OFFSHORE COMPRESSION SYSTEM DESIGN FOR LOW COST HIGH AND RELIABILITY

Carlos J. Rocha de O. Castro, carlos.rocha@chemtech.com.br
Antônio Dias Carrijo, antonio@carrijo.net
Chemtech – Siemens, Rua da Quitanda, 50, Rio de Janeiro, RJ

Alexandre França Cordeiro, e-mail
Chemtech – Siemens, Rua da Quitanda, 50, Rio de Janeiro, RJ

Abstract. *In the offshore oil fields, the oil streams coming from the wells usually have significant amounts of gas. This gas is separated at low pressure and has to be compressed to the export pipeline pressure, usually at high pressure to reduce the needed diameter of the pipelines. In the past, this gases where flared, but nowadays there are a increasing pressure for the energy efficiency improvement of the oil rigs and the use of this gaseous fraction. The most expensive equipments of this kind of plant are the compression and power generation systems, being the second a strong function of the first, because the most power consuming equipments are the compressors. For this reason, the optimization of the compression system in terms of efficiency and cost are determinant to the plant profit. The availability of the plants also have a strong influence in the plant profit, specially in gas fields where the products have a relatively low aggregated value, compared to oil. Due this, the third design variable of the compression system becomes the reliability. As high the reliability, larger will be the plant production. The main ways to improve the reliability of compression system are the use of multiple compression trains in parallel, in a 2x50% or 3x50% configuration, with one in stand-by. Such configurations are possible and have some advantages and disadvantages, but the main side effect is the increase of the cost. This is the offshore common practice, but that does not always significantly improve the plant availability, depending of the previous process system. A series arrangement and a critical evaluation of the overall system in some cases can provide a cheaper system with equal or better performance. This paper shows a case study of the procedure to evaluate a compression system design to improve the reliability but without extreme cost increase, balancing the number of equipments, the series or parallel arrangement, and the driver selection. Two cases studies will be critically evaluated for several options, and a special evaluation of a jet compressor application will be explained, as well as the associated advantages and drawbacks. The result of the paper will show a comparison, for each case, the reliability, power consumption as well as the comparative price increase (in % of a reference system) of each system, including the influence over the power generation module. The aim of this paper is discuss some common design procedures with some real values.*

Keywords: *compressor, reliability, availability, cost*

1. INTRODUCTION

Most part of the offshore oil fields in Brazil presents a stream that is a mixture of compounds that at the atmospheric pressure and temperature forms both a liquid and a gaseous phase. One have to consider the gaseous fraction at the atmospheric conditions because the ultimate condition of transport and usage of the oil is the atmospheric pressure and temperature, at the tanks of the FPSOs or the storage tanks at the refineries.

Due this, the oil is progressively decompressed from the received pressure (the reservoir pressure minus the well oil column and the pressure loss at the well and risers) down to the atmospheric in successive steps. When the pressure is reduced the lighter compounds pass to the gas phase and are separated from the liquid phase of the oil.

This gaseous fraction, however, is a mix of several hydrocarbons that usually goes form the methane (C1) to the hexanes (C6), water saturated and with several contaminants, like CO2 or SOx.

The collected gas has two possible final destinations: the market, or the internal usage. To be delivered to the market the gas has to be treated to reach the ANP standards, and transported to the distribution pipelines. To be transported the gas is injected in subsea pipelines and send to gas processing units, where the heavier compounds will be separated from the light compounds by temperature reduction, in such a way that at typical environmental temperatures and transportation pressure no amount of condensate is formed, what could be lethal to the most part of industrial burners or gas turbines combustion chambers. Also, the composition has to be kept in constant values. A variation in the composition also changes the LHV, which can cause unexpected load changes at the thermal equipments.

Internally the gas can be used as a fuel source for heaters or gas turbines for power generation, or used in the so called gas lift, where gas is injected at the reservoir to increase the oil recovery.

Both destinations require that the low pressure gas (from the primary separation process) is compressed to pressures in the range of 150 to 400 bars.

A general scheme of the gas separation and final compression is presented at the Figure 1. The intermediate processing causes a pressure drop in the gas to 25bar (C3+ separation). The stabilization extract the gaseous fraction from the liquid is called condensate stabilization (if the liquid fraction is very light oil) or oil stabilization, and the goal is extract all the gaseous fraction form the liquid fraction in such a way that the liquids can be stored at the atmospheric conditions without originate flammable gas release.

