Well Performance and Nodal™ Analysis Fundamentals

Skill Module Overview

Introduction

- This fundamental level PetroAcademy module addresses well performance and how an oil or gas or even an injection well’s overall operation and function may be analyzed and/or planned
- The prime industry analytical tool for doing so employs the technology and principles known as oilfield Nodal™ Analysis or System Analysis
- Stated below is a summary outline of the module layout or work plan you will be guided through and asked to follow:

  A. The module description is presented to illustrate the overall layout of the module
  B. The module objectives are presented
  C. A series of PowerPoint lectures are presented, interspersed with several basic exercises and problems you are asked to work
  D. The module includes an Oil Completion Case Study and a Gas Well Completion Case Study
  E. The module concludes with a Post-Assessment
Module Description

- This module develops the principles necessary for managing well performance, either in:
  - A predictive mode looking forward in a planning study, say for a Plan of Development proposal; or
  - For actual well problem diagnostic analysis purposes of oil and gas wells operating in the field
- Analytical and empirical equations are developed to predict well system performance
- Both simple and complex inflow equations are matched with tubing outflow models to create well system models
- Several increasingly complex nodal analysis exercises are worked
Learning Objectives

This module will cover the following learning objectives

1. Develop inflow and outflow models and work several exercises to illustrate well completion design methods
2. Examine reservoir flow, downhole completion, tubing, surface choke and flowline models to exemplify reservoir-to-separator-inlet systems
3. Develop sensitivity models to examine tubing size options, reservoir depletion effects, water cut rise effects, decreased gas / liquid ratio effects, well depth effects, surface pressure and temperature effects, formation permeability effects, PVT effects, and other complex sensitivities to assess the performance of any perceived well reservoir and its mechanical well configurations
4. Examine artificial lift completions to highlight how analyses developed for flowing wells also apply to wells on artificial lift

5. Evaluate optional well data parameters using system analysis principles to optimize overall well performance
6. Assess and analyze formation damage skin effects using system analysis principles
7. Apply a broad array of both reservoir and mechanical sensitivities to evaluate and accurately predict well performance for wells producing any combination of oil, gas, condensate, and produced water
8. Work several exercises through to their conclusion to develop self-confidence in applying system analysis principles
Key Concepts

Several "key concepts" covered in this module are listed below:

A. The concept of a “system” is presented and pressure terms are defined

B. Additional terms are reviewed such as Inflow / Outflow, deliverability, PVT behavior, gas compressibility, fluid properties, and an exercise to review properties is worked

C. The two Basic Principles of System Analysis are presented

D. A summary of multiphase wellbore hydraulics which addresses the three major components of pressure drop in pipes is reviewed

E. Commonly applied tubing flow correlations are summarized for vertical wells, deviated wells, and horizontal flow in pipe

F. The importance of understanding phase behavior in tubing as well as in the classic reservoir domain for oil and gas wells and reservoirs is reviewed

G. The five factors influencing reservoir inflow performance are presented

H. Empirical and analytical Inflow equations for planned oil and gas reservoir well completions are presented and several Inflow exercises worked

I. Mechanical Outflow considerations are presented and the effects of system friction, gravity or head, and fluid acceleration upon system pressure drop are developed

J. The application of system Hold Up and Slip are presented which allow mathematical assumptions of fluid flow to be modeled to create accurate flow correlation models

K. Several applied nodal analysis exercises are worked

L. Case studies are presented for detailed analysis
Why This Module Is Important

- In the last 20 years or so, many software tools have been developed for engineers to rapidly model and study the interaction of:
  - A hydrocarbon formation asset’s geological properties
  - Reservoir fluids
  - Mechanical well completion and processing facilities
- Perhaps the most important advancement in this discipline is the ability to understand, define, and combine the sum of reservoir fluid flow effects

Why This Module Is Important

- Basic system components through which reservoir fluids flow include:
  - Reservoir fluid flow to the well
  - Flow through the well’s perforated or open hole (or frac pack or gravel pack or other) downhole completion
  - Flow to the surface in the production tubing string
  - Flow through a surface choke
  - Flow through a flowline to the entrance of a first stage separator
- Other components that may be modeled in a system analysis include:
  - Downhole choke
  - Tapered tubing string diameters
  - Wellbore skin
  - Water cut change
  - Reservoir pressure change
  - Water and gas gravity sensitivities
  - Gas / liquid ratio sensitivities
  - Flowing tubing surface pressure sensitivities
  - Flowline diameter sensitivities
Why This Module Is Important

- Principles developed in analyzing a producing system apply for both initial phases of naturally flowing wells, as well as wells on artificial lift.

Describes the study and design of the resultant sum of individual system components in place.

This permits the technical optimization of a flow path for exploiting hydrocarbon reservoir fluids.

System Analysis
Nodal Analysis™

Why This Module Is Important

- This technical optimization of a flow path for exploiting hydrocarbon reservoir fluids is what constitutes a system analysis study.

A completion system for a well has been defined as possessing the following elements, for which each system component has had a mathematical model developed:

(a) Flow through the reservoir
(b) Flow through the casing perforations
(c) Flow up the tubing string
(d) Flow through a surface choke
(e) Flow through a flowline of specific length to the separator.
Why This Module Is Important

- This technical optimization of a flow path for exploiting hydrocarbon reservoir fluids is what constitutes a system analysis study.
- A completion system for a well has been defined as possessing the following elements, for which each system component has had a mathematical model developed:
  - If all of these components have been optimized to minimize excess pressure drop, and the models are mathematically linked together, then it may be said that the system is optimized.

Why This Module Is Important

- This module leads the student through various elements of system analysis, including:
  - Phase behavior and multiphase flow
  - Principles of reservoir inflow and outflow
  - Well completion design and optimization
- The study of how reservoirs produce and how well completions components are sized to match reservoir flow provides the engineer with the foundations of system analysis principles.
Before you Begin…

A start up discussion with the instructor

Module Start Up Discussion

- Welcome to this Well Performance and Nodal™ Analysis Fundamental Level module.
- You have had the opportunity to review this module’s Introduction, Description, Objectives and Layout
- Hopefully, this initial overview has provided a summary of the pathway through the presentation and discussion of “Well Performance and Nodal Analysis.”
- Before you begin the module, the following are three additional important items...
First, you will soon be reviewing Inflow and Outflow concepts to evaluate wellbore fluid production and mechanical tubing designs to complete wells.

A key module concept is the awareness of fluids flowing through a production “system” (to be defined) which undergo changes in pressure and temperature.

These changes will affect the properties of reservoir fluids. Examples are changes in fluid viscosity, density, compressibility, formation volume factor, etc., all due to pressure and temperature changes.

These are called PVT changes or changes in Pressure, Volume, and Temperature effects.

An example of these changes follows…

Here is a general sketch of a flowing oil well with associated gas.

As fluid flows from the reservoir, pressures and temperatures change.

These pressure and temperature changes affect fluid properties.

Assume for this example that the well is a gas producer.

Example: Examine the effect of pressure and temperature on gas compressibility.
Module Start Up Discussion

**Example:**
Determine the gas “z” factor and note how it is used to determine the gas viscosity.

\[ \gamma_g = 0.68 \]

\[ p_{res} = 2258 \text{ psia} \ (15,568 \text{ kPa}) \]

\[ T_{res} = 196^\circ \text{ F} \ (91^\circ \text{ C}) \]

- Data is provided for this example.
  - Gas density
  - Reservoir pressure
  - Reservoir temperature

- This problem can be calculated by hand but it is more readily doable using the vast number of computer software programs on the market.

- Later in the module, a nodal analysis software program is utilized to determine gas compressibility.

