Improvements and Advantages of Electrical Submergible Pumps

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Briefly, an electrical, centrifugal, submergible pumping unit consists of a multistage centrifugal pump directly connected through a protector section to a submergible electric motor.

The outside diameter of the entire assembly is such that the unit can be installed in wells completed with standard size casing. There are four main categories—units for wells with casings of 4-1/2 in. O.D., 5-1/2 in. O.D., 6-5/8 in. to 7 in. O.D. and 8-5/8 in. and larger O.D.

In operating position, the unit and cable are suspended on tubing with the motor and pump submerged in the well fluid. The cable is fastened to the outside of the tubing, supplying power to the motor, as shown in Fig. 1. A cross-sectional view of the assembled unit is shown in Fig. 2.

The submergible motor, Fig. 3, is filled with a special dielectric oil to insure proper lubrication and help efficiently transfer internal heat to the produced well fluid. Motors for the various size well casings are available in the following sizes:

Well Size	Maximum Single Motor	Multiple Motors
4-1/2" O.D. Casing	25-1/2 H.P.	127-1/2 H.P.
5-1/2" O.D. Casing	120 H.P.	200 H.P.
6-5/8-7" O.D. Casing	225 H.P.	400 H.P.
8-5/8" O.D. or larger	260 H.P.	520 H.P.

The protector section, Fig. 4, provides a method of equalizing the internal pressure within the motor and the outside submergence pressure. The mechanical seals in this section prevent water from entering the motor.

The multistage, centrifugal pump, Fig. 5, is available in capacities of from 300 BPD to over 20,000 BPD and in lifts, or total head, up to 12,000 ft. Greater lifts can be achieved if the need should arise. A typical pump performance curve is shown on Fig. 6.

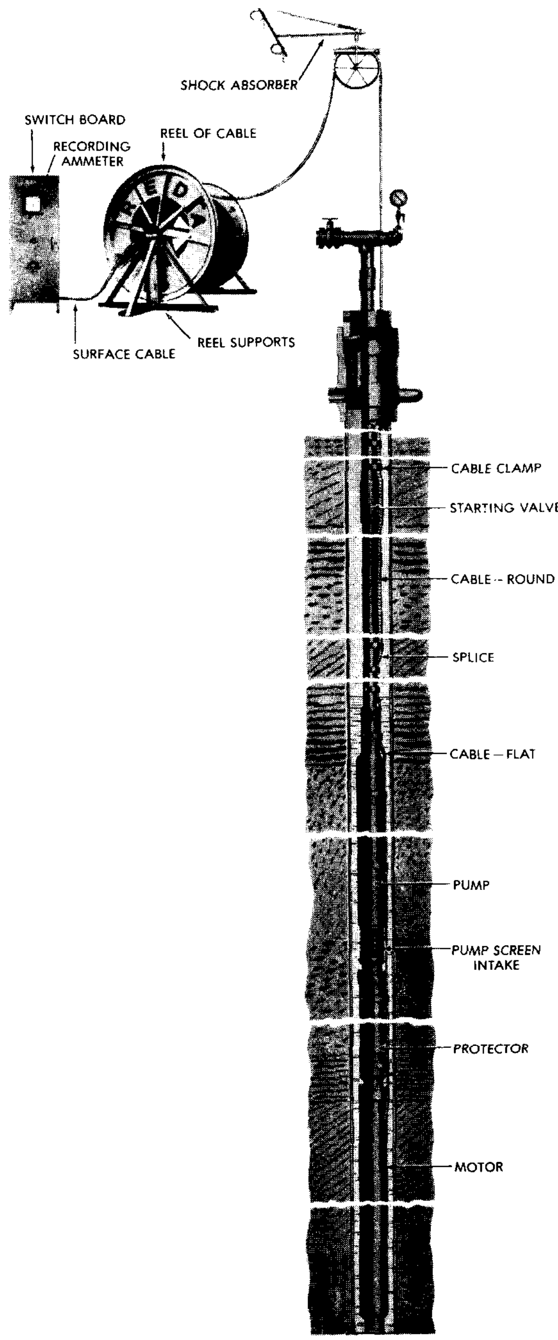


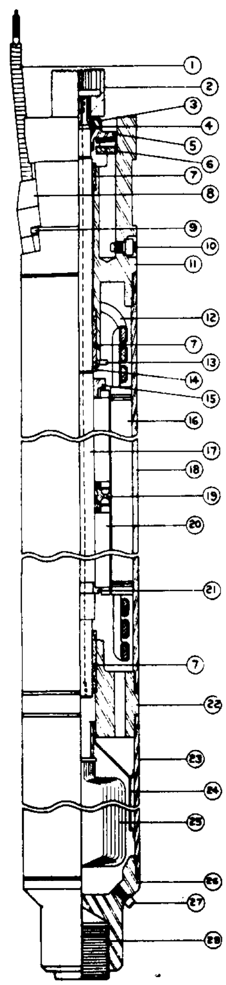
FIGURE 1

Most all pumps are equipped with gas separators, Fig. 7, to provide more efficient pump operation in wells where gas is present in various amounts in the well fluid. This type separator has provided satisfactory pump operation in wells with a gas/fluid ratio of up to 800 to 1000 to one. It has been reported that in some cases the separator has removed about 85 per cent of gas present in the fluid before it enters the pump suction.

The power cable, extending from the surface to the motor, provides power for the motor and comes in many types and sizes. There are four general types of cable, Fig. 8, to meet certain well conditions.

