Learning Objectives

By the end of this lesson, you will be able to:

- Use well performance analysis to finalize production targets
- Explain the ESP principles, advantages and limitations
- Describe the various components of an ESP system
- Identify how to select the right ESP equipment to meet the production targets
- Review the ESP completion design options
- Identify how to perform ESP surveillance and troubleshooting
- Review the factors influencing ESP run-life
Module Contents

- Introduction
- When to Select ESP as Lift Method
- Inflow and Outflow Evaluation
- ESP Theory, Advantages and Limitations
- Various Components of ESP
- The ESP System
- Design Example
- Surveillance and Troubleshooting
- Conclusions

Module Schedule

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<th>S. No.</th>
<th>Topic of Discussion</th>
<th>Activity</th>
<th>Time (mins)</th>
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<tbody>
<tr>
<td>1</td>
<td>Pre Assessment Evaluation</td>
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<td>Module Introduction and Learning Objectives</td>
<td>Narrated Slideshow</td>
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<td>Operating ESP Completions</td>
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<td>Evaluate Well Inflow</td>
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<td>ESP Downhole Components</td>
<td>Virtual Session 1</td>
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<td>9</td>
<td>ESP Power Cable and Accessories</td>
<td>Narrated Slideshow</td>
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<td>ESP Surface Systems</td>
<td>Narrated Slideshow</td>
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<td>11</td>
<td>ESP Cable Voltage loss Exercise</td>
<td>Exercise</td>
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<td>ESP Completion Options</td>
<td>Narrated Slideshow</td>
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<td>13</td>
<td>ESP Design Example</td>
<td>Virtual Session 2</td>
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<td>14</td>
<td>ESP Start Up</td>
<td>Virtual Session 2</td>
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<td>ESP Monitoring and Diagnostics</td>
<td>Narrated Slideshow</td>
<td>4</td>
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<td>16</td>
<td>ESP Run Life Enhancement</td>
<td>Narrated Slideshow</td>
<td>3</td>
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<td>17</td>
<td>ESP Case Study</td>
<td>Exercise</td>
<td>45</td>
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<tr>
<td>18</td>
<td>Module Summary</td>
<td>Narrated Slideshow</td>
<td>3</td>
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<td>19</td>
<td>Post Assessment</td>
<td>Evaluation</td>
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<td></td>
<td><strong>Total Duration</strong></td>
<td></td>
<td><strong>6 Hrs</strong></td>
</tr>
</tbody>
</table>

VS1 = Virtual session 1
VS2 = Virtual session 2
ESP Introduction

*Large Volume Artificial Lift*

---

Typical ESP System

- Switchboard
- Amp Meter
- Surface Cable
- Vent Box
- Wellhead
- Drain Valve
- Check Valve
- Cable Round
- Splice
- Motor Flat
- Pump
- Intake
- Seal Section
- Motor
- Tubing
- Casing
- Transformers
ESP with Packer

Lift / Rate – High Volume

2. Elimination Process

High Volume
Hydraulic Jet Pumps, Pumping, and Gas Lift
### ESP Advantages

- High volume and depth capability
- High efficiency over 1,000 BPD
- Low maintenance
- Minor surface equipment needs
- Good in deviated wells
- Adaptable to all wells with 4-1/2” casing and larger
- Use for well testing

### ESP Limitations

- Available electric power
- Limited adaptability to major changes in reservoir
- Difficult to repair in the field
- Free gas and/or abrasives
- High viscosity
- Higher pulling costs
- Run life
**ESP Considerations**

- **Operating Depth (TVD):** 1,000' - 10,000' TVD, Maximum 15,000'
- **Operating Volume:** 200 - 20,000 BPD, Maximum 30,000 BPD
- **Operating Temperature:** 100°F - 275°F, Maximum 400°F
- **Wellbore Pump Deviation:** Placement - <10° Build Angle
- **Corrosion Handling:** Good
- **Gas Handling:** Poor to Fair
- **Solids Handling:** Poor to Fair
- **Fluid Gravity:** >10° API
- **Servicing:** Workover or Pulling Rig
- **Prime Mover Type:** Electric Motor
- **Offshore Application:** Excellent
- **System Efficiency:** 35%-60%

*Special Analysis Required*
Well Inflow Evaluation

Determine the Production Target

Pwf and hence the Target liquid production rate is determined using Inflow calculations

- Pwf and Qliq

![Graph showing Pwf vs Qliq]
Back to Work Plan

- Discuss with your reservoir engineers how they estimate the liquid production rate target and the expected Pwf for their wells
Total Dynamic Head (TDH)