Module Start Up Discussion

- In a nodal analysis program, the software breaks up a tubing string into very small increments and calculates the change in all oil, gas, water properties as temperature and pressure change.

- This and other complex assumptions allow the flow of these fluids to be determined as their fluid properties change.

- PVT behavior is very important to production engineers in solving complex production problems.
Module Start Up Discussion

You will be working Inflow exercises and several Microsoft Excel worksheets are provided to assist.
You may also do the calculations by hand if you wish.

An example of the Excel worksheets is illustrated on the following slide.

The key message is:

**Enter data ONLY in the yellow cells.**

The Excel worksheets provided may be used and data may be entered using either field units and/or metric units.

But Remember... Only enter data into the **yellow cells.**
Module Start Up Discussion

You will be working more complex Inflow (reservoir) and Outflow (tubing) combined exercises (and both the oil Case Study and the gas Case Study) using the System Nodal Analysis Program (referred to as the “SNAP” program).

A few conventions follow in the remaining Module Start Up Discussion slides:

1. The first of which being data entry conventions and tabs.
2. The next being that SNAP nodal analysis runs may be executed and interpreted in both metric units and field units.

Look at SNAP in the following illustrations…

Module Start Up Discussion

The basic SNAP screen looks like this after the program has been loaded and a base case file opened (provided).
Moving back and forth between metric units and field units is accomplished by clicking on the “Edit” tab.
Clicking on the “Units Preference” tab within the “Edit” tab will then open the “Units Dialog” box. Simply select the desired field or metric units.

Module Start Up Discussion

- SNAP data entry is straightforward and all exercises provide all data required and assumptions necessary for working the exercises.
- You will be required to “think” through problems as some exercises do not provide “canned” solutions.
- The challenge is there, and nodal analysis work is very rewarding when office studies lead to successful field operations and expected production or better rate produced.
- Mid-module, there will be a live instructor session to further review your progress with the module topics, the exercises, and the SNAP software.
Learning Objectives

This section will cover the following learning objectives:

- Develop inflow and outflow models and work several exercises to illustrate well completion design methods
Well Performance is about understanding how to optimize the "system."

The system is comprised of components.

Each component can be individually modeled.

The components can be connected to create a "system" model.
Although the system includes all components from the reservoir out to the export valve, focus will only be on the components of the system from within the reservoir to the separator.

Why... only to the separator?
- A constant pressure is maintained on the separator by a back pressure regulator.
- The system has a pressure boundary at the separator inlet.
- And, the system has a pressure boundary within the reservoir.
- From within the reservoir to the separator inlet, the downhole engineers control operations.
In a system, the pressure (and temperature) will vary with rate.

It is mathematically helpful when evaluating well performance to: start calculations working from the boundaries and then working back to one point from each boundary.

This one point, \( P_{wf} \), is normally chosen at the mid perforation interval depth in the well bore.

System Pressures Terms
- \( P_{res} \) – Reservoir pressure
- \( P_{wf} \) – Bottomhole flowing pressure
- \( P_{ftp} \) – Flowing tubing pressure
- \( P_{chk} \) – Choke inlet pressure
- \( P_{sep} \) – Separator inlet pressure
The System

- Outflow – Downstream of this point; primarily tubing and mechanical influences.
- Inflow – Upstream of this point; primarily formation influences.

Dividing the system as shown with a boundary defines pressures and temperatures:

- Outflow – Downstream of this point; primarily tubing and mechanical influences.

Principles developed which follow for oil well liquid rate (that is, oil plus water plus associated gas) will apply for both wells on natural flow and wells later placed on artificial lift as reservoir pressure declines.

These principles will be evident when studying artificial lift systems.
For gas wells, the system is sometimes divided at the wellhead.

The well delivers based on the backpressure it sees.

Gas well performance is defined as its **deliverability**.

In all well completions, pressures and temperatures fall as reservoir fluids (oil, gas, condensate, water) flow from the reservoir to the surface.

Fluid properties are dependent upon PVT conditions.
Some fluid properties that are dependent upon PVT conditions:
- Oil formation volume factor
- Oil viscosity
- Gas density
- Gas "z" factor (compressibility)
- Many others

As these properties affect how fluids flow, they must be modeled in system analysis studies.

An Important Principle
- Flow in pipe (e.g., tubing, flowline) or in porous media (e.g., formation) is related to the pressure difference between two points.
- The greater the differential, the greater the flow rate, everything else being equal.
- Flow direction is always from higher to lower pressure.
- When the pressure differential approaches zero, flow stops.
Note that all of the energy driving flow through this system in a naturally flowing well completion is supplied by the reservoir as a function of \((P_{\text{res}} - P_{\text{wf}})\).

Artificial lift methods are discussed in the *Gas Lift and ESP Pump* and *Rod, PCP Jet Pumps and Plunger Lift* core modules.

The greater the difference between the reservoir pressure and the separator inlet pressure, the greater the potential flow rate.
The System

- Acting against this differential and decreasing the flow rate are a number of important factors:
  1. Vertical height of flow (head)
  2. Friction of flow in tubing and pipe
  3. Friction of flow in the formation

System Pressure Drop

Note greatest pressure drop is due to skin and in the production tubing.

- Reservoir
- Skin
- Perforations
- Tubing
- Wellhead
- Choke
- Flowline
- Manifold
- Separator
- Stock tank

Produced Fluids Pressure as they Move Through the System
Basic Principles

Inflow to any node
\[ p_{\text{res}} + \Delta p \text{ (upstream components)} = p_{\text{node}} \]

Outflow from any node
\[ p_{\text{sep}} + \Delta p \text{ (downstream components)} = p_{\text{node}} \]

- Conditions:
  1. Flow into a node equals flow out of a node
  2. Only one pressure can exist at a node
  3. Only one temperature can exist at a node
System Pressure Drop

Example #1: choose the reference inflow "node" at the tubing mid-point

Note greatest pressure drop is due to skin and in the production tubing.

- Reservoir
- Skin
- Perforations
- Tubing
- Wellhead
- Choke
- Flowline
- Manifold
- Separator
- Stock tank

Produced Fluids Pressure as they Move Through the System

Outflow from any node

\[ p_{\text{node}} = p_{\text{sep inlet}} + \Delta p (\text{downstream components}) \]

Inflow to any node

\[ p_{\text{node}} = p_{\text{pres}} - \Delta p (\text{upstream components}) \]

Oil / Gas System Analysis

Basic Principles

Choose the node of interest at the midpoint of the tubing

Next: Basic Nodal Analysis Principle #2

1. Flow into a node equals flow out of a node
2. Only one pressure can exist at a node
3. Only one temperature can exist at a node
System Pressure Drop

Note greatest pressure drop is due to skin and in the production tubing.

- Reservoir
- Skin
- Perforations
- Tubing
- Wellhead
- Choke
- Flowline
- Manifold
- Separator
- Stock tank

Example #2: NOW choose the reference inflow “node” at $P_{wf}$

The System

- In this Example #2, the selected “node” is now at $P_{wf}$.
- As $P_{wf}$ changes (is managed by Production Operations, say – by changing the choke setting), the “drawdown” ($P_{res} - P_{wf}$) will change.
- The greater the drawdown of the well, the greater the resultant liquid flow rate.
Oil / Gas System Analysis

Basic Principles

- A plot of node rate vs. node pressure produces a curve for both inflow and outflow at each node.

- The intersection of the curves satisfies the conditions of inflow and outflow.

