Decline Curve Analysis for Oil Production Forecasting

A Practical Shell Guide

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NOTICE

A reserves "how to" document provides guidelines and best practices on a common topic to help ensure that methods and practices are applied in accordance with the rules and requirements for proved reserves reporting. To ensure consistency across Shell, such documents are prepared, extensively reviewed and provided for staff use. These guidelines are not stand-alone but must be fully integrated with all other reserve requirements to produce compliant results.

This document must be read in the context of the EP1100 requirements, the definitive version of which can be found at sww.shell.com/ep/rvr.

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General Considerations

One of the oldest techniques for forecasting oil and gas production from producing fields, Decline Curve Analysis (DCA) remains an important tool for the modern reservoir engineer. The transparency of the method makes it particularly attractive for supporting the estimation of reserves that are compliant with the United States of America's Securities and Exchange Commission's (SEC's) requirements. The practice of DCA has developed over the years through both theoretical and empirical considerations. Although the fundamental principles are well known and understood, there are aspects of the practical application of the method that are open to interpretation and which can therefore lead to a range of forecasts and reserve estimates.

This document is intended to provide 'best practices' guidance to the practicing reservoir engineer whose task it is to estimate SEC compliant reserves for producing oil fields using DCA, to reduce the variability in the application of the various methods and to promote consistent practices throughout the Shell organization. It is one component of a broader training program implemented by Shell on the subject of DCA. An important accompanying component of this program is the training material developed by Wim Swinkels and R.T. (Bob) Miller.

Shell's interpretation of the SEC rules and regulations are set out in the document 'Petroleum Resource Volume Requirements', (EP-1100). The EP-1100 document is the definitive reference that all Shell staff involved in estimating SEC compliant reserves must follow. As the document is updated periodically, those parts of the document that pertain to DCA are not quoted here. The user of this DCA manual is therefore encouraged to consult the EP-1100 document to ensure that she or he is fully acquainted with the most recent Shell views on all matters relating to reserve estimation, including the use of DCA. In summary, the EP-1100 document:

- recognizes the difficulties associated with estimating Proved Reserves that are SEC compliant using sophisticated techniques such as reservoir simulation, and consequently encourages the use of simple DCA for production forecasting from reservoirs which have sufficient historical production data showing clear production trends, and where the production trends are due to the physical processes taking place in the reservoir;
- stipulates that forecasts based on DCA methods must always be done at the lowest producing level except where there is evidence of interference or usable data exists only at a higher level;
- encourages the use of DCA in a support role to ensure that the requirements of reasonable certainty are satisfied in those instances where forecasts are based on reservoir simulation.

The subject of DCA is discussed in this manual in the context of its use for analyzing existing production data for trends that are then projected into the future and used to support Proved Reserve estimates. By definition, these are Proved Developed Reserves. However, there is scope for making forecasts that can be used to estimate Proved Undeveloped Reserves by combining the principles of DCA with analogue studies. This topic is not covered in this manual. Other uses of DCA not discussed in this manual include its role in support of other methods, such as numerical simulation or volumetric estimates, where the DCA trends provide useful additional information, but are not sufficiently robust to be used as the primary reserve estimation tool.

In this document the term DCA is used in a broad sense to cover a variety of types of trend analyses of production data used for production forecasts and estimating reserves. In addition to the common methods in which oil and gas rates are analysed, trends in gas-oil-ratio, water-cut, water-oil ratio, etc. are all considered to form part of the DCA method. This document does not attempt to provide a theoretical basis for DCA and deals specifically with the practical application of the method. Furthermore, the P/Z technique used for gas fields is not covered in this text.

While the focus of this document is on the application of DCA for estimating SEC compliant Proved Reserves, DCA can and should where appropriate, also be used for estimating Expectation Reserves. It is often greatly beneficial, when carrying out DCA in support of Proved Reserve estimates, to make forecasts suitable for supporting Expectation Reserves at the same time. This helps to balance perspective, and to encourage the analyst to consider the difference between that which can be considered 'reasonably certain', and that which is 'expected'.

The focus of this text is on the use of DCA for analyzing trends in production from oil reservoirs. However, many of the principles described in this text can be adapted and applied to gas wells.

The Golden Rule of Decline Curve Analysis

Extracted from Thomas Frick's 'Petroleum Engineering Handbook of 1962', in the section dealing with the subject of ‘Production-decline curves’

‘The basic assumption in this procedure is that whatever causes controlled the trend of a curve in the past will continue to govern its trend in the future in a uniform manner’

1 Equations and Nomenclature

The DCA literature abounds with contradictory terminology. In this chapter, the nomenclature selected by Shell is summarised.

1.1 Basic Equations and Symbols

Shell has adopted a set of standard symbols, which are fully described in Shell's DCA training material. In this manual, we have limited the equations, symbols and nomenclature to the essential ones needed by a reservoir engineer estimating reserves for producing assets using DCA. The symbols used in this text, together with their dimensions in square parentheses, are

$t =$	time
$q_t =$	(instantaneous) oil production rate at time t [volume per time unit]
$q_i =$	(instantaneous) initial oil production rate (at time $t = 0$) [volume per time unit]
$N_t =$	cumulative oil production at time t [volume]
$b =$	hyperbolic exponent [dimensionless]
$D =$	effective decline factor [per time unit]
$d_i =$	initial nominal decline factor [per time unit]

The term 'initial' signifies the point at which the decline function begins, and is a point selected by the analyst somewhere in the historical dataset. The time, as used in our formulae, is set equal to 0 at this point (i.e. $t = 0$). In this text, reference is frequently made to 'time steps' (Δt). This term is used to signify some increment in time, such as 1 day, or 1 month, or 1 year.

The expression that forms the basis for all DCA is

$$q_t = \frac{q_i}{(1 + b \cdot d_i \cdot t)^{\frac{1}{b}}}, \qquad \text{Equation 1}$$

which gives the explicit relationship between the instantaneous production rate and time. It should always be remembered that q_t (including the special case q_i) is the <u>instantaneous</u> rate at time t (or $t = 0$), and is not an average value over some interval of time. All other forms of the equations commonly used in DCA can be derived from this equation. For example, the relationship between cumulative production and time is obtained by integrating Equation 1 from initial conditions to some time, t,

$$N_t = \frac{q_i}{d_i(1-b)} \cdot \left(1 - (1 + b \cdot d_i \cdot t)^{\left(1-\frac{1}{b}\right)}\right), \qquad \text{Equation 2}$$

which is referred to as the 'integral form' of the equations.

As will be discussed in later sections, the value of the hyperbolic exponent, b, varies from 0 to 1, i.e. $0 \le b \le 1$. However, it is clear that 0 cannot be substituted directly for b in either Equations 1 and 2, so when we refer to b taking on a value of 0, we are actually referring to the limiting case as b is made smaller and smaller and 'tends to' a value of 0.

Besides the independent variable time, the three basic parameters in Equations 1 and 2 that characterize a declining production trend, and which we strive to determine when carrying out DCA, are the initial rate, q_i, the hyperbolic exponent, b, and the initial nominal decline factor, d_i. Having completed a DCA on the production from a well, an analyst should have an appreciation of the values of each of these parameters for that particular well. The significance of each is discussed in the following sections.

Initial rate (q_i)

This is the instantaneous flow rate at time $t = 0$, and is the easiest of the parameters to determine. It is the rate at the start of the decline function, and occurs somewhere in the historical part of the dataset. It is invariably important to consider another important rate, namely the rate at the transition from history to forecast, referred to as the first rate of the forecast. Generally, a forecast begins on the day that the history ends, and the first rate of the forecast is ideally equal to the last recorded rate of the history. It is however, not always prudent to select the last historical rate as the value of the first rate of the forecast, as it frequently better to maintain a continuous trend from history to forecast, which may not necessarily pass through the exact value of the flow rate on the last day of the history period. This aspect is described in detail in Chapter 6.

The hyperbolic exponent (b)

The term b, which has no units, is referred to as the hyperbolic exponent, and the general form of Equation 1 is regarded as the hyperbolic equation. It is generally accepted that b can range in value from 0 to 1 in the context of DCA for oil and gas wells. However, there are cases where the value of b exceeds 1.

The term b occurs in two places in Equation 1. Firstly, it appears alongside the initial nominal decline factor d_i as an effective 'scaling factor' of the time axis. Its function in this regard is similar to the mathematical function of d_i described in later sections. Of more importance is the occurrence of b in a mathematically powerful position in the exponent of the denominator of Equation 1. It is in this capacity that a large values of b (i.e. close to 1.0) has a dominant effect on the shape of the curve of q_t vs. t at as t becomes large. A high value of b (close to 1) causes the late time 'tail end' of the curve to remain elevated. For a given set of values of q_i and d_i, the short-term shape of the curve is not greatly affected by the value of b, while the long-term shape is. If $b = 0$, the tail declines rapidly, while if $b = 1$ (or greater), the tail continues for much longer. The higher the value of b, the flatter and longer the tail.

The value of b is normally obtained by fitting Equations 1 or 2 to real data points, using some form of data-fitting algorithm (such as least squares). Because the value of b has a subtle effect on the shape of the curve when the time interval is short, attempting to estimate the value of b by curve fitting can prove to be very insensitive, especially when real, noisy data are being considered. Consequently, it is often possible to fit a spectrum of curves represented by a wide range of values for b to the same dataset quite convincingly. However, because the value of b dominates the shape of the curve in late times, these curves can lead to very different estimates of recovery when used for forecasting. In particular, software packages that automatically return a value for b that gives the 'best fit' to a dataset without warning the user of how much better this 'best fit' is than any other fit, can be extremely dangerous for the purposes of reserve estimation. Reliability in the value of b increases as the maturity of the well's production increases.

The discussion so far may give the impression that b is merely a mathematical parameter that is obtained through a statistical fit of a function to a dataset. However, such a view does not give credit to the scientific and engineering grounding of DCA. In reality, the value of b captures a multitude of physical phenomena. There are many theoretical considerations that support the selection of a particular value of b over another. Various published works exist on the selection of the value of b for a particular drive mechanism.

We distinguish two special cases of the hyperbolic decline function, namely exponential decline when $b = 0$ and harmonic decline when $b = 1$. When b takes on one of these two values, the terms 'exponential' and 'harmonic' are used. The term 'hyperbolic' covers the full range of values for $0 \le b \le 1$. The term 'general hyperbolic decline' is often used to describe those cases that are neither exponential nor harmonic, i.e., for $0 < b < 1$. These are described in turn below.

Exponential decline. As the value of b tends to 0, Equation 1 takes on the form of an exponential function, i.e. rate (q_t) is an exponential function of time (t) and we refer to this as exponential decline. In this instance, Equation 1 reduces to the simple form

$$q_t = q_i e^{-d_i t}, \qquad \text{Equation 3}$$

while the integral from of the equation (Equation 2) becomes

$$N_t = \frac{q_i}{d_i}\left(1 - e^{-d_i t}\right) = \frac{q_i - q_t}{d_i}. \qquad \text{Equation 4}$$

This is the simplest of all the decline equations and the easiest to work with. An exponential function has the following characteristics:

- It is often referred to as the 'constant decline function', because the ratio between the rates at the end of two consecutive time steps is always constant, i.e.

$$\frac{q_{t+\Delta t}}{q_t} = e^{-d_i \Delta t}. \qquad \text{Equation 5}$$

This expression shows that the rate decreases by the same fraction or percentage over each time step.

- A plot of $\ln(q_t)$ vs. t (natural logarithm of rate vs. time) is a straight line, with slope equal to $-d_i$, and y-intercept equal to $\ln(q_i)$,

$$\ln(q_t) = \ln(q_i) - d_i t. \qquad \text{Equation 6}$$

- A plot of $\log_{10}(q_t)$ vs. t is a straight line, with slope equal to $-C_1 d_i$, and y-intercept equal to $\log_{10}(q_i)$,

$$\log_{10}(q_t) = \log_{10}(q_i) - C_1 d_i t, \qquad \text{Equation 7}$$

where C_1 is the constant

$$C_1 = \frac{1}{\ln(10)} = 0.43429\ldots. \qquad \text{Equation 8}$$

Similarly, a plot of q_t against t is a straight line if a linear scale is used for the x-axis, and a logarithmic scale is used for the y-axis.

- A plot of q_t vs. N_t, is a straight line with slope equal to d_i and y-intercept equal to q_i,

$$q_t = q_i - d_i N_t. \qquad \text{Equation 9}$$

- The exponential function provides the most conservative forecast of the family of hyperbolic-type functions used for forecasting oil and gas production. It is used more than any other hyperbolic function for the purposes of estimating Proved Reserves, as it invariably represents a 'high confidence' case.

Harmonic decline. When $b = 1$, the resulting equation is referred to as 'harmonic'. (This is in fact a misnomer, as the function is not harmonic in the mathematical sense, i.e. it does not satisfy Laplace's equation). Nonetheless, if $b = 1$ then Equation 1 simplifies to:

$$q_t = \frac{q_i}{(1 + d_i \cdot t)}, \qquad \text{Equation 10}$$

and the integral form of the equation simplifies to

$$N_t = \frac{q_i}{d_i}\ln(1 + d_i t) = \frac{q_i}{d_i}\ln\left(\frac{q_i}{q_t}\right). \qquad \text{Equation 11}$$

The harmonic function has the following characteristics:

- A plot of $\ln(q_t)$ vs. N_t is a straight line, with slope equal to $-d_i / q_i$, and y-intercept equal to $\ln(q_i)$,

$$\ln(q_t) = \ln(q_i) - \frac{d_i}{q_i} N_t. \qquad \text{Equation 12}$$

- The ratio between the rate at the end of a time step and the rate at the end of the preceding time step is a declining function of t, i.e.

$$\frac{q_{t+\Delta t}}{q_t} = 1 - \frac{d_i \Delta t}{1 + d_i t}. \qquad \text{Equation 13}$$

This expression shows that with every time step, the rate decreases by a percentage that gets smaller as time progresses.

- The harmonic function provides the most optimistic forecast of the family of hyperbolic-type functions used for forecasting oil and gas production (except of course when the value of b exceeds 1). It is not as commonly used for estimating Proved Reserves as the general hyperbolic and exponential decline functions. Indeed, if the harmonic function is used for this purpose, a strong argument is needed in support of it being a high confidence case.

General hyperbolic declines. When $0 < b < 1$, Equations 1 and 2 apply, with the following characteristics:

- No plot results in a straight line when $0 < b < 1$.
- As with the harmonic function, the ratio between the rate at the start of a time step and the rate at the start of the preceding time step is a declining function of t, but in this case, the rate at which the ratio gets smaller, is inversely proportional to the value of b.
- The degree of conservatism of a hyperbolic function is inversely proportional to the value of b. Low values of b give more conservative forecasts than high values of b, and are more likely to be used to support Proved Reserves.

The initial nominal decline factors (d_i)

The initial nominal decline factor d_i, defines how rapidly the instantaneous production rate (q_t) declines with time. d_i is the most important parameter in the decline functions which we strive to determine through DCA. For the purposes of production forecasting, d_i has a numerical value greater than 0. The smaller the value of d_i, the slower the rate of production decline. The mathematical interpretation of d_i is that it is nothing more than an inverse scaling factor applied to the time axis. The smaller the value of d_i, the more the production profile is stretched in the direction of the x-axis. If $d_i = 0$, then the production profile is stretched to infinity, there is no decline, and $q_t = q_i$. If d_i has a very high value, then the production profile is squashed up, and the decline is precipitous.

d_i has units of inverse time. However, its physical significance is not always easy to comprehend. For the hyperbolic function, i.e. for $0 \le b \le 1$, the role of d_i can be gleaned by taking the derivative of q_t with respect to t in Equation 1, and setting the time equal to 0,

$$\left.\frac{dq_t}{dt}\right|_{t=0} = q_i d_i, \text{ or } d_i = \frac{1}{q_i}\left.\frac{dq_t}{dt}\right|_{t=0} \qquad \text{Equation 14}$$

which shows how d_i is related to the slope of the production rate vs. time curve at $t = 0$. In other words, if we have q_i and the slope of the tangent to the q_t vs. t curve at $t = 0$, we can calculate d_i directly. More generally, d_i is estimated by fitting the equation to the actual production data spanning a period of time.

The use of the effective decline factor (D)

It is frequently convenient to consider a parameter called the effective decline factor, D. This is a practically useful parameter that does not appear in any of the equations discussed so far. D is defined as

$$D = \frac{q_t - q_{t+\Delta t}}{q_t}, \qquad \text{Equation 15}$$

and is the difference between the instantaneous rate at a given time t, and the rate at the end of the subsequent time step $t + \Delta t$ expressed as a fraction (or percentage) of the rate at time t. Put differently, it tells you by what fraction the instantaneous rate at some point in time will decrease over the next time step.

Unlike the initial nominal decline factor, d_i which is the single value equal to the slope of the tangent to the curve of q_t vs. t precisely at $t = 0$, the value of D both changes with time (except in the special case of exponential decline) and depends on the size of the time interval, Δt. Both of these properties affect the way in which D is used.

Because the numerical value of D depends on the time interval, it is necessary to stipulate the time interval over which the calculation is done, for example 1 day, 1 month or 1 year when quoting a value of D. If the time interval is not stipulated, then the value of D is meaningless. Most commonly, the time interval chosen is 1 year, and D is typically expressed in 'percent per annum', which tells you by what percentage the instantaneous rate will decline from, say 1ST January this year to 1ST January next year.

Because D is a constant with respect to time for $b = 0$, it is particularly useful when working with exponential decline. In this instance, D is related to the initial nominal decline factor, d_i, through the simple relationships

$$D = 1 - e^{-d_i \Delta t}, \text{ and } d_i = \frac{-\ln(1 - D)}{\Delta t}. \qquad \text{Equation 16}$$

Note that the time step, Δt, appears in both these equations. For exponential decline, D takes on a constant value that is useful for characterizing the performance of a well. Any analyst undertaking a DCA study of a number of wells in a reservoir should have an acute awareness of the effective decline parameters of the wells and how these compare with one another. The first question an analyst should expect after having carried out a DCA is *"…and what are the decline rates of the wells?"*.

D also has an important function when the hyperbolic equation is used, particularly for high values of b. When extrapolations are made far into the future with a high value of

b, the effective decline parameter becomes very small, and may become unreasonably small. It is therefore always necessary to exercise caution when extrapolating production rates into the distant future with a high value of b. It is insightful to include, on a plot or table of rate vs. time, the changing value of D as a function of time. This permits an informed judgment to be made as to whether the decline rate is still reasonable or not, and if necessary to decide upon, and impose, a limiting minimum value below which D should not be permitted to go. The minimum permissible value of D depends on circumstances and there is no value that can be applied universally. The analyst must make a judgment on the minimum value for D that is suitable for her or his particular circumstances. For example, analogue information from other wells in the same reservoir can be a very useful source of information to support the selection of a minimum value for D. The numerical value of D can be determined by

$$D = 1 - \left(\frac{1 + bd_i (t + \Delta t)}{1 + bd_i t} \right)^{-\left(\frac{1}{b}\right)} . \qquad \text{Equation 17}$$

Note that D is a function of b, d_i, t and, importantly, Δt. Note also that while the value of the initial nominal decline factor d_i can be changed very easily from one unit of time measurement to another, say from 1/day to 1/year by multiplying by 365, this is NOT the case for the effective decline parameter D. This is because the effective decline factor has no units. It is therefore incorrect to say, for example, *"my effective decline is 3% per month, and therefore must be 12*3%=36% per annum"*. If the value of Δt is changed, then the corresponding value of D must be re-calculated from Equations 15, 16 and 17.

Consistency of units

It is very important to ensure that a consistent set of units is being used. If q_t is expressed in units of stb/d, then q_i must also be expressed in stb/d, N_t will be expressed in stb, t must be measured in days, and very importantly, d_i which has units of inverse time, must be expressed in 1/day, when the formulae are used. It is frequently convenient to consider d_i in different units from those used in the formulae, say for comparative purposes, and the value of d_i can easily be converted. For example, if d_i is expressed in units of 1/day, and we what to know what the corresponding numerical value is in units of 1/year, we simply multiply d_i by 365.

1.2 Other Terminology

Reasonable certainty. *'The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.'* (SEC guidelines, March 31, 2001).

High confidence. In many aspects of applying DCA the analyst is faced with making decisions, such as selecting the appropriate historical interval for trend analysis, or selecting the decline rate. When there is more than one option to choose from, and the analysis is being used to underpin a SEC compliant Proved Reserve estimate, then a 'high confidence' option should be selected. In this context, a 'high confidence' option does not mean the option which you are the most confident is correct, or which you are confident is closest to the truth, or for which you are the most confident of its accuracy (all of which would lead you to your 'expectation' case). A 'high confidence' option is an option that you are reasonably certain will result in a reserve volume that is more likely to increase in future as more data become available, than it is to decrease.

TRV. Technically Recoverable Volume. The volume of oil or gas estimated to be recoverable from a well, reservoir or field over its full production life from the start of production until a technical limit is reached (such as a maximum value of water-cut, or a maximum value of GOR, or end of well life), but with no economic 'cut-off' limits being applied. TRV is the sum of the historically produced volumes and the volumes yet to be produced. This is not a reserve, which is the remaining volume of oil or gas that will be economically recovered from a particular date forward. TRV is a useful entity to use for year-on-year comparisons, as it relates to a fixed start date and is not affected by fluctuating economic parameters. Be aware that the term TRV is ill-defined in the literature, and is used by different people to mean different things.

Nomenclature:

abscissa	the '*x*'- or horizontal axis of a graph
ordinate	the '*y*'- or vertical axis of a graph
linear-log	refers to a plot on which a linear scale is used on the abscissa, and a logarithmic scale is used on the ordinate
WOR	water-oil ratio
fw	fractional water-cut
fo	fractional oil-cut
GOR	gas-oil ratio
CGR	condensate-gas ratio

2 Different Plots and What They Mean

This section describes the variety of plots that can be used in DCA. The merits and dangers of each are listed, and guidance is given as to the preferred type of plot to use in particular circumstances. It is not possible to be prescriptive in this matter, and indeed, a reservoir engineer carrying out DCA, would do well to try several different plots in the process. It can be quite surprising to see how different a dataset looks when plotted in a different way.

