The Importance of Energy Efficiency Projects in Offshore Petroleum Production Facilities

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a. Background

The analysis of the Brazilian Gas Production Balance (National Agency of Oil, Natural Gas and Biofuels - ANP/2011) shows that in the last 10 years the increase in the internal gas consumption was 105 %, which is higher than the increase in the national gas production in the same period. The gas flaring and losses reported in this period had an increase of 2 %, reaching in 2010 an amount equivalent to 11% of the gas produced (62,8 millions of cubic meters per day), which is lower than its internal consumption (15 %), according the Figure 1. According the ANP the internal consumption is defined as a portion of the production used to supply the needs of the production facilities.

This relevant increase in consumption of the petroleum production and exploration sector (E&P) is due to several reasons, as the increasing offshore petroleum processing capacity, the demand for non-energetic fuel gas uses and also the high rate of increase in water content in the oil production (as the production curve decreases with time, a higher thermal energy supply is required). The word internal consumption refers to the oxidation of fuel gas to produce other compounds such as CO_2 and H_2O, which is usually the case of energetic uses that aim the production of both electrical and thermal energy (e.g. gas turbines, furnaces and other thermal machines). The term “non–energetic uses “refers here to cases in which the molecular structure of the gas is not modified, as is the case of any physical process such as desaeration, flotation, stripping gas, sealing of chemicals vessels, and other uses.

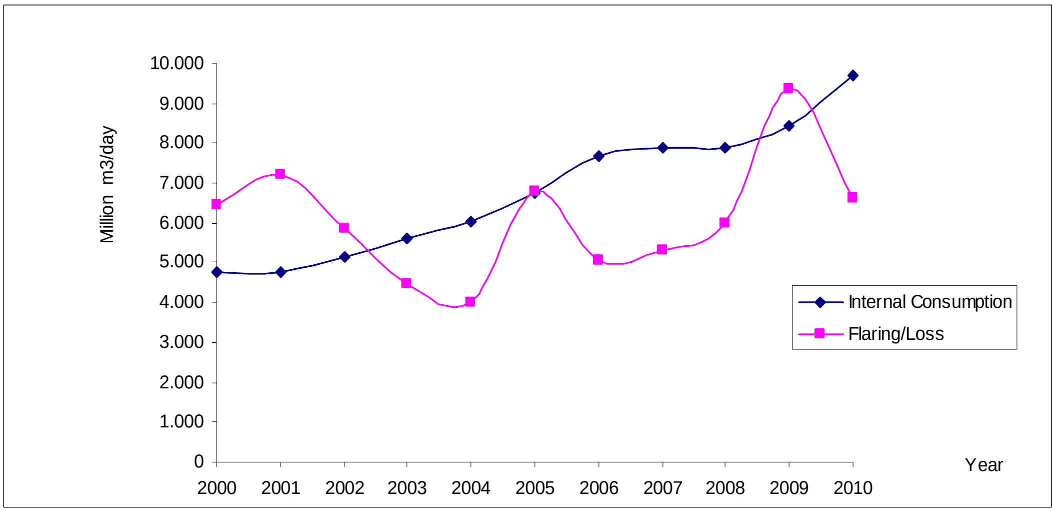

Figure 1: Evolution of gas internal consumption, flaring and loss in the period (2000 -2010)

The Brazilian market needs to increase the natural gas supply in a scenario of intensive E&P demand for energy, which is currently obtained from natural gas produced by offshore petroleum production facilities, often in deep waters. Such challenge motivates researchers to develop new technological routes, aiming at increasing the efficient utilization of the natural gas, by reducing its internal use, flaring and losses. The conditioned gas specification adopted by designers of offshore production facilities is the one established in the Decree 16/2008 of ANP, which refers to gas processing and is mandatory only for sale gas. The consequence of this pattern is the venting of CO_2 that exceeds the required 3 % limit (South and Southeast Region). Another situation is the removal of high molecular weight compounds (condensate) in gas processing plants (fuel gas facility and gas compressor package), reducing the energetic fuel gas energetic value.

