Trends in oil and gas field development

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Objekttyp: **Article**

Zeitschrift: **Bulletin der Vereinigung Schweiz. Petroleum-Geologen und -Ingenieure**

Band (Jahr): **58 (1991-1992)**

Heft 132

PDF erstellt am: **17.07.2024**

Persistenter Link: https://doi.org/10.5169/seals-215189

Bull. Swiss Assoc. of Petroleum Geol. and Eng., V. 58, Nr. 132, May 1991 - p. 1-16

Trends in oil and gas field development

by J. VAN DAM*
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Zusammenfassung

Es werden grössere Zusammenhänge für technische und wirtschaftliche Anforderungen bei unterschiedlichen möglichen Entwicklungen von Oel- und Gas- Feldern aufgezeigt.

INTRODUCTION

There is much in common in developing an oil field or a gas field. Both make use of production wells, surface processing facilities and at least initially, of a field tansportation pipeline system to some common point, where the product is lifted or exported to its market destination. It is at this point that the main difference between planning and economics of oil & gas field development occurs. Crude oil can be stored (after stabilisation) for varying lengths of time until offtake occurs. This in turn could be by many means ranging from trucks (Sirikit field Thailand), trains (Schoonebeek, The Netherlands), pipelines (mostly offshore fields), and or marine or inshore tankers. The crude oil can moreover be sold all over the world in larger or smaller lots. There is thus a very large degree of flexibility in handling and marketing the product.

In the case of gas fields this is generally not the case. The natural gas produced is not so easily stored in large quantities and not so easily transportable. One needs in most cases dedicated customers, and in view of the often high costs of installing the transport facilities (since generally the customers don't live next door to the gas field) longterm sales contracts for large quantities of natural gas, before field development can be considered and decided. There is another important difference; the physical characteristics of natural gas , both as it behaves in the subsurface hydrocarbon reservoir, as well as inside the wellbore and at the surface in the processing and offtake facilities are quite different from those of crude oil. This often calls for different well development patterns, special provisions in the wellbore, and different surface facilities which can either be more or less complicated than those needed for oil field development.
In more general terms, gas field development lacks the flexibility that characterises oil field development and the planning and implementation stage before natural gas can be produced is considerably longer.

In the course of time these differences, very distinct in the past, have become far less so today, when venting or flaring of associated gas, inevitable by-product in any oil field development, is no longer allowed. Could the produced associated gas in the past be considered as a waste-product which could be released into the atmosphere (direct or after burning) to the extend it was not required for use at the location of production, today, both for reasons of conservation of natural gas energy resources and of the environment, most countries have rules and regulations that prohibit such practice.
Therefore nowadays in nearly all cases an oil field development decision can only be

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made after giving careful consideration to the use (mostly through sales) or conservation (e.g. by re-injection into the reservoir) of the produced associated gas; as a consequence the economics and development options of oil and gas fields are approaching a common course. Also modern gas transport technology, which renders two-phase gas and liquid flow through pipelines over large distances and in large quantities possible, tends to obscure the difference between oil and gas field development and economics even more.

Obviously it is not a practical proposition to explain the differences between oil and gas field production and commercialisation in an orderly fashion, starting at a point in time, when such differences are much obscured. Therefore this paper will start somewhere in the beginning of the sixties, when outside the USA and Europe most of the world gas reserves remained undeveloped because of lack of nearby and profitable markets. In the course of the story due attention will be given to the manner in which modern technology and concern for conservation of energy resources and of the environment caused the pattern to change.

What is an oil field, and what a gas field?

The most convenient way to answer above question is to make the distinction according to the state of the »reservoir-fluid» in the reservoir at initial formation pressure and temperature, i.e. is it in a gas or liquid state ? This is further illustrated in the pressure-temperature diagram shown in the illustration. The pressure-temperature diagram shows the state of the reservoir-fluid (a mixture of hydrocarbons and non-hydrocarbons such as H_2O, CO_2, N_2, H_2S, etc.) at various pressures and temperatures. It contains a two-phase envelope, within which the pressures and temperatures are indicated at which a coexistence will occur of both a gas and a liquid phase. It also indicates the critical point, i.e. the critical pressure and temperature , where the distinction between liquid and gas phases disappears. Within the envelope lines are drawn of constant percentages of liquid volume in the total mixture. Outside this envelope the reservoir fluid occurs in one phase only; liquid if pressures are higher than those on the upper side of the envelope and temperatures below the critical temperature. All the other points outside the envelope correspond to a single gas phase.

A hydrocarbon accumulation would normally be called a gas field, if at initial conditions its reservoir pressure and temperature coincide with a point in the single gas phase on the pressure-temperature diagram. This definition is accepted worldwide , also by government authorities, to determine the legal regime under which the field will be developed and operated.

Some complication arises if a thin oil rim exists at the bottom of the accumulation. If this oil rim is commercially exploitable, the field will generally be classified as a combined oil and gas field, where both phases will be produced and sold, albeit not necessarily at the same time. The Norwegian Troll field in its western extension is a good example of such a case.

