As covered in the following modules:

- Gas Lift and ESP Pump Core
- Rod, PCP, Jet Pumps, and Plunger Lift Core

**Learning Objectives**

This section will cover the following learning objectives:

- Identify the most common artificial lift technologies employed by petroleum engineering operations to exploit and maximize hydrocarbon recovery
- Understand how and why wells, which initially produce under naturally flowing conditions, must ultimately be mechanically assisted to produce major volumes of remaining reserves
- Recognize the engineering design and operations characteristics of: beam pump systems, gas lift systems, electrical submersible pump systems, progressing cavity pump systems, and plunger lift systems
Well Pressure Terminology

- **Pres**: reservoir pressure
- **Pwf**: flowing bottom hole pressure (well flowing)
- **Pftp**: surface pressure (flowing tubing pressure)
- **Psep**: separator inlet pressure

**(Pres - Pwf)** is referred to as “drawdown”

Nodal Analysis principles illustrate how flow from the reservoir to the well is observed, measured, and managed by various test methods.

The data above illustrates one method to quantify how reservoir energy provides flow rate into a well as a function of 

\[ f(P_{res} - P_{wf}) \]

Call this data the “Inflow” representing Well “A” for a well on natural flow
The data below illustrates another method to quantify how reservoir energy provides flow rate to a well as a function of \( P_{res} - P_{wf} \).

Call this data the "Inflow" representing Well "B" for a well on natural flow.

What is different?

- **Well “B”**
  - Pressure at \( P_{wf} \) is above bubble point pressure
  - Inflow curve is a straight line

Two different cases, “A” & “B”, based upon conditions at the chosen node \( P_{wf} \) with regard to fluid Bubble Point pressure.
Nodal Analysis principles also illustrate how flow to the surface in tubing is observed, measured, and managed.

The curve above illustrates a specific size of tubing and the bottom hole pressure ($P_{wf}$) under specific conditions.

To create the tubing curve, or Outflow data, $P_{wf}$ is the pressure at the base of the tubing string that is available to deliver all of the reservoir fluids—oil, gas, condensate, and water—to the surface and possibly through the choke and flowline to the separator.

$P_{wf}$ is also simultaneously working with the reservoir to create the Inflow curve.
From Nodal Analysis™

Combining the reservoir and tubing pressure requirements of a producing zone establishes a "well performance" or nodal analysis model. Another term for nodal analysis is "system analysis."

Thus, for a specific amount of reservoir energy and specific tubing size, an equilibrium for rate $Q$ and $P_{wf}$ results.

From Nodal Analysis™

Artificial Lift provides the opportunity to recover remaining reserves when there is no further intersection of well inflow performance and tubing string performance curves.

Reservoir energy has depleted and the capacity of the tubing in place is too great for the remaining reservoir energy.
Artificial Lift provides the opportunity to recover remaining reserves when there is no further intersection of well inflow performance and tubing string performance curves.

For a gas well where reservoir pressure has dropped and water invasion has occurred…

…the identical parallel story for gas reservoir depletion will also be presented.

Reservoir energy has depleted and the capacity of the tubing in place is too great for the remaining reservoir energy.

Artificial Lift Type Selection

1. **So, what is the best process for selecting the most appropriate artificial lift completion type for an oil reservoir well?**

2. **And, how can gas wells be dewatered after the remaining energy from a gas reservoir is mostly depleted?**
Artificial Lift Type Selection – “Defining the Need”

How is artificial lift selection conducted?
- Careful consideration of current and future well conditions is necessary
- Many rules-of-thumb exist and many options to analyze
- There is no single technique that provides a quick and easy answer

Pre-Planning Data and Engineering Considerations
- Anticipated well production rate over time (inflow)
- Anticipated well / zone life
- Anticipated GOR / GLR over life
- Anticipated water cut over life
- Well / zone depth
- Temperature gradient
- Casing / tubing restrictions
- Hole geometry / deviation
- Power availability (electricity, lift gas, fuel gas, power fluid, etc.)
- Sand production
- Scale tendencies, asphaltenes, paraffins
- Offshore or onshore
- Costs
- Other

Company “A”
- Oil Production From A/L
  - ESP 49%
  - BP 32%
  - PCP 8%
  - Gas Lift 4%
  - Plunger 3% (gas wells de-watered)
  - Hydraulic 2%
  - Other 4%

Company “B”
- Oil Production From A/L
  - Gas Lift 65%
  - BP 20%
  - ESP 13%
  - Jet, Hydraulic Pump & PCP < 2%
Three Examples of Artificial Lift Type Variance by Company

Company “C”

- Oil Production From A/L
  - Beam Pumps 82%
  - Gas Lift 10%
  - ESP 4%
  - Hydraulic 2%
  - Other 2%

These three examples reflect the different reservoir and operating conditions that govern the optimum selection of artificial lift completion type.

Though these individual company artificial lift requirements vary significantly, the greatest number of wells on artificial lift worldwide by far employ beam pump completions.

