TOTAL

GUIDE & MANUAL

RESERVOIR ENGINEERING

GM EP RES 005

Production forecasts using Decline Curve Analysis

00	09/2017	First Issue
Rev.	Date	Purpose of the revision

Owning entity: DSO/GIS	Managing entity: DSO/GIS
Other Approving entity(ies):	

Original Version

Contents

1. Scope

This document provides a methodology and technical recommendations to forecast 3-phases production using Decline Curve Analysis (DCA) coupled with sound reservoir engineering / petroleum engineering practices

2. Reference documents

The reference documents listed below form an integral part of this Guide & Manual.

External Documents

Unless otherwise stipulated, the applicable version of these documents, including relevant appendices and addendums, is the latest revision published at the effective date of this document.

Reference	Title
Not applicable	

Total Standards

Unless otherwise stipulated, the applicable version of these documents, including relevant appendices and addendums, is the latest revision published.

Reference	Title
CR EP RES 001	Reserves and Resources Definitions and Classification
GM EP RES 001	Technical guidelines for evaluating reserves and contingent resources
CR EP EXP 100	Production and injection performance monitoring
GM EP EXP 100	Production and injection performance monitoring

3. Key points

This GM describes the step-by-step workflow to use while performing Decline-Curve Analysis on **conventional oil fields**:

Step 1: Data review

1a. Compilation of all the available production data & information

Distinguish reservoir signature from artefacts => Discard spurious data

1b. Creation of composite plots

Step 2: Decline matching

2a. Determination of the lowest level of reliable production allocation:

Forecast at group level? at well level?

2b. Determination of the most representative flowing period

Long enough to be representative of the future production conditions

2c. Knowing the 3 Arps type of decline

Harmonic, hyperbolic & exponential declines

2d. Selection of the most relevant regression

Q vs Np (exponential)? log(Q) vs log(1+b.Di.t) (hyperbolic), log(fo) vs Np (harmonic)….

Step 3: Base case DEV forecast

3a. Assessment of constrained potential & uptime factor

3b. Assessment of technical cut-offs

3c. Assessment of economical cut-offs

3d. Assessment of facilities constraints

3e. Combination of the best regressions to calculate the 3-phase profiles.

3f. Specific case of recent additional work

Production acceleration only? Positive incremental reserves?

3g. Arithmetic aggregation to field level

3h. QC at field level *(consistency with field & facilities constraints)*

Step 4: low case & high case DEV forecast

4a. Determination of the main uncertain parameters driving the forecasts

4b. Selection of the most representative flowing period for the low & high cases

4c. For the low & high cases, work at higher level than at wells level

to avoid the "Portfolio effect"

4d. QC of results

(consistency with facilities constraints, comparison with the base case DEV, comparison with other methodologies)

Figure 1: Recommended workflow for DCA studies on conventional oil fields

For gas fields, instead of extrapolating gas rate decline, it is much preferred to extrapolate reservoir pressure decline through material balance analysis and then to derive gas rate evolution through an integrated model (reservoir/well/surface modeling with Petex suits or GasPal for example).

4. Nomenclature

- b: Arps' decline exponent [dimensionless]
- B: formation volume factor (reservoir volume/surface volume)
- c: compressibility
- D_i: nominal (or instantaneous) initial decline rate [time^{-1}]
- E_g: underground gas expansion (= B_g - B_{gi})
- f_o: fractional flow of oil (= Q_o /(Q_o+Q_w), also called oil cut)
- f_w: fractional flow of water (= Q_w /(Q_o+Q_w), also called water cut)
- G: connected gas-in-place (surface-measured)
- G_p: cumulative gas produced
- N: original oil-in-place
- N_p: cumulative oil production
- P: reservoir pressure
- q (or Q): rate (oil, water or gas)
- q_i: initial rate (Arps' decline law)
- ΔP: difference in pressure or pressure drop
- R_s: solution (or dissolved) gas-oil ratio
- S_{wi}: initial water saturation
- t: time
- W: total water volume of the aquifer
- W_e: cumulative water influx
- W_p: cumulative water production
- Z: gas compressibility factor
- μ: viscosity

Subscripts:

- a: at abandonment
- c: cumulative (WOR_c, f_{wc})
- f: formation
- g: gas
- i: initial
- inj: injected
- liq: liquid (oil+water)
- o: oil
- p: cumulative production
- pot: potential
- r: reservoir
- t: total
- u: ultimate
- t: total
- w: water

Abbreviations:

- BHP: bottom hole pressure
- BHFP: bottom-hole flowing pressure
- THP: tubing head pressure
- WHP: well-head pressure
- HP/MP/LP: high pressure / medium pressure/ low pressure
- BT: water breakthrough
- BSW: basic sediment and water
- GLR: gas-liquid ratio (= Q_g /Q_{liq})
- GOR: gas-oil ratio (= Q_g /Q_o)
- WOR: water-oil ratio (= Q_w / Q_o)
- II: injectivity index
- IPR: inflow performance relationship
- PI: productivity index
- VLP: vertical lift performance
- VR: voidage replacement
- WOC: water-oil contact
- GOC: gas-oil contact

5. Introduction

Decline curve analysis (DCA) consists of a graphical procedure of curve-fitting past production performance (rates and/or ratios) in order to forecast future performance of hydrocarbon wells.

DCA is one of the oldest techniques used to forecast production from existing wells or groups of wells (platform, reservoirs, fields), when a sufficient and representative production data is available.

DCA is widely used in the Group. Around 70% of conventional fields in production have technical forecasts estimated with DCA:

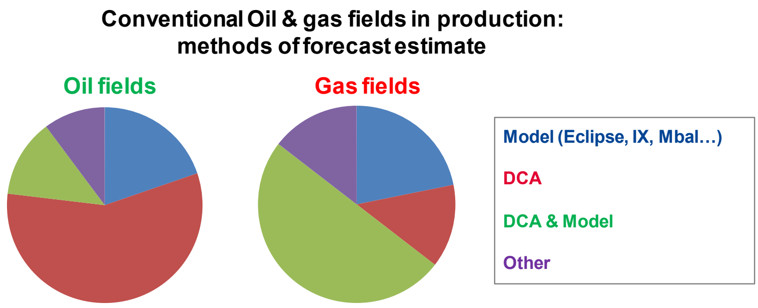

Figure 2: Number of fields per forecasts method

The objective of this G&M is to provide practical methodology, guidance and technical recommendations to forecast 3-phase production using Decline Curve Analysis (DCA).

This G&M is dedicated to conventional oil & gas fields. A specific G&M will address Decline-Curve Analysis for unconventional fields.

The reader will find in this G&M the following terms “low estimate”, “best estimate” and “high estimate” used to respectively calculate 1P/1C, 2P/2C and 3P/3C reserves / resources.

Many textbooks and technical papers in the public literature address DCA. Some of these textbooks and the more relevant technical papers have been combined with existing practical experience within Total to provide the guidance covered in this document.

This document is divided into 13 main chapters and one appendix which address the following items:

- **Chapter 6** describes the field of application of DCA
- **Chapter 7 to 11** describes the step-by-step workflow to perform a DCA study on conventional oil fields.
- **Chapter 12** describes the common pitfalls to avoid while doing a DCA study.
- **Chapter 13 & 14** presents 2 examples of DCA studies performed on conventional oil fields, at well level and at field level.
- **Chapter 15** focuses on the Decline-Curve Analysis for gas fields
- **Chapter 16** presents example evaluations of 3 gas fields
- **Appendix 1** describes in detail Arp’s theory of DCA.

6. DCA field of application

There are in fact two types of decline curve analysis, namely “type curve matching” and “curve fitting”:

- “Type curve matching” aims at interpreting both the transient flow period and steady-state flow period. “Type curve matching” is an analytical approach and is not covered in this document.
- “Curve fitting” is the most commonly used method and is only applicable to the pseudo steady-state flow period.

  It is based on the equation first documented by J. J. Arps in 1945. Arps’ equations are not grounded in physical principle but based on empirical observation of production decline. They are therefore simple to use, not requiring any reservoir or well parameters, but only applicable for boundary-dominated flow regime.

6.1 Field of application

Decline Curve Analysis (DCA) is one of several methodologies (analogy, material balance, reservoir modeling…) used to forecast hydrocarbon production and estimate EUR (Estimated Ultimate Revovery) from existing wells or groups of wells (platform, reservoirs, fields).

Guideline n°1:

DCA can allow **quick and reliable evaluation of mature fields** to be performed.

It can be also used **to quality-check the results of more sophisticated forecasting tools** e.g. reservoir models.

6.2 Prerequisites to perform DCA

DCA consists of a graphical procedure of curve-fitting past production performance (rates and/or ratios) in order to forecast future performance of hydrocarbon wells.

Guideline n°2:

DCA requires a sufficient representative period of historical production for the establishment of an observable trend.

The trend can be:

- **constant** (e.g. liquid production vs time under specific conditions)
- **decreasing** (e.g. log(f_o) vs Np)
- **or increasing** (e.g. WOR vs time)

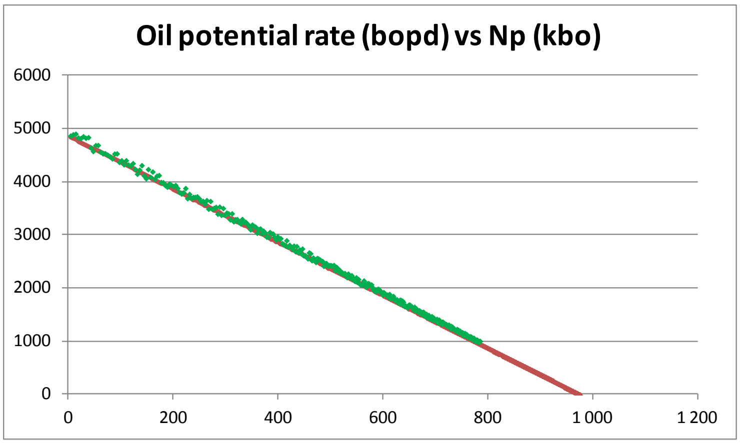

Figure 3: Example of observed decreasing trend (oil potential vs Np)

6.3 Factors governing production decline

Production decline is basically due to the combination of:

- **Reservoir effects**
  - Depletion
  - Water invasion and/or increasing gas saturation
  - Interface (WOC/GOC) movements
  - Change in drainage area/well interference effects,
  - Flood front movements in injection or water-drive processes,
- **Inflow performance evolution:**
  - Transient effects
  - Relative permeability effects
  - Changes in fluid properties (B_o, B_g, μ_o, μ_g) with pressure depletion,
  - Skin evolution (scale, fines migration at well-bore...)
- **Outflow performance:**
  - Changes in completion
  - Scales, paraffin, asphaltenes deposits in the tubing
  - Lift performance (natural or artificial lift)
  - Change in lift performance
  - Cross-flow (for multilayer wells)
- **Field management:**
  - Additional voidage through new wells and/or remedial work on producers
  - Change in the production mechanism
  - Operating philosophy (choking / unchoking)

- **Surface constraints:**
    - Production issues (shutdowns...)
    - Network back-pressure evolution
    - Facilities capacities

These numerous parameters are not easy to differentiate and DCA techniques are therefore grounded on simplified assumptions.

6.4 Pseudo-steady state conditions

Guideline n°3:

Forecasts generated by decline curves represent production from reservoirs **under pseudo-steady-state (boundary dominated flow) conditions**.

During the early life of a well, the decline curve method should not be applied as the well is still in transient flow (the reservoir boundaries have not yet been reached).

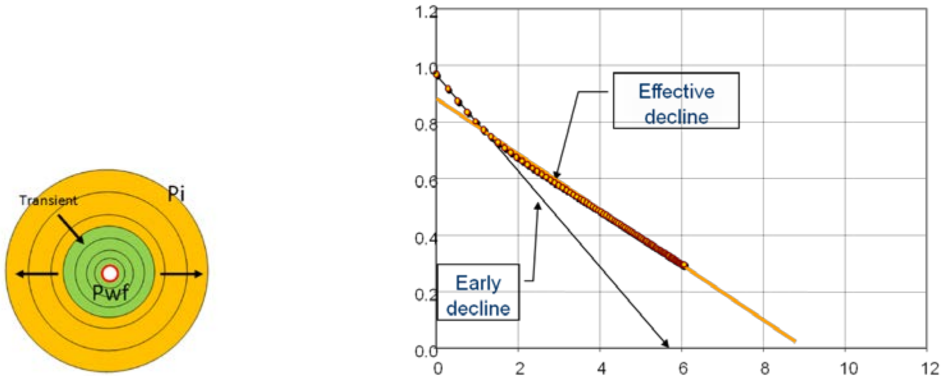

Figure 4: Transient vs pseudo-steady state regime

6.5 Stable reservoir & operating conditions

The observed production decline should not be the result of external causes such as change in operational policy, well damage, production controls and/or equipment failure.

Guideline n°4:

Reservoir and operating conditions should be as stable as possible over the production period considered representative for DCA, and have to be assumed to remain unchanged over the whole production forecast period.

Ideally the well being analysed should have been producing either at full capacity (“wide open”) or with constant operating conditions (same choke size, same artificial lift...) or a constant well-head pressure.

The example below shows the impact of a change in production mechanism on an established trend :

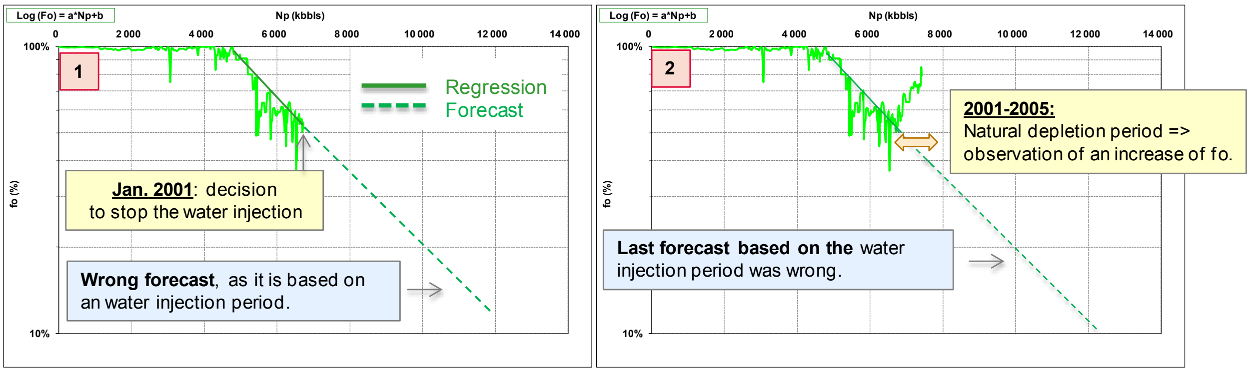

Figure 5: Example of curve-fitting with changing operating conditions

Thus, the following parameters should be analyzed and understood in order to conduct a proper DCA study:

- Well count variation: infill drilling;
- Changes in flowing conditions: over/under injection at injectors, choke variations at producers…
- Changes in well drainage area: interferences due to existing or future infill drilling;
- Changes in inflow/outflow performance: well stimulation, workover to run a new completion with a different tubing diameter …
- Change in lifting method: ESP (Electrical Submersible Pump) or gas lift …
- Change in network pressure: e.g. compression project.
- …

7. Generic workflow for DCA of conventional oil assets

A generic DCA workflow is given below:

Step 1: Data review

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1b. Creation of composite plots

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4c. For the low & high cases, work at higher level than at wells level

to avoid the "Portfolio effect"

4d. QC of results

(consistency with facilities constraints, comparison with the base case DEV, comparison with other methodologies)

Figure 6: Recommended workflow for DCA studies

8. Step 1: Data review prior to the decline curve analysis

8.1 Sub-step 1a: Data review

Guideline n°5:

A comprehensive review of the data should be performed to isolate the reservoir signature from any artefacts created by spurious data.

This is typically the most challenging step and the analyst is encouraged to perform the data review and diagnostics with care.

An immediate exercise of best fitting the oil decline should be avoided.

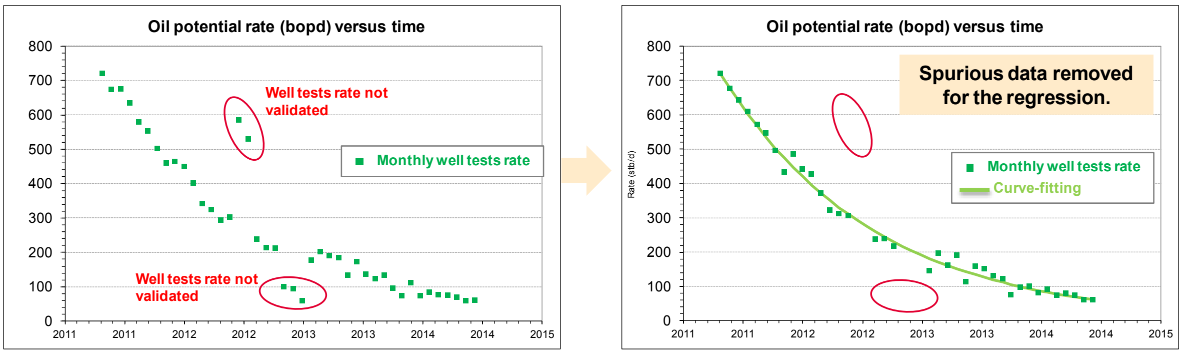


Figure 7: Removal of spurious data before the regression

8.2 Sub-step 1b: Composite plots

Many softwares can be used to analyze historical well/reservoir/field performance: Excel, OFM, T-More (Total in-house application)...

Guideline n°6:

Prepare composite well plots in order to:

- Review all the production/injection and monitoring data
- Understand the historical changes
- Establish the reliability of reported rates/potentials and their link to well tests (e.g. reliability and test frequency of reported water cuts in well production records).
- Establish the lowest level of reliable production allocation and the range of uncertainty in the allocated production data (is the lowest level of reliable production at well level, at gathering station level, at platform level, at field level?).
- Detect potential interference effects between wells.
- Understand the basic physics of well/reservoir performance (e.g. are oil rates declining due to pressure decline or due to water cut increase, etc...
- Assess well and facilities capacities

The following data can be part of the composite plots:

- Production and injection histories: oil/water/gas rates & potentials, injection rates, water cut, GOR, choke sizes, THP, PI & II evolutions etc.,
- Reservoir pressure evolution (BHP, comparison with saturation pressure), voidage history
- Production test history, salinity measurements ...
- Number of active wells (producers & injectors)
- Well and field events: work-overs, stimulation campaigns, annotation of key operational changes such as changes in lifting method capacity, changes in back pressure ...
- For artificial lift: pump design and operating parameters (e.g. rpm=revolutions per minute)

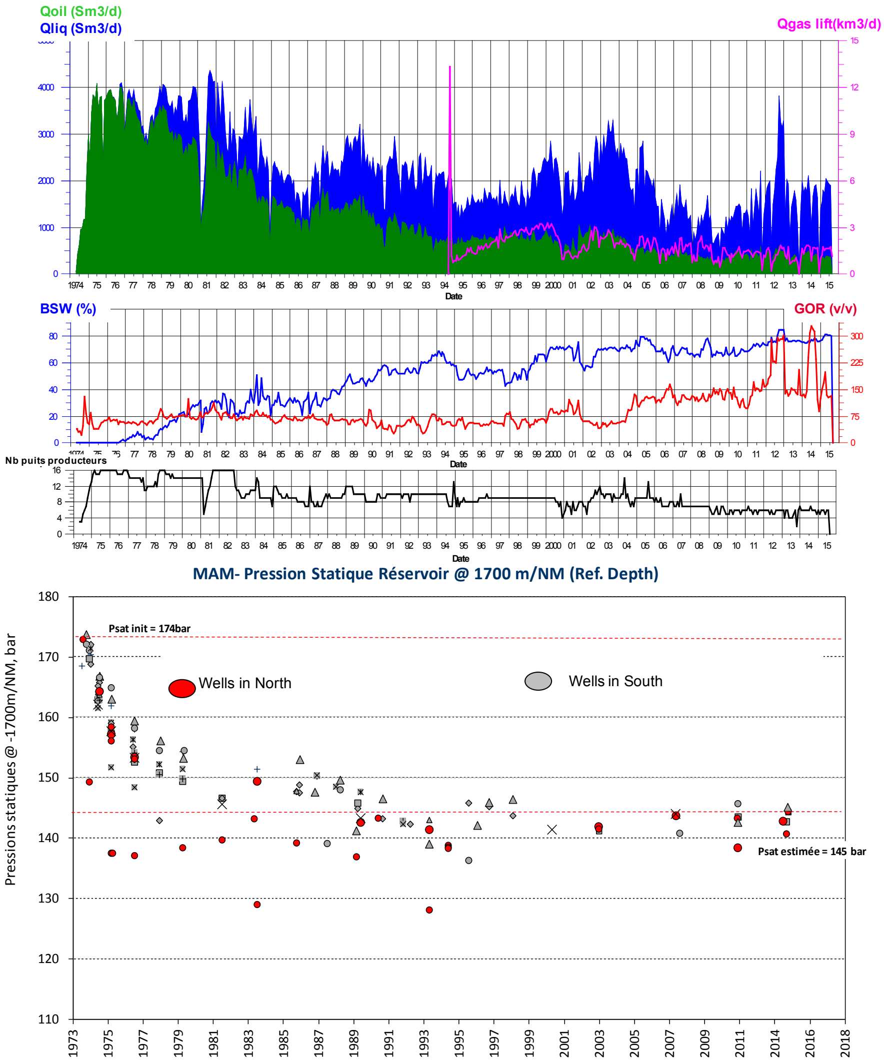


Figure 8: Example of a composite plot for a field without injection

9. Step 2: Decline matching of conventional oil assets

9.1 Sub-step 2a: DCA to be performed at well level? Or at wells group level?

DCA can be carried out at field, reservoir, platform, gathering station, well group, well or production string level.

Choosing the level of detail at which the analysis will be carried out, will very much depend on the existence (or lack thereof) of meaningful characteristics and on the reliability of production allocation at those different levels.

The following issues should be considered when establishing the level at which DCA will be performed:

- Reliability of production allocation. **In all cases DCA should not be undertaken below the lowest level of reliable production allocation**;
- New or recently drilled wells, which may bias the underlying field decline (e.g. new wells might be dry producers in a water drive field with older wells producing at high water cuts);
- Wells shut-in or abandoned during the evaluation period (note that if doing a decline analysis at field level, the abandonment of some wells would be included in the established field decline);
- Wells producing from different reservoirs or having different production mechanisms within the same field;
- Wells producing commingled from different reservoirs;
- Observed interference effects (this may justify grouping the wells showing interference as one group for DCA);

Guideline n°7:

Analysis at well level (unless well production data are not reliable) **is the recommended starting point.**

This allows checking consistency between DCA and the well inflow-outflow parameters.

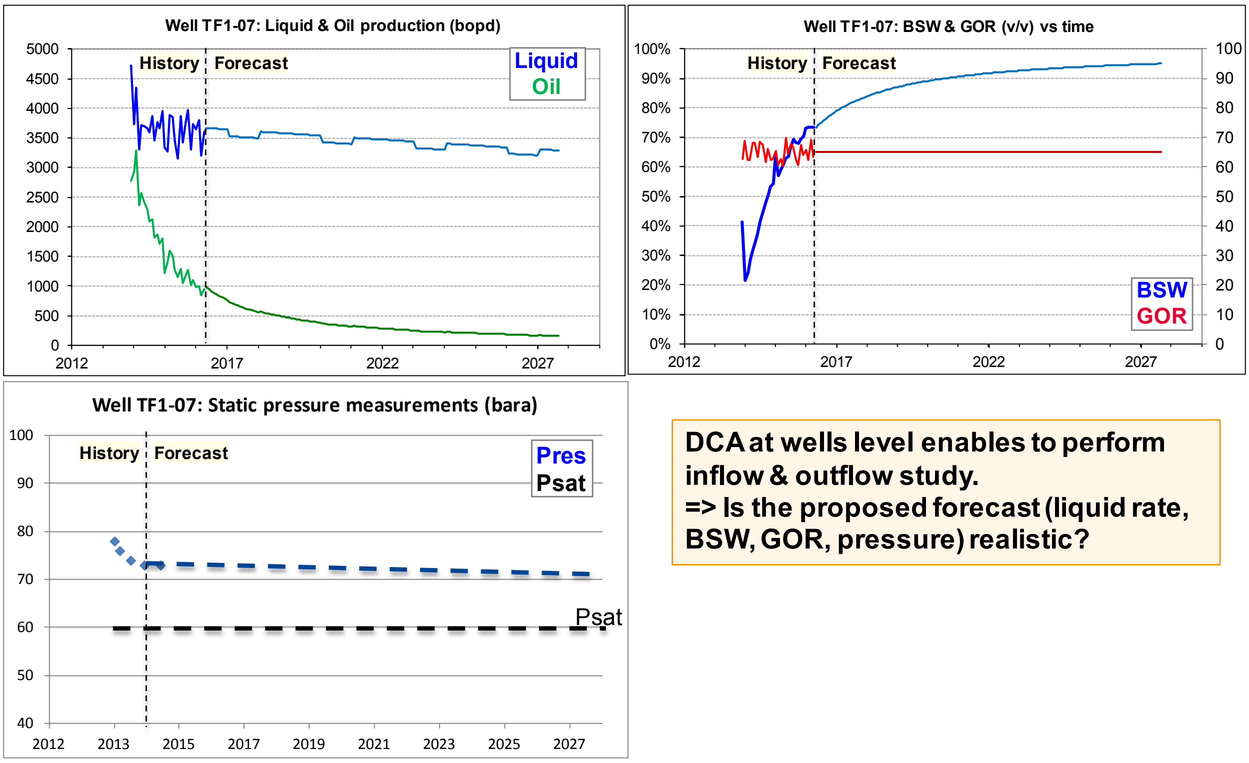


Figure 9: DCA at well level enables to check the inflow & outflow performance

> **Guideline n°8:**
>
> **In case of inaccurate well back-allocation or when interference between wells has been observed, grouping wells exhibiting similar behaviours can be more representative.**
>
> **New wells (**having a too short production history) **should be excluded from any analysis at group of wells level and their forecasts should be estimated separately.**

The main drawback of realizing decline analysis on a group of wells is that the production rate per well is not a direct output, which creates an issue when **considering outflow technical cut-offs**.

> **Guideline n°9:**
>
> It is recommended to undertake DCA at the lowest level for which reliable production information exists (e.g. well or group of wells) and **to compare the aggregated results with those using a higher level of analysis (e.g. platform/field analysis).**

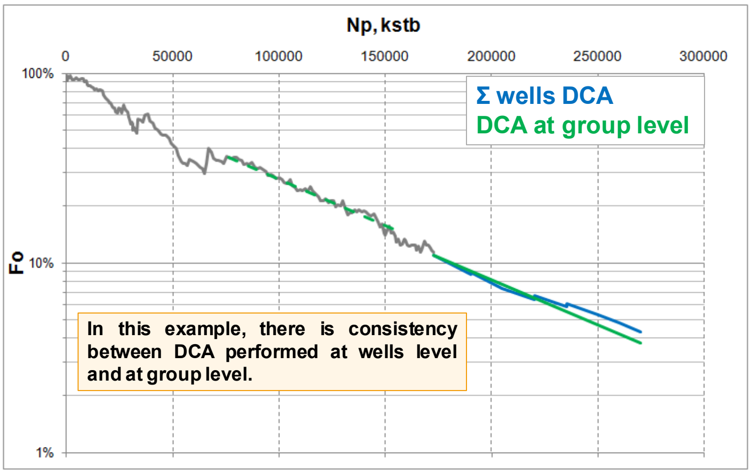


Figure 10: DCA at wells level vs at group level

9.2 Sub-step 2b: Representative flowing period

The choice of the most representative flowing period is very important for a reliable DCA.

For that reason the choice of this period should be made by examining the composite plots, combining as many data as possible (oil potential + liquid potential, injection rates, pressures, chokes etc.) and by not considering only the key parameter i.e. oil rate only (as it is often the case).

Guideline n°10:

Special attention should be paid to the **stability of the operating conditions and to the production mechanism(s).**

It is therefore important to **isolate in the history the period that will best represent the expected future production conditions of the well (or group of wells)**

The situation at the end of the history is of course of prime importance but the evaluator should also consider if the conditions existing at this time will prevail in the forecast period (e.g. might water injection be resumed if the injector supporting the well under analysis is shut-in at the end of the history?).

If the situation existing at the end of the history will likely change in the forecast period, then the retained period should be selected so as to correctly represent the future production conditions. In this instance the last historical interval would not be included in the regression.

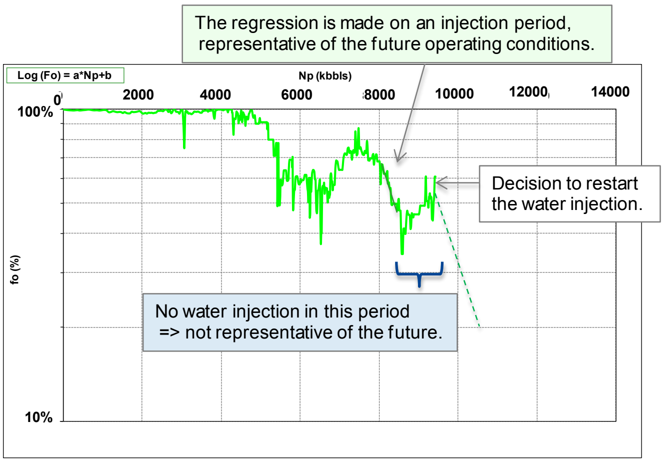


Figure 11: Selection of a period which is representative of the future operating conditions

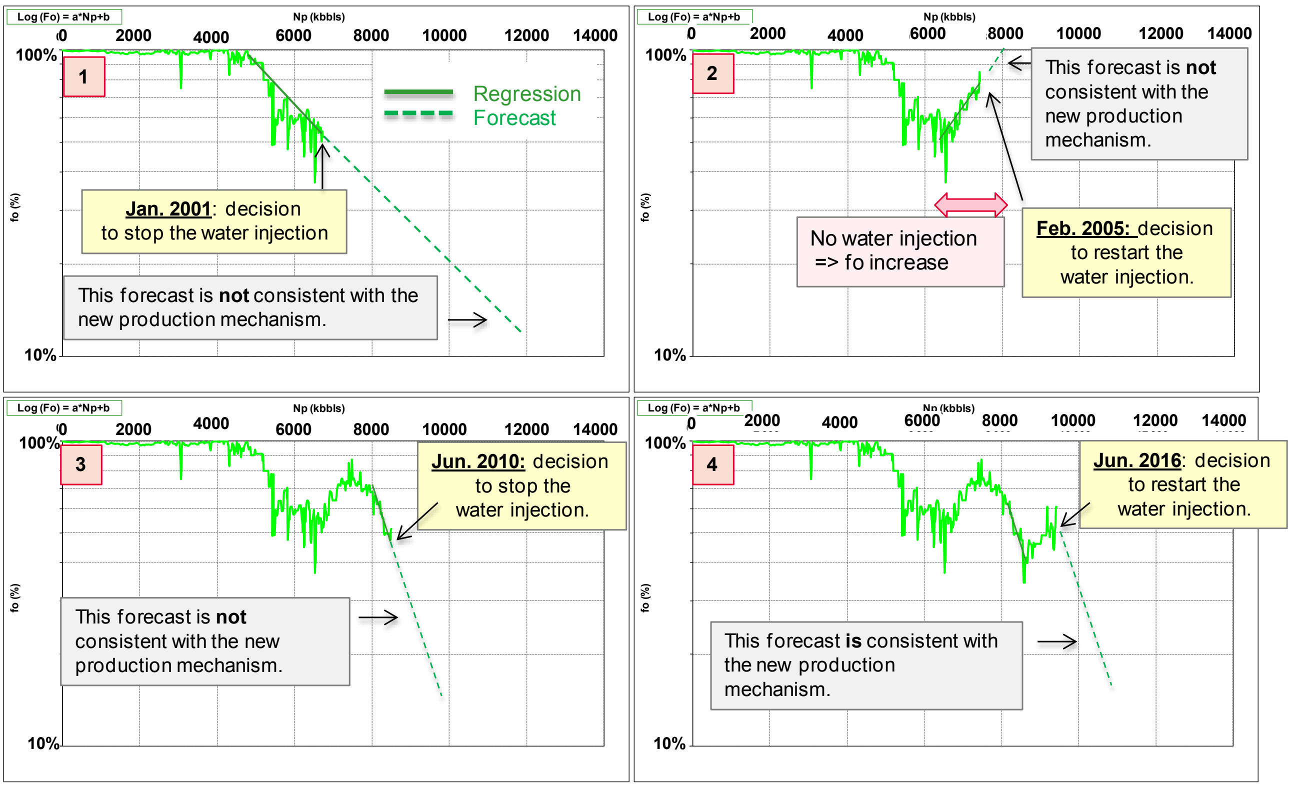


Figure 12: Curve-fitting while modification of the production mechanism

Guideline n°11:

In situations where no decline is observed in the production (e.g. due to strong water drive and the wells producing dry oil) or if a decline cannot be reliably established (e.g. due to too low water cut, typically less than 50%), the use of analogy, numerical simulation or other approaches are obviously required.

