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Resilience of the US shale production to the collapse of Oil & Gas prices

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Summary
In less than 10 years, the shale oil & gas revolution has allowed the United States to become gas independent and reduce their oil dependency by half. However, this unexpected influx of hydrocarbons caused a successive collapse in gas (2012) and oil prices (2014) with a significant impact on drilling and fracturing activities. As a matter of fact, between late 2014 and early 2016, the number of operating rigs was divided by four. Many analysts predicted that this downturn would lead to a rapid and significant slowdown in production.

Nevertheless, the retrospective analysis of big shale gas plays over the 2008-2015 period shows that the aggregate production of the three major gas plays (Barnett, Haynesville and Marcellus) has not stopped increasing. Over the past two years, and with 4 times less operating rigs, this growth has been even more significant than that observed before the collapse of gas prices.

Total developed a specific model to understand this resilience, which results from three factors: (1) the drilling of a large portfolio of wells at different maturities; (2) the improvement of operational performance; and (3) the increase in reserves per well thanks to innovative completion and fracturing technologies as well as the identification of sweet areas. Maintaining a production plateau requires a critical activity that declines with the number of wells put on stream, the improvement of operational performance and the reserves per well. The model shows that at the end of a development, the critical activity can be 5 to 10 times lower than that required during the ramp-up phase.

The same model was used to simulate the production history of 5 big plays (Barnett, Haynesville and Marcellus for gas; and Bakken and Eagle Ford for oil). The history match is performed by calculating the best decline curve per well using a least squares algorithm. The method achieves an excellent match of production history with a good coherence between calculated and actual reserves per well.

To test the resilience of the plays, the production history was extended over 10 years (2015-2025) to pursue a decline strategy (no new wells put on stream during that period). The results show that resilience differs from one play to another depending on its maturity and the size of its well portfolio.

Introduction
Between 2006 and 2015, US natural gas production has increased by 42%, going from 50.7 Bcf/day to 72.5 Bcf/day. During the same period, the liquid (oil + LPG) production was brought from 6.8 Mbopd to 12 Mbopd. This unprecedented ramp-up is called “the shale revolution”. In late 2015, shale gas (42 Bcf/day) accounted for 58% of the US gas production, and shale liquids (6 Mbopd) for 50% of the US liquid production. For gas, the “champions”

are Barnett (Texas), Haynesville (Texas/Louisiana) and Marcellus (Ohio/Pennsylvania); for oil, they are Bakken (North Dakota), Eagle Ford (Texas) and Permian (Texas/New Mexico).

A major consequence of this unexpected supply was the impact on prices (**Figure 1**). The first major event was the collapse of Henry Hub, which fell below 2US$/MBTU in April 2012. Consequently, most operators diverted their development activities (i.e. drilling and fracturing) to oil.In 2009, 1.500 rigs were drilling for gas against only 200 for oil. In mid-2012, the situation was reversed with nearly 1.500 rigs (i.e. 75% of the American fleet) drilling for oil and less than 500 drilling for gas. The “double punishment” occurred in autumn 2014 when oil prices collapsed following OPEC’s decision not to reduce its quotas. As a result, in a few months, the drilling activity was reduced by 75% with less than 500 rigs (400 for oil and 100 for gas) operating in early 2016. It is estimated that between 2014 and 2015, the investments in shale have been reduced by 40%.

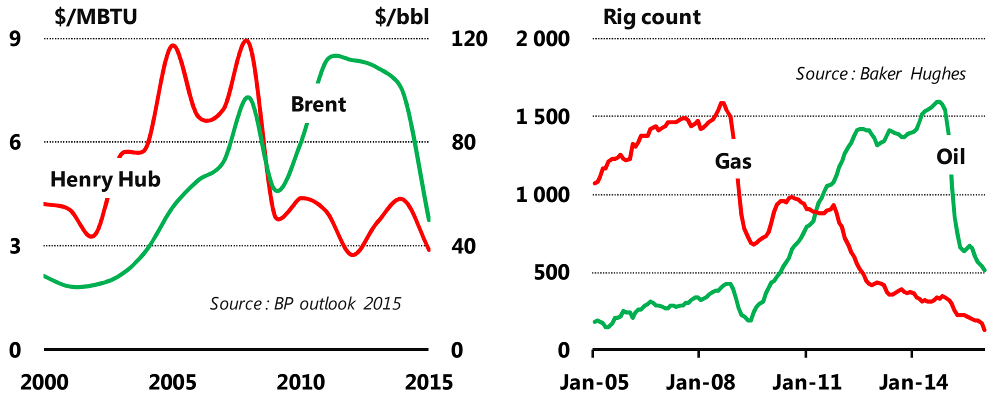


Figure 1 – Oil & gas prices on an annual basis
Rig count in the US from 2005 to 2016
Data source: BP energy outlook 2015, Baker Hughes

Many analysts have then considered the shale oil & gas as a “*speculative bubble*”[1] and predicted that the dramatic decrease in development activities would induce a rapid and significant fall in production. This argument mainly relied on the fact that shale wells decline quickly and roughly produce 80% of their ultimate reserves over a three-to-four-years period. The goal of this paper is to determine if shale production is resilient (or not) to the dramatic decrease in drilling and fracturing activities resulting from the successive collapse of prices. If yes, what are the main drivers of this resilience?

