

Recommended Practice for Gas Lift System Design and Performance Prediction

API RECOMMENDED PRACTICE 11V8
FIRST EDITION, SEPTEMBER 2003

REAFFIRMED, MARCH 2015



AMERICAN PETROLEUM INSTITUTE

Recommended Practice for Gas Lift System Design and Performance Prediction

Upstream Segment

API RECOMMENDED PRACTICE 111V8
FIRST EDITION, SEPTEMBER 2003

REAFFIRMED, MARCH 2015



AMERICAN PETROLEUM INSTITUTE

SPECIAL NOTES

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

API is not undertaking to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations under local, state, or federal laws.

Information concerning safety and health risks and proper precautions with respect to particular materials and conditions should be obtained from the employer, the manufacturer or supplier of that material, or the material safety data sheet.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. Sometimes a one-time extension of up to two years will be added to this review cycle. This publication will no longer be in effect five years after its publication date as an operative API standard or, where an extension has been granted, upon republication. Status of the publication can be ascertained from the API Standards department telephone (202) 682-8000. A catalog of API publications, programs and services is published annually and updated biannually by API, and available through Global Engineering Documents, 15 Inverness Way East, M/S C303B, Englewood, CO 80112-5776.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this standard or comments and questions concerning the procedures under which this standard was developed should be directed in writing to the Director of the Standards department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should be addressed to the Director, Business Services.

API standards are published to facilitate the broad availability of proven, sound engineering and operating practices. These standards are not intended to obviate the need for applying sound engineering judgment regarding when and where these standards should be utilized. The formulation and publication of API standards is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

All rights reserved. No part of this work may be reproduced, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 1220 L Street, N.W., Washington, D.C. 20005.

FOREWORD

This Recommended Practice (RP) is under the jurisdiction of the API Committee on Standardization of Production Equipment (Committee 11).

This document presents RPs for the design of gas lift systems. Other API Specifications, API RPs, and Gas Processors Suppliers Association (GPSA) documents are referenced and should be used for assistance in design and operation.

Introduction to Gas Lift System Design and Performance Prediction

API RP 11V8 *Recommended Practice for Gas Lift System Design and Performance Prediction*, provides two functions:

- A broad overview of gas lift systems and various major types of gas lift operations.
- Recommended practices for gas lift system design and for modeling methods used in performance prediction. All key system components are reviewed to provide guidance for engineers, technicians, well analysts, and operating personnel who are involved in gas lift system analysis, troubleshooting, design, and optimization.

The primary purpose of this API Recommended Practice (RP) is to emphasize gas lift as a system and to discuss methods used to predict its performance. Information must be gathered and models validated prior to a system design, which must precede wellbore gas lift mandrel and valve design. The subsurface and surface components of the system must be designed together to enhance the strengths of each and to minimize the constraints.

This recommended practice bridges and enhances the general information from the *API Gas Lift Manual* (Book 6 of the Vocational Training Series) and the technical details of other API Gas Lift RPs, each of which contain information on a specific subject or part of the overall gas lift system. The gas lift system designer or operator should have and become familiar with the full set of documents from the API (American Petroleum Institute), GPSA (Gas Processors Suppliers Association), and ISO (International Standards Organization) that relate to gas lift system components:

API Gas Lift Manual (Book 6 of the Vocational Training Series)

API Spec 11V1—*Gas Lift Equipment*

API RP 11V2—*Gas Lift Valve Performance Testing*

API RP 11V5—*Operation, Maintenance, and Troubleshooting Gas Lift Installations*

API RP 11V6—*Design of Continuous Flow Gas Lift Installations*

API RP 11V7—*Repair, Testing, and Setting Gas Lift Valves*

API Spec 12GDU—*Glycol-Type Gas Dehydration Units*

API Spec 12J—*Oil and Gas Separators*

API Std 617—*Centrifugal Compressors for General Refinery Service*

API Std 618—*Reciprocating Compressors for General Refinery Service*

API Manual of Petroleum Measurement Standards (MPMS)—Chapter 5, *Metering*; Chapter 14, *Natural Gas Fluids Measurement*

GPSA—*Engineering Data Book*

ISO 17078—*Gas Lift Equipment Specifications*

FOREWORD

This Recommended Practice (RP) is under the jurisdiction of the API Committee on Standardization of Production Equipment (Committee 11).

This document presents RPs for the design of gas lift systems. Other API Specifications, API RPs, and Gas Processors Suppliers Association (GPSA) documents are referenced and should be used for assistance in design and operation.

Introduction to Gas Lift System Design and Performance Prediction

API RP 11V8 *Recommended Practice for Gas Lift System Design and Performance Prediction*, provides two functions:

- A broad overview of gas lift systems and various major types of gas lift operations.
- Recommended practices for gas lift system design and for modeling methods used in performance prediction. All key system components are reviewed to provide guidance for engineers, technicians, well analysts, and operating personnel who are involved in gas lift system analysis, troubleshooting, design, and optimization.

The primary purpose of this API Recommended Practice (RP) is to emphasize gas lift as a system and to discuss methods used to predict its performance. Information must be gathered and models validated prior to a system design, which must precede wellbore gas lift mandrel and valve design. The subsurface and surface components of the system must be designed together to enhance the strengths of each and to minimize the constraints.

This recommended practice bridges and enhances the general information from the *API Gas Lift Manual* (Book 6 of the Vocational Training Series) and the technical details of other API Gas Lift RPs, each of which contain information on a specific subject or part of the overall gas lift system. The gas lift system designer or operator should have and become familiar with the full set of documents from the API (American Petroleum Institute), GPSA (Gas Processors Suppliers Association), and ISO (International Standards Organization) that relate to gas lift system components:

API Gas Lift Manual (Book 6 of the Vocational Training Series)

API Spec 11V1—*Gas Lift Equipment*

API RP 11V2—*Gas Lift Valve Performance Testing*

API RP 11V5—*Operation, Maintenance, and Troubleshooting Gas Lift Installations*

API RP 11V6—*Design of Continuous Flow Gas Lift Installations*

API RP 11V7—*Repair, Testing, and Setting Gas Lift Valves*

API Spec 12GDU—*Glycol-Type Gas Dehydration Units*

API Spec 12J—*Oil and Gas Separators*

API Std 617—*Centrifugal Compressors for General Refinery Service*

API Std 618—*Reciprocating Compressors for General Refinery Service*

API Manual of Petroleum Measurement Standards (MPMS)—Chapter 5, *Metering*; Chapter 14, *Natural Gas Fluids Measurement*

GPSA—*Engineering Data Book*

ISO 17078—*Gas Lift Equipment Specifications*

CONTENTS

	Page
1 OVERVIEW OF A GAS LIFT SYSTEM	1
1.1 Major Components of a Gas Lift System	1
1.2 Ways in Which System Components Interact	3
2 TYPES OF GAS LIFT SYSTEMS	4
2.1 Continuous Gas Lift	5
2.2 Intermittent Gas Lift	6
2.3 Gas Lift with Plunger	8
2.4 Gas Lift Tubing/Packer Alternatives	8
3 INFORMATION REQUIRED FOR EFFECTIVE GAS LIFT	9
3.1 Fluid PVT Data	10
3.2 Flowing Pressure and Temperature Surveys	12
3.3 Production Tests	14
3.4 Gas Lift Valve Performance Information	16
3.5 Field Constraints	18
4 WELL DELIVERABILITY	22
4.1 Basic Models	23
4.2 System Models	29
5 FACTORS WHICH AFFECT POTENTIAL PRODUCTION RATE AND GAS INJECTION REQUIREMENT	34
5.1 Casing Pressure and Gas Injection Rate	34
5.2 Depth of Injection	34
5.3 Casing, Tubing, and Flowline Sizes	36
5.4 Gas Lift Valves	38
5.5 Reservoir Depth, Pressure, and Temperature	39
5.6 Well Inflow Productivity	39
5.7 Percent Water in Produced Fluid	40
5.8 Solution and Free Gas In Produced Fluid	40
5.9 Operating Separator Pressure	41
5.10 Wellbore Deviation	41
6 OTHER GAS LIFT DESIGN CONSIDERATIONS	42
6.1 Gas Supply	42
6.2 Gas Lift Gas Distribution System	51
6.3 Injection Gas Measurement and Control	52
6.4 Gathering, Testing, and Handling of Produced Fluids	55
6.5 Special Design Cases	56
7 GAS LIFT OPTIMIZATION	57
7.1 Economic Basis for Optimization	58
7.2 Determination of Gas Lift System Economic Costs and Benefits	58
7.3 Implementation of Field Optimization	59
7.4 What is Practical and What is Impractical	63

	Page
8 COMPUTER DESIGN TOOLS	63
8.1 Vertical Pressure Profile Models	64
8.2 Vertical Temperature Profile Models	66
8.3 Well Inflow Performance Models	67
9 OPERATING CONSIDERATIONS	69
9.1 Gas Lift Operators' Problems	69
9.2 Design Strategies for Effective Long-term Operation	71
9.3 Check List of Gas Lift Problems and Recommendations	73

Figures

1-1 Gas Lift System	1
1-2 Gas Lift Valves and Mandrels	2
1-3 Injection Pressure Operated (IPO) Gas Lift Valve	3
2-1 Flowing and Static Gas Lift Gradients	5
2-2 Intermittent Lift Cycle	6
2-3 Two-packer Chamber	7
2-4 Insert Chamber	7
2-5 Gas Lift with Plunger	8
2-6 Open Installation	9
2-7 Semi-closed Installation	9
3-1 High, Low, and Correct Calculated Gradients Obtained by Adjusting Fluid Properties	12
3-2 IPO and PPO Valves	17
3-3 Wellhead Pressure Delivery Area	20
3-4 Production Delivery vs. Injection Gas	21
4-1 Produced Fluid and Injection Gas Pressure Gradients	24
4-2 Gas Lift Deliverability Curve Showing Measured Tests	25
4-3 Temperature Gradients	27
4-4 Reservoir Inflow Performance (PI)	28
4-5 Inflow–Outflow Performance	29
4-6 Inflow–Outflow Performance with Natural Flow and Gas Lift	30
4-7 Equilibrium Curve for Low PI Well	31
4-8 Equilibrium Curve for High PI Well Showing Unloading Rates	31
4-9 Production and Gas Injection Tests Identify Under-performing Wells	33
4-10 Wellhead Delivery Curves and the Flowline Curves	33
5-1 Equilibrium Curve Rates and Pressures, High PI	35
5-2 Equilibrium Curve Rates and Pressures, Low PI	35
5-3 Production Delivery vs. Injection Gas	35
5-4 Inflow–Outflow Performance	37
5-5 Wellhead Pressure Delivery	37
5-6 Valve Types	38
5-7 Flow Regime Change with Inclination Angle	42
6-1 Brake Horsepower per Million cu.ft/day vs. Overall Compression Ratio	44
6-2a Production vs. Injection Gas and Separator Pressure, High PI	45
6-2b Production vs. Injection Gas and Separator Pressure, Low PI	45
6-3 Production vs. Injection Gas and Injection Pressure	46

	Page
6-4 Compressor BHP/STB vs. Separator Pressure	47
6-5 Water Content of Hydrocarbon Gas	49
6-6 Pressure-Temperature Curves for Predicting Hydrate Formation	50
6-7 Trunk Line Piping Distribution	52
6-8 Combination Piping Distribution	52
6-9 Orifice Plate and Meter Run Fitting	53
7-1 Production Rate vs. Injection Gas for Various Depths of Lift	62
8-1 Reservoir Inflow Performance	68

Tables

3-1 PVT Data and Adjustment to Match Bubble Point	11
4-1 Gas Gradient vs. Pressure and Specific Gravity	26
6-1 Brake Horsepower Per STB vs. Separator Pressure	47
7-1 Input Data	60
7-2 Production Performance	60
7-3 Economic Optimization	61

Recommended Practice for Gas Lift System Design and Performance Prediction

1 Overview of a Gas Lift System

This section provides a broad overview of the various components of a gas lift system and how these components interact with one another.

1.1 MAJOR COMPONENTS OF A GAS LIFT SYSTEM

The components of a gas lift system can be grouped as follows:

- a. Gas compression and distribution system.
- b. Subsurface equipment.
- c. Gas and liquid gathering system.

A. Gas Compression and Distribution System

A typical gas compression and distribution system is composed of a compression and dehydration plant, manifolds, gas lines, meters, and rate control devices as depicted in Figure 1-1. The compressor station receives gas from the low pressure separator and gathering system, or from gas wells, or from the sales pipeline, and compresses it to a pressure suitable for gas lift operations. The compressor discharge pressure typically ranges from 800 psig – 2000 psig, although other pres-

ures are used as needed, based on reservoir pressure, well productivity (PI), and gas lift valve constraints.

The amount of gas required depends on a number of criteria:

- Number of wells and the depth of the injection point.
- Amount of oil and water to be produced and the water fraction.
- Amount of formation gas produced.
- Reservoir pressure.

Compressor options are based on the required gas rate:

1. Small reciprocating units can compress a few million standard cubic ft per day—sufficient for a small field with a few wells.
2. Large reciprocating units can compress from a few million to a hundred million standard cubic ft per day—for large on-shore fields with numerous wells.
3. Centrifugal compressors can compress from a few million to more than a hundred million standard cubic ft per day—for numerous wells in large oil fields, especially offshore.

Gas lift uses the same surface facilities that process formation gas, since most fields require compression, dehydration,

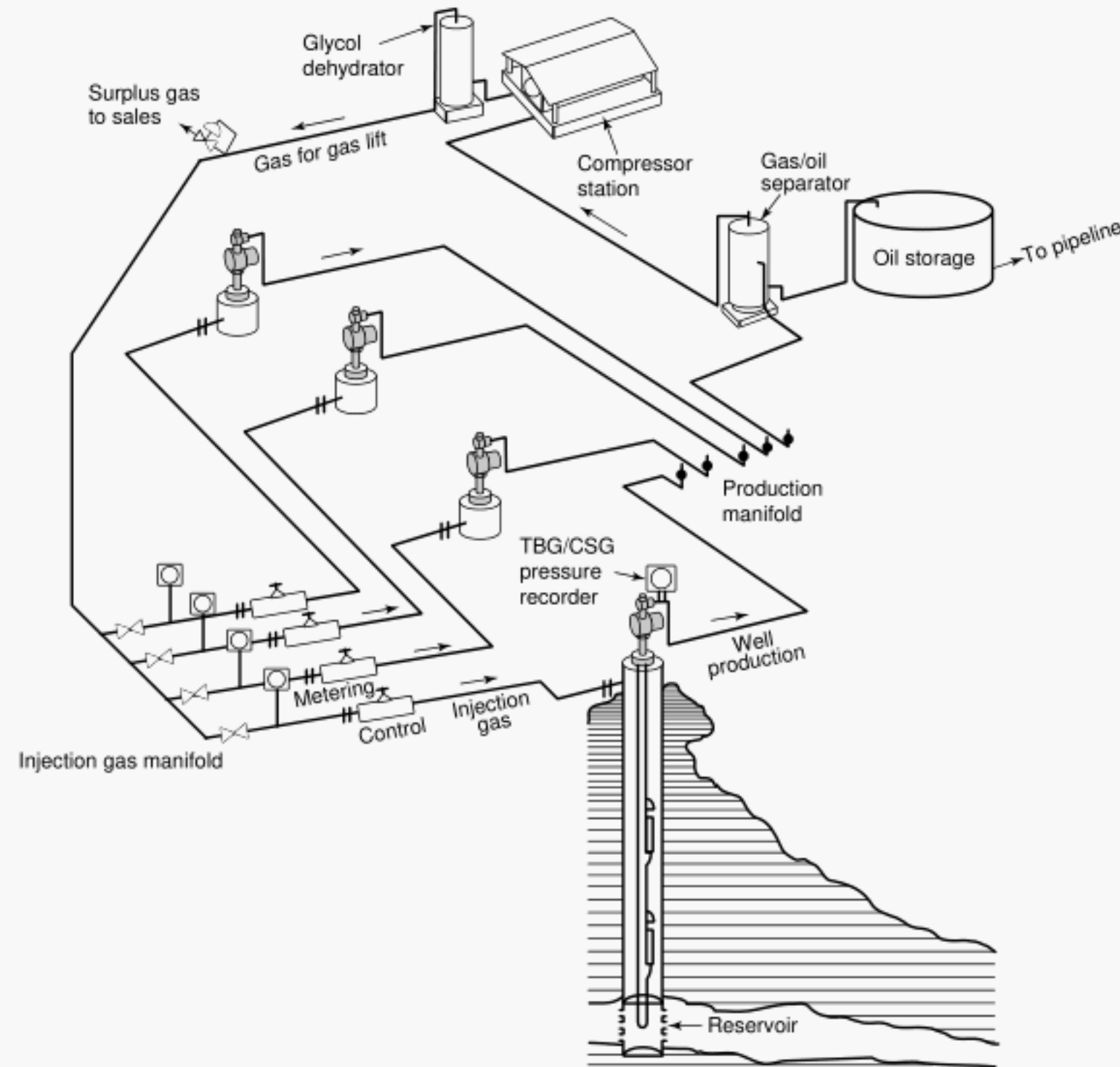


Figure 1-1—Gas Lift System

and treating to send the gas associated with the oil to sales, fuel for utilities, a natural gas liquids recovery plant, or to a re-injection plant. Lift gas is cycled in a closed loop that utilizes the existing facility, but often requires added low pressure compression capacity, and added high pressure compression capacity to raise the gas pressure to that needed by the gas lift process.

Gas lift gas distribution pipelines connect the compression plant with the wells either directly or through field injection manifolds. The working pressure rating of the piping system should equal or exceed the maximum discharge pressure of the compressors. The diameter of the pipeline depends on the flow rate, the number of wells, and the length of the pipelines. The distribution piping pattern can have different forms:

1. Random, connecting from one well to another.
2. An oval ring with individual well connections.
3. Major pipelines to field manifolds, with wells connected to the manifold.
4. Combination of methods.

Gas injection manifolds in the field can reduce the total installed pipe length and centralize operations such as gas flow measurement and control. The optimum number of manifolds to be installed will depend on the total surface area of the field and the number of wells. The number of wells per manifold may range from less than ten to more than thirty.

B. Subsurface Equipment

Tubing in a gas lift well usually has several gas lift valves and mandrels installed at different depths as depicted in Figure 1-2. The number of valves to be installed depends primarily on the:

1. Depth of the well.
2. Kill or static fluid gradient.
3. Reservoir pressure.
4. Available injection pressure.
5. Gas lift valve design method.

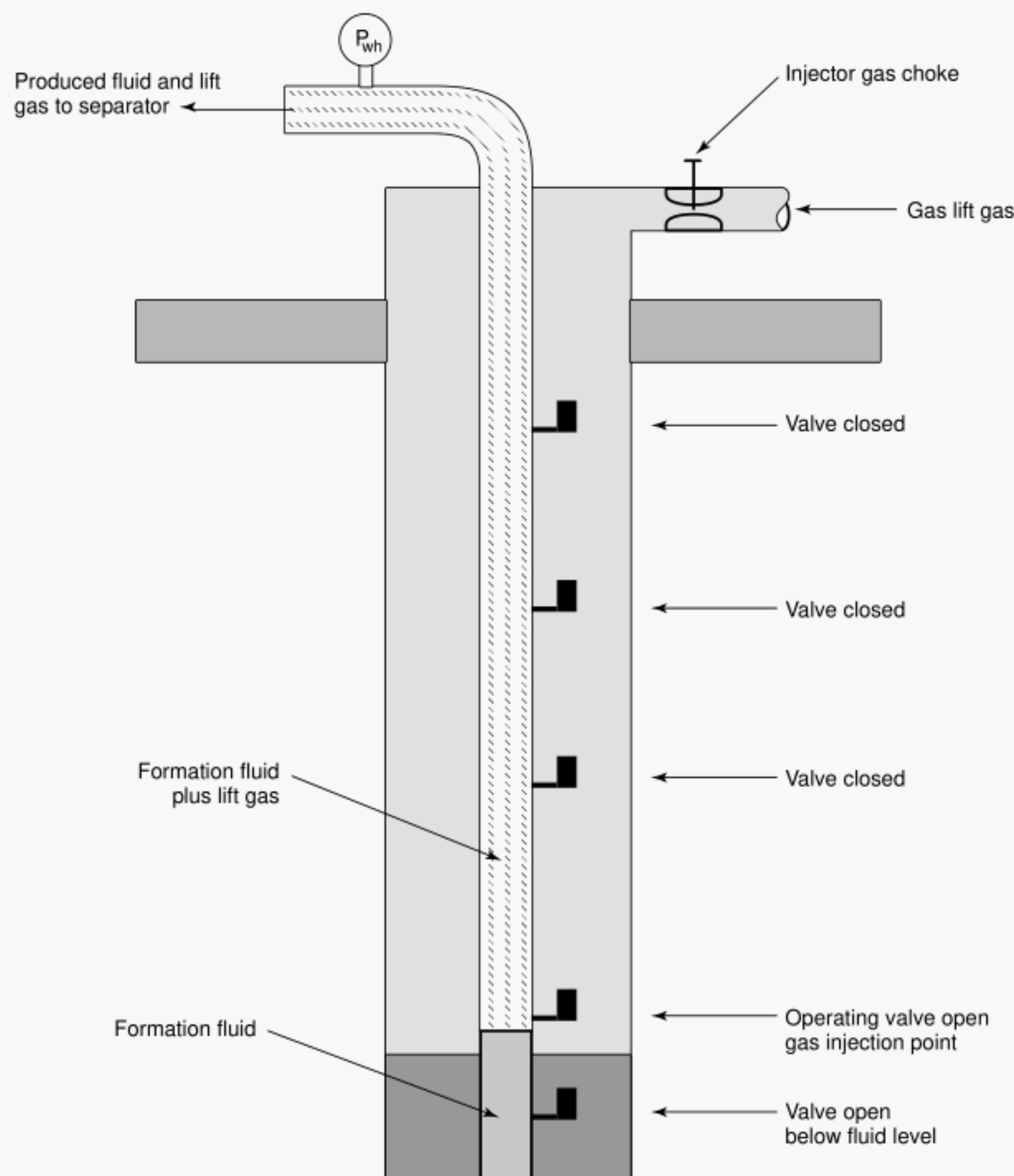


Figure 1-2—Gas Lift Valves and Mandrels

Gas lift valve installation and retrieval methods are:

- Conventional valves and mandrels installed/retrieved with the tubing.
- Wireline installed/retrieved valves set inside the pocket of a side-pocket mandrel in the tubing string.
- Special valves and mandrels installed/retrieved with coiled tubing.

Important, fundamental concepts about valves, Figure 1-3, are:

- Valves control the point of entry of the compressed gas into the production string and act as a pressure regulator.
- Valves have cross-sectional areas at the bellows (A_b) and at the stem/port (A_p) that pressure acts on:
 - nitrogen pressure (P_b) and/or a spring forces the stem/ball to close on the port seat,
 - injection gas (P_g) and fluid production (P_f) pressures provide the counter forces that act to open the valve.
- Valve port size may be a constraint to the maximum amount of injected gas, but the optimum gas rate is adjusted with the surface injection choke or controller (a choke in the valve can also be used).
- A reverse flow check valve, mounted below the port of the valve, prevents flow from the production fluid conduit back into the gas column (not shown).

An orifice can be used in lieu of a valve at the expected depth of injection. The orifice consists of the orifice (port) and the reverse flow check, but does not have a bellows and stem, so it is not a valve that can open or close.

Usually, the gas lift valve allows the injection gas to flow from the tubing-casing annular space into the production tubing. But alternatively, a gas lift valve can be installed to allow the gas to flow from the tubing into the annular space where it mixes with the production fluids coming from the reservoir. This is done when the gas and oil flow rates are high and require the annular area to minimize pressure loss. Casing corrosion due to annular flow is difficult to remedy, thus flow up the casing annulus is usually not recommended and often prohibited.

C. Gas and Liquid Gathering System

The multiphase gas-liquid flow from the well is transported either directly or through a gathering manifold to a separator station. Pipeline (flowline) sizing is dependent on the connection method:

- Directly connected flowlines—the diameter of the gas/oil/water pipeline depends on the flow rate, topography,

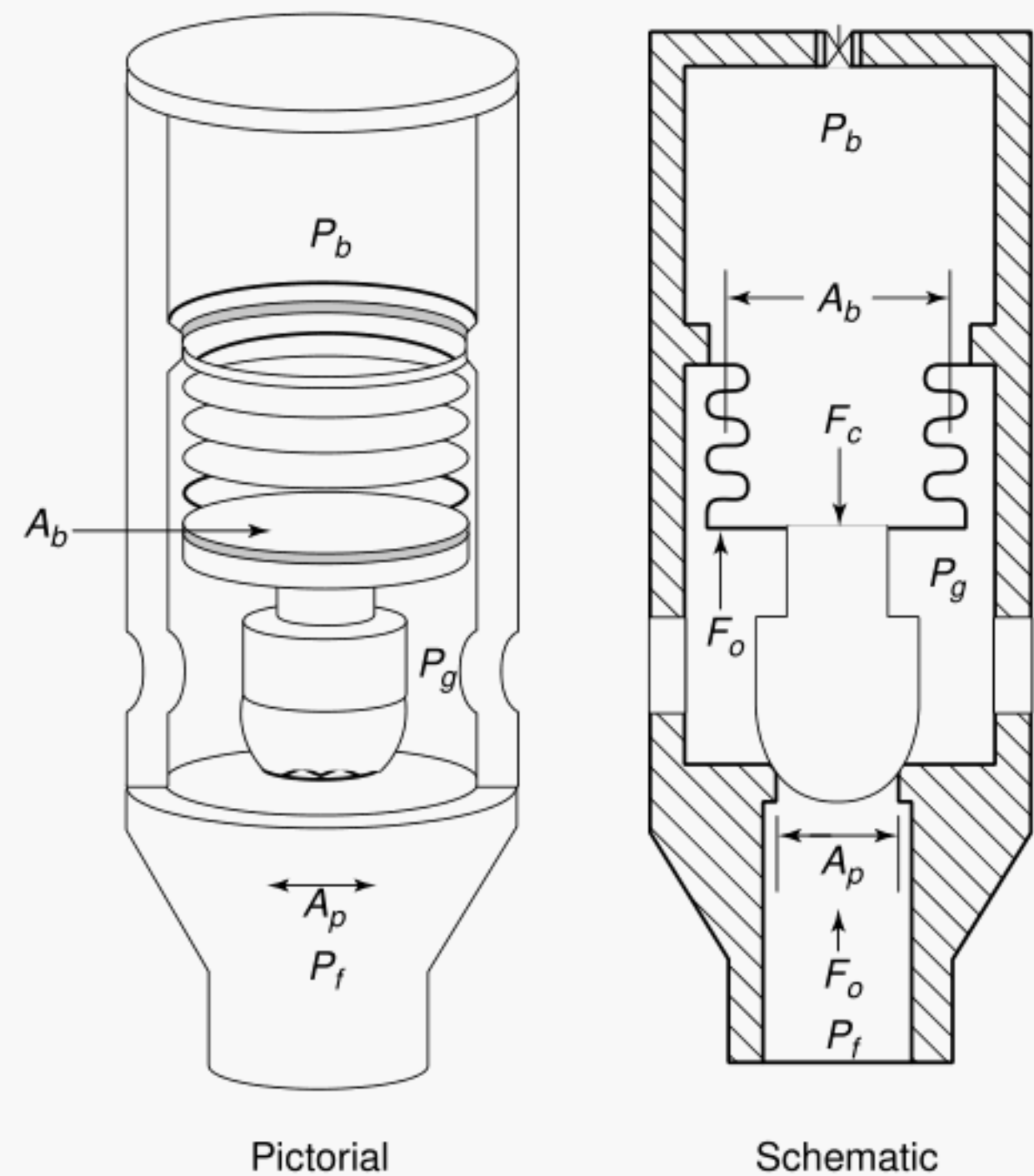


Figure 1-3—Injection Pressure Operated (IPO) Gas Lift Valve

and distance traveled, and it is usually equal to or greater than the diameter of the production tubing. Modeling of production rate vs. wellhead pressure for several flowline sizes aids in selecting an optimum size.

- Manifold connected flowlines—in large fields where the wellheads are distant from the separation plant, gathering manifolds can minimize total pipeline length. The wellhead to manifold connection is sized as stated above. From the manifold, usually two flow lines connect with the flow station. One is the production pipeline, used to transport the commingled flow from all the wells (except for the one being tested), and is sized for total flow including future water increases plus lift gas. The other is a smaller diameter test line and is used to connect only one of the wells to the test separator where its fluid and gas production is measured.
- A test separator located at the manifold is an option to avoid the need for the small test line and associated purging methods for long test lines.

From the separator flow station, the low-pressure gas is returned to the compression plant to complete the cycle.

1.2 WAYS IN WHICH SYSTEM COMPONENTS INTERACT

Each component interacts with the rest of the system in ways that can considerably affect the required gas injection

and the achievable oil production. The key objectives with all components acting as a system are:

- Deep injection of gas.
- A stable injection gas rate that:
 - reduces density in the production string,
 - lowers the flowing bottomhole pressure,
 - induces greater flow from the reservoir.

Gas compression and distribution must provide a steady, constant pressure supply of dehydrated gas at an adequate rate for all wells served:

- Low gas pressure causes the point of gas injection to be too shallow.
- High gas pressure deepens the point of lift when the unloading valve pressures are appropriately set.
- Gas rate, liquid rate, and the mixture density control the flowing bottomhole pressure.
- Injection gas rate must be matched to the liquid rate and tubing size because:
 - inadequate gas will not sufficiently reduce density,
 - the resulting low fluid velocity permits excessive liquid holdup,
 - excessive gas causes friction pressure loss to increase.
- Injection gas rate is adjusted with a surface choke or gas flow rate control valve.

Gas and liquid gathering components must be properly sized to allow maximum production:

- Well production is limited by the imposed system back-pressure created from:
 - high separation pressure,
 - a flow line with a small diameter,
 - a long flow line with diameter too small for the distance.
- Pipe sizing should be based on realistic flow rates since:
 - excessively large diameter can cause severe slugging,
 - too small of a diameter results in excessive friction losses.

The subsurface gas lift design is used to achieve the objective of reduced density and low flowing bottomhole pressure:

- Gas lift mandrel spacing:
 - enables the well to unload the kill fluid with the available kickoff pressure,

- must be correct between valve mandrels or the unloading stops prematurely and effective, deep lift is not attained.

- Gas lift valve pressure settings:
 - are based on a specified gas injection pressure,
 - are affected by valve type and size,
 - permit the valve to close after unloading and transferring to the next deeper valve.
- Valve port size and gas/fluid pressures influence the gas flow throughput, but primary control is by the surface choke or controller.
- An injection pressure operated valve (IPO) will react mainly to the gas injection pressure.
- A production pressure operated valve (PPO) will react primarily to the production fluid pressure.

The system can be operated with continuous injection into each well or with intermittent injection into some wells, provided the pulsing gas pressure does not adversely affect the continuous flow wells.

2 Types of Gas Lift Systems

The gas lift system type will be determined by the most effective gas lift method, continuous or intermittent. Choice is based on the well and the gas distribution system conditions:

- Producing rate and tubing diameter.
- Static bottomhole pressure (SBHP).
- PI.
- Gas piping diameter.
- Gas injection pressure and available rate.

Intermittent lift applies only when rate, SBHP, and/or PI are too low for effective continuous gas lift. The choice is related to the tubing size as well, since continuous flow might be maintained by reducing tubing diameter to increase fluid velocity.

Water or gas coning or sand production may influence selection:

- Steady continuous flow is preferred.
- Pulsating intermittent flow aggravates an existing sand production problem.
- Gas piping restrictions are greater constraints with intermittent lift.
- Surging continuous flow contributes to these same problems.

Future conditions such as water cut, SBHP, formation gas-liquid ratio (FGLR), and productivity index (PI) should be

considered in planning the installation with either type of gas lift system.

2.1 CONTINUOUS GAS LIFT

Continuous gas lift requires constant injection of high pressure gas into a flowing fluid column:

- To reduce mixture density,
- Which lowers flowing bottomhole pressure (FBHP), and
- Increases the production from the well.

RECOMMENDED PRACTICE: Continuous gas lift is best for most wells, especially for high capacity wells and for wells in which flowing bottomhole pressure pulsations must be minimized because of sand, gas, or water production, or due to reservoir gas or water coning.

Figure 2-1 shows the flowing gas lift and static fluid gradients. With the well shut-in and without gas injection, the well-

head pressure plus the static wellbore gas and liquid pressure gradients equal the SBHP.

When gas is injected into the tubing, the fluid gradient becomes lighter from the point of gas injection to the surface. This reduces the FBHP and creates the drawdown needed for a higher production rate.

The flowing bottomhole pressure (FBHP) is a function of the:

- Flowing pressure gradient above the point of gas injection.
- Formation fluid pressure gradient below the point of injection.
- Flowing wellhead backpressure.

To attain lift effectiveness at the lowest injection gas-liquid ratio (IGLR):

- The point of gas injection should be at the deepest valve.
- High distribution pipeline pressure and properly set unloading valves permit lift from the deepest valve (if the deepest point is an orifice, the operating injection pressure may decline substantially).

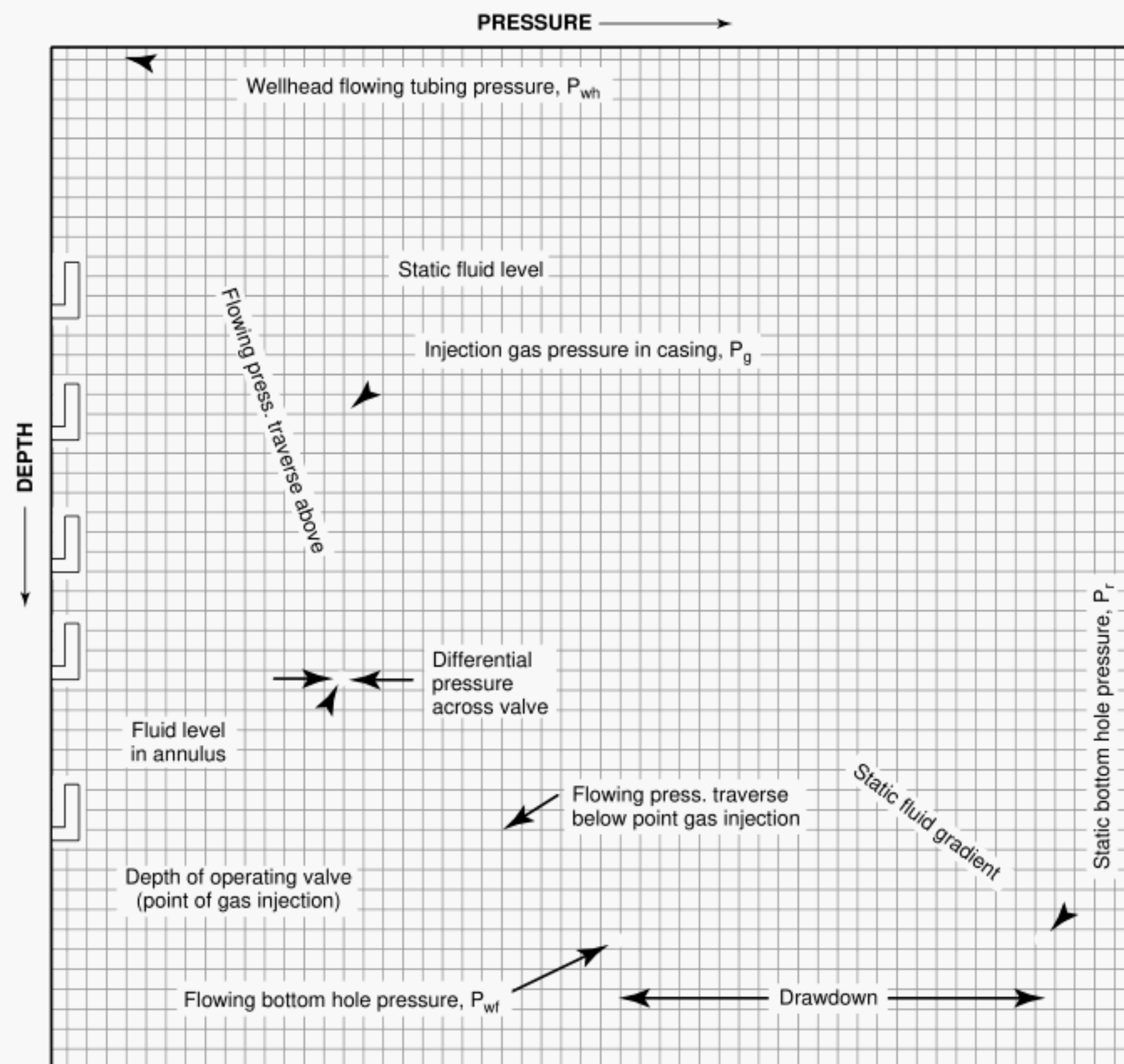


Figure 2-1—Flowing and Static Gas Lift Gradients

Continuous gas lift can only achieve a flowing gradient of approximately 0.10 psi/ft – 0.15 psi/ft, depending on the liquid flow rate. This limitation must be considered when applying the technique to wells with low SBHP.

2.2 INTERMITTENT GAS LIFT

Intermittent gas lift applies large rates of gas for a short time duration. The production cycle consists of a liquid slug followed by a gas slug, followed by tail gas until the intermittent cycle is repeated. The large rate of gas and low rate of liquid causes the flowing gradient to be approximately 0.05 psi/ft, after the slugs have surfaced, thus the method is applicable to low SBHP wells. However, the lift effectiveness is diminished and more gas is required, in terms of standard cubic ft (scf) of lift gas per stock tank barrel (bbl) of liquid produced. The injection gas can be controlled by a choke or by a control valve.

RECOMMENDED PRACTICE: Intermittent gas lift should be applied to low rate wells, caused by high SBHP but low PI, or by low SBHP but high PI. Intermittent lift should incorporate tubing flow and IPO unloading valves, with a large ported pilot operating valve.

In Figure 2-2 a complete cycle of intermittent gas lift operation is illustrated. The cycle phases are:

1. The operating valve is closed, the standing valve is open, and fluid from the formation accumulates inside the tubing above the operating valve.
2. The controller and operating valve are open, the injection gas enters into the tubing and displaces the liquid slug toward the surface. At this time, the standing valve closes, preventing high-pressure gas flow into the formation.
3. The controller closes, which stops the inflow of gas into the annular space, and the operating valve will close when the annular pressure reaches the valve closing pressure.
4. If choke control is used, then the choke constraint (choke area is smaller than the valve port area) causes the gas injection pressure to decline to the valve closing pressure. This method minimizes intermittent cycle disruption of other wells.

Intermittent gas lift is recommended for low rate wells, but defining where continuous lift should end and intermittent lift should begin varies. Important disadvantages of intermittent lift are the limited maximum production rate and its pulsating effect on the gas distribution piping which could destabilize other wells. Also, the method is not suited for deep lift through small tubing. Finally, an intermittent lift well gas slug

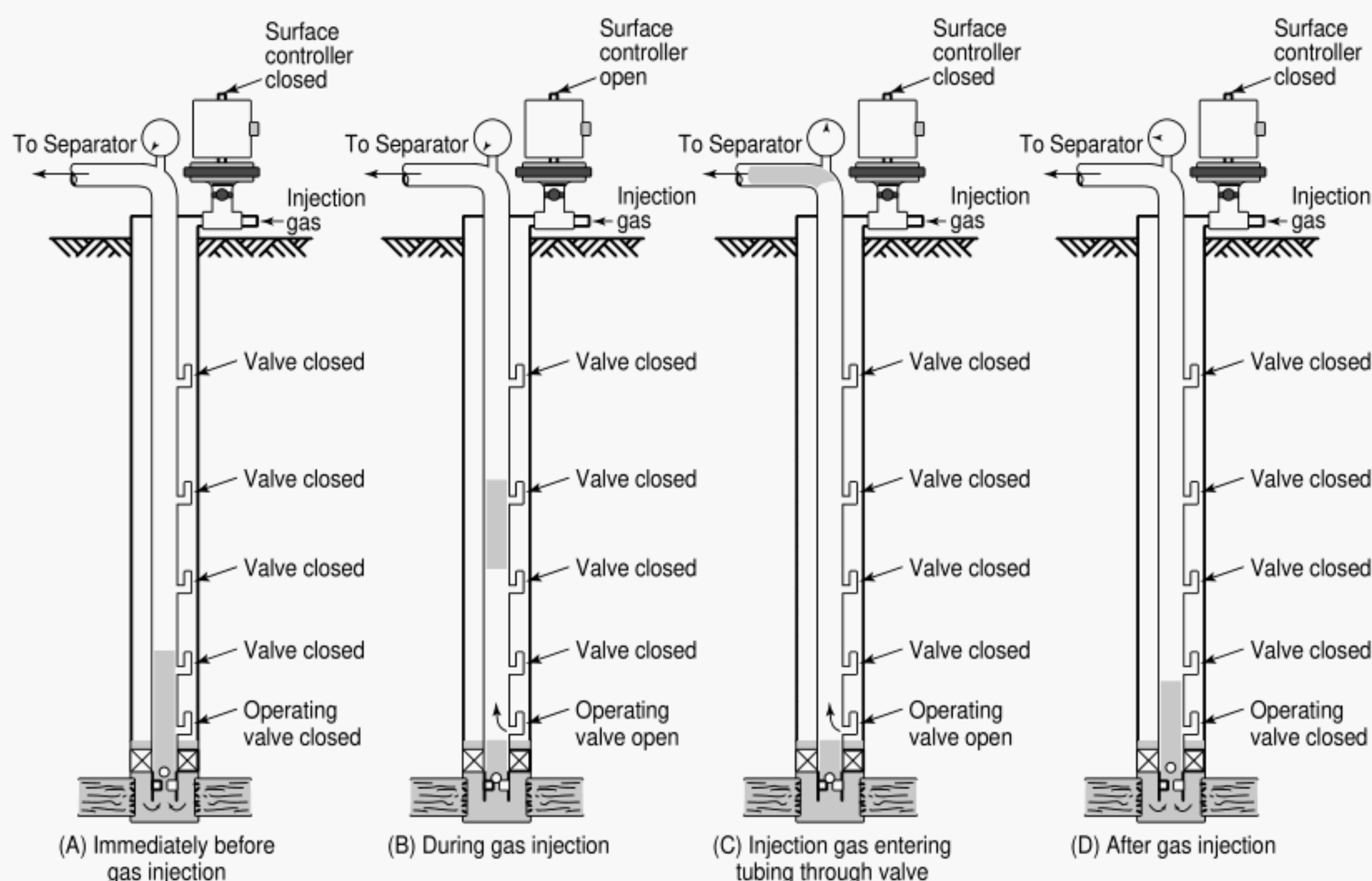


Figure 2-2—Intermittent Lift Cycle

may be difficult to handle in a small closed system, and intermittent wells could adversely affect the performance of the continuous wells due to supply pressure fluctuations. Increasing the gas storage volume using old wellbores or large diameter pipelines is beneficial.

Intermittent lift production rate strongly depends on the liquid slug volume that is lifted. Low reservoir pressure wells can use bottomhole chambers to reduce the backpressure and to allow accumulation of a large slug size.

Chambers can lift more fluid per cycle but require more time to fill the chamber, which results in fewer cycles. Also, gassy or foamy wells will have less liquid accumulation in the chamber, which affects net liquid production.

RECOMMENDED PRACTICE: The chamber type of installation should be evaluated for high PI and low BHP intermittent lift wells. A chamber allows the lowest BHP possible to be attained and produces adequate rates by using the larger volume to store fluids for lift.

A. Two-packer Chamber

A two-packer chamber, Figure 2-3, accumulates a large volume of liquid with a minimum amount of pressure on the formation. The lift process is:

1. The operating gas lift valve is closed and the reservoir fluid flows into the chamber.
2. Well fluid flows up through the open standing valve, perforated nipple, chamber space, and tubing string.
3. The bleed ports are open, allowing gas to escape from the chamber space into the tubing from a point near the top of the chamber.
4. The operating gas lift valve opens and gas is injected into the chamber.
5. The resultant extra pressure (a small choke can be used as a bleed port) closes the standing valve and bleed ports.
6. The accumulated liquid slug is u-tubed from the chamber into the tubing string and lifted to the surface.

B. Insert Chamber

The insert chamber, Figure 2-4, is often used in an open hole completion, but can be used in wells with a long casing perforated interval. Not as large as the two-packer chamber, its slug is less because of the smaller diameter required to fit inside the casing. Venting in both the outer and inner annular space is crucial for liquid accumulation in the chamber.

