

Dynamic Simulation of Gas-lift Wells and Systems

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Foreword

This recommended practice is under the jurisdiction of the API Committee on Standardization of Production Equipment (Committee 19).

This document presents recommended practices for dynamic simulation of gas-lift wells and systems. Included are steady state models, pseudo steady state models, and dynamic numerical models. Other API specifications, API recommended practices, and Gas Processors Suppliers Association (GPSA) documents may be referenced in system design and operation.

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Dynamic Simulation of Gas-lift Wells and Systems

1 Scope

This recommended practice (RP) provides guidance and background for the application and use of dynamic simulation of gas-lift wells and their related systems. Discussion is included for use of steady-state, “pseudo” steady-state, and dynamic numerical models. Also presented are guidelines to facilitate the application of these techniques to optimize well/system integrity, operations, life cycle design, and production. Additionally, a range of artificial lift and natural flowing systems and topics (e.g. gas well liquid loading) are addressed. The dynamic simulation recommendations (e.g. stable flow, hydrates, waxes, corrosion, liquid loading, and complex wells) can be implemented in other production systems (e.g. natural flowing wells).

This RP is also designated for managers, production technologists, reservoir engineers, facilities engineers, production engineers, well testing engineers, well analysts, operators, and researchers who want to gain a general understanding of dynamic simulation, areas of application, added values, and benefits. The contents compare transient vs steady-state techniques and provide readers with when and how each technique may be effectively applied.

Not included are technical requirements for the hardware of the dynamic simulation system, the specifics of the system calculations, the responses to the output of the dynamic simulation data output, and specifics of what actions are required after the provided data is considered.

An extensive bibliography is provided of documents for additional information on the topics included.

2 Normative References

There are no normative references in this document.

3 Terms, Definitions, Abbreviations, and Symbols

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1

beaning-up

The process of increasing the wellhead choke size to adjust the flow rate for adjustable choke.

NOTE For fixed chokes, it is the same process, excluding shutdown periods.

3.1.2

black oil correlations

Assumes that the reservoir fluids consist of three phases: oil, water, and gas.

NOTE These are defined with a minimum of information [specific gravity, gas-oil ratio (GOR), and water cut], with gas dissolving in oil and oil vaporizing in gas. Water is assumed to be inert. Use correlations to determine the fluid properties at different pressures and temperatures (P-T).

3.1.3

boundary conditions

Fluid type, flow rate, pressure, and temperature values assigned to the selected model boundaries (inputs, outputs, and surrounding environment of the model) used in solving the differential equations that apply to dynamic simulation.

3.1.4

bull heading

A process to forcibly pump fluids from an external source into a wellbore to displace existing fluids.

NOTE Bull heading can be used to stop the well from flowing or to provide lighter fluid to prompt underbalance conditions.

3.1.5

commingling

A process where fluids from different producing formations are combined and produced through a single conduit.

3.1.6

cross-flow

The flow of reservoir fluids from one productive formation into another.

3.1.7

distributed inflow performance relationship

distributed IPR

Methodology is used to divide the reservoir's productive intervals into zones and calculating individual inflow performance relationships (IPRs) for each separate zone.

3.1.8

drift-flux model

A model that treats phases as a mixture.

NOTE Gas is assumed to be drifting along with liquid, and the gas velocity can be described by a slip relation.

3.1.9

dynamic simulation

Multiphase flow transient numerical simulation.

NOTE Multiphase flow transient numerical simulation is a fundamentally different technique to pseudo-steady-state simulation. The term **pseudo-steady-state simulation** is defined in 3.1.33.

3.1.10

dynamic water and gas coning

The change in oil-water or gas-oil interface profiles in the near-wellbore area as a result of reservoir pressure depletion during production life and/or as a result of drawdown on wellbore production pressure above a critical value.

3.1.11

field life cycle

Changes in operating conditions from the moment the field is opened to production until it is closed and abandoned.

3.1.12

flashing

The process of rapidly reducing the pressure of a hydrocarbon sample to lower pressure and temperature in steps to determine its components at each step

3.1.13

flow assurance

Ensuring optimum and continuous flow of hydrocarbon streams from the reservoir to the point of sale.

3.1.14**flow regime**

Prevailing gas, oil, and water geometrical distribution when flowing through a pipe.

3.1.15**flow regime classes**

Common flow regimes for gas-liquid mixtures such as bubble flow, dispersed bubble flow, plug flow, slug flow, froth flow, mist flow, churn flow, and annular flow.

3.1.16**Forchheimer inflow performance relationship model****Forchheimer IPR model**

An IPR model developed by Forchheimer and widely accepted and applied in gas wells.

3.1.17**hydrates**

Solid ice-like crystalline compounds formed by water and natural gas molecules at high pressures and low temperatures.

3.1.18**hydrodynamic slugging**

Slug flow conditions caused by gas flowing at a fast rate over a slower flowing liquid phase.

NOTE The gas will form waves on the liquid surface, which can grow to bridge the whole cross section of the line. This creates a blockage on the gas flow, which travels as a slug through the line.

3.1.19**intelligent wells**

Refers to well completions where data recording and well control can be performed remotely.

NOTE A well equipped with monitoring equipment and flow control components can be adjusted to optimize production remotely, either automatically or with operator intervention.

3.1.20**Joule-Thomson cooling**

Describes the temperature change of a gas when it is forced through a valve or porous medium while the entire system is kept insulated so that no heat is exchanged with the environment.

NOTE The change can be positive or negative. For each gas, there is an inversion point that depends on P-T, below which it is cooled and above which it is heated. The magnitude of the change of temperature with pressure depends on the Joule-Thomson coefficient for each particular gas. The Joule-Thomson effect often causes a temperature decrease as gas flows through pores of a reservoir to the wellbore. At room temperature, all gases except hydrogen, helium, and neon cool upon expansion by the Joule-Thomson process. Joule-Thomson cooling can result in the formation of hydrates (ice crystals) when a pressure drop is taken across a control valve or choke.

3.1.21**kickoff**

Refers to bringing an off production well back to production when there are only formation fluids in the wellbore.

3.1.22**kickoff water cut limit**

Water cut critical value that does not allow a natural flowing well to start without gas-lift.

NOTE Above the water cut limit, the right amount of gas-lift gas needs to be injected to start production.

3.1.23**liquid holdup**

Refers to the liquid stored in well and flowlines at certain production conditions.

NOTE When gas flows at a greater velocity than the liquid, slippage takes place and liquid holdup occurs.

3.1.24**mechanistic models**

Mathematical models describing the multiphase flow mechanisms (including related fluid properties and physical relationships) using physical flow equations for each of the phases within the system.

3.1.25**multilateral well completions**

Completions that have more than one wellbore branch radiating from the main borehole.

3.1.26**multilayer well completions**

Completions that have more than one producing reservoir layer.

3.1.27**multipointing**

The situation where gas-lift injection gas enters the production stream from more than one point.

3.1.28**non-Darcy skin**

A rate-dependent skin effect that is due to turbulent flow conditions taking place near the wellbore.

NOTE The fluid flow in this case deviates from Darcy's law, which assumes laminar flow in the reservoir. Non-Darcy turbulent flow and associated skin are typically observed in high-rate gas wells when the flow converging to the wellbore reaches flow velocities exceeding the Reynolds number for laminar flow.

3.1.29**pig**

A mechanical device run or pushed through a flowline or along a wellbore to clean wax, paraffin, or other blocking material from the line.

3.1.30**pseudo-steady-state techniques**

Techniques using steady-state snapshots at different points in time to describe and analyze changes vs time.

3.1.31**quasi-dynamic inflow performance relationship****quasi-dynamic IPR**

An IPR model where variables such as pressure, temperature, permeability, and skin can be input as time series (repeated snapshots of linear timing).

3.1.32**real-time modeling**

Real-time data captured by a supervisory control and data acquisition (SCADA) system are input in a dynamic simulator that is used to monitor, advise, and control the production/injection system to obtain optimum flow assurance and production.

NOTE The main objective in developing the online model is to decrease the operational difficulties of the system by optimizing production, by improving the rules used to control the inflow into the wellbore, and by decreasing the time necessary to model required alternatives to select an optimum.

3.1.33**riser gas-lift**

The process where gas-lift injection gas is injected at the base of the riser.

NOTE The riser is a vertical pipe that transmits fluid from the seabed to the surface of an offshore platform.

3.1.34**slugging flow**

A multiphase flow regime characterized by a series of liquid plugs (slugs) separated by relatively large gas bubbles.

NOTE In severe slugging conditions, the gas bubble occupies almost the entire cross-sectional area of the pipe. The resulting flow alternates between high-liquid and high-gas composition zones.

3.1.35**steady-state simulation**

Simulation designed to give insight into the steady-state behavior of the system by using a dynamic simulator.

NOTE When opening the well to production, the time required to obtain steady-state conditions is calculated and the values of the key variables (P-T and rate) are validated. Also, the simulation runs will indicate if no steady-state conditions are reached.

3.1.36**subsurface safety valve****SSSV**

A valve installed at a certain depth in the wellbore that can be closed remotely to isolate the tubing above the valve and wellhead from reservoir fluids in an emergency or planned shutdown.

3.1.37**superficial velocity**

Velocity of a single component (oil, water, gas) in a multicomponent flowing situation, taking into account the full cross-sectional area of the pipe.

3.1.38**terrain-induced slugging**

A slugging condition generated by changing elevations in the pipeline that follow the ground, seabed, and/or riser.

