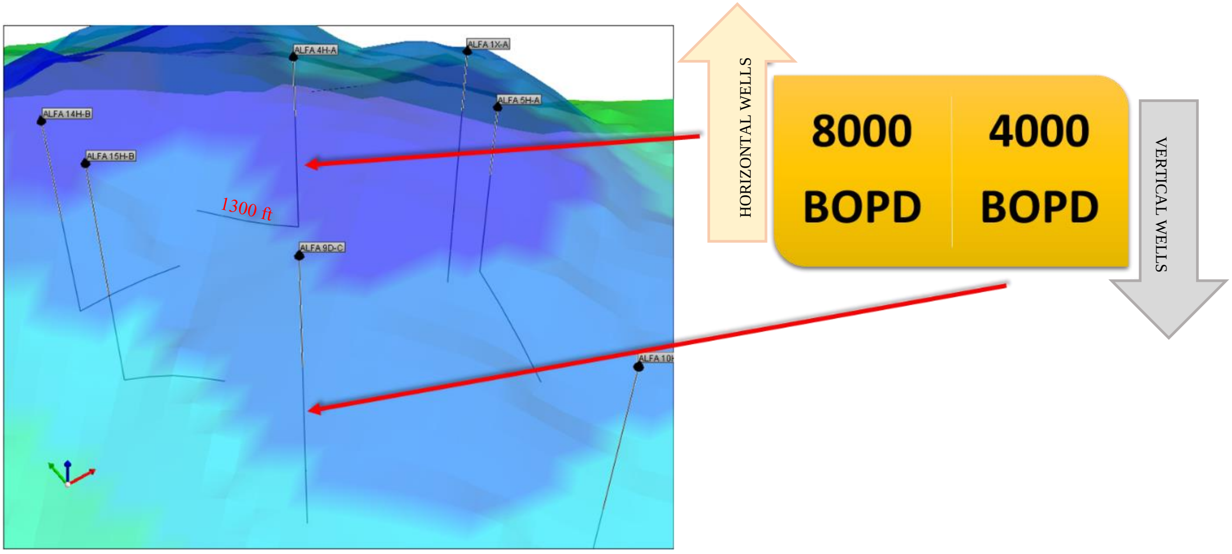


Figure 64. Design for horizontal and vertical well

- Model Validation

The OOIP value obtained in the simulation presents a variation of less than 6% of the OOIP with respect to that obtained from the Volumetric Method, in such a way we validate our simulation model. (See Table 20)

OOIP (MMBls)	Volumetric M.			Simulation
	P10	P50	P90	
Chonta	67.4	67.4	78	66.1
Vivian	287.1	329.3	373.1	274.2

Table 20. Vivian and Chonta OOIP.

- Cumulative Production

	Scenario 1		
	Oil (MMBls)	Water (MMBls)	Gas (BCF)
Chonta	14.6	0.1	11.9
Vivian	134.3	316.2	8.0

Table 21. Cumulative production - scenario 1

	Scenario 2		
	Oil (MMBls)	Water (MMBls)	Gas (BCF)
Chonta	17.6	2.6	24.2
Vivian	145.6	452.1	8.7

Table 22. Cumulative production - scenario 2

- Recovery Factor

From a point of view of greater oil recovery, we can say the scenario 2 (from simulation) is the most optimal since its recovery factor is very close to the theoretical values obtained by correlation. (See Table 23).

	Theoretical Correlation	Analytical	Scenario 1	Scenario 2
Chonta	29.31%	18.94.%	22.0%	26.6%
Vivian	59.26%	51.11%	49.0%	53.1%

Table 23. Comparison of recovery factor.

➢ Productive Performance of the Whole Field

Total production of the field (for Vivian and Chonta) compared for the simulation scenario 1, 2 and the real behavior of the analogous field of study “Capahhuari Sur”. So, the better option it is the scenario 2 which represent a better production behavior. This will be taken it for the development plan of the oil field. The economic analyzes will confirm whether scenario 1 or 2 is the most optimal and profitable for the company. (See Table 24)

20 Years of Exploitation			
Cases	Np (MM BLS)	OOIP (MM BLS) V+C	R.F Field
1	148.83	340.30	43.7%
2	163.18	340.30	48.0%
Real (CPS)	150.92	340.30	44.4%

Table 24. Comparison of field development in 20 years.

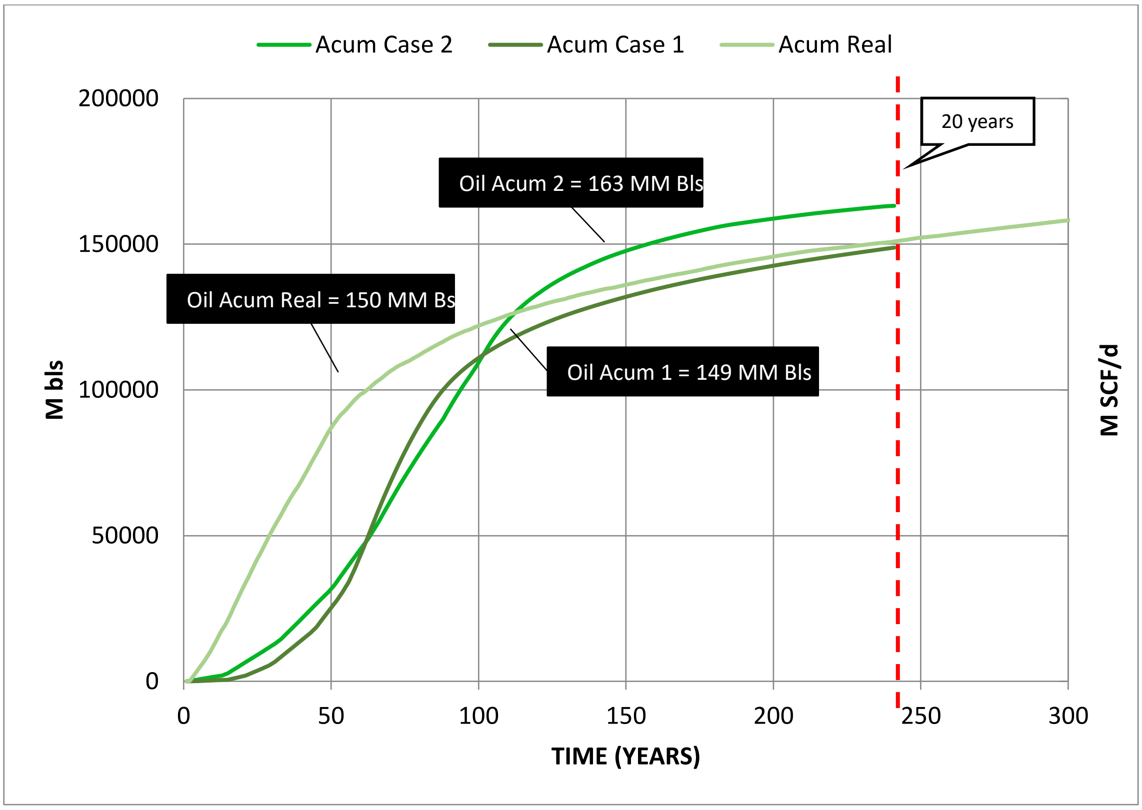


Figure 65. Comparison of production scenarios.

➢ Well and Platform's Locations

As a result of the simulation analysis, the locations for the wells and platforms obtained from scenario 2 are proposed for the development of the field in the Figure 66 and Figure 67.

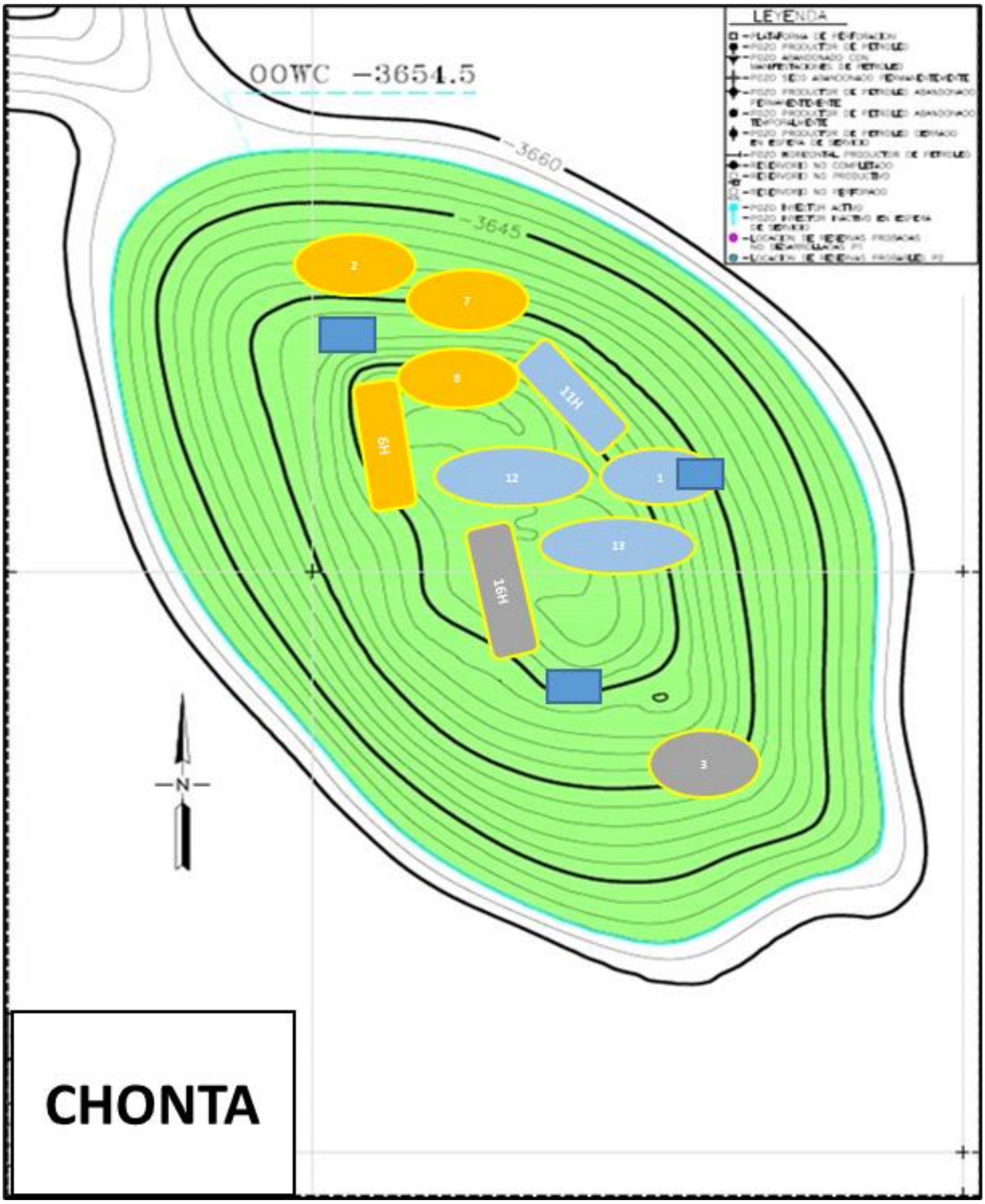


Figure 66. Well locations in Chonta.

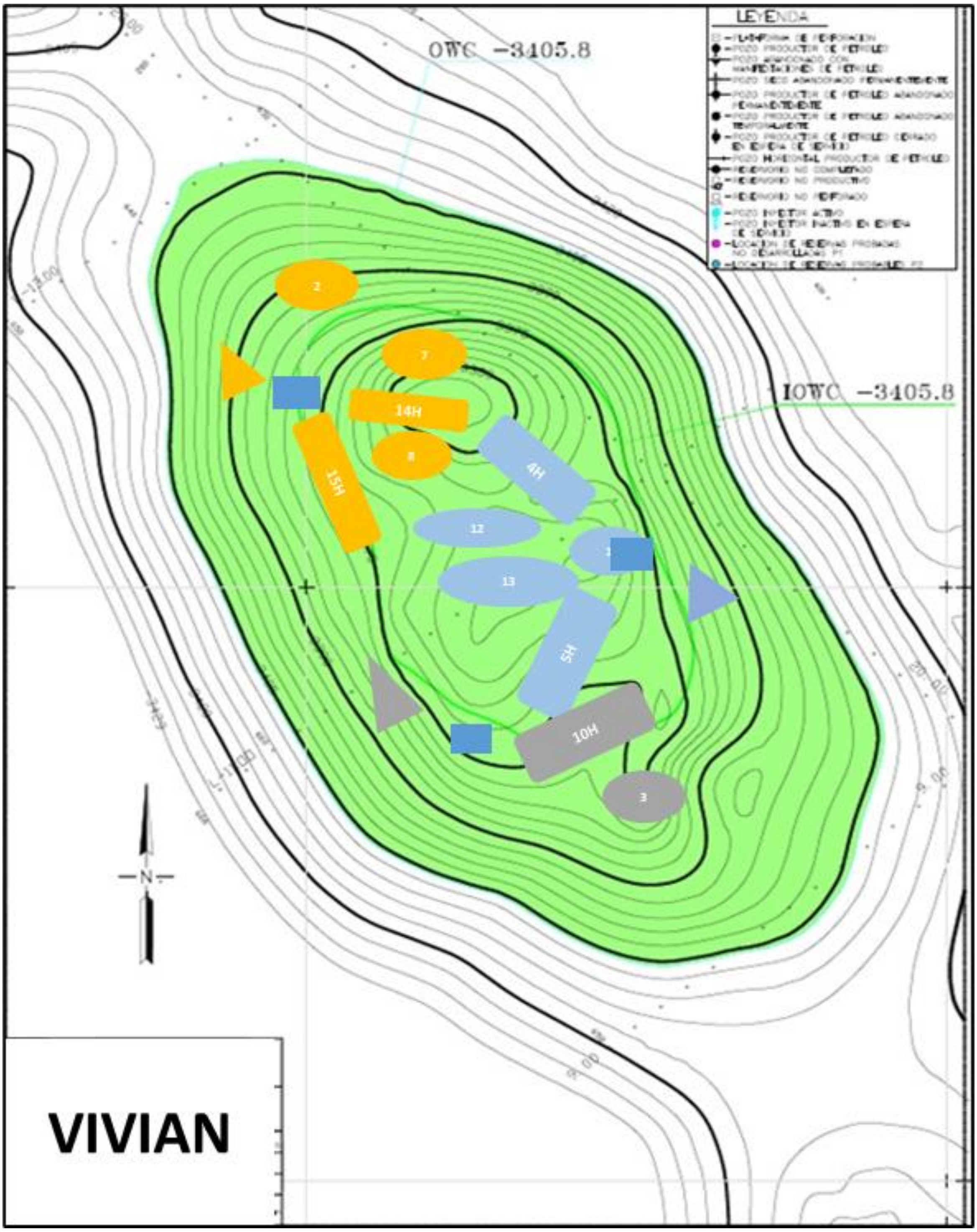


Figure 67. Well locations in Vivian.

4.2.5 Classification of Reserves

The results obtained through numerical simulation and taking into account for the volumes of hydrocarbons recoverable through primary methods through the calculation of the theoretical recovery factor for each reservoir; we can classify the volumes according to the classification set out in the guide of Petroleum Resources Management System - PRMS (Society of Petroleum Engineers, 2018). (See Figure 68).

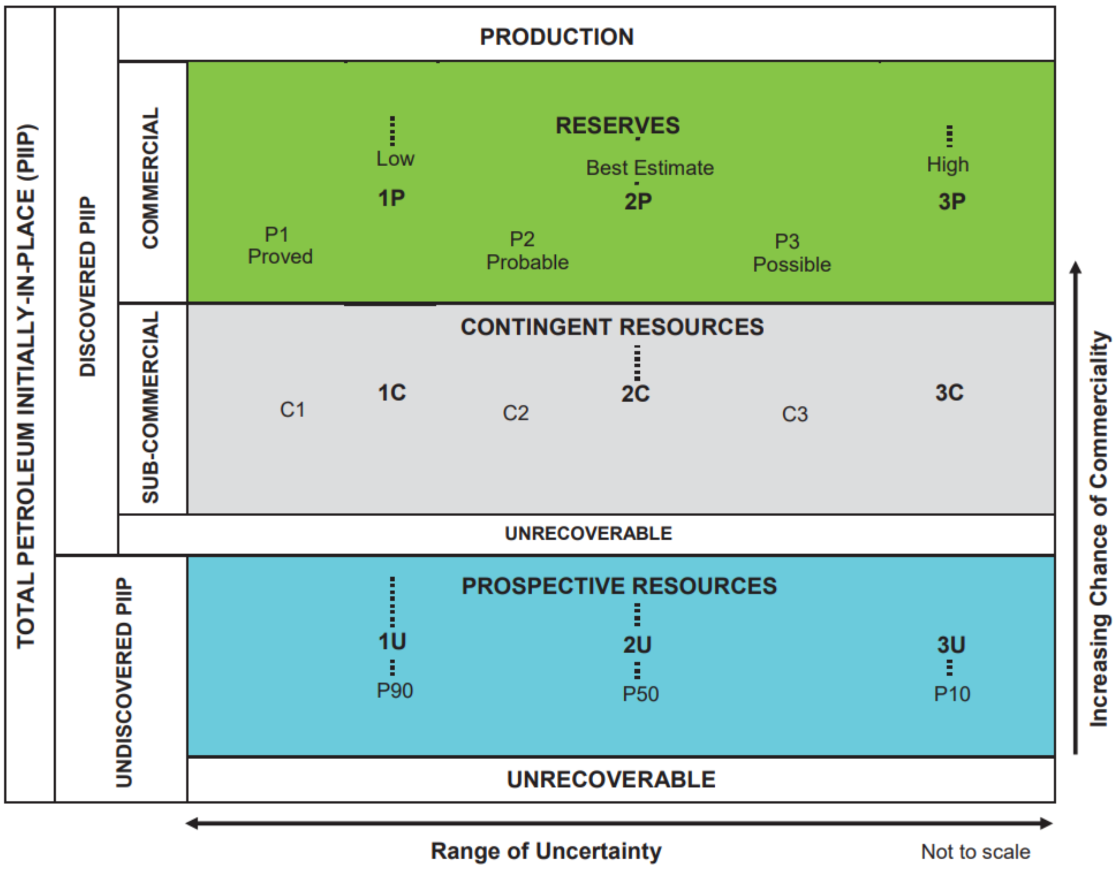


Figure 68. Classification of resources according to (source: PRMS, 2018).

Based on the information mentioned in the last section, the classification by Resources is made for each reservoir. Due it is a Lead oil field; all calculated volumes are classified as a Prospective Resource. Once the ALFA 1XD discovered well reaches its final depth in November 2029, it is expected to discover the accumulations of hydrocarbons calculated in this work and to be able to classify them into reserves (recoverable volumes) and contingent resources (existing volumes but not recoverable due to technical or economic factor), in such a way that according to the maturity of the probability of existence of the OOIP (see section Probabilistic) present the values for each classification. (See Figure 69 and Figure 72).

- **Vivian Reservoir:**

<table>
<tr><td colspan="8">Classification of Reserves and Resources - Capahuari Sur Extension Field - Vivian Formation</td></tr>
<tr><td rowspan="10">OIL
TOTAL IN SITU</td><td rowspan="7">OOIP</td><td colspan="2"></td><td colspan="4">PRODUCTION</td></tr>
<tr><td rowspan="2">P 10</td><td rowspan="2">287.1</td><td rowspan="3">Recoverable</td><td colspan="3">Reserves</td></tr>
<tr><td>1P</td><td>2P</td><td>3P</td></tr>
<tr><td rowspan="2">P 50</td><td rowspan="2">329.3</td><td>170.146</td><td>195.117</td><td>221.102</td></tr>
<tr><td rowspan="3">Not Recoverable</td><td colspan="3">Contingent Resources</td></tr>
<tr><td rowspan="2">P 90</td><td rowspan="2">373.1</td><td>1C</td><td>2C</td><td>3C</td></tr>
<tr><td>116.990</td><td>134.159</td><td>152.027</td></tr>
<tr><td colspan="3"></td><td colspan="4">NO RECUPERABLES</td></tr>
<tr><td colspan="4" rowspan="2">OOIP NOT DISCOVERED</td><td colspan="3">Prospective Resources</td></tr>
<tr><td>1U</td><td>2U</td><td>3U</td></tr>
</table>

Figure 69. Resource classification according to PRMS for the Vivian reservoir.

Also, it is possible classify the proven reserves, for this we are located at a point during the life of the field because the subclassifications of reserves vary over time due to production of the reservoirs.

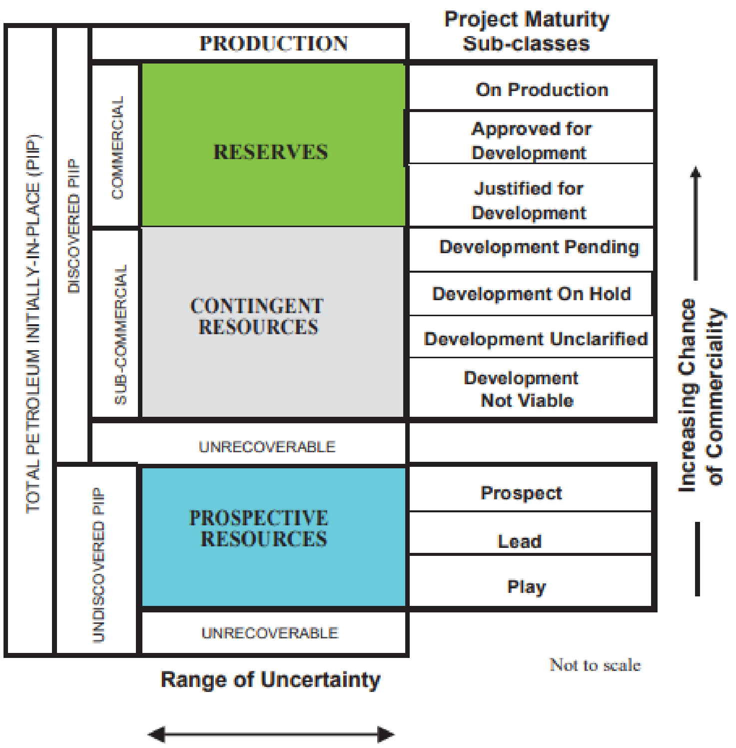


Figure 70. Sub-classification depending on the degree of maturity of the project.

We focus on the sub-classifications of proved reserves 1P, since we have considered this volume for all the calculations; and we consider this classification as if we were in January 2031, having a field already developed.

Reserves 1P (MMbbl)		Wells	Criterion
On Production	0.0	None	Production Start
Proven Developed Reserves	56.635	4H y 5H	Shot sands
Proven Developed Reserves in No Production	26.163	1X, 2D y 3D	Sand Behind csg
Proven Undeveloped Reserves	87.348	Development plan	Future wells to drill

*Date of reference 01/01/2031

Figure 71. Classification of Reserves according to PRMS (2018) for the Vivian reservoir.

- **Chonta Reservoir:**

Through the same analysis the volumes for the Chonta formation are presented:

Classification of Reserves and Resources - Reservoir Capahuari Sur Extensión - Formation Chonta								
ORINAL OIL IN PLACE	OOIP			PRODUCTION				
		P 10	57.9	Recuperable	Reserves			
					1P	**2P**	**3P**
		P 50	67.4		16.974	19.754	22.847
				No Recuperable	Contingents Resource			
		P 90	78		**1C**	**2C**	**3C**
					40.942	47.645	55.108
				NO RECUPERABLE				
	OOIP NO DESCOVERY				Prospective Resource			
					1U	**2U**	**3U**

Figure 72. Resource classification according to PRMS for Chonta reservoir.

Reserves 1P (MMbbl)		**Wells**	**Criterion**
On Production	2.0	1X, 2D y 3D	Production Start
Proven Developed Reserves	3.799	1X, 2D y 3D	Shot sands
Proven Developed Reserves in No Production	0.000	There are no more wells until now	
Proven Undeveloped Reserves	11.192	Development plan	Future wells to drill

* For 01/01/2031

Figure 73. Classification of reserves according to PRMS for Chonta reservoir.

It is important to mention that the reserve classification tables (Figure 71 y Figure 73) will vary each year due to the development of 1P reserves through development wells, so the tables are only validated for the given date (01 / 01/2031).

Summary: Reserves and Resources for Chonta and Vivian

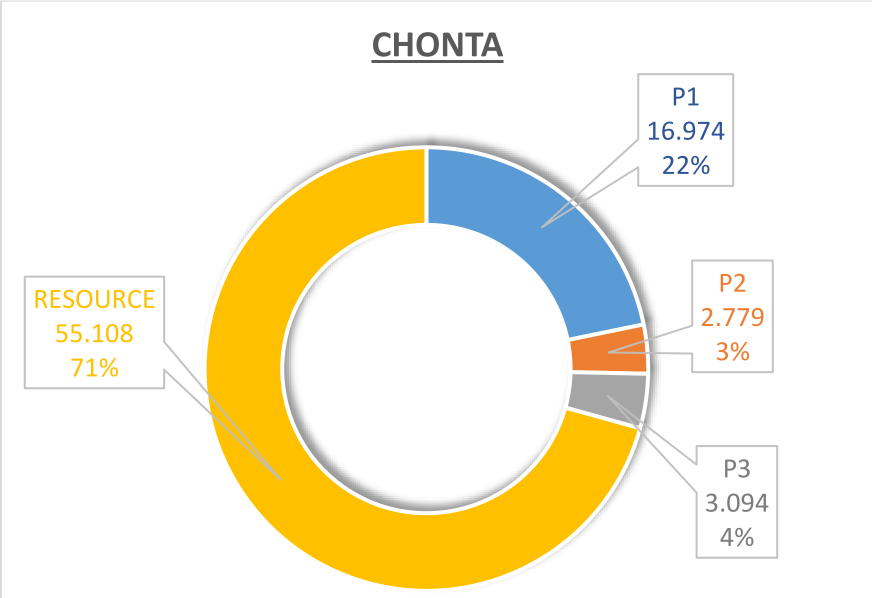


Figure 74. Reserves and resources in Chonta.

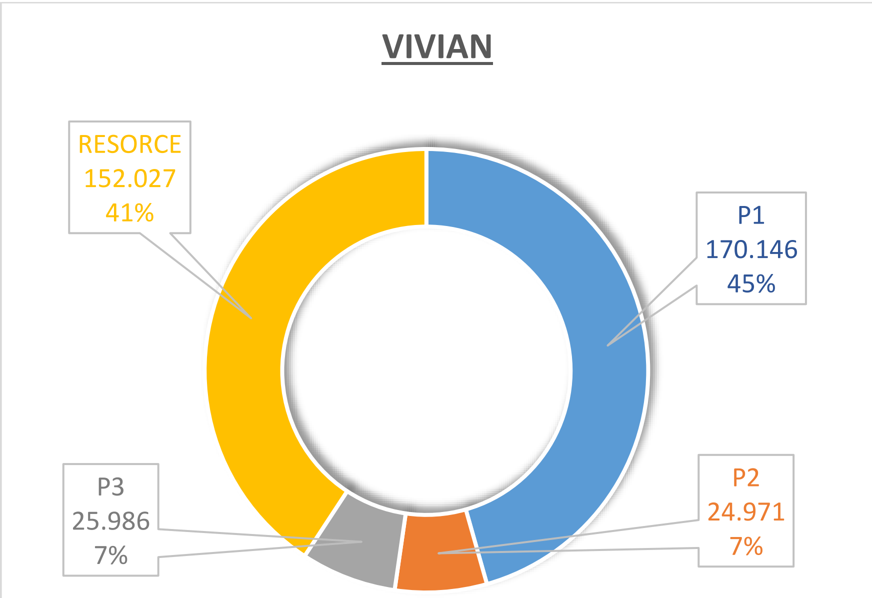


Figure 75. Reserves and resources in Vivian

4.3 Drilling Engineering

For the field development two possible scenarios were studied by reservoir engineering area. Finally, the second was chosen because it shows a better production performance.

4.3.1 Definition of the Objective of the Drilling Program

The Capahuari Sur Extensión field exploration and development project was planned considering sixteen wells, three of them will use to identify and limit the reservoir areal extension.

According to the optimal production scenario the field requires directional and horizontal wells to reach the largest area as possible from every drilling platform

- 1 vertical exploratory well
- 7 directional producing wells
- 5 producing horizontal wells in the Vivian formation
- 3 producing horizontal wells in the Chonta formation

Environmental impact is an important factor during drilling operations in the Peruvian jungle, so all the wells are going to be distributed in three platforms (A, B, C).

It is important to note that these previously classified directional wells maintain a vertical trajectory in the Vivian and Chonta producing formations.

Based on reservoir simulation horizontal wells will present a higher initial production than obtained with vertical wells because they present a largest well-reservoir contact area.

For this scenario, the following objectives were achieved:

- Reduce the number of development wells in the field.

- A higher recovery factor.

These objectives mean lower operating costs, as well as higher accumulated production of hydrocarbons.

4.3.2 Poral Pressure

Poral pressure, also called formation pressure, is defined as the pressure exerted by the fluid trapped in the poral space of a rock. It is a function of the formation fluids and depth. It could be classified in normal or abnormal pressure.

4.3.2.1 Normal pressure

It is the pressure exerted by a column of water (8.33 ppg) that extends from surface to a given depth (See Figure 77).

4.3.2.2 Anormal pressure

It is defined as the pressure greater or less than the hydrostatic pore pressure, the causes of these abnormal pressures are related to different geological, geochemical, geothermal, and mechanical events.

$$P_P = S-(S-P_N)*\left[\frac{R_O}{R_N}\right]^{\alpha}$$

$$P_P = S-(S-P_N)*\left[\frac{C_N}{C_O}\right]^{\alpha}$$

$$P_P = S-(S-P_N)*\left[\frac{\Delta T_N}{\Delta T_O}\right]^{\alpha}$$

Figure 76. Eaton method - estimation of the pore pressure from seismic velocities (source: Ojeda & Mateus 2009).

The initial pressure of each reservoir is known (data), therefore, for practical purposes, we calculate the pore pressure gradient considering an average depth for each formation.

- Poral pressure gradient for Vivian formation: 0.463 psi/ft.
- Poral pressure gradient for Chonta formation: 0.468 psi/ft.

It is important to highlight the following assumption, each calculated gradient is considered constant throughout the formation, since the variation of the gradient is minimal in the same formation.

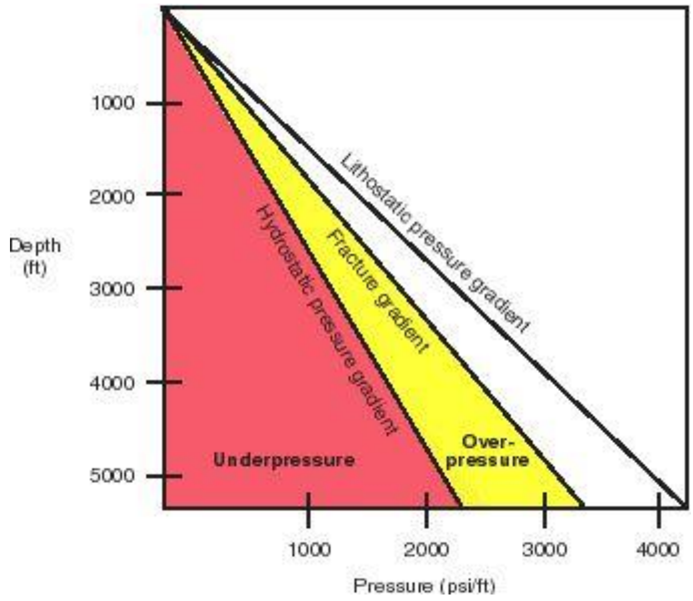


Figure 77. Pressure vs depth (Source: Schlumberger/Oilfield Glossary).

4.3.3 Fracture Pression Gradient Prediction

Fracture pressure is defined as the pressure at which a formation rupture occurs. The pressure gradient, generally expressed in psi / ft [kPa / m], at which a specific range of formation breaks and admits fluid.

Determination of the fracture gradient is a key requirement for designing and analyzing hydraulic fracturing treatment.

4.3.3.1 Theoretical determination

Design a well plan begins for the construction of the drilling operating window, which requires of poral and fracture pressures.

Fracture gradient identification allow drilling engineers anticipate operational problems like fluid loss circulation or no planned formation fracture. This gradient can be calculated by different equations, all depend in the amount of input data.

- Matthews & Kelly (1967).
- Eaton (1969).

- Daines (1982).

The most certain equation used in the industry, according to experts (Gonzales, 2015), is the equation given by Ben Eaton. Eaton introduced the Poisson ratio in the fracture gradient determination, obtaining a better result.

Currently Poisson's ratio is an unknown value, so for this case we will use the Matthews and Kelly correlation (See Equation 16 and Equation 17) due to its similar precision and the available data.

4.3.3.2 Matthews & Kelly correlation:

$$F = \frac{P}{D} + Ki\,\frac{\sigma}{D}$$

Equation 16. Matthews & Kelly correlation.

where:

• F= Fracture pressure gradient (psi/ft).

• P/D = Poral pressure gradient (psi/ft).

• σ/D = Matrix stress gradient (psi/ft).

• Ki = Matrix stress coefficient.

4.3.3.3 Matrix stress estimation:

$$\frac{S}{D} = \frac{P}{D} + \frac{\sigma}{D}$$

Equation 17. Matrix stress.

Where:

• S/D: Overload gradient (psi/ft).

• P/D: Poral pressure gradient (psi/ft).

• σ/D: Matrix stress gradient (psi/ft).

Ki is determined empirically by using the correlated curves for formations with abnormal pressures, for this we determine the equivalent depth under normal pressure conditions.

Replacing the values in the previous equations, we obtain the Table 25.

RESERVOIR	Ki Coefficient	Fracture Gradient (psi/ft)
VIVIAN	0.62	0.795
CHONTA	0.75	0.867

Table 25. Results of the Vivian and Chonta fracture pressure gradient.

4.3.4 Determination of the Operating Window

One of the most critical stages in the development of the field is the construction of the drilling operating window. A design with high uncertainty will take us away from the objective.

Well instability includes conditions that cause compression or stress failures in the rock present in the well walls.

The operating window is the interval between the Pore Pressure and the Fracture Pressure. We have this space to drill the well without breaking the rocks or borehole collapse. Usually, the mud weights oscillate within this space. (See Figure 78).

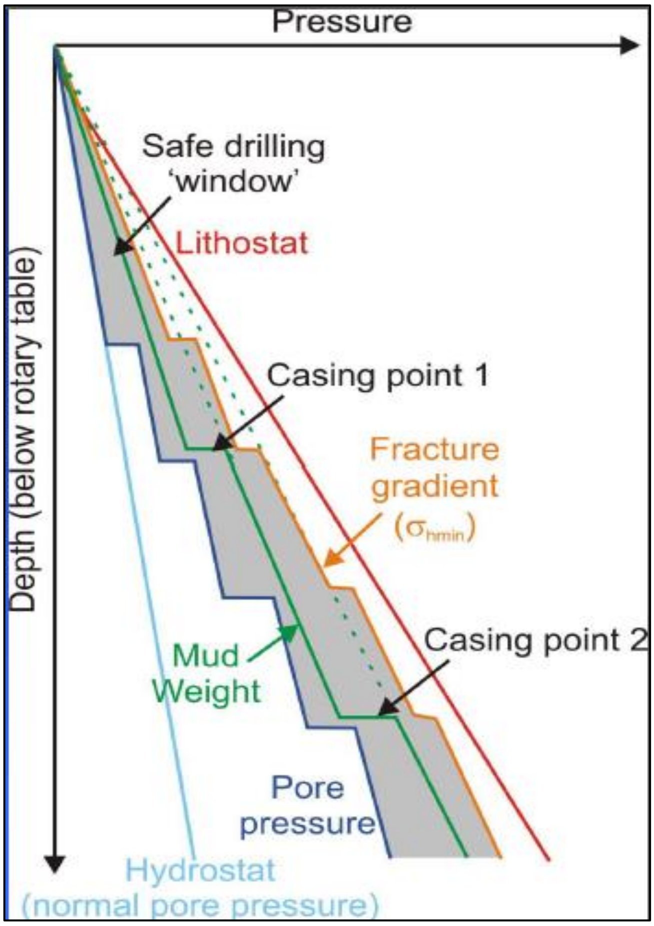


Figure 78. Referential drilling window (source: LUSI, Drilling facts and analysis-AAPG International conference and exhibition).

Is necessary to develop a well stability model to have a better understanding of the mechanisms that cause the rock failure, as well as the types of stress in the well walls.

The information available for the actual window design is relatively scarce. We do not have a series of lithology or geophysical loggings, since we are facing a field classified as lead.

For these reasons and for the purposes of the project, we consider an ideal operational window (See Figure 79) with the values of pore pressure gradient and fracture previously calculated.

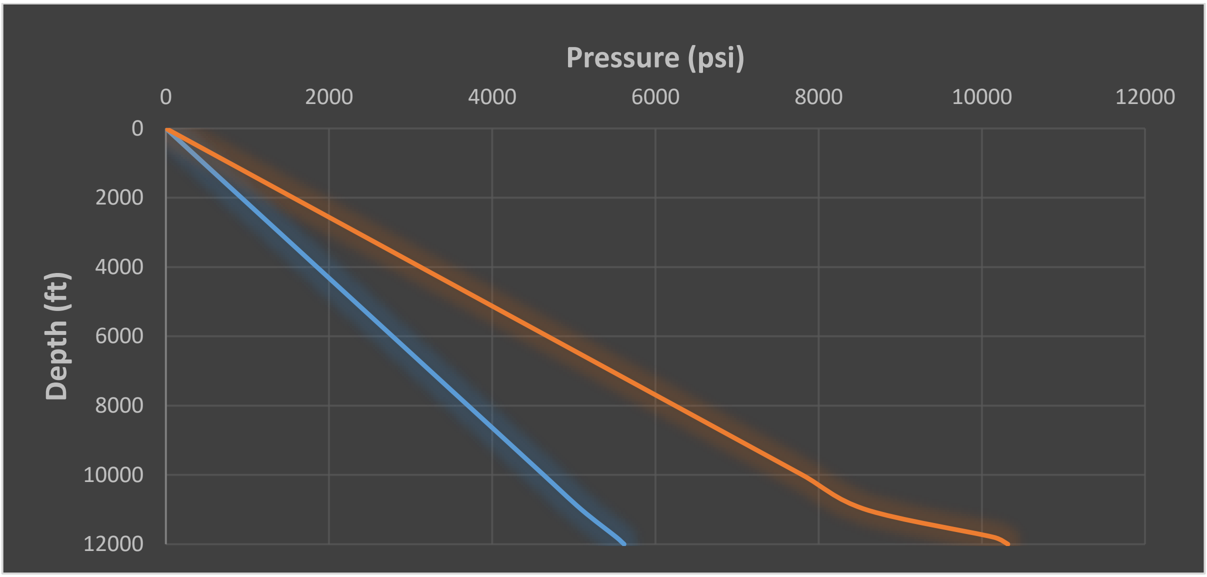


Figure 79. Drilling window of Alfa 1X well.

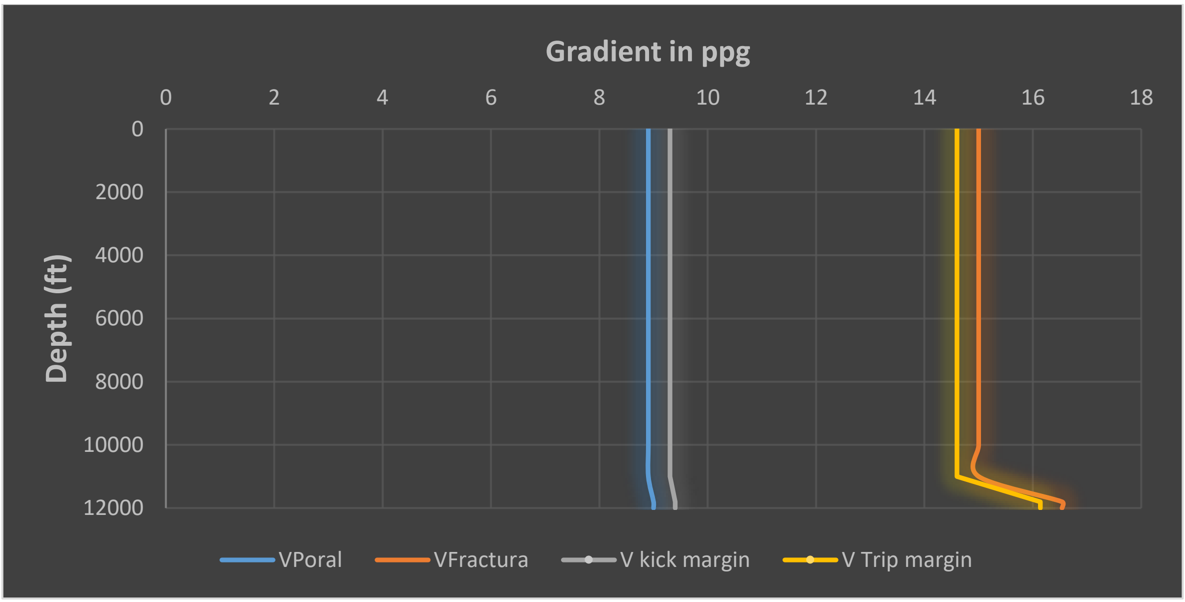


Figure 80. Drilling window in ppg of Alfa 1x well.

4.3.5 Preparation of the Drilling Program

4.3.5.1 Well details

The general information of the exploratory well is shown in the following Table 26.

BASIC DATA	DETAILS
WELL NAME	ALFA 1X-D
COUNTRY	PERU
LOCATION	MARAÑON BASIN
BLOCK	192
WELL TYPE	VERTICAL
TOTAL DEPTH OF THE WELL	12 300 FT
EXPECTED HYDROCARBON	OIL

Table 26. Details of the exploratory well.

4.3.5.2 Well targets

The exploratory well target formations are shown in the following Table 27.

DRILLING TARGETS	FORMATION
PRIMARY OBJECTIVES	VIVIAN
SECONDARY OBJECTIVES	CHONTA

Table 27. Well targets

In terms of production, Vivian formation is better than Chonta formation because it will produce across field productive life while Chonta only will produce for an average of five years.

4.3.5.3 Casing setting depth

For the casing setting depth, we consider the pore pressure and fracture gradients as constant values. On the other hand, we need an offset well geomechanical model to determine the shoes. However, we do not have such a model available since we are facing a prospective field.

However, it is valid to place the setting depth as shown in the diagram of Well 1X, since the depths taken are in the common correct range of the northern Peruvian jungle. The intermediate casing shoe is at 9330ft, to isolate or fully cover the "Pozo Sand" formation. In this way, we can avoid a water ingress (water injection).

The types of Casing that we will use during the drilling and completion of the well are conductor, surface, intermediate, and liner.

The conductor casing will be placed in the first 100 m to protect the deconsolidation of superficial zones under the equipment. We see the settlement depths in the Figure 81.

WELL DIAGRAM

CAPAHUARI SUR EXT 01X

CASING

OD	GRADE	WEIGHT	THREAD	DEPTH (ft)
13 3/8"	H-40	48.0#/FT	Buttres	984.00
9 5/8"	N-80	53.5#/ft	Buttres	9500.00
7"	N-80	29#/FT	Buttres	12300.00

NOTES:
- EXPLORATORY WELL

DRILLING:
- BEGINNING: JANUARY 01, 2029
- END: MARCH 10, 2029

COMPLETATION:
- DATE: APRIL 15,2029

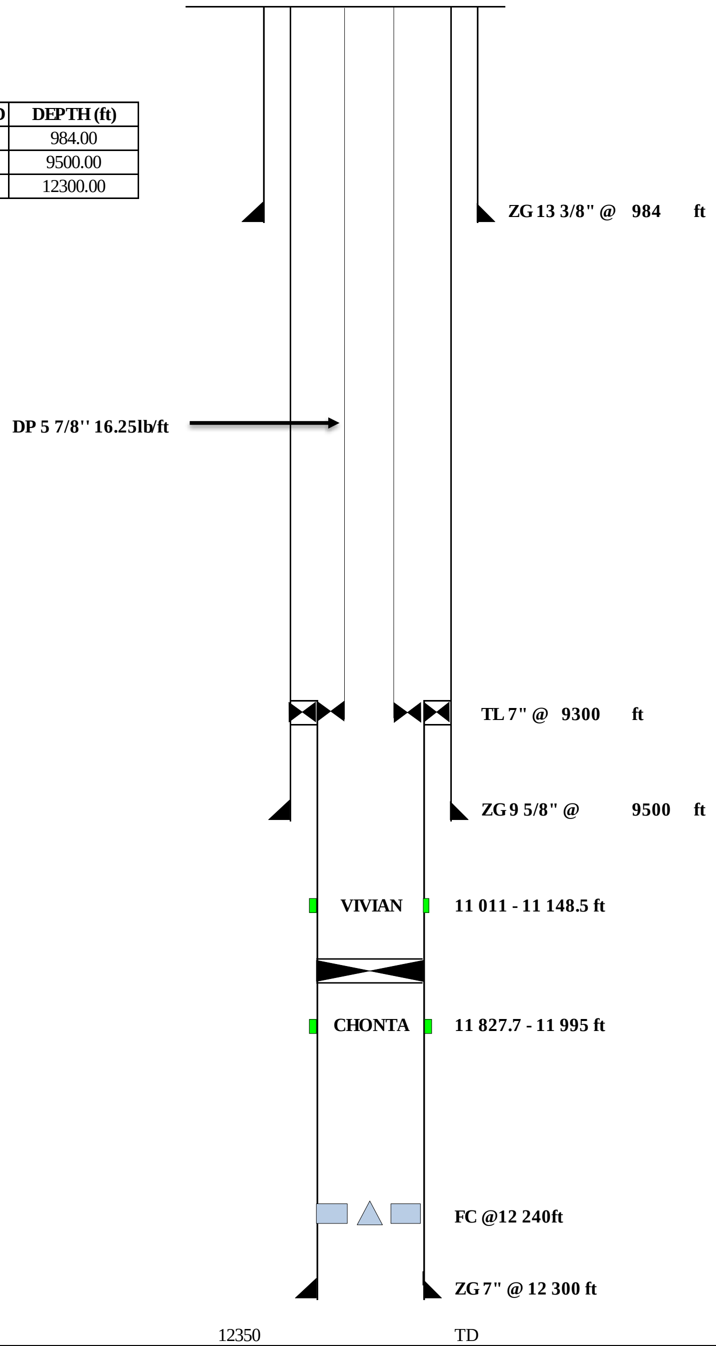


Figure 81. Well diagram – Alfa 1X.

4.3.5.4 Drilling equipment

The drilling rig selection took into consideration the rigs used in analog fields and similar wells depth to avoid every problem related with power or capacity of the rig.

A drilling rig equipment consists of five systems:

- Elevation System.
- Rotating System.
- Circulation System.
- Security System.
- Power System.

4.3.5.5 Casing design

4.3.5.5.1 Surface casing design

The data for the casing design is shown in the following Table 28.

Casing Diameter (in)	13 3/8
Pore pressure gradient (psi/ft)	0.468
Fracture pressure gradient (psi/ft)	0.867
Depth (ft)	984
Maximum mud density (ppg)	8.9

Table 28. Data for the casing design.

- **Methodology**

Step 1:

API design factor:

Safety factors allow us to make casing string design safe and reliable.

The following typical safety factors used are established in accordance with the hydrocarbon exploration and exploitation regulations (MEM, DS 032-2004) and are presented in the following Table 29.

API FACTORS	VALUES
Collapse	1.125
Burst	1.100
Tension (Body)	1.250
Tension (Joint)	2.000

Table 29. Typical API design factors.

This means that if you need to design a string where the expected maximum tensile force is 100,000 lbf, you will select a pipe that can handle 100,000 * 1.25 = 125,000 lbf in tension.

Step 2:

It is important to note that we will assume the most extreme conditions possible for the casing design.

- **By Burst**

$$\boxed{(Burst)\,Pressure\ inside\ casing = \nabla\ Poral\ Pressure\ \left(\frac{psi}{ft}\right) * Depth\ (ft)}$$

Equation 18. Calculation of internal pressure of the casing.

Pressure inside casing = 0.468*984 = 460.1 psi

- **By Collapse**

$$(Collapse) Annulus\ Pressure = 0.052 * \rho\ max\ mud\ (ppg) * Depth\ (ft)$$

Equation 19. Calculation of casing annular pressure.

Annulus pressure = 0.052*8.9*984 = 455.4 psi

Step 3:

Determine the required burst and collapse strengths (See Equation 20 and Equation 21)

- **By Burst**

$$Burst = Pressure\ inside\ casing\ (psi) * Design\ Factor$$

Equation 20. Burst strength required.

Pb = 460.1*1.1 = 506 psi

- **By Collapse**

$$Collapse = Annulus\ Pressure\ (psi) * Design\ Factor$$

Equation 21. Collapse strength required.

Pc = 455.4*1.125 = 512.3 psi

Step 4:

Select the appropriate casing that meets the calculated required strength. For the selection of the casing, the tables (See Figure 82) provided by the Applied Drilling Engineering book (SPE, 1986) were used.

Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Threaded and Coupled: Drift Diameter (in.)	Threaded and Coupled: Outside Diameter of Coupling (in.)	Threaded and Coupled: Outside Diameter Special Clearance Coupling (in.)	Extreme Line: Drift Diameter (in.)	Extreme Line: Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)
10¾	51.00	C-90	0.450	9.850	9.694	11.750	11.250	9.694	11.460	3,400	1,310
	55.50	C-90	0.495	9.760	9.604	11.750	11.250	9.604	11.460	4,160	1,435
	51.00	C-95	0.450	9.850	9.694	11.750	11.250	9.694	11.460	3,480	1,383
	55.50	C-95	0.495	9.760	9.604	11.750	11.250	9.604	11.460	4,290	1,515
	51.00	P-110	0.450	9.850	9.694	11.750	11.250	9.694	11.460	3,660	1,602
	55.50	P-110	0.495	9.760	9.604	11.750	11.250	9.604	11.460	4,610	1,754
	60.70	P-110	0.545	9.660	9.504	11.750	11.250	9.504	11.460	5,880	1,922
	65.70	P-110	0.595	9.560	9.404	11.750	11.250	—	—	7,500	2,088
11¾	42.00	H-40	0.333	11.084	10.928	12.750	—	—	—	1,040	478
	47.00	J-55	0.375	11.000	10.844	12.750	—	—	—	1,510	737
	54.00	J-55	0.435	10.880	10.724	12.750	—	—	—	2,070	850
	60.00	J-55	0.489	10.772	10.616	12.750	—	—	—	2,660	952
	47.00	K-55	0.375	11.000	10.844	12.750	—	—	—	1,510	737
	54.00	K-55	0.435	10.880	10.724	12.750	—	—	—	2,070	850
	60.00	K-55	0.489	10.772	10.616	12.750	—	—	—	2,660	952
	60.00	C-75	0.489	10.772	10.616	12.750	—	—	—	3,070	1,298
	60.00	L-80	0.489	10.772	10.616	12.750	—	—	—	3,180	1,384
	60.00	N-80	0.489	10.772	10.616	12.750	—	—	—	3,180	1,384
	60.00	C-90	0.489	10.772	10.616	12.750	—	—	—	3,360	1,557
	60.00	C-95	0.489	10.772	10.616	12.750	—	—	—	3,440	1,644
	60.00	P-110	0.489	10.772	10.616	12.750	—	—	—	3,610	1,903
13⅜	48.00	H-40	0.330	12.715	12.559	14.375	—	—	—	740	541
	54.50	J-55	0.380	12.615	12.459	14.375	—	—	—	1,130	853
	61.00	J-55	0.430	12.515	12.359	14.375	—	—	—	1,540	962
	68.00	J-55	0.480	12.415	12.259	14.375	—	—	—	1,950	1,069
	54.50	K-55	0.380	12.615	12.459	14.375	—	—	—	1,130	853
	61.00	K-55	0.430	12.515	12.359	14.375	—	—	—	1,540	962
	68.00	K-55	0.480	12.415	12.259	14.375	—	—	—	1,950	1,069
	68.00	C-75	0.480	12.415	12.259	14.375	—	—	—	2,220	1,458
	72.00	C-75	0.514	12.347	12.191	14.375	—	—	—	2,600	1,558
	68.00	L-80	0.480	12.415	12.259	14.375	—	—	—	2,260	1,556
	72.00	L-80	0.514	12.347	12.191	14.375	—	—	—	2,670	1,661
	68.00	N-80	0.480	12.415	12.259	14.375	—	—	—	2,260	1,556
	72.00	N-80	0.514	12.347	12.191	14.375	—	—	—	2,670	1,661
	68.00	G-90	0.480	12.415	12.259	14.375	—	—	—	2,320	1,750
	72.00	G-90	0.514	12.347	12.191	14.375	—	—	—	2,780	1,869
	68.00	C-95	0.480	12.415	12.259	14.375	—	—	—	2,330	1,847
	72.00	C-95	0.514	12.347	12.191	14.375	—	—	—	2,820	1,973
	68.00	P-110	0.480	12.415	12.259	14.375	—	—	—	2,330	2,139
	72.00	P-110	0.514	12.347	12.191	14.375	—	—	—	2,890	2,284

Size (in.)	Weight (lbm/ft)	Grade	**Internal Pressure Resistance, psi: Plain End or Extreme Line	Round Thread: Short	Round Thread: Long	Buttress Thread, Regular Coupling: Same Grade	Buttress Thread, Regular Coupling: Higher Grade	Buttress Thread, Special Clearance Coupling: Same Grade	Buttress Thread, Special Clearance Coupling: Higher Grade	*Joint Strength—1,000 lbf, Threaded and Coupled, Round Thread: Short	Round Thread: Long	Buttress Thread: Regular Coupling	Buttress Thread: Regular Coupling Higher Grade†	Buttress Thread: Special Clearance Coupling	Buttress Thread: Special Clearance Coupling Higher Grade†	Extreme Line: Standard Joint	Extreme Line: Optional Joint
10¾	51.00	C-90	6,590	6,590	—	6,590	—	4,150	—	692	—	1,287	—	1,112	—	1,465	—
	55.50	C-90	7,250	6,880	—	7,250	—	4,150	—	771	—	1,409	—	1,112	—	1,595	—
	51.00	C-95	6,960	6,880	—	6,960	—	4,150	—	927	—	1,354	—	1,151	—	1,529	—
	55.50	C-95	7,660	6,880	—	7,450	—	4,150	—	1,032	—	1,483	—	1,151	—	1,675	—
	51.00	P-110	8,060	7,860	—	7,450	7,450	4,150	4,150	1,080	—	1,594	1,594	1,370	1,594	1,820	—
	55.50	P-110	8,860	7,860	—	7,450	7,450	4,150	4,150	1,203	—	1,745	1,745	1,370	1,745	1,993	—
	60.70	P-110	9,760	7,860	—	7,450	7,450	4,150	4,150	1,338	—	1,912	1,912	1,370	1,754	2,000	—
	65.70	P-110	10,650	7,860	—	7,450	7,450	4,150	4,150	1,472	—	2,077	2,077	1,370	1,754	—	—
11¾	42.00	H-40	1,980	1,980	—	—	—	—	—	307	—	—	—	—	—	—	—
	47.00	J-55	3,070	3,070	—	3,070	3,070	—	—	477	—	807	807	—	—	—	—
	54.00	J-55	3,560	3,560	—	3,560	3,560	—	—	568	—	931	931	—	—	—	—
	60.00	J-55	4,010	4,010	—	4,010	4,010	—	—	649	—	1,042	1,042	—	—	—	—
	47.00	K-55	3,070	3,070	—	3,070	3,070	—	—	509	—	935	935	—	—	—	—
	54.00	K-55	3,560	3,560	—	3,560	3,560	—	—	606	—	1,079	1,079	—	—	—	—
	60.00	K-55	4,010	4,010	—	4,010	4,010	—	—	693	—	1,208	1,208	—	—	—	—
	60.00	C-75	5,460	5,460	—	5,460	—	—	—	869	—	1,361	—	—	—	—	—
	60.00	L-80	5,830	5,820	—	5,830	—	—	—	913	—	1,399	—	—	—	—	—
	60.00	N-80	5,830	5,820	—	5,830	—	—	—	924	—	1,440	1,440	—	—	—	—
	60.00	C-90	6,550	5,820	—	6,300	—	—	—	1,011	—	1,517	—	—	—	—	—
	60.00	C-95	6,920	5,820	—	6,300	—	—	—	1,066	—	1,596	—	—	—	—	—
	60.00	P-110	8,010	5,820	—	6,300	6,300	—	—	1,242	—	1,877	1,877	—	—	—	—
13⅜	48.00	H-40	1,730	1,730	—	—	—	—	—	322	—	—	—	—	—	—	—
	54.50	J-55	2,730	2,730	—	2,730	2,730	—	—	514	—	909	909	—	—	—	—
	61.00	J-55	3,090	3,090	—	3,090	3,090	—	—	595	—	1,025	1,025	—	—	—	—
	68.00	J-55	3,450	3,450	—	3,450	3,450	—	—	675	—	1,140	1,140	—	—	—	—
	54.50	K-55	2,730	2,730	—	2,730	2,730	—	—	547	—	1,038	1,038	—	—	—	—
	61.00	K-55	3,090	3,090	—	3,090	3,090	—	—	633	—	1,169	1,169	—	—	—	—
	68.00	K-55	3,450	3,450	—	3,450	3,450	—	—	718	—	1,300	1,300	—	—	—	—
	68.00	C-75	4,710	4,550	—	4,710	—	—	—	905	—	1,496	—	—	—	—	—
	72.00	C-75	5,040	4,550	—	4,930	—	—	—	978	—	1,598	—	—	—	—	—
	68.00	L-80	5,020	4,550	—	4,930	—	—	—	952	—	1,545	—	—	—	—	—
	72.00	L-80	5,380	4,550	—	4,930	—	—	—	1,029	—	1,650	—	—	—	—	—
	68.00	N-80	5,020	4,550	—	4,930	4,930	—	—	963	—	1,585	1,585	—	—	—	—
	72.00	N-80	5,380	4,550	—	4,930	4,930	—	—	1,040	—	1,693	1,693	—	—	—	—
	68.00	G-90	5,650	4,550	—	4,930	—	—	—	1,057	—	1,683	—	—	—	—	—
	72.00	G-90	6,050	4,550	—	4,930	—	—	—	1,142	—	1,797	—	—	—	—	—
	68.00	C-95	5,970	4,550	—	4,930	—	—	—	1,114	—	1,772	—	—	—	—	—
	72.00	C-95	6,390	4,550	—	4,930	—	—	—	1,204	—	1,893	—	—	—	—	—
	68.00	P-110	6,910	4,550	—	4,930	4,930	—	—	1,297	—	2,079	2,079	—	—	—	—
	72.00	P-110	7,400	4,550	—	4,930	4,930	—	—	1,402	—	2,221	2,221	—	—	—	—

Figure 82. Casing properties.

Casing selection

Based on the burst and collapse requirements for the surface casing string, H-40 grade pipe meets the minimum requirements, including tension stress. See Table 30.

SELECTED CASING	
Diameter (in)	13 3/8
Nominal Weight (lbm/ft)	48.0
Grade	H-40
Burst (psi)	1730
Collapse (psi)	740
Yield Strength (1000lbf)	541

Table 30. Selected surface casing.

Comparison

The comparison between the required casing with the selected casing is shown in the Table 31.

	REQUIRED	SELECTED
BURST (psi)	506	1730
COLLAPSE (psi)	633.2	740

Table 31. Comparison between required casing and selected casing.

The selected casing (13 3/8, 61.00 # / ft, J-55) meets the design requirements for burst and collapse casing.

Step 5:

After meeting the requirements (burst and collapse), the next step is to consider the tension stress. The design is considered in the most extreme conditions possible, that is, there is no buoyancy effect. See Equation 22.

$$\boxed{Tension\ stress\ (lbf) = Nominal\ Weight\ \left(\frac{lb}{ft}\right) * Depth(ft)}$$

Equation 22. Calculation of tension stress.

Tension stress = 48.0*984 = 47 232 lbf

Step 6:

We must verify if the selected casing meets the tension stress requirements. (See Table 32).

	REQUIRED	SELECTED
TENSION (Lbf)	47 232	541.0

Table 32. Selected and required tension stress.

Therefore:

SELECTED CASING: 13 3/8'', 48#/ft, H-40

4.3.5.5.2 Intermediate casing design

The data for the casing design is shown in the Table 33.

Casing Diameter (in)	9 5/8
Poral pressure gradient (psi/ft)	0.468
Fracture gradient (psi/ft)	0.867
Depth (ft)	9500
Maximum mud density (ppg)	11.0

Table 33. Data for casing design.

- **Methodology**

Step 1:

The following typical design factors used are established in accordance with the hydrocarbon exploration and exploitation regulations (MEM, DS 032-2004) and are presented in the Table 34.

API FACTORS	VALUES
Collapse	1.125
Burst	1.100
Tension (Body)	1.250
Tension (Joint)	2.000

Table 34. Typical API design factors.

Step 2:

It is important to note that we will assume the most extreme conditions possible for the casing design.

- **By Burst**

$$(Burst)\,Pressure\ inside\ casing = \nabla\ Poral\ Pressure\ \left(\frac{psi}{ft}\right) * Depth\ (ft)$$

Equation 23. Calculation of internal pressure of the casing.

Pressure inside casing = 0.468*9500 = 4 446 psi

- **By Collapse**

$$(Collapse)\,Annulus\ Pressure = 0.052 * \rho\ max\ mud\ (ppg) * Depth\ (ft)$$

Equation 24. Calculation of casing annular pressure.

Annulus pressure = 0.052*11.0*9500 = 5 434 psi

Step 3:

Determine the required burst and collapse strengths.

- **By Burst**

$$Burst = Pressure\ inside\ casing\ (psi) * Design\ Factor$$

Equation 25. Burst strength required.

Pb = 4 446*1.1 = 4 890.6 psi

- **By Collapse**

$$Collapse = Annulus\ Pressure\ (psi) * Design\ Factor$$

Equation 26. Collapse strength required.

Pc = 5 434*1.125 = 6 113.2 psi

Step 4:

Select the appropriate casing that meets the calculated required strength. For the selection of the casing, the tables (See Figure 83) provided by the Applied Drilling Engineering book (SPE, 1986) were used.

Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Drift Diameter (in.)	Threaded and Coupled: Outside Diameter of Coupling (in.)	Threaded and Coupled: Outside Diameter Special Clearance Coupling (in.)	Extreme Line: Drift Diameter (in.)	Extreme Line: Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)
8 5/8	36.00	C-95	0.400	7.825	7.700	9.625	9.125	7.700	9.120	4,350	982
	40.00	C-95	0.450	7.725	7.600	9.625	9.125	7.600	9.120	6,020	1,098
	44.00	C-95	0.500	7.625	7.500	9.625	9.125	7.500	9.120	7,740	1,212
	49.00	C-95	0.557	7.511	7.386	9.625	9.125	7.386	9.120	9,710	1,341
	40.00	P-110	0.450	7.725	7.600	9.625	9.125	7.600	9.120	6,390	1,271
	44.00	P-110	0.500	7.625	7.500	9.625	9.125	7.500	9.120	8,420	1,404
	49.00	P-110	0.557	7.511	7.386	9.625	9.125	7.386	9.120	10,740	1,553
9 5/8	32.30	H-40	0.312	9.001	8.845	10.625	—	—	—	1,370	365
	36.00	H-40	0.352	8.921	8.765	10.625	—	—	—	1,720	410
	36.00	J-55	0.352	8.921	8.765	10.625	10.125	—	—	2,020	564
	40.00	J-55	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,570	630
	36.00	K-55	0.352	8.921	8.765	10.625	10.125	—	—	2,020	564
	40.00	K-55	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,570	630
	40.00	C-75	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,990	859
	43.50	C-75	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,730	942
	47.00	C-75	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,610	1,018
	53.50	C-75	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,350	1,166
	40.00	L-80	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,090	916
	43.50	L-80	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,810	1,005
	47.00	L-80	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,760	1,086
	53.50	L-80	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,620	1,244
	40.00	N-80	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,090	916
	43.50	N-80	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,810	1,005
	47.00	N-80	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,760	1,086
	53.50	N-80	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,620	1,244
	40.00	C-90	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,250	1,031
	43.50	C-90	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,010	1,130
	47.00	C-90	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,000	1,221
	53.50	C-90	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,120	1,399
	40.00	C-95	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,320	1,088
	43.50	C-95	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,120	1,193
	47.00	C-95	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,090	1,289
	53.50	C-95	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,340	1,477
	43.50	P-110	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,420	1,381
	47.00	P-110	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,300	1,493
	53.50	P-110	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,950	1,710

Size Outside Diameter (in.)	Nominal Weight (lbm/ft)	Grade	**Internal Pressure Resistance, psi: Plain End or Extreme Line	Round Thread Short	Round Thread Long	Buttress Thread Regular Coupling Same Grade	Buttress Thread Regular Coupling Higher Grade	Buttress Thread Special Clearance Coupling Same Grade	Buttress Thread Special Clearance Coupling Higher Grade	Joint Strength—1,000 lbf, Threaded and Coupled: Round Thread Short	Round Thread Long	Buttress Thread Regular Coupling	Buttress Thread Regular Coupling Higher Grade†	Buttress Thread Special Clearance Coupling	Buttress Thread Special Clearance Coupling Higher Grade†	Extreme Line Standard Joint	Extreme Line Optional Joint
8 5/8	36.00	C-95	7,710	—	7,710	7,710	—	6,340	—	—	789	976	—	927	—	963	936
	40.00	C-95	8,670	—	8,670	8,670	—	6,340	—	—	904	1,092	—	927	—	1,042	979
	44.00	C-95	9,640	—	9,640	9,640	—	6,340	—	—	1,017	1,206	—	927	—	1,113	979
	49.00	C-95	10,740	—	10,380	10,740	—	6,340	—	—	1,144	1,334	—	927	—	1,113	979
	40.00	P-110	10,040	—	10,040	10,040	10,040	6,340	6,340	—	1,055	1,288	1,288	1,103	1,288	1,240	1,165
	44.00	P-110	11,160	—	10,380	11,160	11,160	6,340	6,340	—	1,186	1,423	1,423	1,103	1,412	1,326	1,165
	49.00	P-110	12,430	—	10,380	11,230	11,230	6,340	6,340	—	1,335	1,574	1,574	1,103	1,412	1,326	1,165
9 5/8	32.30	H-40	2,270	2,270	—	—	—	—	—	254	—	—	—	—	—	—	—
	36.00	H-40	2,560	2,560	—	—	—	—	—	294	—	—	—	—	—	—	—
	36.00	J-55	3,520	3,520	3,520	3,520	3,530	3,520	3,520	394	453	639	639	639	639	—	—
	40.00	J-55	3,950	3,950	3,950	3,950	3,950	3,660	3,950	452	520	714	714	714	714	770	770
	36.00	K-55	3,520	3,520	3,520	3,520	3,520	3,520	3,520	423	489	755	755	755	755	—	—
	40.00	K-55	3,950	3,950	3,950	3,950	3,950	3,660	3,950	486	561	843	843	843	843	975	975
	40.00	C-75	5,390	—	5,390	5,390	—	4,990	—	—	694	926	—	926	—	975	975
	43.50	C-75	5,930	—	5,930	5,930	—	4,990	—	—	776	1,016	—	934	—	975	975
	47.00	C-75	6,440	—	6,440	6,440	—	4,990	—	—	852	1,098	—	934	—	1,032	1,032
	53.50	C-75	7,430	—	7,430	7,430	—	4,990	—	—	999	1,257	—	934	—	1,173	1,053
	40.00	L-80	5,750	—	5,750	5,750	—	5,140	—	—	727	947	—	934	—	975	975
	43.50	L-80	6,330	—	6,330	6,330	—	5,140	—	—	813	1,038	—	934	—	975	975
	47.00	L-80	6,870	—	6,870	6,870	—	5,140	—	—	893	1,122	—	934	—	1,032	1,032
	53.50	L-80	7,930	—	7,930	7,930	—	5,140	—	—	1,047	1,286	—	934	—	1,173	1,053
	40.00	N-80	5,750	—	5,750	5,750	5,750	5,140	5,140	—	737	979	979	979	979	1,027	1,027
	43.50	N-80	6,330	—	6,330	6,330	6,330	5,140	5,140	—	825	1,074	1,074	983	1,074	1,027	1,027
	47.00	N-80	6,870	—	6,870	6,870	6,870	5,140	5,140	—	905	1,161	1,161	983	1,161	1,086	1,086
	53.50	N-80	7,930	—	7,930	7,930	7,930	5,140	5,140	—	1,062	1,329	1,329	983	1,229	1,235	1,109
	40.00	C-90	6,460	—	6,460	6,460	—	5,140	—	—	804	1,021	—	983	—	1,027	1,027
	43.50	C-90	7,120	—	7,120	7,120	—	5,140	—	—	899	1,119	—	983	—	1,027	1,027
	47.00	C-90	7,720	—	7,720	7,720	—	5,140	—	—	987	1,210	—	983	—	1,086	1,086
	53.50	C-90	8,920	—	8,460	8,920	—	5,140	—	—	1,157	1,386	—	983	—	1,235	1,109
	40.00	C-95	6,820	—	6,820	6,820	—	5,140	—	—	847	1,074	—	1,032	—	1,078	1,078
	43.50	C-95	7,510	—	7,510	7,510	—	5,140	—	—	948	1,178	—	1,032	—	1,078	1,078
	47.00	C-95	8,150	—	8,150	8,150	—	5,140	—	—	1,040	1,273	—	1,032	—	1,141	1,141
	53.50	C-95	9,410	—	8,460	8,460	—	5,140	—	—	1,220	1,458	—	1,032	—	1,297	1,164
	43.50	P-110	8,700	—	8,700	8,700	8,700	5,140	5,140	—	1,106	1,388	1,388	1,229	1,388	1,283	1,283
	47.00	P-110	9,440	—	9,440	9,160	9,160	5,140	5,140	—	1,213	1,500	1,500	1,229	1,500	1,358	1,358
	53.50	P-110	10,900	—	9,670	9,160	9,160	5,140	5,140	—	1,422	1,718	1,718	1,229	1,573	1,544	1,386

Figure 83. properties of casing.

Casing selection

Based on the burst and collapse requirements for the intermediate casing string, N-80 grade tubing meets the minimum requirements, including tension stress. See Table 35.

SELECTED CASING	
Diameter (in)	9 5/8
Nominal Weight (lbm/ft)	53.5
Grade	N-80
Burst (psi)	7930
Collapse (psi)	6620
Yield Strength (1000lbf)	1244

Table 35. Selected intermediate casing.

Comparison

The comparison between the required casing with the selected casing is shown in the Table 36.

	REQUIRED	SELECTED
BURST (psi)	4 890.6	7930
COLLAPSE (psi)	6 113.2	6620

Table 36. Comparison between required casing and selected casing.

The selected casing (9 5/8, 53.5.00 # / ft, N-80) meets burst and collapse casing design requirements.

Step 5:

After meeting the requirements (burst and collapse), the next step is to consider the tension stress. The design is considered in the most extreme conditions possible, that is, there is no buoyancy effect. See Equation 27.

$$Tension\ stress\ (lbf) = Nominal\ Weight\ \left(\frac{lb}{ft}\right) * Depth(ft)$$

Equation 27. Calculation of tension stress.

Tension stress = 53.5*9500 = 508 250 lbf

Step 6:

We must verify if the selected casing meets the stress casing design requirements. See Table 37.

	REQUIRED	SELECTED
TENSION (Lbf)	508 250	1 244 000

Table 37. Selected and required tension stress.

Therefore:

SELECTED CASING: 9 5/8’’, 53.5#/ft, N-80

4.3.5.5.3 Casing amount

Finally, we determine the number of casings that will be used for the well design. See Table 38.

	Nominal Weight & Grade	Shoe depth (ft)	Casing length (ft)	Required	Total
Conductive Casing 20”	72 #/ft, N-80	328	40	9	11
Surface casing 13 3/8”	48 #/ft, H-40	984	40	25	27
Intermediate casing 9 5/8”	53 #/ft, N-80	9500	40	238	240
Liner 7’’	29#/ft, N-80	12300	40	75	77

Table 38. Number of casings.

4.3.5.6 BOP requirement

The BOP selection depends on Maximum poral pressure we will find during drilling operations, in this case is 7000 psi, plus a safety margin.

For these operations we will use a 10000 psi BOP to assure a safety operation. See Figure 84.

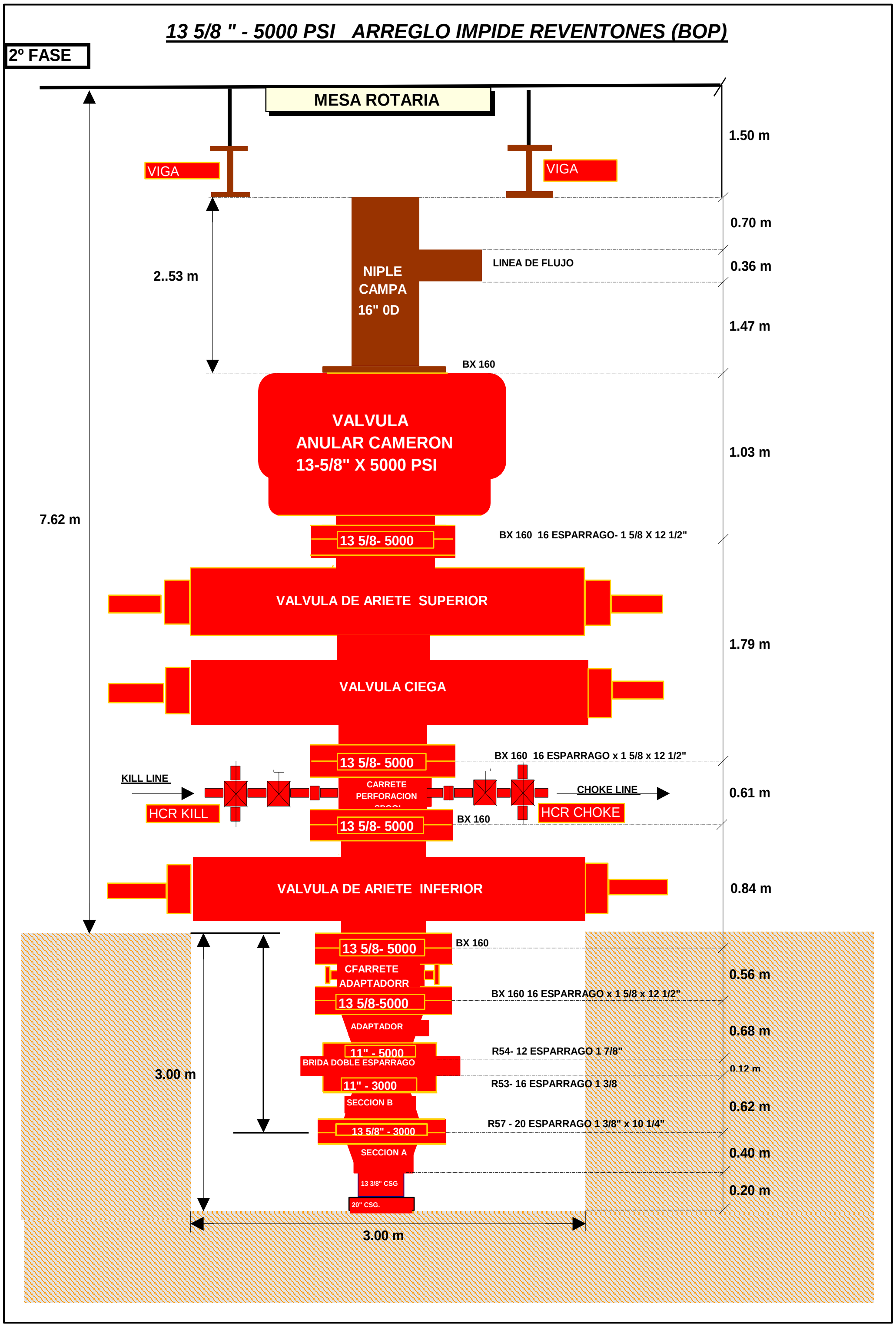


Figure 84. BOP design.

4.3.5.7 Mud program

4.3.5.7.1 Drilling fluid

Drilling fluids are important and necessary for the development and success of drilling an oil well. Good drilling fluid design could prevent problems such as lost circulation, stuck pipe, hole instability, and low rates of penetration.

Functions performed by drilling fluid:

- Clean the cuttings generated in the background and bring them to the surface.
- Provide enough pressure to avoid blowouts.
- Keep clippings in suspension.
- Cool and lubricate the drill string as well as the bit.
- Transmit hydraulic power to the bit.
- Give a floating effect to the pipes.
- Maintain well integrity.
- Improve the rate of penetration.
- Generate a waterproof crust on the walls of the well.
- Avoid contamination to the producing formation.

The selection of the drilling fluid to use is subject to rheology, cost, and environmental considerations.

4.3.5.7.2 Drilling fluid program

For the selection of the drilling fluid, we consider the reports of fluids used in offset wells, in this case belonging to the similar field Capahuari Sur.

For the calculation of the required mud volume, the design of the CapSur27 well will be considered since there is more information on this well. For the calculation the following Equation 28 will be used.

$$V(bbls) = \frac{(D1^2 - D2^2) * h}{1029.4}$$

Equation 28. Volume of fluid in string.

Where:
D1: Larger diameter.
D2: Minor Diameter.
h: Height of fluid column.

$$V = 900\ bbls$$

This value represents the volume that will be used in the well, but we must add the volume of the tubes and the volume that will flow out of the well. Therefore, there will be a volume of 600 bbls that belongs to the drilling fluid tank (tank 1) and there will be another 400 bbls tank (tank 2) in case of any problem that may occur with the previous tank.

$$Vtotal = 900 + 600(tank1) + 600\ (tank2)$$

$$Vtotal = \ 2\ 100\ bbls$$

4.3.5.7.3 Results

Results are obtained for the mud program.

Alfa 1-X Well

The results are obtained for the mud program of the Alfa 1-X well, an exploratory well with Vivian and Chonta targets. See Table 39.

Mud Program			
Range	**Weight**	**Plastic viscosity**	**Yield Point**
0-1500	8.5 - 8.9	18-20	20-25
1500-5000	9 - 9.2	20-22	23-24
5000-8000	9.3 - 9.6	22-24	20-21
8000-12300	9,6 - 11,0	24-30	23-25

Table 39. Mud program.

4.3.5.8 Drill string design

4.3.5.8.1 Drill string

They are sequentially assembled metal components that make up the bottom assembly (BHA) and the drill pipe. They fulfill the following functions:

- Provide weight on bit (WOB).
- Drive the fluid in its circulation cycle.
- Perforability test (Drill of Test).
- Give verticality or directionality to the hole.

- Protect the pipe from sagging and twisting.
- Reduce doglegs and staggering.
- Ensure the lowering of the casing.
- Reduce vibration damage to drilling equipment.
- Serve as a complementary fishing tool.
- Give depth to the well.

4.3.5.8.2 Drill string design

Using the information obtained from geology and offset wells, is possible to determine the required WOB to drill the well. See Figure 85.

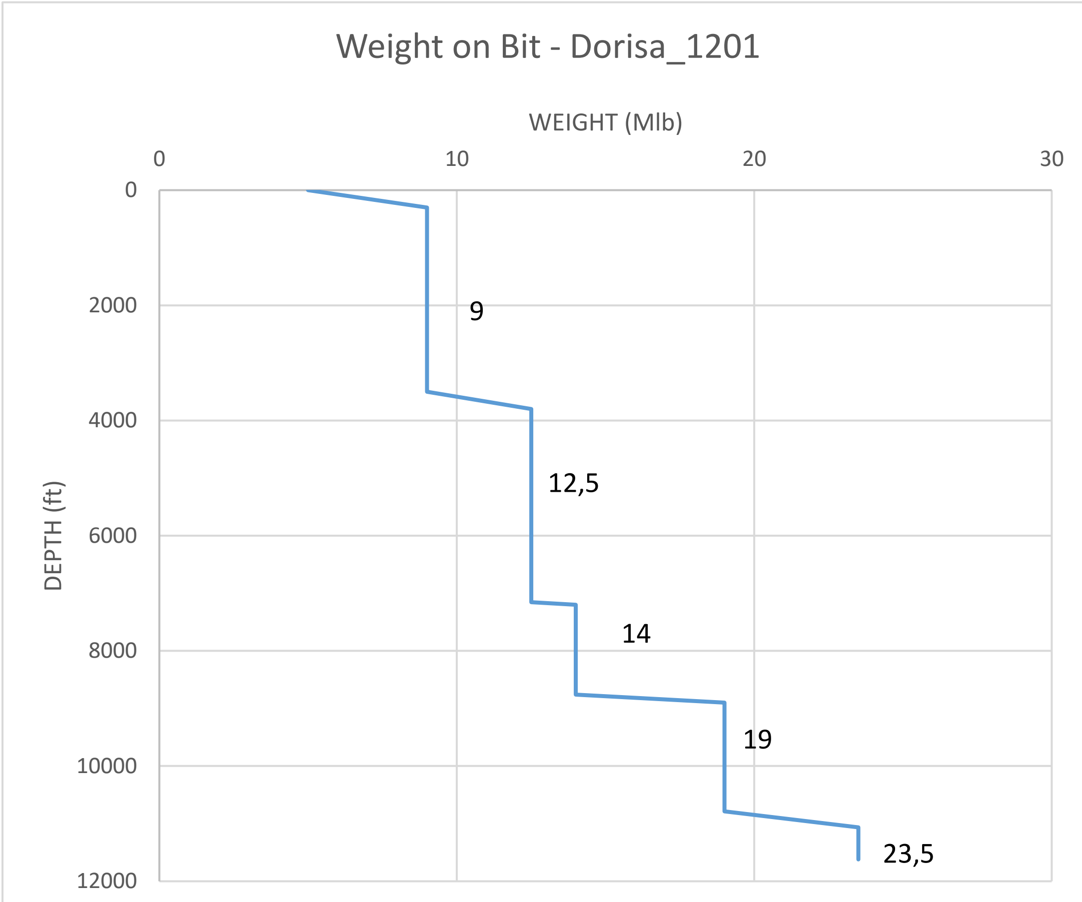


Figure 85. Weight on bit.

For drill string design we must consider the maximum required WOB in the illustration above.

The following equations and / or methods used to determine the designs were elaborated taking as reference the following presentation. (According to Schlumberger, 2014).

4.3.5.8.3 Calculation of the float factor

To determine the float factor, we use the following Equation 29.

$$Bf = 1 - (0.015 * \rho m)$$

Equation 29. Float factor.

Where:

- Bf: Buoyancy factor
- ρm: Mud density

4.3.5.8.4 Downhole tool design

The downhole tool or "BHA" is a set of heavy pipes, drill collars or heavy drill pipes, which is intended to generate the necessary weight to drill and keep the drill pipe string in tension.

The design of the downhole tool must contain the neutral point, the height at which the force changes from tension to compression. Therefore, a 15% safety factor is used as a good design practice. See Equation 30.

$$BHA\ real\ weight = \frac{WOB * S}{Bf}$$

Equation 30. Real weight of BHA.

Where:

- WOB: Weight on bit (lb)
- S: Security factor (1.15)
- Bf: Buoyancy factor

With the weight of the tool we can calculate the required drill collar length. See Equation 31.

$$Ldc = \frac{WOB * S}{Bf * Wdc}$$

Equation 31. Real length of drill collar.

Where:

- Ldc: Drill collar length
- WOB: Weight on bit
- S: Security factor (1.15)
- Bf: Buoyancy factor
- Wdc: Drill collar weight

4.3.5.8.5 Results

FIRST SECTION13 3/8"		
DESCRIPTION	**QUANTITY**	**OD**
DRILL PIPE	25	5 7/8
SHWDP	7	5 1/2
X-OVER	1	6 5/8
DRILL COLLAR	7	8 1/16
FLOAT SUB	6	8

Table 40. First section 13 3/8''

SECOND SECTION 9 5/8"

DESCRIPTION	QUANTITY	OD
Drill Pipe	275	5 7/8
HWDP	12	6 2/3
HYDRA JAR	1	6 1/2
HWDP	2	5
DRILL COLLAR	9	6 4/5
X-OVER	1	8 3/16 * 6 7/16
DC	2	8 1/16
STBX	1	8
DC	1	8 1/16
NEAR BIT CON FLOAT VALVE	1	8

Table 41. Second section 9 5/8''

THIRD SECTION 7"

DESCRIPTION	QUANTITY	OD
Drill Pipe	370	5 7/8
HWDP	7	5 1/2
HYDRA JAR	1	6 5/8
HWDP	10	6 5/8
DRILL COLLAR	8	6 1/4
STABILIZERS	1	6 1/4
DRILL COLLAR	1	6 1/4
NEAR BIT	1	6 1/4

Table 42. Third section 7''

4.3.5.8.6 Potential problems during drilling

POTENTIAL PROBLEMS			
EVENT TYPE	**MANIFESTATIONS**	**PREVENTIVE**	**MITIGATION**
- Pit Cleaning Deficiency.	- Increase in pressure. - Excessive drag when removing the pipe.	- Pump low rheology pills followed by a viscous pill every 150 meters drilled. - Double check the pipe after drilling a stand.	- Pump viscous pills every 03 stands. - Circulate longer before the connections.
- High temperatures.	- High viscosity of the mud.	- Keep fresh mud in the system. - Use Desco with soda.	- Add water to the system.
- Highly reactive formations	- Excessive over pull during calibration trips.	- Make short trips to the 9 5/8” casing window every 300 meters and / or according to the trip plan.	- Take out with rotation and circulation. - Drive after finishing the problem bar.
- Fluid losses.	- Reduction of the levels in the tanks.	- Add bridging material before entering Pozo Sand, Vivian and Chonta. - Lower 5” DP pipe at 60 seconds per bar during trips in front of Pozo Sand, Vivian and Chonta. - Lower casing from 7” to 60 seconds per tube. - Do not exceed 10.6 ppg of mud weight.	- Pump pills with LCM, maximum concentration 50 lbs / bls (Slim pulse). - Take out directional tools and pump pills with an LCM of 120 lbs / bls.
- Differential paste.	- Failure to reciprocate or rotate the pipe - full circulation.	- Add bridging material before entering Pozo Sand, Vivian and Chonta. - Do not stay static for more than 05 minutes in front of Pozo Sand, Vivian and Chonta.	- Pump pills with chemical release.
- Stuck pipe.	- Failure to reciprocate or rotate the pipe - full circulation.	- Carry out calibration trips according to the drilling program. - Do not overstress the pipe more than 60 Mlbs (MOP = 60 Mlbs) during the calibration trips to the 13 3/8” shoe - Remove rotating and with minimal circulation. - Circulate each bar after backreaming.	- Hammer repeatedly in the opposite direction to the movement prior to the stuck pipe.

Table 43. Potential problems during drilling.

4.3.5.9 Selection of drill bit

Tricone Drill Bit

They are made up of three cutter cones that rotate on their own axis. This type of bits is classified depending the type of cutting structure, they can have milled steel teeth or tungsten carbide inserts.

Tricone bits consist of three components:

- The structure of cut or cones.
- Bearings.
- Drill body.

Tricone bits have a wide range of operation, from very soft to hard formations

PDC Drill Bit (Polycrystalline Diamond Compacts)

PDC bit used synthetic diamonds as a cutting structure. These cutters are manufactures in form of pads (diamond compact) and are mounted on the bit body.

The structure of a PDC bit is made up of three parts:

- The cutting structures.
- The body (also called the crown)
- The spike (shank).

High strength for drilling in hard to medium-hard formations, and in some cases soft formations.

IADC Classification of Drill Bit

The IADC (International Association of Drilling Contractors) has developed a standard system for classifying bits, using a code. By reading this code, the driller can evaluate bits from different manufacturers and select the right bit for a certain job.

The AIDC classification system only gives approximate information about the Drill Bit. It is a simple and functional starting point for buying bits from different manufacturers. See Table 44.

1		2	
Series		Formation type	
Steel Tooth	1	Soft	1, 2, 3, 4
	2	Medium	1, 2, 3, 4
	3	Hard	1, 2, 3, 4
Tungsten Carbide Tooth	4	Soft	1, 2, 3, 4
	5	Soft to medium	1, 2, 3, 4
	6	Medium	1, 2, 3, 4
	7	Hard	1, 2, 3, 4
	8	Very hard	1, 2, 3, 4

3	
Bearing / Gauge	
1	Standard open roller bearing
2	Standard open roller bearing, air-cooled
3	Standard open roller bearing with gauge protection
4	Sealed roller bearing
5	Sealed roller bearing with gauge protection
6	Sealed friction bearing
7	Sealed friction bearing with gauge protection

4 (unrequired)	
Additional features	
A	Air application (journal bearing with air nozzles)
B	Special bearing seal
C	Center jet
D	Deviation control
E	Extended jets (full length)
G	Extra gauge/body protection
H	Horizontal/steering application
J	Jet deflection
L	Lug pads
M	Motor application
S	Standard steel tooth model
T	Two cone
W	Enhanced cutting structure
X	Predominantly chisel tooth inserts
Y	Predominantly conical inserts
Z	Other shape inserts

Table 44. IADC code classification for roller cone bits (source: Best drilling bits).

Drill Bit Selection Criteria

It is advisable to opt for the toothed-type drill bit for the first depth intervals as they correspond to soft formations and their trajectory is clearly vertical. In addition, this type of drill has a lower cost and provide greater stability.

PDC (Polycrystalline Diamond Compact) bits are used to drill hard formations (deeper intervals) and have high penetration speed. However, they have a high acquisition cost, for this reason they are usually rented.

Drill Bit Selection

Drill bit selection depends on formation characteristics. Based on this we selected tricone bits for shallow formations and PDC bit for deeper formation because the last present greater compressive strength. See Table 45.

Interval	Make/Bit Type	IADC	Nozzles	Pump Press (PSI)	Flow Rate (GPM)
0 – 300 ft	Triconic (Serrated)	S243	3x18's	2 700	800
300 – 984 ft	Triconic (Serrated)	134	3x20's 2x12's & 8x11's	3 400	1100
984 – 9500 ft	Triconic (Inserts) o Broca PDC	116S 117	3x14's & 4x15's	3 700	900
9500 – 12300 ft	Broca PDC	M422 M223 M223	5x10's & 3x11's	2 700	500

Table 45. Drilling bit.

4.3.5.10 Cementation program

Cementation is a process that consists of placing a cement slurry in the annular space formed between the hole and the pipe (Casing) installed in the well, in order to create a hydraulic seal in this place.

Cementation is the most critical stage during drilling because its repair is complicated and expensive. The first stage consists of cleaning the well with a wash fluid (Newtonian fluid) to achieve a good formation-cement adhesion. We need to know the following properties of the wash fluids:

- Density
- Plastic viscosity
- Reynolds number
- Dilution time of the mud cake

With these parameters the volume and the pumping speed of the wash fluid are calculated.

4.3.5.10.1 Cement slurry design

In oil well cementing exists two types of cement slurry

- Lead slurry: High density
- Tail slurry: Low density

It is obtained from tables (Halliburton, 1994): data on weight, volume, water yield and additives, to prepare various slurries.

The density of the cement slurry is determined by the Equation 32.

$$\rho l = \frac{Wl}{Vl}$$

Equation 32. Cement slurry density.

Where:

- ρl: slurry density (ppg)
- Wl: slurry weight (lb)
- Vl: slurry volume (gl)

Slurry performance. See Equation 33.

$$r = \frac{Vl}{7.48}$$

Equation 33. Slurry performance.

Where:

- r = Slurry performance (ft3/Sx)
- Vl = Slurry volume (ft3)

From the laboratory, the plastic viscosity and the value of the elastic limit were obtained.

4.3.5.10.2 Volume of scrubbing fluid

To calculate the volume of the wash fluid it is necessary to know some parameters previously obtained.

• Hole diameter.

• Inner diameter of surface casing.

• Outer diameter of surface casing.

• Inner diameter of intermediate casing.

• Outside diameter of intermediate casing.

• Floating collar depth.

• Top of cement.

In some equations it is necessary to consider an equivalent diameter. See Equation 34.

$$De = 0.8165 * (D1 - D2)$$

Equation 34. Equivalent diameter.

Where:

- De: Equivalent diameter (in)
- D1: Major diameter (in)
- D2: Minor diameter (in)

The rate at which the wash fluid is estimated, this rate will allow the removal of the mud cake in the well.

We calculate the annular velocity from the Reynolds number. See Equation 35.

$$Nre = \frac{928 * \rho\mathrm{wf} * \mathrm{v} * \mathrm{De}}{up}$$

Equation 35. Reynolds number.

Where:

- Nre: Reynolds number.
- ρwf: Density of scrubbing fluid (ppg).
- v: Annular velocity (ft/seg).
- De: Equivalent diameter (in)
- up: Plastic viscosity (cp)

Then, we estimate the volume of the wash fluid with the Equation 36 and Equation 37.

$$hfl = v * removal\ time$$

Equation 36. Washing fluid height.

$$Vfl = hfl * (\frac{D_1^2 - D_2^2}{1029.4})$$

Equation 37. Scrubbing fluid volume.

Where:

- hfl: Wash fluid height (ft)
- v: velocity (ft/seg)
- Vfl: Wash fluid volume (bbls)
- D1: Major diameter (in)
- D2: Minor diameter (in)

4.3.5.10.3 Calculation of cement volume

We calculate the volume of cement with the Equation 38 and Equation 39.

$$Va = \frac{(D_1^2 - D_2^2)}{1029.4} * h$$

Equation 38. Annular volume.

$$Vt = \frac{(ID^2)}{1029.4} * h$$

Equation 39. Pipe volume.

Where:

- Va: Annular volume (Bbls)
- Vt: Pipe volume (Bbls)
- D1: Major diameter (in)
- D2: Minor diameter (in)
- ID: Inside diameter (in)
- h: height (ft)

Sacks of cement required. See Equation 40.

$$Sx = \frac{Vc}{r}$$

Equation 40. Sacks of cement.

Where:

- Sx: Sacks of cement
- Vc: Volume of cement inside the well (ft3)
- r: efficiency (ft3/Sx)

4.3.5.10.4 Static and dynamic hydrostatic pressure

From the speed, we have the operating rate. See Equation 41.

$$v = \frac{13.476 * 4 * Q}{pi * (D_1^2 - D_2^2)}$$

Equation 41. Operating speed.

Where:

v: velocity (ft/seg)

Q: Rate (BPM)

D1: Major diameter (in)

D2: Minor diameter (in)

Cement Slurry is a non-Newtonian fluid. In this case, the plastic Bingham model is used.

To determine the flow regime, it is necessary to calculate the critical velocities. See Equation 42 and Equation 43.

$$Vc\ transition = \frac{1.32 * (Up + \sqrt{U_p^2 + 7.6 * pl * (D_1 - D_2)^2 * Yp})}{14.08 * (7.875 - 5.5)}$$

Equation 42. Critical velocity in the transition flow.

$$Vc\ plug = \frac{0.4354 * Yp * De}{Up}$$

Equation 43. Critical velocity in plug flow.

Where:

- Vc plug: Critical velocity in plug flow (ft / seg)
- Vc Transition: Critical velocity in the transition flow (ft / seg)
- Yp: elastic limit (lb / 100ft2)
- Up: plastic viscosity (cp)
- D1: Major diameter (in)
- D2: Minor diameter (in)
- ρl: Cement Slurry density (ppg)

For best results, the cement slurry should work in a laminar flow regime and in this condition calculate the Reynold number (Nre) and the friction factor (f). See Equation 44 and Equation 45.

$$Nre = \frac{928 * pl * v * De}{Up + 5 * \left(\frac{Yp}{Up}\right) * (D1 - D2)}$$

Equation 44. Reynolds number.

$$f = \frac{16}{Nre}$$

Equation 45. Friction factor.

Where:

• Nre: Reynolds number

• ρl: Cement Slurry density (ppg)

• v: velocity (ft/seg)

• De: Equivalent diameter (in)

• Up: plastic viscosity (cp)

• Yp: elastic limit (lb / 100ft2)

• D1: Major diameter (in)

• D2: Minor diameter (in)

• f: friction factor

The friction factor is calculated with the Equation 46.

$$Pf = \frac{0.039 * pl * h * v^2 * f}{De}$$

Equation 46. Friction pressure.

The hydrostatic pressure in the well is calculated with the Equation 47.

$$Ph = 0.052 * pl * h$$

Equation 47. Hydrostatic pressure.

Where:

• Pf: Friction pressure (psi)

• Ph: Hydrostatic pressure (psi)

• ρl: Cement Slurry density (ppg)

• f: friction factor

• v: velocity (ft/seg)

• De: Equivalent diameter (pulg)

4.3.5.10.5 Operation time

Determine the operating time. See Equation 48.

$$T = \frac{Va + Vt + Vfl}{Q}$$

Equation 48. Operation time.

Where:

• T: Operation time (min)

• Va: Annular volume (Bbls)

• Vt: Pipe volume (Bbls)

• Vfl: Scrubbing fluid volume (Bbls)

• Q: Rate (BPM)

4.3.5.10.6 Results

SURFACE CASING	
Hole diameter	16 in
Casing diameter	13.375 in
Cement	D
Main density	16.45 ppg
Fill density	12.12 ppg
# Sacks of cement	393 Sx
Operating time	18.43 min
Volume	73.7 bbls

Table 46. Cementation of surface casing

INTERMEDIATE CASING	
Hole diameter	13.5 in
Casing diameter	9.625 in
Cement	D
Main density	16.45ppg
Fill density	12.12ppg
# Sacks of cement	4273 Sx
Operating time	200.7 min
Volume	802.8 bbls

Table 47. Cementation of the intermediate casing

4.3.5.10.6.1 Liner

The following Table 48 shows the cementation of the 7” liner:

LINER 7’’	
Hole	8.5 in
Liner	7 in
Cement	G
# Sacks of cement	750 Sx
# Reynolds	1637.68
Friction pressure	121.89
Hydrostatic pressure at the bottom of the well	6973.1 psi
Fracture pressure	8565.96
Operation Time	170.32 min
Mix density	15.79 ppg
Mix volume	153.27 bbls

Table 48. Cementation of the liner

4.3.5.11 Wellhead

In the selection of the Wellhead, general considerations were taken based on drilling reports from offset wells. For the design, a head with two sections is chosen, due to the liner that presents (API 6A Standard). See Figure 86.

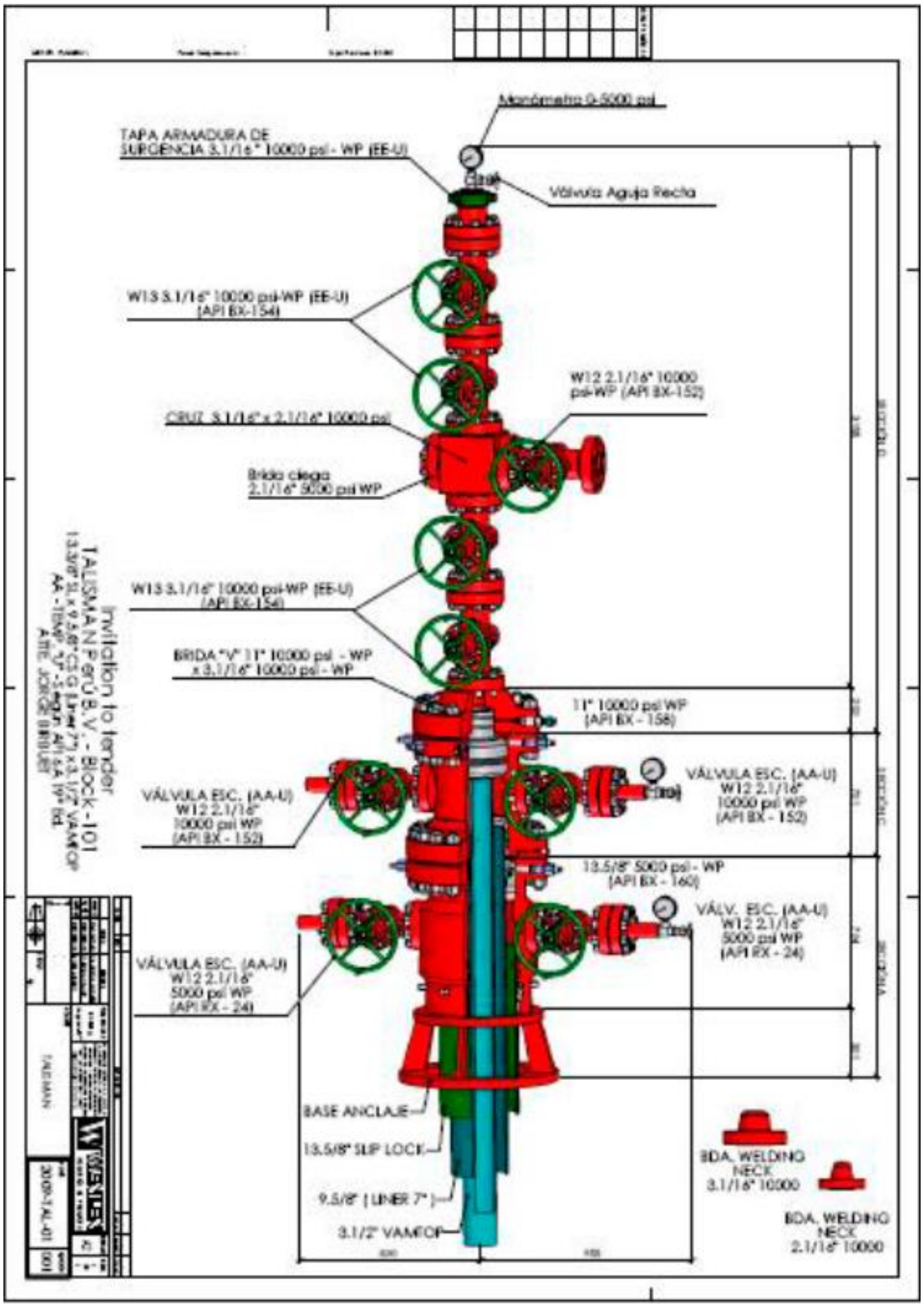


Figure 86. ALFA 1X wellhead.

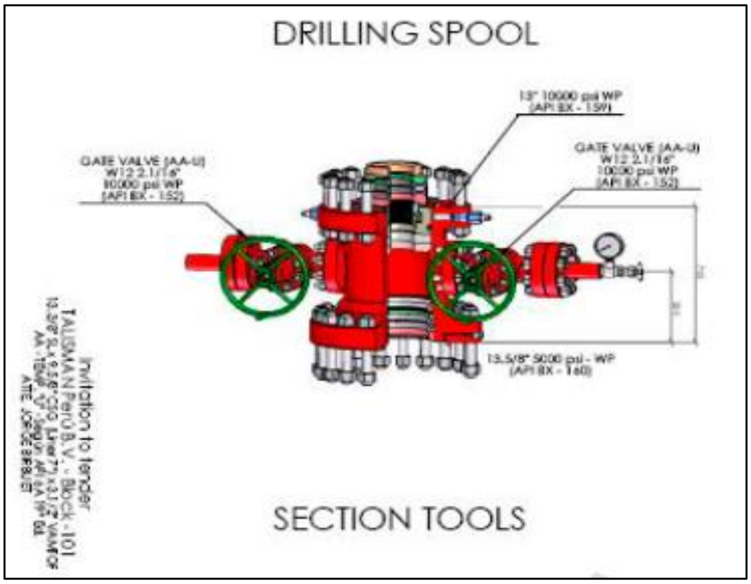


Figure 87. ALFA 1X drilling spool.

4.3.6 Drilling Equipment Sizing

Drilling depth	12300ft
Drill type	Eléctrico / 2500HP
Mast	150 ft
Drawworks	National 1320 UE 2000 HP
Tower capacity	1 100 000 Lbs
Crown type	Lee C Moore
Traveler block	1 100 000
Drill wire	1 3/8" - 5000 ft
Substructure	Lee C Moore
Top Drive	1000 HP,37 500 lb-ft, TDS11SA AC/Hidráulico -VARCO
Rotary table	37 1/2", 1 400 000 Lbs, 1000 HP
Pump type	3 x 2000 HP (LEWCO) Triplex WH1612
Mud tank capacity	2000 BBls
Water tank capacity	25 000 Gls / 595 Bbls
BOP system	Cameron 13 5/8": Anular 5M, Doble 10M, Simple 10M

Table 49.Drilling equipment.

4.3.7 Projection of Drilling Time

The projection times of the drilling for exploratory and development well have been divided into.

4.3.7.1 Exploratory wells

For exploratory wells, a longer drilling time is considered because it requires a special program to obtain information, which will allow us to identify and adjust our model of the field with the properties found, such as petrophysical, geological, etc. For that, more types of logs and tests are made to the well; some of these are described below.

- Gamma ray log
- SP log
- Resistivity log
- Density log
- Neutron log

These parameters have been taken into consideration for the Alfa 1-X exploratory well. The time taken for drilling is described in the Table 50.

	ACTIVITIES	Depth (m)	Hours	Cum. Hours	Cum. Days
1	Drilling start	0	0	0	0.0
2	Shallow drilling	300	120	120	5.0
3	Lower surface casing and cementation	300	80	200	8.3
4	Main drilling 1	2600	250	450	18.8
5	Take out string	2600	70	520	21.7
6	Sampling	2600	130	650	27.1
7	Take out string	2600	90	740	30.8
8	Main drilling 2	3900	340	1080	45.0
9	Electrical logs	3900	160	1240	51.7
10	Lower production and cementing casing	3900	260	1500	62.5

Table 50. Drilling time of an exploratory well.

