Viability of the Offshore Oil and Gas Industry around 50 UD$ / barrel. (Part 2 of 3).

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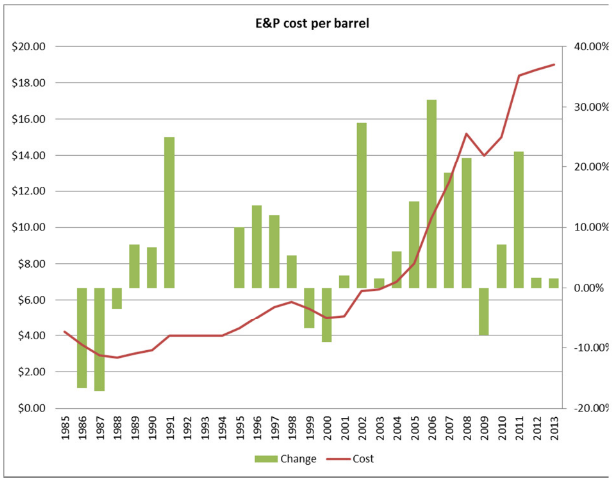
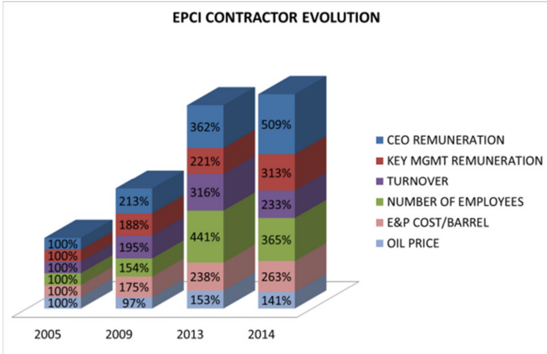


Rising cost of E&P per barrel. Source: Douglas-Westwood

If you only look at the period covering 2005 to 2013 then the Offshore E&P costs per barrel have increased at a rate of about 10% per year. Whereas if you look at the period 1985 to 2005 the Offshore E&P costs per barrel increased at a rate of 3.5% per year. One should wonder about the reasons for this sharp increase.

Looking at the evolution of an EPCI contractor

If we tabulate the oil price and the E&P cost per barrel together with some of the figures reported in the annual reports of years 2005, 2009, 2013 and 2014 of an Offshore EPCI contractor and using 2005 as the base index for each parameter, then we obtain the following stacked bar charts. It is worthwhile to point out that the scope in 2014 of this contractor remains largely unchanged compared to the scope in 2005. It is also worthwhile to highlight that all contractors have different figures.



If the number of employees have increased by a factor of 3.65, the remuneration costs of the CEO has increased by a factor of 5.09 and the key management remuneration has increased by a factor of 3.13 in the period 2005 to 2014, then it is not too difficult to understand that the EPCI has substantially contributed to the increase in E&P per barrel costs! Between 2009 and 2014, the number of employees of the upstream branch of Shell increased by a factor of 1.43 to compare with a factor of 2.37 for this contractor. So what is hidden behind these increased EPCI contractor costs?

Some actual examples from the trenches:

1) A painting example

This is a colorful example from the execution of an EPC project. In 2011, the client (operator) placed a contract with the main contractor, who, in turn, placed a contract for part of the scope with a subcontractor, who, in turn, placed a purchase order for a small part of its scope of work to a welding and machining specialized company who outsourced the coating of the parts. Due to the criticality of the part (a mooring equipment), this activity was defined with a "WITNESS" in the "ITP" (Inspection and Test Plan) – furthermore the specification required the activity to be supervised by a level 3 FROSIO inspector. When the coating activity took place, the following people were mobilized:

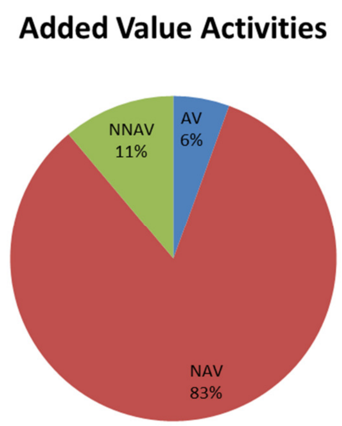
- The client representative (because he wanted to show that the company takes all fabrication steps seriously, and because he had a day to spare),
- The main contractor representative (because his client was there),

- The sub-contractor representative (because his client was there),
- The machining and welding specialist representative (because his client was there),
- The coating representative (because his client was there),
- The representative of the third party certifying body (because the specification required it),
- The level 3 FROSIO inspector (because the specification required it), and,
- The "poor guy" holding the brush (because actually someone had to add value to the activity).

