BULETINUL Universităţii Petrol – Gaze din Ploieşti	Vol. LXVIII No. 3/2016	11 – 19	Seria Tehnică

Using an Integrated Asset Model to Prove Feasibility of Installing a Field Compressor for Mature Dry Gas Reservoirs

Liviu Dumitrache*, Iulian Nistor**, Silvian Suditu**, Ana-Maria Badea**

* Petroleum – Gas University of Ploiesti (Ph.D. student); Schlumberger
e-mail: dumitrache.liviu@gmail.com

** Petroleum – Gas University of Ploiesti, Bd. Bucureşti 39, 100680, Ploieşti

Abstract

The big majority of the Romanian dry gas reservoirs are considered to be mature dry gas reservoirs with high recovery factors, implicitly not much more gas to be extracted under current technical and economic conditions. As gas is much more mobile than oil, these mature reservoirs have been properly developed with the optimum number of wells and have reached current reservoir pressures which allow production to be injected in the national grid, therefore, drilling new wells or infill drilling to increase the current recovery factors will not be of much help on its own.[6] The required solution will have to increase the pressure drawdown on the reservoir in order to increase the production and allow at the same time the production to be injected into the national grid in order to be reach the end consumer being either industrial or population. A theoretical case study with academically purposes is being presented indicating the necessary steps and outcome of implementing a field compressor for a 3 well mature dry gas reservoir.

Key words: *mature gas reservoirs, reservoir simulation, grid, ECLIPSE, Petrel, integrated asset model, IAM, compressor.*

Introduction

The reservoir in cause has been developed at the beginning of 1980 and has seen the first gas in January 1983. From geological point of view this represents an anticline and only one formation is being productive, i.e. only one sandstone layer which has a very good porosity, however, poor permeability.

Three wells have been drilled to develop the field and have been connected to a surface network which includes gathering lines flowing into a manifold and a connection line to the national gas pipeline grid. In order to be able to inject in the grid the wells need to produce at a specific flowing bottom hole pressure. Implicitly, this is the constraint we are imposing on the wells' production and limit the recovery factor of the field.

The plateau production of the field at its beginnings was 90,000.00 scm/d. Since 1983 until nowadays, the field's production has declined considerably to a value of 4,500 scm/d. The initial reservoir pressure was averaging 95 bars and the current pressure is around 30 bars. The required pressure to inject in the national grid is 20 bars.

The key factor in enhancing the current production of the field and increasing the recovery factor is to minimize the current reservoir pressure. In order to do so, we need to insert in the surface network a compressor which can handle the production of the wells and decrease the pressure upstream its location. This pressure decrease will transmit further to the wellhead and further to bottom hole and the current pressure drawdown on the reservoir will be increased meaning higher gas flowrates.[7]

The required steps in making this analysis are:

1. Create a static model of the reservoir;
2. Create a dynamic model using a reservoir simulator;
3. Create a surface network model;
4. Couple the subsurface dynamic model with the surface network model;
5. Analyse results and provide a production incremental;
6. Run economic analysis.

If the installation of the compressor proves to be economic than the next stage of implementation is required.

The current article will stop at point number 5 as the economic analysis is outside of its purpose.

Creating a Static Model of the Reservoir

The structure is represented by an EW un-faulted anticline. For simplicity, average values have been used when creating the static model in Petrel. The structural map together with the wells position is being presented in Figure 1. The average thickness of the reservoir is around 25 m and remains quite constant throughout the whole reservoir. The GWC has been assign as gas down to as none of the wells have shown water on the logs, nor produced any during production tests or throughout production life and has a value of 960 m. The average values of the properties used for model generation are for porosity: 0.25, horizontal permeability: 0.75 mD, vertical permeability 0.05 mD. The gas initially in place for this reservoir has been estimated to be approx. 486 MMscm.

