EMPIRICAL NODAL ANALYSIS AND LINEAR FLOW RATE TRANSIENT ANALYSIS TECHNOLOGY APPLICATION TO BLACK OIL VACA MUERTA WELL AND RESERVOIR SURVEILLANCE

Jack Trueblood[1], Marisol Najera[1], Hugh Grier[1], Somnath Mondal[1], Ruijian Li[1], Xin Liu[1], Peter Zannitto[1]

1: Shell. jack.trueblood@shell.com, hugh.grier@shell.com, marisol.najera@shell.com, somnath.mondal@shell.com, ruijian.li@shell.com, x.liu2@shell.com, peter.zannitto@shell.com

Keywords: Vaca Muerta, Stimulated Rock Volume (volumen de roca estimulada), Linear Flow Diagnostics (diagnósticos de flujo lineal), Rate Transient Analysis, Drawdown, Choke Management, Nodal Analysis (análisis nodal), Inflow Performance Relationship, Vertical Lift Performance, Liquid Loading (carga de líquido)

ABSTRACT

La vigilancia de pozos y yacimiento juega un papel crítico durante la vida temprana de los recursos no convencionales. Este documento se centra en las iniciativas de vigilancia de Shell en su desarrollo de petróleo negro en Vaca Muerta. Shell aprovecha la experiencia significativa de sus activos ricos en líquidos a nivel mundial (Permian, Duvernay). Los componentes clave de la estrategia de vigilancia de Shell son herramientas para diagnosticar el régimen de flujo lineal que es una característica de los pozos fracturados hidráulicamente para obtener información sobre el tamaño del volumen de roca estimulada (SRV) y para monitorear la "vía" histórica de intersección del Inflow Performance Relationship (IPR) y Vertical Lift Performance (VLP). Estas herramientas se incorporan a la estrategia de vigilancia de Shell Argentina en tres áreas principales: predicción temprana del rendimiento de los pozos, optimización del choke management, y instalación de levantamiento artificial.

1. Los diagnósticos de flujo lineal utilizando RTA determinista se pueden utilizar para estimar el tamaño del SRV de reservorios fracturados hidráulicamente. Esta métrica ha demostrado ser un indicador confiable del rendimiento del pozo. Durante el aumento a la producción máxima y la declinación temprana, no hay datos de rendimiento suficientes para llevar a cabo el análisis de la curva de declinación (DCA). Sin embargo, las pruebas diagnósticas del régimen de flujo lineal que utilizan tan sólo 30 días de producción se pueden utilizar potencialmente para predecir el EUR.
2. El choke management y estrategia de drawdown afecta la limpieza, los caudales tempranos de hidrocarburos, la producción de arena y la estabilidad de fractura (incrustación/trituración de agente sostén, cierre de fracturas). Se utilizaron métodos de diagnóstico de RTA de flujo lineal para llevar a cabo un análisis de una prueba de aceleración de choke management de múltiples pozos para analizar producción acelerada y rendimiento del reservorio. Además, se utilizó un análisis nodal modificado utilizando puntos de operación de pozos históricos (intersección de VLP/IPR) para estudiar la aceleración y aumento de producción y caudales líquidos para un plan acelerado de choke management. Los descubrimientos se utilizan para crear un procedimiento estándar operativo para el choke management.
3. El monitoreo de VLP/IPR se utiliza para optimizar el tiempo para la instalación de levantamiento artificial. Dado que los pozos fracturados de shale exhiben un período de flujo lineal transitorio,

los IPRs no se pueden caracterizar fácilmente. El cálculo de curvas VLP y una calculadora BHP basada en redes neuronales para monitorear los puntos operativos históricos de VLP/IPR se utiliza para calcular el tiempo hasta el inicio de un régimen de flujo inestable (carga de líquido). El impacto en las tendencias de producción de pozos se cuantifica e incorpora con los costos de levantamiento artificial para optimizar el tiempo de instalación de levantamiento artificial.
Estas iniciativas de vigilancia se ponen en práctica en el desarrollo de Vaca Muerta de Shell y han creado valor al acelerar la producción de petróleo, mientras se optimizan los gastos de capital. Hasta la fecha, Shell ha observado un incremento del petróleo >20% en los primeros 6 meses de producción como resultado de choke management acelerado, guiado por estas técnicas de vigilancia.

