EnSys Yocum
MULTIPHASE FLOW TECHNOLOGY

GOSPSIM 3.3 – Technical Description

Simulation of 3-phase Gas/Oil/Water Separation Facilities
Conventional (One g) Separation Process and Cyclonic Centrifugal Force Technologies

Sections to this technical paper include an Overview, Detailed Description of GOSPSIM, Field Case Studies and Applications Involving Chemicals Treatment.

I. Overview

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 GOSPSIM 3.3 3-phase Separator Simulation. Model.

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Gravity Separator Simulation

The following are key features of GOSPSIM with respect to gravity separation:

(1) The model can be run in two basic modes:

(a) the design mode which sizes the separator for the specified oil, water and gas rates given the separator pressure, temperature and fluid properties. In this mode, the separator is sized to 1.0 percent water cut in the oil, 0.1 to 0.5 gal per of liquid carry over per mm scf of outlet gas, and gas carry under of 0.02 GVF or less. Design droplet sizes may be input or provided by the model.

(b) 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 in response to varied flow rates, water cut, physical properties, internals, liquid levels and separator conditions.

Several approaches are compared within the model to arrive at a separator design size:

(a) the use of model-contained EnSys Yocum engineered field test data bases to establish liquid and gas residence times. Our simulation efforts commenced in the 1970's and early 80's based on approximately 200 production tests that had been carried out on gas/ oil separators in thirteen fields with different reservoir fluid properties. An extensive data base of fluid properties has been constructed, permitting the model to achieve high accuracy with simplified methods and within real world data limitations.

(b) sizing for gas capacity based on entrained liquid droplet settling theory. The maximum gas velocity to avoid liquid re-entrainment is calculated;

(c) 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 and compared to the terminal velocity of the rising oil droplet to calculate a design factor expressing non-ideality;

(d) water droplet settling theory based on Stoke's law;

(e) overflow velocity analysis;

(f) calculation of maximum oil pad thickness;

(g) 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. For conventional FWKOs with a water-wash coalescing section, this diameter correlates closely with oil viscosity and can be increased by installing an electrostatic treater.

An 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 distribution of oil droplet sizes affects water cleanup strategies to meet water discharge quality requirements.

(5) Other model features include:

(a) 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).

(b) effect of slug and surge flow on separator size

(c) vessel weight and cost calculation

(d) accounting for the separator volumes occupied by foam and emulsion layers

(e) slenderness ratio optimization

(f) inclusion of electrostatic treaters and separator heaters.

Cyclonic Separator Technology Simulation

The incorporation of cyclonic centrifugal force technologies with the conventional (one g) 3-phase separation process are described below.

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, GOSPSIM 3.3 now incorporates some of the more widely applied cyclonic unit performance characteristics and design limits.

II. Detailed Description

I. Gravity Separation

A. High viscosity stable emulsions

Separator design for high viscosity emulsions present particular challenges and the following method is employed:

A calculation is performed for gas carry under based on the gas bubble size distribution and liquid residence time. The distribution is log normal, with the distribution parameters under user control, specifically the median gas bubble size and the geometric standard deviation. The model contains default values for these parameters of 127 microns median gas bubble diameter and a geometric standard deviation of 2.1, corresponding to a gas bubble size range of 20 to 1000 microns, characteristic of gas bubbles rising through boiling liquid.

The program calculates the cutoff gas bubble diameter based on the liquid residence time and terminal velocity of rising gas bubbles based on Stokes law. The corresponding gas carry under is calculated based on the volume of gas bubbles which remain entrained in the liquid. The cutoff diameter is the diameter below which gas bubbles will carry under with the separator liquid bottoms.

B. Physical Properties Representation

Fluid properties are accurately defined and tied to each increment of flow calculation by physical properties equations contained in the model. The correlating equation coefficients are input through the user interface and are derived from regression procedures contained in an EXCEL spreadsheet. The EXCEL spreadsheet accepts user input of physical properties values as a function of pressure and temperature across a range of conditions characteristic of the system being modeled. These include mixture density, liquid phase density, gas density, gas to oil ratio (GOR) and liquid phase viscosity.

With hydrocarbon and water phase present, water and oil viscosities are input separately. Alternative mixing rules contained in the EXCEL spreadsheet are applied giving the user the option to choose and to input their own correlations. If there are specific emulsion viscosity correlations available, or laboratory data, these can be entered into our physical properties program. The effects of sand content and gas cutting on the separator liquid viscosity are considered. For non-Newtonian fluids, given suitable physical property correlations, we can build in a velocity-dependent viscosity function which can be applied within each increment of the flow system.

The physical property values required by the EXCEL spreadsheet can originate from laboratory PVT analysis of the reservoir oil, or be generated from equilibrium flash data obtained from S-R-K, Peng Robinson, a compositional reservoir fluid analysis, or other suitable equilibrium flash programs available.

C. Slug Flow Prediction

By applying that part of the GOSPSIM Model which simulates the gas oil separator approach and exit piping described below, the impact of slug flow on the performance of the separator is calculated. If the model determines that the flow through the approach piping is in slug flow, the mean and maximum (at the one-percent probability level) slug lengths are predicted, along with their corresponding frequencies.
If a riser enters the separator, the model distinguishes between slug flow and severe slug flow and calculates the extent to which the slug exceeds the riser length. The percentage level rise in the separator is calculated for all of the above to determine the capacity of the separator to respond to slug flow.
Correlations and calculation procedures, based on test data, have been incorporated into the model to predict slug flow in pipeline riser and control valve systems. The model is used to define the physical design requirements of the slug catchers since the formation of slugs cannot be avoided across the full range of pipeline operating conditions. Our slug size and frequency correlations are validated against a number of tests carried out in 12 and 16-inch lines in Prudhoe Bay. This database, and enhancements, provide a comprehensive field data to serve as the basis for our procedures.

The software distinguishes and flags gradations of slug flow severity, including severe slugging, and reports Schmidt's prediction of severe slug flow in risers or other elevation changes.

Risers receiving multiphase flow from long flow lines are conducive to slug flow, where the liquid slug may be several times the length of the riser. The Pots Severe-Slugging Group Number is used to predict the size of riser slugs, defined by the dimensionless number:

$Ii_{ss} = (zRT/M\ w_g)/(L_f\ y_{gF}\ w_L)$
If the slug flow volumes are excessive a slug catcher is sized and designed for the application.
Increase Separator Throughput Capacities

II. Cyclonic Centrifugal Force Technologies

The inlet G/L Cyclone Internals are installed in three phase Gas/Oil/Water Separators to obtain increases in the separation throughput capacities of one g separators while maintaining satisfactory minimum standards of liquid carryover in the gas outlet stream and gas volume fraction in the exit liquid stream.

Production experience has shown that the addition of the Inlet Cyclone Internals may also provide other improvements to the operation and production capacity of a separator as described below.

A. Defoaming Capability

Depending on the foaminess and difficulty of separation of the entering crude oil/gas/water mixture, optimally designed inlet cyclones may apply sufficient centrifugal force to the spinning gas/liquid mixture so that the foam is suppressed as the liquid phase is forced against the wall. Concurrently, the gas phase is spun out in a double spiral - first down the cyclone and then the gas is guided up the inner core to the gas outlet. This can be a major advantage in separation because high loading of foams causes reduction in production capacity since more residence time is required in a gravity separator to settle out the foam.

Two of the main ways to remove foam in the gas/liquid phase and emulsions in the oil/water phase have been to apply heating above 160 Deg. F. Subsequently, many foam micelles burst and the foams dissipate. The application of specific chemicals also minimizes foams and emulsions. It has been found that cyclonic units, namely multiple vortex tubes can mechanically eliminate many foams from the flowing gas/liquid mixtures provided that a sufficient level of centrifugal force (g's) can be applied to the swirling fluids. If multiple vortex tubes can be successfully applied to eliminate foams, expensive chemicals and/or heaters can be eliminated or reduced.

Experience shows that centrifugal forces of at least 150 –200 g must be developed to suppress foam into the swirling liquid phase against the wall and flowing down to the liquid exits. The defoaming capability also reduces liquid carryover (LCO) into the gas outlet and GVF (Gas Volume Fraction) in the liquid outlet. There are often critical problems with the occurrence of foaming and emulsions in gravity separators.

In recent years, an important finding has been the effects of multistage vortex tube internal designs installed in separators. It is important to reduce the effects of incoming slug flows on separator capacities and process performance via slug flow mitigation. This is achieved in multistage vortex tube designs. As the train of liquid slug length followed by the gas bubble length enters the separator, they are distributed by the centrifugal inlet devices equally into the vortex tubes (four, six, or eight tubes in most applications) which break the slugs into smaller pieces, mitigating their length effects. In addition, the vortex level in each tube processes up and down, depending on whether gas rich or liquid rich slugs are entering, thus allowing separation of oil and gas to take place. This process eliminates the liquid slugs and the follow on gas bubbles.

B. Description of Inlet Cyclones

Exhibits I and II show examples of gas/liquid cyclones currently in use in oil/gas industry. The performance correlations for these specific devices have been developed and are now incorporated in GOSPSIM 3.3.

