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# THE USE OF CALCULATED DENSITY ON AN OFFSHORE HIGH PRESSURE WET GAS METERING SYSTEM

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## SUMMARY

The paper details an investigation into the use of calculated density on an offshore high pressure wet gas metering system. The condition of the gas at the metering system, including the presence of water and methanol, is considered for a typical wellstream and minimum process system. Likely changes in gas composition are calculated and the methods currently used for obtaining gas composition are reviewed. Data from offshore chromatographs is used to estimate the uncertainty in gas composition. The methods available for the calculation of density are reviewed, with consideration given to the inclusion of water and methanol and the high operating pressure. The uncertainty of calculated density is estimated using the uncertainty of the gas composition and methods available to calculate compressibility.

## NOTATION

$\rho_1$ = Calculated upstream density ( $kg/m^3$ )

$Z_1$ = Compressibility at line conditions

$Z_b$ = Compressibility at base conditions ( $P_b$ & $T_b$ )

$P_1$ = Upstream measured pressure (barA)

$P_b$ = Pressure at base conditions (1.01325 barA)

$T_1$ = Upstream temperature (°K)

$T_b$ = Temperature at base conditions (288.15 °K)

Mw = Molecular weight of the gas ( kg/kmol )

R = Universal gas constant (bar $m^3$ kmol K)

## 1 INTRODUCTION

In the Southern Basin of the North Sea calculated density is used on offshore 'wet gas' metering systems because live measurement, using conventional vibrating element densitometers, has proved to be unsuccessful due to liquid contamination.

On earlier metering systems density was often calculated from the live measurement of Real Relative Density (RD), Pressure and Temperature with Compressibility (Z) and Base Compressibility ($Z_b$) obtained from sampling.

$$\rho_1 = \text{Real RD} * \text{Density of air} * \frac{P_1 * T_b * Z_b}{P_b * T_1 * Z_1}$$

The density of air is also at the same base conditions as $P_b$, $T_b$ and $Z_b$.
In essence the Molecular Weight (MW) is measured by the live measurement of RD with Z and $Z_b$ calculated from a fixed composition that is manually entered into the flowcomputer system. The accuracy of this method is dependent on the change in gas composition and the frequency of sampling.

With the introduction of gas chromatography on offshore metering systems density is now calculated from live measurement of pressure and temperature with the MW and Z calculated from the most recent chromatograph analysis.

$$\rho_1 = \frac{P_1 Mw}{R\,T_1\,Z_1}$$

## 2 THE WELLSTREAM

In order to establish the condition of the metered gas stream, and any possible variations in the gas composition, a typical gas reservoir wellstream and process facility was considered. The reservoir contains gas, liquid hydrocarbons (condensate) and water. The produced wellstream, although mainly gaseous, is at its hydrocarbon and water dewpoints and is likely to contain some free water. The composition of the wellstream depends on the equilibrium conditions in the reservoir and hence pressure and temperature. Due to the drop in pressure and temperature at the wellhead condensate will be formed in the wellstream. This is best illustrated by the phase envelope, which for the typical wellstream is detailed on Figure 1.

The bubble point and dewpoint lines are calculated from the wellstream composition. The shape and location of the phase envelope changes with composition but not pressure, temperature or flow. The C7+ components have a significant effect on the dewpoint curve of the phase envelope. $CO_2$ and $H_2S$ lower the cricondenbar. $N_2$ raises the cricondenbar whilst $H_2O$ does not have much effect except at high pressure and temperature.

## 3 THE PROCESS SYSTEM

In most gas/condensate reservoirs the wellhead condition is within the two phase region as shown on Figure 1. It is therefore necessary to separate the gas and condensate to allow the gas and condensate to be individually metered and the flow from the reservoir controlled. A typical process system is detailed on Figure 2.

The wellstream from individual wells is controlled by a choke valve before entering the production manifold. Methanol is often injected into each wellstream to prevent the formation of hydrates.

The wellstream leaving the production manifold enters a separator, often three phase, where gas, condensate and water are separated. The gas and condensate streams are metered before being commingled, sometimes with the water, for transportation to shore. The separator is often operated over a range of pressures depending on the pipeline operating pressure. The pressure drop across the choke valves will result in a drop in gas temperature. Due to the process of separation the gas leaving the separator is at its dew point and the condensate at its bubble point.

The ratio of gas to condensate varies with different separator operating pressures and temperatures and is indicated by the position in respect to the quality lines, as detailed on Figure 3. For the typical wellstream the normal wellhead conditions was between 98% and 99.8% vapour. As the ratio of gas to condensate varies the gas and condensate compositions will also vary. The quantity and composition of both gas and condensate streams were obtained from 'flash calculations' at the separator operating pressure and temperature.

## 4 VARIATIONS IN GAS COMPOSITION

From the typical wellstream composition and separator operating conditions a series of flash calculations were performed, using the 'Hysim' process simulator, with the Soave, Redlich, Kwong equation of state. The short term changes in gas composition and possible errors in density are detailed on Figure 4. The resulting gas composition at the typical operating pressure and temperature of 130 Bar , 30 °C respectively was used as the base case. Further flash calculations were performed at 10 Bar intervals, with the corresponding drop in temperature. In each case the true density was calculated from the resulting gas composition at the pressure and temperature. The possible error in density was then calculated by comparing the true density with the density calculated from the base composition at the operating pressure and temperature. As shown the gas composition did change with separator operating conditions , particularly the C5+ components. For a change of 10 Bar the error in calculated density was 1.2 % if the composition is not changed in the calculations.

The typical wellstream used has a Condensate to Gas Ratio (CGR) of 1.92 Barrels/MMSCF. CGR's for other gas/condensate fields vary between 1 to 6 Barrels/MMSCF. The variation in gas composition due to changes in separator operating conditions did not appear to be directly related to the CGR.

It can therefore be concluded that for a 'single reservoir' there are two causes for changes in gas composition :-

a)The longer term change as the reservoir depletes and the pressure drops. The change in equilibrium between the gas and condensate in the reservoir will result in a change in wellstream composition. This change is, however, relatively small and slow.

b)The short term change due to different separator operating conditions, which in this case did cause a change in gas composition significant enough to introduce an error in calculated density.

There are also fields that consist of a number of small individual reservoirs where individual wells produce wellstreams of different compositions. For both single or multiple reservoir fields changes in gas composition can occur in the short term.

## 5 CONDITION OF THE GAS STREAM

Although the gas stream leaving the separator is at its hydrocarbon and water dewpoints it is the condition as it passes through the orifice plate that is of interest . Therefore the pressure drop along the pipework between the separator and the orifice plate was considered , at worst case with a flow conditioner installed in the upstream pipework.

An upstream pipe configuration of 20 metres of 12" pipe and 4 bends was used to calculate the pressure drop between the separator and the flow conditioner. The larger 12" pipe was used to minimise the pressure drop. The pressure drop across the flow conditioner was calculated using a pressure loss coefficient of 2.2. The resulting temperature drop was calculated assuming an Isenthalpic expansion. The pressure and temperature drop between the separator and the meter was calculated to be 0.153 Bar and 0.04 °C respectively.

Again flash calculations were performed using the 'Hysim' process simulator. The results detailed on Figure 5 show that although a relatively small amount of condensate was produced ( 0.0306 m3/hr, which is 0.0026% of the total flow) the calculated gas composition did not appreciably change. It is, however, not clear whether the condensate passes through the orifice in the form of a mist, droplets or as a liquid flowing along the bottom of the pipe, and therefore its affect on density.

The formation of condensate could be reduced by minimising the pressure drop by installing fewer bends and larger diameter pipe and installing lagging to prevent further heat loss by radiation. It could also be prevented by heating the gas which would result in additional plant and cost.

The amount of water produced was calculated and found to be insignificant.

As methanol is injected into the wellstream upstream of the separator to prevent hydrate formation the gas stream will contain water and methanol in the gaseous state.

### 5.1 WATER CONTENT

It is very likely that water will be present in the reservoir and therefore the wellstream. Any 'free water' will be removed in the separator. The amount of water vapour present in the gas from the separator will be dependent on the pressure, temperature and composition of the gas. As there is free water in the wellstream it was assumed that the gas is saturated with water vapour at the operating pressure and temperature and is therefore always at its water dewpoint. As detailed on Figure 6 at the typical operating conditions the water content of the gas was calculated to be 0.056 mol%. The error on calculated density when water is not included was calculated to be -0.1 % of reading.

Water content can be derived from sampling, on-line measurement or calculation/empirical methods.

### Sampling

A gas sample would be analysed for dewpoint/water content at an onshore laboratory using a direct method, probably the Karl Fischer or Dewscope (Chilled Mirror) method. A direct method has a direct relationship between the measured quantity and the water vapour content. The Karl Fischer method uses the titration of absorbed water vapour with iodine and measures directly the water content per unit volume of gas . In the Dewscope the chilled mirror is used to measure the temperature at which water condenses on its surface, as it is gradually cooled , and hence the water dewpoint of the gas.

The major problem with sampling is the precautions necessary to ensure that the gas sample is at the sampling pressure and temperature and therefore representative. The sample should not be contaminated with moisture from the atmosphere or any residual moisture present in the sample container before the sample is taken.

### On-Line Measurement

Most on-line water content measuring instruments use hygroscopic sensors that respond to the water vapour in the gas stream. Measurement is based on either Electrolytic, Capacitance, Mass Change (quartz crystal) or Conductivity principles. As the measurements are indirect, i.e. do not have a direct relationship with water content, calibration of the sensor is necessary. Calibrations are performed by either replacing the sensor with a pre-calibrated sensor or by calibration with a dry inert purge gas. The measurement accuracy can be affected by contamination of the sensors by $CO_2$, $H_2S$ and methanol present in the gas stream. It has suggested [1] that variations in gas composition can produce dewpoint measurement errors of between 2°C to 3°C with hygroscopic instruments.

Some on-line direct measuring instruments are available using the chilled mirror or automatic high pressure Karl Fischer methods. The chilled mirror instruments often have operational problems due to the contamination of the mirror by heavy hydrocarbons and other components present in the gas. The Karl Fischer instrument although automated, requires the reagents used to be constantly checked.

When measuring the water dewpoint it is necessary to perform further calculations to obtain the water content.

### Calculated Methods

The water content of the gas can be calculated from the gas composition using an equation of state. This is, however, a reasonably complex calculation that requires specialist software, which although available for off-line calculations is not available in flowcomputers for on-line calculations of water content. It is also questionable whether the amount, or effect of water content, would justify the cost of incorporating this type of software in a flowcomputer.

An empirical method for obtaining the water content of lean sweet natural gas is detailed in Gas Conditioning and Processing Volume 1 by John M Campbell [2]. It consists of a graph of water content versus water dewpoint for different pressures.

