A case for shale optimization

Kevin McKenna* argues that with the large scale of drilling programmes common in today's onshore shale plays, relatively small optimization of workflows in all stages of the field life cycles can have a dramatic multiplied effect on the economic viability of projects.

The unprecedented growth of shale plays in the E&P industry has brought a new perspective and focus to the familiar challenge of integrating the geoscience and engineering disciplines. Unconventional drilling programmes go forward at a relentless pace to meet production goals and maintain leasing rights onshore, creating overwhelming amounts of production data. Historical well data is plentiful in most cases, but varying levels of vintage and quality make data selection and quality control a challenge. 2D or 3D seismic data may or may not exist in areas of interest and acquisition, and processing of new data may not be practical in a timeframe that can make a meaningful impact on a project. Even when 3D seismic is available, geoscientists often struggle to show its relevance to their engineering colleagues in a world dominated by rig and stimulation schedules.

Because tens and even hundreds of wells are drilled in a typical shale play annually, relatively small optimizations of E&P processes and data can be multiplied to have great effect on economic success or failure of a project. In the context of shale plays, geoscience workflows must be tuned to integrate and interpret large volumes of valuable production data from the field and deliver operationally useful feedback in a meaningful timeframe. Optimal performance can be achieved through smart use and acquisition of fit-for-purpose data in an integrated model that can be updated just in time. The model should provide up-to-date and predictive information about key operational issues including geosteering, well location, stimulation, and completion design.

How can such a holistic model be created and maintained to be highly useful operationally? All available data must be efficiently obtained and parsed for its relevant value. Accurate depth horizons for target formations is a key early step for understanding the play, so velocity modelling and depth conversion is important. When 3D seismic data is available, it may provide valuable information about reservoir quality and fracture effectiveness, as well as information about stratigraphy and reservoir architecture. When 3D seismic data is unavailable or of insufficient quality, new time- and cost-efficient technologies like borehole seismic imaging (BSI) and wellbore trajectory imaging (WTI) can provide high-resolution, localized seismic detail for operational decision support.

As reservoir understanding increases, tangible correlation between seismic data and rock physical properties can be established and integrated in a 3D reservoir model useful for reservoir simulation and matching of historical production. Information about stimulated hydraulic fractures from net pressure mapping, production logs, radioactive and chemical tracer data, and fracture mapping from microseismic data should be incorporated in the model as it is acquired. This pragmatic connection between geoscience and operational data is a key requirement to keep models useful and relevant in shale plays.

Data: what do we have and what can we get?

According to Albert Einstein, 'the mere formulation of a problem is far more important than its solution.' To correctly formulate the problem for any shale play the data must first be assessed for content and quality. Many shale plays were once the source rocks for very old conventional onshore plays. Well data may go back 100 years or more, and much of it may contain antique logs and little interpretation. Only a few wells may actually penetrate the formations of interest.

Unfortunately, wells drilled more recently with modern log suites are often located in the same place as older, less useful wells. The wheat must be separated from the chaff to find a subset of historical wells that will provide meaningful information about today's shale play. Then rigorous petrophysical analysis and editing should be performed on the logs to make sure they are useful for the purpose at hand. This may include tying seismic to wells, formation quality assessment, and facies and petrophysical analysis.

Seismic data must also be assessed. Is surface 3D seismic available? Is it of sufficient quality to image the formation of interest for the purpose of geosteering? Even when the answer to the first question is yes, the answer to the second is most often no. When no useful seismic data is available, the decision is often made to go without or to acquire some new surface 3D data, which may take up to two years acquire and process. Drilling without seismic can be risky in stratigraphically and structurally complex areas with relatively thin target zones that are all too common in shale plays. An often overlooked, but practical, alternative is to acquire borehole seismic imaging (BSI) and wellbore trajectory imaging (WTI).

