Drilling an exploration reservoir section in the North Sea

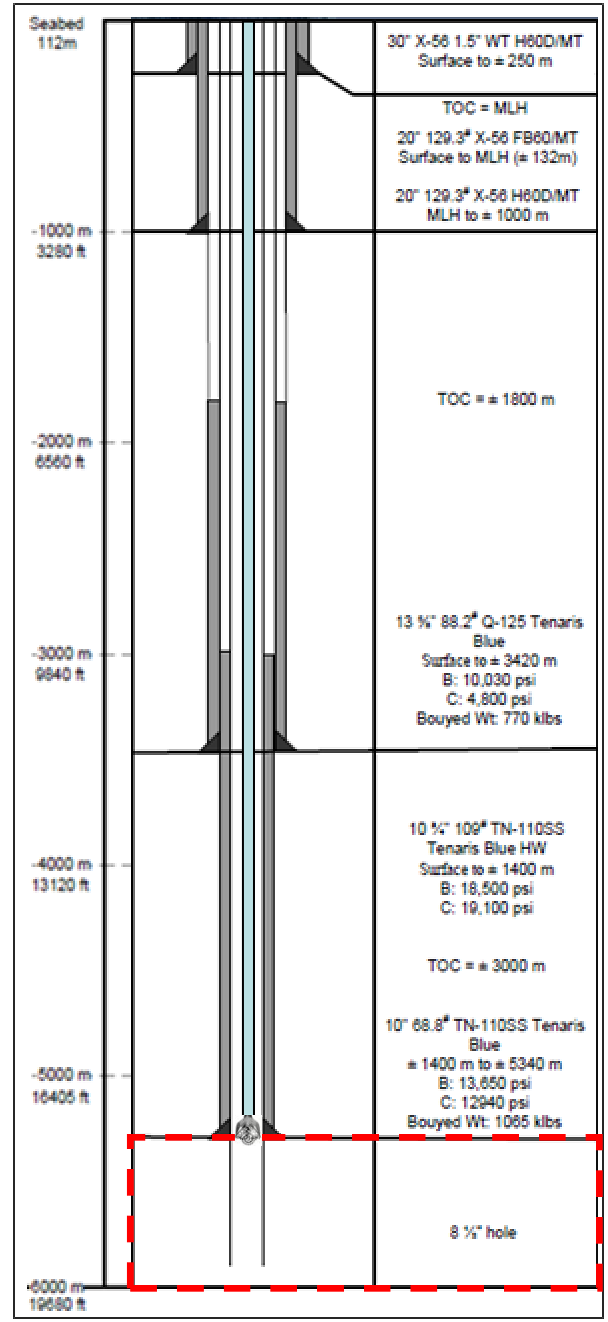
Norsk olje&gass

”Sharing to be better”

- Under the direction of Norwegian Oil and Gas, a joint industry task force of Operator and Drilling Contractor personnel has been formed to recommend ways to reduce the number and potential severity of well control events on the NCS.
- One team recommendation was communicating actual well control incidents that have recently occurred on the NCS so lessons are shared and understood.
- This is the seventh in a series of case histories. The incident highlights the importance of appreciating and realizing that an incident seldom develops on a single cause. The lesson shows that a number of issues had to be addressed and mitigated.
- Please take some time to review this case history with the drilling crew and discuss the questions raised during the presentation. Please invite and encourage related drilling service personnel to participate.
- It is hoped that sharing of incidents is helpful and any feedback is welcome.

Drilling 8½" Reservoir

- Drilling a HPHT wildcat exploration well in the North Sea.
- Top reservoir at 17,400ft TVD and below a 6,600ft salt section.
- Large variance in reservoir pore pressure prognosis:
  - P10 (low estimate) = 13.2 ppg
  - P50 (most likely) = 15.9 ppg
  - P90 (high estimate) = 16.2 ppg
- A 16.2 ppg drill-out MW was selected to avoid a possible underbalanced scenario.



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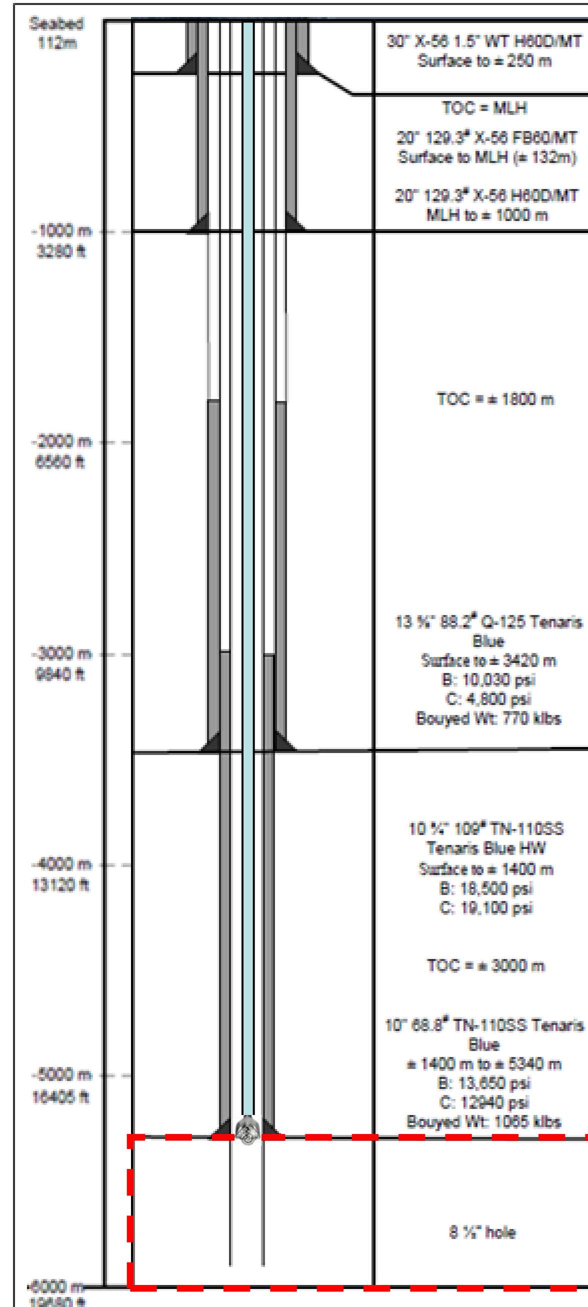
- <u>Consider</u>: Should the drill-out MW be based on the P10, P50 or P90 pore pressure estimate? …..Discuss.



