Theory and Case Study of Safety in Engineering

Every workplace needs to be safe, and the upstream oilfield is no exception. Without a reasonable expectation of safety (a moving target at all times) operating becomes more and more difficult as problems pile up. They may grow slowly in the form of fines, lost work incidents and minor spills, or they may suddenly become obvious as a result of a major incident on TV and local media. In all cases large or small, there is inevitably a long chain of events and decisions possibly stretching back for years and across multiple people, companies and organizations that lead to the events that are actually problematic. As a result, many projects are picked up by a person, organization, or company with a lot of decisions already made which will determine the basic nature of the work that you will be involved in. As engineers and professionals in industry, safety is our duty as much as it is for anyone else.

Theory: How Do You Create Safe Operations?

Ask this question to a group of people, and they will all have different answers. A few of the common ones in the upstream oilfield might be like this:

- Hire experienced people
- Promote a corporate culture of safety
- Conduct emergency drills
- Have safety/rescue equipment on site
- Have a dedicated HSE rep on location
- Reduce risks
- Write detailed procedures
- Have standard work practices
- Perform JSA's
- Have awards for safety
- Hire good contractors/subcontractors
- Get good quality materials
- Watch out for H2S and methane leaks

These are all different answers, *and none of them are wrong!* As engineers and professionals in industry, we are called on to ask the bigger questions which shape the environment in which these answers make sense. There is an easy way to create a framework for safe operations. Start from the overarching and unachievable position of attempting to eliminate ALL risks and ensure nobody ever gets hurt EVER. The only way to do this is not to perform anything. No job, no action, no damage. Simple but utterly unachievable. Given that this is desirable when we DO have operations we have to ask how to most closely approximate this ideal condition by asking the following questions

- Why is the work being done at all?
  - Is there a way to simplify or eliminate it with equally good outcomes for the project?
- In what ways are people exposed to risks in the conduct of the work?
- Are we counting on extraordinary skill or ability from the workforce?
- What options, choices or opportunities do the crews on location have if something goes wrong?

