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KEY FACTORS IN SHALE GAS MODELING AND SIMULATION

MODELOWANIE I SYMULACJA NIEKONWENCJONALNYCH ZŁÓŻ GAZU ZIEMNEGO Z ŁUPKÓW - KLUCZOWE PARAMETRY

Multi-stage hydraulic fracturing is the method for unlocking shale gas resources and maximizing horizontal well performance. Modeling the effects of stimulation and fluid flow in a medium with extremely low permeability is significantly different from modeling conventional deposits. Due to the complexity of the subject, a significant number of parameters can affect the production performance. For a better understanding of the specifics of unconventional resources it is necessary to determine the effect of various parameters on the gas production process and identification of parameters of major importance. As a result, it may help in designing more effective way to provide gas resources from shale rocks.

Within the framework of this study a sensitivity analysis of the numerical model of shale gas reservoir, built based on the latest solutions used in industrial reservoir simulators, was performed. The impact of different reservoir and hydraulic fractures parameters on a horizontal shale gas well production performance was assessed and key factors were determined.

Keywords: shale gas, unconventional gas, reservoir simulation, hydraulic fractures, shale gas extraction, stimulation, hydraulic fracturing, key parameters, sweet spot, Blue Gas.

W celu udostępnienia zasobów gazu ziemnego ze złóż łupkowych i maksymalizacji wydajności horyzontalnych odwiertów eksploatacyjnych stosowane jest wielostopniowe szczelinowanie hydrauliczne. Modelowanie efektów stymulacji oraz przepływu płynów w ośrodku o ekstremalnie niskiej przepuszczalności jakim jest skała łupkowa różni się znacznie od modelowania złóż konwencjonalnych. W związku ze złożonością zagadnienia występuje znaczna ilość parametrów mających wpływ na przebieg wydobycia. Dla lepszego zrozumienia specyfiki złóż niekonwencjonalnych konieczne jest określenie wpływu poszczególnych parametrów na całość procesu wydobycia gazu oraz identyfikacja tych o największym znaczeniu. W efekcie może się to przełożyć na projektowanie bardziej efektywnego sposobu udostępnienia zasobów gazu ze złóż łupkowych.

W ramach niniejszego opracowania przeprowadzono analizę wrażliwości numerycznego modelu symulacyjnego złoża gazu z łupków zbudowanego w oparciu o najnowsze rozwiązania stosowane w prze-

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mysłowych symulatorach złożowych. W wyniku tej analizy określono parametry o kluczowym wpływie na przebieg eksploatacji i maksymalizację wydobycia gazu ze złoża.

Słowa kluczowe: gaz z łupków, gaz niekonwencjonalny, symulacja numeryczna, szczeliny hydrauliczne, wydobycie gazu, stymulacja, szczelinowanie hydrauliczne, kluczowe parametry, sweet spot, Blue Gas

1. Introduction

Extraction of natural gas from shale rocks, tight rocks (also production of coal bed methane) – successfully implemented in the USA in the last decade – is a game changer technology. This process stimulates the American economy (IEA, (2011, 2012); EIA 2013). Natural gas is the most important energy carrier with high public acceptance and according to the IEA reports world gas demand will increase in the next 30 years (IEA (2011, 2012)). This increase of natural gas demand in power generation processes also results in the development of gas combined cycle technology (CCGT), reaching a high cycle efficiency – more than 50% (Siemek & Nagy, 2012). Natural gas is also an important energy source for the transition time towards a low-carbon economy (IEA 2011, 2012; MIT 2011; Siemek et al., 2009; Nagy & Siemek, 2011). The high gas import dependency (Siemek et al., 2019; Nagy et al., 2009) leads Poland to search own way to increase its energy safety in next twenty years.

As the natural gas (and/or oil) recovered from the shale rocks is quite "conventional", the term "unconventional" refers to methods, knowledge and approach applied to recover hydrocarbons from such type of reservoirs (in comparison with so called "conventional" reservoirs) rather than to natural gas itself.

Massive hydraulic fracturing treatment, till now mainly hydraulic, is the only method that allows for economically effective gas production rates from unconventional shale gas reservoirs. However, one can say that „unconventionality" of these reservoirs decreases with time as the knowledge and technology increases and that nowadays shale gas is bit less „unconventional" than it was few years ago.

Similar situation is observed in terms of modeling and simulation of unconventional reservoirs. The technology of shale gas production in a certain sense surprised, or ahead of, the creators of numerical reservoir simulators. Models used earlier did not take into account (and to some extent so far) the specificity of shale rock reservoirs. Modeling deposits of this type therefore requires methods at least equally unconventional, as the way to make them available.

Recently it is becoming more and more obvious that the Polish gas-bearing shales differ significantly from US deposits. Unfortunately (after the Polish experience) the technology should be modified to specific geological and local requirements and the new technology has to apply with modification to compensate the variety of properties of reservoir rocks (Poprawa, 2010; PGI, 2012; Nagy et al., 2013; Siemek et al., 2013; Kaliski et al., 2012).

The differences are so significant that there is no obvious deposits of "analogous" to which we can refer and directly benefit from the experience of US companies. In view of the differences in the parameters describing the so-called shale reservoirs the need of probably other than the American (in some extent) methods of stimulation and development arises. Moreover, also there is a need to understand the mechanisms of flow in the Polish shale for their proper modeling and simulation of production of hydrocarbons (gas and/or oil/gas condensate). The lack of gas production profile of polish shale well with ongoing continuous production strongly hinders the issue. However, it seems that one should look for a way to understand the relevant mechanisms of the gas flow in shale rocks, to model it effectively and consequently provide an effective way of development of unconventional hydrocarbon resources in Poland (Klimkowski & Nagy, 2014).

To assess the impact of different reservoir and hydraulic fractures parameters on a horizontal shale gas well production performance, sensitivity analysis (SA) was performed on a range of parameters (variables, factors) with three sample values, called low, medium and high, for each parameter. From the reservoir parameters matrix permeability and porosity, natural fracture spacing and conductivity (and resulting porosity and permeability) as well as adsorbed gas content were investigated. Hydraulic treatment results were incorporated by the primary hydraulic fracture spacing, extent and permeability. Moreover, initial water saturation in both natural and hydraulic fractures and effect of diffusion were taken into account. The parameters used for SA and their values are summarized in Table 1 and Table 2. The cumulative gas production was used as the objective function of the analysis and a base case simulation model was prepared as the reference for the results of analysis.