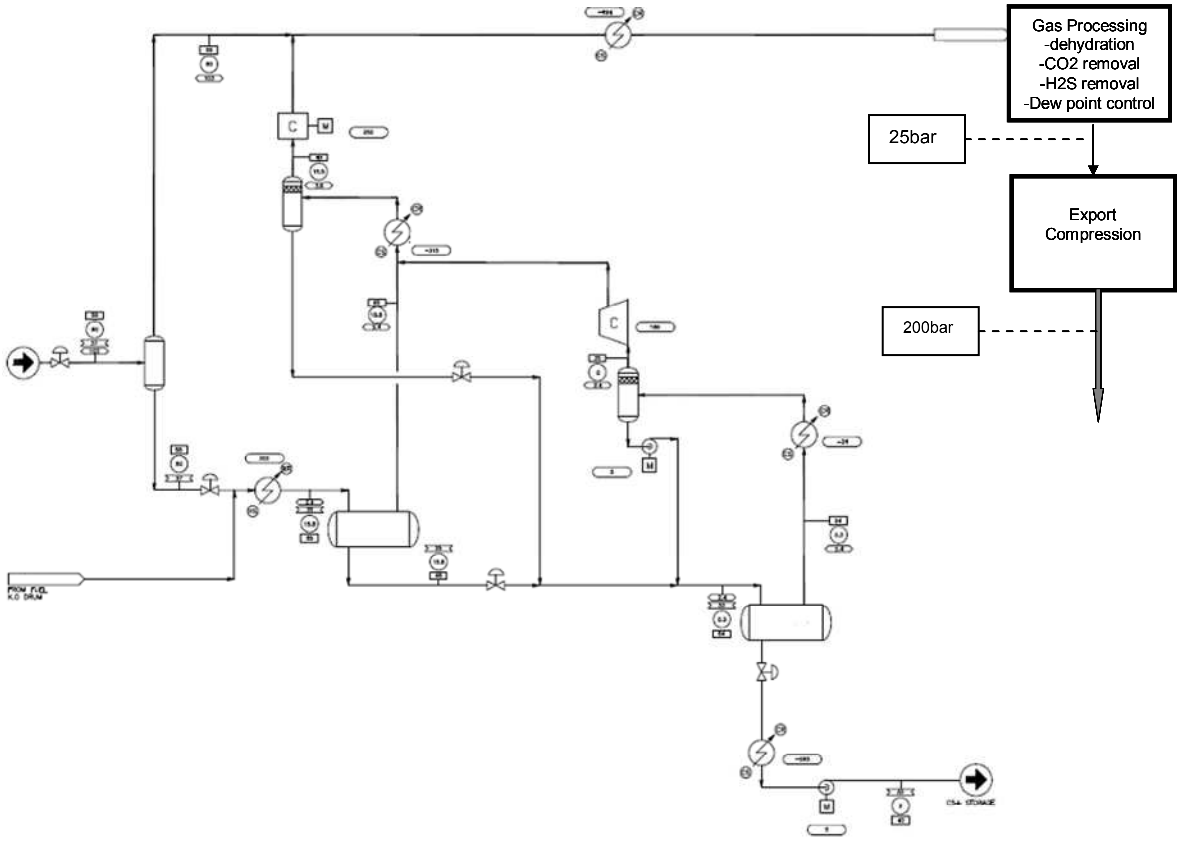

Figure 1: General Processing flow diagram

The case presented at this paper is a recent project performed by CHEMTECH, considering an inlet stream of 3 MNm^3/day, with the composition described at the Table 1. The system is designed to collect the gas and inject in a dedicated subsea pipeline to be transported to a land gas processing unit (GPU). The gas inlet conditions at the 1st gas-liquid separator are: 80 bar and 50.5 ºC.

The entire compression system is usually separated in two sub-systems: the gas recompression and the export compression. The first compress the gas from the two phase separators up to the inlet pressure and the second up to the pipeline pressure. The main variables of the entire system are: the number and pressure of the stabilization stages, the type of compressor at each stage, the pipeline pressure, the number and arrangement of the export compressors, and of course, the flowrate.

Table 1: Well gas composition (before and after the processing).

Component	Reservoir		exported
	wt %	mole %	mole %
CO2	0,12	0,07	0,01
H2S	0,00	0,00	0,00
N2	2,16	1,87	1,94
C1	54,70	82,85	86,79
C2	7,51	6,07	6,28
C3	5,36	2,95	2,78
i-C4	1,38	0,57	0,48
n-C4	2,20	0,92	0,75
C5+	26,57	4,71	0,97

The gas properties and equipment dimensioning was done with the Chemcad®. The compressors data for preliminary selection was taken from supplier's information from previous similar projects.

2. THE COMPRESSION SYSTEM

The condensate stabilization process can be understood following the phase diagram. First is important to characterize the reservoir fluid. According the characteristics, the fluid can be characterized as a “volatile oil”, because the reservoir conditions are close the critical point, but before the bubble point, and the fluid characteristics follow the general conditions: γ_o<45^o API, 2000 < (GOR)$_i$ < 3300 scf/STB, B_{oi} > 2.0 RB/STB, 12.5 < C7+ < 20 %.
The Figure 2 (a) show the general rule to fluid classification and the Figure 2 (b) show the typical phase diagram for such fluid.

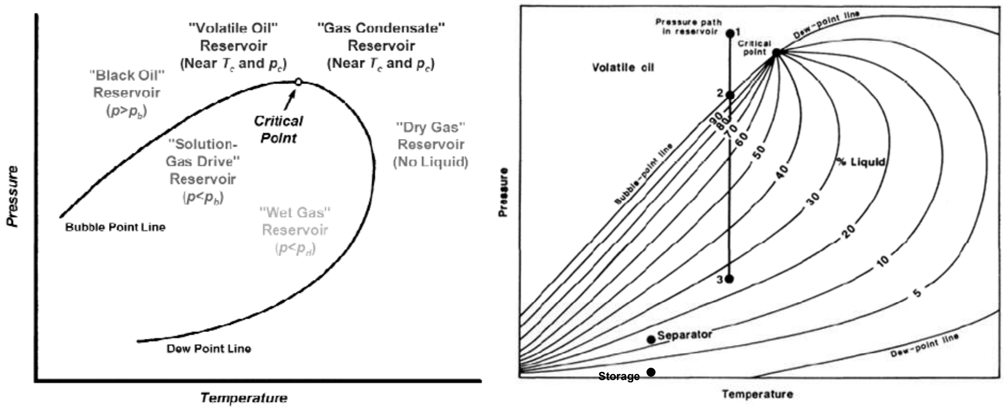

Figure 2: Fluid characterization (a) and gas release with the pressure and temperature (b)

2.1. System caracteristic curve

The main source of pressure loss is the pipeline. For this project is considered a 180km pipeline with 16” of internal diameter, and 150 m of elevation. The delivery pressure at the processing unit is 80 bar, requirement of the turbo-expansion system for gas heavier compounds separation.