Note the broad difference in AL types installed

Major Types of Artificial Lift Illustrated

Selection Guide

- Low rates
- Heavy oil
- Some sand
- Low gas
- Power fluid
- Temp tests
- High cost
- Very high rates
- No sand
- Low gas
- Power source
- High rates
- Gas supply
- Offshore production
- Gas well
dewatering
- Final depletion
- Very low cost
- Heavy oil
- Some sand
- Low gas
- High viscosity

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## Artificial Lift System Application Matrix

<table>
<thead>
<tr>
<th>Artificial Lift System</th>
<th>Operating Depth (feet)</th>
<th>Operating Volume (Typical, bpd)</th>
<th>Operating Temperature (F)</th>
<th>Corrosion Handling</th>
<th>Gas Handling</th>
<th>Solids Handling</th>
<th>Fluid Gravity (API)</th>
<th>Servicing</th>
<th>Prime Mover</th>
<th>Other Requirements</th>
<th>Offshore Application</th>
<th>Overall System Efficiency</th>
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</thead>
<tbody>
<tr>
<td>Beam Lift (Rod Pump)</td>
<td>300–14,000</td>
<td>0.8–794.9 m³/D</td>
<td>37.8–287.8°C</td>
<td>Good to Excellent</td>
<td>Fair to Good</td>
<td>Fair to Excellent</td>
<td>&gt;35</td>
<td>Workover or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Limited</td>
<td>45%–60%</td>
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<td>Progressing Cavity</td>
<td>2,000–6,000</td>
<td>0.8–715.4 m³/D</td>
<td>23.9–121.1°C</td>
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<td>Excellent</td>
<td>Excellent</td>
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<td>Workover or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Good</td>
<td>45%–60%</td>
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<td>Gas Lift</td>
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<td>31.8–4770 m³/D</td>
<td>37.8–204.4°C</td>
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<td>Plunger Lift</td>
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<td>IC Engine or Electric Motor</td>
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<td>Excellent</td>
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<td>Poor</td>
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<td>Good</td>
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<td>Poor</td>
<td>&gt;35</td>
<td>Workover or Pulling Rig</td>
<td>Natural Gas &amp; Compressor</td>
<td>Excellent</td>
<td>15%–40%</td>
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<td>Submersible</td>
<td>7,500–17,000</td>
<td>31.8–4770 m³/D</td>
<td>(37.8–204.4°C)</td>
<td>Good</td>
<td>Good</td>
<td>Poor</td>
<td>&gt;35</td>
<td>Workover or Pulling Rig</td>
<td>Electric Motor</td>
<td>Excellent</td>
<td>15%–40%</td>
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<tr>
<td></td>
<td>5,000–15,000</td>
<td>31.8–4770 m³/D</td>
<td>(23.9–121.1°C)</td>
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<td>Good</td>
<td>Poor</td>
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<tr>
<td></td>
<td>1,000–15,000</td>
<td>31.8–4770 m³/D</td>
<td>(23.9–121.1°C)</td>
<td>Good</td>
<td>Good</td>
<td>Poor</td>
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<td>Workover or Pulling Rig</td>
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<td>(23.9–121.1°C)</td>
<td>Good</td>
<td>Good</td>
<td>Poor</td>
<td>&gt;35</td>
<td>Workover or Pulling Rig</td>
<td>Diesel or Water, Diesel</td>
<td>Good</td>
<td>15%–40%</td>
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</table>

### Artificial Lift Selection: An Elimination Process

**Graph:**
- **Higher Volume**
  - Gas Lift
  - Electric Submersible Pump
  - Hydraulic Jet Pumps
- **Vertical Lift Depth (m)**
- **Barrels per Day (m³/day)**
- **Prime Mover**
  - IC Engine or Electric Motor
  - Electric Motor
- **Other Requirements**
  - Fuel Gas or Electrical Power
  - Natural Gas & Compressor
  - Diesel or Water, Diesel
  - Diesel or Water, Diesel
  - Diesel or Water, Diesel
- **Offshore Application**
  - Limited
  - Good
  - N/A
  - Good
  - Excellent
- **Overall System Efficiency**
  - 45%–60%
  - 45%–60%
  - 45%–60%
  - 45%–60%
  - 45%–60%

PDF of the matrix is available for download in the list of resources in the PetroAcademy activity.
Well: An offshore well has the following data available. What artificial lift system is the best choice?

Why? What is missing from the data and the matrix below which would further guide selection?

Data:
- 10,000’ (3048 m) TVD
- 950 bfpd (151.04 m³/D) oil and water
- 12% w.c.
- 200°F (93.3°C) bottom hole temperature
- trace H₂S
- high salinity formation water
- 1000 scf/stb (178.1 m³/m³) GLR
- minimal sand
- Electricity available
- Gas supply available
- Long term, reservoir drive mechanisms well understood.

