Response to Merza's "Oil Reserves, Production, Service Contracts, and PSAs. By Tariq Shafiq

I wish to thank my esteemed colleague Dr. Ali Merza for his comments on my above named paper, published recently on the website of Iraqi Economists Network. Let me say From the onset that I find most comments of this type are not only helpful to the readers but also to me, especially at this time while I am writing a book on my 60 years experience of Iraq and the Middle East oil. I also admit that my past experience has been limited to writing and debating with professionals of more or less my type of profession in petroleum engineering, management and techno-economics. However, Ali is an economist and oil technocrat in his own right. His comments should be of great importance and benefit to me in my present endeavor of writing to reach, as well, intellectuals and the public at large.

I will reply to al-Akh Ali in the same order as in his above commentary

Re**- Oil resources and reservoirs**

I find that his comments must be routed to my omission to detail definitions, which I shall endeavour to cover here.

Many if not all definitions, which I am covering below may require going over to help revolve some of Ali's comments and enlighten the reads as well. Many standard definitions (Akh Ali referred to some) make the usual jargon petroleum engineers, like myself, often use without a mention of their definition; some are standard and others are derivation thereof. They are mainly:

a) Reserves
b) Reserves or Proven reserves, Probable and Possible
c) Oil-in-place
d) Ultimate reserves
e) Potential Reserves
f) Oil-In-Place and
g) Potential oil-in-Place

The standard definition of **Oil reserves (a) or proven reserves (b)** is:

The amount of **technically** and **economically recoverable** oil, in barrels or tons, at standard surface temperature and pressure**.** They are often given a degree of certainty as **proven**, having high degree of certainty, **probable** or **possible.**

Proven reserves are often referred to as simply **Reserve/s** unless described as **Probable or Possible or Potential,** yet to discover. I often use the latter (Potential) to indicate as existing in possibility and opposed to actual, yet to discover.

Different classifications of **reserves** are related to their degree of certainty or Probability, 1P, 2P and 3P. Can be **present proven or oil-in-place**, **potential (yet to discover).**

Oil-in-place refers to the estimated oil that exists in the pore space of the reservoir formation/s or of the field/s in question. Or **Oil-in-place** can refer to the estimated reserves for an **"anomaly",** which is a feature (often structural) yet to be drilled in order to ascertain whether it is oil field or not.

Different classifications of **reserves** are related to their degree of certainty or Probability, 1P, 2P and 3P. Can be **present**, or **potential.**

Reserves may refer to the **oil** or **gas** of a **reservoir formation/s**, **a well** (where one assumes a circular boundary where the well is at it center) for **a field**, **a country**, or the **world**.

However, reserve/s is a dynamic concept, which changes up-word (often, when reserves are said, justifiably, to be growing) or down-word (seldom, hence initially estimate of reserves is often very conservative) when either or both technology or economic conditions change. Higher price allows additional reserves to be sought and thus reserves increase or grow. Higher recovery transfers more of the oil-in-place to reserve category (proven reserves).

However, the oil-in-place does not change, it remains fixed when economic (cost of extraction) changes or technology improves. As a matter of fact both the price increased and technology advanced enabling better recovery which increased from 25 % or less to a global average of 35% (estimated by BP over two or three decades ago) to 49% in Norway and 50-60% in the North Sea. And the target is 80%. However, the volume of the pore spaces (containing the oil) of the formation remain constant. As such it does not change with the change of the economic or technical parameters.

For the above reason, I have always preferred to refer to the **oil-in-place** reserves and promoted its use (being a fixed quantity) rather than **Reserves** (dynamic concept). But, the industry has remained to traditionally use **Reserves** instead of **oil-in-place**.

Therefore **oil-in-place** denotes the total estimated amount of oil of an oil reservoir or field. It includes both the producible and non-producible oil.

