Final version 14 March 2007 for Petroleum Africa

What's Wrong with Reserves?

by Jean Laherrere jean.laherrere@wanadoo.fr

The publishing of data is a political act, one depending largely upon the image the author would like to portray i.e. rich in front of the banker, the shareholder, or alongside quotas; poor in face of taxes. Most debates argue over words that are not clearly defined (as oil or reserves) and which are distinct from their authors, resulting in often useless discussions.

Wording ambiguities

Gas means gasoline for some, but natural gas for others. M means thousand for the US industry (outside computers) but million (= mega) in metric countries. Billion is thousand millions in the US, but million millions (square million) in Europe. Webster's definition for billion is a very large number, which is not very precise!

Reserves Definitions

There are currently several reserve definitions in use:

- **US:** all energy companies listed on the US stock market are obliged by the SEC to report only proved reserves (**1P**), assumed to be the **minimum;** these reserves are audited.
- **OPEC:** because quotas depend upon reserves, OPEC members report proved reserves (**1P**), which is their wish being non-audited.
- **FSU classification**: ABC1 (1979) reports **maximum** theoretical recovery, being equal to proven plus probable plus possible (**3P**).
- **Rest of the world:** SPE/WPC (1997) regulations (I was a member of the task force) report reserves as proven plus probable (**2P**), close to the **expected value**.

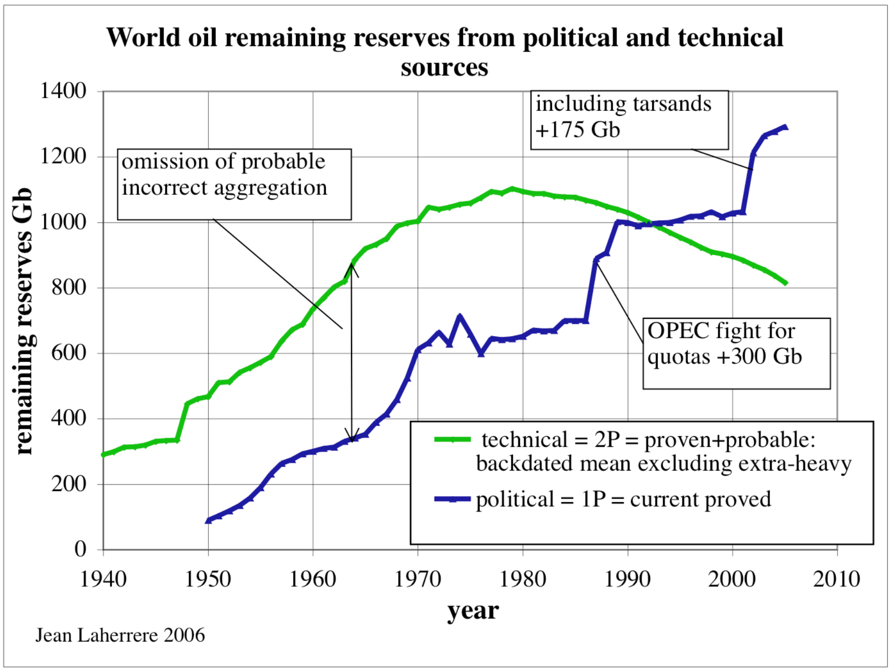
Proved reserves (1P) tell bankers that the company will not be bankrupt, but development decisions are taken on mean reserves (2P). The aggregation of proved reserves is incorrect, as it underestimates the total. Thus, national proved reserves are more than the addition of field proved reserves, and therefore world proved reserves are more than the addition of all national proved estimates.

SPE 2007 definitions show how misleading simple addition can be as only mean (proven plus probable) data should be added. Perceived reserve growth occurs when reserves are initially reported at the *minimum* (proved) and then simply added, which does not happen statistically when reported as proven plus probable, which is already the *mean (expected) value*.

Proven plus probable reserves estimates are confidential in all countries except the UK (DTI), Norway (NPD), and federal US (MMS). In Russia, divulging oil (but not gas) reserves can be punished by 7 years jail!
Scout companies sell reserve databases but they are very expensive, dealing with huge quantities of data (about 24 000 fields outside the US and Canada non-frontier provinces).

