Society of Petroleum Engineers

SPE 69514

Optimization of a Mature Oil Field by Changing Lifting System

Pablo Prado & Mario Brarda, SPE, Petrolera Perez Companc S.A

Abstract

All wells in Entre Lomas Area, after a initial period of natural flow, requiered an artifitial lifting system. Gas-Lift system suited very properly the field characteristic.

As the reservoir pressure declined and the water-flooding expanded, it became necessary to change the lifting system progressively from Gas-Lift to Sucker Rod Pumping (SRP) or Electrosubmersible Pumping (ESP).

With almost half of the wells already converted, the remaining did not appear economically attractive for conversion at the individual well basis. Therefore, a global conversion project for the remaining wells was considered, which ultimately yielded additional profit that made total replacement affordable.

Introduction

Entre Lomas Area, operated by Petrolera Pérez Companc S.A. since 1968, is located between the Río Negro and Neuquén provinces in Argentina (**Fig. 1**).

The most important oilfields, Charco Bayo and Piedras Blancas, have mainly two pay zones: Tordillo Formation (oil at 2300 m depth) and Quintuco Formation (gas at 1900 m depth).

Initialy the Tordillo Fm. flowed naturaly with GOR values over 300 m3/m3 due to its solution gas-drive mechanism.

As the reservoir energy declined, it was decided to turn to the Gas-Lift artifitial lifting system, taking into consideration the reservoir depth, the high well GOR's and the presence of fracture sand due to stimulations jobs.

Afterwhile, it was also decided to start a secondary recovery project by injecting freshwater .

Since the circulating gas in the Gas-Lift network was rich, a Liquid Petroleum Gas (LPG) recovery plant was set up, in order to obtain Propane, Butane and Gasoline. On the other hand, the oil associated gas was used to fuel the compressor engines and heaters, and its surplus, once treated for dew point conditioning, injected into the gas sale pipeline (**Fig. 2**).

As the reservoir pressure further declined and the water cut increased as a result of waterflooding, Gas-Lift system was growing less and less effective. This was because the fluid columns to be lifted were heavier, and in addition, there appeared emulsions, thus making it necessary to count on increasing quantities of injected gas at higher pressures. These effects increased the bottomhole flowing pressures (Pwf) and the lifting grew difficult.

Under these conditions, the only possibility to optimize the well production was to turn to another lifting system (mainly Sucker Rod Pumping), so as to decrease the bottomhole flowing pressures, which yielded an oil production increase enough to pay for the necessary investment.

Hereafter, more wells were chosen for conversion, according to their degree of inneficiency and their prospective production gains.

Yet, as more and more wells were converted from Gas-Lift to SRP or ESP, the oil production increases dropped to such an extent that, with half the wells still waiting for conversion, the economic parameters did not result satisfactory (**Fig. 3**).

Under the above mentioned conditions, the following alternatives were analyzed:

1. To continue with the current situation, and periodically assess the convenience of converting the lifting system in particular wells.
2. To make a comprehensive analysis of the field operation in order to get additional gains other than those from the oil increase, thus making the conversion of the remaining wells profitable.

This last alternative proved that, although the individual conversion was not economically viable, total conversion of the remaining wells opened up new opportunities for the field exploitation, with healthy profits to finance the whole project.

Analysis method

The first alternative above was well known but offered only partial solutions to the main problems: greater bottomhole flowing pressures and low water-flooding sweeping efficiency, with the resulting production loss and oil recovery factor reduction.

The second alternative above opened new opportunities for development that had not appeared feasible up to that moment, but involved threats that deserved further consideration.

Converting all the Gas-Lift wells entailed substantial changes in the operation scheme, affecting not only wells, but also Motorcompressor Stations, the LPG Plant, gas sales, etc., which should also be weighed in the project analysis.

To this effect, all Gas-Lift wells conversion was considered, and the effects of this conversion on the other field operations were individually evaluated, thus establishing oportunities and threats (pros and cons) for each stage of the process. For example, with the elimination of the Gas-Lift system network, some compressors became available to produce gas well gas at a lower backpressure, with the subsequent sales increase. This gas in turn, could be processed in the LPG Plant, increasing the LPG production; and so forth with the rest of the operations.