NOTE Liquid can accumulate at low points of the pipeline until sufficient pressure builds up behind it. Once the liquid is pushed out of the low point, it will form a slug.

3.1.39**Thornhill-Craver equation**

An equation used to predict the rate of gas passage through a given orifice size.

3.1.40**transient flow**

Flow where the velocity and pressure change over time.

3.1.41**unloading**

The process of displacing initial annular and/or tubing fluids in the well when gas-lift injection gas is started.

3.1.42**Vogel inflow performance relationship model****Vogel IPR model**

IPR model, developed by Jack Vogel, is widely accepted and applied in oil wells.

3.2 Abbreviations

BHP	bottomhole pressure
CCE	constant composition expansion
CVD	constant volume depletion
DST	drill stem test
DTHYD	difference between hydrate formation temperature and fluid temperature
EOS	equation of state
EOT	end of tubing
E&P	exploration and production
ERD	extended reach drilling
ESP	electrical submersible pump
FEED	front end engineering design
GLM	gas-lift mandrel
GLR	gas-liquid ratio
GOR	gas-oil ratio
HIPPS	high integrity pressure protection system
HP-HT	high pressure, high temperature
HSE	health, safety, and environment
ICD	inflow control device
ICV	intelligent control valve
ID	internal diameter
IPC	intake pressure curve
IPO	injection pressure operated (gas-lift valves)
IPR	inflow performance relationship
ISA	International Society of Automation
JT	Joule-Thomson
k-h	permeability-thickness
LCM	lost circulation material
LDHI	low dosage hydrate inhibitor
MD	measured depth
MEG	monoethylene glycol
MeOH	methanol
MODU	mobile offshore drilling unit
OD	outside diameter
PBR	polished bore receptacle
pH	measure of acidity or alkalinity
PI	productivity index

PPO	production pressure operated gas-lift valve
PR78 SRK-P EOS	Peng-Robinson 1978 equation with modified mass for heavier compounds, Soave-Redlich-Kwong with Peneloux volume correction, equation of state
Pres	reservoir pressure
P-T	pressure-temperature
PTRO	test rack open pressure
SCSSV	surface control subsurface safety valve
SCADA	supervisory control and data acquisition
S/I	shut-in
SSD	sliding sleeve door
SSSV	subsurface safety valve
SS Tree	subsea tree
THP	tubing head pressure
TOC	top of cement
TVD	true vertical depth
VPC	Valve Performance Clearinghouse

3.3 Symbols

Cv	valve flow coefficient
Pcf	casing pressure
Piod	gas-lift valve injection pressure at depth
Ptf	flowing tubing pressure
Pvot	gas-lift valve opening pressure at temperature
PVT	pressure-volume-temperature
Pwf	flowing bottomhole pressure
Qg	gas flow rate
Qo	oil flow rate
Qw	water flow rate
Tf	fluid temperature
Thyd	hydrate formation temperature
Trvl	valve stem travel

4 Introduction to Dynamic Simulation of Gas-lift Wells and Systems

4.1 General

The purpose of this recommended practice (RP) is to explore the dynamic nature of gas-lift well and system operation and how various types of gas-lift simulation models can be used to understand and optimize their performance and ensure health, safety, and environment (HSE) integrity.

The development of oil and gas fields is moving toward increasingly hostile environments requiring offshore, subsea, and deepwater facilities and more complex well completions. The use of long horizontal, multilayer,

multilateral, big-bore, and intelligent wells has become more prevalent. High pressure, high temperature (HP-HT) reservoirs and deepwater environments present more complex production chemistry and flow assurance problems. These unique features and flow assurance requirements merit detailed dynamic analysis in wells and integrated production systems. Multiphase flow transient conditions need full evaluation and understanding for a sound engineering design. Therefore, it is essential to accurately model gas-lift systems to maximize production, contain operating problems, reduce risk and uncertainty, and ensure human, safety, and environmental integrity.

This section provides an introduction to dynamic simulation, and Section 5 focuses on the recommendations for the implementation of dynamic simulation in gas-lift wells and systems. The following annexes provide further clarification when required.

- a) *Case Histories*: Annex A presents case histories of the use of dynamic simulation and pseudo-steady-state techniques in actual practice.
- b) *Implementation of Dynamic Simulation*: Annex B presents applications, benefits, and implementation of dynamic simulation.
- c) *Information Needed for Dynamic Simulation*: Annex C presents information that is needed to implement the dynamic simulation process.
- d) *Information Provided by Dynamic Simulation*: Annex D presents information that is provided by the dynamic simulation process.
- e) *Gas-lift Systems, Wells, and Functions and How These Require Use of Dynamic Simulation*: Annex E presents gas-lift systems, wells, and functions and how and where dynamic simulation is used to address these functions.

4.2 Definition of Steady-state Models

Most gas-lift design and diagnosis programs use steady-state models. These are used to design gas-lift installations and are often used to analyze the performance of these systems. These models assume constant injection pressure, constant injection rate, and constant production rate and pressure. They assume a single injection gas pressure gradient in the annulus and a single production pressure gradient in the tubing.

These programs have been and continue to be used very successfully for gas-lift design and for diagnosis of many gas-lift problems. They are provided in most readily available gas-lift software packages and are taught in most gas-lift design textbooks. They are used to space gas-lift mandrels and to design gas-lift valve sizes and set pressures. A recommended practice when using these models is to be conservative in the design so the well can be safely unloaded to the desired operating depth and operate continuously at that depth.

There are limitations with the steady-state models, especially when wells are not flowing at steady-state conditions (i.e. flowing at stable flow/pressure). This will be explored in more detail in this RP.

4.3 Definition of Pseudo-steady-state Models

"Pseudo-steady-state" models, or perhaps more appropriately "pseudo-dynamic" models, use steady-state snapshots (progressive or multisensitivity model) in time to simulate or approximate fully dynamic performance. They are used to assist in designing gas-lift installation. They are used to evaluate a design to determine if the well will produce in a stable manner once it is placed on gas-lift. And, they can be used to diagnose an existing unstable operation. Here conditions are adjusted until the model's output approximates the observed dynamical performance. When it does match, this gives a good idea of the cause of the instability.

There are several readily available “pseudo-steady-state” or “pseudo-dynamic” models available. There are courses that provide training in how to use them. Typically, these models are used by more experienced gas-lift engineers and well analysts.

These models are typically used when terrain-induced slugging does not exist or can be neglected and/or when there are no relevant phase changes in the system under study. There are many examples of successful use of these models. A case history of one such use is presented in Annex A.

There are limitations with the pseudo-steady-state models, especially when the maximum pressure, temperature, and fluid velocities need to be known and when wells are severely slugging. This will be explored in more detail in this RP.

4.4 Definition of Multiphase Flow Transient Numerical Simulation Models

Many gas-lift wells exhibit dynamic (constantly changing) pressure and flow rate fluctuations. The dynamic behavior of wells and systems can be understood, designed, operated, and diagnosed using a detailed dynamic simulation process. This is particularly important in the surveillance and troubleshooting of gas-lift systems.

“Dynamic simulation” is a shortened version of the term “multiphase flow transient numerical simulation”. The application of multiphase flow transient numerical simulation (dynamic simulation) techniques in wells can help ensure the following.

- a) Production or active wells/field life cycle is based on sound engineering design.
- b) Optimal operational guidelines are observed.
- c) Optimization of operational issues is achieved.
- d) Production optimization is obtained.
- e) Minimization of the risks, safety hazards, and environmental impacts are predicted and practiced.

4.5 Dynamic Simulation Basic Concepts

Dynamic simulation is a method that is capable of modeling the well/system multiphase flow behavior from static initial conditions (zero rates) to a defined set of dynamic flow conditions. This simulation can also be performed to evaluate whether any specified set of conditions are achievable. Therefore, the range of applicability of dynamic simulation is typically broader than that of steady-state techniques. In gas-lift systems, the maximum benefits of dynamic simulation are obtained when it is applied in real time ^{[14] [15] [16]}.

Dynamic simulation does not replace steady-state techniques, but completes the areas not fully covered by them ^{[17] [18] [19]}. Steady-state techniques do not describe transient events in wells or systems. Pseudo steady state can approximate dynamic models if:

- a) induced slugging or phase segregation is not a concern and
- b) maximum values for fluid velocities and its pressures/temperatures are known.

Terrain-induced slugging can occur in long flowlines that go uphill and downhill, horizontal portions of wells that have an undulating profile, and/or in vertical risers from the seabed to an offshore platform.

Dynamic simulation techniques use a one-dimensional transient multiphase flow numerical simulator program. These programs are capable of modeling the hydraulic and heat transfer effects at any point and time in wells, pipelines, risers, and networks—from the reservoir to the facilities ^[9,10]. Well hardware such as valves, chokes, packers, compressors, separators, and controllers can be included in the simulation model. Annular flow and

countercurrent heat transfer effects can be modeled when necessary. Fluid composition is input as a fluid file and a proper fluid characterization^[11] is necessary. The simplistic black oil input is optional and only recommended for particular applications when there are no phase changes in the system and/or the simplified fluid description is not going to affect simulation results. Dynamic simulation provides the possibility of building a virtual well model that can be used to analyze “what-if” scenarios and predict specific multiphase flow behavior results at any stage of a well’s life. It may be used to help understand transient well/system behavior and determine the optimum process to minimize transient problems (including liquid holdup, pressure and temperature trends, and profiles)^[7]. Following the dynamic simulation process validation, the results may be used as a virtual gauge and/or a virtual downhole temperature survey during production/injection. New field developments in complex operational situations benefit from this technique by its contribution toward optimizing the operational, production, and HSE integrity during the design and operation of production systems^[8] (see Table 1 and Figure 1).