However, because of **reservoir characteristics** and the limitations in **petroleum extraction technologies,** only a fraction of this oil can be brought to the surface, and it is only this producible fraction that is considered **reserves. The ratio of producible oil (**or simply: reserves) to the **total oil-in-place** for a given reservoir, field or country is referred to as the **recovery factor.** Recovery factors vary greatly among different oil fields and geological horizons. The recovery factor of any particular field may change over time based on the operating history and in response to changes **in technology and economics**. The recovery factor may rise over time if additional investment is made in **enhanced oil recovery** techniques such as gas and oil injection to complement the natural water drive.

Re. (1-1) and (1-2) Comment

I must point out that almost all my tables used for information and/explanation belong to power point presentations, which at the time of use, were accompanied with explanation. Say for example, the oil-in-place (in one specific table which Akhi Ali referred to) does correctly translate the reserves in the table into its original oil-in-place but with no mention of the Recovery Factor that had been used.

The comment, however, that the oil-in-place or potential oil in a particular table, for example table 2, differs from the potential oil-in-place mentioned in page 5 must have arisen because the one in table 2 refers to the reserves mentioned there while the potential reserve figure in page 5 refers to the in-house calculated **potential reserves** (of the mentioned study), yet to be discovered.

I may mention at this juncture that I and my team of Petrolog & Associates were the first and only team who have gone through a 3.25 man-year study for publication by the CGES to market and on on a multi-client basis study. The reserves figure of **455 billion barrels (Bb)** (which akhi Ali referred to was converted into a potential proven reserves of **216 Bb** (yet to be discovered) using the assumption given there.

Re-(1-3) Comment

Please note that although I was the advisor to the IEA on the Iraqi project study you are referring to, IEA chose ‘ultimately recoverable resource’ of 232 Bb from the USGS studies and not from our Petrolog study. That is their choice, though I believe ours of **216 Bb** (**potential reserves) plus 115 Bb** present **reserves which equals** to **331 Bb** of **total present reserves** or present **recoverable resource** of **Iraq oil potential reserves**.

I must mention at this juncture that reserves figures of such renounced international organization often suffers from lack of up-to-date data, which were and still are, kept by governments and companies alike in strict secrecy. Reserve estimate, such as ours, are carried out by professional Iraqi geologists, geophysicists and petroleum engineer who have collected and studied all the data required throughout their life career.

As to what is the mostly like reserves of Iraq, clearly I believe our Petrolog’s study, as I said in this paper, is the most likely, though remains a conservative estimate for the technical reason given there and for lack of inclusion of the Kurdistan discoveries. Since 1994 I have announced my prediction in a geological conference in Amman that Iraq reserves are on par with Saudi Arabia. At that time Reuters announced about it and the BBC followed.

It is be unprofessional for ethical reasons to name a reference figure for Kurdistan oil reserves having worked with the IEA on their Iraq study, as their advisor. However, an estimate of their reserves can me made from the IEA estimate of their future production of 500,000-800,000 barrels per day in 2020 and up to 1.2 million barrels per day in 2035. In light of this IEA production forecast of Kurdistan reserves of 45 Bb must be an exaggeration. A reserve of around 12 but less than 24 Bb is a likely estimate, which is considerable in the global eye. It invites global IOCs to flock taking their turn to acquire PSAs, especially when the fiscal contractual terms are very generous, which they are indeed.

Re-1-4 Comment

I have commented to the Iraq Oil Forum on Iraq revised reserves. In summary while I do not suspect that Iraq present known reserves can be as high as 143 and 150 Bb, on the ground that the 115 Bb Iraq reserve was based on past conservation recovery factors 25% and up to 30% average. However, modern development technology and enhanced recovery are bound to produce much higher recovery. However, until and unless Iraq fields' reservoirs are produced and observed over reasonable periods of time and observation are taken (as the case under the present Service Contracts) which provide evidence of higher sweep (of water to the oil ahead of it) efficiency and accordingly justification for higher recovery factors and higher reserves estimate. The above revised of 143 and 150 figures have been based on estimates from studies made by the IOCs and not field observation, which are yet to be made.

