Design Development of Underground Storage Caverns at Texas Eastern's Mont Belvieu, Texas, Terminal

by

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ABSTRACT

A discussion is presented covering the design and construction of a Liquefied Petroleum Gas Storage Cavern in Barbers Hill Salt Dome at Mont Belvieu, Texas.

The design and construction are inter-dependent. The design is developed hand-in-hand with construction methods. The casing program is developed; first, dependent upon hydraulic requirements and secondly as affected by construction methods. Construction methods discussed include selection of pilot bits and reamers for the bore hole; maximum hole angle allowable, drilling mud, logging, cementing casing in normal situations and also with lost circulation, and welding of casing and mounting of the Christmas Tree.

After the shaft is drilled, cased, and completed, initial leaching is discussed. The initial leaching allows development of space at the lower end of the potential cavern to accumulate insolubles which are not circulated from the developing cavern. The final stage of leaching and conversion to operational use is discussed. Also presented are means of evaluating the daily amount of salt leached.

In Appendix, a sample development is presented.

INTRODUCTION

The design of an underground storage cavern in a salt dome is dependent upon construction procedure and subsurface problems as these become evident. Since the design and construction are inter-dependent, this discussion will handle both as a single topic.

There are three basic factors that must be considered in salt dome storage cavern development. These factors are (1) the product to be stored; (2) flow rates at which it will be placed into and withdrawn from storage; and (3) the geology of the dome in which the cavern will be constructed.

Once the type of product to be stored is known flow rates for injecting product into the storage cavern are estimated based on the quantity and source of supply; i. e., pipeline or from surface storage bullets. The discharge rate from the cavern is likewise dependent upon the same factors. Sometimes the geology of the dome is known in detail but often it is not available. Usually the approximate depth to the top of the cap rock and the depth to the top of the salt mass is known.

The depth to the cap rock in the area of Texas Eastern's operations on Barbers Hill Salt Dome at Mont Belvieu, Texas, varies from 420 feet to 600 feet. The salt is approximately 1,400 feet below the surface. The total depth of the salt mass is unknown.

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CASING REQUIREMENTS

Five or six strings of casing will be required for the cavern. These are: (1) conductor casing, (2) surface casing, (3) protection casing, (4) salt casing, (5) blanket tubing, and (6) brine tubing. (Figure 1)

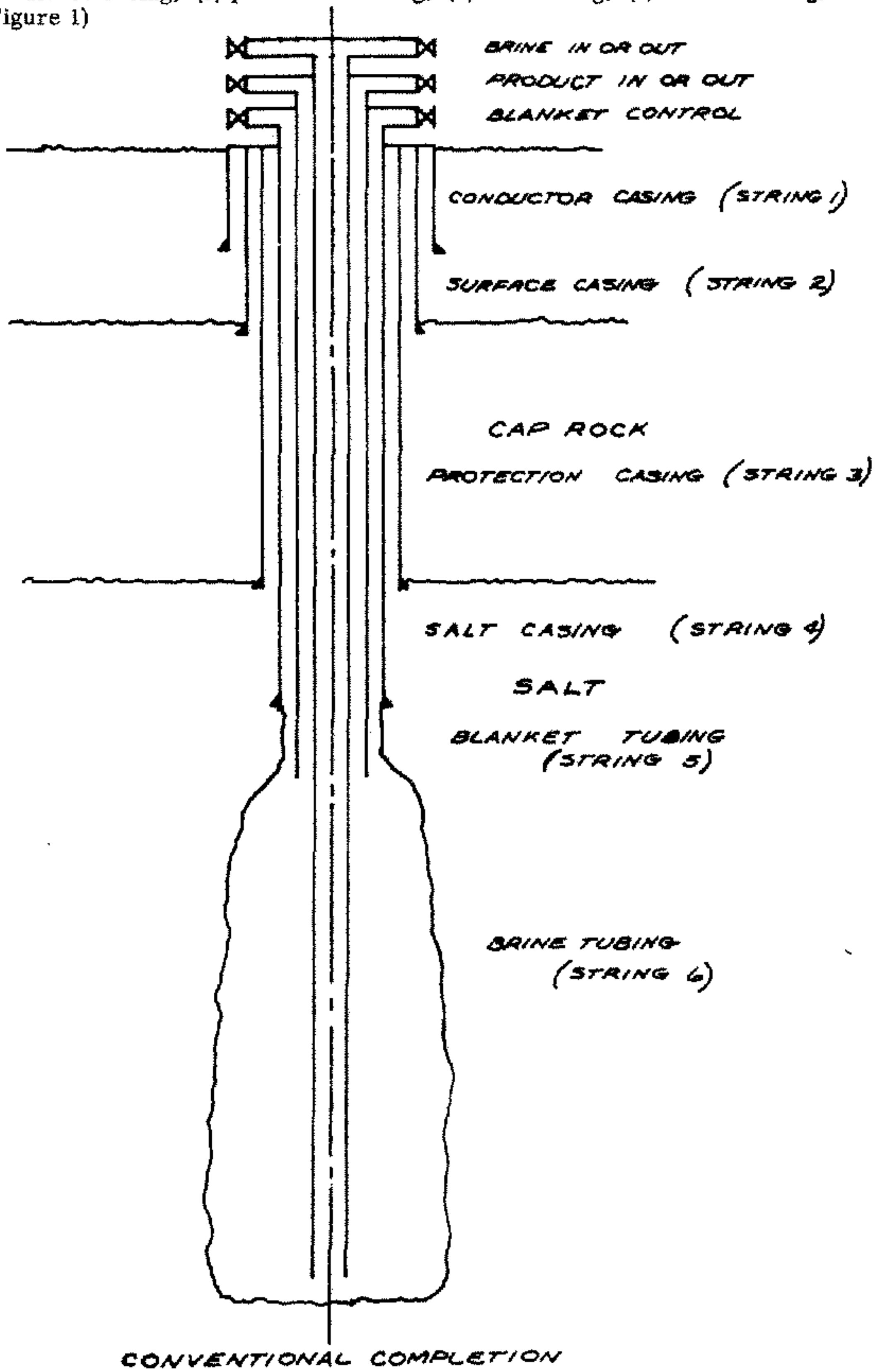


Figure 1.

If the top of the cap rock is determined to be greater than 500 to 600 feet in depth or if abnormal (high pressure) or subnormal (low pressure or theif zones) earth pressure conditions are encountered the conductor casing is required. This casing is utilized to withhold unconsolidated material near the surface from the bore hole and to prevent creation of a cratering condition under the drilling rig substructure. This casing is normally set at depths less than 150 feet and frequently is only 30 to 40 feet deep.

The surface casing is set approximately five feet into the cap rock. The use of this casing is to withhold unconsolidated matter from the bore hole should caverns or theif zones causing loss of circulation of drilling fluids be encountered.

The next two strings of casing are set into the salt mass. One string is cemented approximately 100 feet, and the other string is cemented 500 to 600 feet into the salt.

The first casing cemented in the salt is called the protection casing. The purpose of this casing is to form a seal at least at its lower end when loss of circulation of drilling fluids has been encountered in the cap rock. Often, when substantial loss of circulation is encountered, cementing of the protection casing is difficult because the cementing material will flow into the caverns and voids causing the loss of circulation. Another purpose of this casing is to furnish additional corrosion protection against sulfate waters occurring in the cap rock. Hence, this casing is to form a "back-up" for the cementing of the next casing string and afford corrosion protection.

The second of the two casings is the salt casing. This casing provides the actual shaft of the storage cavern. The depth to the bottom of this casing is determined by both geological and operational conditions which will be discussed.

All of the previously discussed casings are cemented in place from top to bottom.

For the completed shaft, preparatory to leaching the cavern, two additional casings are required. These casings are the blanket tubing and the brine tubing. These casing strings are suspended concentric tubings. The outer or larger diameter tubing is suspended so its lower end is 100 to 200 feet below the lower end of the salt casing. The purpose of this tubing is to contain a hydrocarbon "blanket" between it and the salt casing to prevent leaching of salt at the base of the salt casing by unsaturated brine leaving the cavern during leaching operations. The inner or smaller diameter tubing is suspended so its lower end is less than 30 feet from the bottom of the drilled bore hole of the cavern. This tubing is used to introduce wash water into the cavern so the salt may be leached and for brine flow during operation. The brine formed is then removed through the annulus formed by the blanket tubing and the brine tubing. This annulus is also used for product flow during operational use.

The blanket and brine tubing diameters are determined by factors previously mentioned: rates of injection and withdrawal of product. The other casing diameters are determined by drilling techniques.

