Improvements in ESP Designs in
Non-consolidated Sandstone Reservoir and Mature Field, Marine Region, Mexico*

Emaglin Hernandez Medina¹, Sarita Sandoval Perez¹, Saul Gomez Saavedra², Hermilo Ramos², Juan Jesus Guerrero², and
Gustavo Gonzalez²

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²Pemex Exploracion y Produccion

Abstract

This presentation documents field experiences and integral solutions implemented in wells through technical analysis between Baker Hughes, a GE Company, through multidisciplinary work with our main client in Mexico.

The integral solutions evaluated include:
- Productivity evaluation and definition of critical pressure drop per well through nodal analysis
- Evaluation of reservoir characteristics and optimal production rates and fluids properties
- Drainage area analysis between nearby producing wells
- Analysis of existing well completion and sand control techniques
- Implementation of corrective cleaning in producing wells through ESP (Electrical Submersible Pump) systems
- Improvements in ESP designs, like special configuration, such as stabilized pumps, mixed flow stages, abrasion resistant materials, and others. As well techniques of surveillance, monitoring and diagnosis of wells
- Improvement of ESP completion through implementation of downhole tools to separate solids that extend the ESP run life
The success of this evaluation has several key factors based on the goals set by the operator and the ESP supplier. This common goal is maximizing ESP run life and well performance without adding to well downtime. This presentation describes several benefits achieved through interdisciplinary work, including expanded reservoir evaluation, lower completion analysis enhanced and well productivity.
Improvements in ESP designs in Non-consolidated sandstone reservoir and mature field Marine Region – Mexico

Emaglin Hernández Medina, Sarita Sandoval Perez
S. Gómez Saavedra, H Ramos, J. Jesús Guerrero, Gustavo González.
Today’s agenda

- Introduction.
- Workflow: Productivity and Reservoir evaluation.
- Description & Considerations for improvements in ESP designs.
- Reservoir characteristics.
- Productivity analysis & Improvements in ESP designs.
- Implementation of downhole tools to separate solids that extend the ESP run life.
- Conclusions.
Once natural lift becomes insufficient, artificial lift methods are employed to lift the fluid, allowing additional flow.

The electrical submersible pump systems deliver an effective and economical way of lifting large volumes of fluids from great depths under a variety of well conditions.

The ESP is a very versatile artificial lift method that can be operated in different and harsh environments all over the world.

In most fields in the marine Region of Mexico, the ESP is the most adequate system due to the reservoir and well conditions.
The problems associated with sand production in wells of the Marine Region fields in Mexico have been extensively evaluated through many technical studies: optimal completion analysis for each specific well, geomechanical models to determine premature sand production as well as risk matrices of the well completion and productivity analysis.

This work provides some of the proposed solutions that were executed in wells with running ESP during the well screening and designing in order to mitigate sand production issues based on the well productivity to improve the ESP performance and reliability.
Typical sand problems observed in the field

- High fluid velocity
- Unconsolidated formation
- Failures in Downhole completion systems
- Reservoir pressure depletion
- Sudden changes in flow rates or high flow rates

Geomechanical model for a reservoir involves detailed knowledge of:
- In situ stress orientations
- In situ stress magnitudes
- Pore pressure
- Rock Mechanical Properties

Typical sand problems observed in the field include:
- Reservoir pressure depletion
- High fluid velocity
- Unconsolidated formation
- Failures in Downhole completion systems
- Sudden changes in flow rates or high flow rates
Generally, any ESP equipment failure in offshore operations is extremely costly.

The production losses and workover cost associated with ESP failures represent a significant impact on any project economics.

The run life of an ESP installed in wells of a Jurassic reservoir used to vary between 2 months (most critical condition) to 8 months (more optimistic application).