In the course of this paper we will however avoid such fine distinctions, and proceed on the basis of a clear case for either oil or gas field development. Even then the development policy to be adopted will much depend on the initial position of pressure and temperature on the pressure-temperature diagram. A few examples:

PHASE RELATIONSHIPS HYDROCARBON MIXTURES

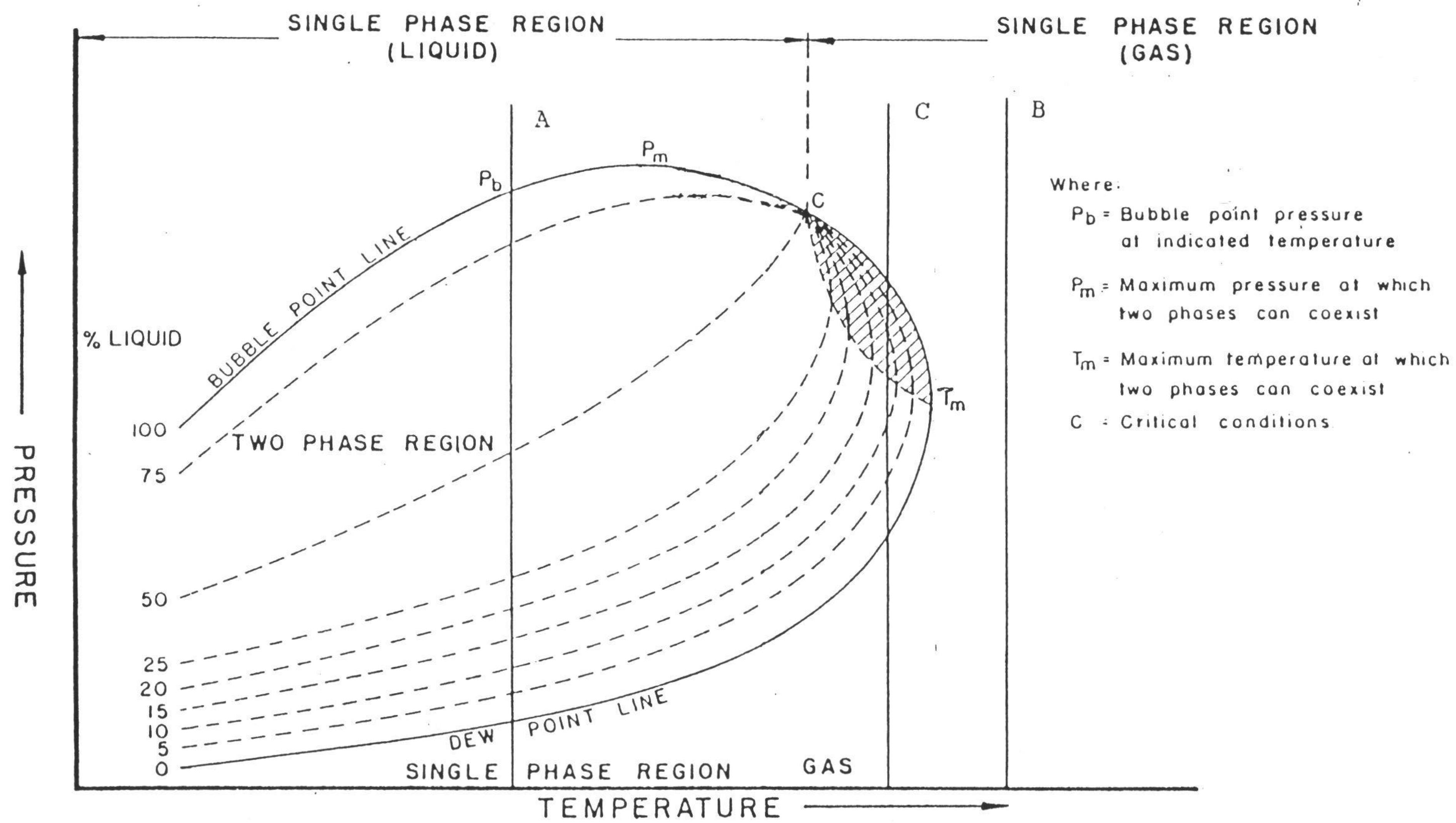

Fig. 1 Pressure-temperature diagram of a hydrocarbon fluid system

— *At point A on the pressure-temperature diagram in the illustration we have an undersaturated oil field. If during production the pressure declines (at isothermal conditions, because of the large heat capacity of the reservoir rock and pore fluids), the reservoir pressure will reach a point on the two-phase envelope, the «bubble point», at which a gas phase will separate from the oil within the reservoir. This is called the associated gas.*

— *From there on a two-phase flow regime will prevail within the reservoir. One will also observe that at pressures below the bubble point the percentage liquid will gradually decrease.*

— *At point B we have a dry gas field. At decreasing pressures the reservoir fluid remains in the gas phase, and single-phase flow conditions will prevail throughout field life.*

— *At point C we have a so-called retrogade condensate (gas) field. At a certain pressure, the «dew point» pressure, a liquid phase will separate within the reservoir. When further lowering the pressure the liquid quantity will increase, until it reaches a mximum. Thereafter at further lowering of the pressure the liquid phase will gradually evaporate and under certain conditions of gas composition, totally disappear again. In these fields it is possible to have besides the gas exploitation a more or less important liquid recovery scheme.*

The non-hydrocarbon components

All natural gas reservoirs contain interstitial water attached by capillary forces (i.e. surface tension) to the pore system of the reservoir. As a consequence all natural gas accumulations are saturated with H_2O at reservoir conditions. In addition most of the accumulations contain at least minor quantities of CO_2 (sometimes even more), and in certain regions (e.g.the Rotliegend gasreservoirs of northwestern Europe) varying quantities of N_2. Most gas accumulations in the Middle East contain H_2S, as do for example accumulations in Canada and Lacq in France. The consequences of the presence of the non-hydrocarbons are manifold:

— *The presence of water in the wellhead stream gives rise under certain conditions of pressure and temperature to the formation of hydrates, a solid cristaline structure of hydrocarbon components and water, which may block well chokes, valves and pipelines and the formation of which needs to be prevented, or directed towards parts of the production system where it can do no harm and can be safely dealt with.*