Correlations have not yet been developed for the variety of cyclone designs. However, general empirical relationships have been established for centrifuges shown in Exhibit IV.

Centrifugal Force multiples of gravity correlated with Centrifuge Diameter in inches with various designs of centrifuges as parameters. This correlation is only indicative of the performance of cyclones and cannot be used in a detailed process design. Some production data on cyclones with respect to foaming is available.

A cyclone is a separating chamber in which the gravitational acceleration is replaced by the centrifugal acceleration. The centrifugal separating force may vary from five times gravity in very large diameter low resistance cyclones to 2500 times gravity in very small high resistance cyclones. The spiral velocities in the cyclone may reach several times the average inlet velocities. Cyclones can be more efficient for separating liquids from gases than separating solids from gases and liquids since coalescence can capture the liquid phase and the liquid is easily drained along the cyclone wall down to the liquid exit. However, precautions are necessary to prevent the re-entrainment of the gas phase in the exiting liquids.

In a cyclone the gas path involves a double vortex with the gas spiraling downward at the outside and upward at the inside. When the gas enters the cyclone tangentially the velocity undergoes a redistribution so that the tangential component of velocity (Vt) increases with decreasing cyclone cylindrical radius (R). This also increases the tangential velocity several times over the entering velocity as the gas spirals in multiple turns down the cylinder to the liquid exit. Experimental studies show the relationship of Vt with the reciprocal of R to be raised to the 0.52 for one cyclone and varying from 0.5 to 0.7 for different cyclones. The radial component of velocity, (Vf) is directed toward the center and helps separate the gas phase from the liquid phase.

When a body of mass (M) is acted upon by a force (F), it is accelerated in the direction of that force at a rate which is inversely proportional to the mass. When F is removed, the body continues its motion in the same direction at the constant velocity (V). Acceleration is zero until the mass is acted on again by a force. If the body is constrained to move in a circular path as in a cyclone or a centrifuge, its scalar velocity remains V, but its vector velocities change continuously. The change in the tangential vector velocity is expressed as the centrifugal acceleration which equals the square of the angular velocity (omega in feet per second) divided by R, the radius of the circular path in feet. The centrifugal acceleration AC creates a centrifugal force FC where FC equals the product of the mass times the square of the angular velocity omega divided by the radius of the circular path R of the cyclone cylinder.

An important concept in cyclone technology is the relative number of gravity forces developed by the centrifugal forces compared with the 1 G. gravity of the gravity separator. This is an important measure of the additional performance obtained from cyclones above the gravity separator performance. The relative centrifugal force RCF is defined as the square of the angular velocity (omega) times the radius R of the cyclone circular path divided by the acceleration of gravity G.

The number of G's required in the cyclones to suppress the foam generated from the incoming reservoir gas/liquid mixtures is a critical design determination in any separator plant process design. Severe foams limit the capacities of gravity separators and consequently limit the capacities of the upstream well/ trunklines feeding the separator.

This often represents increased process plant investment as well as significant producing rate limitations. If cyclones can be designed to suppress foams at a reasonable cost, it eliminates the need for corrective actions such as chemical treatments or application of heating. The relationship between cyclonic gravity forces and the suppression of foams has not been studied in sufficient detail to provide engineering correlations at a high confidence level. However, experience shows that creating G forces in the cyclone of 100-200 G's has been successful in defoaming specific reservoir crude oil/water/ gas mixtures. It has also been noted that cyclones providing only moderate G forces in the 25-50 G range do not act as de-foamers.

The multistage cyclonic vortex tube designs and certain specific de-sander designs have been adapted to the removal of sand from the reservoir mixtures with special designs for sand removal at the bottom of the cyclone cylinder.

C. Description of Cyclone Technologies Incorporated into GOSPSIM 3.3

The fundamental equations, empirical correlations and calculation methods for widely applied cyclones have been incorporated into GOSPSIM 3.3. Other cyclonic devices like GLCCs are not included because field empirical performance correlations are not yet available.

Examples of gas/liquid cyclone designs incorporated in GOSPSIM 3.3 are described below. As more information is obtained from field applications, additional correlations will be included in GOSPSIM 3.3.

Exhibit II shows a cyclone designed to remove small quantities of liquids from large volume gas flows. These units are modified for use in gas/condensate field and pipeline flow and processing. Because relatively low liquid/gas ratios reduce the flow capacity of expensive gas pipelines, the removal of the associated liquids in the cyclone decreases the investment in gas fields. Special features in this type of cyclone design are listed below:

The tangential inlet establishes the tangential feed.
The baffle plate serves to create a stilling chamber for removal of residual gases from the liquid phase.
The inner vortex tube causes the gas to rise up the tube to the outlet.

Note that the liquid "creep" (film) that flows along the gas outlet pipe wall will re-entrain liquid in the gas phase, thereby reducing the efficiency of liquid removal from the gas phase and causing increased liquid carryover (LCO). In addition, the liquid spun out against the cylinder wall flows down to the liquid stilling chamber.

Exhibit II illustrates improvements where the liquid “creep” (film) on the gas outlet wall is diverted near the top into a recycle line. The liquid is recycled into the stilling chamber below the baffle.

Another refinement would be to have a double walled cylinder with some perforations. Considerable liquid flows between the two walls will not enter into the liquid creep. As a result, the downstream pipeline operating efficiency increases because the multiphase pressure drop due to the gas and liquid phases is reduced. Therefore, this adaptive cyclone technology developed in the last few years is now essential in finding the optimum economic design of gas/condensate pipelines.

Exhibit III shows the design of a dual vortex tube that is containerized. Note that all phases can be separated - gas, oil, water and sand. Over 300 Vortex Tube designs of this type have been installed in field separators in recent years. These cyclonic vortex tubes can also be containerized and installed in front of gravity separators. However, this is not as beneficial as installing the vortex tubes internally in the gravity separator at the inlet. Six stages of vortex tubes are installed in the gravity separator. The vortex tubes can vary from 4 to 24 inches in length, but are usually 6 to 12 inches. The depths of the tubes depend on the diameter of the separator, but are usually 50 to 72 inches.

Several of the usual claims for installing multiple vortex tubes integrated with the gravity separators are listed below. These tend to apply to the standard range of solutions. Very difficult separations require some adjustment of these claims. Besides the capabilities already discussed, the following claims are made:

At optimum conditions liquid carryover is reduced to liquid particles of 7 microns.
and 99 % removal of solids.

For new applications reduced vessel size because of reduced residence times while still obtaining superior separation.

Retrofits of existing gravity separators show large increases in flow throughput and improved separation. This is the basis of the claim that all of the company’s separators must be retrofitted to obtain maximum flow performance and the resulting reduced investment and operating costs.

Minimum pressure losses in normal operations (0.5 to 1.0 psi).

D. Integration of the Cyclonic Technologies Into GOSPSIM 3.3

GOSPSIM 3.3 may now be used to design, optimize, plan, and operate three phase separation process facilities that include cyclone technology equipment and designs in addition to conventional gravity separators.

Despite many efforts in the past, no theoretical models have been developed for cyclone performance. However, extensive field data has been correlated that provides performance relationships for vortex tubes and other cyclones. These are included in GOSPSIM 3.3.

Correlations have also been developed for pressure drop estimates. The empirical developments are grounded in the established theoretical fluid mechanical and thermodynamic relationships. No agreed upon pressure drop correlation has yet been established for gas/liquid cyclones. However, some factors influencing the pressure drop are:

Creep of liquid phase up the central gas column spiraling up to the gas outlet. This results in entrainment (LCO) into the gas exit stream and separator capacity may be reduced or special precautions taken to remove the LCO.

The compression effects due to the increases of velocity in the centrifugal force actions.

Wall friction occurring due to the downward flow of the liquid film to the liquid outlet.

The calculation process is as follows:

- The inlet centrifugal velocity is distributed between the liquid film velocity and the gas velocity in the central core rising to the gas exit. This is guided by the relative velocities of the gas outlet and liquid outlet streams.

- The friction factor is calculated from the Reynolds Number in the liquid phase flowing down the wall. The pressure loss is then calculated from the Fanning equation.

- The inner core of the upward flowing gas and liquid pressure losses are calculated.

Experience with cyclones shows that the pressure drops can vary between 5-20 times the inlet velocity and density equivalent pressure head (velocity head). In gas/liquid separation practice, cyclone pressure drops usually do not exceed 2-3 PSIG and are often around 1 PSIG.

