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Benefits Derived from the Application of Virtual Metering Production Simulation Software (VMSS3)

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1 INTRODUCTION AND BACKGROUND

The original purpose of the client companies who sponsored our VSSM3 simulation technology research and development effort spanning several years was to provide a technical tool to optimize the design of the total integrated producing system, starting at the reservoir and flowing through to the terminal. While there are many sub- optimizations in the design of the equipment and producing facilities, there is an overall optimization. An important finding was that test separators did not have to be installed on offshore platforms, nor did they have to be installed in remote mountainous locations because the engineering software model technology could calculate the producing systems as accurately as non-engineered flow measurement. This reduced the size of platforms and eliminated the test lines.

An important aspect of design optimization is the identification and avoidance of infeasible flow situations into future years due to such as slug flow, cease flow and increasing water cuts and gas fraction. This includes designing adequate and economic gravity and cyclonic gas-oil-water separation facilities to handle high viscosity emulsions and calculating gas oil separator liquid carry over and gas carry under effects.

For well testing applications, the well simulation section of VMSS3 is used to compute the downhole multiphase flow rates at the reservoir pay entrance to the wellbore with the flow rate measured in the surface section. This technique aids in well testing, whereas the installation of downhole pressure and temperature gauges has proved to be expensive, with the gauges destroyed under severe downhole conditions. Thus the provision of the PTQ information by the computer simulation model saves costs. The number of wireline trips to measure downhole conditions are reduced since a direct measurement is only required to update the simulation model.

A typical flow allocation example is an offshore platform with seven wells each equipped with a flow choke. At the production and test manifolds the individual wells are metered by a multiphase meter (MPM). The multiphase flow then continues to a high pressure separator where the exiting water, oil, and gas phases are measured by single phase meters. The oil and gas meters are periodically checked by meter provers. The VMSS3 simulation is then applied from the wellhead pressure and temperature points, through the exit meters and to the separator.

The multiphase flow rates at the wellhead has been predicted by VSSM3 to $\pm$ 1 – 2% accuracy with accurate input data from PVT data and the Scada type Data Acquisition System on pressures, temperatures and metered exit rates. Operators are requesting improvements in multiphase flow rate measurements to an accuracy depending on the input data, better than $\pm$ 5% Current accuracies are currently in the $\pm$ 13 – 16% range observed in Gulf of Mexico production operations. The multiphase flow rates allocated can be translated by VMSS3 to the standard P/T conditions to provide standard conditions liquid and gas rates, and may also be translated to the bottom hole conditions (P/T) to provide the estimated flow rate from the reservoir into the wellbore. The standard conditions information is important for accounting, tax and royalty calculations, as well as for production management.

Many oil/gas condensate fields experience fairly rapid declines in reservoir pressures as well, as increases in water cuts and gas/oil ratios entering the wells. The VMSS3 system operating online in real time calculates these effects and displayed in SCADA type systems. Among the decisions that can then be made by management are to minimize or control slugging effects, to improve metering to better calculate the actual liquid and gas flow rates, to analyze the benefits of gas lifting or downhole pumping operations and to resize lines or separators.

2 MSS3 MATHEMATICAL AND ENGINEERING BASIS

The earliest formulation of the engineering computational procedures that underlie VMSS3 date back to the 1960's and form the original basis of the EYI simulation models. The equations applied are grounded in basic chemical and petroleum engineering and extended to reflect the results of a large body of field production data and incorporating laboratory crude oil assays to determine fluid properties.

Extensive investigations were made of the various numerical analysis integration techniques to determine the most rapid and accurate calculation algorithm. As will be discussed later on, the virtual metering production simulation procedures were tested against several hundred well and gathering system engineered production tests and adjustments were made to the sets of equations and coefficients. As technical improvements are made in the areas of multiphase flow and phase separation technology, these will be incorporated in the VMSS3 calculation system to further extend its range and to reduce the uncertainties and improve accuracy.

Figure 1 shows a sketch of a typical integrated producing system starting at the reservoir and flowing through to the exit single phase oil and gas meters which is calculated by the VMSS3 simulation software.

The most general VMSS3 calculation procedure starts at the reservoir pressure and temperature (PO/TO) and the initial assumption of the production system multiphase mass flow rates (MOO, MGO, MWO). The sets of equations and their empirical coefficients which number approximately 25 equations and 100 coefficients are solved for the each well increment with the length chosen to assure linear change in the process variables across the increment. An iterative substitution algorithm solves for the phasal flows and conditions at the end of each increment values (P1, T1, MO1, MG1 and MW1). These end values are the input values to the second increment, and so on. The calculation proceeds stepwise along and up the well configuration. The well potential curve (referred to as the P/Q chart) is calculated for the wellhead position.

Calculations may continue along the surface gathering lines (including underwater and buried pipelines) and may also include flow devices and equipment elements located within a specific flow increment. The sum of the flows of the incoming flowlines join at the production manifold to enter a 3-phase gas, oil, water separator which is modeled by the EYI GOSPSI M multiphase separator simulation program. Separators may also be located at the wellhead or intermediate points. Multistage separators may be represented and at the exit of the last stage separator, the single phase meters measure the oil and gas flow rates from each stage of separation which are converted to standard conditions stock tank barrels per day, MMSCFD and gas/oil ration (SCF/B).

The results of the VMSS3 calculation process are the pressure and temperature profiles as a function of length along the system configuration for the corresponding multiphase mass and volumetric flow rates. These basic PTQ/M curves are converted to the standard conditions at the end of the system (at 14.73 psia and 60 degrees F) which gives the values of liquid and gas flow rates used in accounting and product sales and production monitoring and control.

3 OVERVIEW OF THE VMSS3 MATHEMATICAL AND ENGINEERING BASIS

- Multiphase fluid flow pressure/flow equations and correlations.
- Prediction of the flow regimes occurring in each increment.
- The applicable heat transfer equations for the wells and gathering systems.
- The physical properties equations and coefficients derived from regression analyses of the PVT Laboratory data on the reservoir fluid covering the entire operating range of pressures and temperatures.
- A stepwise incremental numerical calculation algorithm developed to achieve reasonable accuracy and speed of computation. An integrated calculation is performed from well bottom hole to system terminus.

- These procedures were validated against field production data in 422 well and gathering systems. In addition, research and development findings at the pilot plant and laboratory level were incorporated into the equations.

4 MULTIPHASE FLOW REGIME PREDICTION

In the p/t change across the increment the flow regime (pattern) existing in the increment influences the effective pressure drop and density values.

Empirical flow pattern maps from the technical literature are statistically regressed to develop the equation sets and associated coefficients that characterize each flow regime.

Foam probe testing in multiphase pipelines was found to vary from published correlations. For a predicted homogeneous regime, the flow pattern in fact was 25% stratified flow and 75% foam flow with decreasing mixture density across the pipe cross section. Therefore the actual flow regime models, the frictional and elevation pressure drops and the applicable densities were adjusted.

The correlated flow regimes in each increment are bubble, stratified, froth/foam, annular/ mist, and slug flows.

When slug flow is predicted in the increment a separate slug flow subroutine is invoked to predict the size and frequency of the liquid slugs and following gas bubbles.

5 MULTIPHASE FLOW PRESSURE GAIN/ LOSS CORRELATIONS

The basic Bernoulli flow equation states that the overall pressure drop across the increment is equal to the sum of the frictional pressure loss plus the elevation change (either +/-) and the acceleration pressure loss (for large velocity changes). Depending on the flow regime in the increment the frictional pressure loss is calculated from Fanning's equation modified for multiphase flow and based on empirical correlations both pilot plant and from field data.

The frictional pressure loss correlations depend on the flow regime and are expressed as functions of dimensionless numbers. These include the Reynold's number for viscous and turbulent forces as affected by roughness factors, the Froude number for gravity forces and the Weber number where interfacial tension forces are important. (mostly in separation processes) and the Mach number in high velocity and critical flows. There may be more than one component to the frictional pressure losses depending on the flow regime.

Correlating equations and coefficients have been developed for the elevation pressure changes, largely from field research. The elevation pressure drop increases in upward multiphase flow. In downward flow there is usually a degree of pressure recovery, but it varies from low recovery to 100% depending on the flow regime in the downhill flow increments. Acceleration pressure losses occur when there are large velocity head changes such as occurring in high velocity gas/ gas condensate lines and in both subsonic and sonic flow.

