MIXED GAS-OIL SUBSEA PIPELINES IN OFFSHORE TECHNOLOGY: TECHNICAL AND ECONOMIC ASPECTS

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ABSTRACT

The choice of gas separation and transportation mode in offshore applications may significantly affect the project profitability. Main alternatives are separation on board the platform with the utilization of separate subsea pipeline for single-phase gas and oil transportation, and remote separation with multiphase transportation of the gas-oil mixture in a single pipeline. In order to assist the project engineers during the feasibility study phase, the problem's relevant technical and economic issues are analysed in this paper after preliminarily describing the two process schemes. In particular a computer model is developed in order to simulate the two-phase flow of the multi-component mixture adopting the Beggs and Brill model, which showed to be the most reliable approach in this application. A cost comparison with reference to a hypothetical but realistic case study is finally carried out to assess the convenience of the multiphase flow solution. This option appears to be especially attractive when multiple-well fields exist which can be developed in an integrated manner by providing a single centralized separation plant.

Keywords. Offshore technology, Gas - oil separation, Economic analysis, Natural gas production, Subsea pipeline.

NOMENCLATURE

A	Allowance for additional mass (t)
BBL	Oil barrel
CAPEX	Capital Expenses (k€)
D	Drilling mass (t)
FSU	Floating Storage Unit
G	Gas production (m^3/day x 10^6)
HP	High Pressure
J	Mass of jacket (t)
L	Liquid production (m^3/day x 1000)
LP	Low Pressure
M	Dry mass of facilities (t)
NPV	Net Present Value (k€)
STP	Standard Temperature and Pressure conditions
W	Amount of water injected (m^3/day x 1000)
WD	Water depth (m)
S	Number of drilling slots of the platform
ΔP	Pressure drop (MPa)
α	Coefficient
β	Coefficient
γ	Coefficient

INTRODUCTION

In year 2000 about 90% of the world energy requirements of 8752.4 millions of petroleum-equivalent tons have been satisfied by fossil fuels (40% oil, 24.8% natural gas, 25% coal), while the contributions of nuclear energy (7.6%) and hydroenergy plus other sources (2.6%) remain still minor. However, while the role of petroleum is slowly declining (in 1970 it covered 50% of energy needs reducing to 40% in recent years), natural gas consumption is steadily rising and today it covers 24.8% of total energy demand. In the future it is foreseen that natural gas will play an even greater role thanks to the high efficiency of its combustion and the low environmental impact due to the low emission of sulfur compounds and particulates.

In Italy natural gas represents about 80% of hydrocarbon reservoirs, with numerous but small sized fields, mainly distributed in northern Italy, the Adriatic region and Sicily. The average investment for the exploitation of a small-medium sized offshore field in the Adriatic sea, including a six-leg platform, subsea pipeline and onshore treatment plant, is about 50 millions Euro. In Italy, as far as offshore applications are concerned, about 110 productive installations have been developed, including single platforms, clusters and submarine wellheads totaling about 400 wells, while nearly 430 wells have been drilled onshore. In 1999 about 16.2 billions cubic meters of natural gas have been produced in Italy totaling about 27% of the overall domestic consumption.

Natural gas is a mixture of methane, other condensible higher hydrocarbons, and minor quantities of inert gases, acid gases and water. Reservoirs may contain natural gas only or gas associated with oil and forming a gas cap above its surface. Otherwise natural gas may be dissolved in the oil. Therefore at the production stage natural gas may be classified as dry (biogenic), i.e. free of heavy fractions which may condense in the pipeline, or wet (thermogenic) i.e. in a mixture with condensible hydrocarbons.

In the past the presence of natural gas in an oil reservoir was considered to be a drawback due to the greater flexibility in transporting oil instead of gas, so that gas was usually burned at the well. Nevertheless, the increased consciousness of natural resources depletion has led to a new attention to the efficient exploitation of oil-gas reservoirs. However, extracted natural gas needs to be separated from oil, water and contaminants traces before transmission and distribution to the public. Otherwise corrosion, condensation and other operational and environmental problems may arise. Furthermore, water is often a significant percentage of the produced fluids and it is not economic to transport large volumes of water over long distances.

Therefore, in the future the problem of gas separation will likely become even more widespread and significant with the exploitation of new and more "difficult" gas fields.

In offshore plants typically each installation is equipped with his own gas-liquid separation system in order to overcome the difficulties associated with multiphase flow. However, it may be economically convenient to convey the multiphase extracted fluid in subsea pipelines and perform the separation process in a single centralized station especially when a platform is integrated in a production network. In this case there is the opportunity of developing offshore oil fields through existing infrastructure with an integrated approach avoiding the design of redundant facilities, using an unique separation centre that could provide the treatment of the whole production. In this way it is possible to construct satellite platforms that require very simple system controls and minimum facilities, whereas production is sent to a central processing platform for further treatment from where the produced hydrocarbon is sent to shore after separation in order to considerably reduce capital expenses. In fact, until now the high spread existing between costs and revenues led the companies to design each field with its own facilities, but in a near future, when the capital expenses will grow up, especially in ultra deep water fields, the spread will be reduced and a very high level integration and rationalization will be necessary. An example of such a solution is the Val d'Agri onshore field (Basilicata region in Southern Italy) where almost the entire fifty-wells production is connected by two-phase flow gathering lines to an unique large oil-processing center.

