Risk Informed Decision Support for UDW Drilling

Oil and Natural Gas

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Summary of LANL Analyses

Status update and a review of preliminary findings

- Over the past three decades there has been a steady decrease in 'major' kick frequency; more recently, frequency is about 1 in 10 wells. A majority of the kicks occur in the shallower regions where the primary hazard is the release of natural gas, some condensates and synthetic mud to the environs. A small fraction (1 in 100 wells) kick while drilling and cementing in the target region where oil and other condensates present blowout hazard.
- Ultra-deep water formations stratigraphy and reservoir properties are significantly different compared to previous operational experience.
- Our modeling efforts included development of accident progression event trees that enumerated an exhaustive list of possible accident sequences; barrier analyses that quantified reliability of each barrier; and physics-based well dynamics models that explicitly captured timing of events. We have used a generic well design and well operations that are consistent with IADC and API guidance.
- Important barriers in place to mitigate a kick (e.g., Lower Marine Riser connection (LMRP), Blowout Preventer (BOP) and Drill Pipe Safety Valves) are vulnerable to control system and design deficiencies. They are also susceptible to operators instinct not to cause unnecessary damage to the well or release synthetic mud into environment.
- Our preliminary findings provide insights into risk-importance of several technologies that are being proposed or in the initial testing and deployment phase. Accelerating their deployment would likely lower the risk of uncontrolled release of formation HCs into the environs.

Summary of Preliminary Analyses
Risk-ranking of examined technologies

1. Real-time data transfer (testing and deployment stage with limited band-width)
2. VSP Look ahead with PAB in the target region (early deployment stage; mixed industry buy-in)
3. Automated Early kick detection system (in use, but not mandated with QA and surveillance requirements and standards). Following additional capability will improve performance
   - MWD with “Positive” HC detection
   - Sensors for flow, temperature and pressure in the well at different locations
   - Direct pore pressure measurement
4. Improved operator training & controls assisted by automated MWD systems (in use, but not mandated with QA and surveillance requirements and standards)
   - Connection, hole cleaning and lost-circulation repair
   - Casing run and Cementing (location of casing pipe versus BOP)
   - Tripping/Swabbing (along with PBL drill-pipe bypass tool & improved procedures and controls)
5. Reliable multiple drill-pipe blowout preventers (in addition to modern Kelly stab-safety valve)
6. “Emergency containment and production” infrastructure (Reliable LMRP disconnect, etc.)
7. Robust BOP with double annular preventer, minimum 3 pipe rams and shear ram. Improved closure reliability and operability
8. 3-D/4-D Seismic & Improved pore pressure prediction during planning and after salt region
9. Improved well control and response modeling to aid reliability based well design (vs worst case discharge)

Mechanics of a kick and blowout

- Incipience of a kick when P_p > BHP
  - Unanticipated high P_p
    - Measurement uncertainties
    - Sub-salt formations w/ limited seismic
    - Multiple “pay sands”
  - Low Bottom Hole Pressure
    - Incorrect mud weight or replacing mud too soon (human failure)
    - During connection, stuck-pipe, pumping break (reliability and human)
    - During tripping, swabbing & surge (human failure)
    - Loss of mud to environment or to formation (e.g., LMRP disconnect, casing/shoe failure, formation breakdown when BHP > P_{fract})
    - Gas cut mud (natural)
    - Poor cementing at the bottom hole (human/materials/procedures)
- Major kick (influx > 20 bbl) and possibly blowout result when
  - Reservoir is of high quality, and
    - Large P_p, porosity (φ), permeability (k), compressibility (c), and low viscosity (μ)
    - Reservoir height (h) and hole size (R_w)
  - Formation does not breakdown ‘self-terminating’ the kick
  - Active controls fail to contain and terminate the kick

$$q_{HC} = \frac{1.77X10^{-2}\, hk(P_p^2 - BHP^2)}{\mu_{HC} Z T \ln\left[\frac{4kt}{1.02\gamma\varphi c R_w^2}\right]}$$

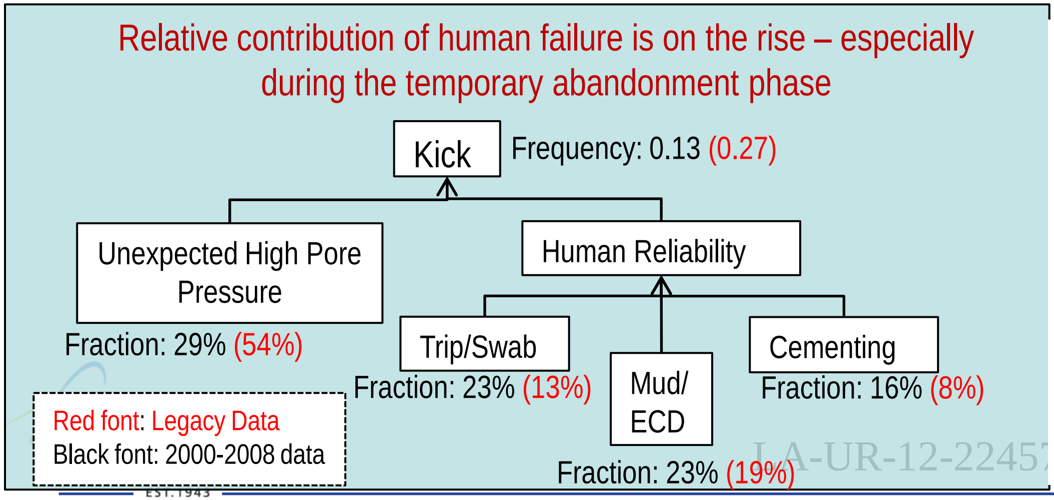
q_{HC} = *flow rate from reservoir (kg/s)*
T = *reservoir temperature (K)*
C = *reservoir compressibility (Pa^{-1})*
μ_{HC} = *HC fluid viscosity (kg/m.s)*
P_p = *pore pressure (Pa)*
Φ = *porosity*
R_w = *wellbore radius (m)*
h = *reservoir height (m)*
k = *permeability (m^2)*
Z = *gas factor*
t = *time (s)*
Υ = *Euler constant*
BHP= bottom hole pressure (Pa)

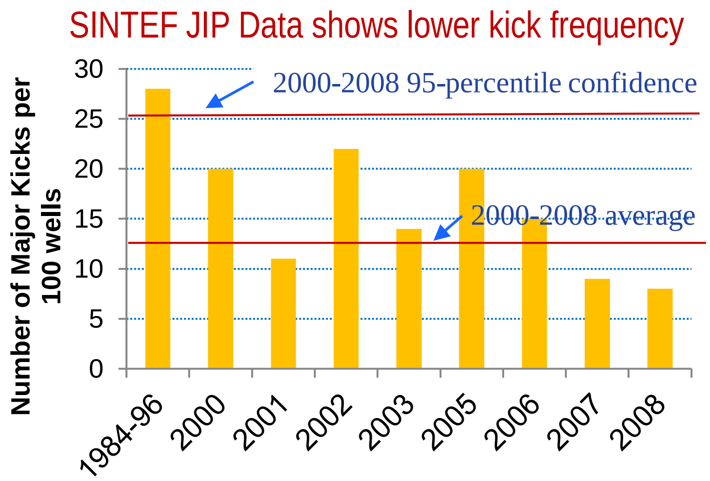
$$BHP = BHP_{MW} + BHP_{fr} \pm BHP_{srg/sw}$$

BHP_{MW} hydrostatic pressure (psi)
BHP_{fr} friction-loss in annulus (psi)
$BHP_{srg/sw}$ loss or gain (psi)

Kick Likelihood and Causes during Drilling and TA Phase
Results of Preliminary Analyses

- In UDW wells there is a narrow pressure window between pore pressure and formation fracture pressure (often < 1 ppg). Operational history from the past three decades indicates a clear trend of decrease in kick likelihood during <u>drilling</u>.
  - Median kick frequency between 2000-2008 is approximately 1 in 6-10 wells (or @ 95-% confidence:1 in 3 wells). This is much lower than 0.27 (or 1 in 4) experienced during 1984-1996
  - Most of the kicks occur in shallow regions due to unexpected high pore pressure resulting in release of sour-methane gas and synthetic drilling mud.
  - Less than 10% of the kicks occur in the target region (at critical depth) where there is potential for release of crude and other condensates into environment.
- Kick Occurrence, therefore, can't be discounted during drilling or cementing operations in the target region with a likelihood of 1 in 50-100 wells.
  - Use of advanced technologies has reduced kick likelihood due to unexpected high pore pressure
  - Kicks due to human and equipment failure continue to be an issue