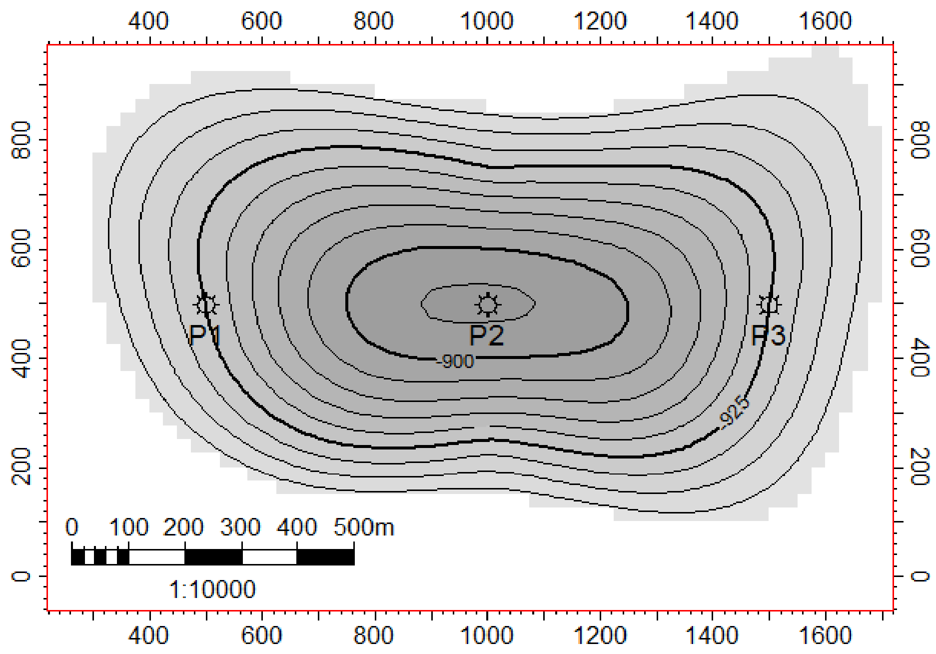

Fig. 1. Isobathic structural map with wells' positions

The field has been developed with producers P1, P2, and P3 which are opening the whole reservoir as per the below E-W cross section. Structurally, Well P2 is highest well on the field, while P1 and P3 are approximately at the same depth as can be seen in Figure 2.

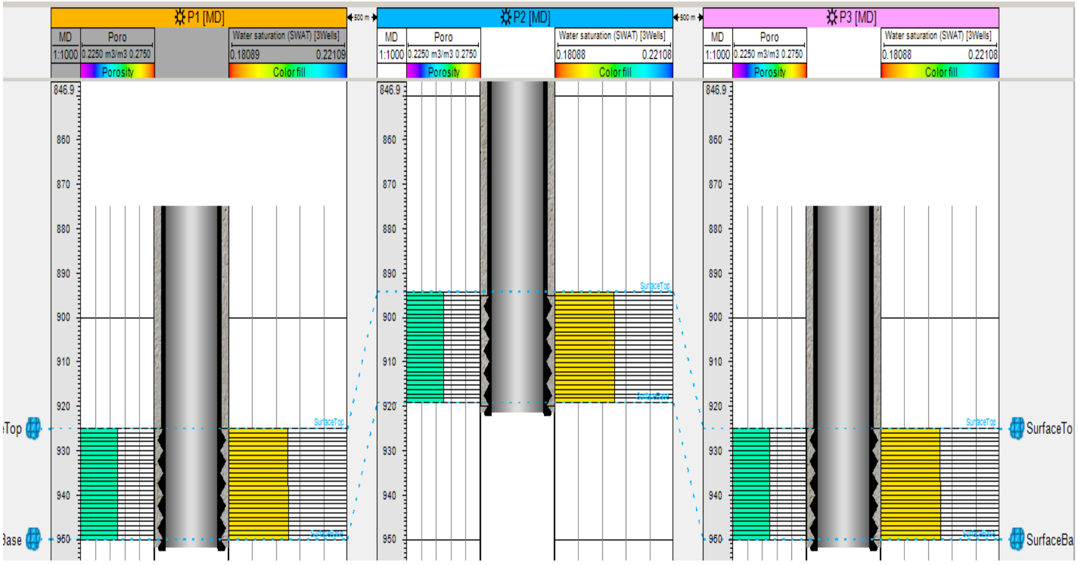

Fig. 2. E-W Wells cross section

Creating a Dynamic Model of the Reservoir

The behaviour of the field has been quite well approximated by dynamic simulation which has been run between January 1'st 1983 and April 1'st 2016. The purpose was to determine the current remaining in place reserves, where do we situate with the recovery factor of the field and how can its production be improved [3]. The following figures give answers to the above.

