Invited review
Reservoir modeling of shale formations
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ABSTRACT

Economic production from shale has been intimately tied to hydraulic fracturing since the first signs of success in Barnett Shale in the late 90s. The introduction of horizontal wells and multi-stage hydraulic fracturing was met by a huge move by operators toward developing shale formations that were mainly ignored in the past. Today using pad drilling, multiple horizontal wells share surface facilities and infrastructure, a development that minimizes the industry's environmental footprint. To understand production from shale reservoirs one must understand the network of natural fractures in the shale and the role of hydraulically induced fractures and their interaction.

Hydraulic fracturing has been around and been studied by engineers for decades. Analytical, numerical and data-driven models have been built to explain their behavior and contribution to flow. Contribution of natural fracture networks to storage and flow in carbonate (and some sandstone) reservoirs had led to the development of techniques to study and model them. Since they are the predominant source of porosity and permeability in shale, more attention has been focused on their characteristics in the recent years. Studies of methane production from coal seams in the mid 80s provided insights on sorption as a storage mechanism and desorption and diffusion as a transport phenomenon in reservoirs that came to be known as CBM (Coalbed Methane). Today, production from shale is mainly modeled based on lessons learned in the past several decades where all the above techniques are integrated to create the modern shale reservoir models.

The coupling of hydraulic fractures and natural fracture networks and their integration and interaction with the shale matrix remains the major challenge in reservoir simulation and modeling of shale formations. This article reviews the methods used by scientists and engineers in recent years to understand the complexities associated with production from shale. This will shed light on the commonly held belief amongst some of the best minds in reservoir engineering (those that have been intimately involved in modeling production from shale) that there is much to be learned about this complex resource and that our best days in understanding and modeling how oil and gas are produced from shale are still ahead of us.

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1. Introduction

Mitchell¹ and his team of geologists and engineers began working on the shale challenge in 1981, trying different combinations of processes and technologies before ultimately succeeding in 1997 with the use of a “slick-water” frack that made Barnett Shale economical to develop and in turn changed the future of the US natural gas industry (NGW, 2011). Continuing on Mitchell’s success progress followed a path that included horizontal wells, multi-stage hydraulic fracturing of lateral wells and pad drilling, and the rest is history.

Since the recent success in overcoming the technical difficulties to unlock the huge potentials of oil and gas production from shale is very much tied to natural fracture network, hydraulic fracturing, and horizontal drilling, a quick look at the characteristics of each would be an appropriate start. Instead of providing a detailed survey of the body of research and development that has been dedicated to these subjects, the objective here is to provide a high level assessment of these technologies. For example as far as the modeling of the impact of the hydraulic fractures in the reservoir simulation and modeling of the shale formations are concerned, the two major approaches used namely, Explicit Hydraulic Fracture modeling versus Stimulated Reservoir Volume approach are examined.

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¹ Mitchell Energy & Development. He sold his company to Devon Energy in 2002 in a deal worth $3.5 Billion.
2. Natural fracture network

Reservoir development is impacted by natural fractures in three ways. First, natural fractures are planes of weakness that may control hydraulic fracture propagation. Second, high pressures from the hydraulic frac treatment may cause slip on natural fractures that increases their conductivity. Third, natural fractures that were conductive prior to stimulation may affect the shape and extent of a well’s drainage volume (Dershowitz and Doe, 2011).

Natural fractures are Diagenetic fractures and/or tectonic fractures. Natural fractures are mechanical breaks in rocks, which form in nature, in response to litho-static, tectonic and thermal stress and high fluid pressure. They occur in a variety of scales and with high degree of heterogeneity (Tran et al., 2002).

The most common technique for modeling Discrete Natural Fracture (DNF) network is to generate them stochastically. Using Borehole Image Logs some of the initial characteristics of the DNF can be estimated and used in their stochastic generations. Parameters such as Mean and Standard Deviation of Fracture orientation, form of Fracture Length Distribution, averages for fracture length, aperture, density of center points and relative frequency of termination are among those that need to be provided (guessed or estimated) so that the stochastic algorithms can generate a given Discrete Natural Fracture (DNF). Sometimes such exercise is performed in multiple sets, changing the aforementioned parameters in order for the generated networks to resemble some of the observed characteristics in the outcrops. Fig. 1 displays typical DNF networks that are generated using stochastic techniques.

