

PROVEN METHODS FOR DESIGN AND OPERATION OF GAS PLANT LIQUID SLUG CATCHING EQUIPMENT

**Russell P. Kimmitt
Pearl Development Company
Bailey, Colorado**

**Chris R. Root, P.E.
Duke Energy Field Services
Denver, Colorado**

**R. Bret Rhinesmith, P.E.
Pearl Development Company**

ABSTRACT

This paper presents methods to design gas plant inlet liquid slug handling facilities. In addition, the paper also addresses some of the problems that have been described by GPA's Operations & Maintenance Committee in panel discussions at the 78th Annual Convention and in various regional GPA forums.

This paper presents a seven (7) step design process that includes the design basis development and operational definition such as conditions of service (COS), pigging frequency, turndown, and start-up. Pipeline simulation issues are addressed including the determination of line size, fluid flow regime, line pressure drop, and liquid hold-up volume. Based on pipeline simulations and configurations, slug sizes can then be determined. Prior to finalizing liquid slug handling facility design, design sensitivities are considered and evaluated. Detailed design methods are described for the plant inlet separation system to handle gas, liquids, and solids. This discussion includes a comparison and applications guide of the different slug catcher types. This integrated process for pipeline and separation design allows individuals to specify new facilities and troubleshoot existing plants.

Also included in the detailed design section is a discussion of mist eliminator use/orientation, secondary gas separation equipment, solids handling systems, instrumentation considerations, header design, three-phase separation, and intermediate liquid vessels. The impact of phase behavior as well as the pipeline system (high-pressure trunk-line, gathering) is included in the paper. Finally, a case study is presented including available operating performance data from a previous design.

PROVEN METHODS FOR DESIGN AND OPERATION OF GAS PLANT LIQUID SLUG CATCHING EQUIPMENT

INTRODUCTION

The design of inlet liquid handling facilities (slug catcher) for gas pipeline systems has received much attention during the past few years without offering specific calculations and guidelines to allow engineering and operations personnel to specify or troubleshoot systems. The consequences of poorly designed and operated systems may result in downtime, equipment damage, and process upsets.

This paper attempts to take the veil away from the mysteries of slug catcher design and operation. This is done by bridging between the art and science of slug catcher design by providing a calculation strategy, discussing options and sensitivities, and providing a case study.

DESIGN PROCESS

The overall calculation strategy for liquid slug catcher design is an iterative method that is integrated with the pipeline system design. As such there are seven basic steps:

1. Design Basis Development
2. Operational Definition
 - Natural Flow Systems
 - Pigged Systems
3. Pipeline Simulation (steady-state and/or dynamic)
 - Line Size Selection
 - Fluid Flow Regime
 - Line Pressure Drop
 - Liquid Hold-up Volume
4. Slug Size Calculation
 - Pipeline Slugs
 - Terrain Slugs
 - Riser Slugs
5. Design Sensitivities
 - Phase Behavior
 - Flow Variance (e.g. turndown and provisions for expansion)
 - Operational Variances (start-up, shut-in, missed pig, ambient temperature)
 - Design Factor
6. Slug Catcher Design
 - Configuration
 - Vessel
 - Pipeline
 - Multiple Pipe
 - Mist Extraction / Secondary Gas Separation

- Solids Handling
 - Instrumentation
 - Header (inlet, gas outlet, and liquid outlet)
 - Three-Phase Separation
 - Intermediate Liquid Vessel
7. Operational Feedback - Case Study

Depending on the results of various steps during design, it may be necessary to repeat or revise previous steps to arrive at an optimized design. These basic design steps are outlined in the paper along with one complete case study and several examples. Other critical pipeline system design steps that have less impact on the slug catcher design such as field compression location and optimization, pipeline shut-in, solids (paraffin or hydrate), line rupture, velocity limits, pipeline layout, and pipeline material selection are omitted from this paper. In addition, the primary focus is onshore pipeline systems.

DESIGN BASIS DEVELOPMENT

The most important step in the process is setting an appropriate design basis for the pipeline system design and corresponding slug handling operational definition. This step may be dependent upon reservoir engineering results, production methods, and gathering system designs. Flexibility is important because reservoir predications may not be accurate. Consideration of operating and maintenance issues early in the process can prevent costly changes later in the field. Many of the issues cited as operating problems in pipeline and slug catcher systems often represent changes to the original design basis of the system. The overall design basis and operational definition for the integrated pipeline system and liquid slug handling facilities includes many items:

1. Design Basis
 - Composition (gas composition, heavy-end characterization, and off-design cases)
 - Design capacity and turndown requirements
 - Inlet temperature (design and off-design)
 - Inlet or outlet pressure specification or range and maximum shut-in pressure
 - Pipeline topography (elevation profile, distance, burial depth, water depth, and risers)
 - Ambient Conditions (such as ground and air temperatures and soil type)
 - Seasonal variations (temperature, pressure, and composition)
 - Production variations
 - Start-up considerations (time to restart)
 - Corrosion issues (inhibitors, hydrogen sulfide, carbon dioxide, and water content)
 - Contaminants (solids, scale, sulfur compounds, paraffins, water, hydrates, and pour/cloud point)



Figure 1 – Gas Sampling

2. Operational Definition

- Pigging type and frequency
- Accessibility to pig launchers and pig receivers
- Maintenance decisions (slug catcher inspection frequency, solids removal needs)
- Government regulations (inspection type and frequency)

The importance of these items is discussed in various sections for both natural flow (un-pigged) and pigged pipeline systems. The interrelationship between these items and various design decisions is also described. A determination is made at this point in the design process if the system will be natural flow or pigged to remove liquids. This overall decision will depend on the design basis, operating philosophy, the relative amount of gas and liquid in the pipeline, and the location.

Natural Flow Systems

Many multiphase systems, particularly those that are offshore or are handling a large amount of liquids, are designed to operate at steady-state liquid hold-up conditions and are not pigged. This is frequently the case when the full well stream (gas and liquids) is being transported in the line to a central processing site. Multiphase flow lines can reduce initial capital costs and can be an integral part of the field development plan. Provisions for pigging are still provided in these lines to allow for pipeline cleaning and inspection, which are likely to be required during commissioning. Also, pigs are sometimes run as part of a corrosion inhibitor application program in these systems.

For pipelines with large liquid hold-up volume (due to line size, line length, rich gas composition and/or topography), economics may preclude designing the slug catcher for the full amount of liquid hold-up in the line. In this case, some other design basis such as time needed to “unload” the line when increasing the flow rate during start-up, expected terrain induced slugs, or turndown may govern the slug catcher design basis.

Other situations where the line is typically not pigged are dry gas or dense phase situations, although adequate consideration of pressure changes during start-up and shutdown is still needed to ensure that any liquids that do form in these instances can be handled. Use of existing pipelines that have line restrictions (smaller valves or changes in pipe diameter) or looped sections in a new pipeline system design may also limit the ability to pig the system, although the use of multi-diameter pigs can be effective.



Figure 2 – Pipeline Topography for Natural Flow Systems

Pigged Systems

In many instances pipelines are pigged to reduce pressure drop by lowering liquid hold-up volumes. This is also beneficial for reducing slug catcher size and reducing corrosion from any free water and other contaminants in the line. This is frequently the case in wet gas situations where liquid is only formed due to condensation in the pipeline (no free liquid is entering the line). Automatic sphere or ball launchers, see [Figure 3](#), may be used to allow frequent pigging of the line. The design basis for pigging frequency will have a significant impact on slug sizes from pigging and the required slug catcher size. Ideally the pigging frequency can be selected to optimize life-cycle costs (operating costs of pigging and pressure drop “value” versus installed costs for the slug catcher and pig launching system), although other operational factors may control the decision.

For example, in the case represented by [Figure 4](#), natural slugging was not predicted. Therefore, the calculated liquid hold-up volume of 440 bbl is the maximum predicted slug size. If pigs are run often enough so that less than 440 bbl condenses, then the slug volume is less and the liquid slug handling equipment size is reduced. To achieve this benefit, the pigging frequency has to be greater than 0.35 pigs per day (or one (1) pig approximately every third day). If two (2) pigs are run each day, then the slug volume is reduced to approximately 80 bbl.



Figure 3 – Automatic Ball Launcher

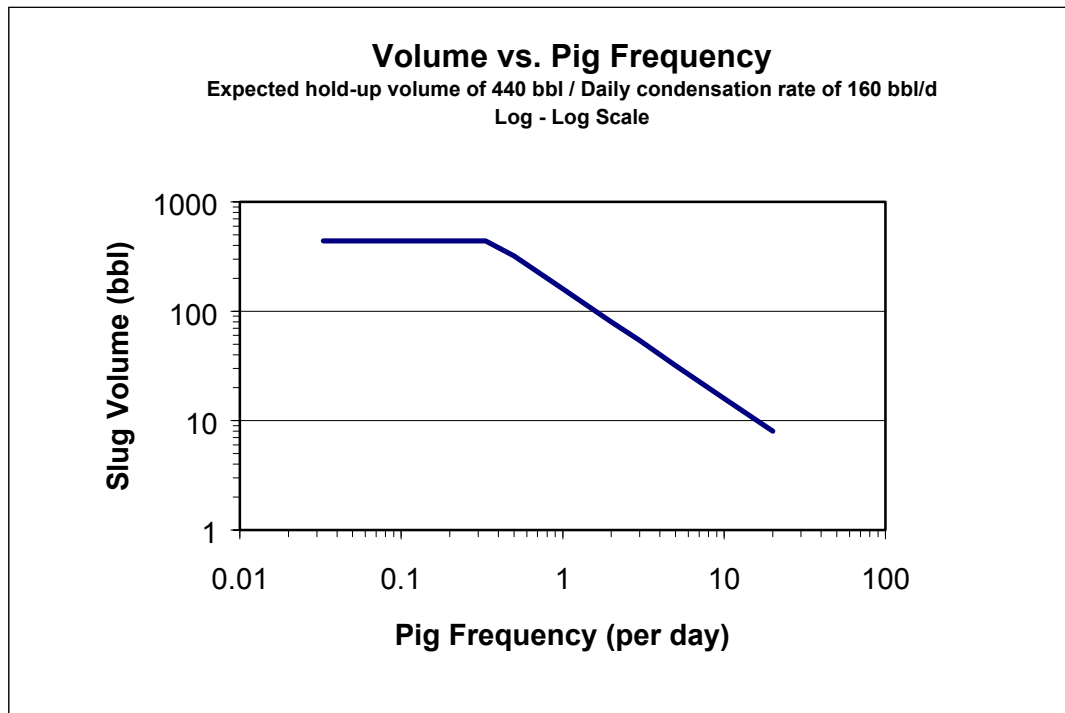


Figure 4 – Volume vs. Pig Frequency

Other factors that will greatly influence slug catcher sizing in pigged lines are gas composition, heavy-end characterization, and heat transfer. Having an accurate gas composition that predicts the expected liquid condensation rates is essential. Off-design consideration such as summer/winter operation and impact of changes in composition from multi-source systems is also necessary.

