GAS PRODUCTION FROM SAN ALBERTO AND SABALO FIELDS

Kleber Galvão de Oliveira Pádua
Petrobras Bolivia – E&P

Abstract

This paper portrays the development plan of San Alberto and Sabalo Fields, main suppliers of the Bolivia – Brazil gas export.

Main reservoirs are deep and naturally fractured. The well deliverability is high (over 2.0 MMsm3/d)

Dual porosity numerical simulation is the basis to forecast production behaviour. From the vertical multiphase flow in pipes, the minimum and maximum gas rate per well are determined accounting liquid holdup and erosional velocity. A theoretical well flow model, that incorporates the temperature effect, matches the empirical data and supports the observation of an increase of wellhead temperature with gas production.

Ultimately, the development plan, inherently dependent of the gas demand, is phased (4 gas plants of 6.6 MMsm3/d each) allowing a more flexible production scheme and speeding the facilities build up. The completion design includes a 7.0 inches tubing size with a stacked system enduring a greater production rate and allowing flexibility to tackle a possible water encroachment. Preliminarily, long time and interference tests are planned to take the opportunity of the low initial demand. Afterwards, a commingled system of production is devised whereas the communication is confirmed and no water contact is detected. Otherwise a selective one is projected.

Introduction

San Alberto and Sabalo Fields are located in San Alberto and San Antonio Blocks situated at south of Bolivia, near Argentina. Figure 1 shows the location map of the Blocks.

They were discovered in 1998 and 1999 respectively. The development plans were designed during year 1999 and 2000, to be accomplished in years 2000 to 2002. The participants in both blocks[1] are the same: Andina holds 50%, Petrobras 35% and TotalFinaElf 15%.

Current gas reserves[1, 2] of each field are greater than 5 TCF. The production of San Alberto Field started in January 2001. The average rate, during this year, is around 115MMcf/d of residue gas and 2,450 barrels of condensate. The production is currently limited by contracted demand.

The development plan of both fields is inherently dependent of the gas export contract Bolivia - Brazil. Figure 2 depicts the gas demand curve of the gas export to Brazil (5.4 Tscf of contracted reserves and 22 MMsm3/d of plateau production). The gas demand curve is to be matched with the supply ones from San Alberto and Sabalo Fields. The build up of the gas demand curve is steep posing a challenge to a rapid, integrate and robust development plans to both fields.

Characterization

San Alberto and Sabalo Fields are north - south direction elongated geological trends along with the Andes, situated in the geologic area known as Subandino Sur. Figure 3 depicts the schematic map of the fields.

Subandino Sur is structurally characterized[3] by tight folding, multiple thrust and normal faulting, which developed as the stratigraphic section underwent complex compression during crustal foreshortening associated with the Andean uplift. Figure 4 portrays the schematic structure of the fields.

Both fields comprise three main reservoirs: Huamampampa, Icla and Santa Rosa, corresponding to sandstones intercalated with shale and siltstones. The zonation is mainly based on the stratigraphic criteria[4]. The reservoirs are deep (> 3000 m), bearing gas in low porosity rocks with natural fractures. No water gas contact has been detected so far. Current gas reserves[2] of each field are greater than 5 TCF leading to a potential production over 10Tscf of gas reserves and 30MMsm3/d of plateau production. Table 1 describes the typical rock parameters of the fields[5, 6].

There were several PVT data analyses from both fields[7]. Fluid characteristics vary from dry to condensate gas in an over-pressured environment with normal temperature gradient. These differences may be disregarded because they are in the same order of magnitude of the accuracy of the measurements. Otherwise, they may infer partial communication and/or the effect of the temperature on the generation (maturation) of the fluid. The results of drop out test suggest a negligible production of liquid during pressure depletion. This indicates that the fluid in San Alberto Field may be considered as a dry gas. The condensate gas ratios (CGR), as applied in the reservoir numerical modeling, are in the range of 10 o 30 stb/MMscf.

Several well tests are performed [8]. The evaluation of well test data suggests reservoirs with an early naturally fractured reservoir behavior. The wells have a high deliverability with an AOF in the range of 3 to 8 MMsm3d. Table 2 shows typical reservoir parameters of San Alberto and Sabalo Fields

Modeling

The modeling is inherent dependent on the level of characterization of the field. Figure 5 exposes the relation of characterization and modeling applied to the study.

Reservoir numerical simulations are performed to guide the development plans. The available data to build the structure framework are extracted from the wells drilled, seismic lines, well tests and field study. A complex simulation grid is constructed using commercial pre-processors with corner point option [9,10]. A dual porosity model is used to mimic the matrix and the fracture system of the naturally fractured reservoirs. The water gas contact is here assumed to be 200 m bellow the lowest known gas (LKG) depth.

Preliminary reservoir studies involved an equation of state matching of PVT that was used in a simplified compositional simulation. The results suggested a negligible effect of the phase segregation due to the small drop out (less than 0.5 %) in the range of estimate reservoir pressure depletion. They also indicate a small difference among fluid properties. The average Z factor difference, for instance, is lower than 5 %.