The same activity in 2002 would typically have mobilized the following people:

- The "poor guy" holding the brush (because actually someone had to add value to the activity).
- The level 3 FROSIO inspector (because the specification required it), and,
- The certifying body representative would have reviewed the coating documentation during the documentation review of the whole part at the machining and welding specialist.

Intuitively, most people feel that the 2002 approach is the most reasonable (rightly so).



If we just quickly analyze this activity without going into any details, the only added value is taking place when the part is being prepared and coated by the operator, the FROSIO inspector and the certifying body representative do necessary non added value work and the rest of the representatives "perform" non-value added work. There will be travel expenses for most of the representatives, and there will be lunch expenses for all but the operator. All these expenses are booked as costs to the various companies' projects (and are a burden to the CAPEX). On this activity alone you find that at least 83% of the steps are non-added value steps – i.e. waste.

Note: One of the greatest dangers of the Non-Added Value (NAV) activities is that with time they tend to be considered Necessary Non Added Value (NNAV) activities.

2) Engineering manhours

In 2004 a CALM buoy system (buoy, PLEM, anchors, subsea and floating hoses, umbilical, installation) required X manhours to engineer (which at the time felt like a bit too much for a mature design). In 2012 the same scope required 4X manhours to engineer. This increase is partially attributed to increased client involvement in these "small" projects.

3) Project management manhours

On a proposal for a critical equipment destined for a FPSO the project management manhours went from Y manhours (which was already quite a lot compared to earlier similar projects) in 2008 to 1.82Y manhours in 2011 (when the "last" revision of the proposal was made just prior to award). The increase in manhours was motivated by the increase in follow-up of vendors and suppliers as well as the increase in workload for compiling the dossier of the vendor documents (the increased surveillance of the vendors was a direct consequence of the Deepwater Horizon accident). During the execution of the project, even the greatly increased allocation of manhours was insufficient because of:

- greatly changed terms and conditions to be applied on all vendors and suppliers (back to back from the main contract)
- administration before and during execution,

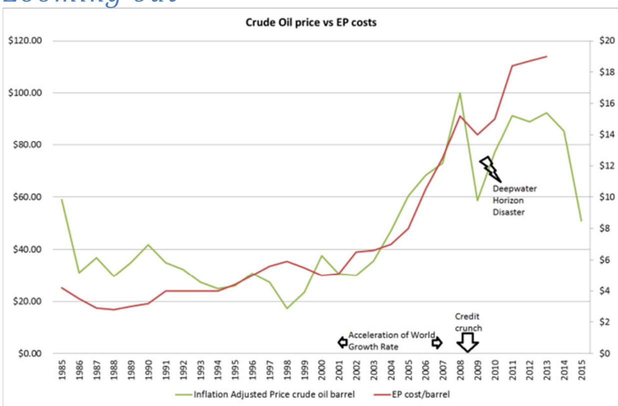
- QA and QC activities before and during execution,
- Risk management shifting from a technical focus to a contractual / financial focus.

4) Specialist support

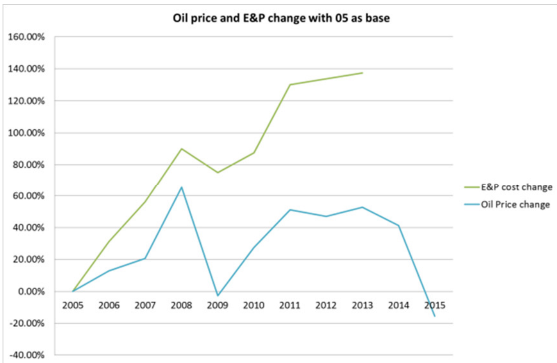
The turret structure of an FPSO located in the Timor sea was experiencing vibrations which seemed to be originating from the swivel stack; and more precisely from a high pressure gas swivel. The operator requested the mobilization of a specialist to assess the swivel stack. After a lot of discussion and negotiation, a specialist was dispatched from the south of France. The specialist flew from nice, to Darwin via London and Singapore. He mobilized onto the FPSO by flying from Darwin to the FPSO via Truscott. He spent a week onboard (among other things waiting for an offload to be completed so that the FPSO could be forced through a couple of rotations) and verified the assumption that the delta pressure which the primary seal is subjected to was causing a stick and slip phenomenon. The entire mobilization took 14 days (because there was a snow storm that paralyzed London Heathrow for a couple of days), the operator was invoiced approximately 30,000 US$.

A different approach could have been for the operator to require from the OEM a short engineering study that would put forward the 5 most likely causes of the vibrations and ways to verify these scenarios. Such a study could have included a 4 hours brainstorming video conference with the operator providing as much details and the OEM gathering the best persons suited for this (3 or 4 persons). All in all this way forward probably would have cost the operator 4,000 to 5,000 US$. The operator would have proceeded with the verification on his own (which would not have been a problem since the specialist was not allowed to touch any of the equipment – HSE regulations).