DNF models have many advantages over conventional Dual Porosity (DP) approaches, especially in heterogeneous reservoirs where the dominant flow mechanism is through the network of fractures rather than the reservoir matrix. The DFN approach is based on the stochastic modeling concept and therefore, every realization of the Discrete Fracture Network will produce different results. As such, DFN-type modeling is not a direct competitor to DP reservoir modeling. Rather, it provides an additional insight into the potential variability of production histories (Akbarnejad-Nesheli et al., 2012).

Despite the different techniques used to generate natural fracture networks, the fact remains that the only tool that can provide “some” information about the nature and distribution of natural fracture network is Borehole Imaging. Even in the presence of extensive Borehole Imaging, no one knows what the fracture propagation might look like a few inches beyond the wellbore. Therefore, all existing approaches remain at the level of a non-unique proxy of the natural fracture network.

3. Hydraulic fracturing

Modeling hydraulic fracture treatment is almost as old as the practice itself. Because hydraulic fracturing process involves overcoming the in-situ stresses in the formation in order to break the rock, rock mechanics are incorporated in hydraulic fracturing modeling. Attempts to model hydraulic fracturing include analytical (Shlyapobersky, 1985; Nolte, 1988; Valko and Economides, 1993; Cheng et al., 2009; Xu et al., 2009), numerical (Barree, 1983; Settari, 1989; Pak and Chan, 2004; Ribeiro and Sharma, 2012), and data-driven (Mohaghegh et al., 2000) approaches.

Examples of hydraulic fracture modeling are shown in Figs. 2 and 3. One thing that analytical and numerical techniques have in common is their calculation of an idealized shape for the hydraulic fracture. This is due to the fact that these techniques conform to the inevitable geometrical underpinnings that are included in the assumptions made to develop these models. Most of the techniques either start, or end up, with reasonably well behaved hydraulic fractures (See Figs. 2—4). When these models are used in conjunction with reservoir simulation and modeling of shale formations (especially in the explicit frac modeling technique that will be covered in the next section), they usually pass on certain calculated parameters to the reservoir simulation that represent the impact of hydraulic fracturing on the formation. These calculated parameters are hydraulic fracture length, fracture height, fracture width and fracture conductivity. As discussed in the next section of this article, these parameters represent “Soft Data” and their major utility is to achieve a history match in the reservoir simulation model.
When it comes to shale, regardless of the technique used to model the impact of hydraulic fractures, the lessons learned have been eloquently articulated by King in a recent article (King, 2010). He identifies the following:

- No two shale formations are alike. Shale formations vary spatially and vertically within a trend, even along the wellbore.
- Shale “fabric” differences, combined with in-situ stresses and geologic changes are often sufficient to require stimulation changes within a single well to obtain best recovery.
- Understanding and predicting shale well performance requires identification of a critical data set that must be collected to enable optimization of the completion and stimulation design.
- There are no optimum, one-size-fits-all completion or stimulation designs for shale wells.

In the opinion of this author, King’s identification of the above lessons, after reviewing and citing a very large number of articles,2 indicates that current practices in modeling hydraulic fracturing and their impact on production from shale wells, leave much to be desired.

Stressing that shale formations are heterogeneous and that rock characteristics change, even throughout a single lateral, and that such changes in stress and reservoir characteristics must dictate modifications in stimulation design to obtain best recovery, points to a simple fact (that is a shortcoming in our industry’s practices) that many subscribe (at least in practice) to a “one-size-fits-all” strategy when it comes to stimulating shale wells.

Furthermore, he identifies the collection of a critical data set that should be used as the basis for the design of hydraulic fracturing. This article introduces the terms “Hard Data” and “Soft Data” in the context of hydraulic fracturing of shale wells to point to the set of data that is required, and should be used explicitly, in order to design optimum (fit for purpose) frac jobs for each stage in a given shale well.

