PUMPING HEAVY LOADS WITH THE MARK II

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INTRODUCTION

The ever-increasing demand for additional energy sources and hydrocarbon products has pushed the search for new petroleum reserves to ever greater depths. As depths increased and well loads became successively heavier, the need also arose for higher capacity and more effective artificial lift systems.

In the past, the simplicity, efficiency, and reliability of the beam pumping unit have made it a favorite with many operators, when pumping loads were light to medium. But when large volumes were to be lifted from deep wells, or massive volumes from shallow to medium depths, this historic system was often incapable of producing the required fluid, and other artificial lift methods had to be employed.

Challenged by these limitations, designers of the various components of the beam pumping system redoubled their efforts to increase beam pumping capacity by upgrading and improving: (1) bottomhole pumps, (2) pumping units, (3) prime movers, and especially (4) sucker rods.

One beam pumping innovation, which has now been in service for some years, is the so-called Mark II unit (Fig. 1) made up of the traditional components of walking beam, post, cranks, horsehead, pitman, etc., but rearranged to form a reversed-type geometry, with certain unique functional and kinematic properties.

FIG. 1—MARK II UNIT

DESIGN GOALS

The Mark II functional design goals can be briefly summarized as follows:

1. To develop a push-up geometry that reduces maximum off-bottom (polished rod) acceleration by a significant amount, tending to reduce rod and structural loads
2. To increase fill time and maximize plunger stroke, for a given pumping speed
3. To design a unique torque factor schedule that tends to distribute the torsional load more uniformly around the entire crank circle, rather than working maximumly at mid-up and down strokes. This arrangement tends to reduce the size requirement of both prime mover and speed reducer without sacrificing efficiency while performing a given amount of work at the polished rod.
4. To design a unit that can effectively transmit maximum safe work per stroke from the surface unit to the bottomhole pump.

Rigorous field studies of the unit across the entire spectrum of pumping, and confirmed by the latest predictive and diagnostic techniques, show the Mark II: (1) normally smooths out and reduces the peak torque by a substantial amount—in many cases enough to reduce gear reducer and prime mover by one (or more) API size; (2) often reduces rod and structural load significantly; and (3) on applications where neither peak torque nor rod and structural load are appreciably reduced, frequently the Mark II plunger travel per stroke is dramatically increased. Under ordinary pumping conditions, the Mark II normally produces one or more of these three desirable characteristics.

Much has been previously written about the Mark II's design goals, field tests, and performance, a good deal of which can be summarized in a single paragraph from the production manual of an oil company that has used the Mark II extensively.

> "The Mark II unit geometry tends to decrease both the maximum polished rod load and the minimum polished rod load; thus, creating a more desirable operating range with the sucker rods. This type of geometry tends to maximize the overtravel at the pump—thereby increasing the amount of production per stroke. The negative torque on the gear reducer is kept to a minimum—thus, reducing the operating costs. In many cases it is possible to use a smaller size Mark II where a larger size conventional unit would be needed. The choice of a Mark II will often allow the use of a smaller prime mover which will reduce operating costs even further. Occasionally a less expensive sucker rod string can be used due to the lessening of well loads."

To date there are nearly 5500 Mark II pumping units in service (among some 260 different oil companies), and they range in stroke length and capacity from 64 in., 80,000 in.-lb to 216 in., 1,280,000 in.-lb. The Mark II unit is manufactured in some 50 to 60 API combinations.

IMPORTANT CONSIDERATIONS

Besides the functional ability of the unit itself, there are three other considerations of much importance when lifting heavy loads with the beam pumping system. They are: (1) sucker rod capacity, (2) clearance between rods and tubing (fluid passageway), and (3) optimum pumping mode.

It has been said that no pumping unit is better than the poorest rod in its string. It could also be argued that in many beam pumping applications, the limiting factor is neither the capacity of the surface unit, prime mover, pump or rods, but the volume of fluid passageway between rods and tubing. A third item of equal importance is selection of the proper pumping mode (i.e., stroke length, speed, plunger diameter, rod design) for a given depth and fluid requirement. A brief examination of these three factors should help place in better focus any investigation of heavy beam pumping.

Improved Sucker Rods

In recent years several rod manufacturers have developed new heat-treating techniques and processes that significantly increase the capacity of the sucker rod, pushing its working stress and load range well above that of traditional values. One of these methods is the quick-cycle, quench and temper process that increases the working capacity of the rod string substantially. Use of this improved technique provides a fine grain, needle-like structure in the rod which helps obviate tensile failures. Its yield to tensile ratio has almost doubled and its resistance to fatigue has been raised measurably.

A second advance in rod technology is the development of a new system which involves a continuous, couplingless, rod that can be spooled up at the well site. The complete elimination of couplings in this rod removes one of the most troublesome problems of sucker rod longevity. Of further importance is the fact that by eliminating the couplings, frictional loads are significantly reduced; and of additional importance, the fluid passageway has been cleared of the many obstructions afforded by each individual rod coupling.

Still another outstanding development is a new series of sucker rods, stress rated from 40 to 50 thousand psi. This exceptional stress resistance is brought about by end-forged rods, heat-treated, liquid-quenched and tempered to provide additional core stress capacity. Additional strength is added to the rods by hot quenching and strain aging. Finally, these new rods are induction heated shoulder to shoulder, to a controlled depth, and then liquid-quenched. To further increase compressive prestress, the rod is shot-peened. Pin ends are machined with rolled threads. By pushing the working stress capability of the rod string to 40 and even 50 thousand psi, beam pumping capability has been dramatically increased.

Adequate Fluid Passageway

Perhaps the most commonly overlooked and yet important consideration is the annular clearance between the ID of the tubing and the OD of rods and couplings. It is often impractical to produce large volumes from deep wells unless the fluid passage is adequate. A simple rule of thumb is to design the tubing and rod string clearance such that, when producing maximum fluid, the greatest upward velocity of the fluid at the point of minimum flow area does not exceed the maximum upward velocity of rod and couplings. Similarly, on the downstroke, the larger the annular clearance, the smaller the rod-coupling-piston effect (dash-pot), the smaller the irrecoverable energy loss, and in general, the higher the minimum polished rod load.

