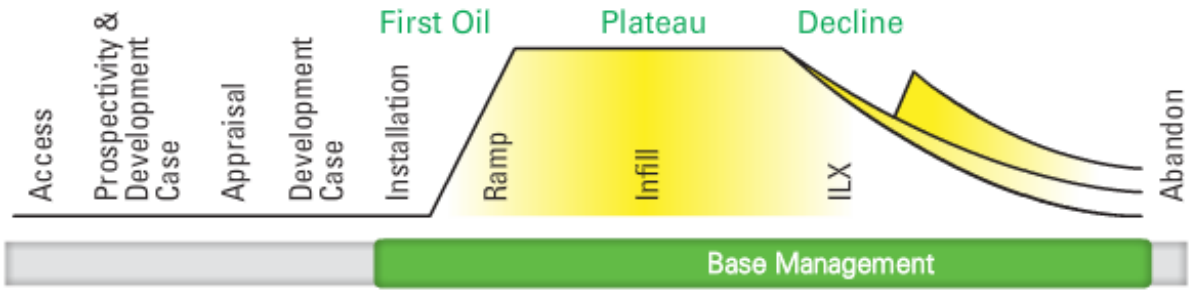
Base Management at BP

Base Management Workshop Agenda

- What is Base Management?
- Why is it important?
- How do we do it?
- Base Management Examples

Base management common process



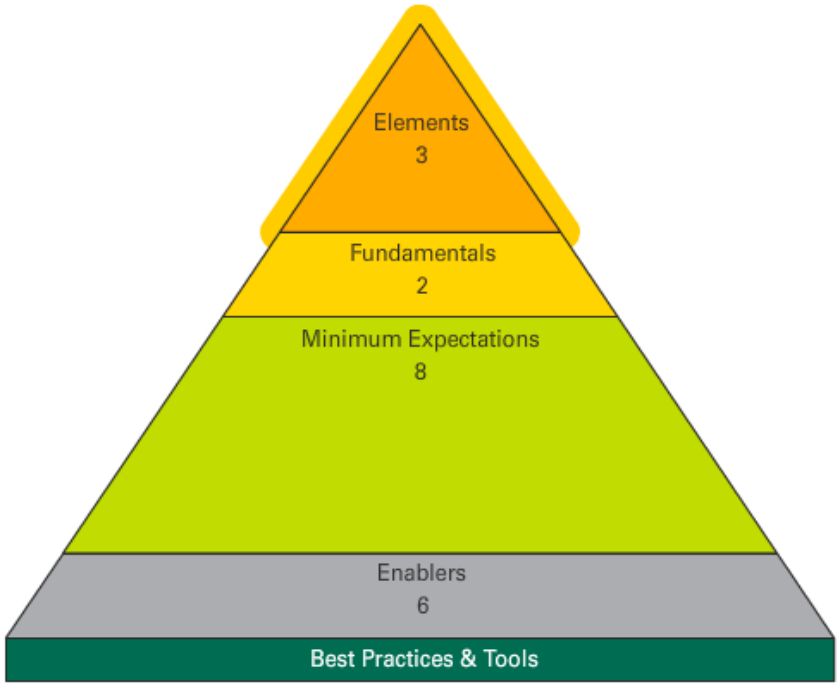
The Base Management common process:

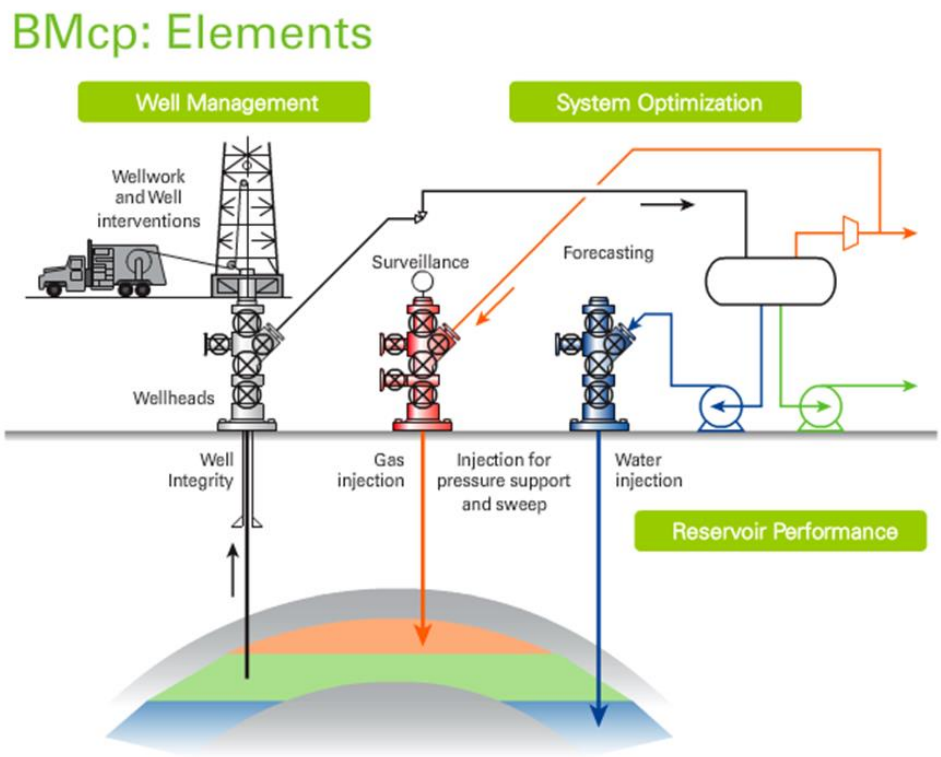
- Developed by a multi-disciplinary group of senior practitioners from around the globe.
- Sets out the framework for managing our production base.
- Supports the efficient delivery of BP's proved developed reserves.

