

DCA AND EUR DOCUMENTATION

1.0 Production Decline Curve Analysis (DCA) and Estimated Ultimate Recovery (EUR) in Catalyst

From the start of production, every oil and gas well is a declining asset. Typically, there is a fixed amount of hydrocarbons a well will produce over its lifetime, and each month the well produces, the remaining recoverable amount decreases. Production decline analysis is a basic tool for forecasting production from a well. After a well's maximum production level (or IP) has been reached, there is a decline in production, mainly due to some combination of pressure depletion, displacement of another fluid (gas or water) and changes in relative fluid permeability. Plots of production rate versus production history (time or cumulative production) illustrate declining production rates as cumulative production increases. The estimated ultimate recovery (EUR) is obtained by extrapolating the trend to an economic production limit (or point at which it is no longer worth producing the well).

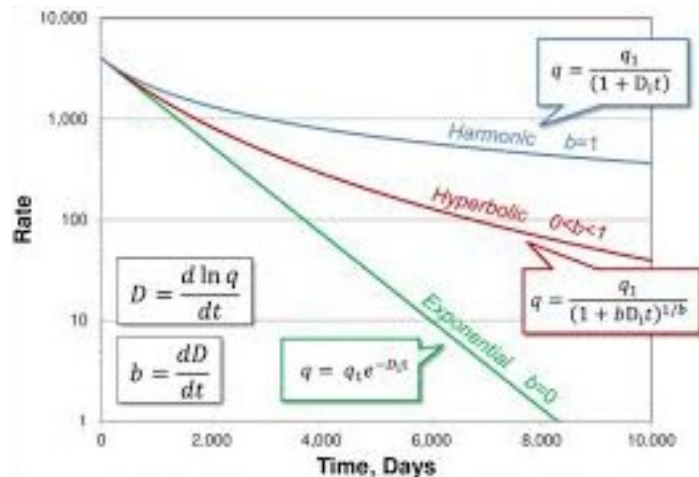
J. J. Arps (1945, 1956) developed the initial series of basic decline curve equations to model well performance. These models are exponential, hyperbolic and harmonic (Figure 1). The models show the trend that best fits the production profile of the well.

The models are based on the following equation:

$$q_t = \frac{q_i}{(1 + bD_it)^{1/b}}$$

In the equation above, q_i = initial production rate, q_t = the production rate at the given time, t = time, D_i = initial decline fraction, b = hyperbolic exponent from (0 to 1). The equations are classified as exponential, hyperbolic, or harmonic, depending on the value of the exponent 'b' that characterizes the change in production decline rate with the rate of production. For exponential decline, 'b' = 0; for hyperbolic 'b' is generally between 0 and 1. Harmonic decline is a special case of hyperbolic decline where 'b' = 1.

Figure 1: Types of Decline Models, from Martin (2015) after Arps (1945)



The type of decline model used tends to be dictated by the type of reservoir being considered. High permeability single phase oil and gas wells at high pressure tend to exhibit an exponential decline (see [Section 1.1](#) below). Low permeability gas and oil reservoirs are generally produced using horizontal drilling and multi-stage fracturing, which is better modelled using a hyperbolic decline ([Section 1.2](#)), where the early steep decline results from flow within the fracture network and the late shallower decline represents the reservoir matrix contribution. Often, the reservoir matrix contribution exhibits “infinite-acting” flow behaviour, which results in a b factor greater than 1, which is termed as “beyond hyperbolic” decline (Whitson, 2024).

Although a decline curve can be depicted by one of the models shown above, in many cases the decline is represented by an assimilation of the hyperbolic and exponential models. It has been seen that hyperbolic or harmonic models alone have historically tended to overestimate cumulative production. Due to this, a conservative model will normally have a “transition” point in which a hyperbolic or harmonic decline will transition to an exponential decline.

1.1 Vertical Wells and Exponential Decline Curves

Oil and gas wells producing from conventional (>10 mD) reservoirs under primary depletion (or fluid expansion) generally exhibit exponential decline trends due to their high permeability and good pressure continuity. The trend line has a constant slope, signifying a steady decline over time. The majority of vertical wells in Catalyst undergoing primary recovery are forecasted using this technique. Wells assigned to pools undergoing secondary and tertiary recovery are not included in this analysis, as the pressure support from injection of gas, water or other fluids will increase the recovery and affect the slope of the curve.