2. Shale gas modeling

Modeling the shale gas reservoirs differs significantly from modeling of conventional reservoirs (Andrade et al., 2011). There are two main „problems" with organic rich shales: one is related to complex pore system with distinct physical properties of each element of this system and thus complex interaction between these elements, the other one results from multiple gas storage and transport mechanisms (Arogundade & Sohrabi, 2012; Ozkan et al., 2010).

In shale reservoirs we can find three different naturally occurring porous systems (Ozkan et al., 2011; Clarkson, 2013):

1. gas-wet organic porosity that is a mature form of kerogen,
2. inorganic, primarily water-wet, porosity system and
3. natural fractures.

Fourth pore system is generated by massive hydraulic fracturing treatment (hydraulic fractures).

The quad-porosity model is presented in Fig. 1. The solid tanks represent four different porosity systems and the dashed small tanks represent internal physical phenomena: A/D represents adsorption/desorption effects in organic porosity and G/W represent gas/water dissolution /evolution effects. The valves represent the connectivity between each element of the system (Hudson, 2011).

In numerical simulation naturally fractured reservoirs are modeled with use of one of three main models, namely Dual Porosity (DP), Dual Permeability (DK) or Multi INteracting Continua (MINC). Each of these models has somehow limited abilities to model shale reservoirs. For the purposes of this study solution proposed by Rubin, 2010 (Computer Modelling Group Ltd.) and combining positive features of DK and MINC models was used. This Locally Spaced-Logarithmically Refined-Dual Permeability model (LS-LR-DK) (Fig. 2) is based on a dual permeability (DK) model with an additional, limited to the vicinity of the hydraulic fractures (LS – Locally Spaced) grid refinement and grid blocks are increasing in size logarithmically away from the fractures (LR – Logarithmically Refined). The result is better than the usual dual permeability model representation of transient flow from a matrix with very low permeability

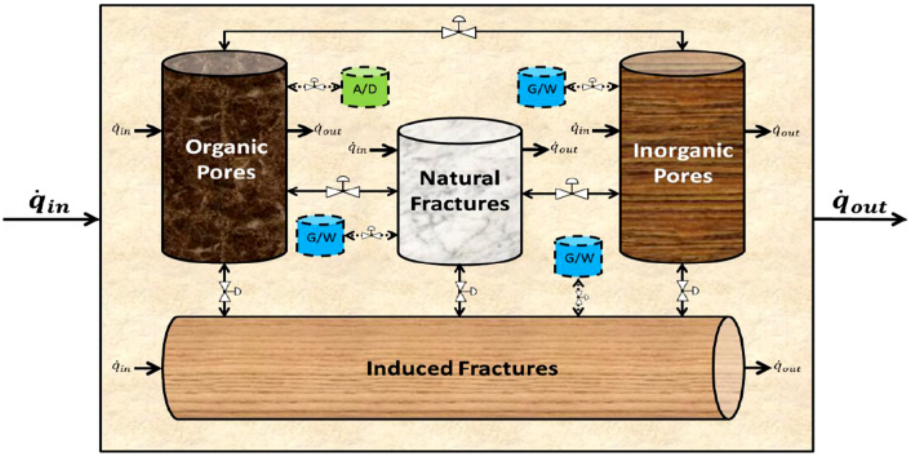

Fig. 1. Tank representation of the quad-porosity system (Hudson, 2011)

to highly conductive hydraulic fracture. A non Darcy flow permeability based correction factor can allow non-Darcy flow to be accurately modeled in fracture conduits modeled explicitly with blocks as wide as 0.601 m (2 ft) (Rubin, 2010; CMG, 2013). This approach provides a very accurate representation of the flow to and in the fracture (including the non-Darcy flow) at a reduced computational power (less time-consuming simulations).

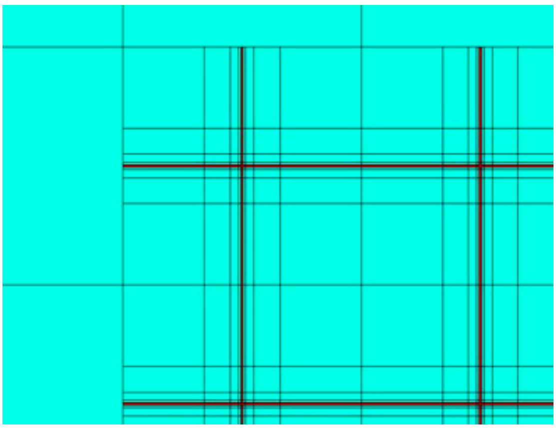

Fig. 2. LS-LR-DK fracture network in SRV (red - hydraulic fracture)

3. Simulation model description

The idealized simulation model was built based on a Cartesian grid with dimensions of $99 \times 49 \times 9$ basic blocks. Dimensions of each basic block (before refinement) are $20 \times 20 \times 9$ m, resulting in overall model dimensions of $1980 \times 980 \times 99$ m. The horizontal well is 1400 m long and in base case it has 15 stages of hydraulic fracturing (100 m spacing).

Gas adsorption/desorption is modeled with use of the Langmuir isotherm. The model incorporates non-Darcy flow in hydraulic fractures and gas diffusion in the rock matrix. A single simulation in Sensitivity Analysis covers a period of 10 years of operation. Initial gas rate is constrained to 200000 Sm^3/day and minimum well bottom hole pressure is set to 30 bar. These data are based on conditions used in one of the best US shale plays like "Haynesville".

Natural gas is modeled as single component methane and the phenomena of change of PVT properties in the confined porous conditions (Nagy & Siemek, 2014) is not incorporated within the model. This is due to the fact the simulators use standard Peng-Robinson or Soave-Redlich-Kwong equation of state to model hydrocarbons PVT behavior (PREOS in this case).

Relative permeability curves for viscous flow in shale matrix were generated with standard correlations for 20% connate water saturation. Curves for gas and water are presented in Fig. 4. For flow in fractures different relative permeability relationship was used, where values of k_r changes linearly from 0 to 1 with increasing phase saturation. For reference purpose initial gas in stimulated reservoir volume of Base Case model (assumed area of SRV is presented in Fig. 3) was assessed to be 475.8 million Sm^3 (including 110.8 million Sm^3 of adsorbed gas). The gas initially in place in other cases may differ in comparison to the reference case because of different porosity.