Applying the best of BP everywhere in BP

91% of production resides in the base

BMcp framework





BMcp elements

A. Reservoir performance
B. Well management
C. System optimization

BMcp summary

The Base Management common process:

- Expert-designed and field proven – by functional and business experts.
- Multidisciplinary – Petroleum and Reservoir Engineers, Geoscientists, Operations and Completions Engineers.
- Applied throughout most of the life of a field – especially plateau and decline, but also in design & planning activities.
- Short to medium timeframe – within a year to 18 months.
- Tasked with the efficient delivery of proved developed reserves – BP's Base.
- Framework focused on 3 key Elements – Reservoir Performance, Well Management, and System Optimization.

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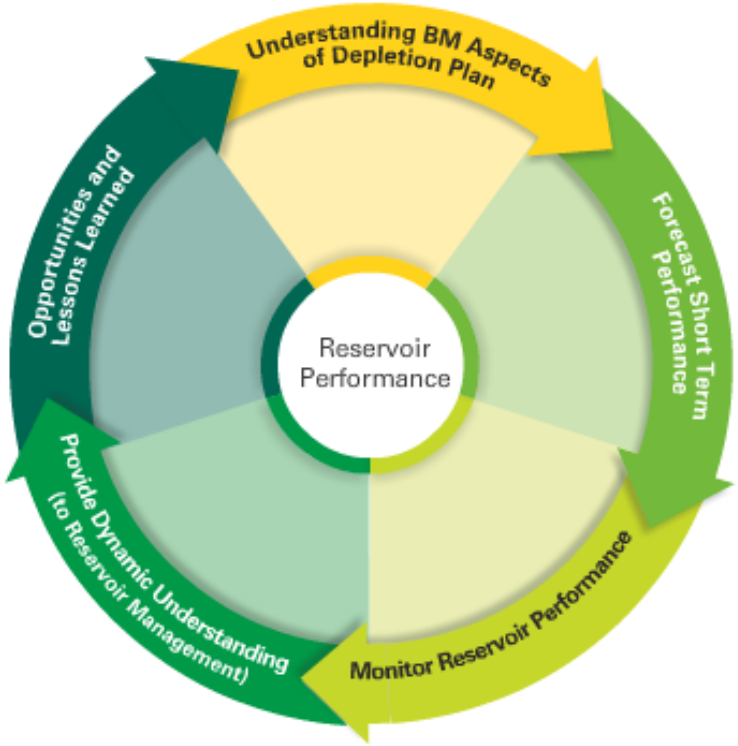
Reservoir performance

Reservoir performance summary



- Understand BM Aspects of Depletion Plan
  - Subsurface Description
  - Implement Depletion Strategy
- Forecast Short Term Performance
  - Technical Forecast
  - GFO Integration
- Monitor Reservoir Performance
  - Short Term Surveillance
  - Analysis
- Refresh Dynamic Understanding
  - Verification
  - Gaps
  - New Findings
- Opportunities and Lessons Learned
  - Hopper
  - Depletion Plan
  - Measure outcome
  - Lessons learned

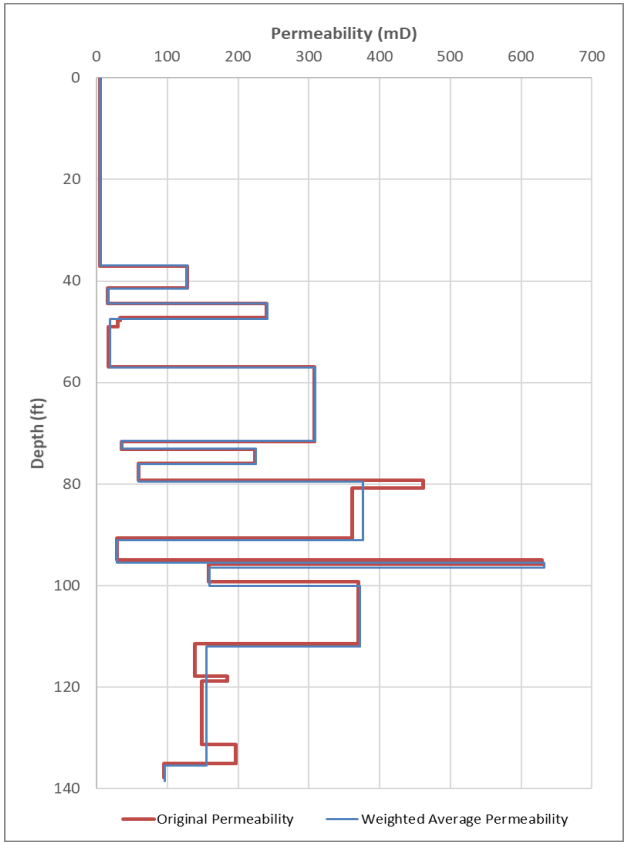
Example 1: Predict Failure of Black-Start Well

- Problem Context
  - Dry black-start gas well suddenly experienced water break-through & progressively deteriorating performance.
  - Converted gas cap injector.
  - 148ftTVD of perforations in casing straddled by 2 packers and 20ft ported joint in tubing (sitting just under halfway point), preventing full wireline logging
  - Downhole surveillance from offset well had shown shallower than expected GWC.
  - Source of water could be either high permeability streaks or bottom-up aquifer drive.
  - Low Cv multi-stage gas choke installed (Cv 18).
  - Gas rate was depleting and choke fully open – which was also bringing well to sand control drawdown limit.
  - Initially, no other proven black-start option existed. Circa 8mmscf/d required.