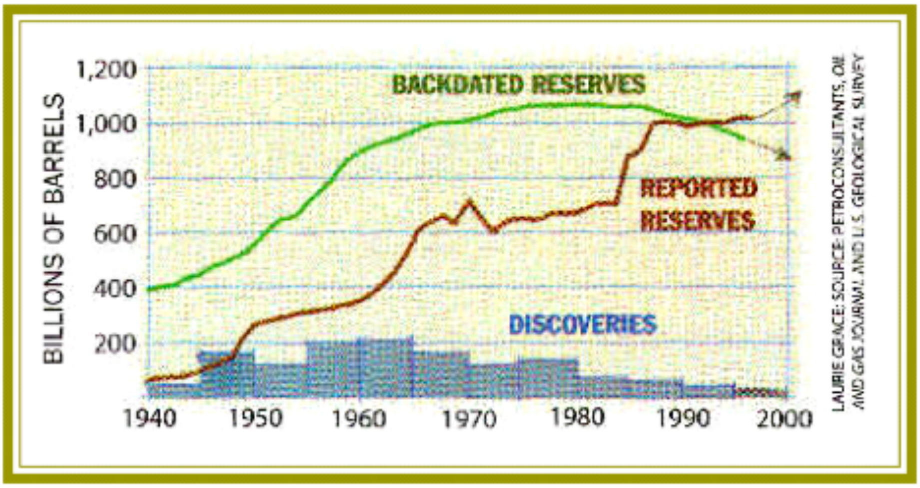
My main graph displays the technical (backdated mean) and the political (current proved) remaining reserves at the end of 2005.

Figure 1: World oil remaining reserves from political and technical sources



The same graph was presented eight years earlier in the *Scientific American*, March 1998, Campbell and Laherrere, "The end of cheap oil."

Figure 2: same graph presented in 1998 in Scientific American



The 2006 graph is identical to the 1998 one, showing that ASPO (The Association for the Study of Peak Oil) does not change as often as some say.

Proven reserves are only financial data and should never been used for forecasting future production.

Unfortunately technical (2P) data are not usually published (except in the UK (DTI), Norway (NPD), and US federal (MMS)), but they can be bought by scout companies such as IHS or Wood Mackenzie, so it is wrong to say that they are confidential; they are only expensive and anyone can buy them.

US DOE/EIA proved reserves as end of 2005; posted October 5, 2006:
US federal agencies are obliged since 1993 to use the International System (SI) of units, and under SI, thousands have to be indicated by a space and not a comma (which is used in some countries to indicate the decimal point).

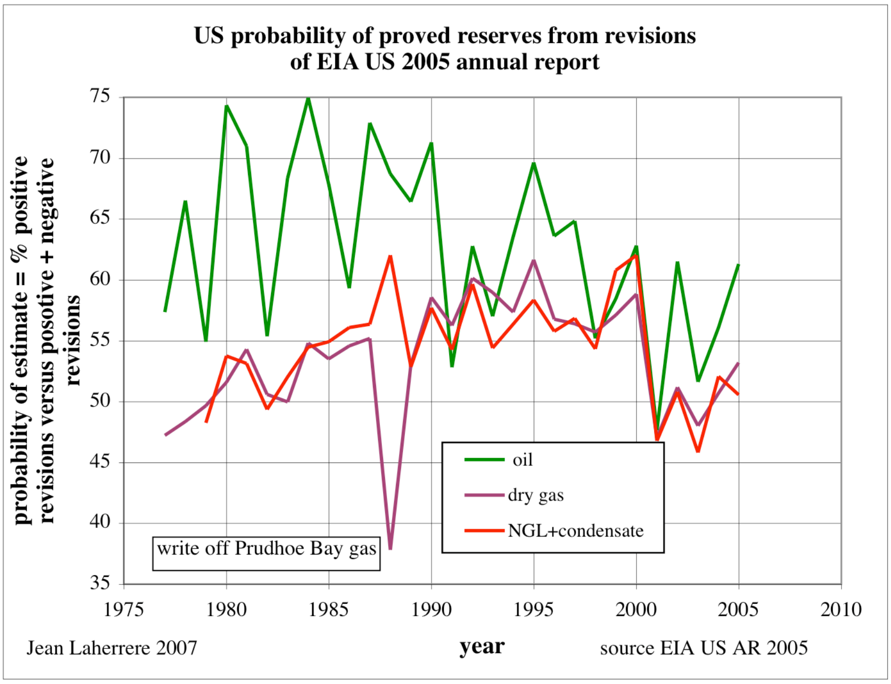
Oil (Billion barrels = Gb)	OGJ	BP	WO	Cedigaz
World	1 292.935 5	1 201.331 538 509 4	1 119.615 3	
Canada	178.792 4	16.500	12.025	
Africa	102.580	114.268	109.759	
Gas (Tcf)				
World	6 124.016	6 359.172	6 226.554 6	6 380.625
Norway	84.26	84.896 5	83.272 1	109.759 02
Africa	485.841	507.826	490.882	508.819

This inventory is misleading because it is incorrectly aggregated, yet is repeated every year.

Reporting any data with more than two significant digits is statistically incorrect because the accuracy of the different estimates varies over 10%.

US proved reserves are assumed to be conservative (reasonable certainty to exist) and for some represent a 90% probability (= P90), but in fact the US DOE's annual report gives the positive revisions as the negative revisions, allowing to compute the probability of these estimates, being the percentage of positive revisions over positive plus negative revisions. The probability varies for oil from 75% to 55% (even below 50% in 2001 where negative revisions were higher than positive revisions). For gas and NGL the probability is worse.