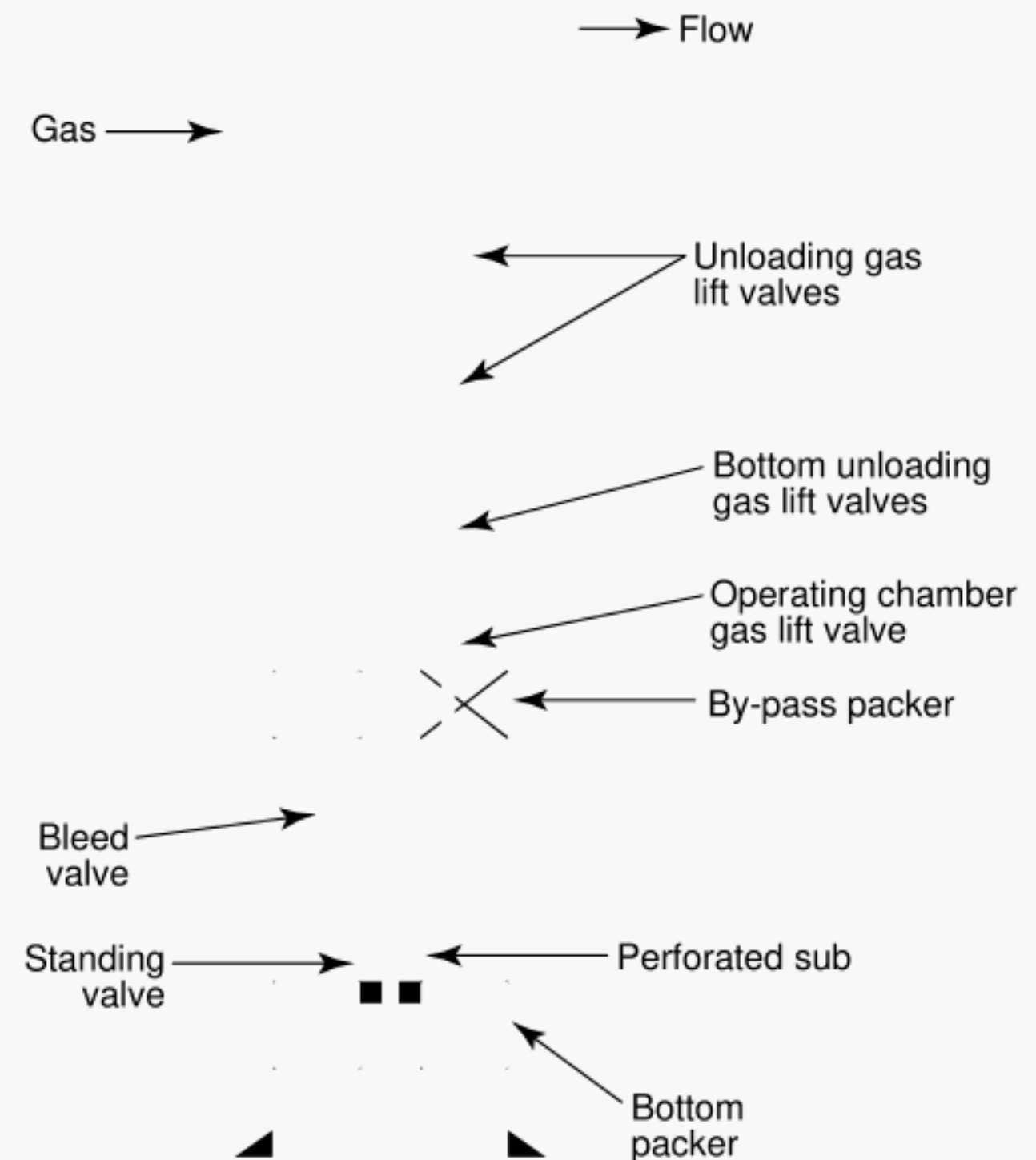


Figure 2-3—Two-packer Chamber

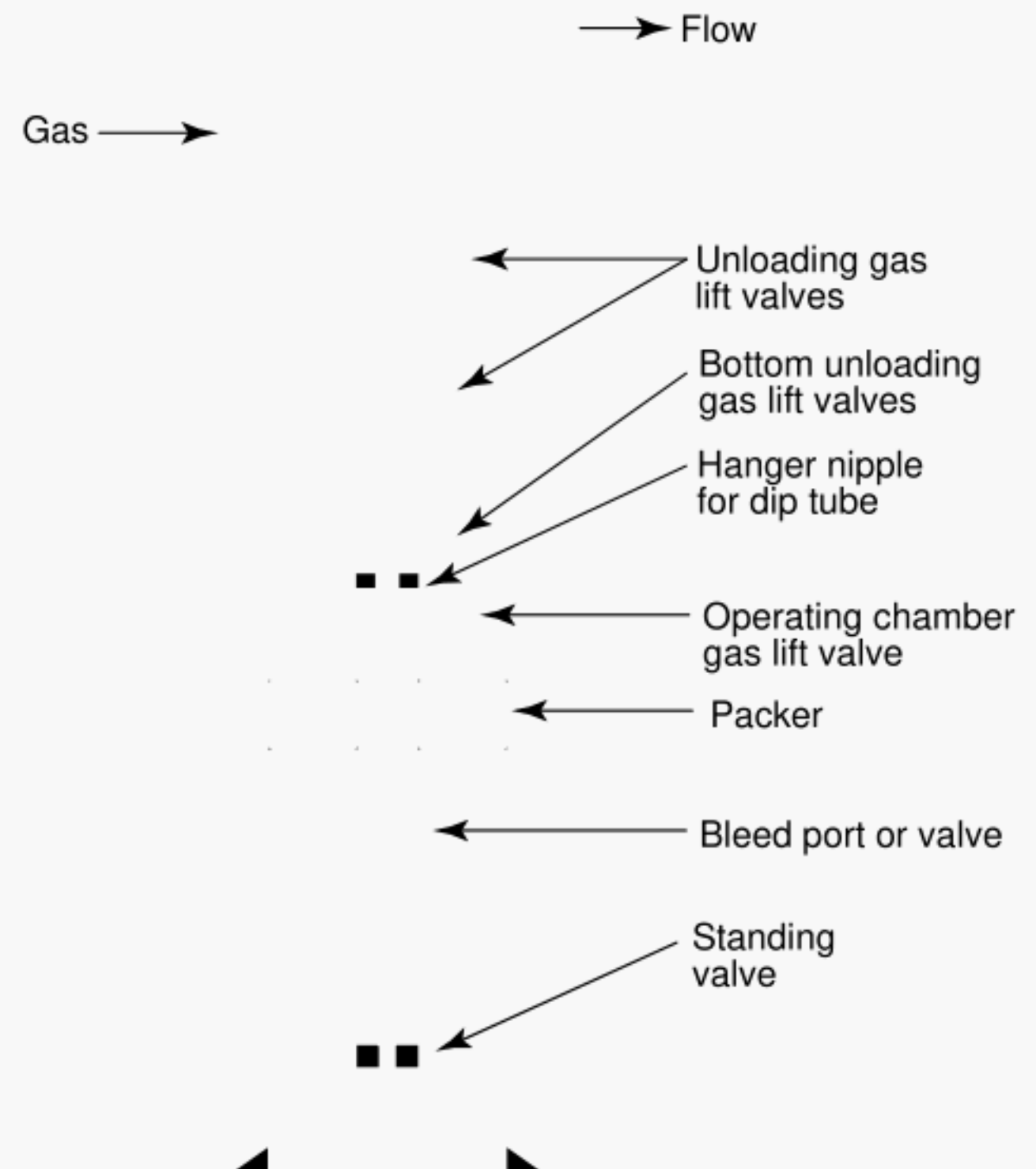


Figure 2-4—Insert Chamber

2.3 GAS LIFT WITH PLUNGER

Gas lift with a plunger can be used as intermittent lift. The piston traverses the length of the tubing string in a cyclic manner, providing an interface between the lifting gas and the produced liquid. The plunger sweeps more of the liquid film from the tubing wall, minimizing the liquid fallback. Sand or solids in the tubing could prevent the plunger from operating successfully, however, plungers are used to control paraffin deposits.

RECOMMENDED PRACTICE: Plunger lift may be used with intermittent lift to improve slug lift effectiveness or in wells whose fluid properties cause the gas to channel through the liquid column. It can also be used in low rate gas wells that are aided with lift gas.

Figure 2-5 shows a down hole plunger installation with the gas lift valve located below the plunger. The surface wellhead equipment shows the lubricator/catcher to hold the plunger for its short time at the top. Two important considerations for plunger installation are:

- Master valve type—the master valve must have a full bore equal to the tubing size to allow plunger passage. Also the valve must not be oversized more than $\frac{1}{8}$ ", since the extra clearance permits excessive gas passage, which could prevent the plunger from being lifted into the lubricator, or could cause the plunger to “hang up” at the valve.
- Tubing condition—the tubing must be gauged and broached (cleaned) before running any subsurface equipment. Damaged tubing, paraffin, scale, asphaltine, or corrosion deposits can prevent successful operation.

2.4 GAS LIFT TUBING/PACKER ALTERNATIVES

The descriptions for downhole tubing/packer arrangements are:

- Open
- Semi-closed
- Closed

A. Open

Open installations, Figure 2-6, have no packer and the tubing is hanging freely in the wellbore. Gas is transported in the casing-tubing annular space to the valve or to the end of the tubing. Constant communication exists between the casing and tubing, which is not recommended. This accelerates cor-

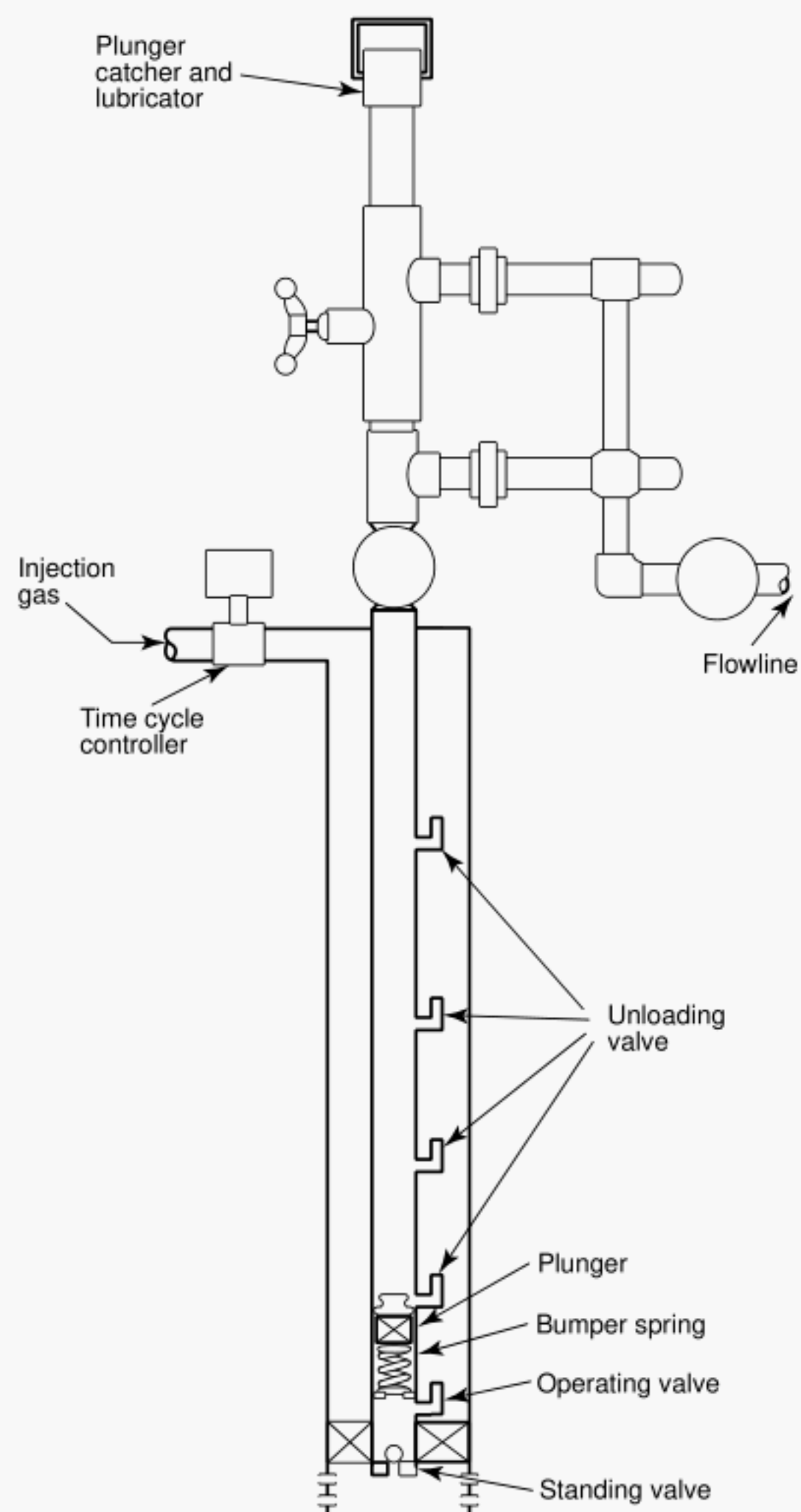


Figure 2-5—Gas Lift with Plunger

rosion, aggravates gas/liquid slugging, and requires unloading every time the well is shutdown, subjecting the valves to additional fluid erosion.

Even though open installations have serious disadvantages, this method may be required for conditions such as repaired casing resulting in a short section of reduced diameter, or deviations and hole crookedness which may prevent a packer installation. Fluid levels obtained during stable flow can be used for estimating flowing bottomhole pressure and for troubleshooting.

B. Semi-closed

Semi-closed installations, Figure 2-7, have a packer as a seal between the tubing and casing, but a standing valve (check valve) is not installed. These installations are suitable for both continuous and intermittent gas lift. Unloading is not

required with every shutdown since all the gas lift valves are provided with a reverse flow check valve.

RECOMMENDED PRACTICE: Packer and tubing, used in a semi-closed installation, is the preferred continuous flow gas lift downhole arrangement.

C. Closed

Closed installations add a standing valve (check valve to prevent reverse flow) to eliminate high pressure gas being exerted on the reservoir. Usually the standing valve is wire-line set in a landing nipple near the packer. The intermittent lift installation often uses the closed completion but continuous flow designs do not require a standing valve.

RECOMMENDED PRACTICE: A closed installation consisting of a packer, tubing, and standing valve is useful in an intermittent gas lift downhole arrangement when the SBHP is low. If sand production, or scale or paraffin deposits are a problem, then the standing valve should not be used.

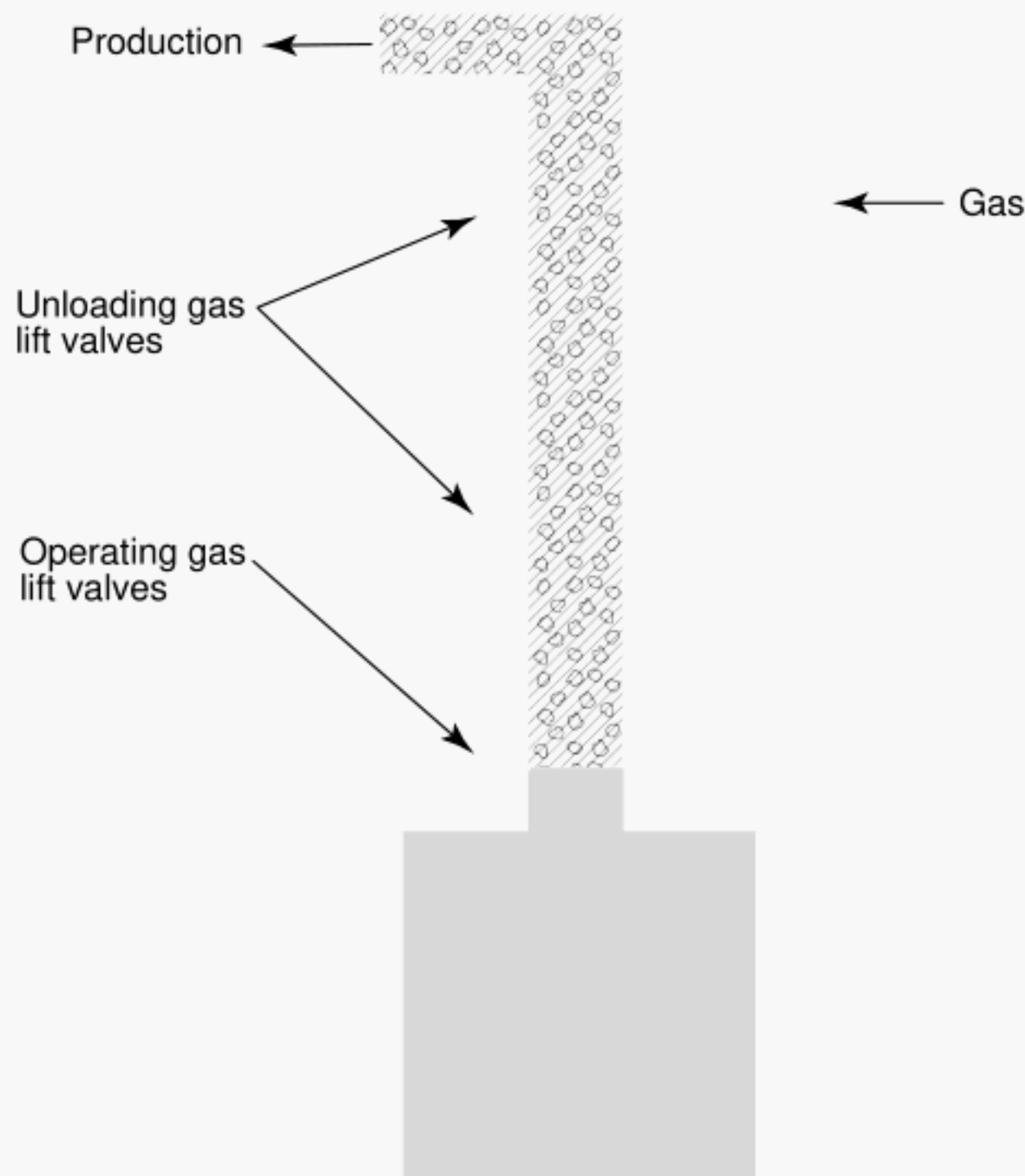


Figure 2-6—Open Installation

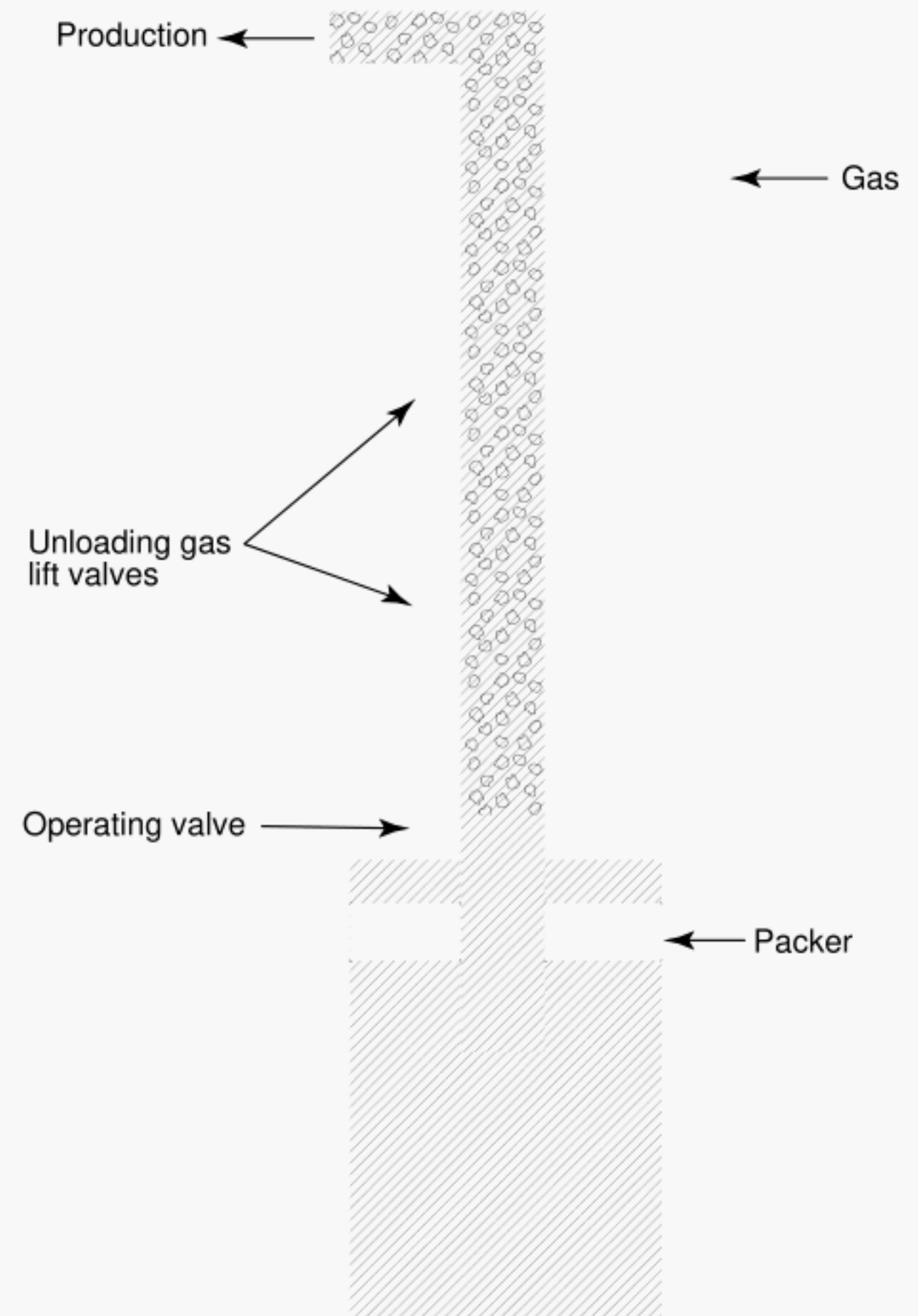


Figure 2-7—Semi-closed Installation

3 Information Required for Effective Gas Lift

Design, performance prediction, optimization, or troubleshooting of a gas lift system requires data that includes:

- Oil, gas, and water fluid properties,
- Producing pressure and temperature surveys,
- Well test production rates,
- Gas lift valve characteristics,
- Identification of constraints such as gas pressure and rate, or back-pressure against the well.

3.1 FLUID PVT (PRESSURE-VOLUME-TEMPERATURE) DATA

RECOMMENDED PRACTICE: Oil, gas, and water fluid property information based on downhole samples and laboratory analysis should be used in gas lift analysis and design work. If downhole samples are not available, then recombined samples of separator oil and gas should be used.

Correct hydrocarbon and water property data for each well will assist in improving the:

- Match of calculated to measured flowing pressure gradients
- Accuracy of computer calculations of flowing pressure gradients
- Reliability of delivery performance models of the wells

The fluid properties from the PVT reports, either by a commercial lab or the oil company lab, are the starting point. They should be based on subsurface or recombined hydrocarbon-pressurized samples obtained during exploration drilling or later during production tests.

A PVT report is generally not available for each well and its reservoir interval. The wells for which data are available must be used as a guide and other wells' data should be adjusted to match measured pressure data.

PVT reports contain two types of data:

- "Flash" data at several pressure and temperature points.
- "Differential liberation" data at various pressure points at constant reservoir temperature.

The flash data are preferred since it simulates the flow up the well to the separator (with laboratory separator pressure and temperature representing facility data). However, the differential liberation data, which is obtained at constant reservoir temperature, should also be considered.

A. PVT Data Available

The hydrocarbon fluid properties that can be obtained from flash data are:

- Gas-oil ratio (GOR) at each stage.
- Gas specific gravity (Gas $SpGr$) at each stage.
- Stock tank API gravity of the oil.

The PVT report flash data for an example oil sample are:

$P_{stg1} = 125$ psig @ 100°F	$GOR_1 = 177$ scf/stb	Gas $SpGr_1 = 0.86$
$P_{stg2} = 0$ psig @ 60°F	$GOR_2 = 67$ scf/stb	Gas $SpGr_2 = 1.39$
	$GOR_T = 244$ scf/stb	Gas $SpGr_T = 1.01$

The total gas-oil ratio, GOR_T , is calculated from:

$$GOR_T = GOR_1 + GOR_2$$

$$GOR_T = 177 + 67$$

$$GOR_T = 244 \text{ scf/stb}$$

The total gas specific gravity, Gas $SpGr_T$, is calculated from:

$$\text{Gas } SpGr_T = (GOR_1 / GOR_T) \times \text{Gas } SpGr_1 + (GOR_2 / GOR_T) \times \text{Gas } SpGr_2$$

$$\text{Gas } SpGr_T = (177/244) \times 0.86 + (67/244) \times 1.39$$

$$\text{Gas } SpGr_T = 1.01$$

The example PVT report also provides:

API oil gravity = 28°API at standard conditions,

Bubble point, P_{bp} = 1270 psig at 250°F reservoir temperature,

Volume factor, B_o = 1.19 bbl oil/stb at the P_{bp} and reservoir temperature,

Oil viscosity, μ_o = 1.25 centipoise at the P_{bp} and reservoir temperature.

Correlations to calculate bubble point pressure are based on fluid properties and temperature. The correlation equations are included in all multiphase flow computer calculations for pressure gradients or well performance models. The calculated bubble point, including any fluid property adjustments, should be compared to the PVT report measured data.

RECOMMENDED PRACTICE: The calculated bubble point pressure should match within 5% when compared to the PVT report measured data. A match is obtained by adjusting gas specific gravity, GOR , and oil API gravity.

The frequently used correlations for solution GOR and bubble point pressure will not give an exact match. However, if the correlations do not provide a reasonable match with measured data for the crude being modeled, then check the PVT reports for GOR , Gas $SpGr$, and API gravity to deter-

Table 3-1—PVT Data and Adjustment to Match Bubble Point

Well	Measured			Adj.	Calc.	
	<i>GOR</i> scf/stb	Oil °API	Form. Gas <i>SpGr</i>	Form. Gas <i>SpGr</i>	<i>P_{bp}</i> @ 250°F	<i>GL</i> Gas <i>SpGr</i>
A	235	26.1	1.01	1.03	1285	0.78
B	225	25.2	0.98	1.03	1253	0.78
C	250	27.3	1.04	1.02	1295	0.78
PVT*	244*	28.0*	1.01*		1270*	

* From PVT report

mine which item(s) may be incorrect. Review all pertinent PVT reports and select those that best represent most of the wells and their reservoir segments.

The PVT data should be adjusted to provide a suitable match between measured and calculated bubble point pressures as well as between measured flowing pressure gradient data and multiphase flow computer calculations. The items to adjust, and the order of adjustment, are:

- Gas specific gravity (Gas *SpGr_T*)
- Gas-oil ratio (*GOR_T*)
- Oil API gravity

This adjustment should not require a drastically different value. Reservoir gas specific gravity should be reviewed as it is often incorrectly assumed to be 0.65. Gas from an oil reservoir is usually heavier.

The three wells from different segments in the same reservoir in Table 3-1 give an example of data which, when gas specific gravity is adjusted, provide a reasonable fit to the bubble point listed. The gas specific gravity was adjusted by trial and error until the bubble point was within the 5% recommended tolerance.

B. PVT Data Not Available

With some wells, PVT data may not be available. New downhole sample gathering is not feasible because the reservoir pressure is below bubble point, or because of a high water percentage (insufficient hydrocarbon quantity in the subsurface wireline sample chamber). However, separator samples of oil and gas can be obtained and recombined on the ratio of the test *GOR* (separator samples from reservoirs below the bubble point would represent both solution gas and free gas).

RECOMMENDED PRACTICE: If PVT data are not available, then the fluid properties should be estimated using measured flowing pressure gradient, temperature, and rate data.

The **first step** is to obtain measured data. If the system is automated, then several items will be in the database. The required items:

- Flowing pressure and temperature data in the wellbore with wireline gauges stopped at numerous depths,
- Injection gas pressure on the casing at the wellhead (24 hr. chart),
- Gas composition and specific gravity (using chromatograph analysis) from a sample of separator gas and from a sample of injection gas,
- Oil API gravity from production test separator sample,
- Water specific gravity from production test separator sample,
- Production tests (rate, water percent, gas-liquid ratio).

The production tests will give results that typically vary 10% or more from test to test. Gas rate is the most common error since separator gas rate is not steady (total measured separator gas less measured gas lift gas gives formation gas). However, the test is adequate as a starting point for matching.

The **second step** is a comparison of the measured wellbore pressure gradient data to the multiphase flow calculated data. In a gas lift well, the wellbore must be divided into the:

- Lower section below the point of injection
- Upper section above the point of injection

The *lower section* fluid flow will have a measured pressure gradient that corresponds to reservoir PVT properties and formation water. The pressure gradient comparison should be from the bottom of the hole upward to the point of injection, as this method will eliminate error due to the injection gas. The calculation model should allow input of data for:

- Gas specific gravity
- *GOR*
- Water percent
- Water specific gravity

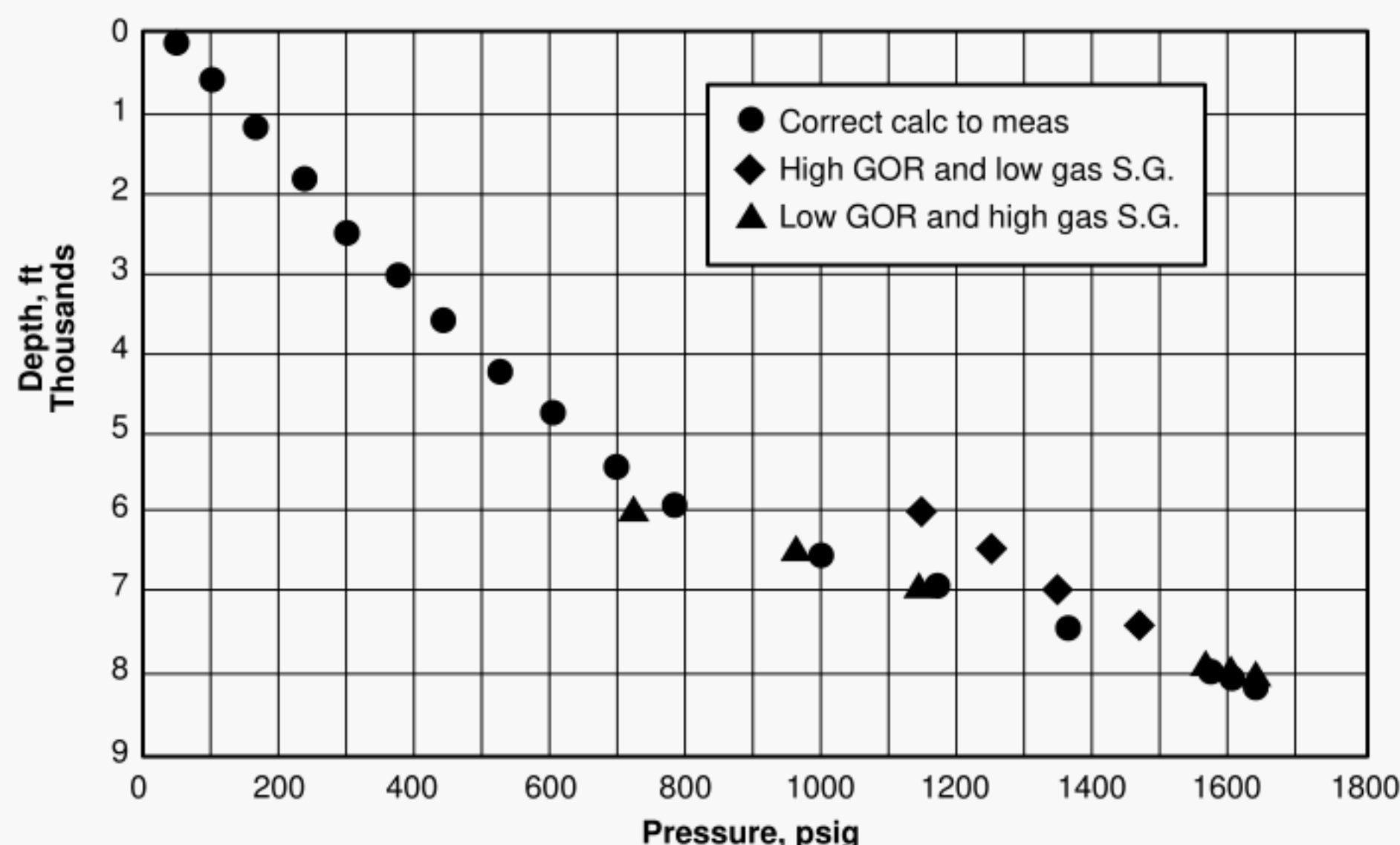


Figure 3-1—High, Low, and Correct Calculated Gradients Obtained by Adjusting Fluid Properties

The initial value of this data can be based on production tests, and then adjusted until a match of the measured to the calculated pressure profile is obtained. The matched pressures indicate that the reservoir PVT and formation water properties used in the final computer calculation are representative of the fluids flowing in the well.

Figure 3-1 illustrates the correct calculated pressure profile, as compared to measured pressure in the reservoir fluid section below the point of injection. Also shown are high and low calculated gradients, caused by different fluid properties, as defined on the graph.

The *upper* section represents fluid flow with gas lift gas added to the reservoir fluid. The additional variables that affect the fluid properties and pressure profile from the point of injection to the surface are:

- Injection gas specific gravity
- Injection gas rate (IGLR)

Injection gas specific gravity is obtained from a sample that is analyzed with the chromatograph. If data are not available, then the injection gas gravity should be estimated by comparing the calculated gas pressure at the valve (in the casing) to the measured fluid pressure in the tubing:

1. Start with the measured gas pressure on the casing (at the wellhead).
2. Calculate the gas pressure at the valve.
3. Adjust the gas specific gravity to give a casing pressure at the gas lift valve injection point that is approximately 100 psi greater than the measured pressure

inside the tubing (the 100 psi difference is based on experience).

The injection gas rate (IGLR) has a strong effect on the comparison of measured to calculated pressure in the upper section. The lift gas rate is adjusted until a Δp match (within 10%) is obtained in the pressure profile comparison from bottomhole to the wellhead.

If the production rate tests are inconsistent (not repeatable), then the liquid rate can also be adjusted to help achieve the match in the upper section.

RECOMMENDED PRACTICE: The calculated pressure difference, Δp (flowing bottomhole – flowing wellhead), should match within 10% when compared to the survey measured Δp data. The lower gradient (below the point of injection) should have a Δp match of 5%.

3.2 FLOWING PRESSURE AND TEMPERATURE SURVEYS

Gradient and deliverability models require good fluid property data for satisfactory results from the multiphase flow correlations, but the key is calibration with a flowing pressure and temperature survey.

Flowing survey objectives and procedural points are discussed in API RP 11V5 *Operation, Maintenance, and Trouble-Shooting of Gas Lift Installations*. Pressure surveys are also applied to well performance models in 4.1 of this RP.

The pressure gradient data are used to:

- Adjust fluid properties.
- Give the flowing bottomhole pressure for a productivity index (PI) calculation or for use in the inflow performance relationship (IPR).
- Confirm the point(s) of injection or find suspected leaks.

The temperature survey data are used to:

- Detect cooling at gas expansion (injection) points.
- Obtain the temperature of the lower operating valves for applying correction factors to the test rack opening pressure calculations.
- Provide measured data for the computer multiphase flow and PVT calculations.

RECOMMENDED PRACTICE: Obtain quality pressure and temperature surveys, coupled with PVT fluid data, and repeatable production rate tests, to calibrate and to select the best multiphase flow correlations and well deliverability models.

A. Pressure Surveys

Points to improve the quality of survey data are:

- Use wireline contractors that specialize in well testing surveys, not just any company that can provide gauges.
- Query the wireline contractor on the frequency of gauge calibration. Every fifth use should be a minimum calibration frequency for mechanical gauges. Electronic gauges are calibrated with their software on every use.
- Use a dead weight tester (or calibrated test gauge) to measure the wellhead flowing pressure and injection gas pressure. This will verify the surface pressure gauges and the wireline gauges.
- If the well is heading (surging or slugging), then keep the wireline gauges at each depth for sufficient time to sense the maximum and minimum pressures. To observe the pressure swings, request chart interpretation at one min. intervals (to obtain pressure vs. time data at each depth).
- Use the recommended practices in API RP 11V5 for gauge installation, stops, and tools on the wireline string and for guidance in running and obtaining the surveys.
- Comply with manufacturer's stop times for temperature equalization when using electronic gauges. This time can be up to 5 min. depending on transducer type and the location in the gauge.
- If using electronic gauges, then obtain data going into the wellbore when the gauge heats and equalizes tem-

perature more quickly (coming out, the gauge has to cool and equalize temperature, which is slower).

Other points that improve the measured to calculated data comparison accuracy are:

- Achieve a stable well test (see 3.3) before beginning or during the survey. If the test separator is busy, then test under the same operating conditions within three days of the flowing survey.
- Obtain at least four data measurements at depths below the (expected) gas injection depth for PVT data validation (and pressure extrapolation if the gauges are not set in the perforations).
- In modeling, use the exact well completion configuration:
 - tubular internal and external diameters, including extension tubes below the packer. A safety valve can be approximated as a tubular length of 20 ft of pipe with the safety valve ID.
 - depth to the mid-point of the perforations.
 - inclination or deviation survey data for measured and true vertical depth (TVD). Define the hole deviation path with an adequate number of MD (measured depth)/TVD data pairs to properly define the deviation of the well. The data is contained in the deviation survey obtained when the well was drilled.
- Be consistent in the use of reservoir data:
 - the reservoir pressure data can come from static surveys. For accurate pressure extrapolation, at least four static stops should be made in the lower wellbore near the perforations.
 - an alternate method is to obtain reservoir pressure from pressure build-up tests. With the pressure build-up test, skin and permeability also can be determined. Permit sufficient shut-in time for the reservoir to cease afterflow and to reach radial flow equilibrium, indicated by the straight line in the build-up data.
 - for trend analysis, compare results with prior data, but only from the same test method, static or buildup.

B. Measured Temperatures

The flowing temperature survey may be conducted on the same wireline trip and the guidelines in 3.2 should be applied. The data are used to:

- Locate the point(s) of injection where gas cools with expansion

- Obtain a flowing temperature profile to serve in valve temperature estimates for the lower valves (the upper unloading valves will have a cooler, transient temperature during initial unloading).

Temperature prediction is important in the design calculations of gas lift valves with nitrogen charged bellows. It is much less important for spring loaded valves. The flowing temperature profile measured in conjunction with a pressure survey represents the producing well. The survey does not give the cooler wellbore temperatures that exist at the start of the unloading process.

- Use the flowing temperature survey for analysis by stopping at (or slightly above and below) each gas lift valve. A cooling effect indicates gas passage. A tubing hole can also be located with numerous stops through the interval of the suspected problem.
- The temperature profile can be used to set the lower valves that are subjected to hot reservoir fluid. The temperatures for the upper valves are not based on the flowing temperature survey. These upper temperatures (for the design calculations) must be estimated from unloading conditions. Section 4.1 recommends temperature models for unloading valves.

3.3 PRODUCTION TESTS

Production tests, which are also known as well tests, are essential for effective gas lift analysis and design. These tests are used to gauge or measure the oil, water, and total gas production rates. The water fraction, and coupled with measured gas injection rates, the IGLR can be calculated.

RECOMMENDED PRACTICE: Production rate tests and facilities should adhere to these guidelines for accuracy, frequency, and duration. The tests should be conducted under normal operating conditions to obtain the most representative data.

API RP 11V5 includes more detailed recommendations on test methods.

A. Test Accuracy

Test methods can range from estimates to accurate testing with a portable wellhead test skid and associated testing company crew. However, most tests are conducted through an existing field test separator and attached meters which should provide repeatability within $\pm 10\%$. Establishing greater accuracy requires use of meter provers that are not usually used for production allocation test equipment.

Conditions that promote acceptable, repeatable tests are:

- High production rate relative to the tubing and flowline size (mixture velocity is maintained at 10 ft/sec. or greater to minimize phase segregation and severe slugging).
- Steady non-slugging flow.
- Intermittent well testing should be conducted for a sufficient number of cycles to obtain a good average production rate.
- Gas, oil, and water meters (and their associated outlet control valves downstream of the meter) sized to operate at the mid-point of their full-scale range. Dual meters (and control valves) should be used when the test vessel will be used for both very high rate and very low rate tests. The piping between the separator and the meter should be short with no restrictions.
- Separator purge time, linked to the well's rate, which eliminates the initial instability and diminishes the effects of the prior well's test.
- Test flowline purge time (for wells linked to the station via a test line) that establishes new equilibrium gas, oil, and water flow regimes and liquid holdup in the pipeline.
- Test duration that permits the rate to stabilize at the test separator pressure (which should give the same flowing wellhead pressure as created by the production separator pressure).
- Shrinkage factor (reciprocal of volume factor at separator pressure and temperature) based on PVT data applied to obtain stock tank barrels.
- Meter temperature compensation (either in the meter or with the shrinkage factor).
- Gas samples and chromatograph analysis for specific gravity applied to gas measurement.

Test accuracy in low rate wells is usually poor. The biggest problem is the low rate (relative to tubular size) and slugging. The gas and liquid rates are not repeatable and the true rate is difficult to determine.

Obtaining a stable condition may require a high injection gas rate, resulting in an IGLR of 2000 scf/stb or greater. For field optimization, the well may be returned to the lower injection rate after testing.

If severe slugging cannot be controlled by injection rate variation or by adjustments on controls, then a station inlet choke may be necessary to dampen the slugs. This will raise the wellhead pressure and reduce the test production rate, but it may be the only technique that will yield repeatable tests.

Measurement inaccuracy due to surging through poorly sized meters/control valves (on the separator outlet piping) is

another problem. The control valve trim should be resized for the lower rates and meters adjusted, where possible, so that continuous and steady throughput is attained.

If the float/control valve controller is on periodic (dump) control mode, then the control valve trim should be sized for a rate that does not exceed the maximum meter range. For guidance on separator sizing and design, refer to API Spec 12J *Oil and Gas Separators*.

Meters in production service may not be able to give the $1/2\%$ — 1% accuracy obtained in the manufacturers lab with clean water. Thus a more realistic expectation is 5% — 10% accuracy since these meters are usually not proved (except when custody transfer occurs).

RECOMMENDED PRACTICE: A three phase test separator with properly sized meters, control valves, and computer data collection should be used for production testing of gas lift wells.

Test quality is related to the quality of the test facility. The cost and resulting quality can be ranked as follows:

1. Properly sized meters and frequent computer data collection, storage and averaging of results give the best tests.
2. Good meters (or tank testing for liquids) give the next best test.
3. Liquid rate estimates by timing separator fill-up are poorest.

The facility can also be rated by its ability to separate the phases:

1. A good three-phase test separator with proper metering is best.
2. A two-phase vessel can be used, but samples must be taken at the wellhead (or other highly turbulent point, such as the inlet test manifold) to estimate water fraction, which can vary from sample to sample.
3. Liquid residence time aids phase separation and metering. Time guides, from API Spec 12J, are:
 - 2 min. for two-phase separators.
 - 5 min. for three-phase separators.

B. Test Frequency

Continuous monitoring of each well is the ideal method for gas lift optimization. For periodic testing, the frequency may be based on:

- Regulatory requirements

- Company policy
- Reservoir and production management considerations.

Testing more frequently than once per month can often be justified for the following reasons:

- Rapid reservoir pressure loss is suspected and rates are used to estimate the percentage exponential decline (static 24-hr shut-in pressure or build-up testing should also be done).
- Water break-through from a waterflood or natural drive is occurring and frequent testing is used to observe the change in water fraction (water samples are important also).
- Lift gas allocation is adjusted based on the last test in an attempt to maximize oil. Gas allocation improves oil production only when measured wellbore flowing data are used to calibrate the computer model.
- Depth of injection is obtained by comparing the test separator rate to a computer model rate prediction at each mandrel (the model should be validated with a flowing gradient survey). An action response is generated if the well is found to be lifting at a shallow point.

RECOMMENDED PRACTICE: Test frequency guidelines:

1. More frequent than monthly testing if oil maximizing and gas allocation adjustments are being attempted (flowing gradient surveys should be implemented to validate a computer delivery model and the PVT fluid property data).
2. Monthly, if sufficient test separators are available.
3. Less frequent testing may be adequate if the well conditions are not changing, if gas lift gas allocation is not a priority, and if other methods of well surveillance are provided.
4. Sequentially test wells, keeping a well on test at all times.

C. Test Duration

The duration needed for a representative well test is a combination of:

- Purge time to remove the effect of the prior test.
- Time to attain rate stability.

- Test time.