The water content in kg/$10^6$ std $m^3$ (100 kPa and 15°C) is converted to mol fraction of water yw using :-

$$yw = \frac{\text{water content kg}/10^6 \text{ std m}^3}{\text{MW water} * \text{kmol gas} / 10^6 \text{std m}^3}$$

$$yw = \frac{\text{water content kg}/10^6 \text{ std m}^3}{18 * 41740}$$

The likely error associated with this method is quoted as 3 to 5 %. There are further corrections to apply if there is $CO_2$ and $H_2S$ present in the gas.

An alternative method is that detailed in the paper Equilibrium Moisture Content of Natural Gases by R.F Bukacek ref [3]. The method uses the equation :-

$$W = A/P + B$$

where
W = the water content in pounds per MMCF (14.7 psia 60°F)
P = the pressure in psia
A = a constant proportional to the vapour pressure of water.
B = a constant depending on temperature and composition.

Values for A and B are given in tables for varying temperature. The equation is based on tests carried out on a series of binary mixtures and natural gases in the pressure range 69 to 680 Bar and at a temperature of 220°F. This temperature was chosen to ensure that the heavier hydrocarbons were kept in the vapour phase. However, the constants are stated for a temperature range of -40°F to 460°F although there is an element of doubt as to the validity of this correlation at temperatures below the critical temperature.

The results, obtained for typical operating conditions, from the Campbell and Bukacek methods are detailed below. As shown there is very little difference between the methods.

| Pressure | Temperature | Campbell | Bukacek |
|---|---|---|---|
| BarsA | °C | mol % | mol % |
| 130 | 30 | 0.059 | 0.056 |
| 120 | 25 | 0.044 | 0.045 |
| 110 | 20 | 0.037 | 0.036 |
| 100 | 15 | 0.028 | 0.029 |

### 5.2 METHANOL CONTENT

In the absence of offshore dehydration it is necessary to inhibit the formation of hydrates. Hydrates are formed by the combination of free water and hydrocarbon molecules into an ice like solid. The temperature at which hydrates form is dependent on pressure and gas composition. The higher the pressure the higher the temperature at which hydrates form. To suppress the hydrate formation temperature below the operating temperature either glycol or methanol is injected into the wellbore, or the wellstream upstream of the separator.

Methanol is most commonly used due to its suitability at low temperatures and its corrosion inhibiting properties but has one disadvantage in that it is volatile and is therefore distributed between the water, condensate and gas phases. The quantity of methanol injected has to be sufficient to compensate for this whilst maintaining the water/methanol concentration to ensure adequate hydrate suppression in any part of the system. This includes the wellbore, wellhead, separator, pipeline and reception facilities. It is often necessary to inject up to 3 times that required in the water phase to maintain the required methanol/water concentration. The amount of methanol in the gas stream is dependent on the pressure, temperature and methanol/water concentration and can be calculated, using methods such as that detailed in the GPSA Engineering Data Book [4] or be determined from sample analysis using chromatography [5].

On some wet gas systems a minimum of 25 weight % of methanol in the free water is used which equates to 0.4 mol% of methanol being present in the gas stream leaving the separator.

In the early years when the wellhead pressure is high hydrates could form in the wellbore or wellhead. It is, however, the conditions at the reception facilities that usually dictates the methanol injection rate during the rest of the field life. This is primarily due to the drop in temperature along the pipeline to shore. It was therefore assumed that the methanol content of the metered gas stream will be in the order of 0.2 to 0.6 mol% over the life of the field.

Although the methanol content is relatively small it is thought that methanol is detected by some gas chromatographs and is included in the C6+ peak. It was calculated that not including 0.6% mol% methanol in the gas composition used to calculate density would introduce a density error of +0.32% of reading.

## 6 METHODS TO OBTAIN GAS COMPOSITION

Currently there are 3 methods used to obtain the gas composition; spot sampling, automatic sampling and on-line gas chromatography.

### 6.1 SPOT SAMPLING

Spot samples are taken manually from a sample point located at a position that gives a representative homogeneously mixed sample. Samples are collected in stainless steel cylinders that have been thoroughly purged with line gas. The sample cylinder is then shipped onshore, usually to a recognised laboratory, for analysis. On receipt at the laboratory the cylinder is checked for leaks and placed in an oven, usually to soak for at least 24 hours at 20°C above the sampling temperature. A sample is then analysed in a laboratory chromatograph to provide an analysis to $C_{10}$. Samples can also be analysed to determine the water and methanol content.

## 6.2 AUTOMATIC SAMPLING

An Automatic Sampler collects a sample from the gas stream and passes it to a sample cylinder on a time or flow proportional basis. The sample is either 'grabbed' from the flowing stream, or collected from a sidestream, by a solenoid initiated sample valve. When full, or after a set time period, the sample cylinder is removed and transported to shore for analysis at an approved laboratory. Although the gas composition represents the average over the sample period it typically takes one month to collect the sample and one month to obtain the sample analysis. This delay is undesirable when using the gas composition to calculate physical properties. When sampling is used density is often calculated from the measured RD with Z and $Z_b$ calculated from the last gas composition. Although this does reduce the dependence on gas composition significant errors can still exist on calculated density.

## 6.3 GAS CHROMATOGRAPHY

A continuous gas sample is taken from the gas stream by a sample probe and conditioned before entering the gas chromatograph. The gas chromatograph consists of a sample injection system, a chromatographic column and detector as shown on Figure 7.

A precise volume of sample gas is injected into the column. The column contains a stationary phase, either an active solid (gas solid chromatography) or an inert solid coated with a liquid phase (gas liquid chromatography). The gas sample is transported through the column by a carrier gas. As the gas sample passes through the column the stationary phase retards the components of the sample. Therefore each component moves through and elutes from the column at different times. The separated components are measured by a detector that produces an electrical output proportional to the concentration of the component which is shown, as detailed on Figure 8, as a series of peaks on a chromatogram. The area under each component peak is proportional to the total mass of that component. Therefore the weight percent compositions are calculated from the area ratios on the chromatogram, or from the peak height.

The sample valve, column and detector are housed in a temperature controlled oven. To separate all of the components in a typical natural gas, and provide a fast response, multiple columns are often used. An analysis time of 7 to 8 minutes is typical for an on-line gas chromatograph. The analysis would include $C_1$ to $C_6$+, $N_2$ and $CO_2$.

The chromatograph is calibrated by routine analysis of a calibration gas of known composition. The calibration gas would be representative of the gas stream and be either gravimetrically prepared or sales quality line gas analysed at an approved laboratory. From the analysis of the calibration gas response factors, based on either peak area or height, are calculated for each component. The response factors are then averaged, depending on the number of calibration runs, and stored in the chromatograph. The component concentrations in each subsequent analysis is calculated from the response factor and the measured component area or peak height.

The use of gas chromatographs on offshore platforms has increased in recent years. However the major problem in using on-line gas chromatography on a wet gas metering system is the design and efficiency of the sampling and pressure reduction system.

It is necessary to reduce the sample from line pressure to between 1.0 to 2.0 Bar before introduction to the analyser. This large reduction in pressure is a potential problem as the drop in pressure and hence temperature would certainly result in the formation of condensate and water. This would result in a change in gas composition and hence physical properties and more importantly could contaminate the chromatograph columns causing failure and the need for lengthy maintenance.

To overcome the problem the pressure is usually dropped in multiple stages, introducing heat at each stage to keep the sample above the hydrocarbon dewpoint and the initial sample temperature, to avoid condensate and water drop out. The setting of the pressure regulators and the amount of heat introduced would be calculated to ensure that the sample temperature is always above the dewpoint line on the phase envelope as shown on Figure 9.

# 7 COMPARISON OF METHODS

## 7.1 ACCURACY

The accuracy of each method was investigated and the results shown on Figure 10. A statistical analysis of the gas compositions obtained by gas chromatography, spot and time proportional automatic sampling, on an onshore terminal and a number of offshore platforms was carried out. The standard deviation gives an indication of the degree to which individual component concentration vary from the mean. As shown the standard deviations are generally one order greater for sampling than gas chromatography. This indicates that the gas composition obtained from sampling varied more than that obtained from on-line chromatography.

Due to the long time period over which the samples were taken it is not clear whether the variance is due to the method or genuine changes in gas composition. Unfortunately it was not possible to compare data from all methods, for the same field, over the same time period.

It was assumed that for Field A the variance in composition was a result of the method as the field has very consistent physical properties.

The data from time proportional sampling and on-line gas chromatography was compared for Field B, which has a relatively constant composition. However data was not obtained over the same length of time. In order to establish a reference the gas chromatograph calibration data was used. The chromatograph performs daily three consecutive calibration runs. The first run is ignored and the mean of the second and third runs are used to update the response factors and hence calibrate the chromatograph. The mean of the second and third calibration runs, using the previous days response factors, are reported by the chromatograph. This is therefore an analysis of a sample of constant composition and over a period of time is a good measure of the long term stability of the chromatograph. As shown over a period of 4 months, the component standard deviations for calibration gas are small. The hourly averages over a day also gave comparable component standard deviations and it is assumed that separator operating conditions and hence gas composition did not change significantly during the day. The component standard deviations of daily averages from the chromatograph over a period of 4 months and the monthly automatic samples are significantly higher. The results therefore confirm that the gas composition did change with time. It also gave an indication of the stability of the gas chromatograph operating in an offshore environment which was confirmed by the data obtained from Fields E and F .

## 7.2 RELIABILITY

It is difficult to quantify and therefore compare the reliability between methods. It is fair to say that the reliability of a gas chromatograph or an RD analyser is primarily dependent on the design and operation of the sample system. The contamination of either device by condensate carried over from the separator, which does happen, is a potential problem which must be taken into consideration during the design of the sample system.

## 7.3 COST AND MAINTENANCE

Although spot sampling is the most cost effective and maintenance free solution it is unlikely that all parties would agree to this method being adopted. At the time of contract negotiation there is often only very preliminary well test data available to determine any likely variations in gas composition. It can be argued that even if the gas composition was constant, to verify it would require a high frequency of spot sampling. The method is not suitable if there are short term change in gas composition .

Automatic sampling has the disadvantage of high capital cost, the maintenance necessary to achieve the required reliability and the time taken to collect, transport and analyse the sample. This delay is undesirable, particularly when the gas composition is used in the calculation of physical properties.

The gas chromatograph has the advantage that an analysis is provided every 7 to 8 minutes and can be automatically transferred to the flowcomputer system for the calculation of physical properties and the daily composition for allocation. There is, however, a need for routine spot samples to be taken to define the split of the $C_6$+ component. Spot samples are typically taken every 3 months for this purpose.

The use of manual samples for obtaining water content is not really practicable due to the complex procedure and precautions necessary to obtain a representative sample. The cost of an on-line instrument, maintenance and calibration is difficult to justify. The use of calculated water content is normally adequate for most applications.