All these individual modifications were possible only granting the total conversion of the lifting system. Therefore, they were included in the conversion project evaluation, and the results were significantly different.

With this analysis method, it was proved that while the isolated individual conversion was not economical, total conversion promised important economic and operative benefits.

Below, there is a detailed analysis of the implicit opportunities and threats as well as their consequent results.

Opportunities

Oil production increase. Out of all the artificial lifting systems, those which showed characteristics compatible with our field conditions were assessed, such as fluid flowrates and properties, formation depth, reliability and development on the local market, necessary know-how, etc. Sucker Rod and Electrosubmergible Pumping appeared as the most suitable for this application.

The Gas-Lift conversion into SRP or ESP, under the existing conditions, allowed for a reduction in the flowing well pressure with the subsequent production increase.

Although this increase was not meaningful, it was in line with the initial estimations - over 0.5 m3/d of oil per well. Besides, for the purpose of an economic appraisal, this increase was regarded as having a future decline identical to the current one (Gas-Lift), setting aside the eventual improvement in the hydrocarbons final recovery, expected from a better waterflood sweeping. (**Fig. 4**)

Gas consumption decrease. The Gas-Lift networks entail gas consumption and losses, as follows:

Motorcompressor Stations. The gas gathered in the batteries is compressed for later reinjection in the Gas-Lift system, by means of alternative compressors driven by gas fueled internal combustion engines. This gas is obtained from the gas circulating in the net and its consumption is proportional to the compressed gas volume, which determines the number of compressors needed on service.

With the Gas-Lift elimination, it became necessary to compress only the oil associated gas – 15% of the circulating total - resulting in a proportional reduction of the on-service motorcompressors and the corresponding gas consumption.

Field heaters and dehydration plants. In order to prevent gas-hydrate formation in the Gas-Lift distribution net, gas is dehydrated in absorption plants, using Triethylene glycol (TEG). Besides, the gas is heated prior to the pressure drop in the regulation of the injected gas flow. In both cases, the gas consumed comes from the circulating gas in the system.

As the distribution network was eliminated, it was possible to avoid the heating gas consumption. Yet, the dehydration plants were maintained, since they contributed to further gas conditioning processes.

Field leaks. Oil lifting using Gas-Lift method requires a vast gas distribution pipe network, involving Compressor Stations, main and secondary gas pipelines, manifolds and well gas injection lines.

This is far from a closed circuit, there being leaks due to aging, which are difficult to detect since they are mostly located in inaccesible areas, not frequently visited.

Measuring gas leaks volumes in the Gas-Lift circuit is complex and uncertain, since it is carried out indirectly.

With the elimination of the distribution pipe network, the associated leaks were avoided, there remaining only those in the Compressor Plants, easy to detect and mitigate.

Operative Vents. The continuous Gas-Lift system, and mainly the intermittent one, produces an unstable gas-flow to the production batteries and the compression stations. As this thruput is variable and pulsating there are shortages or surpluses of inlet gas in the Compressor Stations, which bring about the opening of safety valves and the corresponding operative vents.

Measuring this phenomenom is extremely difficult because the instantaneous gas flowrates are very high and over a very short period.

A stable system, with fixed and constant flowrates, allows for the prevention of venting which results in losses of gas volumes, now turned available for sale.

System make up. As explained above, the Gas-Lift is not a strick closed circuit, needing a permanent gas refill that, according to different situations, ranges between 10% and 15% of the total circulating gas.

This system refill generally consists of the very same associated gas produced by the wells. Hence, having either enough associated gas or an external gas supply becomes critical for its operation.

In the mid 90s, all associated gas was consumed by the Gas-Lift network, which indicated a growing and permanent demand from back-up gas wells for the system operation (**Fig. 5**).

Thanks to the reductions in consumption and operative vents it was possible to quit using back-up gas volumes , and hence to have those volumes available for sale.

Thus, the associated gas covers the all present consumption needs, and a surplus is available for sale. This ensuing positive balance of gas is one of the main factors in the economic evaluation of the whole conversion project.