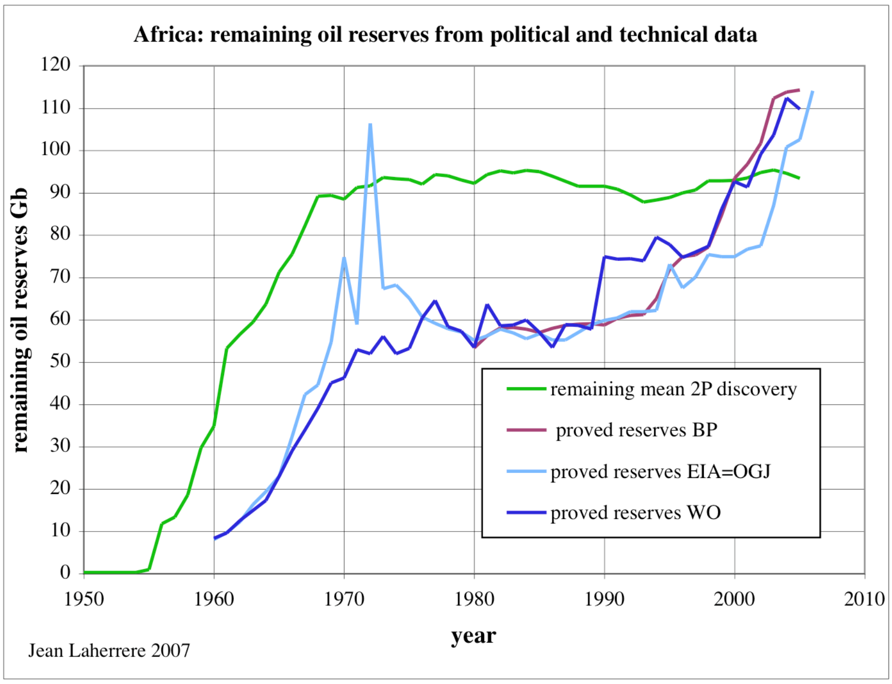
Figure 3: US probability of the estimate of proved reserves from revisions of USDOE annual reports



This graph shows that US operators do not precisely follow SEC rules, leading them to report a value closer to 2P than to 1P. SEC rules were written in 1977, compared to SPE rules which have been changed several times, and disregard probabilistic approaches. SPE/WPC/AAPG (1997) reserves definitions are used internally now by most operators. In fact IOCs use several different reserves figures; internal ones used by geologists or reservoir engineers and external ones for the SEC or DTI. The rest of the world (Canada dropped SEC rules in 2003) reports proved plus probable. As long as only proved reserves will be used, all forecasts based on such data are flawed.

Plotting current proved reserves and backdated mean remaining reserves for Africa at the end of 2006 reveals a huge difference, as in the first graph for the world.

Figure 4: Africa remaining oil reserves from political and technical sources



The Cause for Confusion

Ambiguity is often favored by purpose but many confusions show imperfect knowledge as shown by the following:

• Oil and liquids: oil can vary from regular (former conventional) oil of Campbell (66 million bpd,) to crude oil (73 million bpd) and finally to all liquids including NGLs, synthetic oils from coal (CTL), biomass (BTL), and refinery gains (85 million bpd in 2005).

• The term “liquids” may be restricted to hydrocarbons (Campbell) or to all liquids including everything that burns (olive oil).

• Oil production in the US includes condensate produced at the wellhead, but excludes NGL production totals. OPEC oil production excludes condensate. The UK reports only condensate while Norway reports condensate in cubic meters and NGL in tonnes (metric tons).

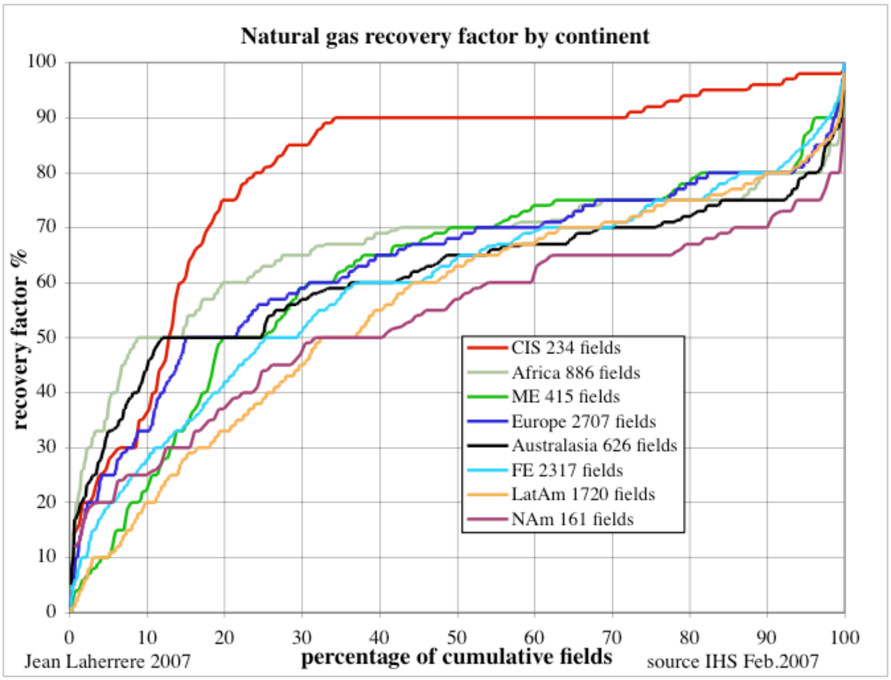
• Conventional versus unconventional: there is no consensus. In the past, conventional was primary and secondary recovery, with the rest being unconventional. Some exclude heavy oil such as arctic and deepwater. USGS and SPE define conventional as having water-contact with dynamic aquifer.