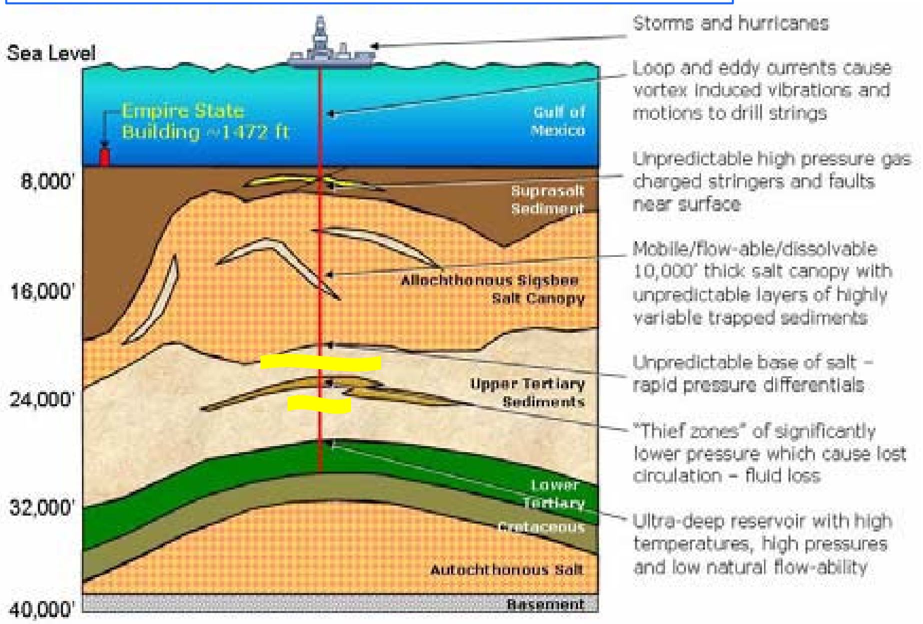
Stratigraphy and Heterogeneity impact on UDW Drilling
History is not indicative of future performance

- Ultra-deep water plays have unique characteristics different from the past history.
  - Reservoirs are often at greater subsea depths: 20,000 to 30,000 ft and often have HPHT (>15,000 psi & >180ºF)
  - Seismic imaging of subsalt reservoirs is often poor
  - Reservoirs are consolidated, cemented and have low rock compressibility. They often have lower porosity and permeability but with local seismic fault regions that could have very high permeability
  - Increased diagenesis in sands with volcaniclastic components reduces compressibility, increases drilling time and, affects mud chemistry (gelatin)
  - Lower overburden significantly lowers window between pore pressure and formation fracture pressure in the target region; some times window less than ½ pound-per-gallon (or 200 – 300 psi)
- These conditions have significant impacts on kick outcome

Table 1. History (Dobson) shows that sub-salt depth wells are difficult to drill and likely to kick more often.

Well History (2003-2010)	< 1000 ft Water depth (263 wells)	> 3000 ft Water depth (sub salt)	> 3000 ft water depth (non subsalt)
average days to drill	35	97	54
total non productive days	4	29	9
Important Contributors to Non Productive Time			
Stuck pipe	2.20%	2.90%	0.70%
Wellbore instability	0.70%	2.90%	0.90%
Days to Instability	0.245	2.813	0.486
Lost circulation	2.30%	2.40%	2.00%
Days of Lost Circulation	0.805	2.328	1.08
Kick	1.20%	1.90%	0.80%
Days of Kick	0.42	1.843	0.432
BOP Failure	1.40%	5.60%	3.80%
Days of BOP Failure	0.49	5.432	2.052
Case head fail	0.40%	2.10%	2.20%
Rig fail	1.30%	6.30%	3.50%

Phenomenological description of the challenges (Chevron)



Accident Progression Event Tree – Overview

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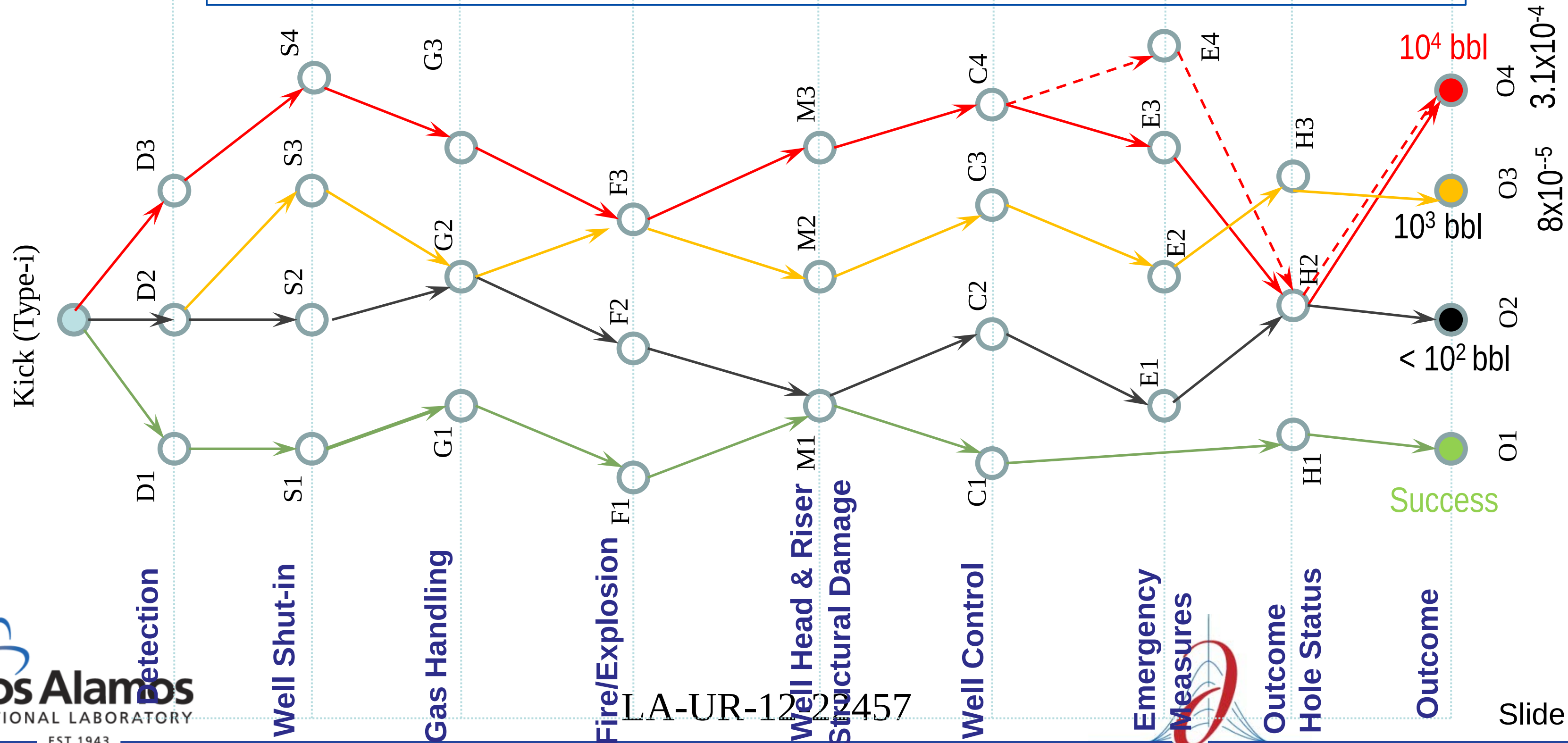
- Possibility theory provides a good framework for enumerating, characterizing and ultimately quantifying very low frequency and high consequence accident sequences
- Accident progression event tree is a method used to functionally examine potential outcomes of each postulated operational incident and the barriers in place to mitigate.
  - Example below illustrates four ‘dominant’ accident progression scenarios associated with a kick (unanticipated influx of reservoir HCs into the well). In reality numerous such scenarios are possible, but they are ‘binned’ into these four scenarios to simplify description without losing accuracy

$$P^{Red} = P(D3|kick) \,.\, P(S4|D3) \,.\, P(G3|S4) \,.\, P(F3|G3) \,.\, P(M3|F3) \,.\, P(C4|F3,M3) \,.\, P(E3)$$