EXHIBIT I – VORTEX TUBE SEPARATOR

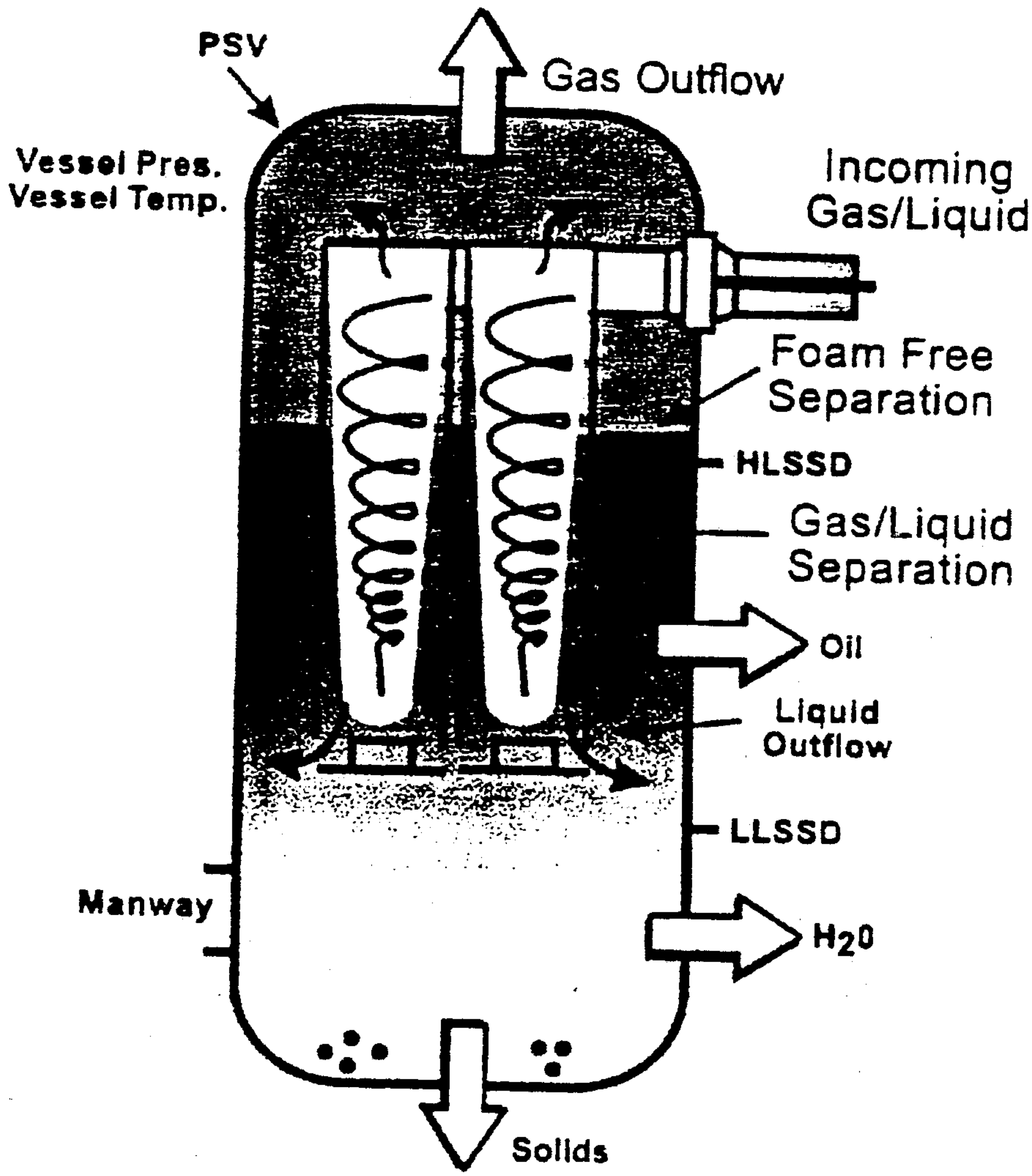
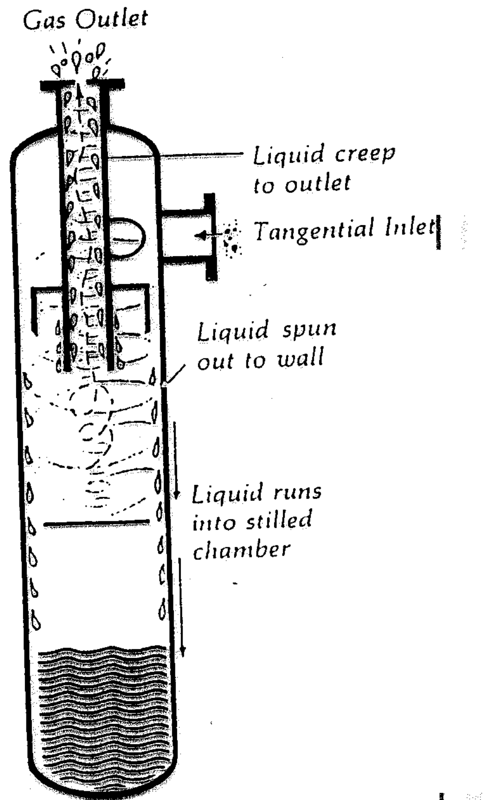
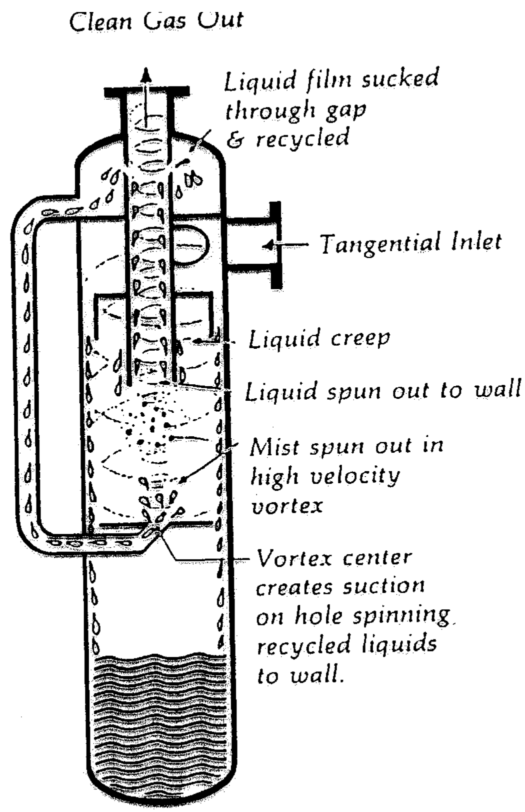


