Well integrity life cycle

Øyvind Lunde
Conocophillips

Agenda:

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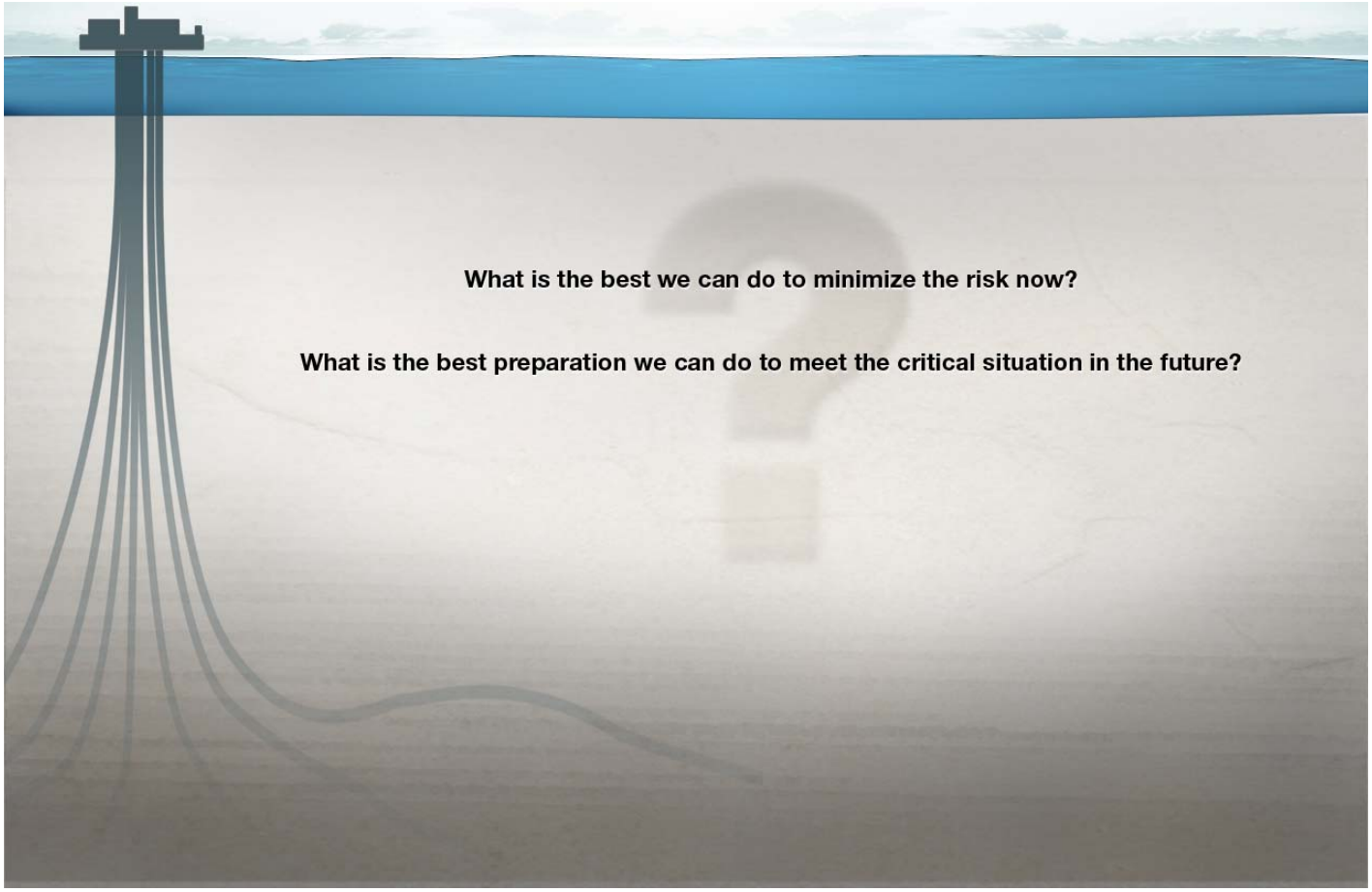
2. Wells integrity lifecycle timeline
3. Design and Plan
4. Placement of casing shoes
5. Isolation
6. Wells Operating envelope
7. Systems and maintenance during operation
8. Slot recovery and P&A



- This presentation is meant to create a discussion on what is important to consider and how we can improve the way we plan, design, make, operate and end a well with a Well Integrity Life Cycle approach.