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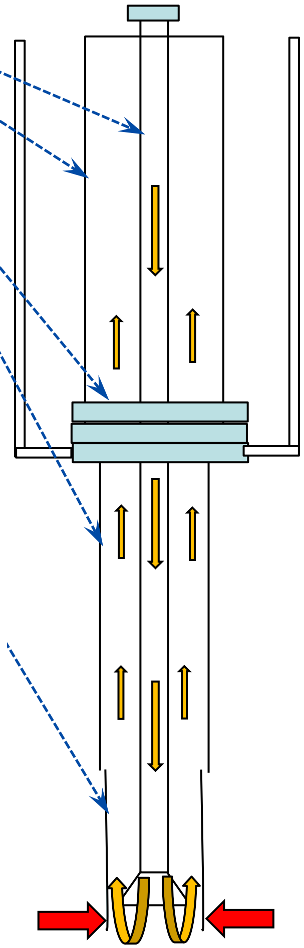
Time scale of Accident Progression
Results of LANL 2-D Well Dynamics Modeling

Nominal Geometry

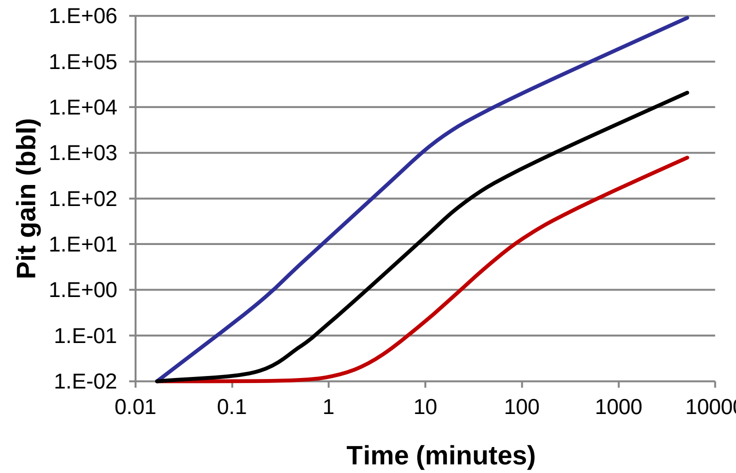
Drill Pipe	5.5 in. OD (0.4 in. thick)
Riser	16-in. ID (0.35 in. thick)
BOP	- 5000 ft. (height)
Casing	9 5/8 in. OD (8.9 in. ID)
TVD	18,500 ft.
Hole size	8.5 in. ID
Hole	500 ft.
Flow	250 gpm (base case)



Reservoir Properties

Parameter	**Units**	**Neogene**
Reservoir Thickness	ft	50
Porosity	%	28
Water Saturation (Sw)	%	25
Permeability	mD	500
Rock Compressibility	µsips	12
Reservoir Pressure	psia	11, 000
Reservoir Temperature	F	186
Saturation Pressure	psia	5, 000
API Density	API	32.0
Gas-to-Oil Ratio	Scf/stb	1, 000
Absolute Open Flow	Stb/d	33, 000

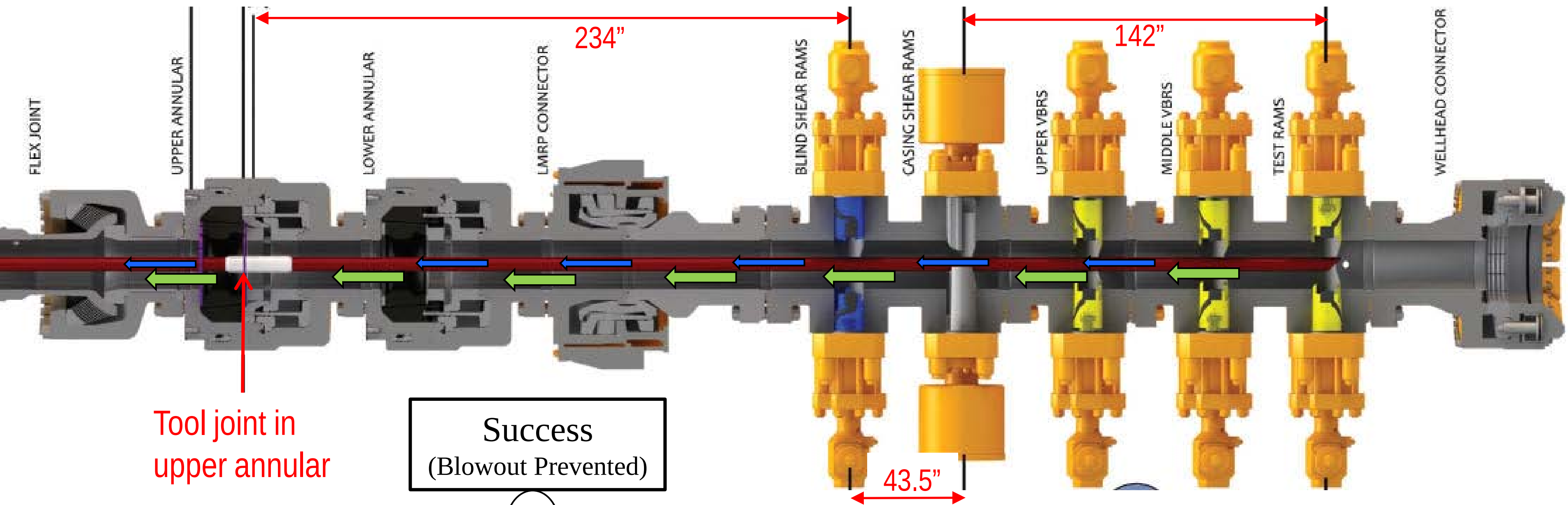
Transient Response of an Idealized Kick

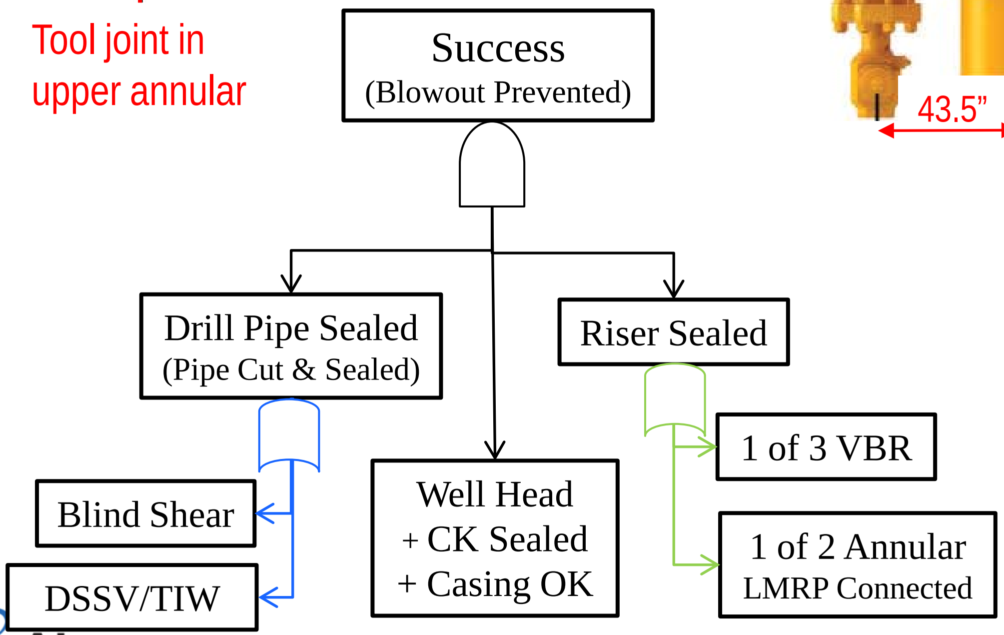


Preliminary Model Results for blowout rates (bbl/d)

Pathway	Eff. Reservoir Height (ft)		
	50-ft	25-ft	5-ft
Drill Pipe (undamaged)	22, 500	17, 200	5, 200
Drill Pipe (25% Area)	13, 500	TBD	TBD
Annulus (undamaged)	30, 000	18, 100	5, 500
Annulus (25% Area)	15, 000	TBD	TBD
No Drill Pipe	31, 000	19, 400	5, 500

BOP Functionality during Blowout





- EDS (Deadman switch) releases LMRP
- Weekly test of control systems
- 2-week Pressure Testing of VBR
- 4-week Pressure Testing of BSR
- Casing ram can shear the pipe. BSR can then be used to seal the pipe
- Procedures call for the tool joint in the upper annular

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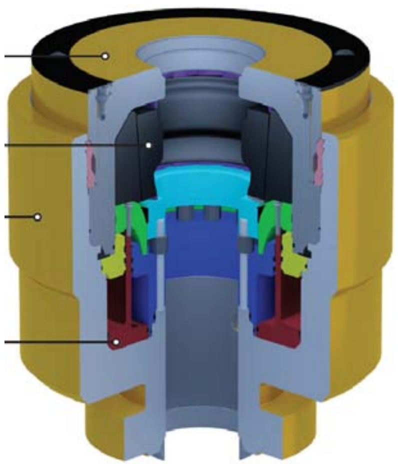
Annular Performance & Reliability