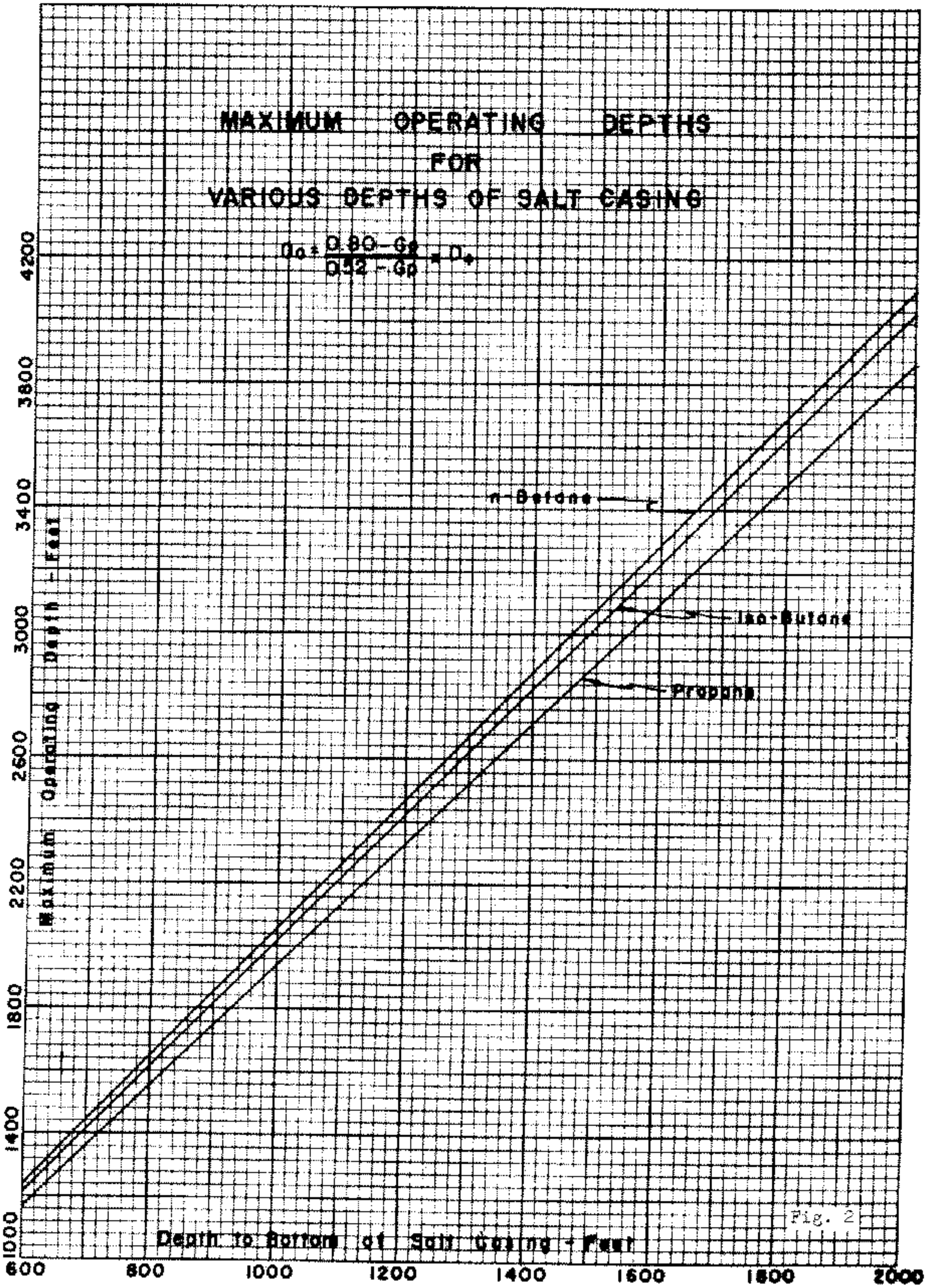
PRODUCT HYDRAULICS

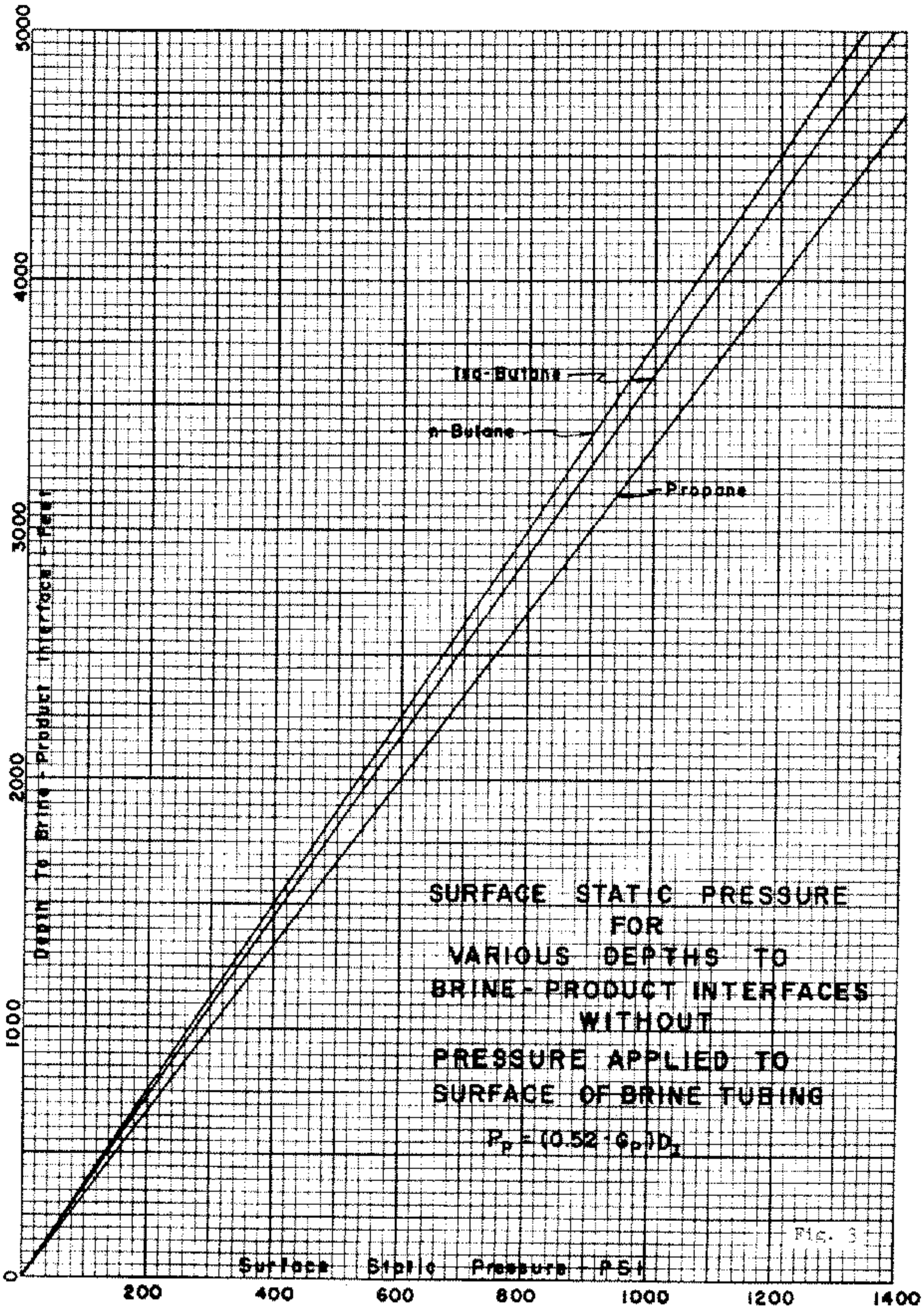
To evaluate the hydraulics of the blanket and brine tubings, the maximum depth of the operating product-brine interface and the depth of the salt casing will have to be determined. The maximum operating depth is determined from: (Figure 2)

$$Do = \frac{0.80 - G_p}{0.52 - G_p} \times D4 \qquad \text{(Eq. 1)}$$

This relationship allows a maximum pressure gradient of 0.8 psi per foot of depth to be applied to the salt mass at the bottom of the salt casing which is the weakest point in the cavern. It is believed that pressure gradients in excess of 0.9 psi per foot applied at this point will "hydrofrac" the salt. Sometimes, the maximum product injection pressure available is a limiting factor. The static product pressure at the surface of the cavern shaft is: (Figure 3)

$$P_p = D_1 (0.52 - G_p) + P_t \qquad \text{(Eq. 2)}$$


MAXIMUM OPERATING DEPTHS
FOR
VARIOUS DEPTHS OF SALT CASING
Do = D.80 - Gp / D52 - Gp = D+
n-Butane
Iso-Butane
Propane
Maximum Operating Depth - Feet
Depth to Bottom of Salt Casing - Feet
1000
1400
1800
2200
2600
3000
3400
3800
4200
600
800
1000
1200
1400
1600
1800
2000
Fig. 2



5000
4000
3000
2000
1000
0
200
400
600
800
1000
1200
1400
Depth To Brine - Product Interface - Feet
Surface Static Pressure - PSI
Iso-Butane
n-Butane
Propane
SURFACE STATIC PRESSURE
FOR
VARIOUS DEPTHS TO
BRINE - PRODUCT INTERFACES
WITHOUT
PRESSURE APPLIED TO
SURFACE OF BRINE TUBING
$P_p = (0.52 \cdot G_p) D_2$
Fig. 3

The actual injection pressure required will be greater than this due to the friction of the system.

By having set the maximum operating depth or desired operating depth, the depth of the salt casing, and accordingly the depth of the blanket tubing (100 to 200 feet below the salt casing), the operating hydraulics may be evaluated.

The most suitable relationships for the computation of hydraulic losses in circular and annular flow systems are:

$$N_r = \frac{3,162.82\ QS}{U(d_2 + d_1)} \qquad \text{(Eq. 3)}$$

When a Reynolds number greater than 2,300 is determined from the above equation, the next equation is used to determine the friction loss:

$$P_{tf} \text{ or } P_{af} = \frac{13.5075\ Q^2 SLf}{(d_2 - d_1)^3\ (d_2 + d_1)^2} \qquad \text{(Eq. 4)}$$

When these equations are used for circular flow passages it will be noted that the above equations reduce to more easily recognized forms by allowing d_1 to equal zero. In annular flow passages the flow across pipe and couplings should be computed separately and totaled.

Operating characteristics may be determined by substituting values in:

$$P_d = P_a + D_I\ (.52 - G_p) - P_{af} + P_{tf} + P_{ee}) \qquad \text{(Eq. 5)}$$

which is valid when discharging product to the pipeline or to surface storage.

When product is being injected the following relationship is true:

$$P_I = D_I\ (0.52 - G_p) + (P_{af} + P_{tf} + P_{ee}) + P_a \qquad \text{(Eq. 6)}$$

At low product discharge flow rates the value of P_a in equation (5) calculates to be a negative number and indicates only a flooded suction is necessary to achieve flow. In practice this is not true, and sufficient pressure must be applied to the brine entering the brine tubing to overcome all entrance losses in the Christmas Tree manifold.

CASING PROGRAM

After completion of the hydraulic analysis, suitable blanket tubing and brine tubing diameters are chosen.

These diameters allow selection of the other casing sizes. The blanket tubing will be suspended inside of the hole drilled through the salt casing. The diameter of the salt casing must then be sufficient to pass the drilling bit with some diametral clearance. Also, the drilled hole must pass the couplings of the blanket tubing with sufficient diametral clearance. This same analysis must be applied to each successively larger diameter casing until the entire casing program is developed.

DRILLING BIT AND REAMER SELECTION

Having selected the casing program, the drilling planning may now be developed.

