HIGH RATE SUCKER ROD PUMPING AND ITS ECONOMICS

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ABSTRACT

High rate rod pumping continues to be an important artificial lift method in many fields around the world. Just what are the production limits and the loads for the largest rod pumping units? A comparison of the largest convention unit, air balanced unit, an improved geometry unit, and an ultra long stroke pumping system shows the potential production limits at various pumping depths. The key element in design is not to overload the sucker rods so that frequent fatigue failures occur. Also to prevent premature failures, do not overload the unit gear box and structure rating.

The common goal in selecting, installing and operating any artificial lift system is to make the highest present value profit (PVP) -- net discounted income. All factors must be considered in picking the correct type, kind and size of lift method. Close attention to the various attributes of each lift method is recommended. The designer should consider the initial installation costs, possible production rates, and operating costs. The most difficult of these factors to obtain is the operating cost for the lift conditions to be encountered. Operating cost estimates must be made for typical fixed and variable costs plus the cost for energy and pumping repair and maintenance costs. Cost data from an analog field are most beneficial. Once the designer has the basic cost data, an overall economic analysis can then be made for the various artificial lift methods. Thus, by a combination of proper selection, design, and operating practices, near maximum profits will be realized.

INTRODUCTION

Sucker rod pumping is by far the most common type of artificial lift method in the USA. It remains the preferred lift method (especially for land locations) and typically is the most profitable choice. In general, sucker rod pumping is not considered a high rate lift method; however, relatively high volumes can be pumped by using large surface units and loading the sucker rods to near their failure endurance limits. This paper is a comparison of the rates possible by use of the largest commercial units and 115 k and 140 k tensile strength sucker rods. To be a successful operation, the operating costs must be kept low and the oil recoverable reserves produced in a reasonable time period. The economics of a typical artificial lift installation will be examined on a before tax basis. The results will give the designer some guidelines on the more important parameters to maximize profits.

It is widely stated that a long, slow stroke unit with a big bore pump is the preferred sucker rod pumping method [1]. The question comes up as to how long a stroke, just how slow the strokes per minute, what size a plunger, and how important are these parameters to the over-all economics. The results must be that the desired production volumes are met and operating costs are reasonable. Many of the attempts in the past to use "unique design" long, slow stroke units proved unsuccessful primarily due to excessive maintenance costs. Also, sustained high production rates were not maintained and lower or equal operating costs were not achieved. What choices do we have today in selecting high rate sucker rod pumping equipment and what are the economic ramifications?

SELECTION and COMPARISON

The largest commercial units were selected to make this general theoretical study. The following units were evaluated to determine their approximate lift rates at various depths with 115 k and 140 k tensile strength sucker rods:

Conventional 1824D-365-192
Mark II 1824D-427-216
Air Balance 2560D-470-240
Rotaflex 1100--320D-500-306

The results are tabulated in Tables A, B, C, and D. A number of general assumptions were used in making these calculations. In no case were the allowable loads on the sucker rods, gear box or structure rating exceeded. For the sucker rods, the Modified Goodman Diagram was used with a service factor (SF) of 1.0 in all cases [2]. There was no restriction on the size of the plunger; therefore the casing size needs to be large enough to accommodate the plunger and the tubing. To accommodate the larger plungers, the design may require the use of on-off tools. From a practical side, the casing needed to be 5.5-inch O.D. casing for 2 7/8-inch O.D. tubing and 7.0-inch O.D. casing for 3.5-inch O.D. tubing. In all cases the tubing was considered anchored--thus no tubing stretch. The Specific Gravity of the lifted fluid was 1.0 and the wells were assumed to have a fluid level at the pump.

The designs are based on a modified API RP 11L approach [3]. Thus the following general assumptions were assumed:

Modified Sine Wave Motion (conventional unit)
Full Pump Fillage (parallelogram bottom hole card)
Steel Sucker Rods (designed for equal stresses at each taper)
Small Prime Mover Slip (5 to 8 percent)
Negligible Fluid Acceleration Loads
No Abnormal Friction
No Unusual Mechanical Problems and Correctly Counterbalanced..

For the Mark II and Air Balanced Units, the design calculation modifications as proposed by Griffin were used [4]. Relatively good approximations were found between the API RP 11L and the wave equations for the **rod loads** of all units. At low pumping speeds (N/No' less than 0.25) the dynamic loads increase almost linearly and are relatively small. The limiting conditions (rod stress, structure rating, gear box size, spm, or minimum polished rod load) were found and listed for each case. If two or more limiting conditions were found (within 5% of the limit), these were also noted in the tables--the more important one listed first.

As might be expected, in general the longer stroke units produced slightly higher rates and the higher strength and larger rods produced significantly higher rates. The results are shown in Tables A (Conventional unit), Table B (Mark II unit), Table C (Air Balanced unit), and Table D (Rotaflex unit).

A bar graph of the possible production rates for the 140 k psi tensile strength rods are shown in Figure 1 and Figure 2. Note that there are ranges or cases where a specific unit performes better than the others. Such cases need to be carefully considered by the designer and further explored using actual field conditions and a good wave equation.

The pumped rate when using a conventional unit was typically limited by the maximum rod stress as derived from the Modified Goodman Diagram (MGD). At shallow depths (2500 and 3500 feet) with a 4.75 inch bore pump, the gear box was sometimes the limiting factor; whereas, at deeper depths a smaller gear box could be used. The structure rating is not adequate for the conventional unit when loading 1 1/8-inch high strength (140 k psi) sucker rods with only a 365 structure but is adequate for loading 1-inch rods for depths no greater than 8500 feet. Thus, the conventional unit compares more favorable with the other units when 1-inch tapered rod strings are used.

The large Mark II is not typically limited by gear box size, or structure rating. It is often limited in wells less than 5000 feet when using large bore pumps by the low minimum polished rod load. Like the conventional unit, the normal limiting factor is the rod stress. The large Mark II compares very well with their longer stroke competitors--especially at depths greater than 5000 feet. When using Mark II units, a careful investigation of the minimum loads with a good wave equation program is recommended.

The air balanced unit will produce at comparable or higher rates than the Rotaflex 1100 unit. The largest air balanced unit is typically limited for depths greater than 3000 feet by the rod string stress rating. Only at shallow depths with large plungers does the 2560 D gear box become loaded. Since the gear box is expensive, the designer should carefully explore use of a smaller gear box by use of a good wave equation design program. The initial cost of this large air balanced unit is relatively high.

The Rotaflex 1100: 320D-500-306 unit was not typically limited by the gear box or the structure rating. Like the other units, the normal limiting design factor is the maximum rod stress. The maximum rated strokes per minute (SPM) is the limiting factor for several design cases listed but in all cases the rods are loaded to at least 85 percent of their ratings by the Modified Goodman Diagram (MGD). Thus the suggested limit of 4.5 SPM by the manufacturer appears reasonable to achieve low (long range) maintenance costs. The rates of the Rotaflex 1100 appear in some cases to be comparable to the largest air balanced unit but at a lesser initial cost. In addition, the reduced SPM and the resulting reduced reversal cycles per year may decrease failures. The biggest rate advantage appears to occur in shallow wells when using 1-inch sucker rods. Actual operating costs are key to which choice is best.

