PIPELINE PIGGING

BY

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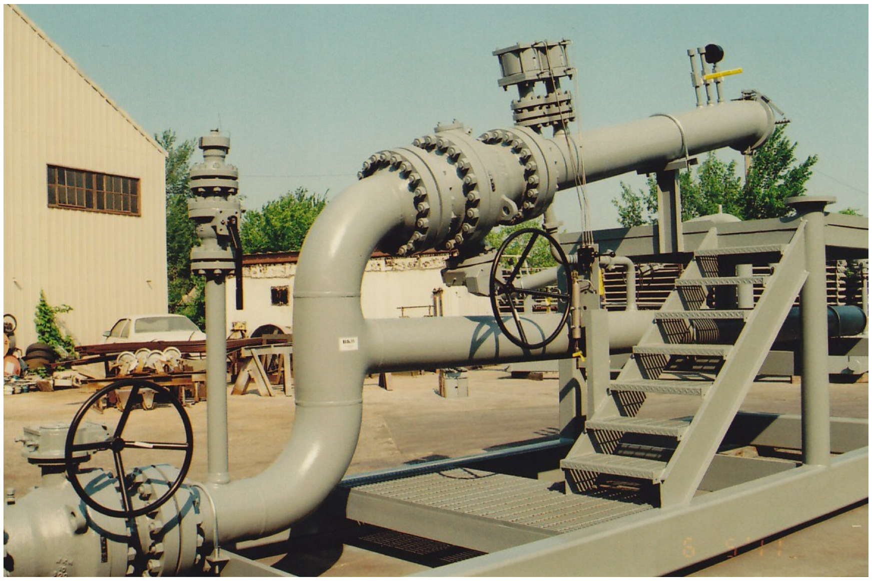

10” Sphere Launcher, skid mounted, with block valve and blow downs.

10” Sphere Receiver, skid mounted, with block valve and blow downs.

PIPELINE PIGGING EQUIPMENT

BY

BKW, INC.

BKW, Inc. is the leader in advancing the state of the art in pipeline pigging and has advanced pipeline pigging into an engineered science.

BKW, Inc. is proud to present this booklet containing engineering design and specifications for pipeline pigging. BKW is available to provide your company with the most efficient pigging system to meet your needs.

The pigging advancements are a result of experience and the need to provide new equipment to perform difficult and new challenges.

Items that advanced pigging technology:

- Tadpole pig for traveling through short radius ells and tees without hanging up. *
- Simplicity sphere launch pins fabricated from off-the-shelf material. Seal changing with minimum teardown onsite.
- Piggable Y's and switches fabricated to meet clients configuration. Y's and switches designed to replace expensive pig traps and reduce maintenance costs.
- Pig trap trays to allow easy loading and unloading large diameter pigs in and out of pig traps.
- Light weight jib cranes with 360° rotation for loading and unloading pigs.
- Ball Hook for easy handling spheres during loading and unloading in launchers and receivers.

* Patented

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The pictures below show a 42” pig trap tray with ram designed for a pig trap barrel set up for smart pigs. The tray is not designed for smart pigs, but is used to run cleaning pigs on a weekly basis. The ram is equipped with two extensions to push the pig 20 feet into the barrel. A 5 HP hydraulic power pack is used to operate the ram. The pig trap barrel centerline is almost 6 feet above grade requiring a ladder and platform to enable the workers to work the pigs and ram extensions.

20” ANSI 600 Y with straight run and 90° lateral for underground use. The unit has a 3 diameter radius bend for handling smart pigs.

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EACH pipeline system is unique. The final selection of a pigging system will be based upon the pertinent factors involved in that particular system. This article provides information and guidelines only. It is not to be construed as a design standard.

Purpose of pigging. Pipeline pigging is used to accomplish various operations inside an in-place pipeline system. The only alternative to running pigs is to uncover the pipe and cut out sections. Operations accomplished by pipeline pigging are as follows:

Adapted from ASME Petroleum Division paper 78-PET-74, "Art of Pigging," presented at Energy Technology Conference, Houston, Tex., Nov. 5-9, 1978.

1. Periodic removal of wax, dirt, and water accumulation from lines.
2. Product separation to reduce the amount of interface in the transition zone between different types of flowing crude oil or refined products.
3. Control of liquids inside a pipeline. Examples are reducing liquid accumulations in two-phase-flow pipelines, filling pipelines for hydrostatic tests, dewatering pipelines following hydrostatic tests, drying operations, and purging hydrostatic test water with petroleum liquid.
4. Inspection of pipelines for detecting dents, buckles, or excessive corrosion using gauging pigs and electronic or caliper type pigs.
5. For application of internal coating to the walls of the pipeline for corrosion protection.

Types of pigs. Pipeliners' imaginations have run wild in designing and building a pig. Many pigs have been made on the right-of-way when a special problem had to be solved. Some of these pigs are now available as standard off-the-shelf items.

The term pig means any device that is used inside a pipeline and can usually be classified as pigs, spheres, and foam-type pigs (Fig. 1). The pig generally consists of a steel body equipped with rubber or plastic cups for sealing purposes.

Brushes or scrapers are attached to the steel body with springs to force the brushes against the pipe walls.

Generally a device other than a brush-type pig will be referred to by a more definitive name such as sphere, squeegee, etc.

Pigs that do not have brushes or scrapers are usually equipped with extra cups called squeegees. This type of pig is used where extra sealing is

Fig. 1

Types of pigs

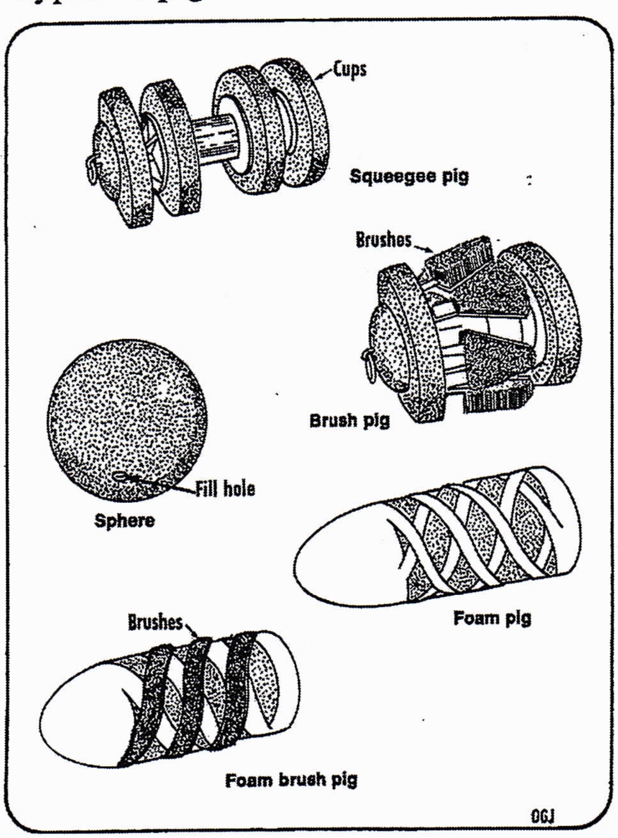
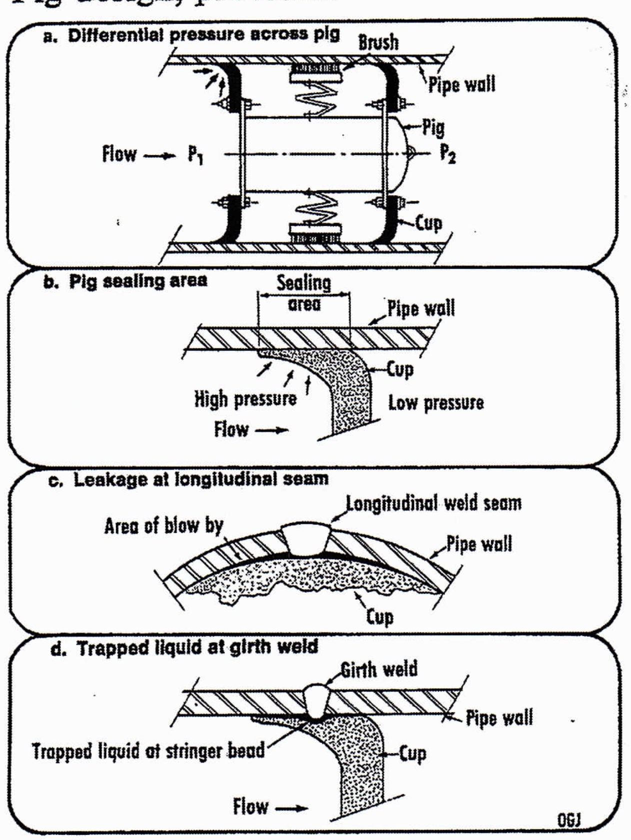


Fig. 2

Pig design, problems



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required such as in separation of batches in refined products and crude-oil pipelines, and hydrostatic test and drying operations in pipelines.

Pigs are available for just about any purpose and pipeline system. Some pigs are long for going through check valves, some are short for negotiating weld ells, and some are long and hinged in the middle for both applications.

Foam pigs are made of an open-cell-type foam with a hard rubber or plastic wrapper. These pigs are also made in brush form.

Foam pigs are available in various lengths and styles. However, the length is usually twice the diameter. Foam pigs form a seal against the inside of the pipe by compressing the foam and do not seal from pressure differential as other types of pigs do.

Spheres are round rubber or plastic balls. These balls are hollow and filled with a liquid. The ball is pumped-up to the required diameter and inserted in the pipeline.

Spheres are primarily used for batch separation and liquid control in two-phase flow lines because the pigging can be easily automated.

Sealing. In order to move a pig through a pipeline, a pressure differential is required across the pig. This pressure differential provides the force to overcome friction of the pig against the inside of the pipe wall.

The force to move the pig depends on several factors such as travel uphill or downhill, friction coefficient and force between the pig and pipe walls, and the lubrication available such as dry gas or crude oil.

The cups are designed so the pressure differential ($\Delta P = P_2 - P_1$) across the pig is used to create a seal between the pig and the pipe wall (Figs. 2a and 2b). The force required to move the pig through the pipe, $F = \Delta P \times A$, lb, where A = pipe cross-sectional area.

The cups of a pig are usually 1/16 to ⅛-in. larger than the inside diameter of the pipe. This cup is designed to minimize blow-by while reducing wear on the cups.

Some blow-by will always occur at the longitudinal weld on the pipe (Fig. 2c) because the cup will bridge over the seam and leave two channels on either side. The amount of blow-by depends on the amount of protrusion of the longitudinal weld and the stiffness of the cups.

As cups become softer, blow-by decreases. However, the wear rate increases. Therefore, a trade-off has to be made. The blow-by caused by the longitudinal seam also occurs when using spheres and foam pigs.

The amount of inflation of spheres depends upon the service and usage. In refined-products pipelines, the spheres are sometimes used to separate batches of products to reduce product contamination.

Three spheres will be injected as the product changes from one batch to another. The spheres will reduce the interface by about 50%.

The spheres are inflated to a diameter of about 2% more than the ID of the pipeline (Fig. 3). This is the optimum inflation to provide a sufficient seal without excessive wear.

The pressure P_3 inside the sphere is sufficient to expand the sphere against the pipe wall to form a seal when the sphere is subjected to maximum working pressure. On new pipeline systems, experimentation will be required to obtain the desired results with a minimum amount of wear on the spheres.

In two-phase flow service, the spheres are sometimes under-inflated to allow some blow-by to lower the density of the liquid ahead of the sphere. This will provide a more-constant velocity of the sphere in hilly terrain.

