MAXIMIZING VALUE AND ROBUSTNESS OF SHALE FIELDS WITH OPTIMUM FIELD DEVELOPMENT STRATEGY

Ibnu Hafidz Arief[1], Irfan Ahmed[2], Olga Barvalina[3], Dominic Smith[4], Ricardo Walker[5]

1: Equinor ASA. iari@equinor.com

2: Equinor ASA. iahm@equinor.com

3: Equinor ASA. olgb@equinor.com

4: Equinor ASA. dosm@equinor.com

5: Equinor ASA. riwa@equinor.com

Keywords: Vaca Muerta, Shale Fields, Field Development Strategy, Well Spacing, Cluster Spacing, Fluid Intensity, Hydraulic Fracture Stimulation Parameters, Production Optimization

ABSTRACT

Este artículo tiene como objetivo demostrar como los factores que controlan la producción de crudo, y los costos operativos (OPEX) y de inversión capital (CAPEX) pueden ser optimizados tanto con un diseño eficaz de las terminaciones como con un espaciamiento adecuado entre pozos.

Los yacimientos del tipo ‘shale’ como los encontrados en la Fm. Vaca Muerta son mejor conocidos por su baja productividad asociada a la baja permeabilidad de su roca y la capacidad de fluir naturalmente. Para producir los hidrocarburos de dicha formación se emplea la costosa técnica de fracturación hidráulica causando un incremento significativo del CAPEX por pozo, que a su vez combinado con la variable productividad de la formación conlleva a tener rangos volátiles y reducidos de rentabilidad económica. Bajo este escenario la optimización de los aspectos comerciales, operacionales, y del subsuelo del activo toman una importancia primordial para las operadoras.

Hemos conducido un análisis de datos de producción y terminación encontradas en el domino público, integrándolas con la descripción actual de la geología y geomecánica del área. El resultado es un modelo que está fundamentado en modelos estadísticos de datos (Ochoa *et al.*, 2022). El estudio confirma que existe un efecto directo de los diferentes tipos de terminación y espaciamiento en la producción y como estos parámetros pueden ser optimizados para incrementar la vida económica del activo. Esta estrategia se puede ir ajustando para optimizar la rentabilidad asociada a las mejores áreas del bloque (sweet-spots) y conjuntamente evitar una sobre exposición de capital en las áreas menos atractivas desde el punto de vista del subsuelo convirtiéndolas al mismo tiempo en áreas más rentables. Basado en estas observaciones el articulo propone una metodología para poner en práctica la optimización del valor del activo.

Los resultados del estudio se pueden resumir en dos puntos principales: 1) la productividad del pozo está directamente correlacionada al tamaño de la fractura hidráulica, esto quiere decir que mientras más superficie de producción es creada, por ejemplo incrementando la intensidad de fluido y/o creando más fracturas por etapa, mayor serán los incrementos iniciales en la producción

de hidrocarburos, y 2) menor espaciamiento entre pozos (más pozos por área) no incrementa el factor de recobro areal lo suficiente como para justificar mayores incrementos de capital, (i.e. más pozos). En resumen, una alta densidad de pozos podría erosionar severamente el valor en vez de agregarlo, marginalizando así el retorno económico.
El espaciamiento de los pozos, los diseños de las terminaciones que incluyen intensidad del fluido y espaciamiento entre clusters, son factores que controlan el valor económico de los desarrollos en 'shales'. Por último, cabe mencionar que el desarrollo de la Fm. Vaca Muerta avanza rápidamente con muchos de los bloques entrando en la fase crítica para beneficiarse con optimizaciones de este tipo.

INTRODUCTION

In 2019, McKinsey published a report which describes the performance of 36 independent US companies in the period 2010-2018 (Brown *et al.*, 2019). The report shows that while the companies increased their oil production during this period, they failed to produce annual positive cashflow. The key reason was due to focus on increased oil production with less consideration to the capital expenditure. The focus during this period on volumes over value was partly driven by the stock market that is more volatile to productions than the free cash flow.

Steps taken by most operators to increase oil production are by drilling more wells and with larger completions. This trend is displayed in Figure 1, showing the evolution of well spacing and stimulations in Eagle Ford. Justification for tighter well spacing could come from the subsurface evaluation, which concludes that the hydraulic fracture geometry which contributes to the production is relatively "short/small". This understanding facilitates a reduction in well spacing without significant production interference. Figure 2 illustrates why operators opt for tighter well spacing. The graph shows that the unit recovery factor/EUR linearly increases as more wells are added into the unit during early development. Such a scenario is potentially the optimal development strategy if the hydraulic fracture geometry is as shown.

However, the main issue is that the fracture geometry is uncertain. This makes finding the optimum field development strategy such as determining optimal well spacing and well stimulation become a challenging task. Unfortunately, there is not a direct data acquisition that is unanimously accepted by the industry to determine these effective fracture geometries, and interpretation can be subject to predetermined thinking of engineers.

Operators generally decided upon the field development plan, including the well spacing and the number of wells during the early development and infill phase. It can be challenging to revise the spacing plan later on and it is critical not to over appraise too far into the full field development.

Figure 3a illustrates a field development scenario with "tight" well spacing. Such a scenario is best implemented under the assumption of "short" fracture geometry. However, if the "true" fracture length is greater than expected, as shown in Figure 3b, this field development strategy will produce non optimal economical value due to production interference. As a result, the oil production is no longer proportional to the total well capital expenditure.

Alternatively, a “wider” well spacing development, as shown in Figure 4a, could be deployed under the assumption of “long” fracture geometry. However, if the “true” fracture geometry is smaller than estimated (Figure 4b), this scenario will leave oil reserves undeveloped. Although this development strategy is also non--optimal, but it is still preferred to the first strategy due to significantly lower capital expenditure (4 vs. 7 wells CAPEX).

The development characteristic of unconventional fields is, in many ways, the opposite of the onshore conventional field (permeabilities in the order of millidarcy to Darcy reservoirs). The most fundamental difference between onshore developments is that conventional fields produce significantly larger volumes per well, with well CAPEX generally half or less. This makes the profitability window of unconventional developments is significantly smaller than the conventional. Operators of conventional fields can still make profit with sub-optimal field development, while the operators of unconventional fields could easily generate negative cashflows.

The objective of this paper is to describe a field development strategy which maximises barrels produced per dollar invested and prioritizes value over volumes. It is based on field observations and established concepts in petroleum engineering.

METHODOLOGY

In this study, we first discuss the concept of recovery factor. Understanding recovery factor is critical to unconventional reservoir development, the concept is widely accepted in the industry and fundamental to reservoir engineering. However, based on the authors experience, it is rarely fully appreciated in development plans of unconventional reservoirs.

Secondly, we examine the effects of engineering variables, predominantly the hydraulic fracturing job, to well productivity. The objective is to understand the relationship between stimulation job optimization from the well to field development strategy level.

Thirdly, we analyse fracture hits and well interference. This includes a literature review and closely examining several study cases from publicly available data. The purpose is to understand how these well interference events influence the field development strategy.

Finally, we aggregate the learnings from previous steps to establish a field development strategy that is aimed at maximizing the field potential economic value. This includes the types of pilot programme that can be implemented to further mature a development plan.

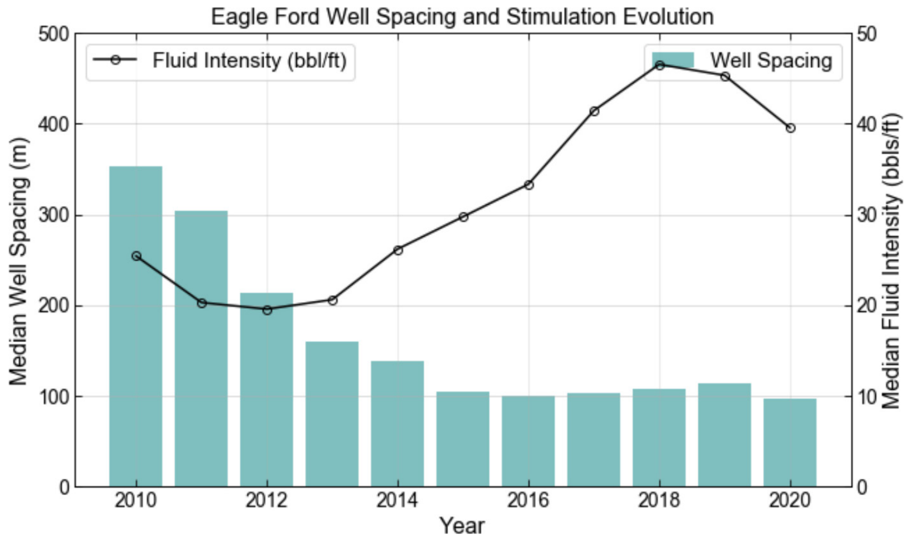


Figure 1. Evolution of well spacing and stimulation sizes in Eagle Ford. Source: public data from the Enverus Energy platform.

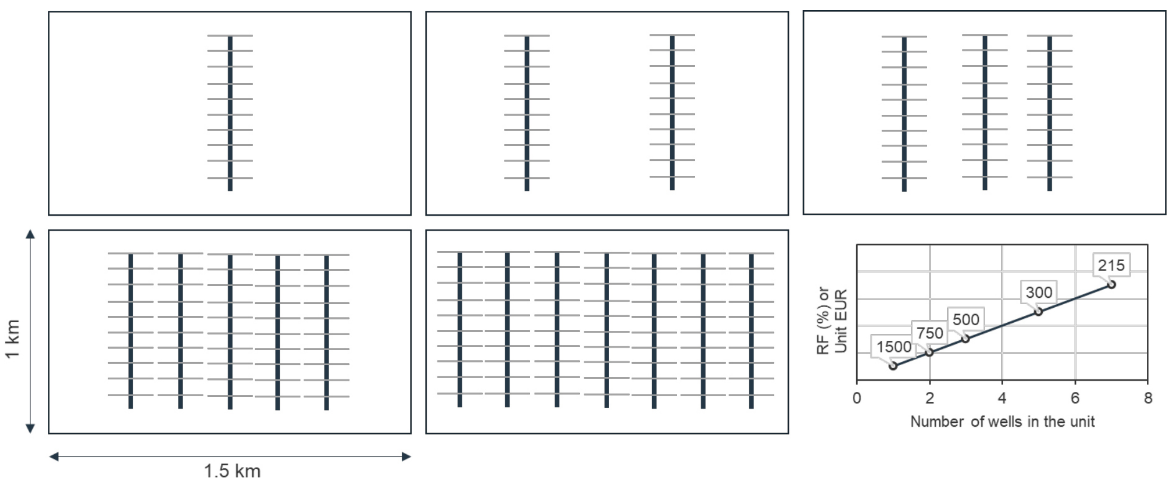


Figure 2. Justification for tighter well spacing, RF/EUR linearly increases as more wells are added into the unit provided all wells have the same EUR.

