Deep water session

**Artificial lift studies for the Deepwater Girassol Oilfield Development**

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**Abstract**

The Girassol field gives an example of artificial lift compromise under deepwater situation with significant lengths of flow lines including major flow assurance issues and heavy well works. As usual, studies are based on three major issues with iterations: artificial lift need evaluation, selection and design. Finally, the riser base gas-lift has been preferred as the best compromise.

The deepwater situation increases the overall cost impacts. Thus, the stake is higher to minimize the artificial lift needs under flowing conditions and to clarify the needs for restart.

Maximizing the production capacity of wells under natural flow mainly involves back pressure, tubing and flow line diameter, inflow capacity with reservoir pressure maintenance and productivity index. It especially includes the daisy chain option with optimization of well routing and location. It also involves the optimization of sand control and the use of horizontal wells under deepwater environment. The reservoir simulations are used to get the overall sensitivity.

The restart situations strongly affect the start time of artificial lift especially under deepwater situation. The initial restart, the implications of tubing and flow line configuration, riser and slugging, have been clarified including transient flow simulations.

The artificial lift selection to cover the remaining need for restarts and production boosting has especially taken into account the flow insurance with slug control and pigging. It has also accounted for the unconsolidated reservoir, the low artificial lift need, the gas handling, the riser base depth, the reliability, the strong productivity. For the first oil phase, a specific artificial lift method has been studied.

The design of the artificial lift conditions has focused on reliability and flow insurance implications. It has involved the impacts of the temperature and the lift gas injection on the riser design, the monitoring and access to the riser base, the compression design. A dynamic control has been decided to operate more smoothly and efficiently from the well to topsides.
Artificial lift studies for deepwater Girassol field case
presentation outline

• evaluation of needs
• reduction of needs optimisation requirements
• overall architecture selection
• design of equipments
Girassol field presentation & location

- Sea water depth 4,400 ft (1,350 m)
- Prodcution: 200,000 bopd, 300,000 blpd, 2 Mbbls oil storage
- Water injection: 390,000 bpd, gas injection: 280 MScft/d

ASME gas-lift workshop 2001 - artificial lift selection & design
evaluation of flow performance needs & options

- slug prevention and management
- hydrate prevention
- deposit prevention, pigging
- restart needs
- production boosting needs
lift requirements during restart and after restart

Overall dynamic simulator
for restart needs
and special checks

DSPICE
Topsides dynamic simulator

Olga
Transient flow simulator
from bottom hole to riser head

Reservoir simulations
for after-restart needs
& production boosting

Enhanced VFP tables
for reservoir simulations

+ post check

Network simulations
with reservoir simulation results

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reduction of artificial lift needs

flow line & tubing diameter selection
inflow capacity with horizontal drain

FPSO

Coflexip 300m

Riser 1300 m

0 m / 15°C

-1350 m / 4°C

Well 5'' 1/2 - 7''

Flow line 8''
ID
4 km

sand face = D or H

-1200 m / mud line 66°C

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TOTALFINA ELF
Operating flow rate = inflow + outflow (tubing & flow line)

![Graph showing pressure vs. liquid rate for different tubing sizes](image)

- **Horiz. drain**
- **Initial design**
- **60,000 bblpd**

- **Tubing 5"1/2**
- **Tubing 7"**
- **IPR**

ASME gas-lift workshop 2001- artificial lift selection & design
## Maximum liquid rate and GOR (700 to 1 700 Scf/bbl)

### Target rate: up to 40 000 bpd (6 400 m³/d)

<table>
<thead>
<tr>
<th>GOR Scf/bbl (Sm³/m³)</th>
<th>Tubing OD</th>
<th>Max. Gross bldp (m³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>700 (130)</td>
<td>5’’1/2</td>
<td>46 000 (7 300)</td>
</tr>
<tr>
<td>1 700 (300)</td>
<td>5’’1/2</td>
<td>36 000 (5 800)</td>
</tr>
<tr>
<td>1 700 (300)</td>
<td>7’’</td>
<td>48 000 (7 600)</td>
</tr>
<tr>
<td>700 (130)</td>
<td>7’’</td>
<td>60 000 (9 500)</td>
</tr>
</tbody>
</table>

5’’1/2 tubing does not reach production target with max GOR

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**Topsides inlet pressure**

**FPSO inlet Pressure selection involves:**

- separation sizing
- compression requirements
- production capacity / well characteristics
  
  Pressure sensitivity: 5 bars = less than 3% at 60,000 bblpd

- light cuts recovery

>> design = 20 bars
Slugging map for P20 (down slope line)

Combination of 2 slugging types:
- riser induced
- hydrodynamic

>> thresholds!