In order to assist project engineers during the planning phase, in this paper the problem of mixed gas-oil transportation is discussed in comparison with the traditional single phase transport, and an economic feasibility analysis is carried out with reference to a representative case study.

COMPARISON OF OFFSHORE TECHNOLOGIES FOR GAS-OIL PRODUCTION

When planning new offshore oil and gas extraction installations the gas production system has to be chosen among different technical solutions early in the project definition phase in order to perform economic feasibility analyses. In this framework one of the main design aspects is the problem of separating gas from water, oil and condensable hydrocarbon vapours.

Several choices exist for the production and separation facility. These may be summarised as:

- Subsea separation processing.
- Platform on-board separation and use of two separate pipelines for transport of single-phase fluids (gas and oil).
- Mixed gas-oil transport in single pipeline from off-shore platform to an on-shore separation plant or a centralized treatment platform.

Subsea separation at wellhead (Figure 1), is a higher risk option usually justified only for deep sea extraction where traditional offshore platforms technologies reach their operational limits (Charters, 2001; Radicioni and D'Aloisio, 1999; Song and Kouba, 2000). Investment costs may be up to 17% higher than traditional techniques and maintenance in case of failures is more costly. Moreover the risk of high downtimes may jeopardize the profitability when a rapid pay back is sought resorting to intense extraction of hydrocarbons from the reservoir during the first years of operation. Therefore it is seldom utilized except in deep extraction where traditional platforms with jacket reach their operational limits (350/400 m). This option will thus not be further discussed in this work.

The second one is the most common solution used by oil companies to separate hydrocarbons and water. Figure 2 illustrates this field development concept. Here, the process section of a hydrocarbon production facility is shown in a very simplified form. Oil from a platform well and a subsea well is sent to a separator, which removes the produced water and gas from the oil (Arnold and Stewart, 1986). Oil and gas are sent to shore after pumping and compression respectively through separate subsea pipelines, while water is injected back into the reservoir. There are alternative ways of handling the produced gas if it is not profitable to sell. One is to compress the gas and to inject it into the reservoir for the purposes of pressure maintenance or gas conservation. Another option is flaring. No compression facilities are needed for flaring. Gas flaring is now generally not practiced, except in emergencies, as it is a waste of energy resources.

In the third system only a preliminary separation of water and solids is carried out on the platform and the extracted fluid is conveyed through a single subsea pipeline to a remote treatment plant giving rise to a multiphase flow when pressure and temperature reduce during transportation.

A further option includes dense phase transportation (Ingham and Carrico, 1994) which implies a further gas compression to avoid multiphase flow onset in the pipeline. However, this solution requiring a compressor station and the consequent energy consumptions may be considered only in peculiar applications and will not be dealt with here.

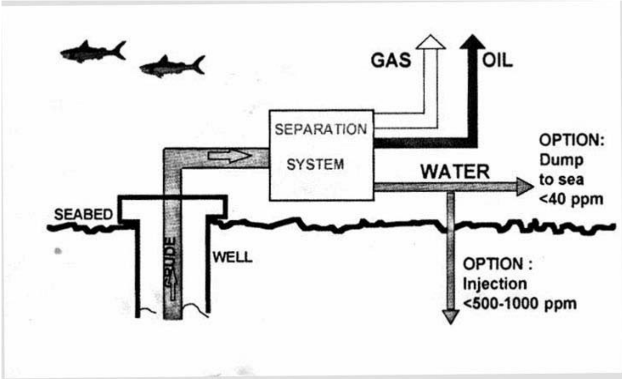


Figure 1. The seabed separation concept.

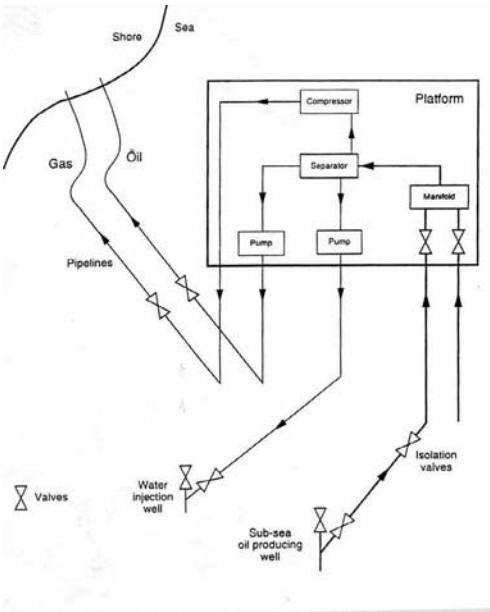


Figure 2. The field development concept with onboard separation.