6 TEMPERATURE LOSS CORRELATIONS

The temperature drop profile is developed in the well section starting at reservoir temperature and calculated increment by increment along and up the well configuration to the wellhead. Field based heat transfer equations and correlations as a function of the mass flow rate have been developed to generate the well temperature profiles. The factors include a heat loss from the well into the earth sink, flashing temperature drop as gas evolves, temperature drops across chokes or valves due to high pressure drops (Joule Thompson effect). Our data bank includes over 200 wells.

The empirical temperature drop correlations for the gathering pipelines, flow elements, and flow devices are extensive. Thermal conductivity and heat transfer coefficients from the literature and from field production tests have been developed for above ground lines, buried lines, underwater lines, lines painted aluminum to reduce radiation input, various coatings, temperature drops across flow chokes, and control valves.

Other multiphase flow models have not treated temperature changes to the extent found in VMSS3 Some methods use averaging techniques which cause an unnecessary error up to ± 10-20% in the flow rate calculations, reduced by VMSS3 heat loss prediction subroutines.

7 WELL POTENTIAL CURVES (P-Q CHARTS)

Figure 2 shows a resulting VSSM3 well potential curve or the P-Q chart for a well. The VMSS3 simulation calculations are extended from the existing reservoir conditions to consider future lower reservoir pressures. There are normally changes in the gas/oil ratios and the water cuts over time. The effects of changes are also calculated to give a more complete picture of the well's performance during its productive life.

Analysis of the well potential curve shows that at lower multiphase flow rates the slug flow regime occurs in the well. In this region the wellhead pressure values fluctuate around an average value and the predicted flow rate accuracy is in the range of ± 5%. The initial shut in wellhead pressures are also calculated corresponding to the "cease flow" condition of the well.

Above the critical rate where slug flow effects disappear and wellhead pressures become stable, corresponding to homogenous flow regimes (foam, froth, annular/mist and mist flow regimes), the accuracy of the VMSS3 calculations are excellent and in the ± 1-2% range. This accuracy is attained with accurate laboratory PVT data, converted to regressed equation form and reflected in the iterative calculation of each well increment.

Well calculations have been made in other fields where PVT data was limited and lower accuracy was obtained. The well potential curves are also extended to lower reservoir pressures to give flow rate predictions as reservoir pressures decrease over time. The well potential curves are also developed for expected changes in gas/oil ratios and water cuts that are predicted by the reservoir simulation model.

8 INTEGRATED SOLUTION : RESERVOIR PAY/ WELL/ GATHERING PIPELINE/ HP SEPARATOR

VMSS3 can be applied to calculate the overall integrated performance of the reservoir, well and gathering system as shown in Figure 3. The well potential curves as a function of time periods of production(years) are plotted on the diagram as are the pipeline gathering system potential curves with the option of varying first stage separator pressures as a parameter. The expected production for each period of time can be derived from these curves at the intersection point of the well and gathering line potential curves, representing the multiphase flow rate and the wellhead pressure at a time related reservoir pressure.

Production alternatives such as well workovers, gas injection and submergible well pumps may be introduced at specified times. Note that the hilly terrain gathering pipeline/separator facility starts flowing in slug flow below a certain rate. and provisions must be made at the separators to handle the train of liquid slugs and gas bubbles which are predicted. Another alternative would be to commence gas lift operations. Design standards may well specify avoidance of severe slug flow because of the resulting production capacity reductions and the inherent dangers of long high velocity high quality liquid slugs.

9 RESERVOIR FLUIDS PVT PROPERTIES

The accuracy achieved in the formulation of the PVT laboratory data for the reservoir fluids entering the multiphase flow system is a key to accurate flow prediction. The PVT properties include oil, gas and mixture densities, viscosities and gas/oil ratios, expressed as functions of pressure and temperature through the operating range of the production system. The range is from the reservoir pressure and temperature to standard conditions. An example of the mixture density property as a function of P & T above and below the bubble point for a reservoir fluid with S.C. of 34.2 deg API and 562 Gas/ Oil Ratio (scf/b) is shown in Figure 4. Experience on 65 reservoir fluids laboratory PVT Analyses has shown that accuracy in the ± 0.5 - 1% range have been obtained, far superior to standard correlations and critical for accurate well multiphase rate estimates.

Our data banks that have been developed are among the most extensive and comprehensive in the production industry and include 65 reservoir fluids that have been correlated over a broad temperature range (for at least at three temperatures) and over the entire pressure range, above and below the bubble point. This may include upper range pressures of 15,000 psi for gas condensate fields and 2500 psi in Middle Eastern fields, extending down to atmospheric pressure. To determine the physical properties prediction to the ± 0.5 - 1% range a set of 12 equations and 55 coefficients is employed in VSSM3. These enter into each flow increment calculation. Our fluid data bank reflects the development of 3575 regression coefficients and 780 regressed equations.

With limited PVT data for a reservoir, the VSSM3 model can generate a complete fit to represent the reservoir fluid. In many field applications the PVT data is limited to only one temperature, normally the reservoir temperature. The data bank allows for the extension of the PVT data to a broad temperature range (60-250 degrees F) that is required to simulate the reservoir pay, well, gathering pipeline system and separator stages.

A Virtual Memory Data Bank has been created in the computer memory based on the regressed PVT data for 65 reservoir fluids covering a wide range (8 – 46 API gravity /120 to 6000 scf/b GOR). This accurate resource has proven to be invaluable in new field applications where the PVT data were limited or incomplete.

Brelvi and other researchers as well as EYI have found errors in the liquid density prediction of ± 10% or more using standard equation of state model calculations. These methods are inadequate for achieving the degree of accuracy in multiphase well flow rates and in the design and optimization of producing systems that are achieved by VMSS3. There are other fluid properties that are required in the calculations such as specific heats, surface tensions, and thermal conductivity which are correlated based on empirical and theoretical methods and which are correlated as functions of pressure and temperature.

10 STARTUP OF WELLS AND GATHERING LINES

Wells/gathering lines may shutdown for various reasons, maintenance, operational problems, new construction, and cease flow conditions in the system.VMSS3 contains subroutines that simulate the options that may be available for restarting the wells and gathering lines. For gathering lines, a subroutine computes the distribution of the liquid and gas phases along the line at equilibrium with the environment.

11 WELL SUBROUTINES

- After shutdown compute the final equilibrium condition of the well. Determine the heights of the liquid and gas columns and the resulting pressure and temperature profiles to the wellhead.
- Compute if the well can start on its own if the wellhead pressures can be reduced sufficiently

- Calculate start up options:
  - short tube kickoff gas injection
  - downhole pump for startup
  - install gas lifting
  - lighten the density of the liquid column, LNG or nitrogen injection.

12 GATHERING LINE SYSTEMS SUBROUTINES

- The pressure and temperature profiles along the line are computed.
- Estimate the lengths of the liquid and gas legs formed in hilly terrain and their relative location along the line.
- Calculate the head of the line pressure required to overcome the sum of elevation pressure drops to initiate flow against the separator back pressure.
- Predict separator operations to unload the liquid and gas slugs from the line during the transient period. Determine the inlet valve size and allowable flow rates to safely unload the line based on pumping and gas flaring capacities.
- Compute the head of the line pressures and the gas injection flow rates to reduce the density in the line and reduce the size of the liquid slugs and increase their gas quality
- Employ the pigging subroutine to calculate the initiating pressures and the optimum pig velocities to unload the transient flow in the safest manner combined with operations of the separators

13 SUBROUTINES FOR HOLDUP, SAND DEPOSITION, HYDRATE FORMATION, ASPHALTENE/WAX DEPOSITION, LINE PIGGING

- Holdup correlations are calculated at each increment and the total holdup computed at the end of the line,
- Based on empirical studies a set of equations and correlations has been
- developed for the calculation of sand deposition settling rates and volumes in each flow increment.
- Pressure and temperature charts that correlate with incipient hydrate formation conditions may be calculated in each flow increment. When the critical condition is reached an output warning statement is given. These charts and correlations are under further development and come primarily from pilot plant research.
- Based on empirical field data subroutines for estimating the deposition of waxes or asphaltenes are available from data in the technical literature.
- Pigging subroutines have been developed to calculate the initiating pressures and the optimum pig velocities to unload the line for cleaning purposes (sand/wax etc. removal)

14 RESERVOIR INFLOW PERFORMANCE THROUGH PAY INTO WELLBORE

The VMSS3 calculation begins at the reservoir pressure and temperature (Pr/Tr) at a specified well depth. The pressure drop from the reservoir into the well (flowing through the reservoir pay) is measured by the difference in Pr-Pf (the flowing bottom hole pressure). the reservoir inflow performance simulation depends on the reservoir properties and on the wireline production testing and measurements.