Future focus during construction

Construction

Operation

S.R/P&A

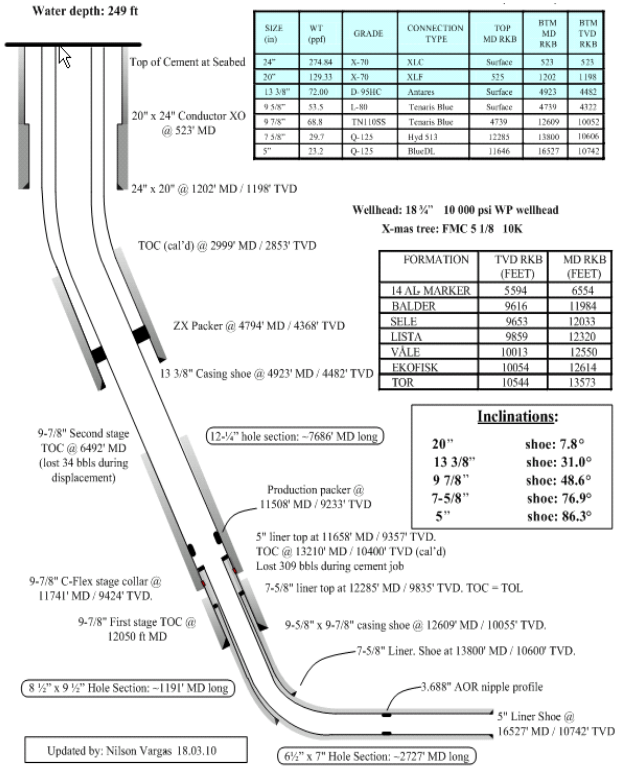
Well Life cycle - timeline

Historical focus during construction

Current focus during construction

Design and Plan

- Many reasons to choose a design but in a well integrity perspective it is of the uttermost importance to high light the following:
  - Use a design that is optimized with respect to the formation in the specific area (to make sure to have integrity in all relevant layers)
  - Design envelope fit for purpose
  - Materials used (corrosion/erosion etc)
  - Reliability of equipment
  - Monitoring capabilities
  - How to avoid Sustained casing pressure, X-flow and how to have "the best defense" against collapses.

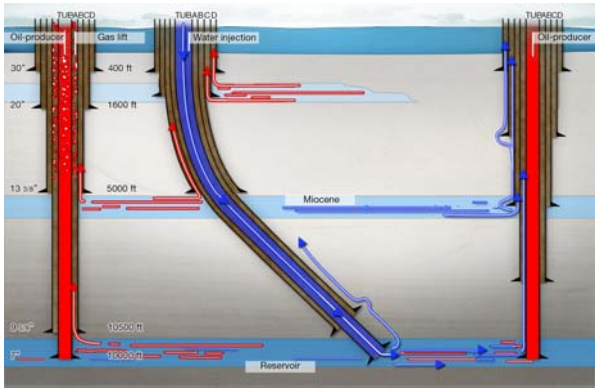


SIZE (in)	WT (ppf)	GRADE	CONNECTION TYPE	TOP MD RKB	BTM MD RKB	BTM TVD RKB
24"	274.84	X-70	XLC	Surface	523	523
20"	129.33	X-70	XLF	525	1202	1198
13 3/8"	72.00	D- 95HC	Antares	Surface	4923	4482
9 5/8"	53.5	L-80	Tenaris Blue	Surface	4739	4372
9 7/8"	68.8	TN110SS	Tenaris Blue	4739	12609	10052
7 5/8"	29.7	Q-125	Hyd 513	12285	13800	10606
5"	23.2	Q-125	BlueDL	11646	16527	10742