Therefore in most cases the alternative lies in adopting an on-board or remote separation system with single-phase or multiphase fluid transportation.

Different costs and performances characterize the two options.

In the first case a more complex and costly on-board installation is required including also a doubled subsea pipeline, while in the second case on-board equipment is simplified but greater design problems exist owing to difficult to predict multiphase flow phenomena. Liquid velocity may be up to ten times lower than the gas with a progressive accumulation of the liquid phase (holdup) which may lead to pipe obstruction and dangerous inertial effects. The increased friction coefficient leads to higher pressure losses which require greater piping diameter and thickness considered that at the delivery point the fluid must possess anyhow a pressure level high enough to enable the separation process and to respect the minimum supply specification of the users. However, these critical aspects are balanced by the benefits deriving from reduced capital expenditures such as mainly the utilization of a single pipeline, lower weight offshore structures with minimum facilities required, less complex installation and transport operations.

As far as the separation plant itself is concerned there is no significant cost difference. On shore it operates in part at lower pressure but with greater volumetric flow rate so that it may be considered ininfluent in a differential economic analysis unless there is the possibility of utilizing an existing facility. In this case there is no need to duplicate the plant on board the platform and the entire plant cost is saved with the multiphase transport option. Referring to pipelines a single larger pipeline substitutes two smaller sized subsea pipelines and the trade off depends from specific site conditions and travel distance. An economic advantage comes instead from the smaller size of the platform. However the choice will not affect the overall platform structure and its auxiliary plants but only the gas treatment plant and the pipelines layout. Operating costs are instead largely unaffected as such plants are usually unattended. Summing up, if a new separation plant has to be built anyhow the main advantage of the multiphase solution lies in the capital investment related to the single pipeline and the savings from the simplified platform structure.

SIZING AND COSTING OF OFFSHORE INSTALLATIONS: AN OVERVIEW

The main cost items in offshore fields exploitation are the platform and the subsea pipelines (McClelland and Reitel, 1986; Vincent-Genod, 1984).

It is always dangerous to quote costs as they readily become obsolete with changing economic conditions and technological advances.

However, here some indicative costs are given although they should be used with the utmost caution (the following costs data are in US dollars circa 1990, while actual vendor quotations will be utilized for the case study analysis in the next section). Fixed platform facilities cost \$30000 per tonne installed. The platform structure (jacket) costs \$9000 per tonne installed. In general, flat plate steel construction costs 20 to 25 man hours per tonne and complex steel construction, i.e. curved plates, etc., costs 80 plus man hours per tonne. A 3000 m well drilled from semi submersible platform costs \$6 million. A Floating Storage Unit (FSU) with 20000 m^3 capacity costs \$100 million. A new addition of drilling facilities can increase the cost to \$190 million.

To be close or inside a network has a direct effect on the mass of the facilities and therefore on the capital costs. Generally speaking the platform mass can be estimated by the following parametric expression:

$$M = 580\,(L\cdot\alpha)^{0.47} + 3000\,(G\cdot\beta)^{0.47} + 630(W\cdot\gamma)^{0.47} + S + D + A \qquad (1)$$

where M is the dry mass of deck facilities in tonnes, L is the gross quantity of liquid produced (i.e. oil and water) in 1000 m^3/day, G is the quantity of gas compressed for sale or injection in million m^3/day. W is the water injected in 1000 m^3/day, S is the number of drilling slots at the platform, D is the drilling mass which is 3900 tonnes for platform drilling, 1200 tonnes for tender-assisted drilling and 0 tonnes for jack-up assisted drilling, and A is the general allowance for any unforeseen masses in tonnes, which may be zero. α, β and γ are uncertainty factors (1÷1.5). For satellite platforms the mass platform process and drilling facilities is D plus 2000 tonnes in all cases. The above numbers exclude the mass of the oil and water in the facilities.

The cost of the supporting sub-structure is proportional to the mass too. The sub-structure or jacket mass includes the piles, dependent on the water depth, and is related to the mass of dry topside facilities and the number of drilling slots.