INTRODUCTION

The Vaca Muerta represents a historic development as the first economical unconventional play outside of North America. Belonging to the Late Jurassic, the Vaca Muerta is a petroleum-rich target that serves as one of the main source rocks of the Neuquén Basin. The formation has dominant organic-rich lithofacies (>2% TOC) up to 270 meters thick, with interbedded, low TOC lithofacies generally less than 1 meter thick (Minisini & Sanchez-Ferrer, 2020). With technically recoverable resources of 16 billion barrels of oil and 308 trillion cubic feet of gas, the Vaca Muerta presents a sizable opportunity for unconventional hydrocarbon development (IEA, 2019).

In the Shell-operated acreage shown above, the targets of interest are the Lower Vaca Muerta and Upper Vaca Muerta. Within these landing zones, the porosity ranges from 6 to 11% and the recovery mechanism is rock and fluid expansion via pressure depletion. The fluid type is black oil with 37° API gravity and producing gas-oil ratio (GOR) of 550 scf/stb.

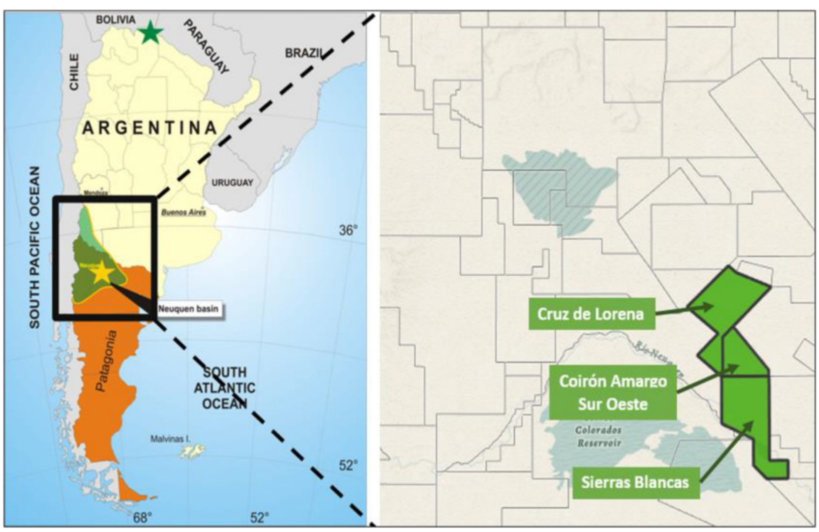


Figure 1. Shell-operated Black Oil Vaca Muerta Blocks

The first horizontal wells drilled in this acreage had lateral lengths around 500 meters and conservative choke management strategies to minimize conductivity loss due to fracture damage. However, over time Shell's field development plan has evolved to drill longer laterals (now exceeding 3,000 meters) with more aggressive drawdown strategies. Technological developments, numerous in-house tools, and key learnings from other Shell unconventional assets (Permian, Duvernay) have enabled Shell Argentina to deliver better well performance and greater value.

LINEAR FLOW DIAGNOSTICS USING RATE TRANSIENT ANALYSIS

One of the most important, yet challenging, parameters to quantify in the realm of hydraulically fractured wells is the Stimulated Rock Volume (SRV). Given the fast cycle time of unconventional plays and early stage of Shell's Vaca Muerta developments, it is particularly important to accurately quantify this parameter early in a well's life. Learnings from this process are instrumental to key field development decisions, such as completion design and well spacing. One standard method to qualitatively estimate SRV, which in turn is a good indicator of well performance, is through linear flow diagnostic plots using deterministic RTA, recently described by Ibrahim *et al.* (2020).