The wells are modelled[11] with the objective to estimate the well performance, the wellbore pressure drop and ultimately, to investigate and optimize the wellbore completion scheme. The methodology adopted here is to match the DST results (pressure, temperature and volumes) and then extrapolate the well model to different conditions. In the study, the modified model of Hagedorn and Brown provided the best matching. The model proved to be robust since it was applied to all investigated cases with a correction factor around 1.1. This correlation is further utilized to extrapolate the well performance to different conditions in order to investigate the well completion scheme for tubing sizes 5.5 and 7 inches. The vertical multiphase flow tables (pressure drop along the tubing to be used in the numerical simulation) were then built. The tables are constructed using the gas condensate properties and the DST measurements and results.

From the vertical multiphase flow study; the minimum and maximum gas rate per well are then investigated. The minimum gas rate per well is the one to avoid the liquid accumulation against the formation, the liquid loading. The continuous accumulation of liquids in the well tubing will impose additional backpressure against the formation that may affect the well production capacity and hence kill the well. In order to solve this problem it is necessary to give the gas phase sufficient transport energy to increase the flow velocity to allow the removal of all drops out of the well. Applying the Turner et al model does the analysis of minimum gas flow rate to keep the well continuously unloaded. In order to determinate the maximum gas rates per well, the erosional velocity criteria is applied by using the API RP14E, which recommends the limit of the maximum allowable gas velocity in the tubing.

The results of the above study revealed that the maximum gas rate (at 1500psia-wellhead pressure) in a 7” tubing size completion scheme is significantly higher than that of a 5.5”. However, in case of sand production, the erosional velocity may limit the maximum gas rate and reduce the significant advantage of using a 7” completion scheme case. An eventual water encroachment may also pose another significant problem and reduce the advantage in using the 7” tubing size completion scheme. The minimum gas rate that unloads liquid in the bottom hole of 7” tubing size case (810 Msm^3/d) is significantly greater than that of the 5.5” (470 Msm^3/d). Sand production and water encroachment problems have not been detected so far. However, the probability to occur a water encroachment / sand production problem is not negligible based on analogue fields. The study concludes that the advantage of using a 7” completion scheme may be significant in spite of the possible cases of sand production or water encroachment that may reduce that benefit. The investigation suggests a 7” completion scheme and the modified Hagedorn and Brown model with L around 1.1.

A variety of sensibility analysis is considered to perform the reservoir and well modeling, involving capillary pressure, fracture to matrix characteristics[12], well deliverability, early water eruption and san production.

Wellhead Temperature Behavior

The design of gas facilities, such as gathering lines and plants, requires precise and reliable information on the wellhead temperature of gas wells. For example, an under-predicted wellhead temperature may lead to an exchanger heater that would not be able to heat the gas up to a temperature necessary to properly process the gas according to sales specifications.

The wellhead temperature mainly depends on the gas flow rate and production life. In most gas wells around the world, the wellhead temperature decreases when the gas production increases. The diminution can be explained by the Joule-Thomson effect that relates temperature reduction with pressure drop (draw-down). This is because the increase of the gas production is inherently dependent on the pressure drawdown and bottomhole pressure drop. Consequently, according to the law of gases (PV=constant) the bottom hole temperature decreases. This phenomenon, usually called Joule-Thompson effect, is the dominant one that impacts the wellhead temperature in most gas wells around the world. Other effects, such as heat convection, work the opposite way, yielding a wellhead temperature increase with an increase in gas velocity. However, these are usually negligible relative to the Joule-Thomson effect.

Well testing and production in different wells of San Alberto Field provide actual data of wellhead temperature at different gas production rates. Figure 6 describes the typical wellhead temperature behavior for different gas production. The results expose an unusual increase of wellhead temperature for gas rate lower than 1.0 MMsm3d (on average).

A comprehensive investigation of the uncommon wellhead temperature behavior was then undertaken. The study is performed matching well test data with complex fluid flow models in pipes. A theoretical well flow model matches the empirical data and supports the above explanation. These models encompass not only the Joule-Thompson effect but also other ones, such as the heat conduction and convection, which work in the opposite way of the Joule-Thompson effect. The heat conduction occurs transversally to the gas flow, when a volume of gas looses energy (temperature) to the earth, along its journey inside the well tubing from the bottom hole to the wellhead. The heat convection occurs with the mass transfer from bottomhole to wellhead. In this case, the greater the gas velocity (or the greater the gas production), the lower is the temperature drop along pipe. The adjusted model offers an accurate estimate of the wellhead temperature in high productivity wells at different gas production rates.

Figure 6 depicts the results of the investigation. They indicate that the odd temperature behavior is only represented when the heat convection and conduction effects are incorporated in the fluid flow model in pipes along with the commonly applied Joule-Thompson phenomenon. Moreover, the uncommon wellhead trait occurs only in wells with high deliverability. The uncommon combination of well deliverability, well depth, temperature gradient, pressure gradient and tubing size lead to a an unusual wellhead temperature behavior with production that may impose significant error in planning plant facilities. This is an atypical case of a wellhead temperature increase, instead of decrease, with increased gas flow. The high productivity of these wells explains the increase. The greater productivity brings about a lower than usual draw down and an exceptional gas velocity that lessens the Joule-Thomson effect and enhances the impact of heat convection. The dominance of heat convection over the Joule-Thomson effect ultimately leads to the uncommon case of an increase of wellhead temperature with an increase of gas production.