- For a water depth up to 105m:

$$J = (WD/95)^{1.15}\,(4200 + 0.06\,M + 34\,S) \qquad (2)$$

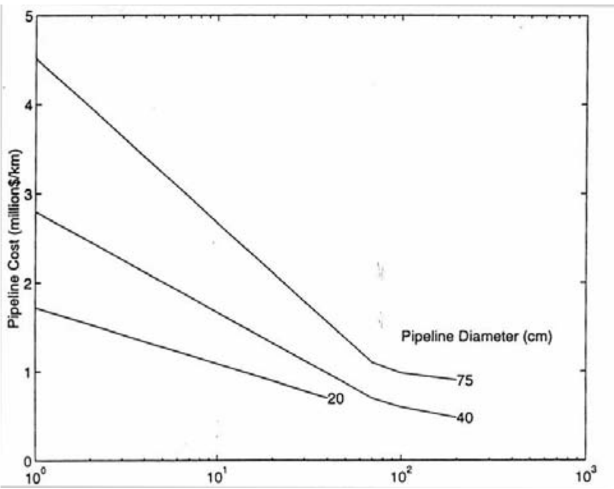
- For water depths 105 to 175m:

$$J = (WD/160)^{1.35}\,(6200 + 0.13\,M + 61\,S) \qquad (3)$$

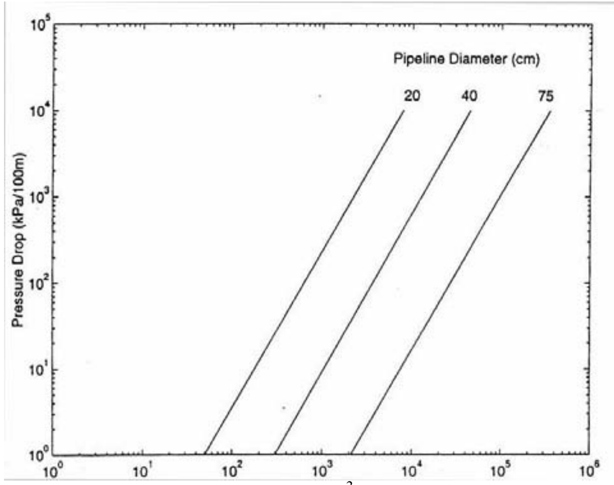
where J is the mass of the jacket in tons, WD is the water depth in meters, M is the dry mass of facilities in tons and S is the number of drilling slots at the platforms.

The size of the floating storage unit is a function of the oil production and the size of storage at the terminal. A typical size for FSU is 10 days maximum throughput. Sizes vary from 8000 m^3 to 40000 m^3.

The pipelines are a major component of a field development (Vincent-Genod, 1984). The diameter of pipelines depends on many factors. The important factors are the length of the line, the type of fluid transported (i.e. gas, oil or water), the flow rate, and the difference between the inlet pressure and the outlet pressure. Most of the time the unknowns are the diameter of the line and the pressure drop. One of these must be chosen in order to be able to calculate the other. Pipeline costs are illustrated in Figure 3.



Length of line (km)
Figure 3. Pipeline costs.



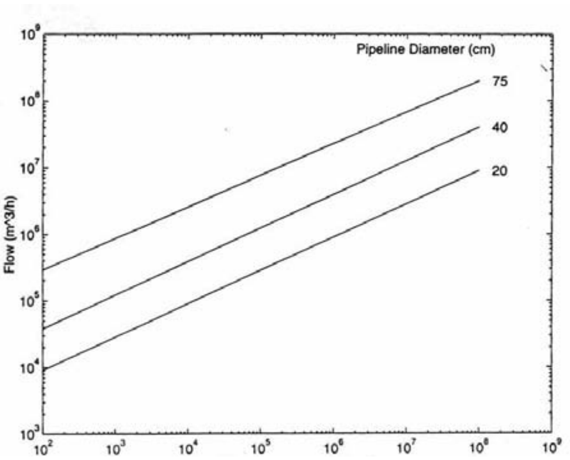
Flow (m^3/h)
Figure 4. Oil pipeline sizing

The water and oil pipeline calculation is a simple one since pressure drop against flow rate gives the diameter. For gas pipelines the square of inlet pressure minus the square of outlet pressure divided by the length of the line versus the flow rate gives the diameter. Figures 4 and 5 show pressure difference – flow rate curves for oil and gas respectively. Gas is often transported at an inlet pressure of 70 to 14 MPa. Figure 6 gives instead typical pressure drop values for a two-phase flow in a pipeline.

