Unlocking the Future for a Mature Asset: Surveillance and Complex Wellwork Combine to Extend Field Life

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Introduction

- Ravenspurn North field has recently seen 3 non-flowing wells reinstated by applying a new technique in the North Sea and by setting several “world firsts”

- This presentation DOES NOT focus on the well intervention itself (covered at 2010 ICOTA round table and in SPE 143313) – instead this presentation tells the story of **how this project was sanctioned** – specifically:
  - The role of rudimentary surveillance and reservoir engineering to unlock potential
  - How the business case was constructed to justify such a complex, high technical risk intervention in a mature asset
  - How using a phased approach helped unlock this project for sanction

- With Phase 1 completed successfully and planning for Phase 2 underway, this presentation reflects on the techniques employed to unlock this complex project which could be of interest to anyone facing a challenging project on a mature field
Background

- Ravenspurn North was developed 1989 – 1993 by Hamilton Bros
- Consisting of:
  - central manned platform / welltower complex
  - 2 normally unmanned satellite welltowers
  - Total 42 wells
- Operatorship transferred to BP 1998 (partnership: BP 53.5%, E.ON Ruhrgas 28.75%, Centrica 17.75%)
- By 2006 50% wells had ceased to flow and many cyclical producers

*Extensive infrastructure and dropping production. By 2006 Ravenspurn North’s longer term viability was in question*
Subsurface & Wells State of Play

- Remaining resource potential unclear
- P/z data based on surface pressures measured during shutdowns and echometers
- Significant scatter in data leading to uncertainty in resources remaining
- IS THERE REMAINING POTENTIAL IN NON-FLOWING WELLS?
  
  - And if pressures are high… why did wells cease flowing??
    - Minimal data from downhole on condition of wells
Unlocking the understanding

A two-prong approach:

1. **Detailed reservoir review**
   - Revisit allocations
   - Compare mapped volumes and recovered volumes and determine potential differences / recovery factors

2. **Acquire downhole surveillance**
   - Pressure data to corroborate P/z
   - Mechanical status data to understand if any reason for wells ceasing to flow
Reservoir Review Findings

- Recovery factors variable across field; lowest in North
- Highest concentration of well failures in North where recovery factors are lowest

Review of reservoir data suggested a potential prize in ST3 area from reinstating non-flowing wells
Surveillance Findings

- Rudimentary surveillance undertaken on every well on ST3
  - Pressure gradient survey
  - Tag fill and sample

- High HUD in nearly every ST3 well – typically 1000ft above the reservoir
- Sample of fill from HUD indicated frac proppant
- Pressure significantly higher than expected confirming remaining potential
- Some flowing wells displayed high HUD too possibly impairing productivity and putting future production at risk

**Surveillance provided greater clarity of reservoir potential and what was required to reinstate wells**
Summary of Proposed Interventions

Proposed way to **cleanout wells** and **prevent recurrence** of solids loading as follows:

1. Use concentric coiled tubing to cleanout proppant
2. Mill out nipples to accommodate completion extensions
3. Make up intervention and testing string
4. Reinstate completion packer and cement annulus

First use in North Sea of technique
Deeper application than ever done before

**How concentric coiled tubing works**
*(courtesy Baker Hughes)*

= Lots of new techniques, lots of uncertainty over timings

**Reinstating these wells would be complex, relatively expensive and involve a high degree of technical risk – requiring solid justification to sanction**
Building the Business Case

Key to unlocking this project was being able to articulate its full strategic value and commercial impact on the lifecycle of the asset

- Not just gas rate benefit…
- Importantly:
  - Deferral of decommissioning costs
  - Resources accessed by wellwork
  - Resources accessed by extended COP

Understanding the full business case made undertaking these complex interventions worthwhile – turning a set of marginal well interventions into a key strategic component for the asset
...and Packaging into Phases

- The need for phasing
  - Large number of options
  - Only delivery of the entire package would yield large business benefits
  - BUT large technical risks to delivery

- The project was phased to
  - make Phase 1 a palatable financial risk on unproven techniques / potential
  - whilst retaining line of sight to full potential of the project

<table>
<thead>
<tr>
<th>Phase</th>
<th>Scope</th>
<th>Objectives</th>
<th>Economics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase 1</td>
<td>Cleanout small subset wells</td>
<td>Prove cleanout techniques</td>
<td>Economic on standalone basis but not capable of delivering material change for asset</td>
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<tr>
<td></td>
<td></td>
<td>Prove reservoir / well potential</td>
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<td></td>
<td></td>
<td><strong>De-risk Phase 2</strong></td>
<td></td>
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<tr>
<td>Phase 2</td>
<td>Cleanout up to 20 further wells</td>
<td>Efficient delivery of cleanouts incorporating lessons from Phase 1</td>
<td>Execution materially impacts asset</td>
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*Phasing the project was key to minimise financial exposure to undertake a high technical risk project whilst retaining visibility of the larger prize at stake*
Phase 1 Rig or Not?