SUCKER RODS

The key to successful sucker rod pumping is to have long sucker rod life without failures. It is ridiculous to assume a steel sucker rod life of only 10 million reversals. There are countless wells with steel rods that have over 100 million reversals--which would be about 20 years if running at 10 SPM. These are wells with relatively low stresses and minimal corrosion. Figure 3 is typical laboratory data for API class C steel sucker rods with 93,000 psi tensile strengths. These data are for polished steel rod specimens run with full stress reversals from tension to compression at relatively high revolutions per minute. Note that for tests run in air, there were fatigue failures until stress levels decreased to about 40,000 psi (at 10 million cycles). In general, no more failures occurred if the stress levels were kept less than 40,000 psi. Thus, in the laboratory based on numerous test of steel rods, if 1 to 10 million cycles were achieved without failure, no fatigue failures would be expected regardless of the number of cycles. This stress level is called the endurance limit.

Similar tests run on steel specimens in a corrosive environment without inhibition, showed that the performance was not nearly so good. In fact, for such conditions, there is no endurance limit and such steel rod specimens will fail in only a few years depending on the stress level. In the case shown and for stress of 30,000 psi, a life of only 2 years might be expected at 10 SPM. Performance of commercial steel rods in oil wells is normally different from these two laboratory tests. The rods are not polished specimens, are not flexed from tension to compression, have a much slower flexture rate, and operate in a "semi-corrosive" environment--even when inhibited. Some laboratory data were obtained to more closely match typical oilfield operating conditions and such data combined with field data indicated an "experience" performance as shown in Figure 3. Such data were used by Shell in West Texas in the 1950's and led to the conclusions that stress levels in API class C and K rods should be kept below 30,000 psi. The question was "how much less stress and what effect did load range have on the life of API Class C and D sucker rods?".

Goodman, Johnson, Wohler, Bauswchinger and other investigators (in the 1930's) showed that the number of cycles of stress required to cause failure depends on the range of stress. Goodman found that the endurance limit for polished steel specimens for a full stress reversal was about 1/3 of the tensile strength and for a zero to tensile reversal was about 1/2 the tensile strength--reaching the apex of the tensile strength of the steel rod at zero load range. The plot of such data became the Goodman (or Goodman-Johnson) Diagram and showed the effect of range of stress on endurance limit of steel. This diagram was used in machine design of steel but with various applied safety factors.

An API committee on sucker rods adopted the Goodman diagram. The problem was "what safety factors should be applied for typical oilfield use of commercial sucker rods?" Reportedly after much discussion, the committee selected a safety factor for the endurance limit of T/1.75 at the apex with no load range and of T/4 at the Y-intercept with 100% tensile load range. The result was the Modified Goodman Diagram (MGD) and this guideline was considered by most users to be a conservative (safe) guideline where corrosion was not a factor. Provisions were made to apply an appropriate service factor to adjust the stress values downward based on the severity of corrosion.

An example for an API class C rod with 90 k tensile strength is shown in Figure 4. Although the original design selection was somewhat arbitrary, the MGD has been used successfully for many years by the industry. Without ample field data, the MDG is considered a good design method for steel sucker rods. Where an excellent inhibition program is in place and the rod handling practices are good, a SF of 1.0 is recommended. Experience in the field may require lowering the SF to 0.9 or 0.8. If a SF value of less than 0.8 is needed, the operator needs to change the design of the rod string or to improve inhibition and handling practices.

There are numerous other consideration for steel sucker rods. Should higher tensile strength rods be used to raise the endurance limit to permit higher rod loads? This study used the API class D rods with minimum tensile strengths of 115 k psi and "Special Service" rods with minimum tensile strength of 140 k psi--utilizing the Modified Goodman Diagram to establish the endurance limit. See Figure 5 and Figure 6. Such an approach appears reasonable. High strength rods are more "temperamental" and must be handled with care. They are more notch sensitive and are subject to failure due to sulfide stress cracking. An excellent inhibition system should be maintained when using such rods. Some operators have found the API class D rod to be borderline for using in sour service. Some quenched & tempered (Q&T) API class D rods appear suitable for sour service if inhibited. There is also the "EL" rod that is induction case hardened and is rated by the manufacture to 50 k psi for all tensile load ranges. Norris has modified the API Modified Goodman Diagram from T/4 to T/2.8 at the Y-intercept for its Norris 97 rod--which means much higher rod stress loading. Such rods require proper handling and inhibition if fatigue failures are to be minimized.

With the above background, the question still arises as to how important are the number of reversals for typical steel rods used in oil wells. The answer is "it depends." If the stress levels are kept to the values recommended by the Modified Goodman Diagram, if there is an excellent inhibition program to minimize corrosion, and if the rod handling practices are good, then the number of reversals may exceed 100 million cycles with only a few fatigue failures. Thus, the number of cycles for such conditions have little impact on total rod failures in a 20 year period. Experience has shown time-after-time that **even** if the stress and SPM are kept relatively low, corrosion and poor handling practices will result in numerous rod failures. Thus, the number of cycles is not so important as good operating practices. Undoubtedly there are cases where the rod stress levels are high and/or the inhibition is poor. In such cases it may well be that the number of cycles becomes important as far as fatigue failures. To best answer this question objectively requires good field data over a number of years. Data for the equipment of concern must be gathered keeping all other variables constant. Such information is extremely difficult to obtain and analyze. A limited amount of such data implies that the number of cycles is somewhat important but difficult to quantify.

PUMPS

The pump bore (plunger size) is an important parameter in high volume rod pumping as noted by Gault and others [5]. The API design method and various wave equations show that for a fixed volume of fluid to be lifted to the surface, a bigger pump bore is more efficient at its relative low SPM as compared to a smaller bore pump at its higher SPM. There is less overall friction and wasted energy. My analogy is the case where 1000 pounds of sugar must be carried upstairs in a time frame of 1000 seconds. There are many choices on how to do this work. One could pick up the 1000 pounds and struggle up the stairs in 1000 seconds--a poor choice if you wreck your back. A second choice might be to make 100 trips carrying 10 pounds each taking ten seconds--much running and waste of shoe leather--not very efficient. Better choices might be carrying 100 pounds in 10 trips taking 100 seconds each or carrying 200 pounds in 5 trips taking 200 seconds each trip. If you have a strong back, then the 200 pound load might be a good efficient choice. Remember it takes considerable energy to carry yourself up and down the stairs without doing useful work (like picking the rods up and setting them down).