Gas well gas production increase. Almost since the very beginning of the exploitation, Entre Lomas Area has had four gas Compression Stations with a capacity of 1.800.000 m3/d.

As time went by, and the Gas-Lift wells decreased due to the partial conversion to other lifting methods, it was expected to have a decrease in the circulating compressed gas.

Nevertheless, this was not so, since the consequent increase in the watercuts and flowrates (**Fig. 6**) made it necessary to inject greater quantities of gas, and as a result, the compressed volumes remained almost constant and to the limit of the plant full capacities.

Moreover, there were gas wells that flowed to a Turbocompressor Plant (TC), which captured gas at 220 psi and discharged it at sales gas pipeline pressure – about 900 psi. The suction pressure meant a flowing wellhead pressure of 300 psi.

With the elimination of the Gas-Lift system, and greater compression capacity availability in the Motorcompression Stations, it was possible to gather these gas wells through the production batteries, thus bringing down the flowing wellhead pressures significantly (under 100 psi) generating a production increase and additional gas volumes available for sale.(**Fig. 7**).

Liquefied gas production increase. Gas well gas -now captured by the Motorcompressor Stations- and oil associated gas are compressed and later processed in the LPG Plant in order to obtain Propane, Butane and Gasoline. Since this gas well gas contains a much higher mole percent of these components than the existing in the previous Gas-Lift network, the LPG production was sharply increased by over 50%.

LPG Plant and Motorcompressor Stations work pressure reduction. The growing demand for flowrates and pressure in the Gas-Lift network in order to keep an acceptable level of lifting efficiency, made it gradually necessary to increase the injection pressure, with the ensuing over demand on the network facilities.

After the Gas-Lift system elimination, the gas pressure has to be enough only to be processed in the LPG plant and later enter the sales pipeline, which entails over a 10% reduction of the working pressure on these facilities, with the consequent benefit in the operation reliability and safety, and maintenance cost reduction as well.

New production perspectives. The Gas-Lift system was hindered by its lack of capacity to produce efficiently zones located in the casing-tubing annulus above the production packer. Besides, in case of having productive formations at considerable distances (over 100 m approximately) the Gas-Lift is not the most suitable lifting system, since it demands a compromising solution to produce both zones simultaneously **(Fig. 8).**

As in our case there are oil and gas pay zones above the packer, the installation of lifting systems such as SRP or ESP, enabled those reservoirs to be put in production without the Gas-Lift limitations.

This possibility of incorporating new productive zones stands for a strong upside of the conversion project, with a marked emphasis on its economic result and the optimization of the exploitation of the different reservoirs.

Lifting system unification. At the end of 1998, Entre Lomas Area had a significant number of wells under Sucker Rod Pumping, with considerably fewer pulling jobs if compared with this system beginnings.

The lifting system unification to Sucker Rod Pumping (only 7% were converted to ESP) enabled the focusing on personel capacitation and training, the optimization in the use of resources and contractor companies,etc., taking advantage at the same time of the know-how evolving from that system previous operation, which is highly regarded in the frame of the oil industry based on our field characteristics.

Assets sale. All the modifications to the field production scheme, left a trail of facilities either with idle capacity or shut down. Such is the case of the Motorcompressors - 30% down - and the Turbocompression Plant, which was completely shut down.

As a result, these assets remained in good operating conditions, available for an eventual sale and investment recovery.

Threats

Any project, no matter how attractive it might look, and especially when it involves drastic changes in a field operation, entails inconveniences and threats that may endanger its whole feasibility.

Among the ones detected here, as well as the possible solutions found to them, the following can be mentioned:

Oil associated gas uncertainty. The oil associated gas from a Gas-Lift well is determined as the difference between the total gas measured in the battery, which includes the associated gas, and the injected one, which is measured separately. Therefore, the asociated gas is determined indirectly, and any error in the measures is carried to the final figures.

This was easily seen when a Gas-Lift well was converted into Sucker Rod Pumping and the associated gas was measured directly, resulting in lower quantities.

Another element to be considered, though of a minor influence, was the injection gaslines leaks, which resulted in an overestimation of the associated gas figures.

