Development of understanding of pressure-flow behaviour in the MC252 system

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Basis of decision making on data acquisition

- Any data acquisition effort has been justified by the significance of the decision that the data would be used to support
- Data acquisition not in support of significant decisions was of low priority
- The practicality of obtaining data of sufficient accuracy was also a key factor in prioritisation of data acquisition effort

Measurement of two-phase flow

- Fluids leaving the MC252 system comprise both gas and oil, a two phase flow
- Measurement of flowrate of a two-phase flow system is inherently very difficult
- Numerous researchers and vendors around the world have spent much effort over many years to develop two-phase/multiphase measurement systems
- It would be possible to deploy such a system on MC252, but this is deemed of lower priority than collection or containment efforts, especially when collection efforts will also provide a direct measurement of flowrate
- Many other techniques have been suggested, but none are felt to be sufficiently accurate or easy to deploy

Units of measurement

- Important to ensure consistency in use of units
- Oil flowrate is best described in stock tank barrels of oil per day – this provides a consistent conversion factor and the most appropriate representation of oil rate reaching the surface
- Some may report the volume flowrates leaving the riser in barrels per day without taking into account the gas content or shrinkage of oil to stock tank conditions, which gives a much higher value

NOAA estimates

- 1 mbd original estimate
- 5 mbd estimate issued on April 28

Flow path scenarios

- Modelling of potential flow paths through the well, and reservoir delivery, was undertaken to establish potential flowrates
  - Is flow up the casing and/or annulus?
  - Is there drill pipe through the BOP as designed, or different to design, or dropped?
  - How much reservoir is exposed?
  - What is the skin (resistance to flow out of the reservoir)?
  - All the above were unknown after the incident
- Gives a wide range of plausible flowrates, as quoted in response to Congress by BP

Proportional change in flowrate

- Plotted flowrate against wellhead flowing pressure (WHFP) for the various plausible scenarios
- Observed that the proportional change in flowrate for a specified change in WHFP is not strongly dependent on flowpath/reservoir scenario
- Allowed decisions on remediation to be based on resultant proportional change in flowrate given the predicted change in WHFP, without being dependent on knowledge of the absolute flowrate
- Needs measurement of WHFP to be made

WHFP pressure measurement

- Existing pressure transducer at base of BOP was reinstated to give WHFP measurement
- Initial readings of ~3800 psi with direct electrical connection to ROV gave confidence that proportional increase in rate of less than two times would occur if all back pressure removed
- Calibration during top kill uncoverac an under-read of 966 psi, with stable acoustic signal transmission
- With test rams closed, pressure remains in the corrected range 4000-4400 psi, with seabed at 2259 psi
- Losing all this back pressure would result in a flowrate increase of up to ~40%

Prof Wereley measurement

- Prof Wereley of Purdue University made a time of flight velocity measurement of flow from the riser end and interpreted it as an oil flowrate of 70 mbd
- This prompted an assessment of gas volume %, oil shrinkage, and flowpath area, each of which reduces the estimate of oil volume flowrate reaching the sea surface
- A more thorough interpretation of his given time of flight measurement gives a flowrate estimate of 15-20 mbd reaching sea surface

RITT measurement

- Reached a highest value of ~10 mbd oil collected through RITT
- This was achieved through angling RITT to low down in pipe to pick up stratified oil, with little free gas
- This is consistent with vessel measured GOR of ~650 scf/bbl which is the remaining gas dissolved in oil at seabed pressure and temperature

FRTG estimate

- Unified Command appointed a Flowrate Technical Group to develop a flowrate estimate independent of BP
- BP provided video data, and basic information on fluid properties, and initial estimate of flow area restriction at trench end
- FRTG first estimated 12-19 mbd, with a high of 25 mbd from some of the analysis techniques

Pressure measurements through top kill

- Opening the test rams prior to top kill resulted in a drop in WHFP from 4400 to 3600 psi
- This is predicted to have resulted in a flowrate increase of ~10-15% for the period of the top kill
- After the three top kill attempts the test rams were closed, and the pressure returned to 4300 psi, thereby returning the flowrate to its earlier value

% flowrate increase on riser removal

- The pressure under the flange just upstream of the riser kink was measured through the mud boost line as ~2600 psi
- On cutting the riser downstream of the riser kink the WHFP dropped by about 50 psi
- On cutting the riser immediate y upstream of the riser kink the WHFP dropped by a further 100 psi
- This equates to a proportional flowrate increase of 2-5% from the previously mentioned scenario modelling
- DoE expected estimates of up to 5% are consistent with this

LMRP cap flowrate measurement

- Reached a highest value of ~15 mbd
- Remaining spillage through several (up to 4) vent ports and through the bottom
- Capacity of vessel up to 18 mbd oil and 35 MMscfd gas

LMRP cap bypassestimate

- Given the flow path areas, and pressure inside the cap, it is possible to make an estimate of the bypass flowrate
- Internal pressure is only very slightly above ambient, and measurement is of the differential to seawater ambient
- Two-phase flow is inherently complex, with potential for instabilities and therefore differing gas-liquid proportions leaving through the different exit routes – several simplifying assumptions have to be made in modelling
- The flowrate estimate is very sensitive to the values of pressure and flow area
- Top hat is at an angle, and the rubber seal is dislodged, making accurate assessment of flow area difficult
- DoE estimate of total flowrate, including the bypass, issued on June 14 is xxx bbl/d