- Question
  - When will the black-start well fail to provide sufficient re-start gas?

Example 1: Predict Failure of Black-Start Well

- Available Data
  - Flows into a 2-phase separator on its own.
  - Acoustic sand monitoring available.
  - Full suite of core samples.
- Approach
  - Full, choked, and no-flow tests to monitor WGR progression showed that the best scenario for gas availability was choked production. Not flowing the well did not arrest the WGR increase.
  - Dynamic simulation to assess stability and start-up concerns, and estimate final WGR.
  - GWC estimation and start-up analysis



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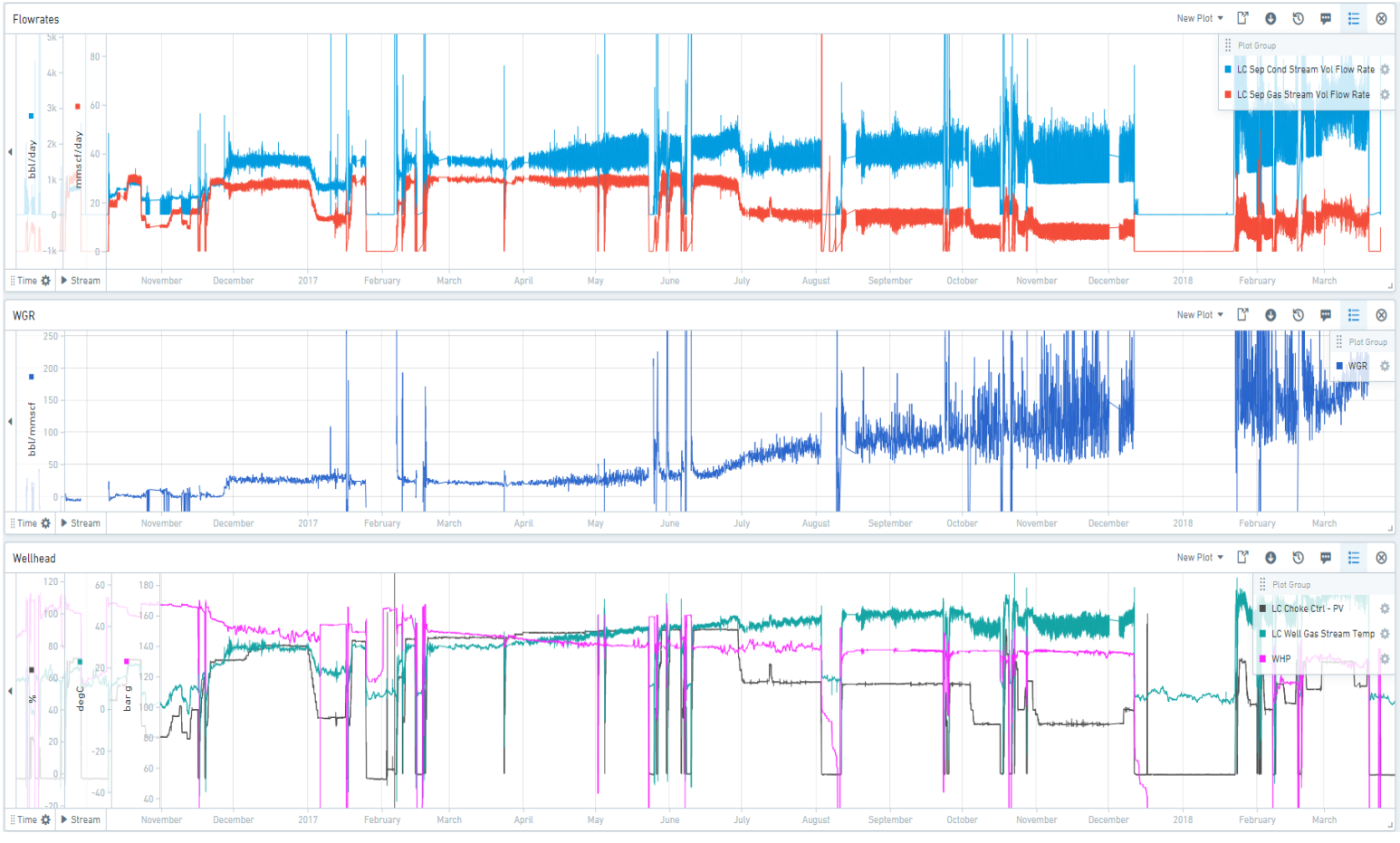