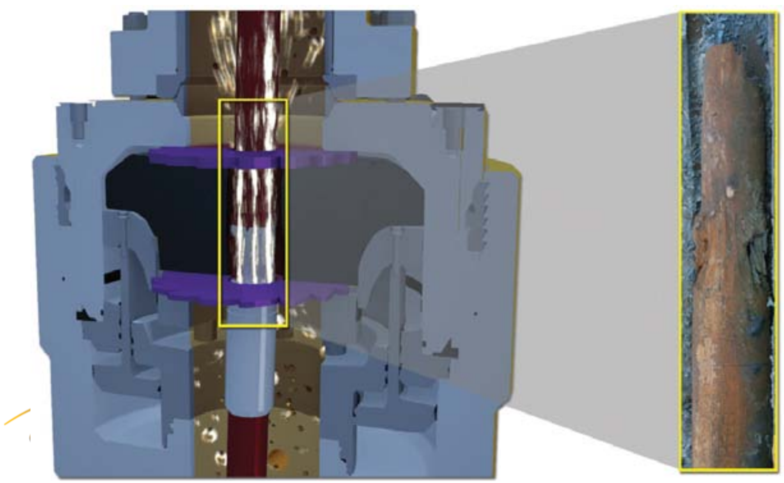


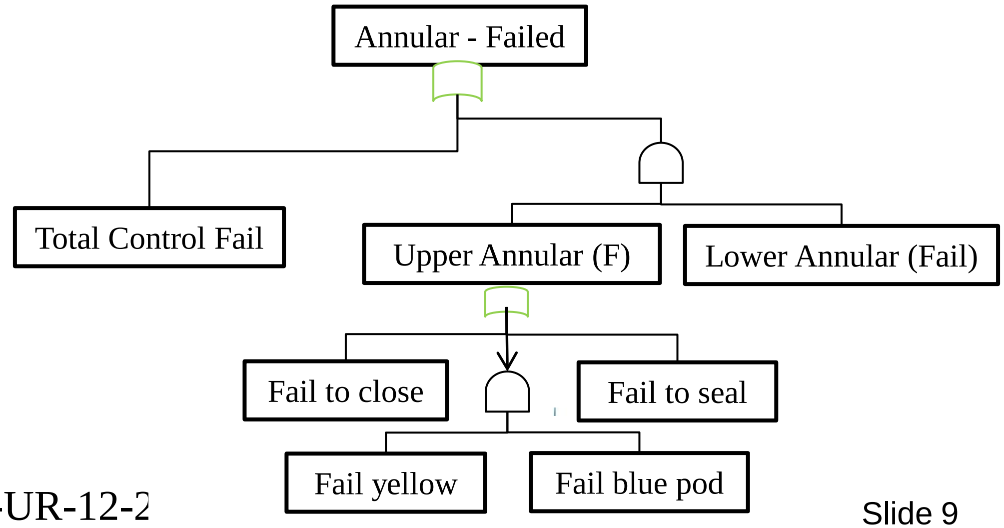
A typical Cameron Annular

An annular blowout preventer has a rubber sealing element that, when activated, seals the annulus between the kelly, the drill pipe, or the drill collar. If no part of the drill stem is in the hole, the annular blowout preventer closes on the open hole.

Failure Mode for the annular preventer SINTEF-1999 JIP 2008-2009	Mean Time to Failure(d)			Test	PFD
	SINTEF		JIP	(d)	
	95%	Avg.	Avg.		
Fail to close	814	1862	4595	14	0.0015-0.008
Fail to seal blowout	629	1242	N/A	190	0.07 – 0.15
Control (MUX one pod)	305	573	430	7	0.006 – 0.012
Control (Total Fail)	845	4009		7	0.0008 -0.004

Fail to seal can lead to erosion of drill pipe





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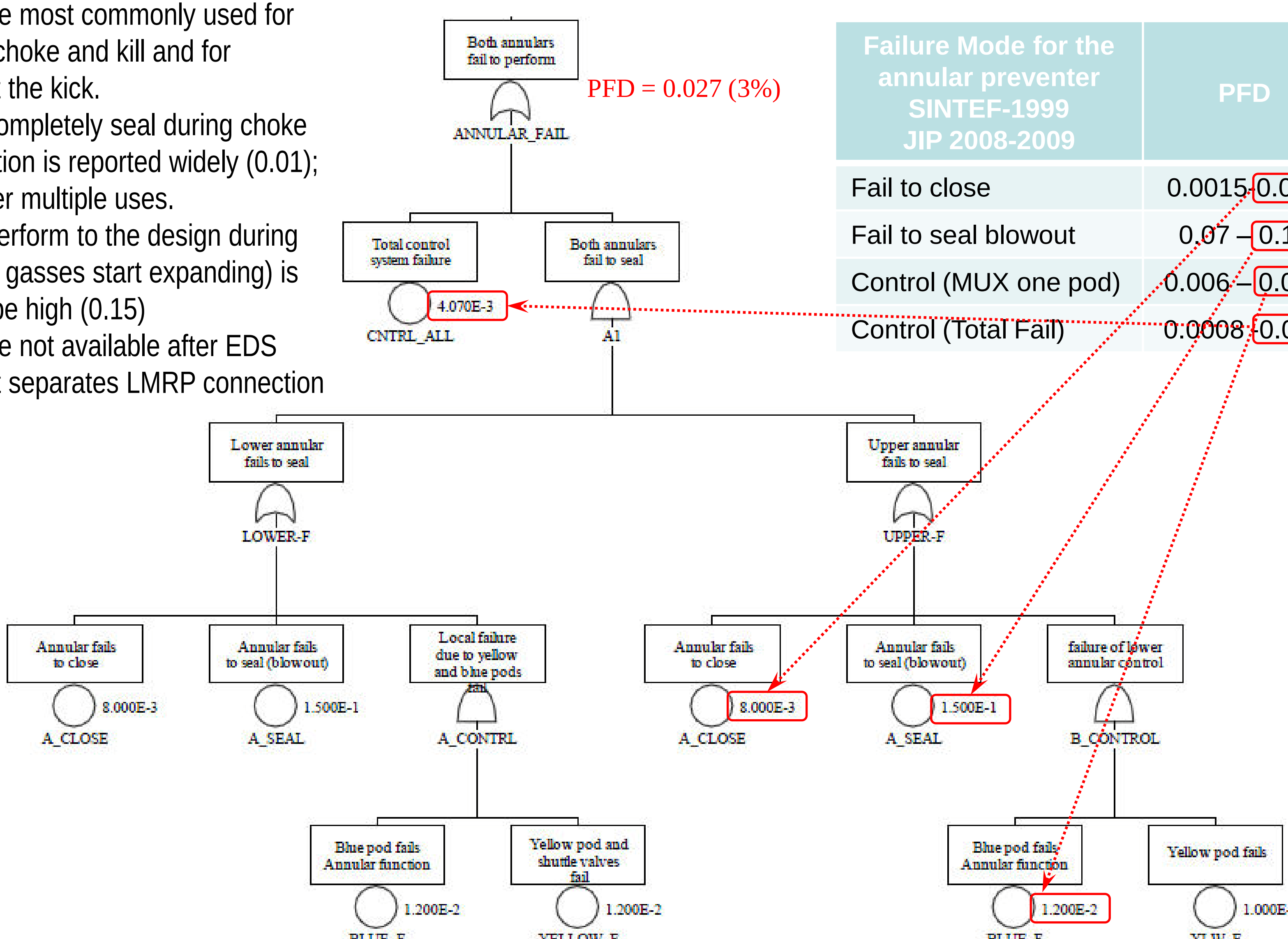
Annular Reliability: Fault Tree

- Annulars are most commonly used for hard shut-in, choke and kill and for circulating out the kick.
- Failure to completely seal during choke and kill operation is reported widely (0.01); especially after multiple uses.
- Failure to perform to the design during blowout (after gasses start expanding) is estimated to be high (0.15)
- Annulars are not available after EDS activation that separates LMRP connection



