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THE MAXIMIZATION OF THE ULTIMATE RECOVERY FACTOR IN MATURE GAS RESERVOIRS IMPLEMENTING WELLHEAD AND FIELD COMPRESSION

1. INTRODUCTION

Mature fields contribute more than 50% of the world's gas production and therefore it is necessary to understand and to optimize the performance of these reservoirs.

The obvious decline of the natural gas reserves associated with relatively reduced volume of the new reserves discoveries reclaim the implementation of a new technical--economical approach of the mature gas field. The ultimate target is in fact the extending the life of the reservoirs, in terms of increasing the ultimate recovery factor.

Exploiting gas reservoirs to the maximum achievable limit with least production and transmission costs is a constant concern of gas industry professionals.

One of the ROMGAZ concepts regarding this problem is to develop compression capacities close to the wells. Many gas wells can be subjected to increased production by reducing the wellhead pressure.

The implementation of this method is imposed by production behavior of the depleted ROMGAZ fields.

2. GAS RESERVOIR CURRENT DEPLETION RATE

Statistical analysis of ultimate and current recovery factors from natural gas reservoirs in Transylvanian Basin today in production, show significant differences between production cumulative and initial gas in place for a part of them.

These are depleted reservoirs with an actual recovery factor very closed to the estimated ultimate recovery factor.

Table 1 illustrates the above mentioned in some of these reservoirs.

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Table 1

Recovery Factors

Field	The estimated ultimate recovery factor	Actual recovery factor
Nocrich	53%	48%
Nocrich Vest	50%	46%
Altana	61%	47%
Altana Est	40%	38%
Beia	76%	73%

3. FIELD COMPRESSION – STUDY CASE

Because most of ROMGAZ reservoirs are highly depleted and national transmission system pressures are high, field compression was considered as a suitable solution.

We will present a number of case studies where field compression was implemented on some of ROMGAZ depleted reservoirs.

1) **Gas production optimization on Nocrich, Nocrich Vest, Altana, Altana Est fields by installing a field compressor and lowering the gathering pressure.**

This four fields are located in the Southeastern part of Transylvanian Basin, close to each other. These are depleted reservoirs, whose production performance is restricted by high gathering pressure.

The major issues identified in this stage of production are following:

- Most wells from the field accumulate water during exploitation due to low reservoir energy, which results in perforations flooding and low productivity.
- Field gathering pressures vary from 11.5 to 15.5 bar, dependent upon the length of gathering pipeline.
- Wells productivity reduction due to collecting pressure close to tubing pressure (Tab. 2).

Table 2

Dynamic pressures

Field	Tubing pressure bar	Gathering pressure bar
Nocrich	8–12	11.2–11,9
Nocrich Vest	13–14	13
Altana	13–17	13–15.5
Altana Est	30	15.5

For rehabilitation of these reservoirs following were considered:

- Gas gathering pressure reduction by installing a field compressor.
- Monitoring production by measuring well pressure all along the production process; at least once a year pressures will be measured after sufficient well shut in periods, allowing achievement of reservoir static conditions.

Production design was made for all wells in production. Analysis of production evolution and of current well status was made per well on the basis of production data, for assessment of flow capacity and effective permeability.

The design concept considers the equation of radial-plane gas flow from production layer to wellbore, dependent on resistance to flow coefficients.

$$p_c^2 - p_s^2 = AQ_g + BQ_g^2 \tag{1}$$

where:

p_c – pressure on supply outline;

p_s – well pressure;

Q_g – well gas flow rate;

A and B – flow resistance coefficients which consider the well imperfections dependent on the degree and method of opening and on collectors physical-chemical characteristics.

Production dynamics were performed on the well, and then summed for the complex and for the total structure. Maximum valorization of reservoir potential is intended by optimum well exploitation.

Initial data used in the calculation program for reservoir behavior during exploitation are:

- Initial gas in place.
- Production cumulative.
- Average daily flow rate per well.
- Number of wells.
- Static pressure at a reference date.
- Gathering pipeline pressure.
- Minimum difference between tubing pressure and gathering pipeline.
- A and B coefficients for resistance to flow through strata.
- Coefficient of resistance to flow through tubing.
- Incremental factor for resistance coefficients.
- Reference year.
- Number of days of reference year.
- Number of days for production forecast.
- Reservoir depth.
- Reference temperature.
- Average reservoir temperature.
- Gas relatively density/relative gas to air density.

