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The US Shale Gas "Revolution": A Review of the Production Performance and Geology to Establish Potential Economic Benchmarks for Australia

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Abstract

Shale plays have created the current natural gas boom in the United States (US) and according to the national Energy Information Administration (EIA, 2013)[49] produced 47% of total daily production by the end of 2013 (approximately 31.8 Bscf/d). Extensive production data from thousands of wells are now available for analysis to provide potential benchmark information for the Australian shale gas industry, which is still in its infancy.

This paper focusses on analysis of publicly available US production data from horizontal wells in five depositional basins reported for the Barnett, Eagle Ford, Fayetteville, and Haynesville shale plays. Type-wells are evaluated which allow estimation of a range of representative initial gas production rate and technical Estimated Ultimate Recovery (EUR) characteristics. The analysis also results in generic recommendations for the minimum sample size and duration required for statistically significant well appraisal programs in shale plays. Such activity phases' primary objective should be to efficiently obtain reasonably reliable type-well performance indicators. The US shale plays' experiences to date provide insight concerning this aspect.

Variability in geological factors including, but not limited to: stress regime, total organic content, thermal maturity, porosity, brittleness, natural fractures, and reservoir pressure can result in production performance that differs substantially both within and between shale plays. Also affecting performance is how the wells are completed. The geology of shale formations is discussed along with recent Australian operational activity, geomechanical considerations, and example economics. Analyses of the US data provide potential technical and economic benchmarks for preliminary comparisons to be made with Australian information, and may help to demonstrate the economic resilience required for exploitation of prospective shale gas resources.

However, it must be recognised that the likely performance characteristics of the prospective Australian shale plays' type-wells are not currently well understood due to lack of data. Significant exploration and appraisal activity is needed to augment the extremely limited shale gas well performance data available in Australia to date.

Introduction

The focus of this paper is on shale gas wells' historical performance, based on the now extensive data available in the public domain concerning production from a number of such unconventional resources plays in the US. The historical production data exhibit very large variations in well performance, both in terms of initial production rates and subsequent declines. These characteristics present significant problems to operating and partner companies interested in developing and potentially commercialising such assets particularly due to the magnitude of the investments involved, the low rates and potentially longterm nature of production, and the inherent technical and economic uncertainties. The volume and nature of well data related to exploration, appraisal, and potential development of such plays lend themselves to the application of probabilistic methods (Dobson et al., 2011)[15].

Fracture stimulation technology may be one of the most important innovations in any industry in the modern era. Although not an especially new technology within the energy industry, relatively recent and large-scale application of "fracking" to unconventional reservoirs in the US has enabled the extraction of previously inaccessible petroleum from rocks including shale formations. In the past decade or so, this US shale gas "revolution" has transformed the country's energy outlook. It has ended domestic decline in petroleum production that had been occurring for decades, and reduced natural gas prices by approximately two-thirds from their 2008 peak, at the time of writing this paper.

Per the SPE-PRMS standard (SPE, 2007)[42] definitions: unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centred gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialised extraction technology. CBM is usually referred to as coal seam gas (CSG) in Australia.

US operating and partner companies developing and commercialising gas production from petroleum deposits, including unconventional reservoirs, are subject to regulatory production reporting requirements. These include public domain data that offer operating and partner companies in the US and elsewhere in the world the opportunity of understanding a number of conclusions that may be interpreted from their analysis. This paper seeks to evaluate the production data from a number of relatively mature US shale gas plays, highlight a number of empirical observations, and derive some key conclusions in the context of emerging interest in such prospective plays in Australia.

Data

Public Domain Production Database

The production data used as the basis for the analysis presented in this paper comprises public domain information from a commercial vendor. The primary focus of the database is historical oil and gas production data along with drilling permit data, transportation data, gas plant and refinery data, and pricing data. The data employed for analysis focused on five shale plays in the United States (Figure 1):

1. Barnett (Fort Worth Basin):	14,703 active gas wells at March 2014
2. Eagle Ford (Texas & Louisiana Gulf Coast Basin):	2,722 active gas wells at March 2014
3. Fayetteville (Arkoma Basin):	4,780 active gas wells at February 2014
4. Haynesville (Arkla Basin):	2,119 active gas wells at March 2014, and
5. Haynesville (East Texas Basin):	929 active gas wells at March 2014

The public domain production data consists of monthly line-item records for each well, including up to 120 parameters per record. Of these, a subset of database parameters was used directly in this study.

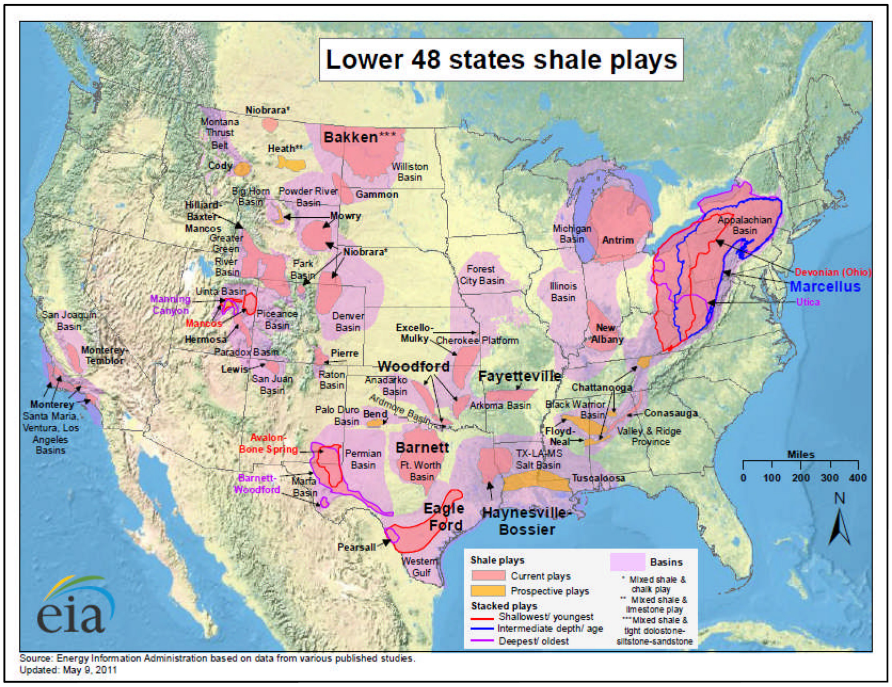

Figure 1—US shale plays map including the five basins studied in this paper (Source: EIA, 2011).

In order to select relevant records a number of parameter filters were applied. A reservoir descriptor parameter was used to include any record containing the primary name of the shale (per the above list) including acceptance of any records with clearly related typo in the record for this parameter. For the above listed shale plays, a basin specification (in brackets) was also applied to select the major geological subset within each shale reservoir. Only records with the production type descriptor denoting gas wells were selected.

For those records satisfying these criteria, the historically increasing number of wells for each of the five geological shale plays studied is illustrated in Figure 2. At the time of the database extractions, reported public domain production data up to and including March 2014 was available. Within these data, the earliest significant application of horizontal wells occurred in the Barnett from approximately year 2004, onwards. It is recognised by the authors that well completions' technology improvements are likely to have been evolving since this time.

In addition to the parameters used for analysis that were taken directly from the public domain database, three additional parameters of interest were defined. The latter were derived from the original database parameters for each well, and were calculated for each monthly data record line-item:

1. Number of months online, an integer number from the first month of reported production
2. Monthly average gas rate derived from the monthly database records of produced gas volume
3. Perforation interval length, being the difference between the upper and lower perforation depth parameters contained in the monthly well records

Methodology

Unconventional Rate Decline Approach

The basis for the shale gas production performance analysis presented in this paper follows the analytical approach described by Duong (2010)[16]. This author's work describes an unconventional rate decline approach for tight and fracture dominated gas wells. The author contends that traditional decline methods such as Arps' rate-time relations and their variations are not applicable to super-tight or shale gas

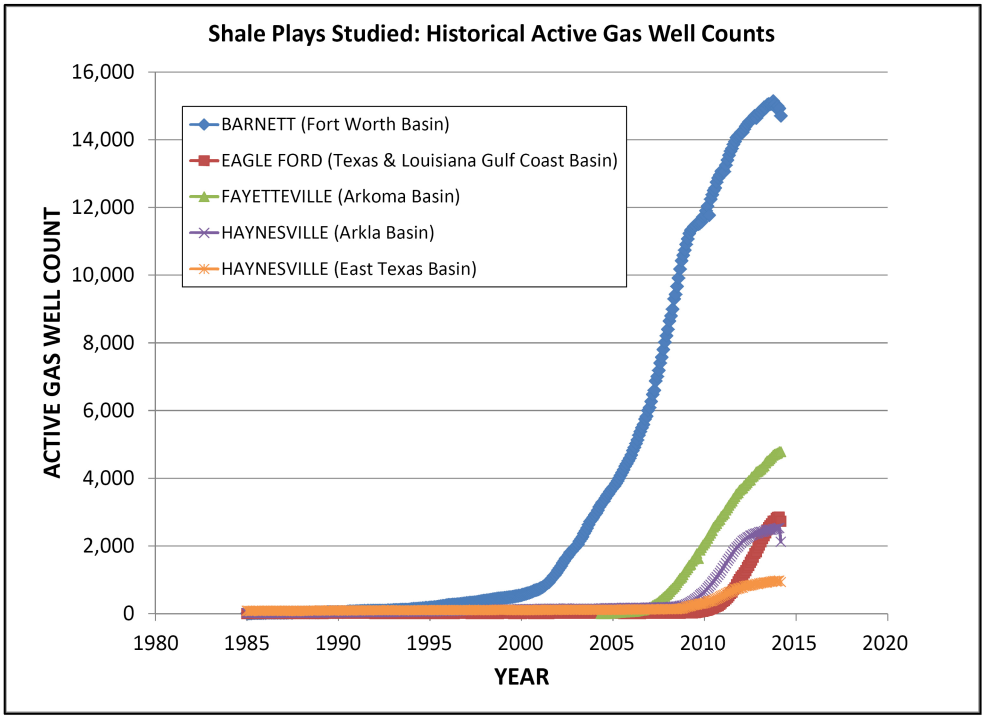

Figure 2—Active shale gas well numbers in the five plays studied – as at end of March 2014.

wells where fracture flow is dominant. In addition, that most of the production data from such wells exhibit fracture dominated flow regimes and rarely reach late-time flow regimes even over several years of production.

Joshi et al. (2013)[25] also observed that traditional Decline Curve Analysis (DCA) methods in use in the industry, particularly Arps' decline model, were originally developed for wells in Boundary Dominated Flow (BDF) regimes. Their proposed revisions to the Duong model are intended to provide better fits to data in BDF. As an example, Joshi et al. cite a figure illustrating different flow regimes in a typical horizontal well in shale with mutli-stage fractures. The BDF regime is depicted after approximately 1,000 months of production. The analysis presented in this paper has not made the same assumption for production forecasting since none of the data available in the shale plays studied herein extend to such long durations. Instead, a new basis for modified fracture dominated flow is presented later in this paper.

Duong (2010)[16] presents the derivation of mathematical equations governing the flow in fracture dominated flow situations. A number of diagnostic plots are used to derive dimensionless time parameters for (analytical, as opposed to numerical simulation) history matching of individual well performance. The parameters derived from the history matching process may then be used for extrapolating forecasts.

The Duong analytical plots and procedures have been applied in the analysis presented here, but not to individual wells' data. Instead, type-wells representing average (i.e. statistical Mean or Expectation) well performance from large subsets within the public domain database were initially derived and then interpreted using the Duong method. One of the benefits of this approach is that the inherent "noise" in the individual wells performance histories is reduced by the averaging process. This, in turn, facilitates more reliable history matching and forecasting extrapolation as described later in this paper.

An initial example is presented below using the public domain database extraction for the Barnett (Fort Worth Basin) shale gas wells described above. A subset comprising a sample of all of the horizontal wells satisfying the previously described data criteria from the public domain database yielded 13,752 (active and inactive) horizontal wells with production data records up to and including March 2014.

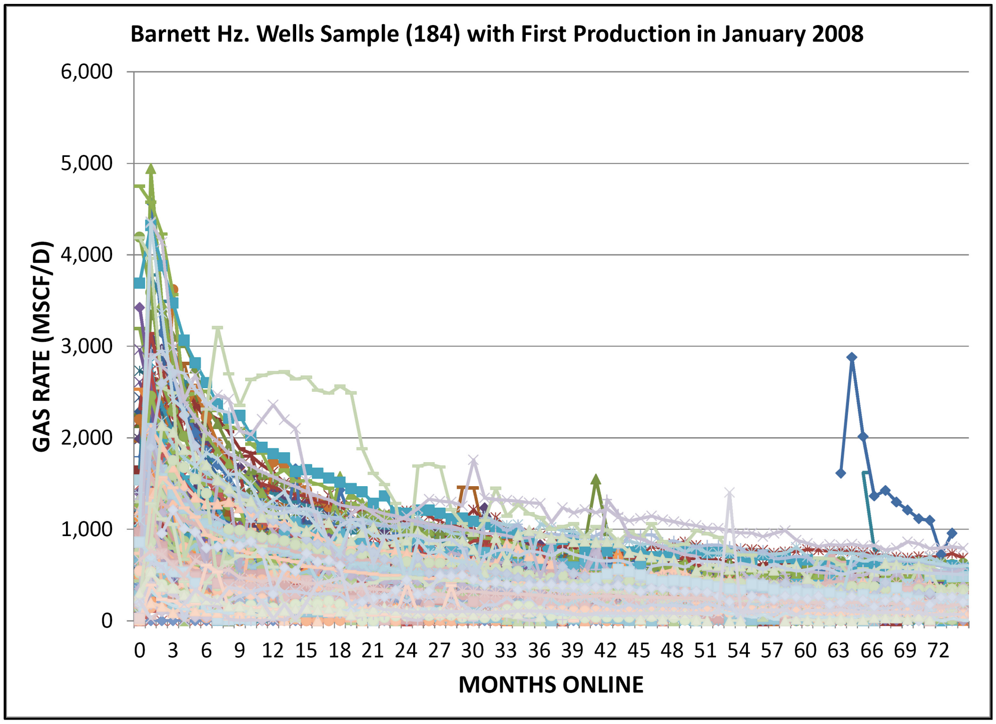

Figure 3—Example of horizontal wells' shale gas production data.

The production rate histories can be plotted against the number of months online for each well. Figure 3 shows a sub-set example of those 184 Barnett horizontal gas wells that had first production in January 2008, of the 13,752 total cited above. This example figure serves to illustrate the very large variation in initial rates and subsequent decline performance inherent in the overall sample, and the general "noise" in the raw data. Also evident in the plot is a late time example of potential operational activity. One of the well's production data (to the right hand side of Figure 3) appears to re-commence after 63 months online at a relatively high rate. This may be indicative of operational disturbance in the data e.g. well work-over or re-stimulation, but no information pertaining to such events is available in the database. However, the latter must be borne in mind during the later analysis presented herein.

Analytical plots were generated that included sample sizes of any selected number of wells, according to specified filter criteria using the available database parameters. The histogram in Figure 4 shows the distribution of monthly average gas rates for the first full calendar month of production for the entire Barnett sample of 13,752 horizontal wells. Again, the very large variation in well performance is illustrated by the "Month 1" rate distribution. The figure shows that the "Month 1" rates are approximately log-normally distributed.

It should be noted that "Month 1" as referred to in this paper is defined as the first full calendar month of production from any particular well. This is because during "Month 0" (i.e. the month in which production commences) start-up may occur at any time during that month. Monthly average gas rates derived for "Month 0" by averaging the produced monthly volume database records by the total number of days in that month are therefore not representative indicators of initial well productivity.

Type-Well Estimation

Continuing the analysis using the entire 13,752 horizontal wells sample from the Barnett (Fort Worth Basin) shale, the wells' average gas rate history may be calculated. The average "Month 1" gas rate of the histogram as shown in Figure 4 is 1.688 MMscf/d. Such an average may be calculated for each of the months online for the sample. The plot of the average gas rate for each month online comprises the wells' average gas rate history for the sample and is illustrated in Figure 5.