Stability is dependent on the rate and productivity (permeability) of the well. The higher rate, high productivity wells stabilize quickly whereas the lower rate wells are slow to stabilize. Key items to establishing stability, and thus test duration, are:

- A wellhead pressure when flowing into the test separator that is approximately the same as flowing into the production manifold. If the test vessel must operate at a higher pressure, then the well must stabilize and a rate reduction should be expected.
- A surging well should exhibit the same slugging pattern whether in production or in test.
- The rate/hr should be steady (steady means the allowable variation is $\pm 10\%$ and not continuously declining or continuously increasing).
- The water fraction (% water cut) test sample each hr should not vary more than 10%.

If production and test conditions, such as wellhead pressure, remain constant, then the purge and rate stability time could be as quick as 2 hr. If conditions are changing, then a guide to test duration based on productivity index (stbpd/psi) is:

PI stbpd/psi	Purge hr	Test hr	Total hr	Comment
> 10	2	4	6	High PI wells stabilize quickly
> 5 – 10	4	4	8	Wellhead pressure should be steady
1 – 5	8	8	16	Rate/hr should be steady
< 1	12	12	24	Rate/hr should be steady

One field guide for purging/stabilizing time is the time needed to produce five tubing volumes. Other operators relate purge time to vessel size and production rate.

This time guide includes vessel purging in the “Purge” time column. However, it does not include purge time required when a well is located at a remote site or wellhead platform and is switched from a common production header line into a test line.

D. Flowline Purging

Purging or displacing fluids in the test line from a remote onshore or offshore well manifold requires a time that should be added to the purge time above. If two test lines connect the remote manifold to the test station, then one line can be purging while the other is in test.

Purging of the test line is more complex than a simple estimate of time based on the volume capacity of the line divided

by the estimated test rate. A preferred method to estimate the time needed for pipeline purging is:

1. Analyze the flow regime and liquid holdup based on those regimes.
2. Use a multiphase flow computer program that lists liquid holdup for the specific geometry of the test line.
3. Holdup is the liquid volume fraction of the pipe based on a computer calculation.
4. Obtain holdup for the prior test rate, gas-liquid ratio, and water fraction.
5. Repeat the analysis for the estimated current test conditions.
6. Calculate purge time from:

$$\text{Purge Time, hr} = \frac{\text{Holdup [Prior Test — Cur. Test Est.], * bbls 24 hr/d}}{\text{Estimated Current Test Rate, bbl/d}}$$

The difference in holdup (*an absolute value*) represents the filling or sweeping of liquid that must occur before the new flow patterns reach equilibrium and the well's production rate and fluid composition are reasonably represented in the test results at the vessel.

Pipeline purge time should be added to the time guide table in 3.3.C. For most situations the time should not exceed 2 hr – 4 hr. If a suitable computer program is not available, then pipe volume divided by estimated rate can give an approximate pipeline purge time.

3.4 GAS LIFT VALVE PERFORMANCE INFORMATION

Gas lift valve performance is the *quantitative* measure of a valve's gas flow rate response to changes in casing and/or tubing pressure for a given valve set pressure and temperature. API RP 11V2 *Gas Lift Valve Performance Testing* describes the methods by which a valve's flow performance can be measured.

RECOMMENDED PRACTICE: Valve performance data should be utilized in gas lift design to ensure adequate gas passage when unloading or producing. The data should be requested if it is not available.

A. Types of Gas lift Valves

Two basic types of gas lift valves commonly used are:

- IPO
- PPO

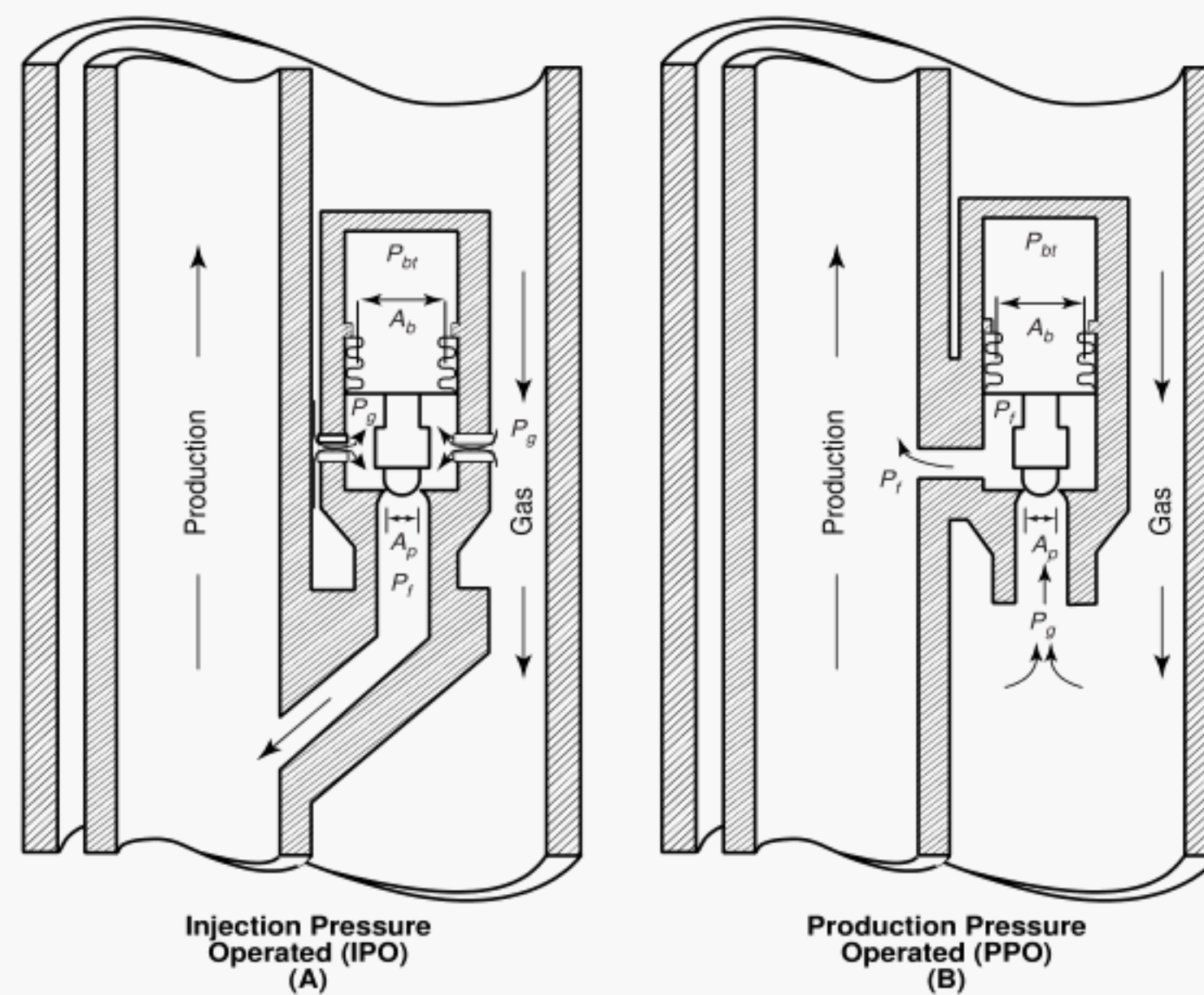


Figure 3-2—IPO and PPO Valves

Both types, Figure 3-2, utilize a bellows and apply a shop-set load (nitrogen pressure, spring, or both) to hold the valve stem/ball on the seat (port). The combination of annulus and tubing pressure acting under the stem and on the outside of the bellows pushes against this preset load and, when sufficient, will cause the stem to move away from the seat. The open port, plus pressure differential, will allow either liquid or gas to flow through the valve.

IPO valves:

- Have a large area of the outside of the bellows exposed to injection gas pressure, thus small changes in injection pressure may result in relatively large changes in stem position.
- Utilize a nitrogen charge in the bellows to provide the preset load (some valves will use a spring rather than or in addition to nitrogen).

PPO valves:

- Have a large area of the outside of the bellows exposed to production pressure and thus changes in production pressure will cause relatively large changes in stem movement.
- Have either a spring and/or a nitrogen charge to preload the bellows and hold the valve stem on the port.

B. Valve Opening

All valves (both IPO and PPO) have a *loadrate*. The loadrate is:

- A measure of the valve stem's resistance to movement and is similar to a spring rate except that loadrate is measured in psi/in.
- An indication of the amount of increase in pressure required causing the valve stem to move away from the seat.

The loadrate will vary between valves from one manufacturer and certainly between manufacturers. API Spec 11V1 *Gas Lift Equipment* and API RP 11V2 describe the methods by which loadrate is measured and terms such as stem travel.

The pressures acting on the stem and bellows generate two forces acting to open the valve:

- Injection pressure acting on the area of the bellows minus the area of the port
- Production pressure acting on the area of the port

When the combination of these two forces equals the preset dome charge times the area of the bellows, the net force holding the valve on the port is zero. An increase in either injection pressure or production pressure will then cause the valve to begin opening. The amount of movement is governed by the loadrate.

For example:

1. A 1 1/2 in. IPO valve with 1/4 in. port (area of port to area of bellows ratio, $A_p/A_b = 0.07$) has:
 - a. a valve bellows pressure (at the temperature of the valve) of 800 psig.
 - b. a loadrate of 450 psi/in.

2. If the annulus injection pressure is 820 psig and the tubing production pressure is 538 psig,
3. Then the force holding the valve stem on the port equals the forces generated by the injection pressure and production pressure.
4. For the same tubing pressure, an increase in annulus pressure of 10 psig will cause the valve to open 0.022 in.

C. Valve Gas Passage Performance

The amount of gas that will pass through a valve will depend on valve stem travel, differential pressure across the valve, temperature affecting nitrogen expansion in the bellows, and flow coefficient of the valve. Refer to API RP 11V2 for details on flow coefficients and the methods by which they are calculated.

Gas passage performance of a valve is governed by the pressure acting on the bellows. Some gas lift valves have been characterized as “throttling” valves and others as “full-open” valves. But, either valve type can “throttle” if the pressures acting on the bellows are insufficient to cause the valve stem to move far enough away from the seat to achieve a flow area equivalent to a full open port. Likewise, either valve can act as a “full-open” valve if the pressures acting on the bellows are large enough.

All valves will be full open when maximum pressure is applied during the process of U-tubing fluid (unloading) and will be throttling at lower pressure when injecting gas. The actual performance is based on the loadrate, the set pressure, the annulus and production pressures, and the flow capacity of the valve.

3.5 FIELD CONSTRAINTS

Physical and/or operational constraints often prohibit the gas lift system designer from having complete freedom to design the gas lift system for optimum operation based solely on gas lift technology. The designer must be aware of these constraints and take them fully into consideration or else the gas lift design may be doomed to failure, or at least to far less than optimum performance.

RECOMMENDED PRACTICE: The entire gas lift system should be reviewed to eliminate or minimize constraints that impair gas lift performance. Constraints that remain must be incorporated into each design.

A. Available Pressure for Injection

Pressure for injection in a gas lift system is controlled by:

- Gas compressor discharge pressure or facility and piping maximum pressure limits.

- Backpressure regulators that send excess compressed gas to the gas plant or gas transmission line.
- Gas plant processing facility, transmission line, or gas wells that provide the gas if the gas supply is not from field compression.

In all options, the *best pressure is that which permits injection near bottom of the well* because deep, efficient lift can be attained and sustained. Economic evaluation of gas circulation rate, pressure, and oil recovery can guide the choice of pressure.

Terms important in system design and in each well’s valve pressure settings are:

- **Compressor Discharge Pressure**

The design discharge pressure for the field compressor(s) should be based on the desired maximum kickoff pressure plus piping system pressure loss (usually not more than 100 psi). Compressor discharge pressure is limited by cylinder or case MWP (maximum working pressure), driver horsepower, or rod load (reciprocating compressors). The discharge pressure can be raised by increasing the set point of the backpressure controller that directs excess gas to the sales transmission line or gas plant, up to the limiting pressure of the safety devices. This action will also raise the field kickoff pressure.

- **Kickoff Pressure**

Kickoff pressure is the highest pressure available at the wellhead (casing) that can be used to start the unloading of dead completion or workover fluids in the casing and tubing. Compressor discharge pressure (or other source) less dehydration system and pipeline losses will equal the kickoff pressure at the well.

System kickoff pressure can be inadvertently lowered if one well’s choke or controller malfunctions and excessive gas is injected into one well. The kickoff gas injection pressure can be made temporarily higher for unloading by two methods:

1. Raise the compressor discharge pressure by resetting to a higher pressure the backpressure controller sending gas to the plant or sales pipeline.
2. Reduce or shut off the gas lift gas to a high rate gas consumer well that is connected to the same branch of the system (be sure that the well will return to production when the gas is restored).

These methods can be applied during the unloading time period of 24 hr – 48 hr and then normal control settings can be restored. This technique will result in the highest possible injection pressure or it can be applied to wells that are difficult to unload.

• Unloading Pressure

The unloading pressure for each valve is used in the calculation to set the test rack pressure of each. The first valve (shallowest) has an unloading pressure nearly equal to the kickoff pressure. Succeedingly lower unloading valves have unloading gas pressures reduced by a pressure difference of about 25 psi between valves (10 psi is a minimum for low pressure systems up to 50 psi for high pressure systems). Each deeper unloading valve lowers the gas pressure until the operating valve, or orifice, and operating pressure is reached.

• Operating Pressure

The gas pressure needed for continuous operation at the point of lift. The pressure depends on whether a valve or orifice is used:

- when a valve is used, the operating pressure is controlled by the valve set pressure, port size, gas rate, temperature, and fluid production pressure.
- when an orifice is used, the operating pressure is controlled by the orifice size, gas rate, and fluid production pressure.

Available operating gas pressure at the lift point is directly related to the number of unloading valves and the gas pressure difference between valves. For example, a well with a kickoff pressure of 1000 psig, six unloading valves, and 25 psi gas pressure difference between valves, would have a surface operating pressure of approximately 850 psig when lifting at the design point.

The valve design method affects the gas pressure difference that is used, which in turn affects operating pressure available at the point of lift.

Thus the *operating pressure* available for injection is a function of:

- Compressor discharge pressure.
- Kickoff pressure at the casing.
- Number of unloading valves.
- Unloading gas pressure difference between valves.

New compressor systems and new wells should be designed to provide gas pressures to accommodate the highest productivity (PI) wells, as these wells have the highest pressures needs. The lower PI wells will be easily lifted with this design approach.

Existing systems may need revisions to maximize oil:

1. The first step is to make available the highest compressor and kickoff pressure.
2. The next step is to reset (and possibly re-space) the valves to utilize this higher unloading pressure.

Thus, the highest compressor discharge pressure will yield the highest kickoff, which will result in higher operating pressure, deeper lift, and more total fluid (and hopefully more oil).

RECOMMENDED PRACTICE: The gas supply should be the highest possible compressor pressure and should be dry (processed to reduce both water and hydrocarbon). This gives the steadiest supply with the highest kickoff and operating pressure that maximizes the oil production.

B. Minimum Wellhead Pressure

Flowing wellhead pressure for a gas lifted well (no choke at the wellhead or at the inlet to the station) is dependent on:

- Reservoir pressure and productivity.
- Density and friction pressure losses in the wellbore.
- Separator pressure plus flowline pressure losses due to friction, terrain effects, and elevation changes.

High reservoir pressure plus good productivity, and low density, gaseous fluid result in the reservoir energy being transmitted to the wellhead, if tubular friction loss is not excessive. Low pressure at the inlet separator and a relatively large flowline minimize the resistance to flow (backpressure). Addition of lift gas aids wellbore delivery but adds to friction losses in the horizontal flowline, and in the tubing, if the diameters are too small.

The minimum achievable wellhead pressure is a function of the backpressure produced by:

- Separator pressure.
- Losses from terrain effects and elevation changes.
- Rate (velocity) induced flowline friction, which is caused by:
 1. Tubular pipeline internal diameter,
 2. Fluid properties,
 3. Gas-liquid ratio,
 4. Liquid flow rate.

When the wellbore tubular, flowline, and separator facility is designed, the anticipated well rate can be calculated and then reservoir withdrawal constraints (or regulatory limits) can be imposed. The tubing and flowline size to achieve the needed rate can then be selected.

During this design calculation procedure, wellhead pressure can be minimized by reducing separator pressure and by

using large diameter pipelines (but not so large as to cause severe slugging at the separator).

RECOMMENDED PRACTICE: Gas lift wellbore and flowline tubular size plus the separator pressure should be designed to achieve minimum wellhead pressure for the following benefits:

- Natural flow time period is extended (although dead wells may need to be unloaded with gas lift).
- Production rate increases.
- Gas lift gas injection requirement decreases.
- Lift point may be deepened, improving effectiveness.

If the existing tubing, flowline and separator pressure cannot be altered, then the minimum attainable flowline pressure with the existing facility can be calculated. The computer calculated values should be compared to measured data as an aid in finding bottlenecks (restrictions to flow). The procedures to use, whether checking an old facility or designing a new one, are:

• Wellhead Delivery Pressure vs. Flowline Pressure

Figure 3-3 has the wellhead delivery curve and the flowline friction loss curve, each calculated for a specific IGLR. The delivery curve shows wellhead pressure vs. rate. The flowline pressure curve shows the friction plus separator pressure that becomes the backpressure at the wellhead. The intersection of the wellhead delivery and flowline curves is the rate that the well should produce when no production choke is used in the wellhead.

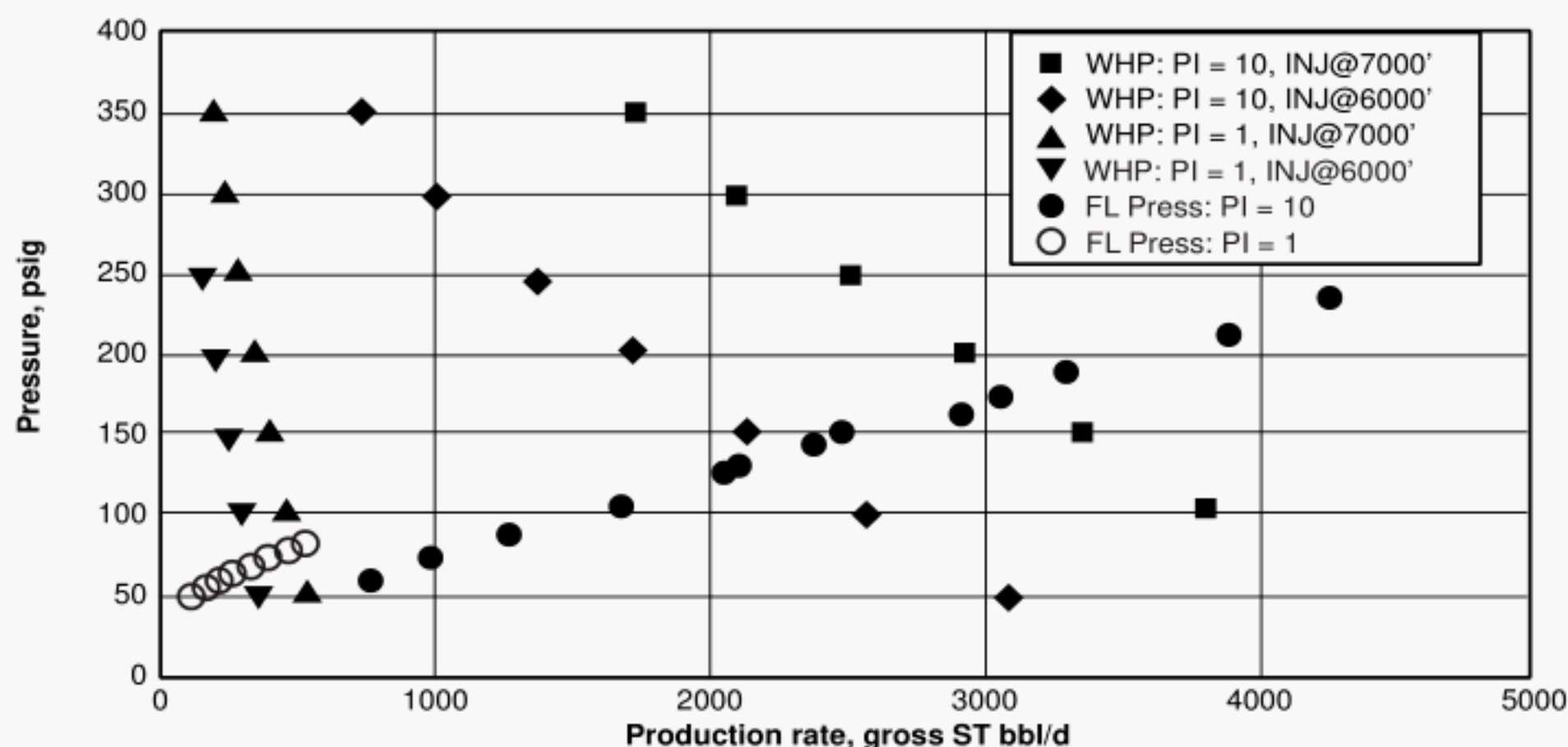


Figure 3-3—Wellhead Pressure Delivery Area

Two wellhead delivery curves are shown, one with a 6000 ft lift gas injection point and the other at 7000 ft injection, to illustrate the benefit of higher gas pressure and deeper injection. Wells with a PI (productivity index) of 1 and 10 are shown to emphasize the importance of reservoir productivity on rate.

• Production rate vs. injection gas-liquid ratio

Figure 3-4 shows production rate delivery vs. IGLR. The curve indicates whether maximum production is being attained or whether excess gas is being wasted in the well. This delivery curve is based on system analysis that includes the separator and wellhead pressure for each specific rate and corresponding IGLR, thus modeling the effect of increasing gas causing greater friction loss in the flowline.

Similarly the benefit of deeper gas injection is shown by comparing the delivery curve with a 6000 ft injection point to the other at 7000 ft injection.

Use these methods to evaluate the minimum attainable wellhead pressure. They permit analysis of the existing well, flowline, and separator or the proposed one. The rate, IGLR, and pressure relationship at the various points should yield a calculated to measured field data match (within 10%) or the reason for the bottleneck should be investigated. The fluid properties and depth of injection affect these results, thus they should be established using flowing pressure surveys before extensive effort is expended.

C. Maximum Gas Availability

Maximum gas availability depends on:

- Compressor station output, or other supply,
- Gas processing for dehydration and condensate removal,
- Pipeline distribution system.

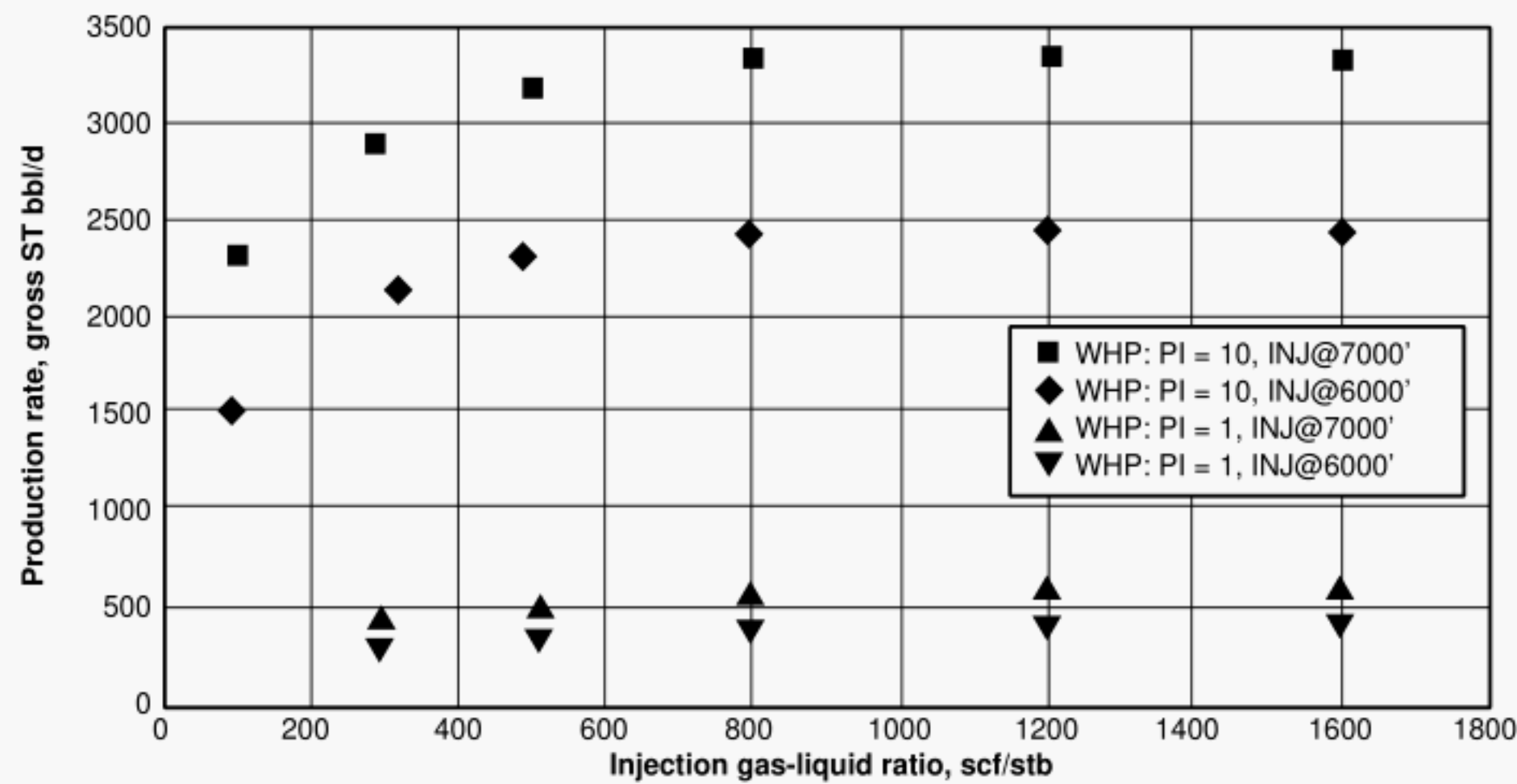


Figure 3-4—Production Delivery vs. Injection Gas

The flow of gas to the wells on any segment of the pipeline system can cause friction loss and limitation in the transport of the gas to the wellhead. Similarly, freezing (hydrates) or liquid accumulation can occur at restrictions or low spots in the pipeline and prevent the desired quantity of gas from reaching the wells.

The pipeline distribution system should be analyzed (use piping segments where pressure gauges can be installed and data can be obtained) by comparing measured and calculated data in an attempt to find bottlenecks that limit gas availability. The procedure is to list each well's rate and pipe data:

Well	Inj Rate mscfd	OD in.	ID in.	Length ft	Gas Choke Pressure psig	Gas Manifold Pressure psig
A	300	2.375	1.939	3000	946	986
B	1250	2.375	1.939	6300	879	986

The gas pressure upstream of the control choke (or control valve) at the wellhead is listed as the choke pressure. The manifold pressure is that at the compressor or field distribution manifold. If the choke is not located at the wellhead, but is at the distribution header, then substitute the pressures downstream of the choke (at the manifold) and at the wellhead (casing pressure).

The gas rates, pressures, temperatures, and gas specific gravity (based on a gas sample and chromatograph analysis) for the wells should be listed and compared to a calculation with the single phase gas flow Weymouth Equation:

$$Q_g = 31.5 \times E \times (T_b/P_b) \times d^{2.667} \times \left[\frac{P_1^2 - P_2^2}{G \times L \times T_a \times Z_a} \right]^{0.5}$$

where:

- Q_g = gas rate, thousands standard cubic ft per day (mscf/d),
- E = pipeline efficiency, fraction (meas. Q_g to calc. Q_g ratio at clean pipe conditions),
- T_b = temperature base, ° Rankin,
- P_b = pressure base, psia,
- d = pipeline inside diameter, in.,
- P_1 = upstream pressure, psia,
- P_2 = downstream pressure, psia,
- G = gas specific gravity,
- L = pipeline length, ft,
- T_a = average gas temperature, ° Rankin,
- Z_a = gas compressibility (deviation) factor at average pressure and temperature.

The results allow comparison for purposes of finding bottlenecks in the pipelines, or low points where liquid can accumulate, as well as for summing the rates from the wells to match to the compressor output.

The maximum gas available from the compressor station is usually the limiting condition:

- On hot days, the compressor output is diminished as gas suction temperature rises (aerial coolers get hotter).
- The power drivers, especially gas turbines, reduce their horsepower to the compressor.
- Gas rate decreases and the gas is redistributed according to the new pressure equilibrium in the pipeline distribution system.

Gas pressure increases are beneficial:

- Pressure increase can be obtained by raising the back-pressure control regulator setting to the sales gas line. This aids the distribution of gas by reducing friction loss. However, the compressor must be capable of the continuous higher load and the piping system maximum pressure rating must not be exceeded.
- Pressure increase can result in a deeper injection point and more efficient lift only if the gas lift valve bellows pressures are designed and set at correspondingly higher pressure. With an existing well, the gas lift valves must be pulled to reset the pressures.

Implementing a higher gas pressure system may be time consuming and costly, but it may improve oil production. Optimization of a limited gas supply is discussed in Section 7 and should be practiced in conjunction with a production delivery curve, rate vs. injection gas, validated with measured data.

RECOMMENDED PRACTICE: Lift gas system design should:

- Attain the highest pressure available within compressor and piping system limitations.
- Provide adequate compressor size and power for the hottest ambient temperatures.
- Utilize dehydration and processing to prevent liquid accumulation in the piping system.
- Use piping design practices that minimize pressure loss and minimize liquid accumulation points (install drain taps at points where liquids will collect).
- Provide gas pressure measuring (gauging) points to check for piping restrictions caused by deposits, hydrates, or liquid accumulation.

D. Other Constraints

Other constraints are any items that:

- Raise wellhead pressure
- Reduce injection gas pressure
- Restrict gas injection rate

Excessively high inlet separator pressure is a constraint to gas lift well delivery because the wellhead pressure will be very high, which creates a high flowing bottomhole pressure, decreasing oil rate and increasing lift gas consumption. The solution is low pressure gas compression that would permit the inlet separators to operate at approximately 50 psig, with the gas compressed up to the existing pipeline condition. New compressor additions might be required.

Low pressure injection gas is a severe constraint if the system must be extended to new, perhaps deeper wells. A potential solution is a booster compressor to raise the gas pressure to a value adequate for use in the new wells. Potential benefit is deeper, more effective lift (in terms of less lift gas volume per barrel of liquid).

Tubular sizes can be a constraint for gas delivery, friction and increased flowline pressure, and/or tubing restriction of reservoir delivery.

Gas dehydration, inoperative or non-existent, can allow hydrates to form at low spots and at restrictions. Gas is blocked or supply is erratic and lift effectiveness is poor.

A final constraint is a compressor that is frequently off line for emergency maintenance or repair. Whenever gas system pressure or volume is interrupted, the lift point tends to jump up to a shallower valve. Due to temperature heating of upper unloading valves, they will remain shut until the wellbore cools. Thus when the gas supply is restored, the well does not automatically unload to the prior operating depth and special troubleshooting efforts may be required. This will prevent the gas lift wells from continuously lifting at a deep point, which reduces effectiveness and diminishes oil production.

Automation of the injection chokes or flow control valves can minimize upsets due to compressor downtime. With a communication link from a central control computer to the actuator on the choke, the gas control device can be quickly readjusted or shut-in to reduce gas lift gas demand to match that available with a compressor off-line. Once the compressor capacity is restored, the chokes can be automatically opened again. The affected wells must be tested to ensure that they are still lifting from a deep point.

4 Well Deliverability

Gas lift design, analysis, and performance prediction requires the use of mathematical models to calculate outcomes based on system designs or changes. The models are calibrated with data gathered from the gas lift well production tests, flowing surveys, and PVT fluid property reports.

The “basic” models predict the pressures and temperatures in the wellbore and flowline. These are used to build “system” deliverability models which couple the reservoir, wellbore, flowline, and separator to give:

- Production rate vs. bottomhole pressure.
- Production rate vs. depth of gas injection.
- Production rate vs. injection gas rate.
- Production rate vs. separator pressure (or wellhead pressure).
- Production rate vs. water fraction.

These models predict the system performance for both total liquid and oil. To insure reliability, the deliverability cal-

culations should match the measured production rate results for the existing conditions.

RECOMMENDED PRACTICE: Use data from existing wells to build wellbore models and system deliverability models. These models can then be used to analyze the gas lift system and to re-design gas lift valve installations. Use data from off-set wells to calibrate models for new wells and systems.

4.1 BASIC MODELS

The mathematical models that predict pressures and temperatures in the wellbore are quite complex, and the calculations require computers. *The quality of the input data will affect the accuracy of the results.* Assumptions, or poor quality data, can lead to poorly selected equipment, needless work-over expenditures, and ineffective operation. However, even given excellent measured data, the models cannot make flawless predictions because they are only mathematical representations, either empirical or theoretical, of physical phenomena.

The two groups of models are:

- Empirical methods have been used for the majority of pressure and temperature models. The correlations are derived empirically by lab experimentation or from oil-field data. These models typically have a $\pm 10\%$ error range when properly applied and when fluid properties are accurate.
- Theoretical methods, or “mechanistic” models, are based on the physics of flow behavior. The mechanistic models require definition of the flow patterns, and then utilize calculations for bubble rise, wall film thickness, shear stress in the film and interface, among others, that are strongly dependent on physical properties. The input data, including temperatures, used to obtain physical property values (density, viscosity, and surface tension) can strongly influence results.

These models simulate *steady-state flow*, which is suitable for considering the effects of design changes in a gas lift well system. The model calculated results should be compared to measured data from a production test and wireline gradient survey, which is also a steady-state condition. Once the model has been adjusted to match measured data, then other design conditions can be simulated.

To model time dependent behavior such as reservoir pressure, water fraction, or injection gas rate changes, several computer runs can be used to observe the change in pressure with rate. Thus the steady-state flow model can be used to calculate time dependent changes, however, a dynamic model might be preferable for studying rapid changes.

Modeling of *dynamic flow*, or rapid time dependent variations in rates, pressures, and temperatures, is much more difficult. Unloading, start-up, shutdown, and rate changes (prior to stabilizing) would be more accurately represented with dynamic (transient) models, which are starting to become available.

RECOMMENDED PRACTICE: Model users can improve design decisions by following these steps:

- Screen the input data.
- Choose and properly apply the models.
- Understand the accuracy limitations of the models.
- Create “basic” models of pressure and temperature gradients validated with measured data.
- Build a “system” model of the flowline, wellbore, and reservoir to predict well performance.

A. Fluid Pressure Profile

Producing fluid pressure prediction model results, Figure 4-1, provide a:

- Flowing production pressure gradient for comparison to the gas pressure gradient. This comparison is used to establish gas lift injection depth. For this example, the depth of lift could be deeper since higher operating pressure is available.
- Flowing bottomhole pressure.
- Calculated pressure gradient that can be calibrated with a measured gradient below the injection point for the production rate of 2293 bfpd (barrels gross fluid per day).

Calibration is the procedure of matching calculated data to measured pressures taken during a well test and flowing pressure/temperature survey. Calibrated models:

- Provide better predictions over a range of conditions.
- Are a reliable predictor of production performance and this accuracy improves the associated economic evaluation.
- Enhance surveillance efforts to discover under-performing wells.

Calibration matching is enhanced by:

- Use of accurate fluid property PVT data.
- Varying fluid property parameters within their normal range of variability to fine-tune the basic model.

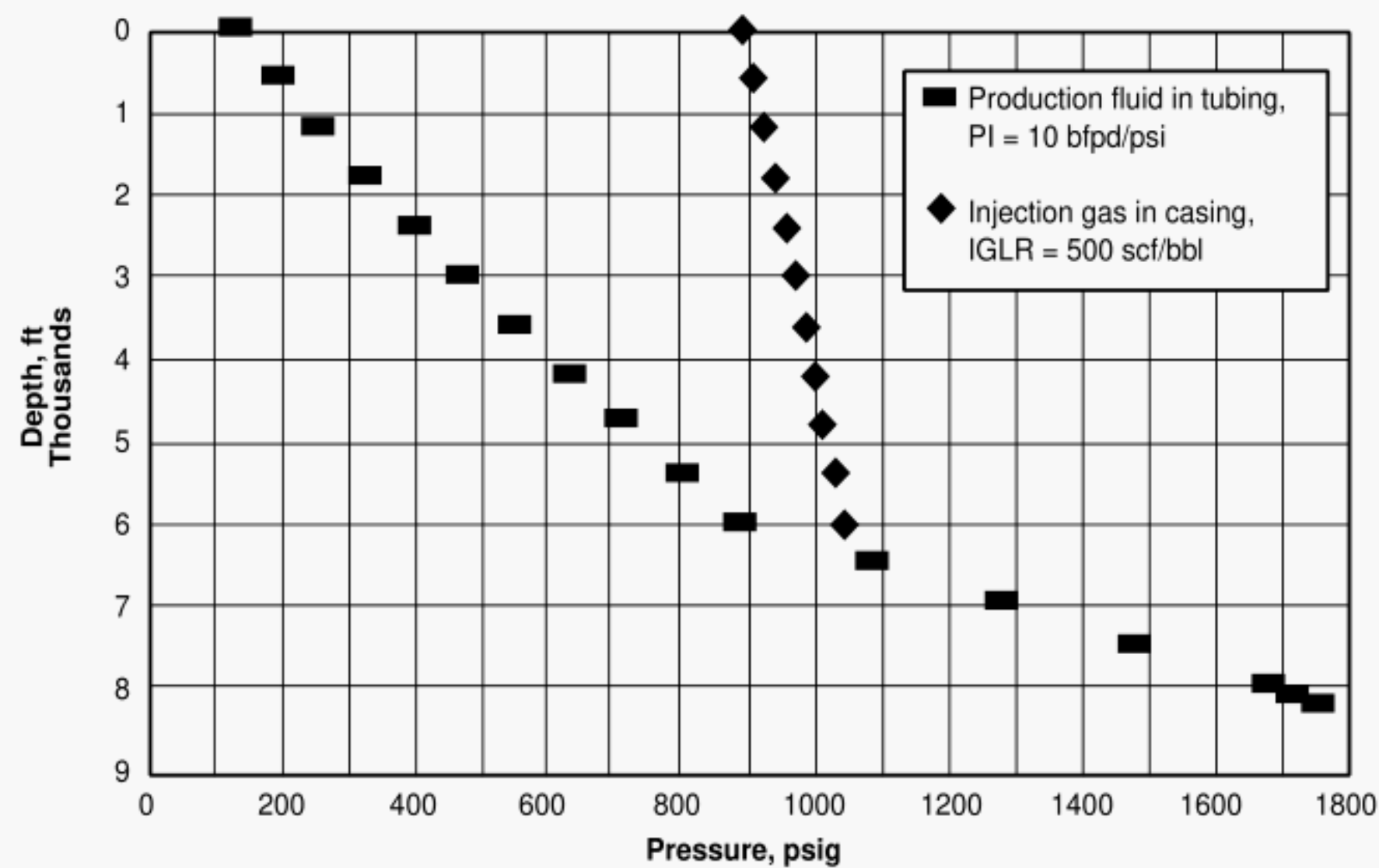


Figure 4-1—Produced Fluid and Injection Gas Pressure Gradients

- Selection of the best of available multiphase models.
- Applying the same model to all wells in the reservoir with similar fluid properties, reservoir behavior, and tubulars.

The matching process requires good measured data obtained with mechanical or electronic gauges. This pressure and temperature data, coupled with production rate results and input gas rates, are the measurements used for comparison to computer calculations.

RECOMMENDED PRACTICE: Use measured data to calibrate models via a **matching procedure**:

1. Use the gradient (psi/ft) of the bottom points below the point of injection to extrapolate the measured pressure to the perforation midpoint. Use this measured flowing bottomhole pressure, P_{wf} , as the input to the computer program model. This provides a bottom up pressure match that is more reliable than a top down match.
2. Force a match of the lower *formation fluid pressure profile* (P_{wf} to tubing pressure, P_f , at the point of injection) by slightly adjusting gas specific gravity, GOR , and water fraction. Use PVT data for the total reservoir GOR since separator calculated GOR is much less accurate.

3. Force a match of the upper *gas lifted pressure profile* (P_f to wellhead pressure P_{wh}) by adjusting the injection gas rate (and its specific gravity). Use chromatograph analysis of the injection gas to obtain gas specific gravity.

4. Modify the procedure:

- if the injection point is inconclusive from the gradient survey, or
- if only the flowing wellhead and bottomhole pressures are measured.

5. Use the calculation model to input the measured gas at each mandrel depth; then choose the depth that causes the wellhead pressure to give the best match.

6. Adjust tubing roughness to aid the match only if the pipe is corroded or has paraffin, asphaltine, or scale deposits (steel roughness is normally 0.0018 in. or 0.00015 ft). However, fluid properties and density are the dominant effects in the lower section of the wellbore, not friction.

The **bottom-up** matching method is preferred when the bottom pressure is steady or if the well is “heading” (exhibits significant pressure surging) at the surface. It is also preferred when the formation fluid properties are unknown and the method of 3.1.B is used to estimate the PVT data.

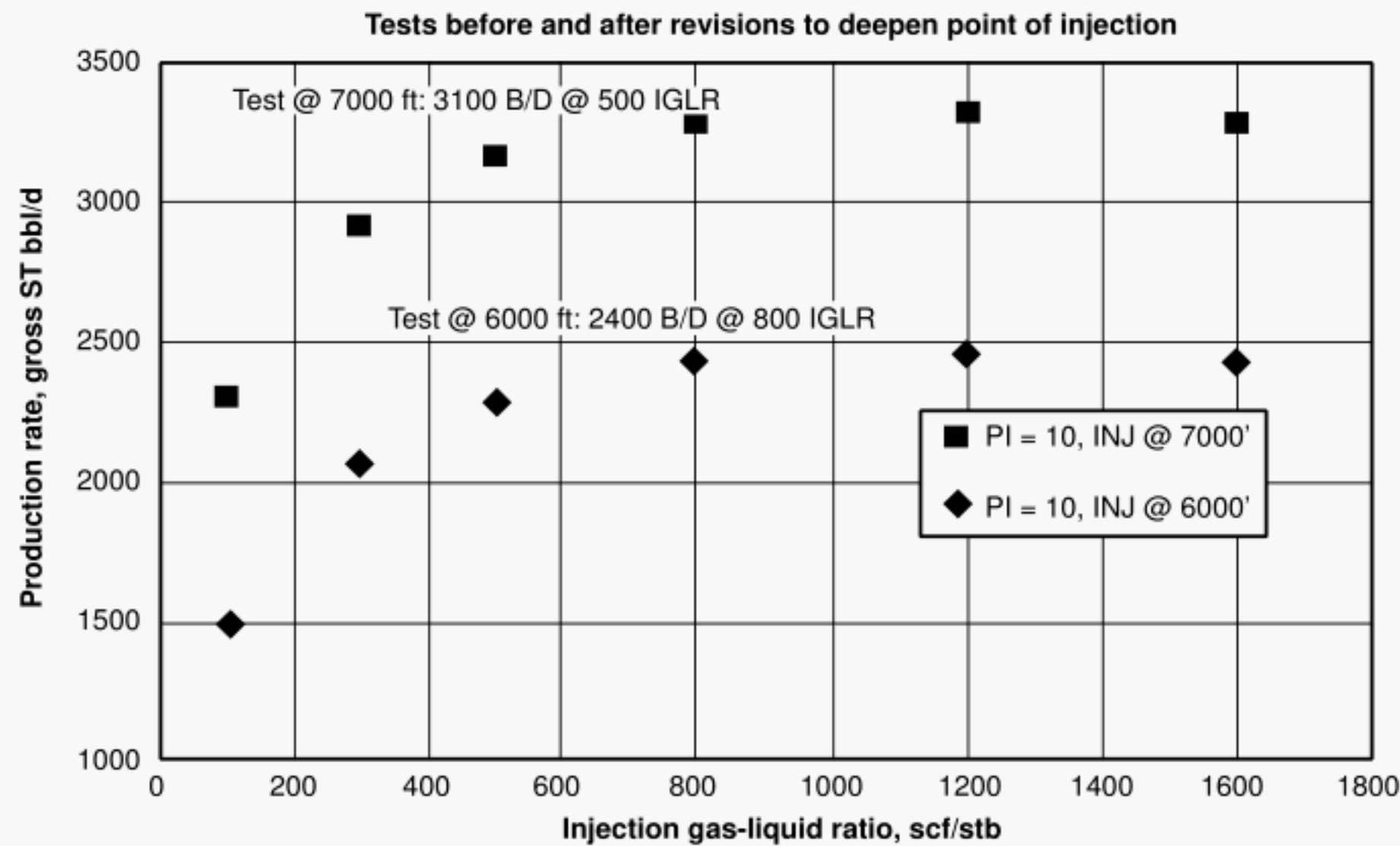


Figure 4-2—Gas Lift Deliverability Curve Showing Measured Tests

The **top-down** matching method is preferred only if the wellhead pressure is very steady or when the bottom few measured pressures do not have a consistent pressure gradient.