Re-Development cost and average cost of production

(2-1) Comment

I am not sure of what is meant by the query following the statement *'fails to establish a relationship with the* ***average cost of production'?*** by saying***:*** *I have concluded that today, the CAPEX is in the region of $7,500-$11,000 and OPEX (operating expense) is in the region of $1.5-$2 per barrel.'*

This conclusion was based on lengthy analysis of past IPC elements of CAPEX (capital expenditure) and application of inflation factors. Any estimate of OPEX (operating expenditure) based on the past IPC or the past direct state development of over some 35 year would no be applicable. The OPEX estimate is in conformity with current oil industry estimates and an Iraqi government figure a year or two ago. For practical reason I cannot see how why my paper of the intended objective title needs to go into improving this estimated parameter other than reference to other estimate. The conclusion from both of these two parameter indicates beyond doubt that Iraq investment and operating cost are a fraction of figures of the international oil industry outside the Middle East and that both are in line with Kuwait and Saudi Arabia, if not less.

In the mean time, such low level costs would still justify the objective of the paper to show why Iraq oil source is a target, even if these two costs were doubled!

(2-2) Comment

I am afraid I can perhaps see now why Al-Akh Ali find it so important to query what he calls the Average Production Cost. But I am sorry to say that the derivation he made in assessing it is based on incorrect understanding of the concept of the **cost of a daily barrel** and how investment is made along the profile of oil field production build up.

The production build up of an oil field resembles a **bell shape**. The left side (so to speak of the bell) represents a pressure and a production capacity build up. The top of the bell is where the Peak plateau point is located, though in practice it is not a point but prolonged and undulating. The right hand side represents the declining life of the field.

There are two ways of estimating, in my practice, the CAPEX. One way, which is the simpler one, is to use the daily barrel cost for the build up side to arrive at the Total CAPEX with its associated OPEX. That leaves the right side of the declining pressure and production capacity to charge only OPEX and not CAPEX cost. Accounting however does accommodate this approach. In reality the further development of our oil fields by IOCs the CAPEX is recovered in the Rumaila Field within the first year. As a result any subsequent CAPEX during any one year is also paid back in the same year as the case with the OPEX.

Let us come back to your method of using the daily barrel cost throughout the life of the field build-up and decline. It does not conform with the true picture of the production build up and decline represented by a bell shaped. In real life, all the infrastructure require to reach the plateau production rate together with water or gas injections facilities are built during the production build-up phase of the left side of the bell. The right side is dominated mostly by workover drillings, repairs plus enhanced or secondary recovery, the cost of which can be, accounting wise, charged to OPEX, especially when there accounts of depreciation is not considered and drilling of producer at the plateau phase are charged the same year when drilled, not along their life duration.

However, I find such details again is beyond the scope and objective of the paper.

Re-(2-3) and (2-4) Comments:

I am afraid akhi Ali the Iraq Service Contract does not include depreciation or amortisation. The investor IOC gets paid back through a high front loading amounting up to 50% of the sales gross return.

The well-head cost which you are detailing is no where required in the accounting procedure under our Iraq service contract.

Future production and contracted plateau in oil service contract

Re-(3-1), (3-2) and (3-3) Comments

I have no basic difference with the comments you made here. My only comment, however, is that it is indeed sad for Iraq to embark on such huge multi billions dollar project but seems to have started without exhaustive pre-studies of Iraq energy and economy, among others including the global energy requirement and the supply and demand thereof.

We should not forget that the negotiation to review the contracted development plans is going to result in heavy penalties. It is going to require extending the already long duration of the contract, as one solution, eliminating the R factor which result in a higher level of remuneration by almost 30% as another solution and an ultimate solution (which is the main one) is for the IOC to maintain the NPV (net present value) at the same original contract with the higher plateau, regardless of the elimination of the work needed as a result reducing the plateau the new lower level. Perhaps, you and/or our economist colleagues with assistance from legal experts can investigate an economic solution with the least loss to Iraq. To start with is there a legal case to have to compensate IOCs? If it can be shown that the execution of the original contract can result in serious unforeseen financial losses to the State? Should there be compensation where in many case, the Plateau can be shown to be unrealistic and/or unlikely to conform to the best oil industry practice? Would it be justifiable to compensate IOC through a revised remuneration commensurate with the same IRR (internal rate of return) of the original contract instead of maintaining the same NPV?

