GUIDE & MANUAL

RESERVOIR ENGINEERING

GM EP RES 804

Technical Guidelines for the evaluation of Reserves and Contingent Resources in Unconventional Reservoirs

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Original Version

Contents

1. Scope

The purpose of this document is to provide the technical guidelines for the application of the CR EP RES 001 and GM EP RES 001 to Unconventional Plays (tight gas/oil, shale gas/oil but not Coal Bed Methane). Prospective Resources are evocated in the document but its definition and evaluation are not within the scope of this work.

2. Reference documents

The reference documents listed below form an integral part of this Guide & Manual.

External Documents

Unless otherwise stipulated, the applicable version of these documents, including relevant appendices and addendums, is the latest revision published at the effective date of this document.

Reference	Title
PRMS 2007	Petroleum Resources Management System (SPE/AAPG/WPC/SPEE) http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

Total Standards

Unless otherwise stipulated, the applicable version of these documents, including relevant appendices and addendums, is the latest revision published.

Reference	Title
CR EP RES 001	Reserves and Resources Definitions and Classification
GM EP RES 001	Technical guidelines for evaluating reserves and contingent resources
GM EP RES 801	Dynamic Simulation of Shale Reservoirs
GM EP RES 802	Rate Transient Analysis for Unconventional Reservoirs

3. Key points

Appendix 1 describes some generalities about unconventional plays. It should be read first if very little is known by the reader about unconventional reservoirs.

The **Stimulated Rock Volume** (SRV) should be assessed with the three following indexes:

- Resources (characterizing the volumes in place)
- Geometry (characterizing the size and dimensions of the combined hydraulic/natural fractures network)
- Productivity (characterizing the productivity of the SRV)

The characterization of the SRV allows delimiting the play into **sectors** of relative **continuity of these indexes**. This characterization can only be done if the proper data was acquired. Critical acquisitions for SRV characterization include, but are not limited to, full wave sonic logs, DFIT, micro seismic, triaxial tests on cores or image logs.

Unconventional plays should be divided into sectors as early as possible if integrated **subsurface studies were performed**. A sector is delimited by **an area** and **a given formation/landing zone**.

If the sectorization process is not possible due to the lack of data or because the studies were not performed, the classification of contingent resources should be **limited to an area of no more than 5km of radius** around the exploration well.

One or more projects (number of wells with spacing according to SRV, gathering network and surface installation) are then defined on each sector and the hydrocarbon volumes associated to these wells can be classified as **contingent resources**.

For each project with contingent resources, an **action plan has to be built** to increase the maturity of the project by **proving statistical repeatability and commerciality**.

The traditional technical PO (Volume, Recovery, Wells, and Surface) in the Total Box should be replaced by the following ones for unconventional projects:

- Volumes (associated to SRV resources)
- Geometry (associated to SRV geometry)
- Recovery (associated to SRV productivity)
- Surface

In the order of complexity **Estimated Ultimate Recovery** can be estimated by:

- Decline Curve Analysis
- Rate Transient Analysis
- Analytical modeling
- Numerical modeling

DCA should only be chosen if time or resources do not allow RTA or analytical modeling.

Numerical modeling should be performed during dedicated studies but should not be used for systematic EUR estimation.

Whenever the well count is sufficient, the use of **statistical tools** should be encouraged to refine EUR estimation.

4. Introduction

This document provides the technical guidelines for the application of CR EP RES 001 on the specific case of Unconventional Reservoirs. It is issued to complement the GM EP RES 001 on matters only related to Unconventional Reservoirs, and it should be applied exclusively on this type of plays.

As stated in the previously mentioned documents, a reliable assessment of the quantities of petroleum available for production and the quantities which are anticipated to be produced within a given timeframe is essential for investment decisions, future planning and external reporting purposes.

Development projects have to be evaluated in a consistent manner across the company and within standards that comply with those agreed across the oil and gas industry. Unconventional Resources are no exception; a classification system is needed in order to benchmark these development projects between each other and with other projects within the company.

4.1 Classification

As stated on CR EP RES 001 the classification system used by the group is derived from the Petroleum Resources Management System (PRMS 2007). This system has to be reported through the Total Box, which is the official internal template to synthesize the stakes expected from all existing/planned projects on any asset.

Table 1: Total Box schematic (CR EP RES 001)

Maturity	Project Maturity Status	Remaining recoverable volumes		
+	Commercial projects on discovered accumulations	Reserves		
		1P	2P	3P
	Sub-Commercial projects on discovered accumulations	Contingent Resources		
		1C	2C	3C
-	Undiscovered exploration potential	Prospective Resources		
		P90	P50	P10
		-	Uncertainty	+

Table 1 synthesizes the structure of the Total Box, this tool consists of different rows that represent different **projects.** Each project has a certain **maturity**, which denotes the probability of reaching the producing status, and for each project three volumes are assigned which represent the range of estimated quantities potentially recoverable from an accumulation by the realization of the defined project. Resources can be classified according to their maturity as:

- Reserves
- Contingent Resources
- Prospective Resources

Prospective resources constitute the potential of an exploratory prospect, as mentioned before these are outside the scope of this document. There will be a GM issued soon by EP/EXPLO about this topic.

In order to mature Prospective Resources into Contingent Resources CR EP RES 001 states that:

Rule 3: In order to be considered as discovered, an accumulation shall have already been drilled (or is likely to be in reservoir and fluid continuity with a drilled area where the presence of hydrocarbons is proven) AND productivity shall have been established.

In Unconventional plays truly dry holes are uncommon and nearly all wells are capable of producing some hydrocarbons, so they present **little or no risk of not finding a hydrocarbon accumulation**. Nevertheless productivity per well is very variable due to heterogeneities, and **establishing the range of productivity of future wells is challenging**. A tested well can help setting a range of productivity, but more wells or other sources of information are needed to obtain a distribution of the productivity. For this reason, **classifying Prospective Resources as Contingent Resources has to be handled with caution.**

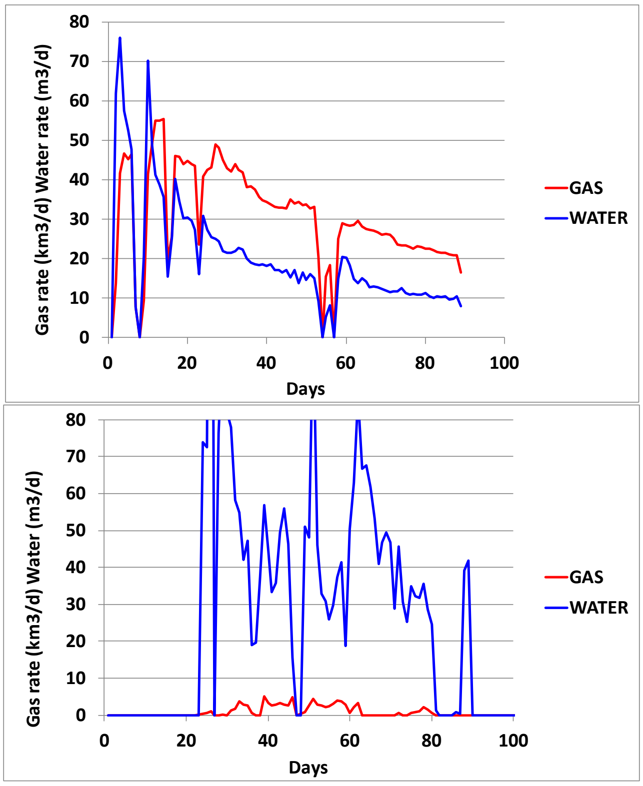

Figure 1: Production test of a Vaca Muerta well (top) and a Barnett well (bottom)

Figure 1 illustrates the difference between 2 production tests from 2 different shale plays. The top example shows an established rate that can be considered as a discovery while the bottom example cannot be considered as an established rate (although some gas was measured at the well head).

4.2 Project-based approach

Once a discovery is made Resources evolve from Prospective to Contingent Resources. A number of "contingencies" have to be removed for these resources to reach commerciality and an efficient way is to evaluate the contingent resources as projects. This is called a **project-based** approach, whereas prospective resources are evaluated with an **object-based** approach.

A detailed definition of a project requires many studies; these studies might prove to be unnecessary in pre-FID stances (sub-commercial projects), for this reason the detail into which the project is defined, depends on the timing in which the project is planned for development.

Unconventional plays have vast resources, so once an unconventional discovery is made, it is common to structure the contingent resources into several projects. These can consist of projects of the same kind, such as different phases of the same development, or can be separated in projects using existing facilities vs. projects needing new facilities, etc.... For this reason it is fundamental to define the scope of each project while structuring the contingent resources into the Total Box.

Structuring the Contingent Resources into projects is fundamental in unconventional plays. The fact that these plays are continuous accumulations makes discoveries in large blocks generally huge. This can be overwhelming, since the development of all the resources at once might require significant amounts of capital that could be considered too risky to commit. On the other hand, identifying different, smaller projects can reduce the exposition and reduce the risk by diversifying the types of projects, for example: gas production for domestic market, condensates for export, gas for electricity generation, etc. The definition of the scope of these projects is fundamental in structuring Contingent Resources, since it provides long term visibility to these; this task should be tackled with a multi-disciplinary approach and consistent with the strategy of the group/affiliate.

4.3 Contingent Resources

Contingent Resources consist of a discovered resource or accumulation with an established well productivity that could be developed with a project that has some “obstacles” or contingencies to come on-stream. Contingencies are risks and uncertainties that prevent the project from reaching commercial status.

CR EP RES 001 clearly distinguishes the difference between risks and uncertainties: stating that Risks are associated with the probability of loss while Uncertainties are associated with the description of the range of the possible outcomes. All contingent resources have risks that are represented through a PO to represent the chance of the project to reach commercial status.

CR EP RES 001 also states that the **subsurface uncertainties are generally captured through the range of contingent resources associated to the envisioned project (section 4.2)**. These are considered relatively constrained into an acceptable range that does not jeopardize the definition/existence of the project. If the range is too wide to find an optimum development strategy, more information is needed. **When additional subsurface information appears necessary to define and / or sanction a project, subsurface elements are considered as risks**.

In the cases where more data / information / knowledge are necessary to reach commercial stage, the contingent Resources should be evaluated based on a **forward-looking information approach**. This means that the evaluation will be based on a number of assumptions which may be incorrect but enable the project to reach a commercial stage if finally proved to be correct. The corresponding evaluation is called a “vision”. The associated risk is taken into account through a dedicated geosciences PO. In unconventional resources these uncertainty is generally but not only related to:

- Well productivity
- Fluid type and content of impurities (CO_2, H_2S, N_2, etc.)
- Mechanical rock properties and stress regime
- Fluid in place density

These uncertainties can be lumped together into **SRV Quality indexes** that are presented in section 5 of this document. The continuity of the hydrocarbon accumulation is quite certain, but the properties that control well productivity (SRVQI) are generally very uncertain. The evaluation of contingent resources in unconventional plays is similar to conventional plays with the **current knowledge** and **current vision**, with their respective "prior" distributions and "posterior" distributions.

As stated in **Rule 19** of CR EP RES 001:

Rule 19: The assumptions retained for the vision are envisaged as <u>forward looking information</u>, thus a <u>dedicated action plan shall be defined</u> with the aim for de-risking these new subsurface assumptions.

The difference between the prior and the posterior evaluation justifies the acquisition and the difference represents the value of information (VOI).

4.3.1 Chance of commerciality and Probability of Occurrence (PO)

As previously mentioned, the Contingent Resources, in opposition to Reserves, have contingencies that prevent the project to reach commercial status. For unconventional reservoirs, the Wells PO should be replaced by a Geometry of SRV (G) PO as the wells feasibility is usually not an issue in unconventional plays while the development of the SRV is critical. This way, the 3 SRV indexes are reflected in the POs:

- Technical:
  - Volumes in Place (V)
  - Geometry of SRV (G)
  - Recovery (R)
  - Surface (S)
- Non-Technical
  - Economics
  - Business

The wells PO could always be included in a business PO if necessary.

It is important to keep in mind that the purpose of the evaluation of these contingencies is to assess the probability of commerciality of the project. It is also important that the **horizon for the evaluation of the resolution of these contingencies is 10 years, as stated in CR EP RES 001**. For this reason, the total PO to be considered has to take into account the global context and has to be validated by the senior management (DIG, COVAL or above). Then the total PO can take one of the following values (Table 2):

Table 2: Probability of Occurrence (PO) classification

Probability	Description
100%	Certain (no risk)
80%	Very likely
60%	Rather likely / more likely than not
40%	Rather unlikely / more unlikely than likely
20%	Very unlikely

4.3.1.1 Technical

These contingencies are divided into Geosciences for the 3 SRV indexes (Volume in place, Geometry of SRV and Recovery) and Technological (Surface).

Geosciences PO (PO_{Geo}) are related to the current knowledge and current vision. This PO represents the chances that the planned acquisition results confirm the vision case. In unconventional plays, **Volume in Place (V)** is related to both petrophysical and structural parameters (porosity, saturations, thickness, pressure…) but also TOC (total organic carbon), maturity or kerogen type for shale plays.

Recovery mechanisms (R) in Unconventional plays are quite complex, the description of the physics that control the recovery of hydrocarbons is not completely understood and its impact is very uncertain.

Geometry of SRV (G) risks are related to the frackability of the rock and the development of the SRV. Different stress regimes, stress anisotropy, geomechanical parameters or natural fractures can have a dramatic impact on the creation of the SRV and its complexity. While these elements are unknown, the risks associated to the geometry of the SRV are very high.

Surface (S) risks include anything related to processing and transport from wellhead to export point (including HSE). In the case of unconventional developments:

- Access to water for hydraulic fracturing and disposal of produced water
- Development of zones in remotes area or topographically complicated

4.3.1.2 Non-Technical

The non-technical contingencies are related to Commercial assumptions for the implementation of the project. These can be categorized into **Economical** and **Business** risks.

Economics take into account factors that are specific to the project like technical costs or the application of the (hypothetical) contractual conditions between the authorities, investors and partners. For example:

- In the case of unconventional plays, some countries may favour the development of domestic resources by more favourable conditions to unconventional plays such as incentives and tax credits (Oil Windfall Profit and Tax act section 29 in the US) improving the economics. These programs are sometimes extended for many years, but the actual extension might not be confirmed very much in advance, representing a risk.

- When significant quantities of hydrocarbons are discovered, the existence of a market could be a problem. In this case, projects will be evaluated differently according to the market they target, since prices may differ.

Business risks can include any element beyond contractual conditions: such as authorizations, financing, local or global business context, group exposure or commitment, etc.

- The commitment of the group to pursue a project has to be consistent with the strategy: projects that are already included in the different cases of the LTP (Long Term Plan), are already considered for development by the group, and hence should obviously have higher PO than projects that are not included.
- In the case that discovered resources far exceed the domestic demand, the need for export facilities requires a bigger investment that the group might not be ready to spend in a near future. In this case the decision could be made after ten years and these projects cannot be booked as Contingent Resources.

4.3.1.3 Global PO

The combination of all the individual PO's is not a straightforward process, since all the risks are not independent. So after evaluating the individual PO's a global PO is estimated, this value is rounded to: 100%, 80%, 60%, 40% and 20%.

4.3.1.4 General rules to fill the PO

In the same way EP/EXPLO has recommendations on which **PS** should be given to an **object** based on available data; guidelines can be made on which **PO** should be given to a **project**:

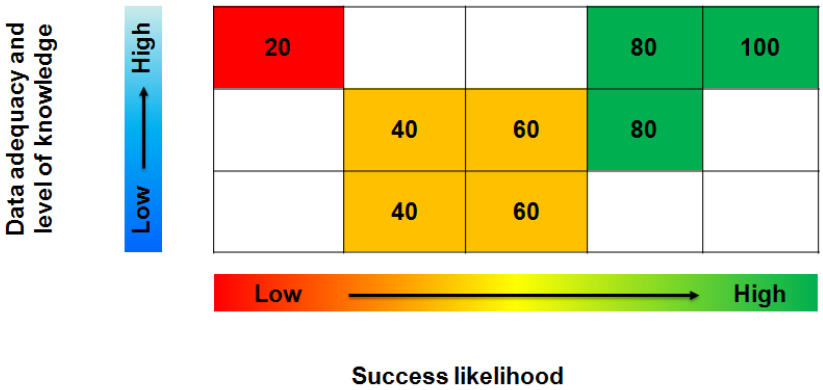

Figure 2 : Guidelines on PO attribution

4.3.2 Classification of Contingent Resources

Contingent Resources are by definition sub-commercial discoveries and need to be classified according to their maturity. The group recognizes two classifications for Contingent Resources: Status C and Status D (more possible categories of contingent resources are currently considered by the Corporate Reserves Group). As stated in CR EP RES 001, the distinction between these sub-classes is related to the probability of reaching commercial stage in a reasonable timeframe (chance or commerciality) which is reflected by its associated PO.

A sector that was discovered by an exploration well or an appraisal well should be classified as Contingent Resources while a virgin sector will still be classified as Prospective Resources.

4.3.2.1 Status C: projects under evaluation

These have a reasonable potential to reach commercial development but due to technical or business reasons are not mature yet. Critical risks and contingencies have been identified and are likely to be resolved in a reasonable timeframe (5 years) with further data acquisition and/or additional studies. In unconventional plays typical examples of these are:

- Projects within sectors (sectors are defined in chapter 5) which have been de-risked and are waiting for sanction. In these cases contingencies could be related to the management decision to pursue the project over other projects that can be more profitable, it could also be related to the concession of a license or the possibility of placing the gas resources in a market.
- Projects within sectors that have not been fully de-risked but have relatively low risks and there is an intention of the group to de-risk them in a reasonable timeframe. In this cases the Type Well Curves/economics/fluid composition are still uncertain so pre-projects could be necessary to increase the chance of commerciality and the PO.
- Status C resources can have a 20% total PO if the uncertainties are high as long as there is an action plan to reduce them.

4.3.2.2 Status D: projects not viable

- Projects within sectors that have been de-risked and have poor results or challenging economics or there is no intention of the group to pursue them in a reasonable timeframe (5 years).
- Projects within sectors that have not been fully de-risked and there is no intention of the group to de-risk them in a reasonable timeframe (5 years).
- Status D resources cannot have a total PO higher than 20%.

4.4 Reserves

As stated on Rule 5 of the CR EP RES 001:

Rule 5:

The following conditions shall be met to recognize reserves on a given project:

<u>Reserves</u> are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves shall further satisfy four criteria: they shall be discovered, recoverable, commercial and remaining (as of a given date) based on the development project(s) applied.

In unconventional plays, large number of wells could be PUD but have to be drilled within 5 years to be SEC reserves. This is very important since once large areas have been de-risked it is common to have several hundred or even thousands of locations to drill within the proven area. Although these locations are already de-risked and EUR can be estimated with low uncertainty, they will be drilled only once the group has decided to do so and capital has been allocated to this end, while the drilling plans of the group may change by factors that do not depend of a particular play, such as petroleum prices, global or local context, or other factors influencing strategy.

On the other hand, having hundred or even thousands of low risk locations "ready to drill" is one of the major advantages of unconventional plays over conventional ones. Once surface facilities are already built, drilling plans can be adjusted to the group strategy, local and global contexts. This flexibility is a major advantage for diversified oil companies with unconventional plays in their assets.

A particular aspect of unconventional projects is the amortization of initial CAPEX. The amortization process is based on the ratio of 1P volumes produced per year over the 1P reserves. In unconventional wells, the 1P production profile declines very fast meaning that a large ratio of the 1P reserves is produced quickly. Amortization happens then quickly which will have an impact on financial results. It is therefore important to not underestimate the 1P in the early life of the wells in order to limit the effect of amortization.

5. Play Sectorization

Segmentation is a term often used in the exploration phases to define different regions of a same play to determine iso-risk zones or **segments** or **geo-domains**.

In the case of development phases, a similar approach can be done in order to define regions of similar characteristics called **sectors**. In each sector it is reasonable to assume that wells drilled within the same sector will have similar production profiles with its similar risks and uncertainties.

In the cases of thick plays, **sectors** can be identified both vertically and horizontally. In these cases each vertical horizon represents a particular sub-play that can have different areal subdivision than the other horizons.

A sector is one delimited area of one landing zone (or formation or sequence) with probable continuity of parameters controlling the SRV indexes (Resources, Geometry and Productivity).

In contrast with conventional reservoirs, unconventional reservoirs have typically a very low risk of hydrocarbon presence since they are continuous accumulations. The major uncertainties tend to be around local reservoir properties that control well productivity and ultimate recovery. **According to the Rule 3 of the CR EP RES 001, productivity has to be established for an accumulation to be considered discovered.**

Although unconventional plays are often described as laterally continuous, they are also notoriously heterogeneous, requiring a greater sampling density than conventional reservoirs to define uncertainties and successful pilot projects to establish a range of recovery efficiencies (PRMS 2007).

For an accumulation, or part of an accumulation within a particular segment to be considered a sector, the uncertainties of productivity of future wells have to be established within a reasonable range. The purpose of the "sectorization" exercise is to represent the specific risks and uncertainties of each zone and to condense the different rock, fluid and geomechanical characteristics into distinct sectors than can be quantified by different type curves.

Characterizing the underlying rock and fluid property trends that control well productivity helps understanding why some sectors are better than others, and hence concentrate our efforts on the sectors with the greatest potential.

5.1 SRV quality indexes

In order to establish the productivity of a given sector, the characteristics that control well productivity have to be constrained; **SRV quality indexes** consist in an attempt to group these characteristics into functional relationships that account for the parameters that control:

- Resources in place.
- Fracture Geometry to be generated.
- Well productivity.

This is an attempt to break down the play productivity into its fundamental elements. Each SRV QI is not necessarily a number that can be determined, but a group of several parameters constrained to particular ranges, to characterize one of the previous aspects that control well performance.

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Table 3 summarizes the main parameters used to evaluate the 3 SRV indexes and an intent to rank them in priorities.

Table 3: Parameters impacting the SRV indexes

	SRV Indexes				Acquisition
	Resources	Geometry	Productivity		
Pressure (bar)	x		x	P0	DFIT/MDT
Fluid type / maturity	x		x		Test/PVT sampling/from Vro
Bo or Bg	x		x		Test/PVT sampling
CGR or GOR	x		x		Test/PVT sampling
Surface (km2)	x				
Thickness (m)	x				
Porosity (%)	x				NMR/NEU
Elastic properties (E, v)		x			Fullwave sonic log/triaxial tests
Shmax orientation		x			Image log
Stress regime (SSFR, NFR…)		x			DFIT/Image log/DEN
Hydraulic fractures dimensions		x			Microseismic
Linear Flow Parameter			x		WHP/ Surface rates/PVT

	SRV Indexes				Acquisition
	Resources	Geometry	Productivity		
Depth (m)	x			P1	
Fluid saturations (%)	x				RES/NMR
TOC (%)	x		x (through desorption)		Spectral GR/Pyrolysis/DEN
Mineralogy	x	x			XRD/Multimin
Shmin magnitude		x			DFIT
Horizontal Stress anisotropy		x			From stress regime
Natural fractures density		x			Image log
Natural fractures orientation		x			Image log
UCS/Shmax		x			Scratch test
Permeability (mD)			x		Step decay
Cum HC per foot			x		Surface rates
Hardness		x		P2	Micro indentation
Temperature (°c)	x				
Brittleness Index		x			From mineralogy
End of linear flow			x		WHP/Surface rates/PVT
Viscosity			x		PVT

5.1.1 SRV Resources

SRV Resources implies understanding sedimentary facies and associated basin scale morphologies, lithological changes in relation with depositional environments, and finally the intimate relations between the most carbonaceous facies (HC production and storage) and those ensuring the rigid frame of the reservoir (hydraulic frac design and management).

The sedimentary model assesses geological facies definition, their lateral and vertical distribution in relation with sequence stratigraphy. It is the key to predict the areas combining the best factors in terms of kerogen content and lithological composition. Facies calibration is based on core micro- and macro-lithological description (including local microfauna), mineralogical and petrophysical analyses.

The good consistency between depositional facies and their mineralogical composition allows defining log based shale types along all the studied wells. Large scale correlations then underline the links between facies associations and the stratigraphic patterns highlighted on seismic profiles.

5.1.1.1 Organic geochemistry

One parameter of the SRV Resources index is TOC or Total Organic Carbon. TOC can be measured on cores with the Rock-Eval pyrolysis technique. In Rock-Eval pyrolysis, a sample is placed in a vessel and is progressively heated to 550°C under an inert atmosphere. During the analysis, the hydrocarbons already present in the sample are volatized at a moderate temperature. The amount of hydrocarbons are measured and recorded as a peak known as S1. Next pyrolyzed is the kerogen present in the sample, which generates hydrocarbons and hydrocarbon-like compounds (recorded as the S2 peak), CO2, and water. The CO2 generated is recorded as the S3 peak. Residual carbon is also measured and is recorded as S4. TOC is calculated function of S1, S2 and S4. High frequency TOC can also be measured on cores using the LIPS (laser induced pyrolisis system). It provides a high resolution TOC log.

In Total, these experiments are performed at the FGO lab.

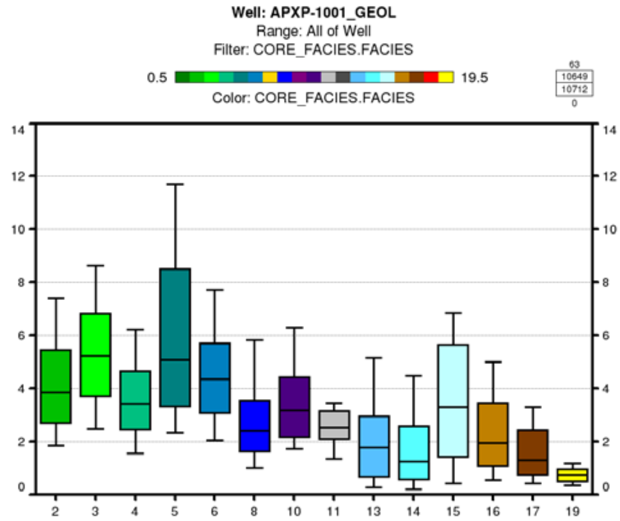


Figure 3: Core TOC (LIPS acquisition) histogram per facies class in well AP.xp-1001

The TOC as measured by FGO on Rock-Eval will be identical to the IOM (Insoluble Organic Matter = Kerogen content) interpreted by ISS/RGM for very mature shale like in the Aguada Pichana area (late gas window, no significant pyrolysable HC left). However for lower maturity shale (oil window, R0<1.2), there is a possibility for the IOM to be much lower than the Rock-Eval TOC because the HC corresponding to the S1 peak is washed away for the IOM measurement.

TOC can also be measured from logs interpretation. Table 4 summarizes the different techniques of organic matter measurement.

Table 4: Different TOC measurement methods

<table>
<tr><th colspan="3">Source</th><th colspan="4">Intermediate results</th><th>Final Result</th></tr>
<tr><td rowspan="2">Core</td><td>(PERM/FGO)</td><td>RockEval (S3 not accounted for)</td><td>S1*</td><td>?</td><td>S2*</td><td>S4***</td><td>TOC*</td></tr>
<tr><td>(ISS/RGM)</td><td>LECO</td><td colspan="2"></td><td colspan="2">IOC***</td><td>IOM*</td></tr>
<tr><td rowspan="3">Log</td><td rowspan="3">COP/INT</td><td>PHI + Resistivity + SW equation</td><td colspan="2">VOL_HC**</td><td colspan="2"></td><td rowspan="3">VOL_HC**
+
VOL_KER**</td></tr>
<tr><td>Density + URAN (+ NMR) + equations</td><td colspan="2"></td><td colspan="2">VOL_KER**</td></tr>
<tr><td>Inelastic/elastic neutron spectroscopy</td><td colspan="4">TOC***</td></tr>
</table>

* in mgHC/g, ** in volume fraction, *** in weight fraction

5.1.1.2 Petrophysics measurements

- **Porosity**

Another parameter of the SRV Resources index is the porosity. Porosity can be measured with different methods at the PERM/PETRO lab: NMR (Nuclear Magnetic Resonance) and pycnometry for example.

An example of diagrams of porosity frequency distribution per facies class (Figure 4) show that:

- F1, F2, F4, F5, F6 and F7 display high porosity values ranging from 14 to 16.7% that could be either related to clay bound water and/or organic matter porosity variations
- "Carbonated pole" F8, F9, F10 display a lower porosity range varying from 11.2 to 11.8%.
- Slope facies F11 display the lowest porosity values (8.3%)

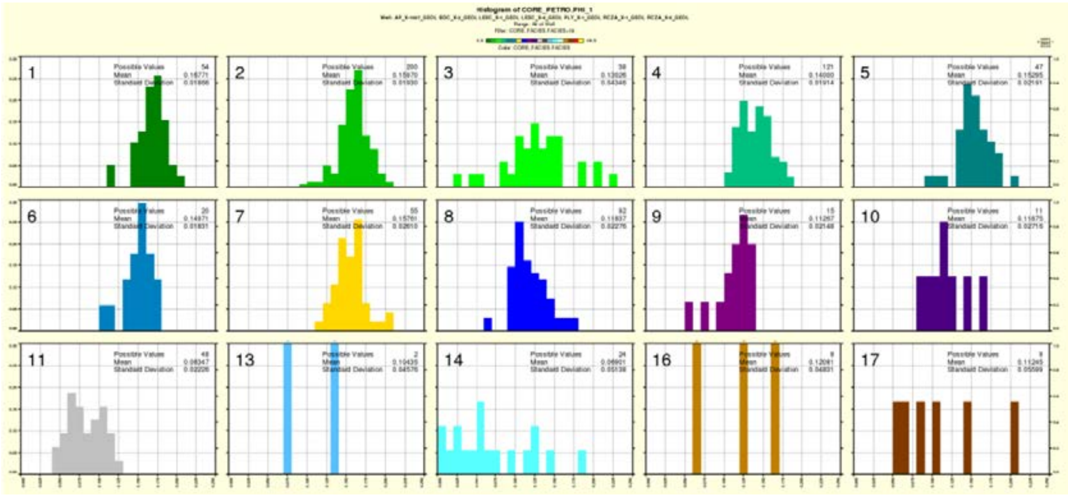


Figure 4: Core Porosity distribution per facies class

In shales, porosity can be intra-granular or associated with organic matter. The last one can form a connected network or not depending on its preservation. The following example shows the comparison between two shales samples of the connected pore network (pores>5nm). Example 1 shows a very small connected pore network associated with organic matter while example 2 shows a very high connected pore network.

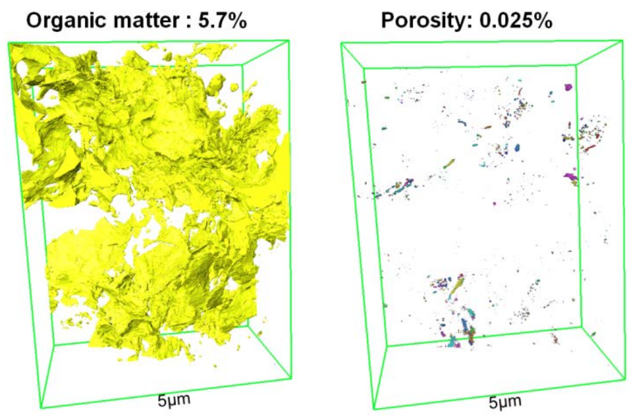


Figure 5: Organic matter and connected porosity of sample 1

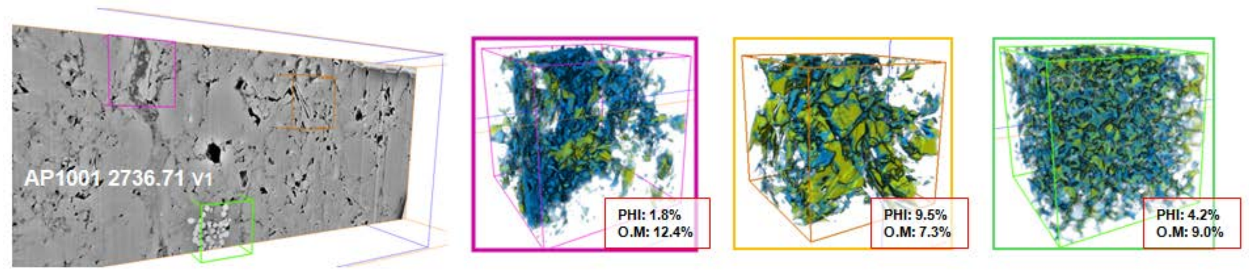


Figure 6: Organic matter and connected porosity of sample 2

- **Saturation**

The third parameter of the SRV Resources index is in-situ water saturation. It is a key parameter regarding HC volumes (direct impact) and production (relative permeability issues). Core values discussed in this study come from two distinct sources: NMR measurements and Dean Stark extraction.

NMR measurements

2D NMR (Nuclear Magnetic Resonance) is a non destructive method commonly used in the industry to provide porosity. Advanced NMR technique, such as 2D T_1-T_2 NMR is also used by the Total Petrophysic Lab's to estimate saturations.

NMR measurements are performed in house on 'as received' samples, then the samples are fully saturated (SW = 1) under pressure with brine and a new measurement is performed. In the case of *gas wells,* the initial water volume is considered as *in situ* water, leading to SW when divided by the total volume of water after complete brine saturation.

Dean Stark extractions

Dean-Stark (time consuming) and Retort fluid extraction (fast, but not always reliable due to the summation of fluid volumes) are the well known standard methods.

The workflow begins with an initial bulk measurement on as-received material. The sample is then crushed and initial grain density and permeability measurements are performed. Pore fluid saturation data is determined by Dean Stark Toluene extraction, followed by further cleaning with chloroform/methanol to remove any residual hydrocarbons impacting porosity.

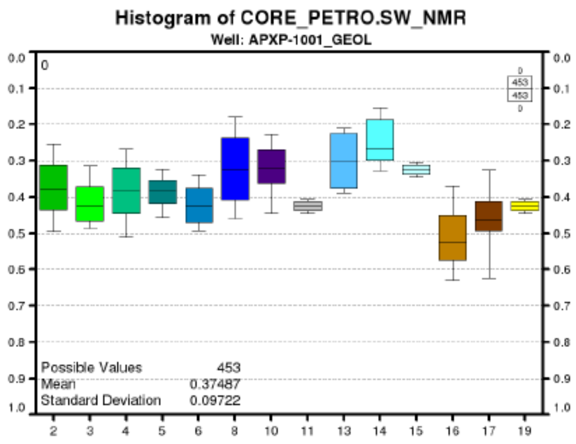


Figure 7: Water saturation distribution per facies

Some keys to understand the relations between facies and water saturation are provided in Figure 8. This plot shows the relations per facies between TOC and clay contents, i.e. two poles in terms of wettability regarding reservoir fluids. One preliminary conclusion is: the highest TOC, the lowest SW, and in the same trend, the highest clay volume, the lowest TOC.