4. “Hard Data” vs. “Soft Data”

“Hard Data” refers to field measurements. This is data that can readily be, and usually is, measured during the operation. For example, in hydraulic fracturing variables such as fluid type and amount, proppant type and amount, injection, breakdown and closure pressure, and injection rates are considered to be “Hard Data”. In most shale assets “Hard Data” associated with hydraulic fracturing is measured and recorded in reasonable detail and are usually available. Table 1 shows a partial list of “Hard Data” that is collected during hydraulic fracturing as well as a list of “Soft Data” that is used by reservoir engineers and modelers.

In the context of hydraulic fracturing of shale wells, “Soft Data” refer to variables that are interpreted, estimated or guessed. Parameters such as hydraulic fracture half length, height, width and conductivity cannot be directly measured. Even when software applications for modeling of hydraulic fractures are used to estimate these parameters, the gross limiting and simplifying assumptions that are made, such as well-behaved penny like double wing fractures, renders the utilization of “Soft Data” in design and optimization of frac jobs irrelevant.

Another variable that is commonly used in the modeling of hydraulic fractures in shale is Stimulated Reservoir Volume (SRV).

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2 In his paper King cites 270 articles about Shale and hydraulic fracturing.
SRV is also “Soft Data” since its value cannot be directly measured. SRV is mainly used as a set of tweaking parameters (dimensions of the Stimulated Reservoir Volume as well as the permeability value or values that are assigned to different parts of the stimulated volume) to assist reservoir modelers in the history matching process.

The utility of micro-seismic events (as it is interpreted today from the raw data) to estimate Stimulated Reservoir Volume is at best inconclusive. While it has been shown that micro-seismic may provide some valuable information regarding the effectiveness of multi-stage hydraulic fractures in Eagle Ford Shale (Inamdar et al., 2011), the lack of correlation between recorded and interpreted micro-seismic data and the results of production logs in Marcellus Shale has been documented (Ciezobka, 2012).

In some shale reservoirs such as Marcellus, as shown in Fig. 4, although the current interpretation of micro-seismic raw data shows locations in the reservoir where “something” is happening or has happened, it does not seem to have much to do with the most important parameter that all parties are interested in, i.e. production. The proven and independently verified value of micro-seismic as a tool for hydraulic fracture effectiveness in production is a debatable issue that remains to be settled as more data becomes available and is published.

Due to its interpretive nature “Soft Data” cannot be used as optimization variables. In other words, one cannot expect to design a particular frac job that results in a well behaved induced fracture with a designed half length, height and conductivity by tweaking the amount of fluid and proppant that is injected. Similarly, designing SRV (size and permeability) by modifying the amount of fluid and proppant that is injected during a frac job or by modifying the injection rate and pressure is not an option.3 Therefore, although “Soft Data” may help engineers and modelers during the history matching process, it fails to provide a means for truly analyzing the impact of what is actually done during a frac job.

5. Reservoir simulation and modeling of shale

Since reservoir simulation and modeling of shale formations became a task to be tackled by reservoir engineers, the only available option, and therefore the solution that has been presented, has been a modified version of existing simulation models. These modifications are made so that the existing simulators can mimic the storage and flow characteristics in shale. Although our information regarding the required characteristics of the simulation models were quite limited (combining Discrete Fracture Networks with Dual Porosity and Stress Dependent Permeability and adding concentration driven Fickian flow with Langmuir’s isotherms — all this does not include the impact of induced fractures), it did not stop us from going forward with the business of modeling. In other word, our choices, especially at the start of this process, were quite limited. Probably the main reason was that the industry was, and still is, in need of tools that can help in making the best possible decision during the asset development process. Although some interesting work has been performed, especially in the area of transport at the micro-pore level, they have not yet found their way into the popular simulation models that are currently being used by the industry.