* *SIGMA³ Integrated Reservoir Solutions. E-mail: k.mckenna@sigmacubed.com*

Borehole seismic imaging

3D BSI is a technique designed to acquire high-frequency seismic images downhole in a timeframe that provides material value during the operational activity of drilling a horizontal well. Similar in concept to 3D VSP, 3D BSI has significant advantage over VSP in both image quality and time-to-image. For both 3D and 2D BSI, a vertical array of geophones is placed into the vertical component of a horizontal well just after it is cased, but before the horizontal component is drilled. Vibrator sources are activated along existing infrastructure (often drilling roads) and the vertical array is removed from the well. The seismic data is then processed and a seismic image is created.

From entry in the vertical well to delivery of processed data, this process takes about 48 hours. Frequency content of the BSI image has been shown to be at least two times that of surface seismic in the same area (Figure 1). Most importantly, by acquiring data near the reservoir, BSI and WTI have the advantage of observing seismic waves below attenuating geologic formations that may deteriorate signal quality of surface seismic. BSI and WTI images have proven to be very useful for geosteering wells in areas with small faults and subtle stratigraphic complexity. BSI also adds valuable frequency content enhancement to 3D surface seismic for the enhancement of seismic attributes which could lead to improved near wellbore reservoir models.

Haynesville Wellbore Trajectory Imaging case study

In Louisiana's Haynesville formation, small faults can alter the optimum trajectory of the well bore. WTI is a 2D application of BSI directed along the planned trajectory of a horizontal well. In this case, WTI provided a timely image used to alter the planned trajectory of a horizontal well to account for a small fault that changed the local dip of the reservoir that would otherwise have caused the horizontal to go out of zone (Van Dok et al., 2012).

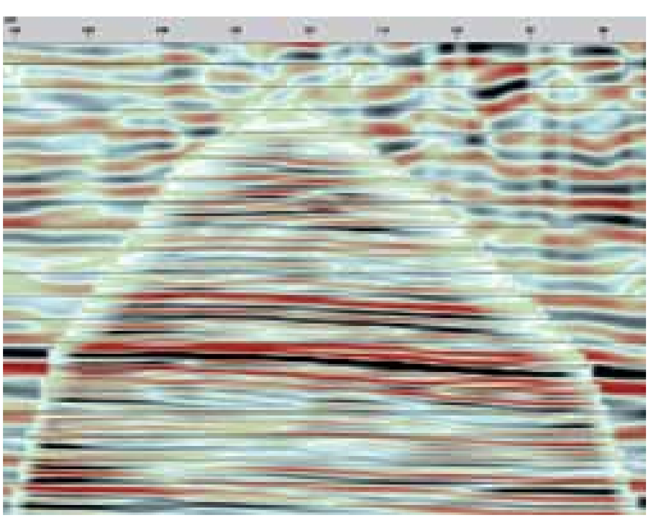

Figure 1 This image shows 3D BSI inside 3D surface seismic. Note the significantly higher resolution of the BSI data.

The design and planning of this survey included a complete illumination analysis to confirm that the target reservoir depth would be properly imaged, as well as a detailed acquisition work plan that corresponded to the drilling of the well. The goal was to occupy the vertical section of well after the casing was completed, but prior to the drilling of the horizontal phase.

The survey design included two setting depths of an 80-level geophone array and 49 vibrator source point locations that would be occupied twice. Upon data acquisition, the raw field data were delivered to the processing center via satellite for immediate processing. The data quality was very good and preliminary processing proceeded without any significant issues. An important factor in the success of this project was the high-resolution result obtained from the time-domain method used for imaging. This method preserved the highest frequencies created by the vibrator source (8–80 Hz sweep) and highlighted small discontinuities in the reservoir.

Key to this method is the upward-continuation process that produces pseudo-receivers at the surface of the earth that can then be processed using conventional processing algorithms, such as surface-consistent statics, surface-consistent deconvolution, and time-domain NMO velocity analysis. Once statics and velocities are resolved, the data are migrated using a standard pre-stack time-domain Kirchhoff algorithm. After migration, the data are analyzed for residual moveout, muted, and stacked and final data filtering and enhancements are applied. For this project, the final time-domain image was delivered for interpretation two days after the data arrived in the processing center.