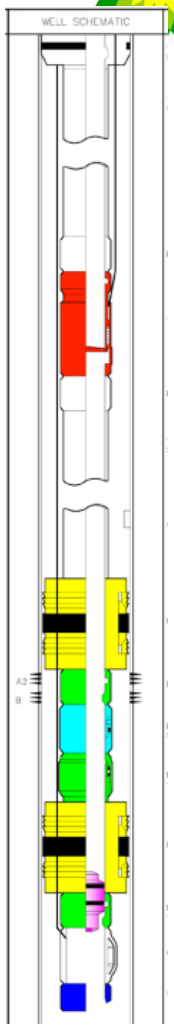

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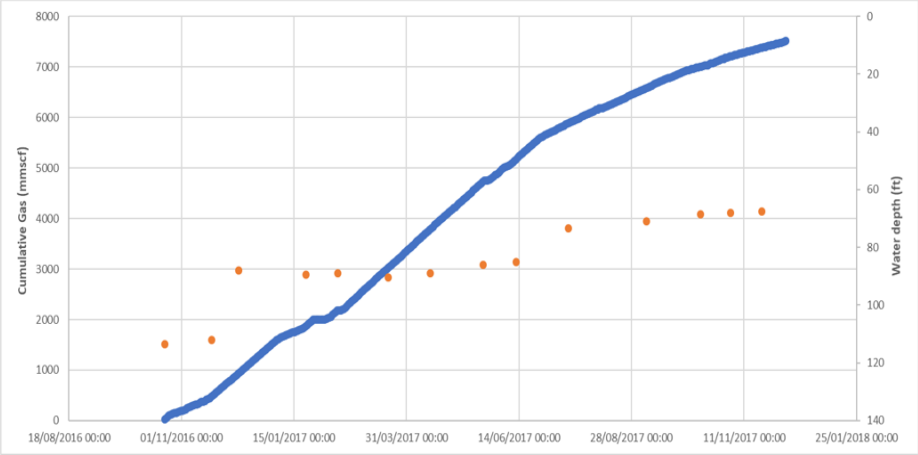
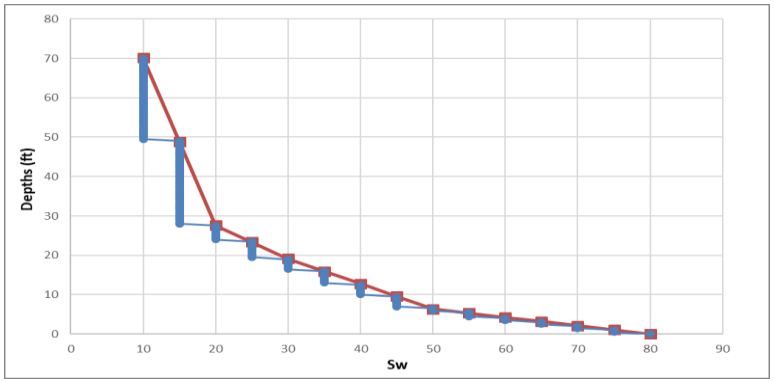
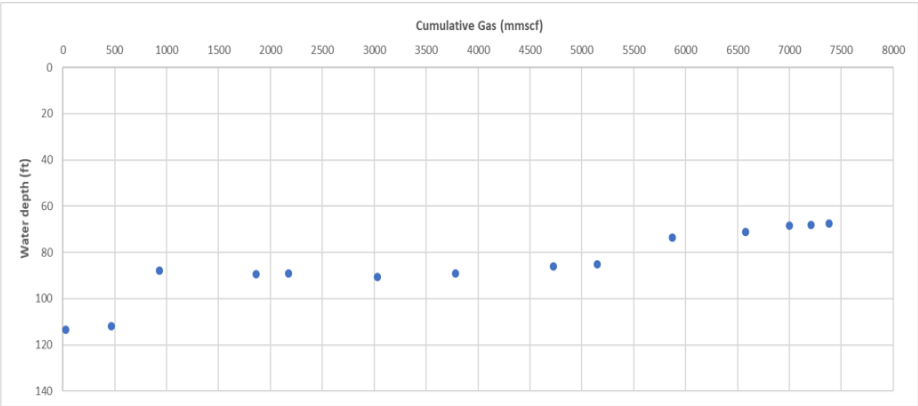
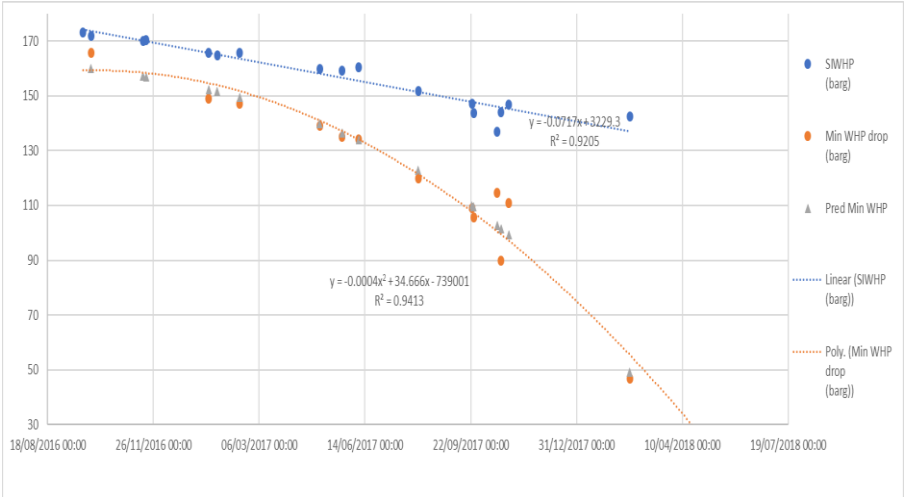
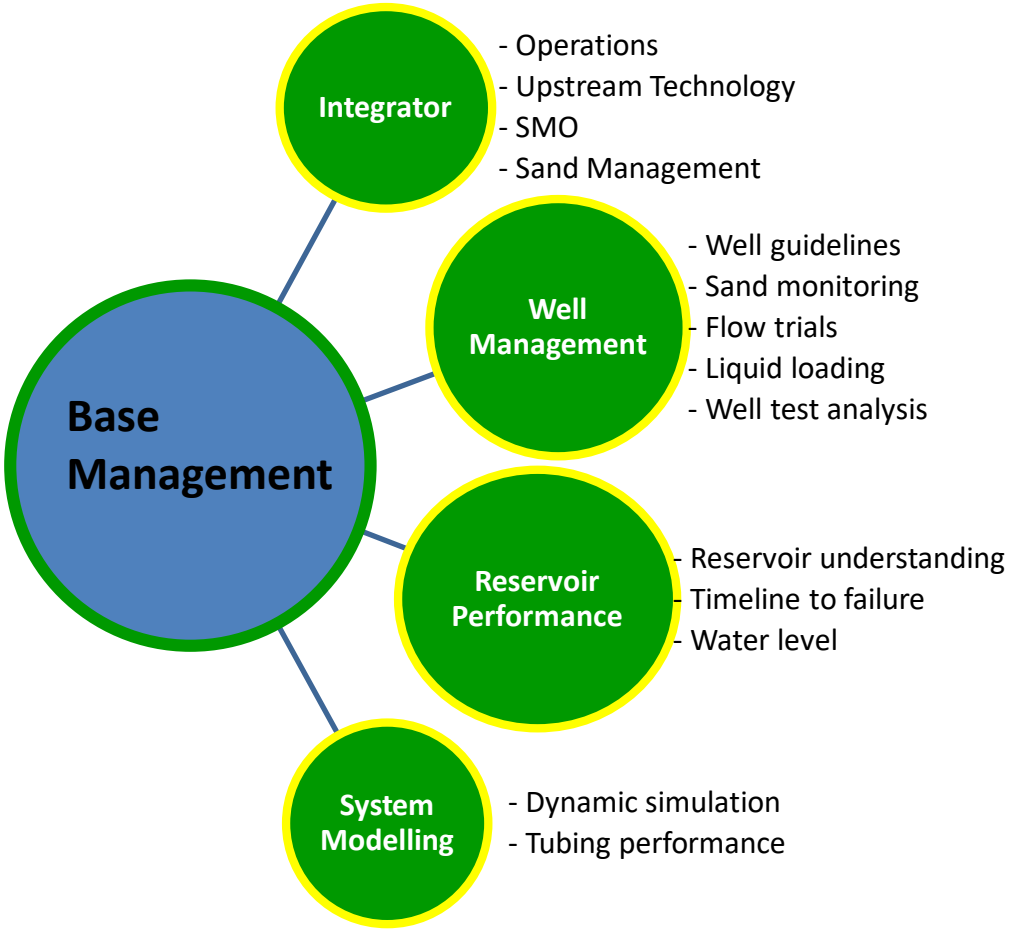