The current state of reservoir modeling technology for shale uses the lessons learned from modeling naturally fractured carbonate reservoirs and those from Coalbed Methane (CBM) reservoirs in order to achieve its objectives. The combination of flow through double porosity, naturally fractured carbonate formation, and concentration gradient driven diffusion that is governed by Fick’s law integrated with Langmuir’s isotherms that controls the desorption of methane into the natural fractures, has become the cornerstone of reservoir modeling in shale. Most of the competent and experienced reservoir engineers and modelers that the author

3 Those who have opted to correlate “hard data” to Stimulated Reservoir Volume through micro-seismic events, are either technically too naive to realize the premature nature of this effort, or trying to justify a service that is provided by their business partners.
The presence of massive multi-cluster, multi-stage hydraulic fractures only makes the reservoir modeling of shale formation more complicated and the use of current numerical models even less beneficial. Since hydraulic fractures are the main reason for economic production from shale, modeling their behavior and their interaction with the rock fabric, becomes one of the most important aspects of modeling storage and flow in shale formations. Therefore, the relevant question that should be asked is: How do the current numerical reservoir simulation models handle these massive multi-cluster, multi-stage hydraulic fractures?

When all the dust settles and all the different flavors of handling massive multi-cluster, multi-stage hydraulic fractures in reservoir modeling are reviewed, all the existing approaches can be ultimately divided into two distinct groups. The first is the Explicit Hydraulic Fracture (EHF) modeling method, and the second is known as Stimulated Reservoir Volume (SRV).4 We will briefly discuss these techniques.

Before examining some details of the EHF and SRV techniques, it must be mentioned that there are a couple of other techniques that have been used in order to model and forecast production from shale wells. These are Decline Curve Analysis (DCA) and Rate Transient Analysis (RTA). These two methods are quite popular among practicing engineers for their ease of understanding and use.

Decline Curve Analysis (DCA) is a well-known and popular technology in our industry. The popularity of DCA is due to its ease of use (and in many cases it can be and is easily misused). When applied to shale wells DCA has many shortcomings. Several authors (Boulis et al., 2009; Cheng et al., 2010; Mattar et al., 2008; Johnson et al., 2009; Can and Kabir, 2012; Ikewun and Ahmadi, 2012) have come up with interesting techniques to overcome some of the well-known shortcomings of DCA, but nevertheless, many facts remains that make the use of Decline Curve Analysis suboptimal.

One of the major criticisms of Decline Curve Analysis is its lack of sensitivity to major physical phenomena in shale wells that has to do with the fluid flow, the hydraulic fracture, and the reservoir characteristics. In cases like Marcellus and Utica shale reservoirs where short periods of production are available, the use of Decline Curve Analysis becomes increasingly problematic.

Rate Transient Analysis (RTA) is a clever technology (Ilk et al., 2011; Al-Ahmadi et al., 2010; Anderson et al., 2010; Nobakht et al., 2010; Nobakht and Clarkson, 2012; Nobakht and Mattar, 2012; Bello and Wattenbarger, 2008) that approximates the essence of reservoir simulation and modeling using a series of analytical and graphical (plotting routines) approaches. RTA’s ease of use and consistency of results are among its strongest points. On the other hand, RTA suffers from the same problems as numerical reservoir simulation and modeling, since almost all of its approaches, especially when it forecasts production, mimics those of numerical modeling.

6. Explicit Hydraulic Fracture (EHF) modeling

When compared with other techniques, Explicit Hydraulic Fracture (EHF) modeling is the most complex and tedious (as well as the most robust) approach for modeling the impact of hydraulic fracturing during numerical simulation of production from shale. The Explicit Hydraulic Fracture (EHF) modeling technique of reservoir simulation and modeling of shale wells couples three different technologies (software applications) and includes the following steps:

1. Modeling the impact of the hydraulic fracture: during this step each cluster of hydraulic fracture is modeled individually using independent hydraulic fracture simulation software applications such as MFrac,5 FracPro,6 etc. These models use the frac job characteristics (recipe) such as fluid and proppant amount

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4 Some have chosen to use alternative nomenclature such as Estimated Stimulate Volume (ESV) or the Crushed Zone.


and rate of injection, along with some reservoir characteristics and stresses, and calculate the characteristics of an idealized hydraulic fracture.

Since these models assume a well-behaved penny-shaped (albeit a deformed penny from time to time – see Figs. 2, 3 and 5) hydraulic fracture, the characteristics they calculate are fracture half length, fracture height, fracture width, and fracture conductivity. This process is repeated for every single cluster of hydraulic fractures. This means that in some cases up to 60 to 70 hydraulic fracture clusters per well (about three clusters per stage) need to be modeled independently.

