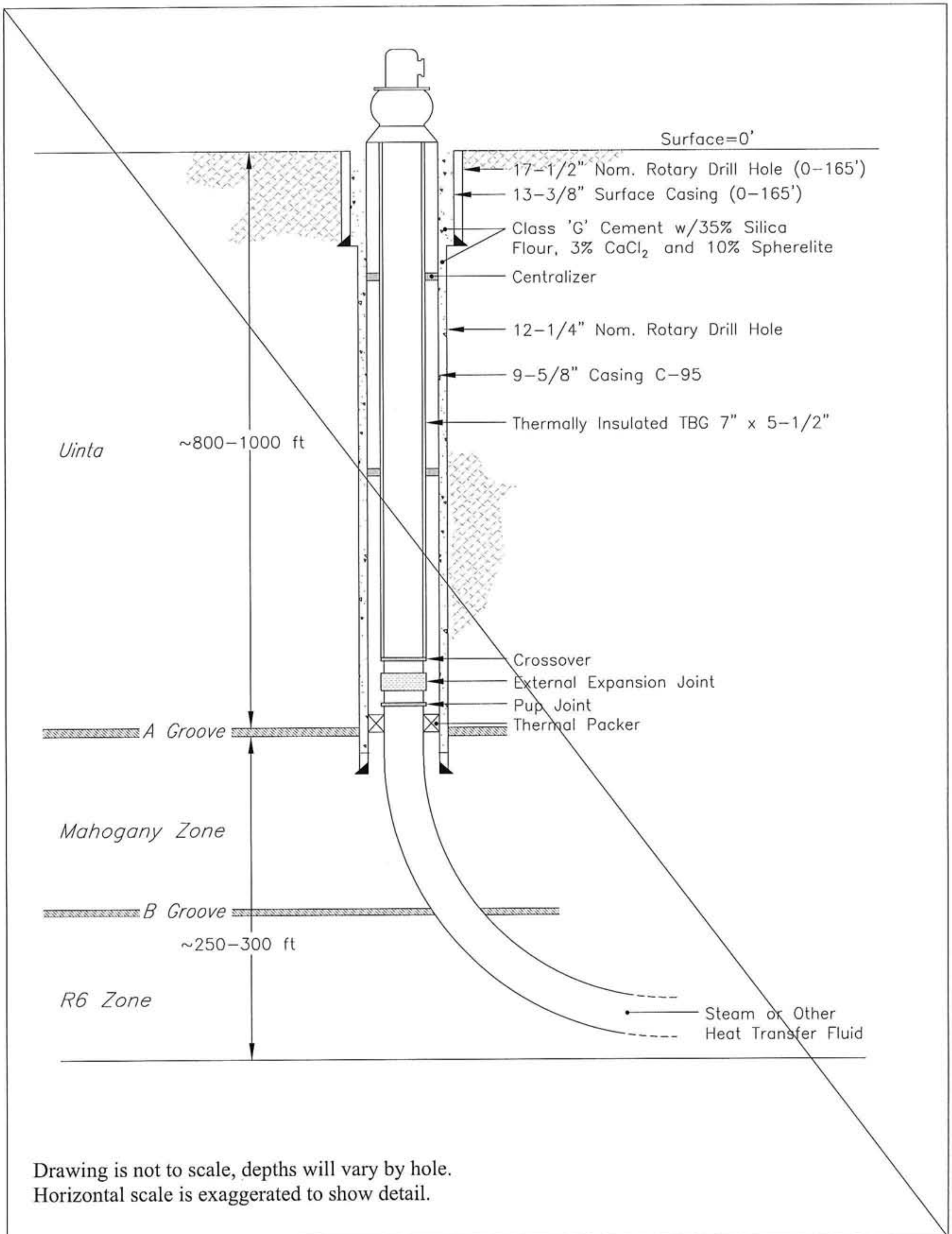
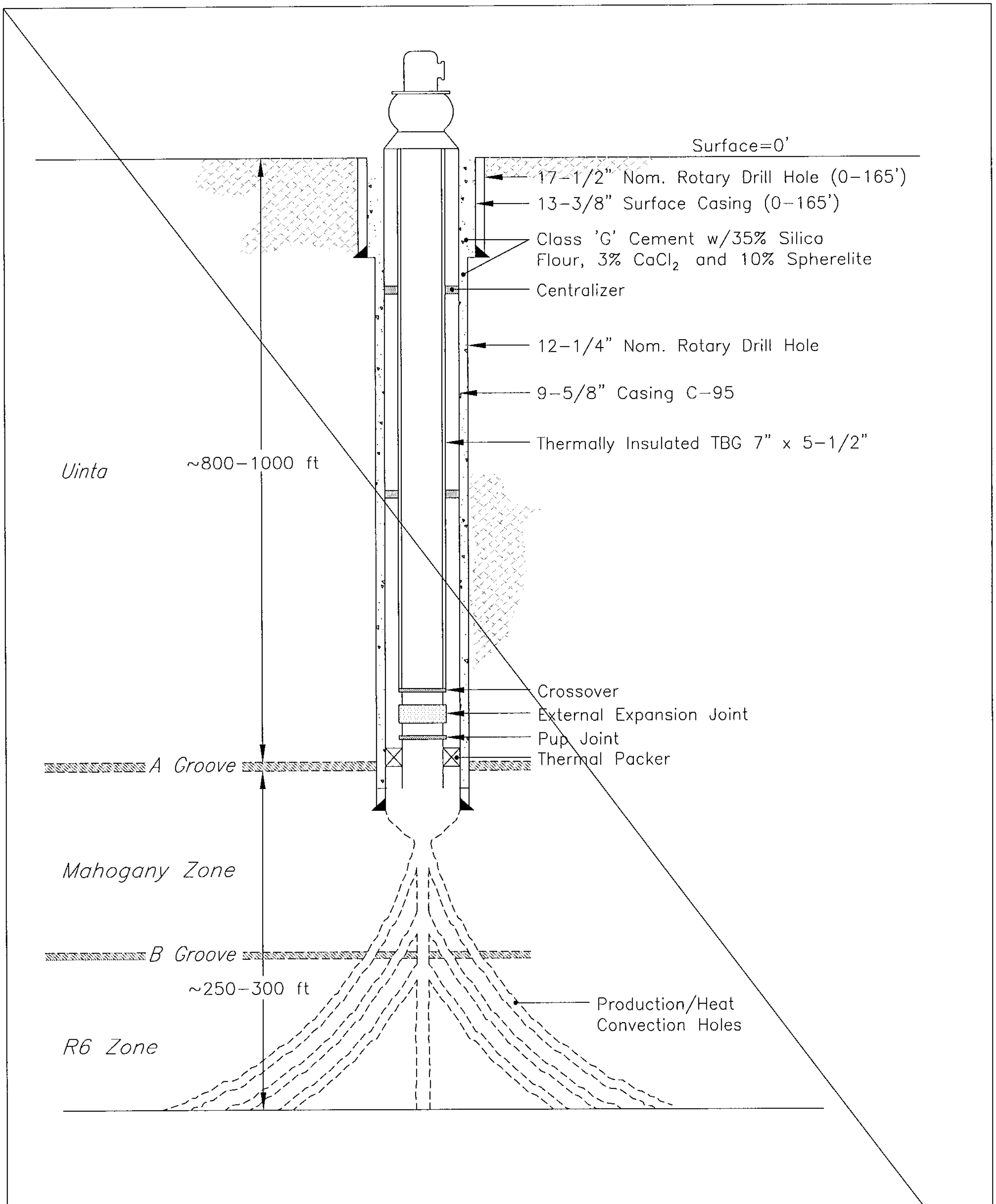
Appendix F
Well Completion Drawings



586-01 EGL Resources [586-01 EGL Mon Wells.dwg Layout: Injection Well):rjl(2-8-2006)

