[Key Facts]

- A solution to the difficulties of production allocation stemmed from integrating periodic testing-by-difference and data-driven modelling.
- With continuous real-time monitoring, highly-variable production, the behaviour of individual wells can be optimised.

dig deep

Well-by-well production allocation in subsea clusters is challenging without separate test-lines. Subsea and downhole measurement devices can help, but may prove unreliable. As Norbert Dolle, reservoir engineer for Shell, explains, the company sought an innovative, integrated approach to simplify production allocation in long subsea tiebacks, which overcame several obstacles in its North Sea Penguins cluster.

Subsea clusters and long tiebacks make production allocation difficult, especially with no test line in place. This was the challenge facing Shell in its Penguins cluster, where field development plans included subsea and downhole measurement devices that ultimately proved unreliable.

Innovative solutions

When its measurement equipment failed or became erroneous, soon after installation in 2002, Shell had little reliable information with which to optimise production allocation and field management. Necessity, however, was the mother of invention. Innovation stemmed from a solution integrating periodic testing-by-difference and data-driven modelling.

With data-driven models acting as continuous virtual flow meters, which related pressure and temperature changes to variations in production rates and verified results from careful testing-by-difference processes, Shell found that it had accurate, reliable data once more.

Furthermore, geochemical fingerprinting of fluid samples, taken during the test, added valuable data on the quality of estimates and the behaviour of fluids in the flowline.

Results from this integrated approach led Shell to believe that, while it should not replace physical measurement devices or well-testing facilities in challenging subsea environments, its solution adds value, particularly as a contingency measure.

Obstacles encountered

The Penguins cluster, first discovered in 1974 and 150km north-east of the Shetland Islands, comprises five fields, which became viable after 30 years of advances in technology and engineering. Currently, eight wells tie back via four drill centres through a 60km flowline to the Brent Charlie platform.

> "Shell chose periodical testing-by-difference to allocate production and better understand well and reservoir behaviour."

The lengthy tieback meant no separate test line was installed. On the platform, a Wet Gas Meter (WGM) and a Multiphase Flow Meter (MFM), downstream of a partial separation/slug suppression device (SSSD), measure total production that is validated periodically by a test separator.

Each well had three bottomhole pressure (BHP) gauges and a downhole venturi meter, enabling production rate estimates. The absence of water production, plus extended application of well-flow correlations, further enabled Shell to differentiate between oil and gas production. Additionally, subsea flowlines had venturis equipped with differential pressure meters and, as contingency, the subsea infrastructure design allowed multi-phase flowmeters at each drill centre. This may seem a robust system in the absence of a test line, however, one downhole flowmeter failed at start-up, though downhole temperatures pushed the extremes of the gauges' operating envelope. Production estimates from other wells proved accurate, but a year later signals from other downhole flowmeters ceased or became less reliable. In 2005 and 2006, flowmeters in two subsequent development wells faced similar issues. Subsea venturis were not equipped with density measurements, so although they seemed to function at subsea manifolds, the data was incorrect. Some venturis' differential pressure transmitter impulse lines were blocked.

Many subsea pressure transmitters, including Tubing Head Pressure (THP), Tubing Head Temperature (THT) gauges, and drill centre and flowline gauges were generally inaccurate. Adding no data to inaccurate data severely compromised field management, preventing accurate performance predictions.

Shell evaluated many solutions, though cost and reliability risks precluded the original fallback plan to install subsea MFMs. Doubts over the underlying reservoirs, subsea and downhole conditions and the accuracy of well measurements led Shell to reject conventional well models based on physical properties and multiphase flow correlations. Shell chose periodical testing-by-difference to allocate production and better understand well and reservoir behaviour.

[Testing-by-difference: controlling the flow]

Testing-by-difference enables the determination of flow rates by reading a group of wells and subsequently retesting a subset of that group under different flow conditions. Shell altered flow conditions, for example, by adjusting the well production choke or Flow Control Valve (FCV).

If the FCV change method is used to create a disturbance, at least three tests must be performed at different FCV settings to generate a PQ curve, from which to estimate the flow rate. This method minimises deferment, but is susceptible to inaccuracies as it is unable to achieve good stable production from other wells. If it is not possible to create measurable change in the total production rate, by changing the FCV setting, then the well must be completely shut-in.

At Penguins cluster, Shell measured the final stabilised liquid production levels at the surface, from step changes in well production after 14 to 16 hours. Gas flow rate response was significantly faster, proving that the three-point FCV change method is impractical.

Testing-by-difference

Determining the rate of a single well in a commingled production stream can be done by measuring the full stream, as well as the stream minus one well. The difference between these rates corresponds to the rate of the removed well (see box 1 above).

This method is particularly useful where test facilities are inadequate or where shutting some wells to test others is unacceptable. The industry frequently uses testing-by-difference, but rarely in subsea tiebacks over 50km.

