EFFICIENCY OF BOLIVIAN HYDROCARBON RESOURCE DEVELOPMENT: CASE STUDY OF A MEGA-FIELD IN THE CONTEXT OF REGIONAL MARKETS AND POLICY FRAMEWORK INCENTIVES

A Thesis

by

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Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

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May 2017

Major Subject: Petroleum Engineering

ABSTRACT

Bolivia is a producer and the main exporter of natural gas in the South American market. The role of Bolivia as a natural gas provider to Brazil and Argentina has recently been put into question. Lagging investments in exploration, partially caused by the hydrocarbon fiscal regime changes that favor the government, has resulted in no major discoveries in the past decade. Current reserves and production are concentrated in three gas-condensate naturally fractured mega-fields in the Southern Sub-Andean province, with two of them producing for more than 15 years.

The aim of this study is to quantify the impact of the past legislation modifications on the allocation of cash flow streams to the government and the contractor, and evaluate the feasibility of future drilling activities in a representative mega-field under the 2015 Hydrocarbon Incentives Law that aims to prevent the looming natural gas supply and demand gap. A review of the profitability of Bolivia's current hydrocarbon extraction arrangements is useful in order to be able to forecast likely future revenue streams. This study briefly outlines the development of the regional gas trade and then proceeds to outline the architecture of the principal cash flows generated by the case study. The concurrent profitability of existing field operations is analyzed from the perspective of both the operator and the state with a range of outcomes depending on a sensitivity analysis of the regional gas price development, under various fiscal regimes and contractual arrangements. The actual optimum rate of monetization of these remaining hydrocarbon reserves in Bolivia will be affected by a requirement of attractive return on

investment considering various gas prices and demand scenarios, as determined by competitive shale gas development in Argentina, offshore gas in Brazil, and LNG imports.

DEDICATION

To my family, for their constant support, encouragement and unconditional love.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Weijermars, and my committee members, Dr. Blasingame, and Dr. Barrufet for their guidance and support throughout the course of this research.

CONTRIBUTORS AND FUNDING SOURCES

This work was supervised by a thesis committee consisting of Professor Weijermars, and Professor Blasingame of the Department of Petroleum Engineering and Professor Barrufet of the Department of Chemical Engineering.

This work was made possible in part by the Ministry of Education of Bolivia which funded the author's graduate studies.

The contents of this document are solely the responsibility of the author and do not necessarily represent the official views of the sponsor.

NOMENCLATURE

E&P	Exploration and Production
DS	Decree Supreme
GDP	Gross Domestic Product
IOC	International Oil Company
LNG	Liquified Natural Gas
NOC	National Oil Company
TCF	Trillion Cubic Feet
YPFB	Yacimientos Petroliferos Fiscales Bolivianos
WTI	West Texas Intermediate

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CHAPTER I

INTRODUCTION

1.1 Scene Setting

Bolivia is one of the most important natural gas producers and exporters in South America. The revenues from hydrocarbon sales to Argentina and Brazil converted Bolivia into the main external provider for these countries, and enabled unprecedented economic growth in Bolivia**.** Over the past two decades, high prices of commodities, growing demand from the exportation markets and hydrocarbon legislation modifications have allowed natural gas production to be a key contributor to the national economy. Gross Domestic Product (GDP) has almost tripled in one decade (Figure 1) and the Foreign-Exchange Reserves increased from $3 billion in 2006 to $15 billion in 2014 (MEF, 2016).

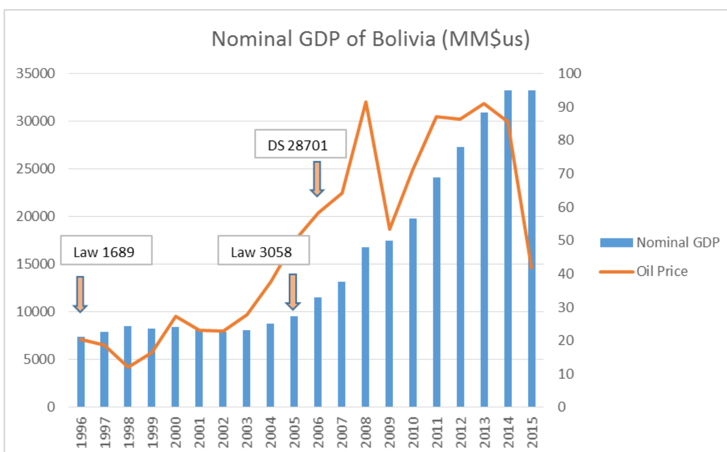

Figure 1. Nominal GDP of Bolivia and WTI oil prices (Adapted from MEF, 2016)

Bolivia gas exports to Brazil and Argentina occur under 20-year contracts. The gas sale agreement with Brazil expires in 2019 (Appendix A1) and the agreement with Argentina lasts until 2027 (Appendix A2). Gas deliveries are priced through an agreed base price indexed to crude oil that allows for price escalation when the index commodity price changes. Bolivia has been able to use the revenues from gas exports to maintain the high levels of revenues which finance social programs and provide considerable to provinces, municipal governments, public universities and other state institutions. However, the country developed a fiscal deficit in 2014, due to a decline in hydrocarbon revenues (IMF, 2014). Capital markets were tapped for government bonds in 2012 for the first time since 1920 (IMF, 2014).

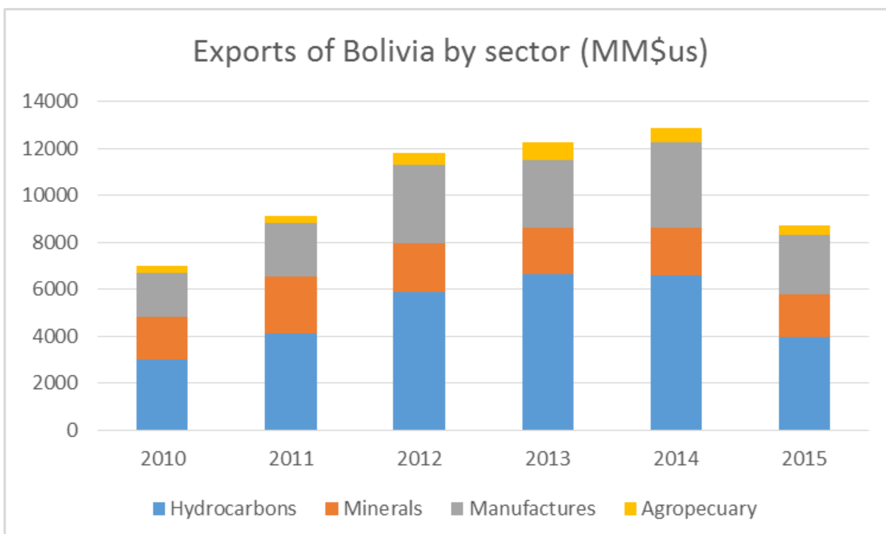

Figure 2. Exports of Bolivia by economic activity (Adapted from MEF, 2016)

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1.2 Problem Statement

Major contributions to GDP growth in Bolivia came from exportation of minerals and hydrocarbons (Figure 2). The historic economic growth of Bolivia was partially enabled by the long-term gas contracts with Brazil and later with Argentina, the change of hydrocarbon legislation in 2005 and 2006 that increased the revenue share of the government, and a period of favorable prices of commodities. These factors have recently varied: the contract with Brazil ends in 2019 with uncertainty of the terms of a possible contract renewal, the commodity boom that fueled the flourishing Bolivian economy showed signs of slowing down in 2015, and the fiscal regime strong taxing has impacted investments in exploration and production (E&P).

E&P investments have fluctuated over the past two decades but were mainly allocated to production and to a lesser extent, exploration activities (Figure 3a). As a result of lagging exploration investments, the natural gas reserves of Bolivia have steadily declined since the early exploration boom in the 1990's with reserves peaking in 2000-2005 (Figure 3b). The exploration contracts signed after the hydrocarbon fiscal regime modifications in 2005 and 2006 were not successful or haven't started drilling activities.

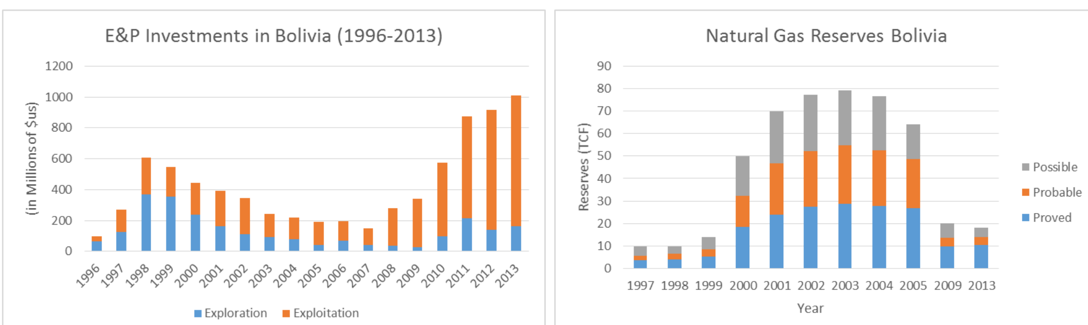

Figure 3. (a) Bolivian E&P investments and (b) natural gas proved reserves (Adapted from YPFB, 2014)

Bolivia's ability to meet the domestic and foreign gas demand has raised concerns. In June 2016, Bolivia could not comply with the contractual gas volumes agreed to Argentina. In turn, Argentina had to import natural gas from Chile to fill the supply and demand gap during the winter season of 2016. Looking towards the future, Chavez-

Rodriguez et al. (2016) predicts that Bolivia will have to develop all reserves, contingent resources and some yet-to-find resources to meet the demand. Chavez-Rodriguez et al (2016) estimates that a $20 billion investment is required to develop the resources necessary to comply with the demand in the period 2015-2030. In parallel, a study by the National Industry Confederation of Brazil (CNI, 2016a) suggests that between $5.4 and $7.1 billion investment in exploration would guarantee enough gas for the domestic market and foreign exports in the period 2015-2026.

What is now at stake for Bolivia is the need to stimulate E&P investments in its hydrocarbon sector to turn around the decade-long decline in Reserves/Production (R/P) ratios and comply with the gas export agreements. In 2015, the Bolivian government approved the Law of Incentives 707 which rewards exploration and exploitation activities to increase the production of oil and condensate. This law aims to accelerate hydrocarbon exploration to find new resources and increase the production in existing fields. Current production and remaining reserves are concentrated in gas-condensate naturally fractured mega-fields in the Southern Sub-Andean province: San Alberto, Sabalo and Margarita. YPFB (2014b) Strategic Plan scheduled 3 production wells drilled in San Alberto, 4 in Sabalo and 3 in Margarita in the period 2015-2019.

A review of the profitability of the Bolivia's current hydrocarbon extraction arrangements is useful for forecasting likely future revenue streams and the feasibility of drilling activities accounting for the incentives. The rate of monetization of the hydrocarbon resources in Bolivia will be affected by a requirement of attractive returns on investment, taking into account regional gas price and demand scenarios, as determined by competitive shale gas development in Argentina, offshore gas in Brazil, and price levels of potential LNG imports. This study uses historic production data of a representative Bolivian mega-field to develop a production forecast model which is coupled with an economic analysis under various price scenarios. This analysis includes, but is not limited to, seeking answers to:

- What was the impact of the change in hydrocarbon legislation in revenue distribution?
- Are current and future operations profitable for the oil company under the current fiscal regime in the studied field?
- What is the proportion of future profits that ultimately go the government and the oil company under different price scenarios?
- What is the impact of the incentives law in the project's profitability?

CHAPTER II

REVIEW OF THE BOLIVIAN GAS VALUE CHAIN

The Bolivian gas value chain is made up of a number of unique elements that govern resource development, fiscal systems, profitability and market dynamics. First, the value chain can be stimulated by fiscal incentives commensurate with geological risk (and other risk premium requirements) to attract E&P investments that could cause an upstream revival of gas production (Weijermars 2016). Second, the regional gas market develops according to supply and demand trends as the outcome not only of Bolivian resource development policies and investments, but also of its partners (Argentina and Brazil). Third, the regional market is influenced by global commodity price developments, partly due to increasing liquefied natural gas (LNG) imports in Brazil and Argentina, and partly due to oil indexing of the existing gas pricing mechanism in Bolivia. This chapter first contains a literature review and a review of the key elements of the Bolivian gas value chain to provide a basis for further analysis.

2.1 Literature Review: Regional Gas Markets

As of December 2015, South and Central America held 4.1% of the global natural gas proved reserves and accounted for 5% of the global gas production (BP, 2016). Venezuela is the major holder of proved gas reserves in South America, followed by Brazil, Peru, Argentina and Bolivia (Figure 4).

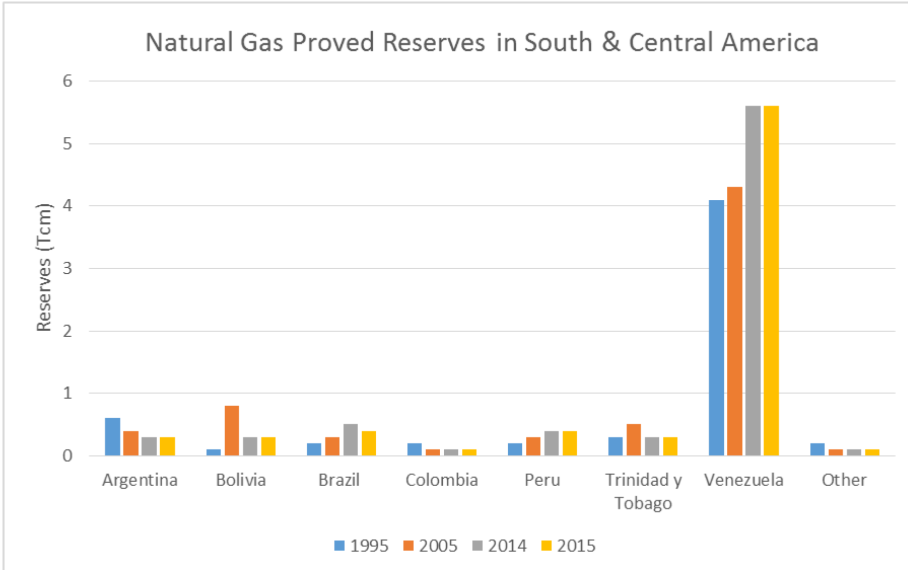

Figure 4. Natural gas proved reserves in South & Central America (Adapted from BP, 2016)

In terms of natural gas production, Argentina leads in the region, followed by Venezuela, Brazil, Bolivia and Peru. However, the three largest producers use natural gas for domestic consumption only. Additionally, Argentina and Brazil import gas through pipeline and LNG cargoes.

The South American gas market is characterized by a low regional integration which results from technical difficulties that hinder new projects, the perception that it is not a priority, and the complex political relations within and between the involved countries (KAS, 2016). The most successful efforts have been the construction of pipelines integrating Bolivia and Brazil, Bolivia and Argentina, Argentina and Chile, and to a lesser extent Colombia and Venezuela.

The first cross-border pipeline in the Southern Cone was built in 1972 connecting Bolivia and Argentina. During the late 90's and early 2000's, seven pipelines were built between Argentina and Chile. In 1996, Brazil and Bolivia agreed to build a pipeline and sales to Brazil started in 1999 as part of a long-term contract. In the Northern Cone, a pipeline connects Colombia and Venezuela. The agreement for gas sales from Colombia to Venezuela started in 2007 and ended in 2015 (Honore, 2016).

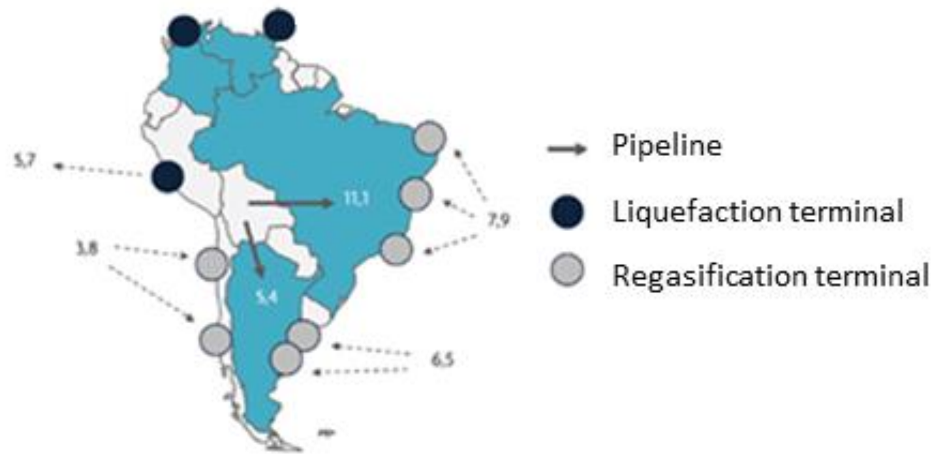

Figure 5. Gas trade in South America in 2014 in billion cubic meters per annum (Adapted from KAS 2016)

Currently, Bolivia is the major exporter of natural gas within the region, providing gas to Brazil and Argentina under long-term agreements. Peru is also a net exporter of natural gas that uses a LNG liquefaction terminal to trade it in the Pacific market (Figure 5). Although historically isolated, the regional gas market in South America has been changing its focus from self-sufficiency and regional integration to building infrastructure for imports and opening to the LNG market. Eight regasification plants were built in the last decade (Table 1).

Table 1. LNG tegasification plants in South America (Adapted from Honore 2016)

Country	Plant	Start-up year	Capacity (bcma)
Chile	Quintero	2009	5.5
	Mejillones	2010	2
Argentina	Bahia Blanca	2008	5.1
	Escobar	2011	5.1
Brazil	Pecem	2008	2.5
	Guanabara	2009	8.1
	Bahia Blanca	2014	5.2

However, the diversification of supply sources is not limited to LNG imports. New discoveries in the pre-salt area in Brazil and the rise of unconventional resources exploitation are expected to substantially increase the regional natural gas supply. According to a report from the U.S Energy Information Administration (EIA 2012), Argentina holds the second largest shale gas resources in the world with 802 TCF of technically recoverable gas. The rest of the countries in the region also have abundant unconventional resource potential as seen in Figure 6.

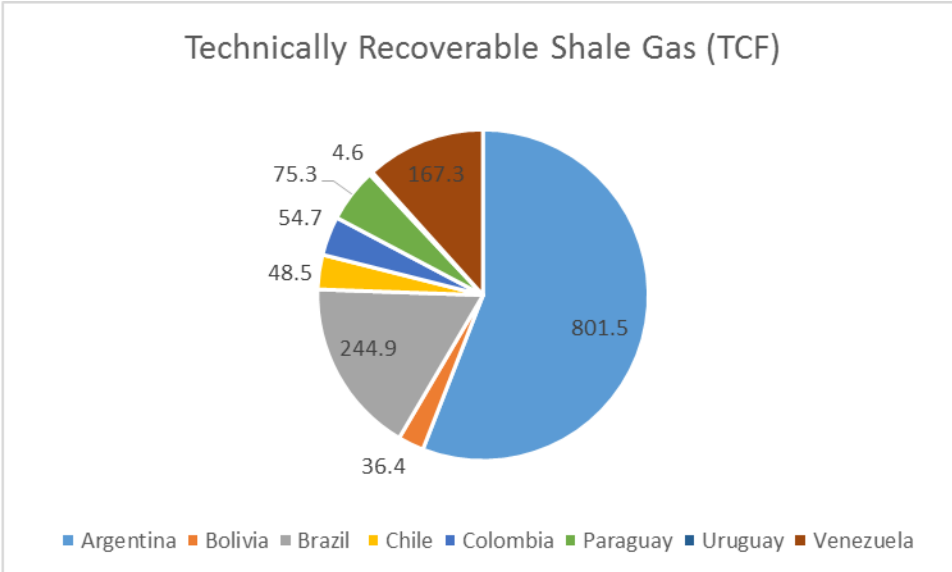

Figure 6. Technically recoverable shale gas in South America (Adapted from EIA, 2013)

This new scenario of an over-supplied market suggests intense competition between LNG and pipeline supplies in the near future (Wood 2016). In addition, unconventional gas will have a big impact in various markets and question the indexation of gas prices to oil (Reymond 2012).

2.2 Bolivian Gas Market Development

Hydrocarbon production in Bolivia is dependent on a relatively small number of fields located in the Southern Sub-Andean province: Sabalo, San Alberto and Margarita/Huacaya. These fields have similar characteristics: naturally-fractured gas-condensate reservoirs that target the Early Devonian formations (Huamampampa, Icla and Santa Rosa).

In 2016, the mega-fields represented 75% of the production of natural gas (MEH 2016). San Alberto and Sabalo have been producing for more than 15 years and their imminent decline could result in difficulties complying with existing natural gas delivery commitments. Nevertheless, the mega-fields are responsible for a large share of the national production of both natural gas and condensate in the coming years. Based on estimated decline rates made by YPFB (2014b) in their 5-year Corporation Strategy Plan 2015-2019, the mega-fields will still be relevant in the following years (Figure 7).