The reservoir inflow performance simulations currently programmed in VMSS3 are the linear production index function relating the flow rate divided by Pr-Pf. For more complex inflows as in fractured reservoirs the delta p is related to q by two or three coefficients which are regressed from the well test data. These are of the form delta p equals a/bq or delta p equals a/bq plus cq squared.

VMSS3 calculates the downhole Pf and Tr from the wellhead Pw and Tw conditions for a specified multiphase flow rate determined downstream. This technique is employed for translating the well allocation flow rate to the reservoir entering conditions so that it may be used in reservoir simulation calculations.

When well drawdown and Horner shut in tests are available, the value of the reservoir properties controlling the reservoir inflow performance into the wellbore can be determined. These properties are permeability, effective pay thickness, porosity, viscosity, the skin factor, and the Dietz factor. The Productivity Index function can be expressed in terms of the reservoir variables and is used to calculate the reservoir pay pressure drop/ flow inflow performance into the wellbore.

A reservoir pay can be considered as divided up into 10 non equal zones. each zone may have different production indices. Zones may have no production and other zones may flow water or gas alone. The model calculates the blended mixture fluid properties of the input streams from the reservoir pay into the well bore located above the reservoir pay.

For horizontal wells the reservoir inflow performance functions described above can apply at any section along the horizontal lateral where production flows into the well either through perforated liners or open hole production. The horizontal lateral can be divided into 10 sections, with different inflow characteristics from each section into the horizontal lateral of the producing well.

15 VIRTUAL METERING (VMSS3) COMPUTED MULTIPHASE FLOW RATES (QM) VERSUS WELL PRODUCTION TEST MEASURED FLOW RATES

The term “virtual metering” denotes that the multiphase flow rates were calculated by computer based production engineering models from the input system configuration, fluid properties, and pressure/temperature data along the system, usually at the reservoir, wellhead, production manifold, gas oil water separator, and at the exiting single phase meters. VMSS3 provides the multiphase flow rates in each flow increment as a function of the pressure and temperature calculated for each increment. A PTQM profile is thus generated along the entire system This is in contrast to multiphase meters that measure the multiphase flow rate at one specific location (flow increment) in the production system.

The following characteristics pertain:

a) The Multiphase Flow Rates are calculated over the possible range of flow conditions from zero to maximum. Any changes in the system configurations, fluid properties or input reservoir flow conditions can be estimated.

b) b. No multiphase meters need to be incorporated in the configuration to provide flow measurements in the homogeneous flow P – Q range. The QM difference between calculated and tests is $\pm$ 1-2 %. At lower flow rates the wells operate in slug flow and the QM calculation is less accurate. The wellhead pressures show fluctuations in this range. Accuracies drop off to $\pm$ 5 % (average whp). A wellhead flow measuring device is desirable in this range. Wellhead separators may improve the accuracy of the QM estimate. Wellhead flow chokes, which are installed for flow control, have been subjected to R & D and when equipped with the new multiphase software can achieve accuracies of $\pm$ 5 – 10 %. Multiphase meters processing three phases have been installed to measure the QM phases. Because of slug flow, partial or cyclonic separators have also been installed at wellhead or downstream junctions.

c) A flow choke is normally necessary either in the well or at the wellhead for control and safety purposes. It has been an objective to develop multiphase software that can be installed in the surface chokes that would provide accurate multiphase flow rate (QM) measurements. Considerable work has been done over the years on trying to develop accurate multiphase flow correlations for the several choke designs. Extensive investigations have been carried out in recent years by Perkins etc. al. and by Dunbar which has improved the accuracy of these calculations. The flow choke can provide redundancy for the virtual metering calculation system. to improve accuracy and reduce uncertainty overall.

The current VMSS3 version has been programmed for high end PC's adaptable to field installation. The VMSS3 computations can now be carried out online with the data input directly from the field's data acquisition and supervisory control (SCADA) system.

Production test data was collected on 250 wells producing from several different reservoirs with varying fluid properties. A downhole wireline test measured the static and flowing reservoir pressures and temperatures at the midpoint of the reservoir pay. The reservoir inflow performance was measured at 2 or 3 flow rates and the wellhead pressure at shut in was determined. The well depth was accurately measured. The inside diameter of the casing and tubing strings, whether flow was in the casing or the annulus, was determined. The downhole choke was a snap on or off type with little pressure drop at the normal open position. Well flow rate was controlled by a wellhead surface choke. The downhole choke was used for safety purposes only.

The validation of the VMSS3 technologies and systems was based on production tests on 422 production systems, 172 gathering pipeline systems and 250 wells. Sixty engineering projects have been carried out in the last 25 years and successive improvements based on field matches have been incorporated in the simulation algorithms. In practice it is proven to be valuable to be able to refer to the past solutions to the production systems while making new applications and defining new field projects. For example, by inspection a specific system configuration design can be checked against a similar production system retained in data bank memory a first idea of the expected performance before funding is committed. to further study. Also newer technologies that are incorporated in VMSS3 can be evaluated relative to the existing solution data banks.

The PVT data was determined from samples of the reservoir fluids analyzed in the PVT assay laboratory and regressed into a set of equations and coefficients within ±1 accuracy. PVT data measurements at the wellhead were made based on exiting single-phase liquid and gas flows. The VSSM3 PTQM simulation calculations were carried out to match both the reservoir and wellhead P and T values. The calculated multiphase flow rate value and the difference was a measure of the uncertainties both in the VSSM3 calculation process and in the accuracy of the engineered production test measurements.

The test data measurements were made by production engineering teams and inaccuracies were minimized. The high pressure wellhead separators were operated to minimize liquid carryover (lco) and gas carryunder (gcu). The optimum liquid level relative to any 24 hour stabilized flow capacity was maintained. The exit single phase streams were measured by calibrated pressure liquid (pd meters) and by gas orifice meters. Before carrying out the tests the meters were tested by meter provers to assure accuracy of fluid measurements to ± 1 - 2%. Therefore, the differences between the calculated and tested QM's were largely due to uncertainties in the VMSS3 calculation algorithms.

16 VIRTUAL METERING (VMSS3) CALCULATED MULTIPHASE FLOW RATES (QM) VERSUS PRODUCTION TESTS ON GATHERING LINE SYSTEMS

The uncertainties associated with well flow calculations are quite different than in complex gathering line systems. The concept of redundancy is based on measuring a multiphase flow rate in two or more ways For example at a specific increment in the system, at the end of the flowline or at the wellhead, by a multiphase flow measuring device and by choke pressure drop calculations. Flow devices installed in practice include orifice and venturi Meters, partial separation and cyclonic separation meters, and three phase multiphase meters (MPMs). At a specific point in the flow system these devices provide a multiphase flow rate volumetric measurement (QO/QG/QW).

To measure slug flow regimes Brill et.al. developed a distance meter for horizontal sections of lines. Extensive field testing was carried out in Prudhoe Bay. Later further developments were carried out by Scott and Pots in extending the correlations to 24” diameter lines. Two densitometers of sufficient radiation energy are placed to define a critical distance along the line. The two sets of instantaneous density data, configuration data, pressure/flow, material balance, and energy balance equations are combined to measure the flow rates of the liquid slugs and gas slugs as well as the size frequency distribution. By integrating over time periods QM’s can be measured. The distance meter has the advantage of being non-invasive and causing no additional pressure drop across the line. Experimental work has been done on distance meters. However, the radiation requirements exceed safety standards in some countries.

Since the virtual metering calculation system calculates the QM’s in each increment of the system, this calculated QM can be compared with the measured QM from the flow device. The redundancy aspect is to iterate between the multiphase meter flow rate measurement and the virtual metering calculation result until a match is obtained. Experience shows that this can reduce the uncertainties in the meter QM measurements and in the virtual metering simulation calculations.

In some production systems, there are additional redundancy checks which can further reduce uncertainties and improve flow prediction accuracy. For example, when several multiphase well/flowlines are entering the production manifold before the gas/oil/water separation plant, the exiting single phase flows from the stages of separation are resulting from the incoming multiphase well/flowlines into the production manifold before the first stage separator. A material balance calculation has been developed to compare the exiting oil, gas, and water flow rates converted to standard conditions with the sum of the incoming QM’s at the entering pressure and temperature condition of the manifold. Corrections and adjustments can be made to the virtual metering simulation calculation and to the flow rates measured by the flow measurement devices. This provides a second redundancy calculation to further reduce uncertainties in QM predictions and to improve accuracy.

