

THE TECHNOLOGY OF ARTIFICIAL LIFT METHODS

Volume 2a

Introduction of Artificial Lift Systems
Beam Pumping: Design and Analysis
Gas Lift

Kermit E. Brown

The University of Tulsa

contributing authors

John J. Day
Joe P. Byrd
Joe Mach

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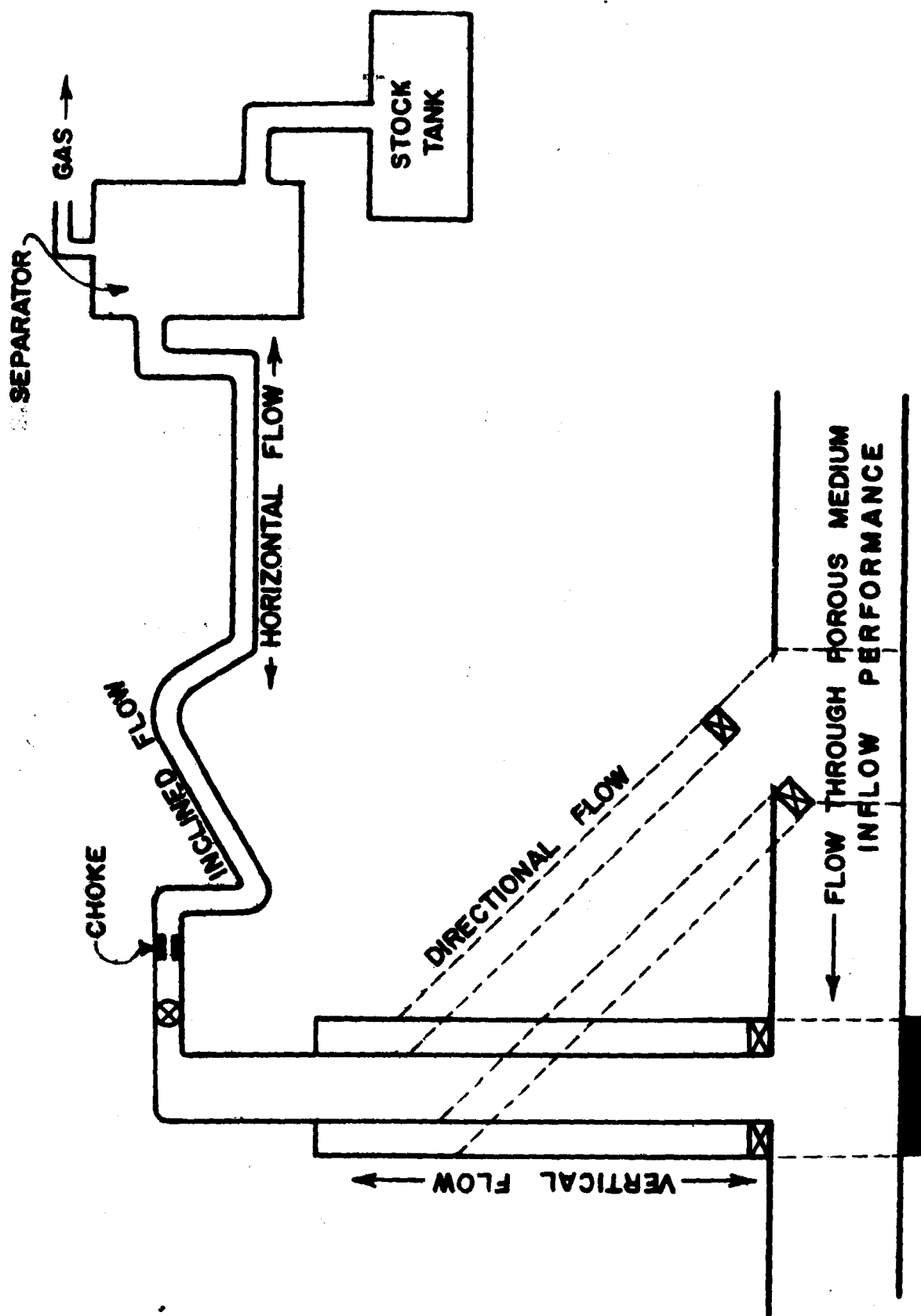
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Volume 2a

Preface

For the first time, all the artificial lift methods are presented in one volume. Volume 2 is published in two separate books, Vol. 2A and Vol. 2B, and is complete with sufficient charts, curves, etc. to plan, design, analyze, and compare all artificial lift methods. Volume 1, published in 1977, gives all the preliminary information needed to use Vol. 2. Volume 1 includes (1) the inflow ability of the well, (2) multiphase flow in pipes, and (3) the flowing well. Although not absolutely necessary, Volume 1 should be studied and used in conjunction with Volume 2. Volume 3, which is also available, includes over 2,200 flowing pressure traverse curves for multiphase vertical flow and horizontal flow, gas production, gas injection and water injection curves.