Other design basis issues in pigged systems include the impact of branched systems on pig volumes and timing. The planned sequence of pigging operation in the various lines upstream of the slug catcher must be determined to predict expected volumes. Finally, consideration of safety factors for missed timing or changes in gas flows during pigging operation is needed. Bypass pigs^[1] have been developed that allow liquid volumes to be evened out. In some cases the use of pigs instead of spheres can improve efficiency^[2].

PIPELINE SIMULATION

A comprehensive review of the pipeline simulation is beyond the scope of this paper, but additional background can be obtained from the references cited. The following provides an overview highlighting the key information and analysis required to design slug catcher systems. Several different methods exist in modeling multiphase flow; however, most equations focus on similar parameters: superficial velocity, density, viscosity, interfacial forces (surface tension), and elevation change. The complexity of the calculations and iterative nature strongly suggest the use of computer programs to perform the calculations. This may not result in increased precision as most correlations model the system within approximately +/- 30% of actual operations, sometimes due to variations between the design basis and actual operations. The impact of differences between the fluid design basis and the original “black-oil” data used to develop many correlations may also limit the precision of the model.

For pipeline designs it is important for the calculation to be carried out in a segmented manner modeling both the length and elevation. A good design practice is to run the model initially with progressively shorter segments (in length and elevation) to determine the minimum number of segments needed to accurately model the system. As the system is divided into more segments the calculated pressure drop and hold-up will usually approach an asymptote value. Since more segments will increase the calculation time by the program an appropriate number of segments can be selected to optimize run time versus accuracy (although this optimization has become less of an issue with today’s faster computer speeds; therefore, selecting too many segments is generally preferred over too few).

Many computer programs are available. The “best” programs will allow for utilizing detailed compositional data, changing equation of state, utilizing different correlations and modeling heat transfer between the fluid, pipe wall, and surroundings. Determining the “best” program may be a corporate decision that is ideally made by calibrating the model to actual operations of similar systems owned or operated by the corporation. By using more than one program and more than one of the available correlations, the designer can critique results and estimate proper contingencies in the design. It is suggested that if a correlation based model is used to simulate a system (such as Beggs and Brill, Eaton, or Baker) the model should also be simulated using a mechanistic approach such as Oliemans or OLGAS. The comparison of results will increase confidence in the system design. In many cases the use of dynamic pipeline simulation programs is recommended as a subsequent step to model the impact transients on the system.



Figure 5 – Pipeline Simulation

Line Size Selection

The line size selection is an important design factor in the design of the associated slug catcher system. For example, the ability for the system to trade increased pressure drop for an annular fluid flow regime can greatly affect the liquid hold up requirement of the slug catcher. The line size should be selected with consideration to flow regime, liquid hold up, and pressure drop. For many multiphase pipelines the adage of “smaller is better” often applies. Studies should be performed to optimize pipe size (pressure drop) to compression (power).

Fluid Flow Regime

In multiphase fluid flow it is important to understand the characteristics of the interaction between the gas and liquid phase(s). Empirical data, often presented in the form of flow regime maps, allows for prediction of expected characteristics. One of the most widely used flow regime map is by Mandhane et al^[3] for horizontal flow, although other options exist. There are also maps available for vertical flow (Aziz et al^[4]) and inclined flow (Taitel and Dukler et al^[5]). For pipeline modeling, due to the elevation changes, the best flow maps are the Taitel and Duckler or Beggs and Brill^[6] due to their sensitivity to pipe angle. When designing a pipeline system, it is important to select a pipe diameter not only for pressure drop concerns, but to achieve the required superficial velocities to remain in the desired flow regime.

There are seven (7) basic flow regime categories for horizontal or near horizontal flow: stratified, slug, plug, wavy, bubble, dispersed, and annular. Depending on the application, the designer may want to operate in any of the seven regimes. For most gas field pipeline applications the operation desired is usually dispersed, annular, wave, or slug flow, in order of preference. Operating in these flow regimes will help minimize pigging frequency and slug catcher capacity requirements.

The designer should adjust pipe diameter to remain in a flow regime that is acceptable but also be cognizant of the pressure drop experienced operating at higher superficial gas velocities. Capital and operational cost of options should be evaluated to select the optimal design. For example, a pipeline can be sized to operate in the annular flow regime with a pressure drop that requires a larger compressor installation or wellhead back-pressure. Alternately, it may be more acceptable to size the pipeline to operate in the wavy flow regime. This approach may lower pressure drop in the piping and therefore compressor size, but at the cost of larger slug catching facilities. At this point in the design process variations should be considered. This may include, but is not limited to, seasonal variances and production strategies.

Stratified flow should be avoided for two main reasons. First of all, if a liquid-phase corrosion inhibitor is being used on a pipeline operating under stratified flow conditions a lack of corrosion protection on the top section of the pipe may result due to condensation on the top pipe wall from the gas phase. Secondly, in a stratified flow regime liquid and gas superficial velocities are relatively low. This leads to the potential for large liquid hold up in the pipe, particularly in any low points in the system. Operating in the stratified flow regime may also maximize required slug catcher capacity and/or pigging frequency to remove the liquid and maintain high pipeline efficiency. In downhill sections of the pipeline, stratified flow may be very difficult to avoid. Care should be taken that this will not be detrimental to pipeline integrity.

Line Pressure Drop

In selecting a pipe diameter, the flowing pressure drop due to frictional losses and elevation change is also important. The pressure losses associated with maintaining superficial gas velocities for dispersed or annular flow can be very high and costly in potential recompression costs or increase in wellhead backpressure. This is important when designing a field piping system where pigging is not going to be used. In these cases, it is important to try to maintain high gas flow to keep liquid hold up as low as possible. However, care should be taken in determining the benefit of this type of operation versus compression requirements. Over short distances high-pressure drop may be an option to minimize pipeline installation and operation cost. It is also important to keep pressure drop and fluid velocities within reasonable limits to avoid erosion issues in the pipe. API 14E provides guidelines regarding erosional velocity limits.

Due to the complexity of two-phase flow, the accuracy of pressure drop calculations can be extreme. There can be wide discrepancies between correlations. The OLGA^[7] dynamic model is considered by some to be state of the art in calculation of pressure drop in systems, however, many of the steady state models such as Modified Beggs and Brill will give adequate results, particularly on pipelines without flow transients. When using a steady-state horizontal correlation, elevation changes can be taken into account using the Flanigan correlation. In all models and computer simulations, it is extremely important to ensure that both the fluid data input and the elevation profile used is as accurate as possible.

Liquid Hold-Up Volume

The liquid hold up calculation is very often the key element in sizing slug catcher facilities. If frequent pigging is not used on the line, and the pipeline is allowed to achieve steady state operation in regard to liquid hold up, the slug volume expected should be estimated as the liquid hold up of the entire pipeline. For “long pipelines” (longer than 5 miles) the liquid hold-up calculation will be important in determining if frequent pigs should be run in the pipe to avoid having large slug volumes. In most cases with a shorter pipeline, the slug catcher should be sized for at least the liquid hold-up in the pipeline.

Mechanistic models such as OLGAS do a superior analysis of hilly terrain piping with the ability to take into account angle according to a recent study^[8]. One of the most widely used correlation-based models used to determine liquid hold up in a pipe is by Eaton^[9]. It is important to have a suitable elevation profile as even small changes in angle over long pipeline distances can greatly affect the liquid hold up volume. It is also important that the pipeline modeling be divided into segments to increase accuracy, as the liquid hold up fraction will change over the entire pipeline routing.

A designer should investigate potential turndown operations for the pipeline. As a result of a lower superficial gas velocity, the amount of liquid hold up in the pipeline may increase. If it is known that operation under significant turndown is expected, calculations should be run for these situations. Pigging frequency may need to be increased to keep the liquid in the line from reaching steady state operation and keep slug sizes within the design of slug catching facilities.

Once the designer feels comfortable with the result, it is usually a good idea to do a “rule of thumb” check to ensure a realistic result has been produced. A general rule of thumb is to assume a total hold-up volume of approximately 15 % to 20% of the volume of the uphill sections of the pipeline. If the comparison is unreasonable, further investigation should be performed to ensure accuracy of calculations or explain why the difference is so severe.

SLUG SIZE CALCULATION

Pipeline Slugs

In some cases it may be necessary to operate in the slug flow regime, particularly in turndown situations of multiphase flowlines. Empirical correlations are available to estimate slug size in horizontal pipelines^[10,11]. A model allows the designer to predict an “average” or 50% probability slug size for a set of conditions. The designer then is able to predict slug sizes at a higher certainty level using statistical analysis. For example, if a slug size of 1200 ft³ is expected 95.4% of the time, the designer can choose to build the slug catcher for this size or choose to design a smaller system at a lower certainty. The approach allows the designer to consider the probability of larger than average slugs against the cost to install facilities to handle them. It is generally impractical to design for slug sizes beyond the 95th percentile; however, the designer may consider it prudent if reliability is extremely critical. The statistical analysis was based on test data from large bore flow lines at the Prudhoe Bay Field and has proven to be useful in the prediction of slug size in similar systems.

Consideration of flow variations is essential in determining the appropriate slug size for slug catcher design. The designer may need to assume the simultaneous slugging of multiple feed lines into a common slug catcher in certain scenarios. For example, six separate feed lines may connect together at the plant inlet. If all are in slug flow, it may be reasonable to assume that two or three of the lines may be slugging into the catcher simultaneously (at a relatively low slug size percentile, such as 68%). This could then be compared to the combined slug size for all flowlines providing 50th percentile slugs or a single-line providing a 95th percentile slug in order to determine an appropriate slug catcher design basis. In most cases, this type of complex analysis is not required.

The following figure is an operating trend developed on a system operating in the slug flow regime. This trend was predicted in the initial slug catcher design. As shown, the liquid level increase was handled by the slug catcher. As expected with severe slugging, the gas rate fell considerably as the liquids flowed into the slug catcher, and pressure rise was significant during the same time frame. Note that in this case the maximum gas flow out of the slug catcher was restricted due to downstream capacity limits, contributing to the pressure rise following slug arrival.