Artificial Lift Selection: Example

Artificial Lift Selection: An Elimination Process

<table>
<thead>
<tr>
<th>Lower Volume</th>
<th>Recip Hydraulic</th>
<th>Recip Rod Pump</th>
<th>PC Pumps</th>
<th>Plunger Lift</th>
<th>Progressive Cavity Pumps</th>
<th>Beam (Rod) Pumps</th>
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<td>Vertical Lift Depth (m)</td>
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<td>100 150 250 500 1,000 1,500 2,000 3,000</td>
<td>100 150 250 500 1,000 1,500 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000 10,000</td>
<td>100 150 250 500 1,000 1,500 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000 10,000</td>
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</table>
Learning Objectives

This section has covered the following learning objectives:

✓ Identify the most common artificial lift technologies employed by petroleum engineering operations to exploit and maximize hydrocarbon recovery
✓ Understand how and why wells, which initially produce under naturally flowing conditions, must ultimately be mechanically assisted to produce major volumes of remaining reserves
✓ Recognize the engineering design and operations characteristics of: beam (rod) pump systems, gas lift systems, electrical submersible pump systems, progressing cavity pump systems, and plunger lift systems
Why This Module Is Important

- Proper artificial lift selection, design, implementation, and operation for producing well completions are critical factors in achieving both optimum production rate control over time.
- Gas lift candidate wells require specific conditions to be in place for engineering selection of gas lift as the artificial lift method of choice.
- ESP candidate wells require a different set of specific conditions to be in place.
- Engineers must evaluate each reservoir’s fluids, lithology, and well completion characteristics to arrive at the proper selection of artificial lift type for each well requiring artificial lift.
- It is possible that a single well may require different types of artificial lift systems over the completion life of a well based upon changing well conditions.

<table>
<thead>
<tr>
<th>Properties/Characteristics/Features</th>
<th>Well A</th>
<th>Well B</th>
</tr>
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<tbody>
<tr>
<td>Production Rate</td>
<td>High</td>
<td>Very High</td>
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<tr>
<td>Gas/Liquid Ratio</td>
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<td>Low</td>
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<tr>
<td>Zonal Gas Production</td>
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<td>Low</td>
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<tr>
<td>Well Geometry</td>
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<td>Offshore</td>
<td>Onshore</td>
</tr>
<tr>
<td>Water Cut</td>
<td>High</td>
<td>Very High</td>
</tr>
</tbody>
</table>
Learning Objectives

This section will cover the following learning objectives:

- Understand the concept of gas lift in both unloading mode and operating mode to start up a gas lift completion and operate the completion over its life.
- Identify the principles of gas lift valve performance and the proper location of the operating valve and unloading valves.
- Recognize the characteristics of lift gas performance analysis to properly establish the most efficient gas lift completion performance conditions.
Gas Lift

- Gas lift works by injection of high pressure gas into the well’s casing / tubing annulus
- Gas injected into the casing annulus enters the tubing and lightens the liquid gradient in the tubing up to the surface

There are two types of gas lift:

1. When gas is continuously injected, this artificial lift method is referred to as **continuous gas lift**
   - It is the most common type of gas lift completion

**PFBH**

**SIBHP**

**Gas Lift**

**PBHP**

**SIBHP**

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There are two types of gas lift:

1. **Gas Lift**
   - Pressure
   - Depth
   - SBHP

2. **Intermittent gas lift**
   - Gas is injected periodically at a high rate
   - Lifting effect is created by displacing slugs of liquid in a piston effect to the surface

**Gas Lift Valve Operation**

- View the mechanical devices required for gas lift
- Gas will enter the tubing through **gas lift valves**
- These valves are installed in **gas lift mandrels** and a typical well might have 5-10 gas lift mandrels
Gas Lift Valve Operation

- Typical gas lift mandrel
  - Orienting sleeve allows pulling and setting valves in deviated wells
  - Guard protects valve latch neck against large tools and coiled tubing, snubbing strings, etc.
  - Thru-bore ID as large as tubing drift
  - Valve pocket with polished seals areas for valve pack-off

- Gas lift valve itself sits inside the mandrel pocket
  - Gas enters through holes in the valve
  - Gas exits through holes in the valve nose
  - Packing
  - Operation: Gas from the casing enters the area between the seals through holes in the mandrel and pocket
  - Mandrel pocket

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Gas Lift Valve Operation

- Important valve parts

  - Dome area which holds nitrogen pressure charge
  - Valve bellows grow in length with internal pressure
  - Valve seat
  - Valve choke
  - Gas exits through holes in the valve nose
  - Check valve seats when fluid velocity is in upward direction

Schematic is an injection pressure operated (IPO) valve (a.k.a. pressure valve)

Gas Lift and ESP Pump Core

- Valve is in the closed position
- What does it take to get this gas lift valve open?
- Look first at the forces trying to close the valve

Closing force \( = P_d \times (A_b) \)

where:

- \( P_d \) = nitrogen pressure
- \( A_b \) = area of the bellows
Gas Lift Valve Operation