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Volume II offers sufficient flexibility to be used as a text or to be used by the engineer in industry in designing installations. Example problems are worked and numerous class problems are included. Eventually, an answer guide will be available.

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Kermit E. Brown

Contents

Chapter 1

Introduction of artificial lift systems

- 1.1 Introduction 1**
 - 1.11 Purpose of artificial lift 2
 - 1.12 Utilization of multiphase flow correlations for artificial lift systems 3
 - 1.121 Introduction 3
 - 1.122 Use of multiphase flow correlations 3
 - 1.1221 Viscosity 3
 - 1.1222 Effect of slippage of fall-back 5
 - 1.123 Summary of multiphase flow 6

Chapter 2

Beam pumping: design and analysis, by John J. Day and Joe P. Byr

- 2.1 Introduction 9**
- 2.2 General considerations 9**
- 2.3 Subsurface pumps 11**
 - 2.31 Tubing pumps 12
 - 2.311 Tubing pumps classified according to type of working barrel 12
 - 2.312 Tubing pumps classified according to type of standing valve 12
 - 2.313 Tubing pumps classified according to type of plunger 12
 - 2.32 Insert pumps 13
 - 2.33 Casing pumps 14
 - 2.34 The pumping cycle 14
 - 2.35 API pump classifications 15
 - 2.36 Pump size selection 15
- 2.4 The sucker rod string—general considerations 20**
 - 2.41 Design of the sucker rod string 23
 - 2.42 Modified Goodman diagram 26
- 2.5 Pumping motion 27**
 - 2.51 Simple harmonic motion (SHM) 27
 - 2.52 Crank and pitman motion 29
 - 2.53 The influence of pumping motion on the rod and structural loading of a beam-type unit 29
- 2.6 The effect of crank-to-pitman ratio on class I and class III geometries 32**
- 2.7 Effective plunger stroke 33**
 - 2.71 Rod and tubing stretch—single rod size 33
 - 2.72 Rod stretch—tapered strings 35
 - 2.73 Plunger overtravel 35
 - 2.731 Coberley's method 35
- 2.8 Calculations for surface equipment 37**
 - 2.81 Counterbalance 38
 - 2.82 Torque considerations 39
 - 2.821 Torque factors 40
 - 2.822 An important aspect of energy conservation in a beam and sucker rod pumping system 41
 - 2.83 Prime movers 42
 - 2.84 Prime mover horsepower requirements 43
 - 2.841 Net lift 43
 - 2.842 Frictional horsepower 44

2.843	Cyclic load factor	44
2.844	Surface efficiency in a beam and sucker rod pumping system	45
2.845	Approximate horsepower formulas	47
2.85	Speed reduction and engine sheave size	50
2.86	API unit ratings	50
2.9	API recommended design procedure	52
2.10	Dynamometers and dynagraphs	59
2.101	The dynamometer card (dynagraph)	60
2.102	Limitation of visual interpretation	63
2.103	Loads from dynamometer cards	65
2.104	Counterbalance effect from dynamometer cards	65
2.105	Polished rod horsepower from dynamometer cards	66
2.106	Torque from dynamometer cards	69
2.107	Factors influencing the shape of dynamometer cards	75
2.108	Permissible load diagrams	78
2.11	Non-synchronous pumping speeds in a beam and sucker rod system	78
2.12	Beam pumping geometry and its effect on rod and unit loading and pump travel	79
2.13	Modern predictive methods	80
2.131	Predicting polished rod dynamometer card shapes	84
2.14	The diagnostic technique	86
2.15	Inertial torque in a beam and sucker rod pumping system	86
2.151	A performance comparison between two beam and sucker rod pumping units of dissimilar geometry considering the influence of inertial torque	89
Nomenclature		91
References		94