If present in sufficient quantities it was considered necessary to include methanol in the gas composition when calculating density. The amount of methanol injected into the wellstream is often measured for control purposes. The methanol content in the gas stream can be calculated for the likely flowrates, pressures and temperatures. The calculated data can be verified by the analysis of the spot samples taken to define the C6+ component.

# 8 THE FULL GAS COMPOSITION

A typical on-line gas chromatograph has the capability to calculate RD, CV, $\rho_b$ and $Z_b$ from the sample analysis. It does however have limitations primarily the breakdown of the C6+ components and addition of components not in the chromatograph analysis. The components not present in the sample analysis, in this case water and methanol, cannot be included. These limitations, although not likely to introduce large errors, combined with the need to calculate line density in each meter run often necessitates the transfer of data and further calculations not available in the chromatograph.

Modern chromatographs have the capability to communicate with host computers through a serial link. It is therefore possible to transfer both the normalised or un-normalised composition and alarms to the flowcomputer system. The favoured method is to transfer the un-normalised composition.

The un-normalised composition is then normalised to 100 - the sum of additional components not in the chromatograph analysis. This would include $H_2O$, CO, $H_2$, $H_2S$ and He.

The $C_6$+ component is then split into the ratios of $C_6$, $C_7$, $C_8$, $C_9$, $C_{10}$ & $C_{11}$ and where applicable methanol. The amounts and hence % split would be determined from occasional spot samples and along with water and methanol entered into the computer system as fixed values.

As each analysis is transferred from the chromatograph the full gas normalised gas composition is calculated and used in the computer system to calculate density.

## 9 UNCERTAINTY OF GAS COMPOSITION USING CHROMATOGRAPHY

As the gas chromatograph is in essence a 'comparitor', comparing sample gas with calibration gas it was assumed that the uncertainty in gas composition obtained from a gas chromatograph consists of a systematic uncertainty due to the accuracy of the calibration gas and a random uncertainty due to the repeatability of the chromatograph.

Calibration gas can either be gravimetrically prepared or sales quality line gas or a prepared sample analysed at an approved laboratory. In this instance the calculations are based on the use of a gravimetrically prepared calibration gas with manufacturers stated component accuracies. Ideally the calibration gas should contain the components present in the chromatograph analysis at the same levels as the sample gas.

To estimate the repeatability of a gas chromatograph in an offshore environment the data from a number of existing installations detailed previously was used as shown on Figure 11. It is assumed that the repeatability is the random uncertainty, both expressed at a 95% confidence level. The repeatability of each component was calculated using :-

Repeatability = Students t * Estimated Standard Deviation

where :-
Repeatability is in +/- mol%
Students t is at a confidence level of 95% and takes into account the number of measurements 'n'.
The Estimated Standard Deviation is calculated in accordance with ISO 5168 [6] 3.2.1.1.

The component repeatability from each of the offshore chromatographs were added in quadrature to give an overall estimated component repeatability. Individual results were ignored if the ratio of the lowest to highest value was greater than 2.0. The Field B Daily

Averages were also not used as the repeatability over that time period could not be solely attributed to the chromatograph.

The repeatability and systematic uncertainties were combined quadratically to give an overall chromatograph uncertainty for each component. The results are detailed on Figure 12.

## 10 CALCULATED DENSITY

When calculating line density it is necessary to calculate the compressibility factor Z at line pressure and temperature. Most of the methods available use an equation of state, with combination rules, to calculate Z and density. In some cases the full gas composition is used whilst other methods use a measured physical property, usually CV or RD, to characterise the hydrocarbon content of the mixture. The equation of state then uses the 'characterised' hydrocarbon content with the nitrogen and/or carbon dioxide content to calculate Z and density. In all cases the methods are derived from actual measurements of Z for given gas compositions within a pressure and temperature range. The extent and accuracy of the database on which the methods are based have a significant impact on the suitability and the accuracy of the method and have to be taken into consideration. For this application consideration was given to use at high pressures and the inclusion of methanol and water.

### 10.1 GENERALISED EQUATIONS OF STATE

A number of P-V-T equations of state have been developed that correlate to specific test data using empirical constants. Examples are Van der Waals, Benedict-Webb-Rubin (BWR), Redich-Kwong (R-K) and the Peng- Robinson equations of state.

There are however limitations on the ability of each of the methods to calculate accurately Z and density over a wide range of gas compositions, pressures and temperatures.

### 10.2 SPECIFIC EQUATIONS

The specific equations are based on accurate data which by regression methods is used to determine virial coefficient constants for use in Virial Equations. Virial equations are derived using statistical mechanics and consideration of intermolecular forces between gas molecules.

#### 10.2.1 AGA NX 19

In 1962 the American Gas Association (AGA) published the NX-19 Report [7] which calculates the supercompressibility factor $F_{pv}$ from a combination of specific gravity or calorific value and the carbon dioxide and nitrogen content of the gas. The compressibility factor Z is then calculated using :-

$$Z = 1/F_{pv}^2$$

The NX-19 calculation has been modified a number of times by users to suit specific gas compositions and is still in use. It is, however, generally limited to a pressure range of 0 to 80 Bar and a temperature range of 0 to 40°C. Examples are AGA NX-19-mod technique[8] for lean natural gases and AGA NX-19-mod/3H [9] for rich natural gases. Test results published in Gerg TM5 [10] show that the difference between the calculated Z and measured Z using the above methods for lean and rich natural gases can be as much as 0.8 and 1.0 % respectively at a pressure of 120 Bar.

In the 1980's it was recognised that a method was required to calculate compressibility over a wider range of pressures, temperatures and gas compositions. Projects were started in America by the Gas Research Institute (GRI) and in Europe by the Group Europeen de Recherches Gazieres (GERG) using a common database. The Americans headed by Professor Starling of the University of Oklahoma published two reports ( GRI Interim and GRI Final ) before final publication of the method in American Gas Association (AGA) Report No 8 1985 [11]. Although both GRI Interim and Final methods are available they have been superseded by AGA 8 1985 , which has become an industry standard. AGA 8, however, has recently been revised and AGA 8 Second Edition, November 1992 [12] published.

### 10.2.2 AGA 8 1985

The AGA 8 1985 report details the calculation of compressibility and supercompressibility factors for natural and other hydrocarbon gases over a range of gas compositions. Other components including water are mentioned and can be included without additional uncertainty provided they do not sum to more than 1 mol%. The characterisation parameters (energy, size and orientation) for the other components are included in the report. Although methanol is not mentioned it can be included with the binary interaction parameters U, V and W taken to be 1.0 . The size, energy and orientation parameters for methanol can be calculated using the methods detailed in the report and data readily available from other sources.

A primary method using the full gas composition is recommended for optimum accuracy. Live measurements of pressure, temperature and the full gas composition are therefore required.

AGA 8 1985 also includes five alternative methods that estimate the methane and other hydrocarbon components in the gas. The five methods use combinations of CV, RD, and mol fractions of carbon dioxide, nitrogen and methane. Method 1 requiring inputs of RD, carbon dioxide and nitrogen content appears to be the most practical option but has the disadvantage that there is additional uncertainty, which is not stated in the report. Water and methanol content are not included which also increases the uncertainty.

The uncertainty limits for the computation of supercompressibility against pressure and temperature are detailed for gas compositions within the stated range. For high pressure applications (130 Bar) the uncertainty in supercompressibility is +/-0.3%.

The uncertainty in computed compressibility factor is detailed in AGA 8 Section 8.3 on the basis of comparisons between computed and experimental compressibility for a number of natural gases. It states that as a general guideline the uncertainties in computed compressibility factors for most natural gases at typical pipeline conditions are expected to be less than +/-0.1%, provided the composition of the natural gas is known accurately. Uncertainties in computed compressibility factors are expected to exceed +/-0.1% in some instances (at pressures above 35 Bar) when the gas composition is not accurately known or when the alternative methods for characterisation are used. The relationship between compressibility and supercompressibility uncertainties is detailed in AGA 8 Sections 8.1 and 8.4 where it states that the relative uncertainty in the supercompressibility factor is one half the relative uncertainty in the compressibility. It is therefore assumed that the uncertainty in compressibility factor Z, for a pressure of 130 barA using the primary method is

= 2 * 0.3 = +/-0.6 % of reading.

### 10.2.3 GERG TM2

The GERG TM2 [13] report was published in 1988 following collaboration between the GERG members, who provided the data set, and Van der Waals Laboratory University of Amsterdam who carried out the correlation. The data set contained over 13,000 high accuracy compressibility measurements from pure, binary, ternary and natural gas mixtures. The resulting Master GERG-88 Virial Equation calculates the compressibility Z with an uncertainty of +/-0.1% over a pressure range of 0 to 120 Bar, a temperature range of -8 to 62°C and a 13 component gas composition .

Minor components, (typically less than 0.1 mol%) not detailed above, can be included by adding them to the major components above that have the most similar PVT behaviour. The groupings are detailed in the report Table 6.1 and include water with carbon dioxide but do not include methanol.

The report does state that the +/- 0.1% uncertainty is applicable to gas phase mixtures and is not applicable to natural gas near a phase separation surface particularly in the vicinity of the critical point.

Use of the GERG equation at pressures and temperatures outside of those stated introduces errors. For the pressure range 120 to 150 BarA the error on Z is predicted to be less than 0.5%. It is therefore assumed that the overall uncertainty in Z due to the high pressure, being outside some of the component ranges, not including water and methanol and the gas being at its hydrocarbon dewpoint, is going to be in excess of +/- 0.5%.

### 10.2.4 GERG TM5

GERG have also published report TM5 which calculates the compressibility factor Z from a restricted set of input variables and not the full gas composition. The Standard (or Simplified) GERG-88 Virial Equation was developed from the Master GERG-88 Virial Equation detailed in TM2 . The input variables are any three from the following : CV, RD, carbon dioxide and nitrogen content with pressure and temperature. The compressibility factor Z is calculated over the same pressure and temperature ranges and with the same uncertainty as the Master GERG Virial Equation in TM2. The same limitations apply with the exception of the uncertainty at pressures above 120 BarA. From tests on five natural gases at higher pressures it states that the uncertainty at a pressure of 130 BarA would be between +/-0.1 and 0.2%. There is, however, the uncertainty in the measurement of CV, RD, $CO_2$ and $N_2$ content, and not including methanol and water. It is also not clear what additional uncertainty should be included due to the gas being at its hydrocarbon dewpoint.

### 10.2.5 AGA 8 SECOND EDITION NOVEMBER 1992

AGA 8 1992 details two methods to calculate Z and density, the Detail Characterisation Method that uses the gas composition and the Gross Characterisation Method that uses CV or RD, $N_2$ and $CO_2$ content. Both methods have utilised the GERG database and are significantly different from those detailed in AGA 8 1985 . Both methods are applicable for a range of gas compositions but are only suitable for the gas phase and should not be used if the gas is within 5 °C and 2 Bar of the Critical Point.