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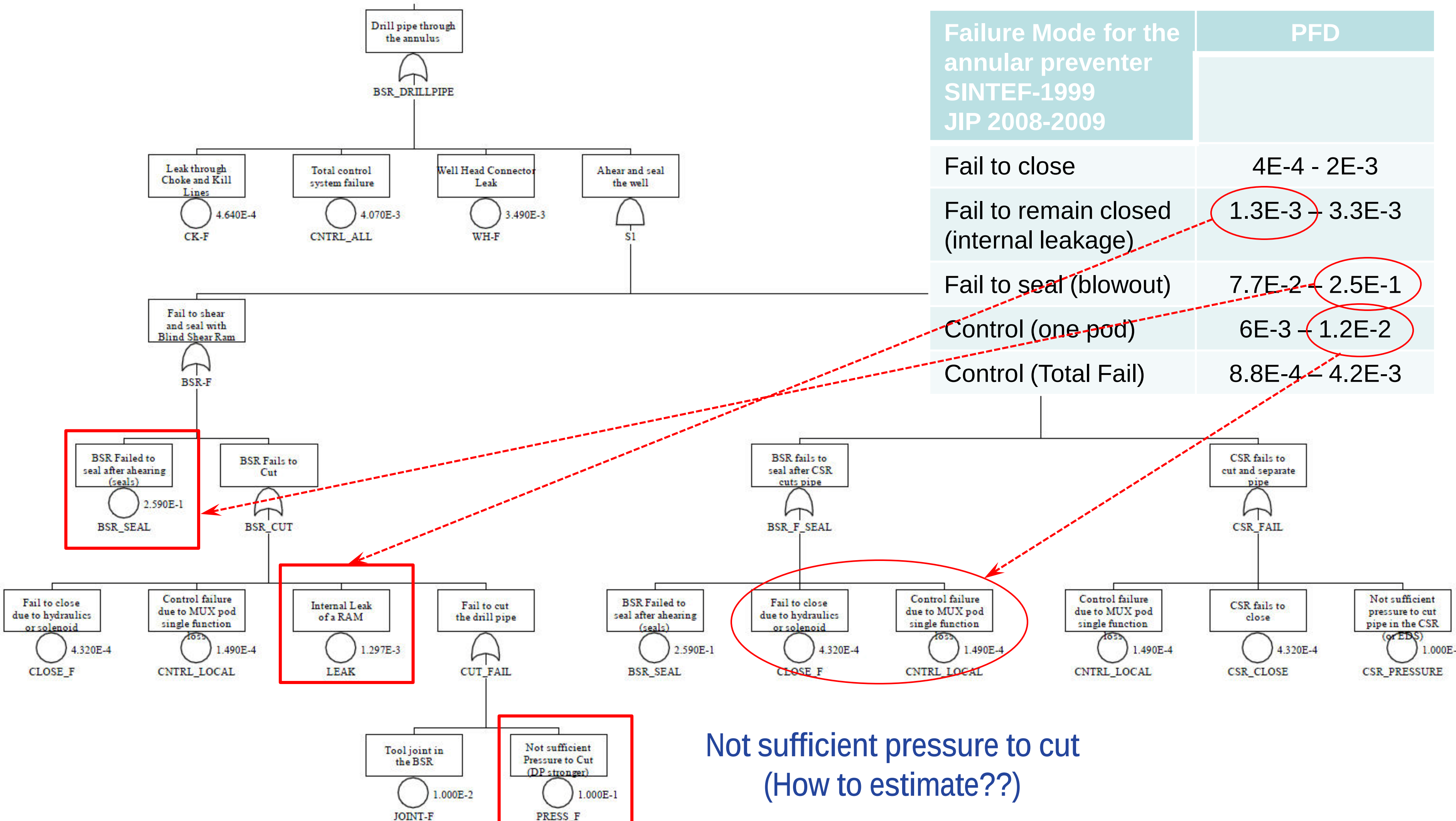
Fault Tree for a BSR/CSR Cut DP & Seal



Failure Mode for the annular preventer SINTEF-1999 JIP 2008-2009	PFD
Fail to close	4E-4 - 2E-3
Fail to remain closed (internal leakage)	1.3E-3 – 3.3E-3
Fail to seal (blowout)	7.7E-2 – 2.5E-1
Control (one pod)	6E-3 – 1.2E-2
Control (Total Fail)	8.8E-4 – 4.2E-3

Not sufficient pressure to cut
(How to estimate??)

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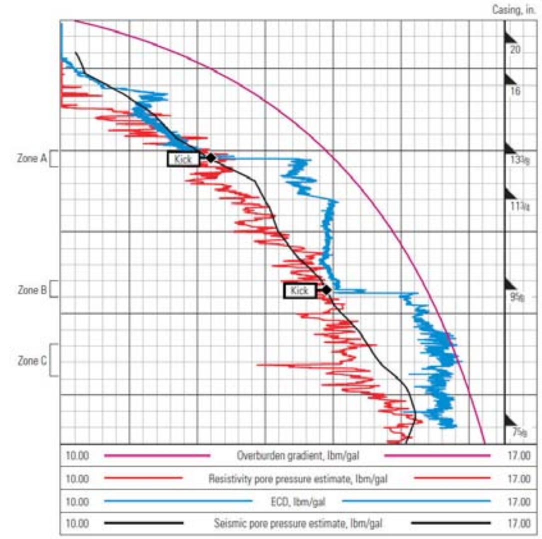
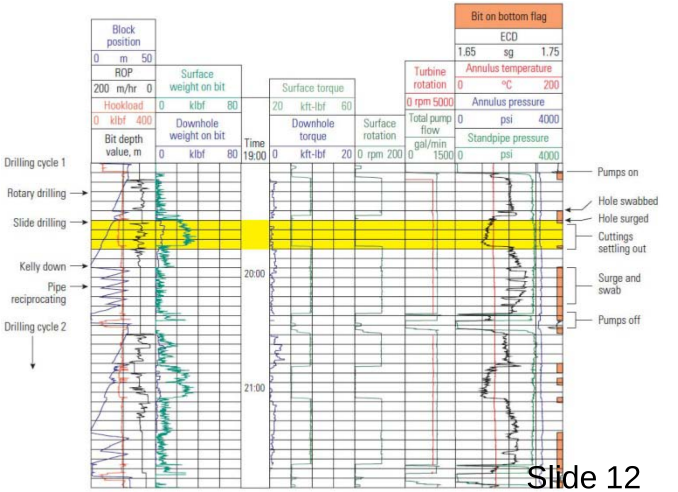
Preliminary Analysis Results

- Present barriers to prevent blowout thru DP have known vulnerabilities
  - BOP and LMRP have a failure Prob Fail on Demand >10%
    - ✓ This failure is dominated by inadequate control system and insufficient design margin (e.g., design does not accommodate back pressure from the well or erosion of internals by fast moving sand and debris)
    - ✓ BOP performs best when annular preventers and rams are activated before kick fluids expand in the casing and create high fluid velocities.
  - TIW Drill Pipe Safety Valves require human intervention under stressful environments and are not reliable
    - ✓ Numerous recorded failures because operator burned hands
- Technology Development, Standardization, Quality Assurance and Insertion will lower blowout likelihood, examples include
  - Predict ahead of bit (PAB) using Look Ahead VSP and Sonic
  - Real-time drilling indicators from MWD/LWD
    - ✓ ECD > PP (confirm continuously in real-time)
    - ✓ ECD < Formation Fracture Pressure (confirm continuously in real-time)
    - ✓ Entry into sand stone formation (alert mud system manager)
    - ✓ Annulus pressure and temperature at multiple locations (surge/swab)
    - ✓ Positive indication of hydrocarbons in the annulus (kick vs breathing)
- Our “sequences” are re-quantified using these technologies to quantify and rank importance of each proposed new technology



MWD and Look Ahead VSP Usage in “Real-Time” can transform operations during drilling by lowering knowledge gaps (above) and alerting human errors (below)



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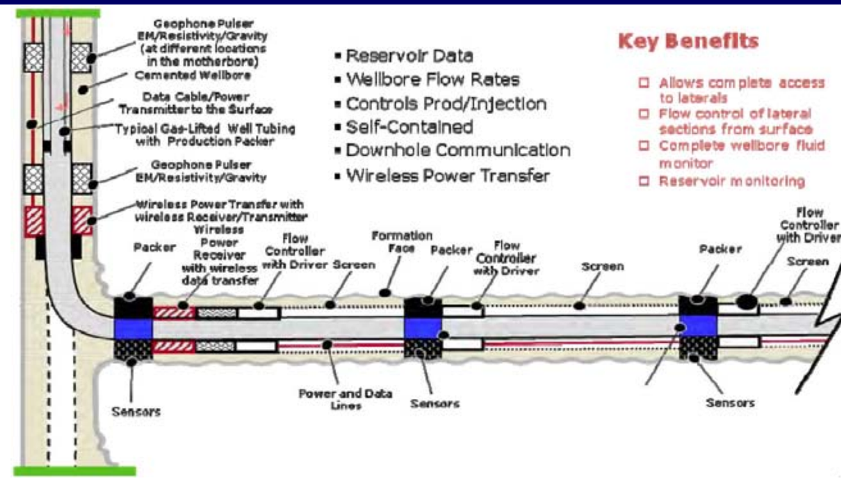
Backup slides (details for discussion)