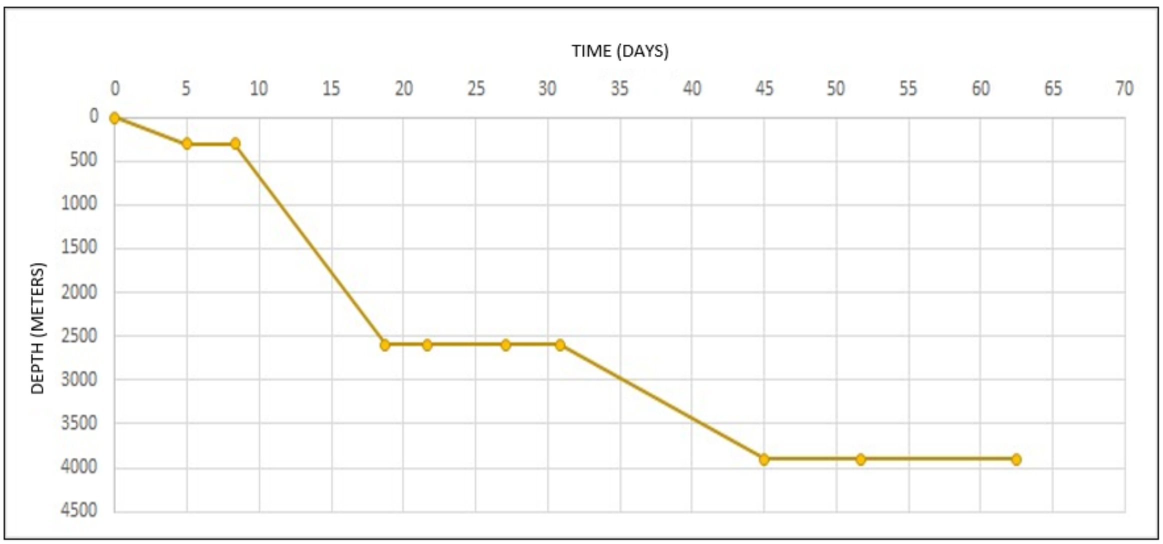


Figure 88. Projection of the drilling time of an exploratory well.

4.3.7.2 Development wells

For the development wells, less time is considered in drilling, because fewer types of records are made to the wells since they have already been carried out in the exploratory wells and each well would also be very expensive. Therefore, only essential tests are performed which are mentioned in the Table 51.

	ACTIVITIES	Depth (m)	Hours	Cum. Hours	Cum. Days
1	Drilling start	0	0	0	0.0
2	Shallow drilling	300	60	60	2.5
3	Lower surface casing and cementation	300	50	110	4.6
4	Main drilling 1	2600	180	290	12.1
5	Take out string	2600	50	340	14.2
7	Sampling	2600	50	390	16.3
8	Take out string	3900	280	670	27.9
9	Main drilling 2	3900	80	750	31.3
10	Electrical logs	3900	260	1010	42.1

Table 51. Drilling time of a development well.

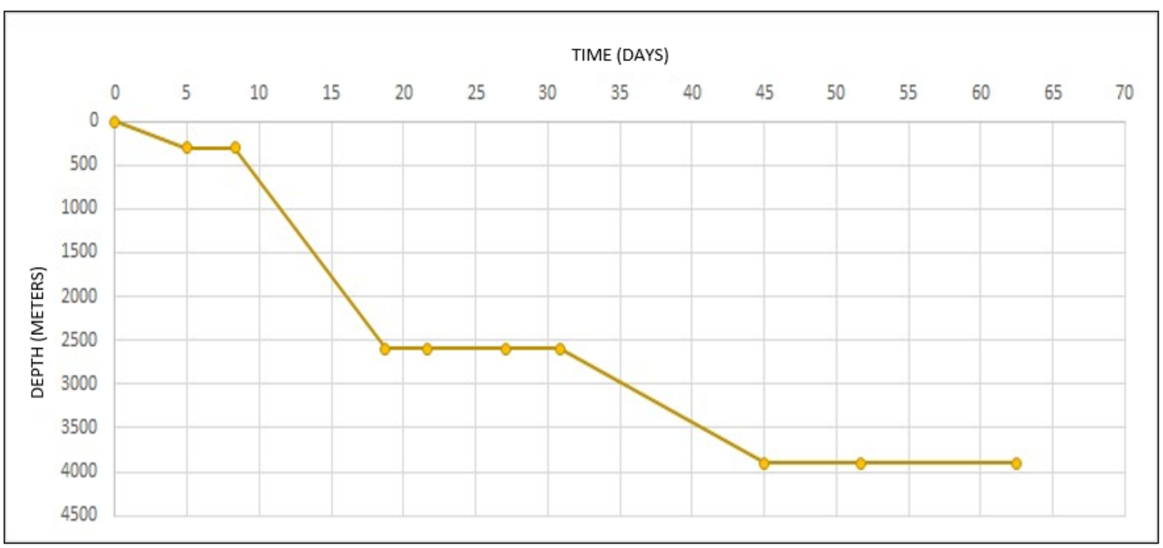


Figure 89. Projection of the drilling time of a development well.

4.3.7.3 Logs and tests to perform the well

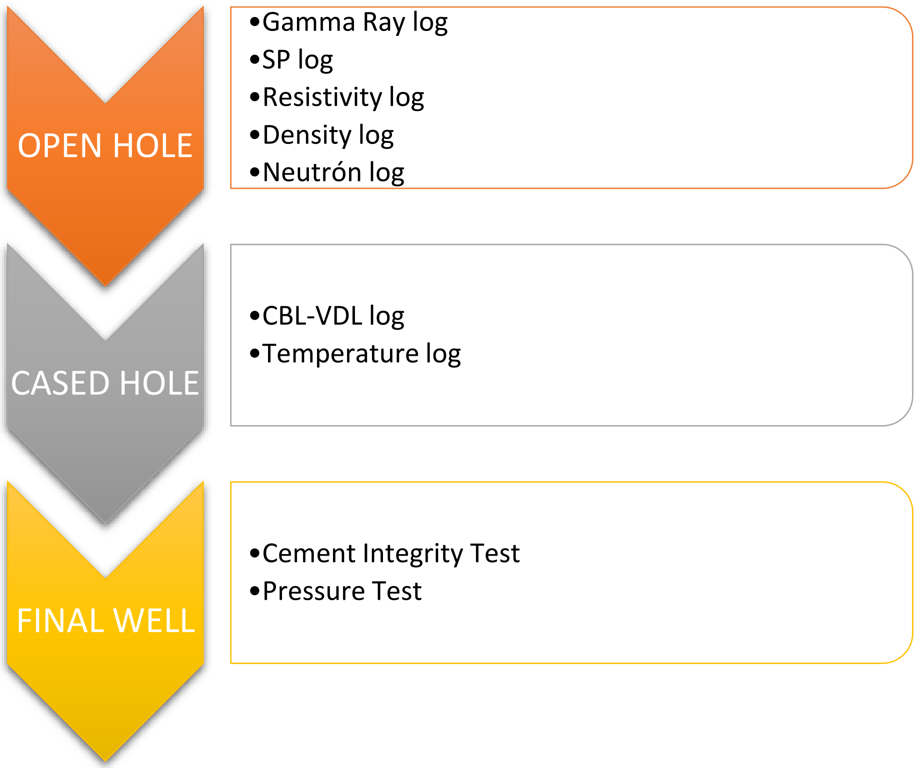


Figure 90. Chronological summary of tests and logs.

4.3.7.3.1 Open hole logs

For the evaluation of the Vivian and Chonta formations, the acquisition of indirect information from the well will be required. This will be done with electrical records.

The records to be taken come in group

- **Gamma Ray Log**: Registers the natural radioactivity of the formations and allows the definition of the tops of the formations to be crossed.
- **SP Log**: It records the difference in electrical potential between the mud and the well fluid and will indirectly allow the resistivity of the formation

water to be obtained. In addition, it indirectly measures the productive capacity of training.

- **Resistivity Log**: Record the resistivity of the formation. If a formation has water, the resistivity reading will be low and if it is high, the resistivity readings will be high, which probably indicates that the formation contains hydrocarbons.
- **Density Log**: Record that measures the density of the formation using Ce 137 as a source that generates GR.
- **Neutron Log**: A record that measures the number of hydrogen atoms in the formation. It allows to determine the porosity of the formation.

4.3.7.3.2 Cased hole logs

The open hole logs allow to verify the condition of the cement used to secure the casing and indirectly the well fluids. These records are to be recorded by Schlumberger.

The following logs will be run:

- **CBL-VDL log**: Records the transit time on the well fluid, casing, cement, and formation. When this time is longer, it would be indicating that the cementation of the casing has been bad.
- **Temperature log**: Record the temperature of the wellbore. It is taken as a base record to be able to compare with future temperature records in order to see the type of fluids and fluid movement.

4.3.7.3.3 Records ending the operation

After the drilling is completed correctly, the equipment is disassembled for transfer to the next base or drilling position. While in the drilled well, it will be complemented with tests such as cement integrity and pressure tests, which are very important to guarantee the correct operation of the well.

- **Cement Integrity Test**: This will be done once the cement has been allowed to set for 72 hours and the time of the test will depend on the depth of the well. The correct cementation of the production casing is evaluated.
- **Pressure Test**: This test is performed to obtain the reservoir pressure, damage and permeability.

The tests carried out for each section of the well type Alfa 1-X are shown below. See Table 52.

HOLE SIZE	MUD LOGGING	MWD/LWD	WIRELINE	
			BASE	OPTIONAL
13 3/8”	Formation Evaluation Logs Drilling Dynamics Logs Pressure Logs	MWD	Gamma Ray Resistivity Sonic Caliper	None
9 5/8”	Formation Evaluation Logs Drilling Dynamics Logs Pressure Logs	MWD	Gamma Ray Resistivity Sonic Caliper	None
7”	Formation Evaluation Logs Drilling Dynamics Logs Pressure Logs	MWD / GR	Gamma Ray Resistivity Sonic Caliper	Imaging Tool Rotary Cores

Table 52. Records ending operation.

4.4 Production, Transport and Storage Engineering

4.4.1 Stimulation

4.4.1.1 Perforating design

During the completion stage of the wells, perforating process is a very important phase, it allows establishing effective communication between wellbore and reservoir.

Based on information obtained from well logs, the depth of the intervals that you want to shoot can be determined, the purpose is to generate holes cross the casing, surrounding cement and in the formation to allow flow of hydrocarbons from reservoir to the well. See Figure 91.

To maximize the recovery of hydrocarbons at the time of perforating, the following must be taken into consideration:

- Canal debris (produced by gunning) must be removed effectively.
- During the process formation damage should be minimized.

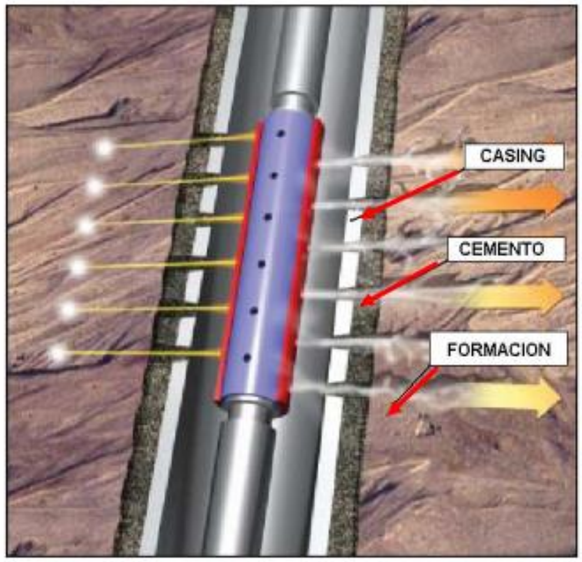


Figure 91. Scheme of perforating (source: Baker Hughes).

The perforating design involves the selection of the entire tool assembly (gun, charges and explosives), shot density, phase or angle between perforations, well deviation, centralization of the tool, diameter of the perforations and penetration depth. See Figure 92.

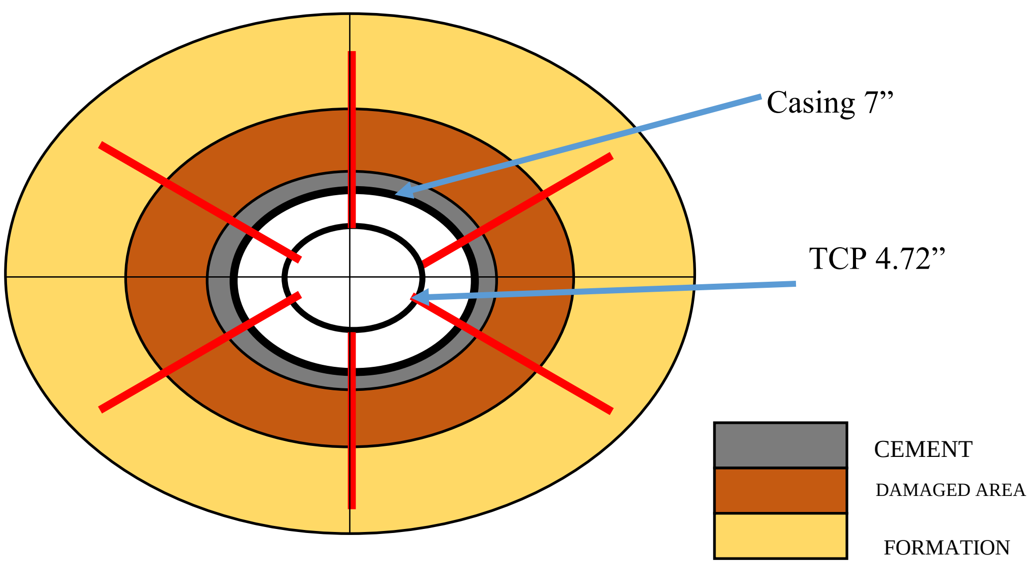


Figure 92. Shot phase 60°.

In the oil industry and in the Block 192 in particular, the most used perforating systems are divided into 2 groups: Perforating with Conventional Wireline and Perforating with charges transported by pipe or TCP (Tubing Conveyed Perforating).

Due to the permeability values of the Chonta formation (100mD on average), the completion of this reservoir requires a high-pressure under-balance for cleaning of the perforations, which prevents debris and fine particles from clogging the throats of the perforated ones, avoiding the decrease in permeability and achieving an optimal productivity ratio. This pressure difference (Under-Balance) is difficult to achieve with conventional methods, for this reason the perforating system that was chosen is the TCP Under-Balance.

On the other hand, due to the high permeability values of the Vivian formation (1500mD on average), it is not necessary to generate an under-balance of pressure in the formation to obtain good productivity. For this reason, the perforating system that was chosen is the Conventional Wireline. In addition, it was determined that this perforating system is sufficient to produce the estimated flow rates of Vivian's producing wells.

The most efficient perforating system for our 2 reservoirs is shown below (See Table 53).

Productive Formation	Perforating System
Vivian	Conventional Wireline
Chonta	TCP Under-Balance

Table 53. Perforating systems used in the Capahuari Sur Extensión field.

4.4.1.1.1 Conventional wireline perforating system

This perforating system uses an electric cable unit and jet charge carriers (cannons) type casing gun which are the most used devices to achieve this purpose. The perforation must be carried out in overbalanced conditions towards the formation that is the hydrostatic pressure necessary to kill the well is greater than or equal to the formation pressure, this is done to avoid high pressures in the annular space and on the surface. See Figure 93.

The perforating with electric cable allows shooting using an electrical connection from the surface through a steel cable (wireline).

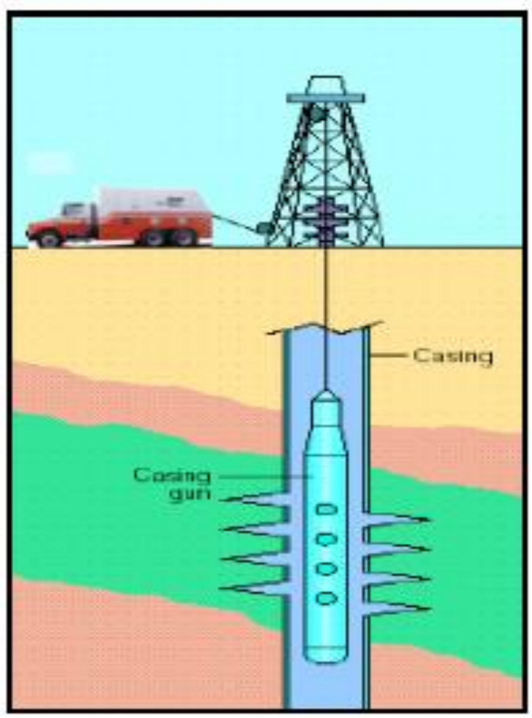


Figure 93. Perforating system with conventional wireline (source: GEOWELL).

From the information obtained from the well logs, we know the productive intervals to perforate. The description of the gun to be used is shown. See Table 54 and Table 55.

There are 13 wells reaching Vivian between directional and horizontal. The horizontal wells will be completed with an open hole since there is no collapse since the rocks are consolidated, so the perforating process is not carried out.

PERFORATED WELLS WITH THE CONVENTIONAL WIRELINE TECHNIQUE						
Field	**Well**	**Interval (ft)**	**Gun Diameter (in)**	**SPF**	**Productive Formation**	**Total Penetration (in)**
CAPAHUARI SUR EXTENSIÓN	ALFA 1X	11020-11100	4.72"	6	Vivian	44.6
	ALFA 02C	11020-11093	4.72"	6	Vivian	44.6
	ALFA 03C	11032-11105	4.72"	6	Vivian	44.6
	ALFA 04H	-	-	-	Vivian	-
	ALFA 05H	-	-	-	Vivian	-
	ALFA 07D	11048-11093	4.72"	6	Vivian	44.6
	ALFA 08D	11062-11102	4.72"	6	Vivian	44.6
	ALFA 09D	11074-11114	4.72"	6	Vivian	44.6
	ALFA 10H	-	-	-	Vivian	-
	ALFA 12D	11063-11111	4.72"	6	Vivian	44.6
	ALFA 13D	11065-11113	4.72"	6	Vivian	44.6
	ALFA 14H	-	-	-	Vivian	-
	ALFA 15H	-	-	-	Vivian	-

Table 54. Characteristics of the perforations for wells of the Capahuari Sur Extensión field-Vivian formation.

Description of gun-charge	
Charge name	Power Jet 4505 HMX
Charge type	Deep Penetration
Casing OD	7"
Gun OD	4.72"
Gun Position	Centralized
Shot phase	60°
Shot density	6 SPF
Average penetration	44.6 in

Table 55. Perforating Characteristics with conventional wireline.

4.4.1.1.2 TCP (tubing conveyed perforating) underbalance perforating system

Traditional methods of achieving clean perforations depend on creating a pressure gradient between the formation and wellbore to induce flow and remove debris from the perforating holes.

To reduce this effect, it is possible to perforate with a pressure below the reservoir pressure (Underbalance), and thus generate immediately a flow from the reservoir to the well. The pressure difference must be sufficient to generate a sudden initial flow to carry the debris, but it must not be excessive so as not to deconsolidate the formation. This underbalance is obtained by lowering the fluid level in the well.

The TCP technique, operated with an under-balance pressure, allows to eliminate the damage created by drilling, cementing and perforating. With this system, deep and symmetrical holes are achieved. Large intervals can be perforated simultaneously on the same trip inside the well. See Figure 94.

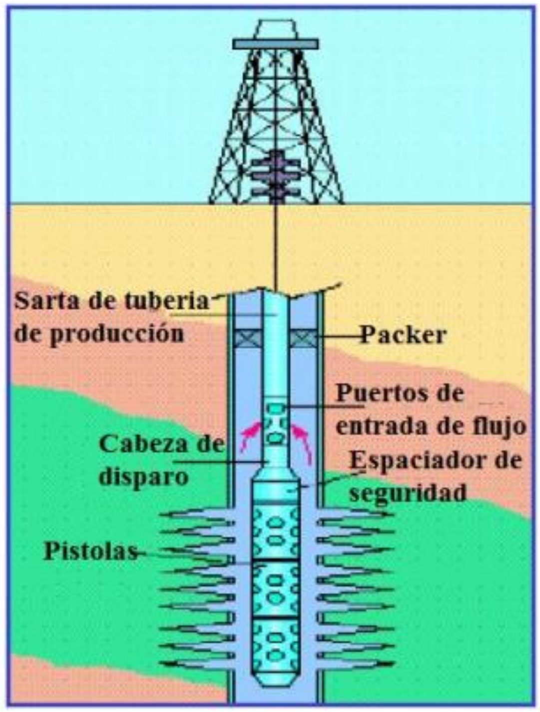


Figure 94. Perforating system with TCP (source: GEOWELL).

From the information obtained from the well logs, we know the productive intervals to perforate. The description of the gun to be used is shown. See Table 56 and Table 57.

There are 10 wells that reach Chonta between directional and horizontal.

PERFORATED WELLS WITH THE TCP UNDER-BALANCE TECHNIQUE						
Field	Well	Interval (ft)	Gun Diameter (in)	SPF	Productive Formation	Total Penetration (in)
CAPAHUARI SUR EXTENSIÓN	ALFA 1X	11850-11870	4.72 "	5	Chonta	40.4
	ALFA 02C	11865-11883	4.72 "	5	Chonta	40.4
	ALFA 03C	11872-11897	4.72 "	5	Chonta	40.4
	ALFA 06H	-	-	-	Chonta	-
	ALFA 07D	11874-11895	4.72 "	5	Chonta	40.4
	ALFA 08D	11882-11902	4.72 "	5	Chonta	40.4
	ALFA 11H	-	-	-	Chonta	-
	ALFA 12D	11892-11893	4.72 "	5	Chonta	40.4
	ALFA 13D	11898-11913	4.72 "	5	Chonta	40.4
	ALFA 16H	-	-	-	Chonta	-

Table 56. Characteristics of the perforations for wells of the Capahuari Sur Extensión field-Chonta formation.

Description of gun-charge	
Charge name	Power Jet 4505 HMX
Charge type	Deep Penetration
Casing OD	7"
Gun OD	4.72"
Gun Position	Centralized
Shot phase	72°
Shot density	5 SPF
Average penetration	40.4 in

Table 57. Perforating characteristics with TCP underbalance.

4.4.1.2 Stimulation design – Vivian Formation

As is known, the wells in the Peruvian jungle present the problem of excessive water production, it is estimated that approximately for each barrel of oil produced between 60 to 100 barrels of water are extracted, in view of this main problem we propose the need to apply a treatment that reduces water production and that at the same time is profitable to be applied to the wells that are necessary in our field.

For the remediation of water intrusions, the problem must be identified and the right treatment will be implemented to reduce or eliminate the high production of water, consequently increase oil production. To avoid producing water, care must be taken when completing the well, it must be avoided to perforate close to the oil-water contact. Possible causes of water production can be due to the lifting of the OWC, by coning or by channeling of water within the formation. See Figure 95 and Figure 96.

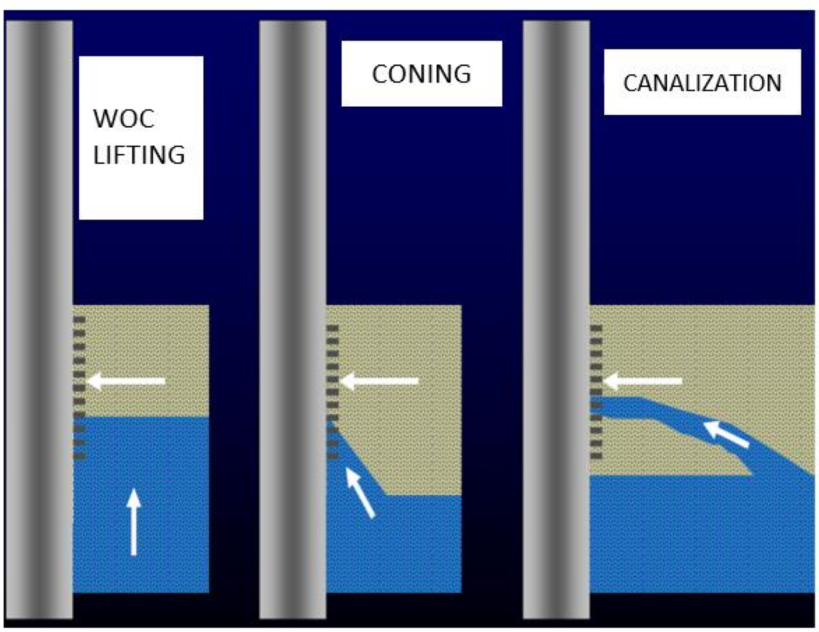


Figure 95. Mechanisms of water production.

The combination of these mechanisms frequently occurs:

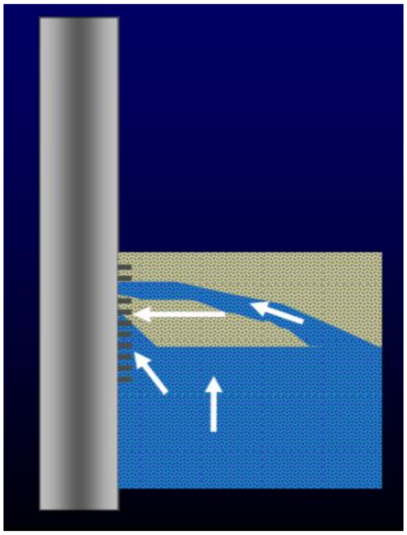


Figure 96. Combination of water production mechanisms (source: Control of water production).

The intrusion of water can be controlled by mechanical solutions (plugs), chemical solutions (polymeric gels) or squeeze cementing. As a first alternative to reduce water production we propose the use of mechanical plugs. See Figure 97 and Figure 98.

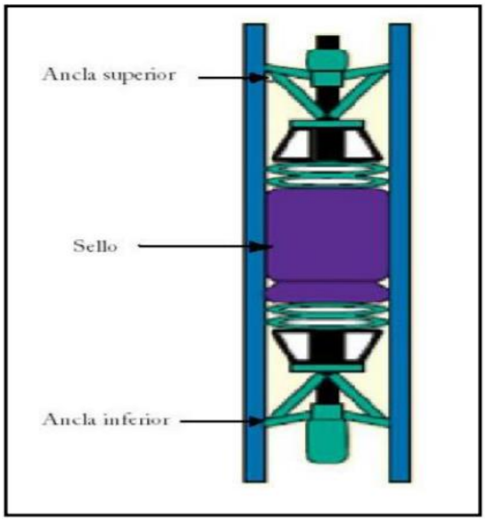


Figure 97. Mechanical plugs (source: Factors that affect the high production of water in fields in eastern Ecuador and possible solutions).

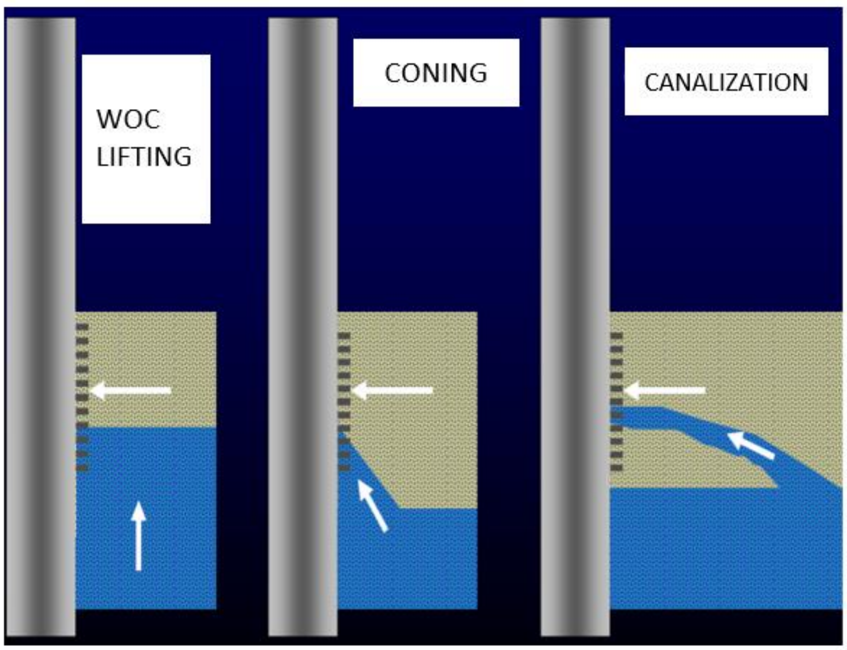


Figure 98. Mechanical methods, plugs (source: Control of water production).

These permanent plugs are intended to isolate a lower interval generally producing water or when the water-oil contact has risen to the producing zone. However, at a certain point it could be drilled for reconditioning in lower areas.

The objective of using this technique to reduce water production is done to achieve:

- ✓ Extend the productive life of the well.
- ✓ Reduce the cost of fluid lifting.
- ✓ Reduce the environmental impact.
- ✓ Minimize the costs of water deposition.
- ✓ Minimize damage.
- ✓ Reduce corrosion problems.

As a second alternative, we have seen it feasible to apply a polymeric gel treatment, this gel modifies the relative permeability that is it allows a greater movement of oil than water. See Figure 99.

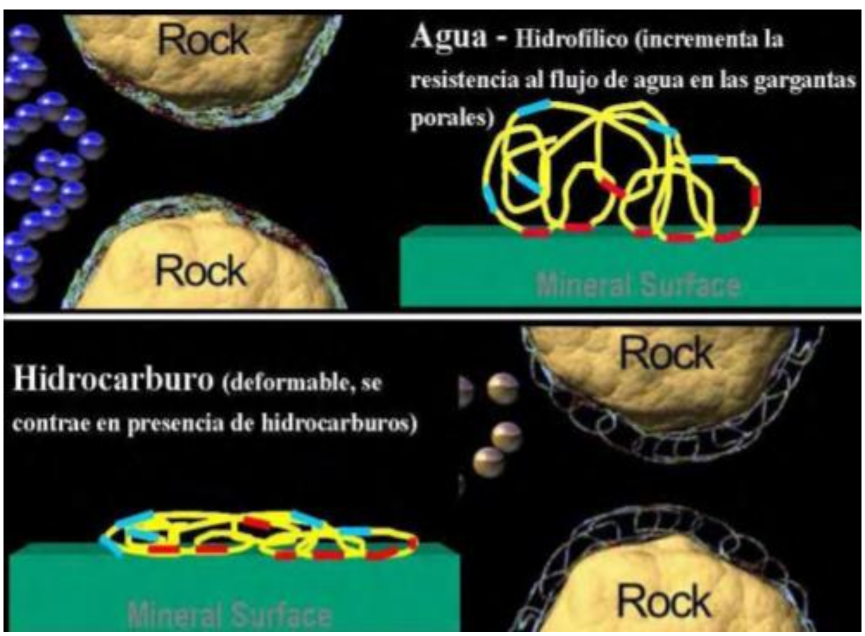


Figure 99. Attraction of the gel to water and passage to oil (source: Water control Pluspetrol Norte. INGEPET 2010).

To carry out the design of the stimulation by means of the polymeric gel we have to see three main aspects:

- The gel formulation.
- The volume to inject.
- The system placement technique.

We can design the system with low initial viscosity to have a greater penetration of the poral throats located within the rock matrix and thus be able to ensure penetration in the water zone, with minimal penetration in the oil zone. (Merino Bautista, 2019) To determine the volume of gelling solution we will use the Equation 49:

$$Vsg = 0.56 * hp * phi * rp2 * Sw$$

Equation 49. Volume of gelling solution.

Equation for calculating the volume of gel solution to be injected:

Where:

- Vsg: volume of gelling solution (bbl).
- 0.56: conversion factor from cubic feet to barrels multiplied by π.
- Hp: thickness of net oil sand (ft).
- Phi: porosity (fraction).
- Rp: gel penetration radius (ft).
- Sw: water saturation around the well (fraction).

The benefits that we can obtain by applying this method are the following (See Table 58):

- ✓ They can extend the life of the productive well.
- ✓ Reduce costs.
- ✓ To reduce environmental concerns and costs.

- ✓ Minimize the water treatment and disposal processes.
- ✓ Reduce well maintenance costs.

Usually	With Polymer
Costs for water treatment and surface injection: * Treatment cost / barrel of water = $ 0.99 / bbl. * Water Injection Cost = $ 0.95 / bbl.	It would decrease the water content and increase the oil production. Minimize the amount of water for final disposal treatments and with that, costs would also be reduced.
The corrosion produced by the excessive production of water causes expenses in maintenance of the production lines and batteries.	It would reduce maintenance costs. It would increase the profitability of the artificial lift system.
The formation water produces an environmental impact and for this there are re-injection costs per barrel of oil produced.	It would reduce water production costs, reduce injection costs and thus reduce the production of environmental impact.

Table 58. Benefits of using polymer gel (own elaboration).

4.4.2 Lifting System Design

4.4.2.1 Background of the ALS used in Block 192

The ubication of the fields in Block 192 has an extremely aggressive operational environment for artificial lift systems; it also involves a strong component of logistics complexity.

Productivity rates range from 0.2 to 60 BFPD / psi. In addition to these variables, there are high water cuts (96% on average).

Initially, the wells produced with low water cut and high bottom pressure, which allowed them to be flowing, then artificial lift was implemented by pneumatic pumping; However, over time and because they were reservoirs with strong water drive, the volume of water to be lifted increased steadily until it did not allow flow to the surface, so that after the first stage of natural flow, there was necessarily than to implement artificial lift methods. They have been used: Intermittent and Continuous Gas Lift, Mechanical Pumping, Hydraulic Pumping, and finally the Electro Submersible Pumping system (ESP).

The most profitable way to produce Block 192 was to initially produce the wells by natural flow. This period was short, due to the increased water cut from the wells. Once the production by natural flow was finished, it was necessary to select an artificial lifting method that allows obtaining the maximum productivity from the wells and each field.

In Block 192, the production mechanism of the Vivian reservoir is by water-driven mechanism, which is quite active, therefore, the coning of the wells originates early, which creates the need to pump more fluid to maintain the production of oil and which in turn results in the use of larger pumps. On the other hand, the production mechanism of the Chonta reservoir is by solution-gas drive.

Taking into consideration the above, we will carry out the design of the artificial lift system for the Capahuari Sur Extensión Field of Block 192. In the specific case of our wells, due to their lithological and reservoir characteristics, it has been determined that the most suitable Artificial Lifting method for the production of the Vivian reservoir is the Electrosubmersible Pumping and for the production of the Chonta reservoir the Gas Lift System will be used.

4.4.2.2 Gas lift artificial system - Chonta Formation

It must be taken into consideration that in Block 192, at the beginning of the field operation, in mid-1975 the pneumatic pumping system (Continuous Gas Lift) was installed in the fields: Shiviyacu, Dorissa, Capahuari Sur and Capahuari Norte, in total 20 wells with high and intermediate degrees API, with low initial water cut and high GOR.

Due to the drive mechanism of the Chonta reservoir, solution-gas mechanism, the most suitable artificial lift system for the production of this reservoir is GAS LIFT.

4.4.2.2.1 Description of the gas lift system

The Gas Lift artificial lift system uses high pressure gas in addition to the formation gas, reducing the density of the fluid, and therefore the hydrostatic pressure of the column to be lifted. There are 2 basic lifting systems with gas lift, which are: continuous lifting and intermittent lifting.

Taking into consideration the antecedents of Block 192, the production of the Chonta formation of the Capahuari Sur extension field will be carried out with the Continuous Gas Lift system.

4.4.2.2.2 Continuous gas lift system

The principle of continuous lift operation is the injection of gas through the deepest valve in a series of GLVs (Gas Lift Valves) located along the tubing See Figure 100.

This system is an extension of the natural flow of the well. In continuous gas lift, the lifting mechanisms involved are:

- Reduction of the fluid density and the weight of the column, which increases the pressure differential applied to the reservoir drainage area.
- Expansion of the injected gas which pushes the liquid phase.
- Displacement of liquid plugs by large gas bubbles.

Advantages

- Low operational and maintenance cost.
- Flexibility - change of flow rates through adjustments to injection rates and / or pressures.
- Simple well completion.
- Easy to change valves without removing tubing, only a slickline kit is needed.
- Workover equipment is required when a total change of equipment has to be made due to a change of zone.

- Flexible lifting method that handles pumping rates from 10 to 50,000 bpd.
- It is the best system that handles sand production, wells deviation and of course gas production.

Disadvantages

- Inefficient in low volume systems, due to gas compression and treatment costs.
- It needs a source of gas supply.
- Difficulty handling heavy and viscous or emulsified crude oils.

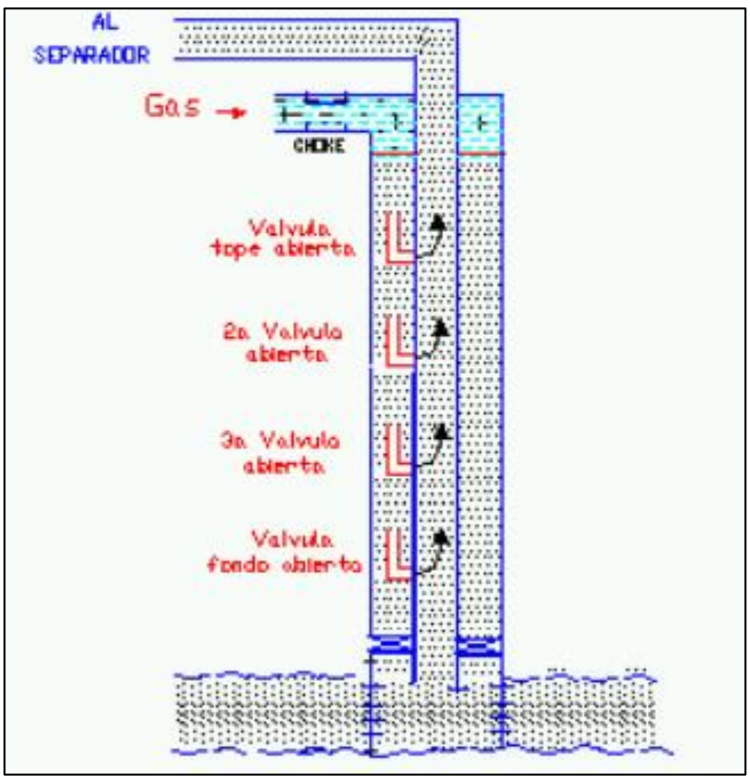


Figure 100. Gas lift - continuous flow scheme.

4.4.2.2.3 Gas lift system design methodology

We will design the Continuous Gas Lift system for the ALFA 01X well in the Capahuari Sur Extensión field, which will produce from the Chonta reservoir.

Table 59 shows the data for the ALFA 01X well that we will use for the Gas Lift design:

Parameters-Chonta Reservoir-ALFA 01X Well		
Pstatic	5600	psi
Qdesign	5500	bfpd
IP	3.809	bbl/psi
Pwf	4157	psi
Grav. Especi gas	0.8	
Temp. Sup	100	°F
Temp bottom	292	°F
Poper.	1050	psi
Pdisp.	1200	psi
Pwf	4157	psi
API	35.5	°API
Sp-gr (oil)	0.847	
Pb	2877	psi
Fw (%)	0.309	
Fw (fraction)	0.00309	
Perforated interval (ft)	11850-11870	ft
Midpoint of the Perforated interval	11860	ft
Depth packer	11850	ft
K abs	79	md
Kro	0.6	
Ko	47.4	md
Hn	20	ft
Uo	0.5	cp
Bo	1.42	bbl/stb
re	750	ft
rw	0.354	ft
Rsi	690	scf/bbl
Wellhead Pressure (Pwh)	200	psi
Pressure drop between valves	25	psi

Table 59. ALFA 01X well parameters for continuous gas lift design.

The production estimate of its first 5 years for the ALFA 01X well is also shown. See Table 60.

ALFA 01X Well - 5 years production					
Month	**Date**	**Qo (Bbls/day)**	**Qw (Bbls/day)**	**Qtotal (Bbls/day)**	**Fw (%)**
0	1/01/2030	0.0	0.0	0.0	
1	1/02/2030	5313.6	4.0	5317.6	0.075
2	1/03/2030	5000.9	3.1	5004.1	0.063
3	1/04/2030	4815.5	3.0	4818.5	0.063
4	1/05/2030	4683.3	3.0	4686.4	0.064
5	1/06/2030	4556.5	3.0	4559.5	0.066
6	1/07/2030	4438.6	3.1	4441.6	0.069
7	1/08/2030	4311.8	3.1	4315.0	0.073
8	1/09/2030	4189.2	3.2	4192.4	0.076
9	1/10/2030	4074.6	3.3	4077.9	0.080
10	1/11/2030	3965.0	3.3	3968.4	0.084
11	1/12/2030	3861.0	3.4	3864.4	0.088
12	1/01/2031	3760.2	3.4	3763.7	0.091
13	1/02/2031	3660.7	3.5	3664.2	0.095
14	1/03/2031	3468.6	3.4	3472.0	0.097
15	1/04/2031	3298.9	3.2	3302.1	0.097
16	1/05/2031	3141.7	3.1	3144.8	0.098
17	1/06/2031	2967.6	3.0	2970.5	0.100
18	1/07/2031	2804.4	2.9	2807.3	0.103
19	1/08/2031	2633.8	2.8	2636.6	0.106
20	1/09/2031	2491.8	2.7	2494.5	0.109
21	1/10/2031	2351.3	2.7	2354.0	0.113
22	1/11/2031	2214.0	2.6	2216.6	0.117
23	1/12/2031	2082.8	2.6	2085.4	0.123
24	1/01/2032	1972.7	2.6	1975.2	0.130
25	1/02/2032	1870.0	2.5	1872.6	0.135
26	1/03/2032	1770.7	2.5	1773.2	0.141
27	1/04/2032	1659.6	2.5	1662.1	0.149
28	1/05/2032	1524.6	2.5	1527.2	0.166
29	1/06/2032	1387.3	2.7	1390.0	0.196
30	1/07/2032	1286.5	2.9	1289.3	0.221
31	1/08/2032	1218.0	2.9	1221.0	0.241

32	1/09/2032	1156.3	3.1	1159.4	0.265
33	1/10/2032	1106.3	3.2	1109.5	0.286
34	1/11/2032	1065.8	3.2	1069.0	0.297
35	1/12/2032	1036.0	3.2	1039.1	0.305
36	1/01/2033	1010.1	3.2	1013.3	0.315
37	1/02/2033	988.8	3.2	992.0	0.327
38	1/03/2033	967.4	3.3	970.7	0.339
39	1/04/2033	949.4	3.3	952.7	0.351
40	1/05/2033	918.2	3.4	921.6	0.369
41	1/06/2033	886.4	3.4	889.9	0.388
42	1/07/2033	847.6	3.5	851.1	0.409
43	1/08/2033	817.7	3.5	821.3	0.432
44	1/09/2033	785.5	3.6	789.1	0.457
45	1/10/2033	757.3	3.6	760.9	0.479
46	1/11/2033	730.6	3.7	734.3	0.501
47	1/12/2033	703.0	3.7	706.7	0.525
48	1/01/2034	682.3	3.7	686.0	0.544
49	1/02/2034	662.4	3.8	666.1	0.564
50	1/03/2034	644.7	3.8	648.5	0.586
51	1/04/2034	625.7	3.8	629.6	0.610
52	1/05/2034	607.8	3.9	611.6	0.634
53	1/06/2034	589.7	3.9	593.6	0.660
54	1/07/2034	576.2	4.0	580.2	0.682
55	1/08/2034	556.1	4.0	560.1	0.715
56	1/09/2034	532.4	4.0	536.4	0.750
57	1/10/2034	512.8	4.0	516.8	0.779
58	1/11/2034	496.0	4.0	500.1	0.808
59	1/12/2034	473.4	4.0	477.5	0.846
60	1/01/2035	456.6	4.0	460.6	0.878

Table 60. Production estimate for the ALFA 01X well.

Table 61 shows the calculations made for the design of the Gas Lift System of the ALFA 01X well:

1. Pwf Calculation		
Static Pressure	5600	psi
Q	5500	bfpd
IP	3.809	bbl/psi
Pwf	4157	psi

2. Fluid Gradient and Dynamic Fluid Level		
API	35.5	°API
Sp-gr (oil)	0.847	
Fw (fraction)	0.041	
Fluid specific gravity	0.854	
Fluid gradient	0.37	psi/ft
Dynamic level = h	11235	ft
Packer depth	11850	ft
Fluid level	615	ft

3. Gas Conditions a la Operating and available Pressure				
Poperating	1050 psi		gas specific gravity	0.8
Pavailable	1200 psi		gas specific gravity	0.8
		From the 3K graph we obtain		
		ΔPoperating		31 psi/1000ft
		ΔPavailable		36 psi/1000ft

4. We correct ΔP for Temperature		
Higher temp.	100	°F
Packer depth	11850	ft
calculated temp.	179.8	°F
background temp.	292	
Real temp.	196	°F

5. ΔPcorrected Calculation	
For Pop= 1050psi	
ΔPcorrected	30.23 psi/1000ft
Para Pdisp=1200psi	
ΔPcorrected	35.11 psi/1000ft

Table 61. Calculations for the design of the gas lift system of the ALFA 01X well.

4.4.2.2.3.1 Continuous gas lift-graphic procedure

- **Determination of the Optimal Injection Point**

In the design of a Continuous Gas Lift installation, the optimal injection point of the operating valve must first be located. See Figure 101.

Procedure:

1. Graph on paper with rectangular coordinates, the depth on the ordinate axis, being equal to zero at the top and presenting its maximum value at the reference point = 11850ft (Depth of the packer).

2. From the PI, calculate the Pwf corresponding to the desired rate (design rate) and indicate this value at the reference depth = 11850ft (Depth of the packer).

3. On the abscissa axis, graph the pressure, with zero at the origin up to a maximum pressure that would be Pwf = 4157 psi.

4. We calculate the dynamic level and the fluid level.

5. Starting from Pwf, extend the dynamic gradient line (flowing gradient) until the ordinate axis intersects. The point at which the gradient intersects the ordinate axis is the fluid level.

6. Mark the operating pressure and the available pressure on the abscissa axis. The operating pressure is generally set 100-150 psi below the available pressure, and this is 50-100 psi below the maximum pressure of the injection gas (start pressure). For our design the P(operation) = 1050 psi and the P(available) is 1200 psi.

7. We calculate the corrected Pressure Gradient and draw the gas gradient line corresponding to the operating pressure and the available pressure until the flowing gradient line intersects.

8. The intersection of the operating pressure and the flowing gradient is the point known as the Balance Point.

9. Starting from the balance point and on the flowing gradient line, determine the Gas Injection Point by subtracting 100 psi from the balance point.

10. We mark the head pressure (Pwh) at the depth of zero. Pwh = 200 psi.

11. Join the injection point and the Wellhead Pressure (Pwh) with a straight line for valve spacing. This line will be the flowing gradient above the injection point.

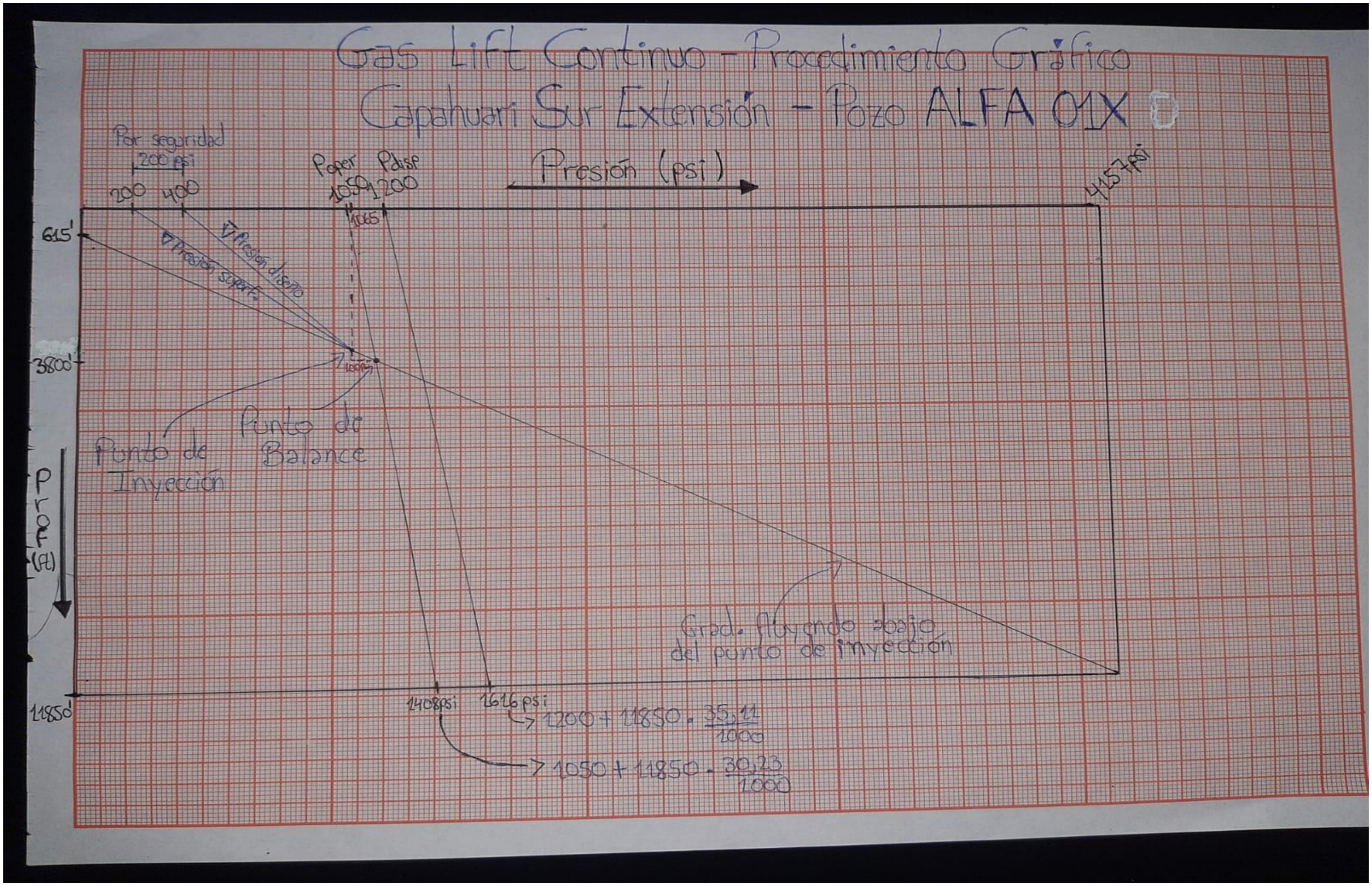


Figure 101. Determination of the optimum injection point - graphic procedure.

- **Valve Spacing**

After determining the injection point, the valve spacing of a Continuous Gas Lift System is determined as follows. See Figure 102.

1) Add 200 psi to the wellhead pressure (Pwh) and mark this point at zero depth. Draw a straight line from this point to the corresponding gas injection point. This line represents the design pressure in the tubing.

2) Draw a line parallel to the dynamic gradient line (Flowing gradient), starting from the Pwh, until intercepting the line of the gradient that corresponds to the available pressure of the injection gas. This point determines the depth of the first valve.

3) Draw a horizontal line, from the point determined in the previous step, until the line corresponding to the design pressure is intercepted.

4) From the previous intersection, draw a parallel line to the flowing gradient until intercepting the line corresponding to the operating pressure of the injection gas. This point determines the depth of the second valve.

5) Draw a horizontal line, from the point determined in the previous step, until the line corresponding to the design pressure is intercepted.

6) The 2 previous procedures are repeated between the design pressure and the operating pressure of the injection gas until the injection point is reached and the number of valves and their depths are determined. For the design of our well, 2 valves were calculated.

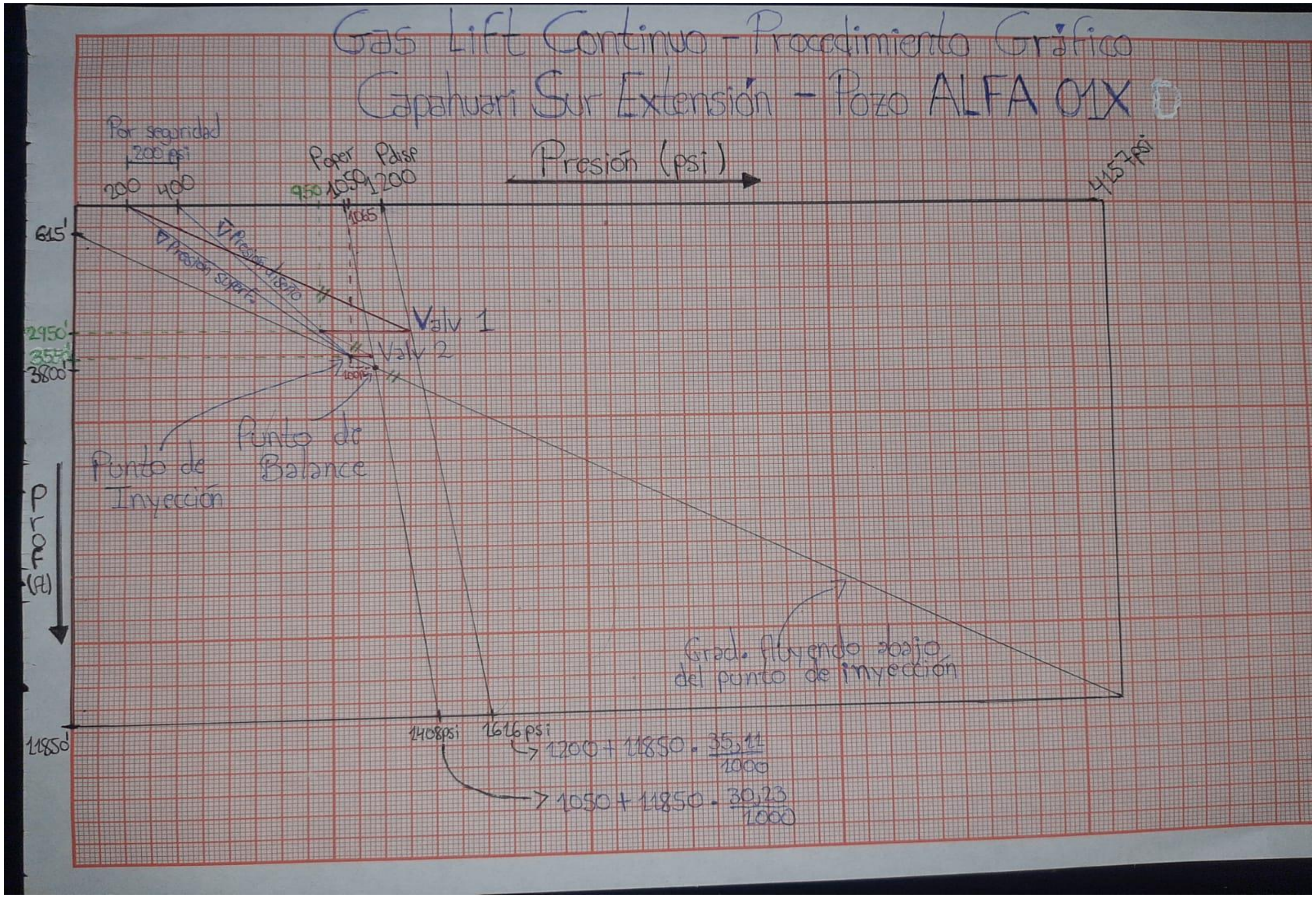


Figure 102. Valve spacing - graphic procedure.