Interpretation of the 2D time-domain image took only hours and clearly showed that a relatively small fault existed along the length of the planned lateral (Figure 2). It also indicated that original well trajectory, based on the regional dip determined from well control and nearby 2D surface seismic, was inappropriate for the subtle local variations present near this well location. Adjustments to the well trajectory were made and subsequent drilling resulted in the wellbore staying in-zone throughout the entire length.

Large geophone arrays and high-resolution processing methods provided the technical means for producing a useful image, but the timing of the entire effort made it both a technical and commercial success and more importantly, costly drilling mistakes were avoided.

Subsurface modelling

Once the initial data has been identified and subjected to substantial quality control, a dynamic model can be constructed. This model is 'dynamic' not in the flow simulation sense of the word, though that can be part of the process,

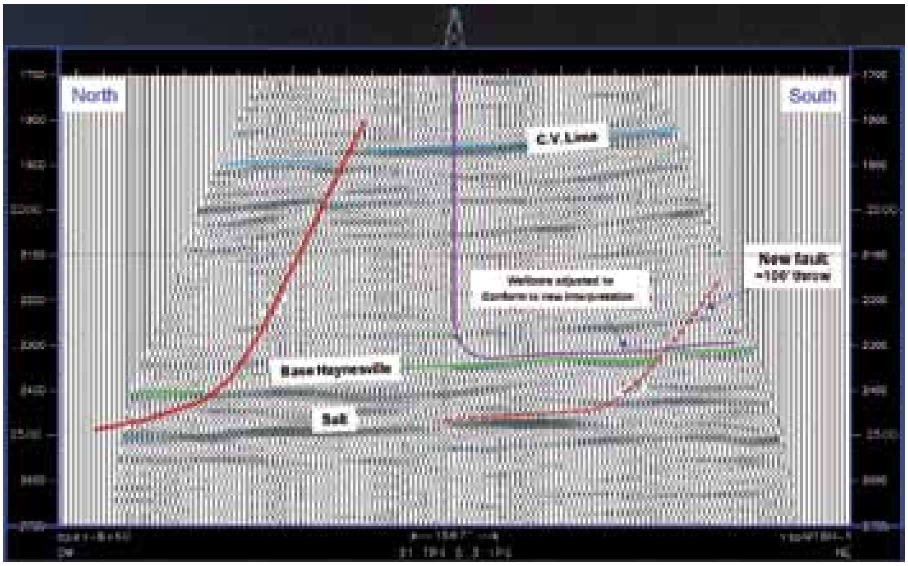

Figure 2 *Interpretation of the final time-domain image showing the location of the target Base Haynesville and the new fault that was interpreted to intersect the planned wellbore.*

but rather in the sense that it will evolve through time as better understanding and new data are acquired. In the fast-paced world of shale play development, it is important to make time-sensitive decisions based on the best information and understanding available at the time. Many expensive decisions will often be made before any full 3D reservoir study can be conducted. It is an important first step to generate a reliable depth horizon for the top of the target formation.

As new data is acquired and subsurface understanding increases, the dynamic model must grow to address more complicated issues. What role do total organic content (TOC), rock brittleness, porosity, closure stress, natural fractures, and pore pressure play in the success of a well? An integrated, scientific approach to identify and interpret key factors and unlock the resource potential of the play is critical to achieving a model that can be predictive in an operational setting.

By maximizing the insight gained from each available data type, dynamic subsurface models identify and predict reservoir rock that meet the necessary criteria for highly successful wells. Success criteria are established through knowledge of rock-physics properties and correlation to production information, plus local knowledge of the field. Wells planned and completed using this type of integrated model minimize risk of poor performance due to poor reservoir quality and significantly increase average IP rates and EURs.

Niobrara subsurface model

A dynamic subsurface modeling workflow was recently applied in the US Teapot Dome area on the Niobrara shale interval with the goal of understanding production drivers and optimizing future well placement (Ouenes, 2012). The data in this area is fairly limited – only 15 wells with sonic and density logs and only one core with some porosity and permeability measurements were available. Fortunately, 3D post- and pre-stack seismic was available over the entire area and a full analysis of the available data could be performed.

