



Shut the Well in on Paper Benefits and Risks

Paul Toorns
9 July, 2010

Benefits of the Capping Stack



1. Assist in Well Kill & Post Kill Operations
 - Diagnosis of well integrity pre kill
 - Ability to backpressure well
 - Stabilisation of well pre and post cementing
2. Possibility of Shutting In Well
 - Full shut in for extended period
 - Temporary Shut in capability
 - Increased pressure / decreased flow.
3. Enable Full Collection Options
 - Multiple vessels, full collection without leakage
 - Ability to use export flow line
 - Possibility of Hurricane well storage option

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8660

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IGS700-000148

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Risks & Concerns for Shutting in



Well & formation Integrity issues

- Can we distinguish between depletion and leakage from the well?
- What is the consequence of leakage, and ultimately breaching to the seabed
- Can we adequately monitor to detect significant leakage from the well.

Operational Issues

- Gauge accuracy and dependability
- Communication and decision making
- Practicalities of opening well

Experimental Method

- Can we tell anything from transient behaviour?
- Do we need to bracket flow rates prior to starting the test?

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Schedule and shut-in procedure
for well integrity test

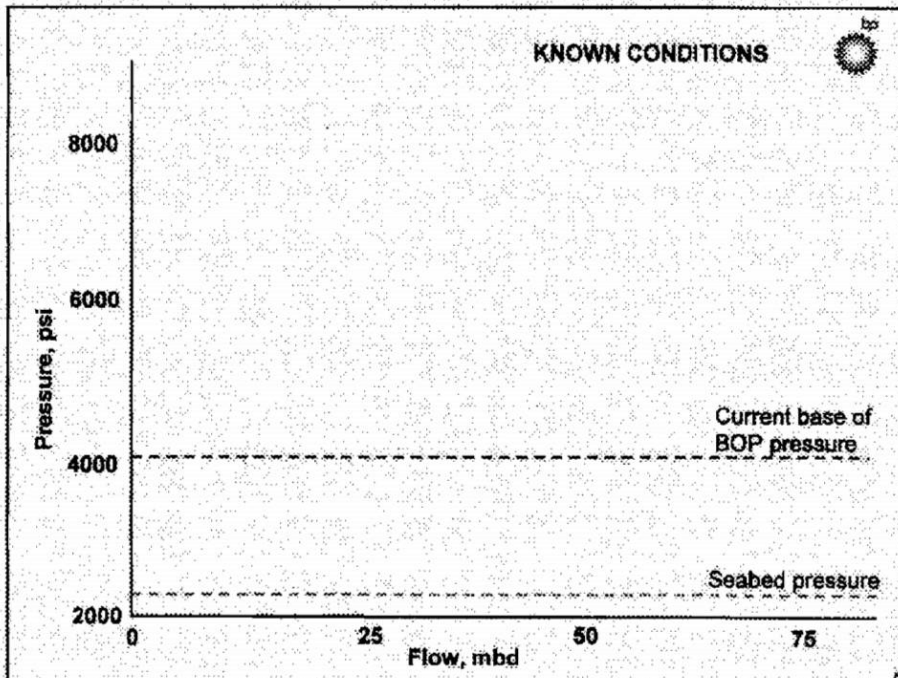
Trevor Hill
July 9, 2010

Schedule



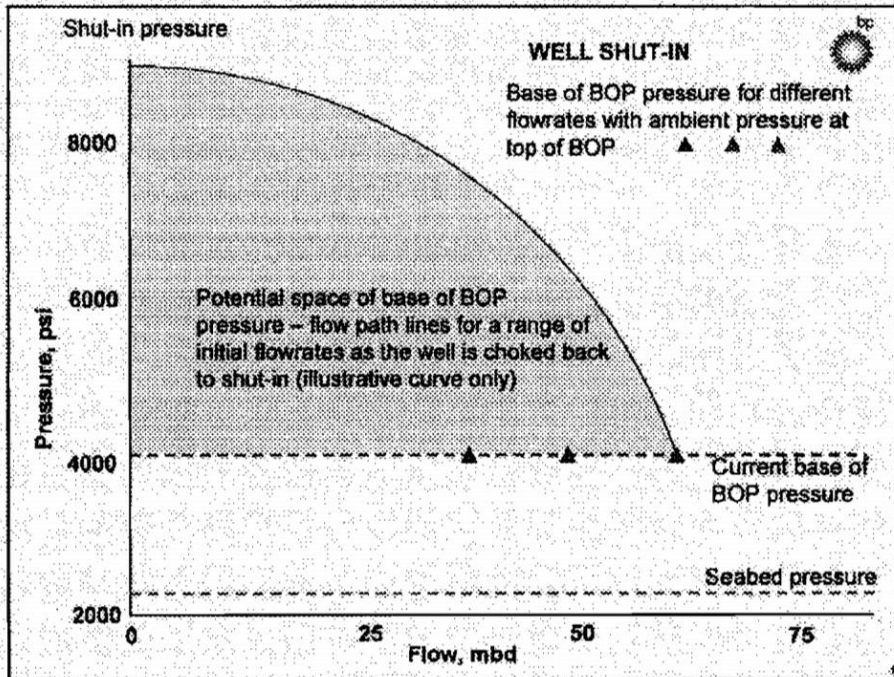
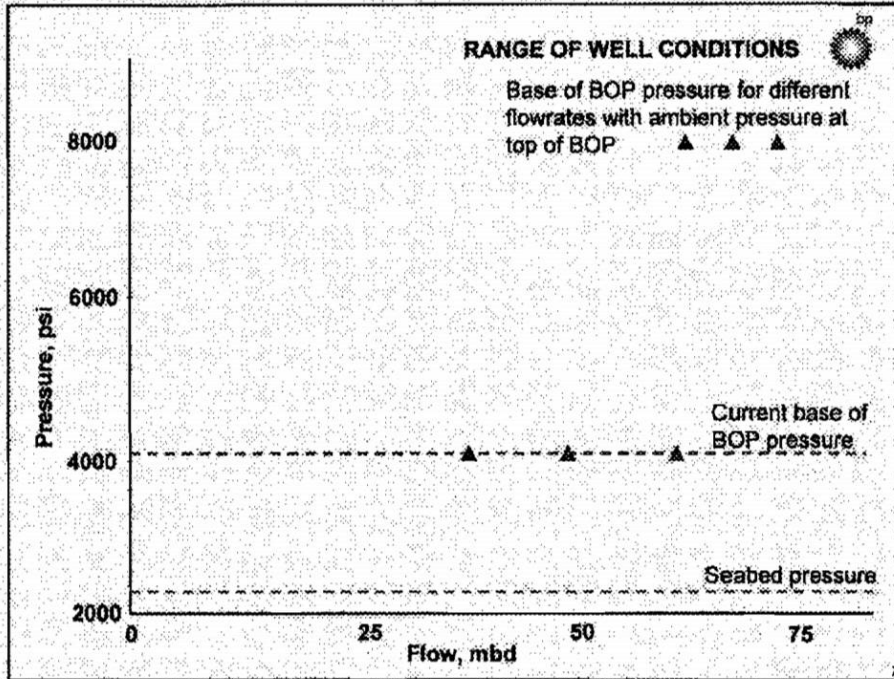
- Earliest start of well integrity test is midday Tuesday, but subject to the operational complexities of 3 ram stack installation
- Contingency schedule is Saturday morning start