Development Plan

An early, complex and detailed development planning is necessary due to long drilling, evaluating and completion time, significant geological and reservoir uncertainty (naturally fractured reservoirs), severe operational risk (deep and over-pressured wells) and a steep build up of the demand curve

The proposed development plan is phased: San Alberto Phase 1 and 2 during year 2001 and 2002 and Sabalo Phase 1 and 2 during year 2003. The reason is to better tackle the geological and reservoir uncertainty, manage the operational risks of drilling and completion and cope with the tight demand schedule[13, 14].

The number of wells (15), schedule and spacing are determined based on the demand curve, the well deliverability, the geological/reservoir uncertainty and the homogeneous drainage concept. The well spacing of San Alberto Field is initially 4 km well spacing (6 wells). The well spacing of Sabalo Field is initially 8 km well spacing (5 wells). Infill wells (4) will be drilled as reservoir depletion occurs in both fields. As an example, Figure 7 presents the planned reservoir drainage scheme of San Alberto Field

Production wells are tied to the gas plant with individual gathering lines (one single line from the well to the plant) because of the negligible additional cost and advantageous flexibility.

The central gas facility is designed to treat the raw gas and output residue gas compatible with the required characteristics under contract. Natural gas from the high-pressure wells passes through separators to remove hydrocarbon liquids, water and partially CO2. Total plant capacity is function of the gas demand plus losses in the transport, fuel gas and contracted swing.

Export lines convey the residue gas from the plants to the internal transport system in Bolivia and finally to the Bolivia – Brazil long-distance pipeline. The total capacity of the export lines account s for an extra phase of 6.6 MMsm3/d allowing flexibility to the overall project. As an example, Figure 8 shows the whole surface facilities of San Alberto Field.

The production scheme involves the early production of the deeper reservoirs and deeper wells. The reason is to optimize drainage. The well production is initially restrained to mitigate a potential early water eruption (2.5 MMsm3/d per well).

A stacked well completion scheme (slide sleeve and retrievable bridge plug) is designed to allow separated production. Figure 9 portrays a typical completion scheme. Permanent downhole pressure gauges are planned to monitor reservoir pressure depletion and early water breakthrough.

Mechanical characteristics of the rock along with the geological stress of the region are continuously investigated and updated to optimize directional drilling and completion schemes and prevent potential production problems (wellbore stability).

Production logging are planned with regular frequency to correlate reservoir and fracture characteristics with real gas inflow.

Real time monitoring is planned to both fields. It will allow constant measuring of the inflow performance relationship (pressure and temperature draw-down between reservoir and well bottom-hole) to investigate possible reservoir damage at early times. It will also provide constant monitoring of the tubing performance relationship (wellbore pressure and temperature drop) to investigate possible unexpected wellbore pressure drop due to local effects (mechanical restriction), fluid hold-up (water/condensate/gas) or flow regime (mist/bubble/etc). The project aims to better evaluate the wellbore behavior (pressure x temperature x production) in the early stage of development of San Alberto and Sabalo Field. The wellbore behavior involves reservoir depletion, liquid drop out, relative permeability reduction, double porosity characteristics, mechanical restriction, liquid (water hold up), etc. The benefits are frequent matching of the real time measurements with a theoretical wellbore and reservoir model leading to an accurate and updated forecasting of the well production, wellhead pressure and temperature. Other benefits are an early assessment of small deviations of the well productivity leading to an early application of solutions to mitigate possible problems as it appear and thus reducing the risk and the number of days of the shut off of a high productivity well (the average production per well is around 3 MMsm3/d). The real time monitoring project is here justified by the high productivity of the wells and by the early stage of reservoir and fluid characterization of the fields.

Long time and interference tests were preliminarily projected to better characterize the reservoir (wellbore stability, sand production, communication among the different zones, gas-water contact and double porosity parameters). They would take the opportunity of the low initial gas demand to accomplish a comprehensive investigation of the reservoir characteristics in the early time of production life. Figure 10 shows a sketch of the tests projected. Unfortunately, they were not implemented due to operational reasons.

A commingled system of production is devised whereas the communication is confirmed and no water contact is detected or a selective system of production may be put upon in case of no communication and / or possible water eruption.

Conclusion

This paper portrays the development plans of San Alberto and Sabalo Gas Fields, main suppliers of the Bolivia – Brazil gas export. The plan is inherently dependent of the gas demand. It involves a comprehensive characterization, modeling and investigation of alternatives and uncertainties.

Firstly, it evaluates the field characteristics and correspondent potential production (over 10Tscf of gas reserves and 30MMsm3/d of plateau production). This helps to estimate the supply curve one can offer to the market. After the gas purchase and sale contract set up (5.4 Tscf of reserves and 22 MMsm3/d of plateau production), the number and schedule of the wells (15) are then planned based on the well deliverability.

Main reservoirs are deep and naturally fractured. The well deliverability is high (over 2.0 MMsm3/d). Dual porosity numerical simulation is the basis to forecast production behaviour. From the vertical multiphase flow in pipes the minimum and maximum gas rate per well are determined accounting liquid holdup and erosional velocity. A theoretical well flow model that incorporates the temperature effect and matches the empirical data supports the observation of an increase of wellhead temperature with gas production.