Rig / Barge Supported Operations
- Accommodation on site
- More efficient (esp. for larger programme)
- Avoids deck space / crane limitations

Standalone Operations
- Shuttle personnel from onshore
- Lower cost
- Technically very challenging within NUI limits

• Best **technical** solution was to use a rig or barge to support operations

• BUT sanctioning rig / barge case was a lot tougher due to the **amount of pre-work and engineering support required** from an already stretched organisation, the **high technical risk** inherent in the operations, the **range in expected results** combined with significantly **higher execution cost**

• Ultimately it was not possible to sanction the rig option and the “standalone operations” option became the only viable option for Phase 1
  - This added new challenges to an already challenging programme (limited deck space, PoB, services, would need to boat spool concentric coiled tubing etc.)

*For a high technical risk project such as this, the more expensive but best technical solution was un-sanctionable leading to selection of the more challenging (standalone) option for Phase 1*
Sanction achieved in January 2010 for 4 month operation to intervene in 2 – 3 – 5 wells commencing July 2010

Sanctioning this project was not straightforward but required careful identification of the key issues and working them in detail. A key lesson was ALWAYS referring to the ultimate prize in Phase 2 to keep interest and priority on Phase 1 of the project

<table>
<thead>
<tr>
<th>Challenge</th>
<th>Solution</th>
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<tr>
<td>Proving ability to deliver this complex intervention on a NUI in standalone mode</td>
<td>Network with other operators to understand their experiences</td>
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<tr>
<td>Complex intervention &amp; new technique creating large uncertainty on timings</td>
<td>Fix time window to manage costs</td>
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<tr>
<td>= difficult to fit into congested plan</td>
<td>Carry uncertainty in benefits from interventions (number of wells, production skin)</td>
</tr>
<tr>
<td>+ difficult to estimate costs</td>
<td>Order equipment and plan for max wells case</td>
</tr>
<tr>
<td>Creating interest in a (necessarily) small Phase 1 project where production skin relatively small</td>
<td>Always presenting Phase 1 with clear linkage to the strategically significant Phase 2 project</td>
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<tr>
<td>Getting the scale of Phase 1 right</td>
<td>Maintaining flexibility to point of sanction to allow project to be scaled according to capital availability</td>
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Execution of Phase 1

- We did it!
- For further details on the intervention please see SPE 143313

And finally with gin pole deployed for running completion tailpipe extensions.
Intervention Results

- The pilot phase of well cleanouts was completed on ST3 June to October 2010 on schedule and on budget.
- Over 1.6 tonnes of proppant was cleaned out of the three wells tackled (over 1 tonne from 1 of the wells!)
- All three wells were cleaned to approx bottom perforation.
- Completion nipples milled in first well but subsequent wells aborted due to operational problems.
- Completion tailpipe extension installed in first well only due milling issues on later wells.
- Wells returned to production with initial rates higher than expectation – now awaiting well stabilisation and further surveillance before sanction Phase 2.

Phase 1 cleaned out the mid-case of 3 wells in the fixed time window. Operational problems prevented setting completion extensions in 2 wells but otherwise complete scope delivered, encompassing several “world firsts” as well as a generally challenging work environment.
### Phase 1: Implications for Phase 2...

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<tr>
<th>Phase 1</th>
<th>Notes</th>
<th>Other Findings</th>
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<tbody>
<tr>
<td>Prove cleanout</td>
<td>Cleanout techniques very effective</td>
<td>• Intervention on NUI in standalone mode worked well</td>
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<tr>
<td>Prove reservoir /</td>
<td>Initial rates on high side of expectation</td>
<td>• Less proppant than expected in 2 wells (bridges at tailpipe) but 3rd well</td>
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<tr>
<td>well potential</td>
<td>Reservoir pressure as expected</td>
<td>continuous fill</td>
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<tr>
<td>De-risk Phase 2</td>
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**Many risks resolved but still unknown**

- Long-term stable rates
- Re-accumulation of proppant in wells
- Enhancement to flowing wells?

*Longer flowing period will increase understanding*

*Additional surveillance required on flowing wells to understand nature of HUD*

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**Overall, Phase 1 achieved its objective of unlocking Phase 2. Although standalone operations worked, the results now actually unlock using a vessel/rig to support the more efficient delivery of Phase 2**
Conclusions

• Rudimentary surveillance and good reservoir engineering identified a material opportunity in a mature asset

• Thorough analysis of the full benefits of well reinstatements unlocked a relatively high cost, high technical risk project

• Project phasing was an important component of sanctioning the project to minimise financial exposure whilst retaining sight of the larger prize

• Planning and delivering a project as complex as this required consistent management and partner support, a dedicated team and the skilful application of technology to deliver

• Phase 1 of the project was successfully completed during summer 2010, delivering a number of “world firsts” to achieve. Full details of this intervention can be found in SPE 143313.
  – Phase 1 alone has extended economic field life
  – Phase 1 has largely de-risked Phase 2 of the project

• The results from Phase 1 are now being used to design a rig / vessel based Phase 2 which will see many more wells cleaned out across Ravenspurn North and materially extend economic field life
Acknowledgments

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