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R&D Council

Overcoming Inefficiencies of Annular Flow in a Hybrid Gas Lift Well

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ALRDC Gas Lift Workshop

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Case Study

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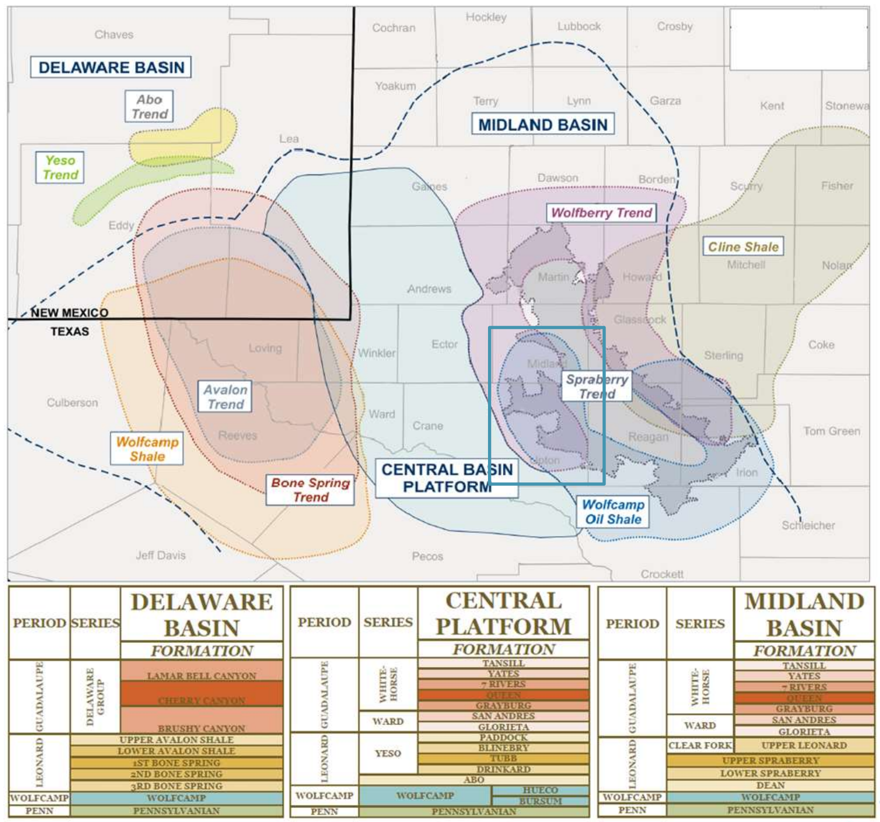
- The operator selected the Wolfcamp A formation in the Permian Basin for the case study.
- Historically this basin has utilized electric submersible pumps (ESP) as the ALS of choice
- Due to low commodity prices and the multiple re-entries of the wells to repair or downsize the ESP caused the operator to select gas lift as an alternative form for this case study



EH2
EH3

Artificial Lift Selection

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- Focused on maximizing production rates from the initial production (IP) of the well while maintaining an Artificial Lift System (ALS) designed to minimize work-overs
- Implemented a dual or “Hybrid” gas lift system to initially produce up the tubing/casing annulus to maximize the IP of the well
  - Provided a tubing flow option for later life production rates without the need of pulling the original ALS system
  - Provided an user friendly surface adjustment to meet the goals and needs
  - Proper selection of gas lift equipment that would allow for later life Plunger Assisted Gas Lift
- Analysed off-set well production history and Bottomhole Pressures (BHP) data help build a Nodal Analysis data set for ALS review. Analysing the data predicted we could hit forecasted rates with the proper selection of tubing size, landing depth, injection pressure, and volumes.