In the following log(f_o) vs Np plot (Figure 13), DCA is not recommended as the BSW has only increased from 0 to 20% (f_o from 100 to 80%).

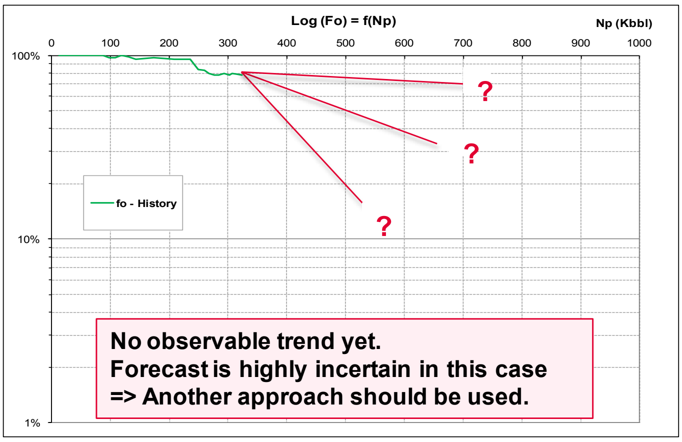


Figure 13: Example of log(f_o) vs Np regression without enough historic data

9.3 Sub-step 2c: Knowing the 3 Arps types of decline: harmonic, hyperbolic & exponential

Application of DCA in the industry today is still based on equations and curves described by Arps.

The theory of Arps equations is described in detail in Appendix 1.

Arps introduced in the 1940s **the concept of production decline** to reproduce the observed behavior of oil fields.

Arps represented the decline rate as a function of the instantaneous rate Q and 2 constants (*K* & *b*):

$$\boxed{D(t) = -\frac{dQ(t)/dt}{Q(t)} = K * Q(t)^b}$$

Arps did not provide physical reasons for the three following types of decline.

- **Case 1 :** $b = 0$ => ***exponential decline***

With b=0, $D(t) = K = D_{initial}$: the decline rate is constant with time (the rate declines of 0.05% every day for example).

Solving the equation $D(t) = -\frac{dQ(t)/dt}{Q(t)} = K$ leads to $\boxed{Q(t) = Q_{initial} \cdot e^{-D_i t}}$

- **Case 2 :** $b = 1$ => ***harmonic decline***

With b=1, $D(t) = K * Q(t)$ $(K = \frac{D_{initial}}{Q_{initial}})$: the decline rate is proportional to the rate. As the rate declines over time, the decline rate decreases also (the rate declines of 1% the first day, 0.99% the second day, 0.96% the third day…)

Solving the equation $D(t) = -\frac{dQ(t)/dt}{Q(t)} = Q(t)$ leads to $\boxed{Q(t) = \frac{Q_i}{(1 + D_i .t)}}$

- **Case 3 :** $0 < b < 1$ => ***hyperbolic decline***

With 0<b<1, solving $D(t) = -\frac{dQ(t)/dt}{Q(t)} = K * Q(t)^b$ leads to $\boxed{Q(t) = \frac{Q_i}{(1 + b.D_i .t)^{1/b}}}$.

b represents the degree of curvature of the line.

Exponential and harmonic declines are special cases of the hyperbolic decline.

- **Other decline: A fourth decline is the constant rate decline.**

In this case, the rate decreases constantly every day (-10 bbl every day for example).

Comparison of exponential, hyperbolic and harmonic and constant declines:

- **b=0: a constant decline rate (0,5% per day for example) leads to an exponential rate decline. This decline leads to pessimistic forecasts.**
- **b=1: when the decline rate decreases with time proportionally to the rate, the rate decline is harmonic. This decline leads to optimistic forecasts.**
- **0<b<1: the decline rate decreases with time and the Arps decline is hyperbolic.**
- **4th decline is the constant rate decline: the rate decrease constantly every day (-10 bbl every day for example).**

Example with:

$D_{initial} = D_i = 0.5\%$

$Q_{initial} = Q_i = 5000$

$b = 0{,}5$ *for the hyperbolic decline*

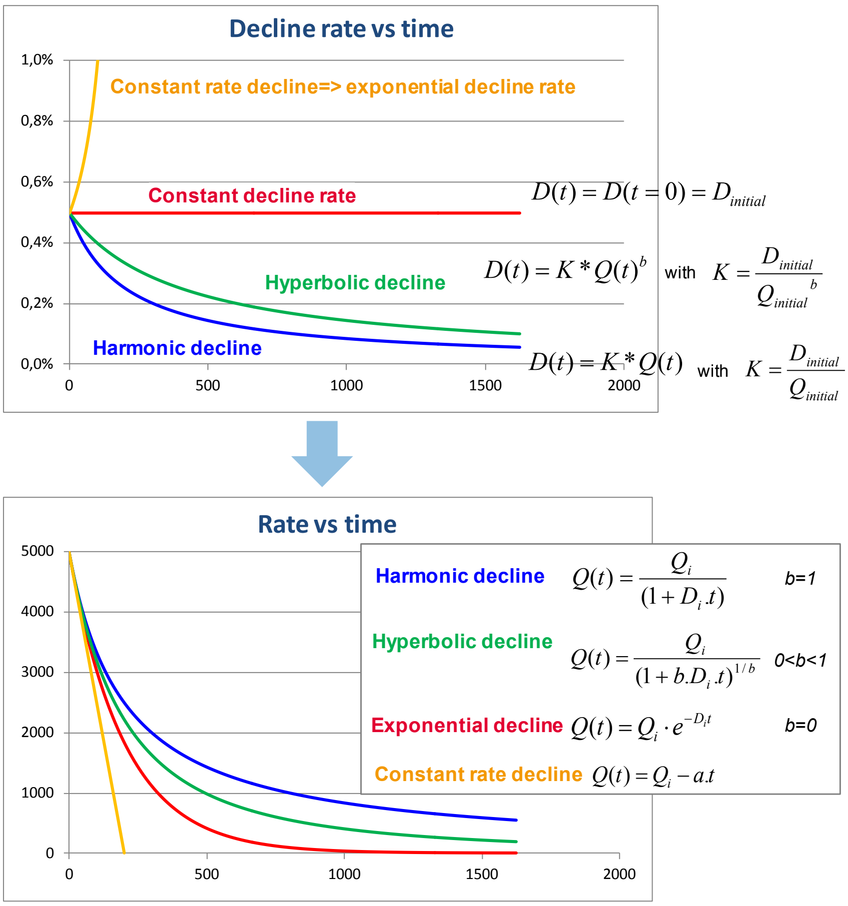


Figure 14: Harmonic, hyperbolic & exponential & constant declines (decline rate & rate vs time)

The initial decline D_i, initial rate Q_i and the b factor impact the rate decline as follow:

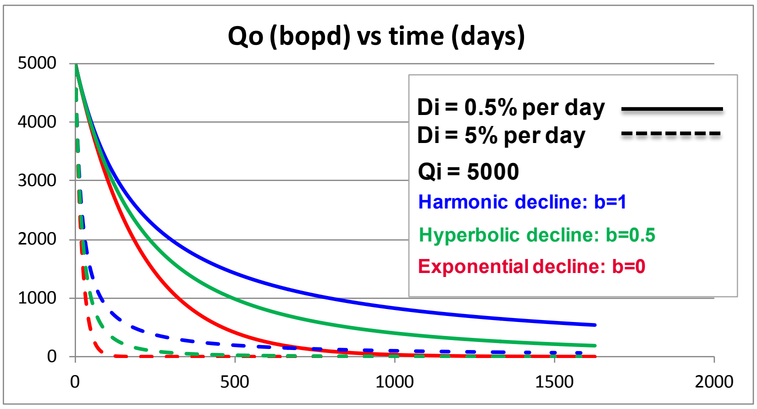


Figure 15: Impact of the initial decline Di on the Arps decline

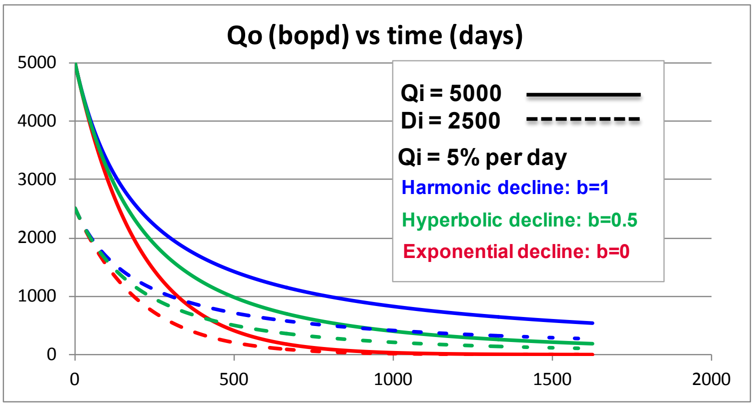


Figure 16: Impact of the initial rate Qi on the Arps decline

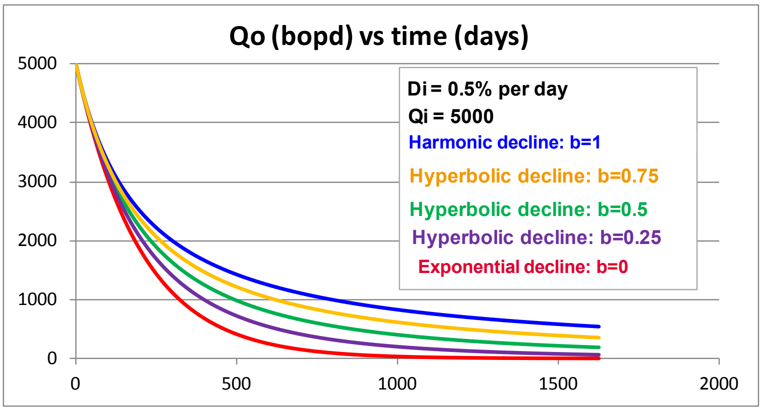


Figure 17: Impact of the b factor on the Arps decline

9.4 Sub-step 2d: Curve-fitting process using the most relevant regressions

Decline Curve Analysis is conducted graphically with the curve matching process which consists in statistically fitting a curve through the retained historical data of a given production parameter.

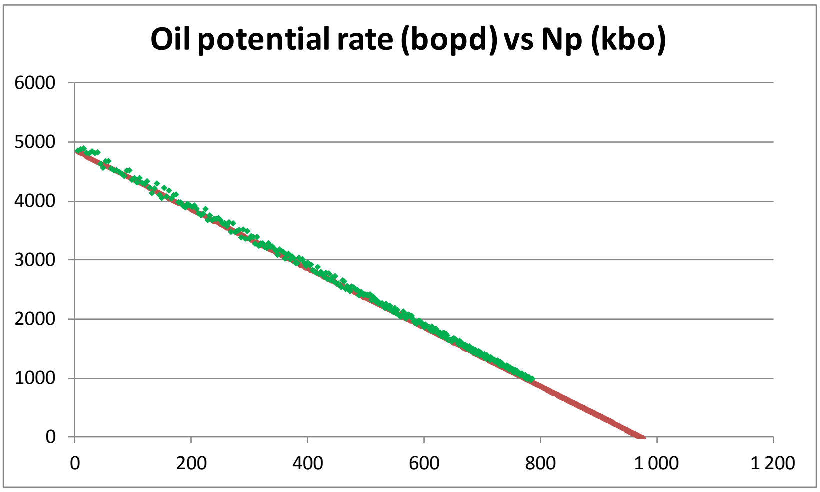


Figure 18: Example of curve-matching process

This is generally done automatically by using existing software packages (Excel, OFM, T-More [tool under development]) or manually/visually based on experience.

After generating production data plots and rejecting both anomalously low and high values, properly identified trends should be obtained in order to perform reliable extrapolations into the future.

Curve-fitting can be performed on rates (oil, water, gas) and/or on ratios (fo, BSW, GOR…). Many variables can be plotted in various combinations.

Production Rate (oil, water, gas, liquid)		**time**
Log(production rate) (oil, water, gas, liquid)		**Log(time)**
Potential Rate (oil, water, gas, liquid)		**Np** (cumulative oil production)
Log(Potential Rate) (oil, water, gas, liquid)	**vs**	**Gp** (cumulative gas production)
BSW or f_o (fo=1-BSW)		**Log (Np), log(Gp)**
Log(f_o)		
WOR (Water-Oil Ratio)		
GOR		
Pressure (WHP, BHFP...)		

Table 1: Plots used for a DCA study

The regressions most commonly used in the Group are:

- Oil potential rate vs Np (cumulative oil production)
- GOR vs Np
- F_o vs Np (instead of BSW vs time) : to be used with care, cf Figure 29
- log(f_o) vs Np (instead of BSW vs time): to be used with care, cf Figure 29
- Liquid potential vs time

Guideline n°12:

It is recommended to perform DCA on **potential rate (rather than production rate) in order to avoid noise introduced by variable uptime.**

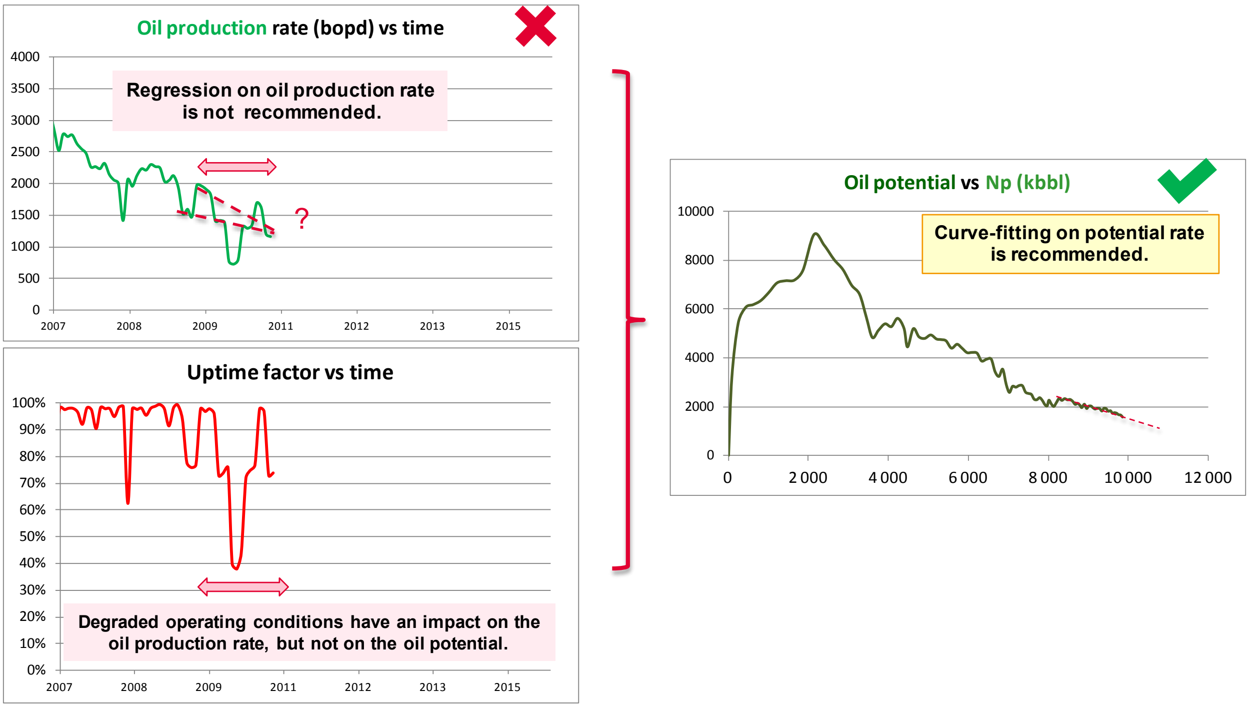


Figure 19: Curve-fitting on oil production vs curve-fitting on oil potential

Guideline n°13:
It is also recommended to plot graphs **vs. cumulative production (rather than time).**

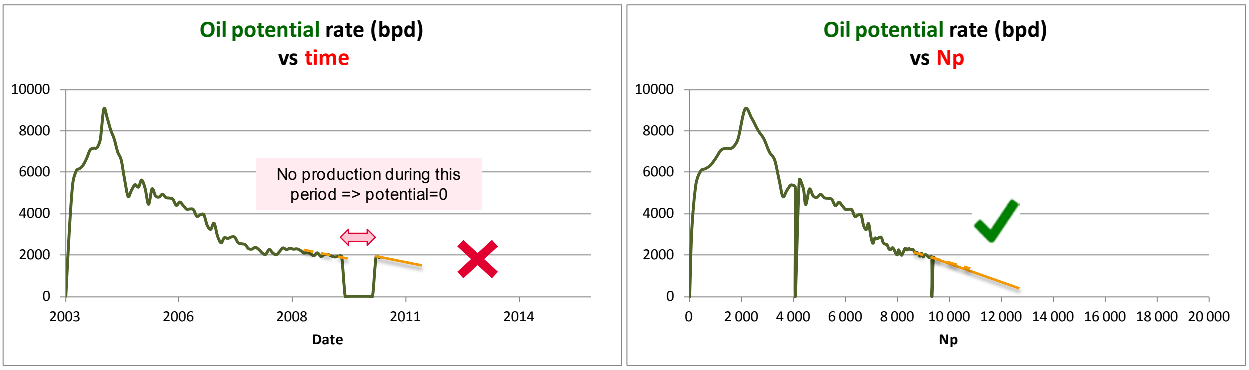


Figure 20: Curve fitting vs time & vs Np

Various indexes (R^2, Mean Square Error, etc.) indicate the quality of a regression. The best fit so obtained will result, when extrapolated forward, in the Best Estimate of future production.

Guideline n°14:

First step of curve-matching process is to **find the combination of variables that will result in a straight line,** which can be used reliably for curve-fitting.

Thus, **many regressions should be tested to find the most appropriate one.**

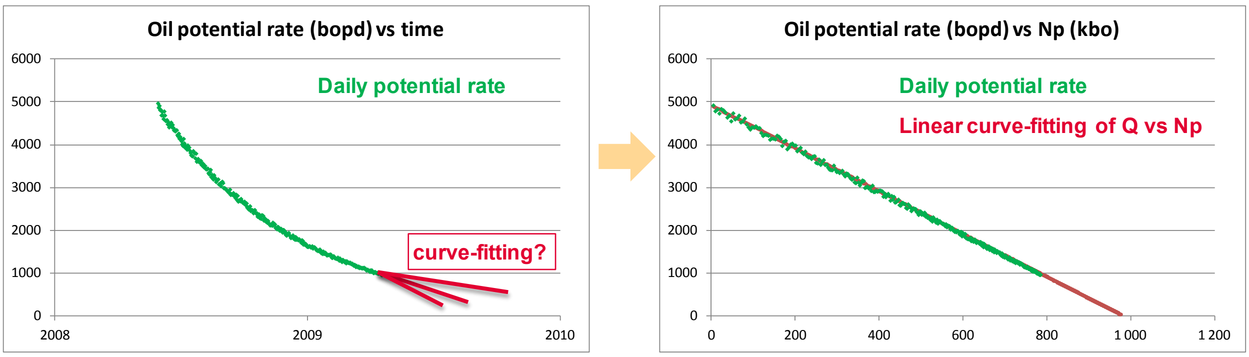


Figure 21: Looking for a straight regression on oil potential

Some regressions are directly linked to Arps declines.

Linear regression obtained with $Q(t)\ vs\ Np$ or $\log Q(t)\ vs\ time$ corresponds to exponential decline and thus will generate forecasts more pessimistic.

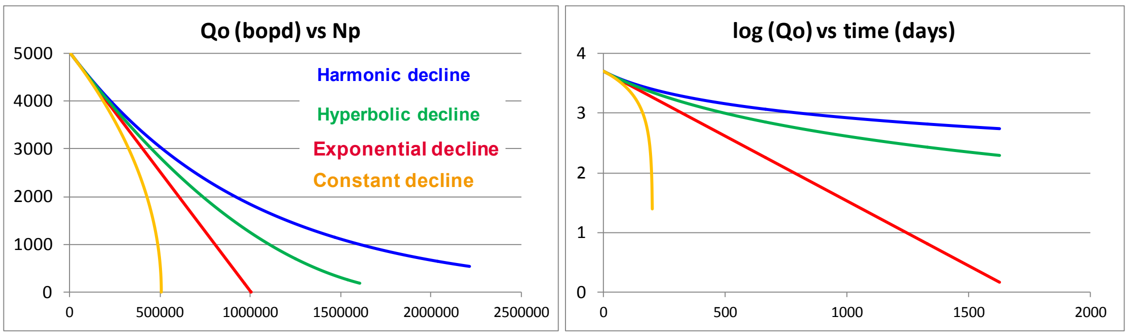


Figure 22: Linear regressions for exponential declines

Linear regression obtained with $\log Q(t)\ vs\ Np$ or $\log Q(t)\ vs\ \log(1+D_i t)$ corresponds to harmonic decline and thus will generate forecasts more optimistic.

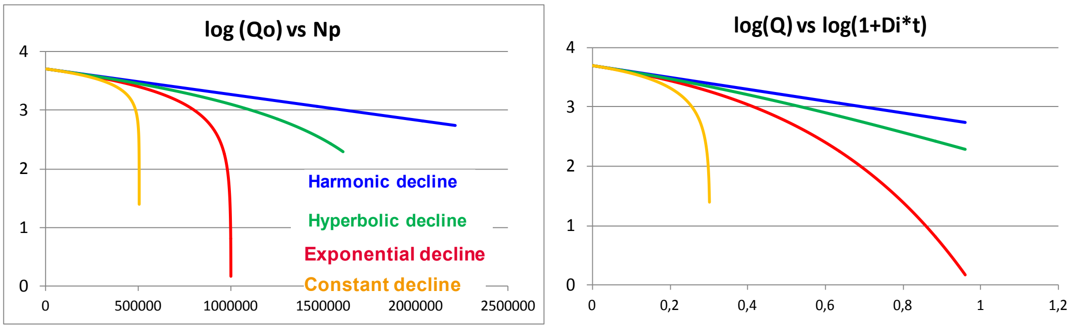


Figure 23: Linear regressions for harmonic declines

Linear regression obtained with $\log Q(t)\ vs \log(1+bD_i t)$ corresponds to hyperbolic decline.

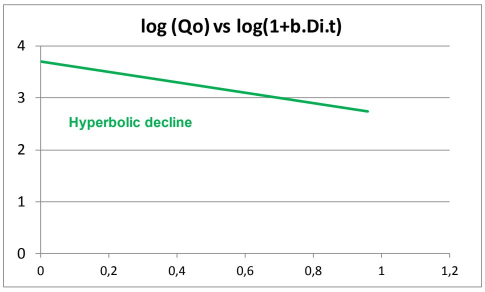


Figure 24: Linear regressions for hyperbolic declines

Linear regression obtained with $Q(t)\ vs\ \ time$ corresponds to constant declines.

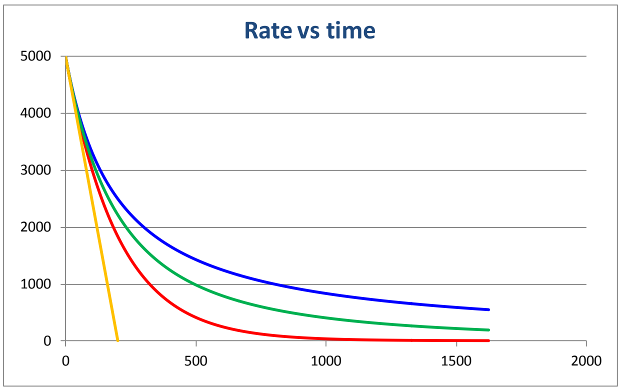


Figure 25: Linear regressions for constant declines

Guideline n°15:

Thus, the 4 following plots should be automatically plotted for any DCA exercise to select the best regression (which gives a linear trend) for the forecast:

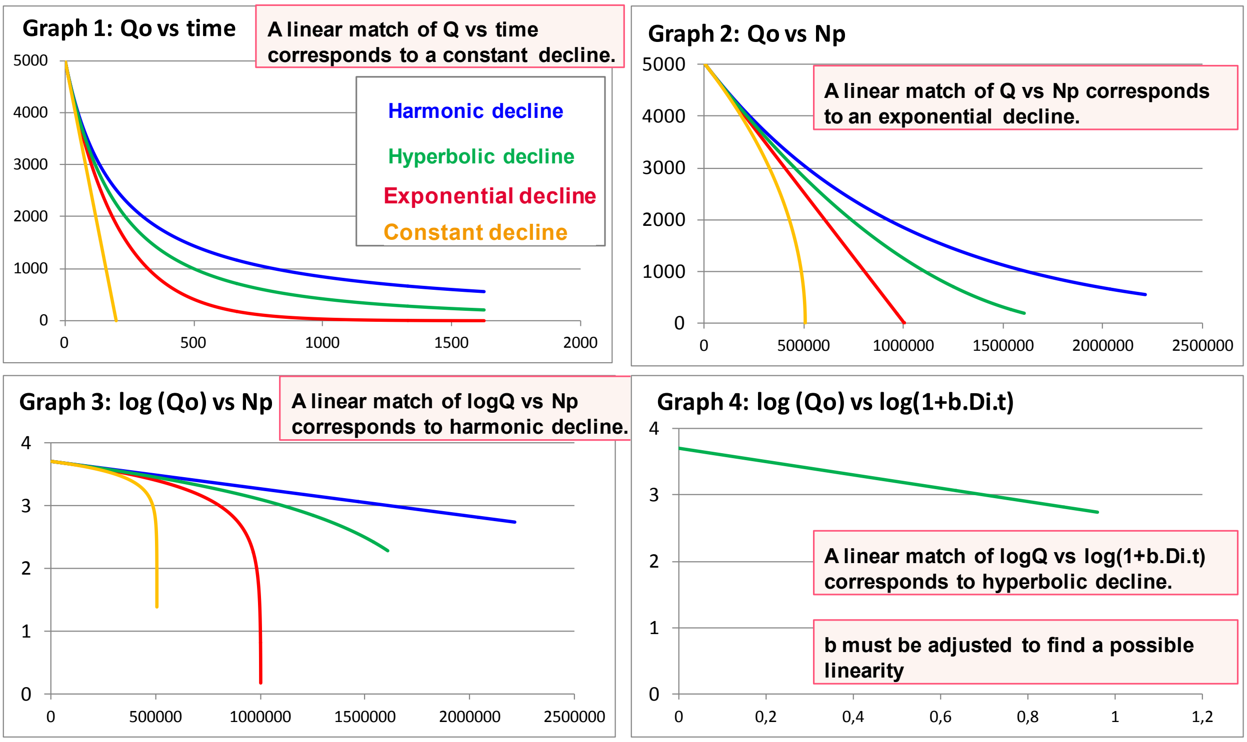


Figure 26: 4 plots to select the best regression for the DCA exercise

The choice of regression will lead to harmonic, hyperbolic or exponential decline. Thus, it should be done with care as it will directly impact the Estimated Ultimate Recovery.

In the following example:

- A regression which will lead to an exponential decline reaches the technical limit (2000 bopd) in 2048. The ultimate recovery is estimated at 1.4 Gboe.
- A forecast with a harmonic decline does not reach the technical limit (2000 bopd) before 2200: the rate is almost flat after 2160 as the decline rate is very low. The ultimate recovery is then estimated at 2.2 Gboe in 2200.

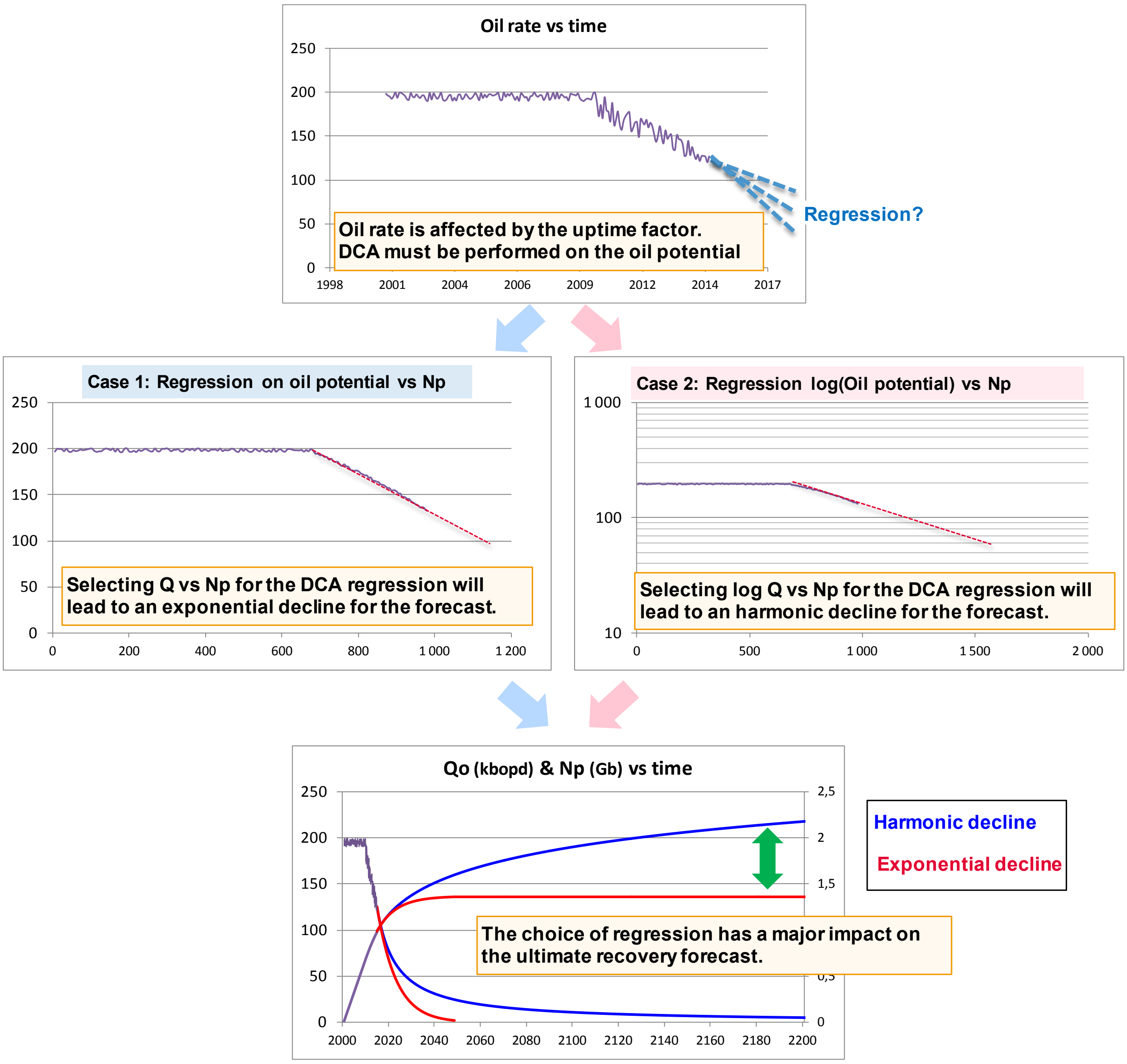


Figure 27: Impact of regression selection on the Estimated Ultimate Recovery

Guideline n°16:

When dealing with oil performance, it is recommended to first define **a hyperbolic decline** taking the representative historical performance period. The hyperbolic decline is both that which is **most commonly found** (cf Appendix I) and **the one providing most flexibility through the varying of b factor during the matching process** (without excluding the possibility to end up with b = 0 or b = 1 if actual data tend to substantiate such value).