Experimental observation of resilience

As shale gas development started several years before shale oil development, it is relevant to look first at the resilience of the three major US gas plays (Barnett/Haynesville/Marcellus). In the Barnett (**Figure 2**), the development activity was significantly reduced after the 2008 subprime crisis, going from a peak of 280 wells per month to 30 wells per month in 2014. However, the production curve continued to grow until 2012, then passed through a flat peak and finally started to slightly decline. Hence, between early 2012 and late 2014, production dropped by 20%, that is only 7% a year. This value is far from the decline of a single well which can reach 70% after three years. Globally, there is a delay of 4 years between activity and production peaks in the Barnett.

The aggregate production curve of the three major gas plays (Barnett, Haynesville and Marcellus - **Figure 2**) is very instructive as it has been continuously growing since 2006 despite a very significant reduction in development activity, which went from 350 rigs in 2011 to only 130 in 2014. The production curve displays three different periods. The first slope is related to a very strong development activity and the second to a reduced development activity. However, the third slope, which corresponds to the lowest activity level, represents the strongest growth. In other words, "*we did much better with 2.5 times less rigs.*" Contrary to the pessimistic expectations of analysts, this retrospective analysis shows that the US shale gas production has remarkably resisted the decline in development activity.

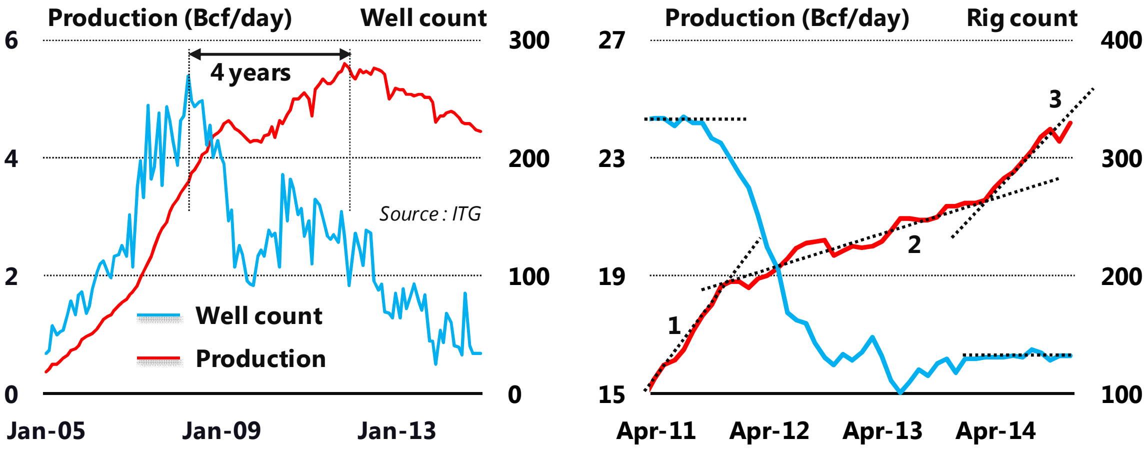


Figure 2 – Production and development history of the Barnett
Production and development history of the Barnett+Haynesville+Marcellus
Data source: ITG

Given the shorter production history and the quite recent collapse in prices, the same conclusions cannot be made for shale oil. However, as highlighted in **Figure 3**, the 70% reduction of activities occurring in early 2014 (from 1500 to 500 rigs operating in oil) only created a 2% production decline in 2015. And this is only for oil; it does not take into account LPG which continued to grow in 2015.

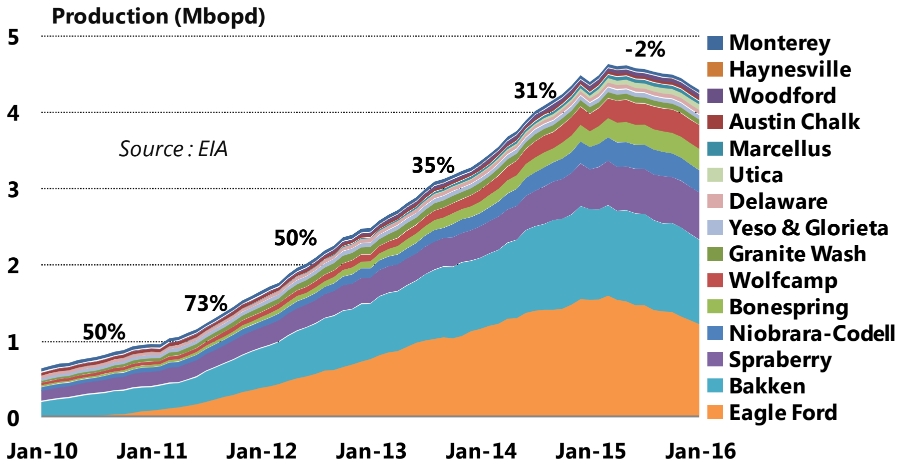


Figure 3 – Shale oil production history
Data do not include LPGs which continue to grow in 2015
Data source: US Energy Information Administration

To highlight and better understand the resilience factors of an unconventional play, Total developed a specific model called **U**nconventional **F**actory **D**evelopment **sim**ulator (UFD^{sim}).

Resilience factors and concept of critical development activity

The UFD^{sim} model has been presented extensively in another paper[2]. It simulates the factory development of a core area by calculating the required development schedule (i.e. number of wells to be drilled, fractured and connected) to reach and maintain a production plateau (see Appendix). The notional case presented in **Figure 4** aims to produce a core area of 3000 km^2 supported by a portfolio of 3,000 wells (each draining 1 km^2) to achieve and maintain a plateau of 1 Bcf/day during around 15 years and then let it decline until the end of the production license. Each well produces according to a similar decline curve: 70% decline over 3 years and EUR of 3.3 Bcf (average “iso-Barnett”) produced over the 30-year license (development + decline).