The match results for a multiphase flow correlation should give a $\pm 10\%$ error range when individual fluid properties (PVT) and quality measured pressures and rates are obtained. Higher errors may result from poorly measured fluid property and rate data.

The **% error** is calculated with the equation below where Δp is delta pressure from bottomhole to wellhead ($P_{wf} - P_{wh}$) for the measured and the calculated values. The percent error is the difference referenced to the measured data:

$$\% \text{ Error} = 100 \times \frac{\text{Calculate } \Delta p - \text{Measure } \Delta p}{\text{Measure } \Delta p}$$

Once a **low percent error match** ($\leq 10\%$) of the calculated to measured pressure data is obtained, the next step is the incorporation of reservoir data, flowline data, and surface facility data into a system model.

If a **high percent error match** results with the available multiphase flow models, review the mechanical completion sketch, well test information, and fluid property data for potential errors. Consider special cases for that well. For example, reducing the effective tubing ID may be appropriate if scale or paraffin buildup is present in the well.

Causes of pressure matching difficulties include:

- Allocating injection gas and formation gas
Formation gas is not “measured”, but is derived from the measured separator (total) gas rate less the measured

injection gas rate. Flash gas downstream of the separator is often unmeasured. Many gas lifted wells make far less formation gas than the quantity used for injection gas, and due to measurement errors, the formation gas calculation can even give a negative number. To improve results, use the measured lift gas rate and raise or lower the formation *GOR* based on PVT data, average historical formation *GOR* data, or the adjusted *GOR* from the match of the gradient below the point of injection.

- Accurately measuring the total liquid rate
Unsteady rates and pressures during the well test, or rates that vary significantly from test to test, are reasons for adjusting the total liquid rate to aid a match. Rate adjustment is also done if the allocation factor (a comparison of total sales rate to the sum of the well test rates, less downtime) is significantly different from one.
- Accurately measuring total gas and injection gas
Total gas from the separator during the well test may not be accurately measured due to flow surging, pressure variation during liquid dumps, or liquid carry-over. Injection gas is single phase and, if steady and dry, is usually a better measurement. Computerized gas meters can improve accuracy since their measurement sampling rate is very frequent and more representative than a 7-day chart.
- Adjusting the water fraction
Water remains in the oil stream and oil in the water stream, even with three-phase separation, affecting the accuracy of the water-cut measurement. Emulsion ten-

dencies can also drastically effect oil-water measured rates, often noted by an apparent oil production rate reduction on cold nights. Also, many locations use two-phase separation, measuring the oil and water together as total liquid. A wellhead, manifold, or separator sample is centrifuged to get the water-cut of the total liquid. If the sample is not representative of the well production, then water-cut accuracy will suffer.

- Flowline pressure losses

With the test separator pressure as a starting point, the test flowline goes from the separator to the wellhead platform (offshore wells), plus a flowline segment from the test manifold to the wellhead. The station to wellhead flowline segment can be adjusted in length (because of the numerous elbows) to give a wellhead pressure matching current test data.

Once the measured and calculated pressure data match from the reservoir to the separator, the delivery model is complete and predictions can be made of rate vs. IGLR. Figure 4-2 shows this deliverability curve with test results marked on the figure. The production test should reasonably match the computer prediction.

B. Gas Pressure Profile

RECOMMENDED PRACTICE: Calculate gas pressure at valve depth based on a measured gas pressure at the casing on the wellhead and a gas specific gravity from chromatograph analysis of a gas sample taken from the injection system.

The gas pressure at depth is dependent on:

- Surface pressure which affects the density and compressibility of the gas. The pressure increase per foot is greater as density increases.
- Temperature at depth which also affects density and compressibility of the gas.
- Gas specific gravity derived from the composition. If heavier gaseous hydrocarbons (or CO₂ and/or H₂S) are present, then gas gravity rises and so does the density of the gas.
- Friction effects are important only when the injection rates are high and/or the area for injection is small, such as:
 - injection down tubing strings.

- high injection rates needed for high rate wells with large tubing strings.
- small casing strings.

- Friction is not significant in a tubing-flow well (e.g., 2³/₈ in. inside 5¹/₂ in.), where the tubing OD is much less than the casing ID. A static gas pressure calculation is suitable.

Static gas pressure at depth can be approximated by:

$$P_g @ \text{Depth} = P_g @ \text{Surface} \times e^{(0.01875 \times G \times L / T_a \times Z_a)}$$

where:

P_g = pressure of gas (psia),

G = specific gravity of gas from chromatograph analysis,

L = TVD of well at valve (ft),

T_a = average temperature from surface to valve (° Rankin, °R = °F + 460),

Z_a = average gas compressibility (deviation) factor.

Note that the solution of this equation is an iterative process, since Z_a is dependent on $P_g @ \text{Depth}$.

The gas pressure prediction is necessary to estimate the lift depth. Where friction effects are not significant, the error of the prediction varies primarily with the gas specific gravity and temperature. If the gas specific gravity is known and gas temperatures can be predicted accurately, static pressures can be estimated with less than 3% error.

Gas pressure can be calculated from a computer program or estimated with a gas gradient based on density. For 125°F average temperature, gradients are given in Table 4-1 as a function of gas specific gravity and pressure:

Table 4-1—Gas Gradient vs. Pressure and Specific Gravity

	Gas Surface Pressure	800	900	1000	1100	1200	1300
		psig	psig	psig	psig	psig	psig
		Gas Grad	Gas Grad	Gas Grad	Gas Grad	Gas Grad	Gas Grad
		psi/ft	psi/ft	psi/ft	psi/ft	psi/ft	psi/ft
Gas SpGr	0.60	0.017	0.019	0.022	0.024	0.026	0.029
	0.65	0.019	0.021	0.024	0.027	0.029	0.032
	0.70	0.021	0.024	0.026	0.030	0.033	0.036
	0.75	0.023	0.026	0.029	0.033	0.036	0.040
	0.80	0.025	0.028	0.032	0.036	0.040	0.044
	0.85	0.027	0.031	0.036	0.040	0.045	0.050

C. Temperature Profile

Flowing production temperature models are derived from empirical correlations based on:

- Geothermal gradient.
- Static surface temperature.
- Production rate.
- Depth of perforations.
- Gas lift gas injection rate.

RECOMMENDED PRACTICE: Temperature affects fluid properties as well as valves set with nitrogen pressure. Temperature correlation calculations should be validated with measured flowing and static temperature surveys.

An empirical temperature model is given in API RP 11V6 *Design of Continuous Flow Gas Lift Installations Using Injection Pressure Operated Valves*. This technique predicts the flowing wellhead temperature based on a flow rate and geothermal gradient using a linear interpolation between the wellhead and bottomhole temperature, as illustrated in Figure 4-3. Often the measured temperature profile is not linear since greater cooling occurs near the surface.

The theoretical, or mechanistic, well temperature prediction models must be provided the following data:

- Geothermal gradient.
- Static surface temperature.

- Production rate.
- Depth of perforations.
- Gas lift injection pressure and rate.
- Heat transfer coefficients for each segment of the wellbore based on:
 - pipe OD, material thickness and composition,
 - annulus fluid between the produced liquid stream and the earth (injection gas provides an insulating effect compared with a packer fluid).

Flowing fluid temperatures are used in fluid pressure modeling to calculate the physical properties of the fluid stream of hydrocarbons and water. Designing the set pressure of the deeper valves is based on the flowing temperature. Also, analyzing the nitrogen-charged gas lift valves requires the temperature at each valve. Recent work on valve tests at Tulsa University indicates that valve temperature is dependent both on production fluid and gas temperatures.

Unloading temperatures are the cooler wellbore temperatures at the start of the unloading process. This temperature effect on nitrogen charged valves must be estimated to calculate the valve set pressure. One method to approximate the transient, unloading temperature is:

- Record the *flowing* wellhead temperature and the shut-in temperature as the well cools. If a workover is required with conventional mandrels, measure (or estimate) the circulating fluid temperature at the surface when the tubing is rerun. If a wireline unit is used with retrievable valves, observe the shut-in temperature.

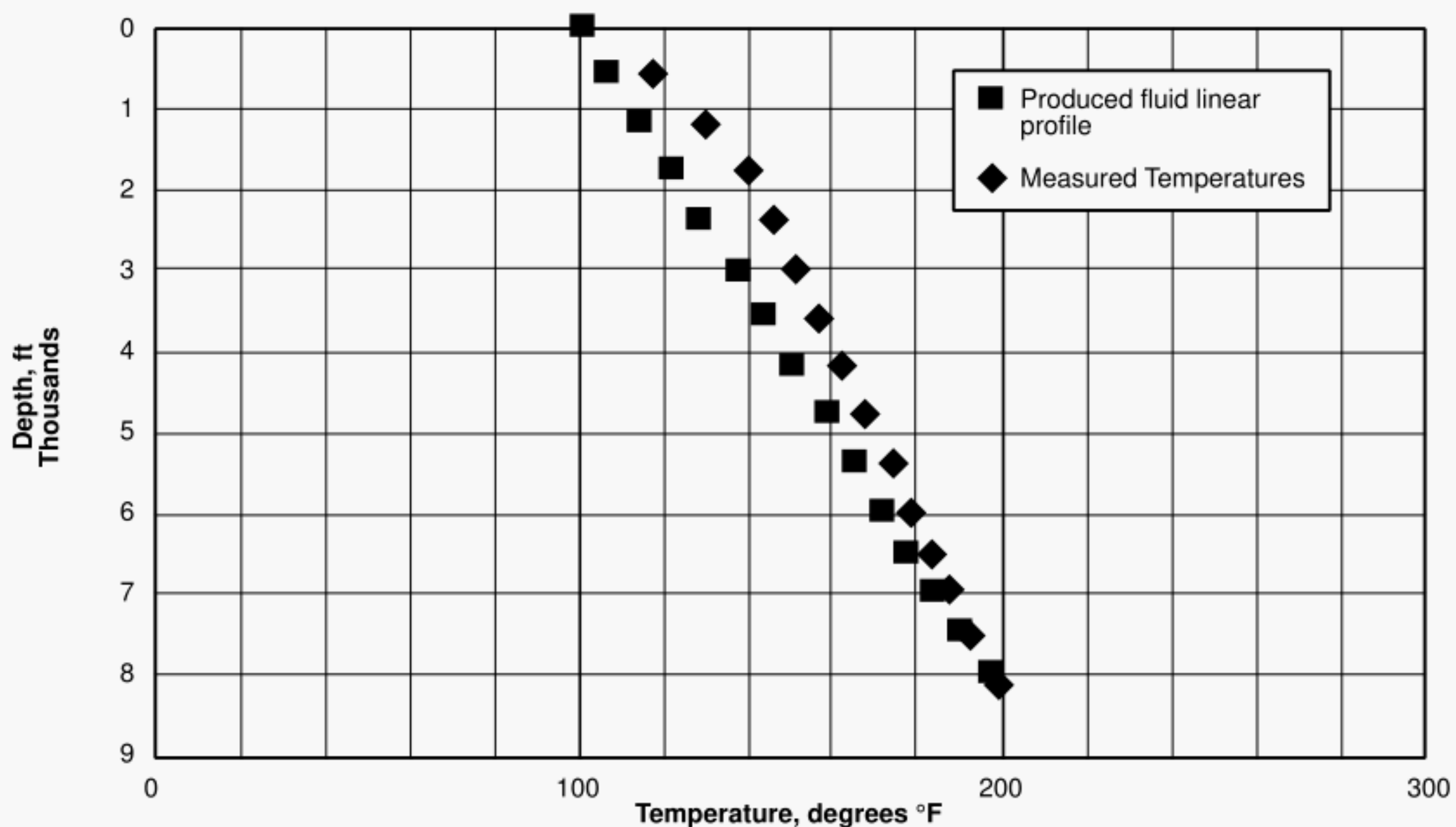


Figure 4-3—Temperature Gradients

- Use the *shut-in* or the *circulating* temperature as the surface temperature, the reservoir temperature at the perforations, and linearly interpolate the temperature at the top three or four valves (where a cool wellbore will undergo heating).
- Use the measured temperature profile for the bottom valves; or if not available, interpolate between the flowing surface and reservoir temperatures for the bottom valves.
- Be wary of wellhead temperatures obtained during a cold weather period. These cold temperatures affect only the upper 500 ft in the wellbore.

Unloading temperatures that are significantly different than predicted cause **either** of two problems:

- *Cooler than predicted* temperatures can cause upper unloading valves to stay open and circulate gas, stopping the unloading process
- *Hotter than expected* temperatures due to quick heating from high PI wells causes premature valve closing and the well will not take gas (unloading stops, the well cools and gas injection restarts, then stops again)

Gas temperature at depth may be based on the static geothermal gradient although the production temperature has a small effect on the gas temperature. The gas temperature at the wellhead will vary from hot to cold with the injection rate, time of year, and pipeline path. The temperature downstream of the gas injection surface choke is often significantly cooler than the compressor station temperature due to gas expansion and pipeline cooling.

The temperature and pressure models of the wellbore represent the multiphase **outflow** of fluids from the tubulars to the surface facility. However, system performance models also require prediction of reservoir delivery, or **inflow**.

D. Inflow Performance

The inflow performance model predicts how much liquid a reservoir will produce as a function of static and flowing bottomhole pressures, Figure 4-4. The inflow model is dependent on the producing zone's reservoir pressure, bubble point pressure, permeability, thickness, fluid properties, skin (indicator of near wellbore damage), and logarithmic ratio of drainage radius to wellbore radius. The inflow models shown are the straight line Darcy PI, Vogel IPR, and the multipoint Fetkovich method. These models are discussed in 8.3.

One useful technique for monitoring the well performance and the quality of well data is to compare a well's inflow performance over time. Another is to plot a well's measured flowing bottomhole pressures against the production rate, comparing this with the theoretical inflow performance and calculated multiphase outflow.

Inflow models of reservoir performance combine with the tubing performance **outflow models** to form **system models** of well deliverability, or **performance prediction**. The inflow performance model is equally important as the outflow model in gas lift well deliverability predictions.

RECOMMENDED PRACTICE: Obtain measured flowing and static pressures and a production well test to validate a reservoir inflow model.

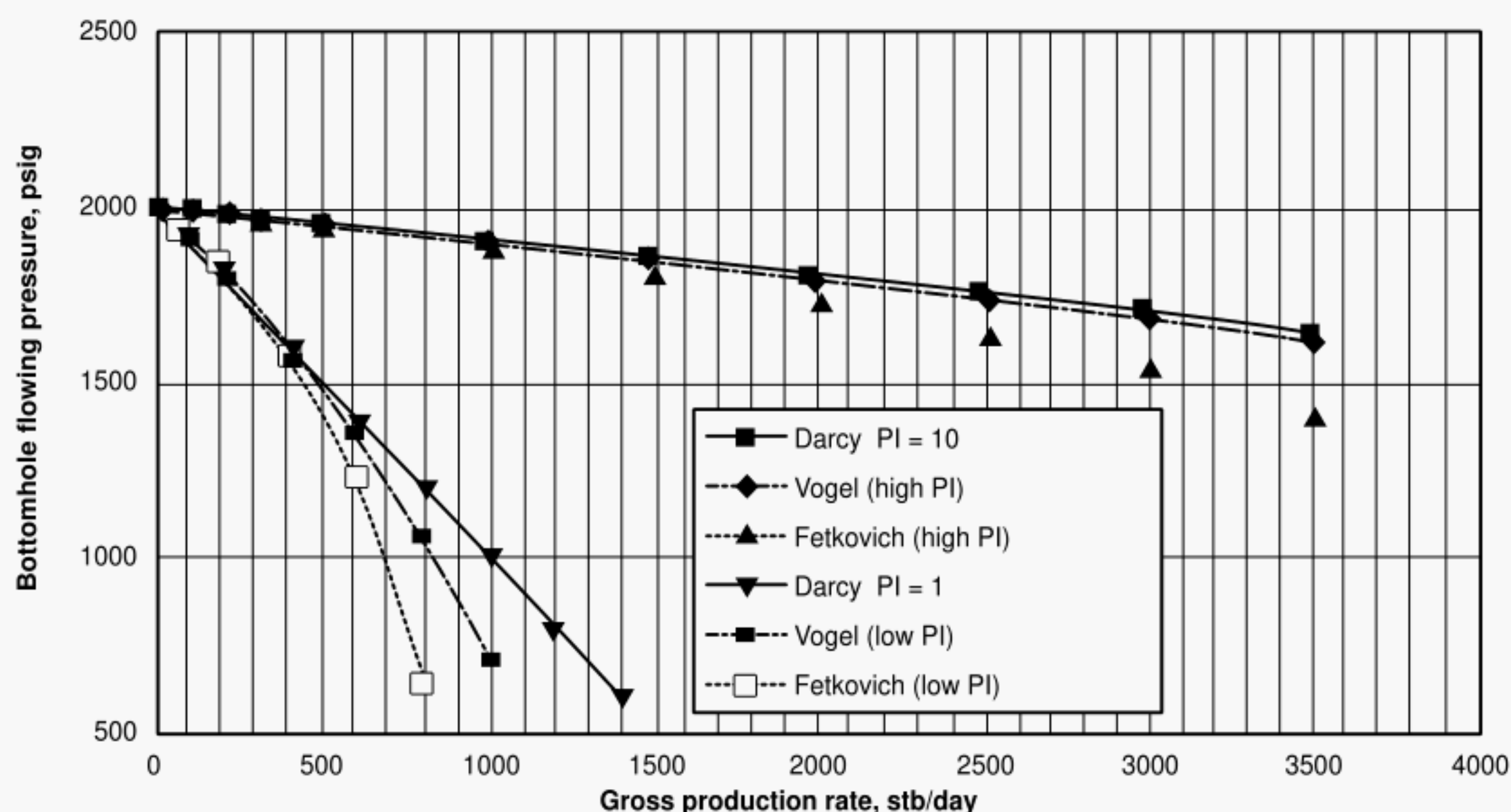


Figure 4-4—Reservoir Inflow Performance (PI)

4.2 SYSTEM MODELS

RECOMMENDED PRACTICE: Use calibrated system models to evaluate potential changes in tubular size, gas lift injection rate, reservoir characteristics, and facility operation.

Performance prediction is the solution of the computer calculated outflow and inflow equations from the *basic models* discussed in the prior section. The joining of basic models gives the larger, more capable *system model* that can predict performance for a well system consisting of separator, flowline, tubing, and reservoir. Extending this concept to multiple wells flowing to the same separator or manifold gives a *network model*.

Various components can be linked to give a system model. The point of reference can be at the bottom of the well (at perforation mid-point) and rate vs. inflow or tubing outflow pressure can be plotted. Another reference point is the wellhead and rate vs. flowing wellhead or flowline pressure can be plotted. Models discussed are:

- Production rate vs. bottomhole pressure.
- Production rate vs. injection depth (equilibrium curve).
- Production rate vs. injection gas rate (production delivery curve).
- Production rate vs. wellhead pressure.

A. Production Rate vs. Bottomhole Pressure

The tubing performance *outflow* curve is superimposed on the *inflow* curve to get a system solution. The intersection of the two curves is the rate which satisfies both the inflow and outflow equations. This intersection is shown for the Well 1 case to be 3100 stb/day and 500 stb/day for the lower PI case of Well 2. Figure 4-5 has the predicted flowrate and flowing bottomhole pressure at the perforation midpoint for each case. When the model matches the well test and flowing survey measured data, then it can be used with confidence to predict performance at other potential conditions.

The far left declining pressure portion of each outflow curve is the computer calculation at low rates. This declining pressure indicates the “unstable” area of the multiphase flow model when low velocity causes the density of the mixture to be high and the resulting bottomhole calculated pressure to be high. If the inflow line intersects the “unstable” part of the outflow curve, the result is highly suspect and should not be used. The production system needs to be altered by lowering wellhead pressure, increasing the IGLR, stimulating the reservoir rock, or a combination of these actions.

The computer generated outflow and inflow curves graphically show:

- When wells will die on natural flow.
- Need for tubing size changes.
- Whether additional lift gas will give an increase in production.
- What water cut fraction causes the well to die.

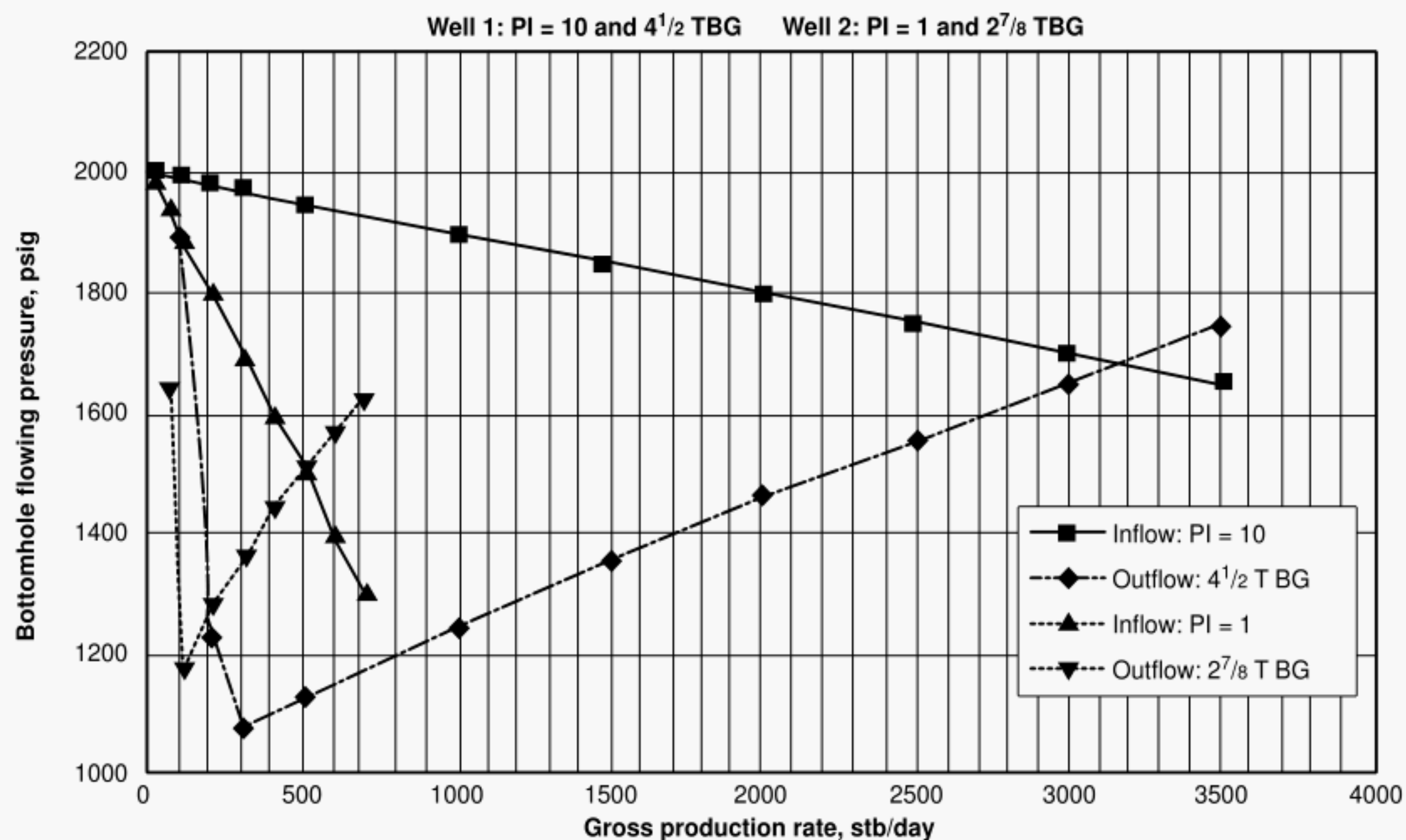


Figure 4-5—Inflow–Outflow Performance

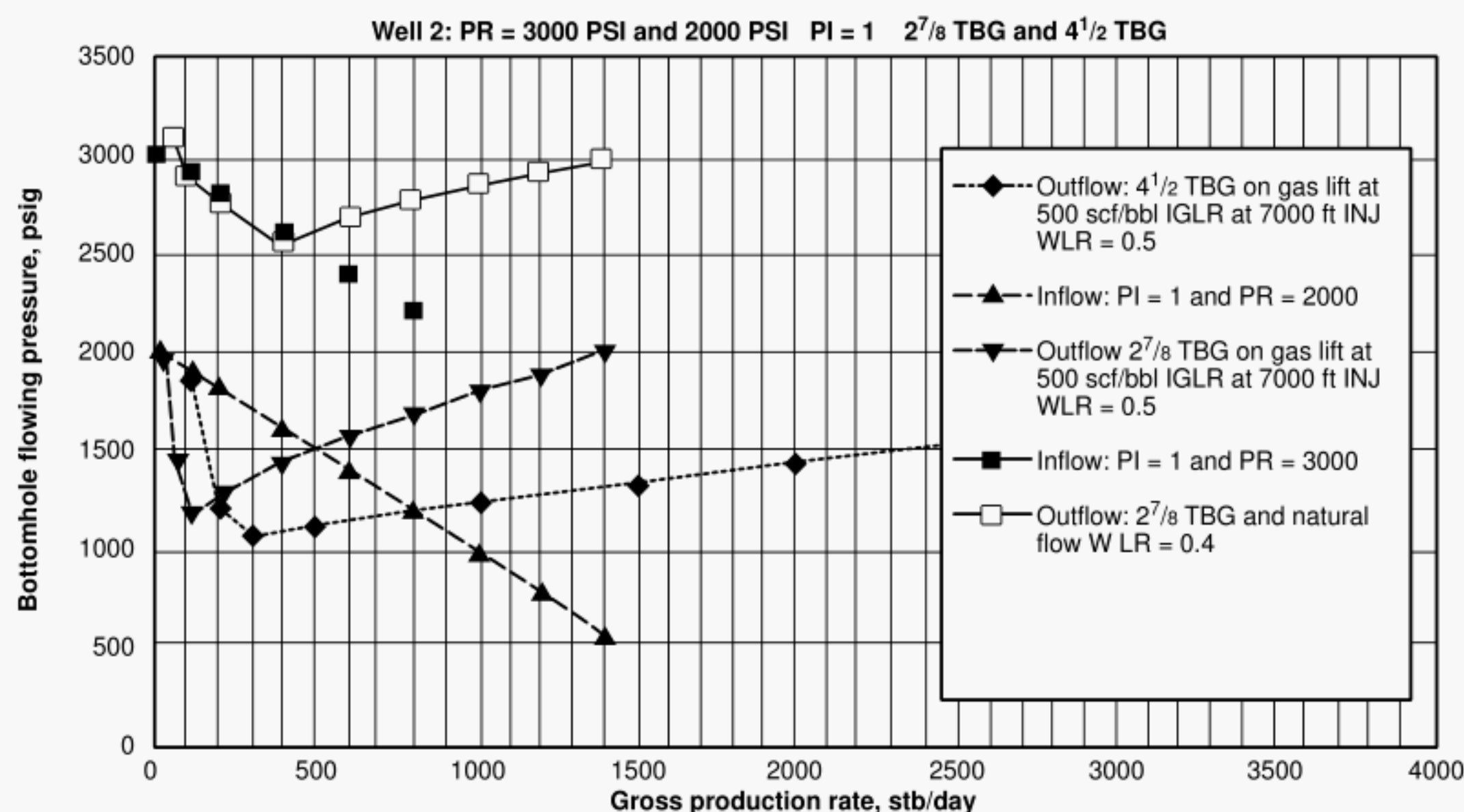


Figure 4-6—Inflow–Output Performance with Natural Flow and Gas Lift

Figure 4-6 illustrates model results with the points listed above and also shows the great usefulness in visually observing the effects of tubular sizes.

Larger tubing will yield a flatter outflow curve, due to less friction loss, resulting in a higher production rate. However, if the tubing is too large, the well will operate near the left of the curve at low liquid rates. In this unstable low flow region, liquid will fall back due to low velocity and the well slowly dies.

B. Production Rate vs. Injection Depth

Production rate is increased when gas is injected at a deeper point. The system equations can provide data to evaluate the production benefits against the cost of redesigning a well to lift deeper. The data are presented in a useful plot of the fluid pressure at the point of lift for each of several depths, with the resulting production rate indicated at each lift depth. Figure 4-7 is known as the “*equilibrium curve*”. Comparing the fluid pressure with the casing operating pressure available at each depth will give the maximum depth of lift and the maximum production rate for a specified gas injection rate.

Equilibrium curves and production delivery curves can be used to evaluate well performance. Accurate application depends on matching the vertical pressure model, fluid property data, and inflow model to the measured data from the well. Once the calibration is done, the analysis could be one of the types listed below:

- Rate vs. gas injection depths in wells where the mandrels are already in place.

The production rate, for a specific injection gas rate, can be calculated for each potential lift depth. The fluid pro-

duction pressure and gas pressure can also be obtained with the calculation. With this, costs can be compared to the benefits of alternatives for achieving the different lift depths.

- Unloading rates from the gas lift valves if the mandrels are already in place.

The equilibrium curve can help design the gas lift valves to be installed in existing mandrels. Since the curve provides the fluid pressure and production rate (for a specified gas injection rate) at each mandrel depth, then the transfer pressure (to unload to the next valve), can be obtained, Figure 4-8.

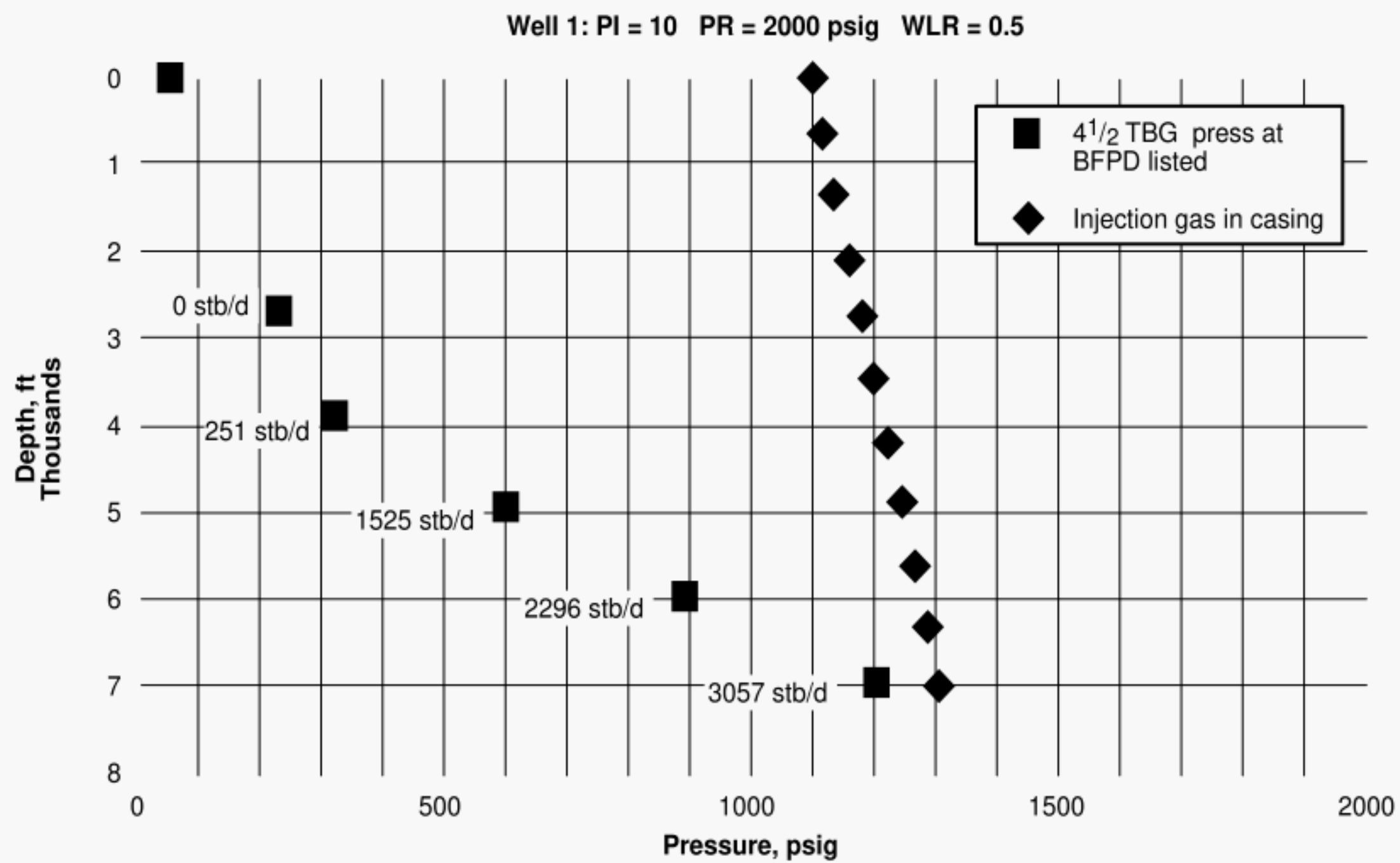
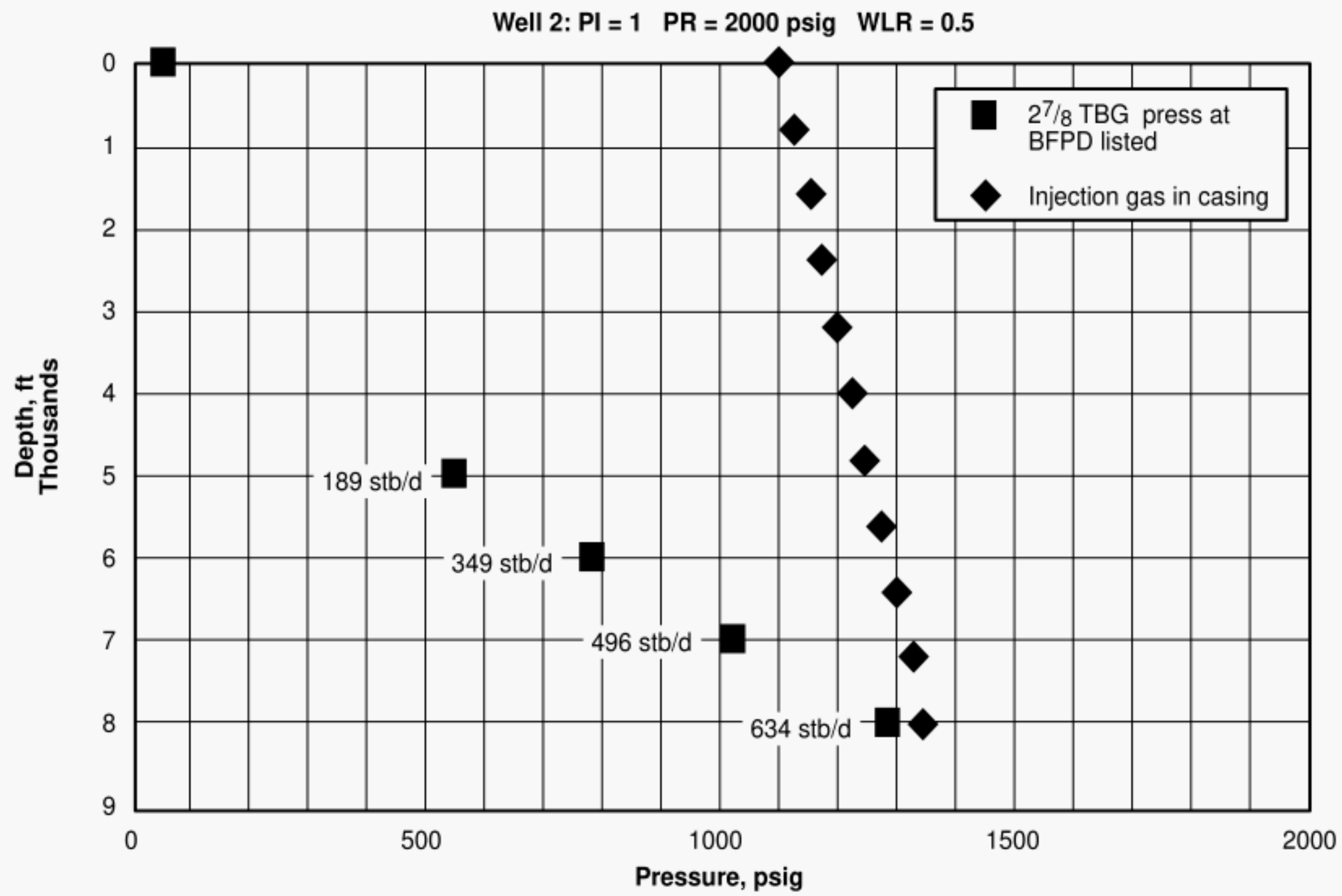
- Required gas injection pressures.

The equilibrium curve is the locus of fluid pressures and associated production rates at various depths, with the maximum depth located at the fluid pressure intersected by the injection gas gradient line. The operating injection pressure, injection depth, and given the injection pressure drop between valves, the required kickoff pressure can be estimated.

- Wellhead (tubing) pressure effects.

For an equilibrium curve to be constructed correctly, the producing wellhead pressure should vary as the production and injection gas rates vary, due to flowline friction (platform wells with very short flowlines may have nearly constant pressure). The model should include wellhead pressure vs. production rate and injection gas rate in the existing or proposed flowline.

- Production (tubing) string sizes.



Each equilibrium curve represents one tubing size. By constructing different equilibrium curves for different tubing IDs, the effects (costs and benefits) of the different sizes can be evaluated.

- Effects of different inflow potentials.

Each equilibrium curve is based on one inflow model, thus different IPRs can be used to evaluate a potential stimulation job to improve the IPR of a well. Similarly, the potential reduction in IPR during a workover (due to skin damage) can be evaluated.

Equilibrium curves can also be used to study other factors in addition to the variables discussed above. These include the effects of:

- Water cuts.
- Fluid properties.
- Gas injection properties.
- Use of different pressure, temperature, and inflow models, provided that comparison to measured data is the basis for establishing accuracy.
- Spacing the gas lift mandrels in a well.

Mandrel spacing design and installation in a well must often be done before sufficient information is available to use an equilibrium curve. Therefore, mandrels can be spaced based on gradient curves from an offset well or from estimates. See API RP 11V6 for a discussion.

C. Production Rate vs. Injection Gas Rate

Production rate delivery usually increases as gas lift gas is injected, however, increasing friction loss in the tubing and flowline diminishes the production gain per increment of gas injected. The production delivery curve is obtained from system equations applied to give production rate vs. injection gas. The computer model can be applied at several depths to evaluate the benefit of deeper injection, with the results used to identify an under-performing well, which can be restored to deeper injection, Figure 4-9. This curve can be used by field operators to determine whether a well test is normal or whether a well has shifted to a shallower valve and is under-performing.

The system model of a flowline, tubing, and reservoir can be used for performance prediction of production rate vs. injection gas (or IGLR). Field-wide optimization and allocation of gas requires a curve for each well. Each curve is used to obtain:

- Optimization of production rate with increasing gas injection rate.
- Rate from each unloading valve for a high PI well.
- Effect of flowline size and wellhead back-pressure with increasing injection gas.

- Required injection gas for each potential tubing size.
- Rate vs. injection gas for various inflow or reservoir conditions.
- Lift gas rate required for each well, and by summing, the field gas rate.

Each rate curve represents one depth of injection. By constructing different curves for each existing or proposed mandrel depth, the effects (costs and benefits) of the different injection rates can be evaluated and visual optimization can be applied for the range of reservoir, tubular, or facility conditions.

An equilibrium curve calculation to establish maximum depth of injection is still needed.

D. Production Rate vs. Wellhead Pressure

The production rate increase with wellhead pressure reduction can be predicted from system models. This tool helps evaluate flowline diameter increases, looping, or separator pressure reductions. The system model calculates the reservoir inflow and tubing multiphase flow pressure loss to give a flowing wellhead pressure vs. rate curve. This data, Figure 4-10, can be compared to the flowline pressure vs. rate curve and the proper size selected for both the tubing and the flowline. The sizes should be selected by considering the production rate, PI, water cut, and quantity of injection gas.

This system can model both natural flow and gas lift. The rate increase above natural flow can be predicted by adding gas at a mandrel depth which is attainable with available injection pressure. The rate is incremented upward by adding gas or increasing the IGLR.

E. Effects of Deeper/Shallower Injection Depths

The model can provide the production rate at various depths to simulate lifting at different mandrels. This is a useful analysis when designing a new system and predicting the production rate vs. injection depth (and associated injection pressure) is desired information. For new systems, the costs for compression can be evaluated and compared to the benefits of high pressure, deep injection:

- Higher production rates are possible.
- Fewer unloading valves are required.
- Less injection gas has to be circulated, thus reducing the compression BHP.

The method can be applied to troubleshoot existing wells:

- Identify under-performing wells when a well test gives a low rate. Compare to a model showing the rate that results when lift is at a shallow depth.
- Evaluate which wells are capable of lifting deeper if the unloading valve pressures are reset to enable deep lift.