Where well temperatures are below 120-130° F. and low amounts of gas are present, standard cable construction is used. In this the conductor

FUGURE 2



No.	Description
1	Flat Cable
2	Coupling
3	Ring-Retainer
4	Ring-Two Piece
5	Runner-Thrust
6	Bearing-Thrust
7	Bushing
8	Flange-Cable
9	Cap Screw & Lockwasher
10	Valve-Drain & Fill
11	Head
12	Leads-Motor
13	Guard-Lead
14	Washer-Upthrust
15	Nut-Rotor Compression
16	Stator
17	Shaft
18	Housing
19	Bearing-Rotor
20	Rotor
21	Ring-Two Piece
22	Support-Bearing
23	Housing-Filter
24	Jacket-Heat Exchanger
25	Bag-Filter
26	Base
27	Plug-Vent
28	Plug-Pipe

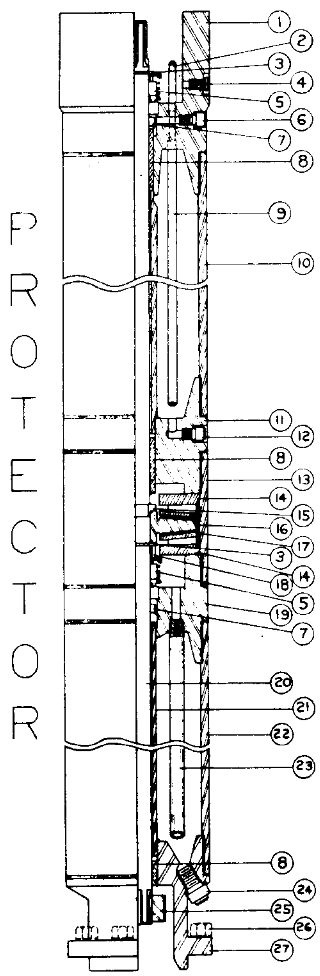
FIGURE 3

insulation is butyl rubber with an oil, water and gas-resistant jacket, all encased in interlocking steel armor.

For wells with temperatures up to 180° F. and a greater amount of gas, a special jacket or covering is put over the conductor insulation with an oil and water-resistant jacket over the conductors, encased in an interlocking steel armor. Where well temperatures over 180° F. are encountered and gas is present in considerable amounts, a high temperature ethylene-propylene rubber insulation is used on the conductors with a lead sheath to protect the insulation from the oil and gas present in the well. This is of a flat configuration but, again, encased in a spirally wound steel armor. Other construction and insulations, as well as conductor materials, are available.

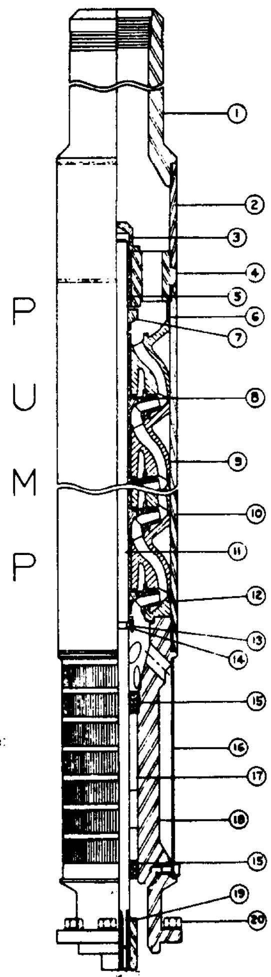
Extending from the main power cable from a point above the pump to the motor is a cable extension with three conductors in parallel of a minimum thickness to allow the cable to pass between the pump and protector section, and inside the casing. This arrangement allows for the maximum diameter of the pump and protector consistent with the size casing in which the unit is being installed.

The surface controls or switchboards used to control the operation of the unit in the well can be of simple design which would manually start and stop the pump, or the fully automatic type, depending on what is desired. They are all equipped with overload protection while others have underload protection with automatic restart after a certain amount of delay after shutting down. Recording ammeters are generally



No.	Description
1	Head
2	Tube-Breather
3	Ring-Snap
4	Valve-Relief
5	Seal
6	Plug-Vent
7	Shedder
8	Bushing
9	Tube
10	Housing
11	Body-Bushing
12	Valve-Drain
13	Housing-Bearing
14	Bearing-Thrust
15	Ring-Two Piece
16	Runner-Thrust
17	Spacer-Bearing
18	Spacer-Seal
19	Body-Seal
20	Shaft
21	Tube-Base
22	Housing
23	Tube
24	Valve-Drain & Fill
25	Adapter-Coupling
26	Cap Screw & Lockwashe:
27	Base

FIGURE 4



No.	Description
1	Head
2	Extension-Head
3	Cap-Shaft
4	Bearing-Upper
5	Bushing
6	Tube-Compression
7	Stop-Key
8	Impeller
9	Diffuser
10	Housing
11	Shaft
12	Diffuser-Lower
13	Retainer-Ring
14	Ring-Two Piece
15	Bushing
16	Screen-Intake
17	Packing
18	Base
19	Coupling
20	Cap Screw & Lockwasher

