

An Alternative Strategy for Evacuating Gas Fields

To compress or not to compress? That is the question

Dr M. S. Akhtar - MSE Consultants Ltd

Dr Akhtar is the Technical Director of MSE and has over thirty years of experience of the design and application of gas compression system for oil and gas production systems. He has acted as consultant for Shell, BP, Centrica, BG and other oil and gas companies on a variety of projects. He has degree in Mechanical Engineering and a PhD from Lanchester Polytechnic (now the University of Coventry).

For new gas fields, initial production is achieved by drilling a sufficient number of wells to maintain free flow while reservoir pressures are still high. Generally speaking, the use of a compression system is delayed as long as possible, until free flow can no longer be maintained.

Compressors are considered to be complex, costly and difficult to design. Hence, during field planning installation of gas compressors is deferred while the reservoir pressures are still high. This is unfortunate since compressors are (thermodynamically) more efficient at delivering greater volumes of gas at higher pressures, as the analysis below will show.

Effect of Pressures on Compressor Capacity

Figure 1 shows gas volumes delivered by a compressor for a range of inlet pressures consuming one megawatt of power. It is based on GPA equations for typical light natural gas with a molecular weight of 19.5. Gas is inter-cooled for pressures below 30 bar and a constant 90 bar export pressure is assumed for all cases.

Thus a compressor consuming 1000 kW of power will deliver approximately 100 MMSCFD at 70 bar but only 12 MMSCFD at 20 bar and 7.6 MMSCFD at 10 bar. To put another way if we want to compress 300 MMSCFD at 10 bar we shall require nearly 40,000 kW of power, compared with 3,110 kW at 70 bar.

Thus higher reservoir pressures "turbo-charge" compressor capacity and boosts production rates. A **correctly designed** compressor increases flow capacity of a well by the application of external power; the actual improvement is a function of pressure and timing. This principle has been used to increase peak production capacity and swing factor, which attracts higher gas price. It can also be used to reduce number of wells for a given contract nomination or drilling of additional wells can be deferred.

Improving Cash Flow and NPV with Compressors

Alternatively for a given number of wells, contract nominations can be increased cost effectively with a simple compression system. Benefits include accelerated production, higher cash flow that increases project NPV and profitability. Capital outlay of a small compressor pays many times over within a short period with increased production rate but at the right pressure and the right time. Compressor availability is less critical since the reservoir can still free flow.

A Typical Case Study

The situation is best illustrated by an example, which typifies many small to medium sized fields. Any similarity with an actual field is purely coincidental.

Gas has been free flowing from a "tight reservoir" over a number of years. The production rates being maintained by drilling additional wells. Finally, the flowing wellhead pressures can no longer maintain the plateau rates and a compression system is installed. Additional gas volumes are needed to cover the capital and the installation costs of a compression system. This will be achieved by lowering the wellhead pressures. The combined effect of peak production rates and lowest wellhead pressures raises the compression power substantially requiring a very large and costly gas turbine engine; capital costs increase with engine power.

However, reservoir simulations showed that extra production rates will not last and after a couple of years will decline sharply forcing the compressor to operate in extended periods of "recycle". Extended

recycling means that the compressor capacity and the engine size is too big for the duty. Clearly, in such cases neither the compressor capacity nor its timing is being optimised.

AN ALTERNATIVE STRATEGY

As an alternative, if compressors are installed earlier, when reservoir pressures are still high, lower powers are needed to compress the same volumes of gas and higher production can be maintained with fewer wells and at reduced capital costs.

Eventually the reservoir pressure and production rates will decline, however, the compressors can be re-designed to match the production rates and avoid recycling. With a smaller engine, the installed power

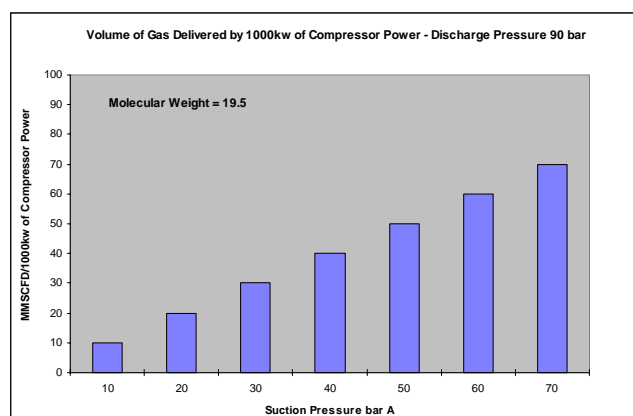


Figure 1

is more fully utilised over the life of the field. Absence of recycling over an extended period ensures that the machine is correctly sized and installed power is optimum for the application.

Optimising Compressor Timing

Clearly, there is an optimum time for installing the compressors to match the number of wells and their frequency, which will provide the contract nominations and yield the best NPV for a given field.

With an integrated model of the **reservoir** and the **compression system** we can analyse the gas deliverability of the field on a year-by-year basis. Studies performed with integrated models identify the best time for compressors, their size and power as wells as the frequency for given field. This aspect is beyond the scope covered here and will be discussed in a follow up paper.

Conclusions

A compressor's capacity to handle larger volumes of gas at high pressures can be used to optimise the optimum timing for its installation, which will add greater value to an asset. The benefits of such a strategy are

- accelerated production rates from the same number of wells
- lower capital expenditure and higher NPV
- higher production rates or bigger swing factor during early field life
- lower engine power
- optimised production over field life

However finding the right timing is the key factor in unlocking this value.