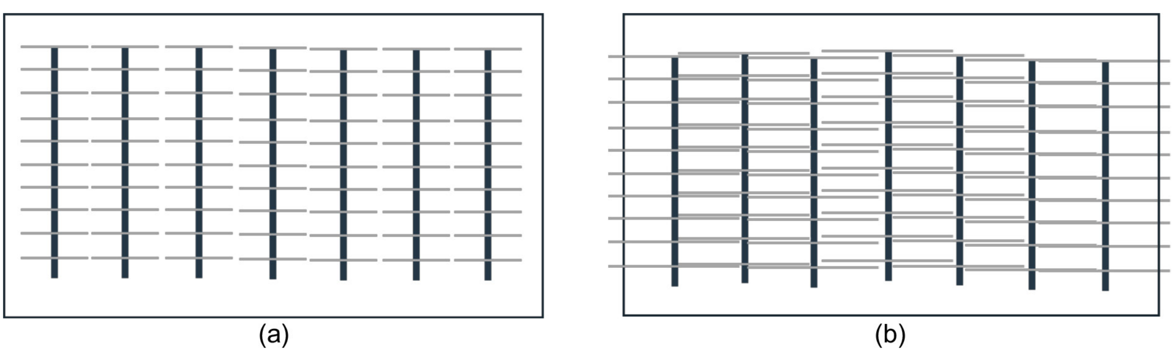


Figure 3. Risks of tighter spacing with fracture geometry uncertainty. (a) predicted fracture geometry (b) actual fracture geometry.

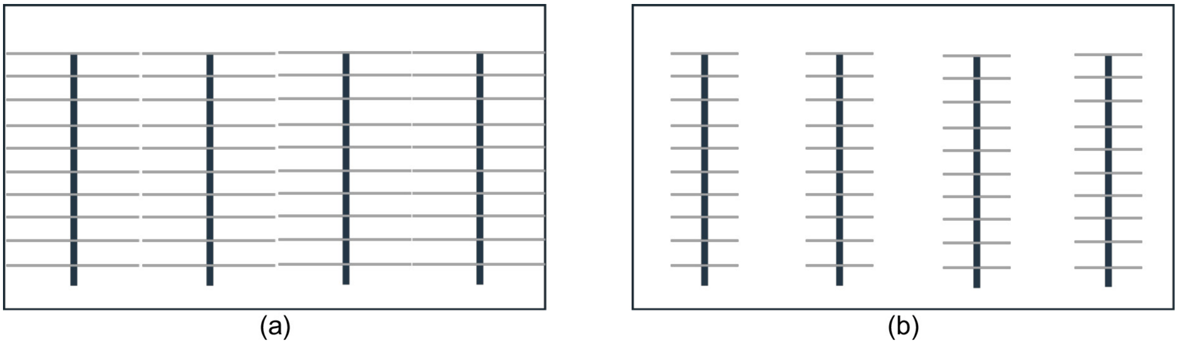


Figure 4. Risks of wider spacing with fracture geometry uncertainty. (a) predicted fracture geometry (b) actual fracture geometry.

RESULTS AND DISCUSSIONS

Recovery factor concept

Recovery factor is a fundamental concept in reservoir engineering that is a direct function of the production driving mechanism. It defines the proportion of the in-place hydrocarbon volume that can be recovered to surface.

In the case of oil reservoirs, there are 3 potential types of drive mechanism found in natural depletion: solution gas drive (reservoir fluid expansion mechanism), gas-cap drive, and water drive. The presence of these drivers varies from one reservoir to another, but all oil reservoirs are produced, in part, by the solution gas drive mechanism. In unconventional oil reservoirs, solution gas drive is the only drive mechanism that occurs. Due to the ultra-low permeability of shale reservoirs, a potential underlying aquifer or overlying gas cap will not support productivity.

A reservoir with only solution gas drive has the lowest recovery factor (Table 1). The recovery factor is also a function of reservoir properties. A higher permeability and more homogenous reservoirs will generally result in higher recovery factor. Table 2 shows the reported recovery factor of different reservoirs with different solution gas oil ratio (GOR).

Recovery factor in unconventional oil reservoirs

Table 2 shows the range of recovery factor for sandstone and carbonate reservoirs. Even though the table does not report the range of recovery factor for unconventional oil reservoirs, but it is a reasonable assumption that the recovery factor of unconventional reservoirs must be lower than these two reservoirs due to the ultra-low permeability and the highly heterogenous nature of shale reservoirs (Zhan *et al.*, 2022). Shale oil reservoirs have been reported to have recovery factor between 2-10% (Sheng, 2017).

Acknowledging the reasonable range of recovery factor in shale oil reservoirs will improve our understanding of hydraulic fracture geometry. It is commonly accepted that determining the effective hydraulic fracture geometry is the most prevalent uncertainty concerning unconventional developments. The principal reason is because there are two unknown parameters which affect the production: fracture geometry and matrix permeability. Different history matching scenario of the production data can be achieved by varying these two parameters.

Recovery factor analysis could be used to rule out certain effective hydraulic fracture geometries that give improbable recovery factors. An example of this can be seen at the Loma Campana field using production data obtained from the public Chapter IV database for well YPF.Nq.Soil-4(h).

To do a recovery factor analysis, we first need to calculate the initial oil in place. As reported in the AAPG Memoir Chapter 15 (Vittore et., al., 2020), the typical porosity and water saturation of the Vaca Muerta formation in Loma Campana is 9.1% 40% initial water saturation. The initial formation volume factor is 1.5 bbl/stb (calculated from the average production gas oil ratio).

Figure 5a shows the oil rate per lateral meter. The production data is fitted with a set of decline curve parameters which are commonly used in Loma Campana (Rahimah, 2021) and the resulting EUR per meter lateral length is 415 bbls/m (Figure 5b). Figure 6a displays the oil in-place per meter lateral as a function of the hydraulic fracture half length (Xf) with the fracture height (Hf). Figure 6b shows different combinations of fracture half length (Xf) and fracture height (Hf) and its respective recovery factor which produces EUR 415 bbls/m lateral. This simple analysis can be used to guide engineers to rule out certain fracture geometries which produce improbable recovery factor. For example, a combination of 40m fracture height (Hf) and Xf less than 230m would result in recovery factor above 10%.

Producing Mechanism	Oil Recovery Range (% OOIP)
Solution gas drive (fluid expansion)	10-25
Gas-cap without gravity drainage	15-40
Gas-cap with gravity drainage	15-80
Gas reinjection without gravity drainage	15-45
Gas reinjection with gravity drainage	15-80
Water-drive	15-60

Table 1. Recovery factor range of different driving mechanisms (Lake L., Edward H., 2006).

Solution GOR (scf/stb)	Oil gravity °API	Sand or sandstones			Limestone, Dolomite or Chert		
		maximum	average	minimum	maximum	average	minimum
60	15	12.8	8.6	2.6	28	4	0.6
	30	21.3	15.2	8.7	32.8	9.9	2.9
	50	34.2	24.8	16.9	39	18.6	8
200	15	13.3	8.8	3.3	27.5	4.5	0.9
	30	22.2	15.2	8.4	32.3	9.8	2.6
	50	37.4	26.4	17.6	39.8	19.3	7.4
600	15	18	11.3	6	26.6	6.9	1.9
	30	24.3	15.1	8.4	30	9.6	
	50	35.6	23	13.8	36.1	15.1	
1,000	15	–	–	–	–	–	–
	30	34.4	21.2	12.6	32.6	13.2	
	50	33.7	20.2	11.6	31.8	12	
2,000	15	–	–	–	–	–	–
	30	–	–	–	–	–	–
	50	40.7	24.8	15.6	32.8		

Table 2. Field statistics of recovery factor in different reservoirs with solution gas drive (Lyons W., 2016)

Recovery factor as a function of stimulation designs

In the previous section we emphasize that the recovery factor of unconventional reservoirs should typically be lower than of the conventional reservoirs. A logical follow up question would be "is it possible for a shale reservoir to have 20% recovery factor by only natural depletions (similar to the average sandstone reservoir)?". The logical answer would be yes, it is possible.

Figure 7 presents a theoretical possibility of a share reservoir to reach the same recovery factor as sandstone reservoirs. Hydraulic fractures typically have millidarcy permeability. One can infer that if a shale reservoir is fully crowded by hydraulic fractures, then it eventually resembles the sandstone reservoir. In other words, recovery factor of a shale oil well can be improved by having a stimulation design with tighter cluster spacing. Figure 8 exhibits an example of the relationship between cluster spacing and recovery factor.

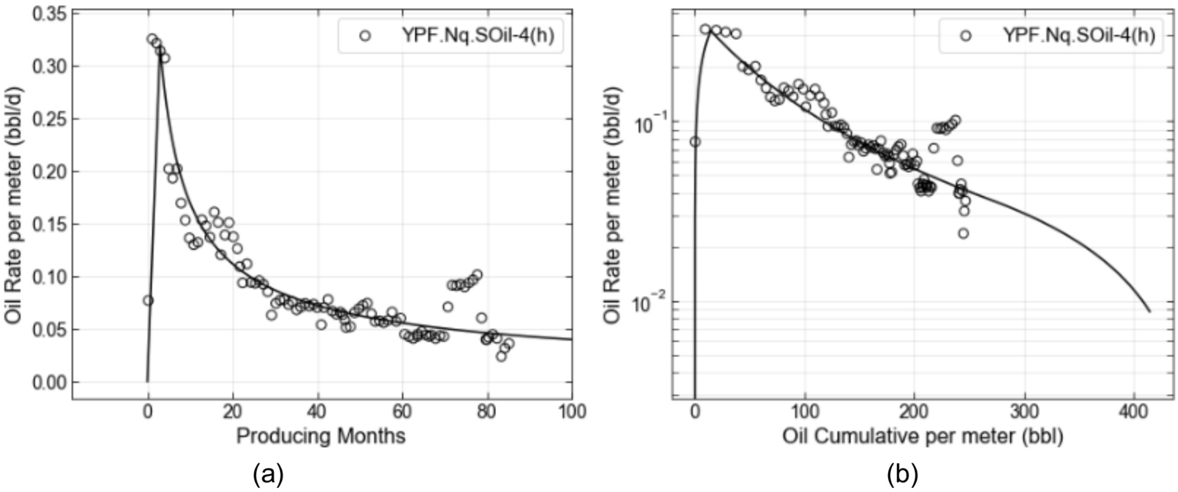


Figure 5. (a) Production profile of well YPF.Nq.SOil-4(h) in Loma Campana. The decline curve parameter is Di = 0.15 (per month), b=1.5 and Dlim = 7% per year. (b) The resulted EUR in the 30-year period is 415 bbls per meter lateral.