The key is to select as large a bore pump as feasible and not overload the rods, structure or gear box and produce the maximum amount of fluid with the lowest polished rod horsepower. The efficiency will be improved and monthly power costs will go down. There are other considerations in making the bore size choice and in selecting the type pump. Rod pumps are preferred over tubing pumps since repairs normally do not require pulling the tubing. Furthermore, bigger bore pumps typically cost more to purchase and more money to repair. Minimizing the pump inventory and reducing the number of stand-by pumps could be significant. As in most things in life, the decision is not always clear cut. Keeping good pump records helps in making the more profitable decision.

PRIME MOVERS

In this paper it was assumed that the same type prime mover was used on the various type units and that the type had no effect on the production rate or rod loads. This assumption is not absolutely correct since the prime movers do alter loads and rates slightly. Gas engines are still used is some locations where there is no electric power in the region or there is some economic advantage. Remember gas engines were the original high slip method used in the oil field. A gas engine with a wide range of speed during a pumping cycle will reduce rod loads. However; they are difficult to time cycle and often hard to start. In general, they have more disadvantages than advantages.

Electric motors are now typically used in most locations where there is a good source of electric power. Again the designer has several choices. One of the most commonly used prime mover is the NEMA D (normally 440 volts and 1200 rpm) that is designed to slip 5 to 8 percent under full load conditions and develop a locked-rotor torque that is 2.8 times the full load torque. There has been much discussion of the use of ultra-high-slip electric motors over the years. If properly sized, they will reduce peak loads but normally at the sacrifice of total lift efficiency. Ultra-high-slip electric motors are typically triple rated and cost more money initially than NEMA D electric motors. One of the keys to improve efficiency is to size the motor closely to the needed size and ensure a reasonable power system power factor. Also it is important to limit rotating inertia to gain maximum slippage effects. Some operators are now using NEMA B motors that are slightly (about 5%) more efficient that the NEMA D motors. One requirement for the NEMA B motor is that loads must be relatively constant (a cyclic load factor near 1.0) and no extreme start up loads. It is not fair to compare various type units with different type prime movers or different plunger sizes unless there is ample data to support the conclusion that certain type combinations cannot or should not be used.

GAS INTERFERENCE

Gas interference is a frequent problem in pumping wells of all types and can diminish rates significantly. Partial fillage of the pump with free gas will reduce the efficiency of all length pumps. The key is to vent the gas up the annulus and pump only the liquids. The use of an effective gas anchor as reported by Clegg and others is recommended--especially use of the natural gas anchor [6]. High rate wells producing significant oil with typical GOR's often experience poor pump efficiencies even with the best of gas anchors. However; **gas locking** should not be a problem. Gas locking occurs only under conditions of near complete fillage of the pump with gas, poor pump spacing, high built-in pump storage on the down stroke, short pump strokes, and minimum liquid slippage by the plunger. Such conditions should be rare with any of the units in this paper.

WEAR AND FRICTION

Enemies to successful high rate rod pumping are wear and friction. Fiction and wear occur in the pump and on the rods and tubing. Theoretically long slow pumping should reduce this problem. Also larger tubing (or smaller rods) and changes in the type materials may be even more helpful. It has been known for years that larger tubing in directional wells significantly reduces rod and tubing wear. Furthermore the sprayed metal coupling will extend sucker rod coupling life. Such couplings need to have a relatively smooth finish to prevent excessive tubing wear. Use of a tension tubing anchor is recommended to keep the tubing from buckling excessively (causing a wear problem) and to eliminate tubing stretch (which reduces production). Rod guides can also be used in areas of excessive wear but their use should be restricted since they often cause more problems than are benefitial. Although wear and friction are real problems, they can often be minimized by proper system design.

OPERATING COSTS

Good reliable operating costs that are meaningful are difficult to obtain. A large part of the problem often lies in the accounting system and procedures. The accounting system for most companies is set up to pay the bills and taxes--not necessarily to allow cost accounting and analysis. The systems are normally on a lease basis not a well basis. Thus, the operating costs on leases with several wells may be difficult to interpret--especially if the wells are in different reservoirs, have different lift methods, or have some flowing wells, gas wells, or service wells. The most useful cost data come from leases with wells equipped with the same type artificial lift and with similar operating conditions. Another accounting problem is the "service utility" cost--those central systems such as a salt water disposal system where costs need to be allocated back to the lease and the well. An equitable allocation system must be derived and reviewed periodically.

A big problem with operating costs' data is the accounting groupings and how good a job is done in coding the costs to the proper categories. The system needs to be simple but costs need to be grouped in meaningful categories. One typical approach is to determine the operating cost per barrel of oil and use this as a common yardstick. This may be great as an overall yardstick but is of little help in analyses of artificial lift or in generating cash flow predictions for various wells on artificial lift producing various volumes of oil and water. Operating costs need to be segregated into routine surface operating costs, routine artificial lift operating costs, and non-routine expenditures. The routine surface costs would be all typical costs for treating and handling the fluids that reach the surface. The routine artificial lift costs would primarily be the energy cost for lifting the oil and water plus the repair and maintenance costs for all artificial lift operations--both surface and subsurface. The non-routine costs would essentially be costs for stimulation, recompletions, or reconditioning.

ECONOMICS

The resulting profit (of most oil wells) will be increased or diminished by the artificial lift equipment choices [7]. The factors that must be evaluated are (a) the oil and gas production over life, (b) the operating cost over life, and (c) capital cost of the equipment. Such an evaluation requires developing a production model, an income discount program, an operating cost prediction model, plus an estimation of the capital cost. Such an analysis needs to be done for a before tax case and after tax case. Normally a before tax case is sufficient for decision making unless there are special tax benefits. This type analysis is a rather lengthy process without a computer program and depends on good assumptions for meaningful answers. The most difficult data to obtain are operating costs. Hopefully in the future such data will be available through the special efforts of Texas Tech.

A simple spreadsheet computer program was developed to make a full life economic analysis for artificial lift installations. A copy of the input and output for a "base case" is shown in Table E. The designer has the option to enter operating cost per month for items that are not rate sensitive and cost per barrel of oil /liquid for items that are rate sensitive. The use of the cost for a barrel of liquid is probably a better approach than using barrel of oil. The user must input monthly pull and repair cost (the total monthly artificial lift repair and maintenance cost) plus the energy cost, lift depth, and lift efficiency.

The "base case" is for a $150,000 rod pumping installation producing 1000 barrels of fluid per day from 5000 feet. The production model assumes a constant rate over life -- often a good assumtion in water floods and water drive reservoirs. An effective oil decline rate of 14 percent was used which resulted in a life of about 14 years and produced reserves of over 314 thousand barrels of oil. The overall result was a maximum PVP (present day value profit--discounted income) of 2.7 million dollars before tax. The analysis ignores all previous capital expenditures and looks only at the proposed changes. The effects of various changes in the "base case" can be easily made and changes in the economics are quickly calculated by the spreadsheet. For example, an increase of 10 percent in lift efficiency would result in a $38,000 improvement in PVP. Thus, if a simple change in the electric motor or type lift system could be done for an additional cost of $10,000, such an expenditure would be worthwhile. If the "pull & repair" costs could be reduced from $200 to $100 per month, an improvement of over $11,000 in PVP would result. A reduction in the power cost from $0.05 to $0.04 per kwh would improve profits by $45,000.