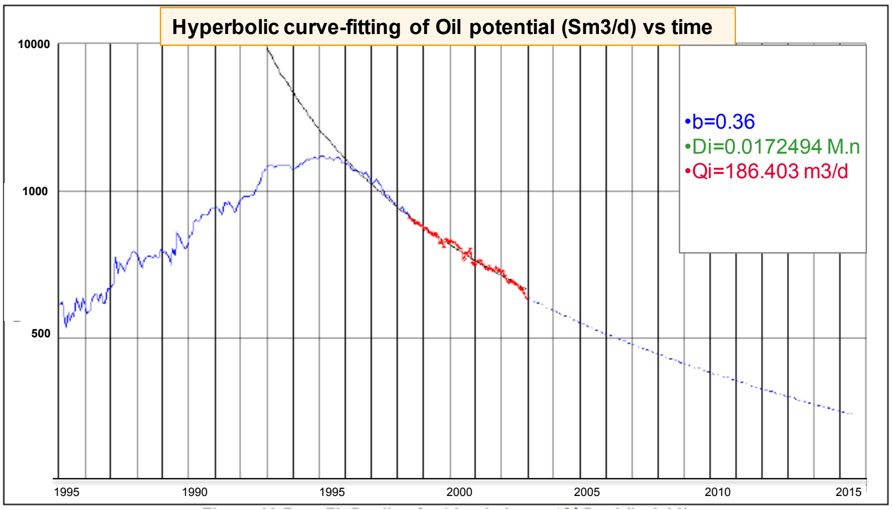


Figure 28: Hyperbolic curve-fitting of Oil potential vs time

In some cases, **several satisfactory matches** of the retained historical data can be obtained with different decline types or decline parameters and **can lead to very different EUR forecasts.**

10. Step 3: Best estimate of production & injection forecasts

10.1 Sub-step 3a: Constrained potential & uptime factor

Production is limited by facilities bottlenecks and planned and unplanned shortfalls.

Uptime factor:

The consideration of wells/facilities uptime is very important to derive reliable forecasts.

Uptime (uptime = 100% - downtime) is measured in % and is sometimes also called system availability.

In most fields, the producing time of the wells is recorded and is used to calculate the uptime factor (= producing time / number of days in the month).

The uptime factor is used for the calculation of what is called the well potential (= monthly production/ uptime factor)

Constrained potential:

Production potential and constrained potential are defined and described in the CR EP EXP 100, GM EP EXP 100**.**

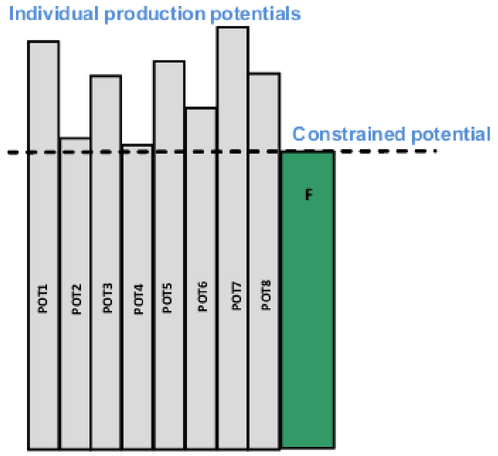


Figure 29: Representation of constrained production potentials

The production parameters represented are defined in Table 1

Abbreviation	Meaning	Definition
POTi (*)	**Individual production POTentials**	Production potentials (POT) evaluated by different entities - disciplines (e.g. Field Operations, Reservoir, Well performance). They correspond to maximum hydrocarbon quantities that can be processed by each element of the production chain, individually taken in existing installations (excluding any debottlenecking CAPEX).
F (*)	**Constrained production potential**	Quantity of hydrocarbons (oil, condensate and gas) that the field can produce via the existing infrastructure. It would be equal to the minimum of the individual production potentials (POTmin) in the absence of interaction between them. In reality, it is obtained by an optimization of the whole production chain. The constrained production potential figures are consolidated by the entity assigned responsibility for them in the affiliate's organization.

Table 2: Definitions of production-potential parameters

The term constrained in “constrained production potential (F)” means that production is limited by a technical bottleneck corresponding either to maximum well capacity, maximum installation capacity or maximum export capacity.

- Maximum well capacity (CPOT 5/6/7) may be the result of reservoir pressure, well productivity, the draw-down limit, the inlet pressure of the gathering lines or the reservoir management plan.
- Maximum installation capacity (CPOT 1/2/3/4) may be due to oil and/or gas and/or water treatment capacities, inlet pressure, etc.
- Maximum export capacity (CPOT 8) may result from network pressure, export pump capacity, etc.

Guideline n°17:

It is recommended **to estimate well future production by forecasting the constrained potential of the well** (rather than production rate) **and then to apply an uptime factor.**

As mentioned in the guideline n°4, reservoir and operating conditions should be as stable as possible over the production period considered representative for DCA, and have to be assumed to remain unchanged over the whole production forecast period.

For example, one could be tempted to perform a DCA study of the following well (cf Figure 31: DCA using a regression on the oil production rate) using a regression on the oil production rate vs time.

With this method, the remaining cumulative oil production is estimated at 643 kbo in the best estimate.

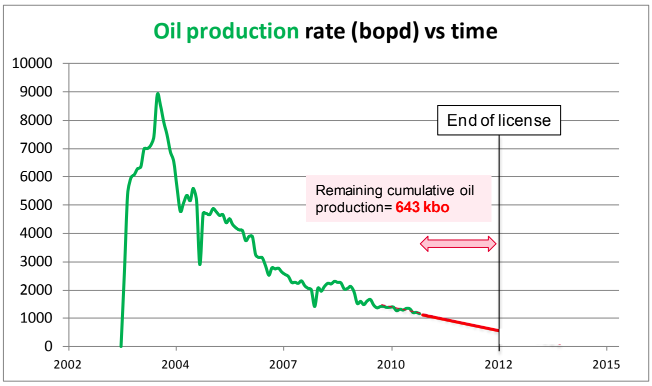
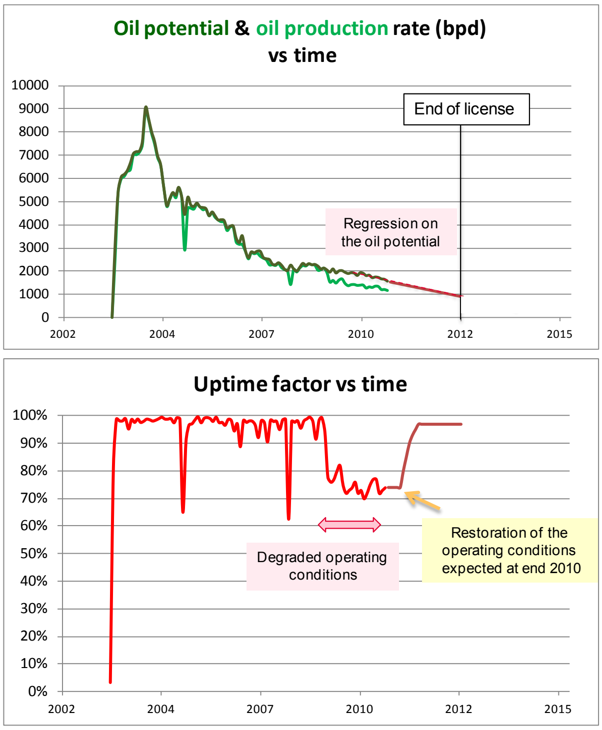


Figure 30: DCA using a regression on the oil production rate

By using a regression on the oil potential rate (production rate /uptime) and combining with an assumption on the uptime factor evolution, the engineer would find a remaining cumulative oil production of 833 kbo, thus 30% higher than with the previous method.



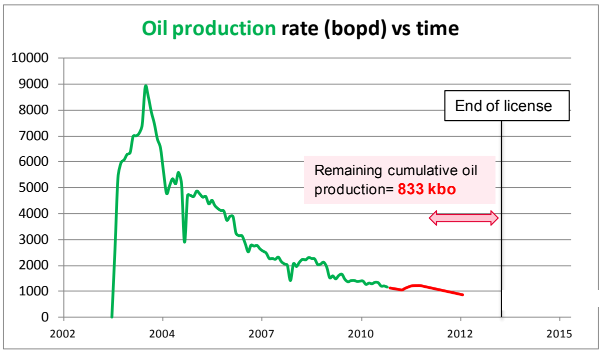


Figure 31: DCA using a regression on the oil potential

Guideline n°18:

The projection of the uptime factor through time has to be made based on:

- **the historical operating performance** of the well/reservoir or field
- **the upcoming operations** to be performed on the well and of the field

Discussion between reservoir engineers, well performance team and production engineers **is mandatory.**

Uptime factor should be validated by the Fields Operation and Planning correspondents.

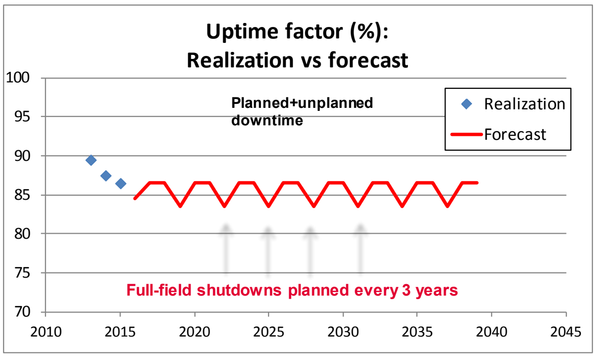


Figure 32: Example of uptime factor forecast based on realization and future planned operations

Several elements should be taken into account:

- Planned full-field shut-down
- Well interventions (stimulation, workover, ESP replacement, …)
- Impact of SIMOPS[1] procedures
- Well/Reservoir monitoring program
- Estimation of unplanned shut-downs (based on historical track record)
- …

It is important for aging fields to anticipate well deterioration which will likely increase well intervention frequency and thereby increase unplanned downtime.

On the other hand it is also possible for well availability to increase through time e.g. in the event of improved reliability of the power supply grid, longer operating life of ESPs, etc... Any planned or expected improvement should be properly documented and justified and incorporated in the best estimate case.

10.2 Sub-step 3b: Well technical cut-offs

Production profiles derived from simple DCA should be truncated in order to take into account the physical limitations at which the wells cease to produce.

Guideline n°19:

Simple technical cut-offs i.e. those not supported by a complete integrated analytical model**,** despite their limitations, can be used to perform quick DCA analysis.

Technical cut-offs can be applied to rates and/or ratios and are defined from:

- Analogous well behavior
- Simple cut-offs from well performance monitoring

Most common well cut-offs are:

- Maximum water cut
- Minimum rate (particularly important for gas wells dying due to liquid loading)
- Maximum GOR
- Maximum GLR (ESP case)

[1] SIMOPS: **SIM**ultaneous **OP**eration**S**, for instance drilling or construction works performed close to or on oil/gas installations in normal or partial operation

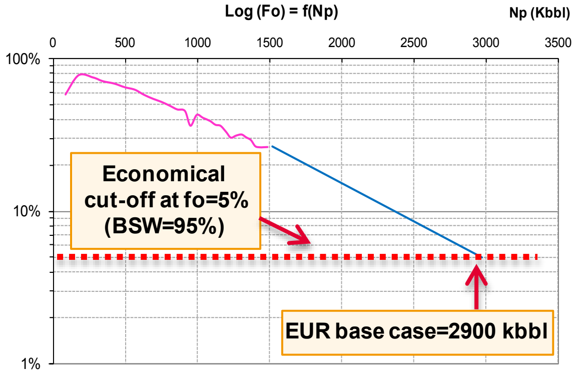


Figure 33: Example of use of simple technical cut-offs

Wells producing shallow unconsolidated pools can cease production suddenly at a certain level of depletion and water cut due to sanding out. In this specific case depletion and drawdown are other parameters to consider in addition to water cut.

Guideline n°20:

It is recommended to determine **well technical cut-offs from full nodal analysis conducted along with well-performance team**. This check is typically performed **using an integrated analytical model e.g. MPG (MBAL-PROSPER-GAP).**

The evaluator should check that the forecast production profiles can be achieved given:

- the **depletion** resulting from the forecasts and injection hypothesis
- the **productivity index** evolution
- the **outflow performance and artificial lift capacities**.

Depletion analysis

The evaluation of the depletion evolution is typically performed using a material balance model matched over the historical period. The projection requires hypothesis regarding the injection scenario (in line with wells injectivity, injection fluids availability, injection pressure …).

In the case where current injection capacities are not sufficient to maintain acceptable depletion, a re-evaluation of production forecasts (reduced withdrawal) might be considered with a particular focus on risk and outflow capacities.

If a material balance calculation cannot be performed, a simple voidage replacement follow-up (monthly and cumulative) can be done to check that production conditions do not vary too much and to establish a qualitative estimate of the injection needs.

The voidage replacement calculation should be done per dynamic reservoir unit.

$$VR = \frac{\text{Injected volume}}{\text{Produced volume}} = \frac{Q_{w,inj}B_{w,inj} + Q_{g,inj}B_{g,inj}}{Q_o(B_o + (GOR - R_s)B_g) + Q_w B_w}$$

Figure 34: Voidage replacement calculation

The reservoir pressure resulting from the material balance will be used in the well performance calculation.

Productivity Index analysis

The first stage consists of evaluating the productivity index evolution during the forecast. This analysis is of course subject to a PI monitoring during the history and a differentiation between skin and fluid effects. It is indeed important to understand the past PI evolution in order to anticipate its future evolution and to take into account a possible decrease of the well productivity.

This inflow analysis also applies to injection wells in order to verify that injectivity indexes are sufficient to achieve injection rate requirements.

Outflow analysis

Once expected inflow performance has been determined, the next step is to check that outflow performance allows the production profile to be achieved.

The objective of the analysis is to check that, knowing the 3-phase production, reservoir pressure and productivity index forecast, the vertical lift performance allows the required BHFP to be reached.

This exercise requires updated VLP tables matched on historical data.

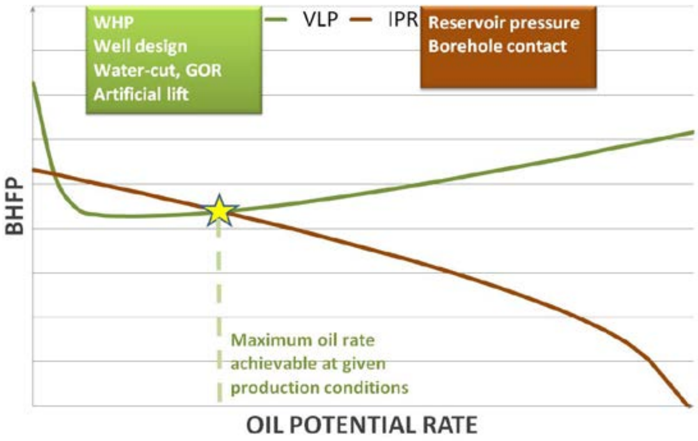


Figure 35: Inflow - outflow nodal analysis

In the case where artificial lift solution is already implemented, future needs can be determined through this well performance analysis (gas-lift rates, pump capacities etc.).

If forecast production figures are not achievable at the given conditions, then the forecasts should be revised accordingly and a remedial solution should be evaluated with dedicated studies:

- Reservoir pressure increase by increasing injection,
- Improve lifting capacities (artificial lift implementation, change tubing size, decrease network pressure …)

This outflow analysis also applies to injection wells in order to verify that available wellhead pressure is sufficient to achieve injection rate requirements.

10.3 Sub-step 3c: Well economic cut-off

Normally the individual well truncation will be driven by one or more of the aforementioned technical constraints.

Guideline n°21:

The well/reservoir/field economic cut-off should be taken into account. It is mandatory to check that the production can cover its variable costs.

The variable costs are those relating to the routine part of the planning and operations activities.

A well forecast should be stopped at the economic cut-off, if the economic cut-off occurs before reaching the technical cut-off.

In a field where ESPs are the lifting method, those pumps have a certain life time and their replacement generates costs. The production between two consecutive ESP breakdowns should be sufficient to cover the ESP replacement costs and all the other well variable costs. A minimum production rate is therefore required to justify the ESP replacement. This is an economic daily (or monthly) rate cut off and not a technical cut-off rate.

Well production to justify a Work-over @ 60$/bbl					
Production gross (bpd)	1000	2500	5000	7500	10000
Work-over cost (MUSD)	4,20	4,20	4,20	4,20	4,20
Electricity cost (MUSD)	0,46	1,15	2,31	3,46	4,62
Chemical cost (MUSD)	0,07	0,17	0,34	0,51	0,68
Maintenance cost (MUSD)	0,05	0,12	0,24	0,36	0,48
Export cost (MUSD)	0,18	0,21	0,26	0,32	0,37
Total cost (MUSD)	4,96	5,86	7,35	8,85	10,35
Minimum oil production (bopd)	68	80	101	121	142

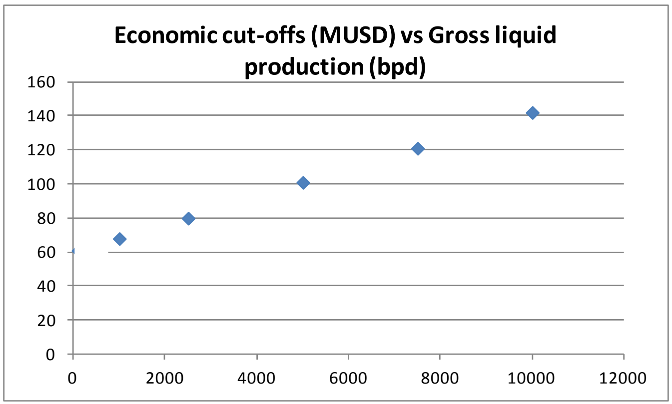


Figure 36: Evaluation of an economical cut-off per well for a field produced with ESP pumps

10.4 Sub-step 3d: Facilities constraints

Surface constraints can present additional technical cut-offs that would typically curtail the production forecasts at field level.

Guideline n°22:

It is highly recommended **to ensure that the maximum surface capacities or operating conditions are sufficient and will not act as bottlenecks in the forecast period**.

These controls should be performed in collaboration with the well performance team. They include, but are not limited to:

- Produced water treatment capacity
- HP/MP/LP separators capacities and particularly gas capacities
- Produced gas handling (compression, export, flaring policy, …)
- Artificial lift capacities (pressures, rates, compression, …)
- Injection or disposal capacities (pump, compression, number of wells, volume, processing, …)
- Electricity generation (e.g. when installing ESPs, etc.)
- Fuel availability (requirement to import fuel to handle future volumes, e.g. in water injection pumps, etc.)
- Surface line constraints:
    - Maximum liquid / gas capacities
    - Turndown rate in the case of a gas field with associated water production (minimum gas rate before killing the line)

10.5 Sub-step 3e: 3-phases forecasts

Guideline n°23:

The forecasts should not focus on the oil phase only but should also consider water and gas production and water or gas injection (if relevant) as they can represent a bottleneck for production facilities.

Several relationships are available to extrapolate rates (or potentials) and ratios. **The combination of these relationships enables the calculation of 3-phase production forecasts.**

Guideline n°24:

When dealing with mature oil assets producing water, a linear match of fo vs Np or log f_o vs. N_p (fo=1-BSW) can be performed rather than direct regression on oil declines or regression on BSW evolution.

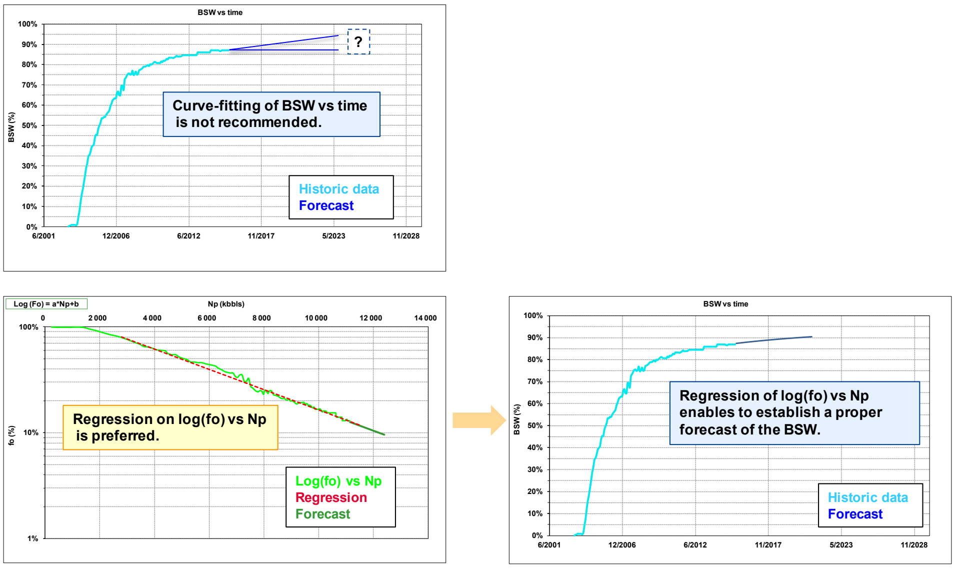


Figure 37: Regression on log(f_o) vs Np is much easier than on BSW vs time

Nevertheless, **these regressions should be performed with care:**

1. **Linear match of fo vs Np corresponds to exponential decline and thus will generate more pessimistic forecast of the Estimated Ultimate Recovery**

   (cf Figure 43: Forecasts of oil field producing water using 2 different methodologies)

2. **Linear match of log(fo) vs Np corresponds to harmonic decline and thus will generate more optimistic forecast of the Estimated Ultimate Recovery. Thus it might not be relevant for the low DEV forecast estimate.**

   (cf Figure 43: Forecasts of oil field producing water using 2 different methodologies)

3. This technique is suitable for **water cuts typically above 50%.**

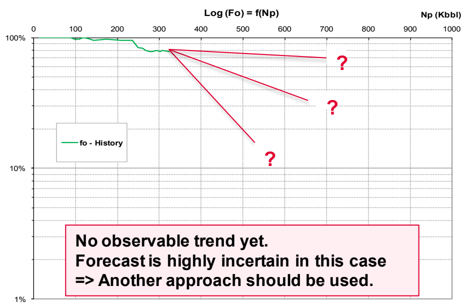


Figure 38: log fo vs Np for high fo

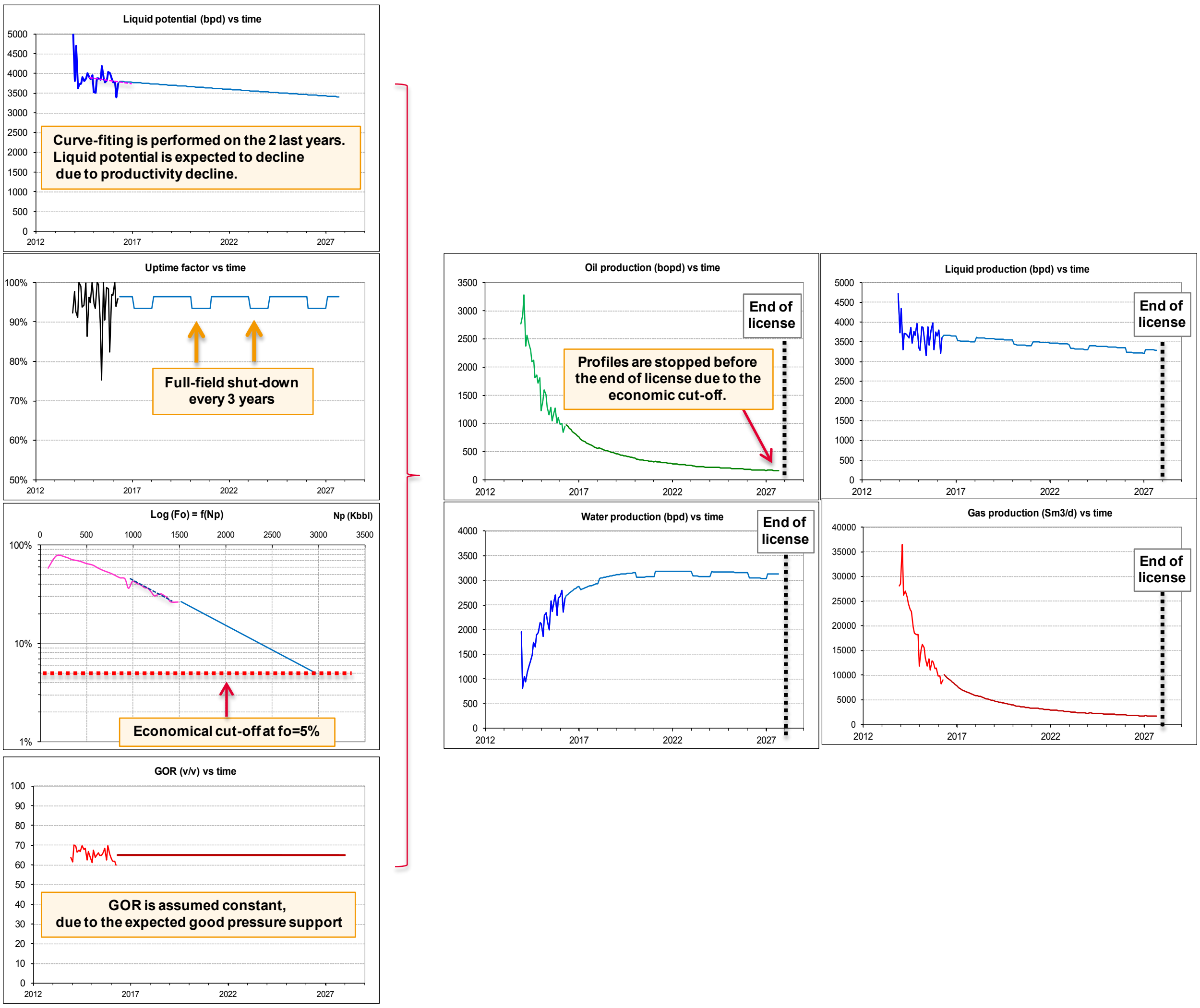


Figure 39: Oil rate forecast through the evaluation of uptime, liquid potential & log(f_o) vs Np forecast

In some cases, log(f_o) vs Np can be matched with **a linear trend** and extrapolated accordingly.

Nevertheless, this match corresponds to harmonic decline of the rate and thus will lead to forecasts more optimistic.

Thus, the user should use this match with care.

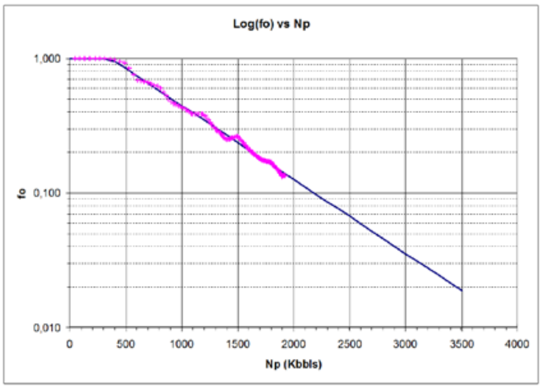


Figure 40: linear match of log(fo) vs Np

The linear trend of log(f_o) vs Np might turn down as f_o approaches small values:

This downturn from the straight line occurs earlier for light oils (with favorable mobility ratios) compared to viscous oils (with unfavorable mobility ratios).

Therefore, care should be exercised when extrapolating a linear trend (i.e. harmonic decline) of log f_o vs. N_p to very low oil cuts.

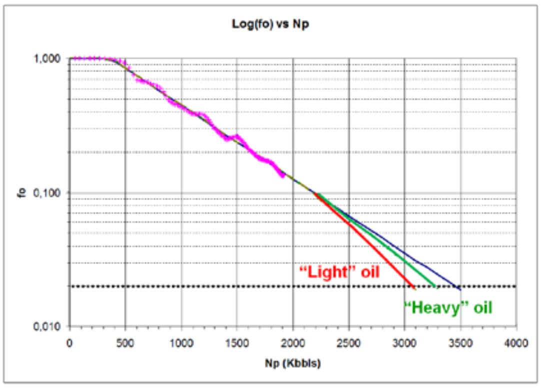


Figure 41: possible change of slope for low f_o

In some cases, **several satisfactory matches** of the retained historical data can be obtained with different decline types or decline parameters and **can lead to very different EUR forecasts.**

In the following examples, selecting the fo vs Np regressions or log(fo) vs Np regression will lead to a difference of 71% in the EUR (Estimated Ultimate Recovery) estimate.

