Introduction to Artificial Lift
What are your Artificial Lift challenges?

- Gassy oil
- Heavy/viscous oil
- Sandy oil
- High water cut
- Dewatering gas wells
- Deep
- Hot
- Low fluid levels
- Offshore
- Uncertainty
- Production optimization
Global Trends

Maturing oilfields

Increasing demand in the east

Shift from gas to oil

Horizontal wells

Unconventional production

Production optimization
The shift toward lower volume mature wells

The case for Production Optimization
Major producer operating 26,000 wells

Plunger Wells 16,000
PCP Wells 4,000
ESP Wells 3,000
Rod Lift Wells 1,000
Other / Natural Flowing Wells 2,000
Gas/Oil Meters 33,000
RTU/PLC Automation 24,000
Oil / Water Production Tanks 12,000
Compressors 3,000
Water Meters 6,000

Integrated Field Management: 5 billion data sets every 24 hours

A field management system is required for production optimization.
The increasing role of unconventional oil

World estimated recoverable oil reserves

- Conventional: 31%
- Shale: 24%
- Heavy Oil: 26%
- Bitumen: 19%

:. Unconventional production is a focus.

Source: IEA World Energy Outlook 2011, 2010
The shift from *vertical* to *horizontal* wells

Steam Assisted Gravity Drainage (SAGD) to mobilize heavy oil

Reaching hydrocarbons in shale
The shift from gas to oil
Global oil demand shifting to the east

Source EIA
Increasing focus on production technologies

![Graph showing revenue growth from 2007 to 2013 for O&G Industry and Artificial Lift. The O&G Industry has a steady increase with a peak of 53% in 2013. Artificial Lift shows a significant increase with 117% in 2013.](image-url)
The Challenge...

Find and produce *more* oil and gas assets

Maximize *productivity* of existing assets
Naturally Flowing *versus* Artificial Lifted Oil Wells

Source: World Oil, Feb 2012

“Based on the states for which the World Oil was able to obtain a breakout of flowing wells versus those on artificial lift, the percentage of U.S. oil wells produced by artificial lift is staying steady at about 95%. That ratio has remained fairly constant throughout the past 10 years.”
95% of active oil wells utilize some type of artificial lift\(^1\).

\(^1\)From World Oil, February, 2012.
What liquids are being lifted?

When is Artificial Lift needed?

1. To raise fluids to the surface when:
   \[ P_{\text{Reservoir}} < P_{\text{Hydrostatic}} + P_{\text{line}} \]

2. To increase the production rate of flowing wells by reducing the producing bottom hole pressure (PBHP = \( P_H + P_L \))

Solutions:
A. Reduce hydrostatic head pressure
B. Reduce the amount of fluid lifted per cycle
C. Reduce line back-pressure
D. Add Energy
Liquid Loading

When the pressure of the liquid column keeps gas from entering the well:

\[ P_{\text{Reservoir}} < P_{\text{Hydrostatic}} \]
Lift Technology by Lift Capacity (BPD)

Plunger Lift

Foam Lift

PCP

Rod Lift

Hydraulic Lift

ESP

Gas-Lift

200 Low

500 Medium

5000 Medium

6000 Medium

35000 High

60000 High

75000 High

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Artificial Lift Market Share by Type
(based on dollars spent)

- ESP: 54%
- RRP: 25%
- PCP: 7%
- GL: 3%
- PL: 4%
- HL: 2%
- Other: 5%

From Spears Oilfield Market Report, Oct, 2011
What do you want out of your lift system?

- Maximum production?
- Flexibility in production rates?
- Lowest purchase cost?
- Lowest operating cost? (Efficiency, consumables)
- Reliability and up-time (Mean-Time-Between-Failures)
- Least Energy Consumption? (Best Efficiency?)
- Minimum noise and visual impact?
- Minimum footprint? (Offshore)
ALS Application Screening Values