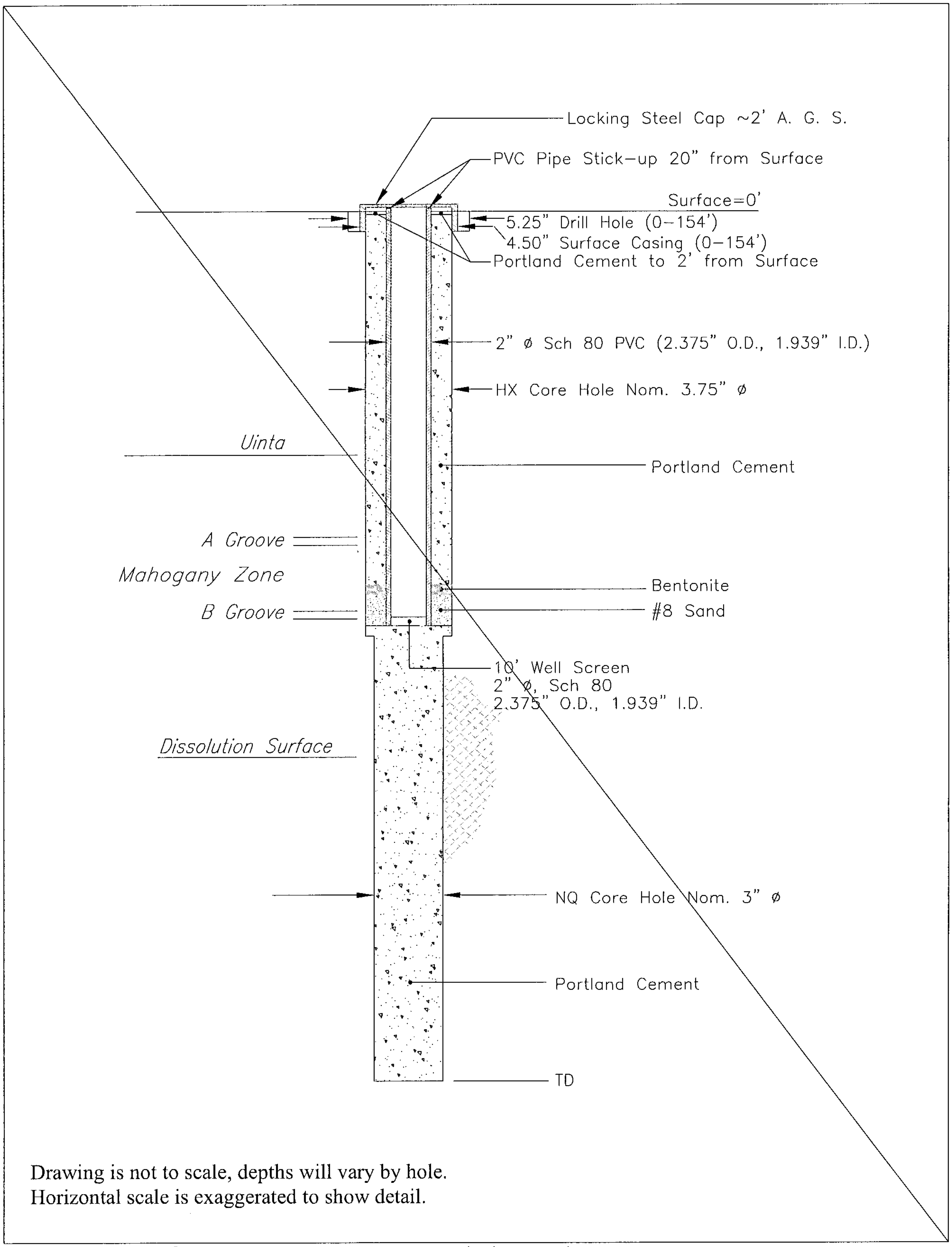
Thermal Heating Well



Drawing is not to scale, depths will vary by hole.
Horizontal scale is exaggerated to show detail.

586-01 EGL Resources [586-01 EGL Mon Wells.dwg Layout: Production):rjl(2-8-2006)

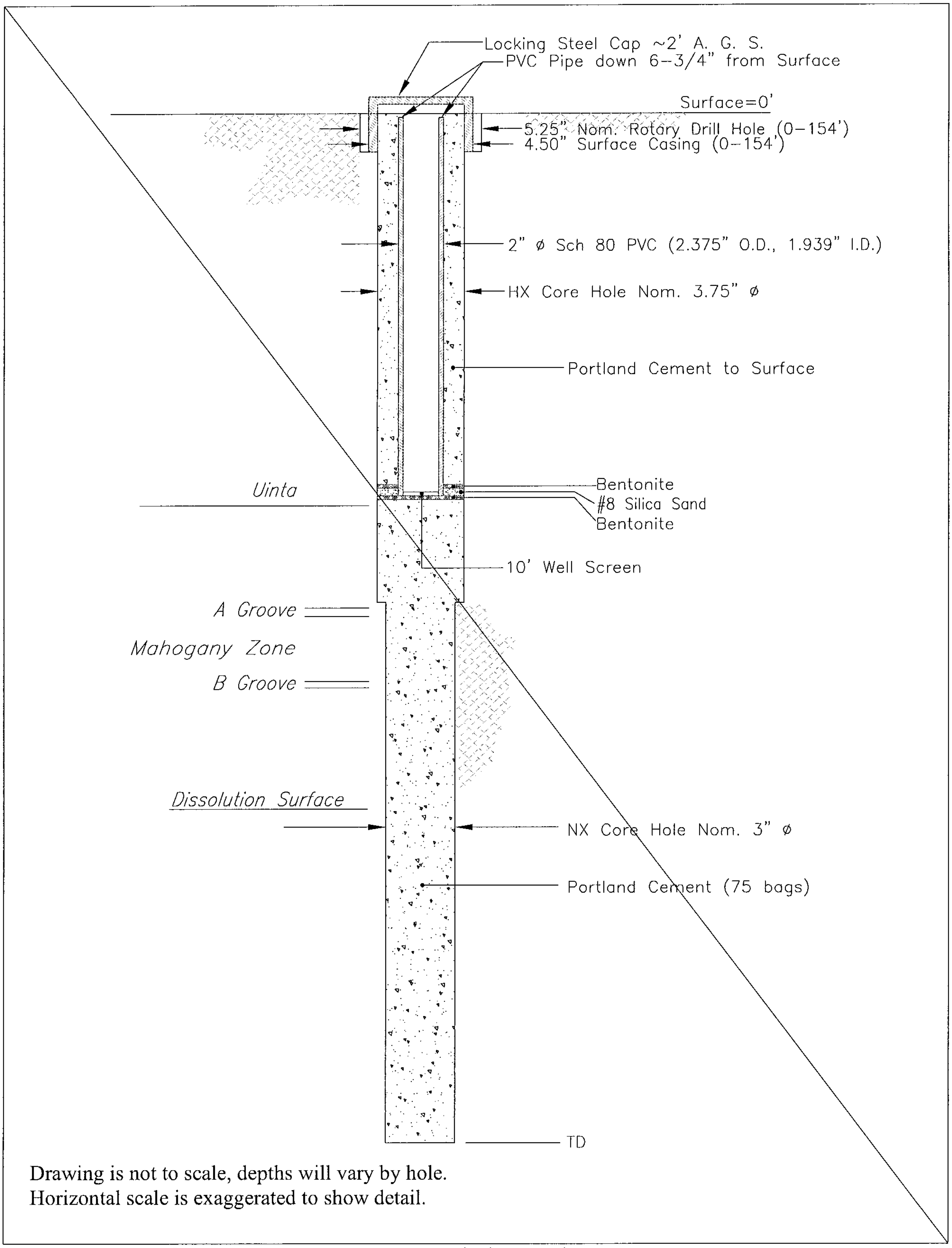
Production Well



Drawing is not to scale, depths will vary by hole.
Horizontal scale is exaggerated to show detail.