Considering one sample: 86% of the failures correspond to broken shafts caused by the accumulation of solids that completely clogged the pumps and the other 14% corresponded to electrical failures.
**Productivity, Reservoir and Evaluation for ESP designs**

Our goal is to provide customers with an integrated service value combination that will optimize each stage of the process, which includes but not limited to: pump design, implementation, and real-time monitoring in order to analyze production performance. (Multidisciplinary teams GPE-ALS support- Mexican Customers):

<table>
<thead>
<tr>
<th>STAGES</th>
<th>1 VERIFY</th>
<th>2 DESIGN</th>
<th>3 SUPPORT</th>
<th>4 OPTIMIZE</th>
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<tbody>
<tr>
<td>OBJECTIVE</td>
<td>Wellbore Model (Set up and Calibration)</td>
<td>Detailed Engineered ESP Design</td>
<td>Reservoir Simulation Support</td>
<td>ESP System Sizing and Optimized Configuration</td>
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<tr>
<td>ACTION</td>
<td>Data gathering, review and analysis</td>
<td>Optimum pump depth</td>
<td>Generation of lift curves for various simulators which:</td>
<td>Carry out nodal analysis</td>
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<tr>
<td></td>
<td>Estimation of well productivity, including production rates</td>
<td>Calculating gas properties and</td>
<td>- Allows for a wider range of system configurations</td>
<td>Stress analysis for equipment and casing</td>
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<tr>
<td></td>
<td></td>
<td>Pump selection, as well as cable and accessories</td>
<td>- Takes into account the heating effect of the pump</td>
<td>Full system testing simulation</td>
</tr>
<tr>
<td></td>
<td></td>
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<td>- Incorporates Baker Hughes' proprietary viscosity correction factors</td>
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<td></td>
<td></td>
<td></td>
<td>Provision of a more representative description of the fluid flow in the wellbore, which is required for reservoir simulation</td>
<td></td>
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<tr>
<td></td>
<td></td>
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<td>Simulation of different scenarios which may include expected variations in the operating system through the well life.</td>
<td></td>
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<tr>
<td></td>
<td>- Nodal analysis</td>
<td>- Sensitivities on pump’s operating conditions are carried out on AutographPC™</td>
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<tr>
<td></td>
<td>- Accurate modeling of the Artificial Lift system using Baker Hughes’ AutographPC™ software</td>
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</table>

(Productivity, Reservoir and Evaluation for ESP designs)
Improvements in ESP designs and integral solutions

The integral solutions evaluated include:

- Evaluation of the reservoir characteristics, optimal production rates and fluids properties.
- Productivity evaluation / definition of the critical drawdown pressure per well through nodal analysis.
- ESP surveillance, monitoring and diagnosis.
- Analysis of existing wells completion and sand control techniques.
- Improvements in ESP designs like special configuration such as stabilized pumps, mixed flow stages, abrasion resistant materials and others. As well as surveillance techniques, monitoring and wells’ diagnosis.
- Improvement of the ESP completion through implementation of downhole tools to separate solids that extend the ESP run life.
- Implementation of corrective cleanings in producing wells through ESP systems.
Reservoir characteristics

Offshore Field – Mexico

Production challenges

Jurassic Reservoir
- Unconsolidated sandstone
- Low reservoir pressure
- Sand production
- Short ESP run lifes (most ESP's failed after operating 5 months or less).
- Decreasing rates due to inefficient lower completion in existing wells: erosion and wear in stand alone, slotted liner, and wire wrapped screen.

Location: Gulf of Mexico (offshore). Reservoir Jurassic

Field development since discovery (1991)
Reservoir characteristics

<table>
<thead>
<tr>
<th>Description</th>
<th>JSO</th>
<th>Units</th>
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<tbody>
<tr>
<td>Discovery</td>
<td>1992</td>
<td>Year</td>
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<tr>
<td><strong>Start of operation</strong></td>
<td>1993</td>
<td>Year</td>
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<tr>
<td>Initial reservoir pressure</td>
<td>581</td>
<td>kg/cm^2</td>
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<tr>
<td><strong>Current reservoir pressure</strong></td>
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<tr>
<td>Temperature</td>
<td>108</td>
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<tr>
<td><strong>Oil Density</strong></td>
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<td>°API</td>
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<tr>
<td>Viscosity @ Pb</td>
<td>2.04</td>
<td>cp</td>
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<tr>
<td>Bo @ Pb</td>
<td>1.29</td>
<td>m^3/m^3</td>
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<td>Bubble Pressure</td>
<td>115</td>
<td>kg/cm^2</td>
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<td>Solution Gas oil ratio @ Reservoir</td>
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<td>m^3/m^3</td>
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<td>condition</td>
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<td>250</td>
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<td><strong>Reservoir rock lithology</strong></td>
<td></td>
<td>Sandstone</td>
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<td>100</td>
<td>m</td>
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<td>22</td>
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<td>Abandoned</td>
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<td>quantity</td>
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Productivity Evaluation