— *The presence of nitrogen is more innocuous, but it reduces the heating value of the gas, which puts a limitation on its use and on the possibility to mix it with pure hydrocarbon gasses, and thus its possibilities to introduce it into common gas pipeline carrier systems.*

— *The presence of carbon dioxide may cause the same difficulties as that of nitrogen. In addition in the presence of water it causes «sweet» corrosion in well and surface facilities, which may become very severe at high pressures. Special measures, such as dehydration of the gas as close as possible to the wellhead, the use of special steel or internal coatings, or the use of corrosion inhibitors are indicated to combat this corrosion.*

— *The presence of hydrogen sulfite renders the gas sour and causes «sour» corrosion in the presence of water. This corrosion maybe very severe if not properly handled* *and can cause early destruction of production and gathering facilities. Moreover a gas containing quantities of hydrogen sulfite is very poisonous and dangerous to life. Elaborate safety measures are required in the production of sour gas. Use of appropriate equipment materials combined with thorough dehydration as close as possible to the wellhead is required to safeguard the life of production and pipeline facilities and to prevent leakage. Removal of the sulfur is required before the gas can be used in common (non-sour service) carriers or e.g. be fed to a LNG plant.*

In the case of oil field development protection of crude oil gathering lines, field processing facilities and crude transportation pipelines against internal sour and sweet corrosion, is both more simple and more difficult. In first instance the crude oil itself may act as an inhibitor against corrosive components like H_2S and CO_2, but this is only true so long as the crude is free of formation water, or if minor quantities of water remain in suspension in the crude and the crude itself remains the wetting phase vis-a-vis the the facilities' internal wall. As soon as the amount of water contained in the crude becomes so large that free water will drop-out, a free water phase will develop at the bottoms of pipelines and facilities, in which the corrosive sweet and sour gas components will dissolve. Severe corrosion of the lower part of pipelines and bottom parts of production facilities may then occur. Since it is not practical to separate all the water from the crude in free water knock-out vessels, nor to dehydrate the crude completely after oil & gas separation, the danger of internal corrosion of production facilities is ever present. In order to protect pipelines, frequent pigging is required to restrict the presence of free water pockets inside the line. Depending on the severety of the corrosion, choice of a thicker wall thickness or of special materials for the production facilities may be required. As in the case of natural gas production, the severety of sweet corrosion was not yet recognised in the sixties, which resulted in several cases in a shortening of the service life of crude oil production facilities.

The presence of non-hydrocarbon components in the reservoir has also an influence on the shape and the position in the pressure-temperature diagram of the two-phase envelope and the iso-liquid-content lines within it. It may cause gasses with similar hydrocarbon compositions to behave quite differently in the reservoir with regard to liquid drop-out during depletion.

Reservoir engineering

The reservoir engineering discipline studies and describes the flow and behaviour of the reservoir fluids (gas and liquids) within the reservoir horizon and before it enters the wellbore. It assists in estimating the hydrocarbon reserves of a field and provides guidelines for correct production techniques to obtain optimum economic recovery of the hydrocarbon components contained in the original reservoir fluids. Such are the number of production wells and their location and any method to be used to conserve reservoir energy or to augment it through water or gas (re)injection, the use of chemicals and heat (e.g.steam).

The difference between the production of oil and gas fields is, that the latter generally are more easy to produce since the flow in the reservoir is principally single-phase (the retrograde condensate gas reservoirs are an exeption). As the viscosity of the gas in the reservoir is normally a factor 50 lower than that of crude oil at reservoir conditions, high flowrates are achieved even in less permeable reservoir rocks. Wellrates in the order

of .5 to 2 million m^3 per day are no exception! As a consequence one needs fewer wells, can use a larger wellspacing and an even spacing of the wells over the reservoir in the initial stages of production is not necessary. This is of importance if some places of the reservoir are difficult to reach, for example on land near urban agglomerations or at sea from the production platforms. In the initial stages of production, the production wells can often be drilled from a single location, relatively closely spaced; as a consequence the initial development and production of North Sea gas fields is often from a single platform.
Moreover, because of the character of single-phase flow, the primary ultimate recovery of natural gas is high under pressure depletion conditions. There is therefore not much scope for (costly) secondary or tertiary recovery operations; in fact pressure maintenance through waterdrive would reduce ultimate recovery through capillary trapping of gas in the pores of the reservoir at high pressures.

In crude oil reservoirs, accurate mathematical modelling of the reservoir for three-phase flow (gas, oil and water), becomes nowadays a primary requirement to determine the optimum production policy for maximum ultimate oil recovery. Unfortunately the accuracy of such models to predict true reservoir behaviour is severely limited by the accuracy of the mathematical model with respect to the description of the reservoir geology. Generally only a very limited data-set is available to describe the geology of the reservoir, i.e. well logging data, limited well core data, and seismic data, limited by the maximum meaningful frequency of the seismic reflections recorded at the surface. This severely limits the detail of the reservoir geology that can be seen in the »interwell area» between the production wells. Modern seismic techniques, both in acquisition, such as Vertical Well Profiling, where the geophones are situated inside the wellbore, and in the development of seismic interpretation systems such as INTEGRATE (Jason Geosystems, Delft) and INTERWELL (Institut Franais du Pétrole, Rueuil Malmaison), which attempt to improve the seismic resolution and to make a forward prediction of certain well-logging features away from the wellbore, are some of the means to improve this situation. Another technique, stochastic modelling of the geology of the oil reservoir, within the constraints of the known data, on the basis of accurate descriptions of geological environments observed in nature, mainly from surface outcrops, is nowadays frequently used to predict the geological architecture of the fields' interwell area.