- **How to get the right Pd?**
  - It is not practical to measure or set Pd; instead, the valve opening is tested in a test rack
  - First, excess nitrogen pressure is applied to the valve and the valve is ‘aged’ (pressure cycled repeatedly and equalized)
  - The valve is brought to *standard temperature of 60°F (16°C)* in a water bath
  - The valve is then placed in the test rack where the valve can be exposed to test rack pressures (using nitrogen) to simulate casing pressure
  - The nose of the valve is exposed to the atmosphere

Gas Lift Valves – Conventional Tubing Retrievable

- Valves mounted externally on mandrel
- External side guards protect valve
- 2-3/8 in. (60 mm), 2-7/8 in. (73 mm), 3-1/2 in. (89 mm), 4-1/2 in. (114 mm) and 5-1/2 in. (140 mm)
- J-55, N-80, L-80, P110, 13-CR
- Mandrels receive 1 in. (25 mm) and 1-1/2 in. (38 mm) valves
### Gas Lift Valves – Conventional TubingRetrievable

#### CM-1 Valves

<table>
<thead>
<tr>
<th>Valve Size</th>
<th>1 in. (25 mm) O.D.</th>
<th>2 in. (51 mm) Nominal</th>
<th>2.5 in. (64 mm) Nominal</th>
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<tr>
<td>API EUE</td>
<td>A: 3.783 in. (96 mm)</td>
<td>A: 4.335 in. (110 mm)</td>
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<td></td>
<td>B: 3.706 in. (94 mm)</td>
<td>B: 4.231 in. (107 mm)</td>
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<td></td>
<td>C: 3.063 in. (78 mm)</td>
<td>C: 3.668 in. (93 mm)</td>
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<tr>
<td></td>
<td>D: 2.910 in. (74 mm)</td>
<td>D: 3.460 in. (88 mm)</td>
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<tr>
<td>API NUE</td>
<td>A: 3.689 in. (94 mm)</td>
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<td>B: 3.586 in. (91 mm)</td>
<td>B: 4.119 in. (105 mm)</td>
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<td>C: 2.875 in. (73 mm)</td>
<td>C: 3.500 in. (89 mm)</td>
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<tr>
<td></td>
<td>D: 2.670 in. (68 mm)</td>
<td>D: 3.235 in. (82 mm)</td>
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**Valve Dimensions**
- A: Lug to Collar
- B: Lug to Collar (Special Clearance)
- C: Collar Diameter
- D: Collar Diameter (Special Clearance)

#### CM-2 Valves

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<th>Valve Size</th>
<th>1.5 in. (38 mm) O.D.</th>
<th>2 in. (51 mm) Nominal</th>
<th>2.5 in. (64 mm) Nominal</th>
<th>3 in. (76 mm) Nominal</th>
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<td>B: 4.206 in. (107 mm)</td>
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<td>D: 2.910 in. (74 mm)</td>
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<td>API NUE</td>
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<td>B: 4.086 in. (104 mm)</td>
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**Valve Dimensions**
- A: Lug to Collar
- B: Lug to Collar (Special Clearance)
- C: Collar Diameter
- D: Collar Diameter (Special Clearance)
Gas Lift Valves – Wireline Retrievable

- Valves run on wireline installed in side pocket mandrels
- Tubing is cut away in all views
- Run into or pulled from the well using specific tools to locate and run or pull valves set in the offset gas lift mandrels
- The tool used for wireline valve replacement is called a "kickover tool" based upon its design
Gas Lift Completion – Unloading

- How is gas injected into a well initially?
  - The process of replacing completion brine with injection gas is called **unloading the well**; it is done only once after the initial completion and after any well servicing where the casing to tubing annulus is filled with liquid.

**Diagram:**
- **Pressure**
- **Completion fluid brine**
- **Depth**
- **SBHP**
- **IPO**

Gas Lift Completion – Unloading

- **Gas pressure and rate** is gradually increased as gas is injected into a well’s casing / tubing annulus.
- The **unloading of the well** begins slowly as the pressure gradient in the casing annulus increases due to injection pressure and rate; gas lift valves open.

**Diagram:**
- **Pressure**
- **IPO**
- **Depth**
- **SBHP**
Gas Lift Completion – Unloading

- Gas injected into the casing / tubing annulus results in the pressure pushing the brine through each of the gas lift valves which are wide open.
- This is a particularly dangerous time for the valves; if the differential is too high, the liquid velocity can be enough to cut the valve seat; then, the valve will not be able to close and the design will not work.

Gas Lift Completion – Unloading

- Operators must allow sufficient time for unloading.
- API RP 11V5 states: take 10 minutes for each 50 psi (0.3 MPa) increase in casing pressure up to 400 psi (2.8 MPa), after which, a 100 psi (0.7 MPa) increase every 10 minutes is acceptable until gas injects into the tubing; to reach 1000 psi (6.9 MPa) should require at least 2 hours and 20 minutes.
- A good practice is to assign an operator to the well for the duration of this operation.
Gas Lift Completion – Unloading

- Once the brine level is below the top valve, gas will enter the tubing and begin lifting the well
- If the tubing pressure is less than the SBHP, the reservoir will begin to contribute
- First production from the reservoir is normally recovered completion brine

Gas Lift Completion – Unloading

- When the second valve is uncovered, gas will begin to enter the tubing
With more gas leaving casing than entering, the injection pressure must fall.