• Peak oil is often discussed without defining the product, and oil peak dates (as ultimate reserves) are compared when they are not dealing with the same “oil.”

Recovery Factor (RF)

Volume-in-place is estimated only from seismic and well data, while reserves are estimated at the end from production data. RF is often reported as a round value and is usually an educated guess. However the RF from IHS at the end of 2006 shows clearly that for gas the FSU classification ABC1 (3P) is quite higher than that of the other continents using 2P definitions.

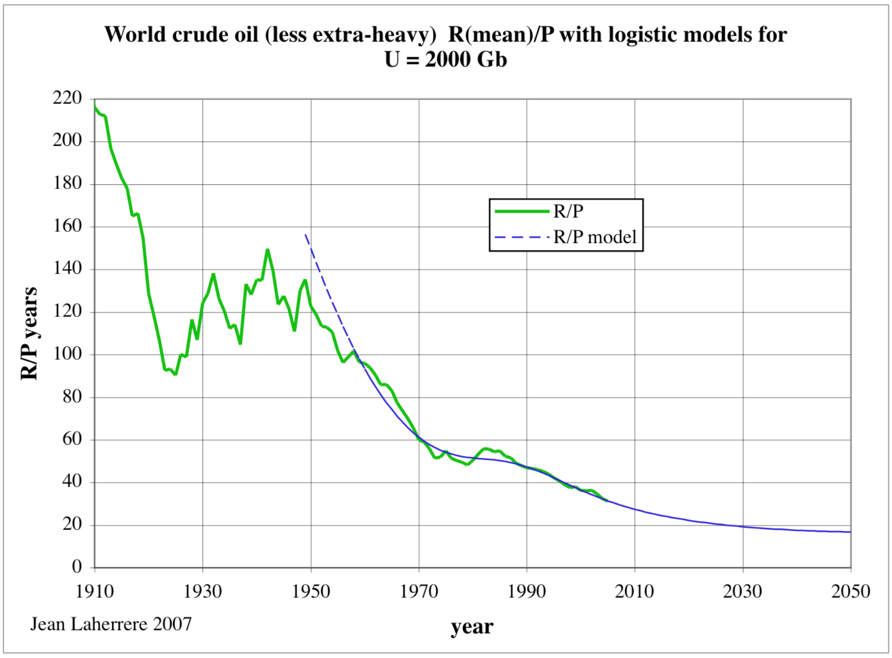
Figure 5: Natural gas recovery factor by continent



Reserves Production Ratio (R/P)

R/P is often used to describe the future as 40 years for oil, but it is a very poor ratio as it assumes that oil production will stay constant for 40 years and will decline to zero the following year. US (current proved) R/P for oil has been 10 years for the last 80 years, showing clearly that it is not a good indicator and also that proved reserves are an obsolete tool. Even using 2P reserves, R/P is curved and tends towards an asymptote (20 years).

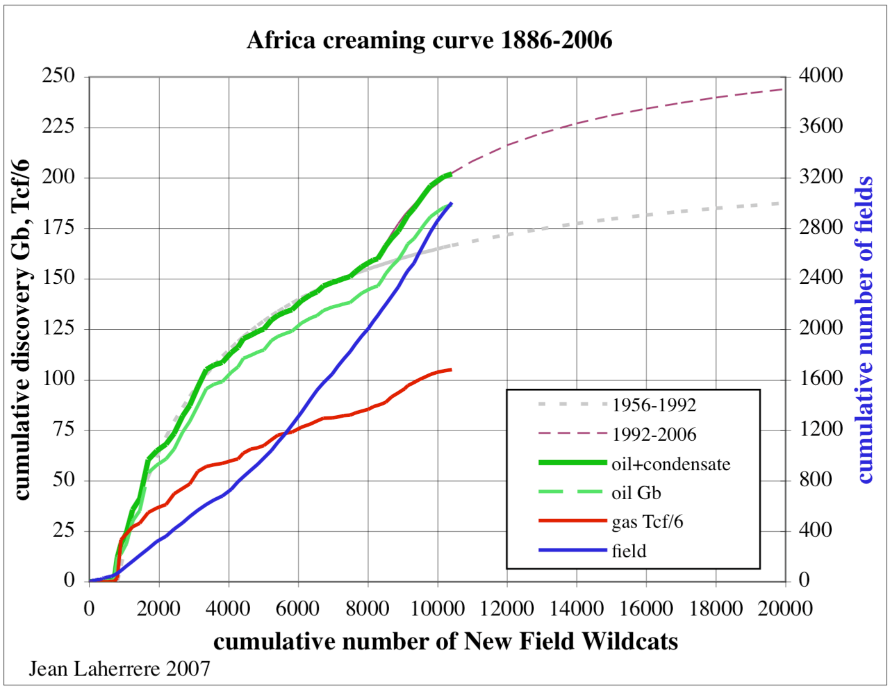
Figure 6: World oil (crude less extra-heavy) R(mean)/P with logistic models for U=2000 Gb