When dealing with low reservoir pressures, the implementation of ALS can help to increase wells’ productivity by reaching lower flowing pressures. Having an accurate characterization of the fluid properties (o/g/w) and understanding the potential risks associated to sand production, play a crucial role during the design, installation and continuous monitoring of the ALS installed in the well.

Low reservoir pressure and water production

Sand production and fines migration

Reservoir simulation at a well level in order to analyze the various completion solutions (ICDs, screens, dual completions) to mitigate sand production and water production.

Inflow Performance Relationship

Geomechanical modes:

Rock Mechanical Properties from Log Data
Sonic Velocity
3D Models based on wells (minimum Pwf)

Nodal Analysis
PVT analysis
(Pb, uo, Density ,SARA analysis (asphaltenes)
Water Analysis (incrustations)

Completions
Artificial Lift
Productivity Evaluation

- PVT analysis and fluids properties calibration
- Nodal Analysis
- Productivity Index estimation
- Sensitivities to reservoir parameters: K, H, Skin, Pws.
- Flow correlation behavior
- Pressure and temperature gradient
- Drawdown analysis before onset of sand production (compressive strength, reservoir pressure)
Critical drawdown - Relevant Previous work

- In 2008, the Operator performed a geomechanic study over the JSO reservoir. Mechanical Earth Models were built to provide the major inputs (i.e. UCS: Uniaxial Compressive Strength and Stress directions) for the sand control technique.

- In 2005, the operator performed a geomechanic study in the field to model the fault leakage potential.
  - Critical Drawdown as a function of compressive strength
  - Estimation of Historical drawdown at completion failure
  - Critical drawdown pressure : ~10-15 Kg/cm²
  - Some wells produce with “no secure” drawdown pressure. Sand production is presented with any drawdown in this reservoir.
  - Some solutions to drain the target area of new wells: Horizontal wells
    - Optimal length of horizontal well (operational efficiency and economic viability)
    - OPTIMAL LENGTH: 600 m to 1000 m
    - Improve solid influx and enhance ESP survivability
Production analysis

Start of Water injection for reservoir pressure maintenance in 2006.

Oil rates scenarios considered Q: 1,300 BPD to 3,000 BPD. Results with lower drawdown involved fluid rates between 1,300 BPD to 2,000 BPD.

Geomechanical model

Understanding reservoir & well connectivity through Geomechanics
Critical drawdown (Geomechanical Previous work)

- Simulations indicate that sand is produced with even lower pressure drops than those indicated in the geomechanical studies due to:
  
  - Stress conditions in the rock.
  - High depletion in reservoir pressure.
  - Orientation of some wells in the reservoir.
  - Formation damage (non-compatible fluids during the completion and drilling operations).
  - Some mechanical failures in existing wells (eroded screens).
Pump surveillance, monitoring and diagnosis through ESP downhole sensor provides valuable information about the ESP and well performance.

Real time analysis enables teamwork and allows to identify possible effects of the interference between the drainage areas of some wells.

Through real time ESP monitoring is possible to identify problems in the equipment and potential difficulties in well productivity and reservoirs.

Data from downhole ESP sensor may be useful in well testing to define some reservoir parameters: static pressure, pwf, k,
Improvements in ESP designs
ESP systems are not particularly good at handling solids production. The synergic work between our customers and BHGE specialists considered the implementation of the proper technology for severe solids production. BHGE has several options available which will enhance the overall operation of the ESPs in abrasive environments.