With as little as 30 days of production, Shell has utilized linear flow regime diagnostic tests to predict estimated ultimate recovery (EUR). This analysis considers the slope of rate-normalized pressure versus superposition time plot, "slope" or "linear flow slope" for short, to evaluate early well performance. Given the linear flow solution for a homogeneous porous media can be derived with the following equations:

$$\frac{\Delta p}{q} = \frac{19.910B}{x_f hn}\sqrt{\frac{\mu}{\varphi c_t k}}ST_{lin} + \frac{141.21B\mu}{khn}s \tag{1}$$

$\Delta p = change\ in\ bottomhole\ flowing\ pressure\ (psi)$
$q = fluid\ rate\ (stb/d)$
$B = formation\ volume\ factor\ (rb/stb)$
$x_f = fracture\ half\ length\ (ft)$
$h = fracture\ height\ (ft)$
$n = number\ of\ fractures$
$\mu = viscosity\ (cP)$
$\varphi = porosity\ (p.u.)$
$c_t = compressibility\ (1/psi)$
$k = permeability\ (md)$
$ST_{lin} = linear\ superposition\ time\ \left(\sqrt{days}\right)$
$s = skin\ (unitless)$

$$ST_{lin} \equiv \sum_{j=1}^{n} \frac{q_j - q_{j-1}}{q_n}\sqrt{t_n - t_{j-1}} \tag{2}$$

And the linear flow diagnostic plot $\frac{\Delta p}{q}$ vs ST_{lin}:

$$slope = \frac{19.910B}{x_f hn}\sqrt{\frac{\mu}{\varphi c_t k}} \quad (3)$$

The inverse of this slope, which will be referred to as Early Productivity Index (EPI), is shown to be proportional to the product of the total area to flow, A, and the square root of permeability, k, as shown in Figure 2 below:

$$EPI = \frac{1}{slope} \propto x_f hn\sqrt{k} \;\; or \;\; \frac{1}{slope} \propto A\sqrt{k} \quad (4)$$

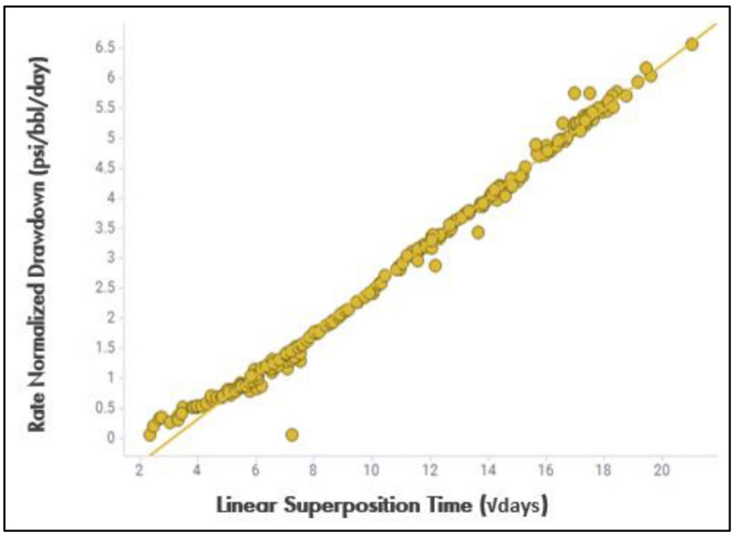


Figure 2. Linear Flow Diagnostic Plot.

Developing EUR vs. EPI Correlation

A sample size of around 30 Vaca Muerta black oil wells was selected to conduct this analysis. All wells have similar completion design and inter-well horizontal spacing, leading to meaningful rate transient analysis comparisons. Independent of rate transient analysis, Shell undertook detailed reservoir simulation modelling on a subset of these wells for history matching and EUR range of uncertainty analysis. Decline parameters were regressed to the simulation model design of experiment results that were then applied to all 30 black oil wells, leading to DCA-based EUR assessments with at least six months of production history.

All wells followed the same choke management plan, exhibited a stable producing GOR of 550 scf/stb, and the vast majority are targeted in the same landing zone. In addition, linear flow regime was observed in all wells and the application of the EUR-EPI method was only applied during observation of linear flow. A good correlation between oil EUR and stable EPI (aka EPI calculated with over 90 days of production) can be identified in Figure 3 below. This observation has been incorporated as a surveillance tool for early prediction of EUR.