TABLE 1

Parameters and their sample values used for sensitivity analysis

Parameter	Unit	Base case	Low	Medium	High
Matrix permeability	[mD]	0.0001	0.00001	0.0001	0.0005
Matrix porosity	[-]	0.04	0.04	0.07	0.10
Natural fracture spacing, and resulting fracture porosity	[m] [-]	20 $2 \cdot 10^{-5}$	5 $8 \cdot 10^{-5}$	20 $2 \cdot 10^{-5}$	30 $1.33 \cdot 10^{-5}$
Natural fracture conductivity	[mD·m]	$0.25 \cdot 10^{-3}$	$0.25 \cdot 10^{-3}$	$0.50 \cdot 10^{-3}$	$1.00 \cdot 10^{-3}$
Hydraulic fracture spacing, and number of fracturing stages	[m] [-]	100 15	100 15	200 8	350 5
Hydraulic fracture extent (one wing), x_f	[m]	150	50	90	150
Hydraulic fracture permeability, k_f	[D]	5	1	5	20
Adsorbed gas	[Sm^3/tonne]	1	0	1	5
Diffusion	[cm^2/s]	0.0006	0	0.0003	0.0006
Fracture water saturation	[-]	0.55	0.20	0.35	0.55

TABLE 2

Natural fracture permeability (nD) depending on natural fracture conductivity and spacing

Spacing [m] / Conductivity [mD·m]	5	20	30
$0.25 \cdot 10^{-3}$	50.0	12.5	8.3
$0.50 \cdot 10^{-3}$	100.0	25.0	16.7
$1.00 \cdot 10^{-3}$	200.0	50.0	33.3

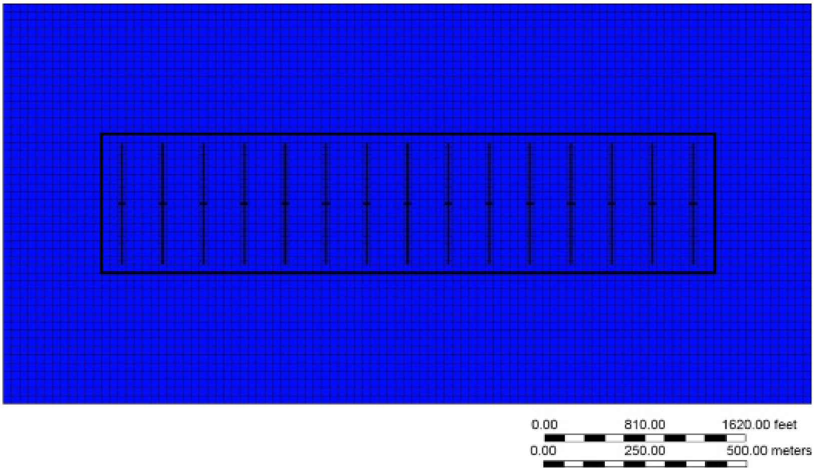

Fig. 3. Assumed area of SRV for initial gas in place calculation

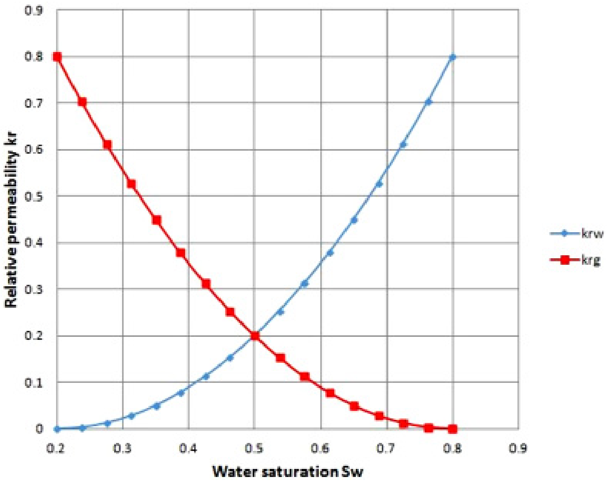

Fig. 4. Relative permeability curves used for viscous flow in matrix

4. Results of Sensitivity Analysis

The input for SA consists of 10 parameters with 3 sample values for each, resulting with parameter space (the number of all possible experiments) equal $3^{10} = 59049$. Obviously it is not possible to perform such an analysis and thus it is necessary to select some reasonably limited set of experiments. According to statistical experimental design theory, to efficiently explore the parameter space, the design (the set of experiments) selected should be a representative subset of all possible experiments. The Latin hypercube design approach was applied to reduce the number of experiments and meet above mentioned requirement. Finally 81 simulations were performed within the SA. The illustrative summary of these runs in comparison with base case simulation results (thick red lines) is presented in Fig. 5. At first glance, the base case ranks in the middle range of SA results.

Based on results of all simulation runs linear and reduced quadratic proxy models were created and then used to determine main (linear) and interaction/quadratic (nonlinear) effect estimates of particular parameters. The effect estimate show how changing the parameter's value change the model's response (objective function). The linear proxy model is described by the equation:

$$y = a_0 + a_1 x_1 + a_2 x_2 + \dots + a_k x_k$$

where y is the model's response (objective function), $a_0, a_1, \dots, a_k$ are the parameters of the proxy model, and $x_0, x_1, \dots, x_k$ are the input variable parameters.

In addition to linear effects (main effects), parameter interaction effects (cross terms $x_i x_j$) and quadratic effects (x_j^2) can be extracted from second degree (quadratic) polynomial model:

$$y = a_0 + \sum_{j=1}^{k} a_j x_j + \sum_{j=1}^{k} a_{jj} x_j^2 + \sum_{i<j} \sum_{j=2}^{k} a_{ij} x_i x_j$$