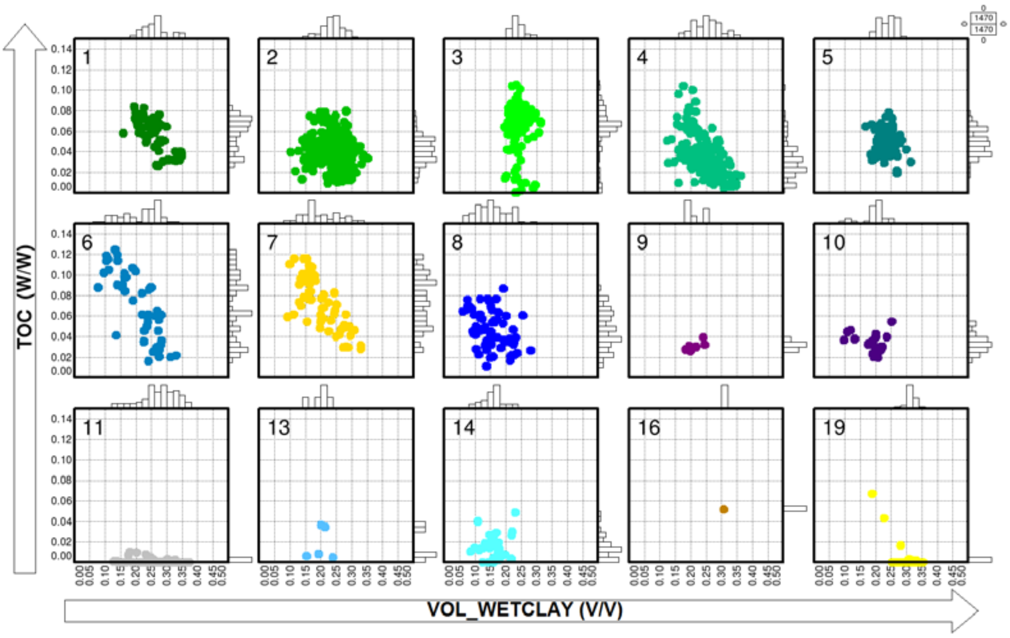


Figure 8: TOC vs. Clay contents relations per dominant core facies

The SRV resources index also includes typical volumetric parameters:

- Developable area
- Thickness
- Pressure and Bg or Bo
- Fluid type and GOR or CGR

5.1.2 SRV Geometry

SRV geometry describes the potential for creating and maintaining open fractures in regions where the SRV resource is high.

The SRV geometry can be described by four indexes which are:

- Fracability : ability to initiate and propagate a vertical hydraulic fracture
- Fracture conductivity: ability of both induced and natural fractures to remain open hydraulically under increased *in situ* effective stresses
- Fracture containment : development of fractures in lateral direction and confined in vertical direction
- SRV Complexity : ability to develop a complex Stimulated Rock Volume

A complete description of the SRV Geometry indexes can be found in the GM EP RES 800.

Table 5 lists the influence of geomechanical factors on each SRV geometry indexes (fracability, fracture conductivity, SRV complexity and fracture containment).

To assess SRV geometry indexes, Total has developed a dedicated workflow that includes laboratory tests on shale cores and Mechanical Earth Modeling (MEM) to obtain calibrated depth profiles of stresses and elastic properties with their associated anisotropy. To improve this workflow, the sedimentary facies information can be accounted for to derive continuous profile of Unconfined Compressive Strength (UCS) from scratch test and continuous profiles of Brinell Hardness Number (BHN) from micro-indentation tests.

Table 5: Influence of geomechanical factors on SRV geometry indexes: fracability, fracture conductivity, SRV complexity and fracture containment.

Geomechanical factors	Fracability	Fracture conductivity	SRV complexity	Fracture containment
Rock mechanical properties				
Elastic properties (E, ν)	**X**			
Hardness (BHN)		**X**		
Stresses				
σhmin magnitude	X			**X**
σHmax orientation			X	
Anisotropy ratio (min/max hor. Stress)			**X**	
Stress regime	**X**		X	
Brittleness Index				
Strength (UCS)/Smax	X			
Natural fractures				
Intensity			**X**	X
Orientation (dip, azimuth)			**X**	

5.1.2.1 Fracability

5.1.2.1.1 Definition

Fracability is a SRV geometry index which qualifies how efficiently a fracture forms (initiate and propagate) and is assessed by understanding the textural complexity of the system in relation to the in-situ stress (direction and contrast). Fracability is a combination of brittleness (rock failure under stress) and fracture growth (Table 6).

Table 6: Geomechanical factors influencing SRV geometry index: fracability and role

Factors influencing *fracability*	Role
Rock Mechanical Properties	
- UCS - Elastic prop. (E & ν)	• Use for Wellbore Stability analysis & mechanical stability of fracture walls • Control fracture geometry (length and width)
Stress Regime	
- Stress regime - Magnitude σ_{hmin}	• vertical growth of HF • Initiation of HF
Brittleness indexes	
- UCS/Smax; Mineralogy index; Sonic based index	• Describes how the rock fails

5.1.2.1.2 Elastic properties

Elastic properties of shale partly control the fracture geometry and the stress shadow effect. In particular Young's modulus in the direction parallel to bedding plane E_{11}, and Poisson's ratios ν_{13} and ν_{12}. .

Elastics properties are measured at core scale on plugs. These measurements are punctual and are used to build log profiles using log data.

5.1.2.1.3 Strength (UCS) properties

The Unconfined Compressive Strength (UCS) may be measured on core plugs or continuously with the scratch test experiment (in this case the UCS is indirectly determined from the experiment).

The scratch test data is considered as robust because it is issued from quasi continuous profile along a core. Input and output UCS values were respectively compared with the sedimentary facies defined by the sedimentologist along the cores and those issued from facies modeling as shown in Figure 9:

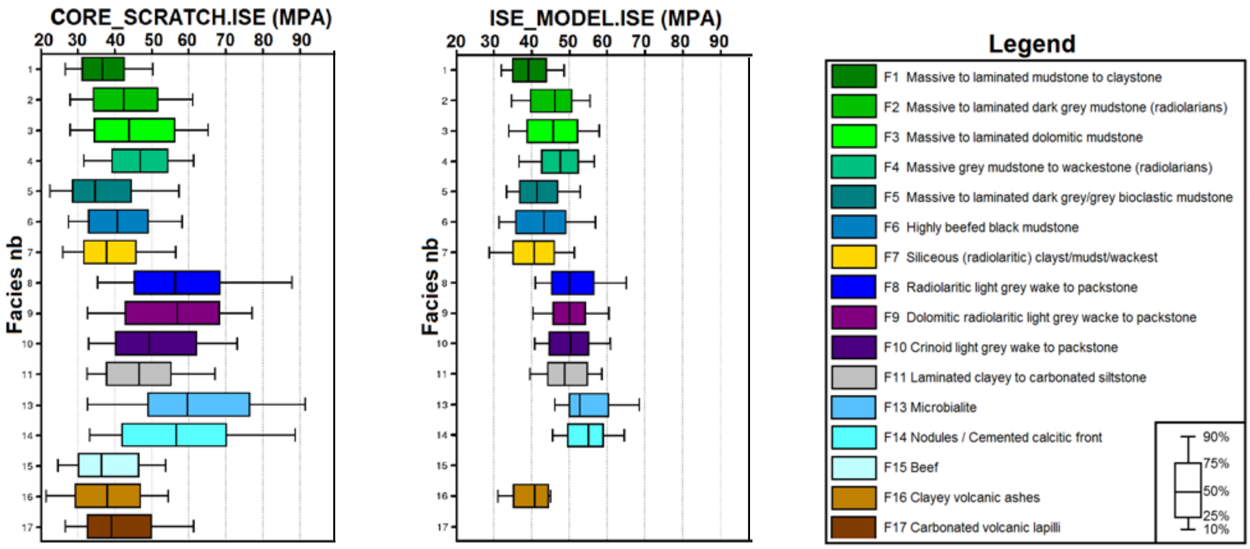


Figure 9- UCS distribution per sedimentary facies of the Vaca Muerta

5.1.2.1.4 Stress Regime

A basic assumption is that the principal stress directions are approximately vertical and horizontal. In this case, the principal stresses are denoted σ_V for the vertical stress, and σ_{Hmax} and σ_{hmin} for the maximum and minimum horizontal stresses.

According to their respective magnitude, the principal stresses can be classified into three different regimes, Andersonian classification (Figure 10): Normal Fault stress Regime, NFR (σ_v > σ_{hmax} > σ_{Hmin}), Strike-Slip Fault stress Regime, SSFR (σ_{Hmax} > σ_v > σ_{hmin}) and Reverse Fault stress Regime, RFR (σ_{Hmax} > σ_{hmin} > σ_v) regime. Depending on the stress regime, the natural fracture networks will be organized differently.

In the context of a Normal Fault Stress regime, the horizontal stresses are low. Mode I fractures (Tensile fractures – Hydraulic fractures) will be vertical and parallel to σ_{Hmax}. Reactivated mode II fractures (shear fractures) will strike +/- 30° to σ_{Hmax}.

In the context of a Strike-Slip Faulting Stress regime, mode I fractures (tensile fractures - hydraulic fractures) will be vertical and parallel to σ_{Hmax}. Reactivated mode II fractures (shear fractures) will strike perpendicular to σ_{Hmin}.

In the context of a Reverse Faulting Stress regime, model I fractures (tensile fractures - horizontal fractures) will be horizontal. Reactivated mode II fractures (shear fractures) strike parallel to σ_{hmin}.

For normal stress (non tectonic regions) and strike–slip stress regime (tectonic regions), a hydraulic fracture will develop vertically whereas in a reverse (or thrust) fault stress regime, a hydraulic fracture will develop horizontally meaning low productivity as vertical permeability can be one decade or more lower than horizontal permeability. Reverse Fault stress Regime is a geological context to be avoided for hydraulic fracturing.

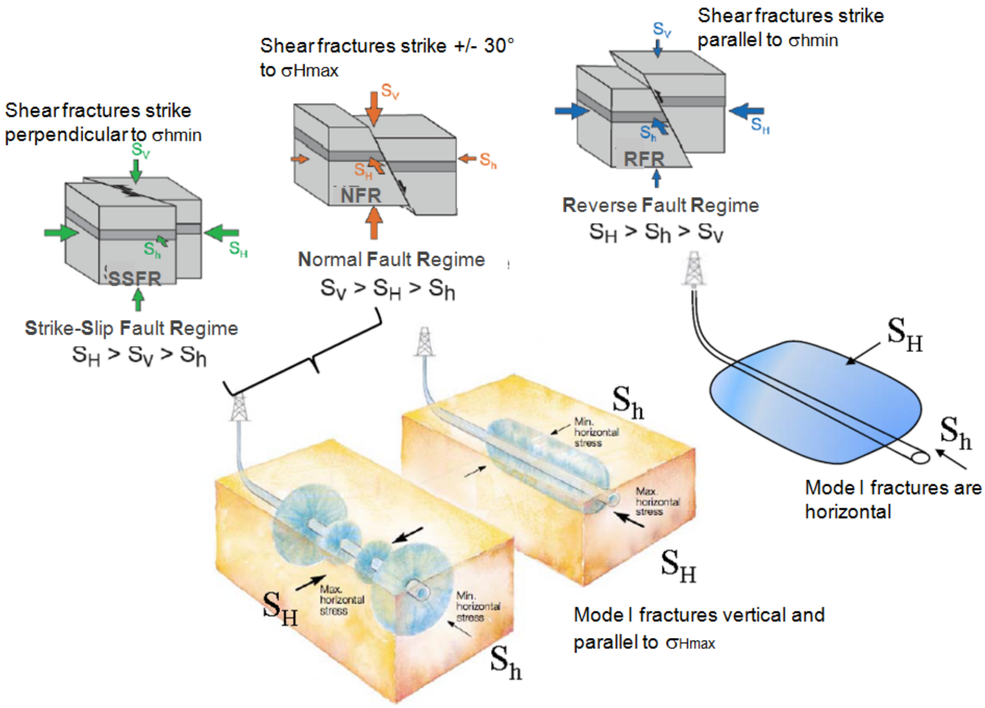


Figure 10- The three faulting stress regimes (SSFR, NFR and RFR) and their consequences on hydraulic fractures Mode I (tensile) and natural fractures Mode II (shear).

5.1.2.1.5 Brittleness Indexes

- Definition:

Brittleness is a common term used to describe how rocks fail. Most rocks deform in a brittle manner at low confining pressure and become ductile above a certain level. There is no unique definition of a brittleness parameter (or Brittleness Index: BI). Mainly there are geomechanical definitions based on tests conducted on core and geological/geophysical definitions respectively based on mineralogy and elastic properties. A literature review was conducted (Vidal-Gilbert, 2015 [1]) and only three indexes were chosen.

- Mineralogy brittleness index

A mineralogy based Brittleness Index is calculated from mineralogical analyses such as bulk XRD-XRF or from mineralogical log using the following formula:

$$\boldsymbol{Mineral - Base : Brittleness\ Index: B10} = \frac{\mathbf{W\ QF + W\ Carb + W\ Pyrite}}{\mathbf{W\ QF + W\ Carb + W\ Pyrite + W\ Clay + W\ OM}}$$

Where: W QF = dry mass % Quartz and Feldspars; W Carb = dry mass % of carbonates (including dolomite); W Pyrite = dry mass % of pyrite; W Clay = dry mass % of clay minerals; OM = dry mass % of insoluble organic carbon (IOM).

- Sonic log based brittleness index

$$\mathbf{B12} = \frac{\mathbf{En+\nu n}}{\mathbf{2}}$$

Where E_n and ν_n are respectively normalized dynamic Young's modulus and Poisson's ratio and are defined as follow:

$$\boldsymbol{E_n} = \frac{\boldsymbol{E - E_{min}}}{\boldsymbol{E_{max} - E_{min}}} \text{ and } \boldsymbol{\nu_n} = \frac{\boldsymbol{\nu_{max} - \nu}}{\boldsymbol{\nu_{max} - \nu_{min}}}$$

Where E_{max} and E_{min} are the minimum and maximum dynamic Young's module for the investigated formation.

- Geomechanical brittleness index

Su et al. (2014) [2] used a geomechanical brittleness index based on UCS. With this information a brittleness index (B13) is defined as the ratio between UCS and σ_{max}.

From scratch test data and sonic log: $\mathbf{B13} = \frac{\mathbf{UCS}}{\boldsymbol{\sigma}\mathbf{max}}$

5.1.2.2 Fracture conductivity

5.1.2.2.1 Definition

Fracture conductivity is the ability of both induced and natural fractures to remain open hydraulically under increased *in situ* effective stresses. Fracture conductivity is assessed with proppant embedment and conductivity measurements under varying conditions of fracture closure stress, fracturing fluids and resident time. Table 7 shows the parameters that influence fracture conductivity and the ways to assess them.

Table 7 - Geomechanical factors influencing SRV geometry index – Fracture conductivity: role and tools to assess these factors

Factors influencing *Fracture conductivity*	**Role**	**Means/methods to assess attributes**
Rock Mechanical Properties		
- Brinell Hardness Number - Creep	• Characterizes risk of proppant embedment • Characterize loss of fracture conductivity over time	• Micro-indentation tests • Permeability test • Creep tests

5.1.2.2.2 Brinell Hardness

The Brinell Hardness of the fracture wall characterizes the risk of proppant embedment.

Micro-indentation measurements with spherical indenter can give access to the Brinell Hardness Number (BHN) on full core (Figure 11).

$$\text{Brinell Hardness} = \frac{\text{Applied Force (kg.f)}}{\text{Surface area of the intender trace on rock (mm}^2\text{)}}$$

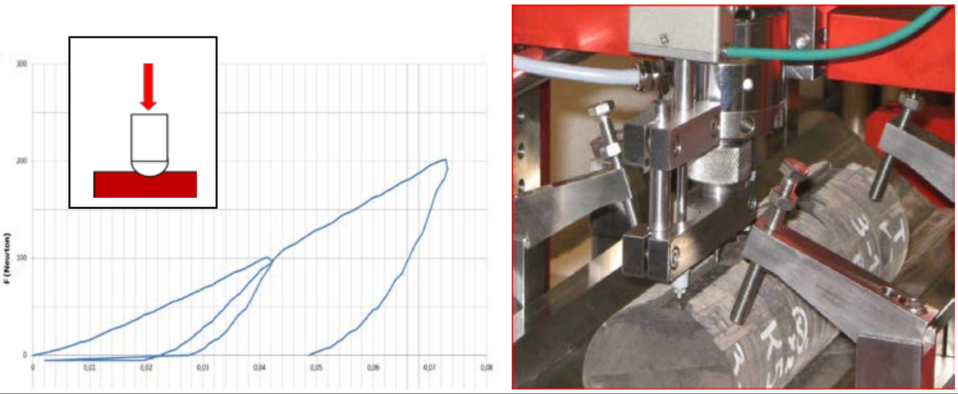


Figure 11 - Micro-indentation test (spherical indenter) to measure Brinell Hardness Number

5.1.2.2.3 Other tests

- <u>Permeability tests</u>

Water and gas permeability of fracture filled with different proppant concentration and under *in situ* effective stress condition is a key parameter for optimization of proppant recipe used in hydraulic fracturing jobs. Total has developed an experimental set-up allowing creating shear fracture on a cylindrical plug of shale rock in a conventional triaxial cell thanks to two specific heels placed on the top and bottom of sample (Figure 12). Permeability tests to water and to gas have been carried out according a specific protocol simulating the change of in situ effective stress and pressure gradient in the near and far field of perforation. These tests were interpreted using Poiseuille's law taking into account the gas compressibility and considering the fracture as two parallel plates. After creating shear fracture in a triaxial cell, Su et al. (2017) performed successively measurements of permeability to gas, to water then to gas.

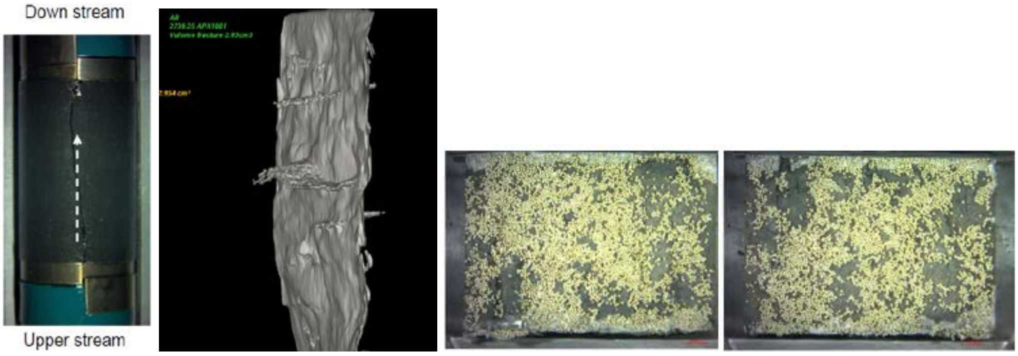


Figure 12 - Protocole to create shear fracture; Shear fracture shape observed with CT scan and proppant placement into the shear fracture after permeability tests

- Creep tests

Creep is non-instantaneous stress-strain behavior where deformation incorporates a time constant that is governed by the viscous properties of the rock. Fracture in shale that is maintained open by proppant may close and lose of fracture conductivity over time.

5.1.2.3 Fracture containment

5.1.2.3.1 Definition

Fracture containment is assessed by understanding the stress contrast from rock class to rock class and also by understanding the rock interfaces between them. Fracture containment is not only due to stress barrier it could be also induced by the presence of weakness planes, laminations effects, ash layers, nodules, beefs or other discontinuities.

Table 8 - Geomechanical factors influencing SRV geometry index – Fracture containment: role and tools to assess these factors

Factors influencing *Fracture containment*	**Role**	**Means/methods to assess attributes**
Stress Regime		
- σ_{hmin} **magnitude**	• Vertical stress variation → stress barrier	• DFIT • Stress model (image log for wellbore stability analysis)
Lamination effects		
- **Ash layers** - **Beefs**	• lamination effects : Vertical geological variation → frac barrier	• Image log • Core description

Table 8 shows the parameters that influence fracture containment and the ways to assess them.

5.1.2.3.2 Stress barrier

The easily identified fracture containment index is the stress barrier between layers of different lithologies. If layering is clearly marked, the stress profile varies vertically. For example in Figure 13, track 10 shows that the modeled fracture is contained due to stress barrier in track 9. The fracture profile (tracks 5 and 10) and fracture width (tracks 6 and 11) are different according to the assumption made on the stress model. With the isotropic stress model, the fracture profile and width show the unsuited growth into the bottom clay rich layer and part of the propped fracture half length is contained out of the reservoir target.

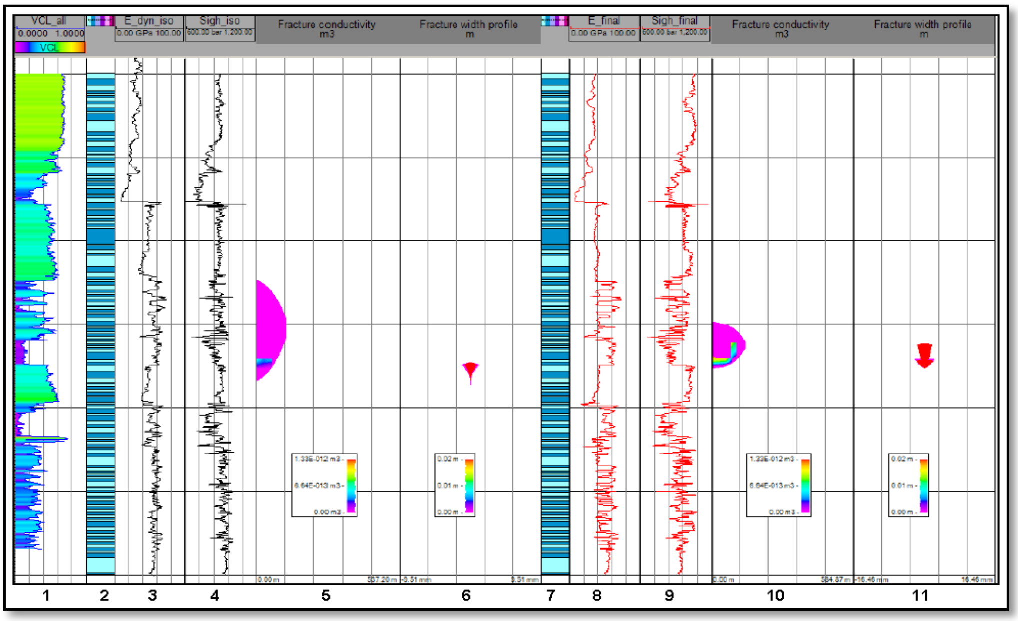


Figure 13 - Effect of anisotropic stress model on fracture geometry. De Gennero et al. (2014) [3]

5.1.2.3.3 Lamination effect

However even if these stress variations locally are not enough to consider them as stress barrier, the targeted facies are acting as planes that weaken the hydraulic fracture.

Suarez-Rivera et al. (2016) show that a primary source of height growth suppression is the pervasive rock layering in mudstones and hybrid reservoir systems, which often exhibit strongly contrasting properties between layers and weak interfaces at their contacts. In some reservoirs and in particular in Vaca Muerta formation, bed parallel ash beds and mineralized veins (beefs) are also present, and all of these interfaces can be weakened further by tectonic deformation.

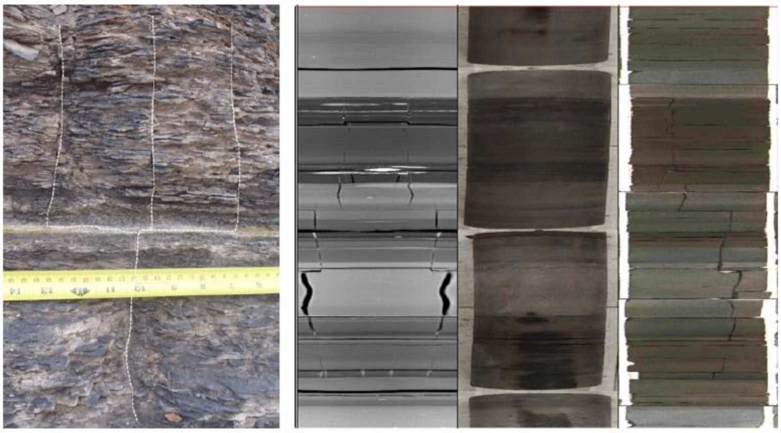


Figure 14 - Examples of interactions between fractures (geologic and core induced) with interfaces associated to the thinly layered rock fabric (left- field example, left center-CT coronal image, right centerwhole core photo and right-slabbed core photo) (Suarez-Rivera et al. 2016)

5.1.2.4 SRV complexity

5.1.2.4.1 Definition

SRV Complexity describes the ability to develop a complex Stimulated Rock Volume in a horizontal plane but also vertically as previously mentioned with lamination effects. Table 9 shows the parameters that influence SRV complexity and the ways to assess them.

Table 9 – Geomechanical factors influencing SRV complexity: role and tools to assess these factors

Factors influencing *SRV complexity*	**Role**	**Means/methods to assess attributes**
Stress Regime		
- **Horizontal stress ratio**	• controls the possible range of azimuths of vertical fractures	• Stress model (image log for wellbore stability analysis)
Natural fractures		
- **NF intensity** - **NF orientation**	• Interaction between hydraulic fractures and natural fractures • NF fracture reactivation	• Image logs, core description, outcrop • Microseismics, seismic data

5.1.2.4.2 Horizontal stress ratio

Horizontal stress anisotropy ratio is defined as the ratio between σ_{Hmax} and σ_{hmin} and it controls the possible range of azimuths of vertical fractures and the SRV complexity.

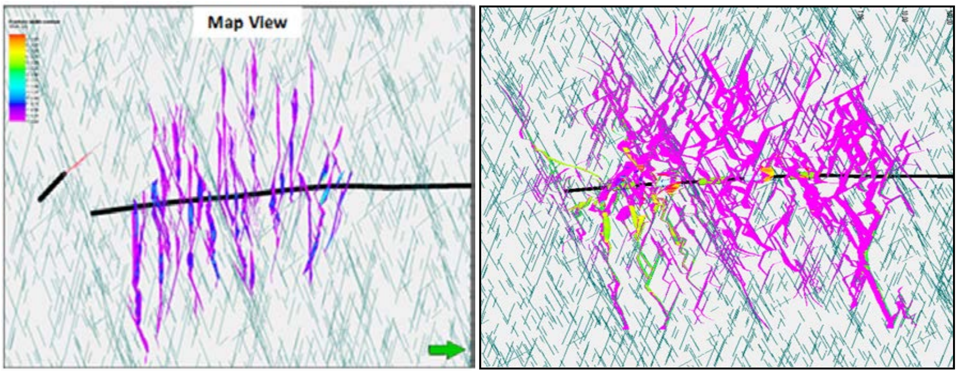


Figure 15 - SRV Modeling showing the effect of horizontal stress anisotropy a) SHmax/Shmin ~1.18 and b) SHmax/Shmin =1.08 on SRV complexity

5.1.2.4.3 Natural fractures

Microseismic event patterns associated with hydraulic-fracture stimulation have recently been described to natural fracture reactivation, and many shale outcrops, cores, and image log contain fractures or fracture traces. Gale et al. (2014) [4] performed a review of natural fractures within 18 shale plays, reveal common types of shale fractures and their mineralization, orientation, and size patterns. They identify three common opening-mode fracture configurations subvertical fractures, bedding plane fractures and compacted fractures. Figure 16 presents two of the three fracture configurations, example from Vaca Muerta core samples.

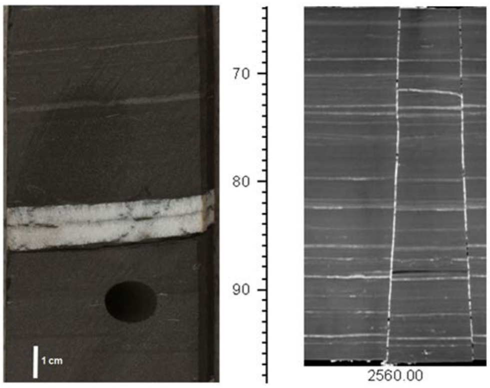


Figure 16 - Types and configurations of fractures: a) bed parallel fractures – beef APx1001 b) subvertical fractures from SR1010 core

Data used is coming from outcrops, core description and few image logs. A wide range of shales have a common suite of types and configurations of fractures. Fracture systems in shales are therefore heterogeneous. Vertical fractures are abundant enough to be widespread in cores and in outcrop. Although shales generally have fewer small-aperture (<30 µm) fractures than other rock types, the overall abundance of fractures at least 1 mm in width is comparable to the fracture abundance in several tight-gas sandstones and carbonates. In their review, Gale et al. (2014) [4] established some statistics on fracture height and aperture for subvertical fractures (Figure 17).

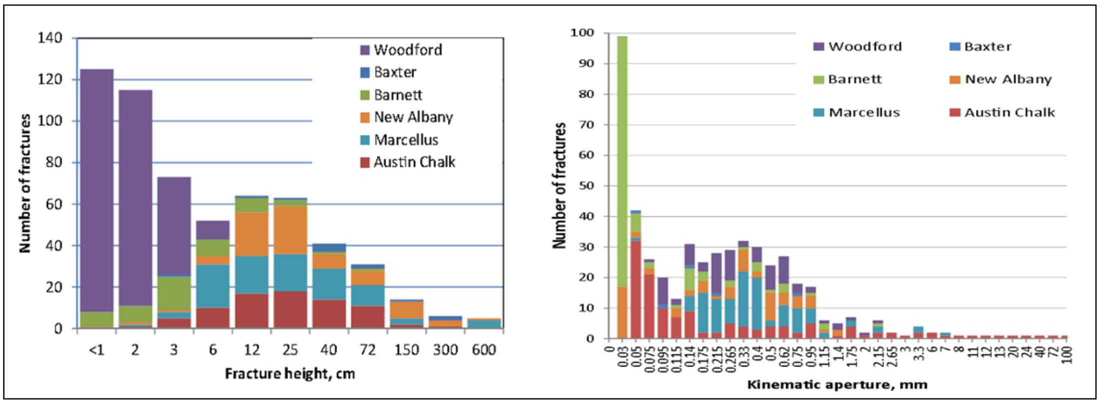


Figure 17- Histograms of (a) fracture aperture size (b) Fracture heights in core only. Color coding is by formation. Fracture numbers are not normalized to core/outcrop length.

In hydraulically fractured wells, there are today 3 independent methods to estimate/calibrate the dimensions of the SRV:

- Microseismic interpretation and estimation of the size of the SRV and fractures
- Frac modeling by matching the treatment pressure of the frac job resulting in an estimation of the size of the fractures
- Rate Transient Analysis: by matching the production data playing with the size of the fractures as a matching parameter

5.1.3 SRV Productivity

Wells in unconventional plays have to be fractured to produce at profitable rates and due to its low to ultra-low permeabilities, produce at transient regime for long periods of time.

Linear flow dominates the early to mid production times on unconventional plays. This flow is characterized by parallel flow lines that converge to a planar surface (the hydraulic fracture). This is typically the case in low permeability reservoirs that produce through large hydraulic fractures. The constant rate solution of the diffusivity equation for a slightly compressible fluid (oil in this case) is:

$$q_o = \frac{A\sqrt{k}(P_i - P_{wf})}{6.3839B_o}\sqrt{\frac{\emptyset c_t}{\mu t}}$$

The relationships between the parameters that define production rate for an oil well (the gas case is analogous) show that it is:

- Proportional to area (fracture area).
- Proportional to the square root of permeability.
- Proportional to drawdown.
- Inversely proportional to the square root of viscosity and time.

The parameters that create the productivity of a well are looked up into detail.

5.1.3.1 Permeability

Characterization of gas and oil shales reservoir is a challenging task since the unconventional reservoirs have tight pore throats and low permeabilities. Shales require careful identification of reliable methods.

Steady-state techniques are time consuming requiring for measurement hours and days of characterization process.

Unsteady-state techniques commonly referred to as "pulse decay". Measurements can be performed either on core plugs or on drill cuttings, the latest known as the GRI method (Gas Research Institute) is the cheaper and faster option. The Total in-house device is known as ''step-decay" which enables a fast and accurate characterization of low-permeability rocks. Measurements on whole-core plugs are recommended as much as possible.
For sake of clarity, diagrams on core permeability distribution per facies class are presented below (**Figure 18)** but do not bring light on permeability variation per facies class, almost all facies display same permeability range (~1microD).
However, sensitivity of permeability to stress was evaluated on selected plugs. Permeability under stress is illustrated for three different facies (**Figure 19).** It shows that permeability decrease with increasing effective pressure.

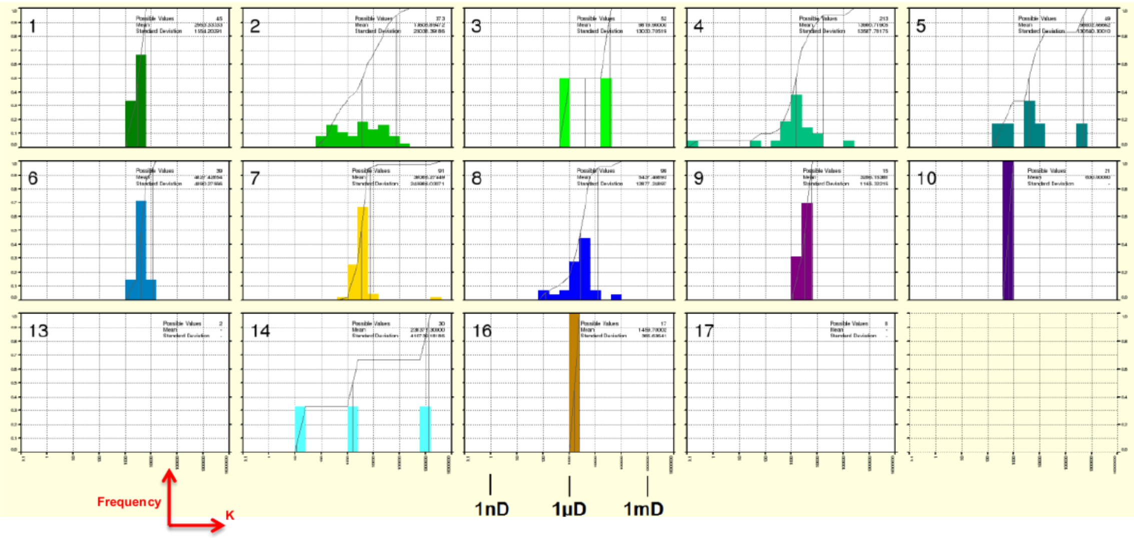


Figure 18 - Core Permeability (K) distribution per facies class

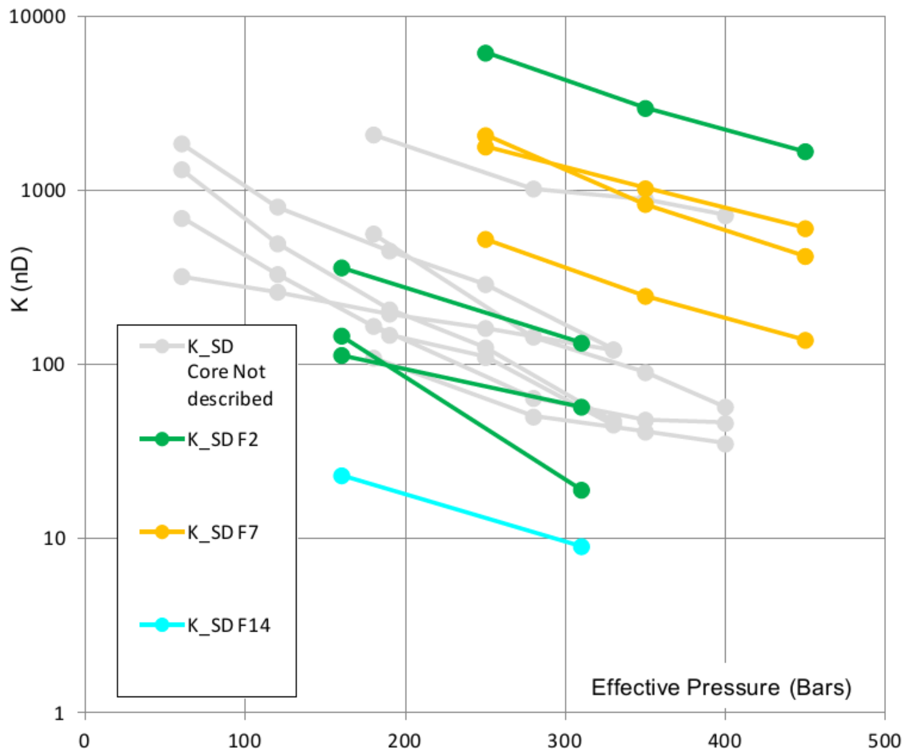


Figure 19 - Permeability step decay vs Effective Pressure. Siliceous mudstone F2, siliceous organic-rich mudstone F7, cemented nodules F14 (facies from Vaca Muerta)

Matrix permeability in shales being hard to evaluate and not necessarily straightforward to use (the effective average permeability of the SRV is enhanced by the fracturation process) a more practical dynamic parameter is used: the Linear Flow Parameter.