EXHIBIT II

CENTRIFUGAL SEPARATOR _CONVENTIO)NAL AND RECYCLE TYPES

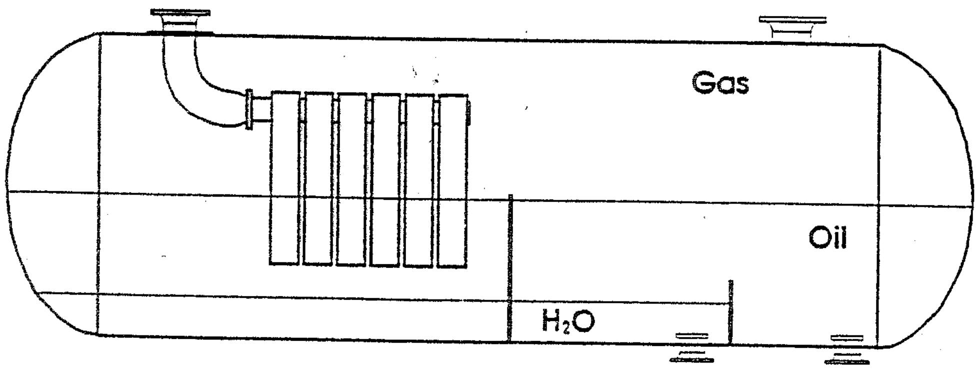


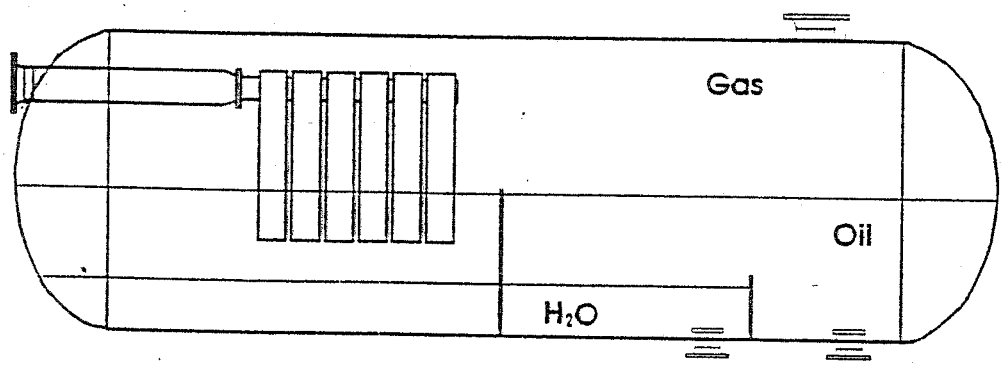
CONVENTIONAL CENTRIFUGAL SEPARATOR



RECYCLING SEPARATOR

EXHIBIT III CYCLONIC –SIX VORTEX TUBES INTEGRATED
WITH CONVENTIONAL SEPARATOR



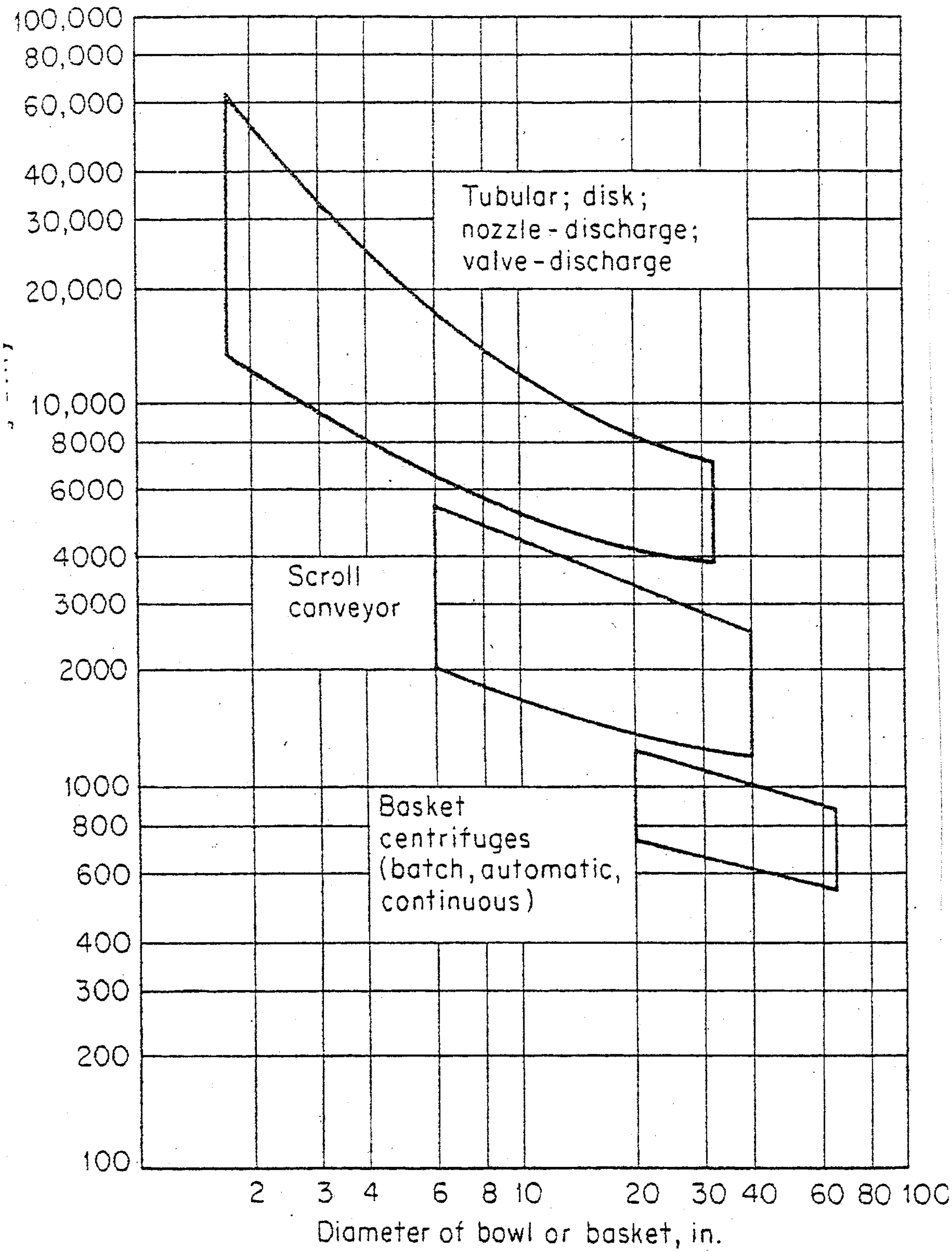


Notes:

- **No Foam / No Additives**
- **At optimum conditions, carryover efficiency of 99% removal of solids and liquid particles down to 7 micron.**
- **New applications – reduce vessel size through reduced residence time, and still obtain superior liquid separation.**
- **Retrofits – dramatic increase in flow thru, with superior liquid separation.**
- **Revolution operates on velocity change, therefore minimal pressure loss. (less than .5 psi)**

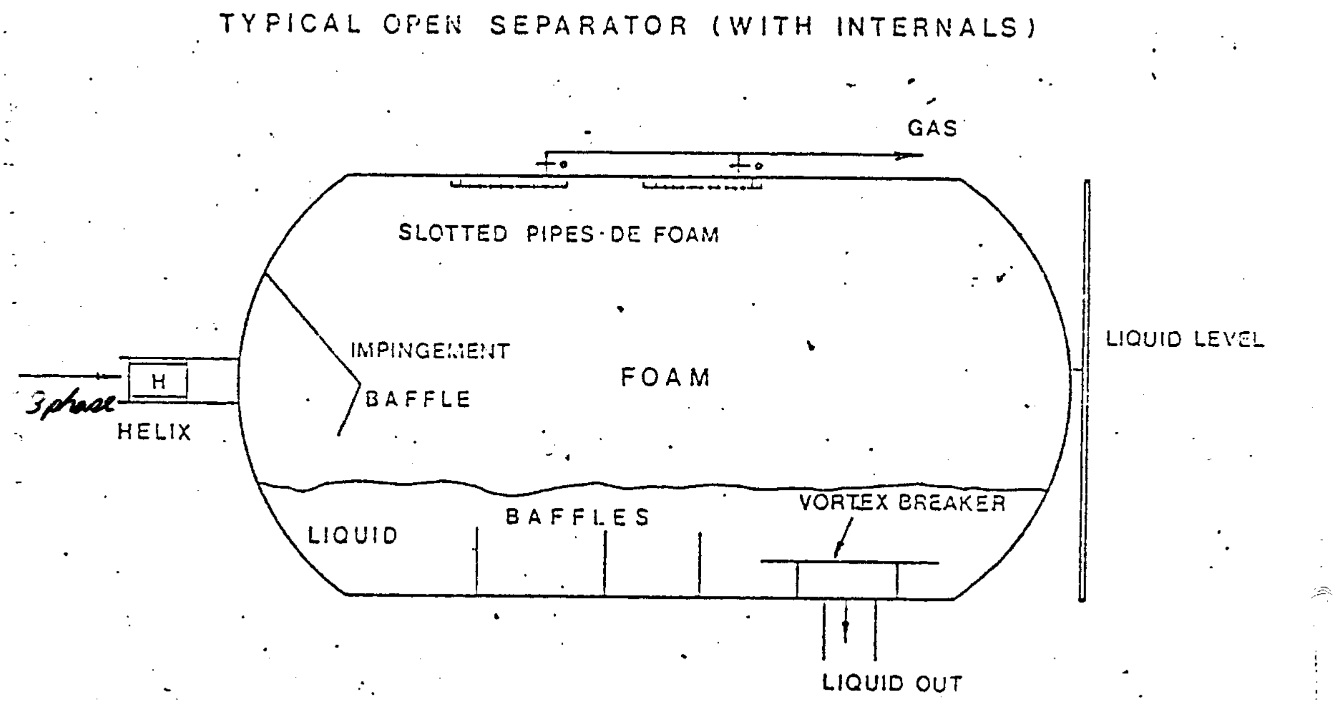
pressure loss. (less
than .5 psi)

EXHIBIT IV – CENTRIFUGAL FORCE VERSUS CENTRIFUGE DIAMETER



Variation of centrifugal force with diameter in industria.

EXHIBIT V- CONVENTIONAL 1 GRAVITY SEPARATOR WITH INTERNALS



III. FIELD CASE STUDIES

A.Separator Capacity Analysis – Four stage, 3-Phase Separation

A platform separator originally designed for gas oil separation collects offshore well flows and the liquid phase flows through a 30 mile pipeline to shore. The water drain from the platform separator is shut in since the water is not suitable for ocean discharge. The high-pressure shore-side separator is also shut in and water is discharged from the intermediate stage for further treating.

High gas lift rates and a one-percent sand content in the inlet flow characterize the platform separator operation. The final stage accomplishes the oil dehydration. The flow scheme is outlined in Figure 1.

The current flow rate through the platform separator is 63,000 BPD oil plus water with a 60 percent water cut. The consequence of the above situation is that approximately 38,000 BPD of water is being pipelined to shore, seriously restricting field production.

Assuming that the platform separator can be revamped and/or expanded, the operator requested that the capability of the onshore separator train to handle a throughput of 90,000 BPD total liquid at a 65% water cut be investigated. The GOSPSIM 3-phase model run results are summarized below. Detailed model results are given in Exhibit VI.

The platform separator was found to be undersized to the extent that the only viable alternative is to increase the platform separator capacity. The on-shore separators were determined to be adequate and also capable of handling 90,000 BPD of oil plus water throughput additional capacity. The detailed findings were:

<u>A. Platform Separator</u>

- The platform separator is undersized by a factor of 4.4 based on running the model in design mode and supported by residence time requirements indicated in the Petroleum Engineering Handbook. The water cut in the produced oil is calculated at close to 5 percent and the 12,200 ppm oil in the water renders it unsuitable for ocean discharge. These results checked current operating experience closely.