The easiest trend for the human eye to identify is a straight line. Therefore, when doing DCA, we tend to use plots that are likely to show us straight lines. While there is nothing fundamentally wrong with this approach, it does frequently lead to a bias towards the use of certain 'favourite' plots, regardless of whether they are the best plots for the type of problem or not. Logarithmic scales in particular are very effective in creating the illusion of a straight line and in some instances, the use of logarithmic axes can be very misleading. This is due to the logarithmic scale 'de-sensitising' the data which is precisely what we do not want. This is not always the case, and in some instance, the use of a logarithmic scale is highly desirable. This is discussed further in paragraphs that follow.

An obsession with straight lines puts one in the undesirable position of being restricted to either exponential decline or to harmonic decline, the two extremes of the spectrum of hyperbolic functions, as these are the only two of an infinite number of possibilities that deliver straight line plots (there are no simple plots that deliver straight lines for decline functions for which $0 < b < 1$). An analyst seeking the best solution will not restrict herself or himself to a straight line plot and will therefore be exposed to a whole new spectrum of possibilities.

However, this text has been compiled specifically (but not exclusively) for the purposes of supporting Shell's efforts respecting the estimation and reporting of SEC compliant Proved Reserves. Proved Reserve volumes, must, by definition, be known to a high degree of confidence. Where uncertainty exists in estimated volumes, a high confidence number must be selected for the purposes of underpinning the Proved Reserve. Where the range of uncertainty in forecast recoverable volumes stems from uncertainty in the hyperbolic exponent for example, a recoverable volume corresponding to a low (high confidence) value of the hyperbolic exponent that still provides a convincing fit to the historical data, should be selected to support the Proved Reserve estimate. The onus rests on the analysts to use professional judgment in selecting decline parameters that are aligned with the SEC’s requirement of ‘Reasonable Certainty’ for Proved Reserve volumes. The use of a higher value of the hyperbolic exponent may be used if it can be supported by a sound analogue case.

In the paragraphs that follow, the different types of plots are discussed. In most cases, a generic plot is included that shows what forms an exponential function and a harmonic function would have on the plot.

2.1 The Reference Plot

The reference plot is an essential component of any DCA and audit trail. It contains a variety of information essential for carrying out a DCA, plotted against time. Fluid rates, fluid ratios, cumulative produced volumes, tubing head pressures, choke settings and artificial lift parameters should all be included as necessary. Precisely what information is included in the reference plot depends on the circumstances. If a large amount of information is included, then multiple reference plots may be necessary. The plot should be annotated with well events and other important operational activities, such as work-overs, changes in separator conditions, etc. It is often desirable to have a reference plot for each well, in addition to a field level reference plot.

The reference plot for a well is used to select the interval for trend analysis and to decide what type of analysis plot is most appropriate for the particular well. It is up to the analyst to decide what data should be included on the reference plots. The guidance is that if a piece of information can influence any decision taken during the DCA, then it should be included. For example, if the gas lift quantity allocated to a well changes, then this should be annotated as it will affect the decision regarding the interval to be used for trend analysis. If a well has developed a high water-cut, then this should be plotted, as it will influence the decision regarding which plot to use for the analysis.

2.2 Rate vs. Time using Linear Axes and the 'Final check' Plot

(q_t vs. t)

It is seldom desirable to carry out a DCA directly on a plot of q_t vs. t (Figure 1). Reservoir performance is particularly vulnerable to being masked by well downtime on this plot. It is consequently often difficult to 'see through' the 'downtime noise' to the underlying reservoir related trend that determines the decline parameters. In almost all cases, a more suitable plot than a q_t vs. t can be found for the purposes of carrying out DCA. This plot is not recommended for carrying out the analysis itself.

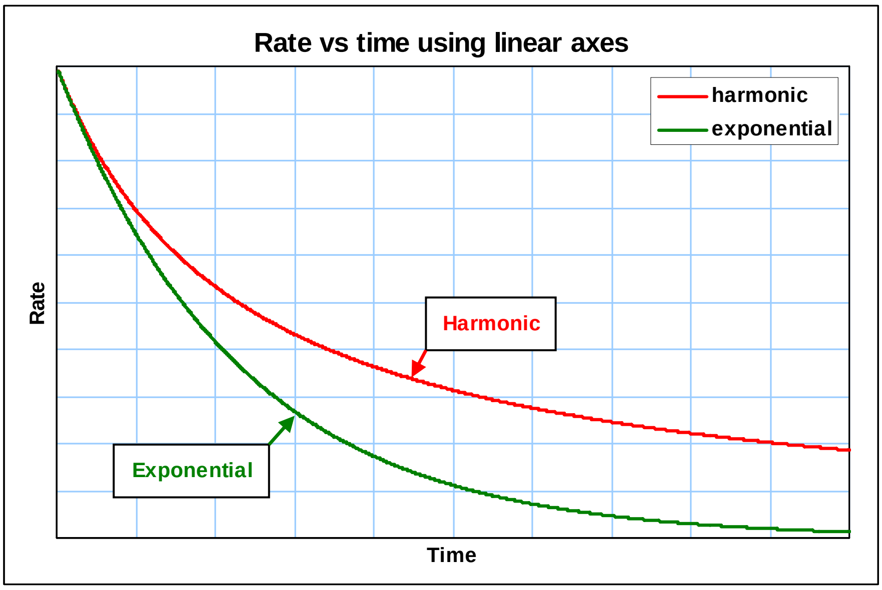

Figure 1: An exponential function and a harmonic function on a rate vs. time plot using linear axes.

However, the q_t vs. t plot does have a vital role in the DCA process. It is the final plot that any DCA should end with, and this 'final check' plot should show both the historical production rates and the forecast derived from the DCA. After all, we are ultimately most interested in the production rate as a function of time, and this plot provides the final check of the reliability of the DCA derived forecast. Points to check on the 'final check' plot are:

- Does the continuity between history and forecast look reasonable? There should be no discontinuity between history and forecast, and there should be a seamless transition from the historical profile into the forecast.
- Does the forecast go on for an unreasonably long time into the future? If so, consider truncating the forecast at a reasonable time in the future. Look at the length of the forecast in relation to the length of the period used to define the trend, and ask yourself the question: "Am I reasonably certain that this trend is sufficiently reliable to support the length of my forecast?"
- Make sure that the profile does not extend beyond the end of the license period (unless an exception has been justified in accordance with the EP-1100 instructions).
- Make sure that the profile does not extend beyond the life of the facilities.
- Is the overall life of the well as seen on the 'final check' plot consistent with the historical statistics of well life? Furthermore, if the forecast is to be used to underpin a Proved Reserve estimate, is the life of the well as portrayed on this plot consistent with a 'high confidence' estimate of the well's production life, based on historical field statistics.

- Does the oil rate reach values that are unreasonably (uneconomically) low? If so, consider terminating the profile at a reasonable rate.

This plot is NOT recommended for direct DCA. It is required for quality control purposes, and this 'final check' plot of q_t vs. t should show the following, preferably for both the Proved and Expectation cases:

- Historical production data.
- The trend(s) fitted to the historical data.
- The forecast(s).
- The truncation point(s).
- The production forecast(s) from the previous year.

2.3 Rate vs. Time using Linear-logarithmic Axes

($\log(q_t)$ vs. t)

A plot showing production rate on a logarithmic axis against time (Figure 2) is very commonly used for the purposes of carrying out DCA. This is a historically important plot and its use dates from the time when reservoir engineers plotted daily production data by hand on a logarithmic scale against time. Forecasts were made by extrapolating straight lines through the data points. A straight line on this type of plot corresponds to an exponential function,

$$\log_{10}(q_t) = \log_{10}(q_i) - C_1 d_i t \, . \qquad \text{Equation 18}$$

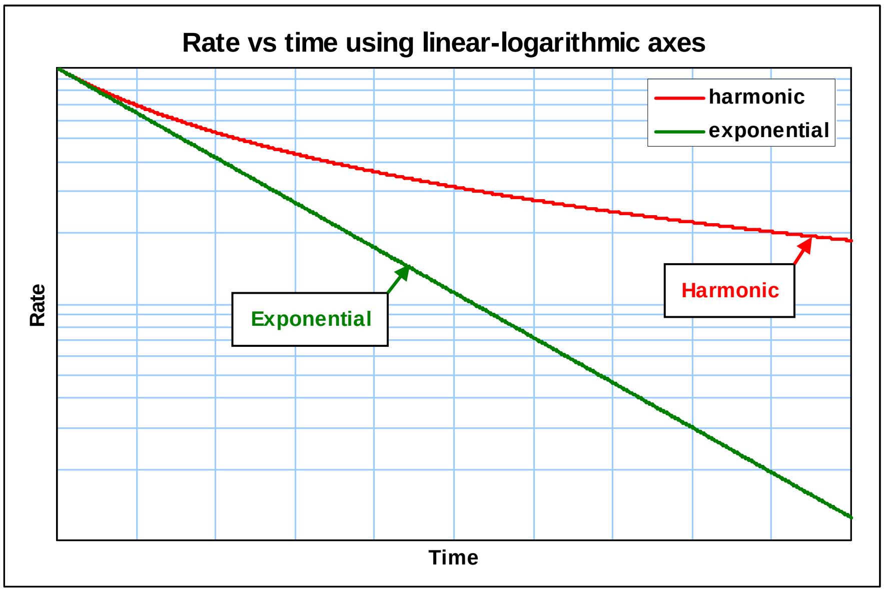

Figure 2: An exponential function and a harmonic function on a rate vs. time plot using linear-logarithmic axes.

Note that plotting rate on a logarithmic scale, as shown in the Figure 2, is equivalent to plotting the logarithm of rate on a linear scale. The former gives a better visual effect, while the latter simplifies mathematical manipulation.

This plot is still widely used today and favoured because it is easy to construct. However, downtime can distort the trends on this plot. In contrast, the rate vs. cumulative production plot (described next) using linear axes, on which an exponential function also appears as a straight line, is less prone to the adverse effects of downtime. Therefore, if there is downtime, it is advisable to accompany the rate vs. time plot using linear-logarithmic axes with the rate vs. cumulative production plot using linear axes.

The rate vs. time plot using linear-logarithmic axes can be very useful for resolving the detail of historical production data when the rates have reached very low values. The use of a logarithmic scale on the ordinate serves to expand the last part of the dataset, allowing fluctuations and important trends that might be compressed and irresolvable on a linear scale, to be seen more clearly. This can be a useful diagnostic tool.

2.4 Rate vs. Cumulative Production using Linear Axes

(q_t vs. N_t)

This plot (Figure 3) is one of the simplest and most useful plots for DCA. Firstly, it reduces (but does not fully eliminate) the adverse effects of downtime experienced with the rate vs. time plot. This is because 'gaps' in the production data during periods of no production disappear when cumulative production is plotted on the horizontal axis instead of time. (However, some problems relating to downtime do still persist; see chapter 8 on the use of 'calendar-day rates' vs. 'producing-day rates'.)

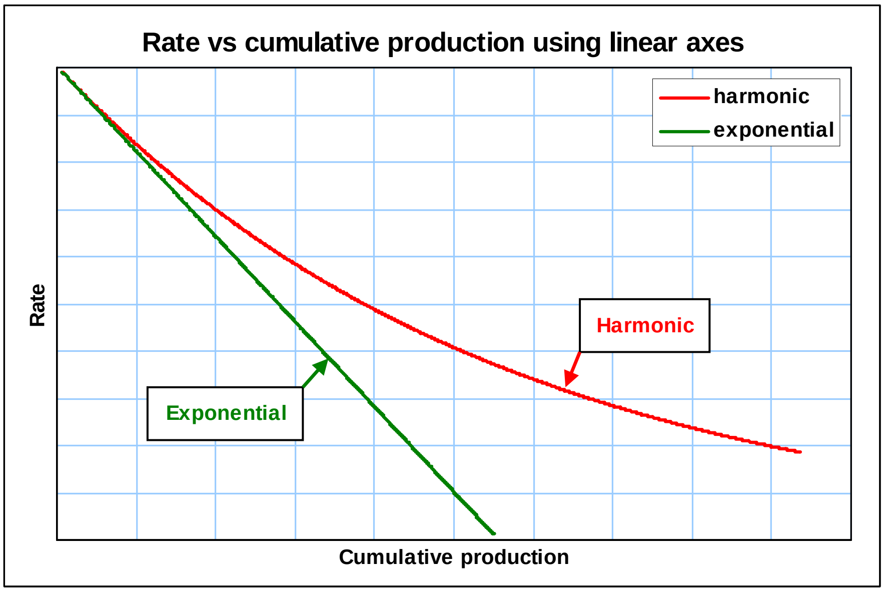

Figure 3: An exponential function and a harmonic function on a rate vs. cumulative production plot using linear axes.

An exponential function ($b = 0$) appears as a straight line on this plot, while the curve for any value of $0 < b \le 1$ is concave. Therefore, by deciding to use this plot, and fitting a straight line through the data points, you automatically select an exponential decline function.

For the vast majority of oil wells, this plot is very useful, and it is strongly recommended that this plot is made whenever DCA is being done. It is useful for testing the effect of different values of b. By changing b and critically reviewing the fit between the theoretical curve and the data points, you can get a good idea of how sensitive the analysis is to the value of b. Invariably, a range of values will give equally convincing fits to the data points. When searching for a 'high confidence' case to underpin Proved Reserves, it is useful to first gain an understanding of the range of uncertainty in b, and then to select a value of b at the low end of this range. This plot is recommended for this purpose because the (high confidence) exponential function results in a straight line on this plot, and as the human eye is drawn to a straight line, there is a greater likelihood of erring on the conservative side rather than on the optimistic side.

Identifying the range of uncertainty in b can be difficult, because the shape of the curve is affected by both b and d_i. However, the influence of b becomes more pronounced later on, while early on the curve is dominated by d_i. In all the plots used in this chapter for illustration, the red (exponential) curve and green (harmonic) curves are seen to coincide early on. This is because the same value of d_i has been used in each, and the value of b has little influence early on. In all case, the curves diverge (significantly) later on, as the value of b (0 for exponential, and 1 for harmonic) becomes dominant. With this in mind, an approach which sometimes works is to:

- Select an early subset of the historical interval to be used for trend analysis.
- Use this subset to estimate a value for d_i. Use some regression method if desired.
- Use the remainder of the curve to fit a range of values for b.
- Select a numerically low (high confidence) value for b from this range.

This plot is recommended for direct use in DCA. (Of course, it must always be accompanied with a 'final check' plot.) If this plot is used, and if an exponential decline function (i.e. a straight line) has been selected, then the straight line can be fitted to the historical data points via some algorithm (say a least squares method), and the intercept and slope of the straight line can be used directly to calculate the values of q_i and d_i, making construction of the rate vs. time forecast easy. If the straight-line fitted to the historical data on the rate vs. cumulative production plot is

$$q_t = c + m \cdot N_t , \qquad \text{Equation 19}$$

where c is the intercept and m is the slope, and if the expression for N_t is incorporated (from Equation 4), then

$$q_t = q_i - d_i \cdot N_t , \qquad \text{Equation 20}$$

from where it follows that

$$d_i = -m , \qquad \text{Equation 21}$$

provided that q_t and N_t are expressed in a consistent set of units. If q_t is expressed in stb/d, and N_t is expressed in stb, then the units of d_i will be 1/day (per day). If for example, q_t is expressed in Mstb/d, and N_t is expressed in MMstb, then the units of d_i will be 1/(1,000days), and the value of d_i will have to be divided by 1,000 to convert it to units of 1/day.

The values of q_i is simply

$$q_i = c + m \cdot N_i , \qquad \text{Equation 22}$$

where N_i is the cumulative production at the start of the forecast.

2.5 Rate vs. Cumulative Production using Linear-logarithmic Axes ($\log(q_t)$ vs. N_t)

This plot (Figure 4) is similar to the previous plot, but a logarithmic scale on the ordinate causes the harmonic function to be a straight line, while all other hyperbolic functions exhibit various degrees of convexity. Therefore, electing to use this plot and fitting a straight line to the dataset implies a priori acceptance of a harmonic function, the most optimistic of the hyperbolic functions. There may therefore be a tendency to over-estimate TRV, and reserves, using this plot.

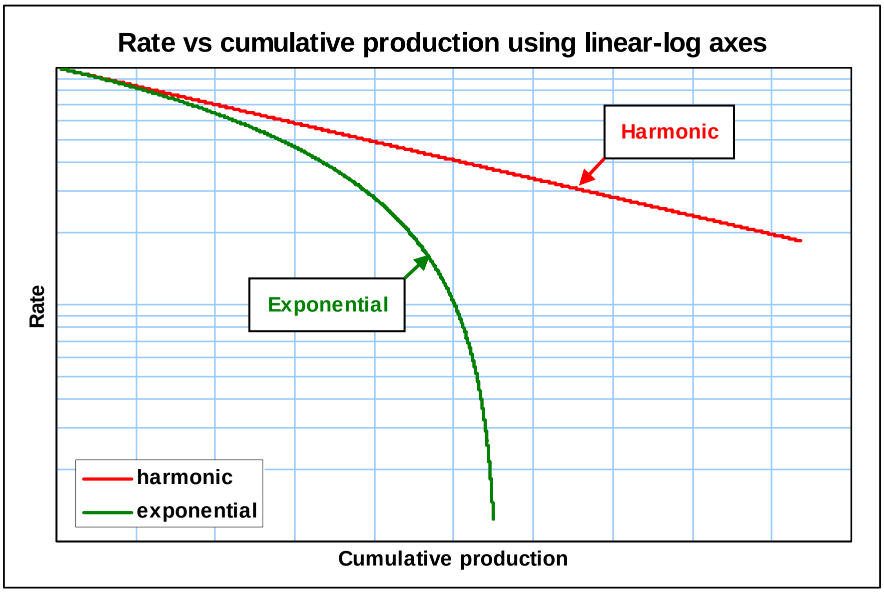

Figure 4: An exponential function and a harmonic function on a rate vs. cumulative production plot using linear-logarithmic axes.

This plot is useful as a diagnostic tool for identifying harmonic behaviour, but other than this, offers little advantage over the rate vs. cumulative production with linear axes. This plot is therefore unlikely to be of much use for an analyst carrying out DCA for the purposes of underpinning Proved Reserves.

2.6 Water-cut vs. Cumulative Production using Linear Axes

(f_w vs. N_t)

This is the classic plot for a well whose oil production rate is declining as a consequence of increasing water-cut (Figure 5). This is typically found in reservoirs with mature active water-floods, or with natural aquifer influx. A great deal of effort has been expended over the years in developing the science and engineering understanding of water-cut development in producing fields, resulting in the publication of numerous sound reservoir engineering methodologies for forecasting water-cut development. This text on DCA covers only a small portion of the very broad subject. Alternative methods that are based on sound reservoir engineering principles can and should be used to support forecasts where possible.

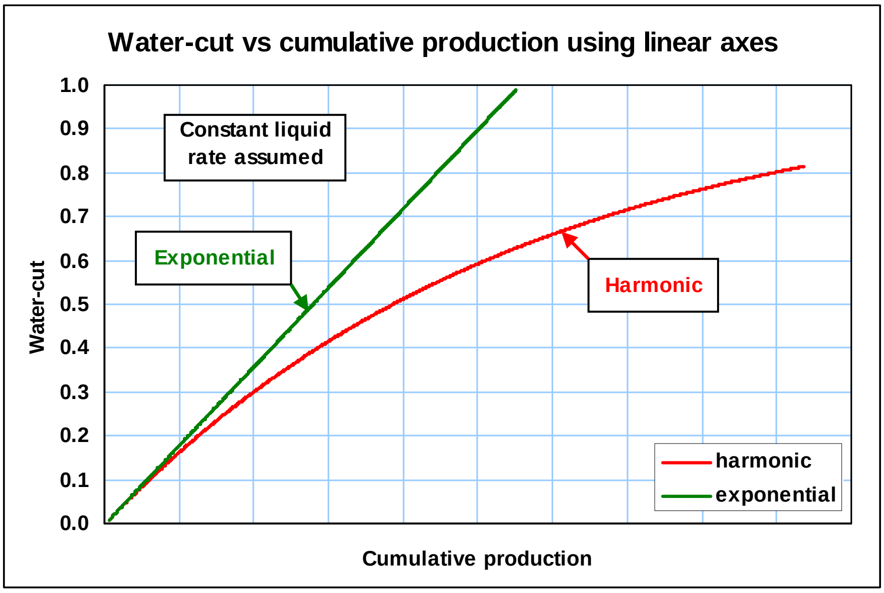

Figure 5: An exponential function and a harmonic function on a water-cut vs. cumulative oil production plot using linear axes, with the assumption that the liquid rate is constant.

In general, extrapolation of a water-cut trend can lead to unreliable results if the trend is not well established. This plot should therefore only be used as the primary analysis tool when the water-cut has reached high values. It is not possible to stipulate above what value of water-cut an analysis will deliver reliable results. It is up to the analyst to make a judgment on this value. For example, analogue information from other wells in the same reservoir can provide a very useful source of information to the analyst in making this judgment.

When the water-cut is still too low for this plot to be used as the primary analysis tool, it still provides important quality control. It is useful to check what the shape of the curve at high water-cut will have to be in order to reach a TRV value derived from the use of some other plot, and to see if this shape is sensible.