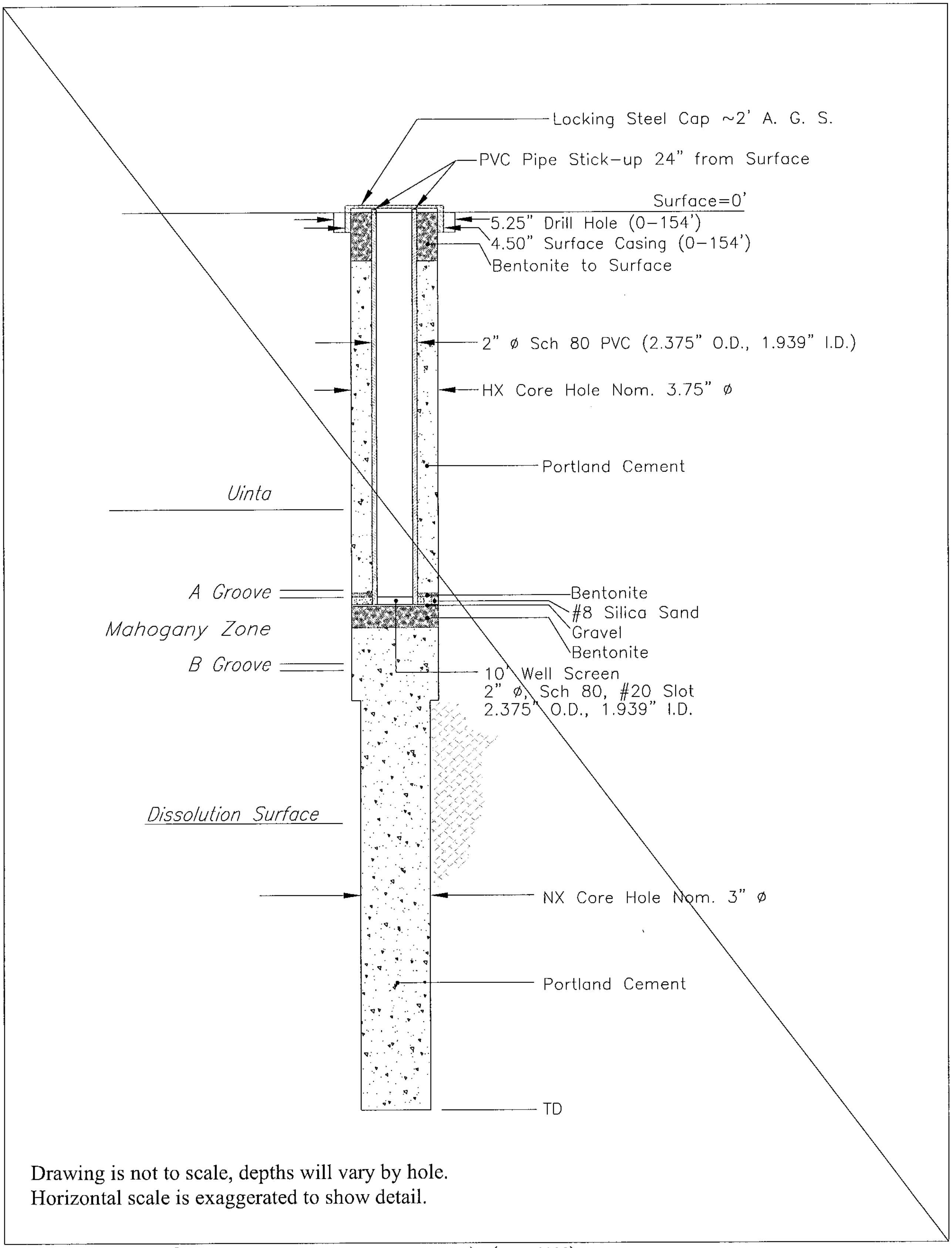
586-01 EGL Resources [586-01 EGL Mon Wells.dwg Layout: Lower):rjl(2-6-2006)

Completion Detail Lower Aquifer Monitoring Well



586-01 EGL Resources [586-01 EGL Mon Wells.dwg Layout: Uinta):rjl(2-7-2006)

Completion Detail Uinta Formation Monitoring Well



586-01 EGL Resources [586-01 EGL Mon Wells.dwg Layout: Upper):rjl(2-7-2006)

Completion Detail Upper Aquifer Monitoring Well

Society of Petroleum Engineers

SPE 55994

Vacuum Jacketed Tubing: Past, Present, and Future

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This paper was prepared for presentation at the 1999 SPE Western Regional Meeting held in Anchorage, Alaska, 26–28 May 1999.

Abstract

Vacuum jacketed tubing has been used for many years in steam flood EOR applications and protection of permafrost. The product more recently has been applied to production tubing for hydrate and paraffin prevention. The paper will discuss case histories and economics of the various past uses of vacuum jacketed pipe along with potential new applications such as vacuum jacketed pipelines. We believe that the superior insulating ability of vacuum jacketed tubing could be an integral part of the rejuvenation of Alaska's oil production in both steam flood and production tubing applications.

Background

Downhole vacuum jacketed pipe was developed in the 1980's to meet the needs of steam injection and permafrost applications. Other types of insulated pipe in pipe systems had been tried, but vacuum insulation, similar to that used for cryogenic and space applications, provided a vastly superior insulating product while minimizing the insulation thickness. This new product allowed more heat to be delivered to the target formation for steam injection enhanced recovery of heavy oil. In far north operations, it prevented the unwanted thawing of the permafrost.

More recently, vacuum jacketed tubing has been used as downhole production tubing in subsea applications to prevent the formation of hydrates and paraffins due to oil cooling. Hydrate and paraffin formation can quickly stop production from a subsea well and cause a costly unplanned shut-in. It provides excellent thermal insulation with a minimal thickness which help keep casing sizes to a minimum.

The future of vacuum jacketed pipe is in subsea flowlines. Paraffin and hydrates are an ongoing concern because of cold water temperature and long tie-back distances. Once again vacuum jacketed pipe has a clear advantage over other insulating materials because of vacuum's superior insulating capabilities with a minimal gap between the carrier and jacket pipe.

Product Description

Vacuum jacketed pipe is a pipe inside a pipe insulated system (See Figure 1). The carrier pipe is covered with radiation barriers and fitted with spacers at regular intervals. The carrier pipe is inserted inside the jacket pipe, and the pipe ends are welded together, forming a thin annular space between the two pipes. The annular space is then evacuated through a port in the jacket pipe using a mechanical vacuum pump. To further improve the vacuum level in the annular space the pipe assembly is heated to drive off moisture and other gases present on and in the pipe materials and radiation barriers. When the appropriate vacuum level is achieved the port in the jacket pipe is plugged and seal welded closed. To insure that gases present in the pipe or hydrogen gas generated from corrosion does not reduce the vacuum level (and therefore the insulating properties) a gas absorptive material, or chemical pump, is installed in the annular space during assembly.

The key benefit of vacuum insulated tubing is superior thermal insulation, principally due to the vacuum in the annulus space between the two pipes. Vacuum insulation has long been used in critical application such as cryogenics. Overall heat transfer coefficients or U-values of 0.06 to 0.3 BTU/(hr-ft^2-°F) can be achieved with vacuum jacketed pipe depending on the spacing between connection points. As a comparison other types of insulated pipe-in-pipe systems have U-values in the range of 0.3-1 BTU/(hr-ft^2-°F).

Three distinct areas of heat loss from vacuum insulated tubing are: main body, centralizers, and connection points (bulkheads or thread area). When the pressure level is reduced below a certain level, heat transfer due to convection and conduction is nearly eliminated. For the main body heat loss, radiation becomes the primary heat transfer mode. Reflective foil, radiation barriers cover the carrier pipe to minimize heat loss due to radiation. Centralizers are welded to the carrier pipe at regular intervals. This allows assembly of the two pipes and maintains the annular gap between the pipes during service. The centralizers allow conduction of heat directly from the carrrier to the jacket pipe, and because of this can be 20-30% of the total heat loss of the vacuum jacketed pipe. The number of centralizers along the length of the pipe are minimized for each application to reduce heat loss. By far the largest portion of the heat loss from vacuum jacketed pipe is from the connection points. At these locations where the vacuum insulated space is interrupted, heat loss occurs from both the short non-vacuum area and conduction of heat from the carrier to jacket pipe through the connection weld. To reduce heat loss in these areas secondary insulation such as external sleeves are used. Still heat loss from the connection area can be over 50% of the total heat loss depending on the application.

EOR Steam Injection

One method of producing heavy oil fields is to lower the oil viscosity by steam injection. Steam injection has been used extensively in Canada and elsewhere around the world to enhance the recovery of heavy crude oils. A typical Steam Assisted Gravity Drain (SAGD) well setup is shown in Figure 2. Horizontal steam injection wells are drilled to direct the steam to the target reservoir. The injected steam forms a steam chamber in the reservoir. Lower viscosity condensate of the steam and oil drains down and is produced through the lower tubing string. Formation of the steam chamber and first oil production can take several weeks to several months depending on the reservoir. One key to profitability of these projects is minimizing the time from initial investment to first oil production. By insulating the steam injection string 30-40% more BTU's are directed to the target formation in the same amount of time.

The decision to use vacuum jacketed pipe is a tug of war between increased capital costs and reduction of the time period from investment to first oil production. Figure 3 shows a typical example. In the example, completion costs were $0.8 million for the bare pipe completion versus $0.9 million when using vacuum insulated tubing. In both cases the well is assumed to produce 300 barrels per day of heavy crude over 3 years. However, when using vacuum jacketed pipe the initial steaming time to reach first oil is reduced by 1 month compared to a bare pipe completion. In the current low oil price environment EOR of heavy oil has a reduced need for vacuum jacketed pipe. However, as the steam injection application has diminished other applications in the oil industry, particularly in offshore projects, have arisen.

Downhole Production Tubing

Build up of paraffins, asphaltenes and hydrates can significantly reduce or stop flow of a production well. This problem is particularly menacing in subsea completions where the tree is located on the ocean floor and a floating rig is required for intervention work. In a typical Gulf of Mexico (GOM) application (Shown in Figure 4) the paraffin content can be very high. Bottom hole oil temperatures of 190°F with over 15% paraffin and cloud point temperatures of 135°F have been encountered. As the oil flows up the tubing the oil temperature decreases due to both heat loss to the formation and pressure drop of the oil. For the example shown, in lower flow rate situations the wellhead temperature would be a mere 115°F, when using a typical bare production tubing completion. Methanol injection can be used maintain the paraffin in solution even at lower temperatures. However, methanol injection represents a continuous additional operating expense over the entire life of the well. Completing the well with 8,000 feet of vacuum jacket pipe from the well head down caused the wellhead temperature to be 160°F, and therefore drastically reduced the need for methanol injection.