The economic spreadsheet can also be used to review the economics of higher lift rates. If the total production rate could be increased by 25 percent to 1250 BFPD and all other input values remain constant, the PVP would increase over $738,000. This assumes the decline rate does not change; thus, reserves increase to over 405 thousand barrels of oil. Such an improvement would not normally be expected. If the reserves are the same, then a decline rate of 17.65 percent must be used and the improvement in PVP is some $94,000. A few more thousand dollars for high rate artificial lift equipment would be easily justified if "pull and repair" costs can be kept constant. The designer simply inputs reasonable assumptions and quickly finds the resulting economic benefits.

CONCLUSIONS

(1) Use of the largest sucker rod equipment along with high strength rods and large rods results in significantly higher production rates.

(2) The ultra long stroke pumping system (Rotaflex 1100) appears most favorable for lifting shallow wells using 1-inch rods. At depths of 3500 feet and deeper when using 1-inch rods, the investigated units have about the same theroretical production rates--with the conventional unit typically on the low side.

(3) When using 1.125-inch high strength sucker rods and using the MGD, the large air balanced unit typically produced the maximum rates. At depths of 6500 feet to 8500 feet, the large Mark II unit produced comparable rates to their longer stroke competitors.

(4) The typical limiting factor to production rates is the allowed stress in the sucker rods. In a few cases the unit structure, gear box, minimum polished rod load, or SPM was found to be the limiting factor to rates.

(5) A full life cycle economic analysis of artificial lift installations is a good approach to determine the benefits of higher rates, lower costs, and improved efficiency. Such an approach can be easily set up on a spreadsheet where changes in the system can be quickly evaluated.

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Table A

Depth (feet)	Rods (k psi)	Rod Taper	Speed (SPM)	Bore (inches)	PPRL (lbs)	MPRL (lbs)	PRHP (HP)	Limiting Item*	Rate (BPD)
CONVENTIONAL-1824D-365-192						(PRICE JAN 96 $96,000)			
CONVENTIONAL-1280D-365-192						(PRICE JAN 96 $86,000)			
2500	115	8	7.0	3.75	23913	2601	38	Rd	2096
2500	140	8	8.0	4.25	28157	1407	54	Rd	3019
2500	115	98	7.6	4.25	29781	2261	52	Rd	2897
2500	140	98	6.1	4.75	31865	4226	47	GB	2812
3500	115	86	6.3	3.25	24794	4152	32	Rd	1343
3500	140	87	6.2	3.75	29931	4587	40	Rd	1704
3500	115	97	6.0	3.75	31679	5593	39	Rd	1681
3500	140	98	8.8	3.75	35325	2022	64	Rd,St,GB	2531
4500	115	86	6.0	2.75	25884	6079	28	Rd	898
4500	140	87	6.2	3.25	30636	5852	35	Rd	1208
4500	115	97	9.3	2.75	30220	3117	50	Rd	1440
4500	140	97	9.8	3.25	36246	2665	68	Rd,St	2017
5500	115	86	8.0	2.25	25510	5327	33	Rd	798
5500	140	86	7.4	2.75	30852	6176	40	Rd	1011
5500	115	97	6.2	2.75	33667	9073	34	Rd	888
5500	140	97	9.8	2.75	36427	4629	61	Rd,St	1431
6500	115	86	7.8	2.00	26555	7096	30	Rd	605
6500	140	86	9.5	2.25	30609	5666	46	Rd	891
6500	115	97	7.6	2.25	33729	9229	37	Rd	748
6500	140	97	10.0	2.25	36117	6409	55	Rd,St	1005
7500	115	86	8.0	1.75	27305	8426	29	Rd	476
7500	140	86	6.9	2.25	33101	10136	34	Rd	584
7500	115	97	7.4	2.00	34931	11541	34	Rd,St	573
7500	140	97	9.1	2.00	36500	9484	46	St	716
8500	115	86	8.3	1.50	28027	9713	27	Rd	372
8500	140	86	7.4	2.00	33535	11116	34	Rd	492
8500	115	97	7.6	1.75	35933	13251	32	Rd,St	457
8500	140	97	8.2	1.75	36406	12451	36	St	496

*Rd = Maximum rod stress w/MGD *GB = Maximum gear box rating

Table B

Depth (feet)	Rods (k psi)	Rod Taper	Speed (SPM)	Bore (inches)	PPRL (lbs)	MPRL (lbs)	PRHP (HP)	Limiting Item*	Rate (BPD)
LUFKIN MARK II-1824D-427-216						(PRICE JAN 96 $110,000)			
LUFKIN MARK II-1280D-427-216						(PRICE JAN 96 $98,000)			
2500	115	87	7.4	3.75	21750	28	28	Rd,MPRL	2483
2500	140	87	5.9	4.75	28610	2164	42	Rd	3019
2500	115	98	7.3	4.25	27775	177	49	MPRL,Rd	3144
2500	140	98	7.4	4.75	31795	7	58	MPRL	3902
3500	115	86	6.4	3.25	23800	2309	32	Rd	1551
3500	140	87	6.6	3.75	28457	2040	41	Rd	2054
3500	115	97	8.2	3.25	26896	21	45	MPRL	2040
3500	140	98	8.1	3.75	31614	139	55	MPRL	2600
4500	115	86	6.5	2.75	24479	3556	30	Rd	1102
4500	140	86	9.0	2.75	25386	428	44	MPRL	1537
4500	115	97	9.0	2.75	28784	445	48	Rd,MPRL	1592
4500	140	97	9.0	3.25	33939	440	60	Rd, MPRL	2117
5500	115	86	7.9	2.25	24352	3237	32	Rd	901
5500	140	86	7.1	2.75	29894	4459	38	Rd	1127
5500	115	97	9.0	2.25	28949	2253	42	Rd	1078
5500	140	97	9.0	2.75	34310	4512	55	Rd	1510
6500	115	86	7.5	2.00	25384	5271	28	Rd	667
6500	140	86	9.2	2.25	29234	3244	44	Rd	1000
6500	115	97	7.4	2.25	32365	6802	36	Rd	838
6500	140	97	7.3	2.75	38714	7243	47	Rd	1126
7500	115	86	7.7	1.75	26108	6511	27	Rd	527
7500	140	86	6.7	2.25	31929	8274	32	Rd	664
7500	115	97	7.3	2.00	33582	8944	33	Rd	651
7500	140	97	9.0	2.25	38222	6294	53	Rd	979
8500	115	86	8.0	1.50	26758	7640	26	Rd	413
8500	140	86	7.2	2.00	32418	9138	33	Rd	562
8500	115	97	7.3	1.75	34456	10887	31	Rd	505
8500	140	97	7.2	2.25	41146	11487	42	Rd	716