- The high horizontal liquid velocity, three times the recommended maximum, rules out structured packing of the Performax type, generally limited to 0.05 feet per second as opposed to the 0.3 feet per second horizontal liquid velocity in the horizontal separator.

- The gas side capacity is not limiting at 55 percent liquid level and there may be room to increase the level somewhat. Gas velocities indicate that mesh pads may help reduce liquid carry over, unless sand migrates to clog.

- Since the separator was evidently designed as a two-phase gas oil separator, we assume the lack of an effective water wash section to provide droplet coalescence. High gas velocity and mixing at the platform header will reduce droplet sizes and, in the absence of data and based on model crosschecks, we have used a design water droplet size of 150 microns and a design oil droplet size of 135 microns. This compares with typical FWKO design values of 200 and 150 microns respectively.

- The maximum oil droplet size (d95) is estimated at 150 microns. Analysis indicates a sufficient number of small oil droplet sizes below 30 microns to produce dirty water, even when applying a hydro cyclone. The operator had in the past installed a hydro cyclone and subsequently removed it, confirming our results.

B. Onshore Separators:

Taken together, the onshore separators are not undersized for the current throughput rate. Ten percent of the high-pressure separator volume is assumed occupied by an emulsion cuff layer. A standpipe test is required to determine the height of the emulsion layer and confirm retention time requirements.

- Higher design droplet sizes are used to reflect some coalescence in the long flow line to shore; also the higher emulsion viscosity in the high pressure on-shore separator will provide more time for oil and water droplets to coalesce as they rise and fall, respectively.

- The onshore separators are not constrained by gas capacity, in fact low gas velocities may make gas outlet mesh pads ineffective. Higher gas specific gravity in the intermediate pressure separator associated with tail-end gas evolution also contributes to a lower gas volume.

- Horizontal liquid velocities of 0.13 feet per second in the high and intermediate pressure separators exceed the recommended maximum of 0.1, although some experts maintain that this is a conservative limit. However, this is well above the 0.05 feet per second horizontal velocity limit for structured packing.

- The intermediate pressure separator is calculated to produce water at 1100 ppm, suitable for downstream treating and subsequent discharge.

- The low pressure separator with residence time in excess of 9 minutes is predicted to dehydrate the oil to about 500 ppm water content

C. 30 Mile Flow Line Simulation

In order to reach shore at a pressure of 175 psig, a platform separator pressure of 685 psig is required for the 30 mile, 12.25 inch I.D. platform-to-shore pipeline. To increase flow in this line significantly, a booster pump located on the offshore platform is required. The back-calculated separator pressure drop checked operating data within 15 psi or 3 percent.

Pertinent observations include:

- The flow is single phase for the first 40,000 feet due to elevation drop from the offshore separator platform. This progresses to elongated bubble flow and then to intermittent slug flow

- An emulsion begins to form as we begin to encounter slug flow at 70,000 feet as additional associated gas evolves

- The mean slug size at end of line is estimated at 40 barrels with a frequency of 45 seconds; the maximum (1% probability) slug volume is estimated at 100 barrels with a frequency exceeding 5 hours

- Line velocities start at 5.3 feet per second and increase to 10 feet per second at the end, providing sufficient turbulence to create the 8 cp at 81 degrees F given.

- The sand settling velocity of 5.5 feet per second computed at the end of the line is below the pipeline exit velocity. However, since both velocity and viscosity are lower at the beginning of the flow line, sand could be settling here. Given changing viscosity and velocity along the line, further study is indicated. At an assumed sand content of one volume percent, the sand slurry is estimated to increase pressure drop by a factor of 1.08.

- The calculated overall heat transfer coefficient for the line to match the given temperature profile is estimated at 3.0 BTU/ft2 hr. This compares with normal underwater lines which range between 1.2 to 2.5 BTU/ ft2 hr.

D. Increased Onshore Separator Train Throughput at 90,000 BPD Total Liquid

- The performance of the high pressure separator is the most affected. The water content of the oil increases to 2.4 percent and the oil in the water to 0.4 percent

- The intermediate stage separator oil in water increases from 1100 to 1400 ppm

- The low pressure separator continues to dehydrate the oil effectively to the 700 ppm level.

- Gas velocities increase and residence times decrease by 35 percent respectively, but gas velocities remain well below maximum, and at a level where gas outlet mesh pads will be effective in reducing liquid carryover to acceptable levels.

- Horizontal liquid velocities increase to 0.18 feet per second where short-circuiting may occur. The installation of baffles and a water wash section in the intermediate stage separator can be investigated if discharge water quality is not acceptable.

E. Corrective Measures Indicated:

- **Install a Replacement Separator**
  Replacement by a separator with larger volume to provide sufficient liquid retention time, with a polishing hydro cyclone to be considered as a second stage. The horizontal oil/water velocity would be reduced to the 0.05 foot per second range where coalescers are usually effective. If higher velocities are specified in order to reduce vessel size, corrugated plates and perforated baffles can be analyzed.

  Designing the first third of the horizontal separator as a sand removal section can address the 1 percent sand content. (Sand disposal, or pumping back into the line downstream of the separator, would have to be considered.)

  The separator could be designed for larger capacity if oil well and gas lift optimization studies show that addition oil and gas can be produced from the existing wells, and from any other potential tie-in wells.

  The use of existing test separators may be considered as a part of this solution, with multiphase meters with suitable PVT software replacing these.

- **Piggy-back an Additional Separator on top of the Existing one**
  As practiced in the North Sea, the additional separator could be piggy-backed on the existing separator. This reduces the loss of production that occurs during replacement.

  The platform weight capacity must be checked to determine if the platform should be reinforced and the piggy-backing of the additional separator is often done to conserve space on the platform. Production flows through both separators. The new separator is sized in conjunction with the existing separator to reduce horizontal velocities to 0.05 feet per second.

- **Employ Advanced Hydro-cyclones**
  Extensive experience with hydro cyclones show that mixtures of water and heavy oil can be separated up to 2% oil in the water; however with light oils, 40 degree API or higher, hydro cyclones are not efficient above 0.5 % (5000 ppm) of oil in water. The calculated oil content of the water discharge is 12,200 ppm, more than can be processed by standard hydro cyclones and the resulting water would contain oil above the 100–200 ppm levels required for discharge into the sea.

  Advanced designs may be available to meet the discharge requirements.
  Multiple cyclones in series each designed to eliminate part of the problem, first gas and sand, then oil and water in two stages may be effective in producing an acceptable water quality.

Exhibit VI

Values shown in italics were based on data provided. Other values comprise calculated simulation results.

	Offshore Platform	Onshore HP	Onshore Int P	Onshore LP
Pressure, psig	675	170	85	60
Temperature, degrees F	160	80	185	170
Separator Diameter, feet	*5.5*	*7*	*7*	*6*
Aspect ratio L/D	*3.5*	*5.5*	*5.5*	*6.5*
Water/oil level, percent of D	35	50	50	20
Oil/gas level, percent of D	55	75	75	80
Inlet Flows @ separator conditions				
Total Flow, BPD	*63000*	*63500*	*66000*	*26500*
Water cut, volume percent	*60*	*60*	*59*	*0.4*
Gas Production, MMSCFD	*60*	*4*	*2*	*0.15*
Water Draw off, BPD	0	0	39000	90
Oil in water, percent	1.2(1)	0.45(1)	0.1	0.015
Water in oil, percent	4.9	1.80	0.4	0.060
Gas carry under, GVF	<0.02	<0.02	<0.02	<0.02
Liquid carryover, gal per mmscf	0.5	0.5	0.5	0.5
Percent separator volume not Available, occupied by emulsion	0	10	0	0
<u>Design droplet diameters, microns:</u>				
Water	150	340	220	500
Oil	135	200	200	200
Oil droplet in gas phase	100	100	100	100
Gas median bubble diameter in the liquid phase	185	185	185	185
<u>Horizontal Velocities/limits, feet per second:</u>				
Gas	1.54/6.2	55/8.4	59/16	11/17

Liquid	.29/.10	.13/.10	.13/.1	.07/.10
Mesh pad flooding velocity	1.3	2.7	2.6	3.2
Oil droplet size distribution, ppm oil remaining at :				
10 microns	40	5	1	0
20 microns	230	25	5	1
30 microns	640	65	15	2
50 microns	2130	235	60	7
100 microns	8090	1180	290	35

Notes:
(1) Water is not produced in these separators.