Foam pigs obtain the sealing pressure because of their oversize. The recommended oversize to obtain the maximum seal with minimum wear is

Fig. 3

Sphere design, problems

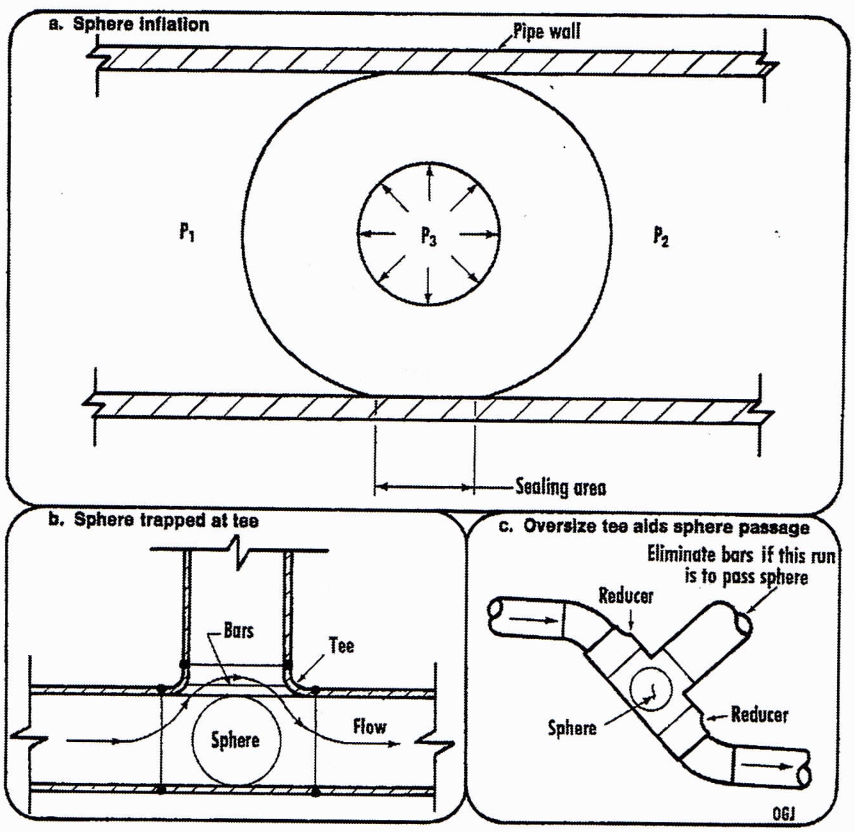


Fig. 4

Cleaning pigs

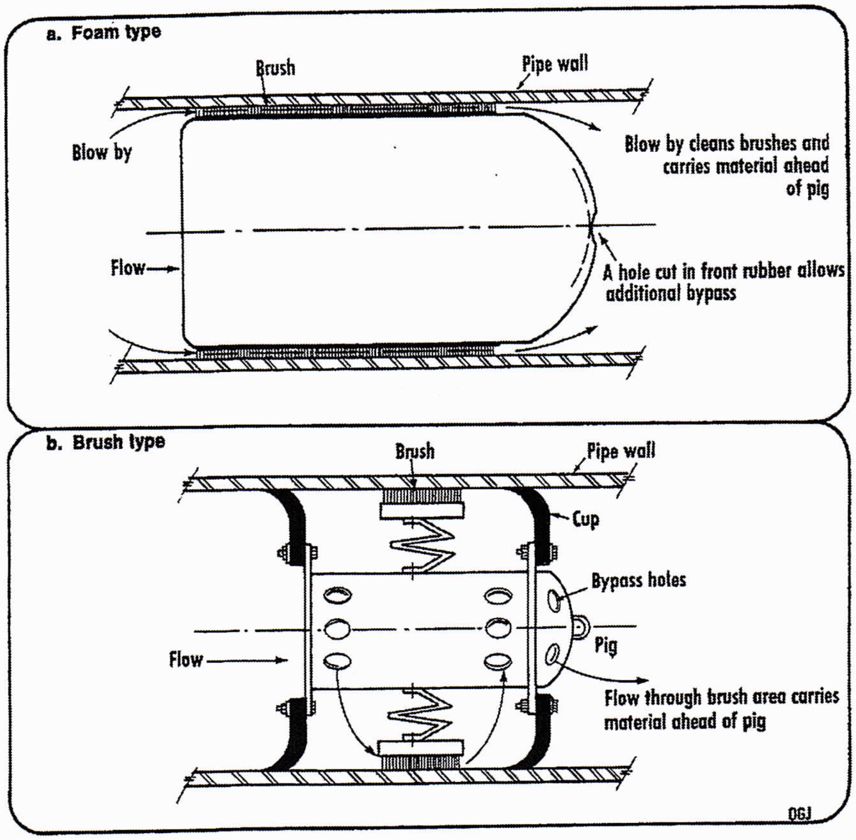


Table 1

Foam pig oversize

Nominal pipe diameter, in.	Oversize, in.
1 to 6	0.250
8 to 16	0.375 to 0.500
18 to 24	0.750 to 1.000
26 to 48	1.000 to 2.000

shown in Table 1.

The oversize dimension is the difference in the outside diameter of the foam pig and inside diameter of the pipeline.

The pressure behind the pig is, of course, pushing the pig ahead. At the same time, the friction of the pig against the walls of the pipe is resisting movement. This has a tendency to compress the pig and increase the pressure on the pipe walls thus increasing the sealing action.

This phenomenon also applies to spheres, however to a lesser extent.

General considerations. An understanding of the problems with pigging and how a pig behaves inside a pipeline will enable an operator to select the type of pigging operations best suited for a particular pipeline system and service.

After the type of pigging operation has been selected then design considerations should be incorporated into the pipeline system to facilitate the pigging operation and to eliminate possible operating problems. This is, of course, done during design and not after construction.

Most pipeliners feel it is easier and cheaper to erase a line on a drawing than cut and weld pipe.

Pigs, spheres, and foam pigs will travel at about the same velocity as the flow of the product, whether liquid or gas. In liquid lines, the flow is constant, and the pig will travel at an even velocity.

However, for gas service, the pig will travel awhile, then stop and rest awhile. This is a result of the pressure differential required to move the pig.

Since the force required to start the pig is greater than the force required to sustain travel, a pig will begin moving at a certain pressure differential, but continue on until a much lower pressure differential is reached. Usually, the pig will stop at a weld.

The force required to move past a weld is added to the friction force. The pig then stops until the pressure differential is attained for restarting the pig. This is particularly true for running pigs against atmospheric pressure during cleaning and testing operations on new construction.

Higher working pressures have a tendency to dampen this phenomenon. However, the start-stop style of travel still occurs.

Caution should be exercised when running a pig with air or gas when it becomes stuck. Increases in line pressure to dislodge a pig have been known to release the pig at such high velocity that the pig will go through the side of thin-wall pipe while trying to negotiate sharp field bends.

Side outlets larger than 50% of the pipe diameter should be equipped with bars to prevent the pig from stopping at the outlet and possibly causing damage to the pig.

Ells should have a minimum radius of 1½ times the diameter, or 3R. Although there are pigs that will negotiate 1½R radius ells, the 3R ells will give the operator a larger selection of pigs.

Pigging operations on gas-transmission pipeline systems are performed primarily to maintain efficiency by cleaning and swabbing the pipe and for emergency situations.

Pipeline sections downstream of compressor stations will require periodic pigging to remove lubricating oil from compressor units. This oil will travel along the walls of pipeline and collect in sag bends causing restrictions in flow.

Mishaps occasionally occur in gas-gathering systems where a slug of liquid will be injected into the pipeline system. When this happens, the liquid acts in the same manner as the lubricating oil and collects in the sag bends causing restrictions in flow. These restrictions can cause hydrates to form that can eventually plug the pipeline.[1 *]

To prevent this, methanol injection and pigging are required to remove the liquids. Automatic line-break controls on mainline-block valves should be investigated for the effects of sudden pressure drops caused by passing pigs.

Two-phase flow pipeline systems use pigs to keep the liquid drop out at a level that will maintain the design efficiency of the system. Cleaning pigs can also be run through these pipelines to remove foreign material that may accumulate.

Cleaning pigs are used in all types of pipelines to increase efficiency. Many articles have been written concerning the increase in efficiency of pipelines as a result of periodic pigging[2 3 4]. This has proven to be the most economical means of maintaining maximum flow rates when compared to adding horsepower or looping

*Such numbers designate references to be presented in Part 2.

with additional pipeline.

The cost of adding pig traps is a small fraction of the cost of the whole pipeline system, and the cost of pigging is very economical. Liquid-pipeline systems also use pigging to remove water from sag bends that may cause internal corrosion.

The cleaning action of a brush pig is caused by the movement of the pig through the pipeline. One pig run can not be expected to do much cleaning. Several runs must be made to accomplish significant results.

The brush or scraper pig should have holes in the pig to allow for bypass (Fig. 4). This is the case for both liquid or gas service.

The bypass will prevent a build-up of material in front of the pig which may cause a plug. The material will be distributed ahead of the pig in the stream and this distribution will increase as more product is bypassed.

An example of the theoretical amount of cumulation that can form in front of a pig is as follows:

Assume a 24-in. diameter pipeline, 100 miles long, in which a pig can remove 1/64-in. or .016-in. of a wax material from the walls of the pipeline. After 100 miles, this would amount to a plug with a total length of 1,450 ft.

Common sense informs the pipeliner that this will not work so adjustments have to be made to ensure problem free pigging.

The material cleaned by a pig will follow the flow at the receiving trap. This means most of the material will go through the side valve rather than into the trap barrel.

Pump stations and compressor stations on pipeline systems using pigging should be protected from slugs of foreign material as a result of pigging.

Foam pigs with brushes have a built-in bypass. The brushes are short and fixed to the pig body. The blow-by occurs through the brush. This blow-by helps keep the brushes cleaned out.

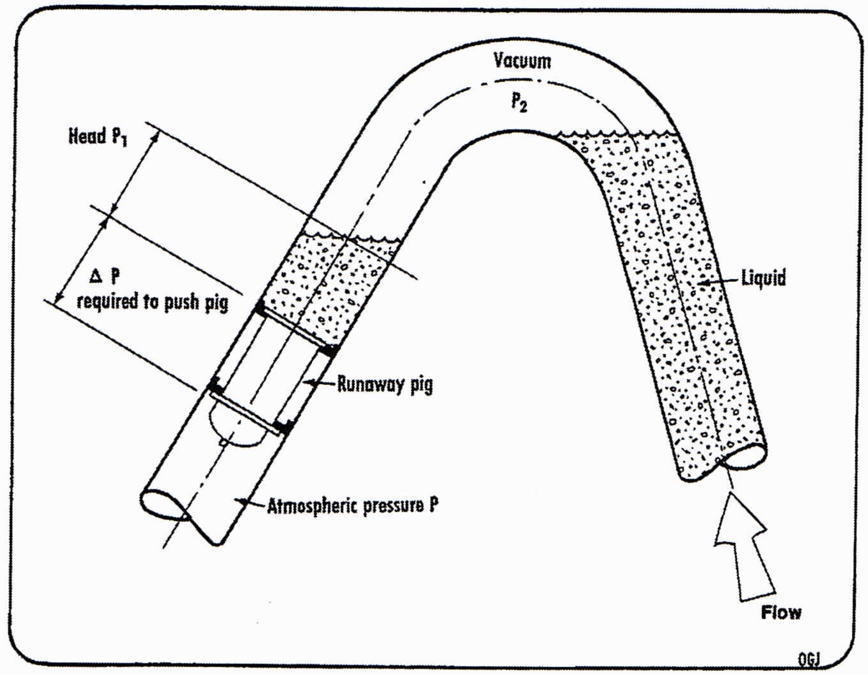
Any accumulations of material will tend to prevent blow-by. If additional bypass area is necessary, the rubber or plastic covering on the nose of the pig can be cut out (Fig. 4) allowing passage of gas or liquid through the open-cell foam body.

Spheres have a peculiar way of winding up where they are not supposed to be. The design of openings, and side taps on pipelines should be carefully considered when running spheres.

In gas or liquid service and at low flow rates, the sphere will usually stop at the launcher-trap side valve tee when launched in a conventional pig trap (Fig. 3). The bars on the tee will apply pressure on the sphere and trap it, and the tee will provide sufficient area for the flow to bypass the sphere.

Fig. 5

Runaway pig



To overcome such stoppage, the tee should be over-sized and set at a slope (Fig. 3c) to allow the sphere to travel freely past the tee branch and on through the pipeline.

Special tees are available that are designed to allow a sphere to pass freely. These tees are oversized and do not require a slope to operate satisfactorily.

All branches 50% and larger of the main line should be equipped with bars or some means of preventing the sphere from entering the branch. Any other branch that could be used while a sphere is in the pipeline such as a blowdown at a main line block valve should have bars.

These precautions will prevent the spheres from being forced into branch connections and causing a disruption. Foam pigs will perform much the same manner at branch connections as spheres.

Spheres have difficulty traversing check valves at low flow rates because the check-valve clapper will not be in the open position. The clapper will be trying to close because of its weight. The energy of flow will be trying to hold the clapper up.

The clapper angle depends on the flow rate and weight of the clapper. This angle is the result of the two forces and occurs in both liquid and gas service.