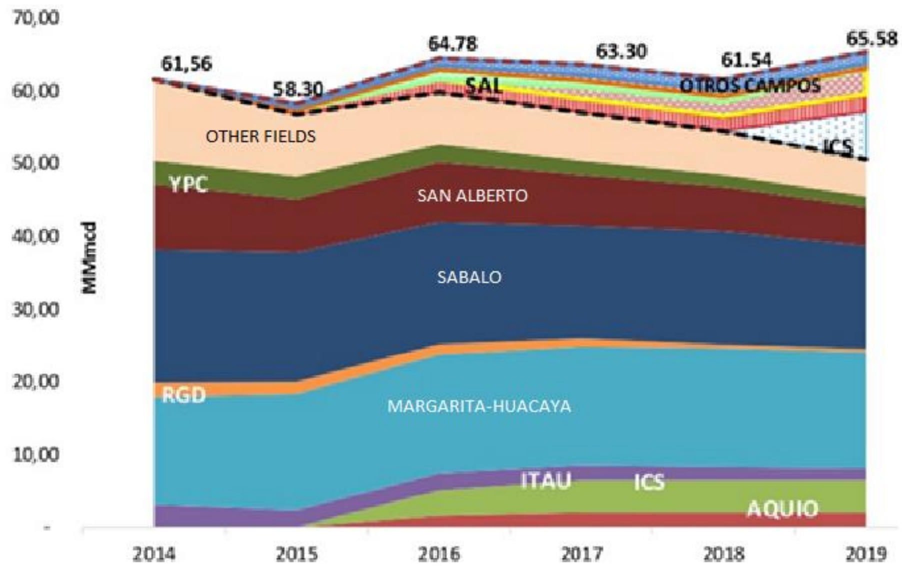

Figure 7. Forecast of natural gas production per field, 2015-2019 (Adapted from YPFB, 2014b)

The current decrease of reserves and production could potentially result in failure to satisfy contractual obligations to supply domestic and foreign markets. Such a decline also hinders the negotiations of a new gas sale contract with Brazil given that the current one ends in 2019. The last time Bolivian hydrocarbon reserves were certified (2013), proved natural gas reserves were 10.45 TCF (YPFB, 2014a). This volume seems insufficient to comply with the demand of a new contract with similar volumes as the current gas sale agreement with Brazil, considering the other prevalent contractual obligations and the growing domestic demand. The investments in hydrocarbon exploration have not been adequate to replace the produced reserves due in part to a perceived lack of legal security in the country, and an unfavorable fiscal system for International Oil Companies (IOC) after the legislation changes and the nationalization of hydrocarbons in 2005-2006.

Looking back, investments in exploration and exploitation started rising in 1997 (Fig. 3a), which led to the discovery of new reserves in the year 2000 (Fig. 3b). The initial investment boom was associated with the contract signed between YPFB and Petrobras for the supply of natural gas for 20 years to the Brazilian market, starting in 1999. A favorable investment environment was created by Hydrocarbon Law 1689 issued in 1996, which reduced the royalties to hydrocarbon discoveries after its issuance from 50% to 18%. In addition, the contractor benefited from a new concessionary system, an environment that facilitated the marketing of hydrocarbons, and the participation of foreign companies in transportation, distribution and industrialization activities (Perrault and Valdivia 2010). Subsequently, investments decreased and reached a low point in 2005-2007 because the contractors were averse to increasing investments after the contract with Brazil was consolidated, and the obligation to drill one well per parcel was annulled in 2001 by the Decree Supreme 26366 (Paz and Ramirez 2013). In this period, the new Hydrocarbon Law 3058 and the Decree Supreme 28701 were issued. The new fiscal regime increased state participation in the revenues of hydrocarbon sales by implementing a 32% direct tax on hydrocarbon production at the wellhead and requiring participation of the National Oil Company. The participation requirement remained variable and was defined in a renegotiation of the contracts with the IOCs that were operating in Bolivia. In effect, the contracts migrated from a concessionary system to a mix of a production sharing system and a service contract.

After 2007, E&P investments began rising again but were mostly directed to exploitation activities. In that period, the supply of natural gas to Argentina was initiated under a new 20-year contract. With these investments, national gas production rose from nearly 40 MMm3/d in 2007 to 59.6 MMm3/d in 2014 (YPFB, 2014a).

The Bolivian government has made efforts to stop the decline of the R/P ratio and to prevent the reduction of the revenues coming from natural gas activities by promoting investments in E&P. In legislative matters, the National Congress issued the Law of Incentives 767 that rewards the production of oil and condensate. In addition, the government plans to execute more than 40% of the investments in exploration through YPFB (2014b) and its subsidiaries in 2015-2019. Nevertheless, the current low-price commodity environment after the oil price slum of since 2014 and the fixed gas prices in the growing domestic market have deterred foreign oil companies from investing on Bolivian exploration. Meanwhile, pressure remains high to find new reserves as the gas demand increases, and negotiations for contract renewal with Brazil are just around the corner.

2.3 Brazilian Gas Market

The Brazilian gas market has three main sources: imports via pipeline from Bolivia, domestic production and imports from LNG plants. As shown in Figure 8, more than

50% of Brazil's gas demand of this hydrocarbon has been covered by imports from Bolivia and by LNG cargoes in 2014 (EPE, 2016).

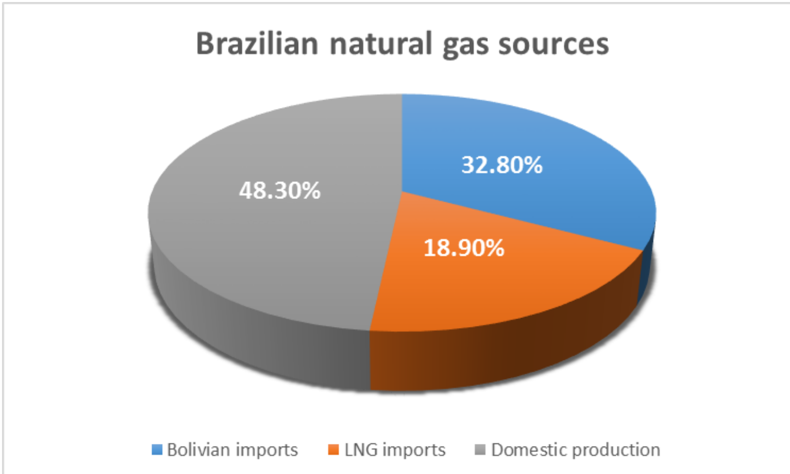

Figure 8. Brazilian natural gas supply sources in 2014 (Adapted from EPE, 2016)

The contract between Brazil and Bolivia for natural gas sales has a duration of 20 years with a maximum quantity of 30.08 MMm3/d. It was signed in 1996, and made effective in 1999 (YPFB, 1996). The contractual natural gas price depends on the prices of a basket of fuel oils, so it is linked to the price of oil (Appendix A.1). The contract ends in 2019 and negotiations for a new deal have already started, but the conditions are rather different than 20 years ago: the Brazilian gas market is being decentralized allowing institutions and state distributors to participate in the supply chain, domestic production has steadily increased, and LNG regasification plants are now available.

Brazil's national oil company, Petrobras, has controlled almost all the natural gas supply chain. However, recent changes aimed to decentralize the natural gas market. Brazil's Law 11909 (2009) created three new categories of consumers: the free consumer, the self-importer, and the self-producer. Each consumer can buy, import or produce natural gas for their own use. When state distributors cannot satisfy their needs, consumers can now independently build pipelines and infrastructure. Petrobras will no longer be the only actor.

The domestic production of natural gas in Brazil has consistently increased. Between 2005 and 2015, production almost doubled from 49 to 93 MMscfd (CNI 2016a). Nevertheless, only 49% to 68% of the total production has been available for the market in the past 10 years due to its common use for reinjection in offshore fields (CNI 2016a). Reinjection is especially prevalent in the Pre-Salt area where technical and economic challenges are faced: the producing fields are far from the shore and CO2 content in the gas is very high. Associated natural gas and carbon dioxide are reinjected to retain field pressure.

Pre-Salt fields already accounted for a third of Brazil’s natural gas and oil production in 2015, where the break-even price was round 45$/boe with an additional 5-7$ per barrel for transport and treatment of the natural gas (Honore 2016). Petrobras plans to gather Pre-Salt basin with three sub-marine pipelines: Routes 1, 2 and 3 with a combined capacity of 41 MMm3/d. Routed 1 and 2 began operating in 2011 and 2016, respectively. Route 3 is planned to start operating in 2018 with a capacity of 18 MMm3d (Figure 9).

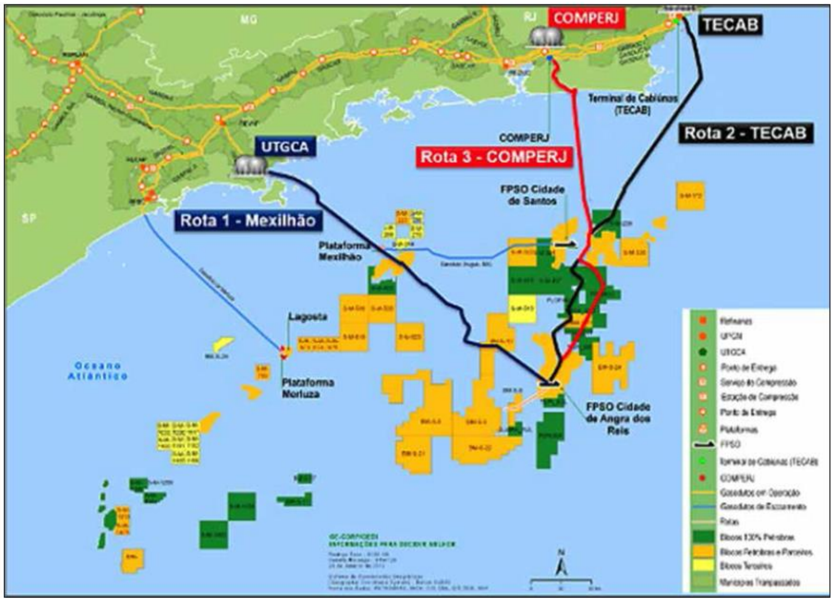

Figure 9. Gathering pipelines from Pre-Salt (Adapted from Petrobras 2014)

Slow paced exploration activities in the Pre-Salt area are partly due to the requirement of Petrobras participation as an operator and a 30% share (KAS 2016). In addition, the fields are located 200 to 300 km away from the coast, at depths of 5000 to 6000 m. below the sea level and in ultra-deep waters of 1900 to 2400 m (Honore 2016). Onshore conventional production offers significant potential but lack of pipelines and distribution networks in these isolated areas remains a barrier for onshore development. In remote regions, one solution is using the gas for electricity generation, since electrical infrastructure is more developed throughout the country. There is also potential for the development of unconventional resources but rigorous environmental legislation and lack of infrastructure in the areas of interest have prevented such development (Gomes, 2014).

Noteworthy, LNG imports are used to supply thermoelectricity plants when hydro supply becomes insufficient. Due to the seasonality of demand, LNG imports are negotiated in the spot market or in short-term contracts in 1-2 years with the main suppliers. However, they could start to play a bigger role in Brazil's natural gas supply due to a greater regasification capacity, uncertainty on the reliability of imports coming from Bolivia, and a new scenario of favorable prices due to global oversupply and low oil prices.

Brazil has three regasification plants with a joint capacity of 41MMm3d (Table 1): Rio de Janeiro (20), Ceara (7), and Bahia (14). A new terminal under construction in Rio Grande do Sul is expected to be functional in 2019 with a capacity of 19.5 MMm3d; 5.9 MMm3/d will be used for electricity generation and the rest will be available for the market (EPE, 2014).

In the future, domestic gas production in Brazil could reach 159 MMm3d in 2025, with approximately 72 MMm3d available for distribution in the natural gas market after reinjection use (CNI, 2016a). As for the demand, EPE (2014) foresees that demand will rise from 109 MMm3d in 2015 to 171 MMm3d in 2024. This means that natural gas imports will still be necessary, and may even increase if the planned thermoelectricity plants are built as expected.

It can be concluded that imports will still play a major role in the supply of natural gas of Brazil in the next 10 years which represents a good scenario for a new gas sale contract with Bolivia. Petrobras (2014) envisaged to maintain the current contractual volumes of production in its 2030 Strategic Plan beyond the finalization of the current contract, with

24 MMm3/d inflexible and 6MMm3/d flexible demand (Petrobras, 2014). However, since the efforts for the liberalization of its gas market in 2011, Brazil could reduce the gas quantities purchased from Petrobras by half and let state distributors negotiate their own contracts (El Diario, 2016).The state gas distributors and companies may not be able to sign long-term contracts with “Take or Pay” clauses which will result in higher volatility and a possible direct competition with LNG imports.

On the other hand, the availability of Bolivian gas for a possible new contract with Brazil will depend on exploratory efforts which have been slow in the past years. Most investments have been allocated to exploitation and low-risk exploration in well-known areas. CNI (2016a) suggests that investments in explorations should round between 5.4 and 7.1 billion dollars to guarantee enough gas for the domestic market, the petrochemical plants and the foreign exports in the period 2015-2026.

2.4 Argentinian Gas Market

Argentina has historically been a producer and consumer of natural gas, which had a share of approximately 50% of the total energy matrix in 2015. It is the largest gas market in South America (approximately 120 MMm3/d in 2015), accounting for 36% of the regional demand (Honore, 2016). In the past decade, a deficit in domestic production due to policies of artificial pricing has forced Argentina to import natural gas via pipeline from Bolivia and via LNG shipments, and to accelerate the development of unconventional gas resources.

The natural gas supply contract between Bolivia and Argentina was signed in 2006 for a duration of 20 years (YPFB, 2006), with scaling volumes reaching a maximum quantity of 27.7 MMm3/d by 2021 (Appendix A.2). The price determination method is based on the prices of a basket of fuel and diesel oils (Appendix A.2). These contracts include the “Take or Pay” and “Deliver or Pay” clauses, which state the obligation of selling and buying a stipulated minimum quantity of natural gas. The contractual volumes were modified in the Addendum signed in March 2010. Previously agreed volumes could not be met due to the delay of gas transportation infrastructure and the insufficient production in Bolivia (Ceppi, 2014).

LNG imports are seasonal and the capacity of the regasification terminals in Bahia Blanca and Escobar (Table 1) is used during winter when domestic consumptions peaks. In contrast to Brazil, Argentina does not plan to expand its regasification capacity but it is trying to replace such imports with domestic produced gas.

As for domestic production, the most promising formation is primarily the Vaca Muerta formation in the Neuquen Basin (Gomes and Brandt, 2016). Although most of the shale activity is focused on the oil-prone zone, shale gas resources are just as important: they are estimated to be 801.5 TCF for Argentinian (EIA, 2013). Exploration and early commercial programs are being developed, and more than 1,101 wells had been drilled by 2015. During that year, unconventional gas production was 235.5 bcf, accounting for 15.5% of the total domestic production (Gomes and Brandt, 2016). Most of it comes from tight gas fields whose combined production reached 14.4 MMm3/d in 2015 and it continues to ramp up. This occurred because tight gas is more competitive than shale gas: the first has a producing cost in the range of 4.5-5 $/MMBTU while the latter has a cost range of 5-5.9$/MMBTU (Gomes and Brandt, 2016).

The Argentinian government has made efforts to provide price incentives for domestic production. The Gas Plan implemented by the government in January 2013 gives an incentive for gas projects of up to 7.5 $/MMBTU for additional production which is above the decline curve agreed between the government and the oil company. This plan has been extended for two additional years ending December 2019. However, the learning curve for unconventional resources exploitation is still steep and significant capital is required to develop these resources. Di Sbroiavacca (2013) proposes a scenario that $16 billion of investments are necessary to reach self-sufficiency in 2022. In a more conservative scenario, Di Sbroiavacca (2013) suggests that Argentina will still rely on imports until 2030. In parallel, the forecast made by the Oxford Institute of Energy Studies (Gomes and Brandt, 2016) estimates that 34 MMm3/d will still be needed from imports by 2027.

2.5 Future Development of the Bolivian Gas Market

The domestic gas market in Bolivia is directed to four types of consumers: residential, industrial, commercial, and thermoelectricity plants. In early 2017, total domestic natural gas consumption was around 12.5 MMm3/d (MHE, 2017) and it has maintained a growing trend in the past decade. The forecasts made by YPFB indicate a 7% demand increase for commercial and residential consumption, and a 5% increase for its use in thermoelectricity plants. This tendency is corroborated by Chavez-Rodriguez et al. (2016) who forecast an annual rate increase of 6.6% between 2012 and 2030. Growth in domestic demand could affect the feasibility of new projects since prices are fixed for the domestic market. Some companies have already asked for a revision of the price determination method.

Additionally, national policy gives priority to the industrialization of natural gas. This aims to maximize the economic and social benefits by investing in petrochemical plants such as a gas-to-liquid (GTL) Plant, ammonia, urea, and polyethylene, or providing natural gas to energy intensive projects such as the steel mega mine “Mutun”. However, the feasibility of these projects depends on the price of natural gas, which will most likely be lower than the prices paid by Argentina and Brazil. For instance, a YPFB feasibility study of the urea plant has shown a ROR of 18.14% with a price of $2.5/MMBTU, and it would take 11 years to recover the initial investment (CNI, 2016a). A larger share of subsidized prices would affect the stakeholders in exploitation activities.

Domestic production of hydrocarbons can increase in both Argentina and Brazil which would result in a reduction of the imports from Bolivia. Argentina has an immense potential for developing unconventional oil and gas. On the other hand, Brazil has increased the production of associated gas from the offshore oil fields in the Pre-salt. Both countries face technical and economic challenges to developing these resources but in the medium term they could compete or replace the gas coming from Bolivia. It is worth remembering that the gas sale contracts with Brazil and Argentina end in 2019 and 2027, respectively.

LNG imports in the region have been increasing, Brazil and Argentina are not the exception. These countries have grown their regasification capacity. Currently, imports via LNG shipments is seasonal: Argentina imports it in winter when the residential consumption peaks, and Brazil buys it for electricity generation when hydroelectric plants fail to fully supply the domestic demand. Prices of LNG have been getting more competitive, but gas coming from Bolivia is still the cheapest.

2.6 Future Regional Gas Demand Scenarios for Bolivia's Gas Price-Making

An estimation of the demand scenarios is necessary to determine the likely future natural gas price, a key input for the economic analysis in Section 5. This price is impacted by the shares of the domestic and foreign natural gas market, since a weighted average of the natural gas prices is assumed (a growing domestic demand will lower the overall price due to its subsidized price). The demand scenarios can be balanced to the current fields' production and shows when the gap between supply and demand is created.

Low demand scenario. This scenario assumes an annual growth of 6.6% for the domestic gas demand according to a study by Chavez-Rodriguez et al (2016). For the Brazilian and Argentinian cases, the lowest contractual demand is assumed (Take or Pay quantities). For the period following the end of the contract with Brazil, a steady demand of 16 MMm3/d is assumed for that market (Figure 10).

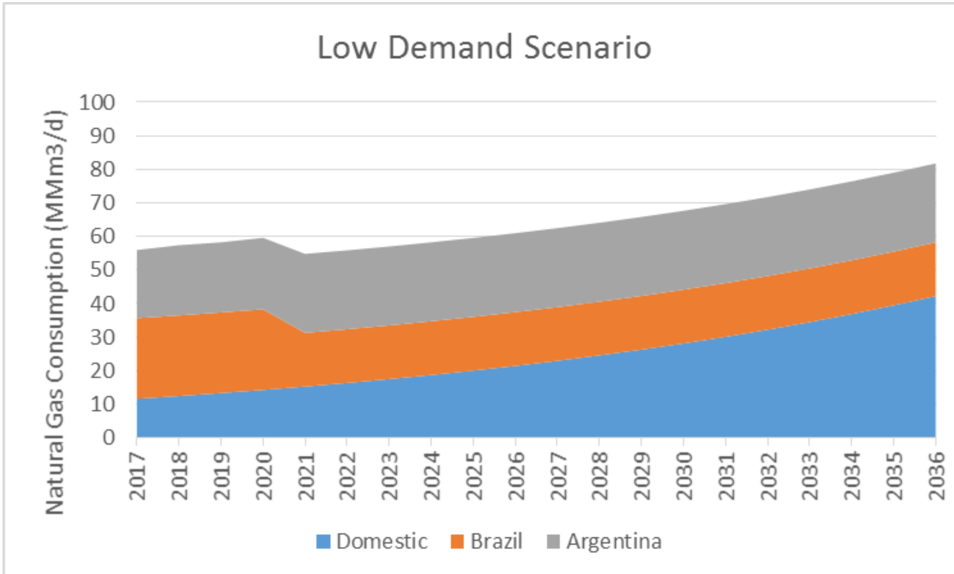

Figure 10. Natural gas low demand scenario assuming "Take or Pay" quantities in the Brazil and Argentina contracts. A contract renewal for 16 MMm3/d is assumed for the Brazilian market after the current contract ends in 2020.