The multiphase pressure drop versus flow rate correlations available in the literature exhibit inaccuracy of up to $\pm$ 300% in the calculated pressure drop values for seven commonly used correlations (Behnia, OG&J, 4/16/91). These multiphase pressure flow correlations have generally been developed in small diameter lines and at the pilot plant or laboratory scale. There was little rigorous field testing of actual large diameter multiphase lines operating in difficult hilly or underwater conditions and with lines of substantial length. The pressure drop effect of flow devices, control valves, surface control chokes, desanding units and orifice, venturi, and MPM meters are reflected in VSSM3 as installed at their locations along the flowline. This improves the realism of the QM measurements.

Because of the large investments required and of the importance of knowing the multiphase flow rates resulting from the designs of the multiphase gathering lines and systems, a large field research program was carried out on 172 actual systems. About 70% of the flowing pipelines tested were operating over hilly terrain or were offshore lines with downcomers and risers as well as control systems in the lines.

The production engineering teams took care to determine the lengths and profiles of the lines in operation as wells as inside diameters, control valve and choke sizes, and determining any other pressure loss elements in the surface lines. Foam probe testing was carried out in some lines to verify flow regime calculated estimates. Pressure and temperature readings were taken at the wellheads and at the end of line manifolds before entering the high pressure separators. Pressure data was also collected across flow elements and devices.

The testing was carried out on lines that either had test separators available in the gas/oil separation plant or where differential flow testing was possible in production testing, or where the other incoming lines could be shut in temporarily to measure the multiphase flow rates from individual flow lines. Results were checked against metered single phase flow rates at the end of the separation processing stages. There were separate gas orifice meters on each stage of separation. The line diameters tested ranged from 8 inches to 36 inches and the line lengths up to 29 miles.

Future field R&D should result in improvements in the underlying equations and coefficients that are used in the VMSS33 simulation package and should help reduce these uncertainties. Substantial progress has been made in the slug flow relationships and these have now been incorporated in VMSS3 as subroutines.

Analysis of the test results show that the uncertainties depended on the flow regimes predominantly flowing in the lines:

- If velocities and densities generally predicted homogeneous flows in the lines, the difference between calculated and measured results were in the ± 3 – 5 % range.
- With stratified flows existing in the line and exiting into the HP Separator differences were found to be in the ± 4.5 – 7.9 % range
- With well developed slug flows in the lines and discharging into the HP separator with fluctuating pressures, the QM differences are in the ± 10 – 13 % range.
- With high velocity/ high Gas/Oil Ratio flow in the lines the annular / mist or mist flow regimes are present, and the differenced in QM are only in the ± 2 – 4 % range.

Figure 5 shows the behavior of multiphase lines with elevation changes, in this case an offshore pipeline with a downcomers and riser in the system. Measurement of flowrates are more difficult because the pressure drops are similar over a broad range of flow rates and the flow rate is not directly predictable from the pressure drop because of errors in measurement. Orifice plates were installed at the end of the lines just before entering the production manifold. Their redundant measurement enabled accurate measurements to be made in the middle range of flow rate.

The elevation pressure drop and the frictional pressure drop (horizontal equivalent length) and the total pressure drops are shown on Figure 5 as function of the system flow rates. The flow characteristic is due to the sum of the two pressure drops acting in the system. Hilly terrain lines show a similar pressure drop/ flow rate characteristic. The friction pressure drop/ flow rate curve shown is characteristic of horizontal lines.

The Figure 5 chart also show the predominant flow regimes operating in the offshore pipeline in three flow rate ranges, annular mist, stratified, and slug flow.

- At the higher QM's the Annular/Mist homogeneous flow regime prevails. VMSS3 is able to calculate QM's to ± 2 – 4 % accuracy. An orifice or venturi at the end of the line equipped with multiphase software can measure QM's to ± 2 – 5 % accuracy. A material balance cast around the separator provides a second redundancy to further improve the multiphase flow rate measurement.
- In the middle range of flow rates the stratified flow regime predominates. VMSS3 on average can calculate stratified QM's to ± 5 - 8 % accuracy. A simple orifice or venturi installation cannot effectively measure QM in stratified flows. Several devices have been designed that are installed before the orifice or venturi for the purpose of remixing the separated phases so the venturi tubes would develop mixed homogeneous flow which would enter the vena contracta. All venturi pressure drop/ flow rate calculations depend on a uniform constant mixture density existing in the vena contracta. Thus the entering stratified flows must be conditioned to meet this requirement.

There are many multiphase conditioning options that work with more or less success depending on the design and costs.

- A set of small diameter tubes installed before the orifice or venturi. The entering mixture velocities are increased and there is mixing. Baffles can be added. Flow conditioning tube design standards are given as an API flow measurement standard.

- The chemical process industry have a lot of experience in mixing phases Some equipment has been adapted to mixing two or three phase flows
- Mixing barrels with labyrinthine flow circuits and Mixing barrels or pipes with internal baffling and/ or small orifices.
- A mechanical high speed agitator to mix the phases in a barrel or tank. This requires a power source.

At the lower flow rates the slug flow regime prevails in the pipeline, Design standards of some producing companies call for avoiding the generation of slug flows in their pipelines and separation facilities because of the loss of flow capacities and the inherent dangers of slug flows. Extensive R&D field and pilot plant work was carried on in the 1978 – 87 period by Brill, Schmidt, et al. to determine the underlying flow phenomena and relations occurring in the term slug flow. They found that there are acceptable slug flow regions (small slugs and bubbles), a transitional flow, and severe slug flow. The severe slug flow range must be avoided. The design standards were relaxed when acceptable slug flow was predicted by their correlations, where this flow regime can be handled without excessive pressure losses or dangers.

Any slug flow entering an orifice or venturi must also be conditioned to form a homogeneous phase in the vena contracta. An addition aspect is that the multiphase measurement device must be equipped with software that can calculate the varying mixture densities versus time characteristic of slug flow. The reported QM values varying with time and must be integrated over a time period.

The conditioning of stratified flows requires similar equipment as described under slug flow, as well as additional multiphase software.

17 MULTIPHASE FLOW MEASUREMENT DEVICES

The general flow measurement standards for fiscal metering are ± 0.25 –1 %. The multiphase flow rate measurements obtained from the integrated (VMSS3) simulation of the production system plus the addition of flow rate measurement devices do not reach this standard of accuracy. Further R & D is needed to improve multiphase flow rate prediction accuracy. Some operators are of the opinion that achieving accuracy of ± 5% or better would be satisfactory and there are already many VMSS3 applications where this level of accuracy has been achieved as evidenced by the engineered production tests when operating in homogeneous multiphase flow regimes.

EYI has devoted considerable development effort to improving the accuracy of multiphase meters through PVT property and software installations and the design of flow conditioning equipment installed before the meters (attempting to assure homogeneous multiphase flows in the orifice or venturi type devices). Specifically:

- EYI has carried out extensive engineering and software development to improve the flow choke as a multiphase flow rate measuring device. (with PVT data of ±1% accuracy). the measured choke flow rates were in the ± 5 - 10% accuracy range. this is an improvement in choke flow measurements compared with the ±25 - 35% accuracy that were found in the earlier years without advanced software. These improvements are due to the highly sophisticated software.
- Considerable work has been done on the dual venturi concept, which provides a set of equations from which the three phases can be calculated with sufficiently advanced software. EYI multiphase flow software for orifices and venturi meters, especially in wet gas operations (5-10 barrels/mmscf) has been improved with the gas phase measurement results of ± 2.8% and liquid flows of ± 6.2%. These flow devices are relatively low cost and often are readily available.
- Several manufacturers have developed commercial multiphase meters (MPMs) of various designs. Technical papers and manufacturers descriptions provide the

information on the different MPMs. The flow measurement devices that have been studied to develop multiphase flow pressure drop versus rate correlations are:

- surface or wellhead chokes as described below
- single or dual venturi meters as described below
- MPMs tend to perform at one multiphase flow rate where the meter control and data acquisition system is calibrated. Changes in flowing conditions require updating of the calibration. Reported accuracy under near ideal flow conditions is ± 10%.
- MPMs are much more expensive than the standard flow devices. with installed costs in the range of $250-500,000. Also, there were substantial operating costs in the first two years in one operation to make adjustments to the device and for calibration.
- As described above, improvements in MPM accuracy are possible if redundancy calculations are employed.