5.1.3.2 Linear Flow Parameter (LFP)

The A*k½ product is generally called Linear Flow Parameter (LFP). This parameter can be interpreted from production data with RTA techniques for a well in transient linear flow with relatively low uncertainty. It incorporates a reservoir *intensive* property (a property that doesn't change with sample size) such as permeability with an *extensive* property (that changes with sample size) such as Area. The facts that it incorporates intensive (permeability) and extensive (area) properties make this parameter dependent on rock quality and fracture design. The derivation of this parameter together with its estimation is explained in detail in GM EP RES 802.

The interpretation of the fracture area (A) in Shale reservoirs has a major impact on our understanding of how these plays produce. The hydraulic fracturing process in shale reservoirs creates propped Hydraulic Fractures and reactivates pre-existing natural fracture networks. The "secondary" network of fractures that is developed enhances the contact area between the reservoir and the well. The LFP for these reservoirs can be interpreted as in several ways:

- A planar fracture approach considers the area described in the LFP calculation as the hydraulic fracture half-length x_f times the height (h_f), times the number of fractures (n_f). And the permeability being the matrix permeability (comparable to the matrix permeability measured in cores).

- A complex fracture model (analogue to the presence of a natural fracture network added to the hydraulic fracture network). In this case the area corresponds to the one of the blocks that constitutes the double porosity reservoir that flow into the network of natural fractures connected to the well.

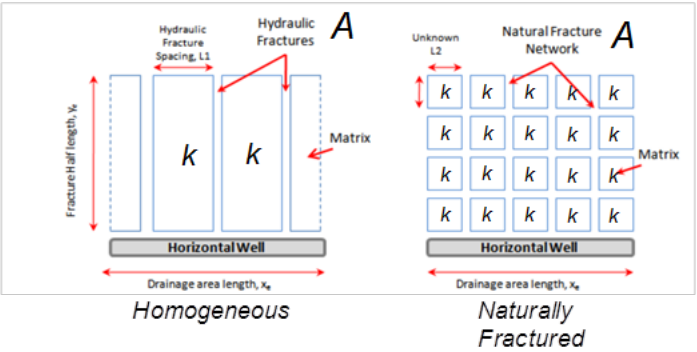


Figure 18: Planar fracture and complex reservoir descriptions.

Although the two models are equivalent in terms of flow description during linear flow, it is important to take into account that the Stimulated Rock Volume (SRV) is different and hence the time of end of linear flow (t_{elf}). In the planar fracture model the pseudo steady state flow that follows the first transient linear flow corresponds to the interference between the hydraulic fractures, while in the complex fracture model (naturally fractured) this corresponds to the depletion of the matrix blocks.

In conventional petrophysics, permeability (k) is a property directly related to rock quality, that is, in general more porous rocks have better reservoir capability and higher permeability. With this approach this parameter is only dependant on rock type. In the case of shale reservoirs hydraulic fracture stimulation jobs are thought to enhance the permeability of the reservoirs by re-activating pre-existent natural fracture networks, in this case permeability would be dependent on rock properties and hydraulic fracture design. **Permeability in shale reservoirs has to be classified based on petrophysical and geomechanical characteristics of the rock**.

The previous paragraphs show that LFP is highly dependent on rock quality and fracture design, a sectorization exercise based on the SRV Productivity QI should consider frac design. Fracture design can vary widely and there are many parameters that can be altered to improve well performance such as:

- Proppant loading and type (mesh size, natural vs. ceramic, concentration, etc.)
- Fluid loading and volume.
- Fluid type (Slick water, gel, hybrid, foam, etc.)
- Stage spacing
- Perforation clusters: number and spacing.

The fact that fracture design evolves very fast, especially on early stages of exploration and appraisal, makes it hard to compare different wells based on LFP only. For this reason LFPs have to be normalized in order to render them comparable, the difficulty of this resides on the multiplicity of parameters that can change rendering all normalizations imperfect.

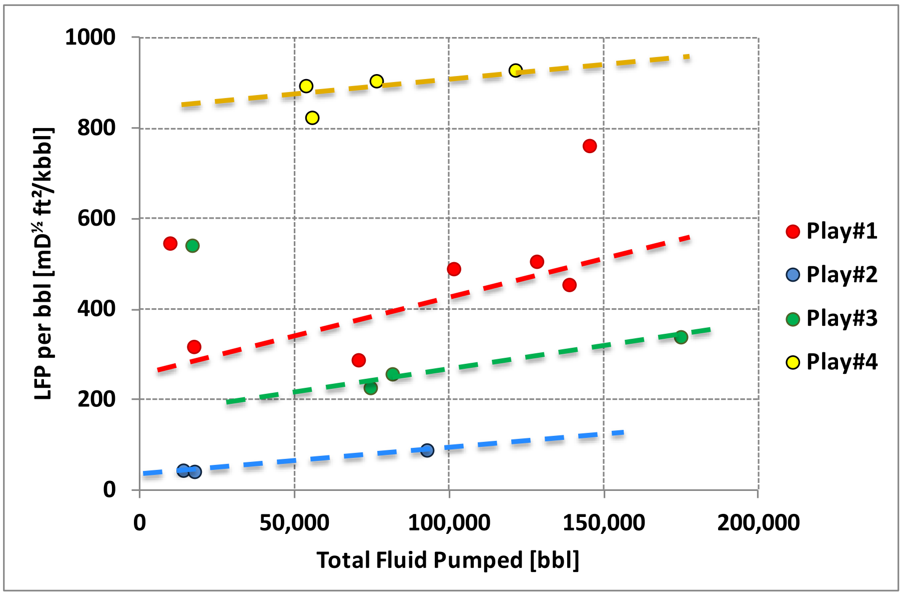


Figure 19: Plot of LFP per barrel for different plays, showing main trends and outliers

Figure 19 shows a scatter plot of LFP per vs. Injected barrels of fracture which constitutes a normalization by injected volume. The plot shows major trends for four different plays showing significant differences in these reflecting differences in this aspect of the SRV productivity index. The plot also shows some points that do not follow the main trends, these could be outliers or may have other differences in frac design, different than injected volume, and hence not captured by this normalization. For a normalization to be appropriate it is fundamental to discuss with frac engineers in order to understand the frac design differences.

5.1.3.3 End of linear flow

Another important parameter is the end of linear flow. This is the time when the flow stops to be transient or linear and switch to a boundary dominated flow (interference between the fracs for example). This transition is clearly visible on the square root of time plot as described in GM EP RES 802. However, this transition occurs typically after a few years of production so it will not be useful to characterize the early productivity of a well but it will impact its EUR. This parameter is of course impacted by the reservoir permeability but also by the completion of the well (number of fracs for example).

5.1.3.4 Cumulative oil or gas per foot of lateral

The LFP is the most adequate parameter to compare wells as it takes into account to initial pressure of the reservoir, the viscosity of the fluid, the choke management, etc... But in some particular situations (when all these parameters are similar for all the wells) a simple cumulative volume of hydrocarbons per foot of lateral length can be useful to compare wells. In some unconventional plays, the reservoir pressure does not vary significantly across the play, all the well are opened on the same choke and the fluid is the same. In this case, a simple 90d cum gas or boe per foot can be used.

5.1.3.5 Fluid type

The solution to the diffusivity equation for transient linear flow shows that viscosity (μ) and formation volume factor (B_o) does have an impact in productivity, both of these properties are fluid type dependent. Unconventional plays, shales in particular, have maturity variations and difference in fluid retention that result in fluid type (and properties) variations. These variations do result in differences in productivity, but the major variations linked to fluid type are related to phase behaviour in the reservoir. Fluid type depends on fluid composition and reservoir conditions (pressure and temperature) and can be classified as:

- **Dry Gas**: gas in reservoir conditions and that does not contain any condensates. Consist mainly of light and intermediate hydrocarbons.
- **Wet Gas**: gas in reservoir conditions but can produce condensate at surface separation conditions and to some degree in the tubing. Does not cross the dew point with reservoir pressure depletion at reservoir temperature. Has a similar composition than Dry Gas.
- **Gas Condensate**: gas at initial conditions but as depletion evolves, reservoir pressure drops below the dew point and condensate is deposited in the reservoir. As reservoir pressure continues to drop the phenomenon of retrograde condensation may be evidenced. Contains a significant amount C_5+ fraction compared to Dry and Wet gas.
- **Volatile Oil**: Oil at reservoir conditions with large quantities of dissolved gas (high GOR) and high API gravity. Have relatively high bubble point and the gas produced can condensate large amounts of condensates. Has large formation volume factors compared to Black Oils.
- **Black Oil**: Oil at reservoir conditions with small quantities of dissolved gas (low GOR) and low API gravity. Has relatively low bubble point and low formation volume factors compared to Volatile Oils.

Figure 20 shows a phase diagram for a reservoir fluid of a particular composition, illustrating the different reservoir fluid type behaviors with changing reservoir temperature.

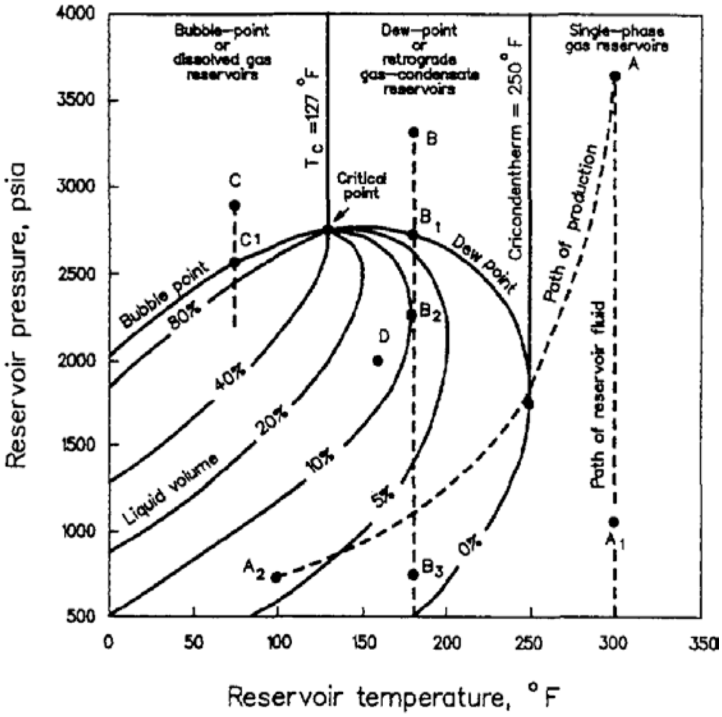


Figure 20: P-T diagram of reservoir fluid illustrating different types of depletion reservoirs (Whitson et al [5])

Fluid type is an important parameter to take into account for play sectorization. Within a fluid type properties might be well constrained, but it is important to consider phase behavior too. In the cases of Gas Condensates it is recommended to further subdivide a sub-play into different CGR windows since the amount of condensate banking (reservoir condensate dropout) may impact the well productivity at different stages of production and hence the type curve.

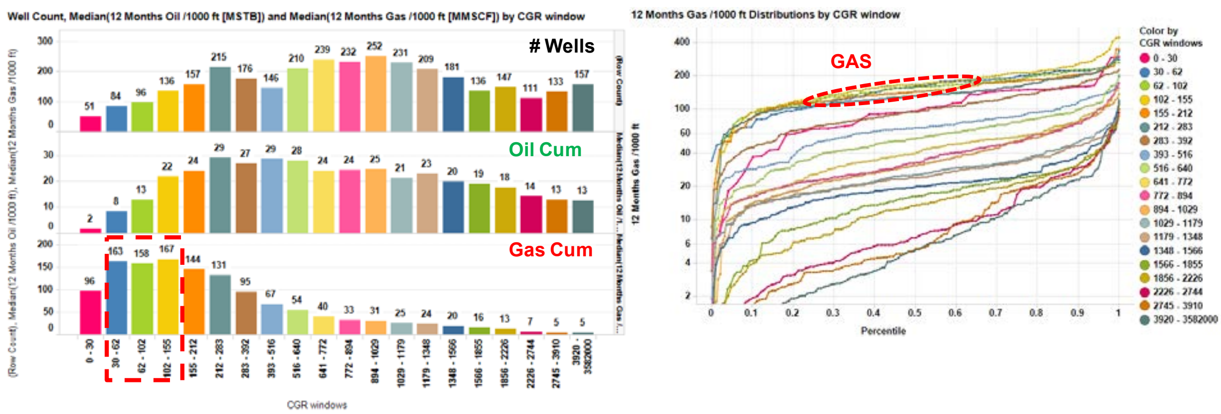


Figure 21: 12 month cumulative per foot of drain distributions per CGR/OGR window, for a particular sub-play in the Eagle Ford Shale.

Figure 21 shows the 12 month cumulative production normalized per foot of drain subdivided into different CGR/OGR windows for a particular sub-play of the Eagle Ford shale. The plot on the left shows that cumulative production varies widely but gas cumulative for the window 30-155 bbl/MMScf (red dotted line) are very similar for this timeframe and the plot of the distributions shows that even the distributions are similar.

Development sectors should be defined considering long term fluid behavior of wells which can be a challenging exercise for Gas Condensate and Volatile Oils, especially in early development phases. **The fluid phase behavior has a major impact in well performance.**

5.1.3.6 Formation Pressure

Pressure drawdown is directly proportional to production rate during linear flow, since flowing pressure (P_{wf}) is a parameter that can be imposed, Formation pressure (P_i) is fundamental for SRV productivity.

In Unconventional formations hydraulic equilibrium within the reservoir is not granted, for this reason there can be non-homogeneous formation pressure distributions at initial conditions. These can be the consequence of complex geological histories that can include unequal uplifts at the play scale and thermal histories that results in heterogeneous source rock thermal maturities. Varying pressure gradients within unconventional plays are very common.

It is usually hard to determine initial pressure distributions in unconventional plays. In the case of Shale the most reliable source of formation pressure is Diagnostic Fracture Injection Test (DFIT), and to do this a well is necessary, so in order to establish the distribution, many wells are necessary.

Sectors definition should always consider the formation pressure.

5.2 Propagation of SRV Quality Indexes

The propagation of the SRV Quality indexes helps to define the different sectors. It is a very difficult task in early stages of play maturity, and becomes easier as more wells are drilled on the different sectors of the play. But at later stages it losses interest since at this point productivity can be observed on actual wells.

5.2.1 Seismic applications

In unconventional reservoirs, 2D and 3D seismic data is used for conventional interpretation such as structure mapping, fault detection and reservoir correlation. 3D seismic data can also be used for more complex tasks including the generation of inversion volumes or specific attributes such as impedance, minimum curvature and coherence. These can help quantify overpressure, fluid types, brittleness, in-situ stresses and natural fracturing. Geomechanical parameters can be estimated with multi-component seismic surveys that capture shear wave data. Natural fracture networks can also be mapped with this technology. These properties and characteristics, calibrated with well data, can be used to calculate SRV Qi and propagate it at the segment and play level

Key steps in the interpretation of 3D seismic data include defining the boundaries of the sector, establishing reservoir continuity within it and quantifying rock properties. These steps are similar to traditional seismic interpretation, but are more complex in unconventional given the low contrast nature of the discrete intervals and the subtle expression of discontinuities.

The interpretation of seismic data needs to be fully integrated with other static and dynamic data in the context of a geological synthesis. The multiplicity of wells presents a challenge and an opportunity to relate groups of attributes to metrics such as initial production rate and EUR, and to use these to characterize other undrilled or less densely drilled sectors.

5.3 Development constraints

SRV QI's are created to subdivide a play into different sectors based on the geosciences risks and uncertainties, and to translate these into type curves specific to these sectors. Nevertheless there are other factors that may constrain development and affect the chance of commerciality or the development design of some sectors in a different way than others, such as:

- Topography or other surface constraints (lakes, rivers, protected areas, presence of towns, acceptability by landowners)
- Proximity to production facilities
- Complex well trajectory
- Contractual terms or legal particularities (license expiration, royalty rates, etc.)

It is important to capture these differences in the sector evaluation exercise since their influence on development decisions can be as or more important than well performance (type curves). **These factors are fundamental to define a project based approach for the different sectors and hence can influence strategic and business decisions on the play.**

5.4 Sectorization example: Aguada Pichana Block (Vaca Muerta)

The sectorizarion process can be better illustrated with an actual example: the Aguada Pichana Block, located in the Neuquen Basin which is in the main province of the prolific Vaca Muerta Shale play.

5.4.1 SRV Resources

The first of the SRV QI is the Resources index, the purpose of this index is to identify variations in the hydrocarbon in-place quantities in the Unconventional play.

5.4.1.1 Depositional environment

This task has to be performed with a thorough understanding of the geology of the play; in this case a sequence stratigraphy study was carried out to understand the depositional environments that can be found within the column. This work also recognized the facies that dominate within each depositional environment.

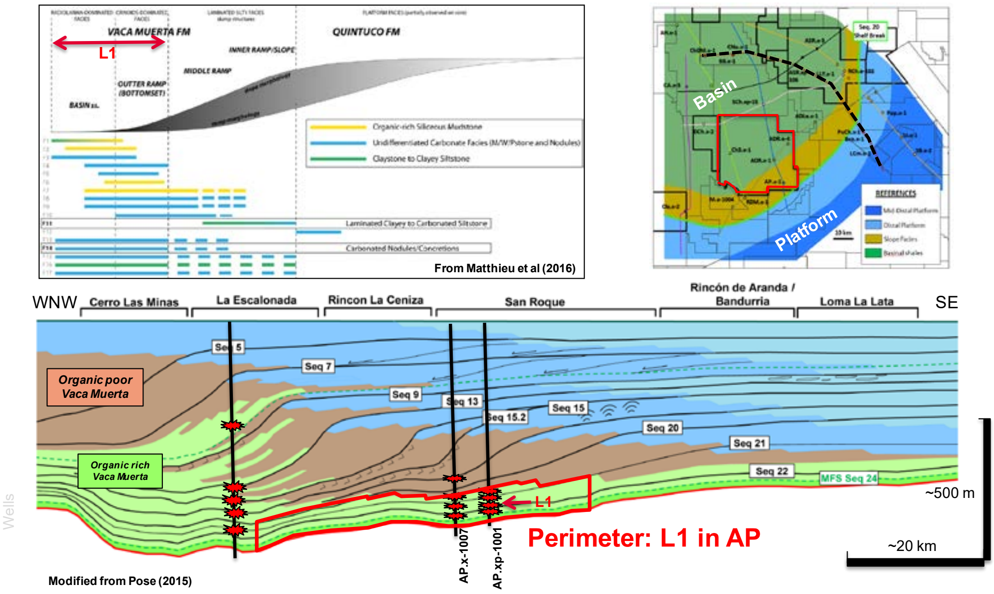


Figure 22: Sequence stratigraphy of the Vaca Muerta play.

Figure 22 shows the result of the sequence stratigraphy interpretation; this analysis identified several sequences within the vertical column. As mentioned before, the segmentation exercise has to be performed both aerially and vertically. The vertical sequence that is chosen for the sectorization exercise is the Sequence 20, also identified as landing point 1 or “L1”. This interval was high graded based on the petrophysical analysis and well results.

The different facies that were described in the sequence stratigraphy analysis were petrophysically characterized with laboratory SCAL and calibrated log analysis. This geological synthesis helps describe the types of facies that can be found, and hence control the properties of the selected interval.

Section 5.1.1 showed that the SRV Resources Qi is based on the petrophysical properties of the shale and these are controlled by the different facies and rock types that dominate in each interval.

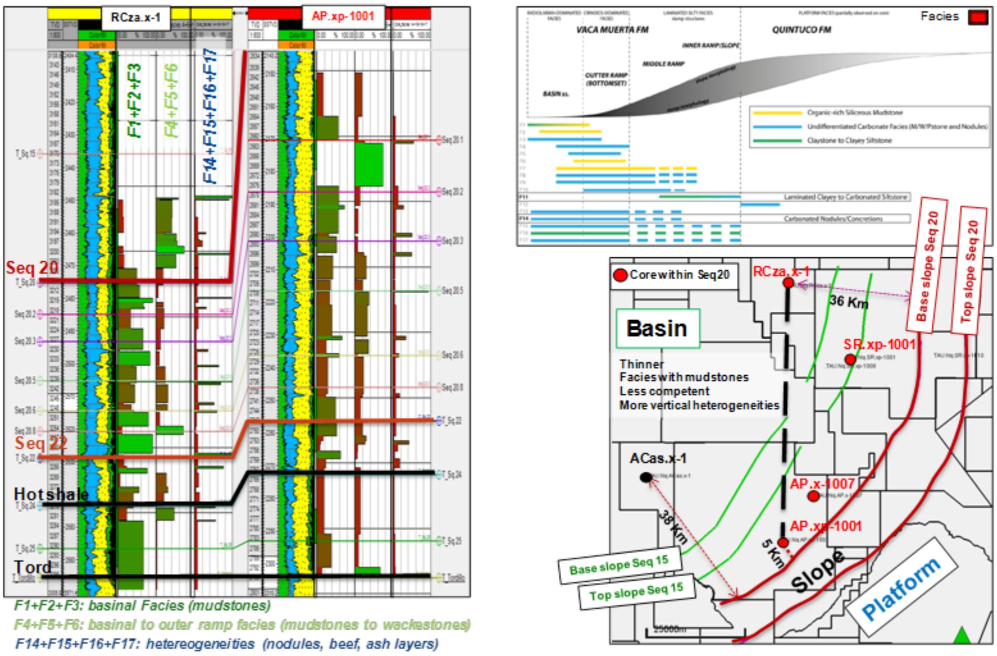


Figure 23: Sequence stratigraphy for the Lower Vaca Muerta near the Aguada Pichana block.

Figure 23 shows a sequence stratigraphy interpretation for the lower Vaca Muerta in the Aguada Pichana block. The target zone "L1" is dominated by basinal depositional environment in the whole of the block, with a transition into slope facies in the south east direction.

5.4.1.2 Petrophysics

With the depositional environment interpreted, the facies that dominate the interval can be evaluated. In this case, facies 1 to 5 will dominate since these characterize in a basin depositional context.

Figure 24 shows a geological correlation between a well in Aguada Pichana and two nearby blocks with exploration wells (Aguada de Castro to the west and San Roque to the east). The petrophysical interpretation shows very similar characteristics for the three wells (with a higher porosity in the case of San Roque). The correlation shows that reasonable to assume that the petrophysical properties of Sequence 20 are very similar for the Aguada Pichana block.

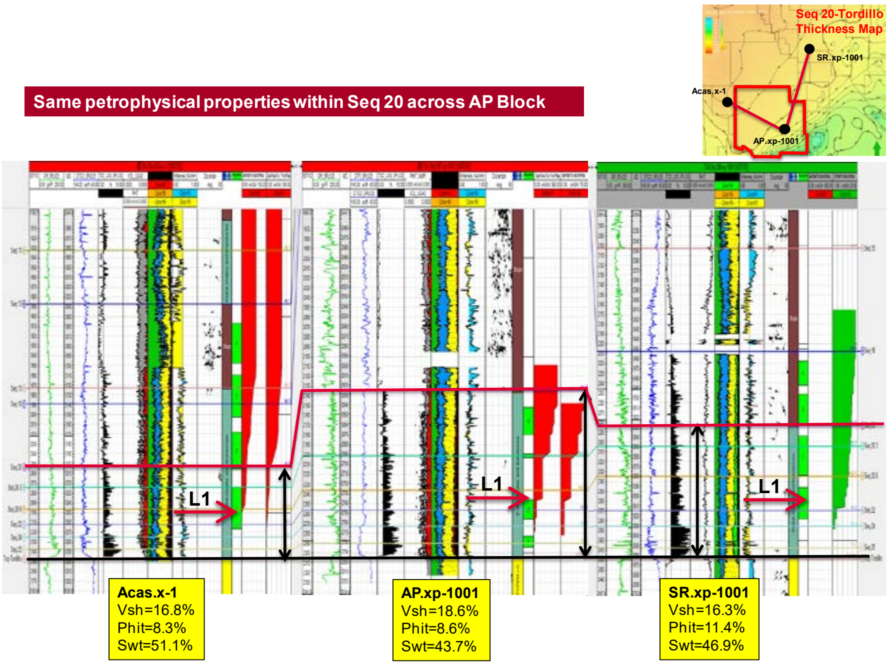


Figure 24: Petrophysical section through the Aguada Pichana and the neighboring Aguada de Castro and San Roque blocks.

5.4.1.3 Thickness

Figure 25 shows an isopach map of the lower Vaca Muerta (Seq 20 to Top Tordillo) for the Aguada Pichana block. We can see that thickness is not a problem for most of the block assuming a 70-100 m hydraulic fracture vertical development. Nevertheless a 120m cutoff was taken in order to consider a margin for fracture growth, assuming different fracture development for different thicknesses. In this case two sectors can be identified.

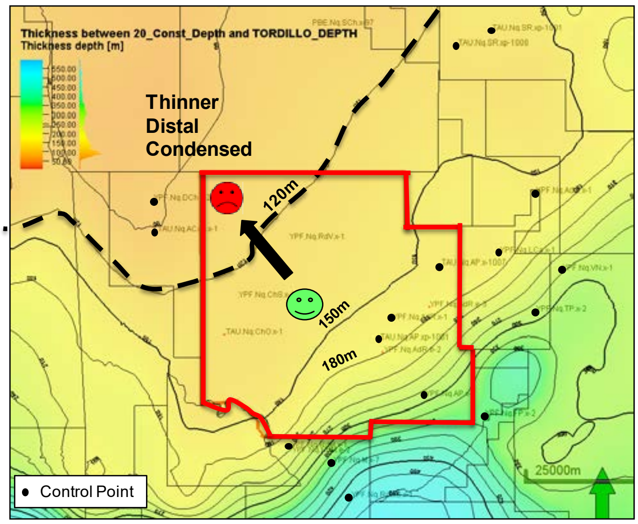


Figure 25: Thickness of L1 in Aguada Pichana block.

5.4.2 SRV Geometry

As previously mentioned the SRV Geometry QI groups the factors that control fracture growth and SRV creation.

5.4.2.1 Brittleness

Brittleness index is one of the SRV geometry indexes. For example brittleness index issued from mineralogical content (BI_10) was used on wells Acas.x-1, AP.xp-1001 and SR.xp-1001 cross section to identify L1 (Figure 26). In this landing point, the BI (track 6) gives a qualitative tendency with "blue value" indicating a less ductile rock (more brittle interval).

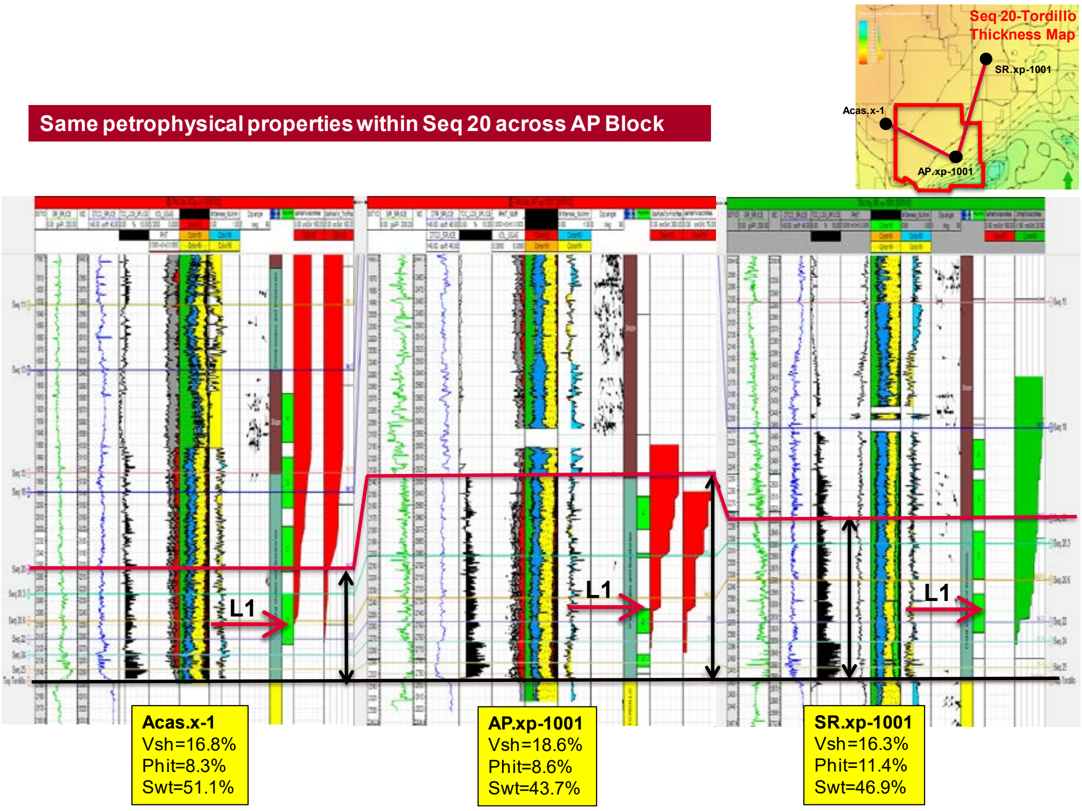


Figure 26 - Petrophysical properties including the Britteness index from mineralogy (BI_10 in track 6) trough Aguada Pichana and the neighbouring Agada de Castro and San Roque Blocks.

5.4.2.2 Stresses

- **Stress orientation**

Maximum horizontal stress azimuth assessment is important to drill the well in an appropriate azimuth first for wellbore stability issues and to optimize the hydraulic fracturing shape. Stress directions are inferred by wellbore stability occurrences such as break-out and/or Drilling Induced Tensile Fractures evidence interpreted on image logs. Total Austral built from the interpretation of DITF on image log a map of stress orientation.

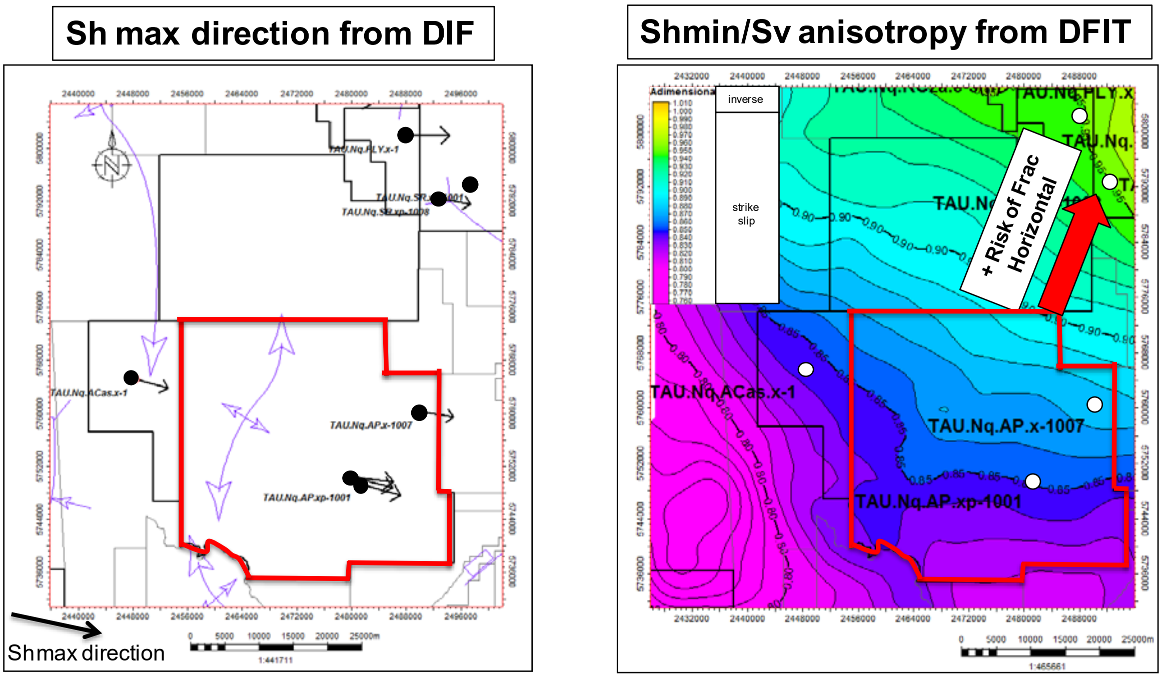


Figure 27: Stress direction and Shmin/Sv anisotropy for the lower Vaca Muerta in AP block.

- **Stress magnitude**

On the 8 exploration wells, 1D Mechanical Earth Models were built with the sonic logs. Vertically at well location, we have a good assessment of stress magnitude and stress regime, varing with lithology. 1D geomechanical models have log resolution (1/2 ft resolution) along the wellbore but no penetration away from it – along the fracture length for instance. Today, it is difficult to create a stress map because stresses are not rock properties and they cannot be interpolated as any other rock properties.

To assess map or cube of stress, it is important to build a 3D Mechanical Earth Model with static elastic properties and realize a stress equilibrium accounting for the fault/fracture presence.

An attempt was performed on a small part of Aguada Pichana block to do the stress initialization accounting for the 1D MEM on APx1001 and the faults interpretation on seismic and small faults/fractures interpreted on microseismics (Figure 29**Erreur ! Source du renvoi introuvable.**).