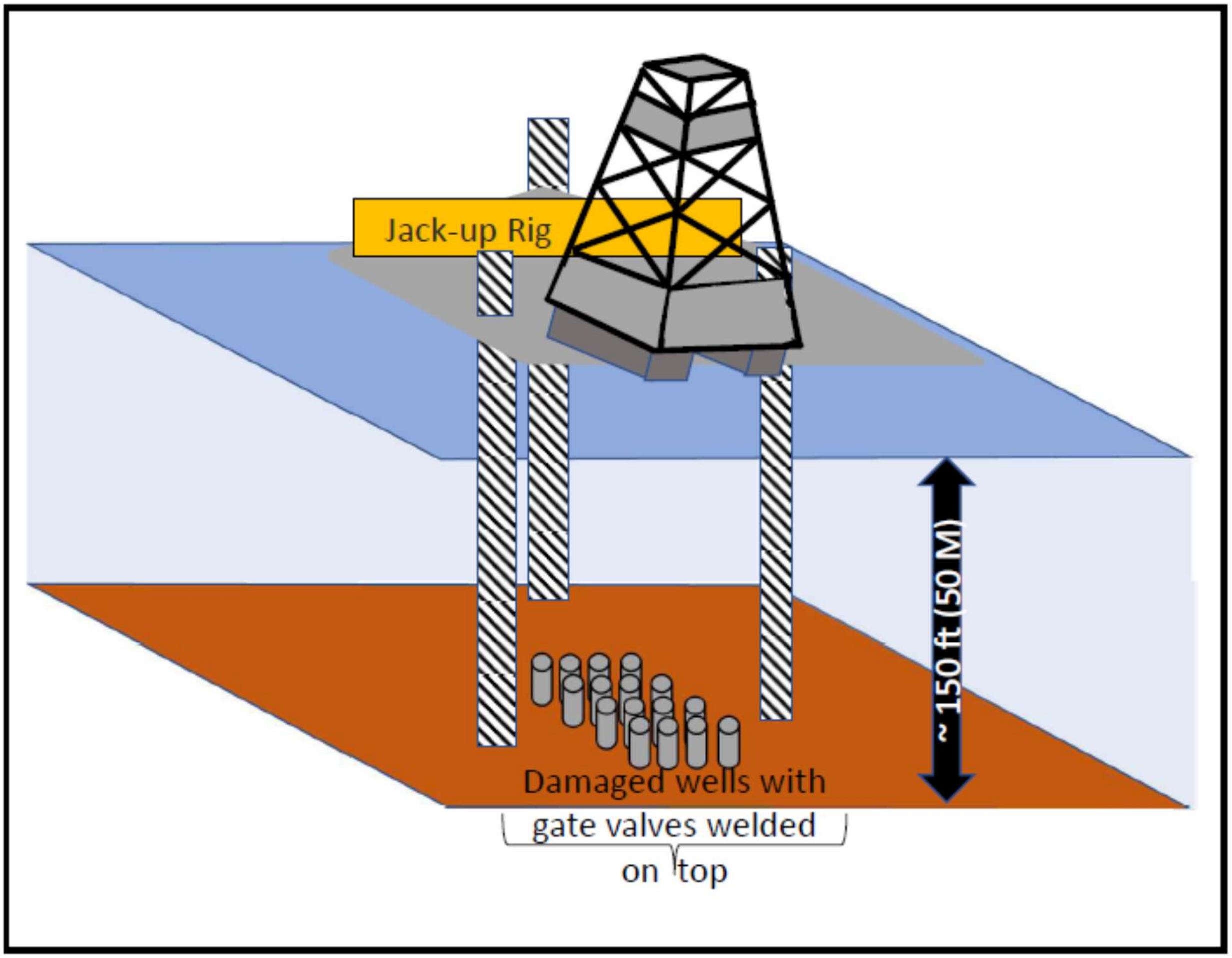
- What are the things that are likely to be difficult or encounter problems on the job, and what can be done to prevent or mitigate them?
- How many safe alternatives are available in the event of a problem before a split second decision is required?
- What are the things that are likely to be difficult or encounter problems on the job?
- How perfectly can a normal person be expected to conduct the operation under ordinary oilfield conditions (meaning simultaneously sleep deprived, physically tired, with poor lighting, while worried about bills and family at home)
- Do the people doing the work have any margin for error or ability to self correct if something isn't right?

These questions may seem, or even be 'obvious' for routine operations, but what about novel ones? Or what if we want to improve existing operations?

Case Study

A group of wells needed to be Plugged and Abandoned on a platform offshore – some 16-32 wells if I recall correctly. Water depth about 150 ft/50 meters. Difficulty: in 2005 pounding waves and high winds from hurricane Katrina knocked over the platform. An incredibly difficult, and complex underwater salvage operation over the course of two years was conducted to remove the debris from the platform, and clear away the surface trees and the portions of the casings and tubing which was in the water column. All of the trees, caissons and other means to access or gain a physical connection to the wells were totally destroyed. However the mandatory subsurface safety valves on the wells were all holding, or perhaps the wells had bridged of, or perhaps the tubing and casing was kinked below the mud line – at any event there was no visible leakage to surface. Teams of divers with special tools were able to cut the damaged portions of the wells away from the portions sticking up from the seafloor, and then attach a gate valve to the top of each piece of tubing sticking up. Depending on the exact conditions of each well the casing strings either had a hot tap installed on them, or were left 'as is' if they already had all the cement and proper fluids in them to be abandoned without further work. Some of the wellheads were no longer vertical. Efforts to straighten them were limited by the risk of creating further damage to the well, or of starting a leak or spill of oil.