Ultimately, a phased development plan is proposed with four sequential gas plants of 6.6 MMsm3/d each. This allows a more flexible production scheme and speeds the facilities build up as follows. Since the well deliverability is high (over 2.0 MMsm3/d), the completion design includes a 7.0 inches tubing size with a stacked system. The first endure a greater production rate in case of no limitation with respect to erosional velocity and a possible water breakthrough. The later allows flexibility to tackle the problem of water encroachment. Preliminarily, long time and interference tests are projected to take the opportunity of the low initial gas demand to better characterize the reservoir (wellbore stability, sand production, communication among the different zones, gas-water contact and double porosity parameters). Afterwards, a commingled system of production is devised whereas the communication is confirmed and no water contact is detected or a selective system of production may be put upon in case of no communication and / or possible water eruption.

Nomenclature

MMsm3/d	Million of standard cubic meter per day
Tscf	10^{12} standard cubic feet

AOF	Absolute Open Flow
M	meter
Z	Compressibility Factor
Km	10^3 meters

Acknowledgments

We thank the team of the department of Reservoir and Reserves of Petrobras Bolivia E&P for their fundamental and efficient cooperation.

We acknowledge permission to publish the paper from Andina, Petrobras and TotalElfFina, partners in San Alberto and San Antonio Blocks.

Conversion Factors

1 bar = 14.5 psi

1 m3 = 35.314 cf

1 m = 3.2808 ft

References

1) Informe Mensual Enero-Febrero 2001. Vice-Presidencia de Negociaciones Internacionales y Contratos. Yacimientos Petrolíferos Fiscales Bolivianos
2) DeGolyer and MacNaughton Report as Dec 31, 2000 on Reserves of San Alberto and Sábalo Field in Bolivia, operated by Petrobras Bolivia S.A**.** 2000
3) Rocha, A. and Pereira, M. San Alberto Field Reservoir Characterization - Intermediate Phase, San Alberto Block, South Sub-Andean Basin, Bolivia, Petrobras Bolivia S.A. 1999
4) Well Core Analysis Reports - from SAL-X-11 and SAL-X-12 Wells Petrobras Bolivia S.A. 2000
5) Trindade, W. Estudio de Simulación de Yacimientos, Revisión B, Campo de San Alberto Petrobras Internacional 1999
6) Pádua, K. G. de O. San Antonio Field Reservoir Study, Petrobras Bolivia S.A. November 1999.
7) San Alberto and Sabalo PVT Reports
8) San Alberto and Sabalo DST Reports
9) Rosa, M. R. da S., San Alberto Reservoir Engineering Study, Petrobras Bolivia S.A. 2000
10) Syrio, J. C., Sábalo Reservoir Engineering Study, Petrobras Bolivia S.A. 2000
11) Neto, S.J.A. and Machado B.R. Multiphase Flow Simulation Report Petrobras S.A. E&P/GETEP August 2000
12) Aguilera R. Naturally Fractures Reservoirs (2nd ed.) PennWell Publishing Company 1995
13) Rosa, M., Pádua, K., Silva, M. and Syrio, J.:'Reservoir Management of San Alberto and Sabalo Fields in Bolivia', III Seminario Interno de Reservas e Reservatórios, Petrobras, 2001.
14) Silva, M., Rocha, A. Syrio, J., Pádua, K., Rosa, M. and Pereira, M.:' Reserves Evaluation and Monnitoring of San alberto and Sabalo Fields in Bolivia', III Seminario Interno de Reservas e Reservatórios, Petrobras, 2001.