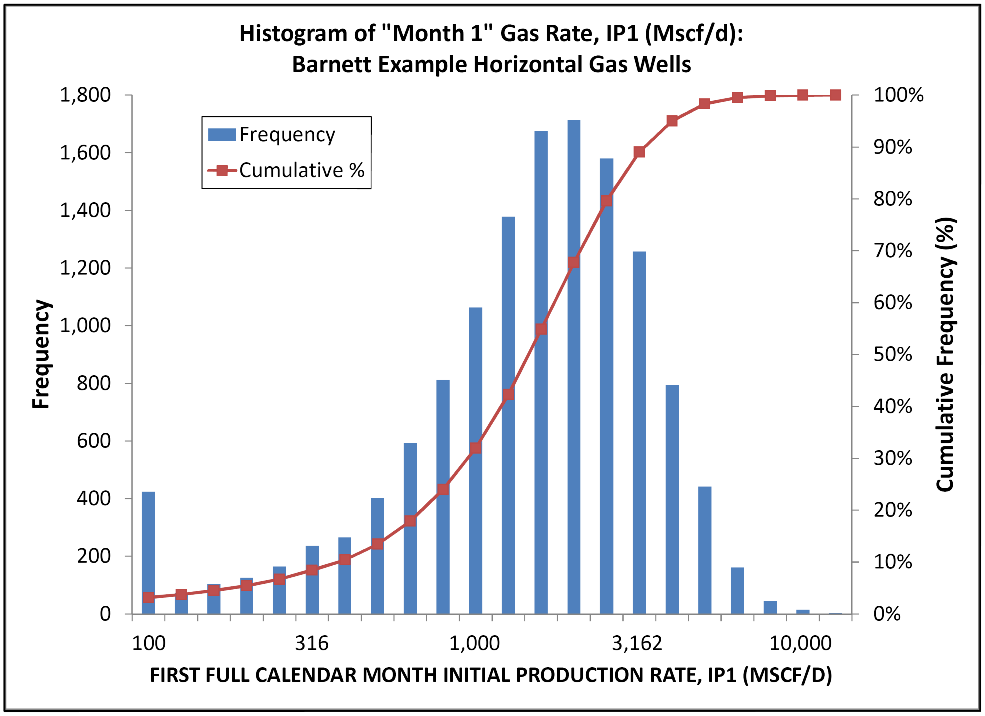

Figure 4—Barnett example distribution of first full calendar month gas production rates – all horizontal wells to March 2014.

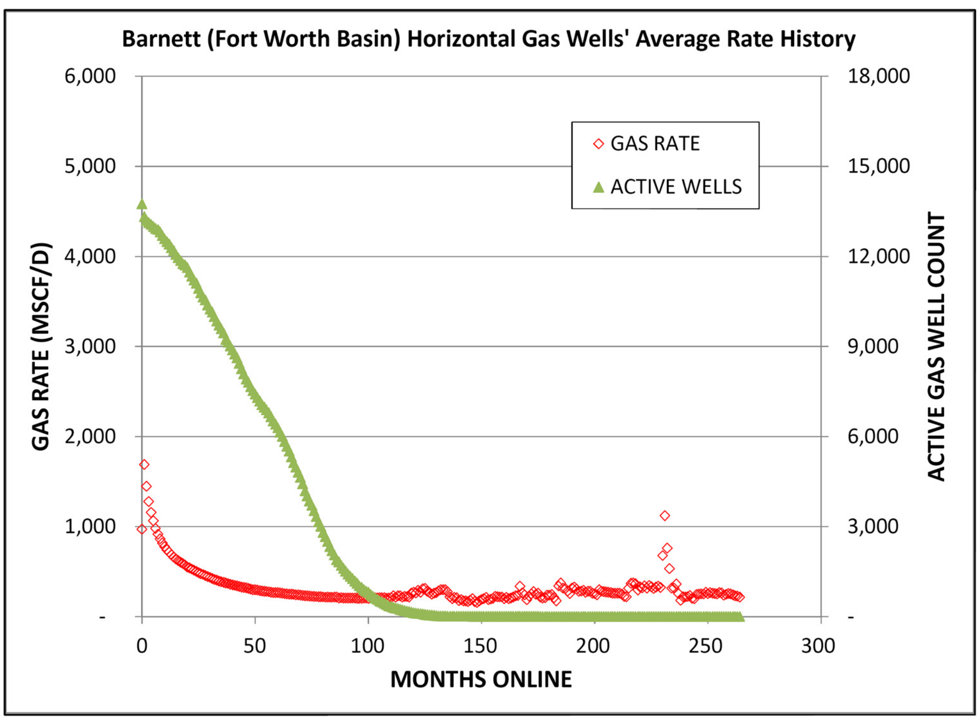

Figure 5—Barnett example average gas rates history – all horizontal wells to March 2014.

The latter plot further serves to illustrate the approximately log-normal distribution in the underlying monthly gas rate for any particular month online. The wells' average gas rate history in Figure 5 is skewed to the low side of the individual wells' distribution when compared to the Figure 3 population subset example. Figure 5 also shows that the late time tail of the wells' average gas rate history is relatively "noisy". This is due to the very small number of wells, with very long production histories, that are being

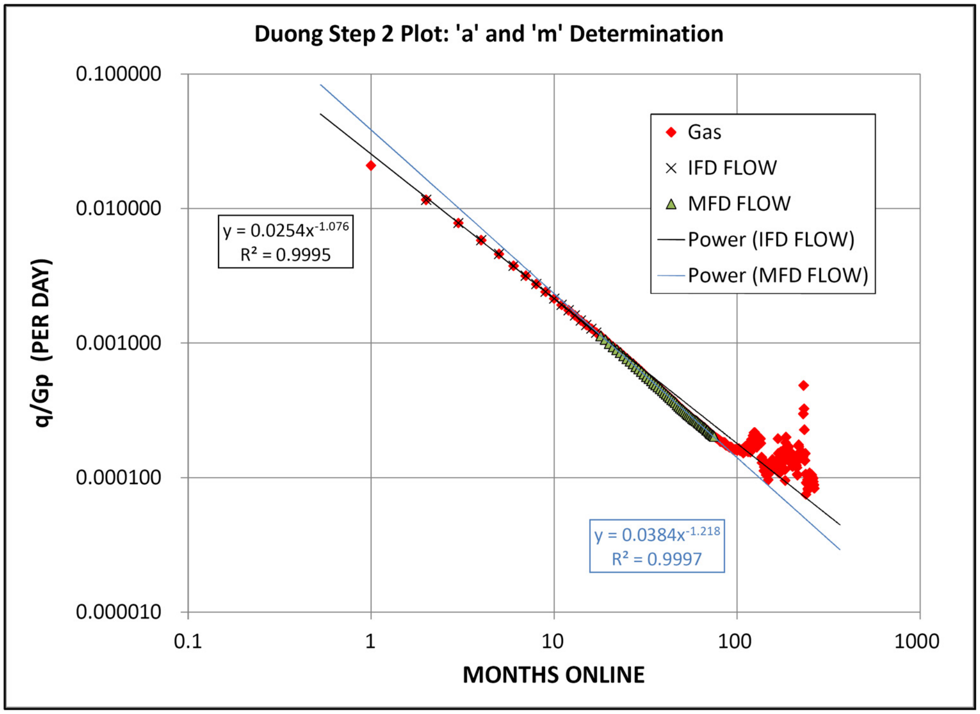

Figure 6—Barnett example: fracture dominated flow diagnostic plot – after Duong (2010)[16].

averaged in the late time tail. This aspect may also exaggerate the impact of potential operational disturbance effects mentioned above for some type-well samples.

Type-well estimation is based upon the wells' average gas rate history, but must eliminate statistical and operational effects in the data that are unrepresentative of a truly typical well's production performance characteristics. Consideration of the "sample tail" effect in the context of history matching and subsequent forecast extrapolation is discussed further below.

Type-Well History Matching

As referred to by Duong (2010)[16] the author's "*Step 2: 'a' & 'm' Determination*" plot, applied to the average gas rate history using the above entire sample of 13,752 horizontal wells, is illustrated in Figure 6. The figure comprises a plot of gas production rate divided by cumulative gas production (q/Gp) versus time for the average gas rate history of the sample.

According to Duong, the data in this "Step 2" plot typically forms a straight line with a slope (m) and an intercept (a) for fracture dominated gas wells. The three field application examples illustrated in the Duong paper consist of individual well plots with daily data of up to approximately 2,000 days in duration. In contrast, the type-well data in Figure 6 consists of monthly data, which is significantly less "noisy" than the daily data, and continues for a longer duration i.e. up to 264 months (approximately 8,000 days).

The initial data (approximately the first 17 monthly points) shown in Figure 6 plots on the unit slope described by Duong. Thereafter, it is observed that the slope changes subtly to a higher value. Duong attributes this latter type of response to "*any deviations from the ideal cases*". The equations formulated by Duong, for which the "Step 2" plot is a diagnostic tool, are predicated on the assumption of fracture dominated flow regimes (either linear or bilinear). The deviation from the unity slope therefore suggests a time-dependent modification of the inherent flow regime associated with the example type-well performance. This "Step 2" plot observation, related to flow regime modification, is consistently observed in all of the type-well analyses conducted by the authors, as summarised in this paper.

This observation is further illustrated by Figure 7 which shows the Duong "*Step 3: q1 Determination*" diagnostic plot for the above type-well example. The "Step 3" plot consists of a chart of gas rate (q) versus

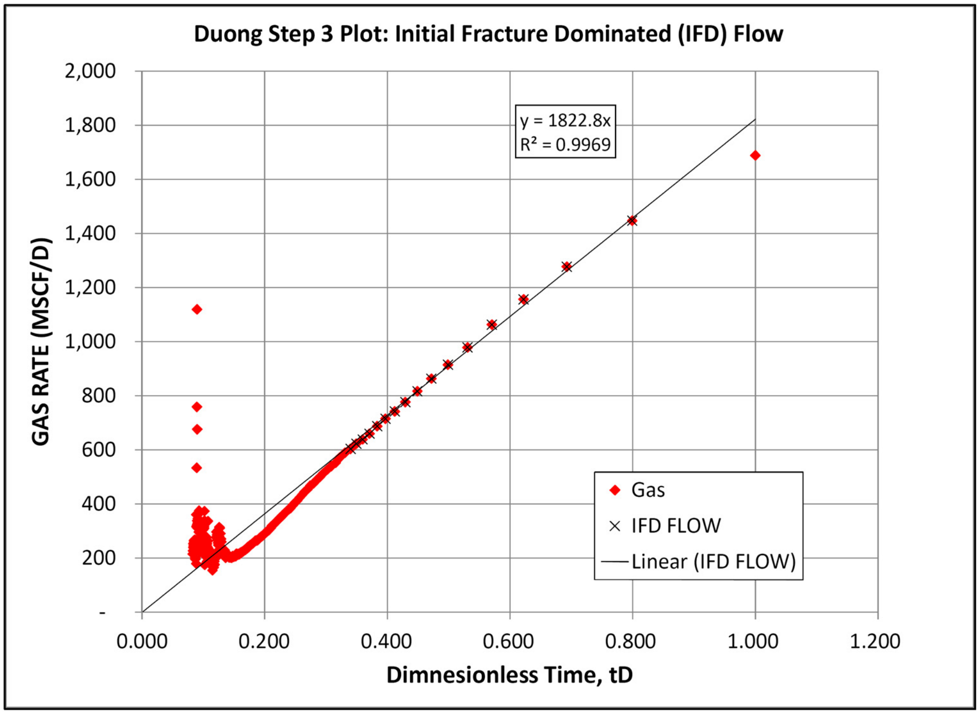

Figure 7—Barnett example "Initial Fracture Dominated" (IFD) flow plot – after Duong (2010)[16].

a dimensionless time parameter (tD) which is a function of the parameters derived from Figure 6 (i.e. the a and m coefficients). According to Duong, and if the underpinning equations apply, the data in this "Step 3" plot should give a straight line through the origin with a slope (q1). Again it is observed that the type-well example in this figure does exhibit this characteristic, but only for approximately the 17 months or so. This early flow regime is herein referred to as "Initial Fracture Dominated" (IFD) flow. Thereafter, the observed subtle deviation from the initial trend is again apparent. (More generally, the evaluations conducted in this paper indicated that the noted deviation usually occurred between one to two years after the start-up of type-well production).

Duong summarises the unconventional rate decline approach for tight and fracture dominated gas wells as follows:

> "*An alternative approach is proposed to estimate EUR from wells where fracture flow is dominant and matrix contribution is negligible. To support these fracture flows, the connected fracture density of the fractured area must increase over time. This increase is possible due to local stress changes under fracture depletion. Pressure depletion within fracture networks would reactivate the existing faults or fractures, which may breach the hydraulic integrity of the shale that seals these features. If these faults or fractures are reactivated, their permeabilities will increase, facilitating enhanced fluid migration.*"

The implication is clear, that geomechanics play an important role in the longer term flow regime performance in shale gas wells. Similar observations have been made by Gupta et al. (2012)[22] in studies indicating a connection between reservoir depletion behaviour and the spatial and temporal distribution of in-situ stresses.

Furthermore, it should be possible to test Duong's suggestion of a continuation of longer term fracture dominated flow, albeit in a modified form. If the slope and intercept of the later time trend exhibited in the "Step 2" plot in Figure 6 is used as the basis for the dimensionless time function (tD) then the "Step 3" plot may be reconfigured as shown in Figure 8. The late time data is also now observed to lie on a straight line through the origin. This suggests that Duong's underpinning fracture dominated equations

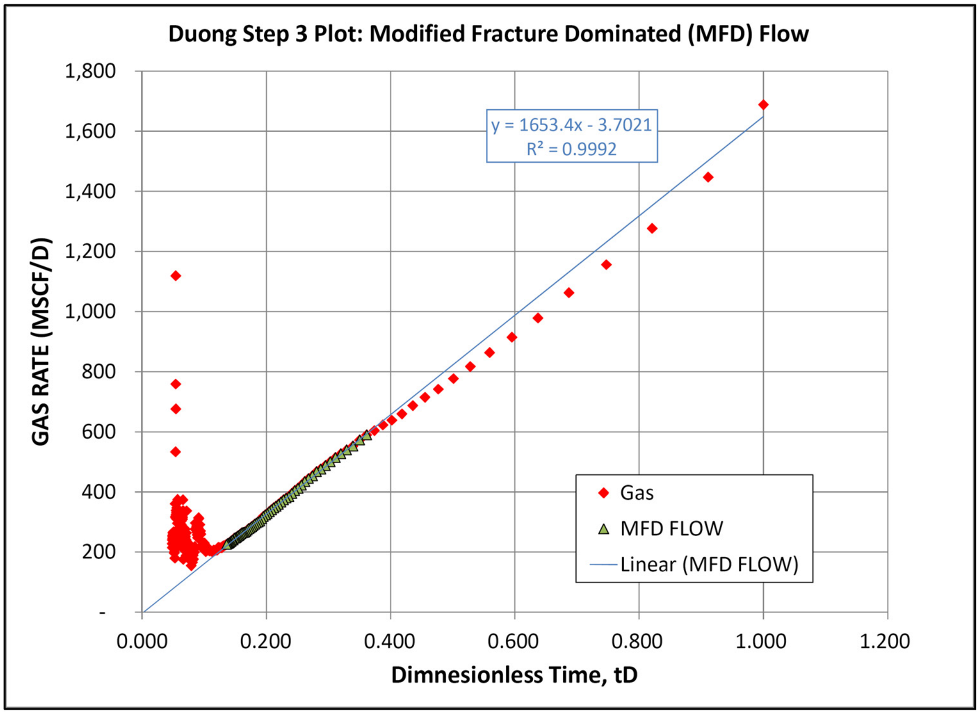

Figure 8—Barnett example "Modified Fracture Dominated" (MFD) flow plot – after Duong (2010)[16].

still apply although in some configuration that may have been modified by the local stress changes induced by early fracture depletion, as cited above by the author. This later flow regime is herein referred to as "Modified Fracture Dominated" (MFD) flow.