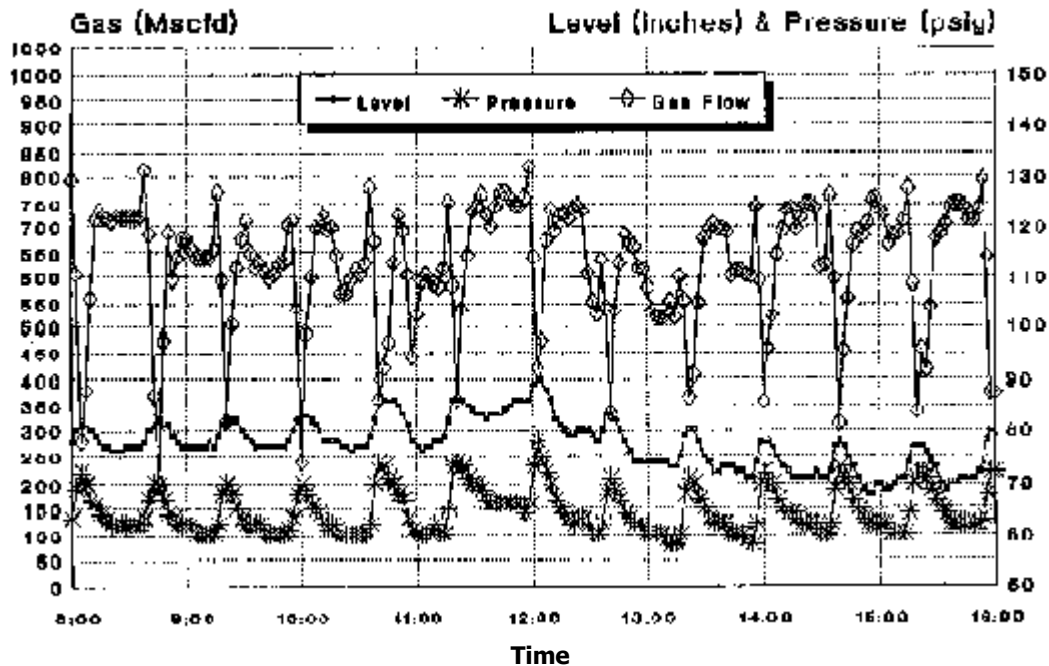


Figure 6 – Slugging – Inlet Separator

Terrain Slugs

Terrain induced slugs can be experienced in extremely hilly terrain. Uphill sections may be severe enough to cause a rise in liquid hold up. As an increase in slope is experienced, the conditions for slug flow become more prevalent over near horizontal installations. Most of the time, the uphill slugs are absorbed through downhill sections and do not affect the plant inlet to any great extent. However, this is not the case if the inlet facility is placed directly after a extreme elevation rise.

Riser Slugs

In the case of riser slugs (usually experienced off shore with the large riser required to come up to the platform or shore), stratified flow in the flowline upstream of a vertical riser pipe that is in unstable (slug) flow regime often leads to severe slugging. A quick check for unstable riser flow is to evaluate the pressure drop in the riser at various gas flow rates. If the pressure drop is predicted to decrease with increasing flow, unstable flow and severe slugging may be expected. Empirical correlations are also available to estimate the size of severe slugs^[12]. Slug sizes of more than four times the riser length can occur^[13]. The use of dynamic models is encouraged to predict slug sizes in these situations.

DESIGN SENSITIVITIES

Thorough design of the slug catcher and the inlet pipeline requires consideration of various sensitivities. Typical considerations include impact of variance in composition, variance in gas rate (e.g. turndown), start-up (unloading), missed timing on pigged systems, and ambient temperature (ground or otherwise).

Phase Behavior

Various operating situations are encountered in slug catcher design. These range from single-phase pipeline operation, wet gas lines (gas with condensation of hydrocarbons and/or water in the pipeline), multiphase lines, and dense phase lines. Compositional and/or phase behavior sensitivities are described for each situation.

For most single-phase pipelines slug catcher requirements are minimal. Sensitivities that might be considered are dehydration failure (or summer shutdown), lube oil carryover from compression, and possibly impact of unprocessed gas entering the pipeline. These cases can then be evaluated with the design steps presented previously to determine appropriate pigging requirements and slug catcher size impacts or to determine that these events are outside of the pipeline's design basis.

In wet gas lines the slug catcher design volume is primarily determined based on the liquid condensation volume. The characterization of the hexane-plus portion of the gas stream will have an impact on the predicted condensation volumes and liquid hold-up. Good characterization to match known separator, wellhead, and/or reservoir conditions is necessary for these calculations to be performed accurately. [Table 1](#) shows the impact of hexane-plus characterization on predicted liquid volume for various characterization assumptions in the Case Study presented later in the paper.

The light characterization case characterizes the C_6+ fraction predominately towards the lighter C_6 , C_7 , and C_8 components, while the heavy characterization case favors the C_8 , C_9 , and C_{10} components. As shown in [Table 1](#), a variation in the heavy end characterization can affect the ability to estimate the potential pigged or hold-up volumes. In other cases, depending on volumes and composition of gas, this effect can be even more significant. The best approach for heavy-end characterization is to obtain an extended gas analysis or a true-boiling-point (TBP) characterization of heavy-ends.

The use of condensate gas ratios is often made to simplify pipeline simulation calculations and calculate hold-up volumes. This assumption should be verified against actual operations or equation-of-state. The impact of heat transfer rate assumptions should also be considered in conjunction with this sensitivity. These two factors (characterization and pipeline temperature profile) will have an impact on phase behavior and hold-up volumes that effect slug catcher design.

In multiphase lines the characterization is equally important, although use of condensate gas ratio (CGR) or gas oil ratio (GOR) may be adequate as the ratio will be relatively constant throughout the line length. Compositional design sensitivities such as variance in CGR should be considered as well as the impact of a full compositional model.

In dense phase designs, careful attention to the characterization is needed to ensure the fluid stays outside the phase envelope at all pipeline operating and shut-in conditions or to predict the amount of condensation that may occur in these instances. Vapor-liquid equilibrium calculations at the "top" of the phase envelope and near the critical point may be inaccurate. Variance in the heavy end characterization or composition (for example from upstream carryover) should be considered as a design sensitivity as well as impact of operating temperature and pressure.

Flow Variance

Flow rate sensitivities should be considered to determine the impact on liquid hold-up in the pipeline and the effect on slug catcher size. Slug flow, which may occur more readily at lower gas rates in both the pipeline and in risers, should be considered in this analysis. Sensitivity analysis on gas rates is important for both pigged and natural flow systems and for both multiphase and wet gas pipelines. An example of the impact of flow rate on hold-up and on predicted slug size is shown in [Figure 7](#).

Table 1 - C₆+ Characterization Variance

C ₆ + Characterization	Daily Liquid Production (bbl/d)	Liquid Hold Up (bbl) and (%)	Pressure Drop (psig)
Characterization #1 Light	160	440 (avg 2.2%)	228
Characterization #2 Heavy	210	540 (avg 2.7%)	231

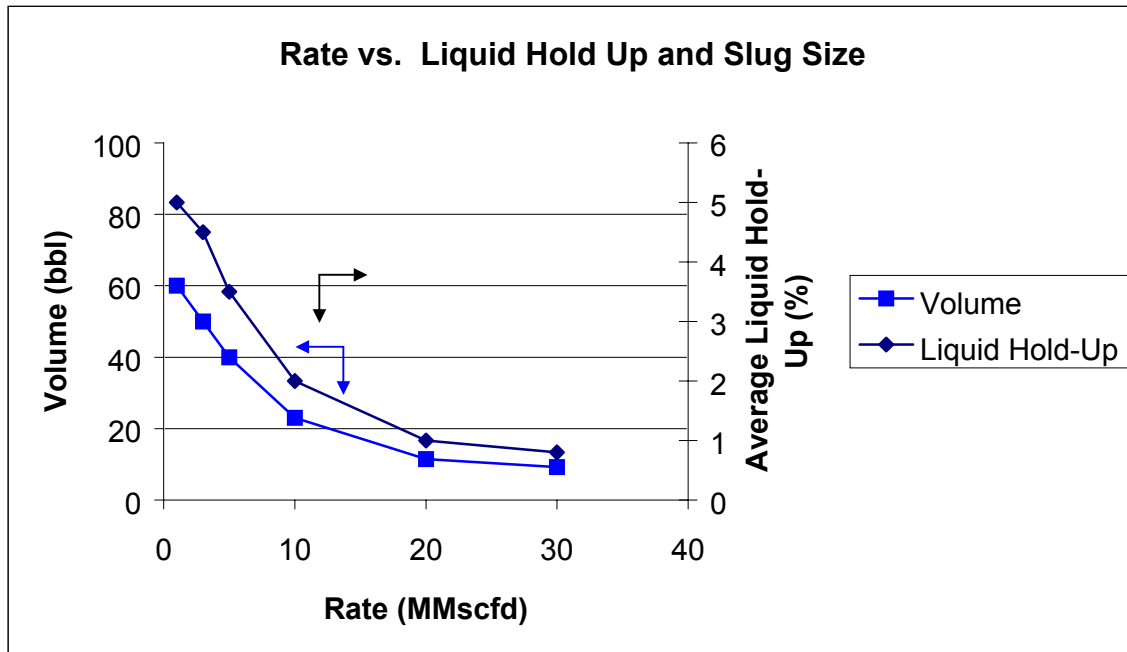


Figure 7 – Rate vs. Liquid Hold-Up and Slug Size

Operational Variance

During start-up, extra liquids may be present in the pipelines due to temperature changes and pressure changes. The impact of increasing the flow rate on hold-up needs to be considered in determining the rate at which the pipeline can be brought on line and/or the implications of slug catcher size. A typical analysis considers the steady-state hold-up curve at various gas rates and calculates the slug volume that must be handled based on unloading the line as the gas rate increases.

The design of a particular slug catcher may require the ability to change from 10% of flow to 100% over a period of 2 hours in a controlled fashion. The difference in the liquid hold up calculation of the two rates over the time period plus adequate contingency specified should be sufficient for the design. For example, as seen in Figure 4 the hold up is 60 bbl at 1 MMscfd and 20 bbl at 10 MMscfd, one could estimate an additional liquid inlet of 40 bbl/hr for the transition time it takes for a new flowrate of 10 MMscfd to traverse the line. The slug catcher should be sized for an adequate residence time plus contingency to handle the peak liquid rate over the “ramp up” period^[14]. Dynamic analysis can be used to improve the precision of these pipeline unloading calculations.

In pigged systems the impact of missed timing of pigs as well as rate changes (a similar analysis to that shown in the previous section) should be considered in designing the slug catcher. Sensitivities such as skipping a scheduled launch on the main pipeline or in branched systems, pigging

of the branched lines out of sequence are possible off-design cases to be evaluated. These cases can be used to determine appropriate slug catcher design safety factors. Some designers suggest sizing the slug catcher for at least the longest uphill section of line to account for missed pigging, although this is sometimes not be feasible for a long pipeline that is routed steadily uphill^[15].