As described below EYI has worked with operators on the system design and flow measurement software for partial separation meters where a well designed cyclonic separator separates the liquid from the gas phase. The phases are metered separately. The accuracy of the PVT data is key here because the measured pressure crude oil rates and high pressures and temperatures must be translated by PVT calculations to the standard conditions to report the liquid and gas flow rates. The separated gas flow rate is measured by orifice, venturi, or vortex shedder flow devices. Problems that occur are the liquid carryover in the gas exit and gas carryunder into the liquid exit. Therefore, the cyclonic separator is a key component of the system and must be carefully designed to have sufficient g forces to accurately separate the phases at the p/t conditions. The g forces also must be sufficient to suppress foaming. Refer to Figure 6 for a sketch of a Cyclonic Separator multiphase meter.

The advantage of partial separation MPMs is that they can meter the pressure crude stream and the high-pressure gas stream with meter provers. In theory the standard measurement requirements at ± 1 % could be achieved with an optimized design. A second advantage noted in the field is the potential ability to handle the incoming slug flows. Cyclone separators exerting g forces of 100-200 have the ability to transform the slug flows into gas/liquid phases with only the location of the vortex varying as a function of the length of the liquid slugs and of the follow on train of gas bubbles. The metering devices have to record the varying flow rate ranges of liquid and gas. The cost of these devices are between standard flow measurement device costs and the more expensive commercial multiphase meters.

18 EYI SOFTWARE FEATURES: PARTIAL AND CYCLONIC SEPARATION AND VENTURI MULTIPHASE METERS

The EnSys Yocum PVT Meter Correction Programs are capable of correcting multiphase meter liquid and gas flow using PVT data that describes the metered fluid. Among the features are:

- Reports oil and gas mass and volumetric flow rates at meter, standard and any other alternate conditions specified by the user, including downhole;
- Reports the gas and oil densities at meter conditions along with pressure and temperature gradients. These gradients are subject to significant variation depending on the meter pressure and temperature;
- Calculates the mass and volumetric fractions of the oil and gas phases along with the mass fraction of liquid remaining as liquid at reporting conditions (standard conditions or as otherwise specified) and the gas to liquid conversion where the reporting conditions are at a higher pressure than the meter conditions;
- Handles the complete range of gas and liquid flow ratios, from 0 to 100 percent liquid. Using the mass fraction values cited above, this feature enables the program to transpose the flow of gas and liquid slugs through the meter to the corresponding gas and liquid flows at standard (or other specified) conditions.

Special features associated with the Venturi Wet Gas Meter Correction Program are:

- calculates separator stage gas ands condensate flows;
- reports gas and liquid flows on an H2S,CO2 and water free basis if desired. The distribution between the liquid and gas phases of these components is accurately represented;
- calculates the calorific content of the gas produced;
- reports the gas, condensate and water densities at meter conditions along with pressure and temperature gradients. These gradients are subject to significant variation depending on the meter pressure and temperature;

Versions of our program have been installed on-line in Prudhoe Bay and the North Sea.

19 EYI SOFTWARE FEATURES: MULTIPHASE CHOKES FOR METERING AS WELL AS CONTROL

An EYI Program calculates the Critical and Subcritical Flow of Multiphase mixtures through chokes. The complex and rigorous calculation procedure utilized is described in SPE Paper 20633 published by T.K. Perkins, Arco E&P Technology. The method has been further refined by allowing the user to introduce physical property changes reflecting the liberation of gas between the upstream flow conditions and the choke throat, and by extending the range of flow conditions for which the program may be used. These extend to bottom hole well chokes for HPHT reservoirs:

Perkins reported testing the method against 1,432 data points with a standard deviation of 15.4 % and no bias detected. The data comprised both critical and subcritical regimes for gas/oil, natural gas/water and other systems. With basic physical property data inputs, our checks against field data for crude oil flow indicate that the spreadsheet program will predict multiphase flow rates within an accuracy of ± 10%. With the user calibration of the choke discharge coefficient against field tests this accuracy should improve.

20 MULTIPHASE CHOKE MULTIPHASE CALCULATIONS

- P up to 10,000 psig and T to 300 degrees F, with allowance for the user to input compressibility factor (z) and Cp/Cv (k) ratio at P and T higher values.
- 3-phase flow systems
- Applicable to MOV and Multistage Choke Calculations
- Applicable to critical and subcritical flow
- Calculation of mass flow rate and volumetric phase flow rates
- or back-calculation of the discharge coefficient (Cd)

21 THREE PHASE GAS/OIL/WATER SEPARATOR

The EnSys Yocum GOSPSIM model employed is a rigorous, multi-phase, steady-state, pressure temperature flow (PTQ) simulator designed for and proven against hundreds of oil and gas field production systems. The version of GOSPSIM applied here encompasses from the well-head through the surface facilities, including separators, to the terminus. Other versions encompass integrated simulation from the reservoir pay and well bore through the surface facilities, multi-well trunk line network systems and, prospectively, horizontal/multi-lateral well systems. The scope encompasses crude with associated gas, gas condensate and gas systems as well as black oil simulation.

Integrated modeling of separators within the context of the entire flow system establishes the approach conditions, including predicted slug size and frequency and the incoming flow regime. The approach flow regime may be stratified and this pre-separation provides additional separating capacity provided that a correct stilling box or flow diverter is installed. However, if the flow regime is homogeneous, separation is aided by passing the incoming flow through a jet forming nozzle which impinges on a target plate to form maximum separation between the gas and liquid phases.

Both (one) gravity and cyclonic centrifugal force technologies are contained in the Separator Simulation. Model. Because of the increasing water cuts, and higher GORs as fields age, increasing difficulty in the separation of the phases due to high viscosities, foaming crude mixtures, slug flows entering the separators, sand collection and disposal, and other problems, it has become economical in many fields to add cyclonic separation technologies.

Effective cyclonic equipment of several designs has been deployed in the field. Production data has become available on some designs. Therefore the Model now incorporates some of the more widely applied cyclonic unit performance characteristics and design limits.

22 EYI SOFTWARE FEATURES: THREE PHASE SEPARATORS

- The design mode which sizes the separator for the specified oil, water and gas rates given the separator pressure, temperature and fluid properties.
- The simulation or operating mode under which the separator size and design basis droplet sizes are specified (or calculated) and the effluent gas, water and oil qualities are calculated
- Based on engineered field test databases to establish liquid and gas residence times. Approximately 200 production tests that had been carried out on gas/ oil separators in thirteen fields with different reservoir fluid properties.
- Sizing for gas capacity based on entrained liquid droplet settling theory. The maximum gas velocity to avoid liquid re-entrainment is calculated;
- Gravity separation of the rising oil droplets based on Stoke’s Law, but also taking into account non-ideality and short-circuiting due to turbulence. The maximum horizontal liquid velocity is calculated
- Water droplet settling theory based on Stoke’s Law;
- Overflow velocity analysis and calculation of maximum oil pad thickness;
- Input retention oil, gas and water retention times based on API 12j common practice, petroleum engineering handbook criteria or bottle/ standpipe tests.
- The minimum water droplet design size corresponding to a 1 % water cut in the effluent oil is taken as an input or calculated. A water droplet design size is back-calculated corresponding to higher (or lower) flow rates, viscosity, other fluid property changes and different separator conditions. This back calculated droplet size is then compared to the above 1 % water cut value to calculate water-in-oil and oil-in water contents based on relationships contained in the model;
- The calculation of the distribution of oil droplet sizes, which affects water cleanup strategies to meet water discharge quality requirements.
- Internals options including inlet diverter plate/downcomer designs of different primary stage separation efficiency, gas outlet wire mesh pads, perforated plates in the liquid zone, wave plates, vanes, wave plates and structured packing. Also a vortex breaker design over the liquid outlet to prevent gas coning at low liquid operating levels).
- Effect of slug and surge flow on separator size
- Vessel weight and cost calculation
- Accounting for the separator volumes occupied by foam and emulsion layers
- Slenderness ratio optimization
- Inclusion of electrostatic treaters and separator heaters.
- The incorporation of cyclonic centrifugal force technologies with the conventional (one g) 3-phase separation process are described in detail.