Reverting to the real time domain (as opposed to the dimensionless time domain (tD) in Figures 7 and 8) the two-stage history match produced by the Duong diagnostic plots is illustrated in Figure 9. It is observed that a close history match is achieved for the representative type-well history. However, the history match breaks down at the tail-end of the type-well data. This is due to the decreasing number of active wells contributing to the average gas rate history in the tail. Relatively few wells in the sample, that have been averaged to describe the type-well, have been producing for very long periods. There comes a point at which the number of wells being averaged is no longer representative of the sample as a whole.

This non-representative "sample tail" effect (which can be seen in each of Figures 5 to 9, inclusive) must therefore be ignored in the history matching process. In addition to statistical significance effects, the sample tail noise may also be indicative of operational disturbance in the data e.g. well work-over or re-stimulation. No information pertaining to such events is available in the production database. However, consistent techniques have been devised to identify the onset of the nonrepresentative "sample tail" effect and have been applied in the subsequent analysis results presented in this paper.

It is recognised by the authors that subsequent modification to type-well flow regime is possible. This could result from further geomechanical effects or well/reservoir boundary effects, etc. However, as illustrated by Figures 5 and 9, the total number of horizontal wells in the Barnett (Fort Worth Basin) shale example with production duration in excess of approximately 110 months is extremely small. Those few such wells that are available may not be a statistically significant representation of type-well performance. Furthermore, the variability in the average gas rate history data that do extend beyond 110 months duration is much greater. The authors therefore contend that interpretation of very late time flow regime effects is extremely challenging and somewhat speculative based on the US shale production histories available to date.

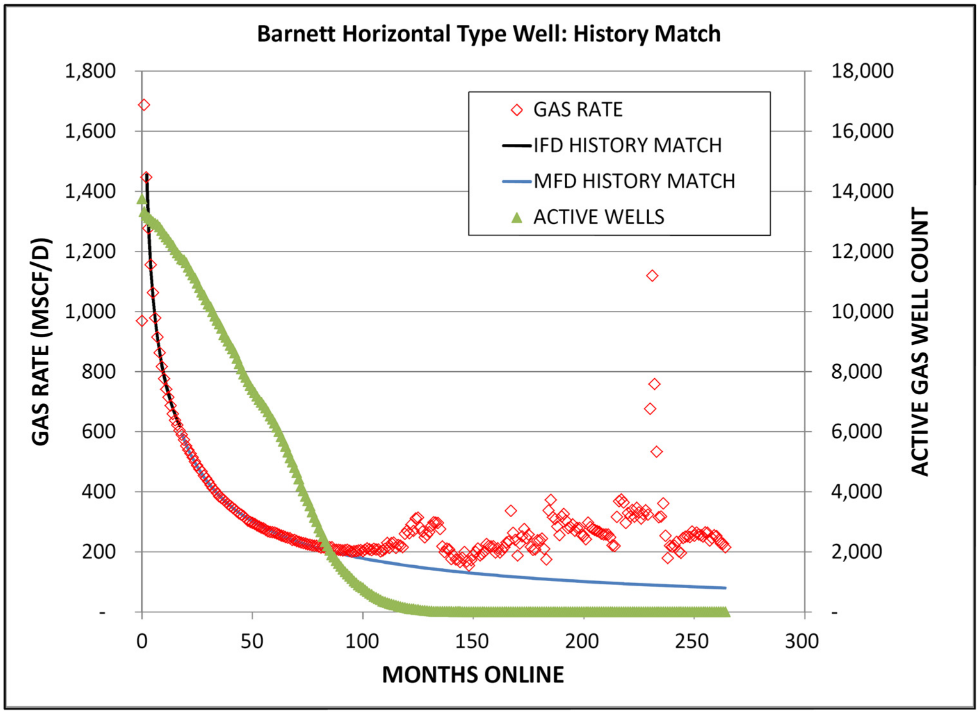

Figure 9—Barnett horizontal type-well example history match.

Type-Well Forecasting

A technical EUR forecast for the example type-well can be generated by extrapolating the history matched decline performance for a long period. The period selected consistently in the analysis presented in this paper was up to a total time of 1,000 months (over 83 years). This facilitates a presentation of the production forecast and associated cumulative recovery in the form shown in Figure 10 for the Barnett example horizontal type-well.

It must be recognised that wherever EURs are quoted herein they refer to these very long term (1,000 months) technical estimates. Commercial constraints will, in reality, likely curtail economic ultimate recovery. Some of the pertinent factors related to this aspect are discussed further in the economics considerations section later in this paper. Example economic sensitivities that might be applicable to curtail the technical EURs are also described in overview later.

Type-well forecasts were evaluated for the five US shale plays listed above, and analysed for a number of factors potentially affecting technical EUR for horizontal wells, including: geological area, operator, production start-up year, perforation interval length, well sample size, and production data duration. The overall effect of well trajectory was also considered, but since the majority of the recent activity and productivity benefits have been realised by horizontal wells in the US shale plays studied, the analysis and results focus on the latter well configurations.

Results

The following description of results concentrates initially on the Barnett (Fort Worth Basin) shale play since this comprised the largest extracted dataset in this study. It is used to illustrate an example of each of the analyses conducted for it as well as the other four US shale plays that were studied. A comparison of the main results between all five shale plays is then also summarised.

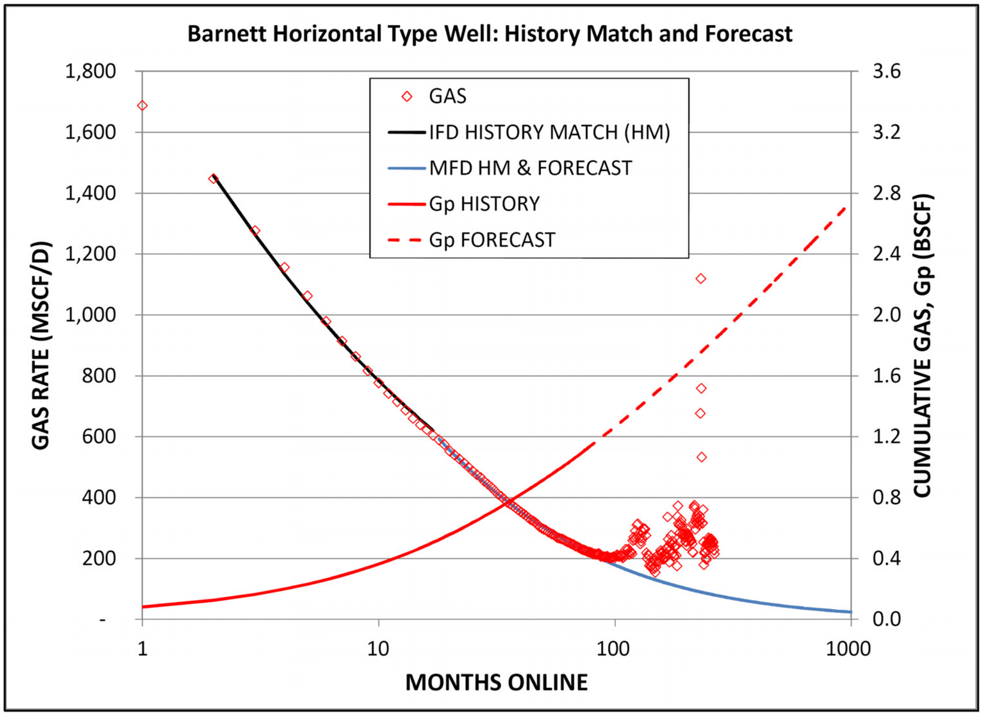

Figure 10—Barnett horizontal type-well example history match and forecast.

Type-Well Assessment by Well Trajectory

Well trajectory identifiers are included in the public domain data in the drill type descriptor parameter. The identifiers included allowed distinguishing between essentially vertical and horizontal well configurations, as reported by the operating companies.

The results of the type-well history matching and forecasting for all historical wells comprising these two categories of well trajectory in the Barnett (Fort Worth Basin) shale play are shown in Figure 11.

The results indicate that the initial gas rate for the horizontal type-well (1.69 MMscf/d) is approximately 2.7 times the vertical type-well (0.63 MMscf/d). Similarly, the technical EUR for the horizontal type-well (2.75 Bscf) is approximately 1.5 times the vertical type-well (1.81 Bscf). However, these technical EURs should be subject to Economic Limit Testing (ELT) which may significantly change the relative economic and/or commercial recovery potentials of the example type-well configurations. These examples are discussed further in the economics discussion, later.

Horizontal Type-Well Assessment by Geological Area (County)

State sub-area identifiers are included in the US public domain database in the county descriptor parameter. The county name identifiers served as a convenient proxy for geological area variation assessment for the purposes of this analysis. Horizontal gas well samples originating from six different counties (including the majority of wells in this basin's dataset) were averaged to generate representative type-wells for each. These were then evaluated using the history matching and forecasting techniques described above.

The results of the type-well analyses for these six county areas in the Barnett (Fort Worth Basin) shale play are shown in Figure 12. The results plotted in this, and subsequent similar figures, comprise type-well technical EUR versus the type-well average monthly gas rate for the first full calendar month of production. The results indicated significant inherent variation of horizontal type-well performance by geological area. Also shown for comparison is the type-well result for all horizontal wells. Since the number of well samples comprising the type-well in each area is different, the type-well result for all horizontal wells represents a weighted average.

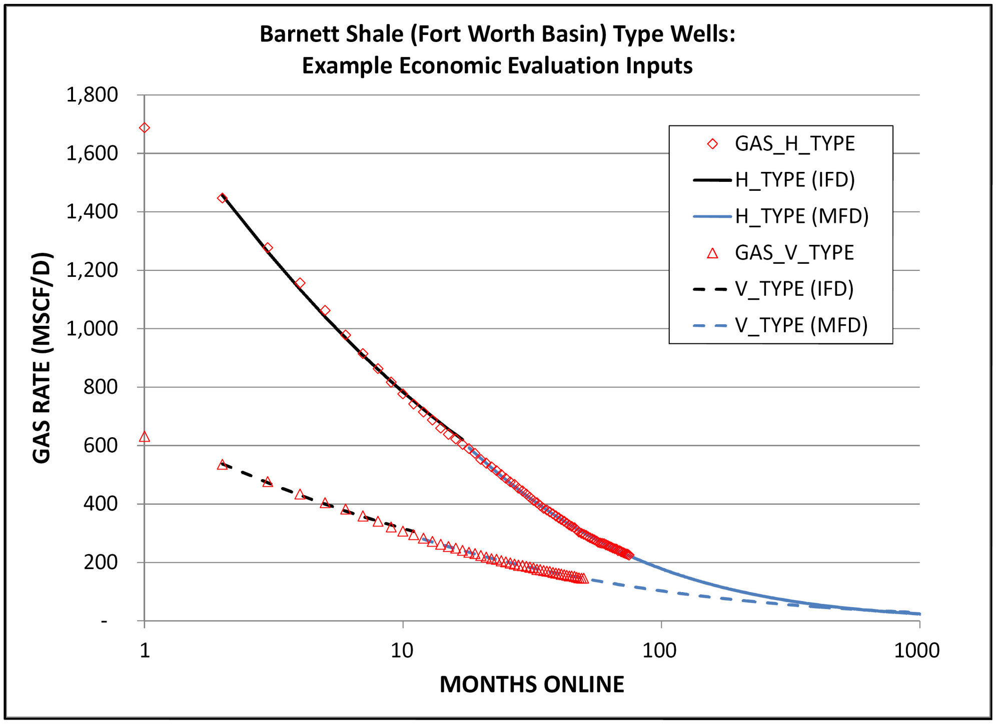

Figure 11—Barnett example type-wells' history match and forecast – well trajectory.

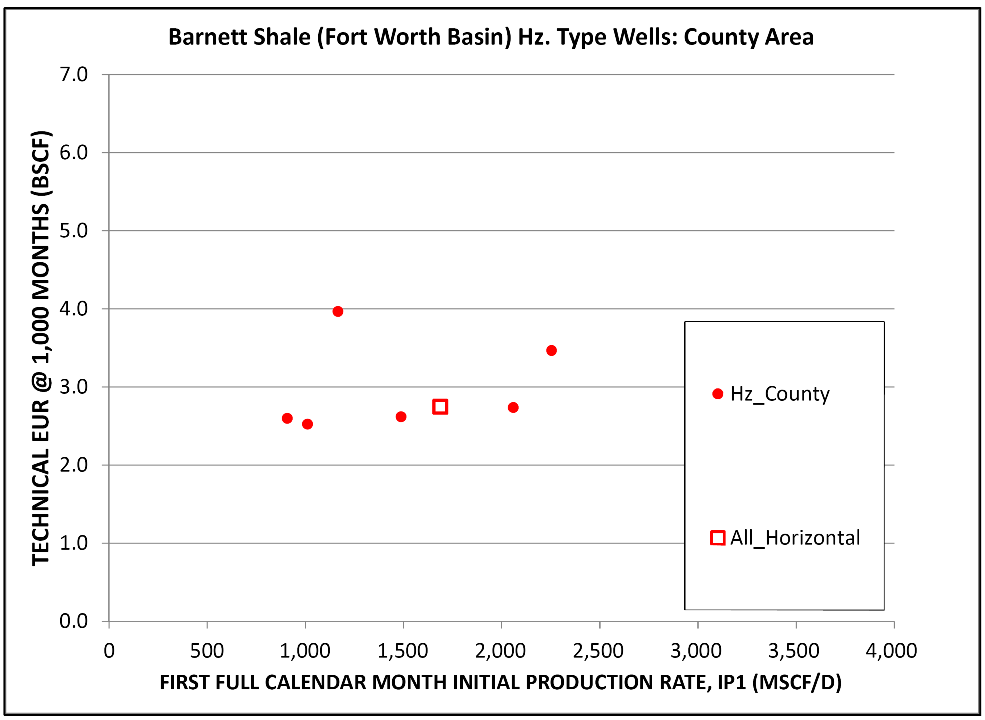

Figure 12—Barnett example type-well EUR forecast results – county areas.

Horizontal Type-Well Assessment by Operator

Identifiers are included in the public domain database in the current operator descriptor parameter. Horizontal gas well samples originating from six different operators (including the majority of wells in this basin's dataset) were averaged to generate representative type-wells for each. These were then evaluated using the history matching and forecasting techniques described above.

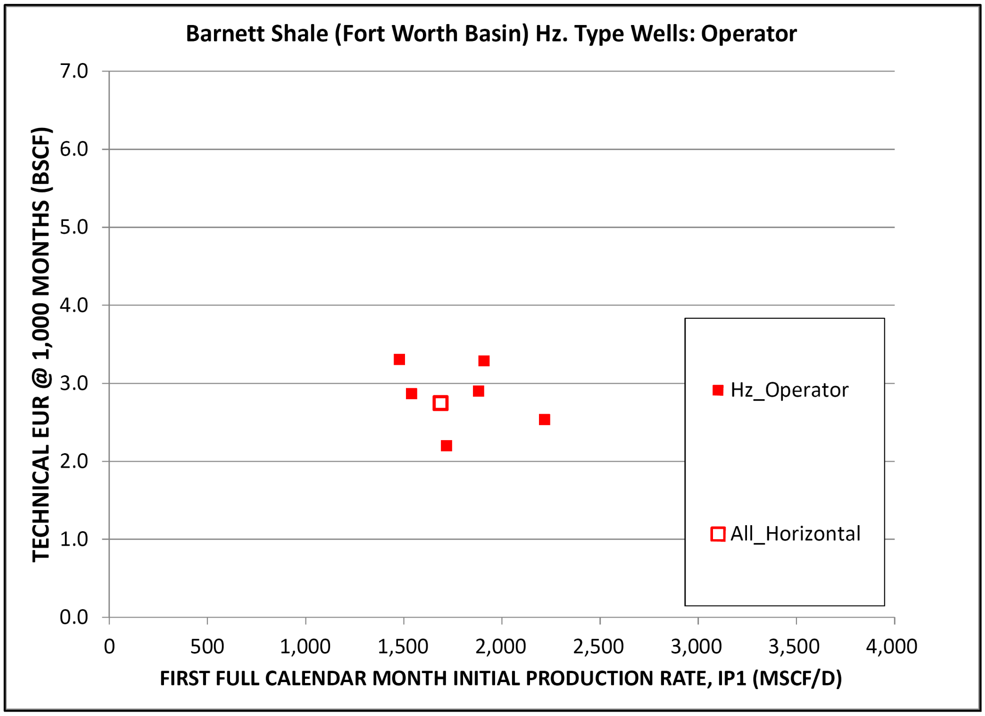

Figure 13—Barnett example type-well EUR forecast results – main operators.