FIGURE 5

SUBMERGIBLE PERFORMANCE CURVE

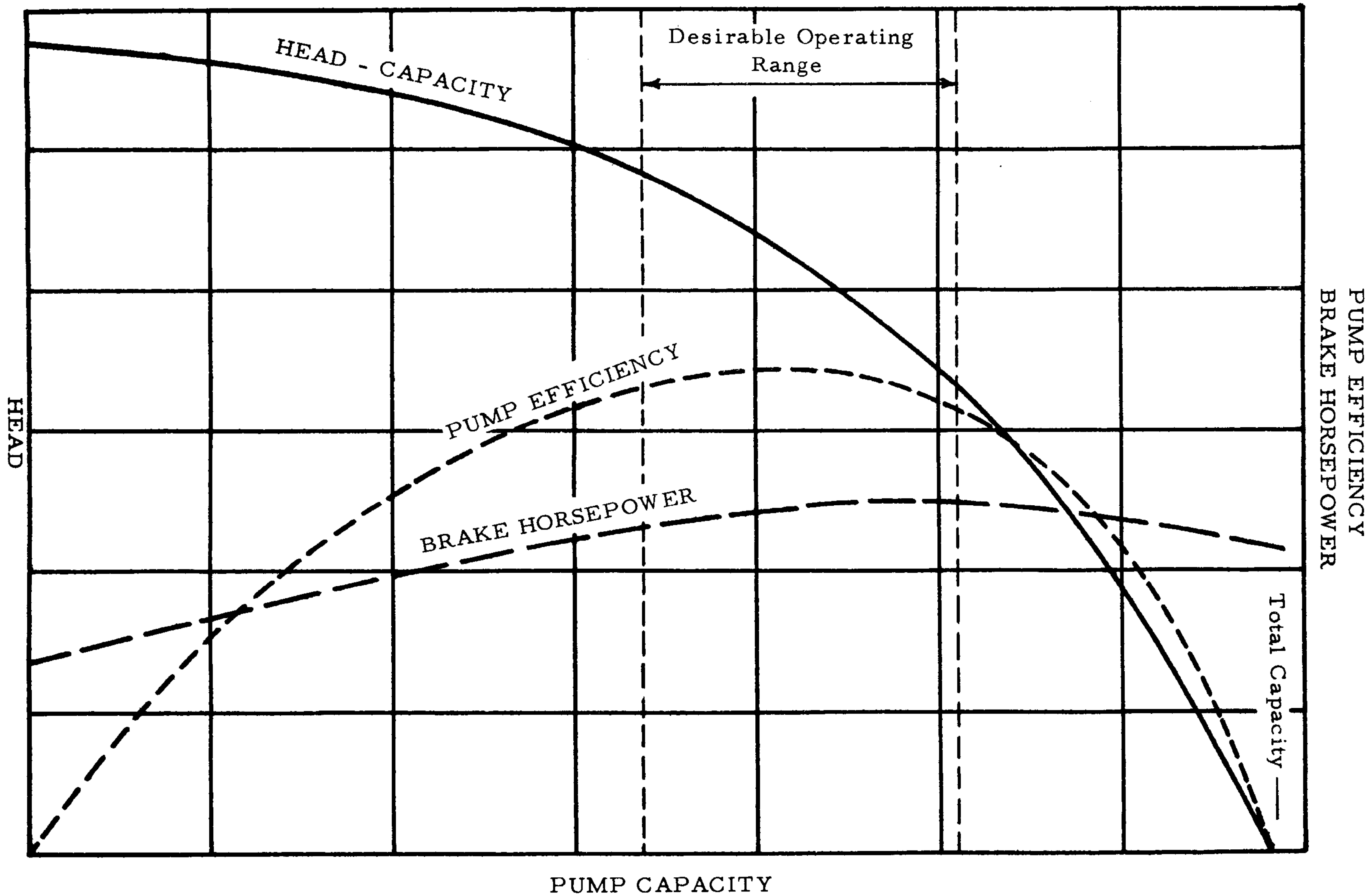
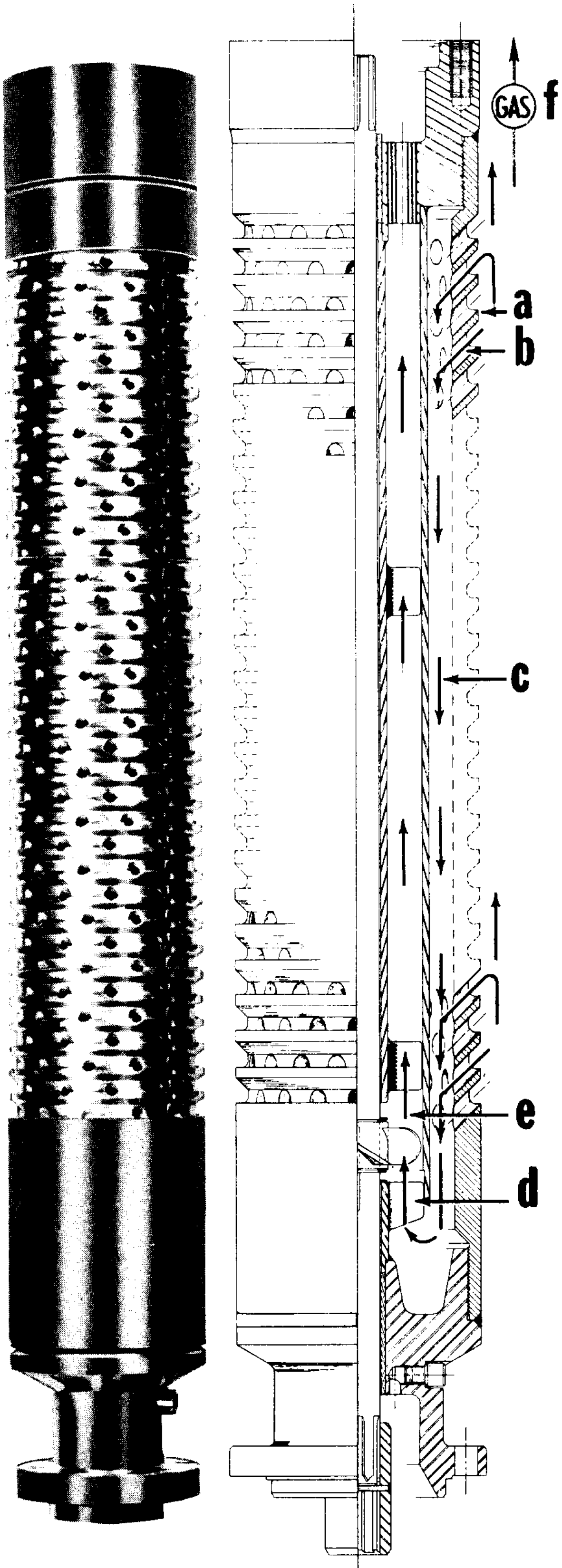


FIGURE 6



GAS SEPARATOR
FIGURE 7

installed to provide a record of operation of the motor, showing time operated and the amount of current being used by the motor.