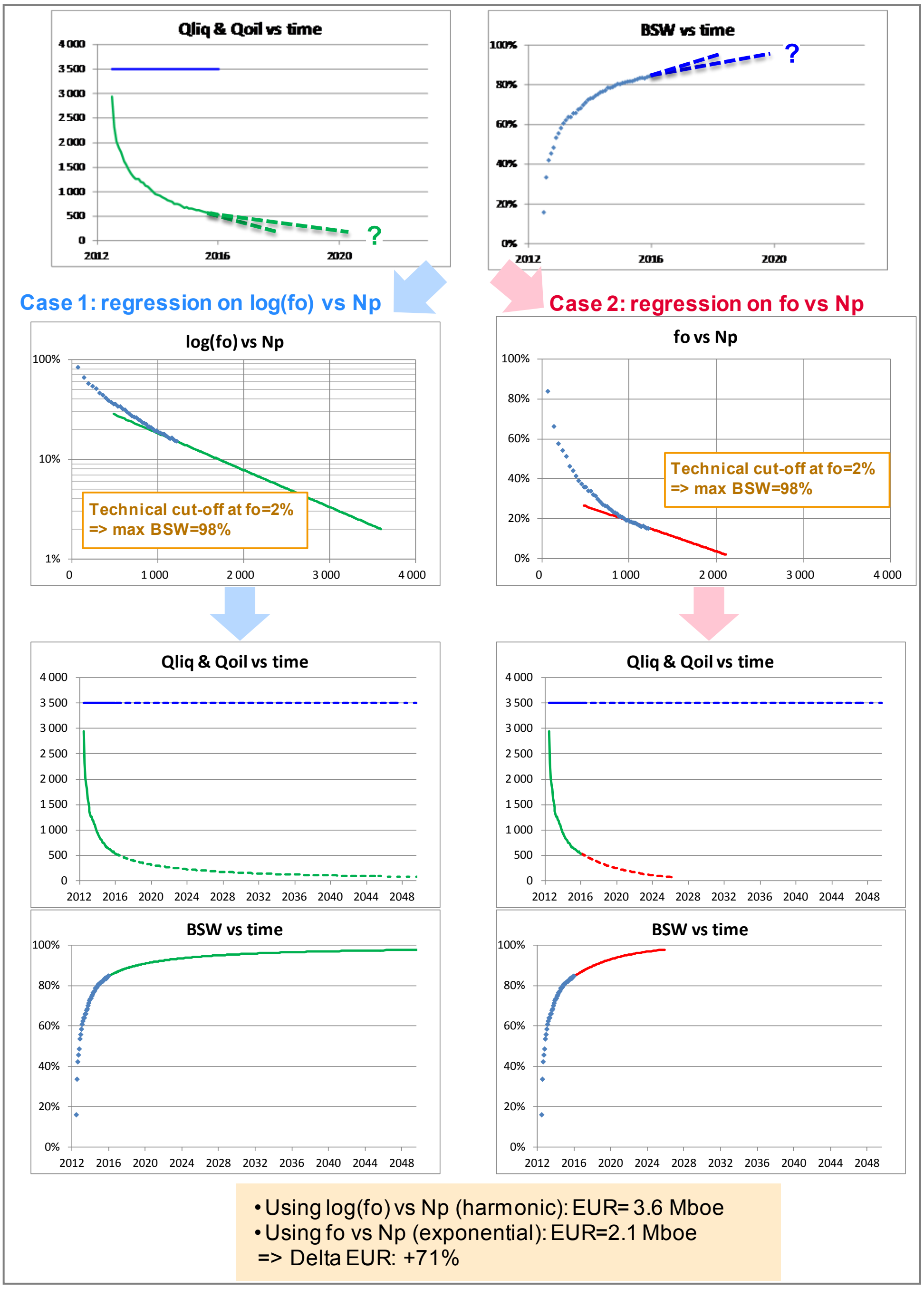


Figure 42: Forecasts of oil field producing water using 2 different methodologies

Guideline n°25:

Many authors (Fetkovich and others) have attempted to interpret Arps' decline theoretically and to relate Arps' decline parameters (e.g. decline exponent "b") to specific production mechanisms or recovery methods.

Drive mechanism / Reservoir	Type of decline	b exponent
Highly undersaturated oil reservoirs (production above bubble pressure) Solution gas drive with unfavorable k_g/k_o Poor waterflood performance Tubing limited wells (both oil and gas flowing wells) Wells with high back pressure High pressure gas wells Gas wells undergoing liquid loading	Exponential	0
Solution gas drive	Hyperbolic	0.3
Gas wells	"	0.4 - 0.5
Gravity drainage Water drive in oil reservoirs	"	0.5
Stratified reservoirs with permeability contrast	"	0.7 - 0.8
Oil reservoirs under very efficient waterflood	Harmonic	1
Low permeability, fractured, very heterogeneous and unconventional plays with long transient periods	Super-harmonic	> 1

Table 3: Indicative decline parameters for various drive mechanisms Not To Be Used

Internally, such relationships were not identified on fields operated by the Group.

Thus, it is recommended to perform DCA without considering these theoretical guidelines.

Guideline n°26:

QC1: The overall 3-phase forecasts should be displayed together with historical data in order to visually control the continuity of both profiles and therefore highlight possible inconsistencies.

In the event that several decline laws are combined to create a 3-phase forecast, the output should always be checked to ensure it remains realistic. It is possible that the act of combing decline laws results in an unreliable output regardless of the "reliability" of the individual laws.

The example below illustrates a quick control that should be performed at the end of the 3-phase rates calculation. An unrealistic liquid rate increase is obtained after few years by combining a linear oil cut decline with a harmonic oil potential decline. In this case the choice of either f_o or oil potential law should be revisited.

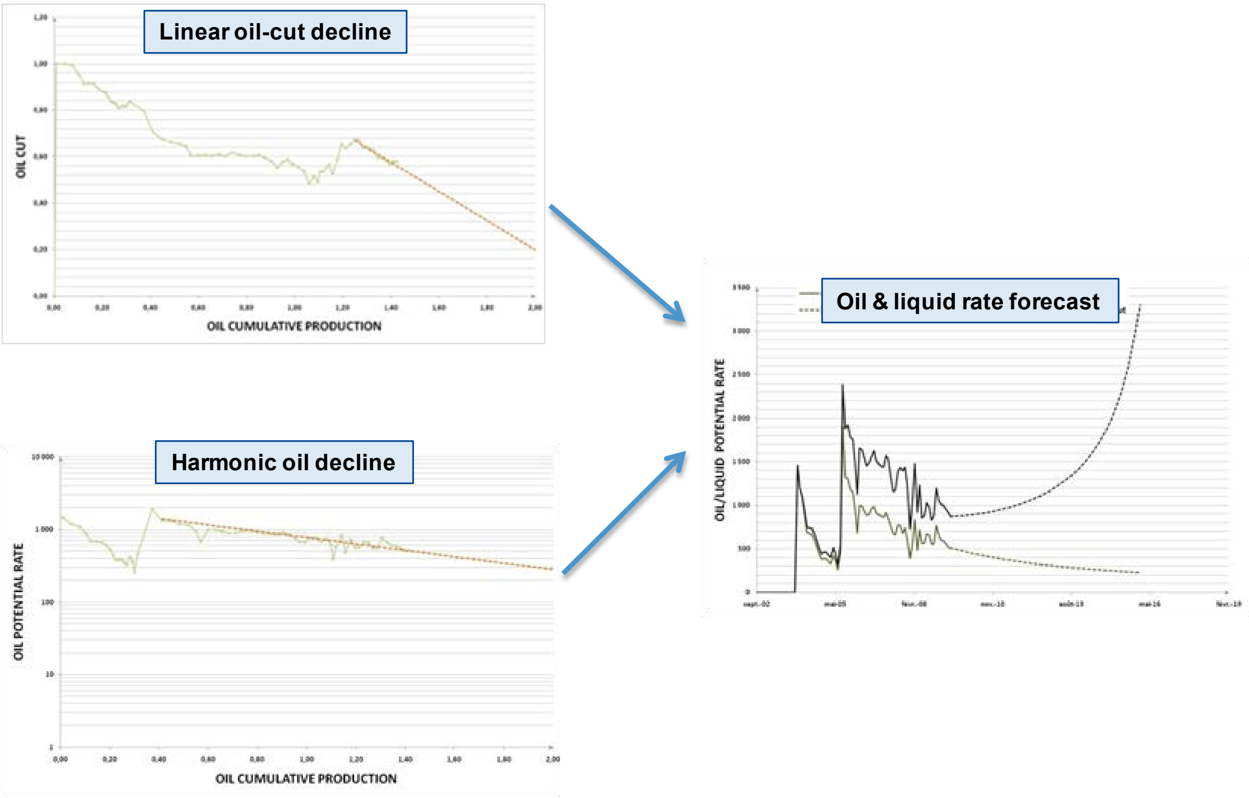


Figure 43: Illustration of unrealistic combination

10.6 Sub-step 3f: Specific case of recent additional work

Oil and gas field management more often than not requires additional works to be performed:

- Well acidification
- Additional perforations
- Water shut-off of individual completion zones
- Change in artificial lift
- Drilling of new wells
- Well shut-in / abandonment
- ...

These operations will have an impact on the trends derived from historical rates and ratios.

For instance new perforations, water shut-off, new drilled wells, well shut-in will generally result in an increase of f_o (decrease of BSW).

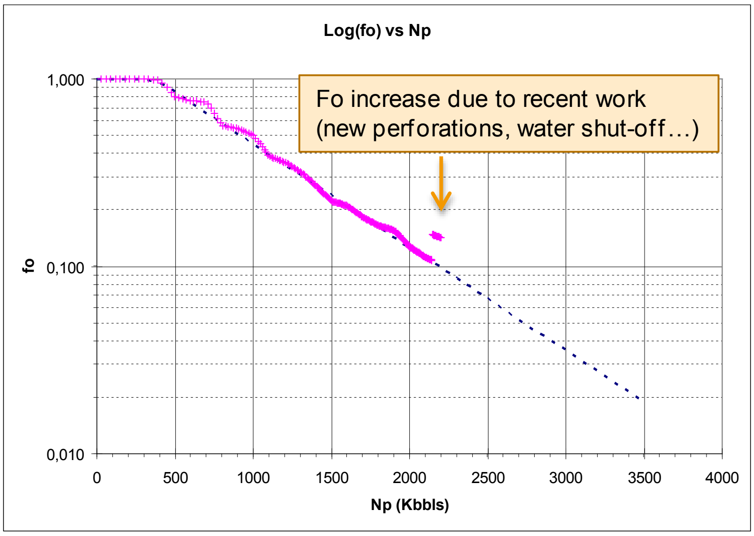


Figure 44: Impact of recent work on fo evolution

DCA forecast with recent additional work is quite difficult to perform due to the short period of available historical data (cf Figure 46: Several options of DCA for recent additional work**).**

Guideline n°27:

When dealing with recent additional work, the historical trends are not always representative of the future performance.

Good reservoir understanding is therefore mandatory to perform appropriate DCA.

The evaluator should determine if **the operations will bring production acceleration or positive incremental reserves or both.**

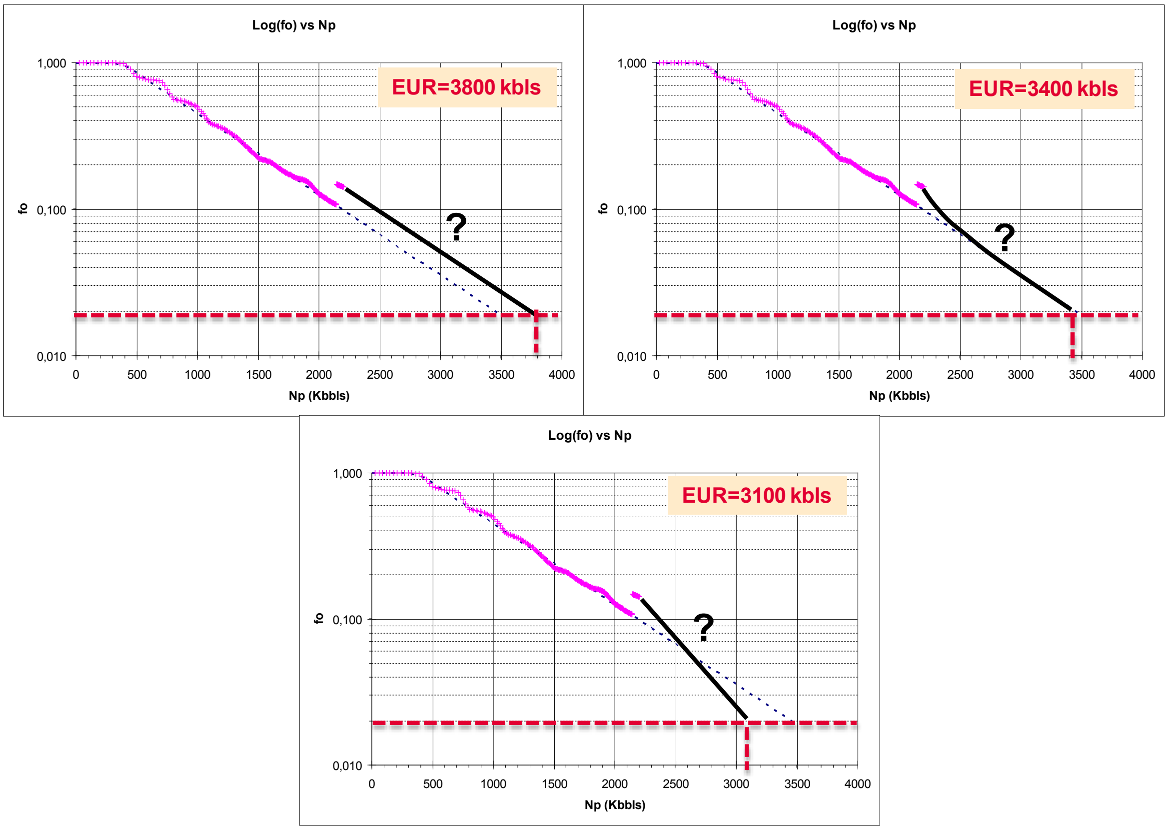


Figure 45: Several options of DCA for recent additional work

- A stimulation of existing completions (acidification for instance) will, in most instances, bring production acceleration only.

  In the following particular cases however incremental reserves can be added: the stimulation is performed on an interval which was not previously contributing to flow, if production is accelerated within a license period, if the technical well cut-off is impacted

- Installation of artificial lift or increase of pump capacity will most likely bring incremental reserves, as the reduction in BHP should increase the drainage area and lower the technical cut-off.

  A reserves decrease may however also be possible if the increase of drawdown results in an increase of water-cut. Moreover, the economic rate cut-off may be higher due to higher operating costs.

Guideline n°28:

Good knowledge of the reservoir is mandatory to evaluate the impact of the recent additional work on the production forecasts.

Guideline n°29:

For operations with production acceleration and no incremental reserves, the log(f_o) vs Np should come back to the initial trend:

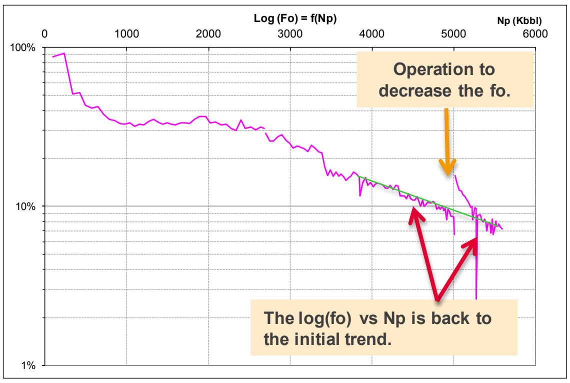


Figure 46: log(f_o) vs Np shape for new work bringing production acceleration only

DCA including recent work for production acceleration only should be performed as below:

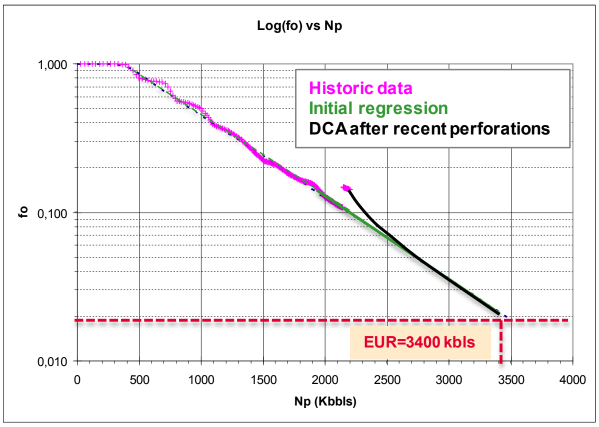


Figure 47: DCA for recent operations bringing production acceleration only

As mentionned in the guideline n°3, after an operation, there is a transient flow period that has to be discarded. DCA assumes a pseudo steady state flow behavior.

Guideline n°30:

For operations with positive incremental reserves, the ultimate recovery should first be evaluated with methods other than DCA.

10.7 Sub-step 3g: Aggregation at field level

Once forecasts are prepared at a given level (well, group of wells or reservoir) they are then summed to field level.

Guideline n°31:

The aggregation process consists in a simple arithmetic sum of all 3-phase forecasts.

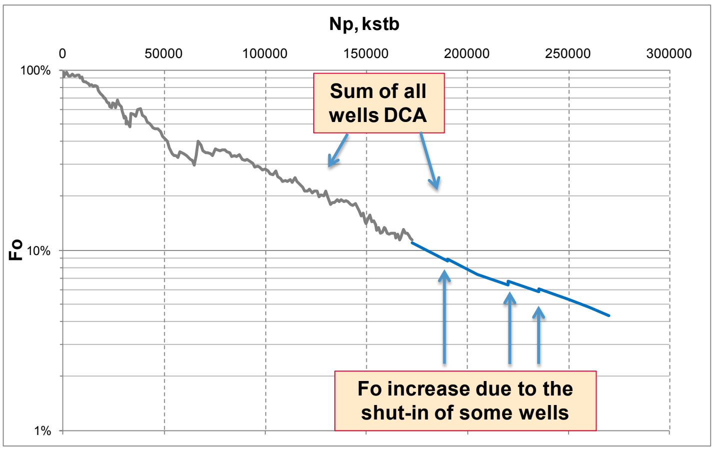


Figure 48: Arithmetic sum of all wells DCA

10.8 Sub-step 3h: QC at field level

Guideline n°32:

QC1: The overall forecasts should be compared with the field and surface constraints (treatment, disposal capacities …).

DCA adjustment should be performed if any of these constraints are violated.

Some roll-up tools (IPSOS, PetrovR...) can be useful to provide forecasts respecting all the surface constraints.

Guideline n°33:

QC2: The global 3-phase forecasts should be displayed together with historical data in order to once again check for new inconsistencies introduced at the aggregated level.

Guideline n°34:

QC3: DCA results should be compared to EUR (Estimated Ultimate Recoveries) obtained from other methods (simulation if available, material balance, review of analogues...) to ensure the reliability of the results.

At the end of the process, the changes in total cumulative production estimate (compared to the previous evaluation) should be explained. Possible justification for variations could be:

- Change of production mechanism;
- Well interventions;
- Change from undeveloped to developed activity;
- Change in surface facility capacities;
- Change in the scope and timing of planned activity (workovers, wells, etc.);
- Better understanding of the field behaviour (e.g. new data);
- Better (or worse) reservoir performance than previously estimated;
- ...

11. Step 4: Low and high DEV forecast estimates

The low and high estimate forecasts should reflect the uncertainty range of the future production forecasts.

For the SEC proved reserves (1PSEC) evaluation, the technical low estimate production forecast should be established based on the reasonable certainty criteria. The reader is referred to CR EP RES 001 and GM EP RES 001 for all aspects of reserves evaluation.

11.1 Sub-step 4a: identification of the main uncertain parameters that drive the forecast

Typical uncertainties impacting the range between best and low/high estimates are:

- Decline analysis itself:

  - Production data quality (allocation errors),
  - Representative history duration,
  - Flow stability during history,
  - Decline parameters (b exponent and/or D_i) accuracy,
  - Free gas production forecasting.

- Parameters used for 3-phase forecasts:

  - Future uptime evolution (integrating assumptions on well or down hole equipment mechanical life),
  - Abandonment rates (i.e. technical well cut-offs),
  - Liquid rate evolution (stable, declining?),
  - ...

- Material balance parameters impacting the reservoir pressure response during forecast:

  - Voidage evolution,

- Communication between reservoirs,
- ...

Guideline n°35:

For the estimation of the low and high estimates forecasts, it recommended to establish low estimate & high estimates assumptions for the **main relevant uncertain parameters only** and to keep the others at their best estimate level (rather than combining all the uncertainties with their low or high estimates).

Guideline n°36:

When dealing with mature oil fields producing water, **the low and high technical estimates can be evaluated based on low & high assumptions on:**

- **the liquid production evolution** (stable or declining faster or slower)
- **the regression of the law log f_o vs. N_p**.
- **the uptime factor.**

Nevertheless, linear match of log(fo) vs Np corresponds to harmonic decline and thus will generate more optimistic forecast of the Estimated Ultimate Recovery.

Thus it might not be relevant for the low DEV forecast estimate.

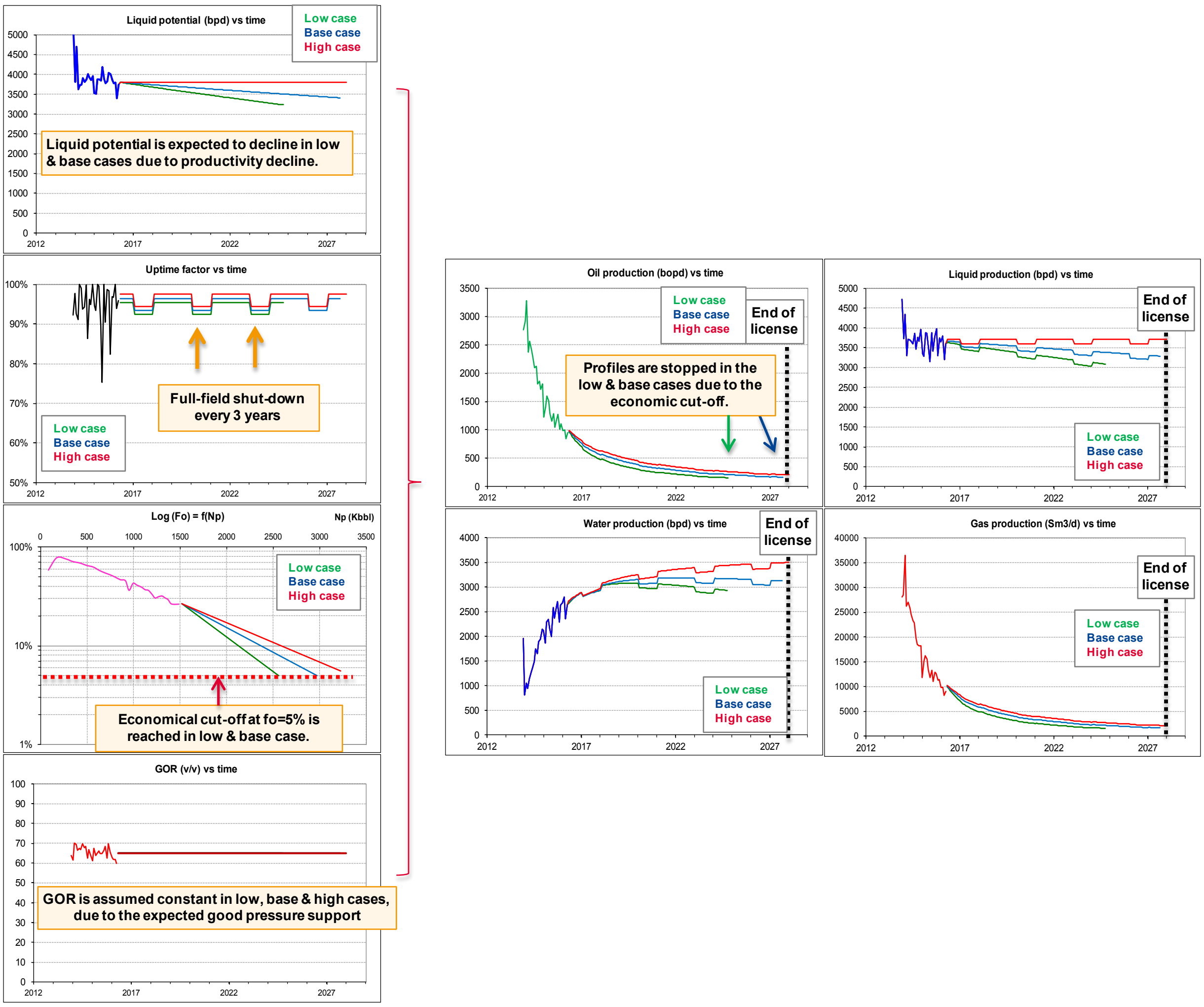


Figure 49: Evaluation of the low, base & high estimate forecasts with DCA

Guideline n°37:

Other curve-fitting approaches should be tested while generating the low & high estimate forecasts, as it could have an impact on the range of uncertainty.

11.2 Sub-step 4b: Selection of representative periods for the low, base and high estimate forecasts

Guideline n°38:

Different periods can be selected for the curve-fitting of the low, base and high estimates.

Figure 50: Selection of representative periods for the low, base and high estimate forecasts

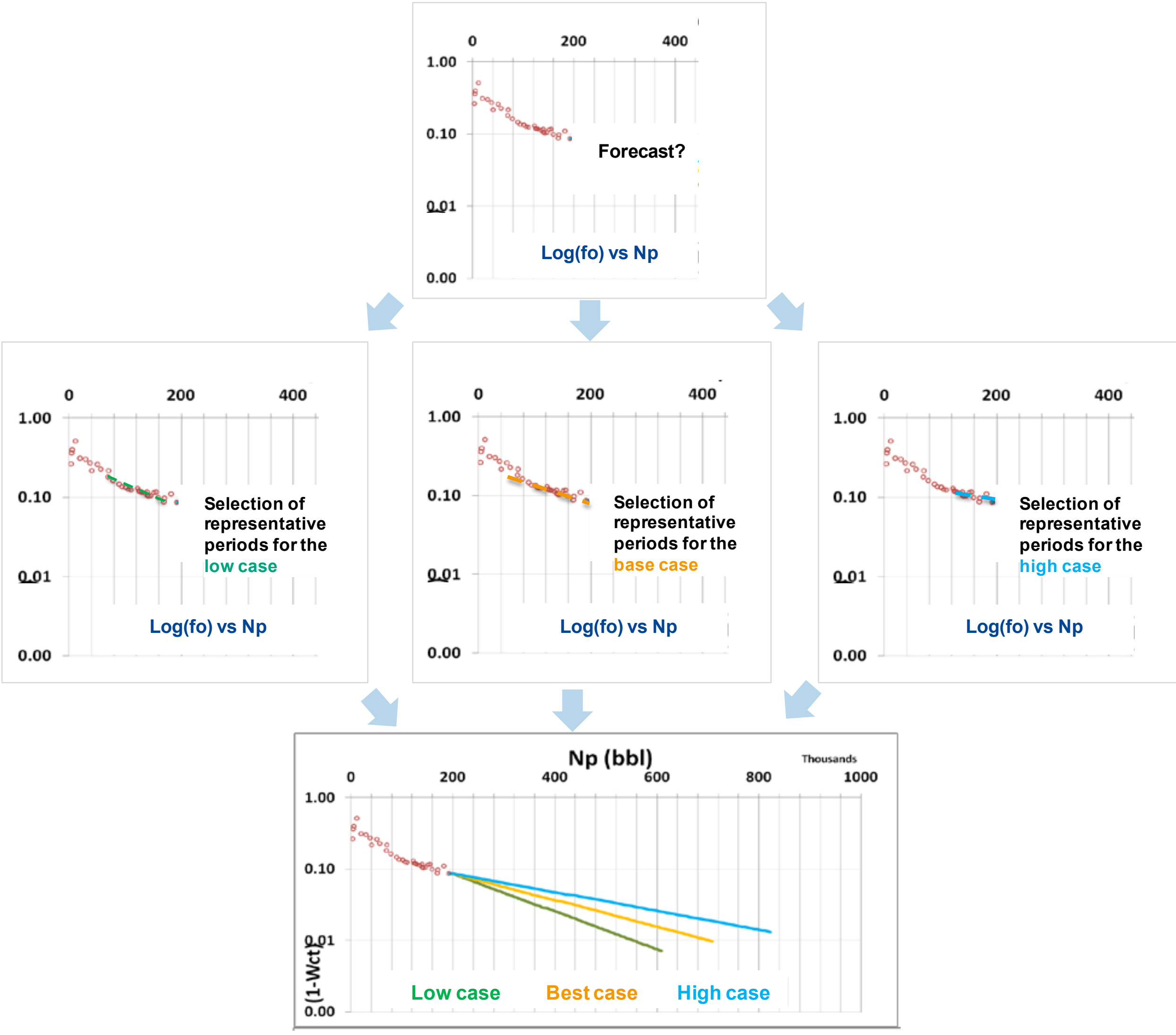


Figure 51: Selection of representative periods for the low, base and high estimate forecasts

Guideline n°39:

Linear match of log(fo) vs Np corresponds to harmonic decline and thus will generate more optimistic forecast of the Estimated Ultimate Recovery.

Thus it might not be relevant for the low DEV forecast estimate.

11.3 Sub-step 4c: The "Portfolio effect"

For fields with a significant well count, the aggregation of the wells low & high estimate DCA forecasts likely introduces **a "portfolio effect"** (also called "compensation effect" or "aggregation effect"):

- the aggregation of all the wells low estimate DCA is more pessimistic than the low estimate from a DCA realized at the group of wells level => $\Sigma(1P) < 1P(\Sigma)$
- the aggregation of all the wells high estimate DCA is more optimistic than the high estimate from a DCA realized at the group of wells level => $\Sigma(3P) > 3P(\Sigma)$

Guideline n°40:

It is recommended to carry out the low DEV forecast estimate or high DEV forecast estimate analysis at a level higher than that of the wells (at group of wells level or at field level) **in order to avoid the "portfolio effect".**

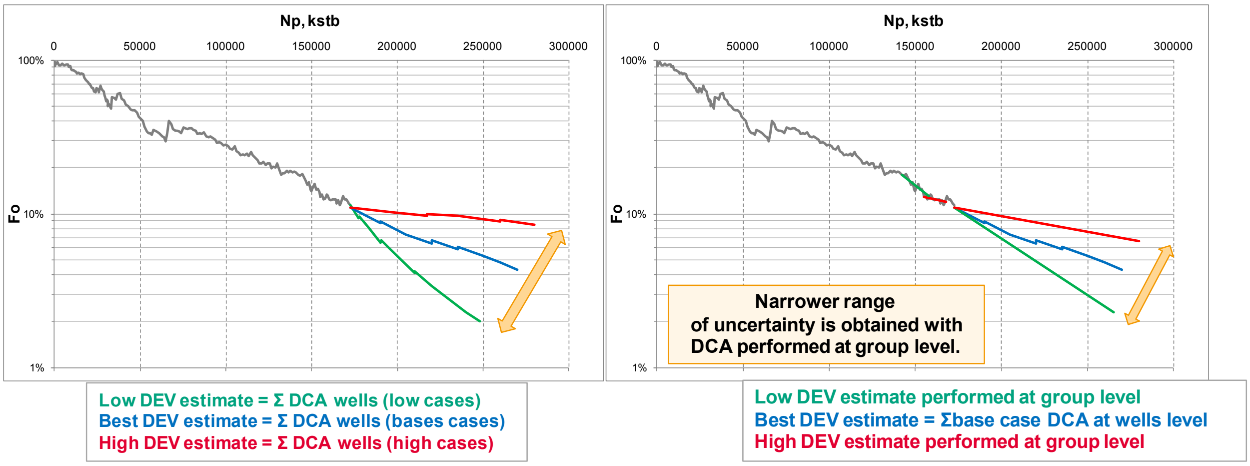


Figure 52: Low & high forecast estimates with DCA performed at wells level vs at group level

An example is presented in chapter 14 "Literature examples of DCA conducted at field level".

11.4 Sub-step 4d: QC of low & high forecasts estimates

Guideline n°41:

QC1: The 3-phase low DEV and high DEV forecasts estimate should be compared with the field and surface constraints.

Some roll-up tools (IPSOS, PetrovR...) can be useful to provide forecasts respecting all the surface constraints.

Guideline n°42:

QC2: The differences from the best DEV forecast estimate should be carefully verified and understood.

Guideline n°43:

QC3: DCA results should be compared to EUR (Estimated Ultimate) obtained from other methods (simulations if available, material balances, review of analogues...) to ensure the reliability of the results.