At large flow rates, spheres will traverse check valves because the momentum of the sphere striking the clapper will push the clapper into the open position. Before the clapper can recover and come down on the sphere, the sphere will have traveled through the check valve.

The sphere momentarily stops when it strikes the clapper, and then the flow accelerates the sphere and carries it on through the valve. As the flow decreases, the momentum of the sphere and the angle of the clapper decrease until the sphere can no longer knock the clapper aside.

When this occurs, the clapper traps the sphere in the check-valve bowl, and flow bypasses the sphere and clapper through the valve body.

Flow rates have to be increased substantially to clear the sphere from the check valve. This flow rate is greater than the minimum required to prevent the sphere from being trapped.

Where traversing a check valve, pigs should be sufficiently long to restrict the flow and maintain a pressure drop that will keep the pig moving. This pressure differential should be large enough to overcome the force of the clapper. Also the check-valve body design should be considered to prevent the pig from being caught in the bowl.

Like spheres, foam pigs have the ability to traverse restricted pipe sections of pipeline systems such as re-

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duced opening valves or plug valves. They are also capable of going through pipelines with large deposits on the pipe wall.

Restricted sections should not be less than 80% of the pipe or damage may occur to the pig. Foam pigs are somewhat flexible and can traverse short radius ells and may even go into the branch line of tees if the full flow is through the branch.

Foam pigs behave much the same way as spheres. The piping must be designed in a similar manner to keep control of the pig at all times.

The first time a pipeline is introduced to a pig is during construction. This occurs during hydrostatic-testing operations. Many techniques are incorporated in loading and unloading pigs from test sections. This is the period when pigs are put to the more severe test. Most rarely survive without damage.

If a pipeline system is tested in sections, the pigs are loaded and unloaded in line-size headers and cages rather than oversize launcher and receiver barrels. Loading is usually done with a side-boom and unloading is accomplished with an oxygen-acetylene mixture.

Most pipeline systems are tested with water. A fill pig is sent ahead of the water to provide a mechanical separation between the fill water and air to prevent mixing.

This pig also cleans out the foreign material left in the pipeline. Sometimes this pig is equipped with a gauging plate for locating dents and buckles.

On pipelines that have internal coating, the system is cleaned out by pumping water ahead of the pig and running the water out at a high velocity with a pig using gas or air[5]. This will keep the water in turbulent condition and prevent rock, gravel, welding rod stubs, and other hard objects from being dragged along the pipe wall by the pig cups and damaging the coating.

Bypass holes are opened in the pig to allow the bypass of gas and improve turbulence. Pigs with steel brushes are not used in internally coated pipelines[6].

When using a sphere for filling the pipeline, the sphere should be underinflated. This is particularly true if there is considerable sand and dirt in the pipeline.

The sphere will not seal, and blow-by will occur. When the sphere rolls over the sand, the blow-by will wash the sand out from under the sphere keeping the sand ahead of the sphere.

Sometimes a back pressure in the pipeline is required ahead of the fill pig in hilly terrain to prevent runaway pigs going down hill. This problem does not occur often and is not recommended unless a careful study indicates that an air lock will occur without the back pressure.

The author . . .


Brian (Butch) Webb

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Under normal conditions the runaway pigs will not allow air to enter the fill section because of the pressure differential required to move the pig through the pipeline.

If a pig starts down hill and the column of water behind the pig becomes greater than the force required to move the pig, the pig will "runaway" or move ahead of the column of water (Fig. 5). This causes a vacuum behind the pig. However, the column of water behind the pig still creates more pressure than the atmospheric pressure ahead of the pig.

Before a pig can run away, Head P_1 (Fig. 5) must be greater than atmospheric pressure P, plus Δ P less vacuum P_2. Therefore, pressure behind the pig is always greater than that ahead of the pig.

Because of the combined pressure of moving the pig and vapor pressure of the water, any leakage will be water bypassing the pig instead of air trying to work back to the vacuum. When the pig finally reaches a point where the pressure required to push the pig becomes greater than atmospheric, the void caused by the vacuum disappears.

The only case requiring a back pressure ahead of the pig is when it is anticipated the pig will go over a very steep incline with a sharp sag bend at the bottom of a hill and the momentum of the pig and column of water will carry the pig past the sag bend and on to a horizontal area of pipeline.

In this case, the column of water will not be greater than the pressure ahead of the pig and air leakage will occur past the pig. Sometimes the pig will back up until the differential approaches that required to push the pig.

When the pig stops there will still be a pressure differential, and air leakage will occur back towards the void. The amount of leakage will depend on the condition of the pig and the fill rate of the pumps to catch up with the pig. This is an extreme case and usually is not considered in pipeline filling.

If a buckle is suspected in the pipeline, a pig equipped with a noise maker, radiation source, or magnet can be run through the pipeline. If the pig becomes stuck, the pig can be located by walking the pipeline with a detection instrument to locate the pig, and the buckle can be removed.

Following filling, the pipeline is usually purged of the water by the gas or liquid to be transported. In the case of liquid, another pig or pigs are used to separate the liquid from the water.

On gas-pipeline systems a pig is used to dewater. In the case of "dry" gas systems, additional pigs will be run through the pipeline to remove any water that may have been missed by the dewater pig[7, 8].

A pressure differential is required to move a pig through the pipeline regardless of the pressure in front of the pig. This pressure behind the pig is always greater than the pressure in front of the pig.

In dewatering operations, if there is any leakage around a pig, it will be gas traveling ahead of the pig. As stated before, the leakage will usually occur at the edges of the longitudinal seams in pipe where the cups bridge over the edge of the weld.

The pig will squeegee most of the water from the pipe walls but a film of water will remain. The thickness of this film depends on the condition of the pig and the roughness of the pipe wall.

Also, as the velocity of the pig increases, the film thickness increases because the cups begin to hydroplane over the liquid. In addition to the film, some water will be left at girth welds if the stringer bead protrudes inside the pipe (Fig. 2d).

Also, liquid will collect inside tees and other outlets connected to the mainline. This liquid will flow back into the mainline after the pig passes the outlet.

Methanol is sometimes used with drying pigs to dilute the residual water and allow the pigs to carry out the remaining moisture[9]. END

The conclusion of this two-part article will appear in the Nov. 27 issue.

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TWO-PHASE-FLOW pipelines transport both gas and a liquid.[10] The ratio between gas and liquid varies. Under certain conditions, constant flow can be maintained without use of pigs, if the flow velocity is sufficient to keep the liquid moving.

But under most conditions, periodic pigging must be maintained to provide the maximum efficiency. Factors affecting two-phase flow pigging are:

- Gas-liquid ratio.
- Volume, operating pressure, allowable pressure drop, and velocity of the gas-liquid.
- Profile of pipeline, particularly the number and magnitude of hills and valleys.
- In the case of offshore pipeline systems, the height of the riser from the bottom of the riser to the slug catcher.
- Size of slug catcher.

Slug catchers are usually sized based on cost and available room.[11] Pigging frequency is based on liquid flow rate and amount being carried by the gas.

If all the liquid can be transported by the gas, pigging frequently can be at the operator's convenience. However, as the percent of liquid that can be carried by the gas decreases, the frequency of pigging increases.

The slug catcher has to be large enough to catch the liquid pushed by the pig. That also determines frequency of pigging.

A major consideration in pigging is terrain. Hill country with numerous hills and valleys, whether onshore or offshore, will trap more liquids than flat country at the same flow rate, operating pressure, pressure drop, and gas-liquid ratio.

The liquids will settle in the sag bends and cause pressure differentials as the gas pushes the liquid level to a point where the gas has to bubble through the column to maintain a flow rate.

As these liquid columns increase in size at each valley, the total pipeline pressure differential increases to the point that the upstream pressure may be increased in excess of the allowable operating pressure of the pipeline system (Fig. 6). The pressure build-up condition is called air-lock.[12]

Such air-lock conditions have also been known to occur during filling, dewatering, and hydrostatic testing operations. Because air-lock can be prevented before it happens, it can be quite embarrassing.

Risers at offshore platforms pose a problem when running pigs to platform in two-phase-flow pipeline systems.

Pressure drops in the pipeline system will be greatly increased and flow rates temporarily decreased in proportion to height.

For instance, a 200-ft riser will increase the pressure drop in a pipeline by a 200-ft head if the column of liquid ahead of the pig is 200-ft long. As the column begins to go up the riser, the pig will stop until the pressure in the pipeline behind the pig builds up to overcome the column head. Flow rate is momentarily stopped during this pressure buildup.

As the pressure increases behind the pig, the pig moves the liquid column up the riser and into the slug catcher. As the pig moves up the riser, the liquid column is reduced and the pig then accelerates in velocity as a result of the gas pressure behind the pig being practically constant.

This velocity can increase faster than the operator desires. The result of this operation is a fluctuating flow rate and a high-velocity slug of liquid. This type of operation can be controlled with proper design and operating procedures.

The only other alternative in this case is to run the pig at such a velocity that the momentum carries the column of liquid and pig on up the riser without stopping. This velocity may also be much greater than the operator wants.

Special pigging operations include cleaning and internal coating of in-place pipelines. Cleaning is accomplished by brush pigging and pickling with acids. Brush pigs are run through the pipeline to remove any material that is loose or can be brushed away.

In some cases where the build-up of material inside the pipe has restricted the area to the point conventional pigs will not travel, foam-type pigs should be used.

Adapted from ASME Petroleum Division paper 78-PET-74, "Art of Pigging," presented at Energy Technology Conference, Houston, Tex. Nov. 5-9, 1978.

Following the pig-cleaning operation, an acid-pickling cycle is run through the pipeline with a pig at both ends of the pickling batch. These pigs are special heavy-duty type with large cups.

The lead pig is inserted in the pipeline and then acid is injected behind the pig followed by the push pig. Usually these pigs are run using air.

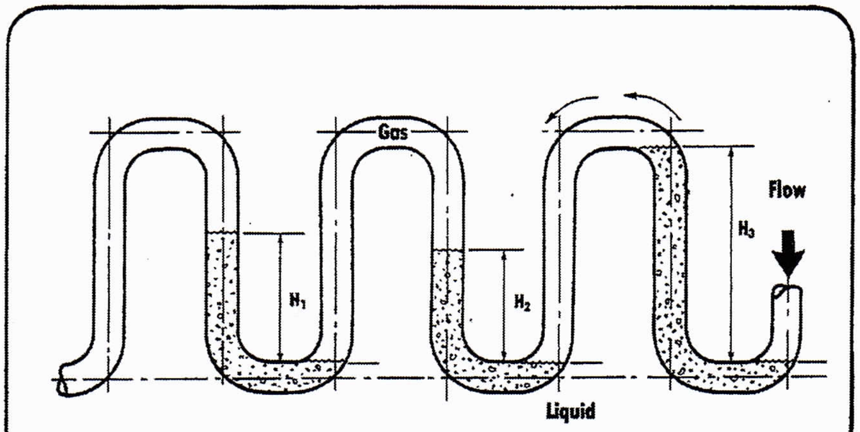
After the pickling batch has been run, a neutralizing agent and a wash is run through the pipeline in the same manner as the pickling batch. Following the wash, the pipeline is thoroughly dried by running several pigs and dry air.

The internal coating is applied in the same manner as the cleaning operations. The push pig on the coating operation is specially designed to uniformly apply the coating at the specified thickness. The cups are designed to use the pressure differential to squeeze the coating on the pipe walls.

All runs through the pipeline must be run at sufficient velocity to be in turbulent flow. This is to keep a slug of liquid ahead of the push pig, even when going down steep grades to ensure that all of the inside of the pipe is in contact with the liquid.

Fig. 6

Head accumulation in two-phase pipeline



Note: Accumulation of heads H_1, H_2, and H_3 is additive. These heads will sometimes exceed the allowable pipeline operating pressure.

Launching/receiving techniques

Facilities. Pipelines requiring pigging during operations are equipped with pig traps. The section of pipeline to be pigged will have a launcher located at the upstream end and a receiver at the downstream end. Distance between traps will vary but the maximum distance will depend on service, location of stations, operating procedures, and material constituting the wear surfaces of the pig.

Materials used in pig cups and spheres can be adapted to practically any type of service. Manufacturers should be consulted if there is doubt the material will be compatible with the service.

For petroleum products, the limiting factor is the amount of lubrication from the service. For instance, in gas-transmission service where the gas is dry, the maximum distance between traps should be 100 miles for pigs and 200 miles for spheres. In crude-oil service, the maximum distance between traps should be 300 miles for pigs and 500 miles for spheres.