FORMATION	TVD RKB (FEET)	MD RKB (FEET)
14 AL₇ MARKER	5594	6554
BALDER	9616	11984
SELE	9653	12033
LISTA	9859	12320
VÅLE	10013	12550
EKOFISK	10054	12614
TOR	10544	13573

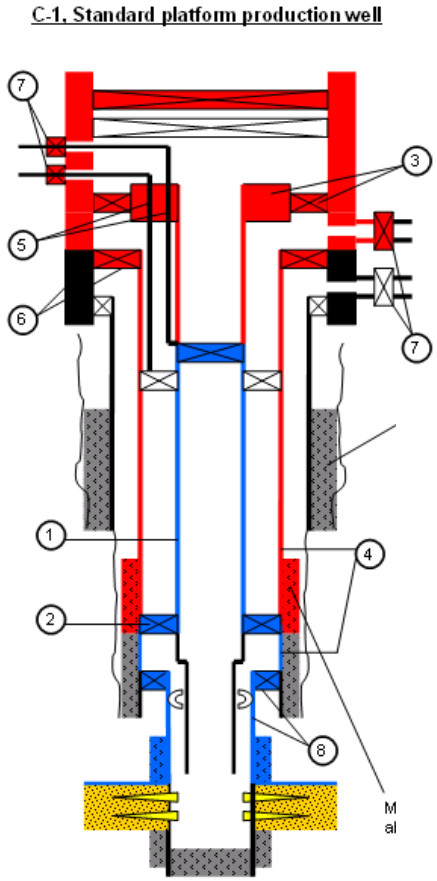
Design and Plan

- Plan:
  - Plan should have input from well integrity personnel or well integrity personnel should be involved in the planning.
  - Plan must always be revised by key personnel
  - Plan with contingences (plan for the unplanned)
  - Avoid unplanned ”quick fix”.
  - Plan the Work and Work the Plan (a plan is a live document).



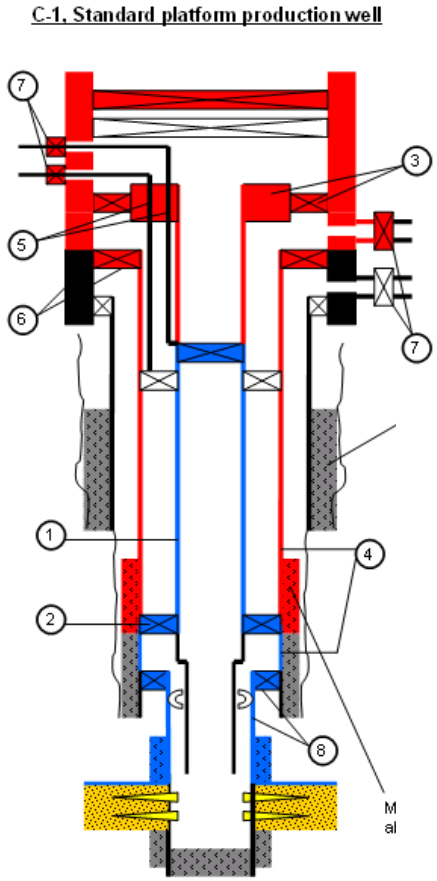
Placement of casing shoes

- Where we place the casing shoes is not only important for the drilling phase of the wells life cycle, it has also a big influence on well integrity in a life cycle approach
- All casing shoes that are set in formation that has enough strength to withstand reservoir pressure will give you increased safety and options with regards to barriers against a reservoir
- Placement of casing shoes and the isolation of these is a deciding factor to avoid sustained casing pressure including leaks of hydrocarbons into annuluses
- Smart thinking with a life cycle approach with regards to placement of casing shoes can increase the lifetime of the well and reduce cost in a P&A phase