How much sand can a pump handle?
Depends on:

- Fluid type: light oil, heavy oil, water cut and emulsions.
- Pump stage configuration.
- Total liquid flow rates.
- Characteristics of solids (hardness, acid solubility).
- Quantity of sand produced, particle size distribution, mineralogy (quantity of quartz) and sand geometry (angularity).
- Other factors such as carbonates and corrosion.
Consequences of sand production in ESP system

**Problem**

- Solid Production
- Productivity index

**Effect**

- Artificial lift system (ESP)

**Consequences**

- Severe wear of vanes (consequence of: abrasion and erosion - radial & axial)
- Broken shaft (high torque for pump clogging)
- Obstruction of the flow area (impellers)-plugging
- Vibration (affects bearings, mechanical seals, etc.)
- Lower efficiency of pump
- Obstruction of perforated interval due large solids accumulation (damage formation)
What strategy to follow?

Handling solids production - ESP

Active control
- Gravel Pack
- Screens
- Frack Pack
- Chemical consolidation

Passive control
- Drawdown control
- Selective drilling
- Oriented drilling technologies
- Handling solids production / ESP

New technologies Implementation

You should evaluate
- Costs and Risks
- Productivity and behavior over time
- Reservoir characteristics
- Environmental impact
- Operational Considerations
- Industrial safety
Example of ESP selection and design for a well

Reviewing available information

- Production data and historic trends
- History of solids production (non-intrusive device)
- Fluid properties
- Well history: including work-overs, treatments, monthly clean-up operations through ESP systems with HCL -10%, etc.
- Granulometric distribution, composition of solids and geometry.
- Previous ESP run life and failure analysis.
- Reduction in well production (decreasing from 2000 BPD to 1200 BPD).
- Excessive sand production in wells with high liquid flowrates (1800 BPD - 2500 BPD ---- Sand volume : 13.49 kg/day).
- Well Monthly interventions : Pumps Clean up (tubing or annular) (10% HCL).
Quantity of sand that falls to the bottom of the well (production interval) and quantity of sand passing through the pump.

- It is necessary to know granulometry of the rock (grain size probability curve).
- With granulometry information and the maximum suspension diameter (Robinson equation).
- Suspension diameter: 225 microns (analysis made in Mexico ESP case Study).

Results indicate: Approximately 68% of the particles will be handled by the pump. Fraction of surface solids is 56.91 ppm.

Granulometric distribution curve (core sample JSO – 4445.8 m)

Conclusion: There is 68% probability to find grains with this particle diameter ≤ 225 microns.

When the fluid and sand properties are known, equation of Robinson allows to determine the widest diameter that can be transported to the surface for a given liquid rate (Q = Velocity * Area).

\[
D_{\text{MAX}} = \sqrt{\frac{V \cdot 18 \cdot \mu}{g \cdot (\rho_{\text{solid}} - \rho_{\text{liq}})}}
\]

Considering:
Q = 1800 BPD, bottom viscosity 0.32 cP @ 200 °F, casing 7¾ inches x 46.1 lb/ft.

D suspension particles = 225 microns.

Particles with diameters less than 225 microns are dragged through the pump (according to the equation) and any particle bigger than 225 microns fall at the bottom of the well.
Geometry and composition of grains

- 38% CLAYS,
- 62% QUARTZ
- (SILICA - HARDNESS: 7 SCALE MOHS)

### FIGURA No. 9

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<th>TAMIZ No</th>
<th>MICRONES</th>
<th>UNIDADES</th>
<th>PESO RETENIDO</th>
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<th>% PESO RETENIDO</th>
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**ANALISIS GRANULOMETRICO:**

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<th>% PESO</th>
<th>UNIDADES PHI</th>
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<td>ACUMULADO</td>
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<td>96</td>
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**TAMAÑO DE GRANO:** 2.34 (0.20 mm)

**ESCOGIMIENTO (phi):** 0.76 MODERADO

**ASimetria (phi):** -0.03 SIMETRICA

**ANGULOSIDAD (phi):** 1.22 ANGULOSA

**PROFUNDIDAD:** 4445.64 m

**NUCLEO:** 7
To determine Material Recommendation Index (MRI) and to select the proper type of abrasive protection and pump configuration, the following information is needed:

- Volume of solids handled by the pump: 56.91 ppp
- Particle diameter: \( D \text{ particle} \leq 225 \text{ microns} \)
- Composition/ mineralogy: 38 clays and 62 quartz
- Hardness of the grains: 7 Mohs