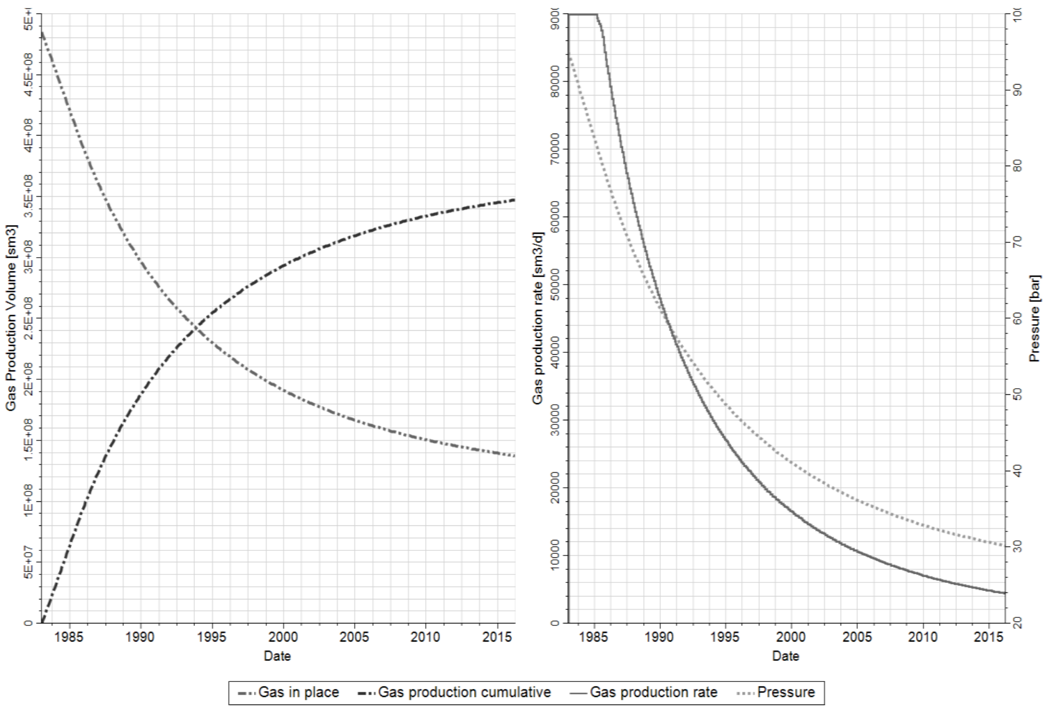

Fig. 3. Field's behaviour comprehensive plot

Figure 3 presents two sets of graphs, on the left-hand side, one can see the variation in time of the gas in place, from 486 MMscm initially to 138 MMscm presently, the difference between the two is the total cumulative production of the field and has a value of 348 MMscm. On the right-hand side, the gas flowrate of the field is presented against the field pressure. The production plateau of the field, 90,000 scm/d, has been maintained February 1'st 1985 after which its production started to decline. The current average reservoir pressure has a value of 30 bars with a field production of 4,500 scm/d.

Analysing the above numbers, one observes that the current recovery of the field is around 72%.

Figure 4 shows the behaviour of the highest well on formation, P2, but the other two wells are not far from this dynamic. From the right-hand side graph we can see that the wells are choked back so that they will not produce more than 30,000 scm/d due to surface network limitation and that they are not producing any water.

From the left-hand side graph, we see the variation of the two important well's pressure, pressure at the drainage radius given as Pressure average (9 point) as reported by ECLIPSE and bottom hole flowing pressure. While looking at the difference between the two pressures, one notices that in order to produce the flowrate, the required drawdown is quite important. This, of course, happens due to the low permeability present on the field.