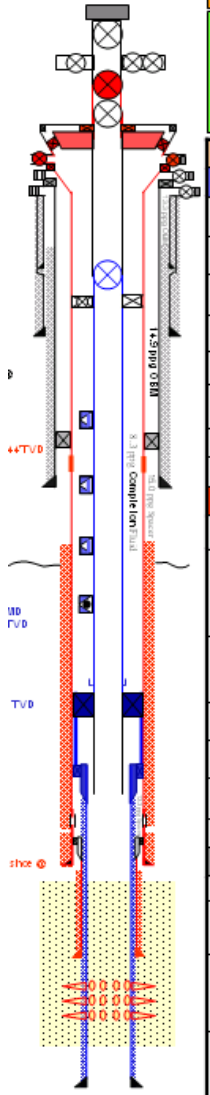
Isolation

- Isolation is probably the single most important barrier element and one of the most difficult to establish and verify.
- When we isolate we are trying to re establish the seal that the formation had prior to penetrating it when drilling.
- Good isolation reduce overall risk and reduce risk of sustained casing pressure.
- Good isolation can increase well lifetime and reduce cost in workovers and P&A.
- We need more isolation tools (medium) in our toolbox and increase our efforts on methods/technology to be able to lift medium. This to ensure proper isolation in all phases.



Wells Operating envelope

- Every well that we make must have a clear operating envelope.
- Make sure to stay within the operating envelope
- If we have any incidents that takes us outside the operating envelope with regards to loads etc., this shall be documented, reported and investigated.
- Avoid any unnecessary strain on the well e.g. evacuated annuli etc. whenever possible.
- Use the well for the purpose that it is designed for.



Comments:

Maximum Operating Pressures*):

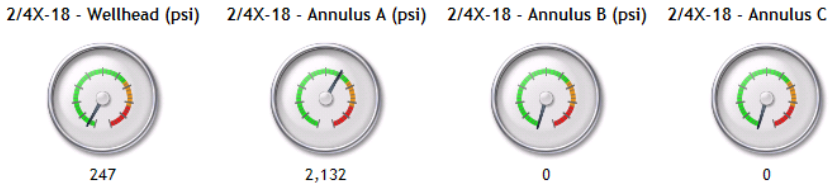
Tubing:	**5000 psi**
A Annulus (Tbg x 9-5/8") :	**3000 psi**
B Annulus (9-5/8" x 13-3/8") :	**1500 psi**
C Annulus: (13-3/8" x 20") :	**200 psi**