Drilling procedures can materially affect the running of casing into the drilled bore hole. Large diameter casing will not readily bend to conform to the curvature of the bore hole if excessive drilling drift angles are permitted. Normal conditions often encountered are abrupt doglegs which are sudden offsets in the hole and spiralled holes. These conditions actually cause undersized holes; i. e., holes where the effective diameter is less than the diameter of the bit which drilled the hole.

Such down-hole conditions are impossible to measure so remedial measures must be conducted in advance.

The simplest measure is using packed hole drilling. Packed hole drilling is a procedure using a bit diameter close to the drill collar diameter in order to minimize lateral drift of the bit. The maximum lateral drift possible is one-half of the difference in drill bit diameter and drill collar diameter. Therefore, the closer these diameters are the less the effect of offset in abrupt dog-legs or in spiralled holes. This drift causes a reduction in effective hole size which is expressed as:

$$\text{Minimum Effective Hole Diameter} = \frac{\text{Bit Diameter} + \text{Drill Collar Diameter}}{2} \qquad \text{(Eq. 7)}$$

If, when drilling a relatively large diameter hole, equally large drill collars are not available the lateral drift may be reduced by drilling a pilot hole and then reaming to full gauge. The minimum effective reamed hole diameter is:

$$\text{Reamer Diameter} + \frac{(\text{Pilot Bit Diameter} + \text{Drill Collar Diameter})}{2} \qquad \text{(Eq. 8)}$$

The bore hole for casing should be drilled and reamed to a minimum reamer diameter that is larger than the casing coupling diameter by the difference in the pilot bit and drill collar diameters or:

$$\begin{gathered}\text{Minimum Reamer Diameter} = \text{Casing Coupling Diameter} + \\ \text{Pilot Bit Diameter} - \text{Drill Collar Diameter}\end{gathered} \qquad \text{(Eq. 9)}$$

By utilizing the packed hole method casings may be run in closer tolerance drilled holes than normally recommended thus achieving a savings in tubular goods and rig time.

DRILL HOLE STRAIGHTNESS

Another important contribution this packed hole method offers is the straightness of the hole which is drilled. Storage wells on a salt dome are generally drilled on close spacing in order to efficiently utilize the area available. Once a drilling hole starts to build angle the horizontal drift will usually continue to develop in one direction and accumulate. Excessive drilling angle may cause minimization of future cavern capacity.

It must be realized that a 1° drilling angle causes 17.5 feet of horizontal drift per 1,000 feet of drilled hole. If a shaft is drilled to a depth of 4,000 feet and an average angle of 3° is developed, the bottom of the hole will be 210 feet laterally from the surface location. Usually the hole drilled in the salt gains the most angle.

When leaching is begun the brine tubing will be lying on the low side of the drilled hole at an angle. As fresh water leaches the salt the brine tubing will tend to plumb itself until it is hanging plumb with the last cemented or salt casing. The result is an elliptically shaped cross section in the cavern (Figure 4). Leaching of the salt is proportional to the area of salt exposed. The large diameter of the ellipse is caused by the brine tubing having plumbed itself from the angled hole. This diameter will be continually enlarged and possibly move in the direction of a nearby well. The result being that the subsurface spacing of the cavern is less than the apparent surface spacing.

ANGLE CONTROL

The angle the drilled hole develops may be controlled by several methods. These are (1) packed hole drilling, (2) drill bit and drill collar stabilizers, (3) use of minimum drilling weight applied to bit, and (4) as a last resort, use of directional drilling control methods.

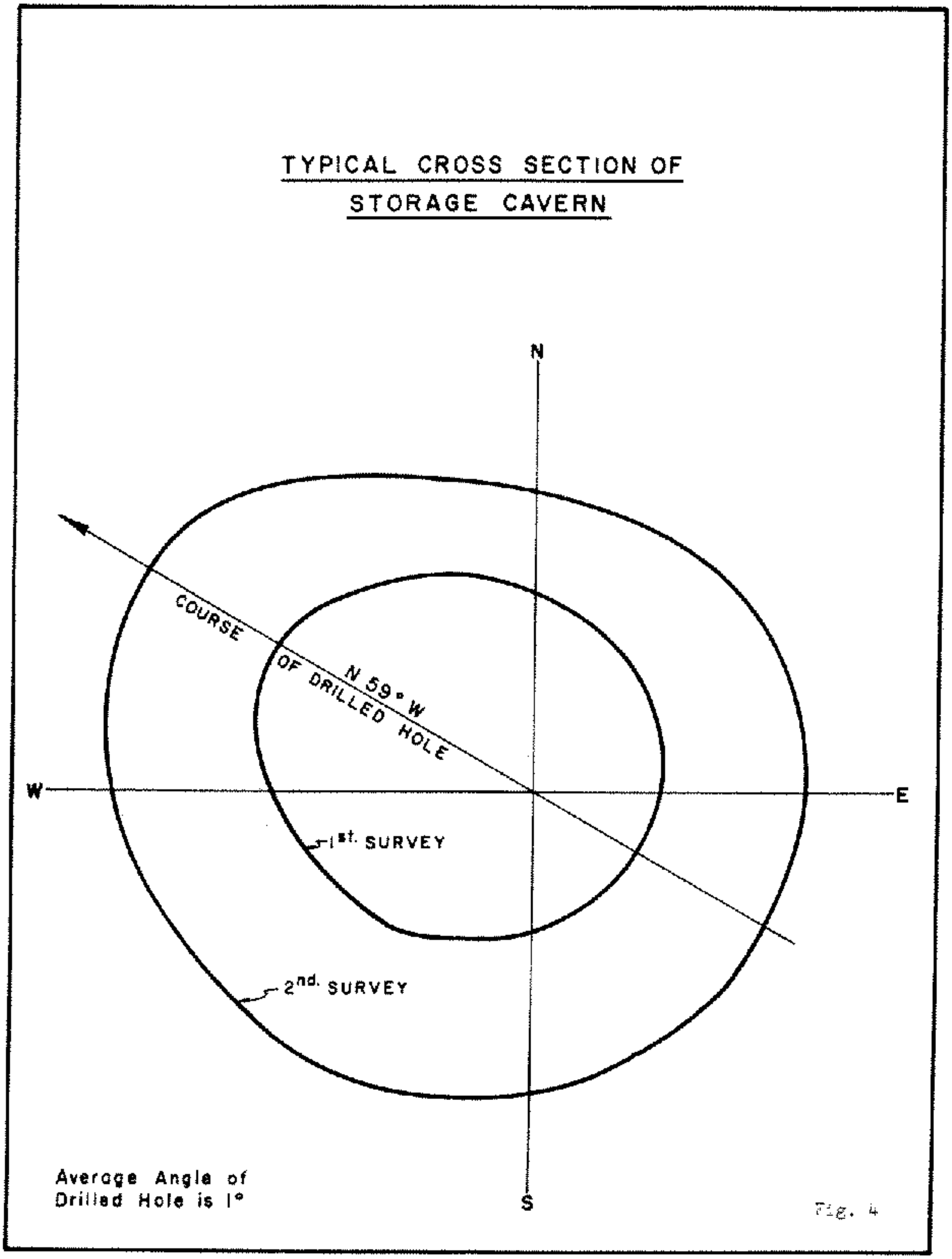

TYPICAL CROSS SECTION OF
STORAGE CAVERN
N
W
E
S
COURSE OF DRILLED HOLE
N 59° W
1st. SURVEY
2nd. SURVEY
Average Angle of
Drilled Hole is 1°

Fig. 4

In the Barbers Hill Salt Dome, sonar caliper surveys indicate elliptical cross sections in the caverns with the long axes of the ellipse pointing to one central location. Since this elliptical section is caused by the angle which the drilled hole developed, it may be postulated the drilled holes attempt to approach a central location. It is well known in oil well drilling that a drill bit will attempt to walk up, dip, or twist so that cutters will be flat on the structure in a hard formation.

In summary, a general rule is the smaller the hole angle the better the finished cavern. Since it is almost impossible to drill a straight hole some angle must be allowed. In most cases a 1° angle is the maximum desirable drift. This may be varied though, dependent upon the vertical height of the cavern, the gross volume of the cavern, the surface spacing between cavern well heads, and the desired wall thickness between caverns.

DRILLING MUD

Drilling mud requirements are minimal. While drilling the softer unconsolidated surface formations a low weight (10 ppg or less) and medium viscosity (40-50 API sec) is generally satisfactory.

Drilling the cap rock anhydrite contaminates the drilling mud causing loss of viscosity due to precipitation of bentonitic gelling material. This is caused by an unfavorable reaction of the calcium sulphate of that cap rock with the bentonite unless the pH of the mud is maintained at an uneconomical high value. Due to this factor no attempt is made to maintain a viscous mud, but mud return velocity is employed to remove cuttings from the hole. A liquid detergent has been added to the mud to control surface tension which reduces the tendency of the drilling bit to ball.

When loss of mud circulation is encountered in the cap rock, dry drilling is conducted. In dry drilling a large quantity of either fresh or brine water is required. This water is pumped into the hole in lieu of mud. All cuttings are then carried into the lost circulation zone. In those cases when the zone is filled with the water or the cuttings act as a bridging agent normal circulation is regained. Drilling without mud return has presented no problem and has become an accepted procedure at the Barbers Hill Salt Dome.

When the salt mass is encountered, the fresh water mud is replaced by saturated salt brine. This replacement is required in order to cause as little leaching of the salt bore hole as is possible. The saturated brine is used as the drilling fluid to the total depth of the hole. The only additives to the brine are lime to increase pH for corrosion control and attapulgites as required to give the brine viscosity to remove cuttings from the hole if the mud return velocity is insufficient.

The desirable annular mud return velocity is in the neighborhood of 100 feet per minute. Such a velocity is normally maintained with the pilot hole and the velocities in the larger reamed hole are maintained as high as available hydraulic horsepower permits with economy.

CEMENTING

After drilling the bore to the desired diameter and angle, the casing is lowered into the bore hole and cemented.

Proper sealing of the casing by cement is one of the most important factors in planning a storage cavern. Volumes of cement required may be estimated by use of caliper surveys of the drilled hole or by "guesstimate" from the size hole drilled with allowance for hole washout. If a string of casing is to be cemented through a lost circulation zone the volume of cement required is a wild guess.