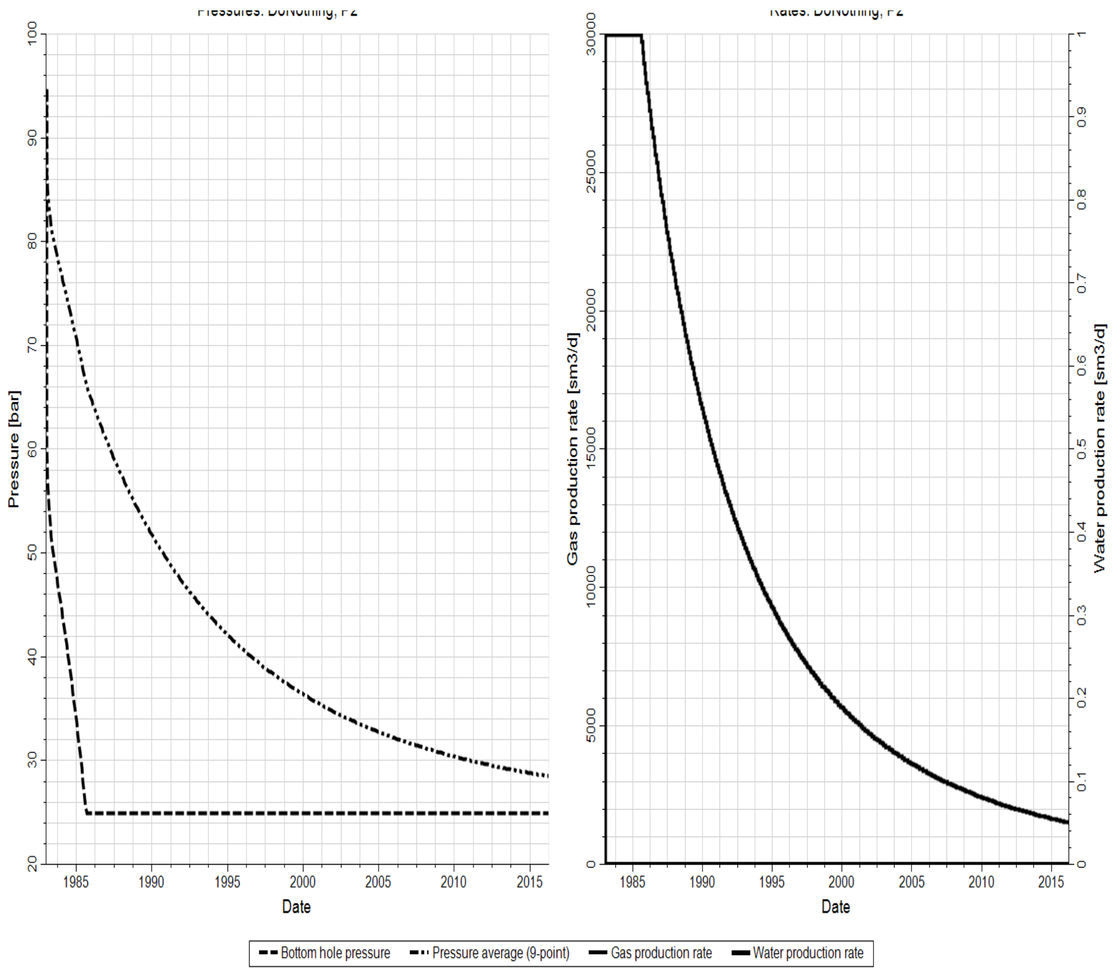

Fig. 4. Typical well behaviour comprehensive plot

Moreover, one notices that the bottom hole pressure curve stabilizes at 25 bars. This is the required pressure at this level in order for the produced gas to be successfully transported to the national grid and sold.

Creating a Network Model of the Surface Gathering Facilities

For this matter PIPESIM wellbore and networks simulator has been used. Wells are flowing from the wellhead through gathering lines to a manifold from which their production is being sent to the national grid through a 4 in pipeline in length of 2.5 km. Figure 5 presents the surface network as modelled within PIPESIM:

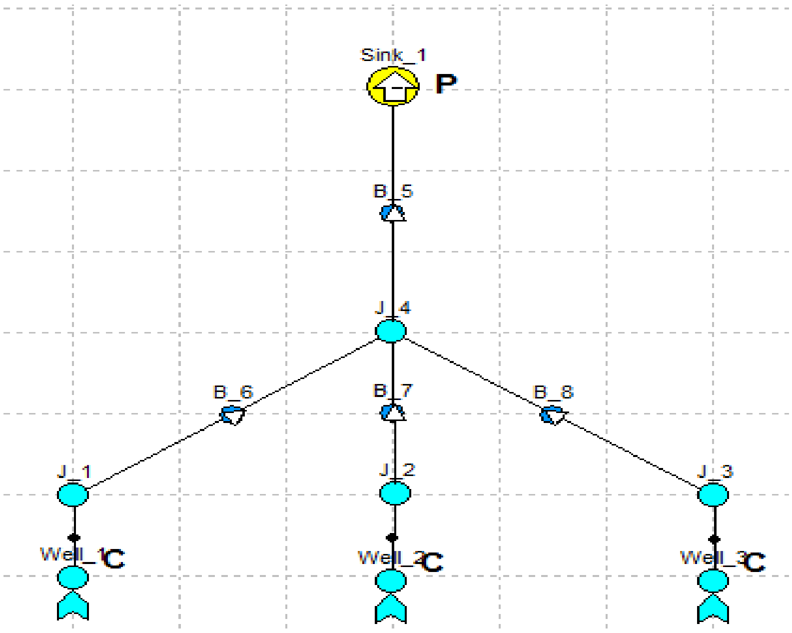

Fig. 5. PIPESIM model of the field's surface network

The gathering lines B6, B7, and B8 have the same diameter as the wells' tubing, 2 7/8 in and range in distance from 1.5 to 2 km. In this case Well-1is well P1, Well-2 is well P2 and Well-3 is P3. The network has been designed to meet the capacity required when the field produced at its plateau level.

Figure 6 presents the variation of pressure and flowrate from the reservoir to the national grid with distance.

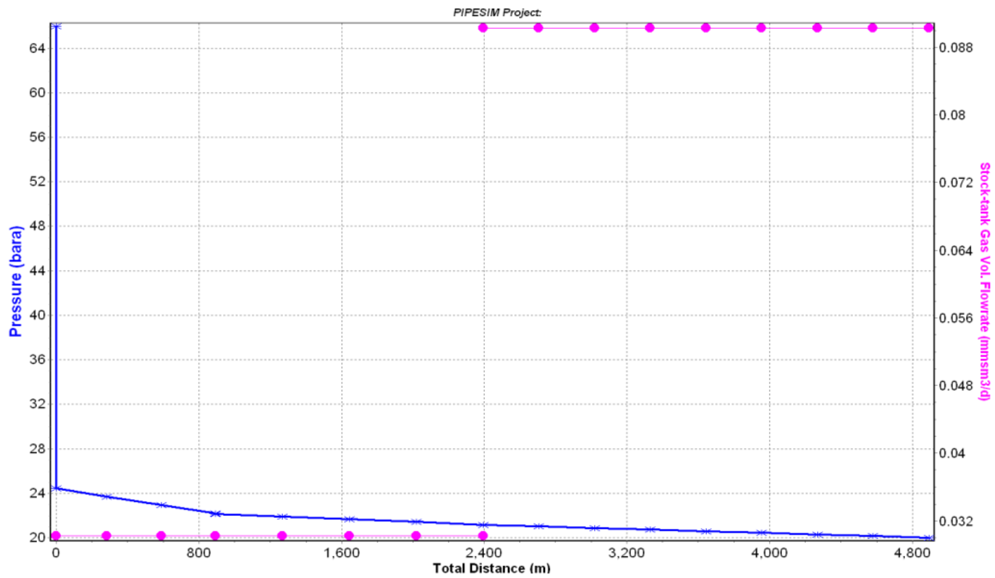

Fig. 6. Pressure–Flowrate (dotted line) against distance profile along Well_2 (P2)–J2–B7–J4–B5–Sink1

The manifold corresponding to J4 can be recognised at 2400 m. This is where all the production from the three wells meet to deliver the field's production. The above behaviour reflects PIPESIM steady state behaviour, i.e. the simulator reflects the behaviour of the network for only specific conditions valid for only one time step. For transient behaviour and implicitly multiple time steps analysis we need to couple the subsurface dynamic model created in ECLIPSE with the surface network model created in PIPESIM with coupler which bear the name of Integrated Asset Modeller. [5]

Creating an Integrated Asset Model

An integrated asset model is considered to be the ultimate tool for future prediction behaviour of the hydrocarbon reservoirs. All limitations or constraints belonging to the reservoir, surface network and surface facilities are addressed from one environment and actions to remove bottlenecks and optimize production of the asset can be analysed and taken. In our example, we are going to use this integrated asset model in order to see the total production incremental given by the field if a compressor would be installed just before the injection point in the national grid.