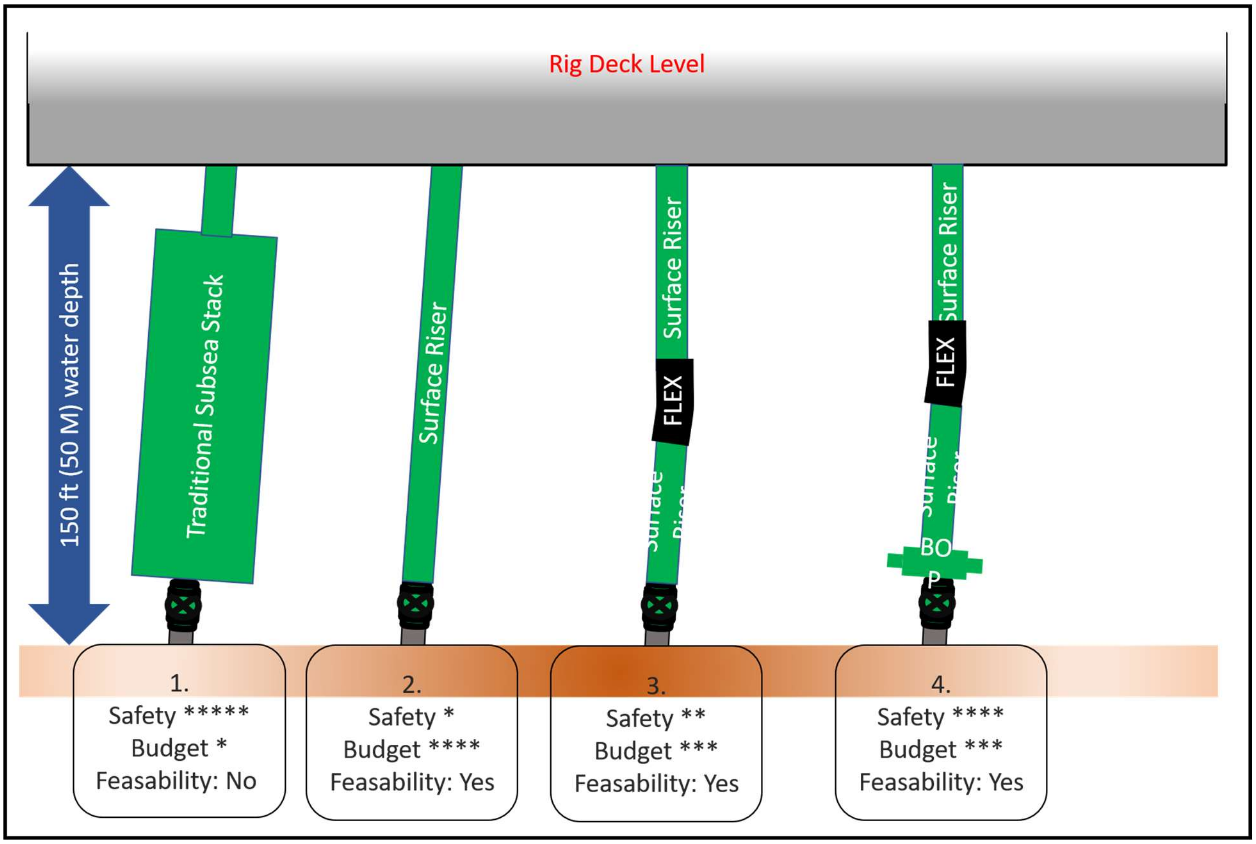
The wells themselves were in a multitude of conditions before the storm: some had been flowing oil or gas wells, others temporarily abandoned, some had fish, sand or other known problems and were awaiting workover and repair. Some were flowing and some were on gaslift. A Jackup rig was the obvious basic tool given the water depth, but how exactly do you safely connect the rig to the wells?



Multiple runs on each well might be required to do everything from slickline investigation, E-line runs to correlate, perforate or cut tubular goods, coiled tubing for squeeze cementing, fishing and cleanout, rig operations to pull tubings and casings, etc. The scope of work was very large. The wells have no proper 'tree' on the subsea. How do you close the well in in the event of an emergency? How do you make the operation as a whole as close to something 'normal' as possible so that the experience and abilities of the people involved are useful?

Decision Process

Starting with 'known' techniques, the process of gaining access to the wells moved in the following way:



Option 1: A traditional subsea stack. Of course it works – it does everything. But some of them won't even fit in 150 ft of water. And can a leaning/tilted well support the weight of the stack without suffering damage? How do you manage to get it underneath a jackup rig which is designed for use with surface BOP's? And if something isn't right with it, how can you service it? Wildly expensive, extremely time consuming, very difficult to utilize, impossible to repair and potentially dangerous if it breaks off a well.