As this uncertainty was one of the main variables in the economic appraisal, it was decided to proceed with the project in two stages.

The first stage involved the conversion of 20% of wells, in an area where the best conditions were granted for recalculating the associated gas directly, and verifying the predicted values.

Once the first stage was completed and the project was adjusted to the new economic conditions, it still proved profitable. As a result, the second stage was launched, which involved the remaining Gas-Lift system.

Energy cost increase. A possible threat was the raise in the electricity fares, since the total conversion project implied over a 20% increase in the field energy consumption. Any change in the price of energy would greatly affect the new operating cost in Entre Lomas Area.

Simultaneously to the lifting conversion project a Turbogenerator was installed in the Area to cover all power needs. This way energy costs were reduced and stabilized so the threat of future energy fares increases was practically eliminated.

Hydrogen Sulfide content. Not only do the sale gas specifications indicate a dew point for water and hydrocarbons, but also a hydrogen sulfide gas concentration wich must be under 2 ppm.

The oil associated gas highly exceeded this value, with average concentrations of over 50 ppm ,which hindered sales.

The solutions analyzed for sweetening were the following:

Hydrogen Sulfide Scavenger line injection. It consists of injecting a chemical product into the H2S contaminated gas flow. This reacts and generates reagents that are eliminated with the water drained in the gas-liquid separators.

At the beginning, since gas sweetening facilities were not available, this method was used in order to sell the excess gas produced as the conversion project advanced, but it was neither economical nor efficient to treat the total gas.

Amine plant: The other system under evaluation was the installation of an absorption and regeneration plant, using amines.

The method consists in bringing an amine based absorbent into contact with the H2S contaminated gas. In the tower, the amines absorb the contaminant and are later sent to a regenerating column where the SH2 is turned into SOx and freed into the atmosphere, while the regenerated absorbent is reused in the process.

Sometimes, apart from an absorption tower it is necessary to set up a residual SOx gas treating system, due to the impossibility to vent them into the atmosphere.

This system has low operating costs , but high initial investment and negative environmental implications.

Solid bed adsorption: It consists of a contaminated gas flow passing through a bed where it is brought into close contact with an OFe adsorbent.

The chemical reaction between H2S and OFe produce SFe, resulting in a progressive deactivation of the bed.

This implies that depending on the reagent charge, the H2S concentration and the gas flowrate, the bed charge must be periodically replaced .

The deactivated bed turns into solid residual waste that must be disposed in a suitable place, however, it shows very low environmental impact.

Despite the high initial investment, considering the operational facilities and the adsorbent charges involved, the operating costs are low.

These advantages were decisive for the final choice of this method for gas treatment in Entre Lomas Area.

Project evaluation and results.

With all the above mentioned considerations in mind, the next step was the evaluation of the lifting system replacement and the jobs involved. As the economic parameters showed a clear profit, a project schedule was prepared.

The two-stage execution allowed for both the confirmation and correction of the initial estimations, before proceeding with the total execution of the project.

The following tasks were performed:

1. 86 Gas-Lift wells were converted to Sucker Rod Pumping.
2. 7 Gas-Lift wells were converted to Electrosubmergible Pumping.
3. 7000 m of new gaslines were laid.
4. 3 gas sweetening plants were installed.
5. The Motorcompressor and LPG processes were re-engineered and the Turbocompressor Plant was shut down.

The following is a briefing of the benefits obtained from the total conversion of the Gas-Lift system.

1. Gas sales increased due to the consumption drop and modifications in the gathering system.
2. Oil production increased.
3. LPG production increased.
4. New production prospects were developed.
5. Facilities operating conditions went back to normal.
6. Assets became available for sale.
7. Efforts were maximized towards only one Lifting System

Table 1 shows the economic appraisal results once the jobs were finished, compared with the Gas-Lift wells conversion at the individual basis, assuming a type well representing an average of the remaining wells at the time of conversion.

Table 2 shows the jobs and the important investment that resulted due to the great number of wells involved.

Fig. 9 depicts the project sensitivity to the variables that directly affected it.

This sensitivity analysis was a decisive element in the final decision to launch the project, because of high degree of uncertainty of some of the variables.