IV Contractor Remuneration Comment

Your statement that: *It is worth noting that $2/barrel is a gross fee, which falls with increasing production [actually with associated step-wise increase in R-Factor; Merza (2011)]. The foreign contractor gets about 49% of the gross fee. The rest goes to income tax (35%) and national counterpart (16*%).

My answer is*:*

You are correct but: you may lead the reader to think that the **rate of return to the companies, as many IOCs claimed, is very meager, which is not the case.** On cash flow analysis, most Service Contracts of rounds 1 and 2 shows a return on investment in the region 20% IRR.

An example, I have carried discounted cash flow calculation for Rumail Field Service Contract using CAPEX $2 and OPEX $2. The calculation produced an IRR of 30%. A senior BP director confessed, as I recall, to a 20% return. The discounted cash calculations shows an important element in that the investor got back all his invested capital in the same first year as a result of the generous front loading of 50% of the all the crude sales from the field. The result is that the CAPEX is paid back annually every year as if it were an OPEX. This resulted in this high level of 30% IRR. And so would the case of the other contract but perhaps to somewhat lower lever. A case in point of much lower IRR is the Luke oil Qurna oil field where the remuneration was set a lower while the CAPEX is predictably much higher than for Rumaila Field, due to its poorer petro-physical reservoir formation and heavier crude oil! Do not ask me why or how the MoO designed that way.

Re-Your V. Libyan production-sharing agreements

You quoted a statement from my paper on page 20 and concluded as follows: *'Libya has managed the grant of as low as 7% in their PSAs a few years ago'. This statement needs to be corrected and qualified*. You then went on enlightening me and the readers by giving detailed highlights of the Libyan PSAs.

I am afraid akhi Ali your comment here as in the above previous case may lead the reader to a wrong conclusion. For this reason, allow me to say as well that such commentary is somewhat out of context. The section of my paper, which you are commenting on deals with Erbil PSAs. It explains how and why these PSAs are illegal and costly to the nation. For you to pick one example I gave, in passing, and ignore the bulk of the explanation and examples or to comment on the validity of the whole section is somewhat demeaning, I am sorry to say. The section was not intended to be a research on PSAs.

Having said this I need to explain the source of the figure **7% profit split** which I quoted. It is not one I researched and came out with. It came from a dear old friend and an Associate of mine (for a long time during part of the time when I was the advisor to the Ministry of Oil and them Minerals from 1968 to 2003), late Dr Shukri Ghanim, the Libyan Minister of Oil. He informed me, during a visit of his to London at that time, of their success to have managed to get a profit split as low as 7%. However, it is important to recall my explanation aimed to convey: while this figure is considered low for Libya, Iraq profit split should be much lower on account of the much lower Iraqi cost than the Libyan cost. What your table tells me now is that the named IOC's **lowest Share is 12% and the average is 18%**. Erbil case remains giving multiple of this figure. But you are **not quoting the like to my 7% profit split.**

The truth may lie in the following explanation:

Your table produces IOCs' average share of 18%, which does not no conflict with my knowledge that: under EPSA-IV, the NOC normally took around 80-90% (leaving 10-20% to IOC) of the oil and gas production, while the foreign company (IOC) must recover capital and operating costs and **eventually makes** a **profit from the remaining share in production**. As a result it should not be surprising that late Shukri's mentioned a figure of **profit split of 7%** (**not average production share**) was obtainable. **You are reporting Production Share while in my paper I am talking about Profit Share.**

With my best and sincere regards to akhi Ali and all our colleagues, members of the IEN.

Tariq Shafiq

TES/27 November, 2013.