Example 1: Predict Failure of Black-Start Well



Predict Failure of Black-start Well

Summary Approach

- Assessment of well test data and sand acoustic trends to understand well performance.
- Worked with Operations and Partners on well operating guidelines.
- Performed dynamic simulation and start-up analysis to understand stability and timeline to failure.
- Completed reservoir performance calculations to understand water level progression.

Answer

✓ Techniques applied determined gas well would fail to free flow ~ Feb 2018

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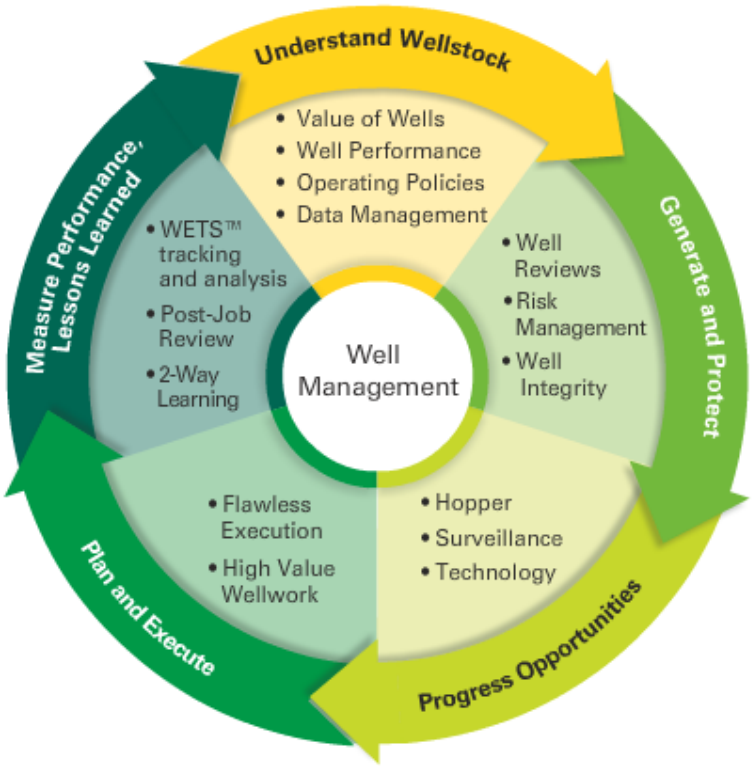
Well management

Well management summary



Well Management

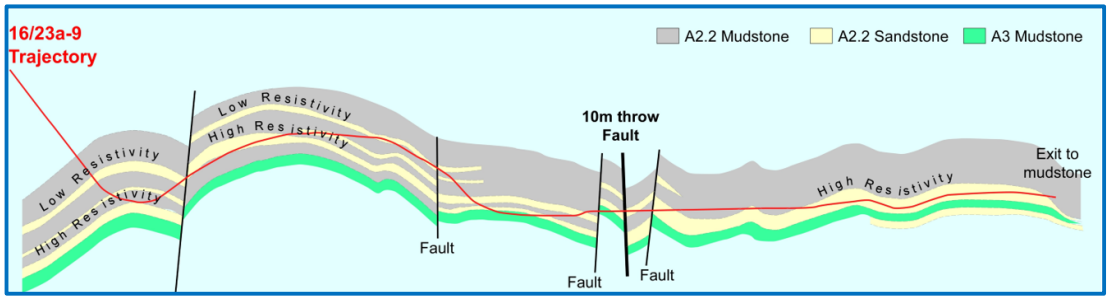
- Understand the wellstock – **Ensure Well Data availability.**
- Protect wellstock – **Well Integrity.**
- Identify opportunities and manage risks – **Well Reviews.**
- Evaluate and rank – **PRODUCTION HOPPER™.**
- Plan and execute well options.
- Measure wellwork impact – **WETS™.**