In order to promote an improvement in energy efficiency performance both in existing and new offshore petroleum production facilities, a number of opportunities have been identified: new fuel gas specification, different from the existing 16/2008 ANP Decree, recovery of CO_2 and natural gas venting, minimization of non-energetic uses and gas recovery from relief operations in lift pipes, exportation pipelines and also from drainage systems.
The results obtained show that with the implementation of changes, the potential increase in gas recovery is roughly 8% (alternative case) of the volume of gas produced, considering only one offshore petroleum production facility (oil processing capacity of 150,000 bpd) that originally did not account for such a gas recovery (base case).

b. Aims

The present paper analyses the result of a simulation study related to a proposed energy efficiency project, between two petroleum production facilities (base case and alternative case) in order to identify the potential reduction of internal gas consumption, flaring /loss and the respective economic feasibility.

c. Methods

The methodology is based on a process simulation, with the use of Hysys software, considering two cases: base and alternative, the former with no energy efficiency project and the latter considering the implementation of gas recovery from venting, flaring and non-energetic fuel gas, and the reduction of energetic fuel gas consumption.

• Base Case

It's an offshore petroleum production facility, whose associated gas production has high CO_2 content and needs to be treated before being supplied via pipelines towards the onshore facilities. The main existing processes required to meet the regular specification are the following: Separation, Compression and CO_2 Removal unit.

● Separation: Physical process that involves primary separation of the three fluid phases and subsequently treatment of the following streams: oil, gas and produced water.

● Compression: Gas compressors are required to meet the pressure energy demand by the lift gas system and gas supply to pipeline (200 bar).

● Removal CO_2 unit: This process is undertaken between the 2nd and 3rd stages of gas compressors. The technology used is the chemical absorption, using amine aq. solution aiming meet CO_2 specification (3 vol. % maximum), according to the 16/2008 ANP Decree. The amine regeneration process uses stripping column and at its top the moisture of water and CO_2 is vented to safe location (gas venting).

● Dehydration: The remaining water existing in gas composition is removed by chemical absorption with glycols, in order to meet the water specification of the dry gas of roughly 40 ppm vol. (maximum). The regeneration system contains both a stripper column and reboiler (electric heaters) that are needed to release the water content existing in wet glycol composition to atmosphere. Such process uses a gas stripping stream (non energetic fuel gas) to help the removal of the residual water, and further is vented into atmosphere (gas venting).

• Alternative Case

This case represents new processes of energy efficiency that can be implemented within the conventional offshore oil process facility, considered in the base case. These processes have as a goal increase de supply of gas to internal market and reduce equivalent CO_2 emissions with the implementation of energy efficiency projects (see Figure 3).

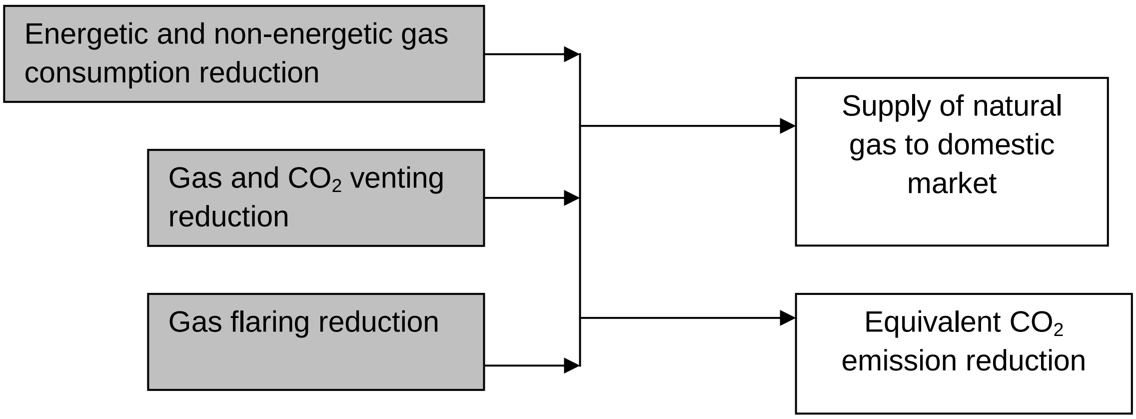

Figure 3 – Summary Diagram of the proposed energy efficiency projects.