The Exponential decline equation is:

$$q_t = q_i e^{-D_i t}$$

Where q_i is the initial production rate, q is the production rate at time t , t is the elapsed production time, D is an exponent or decline fraction ($1/d$). The first step is to determine the IP_GAS or IP_OIL in bbl/d, the most recent production in bbl/d, and the decline period, and solve for the nominal decline rate D .

Solving for the nominal decline rate D_i gives:

$$D_i = -\ln \frac{q_t}{q_i} / t$$

The expected ultimate recovery, or EUR, is the amount of hydrocarbons potentially recoverable, and is represented by the cumulative production (N_p) to time t or q_2 given by:

$$N_p = \int_{t_1}^{t_2} q_t dt = \int_{t_1}^{t_2} q_i e^{-D_i t} dt = (q_1 - q_2) / D_i$$

Vertical wells producing less than 1bbl/d or 25 mcf/d are considered at or near “end of life” so have not been forecasted in Catalyst. In these cases, the EUR is equal to the cumulative production of the well.

1.2 Hyperbolic Decline Curve Models

Low permeability gas and oil reservoirs are generally produced using horizontal drilling and multi-stage fracturing, which is better modelled using a hyperbolic ($0 < b < 1$) or beyond hyperbolic decline ($b > 1$). These models assume the decline rate will change during the life of the well. In Catalyst, these hyperbolic and beyond hyperbolic declines are modelled using Blue River's Energy Analytics for Energy (A4E) Software Suite.

Most of the wells with more than six months of production are analyzed using autofitting algorithms in the A4E software, which calculates a decline curve for the main production streams (gas and/or oil) in each well using available data. It then uses the decline curve to estimate an EUR for each production stream, and finally reports a combined EUR in BOE.

In most DCA software – including the one used - hyperbolic decline curves are comprised of two effective decline rates, one that represents early production - or the initial nominal hyperbolic

annual decline rate (d1) - and one that represents the later production, where the decline rate is essentially exponential (d2). In the models done for Catalyst, a summary table captures the main parameters for each well such as the IP gas or oil, the time on production, the b value, the d1 and d2 value, and the EUR. These are available upon request in the event there is a desire to reproduce this decline in another software package.

Also included in the model parameters and constraints are:

- an outlier threshold, which ignores points more than 3 standard deviations away from the smoothed production curve;
- a “start-stop” algorithm, which ignores significant production jumps in early production and focuses the forecast to times of consistent, more “well-behaved” production;
- Upper and lower bounds for the b from 0.6 to 2.2 - for example, if a horizontal well has limited early production, it will force a hyperbolic decline trend of at least 0.6;
- Guidance on Dmin, where d2 is limited to 8% and the transition occurs within 72 months.

The reason for the large range in b is that the b factor changes with flow regimes and responds to well-to-well boundary interactions (Paradis, 2017). For example, tighter reservoirs tend to have higher b factors, since these have longer transient flow. However, infill wells will have lower b factors than parent wells, due to well-to-well interactions. Since our analysis tends to encompass large regional areas, we need to allow for a wide spectrum of reservoir quality and well to well interaction scenarios. In horizontal wells for most formations, b factors for liquids and oil curves tend to range from about 0.7 to 1.6, while b factors for gas curves tend to range from 0.8 to 2.

1.3 Decline Parameters and Data Availability

In our experience, wells with four years of production data or more tend to have sufficient data such that the models are less impacted by the parameter modifications above. As a result, these declines have been run in the A4E software using autofit parameters and will be less likely to require re-forecasting than newer wells. These older wells will only be re-forecasted should an issue be observed with the initial forecast or the monthly production deviates significantly from the forecast.

Wells with less than four years of production data tend to require significantly more monitoring and this will be the focus of updates in the application. These wells will require at least quarterly changes in the forecast for the following reasons:

- Wells with less than about three years of production often need tighter autofit constraints for guidance

- Wells are often on confidential for the first year and therefore will often not have liquids production available for forecasting (see below), so will need to be re-forecasted once coming off confidential
- Wells with less than 6 months of production often do not have sufficient data points to create a proper decline curve using the autofit parameters. As a result, parameters from a type-well will need to be used to manually create a decline curve for the well until sufficient points are available for the well to be fit using the software algorithms.