This plot (or its inverse, the oil-cut vs. cumulative production on linear axes) is very useful and it should always be constructed when it is known or suspected that water-cut development is the cause of declining oil rates. However, this plot, (alongside several others described below), suffers from a significant short-coming, in that it does not lead directly to an oil rate vs. time forecast, which is what we need to estimate a reserve. In order to derive an oil rate vs. time forecast from the water-cut vs. cumulative production relationship, a forecast of liquid rate vs. time is needed. Without a liquid rate forecast, this plot provides an estimate of TRV, but cannot be used to estimate a reserve.

There are several options for defining a liquid rate vs. time forecast. The simplest and most common assumption is that the liquid rate remains constant into the future. This is frequently an acceptable assumption, but if it is made, then it should be supported with hard data. Furthermore, it must be understood that if this assumption of constant liquid rate vs. time is made (as it has been in the diagram that follows), then a straight line, on a water-cut vs. cumulative production plot, with linear axes, will result in a precisely exponential relationship between oil rate and time. Therefore, if you elect to use the water-cut vs. cumulative production plot, with linear axes, fit a straight line to the data points, and further assume that the liquid rate (oil plus water) remains constant into the future, then you are making the a priori assumption that your oil rate vs. time follows an exponential decline.

An alternative approach for obtaining a liquid rate vs. time curve is to carry out some form of DCA involving the liquid rate itself. This can, for example be by fitting a curve to a plot of liquid rate vs. cumulative produced liquid. If this route is followed, then the resulting 'final check' plot must be reviewed critically, as this approach can lead to an absurd oil rate vs. time curve, which depends on the details of the rate vs. cumulative production relationship. It is seldom necessary to use this method, and for most cases, the assumption of a constant liquid rate is adequate.

Because the water-cut is effectively a parameter that is normalised to have a value between 0 and 1, a degree of 'compression' exists in the curve at high water-cut values. This is a minor disadvantage of this plot, which can be overcome by considering, for example, the water-oil-ratio instead of the water-cut.

When using this plot, it is very important to know what a well's water-cut cut-off value is, and to apply that cut-off before converting to a rate vs. time plot. This cut-off value should preferably be derived from a statistical analysis of historical data. In order to underpin a Proved Reserve, a high confidence (i.e. a low) value of water-cut should be accepted as a cut-off. The cut-off may be related to water-cut indirectly via limitations in the lift capacity of the well, or to economic considerations particular to the well. It is important to apply this water-cut cut-off before converting to the rate vs. time curve, as once the conversion has been made, the all-important link to water-cut is broken. Of course, once the conversion to rate vs. time curve has been made, then all the quality checks that apply to the 'final check' should also be observed.

This plot is recommended for direct use in DCA for wells with high water-cut. It must always be accompanied by a clear statement of the basis for the liquid rate forecast, and by a 'final check' plot. If this plot is used, and if an exponential decline curve (i.e. a straight line) is selected, then the straight line can be fitted to the historical data points via some algorithm (say a least squares method), and the intercept and slope of the straight line can be used to calculate the values of q_i and d_i, facilitating the construction of the rate vs. time forecast. For this plot, this process is a little more complicated than for the plot of rate vs. cumulative production. If the straight-line relationship between water-cut and cumulative production established through the application of some curve fitting algorithm is

$$f_w = c + m \cdot N_t \,, \qquad \text{Equation 23}$$

where c is the intercept and m is the slope of the fitted line, then by introducing the expression for N_t from Equation 4, and assuming that the constant liquid rate is q_l, we get

$$f_w = \left(1 - \frac{q_i}{q_l}\right) + \left(\frac{d_i}{q_l}\right) N_t \,, \qquad \text{Equation 24}$$

from where it follows that

$$d_i = m \cdot q_l \,, \qquad \text{Equation 25}$$

provided that a consistent set of units has been used. If q_l is expressed in stb/d, and N_t is expressed in stb, then the units of d_i will be 1/day (per day). If for example, q_l is expressed in Mstb/d, and N_t is expressed in MMstb, then the units of d_i will be 1/(1,000days), and the value of d_i will have to be divided by 1,000 to convert it to units of 1/day. It is prudent to use a consistent set of units.

The appropriate value of q_i is obtained from

$$q_i = q_l \left(c + m \cdot N_i\right), \qquad \text{Equation 26}$$

where N_i is the cumulative production up to $t = 0$.

2.7 Water-cut vs. Cumulative Production using Linear-logarithmic Axes

($\log(f_w)$ vs. N_t)

This plot (Figure 6) is similar to the previous plot, except that a logarithmic ordinate scale is used. Linear-logarithmic axes cause the last part of a curve with a positive slope (such as water-cut vs. cumulative production), to become highly compressed (in the vertical sense). In the case of water-cut vs. cumulative production, this late behaviour at high water-cut is the most important part of the plot, and it does not help the analysis when it is all squashed up. As mentioned in the discussion of the water-cut vs. cumulative production plot, the water-cut already suffers from a degree of compression, and further aggravating this by using a logarithmic axis is not helpful. This is precisely what we do NOT want when carrying out a DCA, and this plot is therefore not recommended.

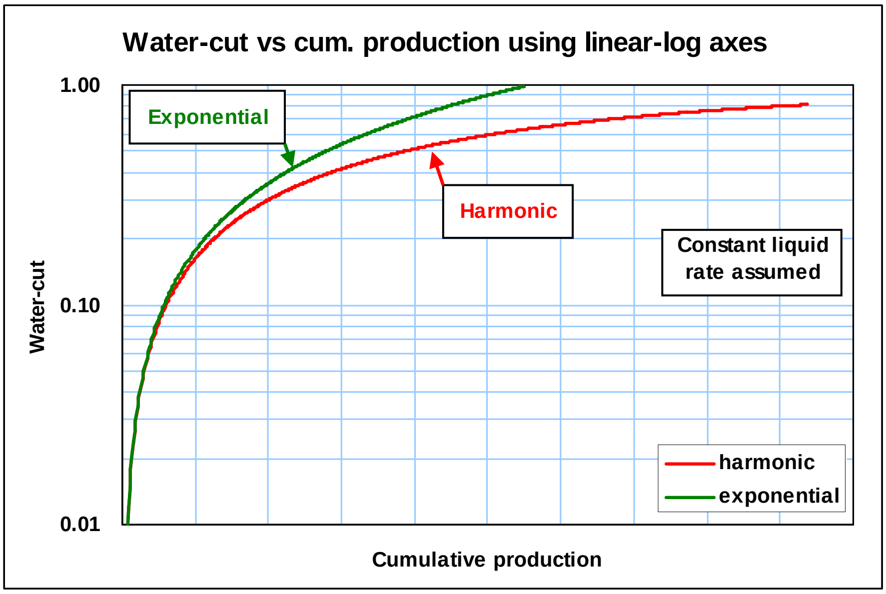

Figure 6: An exponential function and a harmonic function on a water-cut vs. cumulative oil production plot using linear-logarithmic axes, with the assumption that the liquid rate is constant.

2.8 Oil-cut vs. Cumulative Production using Linear Axes

(f_o vs. N_t)

The plot of oil-cut vs. cumulative production (Figure 7) is the inverse of the water-cut vs. cumulative production plot. Everything that applies to the one applies to the other, and they can be used interchangeably. This plot should only be used as the primary analysis tool when the oil-cut is low, say less than about 25%.

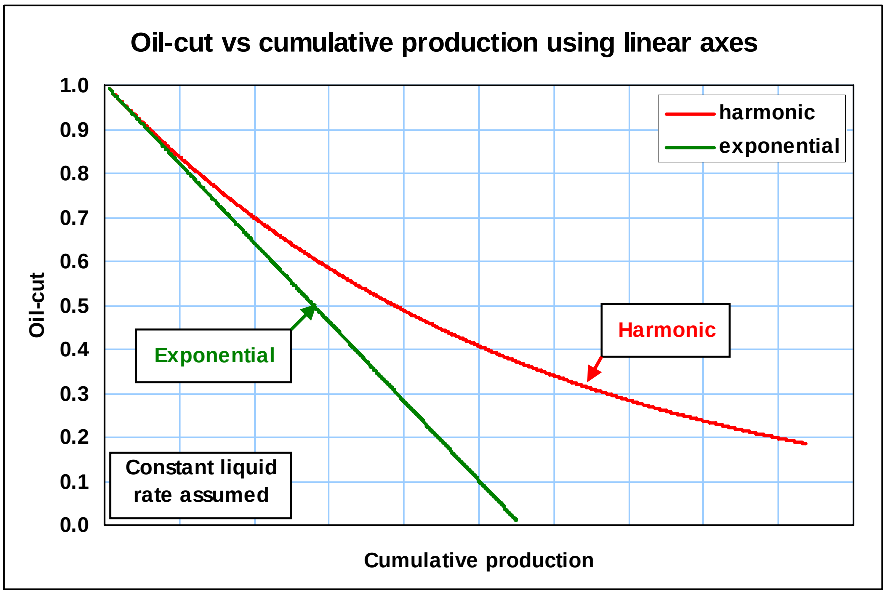

Figure 7: An exponential function and a harmonic function on an oil-cut vs. cumulative oil production plot using linear axes, with the assumption that the liquid rate is constant.

2.9 Oil-cut vs. Cumulative Production using Linear-logarithmic Axes ($\log(f_o)$ vs. N_t)

This plot (Figure 8) is similar to the oil-cut vs. cumulative production plot described in section 2.8 except that a logarithmic scale is used for the ordinate.

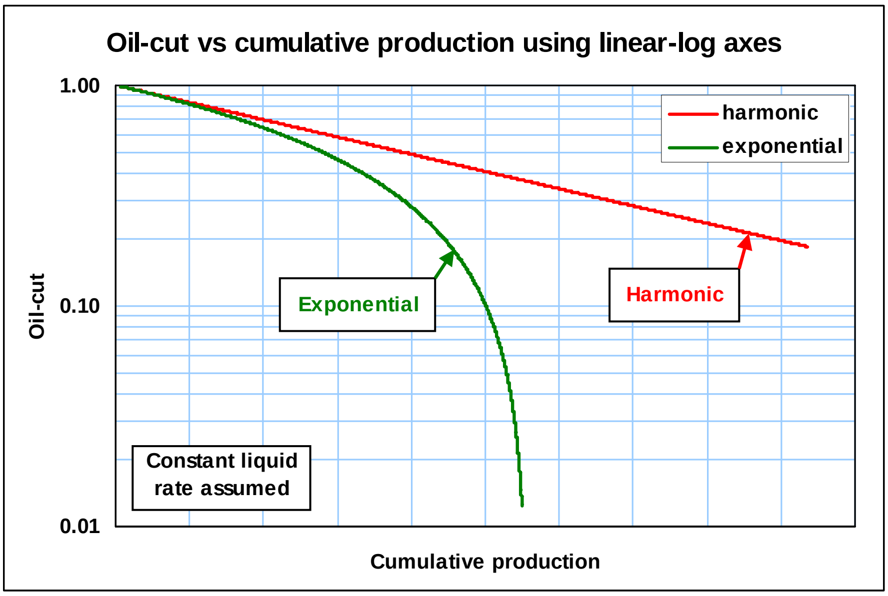

Figure 8: An exponential function and a harmonic function on an oil-cut vs. cumulative oil production plot using linear-logarithmic axes, with the assumption that the liquid rate is constant.

This plot does not provide a direct relationship between oil rate and time, which is required for the purposes of estimating reserves. Therefore, an analysis based on this plot must be accompanied by a relationship between liquid rate and time. If a straight line is fitted to the data points on this plot, and the assumption is made that the liquid rate remains constant into the future (as has been done in Figure 8), then the resulting relationship between oil rate and time is precisely harmonic in nature.

As oil-cut is a declining function of cumulative production (i.e. has a negative slope), the use of a logarithmic scale on the ordinate means that at low values of oil-cut, the curve is stretched in the vertical sense. This is beneficial for observing detail in the part of the curve that is of most interest to us, and for this reason, the use of a logarithmic scale is appropriate in this instance.

This plot is useful for identifying harmonic behaviour, but other than this, offers little advantage over the oil-cut vs. cumulative production with linear axes. This plot is unlikely to be of much use for an analyst carrying out DCA for the purposes of underpinning Proved Reserves.

2.10 The Water-oil Ratio Plot

$$(WOR \textbf{ vs. } N_t)$$

Instead of plotting water-cut or oil-cut, some analysts prefer to plot the water-oil ratio as a function of cumulative production (Figure 9).

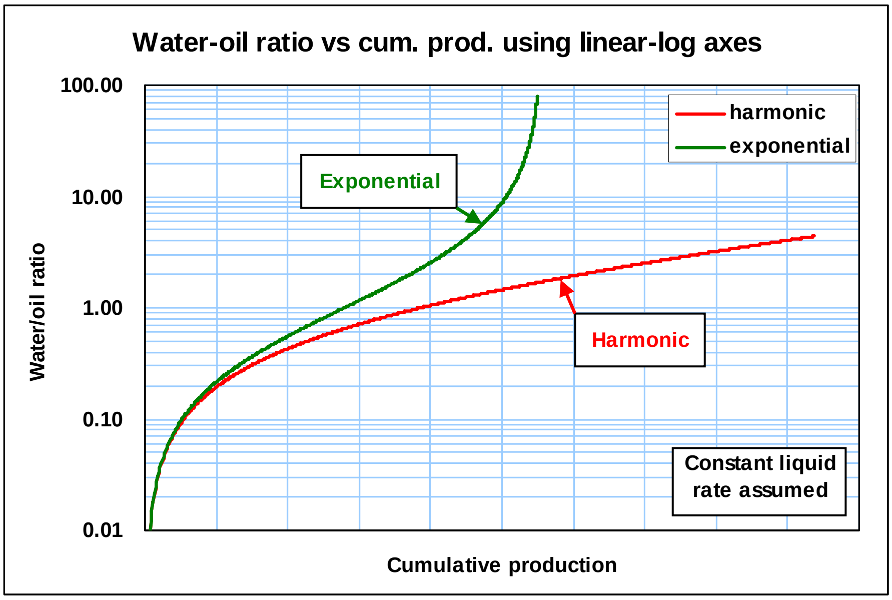

Figure 9: An exponential function and a harmonic function on a water-oil ratio vs. cumulative oil production plot using linear-logarithmic axes, with the assumption that the liquid rate is constant.

The advantage of this plot is that the upper limit of WOR is effectively infinite, and this alleviates some of the compression that occurs in a water-cut or oil-cut plot. Because the water-oil ratio can reach very high values, and span several orders of magnitude, this plot is most frequently made with a logarithmic scale on the ordinate. Despite the earlier stated criticism of the use of a logarithmic scale for a curve with a positive slope, in this instance, the WOR increases so dramatically that a logarithmic scale is appropriate. This plot is useful at very high values of WOR.

This plot does not provide the facility to estimate rate as a function of time directly, and an assumption must be made concerning the future liquid rate in order to complete this vital step. Neither the exponential function nor the harmonic function results in a straight line on this plot. However, if the assumption is made that the liquid rate remains constant in the future, then the harmonic curve will very closely approximate a straight line.

A disadvantage of this plot is that the important part of the trend only becomes apparent at very high water-oil ratios. It is often tempting to fit a straight line to a portion of the curve and to extrapolate this to make an estimate of TRV. Except in the case of harmonic decline, any straight line fitted to any part of the curve and extrapolated will result in an over-estimation of TRV (with the assumption that the liquid rate remains constant in the future). For this reason, this plot is of limited use for an analyst searching for a high confidence forecast to underpin a Proved Reserve estimate.

2.11 The Gas-oil Ratio plots

In circumstances where a well's oil rate declines because of increasing GOR, a plot showing the GOR trend should be constructed and an attempt should be made to identify a historical GOR trend that can be projected into the future. It is often useful to plot GOR against cumulative produced oil when the GOR is reasonably low, or to plot GOR (or its inverse, CGR) as a function of cumulative produced gas when the GOR is very high. A GOR forecast can be utilised in two different ways.

The first way of utilising a GOR forecast is to help in deriving an oil rate forecast. The GOR forecast itself does not lead directly to an oil rate forecast, and only provides the link between a gas rate forecast and an oil rate forecast, and consequently, some form of gas rate forecast is also required. For example, in a field with gas recycling, a well's production may be constrained to a fixed maximum gas rate, and in this case, a constant rate gas forecast can be used, and the conversion from gas rate to oil rate using a GOR forecast is simple. However, it is not always easy to obtain a reliable gas rate forecast, and the GOR trend may be of limited use.

The second way of utilising a GOR forecast is to treat the well as an oil well, and to carry out a conventional DCA and forecast using oil rates. Once this has been done, a forecast

GOR trend can be combined with the oil rate forecast to estimate a gas rate forecast. This can be used as a quality control measure, for example to impose a limiting gas rate. This is a favoured approach when the GOR is moderate. Indeed, for any oil well for which an accompanying gas rate forecast is required, this is the recommended approach. However, if the GOR values are very high, then oil rate data may no longer be reliable, rending this approach unreliable.

Finally, if a well has reached exceptionally high GOR values, then it may be preferable to treat it as a gas well, and to carry out the DCA using gas rates. The oil rate profile can then be estimated by analysing and forecasting a CGR trend.

It is not practical to give specific rules to cover the use of GOR trends in DCA, as there are too many factors that can influence the way the analysis is carried out. Each case needs to be evaluated independently.

2.12 General Comments

From the previous sections, it is clear that there is no simple plot that will show a straight line for the general hyperbolic function. An analyst should therefore be aware that a curve other than a straight line may be appropriate for the particular circumstances. An analyst should not be afraid to deviate from the easy choice of a straight line.

It is also clear that in most cases, the use of a logarithmic scale on the ordinate does not necessarily give a better answer than a linear scale. The habit that some analysts have of defaulting to a logarithmic scale is not good practice. It is better to consider the linear scale as the default, and then to resort to the use of a logarithmic scale if necessary.

3 Best Practices in Documentation and Presentation

Documentation of results is an essential part of carrying out DCA, irrespective of whether it is for reserve estimation, or for field management or business planning purposes. If an analysis is to be repeated at regular intervals, a well documented audit trail makes it easier to carry out the work each time. It is beneficial to spend time initially developing a system that is robust and can be updated easily, than to do a 'once-off' analysis that has to be repeated from scratch every time a revision is required. It is often preferable to show how results have changed since the last time the analysis was done, rather than to build a case from scratch every time. Therefore, as reserves are estimated on an annual basis, it is important to be able to retrieve the results from the previous year, to do the new analysis in the same way, and to demonstrate how things may have changed over the year. This provides the basis for a robust audit trail.

3.1 Presenting Plots

DCA primarily involves the construction of plots, and they are therefore very important items in presenting a reserve case. The visual impact of a plot can be striking and enhance your case, or it can be messy and damage your credibility. A small amount of time spent making a good plot is usually worthwhile. Here is a set of guidelines for presenting plots:

- Use the largest scale possible. On an A4 sheet, don't squash the plot into one corner. Don't try and fit four plots below each other on an A4 sheet in landscape orientation.
- Annotate the axes, with a description (for example, 'oil rate'), the units (for example stb/d) and any multipliers if appropriate.
- If using logarithmic scales, select the absolute minimum number of logarithmic cycles that span the range of interest in your data. Do not, for example, use eight logarithmic cycles from 0.001 to 100,000 for oil rate when most the values actually only vary between 100 and 10,000 stb/d, and are covered by three logarithmic cycles. OFM plot defaults are particularly susceptible to this as they always try to capture the outliers.
- Annotate the curves. OFM plots are frequently presented with no indication of what the different curves are.
- Give the plot a title and a date, so that it will still be meaningful next year.
- Identify the entity being analysed, such as the well name, or the reservoir interval.
- Put useful, pertinent information on the plot, for example, the value of d_i and the value of b. Understand what the units are, and ensure that they are consistent and sensible. OFM can occasionally tabulate useful information, but in alien units. Don't leave it up to OFM to decide on the units.

- Do not put too many curves on the same plot. Annotate the curves.
- On the scales, use sensible major and minor increments. Many graphics packages default to intervals that don't mean anything. For example, when plotting N_t on the abscissa, annotate at say 10 MMstb intervals, not at arbitrary intervals like 8.7658 MMstb.
- Draw grid lines on the plot.
- Ensure that if a copy is made of your plot using a copier that only reproduces in black and white, your curves will still be distinguishable. Use different line types and markers to distinguish between the curves.

3.2 A Checklist for Completeness

This section provides a check-list specifically for those items that are needed for presenting a year-on-year reserves update for Proved Reserves.

- Do you have last year's analysis at hand?
- Do you understand what was done last year and why? (Somebody else may have done the work last year).
- Have you completed a three-way comparison involving the analysis of last year, performance through the year, and your analysis for this year? Do this for both TRV and reserves.
- Can any differences be accounted for?
- Have you checked to see if any audit items were raised during the last year? Have all audit items been attended to?
- Do you have a current map of the field showing well locations?
- Do you have an idea of what operations were carried out on the field in recent times?
- Do you have an idea of what operations are planned for the field in the near future?
- Do you have a working knowledge of how fluid rates and ratios are measured and allocated?
- Do you have an understanding of the uncertainty in your production data?
- Have you screened data for integrity?
- Do you have a very good understanding of the physics of oil recovery from the field?
- If oil rate is declining, do you know why? Is it due to increasing water-cut, increasing GOR, or decreasing pressure?
- Have you prepared a reference plot for each well?

- Do you have your analysis plot(s) for each well?
- Do you have your rate vs. time forecast ('final check') plot for each well?
- Do you have an aggregated field level forecast showing continuity with historical data at field level?
- Have you addressed individual well life-spans, and do you have statistics or analogues to back up a high confidence well life-span?
- Have you applied individual well rate, water-cut or GOR cut-offs, and do you have statistics to support your selection of high confidence cut-offs?
- Do you have facility life information at hand?
- Do you know when the license expires (including any extensions that can be justified in accordance with EP-1100 instructions)?
- Have you compared TRV from all the wells and identified any outliers? Can you explain any outliers?
- Have you compared decline rates for all the wells? Are they consistent? Do they make sense? Are there any outliers? Can you explain these?
- If you are using decline functions other than exponential, do you know what hyperbolic exponents you've used? Have you compared these from well to well? Are there any outliers? Can you explain these? Are you confident that your hyperbolic exponents represents a high confidence case? Can you prove this??
- Have you applied the ELT to estimate a reserve at field level?