Chapter 3

Gas lift

3.1	Introduction	95
3.11	Definitions	95
3.2	Gas lift valve characteristics	96
3.21	Introduction	96
3.22	Gas lift valve nomenclature	96
3.23	Design considerations	97
3.231	Continuous flow	97
3.232	Intermittent lift	97
3.24	Pressure, area, and force relationships	97
3.25	Casing pressure operated valve	98
3.251	Unbalanced bellows valve with pressure charged dome as loading element	98
3.2511	Opening pressure of valve under operating conditions	98
3.2512	Closing pressure of valve under operating conditions	101
3.2513	Spread	102
3.2514	Gas pressure at depth	103
3.2515	Test rack opening pressure	104
3.2516	Standard pressure operated gas lift valve summary example	105
3.252	Unbalanced bellows valve with pressure charged dome and spring as loading element	106
3.2521	Opening pressure of valve under operating conditions	106
3.2522	Closing pressure of valve under operating conditions	106
3.2523	Spread	107
3.2524	Summary examples	107
3.253	Balanced pressure valve	109
3.254	Pilot valves	110
3.255	Gas passage	111
3.26	Throttling pressure valve	111
3.27	Fluid operated valve	112
3.271	Opening pressure of fluid valve under operating conditions	112
3.272	Closing pressure of valve under operating conditions	114
3.273	Test rack opening pressure	114

3.274	Summary examples - fluid valve	116
3.275	Gas passage characteristics	117
3.276	Differential valve	117
3.2761	Opening pressure of differential valve under actual operating conditions	117
3.2762	Closing pressure of differential valve under operating conditions	118
3.2763	Test rack setting procedure for differential valve	118
3.28	Combination valves	118
3.29	Dynamic considerations	119
3.291	Bellows travel and protection	119
3.292	Bellows load rate	119
3.293	Pressure valves	121
3.210	Class problems	121
3.3	Types of gas lift installations	123
3.31	Introduction	123
3.32	Open installation	123
3.33	Semiclosed installations (Fig. 3.32)	124
3.34	Closed installations (Fig. 3.33)	124
3.35	Chamber installations	124
3.351	Introduction	124
3.352	Standard two-packer chamber (Fig. 3.35)	125
3.353	Insert chamber (Fig. 3.36)	125
3.354	Reverse flow chamber installation	125
3.355	Special chamber to save gas for long pay interval	125
3.356	Special chamber installation for sand removal	126
3.357	Open hole chamber installation	127
3.358	Special chambers for bad casing and/or long perforated or long open hole interval	127
3.359	Chamber above packer	128
3.3510	Automatic vent chamber system	128
3.36	Macaroni installations	129
3.37	Dual installations	132
3.38	Pack-off installations	133
3.39	Annular flow	135
3.310	Installations to backwash injection wells	135
3.4	Design of gas lift installations	137
3.41	Introduction	137
3.42	Continuous flow design	137
3.421	Introduction	137
3.422	Factors to consider in the design of a continuous flow gas lift installation	138
3.4221	Requirements of continuous flow valves	138
3.4222	Separator pressure and wellhead flowing pressure	138
3.4223	Location of the top valve	138
3.4224	Injection gas pressure and volume	139
3.4225	Bottom hole temperature (BHT) and flowing temperature	139
3.42251	Introduction	139
3.42252	Kirkpatrick's solution	140
3.42254	Shiu's correlations	140
3.4226	Unloading gradients and spacing of gas lift valves	143
3.4227	Flow configuration sizes and production rates	143
3.4228	Valve settings	144
3.4229	Approximations to be used in continuous flow installations	144
3.42210	Types of installations	144
3.42211	Use of multiphase flow correlations	144
3.423	Design procedure for a continuous flow installation	144
3.4231	Determining the point of gas injection	144
3.4232	Determining flow rates possible by gas lift, by Pedro Regnault	147
3.42321	Introduction	147
3.42322	Solution for a constant wellhead pressure	148
3.423221	Pressure-flow rate diagram procedure	148
3.423222	Equilibrium curve procedure	149
3.42323	Solution for a variable wellhead pressure, by Hugo Marin	155
3.423231	Wellhead pressure-flow rate diagram procedure	155
3.423232	Flowing bottom-hole pressure-flow rate diagram procedure	157