The cited projects are related to the following systems: flaring, venting and fuel gas (energetic and non-energetic use). In practice this may be achieved through integration of the following opportunities related to energy efficiency in offshore petroleum production units:

● New fuel gas specification, different from the existing 16/2008 ANP Decree

The specification established by 16/2008 ANP Decree does not distinguish between the non-energetic and energetic uses, and its application is not mandatory in E&P sector. The heat value of the gas composition source, to be supplied to all non- energetic uses is not relevant, but both the hydrocarbon and water dew point must be adjusted, in order to meet the quality required of the fuel gas.

● Recovery of CO_2 and gas venting

The countless gas vents are not normally considered by the designers as possible sources of recovered, being considered as “featureless sources”. So, both CO_2 and gas venting have great potential of recovery by the existing gas booster compressor and then of being directed to non-energetic uses.

● Minimization of non-energetic fuel gas uses

The intense use of natural gas as a sealing fluid, in chemical tanks and other equipments in offshore processing plants is questionable, because the acid gases (CO_2 and H_2S) commonly present in the produced gas composition, can cause undesirable compounds.

● Gas Recovery from relief operations (lift gas pipes, exportation pipelines and also from drainage systems).

In the case of failure in a pipeline, overpressure in the drainage systems or even a shut down in compressor package, the gas is burned in flaring system and, in spite of the intermittence of these operations, the estimated average daily volumetric flow of the burned gas is equivalent to 1 % of the gas produced in an offshore petroleum unit.

Flaring

The proposed gas recovery is related to possible relief operations of both gas pipeline (hydrate removal, maintenance and others operations) and lift gas headers/pipes (commissioning operations, maintenance and others). In all the aforesaid situations the equipment involved are submitted to high pressure (200 bar), and whereas executed by manual procedure can be recovered by the existing gas processing plant (fuel gas system and compressors), so is completely unnecessary the flaring.

Venting

The proposed recovery depends on the gas specification established by the designers and vendors of gas processing facilities existing in offshore petroleum units. The countless gas vents regularly are not considered by the designers as source to be recovered, due to the assumption considered as “featureless source”. However, considering the present scenery of high capacity of the new offshore petroleum production plants is doubtful the permanence of this assumption. So, all vent gas has great potential to be recovered by the existing gas booster compressor, as demonstrated in Figure 2.

Fuel gas system

Normally the treated gas specification adopted by designers and vendors of offshore petroleum production facilities is the same that established by 16 ANP Resolution (See Table 1). Indeed, this Resolution is applied specifically to marketing and not to E&P sector (offshore petroleum production units) and was planned considering as reference the energetic use (industrial, power plants, and others). So, it is expected to any person that both CO_2 and inert compounds must be as less as possible, in order to maximize the fuel heat value. This Resolution does not consider a different specification, applied for example to non-energetic uses (petrochemical, ironmaster and others) and therefore, limit the inert and acid content at the gaseous moisture.
However, analyzing the gas specification related to each one of the consumers (energetic and non-energetic users) of the fuel gas system, it is true that is unnecessary consider the same CO_2 and inert compounds content according to the 16/2008 ANP Decree.

Table 1: Summary 16/2008 ANP Decree applied to South and Southeast Region

Parameter	Unit	Limit
Gross Heating Value	kJ/m^3	35,000 a 43,000
Maximum Inerts Content (N_2 + CO_2)	vol %	6
Nitrogen	vol %	2
Maximum CO_2 Content	vol %	3
Wobbe Index	kJ/m^3	46,500 a 53,500

Energetic fuel gas use

The simulation study considered a new configuration to the original fuel gas system (see Figure 2), differently of the original case, in relation of the fuel gas feed source, propose the two alternative options, as gas feed source:

Case A: The feed gas source to the fuel gas system comes from the discharge of the second stage (upstream the cooling water), and also consider low CO_2 content (0.02 vol %).