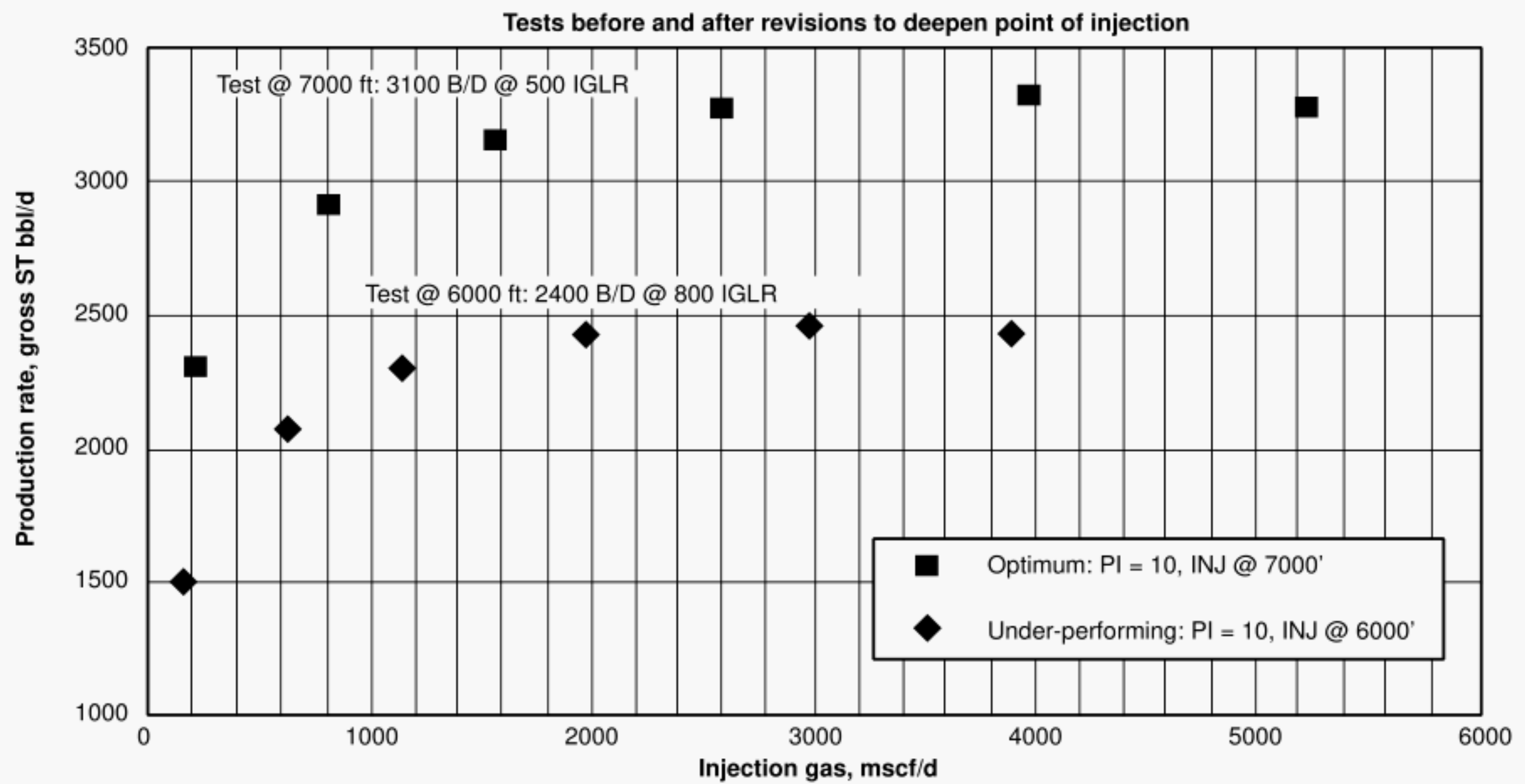


Figure 4-9—Production and Gas Injection Tests Identify Under-performing Wells

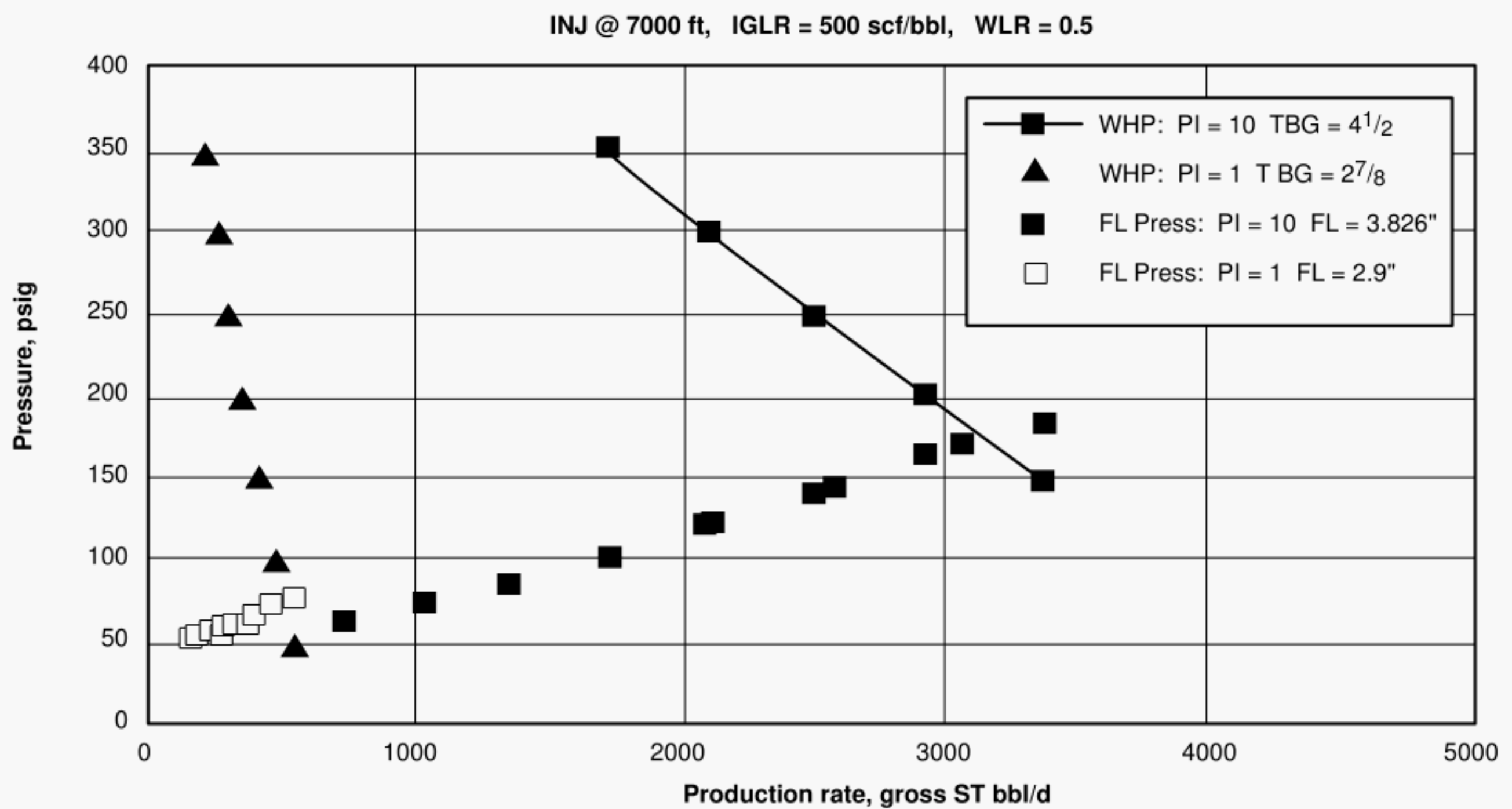


Figure 4-10—Wellhead Delivery Curves and the Flowline Curves

For an existing well, one must make the calculation to certify that the required gas pressure is within the operating pressure available from the compressor and piping system.

F. Predicting Gas Requirements

Injection gas requirements can be established using system models:

- New field systems or designs for proposed wells.
- Future injection gas capacity for water increase and reservoir pressure decline.

The production rate as a function of injection gas rate describes the amount of gas needed for each well, and the model will predict how the gas requirements change as reservoir conditions change.

The key items to be evaluated at future points in time are:

- Water fraction increase.
- Reservoir pressure decline.
- Benefit of lower separator pressure.
- Removal of pressure loss at manifolds, production transfer pipelines, valves, wells.

The model can provide data on production increases or injection gas saved on each well, and the field total is the summation of the individual well's performance.

The summation of each well's gas consumption as a function of time provides the field gas rate and compression requirements. Thus this method becomes the planning tool that permits facility installation at the specific time of need.

5 Factors Which Affect Potential Production Rate and Gas Injection Requirement

RECOMMENDED PRACTICE: The primary beneficial factors which help to increase production rate and reduce gas consumption are high gas injection pressure and low, stable wellhead fluid pressure. Design practices should attempt to achieve these operating conditions.

5.1 CASING PRESSURE AND GAS INJECTION RATE

Casing gas injection pressure is one of the two most important factors. When pressure is raised higher, it may permit deeper injection. However, if the gas lift valves' set pressures are low, then the valves must be reset at higher pressures to utilize the higher available pressure. The deeper injection will:

1. Reduce the density of a greater length of the fluid column—which in turn will,
2. Increase the drawdown ($P_r - P_{wf}$)—which will,
3. Increase the fluid production rate—and/or,
4. Reduce the gas lift gas rate needed per barrel of produced fluid.

When the injection point reaches the valve near the end of the tubing string just above the packer, an increase of the injection pressure will not deepen the lift point. A combination of the higher pressure and proper port (orifice) sizing should create steady gas injection and minimize slugging.

Figure 5-1 shows the effect on production rate when the injection pressure increases. The injection depth increases giving a corresponding rate (bfpd) increase, as listed on the graph at each injection point, although PI has a controlling impact on rate.

The equilibrium curve shows the pressure in the tubing (or in the casing for an annular flow well) and the production rate that can be attained from that depth of lift for the reservoir and piping conditions. The curve represents an equilibrium condition among all the system parameters. At each depth an estimate of the operating gas pressure would be 100 psi – 150 psi greater than the tubing pressure. Calculating or using a parallel line can provide the gas pressure at the surface.

Figure 5-2 has the equilibrium curve for a low PI well to show that productivity has a dominant effect on the production rate. Smaller tubing size, as would normally be installed in a lower PI well, is the only difference other than PI.

Figure 5-3 shows the effect of the gas flow rate, expressed as the IGLR. As the gas flow rate increases, the fluid column in the tubing string becomes lighter (less dense). This in turn reduces flowing bottomhole pressure, which increases the drawdown and the liquid flow rate. However, the benefit of increasing gas has a limit due to friction (in the tubing and flowline) caused by the greater gas and liquid rate.

The system model (see 4.2) can be used to predict performance for use in an economic evaluation of gas pressure and rate.

5.2 DEPTH OF INJECTION

The depth of gas injection should be as deep as possible within the constraints of:

- Kickoff/operating gas injection pressure.
- Reservoir pressure.
- PI.
- Equipment setting depth, such as the packer.

The point of gas injection is a result of the interaction between:

- Available surface injection pressure.

For an existing well, one must make the calculation to certify that the required gas pressure is within the operating pressure available from the compressor and piping system.

F. Predicting Gas Requirements

Injection gas requirements can be established using system models:

- New field systems or designs for proposed wells.
- Future injection gas capacity for water increase and reservoir pressure decline.

The production rate as a function of injection gas rate describes the amount of gas needed for each well, and the model will predict how the gas requirements change as reservoir conditions change.

The key items to be evaluated at future points in time are:

- Water fraction increase.
- Reservoir pressure decline.
- Benefit of lower separator pressure.
- Removal of pressure loss at manifolds, production transfer pipelines, valves, wells.

The model can provide data on production increases or injection gas saved on each well, and the field total is the summation of the individual well's performance.

The summation of each well's gas consumption as a function of time provides the field gas rate and compression requirements. Thus this method becomes the planning tool that permits facility installation at the specific time of need.

5 Factors Which Affect Potential Production Rate and Gas Injection Requirement

RECOMMENDED PRACTICE: The primary beneficial factors which help to increase production rate and reduce gas consumption are high gas injection pressure and low, stable wellhead fluid pressure. Design practices should attempt to achieve these operating conditions.

5.1 CASING PRESSURE AND GAS INJECTION RATE

Casing gas injection pressure is one of the two most important factors. When pressure is raised higher, it may permit deeper injection. However, if the gas lift valves' set pressures are low, then the valves must be reset at higher pressures to utilize the higher available pressure. The deeper injection will:

1. Reduce the density of a greater length of the fluid column—which in turn will,
2. Increase the drawdown ($P_r - P_{wf}$)—which will,
3. Increase the fluid production rate—and/or,
4. Reduce the gas lift gas rate needed per barrel of produced fluid.

When the injection point reaches the valve near the end of the tubing string just above the packer, an increase of the injection pressure will not deepen the lift point. A combination of the higher pressure and proper port (orifice) sizing should create steady gas injection and minimize slugging.

Figure 5-1 shows the effect on production rate when the injection pressure increases. The injection depth increases giving a corresponding rate (bfpd) increase, as listed on the graph at each injection point, although PI has a controlling impact on rate.

The equilibrium curve shows the pressure in the tubing (or in the casing for an annular flow well) and the production rate that can be attained from that depth of lift for the reservoir and piping conditions. The curve represents an equilibrium condition among all the system parameters. At each depth an estimate of the operating gas pressure would be 100 psi – 150 psi greater than the tubing pressure. Calculating or using a parallel line can provide the gas pressure at the surface.

Figure 5-2 has the equilibrium curve for a low PI well to show that productivity has a dominant effect on the production rate. Smaller tubing size, as would normally be installed in a lower PI well, is the only difference other than PI.

Figure 5-3 shows the effect of the gas flow rate, expressed as the IGLR. As the gas flow rate increases, the fluid column in the tubing string becomes lighter (less dense). This in turn reduces flowing bottomhole pressure, which increases the drawdown and the liquid flow rate. However, the benefit of increasing gas has a limit due to friction (in the tubing and flowline) caused by the greater gas and liquid rate.

The system model (see 4.2) can be used to predict performance for use in an economic evaluation of gas pressure and rate.

5.2 DEPTH OF INJECTION

The depth of gas injection should be as deep as possible within the constraints of:

- Kickoff/operating gas injection pressure.
- Reservoir pressure.
- PI.
- Equipment setting depth, such as the packer.

The point of gas injection is a result of the interaction between:

- Available surface injection pressure.

- Static fluid gradient and reservoir pressure.
- Flow rate and flowing pressure gradient.
- PI.
- Number and type of unloading gas lift valves.

When casing gas injection pressure is low and/or the flowing tubing wellhead pressure is high:

- The point of gas injection may be relatively shallow.
- Production rate may be lower than desirable.
- Injection gas rates may be greater resulting in a less efficient installation.

For best performance in all installations:

- Valve setting pressures should be designed to eliminate interference between valves or multipoint injection. The deepest attainable single point is preferred.
- Mandrel spacing should accommodate the highest PI wells in the field.
- Additional mandrels should be installed between the packer and the expected design point of lift to plan for potential future points of lift if the:
 - reservoir pressure diminishes, or
 - PI declines.
- The packer should be installed within 100 ft of the top perforation, (an exception is a dual completion where the upper packer is the constraint to additional valves and deep injection into the lower string).

RECOMMENDED PRACTICE: A wellbore and system design objective should be attainment of the deepest gas injection point possible within the constraints of gas pressure, reservoir pressure, productivity, and wellbore equipment.

5.3 CASING, TUBING, AND FLOWLINE SIZES

RECOMMENDED PRACTICE: Tubular sizes directly affect gas injection pressure at the valve and the flowing wellhead fluid pressure. Sizing practices that follow should be implemented to achieve high injection pressure and low wellhead pressure.

Casing size should be based on:

- Size of the optimum tubing.

- Sufficient clearance for gas lift mandrels (which are eccentric).
- Fishing operations.
- Adequate cross-section area between casing and tubing connections to prevent excessive injection gas pressure loss (or fluid production pressure loss for annular flow).

For continuous flow gas lift:

- The annular area is usually adequate and not an important factor when gas is injected on the annulus. If the production fluid flows up the annulus, then modeling per Section 4 should be done to select a proper tubing/casing size combination.

For intermittent gas lift:

- If the time cycle is controlled by a surface choke, the available annular volume will be a significant factor due to its storage capacity.
- If the annular space is too small, the volume of gas passed when the valve opens may be inadequate to lift the slug.
- If the annular space is too small, the closing-opening pressure spread of the unbalanced valve might have to be widened by altering the port/bellows area ratio.
- If the annular space is big, a pilot valve should be used to prevent excessive gas injection.

Tubing size is based on production flow rate plus the injection gas rate. Sizing objectives are:

- Minimizing flowing bottomhole pressure for the current producing rate range, water-liquid ratio, and injection gas rate range.
- Minimizing flowing bottomhole pressure for the future conditions of increased water and total gross fluid plus injection gas.
- Maintaining fluid velocity in the range of 5 ft/sec. – 15 ft/sec. to give good mixing which will minimize slippage and slugging.
- Intermittent lift liquid accumulation per cycle and gas required for lift is sensitive to the tubing size.

Figure 5-4 displays rate vs. multiphase outflow pressure (at the perforations), superimposed on the inflow pressure curve. This is an excellent tool to evaluate tubing sizes for current and future conditions.

The graph shows several tubing sizes in the plot of computer generated multiphase outflow curves (also called tubing intake curves). The “J curve” shape is caused by liquid holdup and gas slippage at low production rates that result in high mixture densities and a high multiphase pressure at bottomhole. As rate and velocity increase, mixing improves, and

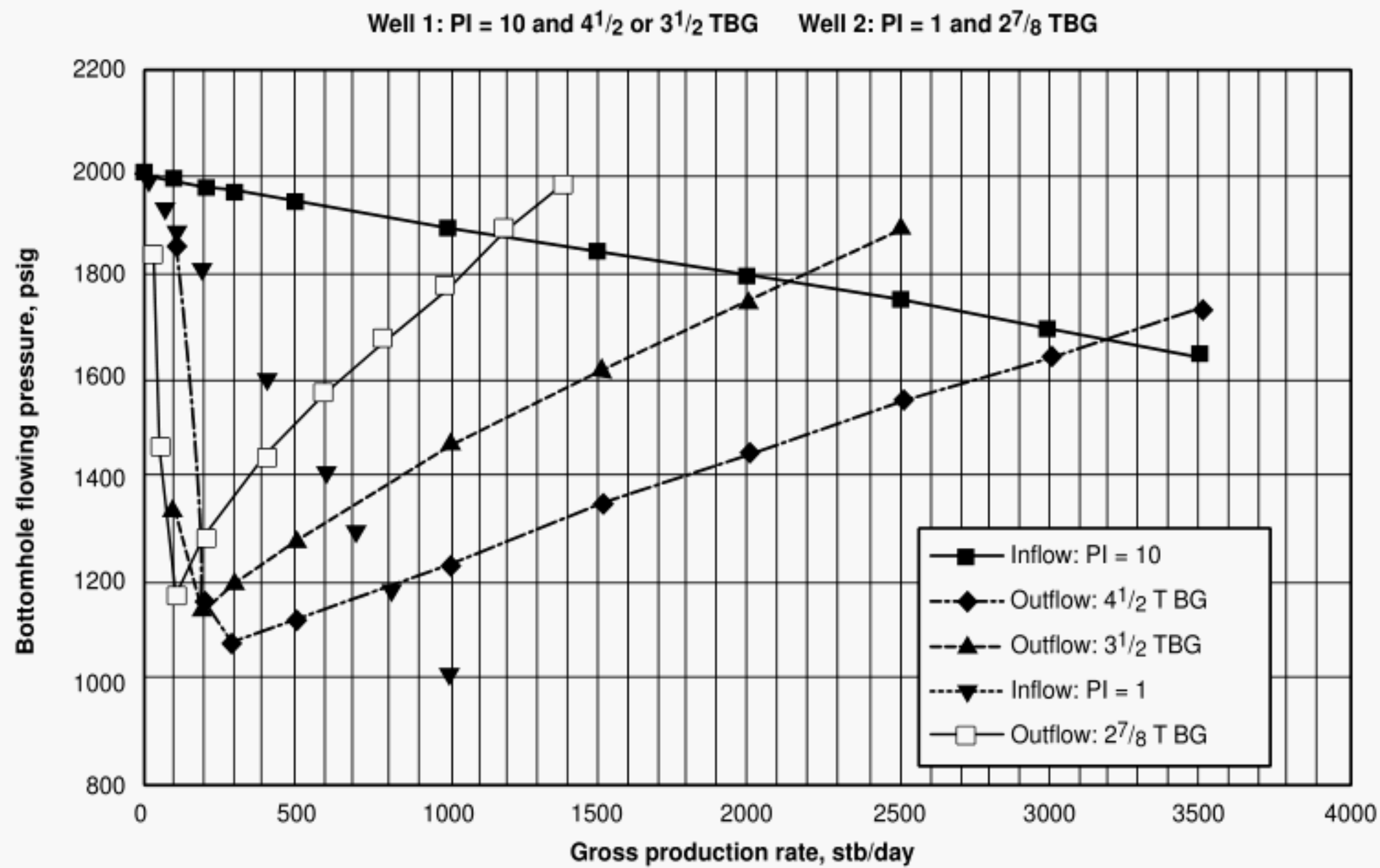


Figure 5-4—Inflow–Outflow Performance

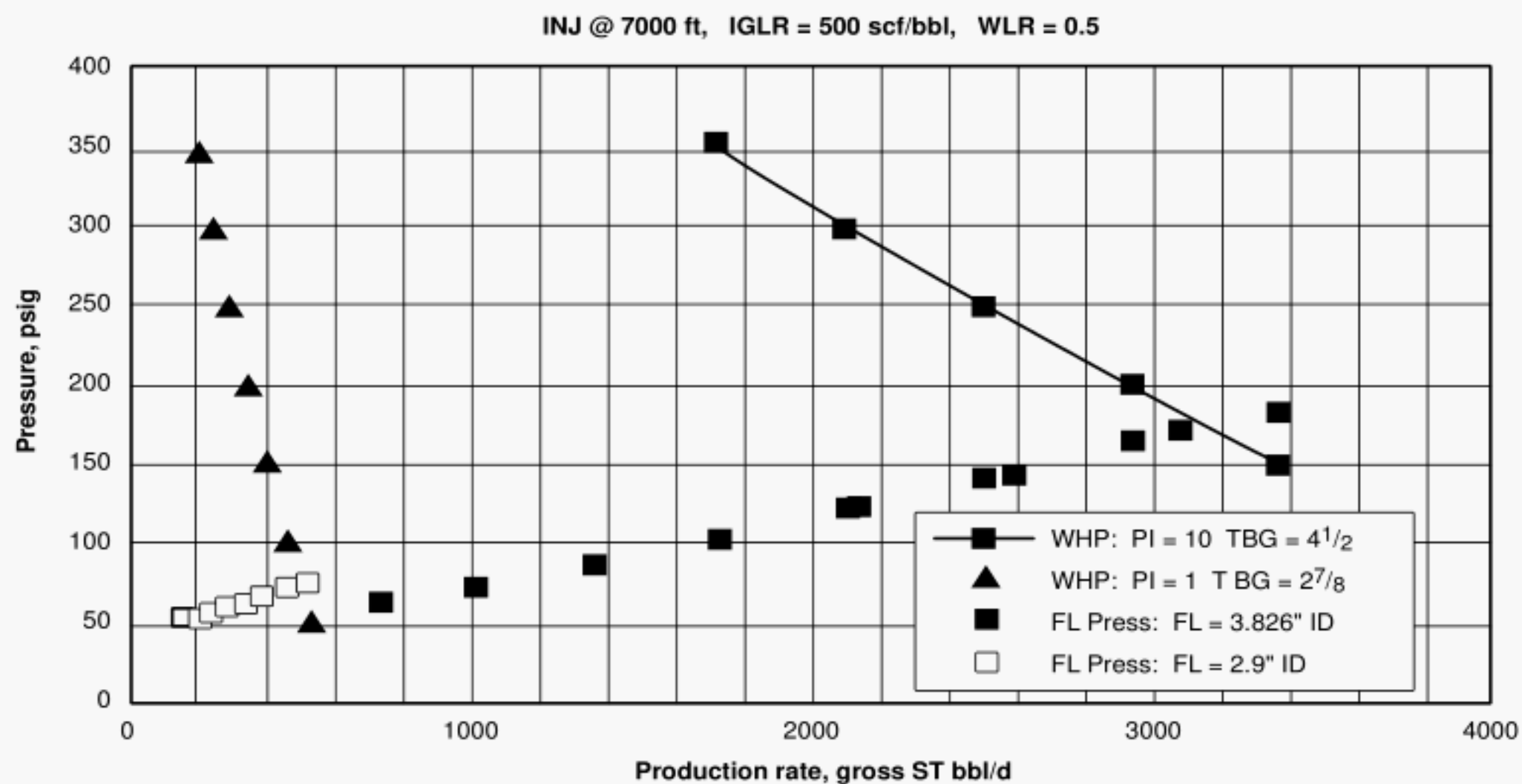


Figure 5-5—Wellhead Pressure Delivery

the bottomhole multiphase pressure reaches a minimum. As rate and velocity get larger, the friction is greater and the bottomhole pressure increases.

Each tubing size curve exhibits a slightly different shape and each should be imposed on the inflow curve.

The “**optimum**” tubing size is that which:

- gives the best rate at current conditions, and

- gives the best rate for future conditions, but if these are different sizes, then
- choose the size to maximize economic return.

Flow line size affects:

- Velocity which increases friction and raises backpressure when the diameter is small.

- Liquid holdup and random slugs which can lead to severe slugging in large diameters.

Figure 5-5 shows the effect of the flowline size on the maximum producible rate. A high PI well needs greater flowline capacity and the piping size for both the tubing and the flowline should be about the same size. The larger tubing and flowline yields a maximum rate greater than 3000 bbl/day. The low PI well is constrained at the reservoir, thus a smaller piping combination is adequate.

The high PI well could potentially benefit from an even larger flowline, but the designer has to consider slug buildup. The 4 in. (nominal) size has higher velocity and friction than a 6 in. However, a 6 in. flowline has larger liquid holdup which is an indicator of the amount of liquid settling in the flowline. This larger quantity of liquid is an indicator of the potential for a larger slug into the separator with possible liquid overflow if the vessel is not of adequate slug capacity.

Size increases of tubing or flowline may have the following benefits or disadvantages:

- Improve the oil production rate, if wellhead pressure is reduced.
- Cause a high PI well to respond to backpressure reductions, but a low PI well may not respond or may decline.
- Cause severe slugging in flowlines or pipelines when elevation changes are present, such as with offshore pipelines and facilities.

Size changes can also require several actions:

- Evaluate equipment clearance inside the casing, especially sidepocket mandrel eccentricity.

- Switch to smaller mandrels than the tubing size due to casing clearance but keep the 1 1/2 in. valve size.
- Evaluate the production rate increment to insure that it justifies the cost of pipe, the installation or workover cost, and the potential risk of reservoir damage (during the workover to change tubing).

5.4 GAS LIFT VALVES

RECOMMENDED PRACTICE: Gas lift valve bellows set pressures should be based on the highest available kickoff or unloading injection pressure in order to achieve deep injection.

The operating gas pressure and depth of injection are related to the valve design and valve type. Most are unbalanced gas lift valves with nitrogen charged bellows, and some have a spring or spring plus nitrogen charge inside the bellows. Figure 5-6 has the two general types of valves:

- Gas IPO
- Fluid PPO

Gas IPO valve design characteristics:

- Injection gas pressure creates the primary force on the bellows to open/operate valve.
- Production pressure effect is based on port size.
- Surface unloading gas pressure should typically drop 25 psi between each unloading valve (10 psi is mini-

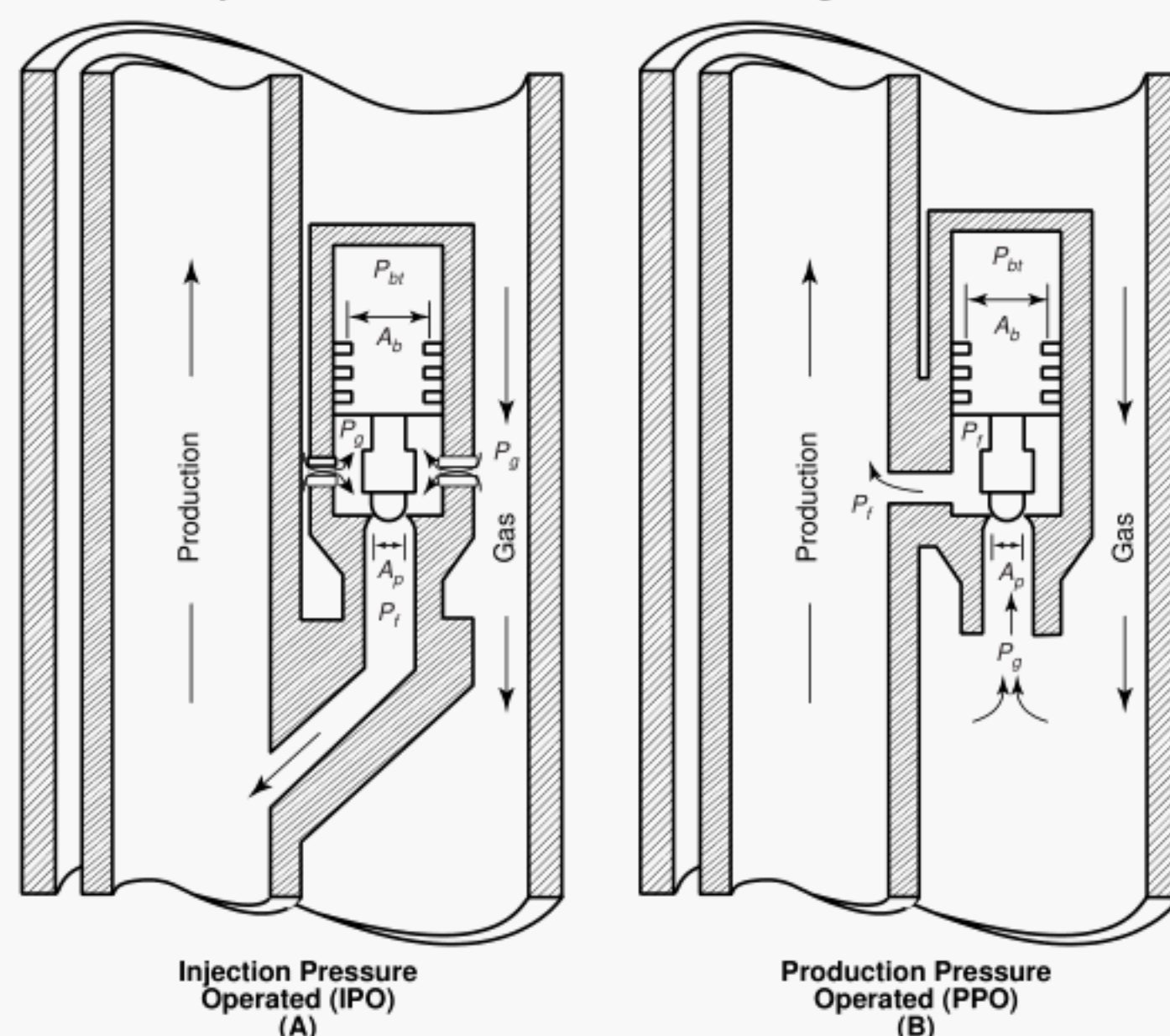


Figure 5-6—Valve Types

mum for low pressure systems and to up to 50 psi for high pressure systems) to minimize interference.

- 1½ in. valves are preferred to 1 in. valves due to better performance, unless casing clearance requires 1 in. valve pockets.
- Large port valves can pass large quantities of gas, but shut quickly when production pressure declines.
- Large port valves can reopen at lower gas pressure when production pressure rises.

Production (fluid) pressure operated (PPO) valve design characteristics:

- Fluid production pressure creates the primary force on the bellows to open/operate valve.
- Injection gas pressure effect is based on port size.
- May be required when the available gas injection pressure is low or erratic.
- Often use a spring instead of, or in addition to, a nitrogen pressure charge.
- Spring set valves have a higher load rate and may have less gas passage capability.
- Spring set valves are not temperature sensitive.

The bellows set pressure of either type of valve is calculated based on:

- The casing unloading gas injection pressure at each unloading valve or operating gas injection pressure at the operating valve, and
- The corresponding tubing production pressure at each valve.

An IPO gas lift valve set pressure mostly controls the injection pressure in the wellbore. The seat/stem (port) size selection and injection pressure control the maximum rate of gas injected. The surface choke or gas rate controller can limit the injection rate to an optimum gas rate that is less than maximum capacity.

The diameter of the seat (port) must be properly selected:

- Smaller seats minimize opening-closing pressure difference (spread) and interference between unloading valves.
- Unloading valves use a smaller seat because a lesser gas flow rate is needed for unloading.
- The operating valve uses a larger seat for increased maximum gas passage.
- An orifice may be substituted for an operating valve. However, when the compressors are shutdown, start-up of a large system may require an external source of gas

supply since gas pressure in the annulus is not maintained.

Other discussion of valve performance is in 3.4, and in API RP 11V2. Gas lift valve design is given in API RP 11V6.

5.5 RESERVOIR DEPTH, PRESSURE, AND TEMPERATURE

RECOMMENDED PRACTICE: Design the compressor discharge pressure and system gas lift injection pressure for the deeper, higher reservoir pressure, higher productivity wells.

Reservoir depth and temperature are interrelated, and initially, so is the pressure. However, pressure declines with fluid withdrawal unless maintained by reservoir injection or a strong water drive. This interrelated reservoir data will affect the gas lift system design as follows:

- Deeper wells often require a higher gas injection pressure to reach a desired deep injection point.
- High productivity wells will often have a high flowing bottomhole and a corresponding high tubing pressure, which requires high injection pressure.
- Reservoir pressure decline results in a production rate decrease and more gas lift gas may be needed to maintain the same velocity for effective lift.
- Reservoir pressure maintenance or restoration will increase the production rate, increase the flowing pressure profile in the tubing, and may raise the required injection pressure.

The deep reservoir will have a high temperature that can affect the nitrogen charged gas lift valves. As the production rate, or water-liquid ratio, is increased, the temperature in the tubing also increases, heating the gas lift valve. The effects are reviewed in 4.1.C.

5.6 WELL INFLOW PRODUCTIVITY

RECOMMENDED PRACTICE: Design the compressor discharge pressure and system gas lift injection pressure for the higher productivity index (PI) wells.

Well production is directly related to productivity index (PI) and reservoir pressure. Wells are qualitatively classified as low productivity or as high productivity. The high PI wells result in:

- High production rates.
- Low quantity of injection gas per barrel of liquid produced.
- High gas lift injection pressure required for deep, effective lift.

The high PI wells set the design criteria for the field gas lift system because the gas injection pressure must be high in order to reach a reasonable depth of injection, and the chosen pressure is more than adequate for the low PI wells.

However, the high PI wells present some design challenges:

- High rates require proper sizing to prevent excessive pressure loss in surface piping, valves, elbows, and manifolds which can cause significant loss of production potential when wellhead pressure is increased—a *facility design problem*.
- High pressure is needed to attain a deep lift point which might require a compressor discharge pressure matched to the wells—a *facility design problem*.
- High rates cause unloading valves to heat quickly which may cause premature closure, resulting in lift at a shallow valve—a *valve design problem*.
- Workover of a high PI well might cause damage (it acts as a low PI well) and a temporary, deep lift point is required until the well “cleans up” and the high PI is restored—a *workover fluids problem*.

The low PI well is easiest to design and reliably set valve pressures:

- The valves can be widely spaced.
- The unloading/flowing temperature range is small, thus an average temperature in the wellbore is adequate for the valve setting calculation.
- High injection gas pressure is still required to attain deep lift.
- Injection gas consumption per barrel of produced fluid is high.

The well testing and flowing surveys discussed in 3.2 should be used to identify the well characteristics. High PI wells benefit greatly from the expenditure for good wellbore pressure and temperature data obtained from flowing surveys, since close valve spacing and exact bellows pressure setting are desirable.

5.7 PERCENT WATER IN PRODUCED FLUID

The production rate often decreases with increasing water cut. This is due to the increase in the flowing fluid mixture density that in turn causes a decrease in the drawdown ($P_r - P_{wf}$).

Typically, the water fraction increase results in:

- Injection gas rate increase to maintain the fluid production constant.
- Oil rate remaining constant only if the total fluid rate is increased with larger tubulars (in capable wells) or if more wells are drilled.

A facility design problem arises as water-liquid ratio increases:

- An emulsion may form, which can be treated chemically.
- Gas lift gas comes from the flashing oil-solution gas mixture in the inlet separator.
- A declining oil rate reduces the amount of gas available for:
 - Make-up gas lift gas,
 - Compressor, dehydration regenerator, and utility fuel,
 - Start-up when the compressor is down.

When field water cut becomes relatively high (about 70%, or perhaps 50% if reservoir pressure has declined) a gas well or gas pipeline might be needed as the gas source for start-up (after compressor shutdown) and transition until the field production stabilizes. When field water is 90%, gas is lost due to solution of gas in the water, which could require an external source of gas.

The demand for gas as water increases can be predicted using the modeling techniques in 4.2.

5.8 SOLUTION AND FREE GAS IN PRODUCED FLUID

The required injection gas depends on the quantity of gas available from the formation. The solution gas in the reservoir oil is denoted by the *GOR*, or when water is included, the gas-liquid ratio (GLR). The total *GOR* is the sum of the solution gas quantity (dissolved in the oil phase) and the free gas in the multiphase mixture. The amount of gas in each category is a function of the reservoir fluid composition (from the PVT report) plus the pressure and temperature at the specific point in the tubing. The PVT data coupled with the methods in 3.1 can be used to better define the *GOR* and other formation fluid properties below the point of injection.

Gas lift gas quantity required is:

- Diminished when reservoir gas, or GLR, is high.
- Affected by the reservoir fluid composition which controls the bubble point pressure.
- Affected by the bubble point pressure of the gas lift gas and reservoir fluid mixture.

The general relationships between bubble point pressure and a gas lifted fluid mixture are:

- A higher bubble point fluid will:
 - Liberate free gas at a deeper point in the well.
 - Reduce density over a greater column length.
 - Reduce flowing bottomhole pressure unless low rates permit slippage and liquid holdup.
- A very low bubble point fluid:
 - Will absorb injected gas lift gas (and is indicated by a heating of the fluid in the flowing temperature survey).
- Bubble point at a given tubing temperature is changed by the injection of the gas lift gas (the gas changes the composition of the produced fluid).
- The bubble point change (with gas lift gas) alters the amount of free gas present which influences:
 - Flow regime.
 - Liquid holdup.
 - Mixture density.
 - Total pressure drop.

However, the interaction of the PVT properties with the phase behavior of the fluid is too complex for generalizations. The model methods and measured data for validation should be used to predict well performance and required gas lift gas. Bubble point correlations such as Standing or Lasater, coupled with other physical property correlations, will give reliable results if PVT reports and flowing surveys are used to calibrate the model.

Compositional models do not necessarily improve the accuracy of predictions because the quantities and properties of the heavy components (greater than C_7+) in the PVT report must often be assumed and these heavy hydrocarbons greatly influence the phase behavior and physical properties of the fluid.

5.9 OPERATING SEPARATOR PRESSURE

RECOMMENDED PRACTICE: Design the gas lift system with a low separator pressure in order to minimize backpressure on the wells.

Separation pressure should be low in order to achieve:

- Low flowing wellhead pressure.
- Prolonged natural flow.
- Highest production flow rate since flow increases as backpressure decreases.

- Reduced quantity of gas lift gas circulating (which reduces compression horsepower).

The methods in 6.1 can be used to link separator pressure (50 psig is a reasonable design objective) with gas compression horsepower.

Economic feasibility studies will define the exceptions or constraints:

- Low separator pressure might significantly increase flowing gas velocity and associated friction in the pipeline (flowline).
- Existing separator stages are linked to compressor suction/discharge stages.
- High separator pressure may be associated with the intake pressure of an existing compressor station.

Generally, additional compression should be evaluated using the modeling techniques of 4.2. Additional discussion of compressors and suction/discharge pressures is in 6.1.

5.10 WELLBORE DEVIATION

Deviated, or inclined, wells will often have a lower production rate or consume more gas lift gas than a vertical well due to additional pressure loss caused by friction and by slippage of gas:

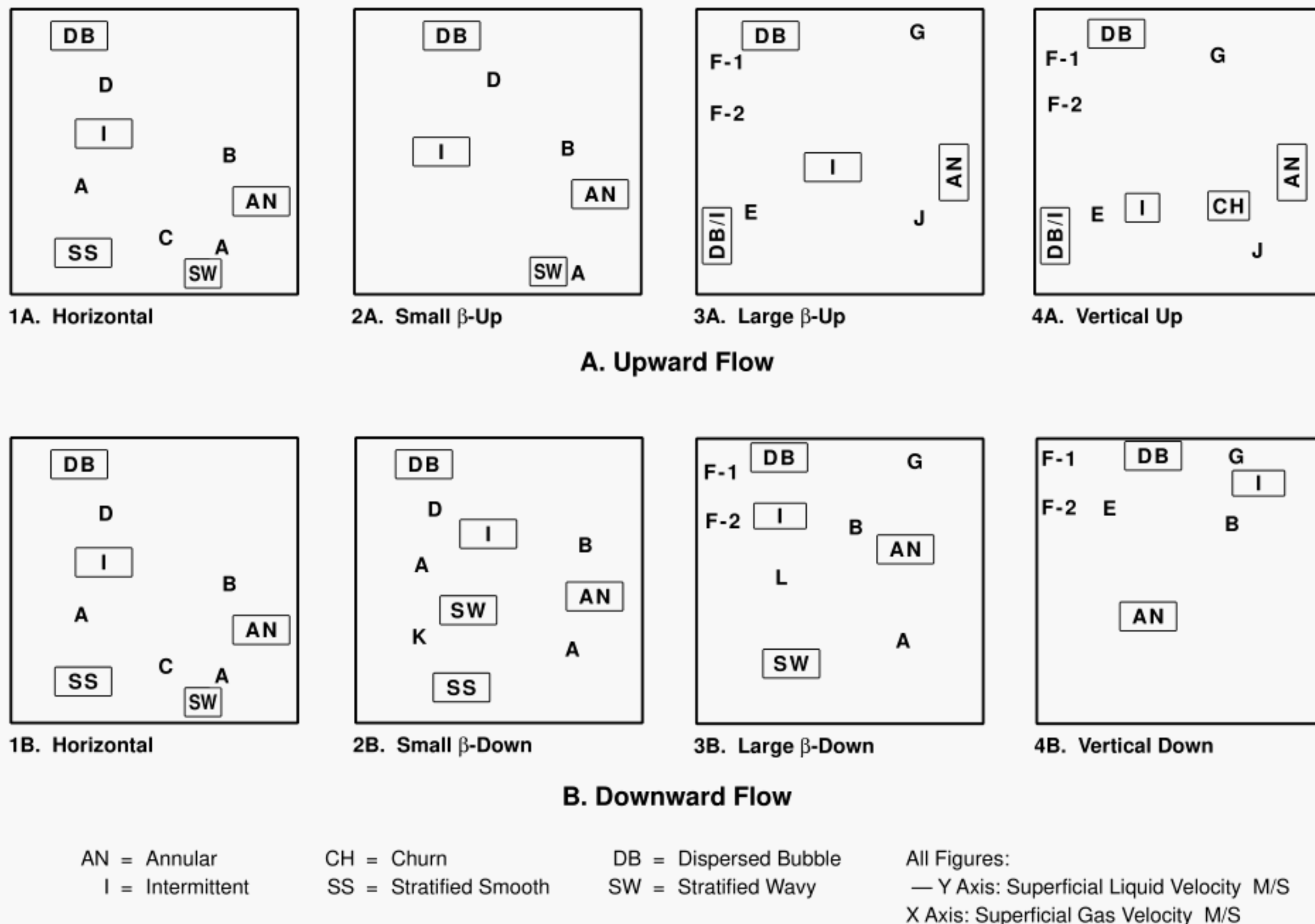
- Inclination affects mixture density due to changes in:
 - Flow regime.
 - Liquid holdup.
 - Slippage between phases.
- Pipe length (measured depth) is greater than a vertical well:
 - Friction pressure loss increases.

Figure 5-7 shows this flow pattern change with deviation angle.

The use of accurate fluid properties and choice of multiphase correlation is even more important for deviated wells. Obtaining measured data for validation can prove to have great economic benefits due to the high cost of repeated work to improve gas lift design on offshore deviated wells.

The well graphs and computer printouts often use MD as this aids installation and wellbore analysis (troubleshooting using flowing pressure surveys). However, the pressure gradient graph can appear abnormal in the highly deviated sections near the bottom of the well. This is caused by the effect of the deviation.

For purposes of graphical spacing of valves, a TVD vs. pressure graph is more helpful. Also, some prefer the true vertical spacing when troubleshooting the point of gas injection from a flowing survey.



Dukler & Taitel, "Flow Pattern Transitions in Gas-Liquid Systems Measurement and Modeling", *Multiphase Science and Technology*—Vol II 1986.

Figure 5-7—Flow Regime Change with Inclination Angle

6 Other Gas Lift Design Considerations

Other design considerations can have a profound impact on gas lift system effectiveness. The system design objectives should include:

- Reliable gas supply.
- Gas distribution to the wells that is free of restrictions or bottlenecks.
- Measurement and control for each well.
- Automating each well's gas injection rate to its production response and to system injection pressure.

RECOMMENDED PRACTICE: Facility engineers design the surface systems and downhole well-bore equipment designers set the gas rates and pressures required. The two groups should exchange information plus understand their impact on the others' operation.

Other specifications should also be obtained and reviewed. These include documents API Spec 11P *Packaged High Speed Separable Engine-Driven Reciprocating Gas Compressors*; API Spec 12GDU *Glycol-Type Gas Dehydration Units*; API Std 617 *Centrifugal Compressors for General Refinery Service*; Std 618 *Reciprocating Compressors for General Refinery Service*; and the GPSA *Engineering Data Book*.

6.1 GAS SUPPLY

One of the most important factors in a successful gas lift system is a reliable supply of dry, high-pressure gas, where both the supply pressure and the rate are stable. While the gas lift supply system is normally considered to be in the realm of the facility engineer, the gas lift well equipment designer must specify the well plus the system pressure and rate capabilities for deep, effective lift.

Gas supply can be from one or more high-pressure gas well(s), but most systems recycle low-pressure produced gas through compression and processing. Compressor start/stop

and the shutdown or start-up of big consumer wells can cause significant pressure fluctuation in the system, thus the designer should consider a control method to automatically and rapidly re-distribute gas to the wells when an upset in the system occurs. Treating is often used to remove water and, in some cases, heavy gas hydrocarbons or sour gas (H_2S or CO_2) contaminants.

PVT reports should be used to obtain reservoir fluid compositions. These data can be used in a computer process simulation of the flash of the fluid, plus gas lift gas, from reservoir to separator pressure/temperature conditions. The gas phase can then be compressed in the simulation model. The simulation results will give:

- Compositions of the gas and liquid phases at each point in the process.
- Condensation of liquids in the compression process (shrinkage of the gas).
- Sour gas components at each point in the process.
- Power requirement.

A. Compressor Power

The compression requirement represents one of the biggest costs in the gas lift facility and potentially requires the longest time in the construction process. The compressor(s) size and horsepower requirements are a function of:

- Gas rate.
- Suction pressure.
- Discharge pressure.

The gas rate, discharge pressure, and suction pressure operating requirements can be estimated using the modeling techniques of Section 4. Once the gas rates and pressures for the individual wells are studied and established, the highest values can be used to set the compressor discharge requirements. With the rate and discharge to suction pressure ratio, the compressor horsepower can be obtained.

The overall total compression ratio (pressure ratio) of discharge to suction pressure is:

$$r_t = \frac{P_d}{P_s}$$

where:

r_t = overall total compression ratio,

P_d = discharge pressure from compressor (psia),

P_s = suction pressure to compressor (psia).