For the 1PSEC reserves evaluation, the low estimate forecast should satisfy the reasonable certainty criteria.

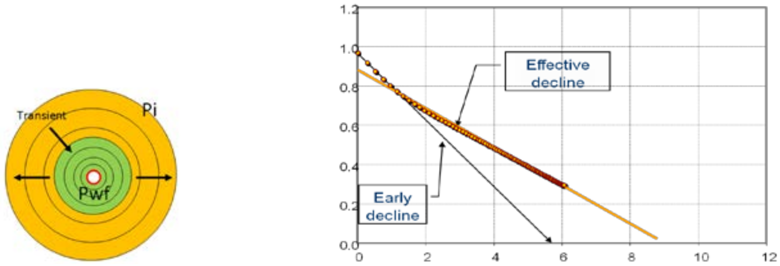
12. Common pitfalls

Many issues should be kept in mind to ensure proper and reliable use of the results obtained through DCA. In each situation, engineering and professional judgment is of utmost importance.

Based on existing industry experience, the most common pitfalls for single well declines are:

- Curve fitting entire the production life, including the transient period;

  => Cf chapter "6.4-Pseudo-steady state conditions"

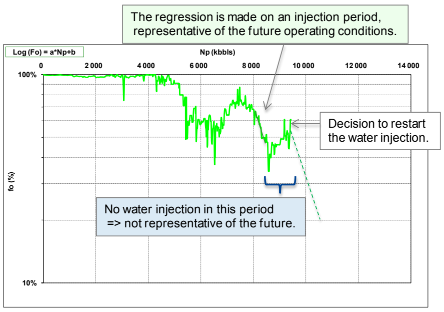


- Working at well level while production allocation (and measurements) are not reliable or exhibit large uncertainties (e.g. > 20%);

  => Cf chapter 9.1 – "Sub-step 2a: DCA to be performed at well level? Or at wells group level?"

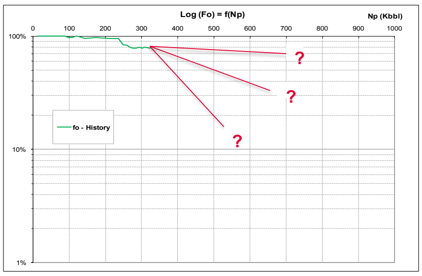
- Windowing data inappropriately by mixing successive recovery mechanisms e.g. for wells producing under-saturated reservoirs, this would lead to the change in oil decline behaviour as the pool is depleted below the saturation pressure being ignored;

  => cf chapter 9.2 – "Sub-step 2b: Representative flowing period"



- Using too short period for the establishment of the decline parameters;

  ***=> cf chapter 9.2* – “Sub-step 2b: Representative flowing period”**



- Fitting historical trends without considering changes in operating conditions such as workovers, increased drawdown, stimulation and pressure maintenance: decline fits should be re-initialized at each change in operating constraint;

  ***=> cf chapter 9.2* – “Sub-step 2b: Representative flowing period”**

- Matching decline without proper consideration of interference effects with neighbouring wells;

  => Cf chapter 9.1 – “Sub-step 2a: DCA to be performed at well level? Or at wells group level?”

- Matching oil decline in pressure supported reservoirs prior to significant water breakthrough (typically yielding optimistic results);

  ***=> cf chapter 9.2* – “Sub-step 2b: Representative flowing period”**

- Extrapolating linear trends of f_w, f_o or WOR vs. N_p at very high water cuts without consideration of possible bending of the relationship;

  => Cf chapter 10.5 – “Sub-step 3e: 3-phases forecasts”

- Matching producing day rate-time decline for wells with significant shut-in times (high downtime) generally yields optimistic results. Rate vs. cumulative production declines are more reliable.

  => Cf chapter 9.4 – "Sub-step 2d: Curve-fitting process using the most relevant regressions"

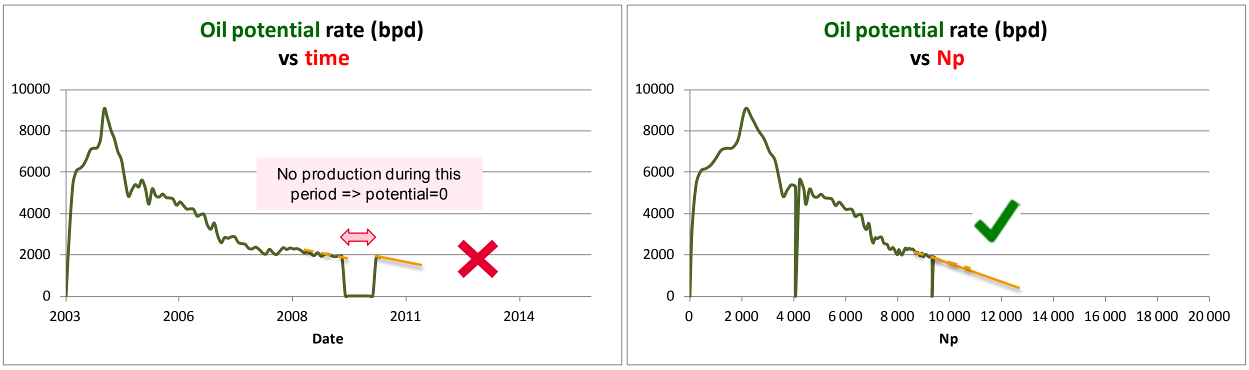


Figure 53: Oil potential vs Np is preferred than oil production vs time

- Focusing the forecast on the oil phase and forgetting the water and gas, which themselves might constitute a bottleneck in the production facilities.

  => Cf chapter 10.5 – "Sub-step 3e: 3-phases forecasts"

  => Cf chapter 10.8- "Sub-step 3h: QC at field level"

Based on existing industry experience, the most common pitfalls for group declines are:

- Curve fitting of group trends in which wells are continually added (typically yielding optimistic results);
- Grouping of wells with different decline characteristics;
- Grouping of wells from reservoirs with different production mechanisms;
- Curve fitting of oil cut (or water cut) group trends in which wells are shut-in due to high water cut (typically yielding optimistic results).

13. Detailed example of DCA application: reservoir produced by two wells

Global reservoir overview

Reservoir X has good properties; porosity ~20%, permeability ~500 mD (lithology dolomite/sandstone).

The oil is under-saturated with low viscosity (0,9 cP). A bottom aquifer is present.

The reservoir is produced by two wells (producers P1 and P2).

Each producer is sustained by a water injector:

- P1 by I1
- P2 by I2

Water injection started approximately one year after production start-up.

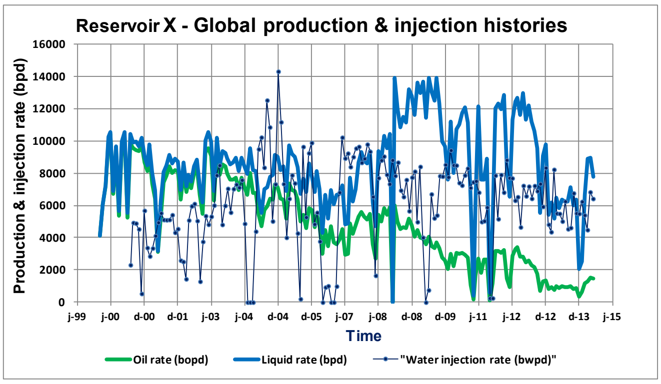


Figure 54: Production & Injection history

The water cut started to increase gradually three years after the production start-up.

Current level of water cut is about 80%.

The recovery factor is estimated to be 39% by mid 2014.

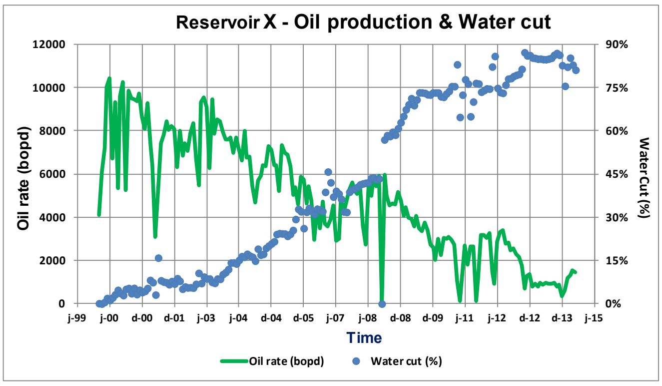


Figure 55: BSW evolution

The reservoir pressure evolution versus bubble point is shown on the following plot.The pressure appears relatively homogeneous and well stabilized for about the past 7 years.

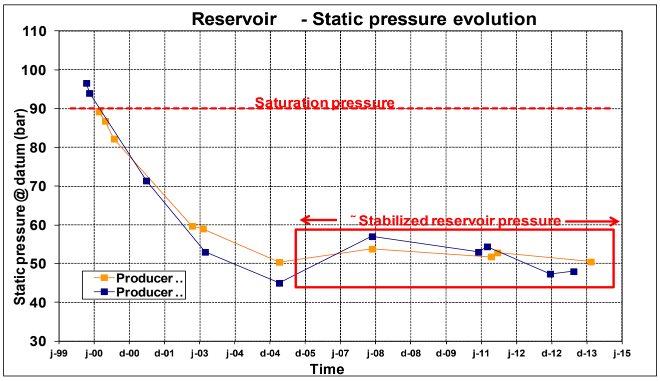


Figure 56: pressure evolution

Overview by well

Pair P1 - I1

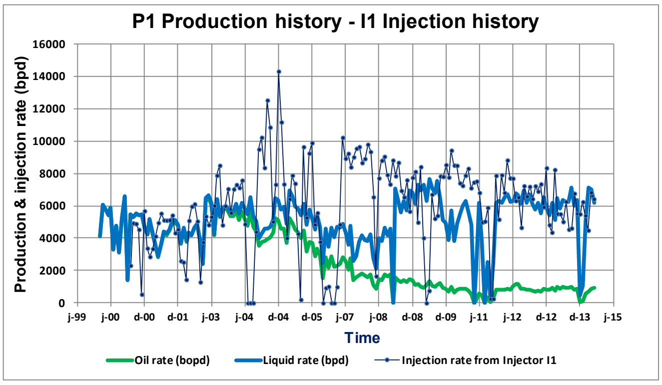
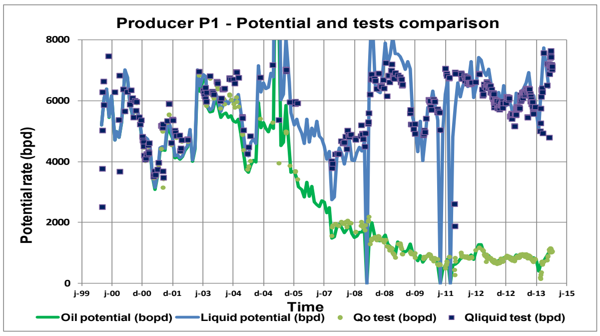


Figure 57: Wells P1 & I1 historic data

Producer P1 has been sustained by the water injector I1 since approximately 1 year after its production start-up.

Water breakthrough occurred approximately 4 years after production start-up (see second graph below).

Despite a decline of the injection rate, the liquid potential appears rather stable over the period mid 2008-2009 and 2011-2014.



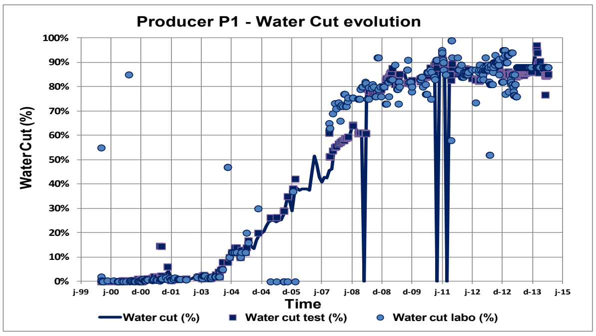


Figure 58: P1 production data

The quality of the production allocation is judged by comparing the rates (or potentials) with the test results.

In this example the oil data appears more accurate than liquid values.

Pair P2 - I2

Producer P2 only received water injection much later when compared to P1. Injection into I2 started about 7 years after P2 production start-up.

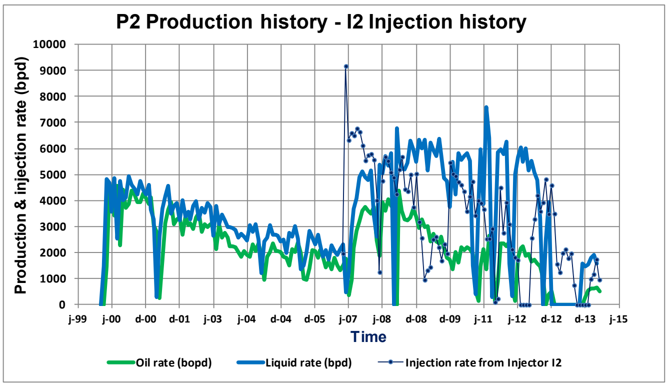
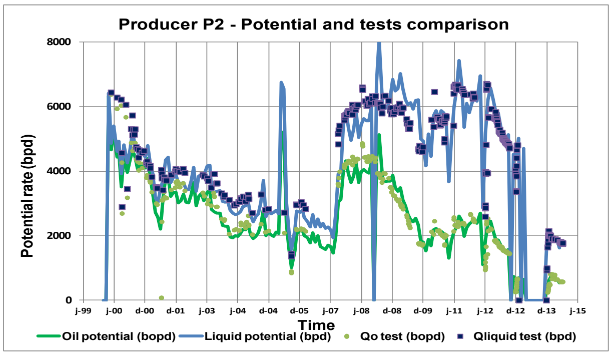


Figure 59: Wells P2 & I2 historic data

Water breakthrough occurred immediately after the beginning of production. Following I2 injector start-up the rate of water-cut increase accelerated and the liquid and oil potentials are noted to have increased until late 2012.

The end of the history shows much lower values of both production (oil and liquid) and injection.

The decrease in production results from a reduction of P2 drain length (sanding out) and from an ESP change (new pump with lower capacity).



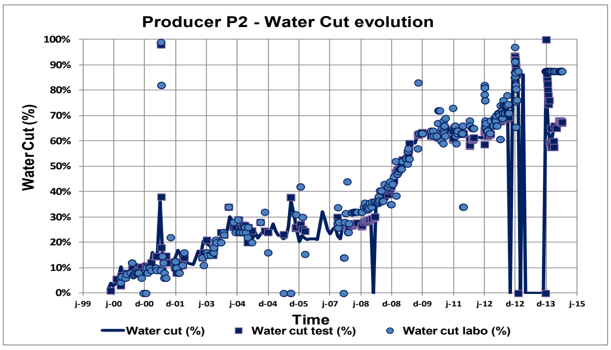


Figure 60: P2 production data

As was done for P1, the quality of the production allocation is judged by comparing the rates (or potentials) with the test results.

Uptime factors

The graphs and table below show the uptime factors of each producer, which tend to decrease through time reflecting the aging of the installations.

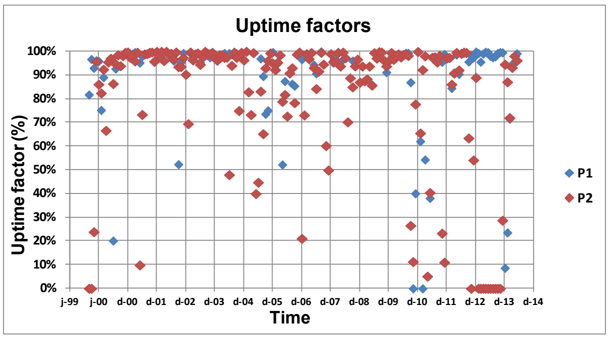


Figure 61: Monthly uptime factor

Forecast of uptime factor has been validated by the Fields Operation & Planning correspondents.

Plots vs. cumulative production

The graph here below shows P1 historical log(f_o) vs Np. The oil and liquid potentials and tests are displayed on a linear scale (right hand scale).

The zoom in the right upper corner details the last 6 years of history exhibiting quite stable liquid production.

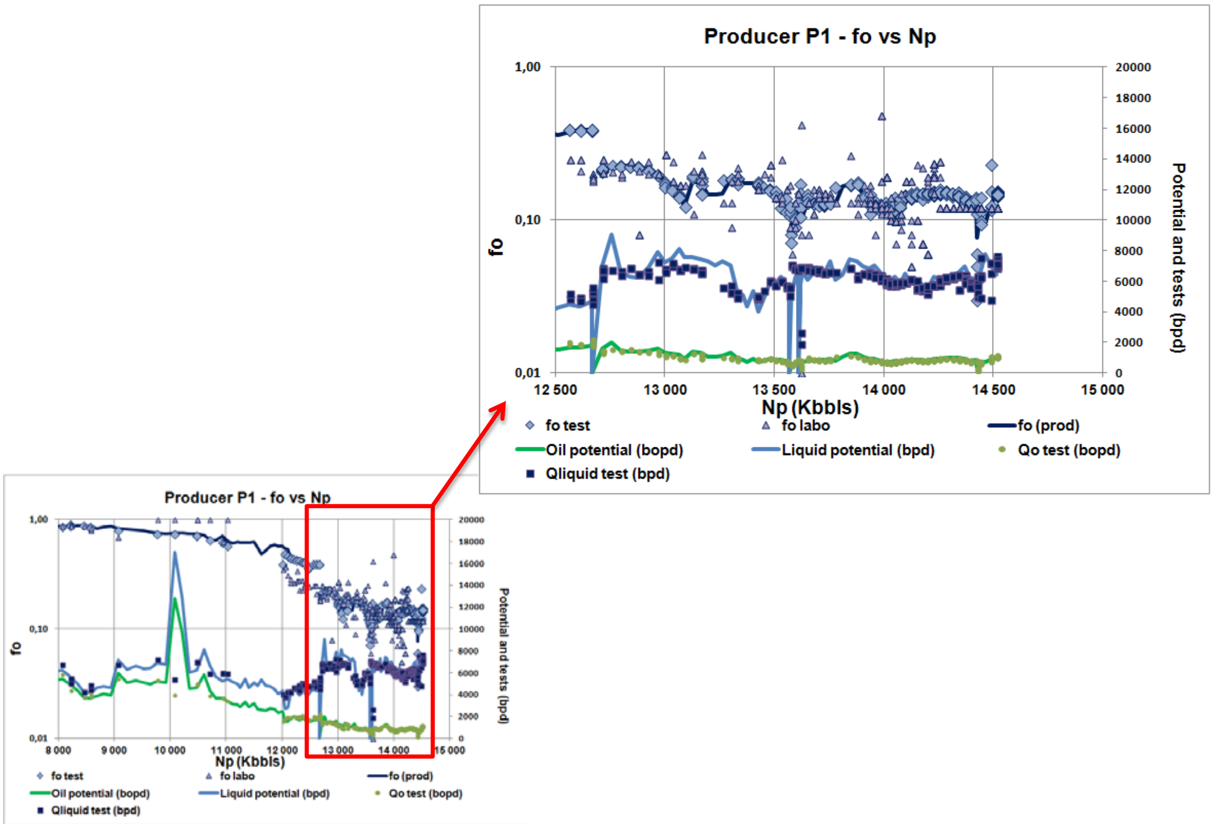


Figure 62: Well P1: fo vs Np

The same type of graph (combining semi-log and linear plots) shows the evolution of the P2 well production parameters versus oil cumulative production.

The zoom in the right upper corner highlights the last 7 years of history.

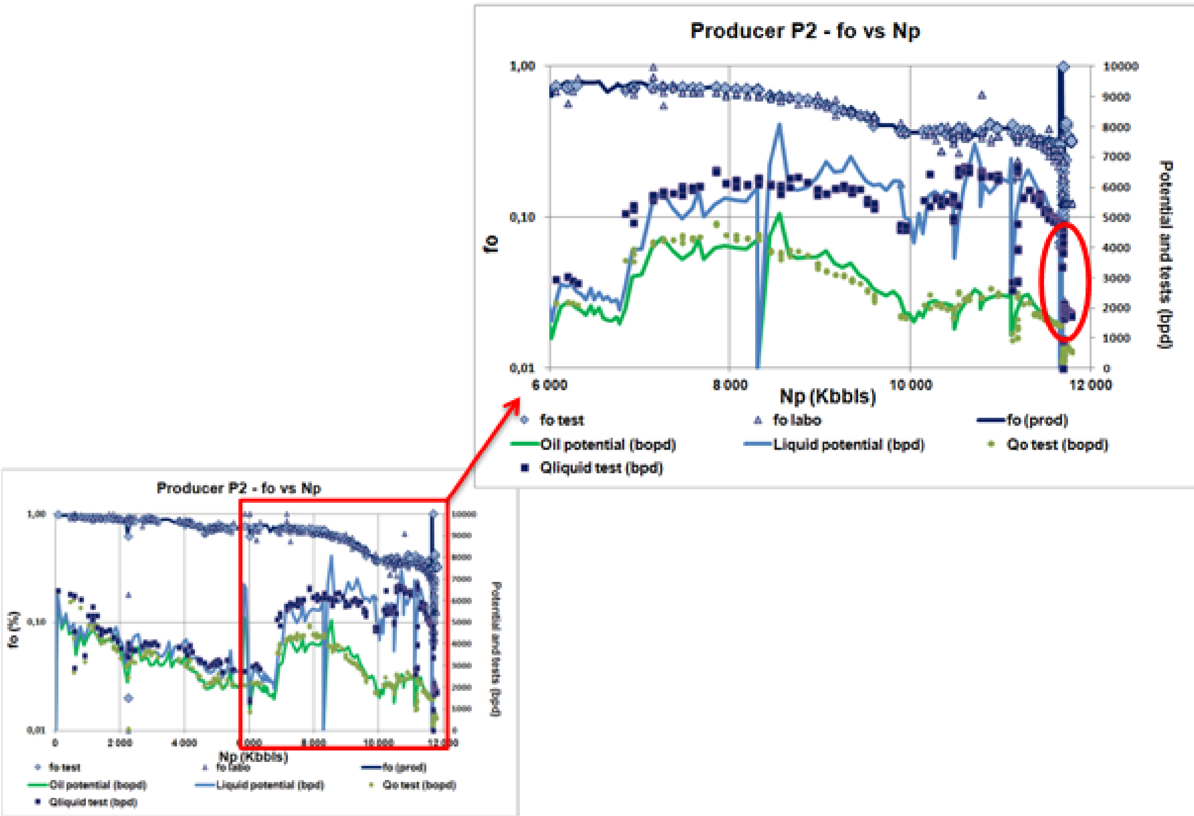


Figure 63: Well P2: fo vs Np

Rather stable liquid production can be observed until at the very end of the history when the change in the well operating conditions results in a significant reduction in the liquid potential.

Choice of representative periods and definition of current trends

Producer P1

The P1 well is rather simple due to the stability of the production conditions exhibited over the last years of history.

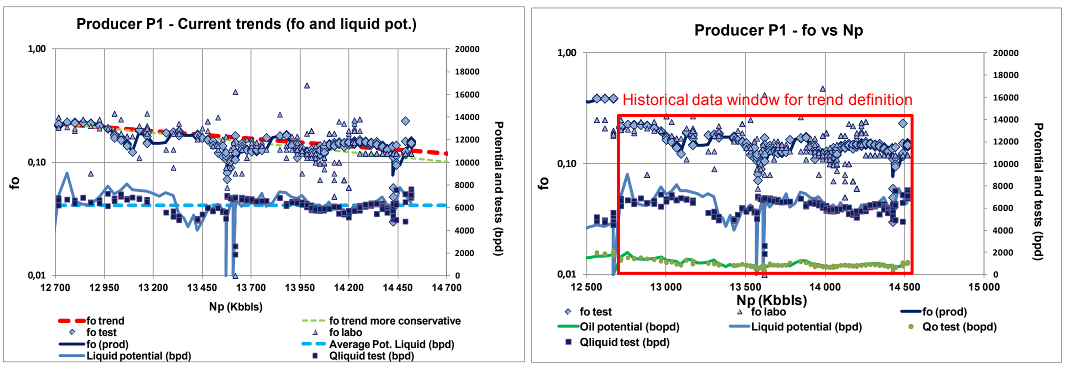


Figure 64: Selection of a representative period for P1 forecast

A regression line log (f_o) = - 0,0001341 * Np (Kbbls) + 1,0475 can be fitted over the chosen period in order to represent the current f_o evolution.

The liquid production is quite stable around 6200 bpd according to the tests performed during the twelve last months. At the very end of the history the liquid production then shows an increase, peaking at 7000 bpd.

It might however be preferable to use the oil potential and tests, which show less scatter than the liquid potential. In that case a regression line log (Q_o pot. in bopd) = - 0,00011912 * Np (Kbbls) + 4,6331 can be fitted over the period in order to represent the current evolution of the oil potential.

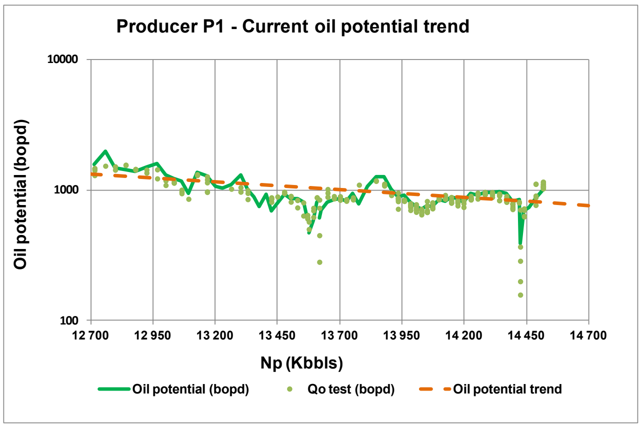


Figure 65: Regression on P1 Oil potential vs Np

As a reminder, selecting log(fo) vs Np for the regression corresponds to harmonic decline of the oil rate and will generate forecasts more optimistic.

Selecting Qo vs Np corresponds to an exponential decline of the oil rate and will generate more pessimistic forecasts.

Producer P2

P2 case is much more tricky due to the change in operating conditions exhibited at the very end of the history.

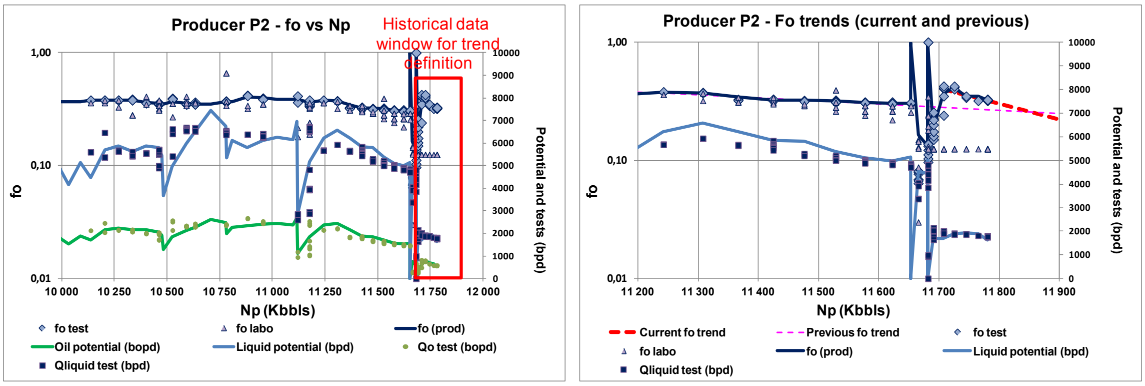


Figure 66: Selection of a representative period for P2 forecast

This change occurred only six months before the end of the history. Obviously this period is the representative period to analyze since those conditions will prevail in the future. The duration of the period is however limited (much shorter than the two years recommended in this guide and manual) thereby reducing the accuracy of the trend definition.

The analyst has therefore to cope with this short historical period in order to try to define representative trends.

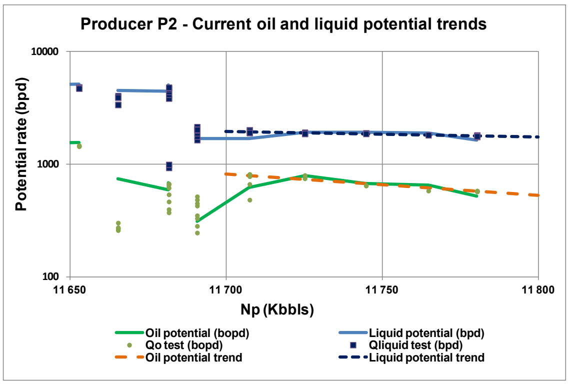


Figure 67: Curve-fitting of P2 well

A regression line log (f_o) = - 0,001337 * Np (Kbbls) + 15,251 can be fitted in order to represent the current f_o evolution.

It is important to notice that this trend is steeper than the trend observed before the well intervention despite a lower withdrawal after intervention coupled with a lower injection level. P2 however resumed production after intervention with a higher oil fraction.

Regression lines can be fitted over the end of the historical period in order to represent the last oil or liquid potential evolutions.

A far as oil potential is concerned, the trend can be estimated by the law log (Q_o pot.) = - 0,0018631 * Np (Kbbls) + 24,708.

The relationship log ($Q_{liq.}$ pot.) = - 0,00046417 * Np (Kbbls) + 8,719 can represent the evolution of the liquid potential.

Building production profiles at well level

Producer P1

By assuming that the operating conditions existing at the end of the history will continue to prevail in the future, the best DEV forecast estimate is obtained by combining the f_o and oil potential historical trends.

The forecasts are generated up to the end of the licence (July 2020) without application of specific technical cut-off. An uptime factor gradually decreasing from 81% till 75% by mid 2020 is furthermore considered.

For the P1 well the two most important uncertainties are deemed to be the level of the future liquid production and the evolution of the well uptime factor.

These dominant uncertainties are carried into the low/high forecasts while keeping the other parameters as per the best estimate.

- The low DEV forecast estimate is obtained by combining the f_o historical trend with a liquid potential constant at 6200 bpd. The uptime factor is assumed to gradually decrease from 81% to 65% by mid 2020.
- The high DEV forecast estimate is derived by combining the f_o historical trend with a liquid potential constant at 7000 bpd. The uptime factor is assumed to gradually decreases from 83% to 80% by mid 2020.