4 Data Integrity and Uncertainty

4.1 Discussion

There is always a degree of uncertainty in the data, and that means that a range of different trends can often be fitted to the dataset. It is important to develop an understanding of the uncertainty in the data, and of the uncertainty that this causes in the forecasts and estimates of TRV.

Accurate measurements of crude oil rates are invariably undertaken at some point in the production system. However, allocation of a field's production to individual wells may not be as reliable as expected. This can reduce reliability in the trends and lead to inaccurate forecasts when well data are analysed.

While oil rates may be measured accurately, at least at field level, the same cannot always be said for water and gas rates, which are sometimes considered side products. The problem can be compounded if the allocation to well level is done poorly. Any analysis that relies on accurate water and gas production measurements will be misleading if these rates have not been measured and allocated accurately. For example, lift gas is produced together with the reservoir gas, and if not accounted for in the metering and allocation process, will distort GOR trends and render analyses based on these trends unreliable. Water injected for hydraulic submersible pumps is produced together with the formation water and if not accounted for can lead to erroneous DCA.

4.2 Best Practices Checklist

- Do you have operational awareness of how fluid rates and ratios are measured and allocated?
- Have you checked for the lowest level at which continuous metering is carried out.
- Do you have an understanding of the uncertainty in your production data?
- Have you accounted for any operational influences on data integrity?
- Do you have an understanding of the uncertainty that doubtful data could impose on the analysis and its predictions.
- Can you differentiate between trends related to reservoir performance and trends related to field operations?
- Do the data sets selected for the analysis reflect the reservoir performance without being masked by field operations?
- Have you checked data stability over the analysis period of time?

- Have you ensured that data sets selected are not masked by infill drilling effect?
- Have you verified data agreement with respect to facility constraints?
- Have you checked for the possibility of well interference effect on data integrity?
- It may be beneficial to include error bars on plots of production data to understand the range of uncertainty.

5 Selecting the Historical Period for Trend Analysis

5.1 Discussion

There are many factors that must be considered when selecting the historical interval for trend analysis, far more than what can be covered in this manual. However, many potential pitfalls can be avoided by simply following what can be regarded as the 'Golden rule' of DCA, stated in Thomas Frick's 'Petroleum Engineering Handbook of 1962', in the section dealing with the subject of ‘Production-decline curves’:

‘The basic assumption in this procedure is that whatever causes controlled the trend of a curve in the past will continue to govern its trend in the future in a uniform manner’.

DCA is based on the premise that we can project a trend established over a period of time into the future provided that the circumstances that caused that trend to develop in the first place continue, unchanged, into the future. We need to understand the gravity of this statement and give serious attention to this when selecting the historical period for analysis. This is particularly true when making forecasts for the purposes of estimating Proved Reserves, as there are a number of strict rules that govern what may, or may not be included in a Proved Reserve estimate.

5.2 Examples

Example 1. Changing historical choke setting.
As an example, consider an oil well that has had its choke opened, by small amounts, at short time intervals over a two year period to slow the rate of production decline caused by pressure depletion. This is a typical, and commonly undertaken, operational activity. If we select this two-year period for trend analysis, and hope to use it for forecasting, then we are tacitly assuming that the choke setting will continue to be opened in the way it has in the past, for as long into the future as the forecast is made. This may of course not be possible, as the choke will reach its limit, and then the well's rate will start to decline at a rate which is greater than that observed during the two-year period, and we will have over-estimated the TRV. Indeed, by fitting a trend to a well's production when the choke setting is actively being changed, means that we are doing a DCA not only on reservoir performance, but also on field operational activities. While a reservoir may continue to respond in a reasonably predictable way, operational activities seldom do. We must therefore always be cautious of operational activities that mask the true reservoir performance trends.

Example 2. Short history.
This is an example of a case where the historical period used for analysis is too short to allow the hyperbolic exponent to be calculated with confidence. This is illustrated in the sequence of figures that follow. The analysis in this case was carried out at reservoir level. (Note that there are very strict guidelines on the use and abuse of DCA at reservoir level and the fact that this example shows an analysis at reservoir level should not be seen as an endorsement of the practice of carrying out analyses at reservoir level- this is merely an example).

The first in the sequence of figures (Figure 10) shows the nine years of historical production data available up to the end of 1985 at which time that the DCA was carried out for the purposes of supporting a Proved Reserve estimate. Periods of active infill drilling are evident as sudden increases in production rate. The second figure (Figure 11) shows the DCA carried out on a plot of rate vs. cumulative production. The analyst appropriately selected the last part of the dataset during which no active infill drilling took place, to analyse the trend. A very convincing straight line trend is evident, which, as a straight line on this plot, corresponds to an exponential decline function. Furthermore, during those periods between infill drilling campaigns, declining production rates are evident, and the same straight line seems to fit all of these short intervals equally well. This lead to confidence that the analysis was robust.

The next figure (Figure 12) shows the production forecast from the start of 1986 onwards based on the trend analysis. Superficially, this seems reasonable. However, the next figure (Figure 13), shows this forecast together with the actual production data over the subsequent 11 year period from 1986 onwards. Clearly the forecast made at the end of 1985 was too conservative. There was no further infill drilling after 1985, and no operational activities that could be blamed for this large discrepancy between actual and forecast rates. A review of the plot of the instantaneous rate vs. cumulative production originally used for the DCA, but with the additional 11 years of production included, is shown in Figure 14. Clearly, the later trend deviated significantly from that which had originally been selected.

When this same plot is made with a logarithmic scale on the ordinate (Figure 15), it becomes clear that the production data actually followed a harmonic decline, which appears as a straight line of this plot. It is also clear that the exponential and harmonic curves are very similar over the short period of data originally selected for analysis. The final figure (Figure 16) shows the rate vs. time plots of the extended historical rate up to 1996, and the two DCA curves, the exponential curve and the harmonic curve. In this case, with the benefit of the extended dataset, it is clear that the harmonic curve is the appropriate curve to use. Once again, there is very little difference between the exponential and harmonic curves over the short period that was originally selected for analysis.

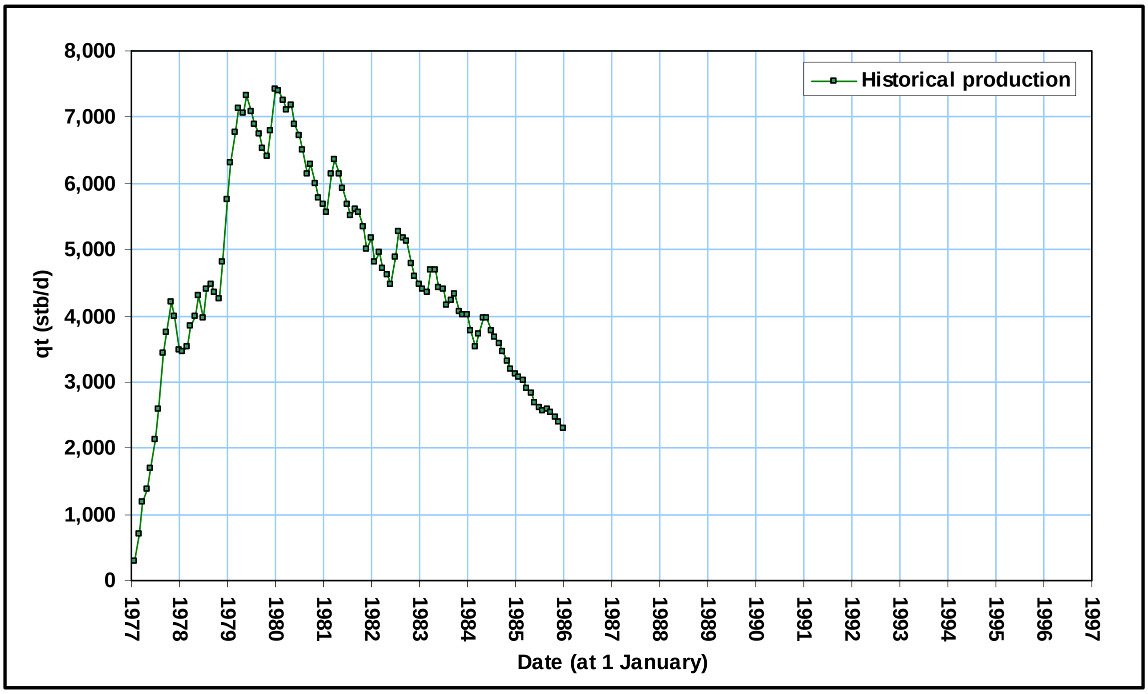

Figure 10: Reservoir level historical production data up to the time that DCA was carried out.

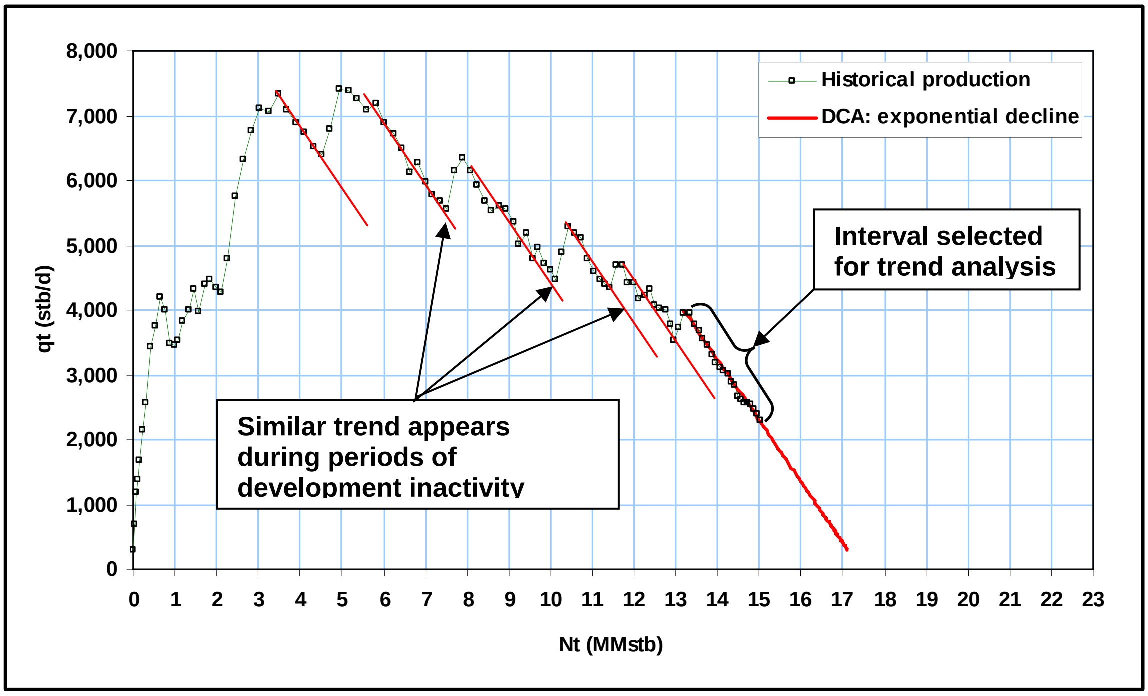

Figure 11: An apparently successful DCA showing a straight line on a plot of rate vs. cumulative production suggesting exponential decline.

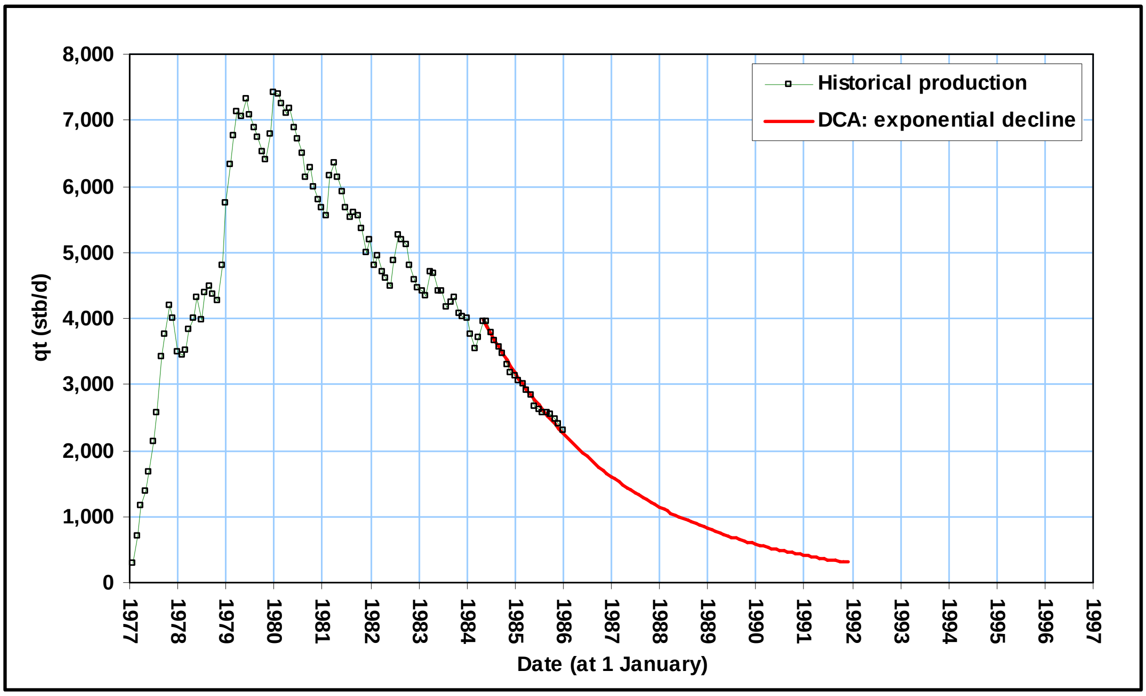

Figure 12: A forecast made with the exponential function derived from DCA.

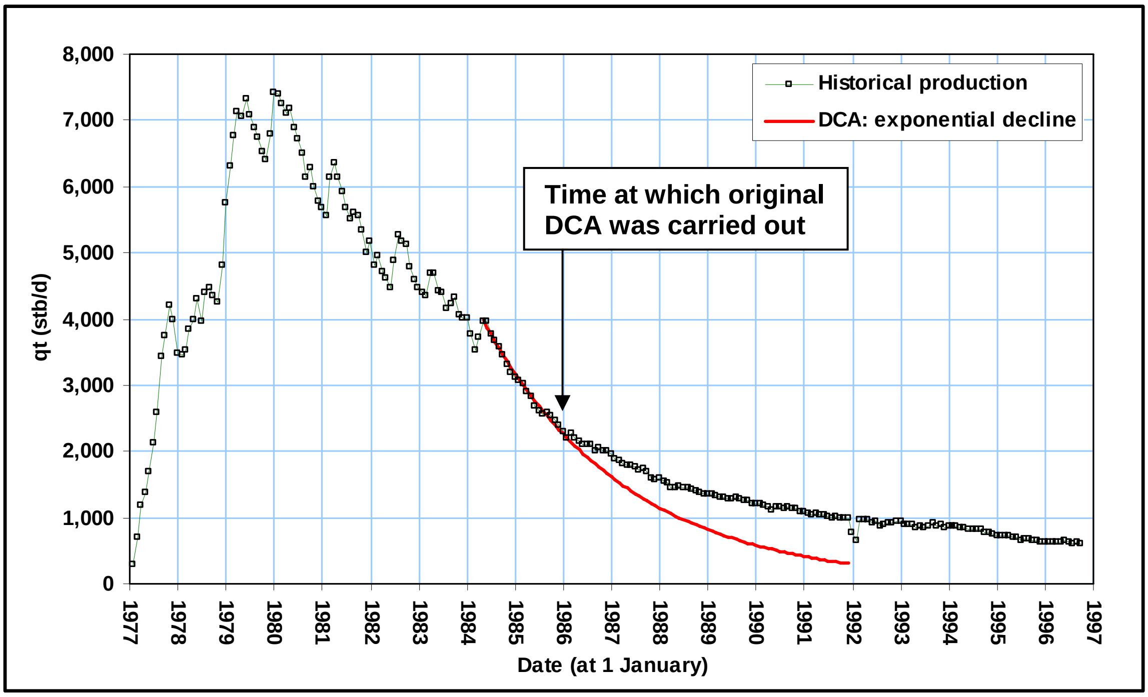

Figure 13: The forecast made with an exponential decline function, together with subsequently obtained production data illustrating the poor quality of the forecast.

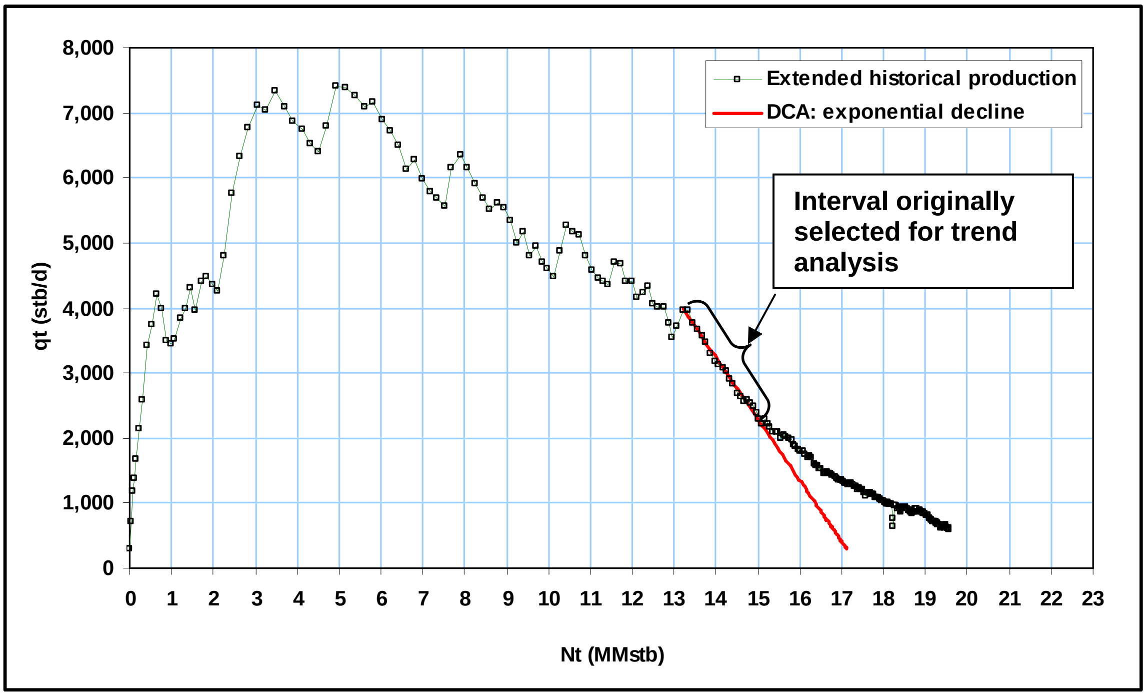

Figure 14: A revisit of the DCA plot (rate vs. cumulative production on linear axes) shows that the actual data deviated from the trend originally chosen.

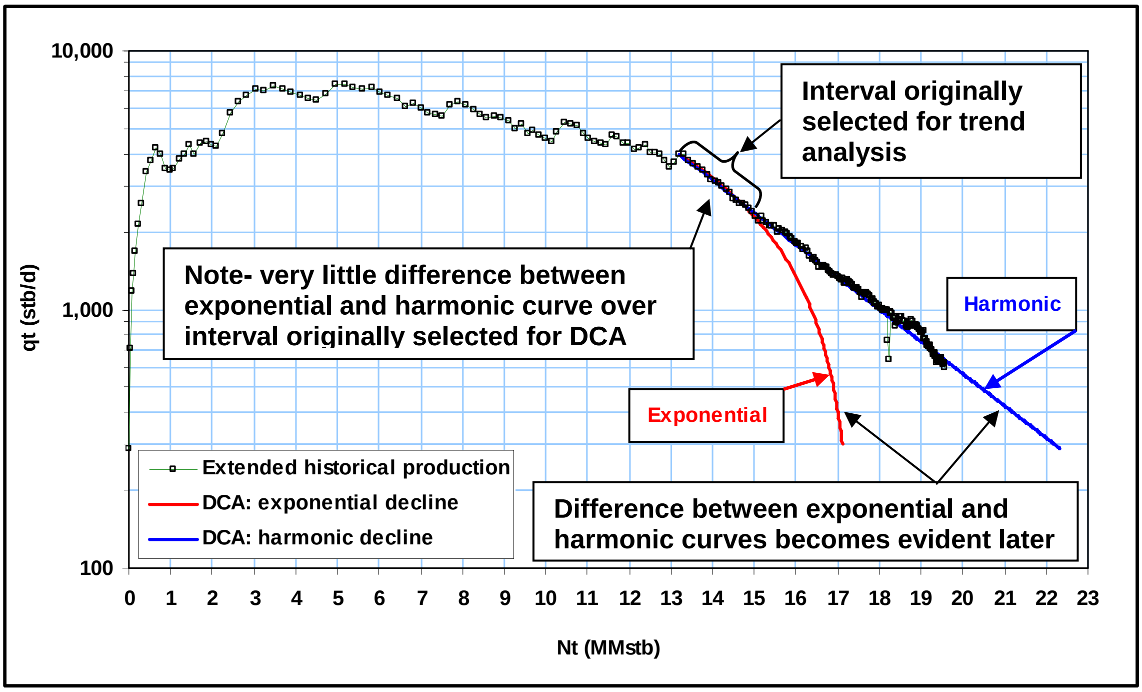

Figure 15: A plot of oil rate vs. cumulative oil production on linear-log axes shows a good straight line trend indicative of a harmonic function.