Reservoir capacity

- The subsurface understanding is that xx-yy MMbbl of oil is in the reservoir
- Aquifer support of reservoir pressure is limited
- Continuous production will eventually begin to reduce near well bore pressure, and therefore begin to reduce flowrates
- For a flow of 20 mbd this effect is expected in zz days, and for 30 mbd in zz days
- Higher production rates than this are inconsistent with the understanding of the reservoir and the steady measured WHFP

FRTG updated estimate

- Estimate of 20-40 mbd issued on June 10

Vessel collection update

- The collection rate of just less than 18 mbd through the LMRP cap up to the Enterprise is being maintained
- A further zz mbd is being extracted via the highest level vent in the BOP stack into the choke line and up to the Q4000 for burning
- Remaining spillage is the minimum necessary to maintain exclusion of seawater from LMRP cap
- Total spillage therefore currently at least – xx mbd

Choking back the flowrate

- Installing a cap that would allow choking back the flowrate would also allow testing of the shut-in characteristics of the well
- Development of full shut-in pressure 8100-8900 psi would confirm rupture discs are intact
- Settling out at a well head flowing pressure lower than 8100-8900 psi as rate is choked back would indicate loss of fluids out of the well

Variations in estimates

- The variability of estimates issued by independent experts illustrates the difficulty of obtaining an accurate flowrate estimate, even when all appropriate correction factors have been applied

Present in the Review 25 Jun 2010.

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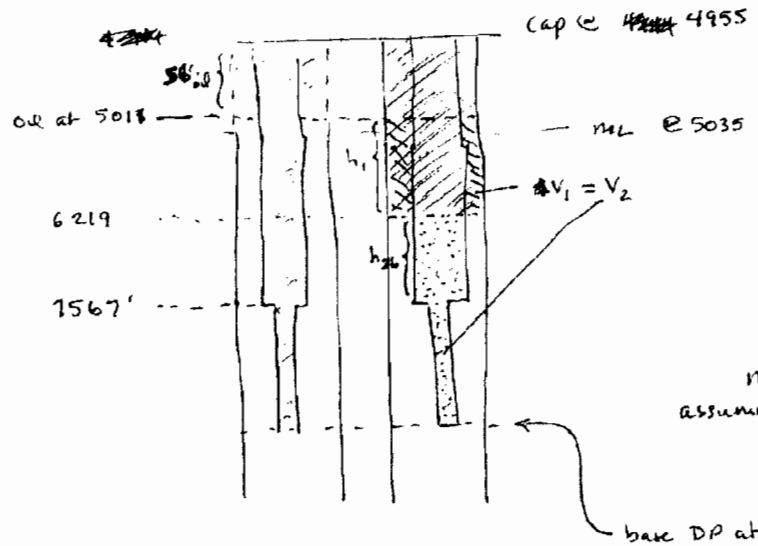


$V_1 = 0.042$ bbl/ft.

$V_{2a} = 5.93$ bbl $= 141$ ft. $\rightarrow (h_{2b}^{*141}) * 0.042$ bbl/ft

$V_{2b} = h_{2b} * .022$ bbl/ft

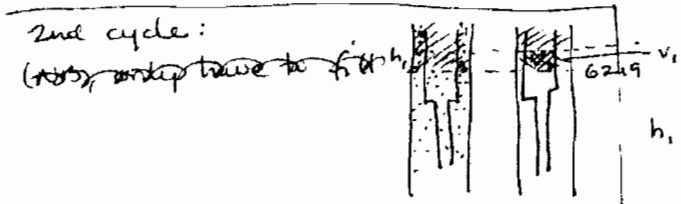
$V_1 = (141 + h_{2b}) * 0.042$ bbl/ft

$= 5.93$ bbl $+ h_{2b} * 0.022$ bbl/ft

macondo

assume oil = .249 psi/ft

2nd cycle:



56' oil head
mud 5011 - 6219
mud 6219 to TD

56' oil head
oil to 6219
mud 6219 to TD.

true || $V_1 = h_1 * 0.042$ bbl/ft

true || $h_1 (.042$ bbl/ft$) = h_2 (0.022$ bbl/ft$) = V_2$

true || $h_1 + h_2 =$ 6249 - 5011

① $V_1 = V_2$ || true

② $V_2 = h_{2b} * 0.022$ bbl/ft + 141 bbl. || true

③ $V_1 = h_1 * 0.042$ bbl/ft

$= 141$ bbl +

not true.

$h_{2b} = h_1 - 141$ ft * } check !

④ $h_1 + h_{2b} = 7567 - 5011$ || true.

$= 2556.$

$h_1 + h_1 + 141 = 2556$

$2h_1 = 2415$

$h_1 = 1208$

13.2 ppg to 5011 + 1208 = 6219 After 1st = libra.

$= .052 * 13.2 * (18150 - 6219) + .249 * (6219 - 4955) =$ 8505 1st cycle

3285 0th cycle.

5220 psi. desr.