High demand scenario. The domestic gas demand growth rate is the same as the low demand scenario plus 2.8 MMm3/d starting in 2018 assuming the installation of the planned polyethylene plant (2014b) Strategic Plan 2015-2019. As for the export markets, the maximum contractual gas delivery quantity is selected and maintained beyond the finalization of the contracts, assuming a contract renewal with the same characteristics (Figure 11)

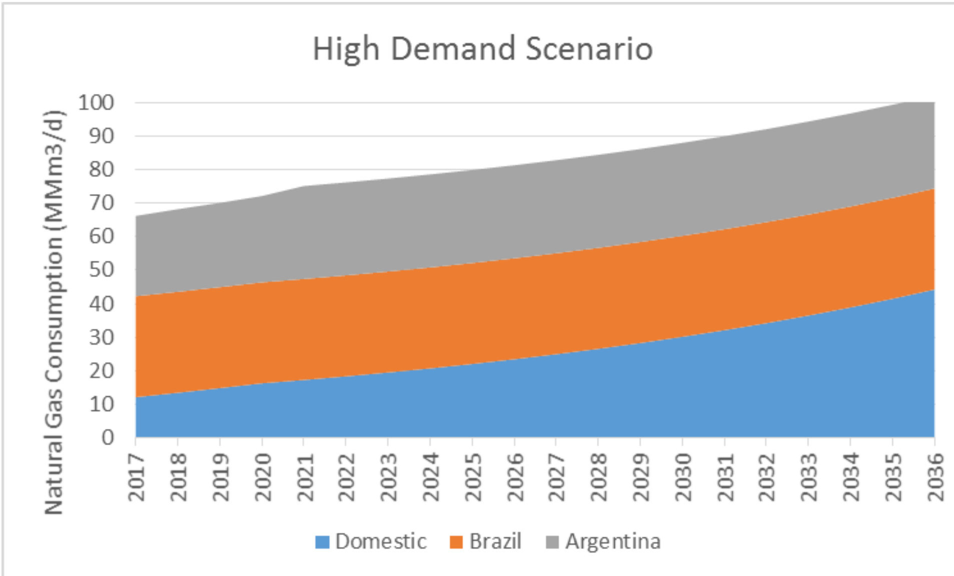

Figure 11. Natural gas high demand scenario: Assuming the installation of the polyethylene plant in Bolivia and the maximum contractual volumes for Brazil and Argentina with the renewal of the contracts after their finalization

Comparing the demand scenarios to the supply of natural gas, a gap is seen to emerge from 2024 onward for the low demand scenario, and in 2020 for the high demand scenario (Figure 12). The assumptions of the natural gas supply are based on the studies made by CNI (2016a) and the expected decline of the existing producing fields made by YPFB (2014b).

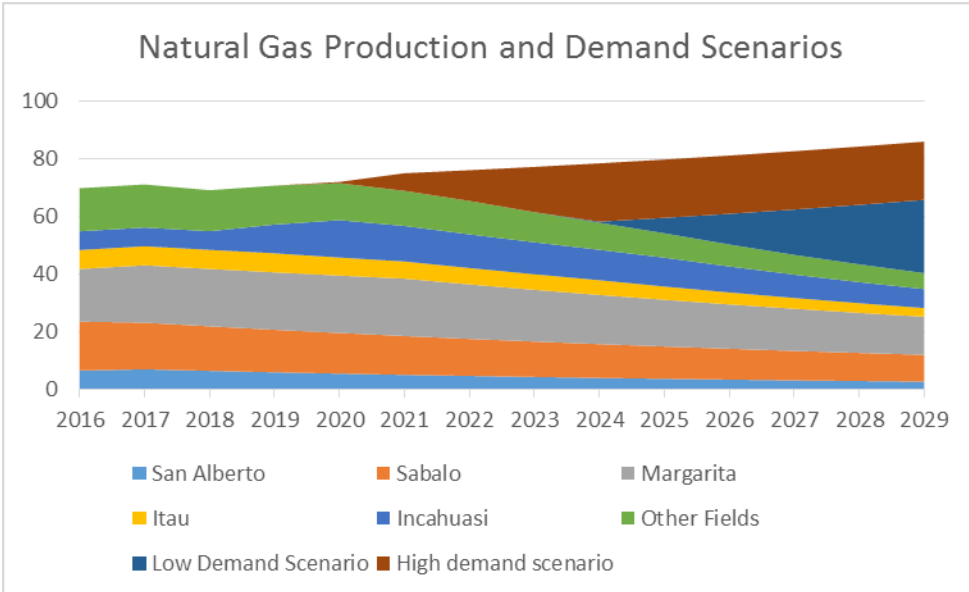

Figure 12. Natural gas supply compared to demand scenarios: A gap between supply and demand can be seen in 2020 for the high demand scenario, and in 2024 for the low demand scenario

CHAPTER III

FIELD PRODUCTION ANALYSIS OF REPRESENTATIVE MEGA-FIELD

In this section, a brief description of the geological setting, the discovery and development of the representative mega-field is provided for proper context. Then, a production forecast is performed using Decline Curve Analysis using historic production information. The outcome will be used as input for the economic evaluation and cash flow presented in Chapter 5.

3.1 Geological Setting

The studied field is located in the Sub-Andean zone of the Chaco basin in Bolivia. The basin comprises a 60-km long narrow anticline which begins in South East Bolivia and ends in Northern Argentina. The Chaco basin can be divided into four sub-provinces: the Sub-Andean Zone, the Foothill Belt, the Sub-Chaco basin and the Izozog high. USGS (2012) indicates that undiscovered natural gas in the area has a mean value of 26 TCF. Bolivia holds 80% of the reserves of the basin, Argentina holds 20% and Paraguay less than 1 % (Zhang et al., 2014)

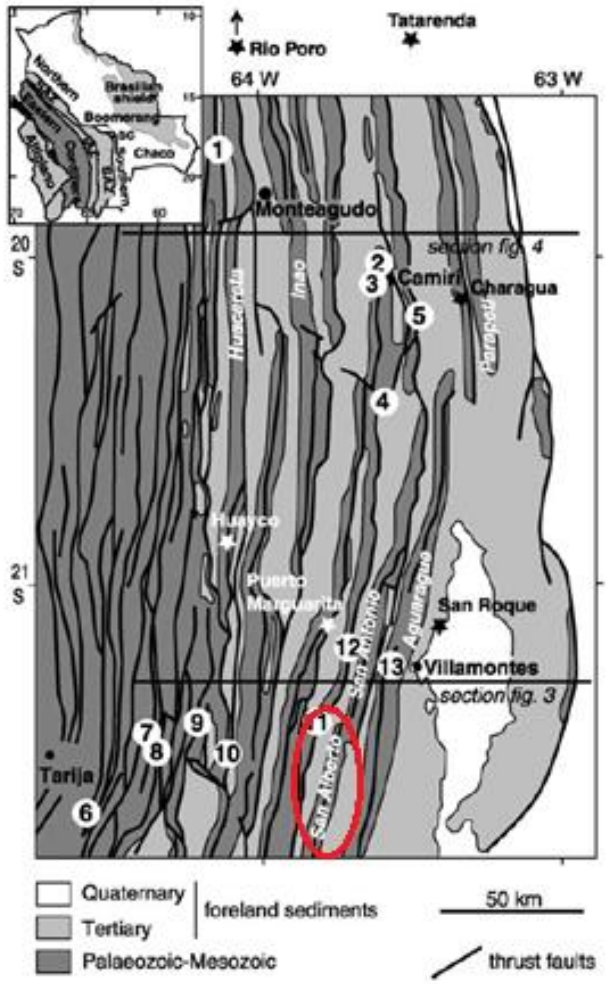

Figure 13. Structural map of the Southern Sub-Andean Zone of Bolivia, circled in red the studied field (Adapted from Moretti et.al, 2000)

The Sub-Andean Zone proper is a fold and thrust belt (Figure 13) with two major detachments, on the eastern margin of the Andes (Figure 14). The zone is characterized by north to north-northeast trending, narrow anticlines (Dunn et. al., 1995). Bolivian hydrocarbon potential is concentrated in this zone comprised of a series of anticline structures, the San Alberto field being a prime example (Mathewson and Bloor, 1998).There are two petroleum systems in the Sub-Andean zone (Figure 14): the

Devonian shale as source rock and the Upper Devonian sands as reservoirs, and the Silurian and Lower Devonian as source rocks (Kirusillas and Icla Formations) and the lower Devonian sands as reservoirs (Moretti et al, 2002).

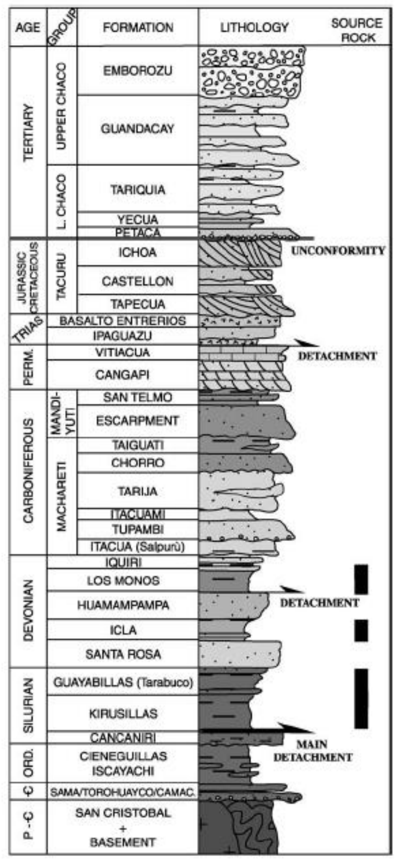

Figure 14. Lithostratigraphic column of the Southern Sub-Andean province with main source rocks marked by vertical bars (Adapted from Moretti, 2000)

Exploration and production technical challenges in the studied field are related to seismic acquisition and a rugged topography. The structures in the Sub-Andean are steep with dips close to 90 degrees and the area has up to 100-m cliffs, making it hard to access. These phenomena along with the poor signal-to-noise ratio contribute to one of the major exploration problems in the zone: obtaining reliable seismic profiles (Ravaut et al. 2002).

The lithology is comprised of hard rock with consistently low values of both porosity and permeability in all the mega-fields: matrix porosity of 5%, fracture porosity of 1%, and fracture permeability in the hundreds of milliDarcies (D'Arlach 2016).

3.2 Development and Production History

The studied field is a gas-condensate naturally fractured reservoir. OGIP was estimated to be 5.3 TCF (Soares 2000). The history of the field goes back to the 60's and 70's, when YPFB drilled eight wells and produced oil from the Miller formation, at depths of around 1000-2000 m. In 1990, based on further geological studies and discoveries in the Argentinian part of the structure, YPFB drilled a well and discovered a gas-condensate reservoir in the Huamampampa formation of the Early Devonian (4500 m. deep).

In 1996, Petrobras Bolivia S.A signed a contract with YPFB for the San Alberto block. Petrobras drilled an additional well, targeting the Huamampampa, Icla and Santa Rosa formations. The results were positive and in 1999, YPFB approved the Declaration of Commerciality of the field. Nine more wells were subsequently drilled (Table 2).

3.3 Production Forecast

Historic production data is available for the entire life of the field since the first production well came on stream in 2001 until 2016 (Figure 15) and on a per-well basis until 2012.

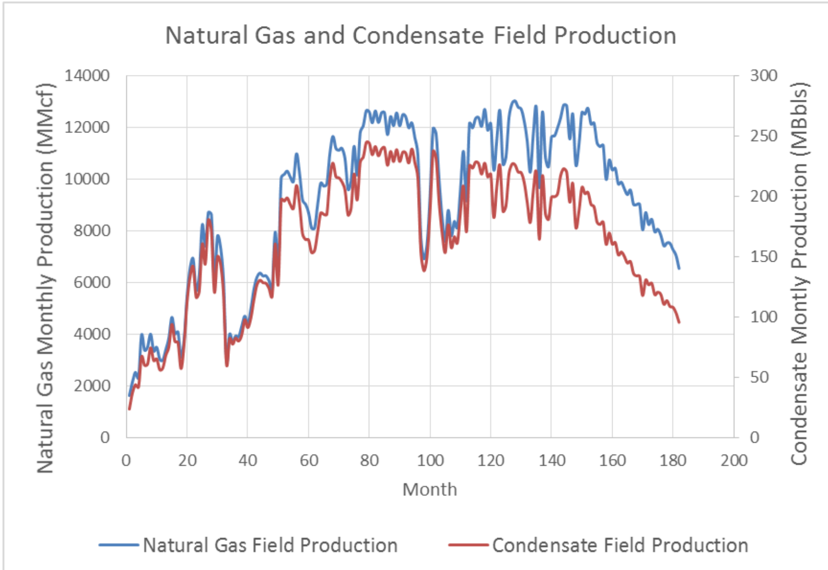

Figure 15. Production history for natural gas and condensate

The ramp up in production lasted nearly 5 years and the plateau was reached in month 78. The reduction in production outputs for months 98 to 109 correspond to the year 2009 when demand of natural gas in Brazil decreased due to the global economic crisis.

Table 2. Well schedule and status

Well	Start of production	Month #	Status
XX1	2001	9	Shut-in
XX2	2001	2	Producing
XX3	2001	1	Shut-in
XX3R	2012	133	Producing
XX4	2001	5	Producing
XX5	2002	17	Producing
XX6	2004	47	Producing
XX7	2011	121	Producing
XX8	2012	136	Producing

Arps (1945) decline curve analysis (DCA) was performed in a per well basis using the monthly production data until 2012 (Appendix C). Using the Arps equations and the least squares method, a fit was obtained for the parameters qi, Di and b. The results were not satisfactory. Some wells do not show any decline and others only have a few months of data. Subsequently, the regression fit was performed for the aggregated production of the field using the last 34 months of data which correspond to the decline phase as seen in Figure 15. The historic match was done for both natural gas (Figure 16) and associated NGL (Figure 17) separately to independently account for the reduction in the ratio gas and liquid production.

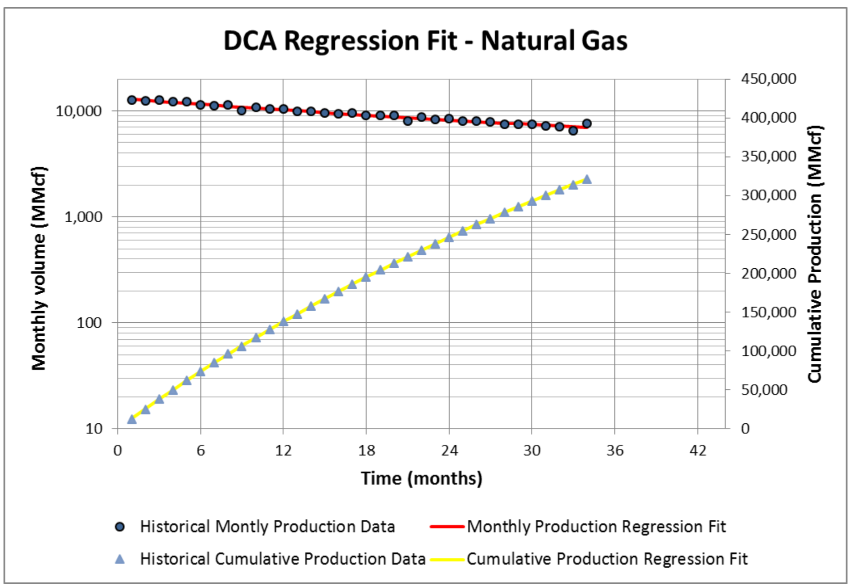

Figure 16. Decline curve analysis regression fit for natural gas production using the last 34 months of available data

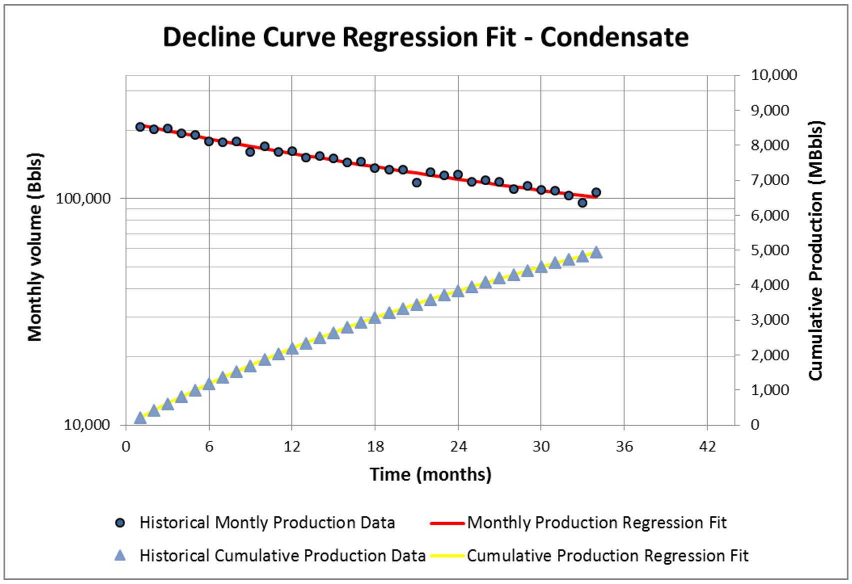

Figure 17. Decline curve analysis regression fit for natural gas production using the last 34 months of available data

The regression fit values of the three parameters of the hyperbolic production forecast type curve are shown in Table 3. These parameters were used to construct production forecast type curves used later in this study (Figure 27, Section 5).

Table 3. Arps decline fit parameters

Parameter	Natural Gas	Condensate
Qi	428,952	7,024
Di	0.279	0.346
b	0.676	0.654

CHAPTER IV

FISCAL REGIMES AND PRICING MECHANISMS

This section addresses two of the major factors that impact an oil and gas project's profitability in Bolivia: the fiscal regime and the price determination methodology. This data will be an input for the cash flow model results of Section 5.

4.1 Fiscal Regime Effectiveness: Generic

Efficiency of a fiscal regime is typically evaluated using two economic indicators: the rate of return due the contractor, and the split of the NPV between the government and the contractor referred as government take and contractor take (Demirmen 2010; Weijermars 2016). A 10 % discount rate is commonly used in the oil and gas industry in estimations of NPV based on future values of cash flows. Different price scenarios and field development plans are tested, while properly accounting ruling fiscal system conditions.

In order to achieve efficiency when profitability of the project improves due to price variation, or unexpected productivity or field size, a tax can be linked to the rate of return on investment or the R factor which is the ratio of the contractor's cumulative revenue to the cumulative cost.

A poor design could lead to the government wanting to revise the fiscal system when there is an unexpected bonanza, or an economic loss for the company in a negative scenario. The contractor prefers stability in contracts, and a revision in the middle of the project will generate disincentives for future projects. Oil companies evaluate investments on explorations depending on a country's geological conditions, political stability, reliability of legal systems, existence of a market and infrastructure, and the fiscal system. A fiscal regime should be simple to apply, provide the conditions to encourage exploration, promote development of fields of different sizes taking into account their technical difficulty, and give equal economic benefits to the contractor and the government (Demirmen 2010). Fiscal regimes should be designed to achieve a win-win situation between them, with an adequate rent for the first and a rate of return on investment commensurate with project risks for the second. In an efficient fiscal regime, the NPV of the contractor before the government take honors the NPV after its take (Mian 2011). Another way to assess the attractiveness of a fiscal system is by the attributes of certainty, clarity, efficiency, equity, flexibility, neutrality, risk sharing, profit sharing and transparency (Abdul Manaf et al 2016).

4.2 Fiscal Regimes and Contracts for Hydrocarbon Activities in Bolivia

Bolivia has had many changes in legislation concerning hydrocarbon exploration and exploitation. In the past 30 years, three major hydrocarbon laws have been passed by the Bolivian Congress: Law 1194 in 1990, Law 1689 in 1996, and Law 3058 in 2005. Congress also issued the Supreme Decree 28701, known as the nationalization decree, in 2006. The key subjects of modifications were the type of contracts to be signed between Bolivia and International Oil Companies, the fiscal system, the participation of the Bolivian National Oil Company, and the hydrocarbon price determination. In this study, the principal focus will be on the legislation valid in 2000 and onwards. A summary graph of the fiscal regime history of Bolivia is given in Figure 18.