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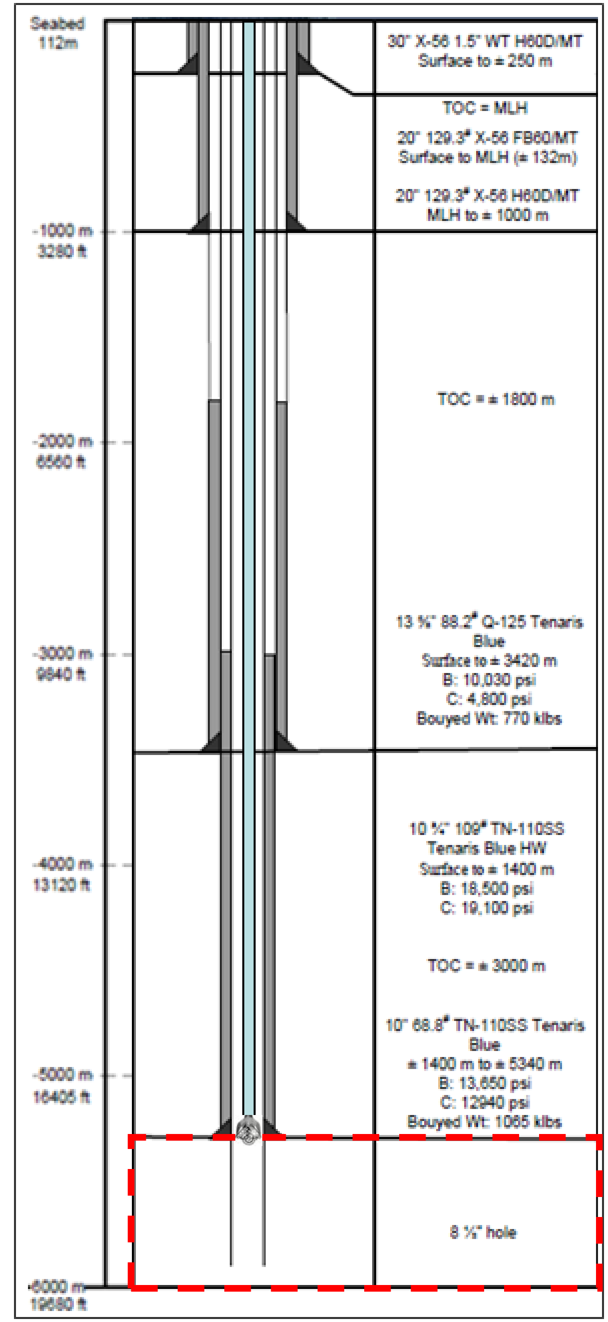
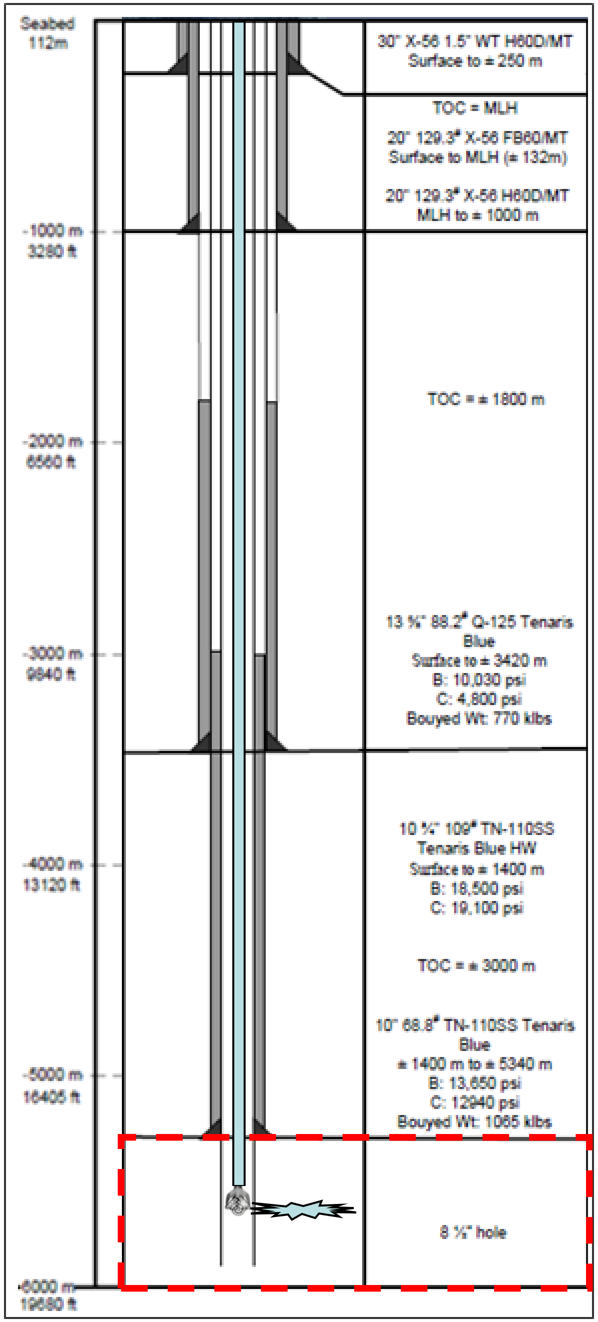
- Consider: Should the drill-out MW be based on the P10, P50 or P90 pore pressure estimate? …..Discuss.
- Drill-out MW was designed to balance the P90 pore pressure estimate. This needs to be carefully evaluated on a well-by-well basis.