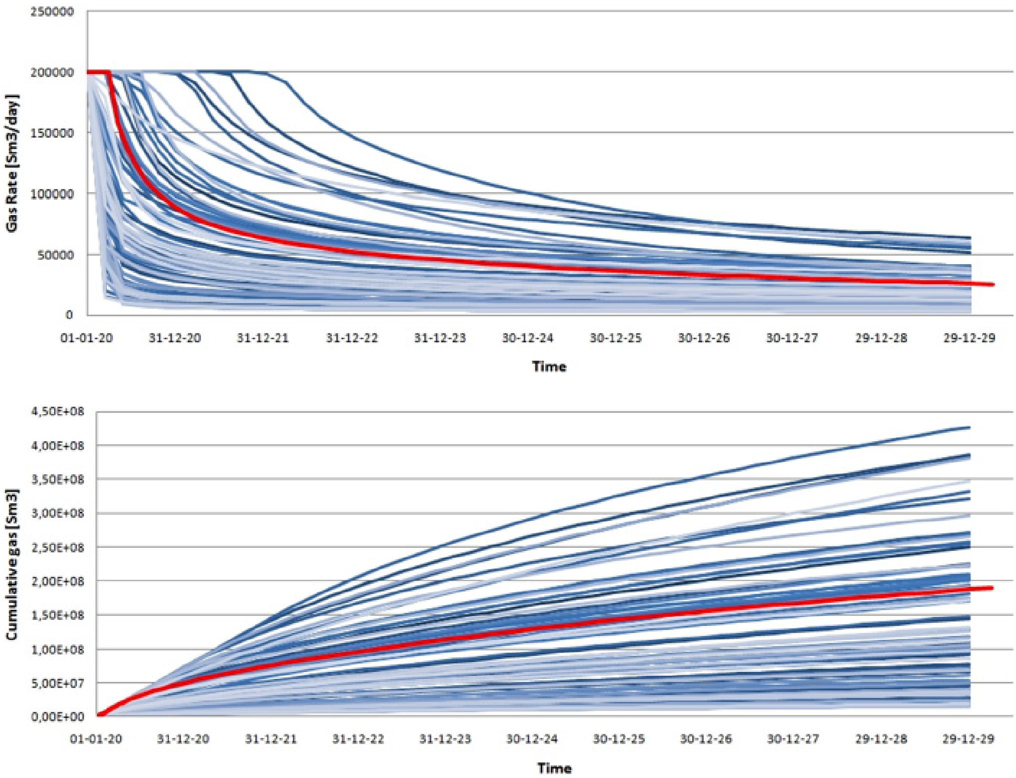

Fig. 5. Gas production rate (top) and cumulative gas production (bottom) for all simulation runs of sensitivity analysis (thick red line represents base case simulation)

At this point it is worth recalling that proxy model is just an approximation of the simulation model and actual change (increase or decrease) of the objective function due to the change of one parameter varies depending on the combinations of sample values of the other parameters.

Key results of SA are presented in the form of tornado plots. Parameters are ordered from having the greatest effect on the objective function to having the least effect. The Maximum and Minimum bars represent the maximum and minimum objective function (cumulative gas) value among all the training jobs. Between them base case cumulative production is presented for comparison.

Linear model effects on cumulative gas production in 10 years period are shown in Fig. 6. Minimum and maximum cumulative gas production are 15.5 and 427.0 million Sm^3 respectively, while the base case production reaches 188.1 million Sm^3. Parameters of the adequate simulation runs are summarized in Table 3. Analyzing the results one should remember that the "worst" and the "best" runs of the set of experiments are not necessarily the worst and the best configurations of sample values possible. They are such in this particular Latin Hypercube design. Also it should be noted that due to the fact that shale rock porosity is one of the parameters being investigated in SA, initial gas in place amount vary between the runs. Thus, recovery factor in, for example, maximum or minimum production case cannot be calculated based on the reference case original gas in place. However, the aim of the analysis is, based on statistically representative subset of all possible experiments, to figure out shale gas simulation key factors, and not to focus on recovery factor of each experiment (simulation run).

TABLE 3

Juxtaposition of parameters of "minimum" and "maximum" simulation runs

Parameter	Unit	Minimum case	Maximum case
Matrix permeability	[mD]	10	500
Matrix porosity	[-]	0.04	0.10
Natural fracture spacing, and resulting fracture porosity	[m] [-]	30 $1.33 \cdot 10^{-5}$	5 $8 \cdot 10^{-5}$
Natural fracture conductivity	[mD · m]	$0.25 \cdot 10^{-3}$	$1.00 \cdot 10^{-3}$
Hydraulic fracture spacing, and number of fracturing stages	[m] [-]	350 5	100 15
Hydraulic fracture extent (one wing), x_f	[m]	90	90
Hydraulic fracture permeability, k_f	[D]	1	5
Adsorbed gas	[Sm^3/tonne]	1	1
Diffusion coeficient	[cm^2/s]	0.0006	0.0003
Fracture water saturation	[-]	0.35	0.35
SRV initial gas in place	[$10^6 \cdot Sm^3$]	476.6	1018.4
Cumulative gas	[$10^6 \cdot Sm^3$]	15.5	427,0

According to Fig. 6 rock matrix permeability has the biggest impact on overall well performance. This means that increase of matrix permeability from 10 to 500 nD causes expected increase of cumulative gas production of 143.2 million Sm^3. According to linear proxy model the second and the third highest impact on the objective function belongs to hydraulic fracture spacing and extent, which in total is good information, since both these parameters are (more or less) under control during fracturing treatment. Next most important parameter is natural fracture spacing,