This will give some indication of the extremes. However, these distances will vary with such factors as sand, wax, and other material that may be transported along with the product.

An example of the toughness of the material used in pigs would be to drag a pig behind a car for 200 miles over a gravel road. It takes little imagination to realize the pig would be worn out after the trip.

This is the same condition for running a pig through a natural-gas pipeline system with sand and other solids inside. Therefore, the type of service and condition is very important when selecting the pigging system.

Design of the pig traps will depend upon operating procedures, service, and location.[13 14] The type of pig must be determined before design of the traps and the pipeline system. This is usually determined by the job the pig must perform.

Pig traps, pig launchers, and other appurtenances on the pipeline are designed in accordance with ANSI B31.8 (1975), "Gas Transmission and Distribution Piping Systems," DOT Standard Title 49, Part 192, "Transportation of Natural and Other Gas by Pipeline," ANSI B31.4 (1975), "Liquid Petroleum Transportation Piping Systems," and DOT Standard Title 49, Part 195, "Rules and Regulations for Liquid Pipelines."

Pig traps. Basic design of traps for brush pigs, squeegees and foam pigs require a barrel, short pup, trap valve, side valve, and bypass line (Figs. 7 and 8). The barrel is the device for loading or unloading the pig and is equipped with a quick-opening closure or blind flange.

The barrel is also equipped with either a concentric or eccentric reducer, depending on the operator's preference. An eccentric reducer makes it easier to load pigs.

Barrel diameter should be 2 in. larger than the diameter of the pipeline. In large-diameter natural-gas pipelines, the barrel diameter can be 1 in. larger than the pipe diameter.

In some instances, operators will use a sliding tray inside the barrel. The tray will slide out of the barrel to facilitate loading or unloading pigs. In this case, the barrel is oversized to accommodate the tray.

The barrel length for traps depends on operating procedures, service, and available space. In the case of offshore platforms, floor space is expensive. If only periodic pigging is required, the traps should be made small as possible.

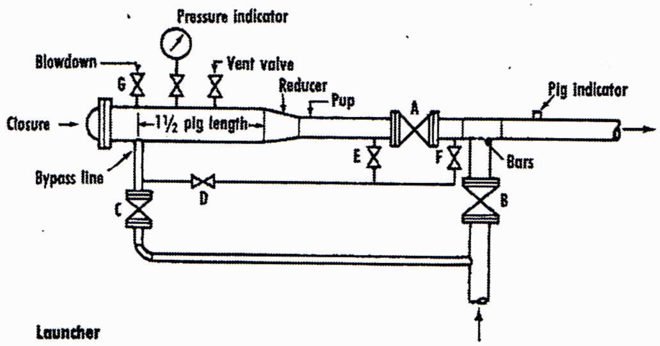
On land pipelines, the length can be increased to accommodate inspection pigs which are usually extra long. Receiving traps can also be increased in length to accommodate additional pigs.

However, for periodic cleaning operations in offshore operations, the barrel length on launcher traps can be 1½ times the length of the pig from the bypass line to the reducer

Launching and receiving procedures

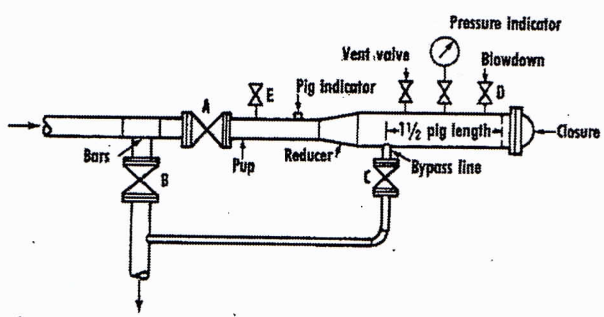
Pigs

Gas service — Fig. 7



Launcher

1. Close Valves A, C, D, E, and F.
2. Blow down the launching trap through blowdown valve G.
3. When the trap is completely blown-down, open the closure door and insert the pig so the first cup is wedged into the line pipe.
4. Close the closure door and open Valve D and E. Purge the trap piping through Valve G by slowing opening Valve F. When purge is completed, close Valve G. If the trap is not equipped with Valves D, E and F, then purge the trap through Valve C.
5. Allow the trap to equalize to line pressure. Then close Valve F and Valves E and D. If these valves are not available, close bypass Valve C.
6. Open trap side Valve A, then bypass Valve C. The pig is now ready for launching.
7. Partially open Valve B. This will force the gas flow through bypass Valve C and behind the pig. The pig will be pushed out of the trap and into the mainstream.
8. When the pig leaves the trap and enters the mainline past the pig indicator, open side Valve B fully, and close Valves A and C.
9. Return all valves to their original operating positions.

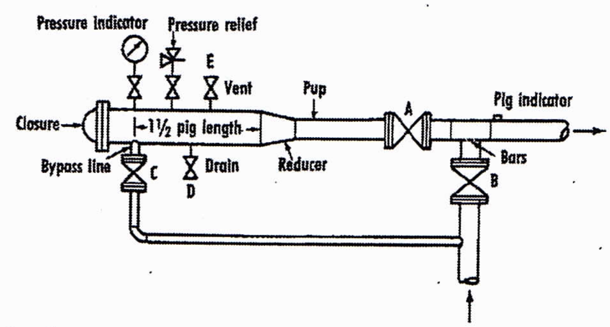


Receiver

1. If trap purging is necessary, open Valves D and E and purge the trap by opening bypass Valve C.
2. After purging, allow the trap pressure to equalize to line pressure by closing Valves D and E with bypass Valve C open.
3. Open Valves A and C.
4. When the pig arrives, it will stop between trap Valve A and the side tee, providing the velocity is not excessive.
5. Partially open side Valve B. This will force the gas flow behind the pig and into the trap and the gas will exhaust out through bypass Valve C.
6. Open Valves E and D simultaneously and blow the trap down. This operation should be conducted so as to prevent sudden movement of the pig within the barrel. *
7. Open the closure door and remove the pig.
8. Close the closure door. Purge the trap as described in Item 1, and equalize the trap to line pressure; then close bypass Valve C.

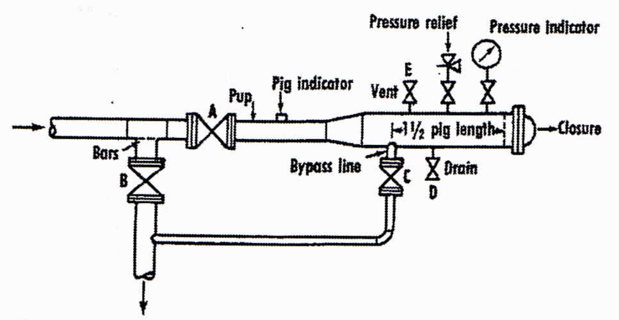
* Close valve A

Liquid service — Fig. 8



Launcher

1. Close Valves A and C.
2. Drain the launching trap through drain Valve D and allow air to displace the liquid through vent Valve E.
3. When the trap is completely drained, open the closure door and insert the pig so the first cup is wedged into the line pipe.
4. Close the closure door. Close Drain Valve D and open Vent Valve E. Fill the trap through Bypass Valve C by venting the air through Valve E. When filling is completed, close Vent Valve E.
5. Allow the trap to equalize to line pressure then close Bypass Valve C.
6. Open Valve A first and then open Valve C. The pig is now ready for launching.
7. Partially open Side Valve B. This will force the flow of liquid through Bypass Valve C and behind the pig. The pig will be pushed out of the trap and into the mainstream.
8. When the pig leaves the trap and enters the mainline past the pig indicator, open Side Valve B fully, and close Valves A and C.
9. Return all valves to their original operating positions.



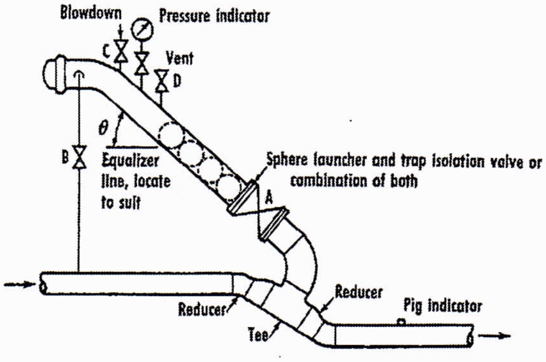
Receiver

1. If trap filling is necessary, close drain Valve D, open vent Valve E and fill the trap through bypass Valve C.
2. After filling, close vent Valve E and allow trap pressure to equalize to line pressure through bypass Valve C.
3. Open Valves A and C.
4. When the pig arrives, it will stop between trap Valve A and the tee.
5. Partially close side Valve B. This will force liquid behind the pig and into the trap and exhaust out through the bypass line and bypass Valve C.
6. When the pig is in the trap, open side Valve B completely and close Valves A and C.
7. Open the drain Valve D and vent Valve E and drain the trap. This operation should be conducted so as to prevent movement of the pig within the barrel.
8. Open the closure door and remove the pig.
9. Close the closure door. Fill the trap as outlined in Item 1, and equalize the trap to line pressure; then close bypass Valve C.

Figs. 7, 8, 9

Spheres

Gas service — Fig. 9



Launcher

1. Close Valves A, B, D, and C.

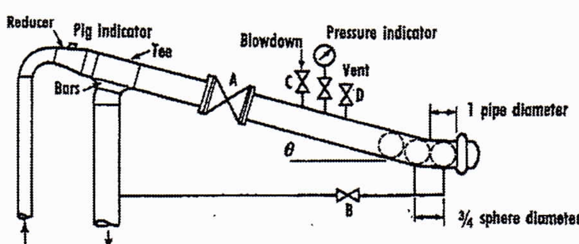
2. Blow-down the launching trap through blow-down Valve C.

3. When the trap is completely blown down, open the closure door and insert the required number of spheres.

4. Close the closure door and open vent Valve D. Purge the launcher barrel through vent Valve D by slowly opening equalizer Valve B. When purging is completed, close vent Valve D.

5. Allow the trap to equalize to line pressure.

6. Open equalizer Valve B, then trap Valve A. The spheres are now ready for launching.



Note: Angle θ will be selected based on size of pipeline system, service, and operation procedures.

Receiver

1. If trap purging is necessary, close Valve A and B and open vent Valve D and purge by opening drain Valve B.

2. After purging, close vent Valve D and allow trap pressure to equalize to line pressure.

3. Open Valves A and B. Trap is ready to receive spheres.

4. When the receiver barrel fills up with spheres, close trap Valve A and drain the barrel through the drain Valve B.

5. Close drain Valve B and blow the trap down through blow-down Valve C.

6. Open the closure door and remove the spheres.

7. Close the closure door. Purge the trap as described in Item 1 and equalize the trap to line pressures; then open Valves A and B for operation.

weld and on receiver traps 1½-times the length of the pig from the bypass line to the closure weld.

A short pup is placed between the reducer and the trap valve to provide head space for the pig. This pup prevents the steel nose of the pig from coming into contact with the trap valve during pressurization. If contact is made with sufficient pressure differential, the pig may damage the valve.

In the case of large-diameter land pipelines transporting natural gas, crude oil, or refined products, the trap valve and side valve should be buried with the barrel above ground. This will provide additional head space on the barrel. This extra length is especially necessary on receiving traps.

In gas service, the velocities at receiving traps can exceed 30 mph. The extra head space is required to stop the pig and prevent it from hitting the closure door.

The bypass line is attached to the barrel near the closure on launching traps and near the reducer on receiver traps. The size of the bypass varies with service, but the diameter is usually a minimum of 22% of the pipeline diameter.

Pig indicators should be located on the barrel pup joint near the reducer on receiving traps, and downstream of the side valve tee on launcher traps. The pig indicator should be located on top of the pipe to prevent foreign material from making the indicator inoperative.

Liquid pipelines require a drain on the barrel along with a pressure gauge, thermal-pressure relief valve, and vent valve. The drain valve should be located in the vertical position directly under the barrel. This is to prevent an accumulation of material from plugging the drain and making the drain valve inoperative.

Gas-pipeline pig traps require a blowdown valve, pressure gauge, and a utility or vent valve. Large-diameter pipelines usually require a lifting device to load and unload pigs. The device is usually installed when the pigs exceed 100 lbs. The device consists of a swivel loading arm equipped with a chain hoist or come-along.