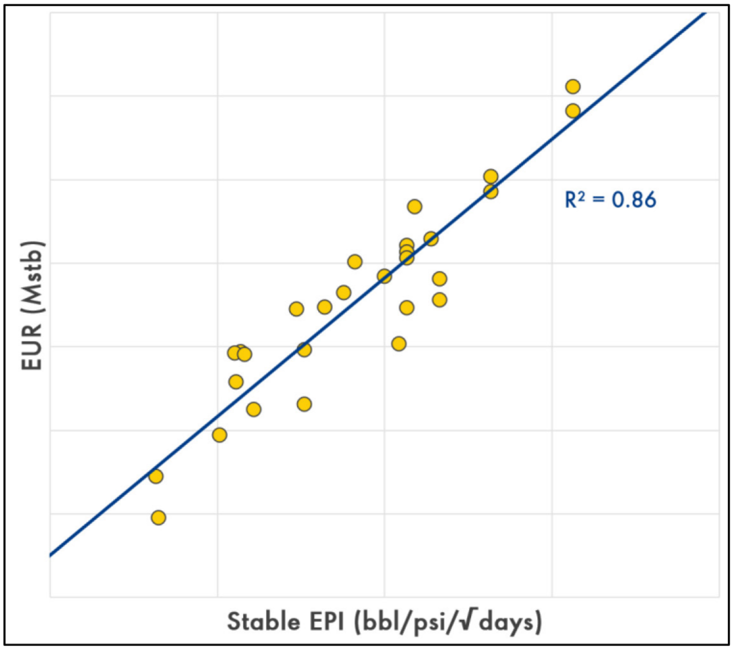


Figure 3. Shell Vaca Muerta Black Oil EUR vs. Stable Early Productivity Index (EPI) Correlation.

Another key variable is drawdown strategy. Shell's early choke schedule had wells flow through an 8/64" choke for the first month of production, followed by the second month at 10/64", and the third month and beyond at 12/64". Thus, the oil EUR vs. EPI analysis was expanded to investigate how the correlation may change in the first 30, 60, and 90 days from initial production. The ranges for oil EUR vs. 30-60-90-day EPI are as follows:

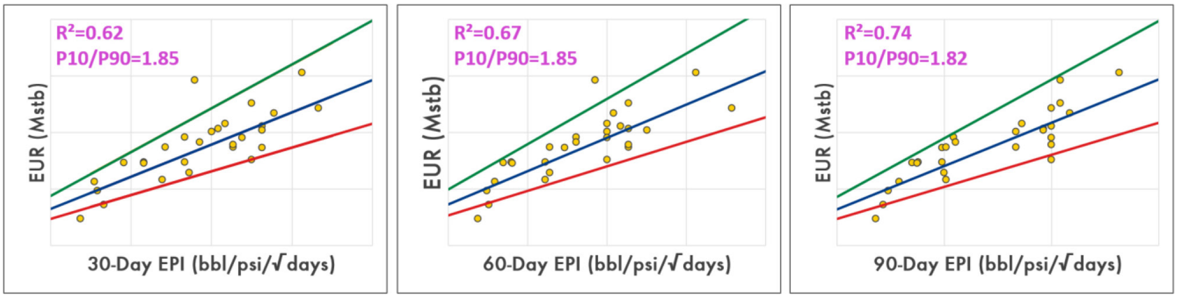


Figure 4. EUR vs. P10 (Green), P50 (Blue), P90 (Red) EPI.

It is important to note the correlation coefficient, R^2, improves within the first 90 days on production. Also, the P10/P90 uncertainty range decreases with more producing days. To further test this correlation against other well performance methods, the EPI-estimated EURs (EUREPI) for all 30 wells were compared to their respective DCA EURs (EURDCA). As shown in Figure 5 below, the overall average error between EUREPI and EURDCA at 30, 60, 90, and over 90 days stayed at less than 2%.

Lastly, a "blind test" was performed on a separate pad not included in the original 30-well sample size. This well pad, consisting of 4 wells, was analyzed once it had 120 days of production and Decline Curve Analysis could be confidently performed on the wells' production declines. The new well pad's EUREPI and EURDCA were subsequently compared to the previously observed Oil EUR vs. EPI correlations, and the resulting maximum average error was 7%.