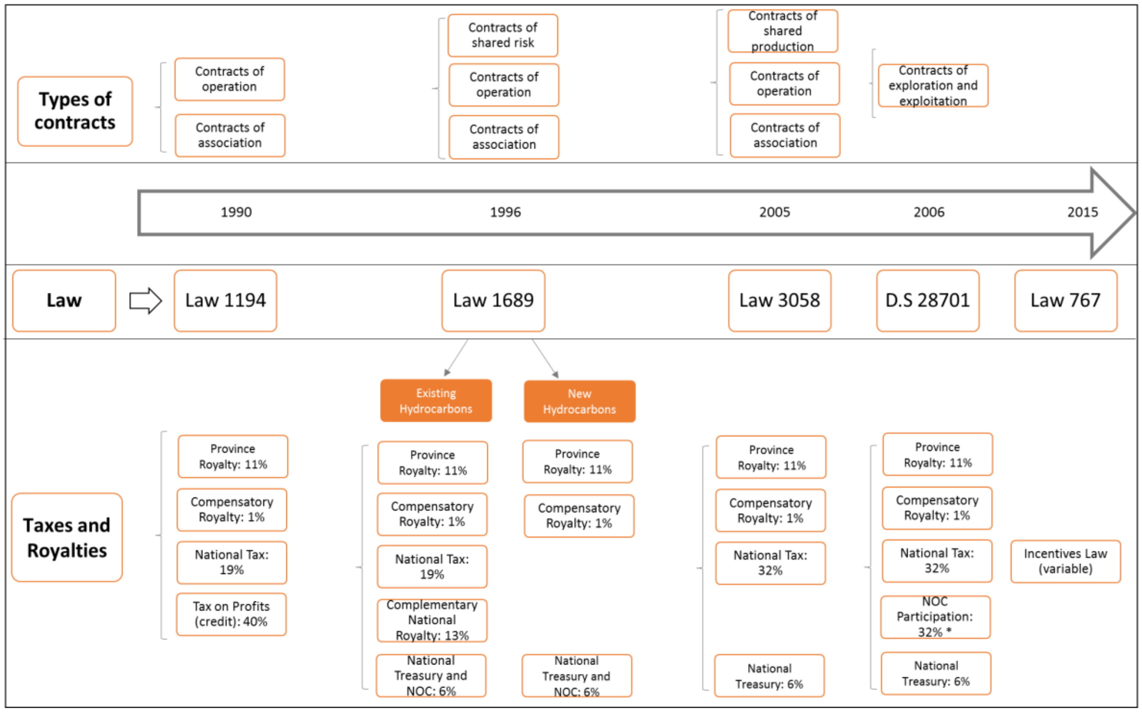

Figure 18. Fiscal regime history in Bolivia (1990-Present)

The principal fiscal rules are briefly outlined below.

Law 1689 (CNB 1996) introduced the Contract of Sharing Risk, which in practice represents a concessionary system contract. This type of contract replaced the former Contract of Operation and Contract of Association stipulated in Law 1194. For this type of contract, the IOC was responsible for all investments and risks in the exploration phase. Once a discovery was made, the NOC would reimburse part of the investments according to its participation in the contract, if any. The IOC was free to commercialize its production to the market of their choice.

Law 3058 (CNB, 2005) re-introduced the contracts of operation and association, and replaced the risk sharing contract for a production sharing contract (PSC). Companies that were already operating before this law was issued were forced to sign contracts under these new conditions which were classified as operation contracts. Forty-four of this type of contract were signed in October 2006. In practice, they are a combination of a PSC and an operation contract: the investments made by the company are refunded once the discovery is made like a PSC contract, but the contractor share is given in money like an operation contract and the resource property remains national. Companies have the right of part of the production, but no ownership meaning that IOCs can't book proven reserves (Ghandi and Lin, 2014). The second type of current contract is the service contract for exploration and exploitation introduced by the Resolution of the Ministry 150-10 in 2010 (Paz and Ramirez, 2013). For this case, after the discovery of hydrocarbons and the declaration of commerciality, a joint venture between YPFB and the contractor must be created, where the NOC remains as the major stakeholder. All rights and obligations are transferred to the newly formed company.

Law 1689 differentiated the fiscal system between existing and new hydrocarbons. Existing hydrocarbons were the ones discovered and certified before 30 April 1996. Companies extracting these existing hydrocarbons were subject to pay the taxes and royalties shown in Table 4. The taxable base was the production at wellhead minus the transportation costs:

Table 4. Fiscal system for existing hydrocarbons (Adapted from Law 1689, 1996)

Royalty or Tax	Percentage
Producing Province Royalty	11%
Compensatory Province Royalty	1%
National Tax (wellhead production)	19%
Complementary National Royalty	13%
NOC and National Treasury	6%

The new hydrocarbons were subject to the taxes and royalties shown in Table 5. The taxable base was the production at wellhead except for the surtax and national taxes.

Table 5. Fiscal system for new hydrocarbons (Adapted from Law 1689, 1996).

Royalty or Tax	Percentage
Producing Province Royalty	11%
Compensatory Province Royalty	1%
NOC and National Treasury	6%
Other national taxes (Indirect)	Variable

The other national taxes included the following:

- Profit tax (IUE) of 25% whose taxable base were the profits made by the company
- Remittance tax (IRUE) of 12.5% on the money sent overseas
- Surtax of 25% on extra-ordinary profits which were to be defined in the contract
- Value added tax (VAT) of 13% applied only to sales in the domestic market.
- Transaction tax (IT) of 3%, applied to sales in the domestic market.

The profit tax could be deducted from the payments of royalties, capital costs (a deduction for depreciation), and previous losses. The surtax taxable base was the value at wellhead. The company could deduct up to 33% of cumulative investments that cannot be transferred to other years, and 45% of the value of production at wellhead per field with a limit of Bs. 250 million. This amount was updated according to inflation and the exchange rate in comparison with the U.S dollar. Law 3058 introduced the Direct

Tax on Hydrocarbons (IDH in Spanish) of 32% on the gross production at wellhead. The new fiscal system is shown in Table 6.

Table 6. Current fiscal system for hydrocarbon exploitation (Adapted from Law 3058, 2005)

Royalty or Tax	Percentage
Producing Province Royalty	11%
Compensatory Province Royalty	1%
NOC and National Treasury	6%
National Tax	32%
Other national taxes	Variable
YPFB Participation* (DS 28701)	Variable

Decree Supreme 28701 (CNB 2006) required an additional participation of the National Oil Company (YPFB) of 32% on the gross production of gas fields that had an average production higher than 100 MMscfd in 2005. In practice this was not the case: YPFB participation is defined in the contract based on the production flow rate and the ratio of the cumulative revenue and the cumulative cost, called the B factor. The greater the B factor, the more participation YPFB is entitled to. The B factor tables for the San Alberto field can be found in Appendix B.

Law 707 was issued in 2015. It creates an incentive for oil and condensate production (Law 707, 2015). The incentive depends on the type of fluid produced (oil or condensate), if production is coming from a new or old field, and whether the field is in the Traditional or Non-Traditional zone (Table 7). This incentive goes only to production directed to the domestic market. The law creates the Fund of Incentives to

Hydrocarbon Exploitation and Exploration which consists of 12 % of the Direct Tax on Hydrocarbon.

Table 7. Incentives according to type of fluid and zone (Adapted from Law 767, 2015)

Type of fluid	Price/Incentive	Traditional Zone		Non-Traditional Zone	
		Incentive Inferior limt	Incentive Superior limt	Incentive Inferior limt	Incentive Superior limt
Oil	Oil Price ($/bbl)	116	20.35	116	20.35
	Incentive ($/bbl)	30	50	35	55
Condensate	Oil Price ($/bbl)	106.29	27.11	106.29	27.11
	Incentive ($/bbl)	30	50	35	55
Additional Condensate	Oil Price ($/bbl)	74	27.11		
	Incentive ($/bbl)	0	30		

In addition, the Bolivian Government has issued reforms to provide a better environment for IOCs to operate in Bolivia.

- DS 2298 was issued in March 2015. It changes the legislation concerning the rights of direct consultation to indigenous communities regarding hydrocarbon exploitation activities. The decree modifies the schedule of the consultation in order to accelerate the process.
- DS 2366 was issued May 2015. The decree authorizes hydrocarbon activities in environmental protected areas, with industry's best practices to prevent and mitigate the environmental impact.

- DS 2549, October 2015, more areas reserved for YPFB, no bidding process, direct negotiations and contract awarding.

4.3 Natural Gas Pricing Mechanisms, Generic

Natural gas prices are usually determined by the market, the price of a competing fuel (usually oil), or regulated by the government. IGU (2016) classifies the mechanisms into 8 categories; the 3 that concern this study are listed below:

a) Oil Price Escalation (OPE). The natural gas price is linked to competing fuels through a base price or escalation clause. The competing fuels are usually oil, gas oil or fuel oil.

b) Gas-on-Gas Competition (GOG). The natural gas price is determined by the market (supply and demand). It is traded at physical hubs or notional hubs. Gas can be bought and sold on a short term basis and long term basis which is usually included in contracts using these prices instead of competing fuel prices. Spot LNG is included in this category.

c) Regulation: Social and Political (RSP). The price is determined by a regulatory entity of the government on a social/political basis, usually to cover increasing costs.

From 2005 to 2015, the pipeline and LNG imports price in the global market has increasingly been determined by GOG at the expense of the OPE mechanism.

In Latin America, GOG has risen mainly due to spot LNG imports in Argentina, Brazil and Chile. The OPE mechanism still represents the largest portion in the Latin American market, accounting for 28% of the total consumption (IGU, 2016).

4.4 Natural Gas Pricing Mechanisms in Bolivia

The natural gas prices in Bolivia are determined by the weighted average of the natural gas prices for each market (e.g. domestic, Brazilian exports and Argentinian exports) in both legislation periods. The domestic market has fixed prices for the industrial, commercial and residential use, while the prices for Brazil and Argentina are stipulated in each contract and are indexed to a basket of fuel oils (Appendix A). Hence, the weighted average gas price depends on the participation of each market over the total production and the WTI price. The historical gas prices for the export markets and WTI oil prices are available for the period 1999-2016 (Figure 19).

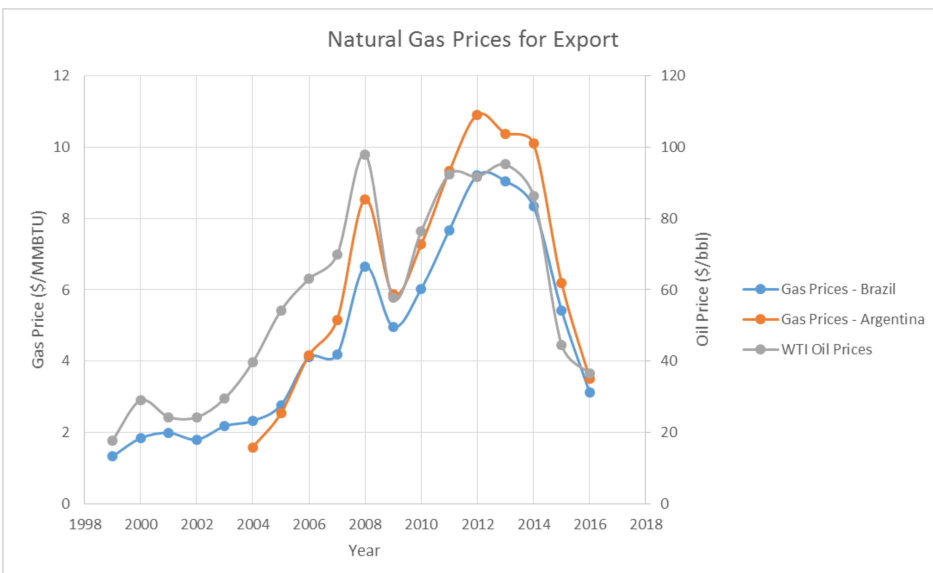

Figure 19. Historical natural gas and oil prices (Adapted from YPFB and EIA, 2016)

The underlying correlation between the WTI oil price and export prices to Brazil and Argentina can be modeled. Using the historical data, a linear regression (Figure 20) was performed for each contract in order to determine future prices (Section 4.5). The correlation coefficient (R^2) is 0.85 for the Argentinian contract, and 0.88 for the Brazilian contract.

$$P_{G,Arg} = 0.1077 * WTI - 0.4264 \qquad \textit{Eq. 4.1}$$

$$P_{G,Br} = 0.0796 * WTI - 0.2915 \qquad \textit{Eq. 4.2}$$

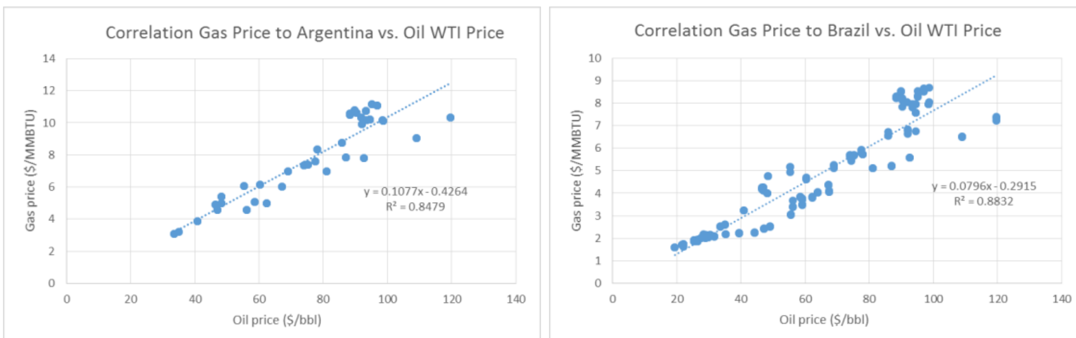

Figure 20. Correlations between gas prices and WTI oil price a) Argentina b) Brazil

As for oil, in the period 1996-2006, the prices were given by an average of a basket of oil prices. In this document, the WTI price is used due to lack of data of the oils considered in that basket. In the current legislation, the oil price for the domestic market is fixed at a price of 27.11 $/bbl before taxes.

4.5 Future Price Scenarios of Oil and Natural Gas

Oil prices have been characterized by being volatile. In recent years, the WTI price has varied from a maximum of $140 per barrel in June 2008 to $26 per barrel in February 2016 (EIA, 2016). To account for the volatility of the prices, five WTI oil price scenarios were considered (Figure 21). The scenarios reach prices of 40, 60, 80, 100, and 120 US dollars per barrel in 2020 and stay constant for the remaining life of the field.

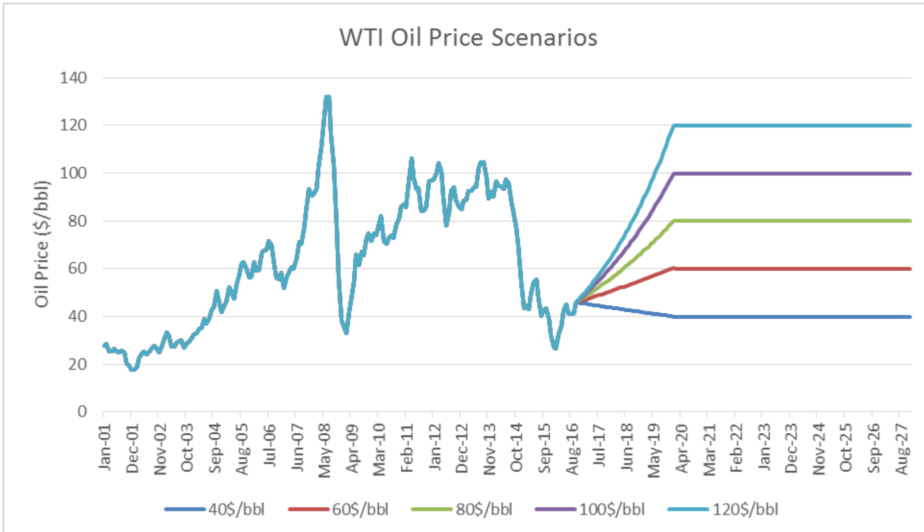

Figure 21. WTI historical prices and forecast for different price scenarios

Based on the oil price scenarios, the linked gas prices for the Argentinian (Figure 22) and Brazilian (Figure 23) markets were calculated using Figure 21. The price determination methodology relies on the weighted average of the real prices to the domestic, Brazilian and Argentinian markets. The domestic gas price is regulated, in 2014-2017 the gas price rounded $1.1/MMBTU (MEH, 2017); this study assumes this constant price for the future.

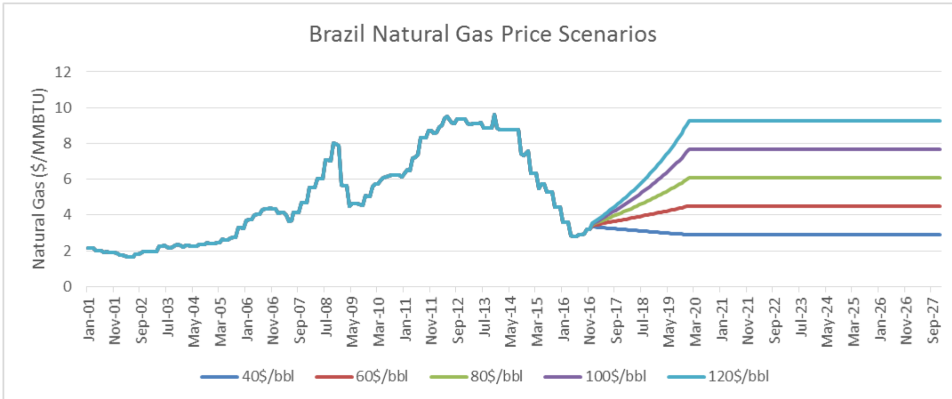

Figure 22. Natural gas historical prices and forecast for different price scenarios to Brazil

The price scenarios of Figure 22 and Figure 23 will be used as input for the economic analysis of Section 5 and perform a price sensitivity analysis.

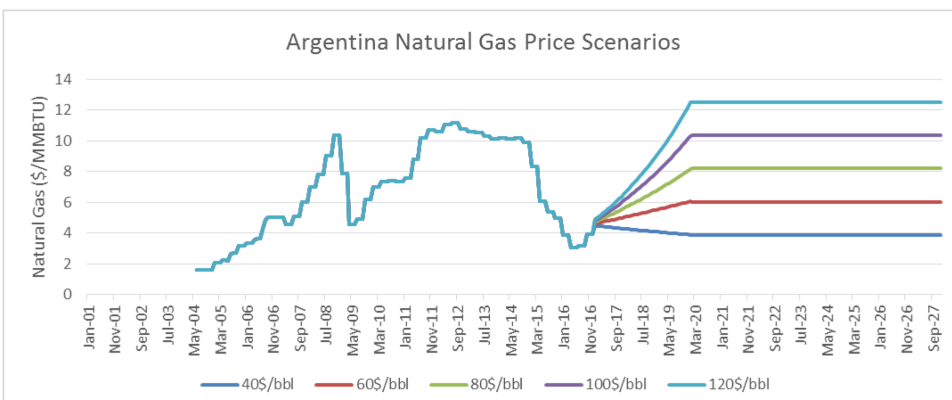

Figure 23. Natural gas historical prices and forecast for different price scenarios to Argentina

CHAPTER V

INPUTS AND FISCAL SCHEDULES FOR ECONOMIC APPRAISAL OF REPRESENTATIVE MEGA-FIELD

In this section, the methodology to calculate the Net Present Value, Government Take and Contractor Take for the studied mega-field are given under different fiscal schedules based on hydrocarbon and tax legislation, and previous work by Medinaceli (2007) on Bolivian fiscal regimes. The results will be used to evaluate the fiscal regime, the stakeholder's interest and the profitability of the representative mega-field for the contractor.

A common industry measure for the profitability of field projects is the Net Present Value of Future Vales (FV_t) at 10% discount rate and the rate of return (IRR) of the contractor. They were calculated using equations 5.1 and 5.2, respectively.

$$NPV = \sum_{t=1}^{n} \frac{FV_t}{(1+r)^t} \qquad \textit{Eq. 5.1}$$

$$\sum_{t=1}^{n} \frac{FV_t}{(1+IRR)^t} = 0 \quad \rightarrow IRR \qquad \textit{Eq. 5.2}$$

In order to evaluate the impact of the incentives law for possible future investments, the NPV and the expected monetary value (EMV) for the company were calculated. An investment with an EMV (Eq.5.3) greater than 0 is considered acceptable.

$$EMV = \sum_{t=1}^{n} NPV * P(NPV) \qquad \textit{Eq. 5.3}$$

In order to compute the net cash flows the applicable tax regime needs to be properly accounted for, which for the production period of the field comprises two periods of fiscal regimes: Period 1 (2001-2006) and Period 2 (2007 onwards), and an additional incentive (2015 onward). These fiscal schedules are described in detail below.