On the basis of production history and considering the current reservoir potential, production continued from the existing wells after a compressor was installed in the field, pressure dropping down to (Fig. 1):

- 4 bar at the wellhead for Nocrich
- 5 bar at the wellhead for Nocrich Vest
- 5.5 bar at the wellhead for Altana
- 8 bar at the wellhead for Altana Est.

Additional production and ultimate recovery factor increasing after the compression installation are illustrated in next diagram (Fig. 1) and Table 3.

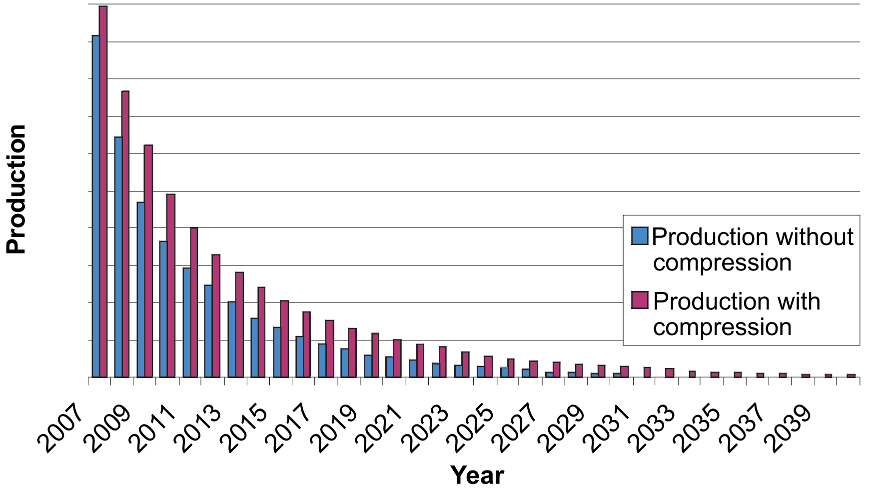

Fig. 1. Altana, Altana Est, Nocrich, Nocrich Vest Production Forecast

Table 3

Recovery factors with and without compression

Field	Estimated ultimate recovery factor without compression	Estimated ultimate recovery factor with compression
Nocrich	53%	58%
Nocrich Vest	50%	60%
Altana	61%	67%
Altana Est	40%	48%

2) **Gas production optimization on Beia field by installing a field compressor and lowering the gathering pressure.**

The field is located in the Eastern part of Transylvanian Basin. This is depleted reservoir, whose production performance is restricted by high gathering pressure.

The major issues identified in this stage of production are following:

– Most wells from the field accumulate water during exploitation due to low reservoir energy, which results in perforations flooding and low productivity;
– Field gathering pressures vary from 6 to 8 bar, dependent upon the length of gathering pipeline;
– Wells productivity reduction due to collecting pressure close to tubing pressure (Tab. 4).

Table 4

Dynamic pressures

Field	Tubing pressure bar	Gathering pressure bar
Beia	6–9	6–8

The model for rehabilitation of this reservoir is the same as previous.

Additional production and ultimate recovery factor increasing after the compression installation are illustrated in next diagram (Fig. 2) and Table 5.