The Detailed Characterisation Method can also be used outside of this range of gas compositions as it includes correlation specifically for gases from hydrocarbon separators containing heavy hydrocarbons (C6+ hydrocarbon dewpoint up to 10 mol%) and water (water dewpoint up to 10 mol%). Methanol is not included as a component nor is any provision made for the inclusion of additional components other than $H_2S$. The method is applicable for the gas phase for temperatures between -130 to 400 °C and pressures up to 2800 Bar, although the uncertainty does increase at high pressures and extreme temperatures.

The uncertainty in computed Z at an operating pressure of 130 BarA and a temperature of 30 °C is stated to be +/- 0.3%.

The Gross Characterisation Method is based on the method used in GERG TM2 and is only suitable for gases within the specified composition, pressure and temperature range (< 120 BarA & 82°C ). Within these limits the accuracy of the method is the same as the Detailed Characterisation Method and is estimated to be less than +/- 0.1%. It is stated that outside of these limits the Detail Characterisation Method is more accurate and should be used.

## 10.3 SELECTION OF METHOD

It is evident that to achieve optimum accuracy, particularly when operating at higher pressures, a full gas compositional method should be used. This excludes both AGA NX -19 and GERG TM-5.

A comparison of the remaining compositional methods is detailed on Figure 13. It could be argued that the later methods AGA 8 1992 and GERG TM 2 will be more accurate as they are derived from and tested against a larger database and hence wider range of gas compositions, pressure and temperatures. There is also the inclusion of other components, in this case water and methanol, to consider.

As shown AGA 8 1985 covers the full gas composition and has the provision to include both water and methanol. Although when including methanol the binary interaction parameters are taken to be 1.0 the size, energy and orientation parameters for methanol are calculated. With the exception of binary temperature interaction parameter the parameters used in the second virial coefficient, which contributes 90% of the final compressibility value, are therefore calculated and included which does give a degree of confidence. However the disadvantage of this method for pressures above 103 Bar is the targeted uncertainty in compressibility of +/- 0.6%.

GERG TM 2 covers the full gas composition with the exception of pentane and additional components. Water can be included by adding it to $CO_2$. The uncertainty in Z increases above 120 Bar to +/- 0.5 % due to the truncation of the virial equation after the third term.

AGA 8 1992 covers the full gas composition with the exception of pentanes and methanol and specifically mentions the inclusion of water and higher concentrations of C6+ components. The uncertainty in Z increases above 120 Bar to +/- 0.3% which is less than the other methods.

To include methanol in both GERG TM 2 and AGA 8 1992 it has to be added to an existing component. As the effect of methanol on Z is due to the mass and the interaction potential there are options :-

1) Add methanol to hexane as they have similar 2nd Virrial Coefficients.
2) Add methanol to Ethane as they have similar molecular weights.
3) Add methanol to water as both are associating compounds which interact with other components.

The differences between Z calculated by GERG TM 2 and AGA 8 1992 are compared on Figure 14 for a composition without methanol or water and each of the above options for including methanol, over the operating pressure range. As shown there is a larger than expected % difference between the methods even for the composition without water and methanol. The % differences due to the method of including water and methanol were much smaller. It was therefore concluded that the major difference was due to the high operating pressure. This was confirmed on Figure 15 which details the % difference for the composition without water and methanol at a lower operating pressure.

For all cases when compared with AGA 8 1985 GERG TM2 gave a lower value and AGA 8 1992 a higher value of Z.

## 10.4 UNCERTAINTIES

### AGA 8 1992 AND GERG TM2 FULL COMPOSITION METHODS

where $$\rho = \frac{P_1 Mw}{RTZ}$$

Having reviewed the uncertainty associated with the calculation of Z the uncertainty of calculated density is the combination of the uncertainties for each of the terms in the above equation.

Compressibility Z - The uncertainty in Z is due to the method of calculation and the uncertainty of the gas composition.

Molecular Weight MW - The uncertainty in MW is due to the method of calculation and the uncertainty of the gas composition . The former is assumed to be negligible and was ignored.

The uncertainties in Z and MW, due to the gas composition, were estimated by varying each component in the typical composition by the chromatograph uncertainty and then normalising the composition. The compressibility and molecular weight were then calculated from each normalised composition. The largest deviations in compressibility and molecular weight were then used as the uncertainty due to the uncertainty of the gas composition.

Uncertainty in Universal Gas Constant R - The uncertainty in R was assumed to be negligible and was ignored.

Uncertainty in Pressure Measurement

The uncertainty of pressure measurement Ep is a combination of the transmitter accuracy, ambient temperature effect and the flowcomputer ADC accuracy

$$Ep = [\,(Et * Pfs/Pm)^{\wedge 2} + (Ete * \text{mod } t/28)^{\wedge 2} + (Eadc * Pfs/Pm)^{\wedge 2}]^{\wedge 0.5} \quad \text{\% of reading}$$

where :-

Et = the manufacturer's stated accuracy in % of span or URV

Pfs = the calibrated span or URV in barA

Pm = the measured pressure barsA

Ete = the manufacturer's stated temperature effect in % of span or URV per 28°C

mod t = the change in ambient temperature from that during calibration °C

Eadc = the flowcomputer adc accuracy in % of span or URV

For a typical pressure transmitter operating in analogue mode :-

Et = +/- 0.15 % of span

Pfs = 150 BarA

Pm = 130 BarA

Ete = +/- 0.175% of span per 28°C

mod t = 5°C

Eadc = 0.1% full scale

$$Ep = +/- [(0.15*150/130)^{\wedge 2} + (0.175*5/28)^{\wedge 2} + (0.1*150/130)^{\wedge 2}]^{\wedge 0.5}$$

$$= +/- 0.21 \text{ \% of reading ( at 130 BarA)}$$

Uncertainty in Temperature Measurement.

The uncertainty of temperature measurement ET when using a Class A platinum resistance thermometer in accordance with BS 1904 as a direct input into the flowcomputer is :-

$$ET = +/-[(0.15 + \frac{0.35-0.15}{100} * \text{mod } T)^{\wedge 2} + (Eadc)^{\wedge 2}]^{\wedge 0.5}\,°C$$

where :-

mod T = the measured temperature

= 30°C

Eadc = the flowcomputer temperature adc

= +/-0.1°C

$$ET = \pm [(0.15 + \frac{(0.35-0.15)}{100} * 30)^{\wedge 2} \quad +(0.1)^{\wedge 2}]^{\wedge 0.5}\ °C$$

$$= \pm\ 0.23°C$$

$$= \pm\ 0.23K$$

ET = +/- 0.076 % of reading. ( at 303.15 K )

There is an interdependence of terms due to pressure and temperature affecting both the compressibility and the density. To overcome this sensitivity coefficients were calculated for each of the variables. The sensitivity coefficient $\theta_j^*$ is the percentage change in $\rho$ as a result of a 1% change in variable $Y_j$. This was achieved by varying each variable by 1% and calculating the resulting percentage change in density.

The uncertainties were then combined using :-

$$E_\rho^2 = \sum_i^k (\theta_j * e_j)^2$$

where :-

$\theta_j$ = the dimensionless sensitivity coefficient of variable $Y_j$
$e_j$ = the uncertainty of each variable
$E_\rho$ = the % uncertainty in density

At 130 BarA the uncertainty using the GERG TM2 Method was estimated to be +/- 0.55 % of reading.
At 130 BarA the uncertainty using the AGA 8 1992 Detail Characterisation Method was estimated to be +/- 0.38 % of reading.

The calculations are detailed on Figure 16 but do not include an additional uncertainty on Z due to the method used to include methanol.

# 11 CONCLUSIONS

The gas composition does vary with separator operating conditions. It is therefore desirable to measure the gas composition with an on-line gas chromatograph.

The gas at the metering system will be at its hydrocarbon dewpoint and depending on the presence of free water, be at its water dewpoint. The use of sampling or live measurement of water content on an offshore platform does present problems. Assuming the gas is at its water dewpoint the water content can be calculated using a method such as Campbell or Bukacek. On wet gas systems it is likely that methanol will be injected to inhibit the formation of hydrates and corrosion and will therefore be present in the gas stream. Although the effect of water and methanol on density counteract each other ignoring them, in the calculated concentrations, would result in a systematic bias of +0.22% of reading. It is therefore concluded that to achieve optimum accuracy, if present in sufficient quantities, water and methanol should be included in the gas composition used to calculate density.

The methanol content could be calculated or determined from sample analysis using chromatography. There is conflicting opinion on the effect of water and methanol on the C6+ peak of some gas chromatographs. Tests are required to establish the effect relative to concentration.

A full compositional method should be used to calculate Z with due regard given to the range of components, and the operating pressure and temperature. Generally the more recent methods should be more accurate as they are derived and tested against a larger database and hence wider range of gas compositions, pressures and temperatures. For the typical composition used there were differences between the Z calculated by the more recent methods, GERG TM2 and AGA8 1992, particularly at high operating pressures. Ideally the method chosen should be tested against measurements of Z over the full gas composition and operating range of pressures and temperatures. The inclusion of additional components, in this case methanol is often not detailed. The method chosen to include methanol did have an effect on the calculated Z and density. It is not clear to the user which method is correct.

The effects on the calculation of Z and density of the condensate present at the orifice, or the use of an equation of state near a phase boundary, are not clear. Although the sampled gas is in this condition, the gas entering the chromatograph will have been conditioned in the pressure reduction system. The condensate will have been removed either by a coalescer or by heating. The condition of the gas entering the chromatograph with respect to the dewpoint line will depend on the amount of heat introduced as shown on Figure 9. The use of either GERG TM2 or AGA 8 1992 equations of state near a phase boundary is discouraged, although it is not clear whether this is due to the lack of test data or the unpredictability of the gas in this condition. If the gas sample is heated so that it is not near the dewpoint line is the gas composition obtained from the chromatograph representitive of the metered stream? Clearly there is a need to investigate the behaviour of gas in his condition and the suitability of calculated density.