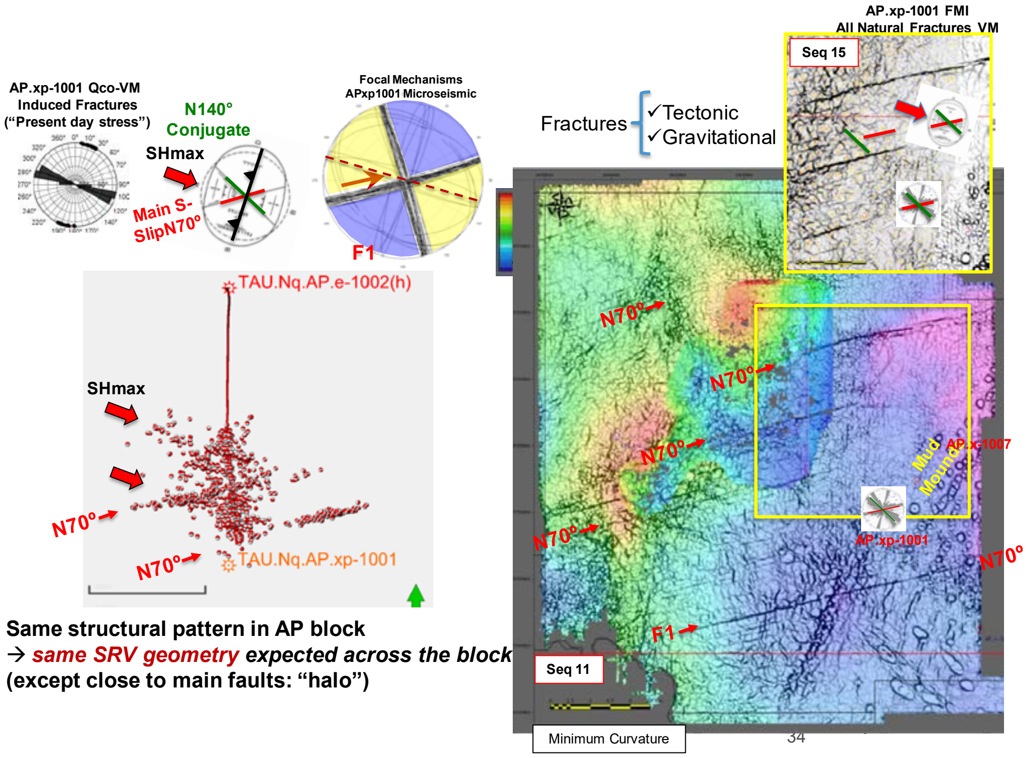


Figure 28 – Microseismic from AP-1002h vs 3D seismic

At this stage of the report, the results are preliminary, but we can notice that with fault/fracture presence we observe stress reorientation and changes in stress magnitudes. Figure 29 shows the changes in initial minimum horizontal stress magnitude close to the faults and fractures interpreted from seismic and microseismics. The area modeled is restricted to the available seismic interpretation. Close to the faults, the minimum horizontal stress changes can reach 10% of the "non-perturbated" stress field form 1DMEM.

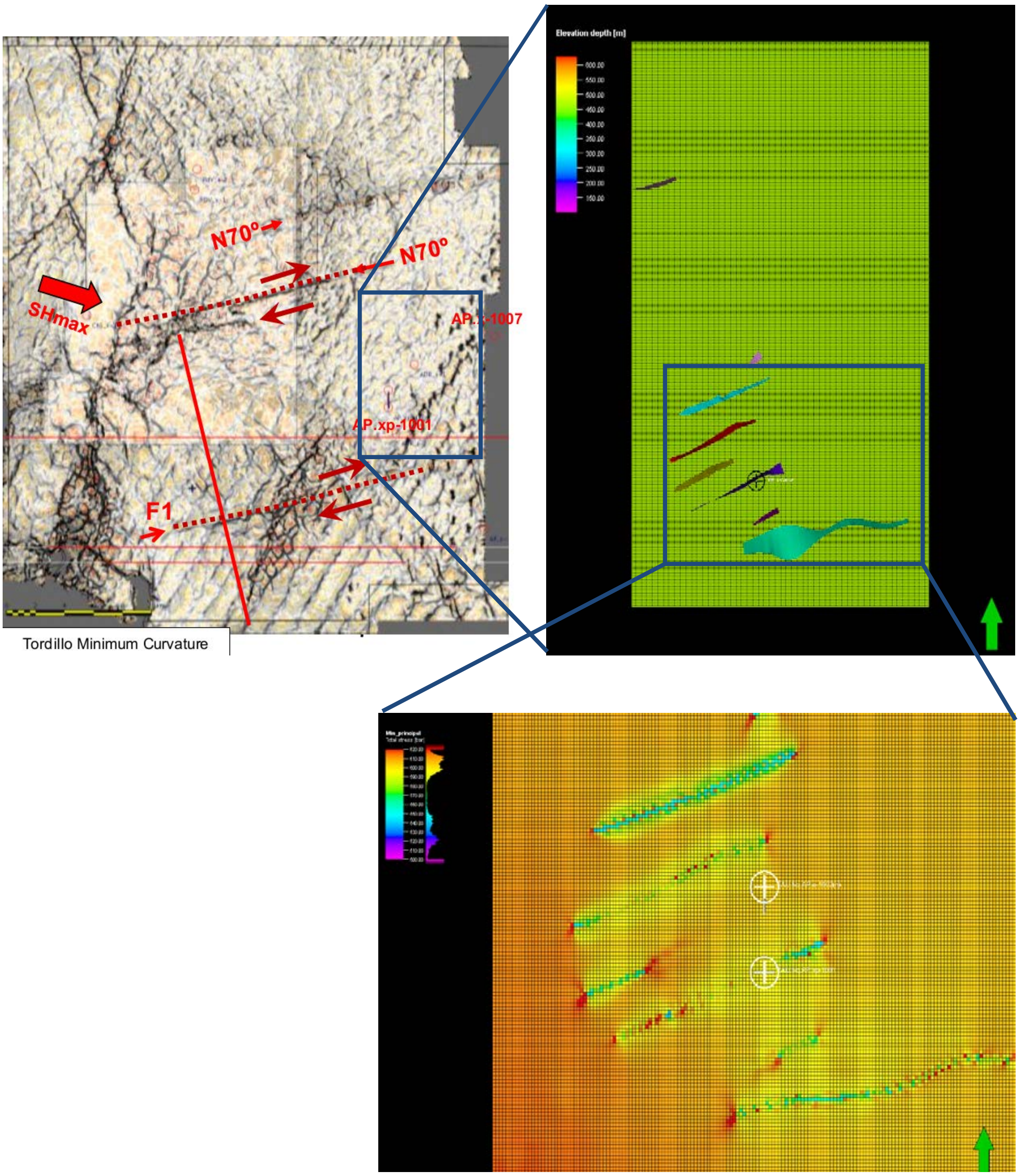


Figure 29 - Modeling of initial minimum horizontal stress (Shmin) on AP1002h, pad#1-4 accounting for 1D MEM on APxp1001 and fault presence.

For the moment, although more synthesis studies are needed there are no reasons to think that, excluding the heavily faulted areas (and a halo zone around them), the SRV geometry QI varies significantly in the AP block.

5.4.3 SRV Productivity

Following the methodology presented in section 5.1.3 productivity will be evaluated based on its fundamental constituents:

- Formation Pressure
- Fluid type
- Linear flow parameter

5.4.3.1 Formation Pressure

In shale plays the most reliable pressure source is the DFIT, provided a linear flow is developed in the after closure period. In the case of the Aguada Pichana block and surrounding blocks, many DFITs have been performed all showing the same pressure gradient. The only direction that doesn't have any pressure calibration is to the South west, but in this case the same gradient was assumed.

With the available data regarding formation pressure, there are no sufficiently significant differences to justify a division of the AP block into different sectors.

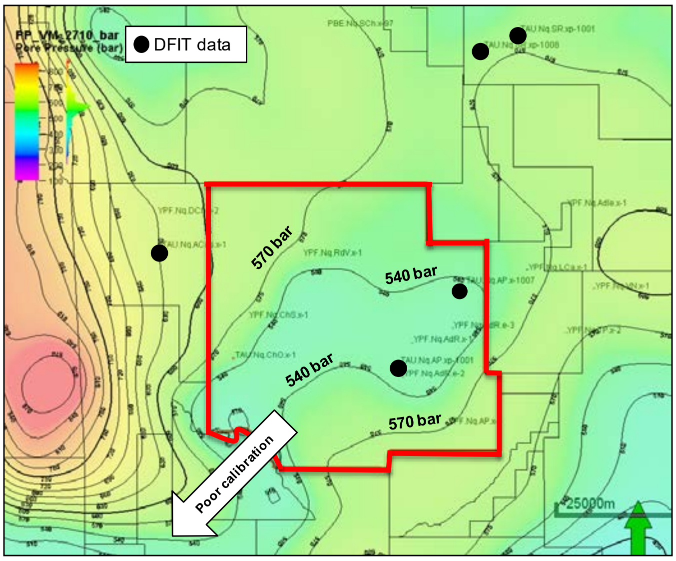


Figure 30: Pressure distribution on the Aguada Pichana block for the Lower Vaca Muerta.

5.4.3.2 Fluid windows

In the aspect of fluid window most of the AP block is contained within the dry gas window with a small part in the wet gas window to the east. There are with many maturity data points in the AP and surrounding blocks.

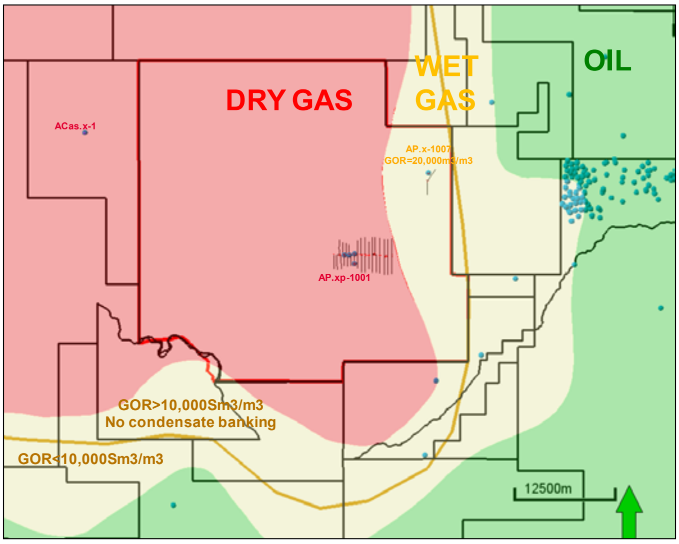


Figure 31: Estimated fluid distribution for the lower Vaca Muerta in the AP region.

Regarding the well in the AP block that was tested in the wet gas window, it yielded a Condensate to Gas Ratio (CGR) of 9 bbl/MMScf which indicates a very lean condensate production. The PVT report of this well couldn't determine the dew point when lowering the pressure down to 1100 psia (formation pressure being 7800 psi), this means that multi-phase flow within this window is unlikely, even on the long term.

Regarding the fluid window there are no elements to divide the AP block into more than one sector. The type curve should have the same gas recovery for all the wells, but a condensate recovery should be considered for the wells in the wet gas window.

5.4.3.3 Productivity and Linear Flow Parameter

Regarding productivity there are many control point in the region of the AP block, the problem of these points is that the great majority come from fractured vertical wells which are not analogous to a "typical" development well for this block. Nevertheless the horizontal wells that were drilled in the region and even the vertical ones had excellent productivities.

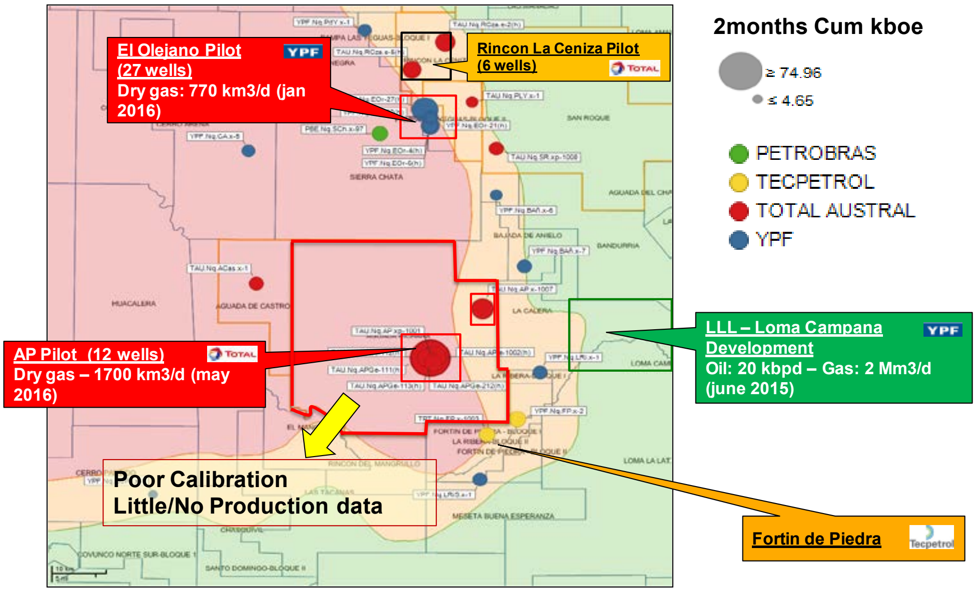


Figure 32: Public production data in the gas window near the Aguada Pichana block.

In order to determine a type curve for development, a pre-development pilot phase consisting of 12 horizontal multi-fractured wells was drilled and connected. The results of this pre-development project were excellent.

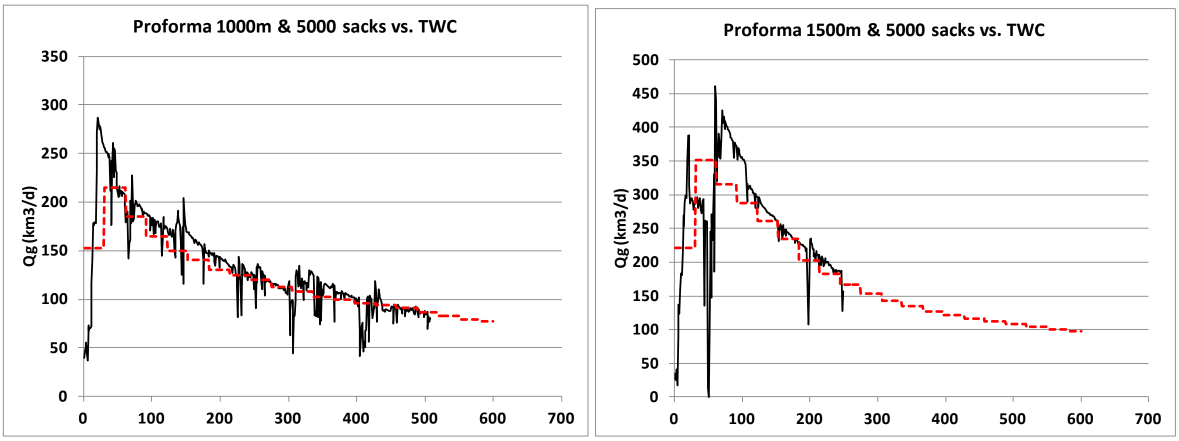


Figure 33: Pre-development results compared to the type curve.

Figure 33 shows the average production of the 1000m and 1500m wells of the Aguada Pichana pilot and the comparison with the type curve built for the wells belonging to this sector.

Figure 34 shows the LFP/ft estimated for the wells in the AP block, although there is a natural variability in the data related to heterogeneities and different fracture design, good productivity is confirmed and consistent for all the wells in the block.

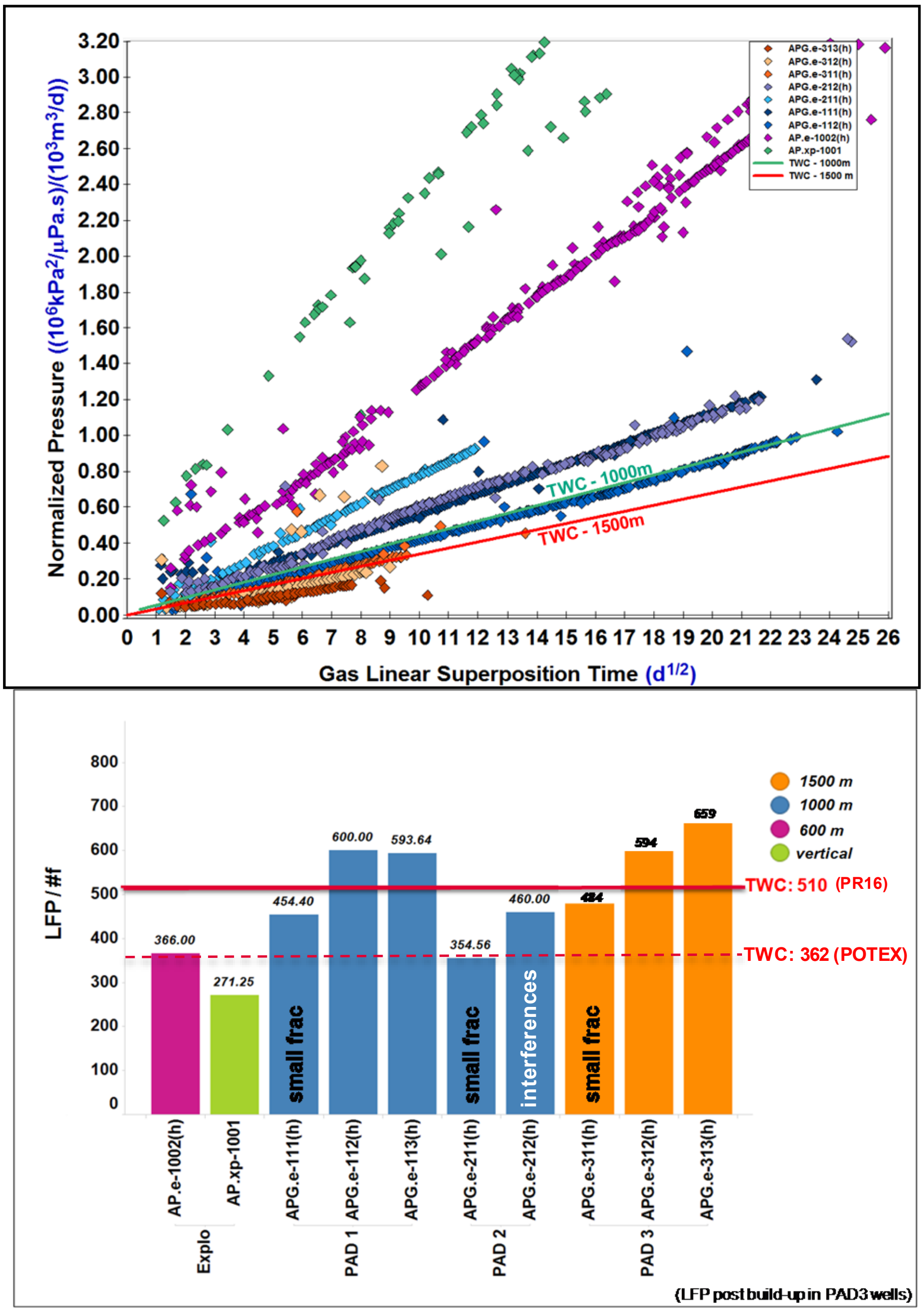
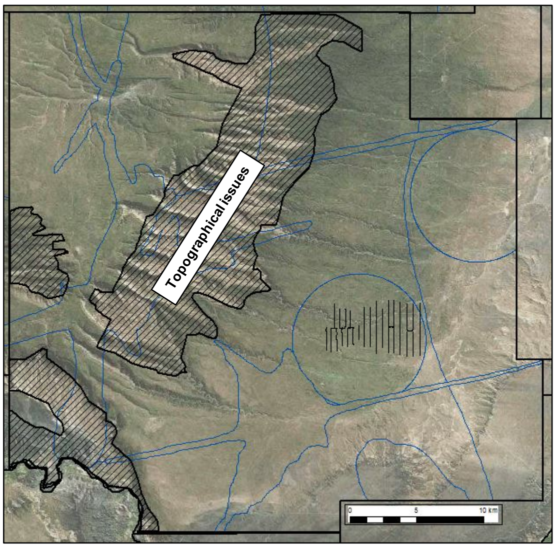


Figure 34: Square root of time plot and normalized LFP estimated for the AP block.

The SRV productivity Qi shows that all the wells in the existing areas have comparable productivities and hence can be represented with the same type curve, normalized by well length and frac design.

5.4.4 Development constraints

In the AP block there is an evident development constraint that is the canyons area. This extensive area, if developed should adapt well and pad design in order to cope with the hurdles that impose this complex topography.



Topographical issues include canyons & flooding areas

Figure 35: Topography on the AP Block

Pads and flowlines locations, together with well length should be modified in order to better develop this area, these differences are so significant that justify a particular development sector.

Another development constraint is the amount of CO_2 in the produced gas. The origin of the CO_2 is inorganic and related to deep faults.

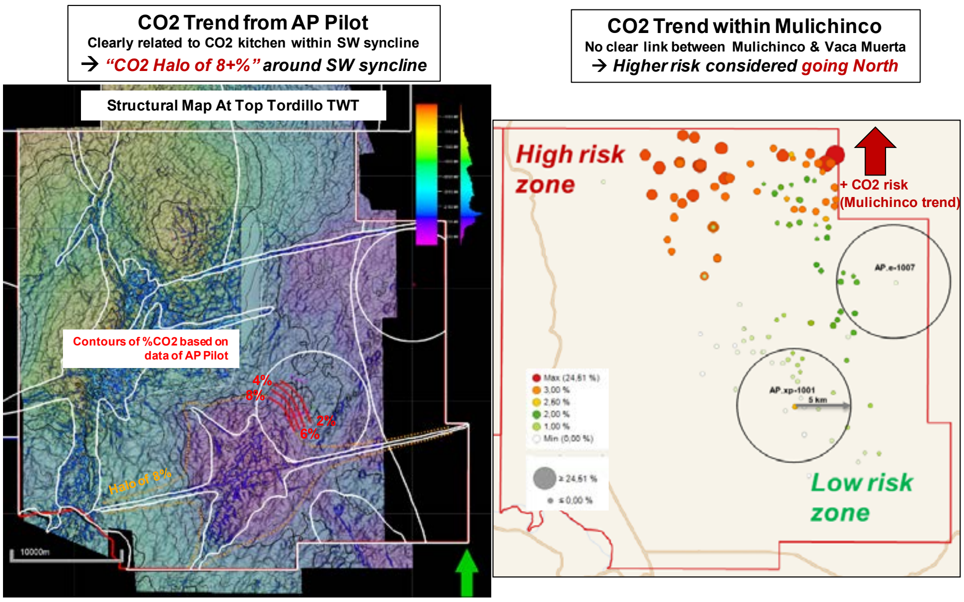


Figure 36: Deep faults in the AP block and CO_2 content in the shallower Mulichinco formation.

Figure 36 shows the location of the deep faults in the AP block and the distribution of the CO_2 in the shallower Mulichinco formation. Even though the correlation of the CO_2 content on the Mulichinco and Vaca Muerta is not established, the Mulichinco CO2 content will be used as a proxy for undrilled panels.

5.4.5 SRV QI based sectorization

The previously shown sectorization exercises were used to create the map in Figure 37. The map shows that the main divisions for the sectors are the deep faults that interrupt formation continuity and hence separate the block into different panels. The identified sectors were populated with hypothetical wells respecting the well design considered for the first development phase.

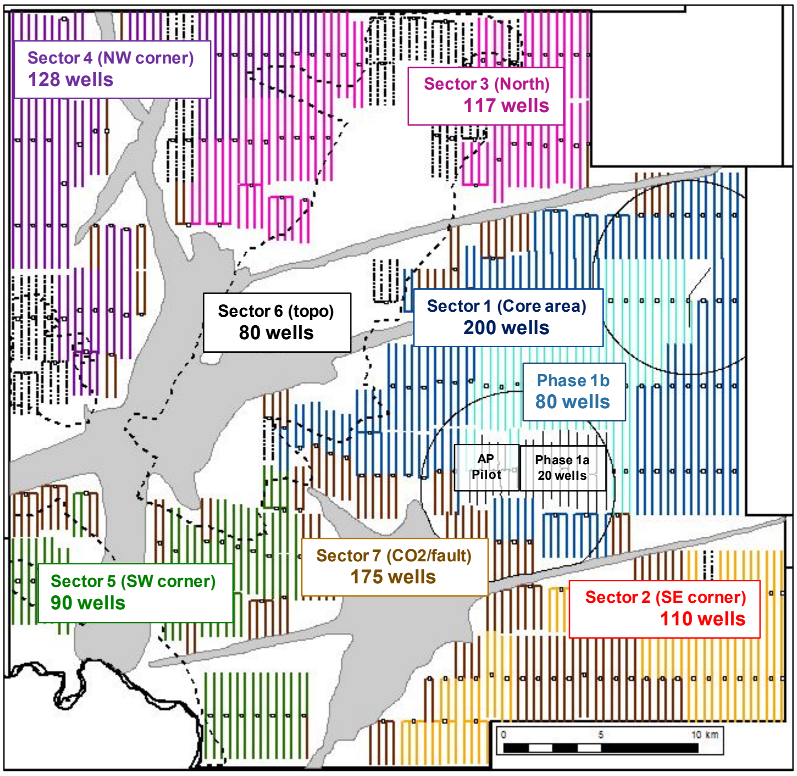


Figure 37: Sectorization of the AP block.

5.4.6 Associated Total Box

The AP Pilot, Phase 1a and 1b are the preliminary development phases of the sector 1, their corresponding resources/reserves status will not be displayed in this document.

SUB COMMERCIAL DISCOVERY	CONTINGENT RESOURCES			Status	P.O			PROJECT DEFINITION	PO			
	1C	2C	3C		geo	tech	total		V	G	R	S
	10	20	30	C	80	80	80	Aguada Pichana Sector 1	100	80	80	100
	20	30	40	C	60	60	60	Aguada Pichana Sector 2	100	60	60	100
	30	40	50	C	60	60	60	Aguada Pichana Sector 3	100	60	60	100
	40	50	60	D	20	20	20	Aguada Pichana slope	20	80	60	100

Figure 38: Example of Total Box (not actual numbers)

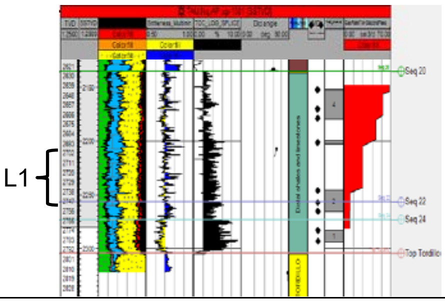
As shown in Figure 38, the remaining sectors to be developed represent a line in the Total Box with its associated number of wells, resources and appraisal work. Each sector will typically need a dedicated pilot + horizontal drain to be de-risked.

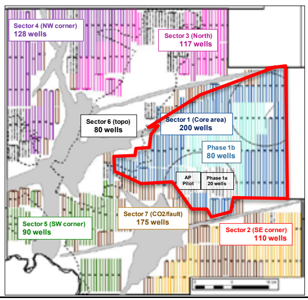
The perimeter of a contingent project can be organized around the 3 following points:

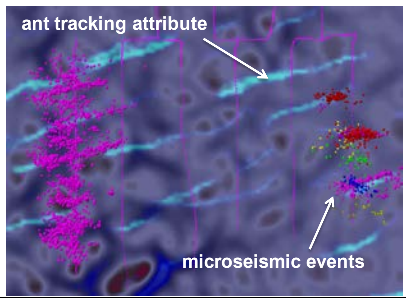
- A formation or 1 landing point of a formation.
- A sector if a subsurface synthesis has been performed. Otherwise a 5km radius around an exploration + appraisal well.
- A geometry of SRV defining a well spacing and so a total number of wells for the sector

Table 10 illustrates the perimeter of the Aguada Pichana sector 1 project of 300 wells.

Table 10: Aguada Pichana, sector 1, landing point 1 project







Formation Vaca Muerta sequence 20.8	Aguada Pichana Sector 1	400 m well spacing

The sectorization process allows a clear view of the future development of a play and ensures that all the resources will be de-risked at the right cost.

6. Appraisal strategy and play maturity

From the exploration to development phases the knowledge on the play increases constantly as more information is collected. At first, knowledge is very poor, and even the presence of the play is hypothetical, on the other hand, on the different stages that lead to development the wells behavior can be predicted with increasing accuracy. A term used to define the degree of knowledge of the play is **maturity**. As maturity of a play increases, uncertainties on the characteristics of the rock are better constrained and its properties can be determined with increasing precision. As unconventional plays become more mature, segments and sectors are more clearly defined, the parameters that control well behavior are mastered as well as the optimum stimulation design, the best landing points and the spacing for the wells in each sector. **Play maturation is a never-ending process where several degrees of maturity can be used to classify the relative knowledge of the play at sector level (extension and defining characteristics), to apply the adequate techniques for resources and reserves evaluation, and identify the risk associated to these.**

This concept is very important, since as a sector becomes more mature, the different projects identified to develop this sector can be better defined, increasing the chance of commerciality, and hence it's PO or PS.

6.1 Play maturity

Monograph 3 [6] classifies the maturity of a play according to the number of wells that have been drilled and the heterogeneity in the performance of these; these phases are: Early, Intermediate, Statistical and Mature.

Early Phase: In contrast with conventional reservoirs unconventional exploration has typically low discovery risk. Major uncertainties tend to be around local reservoir properties that control well productivity and ultimate recovery; these are constrained within the **intermediate phase**. In the **Statistical phase**, aggregation is possible and the risks are reduced significantly.

Figure 39 illustrates the 4 different phases of a play.

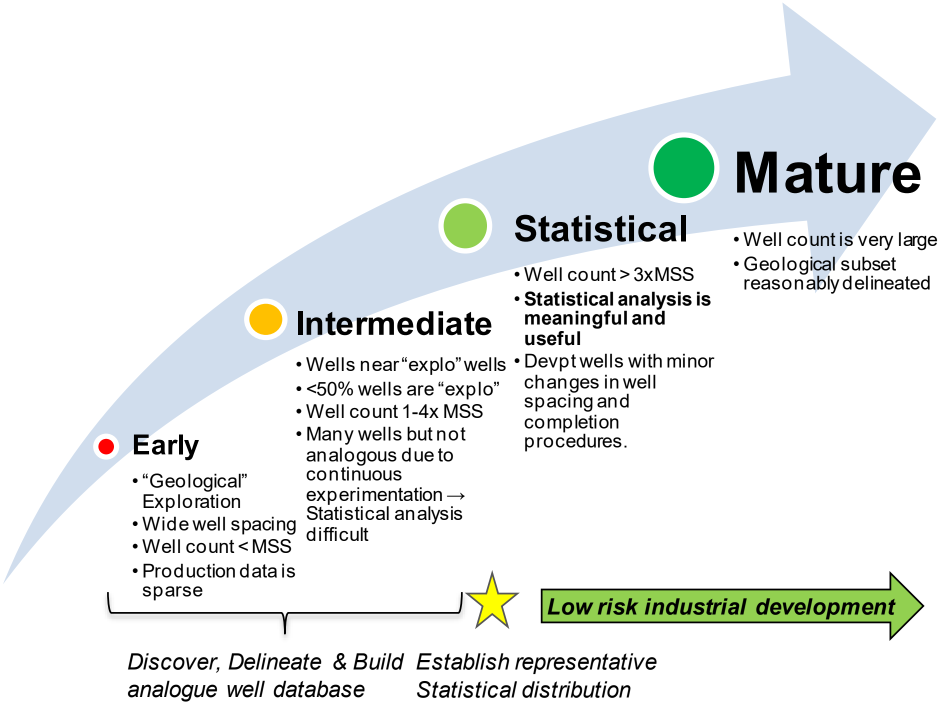


Figure 39: Schema of play maturity from SPEE Monograph 3 [6]

This maturity classification is useful as a general indication of the stage of development of a play, and whether statistical methods can be applied for Reserves evaluation in certain areas of a play. But its main drawback is that it is solely based on well performance and theoretically works when wells were drilled all across the play. **The group believes in the value of the integration of Reservoir Engineering, Geological, Geophysical and Geomechanical methods to reduce the uncertainties in well behaviour.**

6.2 Project Maturation process in Unconventional plays

The group recognizes four stages of maturity for unconventional plays that do not coincide with the ones from Monograph 3 [6]. This is natural, since the two classifications have different purposes: the SPEE defined them as a tool to define PUD reserves, while the group uses them to assess Reserves and Resources classification for a particular sector of a play.

The 4 different phases of an unconventional play development can be illustrated in the following simplified way:

- Exploration ➔ discovery
- Appraisal ➔ prove productivity
- Pre-development ➔ prove statistical for commerciality
- Development (industrial phase) ➔ optimization

The Pre-development phase, specific to unconventional plays, is crucial as it will prove the repeatability of the results. This is an important concept when building the learning curve that will prove the commerciality of the project.

Figure 40 illustrates with a scorpion plot these 4 phases. During the Exploration and Appraisal phases the wells generally do not meet the economical criteria. The goal of the Pre-development phase is to prove the commerciality by reducing CAPEX and increasing EUR. During the industrial phase of the Development, the goal is to find an optimum between CAPEX and EUR: there is typically a pint where increasing the CAPEX will not bring enough production to justify the additional spending.

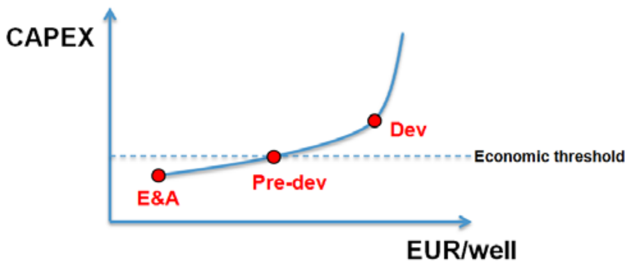


Figure 40: Notional scorpion plot

These 4 phases can also be described by Figure 41. The uncertainty on well productivity can be split into 3 parts: the initial rate, the early productivity and the late time productivity. The Exploration and Appraisal phases will typically address the uncertainty on the initial production. The Pre-development phase will give information about the early life of the wells and only after years of production during the Development phase will information be available on long term declines.

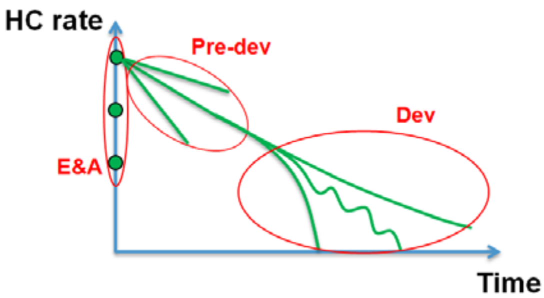


Figure 41 : Reducing uncertainty on well productivity

6.2.1 Exploration

Unconventional plays are continuous accumulations that are extended regionally in which free hydrocarbons are not held in place by hydrodynamics. So the risk of not finding hydrocarbons is nil and almost all wells in unconventional plays are capable of producing at least some hydrocarbons, but it can be challenging to determine early whether a play is of commercial interest. These characteristics render significant Prospective Resources with generally high PO, which is natural since the PS does not account for the notion of commerciality. On the other hand the classification of the commercial portion of these, with their associated chances of commerciality (PO) depends on many factors that exceed the geosciences domain.

Rule 3 of CR EP RES 001 is in line with PRMS 2007 and states that a well has to be drilled and a discovery made in order to upgrade resources from Prospective to Contingent. The term discovery requires not only the presence of hydrocarbons, but also that the productivity is established.