Slide 3

EH2 Minimizing workovers were key for this project
Eric Hale, 5/24/2021

EH3 WIRELINE EQUIPMENT AND SLIDING SLEEVE USED
Eric Hale, 5/24/2021

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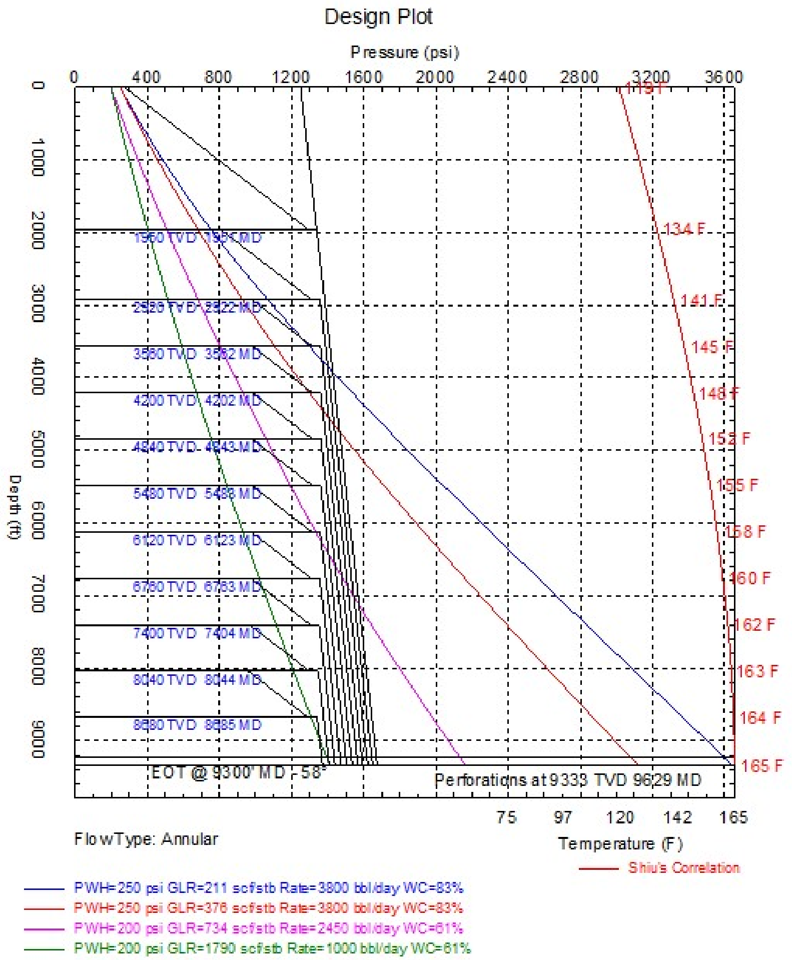
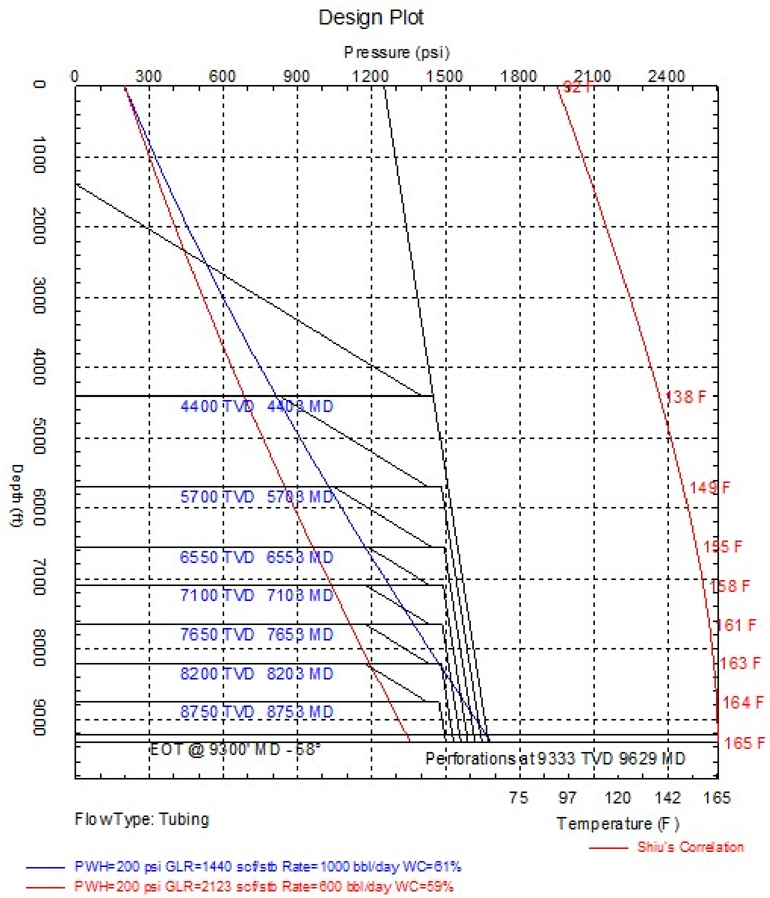
Annular Flow Valve Design Plot-Part #1

- The 1st part of the Hybrid gas lift system was developed based on the Nodal Analysis review from off-set production and IPR data
- The system in place accommodated forecasted IP rates as well as the production rates expected when the system would be switched to the 2nd part of the hybrid system



Tubing Flow Valve Design Plot-Part #2

- The 2nd part of the Hybrid system was developed based on the Nodal Analysis review to help predict liquid loading and unstable flow due to lower/later life production rates flowing up the larger cross-sectional flow area in the tubing/casing annulus.
- The system in place accommodated later life production rates to ease in the conversion from annular flow to tubing flow