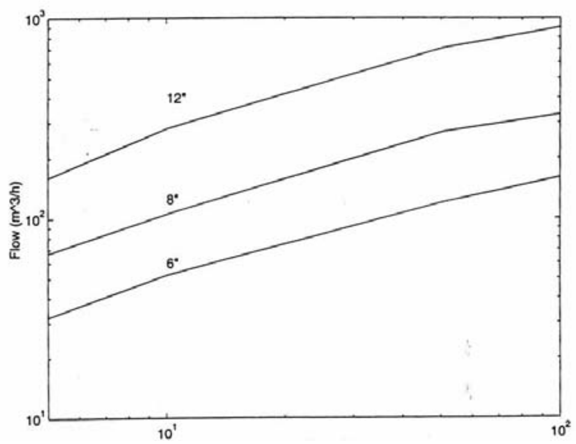
CASE STUDY

System design

In order to highlight the effect that the fluid separation and transportation mode has on the cost and profitability of a gas field exploitation a detailed economic analysis is provided with reference to a field located in the Mediterranean sea 13 km off coast where the sea floor depth is 85 m. The field has an extension of 8 km^2 and the exploitable gas reservoir is estimated to be 3584 millions m^3 STP (standard temperature and pressure). Dry gas composition is: Methane 94.40%; Carbon dioxide 0.39%; Nitrogen 0.52%; Ethane 0.83%, Propane 1.80%; i-Butane 0.97%; n-Butane 0.55%; i-Pentane 0.29%; n-Pentane 0.12%; n-Hexane 0.11%; n-Heptane 0.02%. However, it is a condensed gas (not dry) with traces of 7-10°API heavy oil and water.



$P_1^2 - P_2^2$ (kPa^2/km)
Figure 5. Gas pipeline sizing.



System pressure drop (kPa/100 m)
Figure 6. Typical two-phase pressure drop (well fluids with low/medium Gas-Oil Ratio) .

The study has been carried out under the following hypotheses in order to be more representative of realistic situations where the platform is included in a network of platforms:

- a remote separation plant already exist onshore and can be utilized when multiphase option is chosen;
- the platform is part of a network of existing and future platforms so that provision for integrating into the network pipeline system is given. This means that in case of single phase flow a tie-in to other pipelines is included and in case of multiphase transport the pipeline is oversized to accomodate flow increments deriving from field expansion and new platforms.

Plant equipment has been sized and costed on the basis of the following design data:

- Max static pressure at well head: 26 MPa
- Max dynamic pressure at well head: 19.2 MPa
- Min dynamic pressure at well head: 9.4 MPa
- Well head temperature: 24 °C
- Max total platform throughput:1.2 millions m^3 STP/day
- Max entrained water flow rate: 2 m^3/day
- Entrained water salinity: 15 ÷35 kg/m^3

while the assumed production profile (result of a separate life cycle optimization of extraction economics for the examined site) is shown in Table 1 which constitutes the inlet conditions at the separation plant or the transportation pipeline.

Details about the plant architecture as well its sizing and costing are given in the following for the two competing options schematized in Figure 7.

Table 1. Assumed production profile.

Year	Flow rate (m^3 STP/day)	Well head pressure (MPa)
2001	962000	19.2-19.3
2002	1200000	16.7-16.9
2003	1200000	14.0-14.4
2004	1160000	11.8-12.2
2005	828000	10.6
2006	530000	10.1
2007	306000	9.7
2008	114000	9.5
2009	38000	9.5
2010	20000	9.5

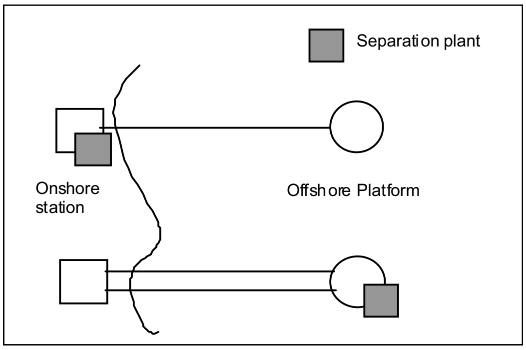


Figure 7. Scheme of plant options.

A) On board separation and single-phase transport

A typical two stage separation system has been devised with a first high-pressure separation of oil-saturated gas from oil, sand and water at the well extraction pressure, and a final low pressure oil-gas separation after a decompression stage. Separated gas and oil are then forwarded on shore through two separate subsea pipelines. Oil is recovered from both the HP and LP separators, but oil coming from the LP separator is heated to 0-5 °C in order to avoid ice formation in the pipeline.

In greater detail, referring to Figure 8, fluid from the wellhead is forwarded to the HP separator. The separated gas (saturated with oil) is sent to the conditioning section while the remaining mixture of water, oil and sand is sent to a flash separator in order to recover light oil fractions and eliminate the solid residue. For safety reason excess gas is vented and flared to avoid any pressure buildup in the vessel. Liquid residue from the flash separator, mainly water, is then treated in a filtration unit to remove suspended solids and avoid pipeline plugging over long times. Recovered oil is sent ashore. Gas coming from the HP separator is depressurized to 6 MPa and reheated through heat exchange with the hotter gas (about 25 °C) entering the pressure reducing valve in order to prevent mechanical damage to the pipeline. During pressure reduction a temperature drop to about -27°C occurs which, being the temperature lower than 10 °C, implies the necessity of glycol injection in the gas stream in order to avoid hydrates formation. The mass of injected glycol is a function of the actual well head pressure as it is related to the temperature drop following the pressure drop. Glycol is also injected to prevent hydrates formation prior to pressure reduction and downstream the HP separator. Separated gas is conveyed onshore through a 13 km long subsea pipeline. About 4 km after the platform a tie-in is installed in order to enable the future connection to further pipelines when other platforms will be operational. Initial pipe size is 10" but after the tie-in the diameter is increased to 14". Gas temperature in the initial part of the subsea pipeline is -27 °C but the tie-in position is such that the gas may reheat before arriving at the junction through heat exchange with sea water in order to avoid any risk of hydrate formation if the treated gas is mixed at the tie-in with wet gas coming from other wells. The oil pipeline has 3" size and is 13 km long.