*St = Maximum structure rating *MPRL = Minimum polished rod load

Table C

AIR BALANCE-2560D-470-240 (PRICE JAN 96 $150,000)
AIR BALANCE 1824D-470-240 (PRICE JAN 96 $120,000)

Depth (feet)	Rods (k psi)	Rod Taper	Speed (SPM)	Bore (inches)	PPRL (lbs)	MPRL (lbs)	PRHP (HP)	Limiting Item	Rate (BPD)
2500	115	87	4.7	4.25	24728	4061	35	Rd	2208
2500	140	87	5.3	4.75	29229	3231	47	Rd	3053
2500	115	98	7.0	4.25	28888	762	59	Rd,MPRL	3375
2500	140	98	7.2	4.75	33299	416	72	Rd,GB,MPRL	4268
3500	115	87	5.6	3.25	24475	3398	35	Rd	1529
3500	140	87	5.8	3.75	29119	3195	35	Rd	2039
3500	115	97	5.1	3.75	31400	5203	41	Rd	1839
3500	140	98	7.9	3.75	33956	95	71	MPRL,Rd	2892
4500	115	86	5.7	2.75	25011	4527	32	Rd	1088
4500	140	87	5.4	3.25	30298	5139	39	Rd	1377
4500	115	97	8.0	2.75	29428	1745	52	Rd	1584
4500	140	97	8.5	3.25	35250	982	71	Rd,MPRL	2260
5500	115	86	6.8	2.25	25053	4506	34	Rd	875
5500	140	86	6.2	2.75	30434	5530	41	Rd	1118
5500	115	97	5.4	2.75	33046	8054	36	Rd	1004
5500	140	97	9.0	2.75	35808	2021	70	Rd	1710
6500	115	86	6.4	2.00	26271	6683	30	Rd	645
6500	140	86	7.7	2.25	30259	5366	45	Rd	945
6500	115	97	6.5	2.25	32999	8089	38	Rd	828
6500	140	97	6.4	2.75	39505	8611	50	Rd	1127
7500	115	86	6.4	1.75	27239	8368	28	Rd	496
7500	140	86	6.0	2.25	32595	9121	36	Rd	683
7500	115	97	7.9	1.75	32677	7553	40	Rd	643
7500	140	97	7.8	2.25	38990	8140	55	Rd	961
8500	115	86	5.4	1.75	28738	11024	23	Rd	391
8500	140	86	6.6	2.00	32822	9687	37	Rd	590
8500	115	97	6.6	1.75	35220	11878	34	Rd	514
8500	140	97	6.4	2.25	41950	12740	46	Rd	730

Table D

ROTAFLEX-1100: 320-500-306 (PRICE JAN 96 $103,000)

Depth (feet)	Rods (k psi)	Rod Taper	Speed (SPM)	Bore (inches)	PPRL (lbs)	MPRL (lbs)	PRHP (HP)	Limiting Item*	Rate (BPD)
2500	115	87	4.0	4.25	25691	5590	40	Rd	2430
2500	140	87	4.4	4.75	30208	5004	52	Rd	3290
2500	115	98	4.1	4.75	32310	6797	51	Rd	3114
2500	140	98	4.5	4.75	32763	5882	57	SPM	3421
3500	115	87	4.5	3.25	25265	4941	37	Rd,SPM	1590
3500	140	87	4.5	3.75	29771	5072	46	SPM,Rd	2061
3500	115	98	4.1	3.75	32326	7099	44	Rd	1917
3500	140	98	4.5	4.25	37990	6394	59	SPM,Rd	2644
4500	115	86	4.5	2.75	25655	5903	33	Rd,SPM	1117
4500	140	87	4.3	3.25	31007	6530	41	Rd	1442
4500	115	97	3.9	3.25	33406	8706	38	Rd	1334
4500	140	98	3.8	3.75	39846	9421	47	Rd	1681
5500	115	86	4.5	2.25	24783	7063	28	SPM	746
5500	140	86	4.5	2.75	30654	7501	38	SPM,Rd	1066
5500	115	97	4.3	2.75	33827	9487	37	Rd	1046
5500	140	97	4.2	3.25	40401	10142	47	Rd	1364
6500	115	86	3.7	2.25	28213	10070	25	Rd	587
6500	140	86	4.5	2.25	29046	9030	30	SPM	713
6500	115	97	4.5	2.25	32872	10755	33	SPM	742
6500	140	97	4.5	2.75	39483	11253	44	SPM,Rd	1044
7500	115	86	4.5	1.75	27149	10322	24	SPM,Rd	450
7500	140	86	4.5	2.25	32872	10620	34	SPM,Rd	683
7500	115	97	3.8	2.25	36565	14341	29	Rd	599
7500	140	97	4.5	2.25	37154	12866	36	SPM	713
8500	115	86	4.3	1.75	29242	11933	24	Rd	412
8500	140	86	4.5	1.75	29332	11588	25	SPM	432
8500	115	97	4.5	1.75	34765	14553	27	SPM	451
8500	140	97	4.5	2.25	41730	15212	39	SPM,Rd	681