The importance of an accurate description of the reservoir geological architecture for three-phase flow must not be underrated. Local trapping of associated gas under pressure depletion conditions may cause this ancient primary production process to be much more efficient, whilst the reservoir geological architecture causing this phenomena (e.g. tidal crossbedded deposits) may cause oil and gas pockets to be by-passed by a waterdrive under pressure maintenance conditions. Ignoring this occurrence could render the comparative economics of pressure maintenance under waterdrive against natural depletion completely invalid. Certain reservoirs would benefit from enhanced gravity drainage techniques, rendered possible through the advent of improved horizontal drilling techniques and completions of horizontal wells, etc.

A very accurate description of the reservoir geology in the interwell area, as required for oil reservoirs, is not so very important for an accurate prediction of production behaviour of natural gas reservoirs. The flow in the reservoir is principally single-phase and the most efficient recovery process is by pressure depletion. Under these circumstances the exact description of minor geological features of the interwell area of the reservoir is of no great consequence. It would seem that this is not the case for retrograde condensate fields, where under pressure depletion conditions a two-phase flow regime will develop. However the optimum recovery of the retrograde condensate would require, at least initially, maintenance of reservoir pressure above the dew point and cycling of the reservoir gas by reinjecting the produced gas dry, after liquid recovery in the surface facilities. The economics of this (seconday) recovery method are however doubtful if there exists a ready market to take all the produced gas after processing.Moreover under pressure depletion conditions re-evaporation of the condensate liquid phase would eventually occur and virtually all the hydrocarbon components of the retrograde condensate gas field would eventually be recovered, be it for the heavier componants only during the later stages of depletion. Again, under these conditions an accurate knowledge of minor geological features in the interwell area of the reservoir would make little difference to the ultimate recovery.

A further, more detailed, description of natural gas field performance under pressure depletion conditions can be found in an earlier publication by the author (1).

Wellcompletions

The wellcompletions of producing gas wells are frequently more elaborate and costly than for producing oil wells. This is caused by a combination of factors:

— *High initial production rates combined with the volume increase of the gas when it rises to the wellhead, requires large diameter well tubulars, in order to reduce pressure losses and to mitigate the corrosion caused by high gas velocities inside the tubulars.*

— *In view of the high open-flow potentials of the gas wells (i.e. the maximum rate of production the well would attain at zero well bore pressure), thorough protection measures for the prevention of well blowouts are required. These entail the installation of downhole safety valves, which will operate safely under severe conditions, and should have a large internal diameter in order not to unduly restrict the wellpotential. This requires in turn a secure attachment of the production tubing to the well casing (the production packers), which will not fail under maximum possible differential pressure. Moreover one needs the installation of permanent well killing facilities and the possibility of downhole circulation of killing fluids (through sleeves or break-plates inserted in the lower end of the tubing), in oder to be able to kill the well rapidly (if not automatically) in case of an emergency.*

— *Because of corrosive non-hydrocarbon components and the inevitable presence of water in the wellbore, wellhead injection of corrosion inhibitors are required, and sometimes the installation of tubulars with internal non-corrosive coatings.*

— *Because of the high inflow rates into the wellbore, sand production is likely to occur. This will interfere with correct operation of the wellcompletion hardware (safety valves, circulation sleeves, mandrels etc.) and cause internal corrosion. The inflow of sand must therefore be avoided. This calls frequently for the application of special sand exclusion techniques during wellcompletion operations.*

— *Because of the low density of the gas very high wellhead shut-in pressures can be expected, which require high-pressure wellhead equipment. Wellheads should moreover be fire resistent, if wells are drilled at a close surface spacing, such as in cluster development on land and, because of restricted space, on offshore platforms.*

(1): JOURNAL OF THE INSTITUTE OF PETROLEUM, VOLUME 54, NUMBER 531-MARCH 1968 ; Planning of Optimum Production From a Natural Gas Field by J. VAN DAM.

This and many more requirements rendered the completion costs of gas wells considerably higher than that of oil wells in the sixties and seventies. Nowadays these differences have largely disappeared, especially in the case of offshore oil field development, where the requirements for oil and gas wells are basically the same.

Natural gas processing facilities

Natural gas processing facilities at the surface are required to condition the gas before it can be delivered to customers and/or transported from the field. The nature and complexity of the processing facilities therefore depends on the gas quality required for the facilities downstream of the field. This will include customers' metering facilities, (trunk)pipelines, process plant (e.g. LPG, LNG, methanol, middle-distillate),electrical powerstations etc.

In the most simple case, where the natural gas is sold (or fed) to a plant for further processing, the field treatment facilities can be restricted to those absolutely necessary for transportation to the plant and for accurate metering of the delivered natural gas (for fiscalisation, royalty and commercial purposes). This entails in any case the removal of free liquids (condensate and water) and to some degree a lowering of the water dewpoint, to prevent water condensation and possibly hydrate formation in the metering facilities, pipe transportation system, and plant. The presence of non-hydrocarbons (CO_2 and H_2S) may call for more elaborate facilities to prevent corrosion. In the sixties and early seventies no special measures were taken for the presence of small quantities of CO_2 in the gas; at that time it was believed that below a minimum CO_2 partial vapour pressure in the gas, no sweet corrosion would occur. Subsequently this so-called threshold level was found not to exist; CO_2 corrosion would occur over time, even at very low partial CO_2 vapour pressures. This caused the need for an expansion of the field processing facilities, in order to obtain a more rigorous water dew point control, either by low temperature glycol drying (if wellhead pressures were high and a pressure drop could be used to lower the gas temperature) or by a glycol dehydration system, where the water present in the natural gas would be absorbed by the glycol. In both cases this requires the installation of glycol regeneration plant, where the absorbed water is removed by evaporation from the glycol. For this purpose heat generation facilities (boilers) must be installed, which adds a complication to offshore platforms due to the presence of gas burners on the platform.