B) Two-phase transportation and on-shore separation

In this case the saturated gas from the wellhead is separated from solid residues only on board the platform and, if required, its pressure reduced before entering the pipeline to reach the requested pressure level compatible for transportation. The pipeline has been sized for a maximum future gas flow rate of 2 millions m^3 STP per day.

The constraints for the design of the two-phase pipeline are the final pressure level, which should be high enough to enable separation and distribution to the users (3-4 MPa), and the inlet pressure imposed by the extraction profile (see Table 1). Diameter and thickness should be reduced as much as possible in order to lower capital investment. During the first years the pressure drop is not a concern as the inlet pressure would be quite high (up to 19.5 MPa) allowing the choice of a small diameter pipe. During the last years of operation instead even if the flow rate will decrease the available inlet pressure will decay to as low as 9.5 MPa with the risk that the minimum onshore pressure can not be guaranteed. Therefore the tail conditions dictate the choice of pipe size and in the first period the extracted gas pressure will be reduced to a suitable level also enabling a lower pipe wall thickness. A maximum pressure limit of 12.5 MPa in the pipeline will be anyhow imposed as dictated by current practice.

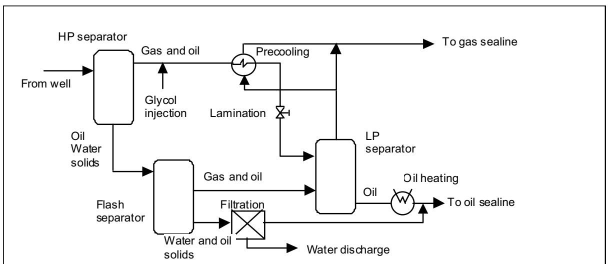


Figure 8. Scheme of a gas-oil separation plant.

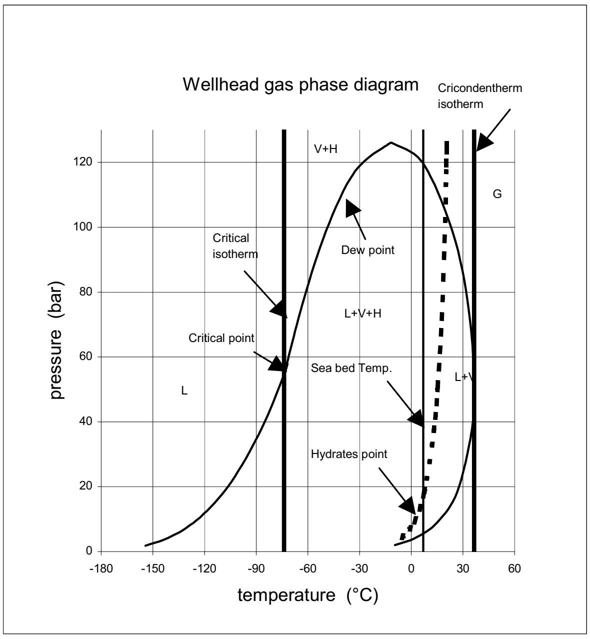


Figure 9. Phase diagram.

Multiphase flows are significantly more complex than single-phase flows (Martin, 1981; Oranje, 1983). One of the most reliable literature methods for predicting the liquid holdup and pressure drop that occur during two-phase flow in inclined pipes is the Beggs & Brill model which is particularly applicable in designing pipelines for hilly terrain and tubing strings for inclined wells (Beggs and Brill, 1973). In order to perform calculations the Beggs & Brill fluid flow model has been utilized on the basis of the phase properties of the actual mixture, obtained from experimental data (Figure 9), and a spreadsheet implementation has been carried out. Specific simulation code has been in fact developed in order to ensure greater flexibility respect commercial programs as far as the peculiar conditions of this application are concerned.

The developed model, based on input data including pipe size and length, the altimetric profile of the pipeline, the mixture composition and its phase diagram, besides knowledge of inlet conditions pertaining to pressure, temperature and flow rate values, enables the computation of flow regime and properties (holdup fraction, pressure and temperature) across the whole length of the pipeline and in particular the overall pressure drop.

Table 2. Results of multiphase flow simulation.