Ultimate Assessment

The best way to assess oil and gas reserves ultimately is to plot the cumulative backdated mean discovery versus the cumulative number of pure exploratory wells (New Field Wildcats= NFW).

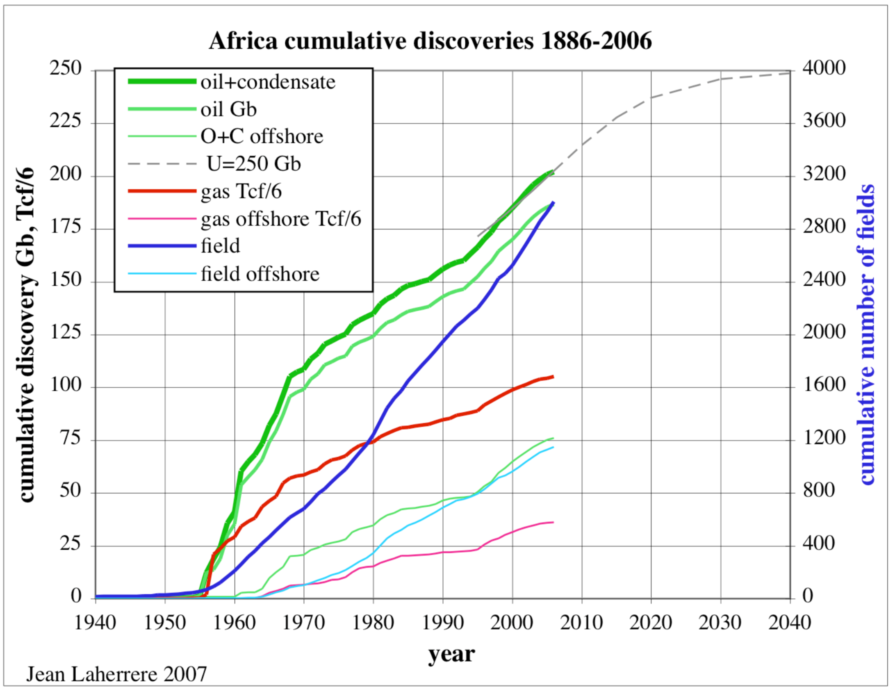
Figure 7: Africa creaming curve 1886-2006



It is easy to model the creaming curve with two cycles (hyperbolas); the first from 1956-1992, and the second from 1992-2006 which includes mainly deepwater wildcats and shows an increase in discovery volume but not in the number of fields (where the break was around 4000 NFW in the 1956 with the discovery of Hassi Messaoud). The discovery of gas in Tcf/6 (= billion barrels of oil equivalent as 1 boe = 6 kcf) displays a similar pattern being roughly half. The ultimate is about 250 Gb for oil and condensate and about 750 Tcf for gas.

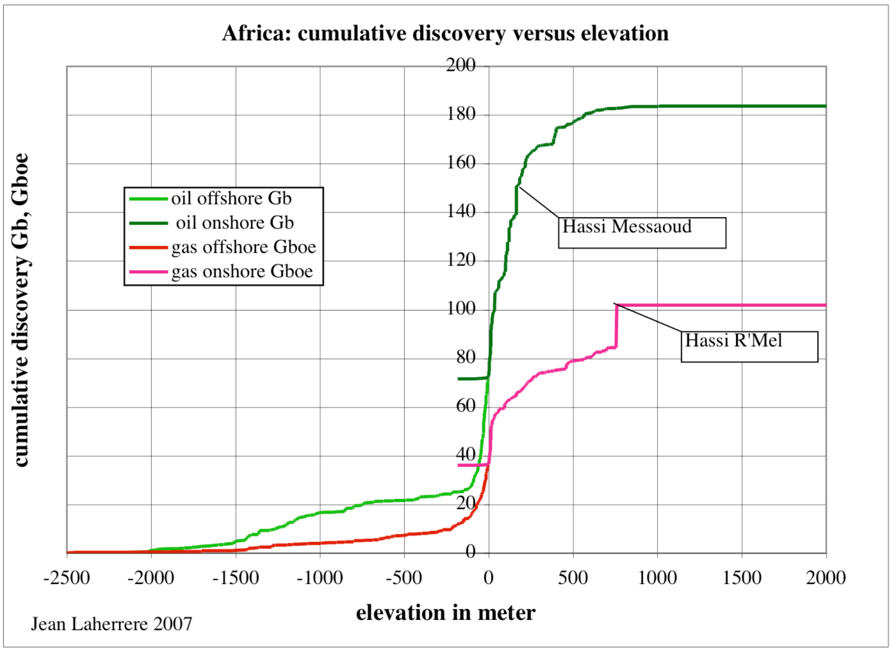
Plotting the same cumulative discovery versus time displays the same two cycles. Offshore cumulative discovery is 75 billion barrels out of 200 billion barrels.