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Hybrid Flow Path

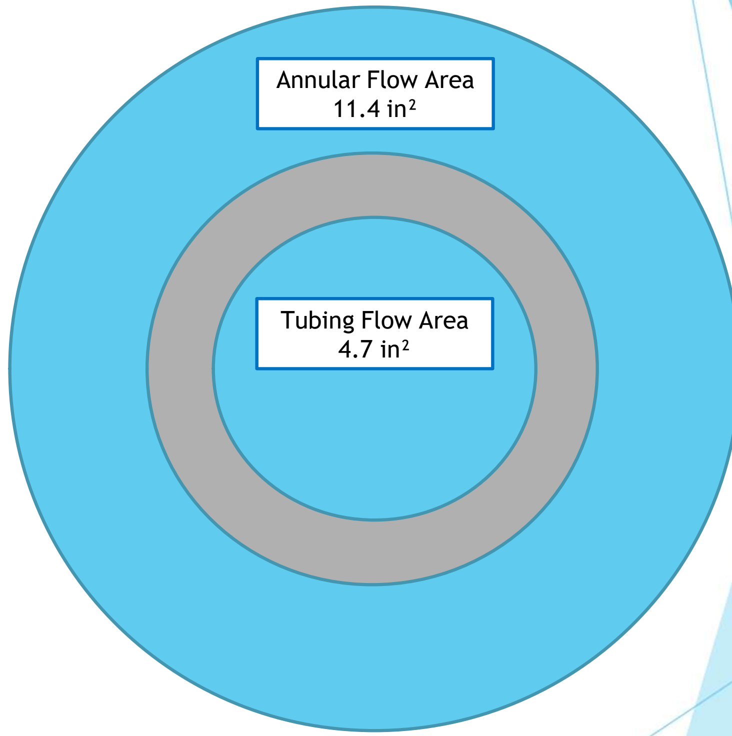
Cross Sectional Area = $\pi(C_{id}/2)^2 - \pi(T_{od}/2)^2$

2-7/8”   6.5#   2.441” ID Tubing =   4.7 in^2

5-1/2”   20#   4.778” ID Casing = 17.9 in^2

5-1/2” x 2-7/8” Annular Space = 11.4 in^2

Equivalent Tubing Flow ID for Annular Space = 3.816” ID



Key Advantages

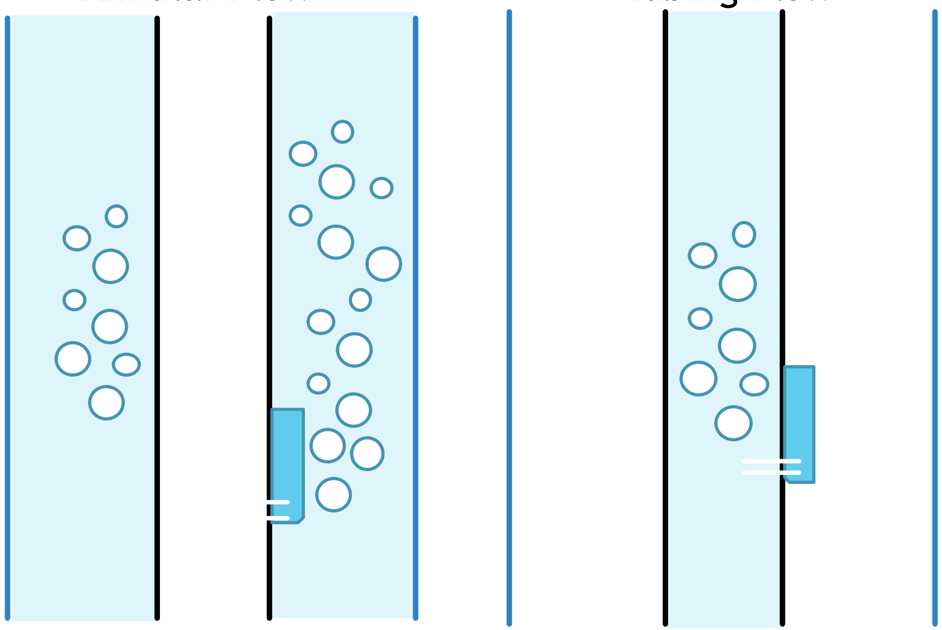
1. Greater flow area compared to conventional tubing flow

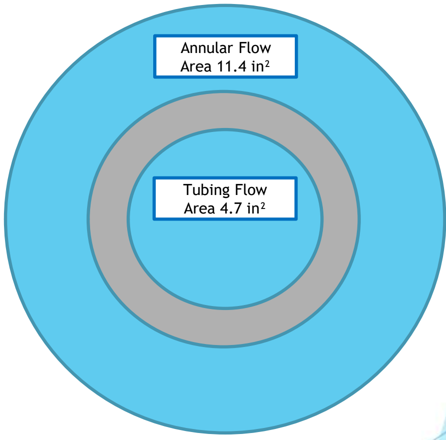
2. Reduced flow path friction, lower FBHP