23 THE EYI MULTIWELL NETWORK TRUNKLINE MODEL

This model is a calculation system for the accurate simulation and prediction of pressure flow behavior, including single and multiphase flow in networks beginning at reservoir sources, with flows through well inflow performance, then through the vertical or incline wells, (up to

100) through connecting flowlines, into branchlines, and then into gathering pipelines (trunklines). Devices and elements may be entered, such as valves, bands, sand removal, pumping chokes, gas lifting and submergible pumping. Advanced accounting for variation in elevation in terrain features, system configuration, fluid properties and critical regimes are incorporated in the system calculations.

The flow rates in each flow line, branchline and trunkline (mainline) and each well are calculated as are the pressure and temperature profiles in each well and section.

There is flexibility in defining a trunkline network system. Wells and connecting lines may flow directly to a mainline junction or the flow from several wells with flow lines may combine to flow into a branchline which then flows to a mainline junction. Lines may be looped. Pump stations may be located at any point in the system. One hundred wells (or source points) and whatever exit points required may be programmed into the model. The model contains a blending procedure for physical properties from any number of wells entering a junction. Calculations reflect the blended properties downstream in the branchlines and mainlines. This powerful feature enables the model to accurately simulate and predict essentially any network system.

24 EYI SOFTWARE FEATURES: MULTIWELL NETWORK TRUNKLINE MODEL

Coefficients are generated for a set of equations relating pressure, temperature, water cut and free gas flow rate for each well/flowline and each branchline in the total network. A first estimate is made of the last junction pressure (furthest from terminal). A test compares specified end pressures with the first calculation results. An appropriate adjustment is made to the last junction pressure and the iterative calculation proceeds until closure.

The model recalculates each and every well, flowline, branchline and trunkline section using the converged flow rate found in each segment. Thus complete calculation detail is made available at each point in the entire system. Exhaustive optimization calculations of various discrete parametric changes can be made. This is done by combining the calculated capacities with cost data to determine the ranking of system on a minimum cost basis.

25 ACKNOWLEGEMENTS

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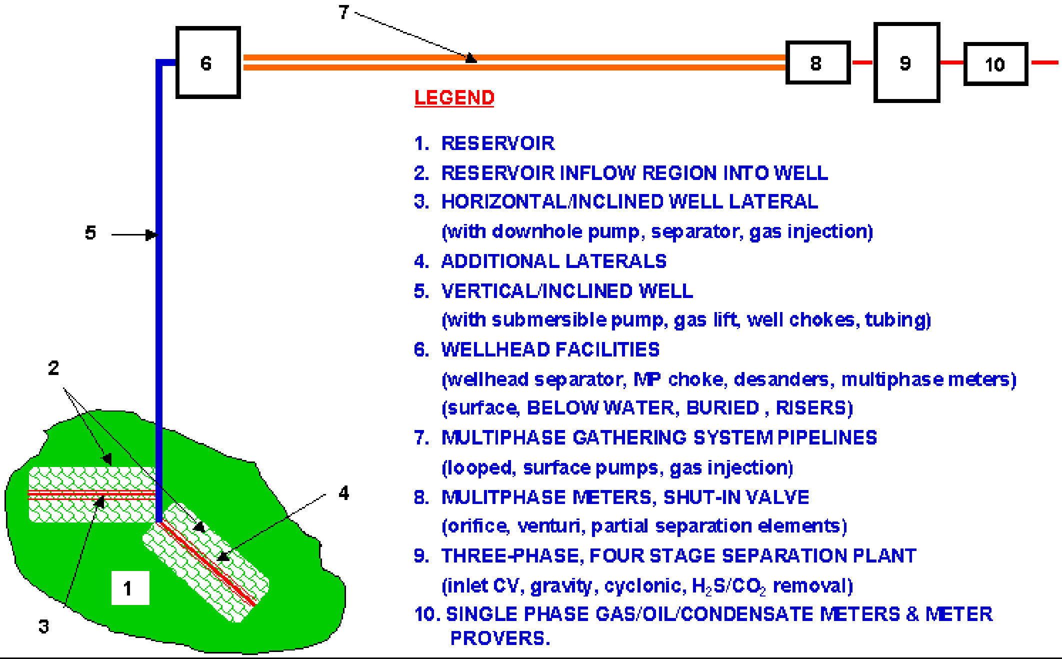
FIGURE 1: BLOCK DIAGRAM INTEGRATED MULTIPHASE PRODUCTION SYSTEM



LEGEND

1. RESERVOIR
2. RESERVOIR INFLOW REGION INTO WELL
3. HORIZONTAL/INCLINED WELL LATERAL
   (with downhole pump, separator, gas injection)
4. ADDITIONAL LATERALS
5. VERTICAL/INCLINED WELL
   (with submersible pump, gas lift, well chokes, tubing)
6. WELLHEAD FACILITIES
   (wellhead separator, MP choke, desanders, multiphase meters)
   (surface, BELOW WATER, BURIED , RISERS)
7. MULTIPHASE GATHERING SYSTEM PIPELINES
   (looped, surface pumps, gas injection)
8. MULITPHASE METERS, SHUT-IN VALVE
   (orifice, venturi, partial separation elements)
9. THREE-PHASE, FOUR STAGE SEPARATION PLANT
   (inlet CV, gravity, cyclonic, H_2S/CO_2 removal)
10. SINGLE PHASE GAS/OIL/CONDENSATE METERS & METER PROVERS.

FIGURE 2: PRESSURE DROP ERRORS TEST VS CALCULATED

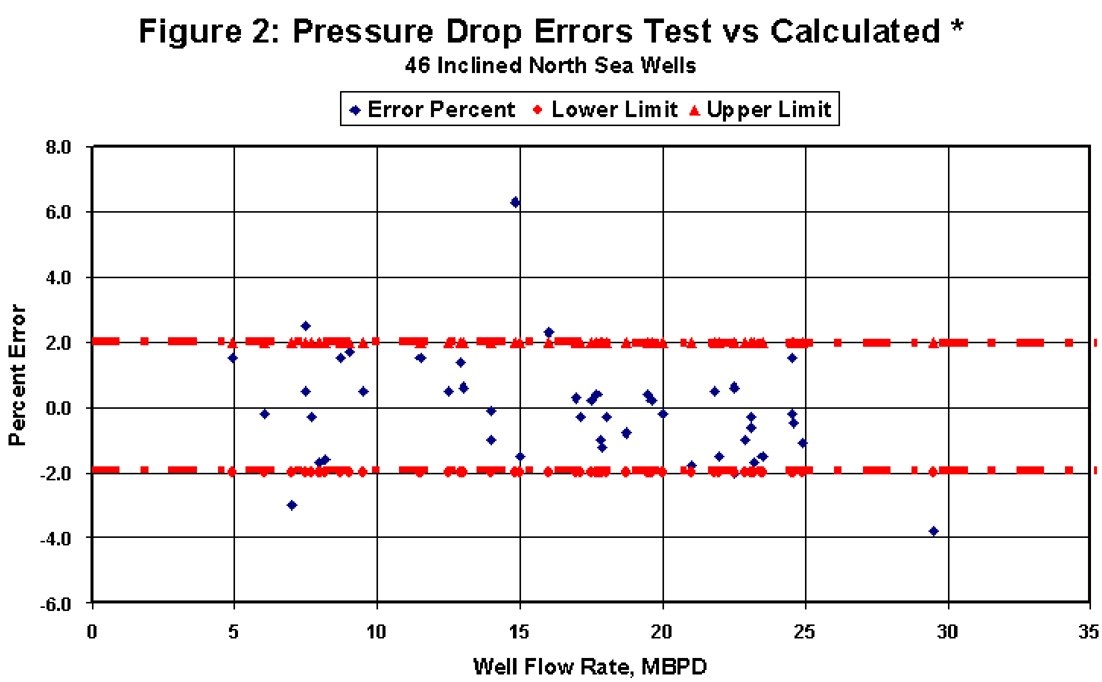


FIGURE 3: EXAMPLES OF WELL POTENTIAL CURVES (P - Q CHARTS)