The tool used to make the coupling of the two models is IAM – Integrated Asset Modeller and in addition to the subsurface and surface network, processing (surface facilities) and financial models can be connected. Implicitly, the economic analysis can be automatically assessed once the economic model is being coupled to the integrated asset model.

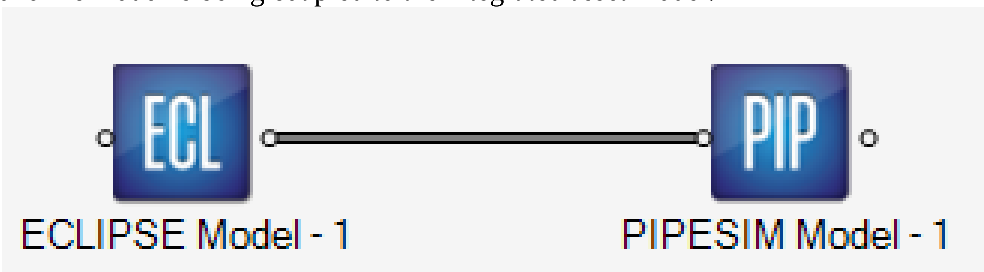

Fig. 7. Main flow diagram of the integrated asset model

Figure 7 shows the logical connection between the subsurface and surface models. ECLIPSE calculates the pressure until the top most perforation, the bottom hole flowing pressure and for the current drawdown of the well supplies a rate. After coupling in IAM, this flowrate is being conveyed to the PIPESIM modelled tubing string. The pressure loss from the bottom hole to the wellhead is being calculated and a value for flowing tubing head pressure is supplied. Further, the pressure losses into the gathering pipeline is being calculated and a pressure at the manifold is being supplied. Next, the pressure losses in the 4 in pipeline and a pressure at the Sync or injection point in the national grid is being determined. In other words, ECLIPSE is being used for calculating the inflow performance relationship curve, while PIPESIM is being used for calculation of the outflow performance relationship curve.

Figure 8 presents the behaviour of the field production, pressure at the manifold and sink pressure from 1983 until today. As we can see the behaviours reflected individually by both the ECLIPSE and PIPESIM models are reflected, meaning that the dimensioning of the surface network and the development scheme have been done properly.

Analysing Results and Providing Production Incremental

In order to accomplish this point, we will run two integrated asset model simulations until 2040. That's when the contract with national agency of mineral resources will end for this field. The first simulation case looks at a do nothing case (figure 9), this means business as usual and the second simulation looks at implementing the field compressor to boost its production and improve the final recovery factor (figure 10). All previous constraints remain in place.

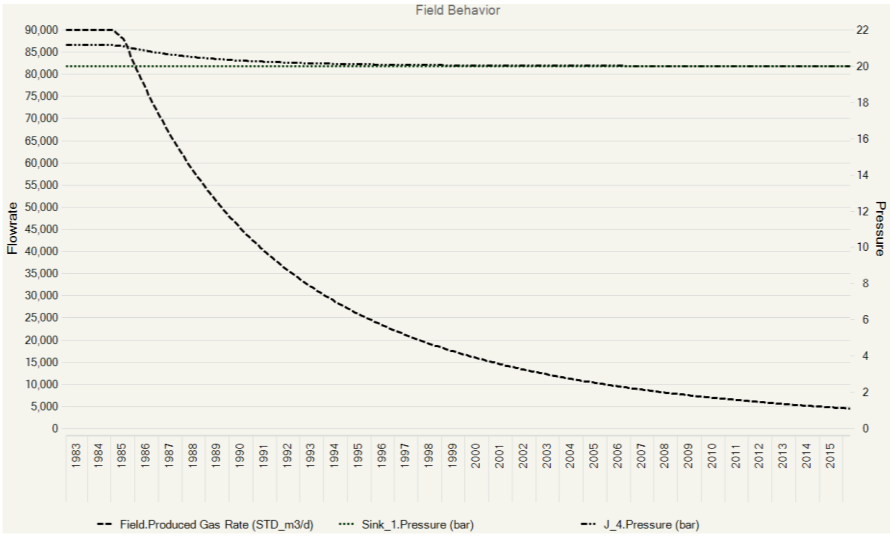

Fig. 8. Integrated asset model comprehensive chart.

