

# Vaca Muerta Shale—Taming a Giant

Unconventional resource plays revolutionized oil and gas production in North America. Because these types of plays provide many challenges to operators, they have been slow to develop in other parts of the world. However, the Vaca Muerta formation in the Neuquén basin of Argentina can now be added to the list of successful producers. The triumph in the Vaca Muerta play resulted from engineers at YPF, SA and Schlumberger collaborating on an integrated approach that includes field- and formation-specific workflows and the application of a dynamic unconventional fracture model to optimize hydraulic stimulation programs.

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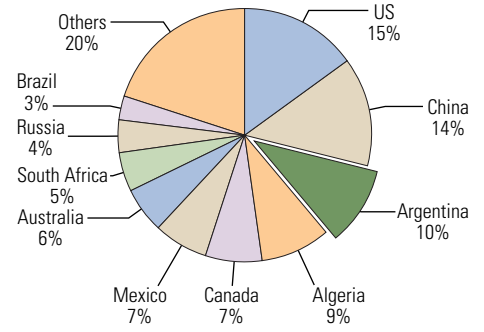
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Coaxing commercial quantities of hydrocarbons from unconventional reservoirs revolutionized the oil and gas industry in North America. The lessons learned there are now being applied in other parts of the world. One of the latest success stories comes from the giant Neuquén basin of Argentina, where YPF, SA is developing the Vaca Muerta Shale formation for production of oil and natural gas.

Production from shale reservoirs traces its roots to activities in the Barnett Shale of north-central Texas, USA. In 1981, Mitchell Energy & Development Corporation drilled a well for the express purpose of producing natural gas from the Barnett Shale; the company then spent 20 years figuring out how to make the play commercially viable. Success in the Barnett was followed by the deployment of new techniques and technologies to find and produce natural gas and then oil from other basins and formations across North America. Recent success in the Neuquén basin of South American has the potential to revolutionize the oil and gas industry in that region in a manner similar to that experienced in North America.

Argentina's unconventional resource plays have been recognized by exploration companies for some time. The Vaca Muerta formation is considered by many experts to have some of the greatest potential for hydrocarbon production in the world (Figure 1). One independent study compared shale resource potential outside North America and ranked the Vaca Muerta formation third globally in technically recoverable gas and fourth in oil.<sup>1</sup>

**Technically Recoverable Shale Gas**



**Technically Recoverable Shale Oil**

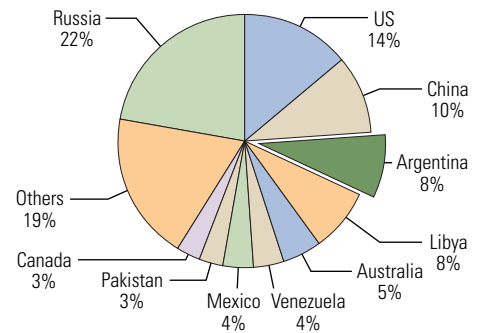


Figure 1. Global shale resources. Argentina has abundant reserves in unconventional reservoirs. Globally, the country is third in technically recoverable shale gas reserves (top) and fourth in technically recoverable shale oil (bottom). The majority of Argentina's unconventional reserves are associated with formations in the Neuquén basin. (Adapted from the US EIA, reference 1.)

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1. US Energy Information Administration (EIA): "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States," Washington, DC: US Department of Energy EIA, June 2013.



Several operators are evaluating the Vaca Muerta play; YPF, however, has been the most active and successful in initiating production to

date. The company established early on that the play has unique characteristics that affect development programs. The fact that the Vaca Muerta

formation has reservoir-specific characteristics that differ from other shale plays comes as no surprise; operators of shale resource plays generally agree that, to maximize production, each play must be approached and evaluated based on its own intrinsic merits. The Vaca Muerta Shale possesses features that enhance its potential to deliver financially viable volumes of hydrocarbons.

To maximize production and reduce the development cycle of the play, engineers at YPF are now using fracture simulators, predictive numerical models and field-specific workflows created from information derived during an extensive evaluation program. The process is helping them understand the effects of rock mechanics on fracture propagation during hydraulic stimulations. The information gained from their workflows and simulations is then used to optimize well spacing, fracture stimulation designs and fracture treatments. The methodology has helped the engineering team reduce the development time of the play compared to the time taken by iterative approaches typically used in other shale developments.

The methodology YPF has taken in developing the Vaca Muerta formation is driven in part because the formation has a combination of factors that differentiates it from other plays: a high pore pressure, a complex stacking pattern of varying lithologies and geomechanical complexity arising from the close proximity of the Neuquén basin to the Andes Mountains. The engineers at YPF have also found fracture gradients in some parts of the basin that are abnormally high, which greatly impacts completion strategies. A thorough understanding of the Vaca Muerta formation's geomechanics and reservoir heterogeneity is crucial for proper field development. With these many factors in mind, YPF has started to move from a traditional, and often costly, trial-and-error methodology of developing resource plays to a model-and-optimize methodology.

This article provides a basic overview of the Vaca Muerta formation and YPF's work in the play to date. The article also reviews workflows devised by the YPF and Schlumberger teams and the simulation programs that are used to optimize both drilling operations and stimulation treatments and briefly discusses current production and future development plans.

### In the Shadow of the Andes

The Neuquén basin lies on the east flank of the Andes Mountains in west-central Argentina (Figure 2). Oil was first discovered there in 1918.<sup>2</sup> The basin is a major source of oil and gas

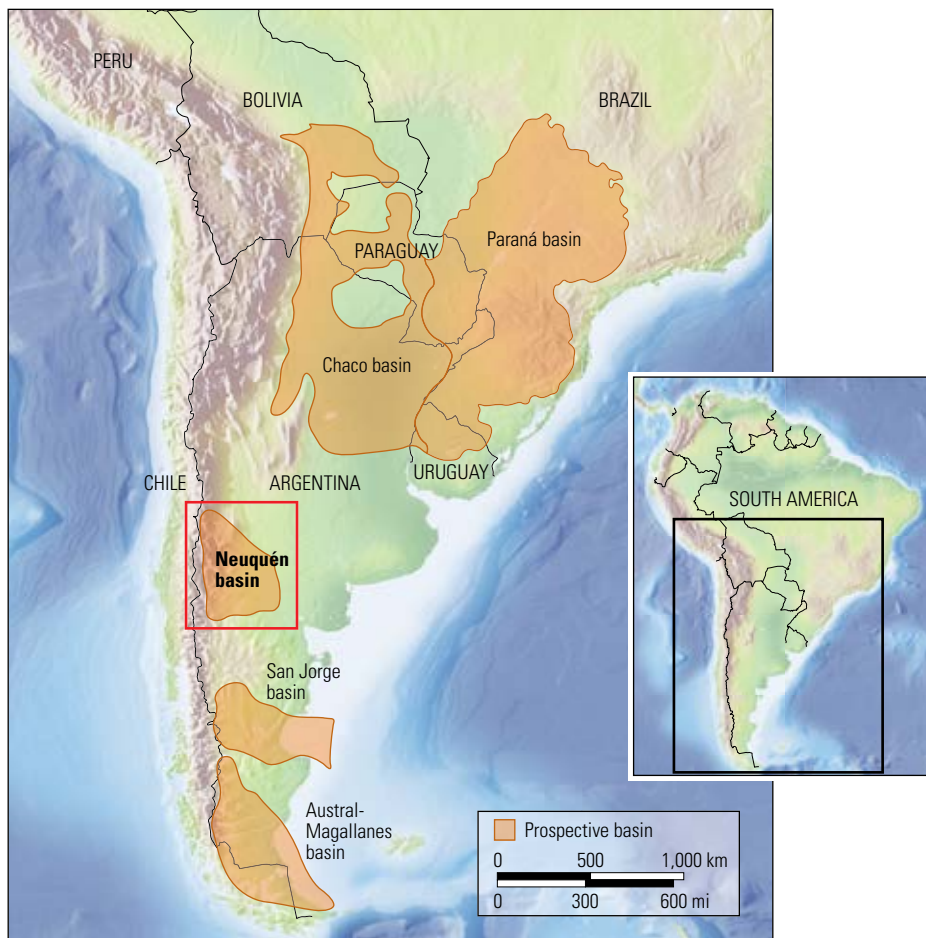


Figure 2. Neuquén basin. Several basins in South America have potential as unconventional resource plays. The Neuquén basin, in west-central Argentina (red box), is the major source of oil and gas production for the country and contains three deepwater marine shale deposits—the Agrio, Vaca Muerta and Los Molles formations. These shales act as source rocks for oil and gas deposits found in conventional reservoirs in the basin.