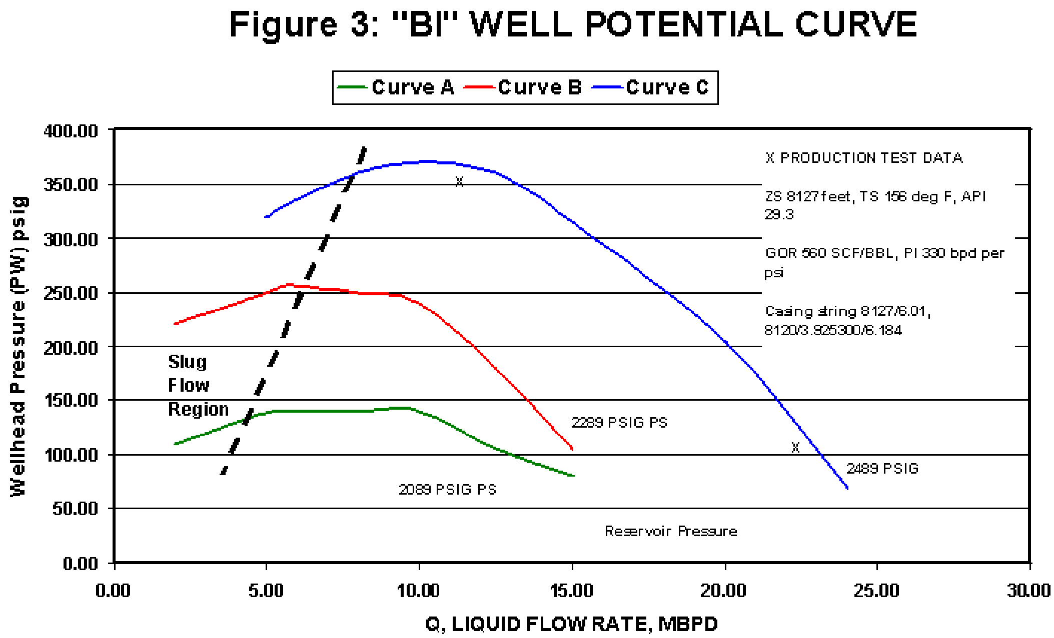


FIGURE 4: RESERVOIR FLUID PVT LAB ANALYSIS

FIGURE 4: RESERVOIR FLUID PVT ANALYSIS EXAMPLE
(34.2 API and 562 SCF/BBL @14.7 psia and 60 degrees F)