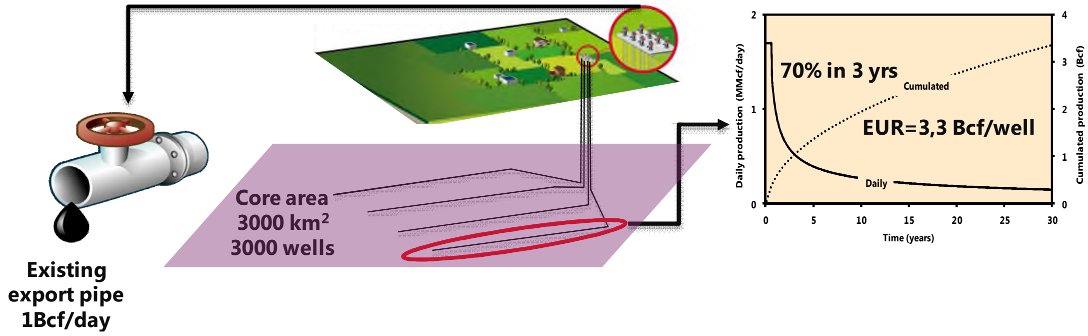


Figure 4 – Simulation of a notional development of 3000 wells

1st resilience factor: well portfolio

As shown in **Figure 5** the 1Bcf plateau is reached after 3 years using 16 rigs. However, the rig number required to maintain the plateau decreases significantly with time and the number of wells put on stream. At the end of the development phase, 4 rigs only are sufficient to maintain the plateau. When the development activity is stopped (i.e. the 3,000 wells have been drilled and completed), the production declines by 50% in 10 years. The decline of a large portfolio of wells is therefore very different from that of an individual well.

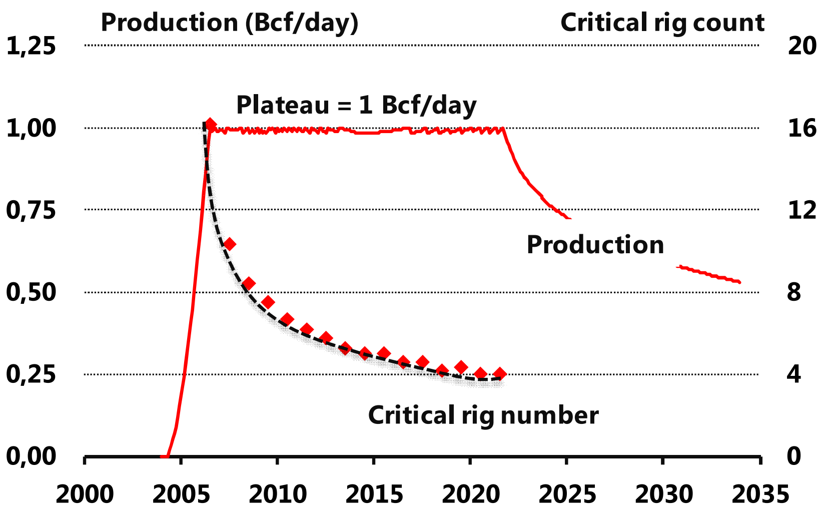


Figure 5 - Simulating a notional development of 3000 wells with a 1Bcf plateau

Data source: UFD^{SIM}

The UFD^{sim} model highlights that a large portfolio of wells drilled at different maturities acts as a "*shock absorber*". The rig count required to maintain a plateau (which we call "***critical rig count***") decreases with the number of wells drilled and connected. Therefore, the number of wells is definitely a first resilience factor.

2nd source of resilience: improvements in operational performance

Apart from the number of wells, drilling and completion time also appear as a resilience factor. For instance, in the Barnett, between 2008 and 2012, the average drilling time has been reduced by 60% whereas the length of the horizontal well has been doubled. In the UFD^{sim} model , improvements in drilling performance are captured through a Drilling Learning Curve (the time required to drill and complete a new well decreases with the number of well drilled). Improving operational performance feeds the well portfolio quicker and reduces the critical rig number faster. Two simulations using 30 days and 10 days (case of **Figure 5**) of drilling time are presented in **Figure 6**. The results show that with 30 days, 30 rigs are initially required to maintain the 1Bcf plateau; at the end of the development, 8 rigs are still needed. With 10 days, the initial critical rig number drops to 16 rigs and the final one to 4 rigs. Therefore, drilling and completion performances appear as a second resilience factor.

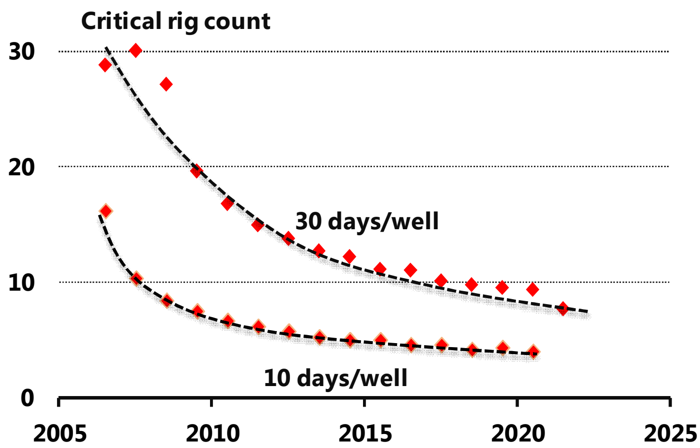


Figure 6 – Comparison of critical activity for two different drilling times
Data source: UFD^{SIM}