In some systems, the assumption of the ambient temperature and type of surroundings are very important variables. For example, a difference of one or two degrees in the assumption of winter ground temperature can result in a considerable amount of additional line condensation and therefore slug size. This is particularly important for systems that are single gas phase at the inlet of the pipeline. The heat transfer calculation and variables become the key factor in determining the slug size.

Design Factor

The maximum slug size from the various design and off-design cases should be selected and an appropriate design factor (or safety margin) of typically 20% or more should be used in establishing the slug catcher design volume. In some cases the safety margin will be provided by design requirements to allow future expansion and an additional design factor may not be needed. In other cases the design factor may be based on the capacity of downstream liquid handling equipment, for example a two-hour surge capacity might be a requirement for a condensate stabilizer system.

For natural flow systems the designer applies the design factor to the maximum volume from predicted from statistical slug sizes, terrain-induced slugs, and line unloading or other operational variances. Keep in mind that the statistical analysis used to predict natural slug sizes may have already provided the necessary safety margin if a high percentile slug size was selected as a design basis (i.e. avoid hidden or double contingencies in establishing design factors). In pigged systems the volumes calculated for various design and off-design cases should be considered similarly and the design factor applied as appropriate.

Slug Catcher Design

Configurations

Slug catcher design is essentially a specialized category or subset of two-phase separator design. For two-phase separator design, there are two calculations that need to be made: 1) liquid hold-up volume and 2) gas handling.

The designer of a generic separator faces the issue of separator orientation. When footprint size is not the dominant concern, the designer typically makes the decision to apply a vertical or horizontal vessel based on the expected gas-liquid ratio. For a slug catcher design the decision of orientation is all but fixed. The average gas-liquid ratio is not the main design concern. The goal is to provide sufficient liquid hold up volume to handle the design case. This criterion will generally point to the application of a horizontal separator or other slug catching device (pipeline or multiple pipe).

There are four variables that must be determined or selected to design the non-inclined, cylindrical slug catcher liquid hold-up volume: diameter (D), length (L), the maximum liquid fraction of cross sectional area that the equipment is designed for (F_L), and the number of parallel slug catchers utilized (N). These four variables are inherently linked to determine the effective volume of the equipment. The value of the variable F is selected based on geometry and type of the slug catcher installed.

For inclined slug catchers, the goal is usually similar to provide the proper liquid hold up volume, although the equations may be more complex depending on how steep the inclination is. If the slug catcher is mounted fairly steeply, the volume can be estimated by calculating the liquid hold-

up as a vertical vessel. If the inclination is gradual, the horizontal vessel calculation can be used for estimation purposes.

For an effective slug catcher, sufficient gas handling capacity is also required. The removal of liquid slugs from a gas stream is a rough phase separation, which is limited by the drag force acting from the gas stream on each individual liquid droplet versus gravitational force on these same particles. While many primary separation applications are designed to allow the carryover of a droplet not bigger than 100 to 150 micron diameter particles and secondary devices such as mesh pads or mist eliminators may be used to reduce droplet size to approximately 10 to 50 microns, slug catcher design often sets a much less demanding goal of establishing stratified flow to separate the gas and liquid phases, particularly if additional downstream separation is adequate. The liquid flowing into the slug catcher causes a rise in liquid level and a reduction in the cross-sectional area available for gas flow. This reduced cross-sectional area increases gas velocity and drag forces on liquids droplets, which increases the size and amount of liquid carry-over. The slug catcher must be designed so the outlet gas flow is not impeded by the arriving liquid flow. A best-case scenario (the design goal) is to provide sufficient gas handling capacity to avoid plant upsets due to momentary loss of flow or pressure to downstream equipment.

Vessel

At low and medium pressure (0 to 500 psig), the wall thickness requirement for a slug catcher may not be a critical factor. With lower pressure, the diameter of the vessel can be larger without requiring a substantially thicker wall. For this application, optimization tends to favor large diameters with shorter lengths and fewer parallel vessels. Typical length to diameter ratio for vessels is usually between 3:1 and 5:1. Multiple vessels may be desirable for maintenance or cleaning reasons, particularly if a solids or corrosion problem exists. Vessels may be used as slug catchers at pressures higher than 500 psig if surplus vessels are available or in offshore installations where space is limited.

Larger diameters allow for more liquid surge volume capacity and for a lower gas velocity. Usually these slug catchers are horizontal; however, vertical units can be used for cramped areas offshore or if suitable surplus vessels are available. Another advantage to vessel type installations is that three-phase separation is more feasible and can be designed into the system.

Internal components are easily incorporated in a vessel type slug catcher. The addition of a vane pack or mist pad is sometimes considered. Other important components include an inlet diverter plate or other diverter technology such as a cyclone, a liquid vortex breaker plate, and for large vessels an internal wave damping baffle.

Vessel slug catchers also have several drawbacks. For one, they must be designed to pressure vessel codes, which may increase the cost. Another factor is that vessels may require more foundation work than other types of slug catchers. Vessels are typically located above ground, which often adds insulation requirements if a water-phase or hydrates are expected in the system.

Horizontal Vessel

Horizontal slug catcher vessels usually use an F_L value of 0.5 to 0.7. The correct sizing is an iterative calculation to ensure enough area is available for gas flow as well as enough liquid hold-up volume. This may be affected by any area taken up by a mist pad or vane pack installation in the horizontal vessel orientation. Based on the liquid slug volume, the slug catcher dimensions can be calculated:

$$V_S = (L) (N) (F_L) (\pi) (D/2)^2 \quad (1)$$

V_S	=	Slug volume, ft ³ [m ³]
L	=	Slug catcher length, ft [m]
N	=	Number of parallel vessels for pipes
F_L	=	Fraction of cross-sectional area available for liquid hold-up
D	=	Inside diameter of slug catcher vessel or pipe, ft [m]

The second calculation is to define by the gas handling capacity, which may be set by the smallest liquid droplet size removed by the slug catcher. Utilizing gravity settling calculations^[16] the cross sectional area requirement of the equipment is calculated for a desired droplet size. With this information, a second equation relates the gas handling capacity to the slug catcher dimensions for horizontal type slug catchers:

$$A_V = (N) (1-F_L) (\pi) (D/2)^2 \quad (2)$$

A_V	=	Cross sectional area available for vapor flow, ft ³ [m ³]
N	=	Number of parallel vessels or pipes
F_L	=	Fraction of cross-sectional area available for liquid hold-up
D	=	Inside diameter of slug catcher vessel for pipe, ft [m]

With three unknown variables, and only two equations, determining the slug catcher dimensions (N , D , and L) becomes an iterative process to optimize vessel cost.

Sometimes it is advantageous to split the inlet to each side of the vessel and put the vessel outlet at the middle for horizontal vessels with vertical mist pads or similar internals. This allows the gas velocity to be significantly reduced and may result in a smaller vessel based on mist extractor sizing (see reference 16, equations 7-10 or 7-11) to balance gas area and liquid hold-up. Note that splitting the gas flow to each end does not provide any benefit with the droplet sizing approach for vessels without internals (see reference 16, equation 7-12) as both the gas volume and effective length are divided in half and consequently the required vessel diameter will remain the same.

Vertical Vessel

A vertical vessel may be used where a small “footprint” is required (offshore), if surplus vessels are available, or if liquid slug volumes are small. In the vertical case the F value is equal to 1.0. The liquid hold up volume available is the working volume of the vessel (usually set by the low liquid and high liquid level alarms or other such devices below the inlet nozzle). The cross sectional area of the vessel is determined simply through common vertical separator calculations^[16]. The area can be larger than the gas handling calculation suggests, if the liquid hold up requirement is controlling and the vessel height needs to be restricted.

Pipeline

When the pressure is higher, the gas flow rate is not prohibitive, and the site topography allows for a long gentle downward slope, the optimization may favor a large value of L and a relatively smaller value of D and N in equation (1), above. This is the case of using the pipeline itself as a slug catcher. In this type of design the pipeline diameter is typically increased in the slug catching section

in order to reduce the gas velocity. By changing the pipeline diameter, either natural flow systems or bi-diameter pigs are required.

The value of N does not always equal one in this type of design, as the pipeline may be looped in the slug catching section. This looping not only decreases the gas velocity to allow better separation, it also allows the gas to flow through one of the lines as a cleaning pig and associated liquids are removed from the other line^[17].

Using the pipeline as the slug catcher has several advantages. One advantage is designing and maintaining the equipment to pipeline regulations, codes, and standards as opposed to more stringent pressure vessel codes reduces costs. Another advantage is that this type of slug catcher is often underground. This reduces the insulation and heat tracing requirements. In addition, external coating is typically more cost effective for an underground piece of equipment than painting, insulation, and heat tracing.

An inlet separator or flash tank may still be required at the inlet to the processing plant to separate the gas and liquids as the liquids are extracted from the pipeline. Also an additional pig launcher /receiver set and additional valves and controls may be needed for the looped line section.

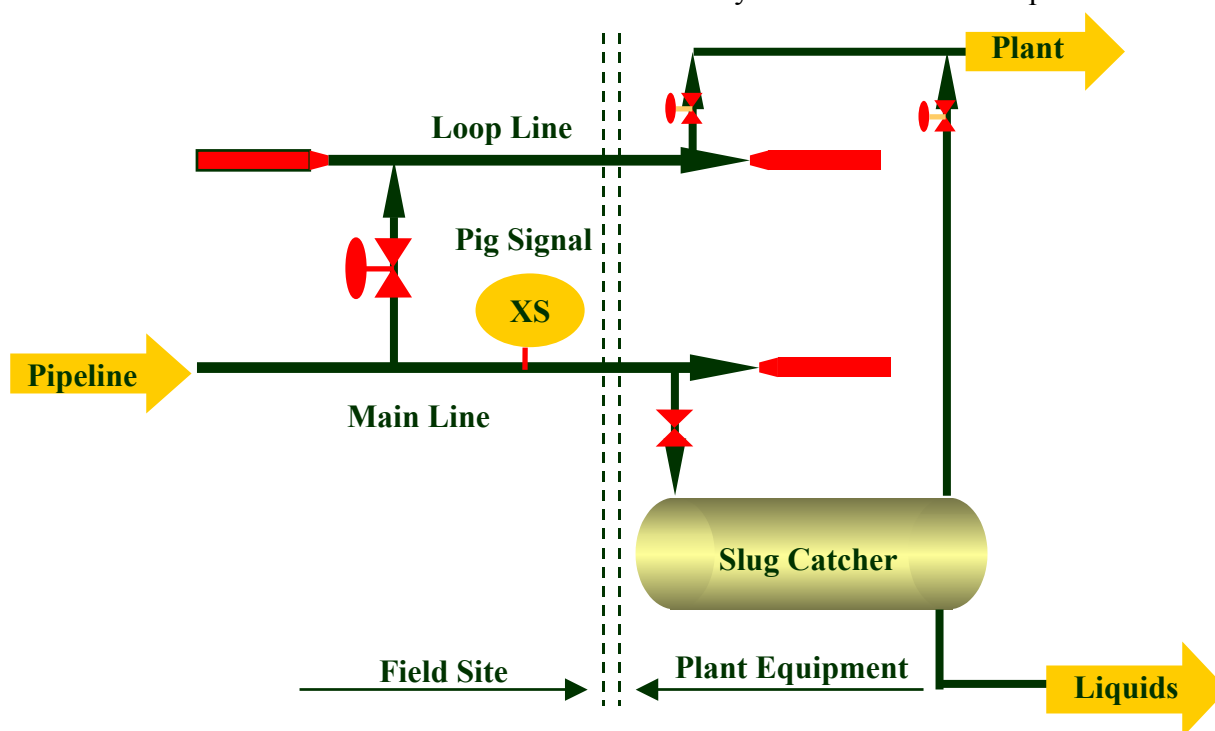


Figure 8 – Slug Catcher Design Pipeline

Multiple Pipe

At the increased operating pressures, slug catcher price optimization tends to favor smaller diameter slug catchers of longer length. This type of slug catcher is known as a multiple pipe or harp type slug catcher. In this type of design, the slug catcher pipes are manifolded to the pipeline. Momentum carries liquids to the last pipe take off point, so the system must be carefully designed so that liquid flow is evenly distributed between the pipes^[18]. Liquid equalization lines are often utilized to balance the liquid levels between pipes.