Case B: The feed gas source to the fuel gas system comes from the discharge of the second stage (upstream the cooling water), and also consider a high CO_2 content (4 vol %).

The Table 2 below presents a summary of the main properties of gas composition related to two alternative options (A, B) and base case.

Table 2: Volumetric Flow and relevant properties respectively to base and proposed case (two options)

Case	Gas Consumption (1000 m^3/d)	Lower Heating Value MJ/m^3	Wobbe Index MJ/m^3	Compressor Power (MW)
Base	142	39.783	48.408	15.2
A	128	43.844	50.561	14.4
B	133	42.258	47.746	14.5

According to the results showed above, both the cases (A and B) demonstrated relevant reduction in gas consumption, respectively 10 and 6 % vol in relation the base case. Additionally for the two proposed cases occurred a reduction roughly 5 %, in overall power required to each one of the existing compressors, due to the removal of the fuel gas stream upstream the third stage.

Non-energetic fuel gas use

In this case, the heat value of the gas composition source, to be supplied to all non energetic users is not relevant but both the hydrocarbon and water dew point must be adjusted in order to assure the quality required of this fuel. One relevant aspect that increases the use of CO_2 high content for these streams (up to 10 vol %) is the low pressure condition (maximum 2 bar) of all non-energetic users, so it can be expected low corrosion rates.

The proposed gas recovery consider the construction of a new header aiming at the collection of the more relevant vent gas pipes, such as the compressor gas seals, produced water flotator and the top of the stripping column (gas dehydration unit). Additionally, it can be included the contribution from the CO_2 vent (CO_2 removal unit), since the CO_2 content does not exceed the maximum value defined by the compressors package and CO_2 removal unit designers.