Power is generally provided by a public utility; however, individual engine generators are used in areas where power is not readily available or for other reasons.

An increasing number of wells are being completed with 4-1/2 in. O.D. casing. High volume pumping equipment requirements for these wells can be met with special designs of the submergible electrical pump. Figure 9 shows a design utilizing pumps of capacities up to 3000 BPD and motor ratings of up to 127-1/2 Hp. There are, however, pumping units of conventional designs with the motor below the pump capable of producing up to 800 BPD. The stages in the bottom intake shown could be inverted to provide a pump to take water from an upper formation and inject it into a lower formation through a packer set between the formations.

Of particular interest is an injection or flooding operation as shown in Fig. 10. In this case the well casing is of large enough diameter to permit the installation of a by-pass tube to bring fluid from the top of the pump back down past the pump and motor to the tubing extending from below the motor through a packer set between the formations. A meter in the system telemeters the amount of water being injected, the pressure gauge on the surface provides information on the injection pressure, and an ammeter on the motor shows the amount of current used by the motor and the time the unit has been in operation.

Many waterflood operations make use of submergible, centrifugal pumps, both for supply wells pumping to storage pits or tanks and for direct injection from the supply wells. A considerable saving in initial investment can be realized when a system can be installed in which the pumping unit in the supply well pumps directly into the repressuring wells.

Dually completed wells can be produced by using a submergible pump to produce the lower zone while a conventional rod pump is used to produce an upper formation. This is illustrated in Fig. 11.

Figure 12 shows the approximate prices of a typical, complete, submergible pump installation.

The price would include all major items of equipment with the exception of transformers. These prices are not included since many installations are made where the public utility company furnishes transformers or the power is supplied by an engine generator.

Figure 13 shows the average lifting costs based on over 35 years of operation with submergible pumps in thousands of wells throughout the world. These graphs show that a barrel of fluid can be lifted at a cost of one cent or less per 1000 feet of lift.

Table I is a study made by Gene R. Ward with Union Oil Company of California, Coalinga, California.[2] This study was made on six wells with high bottom-hole temperatures. Electric power cables are available for service in higher temperature wells such as experienced in the Coalinga area and Barinas, Venezuela area. The highest temperatures experienced to date are in Venezuela where submergibles have been operating successfully since 1957. These wells in the Barinas area have in excess of 285°F. BHT. These cables are of the flat configuration.