It is important to mention that for the economic evaluation of the project, neither the additional gains of oil or gas derived from the development of new prospective zones were considered, nor the eventual higher final oil recovery due to the lifting optimization.

Conclusions

Those projects that initially do not appear economically attractive, may change radically through a carefull analysis of both main variables, as well as related derivations involved in the project.

In our case, where a single Gas-Lift well conversion to Sucker Rod or Electrosubmergible Pumping was not economically viable considering just resulting oil gains, the whole Gas-Lift conversion based on the related ensuing advantages, generated a valuable business opportunity for the company.

It is fundamental to view not only a project itself but its surrounding operations as well, from a creative, ample and integrating view in order to turn the well-known threats involved in the operation of a mature oilfield, into business opportunities for new worth-trying undertakings.

Acknowledgements

The authors would like to thank Petrolera Perez Companc S.A. for permission to publish this paper and all the staff, suppliers and contractors involved in the project, for their efforts and dedication to turn this initially far-fetched project into a profitable reality.

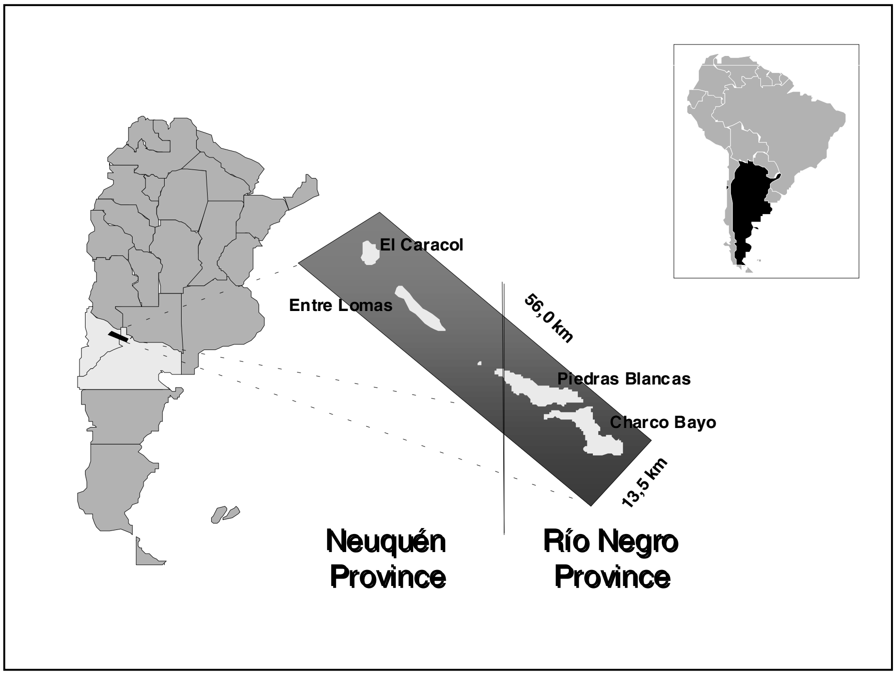

Fig. 1- Area Entre Lomas location and main Oilfields.