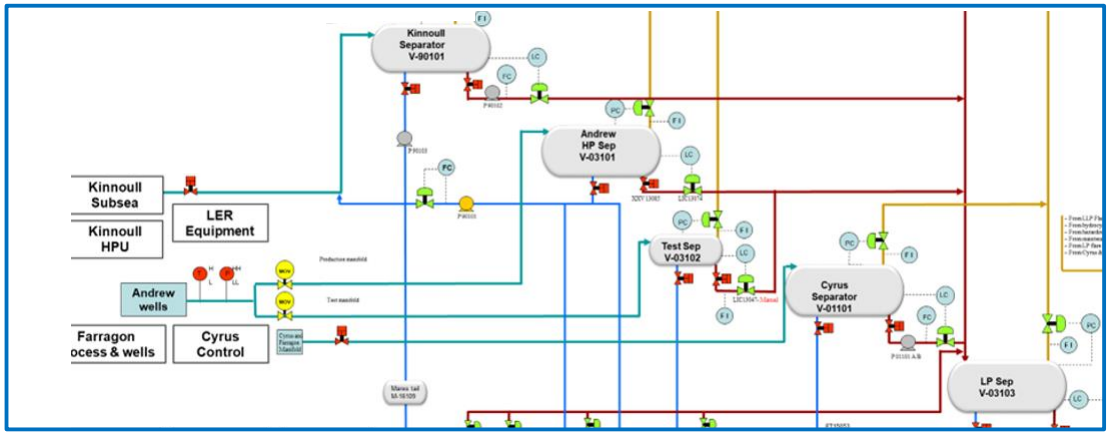
Example 2: New Well Flowback

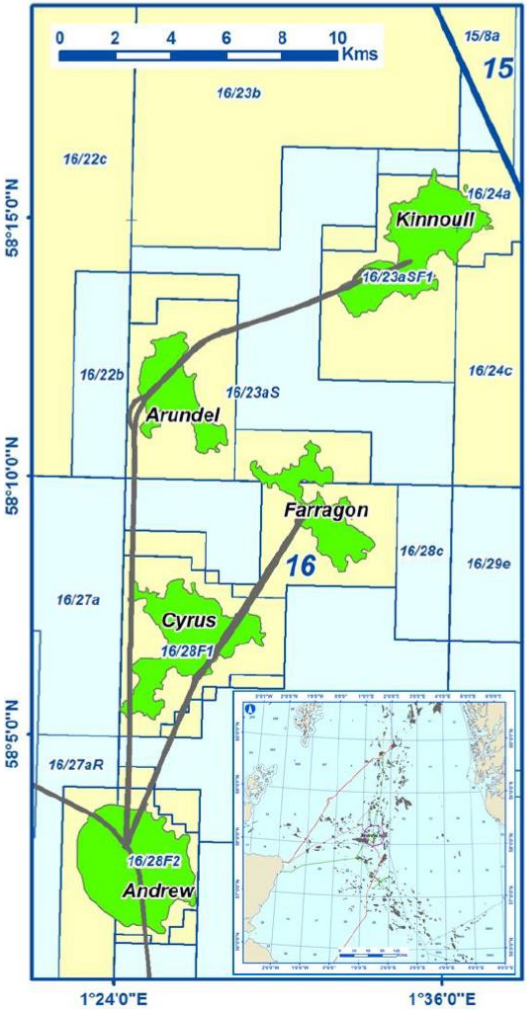
- Context
  - New well start-up, 1400m reservoir section, 160bbls of OBM losses during drilling
  - Drilling rig has installed a cased and perforated completion & circulated the well to filtered brine before departure, as per BoD
  - Subsea well tied into an active subsea pipeline already conveying production from another field
  - Subsea pipeline tied into an offshore platform with a single processing train and multiple flow streams
  - Processed water discharged over-board to sea
  - Lab based fluid testing has confirmed emulsion formation between OBM filtrate and existing production fluids

- Questions
  - How much mud filtrate will come back?
  - How quickly will it come back?
  - Will the quantities cause emulsions, a plant upset and overboard OIW excursion?
  - What are the controls and contingencies?