Diameter (in)	Throughput (m^3/day stp)	Inlet pressure (MPa)	ΔP (MPa)	Outlet pressure (MPa)
10	2.000.000	12.0	1.86	10.13
12	2.000.000	12.0	1.24	10.75
14	2.000.000	12.0	0.96	11.03
10	2.000.000	11.5	1.94	9.55
12	2.000.000	11.5	1.26	10.23
14	2.000.000	11.5	0.98	10.52
10	2.000.000	11.0	2.03	8.96
12	2.000.000	11.0	1.28	9.71
14	2.000.000	11.0	0.99	10.00
10	2.000.000	10.0	2.26	7.74
12	2.000.000	10.0	1.31	8.61
14	2.000.000	10.0	1.02	8.98
10	50.000	9.5	0.71	8.78
12	50.000	9.5	0.71	8.78
14	50.000	9.5	0.71	8.78

Table 3. Platform cost and weight.

Item	Weight (ton)	Cost (kEuro)
Equipment	169	212.0
Electric plant bulk	20	118.5
Instrumentation bulk	44	483.5
Piping bulk	41	348.0
Deck structure	600	3478.5
Jacket structure	1348	5819.0
Foundation piles	1500	2325.0
Wellhead module	64	247.0
Total platform weight	3786	

Pressure gradient is computed including the contributions of kinetic energy variations, altimetric profile variations and friction effects, considering both the surface friction with pipe walls and the internal friction among different phases (slippage phenomena). Such terms are estimated in terms of liquid holdup and friction factors which are accounted for, according to Beggs & Brill model, resorting to experimental correlations. Adopting the model the final delivery pressure has been determined corresponding to different values of flow rate, inlet pressure and pipe size as shown in Table 2. Computations have been performed assuming an inlet liquid fraction of 0.3. A further 30% increase in pressure drop must be allowed to account for concentrated losses and the altimetric profile of the seabed.

Considering that the separation process is responsible for a pressure drop of about 6 MPa and adding the lower limit on distribution pressure it follows that a minimum delivery pressure during the period of maximum production should be about 9.5 MPa.

Therefore inlet pressures lower than 11 MPa should be ruled out, and a 10" pipeline operating at 11.5-12 MPa or, better, a 12" pipeline should be adopted. In case the fluid is extracted from the well at higher pressure levels its pressure would be reduced; otherwise it is sent at the well pressure, with the minimum well pressure of 9.5 MPa being still enough to enable transportation thanks to the reduced flow rate which causes low pressure losses (about 0.6-0.7 MPa) mainly due to hydrostatic pressure. The choice of pipe sizes, consistent with the available inlet pressure profile, enabled to avoid any production loss respect the single-phase transport solution.

Before undergoing pressure reduction and entering the pipeline, glycol injection is carried out to avoid hydrates formation and improve fluid flow properties reducing the amount of slugs and the holdup effect. The same amount of glycol injection is assumed in both transport options. In fact even if higher minimum temperatures are reached in the multiphase transport solution, asking for a lower glycol amount, because of lower pressure drops owing to the absence of the on – platform separation unit, excess glycol is injected to improve the mixture rheologic properties, leading to roughly the same glycol consumption and related operational costs. Furthermore, glycol is recovered and regenerated in the on-shore receiving station.

Respect solution A) the platform lacks the separation equipment, and the flare, while the glycol storage and injection unit and the suspended solids filtration system are still present. The double subsea pipeline instead is substituted by a single 12" pipe operating at 12.5 MPa maximum pressure and 13 km long. The submarine tie-in is avoided as junction with future pipelines carrying fluid from other wells in the same field can be installed on board the platform.

Table 4. Cost and weight of separation plant equipment.

Equipment	Weight (ton)	Cost (kEuro)
High pressure separator	13	161
Low pressure separator (incl. gas cooler and oil heater)	19	269.5
Flash separator and water filters	2.3	21.5
Glycol injection and storage unit	13	220
Flare	11.4	97
Off-gas burner	8	91

Economic analysis

In both cases a four-legged platform with a 96 m long jacket is considered having the weights described in Table 3. Details on weight and cost of the separation plant are given in Table 4.

Table 5. Capital expenses.

Item	COST (kEuro)	
	A) Single phase transport	B) Two-phase transport
Feasibility study	89.5	89.5
Engineering		
Design, project management, Procurement	5472.5	5076.5
Construction supervision, Certifications	512+11.5	846+11.5
Engineering total	**6396**	**5934**
Construction & Installation		
a) Jacket		
Foundation piles	2325	2325
Jacket	5819	5819
Mooring and loading	138+125	138+125
Transport and installation	4053	4053
Jacket Total	12460	12460
b) Deck		
Equipment purchase and installation	1162	1162
Structures (materials and installation)	3478.5	3478.5
Topside facilities	6345	5823.5
Transport and installation	1351	1351
Hook-up and Commissioning	900	900
Deck Total	13486.5	12715
c) Wellhead module	281	281
d) Pipeline		
Construction	2477.5	2340
Laying	4825	2275
Subsea Tie-in	240	
Pipeline Total	7302.5	4315
Construction and installation total	**33770**	**30071**
Insurance	**268**	**268**
Well		
Perforation	7760	7760
Completions	4250	4250
Jackup Rig Logistics	860	860
Well total	**12870**	**12870**
Onshore plant upgrade	**5250**	**5400**
Total Capital expense	**58643.5**	**54632.5**