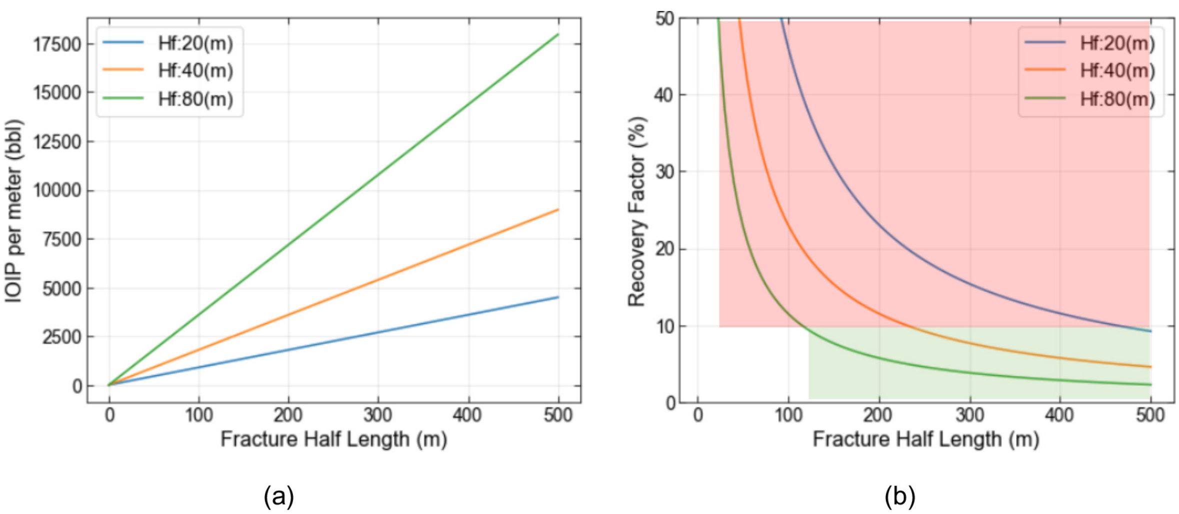


Figure 6. (a) The Initial oil in place per meter lateral as a function of the fracture half-length (Xf) and fracture height (Hf). (b) the recovery factor profile as a function of the fracture half length (Xf) and fracture height (Hf). The red shade indicates the combination of fracture half-length and fracture height which gives recovery factors higher than 10% and the green shade highlights the combination of fracture half-length and fracture height which produces recovery factor less than 10%.

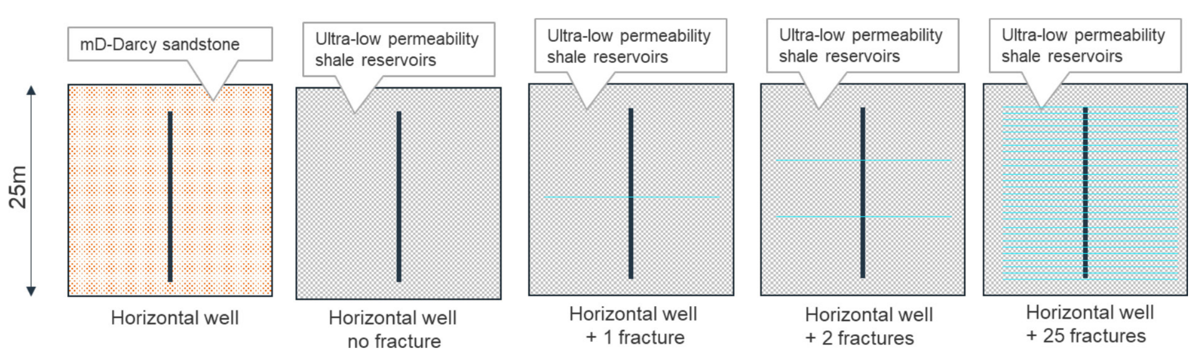


Figure 7. Illustrations of sandstones and shale reservoirs. Recovery factors in shale reservoirs increases with more hydraulic fractures in the system.

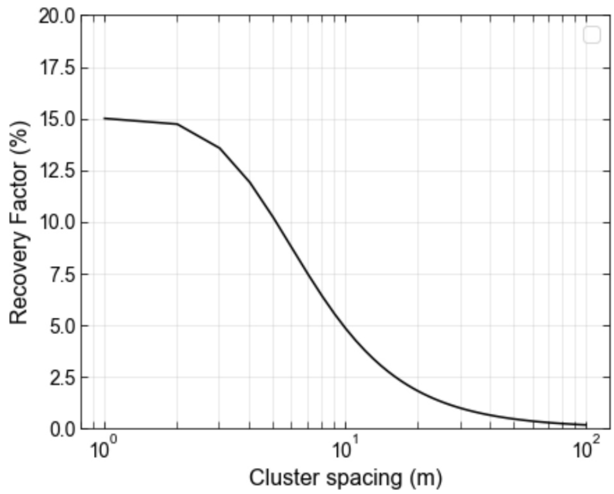


Figure 8. An example of a relationship between recovery factor and cluster spacing.

Recovery factor has a limit

The former section discusses that the recovery factor of shale oil reservoirs can be increased by having more clusters/fractures in a well. Another way to enhance the areal recovery factor is by drilling more wells. However, although the recovery factor in unconventional reservoirs can be improved, it certainly still has a limit. This is clearly seen in the following example from a group of Eagle Ford wells located in the wet gas area of Webb County. Figure 9 exhibits the production of two units; unit-N and unit-S. Despite Unit-N has 50% more wells than Unit-S the total production does not exceed the Unit-S.

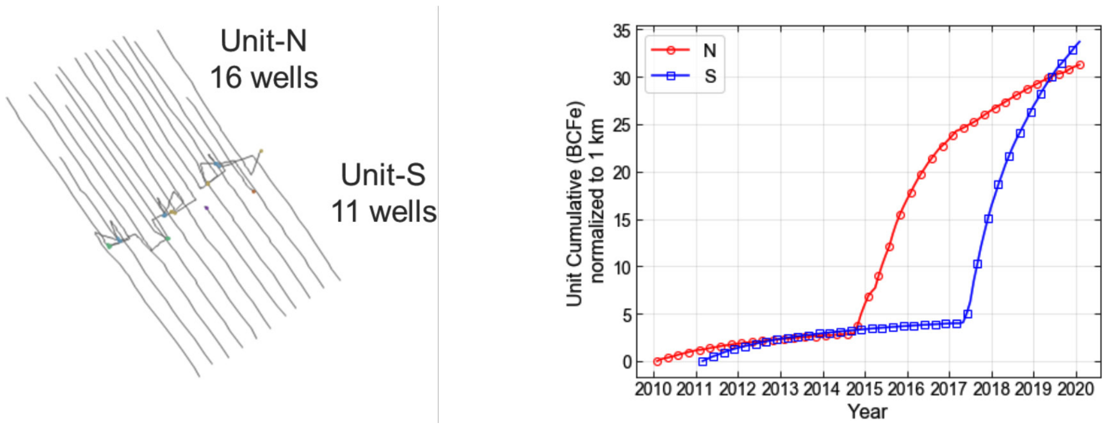


Figure 9. Production data from Eagle Ford wells in Webb County; an example of a unit area production that is not proportional to the number of wells in the unit. Source: public data from the Enverus Energy platform.

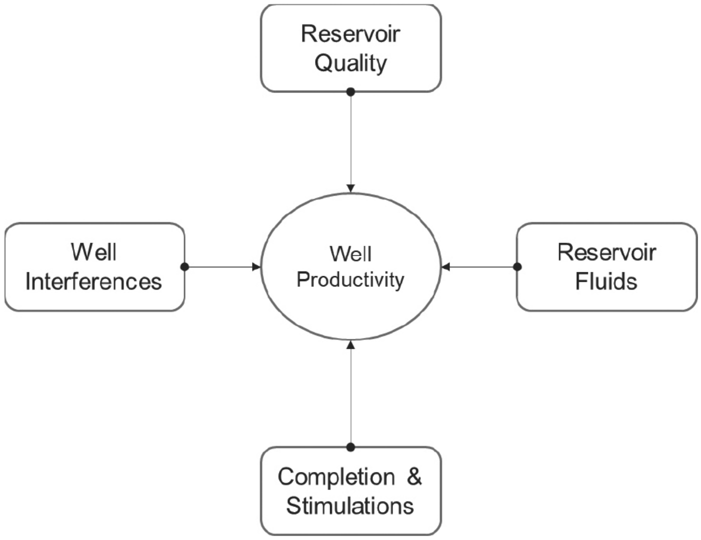


Figure 10. Factors affecting well productivity can be divided into four main categories.

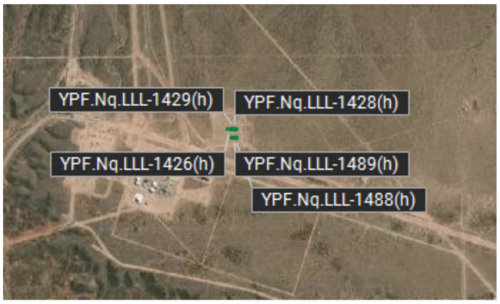
Factors affecting productivity

The factors which affect well productivity can generally be divided into four categories: reservoir quality (petrophysical ang geo-mechanical properties), reservoir fluid, well completion and stimulation job, and well interferences (Figure 10). The first two factors are subsurface related while the latter two factors are the aspects which humans can engineer. The detailed explanation of each factor is as follow:

Reservoir quality. This is the fundamental factor which govern the well productivity. The term reservoir quality is a general term which aggregates several factors such as permeability, reservoir connectivity, porosity, hydrocarbon saturation, reservoir thickness, reservoir pressures, geo-mechanical properties, etc. These parameters could vary in a pad level and certainly will have variations in the field level. This variation can be seen either by looking into the microscopic level of the rock or by the variations in the production profiles.

Figure 11 shows an example of the variation of well productivity at the pad level even though the wells were stimulated with similar fluid intensity (35 bbls/ft) and proppant concentrations (1.3 ppg). With a similar engineering treatment, the productivity variations could be resulted by the subsurface properties.

Reservoir fluid. In comparison to the reservoir quality, the role of the reservoir fluid properties is perhaps more straightforward. Unlike reservoirs which are difficult to characterize, reservoir fluid properties are relatively easier to define. It is because we can physically analyse the fluid and its volumes are also quantifiable during productions.



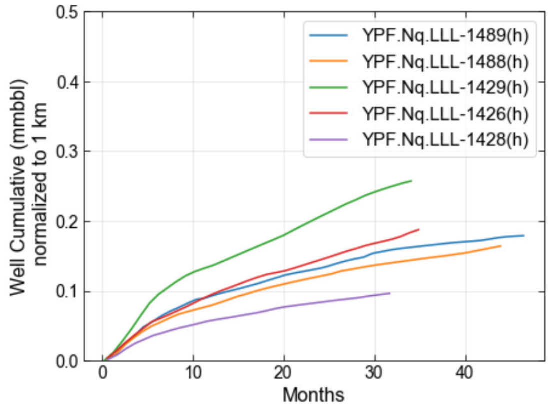


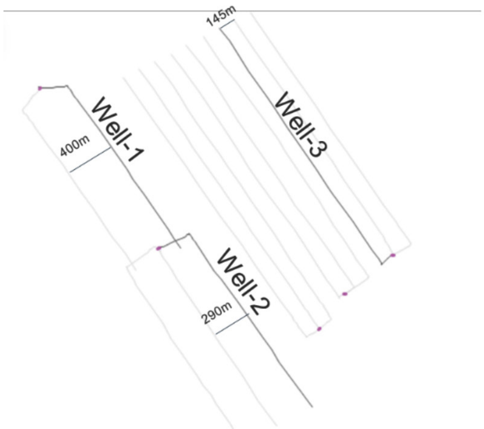
Figure 11. Variations of well productivity in one pad in Loma Campana.