Vacuum Jacketed Flowlines

Similar problems created by paraffins, asphaltenes and hydrates can occur in subsea flowlines. Cold seawater temperatures along with long tie-back distances can lower flowing temperatures below the cloud point and hydrate formation temperature. Chemical injection to prevent paraffins and hydrates from coming out of solution can be used, but again add an ongoing increase in operating costs. Another option: pigging of the flowline requires additional well shut-ins and therefore lost revenue. Thermal insulation of the flowline allows a passive control to the problem which can reduce the need and cost for active intervention such as chemical injection or pigging. To date several pipe-in-pipe systems have been installed using various insulating materials such as foam and glass beads.

The key benefit of vacuum jacketed flowlines versus other pipe-in-pipe insulation systems is superior insulating performance with a reduced insulation thickness. Many aspects of the cost of any pipe in pipe system will be the same. Inner pipe, insulation, and assembly costs will be similar for all systems. However, vacuum insulation allows a much smaller gap to produce the same thermal insulation performance. For example a 6" ID flowline using a typical foam insulation might require a 10-3/4" outer jacket for a U value of 0.25 BTU/(hr-ft^2-°F). In comparison, a vacuum insulated flowline would use an 8-5/8" outer jacket for a U-value of 0.06-0.1 BTU/(hr-ft^2-°F) (See Figure 5). The smaller OD of the vacuum jacketed pipe also requires thinner wall thickness for collapse resistance. Particularly in deep water applications this can significantly reduce the cost of outer jacket pipe (See Figure 6).

Another benefit of the smaller outer jacket pipe size is reduced installation costs. Pipe-in-pipe flowlines can be installed in several different ways: S-lay, J-lay, and reel-lay. In all cases minimizing the time spent on the lay barge is critical because of the large cost involved. Because of the smaller jacket pipe, welding of pipe section on a S or J-lay barge would be reduced. For the 6" ID flowline it could mean a 10-20 minute reduction in the on barge weld time required per joint. With the cost of a lay barge at $75-100 per minute this can quickly become a significant cost reduction. In the case of reel lay welding costs when spooling the pipe would be reduced and larger quantities of pipe could be handled on one reel.

Conclusion

Vacuum jacketed pipe though originally developed for steam injection EOR of heavy crude oil has found many other applications in the oil industry. Vacuum jacketed pipe has the key property of providing a superior insulating product while minimizing the insulation thickness. This has opened up new applications in flow assurance for downhole production tubing and subsea flowlines. These superior thermal properties make vacuum jacketed pipe the lowest overall cost solution to problems.

Vaccum Insulated Flowline

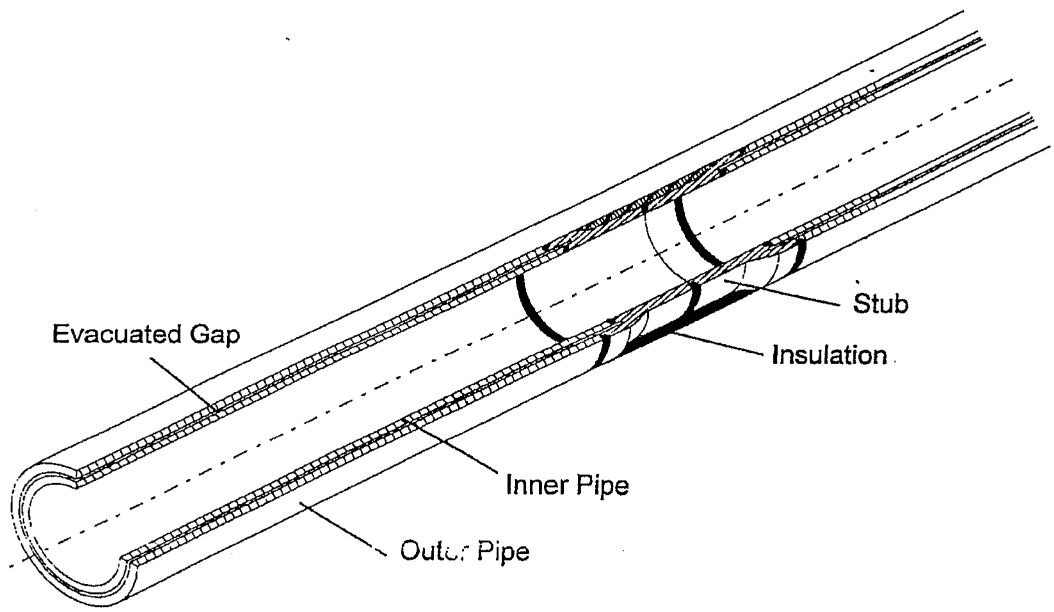


Figure 1

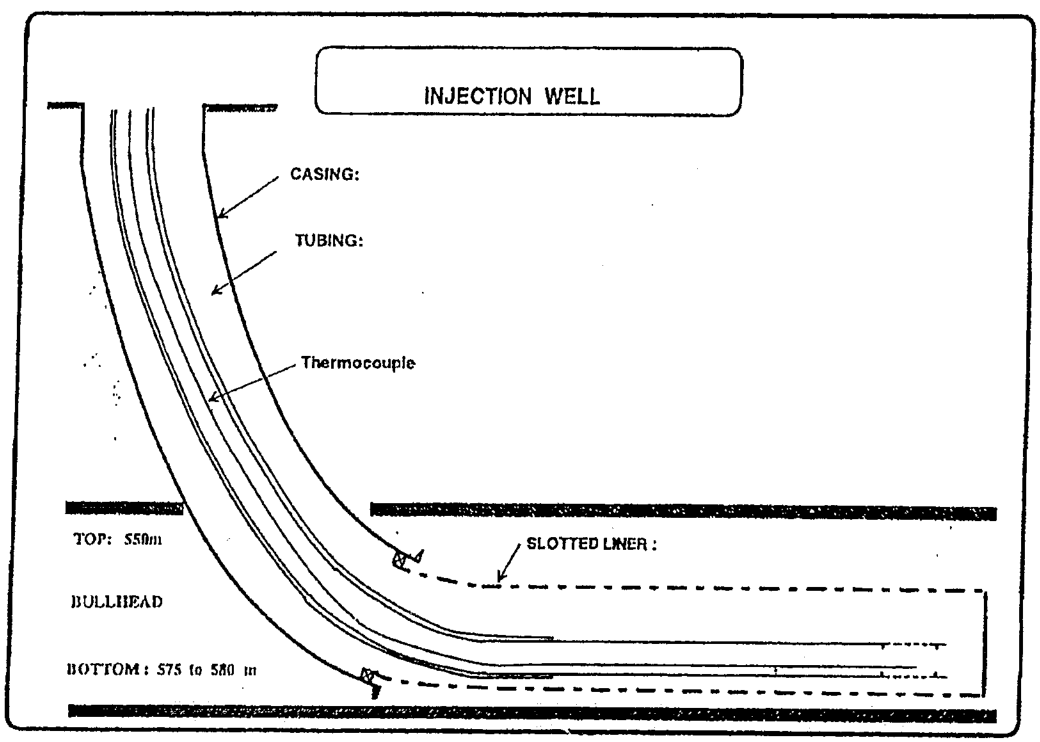
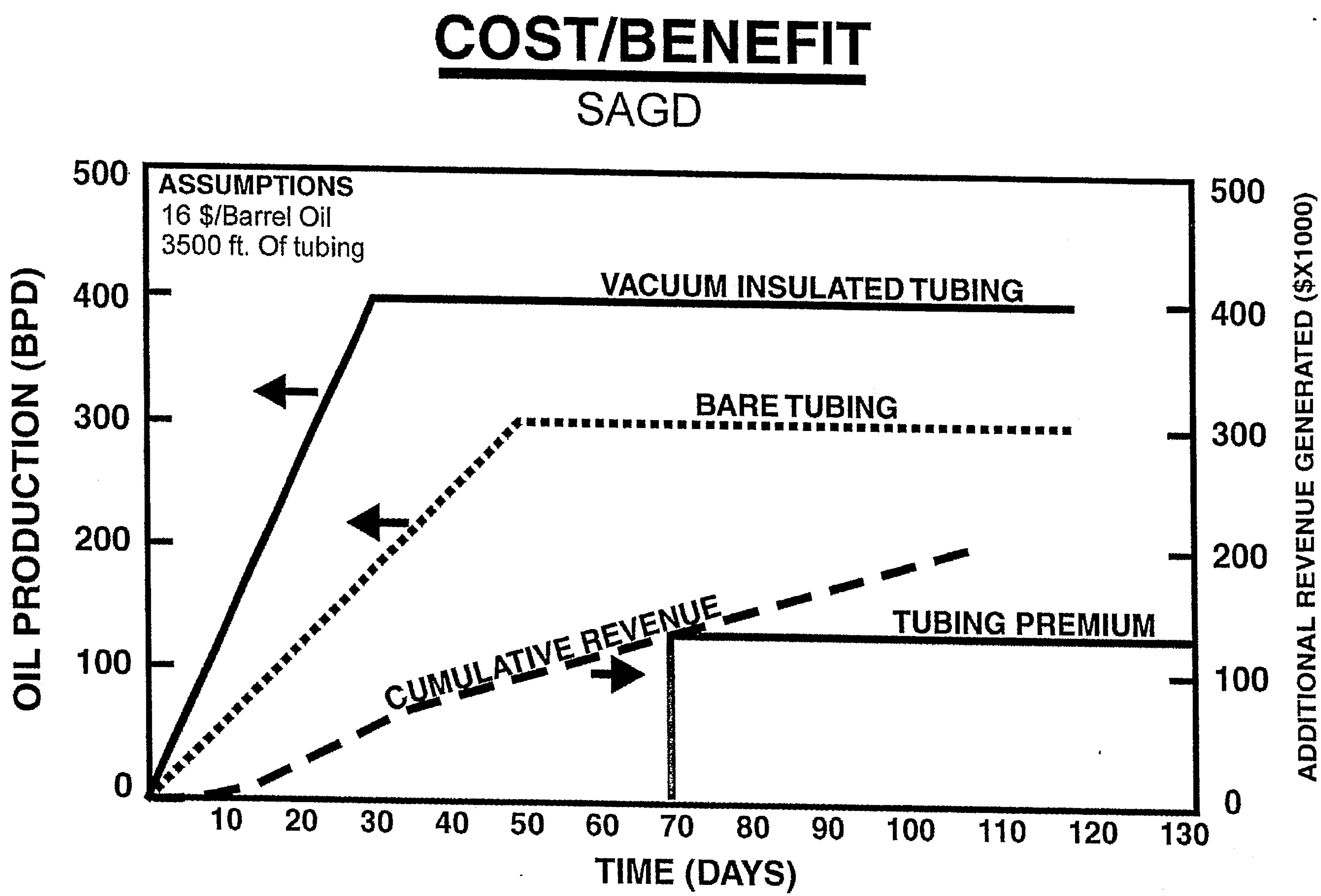