The type cements used vary with the casing being cemented. The purpose of the surface casing is to withhold unconsolidated material from the hole and should be cemented with API Class A (neat) cement slurry. This cement slurry may be mixed with accelerators, such as calcium chloride, up to 3% by volume. This addition of an accelerator allows high early strength of the cement and minimizes rig waiting time. Generally this accelerated cement may be drilled within six to eight hours after placement.

The protection and salt casings are set with their lower ends in the salt mass. The first casing set through the cap rock will be subject to corrosion by sulfate waters in the cap rock. Therefore, a sulfate resistant cement is required for this casing. The various cementing companies have performed sulfate resistance tests of various cement compositions. They can recommend the most economical type for the area of interest. A composition of 50-50 pozzolan mix without any bentonite added is a preferable slurry for the Gulf Coast. This composition is mixed with saturated brine and additional granulated salt in order to saturate the mixing water at downhole elevated temperatures. The cementing program is completed by tailing out or placing around the bottom of the casing an API Class I cement slurry mixed with granulated salt and brine water to permit a denser material to form the lower portion of the seal. The purpose of using supersaturated brine in the cement mix is to prevent any leaching, by mixing water, of the bore hole of the salt as the cement is hydrating and, thereby, causing a possible crevice or channel behind the cement sheath. This method is followed for both the protection and salt casings. This cement is allowed to cure for 48 hours prior to resuming drilling operations.

The method of placement of cement slurry is unique. After the casing is lowered into the bore hole to the desired depth, a bell nipple reducing the casing diameter to 4 inches is welded to the casing. Two-inch tubing is lowered inside of the casing through the 4 inch opening until the lower end of the tubing is approximately 20 to 30 feet above the lower end of the casing. The tubing is suspended and sealed in the 4 inch opening. Drilling mud is circulated through the tubing until the casing is filled to the top of the bell nipple. During the filling operation air is bled off the casing through a valve located in the side of the bell nipple. When the casing is filled with mud the bleeder valve is closed and mud then circulates in the annulus between the casing and the bore hole. After circulation is established cementing commences. The cement slurry is pumped down the tubing and because of the hydraulic seal between the top of the casing and the tubing, the cement so introduced will flow to the bottom of the casing and back up the annulus between the casing and bore hole. This procedure allows the cement to be continuously mixed until cement slurry is returned to the surface. Upon arrival of slurry at the surface mixing is terminated and water or drilling mud is pumped down the tubing until the calculated volume of the tubing is displaced. Then water is pumped into the casing annulus to lower the cement level in the casing to a predetermined level. This is done with the assumption that the highest level of cement slurry inside of the casing is at the bottom of the tubing.

This method of cementing does not require that the casing have as great a collapse pressure resistance as would be necessary with more conventional oil field cementing practices.

In the case of cementing a casing which is suspended through a lost circulation zone, another procedure is used. It is assumed that the static fluid (mud) level is standing at some depth below the surface of the ground. The depth of the zone of lost circulation is generally known. If cement slurry was circulated as described previously it would not return to the surface in the annulus until the zone of lost circulation was either filled or plugged. Hence, the following procedure is used:

Two inch cementing tubing is lowered into the casing as previously described. But the lower end of the tubing is set at the same depth as the lost circulation zone. Mix and pump into the tubing a volume of cement equal to the estimated volume required to fill the casing-hole annulus and the casing proper from the lower end of the casing to the depth of the zone of lost circulation. Displace the cement from the cementing tubing by only pumping into the tubing its own capacity of water. Next pump a volume of water into the casing as computed from the following equation to lower the cement level in the casing to a desired depth:

$$\text{Volume of Water} = (C) \left[(L_c - L_t) \left(2\frac{G_c}{G_m} - 1\right) - L_p \frac{G_c}{G_m} \right] \frac{G_m}{G_w} \qquad \text{(Eq. 10)}$$

After allowing this cement to cure, a second stage of cementing is performed. A volume equal to 1.5 to 2 times the estimated volume from the zone of lost circulation to the surface is mixed and is pumped into the annulus formed by the casing and the hole, from the surface. The plan here is to force all of the water from the static fluid (mud) level to the zone of lost circulation into the zone ahead of the falling cement. Since there is sufficient pressure in the lost circulation zone to support a column of water; hence, it follows that sufficient pressure is available to support a lesser column height of denser cement slurry. When the second stage of cement has been placed and cured a termperature survey is run inside of the casing to establish the top of the cement. Since the last stage of cement was allowed to fall into the annular space there should only be an air space from the top of the last cement to the surface. This void is easily cemented from the surface in a manner similar to the last stage.

CASING TESTING

After the cement has cured, a static pressure test of the cement is conducted on the casings set into the salt mass. The first step is to apply a surface pressure to the casing, which is determined from:

$$P_t = (0.85 - G_m) D_c \qquad \text{(Eq. 11)}$$

This test applies a pressure of 0.85 times the depth to the bottom of the casing at the bottom of the casing. This test is held one half hour to determine there are no leaks in the casing. Next, the cement plug in the bottom of the casing is drilled and at least five feet of new hole is drilled. The same surface pressure is now applied to the casing before the plug was drilled. This test is also held for one half hour. This second pressure application tests the cement seal and/or the salt mass.

If the pressure tests are satisfactory, drilling is resumed. If the tests are not satisfactory, remedial measures are taken to correct any deficiency.

LOGGING

Electric logging is used to verify the top of the cap rock in the surface hole. The top of the salt is also verified by an electric log. The log run is the standard electric log. Cap rock is characterized by the resistivity on all sonde spacings to suddenly increase. The salt-cap rock contact is characterized by sudden reversal or reduction of the resistivity of all sonde spacings to zero.

Upon completion of drilling the bore hole to total depth, a gyrocompass directional and inclination survey is run. The purpose of this survey is two-fold: (1) to determine the location of the bottom of the last cemented casing with respect to the surface location, and (2) to locate the course of the salt bore hole.

WELDING

The several casings which are cemented in place have welded connections rather than screw type connections. Welding is preferred for prevention of leakage which could occur in screw type connections.

The tubular goods used consist of steels of API grades X-42 and H-40 or lesser grades. The major precautionary measure taken with these grades of steel is allowing sufficient cooling time prior to immersing the welded connection into the drilling mud in the hole. This measure is to prevent quenching of the heated weld area and resulting possible failure.

CHRISTMAS TREE

The Christmas Tree is a manifold of valves to permit control of leaching and storage operations (Figure 5). The Christmas Tree assembly (Figure 6) consists of five forged steel sections excluding valves. The lower most section or casing head of the Tree is mounted on and welded to the last cemented casing. The casing head is purchased with a short nipple, of the type casing it is to be mounted on, welded into the mounting recess of this section. This allows stresses developed by welding the casing steel to the Christmas Tree steel to be relieved in heat treating. When this casing head is mounted on the last cemented casing, welding is performed on similar

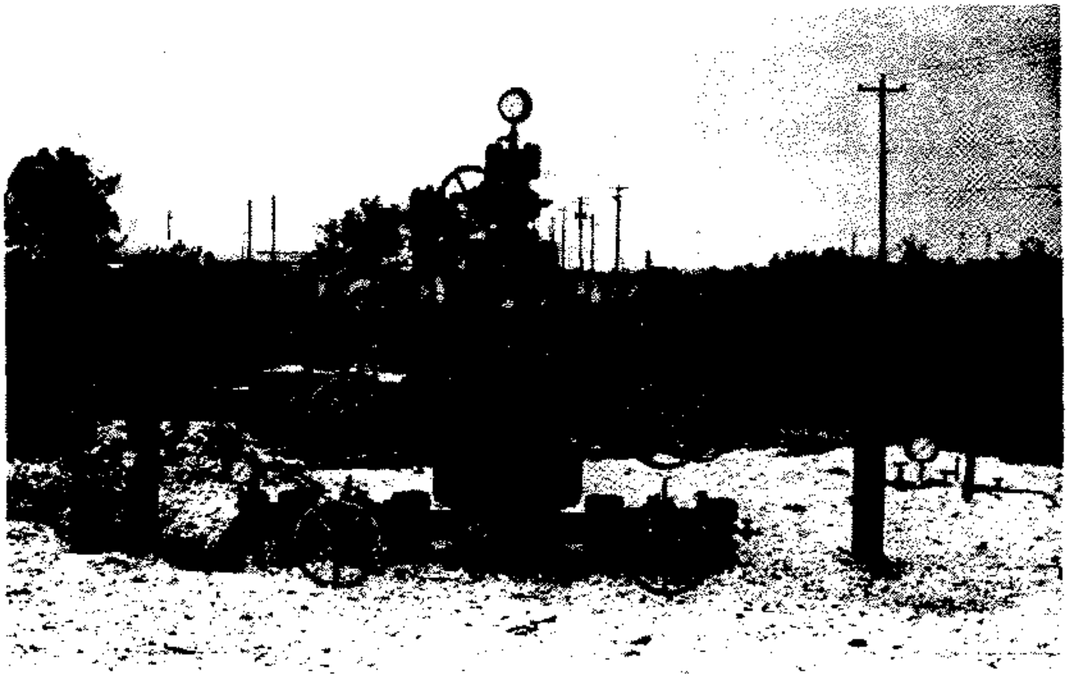


Figure 5.