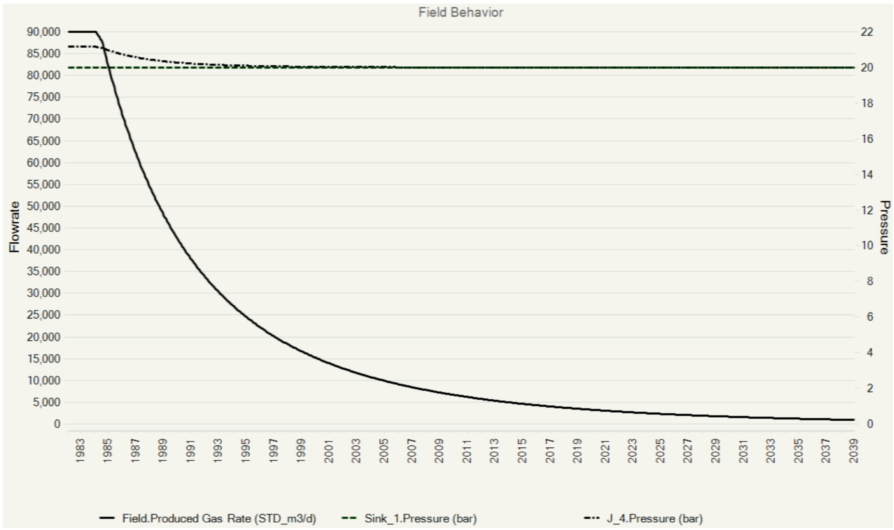

Fig. 9. Extended do nothing case until January 1'st, 2040

If the field is going to be produced under the same scenario, we see that its rate continue to decline until a final recovery factor of 75%. We remember that the present recovery factor has a value of 72% and, implicitly, the scenario will not recover much more gas. In the case of implementing a compressor at the sink, the suction pressure will be allowed to drop to 6 bar while the injection pressure will remain at 20 bar [1].

This means a difference of 14 bar which will transmit in the system until the bottom hole so the drawdown on the reservoir will increase.

At the same time, the compressor cannot handle more than 12,000 scm/d, therefore we will limit the field production at this value. A new short redevelopment plateau can be observed in Figure 10 for the field produced gas rate.

On this plot we can see the pressure dynamics but also the comparison of the two rates for the different cases. If we are to talk about volumes, then Figure 11 shows the clear differentiation of the compressor case with dotted lines both for total gas production cumulative (positive) and remaining gas in place (negative).

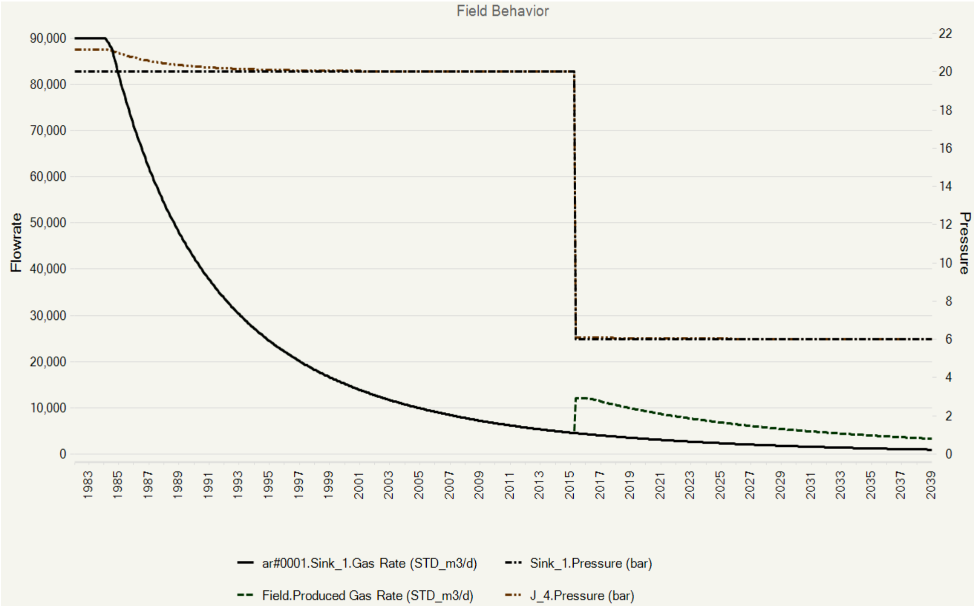

Fig. 10. Extended compressor implementation forecast until January 1'st, 2040 against NFA