MIXTURE DENSITY VERSUS PRESSURE AND TEMPERATURE

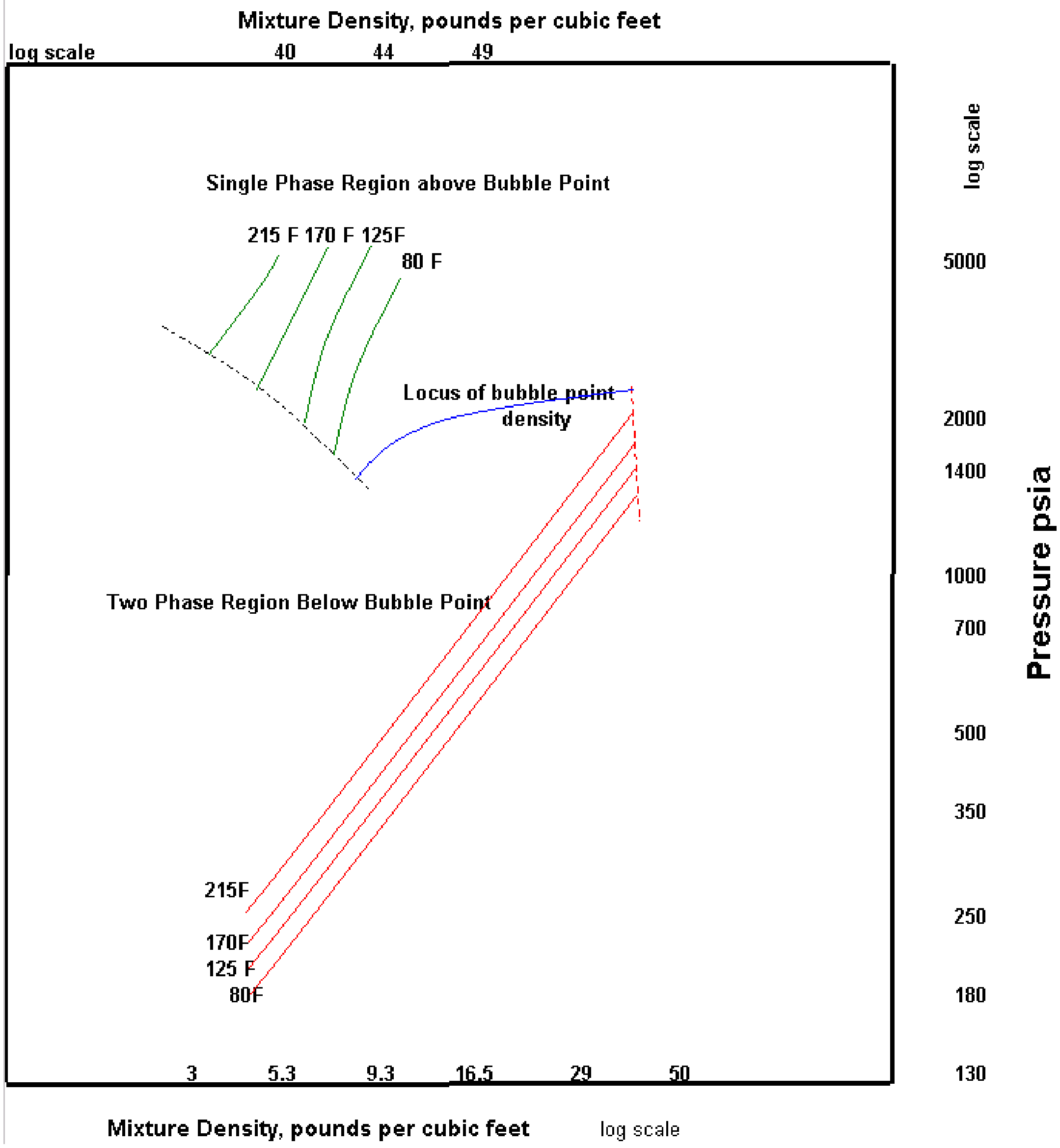


FIGURE 5: NORTH SEA LINES AND RISER

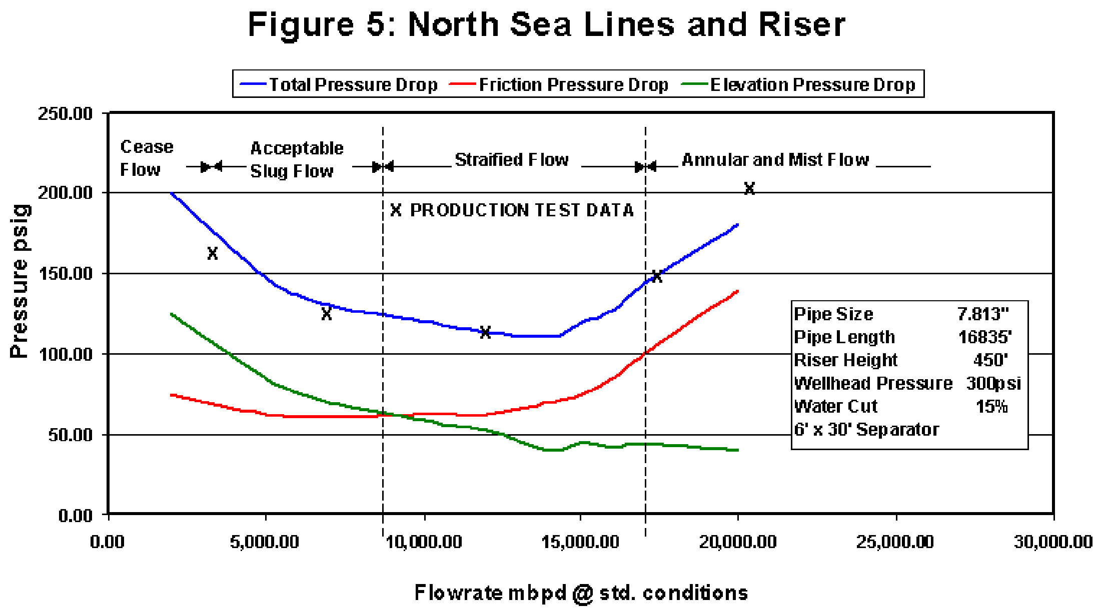


FIGURE 6: INTEGRATED PRODUCING SYSTEM WELL/GATHERING PIPELINE/ HP SEPARATOR

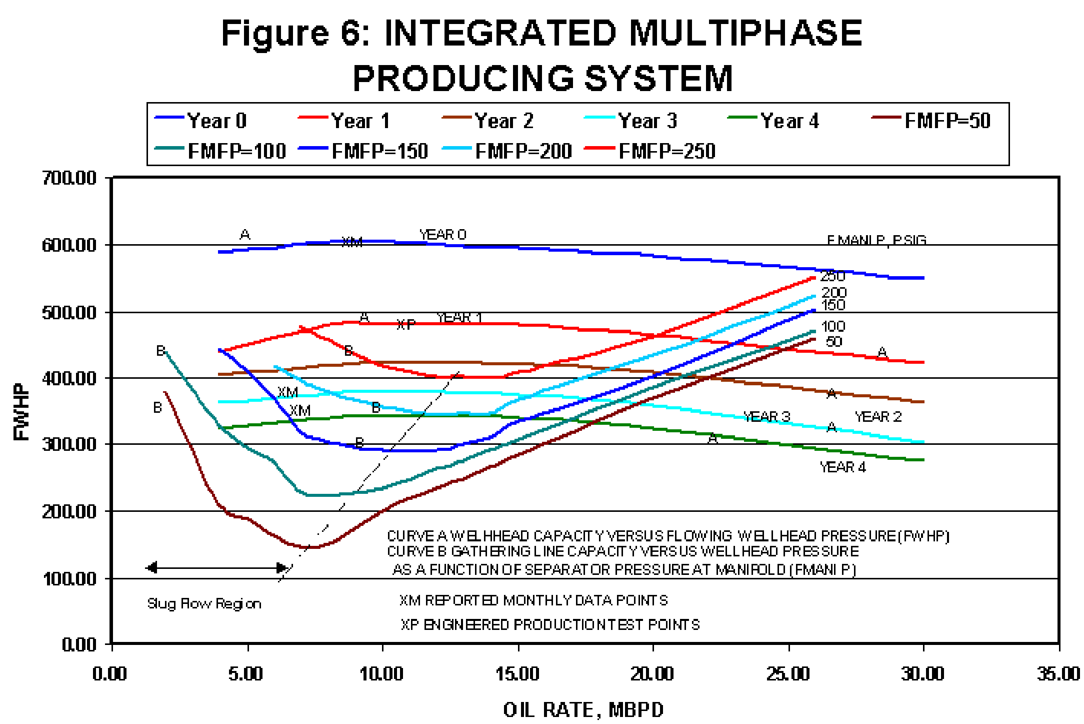


FIGURE 7: MULTIPHASE CYCLONIC SEPARATION METERING

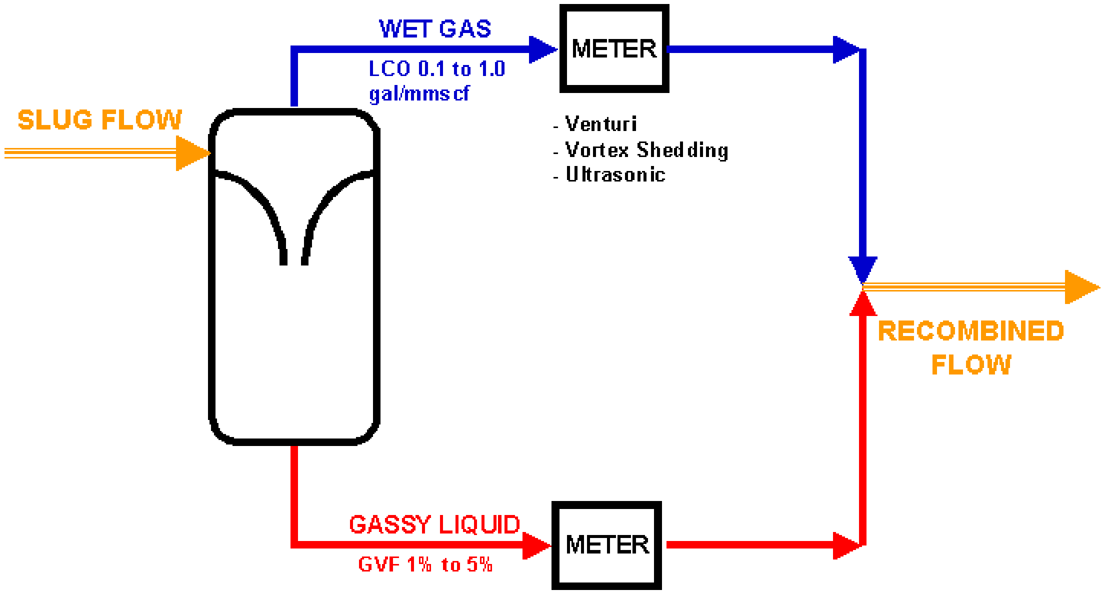


TABLE 1: VALIDATION AGAINST 367 WELLS & SURFACE FACILITIES

OIL FIELD	OIL WELLS			SURFACE SYSTEMS		
	No.	Average Deviation (%)	Maximum Deviation (%)	No.	Average Deviation (%)	Maximum Deviation (%)
AJI	44	0.05	0.50	39	0.67	5.2
AH	31	0.28	0.77	30	0.16	5.1
GS	29	0.08	0.57	25	0.78	2.6
RS	13	0.17	0.79	9	1.4	7.2
MA	31	0.08	0.95	29	0.60	4.0
PA	18	0.33	0.80	14	2.0	6.9
KA	6	0.27	0.75	3	0.51	4.7
BI	11	0.05	0.55	11	0.45	4.2
NS	9	0.04	0.96	9	INSUFFICIENT DATA	
PA	3	INSUFFICIENT DATA		3	3.8	5.7
TOTAL	**195**	**0.13**	**0.70**	**172**	**0.73**	**4.5**
DATA ACCURACY	**± 1 - 2 %**			**± 3.7 - 10 %**		

Over five thousand simulation cases have been carried out on existing production systems. Thus the model has been thoroughly tested and validated against a large quantity of test data, configurations and fluid properties from real systems composed of complex flow and process elements.

TABLE 2: COMPARISON OF MEASURED ERSKINE FLOW RATES VERSUS THE EYI PVT METER CORRECTION PROGRAM

The EYI PVT Meter Correction Program was copmpared against flow data provided by Texaco in the summer of 1998 for the Framo offshore venturi meter. The meter conditions data of 81.62 kpa and 120 degrees C is for flow from a well and for an average of six readings for the period 3-June-98 02:11 through 4-June-98 06:57. The PVT Meter Program densities for gas and condensate were applied to convert to input mass flow rates. The PVT properties were from an Erskine reservoir fluid assay provided by Texaco.

The comparison of Texaco values from single phase separator measurements of gas and condensate as produced from the facility versus our PVT program predictions is given below:

Meter condition flow rates	**Actual**	**PVT Meter Program**	**Difference**
Gas flow rate, cubic meters per hour	**709.3**	**666.4**	**-6%**
Condensate, cubic meter per hour	**62.15**	**64.1**	**+3%**

Standard Condition flow rates	**Actual**	**PVT Meter Program**	**Difference**
Gas flow rate, standard cubic feet per day	**39.85**	**42.59**	**+7%**
Condensate stock tank barrels per day	**7701**	**7553**	**-2%**

The database field data averaged 5192 GOR versus 5728 SCF per barrel for the assay data provided. Making the GOR adjustment would further reduce the 7% error indicated for the predicted gas flow at standard conditions.

TABLE 3: EYI VENTURI METER CALCULATIONS

The following calculations were based on using the 3-stage gas oil separator data as a basis for estimating the properties of the wet-gas system at standard conditions (atmospheric pressure and 60 degrees F), in turn used for calculating the stock tank barrels of condensate flow.

The following average standard conditions properties were calculated based on the field data provided:

Condensate density:	**50.25 pcf, or 44 API**
Gas density:	**0.0573 pcf, or 0.75 specific gravity relative to air**
Gas Oil Ratio:	**34,600**

These values were consistently applied to all of the 4 cases to calculate the condensate flows. The following results were obtained:

	As Measured STB per day	EYI Calculation STB per day	% Difference
Test 1	677	715	-5.6%
Test 2	848	858	-1.2%
Test 3	1147	1137	0.9%
Test 4	1542	1488	3.5%
Average Absolute Error			2.8%