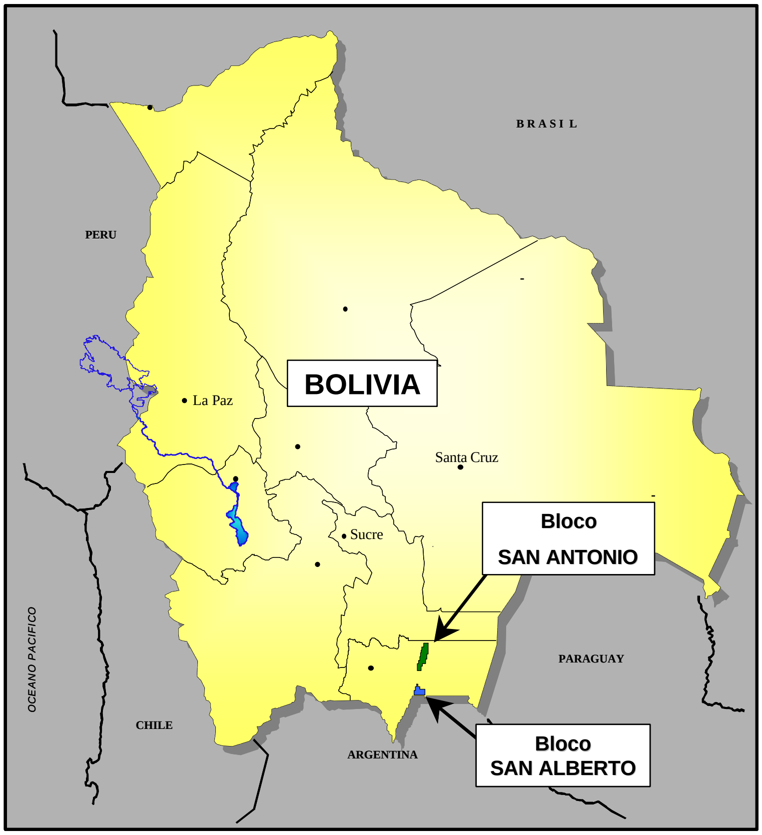

Figure 1 – Location Map of San Alberto and San Antonio Block

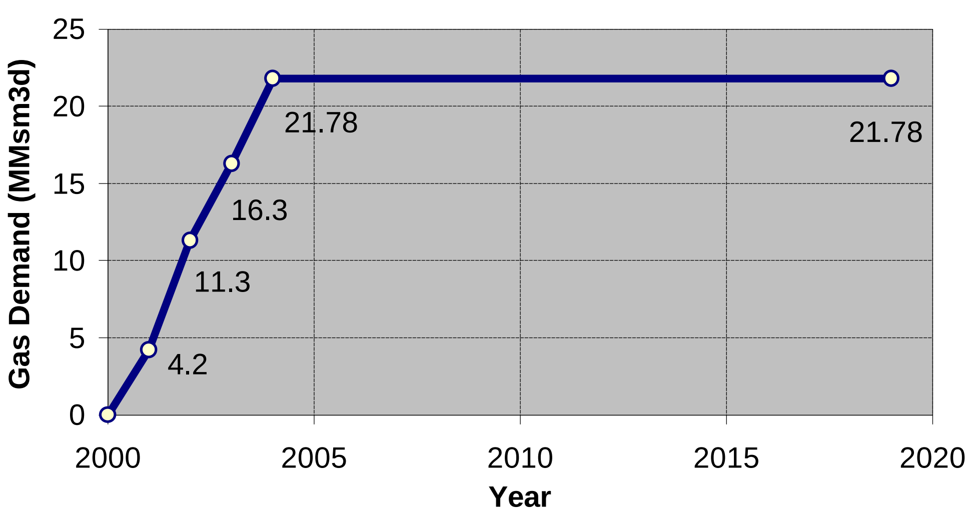

Figure 2 – Gas Demand Curve

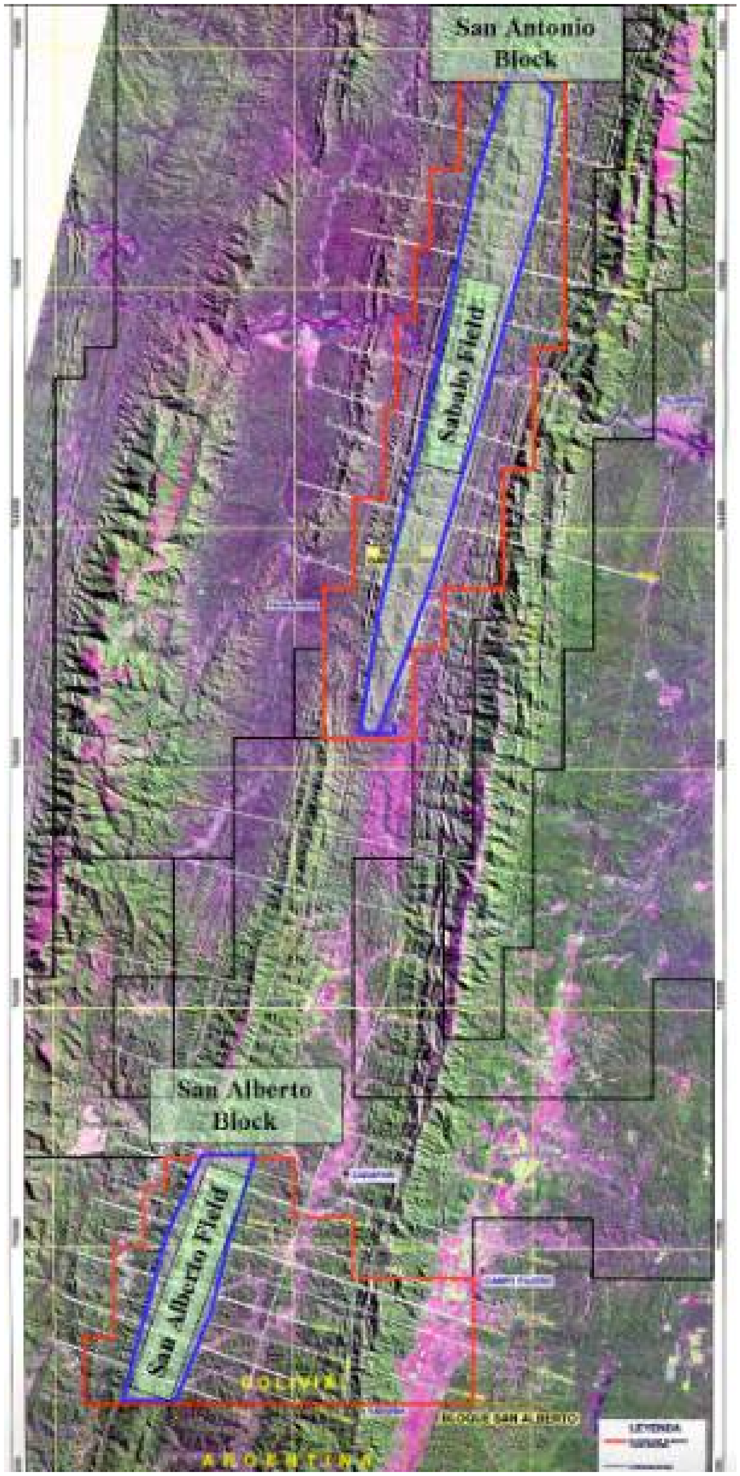

Figure 3 – Schematic Map of San Alberto and Sabalo Field

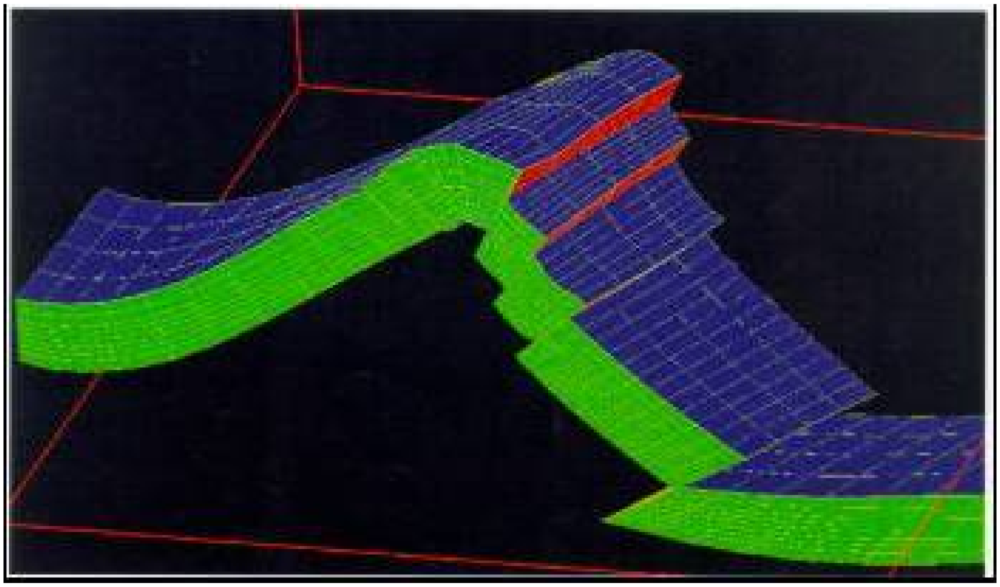