2. Developing a geological model: as in all other serious reservoir simulation and modeling exercises, developing a geological model is a necessary step in the numerical modeling of production from shale. During this step all the geological, petrophysical and geophysical information available to the modeling team is used to develop a reasonably detailed geological model. Even for a single well model this process may generate a detail multi-million grid block geological model. Usually data from all the available wells are used to generate the structural map and volume that is then populated with appropriate data based on availability. This process is usually performed using a geological modeling software application, several of which are currently available in the market and are extensively used during the modeling process. Inclusion of Discrete Fracture Network (DFN) in the modeling process is usually performed during this step. The common approach is to develop the DFN using statistical means and then use analytical or numerical techniques to incorporate the impact of the developed DFN into the existing grid block system developed during the construction of the geo-cellular model.

3. Incorporation of frac characteristics in the geological model: in order to incorporate the hydraulic fracture characteristics into the geological model, first all the wellbores must be included. Upon inclusion of the well bore, all the calculated characteristics from step 1 (hydraulic fracture impact), are imported into the geological model (step 2). This is a rather painstaking process through which the grid system developed during geological modeling is modified in order to be able to accommodate the hydraulic fracture characteristics. Usually a local grid refinement process is required (both horizontally as well as vertically) for this process. The result is usually a detailed model that includes a large number of grid blocks. When building a model that includes multiple pads and wellbores this process may take a long time. Due to the detailed nature of the model, the computational cost of such models is too high. This fact makes full field modeling of shale assets impractical. That is the main reason behind the fact that the overwhelming number of numerical simulation studies conducted on shale formations are single well models. From time to time one may find studies that are performed on a pad of multiple horizontal wellbores rather than a single well, but such studies are few and far between.

4. Completing the base model: completion of the base model usually requires some up-scaling and incorporation of operational constraints. Identification and incorporation of appropriate outer boundary conditions and making a first run to check for convergence are among the other steps that need to be taken for the completion of the base model.

5. History matching the base model: once the base model is completed and runs properly, the difference of its results from the observed measurements (e.g. production rates) indicates the proximity of the model to where it needs to be. During the history matching process, geological and sometimes hydraulic fracture characteristics are modified until an acceptable history match is achieved.

6. Forecasting production: the history matched model is executed in the forecast mode in order to predict future production behavior of the shale well.

A survey of most recent publications shows that many modelers have selected not to use the Explicit Hydraulic Fracture (EHF) modeling methodology. This may be attributed to degree of detail that goes into building and then history matching an Explicit Hydraulic Fracture (EHF) model for shale wells. The amount of time it takes to complete the above steps for a moderate number of wells can be quite extensive. Imagine trying to build a full field model where tens or hundreds of wells are involved. The size of such a model can (and usually does) make running it computationally prohibitive.

7. Stimulated Reservoir Volume (SRV) modeling

The second technique for modeling production from shale wells is known as Stimulated Reservoir Volume (SRV) modeling technique. Stimulated Reservoir Volume (SRV) modeling technique is a different and much simpler way of handling the impact of massive multi-cluster, multi-stage hydraulic fractures in numerical reservoir simulation and modeling. Using SRV instead of EHF can expedite the modeling process by orders of magnitude. This is due to the fact that instead of meticulously modeling every individual hydraulic fracture, in this method the modeler assumes a three dimensional volume around the wellbore with enhanced permeability as the result of the hydraulic fractures (see Figs. 6 and 7).
modifying the permeability and dimensions of the Stimulated Reservoir Volume (SRV), the modeler can now match the production behavior of a given well in record time.

The first question that comes to mind upon understanding the impact of the Stimulated Reservoir Volume on production is how one would calculate, or more accurately, estimate, the size of the Stimulated Reservoir Volume. Given the fact that Stimulated Reservoir Volume results from hydraulic fractures, the next question that comes to mind is whether the SRV is a continuous medium or it has discrete characteristics for each hydraulic fracture and whether or not these discrete volumes are connected to one another. Furthermore, how are the aspect ratios (ratio of height, to width and to length) of the Stimulated Reservoir Volume determined?