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*currently at
4150 psia*

3



Shut-in procedure



- Enterprise will already be disconnected for 3 ram stack installation, but on stand-by with TopHat 7
- 3 ram stack will be installed with rams open and 2 x 3" outlets closed
- Helix Producer will be shut down, isolated, and on stand-by (if commissioned)
- Q4000 will be shut down, isolated, and on stand-by
- At this stage all flow will be out of the top of the 3 ram stack to sea via open rams

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Shut-in procedure continued



- 3" vent line will be opened
- 3" choke will be opened fully
- Middle rams will be closed
- 3" vent line will be closed
- All flow now out of 3" choke to sea

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Shut-in procedure continued



- Close 3" choke by specified increments,
- Increments will be planned in advance, but with operational response possible
- Monitor base of BOP and 3 ram stack pressures throughout
- Hold temporarily when just above bubble point to get single phase fluid in well
- Proceed to closure

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Analysis during test



- Estimates of flowrate will be made as a function of choke valve position, C_v , and pressure drop
- Plot of pressure and estimated flowrate will be developed
- Pressure response will be evaluated before next choke increment

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Pressure response



- Seconds – to see a response to a valve change at the BOP
- Minutes – to judge the magnitude of the response to that valve change
- Hours – to get to quasi steady state once the well is shut in
- Days – for the reservoir pressure to recover and gradually increase shut in pressure to final steady state

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Reservoir Depletion

Bob Merrill
9 July, 2010

Characteristics of Reservoir Depletion / Build Up

Key Parameters: C_r , Aquifer, Q_a (including leakage, if any)

Assumptions: C_r : 12×10^{-6} psia⁻¹ [μ sips]
 Aquifer: 3.8x reservoir oil volume
 Q_a : 36 mbd

Sensitivities: C_r : -200 psia, +100 psia [6, 18 μ sips]
 Aquifer: -800 psia, +100 psia [None, 14x]
 Q_a : -350 psia [60 mbd]

Final M56E Pressure: 9,350 (lowest sensitivity) - **11,350** - 11,600 psia

S.I. Bottomhole (and hence tubing head) pressure will start at 1,500 - 3,000 psia below this (but 90% of this difference will disappear in 6 hours)

cases in red were used for SITHP calculations

11850
- 9350

2500

9350
- 3200

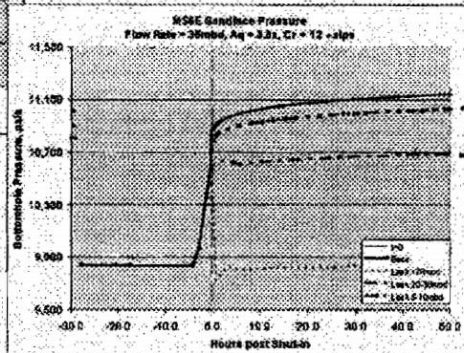
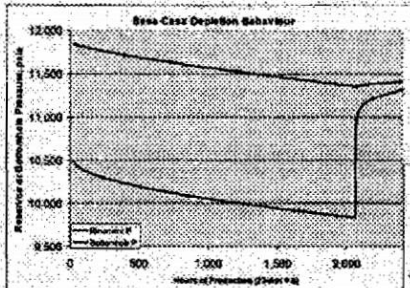
6150

11350
- 9800

1550

Characteristics of Reservoir Depletion / Build Up

Base Case, with Build-Up Characteristics with and without leakage



11350
- 3300

8000

10700
- 3300

7400

11000
- 3300

7700



Macondo SIWHP

Mike Mason
July 9th, 2010

Well Integrity During Shut – In Operations: DOE/DOI Analyses

July 9, 2010



USGS
science for a changing world



Los Alamos



**Lawrence Livermore
National Laboratory**

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Report Outline

- Issues to be Addressed
- Background
- Geologic Conditions
- Wellbore Flow Conditions
- Conclusions and Recommendations

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Issues to be Addressed

- Are geologic conditions conducive to an uncontrolled broach to the sea floor during shut in, assuming a lack of well integrity?
- Can well integrity be assessed by pressure measurements during a shut in?