Figure 4 – Schematic Structure of San Alberto and Sabalo Field

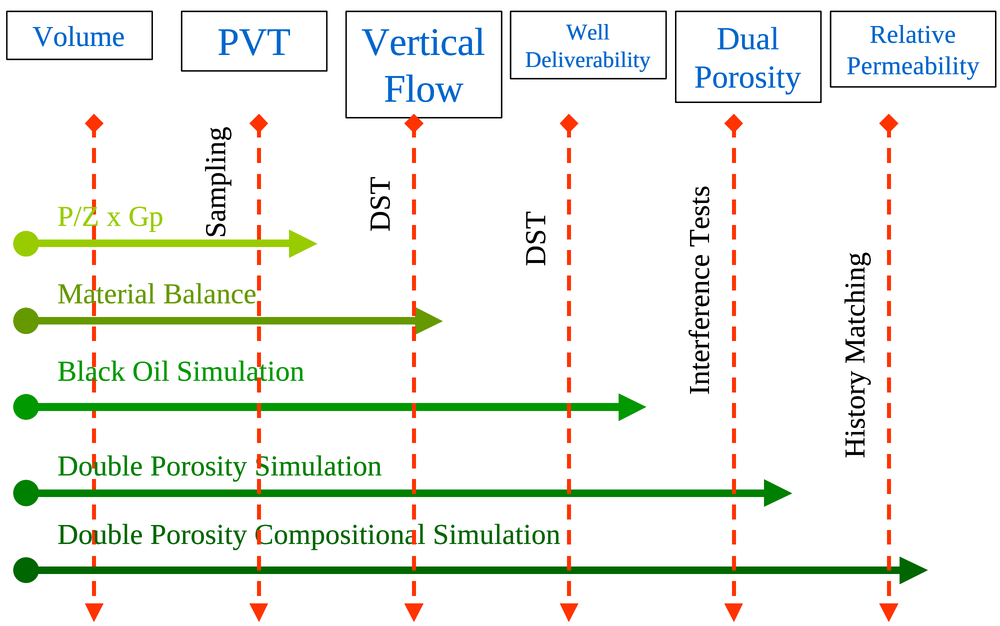

Figure 5 – Schematic Characterization and Modeling

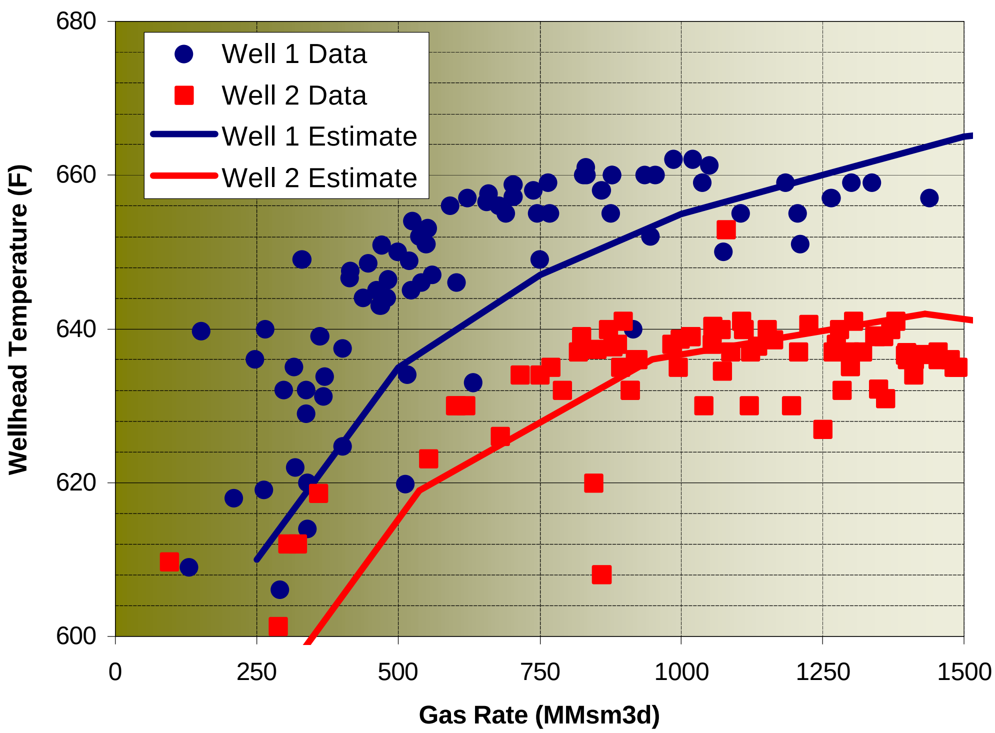

Figure 6 – Wellhead Temperature Behavior

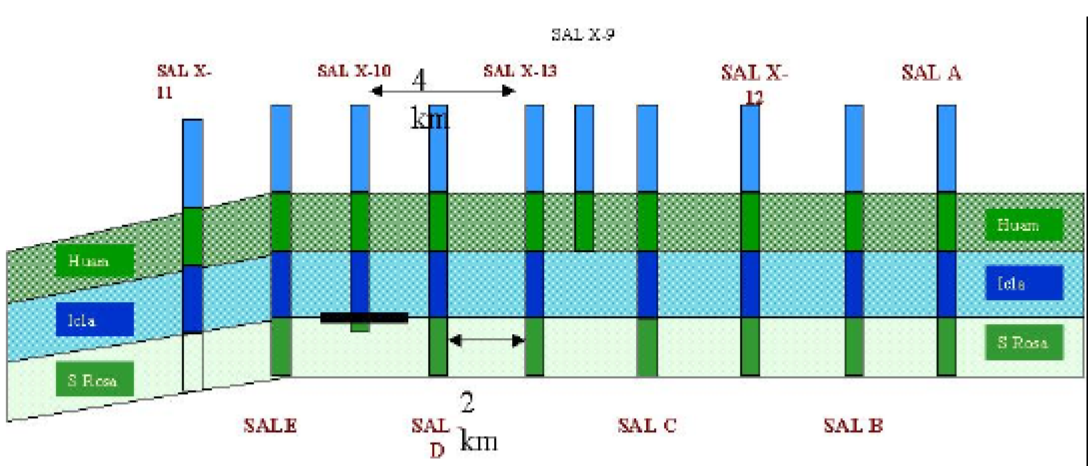

Figure 7 – Schematic Drainage of San Alberto Field