2. Hogg SL: "Geology and Hydrocarbon Potential of the Neuquén Basin," *Journal of Petroleum Geology* 16, no. 4 (October 1993): 383–396.
3. Instituto Argentino del Petróleo y del Gas, <http://www.iapg.org.ar/suplemento/Agosto2015/Produccion%20por%20cuencas.html> (accessed October 30, 2015.)
4. Back-arc basins are geologic features associated with island arcs and subduction zones. Found at convergent plate boundaries, they form when one tectonic plate subducts beneath another, creating a trench. Subduction zones are frequently associated with formation of volcanoes and seismically active areas.
5. Hogg, reference 2.
6. Garcia MN, Sorenson F, Bonapace JC, Motta F, Bajuk C and Stockman H: "Vaca Muerta Shale Reservoir Characterization and Description: The Starting Point for Development of a Shale Play with Very Good Possibilities for a Successful Project," paper SPE 168666/URTeC 1508336, presented at the Unconventional Resources Technology Conference, Denver, August 12–14, 2013.
7. Howell JA, Schwarz E, Spalletti LA and Veiga GD: "The Neuquén Basin: An Overview," in Veiga GD, Spalletti LA, Howell JA and Schwarz E (eds): *The Neuquén Basin, Argentina: A Case Study in Sequence Stratigraphy and Basin Dynamics*. London: The Geological Society, Special Publication 252 (2005): 1–14.
8. Badessich MF and Berrios V: "Integrated Dynamic Flow Analysis To Characterize an Unconventional Reservoir in Argentina: The Loma La Lata Case," paper SPE 156163, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 8–10, 2012.
9. For more on geochemical characterization of source rocks: McCarthy K, Rojas K, Niemann M, Palmowski D, Peters K and Stankiewicz A: "Basic Petroleum Geochemistry for Source Rock Evaluation," *Oilfield Review* 23, no. 2 (Summer 2011): 32–43.
10. Stinco L and Barredo S: "Vaca Muerta Formation: An Example of Shale Heterogeneities Controlling Hydrocarbon's Accumulations," paper URTeC 1922563, presented at the Unconventional Resources Technology Conference, Denver, August 25–27, 2014. Badessich and Berrios, reference 8.
11. Ejofodomi EA, Cavazzoli G, Estrada JD and Peano J: "Investigating the Critical Geological and Completion Parameters that Impact Production Performance," paper SPE 168709/URTeC 1576608, presented at the Unconventional Resources Technology Conference, Denver, August 12–14, 2013.

production from conventional reservoirs—57% of the natural gas and 40% of the total oil production within Argentina come from it.<sup>3</sup> The target areas for shale development in the basin are Late Triassic to Early Cenozoic strata, deposited in a back-arc tectonic setting.<sup>4</sup> Active volcanoes located along the present-day Andean Cordillera produced pyroclastic emissions during various geologic periods, and the resulting ash beds cover large areas of the basin. Ash beds are observed within the shale formations that are targets of current exploration.

The basin formed as a result of sea level changes and tectonic plate movement that began in the Early Triassic period, which were followed by a succession of transgressive and regressive cycles. Restricted access to the open sea during several periods led to the formation of thick evaporite beds.<sup>5</sup> Reactivation of the volcanic arc during the late Jurassic also affected the current basin topography.<sup>6</sup> Present-day basin architecture resulted from uplift and folding during the last Tertiary Andean movement.

The source rocks for oil and gas found in conventional reservoirs of the Neuquén basin are the Cretaceous Agrio formation, Early Cretaceous to Late Jurassic Vaca Muerta formation and the more mature Middle Jurassic Los Molles formation (Figure 3).<sup>7</sup> All three formations are deepwater marine shales and have potential as resource plays. The Vaca Muerta formation is the primary source for hydrocarbons in conventional reservoirs and is in the oil window across approximately 60% of the basin.

The Vaca Muerta formation was deposited between the Tithonian age—a Late Jurassic transgression—and the Berriasian stage of the Early Cretaceous epoch.<sup>8</sup> The characteristics of this organic-rich formation make it a prime target for exploration.<sup>9</sup> These include high average total organic carbon (TOC) levels (1% to 8% and spikes to 12%), moderate depths of 3,150 m [10,335 ft] and overpressured conditions that have a pressure gradient range from 13.6 to 20.4 kPa/m [0.6 to 0.9 psi/ft].<sup>10</sup>

The formation varies from about 60 m [200 ft] to 520 m [1,700 ft] in thickness from the embayment area to the basin center. Matrix porosity varies from 4% to 14%; the average is 9%. Matrix permeability ranges from nanodarcies to microdarcies; the presence of natural fractures contributes to the productive potential of the formation. Shale maturities based on vitrinite reflectance,  $R_o$ , range from less than 0.5% up to 3%, which represents black oil to dry gas.<sup>11</sup> Its

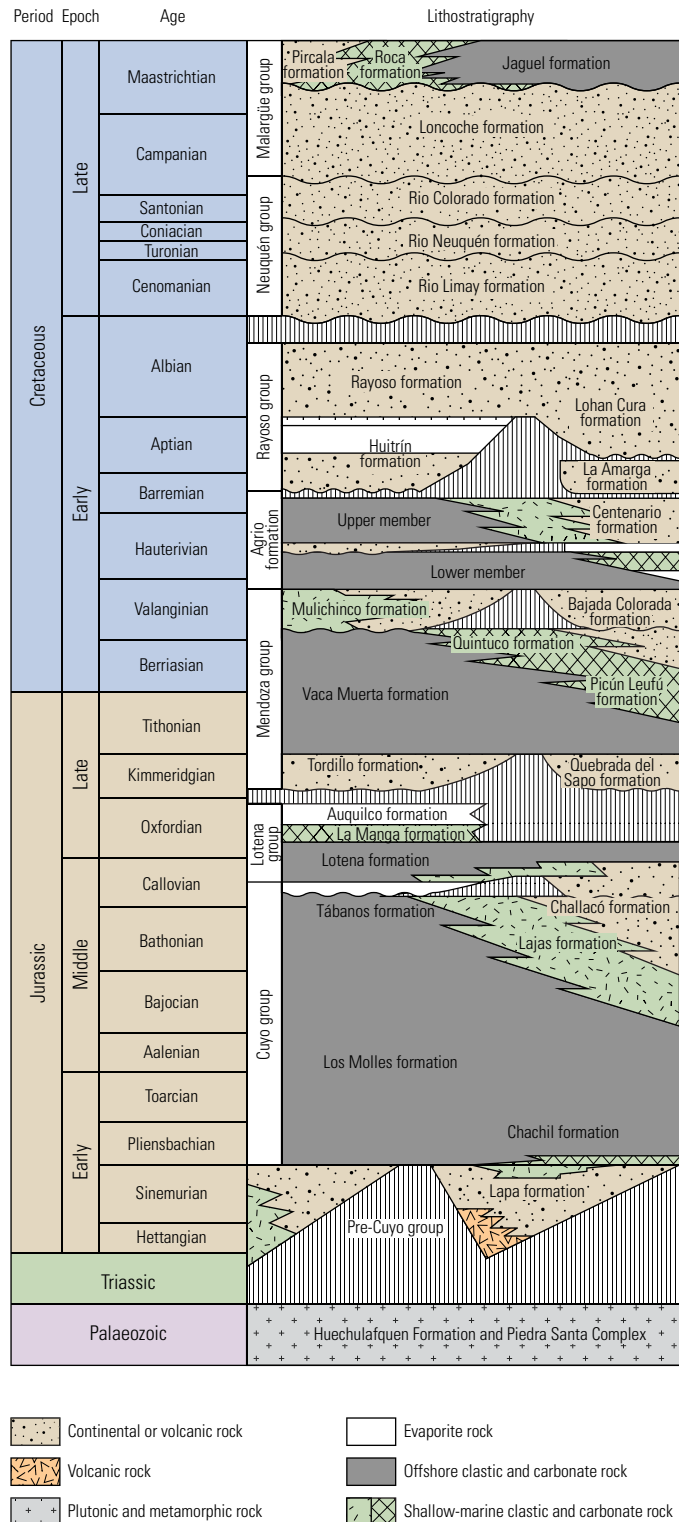


Figure 3. Lithostratigraphy of the Neuquén basin. Three major deepwater marine shale deposits are in the Neuquén basin. The deep Los Molles formation is Early to Middle Jurassic in age. The Vaca Muerta formation straddles Late Jurassic to Early Cretaceous. The Cretaceous Agrio formation lies above the Vaca Muerta formation. The sediments in these formations were deposited during successive transgressive and regressive cycles. Restricted access to open seas and anoxic conditions that existed during deposition preserved their organic content. (Adapted from Howell et al, reference 7.)

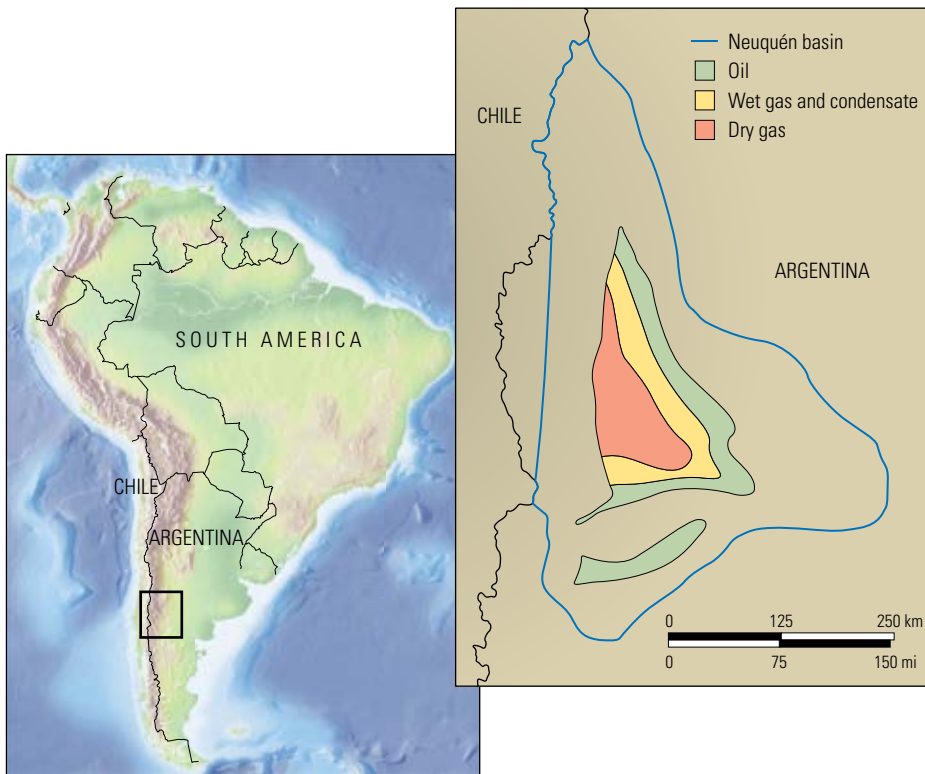


Figure 4. Hydrocarbon type in the Vaca Muerta Shale. Hydrocarbon types in the Vaca Muerta Shale vary throughout the Neuquén basin (blue outline). The eastern and southern regions contain mostly oil (green), the west-central section is predominately dry gas (pink) and the region between the two yields wet gas and condensate (yellow). (Adapted from the US EIA, reference 1.)