3.424	An economic study of a continuous flow gas lift well, by Pedro Regnault	162
3.4241	Introduction	162
3.4242	Example problem	162
3.425	Design of continuous flow gas lift installations based on the most economical volume of gas to be injected, by Victor Mitchell and Jesus Pacheco	166
3.4251	Introduction	166
3.4252	Determination of the most economical total gas-liquid ratio for constant wellhead pressure	166
3.42521	Procedure for the most economical gas lift design	166
3.42522	Short-cut method for determining the most economical gas-liquid ratio	168
3.42523	Example problem to illustrate the most economical gas lift design	170
3.4253	Determination of the most economical gas-liquid ratio for variable wellhead pressure	173
3.42531	Introduction	173
3.42532	Description of the economical slope method	174
3.42533	Description of profit on oil vs. cost of gas injected method	176
3.42534	Example problems for the most economical gas lift design—variable wellhead pressure	179
3.425341	Economical slope method	179
3.425342	Profit on oil vs. cost of gas injected method	181
3.42535	Effect of variables	183
3.425351	Effect of flowline length	183
3.425352	Effect of flowline diameter	184
3.42536	Discussion of results	185
3.42537	Conclusions	185
3.426	Optimizing continuous flow gas lift systems, by Victor Gomez and Harry Hong	186
3.4261	Introduction	186
3.4262	Continuous flow gas lift design for optimization based on maximum rate	187
3.4263	Constant wellhead procedure	187
3.42631	Description of curve fitting and optimization procedure	188
3.426311	Introduction	188
3.426312	Curve fitting	188
3.426313	Optimization procedure	188
3.42632	Field example	189
3.4264	Variable wellhead solution	191
3.42641	Computational procedure	191
3.42642	Description of the optimization procedure	193
3.426421	Introduction	193
3.426422	Cubic spline interpolating scheme	194
3.426423	Optimization procedure	194
3.42643	Effect of variables in optimization of variable wellhead gas lift systems	194
3.426431	Introduction	194
3.426432	Effect of tubing size and flowline size	194
3.426433	Effect of separator pressure	195
3.426434	Effect of water cut	195
3.426435	Effect of available injection pressure	196
3.426436	Effect of productivity index	198
3.426437	Summary	198
3.4265	Conclusions and recommendations	198
3.4266	Field case of economic optimization	199
3.42661	Introduction	199
3.42662	Optimization logic	199
3.42663	Example problem	200
3.42664	Summary	202
3.427	Selection of gas lift parameters	202
3.4271	Introduction	202
3.4272	Mitchell's procedure	202
3.4273	Special design to make selection of parameters in continuous flow gas lift	207
3.42731	Introduction	207
3.42732	Design procedure	207

	3.42733	Selecting parameters	208
	3.42734	Example problem	209
3.428		A new gas lift concept—"two-step gas lift installation," by Juan Faustinelli	211
	3.4281	Introduction	211
	3.4282	Description of the two-step gas lift method	211
	3.4283	Proposed well bore completion for a two-step gas lift installation	214
	3.42831	Parallel two-step completion for wells of Lake Maracaibo, Venezuela	214
	3.42832	Concentric two-step completion	214
	3.4284	Two-step gas lift examples	214
	3.4285	Summary and conclusions	223
3.429		Spacing of continuous flow gas lift valves	223
	3.4291	Introduction	223
	3.4292	Universal design and spacing for all types of continuous flow gas lift valves	224
	3.42921	Introduction	224
	3.42922	Standard pressure operated valves—constant surface opening pressure	224
	3.4293	Design procedure for pressure operated valves—taking 10-20 psi drop in surface closing pressures between valves	230
	3.4294	Spacing and design procedure for fluid operated valves (pressure charged dome)—universal design	232
	3.4295	Spacing and design procedure for combination pressure closed, fluid opened valves	233
	3.4296	Design example for fluid operated, spring loaded gas lift valves	233
	3.4297	Additional spacing procedures	236
	3.42971	Introduction	236
	3.42972	Common procedure for analytical spacing of pressure operated gas lift valves	236
	3.42973	Graphical spacing of pressure operated valves—(25 psi drop in pressure between valves)	238
	3.4298	Discussion on spacing	238
	3.4299	Continuous flow design for differential valves	241
	3.42991	Introduction	241
	3.42992	Design procedure for differential valves (continuous flow)	241
	3.42993	Design example for differential valves (continuous flow)	241
	3.42994	Analytical procedure for spacing differential valves	242
	3.42910	Spacing of completely balanced continuous flow valves	242
	3.42911	Proportional response system	244
	3.429111	Introduction	244
	3.429112	Transfer operation	246
	3.4291121	Transfer point selection	246
	3.4291122	Gas requirements	246
	3.4291123	Gas supply	247
	3.429113	Design example—detailed information available	247
	3.4291131	Preliminary well analysis	248
	3.4291132	Gas lift valve spacing and selection	248
	3.429114	Computer designed example	251
3.4210		Continuous flow gas-lifting directionally drilled wells	253
	3.42101	Introduction	253
	3.42102	Methods for calculating pressure loss in deviated wells	254
	3.42103	Design of gas lift installations	255
	3.42104	Example problems and discussion	256
	3.42105	Summary	257
3.4211		Summary and logical sequence in continuous flow gas lift design	257
3.4212		Class problems	258
3.43		Design of intermittent flow installations	260
	3.431	Introduction	260
	3.432	Intermittent gas lift cycle	261
	3.433	Analysis of pressure recordings during intermittent gas lift cycles	261
	3.434	Factors to consider in the design of an intermittent installation	264
	3.4341	Type of installations	264
	3.4342	Location of top valve depth	265
	3.4343	Available pressures and valve settings	266
	3.4344	Unloading gradients and spacing	267