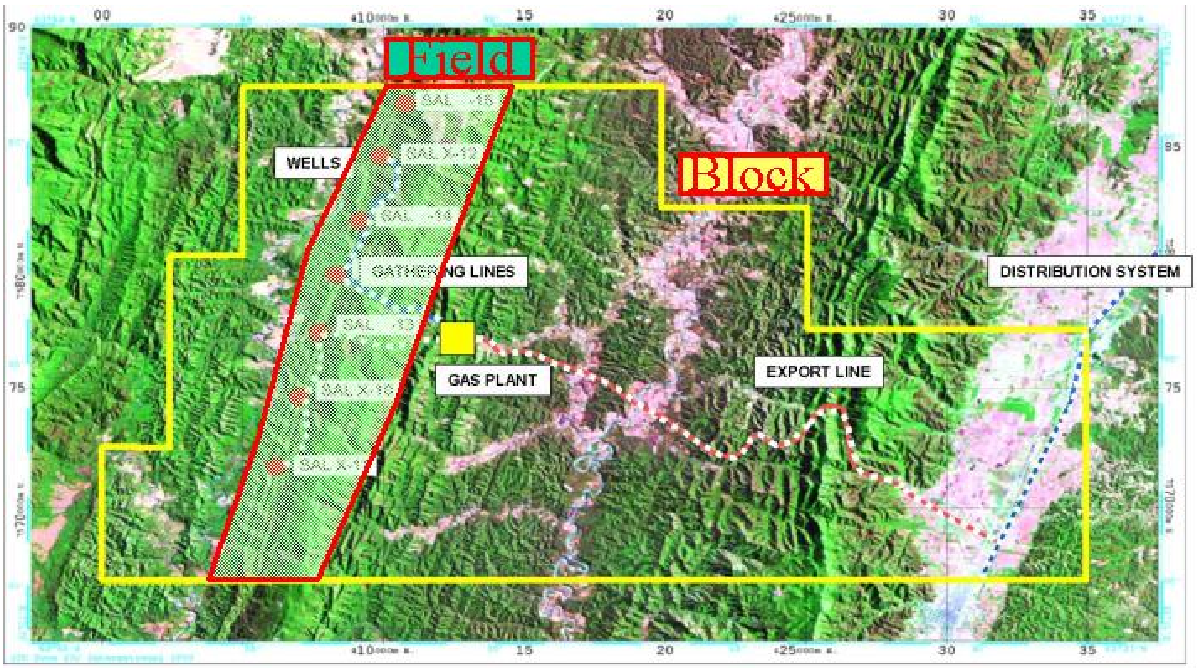

Figure 8 – Surface Facilities of San Alberto Field

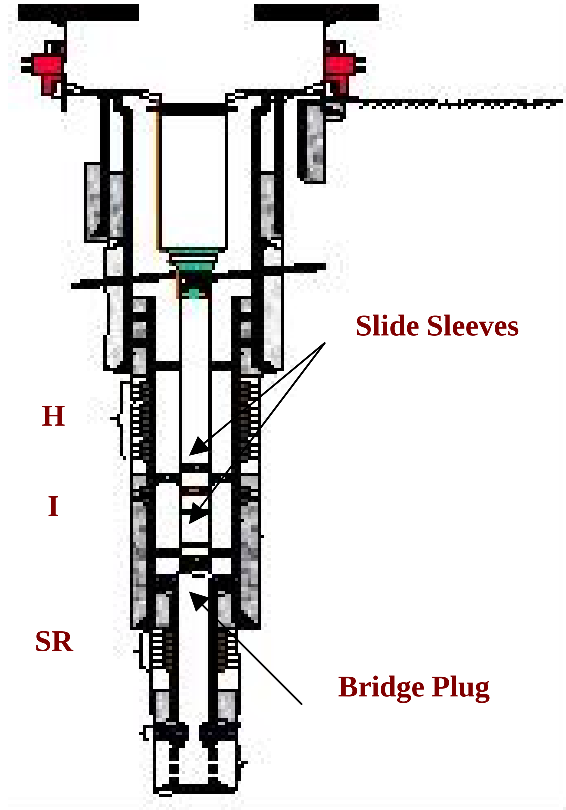

Figure 9 – Schematic Completion Scheme

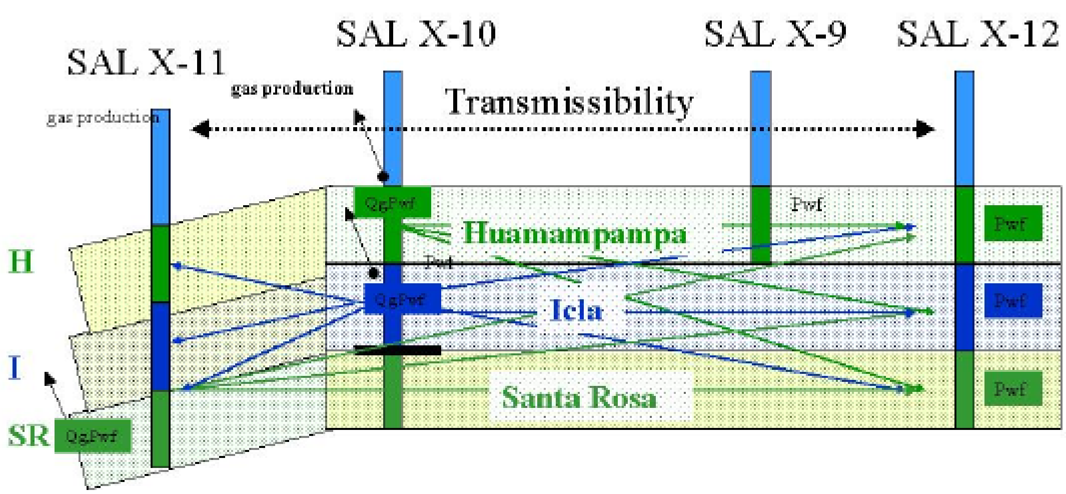

Figure 10 – Schematic Interference Test of San Alberto Field

Porosity	5%
Water Saturation	23%
Fracture/ Total Volume	10%
Gas Net Pay (m)	900
Net to Gross Ratio	75%

Table 1 – Typical Rock Parameters

Fluid	Dry Gas
Molecular Weight	20
Depth (ft)	12000
Temperature (F)	240
Pressure (psia)	8000
Fracture Permeability (md)	10
Matrix/Fracture Permeability Ratio	0.0001

Table 2 – Typical Reservoir Parameters