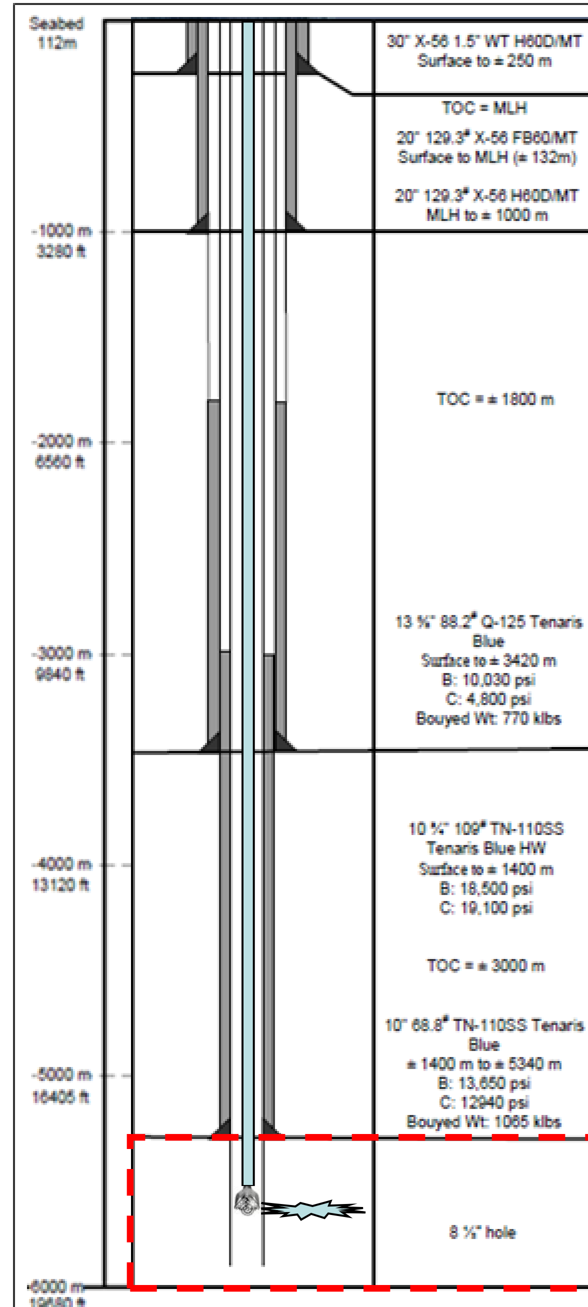
Mud Losses

- Performed FIT below 10” shoe to 18.0 ppg EQMW.
- Drilled 8½” hole with 16.2 ppg MW and ECD of 17.4 ppg.
- Losses occurred at 18,200ft at a rate of 180 bph.
- Stabilized well at 15.5 ppg EQMW using 9.7 ppg pre-mix. Total mud losses = 770 bbls.
- <u>Well Status</u>: Stable well with 16,400ft of 16.2 ppg mud column in lower part of the well and a 1,800ft mud column of 9.7 ppg mud in upper part of the annulus. Equivalent to 15.5 ppg at loss depth.
- With the heavy 16.2 ppg MW in the hole and well loosing if exceeding 15.5 ppg EQMW, how do you circulate out the heavy mud to reduce the MW gradient without inducing new losses? …..Discuss.



Mud Losses

- Performed FIT below 10” shoe to 18.0 ppg EQMW.
- Drilled 8½” hole with 16.2 ppg MW and ECD of 17.4 ppg.
- Losses occurred at 5550m at a rate of 180 bph (28,600 l/hr).
- Stabilized well at 15.5 ppg EQMW using 9.7 ppg pre-mix. Total mud losses = 770 bbls (122,400 l).
- Well Status: Stable well with 5000m of 16.2 ppg mud column in lower part of the well and a 550m mud column of 9.7 ppg mud in upper part of the annulus. Equivalent to 15.5 ppg at loss depth.
- With the heavy 16.2 ppg MW in the hole and well loosing if exceeding 15.5 ppg EQMW, how do you circulate out the heavy mud to reduce the MW gradient without inducing new losses? …..Discuss.
- Developed a stage-in plan that was within the operating envelope of the well. Required to POOH to 1500m.