5.1 Fiscal Schedule for Economic Analysis: Period 1 (2001-2006)

As described in Section 4.2, the fiscal regime for oil and gas activities was ruled by Law 1689 during the initial production period (2001-2006) of the mega-field. The concessionary system defines two sources of income for the government: royalties to the gross revenues of natural gas sales, and indirect taxes. The workflow to obtain the contractor take, government take and their cash flow under Law 1689 is shown in Figure 24. Each step is further explained afterwards. The symbols used are explained in Table 8.

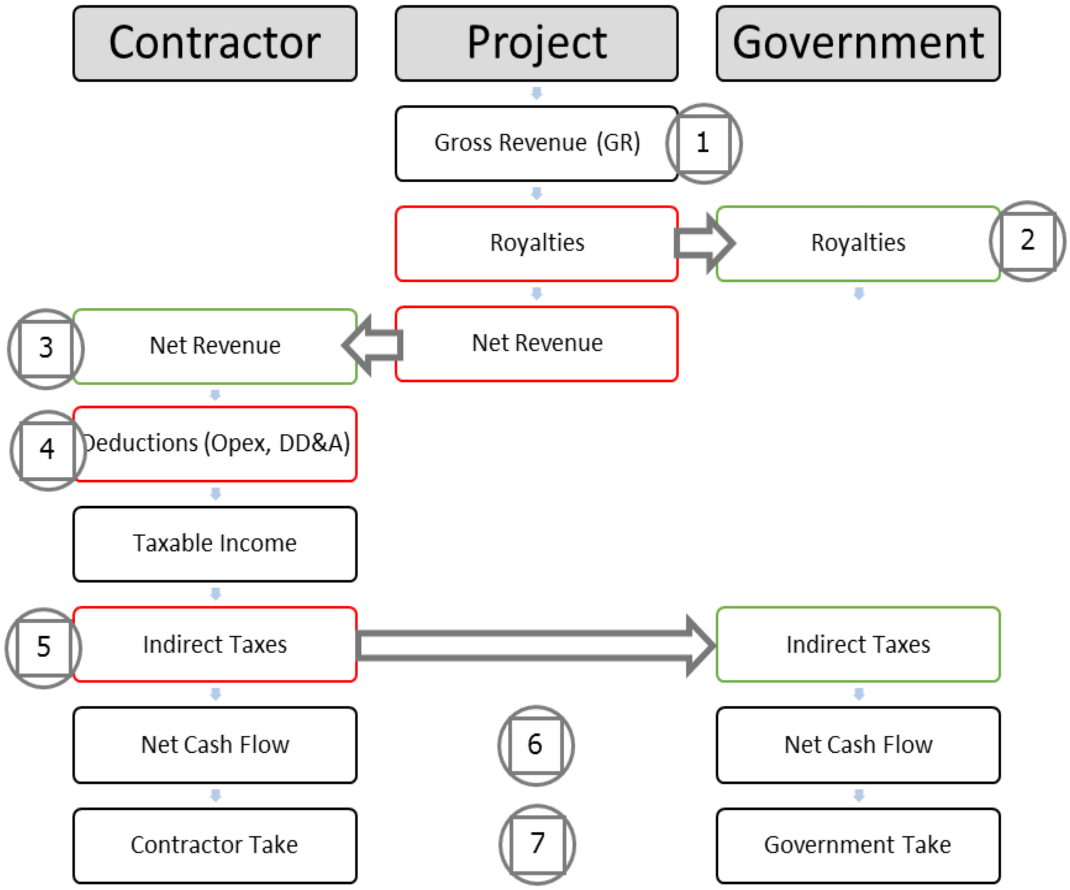

Figure 24. Cash flow workflow scheme: Period 2001-2006 (Modified from Mian, 2012)

1 The gross revenues are calculated by multiplying the gas and condensate volumes by the price of each hydrocarbon.

$$GR = (P_G * V_G) + (P_C * V_C) \qquad \textit{Eq. 5.4}$$

The natural gas price is the weighted average of the price of each market and it accounts for the cost of transportation to the domestic and foreign markets.

$$P_G = \frac{\left((P_{G,Br} - T_{G,Ex}) * V_{G,Br}\right) + \left((P_{G,Ar} - T_{G,Ex}) * V_{G,Ar}\right) + \left((P_{G,D} - T_{G,D}) * V_{G,D}\right)}{V_G} \qquad \textit{Eq. 5.5}$$

The condensate price was in function of a basket of oil prices. Due to the unavailability of these historical data, WTI oil prices were considered in this study.

$$P_C = P_{C,D} - T_C \qquad \textit{Eq. 5.6}$$

2 The royalties are obtained by multiplying the royalty rates by the gross revenues.

$$R_o = GR * (\tau_P + \tau_Y) \qquad \textit{Eq. 5.7}$$

3 The net revenues is the subtraction of the royalties from the gross revenues.

$$NR = GR * (1 - \tau_R) \qquad \textit{Eq. 5.8}$$

4 A portion of the revenues is used for operational expenses, investments, depreciation and other monthly expenses, referred as deductions.

5 The taxable income is the subtraction of the net revenue minus the monthly expenses for the tax on profits (IUE), on remittances (IRUE). The taxable income for the value-added tax (VAT) and the transactions tax (IT) are the revenue of the sales of all the hydrocarbons directed to the domestic market.

Each of them is calculated with the following equations:

$$T_i = VAT + IT + IUE + IRUE + Surtax \qquad \textit{Eq. 5.9}$$

$$IUE = \tau_{IUE} * (NR_t - Opex_i - D_T - Y_P - YPFB_t) \qquad \textit{Eq. 5.10}$$

$$IRUE = \tau_{IRUE} * (NR_t - Opex_i - D_T - YPFB_t - IUE_t - Surtax_t) \quad Eq.\ 5.11$$

The surtax has the same taxable base as the Tax on Profits. Nevertheless, two additional deductions can be made: 45% of the value of the production at the wellhead or $50 million (whichever is lowest), and the cumulative investment for the second time up to 33% per year.

$$Surtax = \tau_{IUE} * (RR_t - Opex_i - D_T - Y_P - NOC_t - X_t - D_T *) \quad Eq.\ 5.12$$

The value-added tax (VAT) and the transaction tax (IT) are only applicable to sales for the domestic market.

$$VAT = \tau_{VAT} * \frac{(P_{G,D} - T_{G,D}) * V_{G,D}}{V_{G,T}} * V_G \quad Eq.\ 5.13$$

$$IT = \tau_{IUE} * \frac{(P_{G,D} - T_{G,D}) * V_{G,D}}{V_{G,T}} * V_G \quad Eq.\ 5.14$$

6 The net cash flow for the contractor is:

$$NCF_c = (RR_t - Opex_i - D_T - Y_P - T_i) \quad Eq.\ 5.15$$

Whereas the net cash flow for the government is:

$$NCF_g = R_o + T_i \quad Eq.\ 5.16$$

7 The government and contractor take is the portion of the combined net cash flow each party takes:

$$GT = \frac{NCF_g}{NCF_g + NCF_c} \quad Eq.\ 5.17$$

$$CT = \frac{NCF_c}{NCF_c + NCF_g} \qquad \textit{Eq. 5.18}$$

5.2 Fiscal Schedule for Economic Analysis: Period 2 (2007 onwards).

During the period 2007 onwards, the fiscal regime was ruled by Law 3058. The system migrated to a mix of a service and a production sharing contract, creating new sources of revenue for the government: an extra Direct Tax on Hydrocarbons and a participation of the NOC. The workflow to obtain the contractor take, government take and their cash flow under Law 3058 is shown in Figure 25. Each step is further explained afterwards. The symbols used are explained in Table 8.

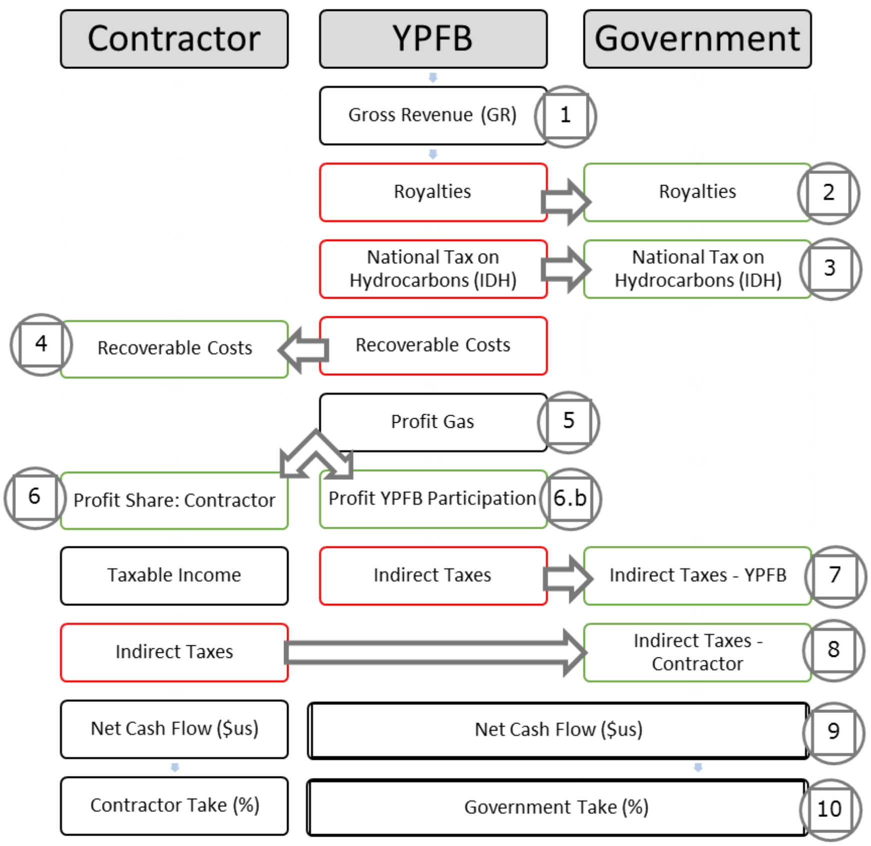

Figure 25. Cash flow workflow scheme: Period 2007 onwards (Modified from Mian, 2012)

1 The gross revenue is calculated as in the period 2001-2007 (Eq. 4.3) except for the condensate price which is fixed for this period at 27.11 $/bbl.

2 Royalties are calculated with the same equation as for the period 2001-2007 (Eq. 4.4)

3 The National Tax on Hydrocarbons is applied on the gross revenues as the royalties:

$$IDH = GR * (\tau_{IDH}) \qquad \textit{Eq. 5.19}$$

4 The Recoverable Costs are defined as the costs, both direct and indirect, that the company incurred for operating and exploiting the field; they are subdivided into exploration, development and exploitation costs. Each field has a limit of costs that can be recovered stipulated in the contract. National taxes are also recoverable but they do not include the royalties, national tax on hydrocarbons (IDH), and the Tax on Profits (IUE). The limit of the recoverable costs is set to 60% of the Net Revenue for this contract.

$$RC_t = \min\{RG_{t-1} + Opex + D\&A + IT + C_A \, , L_{RC} * (RR - T_T)\} \qquad \textit{Eq. 5.20}$$

If the costs are not covered, they are cumulative for the next month.

$$RG_t = \max\{RG_{t-1} + Opex + D\&A + IT + C_A - \left(L_{RC} * (RR - T_T)\right), 0\} \qquad \textit{Eq. 5.21}$$

5 The Profit Gas results from the subtraction of the net revenues minus the recoverable costs.

6 The distribution of the profit gas depends on the B factor and the flow rate (an example of the table can be seen in Appendix B). The B factor is calculated monthly based on the ratio of the cumulative depreciation and revenue of the contractor and the cumulative investments and taxes paid that were not considered for the recoverable costs.

$$B_t = \frac{D\&A_0 + \sum_{i=1}^{t-1} D\&A_i + \sum_{i=1}^{t-1} PD_i}{CI_0 + \sum_{i=1}^{t-1} I_i + \sum_{i=1}^{t-1} T_{Ti}} \qquad \textit{Eq. 5.22}$$

The participation of YPFB is extracted from the table with the B factor and the flow rate (Appendix B).

$$YPFB = \tau_{YPFB} * (GR - R_o - RC) \qquad \textit{Eq. 5.23}$$

Where:

$$\tau_{YPFB}\, f(B_t, q)$$

And the contractor share of the profit gas is:

$$C_p = (1 - \tau_{YPFB}) * (GR - R_o - RC) \qquad \textit{Eq. 5.24}$$

7 8 Both YPFB and the contractor pay the indirect taxes as for the period 2001-2007 except for the surtax which was eliminated.

9 The Net Cash Flow for the contractor will be the recoverable costs plus the share of profit gas minus the indirect taxes.

$$NCF_g = CR + C_p - T_{i,contractor} \qquad \textit{Eq. 5.25}$$

The Net Cash Flow for the government will be:

$$NCF_g = T_i + IDH + YPFB_t + T_{i,contractor} \qquad \textit{Eq. 5.26}$$

The participation of YPFB and the indirect taxes they pay are considered as part of the government share.

The Government and Contractor take are calculated as in the period 2001-2007

5.3 Fiscal Schedule for Economic Analysis of the Impact of the Incentives Law

The incentives law issued in 2015 aims to encourage exploration and exploitation activities. For producing fields, the incentives apply to condensate or oil production, additional to the agreed volumes in the field development plan. The fiscal schedule shown in Figure 26 follows the system given by Law 3058 and the operation contracts but has two main differences: 12% of the national tax on hydrocarbons are retained by the government and directed to the incentives fund (Eq. 5.26), and the incentives for the additional production are added to the contractor profit share (Eq. 5.27). This means the incentives are not subject to royalties, the national tax on hydrocarbons, and YPFB share (this is an assumption of this study because of lack of access to the regulations of Law 707 and Decree Supreme 2830). The symbols used are explained in Table 8.

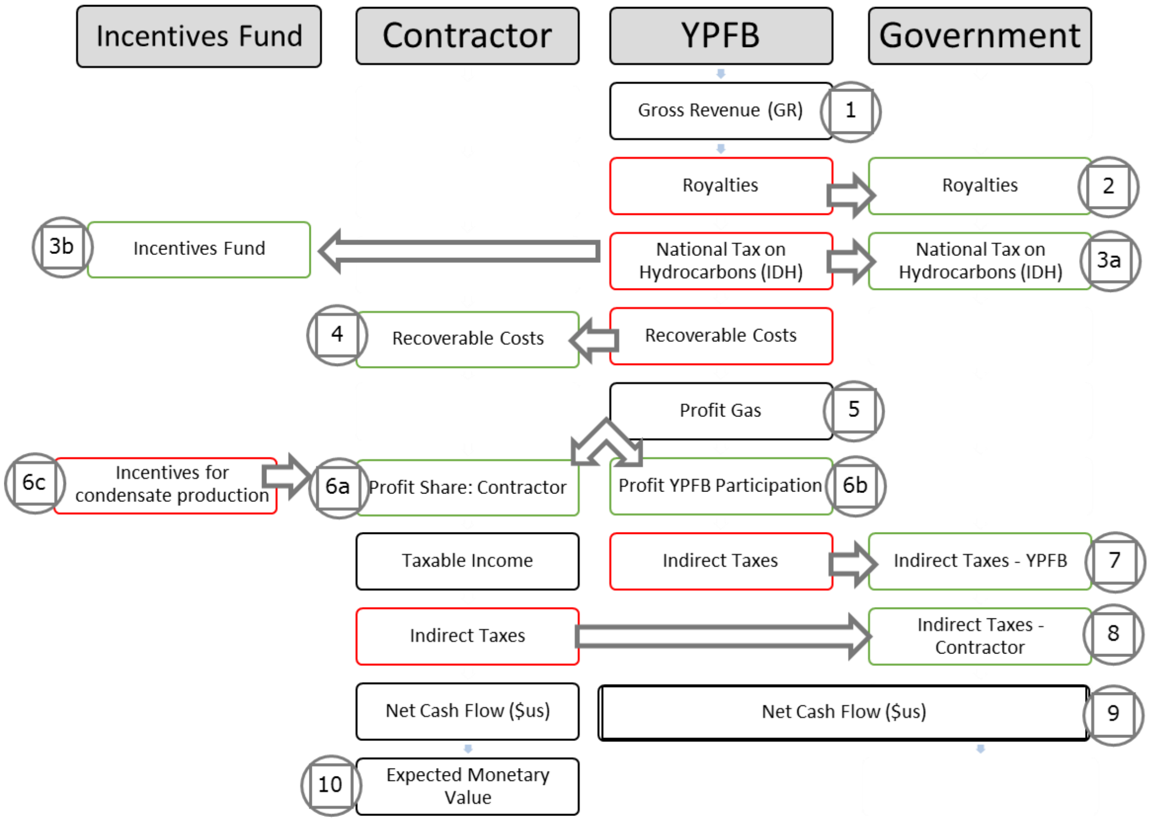

Figure 26. Cash flow workflow scheme including incentives

. 3b The incentive fund is given by eq. 5.27.

$$Incentive\ Fund = 12\% * IDH \qquad Eq.\ 5.27$$

6c The incentives are calculated with equation 5.27 as defined by the Decree Supreme 2830

$$I_t = (-0.6398 * WTI_t + 47.345) * Q_t \qquad Eq.\ 5.28$$

$$27.11 < WTI_t < 74$$

$$30 > P_i > 0$$

The symbols and units used in Section 5.1 and 5.2 are shown in Table 8.

Table 8. Symbols used for the economic analysis in Sections 5.1 and 5.2

Item	Abbreviation	Unit
Natural Gas Price (Total, Brazil, Argentina, domestic)	$P_G, P_{G,Br}, P_{G,Ar}, P_{G,D}$	\$/MMBTU
Gas Transport Fee (Exports, domestic)	$T_{G,Ex}, T_{G,D}$	\$/Mscf
Gas volume (Total, Brazil, Argentina, domestic)	$V_G, V_{G,Br}, V_{G,Ar}, V_{G,D}$	MMscfd
Calorific value	CV	MMBTU/Mscf
Royalties	R_o	\$
Royalty Rate	τ_R	(%)
Gross Revenues	GR	\$
Net Revenues	NR	\$
National Production Tax Rate	τ_{IDH}	(%)
Capital Expenditure	Capex	\$
Operational Expenditure	Opex	\$
Depreciation and Amortization	D&A	\$
Recoverable Costs	RC	\$
Cumulative Recoverable Costs	RG	\$
Indirect Taxes	T_i	\$
Value-Added Tax Rate	τ_{VAT}	(%)
Transaction Tax Rate	τ_{IT}	(%)
Profit Tax Rate	τ_{IUE}	(%)
Remittance Tax Rate	τ_{IRUE}	(%)
B Factor	B	-
YPFB Share	YPFB	(\$)
YPFB Share Percentage	τ_{YPFB}	(%)
Produced volume (Gas, Condensate, Water)	V_G, V_C, V_W	MMscfd
Use of Land fee	L_F	\$bs/ha

(Table 8 Continued)

Item	Abbreviation	Unit
Area of contract	A	ha
Net Present Value	NPV	$
Yearly discount rate	r	%
Internal Rate of Return	IRR	%
Limit Recoverable Costs	L_{RC}	%
Abandonment costs	C_A	$
Incentives	I_t	$
Price given by incentives	P_i	$/bbl
Condensate production subject to incentives	Q_t	bbl

5.4 Additional Input

a) Hydrocarbon Volumes.

Historical values for the natural gas and condensate flow rates are used for the period 2001-2016. For future production of natural gas and condensate, the production forecast was made based on the decline curve analysis of Section 3.3 (Figure 27).

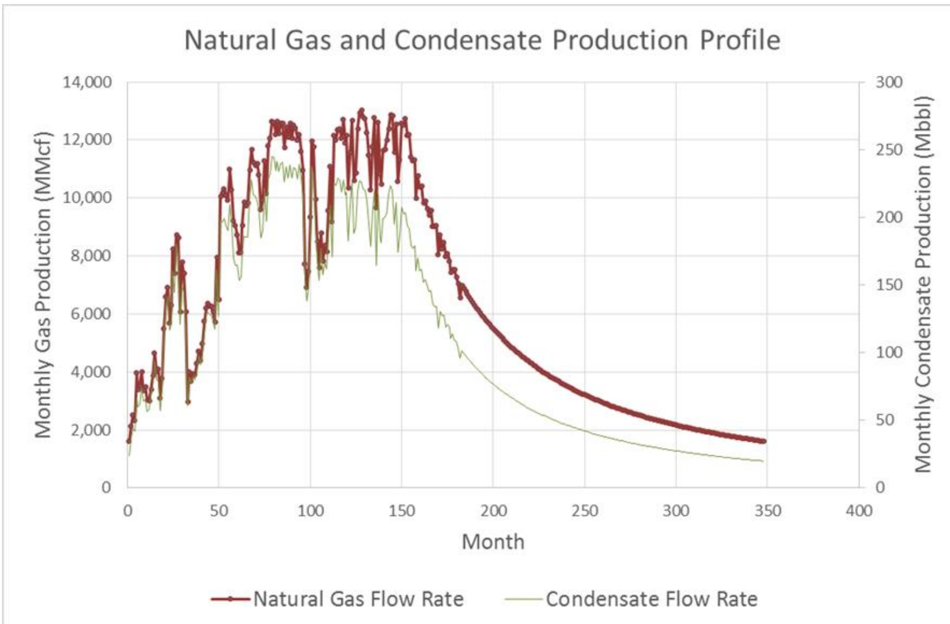

Figure 27. Natural gas and condensate production profile

The historic gas-condensate ratio and the future estimate based on the decline curve analysis of section 3.3 is shown in Figure 28.