3rd source of resilience: improvements in production performance and Estimated Ultimate Recovery (EUR)
By contrast to conventional reservoirs, unconventional plays are very large heterogeneous objects that can extend over tens of thousands square kilometers. The small permeability of the rock only permits recoveries of at most 15% for gas and 6 to 8% for oil. EUR are typically in the range of a few Bcf/well for gas and a few hundred thousand barrels for oil. Given their size and heterogeneity, unconventional plays display a strong spatial variability of their geosciences attributes. Being able to identify high potential areas (called "*sweet spots*") as early as possible should in principle reduce the number of out of target wells, mechanically increase the reserves per well, and therefore the resilience. While apparently attractive, sweet spots exploration can turn out to carry a high risk[3] as it leads to concentrate the development on a targeted area instead of performing a fair evaluation of the complete play. For this reason, sweet spots need to be considered as development objects more than exploration objects.

Improving production performance and ultimate recovery also relies on completion design. It includes increasing the length of the lateral, the number and size of fracturing stages, and the use of slick or X^{link} fluid; and optimizing proppant concentration and proppant ramp-up. For instance, in Haynesville, a dramatic improvement of the EUR/well was achieved through the considerable progress in drilling and completion techniques between 2008 and 2013: laterals 15% longer, water volumes increased by about 30%, proppant concentration up 1.3 times, number of fracture stages doubled and pumping rates approach 80 bbl/min[4].

In the UFD^{sim} model, this dual objective (identifying sweet areas and improving completion design) is achieved by introducing a production learning curve, switching from an initial well decline curve to a better one after having completed a certain number of wells.

The simulation in **Figure 7** was achieved by considering a production learning curve supposed to integrate both improvements in geological knowledge as well as improvements in completion design. The first 1000 wells produce 3.3 Bcf of ultimate reserves, the next 1000 produce 3.7 Bcf and the remaining 1000 produce 4 Bcf. In spite of a limited progress (ultimate reserves per well are only improved by 20% over the whole development period), the production plateau is extended over 10 years while the critical rig number drops from 4 rigs to 2 rigs.

Geological knowledge leading to identify sweet areas and completion design are therefore a third factor of resilience. Among the three resilience factors (size of well portfolio, operational performance and production performances), the third one appears as the most efficient.

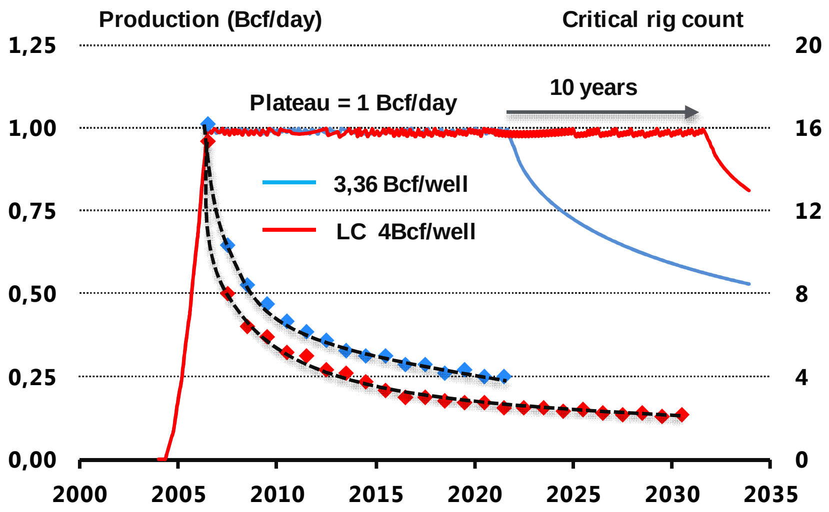


Figure 7 - Simulating a notional development of 1000 wells with a production learning curve
Data source: UFD^{SIM}

Resilience of main US shale plays
To follow the performance of US shale plays, the Energy Information Administration has proposed a single KPI, "the production per rig", which is the additional monthly production from new wells of a given play divided by the corresponding monthly rig count. This indicator implicitly integrates both second (operational performance) and third (production performance) factors of resilience.

As shown in **Figure 8,** the progress is impressive. For Marcellus, between 2011 and 2015, the rig count has been divided by 3,9 (from 141 rigs to 36 rigs) while the production/rig was multiplied by 3.5. Each rig brings today more than 10 MMcf/day compared to only 2.9 MMcf/day in early 2011. For Haynesville, between 2007 and 2016, the rig count was divided by 9,6 (from 239 rigs to 25 rigs) and the prod/rig was increased by 4.5. In other words, the dramatic reduction in the number of rigs was offset by an equally dramatic increase in production per rig.