The multiple pipe slug catcher is usually designed with the multiple pipe sections sloping gently downward and a diameter selected for stratified multiphase flow. The vapor outlets are located on the topside of each pipe at some optimum length down the pipe. This section from the inlet to the vapor outlet can be referred to as the separation section (with a length of L_s). As the outlet lines are

located further down the slug catcher from the inlet, more distance is allowed to achieve stratified flow. At the same time the effective liquid storage volume of each pipe is decreased. The length of liquid hold-up section of slug catcher pipe is referred to as L_h . The slope of the slug catcher is chosen to optimize the ability for separation as well as maximizing the liquid hold up volume per foot of pipe installed. Different slope angles can also be used on different sections to encourage separation and liquid retention^[18]; however, this may complicate the installation.

The length, diameter, and number of pipes used in this type of slug catcher are related as described previously to provide sufficient volume for the design slug size. The fraction of the area used for liquid volume (F_L) is approximately equal to the ratio of the pipe length used for hold-up divided by the total pipe length.

$$F_L = (L_h) / (L_h + L_s) \quad (3)$$

Calculations can also be completed to ensure that stratified flow develops in each pipe in the separation section based on flow regime boundaries. These calculations provide a relationship between pipe diameter (D) and the slug catcher angle (and consequently an indirect relationship to the other variables controlling volume) to optimize the design^[19].

Multiple pipe slug catcher design can use both primary and secondary “bottles” or pipes in their design^[18,20]. The primary bottles are used for incoming flow and the outlet is at some position downstream, similar to a regular system as described above. As liquid fills these bottles, countercurrent gas flow is required due to displacement. This may cause short inconsistencies in gas flow to the plant. To eliminate this problem, the system can be designed with secondary bottles. These secondary bottles do not receive inlet flow from the pipeline. The secondary bottles act as a gas reservoir and allow for cocurrent gas and liquid flow in the system. Liquid from the primary bottles equalize into the secondary bottles where the displaced gas is free to flow into the process without restriction due to counter flow. This type of design is very effective if long, predominately liquid slugs are expected to occur. The multiple pipe slug catcher can also be designed to facilitate future expansion^[15].

Per DOT 192 regulations, the design of multiple pipe type slug catchers require a design factor of 0.4, similar to Class 4 location designs. Therefore, careful consideration must be made to the additional thickness requirements in designing with pipe versus the pipe design used for the pipeline installation. Any internals added to a pipe type slug catcher via internal welding require the slug catcher to be also be built under testing requirements of ASME Section VIII under DOT regulation 192.165 Compressor Stations, Liquid Removal ^[21]. It is recommended to avoid the installation of internals on these units. In the case of larger slug catcher designs (in excess of 100 bbl) it may be advantageous to use a harp type design with a series of vessels rather than or in combination with pipe.

Mist Eliminators / Secondary Gas Separation

Slug catchers do not usually require liquid removal to levels accomplished by a mist pad or vane pack element. The purpose of the slug catcher is to remove bulk liquid flow from the line. However, in some cases, it is advisable to also include an element in the design of vessel type slug catchers (inlet separators) at the front end of a facility or compressor station. This will reduce the liquid loading on the downstream scrubbers and/or separators that protect valuable equipment from potential damage.

The advantages of vane pack designs are that they operate at the same conditions with a smaller “footprint” than a mist pad design. In addition, vane packs are less susceptible to plugging as

compared to mist pads when heavy oil, paraffin, elemental sulfur, hydrate, or particulates are present. Therefore, the vane pack can normally operate with a lower pressure drop and higher efficiency for a longer period of time. This is particularly important at the front end of a gas processing facility where the problem of paraffin and solid contamination is much more prevalent.

Since the vane packs do operate more efficiently, the required vessel size to contain the unit is usually lower than the conventional mist pad. This is usually an economic benefit as the vessel cost can usually be lowered significantly. However, in slug catcher design, the driving factor for vessel size is usually liquid hold up capacity in the vessel as opposed to gas handling area. Depending on the system, a designer could specify either option for mist elimination. It is recommended that vane packs be used if possible for facility inlet separation. It is also recommended that there be a manway to access the element and that the element be installed in a manner that allows for removal and cleaning.

Another important factor in the design is placement of the element in a vessel. Installing a mist eliminator in a horizontal vessel type slug catcher sometimes removes needed liquid hold up capacity in the vessel. One method of minimizing this problem is by lowering the gas velocity by having two gas inlets, one at each end of the vessel, and a single outlet at the center of the vessel (or vice versa). This problem can also be avoided by increasing the length and or diameter of the slug catcher, installing the mist eliminator in a secondary vessel immediately downstream of the slug catcher, or installing the unit in a appropriately sized “boot” off the top of the vessel. In many cases the additional vessel or “boot” installation will be more cost effective than increasing slug catcher size. This works well with vane pack designs as the dimensions of the secondary vessel or boot is minimized to accomplish the desired liquid droplet removal (usually 10 micron). If a secondary vessel is added, the secondary vessel and slug catcher should be installed to allow for the liquid from the secondary vessel to gravity drain back to the slug catcher.

Solids Handling

Solid particles often buildup and settle out in slug catcher. These particles can include sand, iron sulfide, coal fines, and carbonate scales. If a vessel type slug catcher is utilized, it is advisable to include manways for cleaning and inspection access. For pipeline and multi-pipe slug catchers it is advisable to include clean-out connections.

The design of a filtration system depends largely on the particles that need to be dealt with and downstream processing requirements. An acid gas or sour gas pipeline will typically have iron sulfide and/or iron carbonate particulates. Since these particulates are generally smaller than 10 microns in size, special provisions may be required to prevent the entry of these small particles into downstream equipment.

In recent designs, a vertical coalescer or filter separator following the slug catching equipment on the gas outlet to provide secondary gas separation has been effective in removing solids and liquids. The vertical coalescer elements are designed to remove small liquid droplets by coalescing them into bigger droplets on the filter elements. When the coalescing liquid droplets wet the filter elements, the filter micron size becomes effectively smaller and solids tend to be held up on the surface of the liquid droplets. The application of a vertical coalescer downstream of a slug catcher is an excellent way to coalesce small carryover liquid droplets and tie-up small solids at the same time. In this option it is advisable not to include a mist elimination element in the slug catcher design.

Filtration may also be installed on the liquid outlet of the slug catcher or secondary liquid vessel. The filters should be placed at the point where flow is controlled at expected rates to downstream equipment. For example, if the slug catchers are designed to dump extremely quickly to a surge vessel, filtration on the liquid side should be designed for the outlet of the surge vessel. If the slug catcher itself is used for surge capacity, then the filter unit should be placed there. Screens can

also be utilized to protect control valves from debris. It is advisable to ensure these can be blocked in and bypassed as necessary to pull and clean the screens. It is also advisable in some severe cases to have two stage filtration, such as coarse and fine filters or a sacrificial/backup filter arrangement.

Instrumentation

Level Control

The goal of a level control system for a slug catcher is to keep the normal liquid level in the vessel as low as possible so that more volume is available for liquid slug handling. Level control on a slug catcher is best performed with a snap acting controller and valve. The application of a snap acting control enables the maximum release of liquids from the vessel in the shortest period of time. It is important to evaluate the flash gas produced in downstream equipment. This includes vessels, compression, and condensate stabilization.

In all three types of slug catchers, it is possible to use level controllers, multiple level switches, or even differential pressure switches to perform feed forward level control. When an instrument identifies an initial level increase in the vessel or increasing differential pressure in the upstream pipeline, it can throttle a valve downstream of the slug catcher to reduce the flow of the slug and gas. By installing the valve downstream of the slug catcher, the valve should only be in gas service versus liquid, gas, and multiphase flow conditions. This pressure drop in the gas stream wastes horsepower and cuts gas flow through plant, but it is an effective way to occasionally control and distribute the slug volume over a longer period of time to reduce slug handling facility size.

It is certainly the case that without using some sort of feed forward control or operations method to proactively adjust for incoming slug liquid, many facilities with limited slug catcher capacity would be periodically shut down due to high liquid level or have liquid carryover to downstream equipment. The slug catcher vessels are also usually equipped with high and low level alarms and shutdowns. If solids are a significant problem purging the differential pressure switch with gas to prevent fouling is recommended^[15].

Flow Control

In cases where the slug catcher is used as surge capacity for a downstream condensate stabilization unit, a liquid flow control system can be incorporated to keep a steady flow to the downstream equipment. This may be cascaded with the level control.

Pressure Control

In some complex gas processing facilities that are sensitive to variations in inlet gas flow and composition, it may be necessary to make additional provisions to compensate for variations in inlet flow due to slug liquids. One method that is appropriate where inlet compression or residue compression are utilized is the installation of a recycle system. With this system, when the inlet flow is decreased due to an inlet liquid slug, gas from the compression discharge can be recycled to the plant inlet to temporarily keep the plant inlet pressure stable by making up for reduced inlet flow. However, a properly designed and sized slug catcher should eliminate the need for this system.

A choke (inlet line backpressure) is sometimes used to prevent riser slugs^[12]. Occasionally slug vessels or intermediate pressure vessels are used to hold excess gas pressure and allow it to flow evenly to process or to recompression.