Determining the TDH

Defining the Requirement

- The job of an ESP system:
  - To deliver the desired flowrate
  - To deliver the required lift *for* that flowrate

- The head generated by the ESP (Pump discharge – Pump intake) will help deliver the fluids to the surface production system.
Total Dynamic Head (TDH)

- **TDH** = Total Dynamic Head in feet (or meter) delivered by the pump when pumping the desired flow rate

- \( H_d \) = vertical distance between the wellhead and the estimated producing fluid level at the expected flow rate or "net dynamic lift"
- \( F_t \) = the head required to overcome friction losses in tubing
- \( P_d \) = wellhead pressure, the head required to overcome friction in the surface piping & elevation changes

\[
TDH = H_d + F_t + P_d
\]

Net Dynamic Lift

- Knowing the Pwf and pump setting depth, Fluid Level Over Pump (FLOP) and hence \( H_d \) can be calculated

\[
H_d = \text{Pump Setting Depth} - \text{FLOP}
\]

- Specific gravity of fluid mixture can be calculated if water-cut (WC) and specific gravities of oil and water are known

\[
SpGr_{(w+o)} = WC \times SpGr_w + (1-WC) \times SpGr_o
\]

- The pump intake pressure (PIP) can be calculated as:

\[
PIP = \{\text{FLOP(ft) x SpGr}\} / 2.31\text{ft/psi} \quad **
\]

**Assuming the surface casing pressure is zero.**
Frictional Head

- Frictional loss in pipe (Ft) can be calculated using Nodal Analysis programs or using Hazen-Williams equation or chart
  
  \[ Tfloss = 0.015 \left( \frac{BPD^{1.85} (Tlen)}{Tid^{4.87} (C)^{1.85}} \right) \]
  
- Where:
  - \( Tfloss \) = the tubing friction loss in feet
  - \( BPD \) = flow up the tubing (also \( Q_{liq} \))
  - \( Tlen \) = tubing length in feet
  - \( Tid \) = tubing inside diameter (in.)
  - \( C = 120 \) for new steel pipe and 94 for 10 year old steel pipe

Frictional Loss using Chart

Liquid = Water  Temp. = 100°F
S.G. = 1.00  [38°C]  "Old" pipe (10 yrs.) = Schedule 40
"New" pipe = Schedule 40

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Calculate TDH

- $P_d = $ Wellhead pressure (PSI) \times (2.31 / Sg)$

- Calculate TDH (feet) as

$$TDH = H_d + F_t + P_d$$

Back to Work Plan

- Check with your artificial lift team if there is any ESP well with a high flowing tubing pressure, either due to a throttled choke or plugged up flowline (an excessive head demand may put the pump on downthrust)
ESP Cable and Other Accessories

Estimating the Voltage Loss

Cable

- Cable is a critical downhole component of the ESP system
- Cable can be round or flat depending upon the allowable clearance
- Upper and lower pigtails can be spliced on to allow for packers and wellhead connections

Conductors  Spool  Pothead Connection  Cable Splice
Cable Size (AWG)

- American Wire Gauge (AWG): A standardized wire gauge system for the diameters of round, solid, nonferrous, electrically conducting wire

- The smaller the AWG number, the larger the physical size of the wire:
  - The smallest cable size is AWG 40 and the largest is 0000 (4/0)

- The smaller the AWG number, the lower the electrical resistance (hence less voltage drop) and larger its current carrying capacity (amps)

<table>
<thead>
<tr>
<th>American Wire Gauge (AWG)</th>
<th>Diameter (inches)</th>
<th>Diameter (mm)</th>
<th>Cross Sectional Area (mm²)</th>
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<tr>
<td>0000</td>
<td>0.46</td>
<td>11.68</td>
<td>107.16</td>
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<td>0000</td>
<td>0.4096</td>
<td>10.40</td>
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<td>0.3648</td>
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<td>0.2294</td>
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<td>0.2043</td>
<td>5.19</td>
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<td>5</td>
<td>0.1819</td>
<td>4.62</td>
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<tr>
<td>6</td>
<td>0.162</td>
<td>4.11</td>
<td>13.29</td>
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</table>

Cable

- Three copper conductors, one for each phase (can be stranded or solid)
  - 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

Note: Insulation with polypropylene is sufficient for downhole temperatures 205 – 225 F max, but higher wellbore temperatures will require insulation with ethylene propylene diene monomer (EPDM) synthetic rubber
Cable