Completion and stimulation jobs. This is one of the engineering factors which we can alter to increase the well productivity. The key objective of refining the engineering factors is to increase barrels of oil or gas per dollar invested. One of the engineering solutions that is logically and industrially accepted is to increase well productivity by creating longer wells. In the following section, we will thoroughly discuss the effects of completion and stimulation jobs to the productivity and how they affect it.

Well interferences. Well interference is rarely mentioned in the discourse of factors which affect wells productivity. However, there have been various published and unpublished reports that alert its consequences to the well productivity (Miller 2016, Jacobs 2017, Rafiee and Grover 2017, Lindsay *et al.* 2018). Figure 12 shows a clear example of the effect of well interferences to the well productivity. Even though the three wells were completed with similar range of fluid and proppant intensity, the production of Well-3 and Well-2 is significantly lower than Well-1. While there could be an effect of the reservoir quality, but a more apparent explanation is because Well-3 is part of a tighter well spacing area than Well-1. Remember that there is a limit to the recovery factor of an area, and in this case Well-3 productivity is limited by the other neighbouring wells.

Maximizing Well Productivity

Once we decide to develop a shale field, we cannot alter the reservoir quality nor the reservoir fluid content. The only thing that we can do is to engineer the field development to maximize its economic value. In this section, we investigate what are the factors that significantly increase well productivity. While Equinor companion paper (Ochoa *et al.*, 2022) takes on this problem using multi-variates statistics and a machine learning approach, our objective in this paper is to thoroughly understand the mechanism on how the engineering factors influence the well productivity.



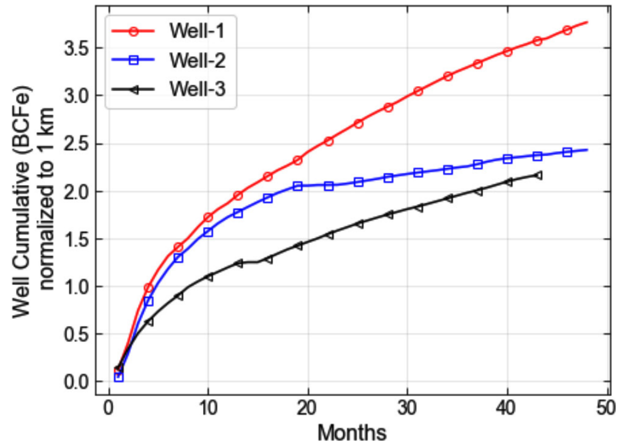


Figure 12. The effect of well interference to the well productivity from Eagle Ford wells located in Webb County. In this example Well-1 is part of a 400m well spacing set-up, Well-2 is part of a 290m well spacing set-up and Well-3 is part of a 145m well spacing set-up. All three wells were completed with fluid intensity 90 bbls/ft (Well-1 & 2) and 110 bbls/ft (Well-3), the same proppant concentrations (0.5 ppg) and the same cluster spacing (20 ft). Source: public data from the Enverus Energy platform.

In this analysis, we investigate the oil production wells from 6 neighbouring fields located in the south of Vaca Muerta: Bandurria Sur, Loma Campana, La Amarga Chica, Sierra Blancas, Cruz De Lorena, and Bajada Del Palo Oeste (Figure 13). In addition, to minimize the effect of reservoir fluids in the analysis, we only consider wells with gas oil ratio (GOR) below 1500 scf/bbls (i.e., 270 sm3/sm3).

We start off our analysis from the fundamental knowledge that what makes shale oil wells productive is the hydraulic fractures. Hydraulic fractures are created by pumping fluids into the rock followed by proppants that has a purpose to keep the fractures open. Please note that proppants do not create fractures. Based on this physics fundamental, a well's productivity is related to the number of fractures in a well, the stimulated fluid volumes in each fracture which determines the hydraulic fracture area, and the proppant concentration which should relate to the propped hydraulic fracture area (Figure 14).

Well production is, given other factors such as fluid, proppant and fracture density are constant, is proportional to well length. The authors understand that there has been a misleading information in the industry that lateral length is the main factor to increase shale well productivity. Hence, many benchmarks between assets are mainly using lateral length as a means for production normalization. However, as will be seen below, starting off from lateral length is not only it is theoretically and intellectually wrong but also it will prevent us from correctly understanding the well productivity problem.

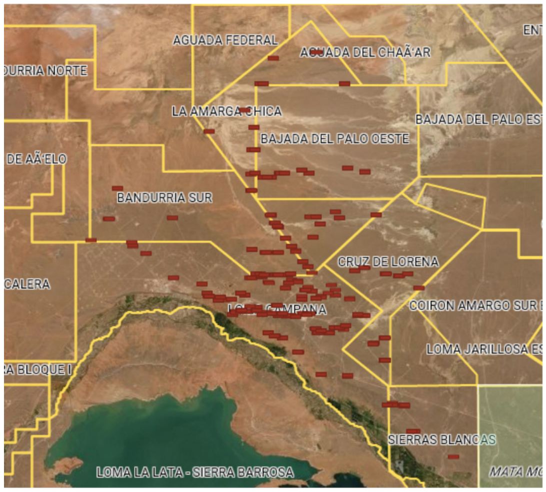
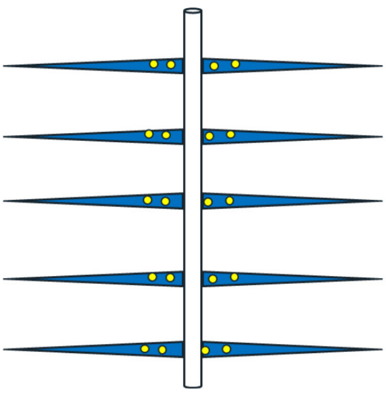


Figure 13. The completion and stimulation job analysis are carried out on the 6 assets/fields located in the south of the Vaca Muerta oil province in the Neuquén Basin.



$$Q \sim f\left(n_f, v_w, \frac{m_{sand}}{v_w}\right)$$

n_f : *number of fractures in a well*

v_w : *stimulation fluid in each fracture*

$\frac{m_{sand}}{v_w}$: *sand concentration in the stimulation fluid*

Figure 14. Based on the physics fundamental, a well productivity should be a function of the number of fractures, stimulation fluid in each fracture and the proppant concentration.

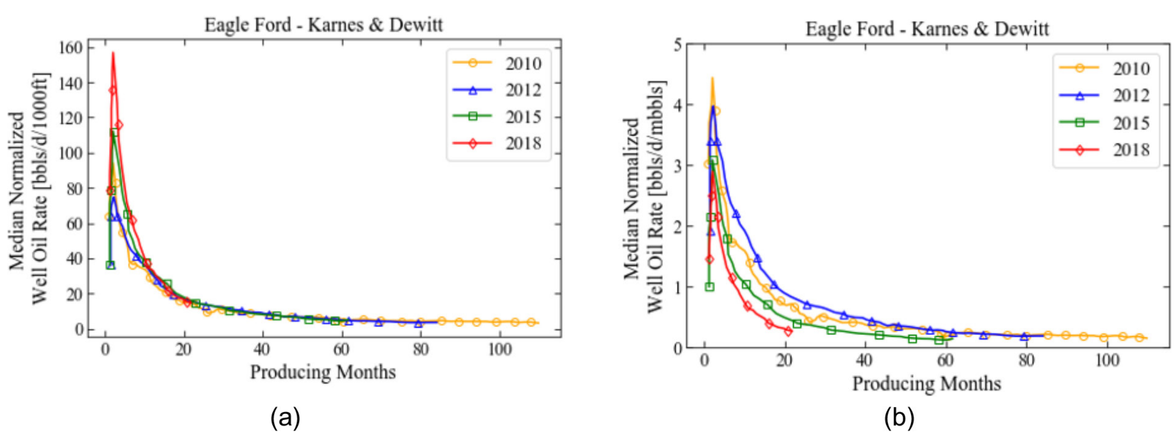


Figure 15. (a) Production normalization using lateral length. (b) production normalization using slurry volume. The figures are from Grover et. al., 2021.

One serious misunderstanding because of production normalizations using lateral length is reported by Grover *et al.* (2021). Figure 15 shows two different production normalizations. A conclusion drawn from the lateral length normalization is that the newer wells (2015 & 2018) are performing better than the older wells which can imply that the development strategy in 2015 and 2018 is successful and it can be repeated in the future. However, a different observation is deduced from the slurry volume production normalization. In this normalization, the production of the newer wells is inferior to the older wells. This is because the newer wells have bigger stimulation jobs with tighter well spacings (Figure 1). The action of this observation would be to revise the well spacing design to maximize the gains of the bigger stimulation jobs.

Figure 16 shows a cross-plot between one-year cumulative productions against well stimulation volume and sand concentrations. The data shows that the production is linearly correlated to the stimulation fluid volume while it appears that increasing proppant concentration does not necessarily increase the well productivity, at least not when higher than 1 ppg.

While the general trend in Figure 16 shows a linear relationship between the first-year production and stimulation fluid volume, the data is clearly scattered. This observation clearly shows that while stimulation fluid volume has a principal effect on production, productivity is also affected by other factors as outlined in Figure 10, and also by discussed by Ochoa *et al.* 2022. Therefore, the scatter is due to the other parameters such as variations in the reservoir quality, well interference effect, reservoir fluid properties and other stimulation parameters.