Figure 8: Africa cumulative oil and gas discovery versus time



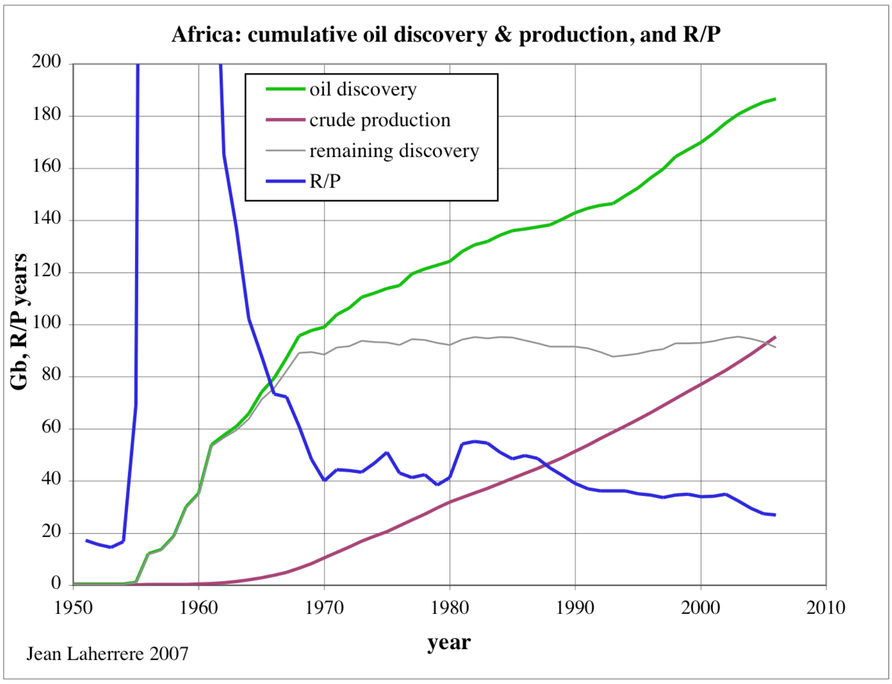
Cumulative discovery versus water depth or onshore elevation indicates that the most productive fields are offshore below 1000 meters of water and onshore less than 500 meters.

Figure 9: Africa cumulative discovery versus water depth and elevation



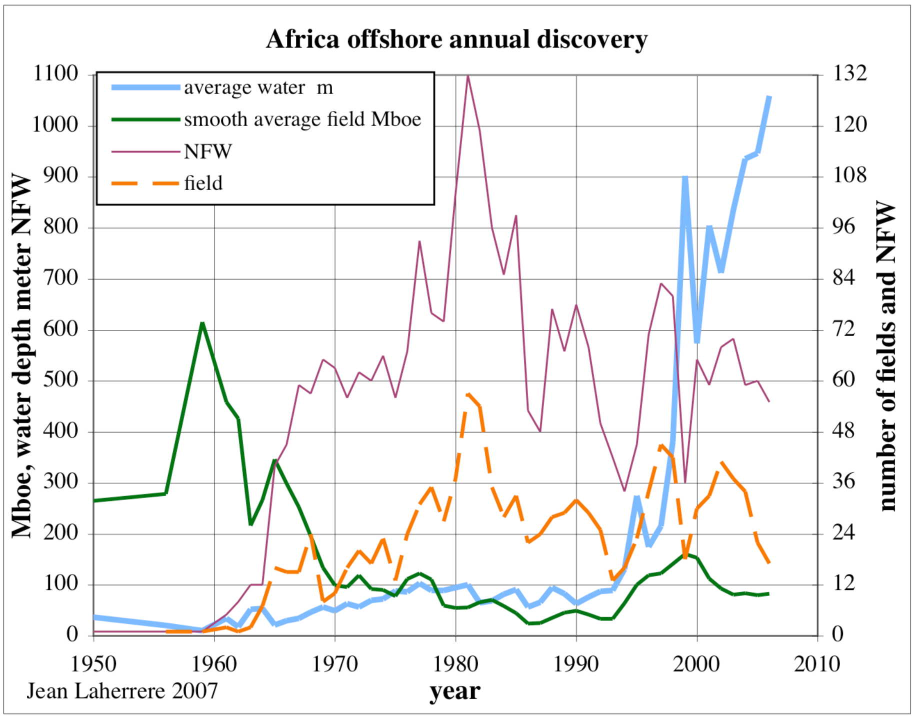
If discoveries have increased significantly since 1955, but from 1968 remaining reserves are constant at about 90 billion barrels, then R/P is decreasing towards 20 years.