- Ranking of insulation materials

<table>
<thead>
<tr>
<th>Model</th>
<th>Max T deg. F</th>
<th>Min T deg. F</th>
<th>Flat Round</th>
<th>Insulation</th>
<th>Jacket</th>
<th>Application</th>
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<td>CTT</td>
<td>190</td>
<td>-40</td>
<td>F</td>
<td>Thermoplastic</td>
<td>Thermoplastic</td>
<td>Shallow wells, Water wells, Low CO₂ Light ends</td>
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<tr>
<td>CPN</td>
<td>205</td>
<td>-30</td>
<td>F/R</td>
<td>Polypropylene</td>
<td>Nitrile</td>
<td>General</td>
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<tr>
<td>CPL</td>
<td>225</td>
<td>-40</td>
<td>F</td>
<td>Polypropylene</td>
<td>Lead</td>
<td>Gassy Wells, High CO₂ H₂S</td>
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<tr>
<td>CEN</td>
<td>280</td>
<td>-30</td>
<td>F/R</td>
<td>EPDM w/Tape</td>
<td>Nitrile</td>
<td>Low to Moderate Gassy Conditions</td>
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<tr>
<td>CEE</td>
<td>400</td>
<td>-60</td>
<td>F/R</td>
<td>EPDM</td>
<td>EPDM w/Tape, Braid</td>
<td>Moderate Gassy</td>
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<td>CEB</td>
<td>300 or 400</td>
<td>R</td>
<td>EPDM w/Extruded Flouro-polymer</td>
<td>EPDM</td>
<td>Gassy Wells</td>
<td></td>
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<tr>
<td>CEL</td>
<td>450</td>
<td>-40</td>
<td>F/R</td>
<td>EPDM</td>
<td>Lead w/Bedding Tape</td>
<td>Hot Gassy Wells</td>
</tr>
</tbody>
</table>

- Cable protection
  - Cast clamps, Lasalle, Canon, Winterhawk
  - Pressed clamps
  - Banding, black iron, super bands
  - Cable saddles
Cable

- Banding – at unit and tubing

![Diagram of cable banding at unit and tubing]

- Banding, near surface

![Diagram of cable banding near surface]
Potheads

Plug-in
Tape-in

Cable Voltage Drop: Industry: 30 v/1000 ft

Voltage Drop Chart

People Providing Solutions™
### Accessories / Check and Bleeder

- **Check valve**
  - Used to prevent backfall of fluid when pump shuts down
  - Minimises downtime after a shutdown
  - Prevents sand falling back down inside pump

- **Bleeder valve**
  - To circulate fluid above pump to kill well
Accessories: Y-Tool

- Y-Tool or ESP bypass system
  - Offsets ESP in wellbore
  - Provides access using bypass tubing to perforations
    - PLTs
    - Logging
    - Perforation
  - Blanking plug in top of bypass tubing to prevent recirculation

Stiff String

- Stiff String / Scraper to check clearances before run-in

Accessories: Instrumentation

- Downhole sensor
  - Installed on bottom of motor
  - Powered through ESP cable
  - Panel at surface to receive signal
  - Typical parameters
    - Intake pressure
    - Discharge pressure
    - Intake temperature
    - Motor temperature
    - Vibration

<table>
<thead>
<tr>
<th>Parameter</th>
<th>E5</th>
<th>E7</th>
<th>Units</th>
<th>Range</th>
<th>Resolution</th>
<th>Accuracy</th>
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<td>Intake Pressure</td>
<td>yes</td>
<td>yes</td>
<td>Pa/Bar</td>
<td>0-5,000</td>
<td>0.1 Pa</td>
<td>0.1%</td>
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<tr>
<td>Discharge Pressure</td>
<td>no</td>
<td>yes</td>
<td>Pa/Bar</td>
<td>0-5,000</td>
<td>0.1 Pa</td>
<td>0.1%</td>
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<td>Intake Fluid Temp.</td>
<td>yes</td>
<td>yes</td>
<td>°C/F</td>
<td>0-125</td>
<td>0.1°C/°F</td>
<td>1°C</td>
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<td>Motor Temperature</td>
<td>yes</td>
<td>yes</td>
<td>°C/F</td>
<td>0-215</td>
<td>0.1°C/°F</td>
<td>1°C</td>
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<td>Vibration - x axis</td>
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<td>yes</td>
<td>G</td>
<td>0-1.0</td>
<td>0.005 G</td>
<td>0.05%</td>
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<tr>
<td>Vibration - y axis</td>
<td>yes</td>
<td>yes</td>
<td>G</td>
<td>0-0.8</td>
<td>0.005 G</td>
<td>0.05%</td>
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<td>Current Leakage</td>
<td>yes</td>
<td>yes</td>
<td>mA</td>
<td>0-250</td>
<td>0.001 mA</td>
<td>0.05%</td>
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</table>
Discuss with your Artificial Lift team if they have had ESP failures due to Cable faults. How this has been addressed in your asset?
What has been the feedback on the actual reliability of ESP bottom-hole gauges in your asset?
ESP Surface Systems
Power Supply and VSD