Figure 6-1 provides a quick estimate of the required gas compression brake horsepower per million standard cubic ft of gas lift gas (BHP/MM) as a function of the overall compression ratio, r_t .

The BHP/MM is used to calculate the horsepower:

$$BHP = (BHP/MM) \times (P_b/14.6) \times (T_s/520) \times Z_a \times Q_{gl}$$

where:

BHP = gas compression horsepower,

BHP/MM = horsepower per million scf from Figure 6-1,

P_b = pressure base (psia),

T_s = suction temperature ($^{\circ}$ Rankin, where $^{\circ}R = 460 + ^{\circ}F$),

Z_a = gas compressibility (deviation) factor at average conditions,

Q_{gl} = gas lift gas required (million scf/d or mmscf/d).

The compression ratio for each stage must also be calculated since interstage cooling is required. The solution is trial and error and a reasonable answer is obtained when the ratio per stage is between 2.0 and 3.5. The discharge temperature from a stage is the limiting factor for each stage's compression ratio. The *GPSA Engineering Data Book* can be used to calculate it.

The relationship of the compression ratio per stage to the number of stages is:

$$r_{stg} = [r_t]^{1/n}$$

where:

r_{stg} = per stage compression ratio (discharge/suction pressure for each stage),

r_t = overall total compression ratio,

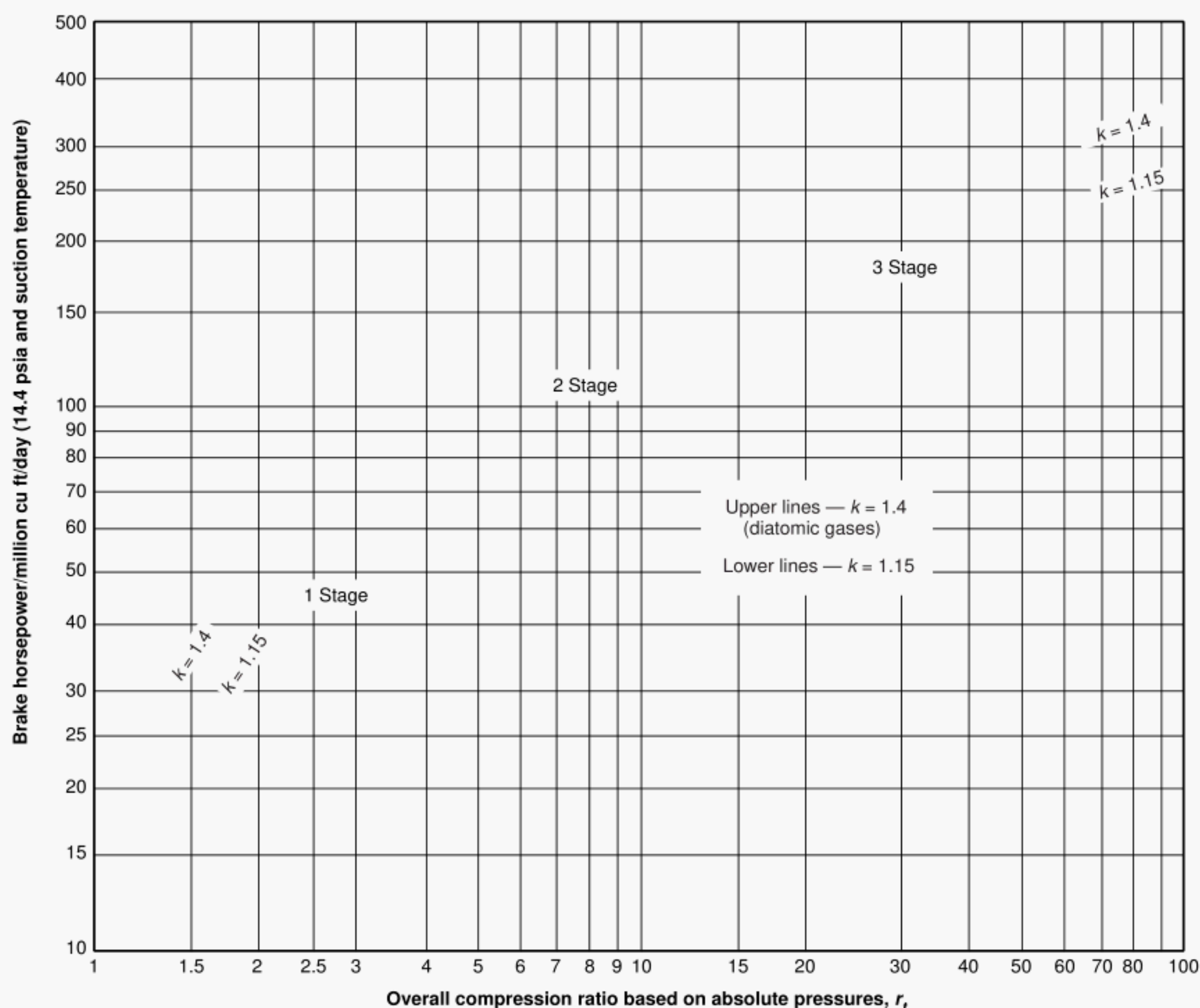
n = number of stages (1, 2, or 3 are the usual number of stages).

API Spec 11P, API Std 617, API Std 618, and the *GPSA Engineering Data Book* are sources for design and operation of compressors.

The gas engine or gas turbine horsepower installed to drive the compressors is often the limitation to gas throughput capacity. The BHP calculated above is an estimate of the gas compression power and 10% – 30% power should be added to compensate for on-site operating conditions, such as hot temperatures in summer, or utilities, or air cooler fans driven by the engine/turbine.

B. Suction Pressure vs. Gas Lift Gas Requirement

The required gas lift gas rate decreases if compressor suction pressure (and separator pressure) is lowered and a corresponding wellhead pressure reduction is obtained. Figure 6-2a and 6-2b portray the production rate vs. IGLR curve representing the gas needed to produce a target production



GPSA Engineering Data Book

Figure 6-1—Brake Horsepower per Million cu.ft/day vs. Overall Compression Ratio

rate. Each curve is for a separator pressure (the suction pressure would be about 10 psi less if the compressor station is adjacent the separator station).

A target rate of 3000 stb/d requires less gas at lower separator pressure and the required gas increases with separator pressure. Alternatively, the IGLR could be held constant at 500 scf/stb and the rate produced at each separator pressure could be estimated.

Similarly the low PI well in Figure 6-2b shows the effect of separator pressure (suction pressure). The gas required to attain 500 stb/d increases as separator pressure increases. The optimum injection gas, viewed on a IGLR basis, should be the criterion for the “best” suction pressure.

The production delivery data can also be viewed based on the injection gas pressure that is directly linked to injection depth if the valve pressures are set correctly. Figure 6-3 shows the drastic change in production rate capability if

higher injection pressure permits a correspondingly deeper injection. The relationship between depth and injection pressure is obtained from the equilibrium curves in Figures 5-1 and 5-2.

A procedure to optimize compression horsepower (BHP) is:

1. Obtain the compression horsepower per million standard cubic ft of injection gas from Figure 6-1 for a calculated total compression ratio (discharge/suction). For this example the operating injection pressure is used. The discharge pressure is the added pressure decline for each unloading valve (25 psi per valve) plus the line loss from the compressor to the well.
2. Obtain the injection gas per barrel (IGLR) for a specific rate (or rate can be obtained for a specific IGLR) from Figure 6-2.

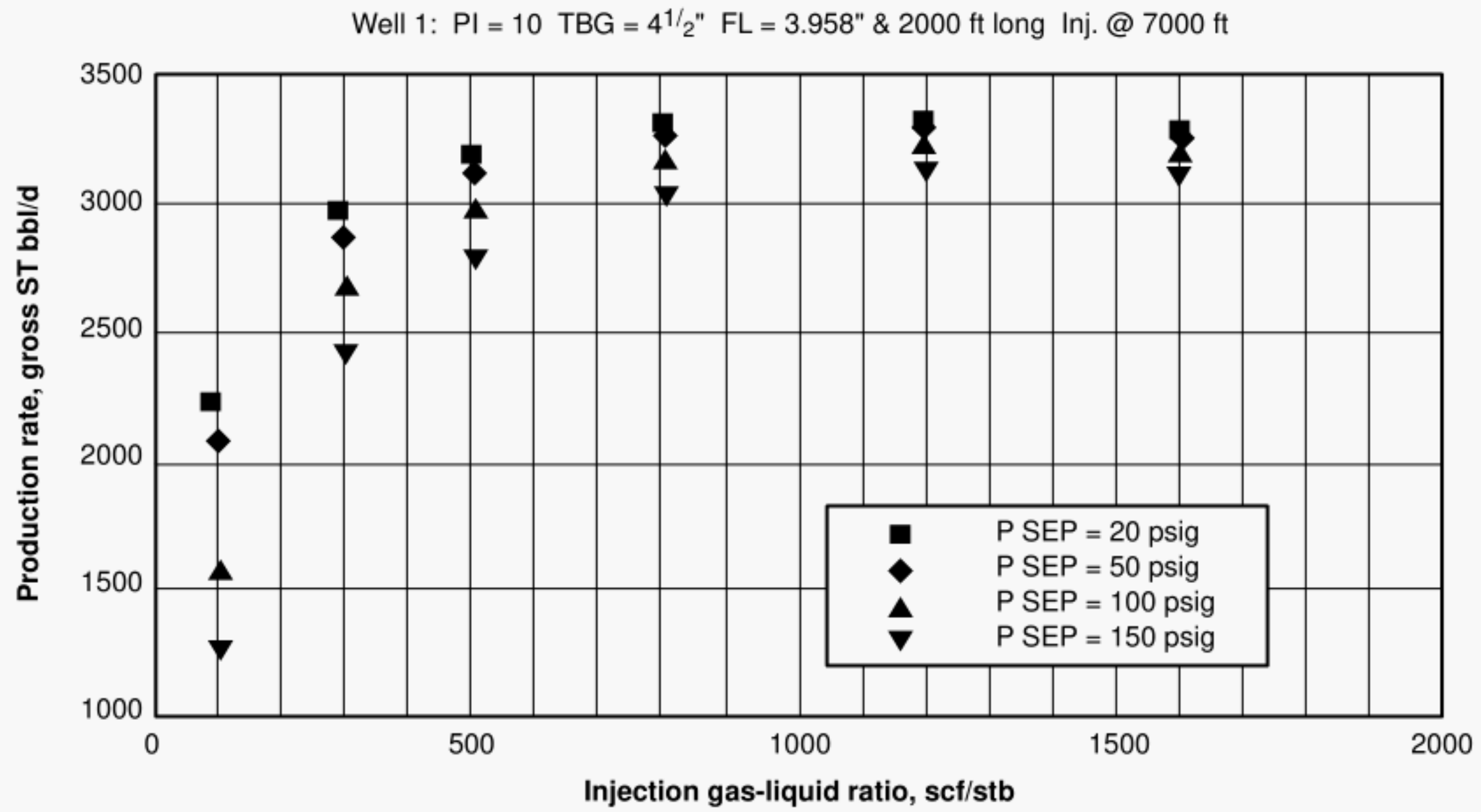


Figure 6-2a—Production vs. Injection Gas and Separator Pressure, High PI

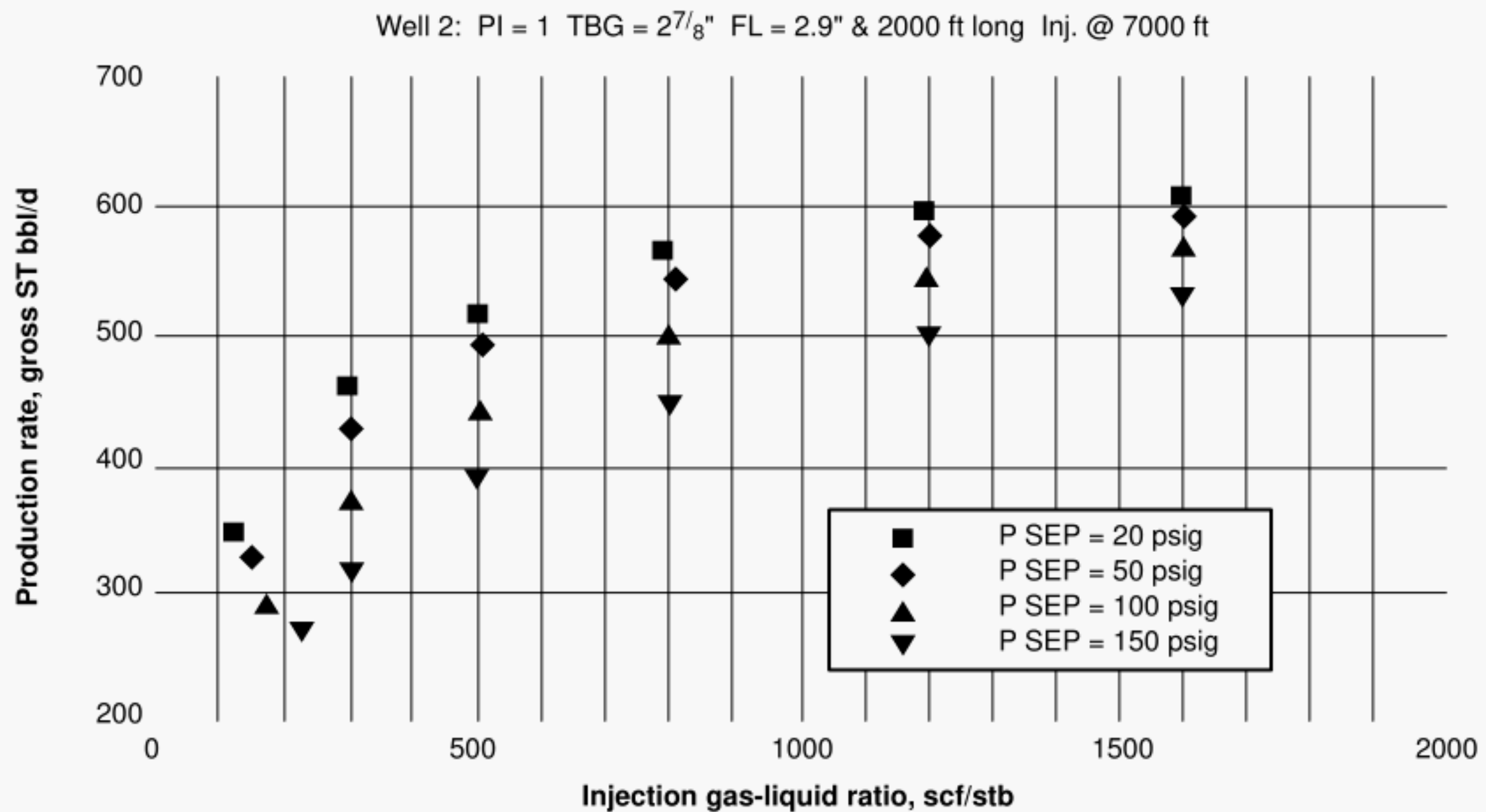


Figure 6-2b—Production vs. Injection Gas and Separator Pressure, Low PI

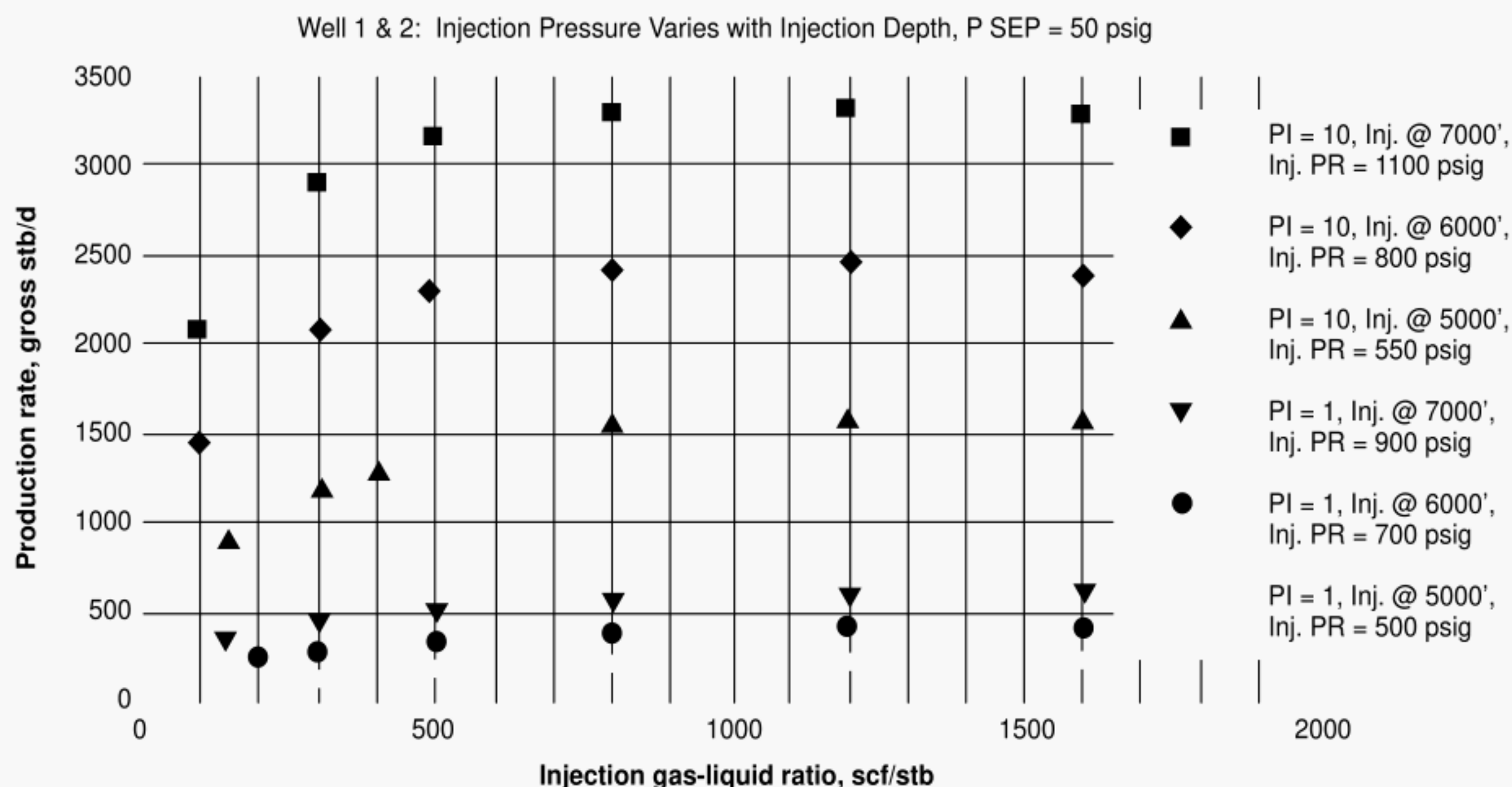


Figure 6-3—Production vs. Injection Gas and Injection Pressure

- Use the two sets of data to obtain BHP/stb. The discharge pressure (P_d) is held constant for the range of suction pressures. Table 6-1 shows the variation in BHP/stb vs. suction pressure for the example wells.

The optimization of brake horsepower per stock tank barrel of produced liquid is shown in Figure 6-4 for the high PI and for the low PI well. This data is for a specified injection pressure and the procedure above would be used for a different value.

RECOMMENDED PRACTICE: Suction pressure (separator pressure) effects should be modeled to calculate the potential gas lift gas and associated horsepower requirement. The model should consist of the flowline and wellbore data. The IGLR required to meet a specified target production rate should be calculated for a range of suction pressures.

The model, based on Section 4 methods, employs the same data used to establish gas lift deliverability:

- Flowline dimensions and length.
- Wellbore tubular data.
- PI.

These data should be considered when evaluating the cost benefit of various system pressures, because lowered suction pressure reduces compressor power until a reversal is observed. The reversal is due to wellhead pressure increase related to the gas expansion at low pressure and ensuing friction pressure loss that counteracts the benefit.

The curves discussed above vary with system components, but generally:

- High PI wells benefit more than the lower productivity wells.
- High injection pressure enables deeper lift and improves effectiveness.
- Model techniques can be used to indicate what combination of suction pressure and injection gas rate produces the lowest compression horsepower.

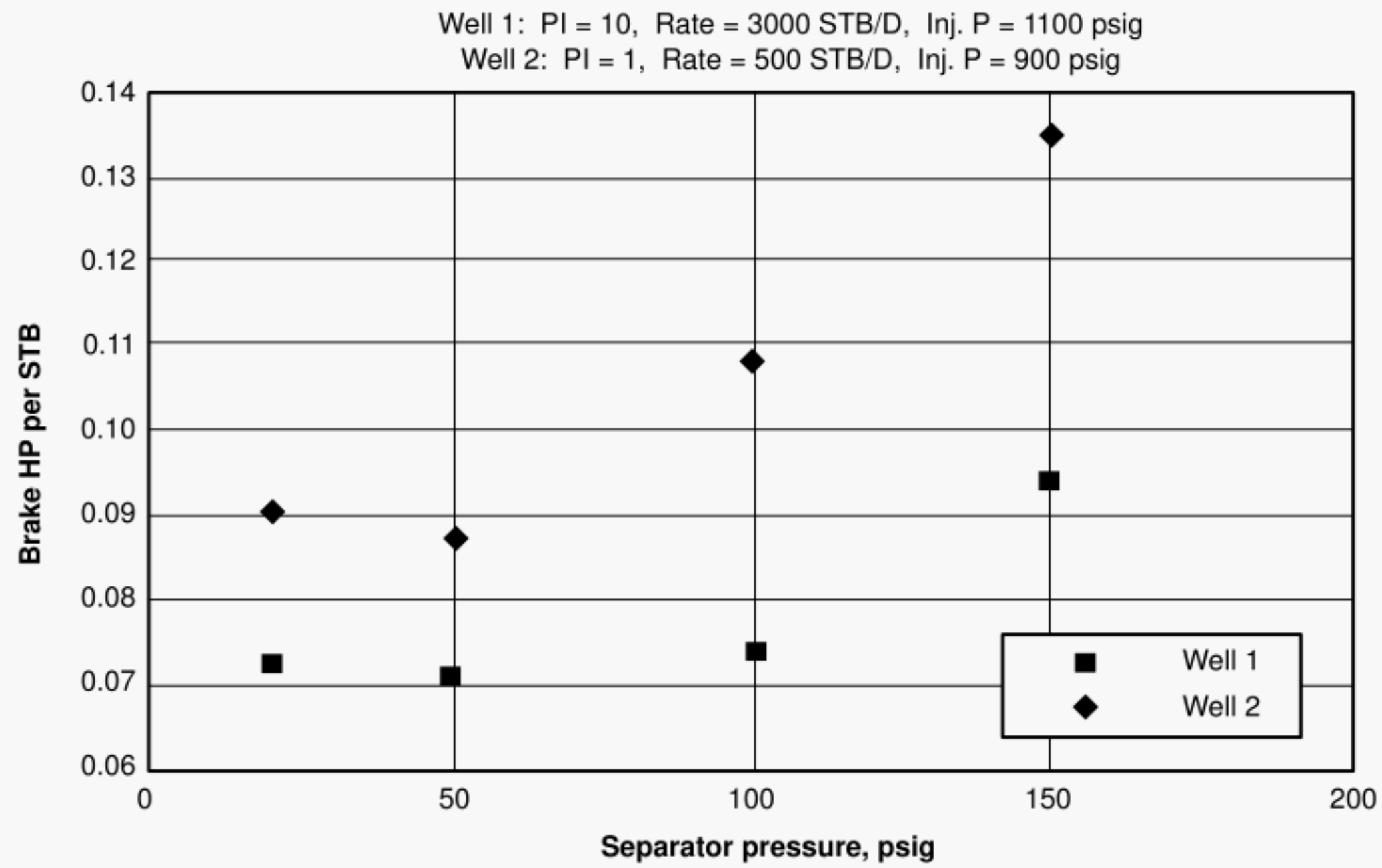


Figure 6-4—Compressor BHP/STB vs. Separator Pressure

Table 6-1—Brake Horsepower Per STB vs. Separator Pressure

High PI Well = 3000 STB/D at Injection Pressure = 1100 psig						
P SEP PSIG	P SEP PSIA	INJ PR PSIA	COMP RATIO	POWER BHP/MM	IGLR SCF/STB	BHP/STB
20	35	1115	31.9	225	320	0.0720
50	65	1115	17.2	185	380	0.0703
100	115	1115	9.7	148	500	0.0740
150	165	1115	6.8	125	750	0.0938
Low PI Well = 500 STB/D at Injection Pressure = 900 psig						
P SEP PSIG	P SEP PSIA	INJ PR PSIA	COMP RATIO	POWER BHP/MM	IGLR SCF/STB	BHP/STB
20	35	915	26.1	215	420	0.0903
50	65	915	14.1	170	510	0.0867
100	115	915	8.0	135	800	0.1080
150	165	915	5.5	112	1200	0.1344

C. Gas Dehydration

RECOMMENDED PRACTICE: Gas lift gas should be dehydrated to minimize water condensation that causes hydrates or corrosion in the piping system. Design for winter conditions since greater condensation occurs.

Gas processed in a plant is the best source of gas lift gas because both heavy gas hydrocarbons and water have been removed. However, in most field processing facilities, only dehydration is utilized to remove most of the water.

Dehydrator size is related to the water content of the gas prior to treatment and of the gas at a design temperature representing a cold temperature due to gas expansion. Water content of hydrocarbon gas, Figure 6-5 is based on laboratory data.

Typical field operating data is used to illustrate the variation in water content in gas at different points:

1. Gas lift gas after the compressor discharge cooler, at 1000 psia and 120°F, contains 100 lb. water per million scf of gas.
2. Field experience shows that cool days and gas expansion through the choke or control device reduces the gas temperature to 40°F.
3. Water content is 10 lb. per mmscf at 40°F and 1000 psia.
4. Dehydrator design is set at 10 lb. water per mmscf which gives a dew point (water condensing temperature) of 40°F.
5. The dehydrator would have to remove 90 lb. water per mmscf.

The 100°F is the dew point at discharge after the cooler and 40°F is the desired dew point in the field. The dew point depression required is 100°F – 40°F or 60°F.

Triethylene glycol (TEG) liquid dehydration units are the most commonly used. These field units typically circulate 3 gal TEG per lb. water removed. Thus for our example data, a 1 mmscf/d gas lift gas rate would require:

$$\text{TEG circulation} = 1 \text{ mmscf/d} \times 90 \text{ lb. water removed / mmscf} \times 3 \text{ gal TEG/lb. water}$$

$$\text{TEG circulation} = 270 \text{ gal/day or approximately } 0.2 \text{ GPM (gal per min.)}$$

The glycol contactor tower (absorber with trays) would have the following approximate capacities at 1000 psi processing pressure:

$$1 \text{ ft diameter} = 3 \text{ mmscf/d capacity}$$

$$2 \text{ ft diameter} = 12 \text{ mmscf/d capacity}$$

$$3 \text{ ft diameter} = 27 \text{ mmscf/d capacity}$$

The *GPSA Engineering Data Book* and API Spec 12GDU should be consulted for more information on glycol dehydrators.

Solid desiccant (dry bed) units are less commonly used for field dehydration. This type is more commonly applied in gas plant processing of gas where TEG is used upstream. The solid desiccant is used for large dew point depression and clean gas. It is not often used for gas lift since the condensate, heavy gas hydrocarbon normally found in low pressure gas, or lube oil from the compressors will foul the desiccant. If those constituents are removed, and a good scrubber to remove liquid water is used, then this method is feasible.

The common solid desiccants are:

- Activated alumina or aluminum oxide.
- Silica gel.
- Molecular sieves which are designed to remove specific particles. The 4A (four-angstrom) size is used for water vapor.

The dry bed system has at least two towers:

- One is in service dehydrating the gas stream.
- One is being regenerated (water removed from the desiccant) by a hot gas side-stream.

The side-stream gas is heated to 450°F – 550°F by a salt bath heater or by a turbine heat recovery unit and then flowed up through the regenerating tower. The hot, water saturated gas is cooled to condense the water, which is removed in a separator, and then the side-stream is returned to be dehydrated. The *GPSA Engineering Data Book* should be consulted for more information.

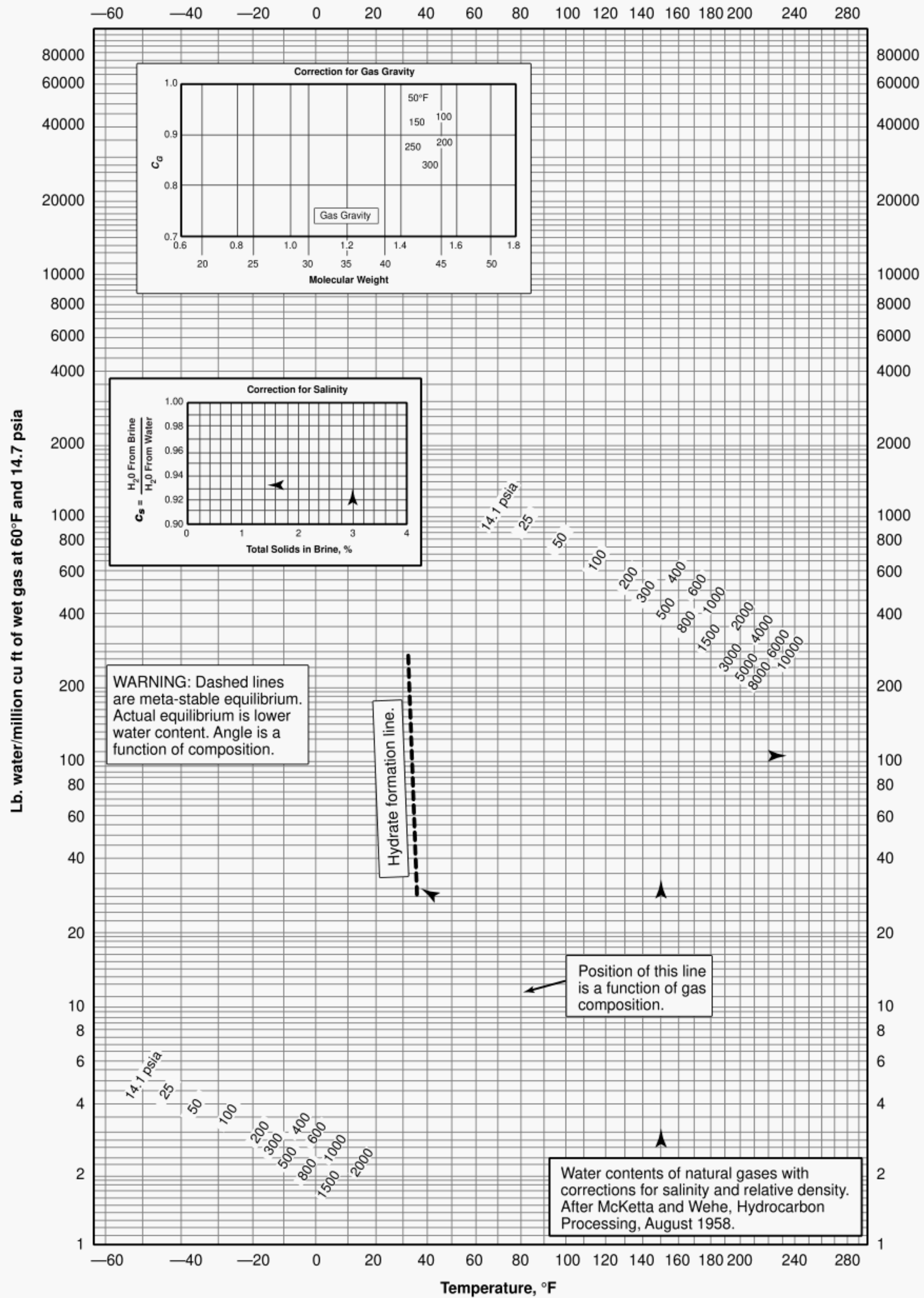


Figure 6-5—Water Content of Hydrocarbon Gas

D. Chemical Additives

Chemical additives that could be used in the gas lift gas are:

- Methanol to inhibit hydrates.
- Corrosion inhibitors (gas-soluble or gas-dispersible).
- Emulsion, paraffin, or asphaltine breakers or dispersers.

RECOMMENDED PRACTICE: Chemical additives in the gas lift gas should be tested to insure that they do not cause solid or gummy precipitates in the gas stream which could plug the chokes, control valves, meters, pipelines, casing, or gas lift valves.

Methanol absorbs water and this action reduces free water and minimizes hydrates during freezing temperature conditions. The effect is called dew point depression, which is a lowering of the water condensation temperature. The cold temperature and the corresponding pressure that can cause hydrates is given in Figure 6-6. Note that the example gas has been dehydrated but has a potential hydrate problem at 40°F and 1000 psia (40°F is the dew point after dehydration). On cold winter nights the gas temperature is likely to drop to 30°F and “freeze” at the choke. There are four choices:

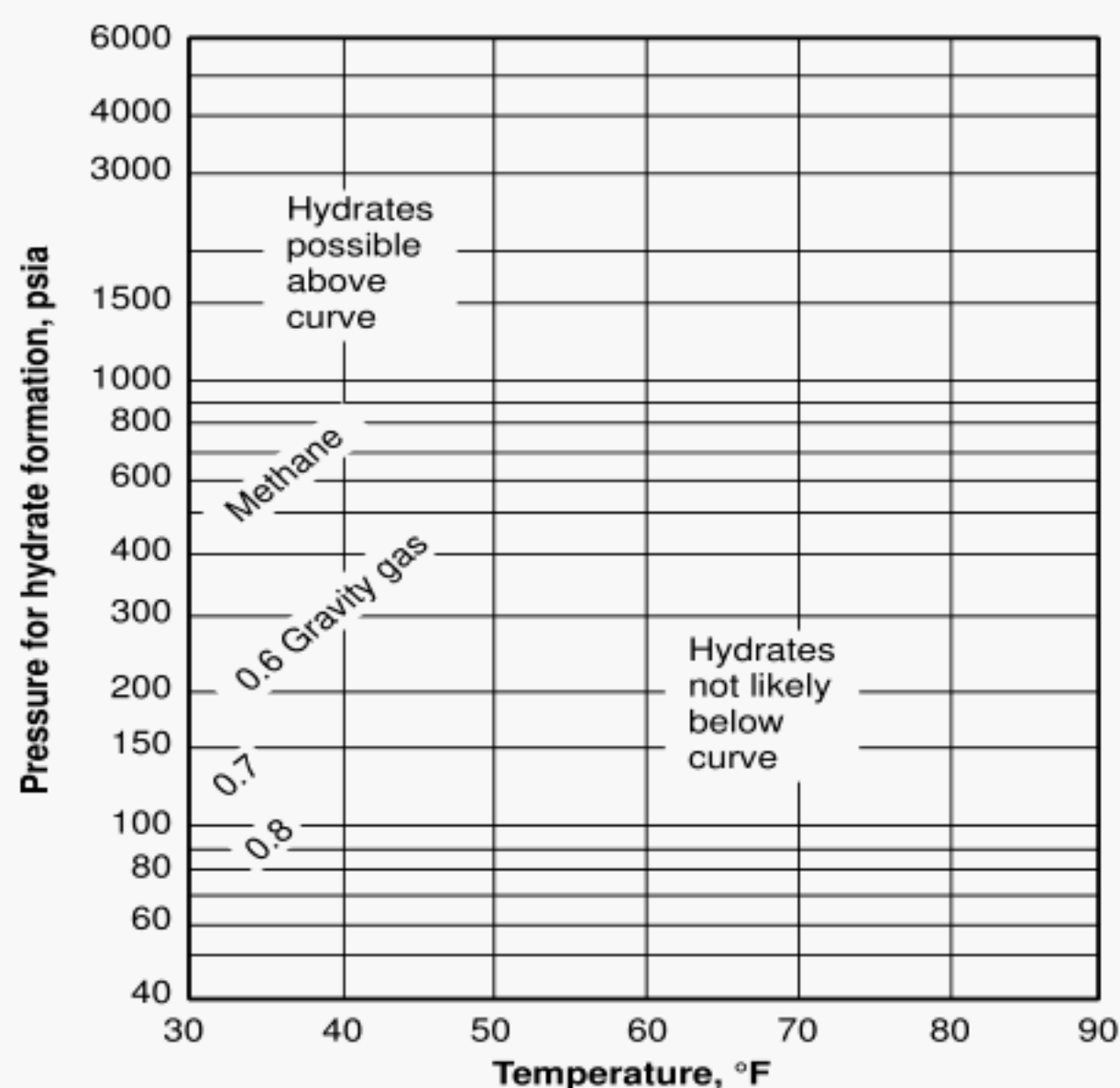
1. Do nothing and let the well die temporarily until the gas temperature warms.
2. Add a heater—either a line heater to heat the gas, or production fluid/gas heat exchanger just upstream of the control device to warm the gas (the produced fluid must be 30°F – 60°F hotter than the gas for effective heat transfer), or a catalytic heater to warm the choke body.
3. Improve the dehydrator to remove water to a 30°F dew point (7 lb. water/mmscf gas).
4. Inject methanol to depress the hydrate point from 40°F to 30°F.

Methanol injection is routinely used since it is effective and readily available but used only on the coldest nights to avoid the cost. Sufficient methanol is needed to:

- Inhibit the water phase, and
- Vaporize into the gas phase.

Methanol required in the water phase is a function of the hydrate point depression. The *GPSA Engineering Data Book* gives the weight percent concentration required:

$$I = (3200 \times d) / (2335 + 32 \times d)$$



CAUTION: Figures 20-15 through 20-17 (in *GPSA Engineering Data Book*) should only be used for first approximations of hydrate formation conditions. For more accurate determination of hydrate conditions make calculations with K_{V-S} .

GPSA Engineering Data Book

Figure 6-6—Pressure-Temperature Curves for Predicting Hydrate Formation

where:

- I = weight percent methanol in water (%),
 d = hydrate point depression (degrees F).

For our example:

1. The hydrate point depression: $d = (40^\circ\text{F} - 30^\circ\text{F})$ or 10°F.
2. The water condensed by the cold temperature is the difference in saturation at each point:
 - 10 lb. water per mmscf at 40°F dehydration dew point,
 - 7 lb. water per mmscf at 30°F cold weather dew point,
 - 3 lb. water per mmscf is condensed.
3. The required concentration of methanol in the water for $d = 10^\circ\text{F}$ is:

$$I = (3200 \times 10) / (2335 + 32 \times 10) = 12.1\%.$$

4. The methanol plus condensed water = 100% of the liquid.

5. The methanol is 12.1% and the remaining 87.9% is water. The water amount is 3 lb. condensed water per mmscf of gas.
6. The 12.1% methanol required for the liquid phase is 0.4 lb. methanol per mmscf [from $(3 \text{ lb.}/0.879) \times 0.121$].

Methanol required to vaporize to the gas phase will be approximately 1.0 lb. methanol per mmscf per each weight percent concentration in the water phase (at gas lift gas operating conditions).

At our example conditions:

1. The methanol in the gas phase is 1 lb. per mmscf per % \times 12.1% = 12.1 lb. methanol per mmscf.
2. The sum of methanol required is:
 - 0.4 lb. per mmscf in the water, plus
 - 12.1 lb. per mmscf in the gas, for a
 - total of 12.5 lb. methanol per mmscf.
3. Methanol density is 6.6 lb./gal, thus 1.9 gal per mmscf of gas lift gas are needed.

Methanol injection pumps (chemical pumps) are located on the distribution pipelines at spots where water might condense and collect, or at gas injection chokes where freezing has been a problem in the past.

Corrosion inhibitors must be soluble or dispersible in the gas phase for effective distribution in the injection gas through the downhole valve. The chemical manufacturers should be consulted and a reservoir fluid composition, a gas lift gas chromatograph composition, and the operating pressures and temperatures should be provided. Water from condensation or hydrostatic testing usually remains in the piping system and, without chemical inhibition, corrosion will occur, especially if CO_2 or H_2S are present.

Emulsion, paraffin, or asphaltine breakers or dispersers must similarly be gas soluble or dispersible for effective downhole placement. This method of chemical distribution can reduce emulsion viscosity and solids deposition in the tubing or flowline that cause pressure loss or plugging.

6.2 GAS LIFT GAS DISTRIBUTION SYSTEM

The configuration of the lift gas distribution system can have a significant impact on the choke/control strategy that is used, and on the impact that the individual wells in the system can have on one another. The gas lift system designer should study pipeline configuration options and streamline the system to provide for the highest pressure and steadiest gas flow to the well. An automation system to control gas injection rate should be considered to counter the effect of pressure distur-

bances caused by compressor or well start-up and shutdown, or by cyclic gas consumption.

In addition, the process simulation techniques of 6.1 should be used to predict gas composition and potential liquid condensation in the piping system. A gas rich in heavier hydrocarbons (propane, butane, and pentane) might require an additional step of gas processing to reduce these components and minimize condensation in the distribution system. An alternate approach is to maintain the heavier components in a gaseous dense phase by use of a high system pressure (a pressure greater than the maximum pressure of the two phase gas-liquid region of the specific gas composition). If condensation is a predicted problem, then the capital and operating costs of the alternative methods should be evaluated.

RECOMMENDED PRACTICE: Gas lift gas distribution piping should be designed to:

- Minimize pressure loss from the compressor to the well to 100 psi or less.
- Provide individual well measurement and control.
- Have sufficient pipe volume to dampen pressure surge, which will minimize interference from one well to another.
- Provide liquid condensate removal with drain pots at low points or pigging capability on larger pipelines.

A. Trunk Line System

Figure 6-7 shows the trunk line gas injection system. Large diameter gas pipelines connect the compression plant with the smaller lines that distribute gas to the wells.

The main pipelines should be as large as economically possible. Good gas lift operation requires steady supply pressure, and the storage effect of large diameters aids this objective. If the reservoir pressure of the wells will decline rapidly and intermittent lift is envisioned, then the larger diameter will reduce the fluctuation effect of one well on the operation of other wells.

B. Spider System

The spider system is a direct pipeline connection from the compressor station to the well. Its advantage is that any pipeline problem affects only one well and not the whole distribution system. The method is most applicable to small systems with relatively short distances from the wells to the compressor. This option is not recommended for a large number of wells because the total pipe footage and associated cost is more expensive than the trunk line or manifold type distribution method.