Admittedly, maximizing this annular clearance in older wells is not always feasible; but whenever possible, certainly in the design of new wells, it should be carefully considered. Failure to do this may result in much higher rod and unit loading.

Many operators taper the tubing string so that maximum clearance is provided as the rod taper increases. Often this beneficially decreases loads in both unit and string.

Use of sinker bars immediately above the bottomhole pump is normally good practice, for it tends to minimize rod buckling by providing adequate force at the bottom of the string to trip the traveling valve. On the other hand, when providing sinker bars in this area, the additional restriction of the fluid passage must also be considered.

Also, when tubing is faultily anchored, it may be that the larger diameter sinker bars (and couplings) in the area immediately above the bottomhole pump, will increase bottomhole rod friction if the cork-screwed tubing is free enough to seize the rod string as the tubing is unloaded.

It is also prudent to maximize the fluid passageway, not only to minimize the frictional forces, but also to reduce the upward velocity of the fluid slug as well. Maximizing the clearance becomes even more important if the fluid-to-tubing friction is a function of some higher power of the slug velocity.

Optimum Pumping Mode

In the 1920's and 30's, since the stroke length of the average beam pumping unit was relatively short, most operators having to lift large volumes had but few alternatives: (1) increase plunger size, (2) increase pumping speed, or (3) a combination of both.

In the 1930's, as well depths and fluid volumes increased, larger pumping units with longer strokes evolved, and many operators selected longer stroke units which could pump greater volumes at lower pumping speeds with fewer rod reversals.

With the development of more advanced and precise predictive (load) techniques, it can now be shown where, to produce large fluid volumes, on many applications, torque and structural load are actually lowered by pumping shorter, faster strokes, rather than longer and fewer ones. In general, the short, fast stroke nearly always reduces peak torque, occasionally reducing peak structural load as well—but often at the expense of a greater number of rod reversals, and a higher and less desirable rod load range, with a lower minimum load, which eventually restricts further increase in pumping speed—and hence production.

Fortunately, there is a good solution to this complex problem in the use of the conventional unit optimizing tables developed by the API (Sucker Rod Pumping Design Book—API 11L3) and the equivalent Mark II optimizing tables designed by Dr. S.G. Gibbs of the NABLA Corp. A thorough study of these two optimizing tables will normally define the areas where fast, short stroke pumping is advantageous, as well as other areas where long stroke slower pumping is best and indeed, often the only sucker rod solution.

HEAVIER CLASS MARK II

In late 1969, a new and heavier class Mark II was developed, having either a 192-in. or 216-in. (maximum) stroke, coupled with several optional API transmissions ranging in size from 640,000 in.-lb to 1,280,000 in.-lb. This new Mark II class employed the same (modular) geometry as before; but the basic structure was made significantly sturdier and consisted of two inherently stable triangular prisms placed back to back. It was hoped that with adequate rods and pump, this new class of Mark II—under normal pumping conditions (i.e., full barrel of fluid, no shrinkage, little gas, nominal friction, etc.)—could effectively lift the following:

DEPTH	VOLUME
10,000 ft	1000 BPD
9000 ft	1050 BPD
8000 ft	1150 BPD
7000 ft	1250 BPD
6000 ft	1500 BPD
5000 ft	1850 BPD

Although not all of these maximum fluid volumes have been realized in the field, some have and these and other field applications will be discussed further in the paper.

Currently, between 15 and 20 oil companies use this new and heavier class Mark II with its swept-back geometry and longer stroke (192 in. and 216 in.). There are nearly 100 of these units in service (or on order) in the Far East, Near East, Europe, Canada, and the U.S.A.

Several months ago a questionnaire was sent out to a number of companies operating this larger class unit, soliciting measured performance data and general comments. Table 1 gives a brief resume of the information received from the various operators. In most cases, only applications involving maximum production are shown. The customer's name and well numbers have been deleted for obvious reasons. Unfortunately, complete information was not received from all operators.

The data included in Table 1 was independently field-measured by the various operators and presented as received. In most cases the pumping units were providing net plunger strokes substantially greater than measured fluid production would indicate; but because of shrinkage, slippage, gas compression, etc., production may have been somewhat reduced. For instance, in the example Well No. 2, Operator B (W. Tex) in Table 1, measured production was 513 BFPD—while the volumetric sweep of the bottomhole pump was 663 BPD—a significant loss of production due to factors over which the pumping unit had no control.

TABLE 1—SUMMARY—MARK II MEASURED FIELD PERFORMANCE DATA

WELL NO.	DEPTH/SUBMERGENCE (Ft.)	PPRL (Lbs.)	MPRL (Lbs.)	PEAK TORQUE* (1,000 In.Lbs.)	SPM	STROKE (Ins.)	PUMP SIZE (Ins.)	RODS	PRODUCTION TEST BOPD	BWPD	BFPD
				Operator A - West Texas							
1	5,152/50	24,500	8,000	---	9.6	192	2.75	86	888	359	1247
				Operator A - Oklahoma							
1	6,769/1,130	28,273	4,789	1,089,765	8.2	216	2.25	97	933	---	933
2	7,039/653	31,363	3,398	1,159,015	8.5	216	2.25	86	498	304	802
				Operator B - Oklahoma							
1	8,009/1,871	30,652	---	932,916	8.5	216	2.25	96	---	---	768
2	7,952/---	28,538	---	1,115,543	9.0	216	2.25	96	---	---	1095
				Operator B - West Texas							
1	6,050/---	29,002	4,335	1,085,267	8.0	216	2.25	96	168	671	839
2	9,075/---	28,232	11,061	999,000	8.18	216	1.75	86	414	99	513**
				Operator C - Oklahoma							
1	8,003/---	---	---	---	---	216	2.25	86	---	---	1050
2	8,001/1,250	37,878	11,564	1,008,000	8.92	216	2.25	96	830	---	830
3	8,025/1,900	37,052	7,080	874,000	8.75	216	2.25	--	1147	---	1147
4	6,100/---	35,802	3,015	1,263,000	7.0	216	2.50	96	140	937	1077
5	6,105/---	38,900	1,410	1,372,000	7.9	216	2.50	96	232	837	1069
6	6,050/---	33,100	2,500	909,000	9.48	192	2.25	96	152	671	823
7	6,106/---	32,250	6,500	967,000	6.62	192	2.25	96	61	806	867
8	7,714/2,700	37,500	7,225	968,600	8.96	216	2.25	97	1020	---	1020
				Operator C - Texas							
1	7,400/620	29,071	4,316	854,300	8.17	192	2.25	--	---	---	604
2	7,710/---	27,449	---	630,796	9.0	192	1.75	86	---	---	807
				Operator E - California							
1	6,504/---	25,960	3,835	791,600	10.0	192	2.25	86	---	---	1014
				Operator F - Canada							
1	3,699/1,393	18,642	753	657,000	8.0	192	2.75	86	---	---	1289
				Operator G - Texas							
1	6,853/---	30,127	4,061	1,201,476	9.0	216	2.25	97	473	438	911
2	6,866/---	35,750	4,750	1,192,900	8.45	216	2.25	97	---	---	823
3	6,860/---	41,000	12,000	1,021,700	8.47	192	2.25	97	---	---	700
				Operator M - Texas							
1	5,068/200	---	---	---	9.0	192	2.25	87	---	---	690