Figure 1 3 Phase 4 Stage Separator and Flow System

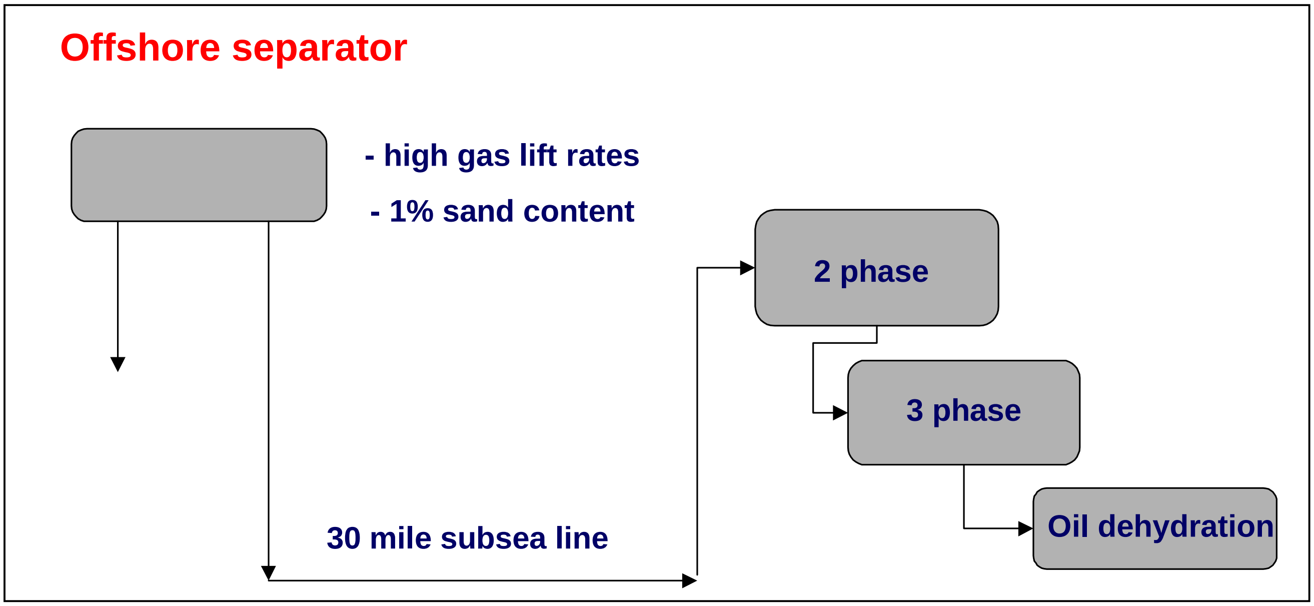
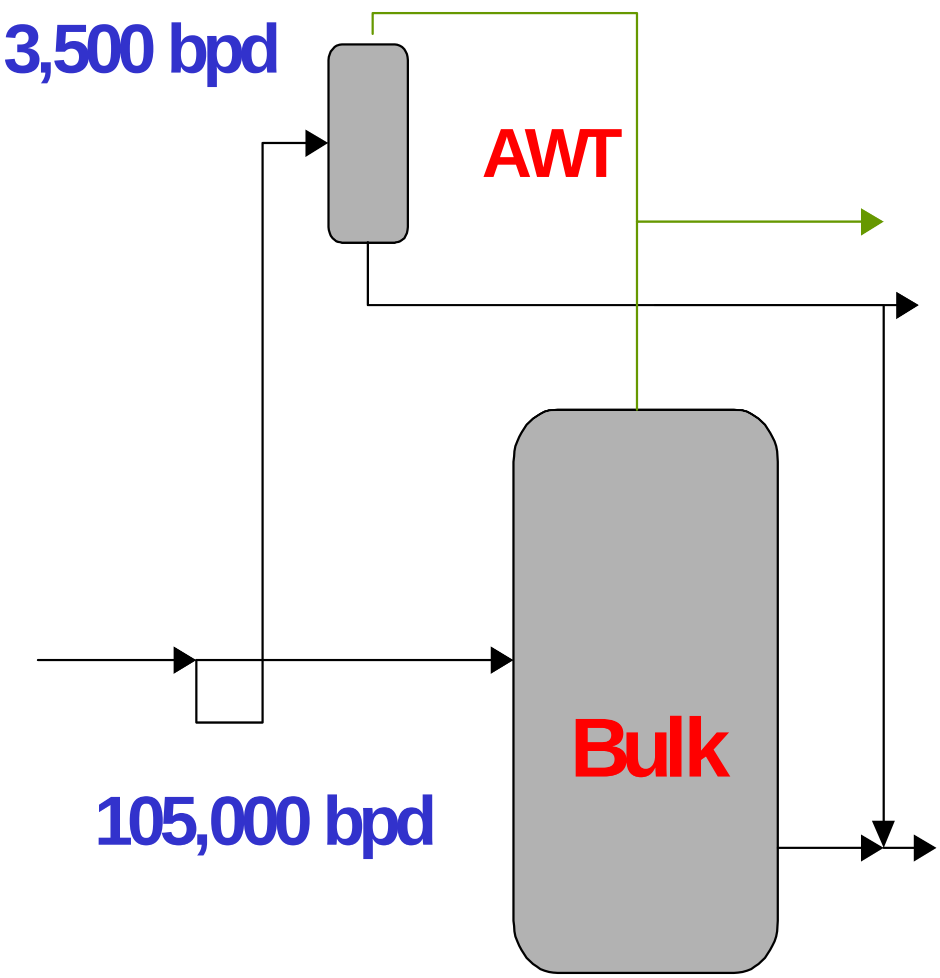


Figure 2 High Viscosity Emulsion De-gassing System



B. Separator Design Analysis – for a 106,000 BPD De-Gasser and AWT Meter Test Separator, for a very high viscosity emulsion.

This project is described in additional detail in an ETCE 2000 paper presented in New Orleans [see EnSys Yocum download files].

The traditional processing scheme in this on-shore field separated oil and gas at the wellhead. Given the large number of wells involved in a four quadrant expansion underway (up to 200 wells under steam flood with high sand content), the operator made the decision to combine the oil and gas at the well head. This necessitated a downstream de-gasser. Gas carry under minimization was essential to reduce metering error (where gas is counted as oil). Given the high 80 percent water cut, the leverage exerted by any hydrocarbon metering error is high. The fluid being transported is a stable thixiotropic emulsion with a low shear rate viscosity of 100 centipoises at 190 degrees F. The operating temperature of the system is 224 degrees F, but with the probability of significantly lower temperature operation.

EnSys Yocum was contracted to check the feasibility of a gravity separator design. Specifically, to provide insights into their initial design and the effect of emulsion viscosity, the GVF carry under target and separator configuration on cost, and feasibility.

In brief, our analysis as outlined below indicated that a very large separator of the order of 20 feet in diameter was required to de-gas the emulsion to the required GVF target. The operator confirmed this through additional study, showing that the local shipping port could not accommodate the large gravity separator required and their decision was to use a cyclonic (GLCC) device. For the details of this study see *"Methods for Optimal Matching of Separation and Metering Facilities for Performance, Cost, and Size: Practical Examples from Duri Area 10 Expansion"*, Marrelli, J. and Rubel, M. (Texaco); Yocum, B.T., Dunbar, D.N. and Tallett, M. (Ensys Yocum); Mohan, R.S. (University of Tulsa); and Brahmantyo, M.K., Montolalu, D., Wahyudi, D. and Solomon, K. (Caltex Pacific).

The study approach and findings are summarized below and in the figures that follow:

A. Detailed Study Approach and Findings

A total of seventeen GOSPSIM cases were run for vertical de-gasser, horizontal de-gasser and vertical AWT separators. Within each case set, the effects of:

- varying inlet diverter design
- using perforated plates (horizontal only)

- water addition to reduce viscosity
- emulsion breaking
- assuming an alternate bubble size distribution (larger bubbles)

were examined. In addition, an AWT sensitivity was run to examine the effect of a 10 psi lower separator inlet pressure as could be caused by sand deposition in well flowlines.

As the size of the vessel increases within each set, the GVF decreases. The vertical AWT and de-gasser designs are generally controlled by viscosity, the only exception being the emulsion-broken cases where the gas side capacity controls. The horizontal separator cases with vessel diameters greater than 10 feet are also controlled by the liquid viscosity, the smaller horizontal vessels being controlled by gas side capacity at a GVF target of 0.02.

Mesh pads or similar devices in the vertical AWT and de-gasser separators are not feasible because the gas velocities are too low, below 30% of flooding velocity. They are feasible for horizontal vessels of 10 foot diameter and below and have the potential to reduce liquid carryover to 0.1 gal per MMSCF, with vessels without mesh pads anticipated to produce 100 gal per MMSCF.

The attached figures and tabulated results show how GVF varies with vessel diameter as size increases, covering the range from 0.15 to less than 0.01 GVF. The L/D aspect ratio is kept constant at 0.7 for the vertical de-gasser, at 5 to 1 for the horizontal separator and 3 to 1 for the smaller AWT separator. The liquid level was maintained at 50% of the vessel height in all cases. Throughput rates were 106,250 BPD for the de-gassers and 3500 BPD for the AWT separator, except for the water addition cases where the rates were 10% higher. Aside from viscosity variations, other PVT properties were as developed for the recent Duri training session. Other than assuming a high-end AWT throughput rate, no other safety factors have been introduced.