➢ Valve Operating Temperature

1) Plot the geothermal gradient between the wellhead temperature and the bottom temperature.

2) At the depth of each valve we draw a line that cuts the geothermal gradient and we determine the operating temperature of each valve, as shown in Figure 103.

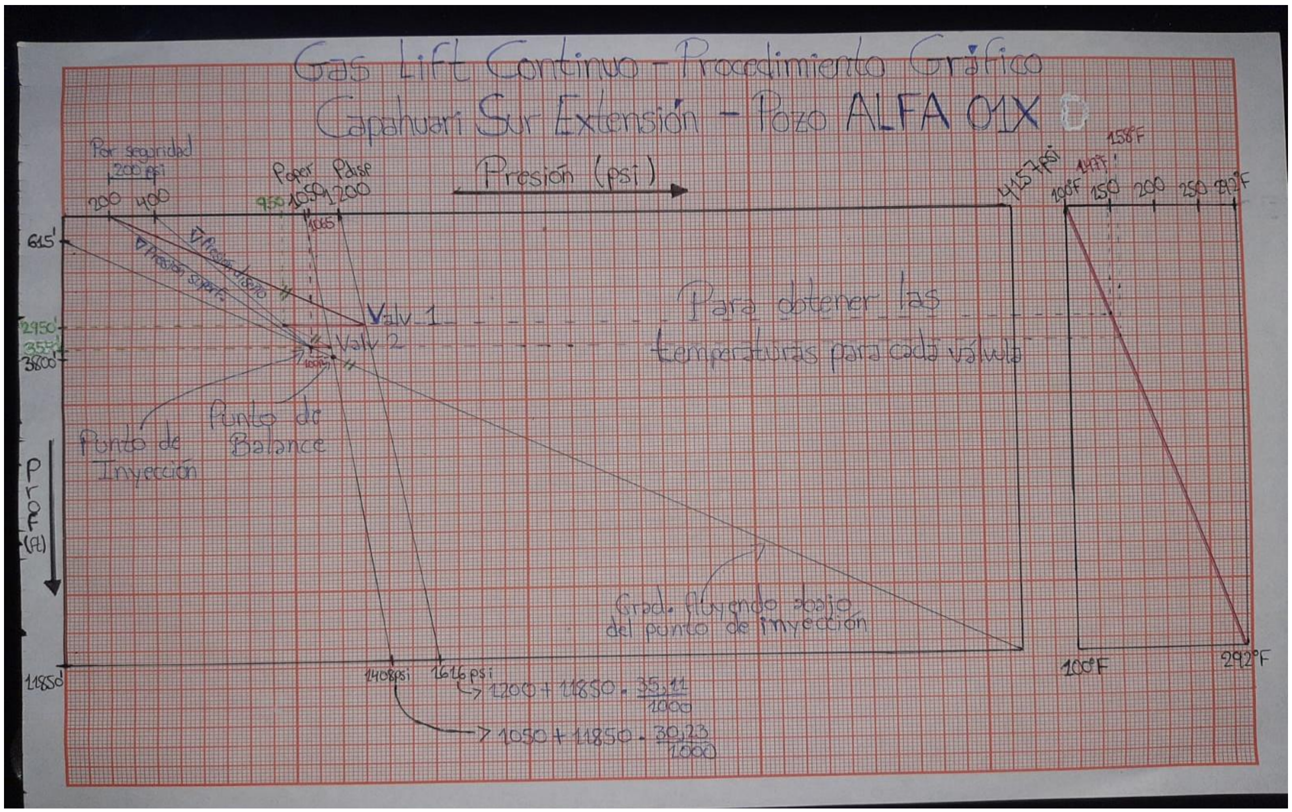


Figure 103. Valves operating temperature - graphic procedure.

From the calculations and our graphic design carried out previously, Table 62 is obtained with the following results:

Valve	Depth (ft)	P design (psi)	Temperature (°F)
1	2950	950	147
2	3550	1065	158

Table 62. Table of the results obtained.

- **Injection Rate**

The injection gas rate is calculated from the Equation 50:

$$Qgi = (GLRassumed - GLRformation) * Qdesired$$

Equation 50. Injection gas rate.

Replacing the values in the formula, we get:

$$Qgi = \frac{(850 - 690)SCF}{bbl} * 5500bbl = 880\ MSCF/day$$

So, the injection rate to be carried out from the surface for the ALFA 1X well is 880 MSCF/day.

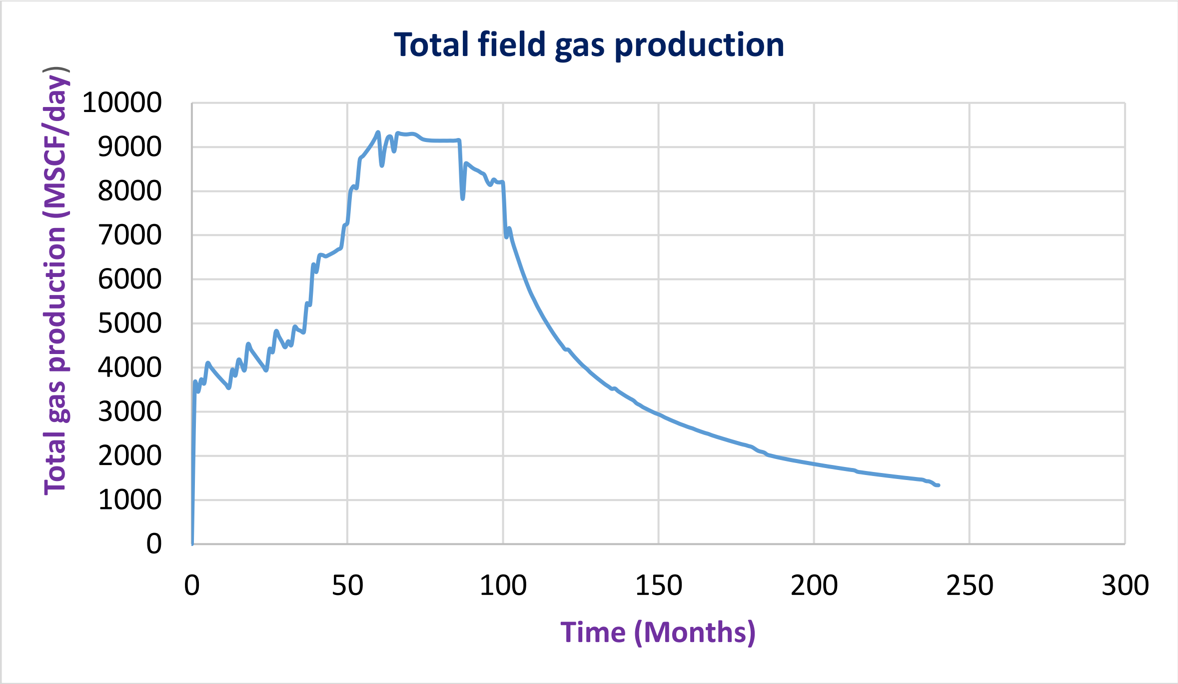


Figure 104. Total gas production from the CSE field.

From Figure 104, we can see that we have enough gas to reinject the wells assisted by Continuous Gas Lift, so that the gas produced from the field, after passing through the separator, will be redirected to the field through a compression unit.

4.4.2.3 ESP artificial lift system – Vivian Formation

4.4.2.3.1 Description of an ESP equipment

Electric Submersible Pumping, commonly known as ESP, is an artificial lift method that consists of a multi-stage centrifugal type subsoil pump, located at the bottom of the well, and this is driven by an electric motor since its fundamental principle is that of transforming electrical energy into mechanical energy through the rotation of the motor, which will transmit a certain rotation to the pump, generating the lift required for the fluids to be transported from the bottom of the well to the surface. See Figure 105.

Among the characteristics of the electric submersible pumping system is its ability to produce considerable volumes of fluids from great depths, under a wide variety of well conditions. It is very advantageous in wells that have high production rates, high productivity, low bottom pressure and low gas-oil ratio.

Electric submersible Pumping is a totally efficient and reliable mechanism to recover or improve production in the well, in addition this system is currently one of the most used in the fields of the Marañon basin, since among its benefits it allows us to produce oil at great depths, as well as at high temperatures and under a wide variety of well conditions.

Figure 105. Typical configuration of an electro submersible pumping string (E. Vargas).

Electric submersible Pumping has proven to be a highly efficient alternative to produce light and medium crude oils worldwide thanks to the advantages it provides compared to other artificial lift methods. This system can handle large volumes of crude from great depths in a variety of well conditions. The Electric submersible Pumping system also allows production to be controlled and programmed within the limits of the well, through the use of a variable speed drive (VSD) and is particularly distinguished because the motor is directly coupled with the pump at the bottom of the well. Another benefit that this system provides is the continuous indication of the pressure and temperature conditions in the well, thanks to the signals transmitted by the bottom sensor, which gives us the pressure and temperature data. It is more applicable in reservoirs with high percentages of water and low Gas-Oil ratio.

The Electric submersible Pumping system is an artificial lift system that uses electrical energy converted into mechanical energy to lift a column of fluid from a certain level to the surface, discharging it at a certain pressure.

In the oil industry, compared to other artificial production systems it has advantages and disadvantages, because for various reasons it may not always be the best, that is, a well candidate to produce artificially with Electric submersible Pumping, must meet characteristics that do not affect its operation. such as high Gas-Oil ratios, high temperatures, the presence of sand in the fluids produced.

Advantages of the Electric submersible Pumping system:

- Can lift high volumes of fluid.
- Handles high water cuts.
- Its shelf life can be very long.
- Simple to operate.
- It can be used in any type of operating facility, land or sea.
- Versatility, different models and sizes.
- High reliability.
- Economic, immediate recovery of investment.

Disadvantages of the Electric submersible Pumping system:

- Very high initial investment.
- High power consumption.
- It is not profitable in low production wells.
- Cables can deteriorate when exposed to high temperatures.

4.4.2.3.2 Equipment of ESP system

The ESP system consists of Downhole equipment (Motor, protector, pump, intake, gas separator, Cable Venting box) and surface equipment (Motor controller Switchboard of Variable Speed Drive VSD, Junction Box). See Figure 106.

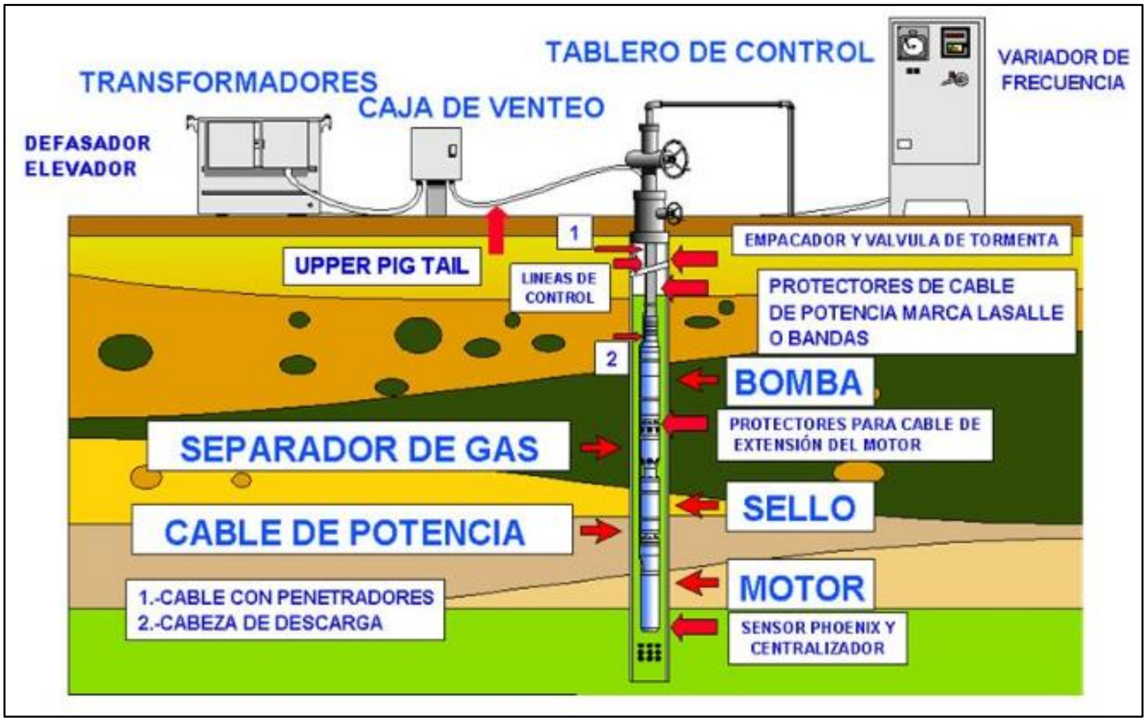


Figure 106. Surface and downhole equipment of an ESP system (E. Vargas).

4.4.2.3.3 Design and selection of ESP equipment

Electric submersible pumping is an efficient mechanism to recover or improve well production, since it allows us to produce at great depths and high flow rates, in this case we will carry out an optimal design of the ESP system that we will apply to our Capahuari Sur Extensión field-Vivian reservoir.

4.4.2.3.3.1 Calculations to be performed for the ESP design

Productivity Index (See Equation 51):

$$\mathrm{IP} = \frac{Q}{Pr - Pwf}$$

Equation 51. Productivity index.

Bottom Hole Pressure Calculation (See Equation 52):

$$\mathrm{Pwf} = \mathrm{Pr} - \frac{\mathrm{Q}}{\mathrm{IP}}$$

Equation 52. Bottom hole pressure.

Calculation of Average Specific Gravity (See Equation 53):

$$\mathrm{Sgprom} = \%\mathrm{W} * \mathrm{Sgw} + \%\mathrm{O} * \mathrm{Sgo}$$

Equation 53. Average specific gravity.

Calculation of Pump Intake Pressure (See Equation 54):

$$\mathrm{PIP} = \mathrm{Pwf} - \frac{\text{Midpoint of perforations} * \mathrm{Sgprom}}{2.31\mathrm{ft/psi}}$$

Equation 54. Pump intake pressure.

Calculation of the Dynamic Height (See Equation 55):

$$\mathrm{HD} = \text{Pump depth} - \frac{\mathrm{PIP} * 2.31}{\mathrm{Sgprom}}$$

Equation 55. Dynamic height.

Calculation of Discharge Pressure (See Equation 56):

$$PD = \frac{Pc * 2.31}{Sgprom}$$

Equation 56. Discharge pressure.

Calculation of Tubing Friction Loss (See Equation 57):

$$Ft = \frac{\text{Tubing friction} - \text{graphic}}{1000} * \text{Pump depth}$$

Equation 57. Tubing friction loss.

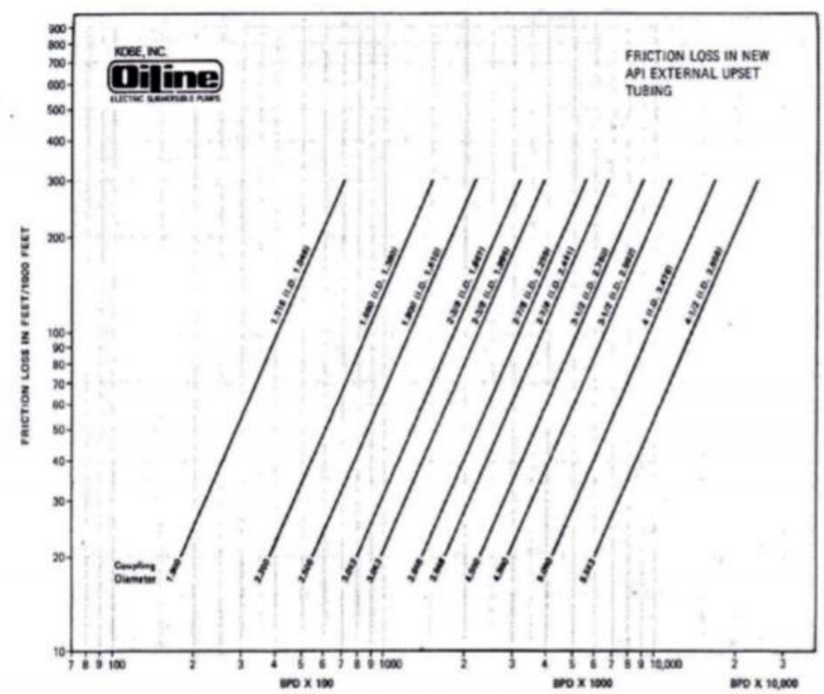


Figure 107. Tubing friction (source: Schlumberger).

Calculation of Total Dynamic Height (See Equation 58):

$$\mathrm{TDH} = \mathrm{HD} + \mathrm{Ft} + \mathrm{PD}$$

Equation 58. Total dynamic height.

Calculation of the Number of Stages (See Equation 59):

$$\#\mathrm{etapas} = \frac{\mathrm{TDH}}{\mathrm{cabeza/etapa}}$$

Equation 59. Number of stages.

Calculation of Brake HorsePower (See Equation 60):

$$\mathrm{BHP} = \left(\frac{\mathrm{BHP}}{\mathrm{etapa}}\right) * \#\mathrm{etapas} * \mathrm{Sgprom}$$

Equation 60. Brake horse power.

4.4.2.3.3.2 Procedure for ESP design

We will carry out the design of Electric submersible Pumping for the Vivian reservoir (ALFA 1X Well), we choose this type of artificial lift for this reservoir due to the high pressures and large flow rates.

By analogy of nearby fields, it is decided that the ALFA 1X well will produce by natural flow during the first year of production, from the second year we will lower the ESP equipment to the well to maintain the optimal oil flow for our field, it is estimated that the time The useful lifetime for the ESP pump will be three years, since the fluid produced will be light oil, then the ESP pump will have to be redesigned every three years of production.

The ESP design for the exploratory well is carried out.

For this, the general data of the exploratory well is needed, which can be seen in the following table (See Table 63):

GENERAL DATA OF THE ALFA 1X WELL		
API oil	34	°API
Sp-gr oil	0.85	
Fw	0.28	
Sp-gr fluid	0.86	
Grad avg fluid	0.37	psi/ft
Pr	4800	psi
WHP	200	psi
Fm Depth	11060	ft
Tubing OD	4.5	in
Tubing ID	3.958	in
Factor	0.00708	
u	2.79	Cp
B	1.1	br/stb
K abs	1288	mD
Kro	0.6	
Ko	772.8	mD
h	80	ft
re	1000	ft
rw	0.354	ft
Pb	349	psi
J(Pb)	17.95	Bbl/psi

Table 63. General data of the ALFA 1X well.

Production estimate of ALFA 1X Well (See Table 64 and Table 65): The production forecast is obtained from the simulation carried out for scenario 2 (See Figure 108 and Figure 109).

Date	Water (BWPD)	Oil (BOPD)	Gas (ft3/day)	Liquid (BFPD)	fw (%)
1/03/2035	2.3	6998	416201	7000	0.03
1/04/2035	2.1	6998	416212	7000	0.03
1/05/2035	2.0	6998	416218	7000	0.03
1/06/2035	1.9	6998	416220	7000	0.03
1/07/2035	2.0	6998	416218	7000	0.03
1/08/2035	2.0	6998	416215	7000	0.03
1/09/2035	2.0	6998	416214	7000	0.03
1/10/2035	2.0	6998	416217	7000	0.03
1/11/2035	1.9	6998	416221	7000	0.03
1/12/2035	1.8	6998	416226	7000	0.03
1/01/2036	1.7	6998	416231	7000	0.02
1/02/2036	1.7	6998	416236	7000	0.02

Table 64. First year production estimate - ALFA 1X well.

Date	Water (BWPD)	Oil (BOPD)	Gas (ft3/day)	Liquid (BFPD)	fw (%)
1/03/2036	1.6	6998	416242	7000	0.02
1/04/2036	1.5	6998	416245	7000	0.02
1/05/2036	1.5	6999	416249	7000	0.02
1/06/2036	1.4	6999	416251	7000	0.02
1/07/2036	1.4	6999	416253	7000	0.02
1/08/2036	7.9	6992	415867	7000	0.11
1/09/2036	14.1	6986	415494	7000	0.20
1/10/2036	43.9	6956	413726	7000	0.63
1/11/2036	122.7	6877	409035	7000	1.75
1/12/2036	202.8	6797	404273	7000	2.90
1/01/2037	298.0	6702	398610	7000	4.26
1/02/2037	376.7	6623	393931	7000	5.38
1/03/2037	526.1	6474	385045	7000	7.52

1/04/2037	703.9	6296	374471	7000	10.06
1/05/2037	872.7	6127	364430	7000	12.47
1/06/2037	1054.2	5946	353633	7000	15.06
1/07/2037	1357.6	5642	335590	7000	19.39
1/08/2037	1567.4	5433	323113	7000	22.39
1/09/2037	1707.8	5292	314764	7000	24.40
1/10/2037	1886.4	5114	304138	7000	26.95
1/11/2037	2077.1	4923	292798	7000	29.67
1/12/2037	2323.4	4677	278148	7000	33.19
1/01/2038	2454.7	4545	270334	7000	35.07
1/02/2038	2696.8	4303	255942	7000	38.53
1/03/2038	3935.4	6065	360698	10000	39.35
1/04/2038	4369.0	5631	334914	10000	43.69
1/05/2038	4722.6	5277	313882	10000	47.23
1/06/2038	5238.0	4762	283227	10000	52.38
1/07/2038	5524.2	4476	266203	10000	55.24
1/08/2038	5966.7	4033	239883	10000	59.67
1/09/2038	6262.8	3737	222275	10000	62.63
1/10/2038	6534.4	3466	206118	10000	65.34
1/11/2038	6773.0	3227	191931	10000	67.73
1/12/2038	7013.9	2986	177604	10000	70.14
1/01/2039	7236.1	2764	164384	10000	72.36
1/02/2039	7422.2	2578	153319	10000	74.22

Table 65. Production estimate from the second to the fourth year - ALFA 1X well.

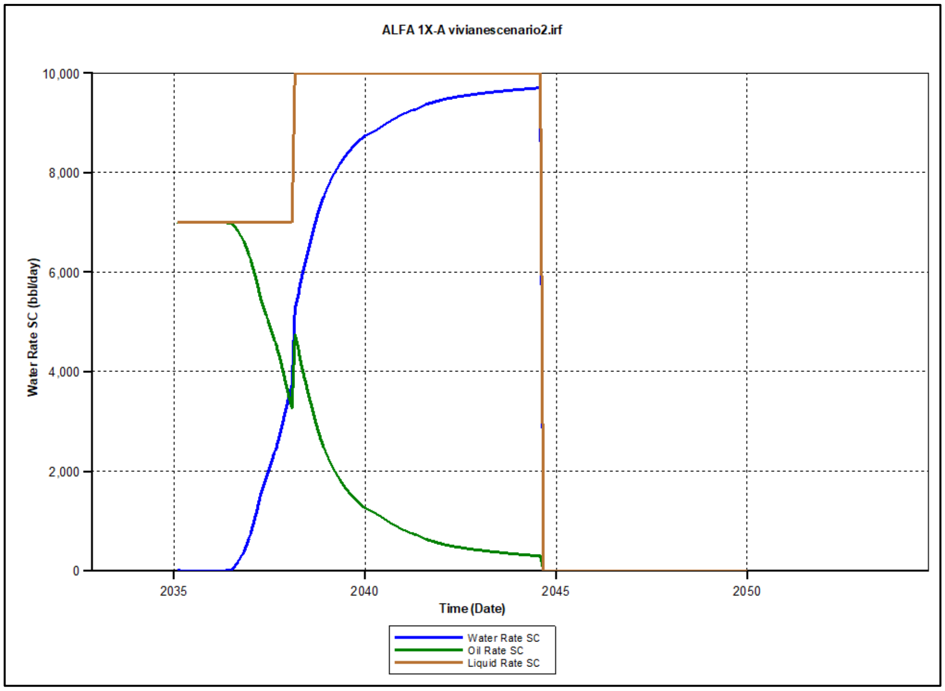


Figure 108. Production estimate for the ALFA 1X well.

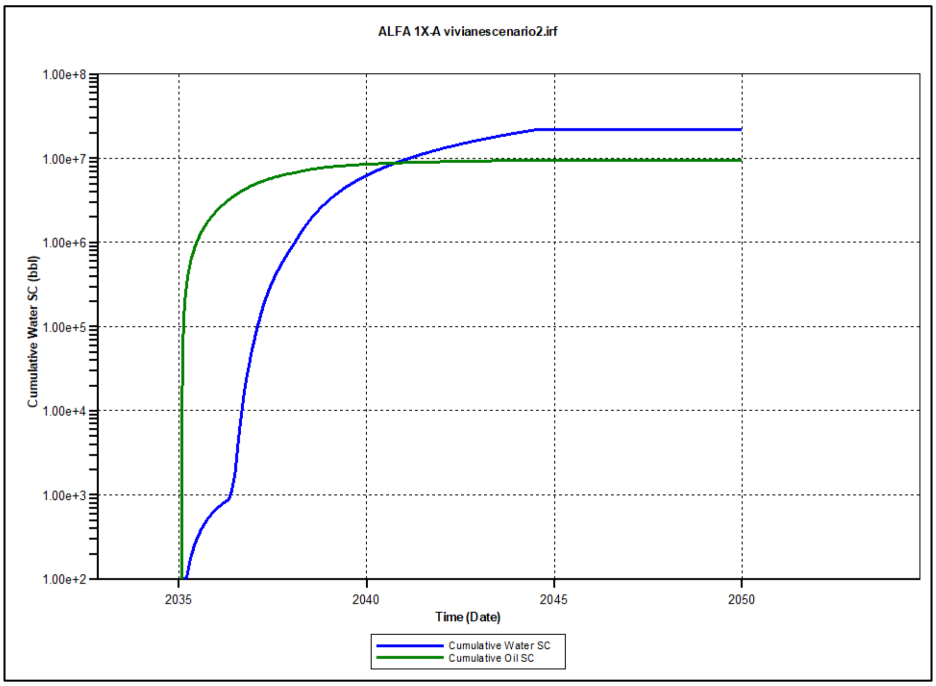


Figure 109. Accumulated production.

According to the analysis carried out, we proceed to design the ESP equipment to be selected for the well, as well as the type of motor and other equipment to be used for the optimal development of the well and the field in general.

The design will be done considering 9 steps.

ALFA 1X well diagram (See Figure 110):

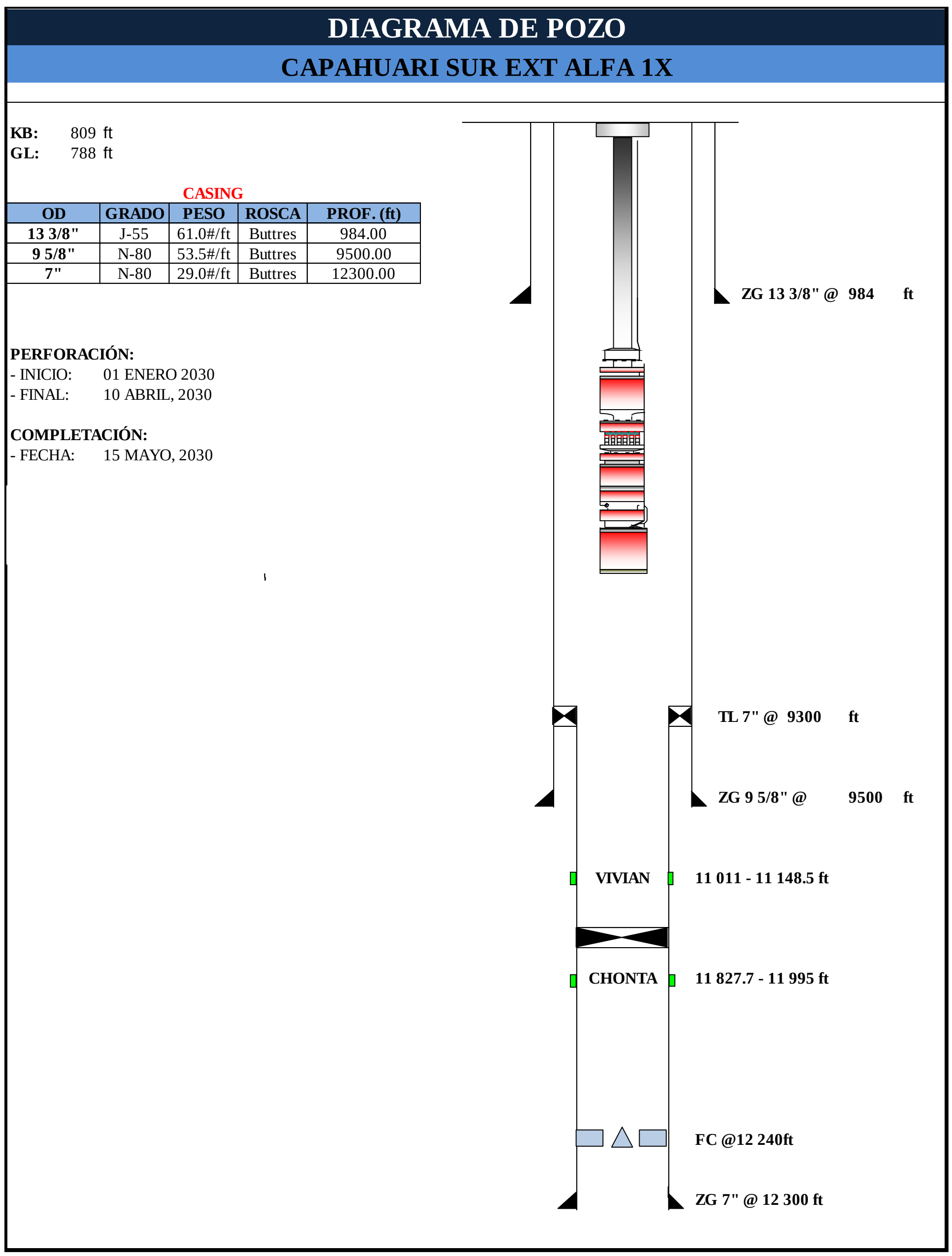


Figure 110. ALFA 1X well diagram.

Operational calculations (See Figure 111):

1. General Calculations		
Fw	27.78	
API	34	
Sg oil	0.85	
Sg Water	1.05	
Grad avg	0.39	psi/ft
SG avg	0.91	
PI	17.95	
Target RATE	7000	BFPD
Pr:	4800	psi
Pwf	4410	psi
CHP	280	psi
Dynamic Fluid Level	288	FT
FLOP	4712	FT
Pressure at Intake conditions		
PIP	2024	psi
Pstatic	2414	psi
2. PVT Calculations at Intake conditions		
SG gas	0.65	
BHT	282	F
Bo	1.12	bls/STB
Z	0.80	

3. Surface Conditions		
Target	7000	BFPD
4. At Pump intake Conditions		
Vol Oil	5647	bopd
Vol Water	1945	bwpd
Vol Total	7592	bfpd
5. Pump THD Calculation		
TOTAL DYNAMIC HEAD:		HL+Hf+Hwhp
HL:	288	FT
Tbg ID	3.958	
F	35	FT/1000FT
Hf	175	FT
THP	275	psi
Hwhp	699	FT
TDH	1161	FT

Figure 111. Operational calculations for the ESP design.

6.- Pump Selection: For this we are guided by the Schlumberger catalog. (Schlumberger, 2017). See Table 66, Figure 112 and Table 67, Figure 113.

To GN10000			#Stages	Selection
HEAD	35	Ft/stg	34	01pump of 38 stages will be used
POWER	3	HP/stg		
BHP	93	HP		

Table 66. Calculation of the Hp consumption of the GN 10000 pump.

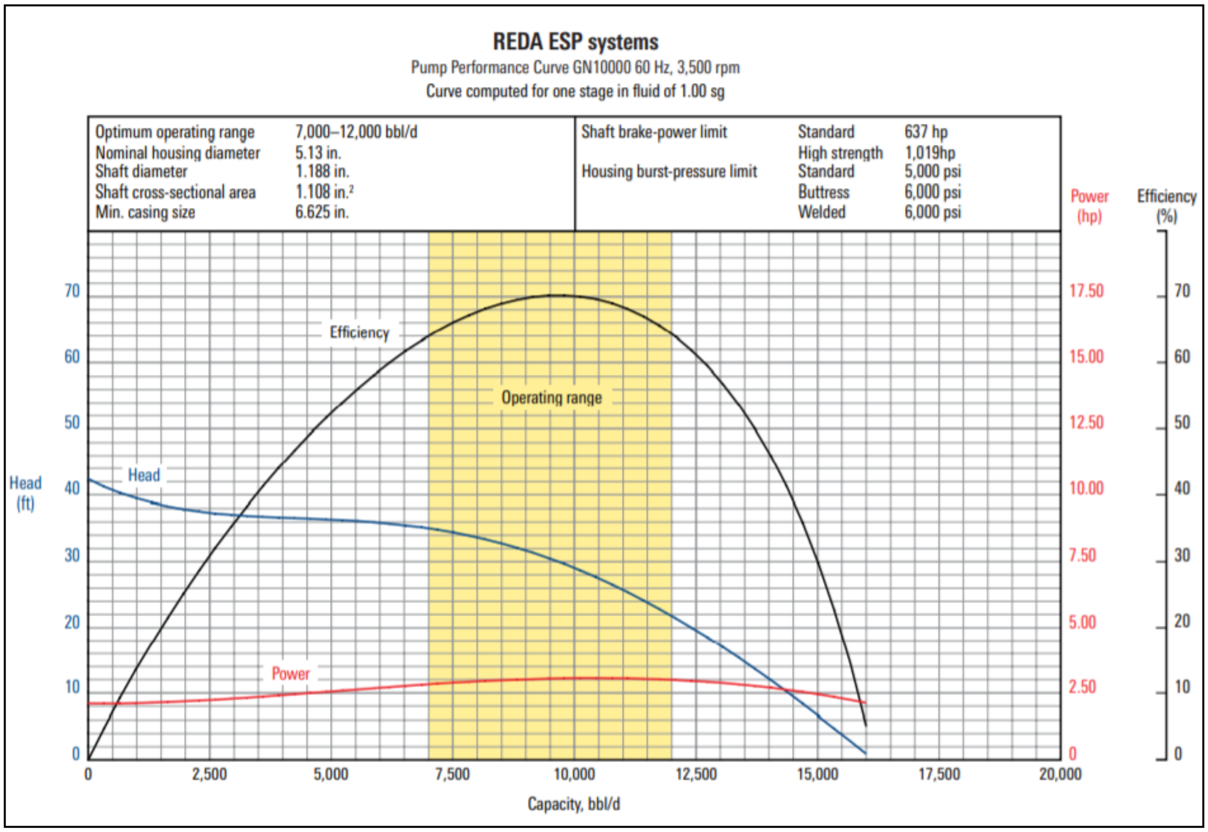


Figure 112. Characteristic curves of the GN10000 pump (Source: Schlumberger).

To S8000N			#Stages	Selection
HEAD	52	Ft/stg	23	01 pump of 28 stages will be used
POWER	3.5	HP/stg		
BHP	73	HP		

Table 67. Calculation of the Hp consumption of the S8000N pump.

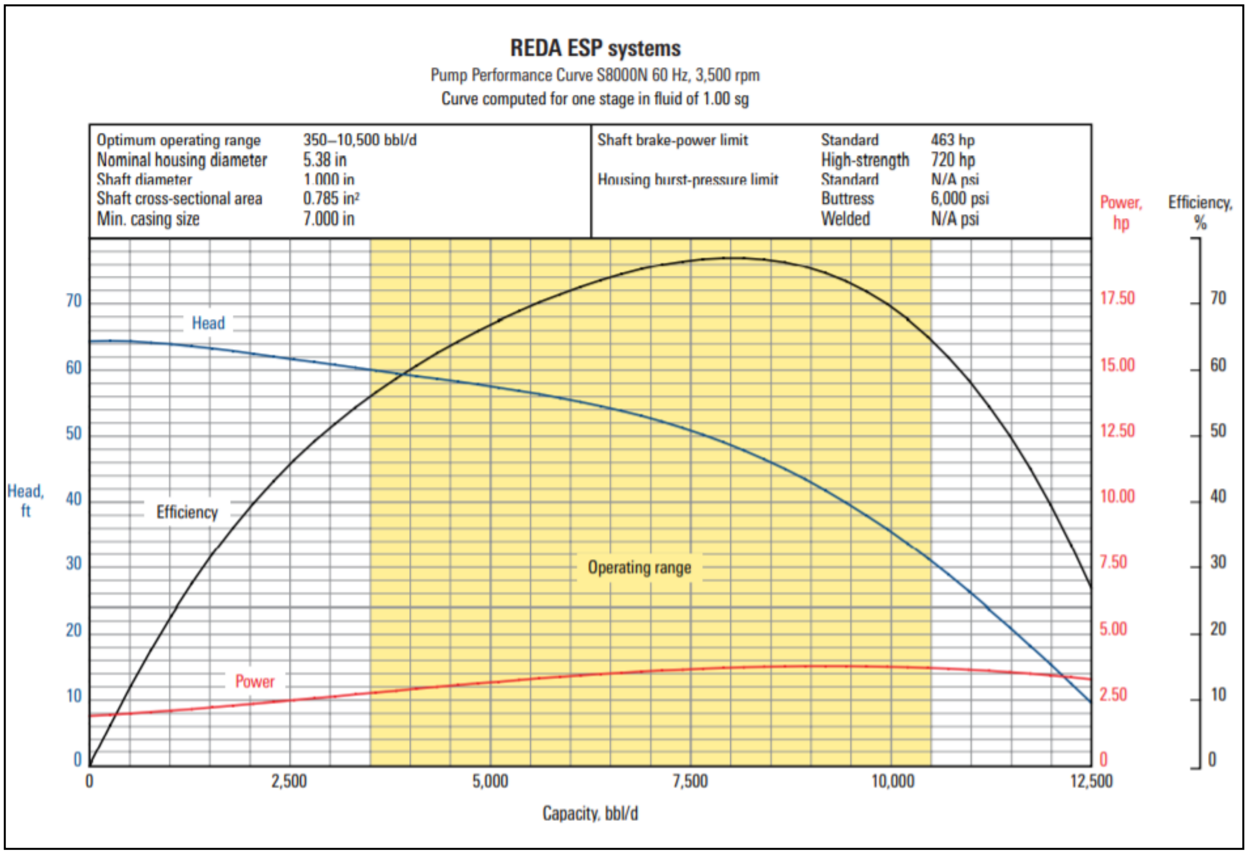


Figure 113. Characteristic curves of the S8000N pump (source: Schlumberger).

7.- Motor Selection:

Considering a safety factor of 1.12 (See Figure 114).

To GN10000								
BHP min	Motor		Voltage	Amperage	Motor Load	Ef. Motor	Pin	Running Amp
104 HP	562 SERIES	150HP	1486	61.1	69.24%	90.00%	2.19	39.40
	562 SERIES	150HP	2393	38.4	69.24%	90.00%	3.52	24.47

To S8000N								
BHP min	Motor		Voltage	Amperage	Motor Load	Ef. Motor	Pin	Running Amp
82 HP	562 SERIES	150HP	1486	61.1	54.65%	88.50%	2.19	31.62
	562 SERIES	150HP	2393	38.4	54.65%	88.50%	3.52	19.64

Figure 114. Motor selection.

The 150 HP motor with a 2393volt / 38.4amp arrangement is selected due to having a lower motor load for the same application.

Using lower amperage is prioritized because of lower energy consumption.

8.- Cable Selection:

The surface voltage (Vsup) is calculated as the sum of the motor plate voltage plus the drop voltage. For this, the depth of the pump intake is considered.

It is calculated for cable # 2. See Figure 115 and Figure 116.

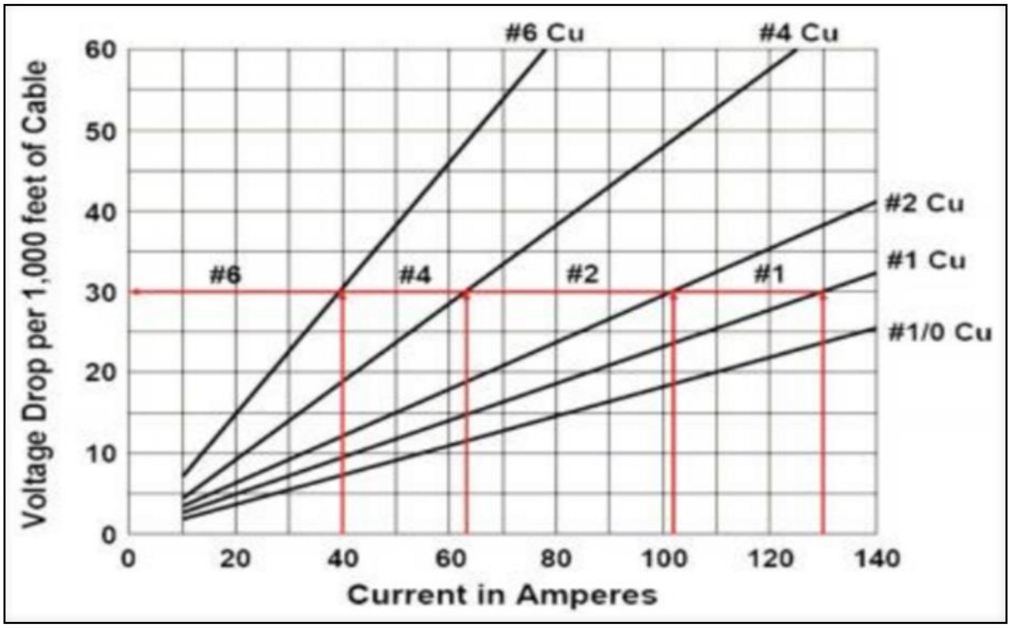


Figure 115 Graphical calculation of the voltage loss in the cable.

Amp	Volt Loss	Vdrop	Vsup
61.1	18 V/1000FT	90 Volts	1576 volts
38.4	13 V/1000FT	65 Volts	2458 volts
61.1	18 V/1000FT	90 Volts	1576 volts
38.4	13 V/1000FT	65 Volts	2458 volts

Figure 116. Voltage losses in the cable.

9.- Surface Equipment Selection (See Figure 117):

Running Amp	POWER CONSUMPTION
39.40	107.42 KVA
24.47	104.03 KVA
31.62	86.21 KVA
19.64	83.50 KVA

STEP UP TRANSFORMER	
Eff	0.98
350 KVA	660AMP
SUT Load:	23.86%
KVA in	85.20

VSD Selection	
Eff	0.99
318KVA	660AMP
VSD Load	26.79%

Figure 117. Energy consumption.

4.4.3 Surface Facilities

For surface facilities, tank batteries are required where the treatment of crude oil that comes from the exploitation areas is carried out. In these batteries, the following processes are carried out.

- Collection
- Separation
- Measurement
- Treatment
- Storage
- Transference

To transport the fluid from the productive areas, it is done through a system of circular section pipes.

Already in the batteries, they first pass through a manifold, this is mechanical arrangement made up of a set of valves, pipes and accessories that generally consist of several pipes placed in a horizontal position, parallel to each other and connected to each of the flow lines. Its function is to collect the production from the wells that arrive at the flow stations and distribute it to the different processes carried out in the tank battery.

These arrangements of valves, connections, and pipes should be such that when required, the flow from each individual well can be isolated for testing purposes.

For our design of the flow lines, we used the “Google Earth Pro” application to calculate the lengths of the flow lines, as well as their altitudes.

According to the location of our wells, we plan to build 3 tank batteries for the collection of fluid in our field, which we will locate near our 3 production zones. See Figure 118.

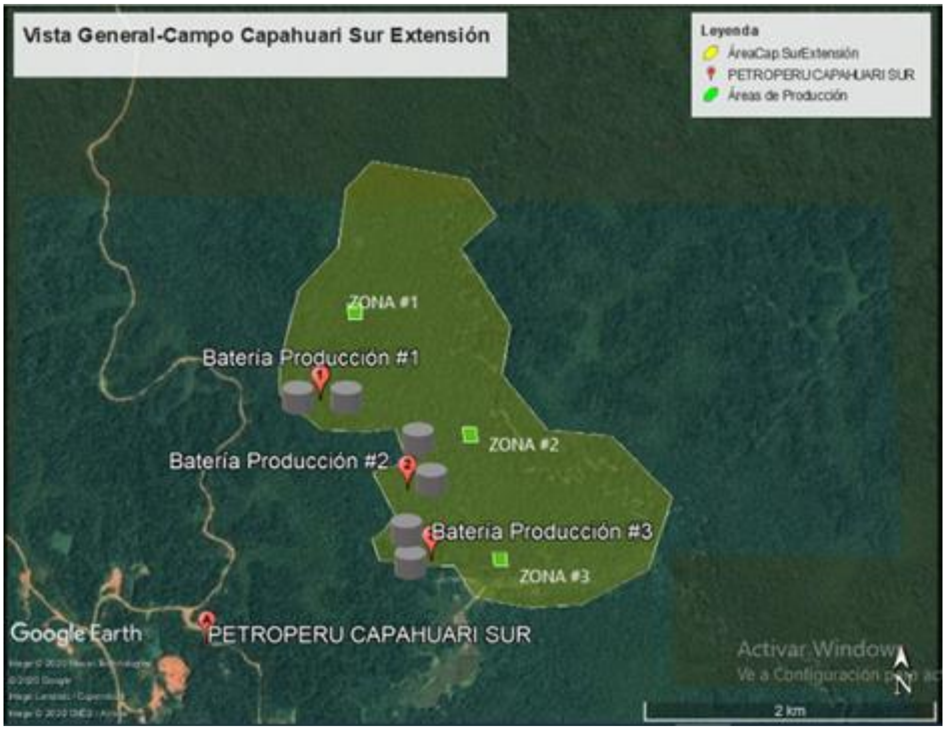


Figure 118. General view of the field and tank batteries.

4.4.3.1 Flow lines

The flow lines are pipes that connect the well heads with the storage tanks in the batteries, these pipes are generally made of steel.

Production from zone # 1 (6 wells) will be directed to battery # 1 where there will be a 6-inlet manifold. The flow lines will be 5-inch pipes, except for the ALFA 6H well line, which produces 3-inch diameter pipes.

In this area we produce from 3 directional wells and 3 horizontal wells located as seen in Figure 119. This area is located north of our Capahuari Sur Extensión field.

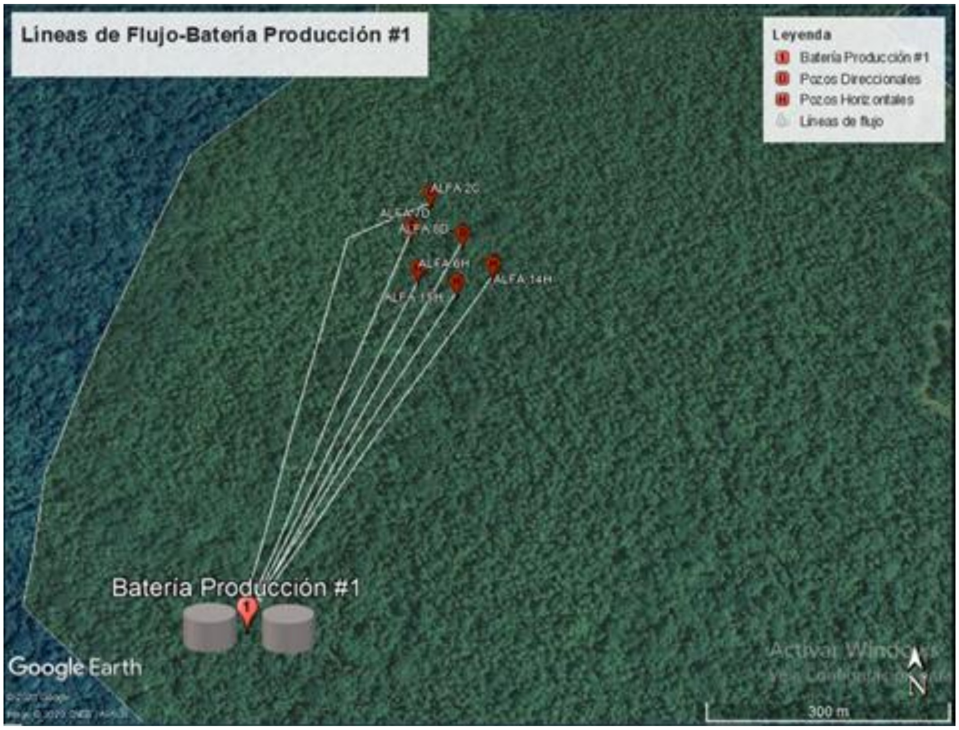


Figure 119. Flow lines in zone # 1.

The production of zone # 2 (6 wells) we take it to the battery # 2 through 5-inch diameter pipes where there will be a manifold with 6 inlets, except for the ALFA 11H well, which produces through a 3-inch flow line. diameter.

In this area there are 3 directional wells and 3 horizontal wells. This zone is located in the central part of our Capahuari Sur Extensión area. See Figure 120.

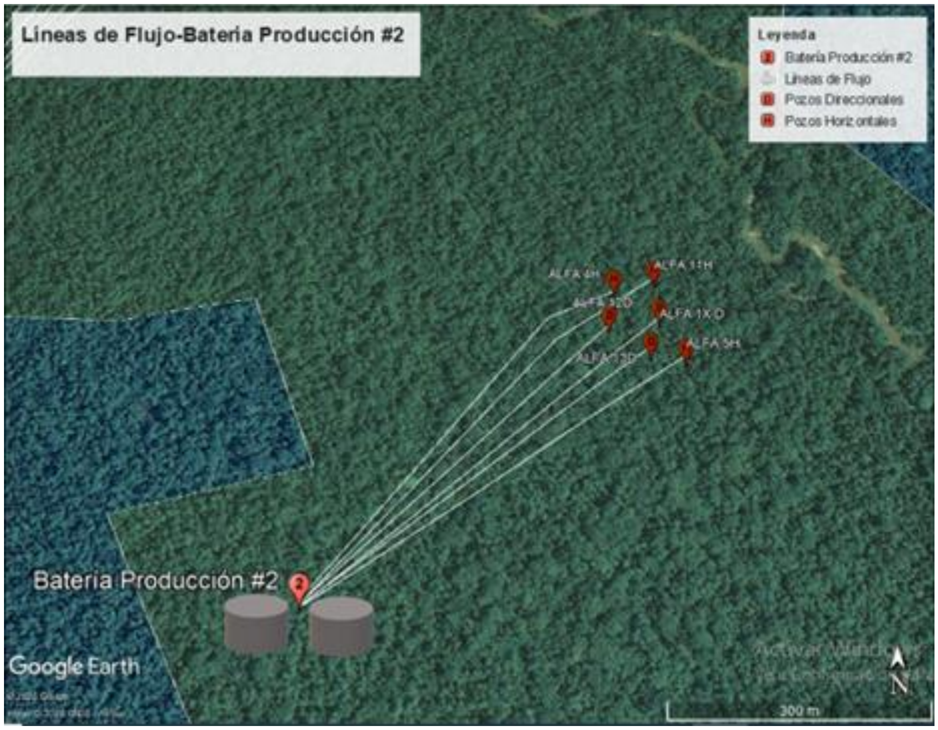


Figure 120. Flow lines in zone # 2.

For zone # 3 we produced from 3 horizontal wells and 1 directional well, this production we take it to the battery # 3 through 5-inch pipe, except for the flow line from the ALFA 16H well, which will use 3-inch diameter pipe.

Upon reaching the battery, they will first go through a manifold that will have 4 inlets.

This area is located south of our Capahuari Sur Extensión field. See Figure 121.