Option 2: A traditional riser with surface BOP's. Obviously very simple, but perhaps a bit TOO simple. When it gets hooked up to or unhooked from a well the only way to open and close the riser and gain access to it with any intervention service is to send a diver down to turn the valve. For that matter, how do you hook it up? The valve has nothing on top of it but studs and a flange. If the well is bent over, how could a diver possibly push the entire surface riser over to connect it to the valve at the correct angle? Divers were definitely required for the project, but how often would this valve have to be actuated? In the event of an emergency of some sort, how long would it take a diver to suit up and get to the valve? Would it even be safe or possible for the diver to get down? How many times could you actuate this valve when it is the final and only method to close the well, and cannot be serviced?

Option 3: Riser with a 3 ft (1 meter) section of coflex hose ~ 5 ft (2 meters) from the bottom end. Solves the bent wellhead problem by limiting the section of riser to manipulate to a short enough piece to manhandle when it's underwater. Ordinarily, coflex hose is not recommended for this sort of service, but there are ways to make it work: Frequent ID inspection is easy to do on such a short section, any tools (motors, fishing grapples, etc.) can be turned off and run through slowly to avoid damage. Certainly not as sturdy as a steel riser, but a viable solution. The shallow depth of the whole project and the fact that no particular amount of tension or compression had to be on the riser made it viable. Collapse resistance in the event that the riser were evacuated of fluids would be a potential concern in deeper water, but not at 150 ft (50 meters). Doesn't solve the diver access issues or the valve reliability issues

Option 4: Install an ordinary blind shear ram on the gate valve, THEN run riser with a coflex section. The following engineering or operational difficulties were analyzed and overcome:

- Do surface BOP's seal from outside pressure? In this case, the answer was yes, provided the pressure wasn't excessive, and at 150' (50 M) it was not.
- Do the fittings leak or potentially leak oil or grease to the environment? Special fittings were used to connect the hydraulic control hoses which could not easily come off, and a tie off point was added to help support their weight near the floor. The closing system for this ram was isolated from any others and used with an environmentally friendly oil so that if a leak were to occur the results would not be damaging
- Will the control oil sludge at reduced temperatures? In this shallow water, in a nearly tropical sea, it was safe, although the environmental oil has a relatively high sludge point compared to normal hydraulic control oils.
- If the hydraulic hoses are evacuated do they collapse under hydrostatic pressure from the seawater above them? No, not with the correct types of premium hoses.
- Can the hydraulic hoses support their own weight over 150' (50 meters) of vertical run without creating a loss in pressure containing capability?
- Is there anything about being submerged that might prevent the BOP from operating? In this case, no – no 'make up air' was required and no potential for vacuum pressure to be introduced might accidentally be created in operation after a careful study of the apparatus and consultation with the original equipment manufacturer.
- Can the BOP work for an extended period in saltwater without suffering damage? The answer was no, BUT, the period was long at least 90 days of submergence could be withstood before rework and inspection was deemed necessary. As it turned out, the operations requiring the BOP's took less than 90 days to complete. Had they taken longer, a second BOP would have been used while the first one was undergoing inspection.

Factors That Made the Solution Work

All the components were 'off the shelf' and well understood by the crews. Special ways to use some of it were required, but what they would do, and how, and how to service them were all well understood and used common techniques. Instead of focusing on the unique and unusual portions of the operation, the crews could focus on the parts which were unknown – the well conditions and what to do about them. All operations were completed successfully, safely, and at lower cost than originally feared. The decision to use an automatic surface controlled BOP turned out to be a key cost saving feature. Aside from being a safety feature (one which thankfully was not needed) it meant that operations on a well could safely continue even in poor weather which might restrict or prevent a diver from working to open and close a well. With the dive team not on constant call to control wellhead valves, simultaneous operations could be conducted in times of good weather, via the rig cementer and coflex hoses connected by divers to check for injectivity on other wells, conduct bullhead cement jobs, and pressure test cement jobs after the riser had been moved off the well. The overall operation was safer, more efficient, easier to conduct and easier to understand and work with than the other options would have been.