Procedures for launching and receiving pigs in various services is included (Figs. 7 and 8) to demonstrate the general practice. This procedure may vary from pipeline to pipeline because of the unique circumstances of each pipeline system and combinations of services.

Concerning the procedure for launching and receiving pigs in gas service (Fig. 7), note that Valves E, F, and D on launcher traps and Valve E on receiver traps are used only in large-diameter land-pipeline service with buried valves. These valves provide an extra margin of safety for purging and protecting the valve gate from damage. For small-diameter pipelines and in restricted areas, these valves can be eliminated. This is a decision of the operator.

Sphere launchers. Sphere launchers differ from pig launchers because they are equipped with extra-length barrels for multiple launching.[15] These extra length barrels are called magazines. This feature of spheres makes them readily adaptable to unmanned launching.

The operator can load the magazine with several spheres, and the launching can be activated either automatically or remotely. This process is used extensively in two-phase-flow pipelines in remote areas.

Various launching mechanisms are available on the market so the selection of launchers is a matter of choice. Launchers consist of check valves, ball valves with only one side of the ball cut out, pins, and rocker mechanisms.

Additional valves are sometimes installed downstream of the launching mechanism to facilitate repairs on the launcher without shutting down the pipeline system.

The launcher will consist of the launcher barrel, launching mechanism, isolation valve, equalizer valve and reducer tee. The receiver will consist of a barrel, isolation valve, reducer tee and a drain that will suffice as an equalizer line (Fig. 9).

Both launcher and receiver should be equipped with a pressure gauge, blow-down, and utility valve. Pig indicators are installed on the launcher downstream of the side-tee reducer and on the receiver just upstream of the tee.

A sphere-launcher barrel or magazine will hold several spheres ready for launching. The length of the magazine depends upon the frequency of running spheres and the frequency of reloading.

In remote areas such as offshore platforms that are affected by weather, a safety factor should be included in the event the reloading schedule cannot be met and pigging must be maintained to prevent shutdown of facilities.

Large magazines can become too long or tilted at an excessive angle, causing excessive weight on the bottom sphere. This will cause the spheres to bind and the release mechanism to malfunction.

The author . . .

Brian Webb

Brian (Butch) Webb is a senior staff engineer with Crest Engineering Inc., Tulsa, Okla. From 1974 to the present he has worked for Crest, primarily on overseas jobs in Indonesia and Iraq. Prior affiliations include design engineer for Williams Bros. Engineering Co., northern division engineer for Trunkline Gas Co., as-built engineer for Fish Service, and welder helper for Brown & Root. Webb holds a degree in petroleum engineering from Oklahoma State University (1957).

To prevent this, the magazine angle should be reduced to cause the magazine walls to absorb most of the weight of the spheres. A recommended angle for the magazine is shown in Table 2.

Table 2

Launcher, magazine angles

Nominal diameter, in.	Angle of launcher mechanism, degrees	Angle of magazines, degrees
4 to 8	45	15
10 to 20	20	10
22 to 48	20	5

The diameter of the launcher and receiver barrels for sphere service is 2 in. larger than the diameter of the line pipe. The barrels can usually hold 10 spheres and have been known to hold 15 spheres.

For convenience of loading and unloading, the closure-door hinge should always be in the vertical to enable the operator to open and close the door without the aid of extra equipment. The receiver barrel should have a horizontal pup near the closure which is one diameter in length.

The blow-down on the launcher and receiver barrels should be near the highest point on the barrel. This would be near the closure on the launcher and at the valve on the receiver. Likewise on the receiver barrel, the drain should be at the lowest point. The drain should tap into the barrel in two places to prevent the spheres from rolling over the drain and stopping flow.

The two drains should be apart a distance of one-half to three-fourths the sphere diameter. The equalizer line and valve on the launcher can be located at operator's convenience.

Hoisting mechanisms should be available to facilitate loading and unloading spheres when the pipeline diameter is 20 in. or larger.

Combination sphere and pig launchers can be designed for special conditions where spheres are required for liquid control and pigs are required for periodic cleaning operations.

Fig. 9 gives the procedure for launching and receiving spheres in gas service. For liquid service, certain modifications must be made for draining the barrels to prevent spillage when the closure doors are opened. The operation is basically the same as that for gas service.

Acknowledgments

The author wishes to express appreciation for information obtained from various people with experience and knowledge in the pipeline industry, including Clinton McClure, Williams Bros. Engineering Co.; Del Moore, Wheatley Co.; Jim Forster, Tom Wheatley Co.; Larry Payne, T. D. Williamson Co.; Bill Fulton, Explorer Pipeline; and Frank Gray, Girard Polly-Pig Inc.

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WST-6-10

Addendum to “Art of Pipeline Pigging” BKW, Inc.
12/30/11

Pig / Y Compatibility

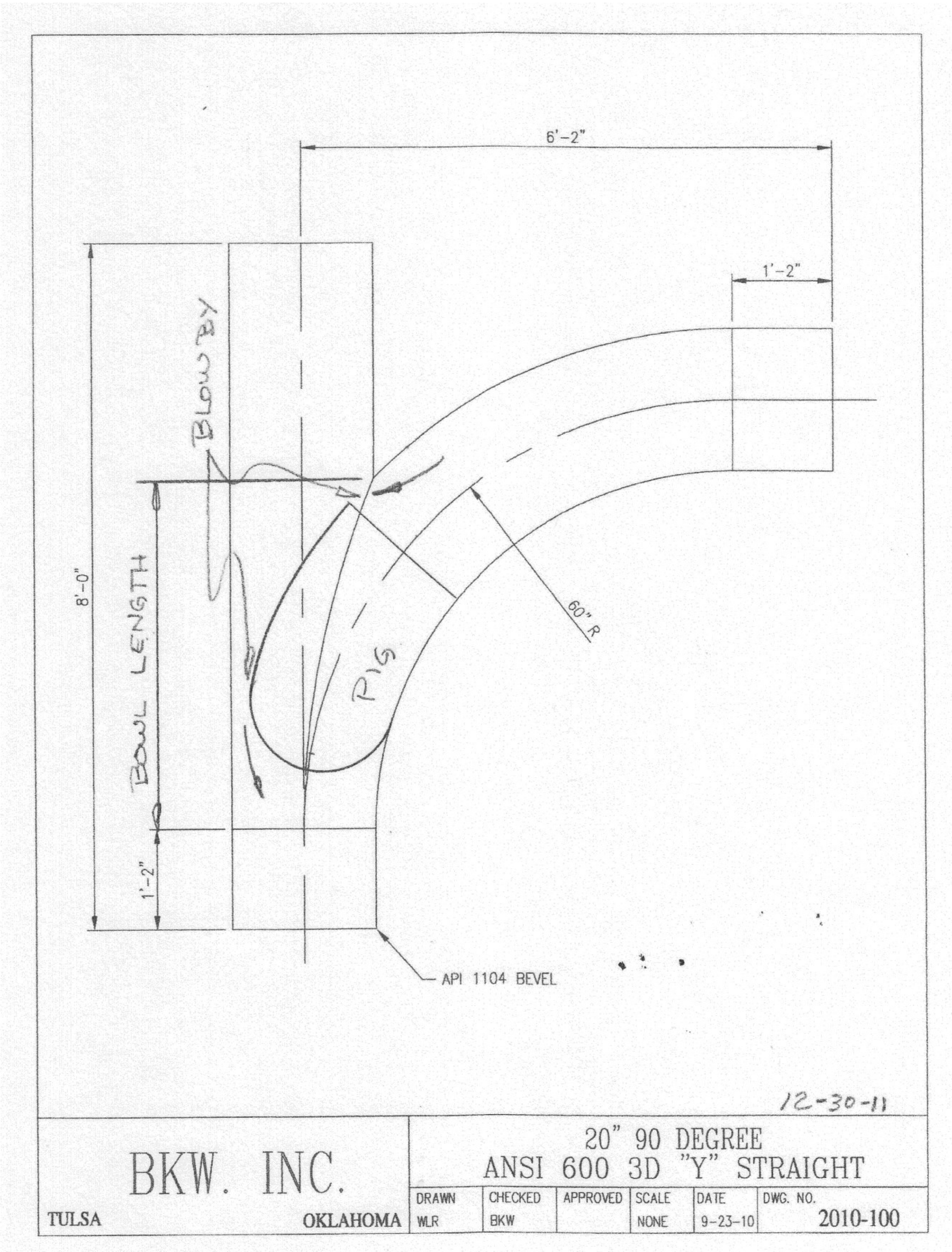
Please reference ASME paper titled “Art of Pigging” and Drawing No. 2010-100.

Bar tees and spheres, pigs and check valves and pigs and Y’s all have to be compatible. The pigging article discusses the problems encountered when running spheres through a bar tee. This same problem exists when running pigs through check valves and Y’s. When running a pig through a check valve, the pig and check valve are designed to be compatible. The distance between the entry and the exit of the check valve is called the bowl length. For check valves to pass pigs, this length has to be less than the length of the pig in order for the front cups on the pig to enter the exit before the back cups leave the entry. If the pig was shorter than the bowl length, the weight of the clapper would hold the pig in the bowl and flow would bypass the pig.

Examine Drawing No 2010-100. Three-diameter radius bends are used in fabricating Y’s to allow the passage of smart pigs. Three-diameter bends reduce the pressure drop required to move the pig through the bend; however, the longer the radius, the longer the bowl length and the more difficult to pass standard pigs because of low flow rates and excessive interference.

Two methods for correcting pig passage problems are the use of longer pigs and reducing the interference between the outside diameter of the pig and the pipe inside diameter. Lengthening the pig will prevent excessive blow by and thus maintain the required pressure drop across the pig to move it through the Y.

The interference should be reduced to reduce the pressure drop required to move the pig through the pipeline. For instance, in a 10-inch diameter pipeline, the flow area is around 79 sq. in. The force behind the pig at 10 psi pressure drop is 790 lbs. This is more than sufficient for good pipeline pigging. Should the pig hit a restriction, the pressure will increase until the pig overrides the restriction and the same applies when chasing liquids. Experienced pipeline operators know there are no two pipelines alike and there is not one operating procedure that is a “fits all”. Start up operations requires experimenting with various pigs, launch frequencies, flow rates and pressure drops until the optimum operating procedure is achieved. In gas gathering systems, flow conditions change, requiring pigging procedures to change, thus experimentation continues throughout the life of the system.


6'-2"
1'-2"
8'-0"
BLOW BY
BOWL LENGTH
PIG
60" R
1'-2"
API 1104 BEVEL
12-30-11
BKW. INC.
TULSA
OKLAHOMA
20" 90 DEGREE
ANSI 600 3D "Y" STRAIGHT
DRAWN
WLR
CHECKED
BKW
APPROVED
SCALE
NONE
DATE
9-23-10
DWG. NO.
2010-100