Zooming out



Returning to a more general view of the Offshore E&P industry, if we superimpose the E&P per barrel costs with curve with the price of the barrel of crude oil curve, then we see that the former usually trails behind the latter and that there seems to be some correlation between the two until 2008. What you also see is that even with sharp drops in oil price the cost curve is quite resilient to decreases. During the period 2002 to 2008, the world growth rate accelerated (both in developing and in developed countries) and all resources (including workforce) were becoming scarcer so it is not illogical that E&P per barrel costs followed.



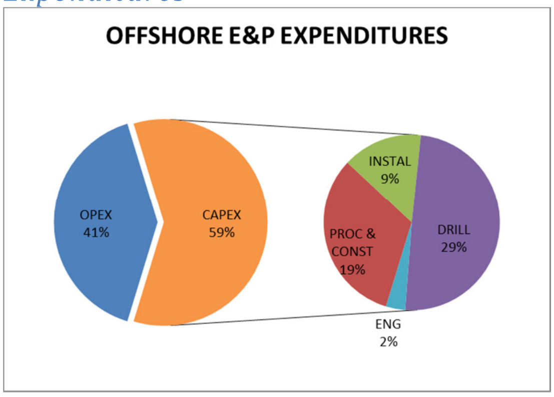
If we zoom in on the evolution of costs and oil price, taking 2005 as the reference, then we can see costs increasing more quickly than oil until 2008 (due to high world growth rate). However, since 2009, when the price of crude oil drops, the E&P per barrel costs only follow to a marginal extent in the decrease, whereas when the crude oil price increases the E&P per barrel costs increase at the same rate.

Reasons for costs increase

Some of the cost drivers that have been put forward by the industry to explain the unreasonable cost increase during the last 10 years are:

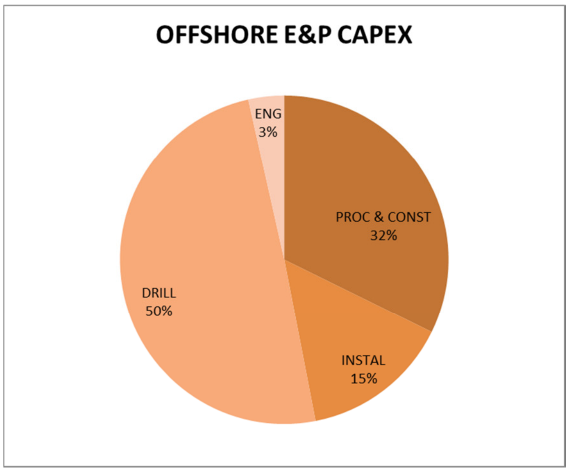
- the consequences of the "Deepwater Horizon Disaster" which occurred in April of 2010.
- the increasing technical challenges, with the ultra-deep water fields, with the HPHT fields, with the harsher environments in the artic water fields explorations.
- the engineering of facilities that are to last 25 to 40 years on station with 99% uptime (i.e. monster projects like Prelude FLNG or Ichthys).
- project management issues.
- skills shortages (however with 200,000 persons laid off in the last year that problem must have solved itself – at least temporarily).

The cost distribution of Offshore E&P Expenditures



Offshore E&P Expenditures, source "Spends and Trends 2008 – 2017"

Looking at the global E&P expenditures for Offshore Oil and Gas for the years 2008 to 2012, you obtain a distribution of expenditures 41% for OPEX and 59% for CAPEX. As seen before, there is room for efficiency improvement in both sectors, in other words, in order to have a real good impact efforts need to be made in both types of expenditures.



E&P CAPEX, source "Spends and Trends 2008 – 2017"

Detailing the costs on the CAPEX end makes it clear that efforts are needed on both the drilling end and on the EPCI end if good results are to be obtained.

Conclusions:

- The E&P costs per barrel in the Offshore O&G industry have increased to a level which is very difficult for the operators to sustain.
- The high crude oil prices have enabled the creation of a lot of decent to very good paying jobs (some of which do not add value).
- The current low crude oil price is a golden opportunity to transform the offshore industry so that it becomes competitive.
- Looking at individual examples, 50% reductions in costs is feasible but activities need to be organized differently.
- All actors along the value stream share a responsibility for the Offshore E&P costs situation and all actors along the value stream can (and should) contribute to transform the industry so that it becomes efficient.
- To become competitive, non-added value work needs to be eradicated, and trust within companies and between companies needs to be found.

Data sources:
The Plateforma Project.
Spends&Trends 2008-2017