The shape of the GVF variation curve as a function of separator size is relatively accurate since it is based on Stokes law considerations. The case assumptions are aggressive in probing possible design alternatives and *in toto* the case results should be viewed as directional rather than definitive for several reasons:

(a) they are based on assumptions which need to be confirmed by laboratory and field tests as to magnitude and feasibility
(b) the case sets are not optimized with regard to parameters such as vessel slenderness ratio and liquid level, which may influence cross-comparisons
(c) optimization goes beyond vessel sizing (where the vessel cost varies directly with the length and with the 2 power of vessel diameter), e.g. there are maintenance cost considerations, the costs of internals, the capital and operating costs associated with adding water to reduce viscosity, and the cost of sand control measures associated with some of the possible alternatives.
(d) the construction feasibility of the options has not been addressed, notably regarding the large diameter vertical de-gassing separators.

B. Implications for Laboratory and Field Testing

The results highlight that several laboratory and field tests that will be useful in reducing uncertainty. We recommend that the following be undertaken:

- Viscosity tests to establish the effects of temperature, water content, solution gas and sand concentration

- Gas bubble size distribution tests in the inlet flow line and the separator, as affected by the emulsion properties, flow line conditions and piping configuration

- Standpipe emulsion settling tests to help establish residence times and de-emulsifier effects; also to determine gas foam formation tendencies.

C. Commentary on results

The initial results appear to favor horizontal vessels, but it is acknowledged that vertical vessels are easier to clean and this finding therefore ties back to sand control measures.

Perforated baffles located in horizontal vessels act to reduce vessel size by coalescing gas bubbles, but again their application links to sand control.

Emulsion breaking to create a low viscosity dispersion depends on matching to the proper chemical additive, if feasible at all, to break the emulsion in the flow lines or a holding vessel.

Reducing viscosity by adding additional water to the well stream emulsion introduces feasibility questions with regard to water availability and the cost of supply and mixing. .

Increasing the sophistication of the inlet diverter appears to offer marginal advantage in the relatively low GOR environment, but this requires additional study.

A run variation increasing the bubble size distribution range from approximately the 20–1000 to the 40–2000 range has a marked influence on vessel size, but this is speculative at this point. Important but elusive considerations here are the degree of gas separation and coalescence of gas bubbles in the approach flow lines and in the separator liquid zone, as the rise. These are topics of some recent research activity.

The diameter versus GVF plots indicate separator diameter begins to increase much more rapidly at around 0.025 GVF, somewhat higher for the AWT separator. (See figures 1,2,3.) This effect somewhat masks the severity of the increase in separator cost however. Figure 4 presents an approximation of separator cost (as a function of diameter squared times length) for the horizontal and vertical de-gassing base cases. Separator cost approximately doubles in going from 0.1 to 0.02 GVF and increases a further 75% going from 0.02 to 0.005 GVF.