In the case of sour gas, even more elaborate field facilities are required, particularly if the wellheadstream is rich in heavier hydrocarbons and water and condensate drop-out must be avoided in the pipeline system.

In case the field gas is to be delivered into the buyers trunk gas transport system, the quality requirements of the delivered gas are a contractual matter and shall meet the contractual specifications. These are generally much more severe, than those required for field use. They include delivery pressure and temperature, limits for heating value, wobbe index, hydrocarbon composition, water and hydrocarbon dewpoints, inert gases (N_2, A, He, etc.), oxygen, CO_2, sulfur, other impurities (glycol, methanol, dust/solids, etc.). The size and complexity of the field treatment may vary from relatively simple facilities (Groningen gas field where initial high wellhead pressures made low temperature glycol drying very efficient) to the very elaborate systems built in North Sea fields recently. However modern subsea pipeline technology, which renders two-phase flow over large distances and in large volumes possible, has reduced the quality equirements at offshore locations, and made it possible to install the processing facilities required for meeting customers' natural gas quality specifications onshore. Thus it has been possible to reduce topside weight and complexity of offshore natural gas processing facilities considerably.

Natural gas pipelines

As already indicated in the previous paragraph, there has been a considerable technological progress in gas transport by pipeline in recent years, by allowing two-phase flow conditions in the lines. In the early years of offshore gas field development it was the policy to restrict the amount of offshore processing plant to the absolute minimum. As in these days the danger of sweet (CO_2) corrosion was not yet recognised in the case of natural gas with a very low CO2 content, the only necessary provisions for conditionning the natural gas before entering the offshore pipeline were, removal of the free water from the gas stream, and the injection of methanol (or glycol) for the prevention of hydrate formation. The required facilities on the platform were thus a large high pressure water/gas separator, for the recovery of free water and some condensate, and facilities to separate the condensate from the water, and to re-inject it in the pipeline, and facilities to dispose of the produced water. Effluent quality requirements in these days were such, that a relatively simple treatment of the produced water was sufficient, before disposal offshore. In addition methanol was injected into the gas pipeline, in order to suppress hydrate formation, until the natural gas reached the onshore process facilities. In order to provide the production platform with a sufficient supply of methanol, the methanol (partially) recovered in the onshore processing plant, was returned to the platform through a pipeline, laid «piggy-back» together with the gas pipeline. This solution was selected in 1968 for the Leman gas field operated by Shell Expro U.K.

Inevitably a drop-out of liquids (water and hydrocarbon condensate) would occur in the gas pipeline, and slugs of liquid would build up, which would cause periodically the arrival of large slugs of liquid at the onshore facilities. In order to receive these without causing danger for and interference with the gas processing plant, slug catchers, i.e. fairly large-sized separator vessels would need to be installed at the entrance end of these facilities. These vessels, which should withstand the maximum pipeline pressure, are very heavy-walled and costly. In order to reduce their size, the slug size which could build up in the pipelines needed to be reduced. For this purpose frequent pigging of the pipeline was necessary, which is operationally inconvenient.

Gas transportation trunklines, both onshore and offshore play a vital role in the commercialisation of gas fields, be it that they are the link to the ultimate customer (who uses the natural gas for household, industrial purposes or power generation) or to a gasplant for further processing prior to delivery to the final customer (e.g. LPG, LNG, methanol, middle-distillate, etc.). They represent in nearly all cases a very high initial capital investment, which has a major bearing on the profitability of gas field development.

It is therefore not surprising, that when the dangers of sweet (CO_2) corrosion were better understood, the quality requirements for natural gas entering these capital intensive facilities became ever more severe. Ultimately the natural gas entering such systems had to meet very stringent quality conditions in order to avoid internal corrosion of the lines.

The occurrence of free water and condensate in the pipeline had to be avoided at all likely combinations of pressures and temperatures in the system. This called for rigid dewpoint control of the natural gas where it leaves the processing facilities and narrow allowances for non-hydrocarbon components and other impurities. This in turn resulted in very elaborate field facilities and hence in more intensive manning of the offshore platforms for operation and maintenance. As a result the offshore facilities became very large, and complex through lack of space. The intensive manning required, increased further due to recent social trends aiming at a reduction of offshore working hours. This, combined with increasingly more severe safety requirements in the wake of recent offshore mishaps resulted in very spacious and extensive living accomodation, and multiple safety and life saving equipment, and hence to spiralling cost increases for each additional processing requirement.

In order to reverse this trend, industry tried in the eighties to reduce offshore gas quality requirements, by allowing, initially minor, amounts of liquid drop-out to occur in offshore pipelines. As a consequence it became neccessary to obtain a better understanding of two-phase flow conditions in pipelines, and to be able to cope with larger slugs of liquid building up in the pipeline. Fundamental and experimental research on the design of slug catchers at the onshore end of the line resulted in a rapid improvement of slug catcher design. In the beginning a slug catcher was simply a very large-sized separator, capable of receiving large slugs of liquid without liquid carry-over, and the size of such slugs was limited by frequent pigging of the line. Examples are the Bacton receiving facilities of Leman field and those at the Brunei LNG plant in Brunei.