Production Challenges and Goals

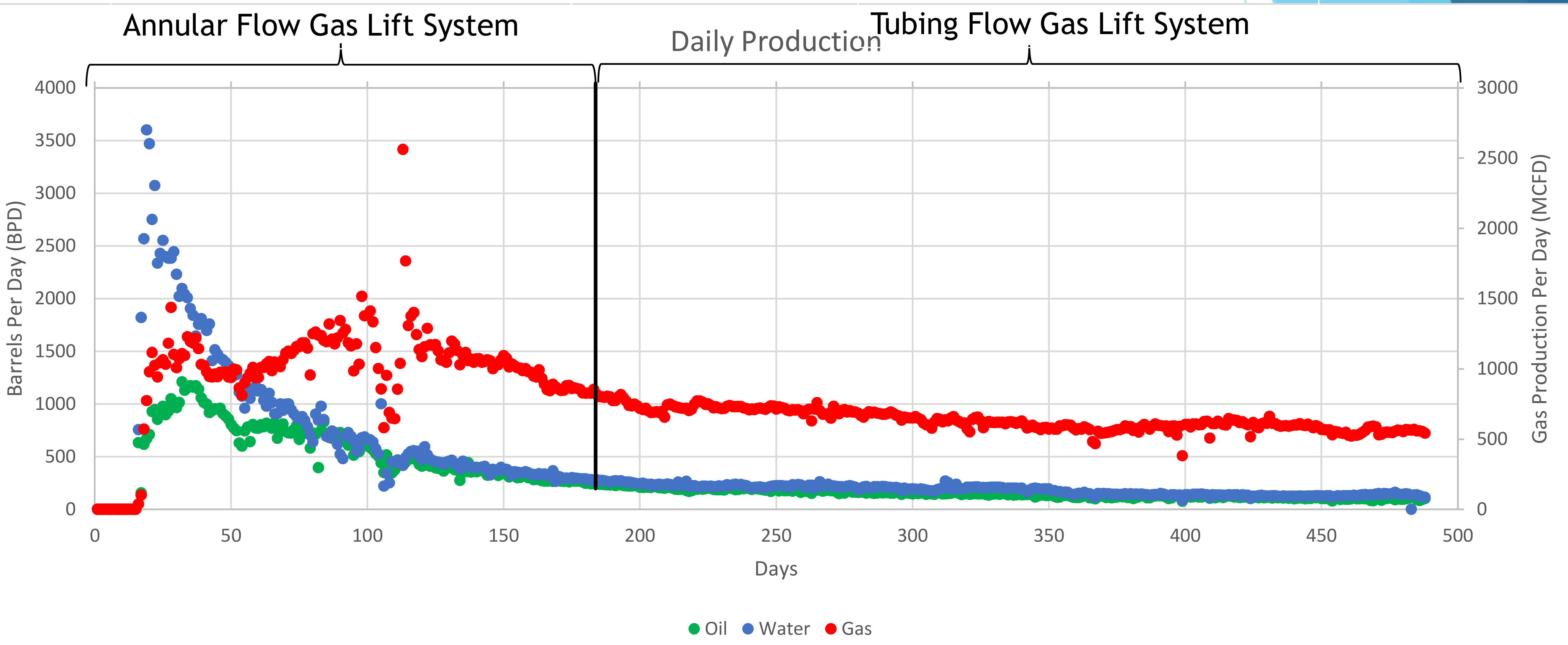
- Utilize the annular portion of the Hybrid System initially to produce the well to full potential and ensure the lowest flowing bottom hole pressure can be achieved
- Operating the annular flow system from mid-low rates before switching to tubing flow
- Minimizing the increase in FBHP when switching from annular flow to tubing flow