Dynamic simulation results provide to the designer and operator the maximum pressures, temperatures, and liquid and gas velocities that are going to be generated in the production system during a particular operation or worst-case scenario analysis. Normally, these maximum conditions occur during transients and are not detected by steady-state models (e.g. peak pressure and temperatures when closing a choke valve). This knowledge ensures that the well system design and the operation will be performed within the well integrity envelop, improving HSE conditions.

Dynamic simulation results are typically used to support project decisions in the following areas (see Table 1).

4.6 Two-phase, Three-phase, and Drift-flux Models

Dynamic simulation models have been available for more than two decades, including the two-phase model (gas-liquid), the extended three-phase model (gas-oil-water), and the drift-flux models. The two-phase and extended three-phase models are based on complex one-dimensional multifluid representations of the multiphase hydrodynamics and are most frequently used. However, drift-flux models are based on a drift-flux formulation that treats the two phases as a mixture. The flowing gas is assumed to be drifting along with liquid where the gas velocity can be described by a slip relationship. Drift-flux models are somewhat simpler and were developed to reduce computing times and to avoid convergence problems when coupled with reservoir simulators^[12].

Two-phase and extended three-phase models^[13] have been verified over a wide range of applications and have been accepted as simulators for transient multiphase flow of oil, water, and gas in wells and pipelines. Three-phase simulators are able to quantitatively predict complex and varied physical phenomena such as slugging and compositional tracking in typical well and pipeline configurations.

Table 1—Applications of Dynamic Simulation

Flow Assurance Threat	Wells	Pipelines	Process Facilities
Flow delivery through field life	— Verification of planned production — Maximum pressure and temperature — Production optimization — Complex wells (intelligent, multilateral, multilayer, etc.) — Artificial lift design—gas-lift, electrical submersible pump (ESP), plunger lift, etc. — Optimal routing to pipelines — Gas-lift compressors shutdown — Ability to restart — Time to establish full flow potential — Cross-flow — Commingling fluids — Water accumulation — Liquid loading — Water cut limit — Reservoir depletion	— Pipeline packing/unpacking — Start-up/shut-in — Operation of twin parallel lines — Application of multiphase pumps — Product composition from comingled fields — Component tracking [i.e. monoethylene glycol (MEG)]	— Control stability — Production optimization — Hot oil circulation — Subsea separation
Liquid surges	— Flow stability — Liquid loading — Velocity strings — Optimal use of gas-lift	— Slug breakup — Designing successful pigging operations	— Vessel sizing — Surge control
Hydrates and wax	— Hydrates potential (when, where) — Wax potential (when, where) — Inhibitor deployment — Subsurface safety valve (SSSV) placement — Wax scrapper runs frequency	— Design of insulation/bundle/heating medium — Inhibitor deployment — Water accumulation	— Handling wax volumes
Integrity and safety	— Production operations — Well cleanup — Well testing — Well control operations — Well blowout/killing operations — Workover operations — Drilling operations — Water accumulation — Annular P-T increased when fluids trapped (no venting)	— Pressurization or depressurization within material limitations — High corrosion risk identification — Reverse flow location and conditions	— Flare system requirements capabilities — Identification of leaks from routine data — High integrity pressure protection systems (HIPPSs)

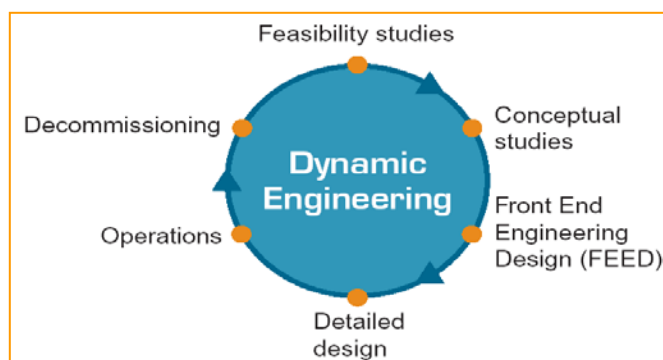


Figure 1—Dynamic Simulation Continuity Illustration

The numerical solution scheme is a semi-implicit integration method that allows for relatively long time steps to get efficient computer run times. A set of coupled first-order, nonlinear, one-dimensional partial differential equations, with rather complex coefficients are used comprising:

- a) five mass conservation equations:
 - gas,
 - hydrocarbon bulk,
 - hydrocarbon droplets,
 - water bulk,
 - water droplets;
- b) two or three momentum conservation equations (depending on software package):
 - gas + droplets,
 - liquid bulk (or 2. oil bulk and 3. water bulk);
- c) one energy conservation equation:
 - mixture (only one temperature);
- d) constitutive equations.

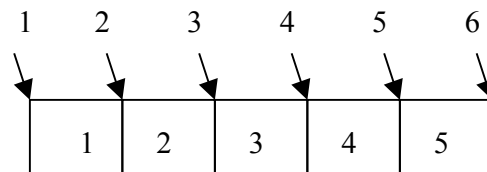
The applied closure laws for mass, momentum, and energy transfer are semi-mechanistic and require experimental verification ^[27] (e.g. using flow loops).

The one-dimensional pipe geometry is typically divided in sections for mathematical simulation (solving of differential equations) (see Figure 2). Section length is selected based on a compromise between accuracy and simulation run-time depending on the case under study. The longer the section length, the smaller the simulation time, but the accuracy is lower. Mass transients generally travel much slower than pressure transients. Therefore, to obtain more stable simulation runs, a staggered grid is used: variables such as pressure, temperature, and liquid holdup are calculated at the center of the section. Boundary variables such as flow rates, flow patterns, and velocities are calculated at the section boundaries (see Figure 3).

To rigorously calculate the radial temperature for each pipe section, a wall thickness and the related properties are assigned to describe the number of radial concentric layers (casings and annular fluid properties) that are based on the well completion schematic (see Figure 4). Pipe section properties include thickness, density, thermal capacity, and conductivity. In addition, the temperature and outer convective heat transfer coefficients of the local environment are required.

Well XX14 - Wellbore Model					
100m - 2 pipes - 8.861"		160 m MODU		ID	Wall
P13	P12	P11			
			130 m Sea Level	8.861"	Wall Riser-air
		P10	0 m SS Tree 7.0625"	8.861"	Wall Riser-sea
		P9	Wellhead 6.25"	6.184"	Wall 1
			70 SCSSV 6.25"		
		P8	345 m 20" Csg shoe	8.861"	Wall 70
		P7	1100 m TOC	8.861"	Wall 345
		P6	1950 m Mandrel 6.18"	8.861"	Wall 1100
		P5	2000 m Nipple 5.75"	6.765"	Wall 1950
		P4	2100 m	8.681"	Wall 2000
		P3	2850 m	8.681"	Wall 2100
		P2	3000 m	6.184"	Wall 2850
		P1	3050 m	6.184"	Wall Reservoir

Figure 2—Section Volume and Section Boundaries



1,2,3,...,5 (inside) : section volumes

1,2,3,...,6 (outside): section boundaries

NOTE 1 P, T, and liquid holdup are calculated at the volume center.

NOTE 2 Qg, Qo, Qw, flow regime, and velocities are calculated at the section boundaries.

Figure 3—Section Volume and Section Boundaries

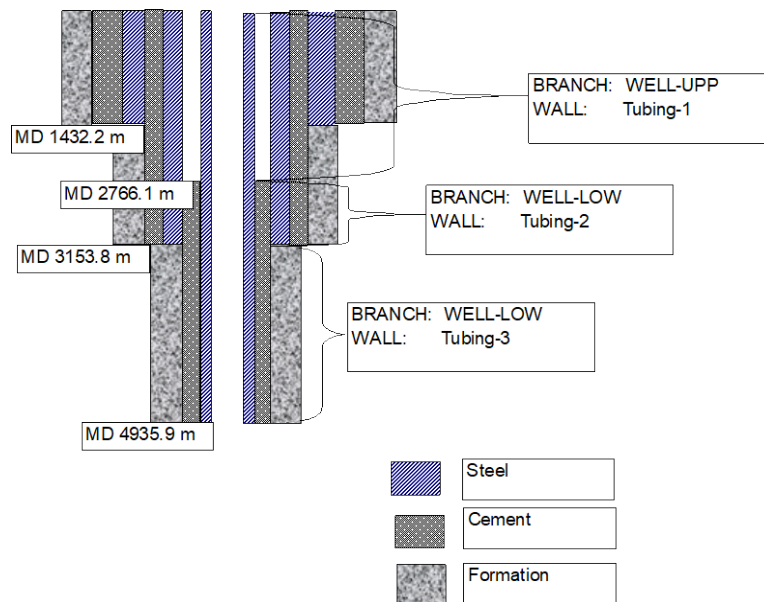


Figure 4—Example Simplified Well Completion Schematic

The average total heat transfer coefficient (overall U-value) concept should not be used in dynamic simulation techniques because it neglects thermal mass and it does not take into account heat-storage; therefore, it should only be used when applying steady-state techniques.

Two basic flow regime classes are modeled—separated (stratified and annular mist flow) and distributed (bubble and slug flow)—which are illustrated in Figure 5.