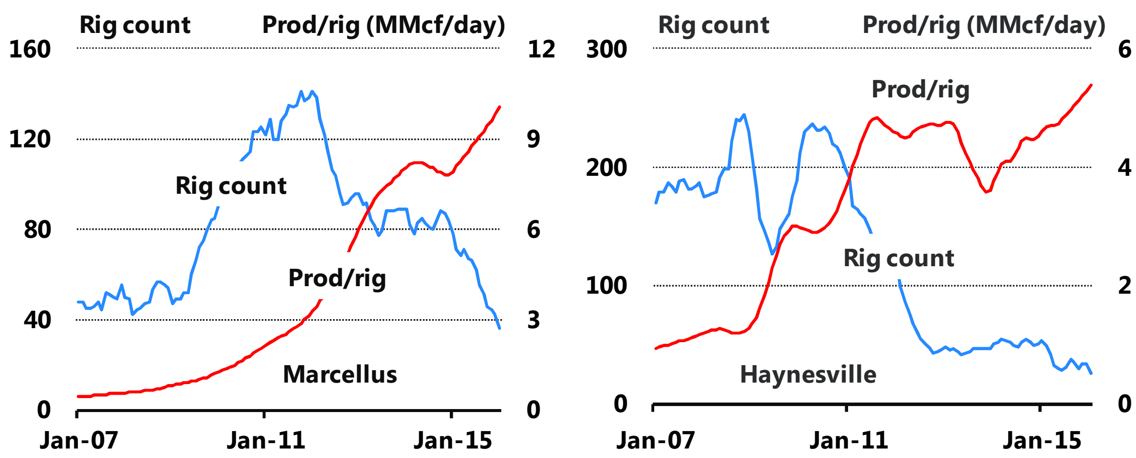


Figure 8 – Evolution of production per rig and rig count for Marcellus & Haynesville
(Data source: EIA)

The resilience of the main US gas plays (Barnett, Haynesville and Marcellus) has been simulated using the UFD^{sim} model. Production and development history (number of wells put on stream on a monthly basis) were recovered from the ITG database. Production was then history matched using a least squares algorithm (see Appendix). Wells were put on stream according to the development history. Each well is supposed to produce according to an average decline curve of the power-law type. The two parameters of the decline curve are used as history match parameters. To check the quality and realism of the history match, the EUR/well from the decline curve is compared with the actual average play EUR issued from the Wood McKenzie database.

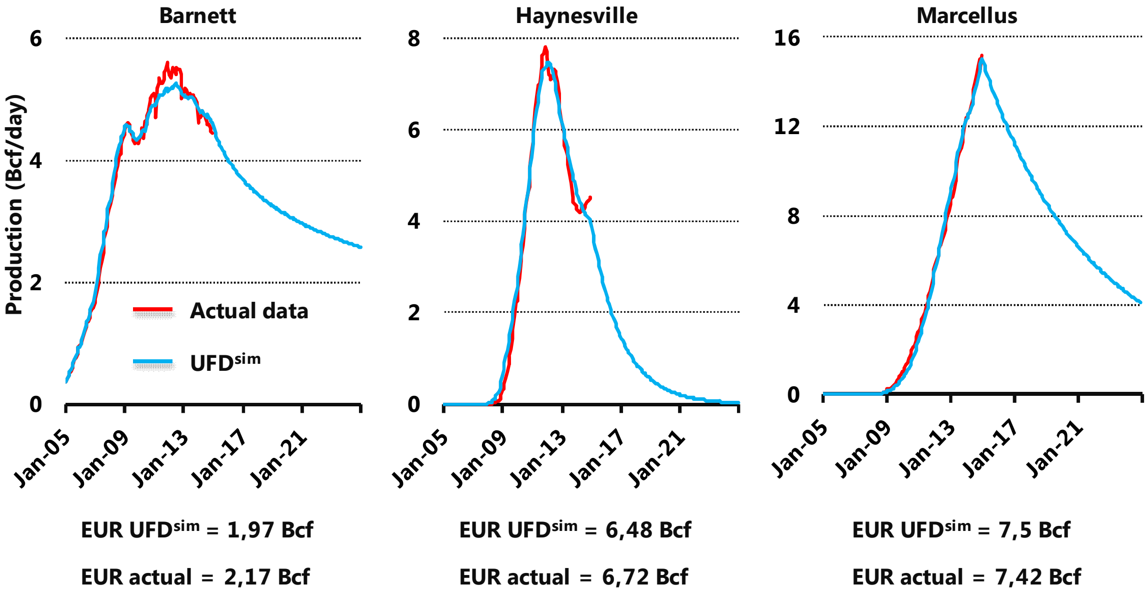


Figure 9 – History match 2005-2014 using the UFD^{sim} model for Barnett, Haynesville and Marcellus. Decline curve "no activity"
Data source: ITG & WoodMac databases and UFD^{sim}

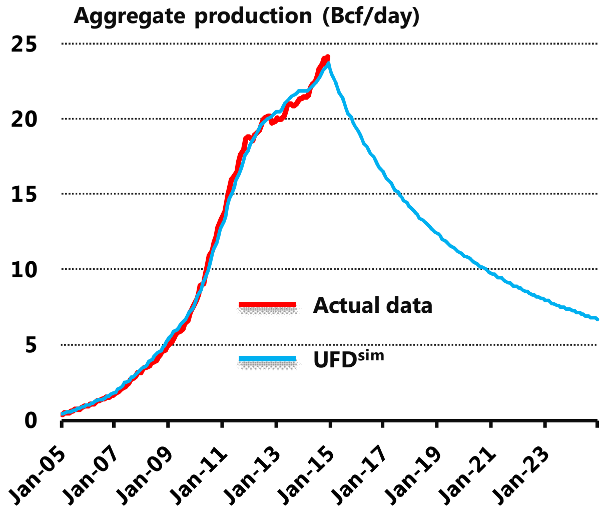
Comparisons between actual and simulated production from the three gas plays prove a remarkable history match (**Figure 9**). Quality control between calculated and actual EUR is also excellent for the three plays. The calibration method therefore appears extremely robust. To test the resilience of the existing portfolio, we have simulated a production decline over the 2015 to 2025 period assuming "*no development activity*" (i.e. no new wells brought into the portfolio). Global results can be summarized as follows (**Figure 9**):

- ✓ Barnett is a mature play with a large well portfolio (nearly 15000 wells in late 2014). It has gone through a production peak in 2012 but since then, despite a reduced activity, production slightly declined. In its state of development and current maturity, this play thus appears extremely resilient. Without any additional activity, its production would decline by less than 50% over the next ten years (2,58 Bcf/day in 2025 against 4,43 Bcf/day end 2014).