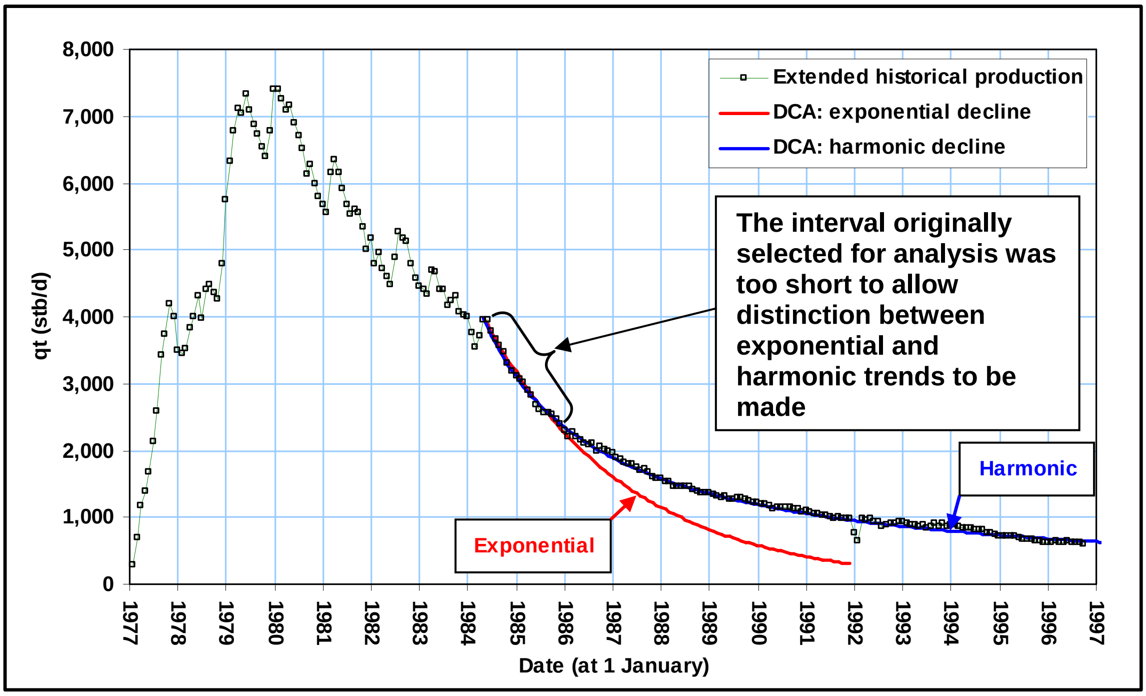

Figure 16: Extended historical data together with the poor exponential forecast derived from DCA on a limited dataset and the much better harmonic forecast derived from DCA that benefited from a much larger dataset.

Important lessons from example 2.

The are two important lessons to be learned from example 2:

Lesson 1: This analysis was carried out at reservoir level, and the historical interval that could be used for trend analysis in this case was very limited because of several infill drilling campaigns. This means that less than two years out of the total period of nine years could be used for analysis. Had the analysis been carried out at well level, it is likely that some of the older wells would have provided much longer periods over which the trends could have been analysed, possibly up to nine years, and it is likely that the true nature of the decline would have been recognised. This is therefore an example in which a well-by-well analysis could have lead to a higher estimate of recoverable volume than a reservoir-level analysis.

Lesson 2: With the benefit of hindsight, the exponential curve originally selected clearly gave an inferior forecast. Had the engineer carried out a sensitivity analysis on the value of b at the time, she or he would have found that almost any value of b from 0 to 1 could have been fitted to the dataset. The engineer would then have recognised that any forecast would consequently carry a high degree of uncertainty. However, if the DCA was being carried out for the purposes of supporting a Proved Reserve estimate (as it was), the engineer would still have been obliged to select a 'high confidence' value of b, which in this case would have been 0. At the time that the analysis was being carried out therefore, the decision to use an exponential function for supporting Proved Reserve volumes was the correct one. This does, however, illustrate the point that Proved Reserve volumes (or at least TRV) can, and indeed should be expected to, change from year to year. In the case of this reservoir, one would expect the TRV obtained from DCA repeated every year from 1985 onwards, to increase year-on-year, as more data become available, and as the harmonic nature of the trend becomes more apparently and more robust, and the uncertainty in the value of b diminishes. This is consistent with the idea that Proved Reserve estimates must have ***'reasonable certainty'*** of being recovered, and that…

'The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.' (SEC guidelines, March 31, 2001).

5.3 Best Practices Checklist

Below is a list of items that should be checked when selecting an interval for trend analysis:

- Data integrity
- Length of period available for analysis
- Changing choke settings
- Changing separator pressure
- Changing gas lift allocation
- Changing ESP speeds
- Work-overs
- Reaching surface facility constraints
- Relaxing surface facility constraints
- Fluctuating production due to fluctuating gas demand
- Interference with new wells
- Changing reservoir management strategies
- Changing water and/or gas injection volumes
- Changing water and/or gas injection patterns
- Changing well count when the analysis is carried out at any level other than at well level
- Stimulations (acid jobs, fracturing, hot oil treatments for wax)

6 The Transition from History to Forecast

6.1 Discussion

Occasionally difficulties can be experienced in the transition from history to forecast. Ideally, this transition should be flawlessly smooth. The rate vs. time 'final check' plot is an important quality control measure in this regard. The transition from history to forecast at reservoir or field level can be particularly problematic when the analysis is carried out at well level, and the individual well forecasts are aggregated to reservoir or field level. The various potential problem areas are illustrated by way of examples.

6.2 Examples and Best Practices

The 'last historical rate' dilemma. Figure 17 shows a perfectly defensible example of how a historical trend for a well was extrapolated into the future. More often than not, there is scatter in the data and the trend, being a best-fit curve to many scattered data-points, may only actually intersect a few of the historical points. As the last historical point is no different from any other historical point, it seldom occurs that the fitted curve actually passes through the last historical point. Indeed, in most cases, it would be quite an unusual coincidence if it did.

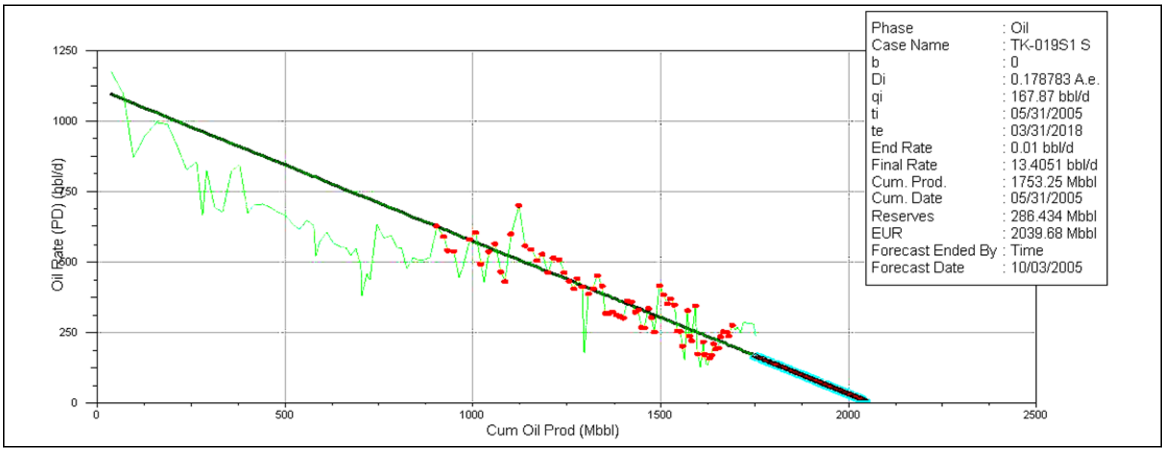

Figure 17: DCA and forecast carried out in OFM.

The question arises as to whether the forecast should be pinned to the last historical rate, or whether the trend from history to forecast should be smooth. There are three parameters that we would like to honour, but we can only ever honour two of them at the same time. These parameters are the last historical rate, the TRV, and the decline rate. Of these three parameters, the most important for the purposes of estimating reserves, is of course the TRV. This dilemma logically leads to three options for the analyst to choose from for making a forecast, each of which dishonours one of the three parameters.

These options are illustrated in Figure 18 (which shows an expanded view of Figure 17) and described below.

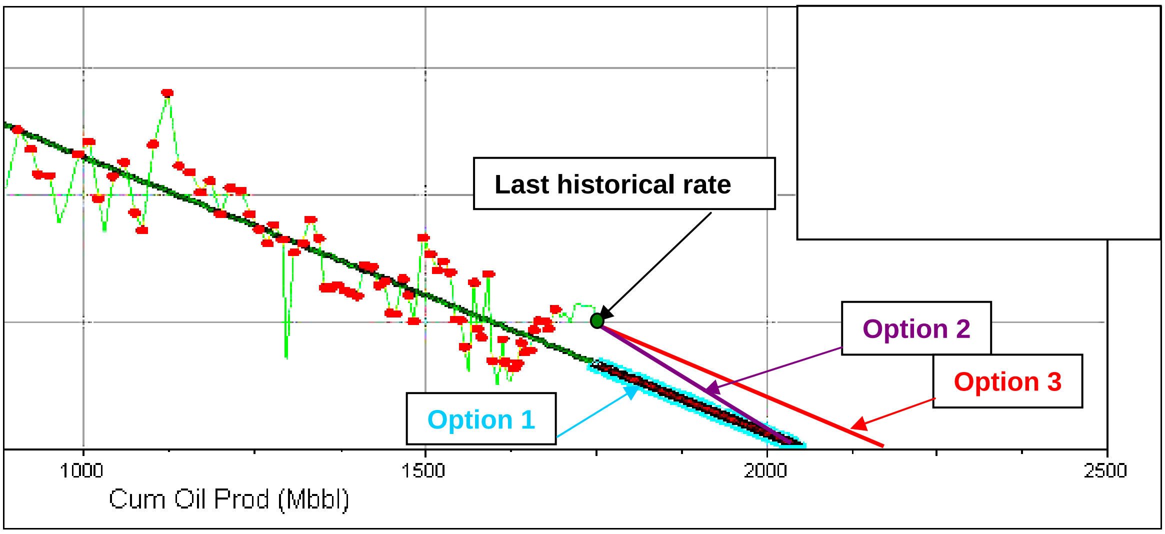

Figure 18: Expanded view of Figure 17 showing different options for extended a trend from the historical period into the future.

<u>Option one</u> shows how the TRV and the decline rate can be honoured, but not the last historical rate at the same time. The historical trend continues smoothly into the forecast, but the last recorded production rate is not honoured. This is a technically defensible option in this instance, as the historically determined trend is preserved in the strictest sense into the future. The problem with this option, however, is that when the mismatch between the last historical rate and the first rate of the forecast occurs repeatedly at well level, the aggregated profile at reservoir or field level can show a very significant mismatch at the point where history ends and forecast begins. If this occurs, the following procedure can be followed:

- Fit a DCA curve to the aggregated forecast. Note that although you may have fitted exponential functions to all your individual wells, the aggregated forecast at reservoir level is unlikely to be exponential and you will probably have a hyperbolic curve. Note the decline parameters (the hyperbolic exponent and the initial nominal decline rate) and the TRV of the curve fitted to the aggregated forecast. Also note the final rate that corresponds to the TRV at reservoir level.

- Create a new reservoir level forecast that gives exactly the same TRV (and final rate of the forecast), by pegging the initial rate of the forecast to match the last historical rate, and by adjusting the decline parameters. This can usually be achieved by making a small adjustment to the initial nominal decline rate. There are no definitive guidelines on how to do this. It may be necessary to try a few different approaches and to visually inspect the results.

- If large changes to the decline parameters are necessary or if there is a substantial shift in the time to reach TRV, than it may be necessary to revisit the individual well DCAs.
- It is not acceptable to simply scale the reservoir level forecast up or down by a factor to force a match between last historical rate and the first forecast rate at reservoir level, as this changes the TRV (and the final rate of the forecast).

<u>Option two</u> shows how the last historical rate and the TRV can be honoured, but not the decline rate at the same time. This option will cause the first rate of the aggregated forecast to match the last historical rate at reservoir level, exactly. This is an acceptable option. It is very similar to option 1, except that the adjustment to the forecast is made at well level, and not to the aggregated forecast at reservoir level. This option is easy when straight lines have been used for the trends, but can be difficult for general hyperbolic functions.

<u>Option three</u> shows how the last historical rate and the decline rate can be honoured, but not the TRV at the same time. As TRV is ultimately the most important parameter that we seek in the DCA, it is not acceptable to disregard it in this fashion when making a forecast. There are, however, a few isolated instances when this practice is acceptable. If, for example, the increase in rate towards the end of the history period is well established (i.e. comprises more than just a few points), and this can be shown to be due to some specific operational factor (such as improved artificial lift), and if there is a proven historical track record of the same decline trend having re-occurred following similar activities in the past, only then is it legitimate to adopt option three.

Continuity of decline rate when $b > 0$. As has been stated in previous chapters, the value of the effective decline rate D decreases with time when $b > 0$. This can cause difficulties when we want to make some change in the profile. For example, if we want a forecast that starts with a rate that does not coincide with the historical trend, as described in option two in the previous section, we need to construct a new forecast with a new start date and new initial rate, but, importantly, we need to use the correct value of the new initial decline factor that is pertinent to that point in time. Remember that we use the initial nominal decline factor d_i in our formulae, and that the numerical value of this parameter that we obtain from our DCA is specific to the start time. If we want to make a forecast starting from some new point, say at $t = t_1$ then we must make sure that we use the correct value of the decline factor at that point. The decline factor at some time $t_1 \geq 0$ is given by

$$d_{t_1} = \frac{d_i}{(1 + b \cdot d_i \cdot t_1)}. \qquad \text{Equation 27}$$

If we start a forecast at time $t = t_1$, then we calculate the value of the decline factor at this point using Equation 27, set the time equal to 0 at this point, and use the new value for the initial decline factor going forward. The use of Equation 27 to define a new value for d_i when the start time is shifted ensures that continuity in the value of D is maintained.

7 Using the Integral form of the Equations for Forecasting

7.1 Discussion

Background

The equation most commonly understood and used by analysts carrying out DCA is Equation 1, which relates instantaneous rate, q_t, to time. Also appearing in this equation is the instantaneous initial rate, q_i. It is important to recognise the significance of the term 'instantaneous' rate. This is not the average rate over a period of time such as a week, or month, or year, but the rate at a single instant in time. For practical reasons, however, we refer to instantaneous rate as the rate achieved on a particular day, which invariably means the average rate for that day. When we provide production profiles for reserve estimation or for development planning purposes, we are generally interested in reporting rates that are averaged over a practical length of time, the 'time step', such as a year, or a quarter, or a month. This commonly used equation therefore does not provide us with the useful information that we need for forecasting. We can use it to work out the rate at any instant in time, but it does not tell us what the average rate will be over a time step.

The problem

If we calculate the instantaneous rate on 1ST January of each year, and (mistakenly) use this as the average for the year, we grossly over-estimate the TRV. Likewise, if we use Equation 1 to calculate the instantaneous rate on the first day of each month, and use this as the average for the month, we still overestimate the TRV, but not to the same extent as when the time step is a year. If we use Equation 1 to estimate the instantaneous rate precisely in the middle of the year and use this as the average rate for the year, we will still overestimate the TRV due to the non-linear nature of the relationship between q_t and t. If we use Equation 1 to estimate the instantaneous rate on every day of the year, and calculate an average of these rates, then we will obtain a reliable answer for the average rate over the year. However, this is not a practical solution, and therefore the use of equation 1 for forecasting is not recommended.

The solution

The solution to this problem is to use the integral form of the equation (Equation 2) which gives the relationship between cumulative production and time, for forecasting. The equation is used to calculate the cumulative production up to the end of each time step, whether this is weekly, monthly or annually. The average production for the time step is then determined by subtracting the cumulative production at the end of the time step from that at the end of the previous time step, and dividing by the number of days in the time step. The conventional form of the equations can still be used to calculate the instantaneous rate at any point in time.

7.2 Example

The example tabulated below (Table 1) and illustrated in the accompanying diagram (Figure 19) shows the forecasts that were made for a well following a DCA. The analysis was carried out at the end of 2000 after the well had produced 10 MMstb. The trend analysis of the historical data (not illustrated) gave an effective exponential decline rate of 30.6 %pa and an estimate for the initial rate for the forecast of 10,000 stb/d on the 31ST December 2000. In Table 1, each entry in blue relates to a specific date, while the entries in maroon are average values.

The columns in Table 1 under the heading 'Daily basis' show the date, the instantaneous rate on that date and the cumulative production up to that data, calculated using Equations 1 and 2. The data under the heading 'Incorrect annual basis', show how incorrect cumulative volumes are calculated if the instantaneous rate at the start of a time step is erroneously assumed to be the average rate for the year. The entries under the heading 'Correct annual basis' show the average annual rates for the year correctly calculated from the cumulative volumes, by taking the difference in the cumulative volume from one date to the next, and dividing by the number of days between the dates. It is only possible to calculate the correct average values over a time step if Equation 2 has been used. This example is illustrated in Figure 19. This example is an extreme case. The error is aggravated when the time steps are long, and when the decline rate is high.

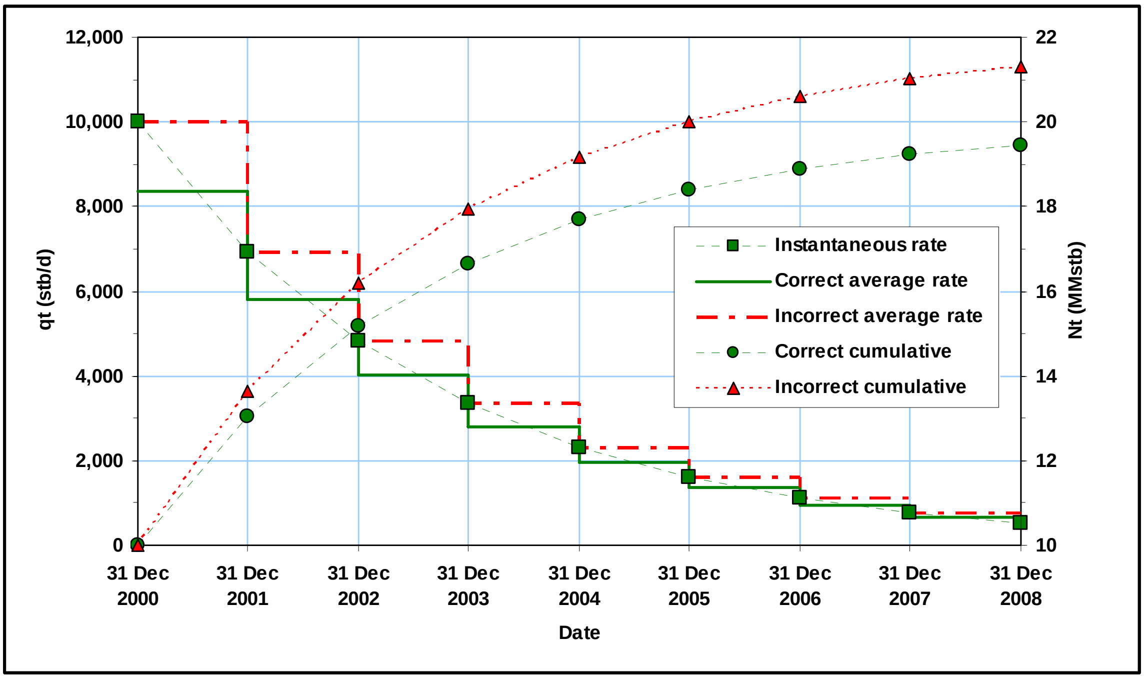

Figure 19: Example of forecasts made using the equations giving the instantaneous rate as a function of time, and the cumulative production as a function of time.

Table 1: Example of a forecast made using the equations for the instantaneous rate as a function of time, and the cumulative production as a function of time.

$q_i =$	**10,000**	stb/d on 31 December 2000	
$b =$	**0**	(exponential decline)	
$d_i =$	**0.001**	per day	nominal decline rate
$d_i =$	**0.365**	per year	nominal decline rate
$D =$	**30.60%**	per year	effective decline rate

Daily basis			Incorrect annual basis				Correct annual basis			
Date	q_t stb/d	N_t MMstb	Year	Av. q stb/d	Date	N_t MMstb	Year	Av q stb/d	Date	N_t MMstb
31-Dec-00	10,000	10.000			31-Dec-00	10.000			31-Dec-00	10.000
31-Dec-01	6,942	13.058	2001	10,000	31-Dec-01	13.650	2001	8,378	31-Dec-01	13.058
31-Dec-02	4,819	15.181	2002	6,942	31-Dec-02	16.184	2002	5,816	31-Dec-02	15.181
31-Dec-03	3,345	16.655	2003	4,819	31-Dec-03	17.943	2003	4,038	31-Dec-03	16.655
31-Dec-04	2,320	17.680	2004	3,345	31-Dec-04	19.167	2004	2,802	31-Dec-04	17.680
31-Dec-05	1,611	18.389	2005	2,320	31-Dec-05	20.014	2005	1,944	31-Dec-05	18.389
31-Dec-06	1,118	18.882	2006	1,611	31-Dec-06	20.602	2006	1,349	31-Dec-06	18.882
31-Dec-07	776	19.224	2007	1,118	31-Dec-07	21.010	2007	937	31-Dec-07	19.224
31-Dec-08	538	19.462	2008	776	31-Dec-08	21.294	2008	650	31-Dec-08	19.462

7.3 Best Practices Checklist

The error of mistaking the estimated production rate at the start of a time interval for the average rate over the time interval occurs most commonly when a spreadsheet is being used for generating production forecasts, although any software package should be checked to see if a similar problem exists or not. Always use the integral form of the equations for forecasting.