In some recent publications and presentations, the concept of Stimulated Reservoir Volume (SRV) has been linked to micro-seismic. In other words, it is advocated that by collecting and interpreting micro-seismic data and identifying micro-seismic events in a shale well that has been subject to multi-stage hydraulic fracturing, one can estimate the size of the Stimulated Reservoir Volume. As we mentioned in the previous section, it should be noted that the evidence that supports such claims is countered equally by evidence that negates it. Furthermore, it has been shown that misinterpreting the size of the Stimulated Reservoir Volume can result in large discrepancies in forecasting the potentials of a given well (See Fig. 8). It is a well-established concept that productions from shale wells to a large degree are a function of the amount and the extent of contact that is made with the rock. Therefore, the notion of production being very sensitive to estimation of the size and conductivity of the Stimulated Reservoir Volume is logically sound.

The sensitivity of production from shale wells to the size and the conductivity assigned to the Stimulated Reservoir Volume explains the uncertainties associated with the forecasts that are made using this technique. Although there have been attempts to address the dynamic nature of the SRV by incorporating Stress Dependent Permeability (opening and closure of the fractures as a function of time and production), the entire concept remains in the realm of creative adaptation of existing tools and techniques to solve a new problem. In the opinion of the author, while SRV serves the purposes of modeling and history matching the observed production from a well, its contribution to forecasting the production (looking forward) is questionable at best. Furthermore, SRV techniques are incapable of making serious contribution to designing an optimum frac job specific to a given well (looking backward).

8. Full field reservoir simulation and modeling of shale

A quick look at the history of reservoir simulation and modeling indicates that developing full field models (where all the wells in the asset are modeled together as one comprehensive entity) is the common practice for almost all prolific assets. There are many reasons that full field models are developed for prolific assets. Reasons for developing full field models include using the maximum static (geologic, geo-physics, and petrophysics) information available to build the underlying high resolution geological model as well as capturing the interaction between wells.

Looking at the numerical reservoir simulation modeling efforts concentrated on shale assets, one cannot help but to notice that almost all of the published studies are concentrated on analyzing production from single wells (Bazan et al., 2010; Chaudhri, 2012; Meyer et al., 2010; Cipolla et al., 2010a, 2010b; Samandarli et al., 2011). There are only two published papers that discuss larger...
The same pad as well as the laterals from offset pads. The idea is shown that the communication takes place between laterals from shale wells do communicate with one another during production. It merely an excuse with limited merit. It is well-established that acreage and/or limited engineering resources), the second reason is required for performing full modeling (specifically for independents, or companies with limited acreage and/or limited engineering resources), the second reason is merely an excuse with limited merit. It is well-established that shale wells do communicate with one another during production. It is shown that the communication takes place between laterals from the same pad as well as the laterals from offset pads. The idea of “Frac Hit” is a common occurrence of such interaction. Furthermore, our studies of full field shale assets have clearly shown the impact on production and interaction between offset pads, offset wells, and offset frac stages. Fig. 9 is a “Frac Hit” example from Marcellus Shale.

Therefore, in order to take maximum advantage of the investment that is made and the data that is collected during the field development in a shale asset and to capture interaction between wells and the impact of reservoir discontinuities (faults) on production, it is important to develop full field models for shale assets. Since a comprehensive full field model for a shale asset may require tens (if not hundreds) of millions of grid blocks (for numerical simulation), one may have to look elsewhere for alternative solutions. Data-Driven modeling may prove to be such an alternative.

9. Data-driven modeling of production from shale, an alternative solution

Since analytical and numerical modeling of “full field” shale assets is either impractical, or leaves much to be desired, data-driven modeling may provide an alternative solution. The argument to justify a fully data-driven approach to this problem is as follows: since we do not fully understand the physics of production from shale in the presence of massive hydraulic fractures, therefore, all of our current modeling practices are essentially proxy modeling of this process, each to a different degree. Consequently, why not use the holy grail of proxy approaches to modeling, i.e. data-driven modeling, to its fullest potential.