3.4345	Differential between valve pressure and tubing load to lift	267
3.4346	Gas lift valve port size	268
3.4347	Percent recovery	272
3.4348	Gas volume requirements for intermittent lift	273
3.4349	Cycle frequency and pressure stabilization time	273
3.43410	Types of valves for intermittent lift	274
3.43411	Single point vs. multipoint injection for intermittent lift	275
3.43412	Summary of design considerations in intermittent lift	275
3.435	Design and spacing procedures for intermittent gas lift installations	275
3.4351	Introduction	275
3.4352	Design procedure for intermittent gas lift well	276
3.4353	Graphical procedure—pressure operated valves (time cycle control at the surface)	279
3.4354	Analytical procedure—pressure operated valves (time-cycle control at the surface) (25 psi drop in pressure between valves)	281
3.4355	Graphical procedure—pressure operated valves (choke control at the surface) (25 psi drop in surface opening pressure between valves)	282
3.4356	Pressure operated valves—graphical procedure, constant valve closing pressure (time cycle control and choke control)	284
3.4357	Design procedure, fluid operated valves for multipoint injection	286
3.43571	Nitrogen charged fluid valve	287
3.43572	Design example for multipoint intermittent lift—spring charged valve	288
3.4358	Intermittent opti-flow design procedure	290
3.4359	Design for combination fluid opened, pressure closed valves	292
3.43591	Introduction	292
3.43592	Design procedure I for the combination pressure closed tubing pressure opened valve (choke control or time cycle control)	293
3.43593	Design procedure II for combination pressure closed tubing pressure opened valves	294
3.43510	Design procedure for completely balanced valves	296
3.435101	Graphical procedure for designing a low productivity intermittent installation for balanced valves	296
3.43511	Design example in which the static fluid level is low in the well and the well has not been loaded with "kill" fluid—balanced valves	298
3.43512	Designing chamber gas lift installations for intermittent lift	298
3.435121	Introduction	298
3.435122	Procedure for designing standard chamber installations	298
3.4351221	Example problem No. 1	299
3.4351222	Example problem No. 2	301
3.435123	Example problem for insert chamber	303
3.435124	Special chamber design for deep wells and low surface gas operating pressure	304
3.4351241	Introduction	304
3.4351242	Design procedure—intermitter control (chamber valve to be operating valve)	305
3.4351243	Design procedure—chamber choke control—chamber valve to be operating valve	306
3.4351244	Special design	306
3.4351245	Field example of deep chamber for low operating pressure	307
3.4351246	Field case no. 2—chamber lift (chamber valve = operating valve)	308
3.4351247	Summary	309
3.436	Detailed design for intermittent flow—a method for determining the production rate	309
3.4361	Introduction	309
3.4362	Calculating the weighted average BHP	310
3.43621	Example 1—calculating the minimum BHP that occurs for one cycle of intermittent lift	310
3.43622	Example 2—calculating the weighted average BHP for one complete cycle (without standing valve)	311
3.436221	Reducing the weighted average BHP	312
3.43623	Example 3—calculating the weighted average BHP for one complete cycle (with standing valve)	313