7.4 Further Considerations

This example illustrates a procedure to avoid potential pitfalls that arise when making production forecasts using long time steps. However, it does not deal with the equally important potential problem that the analyst can be confronted with when trying to define the decline trend in the historical data when the data are only available for large time steps. If for example, we only have average annual production rates, it can be difficult to match the appropriate rate and cumulative volume when constructing a rate vs cumulative production plot for trend analysis. Different values for TRV will be obtained if the average annual rate is matched to the cumulative volume produced at the beginning of the year, the end of the year, or some time in between. A possible solution to this problem is to fit a trend to a plot of cumulative production against time, as the cumulative production at the end of each year is known.

This problem is eliminated when daily rates are used, and becomes increasing problematic as the time step is increased. When monthly average rates are being used, the problem is generally not significant, but the analyst should be aware that the average rate for a month corresponds to a cumulative volume produced at some time during the month, and not to the cumulative volume produced at the beginning, or end, of the month. It may be prudent to plot the average rate for the month against the cumulative volume that is calculated to have been produced half way through the month.

7.5 Discussion

Uptime, and calendar- and producing-day rates

Production data are often reported on a daily basis. However, because it is sometimes impractical to record every well's daily production rates, data are often stored in databases on a monthly basis. This is usually in the form of the total volume produced from each well in the month, or as the average rate achieved by each well during the month. A prudent operator will also record the total time during the month that each well was on stream and producing. This is recorded as a percentage uptime, or as the number of days on stream per well, in each month. With this dataset, it is possible to view a well's monthly production in two useful ways.

The first way is to consider the monthly average production rate for the well. This is the total volume produced from the well during the month divided by the number of calendar-days in the month (28, 29, 30 or 31). This rate is frequently referred to as 'calendar-day' rate, or 'monthly average rate'. In this text, we use the terminology 'calendar-day' rate. The other way of viewing a well's production data is the average rate that the well produced at while it was actually on stream. This is calculated as the total volume produced during the month divided by the number of days that the well was on stream. This is often referred to as the 'producing-day' rate or the 'instantaneous rate'. In this text we use the terminology 'producing-day' rate.

The producing-day rate is always equal to, or greater than, the calendar-day rate. A difference between the two is due to uptime. The two rates are equal when uptime is 100%. Calendar-day rates are affected by variations in uptime from month to month, while producing-day rates are not.

A disadvantage of using calendar-day rates for DCA is that reservoir performance trends can be masked if uptime fluctuates greatly from one month to the next. However, an advantage of using calendar-day rates is that uptime is already accounted for in the DCA, and so the forecast incorporates a projection of the historical effect of uptime. This presents a simple (but imperfect) solution to dealing with uptime, and is therefore popular.

There is a better chance of observing the effects of reservoir performance in the producing-day rates than in the calendar-day rates. For this reason, it seems preferable to use producing-day rates when carrying out DCA, as this allows us to separate reservoir performance trends from uptime, which can be random. The use of the producing-day rate for DCA can present us with difficulties, however, when a forecast is to be made. Uptime must be built into the forecast, and this is not always trivial. Failure to account for uptime correctly in the forecast can lead to very incorrect results. The following sections describe a method for using producing-day rates in DCA (which give the best reservoir performance trends), and accommodating uptime in the forecasts in a simple way.

Note that both calendar-day rates and producing-day rates are average rates, and therefore neither is equivalent to the instantaneous rate (q_t) used in our formulae. The calendar-day rate is the month's production averaged over all the calendar-days in the month, while the producing-day rate is the month's production averaged over the days that well was producing.

The dilemma

The dilemma is the following: By using producing-day rates, we get the 'cleanest' production data for observing reservoir trends, but the forecast can be tricky as we have to account for uptime correctly. On the other hand, by using calendar-day rates, uptime is built into the analysis, and the forecast is easy, but we are in danger of misinterpreting the trend.

A possible solution

A solution to this dilemma is to review the data and make a decision on which approach to take before carrying out an analysis. Create a plot of producing-day rates, calendar-day rates and uptime. If uptime is close to 100%, and does not fluctuate much from month to month, and if the trends in the calendar-day rates and producing-day rates appear to be of similar quality, then it is acceptable to use calendar-day rates for the analysis. This should be the case for the majority of Shell's assets. If on the other hand, uptime fluctuates greatly from month to month, and the calendar-day rates are erratic as a consequence of this, then you should consider using the producing-day rates. In this case, make sure that the forecast takes appropriate account of the uptime. How to do this, is described below.

Dealing with producing-day rates and uptime

The problem of dealing with uptime is quite simply dealt with by including an uptime adjustment into the integral form of the equations. Equation 2 then takes on the form

$$N_t = \frac{q_i}{d_i(1-b)} \cdot \left(1 - \left(1 + b \cdot d_i \cdot U_t \cdot t\right)^{\left(1-\frac{1}{b}\right)}\right), \qquad \text{Equation 28}$$

in which the term U_t is the 'cumulative uptime factor' up to the time t, and is a fraction between 0 and 1. It is defined as the cumulative time that the well has been on stream from the initial time ($t=0$) divided by the elapsed time t. During the historical period, U_t is calculated exactly from monthly uptime figures. For the forecast, it is usually adequate to apply an average uptime factor. If the uptime fluctuation is predictable, caused for example by seasonal effects, or by lifting constraints, then a forecast of the cumulative uptime factor can be made to account for these predictable uptime fluctuations. However, this level of refinement is very seldom justified, and an average uptime factor in the forecast is almost always satisfactory. Remember that the value of

N_t is at a specific instant in time t, and U_t is the cumulative uptime from the start time to time t. The instantaneous production rate q_t can also be calculated with a modified version of equation 1, namely

$$q_t = \frac{q_i}{\left(1 + b \cdot d_i \cdot U_t \cdot t\right)^{\frac{1}{b}}}, \qquad \text{Equation 29}$$

The process is described in the way of an example.

7.6 Examples

Example 1
This example is of a well in a field that was developed with a FPSO unit with limited storage and a dedicated shuttle tanker. The shuttle tanker unlatches when full for a 10 to 14 day round-trip to offload. Wells are choked back during this period and flow to the FPSO's limited temporary storage. Wells may be shut-in when the temporary storage becomes full. The development is in a harsh environment and very prone to periodic weather induced shut-ins during winter months. Additionally, individual wells experience occasional shut-ins for various operational reasons. The result is that the wells experience excessive and sporadic downtime.

The example is illustrated in the series of figures that follow. Figure 20a shows the historical calendar-day and producing-day rates, and the cumulative production plotted against time. The erratic nature of the calendar-day rates, compared with the producing-day rates, is obvious. This is caused entirely by uptime that fluctuates wildly from one month to the next. Figure 20b shows the same production data, together with the monthly uptime and the cumulative uptime. The monthly uptime fluctuates greatly, while the cumulative uptime stabilises around a value which is equal to the average uptime over the entire 60 month period, which, in this case, is 0.612.

Clearly, no reliable reservoir performance related trend can be identified in the calendar-day rates. Indeed, Figure 21 illustrates the difficulty of trying to carry out a DCA on this erratic calendar-day dataset. Clearly the DCA results are not reliable, and cannot be used in this case.

By contrast, the producing-day rates show a good trend that is not influenced by uptime and which reflects reservoir performance remarkably well. DCA using the producing-day rates appears robust, and the results of the analysis are shown in Figure 22. In the final diagram (Figure 23), the production rate and cumulative production forecasts made following the DCA done with producing-day rates, together with the actual production subsequently achieved are illustrated, and the good match confirms that the use of producing-day rates in the DCA produced a reliable result.

Also shown in this final diagram is the forecast of calendar-day rates, which of course was not derived directly from DCA carried out using calendar-day rates, but was derived from the forecast of cumulative production. The best result for this well was therefore obtained by analysing the producing-day rates, and using Equation 28 as the basis for all calculations.

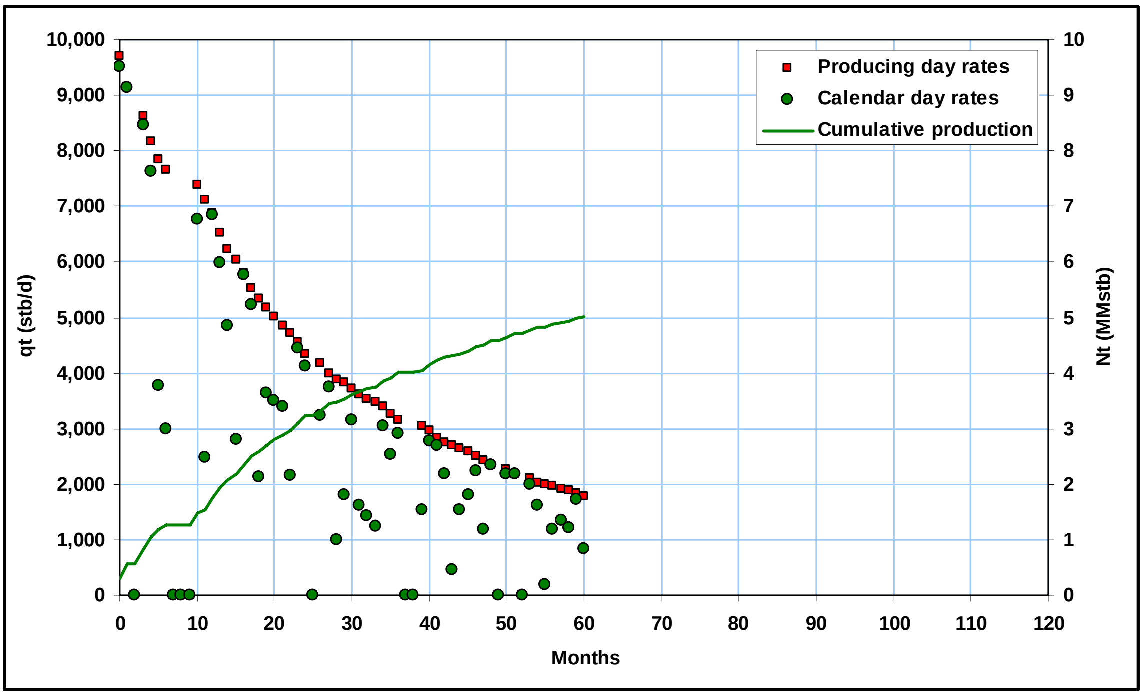

Figure 20a: Historical calendar and producing-day rates and cumulative production for a well that experiences excessive and erratic uptime effects.

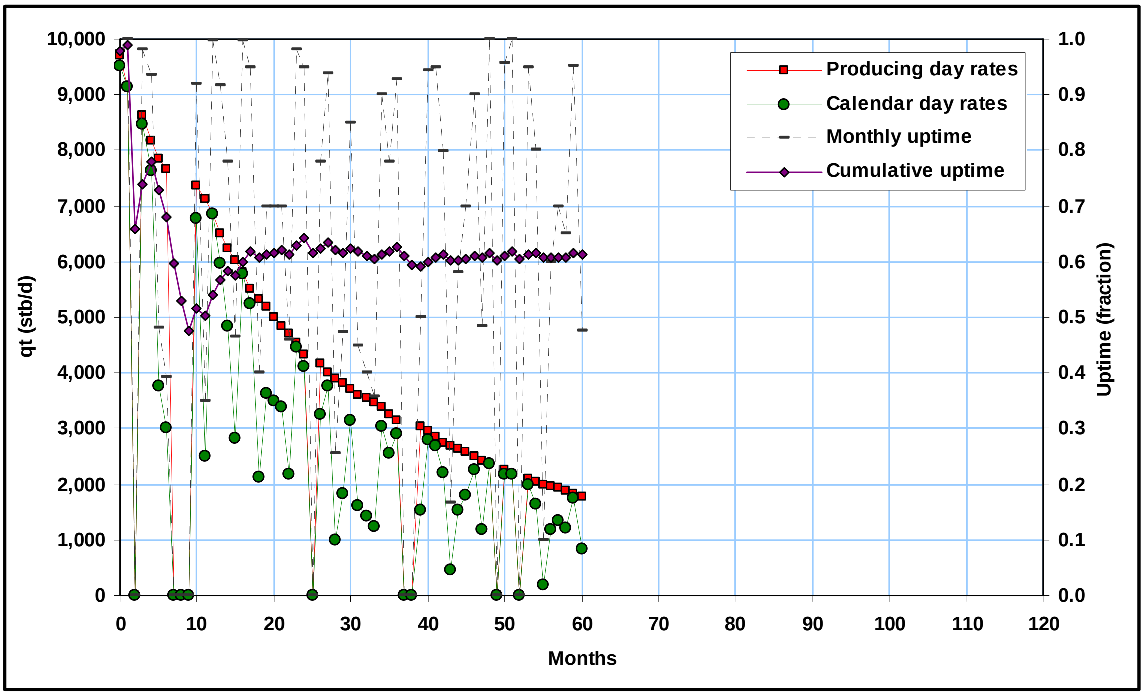

Figure 20b: Historical calendar and producing-day rates together with monthly uptime and cumulative uptime.

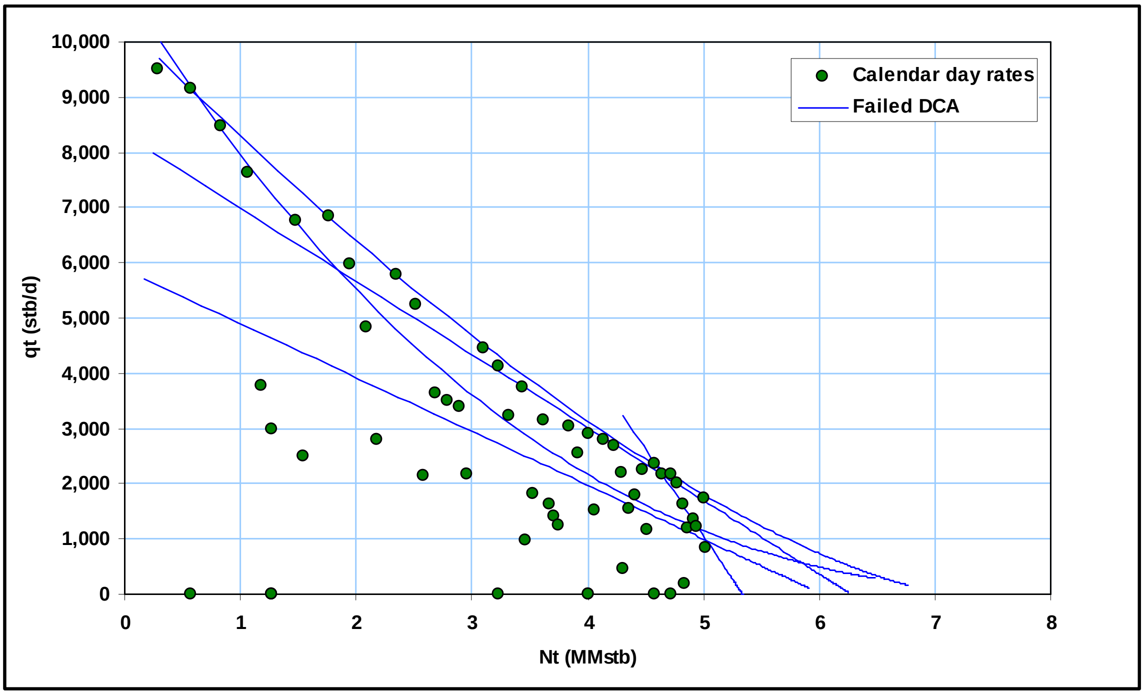

Figure 21: A failed attempt at DCA using calendar-day rates for a well with excessive uptime fluctuations.

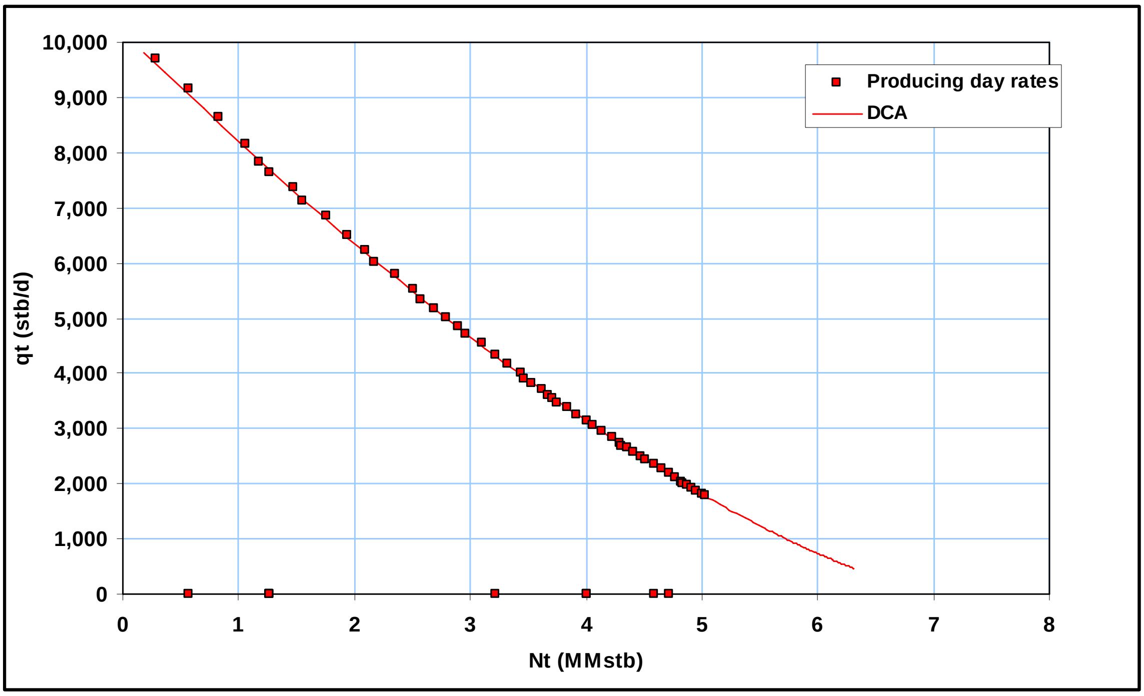

Figure 22: A successful attempt at DCA using producing-day rates for a well despite excessive uptime fluctuations.

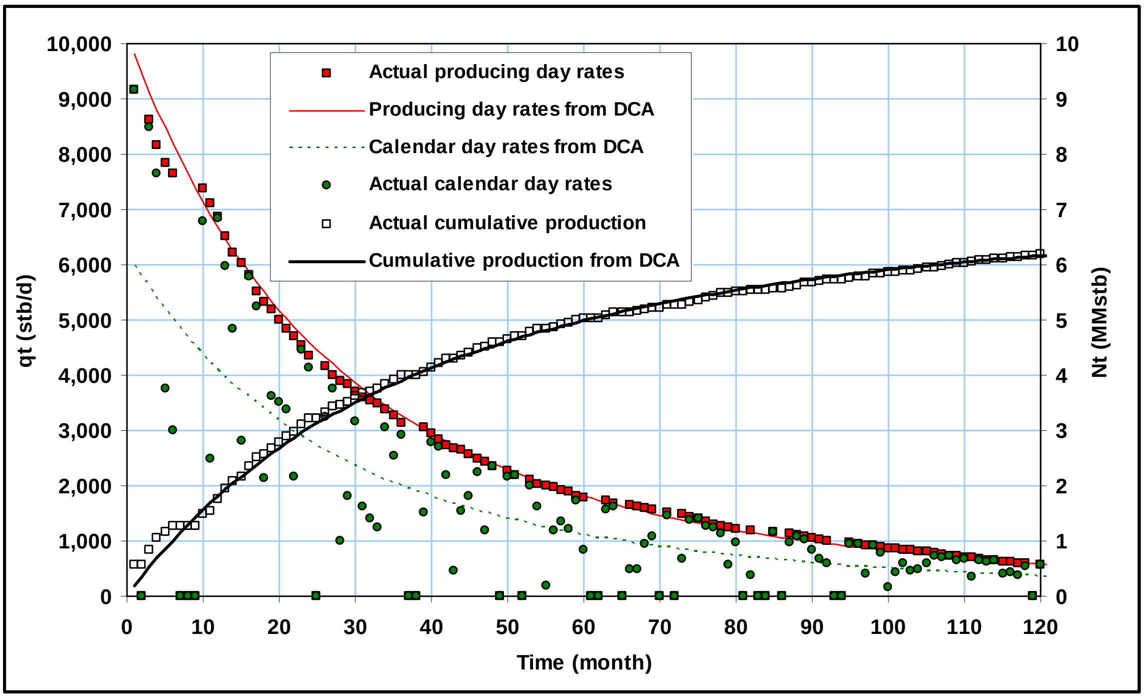

Figure 23: Actual and forecast production for a well suffering from excessive uptime effects. The DCA and forecast were done using producing-day rates.

Example 2

The second example is of a well with a very rapid decline over one year of history. The complete dataset, comprising field production data, DCA results, and a forecast over 1 year, is shown in Table 2.

The columns under the heading 'historical data and information derived from historical data' show the various forms of data that come in from the field. The minimum requirement to complete this part of the table is two data items per month, the one comprising production data (calendar-day rate, or producing-day rate, or cumulative production, or total production during the month), and the other giving an indication of the uptime (number of producing-days, or uptime as a fraction or percentage, or downtime as a fraction or percentage). All other entries are derived from those that are supplied to give a consistent dataset.

Note that some items (uptime, producing-days, production day rates, calendar-day rates) are reported as monthly average figures. These are shown in blue text in the table without shading. Other entries (cumulative production, elapsed calendar-days, elapsed producing-days and cumulative uptime) are specified on a particular date, namely the last day of each month. These are shown in black text in the table against a shaded background. Instantaneous values and average values should not be confused or mixed.