The horizontal type-well results for the six operators are presented in Figure 13. Also shown for comparison is the type-well result for all horizontal wells. The degree of scatter in operator type-well results is similar to the geological area points that were presented in Figure 12, and discussed above. This similarity may be anticipated since the operator type-wells also represent samples from different areas, although the effects of individual company's operational policy (if historically consistent) may be expected to be more pronounced in Figure 13.

Horizontal Type-Well Assessment by Production Start Year

An identifier for each well's start-up date is included in the public domain database in the first production date parameter. Horizontal gas well samples originating from nine different years (from year 2003 onwards, including the majority of wells in this basin's dataset) were averaged to generate representative type-wells for each. These were then evaluated using the history matching and forecasting techniques described above.

A bar graph of the annual horizontal type-well technical EURs is presented in Figure 14. There is no overall trend in these results for the Barnett (Fort Worth Basin) shale play, although an improvement in technical EURs is evident after year 2008. This result may be considered a little surprising as one might expect more prospective "sweet spots" to be targeted earlier. The improvement could be an indication of improving completions' technology evolution and application e.g. more effective fracture stimulation. However, there may be limits to this potential technology impact, possibly driven by changes in reservoir quality as development expands into new areas. Preliminary indications are that poorer horizontal annual type-well results may have been achieved after year 2010 in Figure 14.

Wells commencing production in the last two years (2012 and 2013) are also illustrated in Figure 14 but must be regarded only as preliminary estimates at the time of writing this paper. The latter were inferred by considering the cumulative performance of all wells since 2003 until these times, rather than from annual well start-up samples from only the two specific years of interest. The duration of production data available for the latter two annual samples was inadequate for producing a reliable type-well history

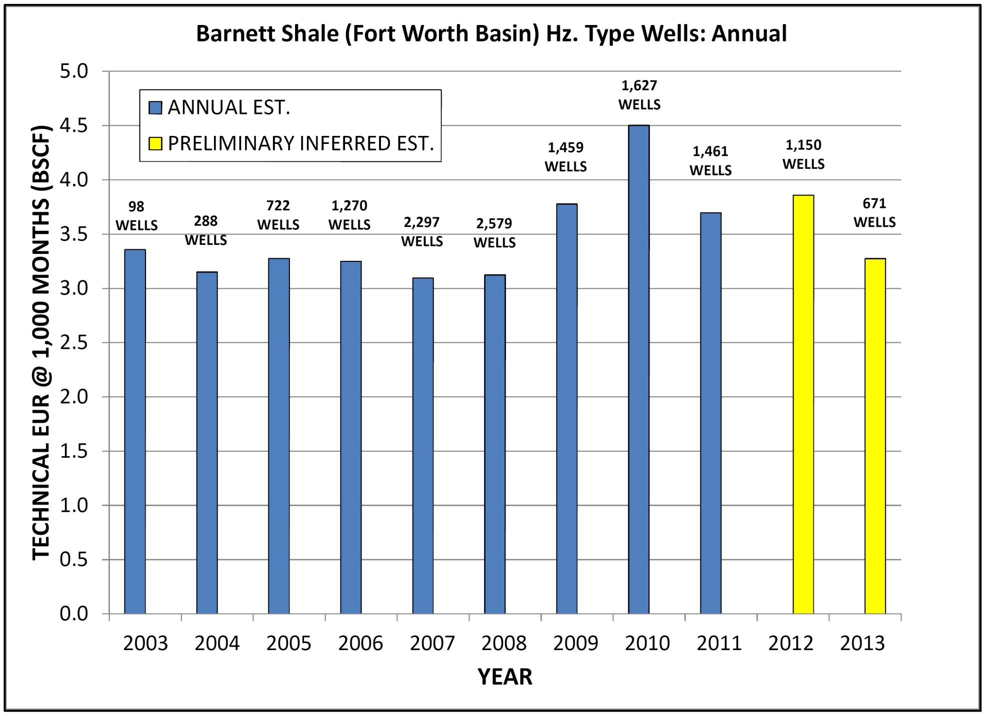

Figure 14—Barnett example type-well EUR forecast results – production start-up year.

match and forecast extrapolation in the authors' opinion. This aspect, concerning adequate sample size and duration, is discussed in more detail below.

Horizontal Type-Well Assessment by Perforation Interval Length

The public domain database used for this study contained no information concerning the number of fracture stimulation stages in any particular well. However, information concerning the reported upper perforation depth and lower perforation depth was included. The difference in these two parameters, i.e. the perforation interval length, was calculated for each well. The latter may be considered as a proxy for the number of fracture stimulation stages employed by the various operators, although this cannot be confirmed by the available information in the public domain database.

Individual horizontal wells' production histories were then selected using filtering intervals applied to perforation length. Horizontal type-wells for the various perforation length intervals were then evaluated as previously described.

The results for thirteen perforation interval lengths studied in the Barnett (Fort Worth Basin) shale play are illustrated in Figure 15. The figure shows a general correlation between technical EUR and perforation interval length. It should be noted that each results point shown represents a sample of different numbers of wells. This may account for some of the variation in results around the general trend, with those comprising relatively few wells being statistically less significant and, hence, less inherently accurate.

Similar trends, of different characteristic curves/gradients, were evaluated for the other plays studied in this paper where perforation interval information was available in the database. For specific shale plays, such relationships could be used to justify the optimal perforation interval length (and the potentially related number of fracture stimulation stages) depending on the inherent capital and operating costs for different completion design options and economic conditions.

Comparison of US Shale Gas Basins Studied

Figure 16 presents a consolidated plot of the results discussed for Figures 12 to 15, above. The figure shows that, for all the various sample types discussed, in the Barnett (Fort Worth Basin) shale play, the

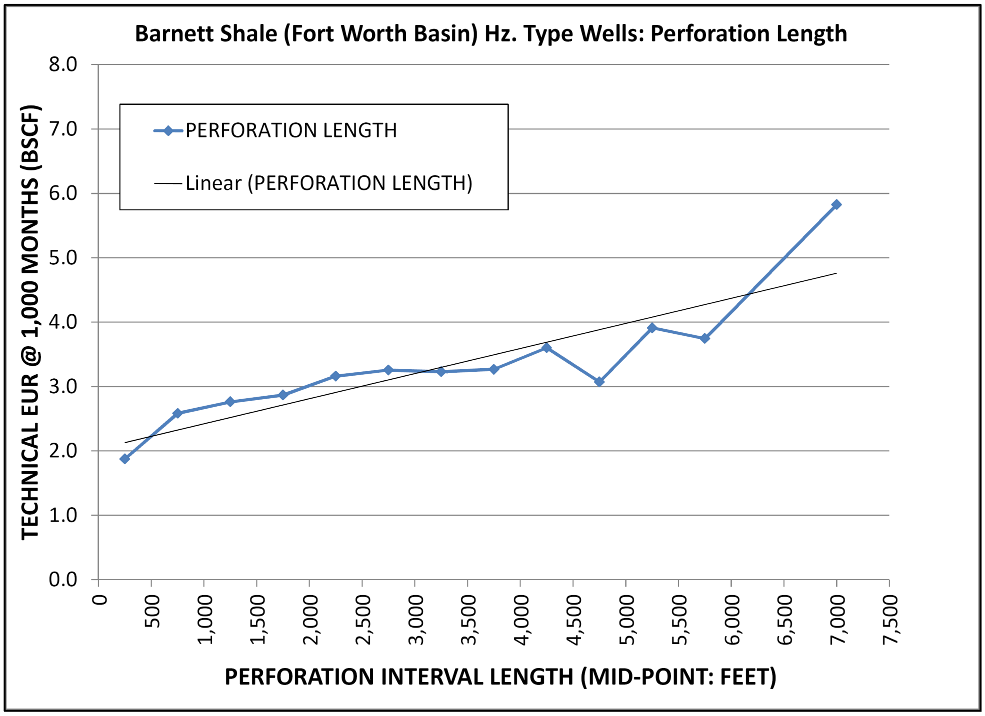

Figure 15—Barnett example type-well EUR forecast results – perforation interval length.

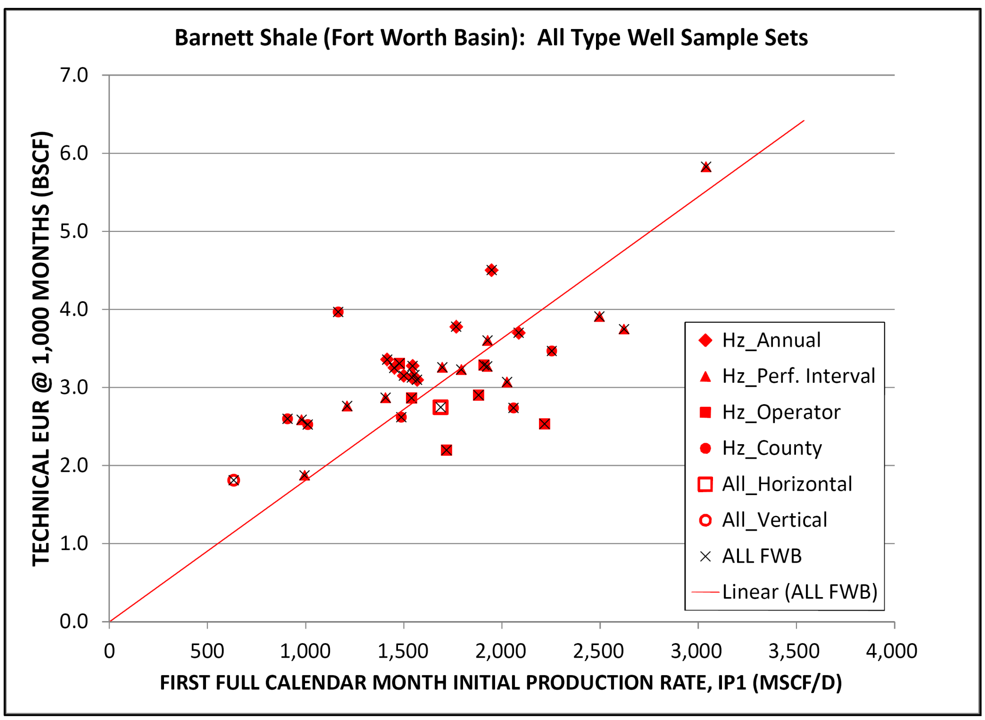

Figure 16—Barnett example type-well EUR forecast results – consolidation.

horizontal type-well technical EUR variability generally occurs within a range of +/− 50% around type-well technical EUR for all horizontal wells.

The main exception to this observation (the data point in the top right corner of Figure 16) relates to the sample for the longest perforation interval considered i.e. those horizontal wells with reported perforation interval lengths between 6,000 to 8,000 feet. As with Figure 15, above, this emphasises the

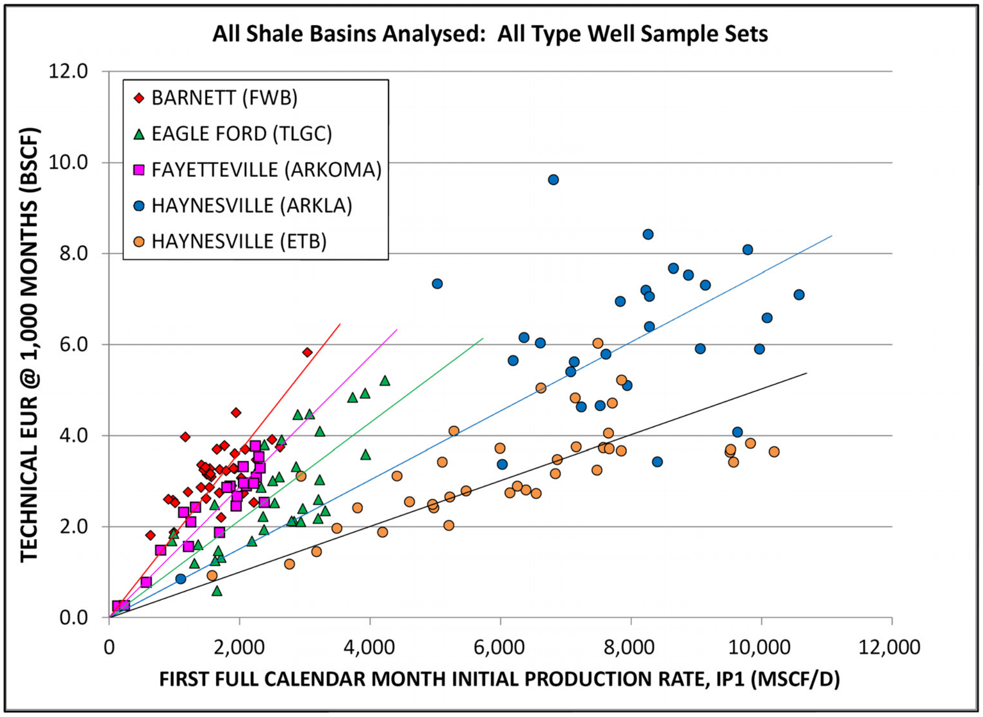

Figure 17—Type-well EUR forecast consolidation results – for five US shale plays studied. It is the authors' opinion that there is currently inadequate public gas type-well performance data in Australian shale plays to justify use of any of the above US performance trends as potential analogues.

imperative objective of maximising economic completion length. However, it is recognised that the outlier effect for this technical EUR result may be exaggerated by the (relatively small) number of wells (207) in the sample with the longest perforation interval length.

The horizontal type-well EUR points shown in Figure 16 form a distribution "cloud" around the type-well point for all horizontal wells. A correlation between the first full calendar month's average gas rate and technical EUR is evident. The vertical type-well point towards the lower left-hand corner is consistent with this correlation if the statistical scatter exhibited by the horizontal type-well points is taken into account. The various kinds of sample type-well points shown suggest that the correlation is characteristic of the Barnett (Fort Worth Basin) shale play geology.

Individual well result points from the same sample population, if evaluated, would be expected to conform to the type-well correlation shown. However, the distribution of individual wells would be expected to have a much greater scatter than those of the type-well (sample Mean) points. Summaries of the relationship between the variance in the population (individual well points) as opposed to the variance in sample Means (type-well points) are further discussed in SPEE Monograph 3 (2010)[43] and, in another context, by Murtha and Ross (2009)[31].

The analyses and results detailed above for the Barnett (Fort Worth Basin) shale play were repeated for the previously listed four other shale plays that were selected for this study.

A characteristic correlation between the first full calendar month's average gas rate and technical EUR was evident, specific to each shale play, as illustrated by Figure 17. The figure shows that type-well performance in the Barnett (Fort Worth Basin) and Fayetteville (Arkoma Basin) shale plays is similar and at the lower end of trends' range for the studied shale plays.