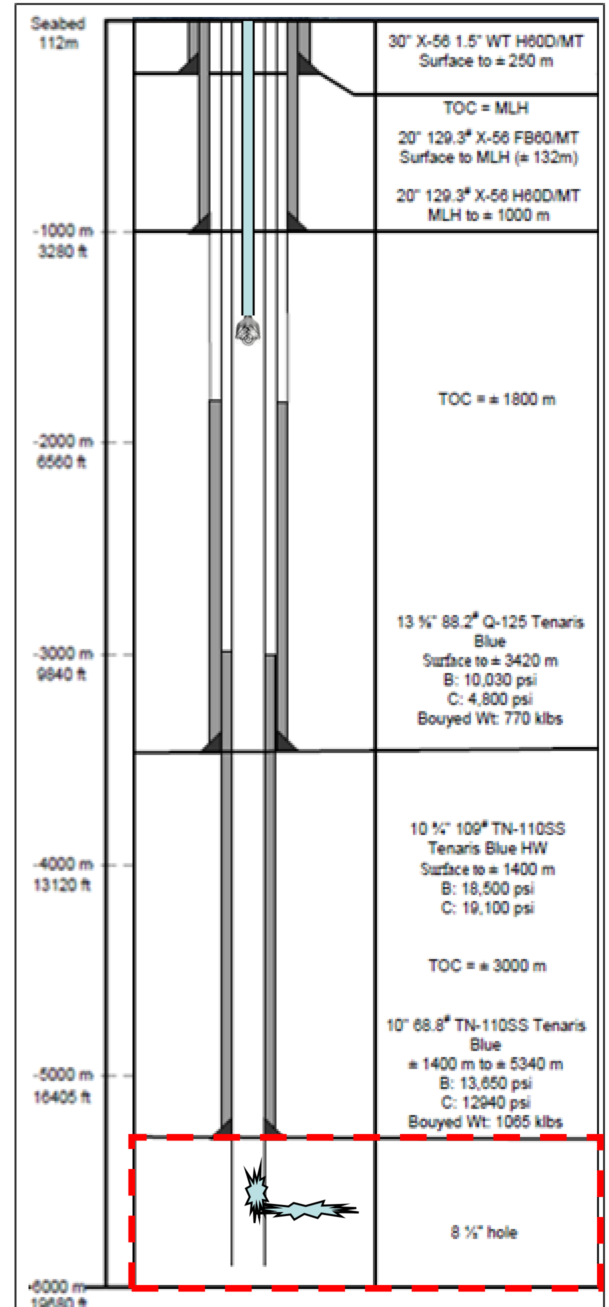


Pull bit back to 4900ft

- POOH to 4900ft and displaced to 9.7 ppg MW.
- With light fluid at bit, observed a rapid increase in flowback of 30 bbls.
- Shut-in well and observe pressures
  - SIDPP = 580 psi / SICP = 435 psi
- Continue to circulate in 9.7 ppg MW keeping DP pressure constant. Observe MW in returns on BU = 12 ppg.
- Observed a 20 bbl gain. Shut-in and observe pressures.
  - SIDPP = 900 psi / SICP = 830 psi
- Circulate in 12 ppg MW as seen in return on previous circulation while maintaining backpressure to regain previous well condition prior to the last gain.
  - SIDPP = 230 psi / SICP = 408 psi
- Circulate in 13.2 ppg MW. Shut-in well.
  - SIDPP = 320 psi / SICP = 320 psi
- Positive response in CP when increasing MW. Bleed-off CP in 25 psi increments. Flow check well via fully opened choke. Observed a slight gain on a decreasing trend to 0.5 bph.

- Based on this, the lower end of the operating envelope was determined to be 14 ppg EQMW to avoid influx. The upper end remained 15.5ppg to avoid losses, resulting in a “safe” operating envelope of 1.5 ppg EQMW.

- This required an updated stage-in plan based on the new operating envelope to avoid gains and losses.

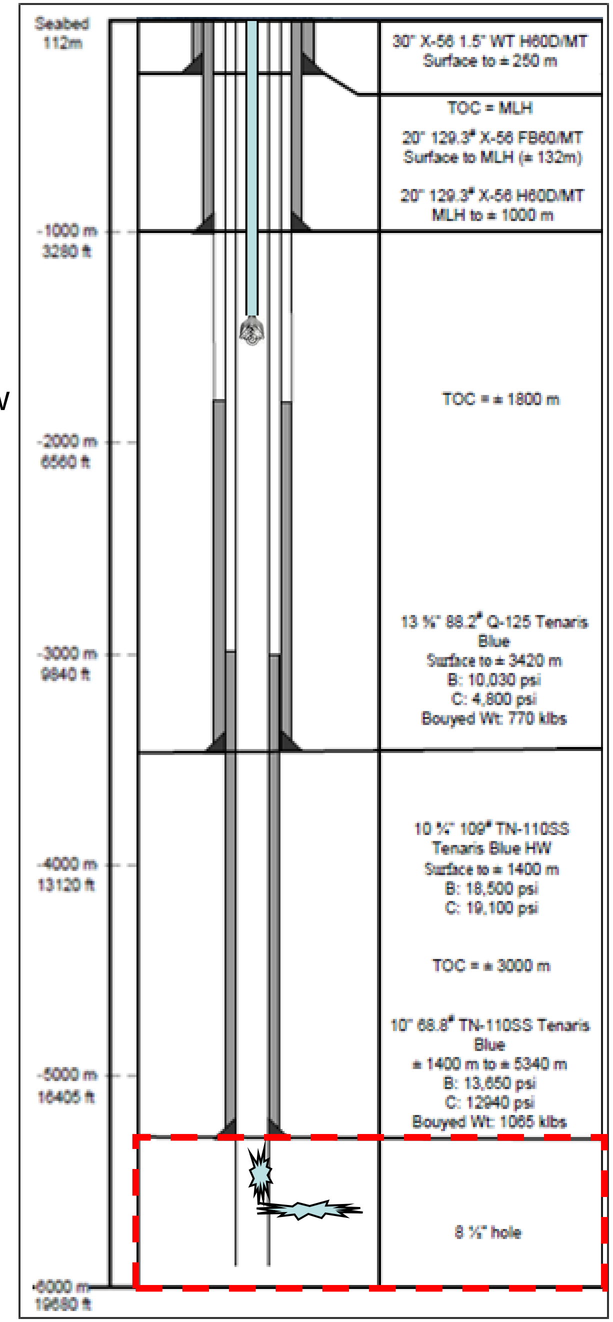


Onshore Support

- The onshore exploration drilling organization was split into two teams working 12-hr shifts to support the offshore crew. This continued 24/7 until the primary barrier was regained.
  - Established team in Onshore Drilling Center (ODC) to have one focal point of contact and video conference available at all times.
  - No change in responsibility between offshore and onshore team.
  - Onshore team prepared forward plans for re-gaining well control to allow offshore crew to focus fully on the well and downhole conditions.
  - Maintained detailed operation and observation log.

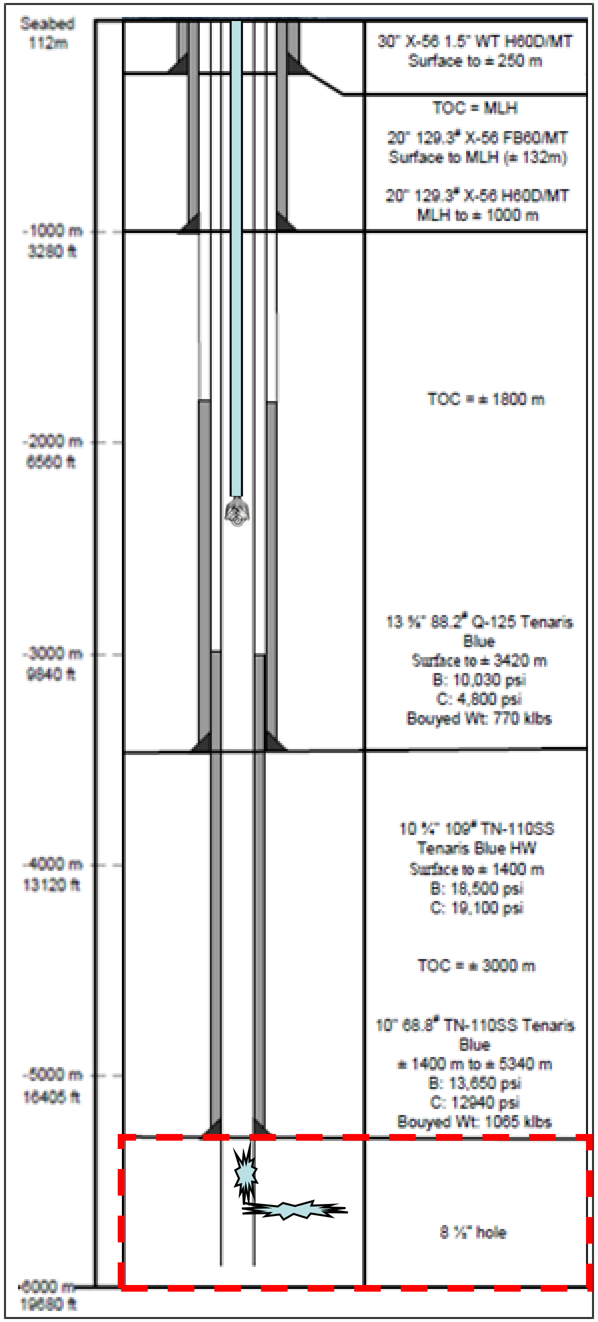
- MI-Swaco COVR real-time hydraulic simulations supported operations 24/7 throughout the well. Using historical well data in the hydraulic model made the stage-in plan more reliable.
  - How far can we stage into the heavy 16.2 ppg mud, circulate out and displace to a lighter fluid?
  - What circulating rate can be used?
  - What is the expected pump pressure during a displacement?