Annular Flow | Tubing Flow





Production History for the Hybrid System



DHG Data

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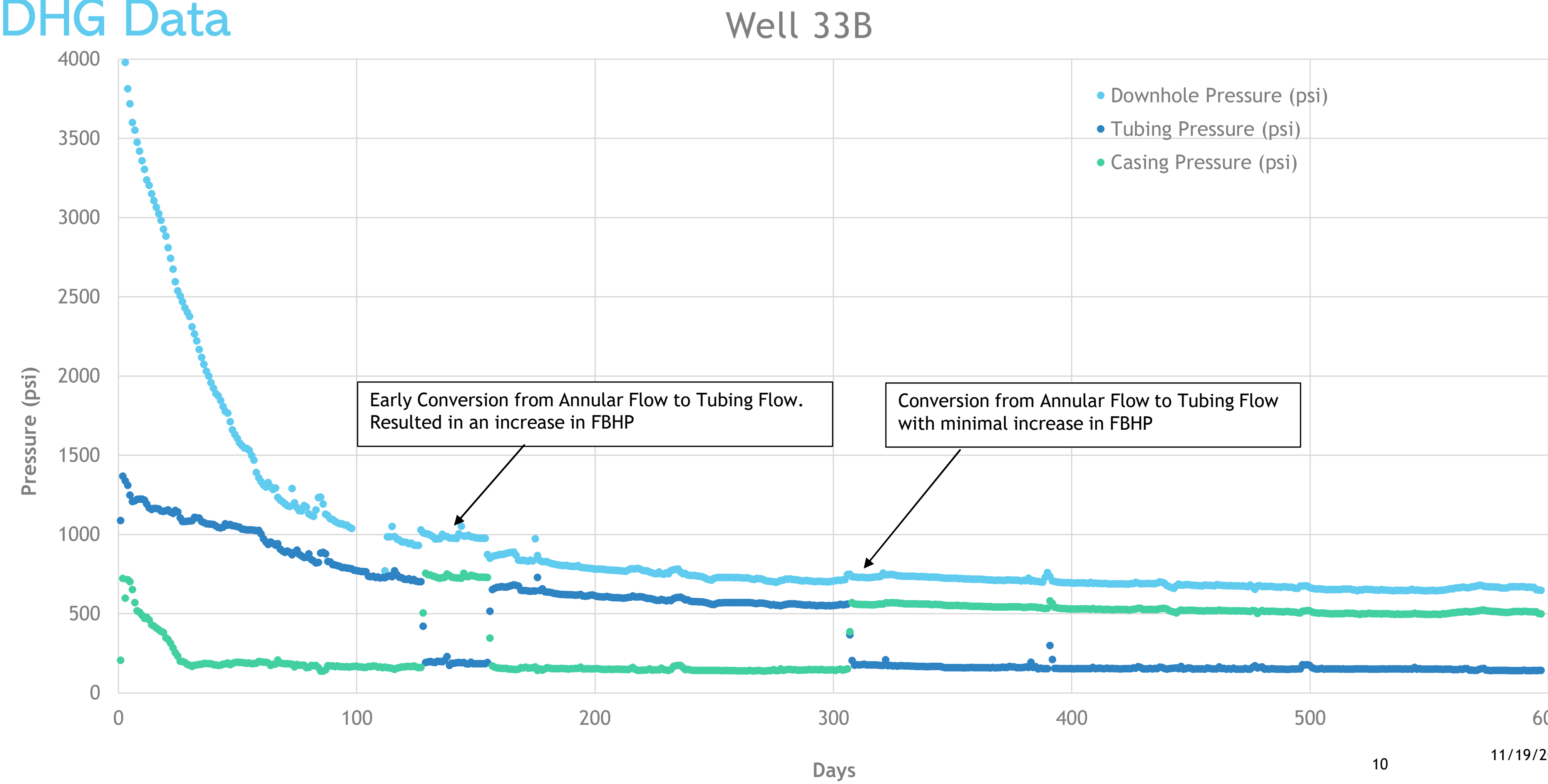
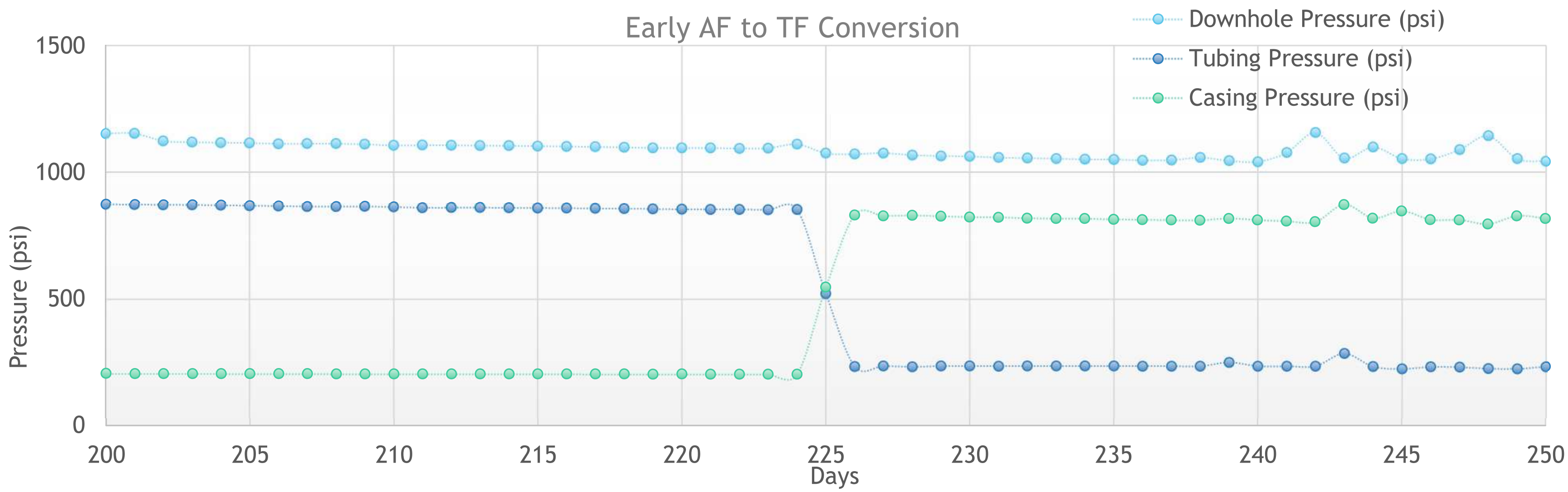
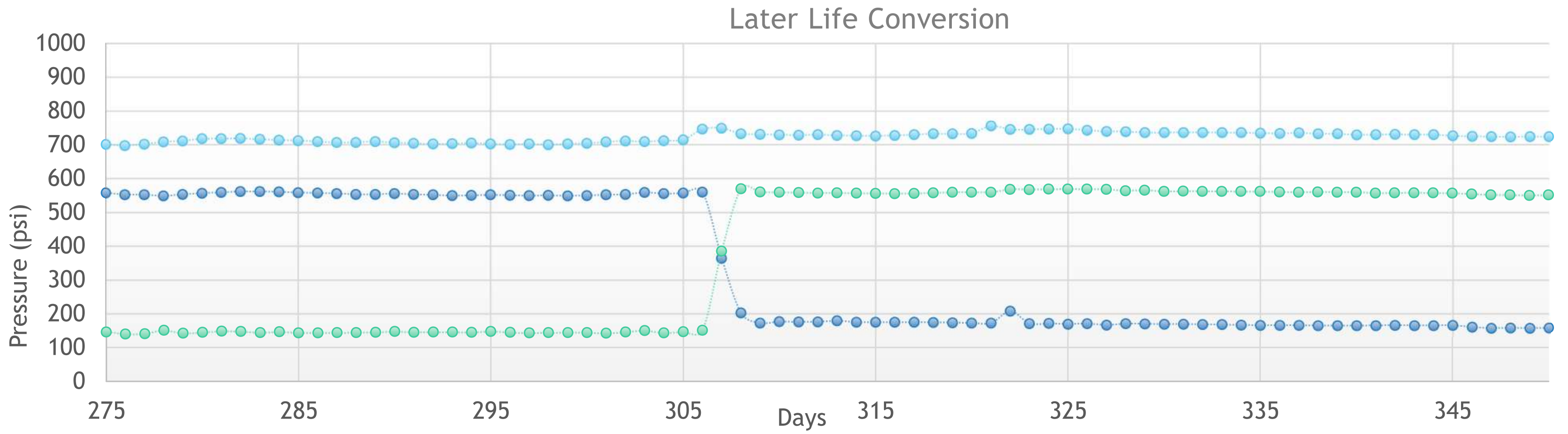
- Downhole Pressure data was closely monitored during the 1st and 2nd part of the Hybrid system to identify the target FBHP when the system should be converted from the Annular Flow to Tubing Flow
- Targeting a minimal change in FBHP was critical to maintaining production while reducing the cross-sectional flow area to help improve flow velocities
- Reduction in injection gas requirements were also key to optimize the system
- The following graphs represent the change in flow area and accommodating FBHP