The two Haynesville basins i.e. East Texas Basin and Arkla Basin are shown to be much better performing trends, being significantly higher than in the Barnett and Fayetteville plays. The Haynesville basins are quite similar in terms of performance characteristic trend lines. However, the cloud of points for the Arkla Basin comprises a significantly higher overall average horizontal type-well than in the East

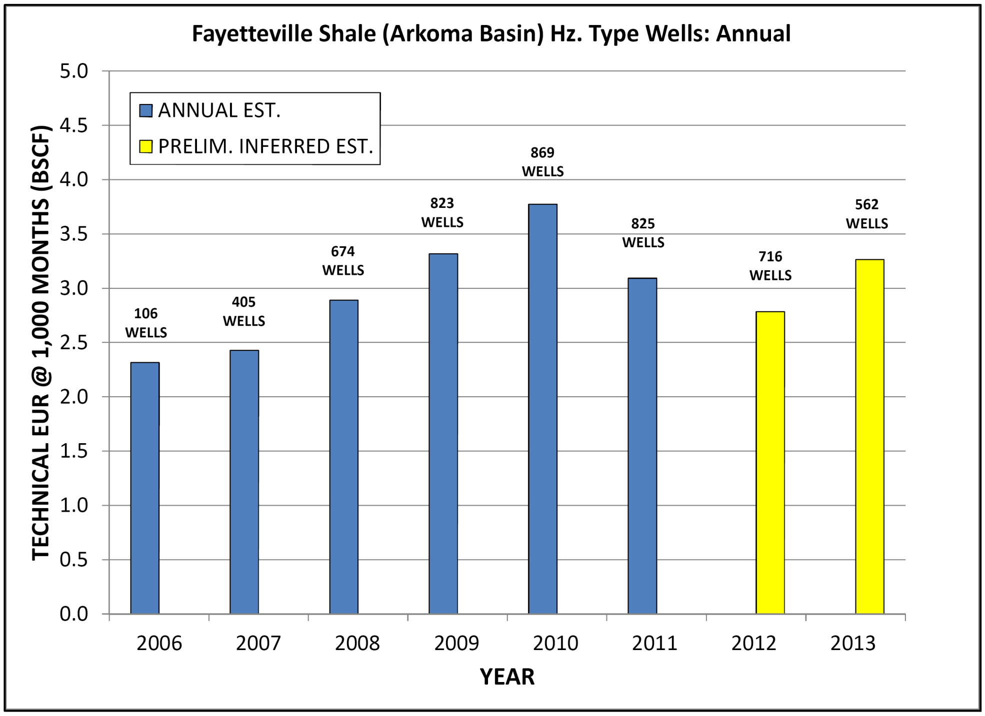

Figure 18—Fayetteville example type-well EUR forecast results – production start-up year.

Texas Basin. The scatter in the East Texas Basin data around the trend line is much narrower than for the Arkla Basin.

The Eagle Ford (Texas & Louisiana Gulf Coast Basin) shale play character is shown to be intermediate between the two high and low trends summarised above.

Horizontal Type-Well Assessment by Appraisal Sample Size and Duration

A second play was selected for the example illustration of this analysis, namely the Fayetteville (Arkoma Basin) shale play. The currently available data for this play example consists of 5,065 (active and inactive) horizontal wells and up to 105 full calendar months of production from any individual well, based upon the reported public domain production data up to and including March 2014. The well sample size analysis focussed on evaluating the historical period of most increase in well numbers in the Fayetteville (Arkoma Basin) shale play i.e. from year 2006 onwards.

The context for this assessment includes the evaluated annual samples' technical EURs, as summarised in Figure 18. As with the similar previous plot (i.e. Barnett example presented in Figure 14) the results for Fayetteville wells commencing production in the last two years (2012 and 2013) in Figure 18 must be regarded only as preliminary estimates at the time of writing this paper. The latter were inferred by considering the cumulative performance of all wells since 2006 until these times, rather than from annual well start-up samples from only the two specific years of interest. The duration of production data available for the latter two samples was inadequate for producing a reliable type-well history match and forecast extrapolation in the authors' opinion.

Figure 18 shows generally increasing annual type-well technical EURs from years 2006 to 2010, inclusive. This result may be considered a little surprising as one might expect more prospective "sweet spots" to be targeted earlier. The improvement could be an indication of improving completions' technology evolution and application e.g. more effective fracture stimulation. However, there may be limits to this potential technology impact, possibly driven by changes in reservoir quality as development expands into new areas. Preliminary indications are that poorer horizontal annual type-well results may have been achieved after year 2010 in Figure 18.

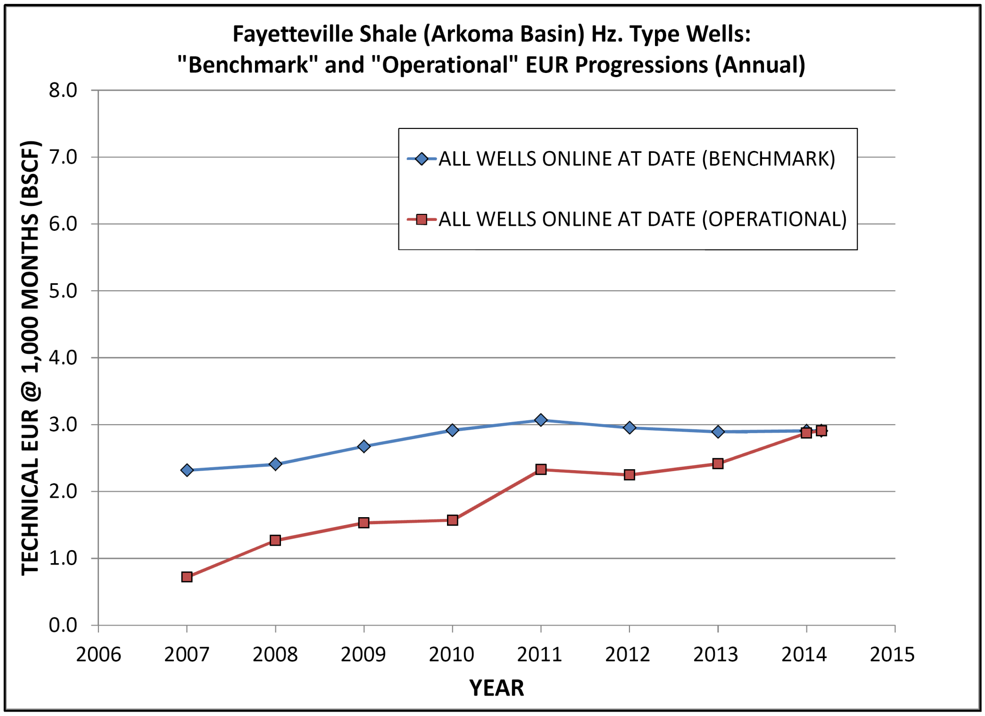

Figure 19—Fayetteville example type-well EUR forecast results progression – annual.

"Benchmark" horizontal type-wells were generated for all the horizontal wells drilled at various points in time. These Benchmarks were defined as using the benefit of hindsight i.e. all the production that was available until March 2014 was employed, for the total number of wells drilled after 2006 until each of the assessment times.

These Benchmark estimates were then compared to horizontal type-wells drilled at various points in time, but now without the benefit of hindsight. Only the production data available for those wells until that assessment time was used to generate the horizontal type-well in the latter "Operational" scenario.

Figure 19 shows the comparison of progression in technical EUR forecasts using the two categories of type-well described above. The Benchmark technical EUR gradually increases initially and then declines slightly over time, as more wells are drilled. This could be due to a more accurate estimate of population technical EUR due to the increased sample size, or it could reflect that generally less productive areas were being drilled later. However, the Benchmark technical EUR history is relatively stable because even for the very earliest times when relatively few wells were available, all the subsequent production data until March 2014 is being used to calculate the type-well for the available horizontal well sample at that time.

A clear contrast between the Benchmark and the Operational technical EUR results is observed in Figure 19. The Operational technical EUR converges with the Benchmark technical EUR over time as more wells are drilled. Both EUR progression curves in Figure 19 show initially increasing trends until the end of year 2010. This reflects the cumulative weighted average effect of the EUR of the component wells drilled in each year (Figure 18) which can be seen to be increasing until 2010.

These effects are also illustrated in Figure 20 which plots the results against the sampled number of wells at each evaluated point in time.

However, it must be recognised that there are two simultaneous factors at work in Figures 19 and 20: the well numbers are increasing over time for both the Benchmark and Operational EUR lines; but the duration of the available individual well production history is also increasing for the Operational EUR result lines.

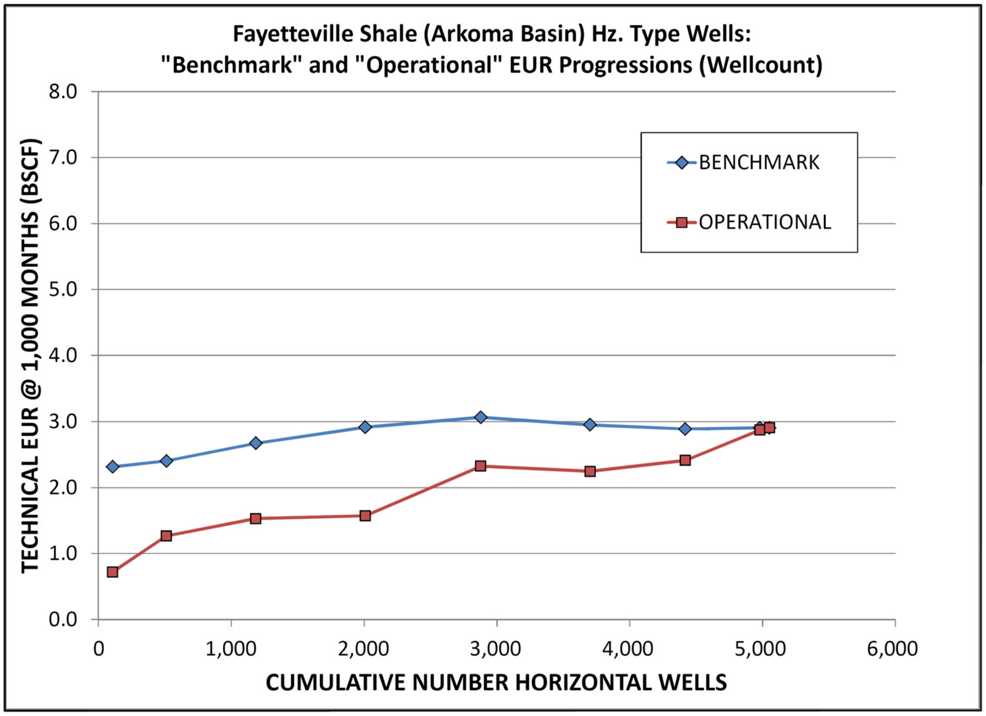

Figure 20—Fayetteville example type-well EUR forecast results progression – well numbers.

Figure 19 indicates that if only the production data that is available at the time from all the horizontal wells drilled to a particular date is used, then the Operational technical EUR may only just be reaching convergence with the stabilised Benchmark EUR around the start of year 2014 i.e. eight years after the start of the data considered in this evaluation. As illustrated by Figure 20, at the time of this convergence 5,065 horizontal wells had been drilled. It is possible that such convergence might have occurred earlier in a situation in which the annual EURs (Figure 14) were more stable.

However, this raises a key question as to which is more important in terms of accurately estimating technical EUR: the number of wells in the type-well sample, or the duration of the available production data?

In order to inform the potential answer to this question, the Operational technical EUR analysis was repeated with constraints on the number of wells included in the type-well sample. Horizontal type-wells were calculated for the first approximately: 300, 100, 30, 10, and 3 wells chronologically drilled from start of year 2006 in the Fayetteville (Arkoma Basin) shale play. This was done by filtering the data set available for type-well inclusion by the earliest month(s) of first production (so the exact number of wells in the samples may differ slightly from the targets stated above).

The results of this analytical approach are shown in Figure 21. With a horizontal type-well sample based on only the first approximately 300, 100, 30, 10, and 3 wells chronologically drilled from start of year 2006, the Operational estimates show different EUR stabilisation plateaus when compared with the Benchmark technical EUR.

If the Operational EUR lines for the first approximately 300 and 100 wells in Figure 21 are considered first, it is evident that their progression lines stabilise approximately four years after year 2006 (i.e. the start of the dataset evaluated). Since the first 300 or so wells to start production came online between 2006 and 2008, the accuracy of these samples' plateaus should be assessed against the Benchmark points at start of years 2007 and 2008 only. Such a comparison shows that a sample of 300 or 100 wells with four years of production data would have closely approximated the Benchmark EURs at 2007 and 2008.

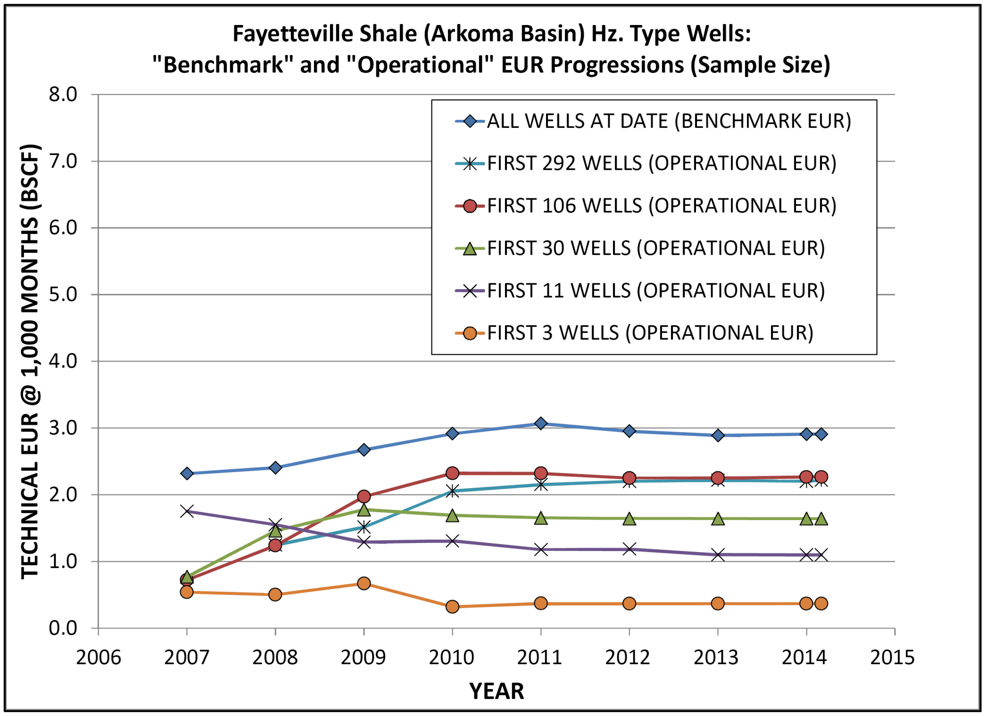

Figure 21—Fayetteville example type-well EUR forecast results progression – sample size and duration.

If the Operational EUR lines for the first 30 and 11 wells in Figure 21 are considered next, it is evident that their progression lines stabilise approximately four to five years after year 2006 (i.e. the start of the dataset evaluated). Since the first 30 or so wells to start production came online during year 2006, the accuracy of these samples' plateaus should be assessed against the Benchmark point at start of year 2007 only. Such a comparison shows that a sample of 30 or so with four to five years of production data would have underestimated the Benchmark EUR at 2007 by approx. 27%. The smaller sample of 11 wells and four to five years of production data would have underestimated the Benchmark EUR at 2007 by approx. 50%.

Finally, it is clear from Figure 21 that the sample of the first 3 wells starting production in year 2006 did not provide an accurate estimate of the Benchmark EUR at any of the assessment times. The type-well from this small sample was simply not statistically significant enough to be representative of the population technical EUR (as represented by the year 2007 point on the Benchmark EUR).

In this example, the type-wells comprising samples of the first 300 and 100 or so wells did provide an accurate approximation of the Benchmark EUR for the relevant timeframe. However, since the performance of the annual type-wells improves from start of year 2008 onwards (Figure 18) the sample sizes comprising approximately the first 300 and 100 wells are inadequate to recognise these later effects.

It can be concluded that the more wells included in a type-well sample; the more likely it is to be representative of the performance of the population as a whole. Also, that a significant duration of production data (several years) is required for such appraisal samples in order that associated type-well history matches and forecasts may yield reasonably accurate estimates of shale play character. Reasonably accurate type-well performance estimates are critical to facilitate reliable development project investment decisions.

Results from the other four US shale plays that were studied showed similar results to those described above for the Fayetteville (Arkoma Basin) shale play. It is therefore recommended by the authors that at least 30 wells with at least 4 years of undisturbed production data should form the basis for appraisal program samples for reasonably reliable type-well technical EUR estimates from fracture dominated gas wells in shale plays.

Once such a sample has been acquired and evaluated, preliminary economic screening evaluation may be assessed, whilst recognising that the nevertheless limited dataset may not be representative of the shale play more generally. Continual evaluation of subsequent appraisal and/or development wells' performance is essential to constantly evolve the understanding of the type-well characteristics relating to the parameters explored in this paper. This should be in addition to correlations with any related (well-specific or general) geological information available to operators.

More data (both well numbers and production duration) should lead to more confidence in forecast results, but what level of confidence is desired? Individual companies may wish to draw conclusions from smaller data sets, but it must be recognised that this would be with inherently less confidence. This uncertainty should be reflected in the range of (Low, Best, High) type-well forecasts used to assess project viability and associated resources, consistent with industry standards e.g. SPE-PRMS (SPE, 2007)[42].