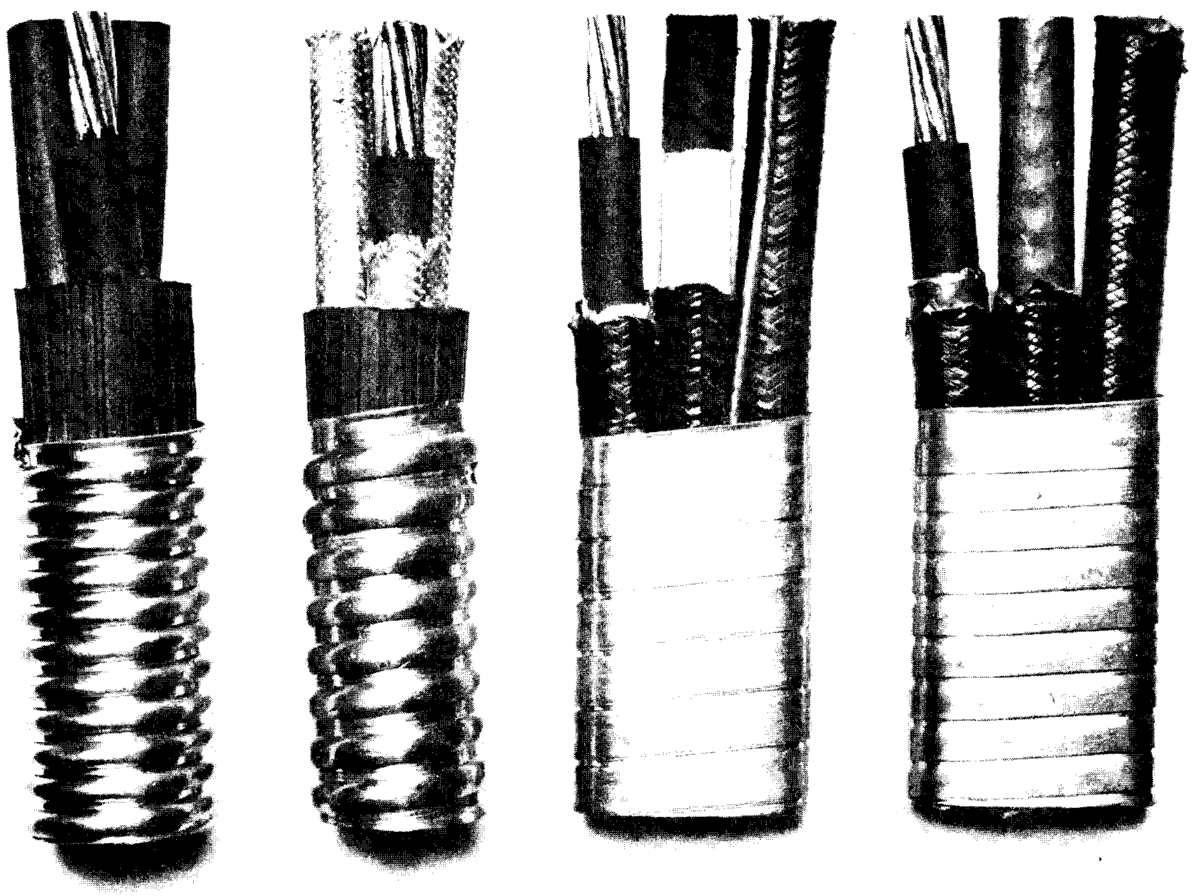


FIGURE 8

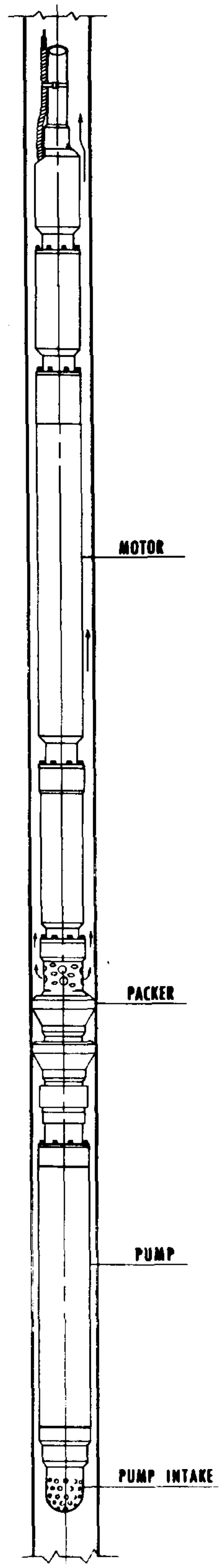


FIGURE 9

Table II shows the lifting cost of these wells on submergible pumps per barrel per 1000 feet of lift.

Table III gives the lifting cost per barrel of fluid per 1000 feet of lift. The study shows the cost per barrel in capacities from 300 to 3000 BPD against heads of 5250 to 5930 ft, and capacities of 4000 to 10,000 BPD against heads of 2640 ft to 2890 ft. The lifting costs in Table III are well substantiated by those found in actual operation as reported by Ward.

As can be seen in Fig. 14[1] submergible pumping equipment compares very favorably in approximate first cost versus the approximate first cost of beam equipment.

Figure 15[1] shows the comparison of lifting cost of beam equipment versus the submergible for various capacities and lifts. Lifting cost includes electricity at one cent per KWH, pulling, repairs and amortization (eight years).

Figure 16[1] compares the approximate cost of hydraulic pumping equipment, including surface equipment, but not power fluid treating equipment, versus the approximate cost of submergible pumping equipment. Here it is seen that the submergible throughout the lower capacities compares very favorably to the hydraulic pumping equipment. However, in the cost for equipment, submergible electrical centrifugal type still does not greatly exceed the cost of hydraulic equipment.

While first costs are an important factor in selecting equipment, operating costs are more important in determining the over-all economics of a program. As can be seen from Fig. 17[1], the hydraulic equipment has a favorable lifting cost (lifting cost includes electricity at one cent per KWH, pulling, repairs and amortization—eight years) in the low volumes and relatively low lifts; however, the increase in cost per barrel of fluid rises very rapidly as the depth increases, whereas the submergible pump has a much slower rise in cost per barrel of fluid as the depth increases.