![Graph showing slugging map and parameters](image-url)
Evaluation of riser base gas-lift
under option = « subsea development with daisy chain »

• enough for production target
• enough for riser restart-up
• efficient for slug control
• well routing flexibility
• short distribution lines, surface control
• riser base access
• compatible / pigging, heat management, well test
equipments: no choke at the injection point?

Riser Base Pressure versus Gas Lift Flow Rate under various Riser Head Gas Lift Pressure

Gaslift line stability: RBP pressure variations effect on gaslift flow rate

- RHGLP = 90 bar
- RHGLP = 110 bar
- RHGLP = 130 bar

RBP (bar) vs. Qgl (kSm³/d) graph showing the relationship between riser base pressure and gas lift flow rate under different riser head gas lift pressures.
Validation of no choke by a dynamic simulation

Gas lift line stability evaluation

RBP versus time

GLFR versus time

Trend data

1.4e7
1.35e7
1.3e7
1.25e7
1.2e7
1.15e7
1.1e7
1.05e7
1e7
9.5e6
9e6
8.5e6
8e6
7.5e6
7e6
6.5e6
6e6
5.5e6
5e6
4.5e6
4e6

Time [s]

100 kSm3/d (3.5 MMScft/d)

400 kSm3/d (14 MMScft/d)

Instable gas lift flow rate

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Choking at the injection point

Sometimes = lower lift gas need

RBP (Riser Bottom Pressure) versus time

Start of gas-lift injection after liquid slug

Constant gas-lift inflow

Girassol design: FCV at riser head

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Pressure for Riser Bottom pressure from Riser Head

Relative error using RBP calculation algorithm compared to hydraulic calculation

- RHGLP = 70 bar
- RHGLP = 80 bar
- RHGLP = 90 bar
- RHGLP = 100 bar
- RHGLP = 110 bar
- RHGLP = 120 bar
- RHGLP = 130 bar
- RHGLP = 140 bar
- RHGLP = 150 bar

RHGLT = 50°C

Qgi (kSm3/d)

Difference (RBPc / VLP simulation) (bar)

0.0% 2.0% 4.0%
Under the more pessimistic reservoir case

**Eruptivity - B3 alternative model 3 - Faulty case**

*Beginning 2007:*
*low gas flow rate from eruptive wells*
*HP compression restart difficult*
Gas-lift characteristics summary

GL supply = 10 - 15 MMScft/d per riser (300-400 kSm³/d)
+ flow control at the riser head
+ no choking at the injection point
+ dynamic controls of GL flow-rate, riser and WH chokes

- high GLFR >> line dP, no buffer effect
  >> stable production

- riser head flow control = compulsory

- no choking >> limits plugging
  >> avoids change-out or actuator
Details of the gas-lift line - one per riser

GASLIFT LINE

Dynamic bundle (*2)
300 m.

Gaslift line 1 = 4*31.75 mm ID
Gaslift line 2

Production line 8"

Gaslift line 1 = 1*79.3 mm ID
Girassol field - final lay-out

Gathering lines after iterations for $/bbl reduction
including dry versus subsea wells comparison

- 39 subsea wells
  - (23 P, 14 WI, 2 GI)
- 5 x 8” prod loops + pigs
- 8 Mm3/d of gas injection
- 5 x 10” injection lines
- riser base gas-lift

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Artificial lift for deep water - highlights

Under the Girassol conditions (water depth = 4,500 ft)

- artificial lift selection involves several aspects of flow performance after increasing the production capacity per well

- riser base gas lift = attractive compromise major reason = slug control