Economic Selection of Artificial Lift

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IMPORTANCE OF PROPER CHOICE OF LIFT

There are usually two or more methods by which any well can be lifted. Proper artificial lift selection requires an objective economic comparison of all possible methods. Too often one or more methods are eliminated because of prejudice, ignorance, or fear of new or different types of lift. When a well first requires lift, any type lift selected will, of course, show a quick payout; however, a comprehensive study may result in several thousand dollars savings during its productive life. As it becomes necessary to "pump" from deeper and deeper depths, the necessity for proper lift selection becomes more important.

The production engineer has two goals in the selection of artificial lift equipment. His primary purpose is to select equipment which will deplete a specific well. His second aim is to select equipment which will result in the most economical depletion. The lift with the cheapest first cost is not necessarily the cheapest to depletion.

Any artificial lift study must be based on well and reservoir characteristics. The better the reservoir predictions, the better the lift study. In most instances our reservoir engineers have enough data by the time lift is required to give us some "ball-park" predictions.

Assume the first well on a lease requires lift. Some of the things we should know or have a reasonable prediction of are:

1. Number of wells expected.
2. Reservoir predictions
3. Availability and cost of high pressure gas
4. Operating costs of various type lifts
5. Equipment life.
6. Surplus equipment that may be used.
7. Possibility of consolidation or commingling production.

Often some of this information is sketchy or not available; however, in most instances enough information can be gathered to permit selection of the most economical type lift.

This discussion is not intended to cover the design of individual artificial lift installations. Ample data is available from text books, technical publications, trade journals, and manufacturers. It should, however, be kept in mind that well capacity and pumping conditions change. For example: an 8500 foot well in a solution gas reservoir requires lift. We design a pumping installation to lift the allowable from TD without thought of bottom-hole pressure or decline in productivity. We end up with a pumping unit capable of pumping 150-160 barrels from 8500 feet; yet, by the time it is necessary to lift from this depth, well productivity has declined to 30-40 barrels.

By matching the pumping unit with well characteristics it is often possible to use a smaller size unot. Conversely, disregard of gas-fluid ratio where gas must go through the pump may find us with a 7 foot stroke unit where a 12 foot to 20 foot or longer stroke is required. For example: 1000 standard cubic feet of .9 feet specific gravity gas at reservoir condition of 200° F and 500 psi occupies 5.85 barrels of space. Thus, if the gas-fluid ratio in the pump is 1000/1 we will have to pump approximately 6.85 barrels to produce 1 barrel of fluid.

It is, therefore, readily apparent that unless formation gas can be vented, much more pump capacity is required. Fig. I shows the effect of gas interference. In this example a 7 inch stroke unit will deplete this well if gas is vented. If gas must go through the pump, a 144 inch stroke unit is required.

ACCURATE COST DATA

Inasmuch as we are interested in depelting a well or wells for the lowest cost, we need accurate cost data; initial, replacement, and operating. Initial costs are easy to determine. Need for replacement parts of pumping installation will vary according to the productive life of the well and useful life of the various pieces of equipment. Here we use our own company experience with the same or similar equipment.

Operating costs are sometimes difficult to determine. This is particularly true for a type lift with which we have had little or no operating experience. Published data and manufacturers' representatives can be helpful in estimating operating costs. Also, other operators are usually happy to tell their experience with various types of equipment.

This is not to say that other operators will tell us their actual lifting costs; however, they will in most instances tell their average pump runs, input GOR, etc. This information, coupled with knowledge of our company policy (pumper work load, salary, benefits, etc.), should allow us to determine reasonably accurate operating costs.

Operating costs are usually expressed in cents/barrel. For an economic comparison over an extended period, these costs are better expressed in $/well/month. This is because a large portion of the operating costs are fixed and do not decline with production. The exception to this general rule is gas lift. Here the volume of gas may or may not decline as production declines. In a solution gas drive, gas use should decline; in a water drive, gas use will increase.