Figure 2



COST/BENEFIT
SAGD
ASSUMPTIONS
16 $/Barrel Oil
3500 ft. Of tubing
VACUUM INSULATED TUBING
BARE TUBING
CUMULATIVE REVENUE
TUBING PREMIUM
OIL PRODUCTION (BPD)
0
100
200
300
400
500
TIME (DAYS)
10
20
30
40
50
60
70
80
90
100
110
120
130
ADDITIONAL REVENUE GENERATED ($X1000)

Figure 3

TYPICAL SUB-SEA COMPLETION

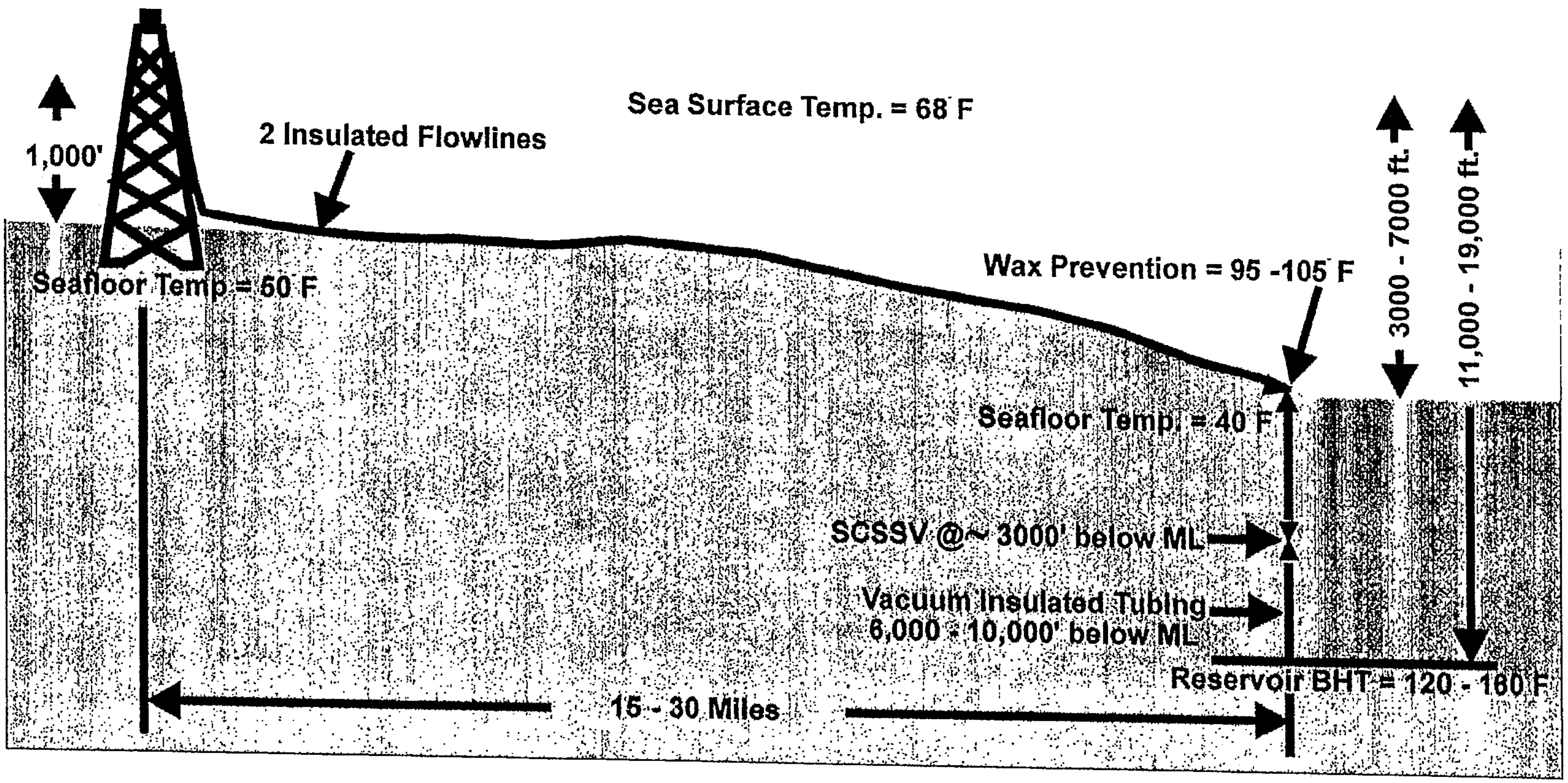


Figure 4

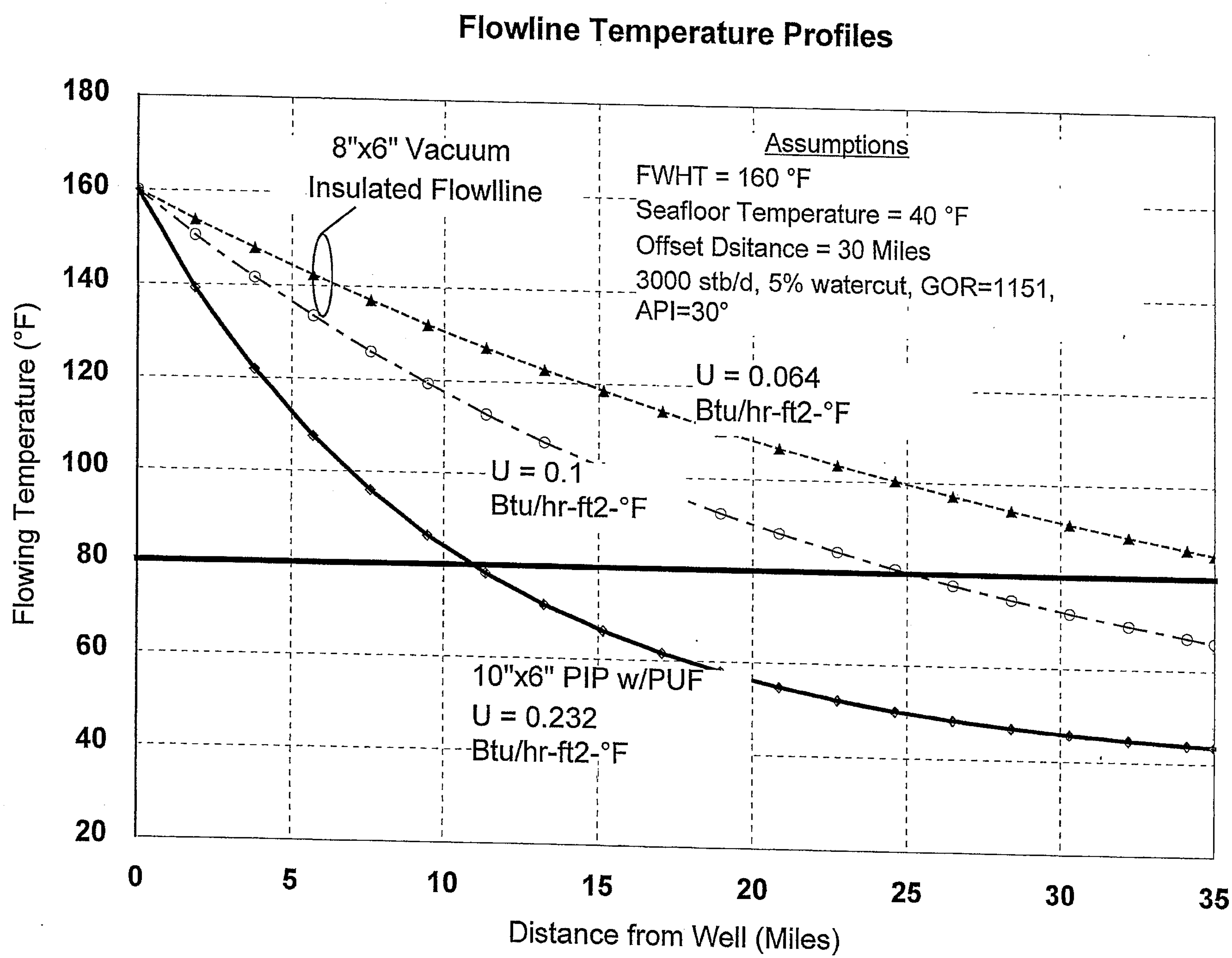

Flowline Temperature Profiles
180
160
140
120
100
80
60
40
20
Flowing Temperature (°F)
0
5
10
15
20
25
30
35
Distance from Well (Miles)
8"x6" Vacuum
Insulated Flowlline
Assumptions
FWHT = 160 °F
Seafloor Temperature = 40 °F
Offset Dsitance = 30 Miles
3000 stb/d, 5% watercut, GOR=1151,
API=30°
U = 0.064
Btu/hr-ft2-°F
U = 0.1
Btu/hr-ft2-°F
10"x6" PIP w/PUF
U = 0.232
Btu/hr-ft2-°F

Figure 5

Pipe-in-Pipe Flowline
Outer Jacket Size

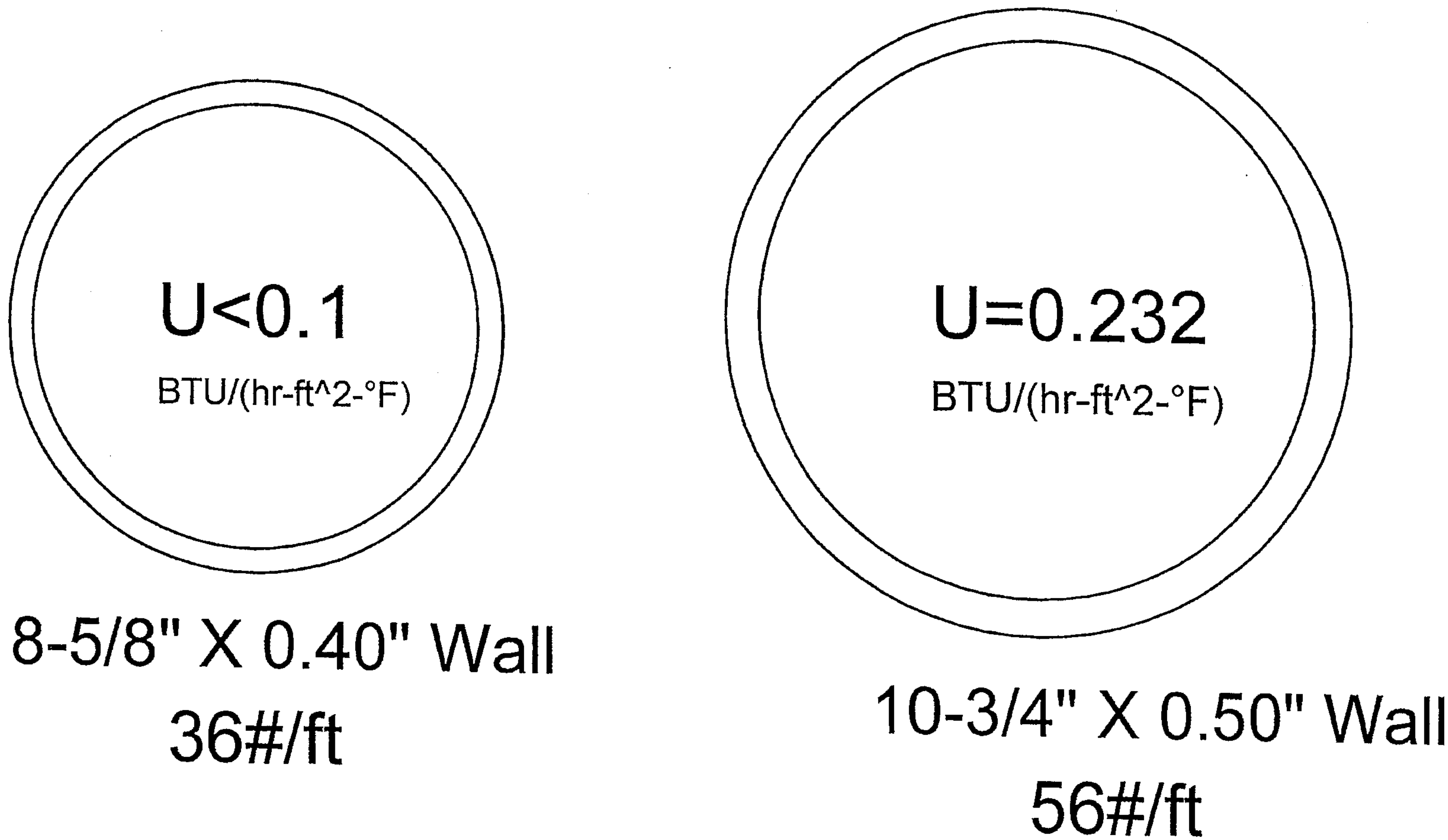


Figure 6

SPE

Society of Petroleum Engine

SPE 18810

The Use of Insulated Tubulars in Thermal Projects

by A.R. Kutzak and D.W. Gunn, Mobil Oil Canada

This paper was prepared for presentation at the SPE California Regional Meeting held in Bakersfield, California, April 5–7, 1989.

Many enhanced oil recovery steam projects are underway in Canadian heavy oil properties. Various well completion designs are employed to optimize the recovery and overall economic performance of these projects. This paper discusses both economic and design considerations regarding the selection of insulated tubulars as well as operational experience in some Canadian heavy oil recovery operations.

INTRODUCTION