Increased experience with two-phase flow combined with the results of research in slug catcher design resulted in ever larger slug sizes being possible and a reduction of complicated and operationally inconvenient line pigging operations. The slug catcher itself became in the process a very large and costly facility, the more so, since it had to be build at pressure vessel specifications and had to withstand the highest pressure ever expected in the offshore line. The progress made through the eighties might be seen in Den Helder (N.A.M.), Bintulu (Sarawak Shell) and St Fergus (Shell Expro), where successively slug catchers of ever increasing size were built.

In order to prevent corrosion of the natural gas lines and hydrate formation, it was however necessary to inject hydrate preventors (methanol or glycol) and corrosion inhibitors into the wellstream, of which only part could be recovered in the onshore facilities, and which might lead to quality specification problems for the delivered natural gas to customers. The most common hydrate suppressor is glycol, which acts also as an inhibitor for sweet corrosion, due to its capacity to absorb large amounts of water. The effectiveness of this absorption process is adversely affected by the presence of hydrocarbon condensate in the line, which may shield the glycol from the water droplets formed through condensation of water at the upper side of the line. Under certain flow regimes this may much reduce the glycol/gas-phase interface and render the corrosion protection of the line less effective. Recent research of this problem has resulted in a specification of design and operating criteria where this problem can be reduced to manageable proportions.

As a result of these modern developments in slugcatcher design and corrosion protection for major offshore natural gas lines, it was made possible to re-design the natural gas field processing facilities of the Troll field in Norway so that minimum natural gas treatment would occur offshore, i.e. restricted basically to free water knockout and glycol injection facilities, like those adopted for the Leman field in 1968. Equally so, the platform is supplied with (glycol recovered after onshore re-generation), through a piggy-back line which will be installed together with, and tied to the natural gas trunkline. Together with the installation of an automated drilling rig, further reducing the manpower requirement at the platform, this results in a very large reduction of deck weight, from 41.000 tons to 15.000 tons. Industry practice clearly show the scales to tip in favour of two-phase natural gas transport.

Markets for natural gas

In order to render development of natural gas fields economical, especially if they are situated at some distance from major users of natural gas, a substantial and profitable market must be indentified for the natural gas to be produced. Moreover firm sales contracts covering a substantial portion, if not all, of the reserves must be concluded, before making the large investment decision to develop the field and to build the gas transport facilities needed to deliver the natural gas to that market.

The market must both be substantial and profitable. This means that many users of natural gas must be identified within a limited area, and that the use of natural gas as compared with other fuels must have ertain advantages, e.g. in flexibility of use, reliability of supply, price, and environmental constraints.

The premium market for natural gas is domestic use, where the price of the alternative fuel is highest, and were flexibility and security of supply are its major attractions. This is the use of natural gas for cooking and space heating in private homes. However substantial markets for this purpose can only be found in densily populated countries, with major urbanised areas. The distribution of natural gas to individual households is generally carried out by public or private utility gas-distribution companies, either already in existence for the production and distribution of city-gas, or to be newly created for the purpose of distributing natural gas. These utilities are generally the end-users of natural gas as far as the production company is concerned, and gas supply contracts should be concluded in principle with these utilities individually.

There remains however an important drawback to this domestic market; the demand for gas by the individual household is not constant and is subject to large variations, daily, weekly and seasonally, particularly if the natural gas is used for space heating. The average daily demand for the calendar year, expressed as a fraction of the maximum demand in any one day, the «loadfactor», may be as low as 15% and generally varies between 15% and 25% with an average of 20%. For the producer of the natural gas field, this is not very economical, since he has to invest in production capacity equal to the maximum demand the utility company may make (contractually) during any one day of 24 hours, the so-called Daily Contract Quantity (DCQ).

There are two solutions to this problem, either negociate with the utility company a higher minimum loadfactor or contract gas sales also to other customers, who have a more constant demand (with higher loadfactors). The utility company can accept higher loadfactors, if it invests in so-called «peakshaving» facilities, in fact smaller or larger storage facilities for natural gas, from which short-period deliveries are possible at high rates. This investment must of course be recovered from a lower price to be paid for the purchased gas. As always this results in an economic trade-off between natural gas producer and the utility company.
The alternative solution is to find customers with a higher demand loadfactor for natu-

ral gas. The first in this category are base load power generation plants. These may have a large yearly demand with loadfactors ranging between 60% and 80%. Even electric peak-load plants command higher loadfactors than domestic use, usually from 30% to 50%. Large industrial fuel users have loadfactors from 40% to 80%. The inclusion of a fair share of these customers in the package of natural gas sales contracts will result in an overall higher loadfactor, but the drawback will be an overall lower average price for the natural gas since the alternative fuel displaced will be heavy fuel oil or coal. A premium in this market is however available, if the customers are situated in areas with stringent stack-gas regulations in order to prevent air pollution. Such areas are found all over Europe and in the Tokyo Bay area of Japan, where natural gas supplies command a high premium over the alternative fuel.

Other, price wise as well as loadfactor wise, very attractive customers for natural gas, are chemical companies which use natural gas as a feedstock. The alternative supply is light crude-oil fractions ex-refineries and or LPG ; the load factor is high, 70% to 90%. The drawback is that very lean natural gas is not a very attractive feedstock, except for methanol and middle-distillate plants, but the price that can be afforded by those plants is much lower, since in these plants the thermal efficiency is low, about 60%-65%. The most economic location for such plants is therefore at the input end of large natural gas export pipelines or near LNG plants, where the alternative price for the natural gas is much lower than at the final customer end. The total demand for such contracts is at present not yet very large, but this may rapidly increase in the future if demand for crude oil alternatives rises.