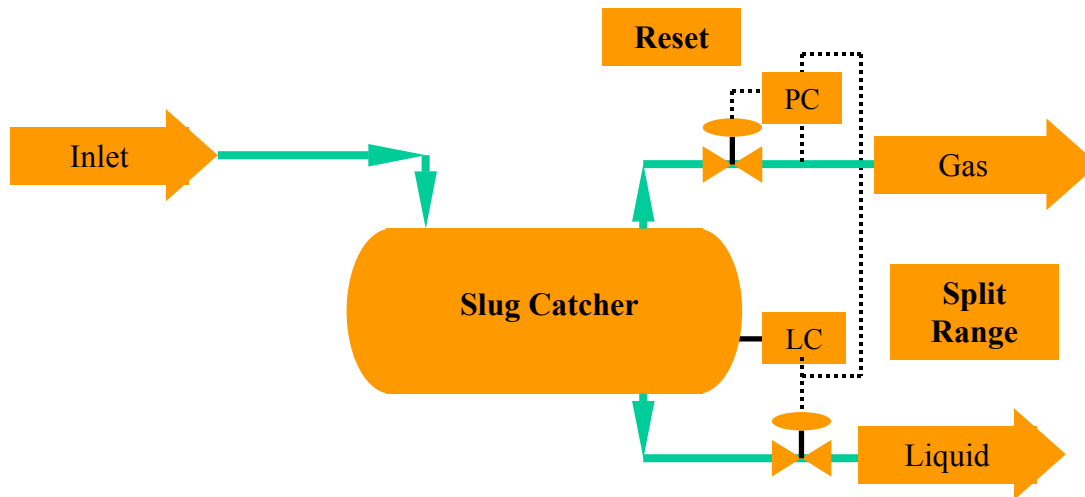


Figure 9 – Slug Catcher Controls

Other Instrumentation

Other devices commonly used are pig signal devices, differential pressure cells, and orifice plates that are used to predict the arrival of slugs into the plants. The pig signal devices are usually mechanical switches that are activated as the pig or sphere pass by the device. In pigged and unpigged systems, differential pressure cells can be used to give indication of a large slug of liquid passing down the pipeline. This is particularly useful to control switching valves over to the looped section of line. Differential pressure indication is best located at uphill sections of the pipe if possible. An orifice plate can also be used to magnify the differential pressure change, however, in pigged systems this needs to be installed downstream of the pig receiver.

Header

In the design of multi-pipe slug catcher installations and multiple vessel installations care is required in the design of inlet and outlet headers. The use of symmetric headers is preferred to encourage equal flow splitting between the various slug catcher vessels or pipes. Orientation of the tee so that the inlet flow is through the “branch” connection and outlet flow exits through the two sides of the tee increases the chance that even flow splitting of liquids and gas will occur. Preferred header design is shown in [Figure 10](#). Use of tees with the flow out the branch has been shown to cause uneven distribution of gas and liquids in the two outlets of the tee ^{[22] [23]}. Even with symmetric inlet piping it is common practice to provide equalizing lines for the gas and liquid to flow between the various slug catcher pipes or vessels. A typical equalizing configuration for a liquid outlet is shown in [Figure 11](#).

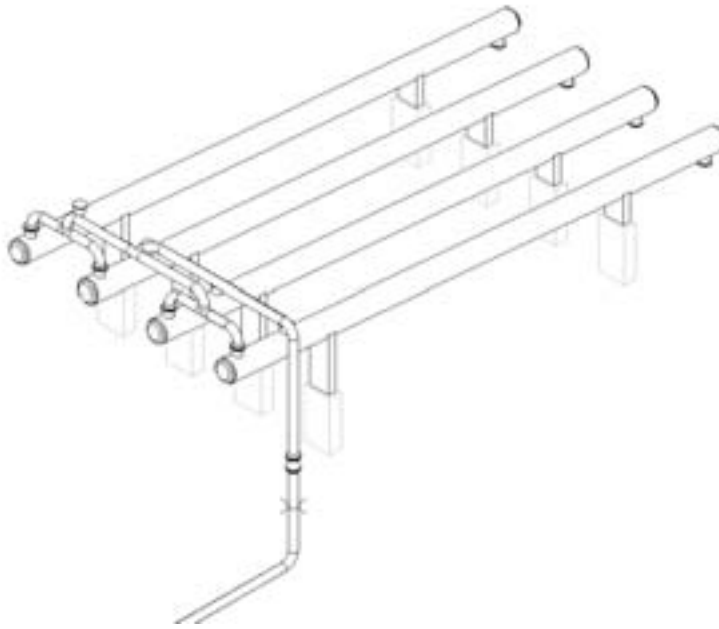


Figure 10 – Typical Inlet Header Design

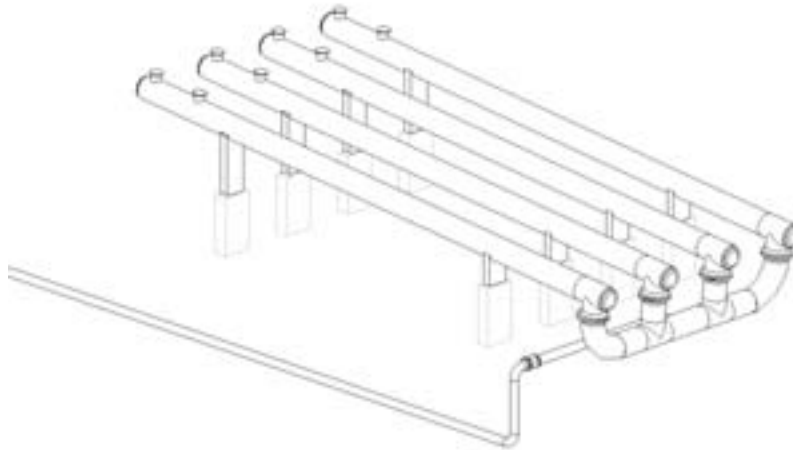


Figure 11 – Liquid Equalization and Outlet Design

The outlet piping should be symmetric as well. Use of asymmetric piping, particularly on liquid outlet lines from multiple vessel slug catchers can cause unequal operating levels to occur due to different pressure drops in the liquid piping system. This can reduce the overall working volume of the slug catcher and increase the potential for liquid carryover into the outlet gas piping. In pipe type slug catchers it is common practice to draw the liquid from an equalizing header at the bottom of the slug catcher to prevent this from occurring. This practice is also used in some well-designed, multiple-vessel-type, slug catcher systems. A typical outlet header arrangement is shown in Figures 11 and 12.

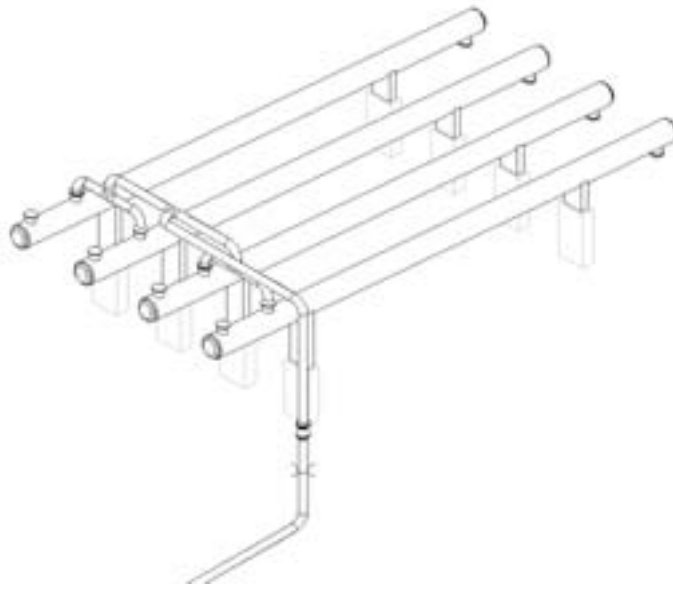


Figure 12 – Outlet Gas Header Design

Utilizing the above design methods, an overall design of a typical multi pipe slug catcher installation is shown in Figure 13.

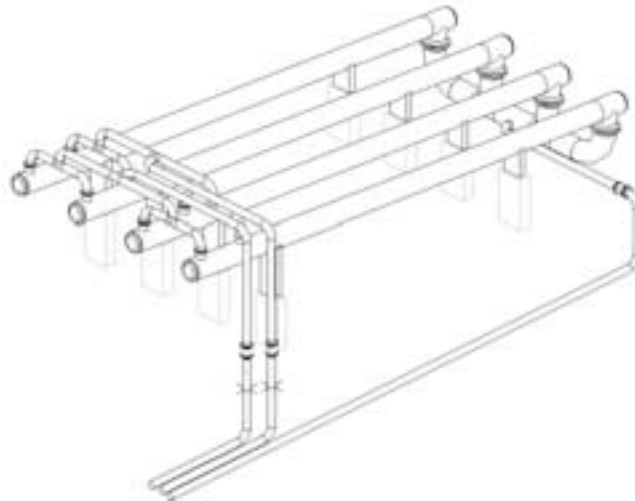


Figure 13 – Typical Overall Design

Often the header piping is designed asymmetrical for other reasons, such as an uneven number of pipes as seen in [Figure 14](#). In this case, the inlet and outlet headers should be oriented from opposite sides to attempt to keep a consistent pressure drop for each pipe bottle.



Figure 14 – Slug Catcher – Inlet End View

In some installations the inlet piping has been designed to encourage stratification of the flow upstream of the vessel to improve slug catcher performance^[24]. This requires a larger pipe diameter and a downward sloping inlet line upstream of the vessel. In another case^[25] the slug catcher was located at some distance from the plant at a low point in the collection system to improve separator performance and reduce the possibility of terrain induced slugs at the inlet of the plant. Gas and liquids are then sent to the plant separately from this vessel.

Mechanical considerations must also be addressed. Forces caused by alternating gas to liquid slugs on the inlet piping can be considerable^[26]. It is important to ensure that the pipe is properly supported and braced in place to avoid mechanical failure or deformity.

Three-Phase Separation

In some slug catchers a separation between water and hydrocarbon liquid phases is made in the slug catcher. It is difficult to ensure that the two liquid phases will split evenly upon entering the vessel, so in this case providing sufficient equalizing lines between the vessels for both phases is required at a point in the vessel where the equalizing lines will not disrupt the liquid-liquid interface. In a pipe-type slug catcher this usually requires use of a liquid equalizing header (as shown in [Figure 6](#)) at an intermediate point along the slug catcher length. For a multiple vessel type slug catcher this requires internal standpipes or weirs to allow the light liquid phase to equalize.

Intermediate Liquid Vessel

To reduce liquid hold up requirements in the slug catcher, it may be advantageous to install an intermediate vessel (e.g. Condensate Feed Drum) for additional liquid surge capacity. The intermediate vessel typically operates at a lower pressure than the slug catcher and it therefore reduces the cost of liquid slug volume capacity. The offset to this cost savings is the flash gas handling equipment. A separate flash gas compressor, inlet compressors, or condensate stabilizer overhead compression may be used to recover the flash gas. The combined installation cost of the compressor unit and intermediate vessel should be weighed against the cost of the larger slug catcher hold up volume. Sometimes this option is used due to the availability of surplus vessels or equipment.