*Based on A.P.I. Torque Factor Method - In-Balance.

Reviewing the measured applications listed in Table 1 emphasizes several facts:

1. Only one of the applications is either torsionally or structurally overloaded when the unit is in proper balance.
2. The instantaneous rate of productivity (per 24 hours) was often well in excess of the 24-hour (average) rate shown.
3. In many cases, large volumes of gas were handled through the bottomhole pump, and if included, would have increased total volumetric productivity by a substantial amount.
4. As mentioned, shrinkage and slippage often resulted in production at the wellhead, substantially less than the actual volumetric sweep of the bottomhole pump.
5. In practically every application shown, a more beneficial pumping mode could have been effected than the one actually used, if maximum optimizing were required.
6. Some of the torsional and structural loads shown above are artificially high because of restricted clearance between rods and tubing.
7. None of the surveys received indicated any serious functional or operational problems with the Mark II units.

PREDICTING MARK II LOADS AND PUMP DISPLACEMENTS

Accurately predicting pumping unit loads and pump displacements is often difficult because of: (1) the large number of variables in a rod pumping system, many of which are continually changing; (2) difficulty in determining the division of labor between pumping unit and reservoir at the instant of testing; (3) the anomalous character of the loads and displacements occurring in an elastic rod string; (4) the relatively long distance between plunger and tankage; (5) the problem of relating instantaneous fluid production rates to instantaneous loads; and (6) the problems of accounting for shrinkage, slippage, gas compression, volumetric efficiency, etc.

All or most of these problems can now be satisfactorily accounted for with the use of the powerful predictive techniques developed independently by the Sucker Rod Research Institute (Midwest Research) and Dr. S.G. Gibbs of the NABLA Corp. Both of these predictive methods are predicated on the solution of the wave equation as applied to sucker rod pumping. The chief difference between the two procedures is that the S.R.I. solution involves an analog computer; while the Gibbs' method requires digital computation. One of the chief reasons these more sophisticated predictive techniques are required is because the geometry of the pumping unit, and its kinematic properties, affect the performance of the entire system. Consequently, a predictive method that is applicable to "conventional" geometry will not apply to units with significantly different motion characteristics.

Recently, Dr. Gibbs developed a more precise predictive technique for all types of pumping unit geometry—which simply required insertion of the unit's linkage dimensions of each particular geometry—along with other pertinent data. Involved in this technique is a digital computer method for simulating the kinematic and torsional characteristics of the pumping unit, wave equation modeling of the rod string, and a downhole pump simulation that is suitable for the design calculations. By inserting Mark II linkage dimensions into this formulation, a set of precise optimizing tables was developed. Table 2 shows one of the optimizing schedules for the Mark II geometry.

In addition to the normal independent data, such as the rod size and taper, pump depth, production, pump diameter, stroke, strokes per minute, etc., the following values are developed:

1. The peak polished rod load was generated using an average damping factor, accounting for rod stretch, harmonics, frictional forces, etc.
2. Minimum polished rod load is determined in the same manner.
3. Maximum rod stress is also determined by regular methods.
4. The Column GRD (Goodman Range Diagram) gives the percentage of actual load range to the safe allowable load for a particular grade of sucker rod shown by the modified Goodman Diagram.
5. Peak torque is developed by generating a synthetic polished rod dynamometer card and then performing a standard API torque factor analysis at approximately 5 degree intervals throughout 360

TABLE 2—MARK II OPTIMIZING TABLES (PREDICTIVE DATA)