*SPM = Maximum rated strokes per minute

Table E

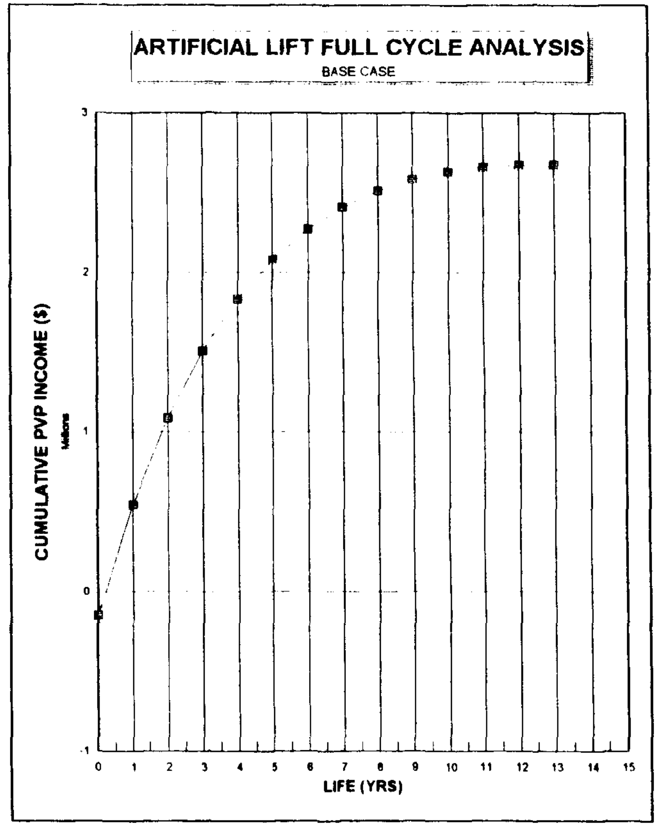
28-Dec-95	ARTIFICIAL LIFT SELECTION # 2		BEFORE TAX	COPYRIGHT(C): VERSION 5.1	
	CONSTANT MAX LIFT RATE			CLEGG & BOONE	
NAME:	BASE CASE		DISCOUNT RATE	8.00	%
INSTALLATION	$150,000	$	OIL PRICE INC/YR	1.00	%
MAX LIFT RATE	1000	bpd	INFLATION	2.50	%
INITIAL GAS GOR	300	ft^3/b	LIFT EFF	50.00	%
INITIAL H2O CUT	85.00	%	LIFT DEPTH	5000	ft
END OIL RATE	20.0	bopd	ENERGY COST	0.05	$/k-W
END GAS GOR	300	ft^3/b	--CALCULATIONS--		
FLAT LIFE	0.00	yrs	INITIAL OIL RATE	150	bbl
EFF DECLINE RATE	14.00	%/yr	a:NOMINAL DECLINE	15.08	%/YR
OIL VALUE	$18.00	$/bbl	Qf:RESERVES FLAT	0	bbl
GAS VALUE	$1.50	$/mcf	Qec: RESERVES DEC	314,607	bbl
ROYALTY	12.50	%	Qt:TOTAL RESERVES	314,607	bbl
DIR.OP (FIXED)	$500.00	$/mo	Td: TIME DECLINE	13.4	YRS
DIR OP(PER BFPD)	$0.20	$/bbl	Tt:TIME TOTAL	13.4	YRS
PULL & REPAIR	$200	$/mo	MAX PVP INCOME	$2,676,719	

UNIT SELECTION: E E or M (OILFIELD = E; METRIC = M)

PRESS [Pg Dn] TO VIEW TABULAR RESULTS PRESS [Ctrl G] TO VIEW GRAPH

OILFIELD UNITS >>>>

PROD LIFE (YRS)	Qol PROD (BOPD)	OIL PROD (BOPY)	GAS PROD (MCFPY)	WATER PROD (BPY)	Qwl PROD (BPD)	TOTAL OIL+H2O (BFPY)	AV H20 CUT RATIO
0.00	150	0	0	0	0	0	0.850
1.0	129	50816	15245	314184	871	365000	0.861
2.0	111	43703	13111	321297	889	365000	0.880
3.0	95	37585	11275	327415	905	365000	0.897
4.0	82	32324	9697	332676	918	365000	0.911
5.0	71	27799	8340	337201	929	365000	0.924
6.0	61	23907	7172	341093	939	365000	0.935
7.0	52	20561	6168	344439	948	365000	0.944
8.0	45	17682	5305	347318	955	365000	0.952
9.0	39	15207	4562	349793	961	365000	0.958
10.0	33	13078	3923	351922	967	365000	0.964
11.0	29	11247	3374	353753	971	365000	0.969
12.0	25	9673	2902	355327	975	365000	0.973
13.0	21	8319	2496	356681	979	365000	0.977
14.0	18	7154	2146	357846	982	365000	0.980



PROD LIFE (YRS)	DIRECT $/fluid VOL COST ($/YR)	DIRECT OPERATING COST ($/YR)	PULL & REPAIR COST ($/YR)	ENERGY HHP COST ($/YR)	TOTAL OP COST ($/YR)	ECONOMICS>>> OP COST DISCOUNTED ($/YR)	>>>>>>>>> REVENUE LESS ROY ($/YR)	INCOME DISCOUNTED ($/YR)	NET INCOME PVP ($/YR)	CUM NET PVP ($)
									($150,000)	($150,000)
0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0	($150,000)
1.0	$74,825	$6,150	$2,460	$24,613	$108,048	$103,969	$828,570	$797,291	$693,322	$543,322
2.0	$76,696	$6,304	$2,522	$25,228	$110,749	$98,674	$719,707	$641,239	$542,565	$1,085,887
3.0	$78,613	$6,461	$2,585	$25,859	$113,518	$93,649	$625,147	$515,731	$422,081	$1,507,969
4.0	$80,578	$6,623	$2,649	$26,505	$116,356	$88,880	$543,011	$414,788	$325,908	$1,833,876
5.0	$82,593	$6,788	$2,715	$27,168	$119,264	$84,354	$471,667	$333,602	$249,248	$2,083,124
6.0	$84,658	$6,958	$2,783	$27,847	$122,246	$80,058	$409,696	$268,307	$188,249	$2,271,373
7.0	$86,774	$7,132	$2,853	$28,543	$125,302	$75,981	$355,868	$215,791	$139,811	$2,411,184
8.0	$88,943	$7,310	$2,924	$29,257	$128,435	$72,112	$309,112	$173,555	$101,443	$2,512,627
9.0	$91,167	$7,493	$2,997	$29,988	$131,646	$68,439	$268,499	$139,585	$71,146	$2,583,773
10.0	$93,446	$7,681	$3,072	$30,738	$134,937	$64,954	$233,221	$112,265	$47,311	$2,631,084
11.0	$95,782	$7,873	$3,149	$31,506	$138,310	$61,646	$202,579	$90,291	$28,645	$2,659,729
12.0	$98,177	$8,069	$3,228	$32,294	$141,768	$58,507	$175,963	$72,619	$14,112	$2,673,841
13.0	$100,631	$8,271	$3,308	$33,101	$145,312	$55,527	$152,844	$58,405	$2,878	$2,676,719