DHG Data


Well 33B
4000
3500
3000
2500
2000
1500
1000
500
0
Pressure (psi)
0
100
200
300
400
500
600
Days
Downhole Pressure (psi)
Tubing Pressure (psi)
Casing Pressure (psi)
Early Conversion from Annular Flow to Tubing Flow. Resulted in an increase in FBHP
Conversion from Annular Flow to Tubing Flow with minimal increase in FBHP

DHG Data


Early AF to TF Conversion
Downhole Pressure (psi)
Tubing Pressure (psi)
Casing Pressure (psi)
Pressure (psi)
1500
1000
500
0
200
205
210
215
220
225
230
235
240
245
250
Days


Later Life Conversion
Pressure (psi)
1000
900
800
700
600
500
400
300
200
100
0
275
285
295
305
315
325
335
345
Days

Hybrid Flow Path Conversion

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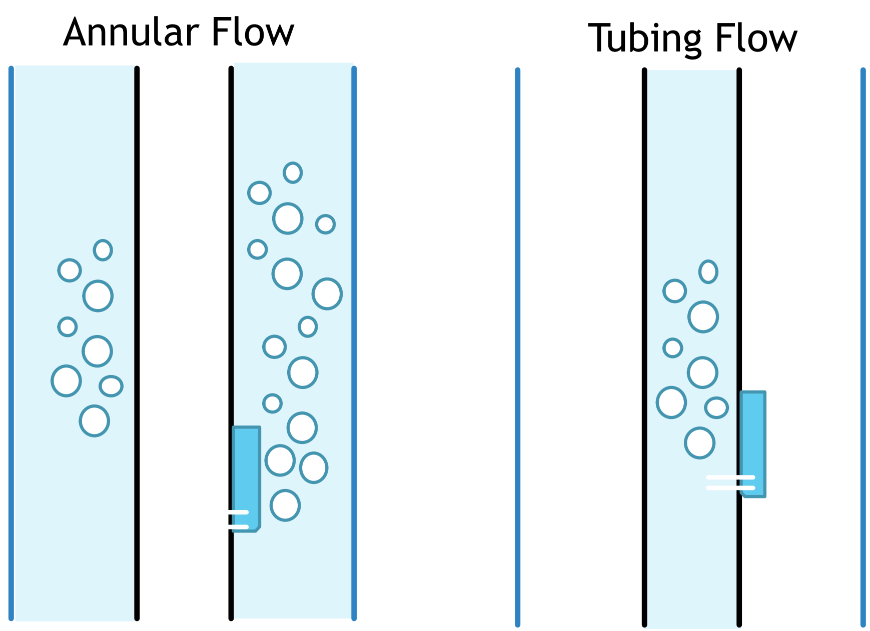
- The Inflow Performance Relationship (IPR) identifies potential production rates.
- The IPR helped select tubing size and ideal flow path
- The IPR identified transition point from annular flow to tubing flow



Inflow Performance Relationship (IPR)