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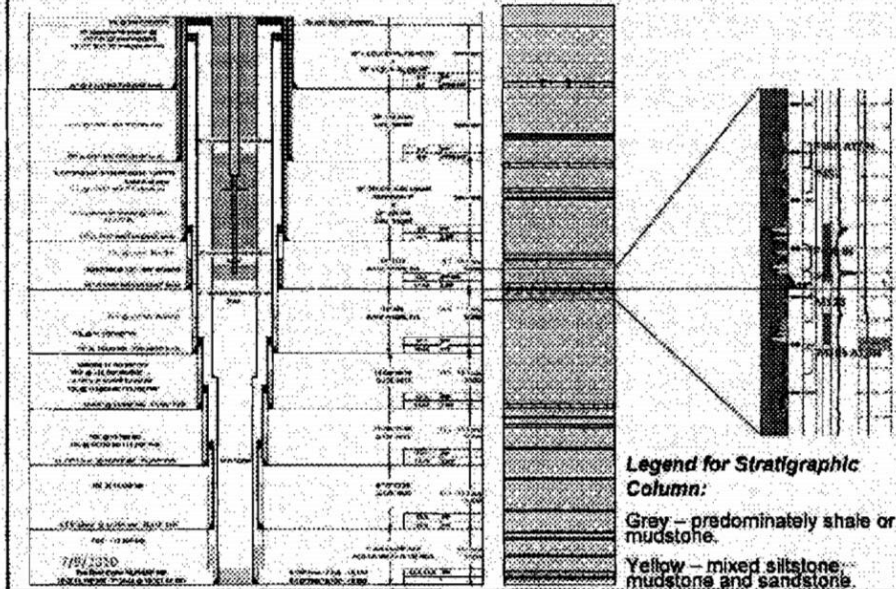
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Background

IGS700-00158

2.1

Reference Geometry - Below Mudline



Advantages of Installing Well Cap

- Well cap will allow full capture of hydrocarbons.
- Well cap has capability of shutting in well at seafloor.
- Well cap provides back pressure, which is beneficial to kill and cement operation.
- Well cap provides new capabilities for quick disconnect as hurricane approaches.

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Possible Shut In Durations

- Shut in test
 - Minimum duration
 - Necessary to manage risk appropriately
- Duration of Shut in Decisions
 - Short duration (<1 day)
 - Short shut in for operational reasons
 - Mid-duration (< 10 days)
 - Hurricane
 - Well kill control/back-pressure enhancement
 - Long-duration (<100 days)
 - Minimize flow to gulf
 - Minimize hazards to personnel
 - Focus resources on well kill

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Geologic Conditions

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Data Reviewed

The following were examined from the Macondo #1 and other wells in the vicinity, including relief wells:

- Logging-while-drilling data (primarily gamma ray and resistivity), wireline logs, and mud logs.
- Geomechanical models and borehole measurements pertaining to in-situ pore pressure, overburden stress (lithostat) and fracturing pressure.
- 3D-seismic, high-resolution 2D-seismic, and side-scan sonar collected pre-drill and post-incident.

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Consultation with BP

Detailed in-house discussions between BP and government scientists and engineers on topics that included:

- Lithologic and structural interpretations.
- Seafloor morphology.
- Drilling history and borehole completion.
- Stress and fluid pressure conditions.
- Geomechanical and fracture propagation modeling.
- Reservoir modeling and borehole fluid flow.
- Kill and cementing procedures.
- Microseismic monitoring and multichannel seismic.

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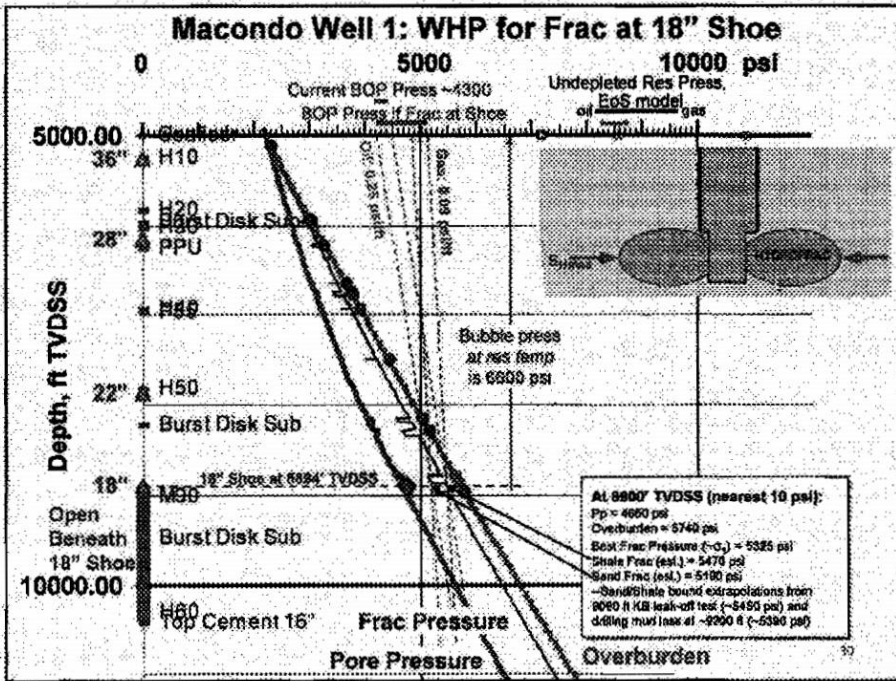
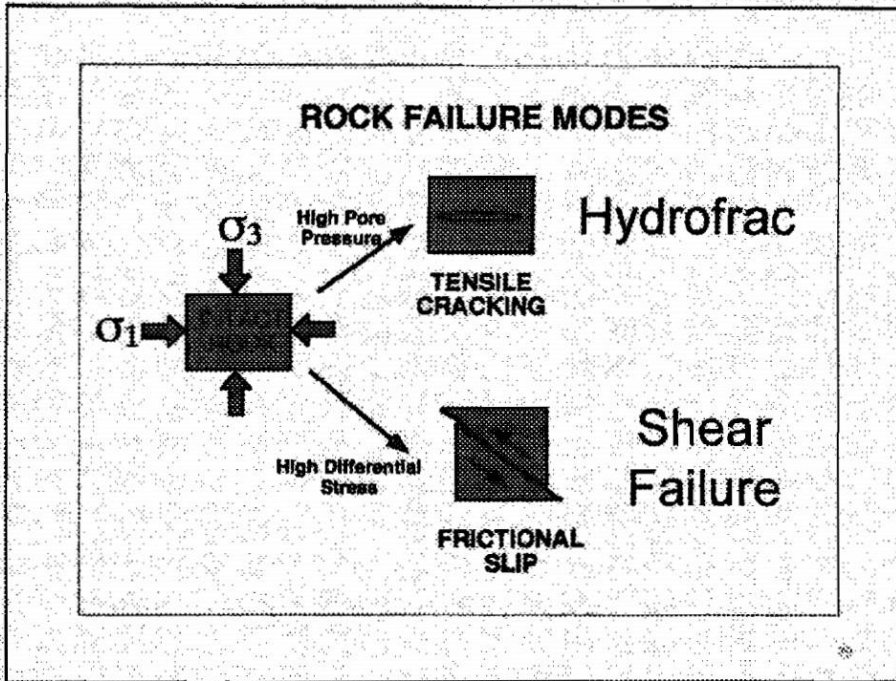
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Geologic Conditions