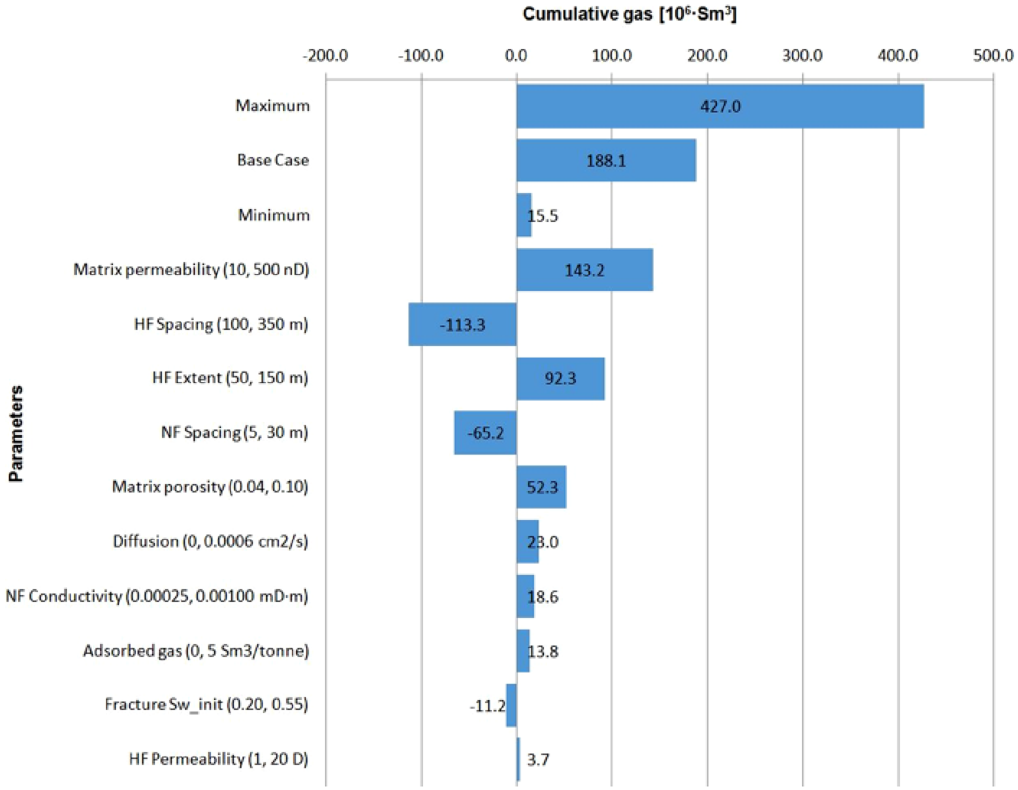

Fig. 6. Linear model effects on cumulative gas production

and what is interesting from shale modeling point of view, conductivity of natural fractures is not of very high importance. Density of natural fracture network has a much greater importance than its conductivity. Based on linear proxy model the fifth biggest impact on production belongs to matrix porosity: increase from porosity of 0.04 up to 0.10 causes expected increase of cumulative gas production of 52.3 million Sm^3. Whereas the effect of diffusion, desorption and initial water saturation of fractures is much smaller than properties of shale rock.

It should also be pointed that, although the extent and density of hydraulic fractures in stimulated reservoir volume are key performance indicators, hydraulic fracture permeability has the least impact on the well performance.

According to Fig. 7 three most important effects are the linear effects of matrix permeability and hydraulic fractures spacing and extent. Next is the quadratic effect of matrix permeability and interaction effects of hydraulic fracture spacing with extent and matrix permeability.

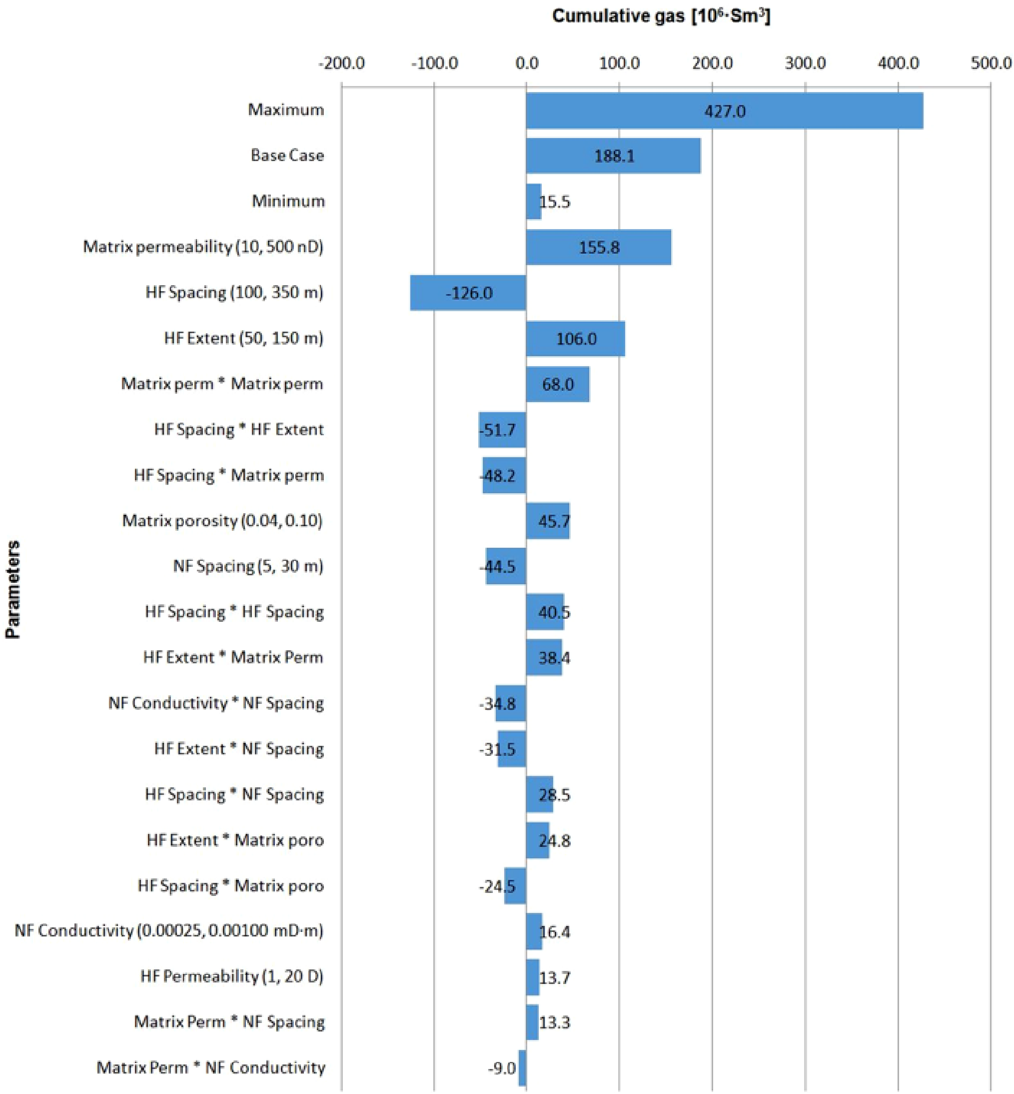

Fig. 7. Reduced quadratic model effects on cumulative gas production

5. Extension of the Sensitivity Analysis

5.1. Focus on key factors

To extend the results of sensitivity analysis base case model was modified in the one-parameter-at-time manner to look more closely at the impact of the parameters indicated by the SA. In subsequent simulation runs effects of hydraulic fracture spacing and permeability, matrix permeability, natural fractures parameters and adsorbed gas content were analyzed. Additionally production period was extended up to 20 years. Results of these simulations are presented in Fig. 8 to Fig. 13.