		ROD NO. 65				PUMP DEPTH 5000					PRODUCTION 400			
PUMP DIA.	STROKE	SPM	PPRL	MPRL	STRESS	GRD	PT	CBM	ITE	PRHP	PMHPD	PMHPC	EI	WRF
1.25	74	22.4	13232	935	29937	100	196	307	32.2	22.4	28.4	39.2	5.811E+01	5694
1.25	86	20.5	13677	911	30944	107	231	339	29.9	22.4	28.4	39.2	7.079E+01	5694
1.25	100	18.9	14042	421	31770	117	265	453	29.9	23.8	31.0	42.8	8.852E+01	5694
1.25	120	17.1	13992	11	31657	119	329	549	28.7	25.6	33.0	45.5	1.176E+02	5694
1.25	168	12.9	12137	158	27459	91	362	888	33.5	24.9	35.1	48.4	1.093E+02	5694
1.25	192	11.4	11748	514	26579	84	412	1250	32.6	24.4	34.6	47.8	1.181E+02	5694
1.25	216	10.2	11328	908	25630	76	433	1473	33.9	23.7	33.9	46.8	1.161E+02	5694
1.25	240	9.1	11199	1124	25338	73	471	1715	34.6	23.6	33.8	46.7	1.245E+02	5694
1.50	64	20.9	12963	1967	29329	88	164	264	34.7	18.9	23.6	32.6	4.015E+01	5799
1.50	74	19.2	12706	1878	28747	85	176	299	36.5	19.6	24.4	33.7	4.369E+01	5799
1.50	86	17.5	13087	1670	29609	92	218	352	33.4	20.2	25.7	35.5	5.765E+01	5799
1.50	100	16.0	13007	1373	29427	93	270	512	30.8	21.1	28.3	39.0	7.379E+01	5799
1.50	120	13.4	13121	1181	29684	96	264	614	35.7	20.1	27.2	37.6	6.946E+01	5799
1.50	144	11.0	12513	1590	28310	85	321	815	34.4	19.3	26.4	36.5	7.745E+01	5799
1.50	168	9.5	12401	1634	28057	83	361	1039	35.6	19.3	29.4	40.6	8.656E+01	5799
1.50	192	8.3	12358	1612	27960	83	419	1415	35.3	19.5	29.6	40.9	1.010E+02	5799
1.50	216	7.4	12207	1733	27618	80	470	1636	35.7	19.6	29.7	41.0	1.123E+02	5799
1.50	240	6.6	11999	2104	27146	75	537	1848	34.3	19.3	32.6	45.1	1.245E+02	5799
1.75	64	18.6	14254	3226	32250	96	162	300	38.2	18.2	22.8	31.5	4.193E+01	5925
1.75	74	17.1	14448	2795	32687	103	203	358	33.8	18.6	23.9	32.9	5.441E+01	5925
1.75	86	15.4	14678	2374	33209	110	251	416	30.4	18.6	25.8	35.6	6.880E+01	5925
1.75	100	13.4	14541	2156	32899	110	253	542	34.0	18.3	25.5	35.2	6.730E+01	5925
1.75	120	10.4	13913	2511	31478	97	296	737	35.4	17.3	24.5	33.8	7.114E+01	5925
1.75	144	8.9	14001	2369	31676	99	373	910	33.9	17.9	27.9	38.4	9.333E+01	5925
1.75	168	7.5	13853	2459	31341	96	418	1141	35.1	17.6	27.5	38.0	1.016E+02	5925
1.75	192	6.5	13539	2639	30631	90	497	1491	33.7	17.3	27.3	37.7	1.166E+02	5925
2.00	64	17.0	15460	3751	34978	111	194	344	32.6	17.0	22.2	30.7	5.119E+01	6069
2.00	74	15.4	15733	3371	35596	119	232	405	30.8	17.5	22.7	31.4	6.392E+01	6069
2.00	86	13.7	15952	3110	36091	126	262	461	30.6	17.5	24.7	34.0	7.322E+01	6069
2.00	100	11.3	15808	3145	35765	123	277	633	33.6	16.7	23.9	32.9	7.298E+01	6069
2.00	120	9.1	15539	3022	35156	119	342	790	34.2	16.8	24.0	33.1	8.940E+01	6069
2.00	144	7.5	15442	2974	34936	118	417	988	33.8	16.7	26.6	36.7	1.076E+02	6069

		ROD NO. 76				PUMP DEPTH 5000					PRODUCTION 400			
PUMP DIA.	STROKE	SPM	PPRL	MPRL	STRESS	GRD	PT	CBM	ITE	PRHP	PMHPD	PMHPC	EI	WRF
1.25	74	21.7	17878	809	29747	102	252	375	29.2	25.3	32.7	45.1	1.143E+02	7839
1.25	86	20.0	18189	1394	30265	101	281	427	28.4	25.3	32.7	45.1	1.295E+02	7839
1.25	100	18.6	19181	446	31915	119	363	544	26.0	27.8	38.1	52.5	1.939E+02	7839
1.25	120	16.6	18574	120	30905	113	422	639	26.3	29.2	39.5	54.4	2.289E+02	7839
1.25	144	14.7	16836	153	28014	95	419	774	30.6	30.0	40.3	55.6	2.119E+02	7839
1.25	168	12.7	15618	718	25987	80	442	1024	32.0	28.4	38.6	53.3	1.959E+02	7839
1.25	192	11.3	14992	1213	24944	72	473	1424	33.0	27.9	38.2	52.7	1.982E+02	7839
1.25	216	10.1	14292	1780	23780	64	473	1688	35.9	27.1	37.4	51.6	1.832E+02	7839
1.25	240	9.1	14142	2004	23530	62	516	1950	36.8	27.5	41.7	57.6	2.009E+02	7839
1.50	64	20.0	16747	2749	27865	79	196	321	32.7	20.3	25.9	35.7	6.664E+01	7917
1.50	74	18.6	16938	2486	28183	82	219	362	33.5	21.7	27.4	37.8	8.035E+01	7917
1.50	86	16.9	16910	2150	28136	84	268	421	31.1	22.4	29.6	40.9	1.016E+02	7917
1.50	100	15.2	16353	2035	27209	80	296	584	31.6	22.6	29.9	41.2	1.093E+02	7917
1.50	120	12.7	15921	1994	26490	76	304	725	34.9	21.4	28.6	39.5	1.036E+02	7917
1.50	144	10.6	15272	2354	25411	69	352	942	35.4	20.9	28.1	38.8	1.122E+02	7917
1.50	168	9.2	15109	2503	25140	66	378	1213	38.3	21.1	31.3	43.2	1.205E+02	7917
1.50	192	8.1	14949	2795	24874	64	449	1614	36.7	21.1	31.3	43.1	1.417E+02	7917
1.50	216	7.2	14722	3197	24496	60	511	1849	35.9	20.9	34.5	47.6	1.574E+02	7917
1.50	240	6.5	14498	3610	24123	56	585	2083	34.5	20.7	34.2	47.2	1.753E+02	7917

degrees of crank rotation. This method of torsional analysis does not involve approximations as do other predictive (torsional) methods.

6. CBM—the counterbalance moment required to bring the pumping unit into correct balance.
7. ITE—the Index of Torsional Effectiveness—a percentage number which shows how well the particular unit geometry and/or mode of pumping converts the polished rod load into the lowest and most uniform crankshaft torque. Selection of the highest ITE in the optimizing table will give the best torsional solution to the pumping mode selection.
8. Polished rod horsepower is the average work per stroke performed at the polished rod. This is an important number giving an accurate measurement of the power delivered to the rod string each stroke.
9. PMHPD—the prime mover horsepower required of a NEMA "D" electric motor, or equivalent internal combustion engine, using a method which considers the efficiency of the speed reducer.
10. PMHPC—the same information—i.e., the horsepower requirement when using

a NEMA "C" motor, or equivalent internal combustion engine.