Heavy Oil steam projects located in Alberta and Saskatchewan, Canada include huff/puff stimulations on single wells and cyclic steam floods. Differing surface facility, well geometry, depth, and reservoir requirements result in innovative steam injection designs. Although steam injection down bare unpacked tubing and/or the tubing/casing annulus is common, technical and economic considerations frequently lead to more energy efficient designs. Some of these designs use insulated tubulars to reduce heat transfer from the steam to the wellbore. Field testing of insulated tubulars, along with testing of completion variations designed to reduce overall operating costs is being done by a few operators. These tests answer some of the questions regarding life of the tubulars, operating costs and their effectiveness in improving casing life or production response.

Well depths vary from 1150 feet (520m) to 1800 feet (350m) true vertical depth, with actual lengths to 2000 ft. (660m) in deviated wells. Well geometries include vertical, directional and slant wellbores.

References and figures at end of paper.

Wells are completed with either N-80 L-80, 7 inch (177.8 mm) O.D. producti casing, and thermal cement to surfac Figure 1 illustrates a typical sla producing well.

Oil gravities vary from 10 to 14 degre API, with viscosities of 1000 to 100,0 centipoises (MPa's) at reservo temperatures. Typical steam injection rat are 1200 barrels/day (190 m3/d) cold wat equivalent, at 1000 - 2000 psia (7 - 14 MP pressure, and generator qualities of 80%.

Early stimulations injected steam down t casing/tubing annulus. Later ste injection down bare tubing, with rods a pump intact became commonplace. Als stimulation tests through insulated tubi were conducted in isolated location Subsequently insulated tubing replaced ba tubing in some steam stimulations, with t objective of improving production whi reducing casing failure potential.