- Any change in conditions changes the curve(s):
  - Separator pressure change
  - Reservoir depletion
  - Water cut change

These principles will be examined to understand the relationship of a reservoir’s energy and the tubing completion required to maximize rate for both natural flow and artificially lifted wells.
Basic Principle #2

- Choosing the optimum tubing diameter for the amount of energy coming from the reservoir is the key to applied nodal analysis solutions.
- For either naturally flowing wells or artificially lifted wells.
- Identical principles apply for gas wells.
Similarly, Temperature in a System

In optimizing the system, the calculation of pressure (and temperature) drop in tubing, flowlines, chokes and other piping restrictions must be considered in system design.

Pressure drop correlations for both subsurface and surface system components are both available and are commonly studied and applied.
Learning Objectives

This section has covered the following learning objectives:

✓ Develop inflow and outflow models and work several exercises to illustrate well completion design methods
Phase Behavior

Well Performance and Nodal™ Analysis Fundamentals

Learning Objectives

This section will cover the following learning objectives:

- Review how conditions of pressure, temperature, and volume affect hydrocarbon liquids and gases
- Review how changes in conditions affect hydrocarbon liquids and gases
- Review the concept of “flow regimes” as hydrocarbons flow through producing systems
- Summarize oilfield use of PVT diagram data to most efficiently produce hydrocarbons
Phase Behavior Theory

Q What happens to the oil and gas as they move through the system?

A As temperature and pressure changes, reservoir fluids' properties change.

- Looking from above, this is a sketch of hydrocarbons flowing up a tubing stream.
Phase Behavior Theory

- Pressure, temperature, volume effects occur throughout a hydrocarbon producing system.

- Looking from above, this is a sketch of hydrocarbons flowing up a tubing stream.

Phase Behavior Theory

- Along the way from the reservoir to the separator, the production stream (oil, gas, condensate, water) undergoes changes. Assume for an oil reservoir:
  - Oil leaving the reservoir drops in pressure and temperature
  - Light hydrocarbons are liberated from the mixture of oil as the pressure falls
  - The oil phase shrinks as the light hydrocarbons leave and oil viscosity increases
  - The gas phase expands as the light hydrocarbons accumulate
  - The volume of each phase determines the fluid’s flow regime, each with its own friction and head properties
Phase Behavior Theory

- Vertical/Inclined flow regimes up the tubing string
  - There is no distinct boundary between flow regimes
  - There are several flow regime models

![Flow Regime Diagram]

Moving Uphole in Tubing

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Phase Behavior Theory

- Why is phase behavior important to operations staff?

  - Operations engineers must be able to accurately predict the properties of produced fluids because these properties are strongly dependent upon flowing pressures and temperatures in the production system; thus, they influence production rate.
  - Proper assumptions, data collection, and classification and use of PVT properties is important to the success of most projects.
  - In most cases, the engineer will work closely with the Reservoir Engineer to gather and create shared PVT data sets.
Phase Behavior Theory

- Reservoir fluids may be composed of hundreds of compounds.
- Only the compositions from C1 (methane) up to some heavier compounds (~C30) can be accurately defined.
- The composition of a compound may change only when parts of the stream leave the system.
- To describe the phase change of a hydrocarbon mixture, a given composition, a phase envelope is used.

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior Theory

Multi-Component System

Critical Point = Liquid/vapor same

Two Phase

Temperature

Pressure

Single Phase Liquid

Single Phase Vapor

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

Phase Behavior Theory

Saturated

Undersaturated

Can dissolve more liquid or vapor

Cannot dissolve more liquid or vapor

Single Phase Vapor

Single Phase Liquid

Temperature

Pressure

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior Theory

Oil has a bubble point where the first bubble of gas will appear as pressure drops.

Phase Envelope / Phase Diagram

Single Phase Liquid

Pressure

Temperature

Vapor condenses

Gas has a dew point where the first drop of liquid will appear as pressure drops.

Retrograde segment

Normal segment

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior Theory

- Phase diagrams are used to characterize or classify oils and gas reservoirs
- Oil and gas classification depends on the location of the initial reservoir conditions point of T & P on the diagram

From their initial condition, liquids are produced from the reservoir.

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior Theory

- From their initial condition, gases are produced from the reservoir.

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
**Phase Behavior Theory**

- In a condensate reservoir, liquids drop out solution in the reservoir.
- The best way to produce this type of reservoir is to:
  - Produce the gas
  - Remove liquids, and then
  - Reinject the gas

**Phase Envelope / Phase Diagram**

- Pressure
- Temperature
- Oil
- Condensate

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

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**Oils may be subdivided into:**

- **Low Shrinkage (Black Oil)**
  - API < 35
  - GOR < 500 scf/stb (90 m³/m³)
  - Black or deeply colored
  - More large hydrocarbon molecules than smaller

- **High Shrinkage (Volatile Oil)**
  - API 30–50
  - GOR 500–8000 scf/stb (90–1425 m³/m³)
  - Medium orange colored
  - Relatively fewer heavy molecules than low shrinkage oil and more intermediates

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Back to Work Suggestions

Well Performance and Nodal Analysis Fundamentals

Leverage the skills you’ve learned by discussing the skill module objectives with your supervisor to develop a personalized plan to implement on the job. Some suggestions are provided.

☑ Meet with a service company lab analysis contractor to determine the PVT and related fluid properties data available for your reservoir fluids.

Summary

- Fluid performance as a function of properties which depend upon pressure and temperature is very important for understanding:
  - Flow in tubing strings
  - Flow in the reservoir
  - Flow at the surface

- PVT information is very important
Phase Behavior Applications and Conditions

Phase Behavior

Liquid Volume Curve for Typical Black Oil

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

Liquids Volume Curve for Typical Volatile Oil

Phase Behavior

- API > 60°
- GOR up to 100,000 scf/stb (17,810 m³/m³)
- Up to approx. 70 stb/mmscf +/- (0.4 m³/1000 m³)
- Produced liquids usually water-white
- Contains predominantly smaller hydrocarbon molecules

No condensate due to lack of heavy molecules

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior

Retrograde Condensate

- As reservoir pressure declines, condensate liquids drop out of gas in reservoir.
- This condensate usually cannot be produced as it occurs in quantities below the critical oil saturation; hence, producing Condensate Gas Ratio (CGR) decreases. (Rich retrograde condensates can produce at high CGR.)
- Condensate drop out can also cause blockage around the well bore.
- As pressure declines, condensate volume would be expected to decrease, EXCEPT, that the phase diagram is also shifting due to the composition of the reservoir liquids changing (that is, getting richer).

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

Phase Behavior

Retrograde Condensate Gas

- API 50°–60°
- GOR 8000–70,000 scf/stb (1425–12,470 m³/m³) or above 100 stb/mmcf (0.56 m³/1000 m³)
  - Rich up to 400 (2.24 m³/1000 m³)
- Tank oil is usually water-white or of a light color; rich condensate can be black.
- Contains relatively fewer of the heavier molecules than low shrinkage oil.

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior

Retrograde Liquid Curve for Typical Lean Gas-Condensate

Liquid Volume % vs. Pressure

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

Phase Behavior

Retrograde Liquid Curve for Typical Lean Gas-Condensate

Retrograde Liquid Curve for Typical Rich Gas-Condensate

Liquid Volume % vs. Pressure

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Phase Behavior

Retrograde Liquid Curve for Typical Rich Gas-Condensate

Liquid Volume %
0 20 40 60 80 100

Pressure

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”

Phase Behavior

Condensate begins to drop out
Negative effect on rate and loss of condensate
Difficult to recover
Compression system in place early in the life of a development plan for the field

This info is from DC Brown’s “Oil & Gas PVT for Experienced Engineers”
Reservoir Fluids Phase Envelopes

Similar Initial Reservoir Pressures for Two Different Reservoir Temperatures
Look at each of four cases

Reservoir “A”

The position of the phase envelope relative to the reservoir temperature, not the reservoir system hydrocarbon composition, is the controlling factor which determines reservoir type.