Gas Lift Completion – Unloading

- With IPO valves, the injection gas rate into the well at the surface must be regulated to control the gas entry to approximately the design rate of one valve.
- Since two valves are passing injection gas, the pressure in the casing annulus will fall.

When the casing pressure falls enough, the top valve will close based on valve mechanics in a good design.

When two valves rather than one are regulating gas, the pressure must fall, causing the second valve to close, leaving only the lower or the operating valve regulating gas into the tubing string.

Gas Lift Completion – Unloading
Since there is still more casing pressure than tubing pressure at the bottom valve, and, the bottom valve is still open, the injection gas will continue to displace the brine in the annulus until the third valve is uncovered.

When all upper unloading valves have closed as described, the unloading mode has ended and the well is now in its gas lift operating mode.

What happens if the third valve injects too much gas?

Once again, with more gas leaving the casing through two valves, the casing pressure will fall until the second valve closes.

Obviously, if there are more valves deeper, the unloading process continues.
Gas Lift Injection Gas Rate

- Observe the effect of injecting different injection rates into the well
- Case “A” is a small amount of lift gas, case “B” is an increased amount of gas, and case “C” is a further increase in gas rate injected
- These three cases would generate three production rates

A graph of production rate vs injection rates generates the lift gas performance curve

Once a well has been unloaded, it becomes the responsibility of the gas lift technician to periodically visit each well with a test separator and establish the optimum gas injection rate to produce an optimum liquid production rate (the lift gas performance curve)
Gas Lift Injection Gas Rate

- In most cases, there is a limited amount of gas available for all the wells.
- The optimum rate must be determined within the constraints of the gas available for a group of wells.

![Diagram showing production rate vs. injection rate with points indicating economic and technical optimums.]

Gas Lift Injection Gas Rate

- Therefore, for all the previously illustrated maximum and minimum gas injection examples illustrated, the theoretical lift gas performance curve has practical upper and lower limits.

![Diagram showing practical lift gas rate operating range.]
Recall that gas lift is a system with gas circulating around the system.

Gas goes into the wells as injection gas, out of the wells in the gas stream, then is removed from the flow stream (separated out) in the separator before being compressed and the cycle repeated.

The impact of the distribution of lift gas to these wells must be considered given a limitation in compressed injection gas rate.

A mathematically optimum gas lift distribution is found when the lift gas (LG) performance curve slope is equal at each well’s operating injection rate.

In other words, if a small amount of gas could be given to any well in a group of wells with an optimum distribution, it would not matter which well got the extra gas; all the wells would benefit similarly.
Gas Lift – CONTINUOUS Gas Lift

- Advantages:
  - Can handle sand and solids production
  - Can be used in crooked and deviated wells
  - Servicing of lift system in well can usually be done with wireline
  - Can monitor well (pressure, temperature, production logs) with wireline
  - Can recomplete some wells through tubing
  - More produced gas helps gas lift, unlike pumps (rod, ESP)
  - Flexible over a wide range of rates and depths (unlike ESPs)
  - Surface equipment at the well has a low profile (unlike rod pumps)
  - Compatible with surface safety valves (so gas lift can be used to enhance production from flowing wells)
  - This system is the most forgiving of artificial lift methods

Continuous gas lift operates most efficiently on moderate to high flow rate wells making significant gas, especially where compression already exists.
Gas Lift – CONTINUOUS Gas Lift

- Disadvantages:
  - Imposes backpressure on the reservoir (unlike pumps or intermittent lift)
  - Requires quality gas supply throughout project life
  - Requires large capital investment (compressor)
  - Injection gas makes formation gas measurement more difficult
    - Total Gas = Injection Gas + Formation Gas
    - Total Gas – Lift Gas = Produced Gas from the Reservoir

Hides its operating inefficiency from casual observations very well

Gas Lift – INTERMITTENT Gas Lift

- Advantages:
  - Lower reservoir backpressure (as low as pumps in some cases)
  - Can be used in crooked and deviated wells
  - Servicing of lift system in well can usually be done with wireline
  - Can monitor well (pressure, temperature, production logs) with wireline
  - Can recomplete some wells through tubing
  - More produced gas helps gas lift, unlike pumps (rod, ESP)
  - Surface equipment at the well has a low profile (unlike rod pumps)
  - Compatible with surface safety valves

Intermittent gas lift operates most efficiently in wells with high PI with low SBHP or low PI with high SBHP where gas lift facilities are available and pumping is not practical
Gas Lift – INTERMITTENT Gas Lift