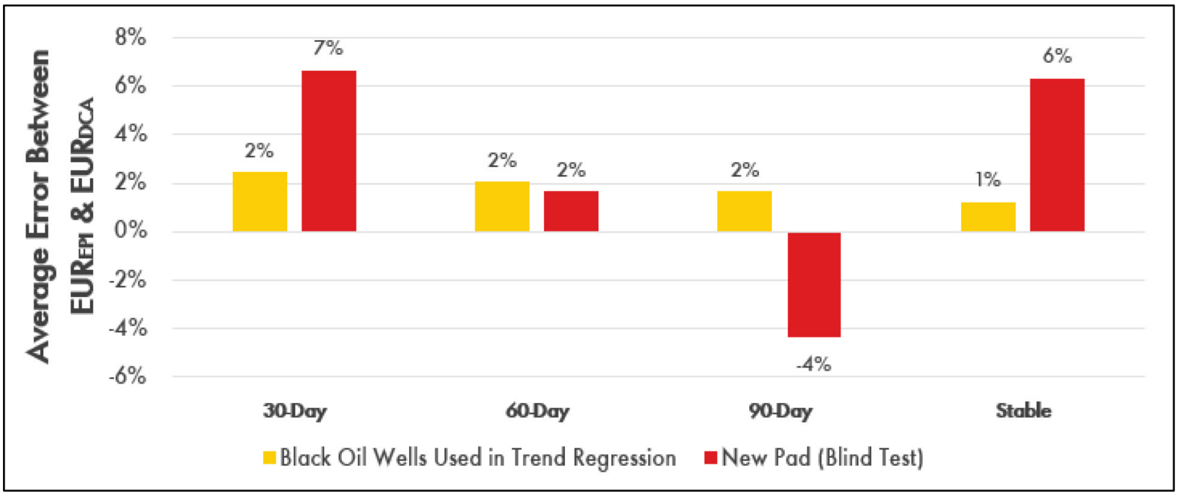


Figure 5. Average EUREPI vs. EURDCA Error for EUR-EPI Correlation. Positive percent error means the EUR predicted from the EPI correlation was greater than the EUR predicted from DCA. Negative percent error means the EUR predicted from the EPI correlation was less than the DCA EUR.

Analyzing these results, it can be deduced that 30-day, 60-day, 90-day, and stable (over 90-day) EPI yield reliable EUR approximations. The observed EUR-EPI correlations have allowed Shell Argentina to make early, informed insights into well performance. This is particularly beneficial as Shell continues to increase its development in the Vaca Muerta and further refine its field development strategy.

MODIFIED NODAL ANALYSIS FOR MULTI-FRACTURED HORIZONTAL WELLS

Nodal system analysis, as proposed by Kermit and Lea (1985), has served as a foundation for engineers to optimize production from oil and gas wells. The basic concept is pressure and flow rate must be continuous at every node (i.e. reservoir, wellbore, wellhead, separator) and thus, the pressure and flowrate at any unknown node can be calculated from a known starting point and estimated pressure drop along the production system. However, this concept was first developed for conventional systems, whose VLP and IPR curves can be reliably predicted for different operating points. In contrast, unconventional systems have complex, transient flow behaviors and the physics of flow is not well defined. This makes predicting IPR curves, and thus the operating path of unconventional wells, extremely challenging.