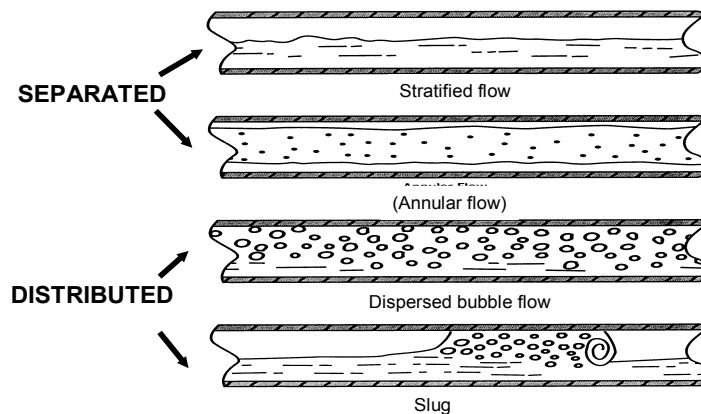


Figure 5—Dynamic Simulator Flow Regime Groups

Transitions between the regime classes are determined on the basis of a minimum slip concept, in combination with additional flow criteria. Flow is divided into gas, vapor, oil, and water droplets, and oil and water film. Changes in fluid composition in the direction of flow are determined based on pressure and temperature changes.

The initial conditions need to be defined, such as:

- starting with the well full of drilling fluids (mud, brine, and/or diesel);
- starting with the well filled with production fluids (water and oil to a measured fluid level and gas).

If the well is connected to a flowline, the flowline initial conditions require definition, such as:

- starting with the flowline filled with gas (empty);
- starting with the flowline filled with water or any liquids.

Each of the following boundary conditions should be defined:

- reservoir [i.e. rock properties, productivity index (PI), IPR];
- topsides (i.e. ambient temperature and wind velocities); and
- surroundings (i.e. seafloor, sea current velocities, and soil temperatures).

The reservoir boundary input should be explicit. The reservoir parameters are given at steady-state reservoir conditions that are adequate when the “predictive” approach is used.

The most commonly available IPR models in dynamic simulators are:

- constant PI;
- Forchheimer model (gas wells);
- single Forchheimer model (high-pressure gas wells);
- Vogel equation (oil wells in gas saturation drive reservoirs);
- Vogel combined with PI (oil wells where reservoir pressure is above bubble point);
- back pressure (gas wells);
- normalized (saturated oil wells);
- tabulated IPR curved (any preferred IPR input).

Software models allow for a quasi-dynamic, time series boundary input (quasi-transient IPR input) for the key reservoir properties such as pressure, temperature, mechanical skin, non-Darcy skin, permeability, and net pay. This allowance is relevant when the model is validated by matching it to the measured data. Nevertheless, the best option is to couple the dynamic well model to a near-wellbore^{[28] [29] [30]} reservoir dynamic simulator^[31] in order to gather all the well reservoir dynamic interactions. The quasi-dynamic IPR input helps to predefine the key variables required in matching the data.

Some simulators offer different visual outputs and variables that can be selected to analyze the results, such as the following.

- a) Trend plots: show the change in a parameter vs. time at a specific location.
- b) Profile plots: show the change in a parameter along the flow path over a period of time, at a specified frequency.
- c) The viewer: a video-like animated representation of a parameter as it changes continuously with time within a simplistic pipe model (see Figure 6).
- d) The available software packages should be evaluated before making a selection.

4.7 Comparison of Steady-state and Dynamic Simulation Techniques

Due to its historic development and the type of operational conditions, the analysis of multiphase flow phenomena can be divided into two different techniques—dynamic simulation (transient) techniques and steady-state techniques—which can be further subdivided into empirical and mechanistic methods.

An advantage of dynamic simulation is that it does not use the flow regime map to define the type of flow. The flow regime map approach is not rigorously accurate. Flow regime transitions cannot be reduced to the parameters of gas and liquid velocity. In the three-phase dynamic simulator, P-T and liquid holdup are interrelated, additionally; phase transfer is a function of P and T. The three-phase interface mass transfer model takes into account condensation, evaporation, and retrograde condensation.

The limitations of traditional steady-state techniques are case dependent and when analyzing steady-state flow cases they are limited by the following.

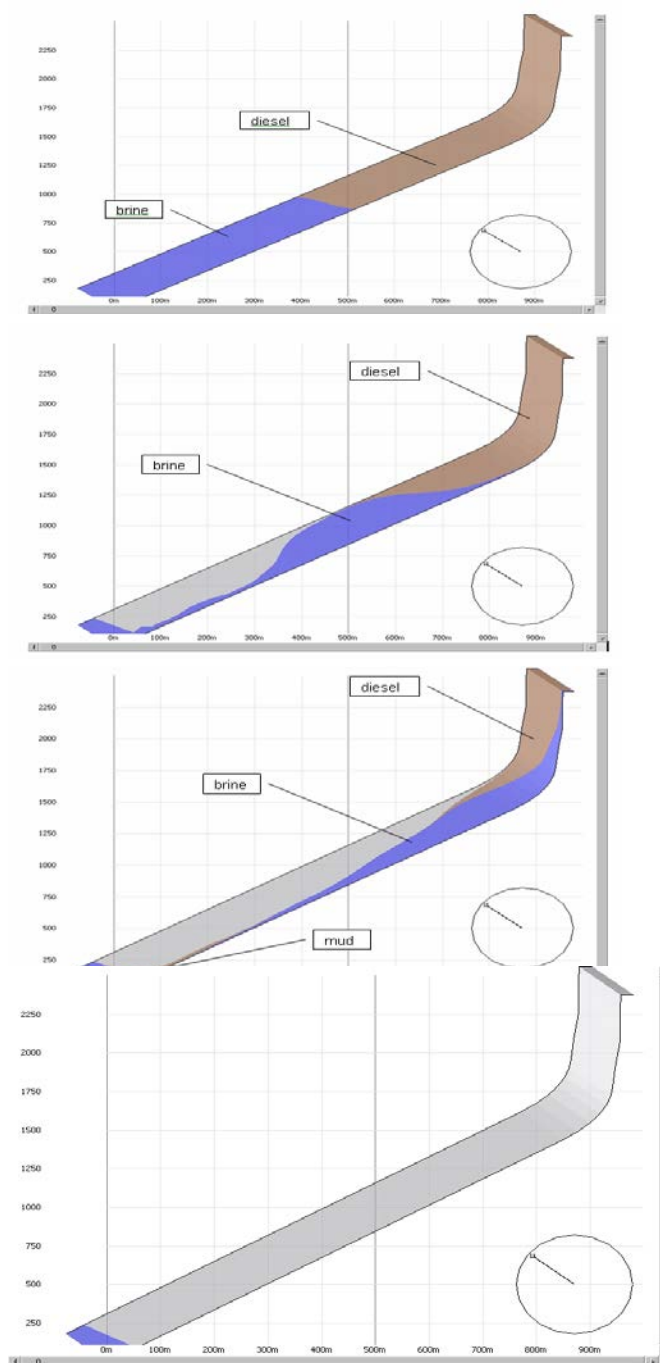
- Unable to predict terrain-induced slugging flow induced by risers, flowlines, and horizontal or deviated wells with terrain changes.
- Unable to perform stability analysis.
- Unable to evaluate transient gas/condensate, gas well liquid load-up issues.
- Use and selection of the ideal flow correlations.
- Unable to identify what maximum pressure, temperature, and fluid velocities will take place during transient condition/time.

The risk taken when using simplified techniques is high if the well completion design possibly generates terrain-induced slugging and is higher if there are phase changes in the system. Steady-state techniques can underestimate maximum wellhead P-T and can give incorrect wellbore P-T gradients or profiles. These techniques do not capture the effects of fluid vaporization and condensation caused by fluid temperature changes. Steady-state techniques do not capture the peak/lows P-T and fluid velocities generated during transients (i.e. valve closure-opening, well start-up, well shut-in, etc.).

4.8 Limitations of Steady-state Flow Evaluations

A limitation of steady-state techniques is that they provide less accurate engineering solutions for cases that are transient in nature, such as:

- a) unpredicted events of periodic stable flows;
- b) flow behavior during well start-up, shutdown, rate changes, well cleanup, well testing, liquid loading, and gas-lift unloading;
- c) dynamic behavior of plunger lift operations;
- d) performing flow assurance studies including:
 - production chemistry,
 - corrosion effects,
 - chemical injection.



Plot 1 = Initial conditions

Plot 2 = Brine arrival at surface (gas in grey)

Plot 3 = LCM (mud) being produced

Plot 4 = Cleanup completed (residual liquid in rat hole)

Figure 6—Well Cleanup with Lost Circulation Material (LCM) Viewer Snapshots Sequence

Flow stability prediction demonstrates a comparison of steady-state and dynamic simulation techniques. Steady-state techniques are not designed for cases where the production system contains a riser and/or the wells are horizontal or highly deviated unless simplifying assumptions are made that make calculations less accurate. In these cases, one of the main applications of dynamic simulation is to determine if the flow is stable in each of the probable well/system design options. Multiphase flow slugging conditions shall be evaluated and understood for a sound engineering design and safe operation. To eliminate or minimize slugging conditions, it is necessary to know what is creating the slugging flow and where it originates. An incorrect prediction of stable flow can lead to selection of the incorrect tubing size. The correct tubing size may eliminate slugging conditions. Dynamic simulation can define and establish the size and frequency of the slugging severity (see Figure 7).