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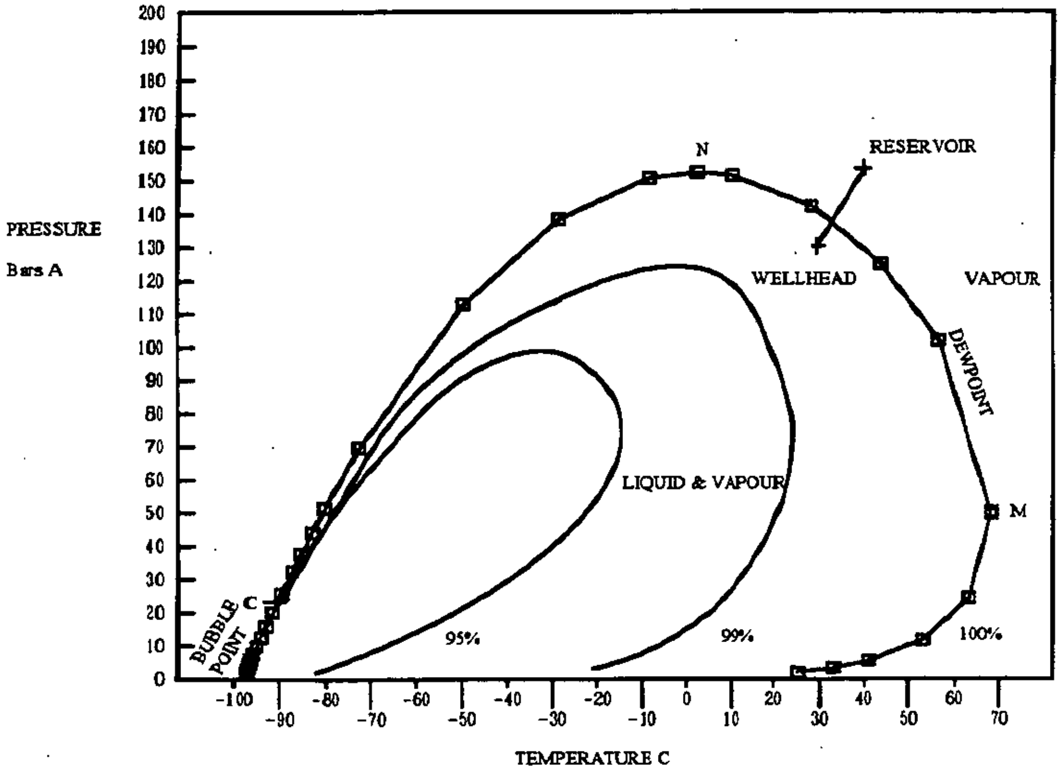


N = Cricondenbar - the maximum pressure at which liquid and vapour may exist
M = Cricondentherm - the maximum temperature at which liquid and vapour may coexist in equilibrum
C = Critical Point - Critical Pressure and Critical Temperature

**FIGURE 1 - WELLSTREAM PHASE ENVELOPE
RESERVOIR & WELLHEAD CONDITIONS**

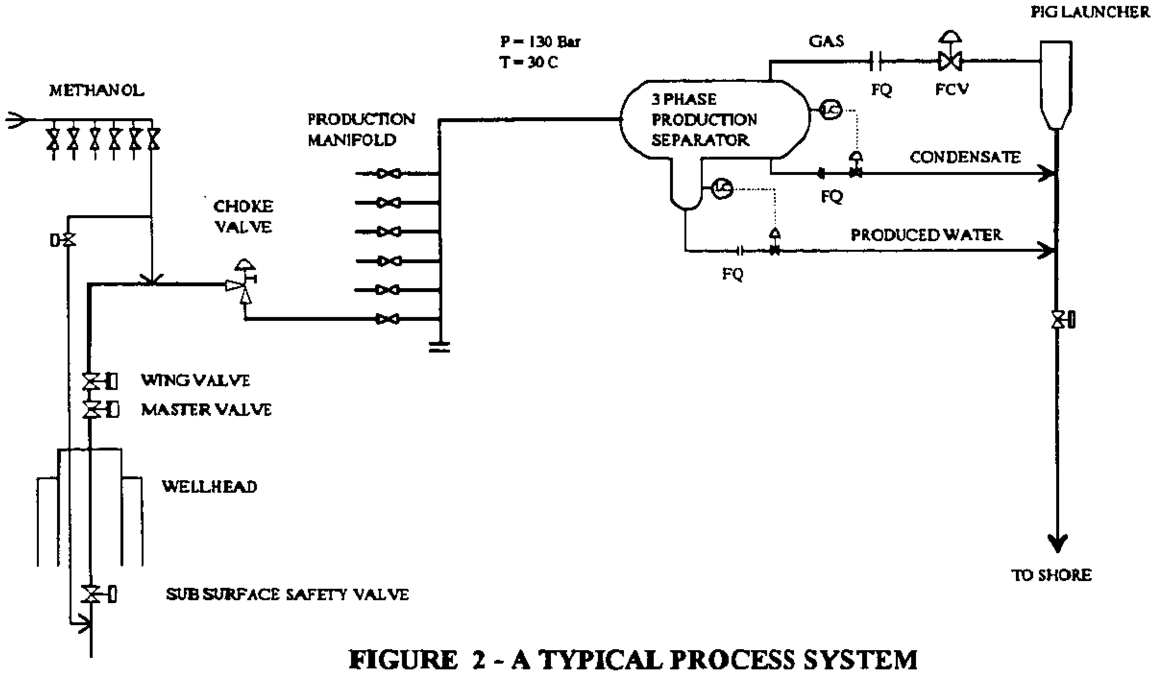
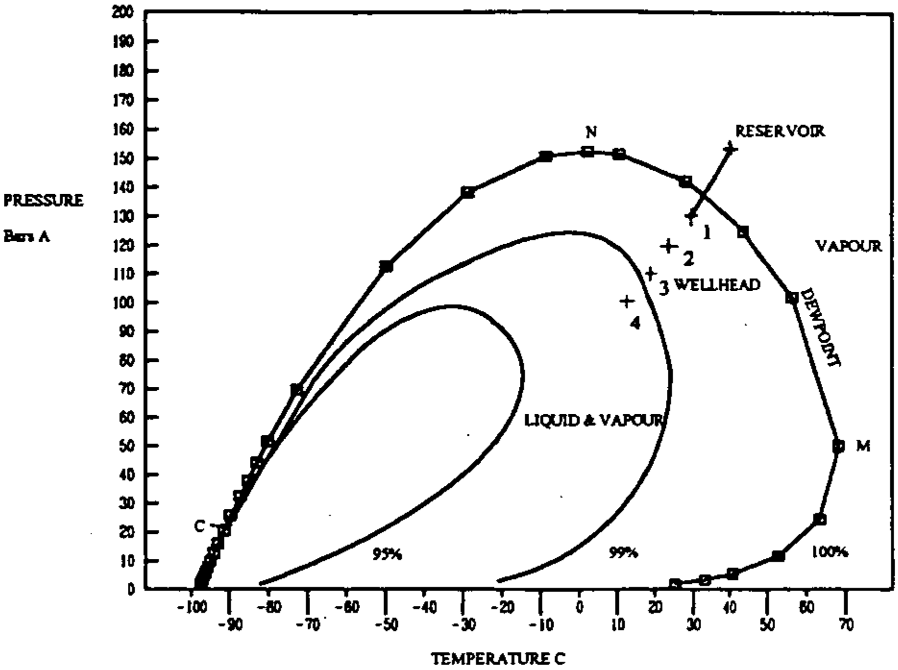


**FIGURE 2 - A TYPICAL PROCESS SYSTEM**



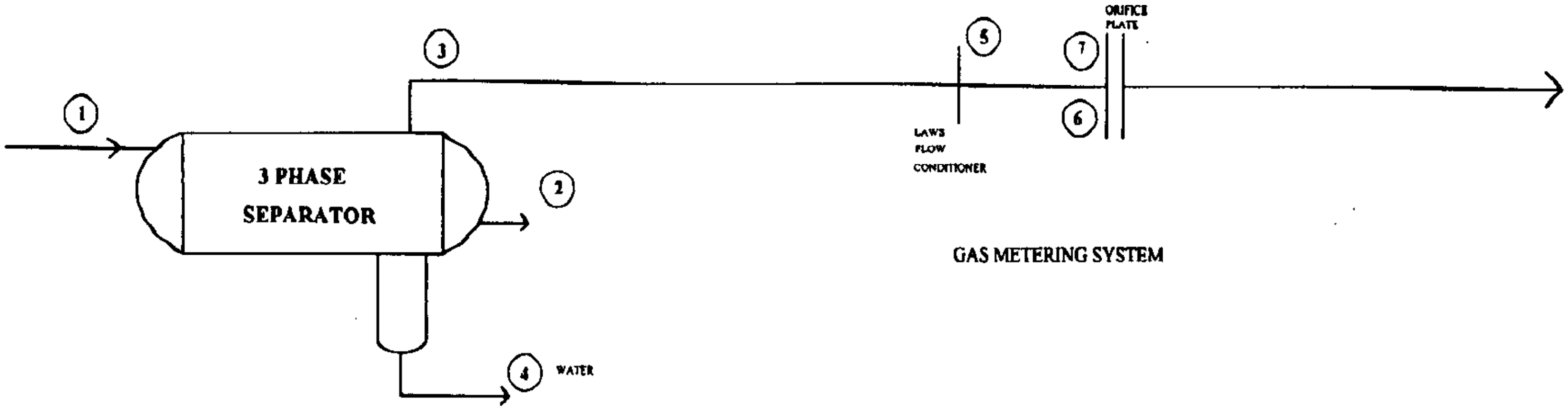
## FIGURE 3 - WELLSTREAM PHASE ENVELOPE CONDENSATE TO GAS RATIO ( CGR )

| | YEAR 1 | | | |
|---|---|---|---|---|
| COMPONENT | 1<br>P = 130 Bar<br>T = 30 C | 2<br>P = 120 Bar<br>T = 25 C | 3<br>P = 110 Bar<br>T = 20 C | 4<br>P = 100 Bar<br>T = 15 C |
| Nitrogen | 2.02 | 2.02 | 2.03 | 2.03 |
| Carbon Dioxide | 0.65 | 0.65 | 0.65 | 0.65 |
| Water | 0.06 | 0.06 | 0.06 | 0.05 |
| Methane | 91.21 | 91.38 | 91.56 | 91.76 |
| Ethane | 3.03 | 3.02 | 3.02 | 3.01 |
| Propane | 0.69 | 0.68 | 0.68 | 0.67 |
| I-Butane | 0.14 | 0.13 | 0.13 | 0.13 |
| N-Butane | 0.2 | 0.2 | 0.2 | 0.19 |
| I-Pentane | 0.77 | 0.75 | 0.71 | 0.66 |
| N-Pentane | 0.77 | 0.74 | 0.7 | 0.64 |
| Hexane | 0.1 | 0.09 | 0.08 | 0.07 |
| Heptane | 0.15 | 0.13 | 0.1 | 0.08 |
| Octane | 0.1 | 0.08 | 0.05 | 0.03 |
| Nonane | 0.05 | 0.03 | 0.02 | 0.01 |
| Decane | 0.04 | 0.02 | 0.01 | 0.01 |
| Undecane | 0.01 | 0.01 | 0 | 0 |
| True Density | 121.53854 | 113.79646 | 105.44496 | 96.65294 |
| Comp. 1 Density | 121.53854 | 115.15993 | 108.08732 | 100.27758 |
| % Difference | 0.00 | 1.20 | 2.51 | 3.75 |