- ✓ Haynesville is also a mature play but following the collapse in oil prices in 2008 (subprime crisis), development was almost stopped. The well portfolio (3699 wells) was insufficient to maintain the production. Therefore, the production of Haynesville is much less resilient than that of Barnett's. Without any activity over the next ten years, the production, which is currently around 4 Bcf/day, will fall to zero by 2025. Haynesville clearly confirms the relevance of the first resilience factor (large well portfolio).

- ✓ In contrast to the mature Barnet and Haynesville, the Marcellus is still in ramp-up phase. The number of wells is substantial (6835 wells have been put on stream in late 2014) but still insufficient for the production to be resilient. Without any activity, the production will drop from 15 Bcf/day in late 2014 to 4 Bcf/day in 2025.

Consequently, the dramatic decrease in development activities pose more a risk to Marcellus (not mature enough) and Haynesville (development stopped too quickly) than to Barnett, which enjoys a much larger well portfolio.



Date	Decline
2015	0,19
2016	0,16
2017	0,15
2018	0,13
2019	0,11
2020	0,1
2021	0,1
2022	0,09
2023	0,09
2024	0,08

Figure 10 –Aggregate production Barnett+Haynesville+Marcellus 2005-20014. Decline curve "no activity"
*Data source: ITG and UFD^sim^*

The aggregate production of the three major gas plays shows once more an excellent history match between the actual data and those provided by the UFD^{sim} model (**Figure 10**). Without any development activity in early 2015, production would decline from 24.5 Bcf to 7 Bcf ten years later. The simulated decline curve features decline rates ranging from 20% in 2015 to less than 10% in 2025.

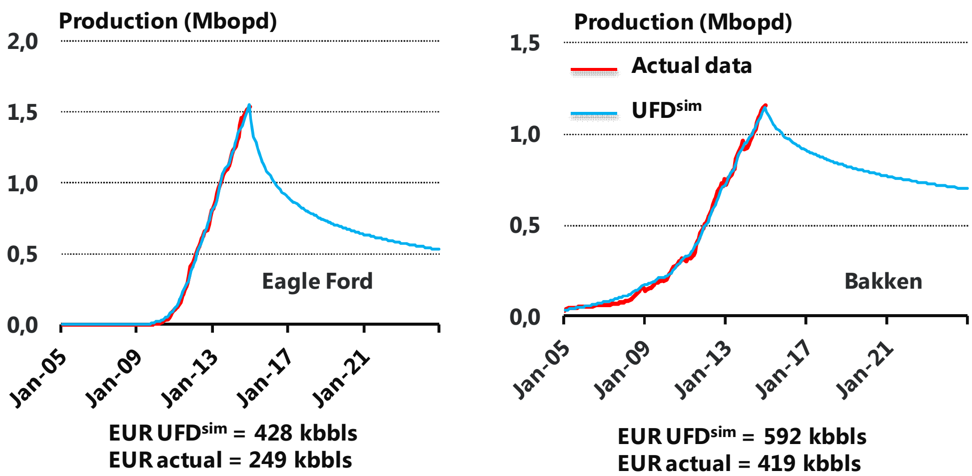
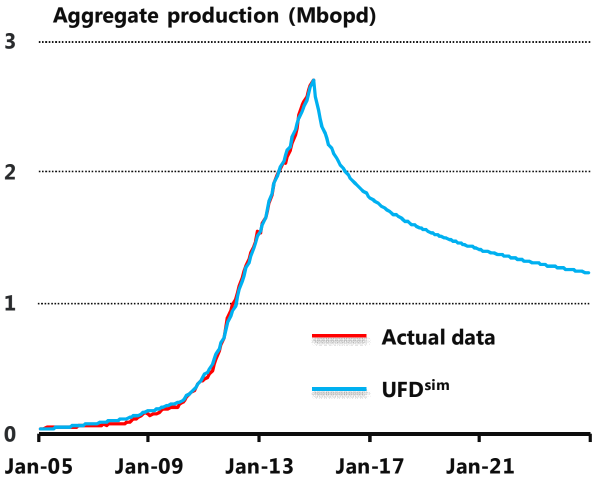


Figure 11 - History match 2005 - 2014 using UFD^{sim} for Eagle Ford and Bakken. Decline curve "no activity".
Data source: ITG & WoodMac databases and UFD^{sim}

The same exercise was performed for the two main oil plays: Bakken and Eagle Ford (**Figure 11**). Comparisons between actual and simulated productions prove again a very good history match for both oil plays. Quality control between calculated and actual EUR remains correct but is not as good as for the gas plays, particularly for the Eagle Ford. The simulations for the 2015-2025 period with "no wells" lead to a better resilience in the Bakken (12500 wells) than in the Eagle Ford (10164 wells). In ten years, the Bakken production declines by less than 50% whereas in the Eagle Ford production is divided by 3.