First of all to establish the presence of an accumulation, sufficient log and core data should be gathered to provide convincing evidence of a significant volume of movable hydrocarbons. The formation characteristics estimated prior to drilling should be confirmed or either changed, in order to update the evaluations of the prospect in the same or other segments. To prove the presence of hydrocarbons is not generally a problem in unconventional plays since they are continuous accumulations.

Next, a fundamental step in the play evaluation is a successful well test; this is the cornerstone to provide evidence for the **commerciality of the segment**. Since wells in unconventional plays have to be hydraulically fractured to produce and the first days or weeks of production are influenced by a clean-up period, the test should be designed to last a significantly longer time to evidence the formation response without the influence of the fracture fluid flowback. Generally a three-month test is appropriate, but this figure is by no means fixed; an excellent well could show a commercial rate with a shorter test, or the well might need a longer test to effectively flow back a larger share of fracture fluids before the formation response is clearly observed.

Some plays, especially the thicker ones, can show commercial or nearly commercial rates with fractured vertical wells. But since development projects need horizontal multi-fractured wells these types of wells are usually needed to show sufficiently compelling evidence of commerciality. For this reason a cost effective exploration program generally needs a pilot vertical well to gather core and log data, and then a horizontal drain to create multiple fractures and prove commerciality with an extended well test.

Core and log data to prove the presence of hydrocarbons and formation characteristics and a well test to give a hint of commerciality are mandatory elements of an unconventional exploration program; but a cost effective source of information to complement these is a **commercial analogue play**. Since the first wells in any new play usually need to climb up the learning curve before reaching the actual productivities of the future development wells, exploration and appraisal wells can show marginally commercial productivities or even sub-commercial ones. A commercial play that can be proved to be sufficiently analogous to the exploratory play can help to set a realistic benchmark for this. This way the future productivity of the play can be estimated, with an associated range of uncertainty, before drilling additional wells, in order to proceed with the study of the play before deciding to pursue further investments. The analogy has to be established in as many dimensions as possible, including:

- Depositional environment
- Mineralogy
- Formation Thickness
- Stress regime
- Fluid type
- Formation Pressure
- Depth
- Petrophysics
- …

It is very important to thoroughly justify the analogy, since the analogue can be fundamental at deciding whether to proceed or not with the appraisal of the play. In cases where initial test are extraordinarily good, an analogue might not be as important, but when initial tests or hydrocarbons in place don't show very compelling evidence, a good analogue can support the decision to proceed with the appraisal of the play. **It is the combined weight of well tests, static evaluation and commercial analogues that supports the decision of considering the resources as discovered and to classify them as Contingent Resources**.

In plays or segments where not much regional information is available (no 3D seismic for example or not enough wells to calibrate the formation), a radius of 5km around the discovery well should be considered to be classified as Contingent Resources, provided the whole circle is contained within one segment, if not this distance can be reduced until the limit of the segment. **To be able go beyond a 5km radius, a sectorization of the area is needed, meaning an integrated subsurface synthesis was performed with the 3 SRV indexes.**

The exploration **Segments** evolve into **Sectors** that consider more risks (resources + geometry + productivity) and are characterized by Type Curves. In order to classify the resources on these into Contingent Resources, the contingencies have to be evaluated and one or several projects notionally identified in order to evaluate their PO.

6.2.2 Appraisal and Delineation

In conventional plays appraisal programs have the intention to delimit the discovery in order to design an optimum development plan to pursue FID; this is not the case for unconventional plays.

In the latter ones, the extension of these is very vast, so trying to delimit the whole play is pointless.

Appraisal and Delineation wells in unconventional plays are generally the same. Since the wells have to be stimulated in order to produce at commercial rates wells are horizontal multi fractured, stimulation costs usually make up a significant part of the total costs. For this reason pilot + horizontal wells are considered a more cost effective approach. This consists in drilling a vertical well to gather log and core data, and then drill a sidetrack in the interval of interest in order to stimulate this drain with several hydraulic fracture stages.

The appraisal and delineation programs consist generally on vertical and horizontal wells which were generally committed in the exploration agreement. These wells are vertical and horizontal and are widespread through the license or licenses. The results of these wells, together with wells from other operators and other sources of information such as seismic acquisitions; can be used to calculate the SRV QIs in order to start establishing the different sectors of the plays. It is fundamental to incorporate as much information as possible of as many sources as possible in order limit the expenditures, since given the size of these plays the cost of these phases can be very high.

The profitability of the different sectors is a fundamental element to be considered to build a project that can implicate one or more sectors. These projects have to be thoroughly defined for the assessments of the contingencies to make it commercial. **The result of the evaluation of these projects combined with the strategy of the group in the play has to be expressed in the Contingent Resources in the Total Box**.

The classification of the identified projects into the different sub-classes is intimately related to the P.O. assigned to the projects, all elements considered, this is the chance of commerciality as explained in more detail in Section 4.3.1.

To appraise a virgin sector, 4 different cases are possible, each one with pro's and con's.

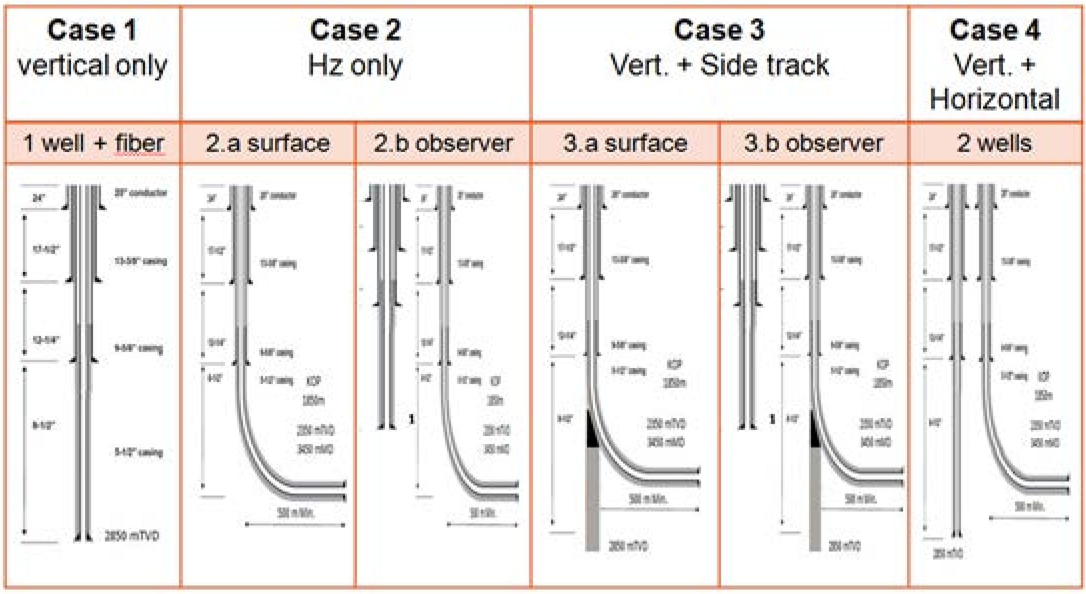


Figure 42 : 4 different appraisal well architectures

Case 2b and 3b illustrate options in case down hole microseismic is required.

6.2.3 Case 1: vertical well

Pro's	• Low cost • Only one borehole • Perform a DFIT, (Initial Pore Pressure) • Gives insight into fracture height (with appropriate monitoring) • Allows testing different landing zone (for thick plays such as VM)
Con's	• HC Production not representative of a development with horizontal wells, • Risk of facing un-conclusive results • No information on lateral variability • No information on horizontal drillability • No possible extrapolation from vertical to horizontal

The resource (static) information will be available but the dynamic information would probably not be representative of a horizontal well.

6.2.4 Case 2: drill directly the horizontal well

Pro's	• Low cost • Only one borehole • Confirm horizontal drillability • If successful, confirm productivity
Con's	• If not successful, no interpretation possible • Landing point criteria • Limited SRV generation • No information on stress direction • No geomechanical data (No Frac design) • No DFIT (No initial pressure)

The resource information might be limited but the dynamic information will be available if the well is successful.

6.2.5 Case 3: drill vertical + side track horizontal

Pro's	• Only one borehole • Confirm horizontal drillability • Coring and logging acquisition in vertical • VSP calibration • Better frac design and well geometry resulting in better production
Con's	• Surface array microseismic monitoring required • Additional Operational complexity : OH sidetrack • Only 5 days to define landing point

In this case both resource and dynamic information will be available at the minimum cost. This is the recommended option most of the time.

6.2.6 Case 4: drill vertical + horizontal

Pro's	• Perform DH microseismic monitoring • Confirm horizontal drillability • Perform a DFIT • Coring and logging acquisition in vertical • VSP calibration • Better frac design and well geometry resulting in better frac production
Con's	• 2 boreholes • Operation complexity • Cost

This is the most comprehensive case in term of data acquisition but it is also the most expensive.

6.2.7 Pre-development

Identified projects are classified according to their chance of commerciality. To reduce uncertainties on EUR and costs for example, a common practice is to launch a pre-development or pilot. The pre-development project consists on a reduced number of wells (generally 10 to 20) to be drilled and connected into Early Production Facilities (EPF) in order to start:

- Assessing the Drilling learning curve
- Assessing the EUR learning curve

This step is a cornerstone before committing larger FIDs consisting of large number of wells, infrastructure and facilities and contracts on a multiyear basis.

6.2.8 Development

When sectors are considered mature enough and the appetite of the group for the different projects is high enough, FID's are committed and development is launched.

As in every development project, unconventional development projects are not free of risk. For this reason it is common practice to launch these in different phases in order to limit CAPEX and exposure. Once several phases are producing, the sector becomes mature, and then statistical methods, such as aggregation can be used to calculate reserves.

For Reserves classification, the SEC allows the booking of future wells to be developed within five years. For this reason, although thousands of undeveloped well locations could have been de-risked, only the ones committed to be drilled in the following five years can be booked as Reserves.

These undeveloped proved locations are split into 2 categories in the Total Box: A2 and B, the A1 category being for producing wells. The difference between A2 and B is the commitment from the company to develop these reserves rather than plan to develop them. It requires an internal sanction for reserves to be upgraded from B to A2 status.

6.2.8.1 Industrial or "factory" development phase

Once a viable process has been established and one or many sectors de-risked, one of the keys to economic projects is to take advantage of the scale of operations. Different projects might be applied sequentially to take advantage of the better reservoir quality areas and lower operating cost areas (due to shared costs between projects). Due to the size of the resources many of these projects focus on the long term, for this reason a phased development approach might give a better understanding of the economics of the projects and the resource recovery. As more information is obtained and the development risks addressed, the development program will be modified continuously.

In unconventional plays the "factory" development concept is mainly an assembly-line approach to field development where similar operations become concurrent (Vassiellis, 2009 [7]). This approach considers that as long as operation intensity is maintained, the production level is in plateau, which is ideal for facility sizing and production marketing. In addition, the building of a materials inventory would ensure smooth execution of the plan without disruptive supply delays and by being able to negotiate procurement of services and material at best terms. Quality assurance and surveillance would also apply as in a manufacturing process.

This approach is not free of risk though; many contingencies have to be evaluated before booking large quantities of reserves.

- Available land should be sufficient to ensure continuous drilling, and although the resource is continues and the sector de-risked, regulatory, environmental or other constraints may apply to different part of the sector.
- Building inventory of materials such as fracturing sands and water for massive fracture stages might be challenging.
- Commodity price cycles and reinvesting risks might require adjustments to these massive developments.

7. Evaluation of Estimated Ultimate Recovery (EUR)

Estimated Ultimate Recovery (EUR) is one of the most relevant parameters for Unconventional wells. It is used to calculate reserves and resources of projects. It is one of the fundamental drivers of development decisions and is central to the valuation of play acreage. But the nature of unconventional plays combined with the uncertainty in the characterization of reservoir and fracture properties results in large ranges of possible EUR values. The multiplicity of models that represent plausible configurations for the wells' Stimulated Rock Volumes (SRV) adds to the complexity of the exercise.

When dynamic data is available, the common methods for EUR estimation on single wells are Decline Curve Analysis (DCA), Rate Transient Analysis (RTA) and Numerical Simulation. Each of these methods has its advantages and drawbacks, DCA has the advantage of simplicity and rapidity but its conditions of application are limited, Numerical Simulation's superiority lies in the robust physical capabilities of the technique and its main drawbacks are the complexity of application and long running times. RTA is based on flexible underlying physical models and constitutes a good compromise of physical reliability and agility of use. Regardless of the method of preference, if mastered, the analyst can maximize the advantage while minimizing the drawbacks.

When a statistically significant number of "analogous" wells are available Statistical EUR determination of undrilled wells is possible. This method relies on a population of existing wells; nevertheless, EUR distributions for the existing individual wells are calculated using individual well EUR estimation methods. For this reason the obtained statistical distribution is subject to the uncertainties used to estimate individual EUR. This method is covered in section 7.5.

The choice of the technique to be used for EUR estimation requires an evaluation of the information and tools that are available, the investment of the resources and time that are appropriate for that specific project and the future use of the results.

For a screening analysis of a competitive bid for hundreds of mature producing wells, the analysis method will need to be very simple and fast. In this case DCA is preferred since the wells are possibly on boundary flow regime where this technique is quite precise. When correctly applied the errors in excess on some wells compensates the errors in defect and hence a proper evaluation is made.

On the other extreme, the case of evaluating the performance of a pre-development consisting on a few of shale gas wells (generally five to ten) with different well designs is quite different. In this case, important decisions, such as well spacing for the development phase or the most convenient landing point have to be made. These decisions will potentially impact hundreds of future wells and their associated facilities and should involve a detailed multi-well RTA study, supported by numerical simulation in order to establish optimum development scenarios with their associated uncertainties.

Table 11: Typical characteristics of several forecasting methods (Monograph 4 [8])

Method	Time required	Minimum Data Requirement	Uncertainty on EUR
Multi-segment Arps DCA	1 minute/well	Monthly production data	25%
SEDM, Duong	5 minutes/well	Monthly production data	20%
Rate Transient Analysis	60 minutes/well	Monthly production data, daily rate and pressure data is preferred, wellbore description, basic reservoir properties	15%
Numerical Simulation	Varies	Monthly production data, daily rate and pressure data is preferred, wellbore description, detailed reservoir properties	10%

Table 11 shows the main features of the most common developed well EUR estimation methods. It shows that the more complex (and complete) methods come with a cost. Before launching a study it is mandatory to set a clear scope and allocate the adequate resources to it, in order to obtain meaningful results.

It is important to keep in mind that EUR is a volume; it does not represent reserves or resources until analysis shows that the fluids are commercially recoverable.

7.1 Common sources of uncertainty

EUR determination is subject to many uncertainties; some uncertainties are related to the available data, production history and uncertainties on measurements. Some sources of uncertainty are specific to the forecasting method while others are common to all methods.

- **Well productive life**: the duration has to be predefined for all methods, there are several criteria used to estimate this. A common criterion is the economic limit which is reached when the rate is insufficient to pay for OPEX/Work over. Due to the recent development of unconventional plays in the USA, statistical information on very long economic production tails is not yet available, **project specific life expectancy studies are recommended to increase the chances that production forecasts don't exceed the lifetime of an average well**.
- **Drainage area**: Transient flow is common during the first years of production on all low permeability reservoirs and since the drainage area is only fixed when boundary flow is set, this value remains uncertain for many years. The maximum possible drainage area is set by the well spacing, but this is only attained in cases where spacing is optimum. Each one of the methods presented on this document has a specific methodology to address this uncertainty.
- **Well clean up and operating conditions:** Fracture fluid clean up and decreasing bottom hole pressures generally produce off trend data. Unless modeled these points should be ignored in order to not influence the long term forecasts.
- **Adsorbed hydrocarbons:** As mentioned in section 0 the presence of organic matter favours the presence of adsorbed hydrocarbons in its surface. Analytical and numerical models can easily account for its effect, but the main uncertainties related to this factor are desorption isotherms (provided Langmuir model is used) and diffusion coefficients of the adsorbed molecules through the organic matter. These two parameters are seldom measured and the mechanics of flow not understood. Nevertheless the impact is shown to be limited to 5% to 15% in a wells productive life [9] [10].

7.2 Decline Curve Analysis (DCA)

Conventional DCA has been by far the most widely used in the industry; it has many flaws but they have been historically addressed with robust empirical workflows and knowledge on the underlying theory. The classical Arps approach has been adapted to Unconventional well decline by the addition of terminal declines, and although widely used there is not an actual model to support it. It is only used to limit the resources that are estimated in unconventional, especially for wells producing in transient flow. The development of Unconventional plays also motivated the creation of Alternative Decline models that are best suited for unconventional wells, and although empirical, have some theoretical bases for support. Nevertheless these models still have some drawbacks that have to be mastered by the analyst to produce relevant EUR estimations.

The main advantages of DCA over other forecasting methods are the simplicity and rapidity of application. For this reason, it is a good starting point for any analysis, and in cases where hundreds or even thousands of wells have to be analyzed it constitutes the only possible alternative. It is also shown to have adequate capabilities to match production trends and the fact that it is available in almost all software packages has facilitated its universal use.

In a case of multiphase flow (G&C or oil) the use of DCA can be tricky as the evolution of CGR or GOR can change over time due to relative permeability effect in the reservoir when pressure drops below the dew point. It is then difficult to extrapolate the current production.

The more general form of Arps decline model is the **Hyperbolic (*0<b<1*)** decline:

$$q = q_i(1 + bDt)^{\frac{-1}{b}}$$

Its complementary forms for b values of 0 and 1 are called **Exponential (*b=0*):**

$$q = q_i e^{-Dt}$$

and **Harmonic (*b=1*):**

$$q = \frac{q_i}{1 + Dt}$$

Where *q* is the rate (oil, gas or water), q_i the initial rate, *D* is the initial decline, t is time and *b* is a factor that controls the variation of *D* with time. The b factor has an important role in the estimation of EUR, and it has been empirically observed that certain conditions are characterized by a certain value of *b*. Arps defined the change in the "loss ratio", 1/D with time as parameter b.

$$b = \frac{d\left(\frac{1}{D}\right)}{dt}$$

The decline model, as defined by Arps requires:

- Production at constant BHP
- Boundary Dominated Flow
  - Constant drainage Area, constant drainage radius with time.
- Constant *b* factor with time
- Constant productivity index
  - Unchanged skin factor (no change in damage or stimulation) during the production period being analyzed.

Wells in unconventional reservoirs with low to ultra-low permeabilities fail to meet this criteria mainly for the following reasons:

- Transient flow dominates production for long times (years).
- Transient flow requires b to vary, and almost always decreases steadily with time.
- BHP often decreases with time, particularly during the first year of the well's life (can be avoided by normalizing with draw down).

7.2.1 Segmented Arps decline method

As mentioned before, the b factor, represents the change in the loss ratio (1/D), as defined by Arps. This means the rate at which rate decline diminishes as production time passes. It has been shown that some particular reservoir configurations generally produce a particular type of decline that can be forecasted with a particular value of b. In the case of unconventional wells, a particular behavior was also observed.

In Arps work the value of b was constrained between 0 and 1, but as lower permeability reservoirs where developed, values higher than 1 started to appear. A b factor larger than one is unphysical on the long term, since the cumulative is infinite as time approaches infinity. In 1987 Long and Davis [11] presented a way to cope with the unlimited production cumulative: this solution consisted by starting the forecast with a b higher than 1, and predefining a minimum decline rate (D_{min}).

Then during the forecast, when the instantaneous decline reaches a value equal to D_{min}, the decline switches to an exponential decline at this preselected decline rate. The value of D_{min} is often in the range of 5 to 10%. This is a particular case of **Arps Segmented Decline**, which consists in producing forecasts with different segments each characterized by a particular type of classic Arps decline curves.

It is important to mention that this behavior was never observed in actual wells, this method was created with the sole purpose of limiting EUR forecasts. Having said this, the importance of this procedure is that it can produce production forecasts that are reasonable and acceptable to regulatory authorities. The procedure has some limitations however:

- It does not honour the physics of flow during transient flow regime (Arps model is a BDF model never intended to model transient flow)
- Values of b in BDF is not necessarily 0. Fetkovich et al (1996) [12] suggested that b will typically be in the range of 0.4 – 0.5 for gas wells in BDF, and solution gas drive oil wells will typically have b values of 0.3. And Fetkovich type curve includes the full range of possible b values from 0 to 1 for BDF.

The method presented by Long and Davis can be adapted to different context by switching the terminal decline from exponential to hyperbolic with a predetermined value of b.

It can be demonstrated that Transient flow requires b values larger than 1, in particular “perfect” transient linear flow b=2 and “perfect” transient bilinear flow =4. Table 12 summarizes some observed behaviours that can be characterized with particular values of b, it also highlights the potential biases that can be introduced in the forecasts in the case that the method is misused.

Table 12: Characteristics of forecasts with different b factors (mod. from Monograph 4)

B value	Theoretical basis	Use	Problems	Potential bias if misused
0	Ideal radial flow of a fixed volume	Trailing exponential, lon-life/low rate wells	Rare in unconventional wells	Conservative
0<b<1	None	Multilayer, Waterfloods	Requires D_{min}, no theoretical basis	Pessimistic
1	None	Results when rate/cum trend is linear	Requires D_{min}, no theoretical basis	Statistically rare
1<b<2	Only possible in transient flow	Very common in early time for unconventional wells	Required D_{min}, no theortical basis, some other methods are preferred for transient flow	Optimistic
2	Ideal Linear flow depletion of infinite Volume	First few months of production	Requires D_{min}, rarely seen, unlikely	Aggressive
4	Ideal bilinear flow depletion of infinite Volume	None	Requires D_{min} in a few years, not very useful	Very Aggressive

In practice D_{min} is used to represent late time uncertainty, it has more influence on the final reserves than b factor. It is an easy to use method that is accepted by regulatory authorities, but does little to provide insight in the understanding of the factors that control well performance and hence does little to increase the understanding of the play.

7.2.2 Practical estimation of b factor, Mottet (2013) [13]

Assuming that the decline goes from hyperbolic with an early time b factor to another hyperbolic with a long-term b factor, an evolution of the "instantaneous" b factor should be seen over time. From the mathematical equation of an hyperbolic decline, $q = q_i(1 + bDt)^{\frac{-1}{b}}$, we can calculate the cumulative as a function of the rate:

$$Np = \frac{q_i^b}{D_i(1-b)}\left(q_i^{1-b} - q^{1-b}\right)$$

In this equation, D_i and q_i are constant so it can be written in the form $N_p = a.q^{1-b} + c$ with a and c constants. If we plot N_p vs. q^{1-b} and try different values of b until maximizing the r^2 of a linear regression, we can calculate the value of the instantaneous b factor at a given point in time. By repeating this operation for each month, we can plot the evolution of the b factor over time (Figure 43). The only limitation of this method is that the data has to be clean and it could be difficult to apply to individual wells with a noisy production history.

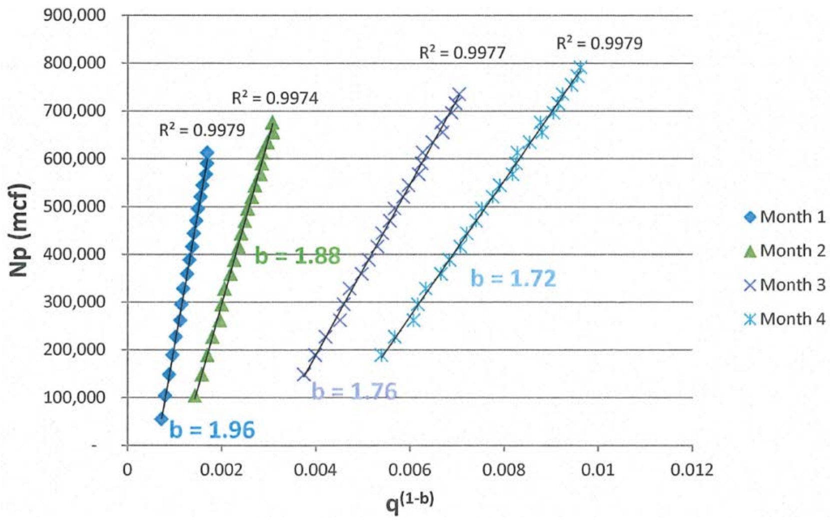


Figure 43: Illustration of b factor calculation per month

Figure 44 shows the evolution of the b factor for a selection of old horizontal Barnett wells and 2 individual wells with clean production. We can notice a constant decrease of the b factor that appears to stabilize around 0.5. The points after 30 to 40 months are probably not valid as fewer and fewer points are available to build the regression. However, this method shows that the long term b factor could be close to 0.5 as suggested by Fetkovitch.

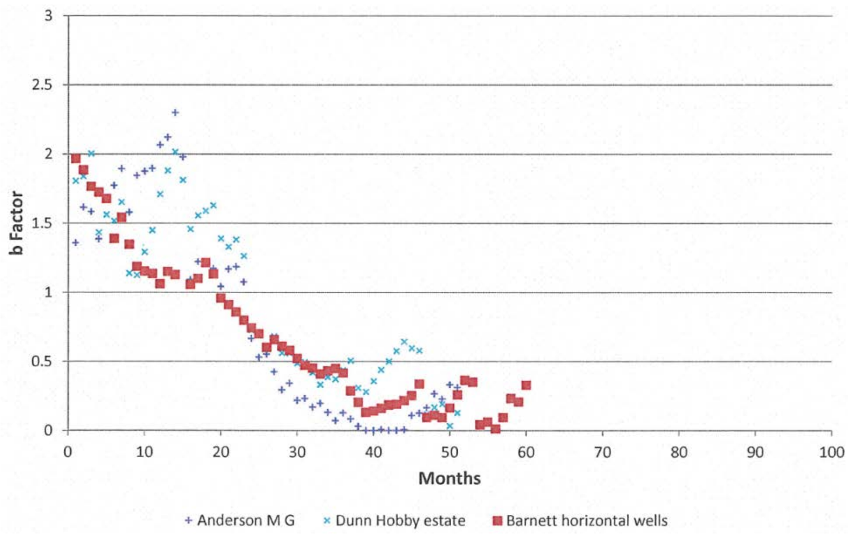


Figure 44: Evolution of b factor with time

7.2.3 Stretched Exponential Decline Method (SEDM)

This method introduced by Valko (2009), contrary to Arps which is a BDF model, is a transient flow model by design. For this reason is applicable to ultra low permeability reservoirs with very long transient periods.

$$q = q_i \, exp\left[-\left(\frac{t}{\tau}\right)^n\right]$$

Advantages:

- Conservative in the sense that as production approaches zero, cumulative approaches a finite value (unlike Arps with b>=1).
- Fits transient data with very with little need to change parameters.
- Disadvantage: the model will not fit BDF
- Simple three parameter model, easy to apply

A problem with this model is that early data, where fracture clean up and falling BHP significantly influences production and tends to provide very conservative, and incorrect forecasts.

7.2.4 Duong

This model presented by Duong 2011 is supported by theory. It is based on the fact that transient linear and bilinear can be modelled by an equation of the form:

$$q = q_1 t^{-n}$$

For linear flow n=½ and for bilinear flow n=¼. We can obtain the relationship between cumulative production and time by integrating:

$$G_p \; or \; N_p = \frac{q_1 t^{1-n}}{(1-n)}$$

Note that two major assumptions in these equations:

- Fracture skin is zero
- Production is at constant BHP

In order to correct for variable BHP

$$q = q_1 t^{-m} e^{\frac{a}{1-m}(t^{1-m}-1)}$$

Advantages: Consistency of forecasts, it forces near-linear flow model to fit bad data that follow a different (and misleading) trend.

7.2.5 Well life and uncertainty

The life of the well will eventually be limited by the well's economic limit, which is reached when production is insufficient to pay for operating costs or reserves are not sufficient to justify a workover. A study presented in the SPEE Monograph 4 [8] reviewed over 94,000 horizontal wells with a first production date of 1970 or later. The data shows that 77% of the 10-year-old wells were on production, 50% of these wells have a life of 23 years or less and about 30% will produce for 45 years or more. For these horizontal wells, the final producing rate is typically from 1% to 5% of the initial rate. However, Monograph 4 [8] recommends that a specific study on life expectancy of unconventional wells should be performed before making recommendations on well life or abandonment rate.

For gas wells a pragmatic approach of considering abandonment criteria of 50 mcf/d or 30 years is commonly found and seems reasonable. There are no clear abandonment criteria for oil wells but it would probably be lower than 30 years.

7.2.6 Comparison

Table 13 summarizes the relationship between the Arps parameters b and D in terms of parameters used in other decline models.

Table 13: Equations for calculation of b and D for simple decline curve models (Monograph 4 [8])

Model	Q	D	b
Arps	$q = q_i(1 + bD_i t)^{\frac{-1}{b}}$	$D = D_i(1 + bD_i t)^{-1}$	$b = \frac{d\left(\frac{1}{D}\right)}{dt}$
Stretched Exponential	$q = q_i e^{-\left(\frac{t}{\tau}\right)^n}$	$D = \frac{n}{\tau}\left(\frac{t}{\tau}\right)^n$	$b = \frac{1-n}{n}\left(\frac{\tau}{t}\right)^n$
Duong	$q = q_1 t^{-m} e^{\frac{a}{1-m}(t^{1-m}-1)}$	$D = \frac{m}{\tau} - at^{-m}$	$b = \frac{\frac{m}{t^2} + amt^{-m-1}}{\left(\frac{m}{t} - at^{-m}\right)^2}$
Linear Flow	$q = q_1 t^{-\frac{1}{2}}$	$D = \frac{1}{2t}$	$b = 2$

Table 14 summarizes the major strengths and limitations of each model.

Table 14: Strengths and limitations of decline models (Monograph 4)

Decline model	Major Strength	Major Limitation
Arps (original)	Easy to use, widely available in commercial software	Requires BDF, constant BHP
Arps (modified)	Easy to use, widely available in commercial software, valid in BDF	Early BDF, late exponential decline required
Stretched Exponential	Transient Flow model	Not accurate in BDF, tends to be conservative in most cases
Linear Flow	Correct physics for many fractured wells	Inappropriate for BDF, optimistic
Duong	Correct physics for many fractured wells (linear flow)	Inappropriate for BDF, optimistic
Duong (modified)	Correct physics during transient flow and BDF	Not available in commercial software

<u>The following workflow can be recommended (Pr. John Lee, Monograph 4):</u>

When time is available, Rate Transient Analysis or analytical models should be implemented.

When time is not available:

- **Check and diagnose data: use daily data, check data consistency, discard periods of liquid loading, fracture clean-up or fracture interference, etc…**
- **Select simple models: SEDM, Duong or simply segmented ARPS. If ARPS is used, use 0.5 for final b factor in BDF (gas wells) or 0.3 (solution-gas-drive oil wells). If well still in transient flow, use the typical value of end of linear flow observed on other wells or analogous wells.**

7.3 Rate Transient Analysis (RTA)

Production analysis techniques, also known as Rate Transient Analysis (RTA) consist in the analysis of the change of production rate with time. These techniques were developed in parallel to Pressure Transient analysis techniques (PTA) and applied with a very similar workflow. But while the PTA theory & usage evolved incorporating more sophisticated analyses, RTA theory evolved while its practice remained based on simple and not always appropriate techniques.

The incorporation of permanent pressure gauges and the development of unconventional plays that have very long transient responses, made the industry aware of the added value of these techniques and the incorporation of these into the day to day tools for reservoir engineers.

An exhaustive review of the RTA technique and support theory is provided in GM EP RES 802, the incorporation of the techniques developed in this document is mandatory before evaluating Reserves and Resources using this technique.

7.3.1 RTA technique overview

Unconventional plays, characterized by an ultra-low permeability in the micro to nano Darcy range, require large stimulation jobs to produce at profitable rates. This particular set-up favors extremely long transient linear flow periods where it is impossible to uniquely determine permeability and drainage area, and hence predict the end of linear flow.

These long transient production periods are generally characterized with Rate Transient Analysis (RTA) techniques, which encompass specialized plots, type curves, flowing material balance and analytical models to estimate formation and fracture parameters as well as estimate EURs and long term production forecasts. The modeling process using the RTA techniques is non-unique during the transient flow period and a probabilistic approach is required to capture the input parameters uncertainties and assess the associated risks in the EUR estimation.

The analytical models that can be used in RTA techniques are very varied and flexible, they go from the simple pioneering work presented by Wattenbarger et al (1998) [14]] to more complex models that integrate a Stimulated Rock Volume (SRV) region around the hydraulic fractures (e.g. Stalgorova et al, 2012 [15]), can be single or double porosity, can include permeability dependence with stress, adsorbed hydrocarbons, etc. These models evolve in parallel to the understanding of these plays.

Analytical models rely on simplified solutions to the diffusivity equation; these are single phase and consider constant fluid properties. Single phase assumptions are correct in dry gas cases, and can be a good approximation for lean gas and low GOR oil cases. But in the case of rich gases and volatile oils this approximation might not be representative of reservoir flow. Fit-for-purpose numerical models are used to evaluate the reliability of the analytical models, correcting for non-linearities such as multi-phase flow and changing fluid properties in short distances and through time. The drawback of these is that they often require very long running times, preventing their generalized application.

Analytical and Numerical models are then used to generate forecasts that provide Estimated Ultimate Recovery (EUR) for these wells. All the previously mentioned factors translate into the EUR as a generally wide range of possible outcomes reflecting the uncertainties in the future recovery of these wells.

7.3.2 Rate Transient Analysis workflow

The RTA technique is very similar to the PTA technique; the fundamental difference is that for the first technique rate variations are more significant while on the second one the pressure variations are more significant. It is very important to know when to apply each technique since the incorrect use of these leads to material balance errors and over-simplifications.

The RTA workflow can be broadly divided into four steps, these are:

1. Preparation of Production and static data.
2. Diagnose flow regimes
3. Characterize the formation and the fracture.
4. Forecast well behavior.

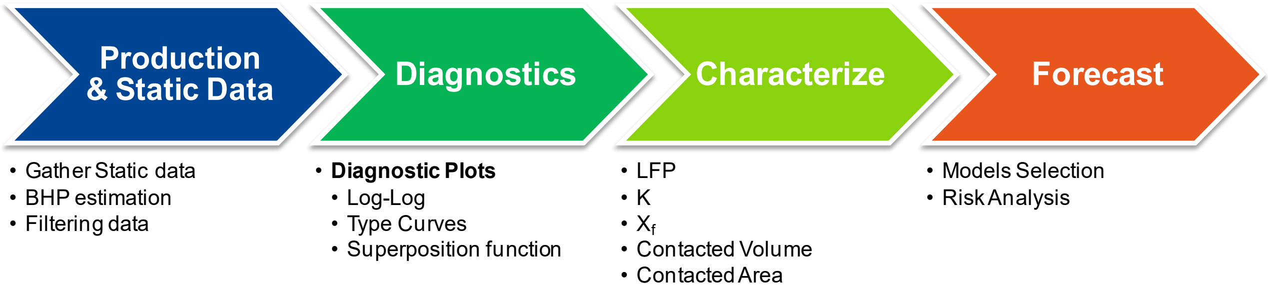


Figure 45: Schematic RTA workflow

A brief description of each step of the workflow is presented below, for a detailed description of each and to get an in depth insight into the technique the reader should refer to GM EP RES 802.

7.3.3 Preparation of production and static data

This step is fundamental for the technique, since it consists in the combination of dynamic and static data into diagnostic plots to derive the characteristics of the formation and the fractures and then forecast its long term behavior. Unreliable input data results in unreliable results.