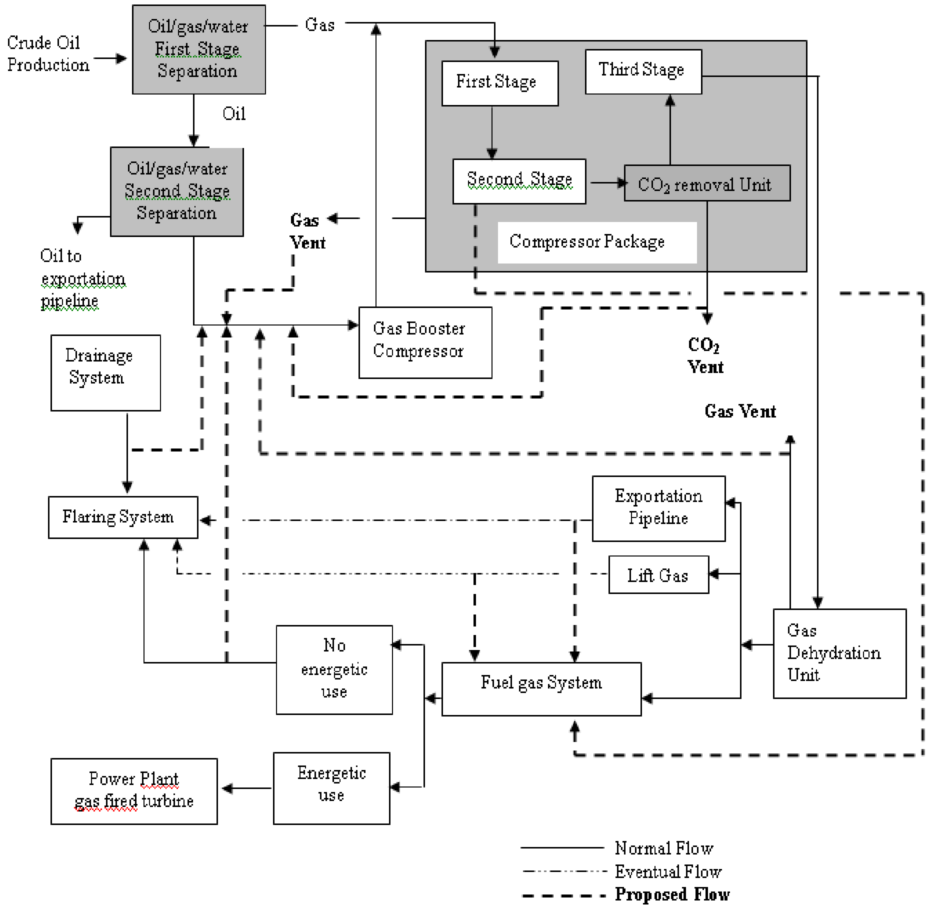

Figure 2- Summary Diagram of the Base Case and Alternative Case

Assumptions

Base Case

Produced gas: 1,5 x 10^6 m^3/day
CO_2 content in produced gas: 4 vol. %
CO_2 specification (treated gas): 0,02 vol. %
Flaring: 4 vol. %.of produced gas flow
Energetic fuel gas flow: 10 vol % of produced gas flow
No energetic fuel gas flow: 2 vol. % of produced gas flow
Gas venting from the Moto-Compressors seals: 0,1 % vol of the inlet compressor capacity
Gas venting from the gas processing facilities: 2 vol % of produced gas flow
CO_2 venting: 2 vol % of volumetric flow at the inlet amine unit
Drainage system: 1 vol % of the gas produced

Alternative Case

Produced gas: 1,5 x 10^6 m^3/day
CO_2 content in produced gas: 4 vol. %
CO_2 specification (treated gas): 2 vol % (according to 16/2008 ANP Decree)
CO_2 specification (energetic and no energetic fuel gas users): 4 % vol (Differently to 16/2008 ANP Decree)

The results presented here consider a plant with a capacity to process 150,000 bpd of petroleum and 1.5 million m^3/day of gas, with 4% CO_2 content in produced gas.

d. Results

A potential flaring reduction of 50 %, a venting reduction of 100 % and a gas consumption reduction of 17 % are possible. In addition to that, an overall gas recovery of roughly 8 vol %, in relation to the gas production is possible. Equivalent CO_2 emissions (including CH_4), reductions of 195,282 ton per day are possible as well.

To better identify the contribution of each of the proposed energy efficiency projects, see Table 3 below.

Table 3- The Potential Flaring, ventilating and gas consumption reduction of proposed energy efficiency projects

Parameter	Base case (vol % in relation to the gas production)	Alternative case (vol % in relation to the gas production)	Reduction (%)
Fuel gas consumption (energetic and non-energetic use)	12 %	10 %	17
Flaring	4 %	2 %	50
Gas and CO_2 venting	4 %	----	100

A discounted cash flow methodology was used, with an analysis period of 17 years, with the assumptions of capital expenditure (CAPEX), operational expenditure (OPEX), return internal tax, discounted rate and others parameters presented in Table 4 next.

Table 4- Financial and cost variables of the proposed case

Parameters	Results
liquid present value	US$ 30.6 millions
Discounted rate	8.8 % per year
Return internal tax	112.5 %
Return time from the implementation of the project	Below 6 months
CAPEX	US$ 6 millions
OPEX	US$ 0.2 millions per year
total income	US$ 95.2 millions
total expense	US$ 40 millions

e. Summary/Conclusions

The study has shown the economic feasibility of the four energy efficiency projects presented here, related to the reduction of flaring, CO_2 and natural gas venting and internal gas consumption (energetic and non-energetic uses). Among the main benefits of these projects are the reduction of gas burning and venting, reduction in the consumption of energetic and non-energetic gas, and improvements in safety, health and environmental conditions in offshore processing facilities that together contribute significantly both to increase the gas supply and reduce the emissions of CO_2 equivalent (include methane).

Considering a capital expenditure (CAPEX) of US$ 6 millions, the economic assessment was favourable, with a net present value of US$ 30.6 million for a project life of 17 years.

The best moment to implement these energy efficiency projects is in the conceptual design phase. The potential for gas recovery is considered relevant, especially if the designer takes advantage of the increased capacity available when the petroleum production declines.

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