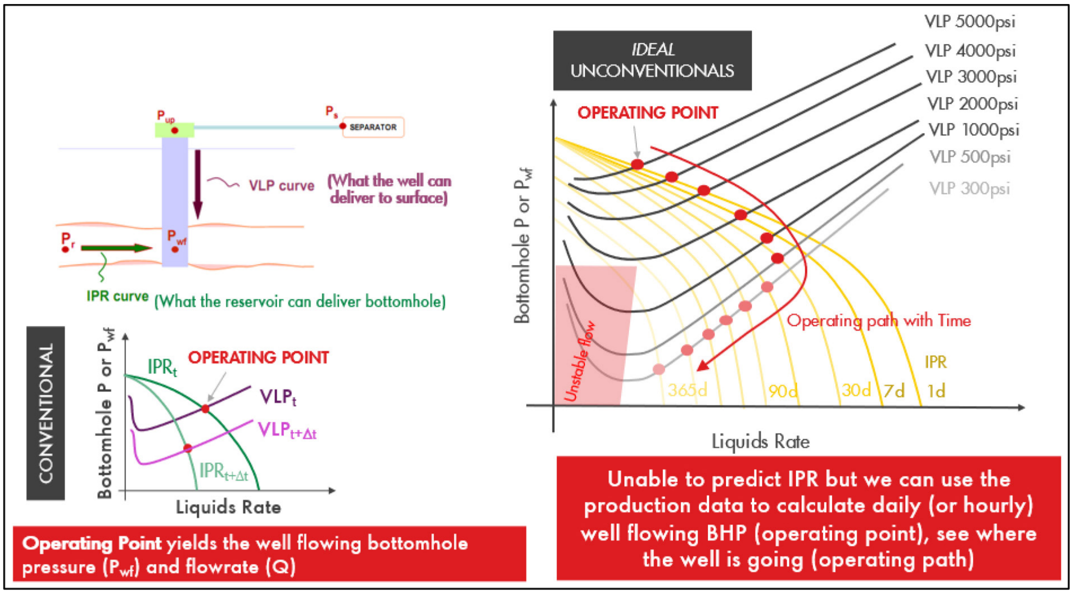


Figure 6. Modified Nodal Analysis for Unconventionals.

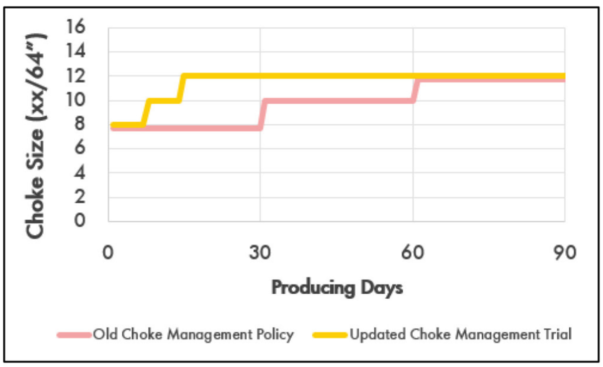
Shell's internal surveillance tool offers a solution to overcome this uncertainty using wellhead production data (flow rates, tubing diameter, tubing length, etc) to estimate the wellbore pressure drop and calculate flowing bottomhole pressure. Rather than generating wellbore flow models for hundreds of wells, which is considerably time-intensive, Shell's surveillance tool employs a machine learning approach using neural networks to build a proxy function to estimate flowing bottomhole pressure for hundreds of wells, all within seconds. Co-visualized with the VLP curves, this provides engineers with a tool to infer the operating pathway through time and predict when wells will reach the minimum bottomhole pressure at which point liquid loading will occur. Two applications of this surveillance tool are discussed in the following sections.

CHOKE MANAGEMENT & DRAWDOWN STRATEGY

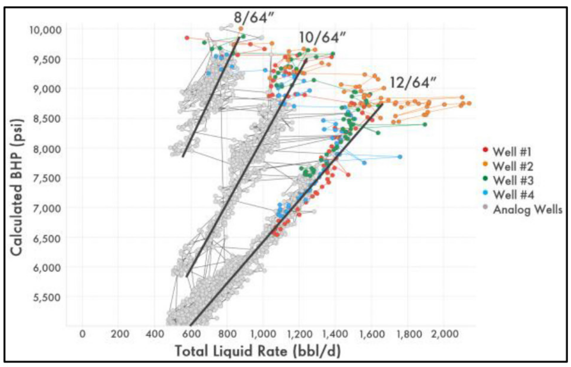
When wells are brought online, choke management is utilized for a variety of surface and subsurface purposes. At the surface level, it is used to preserve the integrity of the well pad facilities and gathering systems by ensuring these facilities are within their pressure and oil/water/gas rate operating envelopes. From a subsurface perspective, choke management is used to optimize reservoir drawdown, manage sand production, and mitigate fracture conductivity loss induced by excessive pressure drawdown. However, identifying the optimal choke management strategy is complex. Through the review of published technical papers and numerous real-world trials, Shell has achieved significant oil production uplift in its Vaca Muerta black oil wells.

Among the technical papers reviewed in this project is one that concentrates on the Loma Campana block, which offsets Shell's black oil acreage. The paper, titled Horizontal Well Productivity Enhancement through Drawdown Management Approach in Vaca Muerta Shale by Rojas and Lerza (2018), examines various drawdown strategies, from conservative to more aggressive, using Rate Transient Analysis. To avoid differences in well performance related to reservoir properties and completion parameters, the nine horizontal wells analyzed are located in the same part of the Loma Campana block and have the same completion designs. Additionally, a representative multi-fracture reservoir model was built to investigate drawdown strategies not yet tested.