Near-real time data to decisions

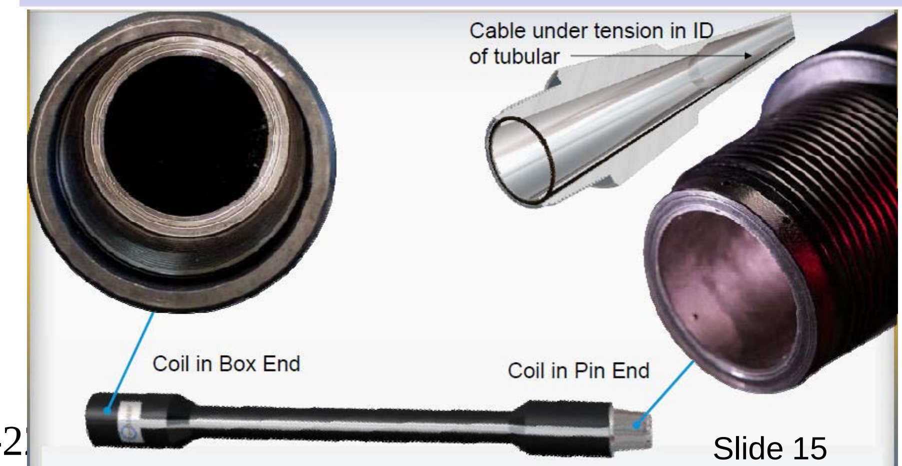
Data pipe for high speed data transfer

- Conventional Technologies (20 – 1000 bits/s)
  - Mud Pulse telemetry
    - Positive Pressure Pulse or Continuous Pressure Wave in
  - Acoustic Pulse along DP
  - EM signal using DP as dipole
- State-of-the-art for high band width real time data transfer
  - In testing and early deployment stage
    - ✓ "Wired" Drill Pipe (in use on several rigs with ≈100 kbits/s)
    - ✓ Enables 2-way communication
    - ✓ Other being developed and proprietary (≈1 Mbits/s)
  - Few documented regulatory and reliability analyses
    - ✓ Reliability requirements
    - ✓ Surveillance and Quality Assurance
- Vulnerability & Reliability Assessments
  - Loosing several hops limiting transfer rate
  - Mud pulse system backup for critical data

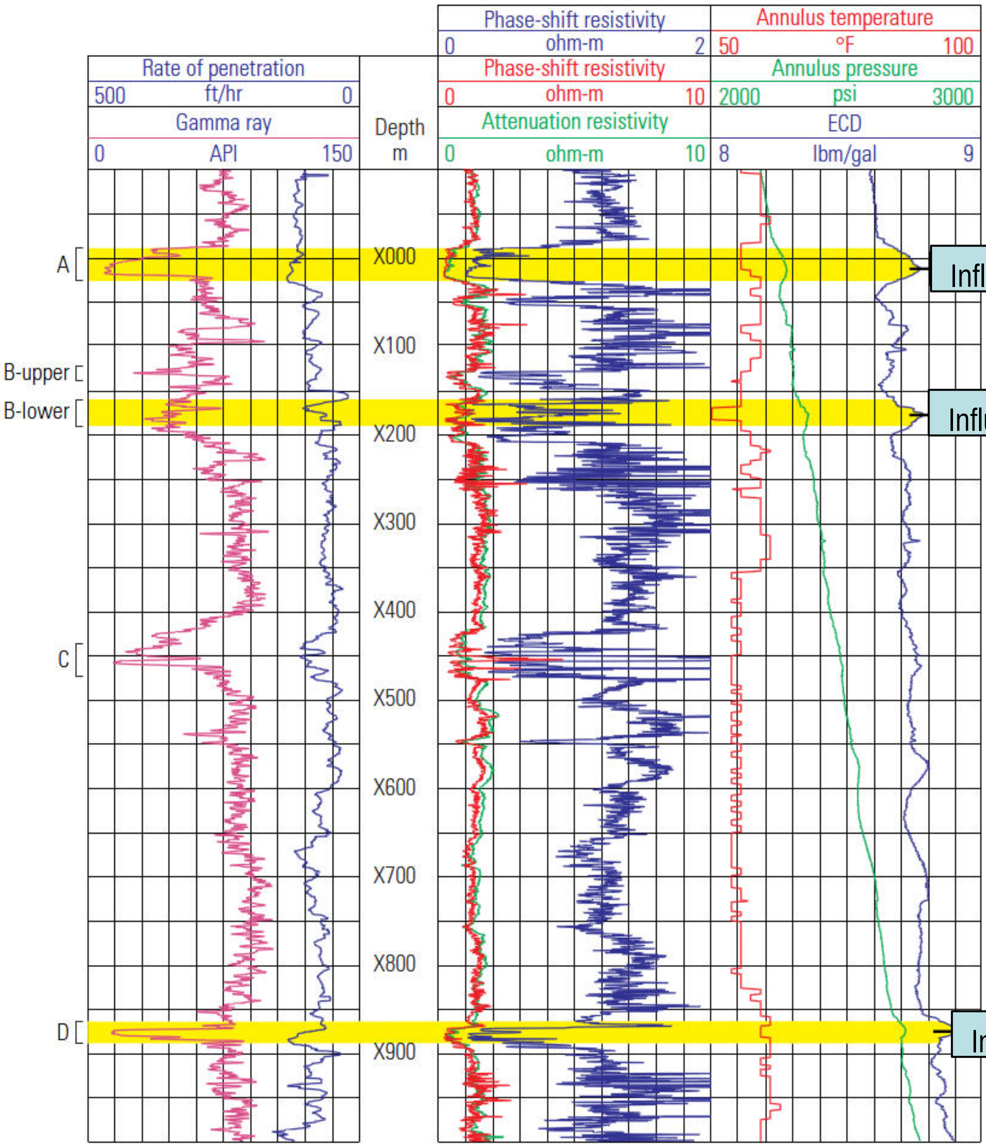


RPSEA Tubel Intelligent Production System for UDW

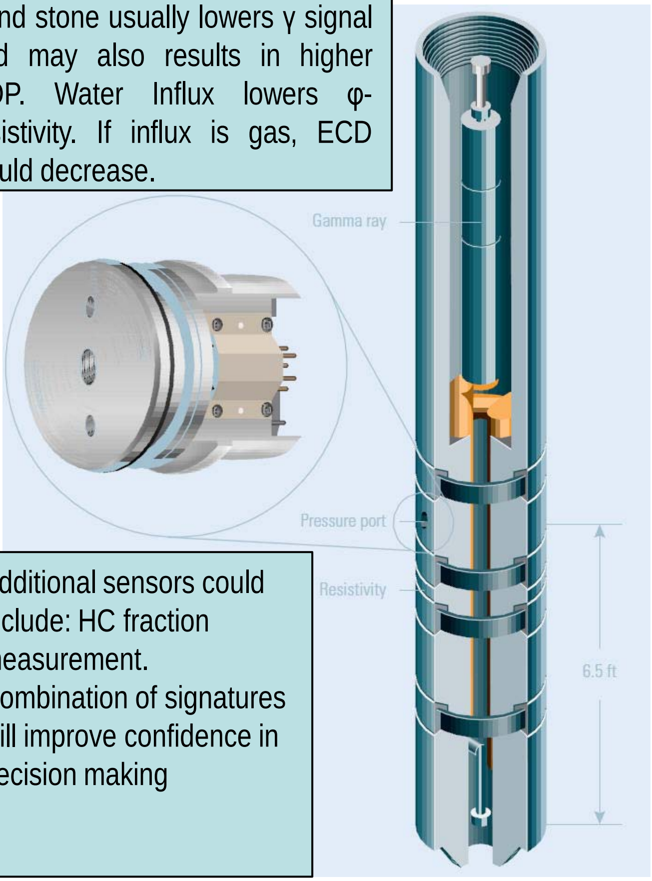
Telemetry Drill Strings for UDW (NOV)



MWD is an example of a new technology
Its use should be standardized and broadened



Sand stone usually lowers γ signal and may also results in higher ROP. Water Influx lowers φ-resistivity. If influx is gas, ECD would decrease.