Figure 10: Africa cumulative discovery & production, remaining reserves and R/P



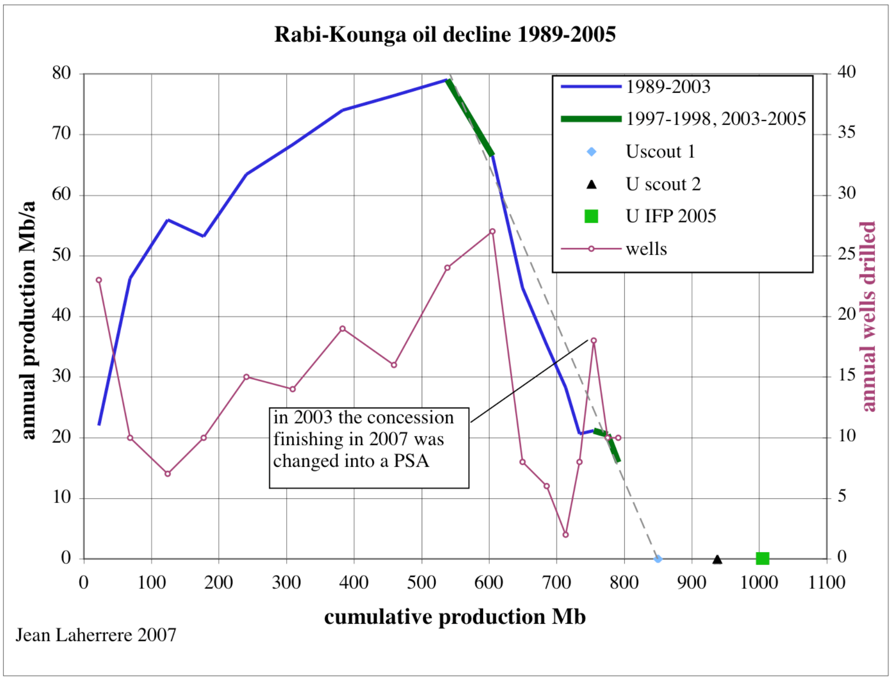
NFW water depth (blue curve) increases in as deepwater goes deeper, NFW number peaked in 1981, but average (smoothed by 3 years) field size (green curve) has peaked in 1959 and 1999.

Figure 11: Africa offshore discovery: NFW water depth & number, average field size & number



Technology is often presented as increasing reserves. In fact, for conventional fields technology allows operators to produce faster and cheaper, but no more at the end. Many examples of technology use in giant fields show that in the end the production collapses: East Texas (US), Brent (UK), Yibal (Oman). For one, the Rabi-Kounga, Gabon's largest oil field, was produced quickly with horizontal drilling and infill wells, but the decline was sharper than expected tending towards lower reserves.

Figure 12: Rabi-Kounga oil decline 1989-2005

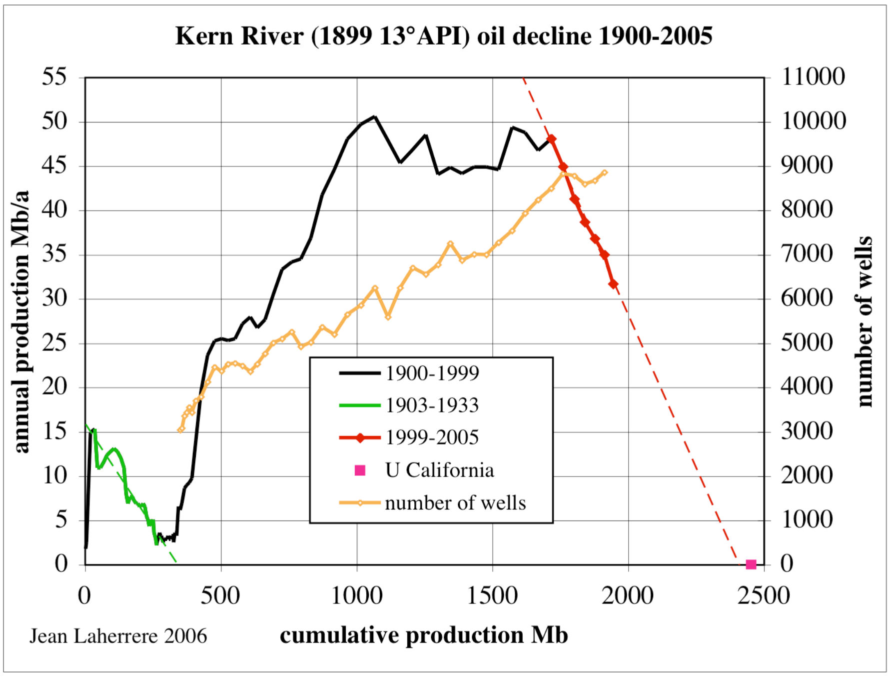


There are only a few examples of reserve growth due, not to technology, but to exceptional geological conditions of the reservoir, such as Ekofisk (compaction of the chalk leading to an 8-meter seafloor subsidence) and Eugene Island 330 (red fault connecting reservoir and source rock).