large gross thickness, areal extent and reservoir properties have placed the Vaca Muerta Shale in the ranks of a world-class resource play.<sup>12</sup>

The deep marine sediments of the Vaca Muerta Shale consist of fine laminations of black and gray shales and limey mudstones mixed with organic material. The anaerobic environment in which these organic materials were deposited helped preserve their organic content. The formation comprises three sections—lower, middle and upper. The lower corresponds to an inner carbonate platform that consists mostly of marls,

carbonates and limestone. The middle was formed predominantly as a slope deposit and has higher siliciclastic content than the other two sections. The upper section returns to a predominately carbonate platform.<sup>13</sup>

The type of hydrocarbon expected in the Vaca Muerta Shale generally depends on the location within the basin. The eastern and southern regions have potential for oil production, the western region is predominately dry gas and the area between the oil and dry gas zones is wet gas and condensate prone (Figure 4).

Property		Source
Seismic and geologic data	Horizons, faults and stratigraphy	Geologic model
Petrophysical data	Water saturation, porosity and permeability	Openhole logs and core data
Geomechanics	Pore pressure, stresses and elastic properties	Mud data, openhole logs and formation tests
Microseismic	Event type and location	Geophysical interpretations
Discrete fracture networks (DFN)	Azimuth, spacing and length	Image logs, image interpretation and model estimates
Completion design	Staging perforation cluster and perforation properties	Job data
Fracture design	Pumping schedule, proppant, fluid volumes and pressures	Job execution data

Figure 6. Data requirements for predictive model.

Effects from the early Cenozoic Andes orogeny introduced structural complexities in the Neuquén basin, especially along the western front.<sup>14</sup> The close proximity of the western Vaca Muerta to the Andes Mountains created stresses and natural fractures that are less prevalent along the eastern edge of the basin. The influence of the Andes on the stress state of the reservoir rocks helps distinguish it from other shale plays, especially those in North America.

### Unlocking Potential

Most unconventional plays have unique features that differentiate them from other plays. In the nascent period of shale play development, operators were looking for the next Barnett Shale. Although lessons learned from the Barnett Shale and other unconventional plays were crucial for hastening commerciality and acceptability of shales as viable prospects, operators realized early on that each new development required a specific and often unique approach. Because of its many distinct characteristics, this is especially true of the Vaca Muerta Shale. Distinctions for the formation include the prevalence of ash beds, complex facies stacking, abnormally high pore pressure and geomechanical stresses resulting from the proximity of the Andes Mountains.

To optimize the development program for the Vaca Muerta play, YPF collaborated with other operators and service companies that had expertise in shale developments. Working with Schlumberger geologists and engineers, YPF engineers devised workflows and simulations to efficiently exploit the Vaca Muerta formation (Figure 5).<sup>15</sup> The objective was to avoid the costly and time-consuming trial-and-error approach commonly employed in the development of many shale plays. Creating and using a predictive model rather than relying on a statistical approach was deemed crucial for financial viability.

To meet the objective of creating a useful predictive model, the team members first defined specific known problems for developing the play. They established data requirements for each stage of the process that included seismic, petrophysical and geophysical data (Figure 6). The existence of 3D seismic data over much of the area was beneficial in creating these models. Hundreds of legacy wells have also been drilled for exploring and developing conventional reservoirs, although the data acquired in those wells may not always provide the type of information needed to define parameters for drilling optimization, well spacing and fracture design in the unconventional sections. Additional data were

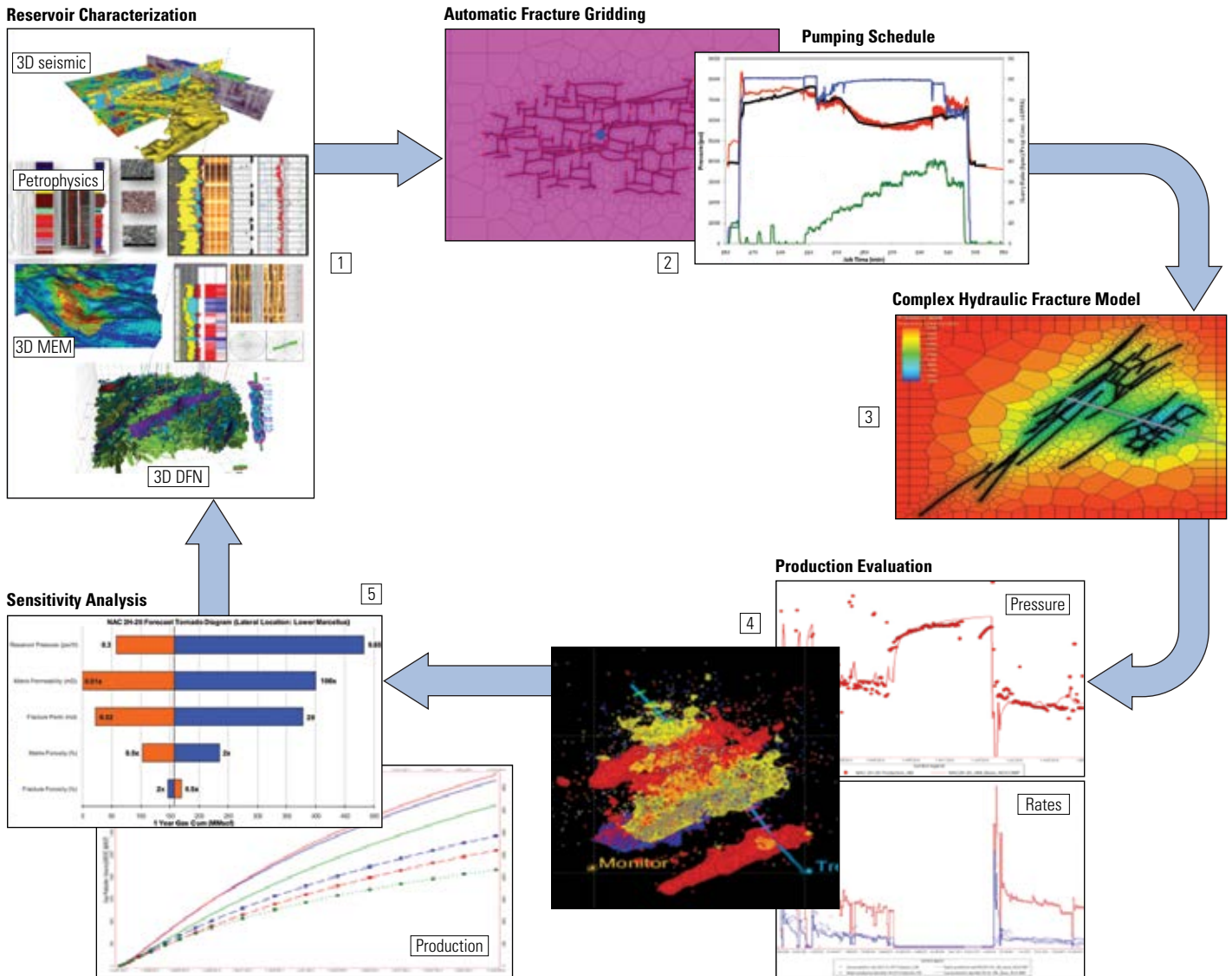


Figure 5. Unconventional reservoir integrated workflow. In developing the Vaca Muerta resource play, engineers at YPF and Schlumberger collaborated on a workflow that reduced the degree of trial and error. Geologists first characterized the reservoir using 3D seismic data, petrophysical data, a 3D mechanical earth model and 3D discrete fracture network models (1). Using these models, they can develop the hydraulic stimulation program based on automatic fracture gridding (2). A complex hydraulic fracture model can be compared to stimulated volumes computed

during treatments (3). During the stimulation treatment, fluid rates and pressures are recorded, and microseismic events may be captured (4). A sensitivity analysis helps engineers understand the effectiveness of the changed parameters (5). If the outcome of the stimulation does not match the model, the empirical data are used to update the simulations. If the stimulation results match the model, additional information, including core and fluid properties, is used to predict production, which can eventually be validated using production logs. (Adapted from Hryb et al, reference 16.)

acquired that were then used to model the formation and create the simulations.