- Static petrophysical data can be obtained through: log interpretation, core and cutting measurements, and when nothing else is available regional or best guess correlations. Petrophysical data has to be estimated through the integration of all available sources, the absence of an industry standard for lab protocols complicates the proper representativeness of the petrophysical properties.

- Static pressure data has a significant influence in interpretation and forecasts. The most reliable source for this information is a DFIT (Minifrac). Other approximations are possible, such as the Eaton method from sonic logs, but calibration with DFIT (at least regional) is strongly recommended. Other sources can be build ups, Perforation inflow tests, etc.
- Fluid properties can come either from PVT reports or correlations. In the case of PVT reports special attention should be taken to sampling conditions. Since these reservoirs produce with very large drawdowns, single phase sampling is challenging and recombination practices require Quality Control.
- Production data (rates and pressures) is affected by strong perturbations due to day to day operations, for this reason it tends to be very noisy. Careful filtering of this data is required, such as: checking for inconsistent points, liquid loading, etc.
- Bottom Hole Pressure calculation can be challenging since many of these wells produce at low rates, and hence tubing flow regime prediction is very uncertain.

7.3.4 Diagnose flow regimes

The production, pressure and static data are combined in specialized plots with the purpose of diagnosing the flow regimes that have been established through the well production life. These specialized plots can be the log-log plot (log of normalized rate vs. log time), different type curves such as Fetkovich's or Blasingame and the Square root of time plot (normalized pressure vs. square root of time). Associated functions such as Bourdet's derivative and integrals can help to enhance the reliability of these diagnostic plots by smoothing the well response.

According to the characteristics that production data shows on these plots, the flow regimes that were developed in the reservoirs can be interpreted. These are used to identify the pertinent superposition functions to transform real time, correcting for variable pressure and rate conditions, and obtain an equivalent constant rate solution. This step is fundamental to the process, since all superposition function introduce bias, so superposition functions have to be used only after flow regime history of the well is interpreted.

7.3.5 Formation and Fractures characterization

Specialized plots using the pertinent superposition time functions are used to estimate the characteristics of the formation and fractures (SRV). Since generally flow regime is transient, **these estimations are non-unique**, so only ranges of possible values for parameters such as fracture half length, permeability, "contacted" Hydrocarbon in place (Nobakht et al, 2011 [16]), etc. can be estimated. On the other hand, parameters that are combination of other parameters, such as Linear Flow Parameter (LFP, $A\sqrt{k}$), can be estimated with limited uncertainty.

The identified ranges of parameters should be constrained by data that can be available from other sources such as:

- SRV dimensions can be constrained with Microseismic surveys.
- Permeability ranges with laboratory measurements and estimations from other sources such as DFIT.
- Contacted Hydrocarbon Volume with other estimations of HCIP and well spacing.

The main parameters that are characterized (with their associated range of uncertainties) in this step are the Linear Flow Parameter and Contacted fluid in place.

The parameters estimated with the diagnostic plots constitute a first approximation of the formation and fracture characteristics. The production and static data can be then input into specific analytical models where the estimated parameters and range of uncertainties are refined through a history matching process. These matches are non-unique but the range of uncertainty is generally reduced with this process. It is advised to check the results of the analytical model with fit-for-purpose numerical models that correct for non-linearities that are not completely corrected by analytical models.

7.3.6 Production forecasts

The interpreted parameters together with their range of uncertainties can be used to estimate future well behavior and EUR. In this step, the models previously used to refine the parameter characterization, are used to perform the forecasts. In order to provide the forecasts it is necessary to forecast the evolution of BHP for all the well life. This has to be done taking into account future well interventions such as artificial lift and variations in the inlet pressure of production facilities.

This technique for forecasting future production could give a high degree of certainty in situations where boundary dominated flow (SRV depletion) has been observed. In cases where boundary dominated flow is not observed, a significant degree of uncertainty is introduced. Misunderstanding of its underlying assumptions will lead to erroneous conclusions.

There are a great number of models that can be used to do this, and a priori there are no “preferred” models since each has its advantages and drawbacks. For this reason it is important to avoid performing all forecasts with a single model type.

The results of the analytical models can be checked with fit-for-purpose numerical models. These models better represent the non-linearities associated with changing fluid properties, multi-phase effects, etc. and hence increase the reliability of the results. In any case, particular attention should be paid to the recovery factor inside the SRV.

7.3.7 Probabilistic and Deterministic approaches

As stated by the SEC, the CR EP RES 001 and the PRMS 2007, reserves and resources evaluations can be either **deterministic** or **probabilistic**. In cases where very little is known in the input parameters of the model, low, base and high values for these can be set in order to provide EUR estimates, this corresponds to a deterministic approach. This is recommended only in cases where little or no production data is available for the well (either because it is undrilled or about to be connected). In cases where some production is available a probabilistic approach is recommended.

In cases where the EUR evaluation is **probabilistic**, the last step of the workflow consists in performing a Risk assessment on the forecasts. Since only one or two transient flow regimes dominate throughout the life of the well, a large combination of parameters render the same quality of history matches. For this reason a manual estimation of uncertainty ranges for the forecasts can be very laborious, unproductive and incomplete. For this reason a Montecarlo type approach is recommended.

A Montecarlo type approach consists in pre-establishing probability distributions for certain parameters, imposing automatic parameter estimation for others, and performing hundreds to thousands of forecasts with imposed stochastic parameters and adjusting the history match with the automatically estimated parameters. This way a complete range of results can be derived from this process, minimizing the "uncovered" parameter ranges. The final distribution of EUR results can be used for evaluating the P10, P50 and P90 cases that correspond to:

- 1P/2P/3P for Reserves
- 1C/2C/3C for Contingent Resources
- P90/P50/P10 for Prospective Resources.

These EUR distributions are determined with analytical models, since running times are much shorter. Once the ranges are identified, it is advised to run the final cases (e.g. P90, P50 and P10) in numerical models in order to correct for non-linearities not taken into account by analytical models.

Figure 46 details the different steps of a probabilistic approach to determine 1P, 2P and 3P values.

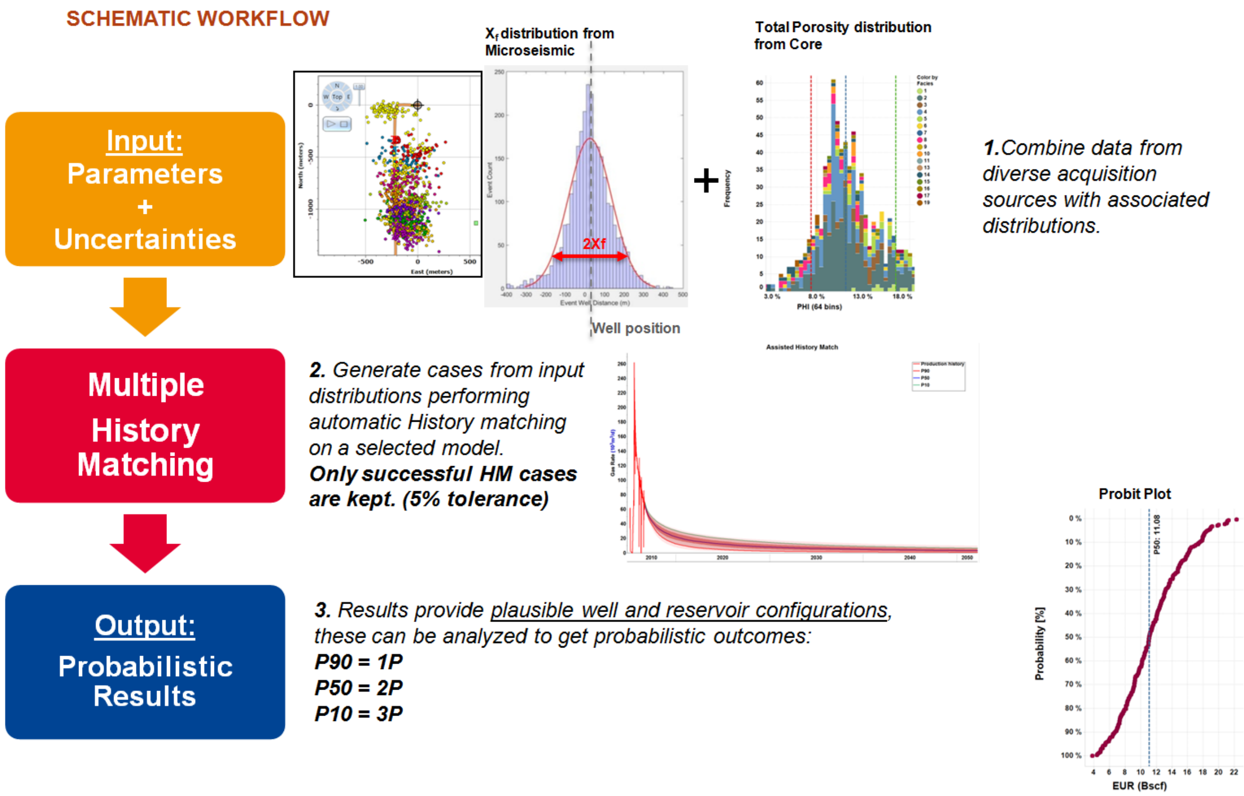


Figure 46: RTA probabilistic workflow

7.4 Numerical Simulation

Simulation of unconventional reservoirs is a relatively recent topic that does not deal with the same problematic as conventional reservoir simulation. The need for unconventional reservoir simulation responds to the lack of validity of DCA and RTA methods to represent several phenomena such as multi-phase, non-linearities and complex SRV configurations. The subject of numerical simulation of unconventional reservoirs is developed in detail in the GM EP RES 801. The RTA techniques have powerful analytical models, but Numerical models have the following specific advantages over analytical ones:

- Large pressure gradients in short distances, consequence of low permeability, result in fluid property changes. This phenomenon is not represented by Analytical models, the impact has to be assessed by numerical models.
- Multi-phase phenomena are not considered in analytical models since these are single phase. Numerical models include these phenomena; nevertheless, critical input parameters such as relative permeability curves cannot yet be measured on cores for unconventional reservoirs.
- In the case of light oil cases, analytical models do not consider the effect of dissolved gas. This is an important driving mechanism for depletion which analytical models do not consider and can have a significant impact on long term hydrocarbon recovery.

The following problematic can be found in unconventional reservoir simulation: SRV modeling, complex transport physics, long transient flow regimes, etc. In general simulations consist of single-well sector models, in case of interference studies more than one well can be included. This is a consequence by the limited propagation of the drainage area in the vicinity of the wells, the large extension of shale plays and the need to have a fine mesh around fractures to correctly represent the high pressure gradients. The Numerical simulation models that are currently recommended by the group for unconventional reservoirs are:

- A dual-porosity model at well scale consisting of one rectangular SRV containing matrix, planar Hydraulic fractures explicitly gridded, and a secondary fracture network in dual porosity, surrounded by an Un-SRV containing only matrix cells. Hydraulic fractures are considered and modeled as bi-wing fractures explicitly represented. The secondary fracture network (natural, induced or not and induced by hydraulic fracturing) is modeled implicitly with the dual porosity option. Multi-porosity option is also used to describe properly the kinetics of fluid exchanges between matrix and fractures with very low matrix permeability.
- A single-porosity model representing only a quarter of a fracture stage, where natural fractures are represented explicitly.
- Fit-for-purpose numerical models that are available in the RTA software platforms, specially conceived to deal with the drawbacks of the RTA technique.
- More advanced numerical simulator integrating the SRV generation through geomechanical modules (3D mechanical earth model, DFN, match of treatment pressure during fracturation, etc…)

SHARP (stands for “Shale Reservoir Performance”) is a dedicated simulation workflow developed in Total to specifically address the issues inherent to the unconventional context. It combines the dual-porosity sector model with an internal uncertainty platform (EST); the same workflow can also be used with single-porosity models. In this workflow, EST defines scenarios that are numerically simulated to generate multiple history matches and estimate production forecast scenarios. The outputs of the workflow are history matched numerical models that represent plausible SRV configurations that honour available information; a spectrum of forecasts from all these possible combinations of parameters is generated too.

Numerical simulation are the most realistic representation of the physical phenomena in unconventional reservoirs, but at the same time is by far the most time consuming of all the EUR estimation methods. This method heavily relies on the information quality and amount of information available, it is appropriate to perform dedicated studies on particular wells at critical decision stages.

7.4.1 General Numerical Simulation Workflow

A general workflow for reservoir simulation for unconventional reservoirs can be illustrated by:

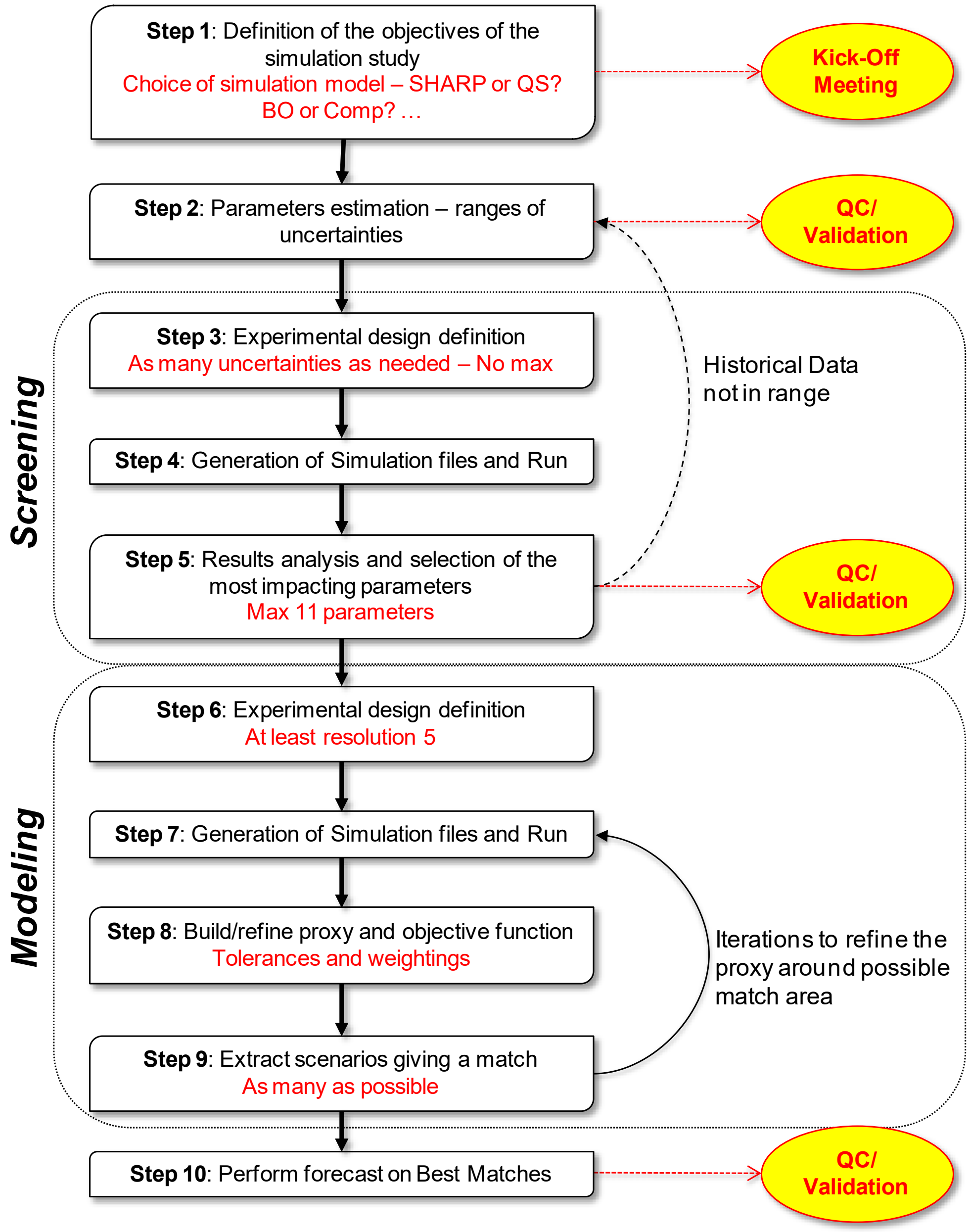


Figure 47: Workflow for an unconventional formation numerical simulation study.

The details of each step can be found in GM EP RES 801. Some generalities of the available models are presented in this section.

7.4.2 SHARP workflow

As previously mentioned the **SHARP (Shale Reservoir Performance)** workflow is an in-house evaluation tool for assessing the range of uncertainty in Resources / Reserves for Shale Gas projects (Mongalvy et al. [17]). The workflow consists of single well models coupled with the internal dynamic uncertainty tool EST, which returns a number of matched reservoir models with their corresponding production profiles.

Hydraulic stimulation generates complex fractures networks. It is reasonable to assume that since hydraulic fractures are propped (at least partially), they have a higher conductivity than re-opened natural fractures, which may be un-propped or slightly propped. Therefore two sets of fractures are defined, with different representation in the model:

- NF: complex un-propped fracture networks including re-opening of pre-existing natural fractures. They are implicitly modeled through dual porosity in the whole SRV.
- HF: highly conductive propped fractures close to the wellbore. They are explicitly gridded in the model.

The model consists in a simple sugar box grid, where all the Hydraulic fractures are supposed to have the same dimensions and all the petrophysical properties are kept homogeneous (as well as natural fracture density). The model is split into two main regions:

- SRV (Stimulated Rock Volume): contains the hydraulic fractures (HF) explicitly gridded, the natural fractures network (NF) modeled through dual porosity and the matrix. Its dimensions are linked to the HF dimensions and drain length.
- Un-SRV: contains only non-stimulated matrix, gridded all around the SRV to match the well spacing or area.

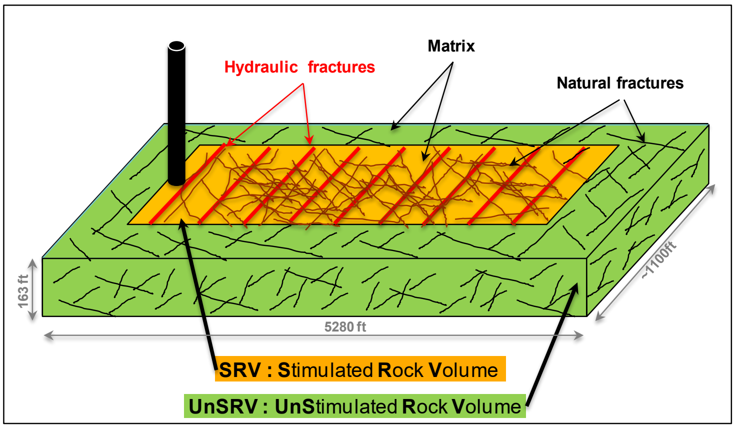


Figure 48: Schematic of the sector model

Desorption of the adsorbed gas is simulated via Langmuir isotherms, within the matrix in SRV and Un-SRV regions. In numerous cases, adsorbed gas has limited impact on the ultimate recovery, and therefore may not be accounted for.

Dual-Porosity model is used to simulate the matrix-fracture interactions, because it responds to the needed flexibility to represent network fracture parameters as variables within a single pre-determined grid. In order to represent correctly transient pressure regimes between implicit fractures and matrix the multi-porosity option is used.

7.4.2.1 Dual-porosity concept

In the SRV, fluids exist in two interconnected systems: the matrix, which provides the bulk of the reservoir volume with very low permeability and the fractures with much higher permeability. To represent these two systems, every cell of the SRV will be divided into two cells: one cell corresponding to the matrix bulk volume, and the other cell corresponding to the fracture (dual porosity).

These two cells will virtually be defined at the same position and at the same depth, but all their properties are independently defined: porosity, permeability, relative permeability curves, compaction tables, initial saturations... A matrix-fracture coupling transmissibility is built to simulate flow between the two systems due to fluid expansion, gravity drainage, capillary pressure etc. One parameter is particularly important to compute this transmissibility: σ, a factor of dimensionality of the inverse of the square root of length, which represents the matrix-fracture interface area per unit volume. This factor can be linked to the dimensions of the matrix blocks with Kazemi's formula:

$$\sigma = 4 * \left(\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2}\right)$$

In this model, flow is permitted between adjacent fracture cells and prohibited between adjacent matrix cells. In addition, to represent correctly transient pressure regimes between implicit fractures and matrix, driving flow kinetics and thus production behaviour, the model integrates a multi-porosity approach.

7.4.2.2 Multi-porosity concept

In these ultra-low permeability domains, transient effects are the dominant flow regime for most of the life of the well. In order to correctly represent these phenomena a Multiple Interactive Continuum approach (MINC) was included for the matrix blocks. The principle is to divide the matrix cells into several subcells to represent correctly the kinetics within the matrix and at the interface with the NF. The sub-cells only communicate with the matrix sub-cell above and below it, and the transmissibility factors and pore volumes are computed as if they were nested in one another.

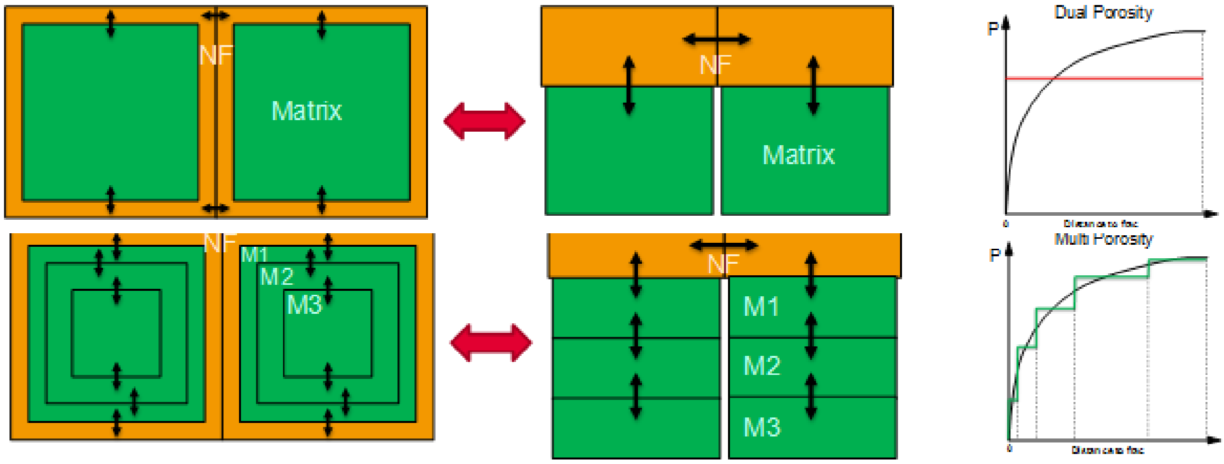


Figure 49: Scheme represented by the dual-Φ [Top] and multi-Φ [Bottom] concept and its equivalent representation in a grid.

This option is essential to model correctly the kinetics at the matrix-fracture interface: due to the very low permeability of the matrix, the dual-porosity model cannot represent the high pressure gradient within the matrix, since only one value of pressure can be assigned per cell. The behaviors would then be distorted. The multi-porosity option can model this pressure gradient, giving behaviors that are consistent with the ones observed in unconventional formations.

7.4.2.3 Coupling with EST

As mentioned previously, due to the complexity of measurements and the lack of standardized laboratory protocols, the uncertainty on static parameters is greater in unconventional reservoirs than in conventional ones. Even more, the transport physics involved are more complex and transient flow regimes result in non-unique parameter determination. For this reason the number of parameter and the uncertainty range are very high and the integration of all the possible sources of information is needed to narrow these ranges.

An experimental design tool (EST) is used to define a proxy that can model all possible simulation responses through a limited subset of reservoir simulations. History matching can be initiated with the proxy, avoiding numerous Numerical simulation, saving much time and computation resources. The proxy is used to fully explore the solution space, using all possible combinations of parameters within their defined ranges. The solution space is iteratively narrowed down around promising areas of the solution space that will enable a history match of the production data. By then, the combinations of parameters leading to a history match are extracted.

These scenarios are numerically simulated with the dual porosity model to validate the history match and get a production forecast. The final products are history matched numerical models to analyze production mechanisms, on which sensitivities can be performed to assess options to optimize recoveries, and a spectrum of forecasts from all the possible combinations of parameters leading to a history match. This spectrum reflects uncertainty linked to the parameter ranges given as an input.

7.4.2.4 Simulation using commercial softwares

The multiporosity option is managed by some simulators with the multiporosity keywords NMATRIX and NMATOPTS. The matrix layer is automatically divided into several sub layers, including the fracture layer and the matrix sub-layers. The NMATRIX keyword defines the number of matrix sub-cells, while NMATOPTS controls the assumed geometry of the matrix sub-cells (linear, radial or spherical), the volume of the outermost matrix cell, and the method for partitioning the pore volume.

In the model, the HF are explicitly gridded, perpendicular to the well drain, regularly spaced from each other. The SRV (area where the NF are defined) is the rectangle limited by the tip of the HF (in y direction) and by the first and last fracture stages plus a half fracture spacing (in x direction). Given the high pressure gradient expected in the vicinity of the HFs, it has been chosen to grid logarithmically away from the HF (as shown on figure 3). Likewise, it has been chosen to grid the UnSRV logarithmically away from the SRV.

Grid building and grid modifications are not an easy process. A grid generator was programmed in VBA in order to facilitate the definition of the relevant parameters such as: Well length Lx, well spacing, Number of fracs, Number of cells, Number of frac stages nf, Frac spacing SPCG, Frac size (half-length Xf, Height Hf, Aperture w), Number of matrix subcells, Initial conditions (Pres, Sw…).

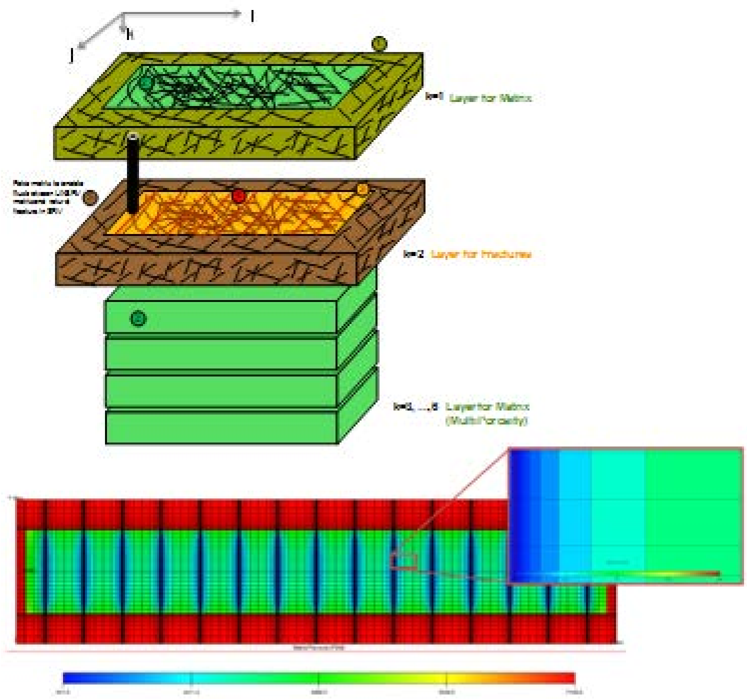


Figure 50: Layers and top view of the grid for a well with 15 frac stages, with NMATRIX=5

7.4.3 Quarter-Stage Model

SHARP model gives consistent results in most of the cases, but in cases with a very large number of fractures and multiphase flow, running times can be very long. Another model has been designed, which could be a potential good alternative to the multi-porosity model. In this model, to avoid the multi-phase flow misrepresentations due to the multi-porosity process, the matrix and fractures have been gridded explicitly. A full sector-model where the matrix and all the fractures are gridded explicitly would be too heavy, that's why the model represents only a quarter of stage. It is assumed that by symmetry and translation, this model will show the same behavior as a whole sector model.

This model has the advantage to be simple, quite small, representing explicitly the matrix-fracture exchanges, and need as input more concrete properties, such as explicit fracture conductivities and block sizes instead of sigma. The HF is gridded on one edge and the well is connected to the base of the HF. An Excel macro has been implemented to generate automatically the grid and the different regions.

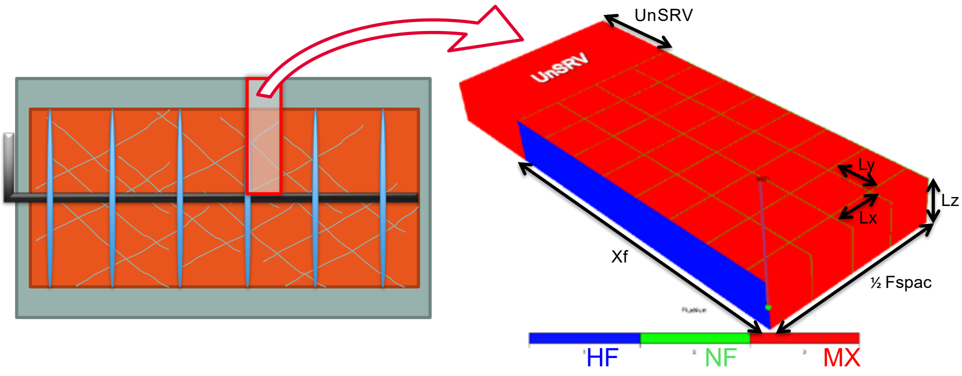


Figure 51: Quarter-Stage Model Overview

The QS model could be used as an alternative to the SHARP model, the use of this tool is recommended in phenomenological models in order to better understand the mechanics of flow, especially in multi-phase cases.

7.4.4 Benefit of numerical models

At this point the reader has to wonder about the need of Analytical solutions when Numerical solutions are more reliable and can reproduce more phenomena than these. The reason is that these numerical models that represent these complex reservoirs usually take more time to run, a typical horizontal multi-fractured well simulation might take from 15 minutes to 3 hours (on a laptop computer). When dealing with hundreds or even thousands of wells, with multiple realizations, long running times are impossible to handle. For this reason the recommended practice is to perform the multiple-history matching with analytical models and then simulating some of the solutions into Numerical models to check the results and gain understanding of the physical processes modelled and the relative impact of the analytical simplifications.

The Numerical models presented in this section are fit-for-purpose for RTA model quality control. Reservoir simulation studies have specific modelling workflows that are covered in GM EP RES 801.

Analytical models don't take into account multi-phase effects, so in the cases that are very sensitive to these, such as **Volatile Oil and rich gas condensate, numerical simulation should be preferred on the long term forecasts**. In these cases, multi-phase effects are evidenced on the long term, so RTA techniques are applicable on the first months or years of production.

In order to illustrate the difference between analytical models and numerical models, an example of a volatile oil producer is provided. This type of fluid has high compressibility and large quantities of dissolved gas that start to affect well behaviour with reservoir depletion. **For this reason, it is strongly advised to use Numerical models for long term production forecasts in cases like this**. On the other hand formation characterization with production data is a very powerful tool in these cases.

Figure 52 and Figure 53 illustrate the differences between numerical an analytical models. In this case the results are derived from production matching with analytical models. The numerical model's response shows that analytical and numerical responses are compatible to the first three months of production, but after this period the numerical model response starts diverging significantly. This suggests that at this time the numerical model starts being influenced by multiphase effects. At this point gas could be freed in the reservoir act as a pressure support mechanism. However, Gas Oil Ratio (GOR) does not increase as the critical gas saturation is not attained.

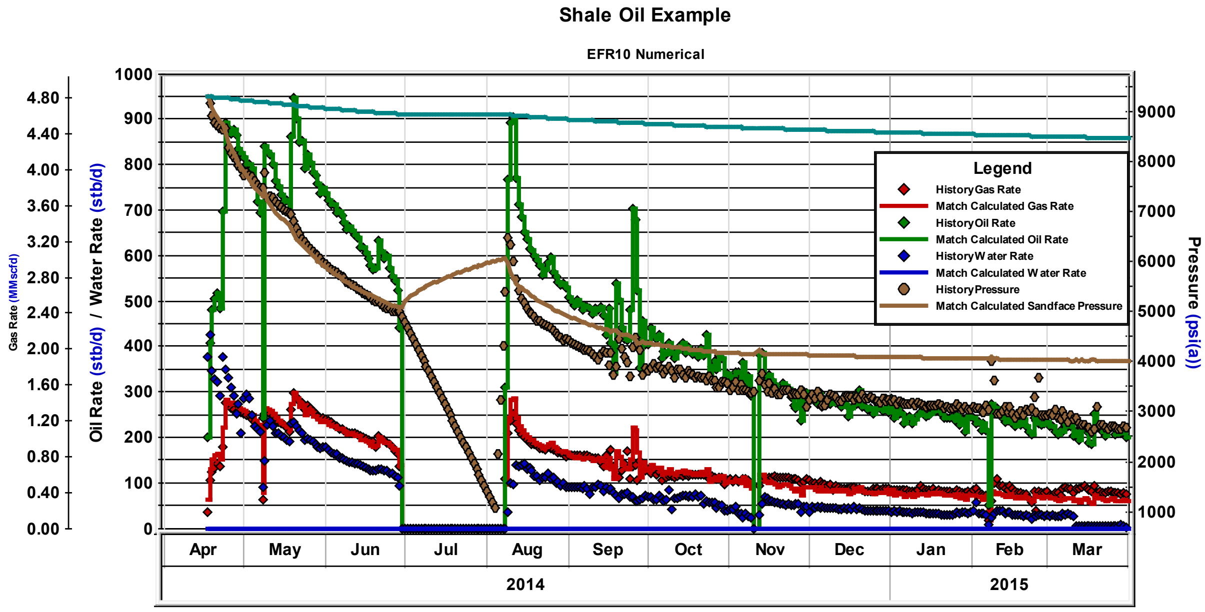


Figure 52: Numerical model with the parameters estimated from analytical model matching.

This match could be improved by modifying several parameters like Relative Permeability curves. Relative Permeabilities are unknown in Shale Formations, for this reason although modifications can be made, there are no benchmark as to whether these are realistic. Another parameter that could be modified is the Un-SRV permeability (K_2) since the added energy of the dissolved gas drive replaces the need of the Un-SRV contribution.

In this case several attempts were performed to obtain a successful match.

	Analytical	Numerical	
X_f	626	430	ft
n_f	10	36	
F_{CD}	1000	2000	
k_1	1372	1200	nD
k_2	100	38	nD
X_I	15	15	ft
Y_e	3000	3000	ft

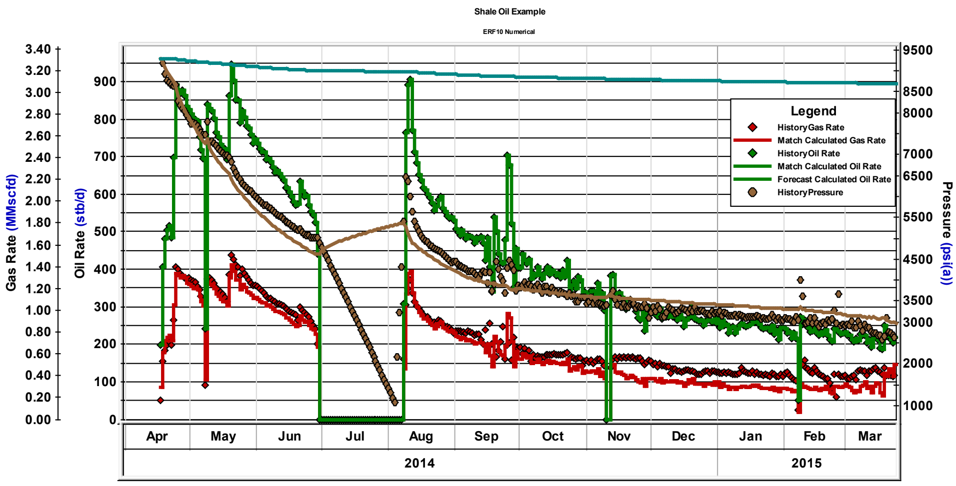


Figure 53: Matched Numerical model with a table comparing the changes in parameters.