Capital investment data for both plant solutions are shown in Table 5. As far as operating costs are concerned instead (personnel, operating labor, maintenance, consumables, fuel for the utilities and maintenance) no major difference exists between the two solutions for a given production level. It can be observed that the on board separation solution bears higher capital investment due to the added cost of engineering and construction (on board separation plant and double pipeline) which is only partially offset by the lower cost for upgrading the onshore plant. However, the main difference is associated to the pipeline system, especially when referring to pipeline laying expenses. Therefore even if the separation plant had not been already available and should have been built, the two-phase transport mode would have been still convenient from the capital expense standpoint.

Table 7. Summary of discounted costs and revenues (kEuro).

	Solution A	Solution B
Net revenues	114698.5	114698.5
Total expenses	93392.5	91214.0
Capital investment	48390.5	45048.5
Operating expenses	9562.0	9562.0
Decommissioning and dismantling	1770.0	2875.5
Royalties	6538.0	6538.0
Taxes	27132.5	27191.0

Table 6. Cost and revenues comparison forecast.

Year	Production		Gross revenues (kEuro)	Investment (kEuro)		Operating costs (kEuro)		
	Oil (kBBL)	Gas (Mm^3 STP)		A	B	Fixed	Variable	Total
1996				17.0	17.0			
1997				72.5	72.5			
1998				746.0	746.0			
1999	11	27	2054.5	11076.0	10762.0	295.0	81.5	376.5
2000	13	32	2532.0	42737.0	39025.0	304.0	96.5	400.5
2001	181	308	25968.0	3995.0	4010.0	1043.0	996.5	2039.5
2002	182	384	33032.0			1050.5	1187.5	2238.0
2003	183	384	34228.5			1056.0	1189.0	2245.0
2004	184	372	34251.5			1061.5	1160.0	2221.5
2005	174	265	25733.5			1014.5	880.0	1894.5
2006	126	170	17095.5			807.0	582.5	1389.5
2007	83	98	10190.5			616.0	349.0	965.0
2008	49	37	4231.0			467.5	154.0	621.5
2009	17	12	1413.5			329.5	51.5	381.0
2010	9	7	822.0			1263.5	29.0	1292.5
2011	4	6	652.0			1244.5	20.0	1264.5
Total	1216	2102	192204.0	58643.5	54632.5	10552.5	6775.0	17329.5

A financial analysis has been also carried out by distributing investment, operating expenses and revenues over the foreseen useful field exploitation period, consistent with the assumed extraction profile, in order to assess the project feasibility and the influence that the engineering choice about separation has on the overall economic performance (Table 6).

Revenues have been computed on the basis of market forecast for the oil and gas price (oil: 13.27 Euro/BBL in year 2000 up to 18.85 in 2010; gas: 0.076 Euro/m^3 STP in year 2000 up to 0.097 in 2010). Production start in 1999 and end in 2008 has been hypothesized. Decommissioning and dismantling starts in 2009 and ends in 2011. Discount rate has been considered as 10% and the total discounted costs and revenues are shown in Table 7.

Table 8. Financial analysis results.

	Solution A	Solution B
Net present value (NPV, kEuro)	21306.0	23484.5
Capital investment present value (CAPEX, kEuro)	48390.5	45048.5
NPV/CAPEX Ratio	0.44	0.52
Internal rate of return	26.1%	27.3%
Maximum financial exposure (kEuro) - year 2000	-50285.0	-46334.0
Pay out time (years from start of extraction)	7.1	6.8

Results of the financial analysis are shown in Table 8. To compute net revenues the royalties (5.7%) and taxes (26%) have been included.

Again the advantage of two-phase transport results even from the profitability point of view and in particular from the Net Present Value (23484.5 kEuro versus 21306 kEuro) and the internal rate of return of the investment. Two-phase solution is not a higher risk option as the maximum financial exposure and the pay out time are slightly lower respect solution A while the ratio of Net Present Value to capital investment is higher.

CONCLUSIONS

In this work the technical and economic issues connected to the choice of a gas separation system for offshore fields exploitation have been discussed. The inherent trade off between multiphase and single-phase fluid transport has been analyzed with reference to a specific case study showing how the solution of remote separation and multiphase transportation through a single pipeline may give substantial benefits in terms of capital expenses and profitability especially when the offshore installation is included in a network of similar units so that a centralization of separation processes may be sought. However, multiphase flow is substantially more complex and difficult to foresee so that an accurate engineering analysis work is required to eliminate any technical risk from this attractive practice.

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