Across Shell's unconventional portfolio, numerous proprietary surveillance tools have been developed to facilitate data analysis and business decisions. One such program connects to Shell's centralized data framework and automatically calculates flowing bottomhole pressure from the latest available production data at daily or hourly frequency to perform modified nodal analysis. With the use of interactive visualizations, engineers are able to interpret trends in well operating points and forecast the onset of liquid loading. One key component in analyzing drawdown strategies is the impact on well productivity, or the volume of fluid produced per unit of bottomhole pressure drawdown. This analysis can be performed using individual well operating points.



(a)



(b)

Figure 7. (a) Updated choke management trial compared to older choke management policy. (b) Trend of daily well operating points for wells on updated choke trial compared to analog wells on older choke management policy.

As a well experiences faster drawdown rates, there is an increasing possibility it may incur fracture conductivity loss, and therefore productivity degradation. This productivity degradation would show a leftward trend in the Calculated BHP vs. Total Liquid Rate curve. In other words, the well will produce a lower total liquid rate from the same change in bottomhole pressure. However, as shown in Figure 7b above, no productivity loss is observed in the four wells tested in the accelerated choke trial. In fact, at each respective choke setting the wells appear to follow the trend of analog wells with more conservative choke management strategies. This implies two key findings: 1) no appreciable fracture conductivity loss occurred and 2) the wells' productivity was preserved even with more aggressive choke management. This strategy was tested on eight other black oil wells and similar promising results were observed, with an average cumulative oil uplift of over 20% over the first 240 days of production.

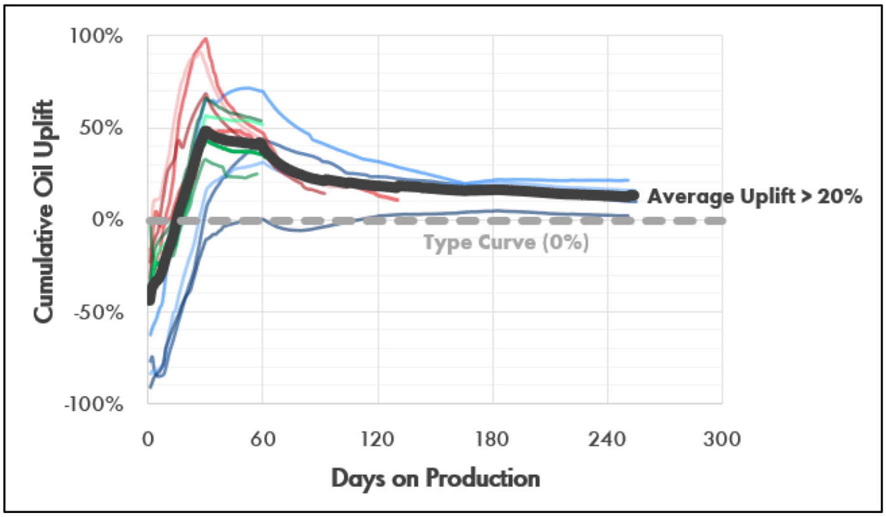


Figure 8. Relative Cumulative Oil Uplift from Choke Acceleration Trials.

ARTIFICIAL LIFT OPTIMIZATION

Another functionality of Shell's internal surveillance tool is to predict when wells will reach the minimum bottomhole pressure at which point liquid loading will occur. Given a well's production history, producing gas- oil ratio, water cut, and tubing dimensions, a range of bottomhole pressure forecasts is generated, as shown in Figure 9 below. With more production history, the range of