OPERATIONAL FEEDBACK - CASE STUDY

Original Design

The following case study involved a gas plant in central Wyoming. The gathering system involved a 30 mile gathering trunkline originally designed to operate at a downstream pressure of 350 psig (plant inlet pressure) under normal operations and 950 psig under short term (plant bypass) operations. The pipeline was designed for a 50 MMscfd flowrate. The pipeline diameter was initially designed with particular attention to the line pressure drop for the low pressure case and was chosen before the slug catcher requirements were determined. These systems should have been designed simultaneously.

The original expected feed flow rate to the plant was provided from a single source. A dew point, single-phase gas stream enters the trunkline, therefore all slug liquid was the result of condensation. A detailed composition for the gas was available and sufficient heavy end data was established in the lab. Throughout this case study, this is known as the expected composition. There was also a less detailed composition available for another site that was to be tied into the pipeline in the future. This will be known as the rich case. [Table 2](#) shows the compositions available.

Hydraulic models established liquid dropout quantities and liquid hold up volumes for the expected case, rich case, and a mixture case as shown below in the table for winter ground temperature conditions (40°F). The fluid flow regime was determined and for all cases and natural slug flow was not anticipated (Hysys predicted a stratified flow regime in all cases). Sensitivities for flow rate between 10 and 50 MMscfd were simulated for the expected and rich composition cases. The Mix case was estimated using available expected future flow split between the expected and rich flowrates to make the 50 MMscfd (64% Expected, 36% Rich).

Table 2 - Case Study Compositions

Composition (mol%)	Expected	Rich
Nitrogen	1.22	1.04
Carbon Dioxide	1.15	2.36
Methane	77.93	71.80
Ethane	13.03	15.02
Propane	4.65	5.90
i-Butane	0.52	0.87
n-Butane	0.87	1.40
i-Pentane	0.17	0.49
n-Pentane	0.16	0.51
n-Hexane	0.09	0.58
n-Heptane	0.03	0.02
n-Octane	0.01	0.01
Benzene	0.06	----
Toluene	0.08	----
Ethyl-Benzene	0.01	----
P-Xylene	0.02	----
Total	100.00	100.00
GPM (C2+)	5.46	6.97
GHV (Btu/scf)	1210	1283

Table 3 - Results of Pipeline Simulation

Composition	Pressure (psig)	Inlet Rate (MMscfd)	Condensation Rate (bbl/d)	Liquid Hold Up (bbl)
Expected	350	10	58	600
		50	153	400
	950	10	103	1660
		50	379	1240
Rich	350	10	188	1240
		50	1070	1200
	950	10	505	4600
		50	2565	3400
Mix	350	50	352	780
	950	50	944	2000

This table was produced using results of the Beggs and Brill correlations as well as the heat transfer calculations available in the HYSYS simulation program from Hyprotech Ltd of AEA Technologies. The Peng Robinson Equation of state was specified for the simulation. Sensitivities were not run under differing fluid flow correlations or equations of states. In hindsight this may have been advisable. The heat transfer rate was calculated using a wet clay soil type that has a high heat transfer coefficient ($U_0 = 1.0 \text{ Btu/hr Ft}^2 \text{ }^\circ\text{F}$). This should have resulted in a conservative estimate (higher liquid drop out).

It was decided that the trunkline would be pigged in order to maximize efficiency of flow. With the high liquid hold up volumes, it was decided that pigs would be run to reduce liquid hold up and enable unloading when changing between high and low pressure operations.

After discussions with the client, it was finally decided to design the slug catcher for the Mix composition low pressure case and the Expected composition/high pressure case. These cases had similar results of liquid hold up. In order to operate at the high pressure plant bypass cases, the client wanted the slug catcher to be built to the MAOP of the pipeline, 1300 psig. Building to this high pressure increased the slug catcher cost and therefore the size was minimized. The final slug catcher design had a 90 bbl of hold up volume and required pigging 4 to 5 times a day. An automatic pig launcher system was installed to ensure timely launching of pigs in the line. No contingency was added for the case of a missed pig.

The slug catcher was designed as a horizontal vessel with a water boot off the bottom since there was a potential for a small amount of water drop-out. It was also determined that a mist eliminator was desired to avoid compressor shutdowns due to high liquid levels in the downstream compressor suction scrubbers. To maximize liquid hold up in the slug vessel, a vane pack was installed in an overhead boot sized for 10 micron separation. As a result, the size of the vessel was a five-foot diameter by fifty-foot seam-to-seam vessel with sufficient area for gas flow and liquid holding volume.



Figure 15 – Case Study Slug Catcher

For cases where a large slug is experienced due to a missed pig or other circumstances, control valves were designed to reduce gas flow and therefore decrease the slug flow. The valves are set up to pinch back on flow as slug catcher levels rise above 75% of vessel capacity. The major drawback of this system is the disruption of steady gas flow to the plant. The inlet control valves were also

designed to make a smooth transition from high pressure operation to low pressure operation and reduce the slug rate due to change in pressure and velocity in the line as well as slowly load the inlet compression.

A high level alarm and shutdown were also installed. The high level shutdown causes an isolation of the plant from the slug catcher. However, the condensate stabilizer system continues to operate in order to lower the level in the slug catcher. An intermediate vessel was not installed to handle surge capacity. Pig signaling devices (mechanical switch type) were also installed at the launcher and receiver.

Current Operation

The operation of the pipeline for the facility has evolved greatly over a short period of time. For various reasons, the basic operation of the line has changed to where the line operates at a higher pressure during normal operation than originally anticipated, approximately 500 psig at the gas plant inlet. As well, the actual gas composition is richer than the Mix case. The current gas flow is approximately 30 MMscfd. Inlet temperature to the plant is close to the design winter conditions.

In order to keep up with the higher liquid dropout, 6 pigs are run per day. If the automatic launcher is unsuccessful in launching a pig, the operations team expect and prepare for a slug size in excess of what the plant can handle by draining out the slug catcher as completely as possible and prepare themselves for a potential shutdown scenario. Below is a trend line of the level in the slug catcher as the slugs arrive throughout the day.

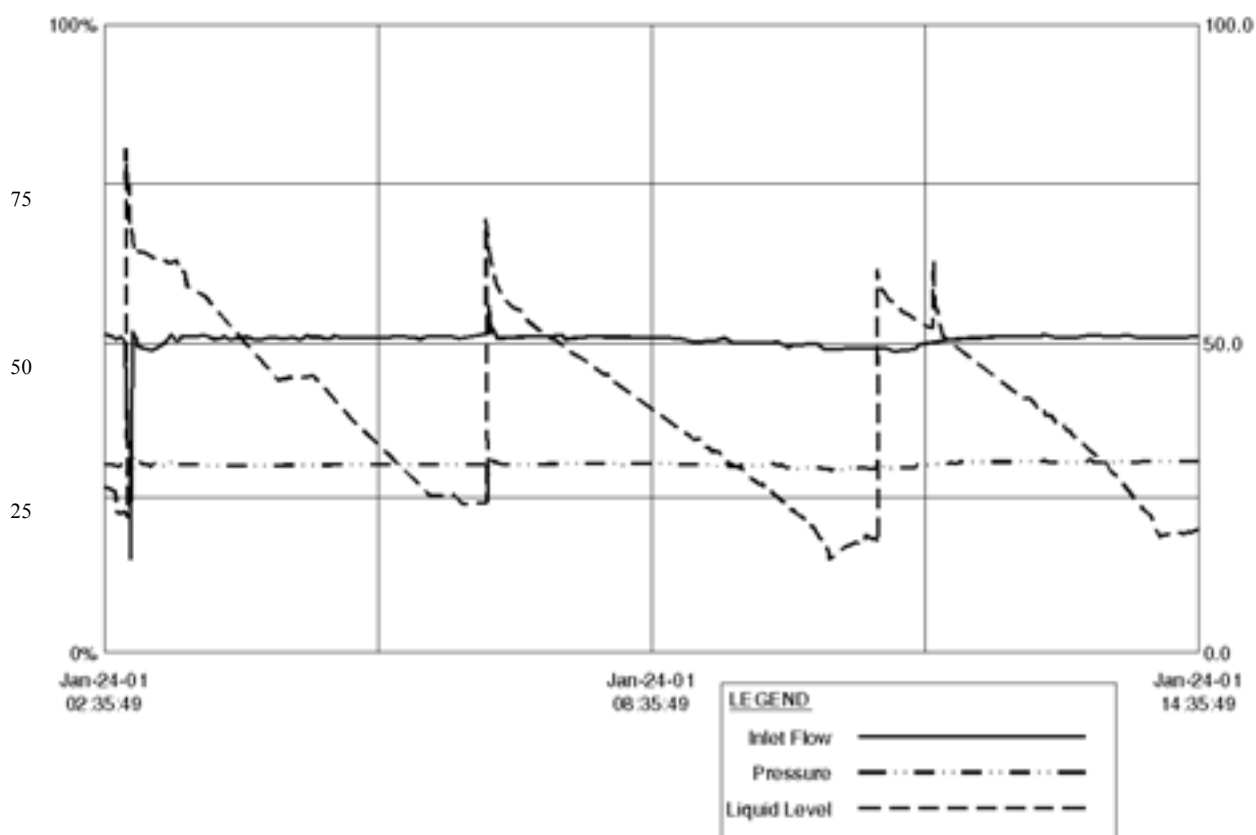


Figure 16 – Slug Catcher Normal Operation

The current liquid condensation rate at 30 MMscfd in the line is estimated at 490 bbl/d based on the change in level on the slug catcher as the slugs are received.

The following trendline is an example of operation when a pig launching is not at consistent intervals. The first pig arrival is obviously not as smooth as desired.