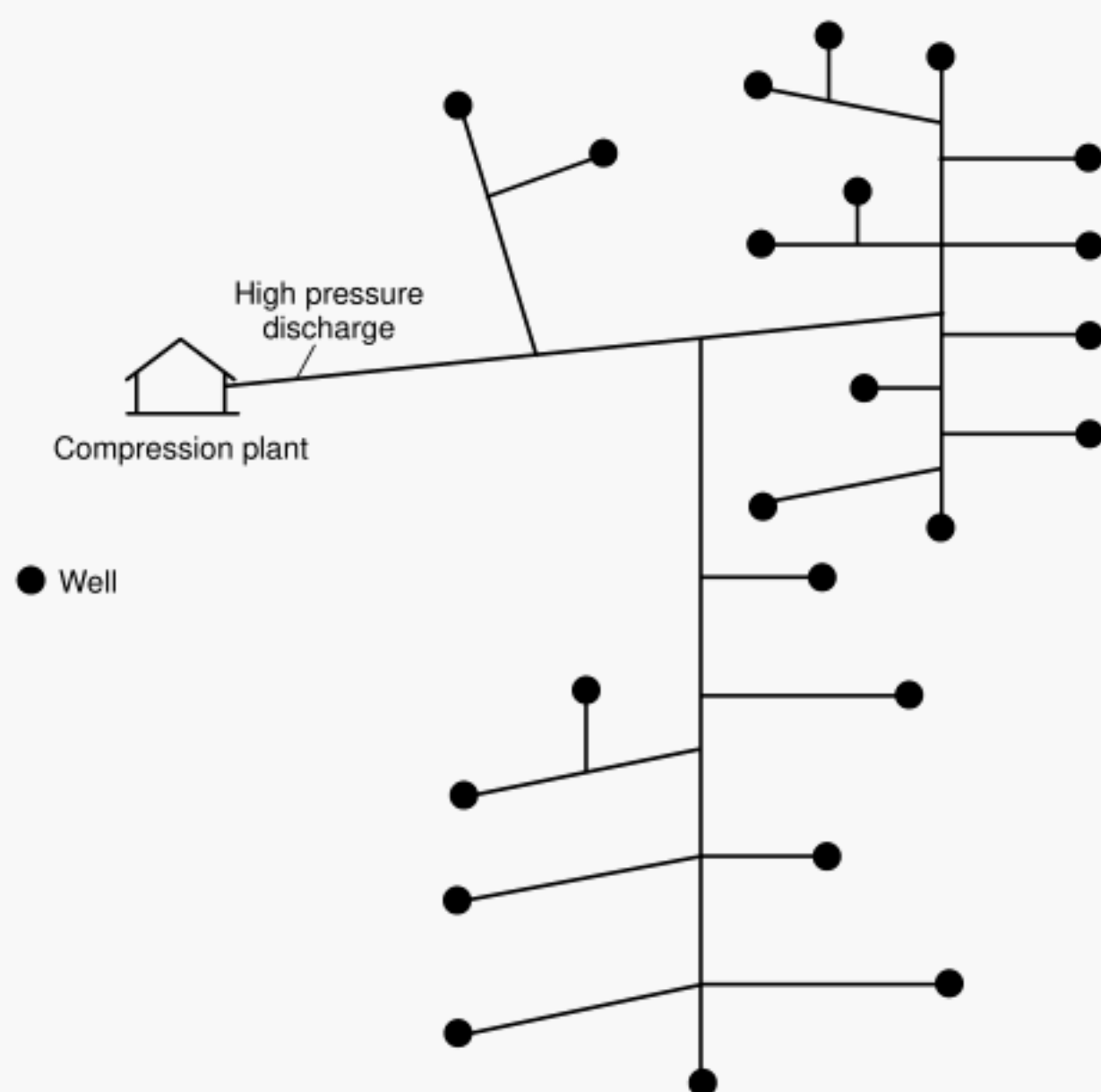


Figure 6-7—Trunk Line Piping Distribution

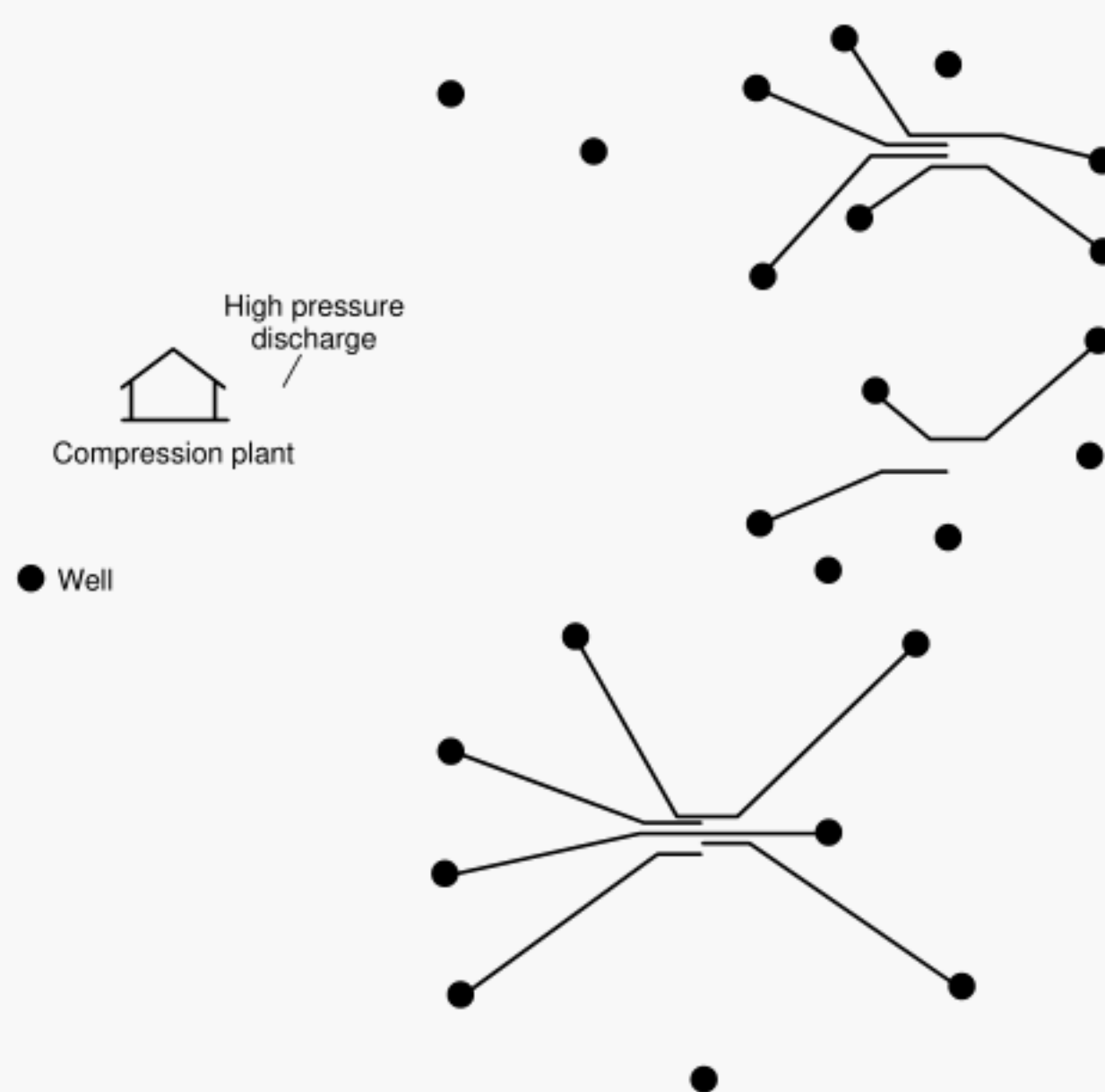


Figure 6-8—Combination Piping Distribution

C. Combination System

A combination of both manifolds and trunk lines are found in the typical field, Figure 6-8. This occurs when one section of the field is developed with numerous new wells and the best alternative is a main pipeline plus a manifold with wells connected to it. Manifolds save on total pipe length and centralize operations such as gas flow measurement and control. The number of manifolds to be installed will depend on the total surface area of the field and the number of wells. Other parts of the field may be developed more slowly with sub-main pipelines and the wells are directly connected to the mains or sub-mains. When the development phase is over, several main pipelines, sub-main pipelines, and manifolds will be installed. The wells will be served by several options:

- Connected to manifolds on the main.
- Directly connected to the main pipeline.
- Directly connected to sub-main lines.

Another combination method is the very large system serving a large anticline reservoir structure with wells around the periphery. The elliptical geometry leads to a ring main pipeline system as the method to reduce pipeline footage. Compressor stations and manifold distribution points are attached to the ring main. The advantage is that one compressor unit out of service may not significantly disturb the operation. The disadvantage is that a whole station shutting down can cause the system to lose pressure and shutdown, unless automated

controls at the wells are used to restrict and redistribute the available gas.

“Telescoping” or “piggy-backing” should be avoided. This denotes laying a small (e.g., 2 in.) line to serve one well, then extending the small line to serve a more distant well, etc. This results in:

- Interference between wells due to the small line diameter.
- Shortage of gas to the last well(s) on the extended line, which reduces production.

The preferred method is:

- Estimate field size, extend a sub-main line of larger diameter (e.g., 4 in.) to the midpoint.
- Install a manifold.
- Use smaller (e.g., 2 in.) connection lines to the wells (if telescoped lines are installed, the original 2 in. line can be taken up and reused).

This method provides steadier gas supply and the increased production pays the cost.

6.3 INJECTION GAS MEASUREMENT AND CONTROL

Effective gas injection measurement and control capability is a fundamental design objective. Gas lift valve design success is improved when a measuring device controls the well's injection gas rate. Gas lift optimization depends on the ability to measure

and control the distribution of gas among a group of wells based on each well's performance and gas system pressure.

RECOMMENDED PRACTICE: Gas lift gas measurement and control equipment should be:
Installed on each well's injection line at the manifold or at the wellhead.
Monitored for gas rate allocation in a effort to maximize oil production.
Automated for data gathering which permits analysis and, by use of calibrated delivery models, injection at an optimum rate.

A. Gas Measurement Methods

Gas flow rates are measured by various methods, but by far the most widely used is the orifice plate due to its low cost and simplicity. Several lift gas measurement options are:

- Turbine meter,
- Vortex shedding,
- Orifice plate.

Turbine meters have some advantages that should be considered:

- A 15 to 1 flow (maximum/minimum rate) ratio.
- Good accuracy when used in steady, non-surging, clean flow.
- Linear scale.
- Digital, pulse count output.

Turbine meters must be sized to operate above the manufacturer designated minimum spin speed, they need calibra-

tion, and the gas flow must be free of solid particles that might damage the blades. The gas rate must be **very steady** for reliable measurement since the manufacturers do not recommend the gas turbine meter for slugging conditions often found at the production or test separator, or in surging gas lift wells.

Vortex shedding meters have some advantages:

- A 100 to 1 flow (maximum/minimum rate) ratio.
- No moving parts and are not as affected by solids as are turbines.
- Digital, pulse count output.

Orifice plate meters consists of a plate and holder installed in the gas line, Figure 6-9, with two pressure taps (upstream and downstream of the plate). The flowrate is proportional to the square root of the pressure differential across the plate. The flow ratio is 3:1 but can be increased with two different ranges on the differential pressure sensor.

The accuracy of the orifice meter is $\pm 1\%$ to $\pm 2\%$ when the gas is dry and the rate is steady. The surging pressure found in gas injection systems reduces accuracy to $\pm 5\%$ while slugging at separator measuring points will reduce it to $\pm 10\%$.

The orifice plate measurement calculation plus guides for application and installation are given in the GPSA *Engineering Data Book* or in the following API standard.

RECOMMENDED PRACTICE: API MPMS, Chapter 14—*Natural Gas Fluids Measurement*, Section 3—*Concentric, Square-Edged Orifice Meters* should be used to calculate the gas flow rate using orifice plates. Construction specifications should also adhere to this standard.

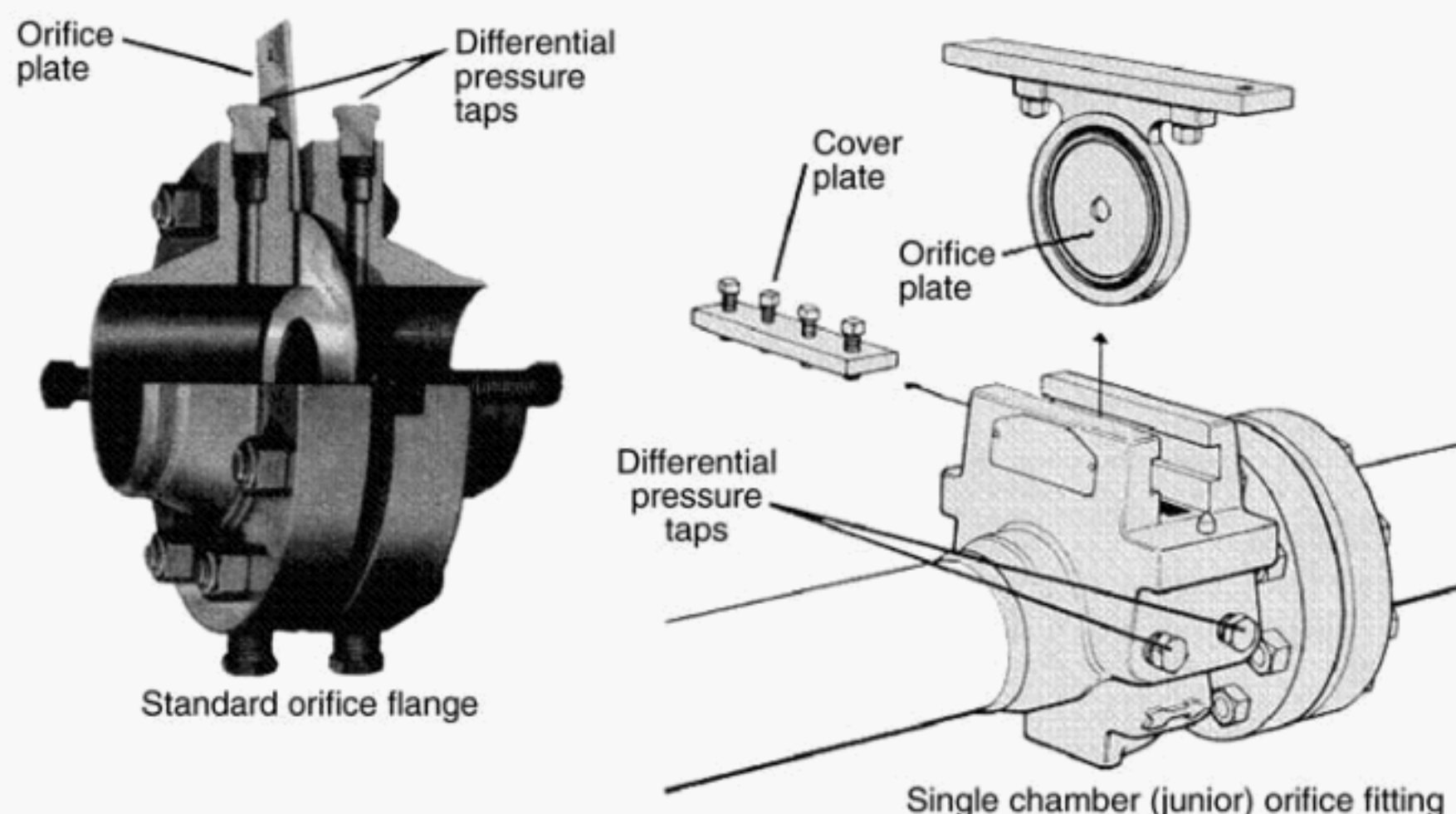


Figure 6-9—Orifice Plate and Meter Run Fitting

This API standard was written in conjunction with the American Gas Association (AGA) and the Gas Processors Association (GPA). It has been approved by the American National Standards Institute and is available as ANSI/API MPMS 14.31-1990. All of these standards are identical but each has their own designation number:

- API MPMS, Chapter 14—*Natural Gas Fluids Measurement*, Section 3—*Concentric, Square-Edged Orifice Meters*
- AGA Report No. 3, Part 1
- GPA 8185-90, Part 1

Pressure differential at the orifice plate is measured with a pneumatic bellows or an electronic differential pressure transmitter. The device is connected to the flange taps to sense the pressure differential across the orifice plate.

RECOMMENDED PRACTICE: Gas flow differential pressure measurement bellows or transmitter should be:

- Placed above the gas line.
- Connected with instrument tubing free of loops that could trap liquids.
- Equipped with local indicator to aid well-site unloading or troubleshooting.

B. Gas Injection Rate Control Methods

RECOMMENDED PRACTICE: Gas flow for each well should be controlled with an:

- Adjustable manual choke, or
- Flow rate controller and actuated choke.
- The control valve should be downstream of the orifice plate to minimize measurement error.

Manual control with an adjustable choke valve is the most widely used method for continuous gas lift operation. The gas flow rate is adjusted to give the desired production flow rate. Usually installed at the wellhead, the choke can be located anywhere along the gas injection line.

Automatic control of gas rate can be used to improve allocation and resulting oil rate. The choke/actuator uses an electronic controller to monitor and control gas rate based on preset limits or control logic. If possible, the controller should be connected via a communication link to the operations center and computer. All new gas lift systems should be installed with automated gas measuring and injection control equipment.

Measurement error is minimized when the control choke is located downstream of the orifice plate. Hydrates (due to pressure drop cooling), turbulence, or casing pressure fluctuation downstream of the choke could cause interference and affect accuracy.

Choke control (not timer control) can also be used for intermittent gas lift. In this case the flow rate through the control choke determines the cycle time (time for casing pressure build-up to open the intermittent gas lift valve). The spread of the gas lift valve and the annulus size primarily determines the volume of gas injected per cycle.

Time cycle control with an actuated surface control valve is more common for intermittent gas lift. The controller opens the valve at regular intervals to inject gas for a predetermined amount of time. This open time is adjusted to control the gas rate injected in each cycle.

C. Automatic Measurement and Control

RECOMMENDED PRACTICE: Automation of the gas flow measurement and control process will:

- Provide faster real-time data leading to improved operation.
- Increase the speed of gas allocation changes with resulting oil increase.
- Reduce the time required to return a well to production after a shutdown.

Automatic measurement and control can provide a fast response to changes in the injection system. This rapid response can help keep the production high, but additional important reasons to install an automatic system are:

- Control gas delivery to maintain stable system and wellbore pressure.
- Gas allocation for optimization.
- Well surveillance and problem well diagnosis.
- Start-up and shutdown.
- Remote control in harsh environments.
- Automated data reporting.

Flow control can be local or remote. For a local control system, a flow rate set point is used to control the rate at a meter by adjusting the actuator on the choke. The control loop consists of the control valve actuator, flow measurement

device/sensor, and the controller. A pneumatic or electronic control system can be used for local control operation.

For remote systems, the set point can be changed from a remote station or by computer logic. Electronic systems are preferred and the transmitters and controllers (remote terminal units, distributed control systems, or programmable logic controllers) are used with the option of electric or pneumatic control valves. In addition to the control system, a means to communicate with the remote station has to be provided. Data transmission to the remote site can be done with telephone circuits (hard wire or fiber optic), radio, satellite, or microwave.

These systems integrate instrumentation, control, and communications technologies and they require experienced personnel for design and maintenance support. The gas control improvement and resulting production increase will pay the cost many times over.

6.4 GATHERING, TESTING, AND HANDLING OF PRODUCED FLUIDS

The gas lift production system is an interaction between the fluid gathering piping, the well testing facilities, and the production fluid handling facilities:

- Gathering pipelines can contain bottlenecks that can inhibit production. Delivery models, validated with measured data, should be used to pinpoint restrictions and to identify them as surface or downhole problems.
- Well test equipment should be properly designed, operated, and maintained to provide reasonably accurate, timely well test data to allocate gas effectively and to identify under-performing wells.
- Production manifolds, separators, oil treating, and salt water disposal equipment are in series for production fluid handling. Any one component can be at its capacity limit and restrict production.

RECOMMENDED PRACTICE: The gas, oil, and water gathering and processing facility should be designed, operated, and maintained as a system of interactive components:

- Pressure and rate data in the gathering pipelines, obtained after initial commissioning, can serve as the baseline for future comparisons to identify restrictions.
- Well test and production facility capacity tests can indicate changes in well rates or in equipment capacity due to solids accumulation.

A. Effects of Various Wellhead Designs

The wellhead, valves, and piping should be streamlined to minimize the pressure loss at the wellhead area. The high rate, high productivity wells suffer the greatest loss due to excessive elbows and small trim safety valves. These items can create an additional pressure loss, and corresponding lost production. Wellhead restrictions also impact intermittent lift by causing liquid slug fallback.

If a production choke is needed on an intermittent well to prevent gas slug effects on surface facilities, then place the choke at the inlet manifold.

The pressure loss caused by high rate could be minimized with a wellhead using a Y block and loop instead of the standard T block. Less costly is an inspection to insure that all valves are full opening, the choke body is removed, and choke nipples are removed. The piping layout should keep elbows to a minimum.

B. Flowline Effects

The flowline represents the component that can create substantial friction pressure loss when the diameter is small and the additional gas lift gas has been injected into the production stream. It also can be the source of severe slugging in a piping network when the diameter is too large. Thus the optimum sizing is difficult and never perfect for future flow conditions.

Generally, the flowline design should:

- Use a diameter equal to or slightly larger than the tubing diameter.
- Have a pressure rating that will contain the shut-in wellhead pressure, especially when the wells are in populated areas, at remote locations, or on platforms.

The pipeline pressure loss vs. rate can be simulated with a calibrated model (see 4.2) for more exact size design. Similar methods should be applied to manifolds and other piping components.

C. Effective Well Testing

Well testing, discussed in 3.3 and in API RP 11V5, is essential for effective gas allocation. In addition, test information coupled with flowing surveys and injection gas measurement can be used to:

- Analyze gas lift injection depth and performance.
- Diagnose many types of gas lift problems.
- Optimize gas injection into gas lift wells.
- Re-design gas lift installations.
- Prioritize gas lift wells for well work.

Fluid properties and flowing density (gradient) characteristics may be adjusted based on the measured data using the techniques of 3.1.

6.5 SPECIAL DESIGN CASES

Special design cases are gas lift applications with different tubular configurations, or with a gas other than mostly methane natural gas:

- Dual tubing completions are lifted with gas supplied from the common annulus.
- Annular flow (in the casing-tubing annulus) can be used to produce more fluid than can be lifted up the production tubing.
- CO₂ can be used for gas lifting in fields under CO₂ flood. N₂ can also be used if an adequate supply is available.

A. Dual Completions

Dual well completions are used in many oil fields and are suitable for simultaneously producing separate reservoirs that:

- Can be controlled with nearly the same weight completion fluids.
- Are reasonably close together.
- Produce moderate rates.

The two most common well configurations for duals are:

1. Parallel strings of 2.375 in. OD tubing inside 7.0 in. OD casing.
2. Parallel strings of 3.5 in. OD tubing inside 9.625 in. OD casing.

Many other combinations of tubing sizes are possible and even concentric strings are feasible, depending on the casing size.

Dual gas lift special problems are:

Mandrel interference—clearance for the mandrels within the casing requires the short string mandrels to be placed one or two joints shallower than the long string. The spacing between each string's sequential mandrels should be slightly different to prevent interference as the short string is installed.

Injection gas control—one zone takes most of the injection gas and the other zone is starved of gas. Significantly different producing conditions can alter the force dynamics on the corresponding valve in each string, which causes differing

amount of gas passage. Gas lift valve selection and design must be carefully implemented.

Design options include:

- Run one string of valves with operating injection pressure designed to lift the best zone and attempt to design the other string (poorer zone) at that operating pressure.
- Use one string of IPO valves and the other string with PPO valves.
- Use production pressure (fluid) gas lift valves in both strings. Relatively small injection ports, or chokes, are normally used to help prevent one string from using all the injection gas.
- Use a very high gas lift gas injection pressure that permits unloading from an orifice valve just above the packer, thus eliminating all the troublesome unloading valves.

RECOMMENDED PRACTICE: Dual completion gas lift should only be used when the following precautions are observed:

- Mandrels should be spaced to prevent interference between strings.
- Valve selection and pressure setting should be designed to prevent excessive gas passage into one string.

B. Annular Flow

Tubing-casing annular area, with its greater cross-section, gives a flow path equivalent to large diameter tubing. Production rate potential is greater, if the reservoir can provide the fluid. Gas lift gas is conveyed inside the tubing to the valve and injected into the tubing-casing annular area.

A preferred alternative is to use a larger tubing size, if it and the larger gas lift mandrels can be inserted with sufficient clearance.

Annular flow is still limited to special applications for these reasons:

- Regulatory agencies may prohibit the flow of production fluids on the casing.
- Corrosion of the casing.
- Production rate decline will cause severe slugging (tubing flow becomes more effective).
- Low rate in annular flow demands excessive injection gas lift gas.

- For offshore wells, annular safety valves may be required.

RECOMMENDED PRACTICE: Annular flow gas lift should be limited in use and should adhere to these design points:

- Mandrels should permit gas to enter at the valve bellows area and exit the nose cone directly to the annular space (IPO valves).
- Valve crossover seats should be avoided since they reduce gas passage.
- Gas passage requiring two valves can be accomplished with two single pocket mandrels spaced approximately 100 ft apart.
- High rate gas friction loss in the tubing must be considered for accurate valve pressure setting.

Annular flow installations in offshore wells may require an annular safety valve or two tubing strings with downhole safety valves. Both tubing strings and a dual packer are set at the safety valve depth and configured for fluid flow from the annular area into the larger tubing/safety valve. The gas would pass down the smaller tubing, through its safety valve, and continue inside tubing to the point of injection.

C. Lifting with CO₂ or N₂

Gas lift with CO₂ rich gas is feasible if precautions regarding corrosion are implemented. The phase behavior of the gas should be analyzed to predict when the fluid is gas or liquid and whether solid hydrates could prevent lift.

RECOMMENDED PRACTICE: CO₂ for gas lift is feasible when the following precautions are observed:

- Dehydrate gas to reduce corrosion.
- If gas is corrosive due to remaining water vapor, then use gas soluble/dispersible corrosion inhibitor injected downstream of dehydration.
- Surface piping valves should be lubricated with special inhibitor grease.
- Tubing can be plastic coated and batch treatment applied based on testing.
- Flowlines can be fiberglass to resist corrosion if treatments are not satisfactory.

- Gas gradient calculations should use the proper gas gravity and deviation factors (z) for CO₂.
- Flowing surveys are needed to validate computer correlations for multiphase flow.

Single point injection through coiled tubing strapped to the outside of the tubing string is one method to isolate the corrosive CO₂ from the casing. The kickoff unloading pressure must be high enough to reach the point of injection, since unloading valves are not used. However, once unloaded, the well requires a much lower operating pressure as drawdown occurs. This method can be used to achieve injection (and inhibitor protection) deep in the well.

Nitrogen gas can be used and it does not have the corrosive effects of CO₂. This gas has been used for gas lift using conventional design methods and movement of gas down the tubing-casing annulus with unloading valves. The gas gravity and deviation factors (z) for N₂ must be used for the gas column. Fluid pressures from the computer model can be validated with flowing surveys.

7 Gas Lift Optimization

Optimizing a gas lift field usually implies producing the maximum oil with the available gas lift injection gas. This objective can be accomplished with well-by-well analyses and model simulation, coupled with field-wide system analyses. The operations and engineering review can yield work plans to improve operation efficiency, to increase oil production through effective gas allocation, to evaluate new capital equipment for increased capacity or automatic operation, and to reduce operating cost. This approach to gas lift optimization can be accomplished through use of the recommended practices listed in this document.

Optimization is based on knowledge of the wells' and system behavior and the ability to change the behavior to improve oil production with the available gas. Optimization cannot be attained with computer programs alone, but the computer models are a key tool when well data and fluid property data are accurate and used to simulate the well and system behavior. Thus the steps necessary to reach optimization are:

1. Gather reliable wellbore configuration data including deviation surveys.
2. Obtain measured flowing surveys coupled with a production rate test and injection gas rate.
3. Use the measured data to validate the computer simulation models.

4. Use good PVT data and adjust using the techniques from Section 3.
5. Obtain gas samples and use the data in the simulation models.
6. Measure wellhead, flowline, and separator pressures for use in a system model.
7. Measure gas distribution pipeline pressures for use in a system model.
8. Use the analysis of each well to correct its problems and attain a deep point of lift.
9. Simulate the performance of each well with a production rate vs. injection gas calculation.
10. Simulate the combined behavior of the group of wells flowing into one gathering manifold or separation station.
11. Alter each well's gas injection rate (for the group of wells) and simulate the effect on the group of wells.
12. Select the injection gas rate for each well that yields the best oil rate for the group of wells.
13. If the cost and revenue data are available, then analyze optimization on an economic basis.

7.1 ECONOMIC BASIS FOR OPTIMIZATION

Optimization in terms of economics—the revenue of incremental oil produced compared to the cost of incremental injection gas required—can be used after each individual well is optimized to attain deep lift. This method needs good data on the cost of operation related to oil and water processing as well as the injection gas compression and processing. The basis is incremental production from an incremental quantity of injection gas, which requires a validated performance curve of each well's production rate vs. injection gas, and by summation, the performance of the field.

Gas lift system optimization on an economic basis should do the following:

- Maximize the incremental daily net cash flow (Daily NCF) at the field level.
- Exceed company's minimum economic criterion at each well.
- Satisfy all the system constraints at the field-level.

The constraints can be field and/or company limitations:

- Gas quantity and pressure based on compressor capacity.
- Produced water handling or disposal capacity.
- Oil separation or treating capacity.

- PI.
- Minimum, company-wide, economic (investment) criteria.
- Finite resources (material, equipment, labor, and money).

RECOMMENDED PRACTICE: Gas lift economic optimization should maximize field-wide, daily, incremental net cash flow within the field-wide constraints while simultaneously exceeding the company's minimum economic criterion for each well. Economic optimization can be implemented after attaining effective lift by utilizing the maximum available gas injection pressure to reach the deepest possible depth of lift.

7.2 DETERMINATION OF GAS LIFT SYSTEM ECONOMIC COSTS AND BENEFITS

Daily oil production can be converted to daily revenue, and daily gas injection can be converted to daily costs. The difference of revenue less cost is the Daily NCF that provides a basis for economic optimization. The incremental Daily NCF for each well:

$$\text{Incremental Daily NCF} = \text{Incremental, Daily Revenue} - \text{Incremental, Daily Cost}$$

where incremental, Daily NCF flow is the:

- change in Daily NCF due to additional injected gas,

where incremental, daily revenue is the:

- extra market value of the extra oil production resulting from additional gas injection, and

where incremental, daily costs are all the extra costs required to inject additional lift gas:

- Extra oil, gas, and water handling costs (separate, compress, dehydrate, inject, etc.)
- Other direct (and local indirect) production costs required to provide the extra gas lift
- Deductions for royalty, taxes, etc.

A company's minimum economic criterion for each well is the incremental return on investment (IROI.) Each well's IROI must exceed the company's minimum requirement.

$$\text{Incremental Return on Investment} = \frac{\text{Incremental, Daily Net Cash Flow}}{\text{Incremental, Daily Costs}}$$

Find the optimum, field-wide gas injection rate, and the optimum, well-by-well, gas allocation that meets the following economic criteria:

- a. Daily, IROI at each well exceeds the company's minimum acceptable ROI
 - IROI is: incremental Daily NCF/incremental costs.
- b. Maximize Daily Incremental NCF for the entire field
 - full-field Daily NCF is the sum of the Daily NCF from each well in the field.

Recommended Practice: Maximize daily, incremental net cash flow for the entire field, and allocate the available lift gas to the wells so that the company's minimum ROI is exceeded for each well.

The following examples use the same field data used in other sections of this document. Table 7-1 lists input data for both the reservoir and the revenue plus cost economic data. The economic data will vary with the price of oil and this will change the optimization answer, but the conceptual basis remains the same. Table 7-2 has the performance curve data of production rate vs. injection gas for two wells. Well 1 has a productivity index of 10 stb/d/psi and Well 2 has a productivity index of one stb/d/psi. Table 7-3 summarizes the economic optimization data for the two wells.

Note: The data in the tables was rounded off by the spreadsheet program, and the incremental numbers may be off by 1.

The economic optimization data provides guidance on incremental net cash flow and when this important benchmark goes negative with increasing injection gas. Also the incremental return on investment (ROI) can be compared to company criteria and this can guide the imposed limit on injection gas. Finally if gas is unlimited and an incremental ROI is not imposed, then the incremental oil per increment of injection gas can be used to define the injection gas limit.

7.3 IMPLEMENTATION OF FIELD OPTIMIZATION

Gas lift operations include three areas of activity:

- Design of the wellbore equipment.
- Surveillance and trouble-shooting.
- Adjusting the operations.

All three provide opportunities for improvements in performance, or field optimization, of gas lift wells and facilities. Surveillance and trouble-shooting is the topic in API RP 11V5 and design of the wellbore equipment is covered in API RP 11V6.

“Side effects” can occur when operators attempt to increase production from individual gas lift wells, or all the field's gas lift wells. Increases in the fluid (liquid plus gas) flowing through a gathering system can cause a system-wide backpressure increase that may reduce production from other wells connected to the system.

The performance of natural flow and gas lift wells can deteriorate substantially when system backpressure increases whereas rod pump or electric submersible pump artificially lifted wells may suffer, but not to the same degree. The total system should be analyzed, including all wells producing into a common gathering system before the primary stage of separation.

RECOMMENDED PRACTICE: Gas lift field optimization should utilize a system analysis to:

- Observe the effect on other gas lift wells.
- Check for detrimental effects on natural flow wells.
- Observe the effect on pumped wells.
- Confirm that total field production is increasing with the optimizing effort.

“Field optimizing” an individual well's production performance is a function of the gas lift injection rate and the depth of injection. Obtain measured field data consisting of one production well test rate with corresponding surface pressures plus wellbore pressure surveys. As reviewed in Sections 3 and 4, the measured data is used to validate the well and system models. The validated model(s) can then predict an “optimum operating rate” calculated using multiphase flow correlations and reservoir delivery equations to simulate the production rate at varying gas injection rates, with one curve generated for each potential lifting depth.

Figure 7-1 shows the effect of lift from shallower and deeper points of lift. The best improvement in effectiveness, in terms of liquid volume lifted per standard cubic foot of injection gas, is to reach the deepest valve possible, within the constraints of injection pressure and manufacturer's valve bellows pressure limit. The data for injection at 7000 ft was used in the economic examples.

Even if the revenue and cost data are not known, the incremental change in production rate for a given incremental change in gas lift injection rate can be used for field optimization. When the slope approaches zero, the production limit has been reached for the well, with its configuration, reservoir, and system operating conditions. Most operators will attempt to stay to the left of the limit, or maximum point, especially when limited gas must be allocated to the wells. However, a gas injection rate that is too low may cause pro-

Table 7-1—Input Data

2000 = reservoir pressure, psig	\$15.00 = gross oil sales price/stb
1270 = bubble point pressure, psig	33.3% = royalty and taxes
50 = separator pressure, psig	\$0.05 = per stb water treatment and disposal
0.5 = water cut fraction	\$0.30 = per Mscf gas treat, makeup and compress
244 = res. gas oil ratio, scf/stb	\$0.00 = capital investment
122 = res. gas liquid ratio, scf/stb	\$25.00 = per (well day) fixed water disposal cost
8200 = perforation depth, ft	\$25.00 = per (well day) fixed injection gas cost
7000 = gas lift injection depth, ft	

Table 7-2—Production Performance

Produced Oil & Water stb/day	Total GLR scf/stb	Injected GLR scf/stb	P_{wf} psig	Total Injected Gas mscf/day	Incremental Produced Oil stb/day	Incremental Injected Gas mscf/day
Well 1 (PI = 10)						
0	122	0	2000	0	0	0
2085	222	100	1792	209	1043	209
2903	422	300	1710	871	409	662
3153	622	500	1685	1577	125	706
3286	922	800	1671	2629	67	1052
3319	1322	1200	1668	3983	17	1354
3273	1722	1600	1673	5237	-23	1254
Well 2 (PI = 1)						
0	122	0	2000	0	0	0
327	262	140	1673	46	164	46
431	422	300	1569	129	52	84
496	622	500	1504	248	33	119
549	922	800	1451	439	27	191
583	1322	1200	1417	700	17	260
600	1722	1600	1400	960	9	260

Table 7-3—Economic Optimization

Total Injected Gas mscf/day	Gross Revenue \$/day	Total Costs \$/day	Daily Net Cash Flow \$/day	Daily ROI %	Incremental Net Cash Flow \$/day	Incremental Cost \$/day	Incremental ROI %	Incremental Daily NCF per Incremental Injected Gas \$/ mscf	Incremental Oil per Incremental Gas Injection stb/mscf
Well 1 (PI = 10)									
0	0	0	0	0					
209	15,638	5,372	10,266	191	10,266	5,372	191.1	49.24	5.000
871	21,773	7,634	14,138	185	3,873	2,262	171.2	5.85	0.617
1577	23,648	8,476	15,171	179	1,033	842	122.6	1.46	0.177
2629	24,645	9,128	15,517	170	346	651	53.2	0.33	0.063
3983	24,893	9,617	15,275	159	(-242)	489	(-49.4)	-0.18	0.012
5237	24,548	9,877	14,670	149	(-605)	260	(-232.6)	-0.48	-0.018
Well 2 (PI = 1)									
0	0	0	0	0					
46	2,453	889	1,564	176	1,564	889	176	34.16	3.571
129	3,233	1,176	2,057	175	493	287	171.4	5.90	0.623
248	3,720	1,376	2,344	170	288	200	144.3	2.43	0.274
439	4,118	1,567	2,551	163	206	191	108.1	1.04	0.139
700	4,373	1,731	2,642	153	91	164	55.6	0.38	0.065
960	4,500	1,852	2,649	143	6	121	5.4	0.02	0.033

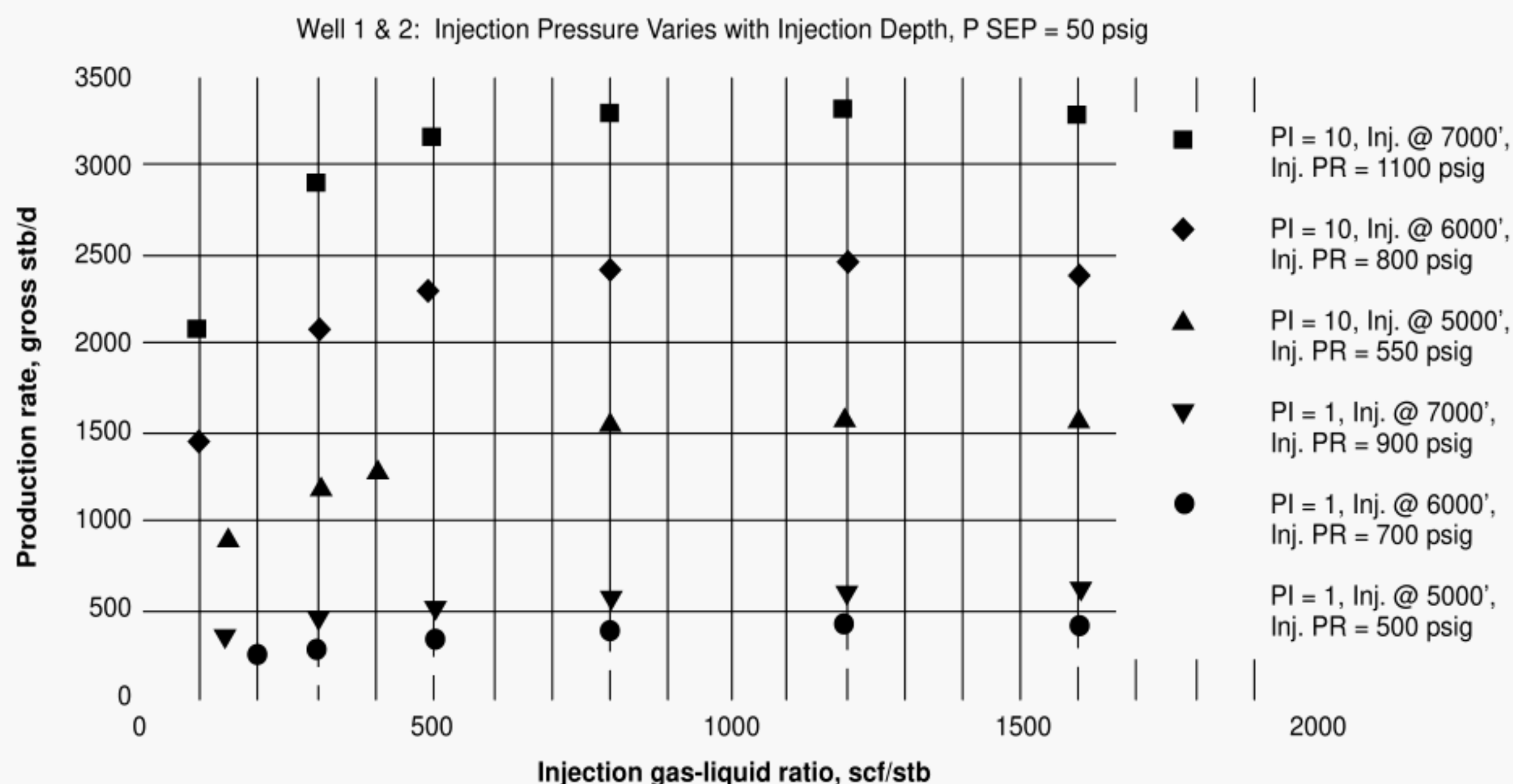


Figure 7-1—Production Rate vs. Injection Gas for Various Depths of Lift

duction rate instability and should also be avoided. A gas rate that is too high can reduce production.

RECOMMENDED PRACTICE: Gas lift field optimization should be based upon:

- A performance curve of production rate vs. injection gas rate.
- A slope of the curve, with a limit set by economic criteria.
- Lift from the deepest valve, within the constraints of injection pressure and manufacturer's valve bellows pressure limit.

The gas allocation among the wells should be based on each well's performance curve and a slope, or limit, defined by economic considerations.

However, a common fault in field operations is gas injection at a rate exceeding the economic limit for the well. Excess gas:

- Wastes compression horsepower.
- Reduces production from the well.
- Overloads the gathering system pipelines and separator.
- Prevents a better well from receiving its proper allocation of gas.

Performance curves should be compared to field well testing. When the computer model has been validated with measured data, the field tests should be a reasonable match. As expected, the field data points are not as smooth as those produced by computer models, and the water may not be constant over the range of tests. However, the field data provides a true well performance curve based on the actual operation of the well.

Field test well performance curves can be very useful for determining if the well is operating beyond its optimum limit (that is, excessive gas is being injected). This surveillance tool aspect can be applied to compare a current field test with the curve produced by a validated computer model. Performance not up to the expectations of the computer model may indicate a problem, such as the well lifting at a shallower valve, or a hole in the tubing.

Also, differences between the field test and the computer produced performance curves may indicate the computer model has not been validated for the well's fluid properties and productivity index (PI). If this is the case, then a field test and well flowing survey can be used to improve the computer model, which in turn can be used to better predict performance outside the range of the field tests.

In practice, the proper allocation of injection gas is an ongoing process based on field and computer performance curves, where new well tests are compared to performance curves. Deviations from the optimum injection and production point should lead to a new allocation of gas or to further investigation on the reason the well is producing less than its potential.

7.4 WHAT IS PRACTICAL AND WHAT IS IMPRACTICAL

Surveillance, troubleshooting, and test-based performance curves are field tools that should be coupled with computer tools and automatic well controls. Computer programs should be validated with good data on the well (fluid properties, reservoir conditions, well mechanical schematic, test rates, and flowing survey pressures). With the full complement of tools, an experienced team of engineers, technicians, well analysts, and operators can accomplish effective optimization of gas allocation.

The following recommended practices are judgments regarding what is practical and what is not practical to achieve in gas lift operations:

RECOMMENDED PRACTICE: Gas lift field optimization methods:

Practical:

- Use design, surveillance and troubleshooting to fine tune the operation.
- Evaluate each well's performance curve to decide if the gas injection rate is at the economic criteria (within system constraints).
- Limit the range of operation on the performance curve between a gas injection rate high enough to prevent unstable operation, but low enough to be economically efficient.
- Allocate gas to wells but use a field system model to observe the effect on natural flow wells and other artificially lifted wells.
- Shut-in non-automated wells according to a performance rating list when gas distribution must be reduced due a temporary compressor shutdown.
- Reduce gas to, or selectively shut-in, each automated well based on a field performance model (due to temporary compressor outage).

Impractical:

- Daily manual adjustment of the gas injection rates to meet an economic criteria.
- Daily manual adjustment of the gas injection rates on a large group (greater than about 10) of interacting wells (automatic control is needed).

8 Computer Design Tools

Gas lift performance prediction and design can be complex and time-consuming, even with effective computer program models and references available. These tools should be used by experienced, trained gas lift system designers in their work, but the results should not be accepted in blind faith by the experienced or the inexperienced person. Field measured, quality data should be used as the criteria for accuracy of the computer tools.

RECOMMENDED PRACTICE: Computer program models for multiphase flowing pressure, flowing temperature, and reservoir inflow performance should be used in gas lift performance prediction and design, but the results should be calibrated and validated by comparison to field measured data.

Data to be gathered for the models, and methods of data adjustment, are discussed in Section 3. The data are applied to well deliverability in Section 4. Gas lift valve design is a separate recommended practice, API RP 11V6. This section discusses the models that should be used in computer programs.

Gas lift models are mathematical calculations that have been written into computer code. Numerous programs exist, created by different computer programmers, thus the same model may give slightly different answers if the results from each model were compared. Similarly, several models are linked together to simulate a gas lift well and the result from one calculation affects the others. The gas lift well components to be linked with different models are:

- Separator pressure—this is the back-pressure on the complete system.
- Horizontal pressure change—a horizontal multiphase flow model, permitting up-flow and down-flow with elevation variations, is used to simulate the pressure change in the flowline and calculate a flowing wellhead pressure.

- Vertical pressure change—a vertical/inclined/horizontal wellbore multiphase flow model, incorporating flow pattern and liquid holdup identification, is used to simulate the pressure change in the tubing/casing and calculate a flowing bottomhole pressure.
- Reservoir pressure drawdown—an inflow performance model is used to simulate the pressure change in the reservoir rock, starting from the reservoir static pressure.

Linking the components together gives the “system” model described in Section 4.

Often the component models are used independently. The vertical multiphase model calculated data should match the measured flowing pressure/temperature survey data to validate the flow model. Then it can be used to simulate a flowing pressure vs. depth profile to determine a well’s gas lift injection depth and flowing bottomhole pressure.

Since the models are mathematical approximations, recognition of potential error is needed. A 10% error in vertical multiphase flow pressure prediction is typical. However, if an accurate set of data and PVT fluid properties adjusted with measured data are used, then error may be reduced to 5% or less. However, since the vertical flow model is linked to the horizontal flow model and an inflow performance model, the total error in estimation of rate delivery can be significant, on the order of 10% – 30%. If measured pressure and PVT data for validation are not available, then the errors potentially could easily exceed 30%.