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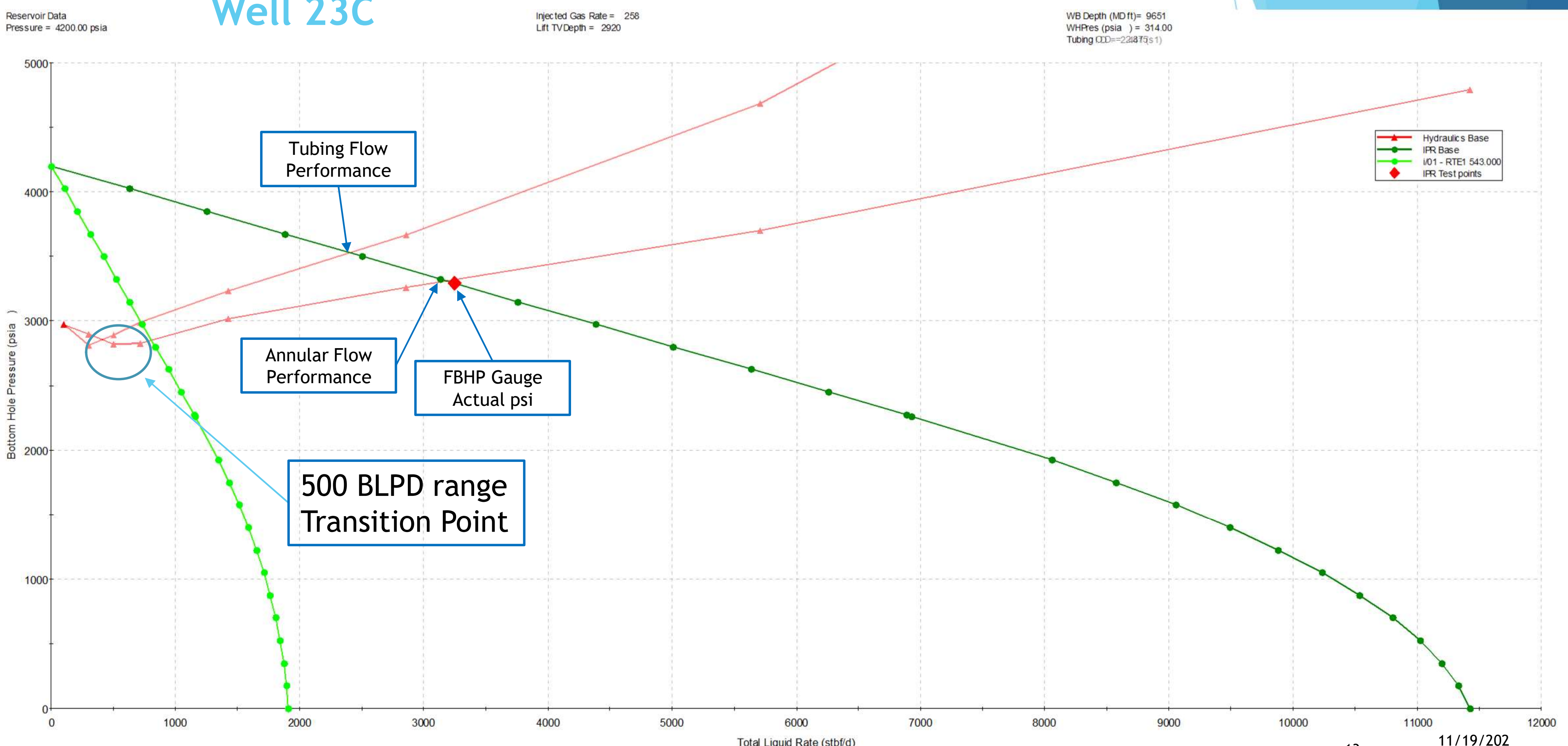