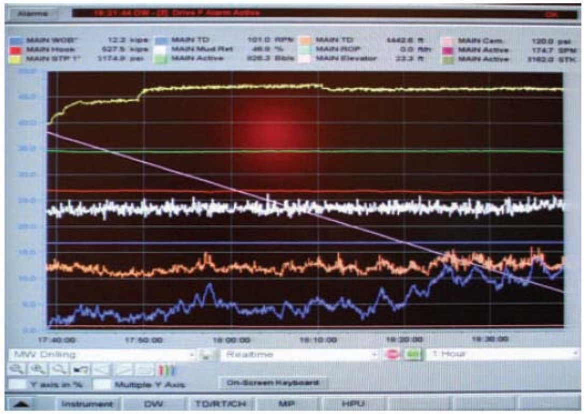
Additional sensors could include: HC fraction measurement.
Combination of signatures will improve confidence in decision making

Near Real-Time Data to Decisions

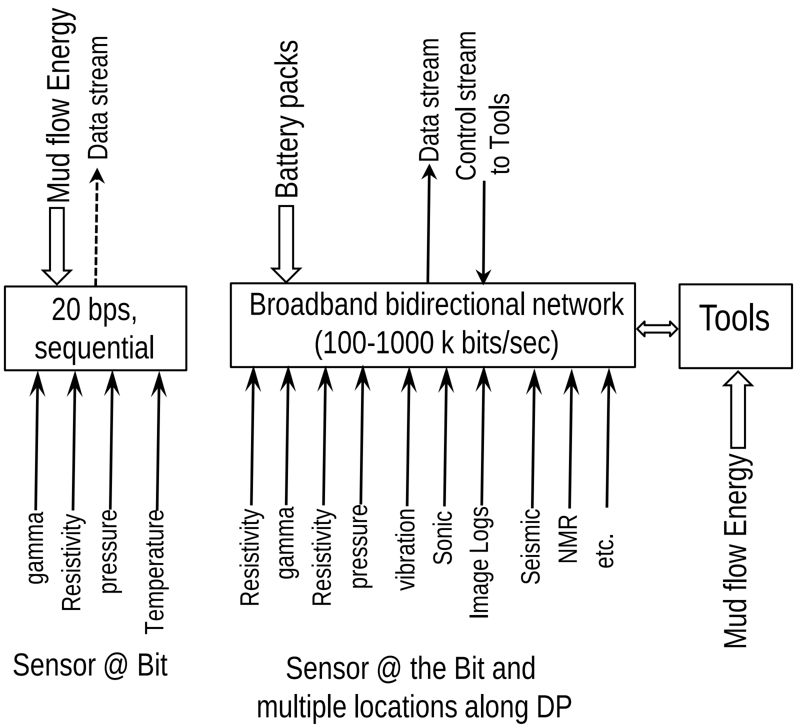
"Automated" Advisory System for kick mitigation

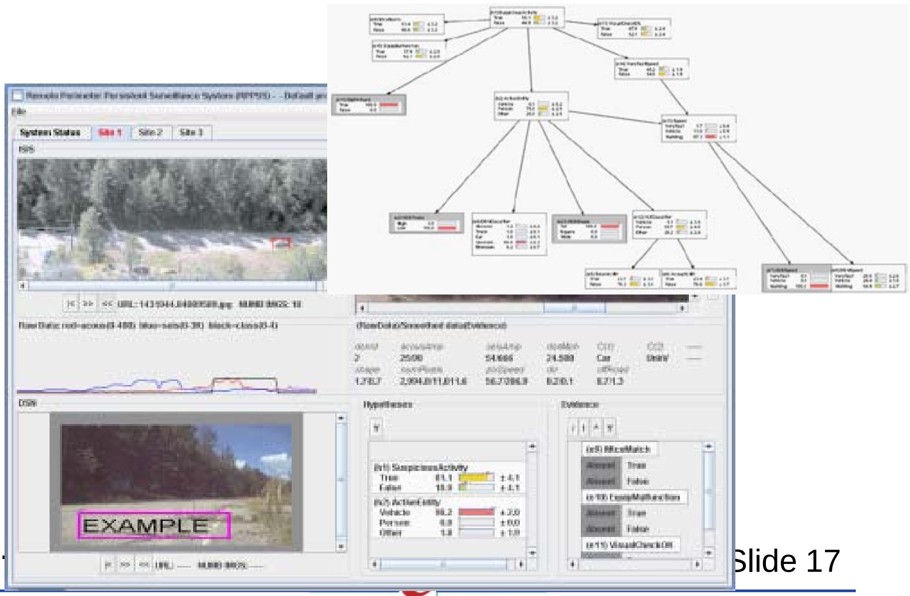
Oil and Natural Gas

- High fidelity modeling to establish signatures, observables and sensors (SOS) engineering
  - Bayesian or neural networks