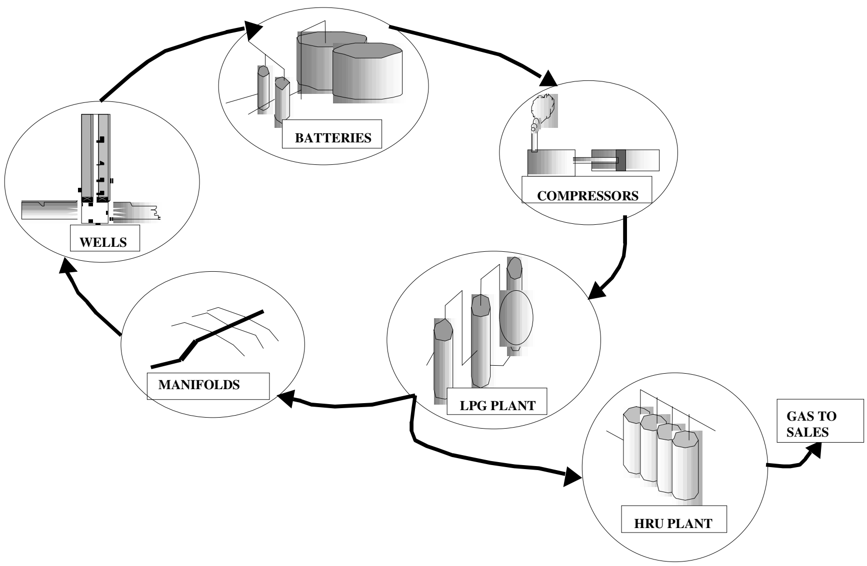

Fig. 2-Gas Lift network and production facilities.

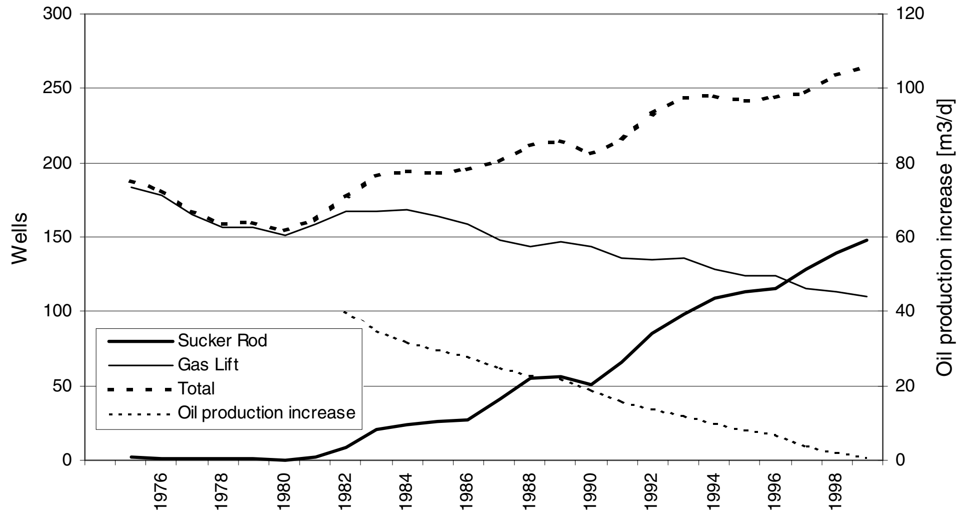

Fig. 3- Well totals and conversion oil increase.

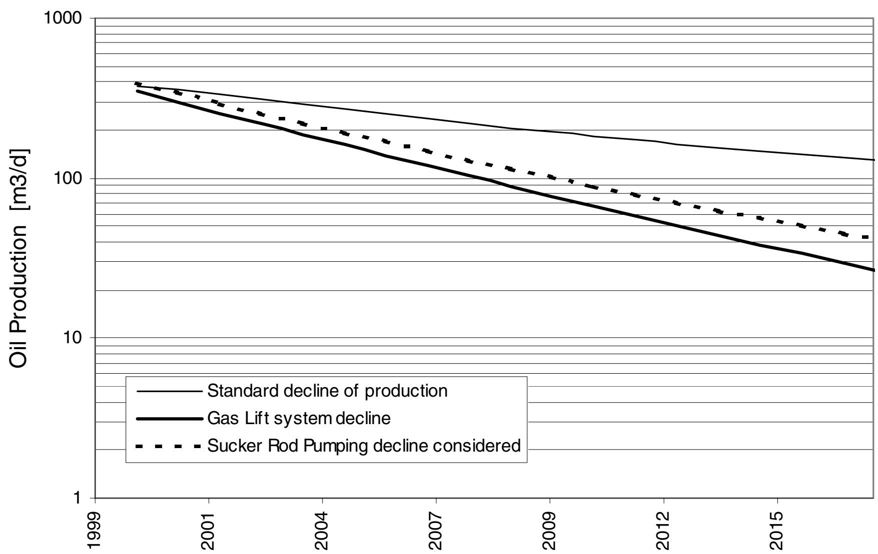

Fig. 4 -Oil production decline.