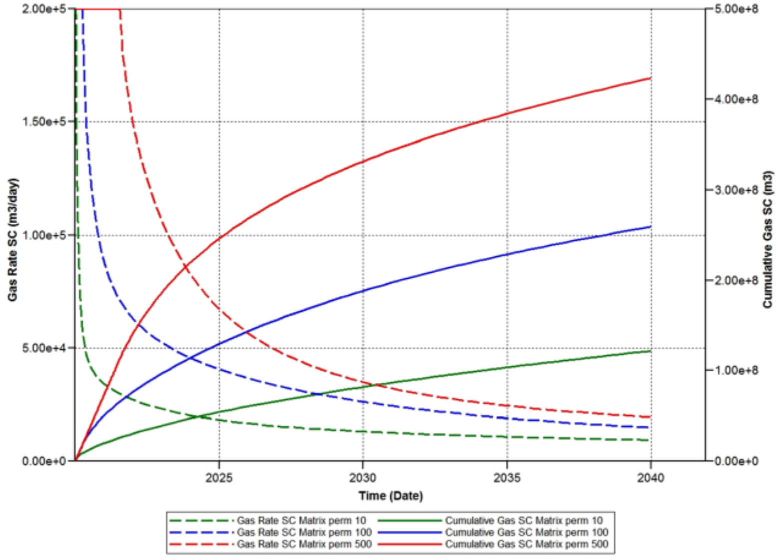

Fig. 8. Matrix permeability impact on the cumulative gas production (recovery of 260 mln Sm^3 during 20 years of production – assuming matrix permeability 100 nD)

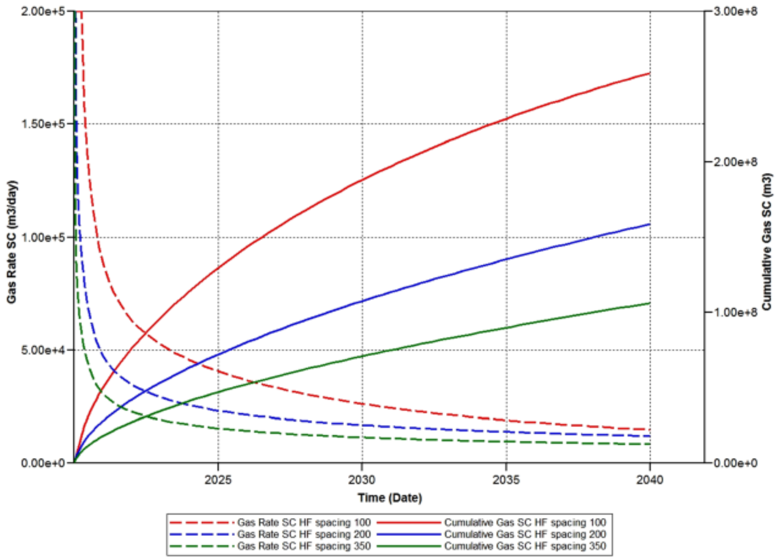

Fig. 9. Hydraulic fracture spacing impact on the cumulative gas production for 100, 200 and 350 m distance between fractures

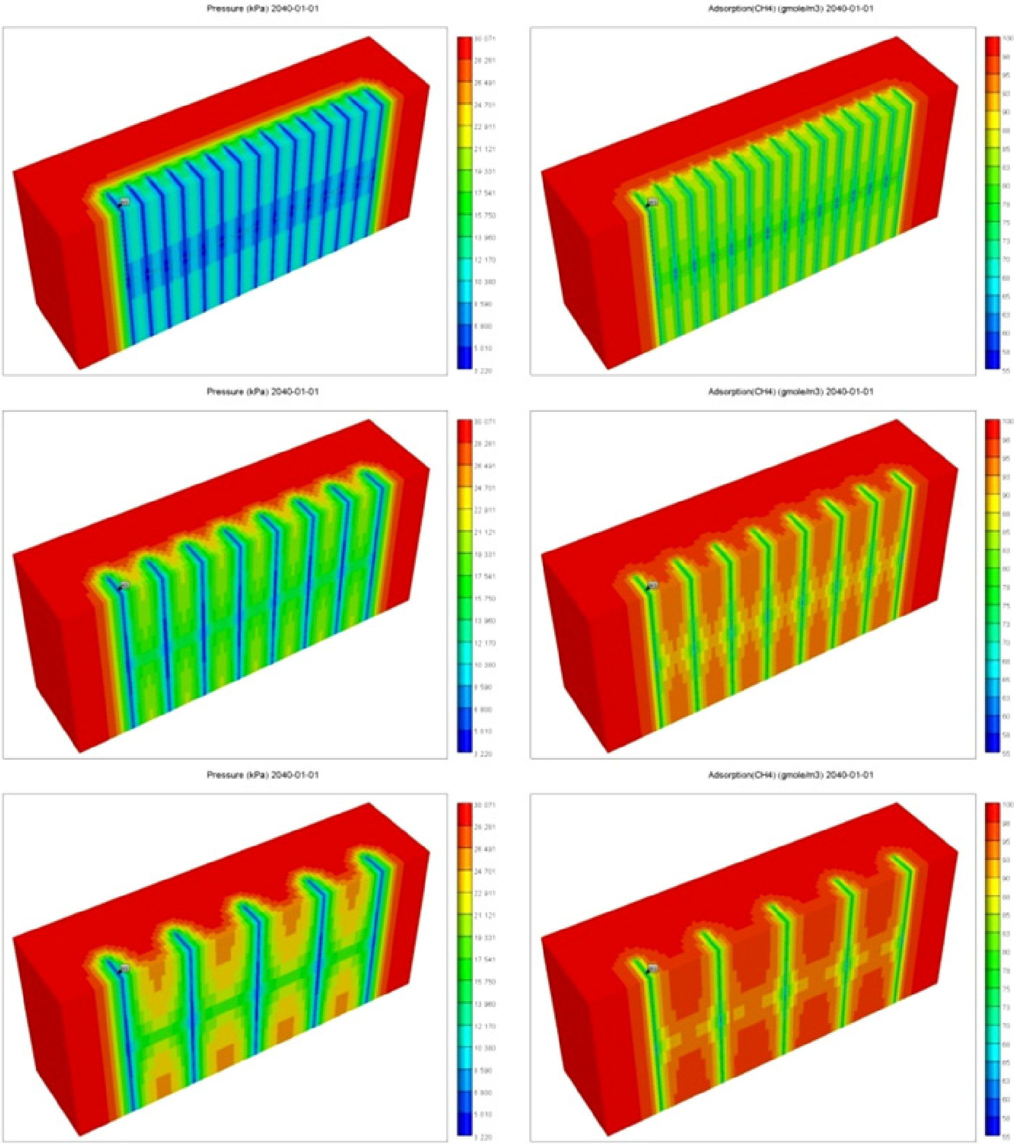

Fig. 10. 3D cross-section along the well: left side – pressure, right side – adsorbed gas after 20 years of production; top to bottom – hydraulic fracture spacing 100, 200 and 350 m

