

OPTIMISING A TIEBACK TO EXISTING FACILITIES

Abstract

This study was carried out for a US oil company operating in the central North Sea. It shows that even short conceptual studies can benefit tremendously from an integrated reservoir–flowline approach to the analysis.

The System

The system of interest was a small offshore oilfield located in close proximity to a number of existing platforms. In common with many other field developments in the maturing North Sea, the development was considered marginal. Hence any improvements to the overall field development economics would have a significant impact on the decision of whether to sanction the development of the field.

Flowline Sizing

Life of Field modelling was performed using an integrated reservoir – flowline model to establish the impact of variations in design parameters on the overall deliverability of the production system. The investigations also addressed the benefits of artificial lift including:

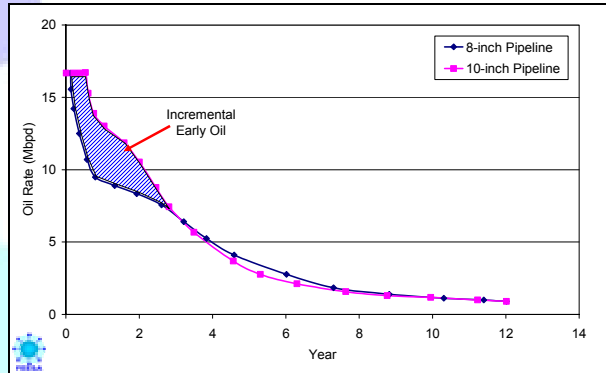
1. Electro-submersible Pumps (ESPs)
2. Downhole Gas Lift Injection
3. Multiphase Booster Pumps
4. Hybrid Lifting Options

In addition, the study also evaluated the impact of tubing size, wellhead locations and pipeline size.

The results showed that the greatest deliverability could be achieved using ESPs with gas lift next. However, gas lift is inherently more reliable than downhole pumps (which can require several workover repairs through field life) and the final decision on artificial lift method also factored in the risk of the ESP failing early in field life.

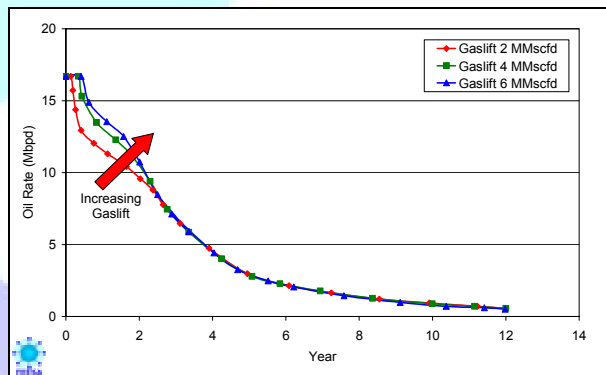
Figure 1 shows the effect of increasing the size of the pipeline transporting production from subsea wellheads to the host platform. Clearly the increase in pipeline size from 8 to 10-inch yields a significant improvement in early oil production and overall recovery.

Figure 1 The Effect of Pipeline Size



The effect of increasing gas lift injection rates is illustrated in Figure 2. The calculations show that significant accelerated oil production is achieved through increasing the injection rate from 2 to 4 MMscfd. However, increasing still further to 6 MMscfd produces only a marginal improvement. This is due to the beneficial reduction in head up the well tubing being counteracted by the increased frictional losses through the tubing and associated pipeline.

Figure 2 The Effect of Gas Lift



Conclusion

This study shows that even for short conceptual studies with tight budgets integrated Life of Field simulations can add real value.