The stimulation fluid volume is a proxy of the total hydraulic fracture area and thus it is correlated to the production. If we further unpack the stimulation fluid volume parameter (Equation. 4) then the production is essentially a function of three parameters: lateral length, stimulation fluid volume per fracture/cluster and the fracture/cluster spacing. Detailed explanations of the three parameters are as follow:

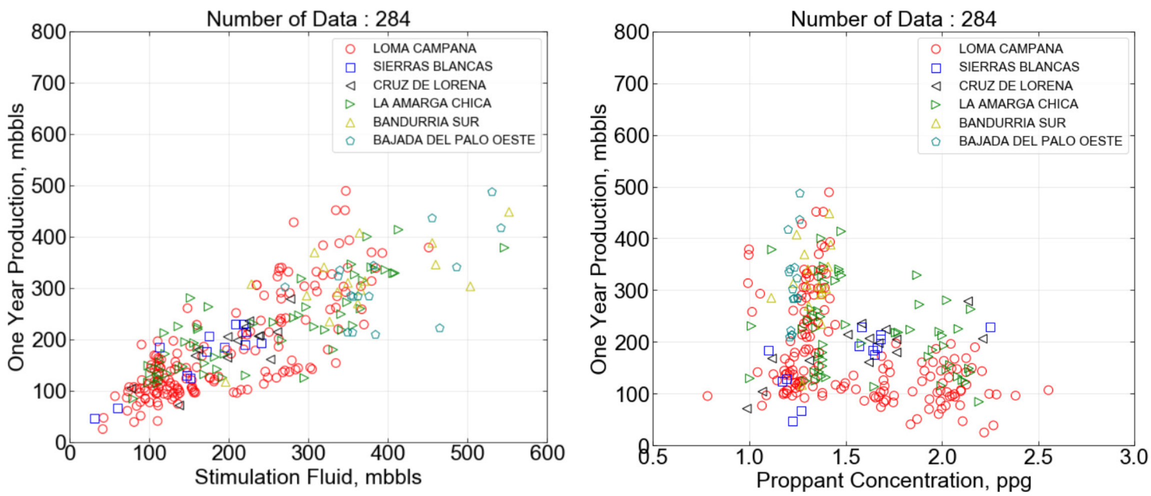


Figure 16. Horizontal well productions plotted against the stimulation fluid volume (a) and against the proppant concentration (b).

$$Q_o(bbls) \sim V_w(bbls) \tag{1}$$

$$V_w(bbls) = v_w(bbls) \times n_f \tag{2}$$

$$n_f = \frac{L\,(ft)}{l_f\,(ft)} \tag{3}$$

$$Q_o\,(bbls) \sim v_w(bbls) \times \frac{L\,(ft)}{l_f\,(ft)} \tag{4}$$

$$Q_o\,(bbls) \sim V_{intensity}\left(\frac{bbls}{ft}\right) \times L\,(ft) \tag{5}$$

$$EUR = IOIP_{connected} \times RF(\%) \tag{6}$$

Q_o	: oil productivity (bbls)
V_w	: total well stimulation fluid volume (bbls)
v_w	: cluster/fracture stimulation fluid volume (bbls)
n_f	: number of fractures/clusters in a well
L	: well lateral length (ft)
l_f	: fracture/cluster spacing (ft)
$V_{intensity} = \frac{V_w}{L}$	: stimulation fluid volume intensity (bbls/ft)
EUR	: estimated ultimate recovery (bbls)
$IOIP_{connected}$	: connected oil in-place volume to the well (bbls)
RF	: recovery factor (%)
m_{sand}	: cluster/fracture stimulation sand mass (lbs)
$C_{sand} = \frac{m_{sand}}{v_w}$	: sand concentrations to the stimulation fluid (ppg)

Lateral length. Longer lateral length has been widely regarded as the means to increase well productivity. If we investigate Equation 4, longer lateral length will improve the well productivity proportionately only if the fluid per cluster and the cluster spacing are kept constant. Figure 17 illustrates a scenario where well productivity will not be improved with longer wells if the hydraulic fracture geometry is smaller. For this reason, it could be a misleading information if we compare the production of different wells with different stimulation jobs by only looking into the lateral length.

Estimated ultimate recovery (EUR) is defined as the connected hydrocarbon in-place volume to the well ($IOIP_{connected}$) multiplied by the recovery factor (RF) as shown in Equation 6. Longer lateral wells will improve the well production and EUR because it increases the connected hydrocarbon volume to the well.

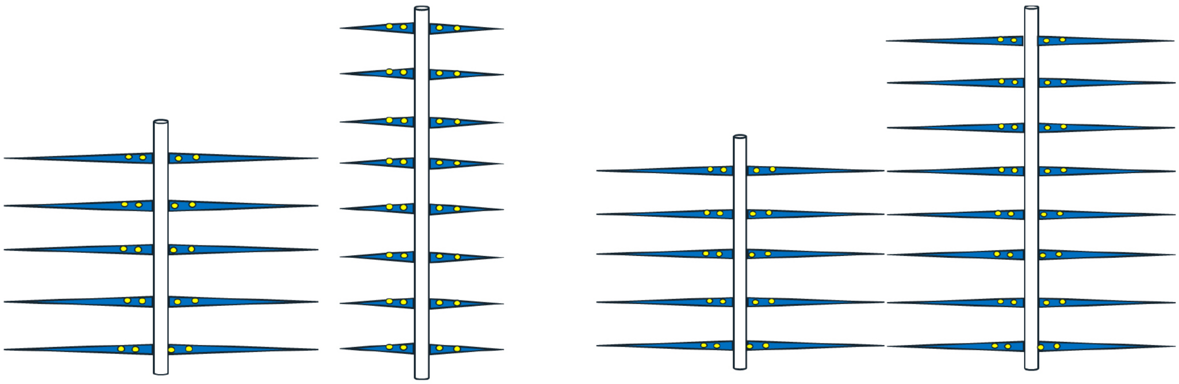
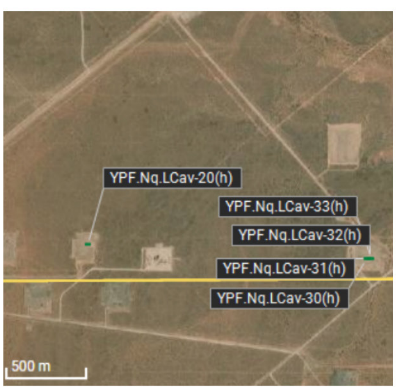


Figure 17. (a) longer lateral length combined with smaller fractures will not increase the productivity. (b) making a longer lateral with similar fractures will give a proportional production increase.

Stimulation fluid volume per fracture/cluster. Another way to increase well productivity is by creating bigger fractures. Bigger fractures can be achieved by injecting more fluids in each of the fractures/clusters. Bigger fracture geometry will enhance the connected hydrocarbon volume to the well which results in higher EUR.

Figure 18 shows the production comparison of YPF.Nq.LCav-20(h) and well YPF.Nq.LCav-30(h), YPF.Nq.LCav-31(h), YPF.Nq.LCav-32(h), YPF.Nq.LCav-33(h) that are located in the south-eastern part of Bandurria Sur field. Well 20(h) is completed with higher stimulation fluid volume per cluster than the other wells (indicated by higher fluid intensity). See Table 3 for the detailed completion and production data. The data shows that well 20(h) is producing 30-40% more oils than the other wells. The higher oil production in well 20(h) can obviously be attributed to a larger fracture geometry, i.e., longer fracs than the other wells. But note this also means that if a completion design similar to the one in well 20(h) is implemented then it should be paired with a 30-40% larger well spacing compared to the other wells.



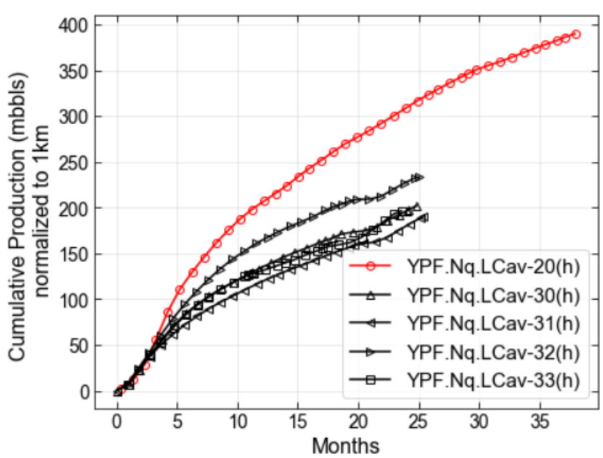


Figure 18. The effect of higher stimulation fluid volume per cluster to well productivity. It can be seen from wells in two neighbouring pads in Bandurria Sur.

Well	Fluid intensity (bbls/ft)	Proppant concentration (ppg)	One Year Production per meter lateral (bbls)	Two Years Production per meter lateral (bbls)
YPF.Nq.LCav-20(h)	59	1.24	205	309
YPF.Nq.LCav-30(h)	48	1.22	134	196
YPF.Nq.LCav-31(h)	48	1.30	118	179
YPF.Nq.LCav-32(h)	47	1.30	163	227
YPF.Nq.LCav-33(h)	45	1.30	130	200

Table 3. Production comparison of wells with different stimulation jobs.

Fracture/cluster spacing. In the previous discussion, we discuss that longer lateral lengths and higher cluster fluid volumes improve wells productivity by means of increasing the connected in-place volume to the well. In the case of tightening cluster/fracture spacing, it either improves the well productivity by increasing the recovery factor of the already connected volume (Figure 19) or improve early production rates.

Figure 19. Illustrations of the tightening cluster spacing. More clusters (tighter cluster spacing) in a well does not increase the size of the connected volume but it enhances or accelerates the recovery of the area in between clusters.

It has been a lengthy discussion in the industry whether it is necessary and or value creating to tighten the cluster spacing. Some industry professionals conclude that tightening cluster spacing is not needed because the system permeability is high enough to flow reservoir fluid within tens of meters away from the hydraulic fractures. On the other hand, other professionals understand that shale reservoirs possess ultra-low permeability with high degree of heterogeneity, thus more hydraulic fractures or tighter cluster spacing is needed to further increase the recovery factor. In order to know which opinion is representative, we should look into the productivity of wells with tighter cluster spacing.

Fortunately, we have one pad in Vaca Muerta which tried tight cluster spacing (4m) and the well has been producing for almost two years which should be sufficient to conclude on the well productivity. The data clearly shows that reducing the fractures/clusters spacing to 4 m does improve well productivity. This is illustrated in an example from a recent four wells pad from the Bajada del Palo Oeste Field (Figure 20).

Two wells of four wells MDM-2062 and MDM-2064 are targeting the Organico layer. One of the well (MDM-2062) was completed with 2586m lateral length and 6 m cluster spacing while the other well (MDM-2064) was completed with almost half the lateral length but with 4 m spacing (Table 4). One might expect that because of the significantly shorter lateral length, the production of MDM-2064 would be significantly lower than the other well. In reality, the MDM-2064 well, despite having 45% shorter lateral length, has been delivering almost the same level of production as MDM-2062. The lateral normalized production of the well with 4m cluster spacing considerably surpass the well with 6m cluster spacing (Figure 21).

This finding is an important piece of information to understand the production characteristics surrounding clusters. Hence, in this case, it can be concluded that the system permeability in the area between clusters is not sufficient to drain the area efficiently, and we can infer that at least within a two-year production period, the hydrocarbon production mainly comes from a maximum of 2 m away from the fracture (Figure 22).

Well	Landing Zone *	Lateral length (m)	Fluid int. (bbls/ft)	Fluid pr cluster (bbl)	Stage length (m)	# Stages	#cluster / stage **	Cluster spacing (m)	Sand Con (ppg)	One Year Production (mbbls)	One Year Production per meter lateral (bbls)
MDM-2062	Organico	2586	54	1065	58	44	10	6	1.2	220	86
MDM-2064	Organico	1427	80	1053	38	37	10	4	1.2	210	146

** The landing zone information is obtained from the Novilabs study (Cross, 2020)*
*** The number of clusters per stage are obtained from Vista Investor Presentation (2019)*

Table 4. Production comparison of wells with different cluster spacing in Bajada del Palo Oeste.