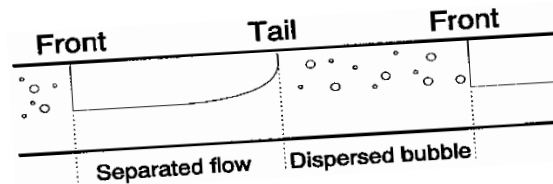


Figure 7—Slugging Flow, Front and Tail of the Gas Bubble

Tracking the development of the individual slugs along the well and flowline is necessary to estimate the volume of the liquid surges from the system. The potential problem areas that may interfere with stable flow are

- tubing, riser, and flowline length and size;
- tubing, riser, and flowline terrain inclination and elevation;
- rate changes;
- condensate-liquid content in gas;
- shut-in/start-up;
- risers.

For subsea and deepwater, the fluid behavior in the well, flowline, and riser define the artificial lift method and not only the wellbore environment. Therefore, it is relevant to integrate the well, flowline, and riser when modeling the production system. Ensuring stable flow, or minimizing unstable flow, is a key practice for well production optimization.

Dynamic simulation shall be applied when the following individual or combined oil and gas production systems and conditions are encountered:

- long horizontal-inclined wells ^[32];
- multiphase production-injection system with risers ^[33];
- tubing and annular flow with relevant countercurrent heat transfer effects ^[34];
- fluid composition that significantly change in the flow path upstream of the system output point due to flashing or condensation ^[35];
- commingling different fluids in multilayer, multilateral wells ^[36];
- intelligent well completions using well flow control and production optimization equipment ^[37];

- gas-lift wells that require prediction during well start-up through to stable flow and optimization. [38–45];
- plunger lift used for gas well deliquification [46];
- gas wells with liquid loading [47] [48];
- ESP wells that required prediction of stable flow and optimization [49] [50];
- transient conditions such as flow behavior during well start-up and shutdown [42];
- flow assurance including performance prediction to produce Newtonian and non-Newtonian fluids, production chemistry, and corrosion [51] [52] [53] [54];
- DST/pulse/multi/single rate well testing including wellbore storage and segregation effects [55] [56] [57];
- well cleanup for removal of drilling and/or completion fluids from the wellbore [55] [57] [58] [59];
- well control modeling including kicks, blowouts, and killing (circulation/dynamic) procedures [60] [61];
- workover evaluations analyzing fluid displacement (annulus-tubing, tubing-annulus) [62].

4.9 History of Multiphase Flow Modeling

The steady-state empirical methodology (originated in the early 1950s) is based on correlations developed from data collected by the researchers. These correlations are equations used for prediction purposes for a defined range of operating conditions. Some correlations perform better than others, and a number of different correlations may be needed to predict the hydraulic conditions of the resulting flow regime. Selecting the best set of correlations affect the accuracy of the predictions. For a good selection process, the specific conditions for which the correlations were developed should be known. Extrapolation beyond these conditions may make the process unreliable. Empirical methods do not address the complex physical phenomena that occur in multiphase flow.

Since the mid-1970s, progress has been made to understand the physics of multiphase flow in wells and flowlines, and several multiphase flow mechanistic models became available to simulate wells and pipelines under steady-state and transient conditions. Mechanistic models try to mathematically describe the multiphase flow mechanisms including related fluid properties and physical relationships.

Mechanistic models may be more accurate and applicable to a wider range of fluids and operating conditions than empirical models. Nevertheless, some mechanistic models have been formulated separately for wells, pipelines, vertical and horizontal flow, one-, two-, or three-phase, and for the prediction of specific steady-state or transient conditions such as the onset of slug flow and annular flow. Furthermore, as with the empirical correlations, some of the mechanistic models have been developed and verified using small-diameter pipes/tubing [<101.6 mm (<4 in.)]; this requires consideration when applying these models to larger-diameter piping systems.

Several of the popular empirical and mechanistic correlations are listed in date order in Table 2, which includes some brief recommended applications.

These empirical and mechanistic models are used as correlations in steady-state software packages, as listed in the software's selection options. One of the advantages of dynamic simulation is that it does not use correlations to connect two nodes in the system. Instead, it solves the set of coupled first-order, nonlinear, one-dimensional partial differential equations at the given boundary conditions for every grid section, in the direction of flow between the two nodes, vs time. In this case, grid section length and number of sections influence the accuracy of the simulation; the longer the section, the shorter the simulation time and the lower the accuracy (see Figure 2).

Table 2—Most Popular Empirical and Mechanistic Multiphase Flow Correlations

Empirical and Mechanistic Correlations		
Name	Published	Recommended Applications
Mechanistic Models		
Gregory	1989	A mechanistic model for vertical flow. Based on Aziz-Gover-Fogarasi.
Ansari	1994	A mechanistic model designed for well flows developed by the University of Tulsa (TUFFP).
OLGAS	1991–2000	A mechanistic model developed using data collected in the 4-8-12" SINTEF flow loop with a 50 m riser. Developed for flows in risers and larger diameters. Covers all well and flowline configurations. Includes P-T and liquid holdup predictions.
Empirical Models		
Lockhart and Martinelli	1949	Horizontal empirical model. Good correlation for laminar flow.
Flanigan	1958	Horizontal flow empirical model.
Poettmann and Carpenter	1960	Used field data to prepare a correlation that treated the multiphase flow as though it were a single, homogeneous phase.
Baxendell and Thomas	1961	Used La Paz and Mara field (Venezuela) data to develop a revision of the Poettmann method to perform better at higher flow rates.
Duns and Ros	1963	Developed for vertical flow of gas and liquid mixtures in wells. Based on experimental work using air and oil.
Hughmark and Dukler	1962–1964	Horizontal empirical model used for gas-oil flows.
Hagedorn and Brown	1965	Developed using data gathered from a 1500 ft experimental well with a tubing diameter of less than 1.5 in. Does not use flow patterns.
Eaton	1967	Horizontal flow empirical model developed for holdup. Does not include angle of inclination and may under-predict holdup in hilly terrain.
Orkiszewski	1967	Developed for flows in vertical and deviated wells.
Aziz, Govier, and Fogarassi	1972	A semi-empirical method designed and tested for gas-condensate flows in wells.
Beggs and Brill	1973–1977	Built for all inclination angles. Mainly used for horizontal flow. Uses exponents based on flow pattern.
Eaton and Oliemans	1976	Improved for frictional pressure losses. Good for gas-condensate or gas-water systems.
Gray	1974–1978	Developed for modeling vertical flow of gas-condensate mixtures in tubes up to 3.5 in. Used only for gas wells. Does not use flow patterns.
Oliemans	1987	Includes angles of inclination. Considers horizontal stratified and wave flow.

Dynamic simulation techniques were pioneered by the nuclear industry to predict two-phase flow transient behavior with the accepted accuracy required to analyze nuclear reactor piping systems since dynamic instabilities could lead to critical plant failures. Computer techniques were first adapted to the oil and gas industry in 1980 (first pipeline simulator was made from a reactor model) and the advance of computer technology enhanced the current use of dynamic simulation.

Dynamic simulation is a technique that has been applied since 1980 by facilities engineers for pipeline and slug catcher designs and by well engineers for well control and well kill operations design. The application of dynamic simulation in producing wells is a practice that requires multidiscipline teams and/or cross-discipline experience to build and integrate the well model (with the corresponding reservoir inflow performance boundary conditions) into an effective total production system model.

5 Recommendations for Implementing Dynamic Simulation of Gas-lift Wells and Systems

5.1 General

The purpose of this section is to provide specific recommendations for implementing dynamic simulation of gas-lift wells and systems. New and experienced users can apply the recommendations in accordance with the following guidance.

- a) Take a class in the use of dynamic simulation models.
- b) Use this document as a text book to enhance their learning.
- c) Work with an experienced user on the first few projects to gain a thorough understanding and to select a model (or models) that best fit their application(s).

Experienced users should read this document to enhance their understanding of dynamic simulation processes, tools, and techniques. They shall evaluate the various dynamic simulation programs, and pseudo-models, and choose the best for each application.

5.2 Choose Type of Model to Use

5.2.1 General

The user should consider using steady-state models in combination with dynamic models during dynamic simulation of a gas-lift well or system.

5.2.2 Steady-state Model

Most readily available gas-lift design and diagnosis programs use steady-state models. These models assume constant injection pressure, constant injection rate, and constant production pressure. They assume a single injection gas pressure gradient in the annulus and a single production pressure gradient in the tubing. See 4.2 for more detailed information.

These programs have been and continue to be used very successfully for gas-lift design and for diagnosis of many gas-lift problems. They are provided in most readily available gas-lift software packages and are taught in most gas-lift design textbooks. They are used to space gas-lift mandrels and to design gas-lift valve sizes and set pressures. A recommended practice when using these models is to be conservative in the design so the well can be safely unloaded to the desired operating depth and operate continuously at that depth.

5.2.3 Pseudo-steady-state Model or Pseudo-dynamic Model

“Pseudo-steady-state” models, or “pseudo-dynamic” models, use steady-state snapshots to simulate or approximate dynamic performance. They are used to assist in designing gas-lift installation. They are used to evaluate a design to determine if the well will produce in a stable manner once it is placed on gas-lift. And they can be used to diagnose an existing unstable operation. Here conditions are adjusted until the model’s output approximates the observed dynamical performance. When it does match, this gives a good idea of the cause of the instability. See 4.3 for more detailed information.

There are several readily available “pseudo-steady-state” or “pseudo-dynamic” models available for use. There are courses that provide training in how to use them. A case history of one such use is presented in A.3.