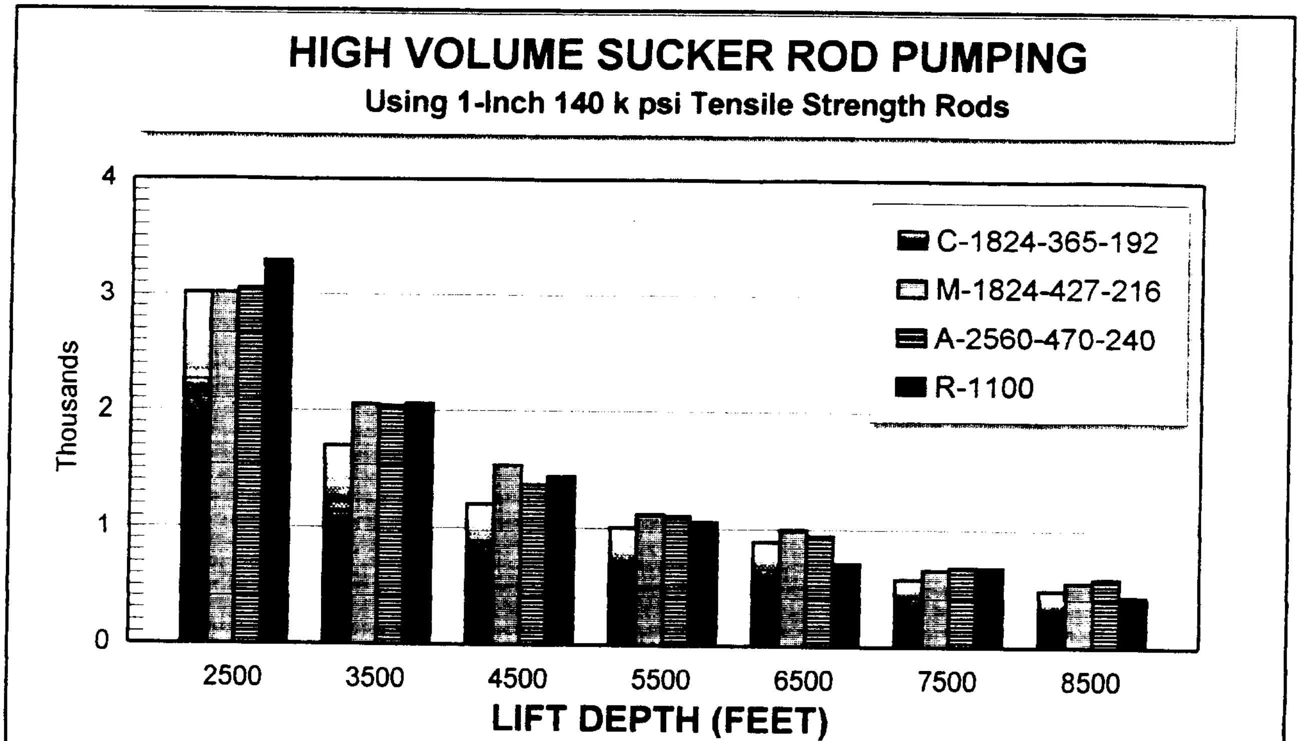


Figure 1

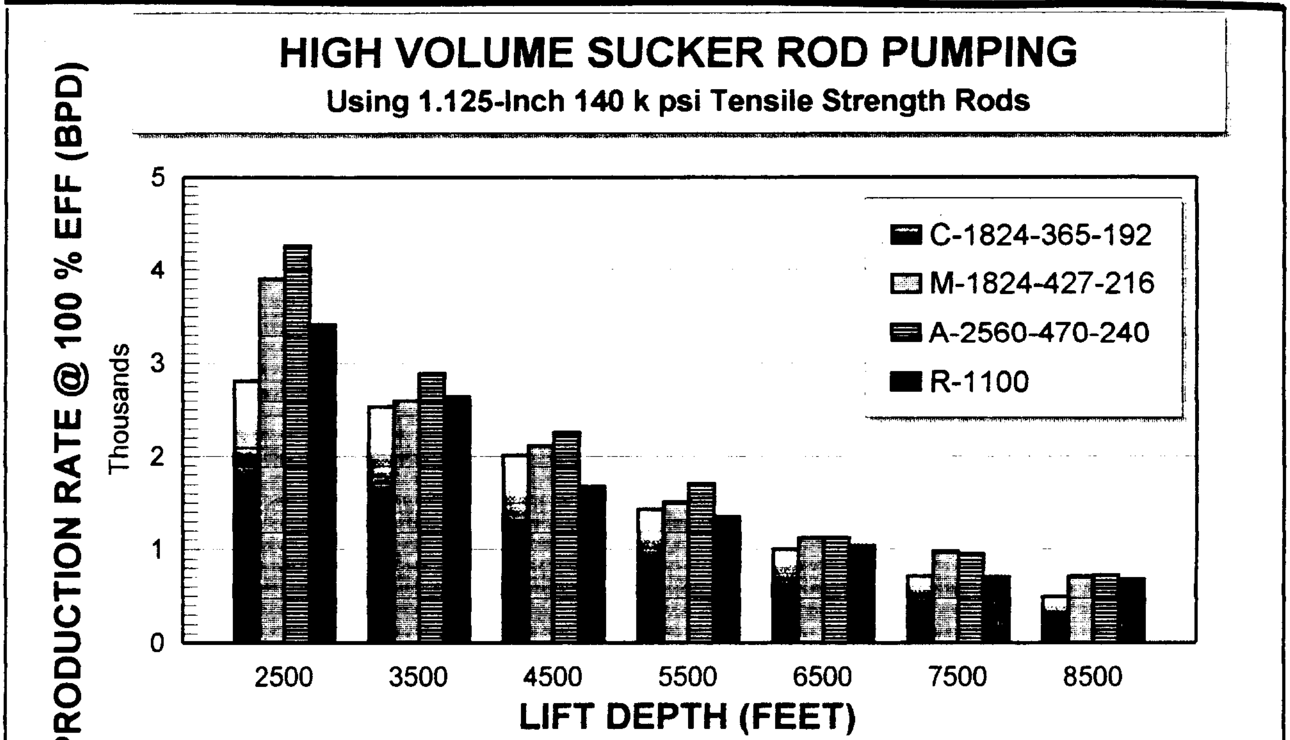


Figure 2

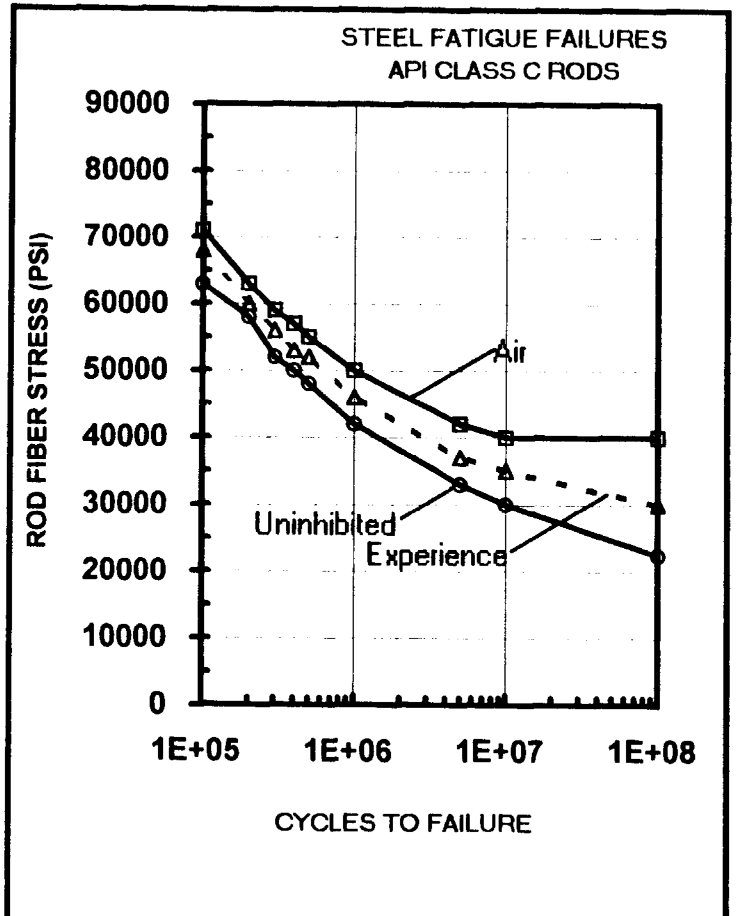
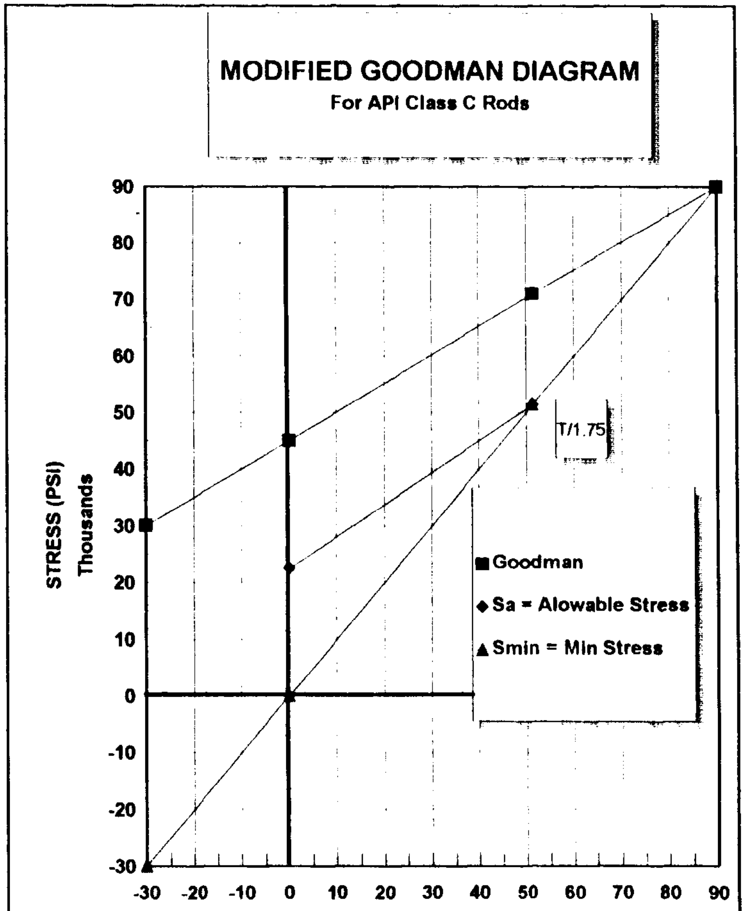