*) These max pressures do not apply to well intervention operations

Barrier Elements	Tests/ Other Verification
Primary Barrier Envelope	
1.1 5" Reservoir Liner	3450 psi w/ 12.0 ppg (Jul 6, 2010) 5000 psi w/ SW (Jul 6, 2010)
1.2 Liner Cement	Lost 20-24 bbls of mud during entire job. Circ. Out 80 bbl spacer. (Jul 3, 2010)
1.3 5" Liner Top Packer	2000 psi w/ 13.3 ppg OBM (Jul 3, 2010) Inflow test to 0 psi differential after displaced to SW
1.4 Production Casing (9-5/8" x 9-7/8", Tenaris Blue connections)	5000 psi w/ Compl. fluid (Jul 6, 2010)
1.5 Production Packer	5000 psi differential from above (Jul 10, 2010)
1.6 5-1/2" Production Tubing	5000 psi burst with Comp fluid (Jul 10, 2010) 5000 psi collapse with Comp fluid (Jul 10, 2010)
1.7 GPM / GLV	5000 psi differential test (Jul 10, 2010)
1.8 DHSV / TRSV	2600 psi inflow test (Jul 10, 2010)
Secondary Barrier Envelope	
2.1 7-3/4" Liner hanger	3600 psi with 12.7 ppg (May 20, 2010)
2.2 Production Casing. *Production casing is common barrier with 1# between 5" Liner Top and production packer.*	9 5/8" x 9 7/8" casing * 3600 psi with 14.9 ppg (May 12, 2010) * 5000 psi w/ Compl fluid (Jul 6, 2010) 7 ¾" liner * 3600 psi with 12.7 ppg (May 20, 2010)
2.3 Production casing cement	* 1932 psi differential inflow test when 9-7/8" shoe drilled (May 12, 2010) * FIT of 13.4 ppg EMW (750 psi w/ 12 ppg mud) on 7-3/4" shoe (May 25, 2010)
2.4 Production Casing Hanger pack-off: (9 5/8")	5000 psi test between seals (May 4, 2010)
2.5 WH (Unihead) & 2-1/16" Valves	A annulus valve tested to 10000 psi. B and C annulus tested to 5000 psi (March 29, 2010)
2.6 Tubing Hanger pack-off	5000 psi from below (Jul 10, 2010) 10000 psi test between seals (Jul 11, 2010)
2.7 X-mas tree body & valves	10000 psi against UMV (Jul 12, 2010)
Other Elements	
24" x 20" Conductor & WH	1000 psi with 10.0 ppg (Dec 26, 2004)
13-3/8" Casing, Hanger Wellhead Body, Valves	Pumped cement job. Plug bumped. 3500 psi with 13.1 ppg mud after cement job (Jan 01, 2005)
C-Flex diverting sleeve	Tested integrity on C-flex to 1000 psi and pulled with 40 Klbs overpull and observed shear to lock the C-flex. Unable to permanent close C-Flex sleeve after cement job due to leaking cups (April 9, 2010).
AHC Packer inflated as compensating measure (for not cementing the production casing annulus into the 13-3/8" shoe).	AHC packer tested to 2500 psi from above (May 10, 2010)
CASV	5000 psi with Comp fluid (Jul 10, 2010) 2500 psi inflow test (Jul 10, 2010)

Systems and maintenance during operation

Source	Date	Well Status	Operative?	Wellhead Limit	Ann. A Limit	Ann. B Limit	Ann. C Limit
ABOF	16MAY2011	GAS_LIFT	1	5000	3000	1500	200



2/4X-18 - Last PM test

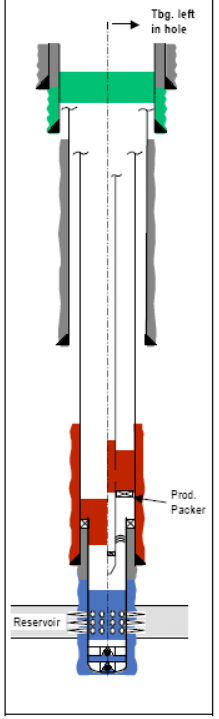
Well	Category	Last Test Date	Last Test Result	Test Comment	Last Accepted Test Date	Next Planned Test
2/4X-18	AFV	13JAN2011	1		13JAN2011	.
2/4X-18	ANNULUS A	15JAN2011	1		15JAN2011	.

- Training.
- Management system
- Proper handover process and documentation.
- Preventive maintenance program on all relevant equipment and at a frequency that is optimized for the well.
- Competent personnel and enough recourses to maintain the wells.
- Important with document control and steering systems, to be able to trend equipment and sources of failure.
- Preventive maintenance is meant to be a proactive system to minimize the risk of failure.
- Experience transfer.

Slot recovery and P&A

- How we design, drill, complete, operate, intervene and maintain a well will have an influence on P&A.
- P&A should be done as soon as possible when a well is no longer producing.
- It is crucial that a good P&A (securing) is done on existing wellbore before re-use of the slot. Failing to do so can cause unintentional leaks into formation or/and a leak into the new well.
- Good isolation when building a well makes it more likely to get an appropriate P&A and will in most cases reduce cost.

9.8.4 Permanent abandonment - Perforated well



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner cement	22	
2. Cement plug	24	Across and above perforations.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
or, for tubing left in hole case:		
1. Casing cement	22	
2. Cement plug	24	Inside and outside of tubing.
Open holes to surface well barrier		
1. Cement plug	24	
2. Casing cement	22	Surface casing.

Notes
1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Construction

Operation

S.R/P&A

Well Life cycle - timeline