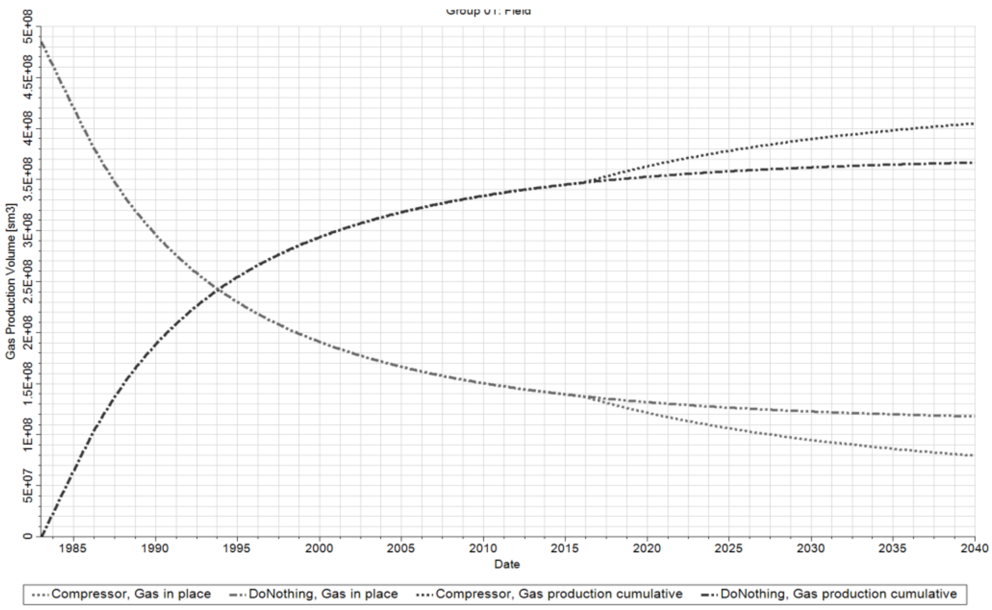

Fig. 11. Forecast comparison for the no further action against compressor simulations

The total cumulative production for the two cases will be approx. 406 MMscm (compressor) against 367 MMscm. The final recovery factors will be 84% against 72%. Implicitly, installing the field compressor will help producing 12% more of the field initial gas in place by January 1st, 2040.

Conclusions

The present article has looked at enhancing the final recovery factor of a small mature dry gas reservoir. This objective will be achieved by installing a compressor before the injection point into the national grid pipeline system. The final recovery factor of the field is being increased from an expected 72% to 84% and an additional total cumulative production incremental of 39 MMscm of gas is being delivered as a result of compressing from 2016 until 2040 when the national mineral resources agency lease contract will expire.

This article has been created for academic purposes and is utilizing data put together as such.

At the same time, this represents a conceptual study which is usually being done before commencing working with real field data and supplies quick and effective answers to challenges encountered in real life. One has to bear in mind that real field analysis has several production packages produced through tens and sometime hundreds of wells. In other words, is always best to start from simple and add complexity along the way.

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Utilizarea unui model integrat în vederea demonstrării eficienței instalării compresoarelor de câmp pentru zăcămintele mature de gaze sărace

Rezumat

Majoritatea zăcămintelor de gaze sărace din România sunt zăcăminte mature cu factori de recuperare înaintați, așadar, din punct de vedere tehnico-economic, trebuiesc identificate soluții de creștere a producției. Deoarece gazele sunt mult mai mobile decât țițeiul, aceste zăcăminte au fost dezvoltate cu un număr optim de sonde și au atins presiuni de zăcământ curente care permit ca producția lor să fie injectată în sistemul national de transport, așadar, forajul sondelor de îndesire pentru îmbunătățirea factorilor de recuperare nu ar fi de ajutor. Soluția necesară în vederea realizării acestui obiectiv ar trebui să marească producția curent înregistrată și să o injecteze în sistemul national de transport pentru a ajunge la consumatorii finali, fie industriali, fie casnici.

Având scopuri academice și de cercetare, acest articol prezintă un studiu de caz ce indică etapele necesar a fi realizate în vederea instalării unui compressor de câmp pentru un zăcământ matur de gaze sărace dezvoltat la începutul anilor 1980 prin trei sonde.