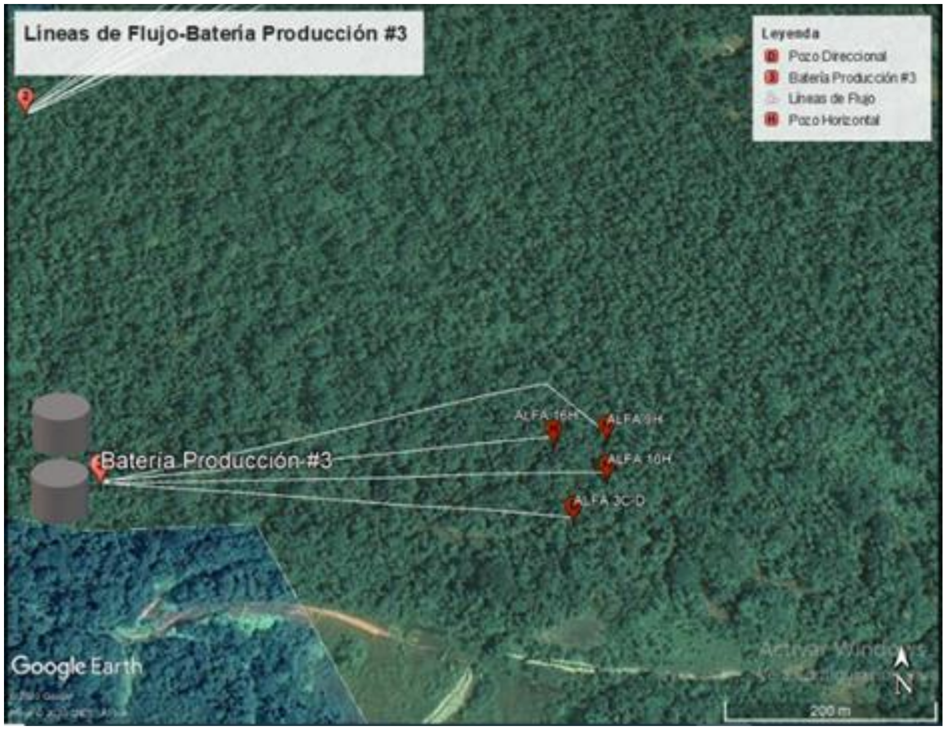


Figure 121. Flow lines in zone # 3.

After locating the batteries, we will do the calculations to find the pressure and friction losses that occur in the flow lines due to the transport of the fluid from the wells to the batteries.

By means of this calculation we can infer what head pressure will be required as a minimum for the flow to arrive from the wells to the batteries without impulse problems.

4.4.3.1.1 Flow lines design from wells

The study of fluid flow in pipes is related to obtaining three parameters that determine the design and subsequent construction of the pipelines and flow lines. These parameters are:

1. The pressure loss “ΔP” along the pipe.
2. The optimal diameter “Ǿ” of the pipe that has the capacity to transport certain required rate, given the pressure drop.
3. The flow rate “Q” that can be obtained with a certain pipe diameter given the pressure drop.

As seen previously, we used the “Google Earth Pro” application to select the ubication of our wells and tank batteries and thus obtain the lengths of the flow lines, as well as the initial and final elevations of these lines. See Table 68.

				Altitude	
Tank Battery	Initial Point Well	Final Point Manifold	Long. (Km)	Initial (m)	Final (m)
Tank Battery #1	ALFA 2C-D	Manifold #1	0.75	230	231
	ALFA 7D		0.64	231	231
	ALFA 8D		0.65	229	231
	ALFA 6H		0.55	231	231
	ALFA 14H		0.61	230	231
	ALFA 15H		0.57	229	231
Tank Battery #2	ALFA 1X-D	Manifold #2	0.6	232	234
	ALFA 12D		0.54	233	234
	ALFA 13D		0.56	232	234
	ALFA 4H		0.6	232	234
	ALFA 5H		0.59	232	234
	ALFA 11H		0.64	232	234
Tank Battery #3	ALFA 3C-D	Manifold #3	0.49	226	228
	ALFA 9D		0.56	228	228
	ALFA 10H		0.52	227	228
	ALFA 16H		0.47	229	228

Table 68. Lengths and elevations of flow lines.

4.4.3.1.2 Pressure loss in flow lines

The total pressure loss (ΔP) in pipes that transport some liquid is a function of 3 parameters:

1. Pressure loss due to friction.
2. Pressure loss due to elevation.
3. Pressure loss due to acceleration.

Considering negligible pressure losses due to acceleration, the total pressure drop is as follows (See Equation 61 and Equation 62):

$$\Delta P_T = \Delta P_e + \Delta P_f$$

Equation 61. Total pressure loss.

Where:

$$\Delta P_e = 0.433 * \gamma_L * \Delta h$$

Equation 62. Pressure loss due to elevation.

ΔP_e = Pressure loss due to elevation(psi)

γ_L = Relative density of the liquid

Δh = Elevation difference between point 1 and point 2 (ft)

To determine the pressure loss due to friction in the flow lines, the Darcy-Weisbach equation will be used (See Equation 63):

$$\Delta P_f = 0.06056 * f * \frac{\gamma_L * q^2 * L}{D^5}$$

Equation 63. Pressure loss due to friction.

ΔP_f = Pressure loss due to friction (psi)

γ_L = Relative density of the liquid

f = Friction factor

q = Flow Rate (bbl/day)

L = Pipe Length (mi)

D = Inside diameter of pipe (in)

The calculation of the friction factor (f) will depend on the value of the Reynolds number (NRe) and the roughness of the pipe (ε). See Equation 64.

$$N_{Re} = 92.2 * \frac{q * \gamma_L}{D * \mu}$$

Equation 64. Calculation for Reynolds number.

Where:

q = Flow Rate (bbl/day)

γ_L = liquid specific gravity

D = Inside diameter of pipe (in)

μ = Liquid viscosity (cp)

For values of N_{Re} < 2300 a laminar flow is considered and the value of the friction factor is given by Equation 65:

$$f = \frac{64}{N_{Re}}$$

Equation 65. Calculation of the friction factor (f) for laminar Flow.

For values of Nre > 4000 a turbulent flow is considered and the value of the friction factor (f) is given by the Colebrook and White equation (See Equation 66):

$$\frac{1}{\sqrt{f}} = -2 * log\left(\frac{\varepsilon/D}{3.7} + \frac{2.51}{N_{Re} * \sqrt{f}}\right)$$

Equation 66. Colebrook and White equation.

As can be seen, the friction factor (f) is included in both sides of the equation, which makes the procedure to obtain f iterative.

You can also calculate the friction factor (f) graphically using the Moody diagram, which is shown in Figure 122.

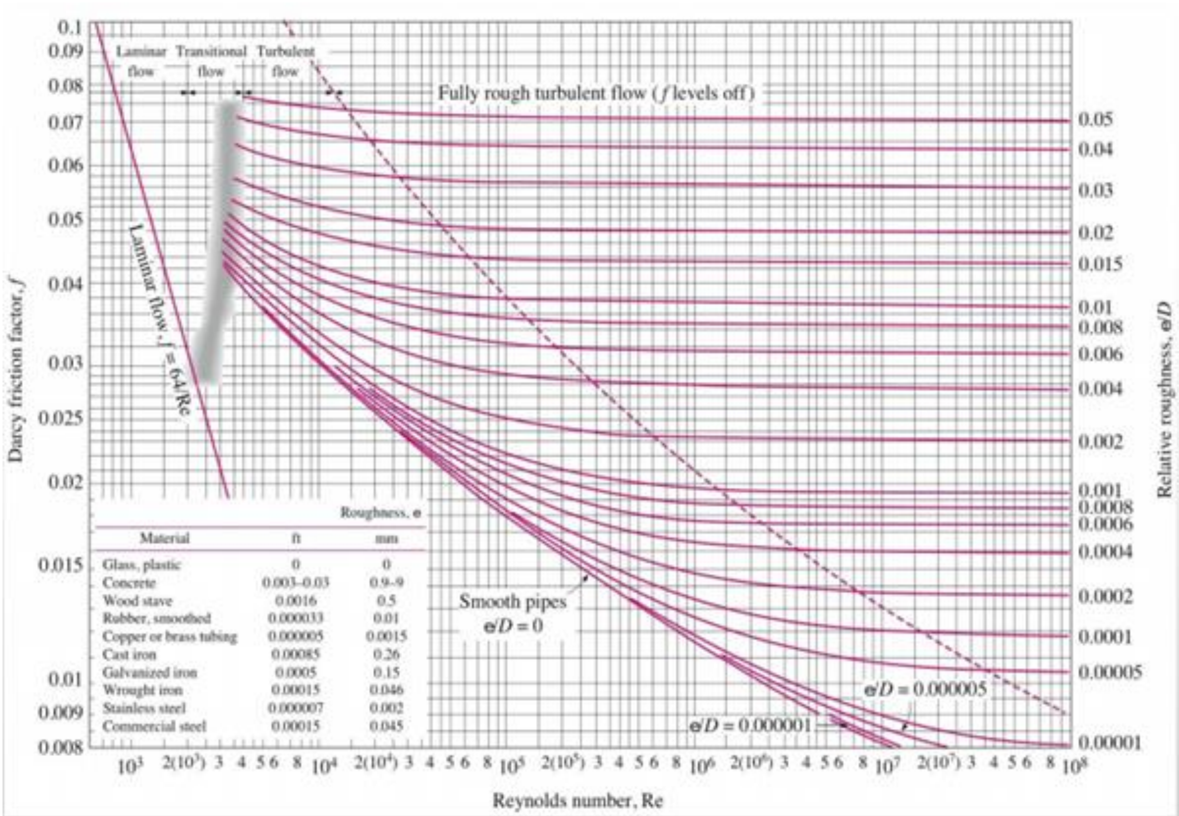


Figure 122. Moody diagram.

Now, knowing the production rates and the properties of the transported fluids such as specific gravity and viscosity, we will determine the pressure drop through the flow lines using the equations mentioned above. See Table 69 and Table 70.

Maximum flow rate	Q
Specific gravity of fluid	γ_L
Pipe diameter	D
Elevations	h
Viscosity	μ
Pipe length	L

Table 69. Parameters to use.

				Altitude												Head loss		
Production Batery	Starting point - Well	Final point - Manifold	Length (Km)	Initial(m)	Final (m)	Q (bbl/día)	OD (pulg)	ID (pulg)	Length (millas)	Sp-gr (fluido)	Viscosity (cp)	N°Re	Flow type	e/D	f	Friction (psi)	Height(psi)	Total (psi)
Battery Production #1	ALFA 2C-D	Manifold #1	0.75	230	231	10000	4.5	4.156	0.466	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	50.247	1.3172726	51.564
	ALFA 7D		0.64	231	231	12000	4.5	4.156	0.398	0.9275	5.687	43417.750	Turbulent	0.0004331	0.023	59.668	0	59.668
	ALFA 8D		0.65	229	231	13000	4.5	4.156	0.404	0.9275	5.687	47035.896	Turbulent	0.0004331	0.0227	70.194	2.6345452	72.828
	ALFA 6H		0.55	231	231	1000	2.25	2.067	0.342	0.8473	0.827	45700.625	Turbulent	0.0008708	0.024	11.154	0	11.154
	ALFA 14H		0.61	230	231	10000	4.5	4.156	0.379	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	40.868	1.3172726	42.185
	ALFA 15H		0.57	229	231	10000	4.5	4.156	0.354	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	38.188	2.6345452	40.822
Battery Production #2	ALFA 1X-D	Manifold #2	0.6	232	234	10000	4.5	4.156	0.373	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	40.198	2.6345452	42.832
	ALFA 12D		0.54	233	234	10000	4.5	4.156	0.336	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	36.178	1.3172726	37.495
	ALFA 13D		0.56	232	234	10000	4.5	4.156	0.348	0.9275	5.687	36181.459	Turbulent	0.0004331	0.0238	37.518	2.6345452	40.152
	ALFA 4H		0.6	232	234	13000	4.5	4.156	0.373	0.9275	5.687	47035.896	Turbulent	0.0004331	0.0227	64.794	2.6345452	67.429
	ALFA 5H		0.59	232	234	13000	4.5	4.156	0.367	0.9275	5.687	47035.896	Turbulent	0.0004331	0.0227	63.714	2.6345452	66.349
	ALFA 11H		0.64	232	234	1000	2.25	2.067	0.398	0.8473	0.827	45700.625	Turbulent	0.0008708	0.024	12.980	2.4067387	15.386
Battery Production #3	ALFA 3C-D	Manifold #3	0.49	226	228	12150	4.5	4.156	0.304	0.9275	5.687	43960.472	Turbulent	0.0004331	0.0225	45.815	2.6345452	48.449
	ALFA 9D		0.56	228	228	4000	2.875	2.563	0.348	0.9275	5.687	23467.833	Turbulent	0.0007023	0.0265	74.931	0	74.931
	ALFA 10H		0.52	227	228	12000	4.5	4.156	0.323	0.9275	5.687	43417.750	Turbulent	0.0004331	0.023	48.480	1.3172726	49.798
	ALFA 16H		0.47	229	228	800	2.25	2.067	0.292	0.8473	0.827	36560.500	Turbulent	0.0008708	0.0245	6.228	-1.203369	5.024

Table 70. Pressure losses in flow lines.

From the results of the pressure losses in the flow lines, it is concluded that the minimum pressure at the wellhead to move the fluids to their respective batteries is in the range of 170-200 psi average, having a pressure in the separator of 100psi and considering a safety factor of 15 psi.

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4.4.3.2 Separation

The separation of fluids within the production stage is mainly related to the separation of the liquid phase and the gas phase that is released from oil under surface conditions. Since the presence of gas can affect the correct operation of the pumps, what is usually done is to separate them and transport them through different pipes. Subsequently, the oil is separated from the water in the wash tanks.

The separation of fluids (oil, gas and water) will be carried out in the tank batteries. For this, a design of the components that will be installed in the batteries is proposed. The first criterion is to know the volumes that these batteries will handle during the entire production period. The volumes that each battery will handle will be in accordance with the number of wells that each one will handle. See Table 71, Table 72 and Figure 123.

	Tank Battery #1	Tank Battery #2	Tank Battery #3
WELLS	ALFA 2C-D	ALFA 1X-D	ALFA 3C-D
	ALFA 7D	ALFA 12D	ALFA 10H
	ALFA 8D	ALFA 13D	ALFA 16H
	ALFA 6H	ALFA 4H	ALFA 9D
	ALFA 14H	ALFA 5H	
	ALFA 15H	ALFA 11H	

Table 71. Assignment of wells to tank batteries.

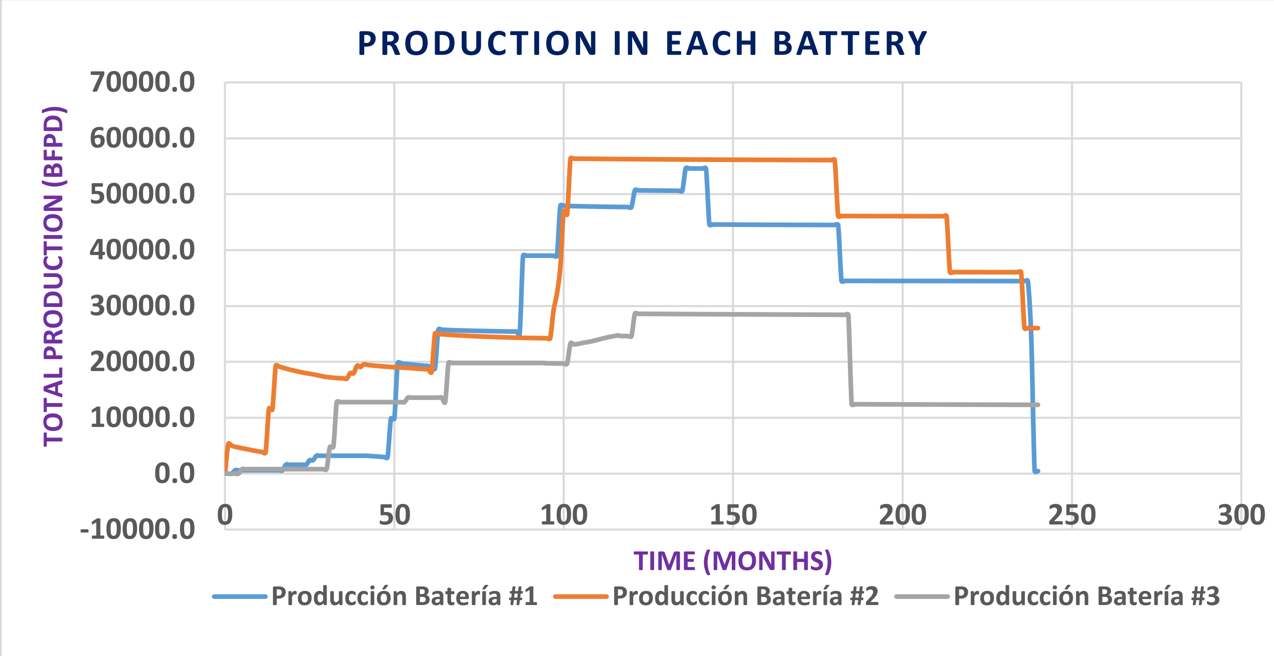

Figure 123. Production per battery.

	Tank Battery #1	Tank Battery #2	Tank Battery #3
Maximum production (bfpd)	54613.7	56363.9	28603.9

Table 72. Maximum production each battery will handle.

Based on the volumes that each battery will handle, the equipment and facilities to be installed in each of these are proposed. See Table 73, Table 74 and Table 75.

BATTERY #1	Equipments	Characteristics	Capacity (Mbbl)	Quantity	Total Capacity (Mbbl)
1Manifold-B1	Manifold 6 inlets	-	-	1	-
1SEP-B1	Three-phase separator - Total (2000 m3/d)	-	-	3	-
1SEP-B1	Three-phase separator - Test (2000 m3/d)	-	-	2	-
1TT-B1	Total Tank	25m Diameter, 9.1m High	28	1	28
1TP-B1	Test Tank	16.4m Diameter, 9.1m High	12	1	12
	Heater-treater			4	
	Desalters			4	
1GB-B1	Gunbarrel	25m Diameter, 9.1m High	28	1	28
1TAP	Oil Storage Tank	25.8m Diameter, 9.1m High	30	1	30
	Oil Transfer Pump	-	-	2	-
	TKs. Oil Skimmer	24.8m Diameter, 9.1m High	27.5	2	55
1TAA	Water Storage Tank	24.8m Diameter, 9.1m High	27.5	2	55
	Water Transfer Pump	-	-	2	-
1MG-B1	Gas Meter	-	-	1	-
1MG-B1	Gas Meter	-	-	1	-
	Scrubber	-	-	2	-
	Compressor	-	-	1	-

Table 73. Sizing of tank battery # 1.

BATTERY #2	Equipments	Characteristics	Capacity (Mbbl)	Quantity	Total Capacity (Mbbl)
1M-B2	Manifold 6 inlets	-	-	1	-
1SEP-B2	Three-phase separator - Total (2000 m3/d)	-	-	3	-
1SEP-B2	Three-phase separator - Test (2000 m3/d)	-	-	2	-
1TT-B2	Total Tank	25.8m Diameter, 9.1m High	30	1	30
1TP-B2	Test Tank	16.5m Diameter, 9.1m High	12	1	12
	Heater-treater			4	
	Desalter			4	
1GB-B2	Gunbarrel	25.8m Diameter, 9.1m High	30	1	30
1TAP-B2	Oil Storage Tank	25.8m Diameter, 9.1m High	33	2	66
	Oil Transfer Pump	-	-	6	-
	TKs. Oil Skimmer	25m Diameter, 9.1m High	28	2	56
2TAA	Water Storage Tank	25m Diameter, 9.1m High	28	2	56
	Water Transfer Pump	-	-	2	-
1MG-B2	Gas Meter	-	-	1	-
1MG-B2	Gas Meter	-	-	1	-
	Scrubber	-	-	2	-
	Compressor	-	-	1	-

Table 74. Sizing of tank battery # 2.

BATTERY #3	Equipments	Characteristics	Capacity (Mbbl)	Quantity	Total Capacity (Mbbl)
1M-B3	Manifold 4 inlets	-	-	1	-
1SEP-B3	Three-phase separator - Total (2000 m3/d)	-	-	2	-
1SEP-B3	Three-phase separator - Test (2000 m3/d)	-	-	1	-
1TT-B3	Total Tank	17.6m Diameter, 9.1m High	28	1	14
1TP-B3	Test Tank	14.1m Diameter, 9.1m High	12	1	9
	Heater-treater			2	
	Desalters			2	
1GB-B3	Gunbarrel	17.6m Diameter, 9.1m High	28	1	14
1TAP	Oil Storage Tank	17.6m Diameter, 9.1m High	30	1	14
	Oil Transfer Pump	-	-	2	-
	TKs. Oil Skimmer	25.8m Diameter, 9.1m High	27.5	1	30
1TAA	Water Storage Tank	25.8m Diameter, 9.1m High	27.5	1	30
	Water Transfer Pump	-	-	1	-
1MG-B3	Gas Meter	-	-	1	-
1MG-B3	Gas Meter	-	-	1	-
	Scrubber	-	-	1	-
	Compressor	-	-	1	-

Table 75. Sizing of tank battery # 3.

In addition, a design is proposed with the components in each battery. In this case, the design of Tank Battery # 2 will be displayed. See Figure 124 and Figure 125.

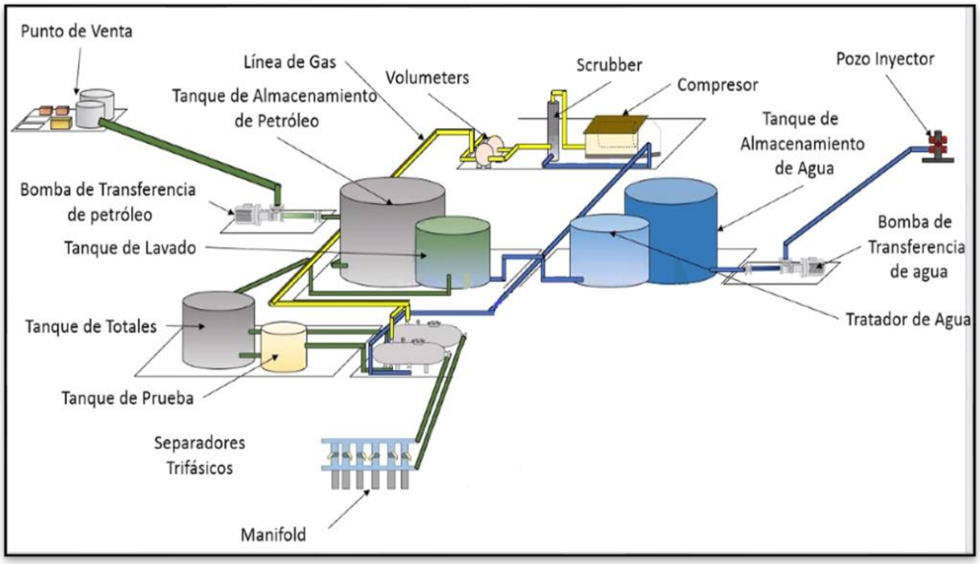

Figure 124. Tank batteries scheme.

Figure 125. Equipment in tank battery # 2.

Next, we will show the separation process that will be carried out in Tank Battery # 2, which will be similar in the other batteries:

Production from the 6 wells corresponding to Zone # 2 will be collected in Tank Battery # 2.

The production path will then be determined by whether the well will enter an evaluation stage (where its production will be measured individually in the test tank) or a normal production stage (where all production will be stored in a single total tank).

In case a well needs to be evaluated, its production will be redirected to a test separator, then the crude oil flows to a test tank to make the corresponding measurements according to the evaluation that is being carried out and finally it reaches to the total tank.

In the event that production from all wells in a zone is proceeding normally, production will flow to a total separator where gas will be separated from the liquid phase. The gas will flow towards the top of the separator to a vol-u-meter, then it will pass through a scrubber where the last remaining water is separated (this remaining water is directed towards the water treatment tank) and finally the gas reaches a station of compression, from which it is sent through a flow line to the area where the wells are located for use in the generation of electrical energy required by the ESP units. While the liquid phase (oil and water) leaves the lower part of the separator through 2 different flow lines.

The oil that comes out of the total separator is directed towards a total tank, then flows to a wash tank where the remaining water that remains in the crude oil is separated, from this wash tank it is sent to the oil storage tank for subsequent pumping to the point of sale in Andoas.

On the other hand, the water coming from the three-phase separator is sent to a water treatment tank, then it is sent to a water storage tank and finally it will be pumped to the injection wells.

4.4.3.3 Fluids treatment

The treatment of liquids, oil and water will be carried out in the wash tank and in the water treatment tank that is located in each battery according to the area in which they are located.

The treatment begins with the separation of the water and the oil. It consists of taking advantage of the density for the separation of the liquids in the wash tank, the water being denser than the oil will be located at the bottom of the tank; and the oil being less dense will be located in the upper part. The treatment also consists of adding chemical products that will help in the separation of the water-oil, in turn also help to reduce the contaminants that can be found in the liquids.

The water is drained through the bottom of the tank, while the oil is extracted through the upper part of the scrubber tank, subsequently the drained water is treated in the water treatment tank, and finally, the already treated water is stored in the water tank. water storage for later use in water injection wells. See Figure 126.

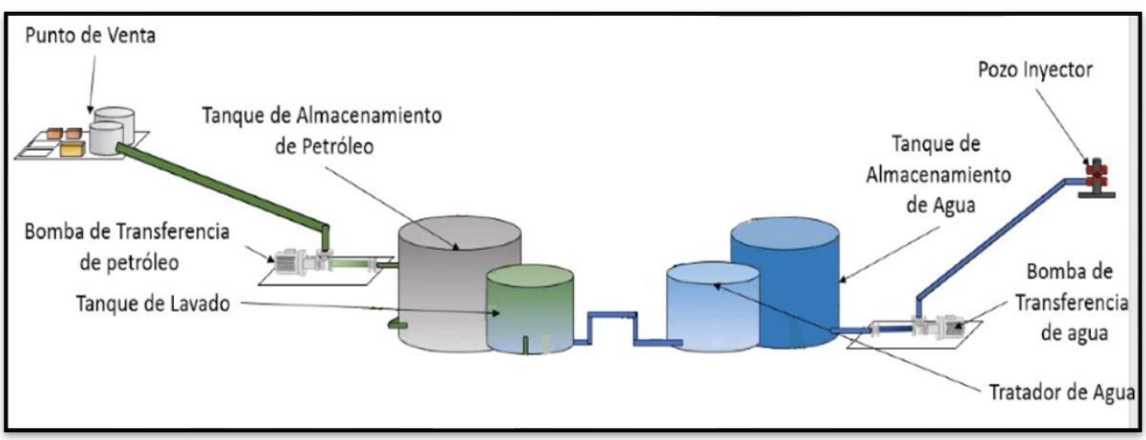

Figure 126. Scheme of water treatment tank and wash tank.

4.4.3.4 Storage and measurement

The oil obtained from the treatment is stored in a oil storage tank located in the battery depending on the area. In this tank, the corresponding measurements are made by taking crude oil samples and evaluating it in a laboratory. The tests that are mainly performed are measurements of salt content, sulfur content, API gravity and BSW.

For this purpose, there are 3 storage tanks located one in each battery, in tank battery # 1 there is an oil storage tank of 30 thousand barrels of capacity, in tank battery # 2 there is an oil storage tank of 66 thousand barrels of capacity because in this battery the crude from batteries # 1 and # 3 will be stored, finally, in the tank battery # 3 there is an oil storage tank of 14 thousand barrels of capacity.

The stored oil will be pumped to the point of sale located in Andoas.

5. AUDIT AND POINT OF SALE

Once the oil treatment has been carried out, all this volume will be stored in the storage tank of Tank Battery # 2, which will be ready for sale. The audit and sale are carried out at Andoas station. The audit allows estimating the volume of oil and then determining the royalties established in the contract with Perupetro. To transport oil from Tank Battery # 2 to Andoas station, it is proposed to use a pipeline.

Because large volumes of oil are going to be sold, a LACT (Lease Automatic Custody Transfer) unit will be used, which will be found in Andoas, we use this unit to have greater precision in the audit of crude oil, because there will be more control in the measurement of operating variables such as pressure, temperature, etc.

In our case, this unit will be connected to the discharge line from a tank prepared to be automatically controlled in quality and quantity of hydrocarbons transferred, it has a rejection unit to ensure that the quality of the product is within acceptable ranges.

The measurement of the quality of crude oil is governed by the following standards:

- **Standard Test Method for API Gravity:**

The standard test to determine the API gravity is ASTM D 1298 / API 9.1, for this test a homogeneous sample is taken, especially if the sample is compositional, the observed temperature is recorded, then the observed API and finally the second observed temperature as well are recorded, then by using Table 3 of ASTM Guide D 1250 the API is corrected to 60 ° F / 15.6 ° C.

- **Standard Test Method for Salts in Crude Oil:**

The standard method for field use is ASTM D 3230, this method allows us to determine the chlorides content in crude oils, since the presence of these generates corrosion in refining units and other equipment, for this norm care must be taken in the cleaning of the materials to obtain a coherent result, in the case of using alcohol solvents, their value as a blank must be measured and subsequently subtracted from the measurement result.

- **Standard Test Method for Water and Sediment in Crude Oil:**

The standard method for field use is ASTM D 4007 / API 10.3, this measurement is also important because it can cause corrosion and problems in refining equipment. The test is carried out on two pears simultaneously, for this method the saturation of Toluene at 60 ° F must be taken into account, it is verified that the demulsifier is diluted in accordance with the norm, the temperature of the centrifuge chamber is verified during the test, the number of rpm is checked of the centrifuge according to the norm and finally the reading of the 2 pears is reported according to the norm.

Procedure for the automatic measurement of oil with the LACT unit:

1. Take a representative sample from the autosampler.
2. Read and record the reading from the control board or on the thermometer installed in the transfer line.
3. Determine the API, BS&W and salt content.
4. Witness the meter change from the control panel or manually at the installation.
5. Witness the issuance of the measurement ticket from the control panel. The difference in volumes is the gross volume transferred.

6. Verify that the repeatability and linearity of the measuring equipment is within the tolerable ranges regulated and established by the manufacturer, whenever necessary and at the request of any of the parties.
7. The measuring equipments must be tested once a week and at any justified time at the request of the parties.
8. Calculate the net volume transferred, discounting the BS&W.
9. Sign the measurement ticket.

The automatic hydrocarbon transfer unit will be similar to the one shown in the following figure (See Figure 127 and Table 76):

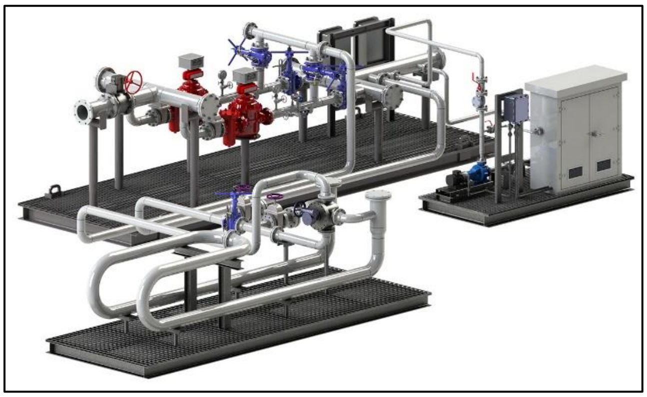

Figure 127. LACT Unit.

POINT OF SALE-ANDOAS	Equipments	Characteristics	Capacity (Mbbl)	Quantity	Total Capacity (Mbbl)
1TAP-Andoas	Oil Storage Tank	33.4m Diameter, 12m High	66	1	66
1TAP-Andoas	Oil Storage Tank (Rejection)	33.4m Diameter, 12m High	66	1	66
1LACT - Andoas	LACT Unit	-	-	1	-

Table 76. Equipments in Andoas.

Once the volume to be sold has been measured, the audit ticket is drawn up with the signature of both parties (ALFA ENERGY - Perupetro).

Next, we observe an example of an audit ticket that we will sign during the production-sale period. See Figure 128.

ALFA ENERGY, PERU Audit Point, Andoas – Block 192 Daily Audit Ticket	
1.-LABORATORY DATA	
Observed API Gravity	34 °API
Temperature	80 °F
API Gravity at 60°F	34.5 °API
Sal Content	8.8 Pounds per-1000 Bls (PTB)
(A) Water and Sediments (BSW)	0.35 %
2.-METER DATA	
(B) Final Counter	235461
(C) Initial Counter	225461
(D) Volume at 60°F	10000 = (B) – (C)
3.- CALCULATION OF AUDITED PRODUCTION	
AUDITED PROD. = D * (1 – A/100)	
AUDITED PRODUCTION	9965 BLS NETOS

Figure 128. Example of an audit ticket for our crude oil.

The following figures show the Andoas station, where the audit and sale of crude oil will be carried out (See Figure 130 and Figure 131).

Figure 129. Point of sale - Andoas station.

Figure 130. Aerial photography - Andoas station.

Next, we will show the conditions to take into consideration, all the criteria and calculations that we have made for the design of the pipeline.

5.1 Conditions to be Considered for the Design of an Oil Pipeline

To properly design a pipeline, it is necessary to know the conditions that affect the fluid in the pipeline.

5.1.1 Characteristics of the Pipeline

The physical characteristics of the pipeline affect the way a fluid will behave in a pipeline. There are 3 parameters that must be considered in the design:

- Internal diameter of the pipe (ID).
- Pipe length (L).
- Relative roughness of the internal surface of the pipe wall.

5.1.1.1 Pipeline internal diameter (ID)

In a pipeline, the pressure loss due to friction is related to the internal diameter of the pipe. When the internal diameter of the pipe decreases, the pressure loss due to friction increases.

With the internal diameter of the pipe, we will also calculate the limit velocity (erosion speed) inside the pipeline to avoid erosion or corrosion of the pipeline walls.

5.1.1.2 Pipeline length (L)

The length of a pipeline affects the pressure drop along the pipeline. The longer the pipeline, the greater the total pressure drop.

5.1.1.3 Relative roughness (ε/ID)

The friction factor (f) is determined by the relation of the Reynolds number (NRe) and the relative roughness of the pipeline.

As the roughness of the internal wall of the pipeline increases, the friction factor increases. Friction factors are usually calculated from the Moody Diagram.

The relative roughness of the pipeline internal wall is the ratio of the absolute roughness, ε, and the internal diameter, ID, of the pipeline. See Equation 67.

$$Relative\ Roughness = {}^{\varepsilon}/_{ID}$$

Equation 67. Relative Roughness Equation.

Where:

ε = Absolute surface roughness of pipeline wall (in)

ID = Pipeline internal diameter (in)

For our pipeline design we consider the value of the relative roughness equal to that of commercial steel. For a commercial steel, we have:

$$\varepsilon = 0.00015\ ft$$

$$\varepsilon = 0.0018\ in$$

5.1.2 Hydrodynamic System of an Oil Pipeline

The system of an oil pipeline depends on the following parameters:

1. Characteristics of the pipe, such as: Size, wall thickness, roughness and pipe grade.
2. Distance or length of pipe.
3. Elevation differential.
4. Properties of the oil to be transported.
5. Discharge pressure and temperature.
6. Required pumping power.

5.1.3 Stable State

The fluid to be transported through a pipeline can be in a stable state or in a transitory state.

The steady state is a system in which the initial conditions remain constant over time.

The steady-state equations are simpler and this leads to a faster solution for each design case.

To carry out the design of the pipeline, we will consider conditions in a stable state, this implies:

- The temperature is considered stable
- Density remains stable
- Stable viscosity
- The flow rate remains stable
- Stable velocity

5.2 Known Initial Data for Oil Pipeline Design

5.2.1 Crude to be Transported

The crude to be transported, from the Capahuari Sur Extensión field, Block 192 and operated by ALFA Energy, has the following characteristics. See Table 77.

Fluid to transport	Light oil
°API	34
Viscosity	5.687 cp
Density	53 lb/ft^3

Table 77. Characteristics of the crude to be transported.

5.2.2 Design Conditions

One of the conditions that we assumed was to consider stable state along the pipeline route, that is:

- Constant and stable temperature along the pipeline
- Constant and stable density
- Constant and stable viscosity

5.2.3 Oil Pipeline Route

The oil pipeline extends from Tank Battery # 2 of the Capahuari Sur Extensión field to the Andoas station. This pipeline will have a length of 7.32 km. and the route was proposed in this way to avoid interfering with the operations carried out in the near field, since we are an independent operator. The route of the oil pipeline is shown in Figure 131.

The coordinates of the Andoas station are shown in Table 78.

Figure 131. Oil Pipeline route from tank battery # 2 to Andoas station.

	East	North
Point of sale Andoas Station	338336	9689839.4

Table 78. UTM coordinates of Andoas station.

5.2.4 Topographic Profile of the Route

For the design of the oil pipeline, the topographic profile was elaborated, whose height and distance data can be seen below. See Table 79.

Distance (m)	Distance (Km)	Height (m)
0.00	0.00	234
1930.00	1.42	254
7320.00	7.32	223

Table 79. Height and distance data of the oil pipeline route.

With these data, the topographic profile for the oil pipeline route is plotted. See Figure 132.

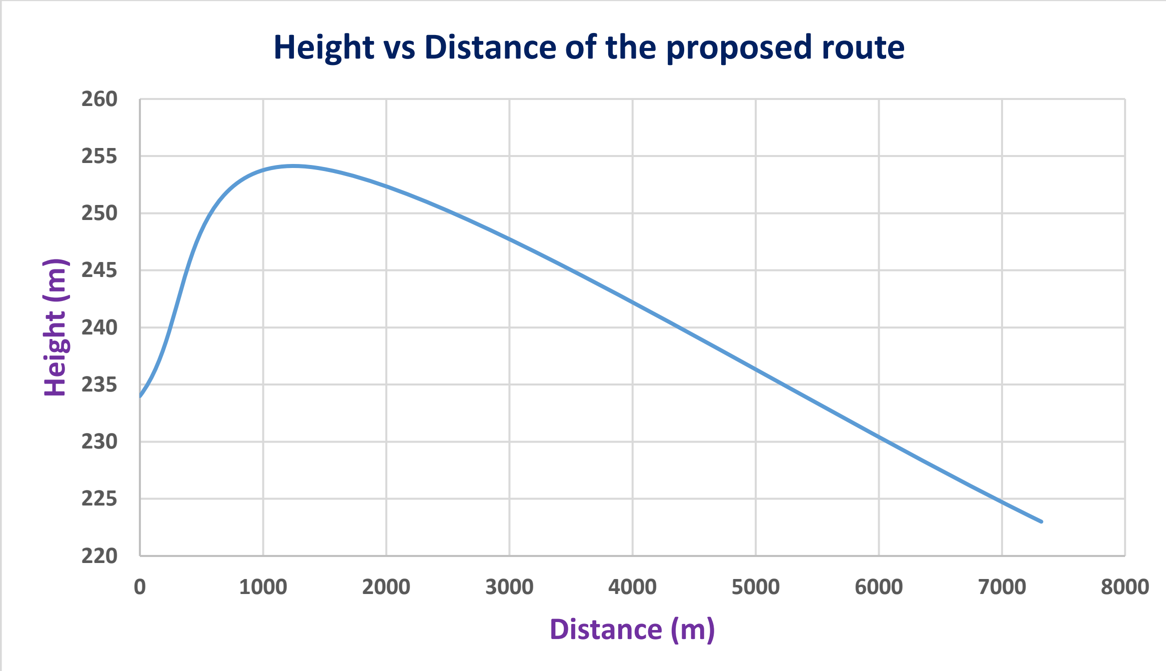

Figure 132. Topographic profile of the pipeline route.

5.2.5 Known Design Parameters

For the design of the oil pipeline, we consider that the design rate (Q) is equivalent to 110% of the maximum rate to be transported (Qmax), See Figure 133. Then:

$$Qdesign = Q = 1.1 * Qmax$$

$$Q = 1.1 * 59597.6$$

$$Q = 65560 bbls/day$$

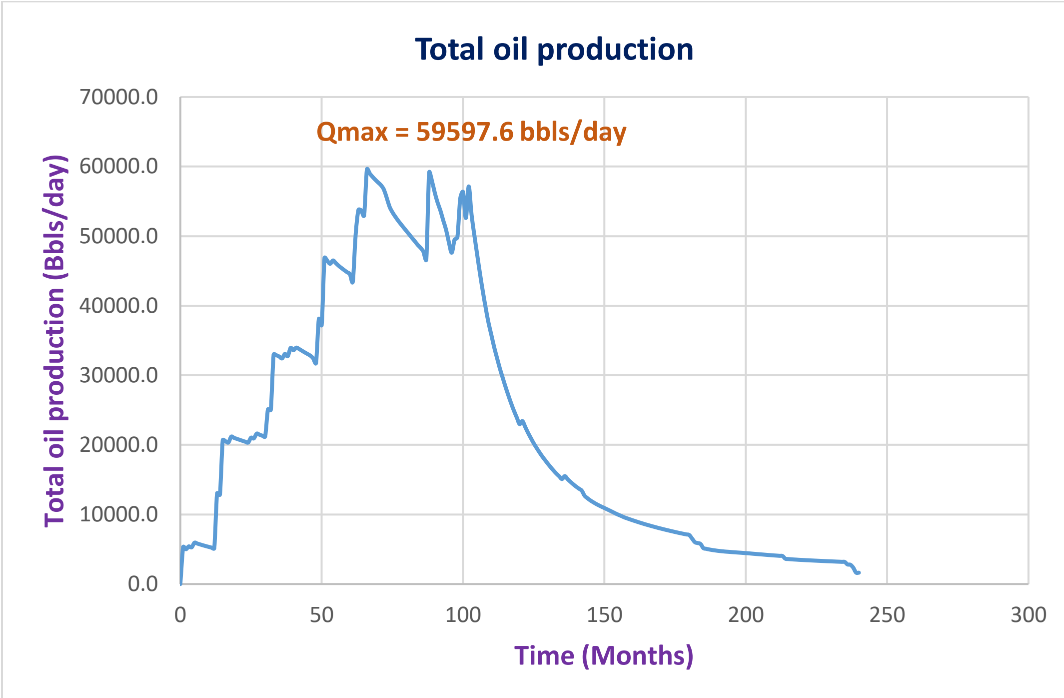

Figure 133. Total oil production of the Capahuari Sur Extensión field.

The parameters for sizing the oil pipeline are shown in Table 80:

Fluid to transport	Light oil
°API	34
Design rate = Q	65560 bbls/day
Viscosity = μ	5.687 cp
Specific Gravity =	0.855
Density = ρ	53 lb/ft^3
Design ambient Temperature = T	80°F
Distance to be transported = L	7.32 km
Initial Height	234m
Final Height	223m

Table 80. Parameters for oil pipeline design.

5.3 Development of an Oil Pipeline Design

5.3.1 Calculation of Erosional Velocity

The basis of the design of an oil pipeline is to ensure its integrity at all times, it is for this reason that whenever the pipelines are designed, special attention is paid to a parameter known as erosional velocity.

Flow lines, oil pipelines and other lines that transport gas, liquid or two-phase flow must be dimensioned based on the flow velocity because they have a main relationship in the erosion or corrosion of the pipe walls.

Erosional velocity will be calculated in accordance with the provisions of API RP 14E. See Equation 68.

$$Ve = \frac{C}{\sqrt{\rho}}$$

Equation 68. Calculation of erosional velocity.

Where:

Ve = erosional velocity (ft/s).

ρ = density of liquid, gas or biphasic mixture (lb/ft^3).

C = empirical constant according to API RP 14E.

According to the API, a value of C = 100 should be used for continuous use oil pipelines, and a value of 125 for intermittent use oil pipelines. In the case that the pipelines are protected with inhibitors, the value of C = 150 to 200 can be used.

$$Ve = \frac{100}{\sqrt{53}}$$

$$Ve = 13.736 \frac{ft}{s}$$

This calculated velocity is the maximum velocity allowed for any section of the oil pipeline.

5.3.2 Calculation of the Allowed Diameter

Knowing our design rate and calculated the value of "Ve", the minimum diameter required is calculated to avoid passing the erosional velocity.

$$Vel < Ve = 13.736 \frac{ft}{s}$$

$$Vel < 13.736 \frac{ft}{s}$$

$$Vel = Q * A$$

$$A = \frac{\pi * ID^2}{4}$$

Where:

Ve = Erosional Velocity (ft/s).

Vel = Velocity inside the oil pipeline (ft/s).

Q = Design rate (bbl/day).

A = Area or section of the oil pipeline.

ID = Internal Diameter.

From the aforementioned equations and making a change in units, the following relation is obtained.

$$ID > 0.1091536 * \left(\frac{Q}{Ve}\right)^{0.5} \quad (in)$$

For our design we have that Q = 65560 bbls/day and Ve = 13.736 ft/s.

So:

$$ID > 0.1091536 * \left(\frac{65560}{13.736}\right)^{0.5} \quad (in)$$

$$ID > 7.54\ in$$

5.3.3 Pipeline Selection

Taking into consideration the minimum diameter calculated, we will choose the appropriate diameter and thickness for the oil pipeline.

Pipe wall diameters and thickness data is based on API SPEC 5L, Specification for Line Pipe, Table 6C. See Figure 134.

Table 6C (Continued)—Plain-end Line Pipe Dimensions, Weights per Unit Length, and Test Pressures for Sizes $6^{5}/_{8}$ through 80 (U.S. Customary Units)

(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Specified Outside Diameter	Specified Wall Thickness	Plain-end Weight per Unit Length	Calculated Inside Diameter[a]		Minimum Test Pressure (psi)[b]									
Size	D (in.)	t (in.)	w_{pe} (lb/ft)	d (in.)		Grade A	Grade B	Grade X42	Grade X46	Grade X52	Grade X56	Grade X60	Grade X65	Grade X70	Grade X80
$6^{5}/_{8}$	6.625	0.562	36.43	5.501	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	5340	5850	6620	7130	7260	7260	7260	7260
$6^{5}/_{8}$	6.625	0.625	40.09	5.375	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	5940	6510	7260	7260	7260	7260	7260	7260
$6^{5}/_{8}$	6.625	0.719	45.39	5.187	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	6840	7260	7260	7260	7260	7260	7260	7260
$6^{5}/_{8}$	6.625	0.750	47.10	5.125	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	7130	7260	7260	7260	7260	7260	7260	7260
$6^{5}/_{8}$	6.625	0.864	53.21	4.897	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	7260	7260	7260	7260	7260	7260	7260	7260
$6^{5}/_{8}$	6.625	0.875	53.78	4.875	Std.	2800	2800	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2800	2800	7260	7260	7260	7260	7260	7260	7260	7260
$8^{5}/_{8}$[c]	8.625	0.125	11.36	8.375	Std.	520	610	910	1000	1130	1220	1300	1410	1520	1740
					Alt.	650	760	910	1000	1130	1220	1300	1410	1520	1740
$8^{5}/_{8}$[c]	8.625	0.156	14.12	8.313	Std.	650	760	1140	1250	1410	1520	1630	1760	1900	2170
					Alt.	810	950	1140	1250	1410	1520	1630	1760	1900	2170
$8^{5}/_{8}$	8.625	0.188	16.96	8.249	Std.	780	920	1370	1500	1700	1830	1960	2130	2290	2620
					Alt.	980	1140	1370	1500	1700	1830	1960	2130	2290	2620
$8^{5}/_{8}$	8.625	0.203	18.28	8.219	Std.	850	990	1480	1620	1840	1980	2120	2290	2470	2820
					Alt.	1060	1240	1480	1620	1840	1980	2120	2290	2470	2820
$8^{5}/_{8}$	8.625	0.219	19.68	8.187	Std.	910	1070	1600	1750	1980	2130	2290	2480	2670	3000
					Alt.	1140	1330	1600	1750	1980	2130	2290	2480	2670	3050
$8^{5}/_{8}$	8.625	0.250	22.38	8.125	Std.	1040	1220	1830	2000	2260	2430	2610	2830	3000	3000
					Alt.	1300	1520	1830	2000	2260	2430	2610	2830	3040	3480
$8^{5}/_{8}$	8.625	0.277	24.72	8.071	Std.	1160	1350	2020	2220	2510	2700	2890	3000	3000	3000
					Alt.	1450	1690	2020	2220	2510	2700	2890	3130	3370	3850
$8^{5}/_{8}$	8.625	0.312	27.73	8.001	Std.	1300	1520	2280	2500	2820	3000	3000	3000	3000	3000
					Alt.	1630	1900	2280	2500	2820	3040	3260	3530	3800	4340
$8^{5}/_{8}$	8.625	0.322	28.58	7.981	Std.	1340	1570	2350	2580	2910	3000	3000	3000	3000	3000
					Alt.	1680	1960	2350	2580	2910	3140	3360	3640	3920	4480
$8^{5}/_{8}$	8.625	0.344	30.45	7.937	Std.	1440	1680	2510	2750	3000	3000	3000	3000	3000	3000
					Alt.	1790	2090	2510	2750	3110	3350	3590	3890	4190	4790
$8^{5}/_{8}$	8.625	0.375	33.07	7.875	Std.	1570	1830	2740	3000	3000	3000	3000	3000	3000	3000
					Alt.	1960	2280	2740	3000	3390	3650	3910	4240	4570	5220
$8^{5}/_{8}$	8.625	0.438	38.33	7.749	Std.	1830	2130	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2290	2670	3200	3500	3960	4270	4570	4950	5330	6090
$8^{5}/_{8}$	8.625	0.500	43.43	7.625	Std.	2090	2430	3000	3000	3000	3000	3000	3000	3000	3000
					Alt.	2610	2800	3650	4000	4520	4870	5220	5650	6090	6960

Figure 134. API SPEC 5L, specification for line pipe, table 6C.

It will be used API 5L-X60 pipe of 8 5/8. in diameter and 0.250 in. thickness.

The flow velocity (Vel) in the oil pipeline is calculated.

$$Vel = \left(\frac{0.1091536}{ID}\right)^2 * Q \ \left(\frac{ft}{s}\right)$$

Next, Table 81 shows the technical data of the selected pipeline.

Pipe diameter (D)	8.625	In
Pipe thickness (e)	0.250	In
Internal Diameter (ID)	8.125	In
Grade X-60 Minimum yield stress (S)	60000	Psi
Design rate (Q)	65560	Bbls
Flow velocity (Vel)	11.83	Ft/s

Table 81. Technical data of the selected pipeline.

5.3.4 Calculation of Reynolds Number (N_{Re})

From the Reynolds equation:

$$N_{Re} = 92.2 * \frac{q * \gamma_L}{D * \mu}$$

Then:

$$N_{Re} = 92.2 * \frac{65560 * 0.855}{8.125 * 5.687}$$

$$N_{Re} = 111846.3 \rightarrow \text{Turbulent flow}$$

5.3.5 Determination of the Friction Factor (f)

For turbulent flows, using the Moody diagram the friction factor (f) is found.

$$f = 0.019$$

5.3.6 Calculation of Pressure Loss

The total pressure loss in the entire oil pipeline can be calculated:

Pressure loss due to elevation:

$$\Delta P_e = 0.433 * \gamma_L * \Delta h$$

$$\Delta P_e = 0.433 * 0.855 * -36.08924$$

$$\Delta P_e = -13.36\, psi$$

Pressure loss due to friction:

$$\Delta P_f = 0.06056 * f * \frac{\gamma_L * q^2 * L}{D^5}$$

$$\Delta P_f = 0.06056 * 0.019 * \frac{0.855 * 65560^2 * 4.548}{8.125^5}$$

$$\Delta P_f = 543.2\, psi$$

Total pressure loss:

$$\Delta P_T = \Delta P_e + \Delta P_f$$

$$\Delta P_T = -13.36\, psi + 543.2\, psi$$

$$\Delta P_T = 529.84\, psi$$

Once the pressure loss in the entire oil pipeline has been calculated, we must select a pumping equipment that has the necessary power to directly transport all the oil from the tank battery # 2 to the Andoas station.

We will use a factor of safety of 50psi for the design pressure of the pumping equipment.

$$Design\ pressure = 529.84psi + 50psi$$

$$Design\ pressure = 579.84\ psi$$

The pumping equipment, located in tank battery # 2, must operate at a pressure of 580 psi to guarantee the transport of oil to the Andoas station.

Finally, Table 82 is shown with a summary of the data used and the calculations made.

			Altitudes													Head loss		
Inicial Point	Final Point	Long. (Km)	Inicial (m)	Final (m)	transport Qmáx (bbl/día)	Q desing (bbl/día)	ID (pulg)	Long (miles)	Sp-gr (fluid)	Viscosity (cp)	N Re	flow type	e/D	f	Friction (psi)	Height (psi)	Total (psi)
Oil storage tank Battery #2	Andoas Stantion	5.1	234	224	59597.6	65560.0	8.125	3.169	0.855	5.687	111846.3	Turbulento	0.0002215	0.019	378.4	-12.15	366.28

Table 82. Total pressure loss in the pipeline.

6. LEGAL STUDY

6.1 Evaluation of the Feasibility of the Project Based on the Hydrocarbons Legislation

ALFA ENERGY develops activities in Hydrocarbons Sub-Sector, maintaining a license contract for the exploitation of Hydrocarbons in Block 192 – Loreto, so the feasibility of the project is governed by current laws and regulations too. See Figure 135.

- The Political Constitution of Peru
- The Organic Law of Hydrocarbons
- Regulations and standards

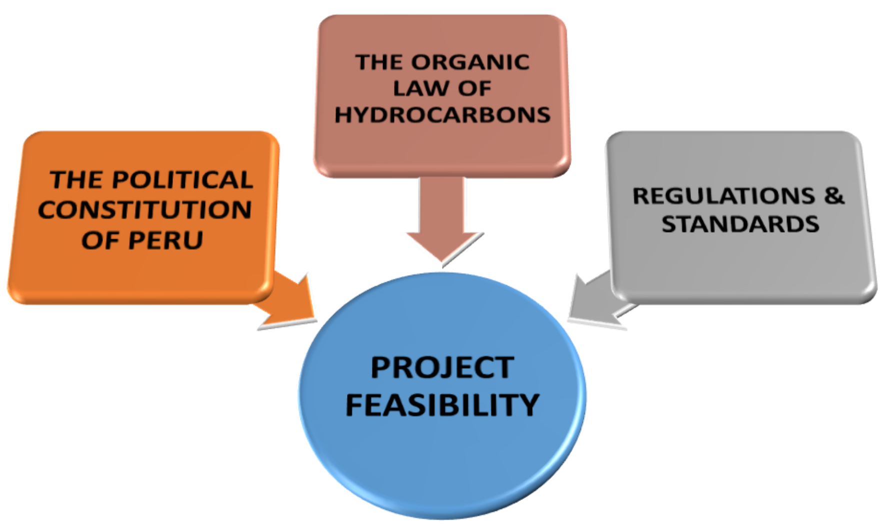

Figure 135. Project feasibility.