An offshore pipeline is one of the most costly items in an offshore gas project. The length usually is large and the installation requires specialized ships and crew, reaching a value of the same order of magnitude of the material expense. The price of a pipeline can be modeled according the length and diameter, being the diameter the only free variable that the system designer can use.

The relation between price and diameter is almost linear, so, the best option to reduce the CAPEX of the pipeline is the reduction of the diameter. It can be achieved, for a defined flowrate and delivery pressure, increasing the injection pressure. Due this, long offshore pipelines usually operate in pressures beyond 150 bar, allowing a material and installation cost reduction at the expenses of a larger compression system, and more power consumption. The best point can be selected by an economical engineering exercise, but as a general rule, the design can begin with pressure between 150 bar and 200bar. The system curve is presented at the Figure 3. The head loss was calculated using the energy conservation equation in the form of the Panhandle B equation, updated for each 2km of the pipeline.

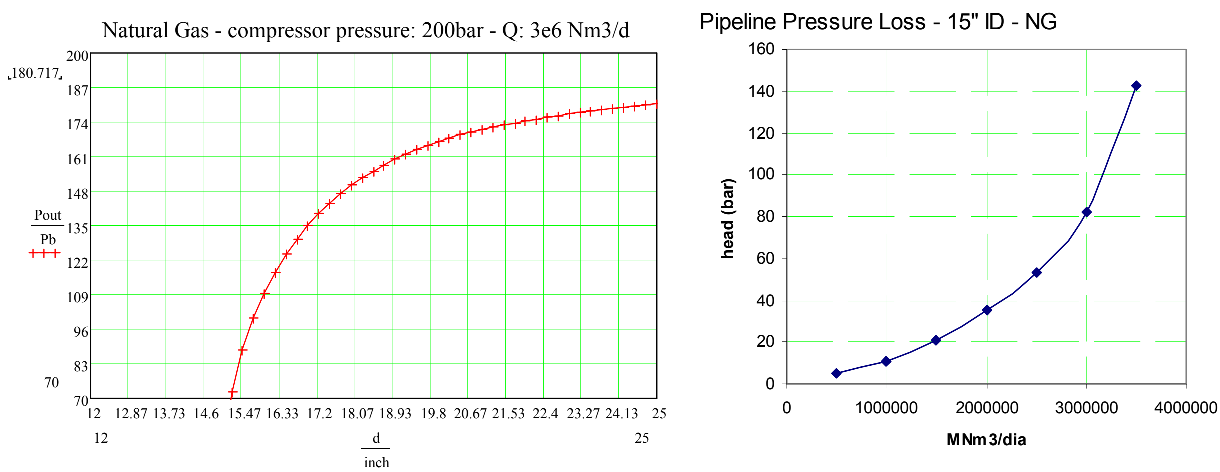

Figure 3: Pressure drop according the pipeline diameter (left) and head loss for a 15”and 180 km pipeline for several flowrates (right).

2.2. Compressor caracteristic curve

The selection of the most adequate compressor have to consider, the fluid, the required compression ration, the flowrate and the envelope of pressure and flowrate at the expected off-design conditions.

The first step is the choice of the machine type and the second is the choice of the machine characteristics. The Figure 4 shows a general chart that considers the typical conditions that each of main compressor types can operate with efficiency that can be used as guidance for the machine selection. For more deep evaluations, the particular charts provided by the main suppliers can be employed.

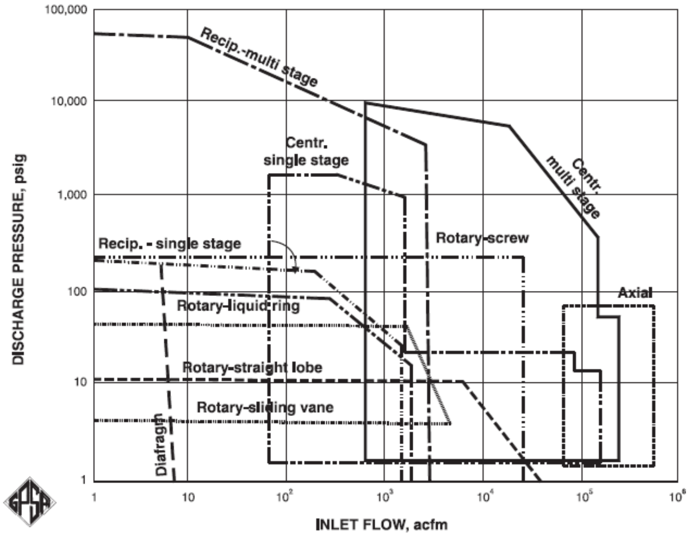

Figure 4: compressor type selection chart with the flow and discharge pressure.

The centrifugal compressor is the most used type for offshore applications because the requirement of large gas volumes and compression ratios. A typical system consists of two or more trains operating in parallel, being each train composed of two or more compression stages (each compression stage is composed of a compressor, a gas cooler and sometimes a knock-out drum). The use of several compressor stages reduces the compression power requirements and helps to avoid condensate formation at the pipeline. Each compressor is composed of a casing with 4 to 6 impellers and a separated surge control system.

For natural gas applications the compression ratio of each case is generally limited to 4:1. Beyond this value the impellers tip speeds become too high and the gas temperature exceeds 160ºC. This combination of mechanical load and temperature is the limiting factor of the standard materials adopted nowadays.

To the selection of the machines, both the type, operation conditions the maintenance and reliability have to be taken into account. It is a recommended practice to use some redundancy level or split the gas production in several trains to avoid that a failure in a single compressor paralyzes the entire platform operation.

If an only export compression fails, the gas production stops, but in some cases, the oil production also have to be stopped. The only option is deviates the gas produced at the separators to a high pressure flare, which usually is allowed to operate only in emergency cases and for limited time.