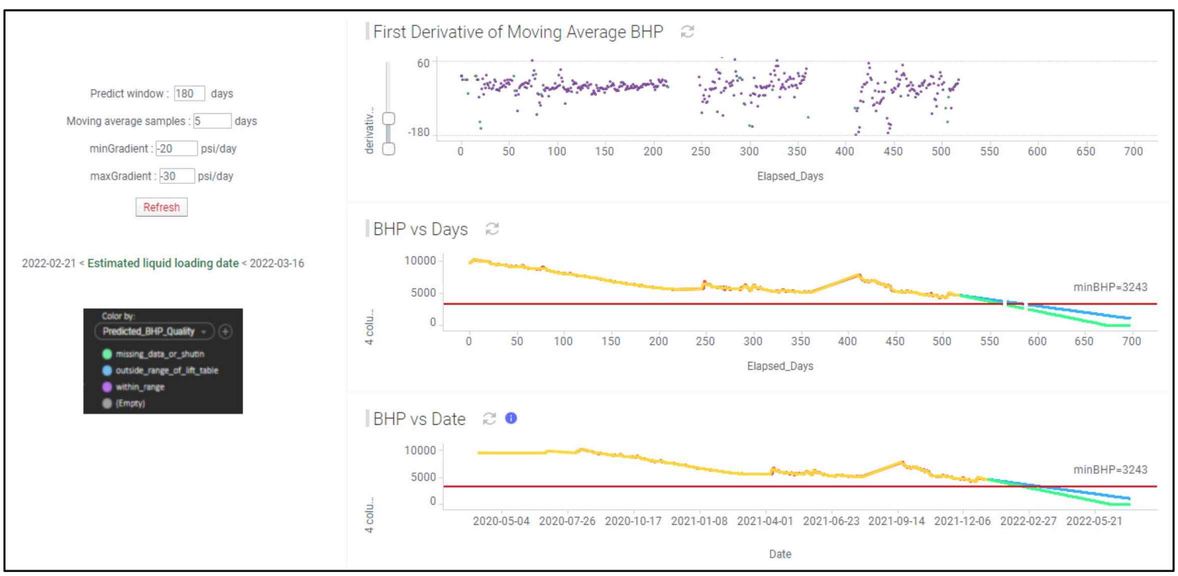


Figure 9. Calculated BHP trend (yellow) & minimum BHP line (red) at which liquid loading will begin to occur.

uncertainty to the onset of liquid loading decreases, and engineers can evaluate the optimal time to install artificial lift.

However, this analysis must consider multiple factors. When a well experiences liquid loading, its production becomes impaired due to backpressure on the formation. If left unchecked, this phenomenon can kill the well. Production deferment, or worse, impairment, has a negative impact on Free Cashflow and Net Present Value (NPV). At the same time, one must consider the capital expenditure (CAPEX) to install artificial lift. It is preferred to delay the CAPEX of artificial lift installation as much as possible to mitigate negative impact on NPV. Thus, optimal artificial lift timing is a balance between production impairment due to liquid loading and value erosion due to capital expenditure.

By implementing Shell's internal surveillance tool to forecast the onset of liquid loading, in combination with fluid level data to evaluate drawdown of existing artificial lift wells, engineers can evaluate the optimal time to install artificial lift based on each individual well's pressure decline. The tool also promotes the integration between reservoir engineers, production engineers, and production operations teams for artificial lift planning purposes. This capability is particularly advantageous in the early life of an asset, such as Shell's black oil Vaca Muerta acreage, where there are a relatively small number of wells, and even fewer that have reached the point of requiring artificial lift.

CONCLUSION

In conclusion, Shell Argentina has leveraged key learnings from other liquids-rich unconventional assets, in addition to innovative in-house digital tools, to guide the development of its Vaca Muerta black oil acreage. A relationship was established to correlate oil EUR with EPI, yielding reliable EUR estimates with as little as 30 days of production. Furthermore, promising results have been observed from Shell's more aggressive drawdown strategy. Through numerous choke acceleration trials, an uplift of over 20% in oil production has been achieved in the first 240 days of production with no observed degradation to fracture conductivity. Finally, Shell's internal surveillance tool has enabled the Argentina asset to facilitate data analysis and business decisions regarding production optimization. The combination of modified nodal analysis and instantaneous bottomhole pressure calculations from machine learning allows engineers to maximize value with optimal artificial lift timing. The key findings from these innovative surveillance techniques are a testament to Shell's dedication to not only develop but also create maximum value from its Vaca Muerta black oil acreage.

ACKNOWLEDGEMENTS

Sincere appreciation to the Shell Projects & Technology team for their hard work to develop innovative tools. In particular, we would like to recognize Somnath Mondal and Xin Liu. Additionally, we would like to thank the Shell Argentina team for its devotion to working as 'Un Equipo'.

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