In contrast, technology (tertiary recovery) is a must in unconventional fields such as heavy oil fields like Midway-Sunset or Kern River (steam and many infill wells) or extra-heavy oil as Athabasca or Orinoco, but their growth must not be extrapolated to conventional fields.

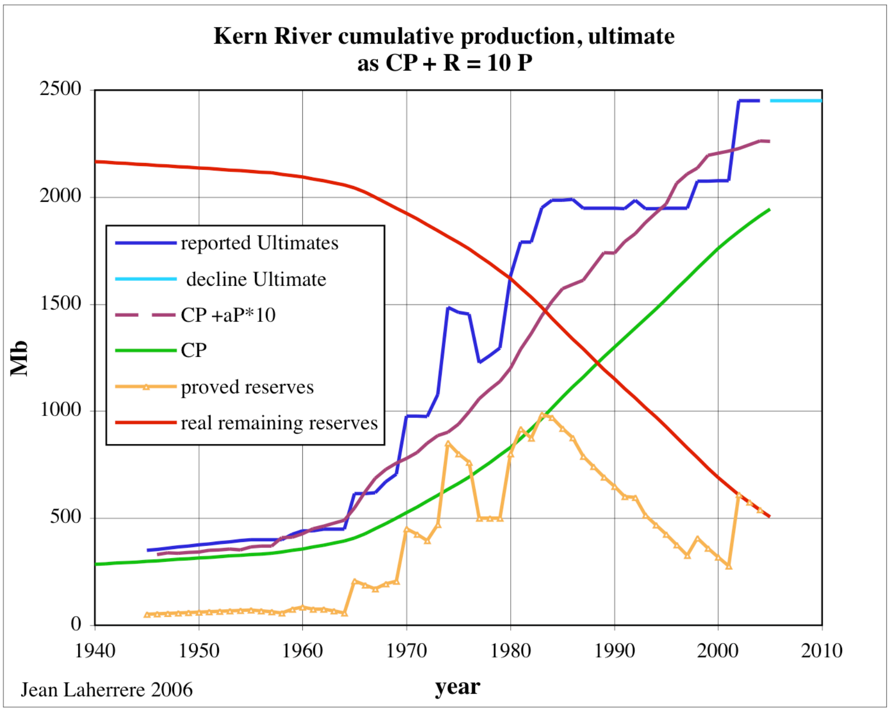
A March 5, 2007 *New York Times* article refers to the Kern River heavy oil field as an example of reserve growth to be applied to modern fields, however it uses an unscientific approach, comparing apples to oranges, conventional fields to unconventional fields, and outdated US practice of proved reserves to rest of the world proven plus probable reserves. Kern River, discovered in 1893 in California, peaked in 1999 with 9000 producing wells, more than 100 years later as production was raised little by little with the slow rate of drilling, but then suffered a sharp decline.

Figure 13: Kern River oil decline 1900-2005



In fact Kern River current reserves were inaccurately computed as 10 times current annual production, so reserve growth had to be expected!

Figure 14: Kern River cumulatrive production, ultimate as CP +R=10P



Conclusion

As long as SEC regulations inhibit IOCs from reporting 2P reserves, and as long as OPEC quotas prevent members from accurately reporting reserves, reserves data will be flawed. Proved reserves are financial (SEC) or political (OPEC) data and should not be aggregated or used in forecasts about the future. Only proven plus probable estimates should be used and only annual production of mature fields is required for a good estimate of reserves, irrespective of all published estimates. Every country should release complete historical field annual production and most disagreements on reserves will disappear for those ready to plot the decline and to extrapolate it. Unfortunately it does not work well when field production is constrained by OPEC quotas or investment. But now quotas are less and less followed and investments are plenty from IOCs for countries which do not deny signed agreements as Venezuela, Bolivia and Russia.

References:

-Laherrere, Jean. “Uncertainty on Data and Forecasts,” ASPO 5, Pisa, July 18-19, 2006 www.oilcrisis.com/laherrere
-Laherrere, Jean. “Comments on SPE Nov 2006 Revised Reserves and Resources Guidelines Available for Industry Review,” 31 January2007, www.oilcrisis.com/laherrere
-Laherrère Jean «Shell’s reserves decline and the SEC’s obsolete rule book » Energy Politics issue II summer 2004 p23-45, draft
http://www.hubbertpeak.com/laherrere/ShellDecline2004.pdf