These compressors can be driven by gas turbines or electric motors. In the second case the electric power is generated by the turbo-generators. In any case, the primary source of energy is the processed gas, which is used as fuel. Due the large availability of fuel at low cost the efficiency is not the most important ranking parameter to the system selection. The maintenance cost and reliability are the main requirements.

2.3. Sub-system equipments

The recompression system is composed of the gas-oil separator, the compressor and sometimes a heater, usually a plate and frame heat exchanger.

The system starts with the heater. The heater located before each separation set raise the oil stream to avoid more gas release. It can be used as heating fluid, hot water, from the gas turbines WHRUs (Waste Heat Recovery Units), or hot gases from the intermediate stages of the export compression system. In the first case a oil-water plate exchanger and in the second a oil-gas exchanger. The oil heater works also as the export compression intercoolers.

The second equipment is the gas-oil separator that is designed with several internals in such a way that no liquids are carried with the gas stream. Before the vessel inlet, a valve reduces the stream pressure to cause the lighter HCs flashing. The vessel is designed to allow a minimum residence time that allows all the gas content is able to be release from the oil stream.

The gas stream is collected at the vessel top, and directed to a cooler (gas-water) and for a knock-out (KO) drum. These equipments are installed to allow the coalescing of some small liquid particles that could be carried by the gas stream. This protects the compressor from liquid ingestion.

The last, the compressor is selected to compress the gas to the immediate previous pressure level, and is selected according the pressure ration and volumetric flowrate. In fact the separators pressure levels are chosen together with the compressor. The best way to avoid excessive equipment costs is select the pressure levels cascade in such a way that a single compressor is able to compress the gas released to the previous pressure level. Other parameters have to be considered but once the most expensive item of the subsystem uses to be the compressors, the measures to reduce its price benefit the system as a whole.

The export compression system, just downstream of the main system has the purpose of collect all the gas processed at the platform and compress to the pipeline conditions. At some points, between the stages can be installed gas bleed points to direct some gas to the turbines fuel conditioning, or gas lift.

The high flowrate suggests the use of centrifugal or axial compressors. The first is the option due the operational control, much more simple, and the higher achievable pressures. A single axial compressor can be able to a pressure ration of 10, but operating at exit pressures of 50 bar as maximum. The alternative compressors could achieve the required pressure, but are low flowrate machines, and several operating in parallel would be necessary for such high flowrate.

Considering that this kind of machines are constructively large, and with complex and more frequent maintenance (due the several moving parts) this in not considered the best choice. There are other issues that reduce makes more difficult the use of these machines. The most known and problematic is large the vibration level.

The export compression is then composed of the KO drums, the coolers and the compressors casings. The Figure 5 explains graphically the importance of the KO drums. Before enter in details must be understood that the gas come from the reservoir and from the separators saturated with water.

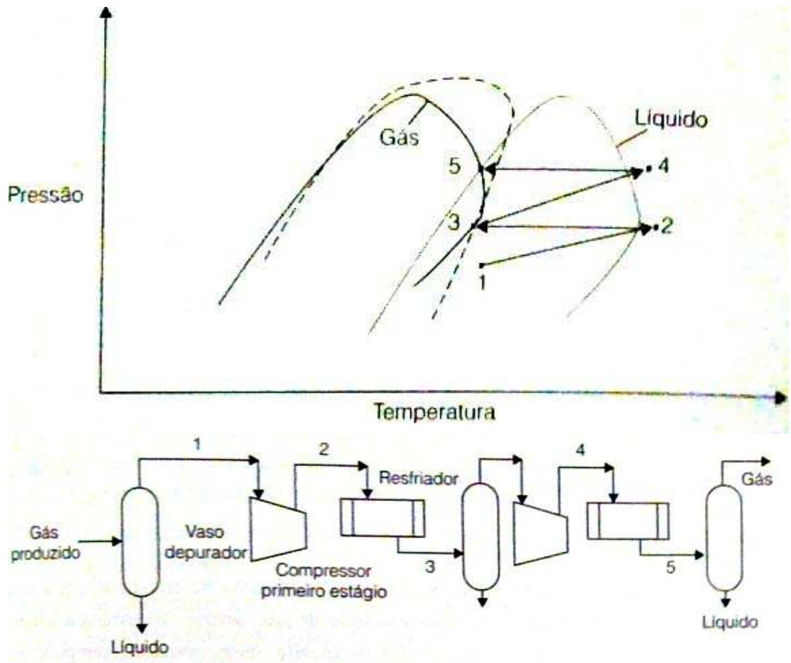

Figure 5: The phase diagram of the compression, cooling and separation process in a typical two stages compressors train

Once, the compression ratio is limited by the temperature of the gas, if only one stage is not enough to achieve the desired pressure, the next stage cannot receive the gas at that high temperature, so the gas have to be cooled. The intercooling here is not just a matter of reduce the compression power, but and operational requirement.

Due the gas cooling it is goes form the superheated condition to saturated, being expected some condensation of liquids, mainly water. To avoid the ingestion of this liquid by the next stage, the KO drums collect it and redirects to the separators. At the exit of the last stage there is a final KO drum to avoid the liquid carriage to the pipeline.

Another problem related to the water removal is the hydrate formation. The hydrate is a solid and stable crystalline structure that can plug the processing plant piping or even the pipeline. The hydrates formation is benefited by low temperatures and presence of free water in the gas.

The pipelines installed deep sea floor are subjected to temperatures that goes form 15ºC to 5ºC. This further cooling of the saturated gas at almost the final compression pressure will allow the water condensation. Then, the free water, the low temperature and the gas will be found together, originating the hydrates.