5.2.4 Multiphase Flow Transient Numerical Simulation Model (a Dynamic Model)

Many gas-lift wells exhibit dynamic (constantly changing) pressure and flow rate fluctuations. The dynamic behavior of wells and systems can be understood, designed, operated, and diagnosed using a detailed dynamic simulation process. This is particularly important in the surveillance and troubleshooting of gas-lift systems. See 4.4, 4.5, 4.6, 4.7, 4.8, and 4.9 for more detailed information. Case histories of using this type of model are presented in Annex A.

5.3 Applications, Benefits, and Methods of Implementation of Dynamic Models

Optimal design and operation of multiphase injection and production systems rely on understanding multiphase flow behavior.

The application of steady-state and/or dynamic techniques should be based on the level of complexity of the production/injection system and the fluids to be modeled. Steady-state techniques should be used only for steady-state conditions. The advantage of steady-state techniques is that the models can be constructed and sensitivities can be run quickly. However, using static techniques for transient conditions may provide inaccurate results.

Dynamic simulation techniques require experienced personnel and allocated time for the building of models and analyzing results. As a result, this may be a more time-consuming technique. Both techniques are normally applied and the challenge is to optimize their combined use without compromising the quality of the design and the operational integrity of the system. Risk reduction and potential catastrophic failures are more difficult to quantify without dynamic simulation.

Steady-state techniques can be useful in providing first-order evaluations for gas-oil field developments to identify the operating scenarios with the most limiting capacity constraints; however, dynamic techniques are needed to accurately calculate capacity requirements. When operating practices are time sensitive, the effect on system design and the calculation of the system capacity requirements is important. Transient analysis should be applied to evaluate maximum P-T and fluids velocities (normally originated during transient conditions) and the possibility of hydrate and/or wax formation, and to establish operational guidelines that apply during shut-in or start-up operations.

Transient models should be built to analyze the start-up and shut-in operations and accurately define the steady-state or unstable conditions and the maximum wellhead pressures, temperatures, and profiles. Once the steady-state conditions have been confirmed and defined by transient simulation, and wellhead P-T and P-T profiles have been validated, these profiles shall be used as correlations in steady-state software for the quickness and reliability of the steady-state technique while obtaining reliable results.

The user should evaluate the gas-lift well and/or system characteristics and assess the impact on improving design, safe operations, and performance understanding leading to production optimization, when applying dynamic simulation. High improving impact shall be obtained in the examples provided between brackets in each case type listed below:

- well type (i.e. horizontal, snake, deviated);
- system type (i.e. subsea gas-lift, riser, sinusoidal flowline);
- well completion type [i.e. big bore (>4 in.), multilayer, multilateral, intelligent];
- well location (i.e. offshore, subsea to shore, subsea to platform, deep subsea);

- produced fluid characteristics (i.e. gas and condensate, three-phase);
- gas-lift gas characteristics (i.e. wet, corrosive, inert);
- production chemistry potential (i.e. hydrates, wax);
- well operation (i.e. kickoff, unloading, start-up, shut-in, testing, production logging);
- gas-lift type (i.e. single-point injection, riser, dual, auto);
- gas-lift optimization (i.e. liquid loading, slugging, annular slugging, conversion to gas-lift).

The user should consider the following issues prior to choosing and when using a dynamic model for simulation of a gas-lift well or system.

- a) Evaluate the causes of instability in a gas-lift well and determine methods to correct the unstable operation (see B.2 and D.5).
 - 1) Potential causes of instability include decreasing reservoir pressure, increasing water cut, oversized tubing for the current fluid production, decreasing total gas-liquid ratio (GLR), and increasing back pressure in the surface gathering system.
 - 2) These problems can be overcome by placing the well on gas-lift and/or resizing the surface piping to remove excess back pressure.
 - 3) Typical problems include caused by instability: unstable operation due to an excessively large port size in an operating valve or orifice, or multipointing on two or more unloading gas-lift valves due to periodical reopening of an upper unloading valve, leaks in the tubing, mandrels, or valves, or changes in the inflow performance of the well.
 - 4) These problems can be overcome redesigning the gas-lift system and/or correcting leaks in the system.
 - 5) To recognize and rectify these instability problems, a tool is needed to model the well in its current flowing condition. It may either be a steady-state or dynamic model, but the flowing conditions typically warrant dynamic modeling to understand liquid loading, phase separation, and gas velocity issues due to multiphase fluid flow in the production tubing. Usually, most completions are not purely vertical and may be highly deviated where theoretical correlations are not capable of accurately predicting the fluid flow results. These wellbore deviations can also generate terrain slugging.
 - 6) Terrain slugging is not desirable because it results in pressure fluctuations, changes in production rate, and variations in the phase fractions at the well outlet. Using a transient multiphase flow simulator provides an opportunity to realize if a well with a sophisticated trajectory will act as a slug generator. In some cases, it may be possible to tune the operational parameters to eliminate this slugging behavior.
 - 7) Risers are an integral part of offshore and subsea production systems, and are part of the well completion and workover operations. Stable conditions defined by using steady-state analysis may be incorrect in this kind of production system. Dynamic simulation offers a means to define the conditions where slugging may interfere with stabilized flow.
- b) Determine the preferred way for start-up of gas-lift in flowing wells (see B.3).
 - 1) Dynamic simulation shall be used to define the optimum time to switch from natural flow to gas-lift.

- 2) In areas where the natural flowing well should be shut-in and kicked off frequently (i.e. hurricane prone areas), the kickoff water cut limit should be defined using dynamic simulation and a safe well shut-in and restart process should be performed. If the water cut is below the kickoff limit, the well can be put back online without gas-lift. If the water cut is above the kickoff limit, the optimum gas-lift scenario can be planned in advance and the well can be restarted.
- 3) Wells may need to be restarted due to:
 - i) high water cut or level in the annulus,
 - ii) low bottomhole pressure (BHP),
 - iii) poor well inflow performance,
 - iv) high back pressure in surface facilities.
- c) Determine the preferred way to unload liquid in gas wells (see B.4).
 - 1) A major issue with gas well production is liquid loading, usually with water but sometimes with condensate or a combination of water and condensate. Depending on the reservoir inflow characteristics, the well may experience loading issues, either due to reservoir pressure depletion, decreased gas rate, or increased liquid production.
 - 2) Gas-lift can be used to address liquid loading by injecting enough gas below the liquid level to exceed the critical flow rate. This is the rate required to lift the gas and an entrained liquid to the surface so the well will remain unloaded.
 - 3) Transient multiphase flow modeling offers new insights into the mechanisms of liquid loading. The onset of liquid loading is triggered by film flow reversal rather than droplet flow reversal, when the droplet drag force no longer exceeds the droplet gravity force. Dynamic simulation matches actual liquid loading better than the "Turner critical velocity concept" model in that it provides a more realistic description of liquid loading.
 - 4) Dynamic simulation should be used to compare results and select the optimum methodology to unload liquid in gas wells.
- d) Determine the preferred way to optimize intelligent or complex gas-lift completions (see B.5).
 - 1) The following components can be used in an intelligent well completion to optimize its performance:
 - i) flow control devices, which are usually hydraulically-operated control valves used to control flows into and out of the reservoir;
 - ii) feedthrough isolation packers that enable hydraulic control lines to be fed through to subsurface control valves;
 - iii) downhole sensors that report pressure, temperature, flow rates, and other parameters such as reservoir fluid concentrations;
 - iv) control systems comprising hydraulic and/or electrical surface systems used to monitor and control subsurface conditions. Intelligent wells require an extra degree of engineering knowledge and analysis.
 - 2) Dynamic simulation shall help optimize the design of intelligent wells. Dynamic simulation should be used to justify the commingling of production zones or to justify the increased complexity of an intelligent well completion to produce from separate zones. Dynamic simulation should be used to optimize the well design and production from multilayer and multilateral well completions.

- e) Identify problems with cross-flow or commingling in gas-lift wells (see B.6).
 - 1) Cross-flow can occur when more than one productive zone is open in a wellbore. It may occur between zones during well shut-in and while the well is flowing with very little drawdown, or when the flowing BHP is significantly higher than the pressure of one of the producing zones.
 - 2) Dynamic simulation should be used to understand transient flow conditions and cross-flow occurrences. It is important to model the well trajectory by creating enough pipe segments to estimate the commingled production from each zone of interest.
 - 3) If cross-flow or commingling is a significant problem, it can lead to reduced production from the lower pressure zone(s), as well as to incorrect reservoir management. To address this, it may be necessary to produce the zones separately. Dual gas-lift or intelligent well completions may be required.
- f) Optimize gas-lift shut-in and start-up operations (see B.7).
 - 1) Operating and flow assurance problems can occur if wells are not shut-in and started up properly. These are purely transient operations.
 - 2) Dynamic simulation can provide guidelines on performing these procedures safely and optimally.
- g) Manage gas-lift systems (see B.8).
 - 1) Gas-lift system design consists of three processes (see [API 11V5](#), [API 11V6](#), and [API 11V8](#)):
 - i) defining major tubing size (monobore, tapered, etc.);
 - ii) determining the spacing of the gas-lift mandrels (GLMs); and
 - iii) determining the size, type (rectangular/venture), and setting of the gas-lift valves and/or orifices.
 - 2) The practical uses of dynamic system models for system management include:
 - i) assisting with gas-lift design (optimum gas injection depth and rate, tubing/annulus countercurrent effect in T profile);
 - ii) confirming or validating that a given design will work properly (virtual unloading simulation);
 - iii) identifying and diagnosing (troubleshooting) transient problems with a gas-lift system;
 - iv) optimizing a gas-lift systems operations and develop a predictive mode for system optimization.
- h) Determine the preferred components of dynamic modeling (see B.9 and B.10).
 - 1) Reservoir, well, surface, and process facilities are typically optimized as individual components. The part(s) of the gas-lift system to be modeled depends upon the objectives of the study. To understand the multiphase flow behavior of the total production/injection system and evaluate the interaction between the tubing, gas injection annulus, flowline, and riser, the total system should to be integrated.
 - 2) However, it is sufficient to model the wellbore of a single well with a short surface pipeline when the well is at early stages in the design of the gas-lift system and/or when the initial troubleshooting efforts are focused on a particular well and case scenario.
 - 3) When focusing on one well, the model can be as simple or as complex as required. The annulus can be included in the model as a flow path and the countercurrent heat transfer effect of injecting a relatively cold lift gas in the annulus and producing a hot reservoir fluid in the tubing can be evaluated.