**Notes**

1)Condensate to Gas Ratio = 1.92 Barrels per MMSCF

## FIGURE 4 - CHANGES IN GAS COMPOSITION WITH CHANGING SEPARATOR OPERATING CONDITIONS



GAS METERING SYSTEM

| | 1 | 2 | 3 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| STREAM | WELLSTREAM | CONDENSATE FROM SEPARATOR | GAS FROM SEPARATOR | INPUT TO METERING | CONDENSATE TO METERING | GAS TO METERING |
| PRESSURE Bar A | 130.00 | 130.00 | 130.00 | 129.847 | 129.847 | 129.847 |
| TEMPERATURE C | 30.0 | 30.0 | 30.0 | 29.96 | 29.96 | 29.96 |
| MASS FLOW kg/h | 137445.00 | 1109.9348 | 136335.08 | 136335.08 | 17.6345 | 136317.44 |
| GAS DENSITY kg/m3 | | | 122.263 | | | 122.138 |
| STD VOL FLOW m3/h | | | 173141.5 | | | 173119.1 |
| LIQ DENSITY kg/m3 | | 554.91 | | | 554.98 | |
| LIQ VOL FLOW m3/h | | 1.9276 | | | 0.0306 | |
| NITROGEN | 2.00 | 0.53 | 2.01 | 2.01 | 0.53 | 2.01 |
| CARBON DIOXIDE | 0.65 | 0.58 | 0.65 | 0.65 | 0.58 | 0.65 |
| WATER | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| METHANE | 90.84 | 46.62 | 90.96 | 90.96 | 46.59 | 90.96 |
| ETHANE | 3.29 | 4.42 | 3.29 | 3.29 | 4.42 | 3.29 |
| PROPANE | 0.69 | 1.85 | 0.69 | 0.69 | 1.85 | 0.69 |
| I-BUTANE | 0.14 | 0.61 | 0.14 | 0.14 | 0.61 | 0.14 |
| N-BUTANE | 0.21 | 1.12 | 0.21 | 0.21 | 1.13 | 0.21 |
| I-PENTANE | 0.79 | 7.05 | 0.77 | 0.77 | 7.06 | 0.77 |
| N-PENTANE | 0.79 | 8.07 | 0.77 | 0.77 | 8.09 | 0.77 |
| HEXANE | 0.11 | 2.08 | 0.10 | 0.10 | 2.09 | 0.10 |
| HEPTANE | 0.17 | 5.70 | 0.15 | 0.15 | 5.71 | 0.15 |
| OCTANE | 0.12 | 6.84 | 0.10 | 0.10 | 6.85 | 0.10 |
| NONANE | 0.07 | 6.48 | 0.05 | 0.05 | 6.47 | 0.05 |
| DECANE | 0.05 | 5.08 | 0.04 | 0.04 | 5.07 | 0.04 |
| UNDECANE | 0.02 | 2.90 | 0.01 | 0.01 | 2.89 | 0.01 |

NOTES

1) PRESSURE DROP BETWEEN SEPARATOR AND ORIFICE CALCULATED TO BE 0.153 BAR.

2) PIPE BETWEEN SEPARATOR AND FLOW CONDITIONER 20 METRES, WITH 4 BENDS AND SIZED AT 12 INCH DIAMETER.. PRESSURE DROP 0.075 BAR