Reservoir “B”

At higher temperature, the gas condensate reservoir would be a gas reservoir and the volatile oil reservoir would be a gas condensate reservoir.
Questions

1. Is this an oil or gas reservoir and what type? Why?

Answer: Starting from reservoir conditions (star P & T), a constant temperature depletion intersects the dew point line. **Gas Condensate Reservoir**

2. What happens to oil as it goes from the reservoir to the stock tank?

Answer: Gas comes out of solution and the total volume of the oil produced shrinks as a result.

3. What kind of fluid type has a liquid with 39 API gravity and a GOR of 2500 scf/bbl (445 m³/m³)?

Answer: High shrinkage volatile oil
This section has covered the following learning objectives:

- Review how conditions of pressure, temperature, and volume affect hydrocarbon liquids and gases
- Review how changes in conditions affect hydrocarbon liquids and gases
- Review the concept of “flow regimes” as hydrocarbons flow through producing systems
- Summarize oilfield use of PVT diagram data to most efficiently produce hydrocarbons
Learning Objectives

This section will cover the following learning objectives:

- Examine the causes of pressure drop in a multi-phase oil and gas producing system
- Summarize the various standard industry flow correlations (mathematical models) that describe hydrocarbon flow in pipe (wells and flowlines)
- Briefly review how well tubing completion design relied upon flowing gradient data prior to the development of and application of computer based software
The System

Multiphase Wellbore Hydraulics

Pressure drop is the sum of changes in
1. Hydrostatic (elevation) component
2. Friction (losses) component
3. Acceleration component

\[
\frac{dp}{dl} = \left(\frac{dp}{dl}\right)_e + \left(\frac{dp}{dl}\right)_f + \left(\frac{dp}{dl}\right)_{acc}
\]

- The components of wellbore flow hydraulics and the elements of total pressure drop over the length of tubing (pipe) include:
  - Fluid hydrostatic pressure
  - Fluid friction
  - Fluid acceleration

Hydrostatic Pressure

- Hydrostatic pressure applies for both compressible or incompressible flow in steady state or transient flow in both vertical and inclined flow.
  - It is zero for horizontal flow (\(\Phi = 0^\circ\)).

\[
\left(\frac{dp}{dl}\right)_e = g \frac{\rho \sin(\theta)}{g_e}
\]
The System

1 Hydrostatic Pressure

- It is the potential energy of fluid based upon height above a reference point.
- It is the cumulative weight above the reference plus any applied pressure.
- It applies even with no flow.

\[
\left( \frac{dp}{dl} \right)_e = \frac{g}{g_c} \rho \sin(\theta)
\]

The change in hydrostatic pressure over a length of tubing or pipe \( \frac{dp}{dl} \) for hydrostatic flow is shown in the equation to be equal to the density of the fluid times the sine of the angle theta times the ratio of the acceleration due to gravity (or standard acceleration of free fall) at any reference point or elevation on earth \( g \) relative to the acceleration due to gravity at sea level \( g_c \). Thus the relationship \( g/g_c \).
The System

2 Friction Pressure Drop

\[ \left( \frac{dp}{dl} \right)_f = \frac{f \rho v^2}{2g_c d} \]

- Applies to any type of flow and pipe angle and always causes pressure drop in the direction of flow.
- The Darcy Weisbach or Moody friction factor (f) is a function of pipe roughness and Reynolds Number (N_R) and is calculated for both laminar or turbulent flow.

The System

2 Friction Pressure Drop

- The friction factor - f - is typically calculated from one of several equations (examples follow) or is determined from the Moody Diagram approach (example follows).

\[ \left( \frac{dp}{dl} \right)_f = \frac{f \rho v^2}{2g_c d} \]
The System – Single-Phase Liquid or Gas

- Friction Factor Equations

\[ f = \frac{64}{N_{RE}} \quad N_{Re} = \frac{1488 \mu (\frac{R_e}{R})^4 (\frac{R}{s}) (d/\varepsilon)}{\mu cp} \]

- \( N_{RE} > 2000 \) Turbulent (Colebrook)

\[ \frac{1}{\sqrt{f}} = 1.74 - 2.0 \cdot \log_{10} \left( \frac{2 \varepsilon}{d} + \frac{18.7}{N_{RE} \sqrt{f}} \right) \]

- Smooth Pipe (Blasius)

\[ f = 0.316 \quad N_{RE} = 0.25 \]

- Complete Turbulence (Nikuradse)

\[ \frac{1}{\sqrt{f}} = 1.74 - 2.0 \cdot \log_{10} \left( \frac{2 \varepsilon}{d} \right) \]

The System – Single-Phase Liquid or Gas

- Moody Diagram for Friction Factors

\[ N_{Re} > 2000 \] Turbulent Flow

Friction Factor

Reynold's Number

Relative Roughness

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The System – Single-Phase Liquid or Gas

Moody Diagram

- The Moody diagram is a dimensionless graph that relates:
  - Darcy Weisbach friction factor, \( f \) (left y-axis)
  - Reynolds Number, \( R_e \) (x-axis), and
  - Pipe relative roughness (right y-axis) for flow in a circular pipe
- It can be used to determine pressure drop or flow rate in a pipe.

Material e (ft)
- Riveted steel 0.003 – 0.03
- Concrete 0.001 – 0.01
- Cast iron 0.00085
- Galvanized iron 0.0005
- Commercial steel 0.00015
- Drawn tubing 0.00005

N\(_{Re}\) > 2000 Turbulent Flow

The System

Acceleration Pressure Drop

- Acceleration measures a fluid’s velocity change due to expansion (or contraction) due to pipe size change.
- Since fluid velocity is related to fluid energy, pressure energy is converted to velocity as energy is expended going through an acceleration or deceleration due to a constriction like a choke or a pipe size change.

\[
\left( \frac{dp}{dl} \right)_\text{acc} = \frac{\rho udv}{\gamma_c dl}
\]
The System

3 Acceleration Pressure Drop

- Transient flow occurs when flow velocity and pressure are changing with time.
  - Examples are the start up or shut down of a pump or the closing or opening of a valve. These are transient flow conditions.
  - Alternatively, without these simultaneous changes occurring, flow is referred to as being steady state.

\[
\frac{dp}{dl}_{acc} = \frac{\rho udv}{g_c dl}
\]

The System

3 Acceleration Pressure Drop

- The acceleration pressure drop component applies for transient flow conditions.
- This component is zero for constant area, incompressible flow.
- Any velocity change will result in a pressure drop in the direction of velocity increase.

\[
\frac{dp}{dl}_{acc} = \frac{\rho udv}{g_c dl}
\]
The System

### Acceleration Pressure Drop

- The acceleration $\Delta P$ drop component is usually small except in low pressure gas in small pipe and well blowout situations (where well shut off capability at the surface has been lost – loss of surface control valves / surface choke).
- In this discussion, blowout conditions will not be addressed / modeled; thus acceleration pressure drop is not considered.

\[
\left( \frac{dp}{dl} \right)_{acc} = \frac{\rho udv}{g_c dl}
\]

The System

- If acceleration is considered to be less than a significant value, that leaves:
  - Vertical component
  - Hydrostatic component
  - Friction component
The System

- Tubing Design Based Upon Pressure Gradient Curves
  - Before the advent of computers to perform tedious flow calculations, actual temperature and pressure flowing profile data was used for well completion design.