Discussion

The above evaluation of the production data from selected relatively mature US shale gas plays has highlighted a number of empirical observations concerning well performance and variability. The following discussion seeks to assess their potential relevance, from geological and economic perspectives, to emerging interest in such prospective plays in Australia.

Recent Australian Operational Activity

Several companies are exploring for and appraising shale gas in Australia, spurred on primarily by high gas prices and the need for additional resources. The geology of these fields and the factors leading to successful fracture stimulation are still not well understood as illustrated by the current activity described below.

To date, the major focus of shale gas exploitation in Australia has been in the Cooper Basin (e.g. Beach and Santos) where the relatively extensive infrastructure (relative to other Australian basins rather than the US basins) is already in place for the production of conventional gas and oil. This potentially allows small volumes of gas to be put on production without the requirement for large cost hurdles to be overcome. The vertical Moomba-191 well in the Cooper Basin was declared by Santos on 19 October 2012 as "*Australia's first commercial shale well with a reported stabilized gas production of ~2.7 MMscf/d from the three fracture stimulation stages in the Roseneath Shale, Epsilon Formation and the Murteree Shale (REM)*" (Santos, 2012)[37].

At the time of writing this paper, Moomba-191 had been producing for some 20 months into the Moomba North gathering system. On 19 December 2013, Santos announced that the vertical Moomba-194 shale gas well recorded a 3.1 MMscf/d peak flow after the well "*was drilled to a depth of 3,368 meters to appraise the gas potential in various unconventional and shale plays. Five standard fracture stimulation stages were placed within selected targets across the Permian section, including the Patchawarra deep coal, Patchawarra tight sand, Upper Patchawarra hybrid shale, Murteree shale and Epsilon hybrid shale zones. Initial production logging indicates all five zones are contributing to gas flow*" (Santos, 20 1 3)[38].

Pitkin et al. (2012)[34] outlined the analysis of Beach's Holdfast-1 (seven fracture stimulation stages) and Encounter-1 (six fracture stimulation stages) vertical wells in the Patchawarra Formation (one fracture stimulation stage in each well) and Roseneath Shale, Epsilon Formation and the Murteree Shale. SA DMITRE (2012)[44] reported gas flow in the Holdfast-1 well from all seven fracture stimulation stages at "*up to 2 MMscf/d*", while the Encounter-1 well was "*fracture stimulated on the Patchawarra interval in April 2012, flowing up to 0.75 MMscf/d, and on the REM package (five frac. stages) in June 2012, flowing 1.3 MMscf/d*".

The identified well results in the Cooper Basin mentioned above are still considered by the authors of this paper as early exploration results and it is understood that Beach and Santos are currently waiting on results from horizontal exploration wells. Beach has planned the Holdfast-2 well with a 600m lateral to a total measured depth of 3,800m with eight fracture stimulation stages (Beach, 2013)[4] while Santos has planned the Moomba-193 horizontal well to a total measured depth of 3,996m with a 900m lateral to be drilled in the Murteree Shale (Beach, 2014)[5]. At the time of writing this paper no well results were understood to be published by Beach and Santos for their horizontal wells.

In Western Australia (WA) two basins have been the focus of shale gas activity: the Perth and Canning Basins; however to a lesser extent than the Cooper Basin. It is understood that no commercial shale gas wells have been declared in WA, to date, with variable exploration results being reported by operators.

In the Perth Basin, North West Energy (NWE, 2013 and 20 1 4)[32,33] recently reported initial results for the Arrowsmith-2 well from three co-mingled zones: the High Cliff Sandstone (one fracture stimulation stage), the Irwin River Coal Measures (IRCM) (two fracture stimulation stages) and the Carynginia (shale) Formation (two fracture stimulation stages). On 19 September 2013 the well was reported to have flowed from the co-mingled zones at 0.91 MMscf/d and 840 bwpd from a 29/64 inch choke. By October 2013 an average co-mingled surface rate of 0.31 MMscf/d was reported, and that the majority of the gas was produced from the Lower IRCM based on production logging results.

No reported production flows or attempted flows from the Canning Basin shale plays are understood to have occurred at the time of writing this paper. However, Buru Energy was granted approval for its Tight Gas Pilot Exploration Program in the Canning Basin by the Department of Mines and Petroleum, in June 2014.

The activity described above demonstrates the recent (but limited) exploration and appraisal of shale plays in Australia to date, principally in the Cooper, Perth and Canning Basins. The published production results above indicate co-mingled flows from deep coals, tight sands and shales in the Patchawarra/REM Formations of the Cooper Basin as well as the High Cliff Sandstone/IRCM and Carynginia (shale) Formation of the Perth Basin. Operators have generally indicated that future horizontal wells will focus more exclusively on the shale formations and the geological review included below therefore also focuses on the shale formations in these basins.

Australian Geological Considerations

The definition of shale in this paper is consistent with the SPE Guidelines for Application of the PRMS (SPE, 2011)[41] and is defined as organic-rich fine-grained mudrocks which "*serve as a source, trap and reservoir for the gas*". They contain adsorbed and free gas and have low permeability. This is distinct from tight gas reservoirs within conventional low permeability reservoirs where the hydrocarbons are trapped hydrodynamically.

A brief geological summary is provided for the key Australian basins below, by way of an introduction, before a tabulated description of example Australian basin shale reservoir properties is listed and juxtaposed against more mature and well known US shale basin plays. The aim is to contextualise the production analyses presented above in this paper. It is not the intention of this paper's authors to draw conclusions from this simplistic tabulation/comparison of reservoir parameters. The tabulation is intended to highlight some of the potentially important factors that need to be considered in further exploration and appraisal of Australian shale plays. It is anticipated that operators would conduct similar but much more detailed analyses for specific shale plays targets: including both a regional geological review of the shale play, in addition to assessing local geological properties of the shale reservoirs.

Furthermore, a brief discussion of the importance of understanding the palaeo and present day geomechanical stress regimes is provided to highlight the need for a holistic analysis of the geological evolution of the shale plays. This would be in addition to characterising important parameters such as Total Organic Content (TOC), Thermal Maturity, and Shale Brittleness, etc.

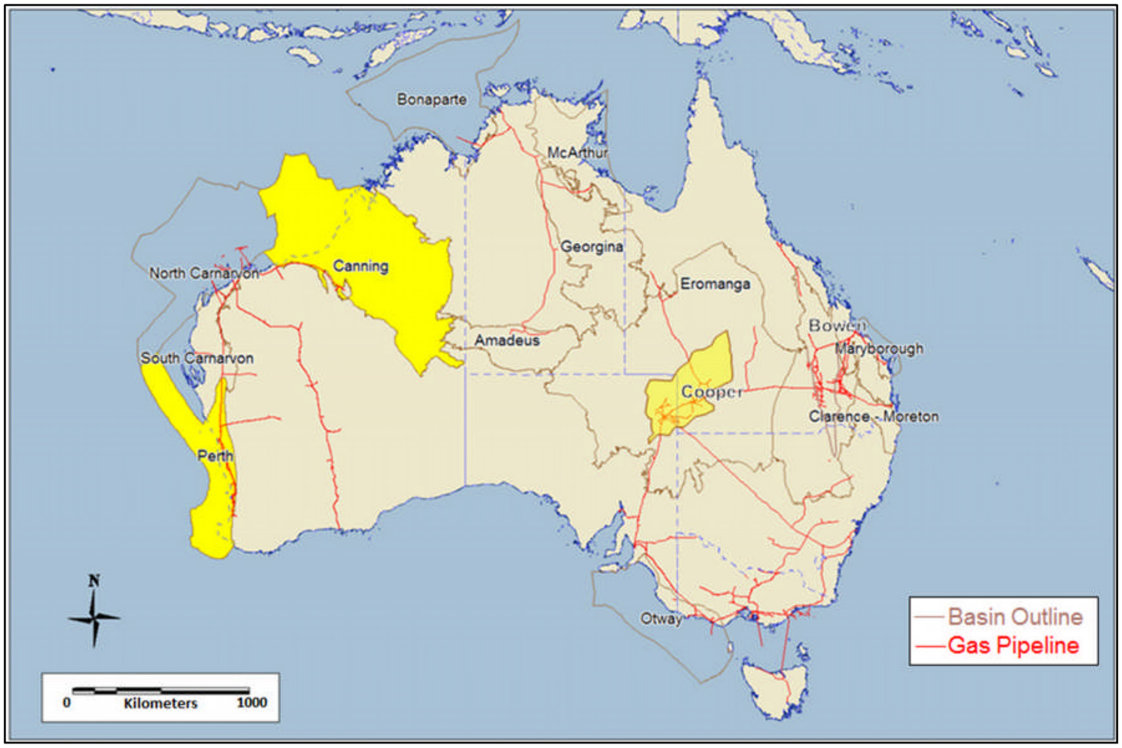

Figure 22—Australian prospective shale plays map (Source: PetroView, 2014 [modified]).

Cooper Basin The Cooper Basin is a Late Carboniferous to Middle Triassic sedimentary basin in the north-east of South Australia and the south-west of Queensland. The Cooper Basin is a sag basin and underlies the south-western Eromanga Basin and this region is often referred to as the Cooper-Eromanga Basin. Covering an area of some 1,000,000 km^2 of central Australia, the Eromanga Basin is Early Jurassic to Late Cretaceous in age. The Cooper and Eromanga Basins are intracratonic i.e. lie within the continental crust, and they are indicated in Figure 22 along with other basins with prospective shale plays as identified in a study by ACOLA (2013)[1].

The Cooper Basin lies unconformably over early Palaeozoic sediments of the Warburton Basin and is overlain disconformably by the Eromanga Basin. The Cooper Basin has three major troughs: the Patchawarra, the Nappamerri and the Tenappera separated by major structural ridges associated with the reactivation of north-west directed thrust faults in the underlying Warburton Basin (SA DMITRE, 2012)[44].

The first commercial conventional gas discovery in the Cooper-Eromanga Basin was made at the Gidgealpa field in 1963 while the first Permian oil discovery was made at the Tirrawarra field in 1970. The first Jurassic oil discovery was made at the Strzelecki field in 1978. The current gas pipeline network is included in Figure 22 to contrast the more developed infrastructure of the Cooper Basin to the Perth and Canning Basins discussed below.

The focus for shale gas exploration to date has been the Early Permian aged lacustrine shales of the Nappamerri Trough even though these also extend to the Patchawarra and Tenappera Troughs. The Roseneath Shale (lacustrine deposition), Epsilon Formation (fluvial-deltaic deposition) and the Murteree Shale (lacustrine deposition) are collectively known as the REM (SA DMITRE, 2012)[44].

Elliot et al. (2010)[18] indicated that the Epsilon Formation consists of sandstones, shales and coals and could provide a deep basin type tight gas opportunity. This would be dependent on whether gas was generated and migrated across the whole area. The underlying Patchawarra Formation (a combination of peat swamp, fluvial deltaic and lacustrine deposition) could also comprise such an opportunity even though the latter is considered a higher geological risk. The published well results of Moomba-191 and −194 described above confirm the reported conclusions that production is possible from a combination of shale, tight sandstone and deep coal formations.

Perth Basin The Perth Basin is an intracratonic, Late Carboniferous to Permian rift basin in the south-west of Australia (Figure 22). The basin is a deep linear trough and has a half graben configuration situated along a passive continental margin extending in a north-south orientation for approximately 1,000 km both onshore and offshore (Reynolds, 2000[35] and Harris, 1994[24]). The sedimentation commenced in the northern Perth Basin in the Ordovician and began in the remainder of the basin by the Carboniferous to Early Permian (Harris, 1994)[24].

North trending Permian regional growth faults marked progressive rifting of the basin. Continental sedimentary rocks at the base of the Permian Nangetty Formation were followed by continental and marine sedimentation, with deposition of the Holmwood Shale, the High Cliff Sandstone, the Irwin River Coal Measures and the Carynginia Formation during the Mid Permian which includes the prospective Carynginia Shale. This was followed by a sedimentary sequence of Late Permian non-marine and shoreline siliciclastics (Wagina Formation) to shelf carbonates (Beekeeper Formation, which is producing gas in the Woodada Gas field). The sedimentary sequence from the Early Triassic to Lower Cretaceous is dominated by shallow marine to non-marine siliciclastics which includes the prospective Kockatea Shale (Crostella, 1995[12] and EIA, 20 1 3[48]).

At the time of writing this paper, the only onshore gas Reserves in Western Australia are those in conventional accumulations in the Perth Basin. The fields are held by AWE and Origin Energy and are located predominantly in the north Perth Basin. They include the Dongara, XAGGS, Woodada, and the Beharra Springs gas fields. No published flow rates are understood to be available for the Woodada Deep-1 shale gas well drilled by AWE.

Canning Basin The Canning rift basin (Figure 22) initially developed in the Early Palaeozoic as intracratonic sag between the Precambrian Pilbara and Kimberly Cratons in north-western Australia. Extension and rapid subsidence occurred in the Early Ordovician followed by compression and erosion in the Early Devonian before additional extension and subsidence in the Late Devonian. Additional compression then subsidence occurred in the Middle and Late Carboniferous to Permian followed by transpressional uplift and erosion in the Early Jurassic (WA DMP, 20 1 4)[54].

The Canning Basin contains up to 18km of sediments of Ordovician to Cretaceous age within the Fitzroy, Willara and Kidson north-west trending, fault bounded troughs within the basin. The two primary shale gas prospective targets in the basin are the organic-rich Ordovician Goldwyer Formation and the Carboniferous Laurel Formation (EIA, 2011)[47]. There are potentially other shale plays in the Canning Basin however scarce data exist to date. The Middle Ordovician Goldwyer Formation was deposited mainly in open marine to intertidal conditions. Highly fossiliferous, it varies from mudstone-dominated in basinal areas to limestone-dominated in some platform and terrace areas. The Goldwyer Formation averages about 400 m thick, reaching a maximum thickness of 736 m in the Willara-1 well in the Willara sub-basin. It is dominated by mudstone and carbonate with a wide variation across the basin (EIA, 2011)[47].

The Canning Basin has been subject to very limited exploration. Exploration began in the basin in the early 1920s after water bores indicated traces of oil at Prices Creek in the Pillara Range. However, the first oil discovery was not made until 1981 with the Blina-1 well drilled above the edge of the Lennard Shelf and recovered oil from the Fairfield group overlying a Devonian Reef. The Blina field was one of five commercial oil field discoveries in the basin likely to have been sourced by the Carboniferous Laurel Formation shale (WA DMP, 2014)[54].

Australian Shale Reservoir Properties

Summaries of the important reservoir parameters for organic-rich, fine-grained shale rocks that are self-sourced and do not require a trapping mechanism in order to accumulate hydrocarbons are described below:

Kerogen is defined as the insoluble organic matter comprising a diagenetic alteration product of organic material laid down with sediments capable of generating petroleum (Vandenbroucke, 2003)[51]. In general the Total Organic Carbon (TOC) is the amount of carbon contained within kerogen that forms the basis of the source rock within the shale.

As sedimentary rock becomes more mature during burial, the kerogen becomes more depleted in hydrogen and oxygen relative to carbon. There are four different kerogen types, which mature along different evolutionary paths on the well-known Van Krevelen diagrams (Seewald, 2003[40] and Vandenbroucke, 2003[51]):

- Type I Kerogen: formed from algal material in anoxic conditions predominantly from lacustrine algae (high capacity for liquid hydrocarbons)
- Type II Lipid Rich Kerogen: found in marine sediments deposited under reducing conditions originating from different sources such as marine algae, pollen and spores, leaf waxes and fossil resins (liquids and gas)
- Type III Kerogen: from terrestrial organic material e.g. land plants; tend to produce coal and generate mainly gas
- Type IV Inertinite Kerogen: oxidised and hydrogen poor which essentially has no hydrocarbon source potential

TOC provides a quantitative means to estimate the total volume of hydrocarbon and comprises of organic carbon retained as hydrocarbons, organic carbon that can be converted into hydrocarbons (convertible carbon) and carbonaceous residue that will not yield hydrocarbon (inert carbon). The gas is stored in the voids of the natural fractures and fracture-connected pore space (free gas), adsorbed to mineral surfaces within pore space or natural fractures, and adsorbed to organic and mineral surfaces of matrix rock not connected to natural fractures (Bust et al., 2013)[8].