In compliance with its contractual commitment, ALFA ENERGY seeks to permanently improve the exploitation conditions in its oilfields, taking into consideration government guidelines for preservation of the environment.

The project consists of drilling 16 development wells in Block 192 to maintain production volumes.

6.1.1 General Rules of the Hydrocarbon Sector

The reforms of the 1990s generated changes in the structure of the State and gave a new framework to the functioning of the Peruvian economy. The 1993 Constitution was part of these reforms, which establishes that natural, renewable, and non-renewable resources are the patrimony of the Nation. Sovereign State can make use of these resources.

The LOH, Law No. 26221 and amendments, contemplate the general rules for all hydrocarbon activities in the country and establish as a principle that the Peruvian State promotes them based on free competition and free access to economic activity, with the purpose of achieving human well-being and national development. They also point out that the activities and prices related to crude oil and its derivative products are governed by rules of supply and demand, with the exception that rates are set for the activity of transporting hydrocarbons through pipelines.

On the other hand, the instruments to access the activities in the subsector depend on the type of operation to be carried out. In the case of exploration and / or exploitation (upstream activities), the signing of an exploration and exploitation or exploitation contract with Perupetro S.A. (License, services or others authorized by the MEM) is required.

Some downstream activities indicated by the LOH, such as the transportation of hydrocarbons through pipelines and the distribution of NG through the pipeline network, require a concession from the “General Directorate of Hydrocarbons” (DGH) of the MEM.

Likewise, companies that wish to operate in downstream activities must have previously registered in the “Hydrocarbons Registry” (HR), whose administration corresponds to Osinergmin since 2010. (In accordance with the provisions of Supreme Decree No. 004-2010- EM).

The general rules regarding legal studies are shown in the Table 83.

General Rules	
(The Political constitution of Peru, Title III: About economic regime – Chapter II: About environment and natural resources.)	Political Constitution of Peru
Juridic stability regime for foreign investment through many guaranties recognize.	Legislative Decree No. 662
Marco law for private investment grow	Legislative Decree No. 757
Law that regulates stability contracts with peruvian government protection of sectorial laws	Law No. 27343

Table 83. General rules regarding legal study.

6.1.2 API Standards

Standards API was formed in 1919 as a standards-setting organization convening subject matter experts across segments to establish, maintain, and distribute consensus standards for the oil and gas industry.

The API standards are mentioned in the next table, which will serve as a guiding instrument at the time of carrying out the activities at each stage to guarantee good practices throughout the project. See Table 84.

INSTALLATION AND DRILLING EQUIPMENT	
API SPEC 2B	Specifications for steel pipe manufacturing
API SPEC 4E	Specifications of structures for drilling and well service
API RP 4G	Operation, Inspection, Maintenance, and Repair of Drilling and Well Servicing Structures
API SPEC 8A	Specification for drilling and production hoisting equipment
API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities
DRILLING	
API SPEC 5D	Specification for Drill Pipe
API SPEC 7	Specification for rotary drill stem elements
API RP 7A1	Recommended Practice for Testing of Thread Compound for Rotary Shouldered Connections
API SPEC 7B-11 C	Specification for Internal- Combustion Reciprocating Engines for Oil-Field Service
API SPEC 7F	Oil Field Chain and Sprockets
API SPEC 7G	Recommended Practice for Drill Stem Design and Operating Limits
API SPEC 9A	Specification for Wire Rope

API RP 9B	Application, Care, and Use of Wire Rope for Oil Field Service
API SPEC 13A	Specification for Drilling Fluids Materials
API RP 13B1	Recommended Practice for Field Testing Water-based Drilling Fluids
API RP 13E	Recommended Practice for Shale Shaker Screen Cloth Designation
API RP 13I	Recommended Practice for Laboratory Testing of Drilling Fluids
API RP 13K	Recommended Practice for Chemical Analysis of Barite
API SPEC 16C	Choke and Kill Equipment
API SPEC 16D	Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API RP 49	Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide
API RP 53	Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells
API RP 54	Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations
WELL COMPLETION	
API SPEC 6A	Specification for Wellhead and Christmas Tree Equipment
API SPEC 6D	Specification for Pipeline and Piping Valves
API SPEC 6FA	Specification for Fire Test for Valves
API RP 14B	Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems
API RP 5A5	Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe

API SPEC 5B	Threading, Gauging, and Inspection of Casing, Tubing, and Line Pipe Threads
API RP 5C1	Recommended Practice for Care and Use of Casing and Tubing
API BULL 5C3	Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties
API RP 5C5	Procedures for Testing Casing and Tubing Connections
API SPEC 5CT	Casing and Tubing
API SPEC 10A	Cements and Materials for Well Cementing
API SPEC 10D	Specification for Bow-string Casing Centralizers
API RP 10B	Recommended Practice for Testing Well Cements
PRODUCTION	
API RP 11S	Recommended practices for operation, maintenance, and fault detection in ESP installations.
API RP 11S1	Best Practices for ESP Assembly Report
API RP 11S2	Best practices for ESP testing.
API RP 11S3	Best practices for ESP installations
API RP 11S5	Recommended practices for submerged cable systems.
API SPEC 11V1	Specifications for Gas Lift Valves and Orifices.
API RP 11V5	Recommended practices for operations and maintenance in Gas Lif installations
API RP 11V6	Best Practices for Designing Continuous Gas Lift.
API RP 11V7	Gas Lift Valve Test and Repair Best Practices.

Table 84. API standards.

6.2 Legal Norms

Our project will follow the general and specific regulations related to each stage of the hydrocarbon industry established by the Peruvian government. See Table 85.

Regulations of supervision of Energy and mining activities from OSINERGMIN	
Exploration and Production	Law No. 26221
Regulations for Hydrocarbon Exploration and Exploitation Activities.	Supreme Decree No. 042-2005-EM
Regulation for the royalty application and remuneration in the oil contracts.	Law N ° 27377
Law for the promotion of investment in the exploitation of resources and marginal reserves of hydrocarbons nationwide.	Law No. 27624
Regulation of Qualification of Oil Companies.	Supreme Decree No. 021-2012-EM
Hydrocarbon Transportation by Pipelines	Law No. 29852
Regulation of the Hydrocarbon transportation by pipeline.	Supreme Decree No. 32-95-EF
Hydrocarbon Storage	Supreme Decree No. 040-98-EM
Safety regulations for hydrocarbon storage.	Supreme Decree No. 032-2002-EM

Modification of the safety regulation for hydrocarbon storage.	Supreme Decree No. 043-2007-EM
Commercialization of Hydrocarbon	Law No. 28551
Regulation for the commercialization of liquid fuels and other products derived from hydrocarbons	
Safety Regulation for the hydrocarbon's storage.	Supreme Decree No. 054-2001-PCM
Safety regulation for the Hydrocarbon transportation	Board of Directors Resolution No. 171-2013-OS-CD
Environment	
Organic law for the sustainable use of natural resources.	Supreme Decree No. 032-2004-EM
Natural Protected Areas Law.	Supreme Decree No. 049-93-EM
Law of the National system of evaluation of environmental impact.	Law No. 28109
The regulation of the Law 27446, Law of the National system of evaluation of environmental impact, is approved.	Supreme Decree No. 030-2004-EM
Marco Law of the National system of environmental management	
General Environment Law.	Supreme Decree No. 081-2007-EM

Regulation of environmental protection for hydrocarbons activities	
Law of the National system evaluation and environmental inspection	Supreme Decree No. 052-93-EM
Law that regulates the environmental liabilities of the hydrocarbon subsector	Supreme Decree No. 036-2003-EM
Law that modifies Law No. 29325 (Law of the National System of Environmental Assessment and Enforcement)	
They establish Maximum Permissible Limits of Liquid Effluents for the Hydrocarbons Subsector.	Supreme Decree No. 030-98-EM
Law of Integral Management of Solid Waste.	Supreme Decree No. 052-93-EM
Regulation of the integral Management Law of waste	Supreme Decree No. 26-94-EM
Social affairs	
Law for the protection of indigenous or native peoples in a situation of isolation and in a situation of initial contact.	Law No. 26821
Law on the Right to Prior Consultation of Indigenous or Native Peoples recognized in Convention 169 of the International Labor Organization (ILO)	Law No. 26834
Guidelines for Citizen Participation in Hydrocarbon Activities are approved.	Law No. 27446

Regulation of citizen participation for the performance of hydrocarbon activities.	Supreme Decree No. 019-2009
Supervision and Inspection - OSINERGMIN	Law No. 28245
The General Regulations of the Supervisory Agency for Energy Investment are approved- OSINERG.	Law No. 28611
Regulation for the Supervision of Energy and Mining Activities of OSINERGMIN.	Supreme Decree No. 039-2014-EM
Labor legislation	Law N ° 29325
Law on Safety and Health at Work.	Law N ° 29134
Regulations of the Law on Safety and Health at Work.	Law N ° 30011
Reference formats of the Occupational Health and Safety Management system.	Supreme Decree No. 037-2008-PCM
Regulation for the Supervision of Energy and Mining Activities of OSINERGMIN.	Legislative Decree No. 1278
Exploration and production	Supreme decret 014-2017-INAM
Regulations for Hydrocarbon Exploration and Exploitation Activities	
Regulations for the application of royalties and remuneration in oil contracts.	Law No. 28736
Law for the promotion of investment in the exploitation of resources and marginal reserves of hydrocarbons at the national level.	Law N ° 29785
Regulation of Qualification of Oil Companies.	Ministerial Resolution No. 571-2008-MEM-DM

Transportation of hydrocarbons by oil pipelines	Supreme Decree No. 012-2008-EM
Hydrocarbon storage	Supreme Decree No. 054-2001-PCM
Safety regulations for the storage of hydrocarbons.	Board of Directors Resolution N ° 171-2013-OS-CD

Table 85. Laws and decrees in hydrocarbon activities.

6.3 Contractual Aspects

According to Peruvian legislation, as a preliminary step to the development of a new hydrocarbon project, an Environmental Management Instrument is required, which assesses the impact of the activities and proposes adequate protection measures for the environment, in such a way that ensure harmonious development of the project without significantly altering ecosystems of the project's area of influence.

The main current and applicable legal regulations that have been considered in the preparation of the EIA are cited. See Table 86.

No. Law	Name of the law
	Political Constitution of Peru
Law No. 26221	Organic Law of Hydrocarbons.
Law No. 26505	Law of private investment in the development of economic activities in the lands of the national territory and of peasant and native communities.
Law No. 26821	Organic Law for the Sustainable Use of Natural Resources.
Law No. 26834	Protected Natural Areas Law.
Law No. 27308	Law on the Conservation and Sustainable Use of Biological Diversity.
Law No. 27308	Forestry and Wildlife Law.
Law No. 27314	General Law of Solid Waste.
Law No. 27446	Law of the National System of Environmental Impact Assessment.
Law No. 27811	Law that establishes the regime for the protection of collective knowledge of indigenous peoples linked to biological resources.
Law No. 28216	Law for the protection of access to Peruvian biological diversity and the collective knowledge of indigenous peoples.
Law No. 28296	General Law of the Cultural Heritage of the Nation.
Law No. 28611	General Environmental Law.

Law No. 28736	Law for the Protection of Indigenous or Native Peoples in a situation of isolation and in a situation of initial contact.
Law No. 29338	Water Resources Law.
Law No. 29785	Law of the Right to Prior Consultation of Indigenous or Native Peoples, recognized in Convention 169 of the International Labor Organization.
D.L. No. 635	Penal Code, Title XIII- Environmental Crimes.
D.L. No. 757	Marco Law for the Growth of Private Investment.
D.L. No. 1079	Legislative Decree that establishes measures that guarantee the Heritage of Protected Natural Areas.
D.S. No. 002-2008-MINAM	National Standards of Environmental Quality for Water are approved.
D.S. No. 002-2013-MINAM	Environmental Quality Standards (ECA) for Soil approved.
D.S. No. 003-2011-MINAM	Modification of article 116 of the Regulation of the Law of Protected Natural Areas is approved.
D.S. No. 004-2010-MINAM	Supreme Decree that specifies the obligation to request a prior binding technical opinion in defense of the natural heritage of Protected Natural Areas.
D.S. No. 013-2010-AG	Regulations for the Execution of Soil Surveys are approved.
D.S. No. 014-2001-AG	Regulation of the Forestry and Wild Fauna Law and its Amendment.

D.S. No. 019-2009-MINAM	Regulation of Law No. 27446, Law of the National System for Environmental Impact Assessment.
D.S. No. 032-2004-EM	The Regulations for Hydrocarbon Exploration and Exploitation Activities are approved.
D.S. No. 034-2004-AG	Categorization of Threatened Species of Wild Fauna and Prohibit their Hunting, Capture, Possession, Transport or Export for Commercial Purposes is approved.
D.S. No. 038-2001-AG	Regulation of the Law of Protected Natural Areas (ANPs).
D.S. No. 057-2004-PCM	Regulation of Law No. 27314, General Law of Solid Waste.
D.S. No. 074-2001-PCM	Regulation of National Standards of Environmental Air Quality.
D.S. No. 085-2003-PCM	Regulation of National Standards of Environmental Quality for Noise.
D.S. No. 001-2010-AG	Regulation of Law No. 29338, Law of Water Resources.
D.S. No. 003-2008-MINAM	Environmental Quality Standards for Air.

Table 86. Current legal laws EIA

7. ENVIRONMENTAL STUDY

Environmental Impact Analysis

The environmental impact analysis aims to identify and assess qualitatively and quantitatively the environmental impacts that could occur as a result of drilling wells in the jungle in Block 192. The importance of identification and evaluation of environmental impacts lies in that these constitute the basis for the elaboration of the Environmental Management Plan (EMP), an environmental management instrument where measures are proposed that will make it possible to avoid or minimize negative environmental impacts for a better conservation of the jungle ecosystem.

The identification and evaluation of environmental impacts has been carried out in accordance with the technical requirements indicated in the Regulation for Environmental Protection in Hydrocarbon Activities approved by Supreme Decree No. 015-2006-EM.

In general, the impacts have been evaluated quantitatively and qualitatively, considering the main environmental aspects of the project and their influence on the receptor elements of the physical, biological, hydrobiological, social and economic environment. (Programa de las Naciones Unidas para el Desarrollo, 2018)

7.1 Analysis Methodology

To identify the environmental impacts of the project, a methodology (See Table 87) based on identifying the environmental aspects of the project was used to analyze the behavior of the environmental elements and components in relation to the projected activities. This qualitative analysis includes the use of cause-effect matrices. This methodology is based on the interaction of project activities and environmental factor to identify and determine environmental impacts.

Assessment of the attributes of environmental impacts

Symbol. The impact sign alludes to the beneficial (expressed as "+") or harmful (expressed as "-") nature of each of the actions that will act on the different factors considered.

Character (Ca): This term defines whether the action or realization of the project is positive +, harmful -, or neutral. Negative Positive Neutral	 -1 +1 0	**Extension (E):** Defines the magnitude of the area affected by the amount, considering as such the relative surface where the impact is felt. Regional Local Punctual	 0.8-1.0 0.4-0.7 0.1-0.3
Intensity (I): The intensity of the impact expresses the importance of the consequences that the alteration of the element will have on the environmental component, being defined by the interaction between the degree of disturbance and the environmental value. Very high high Median Low	 1.0 0.7 0.4 0.1	**Development (D):** It qualifies the time that the impact takes to fully develop, that is, it qualifies the way an impact evolves in time from when it begins or manifests itself until it appears fully with all its consequences. Very fast (<1 month) Fast (1-6 months) Medium (6 - 12 months) Slow (12 - 24 months) Very slow (> 24 months)	 0.9-1.0 0.7-0.8 0.5-0.6 0.3-0.4 0.1-0.2
Occurrence (O): Rate the probability that the impact will occur during the implementation of project activities. True Very likely Probable Unlikely	 9-10 7-8 4-6 1-3	**Duration (Dt):** It corresponds to a unit of time measurement that allows evaluating the period during which the repercussions will be felt in the affected element. Permanent (+10 years) Long (5-10 years) Medium (3-4 years) Short (> 2 years)	 0.8-1.0 0.5-0.7 0.3-0.4 0.1-0.2
		Reversibility (RV): that evaluates the ability of the effect to be reversed. Irreversible Partially irreversible Reversible	 0.8-1.0 0.4-0.7 0.1-0.3

Table 87. Appreciation of the attributes of environmental impacts.

Once we have defined and calculated these values, an equation is applied that allows us to define the Ecological Qualification (Ce). (See Table 88)

$$Ce = \frac{Ca(I + E + Dt + D + R) * O}{5}$$

Negative impact	Environmental Impact Value
Very high	-10 a -8
High	-7 a -5
Medium	-4 a -2
Low	<-2 a -1
Neutral Impacts	**0**
Positive Impacts	**Greater or equal to 1**

Table 88 Levels of importance of the impacts.

7.2 Identification of Environmental Impacts

The identification of environmental impacts has been generated from environmental aspects as well as environmental risk factors for this analysis.

Subsequently, once the impacts have been identified, they are evaluated through an importance assessment matrix, applying the significance formula, according to numerical assessment ranges.

Identification of impacts

For the evaluation of Environmental Impacts, the analysis will be carried out considering the following stages: Pre-Operational (Stage of installation and assembly of the platform), Operational and Abandonment. The following Table 89 shows the activities according to the order of the Project stages.

Stage	Activities that includes development
Pre-Operational (Construction)	Field Preparation for Drilling and Production Facilities
	Take the equipment to the selected area
	Installation of rigs and drilling equipment
	Well Drilling / Casing / Cementation / Completion.
	Treatment of drill cuttings
	Installation of Surface Facilities
Operational (Operation and Maintenance)	Well Testing
	Well Production
	Treatment and Injection of Water in well disposal.
	Maintenance of equipment and facilities
	Field Surveillance
	Well service
Abandonment	Mobilization and demobilization of facilities and facilities / Abandonment of the Well
	Restoration and remediation of the area, transportation of hazardous and non-hazardous Solid Waste, final disposal and restoration of the site

Table 89 Main activities in the project.

In these three stages described in the table above (See Table 89), the General Activities are also taken into consideration throughout the project. (See Table 90)

	Activity that includes development
General activities	Use of Human Resources
	Use of services
	Generation of Domestic Effluents (sewage)
	Solid Waste Generation

Table 90 General project activities

Before proceeding to evaluate the potential impacts of the Project, it is necessary to select the interacting components. The interacting components are identified below: (See Table 91).

Environment	Interactive Environmental Component	Environmental impact
Physical	Air	Increase in particulate matter
		Increase in base noise level
	Land	Soil instability
		Erosive processes
		Soil contamination by hydrocarbon spills
		Soil contamination from spills and sludge infiltration
		Pollution due to poor solid waste disposal
		Improvement of soil quality
	Water	Surface water disturbance
		Groundwater alteration
Biological	Flora	Alteration of biodiversity and abundance of flora
	Fauna	Alteration of biodiversity and abundance of fauna
Socioeconomic	Socioeconomic	Discomfort to the population
		Generation of local employment
		Dynamization of the local economy
	Health	Impact on the health of the local population
		Work accidents

Table 91 Interaction components.

7.3 Assessment of Environmental Impacts

For this section, an Environmental Impact Assessment Matrix (See Table 92) has been made with which an assessment has been given to each identified activity.

Activities by Stages	Environmental Component				
	ATMOSPHERE	WATER	LAND	BIOLOGICAL	SOCIOECONOMIC
	Ecological Rating				
Preoperative Stage					
Field Preparation for Drilling and Production Facilities	-3	-2	-3	-2	0
Take the equipments to the selected area	0	0	-2	-2	0
Installation of rigs and drilling equipment	-1	-1	-2	-3	-1
Well Drilling / Casing / Cementation / Completion.	-2	-3	-4	-2	0
Treatment of drill cuttings	-2	-3	-3	-1	-1
Installation of Surface Facilities	-2	-3	-2	-2	0
Operational Stage					
Well Testing	-2	0	-1	0	0
Well Production	-1	0	0	0	0
Water Treatment and Injection in well disposal	0	-1	-2	0	0
Maintenance of equipment and facilities	0	0	-1	0	1
Field Surveillance	0	0	-1	-1	-1
Well service	-1	-1	-2	-1	-1
Abandonment Stage					
Mobilization of facilities and facilities	-3	-2	-3	-2	-2
Well Abandonment	0	0	-1	0	-1
Restoration and remediation of the area	2	2	4	3	4

Table 92. Environmental impact matrix.

7.4 Cumulative and Synergistic Impacts

In the project area of the Capahuari Sur Extensión Field of Block 192, activities have been programmed for the Exploration stage, which have been identified that would generate, cumulative and synergistic impacts of Medium to High range, mainly due to Seismic activities. (See Table 93, Table 94, Table 95 and Table 96)

In case of developing the project and moving to the Exploitation Stage in this area, cumulative and Synergistic impacts may manifest, mainly on the quality of noise, traffic and tree clearing; that would be of an indirect influence.

The table shows the relationship of environmental impacts identified in this chapter and their cumulative and synergistic condition.

Pre-Operative Stage

Nº	Environmental and Social Impacts	Cumulative Impact	Synergistic Impact
Activity 1: Field Preparation			
1	Increase in base noise level	Yes, it is.	Yes, it is.
2	River traffic	No, it isn't	No, it isn't
3	Deforestation and Clearing	Yes, it is.	Yes, it is.
Activity 2: Take the equipment to the selected area			
1	River and air traffic	No, it isn't	Yes, it is.
2	Increase in base noise level	Yes, it is.	Yes, it is.
Activity 3: Installation of Platforms / Drilling Equipment / Facilities			
1	Increase in base noise level	Yes, it is.	No, it isn't
2	Increase in hazardous waste	Yes, it is.	No, it isn't
Activity 4: Well Drilling / Casing / Cementation / Completion			
1	Soil contamination	Yes, it is.	No, it isn't
2	Increase in particulate matter	No, it isn't	No, it isn't

Table 93 Cumulative and synergistic impacts: Pre - operational stage.

Operational Stage

Nº	Environmental and Social Impacts	Cumulative Impact	Synergistic Impact
Activity 1: Well Production			
1	Increase in base noise level	Yes, it is.	No, it isn't
2	Solid waste disposal	Yes, it is.	No, it isn't
3	Alteration of air quality	No, it isn't	No, it isn't
Activity 2: Water treatment			
1	Alteration of water quality	Yes, it is.	No, it isn't

Table 94 Cumulative and synergistic impacts: operational stage.

Abandonment Stage

Nº	Environmental and Social Impacts	Cumulative Impact	Synergistic Impact
Activity 1: Mobilization and demobilization of facilities and facilities / Abandonment of Wells			
1	Increase in base noise level	Yes, it is.	No, it isn't
2	Solid waste disposal	Yes, it is.	No, it isn't
3	Alteration of air quality	Yes, it is.	No, it isn't
Activity 2: Restoration and Remediation			
1	Soil quality restoration	No, it isn't	No, it isn't

Table 95 Cumulative and synergistic impacts: abandonment stage.

General Activities

Nº	Environmental and Social Impacts	Cumulative Impact	Synergistic Impact
Activity 1: Use of Human Resources			
1	Temporary generation of local employment	No, it isn't	No, it isn't
Activity 2: Use of goods and services			
3	Dynamization of the local economy	No, it isn't	No, it isn't
Activity 3: Generation of wastewater			

1	Alteration of water quality	No, it isn't	No, it isn't

Table 96 Cumulative and synergistic impacts: general activities

7.5 Environmental Management Plan

To reduce the environmental impacts of the project, it is necessary to carry out an Environmental Management Plan (EMP) of the Project, which aims to propose a set of environmental prevention, correction and mitigation measures through various plans and programs that must be implemented during the development and execution of the referred project, according to its stages.

The Environmental Management Plan (EMP) was prepared in accordance with the provisions of Supreme Decree No. 015-2006-EM, Regulation for Environmental Protection in Hydrocarbon Activities.

Components of the Environmental Management Plan

The Environmental Management Plan (EMP) consists of the following programs:

1. Environmental Prevention and Mitigation Plan, which includes general and specific environmental management measures of the possible negative environmental impacts generated.
2. Environmental Monitoring Plan, to verify compliance with the environmental quality standards established in the current regulations and the efficiency of the environmental management measures adopted during the development of the project.
3. Contingency Plan
4. Abandonment Plan

Responsible for enforcing the PMA will be the HSE Department, through coordination with the Exploration Management and the other operational departments to implement, supervise, improve, enforce and audit all employees and contractors that are linked to drilling, production, etc.

7.5.1 Environmental Prevention and Mitigation Plan

Set of measures to prevent, correct and mitigate possible environmental impacts, which were identified.

- **General Environmental Prevention and Mitigation Measures in the Project:**

A. General Measures applied to all Stages
B. Preventive Measures for Traffic
C. Management Measures for Fuels, Lubricants and Hazardous Materials

- **Specific Environmental Prevention and Mitigation Measures for Drilling**

A. Mud Management and Drilling Cuts
B. Waste Management Plan
C. Wastewater Management
D. Occupational Health and Safety Measures

7.5.2 Environmental Monitoring Plan

This plan includes monitoring in the following environmental components:

A. Surface water monitoring
B. Effluent monitoring (domestics e industrials)
C. Soil and sediment quality monitoring
D. Biological environment monitoring
E. Monitoring of drilling coarse cuts
F. Air quality / emissions monitoring program
G. Noise quality monitoring program
H. Flora and Fauna Management Program
I. Clearing and Clearing Program
J. Chemical Substance Management Program
K. Program for the prevention of damage to cultural heritage.

7.5.3 Contingency Plan

The contingency plan for the Capahuari Sur Extensión Field Development project in Block 192 has been prepared in accordance with the hazards and risks identified and evaluated, considering each of the project's processes and activities. This plan contains a set of procedures that describe how ALFA and its contractors or subcontractors will respond to the eventuality of accidents and states of emergency that may occur during Project Operation.

Emergency Levels

The classification of emergencies is made up of three differentiated levels according to the criteria of severity of the initial impact and / or the use of resources that will be required for its control.

Table 97 defines the 3 levels of contingency.

Level 1 Low	Level 2 Medium	Level 3 High
Emergency that can be controlled by the staff working in the place where the event occurs, without requiring any type of support.	Emergency that can be controlled by the personnel of the place with the support of the internal emergency organization.	Emergency that requires the full participation of the organization and external support entities. External response entities, such as OEFA, Specialized Companies (Clean Caribbean & Americas CC&A), Civil Defense, may be called as a precaution, and their intervention may not be necessary.

Table 97. Contingency levels.

Response Action Plan

Before the occurrence of any contingency, the working personnel must recognize, measure and respond quickly to it. Hence, training (sum of knowledge acquired and skills developed) is the key to a rapid response to a contingency.

The sequence for the initiation of response action in the event of a contingency is as follows:

Programs Contained in the Contingency Plan

- Emergency Equipment
- Risk identification
- Emergency procedures
- Programs in case of fire
- Procedures in case of oil spill
- Procedures in case of work accidents
- Procedures in case of Natural Disasters
- Portfolio of entities where to go in case it is required in an emergency.
- Response action taken to face the emergency and prevent further consequences; estimate of the necessary equipment and possible help required from other areas of the company or other companies.

7.5.4 Abandonment Plan

Commonly, the execution of the abandonment phase is conditioned on the results of the drilling tests of the exploratory wells, considering the feasibility of moving to a next phase of exploitation or its definitive abandonment, within the framework of what is indicated in the current legislation. However, for the purposes of the project, the Abandonment Plan has been conditioned to the time of the contract, which is why the guidelines for the Abandonment Stage were established, which corresponds to the last years of the field contract.

Before the definitive abandonment of the activities, these must be communicated to the State entities, as appropriate (DGH, DGAAE, Perupetro) within the framework of the provisions of current legislation.

The minimum activities to be carried out at this stage:

- Demobilization
- Retirement of drilling equipment
- Modular dismantling, removal of the platform (in case it is confirmed that the location of the platform is not of interest for exploitation purposes or also at the end of the contract)
- Cutting and recovery of well conductors
- Put off flow lines
- Carry out an environmental study to capture and support the conditions in which the Abandonment is being carried out

8. SOCIAL STUDY

This study is about the potential effects that the planned project activities could have on the socio-economic and cultural environment. It is specified that social impacts do not affect a delimited area since it corresponds to impacts in terms of social relations that extend fluidly in space.

The potential impacts identified have the character of a formative evaluation, in which a prediction of the impacts is made based on the base values and the prevention of changes that could occur in the presence of the project, according to the requirements of the Ministry of Energy and Mines, expressed in its Community Relations Guide (2001).

8.1 Methodology to Identify Social Impacts

The socio-economic and cultural dynamics present particulars that deserve to be evaluated and, in the perceptions, generated by the characteristics of the project. In this sense social impacts are classified as:

- Direct impacts: are those that can foreseeably derive directly from the project's own activities.
- Indirect impacts: these are those that depend on a complex interaction of social aspects, and their character is less predictable.

The development project of the Capahuari Sur Extensión Field will be developed in the jungle, for this reason the social impacts are mainly related to the activities that take place in it, such as agriculture, farm, fishing, being the social interest groups mainly related with artisanal and industrial agriculture.

The identification of social impacts, levels and degrees of perception of the main social interest groups of the project's areas of interest have been taken into consideration, obtained from interviews as well as citizen participation workshops. Accordingly, the social components will be determined, as well as the social factors to these components.

8.2 Identification of the Area of Influence

The area of direct and indirect influence of the development project of the Capahuari Sur Extensión Field of Block 192 has offset interacting communities, as can be seen in the Figure 136 and Figure 137; reason for which the following groups described in the Table 98 and Table 99 are considered for the analysis of social impacts and for the implementation of the Community Relations Plan.

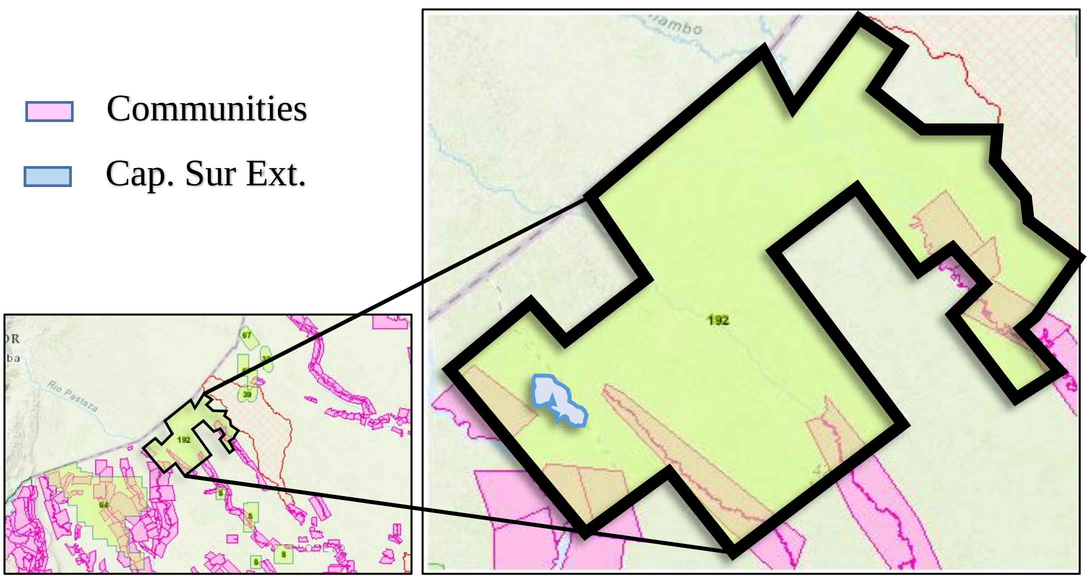

Figure 136 Area of influence.

Groupings	
Pastaza Basin	Federación Indígena Quechua del Pastaza - FEDIQUEP
Corrientes Basin	Federación de Comunidades Nativas del Corriente - FECONACO
Tigre Basin	Organización de los Pueblos Indígenas Kichwas Amazónicos de la Frontera Perú-Ecuador – OPIKAFPE (*ex Federación de Comunidades Nativas del Tigre - FECONAT)*
Marañon Basin	Asociación Cocama de Desarrollo y Conservación San Pablo de Tipìshca - ACODECOSPAT
	Federación de Indígenas del Alto Pastaza (FEDINAPA)
	Organización Interétnica del Alto Pastaza (ORIAP)
	Asociación Interétnica de Desarrollo de la Selva Peruana (AIDESEP)

Table 98 Identification of groups of interest.

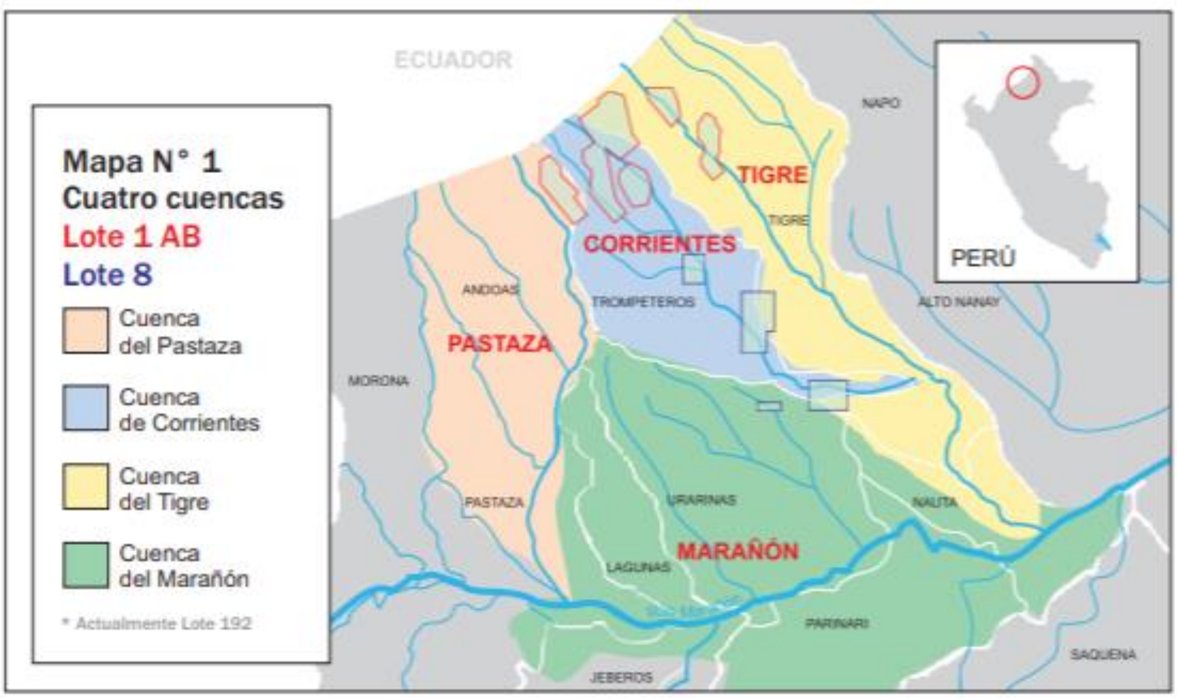

Figure 137 Location of the 4 basins (source: Perupetro).

Native Communities of Direct Influence	Native Communities of Indirect Influence
Comunidad Nativa Titiyacu	Comunidad Nativa 12 de Octubre
Comunidad Nativa Capahuariyacu	Comunidad Nativa Vencedores
Comunidad Nativa Nuevo Andoas	Comunidad Nativa Betania
Comunidad Nativa Nueva Jerusalén	Comunidad Nativa Marsella
Comunidad Nativa Nueva Nazareth	Comunidad Nativa Vista Alegre
Comunidad Nativa Nuevo porvenir	Comunidad Nativa Nuevo Remanente
Comunidad Nativa Alianza Cristiana	Comunidad Nativa Nuevo Canaán
Comunidad Nativa Los Jardines	Comunidad Nativa El Salvador
Comunidad Nativa José Olaya	Comunidad Nativa Teniente Ruiz
Comunidad Nativa Antioquiaç	Comunidad Nativa Andoas Viejo

Table 99 Identification of communities of direct and indirect influence.

8.3 Identification of Main Issues

The key issues are given by the economic, social and cultural aspects in which some type of modification can be predicted due to the activities to be developed in the Capahuari Sur Extensión field of Block 192.

The key issues and direct impacts identified in the study are presented in the Table 100.

Key issue	Potential Social Impacts	Project Activities
Agriculture	Increased security risks	Construction of Platforms and locations
Environmental management	Environmental Pollution	Development of the hydrocarbon exploration project

Table 100 Key Issues and Direct Impacts

The key issues and indirect impacts identified in the study are presented in the Table 101.

Key issue	Potential Social Impacts	Project Activities
Employment	Local employment expectations	Hiring of personnel for the various activities of the project
Social development	Expectations by generation and use of Canon	Development of the hydrocarbon exploration project
	Expectations of social support	

Table 101 Key issues and indirect impacts.

8.4 Evaluation of Social Impacts

8.4.1 Evaluation of Direct Social Impacts

The direct social impacts are constituted as an immediate consequence caused by the project activities in the social, cultural or economic environment. Since the project will be developed entirely in the jungle, the direct impacts are expected to be moderate and primarily related to agricultural activity and distortion of the ecosystem.

Increase in Security Risks

The project includes platform installation, exploratory drilling, development and abandonment activities. Despite the existence of contingency plans, these activities can lead to exposure to security risks for the communities and their activities. (See Table 102).

Judgment	Assessment
Impact Type	Direct
Direction	Negative
Magnitude	Marginal to Low
Duration	Medium term / Long term
Geographic Extension	Familiar / Local
Interest groups	Federation of Native Communities

Table 102 Increased security risks.

Environmental Pollution

The population of the localities of the areas of interest perceives that environmental pollution could affect their living conditions and the economic activities that they carry out. (See Table 103)

Judgment	Assessment
Impact Type	Direct
Direction	Negative
Magnitude	Low
Duration	Long term
Geographic Extension	Local
Interest groups	Federation of Native Communities

Table 103 Environmental pollution fears.

8.4.2 Assessment of Indirect Social Impacts

Employment Related Impacts

The start of operations of a new project sometimes awakens expectations of employment opportunities whether these possibilities are real or not.

The development project of the Capahuari Sur Extensión Field of Block 192, due to its technical characteristics and duration, will not significantly affect the increase in local employment. (See Table 104)

Judgment	Assessment
Impact Type	Direct
Direction	Positive
Magnitude	Marginal or Low
Duration	Long term
Geographic Extension	Indeterminate (according to staff requirements)
Interest groups	Local population

Table 104 Generation of local employment.

Expectations by Generation and Use of Canon

The expectations for the generation of income are one of the main benefits that the population and the interest groups perceive about the development project of the Capahuari Sur Extensión Field of Block 192. These expectations are based on the perception that the projects Exploration and exploitation are one, showing that the population's perceptions of this type of project do not easily differentiate the various stages or phases of hydrocarbon activities. (See Table 105).

Judgment	Assessment
Impact Type	Indirect
Direction	Negative
Magnitude	Low
Duration	Long term
Geographic Extension	Local and District
Interest groups	Population and local authorities

Table 105 Expectations by canon generation

The distribution of the Canon is important to mention, since it has a high impact on the Exploitation Stage of the field, since it generates income for the Loreto region, presenting the following distribution: (See)

- Region Loreto: 52%
- Universidad Nac. Amazonia: 5%
- Inst. Per. Amazonia: 3%
- Conc. Municipales: 40%

DISTRIBUTION OF THE CANON 2020								
LORETO REGION: Law 21678								
Expressed in Thousands of Soles								
PAYMENT PERIOD		**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**
Ley N° 29289 - Contrapartida Nacional		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ley N° 29289 - Servicio de Deuda		2,200.0	2,200.0	0.0	0.0	0.0	0.0	0.0
REGION LORETO	52%	7,761.4	6,774.3	2,511.2	941.0	115.4	445.7	1,139.2
UNIV. NAC. AMAZONIA	5%	746.3	651.4	241.5	90.5	11.1	42.9	109.5
INST. PER. AMAZONIA	3%	447.8	390.8	144.9	54.3	6.7	25.7	65.7
CONC. MUNICIPALES	40%	5,970.3	5,211.0	1,931.7	723.8	88.8	342.9	876.3
TOTAL CANON		**17,125.7**	**15,227.6**	**4,829.3**	**1,809.6**	**222.0**	**857.2**	**2,190.8**
* DISTRIBUTION TO MUNICIPALITIES IS MADE THROUGH THE NATIONAL COUNCIL OF DECENTRALIZATION								

Table 106. Canon 2020 distribution: Loreto region.

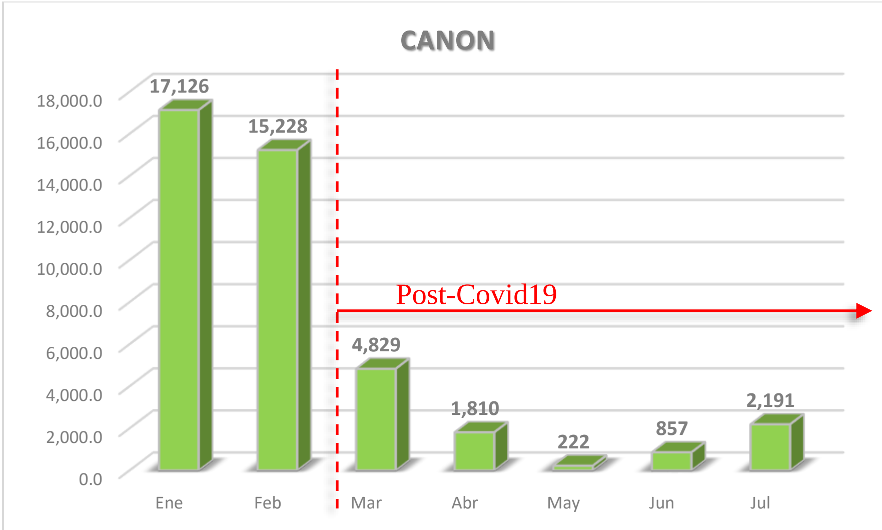

Figure 138. Canon 2020 Income: Loreto region.

From the Figure 138 we can conclude that a reduction in operations, and therefore, in oil production would generate a drop in terms of Canon income in the Project Region, this would mean a reduction in regional project budgets. This is one of the most important aspects of the benefits that field exploitation projects bring.

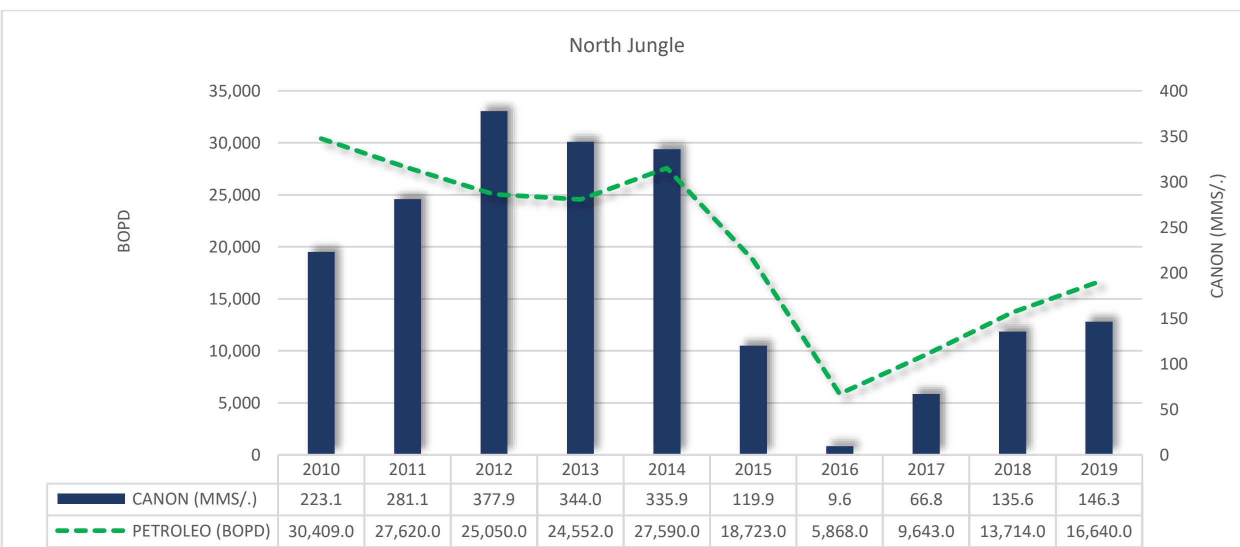

Figure 139. Production history BOPD vs canon: north Jungle.

Expectation of Social Support

In the areas of interest of the project there are expectations for the possibility of benefiting from some specific projects for the locality. It is pertinent to specify that the exploratory drilling activity does not generate profits or income for the company. (See Table 107)

Judgment	Assessment
Impact Type	Indirect
Direction	Negative
Magnitude	Low
Duration	Long term
Geographic Extension	Local and District
Interest groups	Population and local authorities

Table 107 Expectation of social support.

8.4.3 Characterization of Social Impacts

Taking into consideration the evaluations of direct and indirect social impacts, it is summarized in a cause-effect matrix (See Table 108) for each general activity of the various stages of the project.

Activities by Stages	Impact on Health	Security Risks	Risk of Environmental Pollution	Local Employment
	Impact type			
Preoperative Stage				
Field Preparation for Drilling and Production Facilities		-		+
Take the equipment to the selected area				+
Installation of rigs and drilling equipment		-	-	+
Well Drilling / Casing / Cementation / Completion.		-	-	
Treatment of drill cuttings				
Installation of Surface Facilities			-	+
Operational Stage				
Well Testing				
Well Production		-	-	
Crude Transportation	-	-	-	
Treatment and Injection of Water in well disposal.			-	
Maintenance of equipment and facilities				+
Field Surveillance				+
Well service				
Abandonment Stage				
Mobilization of facilities and facilities				+
Well Abandonment				
Restoration and remediation of the area	+		+	+

Table 108. Characterization of social impacts.

8.5 Community Relations Plan

The Community Relations Plan (CRP) of the Capahuari Sur Extensión Field Development Project Extension of Block 192 proposes the execution of six social relations programs between ALFA and the population of the area of social interest (See Table 109) that will give continuity to the citizen participation processes initiated during the preparation of the EIA, which have been formulated in accordance with the policy of social and environmental responsibility of the ALFA Company. In formulating these, the description of the project and the analysis of socioeconomic impacts have been taken into consideration.

8.5.1 Area of Social Interest of the Project

Due to the fact that the Project's operations are carried out completely in the interior of the jungle, far from the cities and population, the Project's area of social interest is made up of the Amazonian communities, whose populations are near to Block 192 because they live close to the area. of interest and their natural resources for survival are mainly in interaction with the activities of the Project.

8.5.2 Stakeholders

The Project stakeholders correspond to all those individuals, groups organized in local, regional and national institutions that interact directly and indirectly with the company, within the framework of the Project activities.

There are three types of interest groups in the Development Project of the Capahuari Sur Extensión Field of Block 192: (i) decentralized entities of the

National Government; (ii) local authorities of the Loreto Region; (iii) union and social organizations.

N°	Programs	Guidelines
01	Communication and Information Program	For a better understanding of the Project and the establishment of positive and trusting relationships. Information activities are carried out on environmental management and mitigation measures, as well as information on opening up local employment programs and community monitoring.
02	Community Socio-Environmental Monitoring Program	Implemented to integrate interest groups related to agriculture and farm activities in the transparent monitoring of Project activities. The Community Socio-Environmental Monitoring program complies with the objectives and measures, according to article 60 and 61 of RM No. 571-2008-MEM / DM.
03	Safety Awareness Program for Exploratory Drilling Operations	Call for informative meetings with the interest groups of the towns in the area of interest.
04	Local Employment Program in the area of interest of the Project	To maximize the opportunities for hiring local labor through adequate procedures for it.
05	Social Responsibility Program	Publicize the Social Responsibility policy and guidelines in the event of hydrocarbon being found
06	Indemnity Program and Settlements	Implementing for the process of definitive and acceptable resolution of the complaints and claims that appear from the Project operations in Block 192.

Table 109 Summary of community relations plan programs.

8.6 Projected Costs of the Management Plan

The Table 110 the estimated annual cost of the environmental management and social plan.

Programs	Estimated Annual Cost (US $)
1) Waste Monitoring Program	**$ 304,220.00**
a) Collection and transport of waste	$ 62,220.00
b) Final disposal of waste	$ 12,000.00
c) Sludge and Cut Management (1)	$ 230,000.00
2) Environmental Monitoring Program	**$ 86,183.03**
a) Surface Water Program	$ 13,786.00
b) Sediment Monitoring	$ 18,933.33
c) Biological Monitoring	$ 33,303.70
d) Wastewater Monitoring	$ 1,560.00
e) Monitoring of drilling cuts	$ 3,600.00
f) Post abandonment monitoring of platforms (2)	$ 15,000.00
3) Contingency Plan	**$ 415,000.00**
a) Spill control equipment (3)	$ 400,000.00
b) Various	$ 15,000.00
4) Community Relations Plan	**$ 26,500.00**
a) Communication and Consultation Program	$ 12,000.00
b) Local Employment Program (4)	$ 1,500.00
c) Involvement and training of Stakeholders on Safety and Environment Issues	$ 5,000.00
d) Participatory Socio-Environmental Monitoring Program	$ 6,000.00
e) Social Responsibility Program (5)	$ 2,000.00
Total Anual	**$ 861,903.03**

(1) Cost per drilling well
(2) Once each time a platform is abandoned.
(3) One-time cost for purchases of spill control equipment.
(4) Corresponds to logistics expenses, payments are part of the project costs.
(5) It does not include costs for the projects to be implemented, since these will be defined based on the priorities identified during the communication and consultation program. It will depend on the success of the exploratory drilling.

Table 110 Estimated annual cost of the environmental and social management plan.

9. MANAGEMENT STUDY

9.1 Managerial, Technical and Administrative Capabilities

9.1.1 Management Skills

They are the capabilities that allow us to effectively lead and optimally manage a complex organization or event. An organization is understood as two or more people who work together in a structured way to achieve a specific objective or a set of objectives.

The most important managerial competencies of the general management of the company ALFA ENERGY are shown below:

- Self-knowledge
- Problem management
- Decision making
- Self-confidence
- Resilience
- Assertiveness
- Emotional regulation
- Ability to delegate
- Social and communication skills
- Vision and strategic thinking
- Empathy
- Leadership

The roles of the manager according to H. Mintzberg. See Figure 140.

Henry Mintzberg's Managerial Roles

Category	Role	Organizational Function	Example Activities
Informational	Monitor	Responsible for information relevant to understanding the organization's internal and external environment	Handle correspondence and information such as industry, societal, and economic news and competitive information
	Disseminator	Responsible for the synthesis, integration, and forwarding of information to other members of the organization	Forward informational e-mails; share information in meetings, conference calls, webcasts, etc.
	Spokesperson	Transmit information to outsiders about organizational policy, plans, outcomes, etc.	Attend management meetings; maintain networks between the organization and stakeholders
Interpersonal	Figurehead	Symbolic leadership duties involving social and legal matters	Attend ceremonies; greet visitors; organize and attend events with clients, customers, bankers, etc.
	Leader	Motivate, inspire, and guide employees' actions; provide opportunities for training; support appropriate staffing	Build trusting relationships with employees; build effective teams; manage conflict
	Liaison	Build and maintain relationships between the organization and outside entities	Work on external boards; create and maintain social networks (real and virtual) with key stakeholders
Decisional	Entrepreneur	Scan the organizational environment for opportunities; foster creativity and innovation	Participate in strategy and review meetings for new projects or continuous improvement
	Disturbance handler	Manage organizational problems and crises	Participate in strategy and review meetings that involve problems and crises; get involved directly with key issues and people
	Resource allocator	Take responsibility for allocation of all types of organizational resources	Create work schedules; make authorization requests; participate in budgeting activities
	Negotiator	Represent the organization during any significant negotiations	Negotiate with vendors and clients; settle disputes about resource allocation

Figure 140. The roles of the manager by H. Mintzberg.

We can classify the managerial levels in 3 organizational levels: (See Figure 141)

Figure 141. Managerial levels.

9.1.2 Technical Skills

They are the skills specifically involved in the correct performance of a given position and are always acquired through academic training or prolonged work experience.

The different areas and departments of the ALFA ENERGY operator are made up of personnel with high technical excellence to carry out the programming, execution, and management of hydrocarbon exploitation processes, in order to bring economic benefits to the country and anticipate possible ecological damage to the environment.

The technical departments have the following skills acquired through a solid trajectory:

- Strength in basic sciences to apply them to the different disciplines of petroleum engineering.
- Solid knowledge of computing, programming, graphic communication, informatics, administration, and project management.
- Consolidated experience in reservoir engineering, production, drilling, planning and administration.
- Analytical thinking, synthesis, and critical reasoning to understand each stage of the oil industry.
- Evaluation of the environmental impacts of the projects and their eventual corresponding mitigation.
- Deep knowledge of the laws and regulations that govern the exploration and exploitation of hydrocarbons in the competent country.