- With 16.2 ppg MW below the bit and 0.5 ppg ECD exerted on open hole while circulating inside cased hole, the operating envelope and allowable stage-in intervals were limited.



Stage in hole

- After staging in to 7090ft, an indication of leaking floats in the BHA was noted. Two plunger type floats were used in the BHA.
- Now, what do you do? …..Discuss.



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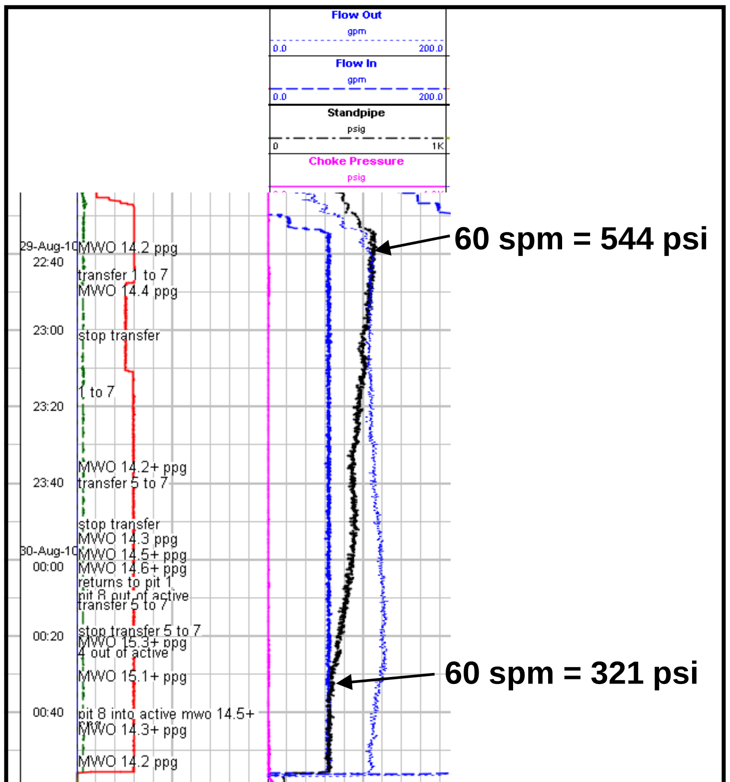
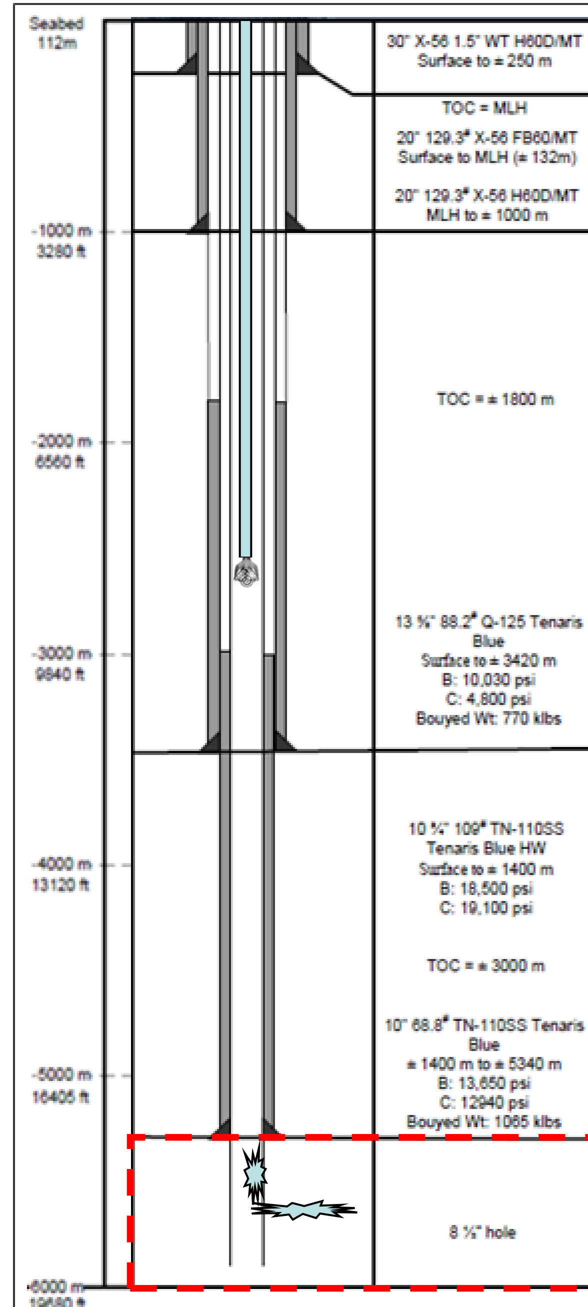
- Now, what do you do? …..Discuss.
- An IBOP was installed in the string to allow stage-in operations to continue.
- With the bit at 8700ft a gradual drop in SPP was observed and it was not according to the simulated pressures.
- What is going on? …..Discuss.