During the course of this study, different post-stack seismic processes were applied to the 3D seismic, including several deterministic and stochastic post-stack inversions, spectral imaging, and volumetric curvature. Each seismic process extracts a different aspect of the information contained in the post-stack seismic that was then used in the dynamic modeling process. Key seismic horizons and faults were interpreted in time and used to build a 3D geocellular grid.

A velocity model was carefully constructed from the seismic data and sonic logs at the wells, which was then used to depth convert the grid. Too often the velocity model is a key source of uncertainty in subsurface models. By examining the velocity functions, their effects on gathers, and the relationship to well seismic measurements, uncertainty in depth can be greatly mitigated.

Because naturally occurring fractures have been documented as potential drivers of production in the Teapot Dome area (Cooper et al., 2006) proprietary continuous fracture modelling (CFM) technology was incorporated into the workflow. A fracture indicator log was created based on well log and core data and was subsequently correlated to an optimized combination of seismic attributes using a patented workflow involving supervised neural networks. The CFM model accurately predicts the location, orientation, and density of fractures.

In this case, modelling showed that selected spectral imaging attributes, curvature, and impedance all played a meaningful role in predicting natural fractures. When using

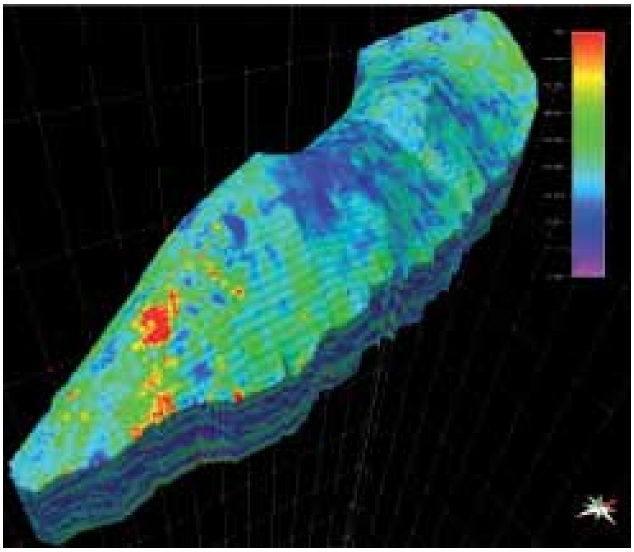

Figure 3 *3D distribution of Brittleness in the Steele and Niobrara shale at Teapot Dome, derived from the Extended Elastic Inversion.*

pre-stack data and elastic inversion, rock mechanical properties, such as lambda rho, mu rho, and the derived rock brittleness, allow an accurate modelling of the key rock properties that influence stimulation success and ultimately the performance of the well. Extended elastic inversion was performed, which provides high-resolution Vp, Vs, and density and additional rock properties that were inverted directly from the pre-stack data.

The dynamic subsurface modelling workflow created 3D models of permeability, porosity, fracture orientation, and fracture density. By testing these modelled properties against blind wells – wells which exist and have all relevant data but are not used in the modelling process – good confidence was established in the predictive capability of the work. A strong correlation was shown to exist between known historical production in the field and the 3D permeability model. Because permeability is strongly tied to natural fracture density in the model, natural fractures were determined to be an important driver for Niobrara production in the Teapot Dome area.

Further modelling of well productivity used cumulative oil production as a proxy for fracture density around the wells. Using only 2D maps of key rock properties and seismic attributes, it was possible to derive a map showing cumulative oil in place for the area of interest. Once sweet spots are identified, at least one more major component of the 'shale puzzle' must be addressed. If great reservoir rock is too ductile for successful hydraulic fracture stimulation, the well will not perform well. By incorporating the brittleness model derived from the elastic seismic attributes, it is possible to identify rocks with good reservoir properties that also have brittleness sufficient for successful frac jobs (Figure 3). The resulting model identifies the optimal locations for wells and completions with significantly mitigated subsurface risk.