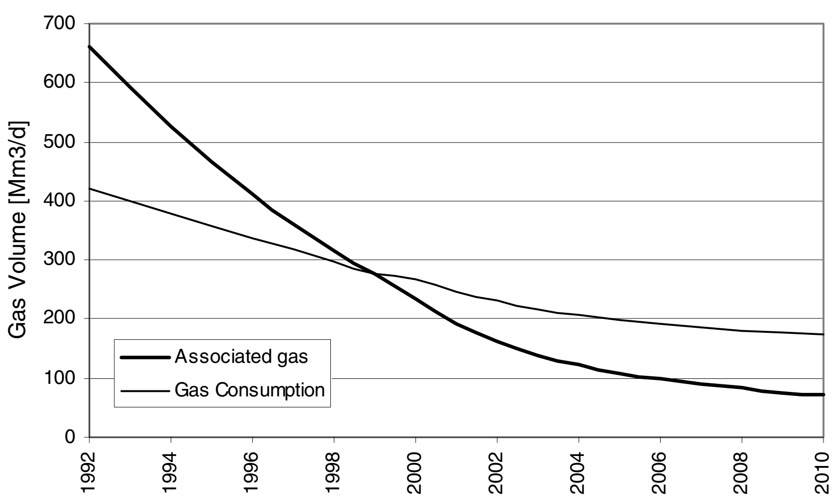

Fig. 5-Gas production vs. consumption.

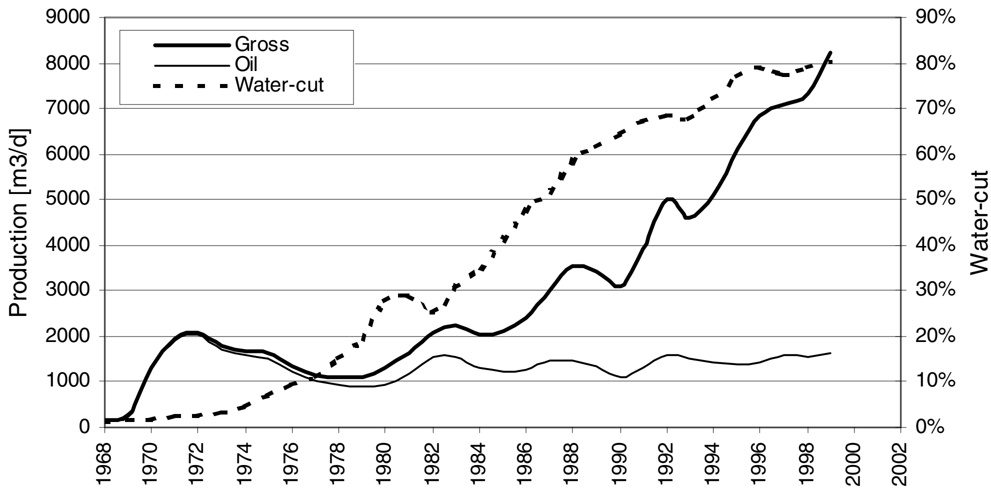

Fig. 6 Gross and Oil production

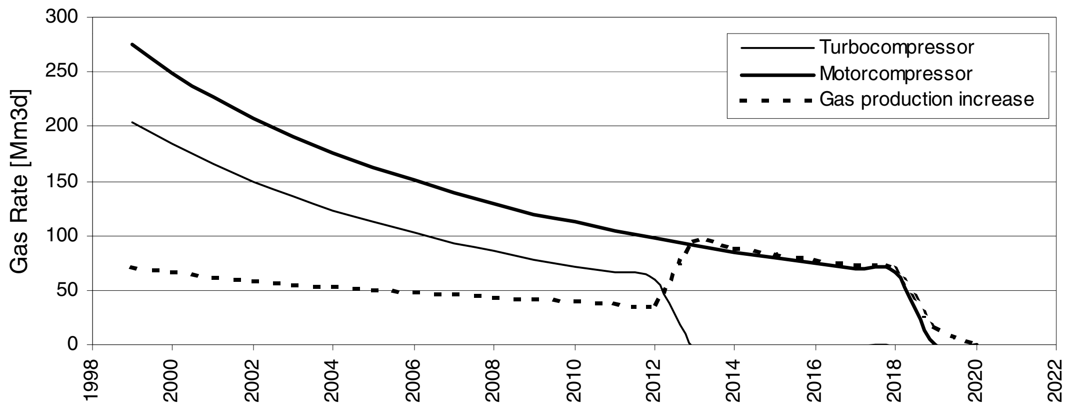

Fig. 7 Gas production increase.