11. EI—the economic index number which gives the most economical pumping combination when considering torsional, structural, and prime mover requirements. By selecting the lowest EI number, the most economical pumping system is thereby defined.
12. WRF—the weight of rods in fluid.

This advanced predictive technique, which actually synthesizes a polished rod dynamometer card and performs among other things a standard API torque factor analysis, usually gives good predictive results, provided accurate data is fed into the mathematical model. Although this system assumes incompressible fluid at the bottomhole pump, and 100% volumetric efficiency, it can be easily modified to any volumetric efficiency desired and also can be modified for gas or fluid pound.

The results obtained reconciling this advanced predictive technique to measured loads have in many cases been very good. Since the same mathematical model can be used for any geometry, it is believed that this predictive technique should be of considerable value to the industry.

CONCLUSIONS

The primary intent of this discussion was to catalog some of the measured performance data of this heavier class Mark II under actual field conditions, rather than investigating its theoretical functional characteristics.

With the advent of these larger Mark II units, and associated equipment—such as improved rods, pump, prime movers, etc.—it is believed that the tried and proven method of sucker rod pumping can be used to produce higher fluid volumes from greater depths with maximum economy, simplicity, and reliability.

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INNOVATED GAS LIFT - PNEUMATIC PUMPING

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INTRODUCTION

Efficient gas lift systems have served the industry many years, and each year has found both operator and manufacturer more conscious of innovated equipment and systems to continually improve the efficiency of artificial lift systems. Gas lift systems have proven to be extremely efficient and flexible when applied to wells with high flowing bottomhole pressures, but have proven to be of limited success in deep wells with low bottomhole pressures.

Conventional chamber installations have been one of the best ways to produce deep wells with low bottomhole pressures. This system allows a well to accumulate large volumes of liquid in a chamber exerting a minimim back pressure on the formation. The liquid is then transferred into the tubing and lifted to the surface. Normally the lift period lasts one minute per thousand feet of lift and no feed-in to the chamber is possible during this period since the pressure inside the chamber is higher than formation pressure. Wells producing large quantities of formation gas have reduced the efficiency of chamber installations and required special completion equipment to cope with this problem.

The automatic vent chamber system was developed to utilize all the advantages of the conventional chamber and to eliminate the two basic disadvantages—no feed-in during lift periods, and the problem of dissipating formation gas. The first problem was overcome by providing a method of venting the chamber of high pressure gas immediately after the transfer of liquids from the chamber into the tubing, allowing the chamber to start filling while the lift period is in progress. The second problem was overcome by allowing the formation gas to vent directly to the casing annulus instead of into the tubing.

Two types of automatic vent chamber (AVC) systems have been proven. One system is gradient-operated by the well liquids in the chamber and the other system is pressure-operated with a time-cycle controller at the surface gas controls. The pressure-operated system is for wells with capacities up to 150 BPD and the gradient-operated system is for wells with higher capabilities.

Figure 1 shows a schematic of the gradient-operated AVC system, and Fig. 2 shows a schematic of the pressure-operated AVC system. Unloading gas lift valves are shown exposed to the casing pressure. These are used, as required, to unload the well on initial kick-off and occasionally to kick-off the well after down-time periods. The bottom gas lift valve lifts the liquid to the surface after it is pumped from the chamber. The special three-way, two-position chamber pressure vent valve opens to u-tube liquid from the chamber to the production tubing and then automatically vents the chamber to the casing when it stops flow of the high pressure lift gas.

The several components of the two systems are illustrated in Figs. 1 and 2 and defined as follows:

1. Chamber Pressure - Vent Valve: This valve is the heart of the system and is made up of a 3-way, 2-position main valve and a choice of two pilots for control of the cycle frequency. One pilot is controlled by the fluid level in the chamber. The other pilot is pressure-controlled from the surface by a time-cycle controller.
2. Crossover Mandrel: This mandrel receives the CPV valve and contains flow courses that connect the chamber to the production tubing, lift gas tubing, and vent ports to the casing.
3. Accommodator: The accommodator serves as a pressure relay. It senses the fluid height in the dip tube and relays this signal to the gradient-operated pilot for cycle control. The accommodator is not required

for the pressure-operated AVC system.

4. Chamber: A bottle-type chamber is used so that the formation may be vented through the casing annulus to the surface. The chamber size is a function of the production desired, the available space, and the operating gas pressure. Chamber sizes may vary from as little as two barrels to more than twelve barrels.