Wellhead

- ESP surface and wellhead assembly
Wellhead

- Wellhead options
  - Mandrel feedthrough
  - Packoff, low pressure

ESP Surface System

- Switchboard

  - Generation System
  - Step-down Transformer
  - Switchboard
  - Junction Box
  - ESP

  high voltage input power (11-15 kV)
  250 – 4000 V input at fixed frequency (50/60 Hz)

- Variable Speed Drive (VSD)

  - Generation System
  - Step-down Transformer
  - Variable Speed Drive
  - Step-up Transformer
  - Junction Box
  - ESP

  high voltage input power (11-15 kV)
  380V or 480 V input at fixed frequency (50/60 Hz)
  380V / 480 V output at desired frequency
  output voltage for ESP at desired frequency
Vented Junction Box

- Due to time and constant exposure, some gas may enter the power cable and migrate to surface
- Junction box (located between the wellhead and switch board) allows any gas migration to be vented to atmosphere, and eliminates possible danger of explosion in the switch board
- Normally located 15 ft. (4.572 m) from wellhead and mounted 2-3 ft. (0.609-0.914 m) above ground level

Common ESP Surface System
ESP Surface System

- Transformers
  - Note voltage drop from 12,500 to about 1000 volts as typical:
  - For VSD would drop to 480 (60 Hz) or 380 V (50 Hz)

ESP Surface System

- Switchboard is combination of
  - Motor starter
  - Overload / underload protective device
  - Recording instrument

- As part of switchboard unit may have
  - Nema 3R Enclosure
  - Load Break Disconnect
  - Fuses
  - Vacuum Contactor
  - Control Power Transformer 50/60 Hz
  - Recording Ammeter
  - Motor Controller
    - Backspin protection or timer
    - Protection for low amps
Surface System/ VSD

- Variable Speed Drive Controller
  - Takes fixed frequency input and converts to variable frequency output
  - Using a VSD allows the speed of the ESP downhole motor to be varied

Surface ESP System: Variable Speed Drive

- Primary Voltage
- Step-Down Transformer(s)
- Portable Power Disconnect
- Portable Power Cable & Terminators
- Sealing Cable Terminator
- Portable Vent Box
- Variable Speed Drive
- Step-Up Transformer
- Cable Exit Shrink CAP
- Down Hole Power Cable
- Down Hole Power Feed Cable and Terminators

**NOTE:** System grounding is not shown but must be provided.
VSD

- Provides flexibility for:
  - Uncertain well performance
  - Changing well conditions with time (WC, THP, PR, PI)
  - Producing the well down to the limit of drawdown (sand, gas, water influx)

- Added advantages:
  - Allows soft starting - reduces start up current
  - Limits the initial rate and permits gradual increase of drawdown as required
  - Permits control of intake pressure
  - Keeps power below power constraints
  - Helps test and produce well at different rates

Back to Work Plan

- Discuss with your ESP team how frequently they use the VSD controller in ESP operation
- Has the VSD been useful for limiting water cut or controlling gas or sand production in any well in your area?
Based on Well Requirements

ESP Completion Options

- Decide on additional downhole equipment in ESP well completion based on specific well requirements / value addition:
  - Downhole production packer
  - Sub-surface safety valve
  - Downhole intelligent control systems
  - What to do with the separated gas (if separator included)
  - Distributed temperature systems
  - Large diameter pump set inside casing vs. smaller pump inside liner?
  - Y-Tool with ADV (Automatic diverter valve)?
  - System to flush the pump with treated water for startup
ESP Design Special Cases

- Special products/solutions are available for the following situations:
  - Excessive gas production
  - High temperature
  - Sand production
  - High viscosity
  - Corrosion
  - Deposition/scaling
  - Well deviation (dogleg severity, DLS) at the proposed pump set depth
  - Any other concerns

- Select the most cost effective solution as applicable, after consulting with the ESP supplier

A Few ESP Completion Options

- Single ESP (Packerless)
- Single ESP with Packer
- Single ESP with Shroud
A Few ESP Completion Options (2)

Single ESP with Y-Tool

Smart Completion Selective System

Dual ESP Completion with POD System**

**ESP System in a sealed environment

Back to Work Plan

Would you prefer to incorporate gas lift mandrels with dummy valves in an offshore ESP completion as back-up (in case ESP fails)? Why or why not?
ESP Monitoring and Diagnosis