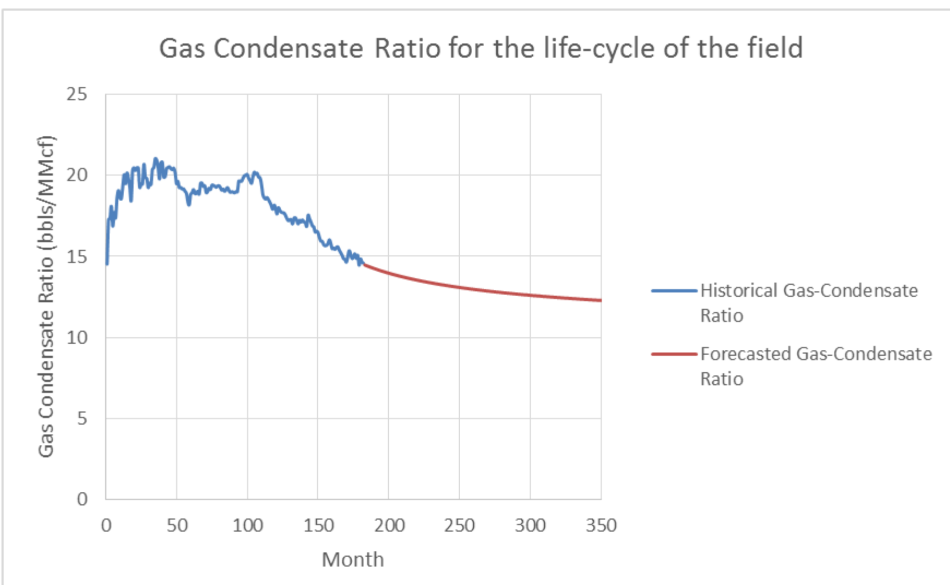

Figure 28. Gas-condensate ratio for the life-cycle of the field showing historic values and the estimated future ratios based on the production forecast

b) Pricing. Equation 5.5 determines that the natural gas price will be the weighted average of the gas price and volume directed to each market. The demand scenarios of Section 2.6 provide these volumes which are used to determine the future prices (Figure 29). The difference of the gas prices given by the demand scenario start at 2% and reach 7% by 2029 for the highest price scenario due to the greater participation of domestic gas demand and the assumed reduction in half of the Brazilian contract beyond 2019. The high demand scenario is taken as the base for the economic analysis assuming that Brazil will continue to buy similar gas volumes after the finalization of the current contract.

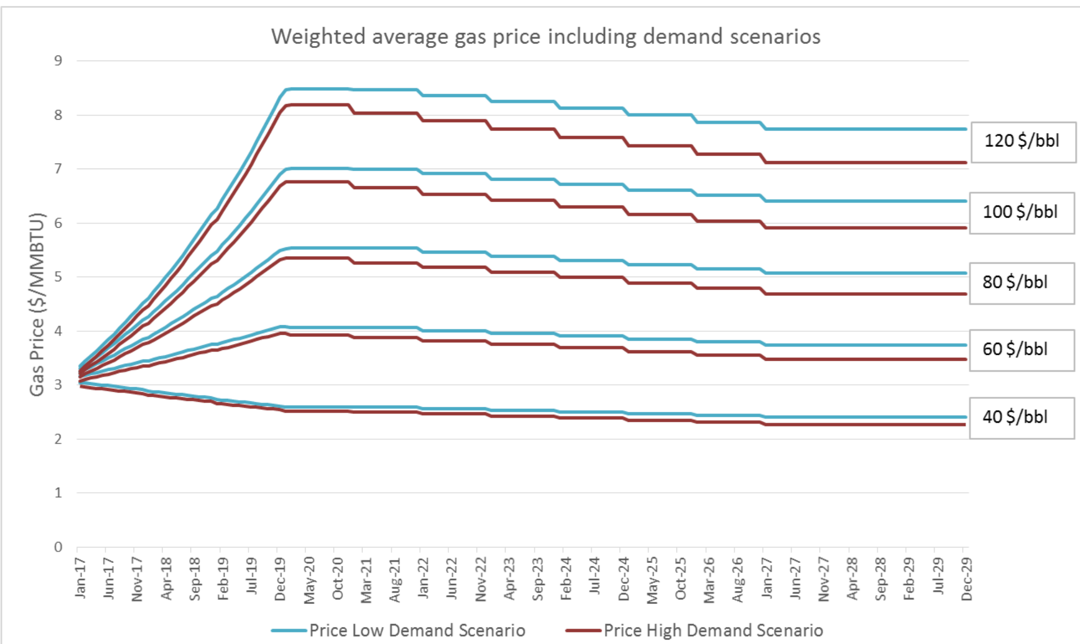

Figure 29. Future weighted natural gas price for the low and high demand scenario for all gas price scenarios considered in section 4.5

c) Capital Expenditure (Capex) and Operation Expenditure (Opex) used in the cash flow analysis are based on approximate data for the studied field as shown in

Table 9. Input data for Capex include expenditures for drilling and completing wells, tie-ins, processing plants and pipelines. Throughout the project, nine wells were drilled. The tie-in pipelines total 37 km with a diameter of 6 inches. The gas treatment processing plant is divided into two modules with a combined capacity of 13.5 MMm3/d.

Table 9. Capital and operational expenditures

Concept	**Cost**	**Unit**
D&C Costs	35 million	$/well
Tie In and Pipelines	40,000	$/inch/km
Processing Plant	130 million	$

d) Depreciation, Depletion and Amortization

Depreciation is calculated with the straight line method. The useful life of different items is detailed in Table 10. Depletion and Amortization are not considered.

Table 10. Years of useful life for depreciation purposes

Concept	**Years of useful lfe**
Wells	5
Tie-in	5
Processing Plant	8
Pipelines	10

e) Royalties and Direct Taxes

Royalties and Direct Taxes are defined according to Law 1689 and Law 3058 detailed in Section 2.2 and summarized in Table 11. These rates are applied to the Gross Revenues of the sale of gas.

Table 11. Summary of royalties and direct taxes

Royalty/Tax	Law 1689	Law 3058
Province Royalty	11%	11%
Compensatory Royalty	1%	1%
National Treasury/NOC	6%	6%
National Tax on Hydrocarbons (IDH)	0	32%

f) Patents

The patents are a fee for the use of the land under contract. Table 12 shows the amount to be paid per year. The area of contract of San Alberto is 14,012.43 hectares. Historic exchange rates were used in the cash flow analysis for 2001-2016 (BCB, 2016) and the future exchange rate is assumed to be Bs. 6.96 per dollar.

Table 12. Land-use patents for Laws 1189 and 3058

Period	Patents (Bs./hectare)	
	Law 1189	Law 3058
1^{st} -3^{rd} year	2.5	4.93
4^{th} -5^{th} year	5	9.86
6^{th} -7^{th} year	10	19.71
8^{th} year and onwards	20	39.42

CHAPTER VI

RESULTS AND DISCUSSION FOR MEGA-FIELD ANALYSIS

6.1 Evaluation of the Fiscal Regime Impact on NPV Distribution: 2001-2016

The effects of the two fiscal regimes on the NPV distribution in 2001-2016, were compared for both the contractor and government perspective. The two fiscal regimes are ruled by Law 1389 (2001-2006) and Law 3058 (2007-2016), see Section 4.2. The results are estimations made by the author and are approximations of the actual NPV distribution and revenues. In 2001-2006, the government take NPV was rounded 56% and the contractor take 44% (Figure 30).

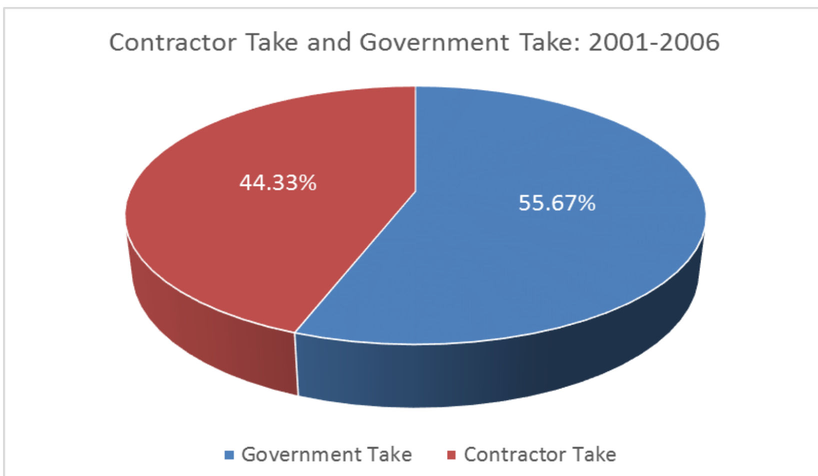

Figure 30. Contractor take and government take in 2001-2006 under Law 1389 and a contract of shared risk

The government principal sources of income were royalties (40.45%) and the Profit Tax (35.44%) as detailed in Figure 31. The value-added tax, the transaction tax, and remittance tax accounted for the other 25.11%. It is worth noting that the surtax on extraordinary profits was not active during this period.

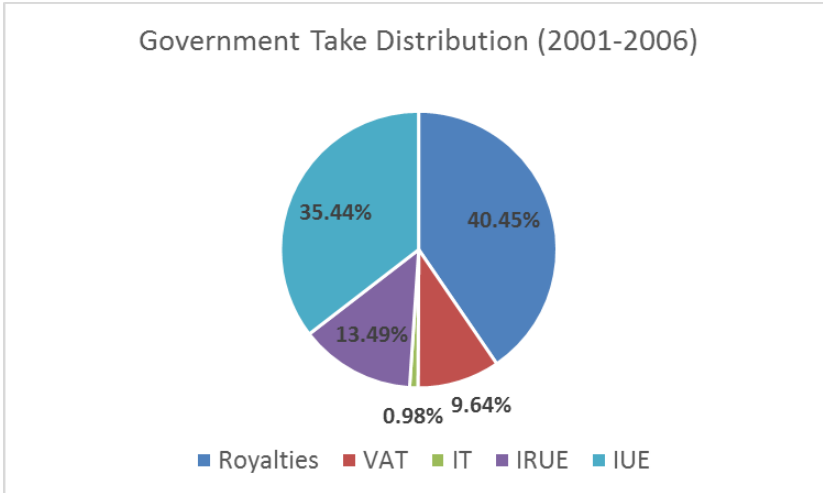

Figure 31. Government take distribution showing the tax breakdown in 2001-2006

In 2007-2016, the government take NPV was 87.82% and the contractor take NPV was 12.18%, representing a variation of more than 30% in favor of the government compared to the previous period (Figure 32).

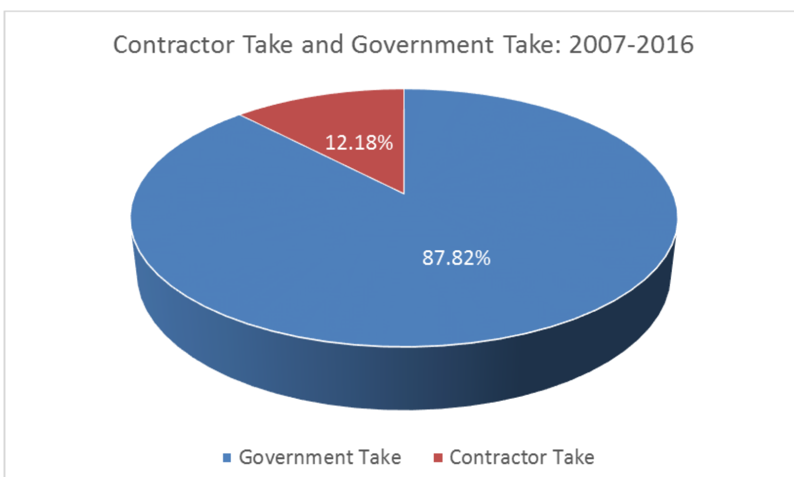

Figure 32. Contractor take and government take in 2007-2016 under Law 3058 and a contract of operation

The government income came from royalties (the direct tax on hydrocarbons was included in this category) accounting for nearly 70% (Figure 33). The share of the national oil company YPFB was 22.45% representing the second source of income for the government in order of importance. The added-value tax, the remittance tax and the transaction tax accounted for approximately 8%, all play a minor role in the government take than in the previous period.

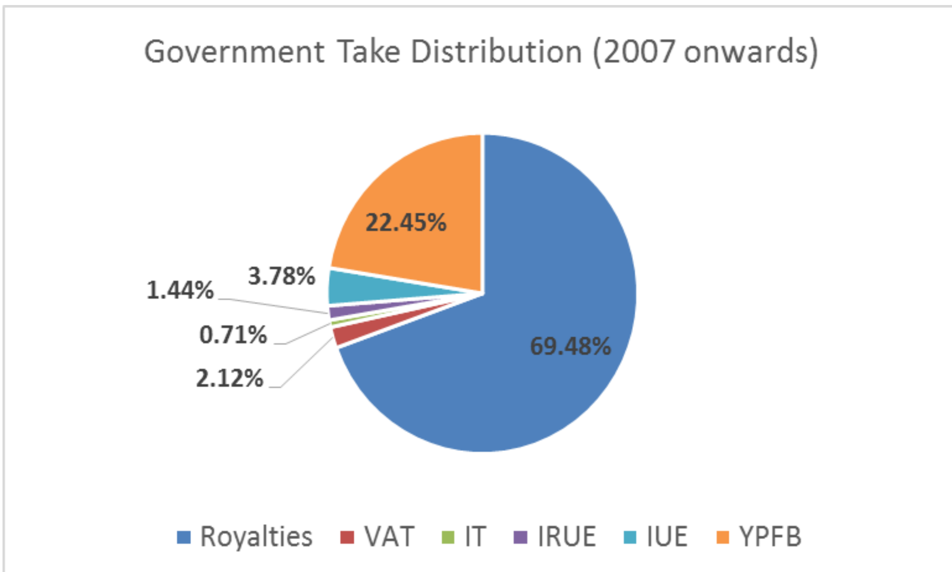

Figure 33. Government take distribution showing the tax breakdown in 2007-2016

The fixed taxes and royalties are applied to the gross revenue of natural gas sales, and increased to more than 70% of the NPV share, making the fiscal system regressive (taxing does not account for profitability of the project), and renders the contractor susceptible to operational losses.

6.2 Forward Economics, Contractor and Government Take under Different Price Scenarios (2016-2029)

This section performs an economic evaluation for the field life cycle of the studied mega-field (2001-2029) under the different price scenario defined in Section 4.

The undiscounted NPV for the contractor is $940 million for the $40/bbl price scenario and $1,200 million for the $120/bbl price scenario, only representing a 27% increase in NPV. This can be explained by the increasing government take in the later years of the project. On the other hand, the undiscounted NPV for the government is $7,386 million for the $40/bbl price scenario, and $9,296 million for the $120/bbl price scenario, accounting for a 26% increase. The government take in the future (2016-2029) is estimated at 97% for the $40/bbl scenario and it stabilizes at 90% for the other price scenarios (Figure 34).

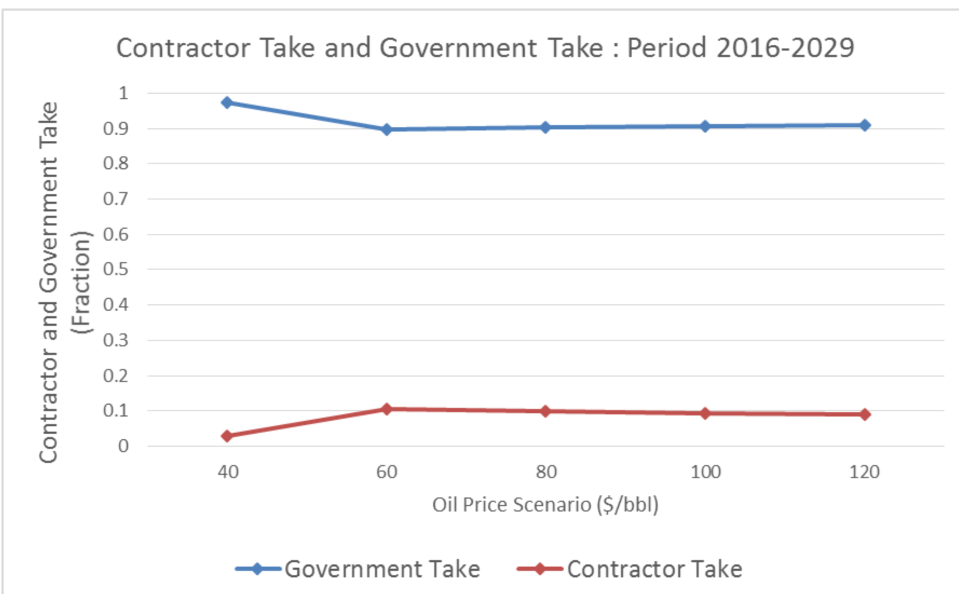

Figure 34. Contractor take and government take under different price scenarios in the period 2016 onwards

The increasing government take is related to the conditions that define the share of YPFB (Appendix B). YPFB's share of the profit gas grows as the cumulative profits of the contractor increases and the production flow rate decreases. This creates a setting where the contractor share of the profit gas gradually decreases in the late life of the field.

The rate of return of the contractor is not heavily affected by the future income (Figure 35). The IRR ranges from 17.7% and 18.1%. The low variation for the IRR can be explained by the greater dependence of the IRR on the early years of the project and the lower revenues for the contractor starting from 2007.

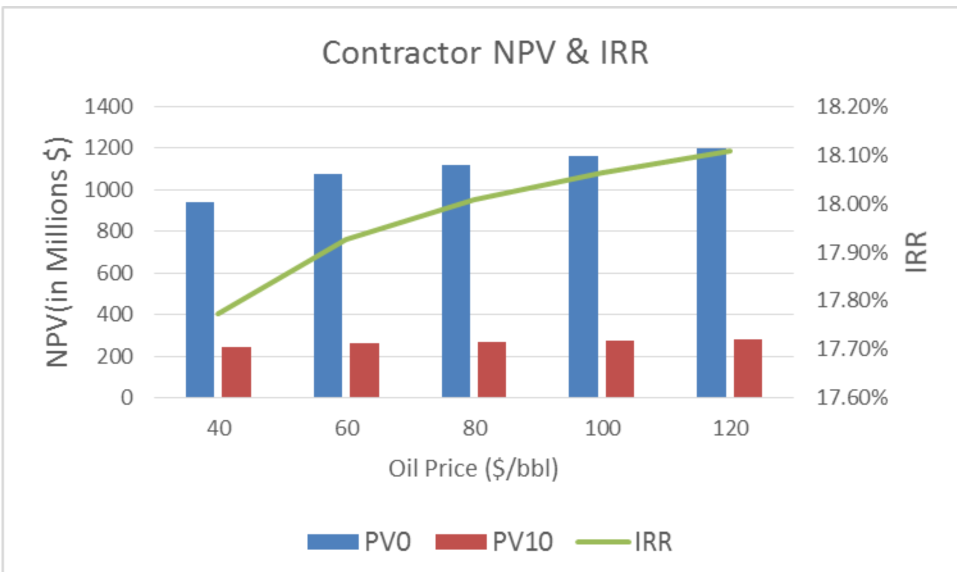

Figure 35. Contractor undiscounted NPV, NPV10 and IRR under different price scenarios

As seen in the field's cash flow breakdown, the contractor take NPV does not increase commensurate to the extra revenues (See Appendix D, Figures 39-43) coming from the favorable price scenarios; the government takes it mostly through YPFB's share. This phenomenon is highlighted in Figure 36: the monthly contractor take steadily increases as the gas price rises does until the B factor triggers YPFB share and causes a drop in the contractor share. The higher price scenario suffers the drop first as the B factor grows faster as cumulative earnings are higher (Appendix B).