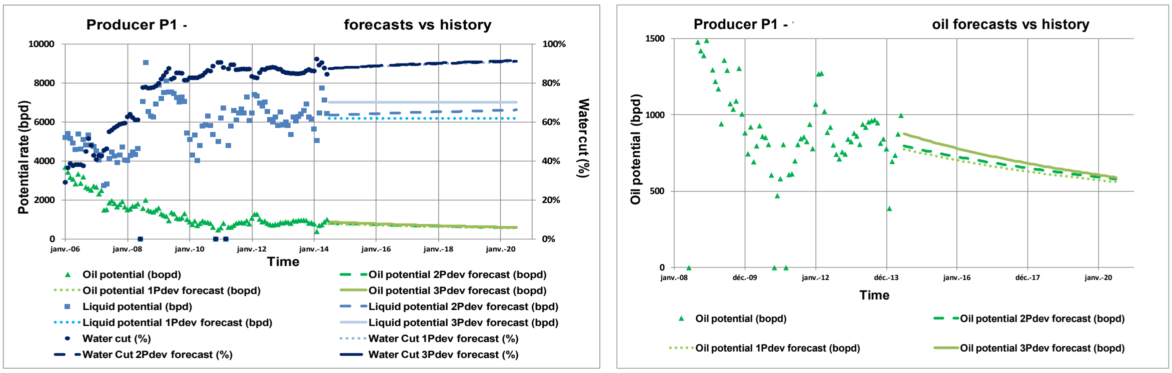


Figure 68: Forecast of the low, base & high DEV forecast estimates

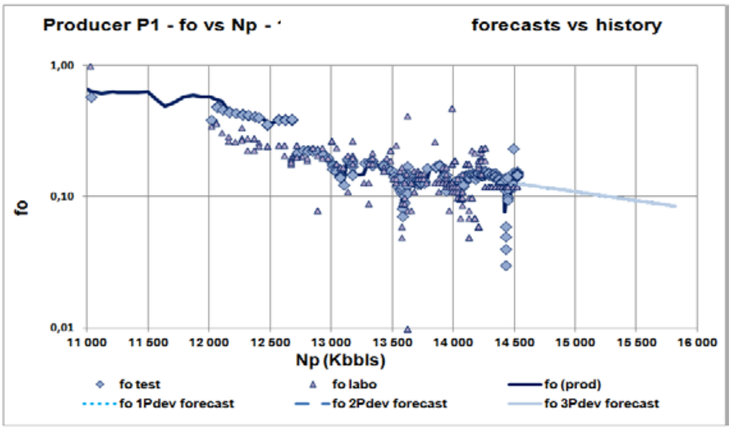


Figure 69: Curve-fitting & forecast of log(f_o) vs Np

Producer P2

It is assumed that the operating conditions existing during the last six months of P2 history will prevail for the duration of the forecast period. The best DEV forecast estimate is obtained by combining the liquid potential evolution seen over this period with a f_o trend. The steep f_o trend fitted over the end of the history is applied up the point of interception with the previous historical trend. The forecast of oil fraction from this point up to the end of licence is then generated using this original trend.

The forecasts are generatued up to the end of the licence (July 2020) without application of specific technical cut-off. An uptime factor gradually decreasing from 79% till 72% by mid 2020 is furthermore considered.

For the P2 well, due to the short duration of the historical period used for the trends definition, the two most important uncertainties are assumed to be the evolution of the oil fraction (f_o) and the oil or liquid potential. The evolution of the well uptime factor seems of comparitavely lesser importance.

These dominant uncertainties are carried into the low/high forecasts while keeping the other parameters as in the best estimate.

- The low DEV forecast estimate is obtained by combining the f_o vs Np historical trend (without further adjustment) with the oil potential trend.
- The high DEV forecast estimate is derived by combining a more optimistic oil-cut trend with a liquid potential constant at 1800 bpd.

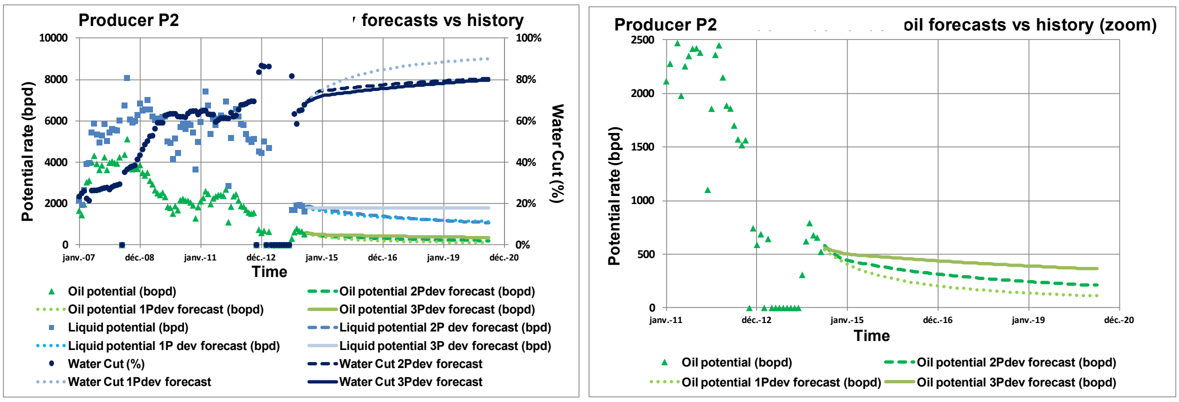


Figure 70: Forecast of the low, base & high DEV forecast estimates

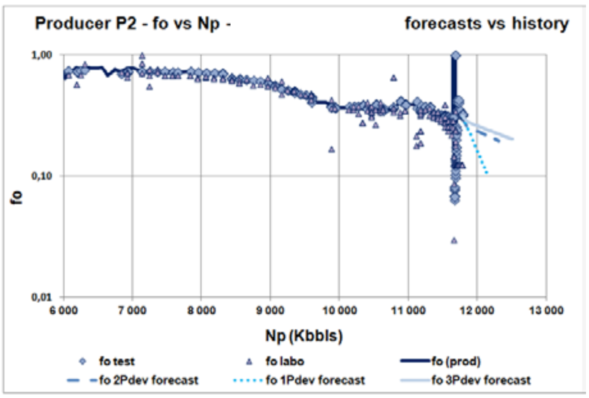


Figure 71: Curve-fitting & forecast of log(f_o) vs Np

Aggregation at reservoir level

In this instance the aggregation at reservoir level is performed arithmetically for the three scenarios due to the limited number of wells producing the studied reservoir.

The resulting reservoir level low, base, high DEV forecasts are displayed below (Figure 73)

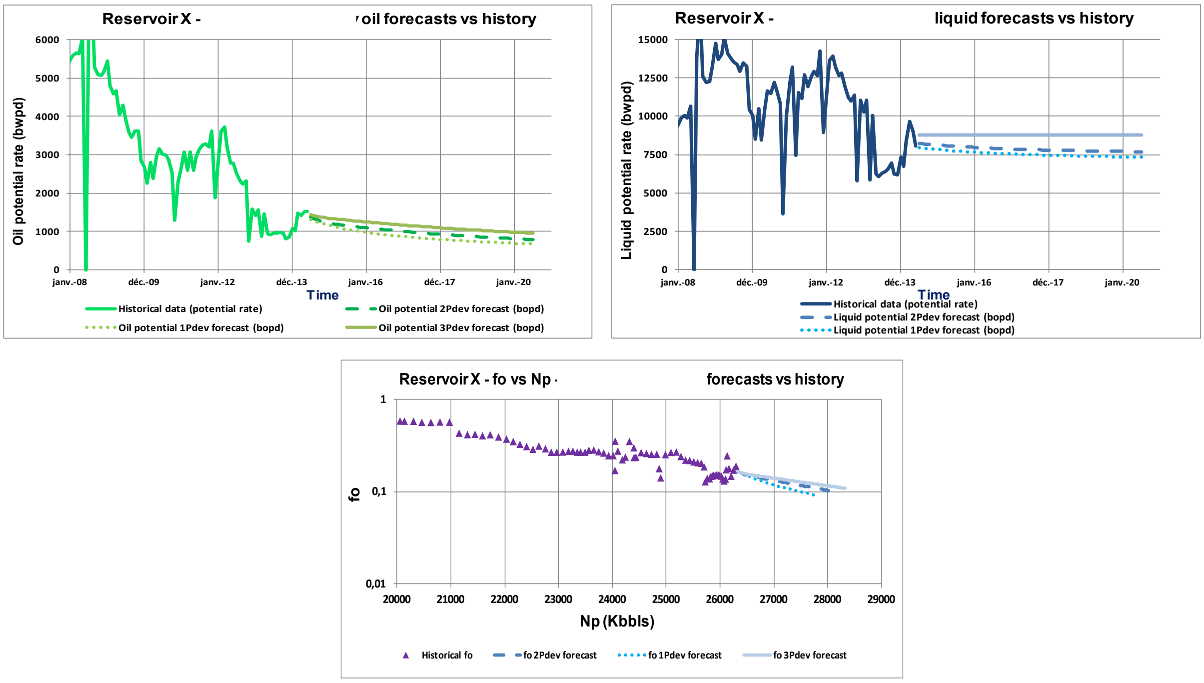


Figure 72: Aggregation at reservoir level

Quick QC steps before final validation

At field level reservoir X is produced with another reservoir Y.

The compliance of the forecasts with the field capacities should therefore be checked by grouping reservoir X and Y forecasts.

The graph displayed below (Figure 74) illustrates an example where best DEV forecast estimate of water profiles are checked against the water treatment capacity of 14000 bwpd.

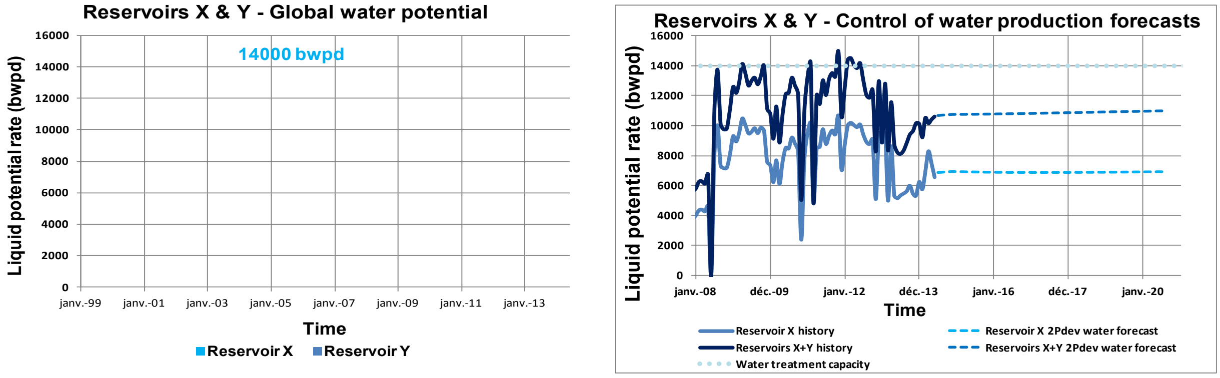


Figure 73: Overall liquid & water production vs surface facilities capacitites

The $\dfrac{low\ case\ DEV}{base\ case\ DEV}$ and $\dfrac{high\ case\ DEV}{base\ case\ DEV}$ ratios amount to respectively 85% and 118%.

Those ratios are respectively:

- 91% and 110% for P1 well
- 71% and 136% for P2 well (the wider range reflects the uncertainty arising from the limited representative production period following the change in operating conditions).

Recovery at end of license from reservoir X reaches 41,4%, 41,8% and 42,3% for the low, best and high DEV estimates.

14. Literature examples of DCA conducted at field level

14.1 Baker's paper reference [25]: Lloydminster 'O' Pool example

The Provost Lloydminster 'O' pool has been on production since September 1973. The oil is heavy to medium with 23.8 °API (0.911 g/cc). Primary production occurred until January 1977 when water injection began. Injection increased significantly in 1995.

A composite production plot is shown in Figure 75.

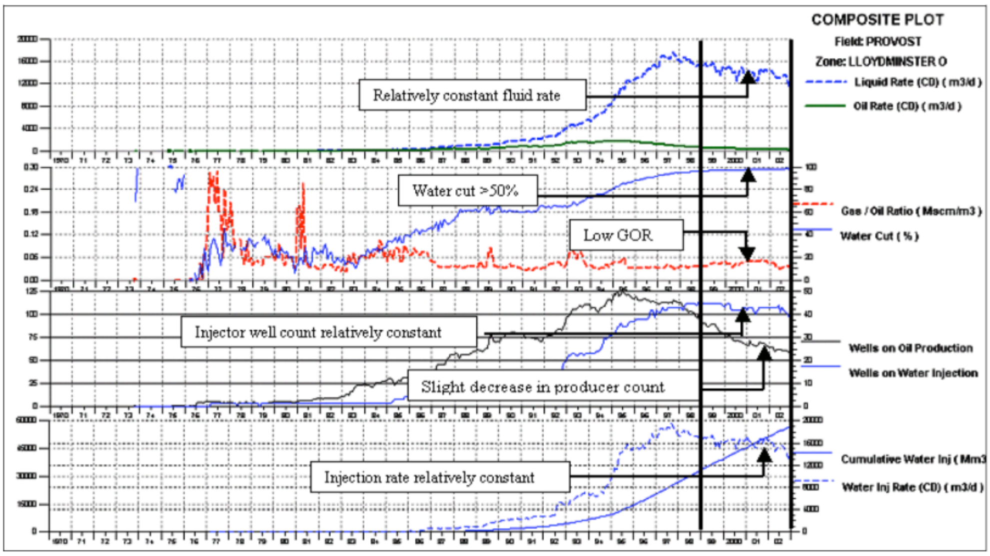


Figure 74: Composite plot

From this plot it can be seen that the most appropriate correlation period for decline analysis is late 1998 to December 2002 (end of production data set). In this time period, the injection rate, injection well count and GOR are about constant. A slight decrease can however be noticed in the producer count. The water cut is above 50%.

Furthermore during this period the VRR (Voidage Replacement Ratio) is close to unity whereas it was quite erratic before 1995.

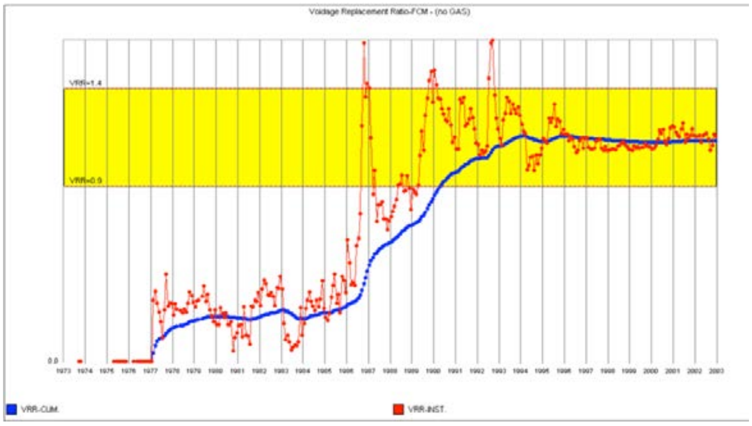


Figure 75: Voidage replacement ratio evolution

The criteria proposed by Baker et al. for the selection of the decline correlation period for waterfloods are globally met in this case.

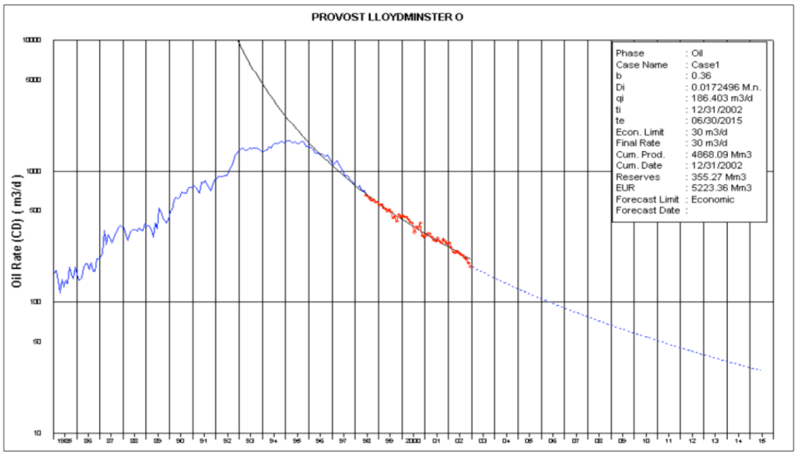


Figure 76: Hyperbolic match of the oil rate vs time

Using commercial software to determine the Arps exponent for the correlation period 1998-2002, it was found that a “b” value equal to 0.36 gave the best fit of the data.

The reader can note the shift existing at the transition between history and forecast that is imposed to honour the oil rated experienced at the end of the history.

14.2 Harrell’s paper reference [26]: risk of errors when working at field level

A field production history is displayed below (Figure 78).

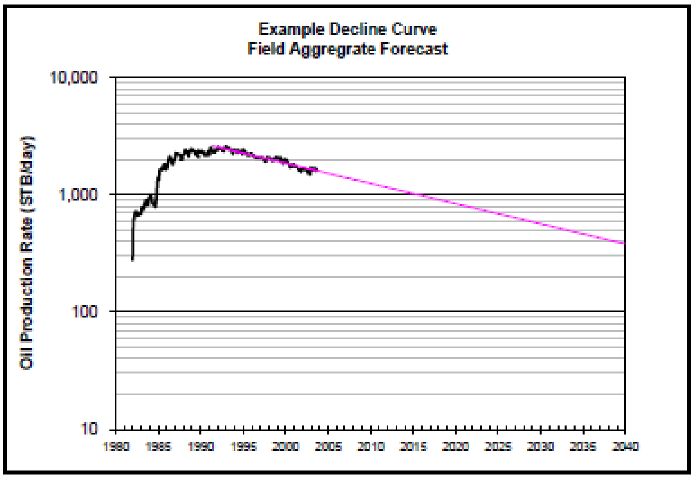


Figure 77: Curve-fitting & forecast of the oil production rate vs time

The historical trend seems to show a continual decline over time which can be projected into the future with a reasonably high degree of reliance based upon the mathematical "best fit" of the historical data.

This projection clearly presents at first glance an appealing case for using the entire production history to obtain a forecast estimate as of the effective date of the analysis. This approach would however be erroneous.

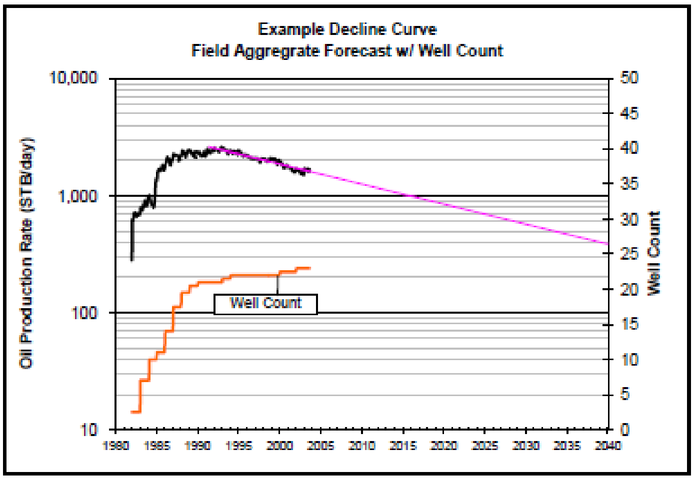


Figure 78: Curve-fitting vs well count

The second graph is the same as the first one but contains additional data about the number of producing wells over the life of the field. This additional data should not be overlooked since it has a significant impact on the previous interpretation of the remaining production. **It indeed becomes clear that the forecast shown on the first figure is not achievable without the continuous drilling of additional wells at the same frequency and with similar results.**

The graph below (Figure 80) is a restatement of the data displayed on the previous plots. The alternate forecast (green dotted line) is based on a constant well count and an average well production (field production divided by well count).

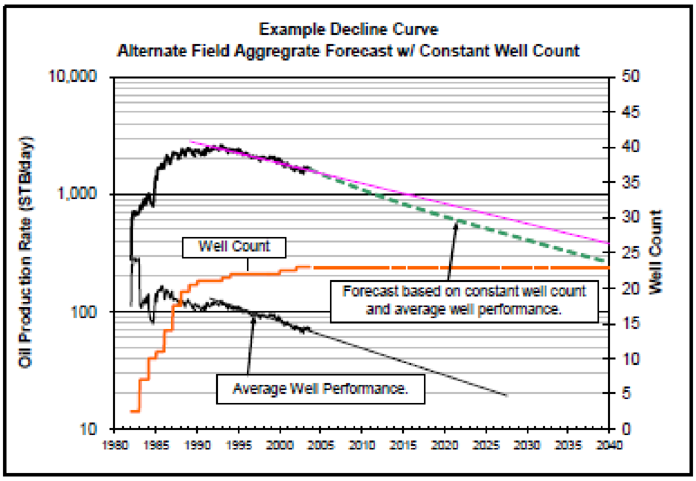


Figure 79: Average well performance forecast

One should however be cautious when using "average well" projections which may have been sustained by continuous impact of production from new wells over time and well-maintenance work.

The last figure (Figure 81) presents a final forecast (red dotted line) in which both effects of drilling and single-event workovers have been removed from the field trend.

This more realistic projection nevertheless needs to be backed up by other approaches.

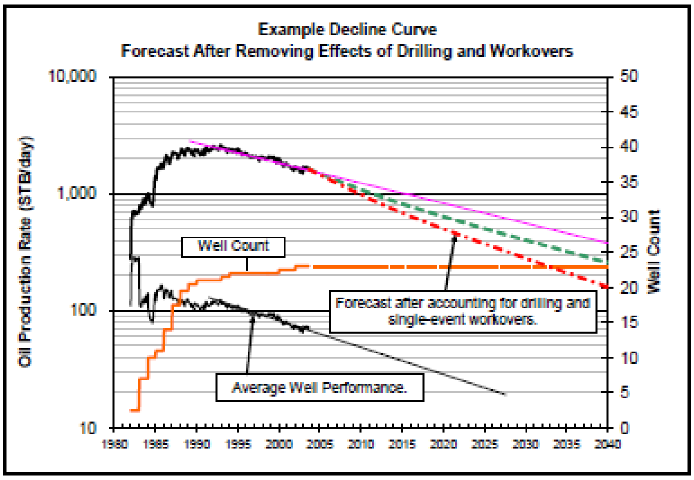


Figure 80: Final forecast

15. Material balance technique for gas (conventional) assets

Material balance is a very useful and common engineering method for understanding the past performance of a gas reservoir and predicting its future potential.

However instead of extrapolating the decline of gas rates, it is much preferred to extrapolate reservoir pressure decline through material balance analysis and then to derive gas rate evolution through an integrated model (reservoir/well/surface modeling with Petex suits or GasPal for example).

15.1 Pre-requisite for material balance method on gas fields

Guideline n°44:

The following conditions are mandatory for the validity of the material balance approach on gas fields:

- Reservoir hydrocarbon fluids are in phase equilibrium at all times and equilibrium is achieved instantaneously after any pressure change;
- The reservoir pressure can be represented by a single, weighted average at any time (**pressure gradients in the reservoir cannot be considered in this method**);
- Fluid saturations are uniform throughout the reservoir at any time (saturation gradients cannot be taken in to account);
- Conventional PVT relationships for normal gas are applicable and are sufficient to describe fluid phase behaviour in the reservoir.

There are essentially four groups of data required for gas material balance:

- Fluid production & injection data (metering)
- Pressure data (monitoring)
- Fluid PVT data
- Petrophysical data (rock compressibility, fluid saturation …)
- Connected volume of fluid in-place (gas, aquifer …)

In general a minimum of 10 to 20% of gas in-place volume should be produced before there is sufficient historical data (pressure & production) to identify a trend with which to perform reliable analysis.

15.2 General gas material balance equation

Material balance is the application of the law of conservation of mass to hydrocarbon reservoirs and aquifers. It is based on the premise that the reservoir space voided by production is immediately and completely filled by the expansion of remaining fluids and rock. This balance is therefore expressed in terms of reservoir voidage.

For gas reservoirs, the general material balance equation is described as:

Withdrawal = Gas expansion + Water expansion & Pore compaction + Water influx

$$G_pB_g + W_pB_w = G(B_g - B_{gi}) + \frac{GB_{gi}(c_wS_{wi} + c_f)\Delta P}{1 - S_{wi}} + W_eB_w$$

with:

- B_g:Gas volume factor
- B_{gi}: Gas volume factor at initial reservoir pressure
- B_w: Water volume factor
- c_w: Water compressibility
- c_f: Formation compressibility
- G: Connected gas-in-place
- G_p: Cumulative gas produced
- ΔP: Difference in reservoir pressure
- S_{wi}: Initial water saturation
- W_e: Cumulative water influx
- W_p: Cumulative water produced

15.3 Volumetric depletion

For most gas reservoirs, the gas compressibility term is much greater than the formation and water compressibilities. Thus, the second term on the right side of the above equation becomes negligible.

$$G_pB_g + W_pB_w = G(B_g - B_{gi}) + W_eB_w$$

When the reservoir pressure is abnormally high, this term is not negligible and should not be ignored.

When there is no aquifer support, the reservoir is said to be volumetric. The equation becomes:

$$G_pB_g = G(B_g - B_{gi}) \Rightarrow \boxed{G_p = \frac{G(B_g - B_{gi})}{B_g}}$$ **(eq.1)**

Moreover,. $B_g = \frac{V_{reservoir}}{V_{surface}} = \frac{Z_{res}nRT}{P_{res}} * \frac{P_{std}}{Z_{std}nRT_{std}}$

Thus, $\boxed{\frac{B_g}{B_{gi}} = \frac{Z_i}{Z}\frac{P}{P_i}}$ **(eq.2)**

The very well-known version (containing only gas terms) is a simplified and rearranged formulation of the general gas material balance equation (using equations 1 & 2 above)**:**

$$\frac{P}{Z} = \frac{P_i}{Z_i}\left(1 - \frac{G_p}{G}\right)$$

with:

Z: gas compressibility (or deviation) factor
Z_i: Initial gas compressibility (or deviation) factor
P: Reservoir pressure
P_i: Initial reservoir pressure

by assuming a **pure volumetric depletion** (insignificant amount of water influx into the reservoir).

In such a case, the reservoir behaves as a tank and pressure, corrected for non-ideal gas behavior, plotted versus cumulative production exhibits a linear relationship.

Typically the gas expansion (the most significant source of energy) dominates the effect of water expansion and pore compaction. It is also assumed that reservoir temperature is uniform and constant.

The gas compressibility (or deviation) factor Z is by definition the ratio of the volume actually occupied by a gas at a given pressure and temperature to the volume it would occupy if it behaved ideally:

$$Z = \frac{Actual\ volume\ of\ \ gas\ \ at\ \ P\,\&\,T}{Ideal\ \ volume\ \ of\ gas\ \ at\ \ P\,\&\,T}$$

Indeed, the volume of a real gas is usually less than what the volume of an ideal gas would be at the same temperature and pressure; hence, a real gas is said to be super compressible.

The real gas equation of state gives:

$$Z = \frac{PV}{RT}$$

Z is determined at the PVT laboratory during a Constant Composition Expansion (CCE) which is a:measurement of P and V during depletion (at constant gas composition).

A typical evolution of Z with P is shown on the following plot:

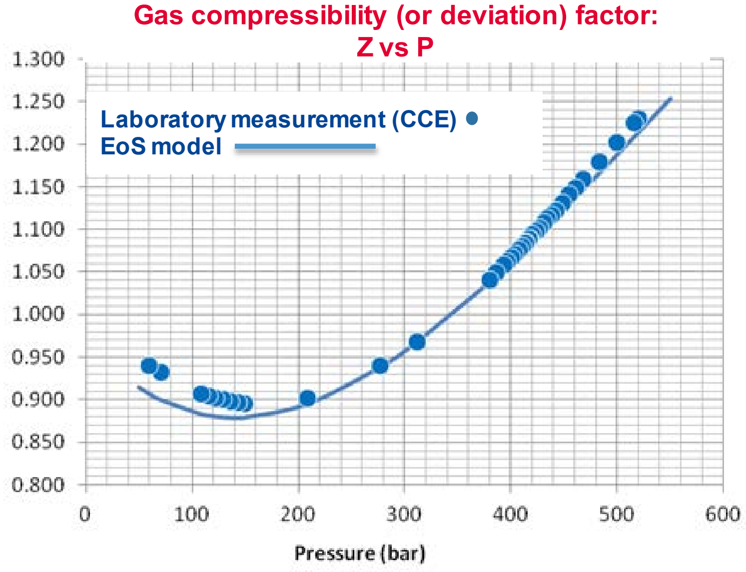


Figure 81: Z evaluation during lab measurement and match with the EoS model

The fluid engineer matches the Z measurement using the Equation of State of the fluid.

Guideline n°45:

Extrapolation of P/Z to abandonment pressure and zero pressure gives estimates of the ultimate recovery and of the connected gas-in-place (G) respectively

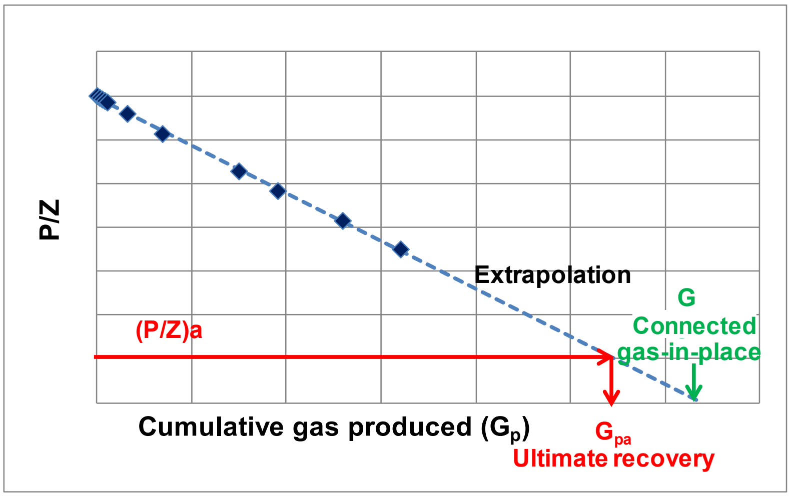


Figure 82: Graphical representation of the material balance for a volumetric depletion gas reservoir

The pressure measurements taken at well locations should represent true average reservoir pressures for the material balance approach for gas fields to be valid (ref. paragraph 15.1).

In high permeability reservoirs, the generally low gas viscosity ensures that small pressure gradients exist away from the wellbore and therefore that the average reservoir pressure can be easily estimated using short-term build-ups or static pressure surveys.

Guideline n°46:

If significant differences in reservoir pressure exist within a given field, the P/Z analysis can be attempted for each well (or by group of wells exhibiting similar reservoir pressures) **and will deliver the effective connected volume of the studied well or group.**

Guideline n°47:

For gas fields, the use of the bottom-hole pressure extrapolation with a well model (Prosper model for instance) **enables to assess the future gas production rate over time.**

The more data that are available, the more accurate will be the definition of the straight line and hence the predicted value of G or G_{pa}. When placing the straight line through the P/Z data, it is usually prudent to consider the first point (i.e. at field discovery pressure) as more accurate and reliable than the others. Regression approaches for the definition of the best fit should take this into consideration.

Guideline n°48:

The reliability of the $\frac{P}{Z}$ analysis greatly depends on the quality of the input data. It is the reason why **down hole pressure measurements after long shut-in periods (ideally with a permanent down hole monitoring system) are preferred.**

Special attention should be paid to the interpretation of build-up pressure measurements in order to derive steady-state values for reservoirs of poor permeability and/or in case pressures result from extrapolation of well head measurements.

Guideline n°49:

A good knowledge of the gas PVT properties is also mandatory, requiring the availability of representative gas samples. It is important to bear in mind that gas composition may also evolve through time.

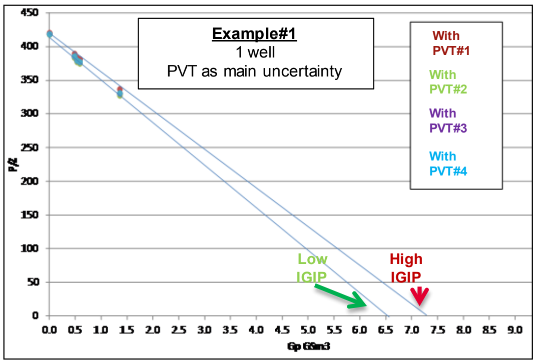


Figure 83: Impact of PVT uncertainty on the P/Z approach

In practice **the ideal volumetric depletion seldom exists** and furthermore a straight P/Z decline line is not a proof of volumetric depletion.