Figure 3



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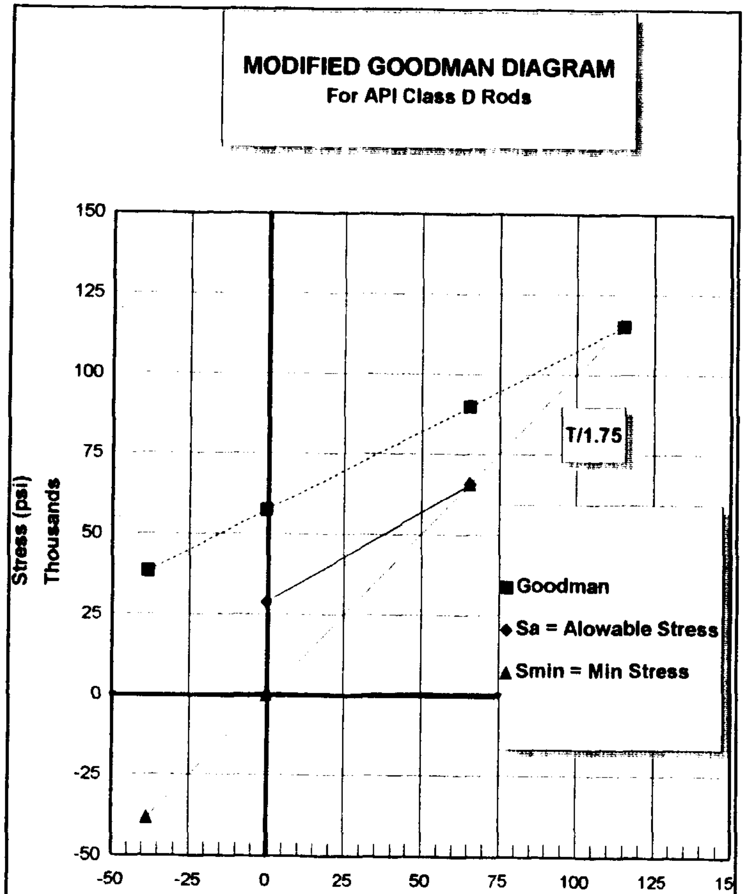

Figure 5

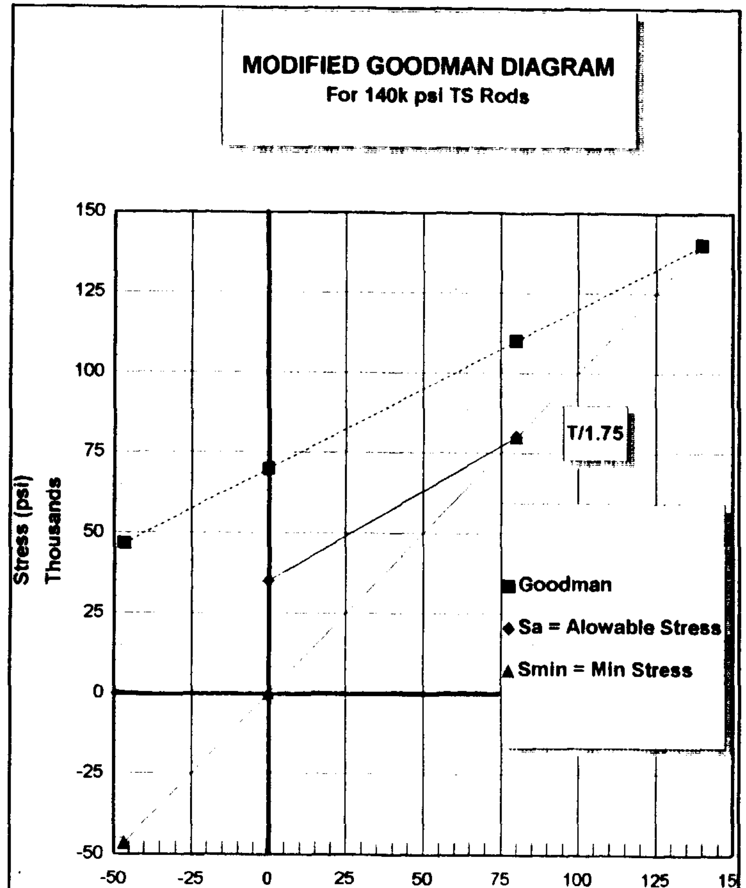

Figure 6