Date	Decline
2015	27%
2016	12%
2017	9%
2018	7%
2019	5%
2020	5%
2021	4%
2022	4%
2023	3%
2024	3%

Figure 12 - Aggregate production Bakken+Eagle Ford 2005-2014. Decline curve "no activity"
Data source: ITG and UFD^{sim}

Once again, an excellent history match is obtained for the aggregate production of the two plays (**Figure 12**). Without any development activity in early 2015, production would decline from 2,7 Mbopd to 1,2 Mbopd ten years later. The simulated decline curve highlights decline rates of between 27% in 2015 to 3% in 2025.

Conclusions

While the collapse of gas and oil prices had an immediate and dramatic effect on the level of activity, production proved to be very resilient. For instance, following the subprime crisis, the lower activity in the Barnett only started to have an impact on production four years later. In spite of a strong decrease in the number of rigs operating in gas plays after the price collapse in early 2012, the aggregated production of the three major gas plays (Barnett/Haynesville/Marcellus) continued to grow steadily and even at a higher rate. In 2015 a rig brings between 5 and 10 times more instantaneous production than it did in 2008.

This resilience can be explained by three main factors; a portfolio effect, improvements in operational performance, and progress in sweet spot identification and completion design. Regarding the portfolio effect, it is important to realize that the decline of a single well does not represent the decline of a large portfolio of wells put on stream at different maturities. As time passes, a growing portion of the global production comes from tail productions, which have lower decline rates and therefore tend to cushion the global decline.

Play by play analysis shows great heterogeneity of resilience between the mature Barnett, the insufficiently developed Haynesville and the immature Marcellus.

The resilience crash test (no new activity over the 2015-2025 period) indicates that the aggregated production of the three gas plays is fairly resilient, particularly over the first three years during which the decline rate remains above 15%. To strengthen the gas resilience of the US portfolio the development should be focused on the Haynesville and Marcellus which are less resilient than the Barnett.

Concerning oil plays, production histories lead to nearly identical conclusions. The Bakken is far more resilient than the Eagle Ford. With no new activity, the production of the Bakken only decreases by 50% in 10 years whereas over the same period the Eagle Ford decline reaches 70%. If the aggregate production of the two plays strongly declines during the first two years, production quickly becomes resilient with decline rates lower than 10% per year.

References

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APPENDIX

Production history matching

The data consist of the monthly production histories of five major unconventional US plays and the associated numbers of wells put on stream every month, provided by the ITG database over a period of 10 years. All wells in a given play are assumed to follow the same decline curve. This decline curve will be extracted from the data by matching production history.

Defining

t = month number starting at 1
s = month number varying from 1 to t
$f(t)$ = decline curve function assumed to be the same for all wells, with $f(t) = 0$ for $t < 1$
$n(s)$ = well connection schedule (number of wells put on stream in month s)
$Q(t)$ = area production in month t (monthly average of daily productions)
T = month of last known production and well connection

The production $Q(t)$ of a play is a sum of time-shifted decline curves

$$Q(t) = \sum_{s=1}^{t} n(s)\, f(t-s+1) \qquad \text{(Eq 1)}$$

Equation 1 expresses that the production in a given month t is the sum of the productions of the wells connected during previous months $s \le t$. The right-hand side of Equation 1 is a convolution product of the functions n and f, and a completely general f could be obtained by deconvolution. That method, however, produces unstable results. Instead, a parametric form is assumed for the decline function, for example

Power-law	$f(t) = A\, t^{\alpha}$	two parameters: A and α
Arps	$f(t) = q_0 \left(\dfrac{1}{1+bDt}\right)^{1/b}$	three parameters: q_0, b, D

The parameters of the estimated decline function $\hat{f}$ are selected to minimize

$$\sum_{t=1}^{T} \left(Q(t) - \sum_{s=1}^{t} n(s)\, \hat{f}(t-s+1) \right)^2$$

Figure 13 displays the Barnett gas production over 10 years and its best fit by a power-law decline curve. It is truly remarkable that such a good match of a 120 points curve can be obtained with just two parameters, leaving 118 degrees of freedom, an indication that the model is robust. The green curve is the fitted power-law decline curve, and, plotted for comparison in brown, the fitted Arps decline curve which is seen to be quite similar.

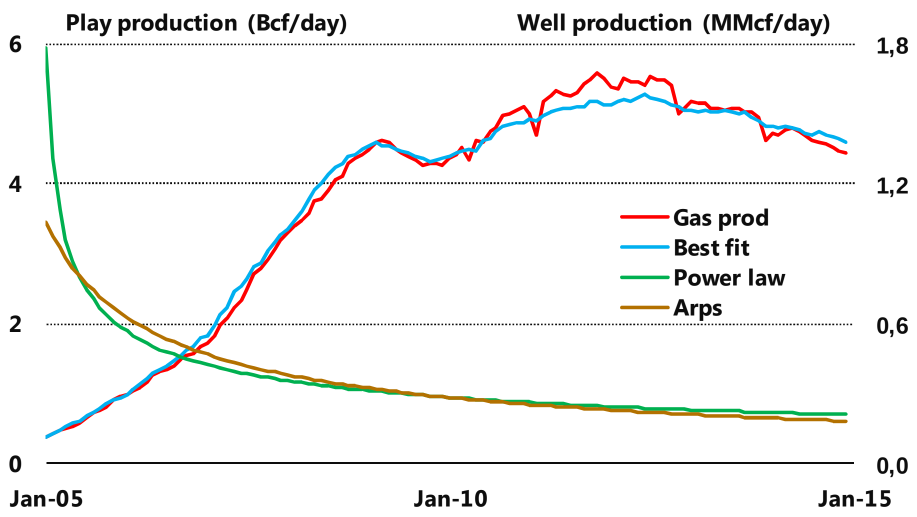

Figure 13 – History matched Barnett gas production and power-law and Arps decline curves fitted by Least Squares