Contracts for the sale of natural gas

One of the principal economic features of natural gas field development, is the substantial market required for development of major natural gas fields situated outside Western Europe and the USA and at a considerable distance from a natural gas market. This requires the construction and installation of long and large diameter pipeline net works, if the natural gas can be transported overland, or the installation of natural gas liquefaction plants (LNG plants) if the market is overseas. These represent very large investments, hence the necessity of concluding natural gas sales contracts, resulting in as high a minimum loadfactor as possible, well in advance of the investment decision. The Government consent and necessary (planning) permissions to lay large diameter lines, or build LNG plants, and for the landing of LNG by tanker to receiving and re-gasification facilities in the harbour at the point of destination, require moreover long lead times and maybe held up for long periods, if there is opposing action. Even in Western Europe major gas field development of the past, such as Lacq and Groningen, both situated on land, and of all the later offshore fields in the North sea and the Norwegian sea fall into this category.

Here we see the major difference between the development and production of an oil field and that of a gas field. Crude oil can be marketed all over the world, and the timing of conclusion of oil sales contracts is ad-hoc, close to the time the oil is produced. The investment decision to start the development of an oil field is therefore based uniquely on the economic merits of the field, i.e. on its reserves, its productivity and its development costs. The assumption regarding the sales of the product is, that it will all be sold at a price, and the estimate of future sales prices is based on scenarios of future oil supply and demand. Procedures for obtaining the permission to proceed, are laid down in concession or production agreements beforehand, and do not require in general excessive time to obtain.

To the contrary, the development decision for a natural gas field must be based on the conclusion of a gas sales contract or a series of such contracts. Here we can distinguish between two basically different types of contract : a «dedication (or depletion) type» contract and a «supply type» contract.

In the dedication (or depletion) type contract, the total reserves of the natural gas field are sold under one contract to the same customer, in other words all the fields reserves are dedicated to him, and this customer is obliged to ultimately deplete the field. Those types of contract are concluded for small and middle-large single fields, where a single customer (e.g. a large natural gas distribution utility) accepts all the produced natural gas in his system, but has also alternative sources of supply, to balance the total demand from all his customers. The dedication type contracts demand accomodation from both sides. The producer will need to respect to a certain extend the buyers' wish for a constant rate of annual supply over as long a period as possible. The buyer needs to understand the producers wish to deplete his field as rapidly as possible. Any natural gas field can produce at a constant rate only over a limited period of time, this period being shorter if maximum offtake rates are higher. Thereafter inevitably a period of declining production rates sets in. A trade-off will again have to be made between producers and buyers requirements, at a price!

Moreover in the case of natural gas field development the producer will try to keep his initial investment, prior to the conclusion of a sales contract, as low as possible. As a consequence the exact size and reserves of the field will not be accurately known until after development starts, as appraisal drilling will be limited. Hence the need for the producer to have contractual arrangements, depending on natural gas reserves determination and subsequent re-determinations, to nominate higher or lower annual offtake rates, and to be able to adjust the contracted «Daily Contract Quantity» (DCQ). Also the start of the production decline period of the field needs to be nominated, depending on the remaining natural gas reserves at that time. Because of this required flexibility by the producer, the buyer needs to have the right of auditing the reserves (re-)determination, and arbitration proceedings need to be agreed in case of disagreement on the correct figure. The buyer will also require for himself some flexibility in nominating higher or lower contractual quantities. His main obligation remains however unaltered, he is obliged to take over time all of the natural gas fields' reserves.

The close contractual relationship between field development and natural gas delivery obligations, removes much of the flexibility of natural gas field development, once the natural gas sales contract has been concluded. In fact the producers options are highest during the natural gas sales contract negociations, and this stage is particularly important for the ultimate economic results of the natural gas field development. As is the case for an oil field, an estimate of future energy prices is an important assumption entering the economic evaluations. In order to protect producer and buyer alike, price indexation provisions are normally entered into the contract in order to allow the purchase price for the natural gas to follow to a larger or smaller extent the market for the alternative product (e.g. crude oil, middle-distillates, fuel oil and coal).

In a supply type contract, the natural gas producer accepts the obligation to deliver, and the buyer the obligation to take, a fixed quantity of natural gas over a number of

years. This far more stringent obligation can be accepted by the producer, if he has a very large reserve of natural gas either situated in a single large field, or in a number of fields from which he can supply. As in the case of a dedication type contract, there are provisions for some flexibility, mainly from the buyers' side, to nominate additional sales volumes and corresponding daily contract quantities. The producers (sellers) flexibilities are much reduced, and particularly the quality specifications are more severe, since the source of the natural gas, contrary to a dedication type contract needs not to be specified. In the latter contract these are tied to the likely specifications of the natural gas produced from the dedicated field. In the supply type contract they may be related to a specific major source of the natural gas to be delivered (e.g. »Groningen quality gas») but not necessarily to any specific field. Since the seller has less flexibility in his delivery obligations, supply type contracts command higher prices.
As in the case of dedication type contracts, price indexation provisions are included to protect both buyer and seller against future fluctuations in energy price levels, so that both the buyer will be able to sell his natural gas to tthe market, and seller that he will continue to obtain the best possible price.

The matching of a set of supply type contracts to the optimum production profile of a natural gas field is an important task for the seller and producer of the natural gas. This was the subject of an earlier and more technical publication by the author of this paper in 1967 (1) , and although published over some 20 years ago, its major conclusions are still valid. The very close inter-relationship between natural gas field development and its market is the most marked difference between oil and natural gas field development. This is also true, and possibly even more so, in the case of LNG transport to the customer.