- **Disadvantages:**
  - Slugs of liquid can upset production facilities
    - Slugs of produced liquids (especially offshore) can be intolerable for efficient operation
  - Limited to low volume wells, usually < 200 bpd (31.8 m³/d), which don’t flow
  - Sand can plug standing valve and stick plunger
  - Requires frequent operator adjustments
  - Requires quality gas supply throughout project life
  - Requires large capital investment (compressor)
  - Injection gas makes formation gas measurement more difficult

**Learning Objectives**

This section has covered the following learning objectives:

- Understand the concept of gas lift in both unloading mode and operating mode to start up a gas lift completion and operate the completion over its life
- Identify the principles of gas lift valve performance and the proper location of the operating valve and unloading valves
- Recognize the characteristics of lift gas performance analysis to properly establish the most efficient gas lift completion performance conditions
Learning Objectives

This section will cover the following learning objectives:

✓ Identify the three critical electrical submersible pump design challenges: solids (sand), gas, and dependable power to maximize ESP run life (as the average industry ESP run life is approximately 2.4 years)

✓ Understand the principles of downthrust, upthrust, pump efficiency, total dynamic head (TDH), number of stages required, and pump horsepower required to successfully operate ESPs

✓ Recognize the characteristics of ESP electrical cable, variable speed drive, and controller components in a functioning ESP
ESP Pumps

- Electric submersible pump consists of downhole equipment

ESP Pumps

- The most important components of the electrical submersible pump system are above ground

ESP Pumps

- Motor
- Equalizer
- Intake
- Pump
- Cable
Electrical Submersible Pumps

- ESP design challenge is proper sizing of the pump
  - Function of reservoir inflow into the bottom of the well
  - Rate at which well is produced is related to flow rate brought into the well as a function of drawdown

- The ESP system will be described
  - Pump
  - Pump intake
  - Motor
  - Equalizer
  - Cable
  - Variable speed drive (VSD)
  - Various operational components

The heart of an ESP pump are its impellers
- These spin at high speeds sucking liquid up into the center, imparting rotational energy to the liquid, and throwing the liquid out at high speed
- Liquid that gets thrown out of the impeller makes room for more liquid that gets pulled in through the center of the impeller
Electrical Submersible Pumps

- To properly use the energy that the liquid now has in rotational motion, the pump has **diffusers** that slow down the liquid and turn it.
- This changes the velocity of the liquid imparted by the impeller into head / pressure.

Electrical Submersible Pumps

- Head generated by the pump can be determined by examining the change in velocity generated by the pump, $V$.
- The two components that make this up are the velocity in the direction of the tip of the impeller, $u$, and along the impeller, $y$.
- Only the component $u$ contributes to head.
- As the flow rate through the pump increases, so does component $y$, which tends to decrease component $u$, and thus the head generated.
Electrical Submersible Pumps

- For a given impeller at a given rotational speed, the more rate, the less head
- Note the plot of the pump curve on the TDH vs. Rate graph
- The pump curve is the head that the pump can supply at a given rate (and rotational speed)

Electrical Submersible Pumps

- The pump curve is not affected by the specific gravity of fluid it is pumping
- At a given rotational speed, the same head is generated
- The higher the specific gravity of the fluid being lifted, the greater the number of impellers required
Electrical Submersible Pumps

- The shape of the impeller influences the fundamental shape of the head rate curve
- Most pumps use **radial** impellers, but they may tend toward the **axial** shape to pick up flow rate at the expense of head

---

Electrical Submersible Pumps

- To generate sufficient head, traditional centrifugal pump manufacturers create a single, very large impeller
- This is the kind of pump used in surface facilities (e.g., waterflood pump)
- The efficiency (and the cost) of this pump is high
- However, this is not a suitable size and shape pump to install in a well
Electrical Submersible Pumps

- In order to create sufficient head to lift liquid to the surface in a normal well, stages are stacked
- Each stage feeds into the one above
- Each stage acts as a small increment of head
- Most ESPs have hundreds of stages, all driven by a single shaft
- The size and cost of each stage is fairly small

When the length of the stacked stages gets unwieldy, the stages are grouped into multiple housings.
Electrical Submersible Pumps

- In most ESPs:
  - The impellers are keyed to the shaft in the rotational direction
  - The impellers are free to move up and down the shaft
  - These impellers are floaters
  - The impellers usually hover inside the housing, ideally with slight downthrust on the wear surfaces below the impeller
    - Forces acting on the impeller are balanced

Electrical Submersible Pumps

- If the flow rate is too high through the pump, the impellers will be pushed to the top of the housing and will suffer wear
- This condition is called upthrust
- Wear in upthrust mode will cause inefficient operation and may induce vibration that leads to pump failure
Electrical Submersible Pumps

- If the head is too high for the pump, the impellers will be pushed to the bottom of the housing and will suffer wear
- This condition is called downthrust
- Pumps are designed for some downthrust
- However, if excessive, the wear will cause inefficient operation and may induce vibration that leads to pump failure

These regions are illustrated on a pump curve:
- Downthrust
- Upthrust
- Safe Area
Electrical Submersible Pumps

- Vendors show an operating range on their pump curves that do not define the safe range, but a range inside of the highest efficiency.
- The relationship of the most efficient range to the danger areas of upthrust and downthrust is not known in most pumps, so the efficiency limits are used instead.