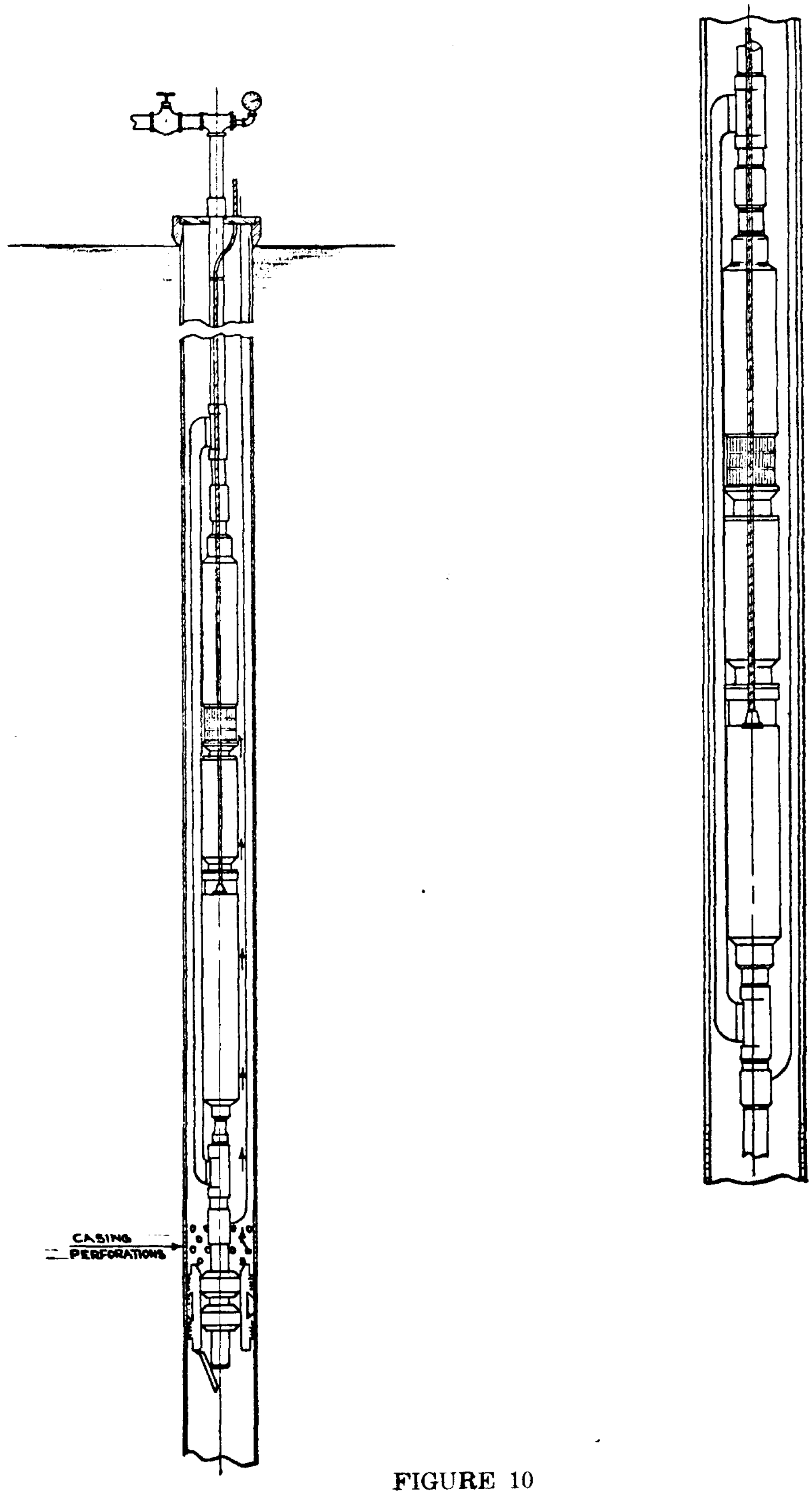


FIGURE 10

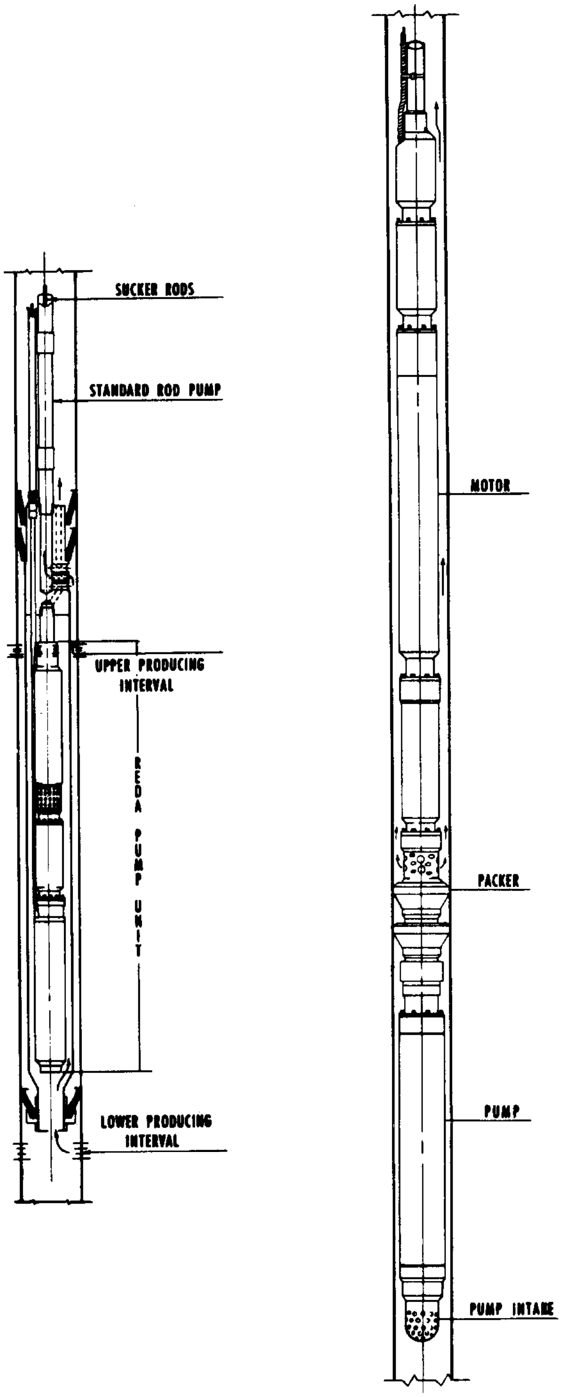


FIGURE 11

PRICES
(APPROXIMATE)