It must be emphasized that these fitted decline curves are not meant to predict the production of the next well (which should be higher). They are statistical averages, representative of a large portfolio of wells, namely

Barnett : 14788, Marcellus : 6835, Haynesville : 3700, Bakken :10164, Eagle Ford : 12499

Extrapolation
History matching looks at the past. Looking to the future, two questions arise:

1. What would be the production if the play was left to decline without any new well?
2. What well connection schedule is required to maintain the production at a given plateau?

In this paper, for ease of presentation, the critical well connection schedule is referred to as the "*critical activity*", or "*critical drilling*", or "*critical rig count*", but the actual controlling factor is the well connection schedule.

If no new well is put on stream after month T the production of the play is equal to

$$Q_T(t) = \sum_{s=1}^{T} n(s)\ f(t-s+1) \qquad \text{(Eq 2)}$$

and an estimate for $t > T$ is obtained by simply plugging the decline function estimate $\hat{f}$ in **Equation 2**.

If new wells are connected in month $t > T$ the production of the play is the sum of $Q_T(t)$ and of the production of wells put on stream in months $s > T$

$$Q(t) = Q_T(t) + \sum_{s=T+1}^{t} k(s)\ f(t-s+1) \qquad \text{(Eq 3)}$$

A plateau starting at the last known production $Q_T = Q_T(T)$ is achieved when $k(t)$ is selected such that

$$k(T+1) = \frac{1}{f(1)}\ [Q_T - Q_T(T+1)] \qquad\qquad t = T+1 \qquad\qquad \text{(Eq. 4)}$$

$$k(t) = \frac{1}{f(1)} \left(Q_T - Q_T(t) - \sum_{s=T+1}^{t-1} k(s)\ f(t-s+1) \right) \qquad t > T+1 \qquad\qquad \text{(Eq. 5)}$$

These *k* values are not integers and should in principle be rounded. If so the plateau will show small fluctuations.

Figure 14 shows a 10-year extrapolation of the gas production in the Barnett in the no drilling and in the plateau cases (red curves). The green curve is a well connection schedule curve (= critical activity). In the plateau case it indicates that about 50 wells per month are required to maintain a plateau at 4.6 Bcf/day.

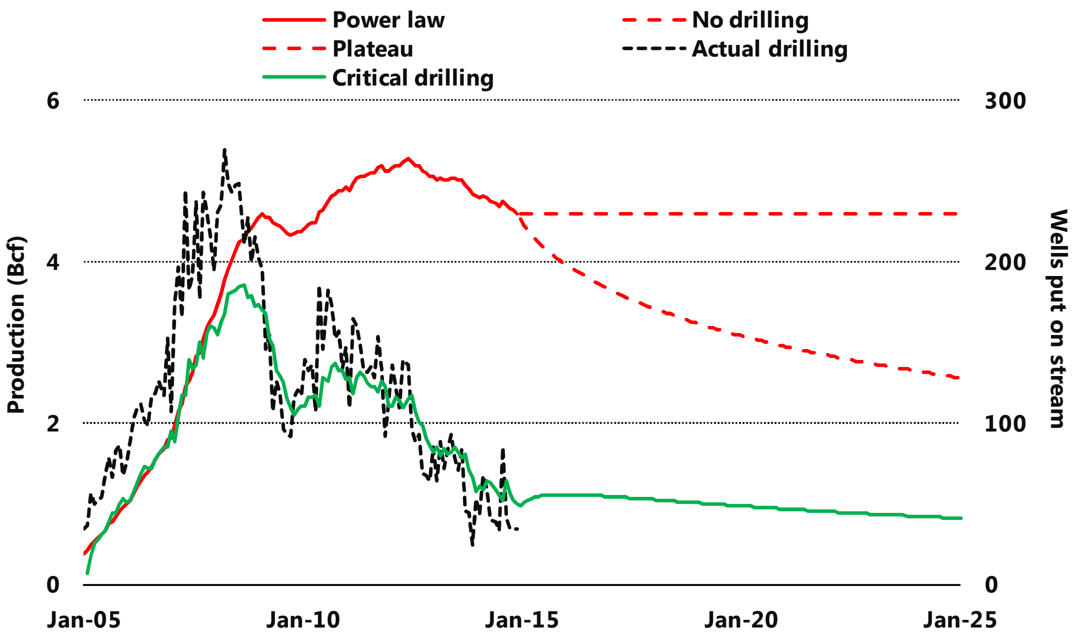

Figure 14 – Gas production extrapolations in the Barnett and critical number of wells to be put on stream to maintain a 4.6 Bcf/day plateau (green curve right of Jan-15).
Left of Jan-15: From Jan-05 to Feb-09: Actual drilling > Critical drilling, so production increases
From Mar-09 to Oct-09: Actual drilling < Critical drilling, so production decreases

Left of Jan-15 the green curve also represents a critical activity value. If the number of wells put on stream (blue curve) exceeds the critical value the production goes up, if it is below the production goes down, and if it is equal the production stays the same. The formula for that critical activity is

$$k(t) = n(t) + \left[Q(t-1) - Q(t) \right] / f(1) \qquad t \le T$$