Can we create a super shale oil well?

Figure 23 shows the comparison of the production statistic of the 6 fields in the southern part of the Vaca Muerta oil province. The two best field performers are the Bajada del Palo Oeste and the Bandurria Sur Fields. Obviously, there could be variations in the reservoir quality among the 6 fields but according to the above discussion, the high performance shown by the two fields could likely be attributed to the higher fluid intensities although low proppant concentrations (Figure 24).

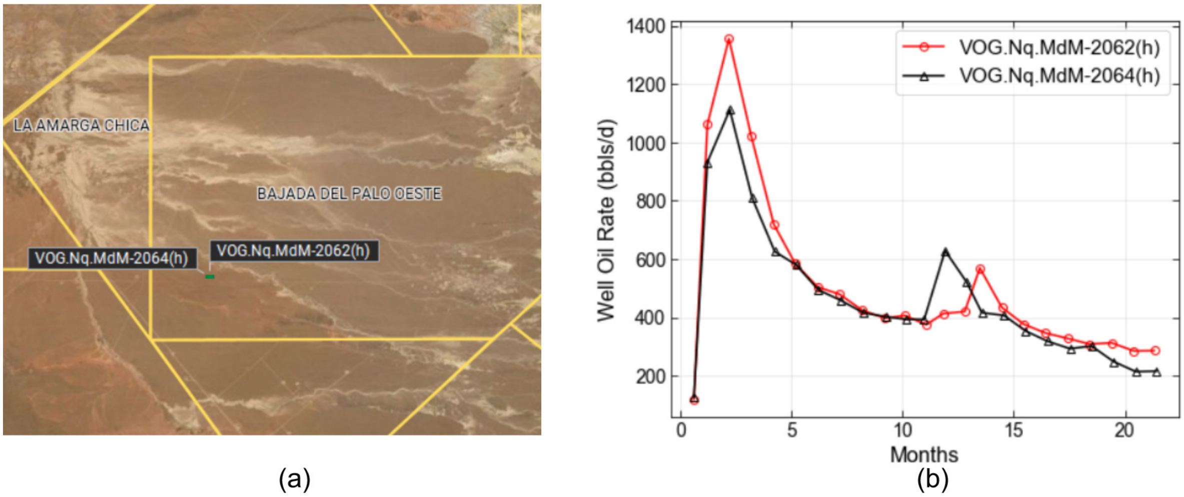


Figure 20. (a) Two wells on the same landing zone and the same pad were stimulated with different cluster spacing. (b) The production profile of the two wells. MDM-2064 can match the production profile of MDM-2062 even though having a 1.2km shorter lateral section.

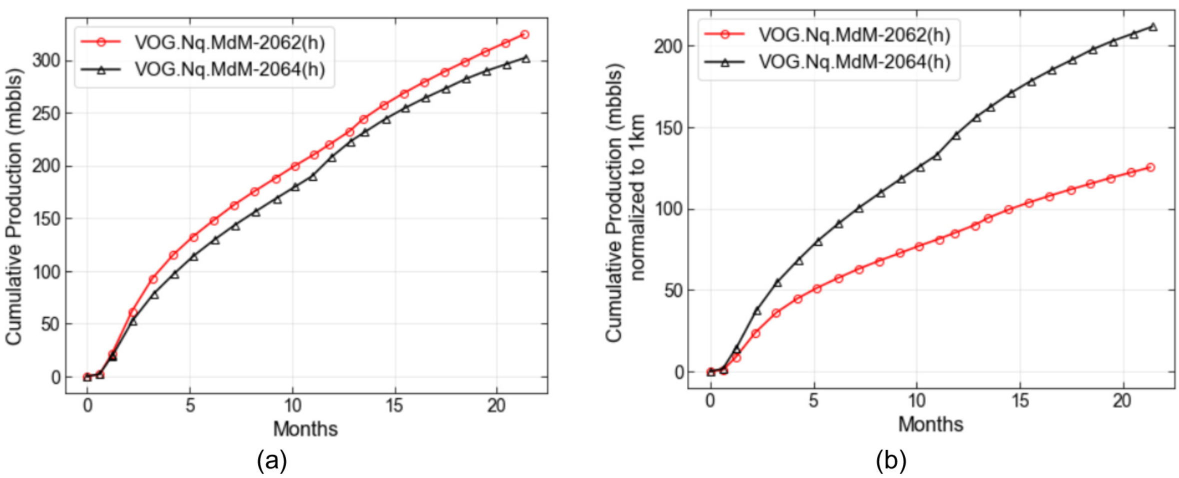


Figure 21. (a) The actual cumulative production of MdM-2064 is just slightly below MDM-2062 but (b) the lateral normalized production of well MDM-2064 significantly surpasses the other well.

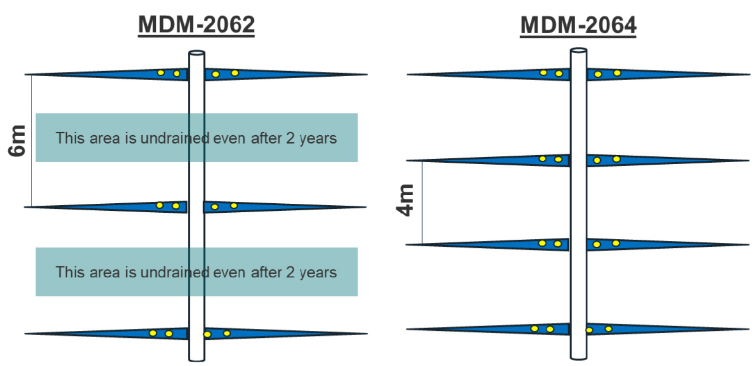


Figure 22. The schematic of cluster spacing in the two wells. The fact that the production of well MDM-2064 can level the production of well MDM-2062 indicates that within the 2-year production period, the drained area is only 2m away from fractures.

Based on the above analysis, we think that the performance of the current wells as shown in Figure 23 could have been further improved with a bigger well stimulation jobs. Figure 25 shows the evolution of the hydraulic fracturing design in Vaca Muerta. The older design is characterized with high stimulation fluid per cluster but with fewer fractures (wider cluster spacing) while the current design is identified with smaller stimulation fluid per cluster but with more fractures.

Our proposed stimulation design to create an outstanding shale well is to employ high stimulation fluid per cluster and accompanied with tighter cluster spacings. It needs to be highlighted here that while we aim to create wells with double production than the current wells, but we will not double the areal recovery factor. It means that we need to accordingly widen the well spacing and reduce the number of wells in the field (remember that in the earlier section of this paper, we emphasize the importance of respecting the limit of areal recovery factor).

To achieve such a high stimulation job then it will eventually increase the stimulation cost. This will lead to a more expensive capex per well. While this is true if we view it from the well level, but with fewer wells needed at the field level, the total CAPEX of the field will be lower. The paradigm that we want to shift is to move from "drilling more wells to maximize the field recovery factor" to "drilling fewer but bigger wells to maximize the field economic value".

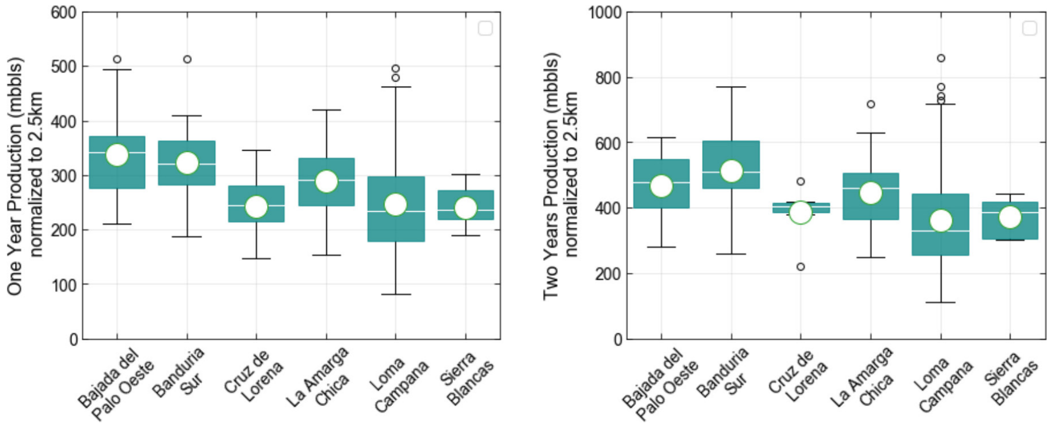


Figure 23. Comparison of the well production statistic of the 6 fields.

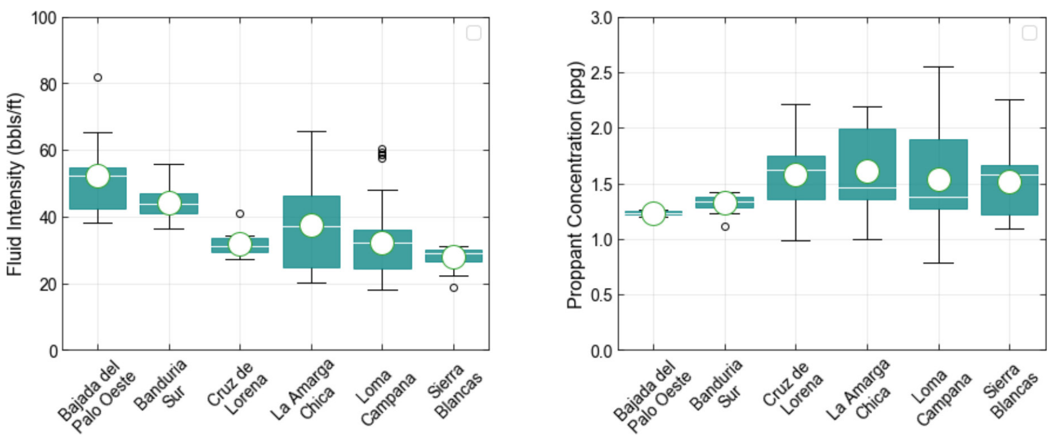


Figure 24. Stimulation design parameters statistic of the 6 fields.