While it is useful, testing-by-difference presented operational challenges that were partly due to the long tieback. It was necessary, for instance, to find a time window for testing when no topside activities could impact the test. Achieving a stable period through the SSSD MPM/WGM system also proved challenging due to slug flow in the pipeline, though overall the SSSD system might also have been unstable

Geochemical fingerprinting

Geochemical production allocation is an adaptation of the oil fingerprinting technology that is already familiar to the industry. Shell's proprietary chromatographic fingerprinting technique – Multi-Dimensional Gas Chromatography (MDGC) – is applied routinely to determine production allocation of commingled fluids (see box 2 on next page).

Overall, geochemical allocations yielded highly reliable data, with less than three percent standard deviation accounting for 12 peak ratios. The reliability of the method could be impacted by changes to the fingerprinting of the end members – though not applicable to subsea cluster – while another source of error could be contamination of the commingled samples by other end members. Backpressure can also potentially affect geochemical allocation results.

In this cluster, the datasets were accurate and reliable. When comparing geochemical fingerprinting and the well test allocations, except for the allocation of one well, the two methods' results differ by less than five percent.

Another interesting application of the fingerprinting technology came from the lack of identification of well A2 oil components in samples taken once production resumed. Geochemical fingerprinting can be used as a natural tracer, to determine residence time of oil in the flowline by finding when A2 disappears and reappears in the samples.

Data-driven models

While periodic testing-by-difference alone would significantly improve understanding of wells and reservoirs, with continuous real-time monitoring, highly-variable production, behaviour of individual wells can be optimised. Real-time estimates make daily well-by-well production volume analysis more accurate and allow individual well production estimates to be continuously cross-validated against BHP, THP, THT readings and MPM/WGM total production measurements.

The industry is starting to realise the potential of data-driven models. Shell often uses them for real-time monitoring of well-by-well oil and gas production through its FieldWare Production Universe (FWPU) application.

The accuracy of these models requires calibration with actual production information. In a subsea environment, without testing facilities, this information derives from testing-by-difference and from short and medium-term production data. FWPU yielded satisfactory production rate estimates, despite the long tieback.

> "Real-time estimates make daily well-by-well production volume analysis more accurate."

FWPU allows users to systematically set up data-driven correlations between production measured in a well test facility and any reasonable combination of continuously-available well production measurements. The resulting well model can estimate liquid and gas production, even producing normally into a commingled flow stream. Users can track the production of each well in real time.

The final FWPU data-driven models, for estimating two-phase production from individual wells, derived from a combination of data from downhole gauges and FlowWatcher venturi, results from testing-by-difference and commingled production data from the Brent Charlie MPM/WGM.

The resulting real-time well production estimates tracked steady-state production figures well. FWPU estimates met with operational expectations, actual production events and total production.

Therefore, it is possible to extend relatively inexpensive FWPU capabilities to the surveillance of subsea well clusters with long tiebacks, even without a dedicated test line.

The models cannot yet account for the dynamics of a long pipeline as they do not accurately replicate dynamic effects. However, it has been shown that FWPU well production estimates, during relatively stable production conditions, are sufficiently accurate to provide good daily well-by-well production totals. Another comparable application of FWPU techniques was successfully completed with multi-zone wells (smart wells).

A complement to test lines

While Shell does not encourage the omission of physical metering devices, or testing facilities in subsea developments, production allocation to individual wells is possible in the most challenging subsea conditions, even if metering devices become unreliable.

Carefully planned and executed in close cooperation with platform operations, testing-by-difference can provide valuable periodic information. Geochemical fingerprinting provides additional quality checks on metered production rates and a better understanding of pipeline flow dynamics.

Shell believes fluid sampling and analysis should always be considered during test sequences, or other dynamic events, alongside data-driven models to add value to existing measurements. It feels these techniques – with low incremental cost and potentially huge value as a contingency when other measurements fail – are a must on any development. ●

Geochemical fingerprinting

Shell's technique of Multi-Dimensional Gas Chromatography (MDGC) is a widely-used quantitative measurement of aromatic compounds in the C8-C10 alkane range of oils. It adapts oil fingerprinting technology, however, this was not feasible in Penguins' subsea system due to the large number of wells producing fluids with different fingerprints.

Shell collected samples, during the testing-by-difference process, to test geochemical fingerprinting as a support to well test results. The fingerprints from MDGC analysis are displayed as starplots using peak ratios of the eleven aromatic compounds.

The 'A' wells fingerprints clearly differ from others and C1 and D2 were shut-in for A2's well test. Stock tank oil samples were collected before and during these shut-ins. Duplicate MDGC analyses were performed on each sample to assess the impact of analytical errors. For the A2 well, the fingerprint of commingled oil, when all wells are flowing, falls between the fingerprints of the individual A2 fluid and the commingled fluid when A2 was shut in – the two later fingerprints acting as end-members. Mixing lines for each of the absolute peak ratios could then be obtained and geochemical allocation calculated for each of the ratios.

Author profile

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