Thermal Maturity is a measure of how long and how much a reservoir has been heated and is most commonly quantified by Vitrinite Reflectance (Ro).

Shale Porosity has a direct bearing on gas in place estimates for shale gas plays. Shales are characterised by complex pore systems with low to moderate porosity and ultra-low to low inter-particle permeability. They contain kerogen porosity as described above and depict a variable pore character (Bust et al., 2013)[8].

Shale Brittleness is important in determining the extent of the natural and/or induced fracture network(s) and is typically governed by the percentage of clay minerals (decreasing clay content improves brittleness), quartz minerals, carbonate minerals and related elastic rock properties such as a high Young's modulus and a low Poisson's ratio. The elastic rock properties are determined from compressional and shear wave velocities and density (ρ) from wire-line and core measurements, to provide an understanding of a rock's incompressibility (λ) and shear rigidity (μ).

Goodway et al. (2006)[21] and Metzner (2013)[29] described and provided examples of how $\lambda - \mu - \rho$ estimates from Amplitude Versus Offset (AVO) 3D seismic inversion data aided in the identification of shale production sweet spots. The authors of the field study examples however indicate that calibration and look back analysis is critical and this requires multiple wells to validate before the approach can be extrapolated to larger areas.

Formation Overpressure affects the proppant required in the fracture stimulation process to maximise the Stimulated Rock Volume (SRV). This is essentially the volume of the reservoir that is engaged by the hydraulic fracturing process.

In-Situ Stress Regime classification at a regional and local level is important as it relates to the horizontal well placement orientations and spacing. Understanding of the palaeo stress regimes and how the subsequent fracture networks were generated, possibly by multiple episodes of deformation, is important in the context of the present day stress regime. It is also a key consideration for any planned hydraulic fracture stimulation process. The stresses and fracture patterns are both critical in controlling the shape and orientation of the SRV (Moos, 2011)[30]. This is discussed further in the section concerning geomechanical considerations, below. Table 1 includes general present day stress classifications cited by various authors for both the prospective Australian and example US shale basins along with other indicative reservoir properties.

Depositional Environment and Shale Thickness understanding is required to assess regional and local lithology variations of the shale and its structural setting e.g. local faults and karsts. Basu et al. (2012)[3] demonstrated an example of how 3D seismic curvature and coherency attributes correlated to production sweet spots in specific horizontal wells in the Eagle Ford Shale. The authors compared qualitatively positive curvature attributes that represented localised extensional stress regimes against production logs and depicted zones that correlated with increased production.

Table 1 summarises some parameters from the three focus Australian shale basins and also includes the well-known US shale basins from which the production data analysed in this paper originate.

Australian Geomechanical Considerations

Geomechanical considerations involve understanding the present day stress system and its effect on the local structural setting which may have been influenced by multiple tectonic episodes of deformation. This subsequently has a bearing on the reservoir behaviour of the SRV after hydraulic fracturing (Rylance, 2013)[36]. Stress states and natural fracture patterns therefore vary widely within shale basins and affect the optimal directions to drill and exploit the natural fractures. US shale play drilling experience demonstrates that, in general, orienting horizontal wells perpendicular to the maximum horizontal stress (σ_{hmax}) allows the wells to encounter sufficient transverse vertical fractures within the stimulated rock volume to maximise production (King, 2010)[27].

Stress classifications are termed Normal, Strike-Slip or Reverse. In the Normal stress scenario the overburden stress is greater or equal to the maximum horizontal stress which in turn is greater or equal to the minimum horizontal stress ($\sigma_v \geq \sigma_{hmax} \geq \sigma_{hmin}$). Shear fractures strike perpendicular to σ_{hmin}, opening mode or "pulling" fractures (Mode I) strike perpendicular to σ_{hmin}. In the Strike-Slip stress scenario ($\sigma_{hmax} \geq \sigma_v \geq \sigma_{hmin}$) shear fractures strike $+/-$ 30 degrees to σ_{hmax} and Mode I fractures strike perpendicular to σ_{hmin}. In the Reverse stress scenario ($\sigma_{hmax} \geq \sigma_{hmin} \geq \sigma_v$) shear fractures strike parallel to σ_{hmin} and Mode I fractures are horizontal (Moos, 2011)[30].

Pitkin et al. (2012)[34] documented analyses the authors carried out for the vertical Holdfast-1 and Encounter-1 wells in the Cooper Basin. Even though the predominant fracture growth after hydraulic fracturing comprised transverse vertical fractures, there is also potential that the minimum horizontal stress at some shale target depths might approach, or in some cases exceed, the vertical overburden stress. The latter would generate the potential for fractures to be oriented in the horizontal plane. This was supported with tiltmeter analysis where the same author demonstrated that the Encounter-1 well tiltmeter data indicated a "*higher percentage of horizontal fracturing than Holdfast-1 well, resulting in higher injection pressures*". In the Holdfast-1 well most fracture "*stages displayed predominantly vertical fracture growth with some horizontal component, potentially related to dip or perhaps fracture complexity*".

These preliminary results demonstrate the limited analysis of shale well data in Australia to date. There is a requirement for significant additional drilling and production exploration/appraisal activities before the most appropriate method for maximising the stimulated rock volumes and subsequent well productivity may be better understood.

Table 1—Prospective Australian and Example US Shale Gas Plays – Indicative Reservoir Properties.[1,6,9,10,11,13,14,17,19,20,23,26,28,30,34,44,45,46,48,50,52,53, and 54]

Shale Play	AUSTRALIA: Cooper Basin	AUSTRALIA: Perth Basin	AUSTRALIA: Canning Basin	US: Barnett	US: Eagle Ford	US: Fayetteville	US: Haynesville
Basin	Cooper	Perth	Canning	Fort Worth	Texas & Louisiana Gulf Coast	Arkoma	1. Arkla 2. East Texas
Basin Type	Intracratonic, Late Carboniferous to Triassic sag basin	Intracratonic, Late Carboniferous to Permian rift basin	Intracratonic, Early Palaeozoic rift basin	Pericratonic Foreland and Thrust belt Palaeozoic basin	Pericratonic Passive Margin Mesozoic basin	Pericratonic Foreland and Thrust belt Palaeozoic basin	Pericratonic Passive Margin Mesozoic basin
Formation	Roseneath Shale, Epsilon Fm, Murteree Shale	Carynginia Shale / Kockatea Fm	Goldwyer Fm	Barnett	Eagle Ford	Fayetteville	Haynesville
Age	Permian	Early Permian / Early Triassic	Ordovician	Mississippian	Cretaceous	Mississippian	Kimmeridgian
Deposition	Lacustrine / Fluvial-Deltaic	Marine	Marine	Shallow Marine	Shallow Marine	Marine Shelf	Marine
General Present Day Stress Classification	Strike -Slip at REM? to Reverse with Depth	Strike -Slip to Reverse with Depth?	Strike -Slip?	Normal	Normal	Strike-Slip	Normal
Fracture Orientation	Fractures Strike parallel to σ_{hmax}? Or Fractures are Horizontal if Reverse Stress Regime is encountered with Depth?	Fractures Strike parallel to σ_{hmax}? Or Fractures are Horizontal if Reverse Stress Regime is encountered with Depth?	Fractures Strike parallel to σ_{hmax}	Fractures Strike parallel to σ_{hmax}	Fractures Strike parallel to σ_{hmax}	Fractures Strike parallel to σ_{hmax}	Fractures Strike parallel to σ_{hmax}
Kerogen Type	II/III	III/II-III	II	II	II	II/III	II/III
Depth (m)	1,830-3,965	1,200-5,000	1,000-5,000	1,900-2,600	1,200-4,500	300-2,200	3,000-5,000
Net Thickness (m)	70-120m	60-150	50-100	30-180	90-145	10-60	60-90
Quartz Content (%)	30-40	25-40	40-50	41	20	20-30	20-33
Carbonate Content (%)	Negligible	5-10	5-20	13	30-60	10	15
Clay Content (%)	35-65	30-60	25-50	23	7.5-15	20-30	25-33
TOC (%)	2-9	1-5	1-6.4	3.0-7.5	2.0-6.5	4-9.8	0.5-5
% Ro	0.95-4	1-1.5	1.3-1.5	1.0-1.74	1.0-2.2	1.1-4	1-2.7
Porosity (%)	3-6	3-6	2-8	4.0-9.0	3.4-14.6	2-8	5-11
Pressure Grad. (psi/ft)	0.72	0.45-0.7	0.43-0.55	0.46	0.5-0.8	0.42	0.84
Horizontal Length (m)	600-900 planned	?	?	400-1,400	900-1,800	NO DATA AVAILABLE	1. Arkla: 1,100-1,400 2. E.Texas: 400-1,800
Average Number of Fracture Stimulation Stages	e.g. Holdfast-2: 8 stages planned	e.g. Arrowsmith-2: 5 stages in vertical well	?	6*	16*	9*	13*
Hz Type-Well IP1 Gas Rate (MMscf/d)	0.75-2-2.6 (4.2 max) NOTE: Vertical well, preliminary daily range only.	0.35-0.91-3.5 NOTE: Vertical well, prelim. daily range only.	?	1.7†	2.5†	2.1†	1. Arkla: 8.3† 2. E.Texas: 6.9†
Hz Type-Well Technical EUR_1000 (Bscf)	?	?	?	2.7†	3.0†	2.9†	1. Arkla: 7.1† 2. E.Texas: 3.5†

Notes: *Source Paper SPE 162534 (Kennedy et al., 2012)[26];
†As derived from the production analysis in this paper.

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Australian Economic Considerations

Fiscal System A simple cashflow model was constructed that would enable the Economic Limit Test (ELT) to be conducted for notional type-well examples under the current Australian Petroleum Resource Rent Tax (PRRT) fiscal regime. The analysis has been conducted on a "standalone" basis, with the well hook-up costs to an evacuation/sales system excluded from the analysis.

In order to illustrate the potential impact of economic limit truncation and sensitivities, example type-wells comprising the overall averages for a horizontal type-well and a vertical type-well in the Barnett (Fort Worth Basin) were selected, per Figure 11 – for notional demonstration purposes only.

NOTE: No inference should be made that the authors consider these type-well examples to be in any way valid analogues for any prospective Australian shale gas plays.

The selected Barnett (Fort Worth Basin) type-well examples relate to the most conservative of the five US shale play characteristics evaluated in this paper (Figure 17). This does not imply that only upside potential to the example economic scenarios exist for Australian shale plays, but merely provides a context based on the US basins studied in this paper. In the absence of statistically significant quantities of shale gas well performance data in Australian shale plays, no justifiable analogues may currently be assumed for type-well performance.

The authors have not made assumptions concerning the nature of potential conceptual development projects in Australia. Such projects would be dependent upon the actual type-well characteristics that have yet to be demonstrated in Australian shale plays. As illustrated by Figure 17, experience in the US has demonstrated that the variability in the characteristics of different shales plays can be even more significant than the variation within a particular shale play. Each Australian shale play's type-well performance expectations must first be justified with statistically significant appraisal sample sizes and several years' associated production decline data, based on the US analysis presented in this paper. Until this occurs optimisation of conceptual project economics is generally considered hypothetical in the opinion of the authors.

In 2012, legislation was passed in Australia to extend PRRT to include onshore oil and gas projects previously not covered by the regime. The new provisions have been in place since 1 July 2012, but finalising the details of the expanded PRRT regime has yet to be completed. For the majority of offshore projects, the PRRT regime is applicable as opposed to the original Royalty/Excise regime. Royalties continue to be applicable to onshore projects subject to PRRT. The cashflow model constructed for the analysis assumes a 10% State Royalty.

The standard ELT is based upon an undiscounted cash flow, including only project-specific liabilities (e.g. Royalties, Production Taxes, etc.) and excludes Income Tax, overhead expenses (other than field), sunk costs and depreciation. The production forecast is then truncated in the year that the annual net operating income goes negative for the last time (unless already truncated earlier for technical, operational or contractual reasons). This analysis has not included any "early" truncation e.g. due to Licence expiry, etc.

Price Assumptions Whilst the shale gas industry is currently in its infancy in Australia, public domain information suggests that achievable gas prices in the region of A$ 8/GJ should be possible, with Santos (2014)[39] recently announcing that gas prices for the east coast markets could be greater than A$ 8/GJ. The latter gas price has been assumed in the example analysis, with 2% per annum escalation applied.

CAPEX Assumptions Currently available public domain information suggests that Australian shale gas well costs are likely to be some 30–50% higher than the equivalents in the US. This analysis has assumed A$ 10MM CAPEX to drill and complete a horizontal type-well, including fracture stimulation costs. Furthermore, A$ 8MM CAPEX has been assumed for a vertical type-well, including fracture stimulation costs. Fracture stimulation stages are expected to cost in the region of some A$ 200–500k per stage in the

Table 2—Economic Limit Test (ELT) and Cashflow Analysis Results for Example Type-Wells.

EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Years to Economic Limit	Pre-tax NPV_0 (A$ MM)	Pre-tax NPV_{10} (A$ MM)	Pre-tax IRR
Horizontal Type-Well	2.743	2.266	42	1.30	−2.88	1.8%
Vertical Type-Well	1.804	1.239	38	−3.51	−5.09	0.0%

example. CAPEX has been assumed not to escalate with time (i.e. "flat" cost assumption) as it is incurred only in the first year in the example.

OPEX Assumptions Currently available public domain information, plus the author's own analysis suggests that OPEX is also likely to be somewhat higher in Australia than for equivalent shale gas wells in the US. This analysis has assumed A$ 100k annual fixed OPEX plus variable costs of A$ 1.0/GJ. It should be noted that the fixed OPEX element could be lower for the vertical type-well and that future economies of scale might be expected for both type-wells once a multi-well project has been developed. OPEX has been assumed to escalate at 2% per annum.

Results of the initial economic analyses are presented in Table 2.

Only the horizontal type-well example satisfies the SPE-PRMS (SPE, 2007)[42] economic criterion for Reserves under the forecast and escalated cost and price assumptions, as the undiscounted pre-tax NPV is positive (IRR = 1.8%). However, both the example type-wells are not likely to be considered commercial by companies, as Internal Rate of Return (IRR) is likely to be below internal threshold/hurdle limits, in the opinion of the authors.

The example results emphasise the need to collect sufficient production data in order to establish representative type-well performance expectations for specific Australian shale plays. Confidence in improved type-well performance expectations would be required for more compelling project economics. Neither of the type-wells evaluated herein is likely to pass the commerciality constraints that companies are likely to apply, based on the assumptions in the example scenario.

Economic Sensitivity Examples

Sensitivity Analyses Sensitivity analyses on gas price, well CAPEX and fixed OPEX were conducted in order to evaluate the most important factors impacting the economic viability of both the example horizontal and vertical type-wells. The "base case" terms are as provided above (A$ 8/GJ gas price, A$ 10MM well CAPEX, A$ 0.10MM annual fixed OPEX).

Sensitivities were conducted individually, and results for the horizontal and vertical type-well examples are shown in Tables 3 and 4, respectively.

As can be seen from the foregoing tables, realised gas price has the greatest impact on economic viability for both the horizontal and vertical type-well examples. In the opinion of the authors, there appears to be little chance of the vertical type-well example being commercial within the bounds of the parameters considered.

For the horizontal type-well example, only a gas price in the region of A$ 10 – 12/GJ or a reduction in CAPEX to A$ 6MM are likely to be commercial. A combination of slightly higher gas price plus a reduction in both CAPEX and OPEX might also realise a commercial development for this example, in the opinion of the authors.

Breakeven Gas Price The required breakeven gas price (pre-tax basis) at a series of discount rates was evaluated. The analyses were based on the "base case" assumptions of: A$ 10MM well CAPEX; A$ 100k p.a. annual fixed OPEX plus A$ 0.10/GJ variable OPEX.

The results in Table 5 show the breakeven gas price for the example horizontal type-well is between A$ 7.5 – 10/GJ as a minimum. Only the breakeven price for the horizontal type-well (approximately A$

Table 3—Sensitivity Study Results for Horizontal Type-Well Example.