- 4) For instance, if the objective is to define the optimum injection depth and gas-lift gas rate, then it is not necessary to include the annulus in the model. If the objective is to determine the actual tubing flowing temperature profile to properly space gas-lift valves, then the annulus should be included in the model to obtain the countercurrent heat transfer effect that will influence the temperature profile.
 - 5) The objectives will define the limits of the model, and eventually the use of an integrated dynamic simulation model is recommended. The model will account for any well/flowline/riser interaction effects.
- i) Determine the optimum automatic control system (see B.7.3).
- 1) When an automatic control system is present, the application of a dynamic simulation process (controller in conjunction with a dynamic simulator) is a good approach to deal with an unstable flowing gas-lift well. This approach relies on dynamic, transient gas-lifted well models to maximize the lift gas efficiency and to capture the well and process knowledge developed in the dynamic models [2,3].
 - 2) The concept of this approach is to analyze well behavior and design stabilizing controllers. Where applicable, estimators can be designed based on a dynamic model of the system.
 - 3) Another approach is to develop a simplified nonlinear dynamic model of the system for a specific case considering the physical principles of gas-lifted wells.

5.4 Information Required for Dynamic Simulation

The user shall compile the following information to prepare for performing a dynamic simulation of a gas-lift well or system.

- a) Define or obtain the pressure-volume-temperature (PVT) properties of the fluids being produced (see C.2).
- 1) Design and operation of a gas-lift well require predicting flowing fluid characteristics. There are various methods to do this including use of "black oil" correlations, PVT compositional tables, and fully compositional modeling.
 - 2) As a rule of thumb, if phase changes are expected in the system (i.e. gas/condensate wells from reservoir to wellhead), a PVT compositional table will give more accurate P-T and liquid holdup calculations than a black oil correlation.
 - 3) Fully compositional modeling is computationally demanding (the hydrocarbon composition is flashed at every in situ P-T) and is recommended when accuracy is imperative. The need for fully compositional PVT modeling is exemplified in a multilayer well completion with commingled production of significantly different reservoir fluids. The produced fluid composition will differ from one flowing BHP to another. It is important to know the hydrocarbon compositions for different reservoirs and adjust them with the appropriate datasets as explained. The dynamic simulator should be able to track the different fluid compositions in the system and the resulting fluid mixes along the producing path. Another example is the tracking of gas of a different composition than that of the produced gas in the gas-lift system. In order to properly evaluate stability in the flow path where there is a mix of two gases, the different gas compositions shall be known and the resulting mix calculated.
 - 4) PVT compositional tables should be the default option in dynamic simulations. The use of "black oil" correlations and/or fully compositional modeling should be justified based on fluid simplicity or complexity, respectively, and on study objectives.

b) Define the geometry of the production path(s) and equipment (see C.3).

- 1) Calculating pressure drop requires estimation of pressure losses due to friction, gravity, and acceleration. The distance traveled by the fluid along the wellbore and in the vertical direction determines the friction and the gravity components, respectively. The resulting multiphase flow regime is affected by well deviation.
- 2) An accurate representation of the well's trajectory is the first step in constructing a transient model for a gas-lift well. It is also important to represent the exact profile of horizontal and deviated wells, because these profiles (ups and downs) can generate terrain-induced slugging.
- 3) In dynamic simulation, the one-dimensional pipe geometry is typically divided in sections for mathematical solving of differential equations. Section length is selected based on a compromise between accuracy and simulation run-time depending on the case under study. The longer the section length, the smaller the simulation time, but the accuracy is lower. In general, short sections should be used to favor accuracy and mainly when liquid holdup estimates are relevant (liquid holdup accuracy is highly influenced by section length).
- 4) To obtain accurate P-T calculations along the well profiles and at the wellhead, the well completion diagram, including all casings and annular fluids, cement and formation thickness, and heat transfer coefficients for each constitutive material, shall be entered in detail. These data are used to estimate the radial heat losses in the wellbore, which are a function of the number of concentric walls. While the use of "overall heat transfer coefficients" to estimate these heat losses is a simpler option and standard practice in steady-state calculations, it is inadequate and should not be used in transient simulations as thermal mass and heat storage effects in the different materials are not considered.
- 5) All equipment able to produce a P-T change should be included in the model.

c) Determine the inflow performance from the reservoir to the wellbore (see C.4).

- 1) IPR is the plot that connects measured flowing BHPs at different production rates. The IPR quantifies the flow resistance in the formation and in the well/reservoir interface. The IPR is a steady-state definition. Studying any transient phenomena should be coupled with a well's inflow performance as the production will vary depending on the changes in flowing BHP (see B.9.2).
- 2) For existing wells, the IPR can be measured with well test and inflow pressure data, or it can be obtained from multirate well test data. For wells not on production, analytical methods may predict the IPR by using the formation permeability and its thickness, expected drainage area, well radius, well/reservoir interface, and the PVT data of the reservoir fluids.
- 3) The IPR has to be entered in the transient simulator in a required format, which can either be a table, the linear PI type, a Forchheimer model, a Vogel inflow performance relationship (IPR) model, etc. Depending on the purpose of the analysis, e.g. for studying the initial start-up of a gas-lift well and its cleanup performance, it is best to use the distributed IPR approach. This requires dividing the productive interval into segments and calculating individual IPRs depending on the segment characteristics, as in permeability. These inflow sources can be input to the transient simulator at their corresponding depths to accurately visualize the inflow distribution and completion fluid cleanup performance including the reservoir thickness. The number of the inflow sources depends on the required level of accuracy. A similar approach can be used in commingled gas-lift producers. If the well is producing from several reservoirs, every inflow zone can be modeled with a separate IPR for a more detailed analysis. Changes in the reservoirs' pressures and temperatures due to depth differences, as well as changes in GLR and water cut, need to be reflected.

- d) Define the boundary conditions that constrain the well operation (see C.5).
- 1) For every source of flow into the wellbore, the reservoir pressure and temperature shall be specified (the reservoir is the lower boundary for the well dynamic model where flow is initiated). The wellhead back pressure and temperature are also required (if we stop the well model at the wellhead then the wellhead is the upper boundary). If the transient model has a wellhead bean or choke, the wellhead P-T needs to be specified downstream of the wellhead choke. The surface injection P-T and the amount of injected gas need to be input, if the injection model starts at the wellhead. Any planned changes in the wellhead and surface injection pressures, or in lift gas injection rate, should be entered as time series to determine their impact.
 - 2) In addition to these boundary pressures and temperatures, the transient simulators require the well's initial fluid content and the associated pressures and temperatures, including the soil temperature gradient, surface-subsea temperature gradient, and ambient temperature. These represent the surrounding well boundary and are used as the start-up conditions for the calculations at time zero.
- e) Evaluate the potential for hydrate formation and/or wax deposition (see D.7).
- 1) Hydrates are solids that can block oil and gas flow. Locations for hydrate formation shall be determined.
 - 2) The transient multiphase flow simulator selects the in situ fluid properties, such as phase fractions and densities, from a previously constructed PVT compositional table.
 - 3) A PVT report normally contains the following laboratory datasets:
 - i) the saturation point,
 - ii) the separator tests,
 - iii) constant composition expansion (CCE),
 - iv) constant volume depletion (CVD),
 - v) viscosity measurements, and
 - vi) hydrate characterization studies, where necessary.
 - 4) Hydrates curves are necessary if hydrate formation studies are required.
 - 5) Dynamic simulation facilitates estimating when, where, and under which conditions hydrates may be formed in a production system, during transient and steady-state conditions, based on the difference between a hydrate temperature (T_{hyd}) and fluid temperature (T_f) at section pressure.
- f) Evaluate the potential for corrosion (see D.6).
- 1) Water accumulations in wells and flowlines can be induced by hilly terrain, well deviations, and changes in flow direction. In deviated and horizontal wells and flowlines, local water cuts can exceed 20 % to 50 % despite low inflow rates from production zones and/or low production rates measured at surface, even with water cut measurements of 1 % or less. The amount of water going in and out the system does not represent the amount accumulated in the low points within the system.
 - 2) Dynamic simulation can determine the points where there is enough water accumulation to originate corrosion. The properties of the water are provided by the PVT compositional table in use. Other water sources and/or drilling fluids can also be input. The density and viscosity values of these fluids at standard conditions are required.

5.5 Information Provided by Dynamic Simulation

Some simulators offer different visual outputs and variables that can be selected to analyze the results, such as:

- trend plots: show the change in a parameter vs time at a specific location;
- profile plots: show the change in a parameter along the flow path over a period of time, at a specified frequency;
- the viewer: a video-like animated representation of a parameter as it changes continuously with time within a simplistic pipe model.