<table>
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<th>&lt; 10 mg/liter</th>
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<td>Moderate</td>
<td>11 - 50 mg/liter</td>
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<tr>
<td>Heavy</td>
<td>51 - 200 mg/liter</td>
</tr>
<tr>
<td>Severe</td>
<td>&gt;200 mg/liter</td>
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</table>

![MOHS Scale Chart](chart.png)
Improvements in ESP designs

1. Mixed flow stages with radial and axial stabilization every three stages (tungsten carbide bushings). Stages made of abrasion-resistant material (Ni-Resist) SSD type.

2. Stages with larger flow area to avoid clogging and stuck stages. (lower erosional velocity which reduces wearing and vibration)

3. Diffuser includes rotary suppressor flaps to reduce damage in pump stages and avoid possible mechanicals failures in housing.

4. Pumps with extended operating ranges that adapt to changing well conditions as production rates change, providing operational flexibility ideally for this reservoir types in which the production index declines rapidly due to the accumulation of solids in the perforated interval.

5. Pump geometry generates higher lift per stage, requiring fewer stages than conventional or radial pumps (less mechanical complexity). Wider stage vane openings reduce pump plugging and give ESP systems enhanced solids and gas-handling capabilities.

6. The Monel shaft material was replaced with Inconel material for a better resistance under plugged and over-torque events.
The pump allows a wider operating range that offers a higher operational flexibility which is needed in this type of sandstone reservoir, where the well production declines are too high due to the gradual solids accumulation in the production interval.

![Graph showing pump performance](image)

- **1500 BPD**
- **4300 BPD**
Improvement in ESP completion through downhole tools to separate solids and extend ESP run life

Downhole Sand separator is designed to separate the sand from the produced fluid before it enters the pump. This device is attached below the ESP motor (base of the motor). The sand separator has no moving parts. The process of separation is done by centrifugal forces generated by the velocity of the fluids in the helicoidally section of the device.

The sizing of the ESP system with the downhole sand separator was the first application tested in wells from Marine Region of Mexico.

The obtained results and the low capital cost of the solution made it possible to standardize the application and use the tool with an ESP for every well in the field.
Downhole Sand Separator

Key Features

- Separates sand particles of 40 Microns and above.
- No well preparation required - RIH with ESP.
- No moving parts.
- Assists gas separation.
- Low capital cost.
- The sand management system offered for different types of sand.
- Collection options.

<table>
<thead>
<tr>
<th>Casing Size</th>
<th>Solid separator OD</th>
<th>Flow rate</th>
<th>Overall Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>5-1/2&quot;</td>
<td>4&quot;</td>
<td>200-1000 b/d</td>
<td>112.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400-1300 b/d</td>
<td>118.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1000-1700 b/d</td>
<td>121.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1200-2000 b/d</td>
<td>123.5&quot;</td>
</tr>
<tr>
<td>7&quot;</td>
<td>5-1/2&quot;</td>
<td>200-1000 b/d</td>
<td>114.5&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1000-2200 b/d</td>
<td>125.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1500-2800 b/d</td>
<td>140.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1800-3600 b/d</td>
<td>148.7&quot;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2500-5000 b/d</td>
<td>165.7&quot;</td>
</tr>
</tbody>
</table>

How it works

1. Solids laden fluid is forced into SandCat intake. Integrated flow seal acts as a barrier to prevent well fluid from bypassing SandCat.
2. Centrifugal chamber drives sand and solids to outer part of chamber allowing de-sanded fluid to enter the SandCat internal central fluid intake.
3. Separated sand and solids are directed to tailpipe (or rat hole) by centrifugal velocity and carried downward by gravity.
4. De-sanded fluid exits into the upper annulus through the discharge sub above the flow seal.

Once tailpipe is filled, production of sandy fluid is resumed to ESP. No plugging will occur.

Minimum particle size separated at varying flowrates.
General Steps:

- With the desired production and well geometry, the separator model was selected (expected production ranges between 1200 BPD to 2000 BPD).