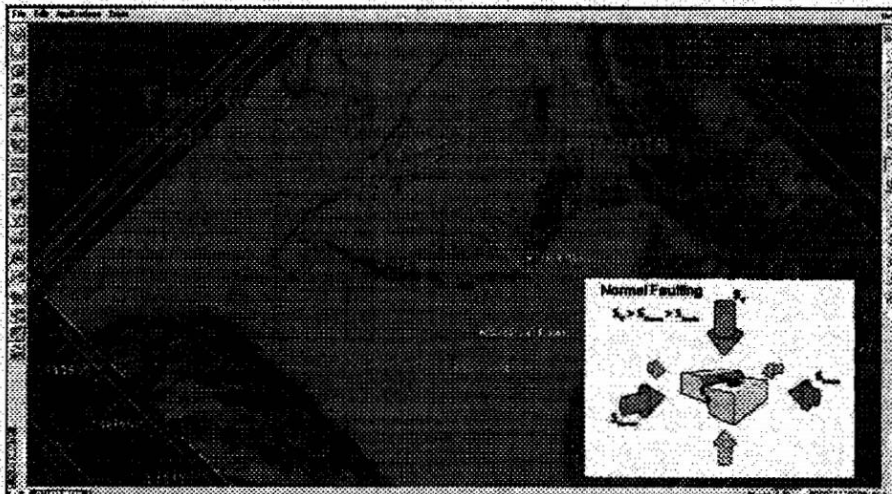
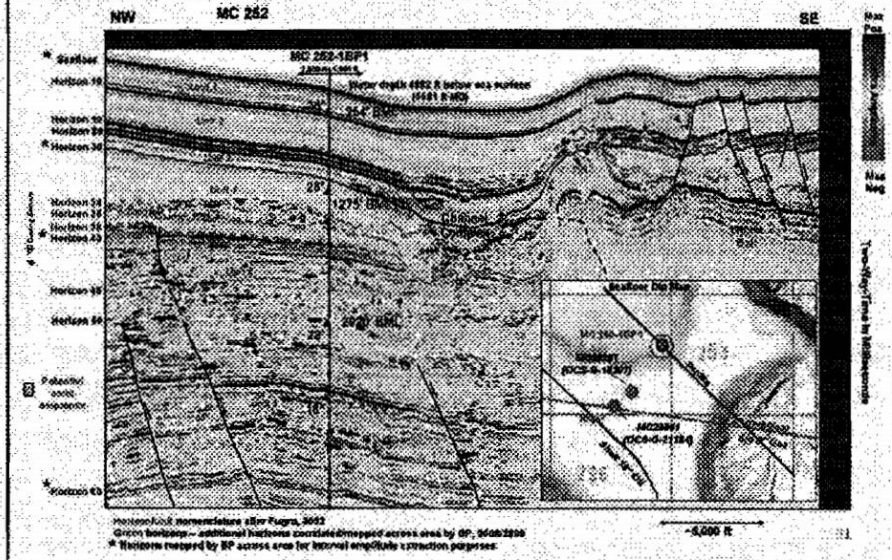
- Data indicate geological formations consist of fine-grained, low-permeability sediments such as shale, mudstones and siltstones, and few permeable sands at or above the 18 inch casing shoe (~4000 ft below seafloor).
- Data indicate extensional stress environment, which is conducive to vertical hydraulic fracture growth.
- Data indicate existence of numerous faults that are potential paths for hydrocarbon flow to sea floor.
- Significant oil and gas flowing from main reservoir 13,000 feet below seafloor to well-head.

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3D Seismic Line 17282 Through Well Location MC 252 #1



5505 feet below sea level: just below seafloor. With depth, this fault intersects the M110 horizon, and could be a conduit for hydrocarbon flow. Also visible are possible degassing or dewatering vents. These are potential sites for monitoring.

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Implications of Geologic Conditions

- In the event of a casing leak, geologic formations and in-situ stress field are conducive to hydraulic fracture propagation from the 18" casing shoe to the seafloor.
- Pre-existing faults can also serve as conduits for hydrocarbon flow to seafloor.
- Limited thickness and areal extent of sand layers at and above the 18" shoe suggest that vertical fracture growth will not be significantly inhibited and that storage for hydrocarbons from a casing leak will be limited.

7/9/2015

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Possible Adverse Effects of Well Shut-In

In the event of a casing leak, geologic conditions are conducive to a breach of the seafloor by hydrocarbons during shut in, which would have serious consequences:

- There would be an uncontrolled release of hydrocarbons into the sea.
- This could result in an inability to control wellhead pressure, which could seriously jeopardize the bottom-kill and cementing operations.

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Wellbore Flow Conditions

7/26/2010

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Flow in Well Issues

- **Principal Questions to be Addressed**
 - A: Can well integrity be determined during short-duration shut-in?
 - B: Can well integrity be determined during longer shut-in?
 - C: Can well integrity be determined by a gradual shut-in?
 - D: Can the flow rate through the disks be bounded?
- Following analysis assumes that all leakage to the formation is through rupture disks.
- Other fluid-flow pathways out of well are also possible. In fact, one reason for doing the shut-in test is to determine if there is significant unknown damage to the wellbore.