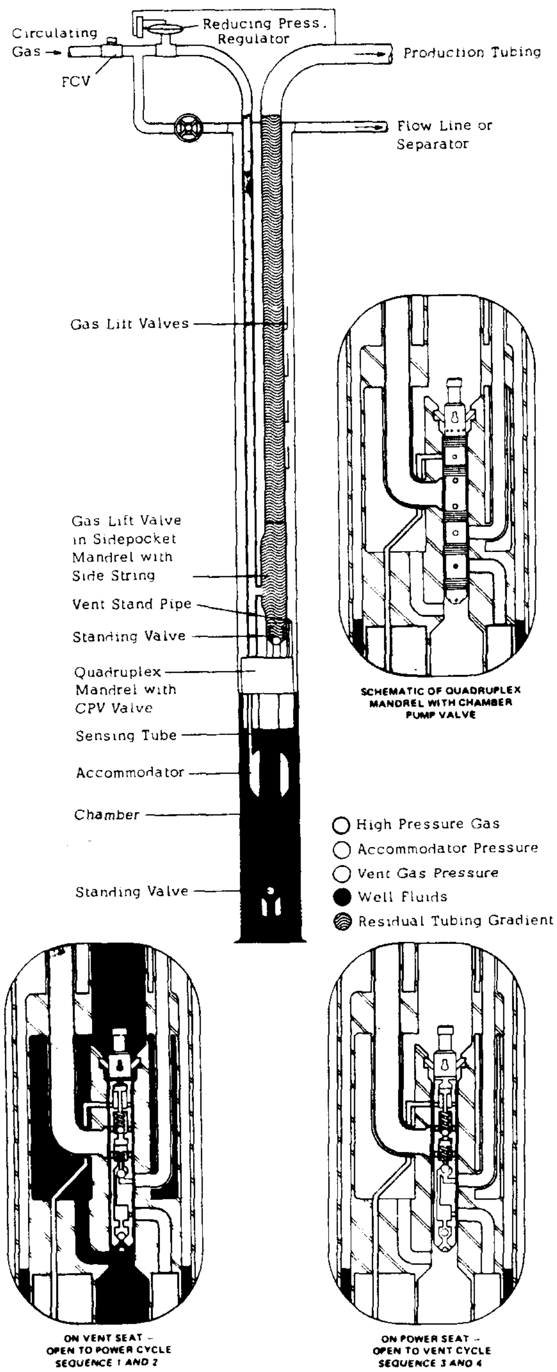

FIG. 1—SCHEMATIC OF GRADIENT-OPERATED AUTOMATIC VENT CHAMBER

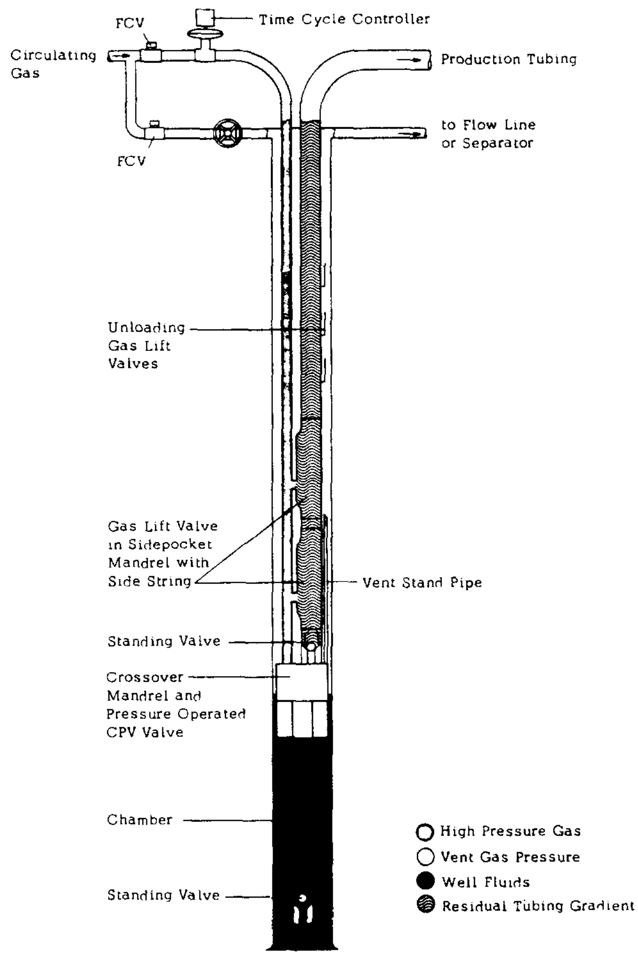

FIG. 2—SCHEMATIC OF PRESSURE-OPERATED AUTOMATIC VENT CHAMBER

OPERATION OF THE AVC SYSTEMS

The operational sequence of the gradient-operated automatic vent chamber is illustrated in Fig. 3. The cycle is separated into four distinct phases as follows:

Phase 1—The filled chamber signals the CPV valve to open the circulating gas port, close the vent port, and allow lift gas to enter the top of the chamber annulus.

Phase 2—High pressure circulating lift gas u-tubes the liquid from the chamber into the production tubing where it is retained by the standing valve.

Phase 3—In this phase, the chamber is empty having completed the pump period. As the liquid leaves the chamber, the CPV valve shifts to its power seat, closing off the high pressure circulating gas to the chamber. At the same time, it vents the top of the chamber to the casing. With the liquid now in the production tubing it may be lifted to the surface using conventional gas lift means.

Phase 4—In this phase, the chamber is venting and refilling. The CPV valve will remain in the vent position until the chamber is refilled. The gas lift system above the chamber is shown in the lift period of an intermitting cycle. The cycle frequency of the chamber determines the cycle frequency of the production tubing. As a function of the chamber size, circulating gas pressure, and production requirements, a system may be designed for a production tubing cycle to occur after one, two or even three chamber cycles.