The entries under the heading 'DCA' show the trend analysis. In this example, the DCA was carried out on a plot of producing-day rate against cumulative production on linear axes (not illustrated). The fitted cumulative production at each point in time (N_t) was calculated using the modified version of the integral form of the equation (Equation 28). In applying this equation, the historical cumulative uptime listed in the column 'Cum. uptime (frac.)' was used for U_t. A good match between observed and calculated data was obtained with a hyperbolic exponent of 0.3, an initial nominal decline rate of 0.002 /day, and an initial rate of 10,000 stb/d, all effective on 31ST December 2005. The instantaneous rate (q_t) is also reported alongside the cumulative production. Once again, this was calculated using the modified form of the equations (Equation 29). Note that the instantaneous rate serves no real purpose in this analysis, and has been included here for interest only. The producing-day rate for each month was calculated by subtracting the cumulative production at the end of the month from the cumulative production at the end of the preceding month, and dividing this by the number of days that the well was producing.

The columns under the title 'Forecast' show the production forecasts. Cumulative production was calculated first using Equation 28. The various production rates (calendar-day and producing-day rates) were derived from N_t. In order to obtain the production rates an estimate of the cumulative uptime, U_t, is needed. The best estimate for this is the final value of the cumulative uptime at the end of the history period, in this case 0.782.

Table 2: Example of DCA in which well downtime is accounted for.

Historical data and information derived from historical data											DCA					Forecast					
											q_i : 10,000 stb/d b : 0.30 dimensionless d_i : 0.005 /day										
Month	Cal. days	Uptime (frac)	Prod. days (days)	Prod. day rate (stb/d)	Cal. day rate (stb/d)	Date	N_t (MMstb)	Elapsed cal. days (days)	Elapsed prod. day (days)	Cum. uptime (frac)	Date	N_t (MMstb)	q_t (stb/d)	Month	Prod. day rate (stb/d)	Date	Cum. uptime	N_t (MMstb)	Month	Prod. day rate (stb/d)	Cal. day rate (stb/d)
						31/12/05	0.000	0	0.00	1.000	31/12/05	0.000	10,000								
Jan 06	31	0.979	30.34	9,196	9,001	31/01/06	0.279	31	30.34	0.979	31/01/06	0.282	8,621	Jan 06	9,288						
Feb 06	28	1.000	28.00	8,237	8,237	28/02/06	0.510	59	58.34	0.989	28/02/06	0.508	7,560	Feb 06	8,076						
Mar 06	31	0.970	30.07	6,997	6,787	31/03/06	0.720	90	88.41	0.982	31/03/06	0.720	6,603	Mar 06	7,067						
Apr 06	30	0.982	29.45	6,072	5,962	30/04/06	0.899	120	117.87	0.982	30/04/06	0.903	5,812	Apr 06	6,196						
May 06	31	0.936	29.01	5,472	5,120	31/05/06	1.058	151	146.87	0.973	31/05/06	1.062	5,149	May 06	5,472						
Jun 06	30	0.480	14.40	5,101	2,449	30/06/06	1.131	181	161.27	0.891	30/06/06	1.134	4,857	Jun 06	5,001						
Jul 06	31	0.392	12.16	4,646	1,822	31/07/06	1.188	212	173.43	0.818	31/07/06	1.191	4,627	Jul 06	4,741						
Aug 06	31	0.440	13.64	4,549	2,002	31/08/06	1.250	243	187.07	0.770	31/08/06	1.253	4,385	Aug 06	4,504						
Sep 06	30	0.650	19.50	4,308	2,800	30/09/06	1.334	273	206.57	0.757	30/09/06	1.335	4,067	Sep 06	4,223						
Oct 06	31	0.730	22.63	3,936	2,874	31/10/06	1.423	304	229.20	0.754	31/10/06	1.423	3,734	Oct 06	3,897						
Nov 06	30	0.950	28.50	3,545	3,368	30/11/06	1.524	334	257.70	0.772	30/11/06	1.524	3,364	Nov 06	3,545						
Dec 06	31	0.900	27.90	3,234	2,911	31/12/06	1.614	365	285.60	0.782	31/12/06	1.614	3,047	Dec 06	3,202	31/12/06	0.782	1.614	Dec 06		
																31/01/07	0.782	1.685	Jan 07	2,922	2,286
																28/02/07	0.782	1.744	Feb 07	2,700	2,113
																31/03/07	0.782	1.804	Mar 07	2,500	1,956
																30/04/07	0.782	1.859	Apr 07	2,313	1,810
																31/05/07	0.782	1.911	May 07	2,144	1,677
																30/06/07	0.782	1.957	Jun 07	1,990	1,557
																31/07/07	0.782	2.002	Jul 07	1,850	1,448
																31/08/07	0.782	2.044	Aug 07	1,721	1,347
																30/09/07	0.782	2.082	Sep 07	1,605	1,256
																31/10/07	0.782	2.118	Oct 07	1,500	1,173
																30/11/07	0.782	2.151	Nov 07	1,403	1,097
																31/12/07	0.782	2.183	Dec 07	1,314	1,028

7.7 Best Practices Checklist

If it is suspected that uptime (=1-downtime) effects might be important, create a plot showing historical calendar-day rates, producing-day rates, and uptime. If uptime effects seem likely to compromise the DCA, then use production day rates in the analysis. In the analysis of the historical trend, use the modified integral form of the equation (Equation 28). This involves keeping a running average of the uptime. For the forecast, also use the modified integral form of the equation, with some cumulative uptime operator. It is not possible to give specific rules as to what circumstances must prevail for either the one or the other method to be selected, and the analyst must apply judgment.

The selection of an appropriate function or value for cumulative uptime for use in the forecast needs careful consideration. It is occasionally adequate to accept a constant value for the uptime factor in the forecast, such as described in example 1 above, where it can be demonstrated that a constant value is reliable. In a case such as this, the final historical cumulative uptime is usually ideal, as it is already an average value over the historical period. A difficulty arises when uptime shows a progressive deterioration, and where it is expected that the uptime may decrease further in the future. The analyst must apply judgment in this case, always ensuring that a forecast made for the purposes of underpinning SEC compliant Proved Reserves, must meet the criterion of Reasonable Certainty.

Remember that, theoretically, a plot of rate vs cumulative production constructed using producing-day rates, and a plot of rate vs cumulative production using calendar-day rates will both extrapolate to the same value of TRV! The one method does not give a higher or lower estimate of TRV than the other method. It is simply that the use of producing-day rates brings out the reservoir performance trend and often allows you to estimate TRV with a higher degree of confidence. The uptime factor in the forecast simply serves to stretch the production curve along the time axis, but should not affect your TRV. The uptime factor can, of course affect your reserve, as your economic limit test is effectively carried out on calendar-day rates.

Remember that if you do DCA on a well by well basis, and use producing-day rates in your analysis, it is important to convert you forecast of producing-day rates vs time to calendar-day rates vs time before aggregating the well forecasts to field level. Your field level forecast will then be in calendar-day rates, which is appropriate for performing the economic limit test.

Remember that some entities relate to an average over a period of time, while others relate to an instant in time. Do not get these confused.

8 Well Production Forecast Limits

8.1 Discussion

Before aggregating to reservoir level, factors that limit a well's life must be taken into consideration. Examples of such factors are:

Rate related economic limit. There may be a flow rate or a fluid ratio limit (GOR or water-cut) beyond which a well can no longer produce economically. The forecast for the well must be truncated when this limit is reached. For example, a mature reservoir may have a database of many wells that have been shut-in after reaching their limiting water-cut. If the forecasts are made for the purposes of underpinning Proved Reserves, then a high confidence water-cut cut-off value must be used. Any notion that it is not necessary to apply an individual well economic cut-off because of a perception that it is dealt with in the economic limit test (ELT) is entirely erroneous, as the ELT is applied at a high level. Once the individual well forecasts have been aggregated, information at well level is lost. Therefore, any knowledge of cut-offs that apply at well level must be implemented at well level prior to aggregation. The limiting value of rate or fluid ratio that the analyst selects should be supported by actual data. The best way to do this is with analogues from the same reservoir.

Mechanical life expectancy. In some reservoir developments, each well has a finite life expectancy, due to corrosion, or some other mechanical reason. When a forecast is made for such a well, the life expectancy of the well must be brought into consideration. When a forecast is made for the purposes of underpinning Proved Reserve estimates, the life expectancy used to truncate the forecast must be shown to be a high confidence option, preferably through the use of analogues in the same reservoir. When deciding on the life expectancy of a well, the analyst should be acquainted with the guidelines on the booking of Proved Developed Reserves when well work-overs (for example, for pump replacements) are anticipated.

Minimum decline rate. When any value of the hyperbolic exponent (b) is used other than a value of zero, (i.e. for $0 < b \leq 1$) the effective decline rate (D) decreases in value from year to year. This can lead to unreasonably low decline rates (and over-optimistic reserve estimates) if the forecast is made far into the future. Therefore, the effective decline rate should be calculated on an annual basis. This will show how the value of D decreases from year to year. If the forecast is being done to support a Proved Reserve estimate, then it is prudent to decide on a minimum value of D and when the forecast value of D reaches this value, to maintain it at this value and not permit it to get any smaller. This effectively reverts from a hyperbolic decline to an exponential decline.

8.2 Examples

This is an example of a forecast with a hyperbolic exponent of 1.0, and an initial nominal decline rate of 0.002 /day. The left hand side of Table 3 shows the harmonic forecast and the effective decline rate, D. During the first year of the forecast, the effective decline is an enormous 42.2% pa. Due to the harmonic nature of the function, the value of D decreases year-upon-year, reaching a very low value of 3.8% pa after 25 years. The analyst recognised that this was unreasonable, and with the use of analogue data from other wells in the reservoir, decided to enforce a minimum value for the effective decline rate of 10% pa. Consequently, when the decline rate goes below 10% pa in 2014, the analyst pegs it at this constant value for the remainder of the forecast (shown in the right hand side of Table 3). The forecast consequently follows a hyperbolic trend from 2006 through 2013, and an exponential trend from 2014 onwards. The difference in the remaining recoverable volume in this case is approximately 1 MMstb, or 7%.

Note that some items (D, average rate) are reported as yearly average figures. These are shown in blue text in the table without shading. Other entries (cumulative production, instantaneous rate) are specified on a particular date, namely the last day of each year. These are shown in black text in the table against a shaded background. Instantaneous values and average values should not be confused or mixed.

This example has been included here merely to demonstrate the danger of long-term extrapolation of a non-exponential function, and should not be seen to endorse the use of harmonic functions, nor should it be seen to endorse the practice of extrapolating far into the future.

Table 3: Example of a forecast made using a hyperbolic function and a limiting decline rate.

With no limit applied to decline rate						With limit applied to decline rate					
q_i =	10,000	stb/d				D_{min} =	10%	pa			
b =	1.00	dimensionless				d_i =	0.0003	/day exponential decline			
d_i =	0.002	/day									
Date	N_t (MMstb)	q_t (stb/d)	Year	D (% pa)	Av. rate (stb/d)	Date	N_t (MMstb)	q_t (stb/d)	Year	D (% pa)	Av. rate (stb/d)
31 Dec 05	0.00	10,000				31 Dec 05	0.00	10,000			
31 Dec 06	2.74	5,780	2006	42.2%	7,508	31 Dec 06	2.74	5,780	2006	42.2%	7,508
31 Dec 07	4.50	4,065	2007	29.7%	4,822	31 Dec 07	4.50	4,065	2007	29.7%	4,822
31 Dec 08	5.80	3,133	2008	22.9%	3,558	31 Dec 08	5.80	3,133	2008	22.9%	3,558
31 Dec 09	6.83	2,550	2009	18.6%	2,821	31 Dec 09	6.83	2,550	2009	18.6%	2,821
31 Dec 10	7.69	2,149	2010	15.7%	2,338	31 Dec 10	7.69	2,149	2010	15.7%	2,338
31 Dec 11	8.42	1,858	2011	13.6%	1,997	31 Dec 11	8.42	1,858	2011	13.6%	1,997
31 Dec 12	9.05	1,635	2012	12.0%	1,742	31 Dec 12	9.05	1,635	2012	12.0%	1,742
31 Dec 13	9.62	1,461	2013	10.7%	1,545	31 Dec 13	9.62	1,461	2013	10.7%	1,545
31 Dec 14	10.12	1,320	2014	9.6%	1,388	31 Dec 14	10.12	1,315	2014	10.0%	1,387
31 Dec 15	10.58	1,204	2015	8.8%	1,260	31 Dec 15	10.58	1,184	2015	10.0%	1,248
31 Dec 16	11.01	1,107	2016	8.1%	1,154	31 Dec 16	10.99	1,065	2016	10.0%	1,123
31 Dec 17	11.39	1,024	2017	7.5%	1,064	31 Dec 17	11.36	959	2017	10.0%	1,011
31 Dec 18	11.75	953	2018	7.0%	987	31 Dec 18	11.69	863	2018	10.0%	910
31 Dec 19	12.09	891	2019	6.5%	921	31 Dec 19	11.99	777	2019	10.0%	819
31 Dec 20	12.41	836	2020	6.1%	863	31 Dec 20	12.26	699	2020	10.0%	737
31 Dec 21	12.70	788	2021	5.8%	812	31 Dec 21	12.50	629	2021	10.0%	663
31 Dec 22	12.98	745	2022	5.4%	766	31 Dec 22	12.72	566	2022	10.0%	597
31 Dec 23	13.25	707	2023	5.2%	726	31 Dec 23	12.91	509	2023	10.0%	537
31 Dec 24	13.50	672	2024	4.9%	689	31 Dec 24	13.09	458	2024	10.0%	484
31 Dec 25	13.74	640	2025	4.7%	656	31 Dec 25	13.25	413	2025	10.0%	435
31 Dec 26	13.97	612	2026	4.5%	626	31 Dec 26	13.39	371	2026	10.0%	392
31 Dec 27	14.19	586	2027	4.3%	599	31 Dec 27	13.52	334	2027	10.0%	353
31 Dec 28	14.40	562	2028	4.1%	574	31 Dec 28	13.64	301	2028	10.0%	317
31 Dec 29	14.60	540	2029	3.9%	550	31 Dec 29	13.74	271	2029	10.0%	285
31 Dec 30	14.79	519	2030	3.8%	529	31 Dec 30	13.84	244	2030	10.0%	257

8.3 Best Practices Checklist

Always give careful thought to those factors that could limit the production profile of a well, such as individual well economic limits, and finite mechanical life. Apply any well level cut-offs to the individual well level forecasts. When carrying out the DCA for the purposes of underpinning a Proved Reserve estimate, always select high confidence cut-off criteria. As far as possible, support your cut-off criteria with analogue data from more mature wells in the same reservoir.

When using trends other than exponential, calculate the effective annual decline factor, and look carefully at how this changes year-upon-year. Compare the effective decline factors with those actually achieved in the more mature wells in the reservoir. Limit the decline factor to some minimum value if necessary. When carrying out the DCA for the purposes of underpinning Proved Reserve estimates, always select a high confidence minimum value for the decline factor. Try, as far as possible, to support your decision regarding the minimum decline factor with analogue data from more mature wells in the same reservoir, or vicinity.

9 Low-level Analysis vs. High-level Analysis

9.1 Discussion

There has been some discussion in the literature regarding the appropriate 'level' at which DCA should be carried out. When we refer to the 'level' at which an analysis is done, we refer to the entity that the production data being analysed pertains to. For example, a 'field level analysis' (which is considered a 'high level analysis') means that production data from a field, i.e., the total oil rate, or gas rate, or fluid ratio for the field, have been analysed. When we refer to a 'well-level analysis' (which is considered a 'low level analysis'), we mean that production data from a well have been analysed.

The generic term 'high-level' refers to analysis at say reservoir, or field level, while the generic term 'low-level' refers to analysis at well level, or possibly even at completion level. Clearly there is an entire spectrum of 'levels' between the very lowest level, namely completion level, and the very highest level, namely field level. We consider field level as the highest level, although it would of course be possible to carry out a 'DCA' at even higher levels than this, such as at country level. Whilst country level analyses may be of use to certain groups such as governments or global analysts, they are of no use to engineers seeking estimates of Proved Reserves.

Ultimately we seek a production forecast at the level at which the 'economic limit test' is to be carried out for the purposes of estimating a reserve. This may, for example, be at field level. If therefore, the analysis has been carried out at a lower level, then the forecasts for all the constituent components of the field at this low level must be aggregated up to field level in order to carry out the economic limit test.

The Shell guidelines (EP-1100) are very clear on the level at which DCA should be carried out, advising that forecasts based on DCA methods must always be done at the lowest producing level (such as at completion level if multiple zones have been completed in a well, or at well level if wells are completed in a single reservoir). Exceptions to this rule are permitted. An example of such an exception is where there is interference between wells so that an individual well's performance no longer clearly reflects the response of the reservoir. Another example of an exception is when usable data exists only at a higher level, caused for example by poor production allocation. If total field decline curves are used (due to interference or well allocation issues, for example), then extreme care must be exercised when using the total field curve to exclude other effects, such as that of infill drilling, that could “prop-up” the decline rate.

This is an important ruling and entirely supported in this manual. A synopsis of the difficulties experienced when carrying out an analysis at either the high level or at the low level is given below.

The high level analysis. An analysis carried out at reservoir or field level is often affected by operational activity, the most common of which is infill drilling. If a trend is established during a period of active drilling, then the use of this same trend for forecasting purposes contains the implicit assumption that the drilling activity will continue at the same level into the future. While this may be a valid assumption in some instances, it is totally unacceptable when estimating SEC compliant Proved Developed Reserves. The SEC (regulation S-X) clearly states that ***'Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.'*** Even if an active drilling program is planned for the future, SEC rules do not allow the volumes that will be recovered from these wells to be classified as Proved Developed Reserves, and so any DCA trend that includes the effect of infill drilling cannot be used for forecasting purposes in this case.

On the other hand, if an analysis is carried out at high level over a historical period during which the well count is constant, the forecast may still be inappropriate, as the finite life span of individual wells will not be accounted for.

It is when analysis is carried out at a high level that the Golden Rule of DCA, (Thomas Frick's 'Petroleum Engineering Handbook of 1962', in the section dealing with the subject of ‘Production-decline curves’) **:*‘The basic assumption in this procedure is that whatever causes controlled the trend of a curve in the past will continue to govern its trend in the future in a uniform manner’***, is most easily broken.

The low level analysis.
The principal of carrying out an analysis at completion level as recommended in the Shell guidelines is commendable but frequently impractical, as it is seldom that production data is allocated accurately to completion level. It is as wrong and misleading to include bad production allocation effects in your decline trend when carrying out DCA at completion level, as it is to include a changing well count in the trend when the analysis is done at reservoir level.

Some of the other aspects that can compromise an analysis at low level are interference effects between wells, and changing allocation of gas lift quantities between wells. A further disadvantage of carrying out an analysis at well or completion level is that field level production constraints cannot easily be accounted for.

9.2 Examples

Three examples are presented below. Two address changing well count when the analysis is carried out at high level, and the third demonstrates the difficulty of doing a reliable analysis at well level when production allocation is poor.

Example 1: Reservoir level analysis with ongoing infill drilling.
Figure 24 shows actual historical production data at reservoir level and an apparently good DCA and corresponding forecast. Figure 25 shows this forecast together with subsequent actual production data. With the benefit of this additional data, the original production forecast based on the reservoir level DCA is seen to be unreliable. This is because the reservoir level production rate had been maintained artificially high by a continuous infill drilling campaign over the years before the DCA was carried out. The trend derived during the DCA therefore included the effect of the drilling campaign as well as reservoir performance factors. Once the drilling campaign came to an end, the reservoir production rate trend reflected the true performance of the reservoir, which had previously been masked.

This example demonstrates that a trend established during a period of active development cannot be used to make a reliable forecast to underpin Proved Developed Reserves. Even if development activity is expected to continue far into the future, it is inadmissible under SEC rules to use a trend established during a period of high development activity for the purposes of making a forecast to underpin SEC compliant Proved Developed Reserves, as the SEC requires that Proved Developed Reserves are attributable to the development as it is at the time that the forecast is made, and must exclude volumes that may be recovered from wells yet to be drilled.

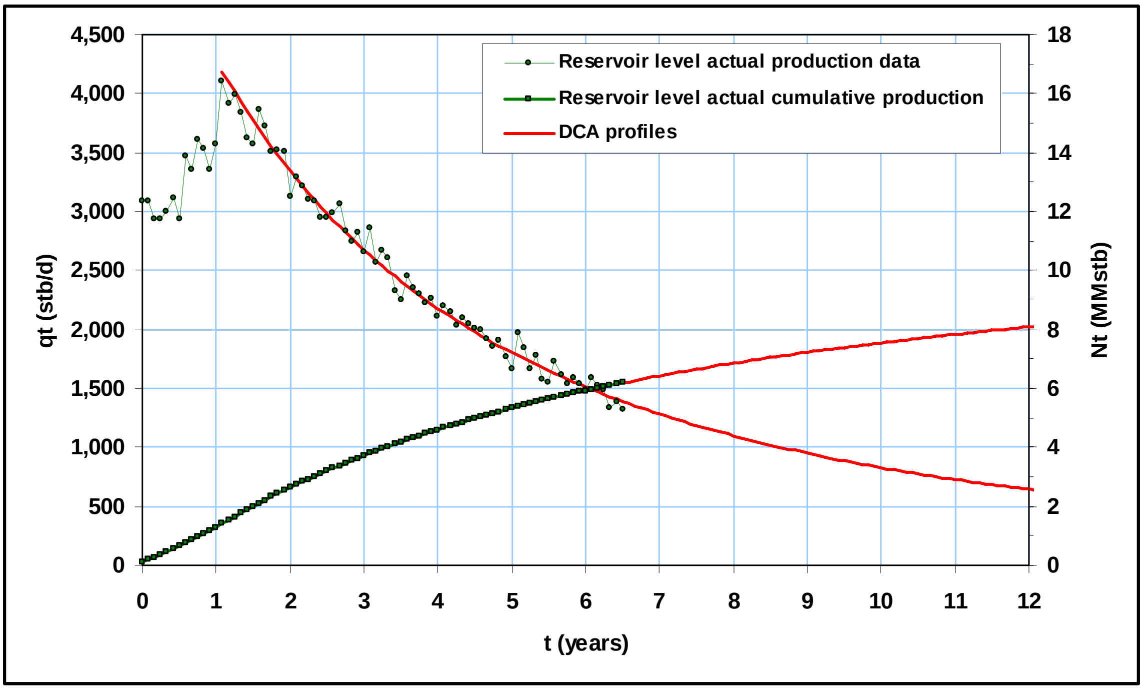

Figure 24: Historical production data and forecasts made from reservoir level DCA.