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Flow in Well Issues Shut – In Pressure (SIWHP)

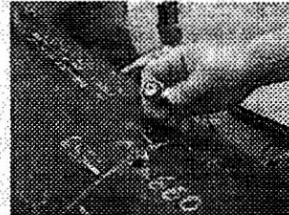
- Principal Uncertainties (1 observation dependent on 3 processes)
 - Extent of gas volumes after shut-in
 - Reservoir depletion
 - Leakage and flow pathways
- Government Assessment
 - SIWHP range: 8250 – 8750 psi (No depletion – No leakage)
 - No independent means of verifying reservoir depletion
 - BP estimates an uncertainty interval of 800 psi
 - Note – the pore pressure reduction associated with reservoir depletions depends on the flow rate, reservoir properties, and the of the reservoir volume.
 - Combined intervals span 1300 psi range

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Flow in Well Issues Leakage Through Burst Disks

- Principal Uncertainties
 - Number of disks open
 - Diameter of disk opening
 - Flow rate through disks
- Government Assessment
 - BP asserts that a maximum of 6 disks could have burst
 - Government has not independently analyzed accident scenario. For the purpose of our analysis, we assume that 6 burst disks have burst.
 - Flow = 550 bopd/disk into formation for 1/8" diameter disks
 - Disk diameter can increase through erosion. Recommend BP testing or analysis.
 - Limited data from other application suggests 6 hours of mud flow would result in < 20% increase flow rate.



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Flow in Well Issues Measuring Leakage at Shut In

- Principal Uncertainties
 - Sensitivity of shut-in pressure to leakage compared to shut-in pressure uncertainty
- Government Assessment
 - Simplified to Complex models – Assumptions in next slide, details in Appendix A and B
 - For every 1% of the flow from well head, shut in pressure will decrease by approximately 50 psi. Thus, for a 1300 psi uncertainty interval, this sensitivity corresponds to a flow of the scale of 25% of the flow from well head (assumes current leakage is small compared to well-head flow).

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Flow in Well Issues Basic Modeling Assumptions

- Modeling requires assumptions of the current well condition.
 - There is a significant resistance to flow in the well as illustrated by the 4300 psi BOP pressure measurement. This can be distributed to a deep and shallow choke. However, from steady flow observations one cannot determine the distribution of these resistances.
 - All wells have some resistance to fluid entering (well drawdown and skin resistance). We cannot measure this, but we can determine this as a function of the total flow rate if we assume other blockages (shallow choke) are small. The total flow rate must include the cross-flow (we have no way to measure cross-flow).
 - Any resistance assigned to a top choke makes the model predictions of well head pressure less sensitive to cross flow.
 - Simple scaling analysis shows that our inability in determining the current condition results in an inability in predict a shut in pressure. Our major unknowns are:
 - distributing resistance between a deep and shallow choke
 - inability in measuring the current cross flow
 - depletion of reservoir
 - elevation head

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Flow in Well Issues

Value of Discrete Steps During Shut-In

- **Principal Uncertainties**
 - Flow Measurement during shut-in
 - Limited number of measurements during shut-in
 - Transient conditions during shut-in
- **BP Technical Staff Estimates of Capability**
 - 3 perhaps 4 discrete measurements
- **Government Assessment**
 - Very difficult to make quantitative determination from 3-4 measurements.
 - Recommend single step shut-in.

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Flow in Well Issues

Flow Rate Bounds - 1

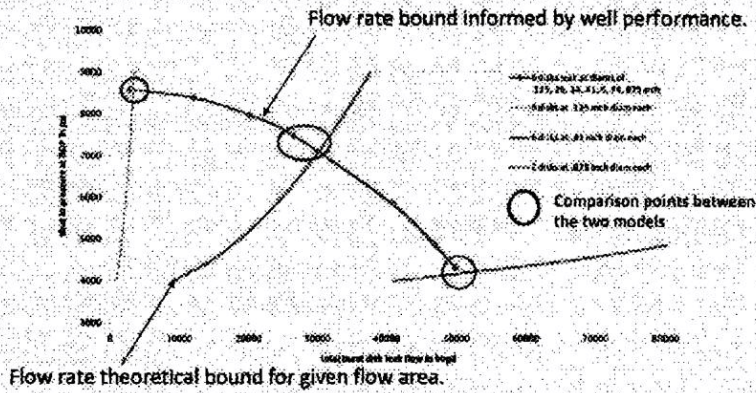
- **Government Assessment**
 - There is no pressure for which it can be conclusively asserted that the well has zero flow out the burst disks.
 - However, flow rate can be bounded (next slide)
 - Bound informed by well performance
 - Theoretical upper bound for given flow area
 - Leakage flow into geologic media must be considered possible for all scenarios.

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Flow in Well Issues Flow Rate Bounds - 2

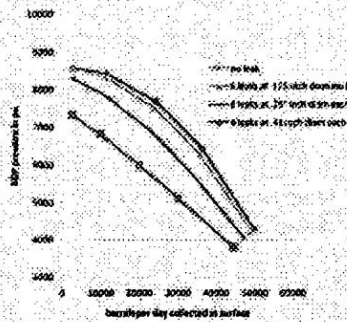
- Government Assessment



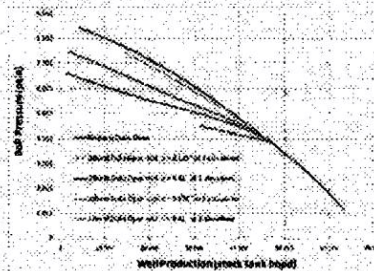
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Multi-Step Shut-in (Quasi-steady Flow) Pore Pressure vs. Fracture Pressure



Assumes leaking into sand
- Currently above sand pore pressure



Assumes no leak until rock fracture
- Currently at or above rock fracture

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Flow Sensitivity To Changes in Sink Pressure

- Scenario
 - Assume leakage from well, if it occurs, is limited to the burst disks (ignores possibly more extreme damage to the wellbore)
 - Model back pressure outside the burst disks as:
 - Pore pressure (conservatively no skin)
 - Fracture pressure
 - Hydrocarbon column to seabed
- Consequences For
 - Leakage flow rate
 - Kill difficulty
 - Broach capping

2/29/2019

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Decision Context/Recommendations Response Determination

- Shut in pressure can be used to discriminate three categories
 - Pressure > 8000 psi
 - Well may have integrity but this cannot be assured due to uncertainties. Leak rates from worst case scenarios are bounded. Broach is possible but there is a low risk of to the well killing and cementing operation.
 - 8000 psi > Pressure > 6000 psi
 - Well does not have integrity. Discharge into formation is no worse than current discharge rate from well head. However, there is a moderate risk to the well killing and cement operation.
 - Pressure < 6000 psi
 - More is wrong in the well than just blown burst disks. Discharge into formation is greater than current discharge from well head, and broach to seafloor is likely for . There is a high risk to the well killing and cementing operation.