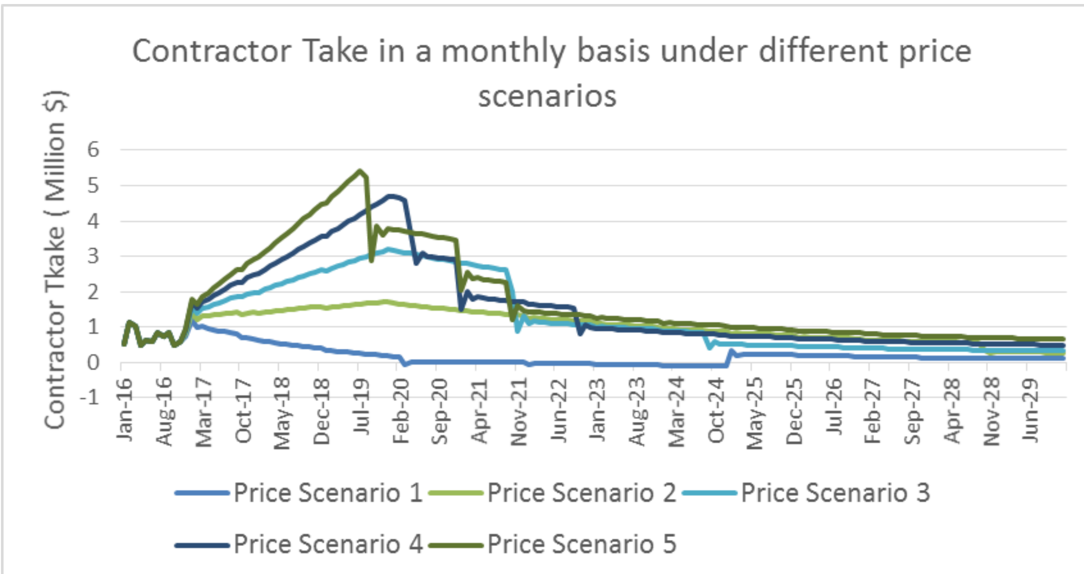

Figure 36. Monthly contractor take under different price scenarios showing the effect of the YPFB share

Future revenues will follow the trend of the past period and have an average distribution of 90 and 10 % for the government and the contractor, respectively. Figure 37 shows the cumulative contractor and government take under different price scenarios, and illustrates the legislation changes and the dimension of the NPV distribution. In the early field life (2001-2006), the cumulative NPV of the contractor and government grew at similar rates. However, in the second period (2007-2014), the government take grew considerably (Figure 37, upper curve) because of the new fiscal system, higher commodity prices and increasing production. In 2015-2016, we see that the rising trend in government take flattens off because oil prices fell and production rates decreased. From 2017 onwards, the government take is more sensible to price changes than the contractor take (Figure 37).

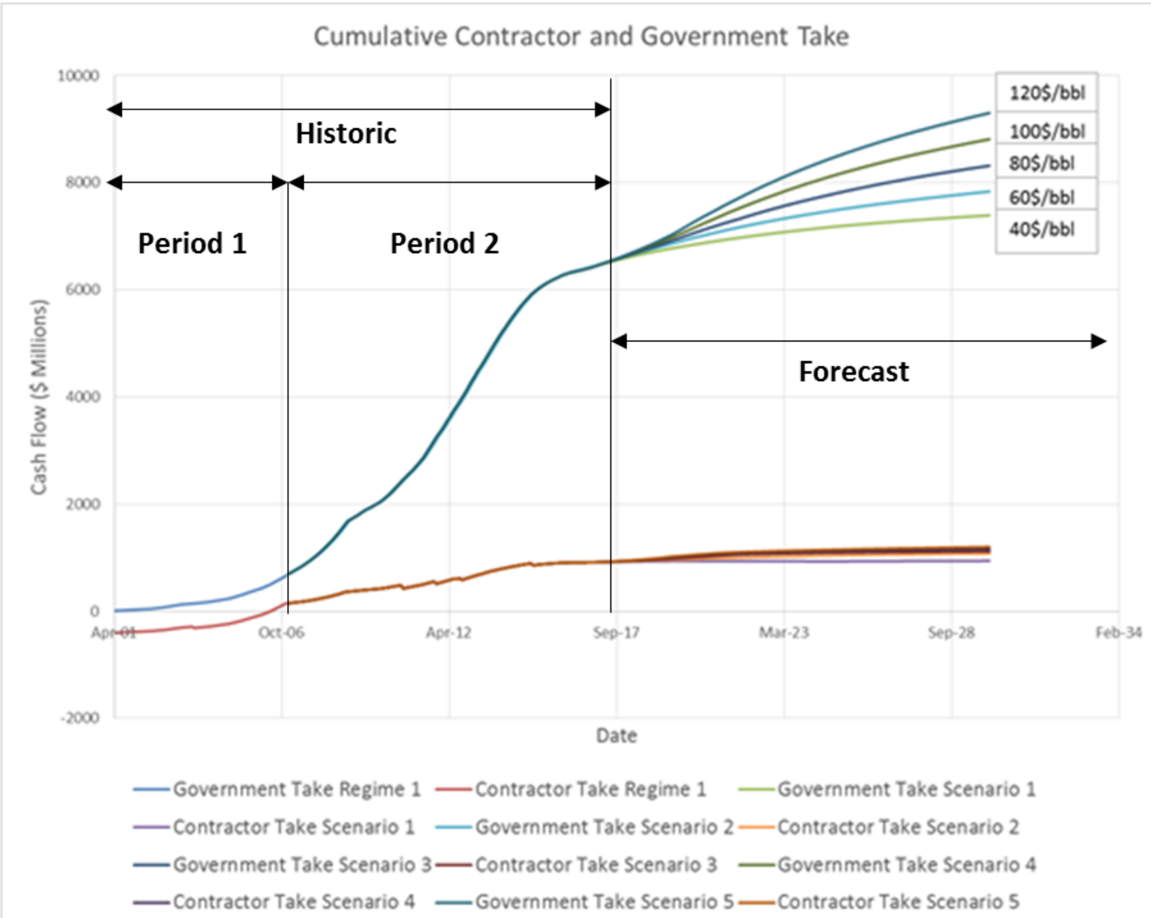

Figure 37. Cumulative contractor take and government ake for the entire life of the field under different price scenarios

6.3 Economic Impact of the Incentives Law on EMV

This section evaluates if drilling infill wells in the mega-field is profitable for the company under different price scenarios and the impact of the incentives law on this decision. Only the $40/bbl and $60/bbl scenarios will be impacted by the incentives because of the range limits of the Incentives Law of \$27 to \$74/bbl oil price (Section 5.3).

EMV was calculated with the following expression:

$$EMV = (Drilling\ cost * Probability\ of\ failure) + (NPV\ contractor\ with\ a\ new\ well\ drilled - NPV\ contractor\ without\ drilling)(Probability\ of\ success)$$

In the period between 2015 and 2019, YPFB (2014b) expects 3 wells to be drilled in this field. An economic analysis using NPV and EMV was performed to assess whether drilling any new wells would be profitable for the company under different price scenarios. The study analyzes the feasibility of the first well in San Alberto. The initial production rate of the first new well was predicted to be 30 MMscfd and the annual decline rate of the field was set at 7.8% by YPFB (2014b). This study assumes the well first month of production is January 2017. Three drilling well costs scenarios were considered: the average of the past wells of \$35 million, \$50 million and a maximum of \$70 million.

In 2006-2014, out of 138 developments wells drilled, 117 were positive and 21 were negative (ANH, 2015). Taking this historical data, the probability of failure of a development well rounds 18%.

The EMV for the \$40/bbl scenario is negative at this probability of failure (Figure 38a). Nevertheless, with the incentives the EMV becomes positive making the project feasible. The EMV for the \$60/bbl scenario is positive at an 18% probability of failure. The EMV for the rest of the scenarios is positive at 18% and are not benefited by the incentives.

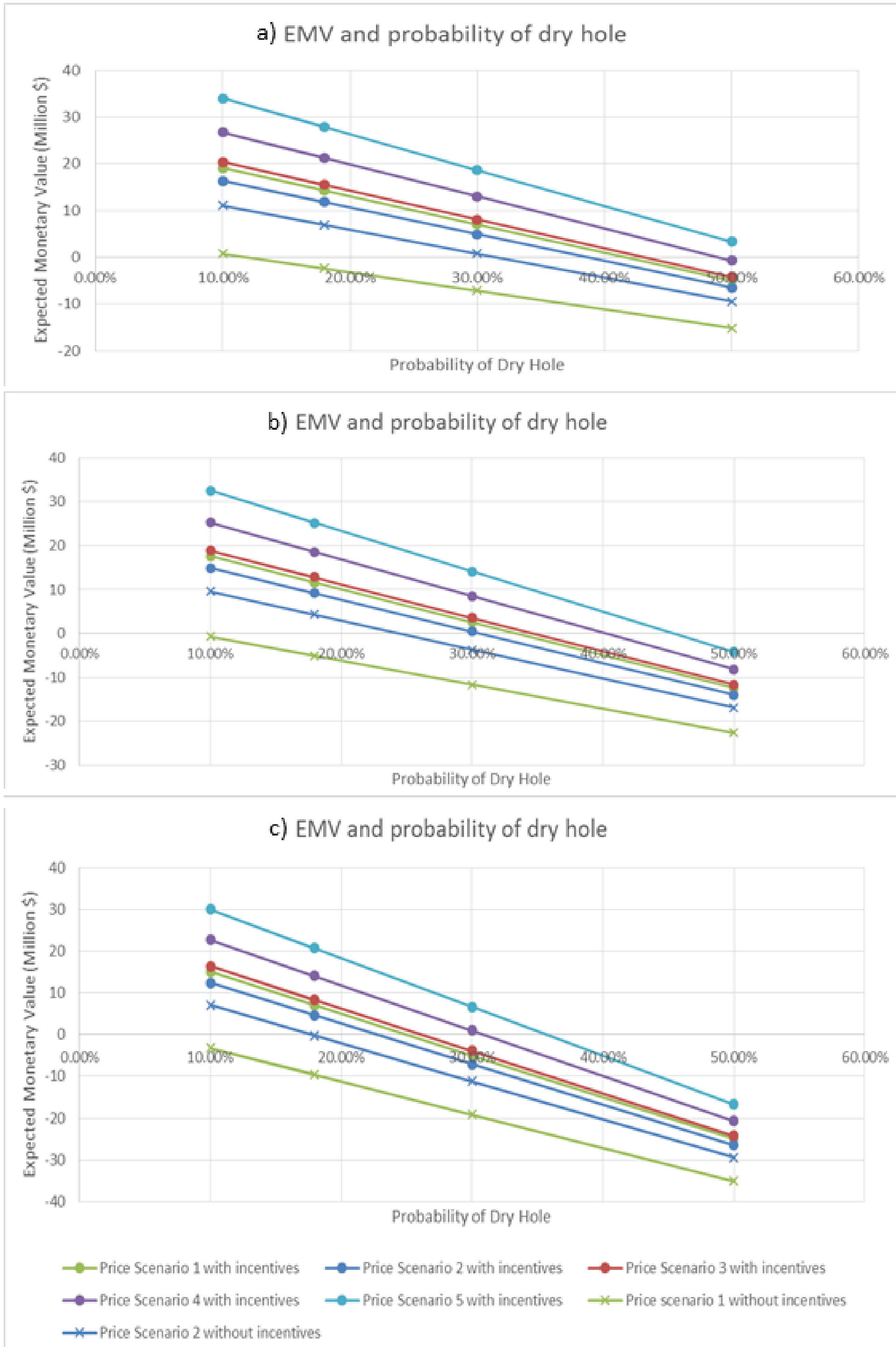

Figure 38. Expected monetary value vs probability of failure under different price scenarios from the contractor's perspective for a well drilling cost of a) $35 million b) $50 million and c) $70 million

The results for a $50 million well cost is similar to the $35 million case. The EMV for the $40/bbl scenario is negative without incentives and becomes positive with them (Figure 38b). Similarly, the EMV for the $60/bbl case is positive with and without incentives. The case of a well cost of $70 million has a negative EMV for price scenarios of $40/bbl and $60/bbl and they become positive with the incentives at 18% probability of failure (Figure 38c).

6.4 Decision Making and Sub-conclusion about the Incentives Law

The incentives fund which collects 12% of the National Tax on Hydrocarbons (Table 13). For the studied field, $64 million are collected by the government for a $40/bbl and $90 million for a $60/bbl.

Table 13. Available incentives fund for different price scenarios

Price Scenario	Available Incentives Fund
$40/bbl	$64,679,470
$60/bbl	$90,590,780

In comparison, Table 14 shows the disbursed incentives to the contractor and the contractor and government NPV take of the revenues generated if the well is a producer. The incentives disbursed to the contractor for the $40/bbl scenario are approximately $22 million that can be covered by the incentives fund generated by the San Alberto field. The government revenues of the production from the additional well is $181 million. Under the $60/bbl scenario, the incentives to the company are $11 million, amount fully covered by the fund generated from the field which is $90 million, and the government revenue coming from the additional well is $282 million.

Table 14. Disbursed incentives to the contractor, contractor and government take for different price scenarios for the new well

Price Scenario	Incentives to company	Contractor NPV	Government NPV
$40/bbl	$22,458,531	$25,078,680	$181,343,910
$60/bbl	$11,396,235	$22,067,148	$282,717,043

With this analysis, we can conclude that the Incentives Law provides good outcomes for both the company and the contractor: it gives the contractor enough incentives to make drilling profitable at different price scenarios and generates an extra revenue for the government much higher than the disbursed incentives to the company.

CHAPTER VIII

CONCLUSIONS AND RECOMMENDATIONS

The change of fiscal regime in the Bolivian hydrocarbon sector in 2005-2006 ruled by Hydrocarbon Law 3058 made a big impact on revenue distribution between the government and the contractor. In the San Alberto mega-field, this study's estimations show that the average government take increased from 56% (2001-2006) to 88% (2007 onward). Despite the reduction of the contractor take, the economic return for the contractor shows an IRR rounding 18%, given by the higher contractor share of the previous system ruled by Law 1689 and the rise of the commodity prices in 2005-2014. In the present scenario of lower commodity prices, the decline phase of the field and an increasing government take through the YPFB variable share, the economics of the field are not so attractive for the company. The future government take averages 90% for all price scenarios, the only exception being the $40/bbl. case which reaches a government take of 96%. The higher government take of the lowest price scenario considered in this study can be explained by the fact that the contractor takes losses during several months because of the high B factor and the cost recovery limit of 60%.

The efforts of the government to encourage exploration and exploitation activities through the Incentives Law of 2015 prove to be efficient for the mega-field case based on the evaluation of the contractor's EMV for drilling one additional well. For the average drilling cost of $35 million of past wells and a historic probability of success of 82% for development wells in Bolivia, the EMV of the $40/bbl price scenario is negative without incentives but becomes positive with the implementation of the incentives. The other considered price scenarios ($60, $80, $100, $120/bbl) result in positive EMVs. The planned wells in the mega-fields will be key to preventing the looming gap between gas supply and demand in the short-term and will give extra time to discover and develop new hydrocarbon resources. Based on the study's results, the author suggests that in this new scenario of production decline and lower commodity prices, efforts need to be made to make E&P activities attractive for the contractor. While the incentives are a step in that direction, they also add another item to an already complicated fiscal system.

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APPENDIX A: SUMMARY OF THE BOLIVIAN GAS SALE AGREEMENTS WITH BRAZIL AND ARGENTINA

Some more details of the Gas Sale Agreements with Brazil and Argentina are given in this Appendix. The price formulas show the correlation with the Fuel Oils, and ultimately the WTI oil price. The contractual volumes and clauses were the basis for the demand scenarios.

A.1 GAS SALE AGREEMENT WITH BRAZIL

Period: 1999-2019

Duration: 20 years.

Price Determination: OPE method

The gas price formula to Brazil is:

$$P_{G,Br} = P_{(i)} * (0.5 * FO_1 + 0.25FO_2 + 0.25 * FO_3)$$

Where:

$P_{G,Br}$= Gas price (US$/MMBTU)

$P_{(i)}$= Base price (US$/MMBTU)

FO_1= Fuel Oil Cargoes FOB Med Basis Italy of 3.5% S2 (US$/ton)

FO_2= Fuel Oil US Gulf Coast Waterborne of 1 % S2 (US$/bbl)

FO_3= Fuel Oil Cargoes FOB NWE of 1% S2 (US$/ton)

The prices of the fuel oils are the arithmetic averages of the daily prices’ inferior and superior limits, published by Platt’s Oilgram Price Report.

The price for the second trimester and onwards is calculated as the average of the current and prior trimesters:

$$P_{G,Br} = 0.5 * P_{G(i),Br} + 0.5 * P_{G(i-1),Br}$$

Volumes and base price values

Table 15. Contractual natural gas quantities (MMm3/d) and base prices ($/MMBTU)-Brazil

Year	Total Flow Rate	Base Flow Rate	Added Flow Rate	Price Base Flow	Price Added Flow
1999	8	8	0	0.95	1.2
2000	9.1	9.1	0	0.95	1.2
2001	13.3	10.3	3	0.95	1.2
2002	20.4	11.4	9	0.95	1.2
2003	24.76	12.6	12	0.96	1.2
2004	30.08	13.7	16.38	0.96	1.2
2005	30.08	14.9	15.18	0.97	1.2
2006	30.08	16	14.08	0.98	1.2
2007	30.08	16	14.08	0.98	1.2
2008	30.08	16	14.08	0.99	1.2
2009	30.08	16	14.08	1	1.2
2010	30.08	16	14.08	1	1.2
2011	30.08	16	14.08	1.01	1.2
2012	30.08	16	14.08	1.02	1.2
2013	30.08	16	14.08	1.02	1.2
2014	30.08	16	14.08	1.03	1.2
2015	30.08	16	14.08	1.03	1.2
2016	30.08	16	14.08	1.04	1.2
2017	30.08	16	14.08	1.05	1.2
2018	30.08	16	14.08	1.05	1.2
2019	30.08	16	14.08	1.06	1.2

A.2 GAS SALE AGREEMENT WITH ARGENTINA

Period: 2007-2027

Duration: 20 years.

Price Determination: OPE method

Gas price formula for gas deliveries to Argentina

$$P_{G,Arg} = P_b * \left(0.2 * \frac{FO_{1_1}}{FO_{1_0}} + 0.25\frac{FO_{2_1}}{FO_{2_0}} + 0.25 * \frac{FO_{3_1}}{FO_{3_0}} + 0.25 * \frac{DO_1}{DO_0}\right)$$

Where:

$P_{G,Arg}$= Gas price Argentina (US$/MMBTU)

P_b = Base price (US$/MMBTU)

FO_{1_1}= Fuel Oil Cargoes FOB Med Basis Italy of 3.5% S2 (US$/ton)

FO_{2_1}= Fuel Oil No 6, 6 API, US Gulf Coast Waterborne of 1 % S2 (US$/bbl)

FO_{3_1}= Fuel Oil Cargoes FOB NWE of 1% S2 (US$/ton)

DO_1= US Diesel, US Gulf Coast Waterborne (USc$/USgal)

The prices of the diesel and fuel oils (FO_{1_1}, FO_{2_1}, FO_{3_1}, DO_1) are the arithmetic averages of the daily prices' inferior and superior limits of the semester prior to the trimester that is being calculated. The daily prices are the ones published on Platt's Oilgram Price Report.

The prices of the diesel and fuel oils (FO_{1_0}, FO_{2_0}, FO_{3_0}, DO_0) are the arithmetic averages of the daily prices' inferior and superior limits of the period between January 1st, 2004 and June 30th, 2006. The base price was calculated so that the final price would be 5$/MMBTU in the first trimester of 2007.

Volumes

The contractual base volumes, and the ones corresponding to the clauses Take or Pay (ToP) and Deliver and Pay (DoP) are in Table A.2.1.

Table 16. Contractual natural gas quantities to Argentina (MMm3/d)

Year	Period	CDC	DOP	TOP
2010	Winter	7.7	5	5
	Summer	7.7	5	5
2011	Winter	11.3	7.7	7.7
	Summer	11.3	7.7	5.7
2012	Winter	13.6	11.6	11.6
	Summer	13.6	11.6	10.4
2013	Winter	15.9	13.5	13.5
	Summer	15.9	13.5	10.4
2014	Winter	19	16.2	16.2
	Summer	19	16.2	12
2015	Winter	20.7	17.6	17.6
	Summer	20.7	17.6	14.5
2016	Winter	23.4	19.9	19.9
	Summer	23.4	19.9	16.4
2017	Winter	23.9	20.3	20.3
	Summer	23.9	20.3	16.7
2018	Winter	24.6	20.9	20.9
	Summer	24.6	20.9	17.2
2019	Winter	25.1	21.3	21.3
	Summer	25.1	21.3	17.6
2020	Winter	25.7	21.8	21.8
	Summer	25.7	21.8	18
2021	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4
2022	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4
2023	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4
2024	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4
2025	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4

Year	Period	CDC	DOP	TOP
2026	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4
2027	Winter	27.7	23.5	23.5
	Summer	27.7	23.5	19.4

APPENDIX B: YPFB PARTICIPATION TABLES

One major source of income for the government in the current fiscal regime comes from the share of the profit gas that the national oil company takes. Appendix H of the operation contracts indicates the YPFB share of the profit gas which depends on the B factor (cumulative earnings and depreciation divided by cumulative investments and taxes not accounted on the cost recovery) and the production rate.