3.4363	Detailed design of intermittent installation	313
3.437	Effect of variables in intermittent lift	316
3.4371	Detailed design for intermittent flow—effect of variables	316
3.43711	Effect of differential between valve pressure and tubing load	316
3.43712	Effect of PI	316
3.4372	Computer solution to the problem	316
3.43721	Effect of differential and PI	317
3.43722	Effect of depth	317
3.43723	Prediction of BHPs	318
3.438	Class problems, intermittent design problems	318
3.44	Comparisons of continuous, standard intermittent and chamber gas lift methods, by Felix Esliat	320
3.441	Introduction	320
3.442	Effect of changing static pressure	320
3.443	Effect of wellhead pressure	321
3.444	Effect of productivity index	322
3.445	Effect of tubing size	322
3.446	Effect of the slippage	324
3.447	Effect of surface injection pressure	324
3.448	Effect of pressure differential across the valve	325
3.449	Effect of differential and cycle time	325
3.4410	Summary	326
3.45	Multiple completions, by Jerry B. Davis and Kermit E. Brown	326
3.451	Introduction	326
3.452	Types of installations	326
3.4521	Introduction	326
3.4522	Parallel tubing string installations	326
3.4523	Concentric tubing string installations	327
3.4524	Commingling of zones	327
3.453	Valve selection for a dual installation producing both zones by continuous lift	327
3.4531	Introduction	327
3.4532	Two strings of combination fluid opened and pressure or fluid closed valves	327
3.4533	Two strings of fluid operated valves (open and close on tubing fluid pressure)	327
3.4534	Two strings of pressure operated valves	327
3.4535	One string of fluid operated valves (open and close on tubing fluid pressure) and one string of pressure operated valves	327
3.454	Valve selection for a dual installation producing both zones by intermittent lift	328
3.4541	Introduction	328
3.4542	Two strings of combination fluid opened and pressure closed valves	328
3.4543	Two strings of pilot operated valves	328
3.4544	Two strings of standard pressure operated bellows valves	329
3.4545	Two strings of fluid operated valves	329
3.455	Valve selection for a dual installation producing one zone by continuous lift and one zone by intermittent lift	329
3.4551	Two strings of combination fluid opened and pressure closed valves	329
3.4552	One string pressure operated bellows continuous lift valves and one string of pilot operated intermittent valves	329
3.4553	Two strings of pressure operated bellows valves	330
3.4554	One string of fluid operated valves (opened and closed by tubing fluid pressure) and one string of pressure operated bellows valves	330
3.4555	Two strings of fluid-operated valves (opened and closed by tubing fluid pressure)	330
3.456	Design of dual gas lift installations	330
3.457	Example designs	330
3.4571	Example set #1	330
3.4572	Example set #2	333
3.4573	Example set #3 (mandrels in place)	333
3.5	Compressor systems	336
3.51	Introduction	336
3.52	Classification of compressor systems	336
3.53	Design of the compressor system	337
3.531	Introduction	337
3.532	Factors to consider when designing a compressor system	338

3.5321	Location of all lease equipment	338
3.5322	The individual gas lift valve design for each well	338
3.5323	Gas volume needed	339
3.5324	Injection gas pressure	339
3.5325	Separator pressure and suction pressure	339
3.5326	Distribution system	339
3.5327	Low-pressure gathering system	341
3.5328	Availability of make-up gas	342
3.5329	Availability of a gas sales outlet	342
3.53210	Freezing conditions (hydrates)	342
3.533	Compressor selection	344
3.5331	Introduction	344
3.5332	Sizing the compressor	344
3.54	Design of a rotative compressor system	351
3.55	Summary	354
3.56	Problems	355
3.6	Gas lift operation, analysis, and trouble shooting	355
3.61	Introduction	355
3.62	Operation of gas lift systems	356
3.621	Unloading processes	356
3.6211	Continuous flow unloading process	356
3.6212	Intermittent flow unloading process	357
3.622	Types of gas injection control	358
3.6221	Choke control	358
3.6222	Regulator control in conjunction with a choke intermittent flow	359
3.6223	Time cycle controller	359
3.63	Analysis and trouble shooting	360
3.631	Introduction	360
3.632	Pressure surveys—continuous flow	361
3.6321	Introduction	361
3.6322	Hypothetical case of flowing pressures surveys	363
3.6323	Field cases of flowing pressure surveys	365
3.633	Flowing temperature surveys—continuous flow wells	367
3.634	Combination flowing pressure and flowing temperature surveys (for continuous flow wells)	369
3.635	Pressure surveys—intermittent lift	372
3.6351	Introduction	372
3.6352	Hypothetical pressure surveys	373
3.6353	Field cases of intermittent pressure surveys	373
3.636	Well sounding devices	376
3.6361	Introduction	376
3.6362	Field cases of acoustic surveys	377
3.637	Surface recordings of casing and tubing pressures	378
3.6371	Introduction	378
3.6372	Continuous flow recorder charts	379
3.63721	Hypothetical charts	379
3.63722	Field cases of two-pen surface recorder charts for continuous flow	383
3.6373	Intermittent flow recorder charts	383
3.63731	Hypothetical charts	383
3.63732	Field cases of two-pen recorder charts for intermittent flow	399
3.638	Surface wellhead pressure	435
3.6381	Introduction	435
3.6382	Effect of back-pressure for continuous flow	435
3.6383	Effect of back-pressure for intermittent flow	437
3.639	Injection gas pressure	439
3.6310	Injection gas volumes	441
3.6311	Total output gas volumes	443
3.6312	Total fluid recovery	443
3.6313	Temperature of the flowline and Christmas tree	443
3.6314	Miscellaneous	443
3.6315	Field case of improved operations	444
3.6316	Summary	444