TYPICAL COMPLETE INSTALLATION

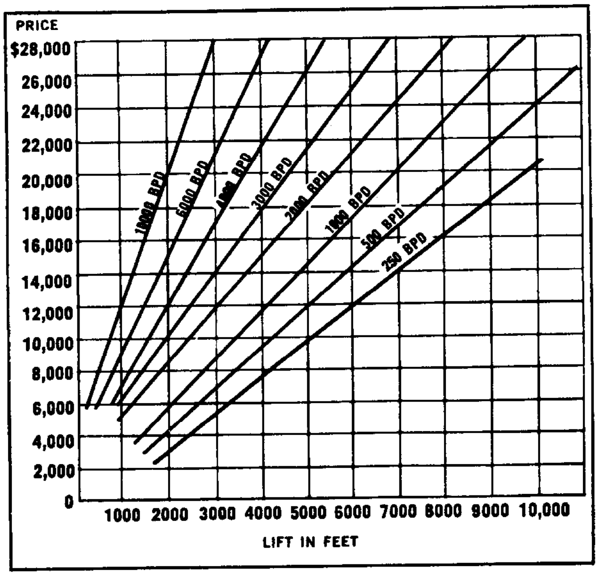


FIGURE 12

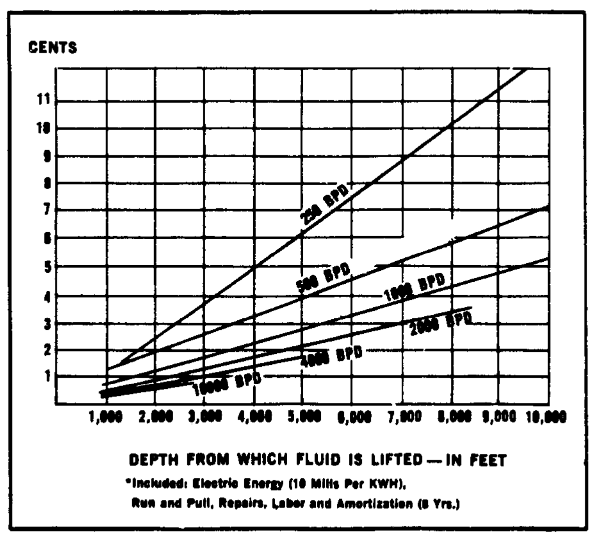


FIGURE 13

TOTAL COSTS IN DOLLARS

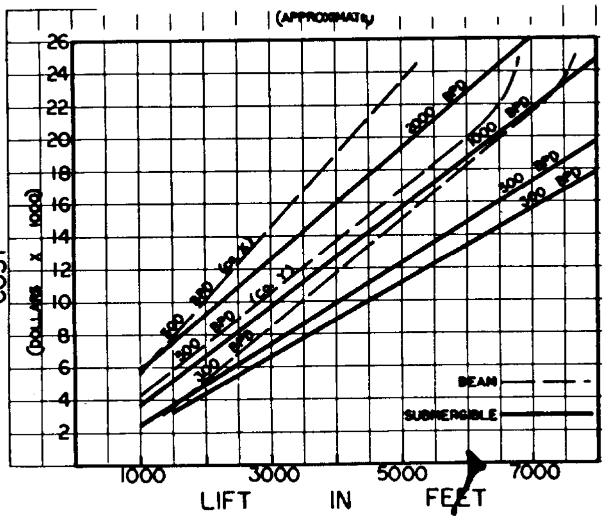
Well	Date On Sub-mergible Pump	Total Days Operating	Total Barrels Produced	Total Power Cost 1.49¢/Bbl. $	Pump Repair $	Protector Repair $	Motor Repair $	Equip. Service $	Pull & Run $	Cable Replacement $	Chemical Treatment $	TOTAL COSTS $
Cagle B-3	5-03-62	1478	4, 796, 015	72, 422	3, 203	1, 254	6, 649	1, 955	9, 113	29, 188 *	2, 242	126, 026
48-31B	10-31-62	1359	4, 507, 939	66, 591	5, 111	776	3, 723	3, 268	11, 774	27, 873	3, 947	123, 003
46-31B	2-22-63	1208	3, 849, 109	59, 200	3, 784	529	1, 364	1, 740	9, 003	29, 122	3, 388	108, 130
Cagle B-10	6-14-63	943	2, 969, 881	46, 300	10, 914	1, 690	7, 058	2, 712	12, 117	24, 207	1, 509	106, 507
Fee 3	2-20-64	714	2, 195, 172	35, 000	3, 080	466	5, 000	1, 075	5, 456	5, 500	990	56, 567
Ex. 3	6-20-65	473	1, 535, 836	23, 200	-	288	3, 755	471	2, 280	-	1, 419	31, 413
TOTAL...		6175	19, 853, 952	302, 713	26, 092	5, 003	27, 549	11, 221	49, 743	115, 890	13, 495	551, 706
				COST PER BARREL IN CENTS								
		% Operating	B/D Average									
Cagle B-3	5-03-62	90.1	3, 240	1.49	0.067	0.026	0.139	0.047	.191	0.607	.046	2.610
48-31B	10-31-62	94.5	3, 310	1.49	0.114	0.017	0.082	0.073	0.260	0.616	.087	2.730
46-31B	2-22-63	89.5	3, 180	1.49	0.098	0.013	0.035	0.045	0.235	0.759	.051	2.720
Cagle B-10	8-14-63	77	3, 150	1.49	0.368	0.057	0.236	0.091	0.409	0.814	.045	3.510
Fee 3	2-20-64	72.8	3, 100	1.49	.141	.021	0.229	.049	0.249	0.251	.042	2.270
Ex. 3	6-20-65	95.5	3, 240	1.49	-	0.018	0.244	0.047	0.148	0	.047	1.990
AVERAGE		86.6	3, 203	1.49	0.128	0.025	0.161	0.058	0.249	0.508	.051	2.640

*** Includes Rental Costs @ $20. 00/day for 720 Days**

TABLE 1

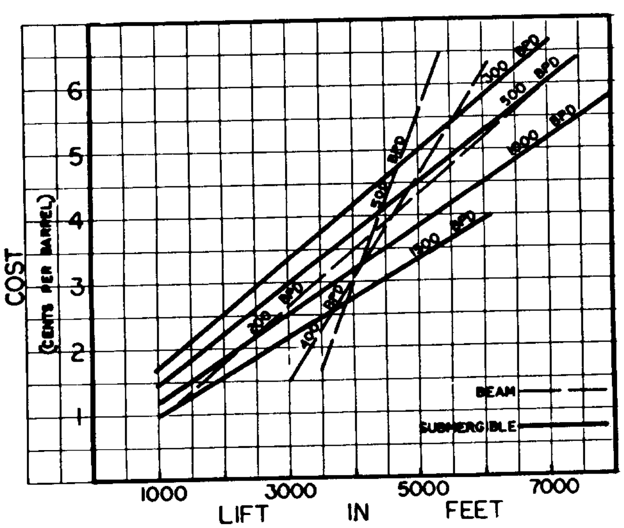
Well	PFL	Lifting Cost/Bbl. 1000 Feet
Cagle B-3	4050	$.0064
48-31B	3900	.0070
46-31B	4200	.0065
Cagle B-10	4450	.0078
Fee 3	4300	.0053
Ex. 3	4300	.0046
Average	4200	.0063