Guideline n°50:

The behaviour of real world gas reservoirs is often influenced by **aquifer influx, compartmentalization or contribution of low permeability zones**. The correct recognition of **these often competing phenomena** (cf chapter 15.4, 15.5, 15.6) can be challenging in particular early in the life of the field under study but is **the key to correctly diagnose the true reservoir behaviour**.

15.4 Gas reservoirs with water influx

A typical P/Z plot for a gas reservoir with active water drive is compared to a volumetric depletion case below.

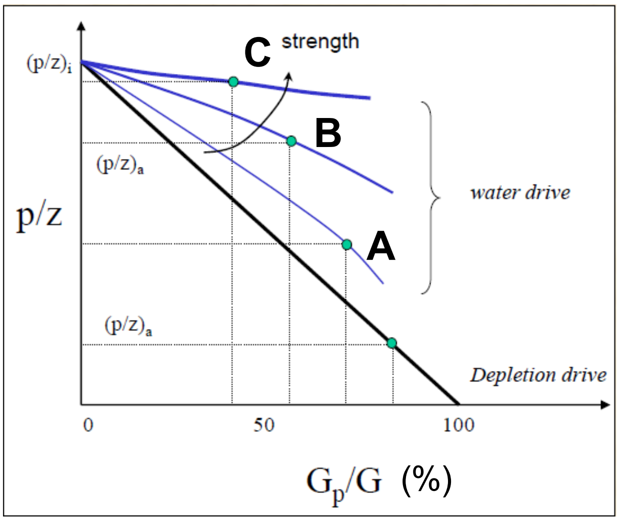


Figure 84: Volumetric vs. waterdrive P/Z trends

If the reduction of pressure leads to an expansion of an adjacent aquifer and consequently water influx into the reservoir, the material balance equation is then modified as:

$$G_p B_g + W_p B_w = G\left(B_g - B_{gi}\right) + W_e B_w$$

with:

- B_g: Gas volume factor
- B_{gi}: Gas volume factor at initial reservoir pressure
- B_w: Water volume factor
- G: Connected gas-in-place
- G_p: Cumulative gas produced
- W_e: Cumulative water influx
- W_p: Cumulative water produced

The equation again neglects the effects of connate water expansion and pore volume reduction.

This model assumes that, because the aquifer is relatively small, the pressure drop in the reservoir is instantaneously transmitted throughout the entire reservoir-aquifer system. The material balance in such a case would be as shown by line A in Figure 85 and might be mistaken as a depletion drive due to very small distortion in the linearity of the P/Z plot.

To provide the pressure response shown by lines B and C of Figure 85, the aquifer volume should be considerably larger than the volume of the reservoir and the instantaneous transmission of pressure throughout the system cannot be assumed anymore. **There is a time lag between the pressure perturbation in the reservoir and the aquifer response.**

The construction of such an aquifer model including this time dependence is more complex and requires the use of the Hurst and Van Everdingen method (references [3] and [9]).

The same set of pressure points (cf Figure 86) can be matched with a model without aquifer activity (IGIP=10000 Bcf) or with a model with less IGIP (IGIP=6750 Bcf) but with more aquifer activity.

The significant difference in IGIP will lead to a significant difference in ultimate recovery.

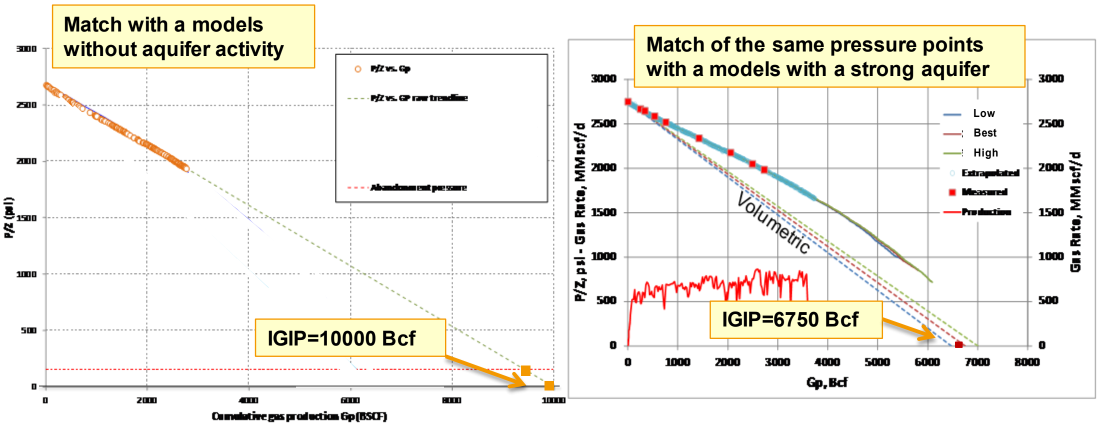


Figure 85: Match of the same pressure points without and with aquifer activity

Guideline n°51:

It is recommended to **always verify the consistency of the connected gas-in-place field estimate(s) derived from the material balance (early time/late time) with volumetric evaluations** based on field maps, well logs, fluid analyses...

If significant differences exist between volume-in-place estimates from the static and dynamic evaluation from early times then the assumption of a pure depletion drive model should be made with caution (at this stage of the field life).

By adopting the nomenclature of Havlena and Odeh:

- $F = G_p B_g + W_p B_w = Total\ gas\ and\ water\ production$
- $E_g = B_g - B_{gi} = underground\ gas\ expansion$

this reduces the equation to the simple form:

$$F = GE_g + W_e B_w$$

Finally by dividing both sides of the equation by E_g gives:

$$\boldsymbol{\frac{F}{E_g} = G + \frac{W_e B_w}{E_g}}$$

The equation can be written as below:

$$\boldsymbol{\frac{G_p B_g}{B_g - B_{gi}} = G + \frac{W_e - W_p B_w}{B_g - B_{gi}}}$$

Guideline n°52:

The Cole plot $\boldsymbol{\frac{G_p B_g}{B_g - B_{gi}}\ vs\ G_p}$ enables to:

- **evaluate the Connected Gas-In-Place** (value at $G_p = 0$), as W_e and W_p=0 at $G_p = 0$.
- **evaluate the aquifer activity**

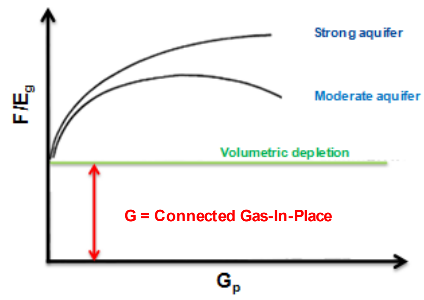


Figure 90: Diagnostic gas material plot to define the drive mechanism

Figure 86: Cole plot to identify the drive mechanism

- If the reservoir behaves as if under volumetric depletion then $W_e = 0$, and the values of $\frac{F}{E_g}$ plot as a straight line parallel to the abscissa and the ordinate value gives the connected gas-in-place G.

- If the reservoir is affected by natural water influx then the plot of $\frac{F}{E_g}$ produces a concave downward arc whose exact form is dependent upon the aquifer size and strength (and also of the gas off take rate).

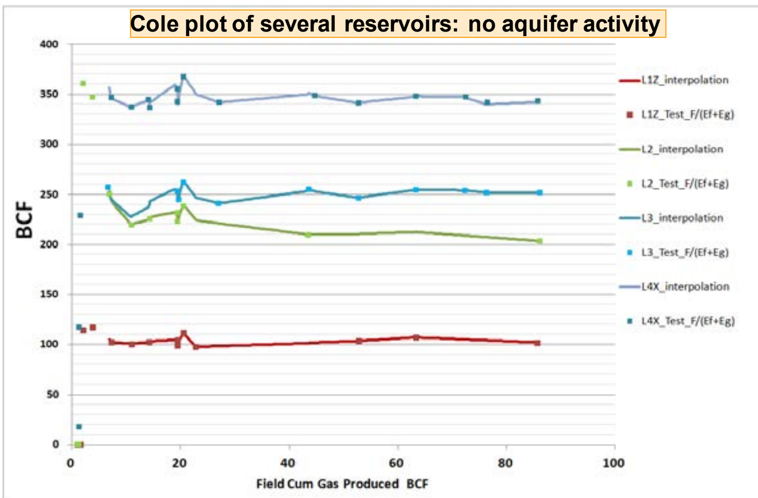


Figure 87: Examples of Cole plot for gas reservoirs without aquifer activity

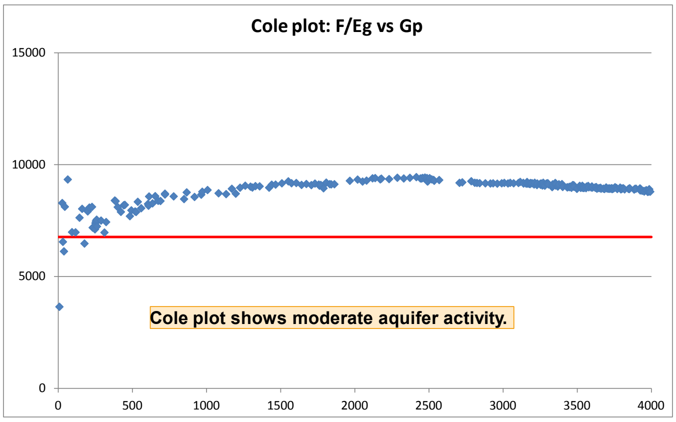


Figure 88: Examples of Cole plot for gas reservoirs with moderate aquifer activity

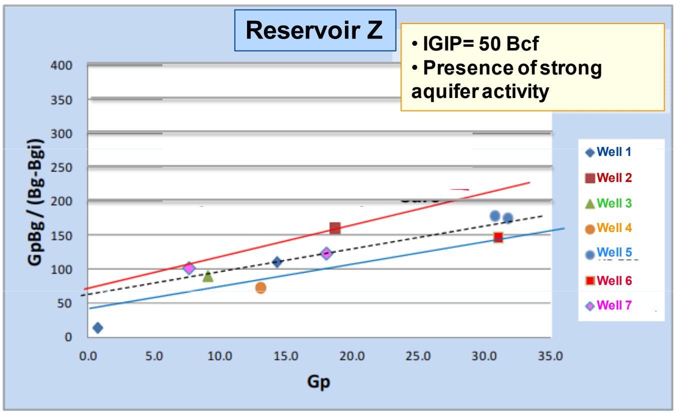


Figure 89: Examples of Cole plot for gas reservoirs with strong aquifer activity

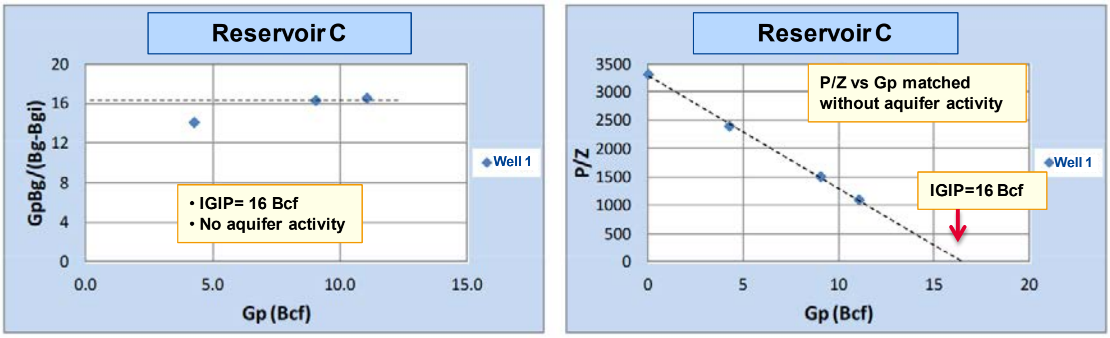


Figure 90: Consistency between Cole plot & P/Z vs Gp

Guideline n°53:

Once the occurrence of water influx is identified, the next step is to decide, with the advice of geophysicists and geologists, on the nature of the aquifer; shape, size and rock properties.

With these assumptions the water influx resulting from the observed pressure drop is calculated.

For an aquifer with dimensions of the same order of magnitude as the reservoir itself, the following simple model can be used:

$$W_e = c_t W \Delta P$$

where $c_t = c_w + c_f$: total aquifer compressibility

W: total water volume of the aquifer

ΔP: pressure drop at the reservoir aquifer boundary

Guideline n°54:

The match of the aquifer performance can be done with Havlena-Odeh plot (cf Figure 92)

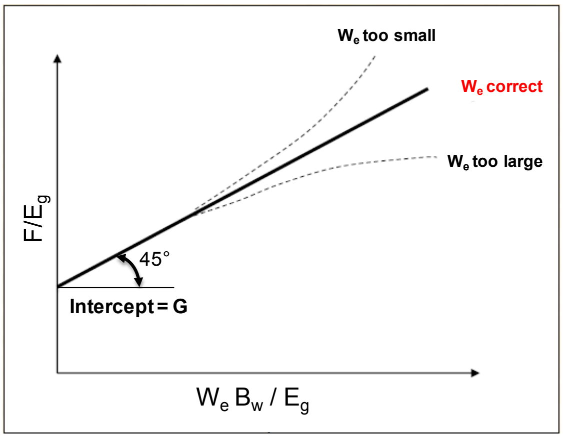


Figure 91: Application of Havlena-Odeh plot in history matching aquifer performance

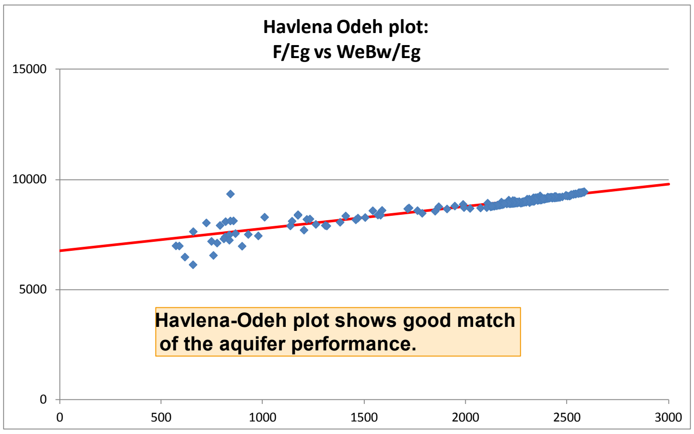


Figure 92: Match of the aquifer performance with the Havlena-Odeh plot

A correct aquifer model will simply provide a straight line of unit slope with an intercept on the ordinate indicating the connected gas-in-place (G). If the selected aquifer model is ill-fitting, the trend will deviate above or below this line dependent upon whether the aquifer is too weak or too strong in providing water.

Success in history matching means that the selected aquifer model can then be used in performance prediction **to determine the pressure decline as a function of the cumulative off take.**

15.5 Compartmentalized gas reservoirs

Other deviations from the straight line P/Z may also be due to partially sealing faults or delayed contribution of low permeability zones.

If the reservoir is compartmentalized or if there is a slow contribution from tighter areas, early P/Z performance is not representative as only after considerable depletion of the main producing areas gas efflux from tight areas or across compartment boundaries becomes visible resulting in an upwards bending of the P/Z plot.

Hower and Collins (reference [14]) presented the diagnostic techniques for detecting and quantifying poorly drained compartments in volumetric gas reservoirs.

Guideline n°55:

At early time the P/Z plot reflects the volume of the directly drained volume, while at late time the line curves over to a trend that reflects the total drained gas-in-place.(cf Figure 94)

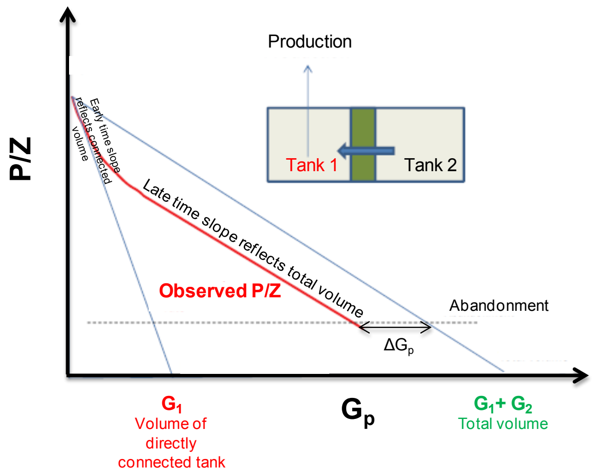


Figure 93: Idealized P/Z behaviour of a compartmentalized reservoir based on a two tank model

The two major assumptions in the formulation of this two-tank model were that the reservoirs were under volumetric control with no water drive and that the well was produced at constant rate.

Hower and Collins showed that the quantity of the unrecovered volumes (ΔG_p on the graph) not only depends on the relative size of the poorly drained compartment and on the parameters of the barrier but also on the production rate from the drained compartment. The greater the production rate, the greater the unrecovered volumes.

Guideline n°56:

Aquifer influx and compartmentalization are easily confused when P/Z plots are analysed separately due to the similarity of their respective signatures. Furthermore it should not be forgotten that both effects can be present at the same time (compartmentalization with aquifer influx).
The correct identification of the reservoir drive mechanism is therefore crucial and this requires a **full integration of all available data**, including seismic (faults presence), geology (facies variation) and production data.

Guideline n°57:

It is important to bear in mind that **the lack of water production is not proof that there is no water drive.**
Premature water breakthrough is in fact seldom observed in both edge water drive fields and developments with wells clustered at the crest of the structure. In such a case the true severity of the water influx will not be directly observable until the centrally located wells suddenly and simultaneously water-out.

15.6 Particular case of over pressured gas reservoirs

In typical reservoir conditions, gas compressibility is greater than the formation rock or residual fluids compressibility.

Abnormally pressured gas reservoirs are generally defined by an average fluid pressure gradient substantially higher than 0.65 psi/ft of depth (corresponding to EMW of 1.5 g/cc).

Guideline n°58:

For abnormally pressured gas reservoirs, the gas compressibility can be much lower and even in the same order of magnitude as the formation.

In this situation, the formation compressibility cannot be ignored since it acts to maintain the pressure at relatively high value.

Guideline n°59:

For abnormally pressured gas reservoirs, a P/Z plot will show for these two distinct slopes:

- The early slope exists during the period of abnormally high pressure (because of formation compaction, crystal expansion and water expansion in addition of gas expansion)
- the latter characterizes the reservoir when the pressure reaches the normal value.

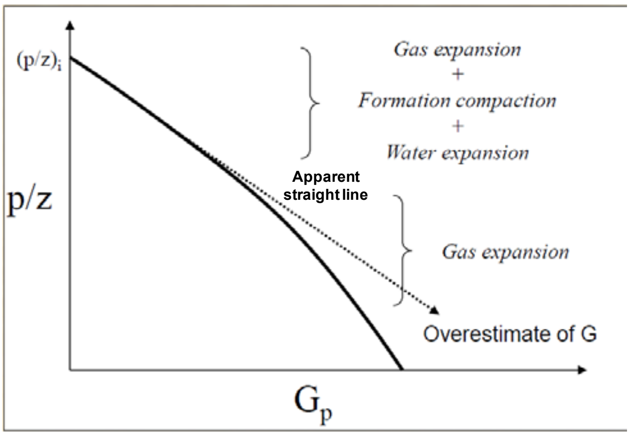


Figure 94: Typical P/Z plot for over pressured gas reservoirs

Guideline n°60:

For abnormally pressured gas reservoirs, **extrapolation of the early slope would result in an optimistic value of the gas-in-place.** In this sense it is similar to the P/Z plot when water influx is present as discussed earlier.

If the second straight line is adequately defined, it may be extrapolated to obtain an estimate of the connected gas-in-place.

If only the first slope is defined, the evaluator should not extrapolate the P/Z to evaluate the IGIP. The material balance equation with all the compressibility terms should be used instead.

15.7 Prediction of future gas performance

The material balance techniques described previously allow the evolution of reservoir to be evaluated as a function cumulative production and in consideration of the production mechanism at play.

Guideline n°61:

The next step of the work is to construct well model(s) (typically with Prosper software) and to match the operating points of each well at the end of the history.

For gas reservoirs with water drive, the challenge is to predict the time of the water breakthrough, which is the event generally causing quickly the loss of the well.

If water arrival has already been observed on certain wells, the time of breakthrough at the remaining wells can be estimated by correlation of the distance or stand-off of the perforated intervals from the initial water contact.

If however the wells are located in a crestal position in the field and have not yet experienced any breakthrough, reference to analogy, 4D seismic interpretation or phenomenological studies is needed. In this instance time to breakthrough remains a critical uncertainty which should be reflected in the forecasts (low estimate, best estimate, high estimate) range.

16. Gas material balance examples

16.1 Example of a gas field with volumetric depletion

This gas field is composed of two reservoirs (A & B) as shown on the adjacent log.

The field development comprises a well head platform with one slanted well (P-1V) and 2 horizontal wells (P-2H & P-3H, 400m drains) located at the top of the structure.

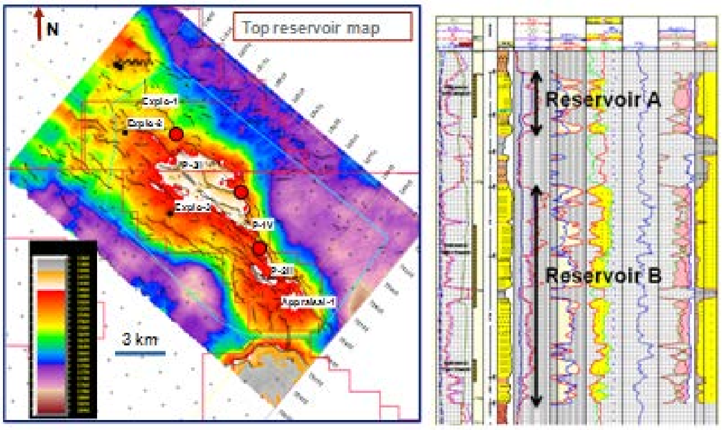


Figure 95: Top reservoir map & well logs

The horizontal wells (targeting reservoir A) were completed with OHGP (Open-Hole Gravel-Pack) in order to control sand production and 9 5/8" tubing to assure high productivity. Both wells are equipped with down-hole permanent gauges.

The slanted well was completed with a 7" tubing, a high water rate gravel pack and a selective completion that allows independent access to reservoirs A and B. Both reservoirs can be isolated (with plug) and the static reservoir pressure can be measured independently (no permanent DH gauges are installed). Due to the selective completion, the majority of historical pressure monitoring has been performed in this well.

The time-pressure graph below shows the good communication between reservoirs A & B through faults (pressure difference of only a few bars). Moreover the measurements made in P-2H and P-3H do not highlight any significant pressure gradients at the field scale (7 km inter-well distance).

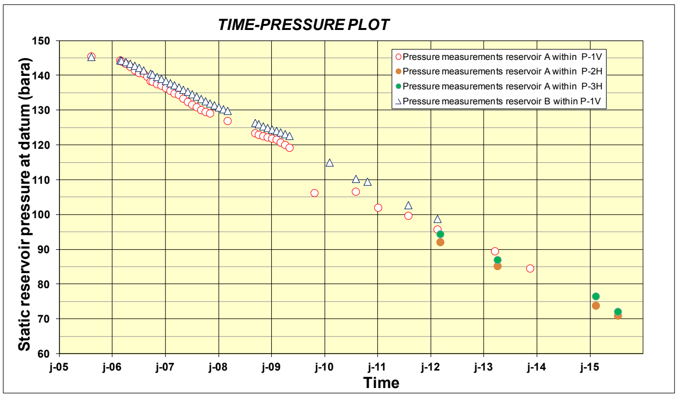


Figure 96: Wells pressure vs time

Analysis of the P/Z exhibits a reasonable linear regression regardless of which reservoir is considered with both trends extrapolating to a gas-in-place volume of about 35 Gsm3 (see Figure 98).

This estimate is more or less in line with the volumetric evaluation of reservoirs A+B (32 Gsm^3 calculated in 2P, 35 Gsm^3 being close to the high estimate figure).

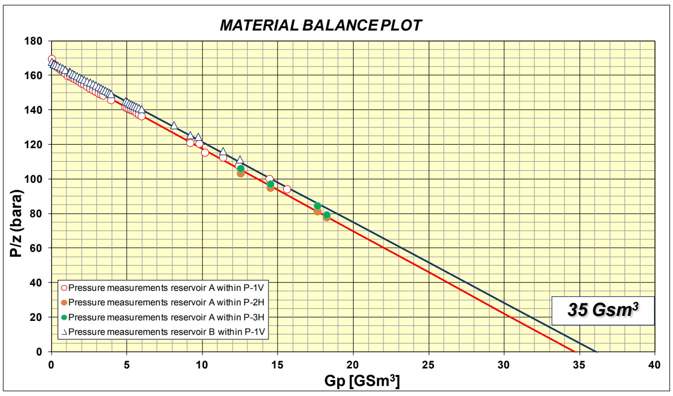


Figure 97: P/Z vs Gp plot

This example therefore approaches the ideal volumetric depletion case, even if the presence of a weak edge aquifer cannot be totally excluded (some water being presently produced by P-1V).

16.2 Example of a gas field with water influx

This field is a shallow miocene carbonate platform with a gas column of 124 m. The reservoir properties are very good: porosity around 28%, permeability between 70-1300 mD. The 4 way dip closure does not show indications of faults.

Gas production started on May 31st 1998 and the pool is currently produced from two platforms by 13 horizontal producers (1000 m reservoir section, 7" tubing). A water disposal well and a well devoted to the observation of the GWC rise complete the development pattern. The wells are not equipped with down hole pressure gauges.

The wells are spread out over the whole structure as shown on the adjacent map.

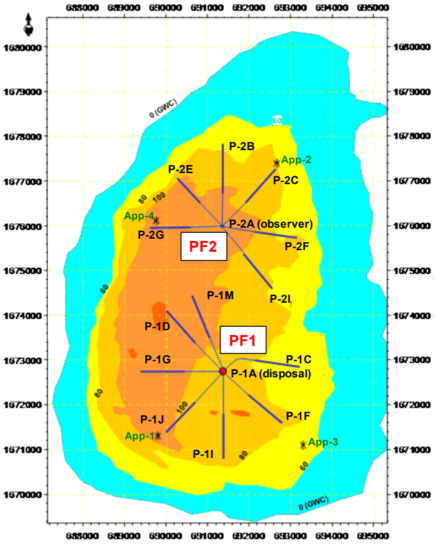


Figure 98: Gas field produced with 2 platforms & wells in star pattern

A few static pressure acquisitions are available that enable the validation of the extrapolated bottom hole data from well head measurements. The pressure data do not reveal significant gradients over the field, which justifies the use of P/Z techniques for the analysis of the field performance (see Figure 100)

The resulting P/Z plots are shown in Figure 100.

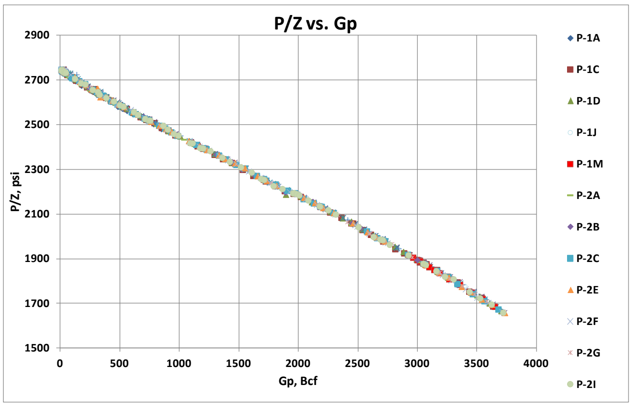


Figure 99: P/Z vs Gp plot

Cole plot enables to highlight a moderate aquifer activity (see Figure 101)

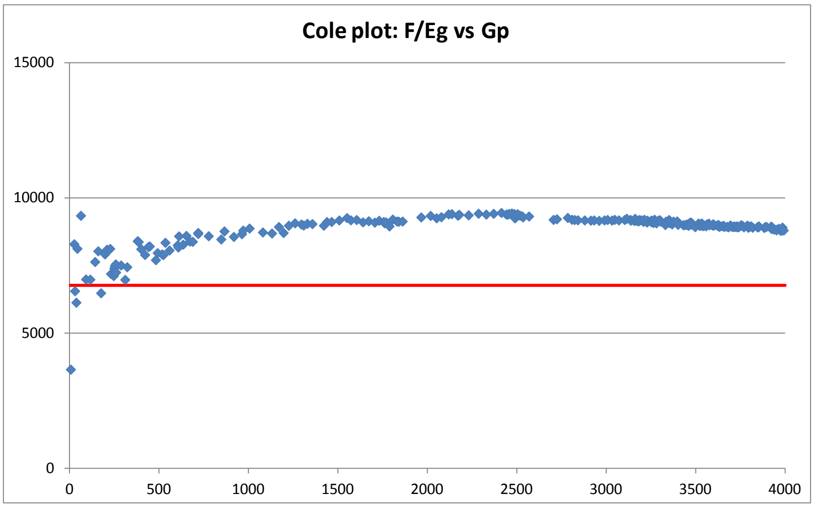


Figure 100: Cole plot showing moderate aquifer activity

The extrapolation of the very early time data of P/Z vs Gp results in IGIP of:

- Low estimate (bleu curve): 6.48 Tcf
- Best estimate (green curve): 6.75 tcf
- High estimate (red curve): 7.0 Tcf

These volumes are in line with the static evaluation (6.7 Tcf certified for the low estimate value in 1993).

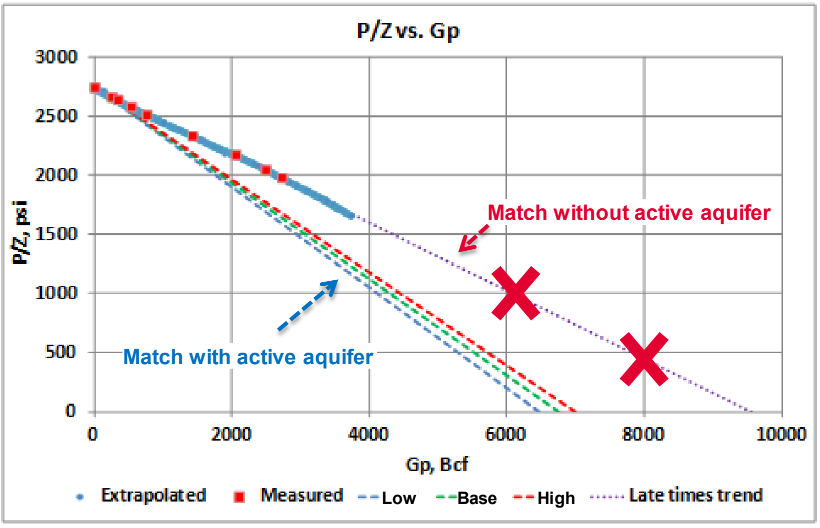


Figure 101: Matches of P/Z vs Gp for the low, base and high estimate

The late time data however exhibits a clear deviation to the linear trend defined from the very early time, which indicates the arrival of energy support through time.

The trend derived from the late time corresponds to an IGIP as big as 9.55 Tcf, which is not consistent with the moderate aquifer activity demonstrated with the Cole plot.

The interpretation of pressure support from the P/Z graph is indeed coherent with evidence of **an active aquifer** on the eastern side of the field (eastern development wells show a rise of the GWC).