Profile plots are very useful analysis tools like in steady-state simulation techniques, but trend plots make the difference being the most relevant analysis tool. Profile and trend plots should be combined to fully understand the multiphase flow behavior. Interpretation of trends plots may initially be difficult for inexperienced users. In gas-lift optimization, trend plots replace the typical gas-lift injection charts and its interpretation provides similar clues for troubleshooting and optimization. The use of the video-like tools (viewer) are an added value of extreme importance to fully understand gas-lift unloading, gas-lift kickoff, well start-up, well shut-in, and similar transient fluid displacement simulations.

The user should consider the information provided by a dynamic simulation model and how this information may be applied. The user shall

- a) Identify the gas-lift well and system problems that can be determined by dynamic simulation (see D.1 and D.2).
 - 1) Many problems can be identified using dynamic simulation. The user shall determine the problem(s) that need to be solved. There are problems that inhibit stable multiphase flow operations such as:
 - i) terrain-induced slugging,
 - ii) inclination/elevation,
 - iii) rate changes,
 - iv) condensate-liquid content in gas,
 - v) shut-in/start-up,
 - vi) risers.
 - 2) Other types of problems include:
 - i) unloading gas-lift valve leaks;
 - ii) incorrect mandrel spacing and unloading valve design;
 - iii) annular heading:
 - downhole operating gas-lift valve and surface lift gas control valve/orifice interaction,
 - annular liquid condensation;
 - iv) density wave instability ^[41];
 - v) nonconstant fluid composition in tubing above gas injection point, when injecting lift gas of different composition than the produced gas;

- vi) compressor pressure fluctuations;
 - vii) interference between gas-lift wells in the system.
- b) Identify the influences of well design and equipment (see D.3).
- 1) Determine if gas-lift injection should occur in the wellbore annulus (define optimum rate and depth), at the subsurface wellhead (for subsurface wells), or at the base of the riser.
 - 2) In offshore wells producing to a platform, gas-lift assistance may be obtained initially by injecting gas in the base of the riser rather than going through a subsea flowline to the wellhead with the pressurized lift gas. The savings from this design change can be significant. Later in the field life, when reservoir depletion occurs and water cut increases, gas-lift injection through the tubing-casing annulus may be required. Dynamic simulation can compare the different scenarios and help to define the optimum approach. It can also forecast the optimum time to switch producing scenarios and methods. The type of well completion, well profile, and well location play a major role in designing gas-lift components and systems.
 - 3) Determine if different types of gas-lift valves (i.e. hydraulically/electrically remotely activated, installed by tractors or by slick line operations, etc.) can provide an optimum deeper injection point. Estimate extra benefit ratio, long-term profitability, and system flexibility as well as troubleshooting options.
 - 4) Determine the optimum type of SSSV and depth location with no production chemistry issues.
- c) Identify the issues related to production chemistry (see D.4).
- 1) The chemistry of the produced fluids can result in formation of wax, paraffin, asphaltines, scale, or hydrates. These can all interfere with normal gas-lift operations. Methods to address each of these shall be understood and addressed.
 - 2) In addition, deepwater operations amplify the environmental and safety concerns. The increased risk associated with long subsea tiebacks, dry-tree risers, and extended export pipelines in cold ambient water should be considered by operators when planning their development scenarios ^[63]. Under these severe conditions, it is important to understand multiphase fluid properties and the design options to prevent or mitigate flow assurance challenges. Dynamic simulation is a tool to provide understanding of flow behavior and the resulting internal conditions at any point of the production system.
- d) Predict and address issues with slugging flow (see D.5).
- 1) Slugging flow is a multiphase flow pattern in which slugs of liquid are separated from each other by bubbles of gas. A liquid film with a varying thickness is present around the gas bubbles. Some gas can be entrained in the liquid slug body in the form of much smaller bubbles. The gas and liquid flow rates, with the corresponding pressures and temperatures, can result in slugging in an oil well.
 - 2) Hydrodynamic slugging is generated by slip between the liquid and gas phases. To determine if slugging flow will occur in a pipe segment, the steady-state flow pattern map for a specific deviation shall be reviewed. This approach helps to explain the hydrodynamic slugging. To define the slugging severity, size of slug and slug frequency dynamic simulation should be applied.
 - 3) Terrain slugging is fully transient and generated by flowline ups and downs and liquid accumulation in the lower points that it is also related to rate and fluid velocity conditions. To define terrain slugging, dynamic simulation should be applied.
 - 4) Determine flow regime and changes vs time, define slugging conditions vs. time and use video-like outputs as an extra tool to fully understand multiphase flow behavior and ensure any proposed solution works.

- e) Identify water accumulations in the flow paths (see D.6).
- 1) Water can accumulate in low spots in well and/or flowline trajectories. The presence of water can inhibit oil and gas flow. It shall be recognized and addressed if it is present.
 - 2) The dynamic simulator provides the resulting trends and profiles for the key variables of:
 - i) pressure and temperature;
 - ii) water, oil, gas, water vapor, water droplets, oil droplets and gas bubble velocities, superficial velocities, and fractions;
 - iii) water film fraction and velocity where sweet corrosion exists only if a water film is wetting the pipeline;
 - iv) flow regime and separated/dispersed flow;
 - v) water wetting—normally it is assumed that water is the continuous phase when the water cut is larger than 30 %; the inversion point is usually somewhere between 30 % and 50 %;
 - vi) water condensation rate;
 - vii) pH;
 - viii) partial pressure of CO₂;
 - ix) shear stress between water film and pipe wall;
 - x) critical velocities and locations for water loading and erosion.
 - 3) Use video-like outputs as an extra tool to fully understand liquid holdup behavior and ensure any proposed solution work.
- f) Identify potential for hydrate formation and prevention methods (see D.7).
- 1) Hydrates can form in gas, gas-condensate, and black oil systems and can block any flowline. Hydrate blockages can form very rapidly when suitable P-T conditions and compositions are present. Severe P-T changes across chokes and/or gas-lift injection valves can create hydrates. Clearing hydrate blockages in subsea equipment or flowlines poses concerns that can be time consuming. Hydrates are the most prevalent flow assurance problem in offshore oil and gas operations.
 - 2) Transient operations such as start-up and shutdown may be very susceptible to hydrate blockages because the production system is likely to fall into the hydrate region. It is important to model transient operations for deep wet and dry subsea wellheads and subsea tiebacks in deep waters; shut-in and restarting from shut-in conditions can create significant flow assurance problems. Hot fluids from the wellbore in contact with a cold flowline can form hydrates during restarting operations. Subsea wellhead conditions at the mudline are also often within the hydrate formation region. As the water depth increases, boundary temperatures decrease and the potential for higher shut-in pressures increases due to additional liquid head, as well as the probability of hydrate formation.
 - 3) In the upper part of the well closest to subsea temperature conditions, the temperature can fall below hydrate and/or wax deposition conditions. The SSSV and all other operational tools should be located in a zone where no hydrate formation or wax deposition is expected as this could compromise their operation. Use hydrate and wax modeling as appropriate to determine the impact of hydrate and wax deposition and to plan remedial hydrate and wax prevention and wax removal schedules.

4) Dynamic simulation can answer the following questions.

- i) What is the predicted hydrate dissociation temperature profile? How far the conditions are from hydrate formation? Where? When?
- ii) When will the temperature fall into the hydrates region?
- iii) How deep below the wellhead will the well experience hydrates problems? When?
- iv) What's the best solution for the well flow assurance problems?
 - pressure control,
 - temperature control,
 - remove supply of water,
 - perform a hot or cold restart,
 - preheating the flowline,
 - flowline depressurization,
 - insulation,
 - inhibitor injection? Where? When?

g) Implement guidelines to prevent hydrate formation (see D.8).

- 1) A significant effort is required in the design phase to develop a production system with an acceptable level of risk. At the beginning of the flow assurance design process, basic design and operating philosophies that cover hydraulics, deliverability, hydrates, and waxes should be clearly set. The challenges of thermodynamically inhibiting production systems under steady-state and/or transient operations can be prohibitive. It may not be possible to avoid the hydrate formation region in all probable operating scenarios. It is therefore important to estimate the risk of forming a hydrate plug during a restart operation or in a new field design. Dynamic simulation is an effective way to reduce uncertainty by screening various inhibition and thermodynamic options.
- 2) Several methods can be used to prevent the formation of hydrates where they occur. The injection of inhibitors is the most commonly used in gas-lift systems, but again several types can be used.
- 3) Inhibitors can provide protection against hydrate formation if sufficient quantities are injected, but under-injecting may accelerate the kinetics of hydrate formation. Therefore, it is typical to overdose to be safe. Significant savings can be obtained using dynamic simulation to estimate the right amount of inhibitor and the times when inhibitor injection is no longer required. The water production rate should be known. The main uncertainty is the amount of the dissolved salts in the produced water and their effect on hydrate formation. Salinity in produced water tends to reduce hydrate temperature, but to be conservative normally the calculated hydrate inhibitor requirements do not account for the inhibitor effect of produced water salinity. However, dynamic simulation can include the effects of salinity.
- 4) Dynamic simulation facilitates the tracking and/or projecting the amount of inhibitor in the well/pipeline to ensure enough inhibitor is available to be effective. Inhibitor can be tracked in both the water and gas phases. Dynamic simulation provides the inhibitor [methanol (MeOH) or MEG] concentration along the well/flowline profile and the time required to reach a desired inhibitor concentration.
- 5) Dynamic simulation allows development of operating guidelines that ensure effective injection rates and distribution of inhibitors for all operating modes.