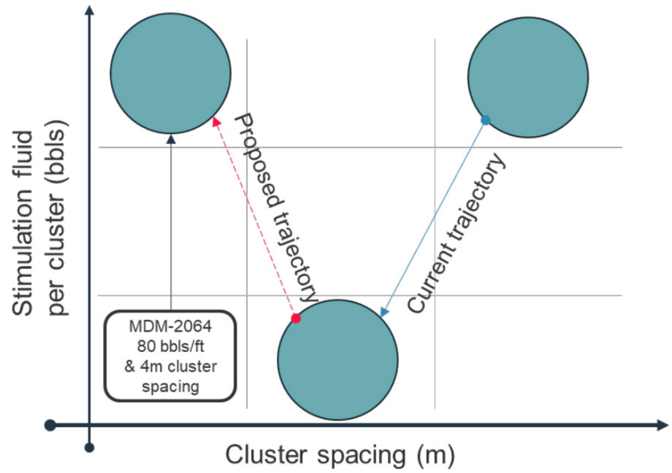


Figure 25. Hydraulic fracture design matrix. The old or legacy hydraulic fracture stimulation design is characterized with wide cluster spacing (>20m) and large injected fluid volume per cluster and the current hydraulic fracture stimulation design is characterized with tighter cluster spacing (6m). We propose the future hydraulic fracture stimulation design to employ high stimulation fluid volume per cluster and tighter cluster spacing (4m) and accompanied with wider well spacing.

Well-spacings prevent the potential gains of big stimulation jobs

Tight well spacing is analytically, numerically, and empirically proven to prevent the potential gains of big stimulation jobs. Figure 26 shows 5 groups of wells (from the Webb County, Eagle Ford basin) with different well spacing. All wells were completed with 6m cluster spacing and fluid intensity ~90 bbls/ft (300 bbls/m). As seen from the average well production of each group, group A gives the highest performance while group E gives the worst performance (Figure 27).

The factor of well spacings and/or well interference is rarely considered when engineers or data scientists use big data to evaluate the effect of well stimulation jobs to well productivity. As a result, they conclude that big stimulation jobs do not significantly improve the well productivity. This conclusion is incomplete. When the well spacing and well interference effect is included into the equation then the correct conclusion should be big stimulation jobs cannot deliver its full potential because of the well spacing and well interference factor.

Drilling many wells are not necessary

Tight well spacings can greatly limit the productivity of wells with high stimulation jobs. If asset owners prefer to develop the fields with tighter well spacings then they should utilize small stimulation jobs. Smaller stimulation jobs generate limited well productivity because it creates smaller hydraulic fracture geometry. But is this strategy better than bigger stimulation jobs and fewer wells? To answer this, let us have a look at a group of Eagle Ford wells located in Webb County (Figure 28a).

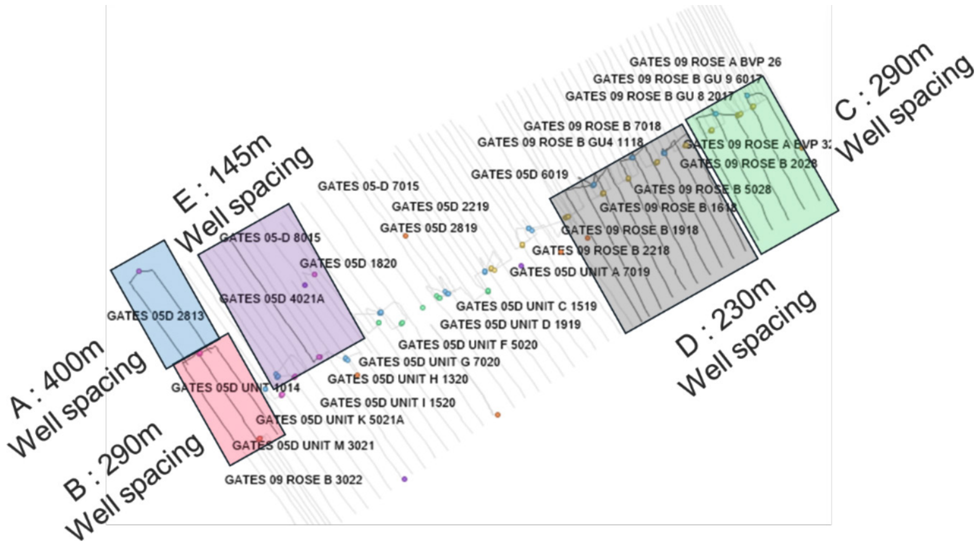


Figure 26. Tight well spacing does limit the productivity of wells with high stimulation job. Source: public data from the Enverus Energy platform.

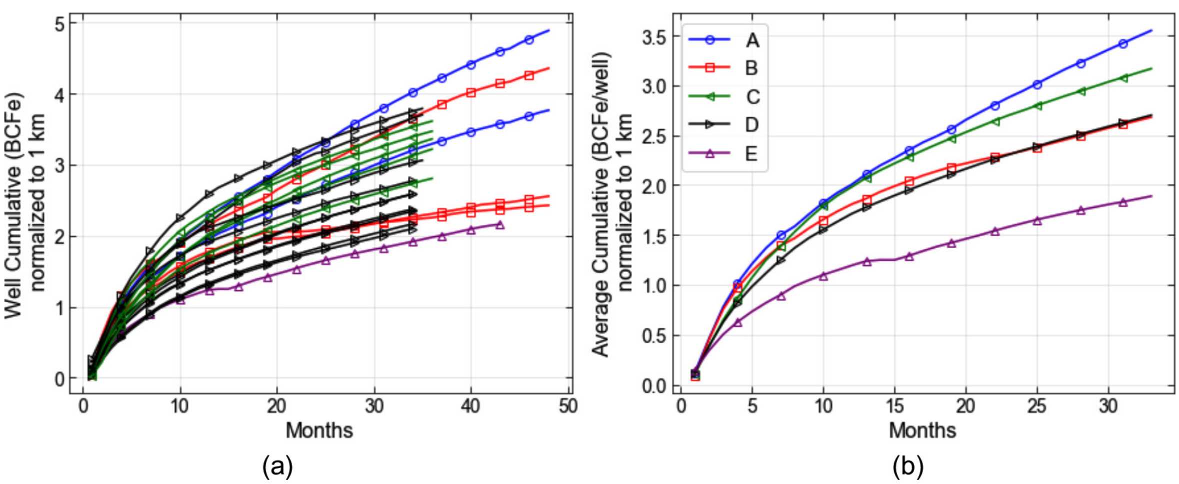


Figure 27. Tight well spacing does limit the productivity of wells with high stimulation job. (a) the production of the individual wells in each group and (b) the average well production of each group. Source: public data from the Enverus Energy platform.

The operator tested 3 well spacing scenarios with different stimulation jobs as shown in Table 5. The set-up of the test allows us to obtain at least two important types of information. First, we can identify the effect of well spacings to the productivity of wells with the same stimulation job (by comparing group A & B) and most importantly we can identify a field development strategy which maximize the economic value of the field.

Figure 28b displays the average well production of each group. The average well performance of group A is superior to the other groups. While the wells in group C delivered inferior performance but its unit production (per 2 km2) is slightly above the other groups (Figure 29). Even though the development strategy implemented in group C produces the highest unit production, but it has the highest capex per produced barrel and hence the lowest economical value (Table 6). On the other hand, the well strategy implemented in group A generates the best economic value because it requires the lowest well CAPEX while delivering productions that is only 15% below the group C.

From this test we learn that drilling many wells in an area is not an optimal field development strategy. Less number of wells does not correlate to low area/unit recovery if high stimulation jobs are applied (tight clusters and big stimulation fluid per cluster). The high stimulation jobs will ensure that we target a maximum recovery and drilling less wells will guarantee low capital expenditures.

Group	Well Spacing (m)	Cluster spacing (m)	Fluid intensity (bbls/ft)	Proppant concentration (ppg)
A	400	6	90	0.5
B	290	6	90	0.5
E	145	6	50	0.5

Table 5. Well stimulation definition

Group	Well Spacing (m)	Number of wells in 2 km^2 unit	Average 3 years well production (BCFe/km)	Average 3 years unit production (BCFe/km)	Assumed Drilling Cost (MUSD/unit)*	Assumed Stimulation Cost (MUSD/unit)**	Assumed WELL CAPEX (MUSD/unit)	CAPEX per Prod (MUSD/BCFe)
A	400	5	3.8	19	13	25	38	2
B	290	7	2.8	19.6	18	34	53	2.7
E	145	14	1.6	22.4	36	38	74	3.3

** Assumed drilling cost is 800 USD/ft*
*** Assumed stimulation cost is 1000 USD/ft per 60 bbls/ft fluid intensity*

Table 6. Summary of the production and capital expenditure of each group.

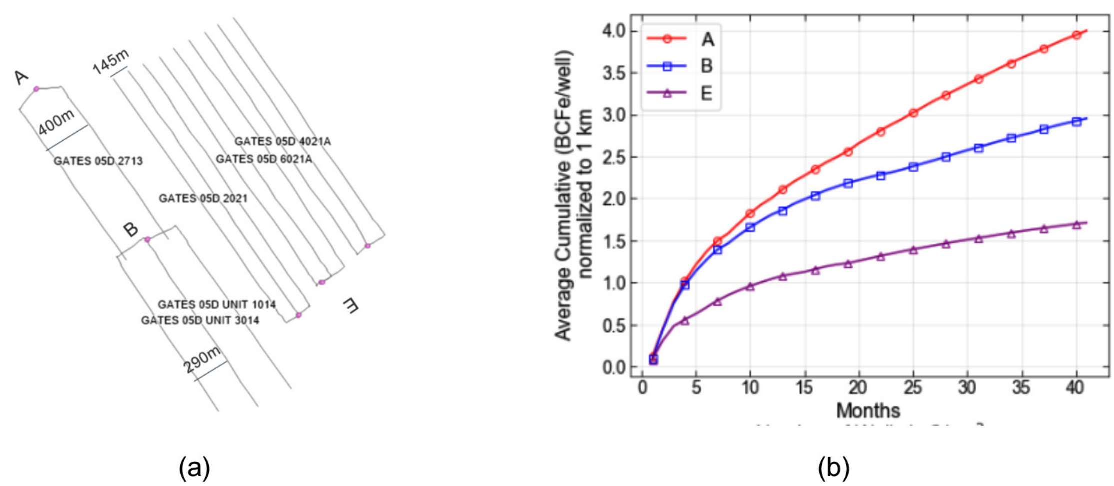
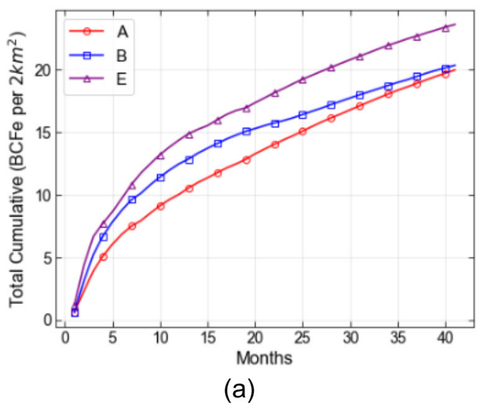


Figure 28. (a) Eagle Ford wells located in the Webb County where the operator tested 3 different well spacing strategies. (b) The average well production of each group. Source: public data from the Enverus Energy platform.