In order to match this case it was necessary to alter the outer zone permeability and severely modify relative permeability curves. The forecasted cumulative production for 25 years is 377 MBbl, 42% less than its corresponding analytical model. The reason for this difference resides in the multi-phase long term behaviour. In cases like this one, it is fundamental to analyze the uncertainties and impact of these with numerical studies.

This example clearly illustrates the impact of multi-phase effects on volatile oil shale wells. As shown in the example these effects that are ignored by analytical models can have a significant impact on well behaviour. It is important to note the fact that the fit-for-purpose numerical models developed for RTA have the objective of correcting the simplifications of RTA Analytical models. Complete simulation studies are generally more complete and should be used in the case of Volatile Oil or Liquid rich gas.

7.5 Statistical determination of EUR for undeveloped locations

The first of the common characteristics within the Tier 1 criteria as defined by the SPEE (presented in section 0) for all Unconventional plays (or Resource plays) is:

- Wells exhibit a repeatable statistical distribution of EUR.
- Offset well performance is not a reliable predictor of undeveloped location performance.

These two characteristics are fundamental in the estimation of EUR on PUD wells.

The technique presented in this section is developed in detail in Monograph 3.

7.5.1 Lognormal distribution

Lognormal is the most important distribution in the upstream exploration and production business. It is commonly the best distribution for Reserves, production rate, capital cost estimates and cycle time forecasts. Massive development of Unconventional plays in the USA has shown that these do show lognormal EUR distributions once enough wells are drilled and connected in a particular play.

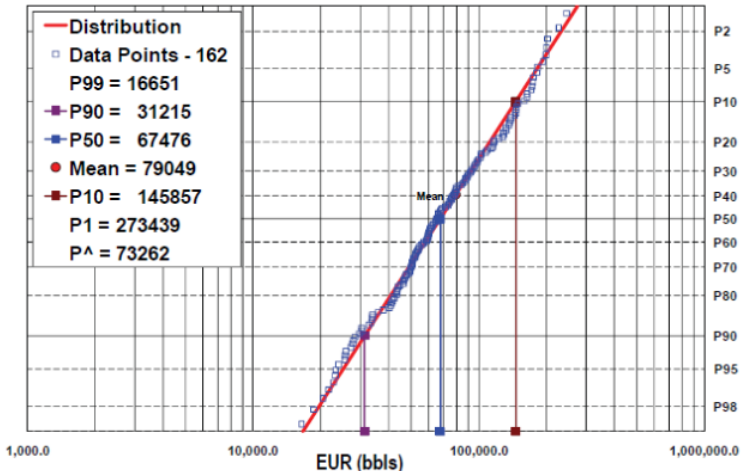


Figure 54: Log normal distribution of EUR

Well performance in unconventional wells depends on several Geological, Geomechanical and Completion design characteristics that can be synthesized with the SRV Qi methodology; this methodology results in the recognition of distinct sectors within an Unconventional play. Each development sector should have an individual EUR distribution that is dependent on its SRV characteristics. The continuous development of a sector permits the evaluation of the EUR distribution with the addition of new wells; this helps to rather corroborate or challenge the sectorization of a particular play.

7.5.1.1 Analogue wells

Wells that share common characteristics (geological, geomechanical, etc...) are said to be **Analogous**. Monograph 3 states that for wells to be comparable the Timing and Technology dimensions have to be considered:

- **Timing:** Unconventional plays are characterized by strong learning curves: D&C costs and duration on early wells are poorer than on recent wells.
- **Technology:** Drilling, Completion and operational differences within unconventional wells vary between operators:
  - Vertical vs. Horizontal
  - Well Spacing
  - Landing Point
  - Fracture design (volumes & rates)
  - Other: Distance between perforation clusters, newly drilled vs. Re-entry wells, etc.

Some of these characteristics are covered by considering wells within the same development sector (such as landing point), other characteristics are pretty obvious (such as vertical vs. horizontal) and other, such as fracture design and wells spacing are less straightforward in the evaluation since it needs a detailed well by well analysis.

To summarize, for wells to be included in the same EUR distribution they have to be Analogous.

7.5.1.2 Minimum Sample Size (MSS)

A common question that arises when estimating EUR distributions is at what point the sector has enough wells to apply statistical methods. This is where the **Minimum Sample Size (MSS)** concept plays a role. The MSS is the minimum number of Analogous wells needed to obtain a reliable statistical distribution for the sector. This value depends on the heterogeneity of the sector, in more heterogeneous sectors more wells are needed, and in cases where well performance is less variable, an indication of low heterogeneity, fewer wells are needed to obtain a reliable statistical distribution. MSS can be directly linked to the maturity of the sector: in order to achieve statistical maturity (as defined by the SPEE), the number of producing analogous wells has to be superior to the MSS. **The MSS represents the approximate minimum number of wells to be drilled in order to have 90% of these with EUR within 10% of the mean.**

The heterogeneity of a sector or group of well can be approximated by the distribution of their EURs, and in order to characterize the heterogeneity the P10/P90 ratio can be used.

Table 15 illustrates the MSS according to the heterogeneity (P10/P90) for a group of wells or sector.

Table 15: MSS depending on the P10/P90 ratio (Monograph 3)

P10/P90 Ratio	Recommended Sample Size	Comments
2	15	Not likely to be seen
3	35	Common Ratio
4	60	Common Ratio
5	75	Common Ratio
6	100	Common Ratio
8	130	Common Ratio
10	170	Possible data quality / analogy issues
P10/P90 Ratio	**Recommended Sample Size**	**Comments**
15	290	Possible data quality / analogy issues
20	420	Possible data quality / analogy issues
30	670	Possible data quality / analogy issues

The heterogeneity or P10/P90 ratio of the sector or group of wells can be approximated by different parameters that can be used as a proxy to EUR. These parameters should be directly proportional to EUR; good parameters for this are the cumulative of the first 6 or 12 months; another parameter which is not as effective is the peak rate. No matter what parameter is used it is important to show that this parameter is a good proxy to EUR for the wells.

7.5.1.3 Proved area

Once a play enters the statistical phase, an area called the proved area could be defined. The purpose of this area is to book more undrilled locations (not only locations that are offsetting producers). The use of a proved area was made possible after the modernization of the SEC rules in 2008. On January 14, 2009 was issued in the US Federal Register (Daily Journal of the US Government) the modernization of the Oil & Gas Reporting (effective January 1st, 2010). This document states introduced a new concept for reserves booking: the reliable technology. **“Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.”**

The use of the proved area is considered by the SEC a reliable technology and any identified undrilled location that respect all other booking criteria (5 year rules, economic, etc...) can be booked as reserves.

The best way to explain how to build the proved area is to use the second example provided in the Monograph 3 of the SPEE.

1. **Estimate the EUR** for each well in the play or within the sector or geological subset.

2. **Prepare a statistical distribution** of EUR or EUR proxy for all analogous wells in the geological subset. The well count should be higher than the MSS. Calculate the Mean, P50, P10 and P90.

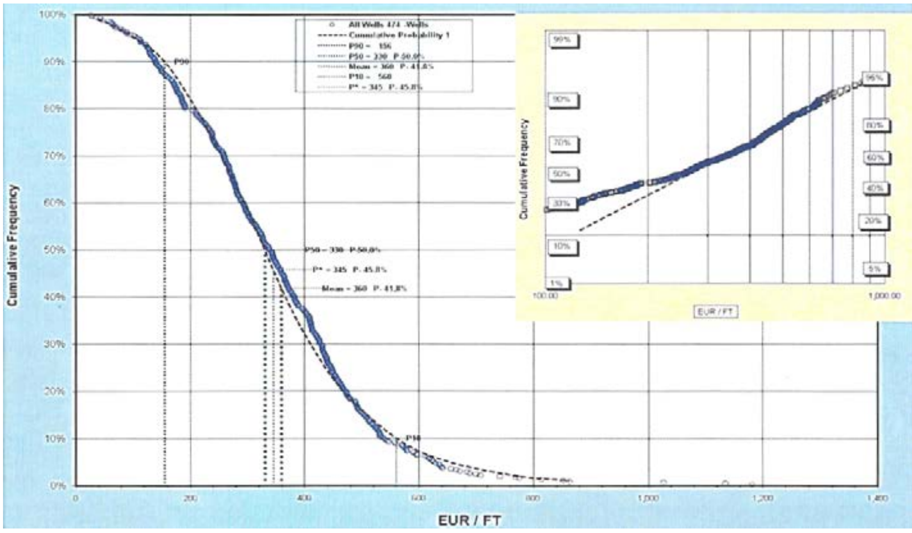


Figure 55: Statistical distribution for analogous wells

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

3. Select randomly a group of **anchor wells** within the geological subset. The number of anchor wells should be higher than the MSS.

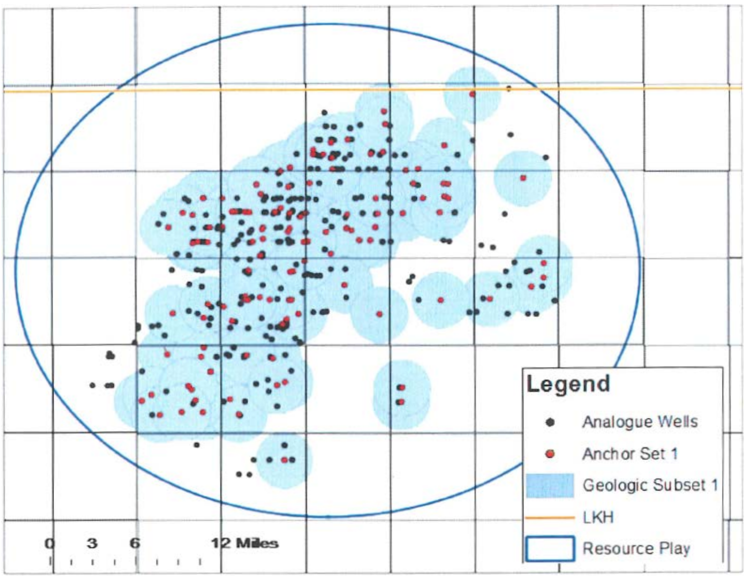


Figure 56: Anchor wells within 2miles radius circle

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

4. **Prepare a statistical distribution** for the anchor wells. Calculate the Mean, P50, P10 and P90. They should be in agreement with the values of the analogous wells. For example the Mean should be **within 10%** of the Mean of the analogous wells.

5. **Draw expanding concentric circles** around each of the anchor wells (for example 1 mile radius, 2 mile radius, etc...). The **test wells** reside in these concentric circles. Test set 1 will be in the 1 mile circle. Test set 2 will be between the 1 mile circle and the 2 mile circle, etc...

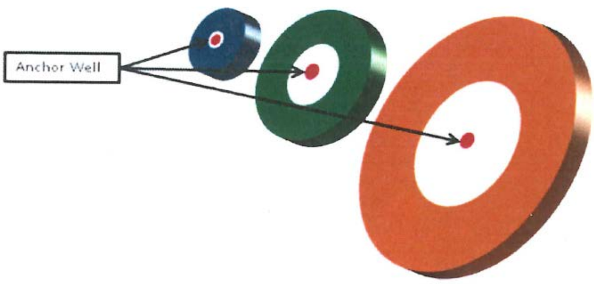


Figure 57: Expanding concentric radii

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

6. **Identify the test wells of test set 1** (anchor wells should not be included) and calculate the Mean. The test sets should satisfy the MSS.

7. **Repeat step 6** for each concentric radius until the test set well count is less than the MSS.

8. **Compare the statistical distributions** of the anchor wells and each test set. If they are similar, the test set passes the test. A practical way to compare the distribution could be to compare the

Mean: if the Mean of the test set is within 10% of the Mean of the anchor wells, it passes the test. In the example below, Test set 3 (between 2 and 3 miles) does not pass the test as the mean is 17% lower that the anchor wells mean.

Figure 58: Well count, Mean and variance for Analogous wells, anchor wells and test wells

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

9. **Map the proved area** for the anchor set. Draw a line between all the wells in the 2 miles proved area (anchor wells + test wells).

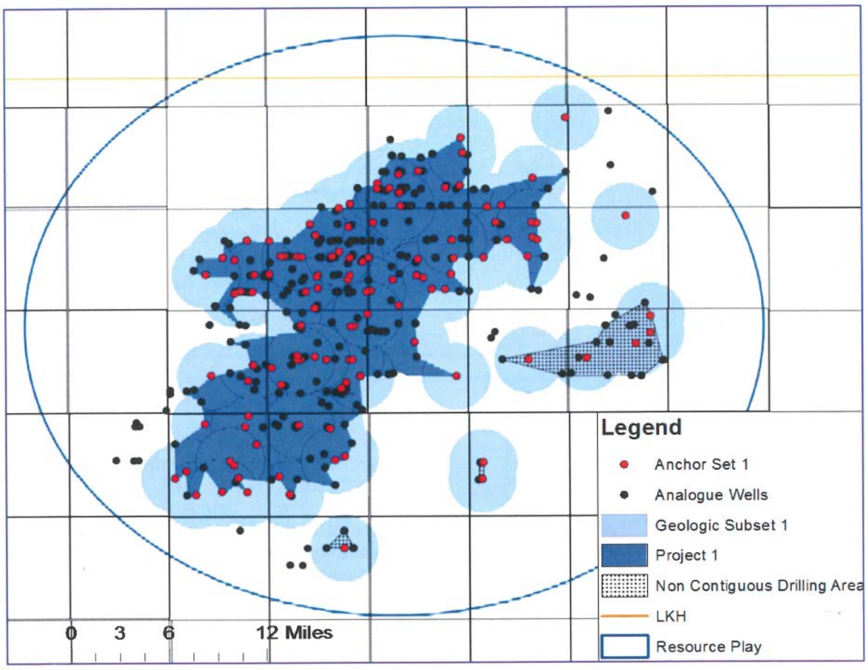


Figure 59: Proved area for the anchor set n°1

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

10. **Determine the final proved area**. As anchor sets are randomly selected, 2 different anchor sets can generate 2 different proved areas. It is recommended to build 4 different proved areas corresponding to 4 different anchor sets and superimpose the 4 maps. It is recommended that **at least 2 overlapping areas** from 2 different anchor sets be used to define **the final proved area**.

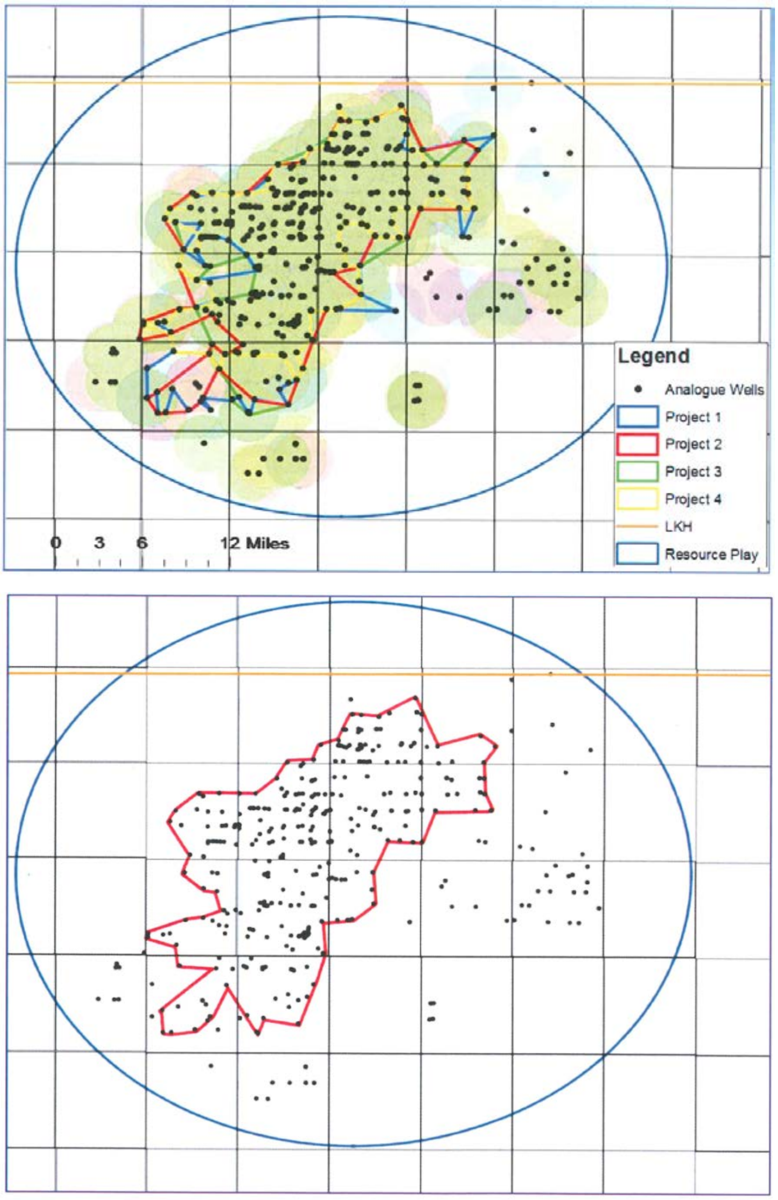


Figure 60: Overlapping proved area and final proved area

(Source: SPEE Monograph 3: Guidelines for the practical evaluation of undeveloped reserves in resource plays)

7.5.1.4 Good practices for "type curve" or "type well" construction

Once an area of analogous wells has been defined, the next step is to build a type curve or type well. Professor John Lee suggested the following workflow:

- well count should be higher than 50
- Normalize production as needed: per lateral length, number of stage, subsurface data if possible (SPE 175967 [18])

- Forecast each well separately rather than forecasting a group of well together
- Avoid the survivor bias or smiling effect (SPE 158867 [19])
  - Include abandoned wells with 0 rate
  - Use constant well count or use data until well count = 50% of original well count
  - If not possible, include forecast for wells with short history

7.5.2 SPA (Smart Predictive Analytics)

This statistical tool was developed on the Utica shale in the US and then transferred to HQ to be used in other assets around the world.

Once a subsurface synthesis has been performed to find reservoir properties driving the productivity of the wells (maturity, pressure, frac barriers, thickness, etc…), the SPA tool can be used to predict the production of future wells. A machine learning process using regression trees is used to find laws between reservoir properties and a target (EUR or 6 months cum). This is illustrated in Figure 61.

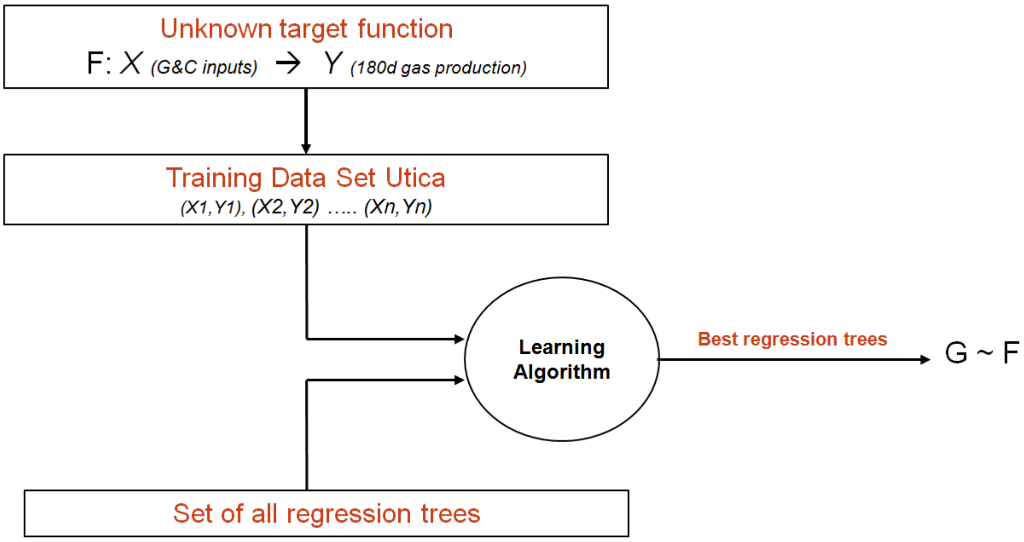


Figure 61: General principles of machine learning

The advantages of regression trees are:

- One of the most accurate learning algorithm
- Provide a distribution of predictions
- Easy tuning + Fast and scalable
- Can deal with categorical data and missing data
- Rank variables by importance

This technique can be used to estimate the monthly production profiles of future wells over a period of time where sufficient production history is available and where the subsurface data is available (map of pressure, frac barriers, etc...)

Figure 62 illustrates the results of the SPA workflow and shows that for a particular well within a given area with an associated TC, the productivity of the wells can vary a lot from the average behaviour due to subsurface heterogeneities.

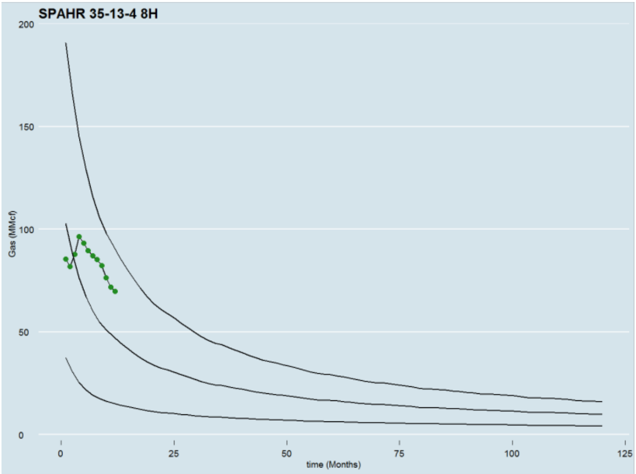


Figure 62: Comparison of the SPA prediction with the TC of the area

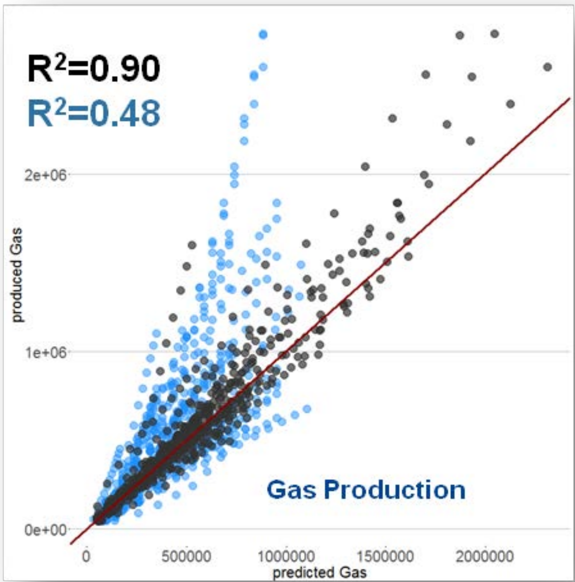


Figure 63: Comparison of EUR predictions between DCA and SPA

Predictive analytics significantly improve predictions compared to DCA. R^2 above 0.8 is exceptional in unconventional performance prediction (Figure 63).

The SPA tool can be used to typically predict the first years of production where data is available but other tools like (analytical models, DCA, ETC...) have to be used to build the rest of the production profile.

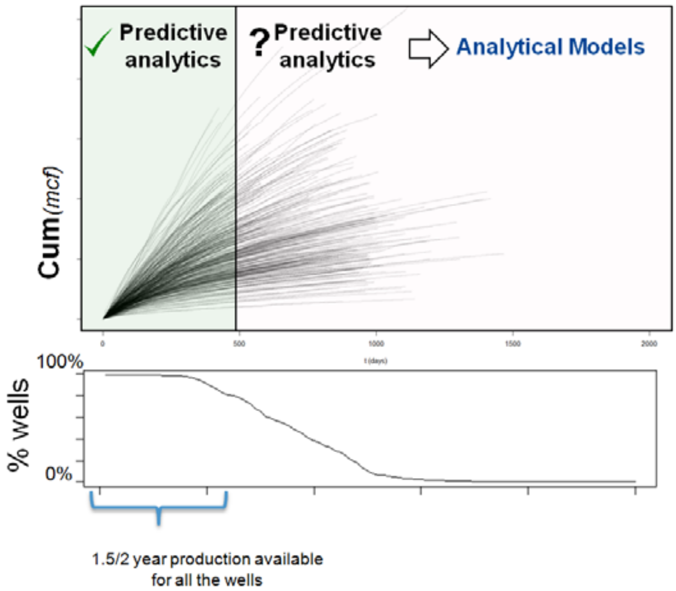


Figure 64: Analytical models for long term prediction

7.6 Aggregation and practical estimation of aggregated 1P

To illustrate the concept of aggregation and why it is important to use it in unconventional plays, let's use a simplified dice example. When rolling 1 die, there is a one in six chance of rolling a six (17%), a two in six chance of rolling a 5 or greater (33%) and an 83% chance of rolling a 2 or greater. If the criterion of rolling 2 or greater per die is held for different counts of dice; then when rolling 1 die we expect a probability of 83% of rolling a two, for rolling 2 dice the probability of a combination of 4 or greater (average of 2 per die) is ~92%, and when rolling 6 dice the probability of rolling the sum of at least 12 is ~99%.

Using a different approach where we hold the probability of occurrence at 90% (1P), when rolling 1 die there is a 90% chance of rolling 1.4 or greater. For 2 dice rolled together there is a 90% probability of rolling a 2.1 or greater and for 100 dice a 90% probability of rolling a 3.3 or greater.

The same applies to wells to be booked in a play. If an operator has only 5 undrilled locations to book, they will be able to book less 1P reserves per well than an operator that has 50 wells to drill.

The standard path to establish 90% probability involves a Monte Carlo simulation. However, these simulations can be time consuming and a more practical approach can be used: the use of the P^= (Mean+P50)/2. The value for P^ approximates the aggregated P90 for most oil and gas data sets when the P10/P90 ratio is less than 5. After 50 wells P^ is a good estimation of the simulated P90 (within 1%) and after 300 wells it becomes slightly more conservative than the aggregated P90.

The P^ term has been tested successfully in several US plays including the Barnett Shale, Woodford shale, Haynesville shale or Bakken shale.

8. Glossary

Symbol	Property	Units
A	Area	ft²
B_g	Gas Formation Volume Factor	fcf/Scf
B_o	Oil formation volume factor	stb/rb
BDF	Boundary Flow	-
BHP	Bottom Hole Flowing Pressure	psia
CAPEX	Capital Expenditures	-
CGR	Condensate Gas Ratio	Bbl/MMScf
c_t	Total compressibility	psi^{-1}
DCA	Decline Curve Analysis	-
DFIT	Diagnostic Fracture Injection Test	-
EPF	Early Production Facilities	-
EUR	Estimated Ultimate Recovery	Bcf / Mbbl / MBoe
FID	Final Investment Decision	-
GOR	Gas Oil Ratio	Scf/bbl
h_f	Fracture height	Ft
K	Permeability	mD
LTP	Long Term Plan	-
LFP	Linear Flow Parameter	$mD^{1/2}.ft^2$
μ	Viscosity	cp
MSS	Minimum Sample Size	-
n_f	Number of hydraulic fractures	-
OGR	Oil Gas Ratio	bbl/MMscf
OPEX	Operational expenditures	-
ϕ	Porosity	%
P_i	Static Initial Pressure	Psi
P.O.	Probability of Occurrence	%
PUD	Proved UnDevelopped	-

P.S.	Probability of Success	%
P_{wf}	Flowing pressure	psi
q_o	Oil rate	bbl/d
RTA	Rate Transient Analysis	-
SPE	Society of Petroleum Engineers	-
SPEE	Society of Petroleum Evaluation Engineers	-
SRV	Stimulated Rock Volume	ft^3
T	Time	days
TOC	Total Organic Carbon	%
TWC	Type Well Curve	-
WPC	World Petroleum Council	-
X_f	Fracture half-length	ft

Appendix 1 Unconventional plays generalities

The use of shale oil dates back as far as 1350, and in 1781 a patent was registered in England for the process of extraction and production of tar and pitch from coal and bituminous shales by Archibald Cochrane, the 9th Earl of Dundonald. Gas from shale formations fuelled the streetlights in Fredonia, NY in the 1820's so the fact that shale formations are saturated with hydrocarbons has been known for quite a long time. Nevertheless unconventional formations such as Tight, Shale and CBM were considered uneconomical hydrocarbon accumulations until the last part of the twentieth century. The combination of several factors such as a favourable hydrocarbon price context, fiscal incentives, cost reduction in the drilling and completion of multi-fractured horizontal wells and the boldness of small independent companies made it possible for these resources to be developed economically.

The techniques which are described in this document are applicable to Tight and Shale formations, CBM techniques differ since the governing production mechanisms are quite different.

The definition of an unconventional play is not the focus of this document. Nevertheless, the general assumptions supported by this document are that an unconventional play is a continuous hydrocarbon accumulation, with very low permeability (within the nano Darcy to micro Darcy range), not held in place by hydrodynamic forces or by a structural trap.

Tight and Shale reservoirs are both characterized by very low permeabilities, although generally Shale formations have lower permeabilities than tight formations (however, exceptions to this tendency exist). At the nano-meter scale, the transport mechanisms that control flow in conventional formations are no longer valid and the physical assumptions models that rule them have to be reviewed.

The presence of organic matter with adsorbed hydrocarbons in significant quantities in shale formations creates an additional storage and production mechanism that adds further complexities to the evaluation of these resources.

Appendix 1

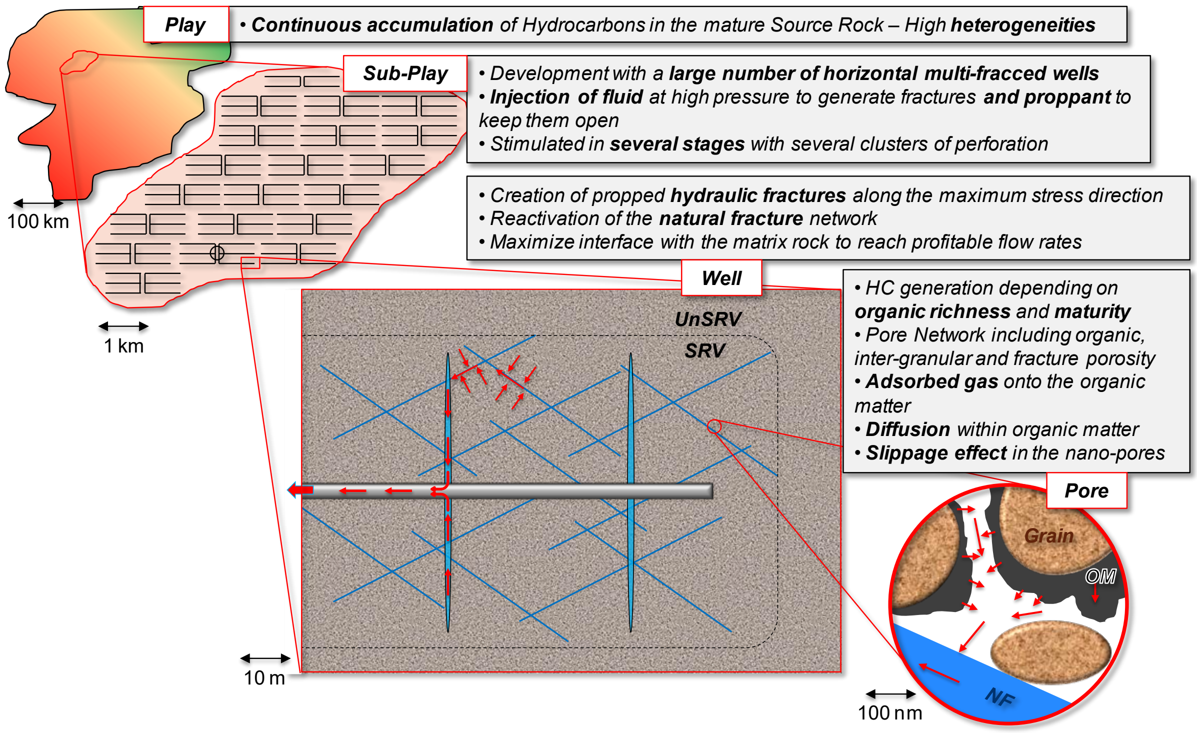


Figure 65: Different scales in a shale play

1 - SPEE Criteria for the identification of an Unconventional play

The SPEE uses the term Resource Play for unconventional play. It defines them with a two Tier criteria system to recognize these by some characteristics that are nearly always observed in these types of plays:

Tier 1 criteria

- Wells exhibit a repeatable statistical distribution of Estimated Ultimate Recoveries (EUR).
- Offset well performance is not a reliable predictor of undeveloped location performance.
- A continuous hydrocarbon system exists that is regional in extent.
- Free hydrocarbons (non-sorbed) are not held in place by hydrodynamics.

The Tier 1 criteria are ordered in order of significance, and if a particular play satisfies these criteria it is very likely that the play is unconventional. The Tier 2 criteria encompass certain characteristics that are commonly observed in unconventional plays. These criteria are not mandatory:

- Requires extensive stimulation to produce at economic rates.
- Produces little in-situ water (except for Coal Bed Methane and Tight Oil reservoirs)
- Does not exhibit an obvious seal or trap.
- Low permeability (<0.1 mD).

2 - Geological Context

Conventional resources occur in petroleum systems where hydrocarbons have been generated and expelled from an organic rich source rocks. The natural buoyancy of these hydrocarbons and local pressure gradients cause these fluids to migrate and subsequently accumulate in either structural or stratigraphic trapping configurations. Accumulations in reservoir rocks with sufficient permeability, pressure and fluid properties that permit the flow of hydrocarbons into a wellbore are classed as Conventional Resources.

In parallel to conventional resources, unconventional resources are those which do not have sufficient reservoir quality or fluid characteristics to be produced by using standard drilling and completions techniques.

Tight reservoirs have several similarities with conventional reservoirs, the fundamental difference being a significantly lower permeability (roughly from 0.1 to 0.001 mD), which generally which comes from either less favorable depositional conditions or from degraded rock properties after deposition. Shales on the other hand are contained within very low permeability, organic rich mudrocks – source rocks. These source rocks have reached sufficient thermal maturity to generate oil and/or gas, and still contain hydrocarbon despite expulsion and migration took place or are taking place.