BASIS FOR USING INSULATED TUBING

Insulated tubulars, when used for ste injection, offer the following benefits:

- Reduced wellbore heat losses.
- Reduced casing problems.

Their use can improve project economics a production response.

Reduced Heat Losses

Insulated tubulars improve the efficiency of heat injection into the reservoir, by reducing wellbore heat losses. These heat losses occur due to three heat transfer mechanisms - conduction, radiation and convection.

The heat loss relationship, as defined by Willhite, is [1]:

$$Q = U\,A\,\Delta T \quad\ldots\ldots\ldots\ldots (1)$$

Commercial computer programs based on heat transfer theory, and industry papers [1] [2] offer heat loss calculation methods. However, these calculations require corrections for well geometry [3], factors such as refluxing [4], and insulation deterioration. The U value of insulated tubing may change over the life of the tubing, depending on insulation degradation. Heat losses also depend on well configuration, deviation, tubing centralization, tubing size, tubing length, steam properties, and injection rate.

Prevention Of Casing Problems

Steam injection down wells with poor cement bonding, inadequate or unsupported casing leads to casing failure. The cause of the failure are excessive casing temperature variations.

Stresses created by thermal expansion are indicated in the relationship [5]:

$$S = \alpha(\Delta T)\,E \quad\ldots\ldots\ldots\ldots (2)$$

Insulated tubulars reduce casing temperature changes, maintaining stresses below the failure level. This level is based on the following:
- casing yield strength
- casing tensile strength
- critical buckling strength

The critical criteria depends on expected cyclic life with elastic deformation, plastic deformation, or the maximum unsupported casing length. [6]

Casing temperature reductions occur due to less heat transfer through insulated tubing than bare tubing. The casing temperature is proportional to the overall heat transfer coefficient U.

Economic Benefits

Economic benefits of insulated tubing are attributable to reduced heat losses.

However, offsetting these benefits are capital cost of the insulated tubing, running costs and tubular/insulation life. Minimizing tubular handling results in cost savings. Actual benefits are project specific.

Ideally, reduced steam injection requirements due to heat loss reductions result in less capital and operating costs.

Potential capital cost reductions include:
- smaller steam generator rquirements (proportional to the reduced heat losses).
- reduced source water requirements (proportional to the reduced heat losses).
- elimination or reduction of well replacement costs, dependent on casing failure rates.

Potential operating cost reductions include:
- reduced steam generator operating time.
- lower fluid lfting requirements.
- reduced water handling.
- less treating requirements.
- reduced fuel gas requirements.
- less remedial servicing to maintain cement integrity for zonal isolation of "wet" zones.

Improved oil recovery due to the higher quality steam is possible.

DESIGN CONSIDERATIONS

Completion design, steam temperature and economic restraints dictate insulated tubing design. Inspections are necessary before, during and after construction of the tubulars. These include x-raying of welds, metal composition analysis, hardness testing, thread inspection and insulation testing.

Figure 2 illustrates an insulated tubing joint.

Size

Various tubing sizes are available. Large diameter inner strings permit rod pumping and logging operations. However, this also results in reduced insulation thickness and hence either less insulating value or requiring more expensive insulation systems. Vacuum insulation with gas sorbing agents provide an effective insulation system, but at greater cost than blanket type systems.

Insulating Value

Insulation levels, determined from thermal conductivity ("k" value) typically are 0.01 Btu-ft./[hr-ft.^{2} -^{o}F] (.02 W/m-C) for vacuum systems and 0.03 Btu/ft./[hr-ft.^{2} -^{o}F] (:07 W/m-C) for gas backfilled/blanket systems. However, insulation degrades in time due to tubular/insulation outgassing and hydrogen permeation. [7]

Gas sorption materials (getters) placed in the vacuum reduce insulation degradation by absorbing gases, particularly hydrogen and carbon monoxide. Hydrogen as H+, a by-product of products such as H_2S, CO_2 and O_2 permeates the steel and recombines to form H_2. This is very thermally active and transfers heat readily from the inner to the outer tube.

Another factor affecting heat loss is refluxing within the tubing/casing annulus. The phenomena occurs due to incomplete removal of water from the annulus, with some of the water remaining as refluxing steam. This increases heat losses significantly. Methods of minimizing refluxing have been discussed in technical papers [4], and include the following industry practices:

- Removing annular water before steam injection.
- Insulating heated surfaces (eg. expansion joints, etc.) to prevent vaporization.
- Continuously maintaining a gas blanket, such as nitrogen, in the casing annulus.

Using long tubing joints (i.e. less collars), insulating collars, evacuating annulii, centralizing tubing and optimizing expansion joint placement also reduce refluxing. The limiting factor is the economic benefit obtained.

Construction

Important mechanical parameters include welding, prestressing, centralization and thread cutting. Adequate strength, ductility and grade tubulars are essential.

Welding the inner tube to the outer tube provides mechanical and sealing integrity of the insulating media. Weld placement and follow-up heat treating affect the thread profile.

Prestressing the inner tube compensates for thermal stress differences between it and the outer tube. During steam injection the high temperature inner tube tends to expand more than the lower temperature outer tube. Resultant compressive loads on the inner tube, without adequate inner tubing prestressing could fail the tubing. Required prestress depends on the relative tubing sizes as well as expected temperature variations. Insulated tubing used for both injection and production requires design flexibility allowing for the outer string being both hotter and cooler than the inner string.

The threads must provide a satisfactory mechanical connection seal to prevent steam leakage. Use of a strong connection with a sealing element accomplishes this purpose.

EXPERIENCE WITH INSULATED TUBULARS

Initially, completions used insulated tubin with blanket/gas backfilled insulatio systems and internal bellows. Subsequen designs had similar insulating systems, bu used prestressed inner tubing instead o bellows. Deployment was in wells wit suspect cement jobs. Later uses include reducing steamer and propane fuel costs o remote locations with small or rental stea generators. Gradually use of the tubular extended to other applications.

Completions in wells with high san production histories and suspecte unsupported casing used insulated tubing t prevent casing buckling. Packers were se immediately above the sand production zone.

Insulated tubing most recently obtained ha vacuum insulation systems and large diameter inner tubing. Design allowed fo production up the tubing and the tubing casing annulus. The tubing was used i vertical, directional and slant wells.

Types of Insulated Tubing Used

Three types of insulated tubing were used.

Fiber Blanket/Krypton Backfilled Insulatin System - purchased 1980.
- internal bellows
- nominal "k" value: 0.02 Btu-ft./[hr.-ft.^{2} -^{o}F] (0.3 W/m-C).
- Inner-Outer tubing diameters: 2.375 in. - 4.5 in. (60.3mm - 114.3 mm)
- Tubing Length - range 3.

Ceramic Fiber/Argon Backfilled Insulatin System - purchased 1983 and 1985.
- Nominal "k" value: 0.02 Btu-ft./[hr.-ft.^{2} -^{o}F] (.03 Wm-C)
- Inner-Outer tubing diameters: .375 in. - 4.5 in. (60.3mm - 114.3mm)
- Tubing Length - range 2.

Vacuum/"gettered" Insulating System purchased 1988.
- Overall "k" value: 0.01 Btu-ft./[hr.-ft. -^{o}F] (.02 W/m-C).
- Inner-Outer tubing diameters: 3.5 in. - 4.5 in. (88.9mm - 114.3mm)
- Tubing Length - range 2.

Insulated Tubing Completion Designs

Completion designs were dependent on casin strength and location of other zone relative to the zone being steam stimulated Three variations of the insulated tubin string completion design, and reasons fo their use, included:

. Expansion joint immediately above th packer and water in the tubing/casin annulus. This design produced heat losse on non-insulated expansion joints capabl of degrading cement above the steam zone.

. Expansion joint at surface with the annulus blown dry, packer immediately above perforations. The use of this design in old wells with H-40 casing resulted in neglibible boil off and no casing damage. Concern over compressional loads causing packer failure or cork screwing of the tubing limited the design to shallow wells.

. No packer or expansion joint, tubing bottom at perforations. This was the least expensive insulated tubing completion and was used where cement integrity immediately above the steam stimulated zone was unimportant. Adequate strength casing was necessary to prevent casing failure. This design resulted in highest overall heat losses.

Thermal packers had thermo-plastic packing elements and external expansion joints. Previous designs, with internal expansion joints had operational problems, including steam leakage at high pressures. Problems occurred on some packers due to inadequate springs used in the packer setting mechanism. The springs took on a permanent set, thus not functioning properly on packer release. Higher temperature rated springs corrected the problem. Operational problems, related to both setting and removing thermal packers were more common on deviated wells.

Running Procedures

Use of the shorter range 2 length tubing eased handling on slant and small service rigs. This tubing did not bow as much as longer tubing, resulting in lower probability of thread galling due to misalignment, especially with slant rigs. Rig operating times were less with the range 2 length tubing strings.