Liquid natural gas

Special attention should be given to those natural gas reserves located in countries from which natural gas transport by pipeline to the market is not feasible because of technical reasons (deep seas,oceans), or economic costs, or political constraints. Natural gas exports from natural gas fields in the Far East and Australia are all in the form of Liquified Natural Gas (LNG), which is sold under a number of supply type contracts mainly to major natural gas distribution utilities or electricity generating companies in Japan. Although each natural gas field supplying the LNG plant is virtually dedicated to that plant, the natural gas sales contracts are no dedication type contracts. In view of the very large investment required for the construction of the LNG plant and for the fleet of (dedicated) LNG tankers, the package of natural gas sales contracts needs to be closely matched to the plants' design capacity and expected economic life. The same applies to the fleet of LNG tankers providing the link between LNG plant and the market.

The natural gas therefore needs to be sold under a number supply type contracts of relatively long duration, with the flexibility to match the ultimate sum of Daily Contract Quantities sold under these contracts to the maximum LNG system capacity, if the combined plant and tanker performance proves to have a capacity higher than the design capacity. This is frequently the case due to de-bottlenecking and/or minor expansion.

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(1) see footnote on page 7

The natural gas field(s) dedicated to the LNG project, need to be developed in the most economic fashion to match the requirements of the LNG supply contracts. This not only calls for the most economic individual field development, but also for optimisation of the sequence in which fields will need to be developed, if the natural gas supplies are to come from numerous fields. Examples are the development of the natural gas fields offshore Sarawak (Malaysia) and those onshore in Nigeria. In the latter case the development of the natural gas fields proper, should also be tied in with the maximum economic utilisation of associated gas production tied to the production of crude oil.

The complexity of the most economical matching of natural gas field performance, LNG plant performance, that of the dedicated LNG tanker fleet and the ultimate natural gas market, is at its maximum in the case of LNG export projects, and requires a very good overall coordination of the project. The economics of such projects, requiring very sizable investments in field development, plant , vessels and equipment, require a secure and profitable market, to which sales contracts need to be secured prior to the project authorisation by investors and financing institutions. The required investments are so large, that in virtually all cases these cannot be secured from equity capital of the producer, and financing agreements with banks and other finantial institutions are a frequent requirement, before the project can proceed.

Also because of the very high initial investment and the long duration of such projects, overall project agreements require many partners and the close involvement of the Government of the natural gas producing country and of financing institutions. It is not surprising that such projects in general take a very long time to conceive and conclude, and it is not infrequent that a decennium passes between the discovery of the natural gas field and the go-ahead for the project, and in addition some 5-7 years before the start of production. As a consequence a very realistic view is required of future developments in the energy market, and a considerable courage of the equity investors in case present overall project economics calculated on the basis of low crude oil prices ($ 12-15 per barrel) are meager.

Nevertheless the longterm security of a considerable annual cashflow from a natural gas project once it is underway, through the working of rather rigid supply type natural gas sales contracts, including indexation clauses to ensure that the price of LNG closely follows developments on the energy markets, encourage many producers to take the risk of a decision to develop. This is not only the case for LNG projects, but also for major offshore development projects such as the Troll field in Norway. It is a decision far more difficult to take, than in the case of oilfeld development, and this is brought out in practice when one reviews all the major natural gas development projects that have seen the light since the early sixties.

Conclusion

This paper has reviewed in some larger perspective some of the technical requirements, that differentiate oil & gas field development. It is clear that the most important differences between the development of a crude oil or a natural gas project stems from commercial considerations, linked to the very important investments required to transport natural gas from its source to the market. From the brief overview given of the many prior considerations, that enter into the preparation of a project to develop major natural gas reserves, it is clear that a decision to proceed with such development takes in general a decade or more subsequent to discovery of such reserves.

The advent of modern technologies to produce liquid hydrocarbons from natural gas through gas synthesis processes, does not yet make much difference to this dilemma, since investments for these plants are large, and thus require large capacity projects and relatively low natural gas prices for its feedstock, which can only be obtained at locations sufficiently remote from major natural gas markets. Eventually economics of these modern developments will become comparable to these of LNG projects, be it that their complexity in overall project coordination will be much less. The liquids produced from such plants will not need such specialized means of transport as LNG and no long term prior sales contracts. If the economics of natural gas synthesis improve through further technical experience, continued research and improved design, this may become a major and new perspective for the future development of natural gas resources, located at large distances of major natural gas markets.

Buchbesprechung

Deep structure of the Alps

F. Roure, P. Heitzmann & R. Polino, Editors

Societé Göologique de France, Mémoire no 156
Société Géologique Suisse, Mémoire no. 1
Società Geologica Italiana, Volume speciale no 1

Der voluminöse Band (368 Seiten) der drei geologischen Gesellschaften fasst den aktuellen Stand der Tiefenstruktur-Forschung in den drei Ländern zusammen; die 29 Artikel sind denn auch vor allem durch Mitarbeiter der drei nationalen Programme (ECORS in Frankreich, NFP-20 in der Schweiz und CROP in Italien) verfasst worden, ein Artikel betrifft die Ostalpen. Durch die Unterteilung in sieben Gruppen wird die Fülle der Artikel gut strukturiert, man findet dabei folgende Gliederung: (1) Einführung, (2) Methoden und physikalische Kennwerte, (3) Geophysikalische Resultate, (4) Alpines Vorland und externe Westalpen, (5) Interne Westalpen, (6) Zentral und Südalpen, (7) Vergleiche und Synthesen.

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