The engineering teams formulated and adopted integrated workflows to help them analyze the old and new data. A 3D geomechanical model was constructed from well log and 3D seismic data. Petrophysical data were acquired from pilot wells and used to fine-tune the models and compute geomechanical properties such as in situ stresses, Young's modulus, Poisson's ratio and pore pressure. To calibrate the modeled results, fracture injection tests were performed in some pilot wells.

As part of their process, the YPF and Schlumberger engineers used history matching to validate predicted responses from the simulations and then compared the model responses with real-world well results. They were able to determine the plausible geometry of existing and created

fracture networks in near real time from these models, which allowed them to make well-to-well optimizations in addition to stage-to-stage modifications during hydraulic fracture operations.

The methodology adopted for the complex hydraulic fracture modeling takes geologic models,

12. US EIA, reference 1.

13. Ejofodomi et al, reference 11.

14. The Andes Mountains were formed by the Cenozoic tectonic shortening of the South American plate as it overrode the subducting Nazca plate, an oceanic plate in the Eastern Pacific Ocean off the west coast of South America.

15. Lacentre P, Pichon S, Suarez M and Badessich MF: "Simulación dinámica integrada de fracturamiento hidráulico y reservorio para pozos horizontales en Vaca Muerta Shale Oil & Gas," presented at the Segundo Jornadas de Simulación, Buenos Aires, July 7-8, 2015.

Completion Quality (CQ)	Reservoir Quality (RQ)
Mineralogy—mainly clay, carbonate and silica	Organic content
Mechanical properties—Young's modulus, Poisson's ratio and tensile strength	Thermal maturity
Natural fractures—presence, density, orientation and condition (open, closed or cemented)	Effective porosity
In situ stress—variations between intervals accounting for mechanical properties anisotropy	Intrinsic permeability
	Fluid saturations—oil, gas, condensate and water
	Organic shale thickness
	Hydrocarbons in place

Figure 7. Data requirements for fracture modeling.

3D seismic models and other data sources to create the 3D geomechanical model.<sup>16</sup> The geomechanical model is combined with discrete fracture network (DFN) models to simulate fracture treatments. Natural fracture models are based in part on image log data that honor mechanical flow units, fracture azimuth, dip angle distribution and fracture density.

A fracture design based on simulator results could then be executed with real-time microseismic monitoring.<sup>17</sup> By using actual production data, the engineers are able to evaluate the effectiveness of the methodology. If the results indicate that stimulation pressures, fracture propagation and stimulated volumes are in line

with predictions, then future production forecasts can be made. When the results are not in line with predictions, the models are updated or modified to reflect the results.

### Reservoir Heterogeneity

The reservoirs of some early shale development projects were treated as if the rocks were isotropic. In the case of organic shales, large variations in formation properties and characteristics can exist both laterally and vertically; the extent of these variations is often much greater than what is encountered in developing conventional reservoirs. Because hydraulic fracturing and horizontal drilling are basic requirements in the majority of

unconventional plays, reservoir heterogeneity, especially regarding geomechanical formation properties, must be understood and accounted for in stimulation and drilling programs.

In shale reservoirs, geologic discontinuities, which include faults, natural fractures, bedding geometry and changes in mechanical properties, influence stimulation results. Evaluation techniques generally treat mechanical properties as affecting the completion quality (CQ) of the reservoir rocks (Figure 7). The CQ is a predictive attribute of the reservoir rocks that depends largely on Young's modulus, Poisson's ratio, bulk modulus and rock hardness. Natural fracture density and orientation, rock anisotropy and prevailing in situ stresses are also incorporated in determining the CQ of the reservoir rocks.<sup>18</sup> The CQ values incorporate information about clay type and volume, which are obtained from spectroscopy measurements as well as mechanical properties. The mechanical properties include Poisson's ratio, Young's modulus and stress profiles computed from acoustic and other petrophysical data.

Along with CQ, the reservoir quality (RQ) of the rocks—another predictive property—determines the economic viability of shale plays. For organic-rich shales, RQ is a measure of the capacity to produce hydrocarbons after hydraulic fracture stimulation. The RQ property is a product of porosity, hydrocarbon saturation, mineralogy, organic content and thermal maturity. Rocks that have a combination of superior RQ and CQ respond to stimulation treatments better than do rocks with poor RQ and CQ properties.

To accurately characterize unconventional resources such as organic shales, the reservoir evaluation often relies on advanced petrophysics based on spectroscopy, nuclear magnetic resonance and dielectric dispersion measurements. Once the formation properties are calibrated using advanced petrophysical data, a minimal dataset may be used to approximate RQ. This minimal set of log measurements includes resistivity, bulk density, porosity, water saturation and pore pressure.

Sweet spots may be determined from a composite quality index (CQI) that accounts for both the RQ and CQ properties. For the completion design, perforation clusters and fracture stages are assigned to the best CQI intervals. The Mangrove engineered stimulation design used in the Petrel platform automates the process of determining the best CQI intervals, and engineers are using completion programs devised from the Mangrove software recommendations (Figure 8).

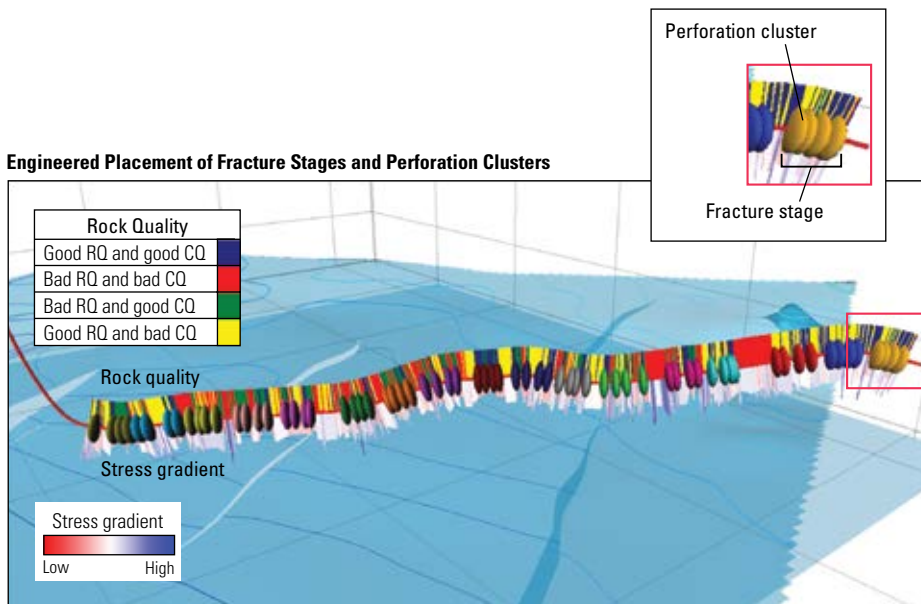


Figure 8. Quality indicators for well completion and design from Mangrove software. Log data are used to generate reservoir quality (RQ) and completion quality (CQ) indicators. These data are processed using Mangrove stimulation design software that automatically highlights optimal intervals based on predetermined cutoff values. By focusing on intervals that have the best RQ and CQ, and eliminating those with poor RQ and CQ, better stimulation results can be obtained compared to those obtained using a geometrical approach in which intervals are completed and stimulated uniformly without regard to the formation properties.

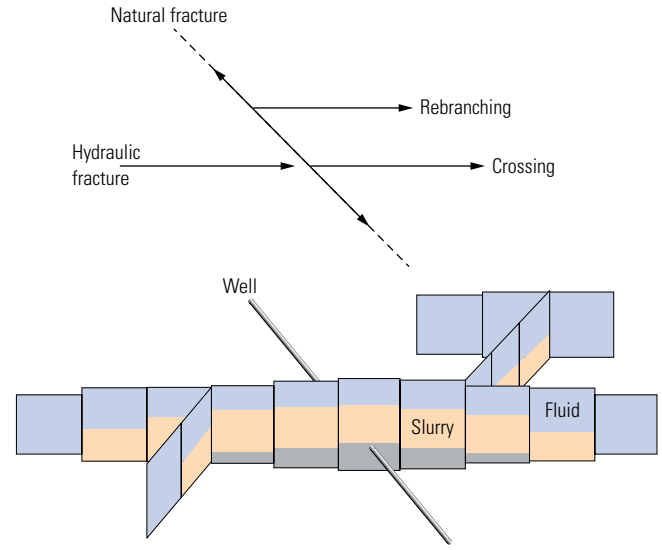
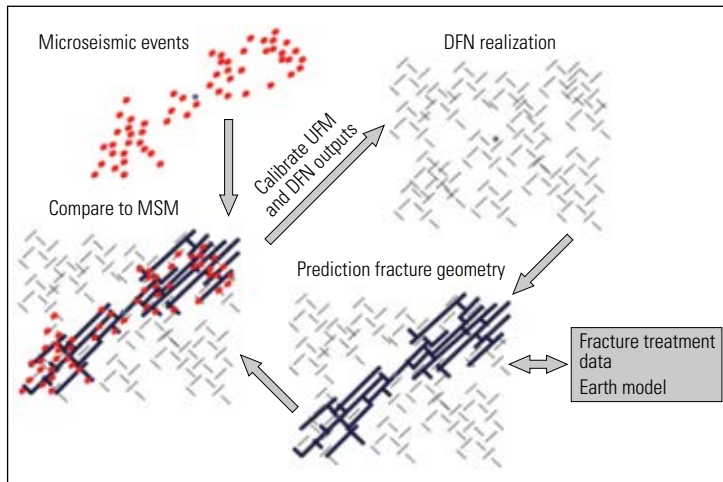


Figure 9. Unconventional fracture model. The engineers at YPF adopted a UFM simulator to characterize Vaca Muerta Shale stimulations. Inputs to the simulation (*left*) begin with recorded microseismic (MS) events that are compared to a microseismic monitoring (MSM) model. The results are used to calibrate the UFM simulation and the distributed fracture network (DFN). The DFN model is used to predict fracture geometry created during hydraulic stimulations. The UFM simulations rely on material balance, geomechanical properties, DFNs and wellbore geometry to predict fracture

propagation properties (*right*). The cell-based outputs of the simulations predict fracture geometry—whether the induced fractures will propagate through existing fractures, rebranch after crossing fractures or follow the track of existing fractures (*top right*). The software computes fracture heights based on these interactions of natural and induced fractures. Proppant transport and settling (*lower right*), which directly impact production and the stimulated volume predictions are generated with the UFM simulation software. (Adapted from Cipolla et al, reference 20.)