When this is the case, there is the need for a more dramatic gas dehydration, in such a way that the gas dew point is safely beyond the lowest temperature that can be found at the sea bed. The dehydration can happened before the export compression entrance or between the stages once the most common process, the use of TEG (Tri-ethylene glycol) is benefited by a pressure around 80 bar. Beyond this pressure the increase of the contactor vessel wall thickness makes the system too expensive.

2.4. Compressor arrangement and compatibility

The second decision refers to the compressor arrangement, which can be in series or parallel. The first can be useful if the overall compression ratio can be achieved with one or two stages. This can be observed in units close to shore, where a pressure of 100bar is enough, or when the reservoir pressure is high and the gas recovered at the separators is small compared to the main stream.

Between the advantages of the parallel arrangement can be found:

- Reduction of the size and weight of the casings, what eases the maintenance activities;
- Reduction of the start-up power. Large power compressors require a large start-up load what causes a high current in the electric motors;
- Reduces the transient perturbations at the Power generation and distribution;
- Improvement of the reliability without production loss or time spending plant start-up operations.

If the compression ration can be provided by only one stage, considering the reasons presented, the operator usually prefer a two units compression system, for the cases where there is no stand-by unit. Ohanian and Kurtz (2003) have shown that a series arrangement of identical machines can provide a better flexibility than a parallel arrangement. It happens because the gas dynamic of a pipeline dictates a relationship between the flow and the necessary pressure ratio.

For the parallel arrangement, the failure of one machine forces the remaining unit to operate at or near choke, at low efficiency. Units in series would require an initial operation of the surge valves, but the remaining unit will soon move to a good efficiency, thus, maintaining a higher flow than in parallel arrangement. The Figure 6 shows the behavior of the two arrangements in such case. The parallel system goes towards the choke while the series goes to the middle of the performance curve.

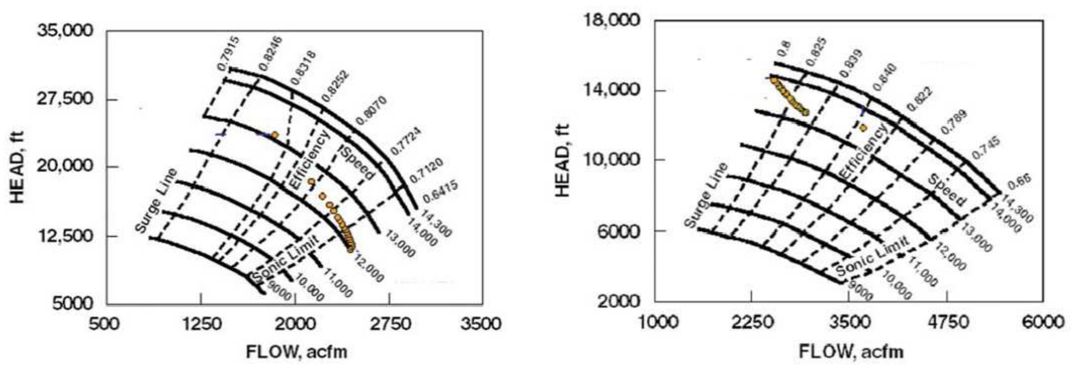

Figure 6: Behavior of parallel compressors without spare, in case of failure of one compressor; and the behavior of series compressors, without spare in case of failure of one compressor.

The parallel unit moves further and further in direction of choke, where no change in the pressure ratio and flowrate is possible. If it happens before the pressure reaches the minimum allowed the entire system can trip.

In the series the operator will have more time to fix the problem before the pressure falls below the minimum level. Should be noted that a large volume and pressure, in the pipeline, will act as a buffer tank, maintaining the pressure at the consumer for some time.

If the system requires two stages will be hardly possible to choose two equal machines, without keep one of them operating out of the best efficiency point. But an alternative solution is the arrangement presented by Mohitpour (2008), and that is the one adopted in this case study. The machine at the middle (Figure 7) acts as a spare unit of the first or the second stage. The major problem in this case is related to the cost, once each machine have to be provided of one driver motor, in opposite to the nowadays practice of installing the two stages at the same driver.

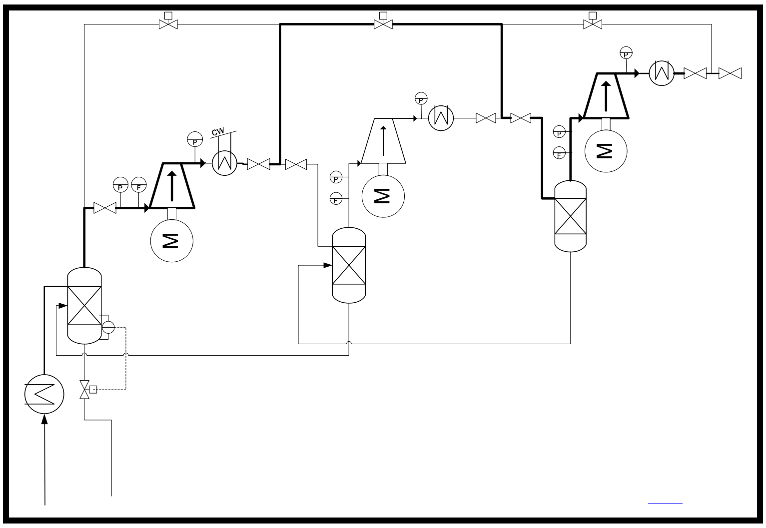

Figure 7: Series arrangement of one spare stage (the one of the middle) that is selected with intermediate characteristics between the two others

There is another concern in the system designed in this project: the "series" operation of the recompression system and export compression. The typical characteristic curves of the alternative and centrifugal machines (Figure 8) shows that while small variations in the flowrate of alternative compressors cause a large change in the heat, for centrifugals it isn't so drastic. The series operation of these machines, subjected to the frequent changes in the process conditions can lead to an unstable situation, once the speed of change of the flow operating point of the machines changes in very different speed.