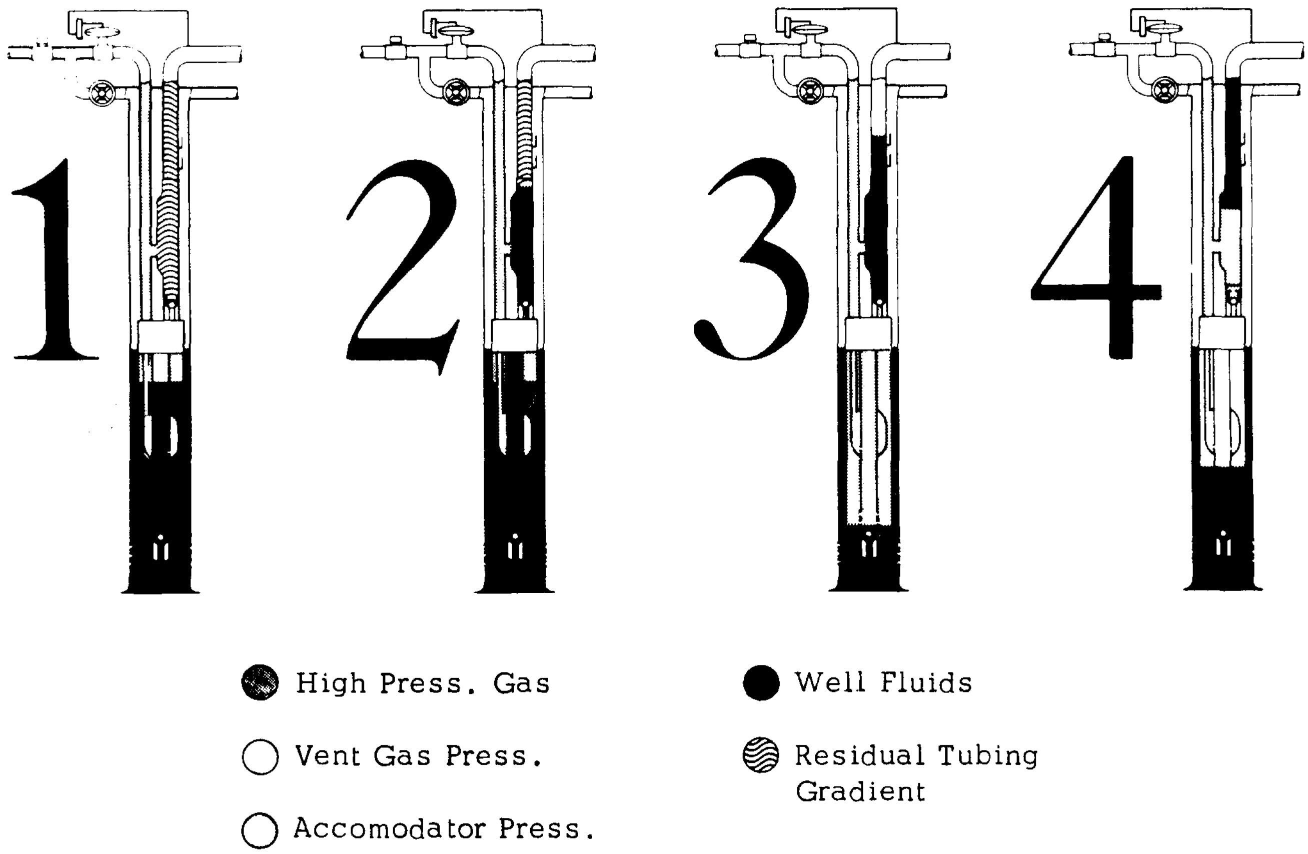

FIG. 3—OPERATION SEQUENCE OF AN AUTOMATIC VENT CHAMBER CYCLE

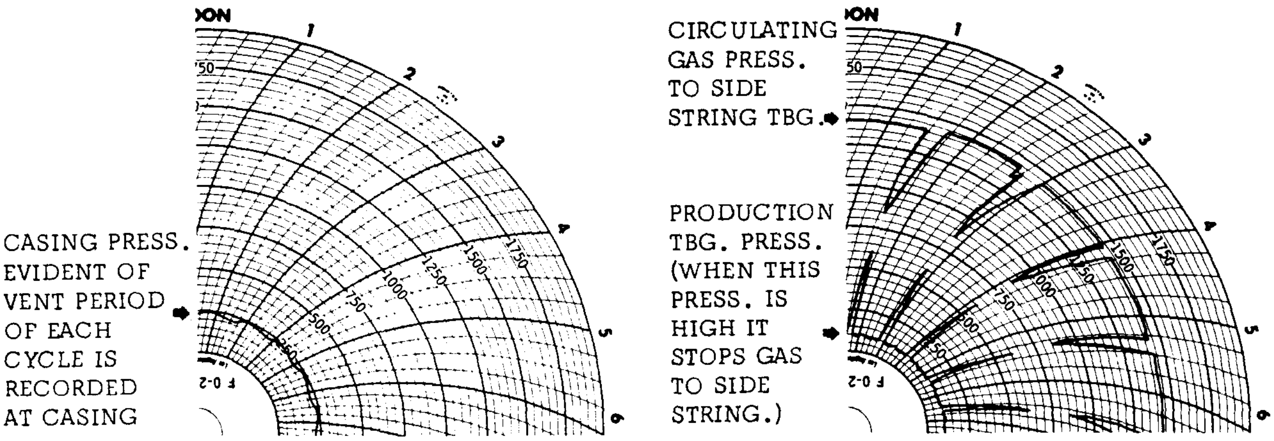

FIG. 4—PRESSURE RECORD OF GRADIENT-OPERATED AVC SYSTEM

This gradient-operated system responds to increasing production capabilities of a well without adjustment of the surface gas controls. The surface controls merely keep a defined pressure on the gas tubing. A production tubing pressure override is used to stop gas input when liquid slug arrives at the surface. As soon as the production tubing pressure declines, the circulating gas is again directed to the gas tubing. This is clearly illustrated in Fig. 4. This pressure record shows that one production tubing cycle is caused by one chamber cycle. The installation can be designed to give one tubing cycle with two or three chamber cycles. This is important because it means that a large liquid slug can be lifted in the production tubing, even when a small chamber is used. Because of its high production capability and efficiency even at low production rates, this is an excellent artificial lift system for unitized fields. The system has another feature which suits the needs of unitized fields—it automatically increases the cycle frequency to match the well's production capability.

As compared with the gradient-operated AVC system, the pressure-operated AVC system must be manually adjusted to match the production capability of a well. Its sequence of operation is similar to that of the gradient-operated system. It uses a pressure-operated CPV valve and therefore does not need the accommodator and sensing tube. Figure 2 is a schematic of the pressure-operated system. The surface gas controls are a time-cycle controller and choke. The timer is adjusted to cycle the chamber valve each time the chamber fills. The operating gas lift valve may be adjusted to function with one or more chamber cycles. Figure 5 shows a pressure record of this system. This record shows that two chamber cycles are pumped into the production tubing before the liquid is lifted to the surface.

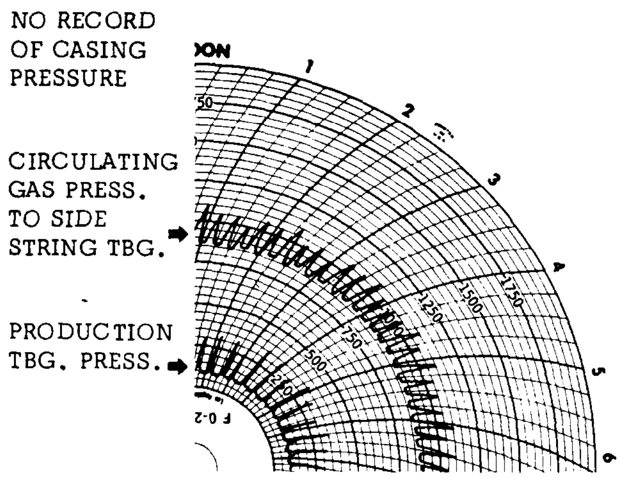

FIG. 5—PRESSURE RECORD OF PRESSURE-OPERATED AVC SYSTEM

In both of these systems, the chamber automatically vents immediately after the CPV valve pumps the liquid up to the production tubing. This allows the chamber to be filling simultaneously with a lift period of the production tubing. This unique feature is one of the reasons that this innovation has led to higher production capabilities. Another important feature is that the formation gas does not have to go through the chamber.