3) PRESSURE DROP ACROSS LAWS CONDITIONER 0.078 BAR

4) PRESSURE DROP ACROSS ORIFICE 0.550 BAR

5) PRESSURE LOSS ACROSS ORIFICE 0.342 BAR

6) TEMPERATURE DROPS CALCULATED USING ISENTHALPIC CONSTANT OF 0.298 K/BAR

FIGURE 5 - THE CONDITION OF GAS STREAM AT THE ORIFICE

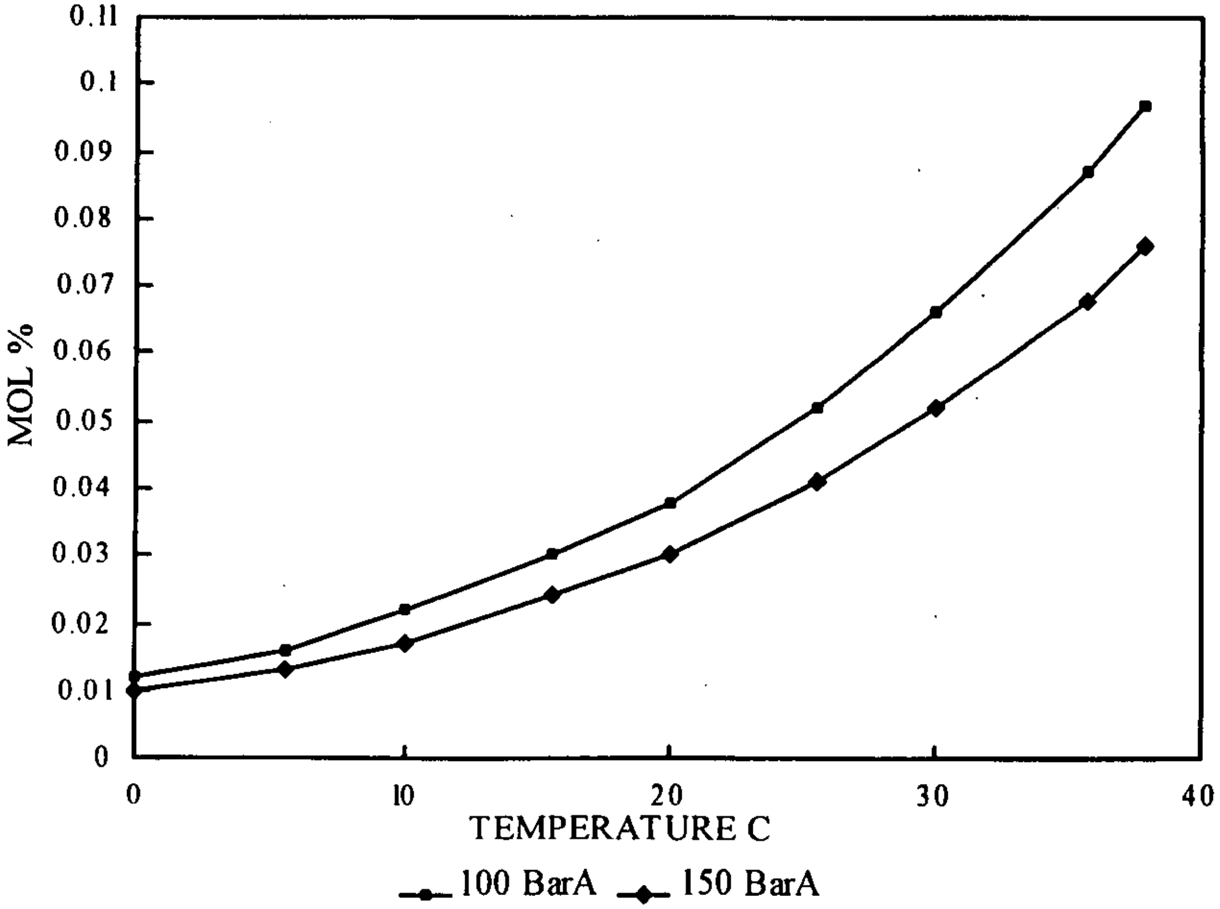


FIGURE 6 - WATER CONTENT OF NATURAL GAS

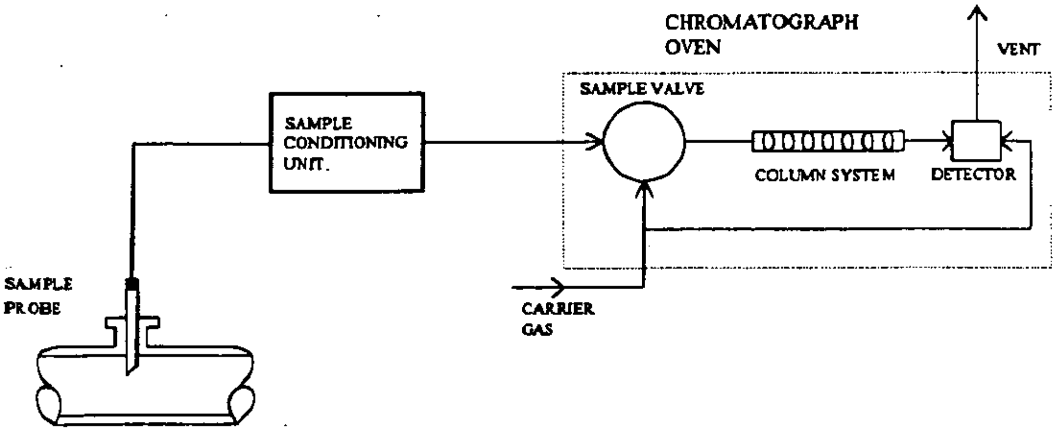


FIGURE 7 - A GAS CHROMATOGRAPH

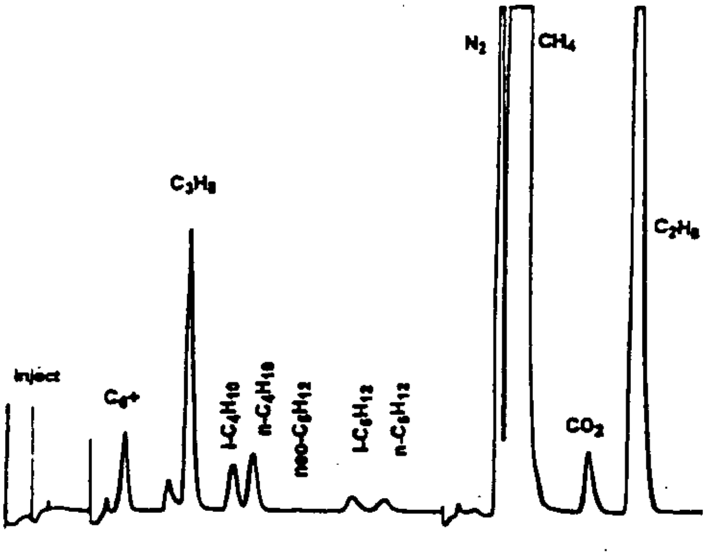


FIGURE 8 - A CHROMATOGRAM

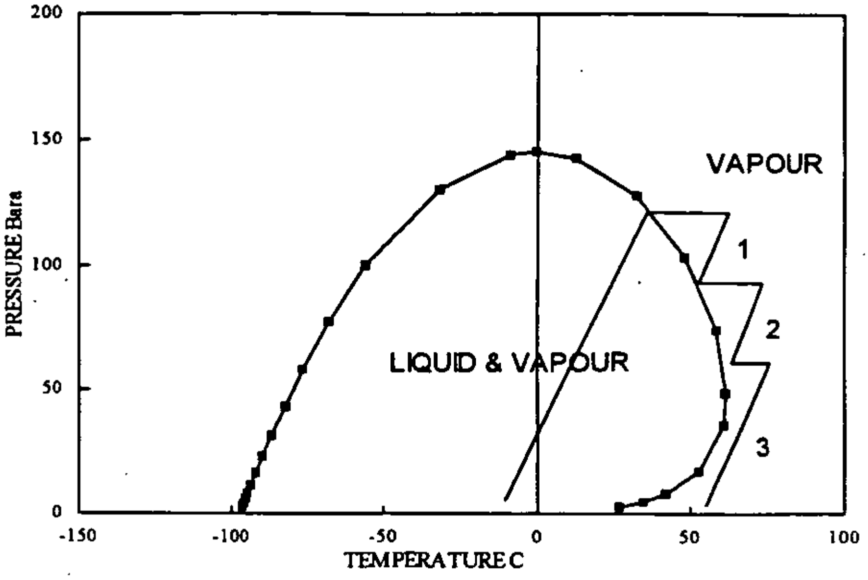


FIGURE 9 - GAS STREAM PHASE ENVELOPE
PRESSURE REDUCTION STAGES

| COMPONENT | SPOT SAMPLING | AUTO SAMPLING | | |
|---|---|---|---|---|
| | FIELD A BI-MONTHLY OVER 6 YEARS | FIELD B TIME WEIGHTED OVER 15 MONTHS | FIELD C TIME WEIGHTED OVER 15 MONTHS | FIELD D FLOW WEIGHTED OVER 21 MONTHS |
| Nitrogen | 0.02 | 0.0739 | 0.0252 | 0.255 |
| Carbon Dioxide | 0.08 | 0.018 | 0.0225 | 0.031 |
| Methane | 0.059 | 0.0673 | 0.094 | 0.4755 |
| Ethane | 0.04 | 0.0623 | 0.0434 | 0.1954 |
| Propane | 0.04 | 0.0191 | 0.0213 | 0.0375 |
| N-Butane | 0.01 | 0.0041 | 0.0034 | 0.0161 |
| I-Butane | 0.01 | 0.0123 | 0.0046 | - |
| N-Pentane | 0.028 | 0.0021 | 0.0014 | 0.0114 |
| I-Pentane | 0.008 | 0.0016 | 0.0019 | - |
| Hexane + | 0.042 | 0.0319 | 0.0501 | 0.041 |

NOTE – Field A samples were taken at the onshore terminal.
All other samples were taken offshore.

**SPOT AND AUTO SAMPLING**
**COMPONENT STANDARD DEVIATIONS**

| COMPONENT | CHROMATOGRAPH | | | | |
|---|---|---|---|---|---|
| | FIELD B CALIBRATION GAS OVER 4 MONTHS | FIELD B HOURLY AVERAGE OVER 1 DAY | FIELD B DAILY AVERAGES OVER 4 MONTHS | FIELD E HOURLY AVERAGE OVER 4 DAYS | FIELD F ALL ANALYSIS OVER 1 DAY |
| Nitrogen | 0.0014 | 0.0016 | 0.0189 | 0.0104 | 0.0027 |
| Carbon Dioxide | 0.0017 | 0.0058 | 0.0167 | 0.0015 | 0.0006 |
| Methane | 0.0062 | 0.0097 | 0.0685 | 0.011 | 0.0105 |
| Ethane | 0.0029 | 0.0015 | 0.0299 | 0.005 | 0.0028 |
| Propane | 0.0014 | 0.0008 | 0.0144 | 0.001 | 0.0012 |
| N-Butane | 0.0003 | 0.0003 | 0.0039 | 0.0006 | 0.0005 |
| I-Butane | 0.0002 | 0.0002 | 0.0024 | 0.0005 | 0.0003 |
| N-Pentane | 0.0004 | 0.0004 | 0.0014 | 0.0004 | 0.0002 |
| I-Pentane | 0.0003 | 0.0003 | 0.0014 | 0.0001 | 0.0002 |
| Hexane + | 0.0029 | 0.0037 | 0.015 | 0.0037 | 0.0058 |

**ON-LINE GAS CHROMATOGRAPHY**
**COMPONENT STANDARD DEVIATIONS**

**FIGURE 10**

|  | CHROMATOGRAPH |  |  |  |  |  |
|---|---|---|---|---|---|---|
|  | FIELD B CALIBRATION GAS OVER 4 MONTHS | FIELD B HOURLY AVERAGE OVER 1 DAY | FIELD B DAILY AVERAGES OVER 4 MONTHS | FIELD E HOURLY AVERAGE OVER 4 DAYS | FIELD F ALL ANALYSIS OVER 1 DAY | CALCULATED CHROMATOGRAPH REPEATABILITY +/- mol% |
| n = | 96 | 21 | 53 | 70 | 183 |  |
| t= | 1.96 | 2.086 | 2.011 | 1.96 | 1.96 |  |
| COMPONENT |  |  |  |  |  |  |
| Nitrogen | 0.0027 | 0.0033 | 0.0380 | 0.0204 | 0.0053 | 0.0068 |
| Carbon Dioxide | 0.0033 | 0.0121 | 0.0336 | 0.0029 | 0.0012 | 0.0044 |
| Methane | 0.0122 | 0.0202 | 0.1378 | 0.0216 | 0.0206 | 0.0380 |
| Ethane | 0.0057 | 0.0031 | 0.0601 | 0.0098 | 0.0056 | 0.0126 |
| Propane | 0.0027 | 0.0017 | 0.0290 | 0.0020 | 0.0024 | 0.0044 |
| N-Butane | 0.0006 | 0.0008 | 0.0078 | 0.0012 | 0.0010 | 0.0018 |
| I-Butane | 0.0004 | 0.0004 | 0.0048 | 0.0010 | 0.0006 | 0.0008 |
| N-Pentane | 0.0008 | 0.0008 | 0.0028 | 0.0008 | 0.0004 | 0.0014 |
| I-Pentane | 0.0006 | 0.0006 | 0.0028 | 0.0002 | 0.0004 | 0.0009 |
| Hexane + | 0.0057 | 0.0077 | 0.0302 | 0.0073 | 0.0114 | 0.0120 |

NOTE SHADED RESULTS NOT INCLUDED

FIGURE 11 - CHROMATOGRAPH REPEATABILITY +/- MOL%
CALCULATED AT 95% CONFIDENCE LEVEL

| COMPONENT | mol % | CHROMATOGRAPH REPEATABILITY +/- mol % | CALIBRATION GAS UNCERTAINTY +/- mol % | CHROMATOGRAPH UNCERTAINTY +/- mol % |
|---|---|---|---|---|
| Nitrogen | 2.02 | 0.0068 | 0.0101 | 0.0122 |
| Carbon Dioxide | 0.65 | 0.0044 | 0.0065 | 0.0078 |
| Methane | 91.21 | 0.0380 | 0.0621 | 0.0728 |
| Ethane | 3.03 | 0.0126 | 0.0152 | 0.0197 |
| Propane | 0.69 | 0.0044 | 0.0069 | 0.0082 |
| N-Butane | 0.20 | 0.0018 | 0.0020 | 0.0027 |
| I-Butane | 0.14 | 0.0008 | 0.0014 | 0.0016 |
| N-Pentane | 0.77 | 0.0014 | 0.0077 | 0.0078 |
| I-Pentane | 0.77 | 0.0009 | 0.0077 | 0.0078 |
| Hexane + | 0.46 | 0.0120 | 0.0046 | 0.0129 |
|  | 99.94 |  |  |  |

FIGURE 12 - UNCERTAINTY IN GAS COMPOSITION MEASURED BY A GC

| COMPONENT | mol % | AGA8 1985 | GERG TM2 | AGA8 1992 |
|---|---|---|---|---|
| Nitrogen | 2.020 | 0 - 50 | 0 - 50 | 0.3 - 53.6 |
| Carbon Dioxide | 0.650 | 0 - 50 | 0 - 30 | 0.04 - 28.94 |
| Water | 0.060 | *1) | *2) | *4) |
| Methane | 91.210 | 50 - 100 | 50 - 100 | 45.2 - 98.3 |
| Ethane | 3.030 | 0 - 20 | 0 - 20 | 0.24 - 9.53 |
| Propane | 0.690 | 0 - 5 | 0 - 5 | 0.02 - 3.57 |
| N-Butane | 0.200 | 0 - 3 | 0 - 1.5 | 0.01 - 1.08 |
| I-Butane | 0.140 | | | |
| N-Pentane | 0.770 | 0 - 2 | 0 - 0.5 | 0.002 - 0.279 |
| I-Pentane | 0.770 | | | |
| Hexane | 0.090 | 0 - 1 | 0 - 0.1 | *5) |
| Heptane | 0.130 | | 0 - 0.1 | |
| Octane | 0.090 | | 0 - 0.1 | |
| Nonane | 0.040 | | *3) | |
| Decane | 0.040 | | | |
| Undecane | 0.010 | | | |
| Methanol | 0.060 | *1) | *2) | not included |
| PRESSURE BarA | 100 - 150 | | | |
| TEMPERATURE C | 15 - 30 | | | |
| UNCERTAINTY Z | | +/- 0.2 % | +/- 0.1 % | +/- 0.1 |
| | | 0 - 130 Bar | 0 - 120 Bar | 0 - 120 Bar |
| | | +/- 0.6 % | +/- 0.5 % | +/- 0.3 % |
| | | 103 - 172 Bar | 120 - 150 Bar | 120 - 170 Bar |

NOTES

1) Additional components can be included provided they do not sum to more than 1 mol %

2) Additional components ( typically less than 0.1 mol % ) are added to major components with similar PVT behaviour i.e. those with similar second virial coefficients.

3) All hydrocarbons higher than C8 are added to C8.

4) Water Dewpoint up to 10 mol %

5) Hydrocarbon Dewpoint up to 10 mol %.