*This is just a starting point!*

<table>
<thead>
<tr>
<th></th>
<th>Gas Lift</th>
<th>Foam Lift</th>
<th>Plunger</th>
<th>Rod Lift</th>
<th>PCP</th>
<th>ESP</th>
<th>Hyd Jet</th>
<th>Hyd Piston</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Max Depth</strong></td>
<td>18,000 ft</td>
<td>22,000 ft</td>
<td>19,000 ft</td>
<td>16,000 ft</td>
<td>8,600 ft</td>
<td>15,000 ft</td>
<td>20,000 ft</td>
<td>17,000 ft</td>
</tr>
<tr>
<td></td>
<td>5,486 m</td>
<td>6,705 m</td>
<td>5,791 m</td>
<td>4,878 m</td>
<td>2,621 m</td>
<td>4,572 m</td>
<td>6,100 m</td>
<td>5,182 m</td>
</tr>
<tr>
<td><strong>Max Volume</strong></td>
<td>75,000 bpd</td>
<td>500 bpd</td>
<td>200 bpd</td>
<td>6,000 bpd</td>
<td>5,000 bpd</td>
<td>60,000 bpd</td>
<td>35,000 bpd</td>
<td>8,000 bpd</td>
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<tr>
<td></td>
<td>12,000 M³/D</td>
<td>80 M³/D</td>
<td>32 M³/D</td>
<td>950 M³/D</td>
<td>790 M³/D</td>
<td>9,500 M³/D</td>
<td>5,560 M³/D</td>
<td>1,270 M³/D</td>
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<tr>
<td><strong>Max Temp</strong></td>
<td>450°F</td>
<td>400°F</td>
<td>550°F</td>
<td>550°F</td>
<td>250°F</td>
<td>482°F</td>
<td>550°F</td>
<td>550°F</td>
</tr>
<tr>
<td></td>
<td>232°C</td>
<td>204°C</td>
<td>288°C</td>
<td>288°C</td>
<td>121°C</td>
<td>250°C</td>
<td>288°C</td>
<td>288°C</td>
</tr>
<tr>
<td><strong>Corrosion</strong></td>
<td>Good to</td>
<td>Excellent</td>
<td>Excellent</td>
<td>Good to</td>
<td>Fair</td>
<td>Good</td>
<td>Excellent</td>
<td>Good</td>
</tr>
<tr>
<td>Handling</td>
<td>excellent</td>
<td></td>
<td></td>
<td>Excellent</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Gas</strong></td>
<td>Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>Fair to</td>
<td>Good</td>
<td>Fair</td>
<td>Good</td>
<td>Fair</td>
</tr>
<tr>
<td>Handling</td>
<td></td>
<td></td>
<td></td>
<td>good</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Solids</strong></td>
<td>Good</td>
<td>Good</td>
<td>Fair</td>
<td>Fair to</td>
<td>Excellent</td>
<td>sand&lt;40ppm</td>
<td>Good</td>
<td>Fair</td>
</tr>
<tr>
<td>Handling</td>
<td></td>
<td></td>
<td></td>
<td>good</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Fluid Gravity</strong></td>
<td>&gt;15°</td>
<td>&gt;8°</td>
<td>&gt;15°</td>
<td>&gt;8°</td>
<td>8°&lt;API&lt;40°</td>
<td>Viscosity &lt;400 cp</td>
<td>≥6°</td>
<td>&gt;8°</td>
</tr>
<tr>
<td>(API)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Servicing</strong></td>
<td>Wireline or</td>
<td>Capillary</td>
<td>Wellhead</td>
<td>Workover</td>
<td>Wireline or</td>
<td>Hydraulic or</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>workover rig</td>
<td>unit</td>
<td>catcher or</td>
<td>or pulling</td>
<td>workover rig</td>
<td>wireline</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>wireline</td>
<td>rig</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Prime Mover</strong></td>
<td>Compressor</td>
<td>Well natural energy</td>
<td>Gas or electric</td>
<td>Electric</td>
<td>Gas or electric</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Offshore</strong></td>
<td>Excellent</td>
<td>Good</td>
<td>N/A</td>
<td>Limited</td>
<td>Limited</td>
<td>Excellent</td>
<td>Excellent</td>
<td>Good</td>
</tr>
<tr>
<td><strong>System Efficiency</strong></td>
<td>10% to 30%</td>
<td>N/A</td>
<td>45% to 60%</td>
<td>50% to 75%</td>
<td>35% to 60%</td>
<td>10% to 30%</td>
<td>45% to 55%</td>
<td></td>
</tr>
</tbody>
</table>
1. **Understand** and predict reservoir potential performance.

2. **Establish** target production levels and conditions.

3. **Eliminate** technically infeasible lift technologies.
   - Required performance
   - Support infrastructure (power, skill base, etc.)