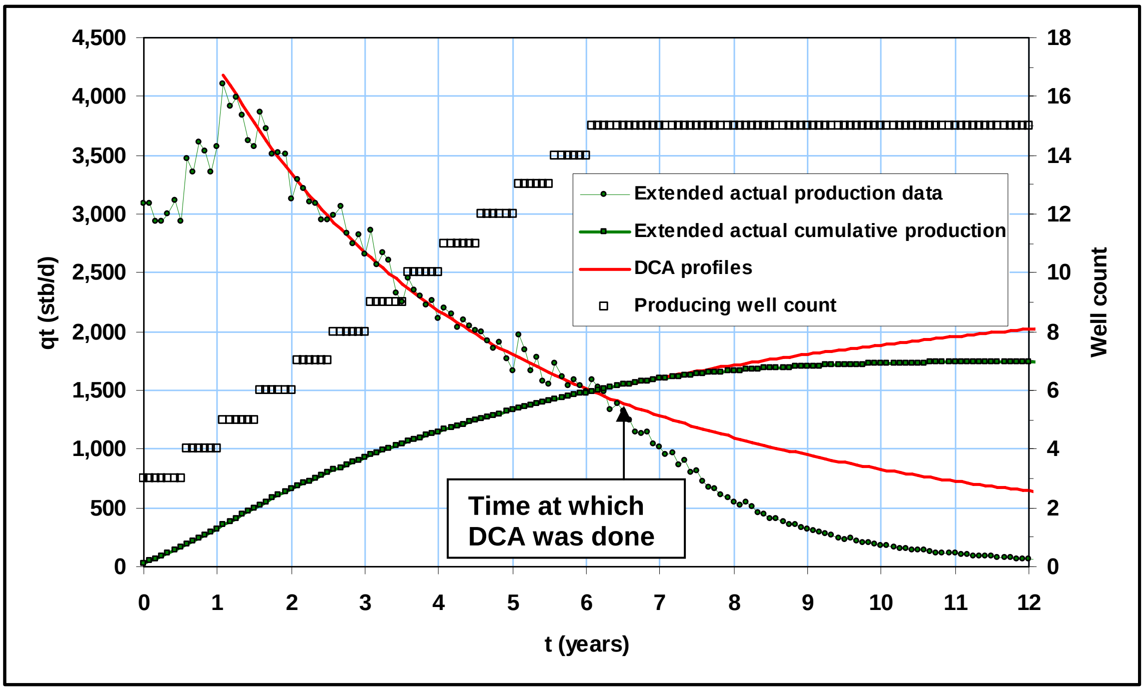

Figure 25: Actual production data beyond the point at which DCA was carried out, and forecasts made from reservoir level DCA, showing the effect of changing well count.

Example 2: Reservoir level analysis with finite well life

Figure 26 shows actual historical production data at reservoir level and an apparently good DCA and corresponding forecast. Figure 27 shows this forecast together with subsequent actual production data. In this example, with the benefit of the extra data, the production forecast from the reservoir level DCA is seen to be unreliable. This is because wells have finite lives, a fact that was not taken into account when the DCA was carried out at reservoir level. Had the analysis been carried out on individual wells, the finite life of each well would have been considered, and the resulting aggregated forecast would have been more reliable.

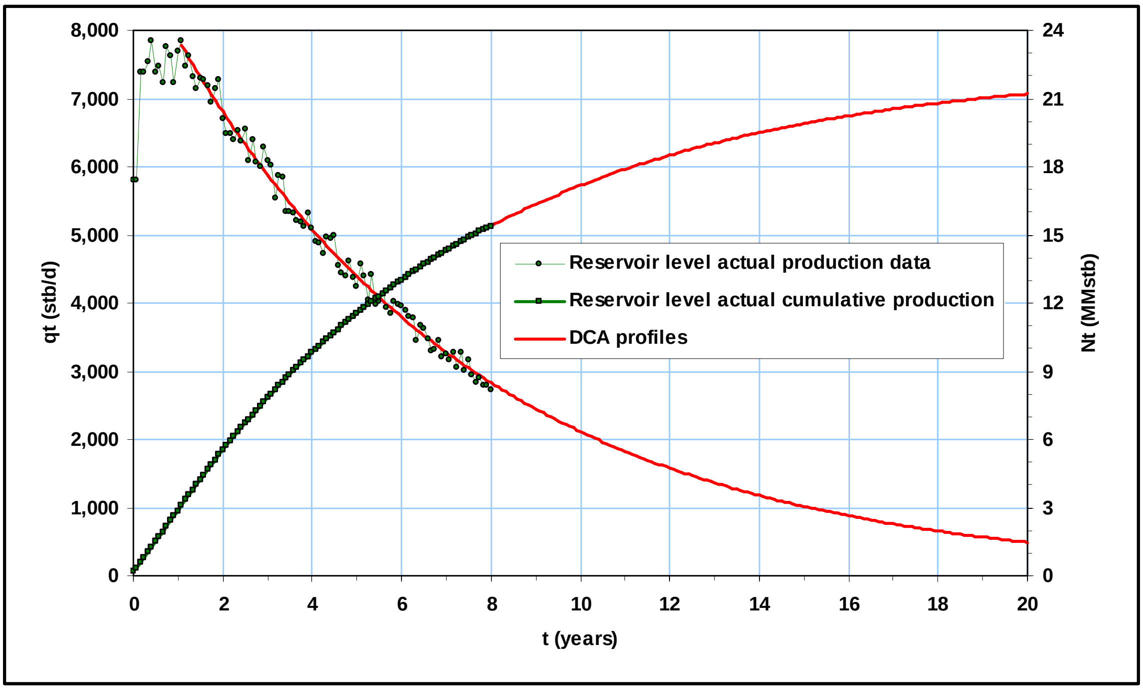

Figure 26: Historical production data and forecasts made from reservoir level DCA.

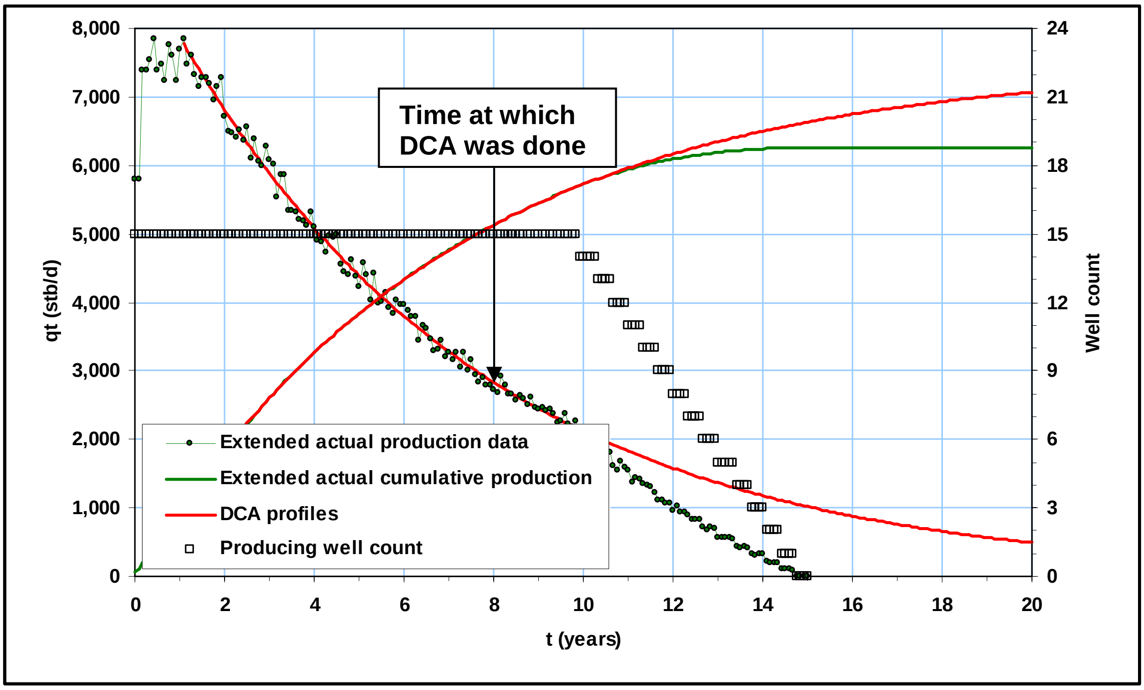

Figure 27: Actual production data beyond the point at which DCA was carried out, and forecasts made from reservoir level DCA, showing the effect of changing well count.

Example 3: Well-level analysis with poor production allocation

This is an example of an attempt to carry out DCA at well level for a 4-well reservoir development in which there is considerable interference between wells, and for which the production allocation to individual wells is poor. Figure 28 shows the DCA carried out on each of the four wells. The production data at well level is clearly poor, and a range of different curves can be fitted to each well's dataset. However, as this analysis was done to support a Proved Reserve estimate, an exponential function was accepted for each well, by fitting a straight line to each plot of oil rate vs. cumulative production. The trends thus established were used to generate a forecast for each well, and the forecasts were aggregated to reservoir level.

Figure 29 shows the reservoir level production data, together with the aggregated forecast obtained from the well-level DCA, and a forecast from the reservoir level DCA. In this example, the DCA carried out at well level provides an inferior result to the DCA carried out at reservoir level.

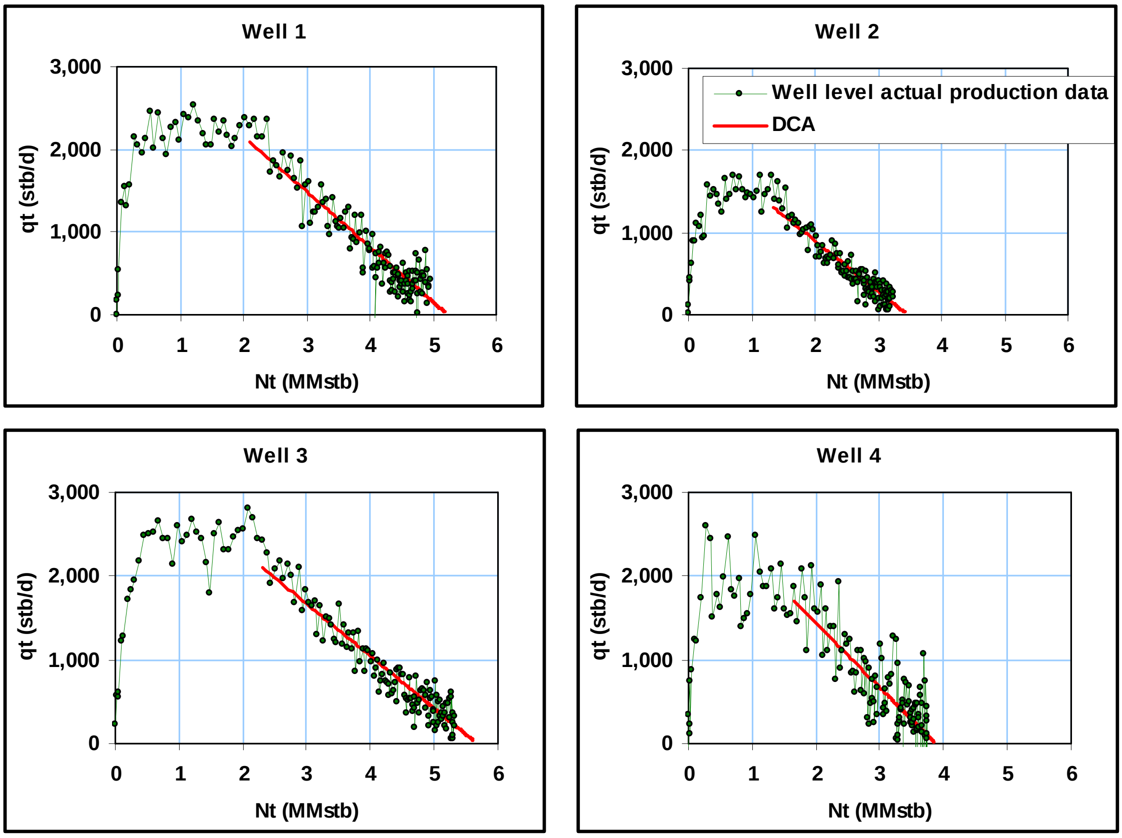

Figure 28: DCA carried out on four individual wells.

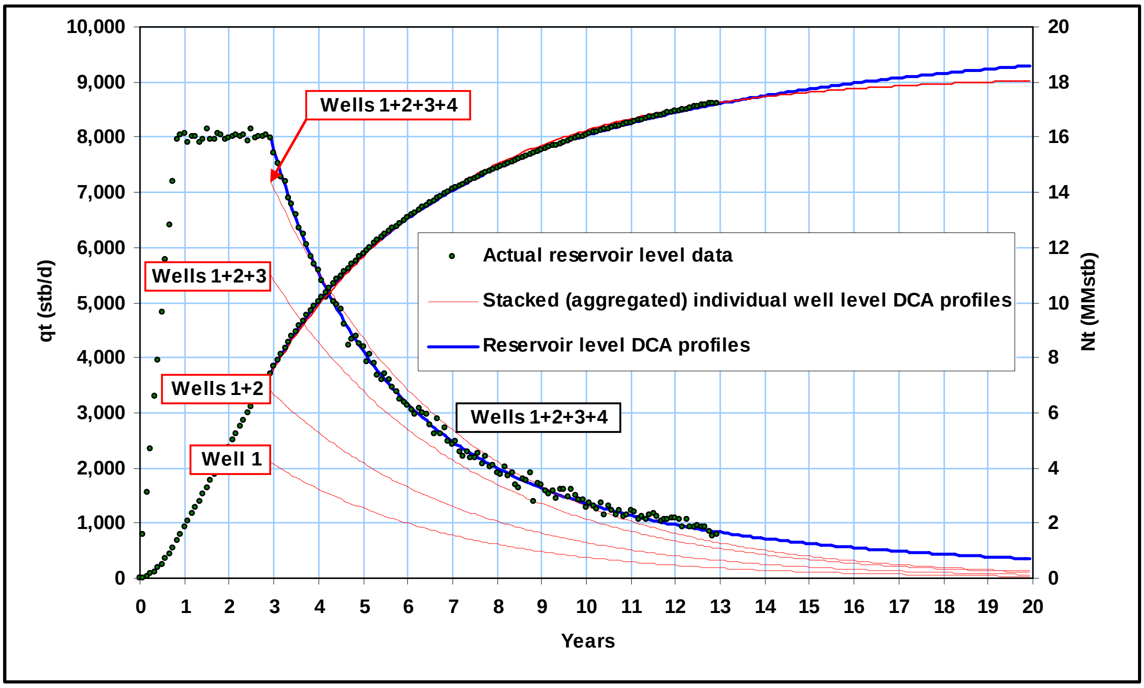

Figure 29: Reservoir level production data and DCA forecast carried out at reservoir level together with aggregated forecast of DCAs carried out at well level.

9.3 Best Practices Checklist

The risk of making an error is far greater when DCA is carried out at a high level than when it is carried out at a low level. For this reason, the general rule must be to carry out DCA at the lowest practical level.

Prior to carrying out a DCA, the analyst should review the data at different levels. The following aspects should be taken into consideration:

- What is the lowest level at which production allocation is reliable?
    - An analysis at any lower level would be unreliable.
- Are there interference effects between wells?
    - If so, a reservoir level analysis may provide a more reliable forecast.
- Are there any operational effects influence data at low level?
- What operational activities have been carried out at field level?
- Obtain a high confidence estimate of well life and apply it at well level.

The possible levels are:

- Completion
- Well

- Formation, or layer
- Production facility
- Reservoir
- Field

The default is always to carry out the analysis at the lowest possible level. Move up to the next level if you can clearly demonstrate that the forecast at the higher level is more robust. It will seldom be justifiable to carry out the analysis at a level as high as field level. In the vast majority of cases, DCA will be carried out at the well level. If an analysis is carried out at well level, the well life cut-off can be applied directly.

If an analysis is carried out at a low level, and the forecasts are aggregated to field level, then it is essential that all fluid rates and ratios, and not just the oil rate, are analysed and forecasts made for these, and that these forecasts are also aggregated correctly to field level. This must be done to test whether any of the fluid capacities and limits exceed the handling and facilities capacities. Adjustments to the forecasts must be made if this occurs.

Finally, the analyst should be aware that if DCA is carried out at a low level (such as well level), and if an exponential decline function is used for each well, then the aggregated forecast at field level will not necessary be exponential in character, but will have a hyperbolic trend with $b > 0$. The value of b for this field level forecast will depend very much on the range of values of d_i selected for the individual wells. Generally, the greater the range in the values of d_i for the wells, the greater will be the value of b for the aggregated forecast at field level. It is possible for a field level forecast which has been synthesized by aggregating exponential well level forecasts, to be harmonic in nature, if there is sufficient variability in the values of d_i for the individual wells. Therefore, when analyzing trends at field level, caution must be exercised in using the value of b to infer anything about the drive mechanism.

10 Equation list

Standard symbols

$t =$ time

$q_t =$ (instantaneous) production rate at time t [volume per time unit]

$q_i =$ (instantaneous) initial production rate (at time $t = 0$) [volume per time unit]

$N_t =$ cumulative production at time t [volume]

$b =$ hyperbolic exponent [dimensionless]

$D =$ effective decline factor [per time unit]

$d_i =$ initial nominal decline factor [per time unit]

$\Delta t =$ time step

$U_t =$ cumulative uptime factor

Basic equations for hyperbolic decline $(0 \le b \le 1)$

Rate vs. time:

$$q_t = \frac{q_i}{(1 + b \cdot d_i \cdot t)^{\frac{1}{b}}}. \qquad \text{Equation 1}$$

Cumulative production vs. time (the 'integral' form):

$$N_t = \frac{q_i}{d_i(1-b)} \cdot \left(1 - (1 + b \cdot d_i \cdot t)^{\left(1-\frac{1}{b}\right)}\right). \qquad \text{Equation 2}$$

Exponential decline. (b =0)

Rate vs. time:

$$q_t = q_i e^{-d_i t}. \qquad \text{Equation 3}$$

Cumulative production vs. time (the 'integral' form):

$$N_t = \frac{q_i}{d_i}\left(1 - e^{-d_i t}\right) = \frac{q_i - q_t}{d_i}. \qquad \text{Equation 4}$$

Constant decline relationship:

$$\frac{q_{t+\Delta t}}{q_t} = e^{-d_i \Delta t}. \qquad \text{Equation 5}$$

Straight line relationship using natural logarithm:

$$\ln(q_t) = \ln(q_i) - d_i t. \qquad \text{Equation 6}$$

Straight line relationship using logarithm to base 10:

$$\log_{10}(q_t) = \log_{10}(q_i) - C_1 d_i t, \qquad \text{Equation 7}$$

where C_1 is the constant

$$C_1 = \frac{1}{\ln(10)} = 0.43429\ldots. \qquad \text{Equation 8}$$

Straight line relationship using cumulative production:

$$q_t = q_i - d_i N_t\,. \qquad \text{Equation 9}$$

Harmonic decline. ($b = 1$)

Rate vs. time:

$$q_t = \frac{q_i}{(1 + d_i \cdot t)}, \qquad \text{Equation 10}$$

Cumulative production vs. time (the 'integral' form):

$$N_t = \frac{q_i}{d_i}\ln(1 + d_i t) = \frac{q_i}{d_i}\ln\left(\frac{q_i}{q_t}\right). \qquad \text{Equation 11}$$

Straight line relationship using natural logarithm and cumulative production:

$$\ln(q_t) = \ln(q_i) - \frac{d_i}{q_i} N_t\,. \qquad \text{Equation 12}$$

Declining decline relationship:

$$\frac{q_{t+\Delta t}}{q_t} = 1 - \frac{d_i \Delta t}{1 + d_i t}\,. \qquad \text{Equation 13}$$

The initial nominal decline factors (d_i) and the effective decline factor (D).

The definition of d_i:

$$\left.\frac{dq_t}{dt}\right|_{t=0} = q_i d_i\,, \text{ or } d_i = \frac{1}{q_i}\left.\frac{dq_t}{dt}\right|_{t=0}. \qquad \text{Equation 14}$$

The definition of D:

$$D = \frac{q_t - q_{t+\Delta t}}{q_t}, \qquad \text{Equation 15}$$

The relationship between d_i and D for exponential decline

$$D = 1 - e^{-d_i \Delta t}, \text{ and } d_i = \frac{-\ln(1 - D)}{\Delta t}. \qquad \text{Equation 16}$$

The relationship between d_i and D for hyperbolic decline

$$D = 1 - \left(\frac{1 + bd_i(t + \Delta t)}{1 + bd_i t}\right)^{-\left(\frac{1}{b}\right)}. \qquad \text{Equation 17}$$

The equations incorporating uptime

Cumulative production vs. time (the 'integral' form) with uptime:

$$N_t = \frac{q_i}{d_i(1-b)} \cdot \left(1 - (1 + b \cdot d_i \cdot U_t \cdot t)^{\left(1-\frac{1}{b}\right)}\right) \qquad \text{Equation 28}$$

Rate vs. time with uptime:

$$q_t = \frac{q_i}{(1 + b \cdot d_i \cdot U_t \cdot t)^{\frac{1}{b}}}, \qquad \text{Equation 29}$$

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