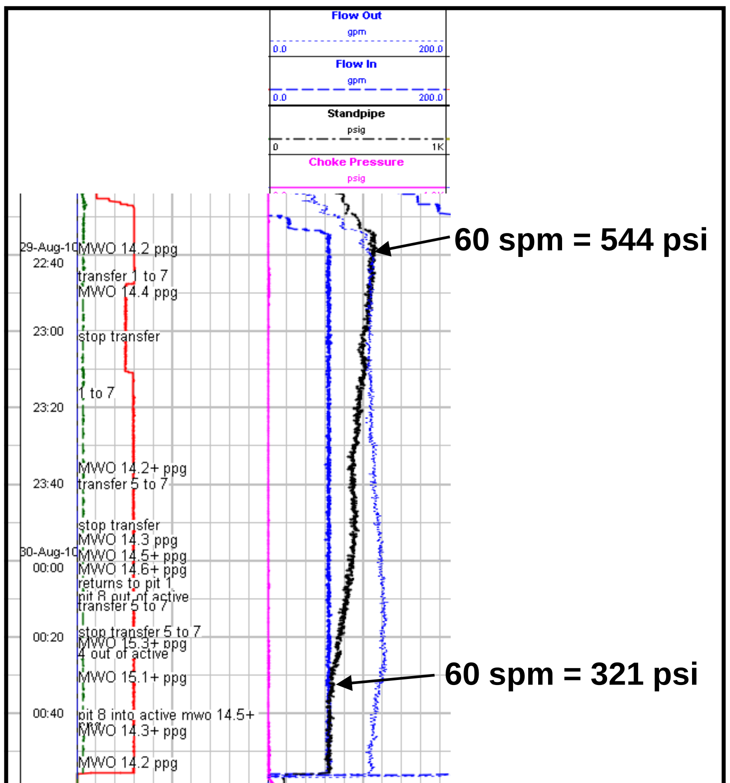


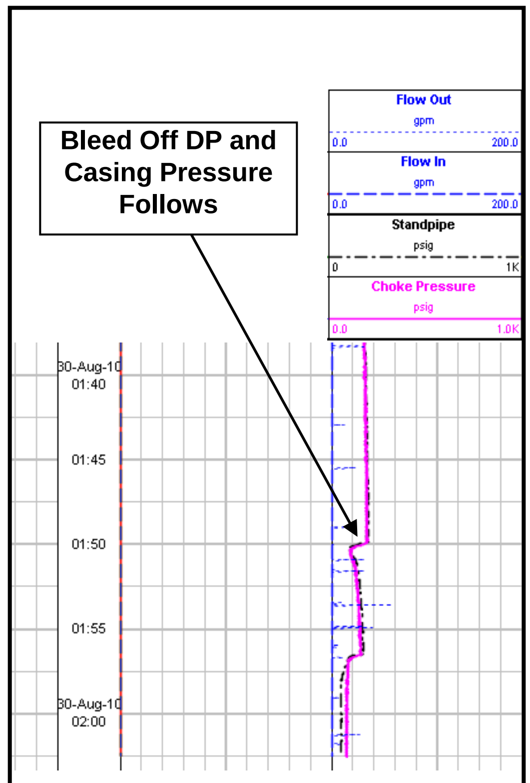


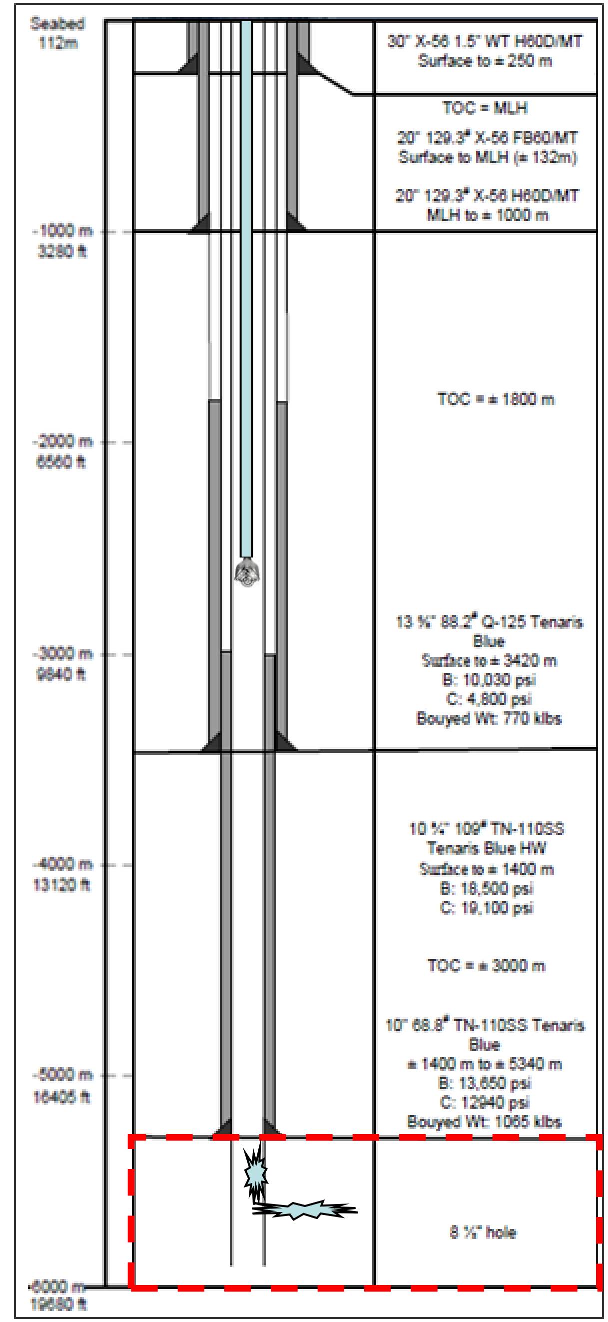
Pressure Communication

- The well was shut-in and observed for pressure build up inside DP and the DP annulus.
- SIDPP and SICP showed to be equal and overlaying each other.

- What is going on? …..Discuss.