7/9/2018

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Conclusions and Recommendations

7/8/2019

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Risk Management Recommendation

- A successful well kill and cementing operation is the highest priority and should not be put at risk.
- The risk posed by a short-term shut-in test is acceptable if the test is required for operational reasons. However, to avoid possible broach to the surface, the shut-in period should not exceed 1 day. We see little value to a step-rate test.
- Intermediate and long-term shut-in could lead to a broach to the sea floor and could jeopardize well kill and cementing operations. Therefore:
 - These operations should only be undertaken after results of short term shut-in test are analyzed by BP and reviewed by the government.
 - Long-duration shut in should not be carried out unless BP can demonstrate the capability to continuously monitor fracture propagation to the sea floor (e.g., AUVs, seismic).

7/9/2019

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Risk Management Recommendation

Recommended Shut-In Protocol

	Short Duration (< 1 day)	Mid-Duration (< 10 days)	Long Duration (< 100 days)
$P > 8000$ psi			
8000 psi $< P < 6000$ psi			
$P < 6000$ psi			

- Green: Risk is low.
- Yellow: Risk is moderate to high.
- Red: Risk is unacceptable.

If wellhead pressure during test stabilizes at < 6000 psi then test should be immediately terminated.

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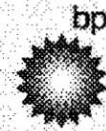
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Government Review Team

- Project POC
 - Sheldon Tieszen - DOE Natl. Labs
- Flow in Well
 - Curtt Ammerman - DOE Natl. Labs
 - Ron Dykhuizen - DOE Natl. Labs
 - Mark Havstad - DOE Natl. Labs
 - Charlie Morrow - DOE Natl. Labs
 - Marty Pilch - DOE Natl. Labs
- Flow in Geologic Media
 - Steve Hickman - USGS
 - Paul Hsieh - USGS
 - Walter Mooney - USGS
 - Phil Nelson - USGS
 - Cathy Enomoto - USGS

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Communications and ROV Plan

Bill Grames
9 July 2010

Communications



Key Roles

- Well Shut-in Test SPA ↔ ROV Command
 - Stacks (Horizon and 3-Ram) SPA
 - Seabed SPA
 - Data SPA
 - Official Logger

Test Duration

Success Case

- Valve movements and initial pressure build-up ~6-12 hours
- Pressure monitoring 24 hours plus

Compromised Integrity Case

- Valve movement and initial pressure build-up 0-6 hours
- Containment vessels on stand-by to resume operation

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ROV Plan



ROV Activities within Procedure

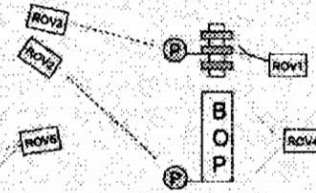
- Base of BOP Pressure Monitoring
- 3-Ram Stack Pressure Monitoring
- Choke Manipulation (open)
- Open choke isolation valves
- Open 3" vent valves
- Close middle rams
- Close 3" vent valves
- Manipulate choke

Indicative Timing

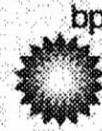
Continuous
Continuous
10 minutes
10 minutes
10 minutes
10 minutes
10 minutes
Duration of test

ROV Placement

- ROV1 Valve Manipulation
- ROV2 Base of BOP pressure
- ROV3 3-Ram Stack pressures
- ROV4 "Metal" leak surveillance
- ROV5 Seabed leak surveillance
- Redundancy provision being developed



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Macondo Overburden Seismic Evaluation Survey

Andy Hill, Marine Geohazards SETA, 9th July 2010

Monitoring.

Subsurface: Defining absence of break out from the well



• **Seismic methods for identification of activity, or change, in the subsurface are:**

- **Active Seismic**

- Acquisition of targeted 2D Seismic Lines over well (Standard, MR or HR)
 - Proven published post-blowout methodology (Norway, Canada and Vietnam):
 - Degree of Ambiguity: low, degree of confidence of identifying charged layer is high.
 - Lower confidence if charge is restricted to a single fracture or fracture zone
- Acquisition of a 3D seismic volume(s) centered on the well location itself.
 - Concern: highly restricted access for 3D until fleet departs to acquire data
- Time lapse repeats of either, or both, of the above to indicate stability and no change.
 - Degree of Ambiguity: low - with repeated volumes showing long term stability

- **Passive: Seafloor Nodes**

- Install Seafloor passive listening array to identify subsurface events and pin point them in XYZ location
- Slow data turn round, model driven processing, however once installed provides ongoing monitoring capability
 - Degree of Ambiguity: low to continuing in subsurface

• **Other methods: Visual Surveys (ROV), Sonar Surveys (AUV) and seabed deformation (tilt meter)**

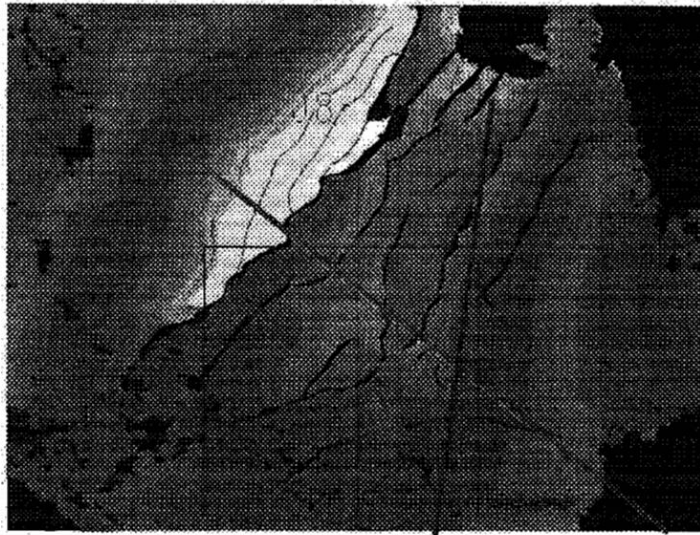
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Aerial View of part of Source Area



