An M&A Evaluator Guidebook

Your job is to seek, evaluate and close merger and acquisition (M&A) opportunities. You know the odds are against you – you might close 1 in 20 or 30 of the deals that cross your desk. For efficiency, use shortcuts to discard deals early. This guide serves to help M&A evaluators navigate acquisitions, forecasting and constructing type wells.

Make a List

Be clear about your goal in acquiring an asset or company. Itemize the characteristics you require and those that would be beneficial but not necessary. Rank the must-have characteristics in increasing order of the time it will take to check this off your list and process the easy ones first. Your first objective is to find a reason to walk from the deal because your requirements cannot be satisfied.

Some factors that may cause you to reject a deal prior to completing a full evaluation could include:

- The target company does not have enough production to satisfy your exit rate shortfall
- You cannot take on more debt, and a share exchange will not be accepted
- Seller's assets are not close enough to your own
- You have developed a mistrust of the seller
- There is an unacceptable liability – debt, legal action, environmental, contractual
- The gap between buyer and seller best estimate of remaining recovery is too great

Sources of Information

Whether you are working on an existing deal or scouting for opportunities, you will never have enough information. Following are some sources that can supplement your evaluation:

- Regulatory filings including annual and quarterly reports, reserves filings, comment letters (SEC) and annual information forms (Canada) – all available from EDGAR in the US and SEDAR in Canada
- Investor presentations and company web sites
- Analyst reports from reputable brokerage firms
- Public data re-sellers
- Research companies (by subscription)
- Government (state and province) websites

Reserves Categories and Reports

Operators should work with best estimate forecasts (proved plus probable) until you think highly enough about the deal that you intend to proceed with a complete evaluation.

In the US, reserve reports are prepared by the owner, audited by the third-party evaluator, and almost universally report only proved values. At the time of sale, the seller may provide a valuation based on its forecasts for all reserves categories or the report may be prepared and/or audited by a third party. In either case, it is possible that the contents are biased toward the seller's interest.

In Canada, forecasts and reserve reports are prepared by a third party and include all reserves categories plus contingent resources. For a sale, the report may be updated to include converted PUD's and changes to the forecasts. These updated reports will reflect a seller's bias.

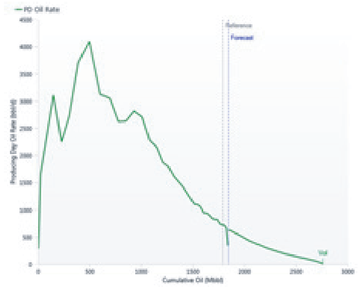
An operator should not rely on a third-party or seller-prepared report. As a minimum, you should do some quality control on the production forecasts and pay close attention to how type wells were prepared and used to assess PUDs. Forecasts are fundamental to a reliable evaluation but are highly subject to evaluator discretion.

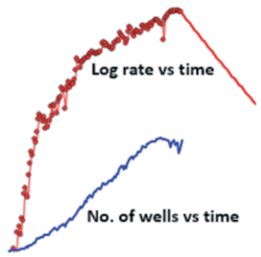
Forecasts From Groups of Wells

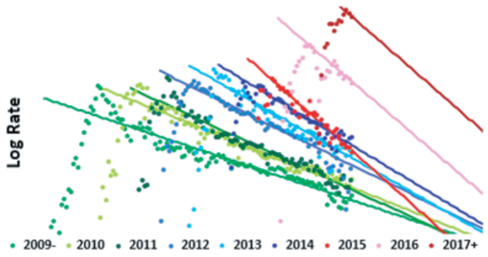
Subject to two caveats, grouping similar wells is a good shortcut for checking forecasts or creating your own. Ultimately individual well forecasts will be required for type wells and economics (fixed well costs).

- The forecast period must exclude new wells that would otherwise flatten the decline. Grouping by vintage (year of first production) is effective.
- Sometimes a change in production trend cannot be observed in a group. Create more than one group to confirm consistency year over year.

When checking forecasts of others, look to confirm that the forecast continues the trend from history, as seen in the plot to the right. If it does not, confirm that the well-by-well forecasts in the group are accurate.







The previous graph pair shows an example where more than 400 wells were drilled over a 10-year period. Normally ongoing drilling will flatten a decline and result in an unreliable forecast. In this case, the pace of drilling resulted in production growth, preventing a decline.

On the right side, the wells were separated into groups by vintage, each group capturing one year of 1st production. The wells in each year may now be reliably forecast because the influence of new producers lasts for only a year, leaving a long period suitable for decline curve analysis. Observe the decline trend is exponential, removing the likelihood of a final low b-value hyperbolic.

The average well rate grew year over year offset by steeper declines. Decline calculations result in similar recovery per well. One might speculate that this production acceleration may relate to more intense fracturing each year. If confirmed, there is a clean data set to identify the optimum fracture intensity for future wells.