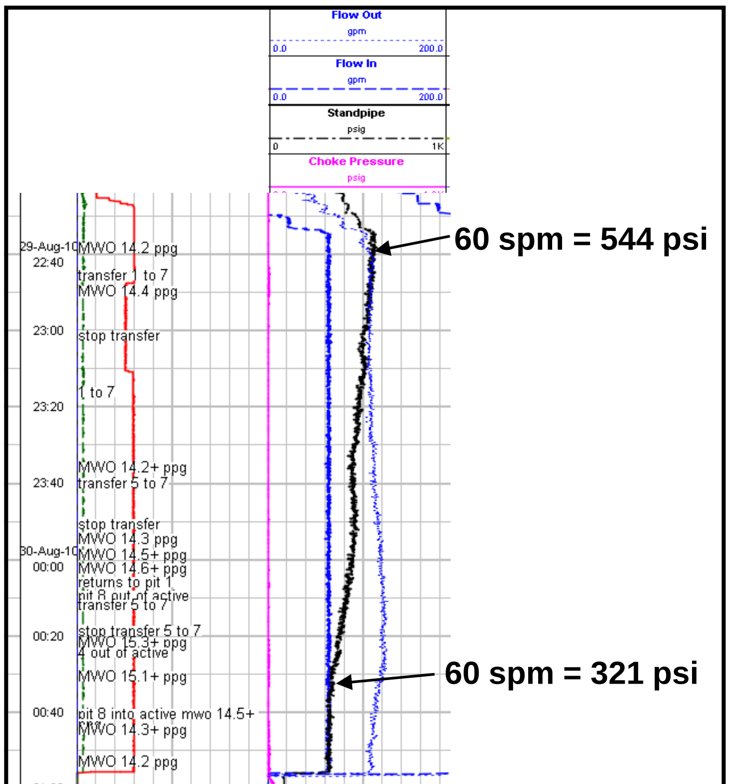


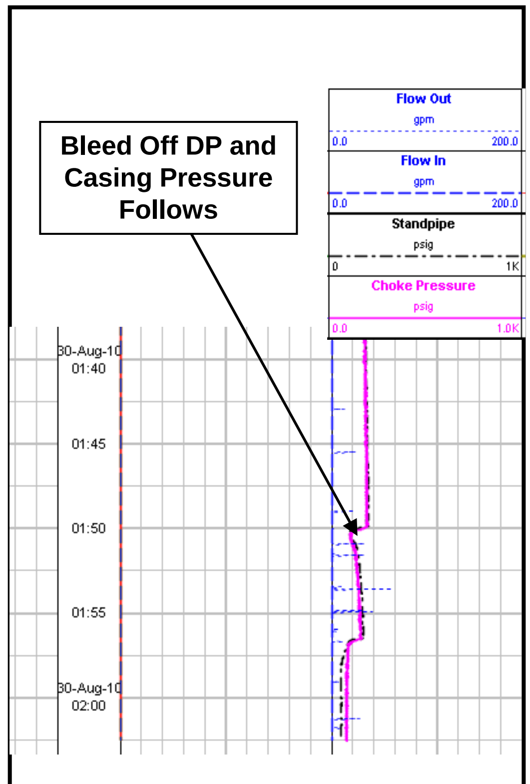


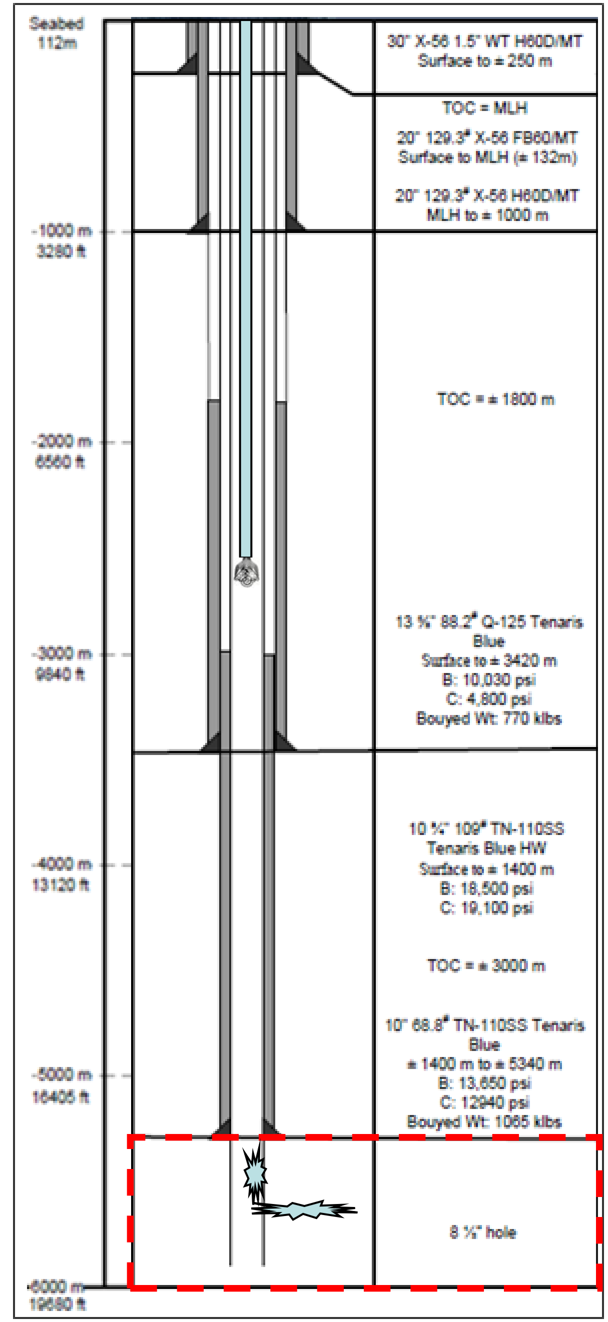
Pressure Communication

Observations:

- Overlaying SIDPP and SICP indicated communication between DP and annulus.
  - Currently two floats in the BHA and one IBOP in the string. Are they all leaking?
- Heavy 16.2 ppg mud is coming back later than expected.
- Pump pressure is much lower compared to MI Swaco's hydraulic model.
- What is going on? …..Discuss.