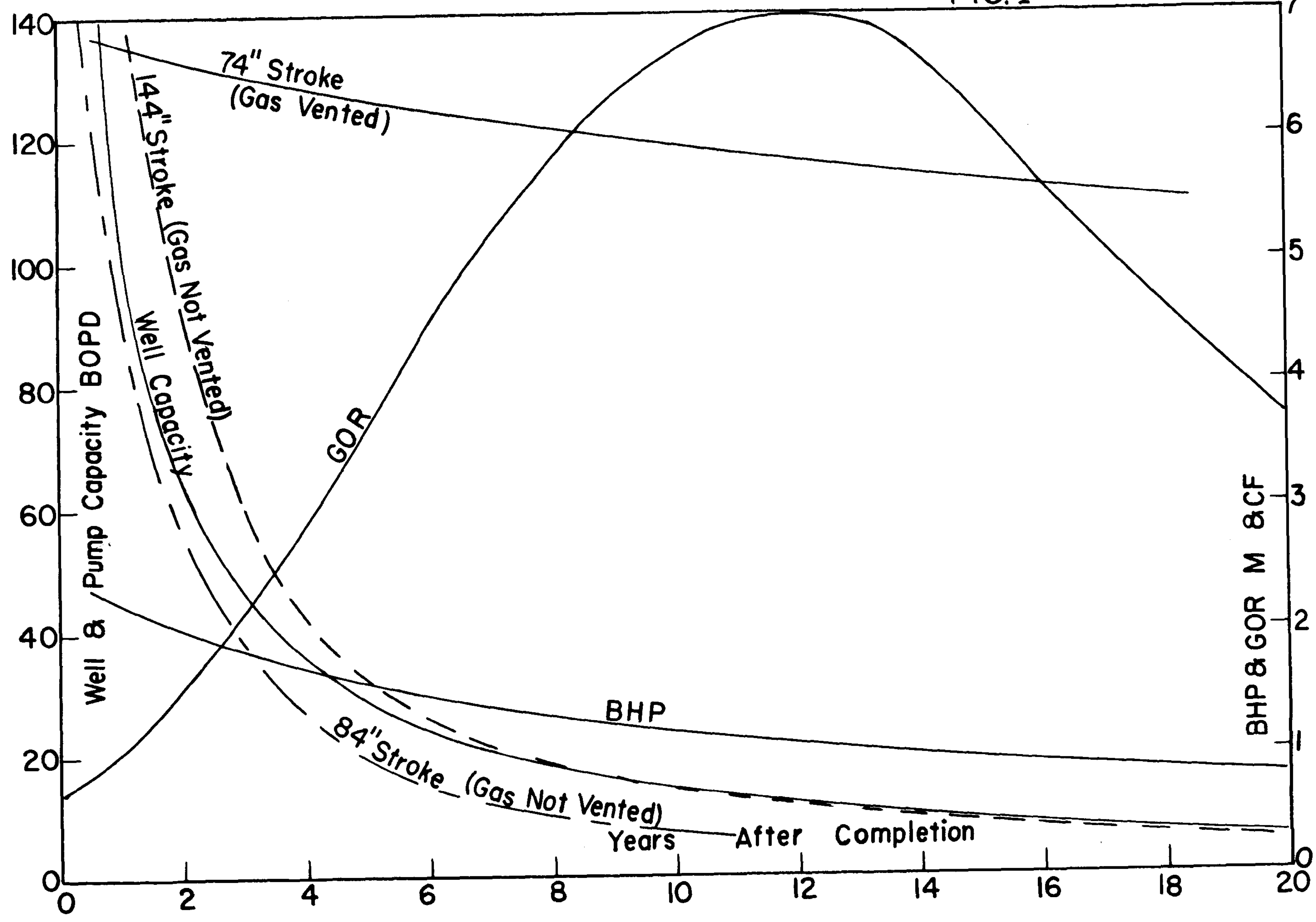
Salvage value of equipment after depletion must be considered. In general, only major long-lived pieces of equipment have an appreciable salvage value. Most operators assign equipment a "life expectancy" and depreciate it uniformly during this period. Sucker rods,

TABLE I

PRESENT WORTH OPERATING COSTS

Years	Present Worth 8% Factor	Rod Pump	Hyd. Pump	Gas Lift Op. Cost	+ Gas Costs	= Total
1	.9610	$ 1, 960	$ 2, 306	$ 1, 442	$ 4, 469	$ 5, 911
2	.8872	1, 810	2, 129	1, 330	2, 914	4, 244
3	.8189	1, 671	1, 965	1, 228	1, 929	3, 157
4	.7560	1, 542	1, 814	1, 134	1, 368	2, 502
5	.6979	1, 424	1, 675	1, 047	1, 033	2, 080
6	.6442	1, 314	1, 546	966	773	1, 739
7	.5947	1, 213	1, 427	892	642	1, 534
8	.5490	1, 120	1, 318	824	508	1, 332
9	.5068	1, 034	1, 216	760	418	1, 178
10	.4678	954	1, 123	701	358	1, 059
11	.4318	881	1, 036	648	307	955
12	.3986	813	957	598	261	859
13	.3680	751	883	552	221	773
14	.3397	693	815	510	186	696
15	.3136	640	753	470	154	624
16	.2895	591	695	434	111	545
17	.2672	545	641	401	88	489
18	.2467	503	592	370	68	438
		$19, 459	$22, 891	$14, 307 +	$15, 808 =	$30, 115