Appendix

Chapter 1

Artificial lift systems

1.1 INTRODUCTION

This text will discuss the various types of artificial lift systems available today. More and more wells in the world are being placed on artificial lift, and the number will continue to increase. The selection of the most suitable type of artificial lift for a well or group of wells can be difficult or easy, depending upon the conditions.

Generally, more than one method of lift can be used. Each method of lift may be classified from excellent to poor in accomplishing the objective. Depending upon the economic considerations, two types of lift (one used later) may possibly be prescribed for a group of wells.

For example, in a "depletion" type reservoir, high initial production rates may be needed, but decreasing pressures and declining inflow capability may require a low rate in the future. In this case, an initial installation of continuous flow gas lift or electrical submersible pumping may be changed to intermittent gas lift, sucker rod pumping, or hydraulic pumping at a later date, or vice versa.

The following list probably represents the relative standing of lift systems based on the number of installations throughout the world. This differs from field to field, state to state, and country to country.

- (1) Sucker rod pumping (beam pumping)
- (2) Gas lift
- (3) Electrical submersible pumping
- (4) Hydraulic pumping
- (5) Jet pumping
- (6) Plunger (free piston) lift
- (7) Other methods

As these methods are discussed, complete design procedures will be given along with numerous example problems.

In addition, other methods are continually being developed and tested. A short discussion on the ball pump and the gas-actuated pump are also given. The ball pump was tried many years ago, and new interest has recently sparked additional development of this lift method. The ball pump uses spherical flexible balls that pass down one tubing string and return through another in order to eliminate the slippage of gas past the liquids. Gas is used as the source of power.

The gas pump has been in the experimental stage for many years. Several field trials have been performed and are installed at the present time. The pump uses gas to actuate a downhole pump and can be used in

conjunction with gas lift. In particular, gas lift unloading valves may be used to reach the pump.

Rothrock presented Table 1.1, showing the distribution of 518,867 oil wells based on a 7% sampling from 200 operators with information on 37,100 wells.¹

TABLE 1.1
CRUDE PRODUCING WELLS (JAN., 1977)

Category	Number	Percent
Rod pumping	409,974	85.21
Gas lift	51,964	10.80
Electrical submersible	9,738	2.02
Hydraulic	9,470	1.97
Total U.S. artificial lift	481,146	100.00%
U.S. flowing oil wells	37,721	
Total U.S. producing oil wells	581,867	

Of the 518,867 wells, 481,146 or 92.7% are being lifted artificially. These are further broken down into 85.2% rod pump, 10.8% gas lift, 2% submersible, and 2% hydraulic. Approximately 383,000 of the artificial wells are strippers (producing less than 10 B/D). Assuming that 100% of the stripper wells are on rod pump, then Table 1.2 shows a re-distribution of the remaining wells.

TABLE 1.2
ARTIFICIAL LIFT WELLS (LESS STRIPPER WELLS)

Category	Number	Percent
Rod pumping	26,974	27.48
Gas lift	51,964	52.95
Electrical submersible	9,738	9.92
Hydraulic	9,470	9.65
Total wells	98,146	100.00%

Table 1.2 shows that the largest percentage of the wells are on gas lift after eliminating stripper wells. Gas lift predominates on offshore wells but, according to Rothrock, is not keeping pace with other lift methods in areas other than offshore.

Submersible pump use is increasing rapidly in West Texas and in some Rocky Mountain areas. Rothrock noted that hydraulic pumping is not growing at the rate of other methods. However, jet pumping is now taking 50% of the hydraulic market, and its popularity will probably continue to grow.