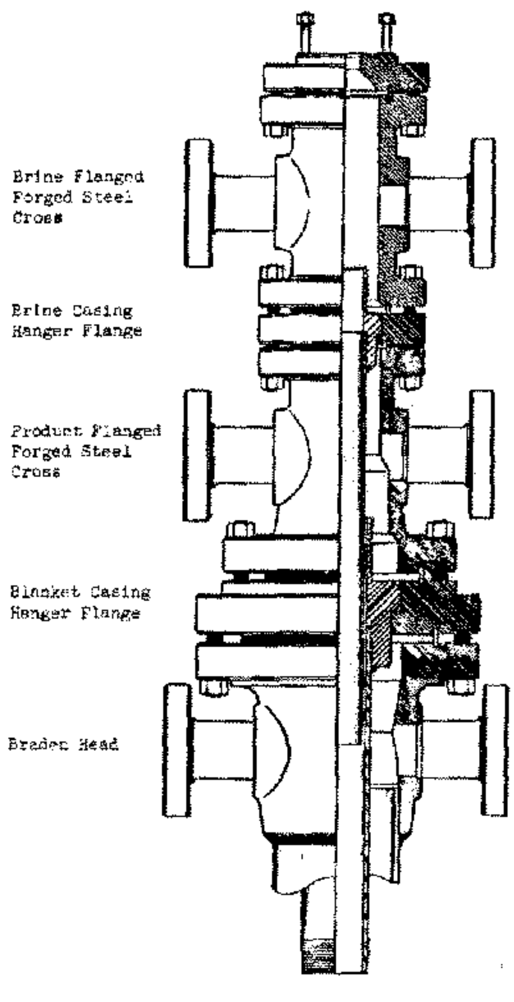


Figure 6.

low carbon steels and undesirable stress patterns do not develop. The casing head has two flanged outlets to permit access to the annulus formed by the last cemented casing and the blanket casing.

The next section is the blanket casing hanger flange (Figure 7). This consists of a nipple of the blanket casing welded through a flange. This nipple suspends the blanket casing.

Above the hanger flange is a flanged forged steel cross (Figure 8). The two horizontal outlets provide access to the annulus formed by the blanket casing and the water tubing.

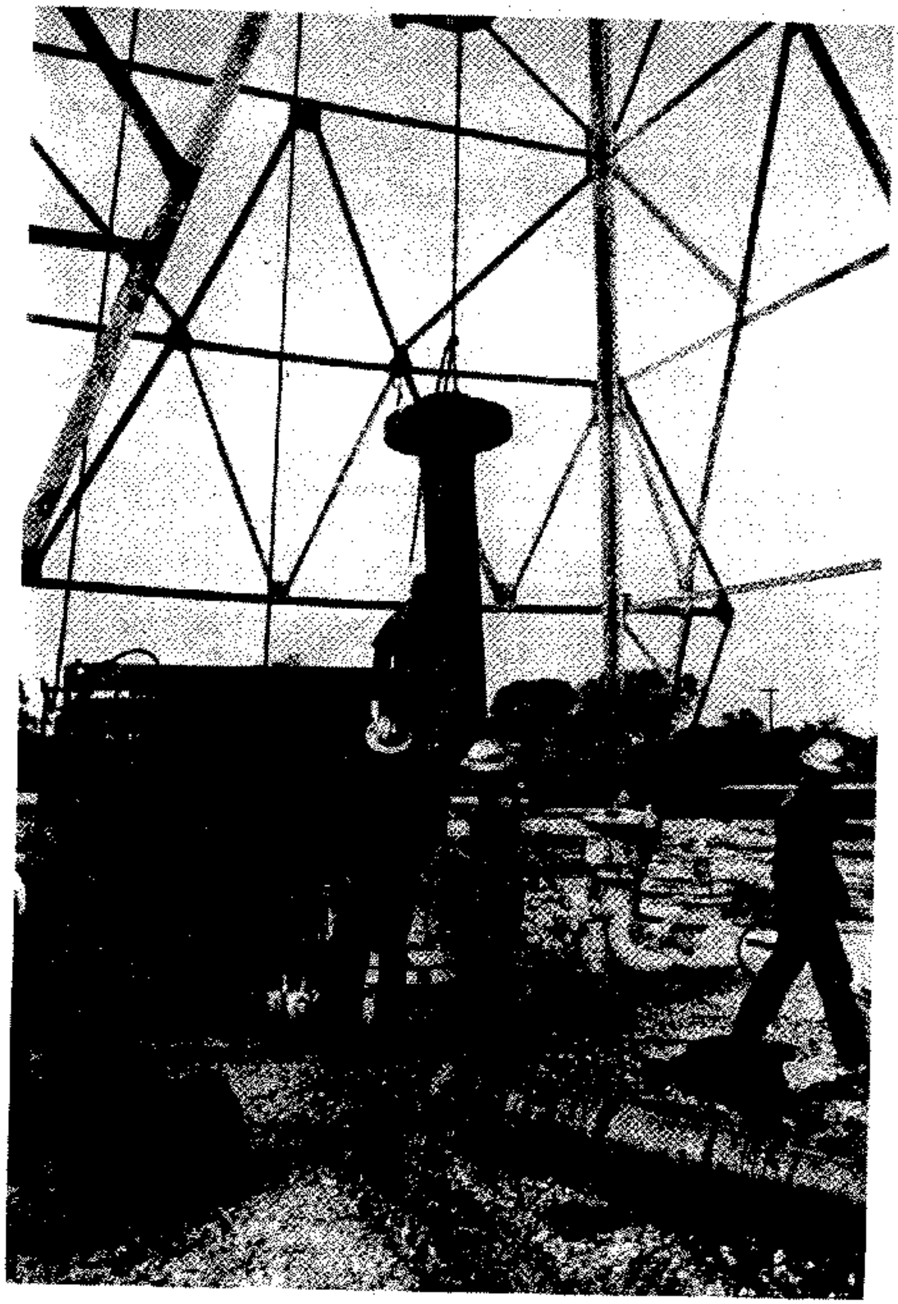


Figure 7.

Figure 8.

Upon this cross is mounted the brine tubing hanger flange (Figure 9). This consists of a nipple of the brine tubing welded through the flange. This nipple suspends the brine tubing.

The last section consists of a flanged forged steel cross mounted on top of the brine tubing hanger flange (Figure 10). Two horizontal outlets provide access to the brine tubing. The third or vertical outlet provides vertical access to the brine tubing.

Seals between all flanges are provided by metal ring joint gaskets. Conventional oil field Christmas Trees utilize rubber sealing elements to prevent communication between flow annuli. Liquified petroleum gas has a detrimental effect upon these rubber sealing elements. The metal ring joint gaskets are not subject to the same deleterious effects of LPG and have been adopted for all seals in the Christmas Tree.

LEACHING PREPARATIONS

Cores of the salt and experience with Barbers Hill Salt Dome show the salt mass contains a fine evenly distributed sand. The sand represents 7 1/2% of the volume of the salt mass.

As the salt is dissolved there is insufficient velocity of the brine leaving the cavern to remove the particles of sand from the cavern. The sand falls to the lower portion of the cavern and fills a space equal to the space it held in the salt mass. Therefore, a volume of sand equal to 7.5/92.5 or 8.1% of the salt volume leached is replaced to the lower portion of the cavern. This sand accumulates and ultimately covers the lower end of the brine tubing. Any failure of fresh water pumping equipment, halting water injection usually causes this sand to plug the brine tubing. Further leaching is impossible until the sand can be cleared from the vicinity of the brine tubing.

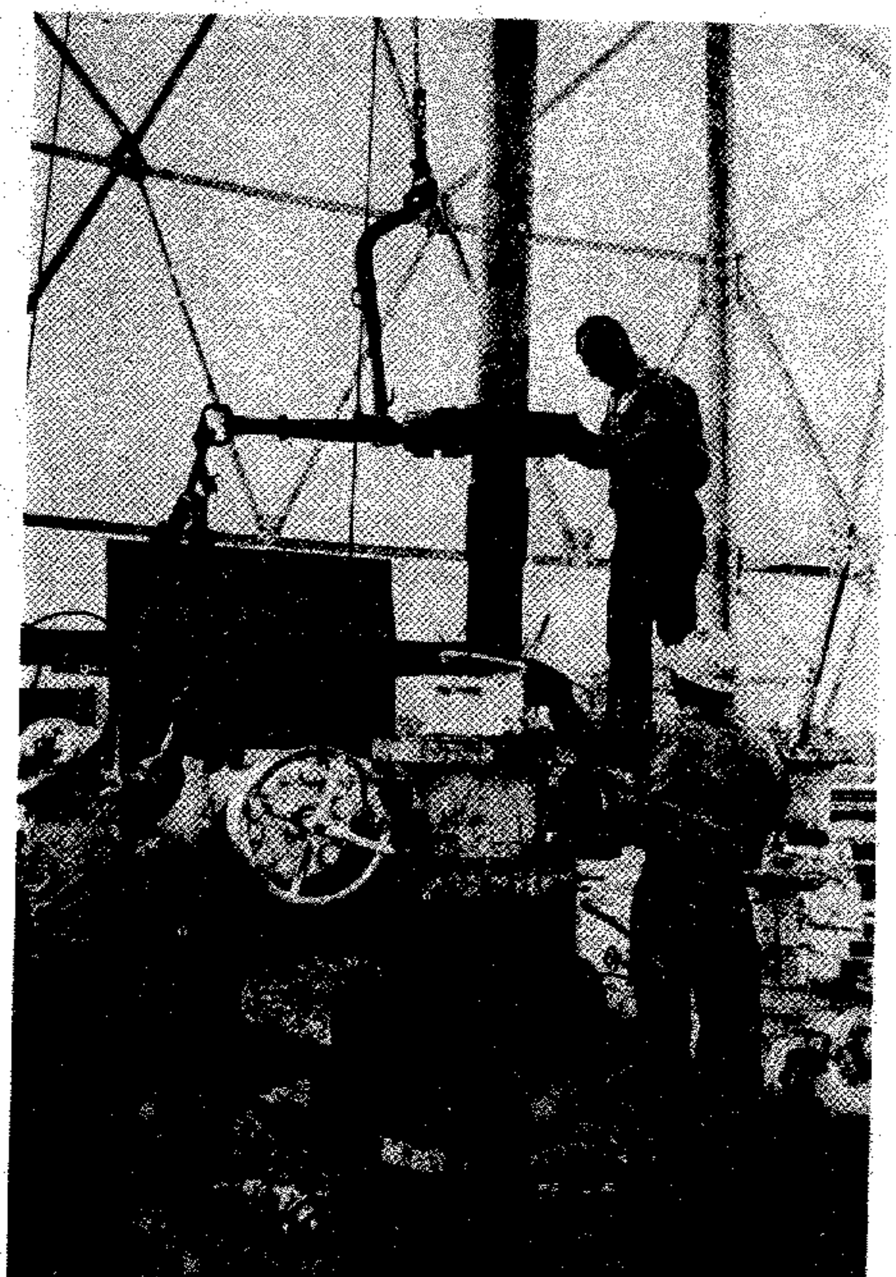


Figure 9.