The critical time when handling insulated tubing was with the tubing and casing hot. Minimizing the risk of failure involved taking the following precautions after steam stimulation:

. Flowed wells back. This allowed well cooling and took advantage of high production rates.

. Pumped hot kill fluid down the tubing after the well died. The tubing was picked up and hung free if the well remained dead.

. Packers were unset and left, allowing element contraction before attempting to pull out of the hole.

Insulation Durability

The thermal conductivity of used insulated tubing was tested in later 1987. Run life exceeded 20 steam stimulations, averaging 30 days per stimulation. Both Blanket/Krypton Gas and Ceramic Blanket/Argon Gas Backfilled insulated tubing systems were tested. Calculated "k" factors resulted from each of the following heat loss measurement techniques:

. heating the inner tube then measuring the heat flux on the outer tube.
. preheating tubing with temperature probes on the inner and outer tubes measuring the temperature decline versus time.
. constant temperature on the inner tube with temperature probes on the outer tube.

The last technique provided calibration of the temperature decline/time technique.

Significant insulation degradation was evident. The tubing tested did not have gas sorption material. Figure 3 illustrates the effect of the "k" value degradation on heat losses.

The most recent insulated tubing purchased was designed for 10 year life. The basis for expected hydrogen permeation rates were analysis of gas samples from annulii of used insulated tubing. The vacuum insulation system allowed for re-insulation of tubing with minimum expenditure.

Thread Life

The insulated tubing used two thread types - modified buttress and modified Atlas - Bradford. These threads were relatively inexpensive to cut, gave good wear life and provided a good seal for high temperature/pressure steam.

The following procedures improved thread life:

- used thermal pipe dope
- moved collars to opposite pin ends when pins became excessively worn
- replaced collars as needed
- kept make-up torques low
- used thread protectors
- chased threads and used modified collars on worn pin ends.

Casing Protection

Case histories included:
- Used insulated tubing on three wells with H-40 grade casing during steam stimulations at 570°F (300°C). The stimulations were successful. Although one well did experience casing problems follow-up analysis showed well servicing procedures caused the problem.

- Steam stimulations caused casing buckling in some wells during steam injection down bare tubing. High sand production rates during previous production had resulted in unsupported casing. Subsequent completion designs with proper packer placement and insulated tubing eliminated the problem.

- Wells with inadequate primary cement jobs were completed with insulated tubing before steam injection.

Casing failures have not occurred on wells steamed through insulated tubing.

CONCLUSIONS

The following may be concluded from this paper:

. Reduced heat losses when injecting through insulated tubing improve steam injection effeciency. Benefits must offset both the original purchase cost and servicing costs.

. Insulated tubing reduces the possibility of casing failure due to thermally induced stresses.

. Well designed completions result in maximum benefit from insulated tubing. To obtain this benefit:

  - Minimize potential for refluxing.
  - employ good operating practices when running tubing.

. New insulation sysems, permit designing for longer insulated tubing life, especially in H2S environments.

. Insulation degradation must be accounted for in heat loss calculations and tubing design.

. Determination of operational requirements before ordering insulated tubing provides correct design. The following are important factors:

  - tubing size (diameter and length)
  - insulation system
  - welding
  - prestressing

. Employment of adequate inspection programs in the manufacture of the thermal tubing ensures all facets meet design criteria.

NOMENCLATURE

A = characteristic surface area, ft.^{2}.
α = casing co-efficient of thermal expansion (approx. 7 * 10^{-6} inches/inch ^{o} F)
E = casing modulus of elasticity, (approx. 29 10^6 lb/sq. in.) - temperature dependent.
Q = heat flow through the wellbore, Btu/hr.
S = stress, lb/in^2
ΔT = characteristic temperature difference, ^{o}F.
U = overall heat transfer co-efficient based c the characteristic surface area A a characteristic temperature difference c Btu/hr sq. ft. ^{o}F.

ACKNOWLEDGEMENT

The authors wish to thank Mobil Oil Canada f permission to present this paper.

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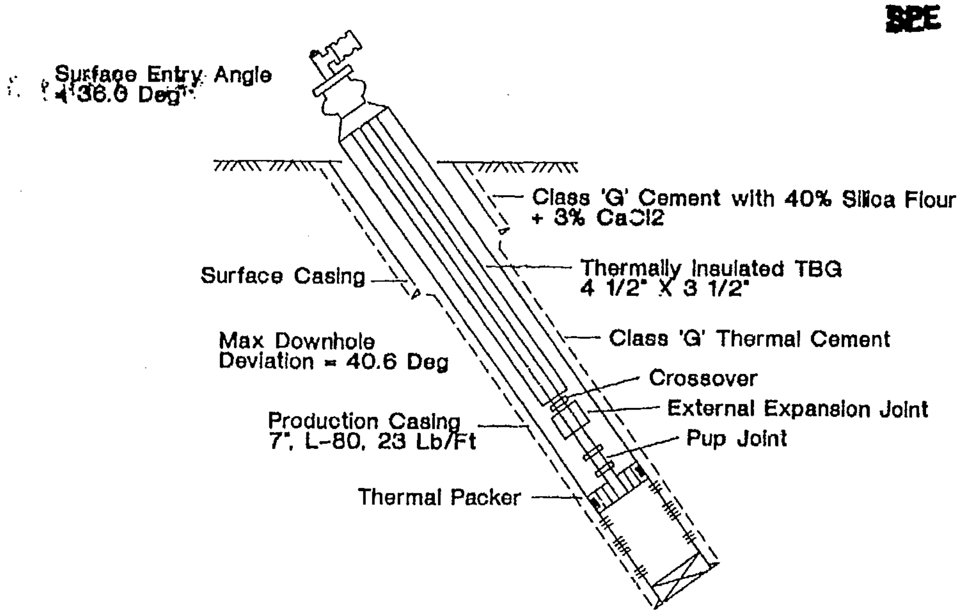

Fig. 1
Slant Well Steaming Configuration

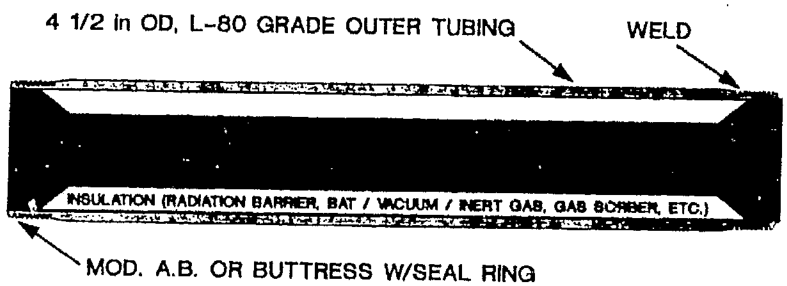

FIG.2 Insulated Tubing Joint

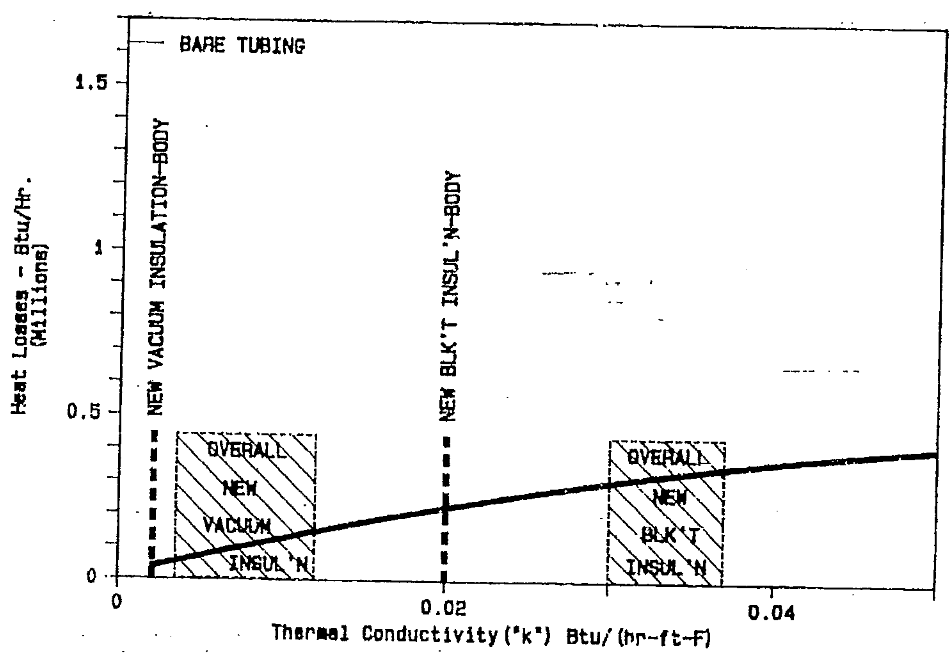

Fig.3 Effect of "k" Value Degradation