4. **Economic evaluation**
   - Acquisition, installation, & training cost
   - Operating cost
   - Reliability
   - Repair/replacement
# Artificial Lift Design Software

<table>
<thead>
<tr>
<th>Lift Technology</th>
<th>Software</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reciprocating Rod Lift</td>
<td>Rod Star, SROD, XROD, QROD, others, WFT csBeamDesign</td>
</tr>
<tr>
<td>PC Pump</td>
<td>CFER PC Pump, Prosper, WFT proprietary</td>
</tr>
<tr>
<td>Gas Lift</td>
<td>Well Evaluation Model (WEM), VALCAL, Valve Performance Clearinghouse (VPC), Prosper, PIPESIM, Dynalift, WellFlo</td>
</tr>
<tr>
<td>Hydraulic Lift</td>
<td>Guiberson Piston Pump, SNAP, Prosper, JEMS</td>
</tr>
<tr>
<td>ESP</td>
<td>Dwight’s SubPUMP, WEM, Prosper, PIPESIM, supplier proprietary, Borets-WFT proprietary</td>
</tr>
<tr>
<td>Capillary/Plunger Lift</td>
<td>WEM, WFT proprietary</td>
</tr>
</tbody>
</table>

Wellflo, Dynalift, JEMS and csBeamDesign are trademarks of Weatherford. All other trademarks are the property of their respective owners.
What is Production Optimization?

Managing production of hydrocarbons *as things change over time*

- Surveillance and measurement – *What is happening?*
- Analysis – *Why is it happening?*
- Design of solutions – *How can performance be improved?*
- Asset management – *When and where?*
- Reporting – *KPI’s and feedback*
Real Results from Production Optimization

SPE study group surveyed PO literature, June, 2010¹:

- **Production Improvements** = 3% to 20% (avg = 3,000 BPD)
- **CAPEX savings** = $42,000 to $345,000 (avg = $200,000)

Value of PO to Shell² from *increased production & reduced costs*:

- 70,000 BPD
- $5 billion accumulated value

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²Cumulative value, SPE#128245, March, 2010.
Key Concepts for Understanding ALS

Inflow Performance Relationship (IPR)
Gas Lock
Cavitation
Pump Turndown Ratio
Formation Pressure = \( f\{\text{distance from well}\} \)
Productivity Index (PI) = \( \frac{\text{Flow Rate}}{\text{Drawdown}} \)

\[
\begin{align*}
\text{PI} = \frac{Q_1}{\Delta p_1} \\
\text{PI} = \frac{Q_2}{\Delta p_2} \\
\text{PI} = \frac{Q_4}{\Delta p_4}
\end{align*}
\]
Inflow Performance Relation (IPR)

Stabilized Formation Pressure

The slope is a function of flow rate, defining a curve known as the:
Inflow Performance Relation or IPR.

Doubling the Drawdown does not Double the Production

Qmax(PI)

SBHP
PBHP1
PBHP2
PBHP3
PBHP4

0
0
Q1
Q2
Q3
Q4

Flow Rate, Q

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Typical IPR versus Reservoir Drive System

Well A (water drive)

Well C (solution gas drive)

Well B
Normal pump cycle (liquid)

**Fill**
- \( P_L < P_P < P_H \)

**Discharge**
- \( P_L < P_P = P_H \)
- \( P_L = P_P < P_H \)
- \( P_L < P_H < P_P \)

\[ P_L < P_P < P_H \]
**Gas Lock**

**Fill?**

- \( P_L < P < P_H \)
- Gas in pump expands, but \( P_L < P \) so no flow.

**Discharge?**

- \( P_L \leq P < P_H \)
- Gas in pump compresses, but \( P < P_H \) so no flow.
Gas Locking in Rod Pumps

The swept volume in the pump is occupied by gas. No fluid is pumped as the pump strokes:

• **Downstroke**
  The gas compresses but does not have enough pressure to open the traveling valve.

• **Upstroke**
  The gas decompresses, but it has higher pressure than the reservoir so the standing valve remains closed.

RESULT: No fluid enters or leaves the pump.
Cavitation in Pumps

1. Low pressure gas bubbles form in liquids:
   - When a pump intake is starved for liquid
   - When localized fluid pressure drops below the vapor pressure of gas in solution
   - When existing gas bubbles are ingested into pumps

2. Higher pressure in the surrounding fluids causes the gas bubble to implode violently.
   - Shock waves
   - Micro-jets impact surrounding fluids and surfaces
Cavitation Sequence
Cavitation Shock Wave

Imploding Bubbles

Shock Wave
Cavitation Micro-Jet
Cavitation Damage
Centrifugal Pump Impeller Stage
Pump “Turndown Ratio”

Turndown ratio is a measure of a pump’s capacity to change production volume:

\[
\text{Turndown Ratio} = \frac{\text{Maximum Volume}}{\text{Minimum Volume}}
\]

For example, a pump capable of 10 to 50 BPD would have a turndown ratio of 5:

\[
\text{Turndown Ratio} = \frac{50 \text{ BPD}}{10 \text{ BPD}} = 5
\]

Pumps with high turndown ratios are helpful when production volumes are expected to vary:
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Questions?