The CQI is a continuous index based on RQ and CQ at each depth, although the completion engineers must account for the interactions that occur in the formation and around the perforation clusters during the stimulation process. A single value of CQ at a given depth can be compared with neighboring CQ values, whereas the RQ values must be integrated over the fracture's estimated vertical propagation length and volume to represent the capacity of the stimulated formation to produce hydrocarbons.

Data acquisition in a vertical pilot well is essential for defining the predicted CQ response, especially in plays such as the Vaca Muerta, where vertical heterogeneity is common. The definition of RQ and CQ for Vaca Muerta play continues to evolve as the formation characteristics are better understood.

### Unconventional Fracturing Model

To effectively produce from ultralow permeability shale formations, operators try to generate closely spaced fractures during stimulations to increase the reservoir contact and increase drainage. However, stress effects may oppose the creation of new fractures in the presence of propagating fractures. To design and properly execute an effective hydraulic stimulation, engineers must understand the interactions of fractures in complex fracture networks typical of those in the Vaca Muerta play.

One distinctive aspect of the YPF workflow is the UFM unconventional fracture model software used to model hydraulic fracture creation and propagation. The UFM modeling is part of the Mangrove software.<sup>19</sup>

Observations from actual jobs show that predicting fracture propagation in multistage hydraulic fracture operations has not always yielded accurate results. Most simulation models do not properly handle complex fracture propagation in the presence of natural and newly induced fractures. The UFM simulation, first introduced in 2011, tackles this weakness in other simulations by determining whether a hydraulic fracture will propagate through an existing fracture, stimulating fresh formation, or if it will be subjugated by existing fractures and simply continue along an existing fracture plane (Figure 9).<sup>20</sup> The crossing model used in the UFM simulation is an essential component in the predictions.

The UFM software also accounts for *stress shadow* effects—the stress exerted on surrounding rocks and adjacent fractures by propagating fractures—in simulating the propagation of multiple or complex fractures. Stress shadow causes restrictions in fracture width, which can significantly reduce the effectiveness of proppant placement to the point of screenout.<sup>21</sup>

When multiple fractures are propagating simultaneously in close proximity, the transport of fluid and proppant into the newly formed

fractures may be adversely affected. The stress shadow results in narrower fracture widths than static propagation models suggest. The predictions from the UFM simulations more closely replicate the dynamics of actual treatments

16. Hryb D, Archimio A, Badessich M, Ejofodomi E, Diaz A, Cavazzoli G, Zalazar F, Lagarrigue E and Pichon S: "Unlocking the True Potential of the Vaca Muerta Shale Via an Integrated Completion Optimization Approach," paper SPE 170580, presented at the SPE Annual Technical Conference and Exhibition, Amsterdam, October 27–29, 2014.
17. For more on real-time microseismic monitoring: Burch DN, Daniels J, Gillard M, Underhill W, Exler VA, Favoretti L, Le Calvez J, Lecerf B, Potapenko D, Maschio L, Morales JA, Samuelson M and Weimann MI: "Live Hydraulic Fracture Monitoring and Diversion," *Oilfield Review* 21, no. 3 (Autumn 2009): 18–31.
18. Glaser KS, Miller CK, Johnson GM, Toelle B, Kleinberg RL, Miller P and Pennington WD: "Seeking the Sweet Spot: Reservoir and Completion Quality in Organic Shales," *Oilfield Review* 25, no. 4 (Winter 2013/2014): 16–29.
19. For more on UFM software processing: Wu R, Kresse O, Weng X, Cohen C and Gu H: "Modeling of Interaction of Hydraulic Fractures in Complex Fracture Networks," paper SPE 152052, presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, February 6–8, 2012.
20. Cipolla C, Weng X, Mack M, Ganguly U, Gu H, Kresse O and Cohen C: "Integrating Microseismic Mapping and Complex Fracture Modeling to Characterize Hydraulic Fracture Complexity," paper SPE 140185, presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, January 24–26, 2011.
21. Screenout occurs when the proppant carried in a treatment fluid creates a bridge across the perforations or in fracture networks. The restriction to fluid flow causes a rapid rise in pump pressure and ends the placement of additional proppant.

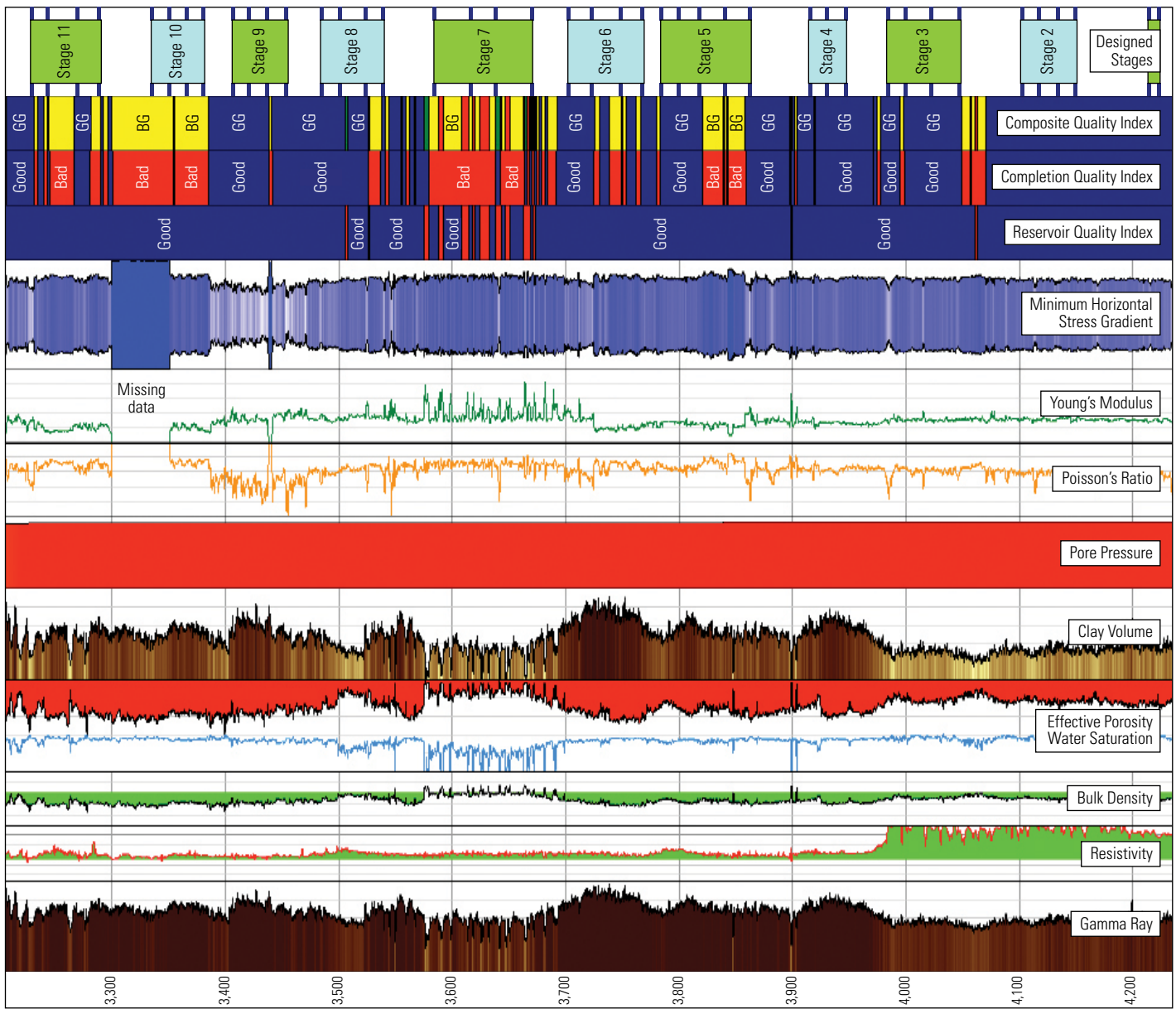


Figure 10. Vaca Muerta Shale completion design. The Mangrove software automatically determines optimal stimulation intervals. The typical inputs of gamma ray (Track 1), resistivity (Track 2), bulk density (Track 3) and water saturation (Track 4) are derived from basic well log data. Effective porosity (Track 4) and clay volumes (Track 5) are computed using data from advanced logging tools, as are mechanical properties such as pore

pressure (Track 6), Poisson's ratio (Track 7), Young's modulus (Track 8) and stresses (Track 9). The RQ and CQ indices (Tracks 11 and 12) are combined to produce a composite quality index (Track 10) from which the stages and perforation clusters are determined (Track 13). Perforation clusters are grouped by similar properties to ensure maximal outcomes. (Adapted from Hryb et al, reference 16.)

because it accounts for fracture geometry, which ultimately controls fluid transport and proppant placement.