Table 17. Example of YPFB participation table for natural gas prices

Q	b for P<=2.65USD/MMBTU									
(MPC/d)	0	0.3	0.6	0.9	1.2	1.5	1.8	2.1	2.4	2.7
0	0.27	0.3	0.33	0.36	0.39	0.42	0.45	0.48	0.51	0.54
176575	0.24	0.27	0.3	0.33	0.36	0.39	0.42	0.45	0.48	0.51
240142	0.21	0.24	0.27	0.3	0.33	0.36	0.39	0.42	0.45	0.48
303709	0.18	0.21	0.24	0.27	0.3	0.33	0.36	0.39	0.42	0.45
367276	0.15	0.18	0.21	0.24	0.27	0.3	0.33	0.36	0.39	0.42
430843	0.12	0.15	0.18	0.21	0.24	0.27	0.3	0.33	0.36	0.39
494410	0.09	0.12	0.15	0.18	0.21	0.24	0.27	0.3	0.33	0.36
557977	0.06	0.09	0.12	0.15	0.18	0.21	0.24	0.27	0.3	0.33
621544	0.03	0.06	0.09	0.12	0.15	0.18	0.21	0.24	0.27	0.3
685111	0	0.03	0.06	0.09	0.12	0.15	0.18	0.21	0.24	0.27

APPENDIX C. DECLINE CURVE ANALYSIS AND RESULTS IN A PER WELL BASIS

This section contains the equations used to find the Arps parameters and the results of the regression in a per well basis used in Section 3. The regression of the Arps parameters allow us to obtain a production forecast which represents a key input for the economic model.

The regression to obtain the Arps parameters was done in Excel. Monthly and cumulative production is available. The model compares the cumulative production data to the one calculated with equation C.2 The solver tool of Excel is used in order to minimize the difference between the calculated Np and the real Np varying the Arps parameters (least square method).

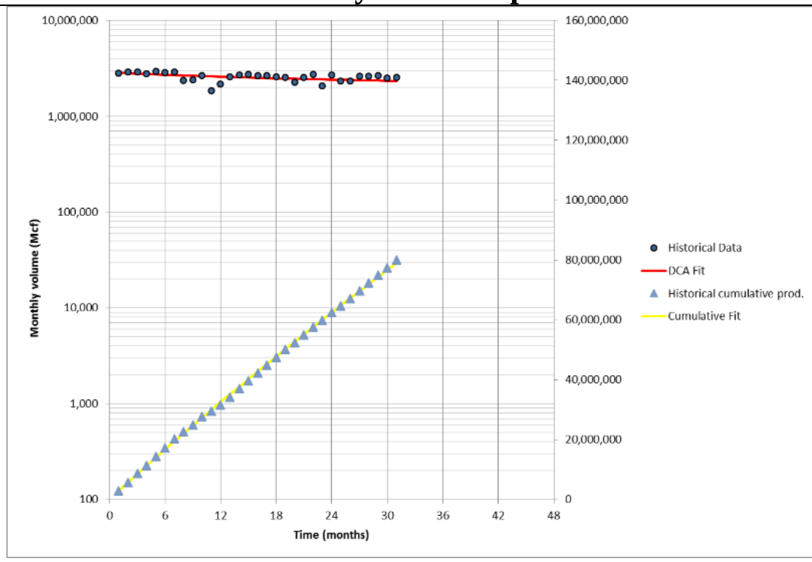
$$q = q_i * (1 + b * D_i * t)^{(-\frac{1}{b})} \qquad \textit{Eq. C.1}$$

$$N_P = \frac{{q_i}^b}{(1-b) * Di} * {q_i}^{1-b} - q^{1-b} \qquad \textit{Eq. C.2}$$

$$min \sum \left(N_{p,calculated} - N_{p,real}\right)^2 \qquad \textit{Eq. C.3}$$

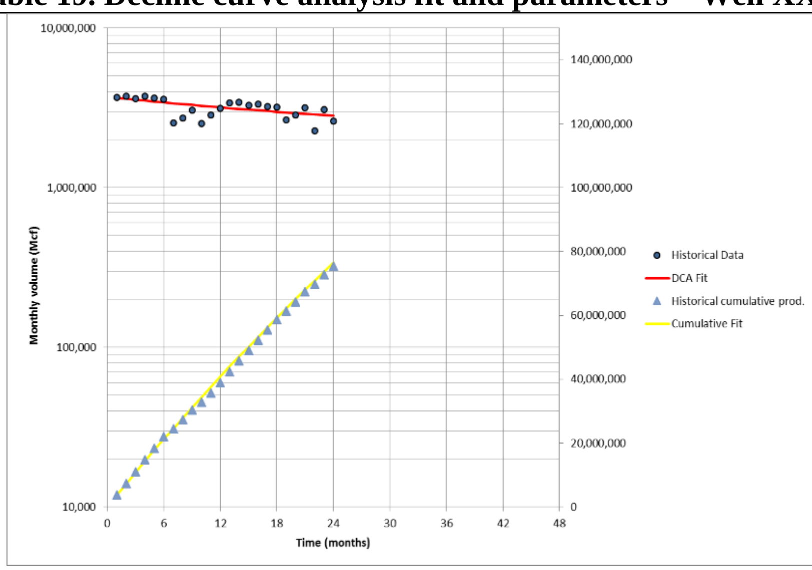
Parameter	**Units**
qi	Volume units/day
Di	1/year
b	dimensionless

Table 18. Decline curve analysis fit and parameters – Well XX2



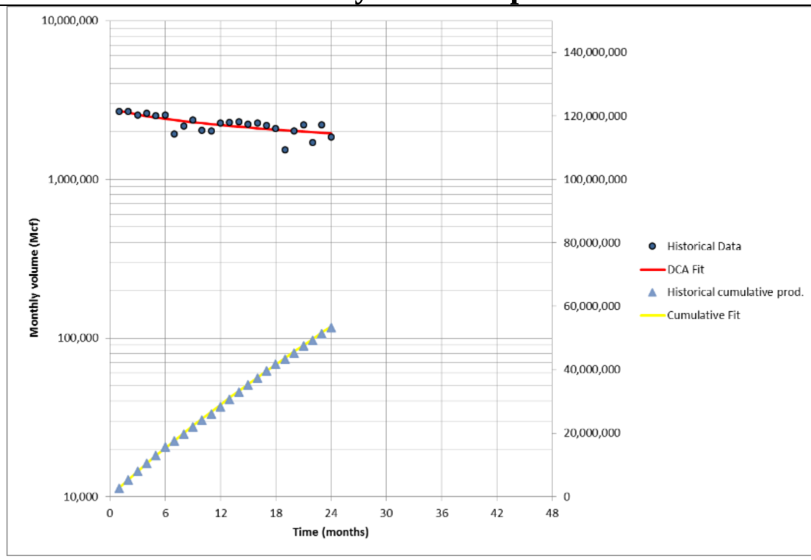
Arps values	
Qi	94570
Di	0.145
b	5

Table 19. Decline curve analysis fit and parameters – Well XX4



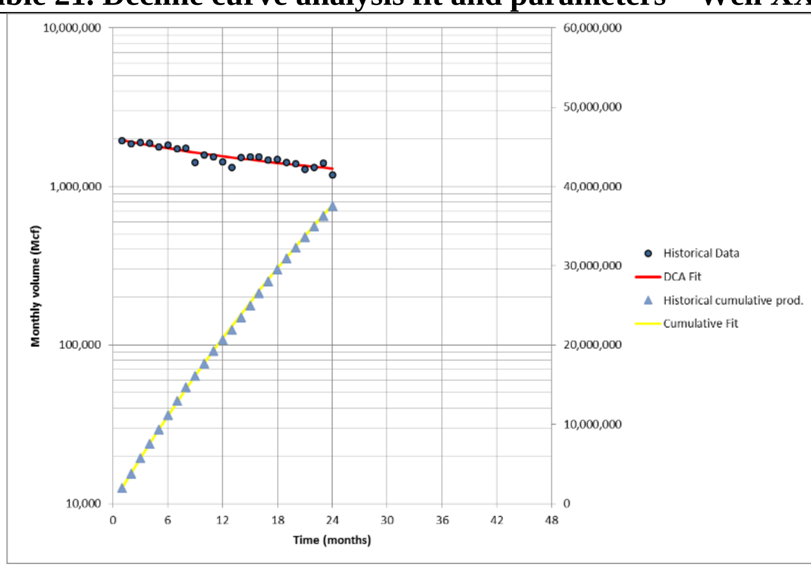
Arps values	
Qi	120804
Di	0.171
b	1.755

Table 20. Decline curve analysis fit and parameters – Well XX5



Arps values	
Qi	90212
Di	0.377
b	4.078

Table 21. Decline curve analysis fit and parameters – Well XX6



Arps values	
Qi	65210
Di	0.314
b	1.634

APPENDIX D: CASH FLOW BREAKDOWN FOR THE ENTIRE FIELD LIFE UNDER DIFFERENT PRICE SCENARIOS

This appendix shows the breakdown of the cash flow under different price scenarios, detailing the share of the CAPEX, OPEX, royalties, indirect taxes, YPFB share and the contractor share. It can be seen that for future operations (2016 onwards), the contractor take does not increase in the same magnitude as the revenues. Through YPFB share, the government collects a big portion of the price uptake.

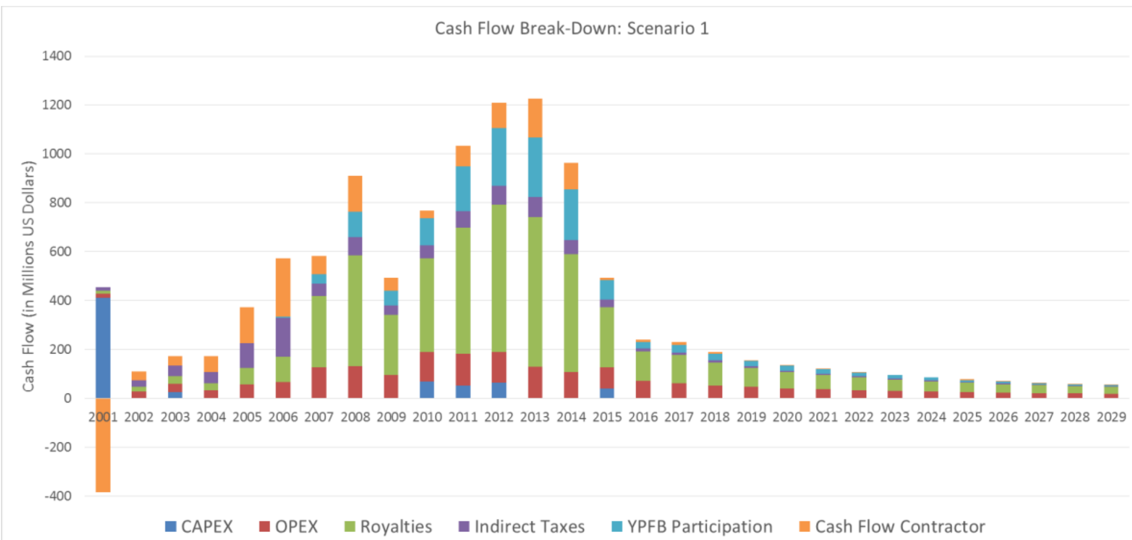


Figure 39. Cash flow breakdown of the project for the 40$/bbl price scenario

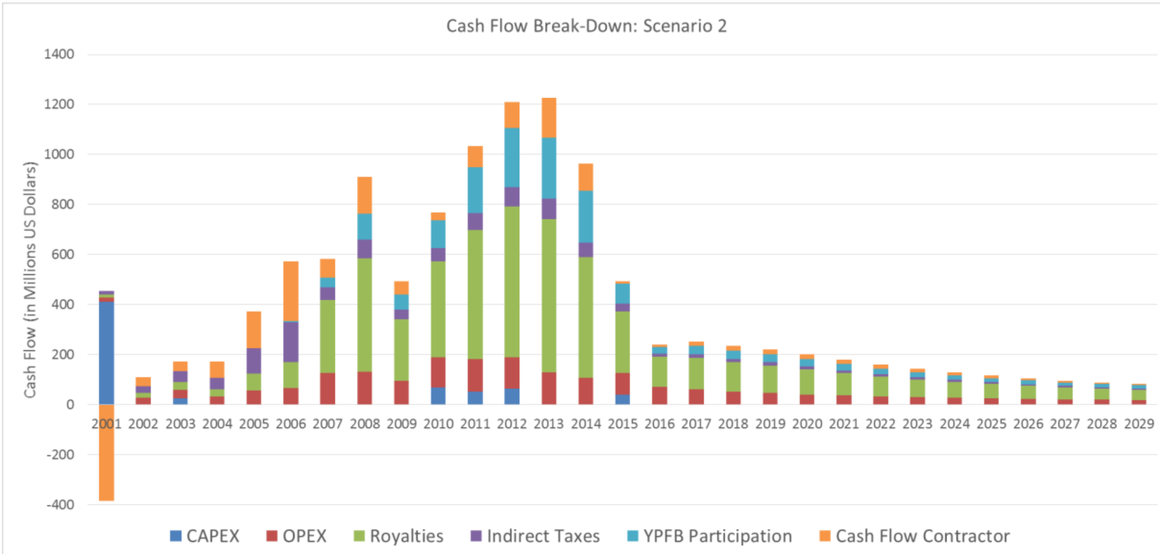


Figure 40. Cash flow breakdown of the project for the 60$/bbl price scenario

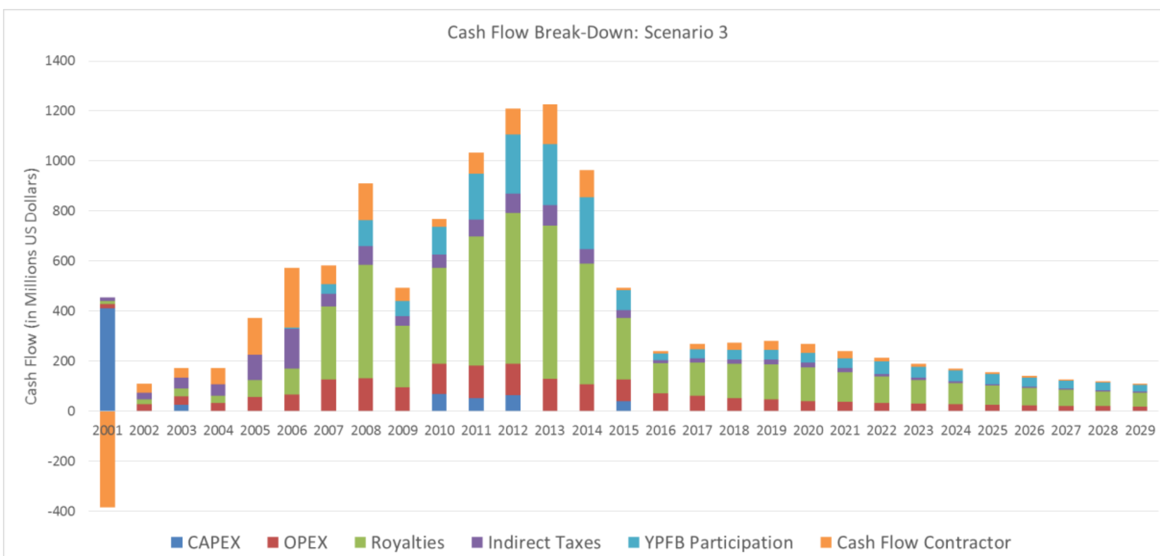


Figure 41. Cash flow breakdown of the project for the 80$/bbl price scenario

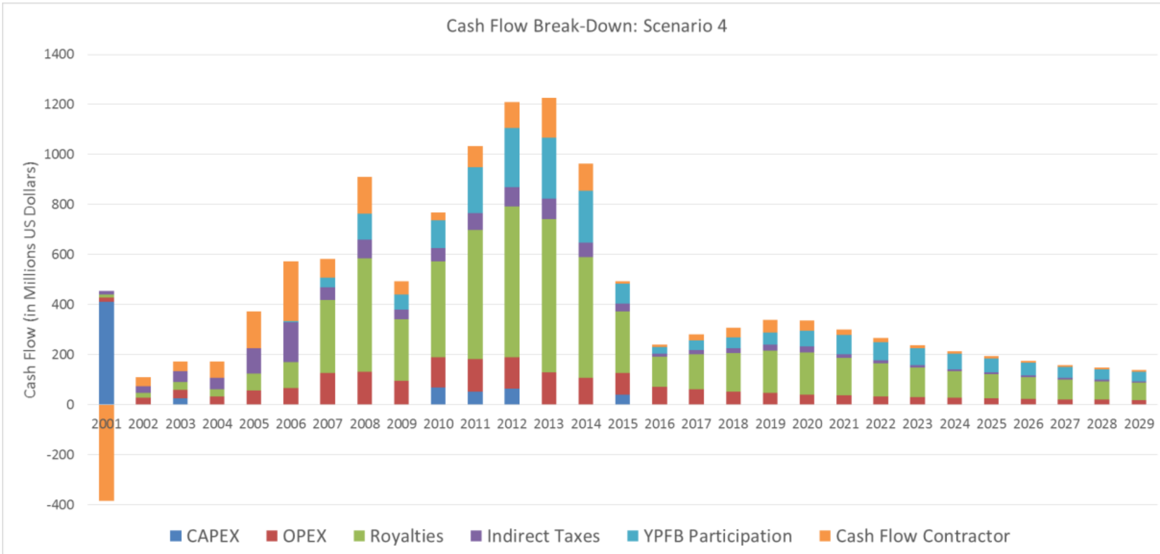


Figure 42. Cash flow breakdown of the project for the 100$/bbl price scenario

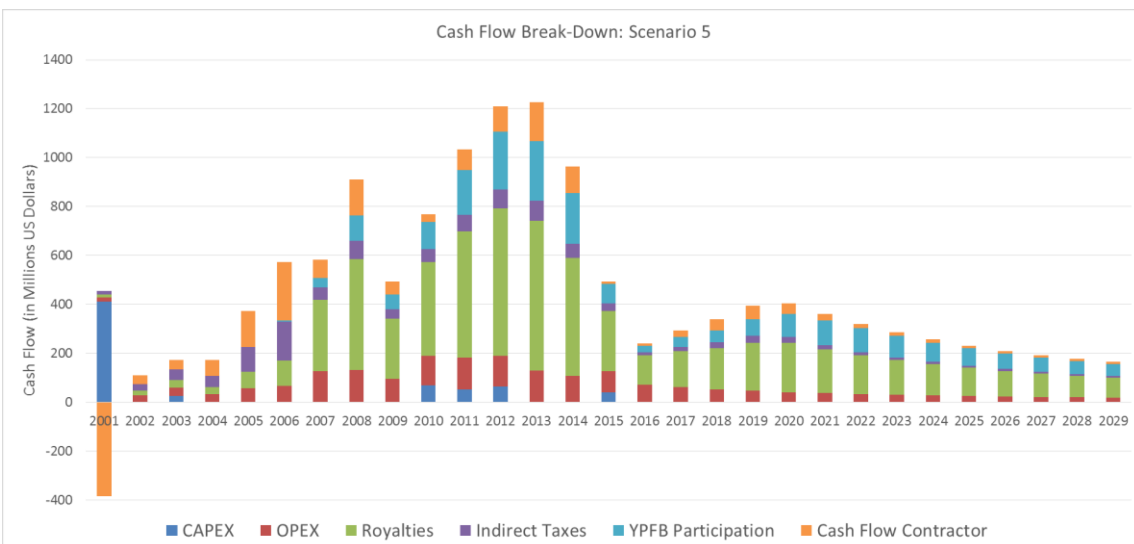


Figure 43. Cash flow breakdown of the project for the 120$/bbl price scenario

APPENDIX E: DATA MANAGEMENT

All work produced and data used in this document was properly preserved in a data management system which contains all codes, sources, presentations, and data so that this study can be reproduced or expanded by students in the research group. The data management diagram is shown in Figure 44

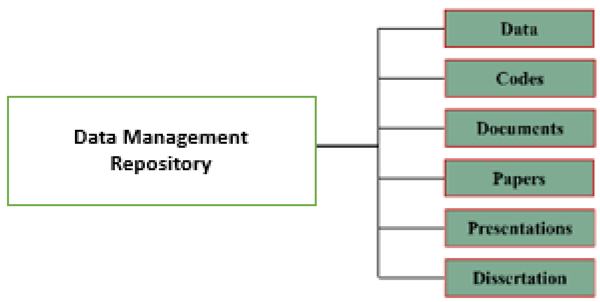


Figure 44. Data management diagram.