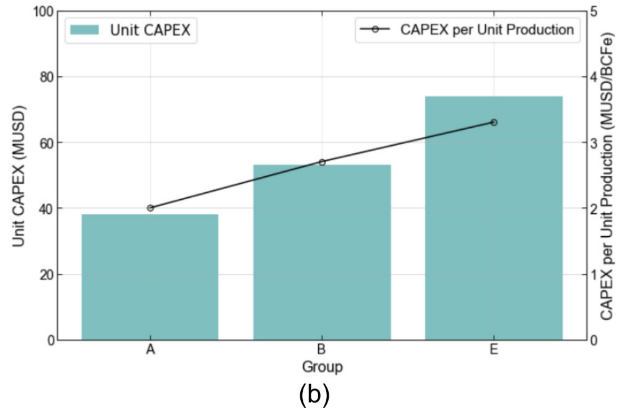
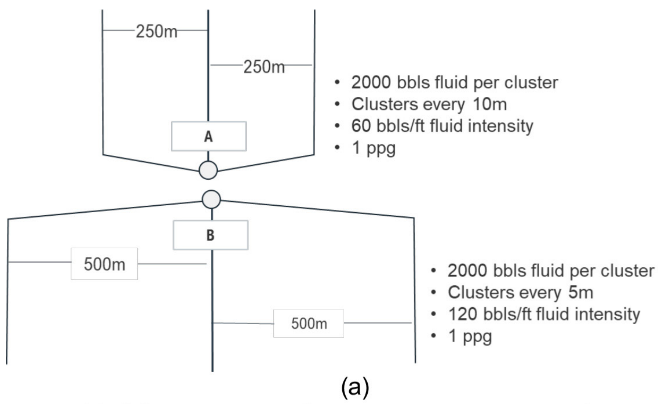


Figure 29. Total unit production (a) and the unit CAPEX and CAPEX per production (b).



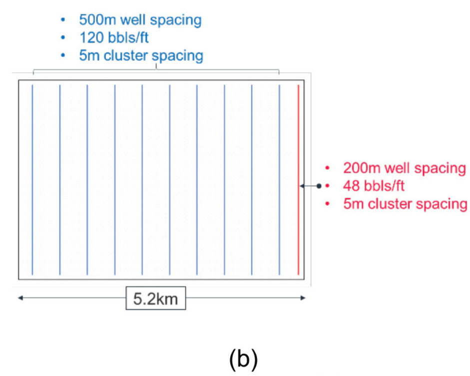


Figure 30. (a) An example of pilot tests that can be performed prior to the development period. (b) an example of wells layout which contains tighter well spacings to maximize the areal coverage.

Proposed field development strategy

Based on the analysis above, we propose a field development strategy that aims to maximize the economic field value and minimize the economic risk. Below are four important points from the above discussion which become the foundation of the proposed field development strategy:

1. The limit of a unit recovery factor is a basic science in petroleum engineering and must be respected. Unconventional reservoirs should have lower recovery factor than the conventional reservoirs for the obvious reasons even if we put millions of wells with millions of fractures.
2. The well productivity potential can be significantly improved by having high stimulation jobs. Well productivity is more sensitive to the number of clusters and stimulation fluid volume per cluster rather than the proppant concentration.

3. The effect of well interference and tight well spacing is real and must not be taken lightly. It is empirically proven to prevent wells with high stimulation jobs to produce at its full potential.
4. Drilling more wells is not the only solution to increase the field production. Having less wells with high stimulation jobs will equally reach the maximum field recovery factor.

Below is the proposed development strategy that is established from the above four points:

1. Before a company decide to develop a certain shale field, it is recommended to obtain a quality estimation of the hydrocarbon in-place. Ensure that the calculated well EUR times the number of wells does not lead to unrealistic recovery factors. The objective is to ascertain that there is a reasonable combination between the estimated well EUR and the well spacing strategy.
2. Build the initial business case with wide well spacings. There are two benefits of using this approach. Firstly, we can maximize the productivity potentials of wells with high stimulation jobs. Secondly, it is psychologically easier to add more wells in the field development scenario than reducing it.
3. Perform a combination test of well spacing and completion design early. It is recommended to test with high stimulation fluid volume per cluster but with different cluster spacings. Figure 30a illustrates the kind of pilot tests which can be done prior to the development period. In this test set-up, the objective is to know if Pad-B can double the production of Pad-A. With a positive result, the development strategy of Pad-B should be implemented in the full field development because it produces the lowest CAPEX per unit production. In some cases, due to the field geometry, it is required to have few wells with smaller well spacing to maximize the areal coverage. However, the fluid intensity must be adjusted accordingly in order to minimize the stimulation cost (Figure 30b).
4. If the asset would like to further test whether the recovery factor can still be improved, we recommend going with a tighter cluster spacing trial rather than a tighter well spacing trial. From the economic perspective, it is cheaper to increase the number of clusters than drilling another well.
5. Proppant concentrations could be another subject of the optimization. For example, operators can test to reduce the proppant concentration down to 0.5 ppg. With a successful result then it will further minimize the stimulation cost.

CONCLUSIONS

Unconventional fields are known to have higher breakeven price than the conventional fields due. The main reason is because unconventional fields do not have high productivity as in the conventional field while it requires higher well capital expenditure. Therefore, the key factor to successfully developing unconventional fields is by maximizing the production return from every dollar spent.

From our study, the most strategic solution to develop an unconventional field is by creating high productivity wells. It can be achieved by creating many fractures/clusters and injecting high stimulation fluid volume in each of the clusters. And when the performance of the individual well is maximized then it is not necessary to invest in high number of wells in the field to achieve maximum recovery.

Another critical aspect to acknowledge is that that there is a limitation of how much we can produce from an area using barely natural depletion mechanisms. By respecting this limit, it will prevent us from overspending capital expenditures in the field.

ACKNOWLEDGEMENT

The authors would like to thank the Argentinean government for making available the production and completion data for Vaca Muerta play through the Chapter IV database. In addition, we also would like to thank Tarun Grover for the consultation, insights and observations of the Eagle Ford wells included in this study. Lastly, we are also thankful for Equinor managements to allow us the publish our work.

NOMENCLATURE

Q_o	: oil productivity (bbls)
V_w	: total well stimulation fluid volume (bbls)
v_w	: cluster/fracture stimulation fluid volume (bbls)
n_f	: number of fractures/clusters in a well
L	: well lateral length (ft)
l_f	: fracture/cluster spacing (ft)
$V_{intensity} = \frac{V_w}{L}$	: stimulation fluid volume intensity (bbls/ft)
EUR	: estimated ultimate recovery (bbls)
$IOIP_{connected}$	: connected oil in-place volume to the well (bbls)
RF	: recovery factor (%)
m_{sand}	: cluster/fracture stimulation sand mass (lbs)
$C_{sand} = \frac{m_{sand}}{v_w}$	: sand concentrations to the stimulation fluid (ppg)
Bbls	: barrels of liquid
Scf	: standard cubic feet
BCFe	: billions cubic feet equivalent

ppg : pounds of sands per gallon of stimulation fluid
mbbls : 1000 barrels
GOR : gas oil ratio (scf/bbls)

REFERENCES

Brown Jeremy, Christ F., Grace T., Sau S., 2019. Paths to profitability in US unconventional. An article from McKinsey & Company. https://www.mckinsey.com/industries/oil-and-gas/our-insights/paths-to-profitability-in-us-unconventionals.

Cross Ted, 2020. Analyzing vista's record-setting vaca muerta wells with oil and gas machine learning models. An article from Novilabs. https://novilabs.com/vista-record-analysis-machine-learning-oil-and-gas-data-model/

Grover, T., Andrews, J., Ahmed, I., Arief, I., 2021. Unified Assessment of Unconventional Resource Plays – Implications for Global Exploration and Development. Paper presented at the SPE Europec featured at 82nd EAGE Conference and Exhibition, Amsterdam, The Netherlands, October 2021. doi: https://doi.org/10.2118/205140-MS.

Jacobs, Trent, 2017. 8. Oil and Gas Producers Find Frac Hits in Shale Wells a Major Challenge. Journal of Petroleum Technology 69, pp. 29-34. doi: https://doi.org/10.2118/0417-0029-JPT

Lake Larry, Holstein Edward, 2006. Petroleum Engineering Handbook: Reservoir Engineering and Petrophysics. Chapter 9 Oil Reservoir Primary Drive Mechanism, pp. 903. Society of Petroleum Engineering.

Lindsay, G., Miller, G., Xu, T., Shan, D., and J. Baihly, 2018. Production Performance of Infill Horizontal Wells vs. Pre-Existing Wells in the Major US Unconventional Basins. Paper presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, January 2018. doi: https://doi.org/10.2118/189875-MS

Lyons William C., Plisga Gary J., Lorenz Michael D., 2016. Standard Handbook of Petroleum and Natural Gas Engineering (3rd Edition). Chapter 5.4 Mechanism and Recovery of Hydrocarbons by Natural Means, pp.5-180. Elsevier.

Miller G., Lindsay, G., Baihly J., Tao Xu, 2016. Parent Well Refracturing: Economic Safety Nets in an Uneconomic Market. Paper presented at the SPE Low Perm Symposium, Denver, Colorado, USA, May 2016. doi: https://doi.org/10.2118/180200-MS

Ochoa Jesus, Gardland L., Salazar J., Pyrcz Michael, 2022. Data analytics and machine learning workflows for optimization of unconventional assets. Case study: Neuquén basin, Vaca Muerta play. Proceeding paper to CONEXPLO even 2022. Mendoza, Argentina.

Rafiee M., Grover T., 2017. Well Spacing Optimization in Eagle Ford Shale: An Operator's Experience. Paper presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Austin, Texas, USA, July 2017. doi: https://doi.org/10.15530/URTEC-2017-2695433

Rahimah A. Karim., Aguilera Roberto, 2021. Vaca Muerta : An Emerging Shale Petroleum Reservoir. Paper presented at the SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition, Virtual, October 2021. doi: https://doi.

org/10.2118/205573-MS.

Sheng, J, 2017. Critical review of field EOR projects in shale and tight reservoirs. Journal of Petroleum Science and Engineering Volume 159, pp. 654-665. https://doi.org/10.1016/j.petrol.2017.09.022.

Vista Investor Presentation, 2019.

Vittore, Franco, Diego T. Licitra, Luciano Monti, Iván Lanusse Noguera, Carlos Hernández, Hernán Reijenstein, and Juan Quiroga, 2020, Full development phase of the Loma Campana block: Black oil to gas and condensate windows, in Daniel Minisini, Manuel Fantín, Iván Lanusse Noguera, and Héctor A. Leanza, eds., Integrated geology of unconventionals: The case of the Vaca Muerta play, Argentina: AAPG Memoir 121, p. 417–444.

Zhan, H., Fang, F., Li, X., Hu, Z., Zhang, J., 2022. Shale Reservoir Heterogeneity: A Case Study of Organic-Rich Longmaxi Shale in Southern Sichuan, China. Energies 2022, 15, 913. https://doi.org/ 10.3390/en15030913.