TABLE 2



Submergible versus beam equipment cost (approximate)

FIGURE 14



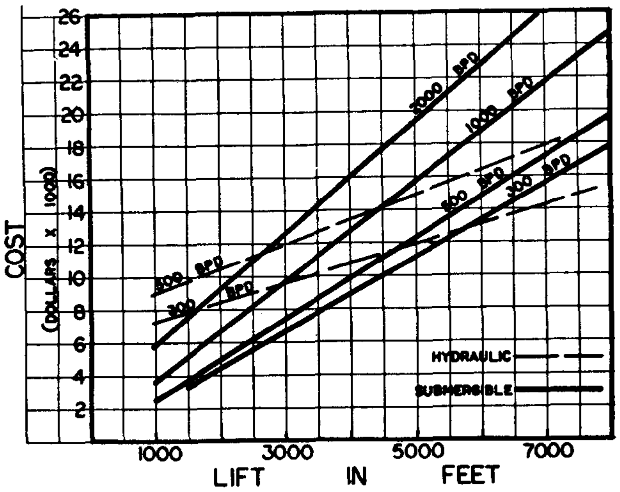
Submergible versus beam lifting cost

FIGURE 15

Based on Wells Producing Non-Corrosive, Sand-Free Fluids in Wells of Moderate B.H.T.

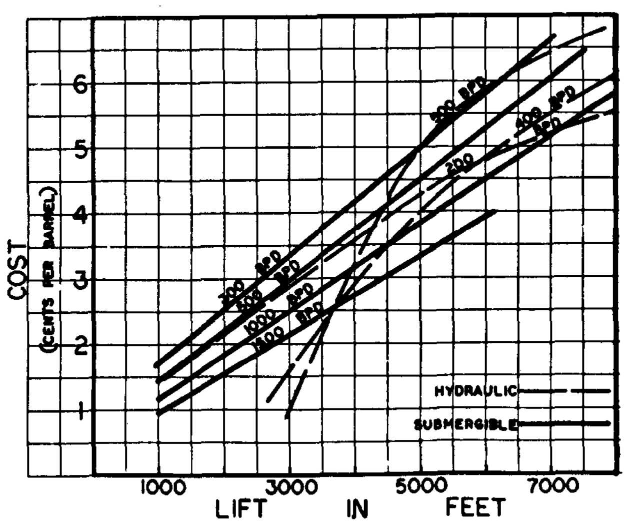
BPD	Lift (feet)	UNIT SELECTION: Size & Type	UNIT SELECTION: Equip. Total Cost	UNIT SELECTION: Power Cons. (KW/hr)	YEARLY LIFTING COST DATA: Electric Energy (10 Mills)	Repair and Exch.	Pull and Run	Amort. (8 yrs.)	Labor	Total	Total Cost per Bbl.	Lifting Cost per Bbl. per 1000 Ft.	Exclusive of Electricity: Total Cost per Bbl.	Exclusive of Electricity: Lifting Cost per Bbl. per 1000 Ft.
300	5330	30 HP - 238D13AE	$10,200	32.2	$ 2,820	$1472	$670	$1275	$668	$ 6,905	$.06306	$.01183	$.03730	$.00700
500	5930	40 HP - 227D16AE	12,378	44.3	3,880	1491	743	1547	668	8,329	.04563	.00769	.02437	.00410
1,000	5660	70 HP - 24D31E	17,289	71.5	6,260	1958	708	2161	668	11,755	.03220	.00568	.01505	.00265
2,000	5570	120 HP - 149G52E	19,867	123.2	10,800	2336	696	2483	668	16,983	.02326	.00417	.00846	.00151
3,000	5250	180 HP - 131G59E	21,440	186.0	16,300	2586	657	2680	668	22,891	.02090	.00398	.00601	.00114
4,000	2890	120 HP - 90G110	15,940	116.0	10,170	2412	435	1993	608	15,618	.01069	.00369	.00373	.00129
6,000	2990	180 HP - 103G180	20,566	176.0	15,400	3585	450	2571	608	22,614	.01032	.00345	.00329	.00110
10,000	2640	260 HP - 44I300	20,939	235.0	24,247	4045	660	3035	608	28,948	.00793	.00300	.00228	.00086

TABLE 3



Submergible versus hydraulic equipment cost (approximate)

FIGURE 16



Submergible versus hydraulic lifting cost

FIGURE 17

Again quoting from Ward's paper:

"For this presentation, investment in the two producing methods was calculated on a barrel per day capacity as follows:

	Submergible Pump Equipment for 5 Wells Including Original Cable	Compressor H.P. Necessary to Gas-Lift Wells
Total Investment	$224,741	$556,800 *
Total Daily Production (BPD)	16,230	10,621
Investment per BPD Capacity	$13.85	$52.47

* 1,856 BHP @ $300/HP

The gas-lift and related production data above are from Wells Cagle B-3, Cagle B-10, 46-31B 48-31B, and Fee 3 prior to the submergible pump conversion."

CONCLUSION

The increasing demand for submergible pumping equipment demonstrates the acceptance of this method of production. Pumping equipment in the lower capacity ranges is in greater demand, as well as equipment for the wells of deeper settings.

Initial lower installed costs along with lower lifting costs have increased the demand for this type of equipment.

Proven performance and dependability have been important factors in the increasing acceptance of submergible pumping equipment.

REFERENCE

1. Riley, E. A. "Mike", "Big-Capacity Pumps Solve Excessive Water Problem," The Petroleum Engineer, Pages B-40, B-44, B-48 and B-50, July 1961
2. Ward, Gene R., "Submergible Pump Operation", presented at spring meeting of Pacific Coast Dist., Div. of Prod., API, May 2-4, 1967