Example 2: New Well Flowback







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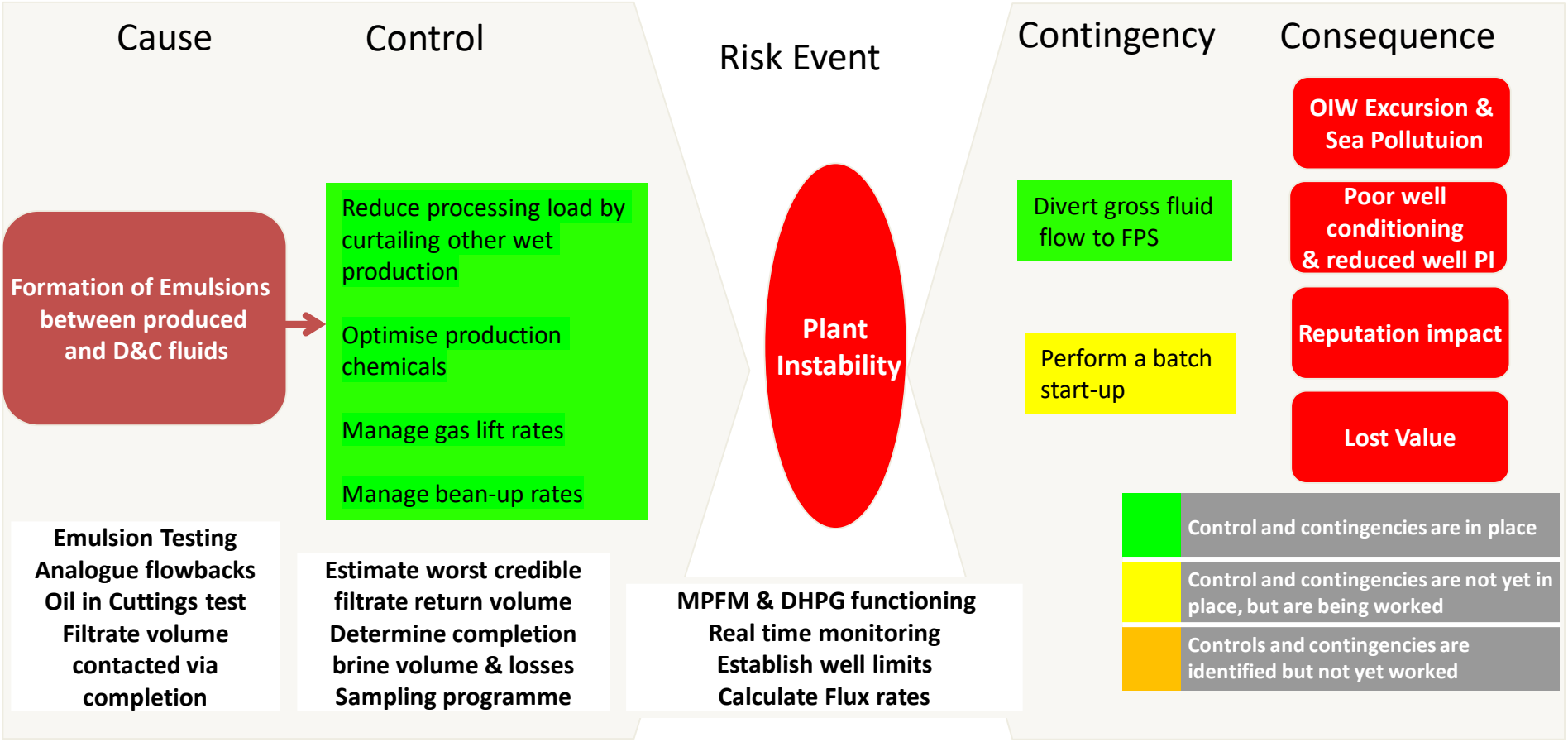

Example 2: New Well Flowback

Summary Approach

- Analogue data review
- Oil in Cuttings Test – to recognise filtrate volume produced with cutting
- Further eroded filtrate volume by normalising to reservoir section normalised
- Managed flow rates at start-up to manage dilution with existing well stock
- Communicated and integrated risk management tactics across stakeholder functions via 'bow-tie'.
- Batch flow to mitigate instability dismissed due to potential impact to well clean-up.
- Amplified need for surveillance activities to monitor for (1) strength of controls (2) any potential event and (3) to verify performance of a contingency (if needed)

Answer

✓ Analogue review, managed flow rates and dilution factor led to maximum OIW < 25ppm. No requirement for FPS contingency

System optimization

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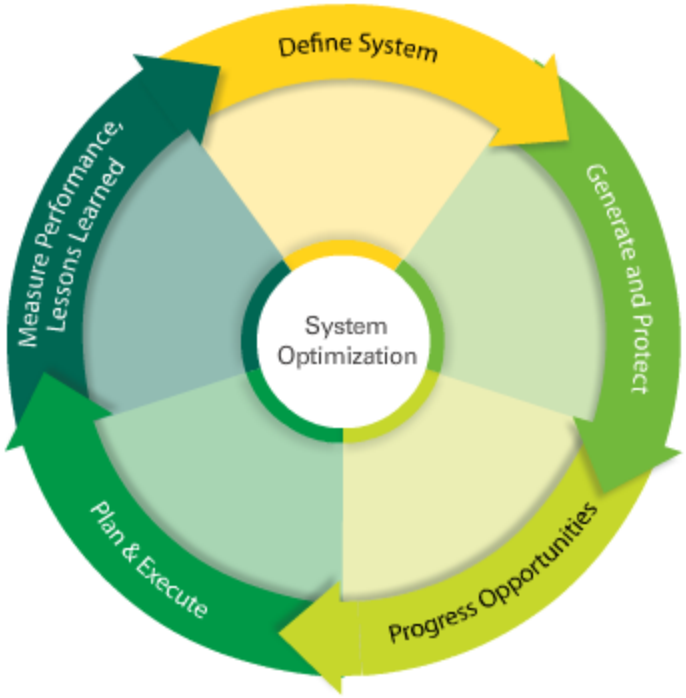
System Optimization Summary



- Define System
  - Components
  - Constraints & Levers
  - Optimization Approach
- Generate and Protect – Within IPC and Growing IPC
- Progress Opportunities – Hopper
- Plan and Execute – Coordination with IFPcp
- Measure Performance and Lessons Learned – Assess and communicate