Top–Down Modeling (TDM) is the application of predictive data-driven analytics to reservoir modeling and reservoir management. Top–Down Modeling (TDM) is a form of proxy modeling that was introduced a few years ago (Mohaghegh, 2009) and was recently applied to several shale formations (Mohaghegh et al., 2012). A reasonably comprehensive application of Top–Down Modeling (TDM) to a Marcellus Shale asset in Southwestern Pennsylvania was recently published (Esmaili et al., 2012a and Esmaili et al., 2012b). A short review of this study is used in this manuscript to describe the data-driven solution as an alternative to full field analytical and numerical reservoir modeling/management of shale assets.

Top–Down Modeling (TDM) has been defined as a formalized, comprehensive, and full field, empirical reservoir modeling approach that is specifically geared toward reservoir (asset) management. In Top–Down Modeling, measured field data (and not
interpreted data) is used as the sole source of information to build a full field asset model, treating and history matching each well individually. This approach minimizes interpretation of the data and invests heavily on all that we know and measure in the field.

TDM uses the production history of each individual well in the asset (oil, gas and water) along with well-head pressure. The production data is augmented by all the “Hard Data” that is collected during drilling, logging and completion of each well. Data used during TDM include well locations, depth, lateral length, number of stages, number of perforations, distance between stages, well logs (gamma ray, density, TOC, SP, Sonic, porosity, etc.), cores and well tests. All the parameters (“Hard Data”) that are measured during the hydraulic fracturing process are incorporated into TDM, such as type and amount of fluids that is injected, type and amount of proppants as well as injection pressure (ISIP, breakdown pressure, maximum pressure, average pressure, closure pressure) and corresponding injection rates. The Top—Down Mode (TDM) is history matched for every single well in the asset. Once training, calibration and validation of a Top—Down Model (TDM) is completed, its utilization is similar to a conventional full field model.

The Top—Down Modeling (TDM) of the Marcellus Shale asset of Southwestern Pennsylvania included 43 pads, consisting of 135 horizontal wells (about 1200 stages and 3600 clusters of hydraulic fracturing). During the Top—Down Modeling, well, reservoir, completion and frac parameters were integrated and correlated with the production profile of individual wells. Fig. 10 shows the results of history matching on several individual wells and Fig. 11 shows the history matching results for the entire asset. Since every individual well is history matched, the degree of hydraulic fractures’ effectiveness can be compared between all the wells in the asset.

The final Top—Down Model has a small enough computational footprint to allow a comprehensive sensitivity analysis. Results of some of the sensitivity analyses performed on a specific pad are shown in Fig. 12.

The advantages of using data-driven technology to perform reservoir modeling are i) no assumptions are made regarding the physics of the storage and production of hydrocarbon in shale; ii) “Hard Data” is used to perform modeling instead of “Soft Data”; iii) use of “Hard Data” instead of “Soft Data” makes it possible to use this model (solving the inverse problem) for the purposes of

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Fig. 10. History match of individual wells in a Marcellus Shale asset that included 135 horizontal wells. In all the plots the Y axis on the left is monthly rich gas production (orange diamonds are field production and green circles are TDM) and the Y axis on the right is cumulative rich gas production (Orange shade is field cumulative production and green shade is model) and the X axis is time (date) — (Esmaili et al., 2012a). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

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9 Another advantage of Top—Down Modeling is that instead of flowing bottom-hole pressure, wellhead pressure can be used in the analysis, as long as the wellbore configurations in all the laterals are similar. In case the wellbore configurations are different, their diversity will also become input to the model.
designing optimum frac jobs; iv) small computational foot print allows full field analysis as well as sensitivity and uncertainty analyses; v) more wells and more data make model development more reliable and more robust.

The disadvantages of using data-driven technology include i) not being able to explicitly explain the storage and transport phenomena in the shale; ii) data-driven modeling is not applicable to an asset with small number of wells (about 10–20 wells are required to start data-driven modeling); iii) long term prediction of the production from a given well (asset) is not a simple and straightforward process.

10. Concluding remarks

As more wells are drilled in shale formations, reservoir engineering, modeling and reservoir management are gaining their rightful place in the asset management of this important energy resource. As reservoir management finds its place in shale, it is
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