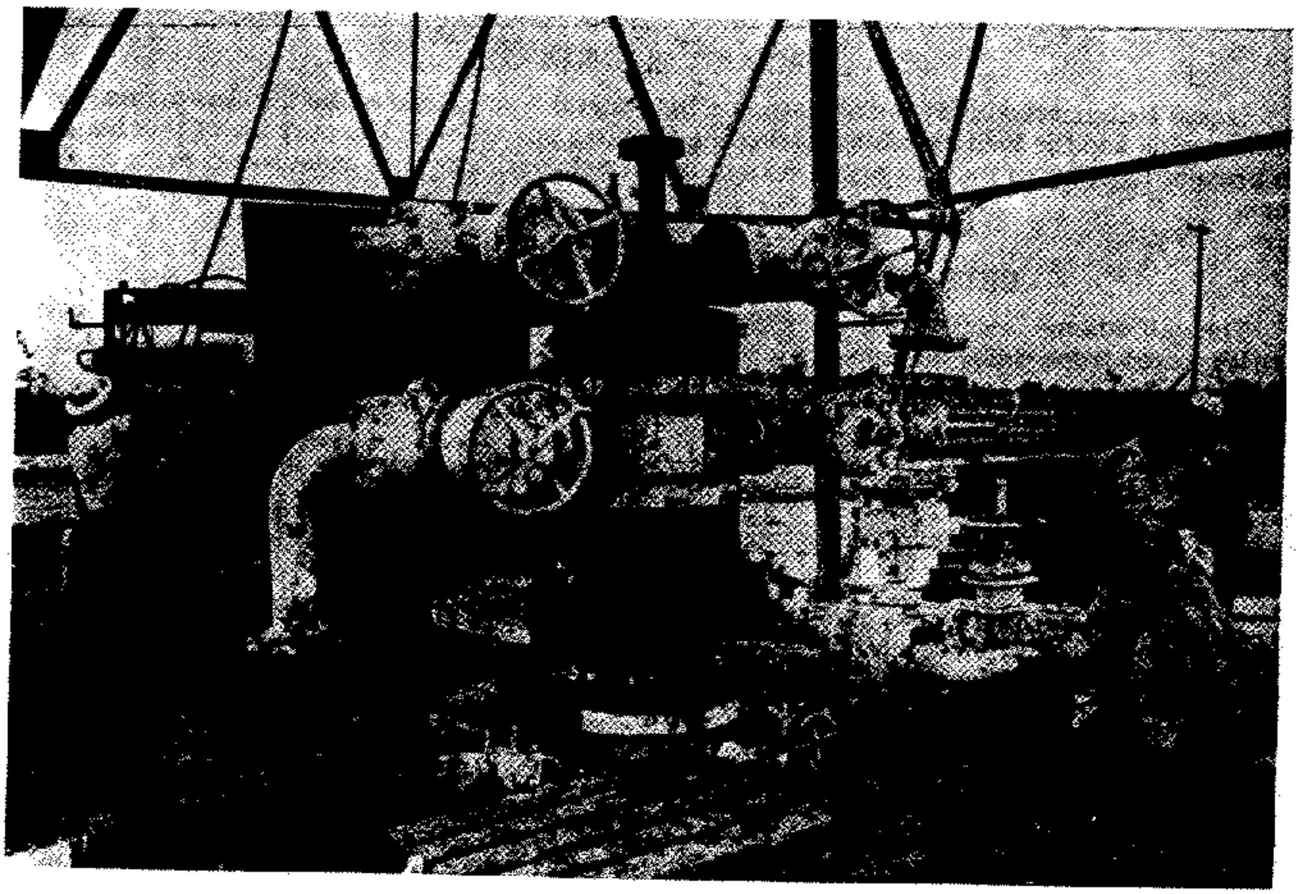


Figure 10.

Clearing of the sand from the brine tubing requires moving a workover rig in to perform the necessary work. This can happen several times during the leaching development of the cavern, adding unnecessarily to the cost of the cavern.

This hazard is relieved by leaching a space in the lower 100 to 200 feet of the bore hole equal to approximately 8% of the anticipated gross volume of the cavern. To perform this leaching the blanket casing is lowered to between 100 and 200 feet from the total depth of the bore hole.

The brine tubing is lowered to as close to the total depth of the bore hole as possible. The lower space is leached in these limits. When the desired space is developed a workover rig is moved in and the blanket casing is raised to a depth with its lower end approximately 100 to 200 feet deeper than the bottom of the last cemented casing. The depth of the water tubing is adjusted so its lower end is at the top of the initial cavern space developed.

With the large volume of space below the lower end of the water tubing available to collect sand, leaching operations may be suspended at any time necessary. This allows more flexible use of leaching water pumps.

PRODUCT BLANKET

Liquid Hydrocarbon (LPG, distillate, or light fuel oil) is placed in the annulus formed by the salt casing and the blanket tubing during the leaching operation. The purpose of this blanket is to prevent leaching of the salt at the bottom of the salt casing by any unsaturated brine in the cavern.

DETERMINATION OF SALT VOLUME LEACHED

The salt volume leached is determined daily from hourly reading of discharged brine salinity and injected fresh water volumes.

The salinity of the brine discharged from the cavern is measured with a Salometer and the brine temperature is observed.

Calculations of salt dissolved are made assuming the entering water saturates to the degree measured on the discharged brine and that a volume of brine remains in the cavern equal to the volume of salt dissolved. This brine which remains in the cavern is assumed to completely saturate in the daily calculations.

Usually two sonar caliper surveys are obtained in the cavern during the period while the cavern is being leached from 1 to 1.5 million barrels capacity. The sonar caliper volumes have agreed favorably with calculated volumes (Figure 11).

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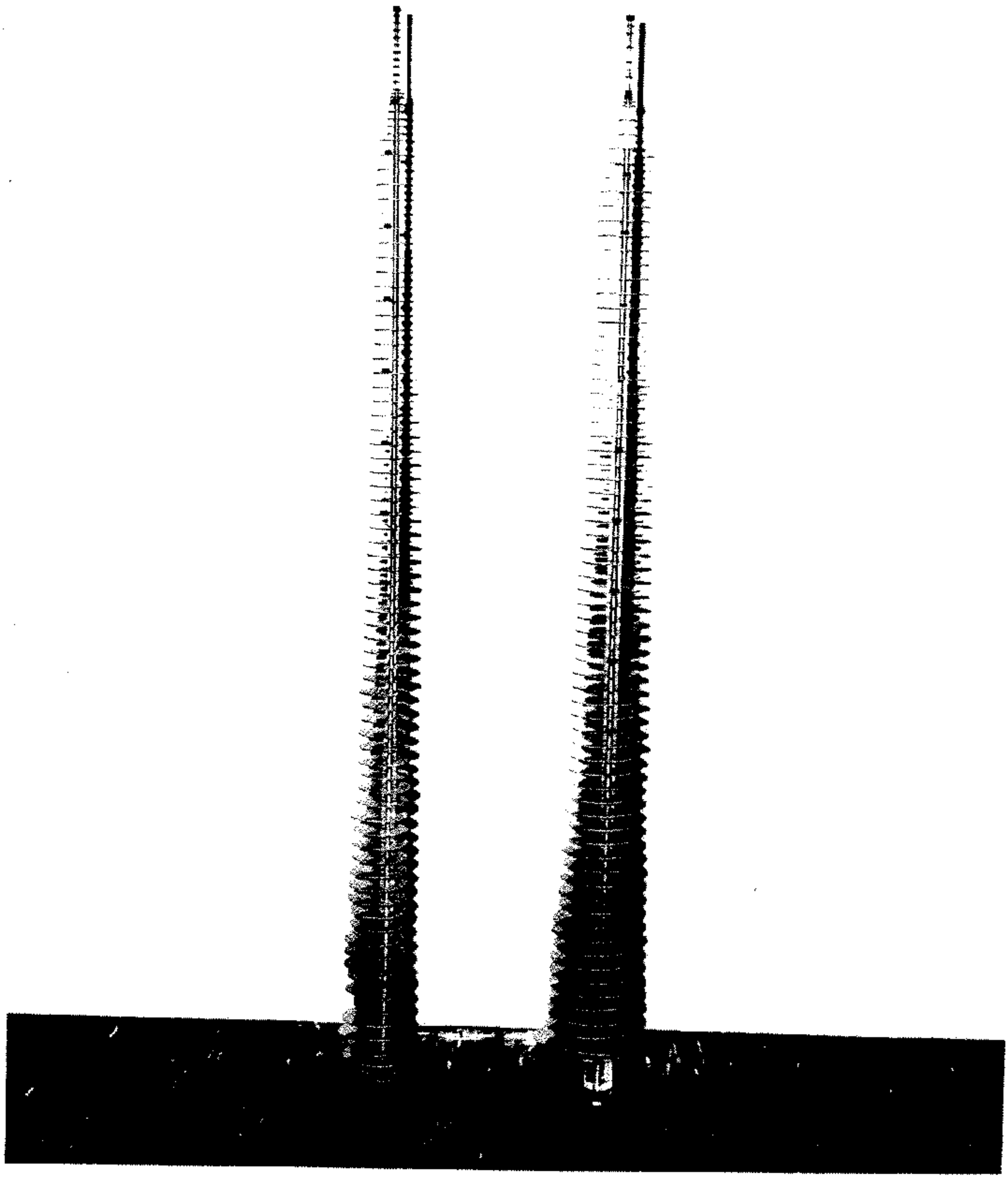

Figure 11.

NOMENCLATURE

1. C = Capacity of casing - bbls. per foot.
2. D_c = Depth to bottom of casing being tested - feet.
3. D_I = Depth to brine product interface.
4. D_o = Maximum operating depth - feet.
5. D_4 = Setting depth of salt casing.
6. d_1 = Minor diameter of flow passage - inches.
7. d_2 = Major diameter of flow passage - inches.
8. f = Friction factor (Crane Co. Technical Paper No. 410, Page A-23 or A-24).
9. G_c = Gradient exerted by cement - slurry - psi per foot.
10. G_m = Gradient exerted by drilling mud in hole - psi per foot.
11. G_p = Gradient exerted by product stored - psi per foot.
12. G_w = Gradient exerted by displacing water - psi per foot.
13. L = Length of flow passage - thousands of feet.