Table 1.3 breaks down total maintenance cost into failures, failure rates, cost per failure, total cost, and percent of each failure spent for well servicing. Also included are costs and rates for well workover.

Two main types of downhole equipment failures are pumps and rods. Each pumping well has a 57% chance of pump failure and a 44% chance of rod failure each year. These rates are additive so each well will average 1.01 failures/year.

Costs to maintain these wells total \$346,000,000, including \$230,000,000 for well servicing. Remaining expenditures translate to approximately 34,000,000 feet of rods and 31,000 bottomhole pumps needed for replacement of worn out equipment plus an additional repair of 180,000 pumps.

Submersible pump failure rates apparently are decreasing based on the 7% sample. Repairs to submersibles by manufacturers are running considerably less than in previous years.

The survey indicates that failure incidence in hydraulic pumps is increasing. Again, this may be due to the small number of hydraulic pumps contained in the survey. In any event, the growth of the hydraulic piston pump market appears to be declining and jet pumping is on the increase.

Gas lift failure rate is the lowest of any form of artificial lift (21%) but costs of individual failures are high compared to the average of all failures. A high portion of these costs, however, is attributable to high cost of service units, crews, and related equipment.

Various lift methods are compared in Chapter 9. Comparisons are quite difficult, but some choices of lift methods are obvious. One example is high volume wells where either electrical submersible pumping or continuous flow gas lift should be considered. Very deep lift must look at hydraulic pumping with installations presently pumping from 15,000 to 18,000 feet, with rates of 300 to 500 B/D. Although these pumps are set at these depths, the effective lift depth may be less. Effective lift refers to that depth to which the flowing bottom hole pressure will support the producing fluids. For example, if the flowing bottom hole pressure is 700 psi and the average fluid gradient is 0.30 psi/ft, the 700

psi will support the fluid $700/0.30 = 2333$ ft. Therefore, if the pump is set at a total depth of 15,000 ft, it is really only lifting from $15,000 - 2,333 = 12,667$ ft and theoretically could be set at that depth and produce the same amount of fluids (neglects tubing well-head back pressure).

Availability of certain power sources will influence the decision on type of lift. All these factors are discussed in detail in Chapter 9.

1.11 Purpose of artificial lift

The purpose of artificial lift is to maintain a reduced producing bottom hole pressure so the formation can give up the desired reservoir fluids. A well may be capable of performing this task under its own power. In its latter stages of flowing life, a well is capable of producing only a portion of the desired fluids. During this stage of a well's flowing life and particularly after the well dies, a suitable means of artificial lift must be installed so the required flowing bottom hole pressure can be maintained.

Maintaining the required flowing bottom hole pressure is the basis for the design of any artificial lift installation; if a predetermined drawdown in pressure can be maintained, the well will produce the desired fluids. This is true regardless of the type of lift installed.

In gas lift operations, a well may be placed on continuous or intermittent lift. In continuous flow, the flowing bottom hole pressure will remain constant for a particular set of conditions, while in intermittent flow the flowing bottom hole pressure will vary with the particular operation time of one cycle of production. In this latter case, a weighted average flowing bottom hole pressure must be determined for one cycle and, hence, for a day's production. Economics enters into the design of any lift installation.

Many types of artificial lift methods are available: beam-type sucker rod pumps, piston-type sucker rod pumps, hydraulic oil well pumps, electrical submersible centrifugal pumps, rotating rod pumps, plunger lift, gas lift, and others. The advantages and disadvantages

TABLE 1.3
DOWNHOLE COSTS TO MAINTAIN U.S.
PRODUCING OIL WELLS (YEAR 1977)

	Failure rate	Number of failures	Average cost, \$	Total cost, \$	Percent well servicing
Subsurface rod pumps	.57	210,277	1,078	226,657,000	60
Sucker rods	.44	164,118	729	119,665,000	79
Submersible pumps	.35	3,390	7,679	26,030,000	15
Hydraulic pumps	1.86	16,397	2,445	41,411,000	40
Gas lift	.21	11,490	4,153	47,713,000	78
Tubing	.12	62,623	1,837	115,027,000	73
Casing	.021	11,043	16,005	176,742,000	51
Total failures	.92	479,878	1,570	753,245,000	61
Workovers	.20	105,145	10,686	1,123,532,000	58
Total maintenance cost				1,876,777,000	59