The UFM software simulates fracture propagation, rock deformation and fluid transport in the complex environment of stimulation treatments by using material balance, geomechanics, DFN models and well geometry. The program delivers fracture height estimates, predicts interactions of natural and induced fractures and models proppant transport.

#### Typical Vaca Muerta Well

The workflow and modeling that YPF uses in the Vaca Muerta development offer considerable flexibility; however, the general process can be outlined for a typical well. A subject well, drilled parallel to another well from the same pad and vertically separated by approximately 260 ft [80 m], was drilled laterally for several thousand feet.<sup>22</sup> Engineers used Mangrove software to determine staging, perforation cluster locations and completion strategy (Figure 10).

The RQ and CQ outputs from the Mangrove processing were limited using predetermined cutoff values initially determined from the fully characterized vertical pilot well. The process for stimulation design comprised the following steps: Identify intervals that have favorable RQ and CQ values based on log measurements along the lateral, determine sweet spots based on CQI, cross-reference CQI with formation properties and information from the vertical pilot well, and stimulate the zones highlighted from the Mangrove processing. The intervals and perforation

clusters were also grouped based on similar stress profiles (one of the CQ indicators) to help ensure that the treatment breakdown pressures would be similar for individual stages. Otherwise, the treatment would have a tendency to follow a path of least resistance and flow through a limited number of perforations, which would not stimulate the rock effectively.

The workflow also allows the design team to simulate scenarios to determine an optimal stimulation schedule. For example, for another well in the project, the predicted results of a hybrid treatment were compared to that of a slickwater-only treatment (Figure 11). The hybrid treatment—a combination of slickwater, gel and crosslink gel—should produce a higher gas rate and maintain that output compared to the simulated results obtained using a slickwater-only treatment.

The predicted normalized flow rate per cluster for the fracture treatment was used to group similar clusters. The treatment consisted of a combination of slickwater, 20 lbm [9 kg] cross-linked gel and 20 lbm crosslinked gel carrying 100, 40/80, 30/60 and 20/40 ceramic proppant (Figure 12). Each stage consisted of 500,000 lbm [227,000 kg] of proppant pumped at a rate of 70 bpm [11 m<sup>3</sup>/min].

22. Hryb et al, reference 16.

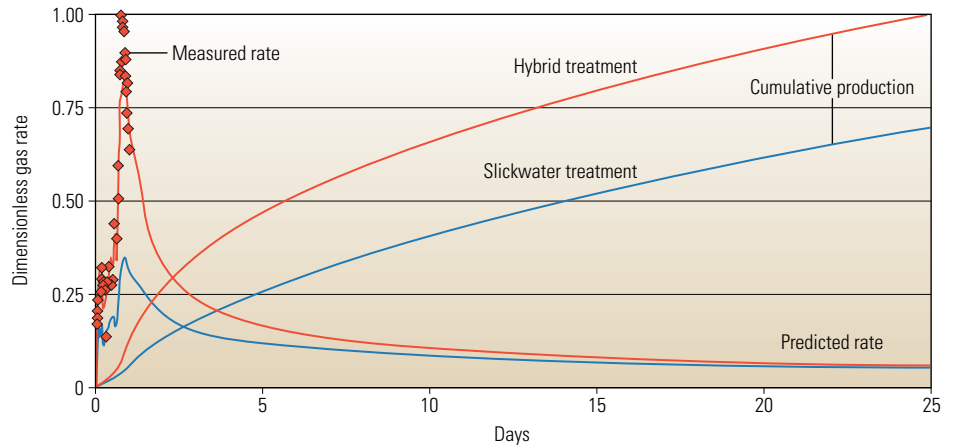
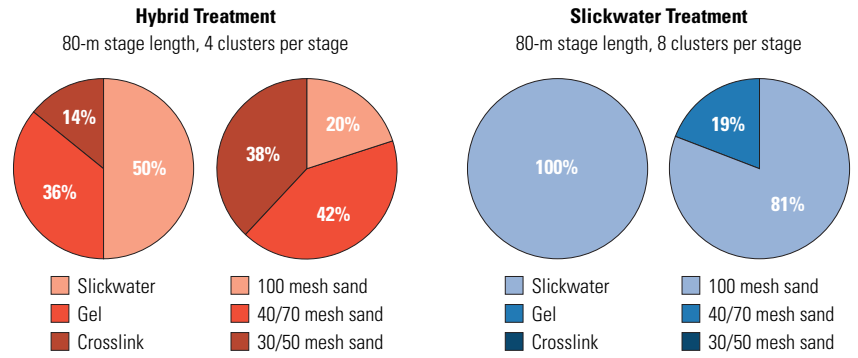


Figure 11. Stimulation simulation comparisons. Engineers modeled and compared treatment scenarios to determine which was more effective. Both designs were based on 80-m [260-ft] stage lengths. The hybrid design (top left) is based on four clusters per stage, and the slickwater design (top right) is based on eight clusters per stage. The hybrid design included slickwater, gel and crosslink gel stages along with a mixture of proppant sizes. The slickwater-only treatment was predominately 100 mesh sand with some 40/70 mesh sand. The cumulative gas production (red line) of the hybrid design clearly exceeds that of the slickwater-only treatment (blue line). The predicted hybrid flow rates are higher than those of the slickwater-only treatment flow rates, and the measured data validates the hybrid system prediction. (Adapted from Hryb et al, reference 16.)

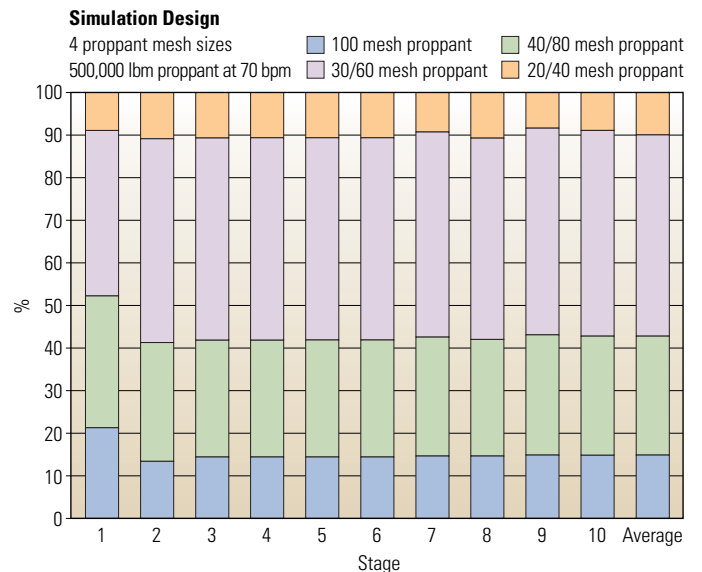
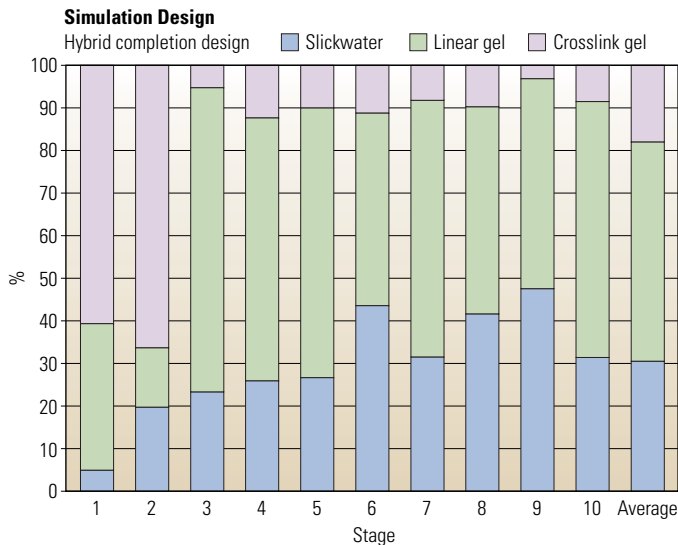


Figure 12. Simulated designs. The hydraulic simulation was optimized for the parameters of the specific well. Each of the ten stages used a specific fluid type and volume (left). Each stage consisted of a mixture of four proppant

mesh sizes (right), pumped as a percentage of the total volume. (Adapted from Hryb et al, reference 16.)