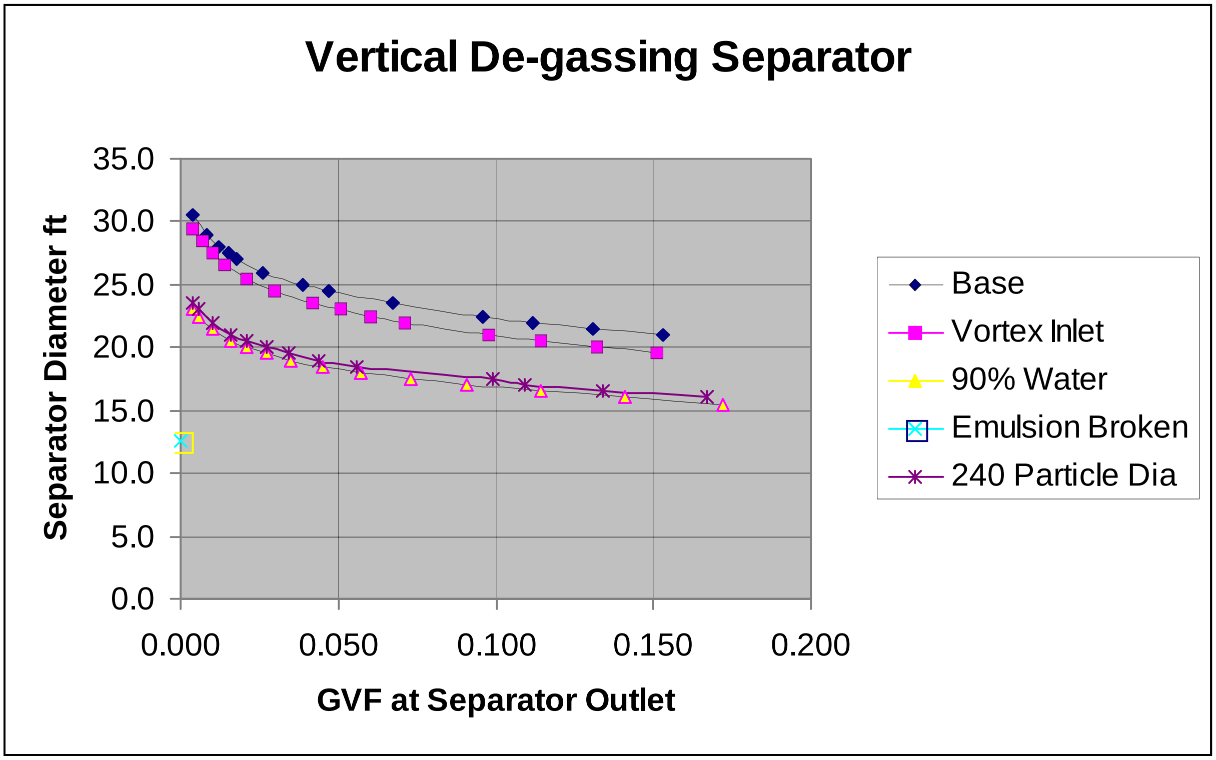


Figure 2

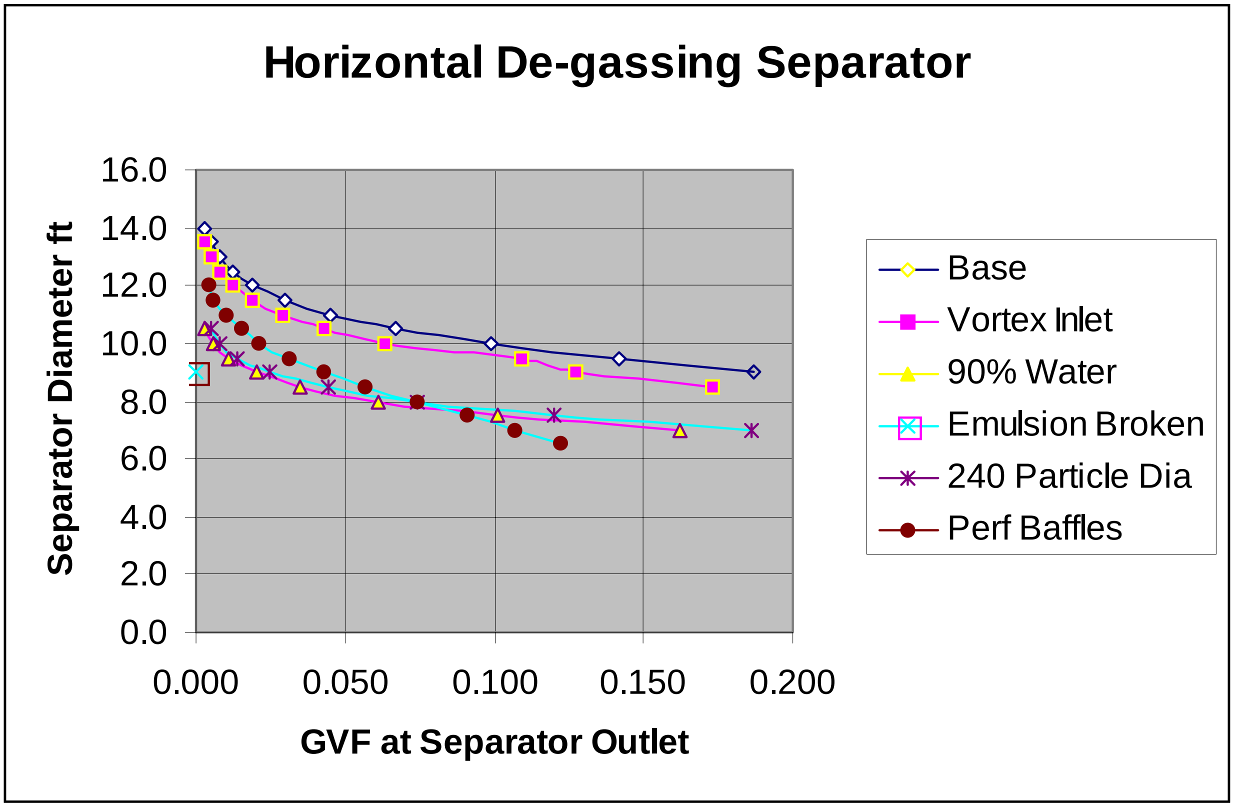


Figure 3

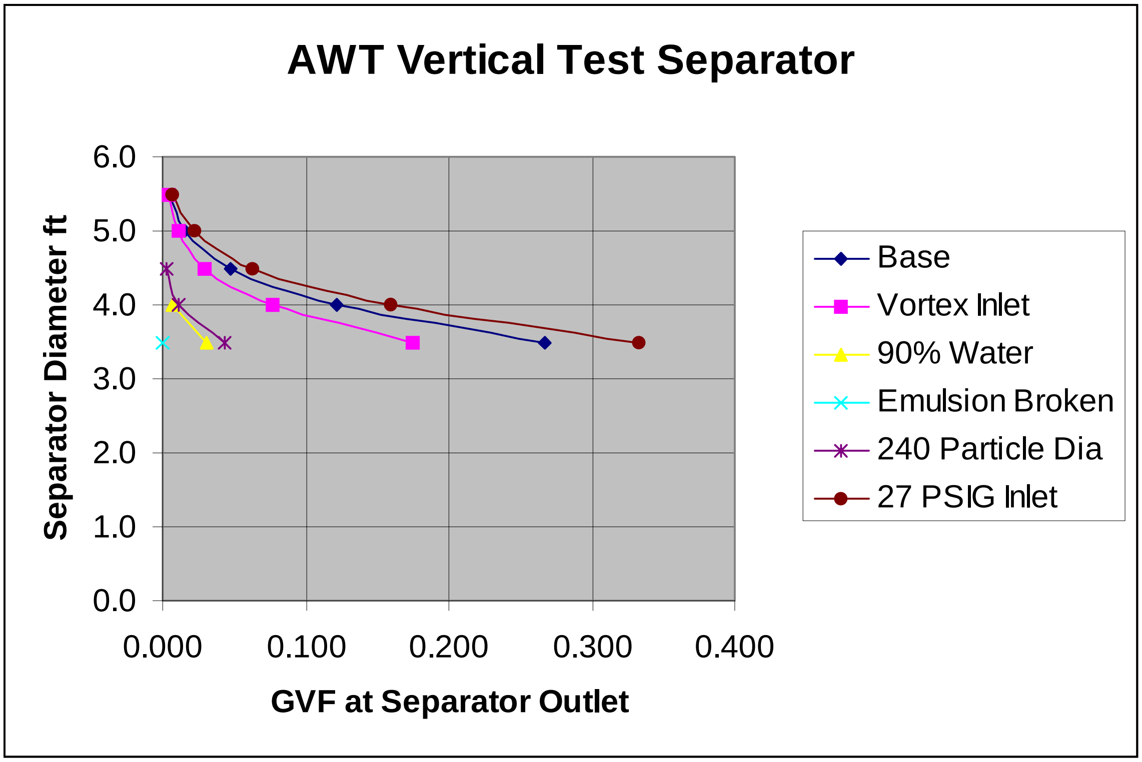


Figure 4

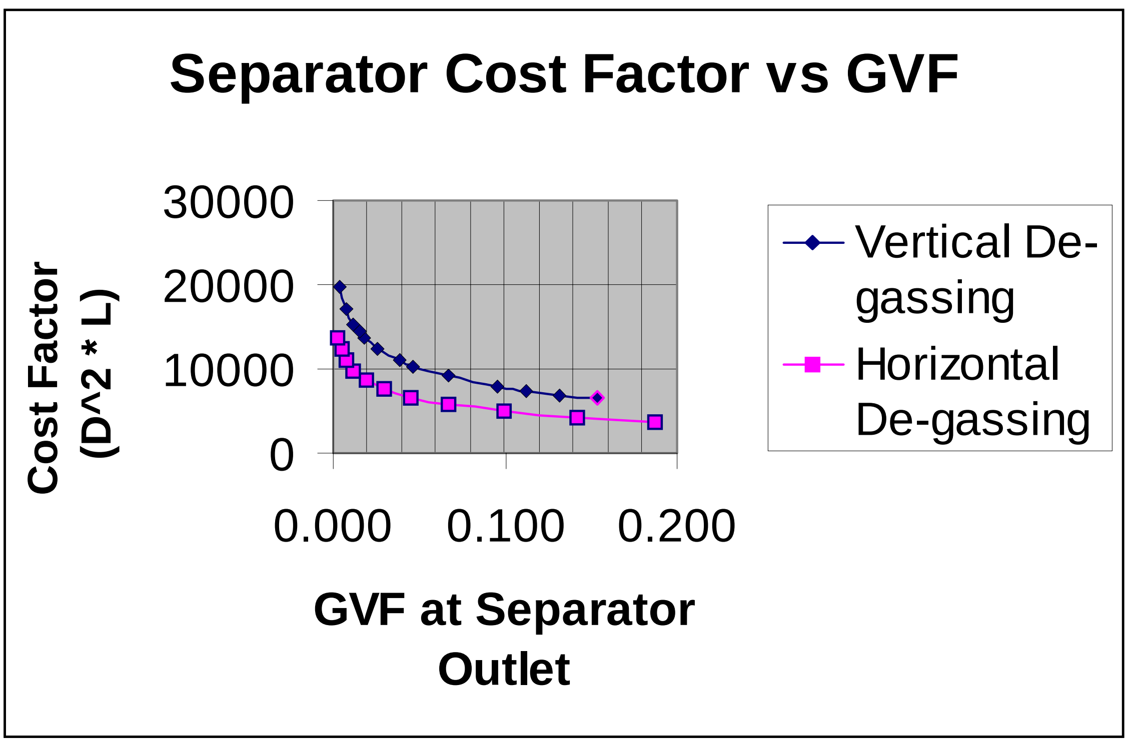


Figure 5

IV. Multiphase Flow and Separation Applications Involving Chemical Treatment

A. Silicone Injection to reduce foaming in first stage separator vessels

Extensive field production tests of separators of various design were carried out in ten reservoirs.

- The reservoir crude oils tested varied in API gravity, GOR, and viscosity. Production capacities in separators varied 50 %, in part determined by the degree of foaminess of the reservoir fluids in the first stage. Liquid carryover and gas carry under also were varied to meet production objectives.

- .Production studies were carried out to find ways of increasing production capacities:

Quantifying percentage gain in capacities from silicone injection and economic rate of return evaluation for applications 1, 3, 5 cc silicone addition per 1000 bbl. of crude oil. Silicone Injection had little benefit under certain process conditions and for certain crude oils, however, very beneficial for several other crude oils under normal process conditions.

Increases in separator capacity has been noted due to silicone Injection foam suppression and corresponding increases in gas/ foam and liquid residence times. This had beneficial effects on liquid carryover and gas carry under
.

The following separator configurational and flow aspects were studied in conjunction with silicone addition:

. effects of various separator internals, wire mesh, impingement plates, vortex plates, wave vanes, perforated baffles, and inlet diverter design on separator capacities
. effects of horizontal, inclined, vertical vessels.
. effects of pressures and temperatures
. effects of inlet piping, pressure drop across control valves to reduce shear and improve bubble distribution, use of stratification of multiphase flow in inlet piping, apply helices and other pre-separation devices
.

B. Water Bearing Acidic Gas Condensate Wells

Multiphase simulation technology has been employed to examine the feasibility of carrying corrosion inhibitors in the gas/liquid mixture so that they would evenly coat the tubing inner wall thus minimize well tubing corrosion.

The solution depended on multiphase velocities being maintained to establish annular/ mist flow . Corrosion inhibitor was injected into the bottom of the well. The flowing multiphase mixture blended it the chemical and distributed into the annular flow layer against the well tubing wall. Based on the volume injected, it was assumed that the wall was coated. The tubing well-head back pressure required to maintain the optimum velocity range for annular mist flow was determined as a function of the tubing diameter.

C. Offshore North Sea Acidic Gas Condensate Well, Gathering and Separation Systems

During wintertime conditions the multiphase fluid pressure drop – Flow Rate relationship results in loss of production capacity unless chemical treatments are made to prevent hydrate formation and consequent flow restrictions with Injection of methanol in critical areas of the system. We have consulted in this area as well as the: application of drag reducing chemicals in pipelines to reduce pressure drops and increase production; injection of corrosion inhibitors for further protection where metallic resistance is not adequate or cathodic protection is weak.;. foaming at low temperatures and defoaming agent injection in the first stage separator as required to avoid loss in production capacity; emulsion breaking in the second and third stage separation vessels, with heaters and electrostatic treatment.

D. Acid Gas/Water Bearing Gas Pipelines Over Hilly Terrain

This work involved situations where large sections of pipeline approaching hilly sections were corroded in the bottom 30 –50 % of the pipe due to liquid holdup in the valleys. We studied:

> the alternative of running intelligent pigs programmed to release corrosion inhibitors in the likely sections driven by gas pressures.
>
> multiphase pressure drop – flow rate and flow regime simulation studies indicated that injecting an aqueous solution of amine inhibitor would stabilize the corroding sections if injected near by. This technology depends on the formation of stratified wavy flow for a sufficient time to deposit corrosion inhibitor in the corroding areas. However, doing this required: (a). adjusting the gas rates to establish a stratified wavy flow regime in the expected corrosion area of the pipeline and (b) adding a sufficient quantity of aqueous solution injection to reach the stratified wavy flow in the corrosion section.
>
> A downstream water leg analysis was conducted to detect corrosion inhibitor.

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