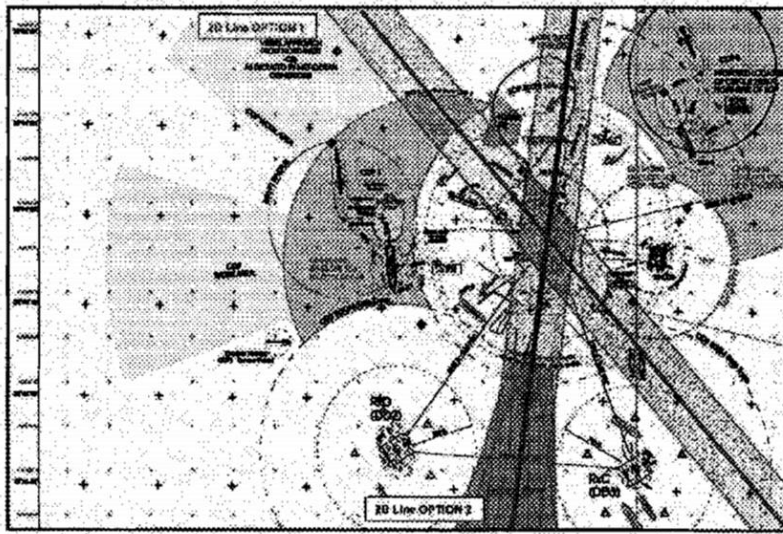
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M110 Structure: Nominal Preferred Line Location



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Safest Offset Line Locations



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Detectability



- **Given acquisition of lines pre-shut in and again post shut in what is the potential for detectability of change?**
- If hydrocarbons are already capable of flow into formation, and have been flowing to formation for a significant period of time detectability of charge is good.
- If hydrocarbons are first forced into the formation as a result of shut-in, detectability is dependant on the volume being forced into the formation during shut in.
- Detectability is then dependant on: thickness of layer accepting charge and volume offered to the formation during that period.
- Seismic Bed Detectability: ~9 – 20ft bed thickness (assumes 40Hz at M110)
- Detectable Charge Volume.

3000 bbls	Below detectability regardless of bed thickness
6000 bbls	At limit of detectability for 10' bed thickness
12000 bbls	Moderate to good opportunity for all cases

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Shut In – BOP Stack Monitoring

W. Leith McDonald
09 July 2010

BOP Stack Monitoring



BOP flanges and connectors to be monitored

- Horizon BOP to Wellhead Connector
- Horizon LMRP to BOP Connector
- Horizon Choke & Kill Lines on BOP/LMRP
- Flexjoint & Angle
- Flexjoint Riser Extension Flange
- Adaptor Spool Flange
- 3-Ram connector to Adaptor Spool
- 3-Ram Choke & Kill Lines
- 3-Ram Top connector opening

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BOP Stack Monitoring Locations



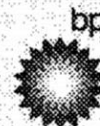
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BOP Stack Monitoring



- Multiple Locations on BOP Stack to be monitored
- ROV Resourcing
 - 1 ROV dedicated to visual inspection
 - 1 ROV dedicated to choke operation
 - 2 ROVs in immediate area for pressure monitoring / visual inspections

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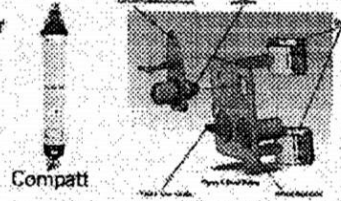
MC252 Sensor Accuracy

July 8, 2010
Matt Gochnour

Pressure Transducers

Hot Stab Pressure Sensor

- Stellar Technology Incorporated (STI) Transducer
 - Model GT1600
 - Scaled and Rated to 20K psi
 - Tested to 10K psi
 - Accuracy (per data sheet) quoted at 0.1 % for static conditions. (20 psi)



3 Ram Stack Integral Pressure Sensors (2 Pressures)

- Teledyne Corman transducers
 - Pressure: 4mA -> 0 psi; 20mA -> 15k psi
 - Calibration data suggests error band of < 0.2 % (30psi)



Pressure transducers and panel on 3-ram capping stack

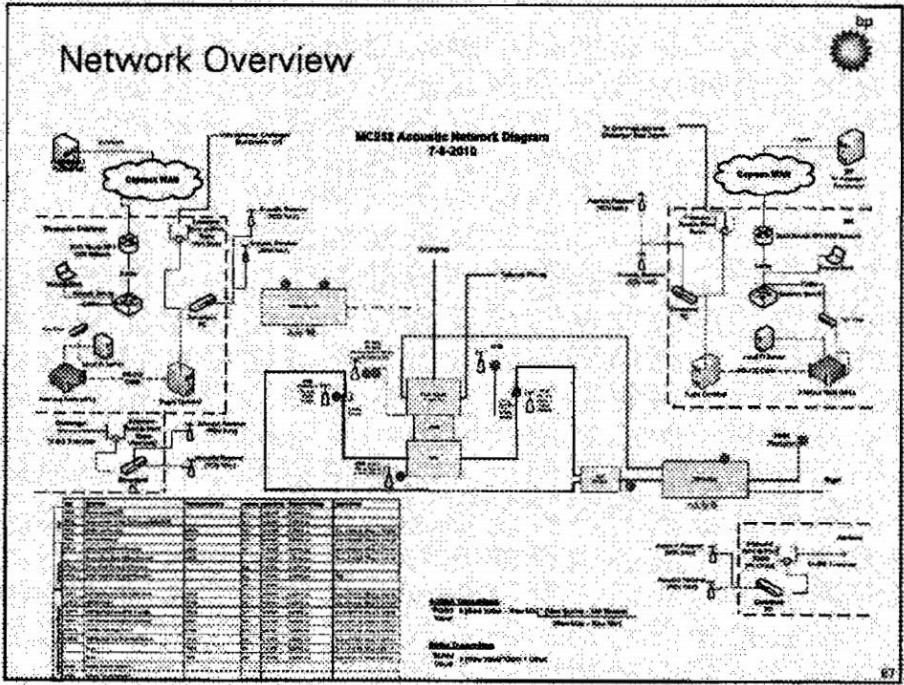
Data Transmission:

- PPT will interface with the acoustic networking system. Roughly 15 seconds between consecutive data points can be expected.