FIG. I


74" Stroke
(Gas Vented)
144" Stroke (Gas Not Vented)
Well Capacity
GOR
BHP
84" Stroke (Gas Not Vented)
Well & Pump Capacity BOPD
BHP & GOR M &CF
Years After Completion
0
20
40
60
80
100
120
140
0
2
4
6
8
10
12
14
16
18
20
0
1
2
3
4
5
6
7

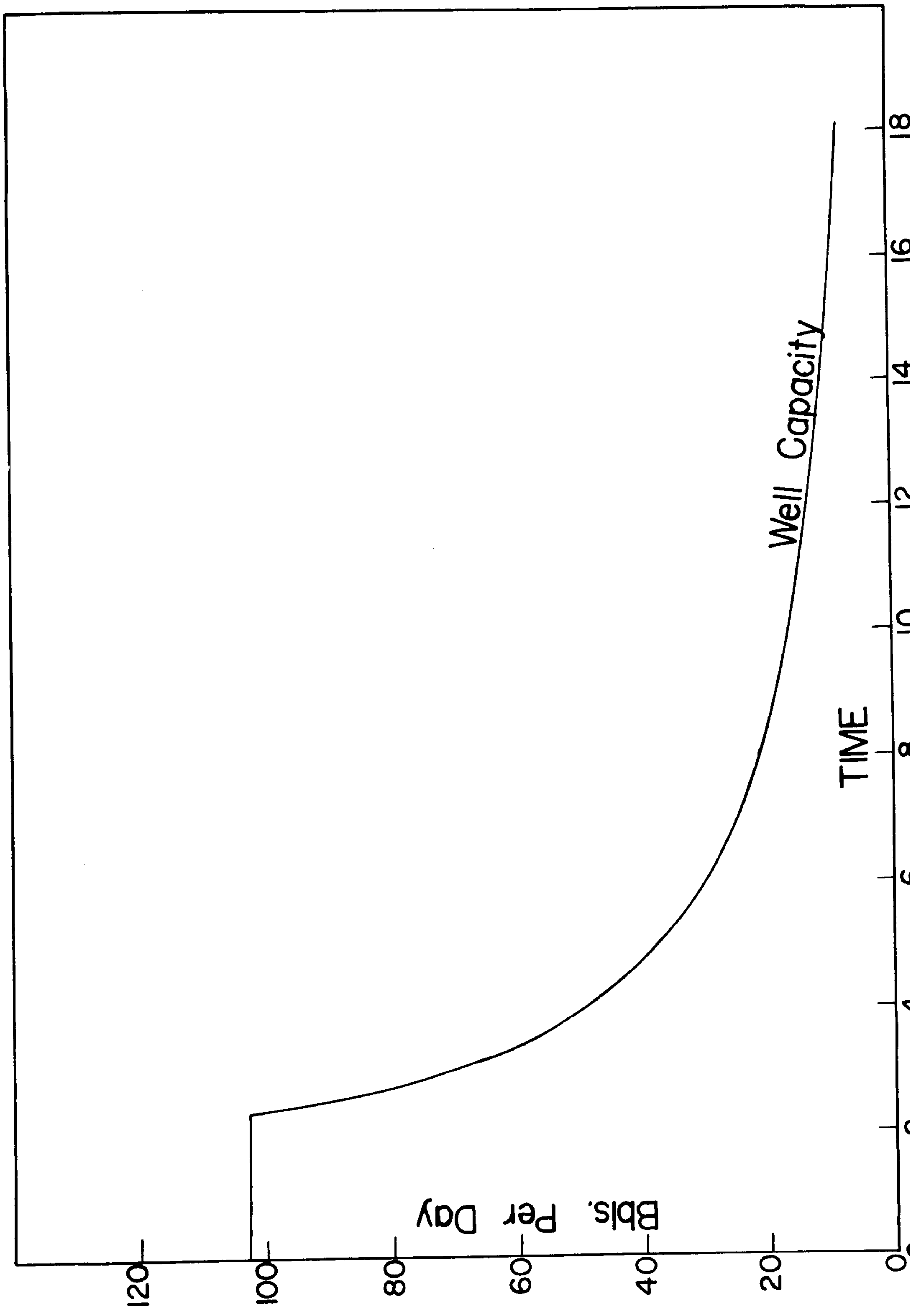

Well Capacity
Bbls. Per Day
TIME
0
20
40
60
80
100
120
2
4
6
8
10
12
14
16
18

FIG. II

bottom-hole pumps, gas lift valves, etc., are usually not assigned a salvage value.