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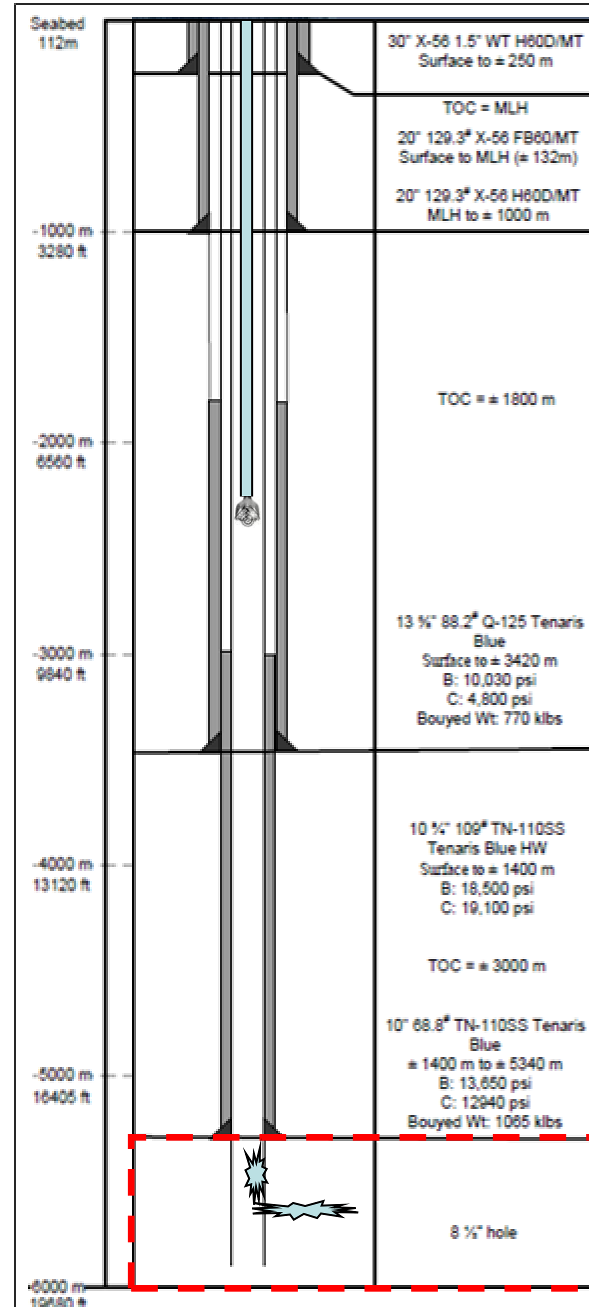
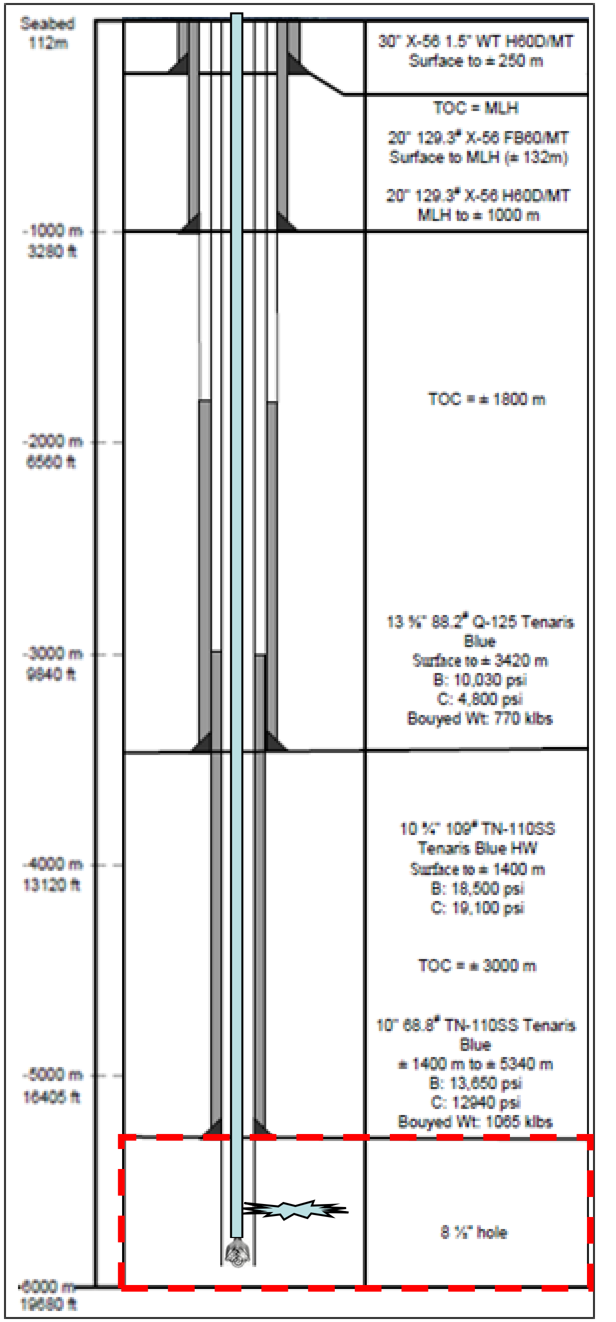
- Heavy 16.2 ppg mud is coming back later than expected.
- Pump pressure is much lower compared to MI Swaco's hydraulic model
- What is going on? …..Discuss.
- These are all indications of a possible washout in the string.
- The string was pumped out 1000ft to 7700ft bit depth and a washout just below a connection was found.

What could potentially be the consequences if not observing and taking the correct actions?



Continue to Stage in hole

- The washed-out stand was replaced and the stage-in operation commenced.
- After a total of 14 stage-in intervals, the well was displaced to 15.2 ppg MW from the 10” shoe, and the well was confirmed static over an open choke.
- No indication of formation fluid was observed.
- The influx observed in the beginning of the stage-in process was all previously lost mud that had returned into the wellbore.
- The MW was further reduced to 15 ppg and the bit was washed in the hole to bottom while limiting ECDs to 15.45 ppg EQMW.
- The well was flow checked and found to be static prior to reducing the MW to 14.8 ppg.
- Following an additional stable flow check, the well was successfully drilled an additional 625ft to TD.



Lessons Learned

- 24-hr support by the onshore drilling team over the 2 weeks it took to fully re-gain the primary well barrier to allow further drilling contributed to the safe execution of a challenging operation.

- The operator will plan for this kind of onshore support if similar well critical events should occur in the future.

- MI-Swaco's PressPro simulations supported the stage-in plan and concerns about the washout in the string.

- An event occurs seldom individually.
  - Losses
  - Fragile well conditions / limited operating envelope
  - Inflow with bit off bottom
  - Leaking floats
  - Washout in string