The System

- Commonly Accepted Tubing Flow Correlations
  - Ansari
  - Hagedorn & Brown
  - Duns & Ros
  - Orkiszewski
  - Beggs & Brill
  - Aziz et al
  - Mukherjee & Brill
  - Dukler
  - Gray
  - Modified Gray
  - MONA Duns, Ros & Gray
  - Cullendar & Smith
  - Olga

These researchers, and others, have developed detailed mathematical models to measure flow in pipe.
No single correlation performs well in all oil and gas design case situations. It is best to always compare calculated pressure drop calculation results to measured values.

Each correlation uses different means to determine $\Delta P$.

Modern nodal analysis programs take advantage of these different tubing flow correlations to be able to calculate total pressure drop for a particular example.
Learning Objectives

This section has covered the following learning objectives:

- **✓** Examine the causes of pressure drop in a multi-phase oil and gas producing system
- **✓** Summarize the various standard industry flow correlations (mathematical models) that describe hydrocarbon flow in pipe (wells and flowlines)
- **✓** Briefly review how well tubing completion design relied upon flowing gradient data prior to the development of and application of computer based software
Learning Objectives

This section will cover the following learning objectives:

- Develop an understanding of standard industry mathematical models to examine variables which quantify a reservoir’s capacity to produce hydrocarbons
- Review how engineers choose the most appropriate flow models to use to represent differing reservoir types
- Compare well performance attributes as a function of different inflow models
1. Why is the well flowing?
2. What would prevent flow from the well?
3. What would make this well produce more?

Ans: $P_{wf} < P_{res}$

Ans: If $P_{wf}$ were equal to $P_{res}$ (no drawdown)

Ans: Further reduce $P_{wf}$

Engineers manage drawdown to establish well rate
Inflow Performance

- The inflow system dictates how much energy is provided to the rest of the system in a natural flowing well.
- Artificial lift adds extra energy; the subject will be covered later.
- For the Inflow system, the lower the pressure at the bottom of the well \( P_{wf} \), the more liquid will flow into the well.
- The pressure at the bottom of the well is the flowing bottom hole pressure, \( P_{wf} = \text{Flowing Bottom Hole Pressure (FBHP)} \).

Artificial lift methods are discussed in the Gas Lift and ESP Pump and Rod, PCP Jet Pumps and Plunger Lift core modules.

Inflow Performance

- There are several methods and expressions to describe (mathematically model) this behavior.
- In general, the relationship between the flowing bottom hole pressure and the amount of the primary phase coming into the wellbore is the well's inflow performance relationship (IPR).
- For oil wells, the rate of liquid entering the well
- For gas wells, the rate of gas entering the well

\[ P_{wf} = f_n(Q) \]

Note: Curved Line
Inflow Performance

In the Field
- Do multiple rate test for any zone
  - Establish initial conditions where flowing bottom hole pressure is equal to reservoir pressure (zero flow rate)
  - Open choke to establish first rate
  - Repeat 3 times to establish four different individual flowing bottom hole pressures and four different flow rates

Two points on the curve are normally all that is necessary to define an IPR relationship.
- The two points (boundary conditions) are:
  - Reservoir Pressure: \( \text{Rate} = 0 \)
  - AOF (Absolute Open Flow): \( P_{wf} = 0 \)
- Normally, \( P_{res} \) and one other point are given.
Inflow Performance

- For 2-phase flow (liquid and gas), gas expands as it approaches the wellbore.
- This gas partially blocks the pore throats open to liquid flow.
- Since the plot is in terms of liquid flow, the effect is a downward curvature of the IPR.
- In other words, a decreasing productivity index at lower pressures.

Consider drawing a straight line instead of a curved line.

When is the line straight and when is it curved?

Carefully review the next two slides.
The System

- \( P_{wf} \) **Below** bubble point pressure

\[ Q \]

Well / Zone “A”

The System

**In Summary...**

- \( P_{wf} \) **Below** bubble point pressure
- \( P_{wf} \) **Above** bubble point pressure
Inflow Performance

- **Curved Line Equation:**
  - A mathematical representation is provided by the Vogel IPR relationship:
    \[
    Q = Q_{\text{max}} \times (1 - 0.2 \left( \frac{P_{\text{wf}}}{P_{\text{res}}} \right) - 0.8 \left( \frac{P_{\text{wf}}}{P_{\text{res}}} \right)^2)
    \]
  - Where \(Q_{\text{max}}\) = AOF

- Vogel developed this relationship by best fit from numerous reservoir simulation runs.
- The Vogel IPR has a long history of use in the industry with very good success.

Inflow Performance

- **Straight Line Equation:**
  - PI = Straight line IPR (slope of line)
  
  - **Productivity Index** (PI also given as \(J\)):
    - \(Q = (P_{\text{res}} - P_{\text{wf}}) \times PI\)
      - Where PI is the **linear** slope

Note: Straight Line
Compare the Two Cases

**Inflow Performance**

<table>
<thead>
<tr>
<th></th>
<th>Pwf</th>
<th>AOF</th>
<th>Rate</th>
<th>Pr</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PI IPR</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Valid only ABOVE</td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td>$P_{Bubble Point}$</td>
</tr>
</tbody>
</table>

<table>
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<th></th>
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<th>AOF</th>
<th>Rate</th>
<th>Pr</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Vogel IPR</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Valid only BELOW</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$P_{Bubble Point}$</td>
</tr>
</tbody>
</table>

Now work the exercises to compare these inflow cases

- Vogel method and Productivity Index (PI) method
  - A new well will be introduced in which $P_{wf}$ will be ABOVE bubble point pressure
  - Later in the life of the well, $P_{wf}$ will drop BELOW bubble point pressure
  - In both cases, inflow curves will be developed
  - These inflow curves will be coupled with tubing performance curves in order to determine what size tubing should be used for each inflow relationship
Back to Work Suggestions

Well Performance and Nodal Analysis Fundamentals

Leverage the skills you've learned by discussing the skill module objectives with your supervisor to develop a personalized plan to implement on the job. Some suggestions are provided.

☑ Meet with a reservoir engineer in your organization to review how Inflow relationships are developed for your Oil wells.
☑ Investigate how sensitive the inflow relationship is to key parameters.
☑ Identify the range of uncertainty these key parameters may have on inflow performance.

Learning Objectives

This section has covered the following learning objectives:

☑ Develop an understanding of standard industry mathematical models to examine variables which quantify a reservoir’s capacity to produce hydrocarbons
☑ Review how engineers choose the most appropriate flow models to use to represent differing reservoir types
☑ Compare well performance attributes as a function of different inflow models
This section will cover the following learning objectives:

- Examine the origin and use of classic gas well testing and gas inflow models and work several exercises to illustrate gas well completion performance.
- Review gas inflow models such as the back pressure or 4 point equation, the Darcy equation for gas wells, and other inflow models specific to gas reservoir performance.
- Assess and analyze formation damage skin effects in gas wells using system analysis principles.
- Model gas condensate reservoirs by varying the gas liquid yield for a condensate reservoir.
Gas Inflow Performance

- **Rawlins & Schellhardt**
  - \( Q_g = C \left( P_r^2 - P_{wf}^2 \right)^n \)

- **Russell & et al**
  - \( Q_g = C r \left( \frac{P_r^2 - P_{wf}^2}{\mu_g z} \right)^n \) with \( \mu_g \) and \( z \) at \( \frac{P_r + P_{wf}}{2} \) (average pressure)

- **Al-Hussainy, Ramey & Crawford**
  - \( Q_g = C_r f[M(\Pi)] \) where \( M(\Pi) = \int_{r_w}^{r_i} \frac{1}{\mu_g B_s} dP \)

---

Gas Inflow Performance

- Gas wells must be periodically analyzed
- Typically Rawlins and Schellhardt equation is used
  - Equation is sometimes referred to as the Back Pressure equation or the Four Point equation
Many other curves to represent multi-phase Inflow take the form of the gas equation:

\[ Q = C \left( P_r^2 - P_{wf}^2 \right)^n \]

- The Bureau of Mines IPR, a.k.a. the Back Pressure equation (Rawlins & Schellhardt 1936).
- The exponent ranges from 0.5 to 1.0.
- The exponent is derived from multiple rates by plotting \((P_r^2 - P_{wf}^2)\) versus rate and finding \(n\), the inverse of the slope; then, find “C” by substituting one test point into the formula.