In the most recent two years, there have been significant improvements in rate with little change in decline factors. This improvement could relate to fracture length or well length. In either case, you have identified well groupings to form type wells and with the type wells evaluate whether these changes were cost effective, influencing the value of the asset.

Individual Well Forecasts

For a complete evaluation, forecasts should be made at the well level. When used, automated forecasts need to be checked and amended as necessary. Modified hyperbolic forecasts must switch at a decline factor that has been substantiated by data. When a well has forecasts for multiple reserve categories, the distribution should be approximately normal.

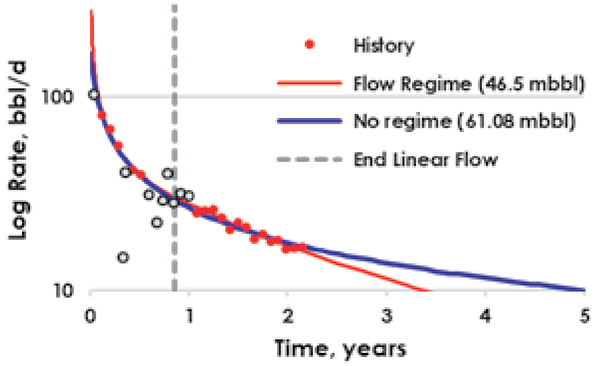
New producers will not have enough data for decline curve analysis. For these wells we recommend multiplying a type well rate-time profile by a constant to align type well and measured rates. Projection of the aligned type well into the future is the new well forecast (Hanson Wade REU, Houston, 2013).

For unconventional wells, a common erroris to forecast using a modified hyperbolic equation without considering there are two flow regimes. The error is compounded by switching to a 2nd segment at an inappropriate decline factor (or time). Often best fits span two flow regimes resulting in a 0.8 < b < 2.0 and an overestimation of remaining reserves (SPE DAPUB Workshop, Denver, Apr 17, 2019).

An example is shown to the right. Linear flow ends at 0.85 years when the nominal decline is 59 %/year. The 2nd segment has a b-value of 0.5 consistent with recommendations of Fetkovitch. The predicted recovery is 46.5 mbbl.

The blue line in the example fits all the data to a hyperbolic equation with b-value of 1.61 and is representative of the common error. The switch to segment 2 is exponential and occurs when the nominal decline is 15%. The recovery of 61.1 mbbl is 31% higher than a proper forecast.

The end of linear flow will depend on total compressibility, half the distance between fractures squared, effective permeability and other factors that are less significant. This implies that gas wells may produce in linear flow 15 times longer than oil wells. As fracture intensity increases the steeper decline of post linear flow will occur much sooner. Do not assume a constant value for the decline at the end of linear flow. Listen to what your wells are telling you and adjust for differing completions.



Type Wells and Puds

Type wells are normally constructed as the average of time shifted (or normalized) analogous wells. When only historical data is averaged, the effect is that wells with no data to average behave as though they continue to produce at the type well rate. More reliable type wells are obtained when both history and forecast are averaged (SPE Distinguished Lecture, Freeborn, 2016-2017). To avoid survivor bias, depleted wells are treated as though they continue to produce with a zero rate.

When the number of analogous wells is small compared with SPEE Monograph 3 recommendations, there is a greater likelihood that the sample will not represent the population (URTeC 2018 2892021). The referenced study shows that having fewer wells than recommended will result in a probability distribution that is flatter than the true population with a larger P10/P90 ratio (i.e. more risk). The small sample type well will overestimate the mean because it places a greater proportion of wells on the right side of the logarithmic distribution.

To put an uncertain population into perspective, examine SPEE Monograph 3's recommendation that a 60 well type well with P10/P90=4.0 will be reliable. If the sample comprised 100 wells, the P10/P90 ratio would have a small 12% increase in reliability from 1.16 to 1.30. However, it is not uncommon for evaluators to have only 20 analogous wells. In that circumstance, the P10/P90 ratio would change from 1.16 to 1.61, a 39% reduction in reliability.

For PUD's, current US practice is to determine a mean type well and assign that profile (and reserve) to every well with the reserve category based on proximity to existing production. The inherent assumption is that if enough wells are drilled, the average performance of the wells will be the same as the mean type well and there will be no risk. However, acreage and well design has uncertainty that can only be described with enough samples. Simply drilling more wells doesn't alter the uncertainty that is not captured in the type well. The practice of assigning the mean forecast to every reserve category is flawed. That's why it's best practice to reduce type well rates when the sample size is smaller than recommended.

About the Author

Randy Freeborn is a subject matter expert in the field of empirical forecasting, type wells and related technology. Currently, he is the Principal Industry Advisor at Aucerna where he is responsible for identifying and inventing engineering technology for inclusion in the company's reserve management software.