Horizontal Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Years to Economic Limit	Pre-tax NPV_0 (A$ MM)	Pre-tax NPV_{10} (A$ MM)	Pre-tax IRR
Base Case	2.743	**2.266**	**42**	**1.30**	**−2.88**	**1.8%**
Price +A$ 4/GJ		2.610	69	13.45	1.73	15.9%
Price +A$ 2/GJ		2.464	56	6.92	−0.58	8.2%
Price -A$ 2/GJ		2.017	29	−3.44	−5.17	0.0%
Price -A$ 4/GJ		1.640	16	−7.20	−7.38	0.0%
CAPEX +A$4 MM		2.266	42	−2.70	−6.70	0.0%
CAPEX +A$2 MM		2.266	42	−0.70	−4.79	0.0%
CAPEX -A$ 2 MM		2.266	42	3.30	−0.98	6.1%
CAPEX -A$ 4 MM		2.266	42	5.30	0.93	16.1%
OPEX +A$ 0.05 MM		1.970	27	−1.09	−3.48	0.0%
OPEX +A$ 0.03 MM		2.082	32	−0.30	−3.25	0.0%
OPEX -A$ 0.03 MM		2.439	54	2.87	−2.63	3.1%
OPEX -A$ 0.05 MM		2.743	83	7.26	−2.24	4.7%

Note: OPEX sensitivity relates to the Annual Fixed OPEX element. No sensitivity analysis on the variable OPEX element.

Table 4—Sensitivity Study Results for Vertical Type-Well Example.

Vertical Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Years to Economic Limit	Pre-tax NPV_0 (A$ MM)	Pre-tax NPV_{10} (A$ MM)	Pre-tax IRR
Base Case	1.804	**1.239**	**38**	**−3.51**	**−5.09**	**0.0%**
Price +A$ 4/GJ		1.793	82	5.21	−2.87	3.3%
Price +A$ 2/GJ		1.535	59	0.05	−3.98	0.1%
Price -A$ 2/GJ		0.918	21	−5.91	−6.16	0.0%
Price -A$ 4/GJ		0.546	8	−7.37	−7.08	0.0%
CAPEX +A$4 MM		1.239	38	−7.51	−8.90	0.0%
CAPEX +A$2 MM		1.239	38	−5.51	−6.99	0.0%
CAPEX -A$ 2 MM		1.239	38	−1.51	−3.18	0.0%
CAPEX -A$ 4 MM		1.239	38	0.49	−1.27	1.6%
OPEX +A$ 0.05 MM		0.871	19	−5.28	−5.65	0.0%
OPEX +A$ 0.03 MM		0.983	24	−4.75	−5.44	0.0%
OPEX -A$ 0.03 MM		1.497	56	−2.02	−4.83	0.0%
OPEX -A$ 0.05 MM		1.804	83	3.12	−4.44	1.3%

Note: OPEX sensitivity relates to the Annual Fixed OPEX element. No sensitivity analysis on the variable OPEX element.

Table 5—Breakeven Gas Price Analysis Results for Horizontal Type-Well Example.

Horizontal Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Breakeven Gas Price (A$/GJ)	Years to Economic Limit
Discount Rate = 0%	2.743	2.215	7.49	39
Discount Rate = 5%		2.371	9.01	49
Discount Rate = 10%		2.500	10.50	59
Discount Rate = 15%		2.600	11.79	68

7.5/GJ) is likely to be realisable at the time of writing this paper, in the opinion of the authors. The economics of the example vertical type-well (Table 6) are such that even at a gas price of over A$ 20/GJ (15% pre-tax IRR), a pre-tax NPV_{10} is only approximately A$ 1.75MM. For a horizontal type-well a breakeven gas price around A$ 12/GJ (15% pre-tax IRR), yields pre-tax NPV_{10} of only approximately A$ 1.50MM.

The example horizontal type-well could possibly be economic under the conditions considered. However, in the authors' opinion, to get a reasonable IRR for a commercial project, a price in excess of

Table 6—Breakeven Gas Price Analysis Results for Vertical Type-Well Example.

Vertical Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Breakeven Gas Price (A$/GJ)	Years to Economic Limit
Discount Rate = 0%	1.804	1.522	9.97	58
Discount Rate = 5%		1.804	13.35	83
Discount Rate = 10%		1.804	17.14	83
Discount Rate = 15%		1.804	20.26	83

Table 7—Breakeven CAPEX Analysis Results for Horizontal Type-Well Example.

Horizontal Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Breakeven Well CAPEX (A$ MM)	Years to Economic Limit
Discount Rate = 0%	2.743	2.266	11.30	42
Discount Rate = 5%			8.40	
Discount Rate = 10%			6.98	
Discount Rate = 15%			6.14	

Table 8—Breakeven CAPEX Analysis Results for Vertical Type-Well Example.

Vertical Type-Well EXAMPLE	Technical EUR (BCF)	Post-ELT EUR (BCF)	Breakeven Well CAPEX (A$ MM)	Years to Economic Limit
Discount Rate = 0%	1.804	1.239	4.49	38
Discount Rate = 5%			3.27	
Discount Rate = 10%			2.67	
Discount Rate = 15%			2.31	

A$ 10.5/GJ (10% pre-tax IRR) would need to be achieved. The vertical type-well would require a gas price in excess of A$ 17/GJ to achieve a similar 10% pre-tax IRR.

Breakeven Well Cost (CAPEX) In concluding the example economic analysis, the required breakeven CAPEX (pre-tax basis) at a series of discount rates was evaluated. The analyses were based on the "base case" assumptions of: A$ 8/GJ gas price; A$ 100k p.a. annual fixed OPEX plus A$ 0.10/GJ variable OPEX.

Results in Tables 7 and 8 show the breakeven well CAPEX would have to be in the region of A$ 6 – 7MM for the example horizontal type-well and A$ 2 – 3MM for the example vertical type-well, in order for the well/project to be commercially viable within the bounds of the parameters considered. For the example vertical type-well, this result is understood to be significantly below the current expectation for the cost of drilling and completing such shale gas wells in Australia. However, the results suggest that the example horizontal type-well could provide the basis for a commercially viable project.

Overall, the economic example results emphasise the need to collect production data to establish type-well performance for Australian shale plays. Such activity may also help to reduce well costs through the availability of more rigs and lessons learned in drilling campaigns. In the event that improved production performance and costs cannot be substantiated, potential shale gas development projects may require some form of fiscal support from government to realise viable economic metrics.

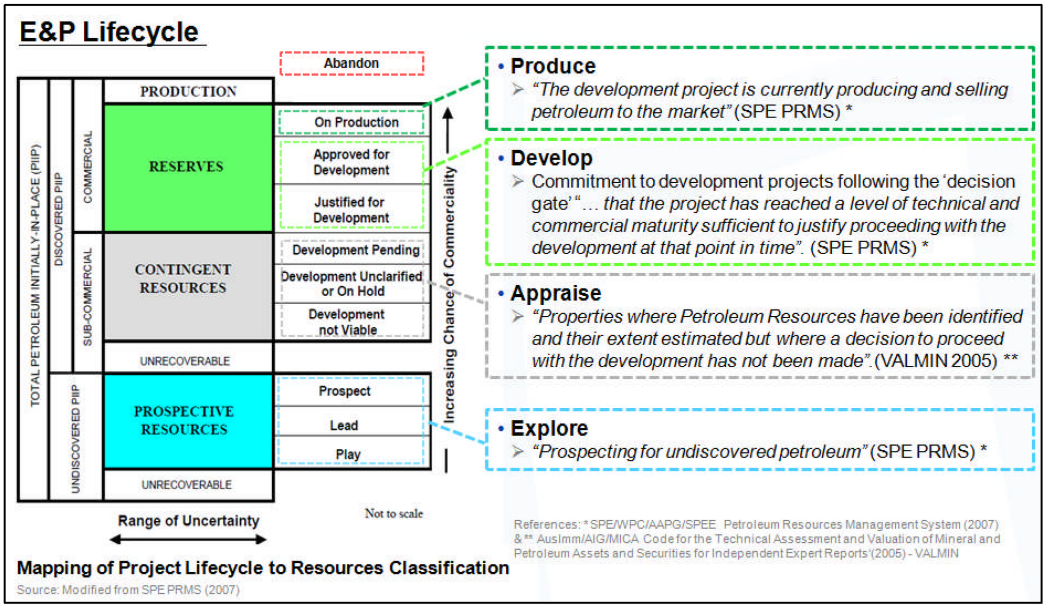

Figure 23—SPE-PRMS (SPE, 2007)[42] and VALMIN Code (AusIMM, 2005)[2] – activity descriptors mapping. The mapping depicted above represents a strong correlation between the lifecycle descriptors and the Resources classification. However the mapping may not always be exact as there is often an overlap between lifecycle descriptors, and therefore it is important to consider other factors when determining the lifecycle phase.

Conclusions

General

The Australian shale gas industry is still very much in its infancy; only a handful of wells have been drilled to test shale plays whereas the US experience has shown that it requires hundreds of wells and a recommended minimum of at least 4 years of production from those wells to establish any meaningful trends from which to predict future performance with reasonable confidence.

Reservoir properties and production characteristics of Australian shale gas plays are, as yet, largely unknown; however, without implying any validity as direct analogues for Australia shale plays, there are now many thousands of wells and many years of production history, available from US shale plays that may provide generic insights and empirical understanding. Five such shale play basins have been retrospectively analysed in this paper.

If analogue reservoir characteristics are confirmed, through drilling, sampling and production of a statistically significant number of future exploration and appraisal wells, it may be possible to apply some of the trends established from the US examples to predict trends in future performance from Australian shale gas reservoirs within a shorter timeframe.

The type-well analyses summarised in this paper exhibited consistent indications of modification to fracture dominated flow regimes, generally occurring between one to two years after the start of production. This observation is likely related to geomechanical stress redistribution effects in response to initial production depletion by the individual wells. The analysis in this paper suggests that Duong's (2010)[16] underpinning fracture dominated equations still apply although in some configuration that may have been modified by the local stress changes induced by early fracture depletion. This later flow regime is herein referred to as "Modified Fracture Dominated" (MFD) flow.

It is recognised by the authors that subsequent modification to type-well flow regime is possible. This could result from further geomechanical effects or well/reservoir boundary effects, etc. However, the authors contend that interpretation of very late time flow regime effects is extremely challenging and somewhat speculative based on the US shale production histories available to date.

The areal variation in well performance is significant within a particular shale play, even for the type-well sample averages evaluated in this paper's analysis. However, characteristic correlations for each are evident between initial monthly production rate and technical EUR. The variation of these characteristic correlations between basins can be even more significant, based on the study of the five US shale plays summarised herein.

Implications for Australian Shale Gas Basin Appraisal Programs

The US analysis presented in this paper has demonstrated the application and value of statistical approaches to large volumes of shale gas production data that may also have merit in similar Australian unconventional resources plays in due course. In particular, the focus in this paper has been on evaluating type-well characteristics from statistically significant sample sizes and production durations based on US shale gas well history. Operating companies should primarily seek to understand such shale gas type-well performance, as part of exploration and appraisal programs. Reasonably accurate type-well performance estimates are critical to facilitate reliable development project investment decisions.

The nature of understanding shale plays requires that the mind-set of operating companies' management, who may be considering their potential exploitation, must be conducive to the use of statistical approaches. The key type-well performance uncertainties relate to initial average monthly gas rate, subsequent decline performance, technical EUR, as well as the commercial environment in which companies operate. For those companies, some key decisions pertaining to exploration/appraisal phase factors that affect type-well results include: well trajectory, perforation interval length, well sample size, well production testing duration/stability, etc.

Empirical observations from the US shale plays analysed in this paper may be informative for the current Australian situation. The technical EURs are correlated to initial monthly gas rates, but the scatter around the correlation is significant even when considering sample averages (Means) as inherently represented by the type-well analyses. The initial monthly gas rates are approximately log-normally distributed: by inference from the previous point, the same may be expected for the individual well technical EUR's distribution. US horizontal shale gas type-wells are significantly better performing in terms of initial gas rate and technical EUR than vertical type-wells evaluated in the same plays. The US data analyses demonstrate a correlation between perforation interval length and technical EUR which emphasises the imperative objective of maximising economic completion length in shale plays.

A significant duration of production data (several years) is required for appraisal well samples in order that associated type-well history matches and forecasts may yield reasonably accurate estimates of shale play performance characteristics. Reasonably accurate type-well performance estimates are critical to facilitate reliable development project investment decisions. Based on the US production data analysis presented in this paper, it is recommended that at least 30 wells with at least 4 years of undisturbed production data should form the basis of appraisal program samples for reasonably reliable type-well technical EUR estimates in shale plays.

It is conceivable that such type-well information could ultimately indicate that potential development projects within a particular Australian shale play are not commercially viable, despite the recommended magnitude and duration of appraisal well performance data acquisition. Operators must recognise the possibility of such an outcome prior to embarking on shale play appraisal programs with very significant associated costs. It may take a significant period to acquire a statistically meaningful sample to realise that the venture may not be commercially viable. A conclusion that may be inferred is that shale play development could be best suited to companies who have conventional oil and gas assets in their portfolio, as a hedge to better mitigate unconventional resources' inherent risks. By corollary, it could be a very risky venture for a start-up company.

In the context of the currently embryonic status of shale play assessment in Australia, the authors note that ensuring public availability of shale play production performance data e.g. through regulatory reporting requirements (as in the United States) could play a crucial role. Such information is key to enhancing current explorers' and/or potential operators' understanding of overall shale play performance characteristics in a time effective manner. Pragmatic regulatory policy, including encouraging transparent availability of production and other shale data, can thus promote possible development project investment decisions being more efficiently justified, to all concerned stakeholders' potential benefit.

Implications for Australian Shale Gas Reserves and Resources Assessments

The petroleum industry commonly uses the activity descriptors 'Explore', 'Appraise', 'Develop', 'Produce' and 'Abandon' in connection with the increasing maturity (respectively) of resources exploitation projects (Figure 23). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

The project represents the link between the petroleum accumulation and the decision making process, including budget allocation. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e. spend money), and there should be an associated range of estimated recoverable resources for that project.

The inherent variability within shale plays, as illustrated in this paper, has significant implications on how such resources are exploited. Whilst it may be possible to declare commercial production from single well projects in areas with established infrastructure, as in the Cooper Basin, it is more likely that a large-scale project will contain multiple localised projects, resulting in the simultaneous occurrence of all lifecycle phases. Exploration, Appraisal and Development projects activities can therefore co-exist within a given tenement. As recognised by Burkholder et al. (2012)[7]: "*In unconventional, the demarcation line between appraisal and development is blurred as teams attempt to simultaneously hold acreage, explore, appraise and develop, ever striving to increase the pace to commercial sanction*".

By definition, under SPE-PRMS, an entity reporting Reserves (Figure 23) in a particular area is concerned with associated development project activities targeting: ". . . *those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.*" In addition, and especially critical for Unconventional Resources: "*To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests.*"

A key conclusion from the activity phases and definitions summary above is that extreme caution must be exercised with respect to up-front declarations of commerciality for large areas/projects in unconventional resources shale plays. Investment decisions for incremental projects (relatively small compared to the total shale play size) are almost certain to be the norm. The latter is driven by the need to gradually evolve understanding of the type-well performance and geological characteristics, whilst assessing incremental projects' viability during continual changes in the commercial environment.

Disclaimer

This paper includes forward-looking statements. This document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of engineering, geoscience and economics data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the paper's recipients and/or actual results. The opinions and statements contained in this paper are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

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Nomenclature

a	= Intercept constant, as defined by Duong (2010)[16].
m	= Slope, as defined by Duong (2010)[16].
q	= Monthly average gas rate (Mscf/d).
Gp	= Cumulative gas production (Mscf).
Ro	= Vitrinite reflectance (%).
t	= Time (months).
tD	= Dimensionless time (function of a and m coefficients) as defined by Duong (2010)[16]
λ	= Rock incompressibility.
μ	= Rock shear rigidity.
ρ	= Rock density.
σ_{hmax}	= Maximum horizontal stress.
σ_{hmin}	= Minimum horizontal stress.
σ_v	= Vertical overburden stress.

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