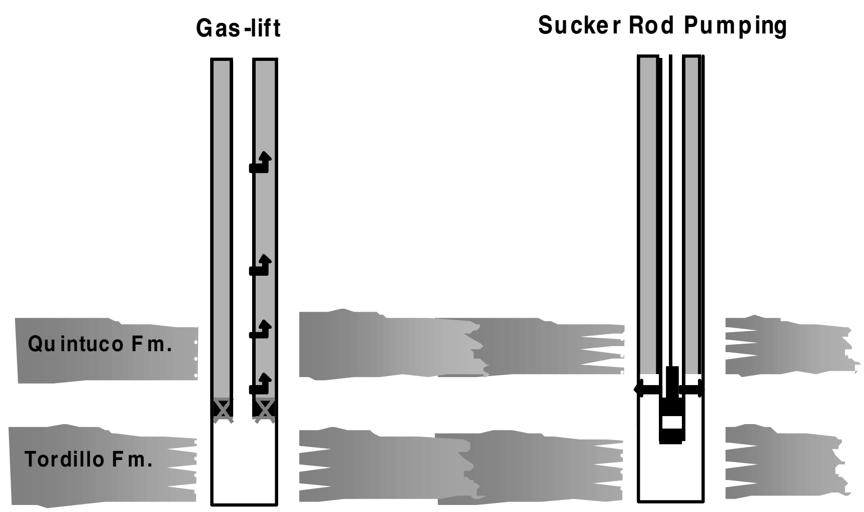

Fig. 8- Lifting system characterístics.

TABLE 1 - ECONOMIC RESULTS

		TOTAL CONVERTION	INDIVIDUAL CONVERTION
NPV 10%	[MMU$]	5.6	-7.1
IRR	[%]	38.2	-
PAY-OUT	[Years]	3.4	-

TABLE 2 - JOBS AND INVESTMENT

GL to SRP wells	86	
GL to ESP wells	7	
New gaslines	7000	[m]
Sweetening plants	3	
Pumping Unit and SuckerRods	7.85	[MMU$]
Electrical Equipment and Submersible Pumps	1.93	[MMU$]
Pulling	0.68	[MMU$]
Jobs in well site	0.28	[MMU$]
Sweetening Plants	1.30	[MMU$]
Total Investment	12.04	[MMU$]

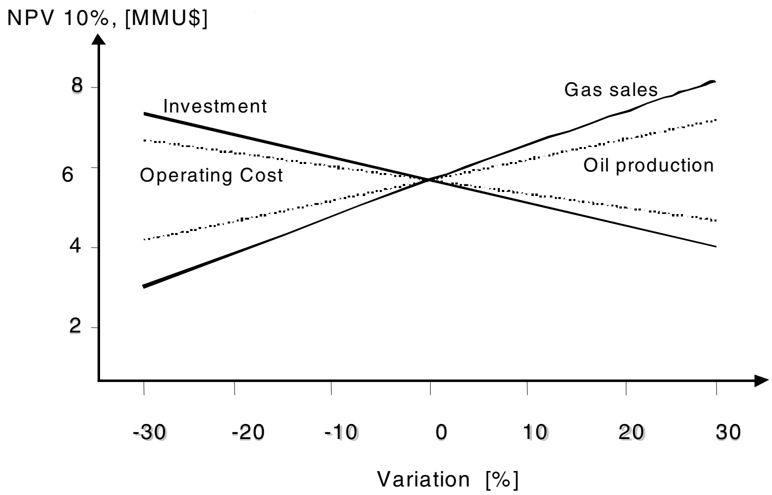

Fig. 9-NPV 10% sensitivity to main variables.