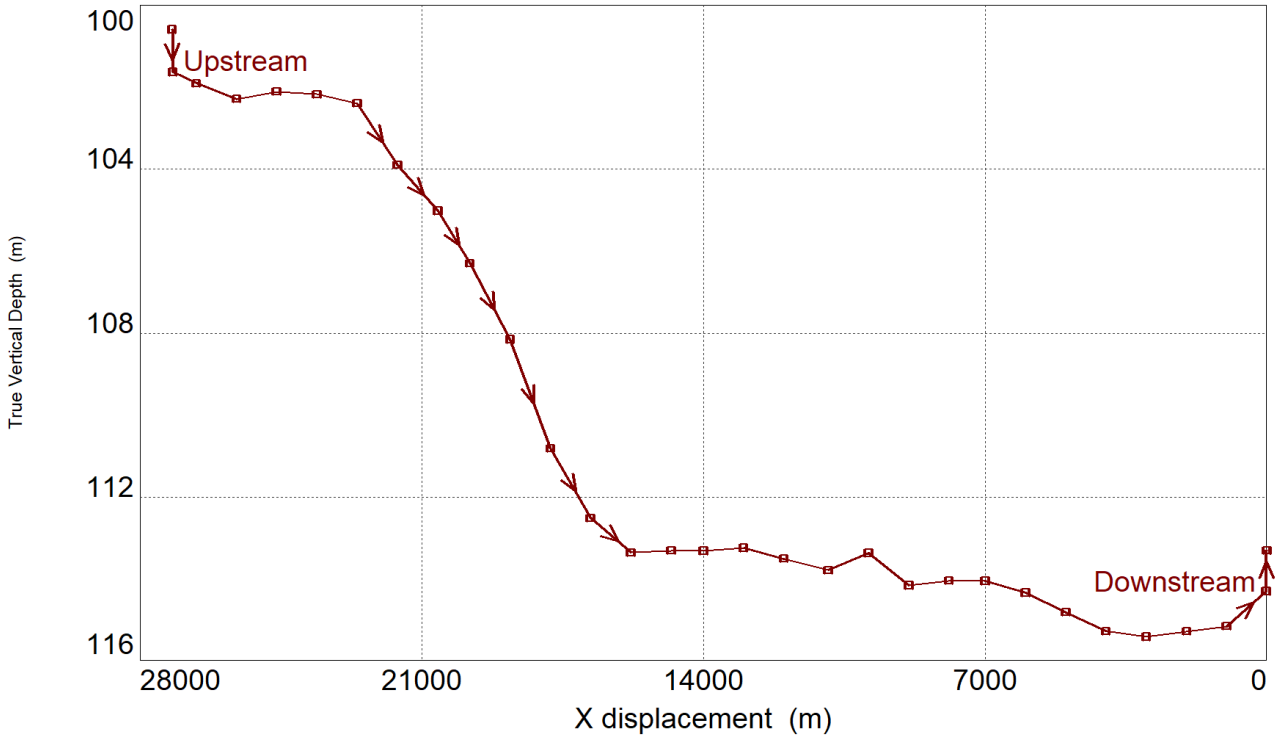
Example 3: Optimise Production in a Constrained System

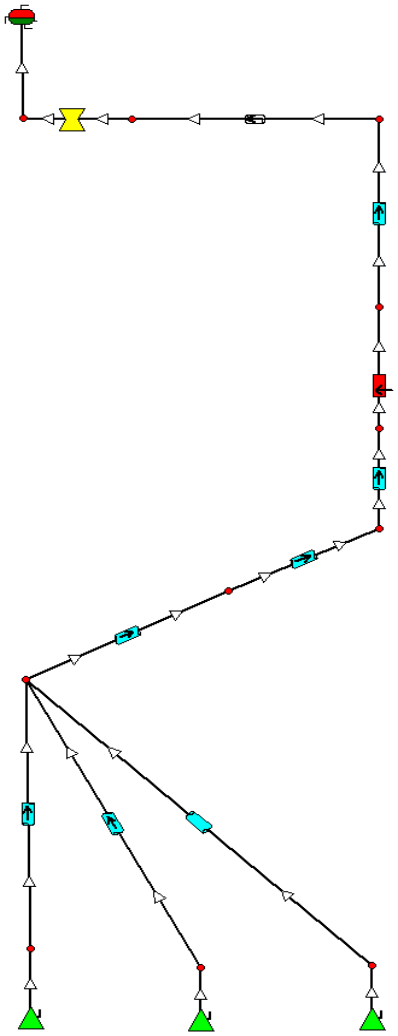
- Context
  - Ongoing production optimisation in low well count, high value subsea system.
    - Producing stably and using steady-state simulation.
    - Well 1: Low watercut, no gas lift.
    - Well 2: Medium watercut, gas lift.
    - Well 3: High watercut, gas lift.
    - Riser gas lift and riser top choke valve.
    - Subsea MPFM.
    - Downward sloping subsea flowline from production manifold to riser.
- Question
  - What is the optimal well configuration to maximise rate?

Example 3: Optimise Production in a Constrained System

- Inputs
  - Well tests.
  - Understanding of constraints.
  - Well matched steady state simulation software with multi-variable optimisation algorithm.
- Opportunities vs. Challenges
  - Reduce riser top choke pressure drop.
    - Historically known to result in flowline and riser slugging.
  - Gas lift naturally flowing well.
    - Gas lift resulted in production increase (from simulation and field trial, but risked accelerating water breakthrough).
  - Shut in wet well to reduce back-pressure.
    - Wet well still produced significant oil rate so request seemed counter intuitive to Ops and assurance was required.

Example 3: Optimise Production in a Constrained System





Optimise Production in Constrained Systems

Summary Approach

- Matched well tests and updated system model.
- Simulated scenarios to test production impact.
- Flow Assurance to determine likelihood and severity of instability.
- Worked with Operations to systematically proceduralise well and topsides changes.
- Reservoir management review to assess impact of increased offtake on water breakthrough.
- Partners assurance on recommended course of action

Answer

✓ Wettest well turned off resulting in reduced back pressure on remaining two wells delivering a 5% production increment.

Questions & discussion

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Base Management Summary

- Base Management expected to operationalise the depletion plan and is seen as the point of integration by other functions
- Base Management in BP is organised into three elements; Well Performance, Reservoir Management and System Optimisation
- Deliver solutions/risk management for both steady state and transient challenges within these 3 elements