APPLICATIONS OF THE PRESSURE-OPERATED AUTOMATIC VENT CHAMBERS

The first application of this technique was installed in Andrews County, Texas, late in 1970. The well was being produced with a conventional intermitting chamber and yielding 30 BPD. It had a formation GOR of 7500 SCF/bbl. The casing was 5½ in., 15.5 lb/ft and the pressure-operated AVC system was installed with 2⅜ in. hydril production tubing and 1½ in. IJ circulating gas tubing. Because of the very low bottomhole pressure, a single time-controlled gas lift valve was installed above the chamber pressure-vent valve.

This first installation increased the production to 50 BPD and a 2530 GLR was required to pump the chamber and lift the liquids to the surface. The gas lift valve was lifting from 8300 ft. The chamber volume was two bbl and its length was from 8300 ft to 8650 ft. The top of the perforation was at 8500 ft.

Several things contributed to this increase in rate: (1) the formation gas is free to go up the casing annulus and vent directly into the flow line, (2) large liquid slugs may be accumulated in the production tubing without causing a high wellbore pressure by "pumping" the chamber liquid into the production tubing, (3) the CPV valve allows the chamber to be filling while the gas lift valve above is lifting the liquid to the surface so a maximum time is allowed for the feed-in period into the chamber.

In spite of the good results, and because of some prototype equipment malfunctions, the system was replaced with a rod pump which produced about 60 BPD.

The second installation was in California in early 1971 and followed an intermitting gas lift system that was producing 91 BPD. This well had 7-in., 23 lb/ft casing, so 2⅜ in. tubing was used for both the production tubing and for the circulating gas tubing. Several intermitting valves were used for unloading the well and a tubing pressure-operated valve was used as the operating valve above the CPV valve. These were located at 8620 ft, and a 2-bbl chamber was below them. This was the first installation to use the vent riser pipe which helped to fill and vent the chamber more efficiently. The well leveled out at 150 BPD and 2560 GLR. Its maximum rate during a stabilization period was more than 200 BPD. In January 1973, the system was producing 120 BPD and using 2800 SCF/bbl to pump the chamber and lift the liquid to the surface. The liquid level in the casing has been located several times with an accoustical well sounder at 8600 ft (this is only 30 ft above the top of the chamber).

In the same field, another well was equipped the same way and the production rate increased from 50 BPD to 85 BPD. This well is producing using an estimated 3000 SCF/bbl of liquid lifted to the surface.

APPLICATION OF THE GRADIENT-OPERATED AUTOMATIC VENT CHAMBER

The gradient-operated AVC system is recommended for wells with higher production rate potentials of 150-180 BPD. The maximum capability has not been defined by field test yet, but it is estimated at more than 800 BPD with 2⅞ in. production tubing from 9000 ft.

In May 1972, the first well was equipped with this system. It had 7-in., 26 lb/ft casing and was equipped with 2⅞ in. production tubing and 2 ¹⁄₁₆ in. IJ circulating gas tubing. Two operating gas lift valves were positioned at 7460 ft and 8148 ft. The gradient-operated CPV valve was located at 8222 ft and a 6-bbl chamber was bottomed at 8726 ft. A slotted liner was set through the producing interval of 8732 to 9157 ft. The system immediately increased the production rate from 94 BPD to 130 BPD. By October 1972, the production was 233 BPD and by January 1973, it was 328 BPD. This installation uses about 2500 SCF/bbl of liquid lift.

One of the primary advantages of the gradient-operated system is exampled by this well. The increased production rates are a result of response to a water flood and, since the surface gas controls merely maintain a defined gas pressure on the gas tubing, the system automatically produces at the higher rate without additional adjustment. The casing fluid level was measured in October 1972 and January 1973 at 8200 ft (just above the chamber) with an accoustical well sounder.

The second installation of this type was installed in June 1972 in a well with 8⅝ in. casing. The well had been making 60-80 BPD by intermitting gas lift. The production tubing was 2⅞ in. and the circulating gas tubing was 2⅜ in. Operating gas lift valves were positioned at 7386 ft and 8049 ft. The gradient-operated CPV valve was at 8124 ft and a 10-bbl chamber was hung below it. The bottom of the chamber was at 8705 ft and the zone was perforated from 8843 to 9108 ft. This system increased the production rate to 140 BPD. By October, the production rate had increased to 170 BPD. In December 1972, it measured 210 BPD. A circulating GLR of 2300 SCF/bbl is required to produce this well.

CONCLUSION

The success of these five installations (three of them pressure-operated and two of them gradient-operated) have proven that the AVC system will lift more liquid than any existing gas lift system that has a producing bottomhole pressure less than that required for continuous flow lift. In two specific cases, the AVC system has outperformed conventional chambers. The automatic feature of the gradient-operated AVC system is naturally suited to wells in unitized fields where production rate increases are expected.

These two conclusions and features mark the AVC systems as important innovations in gas lift. They do, in fact, extend gas lift to wells not previously considered good gas lift system candidates.

After three years of field testing and equipment refinement, this innovated system is ready for wide application. It offers the following advantages to today's operators and production engineers:

1. A gas lift system innovation that expands the application of gas lift to many more wells, especially large production requirements with low producing bottomhole pressures
2. A system that has automatic cycle frequency control that is ideally suited for unitized fields
3. A high production rate system that offers the low operating costs of gas lift
4. A system that has a very low capital investment requirement when gas compression equipment is already in the field
5. A system that vents the formation gas directly to the casing (this allows formation gas to go up the casing to the flow line and it also means that the casing does not have to retain high pressure gas)
6. The CPV valve and operating gas lift valves are wireline retrievable to allow inexpensive access to them for repair or adjustment.