After all our costs have been calculated, we are ready to make an economic comparison. It is theoretically possible to deplete a well with no initial investment but with excessive operating costs; that is by continuous swabbing. It also might be possible to install some type lift, at a great initial cost, that would have no operating cost.

In order to select the most economical type lift we need some method to put the initial and operating costs in their proper perspective. The most equitable method is to convert initial and future costs, and salvage values to a present worth basis. This is done by discounting future costs and salvage value back to the time of initial investment. Interest rate used will vary according to the operator.

Table I shows a hypothetical comparison of various types lift. The assumed data for this comparison is tabulated as follows:

1. Depth - 8500 feet
2. Capacity as shown on Fig. 2
3. Eighteen years "pumping" life
4. Initial costs
   (a) Rod Pumping equipment - $20,000/well
   (b) Hydraulic pumping equipment
       1 well - $18,000/well
       2 wells - $15,000/well
       4 wells - $12,000/well
   (c) Gas lift - $4,200/well

TABLE II

INITIAL & REPLACEMENT COSTS & SALVAGE VALUES

Year	Item	P. W. Factor 8%	Rod Pump 1 Well	Hydraulic Pump 1 Well	2 Wells	4 Wells	Gas Lift
0	Initial	1.0000	$20, 000	$18, 000	$30, 000	$48, 000	$4, 200
7	Replace Engine	.5947	892	892	1, 487	2, 081	-
13	Replace Engine	.3680	552	552	920	1, 288	-
18	Totals		$21, 444	$19, 444	$32, 407	$51, 369	$4, 200
*	Less P.W. Salvage		- 819	- 136	- 308	- 308	
	Net Cost		$20, 625	$19, 308	$30, 099	$50, 061	$4, 200
	Net Cost Per Well		$20, 625	$19, 308	$15, 050	$12, 515	$4, 200

SALVAGE VALUES

Pumping unit original cost $8, 800 (30 year life)	
Remaining life, 12 years 12/30 ($8, 800)	= $3, 520
Cost to salvage	200
	$3, 320
P. W. Value (.2467 x $3, 320)	= $ 819
1-well triplex original cost $2, 500 (25 year life)	
Remaining life, 7 years 7/25 ($2, 500)	= $ 700
Cost to salvage	150
	$ 550
P. W. Value (.2467 x $550)	= $ 136
2-4 well triplex original cost $5, 000	
Remaining life, 7 years 7/25 ($5, 000)	= $1, 400
Cost to salvage	150
	$1, 250
P. W. Value (.2467 x $1, 250)	= $ 308

5. Operating costs
   (a) Rod Pump - $170/well/month
   (b) Hydraulic pump - $200/well/month
   (c) Gas lift - $125/well/month plus cost of gas (5¢/MCF compression cost)
6. Gas engine life - 6 years
7. Pumping unit life - 30 years
8. Triplex life - 25 years
9. 8 per cent interest rate.

It is emphasized that these conditions and costs are assumed for illustration only.

The present worth values for equipment and operating costs (Tables 1 & 2) are then combined to find the overall costs (Table 3).

TABLE III

	Rod Pump	Hydraulic Pump 1 Well	2 Wells	4 Wells	Gas Lift
P. W. Equipment cost/well	$20, 625	$19, 308	$15, 050	$12, 515	$ 4, 200
P. W. Operating cost/well	19, 459	22, 891	22, 891	22, 891	30, 115
P. W. Total costs/well	$40, 184	$42, 199	$37, 941	$35, 306	$34, 315

Based on this comparison, our indicated selection would be as follows:

1. Lift wells by gas lift if gas available at 5¢/MCF
2. If high pressure gas not available
   (a) Lift 1-well lease with rod pump
   (b) Lift 2-4-well lease with hydraulic pump

Our final selection will be made after taking into account the following facts:

1. Surplus equipment that may be used.
2. Possibility of consolidation and/or commingling.
3. Time lapse between initial and subsequent lift installations on multiple well installations.

It is apparent that possession of surplus equipment will materially change our recommendation. Also, a long time lapse between first and later lift requirements on multiple well leases will require discounting future individual well costs back to time of initial installation. For example: the control plant, a major item in hydraulic pumping, must be installed when the first well requires lift.

CONCLUSION

The example covered in this discussion was for singly-completed wells under certain conditions. Dual wells and/or water drive wells will, of course, be different. In these wells our methods of lift should include dual pumps and submergible electrical pumps; however, the method would be the same.

This selection method may seem tedious and unnecessary to some engineers and production men. This may have been true in the past; but, with deeper pumping and long reservoir life, significant savings can be made by a comprehensive lift study.