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February 2012

Piggable Y and Pig Trap Comparison

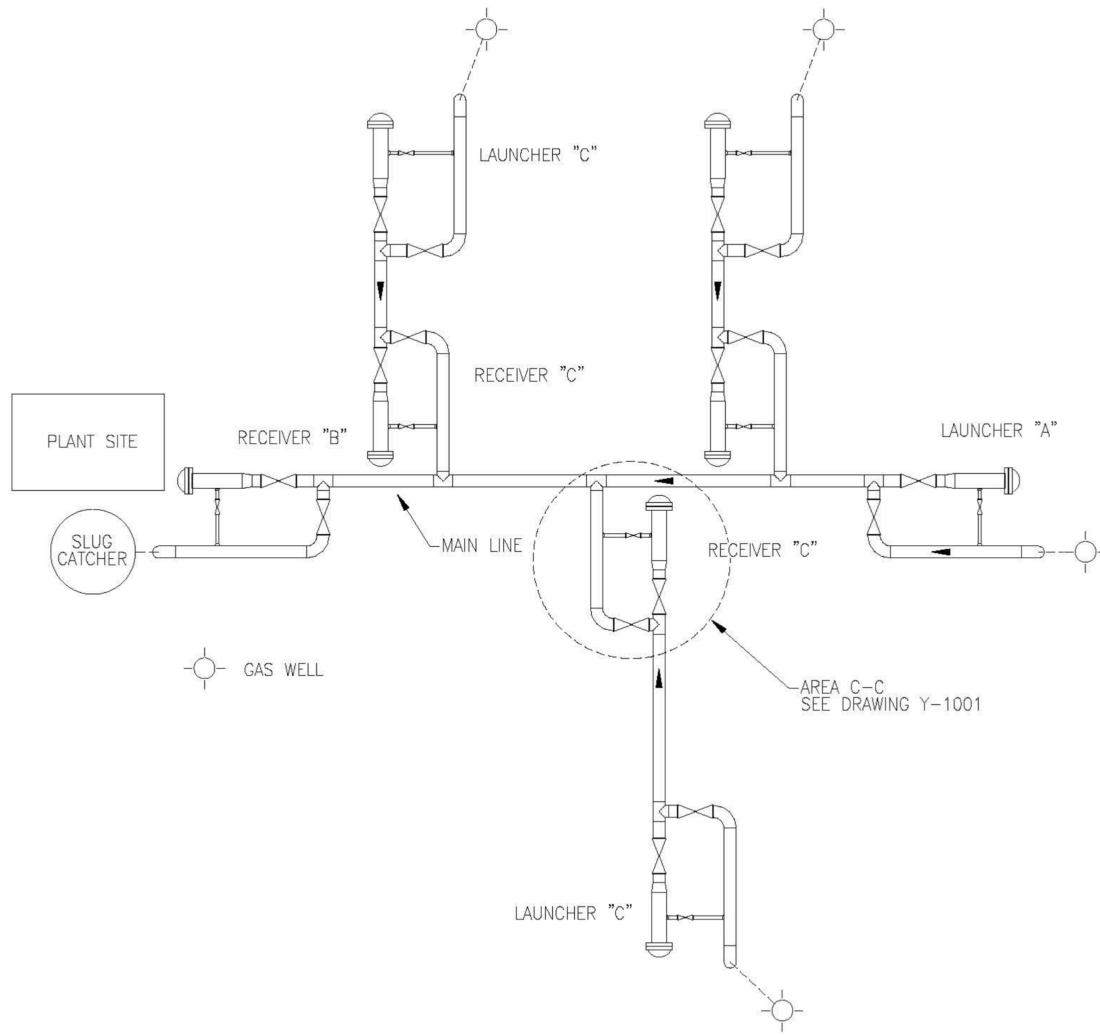
Drawing Y-1000 below shows a typical gas gathering system with pig traps for running pigs. Some gas gathering systems transport dry gas and are not equipped with pig traps since there is not an accumulation of liquids that need to be removed. However, in gas gathering systems that have associated liquids, pig traps are required because pigs are used for removing liquids accumulations, which in hilly country could cause gas lock.

A typical gas gathering system transporting associated liquids will have main trunk lines transporting gas from production to a plant to be processed into pipeline quality gas for sales. When large amounts of liquids are encountered, the plant will be equipped with a slug catcher that separates the liquids from the raw gas and stores the liquids for processing. The size of the slug catcher depends on the produced volume of liquids, the pigging frequency and the design of the gathering system.

The typical gas gathering system will have a flow line with a pig launcher “C” at each well and a pig receiver “C” at the main trunk line. A pig will be launched at the well and push the liquids into the main truck line. As each well flow line dumps liquid into the main trunk line, the volume of liquid accumulates to the capacity of the slug catcher. At this point, a pig is launched at “A” and received at “B” and removes all the liquid in the main trunk line.

The slug catcher capacity and the pigging frequency can be reduced by installing piggable Y’s in place of pig receivers “C” (see Drawing Y-1001). The piggable Y allows the pig from launcher “C” to go into the main trunk line and push the liquids to receiver “B” at the plant site. This reduces the volume of the liquids received at the slug catcher, thus a smaller slug catcher. The pigs launched at each well site will push liquids to the plant site reducing the frequency of launching from launcher A on the main line.

The initial cost of the Y installed is approximately a fourth of the cost of a pig receiver. The Y can be buried, thus appurtenances are not visible aboveground. By eliminating a pig receiver, the pig retrieval expense is eliminated along with the aboveground appurtenances and the access road to the receiver trap. Also, by eliminating the pig trap, the maintenance of the trap and road is eliminated. In addition, the Y radius is 3 diameter thus allowing for smart pig passage should this be required.

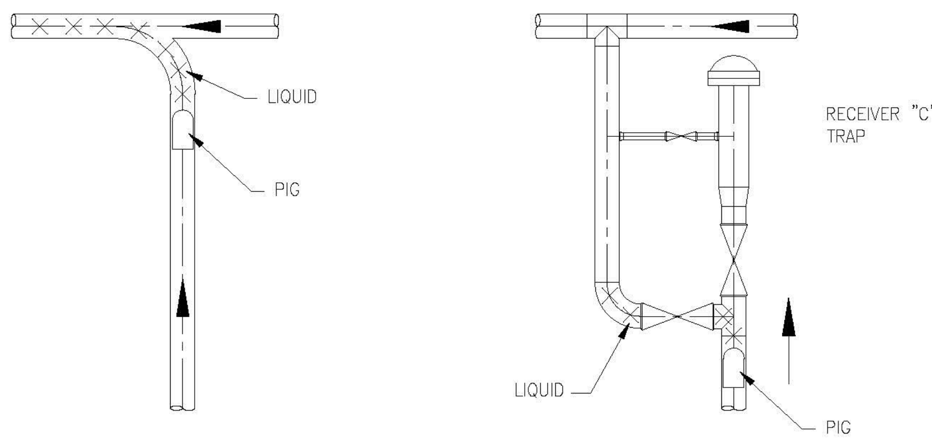


BKW, INC.

TULSA **OKLAHOMA**

TYPICAL NATURAL GAS GATHERING SYSTEM
TRANSPORTING ASSOCIATED LIQUIDS

DRAWN	CHECKED	APPROVED	SCALE	DATE	DWG. NO.
SBS	WEBB	WEBB	NONE	2-13-12	Y-1000



Y TIE–IN

TRAP TIE–IN

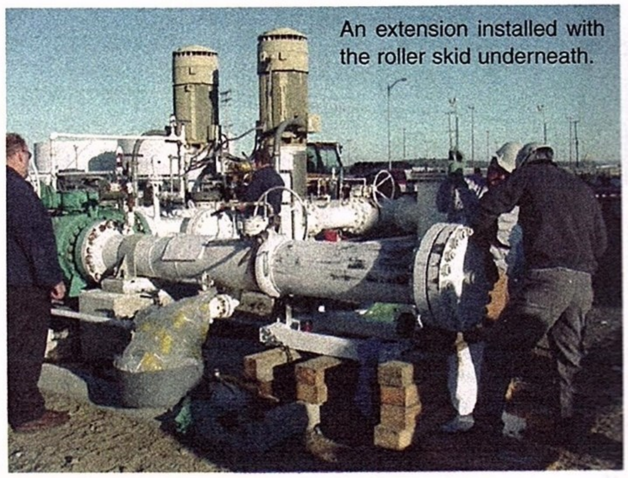
AREA C–C

× = LIQUID

BKW, INC.		PIG RECEIVER PIGGABLE Y COMPARISON					
TULSA	OKLAHOMA	DRAWN SBS	CHECKED WEBB	APPROVED WEBB	SCALE NONE	DATE 2–13–12	DWG. NO. Y–1001

Trap Extensions Designed to Make Life Easier for Pipeline Operators

By **Brian "Butch" Webb**, **BKW, Inc.**, Tulsa, OK



An extension installed with the roller skid underneath.

There are two ways to design pig traps: the first is for cleaning or batching pigs, the second is for smart pigs. Cleaning pigs are short – about a diameter-and-a-half long, requiring a short pig trap barrel for easy loading and removal. Smart pigs are long, up to 10 diameters, requiring long pig trap barrels and specialized equipment for loading and removal. Smart pigs are run at five year intervals.

Depending on pipeline operations, cleaning pigs or batching pigs can run daily. Running cleaning pigs in a pipeline equipped with smart pig traps becomes cumbersome because on a long launcher trap, the pig has to be pushed mechanically all the way to the reducer, and on large-diameter pipelines, the use of powered equipment is required. On the receiving end, the pig usually stops at the reducer and a long pole is needed to hook the nose of the pig to pull it out.

When cleaning pigs are run frequently, several methods can shorten the trap. In order to make life easy on the pipeline operators, one such method is to put a set of flanges on the barrel upstream of the closure. When a smart pig is scheduled to run, the pipeline crew will break the flange and remove the closure. A spool piece is installed between the barrel and the closure which provides the required barrel length to run the smart pig. After the smart pig run the spool piece is removed and normal pigging can begin.

Another method was developed by BKW using an extension on the closure door. As an example, a 12-inch pig trap receiver on a jet fuel line had to be pigged on a weekly basis. This pipeline also has to be smart-pigged every five years. In this case, pig traps were designed with short trap barrels for easy operation.

When the smart pig run was made, the traps were modified using an extension. The extension consisted of a 14-inch threaded closure door with a hole cut out for a 14-inch pipe pup to be welded in place. The 14-inch pipe has a 14-inch flange welded to the other end and a blind attached.

To install the extension, a roller skid was fabricated to lift it into place and allow the extension to roll, thus screwing the extension in to place. The roller skid was supported using a lifting yoke and chains.

The procedure for running the smart pig starts with installing the extensions at both ends and begins by draining the pig trap barrel. After draining, the closure door is opened and the extension is lifted in place using a crane attached to the lifting yoke and roller cradle.

The extension is screwed on the trap barrel and filled with jet fuel and pressured for leaks. After testing, the trap barrel and the extension are drained using the existing system. The blind flange is removed from the extension and the smart pig is loaded and made ready for a run. The blind is installed and the barrel filled with jet fuel. The pig is run and the same procedure is used to remove the smart pig.

Following the run, the trap barrels are drained, the extensions unscrewed from the barrel, and the extensions and lifting equipment stored for the next run in five years. This technique has been used several times since it was developed and its success verified. ***P&GJ***.

BKW, Inc. – Pipeline Pigging Equipment

8" ANSI 600 3-way Switch

24" ANSI 300 Y, 90°, weld-in

Shore Approaches for Fiber Optics Cable in Arctic Conditions

About the authors: Brian “Butch” Webb, BKW Inc., Tulsa, Oklahoma; and Zachary Casey, R.T. Casey, Bel Chasse, Louisiana

A communications company is installing a subsea fiber optics cable from Europe to Asia around North America through the Beaufort and Bering Seas. At various points along the main line branching units are installed to allow for branch legs to be laid to various villages along the coastline of Alaska. These branch legs will provide vital telecommunication service to remote communities and businesses. The villages include Nome, Kotzebue, Point Hope, Wainwright, Barrow and Oliktok Point (Purdhoe Bay). See Exhibit 1 for locations and HDD lengths. This paper will present the many problems and solutions associated with shore approaches in Arctic conditions.

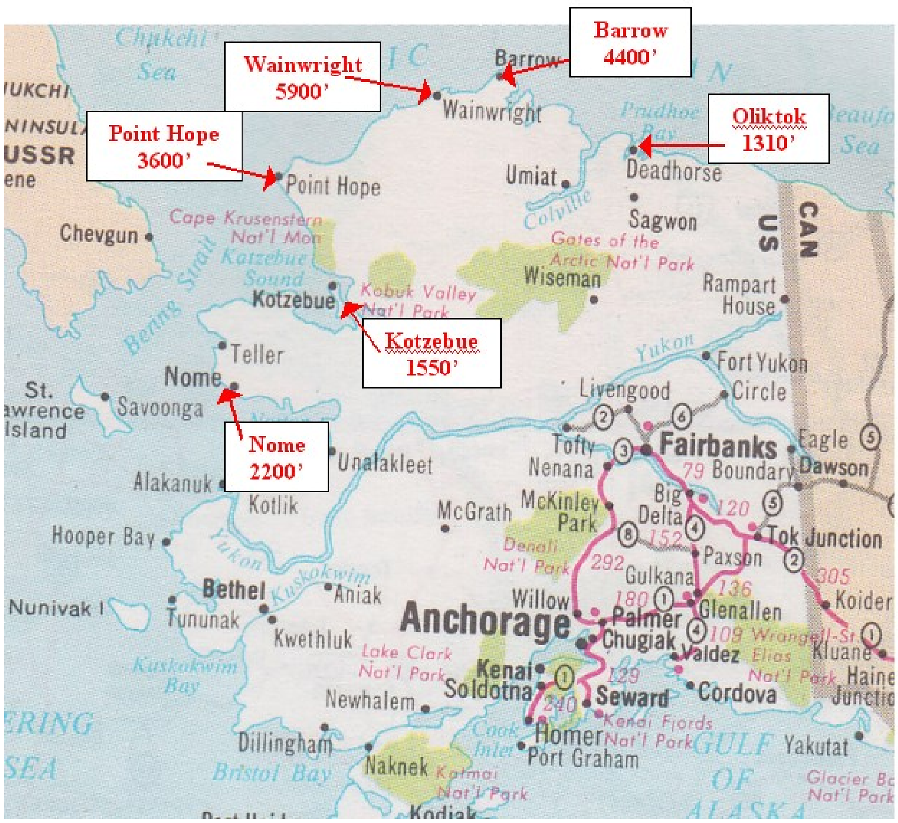


Exhibit 1- Map of HDD locations and lengths

Conditions:

The coastline of Alaska is typically very remote with few towns and accommodations with the exception of Prudhoe Bay. Industry consists mostly of fishing and some tourism. The weather is Arctic conditions and the ocean freezes over almost nine months of the year preventing boat traffic. Ports are non-existent and material, equipment and manpower is usually lightered from ship to shore. As a result, projects preformed in the Arctic require very careful planning and scheduling.