Microseismic fracture mapping

For the dynamic subsurface model to become predictive and operationally useful, it must incorporate information about hydraulic fractures location, orientation, and size. One useful tool for acquiring that information is microseismic fracture mapping. Ideally, a dynamic subsurface model will update in real time when fracture mapping events are received and processed so that the information can be used to support decisions in real time during completion. For that to occur, confidence in the acquisition and processing of microseismic fracture mapping must be established.

Many different methodologies exist for microseismic acquisition and processing, and though they all share some similarities the differences are crucial to the reliability of

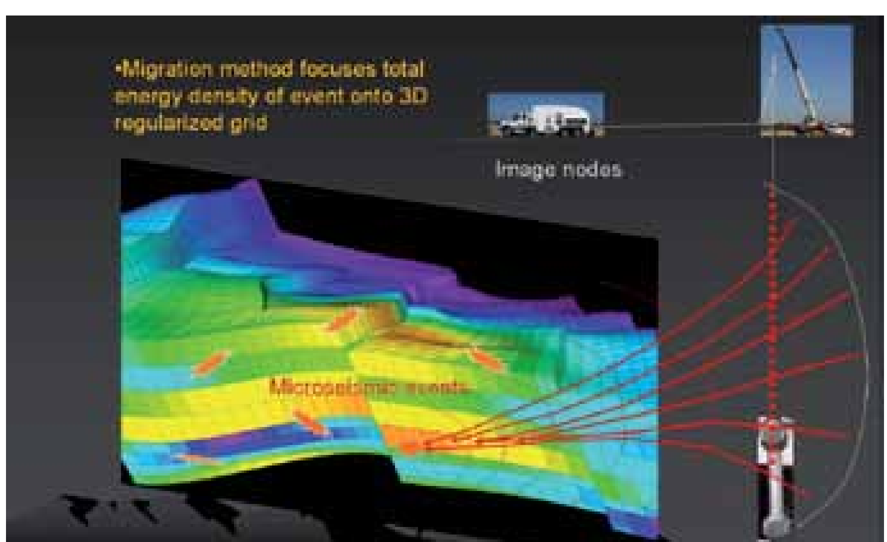

Figure 4 *In a dynamic subsurface model integrating production information, this diagram shows SIGMA³ Microseismic technology using a full 3D anisotropic velocity model for microseismic processing.*

microseismic events as they are reported. Conventional microseismic event location methods consist of simplistic earthquake-like detection calculations. Alternatively, we recommend the APEX methodology, using advanced Kirchhoff depth migration principals and diffraction stacking location solutions. The volume around the treatment wellbore is gridded with image nodes (Figure 4) based on velocity modelling using available sources such as VSP, perf shots, etc. Interactive migration solutions test each node in the model volume as the unique location solution for each seismic event. This comprehensive analysis algorithm produces a repeatable reliable location for every microseismic event.

The microseismic fracture mapping provides locations and magnitudes of events related to the microseismically-stimulated rock volume (M-SRV). In order to constrain the M-SRV with engineering data, the dynamic subsurface model will calibrate the seismically interpreted M-SRV against net pressure mapping from stimulation completion data. The resulting solution, while not unique, is engineered to provide more accurate M-SRV than seismic alone can provide. The contribution of drilling, completions, and stimulation engineers should not be overlooked in the dynamic modelling process as they often have key subsurface knowledge that should be captured.

Conclusion

Given the large scale of drilling programmes common in today's onshore shale plays, relatively small optimization of workflows in all stages of the field life cycles can have a dramatic multiplied effect on the economic viability of projects. In thriving shale plays operators may employ upwards of 20 rigs daily to drill new wells. Production and completion data is being acquired at a staggering rate with valuable insight to be harnessed with proper methodologies and technologies. Shale play optimization is attainable through smart use and acquisition of fit-for-purpose data in an integrated dynamic modelling workflow that can be updated just in time. Key technologies at each stage of the workflow can drive stand-out performance in the unconventional shale realm.

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