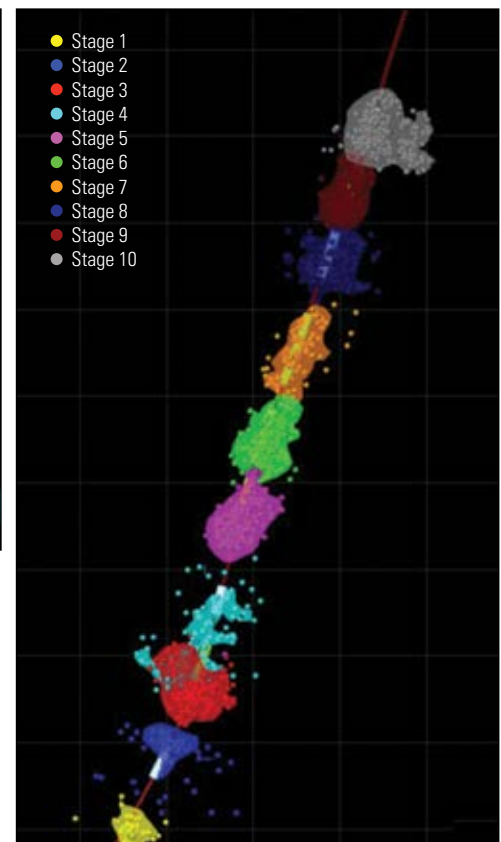
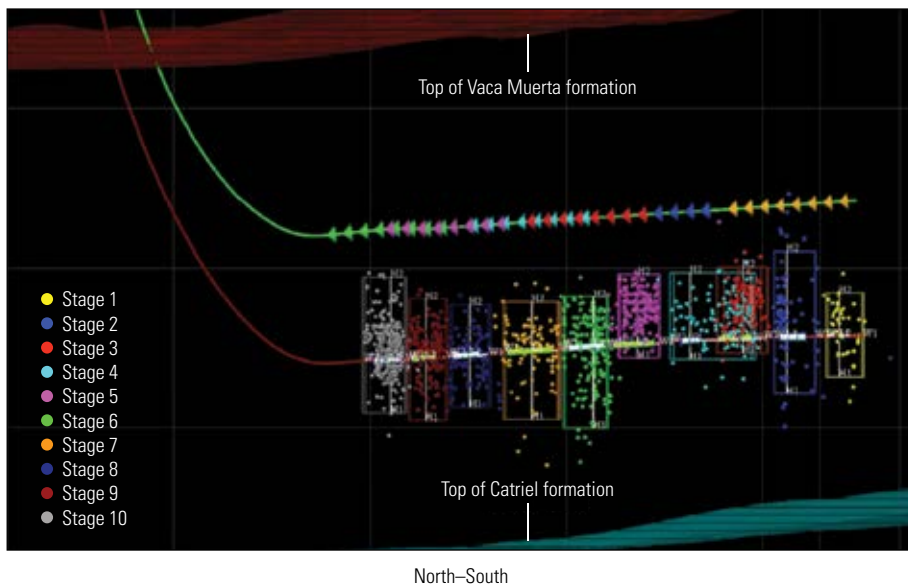


Figure 13. Microseismic monitoring in the Vaca Muerta play. The microseismic events in the treatment well (*left*, lower well) were monitored in the adjacent horizontal well (upper well). Ten stages (color-coded on the map display) were performed from the toe of the well (yellow) to the heel (gray). The survey monitoring tool was positioned across seven intervals (color-coded yellow to green) to maximize event detection. Stages 3 and 5 through 10 have similar stimulated volumes; the later Stages 6 through 10 exhibit more downward growth than that seen in Stages 1 through 5 (*right*). (Adapted from Hryb et al, reference 16.)

The operator used the parallel offset well for microseismic (MS) monitoring to evaluate the effectiveness of the treatment program and to make adjustments to the job during the course of the treatment (Figure 13). Prejob modeling determined that the maximum detectable event location was about 1,300 ft [400 m] away from the monitoring array. During the treatment, the array was moved a total of 7 times during the 10 stages, thus ensuring the MS events were within the detection range of the sensors. Event location uncertainty and event location confidence were enhanced by repositioning the sensor array.

The MS monitoring results indicated dominant fracture orientation of N110°E and little propagation downward and out of the Vaca Muerta formation. Lateral migration was confined to the perforated interval of the stage being treated, which was indicative of good mechanical isolation between the newly stimulated areas of the reservoir and the zones stimulated during subsequent stages.

### Postfracture Analysis

Although the YPF engineers want to avoid a trial-and-error methodology, they still use an iterative process to improve job design and execution based on postjob feedback and continuous improvement of the workflow process. For the example well, the microseismic geometry data acquired using MS monitoring were combined with the pressure data from the stimulation. The team used these data to calibrate the UFM simulation results.

A complex fracture network was modeled for each stage of the stimulation program. Minimum horizontal stresses were calibrated to the observed initial shut-in pressures. The horizontal stress anisotropy was then adjusted to match observed MS events.<sup>23</sup> The fracture direction was predominantly east-west, parallel to the maximum stress direction. Effectiveness of fluid movement and proppant placement was also evaluated during the postfracture analysis.

Creating a complex fracture network is only one part of the objective of a stimulation treatment. The complex network must also have suffi-

cient conductivity to move fluids from the reservoir to the wellbore by way of the newly created fracture system. For the job in question, the modeled results indicated that only about 50% of the fracture network was conductive. With these data in hand, the engineers could use the MS measurements and pressure matching to calibrate the UFM software and make adjustments to future stimulations and help increase the contributing portion of the reservoir. This crucial step of evaluating results and adjusting the models is a routine part of the workflow.

After the UFM software output is properly calibrated to match the observed data, the reservoir simulation models can be tested and adjusted as needed. An additional aspect of simulators that integrates complex fracture modeling is the inclusion of transient behavior typical of shale wells. Transient behavior can be captured from small changes in pressures and flow rates. The Mangrove software used to simulate

23. Horizontal stress anisotropy is the ratio of maximum and minimum horizontal stresses and directly affects the fracture complexity. The smaller the ratio, the more complex will be the fracture network.

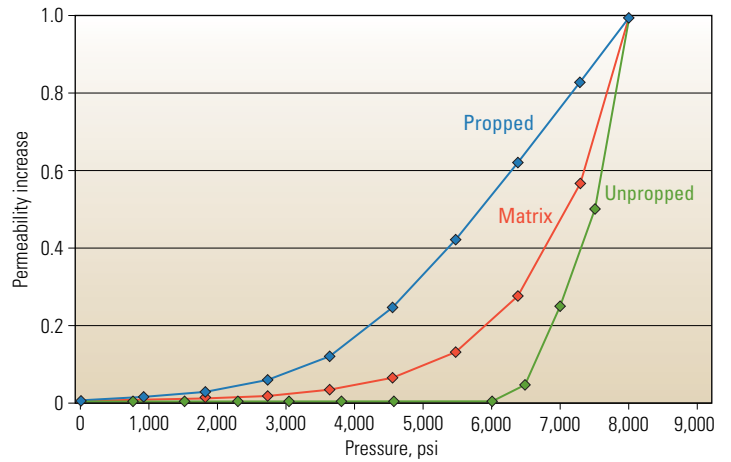
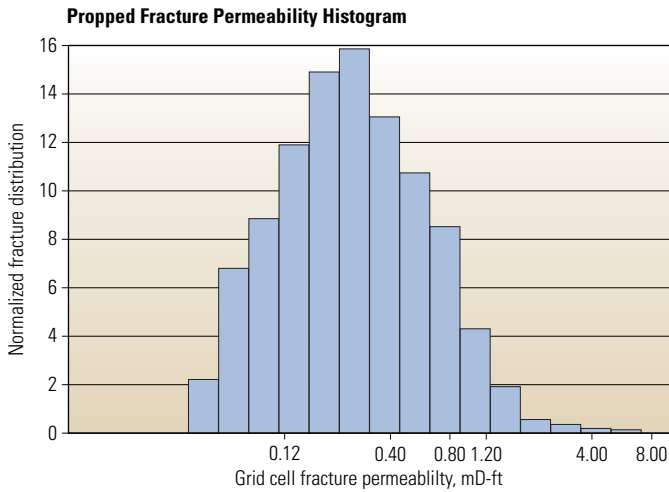


Figure 14. Production predictions from stimulation simulations. The estimated relative permeability (*left*) is a key component in predicting production from fractured reservoirs. The simulator can produce plots for

increases in permeability, detect unstimulated matrix, determine unpropped fractures and quantify the expected production from the stimulated volume and propped fractures (*right*).

production uses small grid blocks in the near wellbore and in the fractures. In this simulation, engineers used 445,000 cells and 19 layers, which provided high-resolution results and fine details. The team used the simulation to determine that the proppant had a tendency to settle out upon fracture closure.

To conduct the history matching, engineers controlled the total liquid flow rates—both oil and water—to match the observed fluid phases and flowing pressures from well tests. From these results, they determined that the most important history matching component for the matrix (as it existed prior to fracture stimulation) was pres-

sure-dependent permeability. For the newly induced fractures, it was both porosity- and pressure-dependent permeability; however, matching the flowing pressures using fixed permeabilities and porosities was not possible. For the modeling, a pressure-dependent permeability/porosity ratio was developed (Figure 14).

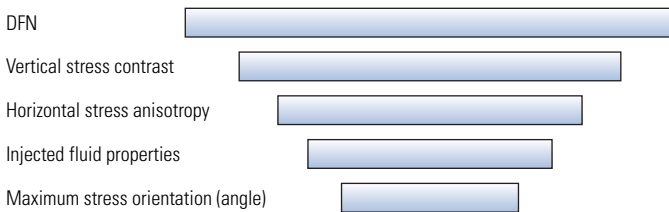
#### Workflow Updates

Now that there are more than 400 wells in the field, the impact of history matching and job modifications becomes more evident. The UFM software outputs, production models and continuous feedback provide an understanding of important variables for future wells and treatments. The

data are used to determine optimal spacing between lateral wells for maximizing production but minimizing negative crosswell impacts.