9.1.3 Administrative Skills

At ALFA ENERGY we know that administrative success depends on performance, good management of personnel and work situations.

The performance is the result of the execution of the administrative skills (See Table 111) of the competent department. According to Robert L. Katz, there are 3 important skills for successful managerial performance:

Technical skills
Use of specific knowledge and the facility to apply work-related techniques. We can mention some like our accounting, programming, engineering skills.
Human skills
They are related to our treatment of people and refer to the ease of interpersonal and group relationships. They include our ability to communicate, motivate, coordinate, and resolve personal or group conflicts within the company.
Conceptual skills
They are related to the vision of the organization or organizational unit. The organization with the environment and its effects on its part is an example of this.

Table 111. Administrative skills.

9.2 Organizational Chart

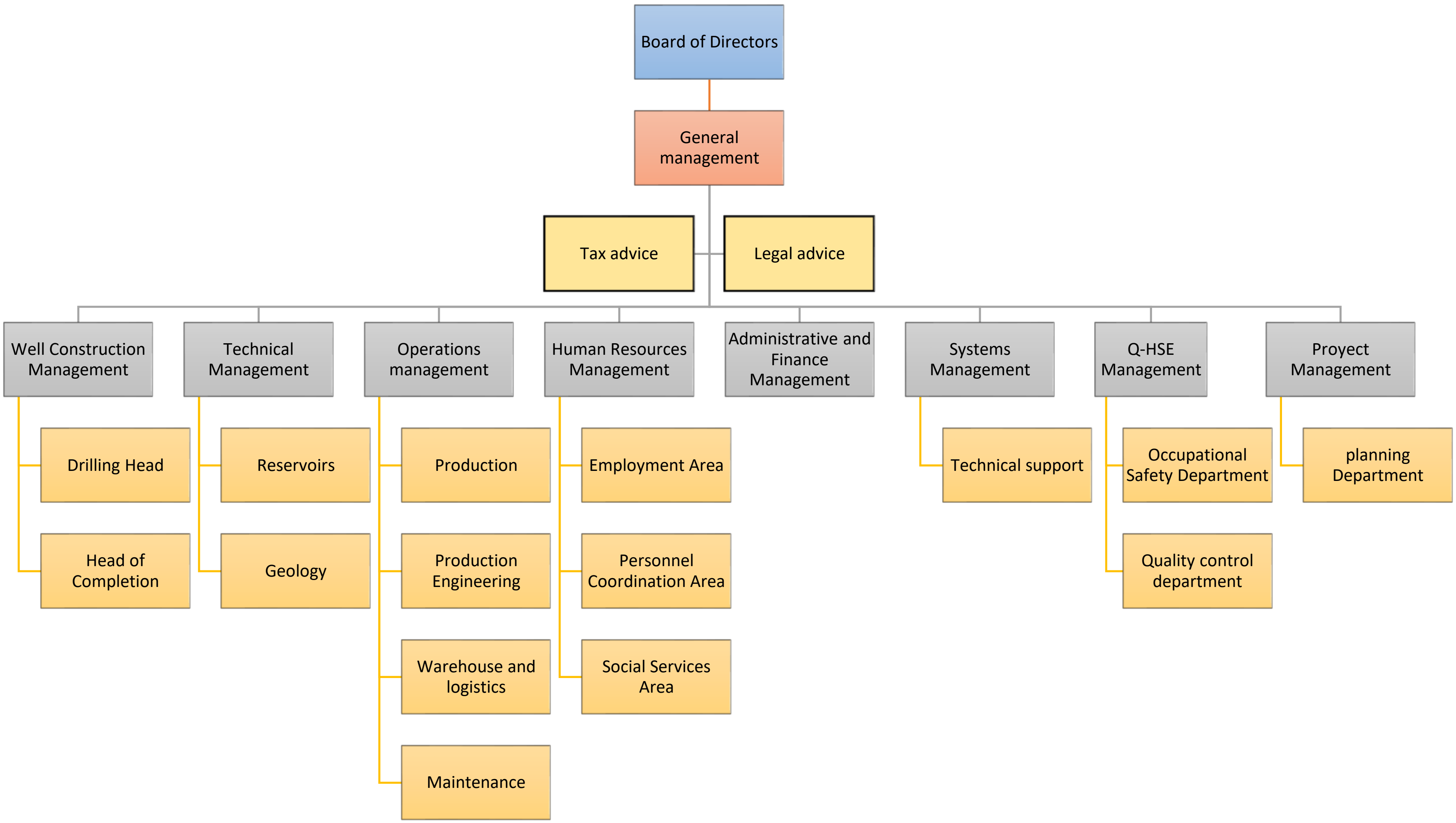

Figure 142. Alfa Energy organization chart.

10. ECONOMIC STUDY

After concluding the Technical Study regarding a future exploitation of the Capahuari Sur Extensión Field, we must estimate the costs of the proposed development plan, taking into consideration the proposed technology for the exploitation of the field during the 20 years of the contract and estimating the costs of the exploration stage for 7 years before the declaration of marketability.

In the present study we have 2 cases for development, the first one proposes 1 exploratory well, 2 confirmatory wells, 16 development wells and 3 water injection wells; a total of 22 wells to be drilled considering 3 locations with all the surface facilities that would be demanded.

The second case estimates to drill horizontal wells to propose a development plan with less wells, it is proposed to drill 1 exploratory well, 2 confirmatory wells, 13 development wells and 3 flank water injection wells; a total of 19 wells to be drilled, of which 8 will be horizontal to compare the recovery factor with case 1, finally it is considered 3 locations in the reservoir with all the surface facilities that it would demand to drill all the wells.

10.1 Economic Considerations

Exploration:

The Peruvian regulatory framework for exploration operations offers us 7 years to carry out this stage, with the possibility of extending it up to 10 years.

- We consider 7 years of exploration that begins in January 2023 and ends in March 2030 with the discovery of commercial hydrocarbons through the exploratory well ALFA 1 X.

- We charge exploration costs such as: field geology, gravimetric, magnetometry, 2D seismic, 3D seismic, engineering and Environmental Impact Study in average costs of 500 MUSD per month.
- It is estimated that the investment amounts for surface facilities (we propose 3 batteries to collect our production) will be 60 MMUSD which will be charged by December 2029.
- Based on the Peruvian economic framework for operators in the exploration stage, we define that there are no royalties in these 8 years.

Exploitation:

Once the exploratory well is drilled and after the engineering study to confirm the volumes of hydrocarbons previously estimated, we move on to the declaration of commerciality of the field, which we estimate to be in March 2033 after 3 months of drilling and analysis of results.

- - The costs for platform assembly, road construction, seismic, EIA, primary tubulars, primary tanks among other actions that we will do in the virgin area, are charged to the exploratory well in both cases.
- For both cases we propose 2 directional confirmatory wells, which will not demand the same investment as the exploratory well since there will be better transportation logistics due to the development of the exploratory well.
- Finally, for both cases, the development wells will have a lower cost because the facilities will already be implemented at the time of drilling.

Based on the costs of a directional development well, we propose 3 injection wells in both cases, taking costs of water treatment, injection, injection pump, among others.

- For case 1, the drilling of directional wells will be the bet for the development of the field, where in each well will produce from both formations. See Table 112.

Case 1 - Vertical Wells			
Type	e/o (MMUSD)	Nº	Total (MMUSD)
Exploration	38.2	1	38.2
Confirmation	19.7	2	39.3
Development	14.2	16	226.6
Inyector	17.1	3	51.3
CAPEX case 1			**355**

Table 112. Summary of well implementation costs for case 1.

The estimated investment for the implementation of the proposed development plan for case 1 is around 355 million USD without counting the exploration stage, this value is charged to "month 0", which is in January 2030 and will serve as a starting point for calculating the NPV and IRR project indicators for case 1.

- For case 2, we consider that the drilling of horizontal wells will demand greater investment, due to the engineering of hole stability to achieve a horizontal length between 1500 to 1800 ft in the reservoirs.

The estimated investment for the implementation of the proposed development plan for case 2 is around 472 million USD without counting the exploration stage, this value is charged to "month 0", which is in January 2030 and will serve as a starting point for calculating the NPV and IRR project indicators for case 2. See Table 113.

Case 2 - Vertical and Horizontal Wells			
Type	e/o (MMUSD)	Nº	Total (MMUSD)
Exploration	38.2	1	38.2
Confirmation	19.7	2	39.3
Horizontal	40.8	6	244.5
Development	14.2	7	99.1
Inyector	17.1	3	51.3
CAPEX case 2			**472**

Table 113. Summary of well implementation costs for case 2.

- A cost of 100 MMUSD is assumed to cover the estimated costs of abandonment in each case.
- The estimated costs for the stimulation and the completion of the wells either by Gas Lift or Electro submersible Pumping system, are detailed in the cost sheets elaborated for each type of well.

Below is the detail of costs for each type of well budgeted. See Figure 143, Figure 144, Figure 145 and Figure 146.

	ESTIMATED DRILLING, COMPLETION AND PRODUCTION COSTS				
	Exploration Well				
	(US $)				
FIELD	**CAPAHUARI SUR EXT**				
BLOCK	**192**				
AVERAGE DEPTH	**11,500**			**Feet**	
AVERAGE TIME OF DRILLING AND COMPLETION	**45**			**Days**	
	WELL JUNGLE		**TOTAL EXPLORATION ONE WELL**		**Subtotals**
X.- EXPLORATION					2,070,000
AIR TRANSPORT	100,000	1	100,000		
FIELD GEOLOGY / MONTH	10,000	96	960,000		
ENVIRONMENTAL IMPACT ASSESSMENT	10,000	1	10,000		
SEISMICS AND PROCESSING	1,000,000	1	1,000,000		
A.- DRILLING					
INTANGIBLES					26,717,210
AIR TRANSPORT	800,000	1	800,000		
CAMP ARMING	10,000	1	10,000		
DRILL BITS	25,000	5	125,000		
ROAD GENERATION AND TRANSPORTATION	2,000,000	1	2,000,000		
PLATFORM AND ACCESSES	2,000,000	1	2,000,000		
DRILLING FLUID SERVICES	500,000	1	500,000		
DRILLING EQUIPMENT COSTS / DAY	120,000	45	5,400,000		
MOBILIZATION AND DEMOBILIZATION	100,000	1	100,000		
WIRELINE SERVICE	170,000	1	170,000		
CEMENTATION EQUIPMENT AND SERVICES	400,000	1	400,000		
SURFACE DRILLING FLUID SERVICES	800,000	1	800,000		
DIRECTIONAL / DAY DRILLING SERVICES	300,000	45	13,500,000		
OTHER INTANGIBLE EXPENSES	200,000	1	200,000		
TANGIBLES					
TRANSPORT	500,000	1	500,000		
SURFACE CASING	20,000	1	20,000		
INTERMEDIATE CASING	37,500	1	37,500		
PRODUCTION CASING	81,710	1	81,710		
Linner 5" y 7"	48,000	1	48,000		
HEAD	25,000	1	25,000		
OTHER TANGIBLE EXPENSES	-				
B.- COMPLETION					
INTANGIBLES					880,000
AIR TRANSPORT	100,000	1	100,000		
WATER TRANSP. Y CATERING	200,000	1	200,000		
COMPLETION FLUIDS	80,000	1	80,000		
CASED HOLE LOG CSG GUN	30,000	1	30,000		
PERFORATING CSG GUN STG	80,000	2	160,000		
WELL SERVICE RIG	100,000	1	100,000		
SUB. Y SURF. TOOLS	50,000	1	50,000		
PHYSICAL MEASUREMENTS AND ANALYSIS	20,000	1	20,000		
TRANSPORTATION AND INSPECTION	80,000	1	80,000		
OTHER INTANGIBLE EXPENSES	10,000	1	10,000		
TANGIBLES					
PRODUCTION PIPELINE	50,000	1	50,000		
C.- PRODUCTION					1,124,000
AIR TRANSPORT	100,000	1	100,000		
FLOW / INSTALLATION LINES	120,000	1	120,000		
PUMPING UNIT ESP	70,000	1	70,000		
ELECTRIC MOTOR	50,000	1	50,000		
ELECTRICAL SUPPLIES AND MATERIALS	15,000	1	15,000		
SISTEMA DE GAS LIFT	-				
SISTEM ESP	100,000	1	100,000		
TRANSPORTATION AND INSPECTION	14,000	1	14,000		
SURFACE FACILITIES AND WATER HANDLING	50,000	1	50,000		
SEPARATORS AND PRODUCTION MANAGEMENT	100,000	1	100,000		
STORAGE TANKS	500,000	1	500,000		
OTHERS	5,000	1	5,000		
D.- RESERVORIES AND GEOLOGY					2,601,000
PVT ANALYSIS	300,000	1	300,000		
CORES	2,000,000	1	2,000,000		
PHYSICAL AND RHEOLOGICAL ANALYSIS OF FLUIDS	1,000	3	3,000		
PLT AND PTA	200,000	1	200,000		
SPECIAL AND CONVENCIONAL LOGS	100,000	1	100,000		
E.- GENERAL AND UNINTENDED EXPENSES					
ADMINISTRATION (LIMA - FIELD) /MONTH	50,000	96	4,800,000		4,800,000
TOTAL (mmUS $)				Total well	**38.2**
UNIT COST				US$/ft	**3,321**

Figure 143. Estimated costs for an exploratory well.

	ESTIMATED DRILLING, COMPLETION AND PRODUCTION COSTS			
	Confirmation Well			
	(US $)			
FIELD	**CAPAHUARI SUR EXT**			
BLOCK	**192**			
AVERAGE DEPTH	**11,500**		**Feet**	
AVERAGE TIME OF DRILLING AND COMPLETION	**45**		**Days**	
	WELL JUNGLE		**TOTAL EXPLORATION 2 WELL**	**Subtotals**
X.- EXPLORATION				350,000
AIR TRANSPORT	100,000	1	100,000	
FIELD GEOLOGY / MONTH	50,000	5	250,000	
ENVIRONMENTAL IMPACT ASSESSMENT	-			
SEISMICS AND PROCESSING	-			
A.- DRILLING				
INTANGIBLES				28,175,626
AIR TRANSPORT	200,000	2	400,000	
CAMP ARMING	100,000	2	200,000	
DRILL BITS	29,110	10	291,095	
ROAD GENERATION AND TRANSPORTATION	1,000,000	2	2,000,000	
PLATFORM AND ACCESSES	1,200,000	2	2,400,000	
DRILLING FLUID SERVICES	300,000	2	600,000	
DRILLING EQUIPMENT COSTS / DAY	120,000	90	10,800,000	
MOBILIZATION AND DEMOBILIZATION	274,688	2	549,376	
WIRELINE SERVICE	240,000	2	480,000	
CEMENTATION EQUIPMENT AND SERVICES	366,365	2	732,730	
SURFACE DRILLING FLUID SERVICES	50,000	2	100,000	
DIRECTIONAL / DAY DRILLING SERVICES	100,000	90	9,000,000	
OTHER INTANGIBLE EXPENSES	-			
TANGIBLES				
TRANSPORT	100,000	2	200,000	
SURFACE CASING	19,003	2	38,006	
INTERMEDIATE CASING	37,500	2	75,000	
PRODUCTION CASING	81,710	2	163,420	
Linner 5" y 7"	48,000	2	96,000	
HEAD	25,000	2	50,000	
OTHER TANGIBLE EXPENSES	-			
B.- COMPLETION				
INTANGIBLES				1,675,000
AIR TRANSPORT	100,000	2	200,000	
WATER TRANSP. Y CATERING	200,000	2	400,000	
COMPLETION FLUIDS	80,000	2	160,000	
CASED HOLE LOG CSG GUN	30,000	2	60,000	
PERFORATING CSG GUN STG	80,000	3	240,000	
WELL SERVICE RIG	100,000	2	200,000	
SUB. Y SURF. TOOLS	50,000	2	100,000	
PHYSICAL MEASUREMENTS AND ANALYSIS	17,500	2	35,000	
TRANSPORTATION AND INSPECTION	80,000	2	160,000	
OTHER INTANGIBLE EXPENSES	10,000	2	20,000	
TANGIBLES				
PRODUCTION PIPELINE	50,000	2	100,000	
C.- PRODUCTION				1,700,000
AIR TRANSPORT	100,000	2	200,000	
FLOW / INSTALLATION LINES	120,000	2	240,000	
PUMPING UNIT ESP	70,000	1	70,000	
ELECTRIC MOTOR	50,000	2	100,000	
ELECTRICAL SUPPLIES AND MATERIALS	15,000	2	30,000	
SISTEMA DE GAS LIFT	30,000	1	30,000	
SISTEM ESP	100,000	1	100,000	
TRANSPORTATION AND INSPECTION	14,000	2	28,000	
SURFACE FACILITIES AND WATER HANDLING	50,000	2	100,000	
SEPARATORS AND PRODUCTION MANAGEMENT	100,000	2	200,000	
STORAGE TANKS	300,000	2	600,000	
OTHERS	2,000	1	2,000	
D.- RESERVORIES AND GEOLOGY				2,601,000
PVT ANALYSIS	300,000	2	600,000	
CORES	2,000,000	1	2,000,000	
PHYSICAL AND RHEOLOGICAL ANALYSIS OF FLUIDS	1,000	4	4,000	
PLT AND PTA	200,000	1	200,000	
SPECIAL AND CONVENCIONAL LOGS	100,000	2	200,000	
E.- GENERAL AND UNINTENDED EXPENSES				
ADMINISTRATION (LIMA - FIELD) /MONTH	50,000	96	4,800,000	4,800,000
TOTAL (mmUS $)			Confirmation Total	**39.3**
			Total Well	**19.7**
UNIT COST			US$/feet	**1,709**

Figure 144. Estimated costs for a confirmation well.

ESTIMATED DRILLING, COMPLETION AND PRODUCTION COSTS

Development Well
(US $)

FIELD	**CAPAHUARI SUR EXT**		
BLOCK	**192**		
AVERAGE DEPTH	**11,500**	**Feet**	
AVERAGE TIME OF DRILLING AND COMPLETION	**45**	**Days**	

	WELL JUNGLE		**TOTAL EXPLORATION 16 WELL**	**Subtotals**
X.- EXPLORATION				280,000
AIR TRANSPORT	100,000	1	100,000	
FIELD GEOLOGY / MONTH	5,000	36	180,000	
ENVIRONMENTAL IMPACT ASSESSMENT	-			
SEISMICS AND PROCESSING	-			
A.- DRILLING				
INTANGIBLES				56,131,063
AIR TRANSPORT	200,000	5	1,000,000	
CAMP ARMING	80,000	5	400,000	
DRILL BITS	25,000	25	625,000	
ROAD GENERATION AND TRANSPORTATION	-	2		
PLATFORM AND ACCESSES	-	2		
DRILLING FLUID SERVICES	300,000	16	4,800,000	
DRILLING EQUIPMENT COSTS / DAY	100,000	225	22,500,000	
MOBILIZATION AND DEMOBILIZATION	100,000	5	500,000	
WIRELINE SERVICE	100,000	5	500,000	
CEMENTATION EQUIPMENT AND SERVICES	300,000	5	1,500,000	
SURFACE DRILLING FLUID SERVICES	50,000	5	250,000	
DIRECTIONAL / DAY DRILLING SERVICES	100,000	225	22,500,000	
OTHER INTANGIBLE EXPENSES	-			
TANGIBLES				
TRANSPORT	100,000	5	500,000	
SURFACE CASING	19,003	5	95,014	
INTERMEDIATE CASING	37,500	5	187,500	
PRODUCTION CASING	81,710	5	408,549	
Linner 5" y 7"	48,000	5	240,000	
HEAD	25,000	5	125,000	
OTHER TANGIBLE EXPENSES	-			
B.- COMPLETION				
INTANGIBLES				3,987,500
AIR TRANSPORT	100,000	5	500,000	
WATER TRANSP. Y CATERING	200,000	5	1,000,000	
COMPLETION FLUIDS	80,000	5	400,000	
CASED HOLE LOG CSG GUN	30,000	5	150,000	
PERFORATING CSG GUN STG	80,000	5	400,000	
WELL SERVICE RIG	100,000	5	500,000	
SUB. Y SURF. TOOLS	50,000	5	250,000	
PHYSICAL MEASUREMENTS AND ANALYSIS	17,500	5	87,500	
TRANSPORTATION AND INSPECTION	80,000	5	400,000	
OTHER INTANGIBLE EXPENSES	10,000	5	50,000	
TANGIBLES				
PRODUCTION PIPELINE	50,000	5	250,000	
C.- PRODUCTION				3,005,000
AIR TRANSPORT	100,000	5	500,000	
FLOW / INSTALLATION LINES	120,000	5	600,000	
PUMPING UNIT ESP	70,000	5	350,000	
ELECTRIC MOTOR	50,000	5	250,000	
ELECTRICAL SUPPLIES AND MATERIALS	15,000	5	75,000	
SISTEMA DE GAS LIFT	30,000	5	150,000	
SISTEM ESP	100,000	5	500,000	
TRANSPORTATION AND INSPECTION	14,000	5	70,000	
SURFACE FACILITIES AND WATER HANDLING	50,000	5	250,000	
SEPARATORS AND PRODUCTION MANAGEMENT	50,000	5	250,000	
STORAGE TANKS				
OTHERS	2,000	5	10,000	
D.- RESERVORIES AND GEOLOGY				2,600,600
PVT ANALYSIS	300,000	1	300,000	
CORES	2,000,000	2	4,000,000	
PHYSICAL AND RHEOLOGICAL ANALYSIS OF FLUIDS	600	10	6,000	
PLT AND PTA	200,000	3	600,000	
SPECIAL AND CONVENCIONAL LOGS	100,000	5	500,000	
E.- GENERAL AND UNINTENDED EXPENSES				
ADMINISTRATION (LIMA - FIELD) /MONTH	50,000	96	4,800,000	4,800,000
TOTAL (mmUS $)			Development Total	**70.8**
			Total Well	**14.2**
Unit Cost			US$/Feet	**1,231**

Figure 145. Estimated costs for a development well.

	ESTIMATED DRILLING, COMPLETION AND PRODUCTION COSTS					
		Inyector Well				
		(US $)				
FIELD		**CAPAHUARI SUR EXT**				
BLOCK		**192**				
AVERAGE DEPTH		**11,500**			**Feet**	
AVERAGE TIME OF DRILLING AND COMPLETION		**45**			**Days**	
		WELL JUNGLE		**TOTAL EXPLORATION 3 WELL**		**Subtotals**
X.-	**EXPLORATION**					160,000
	AIR TRANSPORT	100,000	1	100,000		
	FIELD GEOLOGY / MONTH	5,000	12	60,000		
	ENVIRONMENTAL IMPACT ASSESSMENT	-				
	SEISMICS AND PROCESSING	-				
A.-	**DRILLING**					
	INTANGIBLES					28,550,281
	AIR TRANSPORT	80,000	3	240,000		
	CAMP ARMING	10,000	3	30,000		
	DRILL BITS	29,110	15	436,643		
	ROAD GENERATION AND TRANSPORTATION	-				
	PLATFORM AND ACCESSES	-				
	DRILLING FLUID SERVICES	300,000	3	900,000		
	DRILLING EQUIPMENT COSTS / DAY	100,000	135	13,500,000		
	MOBILIZATION AND DEMOBILIZATION	100,000	3	300,000		
	WIRELINE SERVICE	100,000	3	300,000		
	CEMENTATION EQUIPMENT AND SERVICES	320,000	3	960,000		
	SURFACE DRILLING FLUID SERVICES	50,000	3	150,000		
	DIRECTIONAL / DAY DRILLING SERVICES	80,000	135	10,800,000		
	OTHER INTANGIBLE EXPENSES	-				
	TANGIBLES					
	TRANSPORT	100,000	3	300,000		
	SURFACE CASING	19,003	3	57,008		
	INTERMEDIATE CASING	37,500	3	112,500		
	PRODUCTION CASING	81,710	3	245,130		
	Linner 5" y 7"	48,000	3	144,000		
	HEAD	25,000	3	75,000		
	OTHER TANGIBLE EXPENSES	-				
B.-	**COMPLETION**					
	INTANGIBLES					2,700,000
	AIR TRANSPORT	100,000	3	300,000		
	WATER TRANSP. Y CATERING	200,000	3	600,000		
	COMPLETION FLUIDS	80,000	3	240,000		
	CASED HOLE LOG CSG GUN	30,000	3	90,000		
	PERFORATING CSG GUN STG	200,000	3	600,000		
	WELL SERVICE RIG	100,000	3	300,000		
	SUB. Y SURF. TOOLS	50,000	3	150,000		
	PHYSICAL MEASUREMENTS AND ANALYSIS	-				
	TRANSPORTATION AND INSPECTION	80,000	3	240,000		
	OTHER INTANGIBLE EXPENSES	10,000	3	30,000		
	TANGIBLES					
	PRODUCTION PIPELINE	50,000	3	150,000		
C.-	**PRODUCTION**					1,527,000
	AIR TRANSPORT	100,000	3	300,000		
	FLOW / INSTALLATION LINES	120,000	3	360,000		
	PUMPING UNIT ESP	100,000	3	300,000		
	ELECTRIC MOTOR	15,000	3	45,000		
	ELECTRICAL SUPPLIES AND MATERIALS	14,000	3	42,000		
	SISTEMA DE GAS LIFT	80,000	3	240,000		
	SISTEM ESP	-	3			
	TRANSPORTATION AND INSPECTION	80,000	3	240,000		
	SURFACE FACILITIES AND WATER HANDLING	-	3			
	SEPARATORS AND PRODUCTION MANAGEMENT					
D.-	STORAGE TANKS					51,000
	OTHERS	-	1			
		-	2			
	RESERVORIES AND GEOLOGY	1,000	32	32,000		
	PVT ANALYSIS	-	3			
	CORES	50,000	16	800,000		
	PHYSICAL AND RHEOLOGICAL ANALYSIS OF FLUIDS					
E.-	PLT AND PTA					
	SPECIAL AND CONVENCIONAL LOGS	50,000	24	1,200,000		1,200,000
	GENERAL AND UNINTENDED EXPENSES				Total Inyectors	**34.2**
	ADMINISTRATION (LIMA - FIELD) /MONTH				Total Wells	**17.1**
	UNIT COST				US$/feet	**1,486**

Figure 146. Estimated costs for an Injector well.

10.1.1 Oil Production Forecast

For case 1, the forecast of the fluids produced from Vivian and Chonta through 19 wells and considering the simulation model as input field characterization is as follows: (See Figure 147)

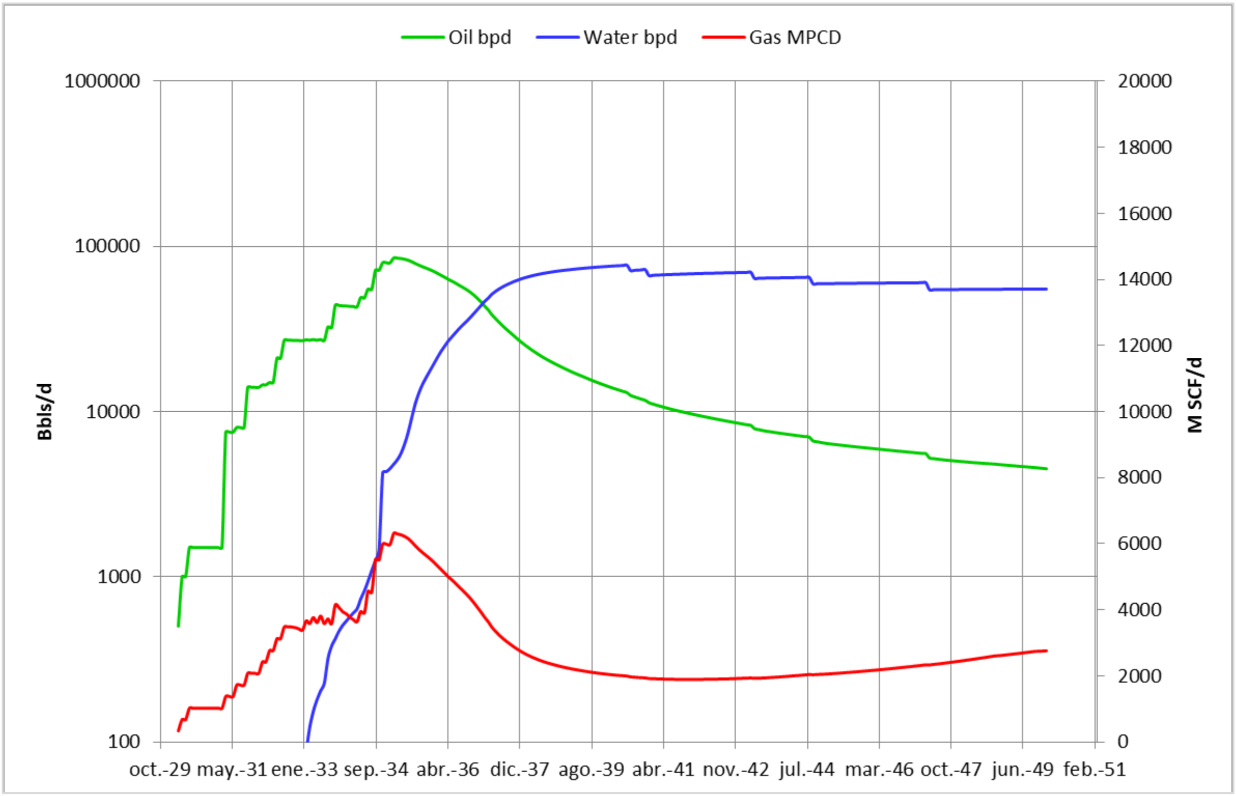

Figure 147. Production of the Capahuari Sur Extensión field, scenario 1.

For case 2, the forecast of the fluids produced from Vivian and Chonta through 16 wells and considering the simulation model as input field characterization is in the Figure 148.

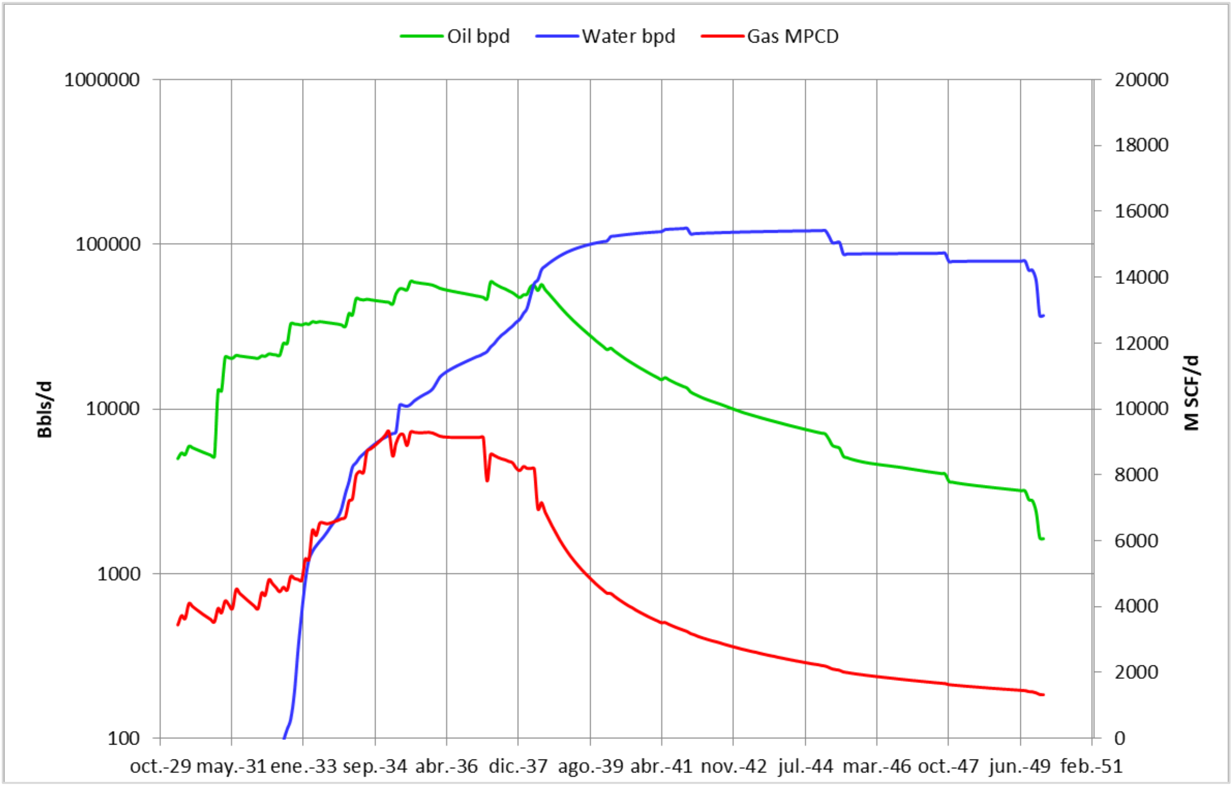

Figure 148. Production of the Capahuari Sur Extensión field, scenario 2.

10.1.2 Crude Oil Price Estimation

The forecast behavior of the price represents different challenges at the time of making a cash flow, since this commodity depends largely on the current global situation, so estimate a behavior at 20 years would be unsustainable, which is why for this economic study we assumed a flat value of 50 USD per barrel of crude oil, based on the basket imposed by Perupetro to block 192. See Figure 149.

REPORTE DE CANASTA ANUAL 2020
ZONA GEOGRAFICA : TODOS ---- TIPO HIDROCARBURO : TODOS

		Ene-20	Feb-20	Mar-20
CANASTA 131	CANASTA	62.8767	55.1481	31.5011
	AGBAMI	62.0007	54.2275	31.1236
	AKPO	61.9393	54.2225	31.1236
	SAHARAN BLEND	64.6902	56.9943	32.2561
CANASTA 192	CANASTA	56.5045	48.2808	27.4770
	LORETO	56.6283	48.4392	27.2568
	MAGDALENA	52.2748	43.4516	23.1632
	MARLIM	60.6105	52.9516	32.0109

Figure 149. Annual basket 2020 of Block 192 (source: Perupetro).

10.1.3 Income Estimates

Revenues are estimated through the real production of the barrels produced, multiplied by the assumed crude oil basket price.

10.1.4 Investment Estimation or CAPEX

Cost information is collected for the activities of Exploration, Drilling and completion of wells in the forest, also estimated cost for the implementation of production facilities and artificial lift, finally estimated costs of testing and testing to better characterize the reservoir and geology.

10.1.5 Cost Estimation or OPEX

We elaborated the following table estimating the monthly costs that would demand the maintenance of the Capahuari Sur Extensión Field in both cases during all its productive life, around 11 MM USD per month or 132 MM USD per year. See Figure 150.

Monthly Expenses	
MAT: MATERIALS AND SUPPLIES	800,000
MTO: MAINTENANCE OF WELLS AND FACILITIES	2,200,000
ST: LABOR, PERSONNEL AND FIELD WORK	1,000,000
ST: ADMINISTRATION AND ENGINEERING LIMA-LORETO	1,000,000
MOD-SERV: SERVICES	1,100,000
SECURITY/SURVEILLANCE	100,000
ENVIRONMENTAL MANAGEMENT PLAN	700,000
SOCIAL MANAGEMENT PLAN	300,000
GGD: DIRECT OVERHEADS	500,000
OTHER EXPENSES: INSURANCE POLICY	50,000
USD	**7,750,000**

Figure 150. Estimate of monthly maintenance costs of the field.

Due the fact that our reservoirs will produce a large amount of water, Peruvian regulations require us to treat and re-inject it, since we are talking about volumes greater than a million barrels of water per day in most of the productive life of the field. There is no industry for the refining of crude oil and no market in the Peruvian jungle, the hydrocarbons produced by the North Peruvian Pipeline (NPP) must be transferred, we estimate the NPP's rate ensuring a constant transport activity. See Table 114.

Transportation and Handling Costs		
Transportation cost	7	USD/bbl
Water treatment	1	USD/bbl

Table 114. Treatment and transportation costs.

10.1.6 Royalty Estimation

Based on Article 3 of the D.S N° 017-2003-EM, for productions between 5 and 100 Mbopd, the percentage of royalties varies between 5 and 20%, and for values higher than 100 Mbopd 20% is required; due to the development of this field and offset fields, we estimate that the production of the field must be around 100 Mbopd in the future, that is why we take the value of 20% for the calculation of royalties. See Figure 151.

Artículo 3°.- Los niveles de Producción Fiscalizada y los porcentajes para determinar la Regalía, según la Metodología por Escalas de Producción para Hidrocarburos Líquidos, son los siguientes:

Niveles de Producción Fiscalizada del Lote MBPDC	Regalía en Porcentaje %
< 5	5
5 – 100	5 – 20
> 100	20

Para el rango de Producción Fiscalizada entre 5 y 100 mil barriles por día calendario (MBPDC), a 5 MBPDC le corresponde 5% de Regalía, para las producciones intermedias se aplica la interpolación.

Artículo 4°.- Para la determinación de la Regalía, aplicando la metodología por Resultado Económico – RRE, para la Producción Fiscalizada de Hidrocarburos, se establecen los parámetros siguientes:

- **La Regalía Fija** es igual a 5%.
- **El Factor "R" Base** es igual a 1.15.
- La Regalía Variable se aplica a partir que el Factor "R $_{t-1}$" alcanza un valor de 1.15.
- La Regalía Variable se aplica en el rango de :

0 < Regalía Variable < 20%

Figure 151. Article 3 of the D.S N° 017-2003-EM.

10.1.7 Estimating the Discount Rate

There are economic models that allow establishing the discount rate that companies should adopt. One of the most recognized is the financial asset balance model also known as Capital Asset Pricing Model or CAPM, which is a model that fits the concept of Country Risk and complemented by the calculation of the Weighted Cost of Capital or WACC (Moix Muntó, 2014). See Equation 69.

$$WAAC = i \cdot (1 - ISLR) \cdot D + R_E \cdot E \qquad \text{E. 3. 3}$$

WAAC: Costo Ponderado de Capital

i: Tasa de Interés de la Deuda

ISLR: Tasa nominal del Impuesto sobre la Renta

D: Porcentaje de la deuda que compone el capital de la empresa.

E: Porcentaje de Patrimonio que compone el capital de la empresa.

Equation 69. Discount rate calculation, WAAC model.

According to this previous methodology, we can assume a discount rate for oil development projects, usually a discount rate between 10 and 12% is imposed and for oil exploration projects, a discount rate between 15 and 20% is estimated; we consider for this study, the classification of exploratory project and the value of 20%.

10.1.8 Depreciation, Amortization and Income Tax

The implementation of income taxes will depend on Peruvian regulations for oil projects in the jungle, it is estimated a tax value of 30% considering the participation of work, regarding the amortization, this value will enter the cash flow from the first month of the project, which will be a fraction of the amount of investment CAPEX during the 240 months of project development.

The summary of the economic considerations for both cases described is presented in the Table 115 and Table 116.

EVALUATION PARAMETERS	
- OIL PRICE US$/bl	50.0
- "R" FACTOR	1.15
- ROYALTIES %	20.0%
- TAX RATE	30.0%
- DISCOUNT RATE	20.0%
- RESERVES (M Bbl)	149
- OPEX MUS$/AÑO	103
- INVESTMENT Total (M US$)	495

Table 115. Summary of economic considerations, case 1.

EVALUATION PARAMETERS	
- OIL PRICE US$/bl	50.0
- "R" FACTOR	1.15
- ROYALTIES %	20.0%
- TAX RATE	30.0%
- DISCOUNT RATE	20.0%
- RESERVES (M Bbl)	163
- OPEX MUS$/AÑO	103
- INVESTMENT Total (M US$)	690

Table 116. Summary of economic considerations, case 2.

10.2 Cash Flow

The result of the cash flow for case 1 with the economic considerations already described, is presented in the Figure 152.

ECONOMIC EVALUATION CASE 1

21 wells Field Capahuari Sur Extensión - Block 192 : Fm. Vivian // Chonta

EVALUATION PARAMETERS	
- OIL PRICE US$/bl	50.0
- "R" FACTOR	1.15
- ROYALTIES %	20.0%
- TAX RATE	30.0%
- DISCOUNT RATE	20.0%
- RESERVES (M Bbl)	149
- OPEX MUS$/AÑO	103
- INVESTMENT Total (M US$)	495

YEAR	Total (mmUS$)
2023-2029	42.0
2030	122.1
2031	91.7
2032	59.6
2033	85.0
2034	105.0
2035	14.2
2036	0.0
	519.42

CASE 1 RESULT	
NPV (20%) MMUS$ =	**270**
IRR =	**38.2%**
PAY OUT (Months)	**73**
ROI =	**0.520**

Year	PRODUCTION (M Bbl) MM Bbl	PRODUCTION VALUE		OPEX	AMORTIZATION	INCOME BEFORE TAX		TAX	INCOME AFTER TAX	INVERSION		CASH FLOW	CURRENT CASH FLOW	ACCUMULATED CASH FLOW
2023-2029										42.0		-42.00	-42.00	-42.00
2030	0.447	17.9		117.4	11.57	-111.10		0.00	-111.10	122.1		-221.61	-184.67	-226.67
2031	2.826	113.06		150	14.70	-51.38		0.00	-51.38	91.7		-128.33	-89.12	-315.79
2032	7.595	303.81		167	19.42	117.75		35.33	82.43	59.6		42.27	24.46	-291.33
2033	11.738	469.51		189	25.60	255.00		76.50	178.50	85.0		119.13	57.45	-233.88
2034	20.792	831.70		216	26.48	589.07		176.72	412.35	105.0		333.84	134.16	-99.71
2035	29.135	1,165.40		245	26.48	893.56		268.07	625.49	14.2		637.81	213.60	113.89
2036	22.158	886.32		244	26.48	616.33		184.90	431.43	0.0		457.92	127.80	241.69
2037	13.341	533.65		246	26.48	260.91		78.27	182.64			209.12	48.64	290.32
2038	8.011	320.45		255	26.48	38.61		11.58	27.03			53.51	10.37	300.69
2039	5.891	235.66		218	26.48	-8.78		0.00	-8.78			17.70	2.86	303.55
2040	4.653	186.11		197	26.48	-36.98		0.00	-36.98			-10.50	-1.41	302.14
2041	3.763	150.52		186	26.48	-61.63		0.00	-61.63			-35.14	-3.94	298.20
2042	3.286	131.45		175	26.48	-69.86		0.00	-69.86			-43.38	-4.05	294.14
2043	2.864	114.56		170	26.48	-82.18		0.00	-82.18			-55.70	-4.34	289.80
2044	2.536	101.42		167	26.48	-92.33		0.00	-92.33			-65.84	-4.27	285.53
2045	2.259	90.35		153	26.48	-88.86		0.00	-88.86			-62.37	-3.37	282.16
2046	2.120	84.81		147	26.48	-88.94		0.00	-88.94			-62.46	-2.82	279.34
2047	1.923	76.91		146	26.48	-95.23		0.00	-95.23			-68.75	-2.58	276.76
2048	1.780	71.19		141	26.48	-96.49		0.00	-96.49			-70.01	-2.19	274.57
2049	1.696	67.84		139	26.48	-97.72		0.00	-97.72	100.0		-171.24	-4.47	270.10
	148.8	**5,952.6**	**#**	**3,667.8**	**495.0**	**1,789.8**	**0.0**	**831.4**	**958.4**	**619.4**	**0.0**	**834.0**	**270.1**	

Figure 152. Cash flow, case 1.

The result of the cash flow for case 2 with the economic considerations already described, is presented in the Figure 153.

ECONOMIC EVALUATION CASE 2

19 wells Field Capahuari Sur Extensión - Block 192 : Fm. Vivian // Chonta

EVALUATION PARAMETERS	
- OIL PRICE US$/bl	50.0
- "R" FACTOR	1.15
- ROYALTIES %	20.0%
- TAX RATE	30.0%
- DISCOUNT RATE	20.0%
- RESERVES (M Bbl)	163
- OPEX MUS$/AÑO	103
- INVESTMENT Total (M US$)	690

YEARS	Total (mmUS$)
2023-2029	42.0
2030	161.4
2031	122.3
2032	100.3
2033	69.1
2034	160.5
2035	17.1
2036	17.1
	689.68

CASE 2 RESULT		
NPV (20%) MMUS$	=	314
IRR	=	41.2%
PAY OUT (Months)		73
ROI	=	0.455

Year	PRODUCTION (M Bbl) MM Bbl	PRODUCTION VALUE		OPEX	AMORTIZATION	INCOME BEFORE TAX		TAX	INCOME AFTER TAX	INVERSION		CASH FLOW	CURRENT CASH FLOW	ACCUMULATED CASH FLOW
2023-2029										42.0		-42.00	-42.00	-42.00
2030	1.993	79.7		117.4	10.17	-47.84		0.00	-47.84	161.4		-199.05	-165.87	-207.87
2031	6.612	264.47		150	16.60	98.14		29.44	68.70	122.3		-36.96	-25.67	-233.54
2032	9.023	360.91		167	22.18	172.09		51.63	120.46	100.3		42.31	24.49	-209.06
2033	12.127	485.09		189	26.24	269.93		80.98	188.95	69.1		146.11	70.46	-138.59
2034	15.823	632.90		216	36.27	380.50		114.15	266.35	160.5		142.16	57.13	-81.46
2035	19.735	789.39		245	37.41	506.63		151.99	354.64	17.1		374.95	125.57	44.11
2036	19.097	763.87		244	38.63	481.74		144.52	337.22	17.1		358.76	100.12	144.23
2037	19.025	761.00		246	38.63	476.12		142.84	333.28			371.91	86.50	230.73
2038	18.424	736.98		255	38.63	442.99		132.90	310.10			348.73	67.59	298.31
2039	11.276	451.05		218	38.63	194.47		58.34	136.13			174.76	28.22	326.54
2040	7.320	292.82		197	38.63	57.58		17.27	40.31			78.94	10.62	337.16
2041	5.359	214.35		186	38.63	-9.94		0.00	-9.94			28.69	3.22	340.38
2042	4.036	161.45		175	38.63	-52.01		0.00	-52.01			-13.38	-1.25	339.13
2043	3.280	131.20		170	38.63	-77.69		0.00	-77.69			-39.06	-3.04	336.09
2044	2.787	111.46		167	38.63	-94.43		0.00	-94.43			-55.80	-3.62	332.46
2045	1.999	79.97		153	38.63	-111.39		0.00	-111.39			-72.76	-3.94	328.53
2046	1.650	65.98		147	38.63	-119.91		0.00	-119.91			-81.28	-3.66	324.86
2047	1.486	59.45		146	38.63	-124.84		0.00	-124.84			-86.21	-3.24	321.63
2048	1.252	50.08		141	38.63	-129.75		0.00	-129.75			-91.12	-2.85	318.77
2049	1.123	44.91		139	38.63	-132.80		0.00	-132.80	100.0		-194.17	-5.06	313.71
	163.4	**6,537.1**	**#**	**3,667.8**	**689.7**	**2,179.6**	**0.0**	**924.1**	**1,255.5**	**789.7**	**0.0**	**1,155.5**	**313.7**	

Figure 153. Cash flow, case 2.

10.3 Economic Evaluation (NPV, IRR, Pay Out, ROI)

Graphing accumulated NPV vs time, we see how the cash flow varies, from a period of only expenditure to the point at which the project begins to generate profits, and how this accumulated profit begins to decrease at the end of life by the concept of maintenance of the field for both cases. See Figure 154 and Figure 155.

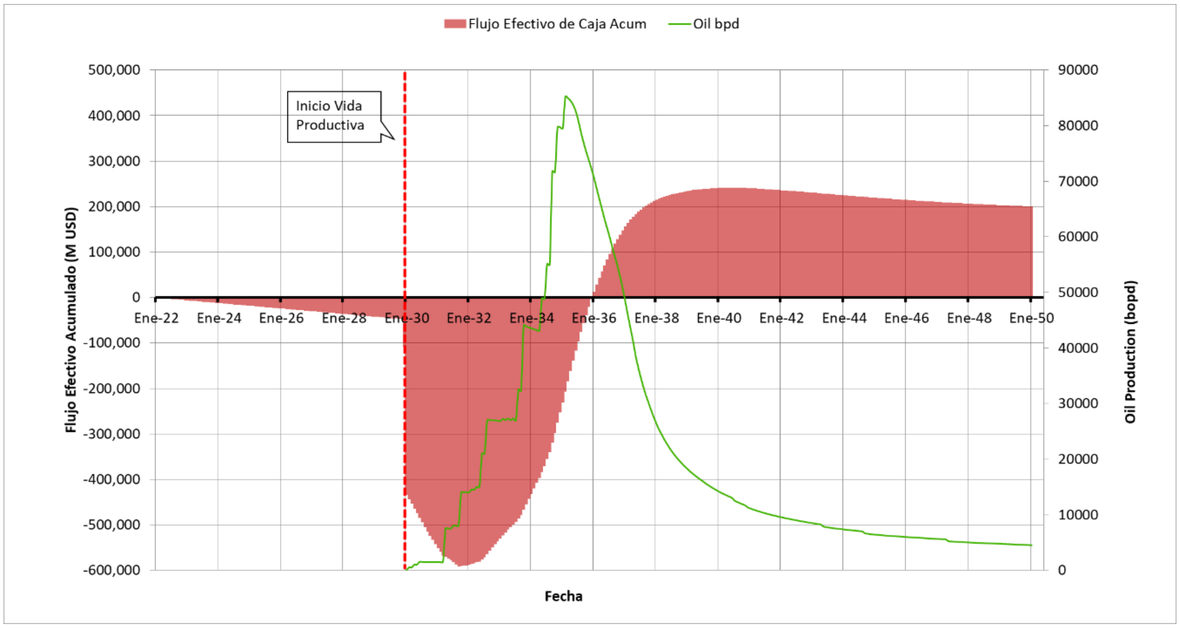

Figure 154. Accumulated cash flow, case 1.

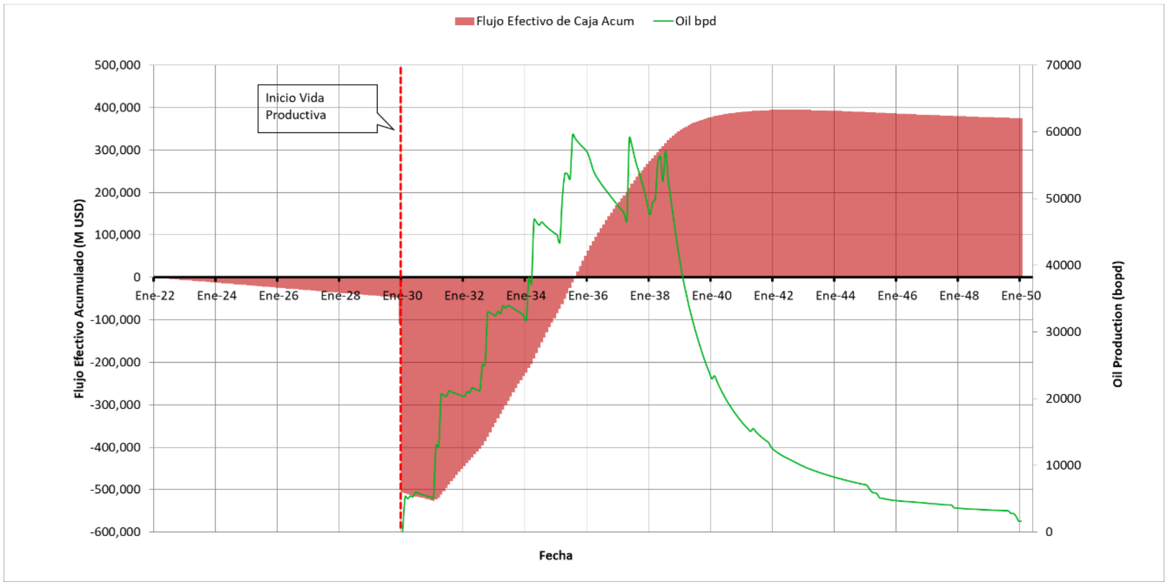

Figure 155. Accumulated cash flow, case 2.

The result for case 1, at the given economic conditions is presented in the Table 117.

CASE 1 RESULT	
NPV (20%) MMUS$ =	270
IRR =	38.2%
PAY OUT (Months)	73
ROI =	0.520

Table 117. Economic evaluation results, case 1.

The result for case 2, at the given economic conditions is presented in the Table 118.

CASE 2 RESULT	
NPV (20%) MMUS$ =	314
IRR =	41.2%
PAY OUT (Months)	73
ROI =	0.455

Table 118. Economic evaluation results, case 2.

Comparing each economic indicator in both cases, case two (viability of horizontal and directional wells), resulted more profitable for each indicator; although case 2 demands a greater investment than case 1, it recovers more oil over the 20 years, which makes it our best case.

10.4 Sensitivity and Risk Analysis

To verify the sensitivity of our results, we compared the project's NPV and IRR indicators for a basket price range between 35 and 65 USD/bbl.

For case 1 it is important to highlight that for a basket value of 40 USD/bbl, the project is unattractive, however, the expectation that the price fluctuates for values greater than 45 USD/bbl would maintain a NPV not only positive, but economically viable so that we maintain viability throughout the project. See Table 119, Figure 156 and Figure 157.