13a. L_c = Depth to bottom of casing - feet.

13b. L_p = Desired length of plug to be left in casing.

13c. L_t = Depth to bottom of cementing tubing and lost circulation - feet gone.

14. N_r = Reynolds number.
15. P_a = Pressure applied at surface of water casing - psi.
16. P_{af} = Annular friction loss - psi.
17. P_{afc} = Annular friction loss couplings - psi.
18. P_{afp} = Annular friction loss pipe body - psi.
19. P_d = Pressure applied at surface of product annulus while discharging product - psi.
20. P_{ee} = Entrance and exit friction loss in Christmas Tree - psi.
21. P_i = Pressure applied at surface of product annulus while injecting product - psi.
22. P_p = Well head product pressure - psi.
23. P_t = Surface test pressure - psi.
24. P_{tb} = Well head brine pressure - psi.
25. P_{tf} = Tubing friction loss - psi.
26. Q = Flow rate - gpm.
27. S = Specific gravity - related to water.
28. U = Absolute viscosity - centipoise.

Appendix

Following the preceding discussion, an example of the design procedure is presented.

The requirement is for 1,000,000 barrels of propane storage. The maximum propane injection rate is to be in the range of 600 to 800 barrels per hour. This rate of 600 to 800 barrels per hour will be received from a pipeline and lesser rates will be received from surface storage bullets. Propane will be discharged from the cavern at a maximum rate of 1,000 barrels per hour. The location of the proposed storage cavern is such that the top of the cap rock is anticipated at a depth of 450 feet and the top of the salt is anticipated at 1,400 feet.

Since the cap rock is at a shallow depth there is no requirement for conductor casing. Three strings of casing will be cemented in place plus the two operational casings. The cemented casings will be: (1) surface casing cemented into the cap rock at 450 feet, (2) protection casing cemented 100 feet into the salt at 1,500 feet, and (3) the salt casing cemented at 1,900 feet or 500 feet into the salt mass.

The maximum operating depth of the cavern, storing propane, is determined from equation (1) to be:

$$D_o = \frac{0.80 - 0.22}{0.52 - 0.22} \times 1,900 = 3,673 \text{ feet}$$

The static surface pressure resulting from this operating depth is determined for equation (2):

$$P_p = 3,673\ (0.52 - 0.22) + 0 = 1,103 \text{ psi}$$

In order to allow an additional factor of safety the static pressure is limited to 1,000 psig and the new maximum operating depth is determined as equation (2):

$$1,000 = D_I\ (0.52 - 0.22) + 0$$
$$D_I = 3,333 \text{ feet}$$

The depth at which the brine tubing is set should be greater than the maximum operating depth to prevent overfilling of the cavern. It is also desirable to minimize the volume of surplus cavity leached. From these factors allow the maximum depth of the brine tubing to be 3,375 feet.

Since the salt casing is to be set at 1,900 feet and the blanket tubing should be suspended so its depth is approximately 200 feet greater than this, the bottom of the blanket tubing is determined to be 2,100 feet.

Thus the upper and lower limits of the cavern have been selected as 2,100 feet and 3,333 feet respectively.

The length of the brine tubing flow passage is 3,375 feet and the length of the annular flow passage is 2,100 feet. Assume the following tubular dimensions for the brine and blanket tubings:

<u>Brine Tubing</u>

5-1/2" J-55 LT & C Casing

Pipe	- inside diameter	4.950 inches
	- outside diameter	5.500 inches
Coupling	- outside diameter	6.050 inches
	- length	8.000 inches
	- per cent of total pipe length	2.22% (30-foot joints)

Blanket Tubing

9-5/8" J-55 LT & C Casing

Pipe	- inside diameter	8.835 inches
	- outside diameter	9.625 inches

This combination of tubing diameters and lengths now allow hydraulic analysis. It is assumed that brine flows in the 5 1/2 inch diameter pipe and propane flows in the annulus formed by the 5 1/2 inch and 9 5/8 inch diameter pipes.

The following valves are determined for brine and propane:

Brine	- Viscosity	2.0 cp @ 85° F.
	- Specific Gravity	1.2 @ 85° F.
Propane	- Viscosity	0.1 cp @ 85° F.
	- Specific Gravity	0.508 @ 85° F.

Solving equation (3) for Reynolds number the following is obtained:

Brine in 5-1/2" pipe

$$N_r = \frac{3,162.82\ (1.2)\ (Q)}{(2.0)\ (4.950)} = 383.37\ Q$$

Propane in 5-1/2" - 9/5/8" annulus (pipe body)

$$N_r = \frac{3,162.82\ (.508)\ (Q)}{(0.1)\ (8.835\ +\ 5.500)} = 1,120.83\ Q$$

Propane in 5-1/2" - 9-5/8" annulus (pipe coupling)

$$N_r = \frac{3,162.82\ (.508)\ (Q)}{(1.1)\ (8.835\ +\ 6.050)} = 1,079.41\ Q$$

The value of Reynolds number for flow in these passages is tabulated in Table I for flow rates from 200 to 2,000 barrels per hour.

The friction factor is determined for the various Reynolds numbers from charts. The author prefers the charts for commercial steel published by the Engineering Divison of the Crane Company in their Technical Paper No. 410. These factors were extracted from Friction Factors for Pipe Flow by L.F. Moody. The diameter of the flow passages of the 5 1/2 inch tubing is 4.950 inches. The equivalent diameter of the annular flow passage must be used. The equivalent diameter is the difference in major and minor diameters of the flow passage, so:

5-1/2" - 9-5/8" (pipe body)

8.835 - 5.500 or 3.335" equivalent diameter

5-1/2" - 9-5/8" (pipe coupling)

8.835 - 6.050 = 2.785" equivalent diameter

Friction factors for the various Reynolds numbers are tabulated in Table I.

The pressure loss per 1,000 feet of flow passage is determined by solving equation (4) which reduces to:

Brine tubing pressure loss per 1,000 feet

$$P_{tf} = \frac{13.5075\ (Q^2)\ (1.2)\ f}{(4.950\text{-}0)^3\ (4.950\ +\ 0)^2} = 0.00546\ Q^2 f$$

Product annulus (5-1/2" - 9-5/8" pressure loss per 1,000 feet of pipe body

$$P_{afp} = \frac{13.5075\ (Q^2)\ (.508)\ f}{(8.835 - 5.500)^3\ (8.835 + 5.500)^2} = 0.00090\ Q^2 f$$

Product annulus (5-1/2" - 9-5/8") pressure loss per 1,000 feet of coupling

$$P_{afc} = \frac{13.5075\ (Q^2)\ (.508)\ f}{(8.835 - 6.050)^3\ (8.835 + 6.050)^2} = 0.00143\ Q^2 f$$

Since the length of the couplings in the tubing string are 2.22% of the length, the remainder or 97.78% is pipe body. Therefore, the above pressure losses in the annulus must be modified for their proportional share. The proportionate values are tabulated in Table I.

Also listed is the composite pressure loss per 1,000 feet of annular flow passage.

The lengths of the brine tubing and product annulus have been determined to be 3,375 and 2,100 feet respectively. The entrance and exit pressure losses are estimated to be 0.500. With this data the total pressure loss in the system due to friction may be determined. These values are tabulated in Table II.

Using the values of pressure loss due to friction at the various rates of flow the necessary brine injection pressure for various product discharge pressures are calculated by equation (5):

$$200 = P_a + 2,100\ (0.52 - 0.22) - 401$$

$$P_a = 200 + 630 + 401$$

$$P_a = 29 \text{ psi}$$

This equation indicates for a 1,000 barrel per hour flow rate, a 200 psi discharge pressure, and the brine product interface at the upper limit of the cavern that only a flooded brine suction need be maintained. Practice, however, indicates a pressure at least equal to the losses in the Christmas Tree manifold must be applied to achieve the example rate.

The same conditions may be used to determine the maximum brine product and interface (or approximate volume in the cavern) depth in the cavern for the flow rate without exceeding the previously determined well head product injection pressure. Equation (6) is used to determine the interface depth for the flow rate by:

$$1,100 = D_I\ (0.52 - 0.22) + 401 + 0$$

$$D_I = (0.52 - 0.22) = 1,100 - 0$$

$$D_I = 2,330 \text{ feet}$$

Hence, when the brine product interface reaches 2,300 feet in depth and there is no back pressure on the brine discharge, the injection rate will have to be reduced to prevent over pressuring the cavern.

Values for the maximum brine injection pressure required for various flow rates when discharging product are tabulated in Table III. The depths of the interface for various flow rates which do not cause limiting pressures to be exceeded are also tabulated in Table III.

Tables I, II, III, IV, and V are contained on pages 656, 657, 659, 660 respectively.

The brine and blanket tubings have been selected as 5 1/2 inch and 9 5/8 inch casings respectively. The other casings may now be selected assuming standard sizes of drilling bits and reamers are used.