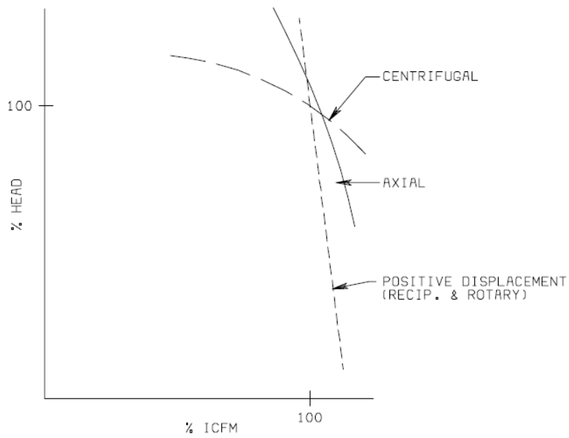

Figure 8: Comparison of the characteristic curves of 3 different compressor types

For these cases a careful transient evaluation has to be performed prior to the selection of the compressors. In the case presented at this paper, this is a minor concern, but just because the amount of recovered gas at the recompression system is much smaller than the main stream of the gas coming from the first separator, and that do not pass through the recompression.

Once designer should have in mind the major limitations and advantages of each kind of machine and arrangement design begin by the common practice, selecting and arrangement, and type of machine (according the pressure ration and flowrate). Then is performed a check to see the reliability, then if the result isn't acceptable another arrangement is selected. If the desired reliability level is achieved another configuration can be selected based in variations of that one to a cost comparison.

We begun considering that the recompression system is responsible to a few part of the produced gas, so the system can operate even in the case of the failure of the machines. A system with two stabilization steps and one compressor for each stage is selected. The first pressure level is attended by a reciprocating compressor and the second, a smaller pressure step, by a centrifugal compressor. Once the speed of these machines are usually quite different at off design operation, to allow a better control each one is provided of a separate electric motor.

The export compression system design requires a pressure ratio of 8, so, at least with two stages. The first trial is with three 50% trains, being one of them as a spare. The system is comprised of 6 KO drums, 6 coolers and 6 compressor casings. One electric motor to drive each train (3 electric motors). The failure rate of each kind of machine was obtained at OREDA (2002). The results are presented below:

Table 2: Main equipment data for the option A

Compression system **A**	Type	number	inlet pressure (bar)	deliver pressure (bar)	inlet temp. (ºC)	exit temp. (ºC)	flowrate (m3/h)	Unit Power (MW)
Stabilization 1st stage	reciprocating	1	15	80	40		154	260
Stabilization 2nd stage	screw	1	0.15	16	35		1300	240
Export compression 1st stage	centrifugal	2	25	71	40	148	2579,1	3087,1
Export compression 2nd stage	centrifugal	2	70	200	40	150	823,6	2930,4
Stand-by 1st stage	centrifugal	1	25	71	40	148	2579,1	3087,1
Stand-by 2nd stage	centrifugal	1	70	200	40	150	823,6	2930,4

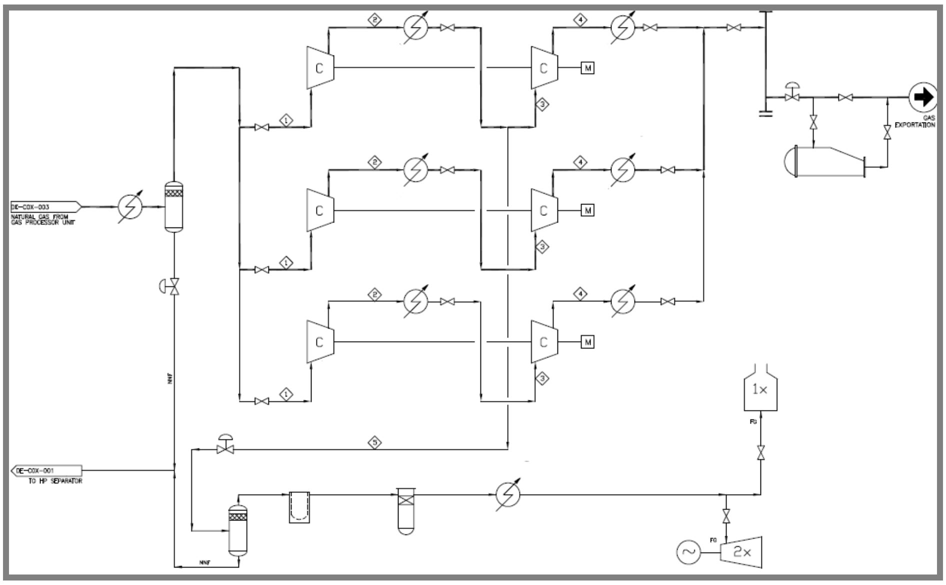

Figure 9: Series 3x50% arrangement being one train in stand-by

The reliability is high but also the investment cost. A second arrangement is chosen as a trial to reach a reduction of the capital cost. The recompression system is already the simplest that is possible, so no change is made. The export compression option that was considered is the series arrangement already presented at the Figure 10. The result data is shown in the Table 3.