8.1 VERTICAL PRESSURE PROFILE MODELS

Gas lift design and evaluation depend on the vertical pressure profile model. The model output of pressure vs. depth is typically called a “vertical flowing pressure gradient curve” or “pressure traverse curve.” Prior to the wide availability of personal computer programs, a main frame computer generated the gradient curves. Each graph represented one rate, water fraction, and pipe size, and each curve was one gas-liquid ratio. Some designers believe that such graphs are adequate; however, the graphs are based on average fluid properties, temperatures, and constant wellhead pressure. A good computer model will provide more accurate answers than a graph.

Papers and studies on multiphase flow in vertical oil wells were initiated in the early 1900s, and up until the 1950s most gas lift designers used simple empirical models (“correlations”). Beginning in the early 1950s, the models were converted to computer code to generate depth-pressure graphs for use by the designer without a computer. In the 1980s, personal computers and multiphase flow programs were readily available to do the complex modeling. These programs can predict pressures based on specific producing parameters, and thus can make better predictions than the published graphs that are based on average properties.

Even with computer models, the key is to gather quality field and PVT data to confirm the accuracy of the model or technique used.

RECOMMENDED PRACTICE: Computer program models for multiphase flow are preferable to generalized graphs of gradient curves.

Good, accurate vertical/inclined multiphase flow models are still difficult to develop due to the complex nature of flow and to the large number of wellbore sizes, rates, and fluid properties. To cover this broad range, a good model should include:

- Flow pattern identification
- Liquid holdup prediction
- Friction pressure loss calculation based on flow pattern
- Fluid physical property prediction

Flow pattern identification—many wells experience several different gas and liquid flow patterns from bottom to wellhead, and the calculated pressure loss is more accurate if the pattern is considered. Difficulty still arises when the in-situ flowing conditions are at a pattern boundary, since the equations for each pattern may not converge to the same result at the boundary. Many programs are based on the work of Dukler, Taitel, and Barnea or modifications of their studies. Their flow pattern predictions include the effect of physical properties and thus give greater accuracy.

Flow pattern maps, based on superficial velocity of the liquid phase and superficial velocity of the gas phase, were established primarily from laboratory studies. Other researchers have developed fluid flow dimensionless groups to predict flow patterns. The typical vertical flow patterns are:

- Liquid—Total liquid flow.
- Bubble—Bubbles of gas have been liberated (this has been subdivided into bubbly and dispersed bubble).
- Slug—Bubbles coalesce into small slugs of gas in a liquid stream.
- Churn—Gas slug size increases and mixes forcefully with liquid slugs to churn the flow stream.
- Annular—Gas fraction has increased and moves in the center of the pipe with droplets of liquid. Much of the liquid moves as an annular film at the pipe wall.
- Mist—Gas flow with a mist of liquid droplets.
- Gas—Total gas flow.

Liquid holdup prediction—the velocity of the gas, oil, and water flowing up the tubing is often different for the gas and liquid phases. This difference in velocity of the gas and liquid

phases is referred to as slip, and the slippage leads to excessive accumulation of liquid, or liquid holdup. Holdup can be defined as the fraction of pipe volume that contains liquid. The empirical correlations to predict holdup are generated in the laboratory, since they cannot be obtained from field data.

Friction pressure loss calculation based on flow pattern—the flow patterns cause variations in friction loss and the better models' equations reflect these changes. Some models ignore slip (and holdup) or simply combine slip and friction to give a total pressure loss. For improved accuracy, the total pressure loss, both from friction and density, should be related to flow pattern, velocity, and liquid holdup. In vertical flow, pressure loss is significantly greater due to density effects than from friction effects.

Fluid physical property prediction—accurate modeling of density is directly related to the quality of PVT data for physical properties and the liquid holdup prediction. The pressure change in a gas lifted vertical/inclined well is dominated by density of the flowing mixture, which is affected by the flow patterns and liquid holdup.

PVT report data are used with either a compositional model or a PVT correlation. PVT correlations, such as Standing or Lasater, are normally used and give good results when calibrated using the fluid property adjustment techniques in Section 3. They compare well with the reservoir fluid compositional models that are extremely sensitive to the amount of heavy crude components in the reservoir oil.

Vertical flow models are described as empirical or as mechanistic:

Empirical models are mathematical correlations of laboratory and/or field test measurements over a limited range of data. The correlations fit their data, but a potential problem exists for cases falling outside that range of data. Such cases may produce reasonable results or completely inaccurate results. Thus, users must know the range of data used to build an empirical model and should compare their calculated pressures to measured pressures.

Mechanistic models are based on theoretical fluid mechanics. These models have greater numbers of equations to describe the physics of flow and they require the flow patterns to be identified to apply specific equations. They use the physical fluid properties in the equations and thus are more dependent on good PVT data. These models should have broader application because they are not limited as is an empirical model with its range of data. However, due to the complexity of multiphase flow, the mechanistic model with its equations may not yield better results than properly applied empirical models.

Whether empirical or mechanistic models are used, predicting the pressure of the producing fluid at various depths in

the wellbore is fundamental to gas lift. Calculation of the pressure at a depth is a function of the:

1. Surface or bottomhole pressure (either can be the starting point of the calculation).
2. Density of the fluid mixture as affected by liquid holdup and fluid physical properties.
3. Friction due to fluid velocity, viscosity, pipe measured length, and pipe surface roughness.

A. Empirical Models

A partial list of correlations available for vertical flow includes:

- **Poettmann and Carpenter** was developed and published in 1952. Their model combined friction and slippage into a single energy loss factor and was used for high rates with low *GORs* (near single phase flow).
- **Baxendell and Thomas** was an extension to Poettmann and Carpenter, but used for high annular rates. It was based on measured data from Venezuelan oil fields.
- **Gilbert** published his paper in 1954 and it was the first to apply vertical flowing pressure gradient curves. His graphs were derived from measured data from the California Ventura field oil wells. The Gilbert graphs were applied to the California wells and those wells with low water cuts.
- **Duns and Ros** published a correlation in 1961 which became the basis for many computer software programs. The correlation, developed primarily from laboratory data, showed potential errors when compared to field tests. Thus, Ros and Gray gathered field data from flowing oil wells and revised the correlation. The model was then referred to as Ros-Gray.
- **Hagedorn and Brown** is a popular correlation published in 1965 and subsequently modified by Brill and Hagedorn to include the effects of holdup and slippage. The modified Hagedorn and Brown graphs were widely distributed and the correlation programmed into computer programs.
- **Orkiszewski** published a correlation in 1967 that also has been the basis for computer programs. This model incorporates the work of Ros, Griffith-Wallis, and others in a general correlation.
- **Beggs and Brill**, published in 1973, is a generalized correlation to handle all ranges of multiphase flow for tubulars at any pipe angle including horizontal flow. This correlation is widely programmed and used for inclined flow. Baker, Lockhart-Martinelli, Eaton, and Dukler did other work on inclined flow.
- **MMSM** (Mobil-Moreland-Shell-Method) is the correlation developed in 1976 by Shell and Mobil. Moreland

used the field and laboratory data of Ros and Gray plus other carefully-screened field data in developing this correlation.

Recommended Practice: Empirical models for multiphase flow pressure prediction should be used with caution and should be validated with measured field data at tested rates.

B. Mechanistic Models

The mechanistic model uses theoretical equations to describe flow and define the flow patterns. Within each flow pattern, equations are applied describing fluid mechanics, such as bubble rise, wall film thickness, shear stress in the film and the interface between phases. The sequence to the pressure loss calculation is:

- Predict the flow pattern.
- Predict liquid holdup for each pattern.
- Calculate pressure drop based on fluid mechanics equations specific to each flow pattern.

Some of the flow models using a mechanistic basis are:

- **Aziz, Govier and Fogarasi** published their general multiphase flow model in 1972. The model was developed mechanistically and then checked against field data.
- **OLGA** is a mechanistic model developed by one of the Norwegian research organizations, IFE, in 1986. It is used in both vertical and horizontal flow.
- **Ansari, et al.** developed a mechanistic model, published in 1990. They provide flow equations for bubble, slug, and annular flow patterns, which are based on those of Taitel, Barnea, and Dukler.
- **Choksi, Schmidt, and Doty** is a mechanistic model published in 1996. Similar to Ansari, et al., it could provide improved results for some cases.
- **Brill, et al.**—models are continuously being developed as result of ongoing multiphase flow research. The work is not proprietary and can be the source for future model development.

The mechanistic model should be compared to the measured data from the wells. PVT data are very important since

the fluid mechanics equations can be more sensitive to fluid physical properties.

Recommended Practice: Theoretical mechanistic models for multiphase flow pressure prediction should have the calculations validated with field measured data. Good PVT data should be used.

Many of the gas lift wells are deviated with high angles, or horizontal, or have up-hill and down-hill horizontal flow in the flowline, or reside on offshore platforms with risers and a sub-sea line to the production station. Some of the models have been modified to use a simple cosine calculation to correct measured length to TVD, subsequently applying the correction to the density component but not the friction component. However, inclined flow is more complex and the mechanistic models are becoming the most widely used.

For best results use the multiphase flow model that provides the most accurate answer for your well conditions, when the calculations are compared to measured data.

8.2 VERTICAL TEMPERATURE PROFILE MODELS

Temperature affects the calculations of vertical flow models, gas pressure gradient, and the pressure setting of nitrogen-charged gas lift valves. Steady-state flowing temperatures are applied to the multiphase flow models, but transient, unloading temperatures are needed for the bellows pressure calculation.

A simple linear temperature profile from the surface flowing temperature to the bottomhole temperature can be used, but this method is often an over-simplification and underestimates the temperature. The actual temperature profile is non-linear with faster cooling near the surface, especially in offshore or arctic operations.

The surface flowing temperature may be unknown, but it must be predicted for use in the design. The bottomhole temperature is usually known from the prior surveys or open hole log data. For both surface and flowing temperatures, actual field measurements should be used if available.

Models developed to predict flowing temperatures are:

- **Kirkpatrick** developed the first widely used temperature model. An empirical graph from field data shows rate vs. the flowing temperature gradient for 2.5 in. ID tubing. A simple correction for rate was listed for 2 in. and 3 in. ID tubing.

- **Sagar, Doty, and Schmidt** provided equations to predict temperature profiles in two-phase flowing and gas lift wells. This model is based on regression analysis of field flowing temperature data and may be an improvement over other models.
- **Alves, Alhanati, and Shoham** is a temperature model that can be used for both wellbore and surface piping. It requires fewer assumptions and is more mechanistic, thus an improvement over the empirical methods.

Temperature models might require heat transfer coefficients for calculating heat loss to the surrounding pipe and formation, so the accuracy of their prediction is dependent on the quality of the heat transfer data.

The temperature used to calculate the bellows set pressure of the upper unloading valves is a transient unloading temperature, not the steady state flowing temperature discussed above. Section 4.1 reviews the unloading temperatures.

RECOMMENDED PRACTICE: Temperature models are required for multiphase flow pressure calculations and the results should be validated with measured flowing temperature surveys.

8.3 WELL INFLOW PERFORMANCE MODELS

An accurate model of the inflow from the reservoir is needed to make a good gas lift design and to predict deliverability for planning future gas requirements. The choices range from linear productivity index models for liquid flow to non-linear models representing gas-liquid flow. These basic models are:

Productivity Index (PI) is the model developed from the Darcy radial flow equation for single phase flow. The productivity index (PI or J) can be related to the parameters in the Darcy equation for pseudo steady state radial flow:

$$J = \frac{(0.00708)(k)(h)}{[\mu_o \times B_o(1 - W_c) + \mu_w \times B_w W_c] \left[\ln \left(\frac{R_e}{R_w} \right) - 0.75 + S \right]}$$

$$Q_1 = (J) \times (P_r - P_{wf})$$

$$P_{wf} = P_r - (Q_1 / J)$$

where the terms and units are:

$J = \text{PI} =$ productivity index (stbpd/psi),

$Q_1 =$ stock tank rate of gross liquid per day (stbpd) from a well test,

$P_r =$ static reservoir pressure (psi) from a static or pressure build-up test,

$P_{wf} =$ flowing bottomhole pressure (psi) from a flowing survey or pressure build-up test,

$k =$ effective permeability (MD) from a pressure build-up test,

$h =$ formation thickness (ft) from log analysis,

$\mu_o =$ reservoir oil viscosity (cp) from a PVT analysis,

$\mu_w =$ reservoir water viscosity (cp) from a PVT analysis,

$B_o =$ fluid volume factor, oil (bbl/stb) from a PVT analysis,

$B_w =$ fluid volume factor, water (bbl/stb) from a PVT analysis,

$W_c =$ water cut fraction (water-liquid ratio) from production test,

$R_e =$ radius of drainage (ft) estimated from acreage spacing,

$R_w =$ radius of wellbore (ft) from bit size or caliper,

$S =$ skin factor from a pressure build-up test.

The straight line PI equation gives reasonably good inflow predictions as long as the Darcy equation assumptions of liquid flow without free gas are reasonably valid. Below the bubble point in the reservoir and/or near wellbore area, the equation may not be valid and certainly becomes non-linear if viscosity, μ , and volume factor, B , are recalculated at each flowing pressure, P_{wf} .

Vogel developed an empirical IPR model for two-phase (oil and gas) flow in solution-gas drive reservoirs. The work is based on reservoir simulation runs for many different PVT conditions. The resulting equation is:

$$Q_1/Q_m = 1.0 - 0.2 \times (P_{wf}/P_r) - 0.8 \times (P_{wf}/P_r)^2$$

where:

$Q_1 =$ stock tank rate of gross liquid per day (stbpd) from a well test,

$Q_m =$ maximum theoretical stock tank rate of gross liquid per day (stbpd) calculated from measured data,

$P_r =$ static reservoir pressure (psi) from a static or pressure build-up test,

$P_{wf} =$ flowing bottomhole pressure (psi) from a flowing survey.

Vogel's work was based on oil flowing below its bubble point, but the equation has been extrapolated for use with gross liquid flow. The equation must be used with test data, Q_1 , P_{wf} , and P_r , to obtain a maximum rate, Q_m . With Q_m cal-

culated, then the rate, Q_1 , or flowing bottomhole pressure, P_{wf} , can be computed for other conditions:

$$Q_1 = Q_m \times [1.0 - 0.2 \times (P_{wf}/P_r) - 0.8 \times (P_{wf}/P_r)^2]$$

$$P_{wf} = 0.125 \times P_r \times [-1 + [81 - 80 \times (Q_1/Q_m)]^{.5}]$$

Fetkovich also developed an empirical equation for two-phase flowing oil wells based on field measurements. He used the multiple well test data method that Rawlins and Schellhart had used for gas well deliverability. The Fetkovich equation is:

$$Q_1 = J' \times (P_r^2 - P_{wf}^2)^n$$

where:

Q_1 = stock tank rate of gross liquid per day (stbpd) from a well test,

P_r = static reservoir pressure (psi) from a static or pressure build-up test,

P_{wf} = flowing bottomhole pressure (psi) from a flowing survey,

J' = back pressure curve performance coefficient, obtained from data,

n = exponent of back pressure curve, obtained from slope of log-log plot data.

When $n=1$, the equation gives values of Q_1 that are less than the Vogel equation—producing an IPR with more curvature.

RECOMMENDED PRACTICE: Inflow models should be:

- Matched to the reservoir fluid flow condition.
- Validated with measured flowing surveys and production rate tests.

In many cases a PI model is adequate in continuous flow gas lift design, especially if the bottomhole fluid is flowing above its bubble point or if the water fraction is high, minimizing the gas. However, the other models do provide different inflow results as the flowing bottomhole pressure reduces. A comparison of the differences between models can be seen in Figure 8-1 for both the high PI well and for the low PI well. Many models combine the equations to use the PI model above the bubble point and Vogel below it.

Darcy PI and Vogel can each be modeled based on a single well test with a measured flowing bottomhole pressure, but multiple rate testing is needed with the Fetkovich equation in order to obtain the exponent (n) and the performance coefficient (J').

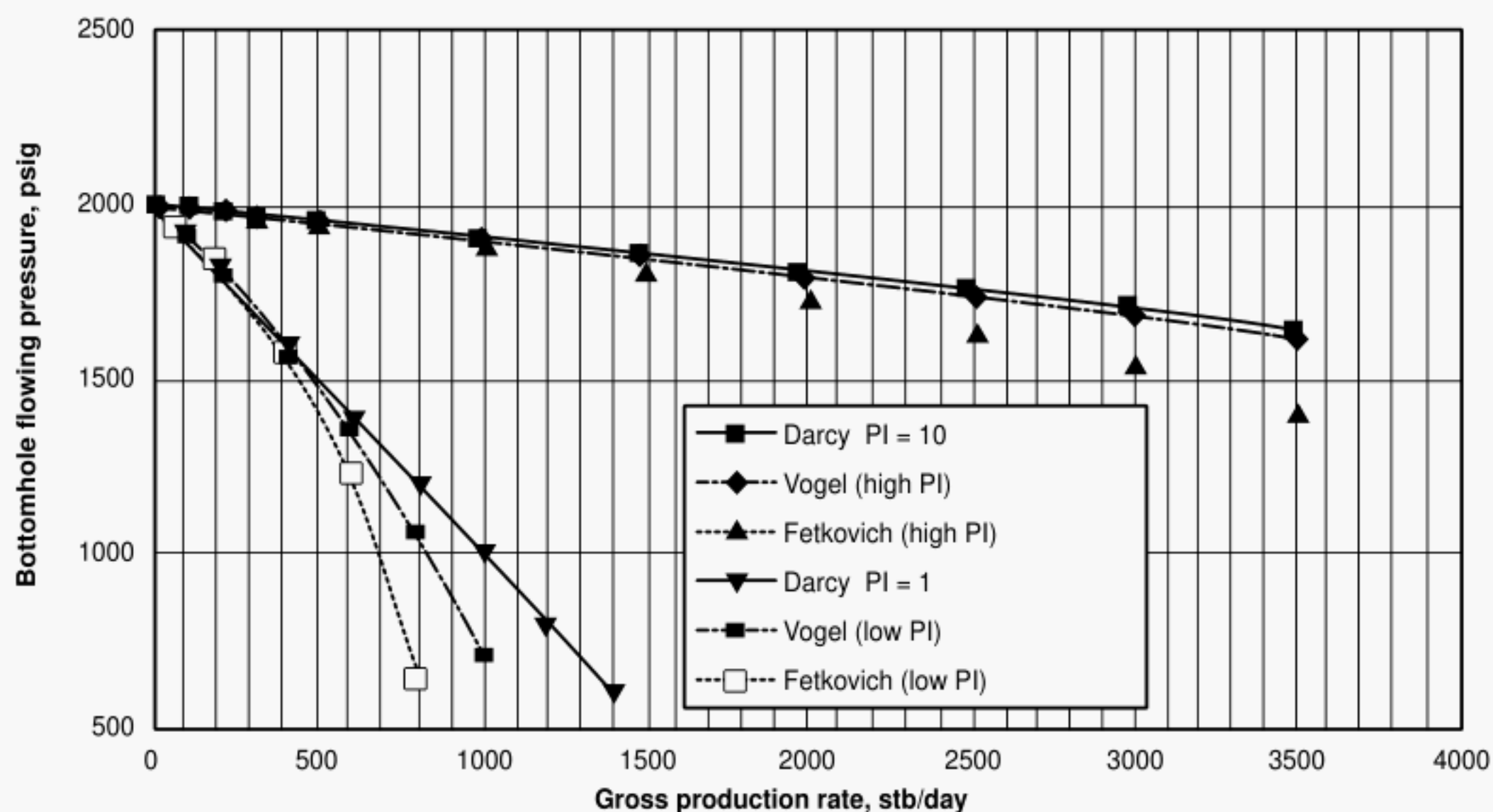


Figure 8-1—Reservoir Inflow Performance

9 Operating Considerations

Gas lift operating recommended practices are contained in API RP 11V5. The purpose of this section is to provide a high-level summary of the key points affecting a gas lift system design and its performance.

9.1 GAS LIFT OPERATORS' PROBLEMS

Gas lift system designers tend to plan new installations based on information for gas injection rate and pressure at each well and, cumulatively, for the system. The gas lift operators in the field can make the system and wells function as intended only when the assumed information is reasonably close to reality.

RECOMMENDED PRACTICE: Design information should be based on:

- Exploration, drilling, or production well tests for oil, gas, and water rates.
- PVT fluid property data obtained from tests of hydrocarbon samples.
- Injection pressure that will provide lift from a depth nearly to the perforations.
- Injection gas rate based on a peak fluid production rate that comes from a study of well delivery vs. water fraction and corresponding reservoir pressure.
- System gas rate is the sum the rates for the maximum number of wells to be served.

A review of the assumed information needed to design a system and the impact on the operators in the field are:

9.1.1 Kickoff Pressure

Assumption: Kickoff pressure available at the well is often assumed to be 100 psi higher than the operating pressure, or assumed to be equal to the compressor discharge pressure.

Reality: The gas lift operator may not be able to provide this pressure, and may have difficulty in initially unloading or kicking off the well. The designer should use the maximum recorded pressure available at the well under normal operating conditions. The available pressure is influenced by these items:

- Pressure and rate capacity of the gas lift compression units can be much lower due to rising gas temperature in hot weather, especially if the design did not provide adequate gas cooling.

- Compressors mismatched in pressure design or stages when more than one is in use.
- Compressor driver may be purposefully set at an operating point less than full load to reduce maintenance, but this action prevents the compressor from developing maximum pressure and rate capacity.
- Excess gas to sales caused by a sales pipeline pressure regulator set point being set too low.
- Distribution system may have a bottleneck affecting all wells or a portion of the wells.
- Well is located at a far-distant point in the distribution system.
- Distribution line to the well may have a low spot accumulating liquid or forming a hydrate.
- Pressure drop at the choke or control valve may be forming a hydrate.
- Another well in the system is taking excessive gas and pulling down pressure.
- Gas re-injection into the reservoir is supplied from the gas lift system.

To increase system pressure to the design kickoff pressure, try these measures:

- Shutting in other wells temporarily.
- Raising the set point of the pressure regulator used to send excess gas to sales.
- Obtaining a temporary rental compressor for additional capacity.

9.1.2 Operating Injection Pressure

Assumption: Operating injection pressure available at the wellhead is assumed to be stable and high.

Reality: This may be difficult to provide for the same reasons listed for kickoff pressure. If operating pressure is not steady, the wells will slug as gas rates cycle up and down, and the lifting point may shift to a shallower valve from the intended operating gas lift valve.

To increase system operating pressure, use the methods listed for kickoff pressure. To keep it stable, automatic control of the injection chokes (or surface control valves) will match gas availability to the total injection at all wells on a continuous basis. If the system is not automated, then develop a priority listing of wells and shut-in the lowest priority wells to match gas availability to total demand. The addition of compression capacity may be required as a permanent solution.

9.1.3 Injection Rate

Assumption: *A steady injection rate is assumed.*

Reality: The operator may not be able to provide a steady injection gas rate, which results in a low oil production rate and slugging, unstable behavior. The inadequate gas rate may be due to:

- Hydrate deposition causing plugging in chokes, pipeline low spots (where water collects), or at any restriction.
- Wells added to the gas lift system without added compressor capacity.
- Compression is undersized or the gas well (or pipeline) supply is not adequate.
- Compressor components (reciprocating compressor valves) have failed, or the pipeline has a partially closed valve, or the adjustable choke is at a lesser set point (perhaps due to vibration).
- Low productivity wells are taking excess gas.

To increase gas supply to the wells:

- Calculate the optimum gas rate for each well and sum for the system, then compare to the available supply to determine if the supply is adequate.
- Test the dehydration system with a water vapor content measurement, check glycol condition, use gas stripping, and estimate gas capacity to evaluate whether added dehydration is needed.
- Check compressors for broken valves (reciprocating compressors).
- Check the pipeline valves.
- Check the lift gas injection choke settings on the wells, especially low productivity wells.
- Check gas rate meters to find excessive consumption; install meters if they are not on each well and at major supply feed points, such as a compressor station, gas well, or pipeline.
- Methanol batch treatments can be used to clean out hydrates or deposits from pipelines, hot oil (or water) can be used in casing or tubing.

9.1.4 Unloading Temperature

Assumption: *Unloading temperature at the depth of each valve must be assumed.*

Reality: The operator can measure the down hole temperature conditions with static and flowing surveys. If the unloading temperature assumptions are incorrect, the well may not

unload and work down to the desired operating gas lift valve. The observed effects are:

- Well ceases to take gas during unloading—caused by valves prematurely closing when they are heated to temperature greater than design temperature.
- Well circulates gas and unloading ceases—caused by valves that will not close because they are cooler than temperature used in design.

To gather temperature data for valve redesign:

- Run a flowing temperature survey (and a pressure survey) in a similar rate well to establish the maximum temperature a valve will experience.
- Run a shut-in temperature survey prior to changing valves to establish the minimum temperature a valve will experience.
- Design unloading temperature will be between the minimum temperature at the first unloading valve to the maximum temperature at the operating valve.

Temperature survey practices are given in 3.2 and models are discussed in 4.1 and 8.2.

9.1.5 Well Characteristics

Assumption: *Well fluid properties and inflow characteristics are assumed, rather than measured.*

Reality: The gas lift operator can provide information for static reservoir pressure, IPR (productivity), and PVT fluid properties. Those data should be measured, not assumed, and the data changes over time.

9.1.6 Gas Lift Valve Performance

Assumption: *The performance of gas lift valves—gas passage rate vs. pressure drop—are assumed.*

Reality: The performance varies between different models of gas lift valves, and the gas lift operator may have trouble unloading or may not be able to inject the desired gas rate into the design operating valve, solely due to a mechanical limitation in a specific valve model. Gas lift valve performance can be verified using procedures described in API RP 11V2.

9.1.7 Gas Lift Operating Philosophy/Strategy

Assumption: *The gas lift facility designer, the wellbore valve designer, and the gas lift operator are assumed to understand each other's philosophy or strategy.*

Reality: The three component groups should have meetings in the field to fully communicate the proposed operating strat-

egy and to review the data to be used in design. The problems to be avoided are:

- Operators, without extensive training or experience in the principles and practices of gas lift, may not know how to operate the gas lift system as intended.
- Designers must know the field limitations and design to them, if correction is not possible.

The gas lift operator has the responsibility for observing and reporting daily behavior of the wells and the lift gas compression/distribution system. However, the facility and the gas lift valve designers have the responsibility to:

- Query gas lift system operators for their needs and for the constraints on their time.
- Make the system effective by insuring that it will work within the limitations of the real world, not only the day it is commissioned, but over the long-term of ten to twenty years.

- Make the system flexible to deal with changes in the distribution system, changes in the number of wells on the system, and changes in well conditions.
- Design to actual operating conditions in the specific field and wells (or to similar wells if this a new field development).
- Use measured data from the wells, including their inflow characteristics, pressure and temperature profiles, and fluid properties.
- Obtain performance characteristics of the gas lift valves to be used.

9.2 DESIGN STRATEGIES FOR EFFECTIVE LONG-TERM OPERATION

The gas lift system is an example of “the only thing that is constant is change.” Continuous gas lift operation is predicated on stable conditions, but the system can be designed to work effectively even with frequent and often unpredictable changes.

Design strategies are offered for consideration in the following table:

Design Guidelines and/or Strategies

Design Objective	Reason for Objective	Design Strategy
Keep the System Pressure Stable	A stable injection pressure minimizes fluid slugging and prevents the injection point from moving to a shallower valve.	Provide a pressure regulator on the sales line outlet of the gas lift distribution system to keep the pressure high, and an automatic control system to <i>rapidly</i> and <i>effectively</i> reduce the injection rates or to shut-in the low productivity wells to keep the pressure from becoming too low when a compressor fails. Also, provide adequate dehydration so the gas is relatively dry to avoid freezing problems which reduce gas rate.
Keep Wells Lifting as Deep as Possible	Deep injection will maximize the drawdown for a given amount of injection gas.	Provide a close-spaced unloading design to assure that the wells can work down to the operating gas lift valve. Additional gas lift mandrels in the vicinity of the desired operating depth will provide flexibility in actual lift depth when well conditions change.
Keep the Injection Rates Stable	A stable injection rate into each continuous gas lift well minimizes slugging and gives the best production rate.	Provide a means to <i>accurately</i> measure and control the gas lift injection rate into each well, so that the rate can be kept stable even with changing system and well pressures.
Keep the Injection Rate into Each Well Optimized	Assure that the available gas lift gas gives the optimum fluid and oil production at all times.	Use accurate, frequent well tests plus flowing surveys to calibrate the computer model used to simulate well and system performance. Use the model to optimally allocate the available lift gas to the wells.
Keep the Gas Lift System Operating Effectively at all Times	Assure that the gas lift resources are being used to maximize operating profit.	Provide a means to train all operating and maintenance personnel in optimization and keep the training current in view of continual staff changes.

9.3 CHECK LIST OF GAS LIFT PROBLEMS AND RECOMMENDATIONS

The following checklist, from API RP 11V5, is a guide to recommended practices for problems encountered by gas lift system operators. It is presented here as a guide for gas lift system designers.

Typical Operating Problems

Problem Area: *Wells are being under-lifted (lifting too shallow, too little gas) or over-lifted (too much gas)*

Recommended Practices:

- Provide effective monitoring procedures and automatic control equipment.
- Use wireline flowing surveys to confirm point of lift.
- Compare actual vs. optimum gas lift performance by simultaneously obtaining a production test, wireline survey, injection gas measurement, and two-pen wellhead pressure data.
- Assure that all valves and other equipment are functioning properly (wireline surveys and surface inspection).
- If gas supply is limited, then allocate it optimally to the most profitable wells.
- If gas supply is excessive, sell gas instead of cycling excess gas through the system.

Problem Area: *Wells are unstable (injection and/or production heading or slugging)*

Recommended Practices:

- Use well pressure monitoring equipment (two-pen charts or sensors on tubing and casing) to detect the magnitude of the unstable, surging operation.
- Distinguish between production heading and injection gas heading.
- Evaluate the cause(s) of instability: production heading from tubing or port size too large, gas rate too low, production choke on flowline, paraffin or solids in tubing or flowline; injection gas heading from improper set pressure on valves or port size too large, gas rate too low.
- Add gas, change port size (on wireline valves), eliminate production choke or restriction to eliminate or reduce heading since it is very inefficient.

Problem Area: *Equipment function and quality*

Recommended Practices:

- Do a systematic check of all components of the gas lift system, checking for partially closed surface valves.
- Routinely monitor all equipment and calibrate meters.
- Establish and practice quality assurance on equipment selection and installation.

Surface Compression, Dehydration, and Distribution

Problem Area: *Compression*

Recommended Practices:

- Maintain a compression facility that can provide adequate gas rate and pressure, even in the hottest months.
- Measure the gas at compressor discharge and compare to the sum of the well injection rates.
- Perform routine compressor maintenance to attain 99% availability.

Problem Area: *Dehydration*

Recommended Practices:

- Dry lift gas to 7 lb. per million scf to avoid water condensation and hydrate formation (3 lb./million scf in cold climates).
- For TEG systems, keep the glycol clean and circulate a sufficient glycol rate to attain the dryness specification.
- For solid desiccant systems, prevent liquid entry with good scrubbers.
- Design the piping system to avoid large pressure drops.
- Periodically purge liquid from distribution lines with purge taps at low points.
- Inject methanol or install heaters to avoid freezing problems during winter weather.

Problem Area: *Gas distribution piping*

Recommended Practices:

- Use a directly connected “spider” style distribution system when economically feasible, or a trunkline and manifold distribution system with larger fields.
- Make the pipe volume as large as possible to dampen pulsations and well-to-well interference.
- Automatic control of injection gas for each well improves allocation and minimizes interference, especially when combining continuous and intermittent lift.

Problem Area: *Lack of gas distribution control*

Recommended Practices:

- Install automatic control of injection gas with computer (local or remote) monitored measurement and choke control.
- Re-evaluate pipe size of the distribution system based on current rates and pressures.
- Consider piping additions to eliminate restrictions (bottlenecks).

Gas Injection Metering and Control

Problem Area: *Metering*

Recommended Practices:

- Use properly installed, well maintained, accurately calibrated meters.
- Use an accurate meter during production well tests and flowing pressure surveys.
- Orifice plate, turbine, or vortex meters are best, but do not use turbines in surging gas flow.

Problem Area: *Control*

Recommended Practices:

- Operate as closely as possible to the optimum design conditions.
- If the well's conditions have drastically changed, then re-evaluate the control point and/or re-design the installation.
- Use a gas flow rate controller to provide consistent, stable flow.
- Measure gas injection pressure at the wellhead downstream of the gas choke or controller.

Gas Lift Valves

Problem Area: *Unloading valves*

Recommended Practices:

- Check two-pen well pressure charts to detect heading caused by valve problems.
- Avoid over-injection with proper port (orifice) sizing or consider use of chokes in the valves.
- Follow unloading procedures in API RP 11V5.

Problem Area: *Operating valve*

Recommended Practices:

- For high rate, high productivity wells, use an orifice valve rather than a pressure-set valve to increase the gas rate capacity and avoid throttling.
- For low productivity wells, use a small port in a pressure-set valve to avoid over-injection, or consider use of a choke in the valve.
- If the well's conditions have drastically changed, then re-evaluate the design for a change of valve set pressure, port size, and depth.

Well Equipment—Tubulars, Completion, Wellhead

Problem Area: *Casing annulus*

Recommended Practices:

- Circulate workover fluid to clean annulus during equipment installation. On wells with low reservoir pressure, consider using a standing valve or retrievable bridge plug to prevent fluid loss to the formation.
- Pressure test to assure that the casing does not have leaks.
- Use special methods to convey gas to the operating depth if the casing is old and cannot hold gas pressure.

Problem Area: *Tubing*

Recommended Practices:

- Carefully select tubing size to maximize production rate and minimize lift gas circulation.
- Keep tubing clean of corrosion products, paraffin, scale, sand, or other solids.
- Size equipment to be restriction-free, such as packer bores or safety valves.

Problem Area: *Completion*

Recommended Practices:

- Conduct wireline surveys annually on key wells to monitor reservoir pressure and flowing bottom-hole pressure.
- If a well becomes impaired, then clean and stimulate the well to restore production.
- If a well has a sand control problem, then minimize pressure surges and heading.

Problem Area: *Wellhead*

Recommended Practices:

- Eliminate flow restrictions such as choke bodies, small diameter valves (check the safety valve) or piping, and excessive elbows.
- Provide easy access for wireline work by installing a crown valve.
- Check for wellhead seal leaks, indicated by wellhead cooling or sweating.

Problem Area: *Wellhead monitoring and control*

Recommended Practices:

- Accurately and simultaneously measure the wellhead production and gas injection pressures; do this consistently, especially when the well is on its production test.
- Do not use production chokes except to control sand or to control severe slugging created by an over-sized tubing diameter or temporarily uncorrectable tubing leak.

Gathering System—Flowline and Manifold

Problem Area: *Flowline*

Recommended Practices:

- Keep flowline clean of corrosion products, paraffin, scale, sand, or other solids.
- Size the line diameter for the expected production rate plus gas lift gas with an objective of keeping a low flowing wellhead pressure.
- Eliminate flow restrictions such as small diameter valves or replacement piping, and excessive elbows.
- Avoid using one flowline for more than one well.

Problem Area: *Manifold*

Recommended Practices:

- Minimize restrictions from small valves or headers, the high PI wells will be most adversely affected.
- Keep manifold valves fully open or fully closed.
- Routinely check for valve leaks, since leaks contribute to poor testing of all wells.
- Automated three-way valves are prone to leakage, use a sonic or infrared monitor to check for leakage from production to test outlets.

Production Rate Testing Facility

Problem Area: *Well test scheduling*

Recommended Practices:

- Test each well often enough to detect changes in performance.
- Test each well long enough to obtain accurate results by monitoring hourly rate change.
- Coordinate well testing with other activities such as wireline pressure surveys and obtain injection gas measurement data plus wellhead pressure two-pen data.
- Consider automatic well testing.

Problem Area: *Test separation*

Recommended Practices:

- Maintain a test vessel pressure the same as the production vessel pressure, if possible.
- If the vessel's pressures must be different, allow sufficient time for the well to stabilize to the new condition.
- Set purge time long enough to thoroughly flush the vessel and the test pipeline (if the wells are remotely located from the test separator).
- Attempt to minimize pressure surging to improve metering accuracy.
- Routinely check and calibrate the well test meters.
- Make good well testing a high priority so it receives the necessary maintenance.

Production Handling Facility

Problem Area: *Allocation of fluids*

Recommended Practices:

- Measure daily the total gas, oil, and water from the group of wells and allocate the fluids based on the individual wells tests [(individual test data/sum of the individual test data) × production data].
- Compare injection gas to total gas measurement for evidence of meter error, surging gas in the vessel, or poor tests.

Problem Area: *Equipment restrictions*

Recommended Practices:

- Calculate gas capacity of existing separators; add separators or modify existing vessels with centrifugal-type internal baffles to increase capacity.
- Check low pressure degassing vessel and/or tank gas capacity and add vapor recovery units as needed.
- Maintain water treating vessels clean to minimize oil carryover and prevent bacterial growth; install system with adequate water capacity to produce the target oil rate.

Guidelines for Collecting and Using Key Operating Information

Problem Area: *Well tests*

Recommended Practices:

- Evaluate “good” vs. “bad” tests based on historical trend data.
- If the test is questionable due to significant hourly rate changes, re-test the well.
- “Good” well tests should be used for optimization, gas allocation, and calibration of models.
- Use a validated gas lift model compared to the well test to find under-performing wells.

Problem Area: *Downtime*

Recommended Practices:

- Detect and account for all downtime.
- Use downtime in total production allocation to the wells and to prioritize maintenance work.

Problem Area: *Pressure and temperature surveys*

Recommended Practices:

- Obtain surveys annually on key wells and biannually for other wells; run surveys when conditions change or when troubleshooting prior to design changes.
- Use the survey guidelines in this RP and in API RP 11V5.
- Obtain a pressure buildup survey if the inflow performance is below normal to distinguish between skin and permeability problems.

Problem Area: *Pressure, temperature, and rate measurements*

Recommended Practices:

- Continuously measure injection gas pressure and rate.
- Obtain well test, pressure survey, and wellhead pressure data simultaneously.
- Gather wellhead pressure data and injection gas rate data during unloading.
- Use pressure and temperature surveys to determine the point of lift and PI.

Guidelines for Effective Surveillance and Control

Problem Area: *Manual operation*

Recommended Practices:

- Motivate people to become competent and dedicated by stressing the economic importance of gas lift.
- Provide on-going training in all aspects of gas lift operation.
- Provide quality measurement and control equipment.
- Perform periodic system reviews to identify bottlenecks and opportunities.

Problem Area: *Automated operation*

Recommended Practices:

- Use automated well testing, gas measurement and control to improve operational effectiveness and increase oil production through improved gas allocation.
- Use automated chokes to re-allocate gas when a compressor is temporarily down.

2003 Publications Order Form



Effective January 1, 2003.

API Members receive a 50% discount where applicable.

The member discount does not apply to purchases made for the purpose of resale.

Available through Global Engineering Documents:

Phone Orders: 1-800-854-7179 (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)

Fax Orders: 303-397-2740

Online Orders: www.global.ihs.com

Date: _____

☐ **API Member** (Check if Yes)

Invoice To (☐ Check here if same as "Ship To")

Name: _____

Title: _____

Company: _____

Department: _____

Address: _____

City: _____ State/Province: _____

Zip/Postal Code: _____ Country: _____

Telephone: _____

Fax: _____

E-Mail: _____

Ship To (UPS will not deliver to a P.O. Box)

Name: _____

Title: _____

Company: _____

Department: _____

Address: _____

City: _____ State/Province: _____

Zip/Postal Code: _____ Country: _____

Telephone: _____

Fax: _____

E-Mail: _____

Quantity	Product Number	Title	SO★	Unit Price	Total
	G11V12	Spec 11V1, <i>Gas Lift Valves, Orifices, Reverse Flow Valves and Dummy Valves</i>		\$ 83.00	
	G11V22	RP 11V2, <i>Gas Lift Valve Performance Testing</i>		\$ 76.00	
	G11V52	RP 11V5, <i>Operation, Maintenance, and Trouble-shooting of Gas Lift Installations</i>		\$ 83.00	
	G11V62	RP 11V6, <i>Design of Continuous Flow Gas Lift Installations Using Injection Pressure Operated Valves</i>		\$ 112.00	
	G11V72	RP 11V7, <i>Repair, Testing and Setting Gas Lift Valves</i>		\$ 78.00	

☐ **Payment Enclosed** ☐ **P.O. No.** (Enclose Copy) _____

☐ **Charge My Global Account No.** _____

☐ **VISA** ☐ **MasterCard** ☐ **American Express** ☐ **Diners Club** ☐ **Discover**

Credit Card No.: _____

Print Name (As It Appears on Card): _____

Expiration Date: _____

Signature: _____

Subtotal _____

Applicable Sales Tax (see below) _____

Rush Shipping Fee (see below) _____

Shipping and Handling (see below) _____

Total (in U.S. Dollars) _____

★ To be placed on Standing Order for future editions of this publication, place a check mark in the SO column and sign here:

Pricing and availability subject to change without notice.

Mail Orders – Payment by check or money order in U.S. dollars is required except for established accounts. State and local taxes, \$10 processing fee*, and 5% shipping must be added. Send mail orders to: **API Publications, Global Engineering Documents, 15 Inverness Way East, M/S C303B, Englewood, CO 80112-5776, USA.**

Purchase Orders – Purchase orders are accepted from established accounts. Invoice will include actual freight cost, a \$10 processing fee*, plus state and local taxes.

Telephone Orders – If ordering by telephone, a \$10 processing fee* and actual freight costs will be added to the order.

Sales Tax – All U.S. purchases must include applicable state and local sales tax. Customers claiming tax-exempt status must provide Global with a copy of their exemption certificate.

Shipping (U.S. Orders) – Orders shipped within the U.S. are sent via traceable means. Most orders are shipped the same day. Subscription updates are sent by First-Class Mail. Other options, including next-day service, air service, and fax transmission are available at additional cost. Call 1-800-854-7179 for more information.

Shipping (International Orders) – Standard international shipping is by air express courier service. Subscription updates are sent by World Mail. Normal delivery is 3-4 days from shipping date.

Rush Shipping Fee – Next Day Delivery orders charge is \$20 in addition to the carrier charges. Next Day Delivery orders must be placed by 2:00 p.m. MST to ensure overnight delivery.

Returns – All returns must be pre-approved by calling Global's Customer Service Department at 1-800-624-3974 for information and assistance. There may be a 15% restocking fee. Special order items, electronic documents, and age-dated materials are non-returnable.

***Minimum Order** – There is a \$50 minimum for all orders containing hardcopy documents. The \$50 minimum applies to the order subtotal including the \$10 processing fee, excluding any applicable taxes and freight charges. If the total cost of the documents on the order plus the \$10 processing fee is less than \$50, the processing fee will be increased to bring the order amount up to the \$50 minimum. This processing fee will be applied before any applicable deposit account, quantity or member discounts have been applied. There is no minimum for orders containing only electronically delivered documents.

There's more where this came from.

The American Petroleum Institute provides additional resources and programs to the oil and natural gas industry which are based on API® Standards. For more information, contact:

- | | |
|---|--|
| • API Monogram® Licensing Program | Phone: 202-962-4791
Fax: 202-682-8070 |
| • American Petroleum Institute Quality Registrar (APIQR®) | Phone: 202-962-4791
Fax: 202-682-8070 |
| • API Spec Q1® Registration | Phone: 202-962-4791
Fax: 202-682-8070 |
| • API Perforator Design Registration | Phone: 202-962-4791
Fax: 202-682-8070 |
| • API Training Provider Certification Program | Phone: 202-682-8490
Fax: 202-682-8070 |
| • Individual Certification Programs | Phone: 202-682-8161
Fax: 202-962-4739 |
| • Engine Oil Licensing and Certification System (EOLCS) | Phone: 202-682-8233
Fax: 202-962-4739 |
| • Training/Workshops | Phone: 202-682-8490
Fax: 202-682-8070 |

Check out the API Publications, Programs, and Services Catalog online at www.api.org.



American Petroleum Institute

Helping You Get The Job Done Right.®

Additional copies are available through Global Engineering Documents at (800) 854-7179 or (303) 397-7956

Information about API Publications, Programs and Services is available on the World Wide Web at: <http://www.api.org>



**American
Petroleum
Institute**

1220 L Street, Northwest
Washington, D.C. 20005-4070
202-682-8000

Product No. G11V81