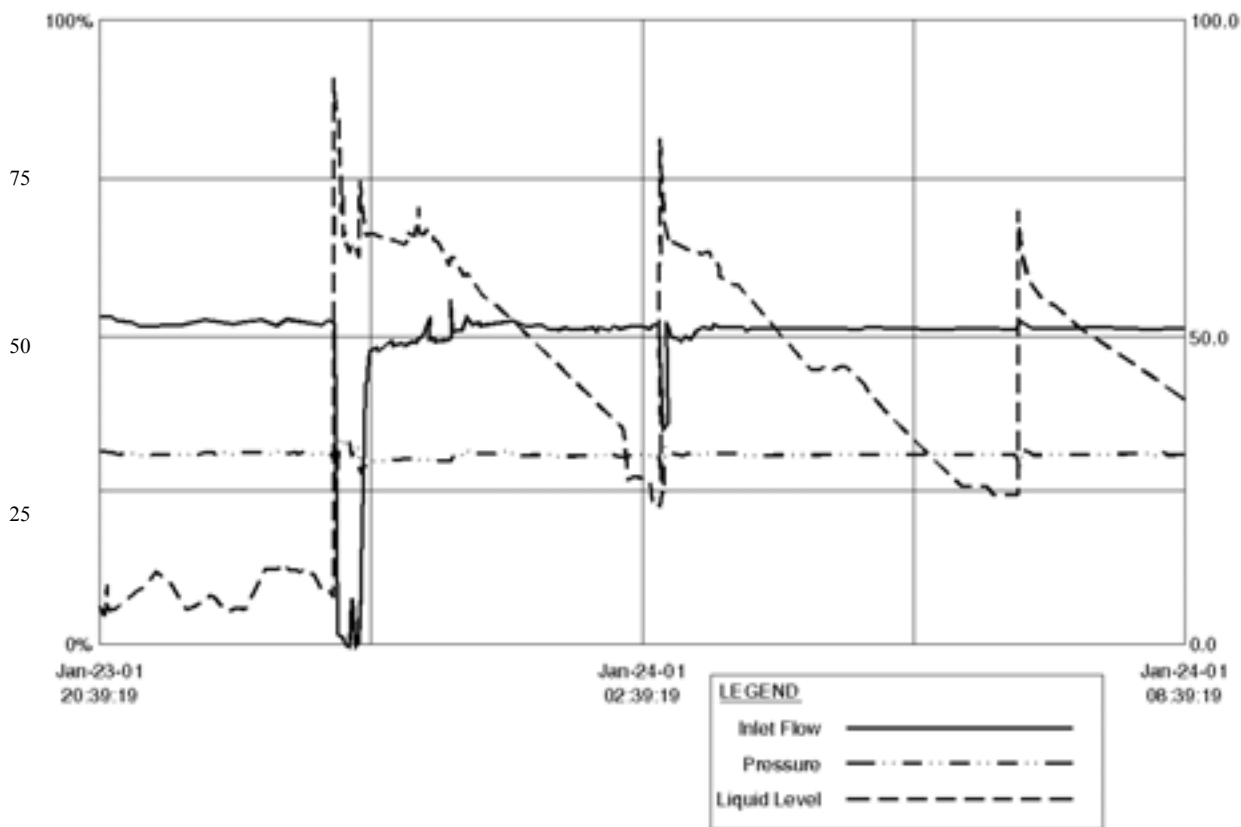


Figure 17 – Slug Catcher Inconsistent Pigging

As you can see from Figure 17, operations tries to prepare for the larger slug by removing as much liquid as possible as they expect the pig coming in. By this time they are aware that a mislaunch of a pig has been experienced and are expecting the extra liquid inlet rate. Unfortunately, this is a recurring problem at the plant due to the inconsistency of the automatic pig launcher and pig signaling devices.

The plant has since installed a secondary liquid vessel to use as a surge drum. As well, the condensate stabilizer system needs to be expanded to keep up with and process the extra liquids from the richer (than original design) gas sources. Overall, the slug catcher is operating adequately; however, operations had to increase the frequency of pigs to accomplish consistent operation.

Due to gas delivery contracts, the line is no longer able to operate to the high pressure required for plant discharge. If this was known in the design phase, a much larger vessel rated to a lower pressure such as 600 psig could have been designed for a similar installation cost.

This example is a case that demonstrates the decisions made during the design process and how those decisions affect the flexibility of the system. The reality of operation may change significantly and therefore the contingency and sensitivity calculations are as important as the base case design. If the system had originally been designed at 3 pigs a day using only the expected composition, the slug catcher would have been undersized for the current operation.



Figure 18 – Complete Slug Catcher Installation

SUMMARY & CONCLUSIONS

A proper slug catcher design requires the designer to understand and focus on a variety of issues such as design conditions, operating philosophy, and pipeline hydraulics to determine the size slug catcher. The actual mechanical arrangement and specific design of the vessel or pipe slug catcher is based on the operating pressure, location, and unit size. Finally, design details must be addressed, including headers, internals, solids handling, and instrumentation. In many cases, similar to the case study that was presented, the design basis will evolve over time. A designer needs to be as aware of potential changes over the life of the project and design the system with appropriate flexibility. Often this is a very tough proposition as the size of some systems may require significant capital investment in order to try to cover all the off-design situations. However, the best possible choice can be made if the design information is gathered and design sensitivities compared in order to make the proper decision on slug catcher size and design.

The technology for flow characterization and slug catcher facility design is readily available in industry. The key to a good slug catcher design is to understand and use the tools available and to carry out the calculations in an informed and organized manner. Utilizing the method brought forward in this paper will help to decrease downtime, process upsets, and equipment damage relating to liquid slugs. It will give the designer and the operator a clear understanding of the capabilities of slug catcher system designs and how to evaluate off-design cases.

ACKNOWLEDGMENTS

The authors would like to acknowledge the following people for their contributions to the paper:

1. Sam Johnson and Frank Zgaynor of Sage Creek Gas Processors, LLC, for their time, patience and information.
2. Kris Vollmer of Pearl Development Company for her contributions to organizing the authors and bringing the paper together.
3. Gary Doven and Pearl's Design Department for their assistance in preparing the drawings.
4. Phil Archer's participation in this paper while he was an employee of Pearl Development Company. Phil was involved in the initial development and rough outline of the paper.

REFERENCES CITED

1. Wu, H.L., Spronsen, G.V., Klaus, E.H., and Stewart, D.M., "By-pass Pigs for Two-phase Flow Pipelines," *75th Annual GPA Convention*, March 11-13, 1996.
2. Meadows, R.E., "Switch from Spheres to Pipeline Pig Improves Gas-Gathering Efficiency," *Oil and Gas Journal* Aug. 1, 1994, pp. 48-50 (from GPA 73rd Annual Convention).
3. Mandhane, J.M., Gregory, G.A., and Aziz, K., "A Flow Pattern Map for Gas-Liquid Flow in Horizontal Pipes" *Int. J. Multiphase Flow*, Pergamon Press, Vol. 1, 1974, pp. 537-553.
4. Aziz, K., Grovier, G.W., and Fogarasi, M., "Pressure Drop in Wells Producing Oil and Gas" *J. Cdn Pet. Tech.*, July-Sept 1972, pp. 38-48.
5. Taitel, Yehuda, and Duckler, A.E., "A Model for Predicting Flow Regime Transitions in Horizontal and Near Horizontal Gas-Liquid Flow" *AIChE Journal*, Vol. 22, No. 1, Jan 1976, pp. 47-55.
6. Beggs & Brill, "A Study of Two-Phase Flow in Inclined Pipes," *SPE 4007 Journal of Petroleum Technology*, May 1973, pp. 607-617.
7. Bendiksen, K.H., Malnes, D., Moe, R., Nuland, S., "The Dynamic Two Fluid Model OLGA: Theory and Application," *SPE Production Engineering*, May 1991, p. 171.
8. Shea, R., Rasmussen, J., Hedne, P., Malnes, D., "Hold Up Predictions for Wet-Gas Pipelines Compared", *Oil & Gas Journal*, May 1997, pp. 73-75.
9. Eaton, Ben A., et al. "The Prediction of Flow Patterns, Liquid Hold Up and Pressure Losses Occurring During Continuous Two-Phase Flow in Horizontal Pipelines", *J. Pet. Tech.* AIME, June 1967, pp. 815-828.

10. Scott, S.L., Shoham, O., and Brill, J.P., "Prediction of Slug Length in Horizontal, Large-Diameter Pipes", *SPE Production Engineering*, August 1989, pp. 335-340.
11. Brill, J.P. et al., "Analysis of Two Phase Tests in Large Diameter Prudhoe Bay Field Flowlines", *SPE* 8305, Sept. 23-26, 1979.
12. Pots, B.F.M., Bromilow, I.G., and Konijn, M.J.W.F., "Severe Slug Flow in Offshore Flowline/Riser Systems", *SPE* 13723, March 11-14, 1985.
13. Hill, T.J., "Gas Injection at Riser Base Solves Slugging, Flow Problems", *Oil and Gas Journal*, Feb. 26, 1990, pp. 88-92.
14. Cunliffe, R. S. "Condensate Flow in Wet Gas Lines Can be Predicted", *Oil and Gas Journal*, Oct. 30, 1978, pp. 100-108.
15. Eggerman, J.R., "Inlet Receiving Pipelines, Receivers, and Instrumentation (Cradle to Grave)", GPM Gas Corporation, *Permian Basin Regional Meeting*, GPA, May 20, 1999, Odessa Texas.
16. Gas Processing Suppliers Association, "Separators and Filters", *Engineering Data Book*, Chapter 7, 11th Edition, 1998.
17. McKee, G. and Stenner, T. D., "Australian Liquids-Handling System Cuts Surges to LPG Plant", *Oil & Gas Journal*, Aug. 6, 1990, pp. 46-56.
18. Oranje, "Terminal Slug Catchers for Two Phase Flow and Dense Phase Flow Gas Pipelines", *ASME Pipeline Engineering Symposium*, 1987, pp. 49-55.
19. Sarica, C., Shoham, O., Brill, J.P., "A New Approach for Finger Storage Slug Catcher Design", *Offshore Technology Conference*, OTC 6414, May 1990, pp. 639-645.
20. Bos and du Chatinier, "Simulation of Gas-Liquid Flow in Slug Catchers", *SPE* 13724, March 11-14, 1985, pp. 357-363.
21. "Pipeline Safety Regulations", *US Department of Transportation*, Section 192.165 (3), Oct. 1, 1992 Edition.
22. Fortuin, J.M.H., Hamersma, R.J., Hart, J., Smit, H.J., and Baan, W.P., "Calculations Predict Condensate Movement at "T" Junctions", *Oil and Gas Journal*, Jan. 21, 1991, pp. 37-40 and "Experiments Verify Predictions of Condensate Movements", *Oil and Gas Journal*, Jan. 28, 1991, pp. 91-93.
23. Martinez, F.F. and Infantini, M., "Phase Behavior and Splitting Analysis: An Operational Tool in Gas Transmission and Distribution", *77th Annual GPA Convention*, March 16-18, 1998.
24. Walter, F.B., "Gas/Liquid Pipeline and Separator Design", *Rocky Mountain Chapter GPA Regional Meeting*, Sept. 12, 1996.

25. Comer, G., "Inlet Gas Compression and Gathering System Installation at Anschutz Ranch East", *Rocky Mountain Chapter GPA*, Presentation, Nov. 13, 1997.
26. Huntley & Silvester, "Hydrodynamic Analysis Aids Slug-Catcher Design", *Oil & Gas Journal*, Sept. 1983, pp. 95-100.