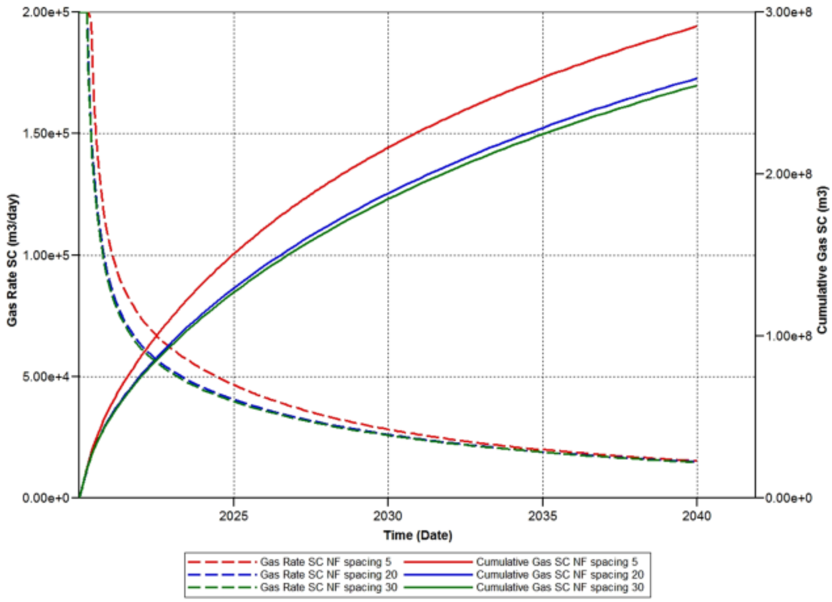

Fig. 11. Natural fracture spacing impact on the cumulative gas production for I and J direction spacing of 5, 20 and 30 m and basic grid block dimension of 20×20 m

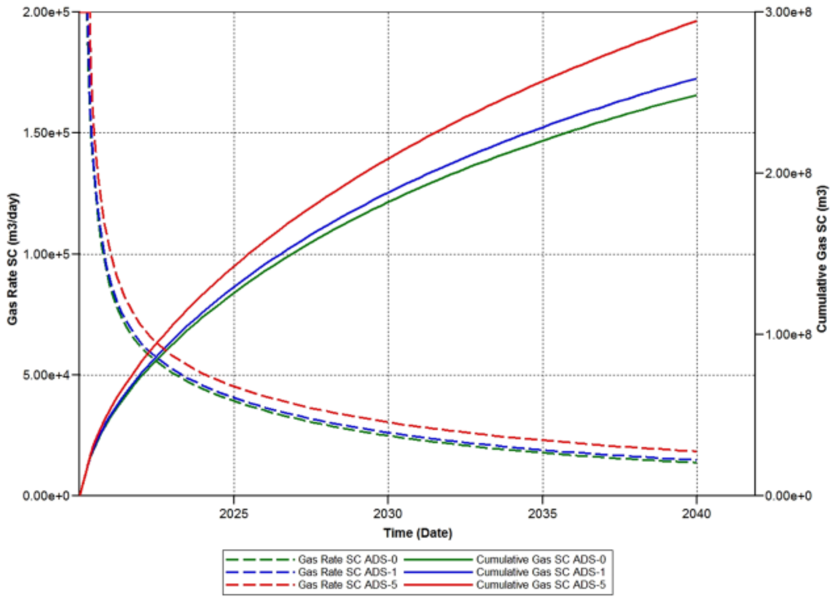

Fig. 12. Adsorbed gas impact on the cumulative gas production for 0, 1 and 5 Sm^3/tone

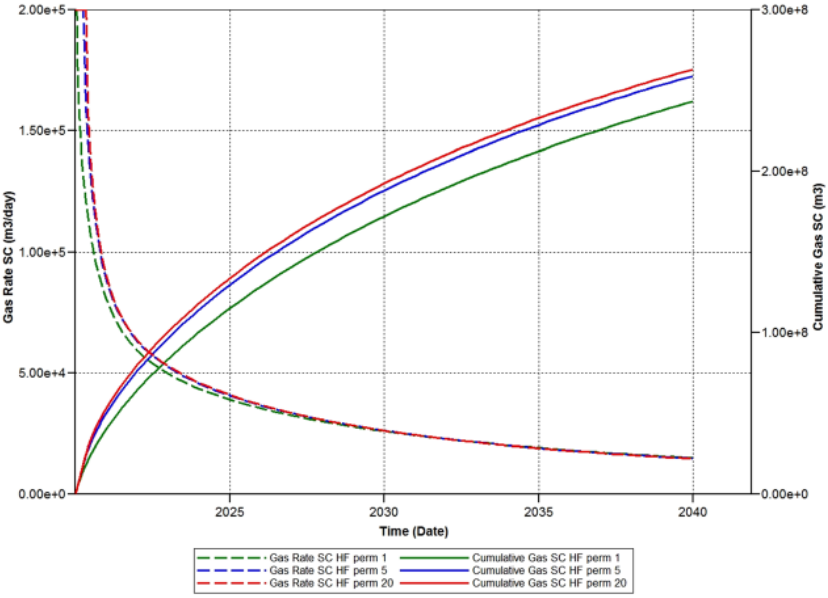

Fig. 13. Hydraulic fracture conductivity impact on the cumulative gas production – 2.5, 12.5 i 50 mD·m (or permability of fractures – 1, 5, 20 D)

5.2. Impact of results of fracturing treatment and SRV modeling approach

Performed sensitivity analysis confirmed that properly designed and executed fracking is crucial for shale gas production performance. Consequently appropriate modeling approach is required to account properly for the fracking effects. Beside standard planar hydraulic fracture a stimulated reservoir volume (SRV) approach is used, based on a “tartan” grid (Fig. 14).

Hereafter effects of fracturing treatment quality, including so called “stress shadowing”, when stress field changed by one fracturing stage can affect another one, are presented. This is represented by reduced extent of some fractures (8 full and 7 limited-extent fractures) or completely not effective treatment in some stages (8 full-extent fractures) compared to 15 full-extent fractures case (Fig. 15). In practice, the efficiency of the fracturing oscillates in the range of 60-70%. Also impact of different representations of the SRV is presented, comparing set of single planar fractures to set of one block wide (20 m) “tartan” SRV and 3 blocks wide (60 m) “tartan” SRV (Fig. 16). These runs were performed with higher adsorbed gas content than the above.