Table 3: Main equipment data for the option B

Compression system **B**	Type	number	inlet pressure (bar)	deliver pressure (bar)	inlet temp. (ºC)	exit temp. (ºC)	flowrate (m3/h)	Unit Power (MW)
Stabilization 1st stage	reciprocating	1	15	80	40		154	260
Stabilization 2nd stage	screw	1	0.15	16	35		1300	240
Export compression 1st stage	centrifugal	1	25	71	40	145	5158,2	5989,0
Export compression 2nd stage	centrifugal	1	70	200	40	149	1647,3	5685,0
Stand-by unit	centrifugal	1	50	140	40	145	3500	5707

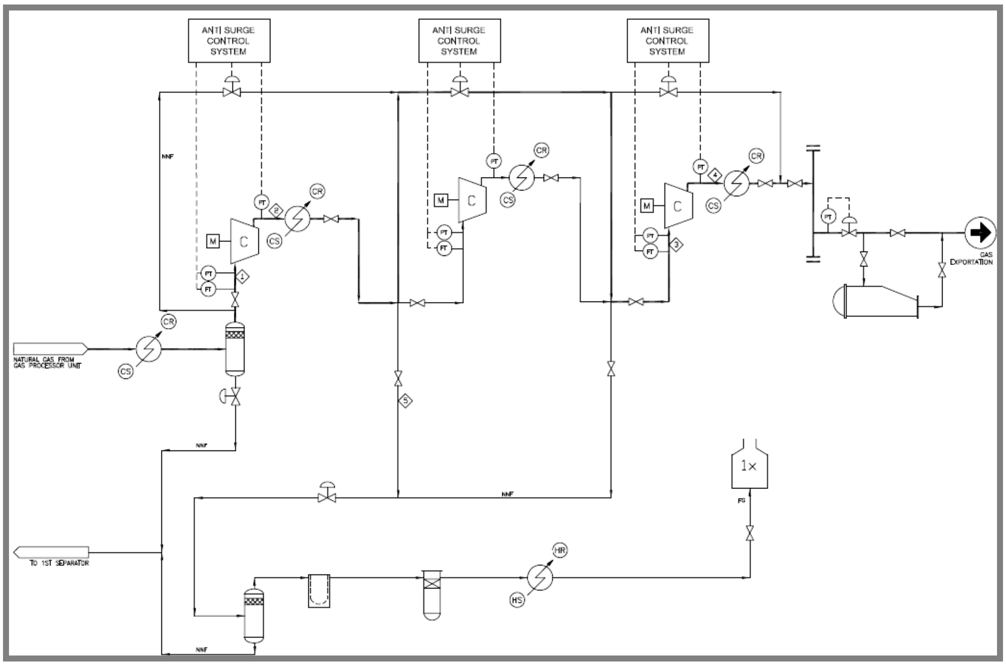

Figure 10: Series 1x100% arrangement with an spare stage, that makes the system availability close to a 2x100% system.

The final checks to develop a complete solution are related to the surge, choke and settling out pressure. The typical limits of surge and choke have to be compared with the expected operational points of the system, what means consider the reduction in the reservoir pressure with the time, and the operation with the recompression system down.

A typical centrifugal compressor curve is presented at the Figure 11. Typically the surge and choke limits are -30% and +30% of the design flowrate in the same head, or 50% if is considered a possible some variation in pressure. An extra care that must be taken regarding the surge operation if the gas is not dehydrated is the possible hydrate formation at the surge line, due the temperature reduction at the recycle valve.

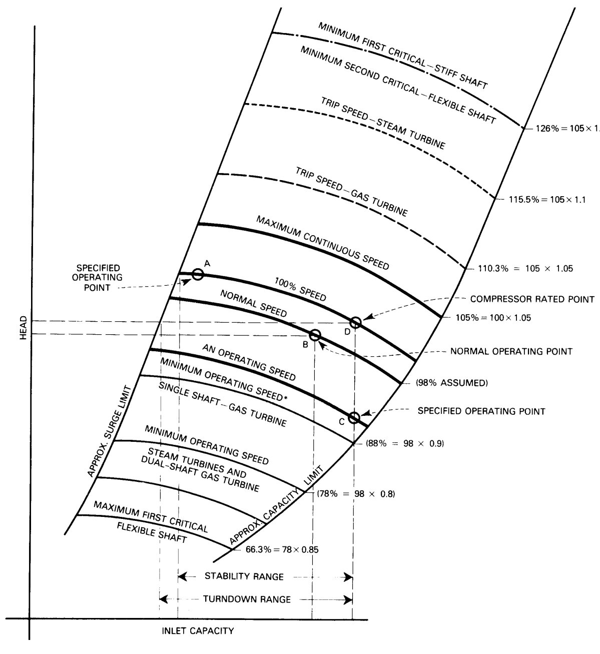

Figure 11: Typical centrifugal compressor performance chart, showing the most important information: the isospeed curves, the surge line and the choke limit.

The settling out pressure is, in most of the cases, just and information needed to provide to the compressor manufacturer and to design the buffer inert gas supply for the seals. The only action that over this that could impact the performance or cost of the system is the reduction of the value. The compressors requires less power at the start-up if the with reduced settling out pressures. This can reduce the electric motor or the turbine turning gear system.

The comparison of the two main parameters is presented at the Table 4. The CAPEX is only related to the equipment purchase, and the MTTF and Availability are for the export compression system. If the power generation and the other process equipment is included the availability will lower (Table 4). So this can be understood as the best achievable availability for the gas production.

Table 4 shows the difference in the MTTF and Reliability by a small gap in CAPEX. The cases C and D are derivates of case B, but with difference arrangements of electric motor C, 1 electric motor for 2 compressors, and D, 1 electric motor for each compressor. At this situation one can note that a little increase in the CAPEX can improve the availability.