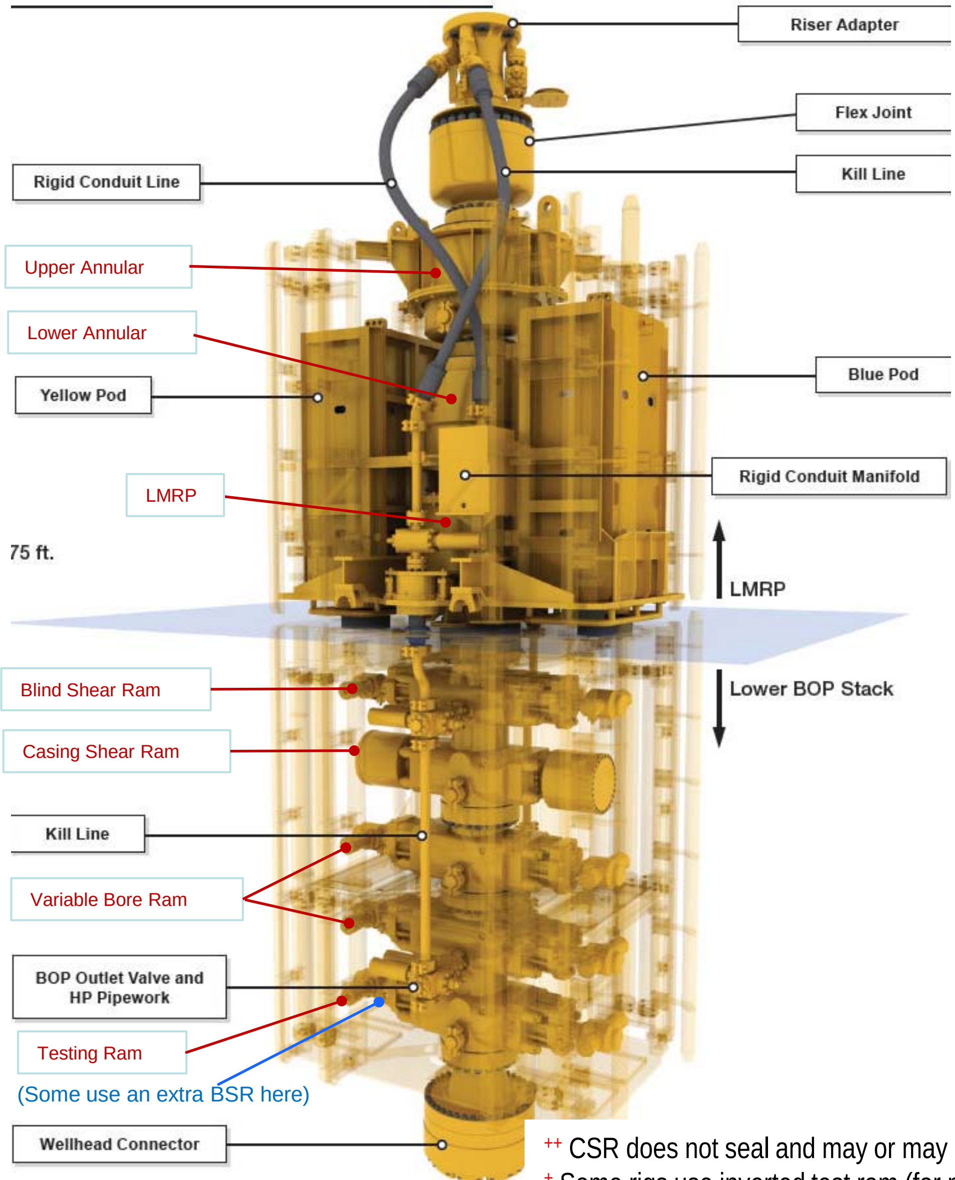


Current approach of "data streaming" is a poor way to enable decisions





BOP Components and Types



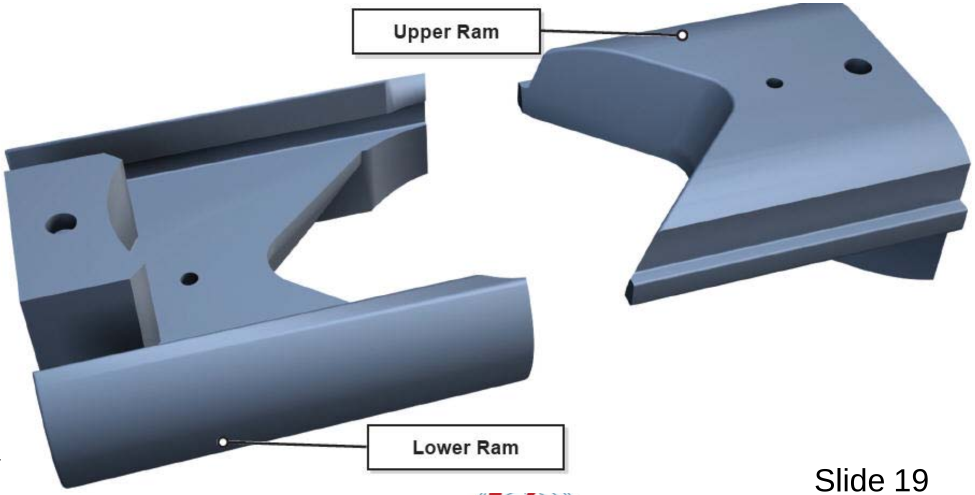
- Improved Control Systems
  - Eliminate single-point vulnerabilities
    - ✓ Valves
    - ✓ Riser along with hydraulic connectors
  - Surveillance of critical systems functionality real-time
    - ✓ Batteries
    - ✓ pressure, temperature, and casing/DP location
  - Improved Concept of Operations
    - ✓ To cut or not to cut
    - ✓ Sequence of actions

- Improved Shears and Seals
  - Diversity of systems
  - Sufficient MOV pressure for CSR/BSR
  - Higher pressure rating to account well pressure
  - Test under real conditions
- Vulnerabilities unresolved
  - Casing in the BOP
  - Erosion, corrosion and chemistry
  - Positive seal after cutting DP

++ CSR does not seal and may or may not be used
+ Some rigs use inverted test ram (for pressure test)

Blind Shear Ram Function and Testing

- Blind shear rams (also known as shear seal rams, or sealing shear rams) are intended to seal a wellbore, even when the bore is occupied by a drill string, by cutting through the drill string as the rams close off the well. The upper portion of the severed drill string is freed from the ram, while the lower portion may be crimped and the “fish tail” captured to hang the drill string off the BOP.
- Casing shear ram is incorporated by some rigs. No specific regulation requiring CSR. CSR is designed to cut through the casing if the blowout causes casing to be pushed into the BOP or blowout occurs while casing is passing through the BOP. CSR is not designed to seal.
- Testing of BSR/CSR:
  - Pressure testing is required every 14 days
  - Function testing (against a stump) : 190 days (Once before installation)
  - Actual Testing: Not done (to prevent damage to BOP)
- Design and Pedigree
  - Designed using correlations (Max Distortion)
  - Third party examination of design documentation (per Interim Guidance – New Requirement)
  - No data or experiments exist to envelope entire spectrum of accident conditions



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Terms of Reference (Lexicon)

- Kick: An incident that results in unintended flow of formation hydrocarbons into the well.
- Blowout: Uncontrolled release of formation fluids and mud after preventive barriers (e.g., BOP) have failed to perform adequately. Blowout may be terminated by natural phenomena (e.g., bridging) or by emergency measures including repairing failed systems.
- Controlled Blowout: A category of blowouts where formation fluids can be diverted to flare as a means for regaining well control. Some amount of mud and smaller quantities of formation fluids may pollute the environment in the process.
- Shallow Gas Blowout: Uncontrolled release of formation fluids (typically methane gas) before BOP has been installed. Many times release occurs at the mudline. If riser is in place, release may occur at the sea-surface
- Subsurface Blowout: Uncontrolled release of formation fluids into another layer of the formation with minimal or no resulting release into sea or environment. Presentation also uses underground blowout for this.
- Deepwater Well: Off-shore well where water depth exceeds 1000 ft
- Ultra Deepwater Well: Off-shore well where water depth exceeds 5000 ft
- HPHT Well: A well with an expected formation pressure in excess of 10 kpsi (69 MPa) and temperature in excess of 300 ^{o}F (150 ^{o}C)
- Well Killed: In this presentation means, well shutdown and rendered inoperable for the future

Accident Progression Event Tree – Explanation

- Operational incident (or accident) is depicted on the left side and the outcomes are depicted on the right. Outcomes range from successful mitigation to large oil spill requiring federal response to bring the well under control and minimize consequences
- Each barrier or mitigating system – in terms of functionality – is depicted as a dashed line.
  - The barriers in the tree include not only those that exist today but also those that are being considered for deployment.
  - First barrier, Event ID # D, relates to detection of the kick. In reality this barrier describes combined performance of a range of systems that are in place already or those that are being readied for deployment
  - Sequence of the barriers is a close representative of IADC guidance for well monitoring and control. Based on analyses, we believe this event-sequence maximizes time available for driller to respond to accident progression
- Due to phenomenological and stochastic causes, not every barrier is expected to perform successfully. Their performance "state" can vary from 'deploys successfully to mitigate (terminate) the accident' to 'fail to perform with little or no impact on accident mitigation.' Thus state-gates of each barrier illustrate different performance states – 1 being successful.
  - In the above example Gate D1 assumes an advanced kick detection system that relies on real-time MWD/LWD with automation that alerts the operator within a minute or two that the well kicked
  - Gate D2 represents present state of the art where many of the kicks are detected during connection. Usually mud pump is tripped while making drill-pipe connection. This suddenly reduces ECD and increases the influx. It is common to look for indications of 'flowing well' at this juncture. Well could flow both from the riser side as well as through the drill pipe depending on kick size. Alternately, watching the pit level indicator is another approach.
  - Finally, Gate D3 represents operators failure to look for signals of kick soon enough to contain the kick before it becomes a major 'blowout'.
- Likelihood of each barrier state is estimated using past operational data coupled with physics based well dynamics models
  - Human reliability is assumed to be a strong function of time available to perform a task and complexity of the task; standard human error assessment and reduction technique (HEART) is used to subjectively estimate human reliability
  - Fault trees were used to quantify performance of engineered systems such as BOPs. However historical operational data was "corrected" or "updated" to represent operating conditions unique to Ultradeep water drilling

Accident Progression Event Tree
Mitigating System or Barrier Damage State Definitions

Function	Symbol	Performance State			
		1	2	3	4
Detection	D	Early Detection[†,¥]	Normal Detection (Pit-gain/@ connection)	Late detection or No detection	
Well Shut-in	S	Circulate out (Soft Shut-in)	Normal[¥] (Hard Shut-in)	Drill Pipe Sheared[¥] (Seal Leakage)	Fail to shut in[¥]
Gas Handling	G	MG Separator	Divert overboard[†,¥]	Diverter Failed[¥]	
Fire/Explosion/Evacuation	F	None	Long Term (> 6hr)	Short-Term	
Wellhead Structure	M	No damage	BOP and Wellhead Housing Leakage [¥]	Riser Collapse & Damage Casing[†,E]	
Well Control	C	Circulate out	Normal[¥]	Well Kill [E,T]	Fail to Control
Emergency Measure	E	Second BOP	Capping	Top Hat[†,E,T]	Relief Well [†,E,T]
Outcome 1: Hole Status	H	No damage [E] Continue Drilling	Capped & Abandoned	UG blowout[E,T]	
Outcome 2: Environmental Pollution	O	Success No Release	Limited Release (≤100 bbl)	Large Uncontrolled Release (1000 bbl)	Severe Uncontrolled Release (≥10000 bbl)

Footnotes:

† At present this functionality exists on a limited number of rigs, but R&D and deployment may be beneficial

¥ Fault trees were used to quantify this probability. Historical data was updated to reflect UDW conditions

E Expert judgment assisted by engineering modeling used to derive this probability

T Sequence timing has significant impact on this probability

Geophysics Data

Blowout flow (bbl/d) through	Eff. Reservoir Height (ft)		
	50-ft	25-ft	5-ft
Drill Pipe (undamaged)	22, 500	17, 200	5, 200
Drill Pipe (25% Area)	13, 500	TBD	TBD
Annulus (undamaged)	30, 000	18, 100	5, 500
Annulus (25% Area)	15, 000	TBD	TBD
No Drill Pipe	31, 000	19, 400	5, 500