PRICE US$/bbl	PAY OUT MONTHS	NPV (MM US$)	IRR (%)
35.00	252	-123	
40.00	85	9	21%
45.00	73	142	31%
50.00	73	273	38%
55.00	72	403	45%
60.00	61	533	51%
65.00	61	662	56%

Table 119. Screening of NPV and PULL values at different basket prices for scenario 1.

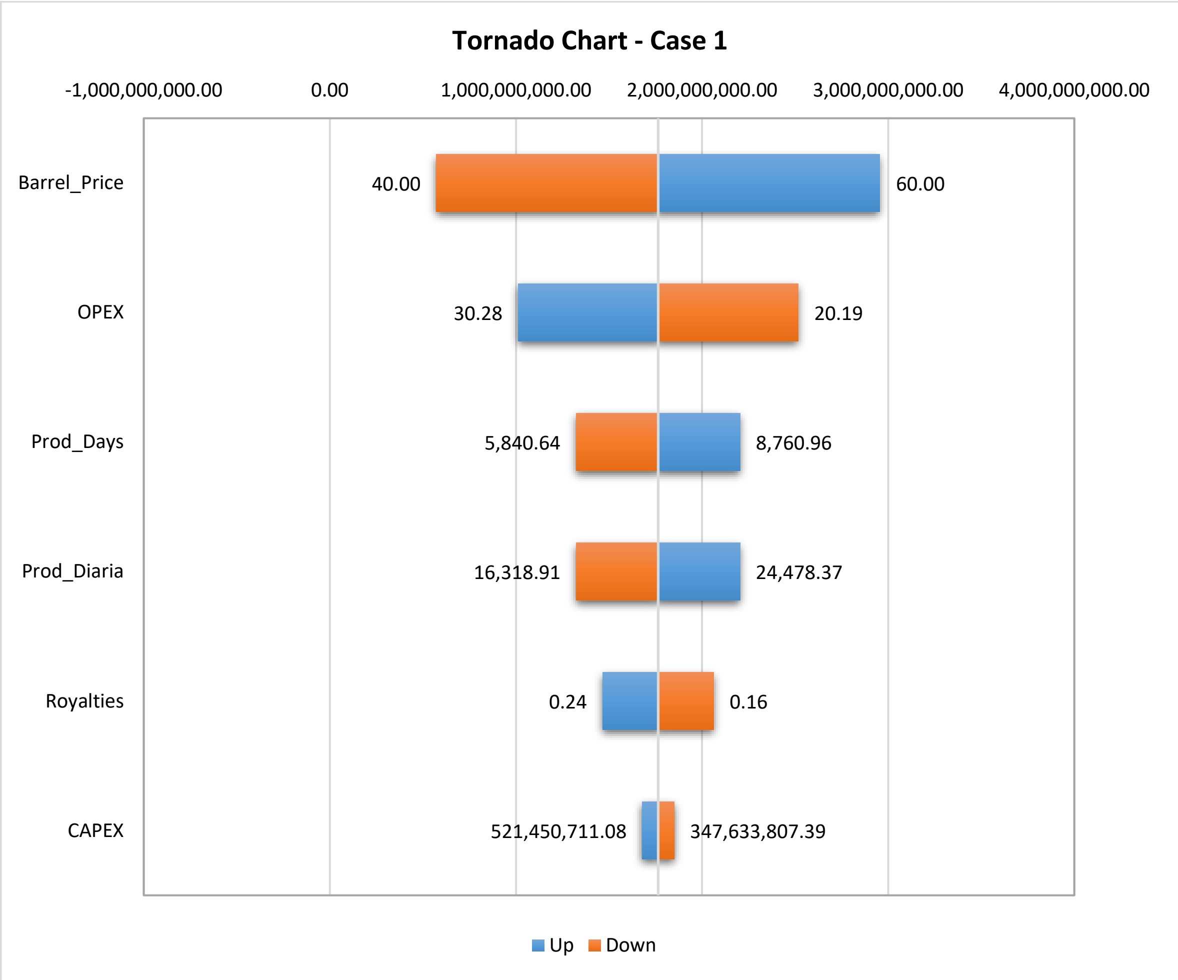

Figure 156. Tornado chart, case 1.

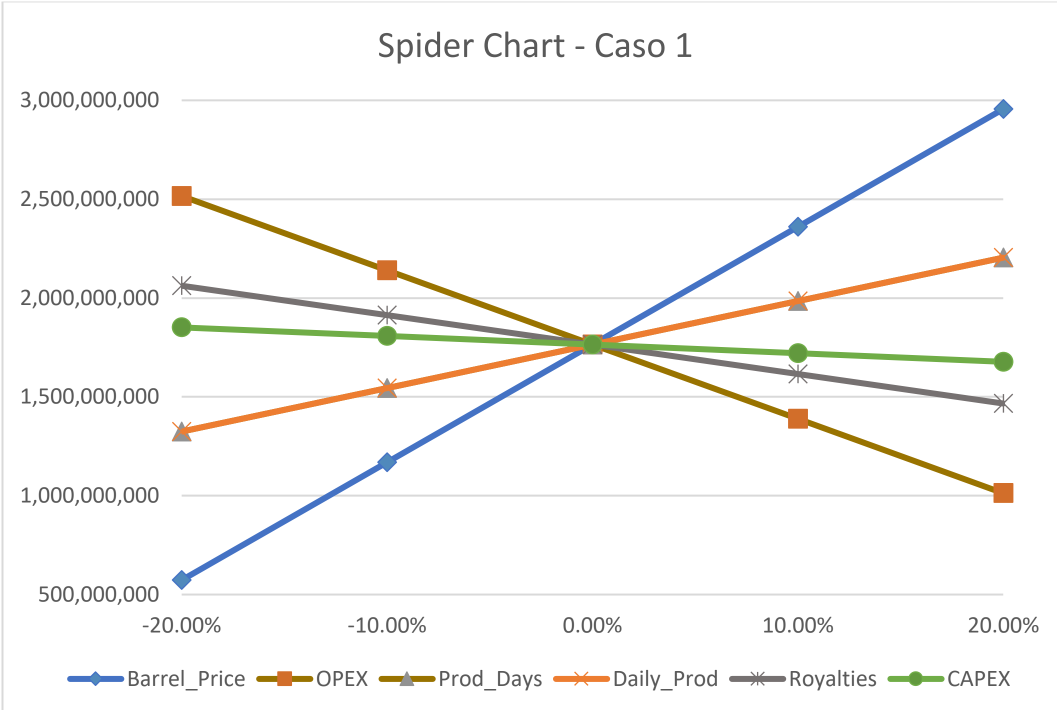

Figure 157. Spider chart, case 1.

For case 2 it is important to emphasize that for a basket value of 35 USD/bbl, the project becomes unprofitable, so we must bet on values greater than 40 USD/bbl, which would be the initial scenario to maintain the viability of the project. See Table 120, Figure 158 and Figure 159.

PRICE US$/bbl	PAY OUT MONTHS	NPV (MM US$)	IRR (%)
35.00	252	-101	
40.00	97	39	23%
45.00	85	177	33%
50.00	73	316	41%
55.00	72	455	49%
60.00	61	593	57%
65.00	49	731	65%

Table 120. Screening of NPV and PULL values at different basket prices for scenario 2.

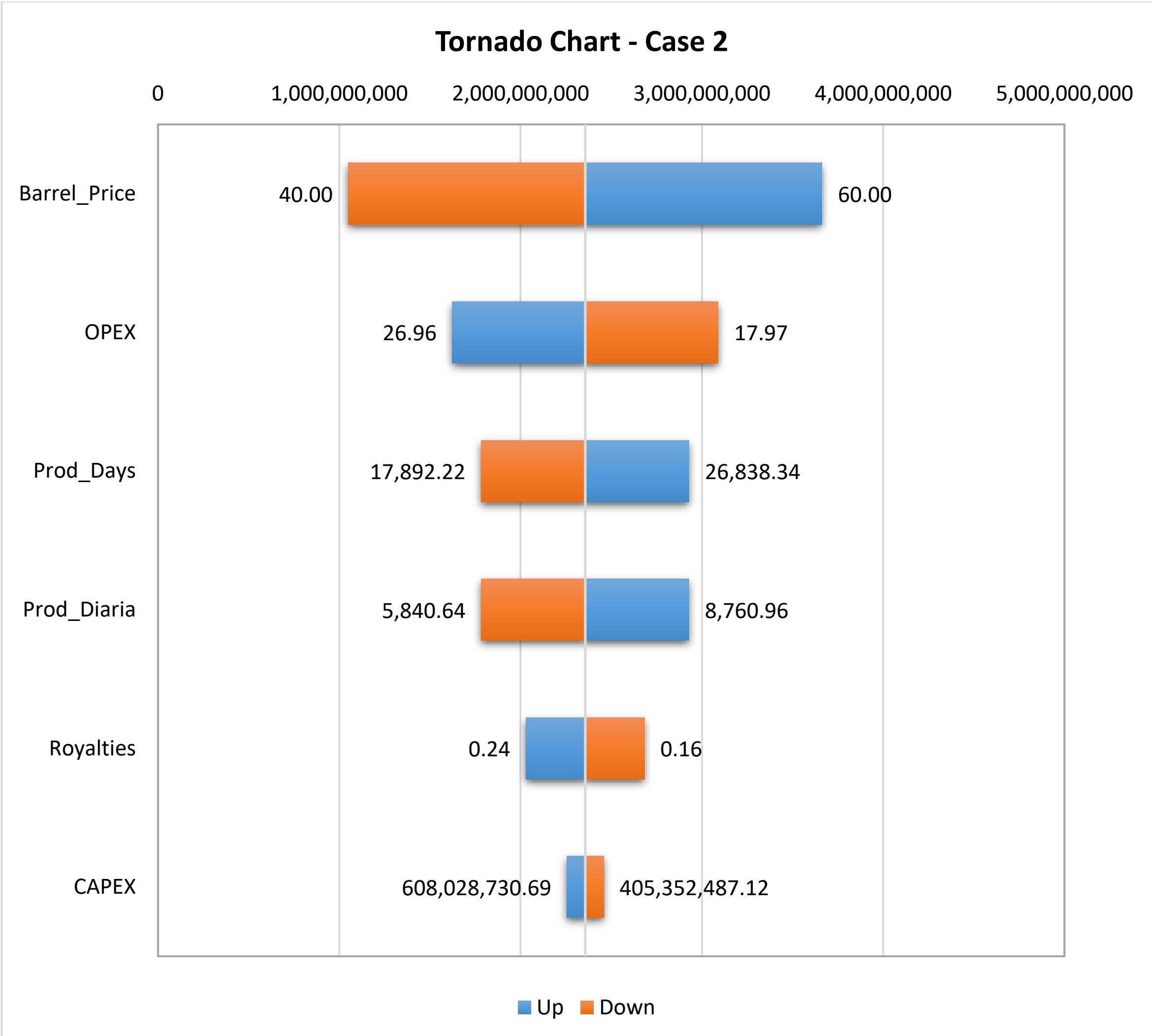

Figure 158. Tornado graph, case 2.

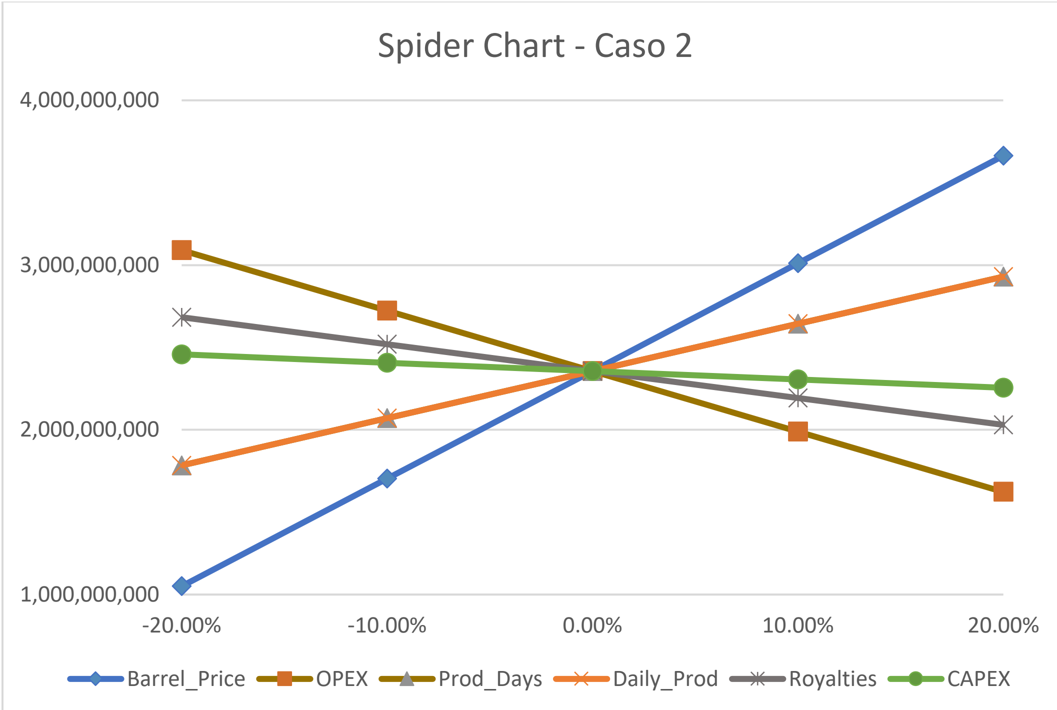

Figure 159. Spider chart, case 2.

11. CONCLUSIONS

The conclusions of this project are as follows:

- The integral analysis of the exploration and exploitation of the field Capahuari Sur Extensión showed it is feasible to carry out this project in a sustainable way in the time and profitable, considering certain uncertainties, integrating the technical, economic, social and environmental variables.
- The reservoirs to be developed present different production mechanisms, Vivian reservoir presents Waterdrive and Chonta reservoir presents solution Gasdrive.
- The aquifer of the Vivian reservoir behaves as a bottom aquifer in the central wells of the structure and as a flanking aquifer in the wells on the edges, this was seen by the analysis of the Chan curves in the Capahuari Sur field.
- The PVT analysis for this field was done through correlation of reservoir engineering literature and adjusted based on representative fluid values from the Capahuari Sur and Capahuari Norte fields.
- Vivian formation declining model was done through production analysis of 9 wells in the Capahuari Sur field in the same drilling campaign, resulting in a factor b equal to 0.39 and a monthly decline Di of 0.029.
- Chonta formation declining model was done through production analysis of 6 wells in the Capahuari Sur field in the same drilling campaign, resulting in a factor b equal to 0.41 and a monthly decline Di of 0.036.
- Theoretical recovery factor of Vivian reservoir using Guthrie correlation is 59.3%; and Chonta reservoir using API correlation is 29.3%.

- Based on the recoverable volumes, 1P reserves of 170.15 MMbls of crude are estimated for the Vivian reservoir, and 1P reserves of 16.97 MMbls of crude for the Chonta reservoir; volumes that are intended to be recovered through the proposed development plans.
- The second simulation scenario (directional and horizontal wells) gives us a higher recovery factor, and the results of hydrocarbon volumes present a conservative forecast (1P), so that we have at least a 90% probability of producing.
- Drilling Schedule has been divided into 3 drilling campaigns, with a total of 16 producing wells and 3 injection wells, in 3 platforms.
- As a result of the drilling program, it has been seen that the approximate time for the drilling of a well is 48 days, only drilling operation, under an optimal scenario without complications in the well, for cases with drilling problems it is estimated a duration of 60 to 80 days.
- Two Perforating systems were determined to be used in the two reservoirs of the Capahuari Sur Extensión Field. For the Vivian reservoir, the Conventional Wireline technique will be used, while for the Chonta reservoir, the TCP Under-Balance.
- Due to the excessive water production in the CSE field (Vivian) and evaluating the mechanisms that produce it, we chose especially consider 2 technologies for its control; first we applied polymer gels as relative permeability reducers and as a second control we considered the use of mechanical and cement plugs, these measures were taken to increase the production of hydrocarbons and prolong the life of the reservoir.
- The Chonta reservoir is characterized by its low water cut and high GOR, in addition, the drive mechanism of this reservoir is by solution Gasdrive.

Due to these characteristics, the most suitable artificial lifting system to produce this reservoir is Continuous Gas Lift.

- Due to the high depths and large flows that Vivian formation presents, it is chosen as an artificial lift system using electro-submersible pumping. This method is feasible to use in deviated wells and is easy to operate from the surface.
- Making an optimal ESP design, it is concluded that the average life of the ESP will be 4 years.
- The design of the surface collection system was carried out, in which the optimal diameters of the flow lines for the collection of fluids were determined, as well as the necessary pressure at the wellhead to reach its respective production battery.
- Due to the location of our wells and the large volumes of fluid estimated to be produced, we considered building 3 production batteries, as well as the equipment and components to be installed in each of them.
- The treatment of crude oil is very important since, if it does not comply with the quality characteristics specified in the contract, it could generate a claim by Petroperu that implies an economic sanction during the inspection process.
- In the water treatment tank, the solids and minerals still remaining in the water are removed until the remaining amount is suitable to be sent to the injection wells.
- In the production batteries, it is indispensable the work done by the separator because if it operates at the right conditions of pressure and temperature would have a better quality of crude.
- Produced water is treated to reduce the environmental effects.

- It has been seen convenient to collect the production of batteries #1 and #3 to battery #2 in order to facilitate their transport to the Andoas Station where the sale of crude oil will take place.
- For the transport of hydrocarbons from the main battery #2 to the Andoas Station an oil pipeline design was made.
- Some wells still maintain a profitable production in 2050, therefore, we can consider looking for a contract extension with PERUPETRO SA.
- Scenario 1, which contemplates 19 wells to exploit the field, by means of the economic considerations detailed in this report, results in an NPV of 270 MUS$, an IRR of 38% and a payout of 73 months: taking into consideration the beginning of the project in January 2030.
- Scenario 2, which contemplates 16 wells to exploit the field, by means of the economic considerations detailed in this report, results in an NPV of 314 MUS$, an IRR of 41% and a payout of 73 months: taking into consideration the beginning of the project in January 2030.
- Scenario 2 obtains better results because the implementation of horizontal wells obtains a better final field recovery factor for each formation compared to case 1 where directional wells are evaluated.

12. RECOMMENDATIONS

- Results of the project allow us to visualize new development opportunities, such as planning a Workover program for the first 15 years of exploitation with opportunities in Vivian's superior sands, identifying hydraulic fracturing projects in Chonta, drilling Infill wells at the top of the structure.
- The exploration of Deep Horizons could be the Cushabatay and Aguas Calientes formation (or lower reservoirs), since offset fields they were proved to be productive, but stimulation work must be done for its development.
- For a better characterization it is recommended to take samples in 3 wells, distributed along the Northwest axis of the structure (as could be the ALFA 2D, ALFA 13D and ALFA 3D wells), in a total thickness of 200 feet per well, focusing the core in the Vivian and Chonta formations.
- With the results of conventional and special core analysis, identify the areas of best petrophysical properties through the identification of Flow Units in each formation.
- Consider the Vivian reservoir with transitory flow during its entire productive life, due to the fact that the reservoir presents an aquifer that supports the pressure considered infinite compared to the dimensions of the structure.
- Consider the Chonta reservoir with transient flow during the first months, after which the pressure disturbance will touch the limits of the reservoir generating a decrease in pressure as it explodes.

- Perform a PVT analysis of a sample of the ALFA1XD discovery well for each productive formation, since, being the first well in contact with the reservoirs, it will have a representative sample.
- Perform water intrusion monitoring through the methodologies explained in this report, being corroborated by a concrete simulation model to be developed.
- Perform a conventional build up test to the ALFA1XD discovery well, focusing on the Vivian formation, which has higher expectations.
- The calculation of recoverable volumes in the development plans presented in the 2 cases considers only 1P reserves for both reservoirs, because they are the volumes most likely to be present.
- The design of gun systems with TCP Underbalance and Conventional Wireline should be designed in such a way that high penetration lengths are achieved, which generates better flow rates.
- The mechanism of water production must be known in order to properly place the mechanical or cement plug.
- For a better interaction between the company and the communities, priority has been given to the implementation of programs for the communities in order to support the Government program for closing gaps. This would have a positive impact on ensuring the stability of the project's operations.
- In the design of oil pipelines and flow lines, the speed of transport of hydrocarbons must be controlled, since at very high speeds (erosion speed) pipe rupture occurs due to the process of erosion and corrosion, and at low speeds there is the formation of deposits that obstruct the passage of fluids.

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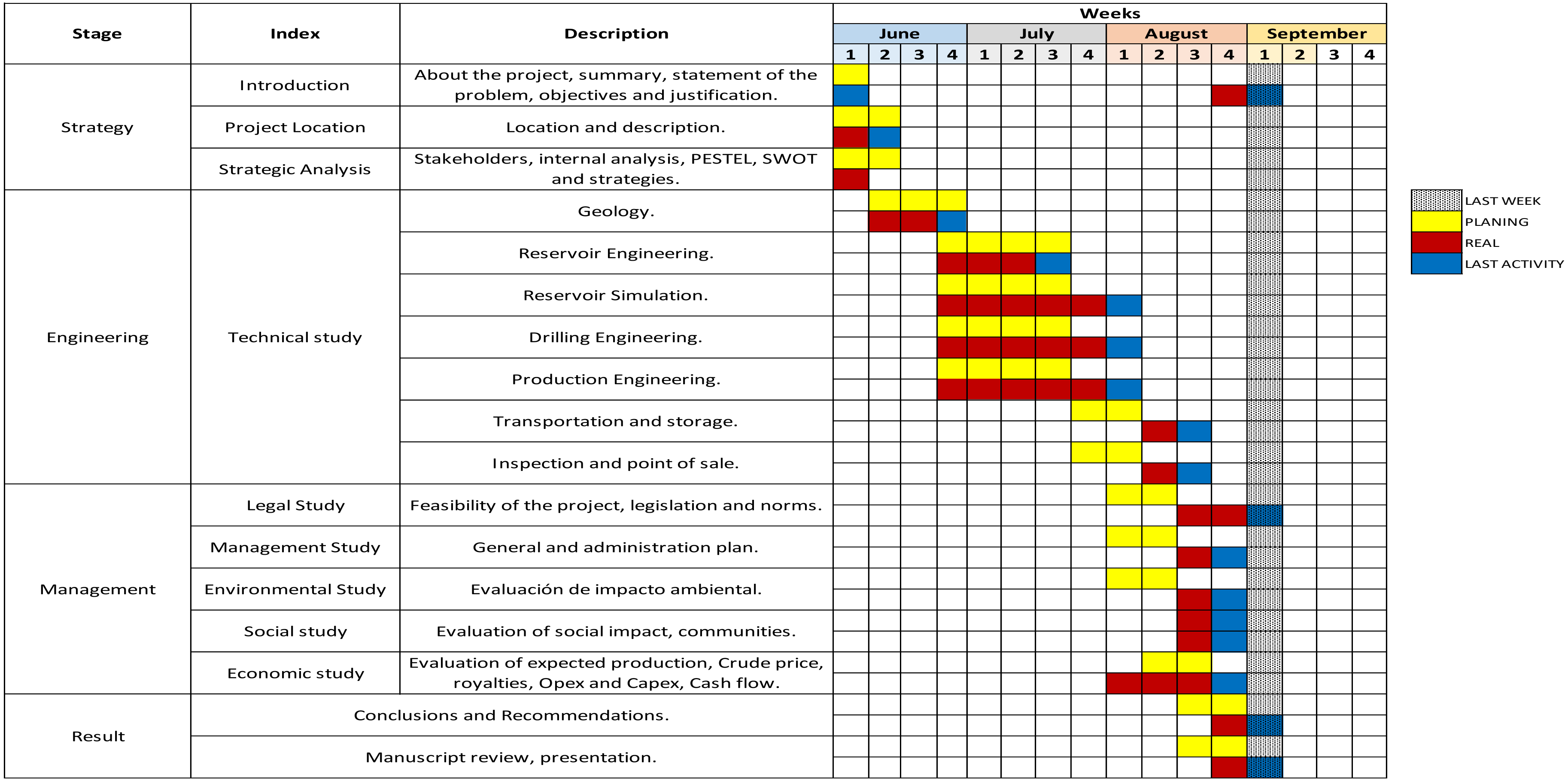
ANNEXES

Annex 1: Schedule of the Project



Annex 2:

Complete PVT table – Vivian

Pressure	Rs	Bo	Uo	Co	Z	Bg	Cg
100	11	1.095	0.959	1.2E-02	0.99	2.1E-01	1.0E-02
300	33	1.104	0.923	2.8E-03	0.98	6.9E-02	3.3E-03
500	41	1.106	0.925	1.4E-03	0.98	4.1E-02	2.0E-03
700	41	1.106	0.950	9.3E-04	0.97	2.9E-02	1.4E-03
900	41	1.106	0.981	6.7E-04	0.96	2.2E-02	1.1E-03
1100	41	1.105	1.018	5.1E-04	0.95	1.8E-02	9.1E-04
1300	41	1.105	1.061	4.1E-04	0.95	1.5E-02	7.7E-04
1500	41	1.104	1.108	3.4E-04	0.94	1.3E-02	6.7E-04
1700	41	1.104	1.161	2.9E-04	0.94	1.2E-02	5.9E-04
1900	41	1.104	1.218	2.5E-04	0.94	1.0E-02	5.3E-04
2100	41	1.103	1.280	2.2E-04	0.94	9.4E-03	4.8E-04
2300	41	1.103	1.347	1.9E-04	0.94	8.5E-03	4.3E-04
2500	41	1.102	1.418	1.7E-04	0.94	7.9E-03	4.0E-04
2700	41	1.102	1.494	1.6E-04	0.94	7.3E-03	3.7E-04
2900	41	1.102	1.575	1.4E-04	0.94	6.8E-03	3.4E-04
3100	41	1.101	1.660	1.3E-04	0.95	6.4E-03	3.2E-04
3300	41	1.101	1.750	1.2E-04	0.95	6.1E-03	3.0E-04
3500	41	1.100	1.845	1.1E-04	0.96	5.8E-03	2.9E-04
3700	41	1.100	1.945	1.0E-04	0.97	5.5E-03	2.7E-04
3900	41	1.099	2.049	9.7E-05	0.98	5.2E-03	2.6E-04
4100	41	1.099	2.157	9.1E-05	0.98	5.0E-03	2.4E-04
4300	41	1.099	2.271	8.5E-05	0.99	4.8E-03	2.3E-04
4500	41	1.098	2.388	8.0E-05	1.00	4.7E-03	2.2E-04
4700	41	1.098	2.510	7.6E-05	1.01	4.5E-03	2.1E-04
4900	41	1.097	2.637	7.2E-05	1.03	4.4E-03	2.0E-04
5100	41	1.097	2.768	6.8E-05	1.04	4.3E-03	2.0E-04
5300	41	1.097	2.902	6.5E-05	1.05	4.2E-03	1.9E-04
5500	41	1.096	3.041	6.2E-05	1.06	4.1E-03	1.8E-04
5700	41	1.096	3.184	5.9E-05	1.07	4.0E-03	1.8E-04
5900	41	1.095	3.330	5.6E-05	1.09	3.9E-03	1.7E-04

Complete PVT table – Chonta

Pressure	Rs	Bo	Uo	Co	Z	Bg	Cg
100	16	1.196	0.907	1.2E-02	0.99	3.2E-01	1.0E-02
300	24	1.199	0.895	7.3E-03	0.98	1.1E-01	6.7E-03
500	33	1.202	0.883	5.0E-03	0.96	6.3E-02	5.0E-03
700	42	1.205	0.871	3.7E-03	0.95	4.4E-02	4.0E-03
900	51	1.209	0.858	2.9E-03	0.94	3.4E-02	3.3E-03
1100	60	1.212	0.845	2.4E-03	0.92	2.7E-02	2.9E-03
1300	70	1.216	0.833	2.0E-03	0.91	2.3E-02	2.5E-03
1500	80	1.219	0.820	1.7E-03	0.91	2.0E-02	2.2E-03
1700	90	1.223	0.807	1.5E-03	0.90	1.7E-02	2.0E-03
1900	101	1.227	0.794	1.3E-03	0.89	1.5E-02	1.8E-03
2100	112	1.231	0.781	1.2E-03	0.89	1.4E-02	1.7E-03
2300	133	1.239	0.755	9.6E-04	0.89	1.3E-02	1.4E-03
2500	145	1.243	0.743	8.8E-04	0.89	1.2E-02	1.3E-03
2700	156	1.247	0.730	8.1E-04	0.89	1.1E-02	1.3E-03
2900	167	1.252	0.718	7.4E-04	0.90	1.0E-02	1.2E-03
3100	179	1.256	0.706	6.9E-04	0.90	9.5E-03	1.1E-03
3300	202	1.265	0.682	6.0E-04	0.91	8.9E-03	1.0E-03
3500	214	1.270	0.670	5.6E-04	0.92	8.5E-03	9.5E-04
3700	226	1.274	0.659	5.3E-04	0.93	8.1E-03	9.1E-04
3900	239	1.279	0.647	5.0E-04	0.94	7.8E-03	8.7E-04
4100	251	1.284	0.636	4.7E-04	0.95	7.5E-03	8.3E-04
4300	276	1.293	0.614	4.3E-04	0.96	7.2E-03	7.7E-04
4500	288	1.298	0.604	4.1E-04	0.97	7.0E-03	7.4E-04
4700	301	1.303	0.593	3.9E-04	0.98	6.8E-03	7.1E-04
4900	327	1.313	0.573	3.5E-04	1.00	6.6E-03	6.7E-04
5100	340	1.318	0.563	3.4E-04	1.01	6.5E-03	6.5E-04
5300	353	1.323	0.554	3.2E-04	1.03	6.3E-03	6.3E-04
5500	366	1.329	0.544	3.1E-04	1.04	6.2E-03	6.1E-04
5700	379	1.334	0.535	3.0E-04	1.06	6.0E-03	5.9E-04
5900	405	1.344	0.517	2.8E-04	1.07	5.9E-03	5.6E-04

Annex 3:

Estimate Petrophysics Well Properties – Vivian

*WELL	*NET_PAYT	*PHI	*Soi	*K
ALFA 1X:V	80	0.165	0.841	1288
ALFA_02:V	73	0.172	0.829	1355
ALFA_03:V	73	0.153	0.845	1430
ALFA_04:V	42	0.167	0.828	1213
ALFA_05:V	68	0.178	0.849	1217
ALFA_06:V	48	0.159	0.860	1348
ALFA_07:V	45	0.184	0.849	1445
ALFA_08:V	40	0.155	0.844	1347
ALFA_09:V	40	0.150	0.849	1243
ALFA_10:V	35	0.176	0.833	1442
ALFA_11:V	35	0.156	0.823	1452
ALFA_12:V	48	0.179	0.836	1353
ALFA_13:V	48	0.161	0.828	1246
ALFA_14:V	38	0.154	0.820	1345
ALFA_15:V	36	0.150	0.860	1521
ALFA_16:V	30	0.170	0.825	1387
ALFA_17:V	30	0.172	0.833	1213
ALFA_18:V	30	0.178	0.836	1231
ALFA_19:V	28	0.157	0.843	1314

Estimate Petrophysics Well Properties – Chonta

*WELL	*NET_PAYT	*PHI	*Soi	*PERM
ALFA 1X:C	28	0.113	0.740	79
ALFA_02:C	15	0.090	0.590	71
ALFA_03:C	13	0.092	0.660	84
ALFA_04:C		0.117	0.710	62
ALFA_05:C		0.111	0.710	71

ALFA_06:C	25	0.114	0.700	70
ALFA_07:C	22	0.107	0.780	50
ALFA_08:C	18	0.106	0.640	92
ALFA_09:C		0.111	0.740	73
ALFA_10:C		0.099	0.680	89
ALFA_11:C	20	0.107	0.750	62
ALFA_12:C	20	0.104	0.670	86
ALFA_13:C	18	0.098	0.640	91
ALFA_14:C		0.099	0.740	66
ALFA_15:C		0.097	0.730	58
ALFA_16:C	15	0.118	0.620	57
ALFA_17:C		0.100	0.700	68
ALFA_18:C		0.105	0.680	70
ALFA_19:C		0.102	0.800	53

Annex 4:

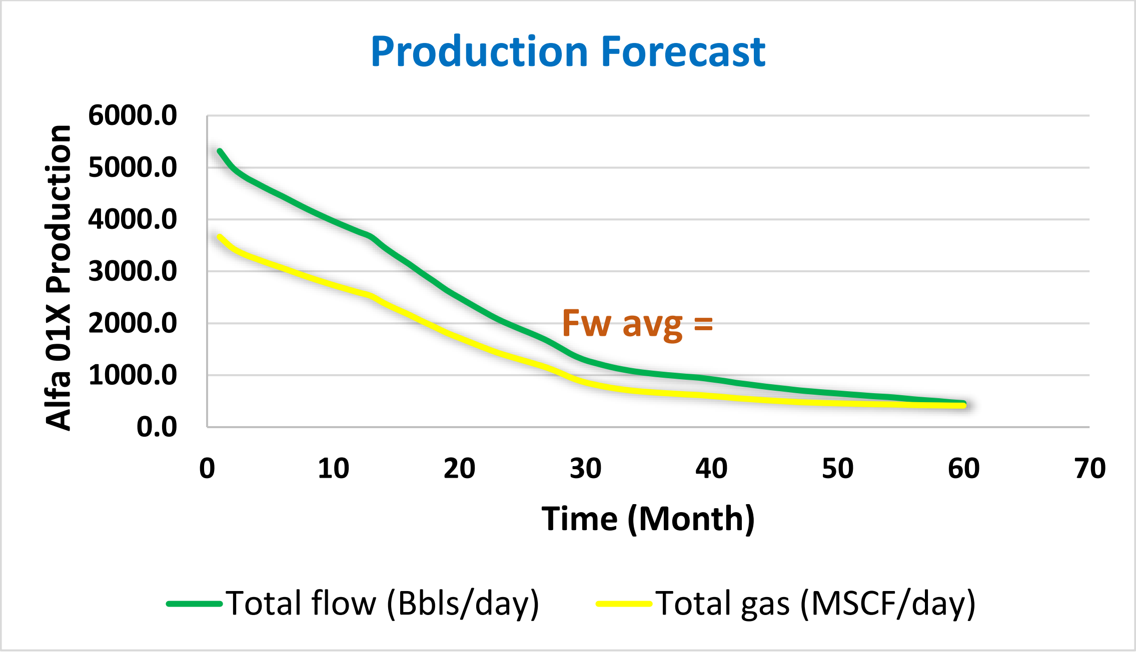
Production with gas lift system (Alfa 01X Well) – Chonta Formation

Month	Date	Qo (Bbls/day)	Qw (Bbls/day)	Qg (MSCF/day)	Qtotal (Bbls/day)	Fw (%)
0	1/01/2030	0.0	0.0	0.0	0.0	
1	1/02/2030	5313.6	4.0	3666.4	5317.6	0.075
2	1/03/2030	5000.9	3.1	3450.6	5004.1	0.063
3	1/04/2030	4815.5	3.0	3322.7	4818.5	0.063
4	1/05/2030	4683.3	3.0	3231.5	4686.4	0.064
5	1/06/2030	4556.5	3.0	3144.0	4559.5	0.066
6	1/07/2030	4438.6	3.1	3062.6	4441.6	0.069
7	1/08/2030	4311.8	3.1	2975.2	4315.0	0.073
8	1/09/2030	4189.2	3.2	2890.6	4192.4	0.076
9	1/10/2030	4074.6	3.3	2811.5	4077.9	0.080
10	1/11/2030	3965.0	3.3	2735.9	3968.4	0.084
11	1/12/2030	3861.0	3.4	2664.1	3864.4	0.088
12	1/01/2031	3760.2	3.4	2594.6	3763.7	0.091
13	1/02/2031	3660.7	3.5	2525.6	3664.2	0.095
14	1/03/2031	3468.6	3.4	2392.0	3472.0	0.097
15	1/04/2031	3298.9	3.2	2275.5	3302.1	0.097
16	1/05/2031	3141.7	3.1	2167.1	3144.8	0.098
17	1/06/2031	2967.6	3.0	2046.3	2970.5	0.100
18	1/07/2031	2804.4	2.9	1934.1	2807.3	0.103
19	1/08/2031	2633.8	2.8	1816.8	2636.6	0.106
20	1/09/2031	2491.8	2.7	1719.0	2494.5	0.109
21	1/10/2031	2351.3	2.7	1622.1	2354.0	0.113
22	1/11/2031	2214.0	2.6	1527.0	2216.6	0.117
23	1/12/2031	2082.8	2.6	1436.1	2085.4	0.123
24	1/01/2032	1972.7	2.6	1360.4	1975.2	0.130
25	1/02/2032	1870.0	2.5	1289.3	1872.6	0.135

26	1/03/2032	1770.7	2.5	1218.7	1773.2	0.141
27	1/04/2032	1659.6	2.5	1142.0	1662.1	0.149
28	1/05/2032	1524.6	2.5	1044.7	1527.2	0.166
29	1/06/2032	1387.3	2.7	939.6	1390.0	0.196
30	1/07/2032	1286.5	2.9	860.5	1289.3	0.221
31	1/08/2032	1218.0	2.9	805.8	1221.0	0.241
32	1/09/2032	1156.3	3.1	759.3	1159.4	0.265
33	1/10/2032	1106.3	3.2	723.7	1109.5	0.286
34	1/11/2032	1065.8	3.2	695.2	1069.0	0.297
35	1/12/2032	1036.0	3.2	675.8	1039.1	0.305
36	1/01/2033	1010.1	3.2	658.4	1013.3	0.315
37	1/02/2033	988.8	3.2	644.7	992.0	0.327
38	1/03/2033	967.4	3.3	629.5	970.7	0.339
39	1/04/2033	949.4	3.3	618.3	952.7	0.351
40	1/05/2033	918.2	3.4	598.8	921.6	0.369
41	1/06/2033	886.4	3.4	580.0	889.9	0.388
42	1/07/2033	847.6	3.5	556.6	851.1	0.409
43	1/08/2033	817.7	3.5	540.6	821.3	0.432
44	1/09/2033	785.5	3.6	523.0	789.1	0.457
45	1/10/2033	757.3	3.6	508.1	760.9	0.479
46	1/11/2033	730.6	3.7	494.6	734.3	0.501
47	1/12/2033	703.0	3.7	480.5	706.7	0.525
48	1/01/2034	682.3	3.7	471.7	686.0	0.544
49	1/02/2034	662.4	3.8	464.0	666.1	0.564
50	1/03/2034	644.7	3.8	457.7	648.5	0.586
51	1/04/2034	625.7	3.8	451.4	629.6	0.610
52	1/05/2034	607.8	3.9	445.9	611.6	0.634
53	1/06/2034	589.7	3.9	440.7	593.6	0.660
54	1/07/2034	576.2	4.0	437.9	580.2	0.682
55	1/08/2034	556.1	4.0	432.6	560.1	0.715

56	1/09/2034	532.4	4.0	426.2	536.4	0.750
57	1/10/2034	512.8	4.0	421.8	516.8	0.779
58	1/11/2034	496.0	4.0	419.1	500.1	0.808
59	1/12/2034	473.4	4.0	415.2	477.5	0.846
60	1/01/2035	456.6	4.0	414.2	460.6	0.878

Production Forecast – Alfa 01 Well



Annex 5:

History Field productivity and recovery factor – Vivian Formation

	PRODUCCION TOTAL DE VIVIAN						
	Qmax (Bbl/d)			ACUM (MBLS)			%
	Bls/d	Bls/d	MScf/d	MMBls	MMBls	MMScf	
	49679.3	122121.4	2954.7	146118	464655	8691	53.1
Años	**Oil**	**Water**	**Gas**	**Oil Acum**	**Water Acum**	**Gas Acum**	**FR**
2030	0	0	0	0	0	0	**0.0**
2031	13332	1	793	4866	0	289	**0.8**
2032	19646	21	1168	12037	8	716	**3.0**
2033	26634	1366	1584	21758	507	1294	**6.3**
2034	37035	4881	2203	35276	2288	2098	**10.5**
2035	49679	9904	2955	53409	5903	3177	**16.2**
2036	48935	17065	2910	71270	12132	4239	**23.1**
2037	49438	25895	2940	89315	21584	5312	**29.5**
2038	48707	62370	2897	107093	44349	6370	**36.1**
2039	29662	97027	1764	117920	79764	7013	**41.4**
2040	18973	114444	1128	124845	121536	7425	**44.4**
2041	13712	122121	816	129850	166110	7723	**46.5**
2042	10185	117815	606	133567	209113	7944	**48.1**
2043	8204	119796	488	136562	252838	8122	**49.3**
2044	6940	121060	413	139095	297025	8273	**50.3**
2045	4866	96300	289	140871	332175	8379	**51.1**
2046	3979	88021	237	142324	364302	8465	**51.6**
2047	3588	86745	213	143633	395964	8543	**52.1**
2048	2994	79006	178	144726	424801	8608	**52.6**
2049	2561	72439	152	145661	451242	8663	**53.0**
2050	1252	36748	74	146118	464655	8691	**53.1**

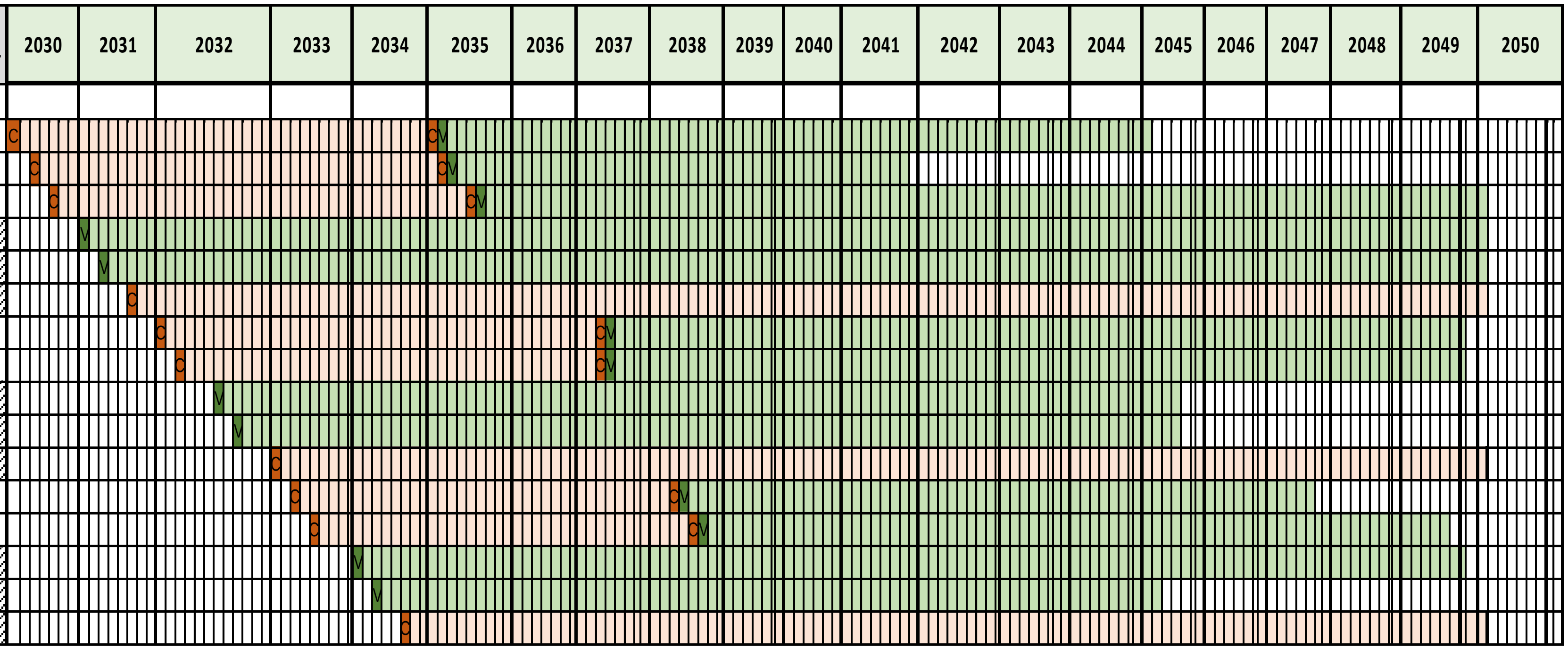
History Field productivity and recovery factor – Chonta Formation

	PRODUCCION TOTAL DE CHONTA						
	Qmax (Bbl/d)			ACUM (MBLS)			%
	Bls/d	Bls/d	MScf/d	MMBls	MMBls	MMScf	
	6591.2	500.5	6256.7	17693.9	2735.9	24607.3	26.6
Años	**Oil**	**Water**	**Gas**	**Oil Acum**	**Water Acum**	**Gas Acum**	**FR**
2030	5005	15	3454	1827	5	1261	**1.4**
2031	4782	27	3299	3573	15	2465	**4.2**
2032	5074	83	3416	5425	46	3712	**6.9**
2033	6591	251	4602	7830	137	5391	**10.1**
2034	6314	437	6053	10135	297	7601	**13.7**
2035	4389	434	6209	11737	455	9867	**16.7**
2036	3385	423	6257	12973	609	12151	**18.8**
2037	2685	500	5640	13953	792	14209	**20.4**
2038	1771	487	4382	14599	970	15809	**21.7**
2039	1232	451	3350	15049	1135	17032	**22.4**
2040	1084	416	2945	15444	1286	18107	**23.1**
2041	970	386	2620	15798	1427	19063	**23.6**
2042	873	365	2351	16117	1561	19921	**24.1**
2043	782	359	2119	16402	1692	20694	**24.6**
2044	694	368	1919	16656	1826	21395	**25.0**
2045	611	388	1750	16879	1967	22033	**25.4**
2046	540	406	1608	17076	2115	22621	**25.7**
2047	483	419	1491	17252	2268	23165	**26.0**
2048	436	426	1390	17411	2424	23672	**26.2**
2049	396	428	1303	17556	2580	24148	**26.4**
2050	378	428	1259	17694	2736	24607	**26.6**

Annex 6:

Well Production time – Capahuari Sur Extensión, best scenario

Nº	PLAT F.	OFFICIAL WELLS	MAIN TARGET	SEC. TARGET
1	A	ALFA 1X	CHONTA	VIVIAN
2	B	ALFA 2C	CHONTA	VIVIAN
3	C	ALFA 3C	CHONTA	VIVIAN
4	A	ALFA 4H	VIVIAN	-
5	A	ALFA 5H	VIVIAN	-
6	B	ALFA 6H	CHONTA	-
7	B	ALFA 7D	CHONTA	VIVIAN
8	B	ALFA 8D	CHONTA	VIVIAN
9	C	ALFA 9D	VIVIAN	-
10	C	ALFA 10H	VIVIAN	-
11	A	ALFA 11H	CHONTA	-
12	A	ALFA 12D	CHONTA	VIVIAN
13	A	ALFA 13D	CHONTA	VIVIAN
14	B	ALFA 14H	VIVIAN	-
15	B	ALFA 15H	VIVIAN	-
16	C	ALFA 16H	CHONTA	-



APPENDIX A

Engineering Standards and Government Regulations Applied in the Project

Engineering Standards

The following engineering standards have been applied in the project:

API SPEC 4F

Specification for Drilling and Well Servicing Structures

This specification states requirements and gives recommendations for suitable steel structures for drilling and well servicing operations in the petroleum industry, provides a uniform method of rating the structures, and provides two product specification levels (PSLs). This specification is applicable to all new steel derricks, masts (including masts with guy lines and service rig masts), substructures, and crown block assemblies with a date of manufacture after the effective date of this specification.

API RP 5A3

Recommended Practice on Thread Compounds for Casing, Tubing, and Line Pipe

The purpose of this recommended practice is to provide means for evaluating the suitability of thread compounds, regardless of composition, for use on API round thread and buttress casing, tubing and line pipe connections in high-pressure service. The tests outlined herein are used to evaluate the critical performance properties of thread compounds under laboratory conditions. When evaluating the suitability of a thread compound, the user should consider full size connection test results and field experience in addition to the results of reduced scale (bench top) test methods like those described herein.

API TR 5C3

Calculating Performance Properties of Pipe Used as Casing or Tubing

This technical report illustrates the equations and templates necessary to calculate the various pipe properties, including the following: (a) pipe performance properties, such as axial strength, internal pressure resistance, and collapse resistance, (b) minimum physical properties, (c) product assembly force (torque), (d) product test pressures, (e) critical product dimensions related to testing criteria, (f) critical dimensions of testing equipment, (g) critical dimensions of test samples.

Equations presented here are intended for use with pipe manufactured in accordance with API 5CT or ISO 11960, API 5DP or ISO 11961, and API 5L or ISO 3183, as applicable. Pipe modified by cold working after production, such as expandable tubulars and coiled tubing, is beyond the scope of this technical report.

ISO 11960:2020

Petroleum and natural gas industries. Steel pipes for use as casing or tubing for wells

This standard specifies the technical delivery conditions for steel pipes (casing, tubing and pup joints), coupling stock, coupling material and accessory material. The standard is also applicable to the following connections: short round thread casing (SC), long round thread casing (LC), buttress thread casing (BC), non-upset tubing (NU), external upset tubing (EU), integral-joint tubing (IJ).

API Recommended Practice 54

Recommended Practice For Occupational Safety For Oil And Gas Well Drilling And Servicing Operations

This Recommended Practice provides procedures for promoting and maintaining safe and healthy working conditions for personnel in drilling and well servicing operations.

The document applies to rotary drilling rigs, well servicing rigs, and special services as they relate to operations on location. It includes sections on flowback operations which are key for safe well testing, revised requirements for facility and site process hazard assessment and mitigation, and introduction of formal risk assessments as well as expanded provisions for offshore operations.

API Bulletin 75L

Guidance Document For The Development Of A Safety And Environmental Management System For Onshore Oil And Natural Gas Production Operations And Associated Activities

This recommendation provides general information and guidance for the development of a safety and environmental management system (SEMS) for onshore oil and natural gas operations, including drilling, production, and well servicing activities, fostering continuous improvement in industry safety and environmental performance.

Many onshore oil and natural gas companies have effective SEMS in place. However, the intent of this document is to provide an additional tool that can assist these and especially other operators in taking the next step toward implementing a complete system at a pace that complements their business plan.

Government Regulations on Petroleum and Environment

The following government regulations were considered in the project:

Government Decree Nº 032-2004-EM

Regulation of Hydrocarbon Exploration and Exploitation Activities

Environmental Protection

Hydrocarbon exploration and exploitation camps and facilities will comply with the standards indicated in the Regulations for Environmental Protection in Hydrocarbon Activities. The Personnel must comply with all matters relating to the protection of the local flora and fauna, in accordance with the provisions of the aforementioned Regulations.

The waste and waste produced during exploration and exploitation will be managed as indicated in the Regulation for environmental protection in hydrocarbon activities.

Government Decree Nº 032-2004-EM

Regulation of Hydrocarbon Exploration and Exploitation Activities

Fuel Storage

Fuel storage in the camp will be strictly controlled. The storage of fuels, lubricants and chemical substances must be in a closed place, with a waterproof cover. Fuel tanks must be equipped with safe valves (which can be locked to prevent unauthorized use). Any leak or contamination of fuel to the ground or water must be reported to OSINERG and MINEM, proceeding to clean it to prevent any threat of contamination.

APPENDIX B

Multiple Constraints, Restrictions and Limitations

The following constraints, restrictions and limitation have been considered in the project

Uncertainties and Risks

Hydrocarbon exploration and exploitation is a high-risk venture. Petroleum geological concepts with respect to structure and hydrocarbon charge are uncertain. On the other hand, economic evaluations have uncertainties related to cost estimation, changing conditions in economically viable hydrocarbon sites, changes in petroleum exploitation technology, fluctuations in hydrocarbon price and market conditions, political situation, community relations, etc. All these issues must be carefully analyzed in order to ensure the profitability of the project for the most conservative economic conditions and diversity of scenarios. In this project, these issues have been considered from a conservative scenario and criteria.

Availability of Geological Data

An inherent feature of petroleum projects is the availability of relevant geological, geophysical and geochemical data. Several information and data sources have been considered to gather proper and significant data to complete the project. The following sources have been considered: National Society of Mining, Petroleum and Energy SNMPE, Geological, Mining and Metallurgical Peruvian Institute IGMMP, Peruvian Geological Institute, Government Ministry of Mining and Energy. All required information and data was finally found and made available.

Safety Considerations

Hydrocarbon exploration and production present diverse safety issues that must be taken into account in the development of the project. It is important to comply with safety standards pointing to satisfy proper safety levels considering their impact in the project budget. Care of human life, well-being and safety is an important issue to take into account throughout the different stages of the project and its life-cycle.

Environment and Sustainability

Hydrocarbon industry faces diverse and broad environmental issues at both local and global levels which could affect the project sustainability. The project considers environmental issues such as potential effluents spills, soil, air and water pollution, habitat protection and biodiversity. The project also considers community relations with local people as an important stakeholder of the project.

Schedule

The project must be completed in one academic semester. It is estimated the project requires an average of 150 hours of teamwork with 4-5 students per team. Considering that, besides the senior design project course, students are enrolled in 3-4 additional courses in the academic semester, students have to plan ahead in order for identify all required activities, distribute the tasks among all team members and, finally, integrate all partial tasks to configure the final project.

Other Constraints

The following constraints have also been considered in the project:

- Geographical and accessibility restrictions that make difficult the transport of materials and equipment.
- Technology availability and applicability in the well(s) area.