Engineers can use the simulation outputs to determine the optimal fracturing fluids, proppant type and volumes, pumping schedules, perforation cluster locations and placement, longitudinal staging along the wellbore, horizontal staging related to other wells, stress shadow effects and the impact of changes made from job to job and from stage to stage. They use these data along with sensitivity analyses to determine which parameters have the greatest impact on well performance (Figure 15). Future hydraulic

#### Uncertainty Analysis, Hydraulic Fracture Model



#### Uncertainty Analysis, Production Prediction

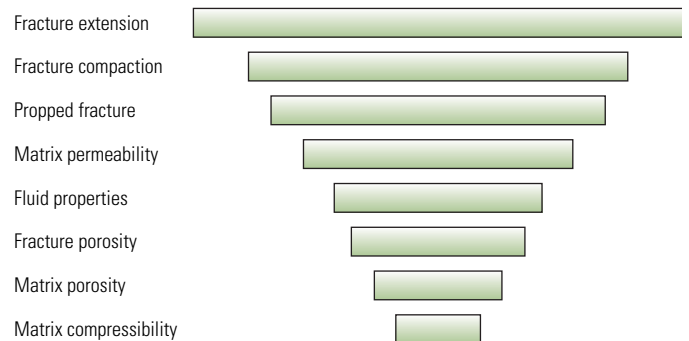


Figure 15. Postfracture calibration of models. Input parameters have some degree of uncertainty because of the nature of the shale formation's heterogeneity and fracture complexity. Uncertainty analyses can be performed after the stimulation program to quantify these uncertainties and determine model sensitivity (*left*). Similarly, evaluation of production results

can provide levels of uncertainty for the inputs used to predict production (*right*). The degree to which this uncertainty affects the simulation can be used to evaluate the quality of the predictions. (Adapted from Hryb et al, reference 16.)

#### Optimization Strategy

- Horizontal landing location
- Various proppant systems
- Various fluid systems
- Fibers
- Perforation strategy
- Impact of natural fractures

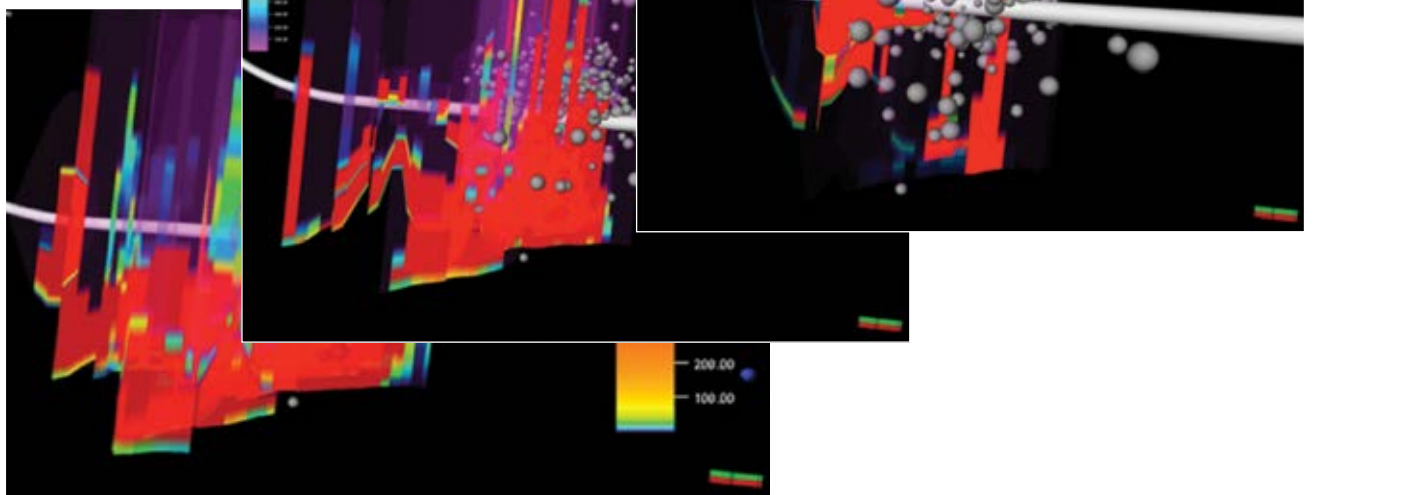


Figure 16. Optimization strategies as part of the standard workflow. After the calibrated and corrected models and simulations become available, engineers can develop optimization strategies. Using the simulations, the team can vary landing location, proppant characteristics, fluid delivery methods, perforation strategies and contributions from existing conditions

to optimize well locations and spacings and field development. Simulations can be presented graphically, and then engineers can compare the results, which helps them choose the best course of action. (Adapted from Hryb et al, reference 16.)

fracture stimulation designs are modified from these simulations to improve efficiency and maximize the stimulated volume.

The workflows used by YPF and Schlumberger put all the analysis tools in a single platform, which simplifies the modeling. The results can be quickly analyzed, and analysts are able to visualize the effects of parameter changes. The results include the uncertainties associated with each variable, which further help in determining which

parameters have the greatest impact on the outcome and the optimal course of action to take.

Engineers compared simulation results that were based on previous generation fracture modeling software with simulations that used the UFM software and found the results more closely matched the empirical data. The engineers attributed the more accurate results to the UFM software's proper treatment of the development and propagation of complex fractures. The level

of uncertainty from these simulation models can be high due to nonunique solutions; however, by using data from individual wells to calibrate the simulations, the analysts can improve the models for future drilling and stimulation programs (Figure 16).

24. Collins PW, Badessich MF and Ilk D: "Addressing Forecasting Non-Uniqueness and Uncertainty in Unconventional Reservoir Systems Using Experimental Design," paper SPE 175139, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 28–30, 2015.

Property		Source
Production history	Oil, gas and water volumes Bottomhole pressure	Production data
PVT	Oil and gas properties	Laboratory measurements Calculated from wellhead pressure
Changes in rock properties	Changes in the matrix Changes in unstimulated rock Changes in conductivity of the propped fractures	Laboratory measurements on core Adjustments in parameters using empirical data Data from service provider
Relative permeabilities	Oil, gas and water permeabilities	Adjustments in parameters using empirical data

Figure 17. Data requirements for generating production predictions.

Not only do the workflows help users understand well dynamics and help them focus on the most critical parameters for adjusting programs, they also benefit the operations. Field personnel are aware of the need for quality measurements such as permeability, fluid saturations, effective porosities and pressure data that will be used in the simulations and modeling. When following these well-defined programs, field personnel can focus on what is required to ensure successful job execution and efficient job operations.

#### Current Status

Compared to its North American counterparts, the Vaca Muerta Shale development is a relatively new play. The first shale gas well in the play that involved hydraulic fracture stimulation was completed in mid-2010 and was brought online in December of that year. Ramped-up development drilling did not start until 2013, when the first cluster of 100 wells operated by YPF was drilled in the Loma Campana block. Spaced at one well per 20 to 40 acres [0.08 to 0.16 km<sup>2</sup>], the majority of the early wells were drilled vertically. Production forecasting is included in the normal workflows, and specific datasets have been defined to ensure the necessary inputs are available for the predictive software (figure 17). Because the development is new, forecasting medium-to-long-term well performance is still a challenge.<sup>24</sup>

Today, several wells that were drilled horizontally and completed using multistage stimulation programs are producing from the Vaca Muerta formation. These lateral wells were initially completed with four to six stages per well; however, more stages, with as many as fifteen stages per well, are being attempted. Most of the wells were drilled vertically, which is in direct contrast to how wells are drilled in the majority of the uncon-

ventional plays in North America, where horizontal well drilling is standard practice. YPF initially chose vertical well configurations for targeting the Vaca Muerta play because of the significant vertical heterogeneity of the formation and substantial pay thickness.

The vertical well methodology employed by YPF engineers is beginning to shift. Although large-scale drilling of horizontal wells that were completed using multistage fracturing did not begin until late 2014, by the end of 2015, approximately 10% of the producing wells were horizontal. This increase in horizontal drilling as a proportion of the total wells drilled has been adopted because engineers at YPF now feel confident that they have identified sweet spots for landing horizontal targets within the vertical portion of the reservoir.

The LLL-992h horizontal well that YPF recently drilled and brought online is a good example of this shift in methodology. The well is regarded as a major milestone for the project as it heralds a transition from drilling primarily vertical wells to drilling a high percentage of horizontal wells. This well, drilled to a lateral length of approximately 6,600 ft [2,000 m], achieved a peak production of 1,630 bbl/d [260 m<sup>3</sup>/d], which far exceeded initial expectations. These results are encouraging the operator to migrate more rapidly from a vertical well architecture to a horizontal well development scheme for wells drilled in both the oil and the gas windows.

In spite of reservoir complexity and heterogeneity, the integrated approach YPF has taken is helping the company develop the play. By understanding the discrete fracture networks through use of the UFM software, engineers and geologists are able to optimize stimulation designs and develop realistic modeling of

proppant placement and fracture growth. Microseismic measurements are used on some wells in real time to adjust programs during job execution and then are used to update and fine-tune existing mechanical models.

The Vaca Muerta Shale is massive, and even though YPF has drilled numerous wells, this operator and others have only just begun the development and commercialization of the play. As more wells come online, and field complexities become better understood, this giant has the potential to revolutionize the oil and gas industry in Argentina as well as encourage operators to explore the possibilities for shale resources in other South American basins. —TS