The match of the aquifer performance can be done with Havlena-Odeh plot (see Figure 103**)**

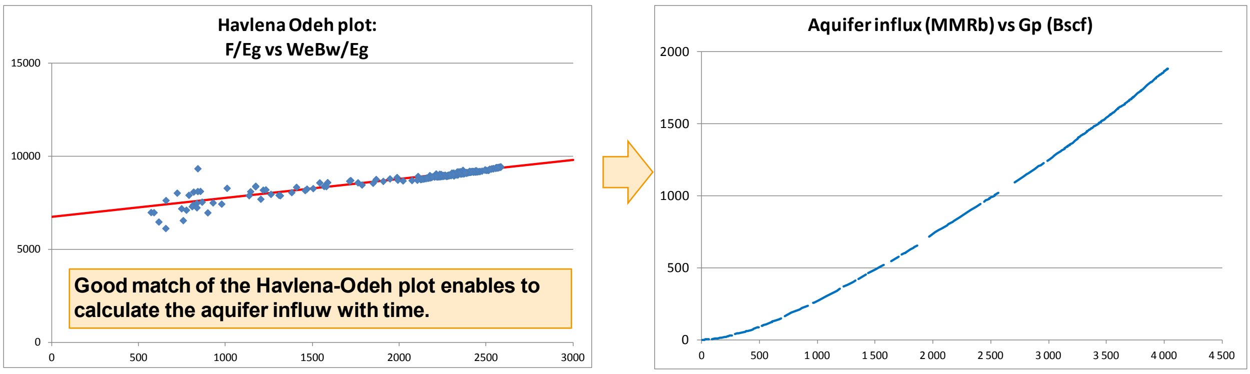


Figure 102: Havlena Odeh plot: match of the aquifer performance & water entry

The rise of the water contact is in fact not homogeneous (higher on east than west) as shown by the 4D seismic acquired in 2012. Moreover water breakthrough has already been experienced on the deepest producer of the structure (P-2F)

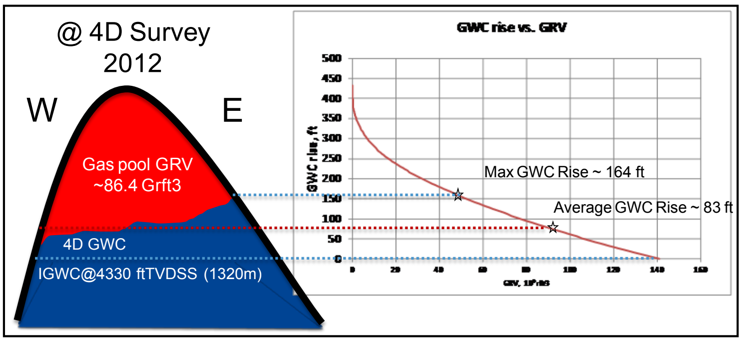


Figure 103: 4D seismic information

In reality the low, base & high estimate profiles are derived from a MBAL/Prosper/Gap model integrating the IGIP range derived from the P/Z early times trends with a reasonable range of parameters with which to describe an active aquifer (see adjacent table).

A water breakthrough sequence based on the 4D interpretation is furthermore accounted for in order to constrain the end of life of the producers.

	1P	2P	3P
IGIP	**6475 Bcf**	**6750 Bcf**	**7000 Bcf**
Aquifer Model	**Fetkovich Radial 180°**	**Fetkovich Radial 112°**	**Fetkovich Radial 112°**
Ri	**16 392 ft**	**16 392 ft**	**16 392 ft**
Re/Ri	**4.6**	**3.8**	**3.5**
K	**200 mD**	**200 mD**	**200 mD**

Figure 104: Low, base & high estimate assumptions for the MBAL/PROSPER/GAP models

16.3 Example of a compartmentalized gas field with late gas effect

This gas field was discovered in 2002 by an exploration well that was tested and then suspended.

The gas accumulation is located in Jurassic sandstones (porosity 20-25%).

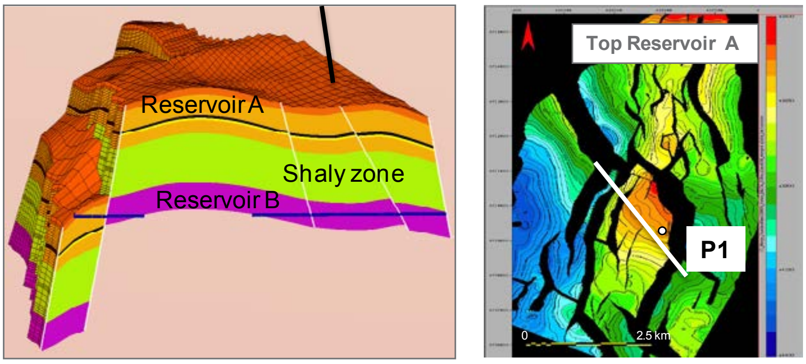


Figure 105: Top reservoir map & 3D modeling

The sequence is composed of two formations (reservoirs A & B) separated by a shaley zone (see Figure 107)

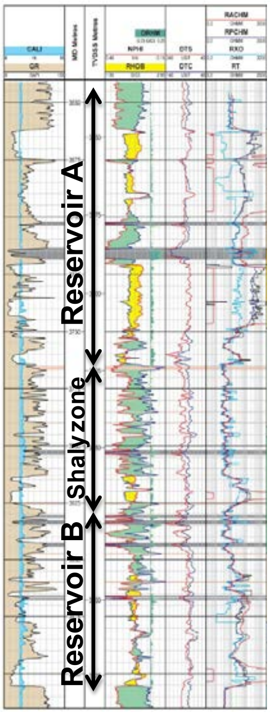


Figure 106: Exploration well logs

In 2005, the exploration well was re-entered, completed and perforated over reservoir A only. The resulting producer (P1) was tested through the completion and a PLT and RPM (cased-hole saturation log) run.

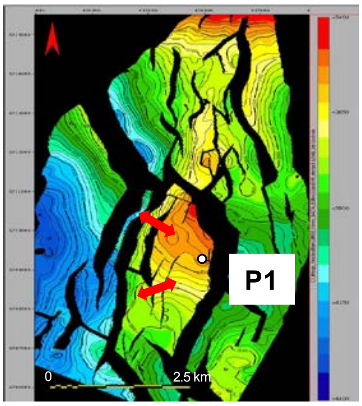


Figure 107: P1 well location

Production started in December 2005. The subsea producer was fitted with wellhead pressure transmitters and a down-hole permanent gauge.

The well head pressure measurements turned out to be unreliable from the beginning and the down-hole gauge failed in 2008.

A first PLT was acquired in March 2010.

Subsea manifold gauges were replaced in 2011 leading to the availability of more reliable WHP estimates.

A new PLT was acquired in October 2014 coupled with a RPM logging.

All available pressure measurements (of variable quality) are displayed on the adjacent P/Z plot (see Figure 109)

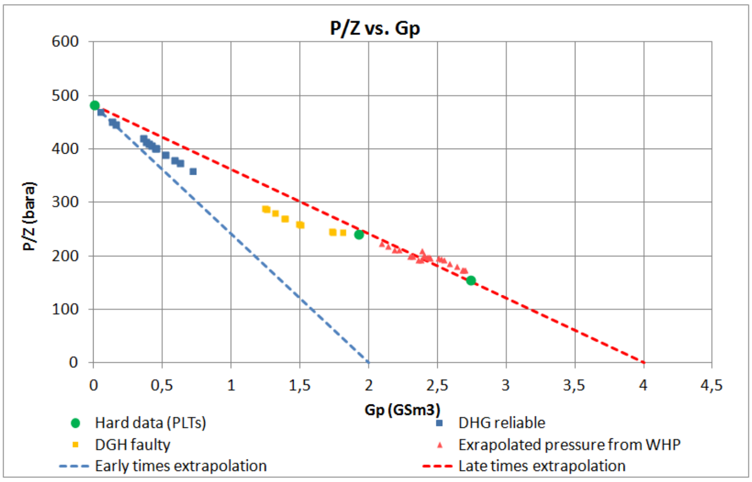


Figure 108: P/Z vs Gp plot

The early historical data suggest a connected volume of about 2 Gsm^3 (blue dotted line), consistent with the 2P IGIP evaluation of the developed compartment.

After several years of production, the cumulative produced gas is close to the IGIP of the developed panel and a deviation is observed on the P/Z plot. **The red dotted line extrapolated to zero pressure suggests a GIP of 4 GSm^3.**

This additional support could be due to:

- The effect of an active aquifer. This is not however considered a likely explanation based upon regional knowledge of the pressure support from connected aquifers.
- The contribution of the gas accumulation within reservoir B. This hypothesis was considered until the RPM logging acquired in 2014 concluded that reservoir B was un-depleted.
- The expansion of gas held in the western panels. The seismic interpretation does show possible pathways between those compartments and the developed panel. Furthermore the geological evaluation of the western compartments provides IGIP estimation consistent with the extra volume derived from the P/Z plot.

Consequently the delayed contribution from the western compartments is the hypothesis currently prevailing and the deviation observed at late times is used for the production forecasts of this gas field.

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Appendix 1 Reminder of the most common decline laws and of their field of application

1 - Definitions and relationships

Arps introduced in the 1940's the concept of production decline to reproduce the observed behaviour of approximately 149 fields onshore US. He proposed a generic analytical model, based on 4 parameters, namely:

- q = rate (oil or gas) [volume.time^{-1}]
    - q_i = initial rate
    - q(t) = rate at time t
- t = time [time]
- b = decline exponent [dimensionless]
- D_i = nominal (or instantaneous) initial decline rate [time^{-1}]

$$\boxed{q(t) = q_i.(1 + bD_i t)^{-\frac{1}{b}}}$$

These empirical relationships of rate versus time distinguished for oil wells three types of decline, depending on the b exponent value:

- b = 0 exponential decline
- 0 < b < 1 hyperbolic decline
- b = 1 harmonic decline

The hyperbolic decline equation is the universal equation and the harmonic and exponential equations are special (extreme) cases of the hyperbolic law. The decline exponent b characterises the evolution of the decline D = - (dq/dt)/q over time.

A b exponent of 0 means that the decline rate is constant (e.g. 5% per year) and the production is said to follow an exponential decline whereas a higher value of b means that there will be less and less decline as time and cumulative production increase and the decline is called hyperbolic. Harmonic decline is a special case of hyperbolic decline with b = 1, the decline rate (D) being proportional to q.

Arps analyzed 149 oil fields' production data to determine the distribution of exponent b. He found that the range of b was between 0 and 0.7 with 91% having b less than 0.5. **No harmonic declines were found** and 12% had a b value less than 0.1 (details on Figure 114).

Decline curves represent production from reservoirs under pseudo-steady-state (boundary dominated flow) conditions. This means that during the early life of a well while it is still in transient flow and the reservoir boundaries have not been reached, **decline curves are not applicable**.

It has to be noted b values above 1 lead to infinite cumulative production when t tends to infinity which is not physical. Cases with b > 1 (super-harmonic decline) can however exist. Unconventional reservoirs typical display decline curves characterized by these high b exponents during the early production periods (for low permeability or tight reservoirs, transient flow conditions can last several years).

The graph here below illustrates the three decline categories:

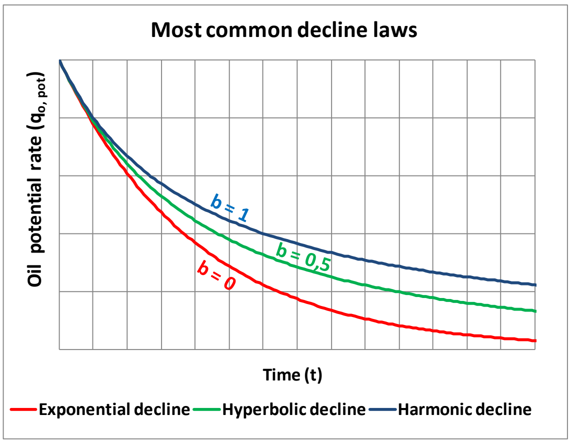

Figure 109: Representation of Arps' declines - Qo vs. time

The table here below shows the various mathematical expressions of the declines depending on the main parameters (N_p being the cumulative production):

	Exponential	Hyperbolic	Harmonic
b	b=0	0<b<1	b=1
D (q)	D_i	$D_i.(q/qi)^b$	$D_i.(q/qi)$
q (t)	$q_i.e^{-D_i.t}$	$q_i.(1 + b.D_i.t)^{-1/b}$	$q_i /(1 + D_i.t)$
N_p (q)	$(q_i-q) / D_i$	$[q_i/((1-b).D_i)]. [1-(q/q_i)^{1-b}]$	$(q_i/D_i). \ln(q_i/q)$
q (N_p)	$q_i - (D_i.N_p)$	$q_i^{\ b/(b-1)} . [q_i - (1-b).Di.N_p]^{\ 1/(1-b)}$	$q_i . e^{-(D_i.N_p)/q_i}$
N_p (t)	$(q_i/D_i).(1 - e^{-D_i t})$	$[q_i/((1-b).D_i)]. [1 - (1+ b.D_i.t)^{1-(1/b)}]$	$(q_i/D_i). \ln(1+ D_i.t)$

Table4: Summary of production decline equations

2 - Decline identification by graphical representations

Decline curve analysis is usually conducted graphically. In order to help in the interpretation the variables are plotted in various combinations of rate, log-rate, time, log-time, cumulative production, log-cumulative production... The intent is to find the combination that will result in a straight line that is easy to extrapolate to a forecast period.

The first plots to test are the log of production rate (preferably potential rate) vs. time and the rate (potential rate) vs. the cumulative production. Under ideal conditions both exhibit straight line relationships for exponential decline. The slope of the lines enables the decline rate (- D_i) to be determined. However in case of intermittent flow conditions the log-rate vs. time graph may give a misleading decline rate. Therefore emphasis should be given to the rate vs. cumulative production graph in preference to the log-rate vs. time plot.

Appendix 1

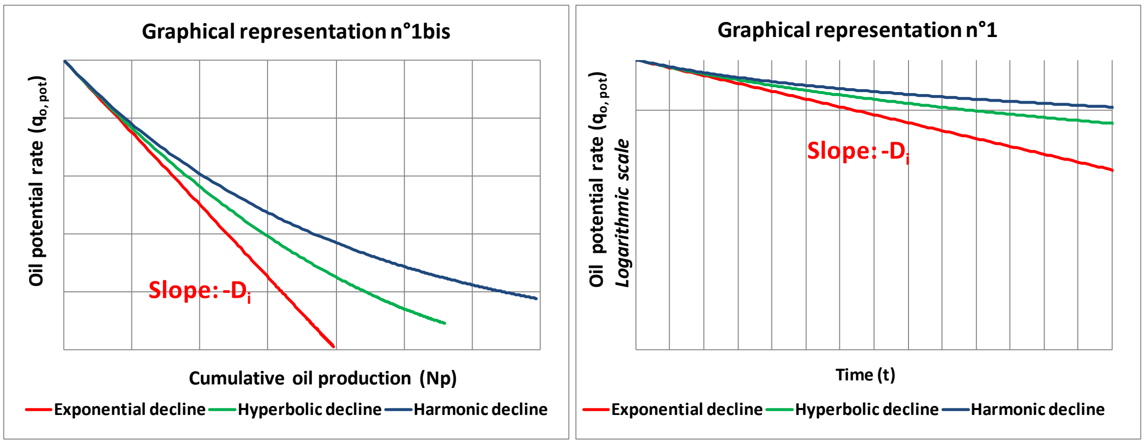

Figure 110: Identification of exponential decline

Exponential decline is the easiest to recognize and the simplest to use when compared to the other decline curves (hyperbolic or harmonic). It therefore tends to be the most commonly used of all decline curves. The reader however should bear in mind that this type of decline may be conservative and leads to an under estimation of future production.

The second plot to test is the log of production rate (preferably potential rate) vs. the cumulative production. This graph exhibits a straight line for harmonic decline. The slope of the line enables to determine the ratio - D_i/q_i.

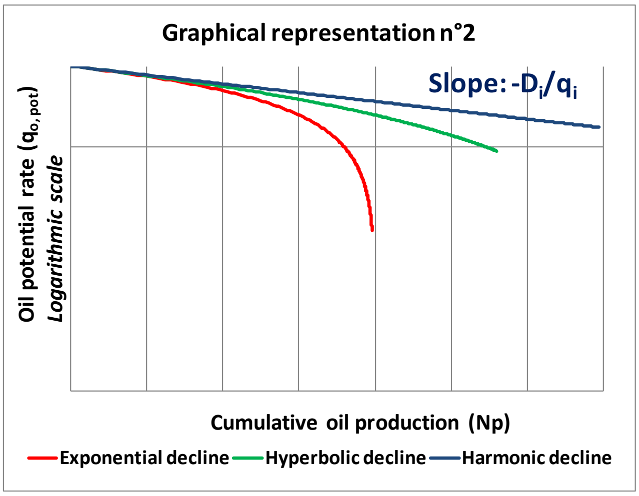

Figure 111: Identification of harmonic decline

The harmonic decline curve tends to over predict the well (or reservoir) future performance.

The challenge with the equation of the hyperbolic decline is to determine simultaneously the three parameters q_i, D_i and b. Hyperbolic decline does not plot as a linear relationship on a Cartesian grid. Plotting rate vs. time or rate vs. cumulative production on semi-log scale does not straighten the hyperbolic decline curve either.

Conventional hyperbolic decline curve analysis was a tedious process (mainly a trial-and-error approach) and this lack of linearity was the main reason for the restricted use of hyperbolic declines prior to the widespread use of personal computers and commercial software.

The verification of the parameters q_i, D_i and b can be performed a posteriori with the following graphical representation:

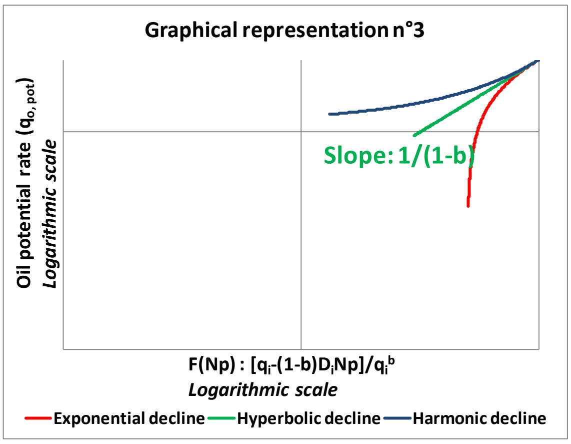

Figure 112: Verification of hyperbolic decline parameters

Extrapolation of hyperbolic declines over long periods of time may result in overestimated EUR (Estimated Utlimate Recovery). To avoid this problem the hyperbolic decline may be converted into an exponential decline at a certain point of time (modified hyperbolic decline).

3 - Field of application of Arps' laws and diagnostic guidance

The generic Arps model was initially empirical.

Figure 114 below provides the distribution of the b exponent published by Arps in 1945 based on the performance analysis of 149 US oil fields:

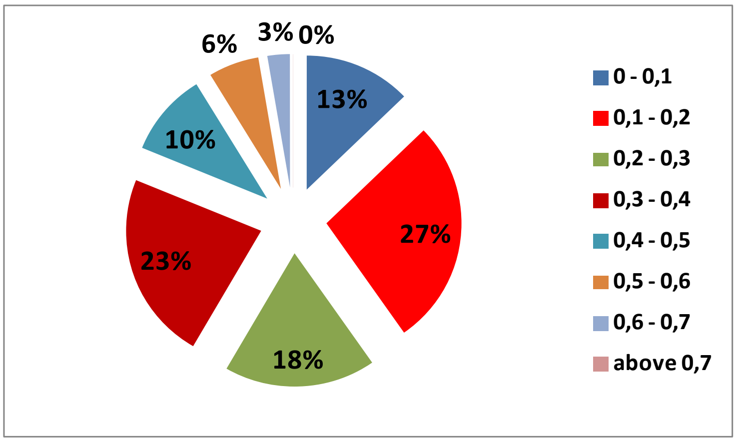

Figure 113: Distribution of b exponent according to Arps' works

Ambastha and Wong examined in 1995 (reference [21]) 78 water flooded oil pools located in the Western Canadian sedimentary basin and concluded that most of those reservoirs followed a hyperbolic decline trend with a b decline exponent of less than 0.5. An arithmetic average b value of 0.29 was obtained based on this analysis.

Baker et al (reference [25]) performed more recently the same kind of analysis for 21 Alberta water flooded reservoirs.

The results of their investigations are summarized in the Figure 115 below:

Appendix 1

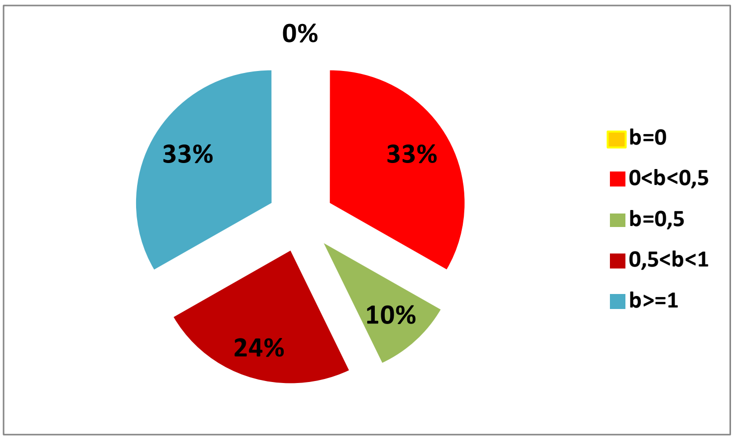

Figure 114: Distribution of b exponent resulting from the works of Baker et al (water flooded reservoirs)

For those reservoirs under water injection, the mean value of the b exponent was found to be 0.68.

For this specific production mechanism, exponential behaviour (b = 0) was not found while 33% of the selected pools revealed harmonic or super-harmonic declines (b ≥ 1), contrary to Arps' observations.

Fetkovich et al mention in reference [17], an unpublished study of water flooded , West Texas fields, values of b ranging from 0 (exponential) to 0.9 (nearly harmonic), therefore not confirming the occurrence of the super-harmonic declines found on the Canadian fields.

In any case, it can be concluded from all those field cases analyses that the hyperbolic trend turns out to be the most common decline.

The table provided hereafter captures the results of many of the investigations, observations and practical experience published in the literature, and should be used as guidance rather than as a rule toassist the reader in narrowing down the typical decline parameters (e.g. b exponent) that might be expected for a given type of reservoir.

The final value of the b exponent that is retained always needs to fit the actual data and should never be imposed based only on the indicative figures shown in this table (Table 5).

Drive mechanism / Reservoir	Type of decline	b exponent
Highly undersaturated oil reservoirs (production above bubble pressure) Solution gas drive with unfavorable k_g/k_o Poor waterflood performance Tubing limited wells (both oil and gas flowing wells) Wells with high back pressure High pressure gas wells Gas wells undergoing liquid loading	Exponential	0
Solution gas drive	Hyperbolic	0.3
Gas wells	"	0.4 - 0.5
Gravity drainage Water drive in oil reservoirs	"	0.5
Stratified reservoirs with permeability contrast	"	0.7 - 0.8
Oil reservoirs under very efficient waterflood	Harmonic	1
Low permeability, fractured, very heterogeneous and unconventional plays with long transient periods	Super-harmonic	> 1

Table5: Indicative decline parameters for various drive mechanisms

Extreme care should be exercised if a b exponent > 1 is required to obtain a best fit of the initial production period. Even if it has been documented in the literature that this type of decline may occur for certain waterflooded , multilayered reservoirs, it may also indicate the existence of transient conditions. It is therefore not recommended to use b exponents > 1 to extrapolate historical short term trends into long term forecasts.

Exponential decline tends to be widely used because it is simpler to implement. However this type of decline is the most conservative decline and may lead to an under estimation of future production if another type of decline actually applies.

In order to avoid any bias when interpreting data, **a hyperbolic decline should systematically be the starting point** when curve fitting the representative historical performance period, as this approach provides more flexibility by varying b factor during the matching process (without excluding the possibility to end up with b = 0 or b = 1 if actual data tend to substantiate such value).

This curve fitting process should first focus on the analysis of the oldest wells (or group of wells) in the reservoir/field, to establish whether hyperbolic decline has ever been established, so that they can be used as analogues for wells with shorter production history.

In many cases DCA is used to represent a specific well (or group of wells) behaviour even if it does not correspond to an analytical solution of a complex system of equations.

4 - Other correlations

Arps' basic equations commonly apply to reservoirs with declining pressure.

Reservoirs where an increasing volume of produced water or gas (or both) takes place with time can use fluid ratio performance plots that have been derived during the last decades. When dealing with these systems that exhibit multiphase flow (e.g. oil + water, oil + free gas), DCA uses relationships of production data (WOR, oil cut, water cut, GOR plots, others) vs. cumulative production. These approaches, which are described below, are used to better capture the evolution of the wells (or group of wells) future performance. This type of DCA is generally split into 2 elements:

- gross rate
- relevant ratio (e.g. water cut, oil cut, GOR, etc.),

rather than working directly on the evolution of the oil rate with time or cumulative production.

As a matter of fact, no general method can be found in the literature to model the expected evolution of a given fluid ratio. Numerous attempts to find a graphical representation exhibiting meaningful trends i.e. a straight line in are described in various technical papers, with the most relevant ones described below.

4.1 - Oil + Water System

In water drive or waterflood reservoirs the most commonly used diagnostic plots for DCA are described below.

Some requirements are normally needed for the application of these relationships to yield meaningful results i.e. straight line correlations, namely:

- Water cut above 50%
- Voidage replacement close to 100%
- Constant number of wells (if relationship applied to a group of wells/reservoir)
- Injection and fluid production rates relatively constant
- Reservoir pressure and flowing well pressures about constant
- Constant Gas Oil Ratio
- Volume of water injected greater than 25% of the hydrocarbon pore volume.

However these requirements are only guidance as in some cases clear trends can be obtained even if some of these requirements are not present.

Various papers have attempted to find the best plot of oil-cut or water cut to get a linear representation of the flow, but there are quite as many solutions as papers on this subject.

Log f_o vs. N_p: The plot of log oil cut (fractional flow of oil or f_o) vs. oil cumulative production or N_p can be used when water breakthrough has already occurred. Nevertheless, it corresponds to harmonic decline of the rate and will lead to forecasts more optimistic.

This simple diagnostic plot generally shows the development of a straight line, reflecting **harmonic decline,** after reaching certain levels of water cut (low f_o values). This trend can be extrapolated at well level to the technical or economic cut-off (whatever occurs first) before aggregation to reservoir or field level.

However, it is highlighted that as f_o approaches low values, the plot of log f_o vs. N_p may turn downwards departing from the exhibited linear trend. This downturn from the straight line occurs earlier for light oils (with favorable mobility ratios) compared to viscous oils (with unfavorable mobility ratios). Therefore, care should be exercised when extrapolating a linear trend (i.e. harmonic decline) of log f_o vs. N_p to very low oil cuts. In some cases, and as the oil fraction reaches low levels, the trend may also change into a linear trend on a Cartesian plot of f_o vs. N_p (i.e. exponential decline).

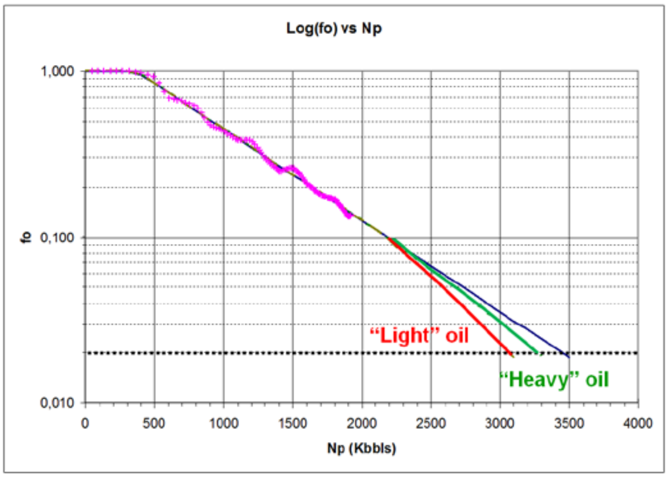

Figure 115: possible change of slope for low f_o

Alternative plots:

The plot of **log (WOR) vs. N_p** results in a linear trend for harmonic decline.

It has been demonstrated to provide more reliable results at lower water cuts.

A variation of the WOR plot is a plot of **log (WOR +1) vs. N_p** which may depict a linear trend at f_w < 0.5 (or WOR < 1.0). This correlation may therefore help define trends for low values of WOR or water cuts.

The plot $\left[\frac{1}{f_w} - \ln\left(\frac{1}{f_w} - 1\right)\right] \quad vs \quad N_p$, known as the Ershaghi x-plot, is a combination of the fractional flow equation and Buckley-Leverett displacement concepts. Under certain conditions (absence of layering effects and remedial profile corrections), plotting this data yields a linear trend (for f_w > 0.5). The formation of a straight line indicates that the performance is controlled by the relative-permeability-ratio characteristics of the reservoir.

The relationship $\frac{N_p}{W_p + N_p} \quad vs \quad N_p$ is a simple plot of cumulative oil fractional flow vs. cumulative oil production and has been reported to yield linear trends with results aligned with production forecasts using simulation in a North Sea field.

Other extrapolation methods are reported in the literature, such as:

- log (f_w) vs. N_p

- $1/f_w$ vs. N_p
- log (WOR) vs. log t
- log (WOR_c) vs. N_p (WOR_c: cumulative WOR)
- log (f_{wc}) versus N_p (f_{wc}: cumulative f_w)
- log (WOR) vs (N_p+W_p)

The recommendation is to try to find the best linearity on either water cut or oil-cut vs. cumulative oil production and to combine with any liquid decline (oil or liquid) to get the water forecast.

In the absence of water breakthrough water-oil contact monitoring or additional studies (e.g. representative analogue) can be used to estimate breakthrough time and analogue wells can be used to establish type water cut or type oil-cut trends.

The existence of shale breaks and high permeability contrasts between completed layers may lead to several water breakthroughs occurring at different times in the different layers and result in a step wise evolution of the water cut.

Special care should be taken in the case of waterflooding where the water cut trend might strongly depend on water injection rate and distribution changes. In waterdrive reservoirs water production may also be sensitive to production rates (e.g. some fractured reservoirs), where the “choking” of a well may result in a reduction in the water cut resulting in trend change.

4.2 - Oil + Gas Systems

Associated gas forecasts are much more difficult to estimate unless production conditions remain above saturation pressure meaning that the predicted Gas Oil Ratio (GOR) should be constant and equal to R_s.

For wells producing below saturation pressure, it is very difficult to predict GOR evolution with empirical laws and any linearity found by graphical approaches has to be checked carefully.

In most cases, to get the best estimate of the forecast gas rate, a reservoir engineer should use his/her understanding of the reservoir behaviour derived from reservoir monitoring and other analysis, in particular from the GOC movement follow-up using material balance, simulation, analytical or analogue techniques.

A key element is the well technical cut off for which water or gas effects, backpressure issues or liquid loading may play a role. Liquid loading issues are critical when analyzing performance trends in gas wells. Proper consideration should be given to planned actions such as the installation of velocity strings or foam jobs to prolong well flowing life to properly establish the well future production performance.

In spite of the above, the following plots can be attempted in order to highlight linear relationship between oil and gas below saturation pressure:

- **GOR vs. N_p**
- **log GOR vs. N_p**
- **log G_p** (cumulative gas production) **vs. log N_p** (cumulative oil production)

If an oil forecast has been established, the GOR trend can be combined with the oil forecast to estimate the gas rate forecast. Special attention should however be paid to the reliability of this approach for very high values of GOR.