ESP

- **Sub pump** shows the recommended operating range by marking it with small squares at the upper and lower limits on each curve.
ESP Manufacturer Pump Curve

24 ft (7.6 m)

Head capacity

800 bbl/d (124 m³)

ESP Manufacturer Pump Curve

Brake Horsepower

0.22 HP

800 bbl/d (124 m³)
ESP Manufacturer Pump Curve

ESP PUMP Curve For 5 ½ in. (140 mm) Well Casing

What about Gas and High Producing GOR Wells?

- ESP pumps do not handle gas efficiently without proper design
- How much gas is too much gas? (This area is one of the most researched items in the recent development of ESPs)
- Too much gas can cause “gas lock” as gas occupies space in the pump, space needed for pumping liquids
- Gas volume increases rapidly, especially below a FBHP of about ~500 psi (3.4 MPa)
How to Handle High GOR Wells

- In a normal well installation without a packer, gas is sent to the annulus by the gas separator.
- The very low gradient for gas means that, for a given FBHP, the gas can still have enough pressure at the surface to flow into the flow line with the pumped fluids.

- Well fluids enter the pump through the pump intake.
- A standard intake has a coarse screen to restrict debris.

Gas Lift and ESP Pump Core

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How to Handle High GOR Wells
- Well fluids enter the intake and gas is routed to the annulus.
- This is accomplished by the pump intake including a centrifugal gas separator.

The objective is to keep the gas volume fraction to the pump at less than 10%.
- This objective is conservative, and, at higher pump intake pressures, the pump can handle 35%+ gas, although the gas still takes up volume required for liquid.
- Free gas is calculated by subpump / can be calculated by:

\[
FG = \frac{\left[\text{GOR} - \text{Rs}\right] \left(1 - \text{wc}\right) \text{Bg} / 1000}{\left[\left(\text{GOR} - \text{Rs}\right) \left(1 - \text{wc}\right) \text{Bg} / 1000 + \left(1 - \text{wc}\right) \text{Bo} + \text{wc}\right]}
\]

Where:
- GOR = gas oil ratio (scf/bbl)
- Rs = solution gas oil ratio (scf/bbl)
- Bg = gas volume factor
- wc = water cut fraction
- T = Temp (Rankine)
- P = pressure (psi)
- Bo = Oil volume factor

Source: PEGS 10641.03, pg35
An ESP motor is not designed like an ordinary motor

- A typical electric motor is shown above
- This is a very efficient shape electrically and for manufacturing the motor

A common ESP motor is the three phase, squirrel cage type, so called because of the rotor appearance
- Efficiency is greatly reduced

An ESP motor is not designed like an ordinary motor

- An ESP motor works on the same principles, but must fit into a long skinny well bore
- This compromise means less efficiency and, thus, greater heat buildup
- Also, normal motors have fans for cooling but the ESP motor has only the flow of well fluids past the motor to cool it
ESP Equalizer

- Why not just seal the motor?
  - An ESP motor undergoes tremendous changes in temperature during normal operation
  - The motor is full of a special blend non-conductive fluid which lubricates and electrically insulates the components; the motor must be full of this fluid to operate properly
  - When the motor gets hot, this fluid needs to expand and the equalizer permits this expansion

Types of Equalizers

- There are two primary types of equalizers
  - The bag type or positive seal protector uses a flexible bag to take the variation in motor fluid volume
Types of Equalizers

- The other kind of equalizer is a **labyrinth seal**
  - It works by a u-tube principle and requires a significant difference in specific gravities between the motor and well fluid
  - Also, it is not useful in deviated wells
  - Submersible pumps are typically placed in the 30° to 40° to 50° deviation angle of the well

ESP Electrical Cable

- Cable is the largest and possibly the most expensive component of the ESP system
  - ESP cable must carry the electrical power to the pump; it may also carry pressure and temperature signals back to the surface
    - Three copper conductors, one for each phase (can be solid or stranded)
    - A layer of electrical insulation
    - A layer of barrier tape to protect the electrical insulation from well fluids
    - A layer of braid to physically protect and contain all of the above around each conductor
    - A nitrile jacket enclosing the three insulated conductors
    - Metal armor to provide the main physical protection and give some extra tensile strength
    - Sometimes an expensive lead sheath is used to keep out H₂S gas
ESP Electrical Cable

- Cable is the largest and possibly the most expensive component of the ESP system
  - All this complexity comes at a cost - up to $50/ft ($164/m)
  - Cables are rated in terms of conductor size, voltage, and temperature rating
  - The biggest challenge is (as is the rest of the ESP system) in keeping the OD as small as possible
  - If ESP high voltage cable were going to be buried or run in a conduit on the surface, it would be several inches in diameter
  - However, in a well, it is restricted to about 1 in. OD (25 mm)
  - This is still not small enough near the pump and motor (usually the largest ODs in the well) and flat cable must be used
  - Flat cable has the conductors in parallel which provide less mechanical protection and more electrical loss