Acoustic Error

- Sonardyne Compatt 5 units are fitted with a 16 bit A/D converter
- Only 12 bits are used to format the acoustic message
- Accuracy of acoustics is known to be +/- 1 bit
- 1 bit = 1.22 mV (5V / 4095)
- Sensitivity (psi / volt) depends on pressure sensor range

Pressure Range	Error
20K	+/- 4.88 psi
15K	+/- 3.66 psi
10K	+/- 2.44 psi



MC 252 Hydrocarbon Measurement Overview

Charles Marth
July 9, 2010

Enterprise



Separated Hydrocarbons are Measured by Two Inlet Separators each with:

- One 3" Oilgear Rotron PV (Proportional Velocity) Oil Meter
- One 6" Barton Master Orifice Fitting for Gas

Hydrocarbon Liquids:

- Custody transfer occurs during lightering operations from shipping vessel at onshore facility
- Measured in storage tanks strapping/sounding method
- Separator oil meters primarily used for operational purposes

Collected Hydrocarbon Gas:

- Separator volumes determined by orifice meter EFM
- Any unmeasured residual flash gas determined by applying a flash factor to the metered oil
- Total gas volume = measured separator gas + calculated flash gas

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Q4000



Separated Hydrocarbons are Measured By Inlet Separator with:

- One 3" Oilgear Rotron PV (Proportional Velocity) Oil Meter
- One 2" Oilgear Rotron PV (Proportional Velocity) Oil Meter
- One 6" Barton Master Orifice Fitting for Gas

Hydrocarbon Liquids:

- Metered at the liquid outflow of the test separator
- Inline VX multiphase meter used to monitor separator meter performance

Hydrocarbon Gas:

- Separator volume determined by orifice meter EFM
- Any unmeasured residual flash gas determined by applying a flash factor to the metered oil
- Total gas volume = measured separator gas + calculated flash gas

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Producer 1



Separated Hydrocarbons are Measured By Inlet Separator at:

- Two Inlet Separators
- Low Pressure Separator
- Degasser

Hydrocarbon Liquids:

- Custody transfer occurs during lightering operations from shipping vessel at onshore facility
- Metered with a 6" NuFlo turbine meter at the outlet of the dry oil tank when offloading to storage vessel

Hydrocarbon Gas:

- Separator volumes determined by orifice meter EFM
- Any unmeasured residual flash gas determined by applying a flash factor to the metered oil
- Total gas volume = measured separator gas + calculated flash gas

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Measurement Oil Checks



Enterprise

- Separator oil meter volume is compared to receiving vessel tank soundings (currently within +/- 4%)
- Separator oil meter volume is diverted to 100 bbl tank for volume comparison

Q4000

- Separator oil meter volume is compared to Vx Multiphase meter (currently within +/- 5%)
- Separator oil meter volume is diverted to 100 bbl tank for volume comparison

Producer 1

- Oil metering will be at ~atmospheric pressure, a spare 6" oil meter will be available for use if indicated
- Metered oil volumes will be monitored against tank gauging of storage vessel

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Time Synchronization

Kate Baker
July 9, 2010

Time synchronization of clocks

- On board data loggers are time synchronized within their system but there is no requirement for synchronization across systems
- PT, Q4000 flow, Enterprise flow and Enterprise boarding pressure data acquisition systems and video were not synchronized during the period 6/26 – 6/30
- Time synchronization survey performed on 7/4 showed differences in clocks based on Coordinated Universal Time (UTC) – 05:00:00 (CDT)

Clock	UTC difference on 7/4	Time read at 12:00:00 UTC	Data stamped
Q4000 acquisition computer	+ 3 min 18 sec	12:03:18	Q4000 flow
Enterprise TDA	+ 3 min 16 sec	12:03:16	Boarding pressure, flow, video
Millenium86 ROV Pilot PC	- 1 min 14 sec	11:58:46	PT data

Pressure & flow recording interval and reference time



Topside Facilities

- Enterprise boarding pressure is recorded every 1 minute; Enterprise and Q4000 report oil flows every 15 minutes.
- Time for both pressure and flow recordings is datumed to the ship-board Insight computer time.

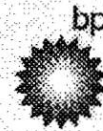
Subsea Choke

- Choke setting change times and sizes will be recorded manually in the operations room as the order is given/executed.
- Time will be datumed to UTC - 5:00:00

Horizon BOP Stack and 3-Ram Capping Stack Pressure Transducers

- One ROV can monitor PT_B with a frequency of 1 reading per gauge every 4 seconds.
- Another ROV can monitor the 2 pressure transducers in the 3-Ram capping stack and 1 stabbed pressure transducer with a frequency of 1 reading per gauge every 4 seconds.
- Pressure sensor readings reference the time clock in the Fugro terminal server located on one of the ROV polling vessels.

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Shut the well in on paper
Potential Outcomes and Responses

9 July, 2010

Potential Outcomes and Responses



Shut in Pressure	Interpretation	Response
$p > x'$	Good integrity (v low leakage)	a, b, c, d, or e
$x' < p < x$	Questionable integrity (leakage or depletion)	a, b, or c
$p < x$	Poor Integrity	a
	Failed Test	

Possible responses

- a. Keep system operating as near current conditions as practicable.
- b. Use capability to apply some extra back-pressure.
- c. Shut well in for limited periods (eg Hurricane)
- d. Shut well in for extended periods.
- e. Top Kill well using 2 Ram stack.

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