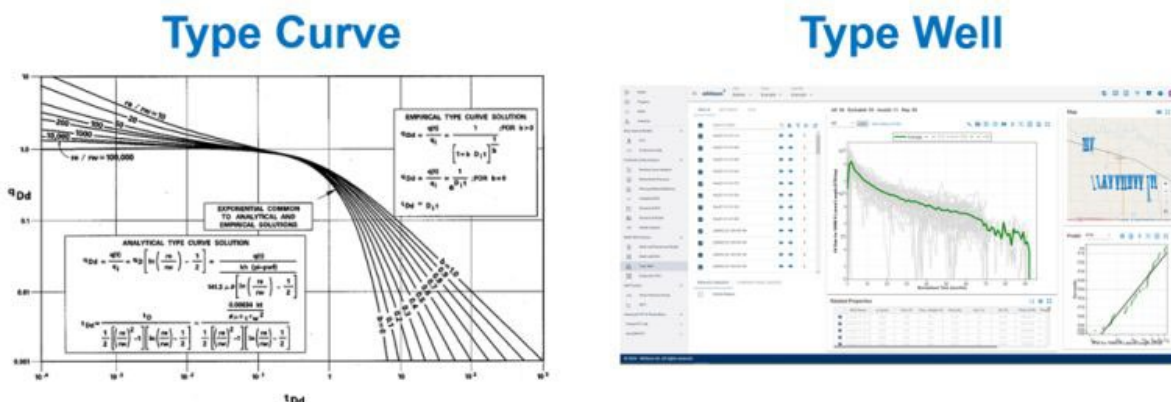
Number and Types of Decline Curves for each Well Forecast

For most horizontal wells, only declines for the wellhead gas and oil streams are available in Catalyst. For liquids-rich unconventional plays such as the Montney, Duvernay and Spirit River, three decline curves have been provided: a pentane+ curve that represents “oil” (pentane, wellhead condensate and oil); an ethane+ curve that includes “total liquids” (ethane, propane and butane added to the “oil” stream) and a marketable gas stream.

1.4 Type-Well Curves in Catalyst

Type-Well Curves are often referred to as “Type Curves” but they have distinct definitions. Type Curves refer to idealized production plots by fitting mathematical models to historical production data or based on reservoir characteristics. Type-Well Curves are derived from actual production data of wells, statistically averaged to represent the expected performance of a typical well.

Clarification: Type Well vs Type Curve



In Catalyst, wells in the Western Canadian Sedimentary Basin (WCSB) are grouped into unique bins (detailed plays) for each formation based on pressure, temperature, facies, and the shape

of the production profile. Wells with more than six months of production were auto-forecasted using Blue River's Energy Analytics for Energy (A4E) Software Suite. Historical and forecasted production data were utilized to generate P10, P50, and P90 Type-Well Curves for each unique bin, as recommended by the Canadian Oil and Gas Evaluation Handbook (COGEH). Currently, the Montney, Duvernay, Spirit River, Clearwater, and Viking formations have Type-Well Curves available.

1.5 EUR Descriptions and Ranking Well Results

All wells in Catalyst will have an "EUR Description", which explains how the well was forecasted or why the well was not forecasted (there are currently nine distinct EUR Descriptions). A significant number of wells are "excluded" due to well status – either production has not started, or well has been suspended, or abandoned, etc. Both horizontal and vertical wells with an active status but have insufficient production data or have not been producing for the last three months or more have also been excluded. Others have been excluded due to being identified as part of an enhanced oil recovery (EOR) scheme, making the forecasting significantly more complex. There are some wells that have been flagged as potentially part of an EOR scheme that still have forecasts, however a note has been made in the EUR description, and the forecast should be used with caution. Older vertical wells actively producing less than 1 bbl/d or 25 mcf/d are considered at or near "end of life" so have also not been forecasted in Catalyst. In these cases, the EUR is equal to the cumulative production of the well.

Active vertical wells not meeting the exclusion criteria have been forecasted using an exponential decline curve as described above. Most active horizontal wells not meeting the above exclusion criteria are forecasted using the A4E software as described above. However, as mentioned previously, wells with less than 6 months of production often do not have sufficient data points to create a proper decline curve using the autofit parameters, and are not currently reporting liquids data as they are still on confidential. CDL will update decline curves on these newer wells approximately quarterly (December, March, June and September) so decline curves for newer wells can be updated based on the latest production. Older wells will only be re-run if the production begins to significantly deviate from its current forecast.

All horizontal wells that have been forecasted are evaluated within their detailed plays to determine their ranking. Wells with the minimum and maximum EURs are used to define the bounds respectively with 100 being the worst. The percentile calculations and ranking is performed for each main production stream (gas and oil) and one for the combined well BOE. The percentiles can be binned to allow easy scoping and comparison across operators and detailed plays.

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