**Gas Inflow Performance**

**Flow After Flow Test**

For **High** Permeability Reservoirs

- \(q\)
- \(P_r\)
- \(P_{wf}\)
- \(T\)

Well Performance and Nodal Analysis Fundamentals
Gas Inflow Performance

**Isochronal Test**
For **Low** Permeability Reservoirs

- Reservoir permeability is significantly below 80 mD
  - In range of 10-20 mD
  - Because of tight nature of lower permeability rock, flowing bottomhole pressure will not stabilize

*Note: All time periods, slowing and shut in, are identical.*

---

**Modified Isochronal**
For **Very Low** Permeability Reservoirs

< 1 mD
Conventional Back-Pressure Test Analysis
Reservoir Inflow Well Test Data Plot

\[ Q = C \left( P_r^2 - P_{wf}^2 \right)^n \]

Note: Work by Fetkovich illustrates that the above equation may be used for oil reservoirs also.
Learning Objectives

This section has covered the following learning objectives:

- Examine the origin and use of classic gas well testing and gas inflow models and work several exercises to illustrate gas well completion performance
- Review gas inflow models such as the back pressure or 4 point equation, the Darcy equation for gas wells, and other inflow models specific to gas reservoir performance
- Assess and analyze formation damage skin effects in gas wells using system analysis principles
- Model gas condensate reservoirs by varying the gas liquid yield for a condensate reservoir
Learning Objectives

This section will cover the following learning objectives:

- Develop general well performance inflow models and work several oil and gas well exercises to illustrate well completion design methods with a primary focus upon quantifying a reservoir's capacity to produce either on natural flow or producing on artificial lift.
- Develop sensitivity models to examine tubing size options, reservoir depletion effects, water cut rise effects, decreased gas/liquid ratios, well depth effects, surface pressure and temperature effects, formation permeability effects, PVT variations, and other complex sensitivities to assess the performance of any perceived well reservoir and its mechanical well configurations.
- Assess and analyze formation damage skin effects using system analysis principles.
- Apply a broad array of both reservoir and mechanical sensitivities to evaluate and accurately predict well performance for wells producing any combination of oil, gas, condensate, and produced water.
Oil and Gas Inflow Performance

- The relationships thus far do not account for turbulence caused by high flow rates.
- Forchheimer’s work with high velocity flow showed that turbulent effects were significant at higher rates.
- Other models are adapted by adding a term for turbulent effects as Forchheimer suggested.

\[
\text{Oil: } P_r - P_{wf} = Aq + Bq^2 \\
\text{Gas: } P_r^2 - P_{wf}^2 = Aq + Bq^2
\]

... where \(a\) and \(b\) are constants

- These equations have the Aq term which is related to permeability and the Bq\(^2\) term which is related to turbulent flow.
- The Aq term is referred to as Darcy flow and the Bq\(^2\) term referred to as the non-Darcy flow term.

Quadratic Equations for Oil & Gas Flow

- Forchheimer Equations

\[
\text{Where } P_{res} - P_{wf} = Aq_o + Bq_o^2 \text{ for oil zone completions} \\
\text{for gas zone completions}
\]

- “A” is defined as the laminar flow coefficient
- “B” is defined as the turbulent flow coefficient
Quadratic Equations for Oil & Gas Flow

Laminar

\[
\text{Oil: } A_o = \frac{141.2 \mu B_o}{k_o h} \left[ \ln \left( \frac{0.472 \gamma_o}{\gamma_e} \right) + S_d \right]
\]

\[
\text{Gas: } A_o = \frac{142.2 \mu B_T}{k_o h} \left[ \ln \left( \frac{0.472 \gamma_o}{\gamma_e} \right) + S_d \right]
\]

where

- \( k_o \) = unaltered reservoir permeability to oil
- \( B_o \) = unaltered reservoir permeability to gas
- \( S_d \) = skin factor due to permeability alteration around the wellbore.

A value for \( S_d \) may sometimes be estimated from the following equation

\[
S_d = \left( \frac{k_o}{k_o} - 1 \right) \ln \left( \frac{r_w}{r_d} \right)
\]

where

- \( k_o \) = reservoir permeability
- \( k_o \) = altered zone permeability
- \( r_w \) = wellbore radius, and
- \( r_d \) = altered zone radius.

Turbulent

\[
\text{Oil: } B_o = \frac{2.3 \times 10^{10} \beta B_o}{k_o h}
\]

\[
\text{Gas: } B_T = \frac{3.161 \times 10^{-11} B_T}{k_o h}
\]

Values of the velocity coefficient \( \beta \) may be calculated from

\[
\beta = \frac{2.34 \times 10^4}{k_o h}
\]

A value for \( B_o \) can be calculated if a value of \( D \) is available from a transient test on an open hole completion.

Inflow Performance

Inflow Equations Can Be Complex...

- Recall that gas in turbulent flow is described by the Forchheimer equation:

\[
P_2 - P_{wf}^2 = aQ^2 + bQ
\]

- The “a” & “b” variables require accurate reservoir data and make the equation complex.

- The “Jones Equation” for gas:

\[
Q = \frac{703 \times 10^4 \text{kh} \ (P_2 - P_{wf}^2)}{[\mu T Z (\ln(r_e/r_a) - 0.5 (C_A / 31.62) - 0.75 + s + DQ)]}
\]

- Where:

\[
\gamma_b \beta / (\mu r_w h_b^2)
\]

where \( h_b \) is the completed h in ft and

\[
\beta = 2.73 \times 10^{10} k_s^{-1.1045}
\]

where \( k_s \) is the near wellbore permeability (same as for oil)

Golan & Whitson, pg 153
Inflow Performance

- A most useful expression is cylindrical or radial flow for flow into a well and is known as the Darcy equation.

  \[ Q = k \frac{2\pi h(P_e - P_w)}{\mu \ln(r_e/r_w)} \]

  where \( r_w \) is the wellbore radius and \( r_e \) the cylinder radius.

Golan & Whitson, pg. 118

Inflow Performance

- Darcy affirmed that pressure varies radially from the well, starting at the \( P_{wf} \) location and increasing out into the reservoir to the \( P_{res} \) location.
Inflow Performance

- **Wellbore Damage or “skin” (pressure drop)**
  - \( s = \sum s_i \) for all things that cause skin
  - \( D = \sum D_i \) for all that causes turbulent flow

**How do all these add up?**

![Diagram showing Ideal well model, Skin effect, Turbulence effect, PVT properties and two-phase flow effect, Actual IPR]

\[
Q = k \frac{2\pi h(P_e - P_w)}{[\mu [\ln(r_e/r_w)] + S + D]}
\]

where \( r_w \) is the wellbore radius and \( r_e \) the cylinder radius.

A most useful expression is cylindrical or radial flow for flow into a well and is known as the Darcy equation.