ESP Surveillance Program

- A good surveillance system
  - Monitors key surface and sub-surface parameters that indicate the health of operating ESP systems;
  - Is ably supported by well performance modeling to identify problem areas
- Useful tools
  - Amp charts
  - Real-time ESP data, well production test data
  - Good record keeping
  - Failure analysis and sharing lessons learned
  - Expertise from ESP companies
  - Use of comprehensive data in the analysis process
Measurements for ESP Systems

<table>
<thead>
<tr>
<th>Pump discharge pressure</th>
<th>Water cut, tubing GOR estimation and well shut in protection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well head pressure</td>
<td>Water cut and tubing GOR</td>
</tr>
<tr>
<td>Pump intake pressure</td>
<td>Gas locking ($P_{bg}$ and free gas volumes), reservoir drawdown, sand control, coning</td>
</tr>
<tr>
<td>$\Delta P_{pump}$</td>
<td>Upthrust and downthrust protection; flow estimation, pump performance (wear, viscosity, materials)</td>
</tr>
<tr>
<td>Motor temperature</td>
<td>Overheating</td>
</tr>
<tr>
<td>Motor amps</td>
<td>Overload/underload protection</td>
</tr>
<tr>
<td>Current leakage</td>
<td>Overheating – insulation breakdown</td>
</tr>
<tr>
<td>Vibration</td>
<td>Fatigue, loading</td>
</tr>
</tbody>
</table>

Inflow vs. Outflow problem

- Less intake pressure, less rate may indicate inflow problem
- More intake pressure, less rate, may indicate deteriorating pump performance, scale, asphaltene, wear, etc.
- Use all the available data for analysis:
  - Surface and downhole parameters, Amps, well test data
  - Measure fluid level if the intake pressure gauge is not working

[Diagram showing data points and lines representing different pressures and depths]
Monitoring

• How is downtime captured?
  - Is the pump on?
  - Is it producing?
  - Is the system protected?
  - Has it lost production
    - Suddenly
    - Gradually
• Flowrate / watercut / PI validation
• Alarms and trips
• Suddenly
• Gradually

Surveillance Process

• Do we understand the well inflow?
  - Flowrate / watercut / PI validation
• Can we gain production (existing/new system)?
• Do we need remedial action?
Discuss with your Production engineering team on how frequently they review the ESP field data along with the well production data to evaluate the combined performance of the ESP, the well and the reservoir.
ESP Run Life Enhancement

Understanding the Causes of ESP Failure

- A detailed database that contains the performance information of all ESPs will give the vital clue: the area that requires attention

- An ESP Failure distribution chart as reported by a Major Operator is reproduced below. This chart highlights the major areas causing pump failures.

- The factors may be different for other assets

![ESP Failure Chart](chart.png)
Ten (10) key factors having the most impact on system run life - Need to understand and then effectively manage these:

1. Equipment sizing, selection and operation
2. Power quality
3. Well deliverability and inflow performance
4. ESP operating temperature
5. Solids production
6. Free gas in pump
7. Depositions
8. Corrosion
9. Equipment monitoring & surveillance
10. Continuous improvement processes

Continuous Improvement Program

Make ESP run life improvement a team goal

- Measure, record and communicate run life performance
- Use down-hole sensors with surface monitoring and surveillance
- Inspect “short runs” and apply root cause analysis techniques
- Engage the ESP service company
Back to Work Plan

☑ Discuss with the Artificial Lift team about the average ESP run life achieved in your company, compared with the industry average (+/-2.5 years)
☑ Investigate the major factors contributing to ESP failure in your company
Module Summary

In this module:

- We have shown that the ESP design starts with the reservoir performance analysis to finalize production targets
- We learned the principles, advantages and limitations of the ESP lift method
- We learned how to calculate the total dynamic head (TDH) that is required for ESP design
- We described in detail various components of the ESP system, at both the surface and the sub-surface, and emphasized how each component can contribute to enhance the run life of the ESP completion
- We learned how to select the right ESP equipment to meet the production targets and to achieve a long service life, while working as a part of the system
In this module:

- We reviewed various completion options with ESP based on well requirements and local regulations
- We performed an ESP design for an example well, starting with basic reservoir, fluid and well parameters
- We presented guidelines to be followed for commissioning and routine start up of ESPs
- We discussed the need and ways of performing surveillance and troubleshooting using well production data and ESP performance data
- We summarized the factors that affect ESP run-life
- We have done various exercises and a case study to demonstrate important concepts presented in the module