For the purpose of this project, historical geology of the Arctic begins 26,000 years ago when the ocean level was approximately 400 feet lower than it is today. This was caused by the Ice Age. As a result, the exposed ground froze. As sea levels rose to current levels the permafrost remains frozen beneath the sea bottom. Minimal geotechnical sampling has indicated that permafrost temperatures in the soil as shallow as 100 feet below sea bottom can be as low as 15-17 degrees F.

Other problems encountered as a result of Arctic conditions include logistics to bring labor and equipment to the jobsite. The Arctic is sparsely inhabited and roads are non-existent. The only method of shipping is by air or by water when the ocean ice has moved offshore; therefore, scheduling is important, and lightering operations must be carefully planned to insure the transportation of heavy drilling equipment can be safely transported from cargo barges to shallow beaches. This generally involves the use of landing craft specifically designed to serve Arctic Alaska.

Lodging and crew accommodations are a problem because few hotels exist in the small villages and housing and meals have to be provided. Walmart's do not exist therefore everything needed has to be brought in when mobilized.

The Arctic environment is fragile. Tundra, when disturbed, may scar and take years to heal. Shorelines are used by the Natives for fishing and major disruptions can cause economic hardships.

Project:

To bring the subsea cable branches to shore from the main cable, various techniques were considered for the shore approach. Those include traditional beach trenching as well as Horizontal Directional Drilling (HDD).

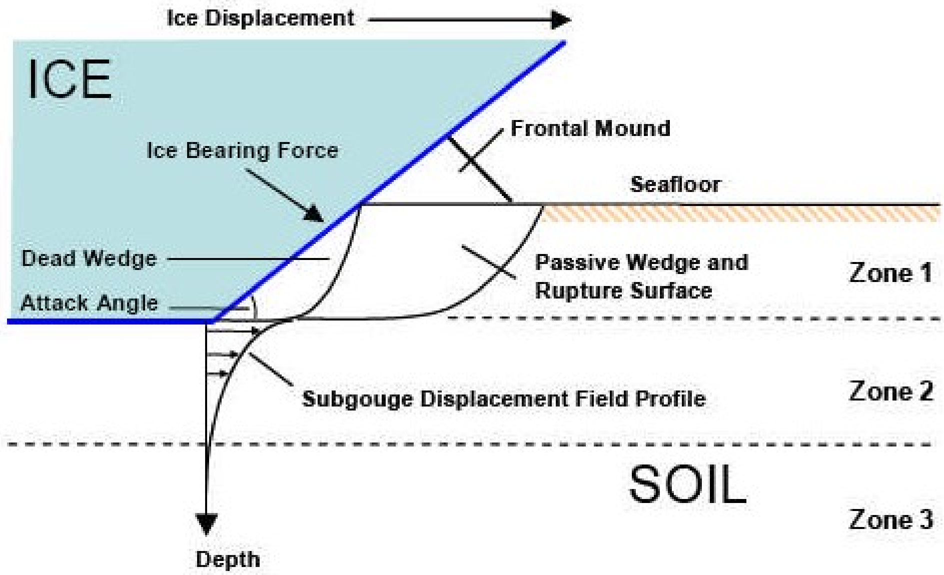
The technique of trenching the shore approach would include traditional methods of excavation to Mean Low Level Water and jet plowing from the water's edge to a depth beyond to the cable. This technique is used in the Gulf of Mexico and also worldwide. However, the known risk from deep ice scour in shallow water would require burial depths, which are unachievable with standard methods. Additionally, the large volume of material removed and the consequent stockpiling of the spoil presents an environmental problem in the Arctic that is not acceptable. The HDD technique eliminates this problem and can extend the shore approach further out to sea without the need for any sea bottom plowing or excavation of fragile arctic coastline.

The HDD technique for telecommunications and power cables normally includes the horizontal bore of a pilot hole from shore, the reaming of the pilot hole to larger dimension and the back pull of a HDPE casing through the reamed bore to be used as a cable conduit. This technique was not acceptable because of logistics and cost. The HDPE casing would have to be fabricated on the Tundra and pulled offshore and then pulled through the HDD bore which is a high risk. Additionally the durations required for the pull back of HDPE casing exposed the drill to freeze the seawater entering the bore. As a result, the drill string used by the HDD for the pilot hole was selected to be used as the casing.

Care was taken to select double white band S-135 drill string with a large diameter to accommodate the armored Fiber Optic cable to be installed. Tool joints with gradual tapers were selected to minimize the risk of cable damage from friction during pull in of cable.

Extensive oceanographic surveys conducted since 1978 indicate the severe risk from ice scour of buried cable had to be addressed. The work led by M.Mellor for the Cold Regions Research & Engineering Lab definitively proved the risks of Ice Scours to cables and pipelines in the Beaufort & Chuckchi Seas. (Mellor, M., CRREL 78-22). Ice scour trenches were measured at a depth of 10 feet to a water depth of ~150 feet. To prevent communication disruption, the fiber optics cable had to be buried to a depth of cover of 10 feet. See Exhibit 2 for ice scour phenomenon.

Exhibit 2- Arctic Subsea Ice Displacement



Source: Grantz et al., 1982; Thurston and Theiss, 1987.

Burial of the fiber optics cable to a depth of 10 feet is a major problem and various techniques have been considered. Both pre-cable lay and post-cable lay methods have been studied; however, cable burial is not a part of this paper.

Solutions:

Because of the severe Arctic conditions and short work span the project requires a well-planned and comprehensive work schedule. Every detail of the work, labor, equipment and material has to be accounted. The location and duration for housing and accommodations has to be established well in advance. Government permitting is essential.

Scheduling includes studies of the timing for ocean ice melts and freeze ups. Frequency and duration of storms and excessive ocean currents has to be addressed. Mobilization and shipping times are included. Any delays that put the project into ocean freeze up will delay the completion for one year.

The HDD bores were unique because the drill pipe was used as the casing. The HDD bore lengths range from 1,550 feet to 5,900 feet. A typical HDD bore consisted of the following:

Following mobilization to the jobsite, landing crafts were used to deliver the HDD equipment to shore. The equipment barge was used as a diving platform at the HDD subsea end. (See Exhibits 3, 4 & 5 showing the dive barge.)

Exhibit 3

Exhibit 4

Exhibit 5

The HDD equipment was set up and the HDD bore completed. (See Exhibit 6 for HDD bore equipment.) The HDD bores penetrated the ocean bottom at a water depth of 50 feet thus the HDD bore lengths varied with each location. (See Exhibit 7 for a typical HDD bore.) During the bore, the friction of the drill string and heat from the drilling mud prevented freezing should the drill string have traveled through permafrost. To prevent freezing of the liquid inside the drill string a system was devised to replace the liquid with air. This system included a pigging system with pig traps, special pigs and an air compressor. (See Exhibit 8 for pig traps under test.)

Exhibit 6

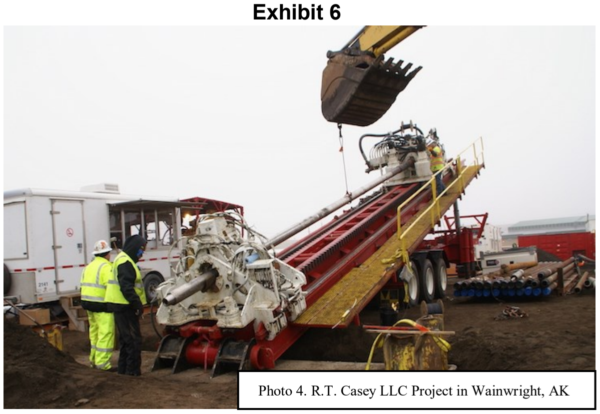
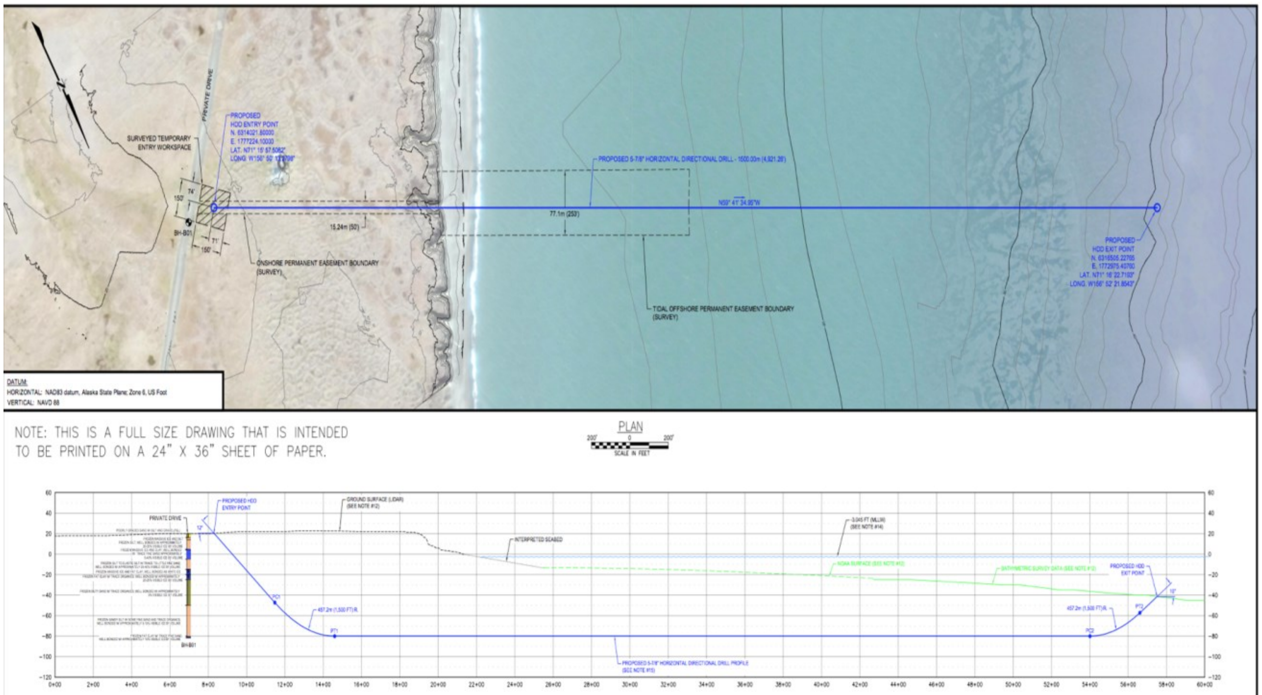


Photo 4. R.T. Casey LLC Project in Wainwright, AK

Exhibit 8

Exhibit 7- RTC Landfall Bore Profile



The drill string consisted of drill pipe with upset connections both inside and outside thus producing internal dual diameters. The diameters were approximately 5” for drill pipe and 4” at the joint. Therefore, a dual diameter disc pig was custom designed and fabricated. (See Exhibit 9 for dewater disc pig, and Exhibit 10 for test pipe used to test dewater disc pig.) The drill string was not sized for standard line pipe; therefore, off the shelf pigs were not available. This also presented a problem for the pig traps. Standard pipe fittings had to be machined and modified to fit on the ends of the drill string pipe. The pig traps were fabricated and were tested by installing on a section of drill pipe (see Exhibit 8). In addition to a pig receiver on the subsea end, a subsea valve was installed to prevent water from entering the drill string after pigging. (See Exhibit 11 for pig receiver and basket.)