ESP Electrical Cable

- Cable is the largest and possibly the most expensive component of the ESP system
  - Gas typically migrates into the cable
  - One problem with most ESP cable is that gas (always present in the annulus) will eventually migrate slowly into the insulation of the cable
    - Unless corrosive gases are present, this does not harm the cable
  - However, if the pressure on the annulus is dropped quickly, the cable will suffer from decompression (just like a diver getting the bends); gas bubbles will expand and burst through the electrical insulation and the cable will short out

Always de-pressure the annulus of a well with an ESP installed very slowly, if at all
A variable speed drive (VSD) provides flexibility to the otherwise fairly inflexible ESP system... at a price

- The variable speed drive (a.k.a., variable speed controller, variable frequency controller, etc.) can change the rotational speed of the motor by changing the frequency of the AC power before sending it down hole to the ESP
- By changing the rotational speed of the pump, the operating range is greatly expanded

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The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price

- Reasons which justify installation of a VSD:
  - Produce the well down to the limit of drawdown (sand, gas, water influx)
  - Soft-start that reduces start up current is included
  - Test and produce at different rates
  - Handle changing inflow performance (water flood response, pressure depletion, deteriorating PI, etc.)
  - Keep power below power constraints
ESP VSD

- The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price
  - A VSD uses high voltage solid-state circuitry to convert the three phase AC into a set of square waves

![Diagram of ESP VSD](image)

ESP VSD

- The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price
  - These square waves are combined to create a pseudo-sine wave for each phase

![Diagram of square waves combination](image)
The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price
- A VSD can only approximate the perfect sine wave that the motor is expecting
- The more steps the VSD is capable of producing, the closer the approximation and the more expensive the VSD
- Each point on the cycle where the voltage is higher or lower than the sine wave is energy that the motor cannot use
- This lowers the overall efficiency and generates excess heat

\[ HP_2 = HP_1 \left( \frac{Hz_2}{Hz_1} \right) \]

This is why smaller motors can be used in an ESP installation if a higher frequency is used.
ESP VSD

- The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price
  - The pump horsepower required from the motor prime mover is a function of motor rotational speed (frequency) cubed
    \[ HP_2 = HP_1 \left( \frac{Hz_2}{Hz_1} \right)^3 \]
  - The higher the frequency, the more horsepower required

ESP VSD

- The VSD provides flexibility to the otherwise fairly inflexible ESP system... at a price
  - This means that, up to a certain design frequency, the motor / pump system is underloaded, and, over that frequency, the ESP motor / pump system is overloaded
  - This gives an upper limit to the frequency possible for a given an ESP system before overloading damages the motor / pump system
This well has an expected rate of about 400 bbl/d (64 m³) at the surface and a downhole volume of about 500 bbl/d (79 m³) and falls in the middle of the 60 Hz curve.

**Advantages:**
- High production rate capability
- Lowest initial cost for unit rate
- Low bottom hole pressure
  - Almost as low as beam pump
  - Should avoid "pump-off"
- Surface equipment is relatively small
- Can be used in deviated wells

**Disadvantages:**
- High repair costs and low salvage value
- Pump life is critical to economics and can vary from ~6 months to ~6 years; a 2 to 3 year run life typical when operated properly
- Pump efficiency low when handling high GOR
- Especially sensitive to solids as the rotor turns at 2500 rpm
- ESPs have a very narrow operating range
- Compared to other artificial lift systems, ESPs are the least forgiving
Learning Objectives

This section has covered the following learning objectives:

✓ Identify the three critical electrical submersible pump design challenges: solids (sand), gas, and dependable power to maximize ESP run life (as the average industry ESP run life is approximately 2.4 years)

✓ Understand the principles of downthrust, upthrust, pump efficiency, total dynamic head (TDH), number of stages required, and pump horsepower required to successfully operate ESPs

✓ Recognize the characteristics of ESP electrical cable, variable speed drive, and controller components in a functioning ESP

PetroAcademy™ Production Operations

- Production Principles Core
- Well Performance and Nodal Analysis Fundamentals
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- Onshore Unconventional Well Completion Core
- Primary and Remedial Cementing Core
- Perforating Core
- Rod, PCP, Jet Pump and Plunger Lift Core
- Reciprocating Rod Pump Fundamentals
- Gas Lift and ESP Pump Core
- Gas Lift Fundamentals
- ESP Fundamentals
- Formation Damage and Matrix Stimulation Core
- Formation Damage and Matrix Acidizing Fundamentals
- Flow Assurance and Production Chemistry Core
- Sand Control Core
- Sand Control Fundamentals
- Hydraulic Fracturing Core
- Production Problem Diagnosis Core
- Production Logging Core
- Production Logging Fundamentals