- The area for flow is the outside area of this cylinder
  \[
  A = 2\pi rh
  \]

- By integrating Darcy’s Law from the wellbore to an arbitrary radius, the following relationship is developed:

Golan & Whitson, pg. 118
Inflow Expression to Predict $Q$ as $F(P_{res} - P_{wf})$

### Inflow Summary

<table>
<thead>
<tr>
<th>Empirical Methods</th>
<th>Reservoir Data</th>
<th>Analytical Methods</th>
<th>Reservoir Data</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil</strong></td>
<td><strong>NOT Required</strong></td>
<td><strong>Gas</strong></td>
<td><strong>IS Required</strong></td>
</tr>
<tr>
<td>• Multirate flow tests</td>
<td></td>
<td>• Darcy equation</td>
<td></td>
</tr>
<tr>
<td>• Vogel equation ($P_{wf} &lt; P_{BP}$)</td>
<td></td>
<td>• Forchheimer</td>
<td></td>
</tr>
<tr>
<td>• PI equation ($P_{wf} &gt; P_{BP}$)</td>
<td></td>
<td>• Other</td>
<td></td>
</tr>
<tr>
<td>• Fetkovich</td>
<td></td>
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<tr>
<td>• C, n back pressure equation</td>
<td></td>
<td>• Jones</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Other</td>
<td></td>
</tr>
</tbody>
</table>

Note that there are many other expressions and equations that are available to describe oil and gas inflow.
Back to Work Suggestions

Well Performance and Nodal Analysis Fundamentals

Leverage the skills you’ve learned by discussing the skill module objectives with your supervisor to develop a personalized plan to implement on the job. Some suggestions are provided.

- Meet with a reservoir engineer in your organization to review how Inflow relationships are developed for your GAS wells.
- Investigate how sensitive the inflow relationship is to key parameters.
- Identify the range of uncertainty these key parameters may have on inflow performance.

Exercise

1. Re-Sketch the curves below to reflect the stated condition.

   - **Reservoir Pressure Decreased**
   - **Increased PI**
   - **Stimulated**

   **Hint:** “A” & “C” are identical

2. Determine the following using a Vogel inflow relationship, assuming the bubble point pressure is 3000 psi (20,685 kPa).
   - There is one well test measurement where the $P_{wf} = 1800$ psig (12,411 kPa) and the liquid flow rate is 500 bpd ($80 \text{ m}^3 / \text{day}$), and, the reservoir pressure $P_{res} = 2000$ psig (13,790 kPa). Water cut is 20%.
   - What is the inflow rate at $P_{wf} = 1000$ psig (6,895 kPa)?
1. Re-sketch the curves below to reflect the stated condition.

2. Determine the following using a Vogel inflow relationship, assuming the bubble point pressure is 3000 psi (20,685 kPa).
   - There is one well test measurement where the $P_{wf} = 1800$ psig (12,411 kPa) and the liquid flow rate is 500 bpd (80 m$^3$/day), and, the reservoir pressure $P_{res} = 2000$ (13,790 kPa) (Water cut is 20%).
   - What is the inflow rate at $P_{wf} = 1000$ psig (6,895 kPa)?

   **ANSWER:** 2035 BFPD (326 m$^3$/d)

---

**Learning Objectives**

This section has covered the following learning objectives:

- Develop general well performance inflow models and work several oil and gas well exercises to illustrate well completion design methods with a primary focus upon quantifying a reservoir’s capacity to produce either on natural flow or producing on artificial lift.
- Develop sensitivity models to examine tubing size options, reservoir depletion effects, water cut rise effects, decreased gas / liquid ratios, well depth effects, surface pressure and temperature effects, formation permeability effects, PVT variations, and other complex sensitivities to assess the performance of any perceived well reservoir and its mechanical well configurations.
- Assess and analyze formation damage skin effects using system analysis principles.
- Apply a broad array of both reservoir and mechanical sensitivities to evaluate and accurately predict well performance for wells producing any combination of oil, gas, condensate, and produced water.
Well Performance and Nodal™ Analysis Fundamentals

Outflow Performance

Learning Objectives

This section will cover the following learning objectives:

- Examine reservoir flow, downhole completion, tubing, surface choke and flowline models to exemplify reservoir-to-separator-inlet systems
- Examine artificial lift completions to highlight how analyses developed for flowing wells also apply to wells on artificial lift
- Evaluate optional well data parameters using system analysis principles to optimize overall well performance
- Apply a broad array of both reservoir and mechanical sensitivities to evaluate and accurately predict well performance for wells producing any combination of oil, gas, condensate, and produced water
Pressure Variance Throughout a Hydrocarbon Producing System

Outflow Performance

- Now... look at the tubing string.
- Also known as the Outflow System
Outflow Performance

**Picture yourself at the bottom of a flowing well looking UP.**
- What would prevent flow from the well?
- What would make this well produce more?

---

Outflow Performance

- The outflow system takes energy from the inflow system and uses that energy (plus artificial lift, if necessary) to get the total fluid rate to the surface.
- For the outflow system, the *higher* the pressure at the bottom of the well, the *more* liquid can be pushed from the well (in order to overcome fluid height / head and possible tubing friction).
- In comparison, recall that maximum reservoir inflow occurs with a *lower* flowing bottom hole pressure.
The outflow system takes energy from the inflow system and uses that energy (plus artificial lift, if necessary) to get the total fluid rate to the surface.

**Inflow:**
Reduce $P_{wf}$ to get greater rate.

**Outflow:**
Increase $P_{wf}$ to get a higher rate from the bottom of the well.

---

**Outflow Performance**

- **This Outflow curve is known by many names**
  - Several typical software curve names are:
    - VLP – Vertical Lift Performance (in Prosper)
    - TPC – Tubing Performance Curve (Industry)
    - Intake Performance Curve (in WePS)
    - Intake Pressure Curve (in SNAP)
    - Outflow Curve, in contrast to the inflow curve (WinGLUE)
Outflow Performance

- Another convenient view of Outflow is on a depth vs. pressure graph. These are the pressures (also temperature) in the tubing.

- This curve is known as:
  - Production Pressure model (WinGLUE)
  - Gradient Curve (Prosper)
  - [Pressure] Traverse (WePS)

- ‘Gradient’ refers to the change in pressure divided by the change in depth.

- The gradient typically gets smaller as gas expands near the top of the well. Sometimes friction here increases very rapidly and the gradient gets higher.
Outflow Performance

- Vertical Lift Performance is simply a display of the pressures from a series of gradient calculations.
- Note:
  - Recall that Inflow principles say to reduce $P_{wf}$ to increase drawdown (as in $P_{res} - P_{wf}$) to increase flow rate.
  - Outflow principles state that an increase in $P_{wf}$ is required to produce a greater rate through the outflow components of the system.
  - Engineers must resolve how to accurately establish $P_{wf}$ to meet the opposing requirements of inflow and outflow.

How are Outflow pressures calculated?

- The pressures in this part of the system are determined by calculating the change in pressure over the length.
- In a single phase liquid over short distances, this can be determined with an equation and done in one step.
- Because the phase fractions are changing along with PVT in multi-phase flow, no analytical solution is practical.
- The calculation become enormously tedious and iterative.
- For this reason, computer programs have been employed since the first attempts were made to model the outflow in wells.
Outflow Performance

- Tubing performance data in the form of flowing gradient surveys has been measured by pressure and temperature instruments since the 1930's introduction of Amerada gauges.

- Modern gauges are very accurate in their ability to measure tubing performance. In addition, mathematical correlations permit engineers to predict vertical, deviated, and horizontal well flow parameters.
Important Outflow Factors:
Holdup, Friction, Flow Regimes and Slip

Outflow Performance

- Liquid Holdup is the mathematical assumption made for flow equations.

\[
\text{Liquid Holdup} = \frac{\text{Volume Liquid in Pipe Segment}}{\text{Volume of Pipe Segment}}
\]

- Liquid Holdup \( H_L \) values vary from 0.0 for all gas to 1.0 for all liquid in a pipe segment.
Liquid Holdup is the mathematical assumption made for flow equations. Liquid Holdup \( H_L \) values vary from 0.0 for all gas to 1.0 for all liquid in a pipe segment.