**FIGURE - 13 A COMPARISON OF METHODS FOR THE CALCULATION OF Z FROM FULL GAS COMPOSITION**

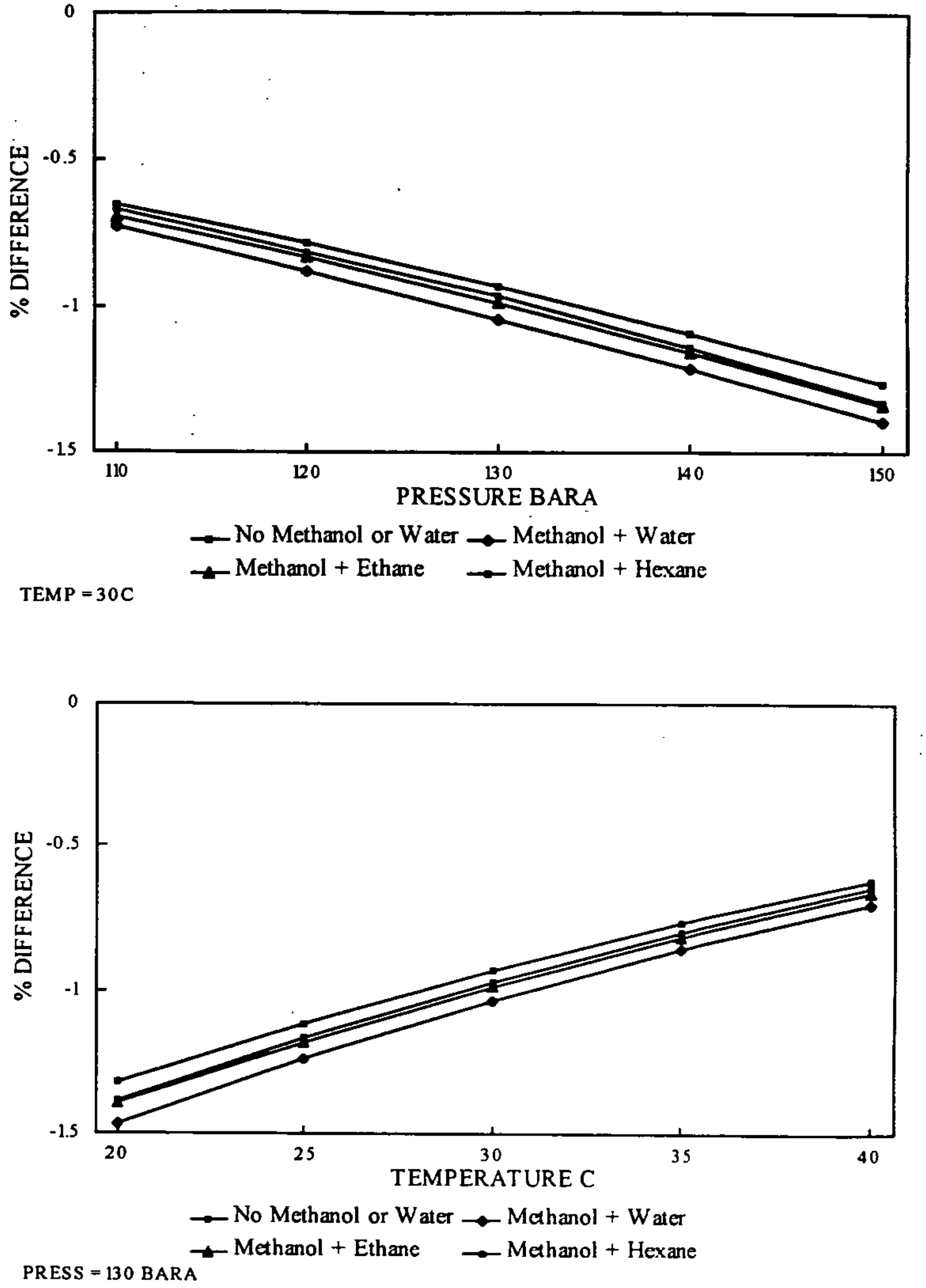
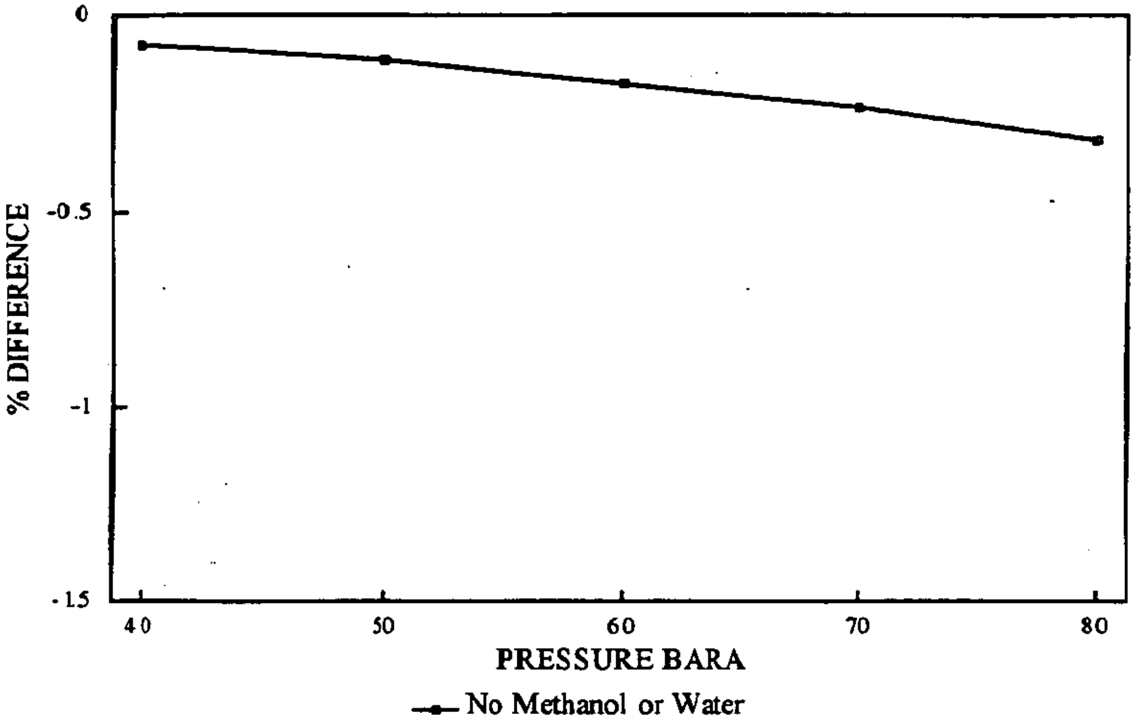
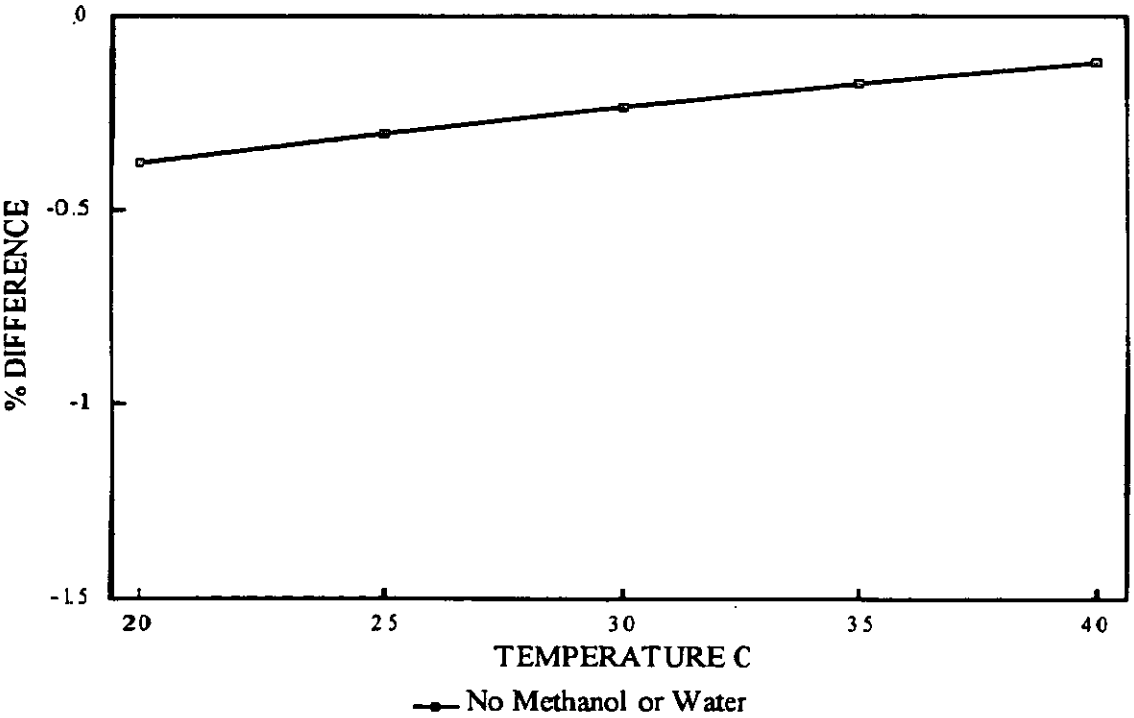


**FIGURE - 14 % DIFFERENCE IN Z BETWEEN AGA 8 1992 & GERG TM 2**

**HIGH OPERATING PRESSURE**



TEMP =30C



PRESS =70 BARA

**FIGURE - 15 % DIFFERENCE IN Z BETWEEN AGA 8 1992 & GERG TM 2**
**LOW OPERATING PRESSURE**

## GERG TM 2

| PARAMETER | VALUE | 1% CHANGE | DENSITY kg/m3 | SENS. sj % | UNCERT. ej % | VARIANCE (sj ej)^2 |
|---|---|---|---|---|---|---|
| Base Case | - | - | 121.6862 | - | | |
| Pressure | 130 | 131.3 | 122.9031 | 1.00 | 0.21 | 0.044102 |
| Temperature | 303.15 | 306.1815 | 120.4814 | -0.99 | 0.076 | 0.005662 |
| Zcomp | 0.78297 | 0.7907997 | 120.4814 | -0.99 | 0.039 | 0.001491 |
| Zcalc | 0.78297 | 0.7907997 | 120.4814 | -0.99 | 0.5 | 0.245064 |
| MW comp | 18.473 | 18.65773 | 122.9031 | 1.00 | 0.065 | 0.004225 |

Total Uncertainty = +/- 0.300544 ) ^0.5 %

= +/- 0.55 %

## AGA 8 1992

| PARAMETER | VALUE | 1% CHANGE | DENSITY kg/m3 | SENS. sj % | UNCERT. ej % | VARIANCE (sj ej)^2 |
|---|---|---|---|---|---|---|
| Base Case | - | - | 120.5010 | - | | |
| Pressure | 130 | 131.3 | 121.7060 | 1.00 | 0.21 | 0.044101 |
| Temperature | 303.15 | 306.1815 | 119.3080 | -0.99 | 0.076 | 0.005662 |
| Zcomp | 0.790671 | 0.79857771 | 119.3080 | -0.99 | 0.039 | 0.001491 |
| Zcalc | 0.790671 | 0.79857771 | 119.3080 | -0.99 | 0.3 | 0.088222 |
| MW comp | 18.473 | 18.65773 | 121.7060 | 1.00 | 0.065 | 0.004225 |

Total Uncertainty = +/- 0.143702 ) ^0.5 %

= +/- 0.38 %

FIGURE 16 - UNCERTAINTY IN CALCULATED DENSITY