Table 4: alternatives reliability data

System	CASE A	CASE B	CASE A + PG + Process	CASE B + PG + Process	CASE C (2x50% and 1 EM)	CASE D (2x50% and 2 EM)
Compressors CAPEX	100%	97%	100%	97%	70%	85%
MTTF	17930	13867	444	1491	7235	33631
MTTR	11	11	29	31	11	11
Availability	99,93%	99,91%	92,73%	97,71%	99,82%	99,96%

Table 5: Reliability data for the main equipments of the two cases (valves, exchangers and vessels excluded)

Equipment	Failure rate	Repair time
Compressor casing A	63.81	13
Electric motor A	10.59	0
Compressor casing B	63.81	13
Electric motor B	10.59	0

These two alternatives give almost the same performance. The trial for a further cost reduced alternatives is presented at the Table 4, but now including the other systems, to avoid a super redundant compression set, but that due the limitations of other systems don't improves significantly the overall availability. A balanced solution is a complex exercise that has to comprise all the most important related systems.

At the analysis can be included also, the loss of availability as a cost item (reduction in production) and the operational costs of maintenance and fuel. The fuel, is available at very low cost, but can be considered the opportunity cost instead the actual cost. The opportunity cost means that the amount of fuel gas that is used, it is not sold. So the sales price of the gas can be used. While the maintenance costs are hard to estimate, the others are readily available using the availability and the compressors efficiency.

2.5. Construction Aspects

The reliability/availability analysis showed that the increment of redundancy have a limited improvement of the overall availability. Better than improve the system performance with stand-by equipments, is the reliability increase of each equipment itself, or the reduction of the maintenance downtime. Great part of the centrifugal compressors failures is associated to liquid ingestion that can cause failure of the delicate gas sealing system, and the gearbox, in several cases due lubrication problems. The change of load for outside the operational range can cause compressor trips. Large compressors take some time to be restarted with acts to increase the averaged downtime, so the process control have a significant participation in the maintenance of low down time at the compression system.

Aspects related to the assembly like alignment between casings and drivers (that can overload and overheat the bearings), balancing and piping assembly (can be causes of vibration), or auxiliaries like lubrication oil cleanness, oil filtering and cooling have to be of the best industry practice.

The reliability importance compared to the efficiency can easily be understood using the data that was provided. Each hour of production loss, means for average natural gas prices, around USD 20,000.00, what covers any slight difference of performance (usually never more than 2%) between different models of modern compressors.

2.6. The jet compression option

The use of ejectors is relatively few used at the gas industry. The most common application is to vacuum generation at steam turbines condensers. The Figure 12 is a proposed layout that could indirectly improve the reliability of machines. With the substitution of the gas recompressors by static equipments the failure rate of that system would be reduced, benefiting the export gas system by the maintenance of a more constant flowrate, avoiding surge and frequent load changes. The reference supplier for this type of gas ejectors is TRANSVAC.

The system uses the gas at higher pressure of the previous stabilization stage to compress the gas of the next stage. The final compression step before the process is done with some gas that is bled from the export compression exit.

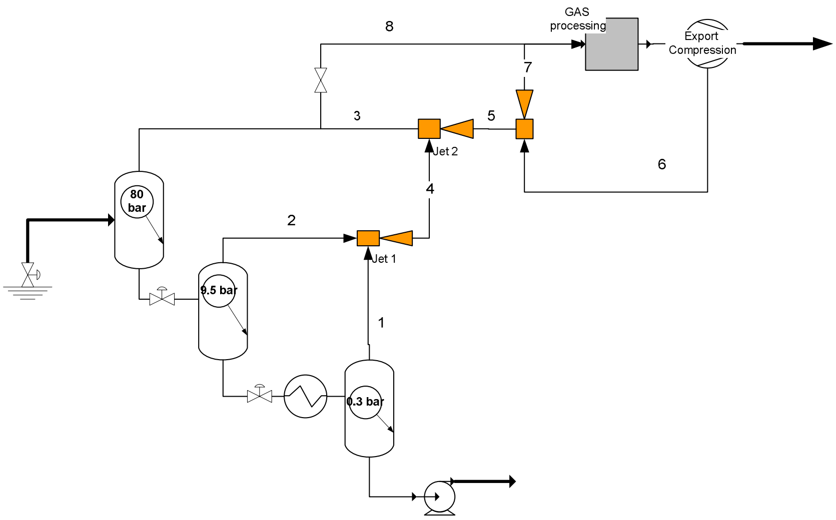

Figure 12: Jet compressors arrangement

Table 13: Process data

Stream data	1	2	3	4	5	6	7	8	9
Temperature (°C)	73.0	85.0	55.0	79.3	41.7	245.9	199.5	48.5	135.7
Pressure (bar)	1.0	9.5	80.0	3.5	15.7	200.0	63.3	63.3	63.3
Total flow (kg/h)	1951	3591	17300	5542	22842	87000	109843	85295	195138

Can be observed that almost 85% of the already treated gas has to be recirculated, what causes a large and unnecessary increment of the flow entering the process, as well as an increase of the compression power from 12 MW to 22 MW.

The maximum achievable improvement of availability does not justify so large increase of the power, processing gas equipment and power generation (to supply the extra compression power).

3. CONCLUSIONS

This real case study gives an overview of the main issues that are discussed at the conceptual design of an offshore compression system. The results show that both systems give a close performance in terms of the most important parameters, the CAPEX and availability, with a small advantages to the option A to exportation system.

When the remaining platform systems are considered, a better balance of the redundancy level that really brings an availability gain can be evaluated, and can be avoided the common cases of plants with large equipments in duplicity but with its performance limited by other minor issues at other equipments.

One should bear in mind that when the remaining system is considered the compression system has a little influence in the global availability.

The remaining design steps are taken together with the suppliers that can provide the actual data of the selected machines.

The reliability, maybe the most important information at the preliminary stages is usually not supplied by the manufactures an have to be chose according the experience of the designer and from independent failure rate data source, as the OREDA.

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