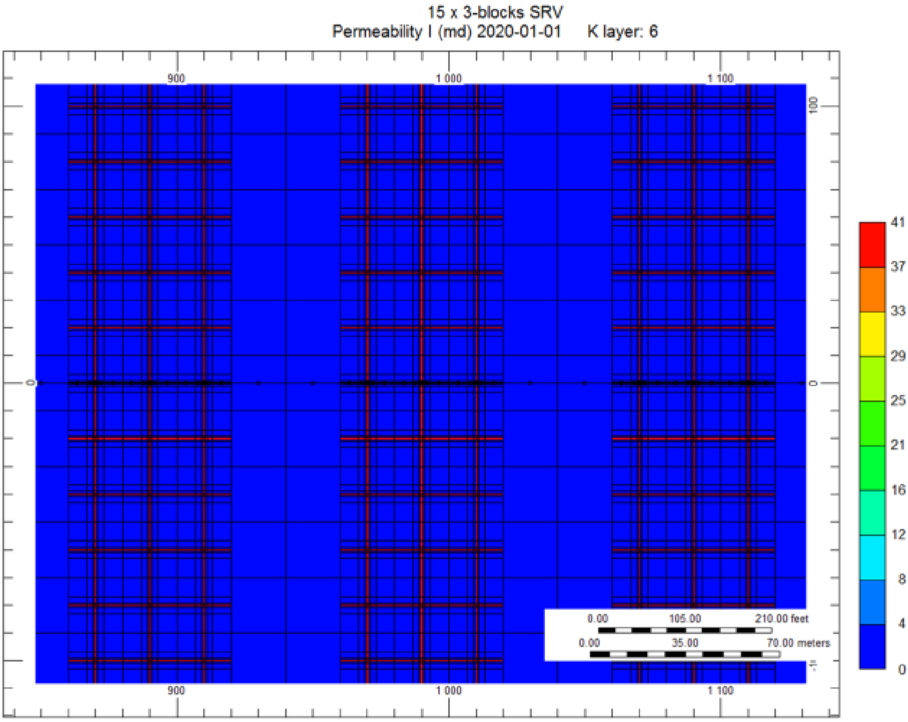

Fig. 14 „Tartan“ grid SRV: set of 3-blocks-wide fracturing stages

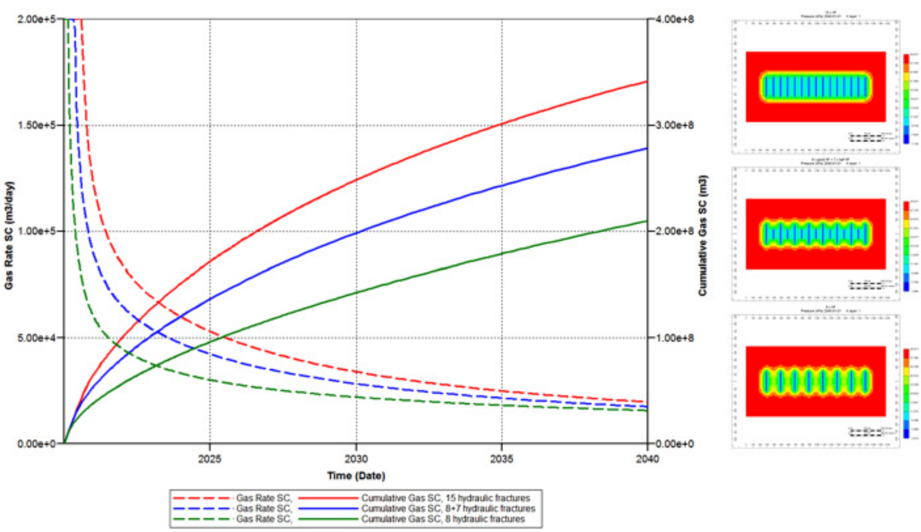

Fig. 15 Impact of quality of stimulation process on production performance.
Different rate and cumulative production as result of density (spacing) and extent of hydraulic fractures (15 „normal“ fractures, 8 “normal” + 7 “poor quality” fractures and 8 „normal“ fractures)

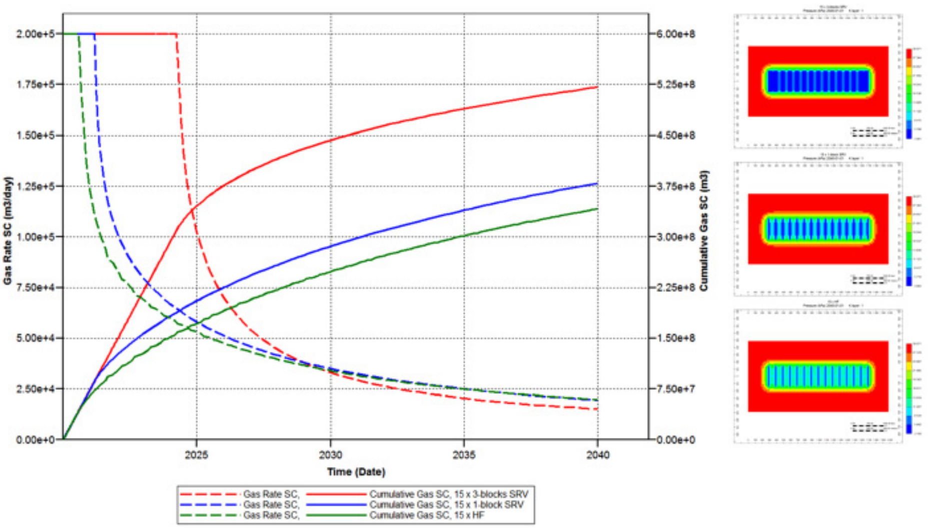

Fig. 16 Impact of the SRV modeling method (15 individual hydraulic fractures, SRV zone composed using 15 1-block-wide "tartan" SRVs and 15 3-blocks-wide SRVs)

6. Conclusions

1. Hydraulic fracture spacing and extent has strong influence on well performance. However, fracture permeability is not of very high importance. There is an evident increase in production between hydraulic fracture permeability of 1 D and 5 D, especially in the initial period of production but increasing fracture permeability up to 20 D does not increase cumulative production much. Moreover, in later period there is no difference in production rate. Summing up, as the contrast between the rock matrix and fracture is so significant it is not necessary to have very high conductive hydraulic fractures. The focus should be on obtaining dense and wide stimulated reservoir volumes (SRV) with complex fracture network.

2. Relatively high permeable shales combined with long and dense hydraulic fractures (effective SRV) can yield improved performance, especially in later phase of production and in shales with low natural fracture permeability. The maximum matrix permeability in this work has been selected as 500 nD, which may be higher than expected in normal situations and is representative only to the best 'sweet spots'.

3. It is necessary to properly determine natural fracture distribution. Relatively dense natural fracture network increases production performance in early phase of production (Fig. 11). Also, more advanced relative permeability model for flow in fractures may be of interest. Conductivity of natural fractures is not of very high importance.

4. High adsorbed gas content can have important impact on production performance in late time production (Fig. 12).

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