Table I

CALCULATION OF FRICTION PRESSURE LOSSES

FLOW RATE BPH	REYNOLDS NUMBER NR	FRICTION FACTOR	PRESSURE LOSS PER 1,000 FT. P_{rf} & P_{at}	PER CENT PIPE OR COUPLING PER 1,000 FT. - %	PRESSURE LOSS PER PROPORTIONATE PART OF 1,000 FT. PSI
Brine flowing in 5-1/2" 4.950 I.D. Casing					
200	76,740	0.0210	4.6		
400	153,480	0.0189	16.5		
600	230,220	0.0180	35.4		
800	306,960	0.0175	61.2		
1,000	383,370	0.0172	93.9		
1,200	460,440	0.0169	132.9		
1,400	537,180	0.0168	179.8		
1,600	613,920	0.0167	233.4		
1,800	690,660	0.0166	293.7		
2,000	767,400	0.0165	360.4		
Propane flowing in 5-1/2" - 9-5/8" pipe annulus					
200	224,166	0.0190	0.7	97.78	0.68
400	448,332	0.0183	2.6	97.78	2.54
600	672,498	0.0178	5.8	97.78	5.67
800	896,664	0.0177	10.2	97.78	9.97
1,000	1,120,830	0.0176	15.8	97.78	15.45
1,200	1,334,996	0.0175	22.7	97.78	22.20
1,400	1,569,162	0.0174	30.7	97.78	30.02
1,600	1,793,328	0.0173	39.9	97.78	39.01
1,800	2,017,494	0.0172	50.2	97.78	49.09
2,000	2,241,660	0.0172	61.9	97.78	60.53
Propane flowing in 5-1/2" - 9-5/8" coupling annulus					
200	215,882	0.0196	1.1	2.22	0.02
400	431,764	0.0186	4.3	2.22	0.10
600	647,646	0.0182	9.4	2.22	0.21
800	863,528	0.0181	16.6	2.22	0.37
1,000	1,079,410	0.0180	25.7	2.22	0.57
1,200	1,295,292	0.0179	36.9	2.22	0.82
1,400	1,511,174	0.0178	49.9	2.22	1.11
1,600	1,727,056	0.0177	64.8	2.22	1.44
1,800	1,942,938	0.0177	82.0	2.22	1.82
2,000	2,158,820	0.0177	101.2	2.22	2.25
Composite annular (5-1/2" - 9-5/8") pressure loss per 1,000 feet of pipe with couplings					
200			0.7		
400			2.6		
600			5.9		
800			10.3		
1,000			16.0		
1,200			23.0		
1,400			31.1		
1,600			40.4		
1,800			50.9		
2,000			62.8		

Table II

SYSTEM FRICTION PRESSURE LOSS

FLOW RATE BPH	PRESSURE LOSS IN 2,100 FT. OF ANNULAR PASSAGE PSI	PRESSURE LOSS IN 3,375 FT. OF BRINE TUBING PASSAGE PSI	PRESSURE LOSS DUE TO EXIT & ENTRANCE FLOW PSI	SYSTEM PRESSURE LOSS PSI
200	1.5	15.5	10.0	27
400	5.5	55.7	20.0	81
600	12.4	119.5	30.0	162
800	21.6	206.5	40.0	268
1,000	33.6	316.9	50.0	401
1,200	48.3	448.5	60.0	557
1,400	65.3	606.8	70.0	742
1,600	84.8	787.7	80.0	953
1,800	106.9	991.2	90.0	1,188
2,000	131.9	1,216.4	100.0	1,448

Table III

MAXIMUM INJECTION AND DISCHARGE RATE, PRESSURES AND INTERFACE LEVELS

FLOW RATE BPH	MAXIMUM DEPTH OF INTERFACE LEVEL LIMITING INJECTION PRESSURE TO 1,100 PSIG	MAXIMUM BRINE INJECTION PRESSURE REQUIRED TO DISCHARGE PRODUCT AGAINST 200 PSI PRODUCT LINE PRESSURE
200	3,577	10 (-403)
400	3,397	20 (-349)
600	3,127	30 (-268)
800	2,773	40 (-162)
1,000	2,330	50 (- 29)
1,200	1,810	127
1,400	-	312
1,600	-	523
1,800	-	758
2,000	-	1,018

The hole size for the 9 5/8 inch casing to be lowered in is determined from equation (9). It is here assumed that 11 1/4 inch diameter drill collars are to be used and the smallest bit used in connection with these drill collars is a 12 1/4 inch diameter bit.

$$\text{Minimum Reamer Diameter} = 10.625 + 12.250 - 11.250 = 11.625''$$

Hence, in this case the 12 1/4 inch bit drills a hole sufficiently large to pass the 9 5/8 inch casing.

The 12 1/4 inch bit will pass through 13 3/8 inch casing, so this size is selected for the salt casing.

The next casing required is the protection casing. Through this casing a hole must be drilled sufficiently large to adequately pass the 14 3/8 inch diameter lifting bands of the 13 3/8 inch casing. Again equation (9) is used to determine the drilled hole size using the 11 1/4 inch drill collars with a 12 1/4 inch pilot bit.

$$\text{Minimum Reamer Diameter} = 14.375 + 12.250 - 11.250 = 15.375''$$

Since the salt casing extends only 500 feet below the protection casing this reamer diameter may be skimped upon and a 15 inch diameter reamer may be used. Such a diameter ream will pass through 16 inch casing. The protection casing will be 16 inch in diameter.

The surface casing must be of sufficient diameter to pass a reamer required for the hole size necessary to pass the 17 inch diameter lifting bands of the 16 inch protection casing.

$$\text{Minimum Reamer Diameter} = 17 + 12.250 - 11.250 = 18''$$

An 18 1/2 inch diameter reamer is a standard size and will be used. This reamer will pass through 20 inch casing which will be used for surface casing. If conductor casing is used it will also have to be sufficiently large to pass the reamer size necessary to pass the 21 inch diameter lifting bands of the surface pipe; again:

$$\text{Minimum Reamer Diameter} = 21 + 21.250 - 11.250 = 22''$$

However, the surface hole could preferably be dug using 7 3/4 inch diameter drill collars and the required reamer size is:

$$\text{Minimum Reamer Diameter} = 21.000 + 12.250 - 7.750 = 25.5''$$

A 26 inch reamer is a standard size and will pass through 28 inch diameter line pipe which can be utilized for conductor casing. Since only a short length of conductor is usually necessary it may be set in a hole diameter only 4 inch to 6 inch larger than its diameter.

Table IV lists the casings, recommended reamer sizes, drill collar and pilot bit sizes, and depths of casing or hole required.

The casing weights per foot and wall thickness are determined by conventional oil field casing design practice.

Cement requirements are estimated from drilled hole diameters and casing diameters plus allowance for hole enlargement due to wash out of the wall of the hole.

Table V lists the casings, hole diameters, depths and estimated allowance for hole wash out, annular capacity per foot and estimated cubic feet of cement slurry required.

After the cement has been placed and cured pressure tests are conducted. The test pressure for the 16 inch and 13 3/8 inch casings are determined from equation (11):

16" casing at 1,500 feet

$$P_t = (0.85 - 10.0 \times 0.52)(1,500) = 495 \text{ psig}$$

13-3/8" casing at 2,000 feet

$$P_t = (0.85 - 10.0 \times 0.52)(1,900) = 627 \text{ psig}$$

Both of the above pressures are applied to the casings at the surface. It is also assumed in this example that the casings contain 10 pounds per gallon drilling mud.

Table IV

CASING AND DRILL BIT PROGRAM

CASING	CASING DIAMETER AND DEPTH REQUIRED	RECOMMENDED REAMER DIAMETERS	PILOT BIT AND DRILL COLLAR SIZES	TYPE BIT
Conductor	28" - 40'	34"	24" - 7-3/4"	Drag Bit-Reamer
Surface	20" - 500'	26"	12-1/4" - 7-3/4"	Rock Bit-Reamer
Protection	16" - 1,500'	18-1/2"	12-1/4" - 11-1/4"	Rock Bit-Reamer
Salt	13-3/8" - 1,900'	15"	12-1/4" - 11-1/4"	Rock Bit-Reamer
Blanket and Brine Tubing	9-5/8" 5-1/2"	-	12-1/4" - 11-1/4"	Rock Bit

The total drilled depth of the cavern shaft is now determined. The brine tubing has been assumed to be at a depth of 3,375 feet. Approximately 25 feet of free space will be allowed below this tubing. This results in the bottom of the cavern being set at 3,400 feet. The volume requirement of the cavern has been set at 1,000,000 barrels. Therefore, the sand space required in the lower end of the cavern is 8% of the capacity or 80,000 barrels. By allowing 200 vertical feet for this 80,000 barrels capacity to be leached, the total drilled depth is 3,400 plus 200 or 3,600 feet.

Upon completion of drilling operation the 9 5/8 inch blanket tubing is lowered to 3,400 feet and the 5 1/2 inch brine tubing is lowered to 3,600 feet.

A blanket volume of propane is placed in the annulus formed by the 9 5/8 inch blanket tubing and the 13 3/8 inch salt casing. The volume of propane required should be sufficient to place the lower level of the propane at approximately a 2,500 foot depth. Using equation (2) this depth of propane blanket will cause a pressure of 750 psi at the surface of the blanket annulus.

After a volume of 80,000 plus barrels has been leached between the depths of 3,400 and 3,600 feet, the propane blanket is removed from the blanket annulus. The blanket and brine tubings are raised so the lower ends are at 2,200 feet and 3,375 feet respectively. The blanket annulus is again filled with propane to its total depth. Leaching of the 1,000,000 barrel capacity is then initiated.

When the desired capacity of cavern is leached the brine tubing is removed and the blanket tubing raised so its lower end is above the bottom of the salt casing. A sonar caliper survey is run in the cavern to determine the shape and verify salt leaching calculations. The blanket tubing is then lowered to approximately 2,100 feet and the brine tubing is lowered to 3,375 feet. The cavern is then ready for operational storage of propane.

Table V

ESTIMATED CEMENT REQUIREMENTS

CASING AND HOLE DIAMETER INCHES	DEPTH OF CASING FEET	% WASH OUT ALLOWANCE	ANNULAR CAPACITY CU. FT. PER FT.	SLURRY REQUIRED CU. FT.	CEMENT AND TYPE MIXING WATER
20" - 26"	500'	100%	1.5053	1,505	Common with fresh water
16" - 18-1/2"	1,500'				
(in 20" casing)	500'	0%	0.6248	312	Sulfate resistant with brine water
(in 18-1/2" hole)	1,000'	25%	0.4704	598	
				910	
Bottom Hole Seal (100' of Salt + 100' of Cap Rock)		25%	0.4704	118	Common with brine water
13-3/8" - 15"	1,900'				
(in 16" casing)	1,500'	0%	0.2927	439	Sulfate resistant with brine water
(in 15" hole)	400'	25%	0.2515	126	
				565	
Bottom Hole Seal (400' of salt and	400'	25%	0.2515	126	Common with brine water
100' of 16" Casing fillup)	100'	0%	0.2917	29	
				155	

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