Researchers Apply Holdup Concepts to Model Tubing Flow

As fluid flows through a pipe, the pressure inside changes. These changes can be described by 3 components:

1. **Gravity Component**
2. **Friction Component**
3. **Acceleration Component**
   - Predominantly an open blowout
**Tubing Performance**

- At the top (lower pressures = higher velocities), friction is significant.
- At the bottom, pressure is dominated by gravity.

**Outflow Performance**

**Vertical Flow Regimes**
- Bubble
- Slug
- Transition
- Mist

**Single Phase**
Liquid Holdup is the mathematical assumption made for flow equations.

Liquid Hold-up Schematic

\[
H_L = \frac{\text{Volume Liquid in Pipe Segment}}{\text{Volume of Pipe Segment}} = \frac{6}{10} = 0.6
\]

Liquid Hold-up Schematic

Liquid Holdup \( H_L \) values vary from 0.0 for all gas to 1.0 for all liquid in a pipe segment.

Outflow Performance

- In inclined pipe, slip is extreme where liquids fall backwards as gas rapidly rises.
- In horizontal flow, the gas phase overrides the liquid phase and flows at greater velocity.

Outflow Performance

\[
\text{Slip} = \text{The flow of gas phase moving relative to the liquid phase}
\]
Outflow Performance

Slip Velocity – Calculated

- In this two phase example of oil and gas flow, slip is calculated as gas velocity minus liquid velocity or
  \[ 7 \text{ ft/sec} - 5 \text{ ft/sec} = 2 \text{ ft/sec} \]
  \[ (2.1 \text{ m/s} - 1.5 \text{ m/s} = 0.6 \text{ m/s}) \]

Outflow Performance

- In oilfield multiphase systems, especially where the density differential of the phases present is great (gas, oil, condensate, water), and especially at liquid rates which are low for a given size of tubing, slip will be great.
  - That is, gas velocity will be much greater than liquid velocity.
  - Consequently, holdup will also be great and increasing as the rate falls causing a significant upturn in the tubing \( P_{wrf} \) requirement curve.
- The \( P_{wrf} \) requirement for tubing is a “U” shaped curve.
- The minimum in the curve is referred to as the minimum stable rate.
- To the left of this value, any flow is unstable.
- Understand that this is (at best) a rough approximation of a very complex phenomena.
**P_{wf} Requirement for Tubing, “U” Shaped Curve**

**Multiphase Flow**
**Tubing IPC P_{wf} Requirement**

- **CASE “A”**: Gas / Liquid Ratio (GLR scf / stb) held Q constant
  - Low G/L ratios require higher $P_{wf}$ due to the greater tubing liquid density
  - Higher G/L ratios result in higher $P_{wf}$ due to friction

- **CASE “B”**: Liquid Flow Rate $Q$ held Gas / Liquid Ratio constant
  - Lower flow rates require higher $P_{wf}$ due to slippage
  - Higher flow rates result in higher $P_{wf}$ due to friction

**Learning Objectives**

This section has covered the following learning objectives:

- Examine reservoir flow, downhole completion, tubing, surface choke and flowline models to exemplify reservoir-to-separator-inlet systems
- Examine artificial lift completions to highlight how analyses developed for flowing wells also apply to wells on artificial lift
- Evaluate optional well data parameters using system analysis principles to optimize overall well performance
- Apply a broad array of both reservoir and mechanical sensitivities to evaluate and accurately predict well performance for wells producing any combination of oil, gas, condensate, and produced water
Learning Objectives

This section will cover the following learning objectives:

- Evaluate optional well data parameters using system analysis principles to optimize overall well performance
- Work several exercises through to their conclusion to develop self-confidence in applying system analysis principles
The “Need to Know” Nodal Analysis Principle

- Being able to understand the reservoir and its performance, and choose the correct mathematical model to estimate that value, how much or how little energy is coming from the reservoir (liquids or gas), sets the stage for being able to design the optimum tubing size.
- Once tubing diameter is chosen, tubing can be engineered in terms of individual components (sliding sleeves, downhole chokes, downhole profiles, etc.).

Nodal Analysis Summary of IPR / IPC Curves

- The “Need to Know” Nodal Analysis Principle
- Given any inflow, choose the tubing size that shows a “U” shape such that the minimum stable rate is to the left of the intersection with the inflow curve.
**Inflow/Outflow Performance**

- Nodal Analysis Summary of IPR / IPC Curves
  - The “Need to Know” Nodal Analysis Principle
  - Given any inflow, choose the tubing size that shows a “U” shape such that the minimum stable rate is to the left of the intersection with the inflow curve.

**Back to Work Suggestions**

- Meet with a production engineer in your organization to review how outflow tubing sizing decisions are reached for your well completions.
- Investigate how sensitive the outflow relationship is to key parameters.
- Identify the range of uncertainty these key parameters may have on outflow performance.
### Learning Objectives

This section has covered the following learning objectives:

- ✓ Evaluate optional well data parameters using system analysis principles to optimize overall well performance
- ✓ Work several exercises through to their conclusion to develop self-confidence in applying system analysis principles
Well Performance and Nodal™ Analysis Fundamentals

Summary

The System – Summary

- Well Performance is about understanding how to optimize the system.
- The system is comprised of components; each component can be modeled by itself.
- The components can be connected to create a system model.
The System – Summary

- Determining the effect of component selection on the system requires modeling each:
  - Inflow and Outflow
    - Inflow requires understanding of reservoir energy… can be challenging
    - Outflow requires selection of size possibilities… pick the optimum

- The Inflow part of the system can be expressed as a function:

  \[ \text{Flow Rate } Q = f(P_{res} - P_{wf}) \]

  (like “A” or “B” below)

  All IPR models are represented by a function that relates \( P_{wf} \) to \( Q \).
The System – Summary

- The Outflow part of the system is expressed as the capacity of tubing diameter where PVT flow performance determines the optimum tubing diameter.
- All mathematical tubing and flowline flow correlations (Hagedorn & Brown, Ansari, Gray, Beggs & Brill, etc.) rely upon “Holdup and Slip” concepts to mathematically model complex flow mechanisms.

![Graph showing relationship between Pwf and Rate]

The System – Summary

- Combining Inflow and Outflow analyses provide a powerful tool for decision making.

![Graph showing expected Pwf and Rate]

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The System – Summary

- Combining Inflow and Outflow analyses provide a powerful tool for decision making.

- Energy coming from the well:
  - Oil
  - Oil and water cut
  - Oil and declining
  - Gas/liquid ratio
  - A brand new well
  - A much older well
  - Gas with varying amounts of liquid

- More sophisticated designs of tubing equipment (downhole jewelry)
  - Sliding Sleeves
  - Plugs
  - Profiles
  - Chokes

- Can be chosen once correct tubing diameter is established
Back to Work Plan

- Assembling nodal analyses studies are a matter of determining your best estimate of inflow from the reservoir, selecting various tubing sizings and determining what would be the optimum selection of tubing.
- Once that diameter is known than the tubing design can be made in terms of downhole devices like:
  - Profiles
  - How to place plugs in the profiles
  - Sliding sleeves
  - Other downhole equipment

Back to Work Suggestions

Well Performance and Nodal Analysis Fundamentals

Evaluate how nodal analysis studies are performed in your organization and determine the source and quality of various data used in the studies.