Exhibit 10- Test pipe

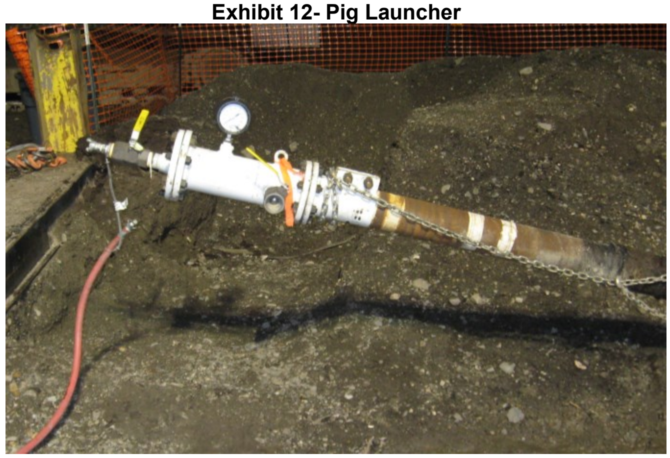
Exhibit 9- Dewater disc pig

Exhibit 11- Pig Receiver and basket

The procedure for dewatering the drill string began by the divers cutting off the drill bit from the drill stem and removing the drill bit. Following this, the divers installed the subsea valve on the drill string and the pig receiver to the subsea valve. A hose was connected to the receiver and ran from the subsea receiver to the barge deck. The hose was chosen over the receiver basket because divers were not required to witness the pig enter the basket and then close the subsea valve to prevent seawater entering the drill string. On some HDD approaches, several hours of dive time was lost due to tidal currents.

On shore the drill string was cut and the pig launcher installed. (See Exhibit 12 for pig launcher.) A disc pig was loaded into the launcher and run using an air compressor. When the pig arrived on the barge deck, the subsea valve was closed.

Exhibit 12- Pig Launcher



The installation of the fiber optics cable was to take place a year later. Therefore, the drill strings were to be charged with air to 70 PSI to prevent seawater from entering. However, the pressure was not able to be maintained and the cause was not determined. Causes could have been a leak at the receiver and the subsea valve, or one of the many pipe string tool joints. To solve this problem, the drill string was filled with a salt brine that had a freezing point lower than the permafrost. (See Exhibit 13 for brine tank.) A procedure was followed that diluted the salt brine when the salt brine was removed from inside the drill string.

Exhibit 13- Brine tank

Installation of the fiber optics cable will begin by pumping water into the drill string from the shore to the subsea valve to insure the drill string has not frozen. Following the water, a soft foam pig could possibly be run to indicate a full opening hole is available to allow passage of the pull pig. If the soft foam pig run is successful a wire line will be attached to the pull pig and pulled to the subsea valve. (See Exhibit 14 for pull pig.) A cable seal was developed to prevent excessive leakage while the pig was being pumped through the drill string. (See Exhibit 15 for cable seal.)

Exhibit 14- Pull pig

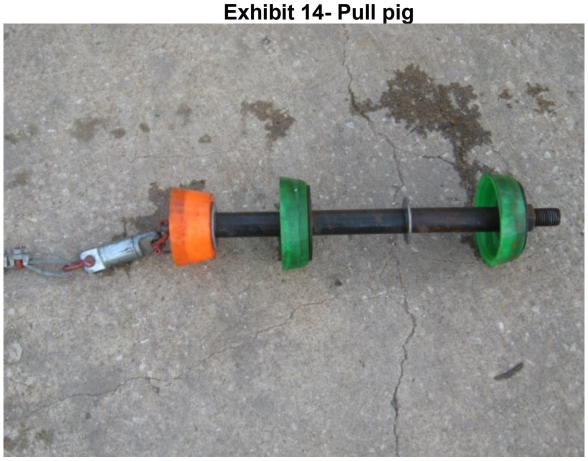
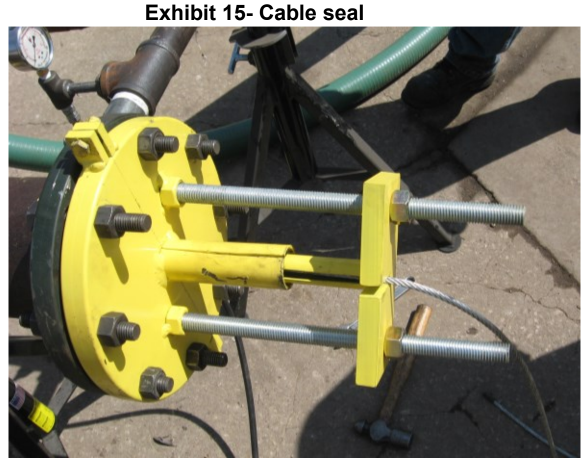


Exhibit 15- Cable seal



Divers will attach a fiber optics pull rope to the wire line and the rope pulled to the pig launcher end and attached to a fiber optics pull winch. The pull rope will pull the fiber optics cable through the drill string to shore. During the design, testing, and operations, extra precautions were taken to prevent any sharp edges from coming into contact with the fiber optics cable during the pull operation. This included the tool joint ends and the cutoff section underwater and on land. Clean up operations will complete the land portion of the project.

Special equipment unique to this project included the pig traps and pigs. The drill pipe require pig traps that had to fit the drill pipe, this included special fabricated fittings that would seal against the pipe and not leak. In addition, the traps had to be attached to prevent slipping off the ends and possibly causing injury.

The purge pig was a typical multiple diameter disc pig that would negotiate the internal upsets at the tool joints. However, when tested as a pull pig the disc pig was not acceptable. Therefore, a test site was set up (see Exhibit 16 for test site) and a pig was developed that would pull 1,400 pounds at 160 PSI without leakage even though design estimated a maximum 1,000 pound pull would be acceptable. (See Exhibit 17 showing a major cup pig.) The pressure drop required to push this pig through the tool joints was thought to be excessive and the center cup was removed. However, should additional pull be required the center cup can be installed.

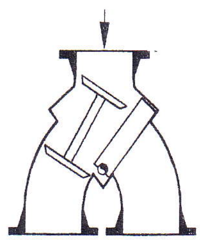
Exhibit 16- Test site

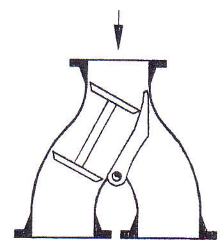
Exhibit 17- Major cup pig

This type of operation under Arctic conditions requires very careful planning. The window of operations is short because of the ice conditions, which can be as short as two months. The cost of mobilizing HDD equipment, dive equipment, and construction equipment including barges, landing craft and manpower cannot be shut down because of one piece of the operation; therefore, everything was thoroughly tested prior to shipping to the jobsite. Any failure causing a delay may postpone the project for another year and this is costly. So planning is paramount.

BKW manufactures two types of Pig Switches: ***Sealing*** and ***Non-sealing***

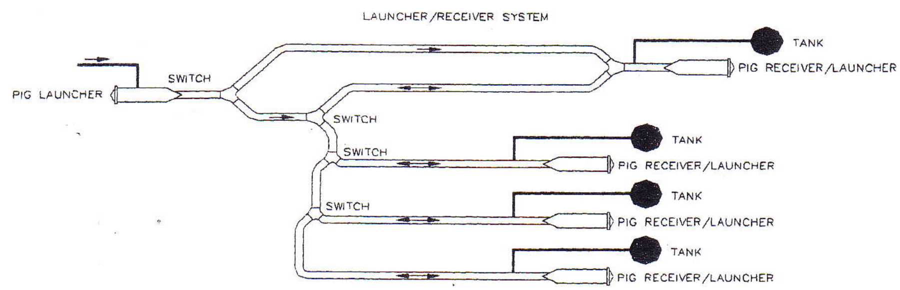
Sealing Switch





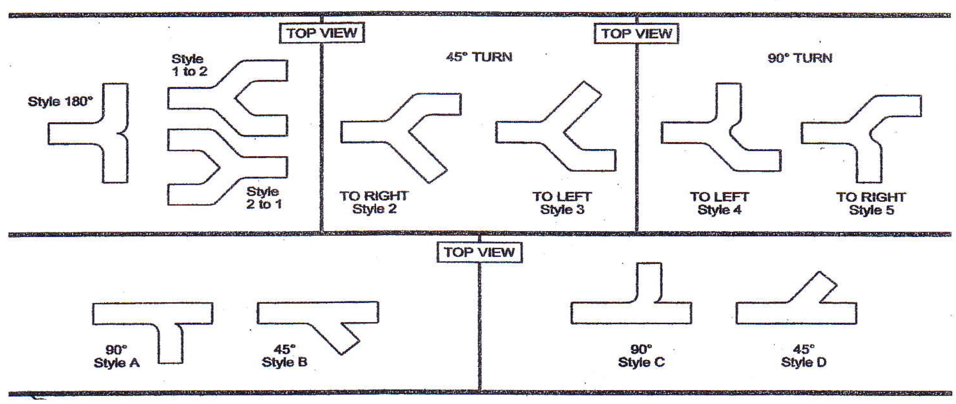
Non Sealing Switch

The diagram below shows some of the uses of the pig switches.



BKW PIG SWITCHES AND Y'S

VARIOUS CONFIGURATIONS



PIGGING EQUIPMENT AND SERVICES OFFERED:

- **Pig and Sphere Traps**: Includes special purpose launchers and receivers, sub sea retrievable traps, multiple automatic pig launchers and receivers.
- **Pig and Sphere 'Y'**: Two into one custom design for pigs, spheres or both.
- **Pig Switches**: One into two configuration, manual or remote.
- **Pig Sealing Switch**: One into two configuration for sealing dead side.
- **Pig and Sphere Handling Equipment**: Trap barrel slides, trays, hoists, environmentally correct pig transporting trailers and skids for truck beds and offshore boat decks. Pigs go from receiver barrel, down the road into launcher barrel.
- **Tadpole Pig**: A cleaning pig that goes through screwed 90° ells and tees.

BKW builds and tests all kinds of widgets because we like to make it exciting. In this case, a test stand was created to test pig cups.

Test stand with installation boom pig cup installed.

Forklift was used to install pig cup into test stand.

Resulting blowout.

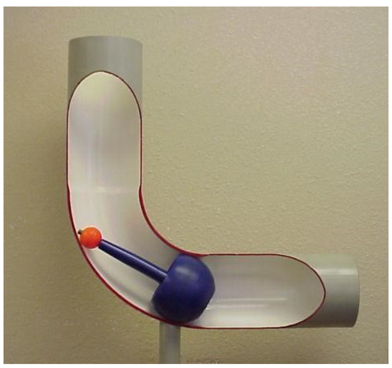
Can't get any better than this!

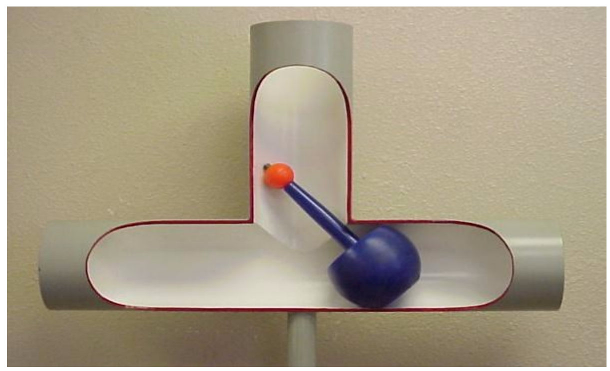
If you have a problem, contact BKW for a solution!
918-836-6767 or bkwinc@aol.com

The tadpole pig was developed to go through 90° ells and tees without an increase in pressure drop. The pressure drop from the back of the pig to the front of the pig is the force required to move the pig through the pipeline. The tighter the pig inside the pipe, the more pressure drop required to move the pig.

A standard cup pig has to bend or deform when going through a long radius (3 radius) weld ell. This requires more force or increase in pressure drop. When dewatering or running pigs in gas service and there is a riser the end of the pipeline, the pig will stick in the 90° ell and pressure has to build up to get the pig to clear the ell. This can take some time. The tadpole pig will not stop because of the design.

In addition, the tadpole pig will go through the lateral in a tee because the pig will go with the flow. This feature allows laterals to be pigged when necessary.





Picture below shows one of two 8-inch ANSI 150 Non-sealing Pig Switches with 5 diameter bends.

16” ANSI 600 Pig Receiver, skid mounted, with trap valve and side tee.

3-way, 6” Pig Switch with air operators.

30” Ball Hook for safely handling spheres.

30” Pig Trap Launcher Tray with gas powered ram for advancing the pig to the barrel reducer