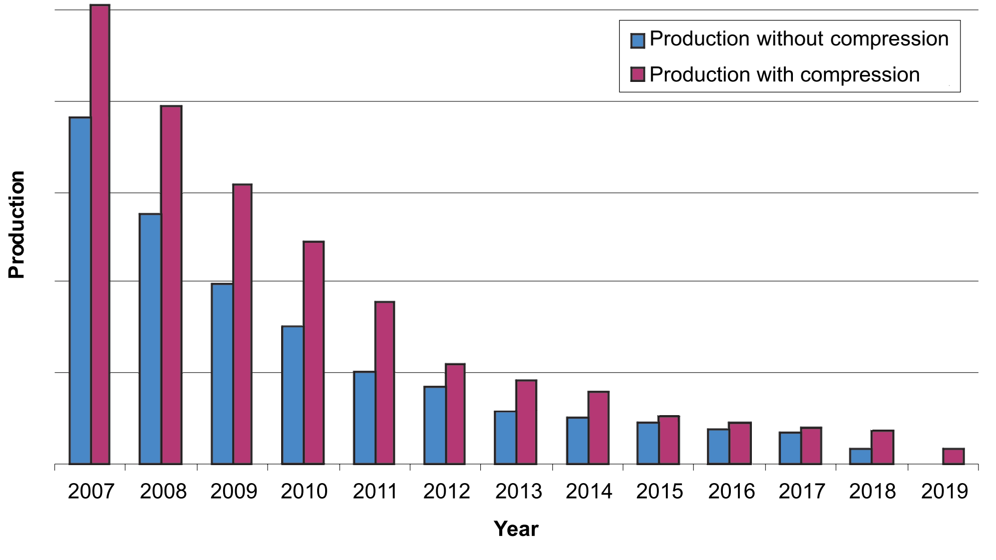

Fig. 2. Beia Production Forecast

Table 5

Recovery factors with and without compression

Field	The estimated ultimate recovery factor without compression	The estimated ultimate recovery factor with compression
Beia	76%	80%

4. WELLHEAD COMPRESSION

It is worldwide recognized that the use of wellhead compressors allows optimum recovery of gas from a reservoir. Differential pressure, the pressure difference between two points, is the force, which drives the gas to flow from the wells to pipeline. No gas will flow from the wells when the wellhead pressure declines to a level of sales line pressure (abandonment pressure), forcing the well to be abandoned.

Romgaz intention is to implement this type of compressors for wells with low pressures, located at long distance from delivery point.

Use of compressor not only increases the recovery of gas from the reservoir, it also increases the production rate and maintains plateau production for a long time. It also protects the wells from liquid loading problem, when the wells faces water accumulation in the wellbore due to low gas flow rate.

It is crucial to design a compressor which can optimize the performance of the compressor. The principles of system analysis can be applied to the inclusion of the compressor, and enhancement in the well performance can be easily evaluated. The principle to remember in this analysis is that the discharge pressure from the compressor is fixed since it is determined by pipeline intake pressure. Therefore, for a given discharge pressure, the suction pressure will have to increase with increase in the flow rate.

In most cases, the relationship between the suction pressure and the capacity of the compressor can be assumed to be linear. On the other hand, for a given well, with increase in suction pressure, the wellhead pressure will increase and hence result in reduction rate. So, as the suction pressure increase the overall contributions from all wells will decrease. By plotting the well performance curve against the compressor performance curve, we can determine the rate at which wells can deliver for a given horse power.

As follows we present a possible candidate for wellhead compression.

The current performance of the well is shown in Table 6.

Table 6

Well performance

Well	Shut in wellhead pressure bar	Flowing wellhead pressure bar	Rate Stcm/day	Δp pipe bar
X	12	9	7000	0.7

The shut in conditions at the well head are available. Assume that the performance of a well can be captured by:

$$q_{sc} = C\left(p_{whs}^2 - p_{wh}^2\right)^n \tag{2}$$

where:

p_{whs} – the shut in wellhead pressure,
p_{wh} – the flowing wellhead pressure,
n – is assumed to be 0.85.

The last column in the table above represents the pressure drop in the pipeline connecting a particular well to the compressor. We would like to install a compressor so that the well head pressure is reduced to increase the production. The pressure at the suction can decrease to as low as 3 bar. The discharge pressure is 12 bar.

We first establish the inflow performance equation based on a single rate test. One the performance is determined; the potential rate at different well head pressures is calculated. For this purpose, we assumed a constant suction pressure of 3 bar. From the formula 2 resulted a flow rate of 15000 Smc/day.

5. CONCLUSIONS

1) As gas wells are produced and reservoir pressures decline, it is becoming necessary to install wellhead compression to maintain production. Without effective compression gas rate and velocity will decrease to the point at which liquids cannot be lifted out of the wellbore.
2) By installing a compressor at the wellhead or in the field, the wellhead pressure can be reduced to increase the gas production and the ultimate recovery factor. These types of compressors are characterized by low to medium throughputs with low to medium compression ratios.
3) We consider that the wellhead and field compression is an essential approach for rehabilitation of the mature gas fields.

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