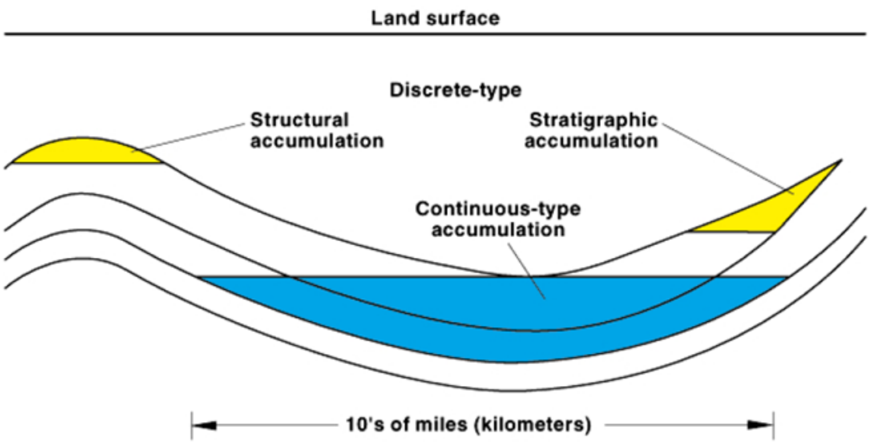


Figure 66: Types of hydrocarbon accumulations

A shale play is a defined geographic area containing an organic-rich fine-grained sedimentary rock that combines many of the following characteristics:

- Clay to silt sized particles
- High percentage of silica or/and carbonates / low clay content (usually less than 40%)
- Total Organic Content (TOC) usually greater than 2%
- Thermally mature source rock
- Low porosity (usually 4%-8%), distributed within the organic matter and within the matrix (inter-granular porosity)
- Small pore sizes and pore throat, hence low permeability (nD to the µD range)
- Hydrocarbon stored under free and adsorbed states

- Large areal distribution
- Hydraulic fracturing required for economic production

The term “play” is used in the Oil & Gas industry to refer to an area where there is an economic quantity of oil or gas to be discovered. In the case of tight and shale play, the risk of not finding hydrocarbons is low as the targeted rock is a known source rock, if adequately mature (meaning that it has undergone favorable pressure and temperature conditions throughout its geological history): the main uncertainty lies on the appropriate characteristics that control well productivity, and hence render its development profitable.

3 - Stimulated Rock Volume (SRV)

The low permeability in unconventional formations makes it necessary for wells to be hydraulically fractured in order to achieve economical production rates.

The hydraulic fracturing process consists in the injection of a fluid, mainly consisting of water and proppant, into the well at high pressure to create propped Hydraulic Fractures (HF) and reactivate pre-existing natural fracture networks. The low leakoff and moderate brittleness allows for very efficient fracturing of these formations. The interaction of the hydraulic fracture with pre-existent natural fracture networks, faults and in-situ stresses that can vary along the formation is fundamental for well productivity.

Hydraulic fractures develop in a complex manner in the proximity of the well. This evidence is supported by other sources of data such as tilt-meter fracture mapping, Mini-frac tests, lab tests, etc.; that also suggest a “secondary” network of fractures is developed, enhancing the contact area between the reservoir and the well. In these cases the characterization of hydraulic fractures becomes more complicated since it should include the properties of this secondary set of fractures, which is very hard to quantify.

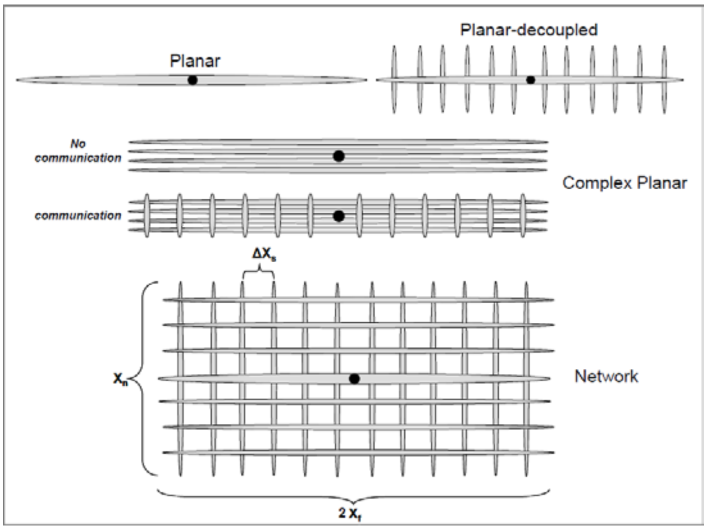


Figure 67: Different hypothetical fracture growth scenarios (Cipolla et al [20])

Fracture complexity can be classified with the terms “large scale” and “small scale”. Large scale fracture complexity is related to network fracture growth and large-scale decoupling (fissure opening), this is the type of fracture complexity that can be most easily evaluated with microseismic. Small scale fracture complexity is related to complex planar growth or planar decoupling. Generally speaking, microseismic resolution is not sufficient to identify these phenomena clearly, although they can be detected using minifrac analysis techniques.

The interplay between fracture conductivity and proppant placement is under continuous debate. An interesting discussion is presented by Cipolla et al [20] that studies the proppant distribution scenarios for large-scale fracture complexity. It concludes that for this type of fracture creation, only the primary set of fractures have a proppant concentration that is sufficient to retain conductivity. For this reason the secondary set of fractures are unpropped and hence its transport properties are very dependent on the geomechanical properties of the formation.

This reactivated network will be unpropped or partially propped and will facilitate the transport of the fluids from the matrix to the Hydraulic Fracture. The extent of the fracture network depends on the reservoir geomechanical properties, the in-situ mechanical constraints, the fracturing fluid properties and the stimulation process used.

Figure 68: Natural fractures observed on outcrops at different scales

The volume of rock within which a network of conductive fractures, connected to the horizontal well has been created is called SRV (Stimulated Rock Volume). The shape and extension of the SRV are usually poorly known; microseismic can provide fundamental information on these parameters. It is important to keep in mind that all events seen on microseismic may not necessarily contribute to production (i.e. faults re-actived but not propped) and that not all fracturing events are detected by the microseismic receivers (fractures created in mode I – opening mode – are said to be a-seismic). These facts further complicate the analysis, since microseismic surveys can only be used qualitatively and as a means of better understanding fracturing mechanisms – in other words, only as a rough indicator of SRV dimensions.

Only the “effective” SRV is relevant, which refers to the volume of rock effectively contributing to production during transient flow. The general consensus is that the effective SRV is significantly smaller than the observed microseismic event cloud, but there is currently no method to visualize the extension of the propped fractures. The broader drainage area (once depletion occurs around the SRV) can include a bigger volume.

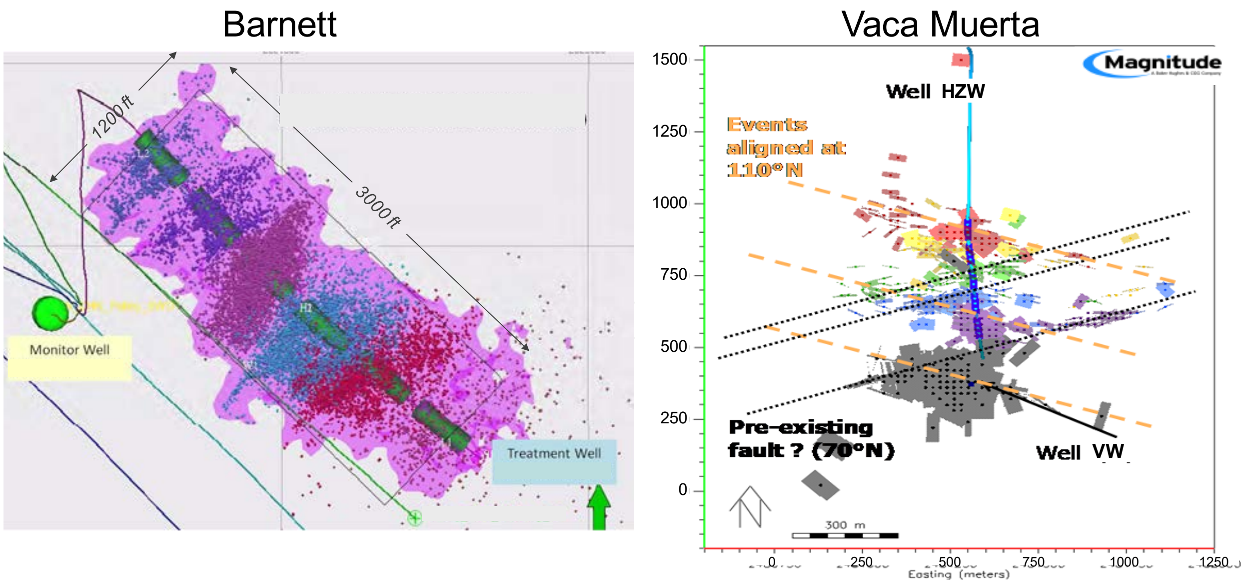


Figure 69: Illustration of two different shapes of microseismic clouds

Thus, all the parameters linked to hydraulic fracturation and geomechanics represent new uncertainties in addition to uncertainties classically met in conventional cases. The lateral extension, height and complexity of the fracture network, as well as the fracture conductivity and behavior with changes in stress, significantly impact the well productivity.

4 - Unconventional plays development

In the timescale of a development project, well drainage area is usually limited to the close vicinity of its SRV, therefore a very large number of wells are needed to fully develop a Tight or Shale play. Tight formations can be developed with fractured vertical or multi-fractured horizontal wells while Shale plays are almost exclusively developed with multi-fractured horizontal wells for economical reason. The fractures in these wells are pumped in several stages, each one having several perforation clusters. The division of each stage into several perforation clusters favours the generation of complex fracture networks. Each stage is pumped one after another in order to generate fractures all along the well drain. The most common technique to stimulate them is the Plug and Perf system, Wu (2015) [21]:

1. Clusters of the first stage are perforated
2. Hydraulic fracture treatment is pumped
3. First stage is isolated with a frac plug
4. The process is repeated until all the stages are completed.

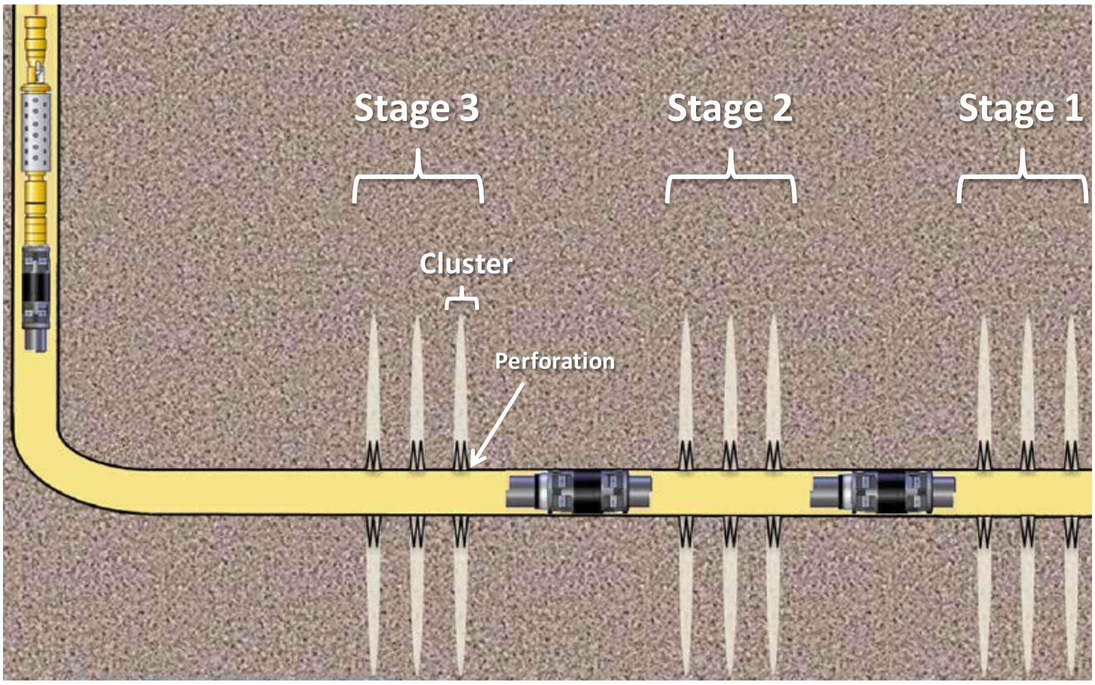


Figure 70: Architecture of a Horizontal Multi-Frac Plug&Perf Well

As a consequence of the low permeability of these formations well drainage area is very limited and a very large number of wells are needed to fully develop an unconventional play.This entrains a repetitive development that can be regarded as an industrial process. This industrialization process, somewhat comparable to a manufacturing process, is essential to reduce development costs in order to achieve profitable development projects. As such, a series of parameters are continuously adjusted and an optimization process is put in place.

The parameters which are adjusted can include:

- the number of shots per cluster
- the number of clusters per stage
- the stage spacing
- the well spacing (lateral drain spacing)
- the frac job design (volume of water, volume of proppant, type of proppant, pumping pressure and rates, etc.)
- other well design parameters (azimuth, diameter…)

A good understanding of the **stress state** and **rock mechanical properties** is needed in order to understand the way the hydraulic fractures will initiate and propagate. The principal stresses will influence the real direction of hydraulic fractures: the fracture will propagate parallel to the maximum horizontal stress.

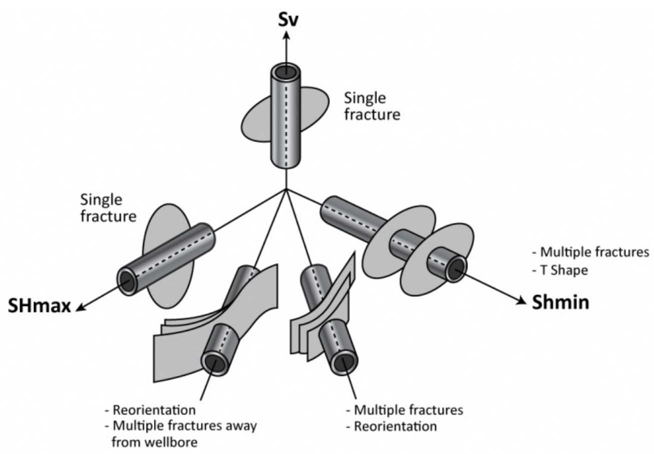


Figure 71: Propagation of the fractures for different wellbore orientations

Stresses can be classified into three different regimes: normal fault stress regime, strike-slip fault stress regime and thrust fault (or reverse fault) stress regime as illustrated on the figure below. For normal stress and strike-slip stress regime (tectonic regions), a hydraulic fracture will develop vertically whereas in a thrust faulting stress regime, a hydraulic fracture will develop horizontally (uncommon case in oil industry in general and in the case of shale gas in particular).

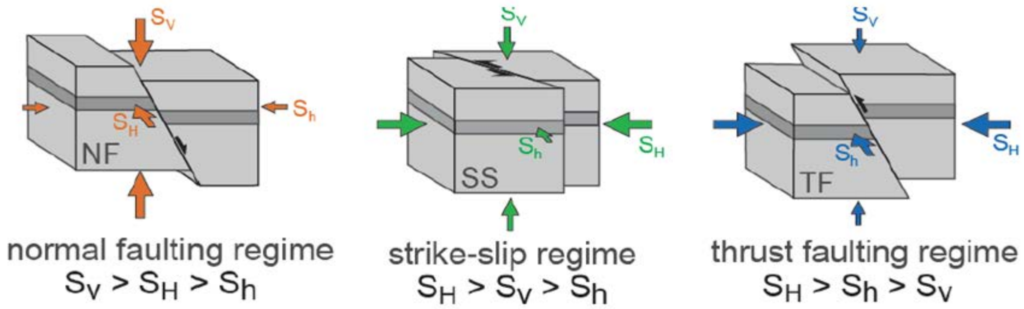


Figure 72: The three different stress regimes

The contribution to production of individual clusters is not uniform, and probably some clusters will not contribute at all. The ratio of producing fractures to the total number of fractures is the completion efficiency. According to some contractors, the average completion efficiency is only 70%, meaning that on average 30% of clusters are not producing, Miller et al (2011) [22].

5 - Hydrocarbon generation and storage in Shale

In the case of Shale, the amount of hydrocarbon in place depends on both the hydrocarbon (HC) fluids that have been generated, the storage capacity of the rock and pressure. The volume of hydrocarbons generated is a function of organic richness and thermal maturity of the source rock.

5.1 - Hydrocarbon generation

The **organic richness** is characterized by the Total Organic Carbon (TOC). It represents the amount of organic carbon present in the rock. It typically ranges between 0 and 20% (higher number can be found), and formations with TOC below 2% are generally considered as not sufficiently rich. The figure below shows an example of correlation between amount of organic matter and the total gas content, Bustin et al (2009) [23].

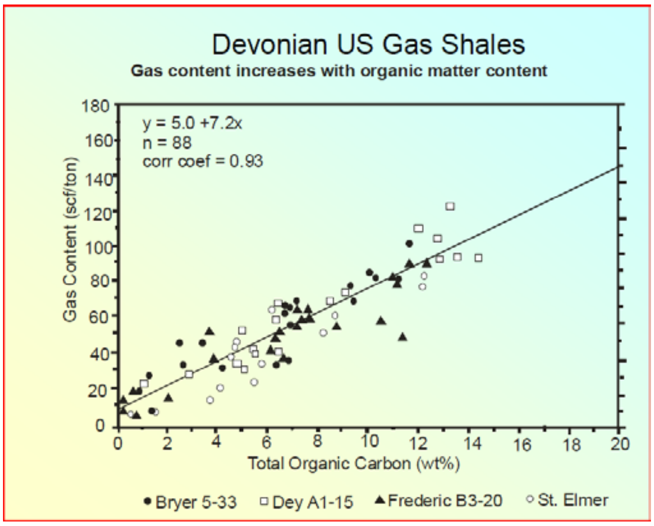


Figure 73: Gas content vs. TOC measured on different Devonian US wells

The **thermal maturity** represents the timing factor in the HC generation process: an immature source rock for which the generation process has not yet started will only contain kerogen (organic matter), whereas in a fully mature source rock, a large proportion of the hydrocarbons have probably migrated out of the source rock towards conventional reservoirs. The degree of maturity of a play can be assessed qualitatively using Rock Eval and Vitrinite reflectance, among other methods. A prospective source rock has to be well within the thermal Hydrocarbon generation window to be a potential shale producer.

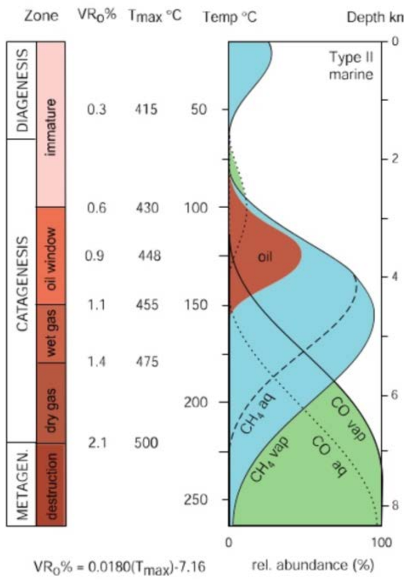


Figure 74: Hydrocarbon generation vs. Temperature

5.2 - Hydrocarbon storage

The present day Hydrocarbon content is also dependent on the retention of hydrocarbons within the source rock, e.i. both a reduced expulsion and a storage capacity. HC is stored both by adsorption onto the organic matter or within the pore network (free).

The amount of **adsorbed gas** in place generally represents from 20% to 70% of the total gas content. It strongly increases with the organic matter content and pressure, and decreases with increasing temperature. The contribution of adsorbed gas in the well production is hard to assess; nevertheless, it is generally considered to be low when compared to free gas production, especially during the first years of production, which are the most important in terms of project economics.

The hydrocarbons produced at early to mid well life come from the pore network; this network can be divided into 4 main porosity systems:

- **Organic porosity**: micro porosity created by the thermal conversion of kerogen to petroleum. It defines a pore network within the organic matter. Increases with maturity, therefore in most of the cases increases with depth as opposite to the reduction of porosity due to compaction.
- **Inter-granular porosity**: pores preserved during the deposition of sediments.
- **Fracture porosity**: induced micro-fractures during the generation of hydrocarbons
- **Clay-bound porosity**

These pore systems form the Total Porosity, but this does not represent the connected pores network. Contributive porosity is defined as the pore systems that are connected in such a way that permits the conductivity of fluid and therefore contribute to production. The constituent pore systems of Effective Porosity are the organic, inter-granular and micro-fractures pore systems. Contributive porosity typically ranges between 2% and 12%.

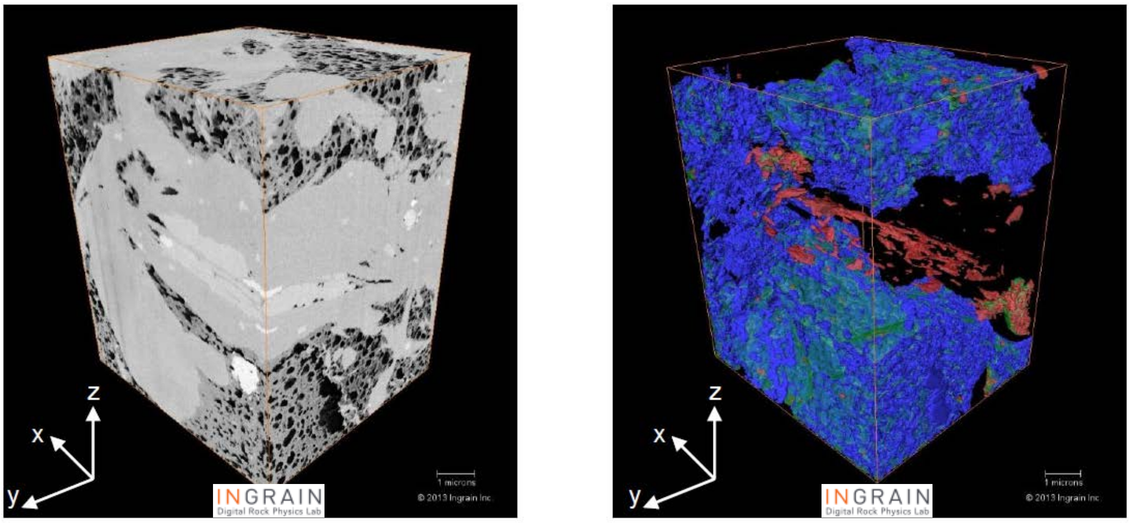


Figure 75: 3D FIB-SEM of a shale sample (left) and associated pore network (right). The connected porosity appears in blue, non-connected porosity in red and organic matter in green

6 - Transport mechanisms

The transport of free hydrocarbons in unconventional reservoirs are (see caveats below), for the most part, modeled with the Darcy flow equation, taking into account the particular non-linearities that are also common in conventional formations. In the case of Shale, the presence of Adsorbed gas and the small scale of the pore throats (comparable to the mean free path of the molecules) complicate the transport physics. Three main non-Darcy transport types have been identified (Mongalvy et al. [17]) and should be accounted for:

Desorption in the matrix bulk: surface phenomena governed by Van der Vaals forces where hydrocarbon molecules detach from the solid surface of adsorbents (Clays and organic materials being excellent adsorbents). This is modeled by the Langmuir isotherm, which assumes an equilibrium that is not reached in practice but represents a limit at infinite time. The process is driven by depletion, and hence more relevant at low pressures. The Langmuir isotherm can be characterized by the Langmuir volume (V_L) and Langmuir pressure (P_L). This is measured in Laboratory, where the storage capacity is computed.

Classical Diffusion in the region and within the matrix pore space: thermally promoted process which tends to homogenize chemical concentration (pressure) in the region and enable particles to jump between adjacent adsorption sites in the pore space. This is characterized by Fick's Law where the diffusion coefficient drives the kinetics of the process. It can be accounted for in flow models by defining the diffusion coefficient, which can be experimentally measured. However, a study has showed that the up scaling of heterogeneities in the reservoir is bypassed in the classical description of desorption-diffusion process. The contribution of this process to flow would thereby tend to be under-estimated.

Knudsen Diffusion in nano pore space: beyond a threshold pressure, the pore size is too close to the gas molecule's mean free path, therefore, fluid flow cannot be treated as a continuum. This then requires that particles are treated individually with statistical quantum physics. F. Javadpour et al. [24] have established a pragmatic approach to quantify the impact of Knudsen diffusion, as an offset from Darcy law. From this method, and assuming a pore throat size distribution centered around 10 to 40 nm and ranging from 4 to 200nm, the Knudsen diffusion should only represent 20 to 40 % of the total flow, and would not deviate notably from Darcy law, for pressures below 1500 psi, becoming more relevant at lower pressures. These pressures will only be reached in mature developed shale plays. This transport process can thereby confidently be neglected at early stages, relatively to other greater uncertainties. It is important to note that the Knudsen Diffusion, when present, tends to increase the apparent permeability of the system. Conventional models ignore this transport process, and are therefore rather conservative on this aspect.

For the Darcy flow representation in the existing flow models, it is important to emphasize that the permeability used for production matching purposes corresponds to an "apparent" permeability. Beyond the conventional problematic of geological upscaling, the apparent permeability also accounts for:

- Theoretical permeability enhancement linked to pore throat size increase as gas desorption increases with depletion
- The desorbed gas may take part of the burden of the effective stress and relieve the fracture closure pressure as for Coal Bed Methane systems (CBM).
- Potential micro fissuring in the matrix triggered by high pressure gradients during production

- The compaction effects if they are not modeled explicitly.

Deviation from laminar to turbulent flow may occur in the vicinity of wellbores and/or in the main fractures. This can be accounted for by Forchheimer type correction factors.

It is reasonable to analyze shale reservoirs using classical flow models as long as the above mentioned shortcuts are kept in mind and the model permits the proper representation of exchanges at interfaces between transport and storage systems and transient pressure regimes.

7 - Dynamic specificities of Unconventional plays

Due to the nature of Shale and Tight Reservoirs presented previously their dynamic behavior presents characteristic differences when compared to conventional reservoirs such as:

- **Very long transients:** The ultra low permeability of unconventionals, in particular in the case of shale reservoirs, results in very long transient flow periods. The consequence of this is that drainage area is continuously evolving. Nevertheless some intermediate “boundary” or pseudo steady states (formally pseudo-pseudo steady states) flows dominate for periods during the life of the well. These usually correspond to the depletion of the SRV, or to interference due to a “fracture hit”, in which cases a boundary flow dominates temporarily before the response of tight matrix influence in the unstimulated volume. Radial flow is never attained and hence permeability is uncertain.
- **High pressure gradients:** Another consequence of the low transmissibility of the medium is the extremely pronounced pressure gradients during production between the hydraulic fractures and the virgin reservoir away from the fractures. These may result in fluid properties varying over very short distances. These variations are not fully captured in analytical models, and for this reason it is recommended to validate the results of these with numerical models (GM EP RES 801). It is not necessary to create a numerical counterpart for every analytical model, but to check the extreme ranges.
- **Long Clean up periods:** The significant volumes of water injected into multi-fractured horizontal wells result in very long clean-up periods where hydrocarbons are produced together with significant volumes of water. During this period productivity of the well may vary, this is sometimes represented as an “apparent” skin.
- **Other non-linearities:** factors that might affect dynamic behavior of these reservoirs such as stress dependent properties, condensate drop out, natural factures and adsorbed hydrocarbons can be taken into account by specific techniques. The influence of these is generally difficult to correctly evaluate since they depend on properties that are not measured independently; many times due to the lack of specific laboratory protocols and sometimes for cost reasons. Nevertheless their influence should be evaluated with at least generic or regional values that can be found in the literature.

8 - Non Mastered concepts and techniques in Unconventional Plays.

Due to the fact that Unconventional plays development is relatively recent, several concepts and techniques that are inherited from conventional reservoirs were questioned by many research groups. Many of these are active subjects of research and although some results are available there is no strong consensus built within their conclusions. Within the many non mastered techniques the most relevant ones are:

- **Relative Permeabilities:** Multi-phase flow in ultra-low permeability media has been modelled with conventional tools (modified in some cases), but the production history of the existing plays is not long enough to extensively validate these techniques. Furthermore there are no experimental procedures to measure relative permeability curves in these types of cores.
- **Bubble Point / Dew Point suppression:** It has been postulated that the capillary forces of nano-pores can affect the phase behavior of the fluids they contain. Some experimental results show a drop of bubble point and dew point in various oil and gas condensates samples. This has not been clearly proven on field scale, but could represent an improvement in recovery from these plays.
- **Pressure dependent formation properties:** The variation of reservoir properties with depletion has been modeled for many conventional fields. The main difference of this effect in unconventional formations is the fact that high pressure gradients exist in short distances and that natural fractures are "manufactured" with hydraulic stimulation. The long term impact of these processes is not yet well understood.

Geoscientists involved in Unconventional development projects should be constantly alert of the evolution of the technique and in communication with the professional community in their domain in order to incorporate the new concepts in their studies.

9 - Flow regimes in Unconventional multi-fractured horizontal wells

Due to the reservoir characteristics of unconventional reservoirs and the geometry of Horizontal multi fractured wells, the expected sequence of flow regimes that may develop once the well is put into production is presented in the figure below.

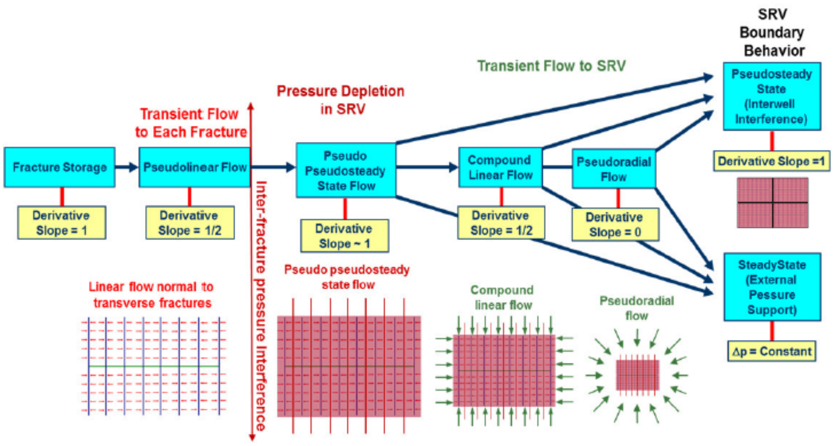


Figure 2: Potential Flow Regimes during MTFW Production

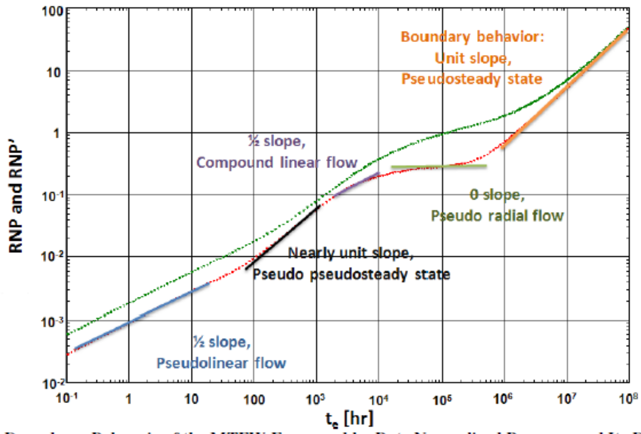


Figure 3: Drawdown Behavoir of the MTFW Expressed by Rate Normalized Pressure and Its Derivative

Figure 76: Theoretical flow successions in Horizontal Multi-fractured wells as illustrated by Bo Song and Ehlig-Economides (2011). Rate Normalized Pressure and its derivative vs time.

9.1 - Storage

This very brief and generally unnoticeable period is dominated by the production of the fluid that is contained in the well and fractures. That might be water, hydrocarbons or very often both. During this period the well acts as a closed volume and at constant rate production pressure varies linearly with time, this would be evidenced by a slope of 1 in a log-log plot but is very often not observed due to its very short duration.

9.2 - Transient Linear Flow

As the drop in pressure propagates into the fracture, the fracture faces contribution to production increases until they dominate the flow; at this point linear flow is established. In shales this flow usually dominates for the first years of production. Linear Flow is characterized by a slope of ½ in a log-log plot.

9.3 - Pseudo-steady state (PSS, Boundary flow)

The fracs start interfering between each other when a certain distance of investigation is reached, the pressure starts falling faster. At the half distance between fractures, the pressure derivative perpendicular to the fractures plane is zero (*dp/dx=0*). This effect is exactly the same as the influence of a no-flow boundary, for this reason a pseudo-steady state flow regime is established, this flow has a unit slope in the log-log plot in cases of constant rate.

When this first pseudo-steady state flow is evidenced, it corresponds to inter-fracture interference, that means that **although a pseudo-steady state is dominant, it does not mean that the ultimate drainage boundaries are reached**. Nevertheless, depending on the diffusivity of the formation, it is possible that this flow may dominate for several years before the following one is established. It is sometimes considered, for practical purposes, that the major part of the drainage area is established with limited or no drainage of non-SRV zones. This assumption is essential in field development plans since it will determine well spacing and so will influence development plans.

9.4 - Compound linear flow

Once the pressure in the SRV has fallen significantly, the rock volume in contact with it (aka Un-SRV or XRV) starts contributing more and more significantly until it dominates the flow. Another linear flow is established between stimulated and un-stimulated rock volumes. This transient flow regime is mostly theoretical, as it would require several years to be established; in practice its detection is not obvious. As any linear flow, compound linear flow presents a ½ slope in the log-log plot.

9.5 - Pseudo-radial flow or boundary flow

At this point two scenarios are possible:

- As the drainage area continues to increase, stream lines start to curve and a pseudo-radial flow is established. It is evidenced by a zero slope on the derivative plot or a straight line in the semi-log plot.
- Neighbouring wells start to influence the producing well drainage area and a pseudo-steady state is established again, evidenced by a unit slope on the log-log plot.

9.6 - Comments on Multi frac well models

The model presented in this section represents a horizontal multi-fractured well with planar fractures. There are many pieces of evidence (core data, geomechanical studies, microseismic surveys, etc.) that show the presence of natural fractures in shale reservoirs, and in fact many authors suggest that these are probably the main contributors to reservoir flow, existing in an inter-connected, reactivated network during the process of hydraulic fracturing.

The planar fracture model could be replaced by a complex fracture model (analog to the presence of a natural fracture network added to the hydraulic fracture network). Although the two models are equivalent in terms of flow description, it is important to take into account that:

- The area described in the LFP calculation would not be the hydraulic frac half-length x_f times the height (h_f), times the number of fractures (n_f), but the area outside the double porosity reservoir blocks that would contribute to the network of natural fractures connected to the well.
- The pseudo steady state flow that follows the first transient linear flow would correspond to the depletion of these reservoir blocks.

The following schema illustrates the two possible models:

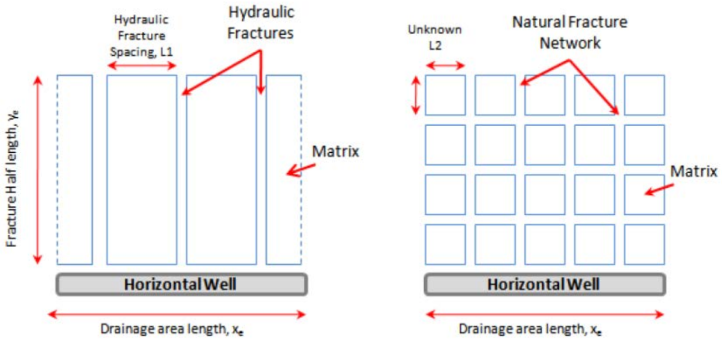


Figure 77: Planar fractures vs. complex fracture type models.

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