- Another factor to be considered for the design of the separator involved the volume of produced sand.

- The case study considers the most critical solid production rates for a well. The design takes into account the new expected liquid production rate: 1800 BPD and the surface solids measurements: 13.49 kg/day. This evaluation estimated a surface fraction of solids: 56.91 ppm.

<table>
<thead>
<tr>
<th>Well</th>
<th>Daily Volume of Sand (not compacted)</th>
<th>Sand height in camera per day</th>
<th>Filling time Chamber of accumulation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ft³/d</td>
<td>m³/d</td>
<td>ft/d</td>
</tr>
<tr>
<td>X-1</td>
<td>10.02</td>
<td>0.28</td>
<td>0.93</td>
</tr>
</tbody>
</table>

Estimation of sand volume produced (sand to be stored in the downhole pipe) in order to calculate filling time of the storage pipe (consider pipe diameter).

Well geometry

Desired production rate

Limitations of the motor sensor connection (maximum weight supported: pipe + wet sand)

Improve ESP completions (Downhole Sand Separator)
Definition of the length “pipe tail” depends on: maximum weight supported by the motor sensor connection (In this case is 16,602 Lbs). This arrangement considers a pipe length of 137 meters (Tubing 3 ½ inch).

The total weight is 7,930 Lbs (weight of the solid separator + pipe tail saturated with wet sand).

### Final Sand Separator Configuration

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Weight (Lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cross over</td>
<td>25</td>
</tr>
<tr>
<td>Packer</td>
<td>80</td>
</tr>
<tr>
<td>Solids separator</td>
<td>65</td>
</tr>
<tr>
<td>Solid accumulation chamber (considering wet sand) 137 m</td>
<td>7760</td>
</tr>
<tr>
<td><strong>Total weight (Lb)</strong></td>
<td><strong>7930</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Tubing chamber</th>
<th>3 ½” x 9.2 Lb/ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing area (m²)</td>
<td>0.00475</td>
</tr>
<tr>
<td>Length (m)</td>
<td>137</td>
</tr>
<tr>
<td>Volume (m³)</td>
<td>0.5534</td>
</tr>
</tbody>
</table>
**Conclusion**

- Improvement in ESP run life (Uninterrupted operation without well intervention for clean-ups through the ESP systems), reduction of drilling costs: 14.4 MMUDS/year (reduction of 6 interventions) and savings of 2.5 MMUDS associated with less well interventions for cleaning up through the pumps.

- Uninterrupted production per well : 2000 BPD during 12 months and more.

- Significant reduction of risks for ESP systems avoiding too many intervention for well cleaning up. (ESP equipment less exposed to chemicals).

- Update geomchanical model considering current reservoir conditions, reduction of pore pressure (continues increase in mechanical stress) and changes in Wells drawdown (inadequate drag forces).

- Conservative production rates per well, considering critical drawdown

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**Run Life (days)**  
**Formation: JSO**

<table>
<thead>
<tr>
<th>Well: X-1</th>
<th>Well: X-2</th>
<th>Well: X-3</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>79</td>
<td>71</td>
</tr>
<tr>
<td>300</td>
<td>274</td>
<td>402</td>
</tr>
<tr>
<td>330</td>
<td>71</td>
<td>225</td>
</tr>
<tr>
<td>315</td>
<td>3</td>
<td>300</td>
</tr>
<tr>
<td>200</td>
<td>71</td>
<td>200</td>
</tr>
<tr>
<td>90</td>
<td>71</td>
<td>200</td>
</tr>
<tr>
<td>50</td>
<td>71</td>
<td>200</td>
</tr>
<tr>
<td>10</td>
<td>71</td>
<td>200</td>
</tr>
</tbody>
</table>

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Application with monthly Clean-up intervention Through ESP system (ESP % HCP)  
Application without Clean-up intervention Through ESP system (ESP % HCP)

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Application with monthly Clean-up intervention Through ESP system (ESP % HCP)  
Application without Clean-up intervention Through ESP system (ESP % HCP)
Thank you for your attention
References

The authors are grateful for the collaboration of the operating company and the multidisciplinary work made it with them, special thanks to the well productivity area and team and the VCD engineering team.

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