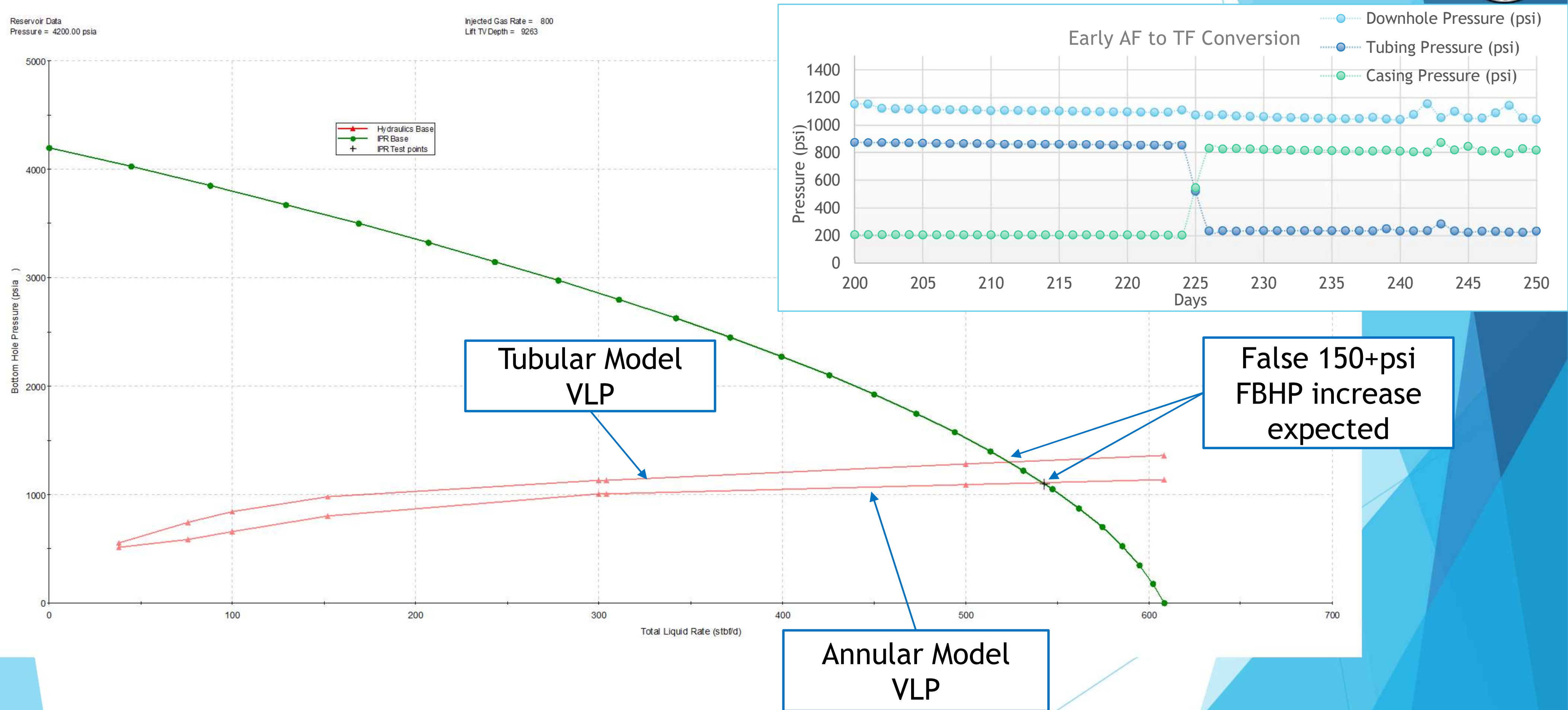
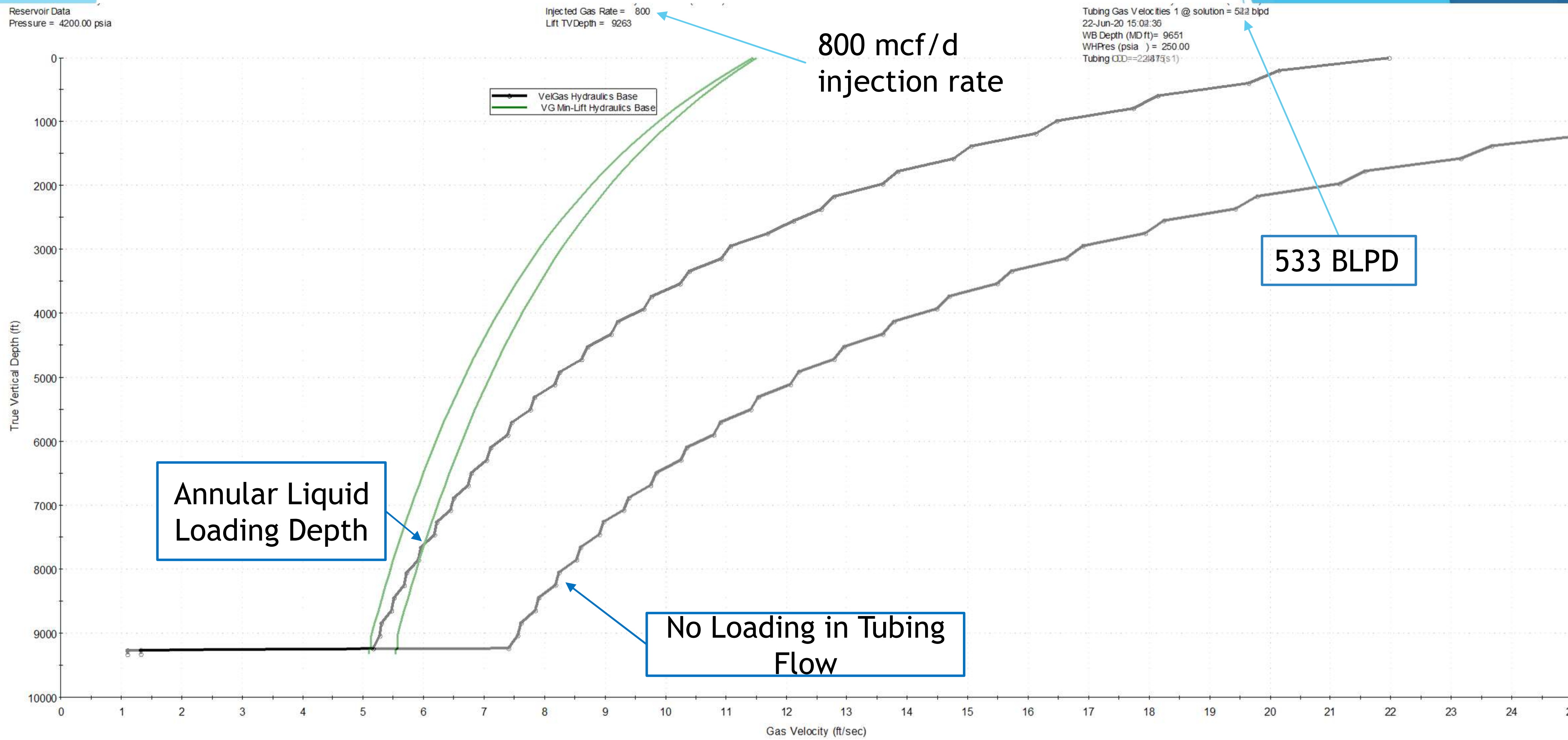
Well 23C



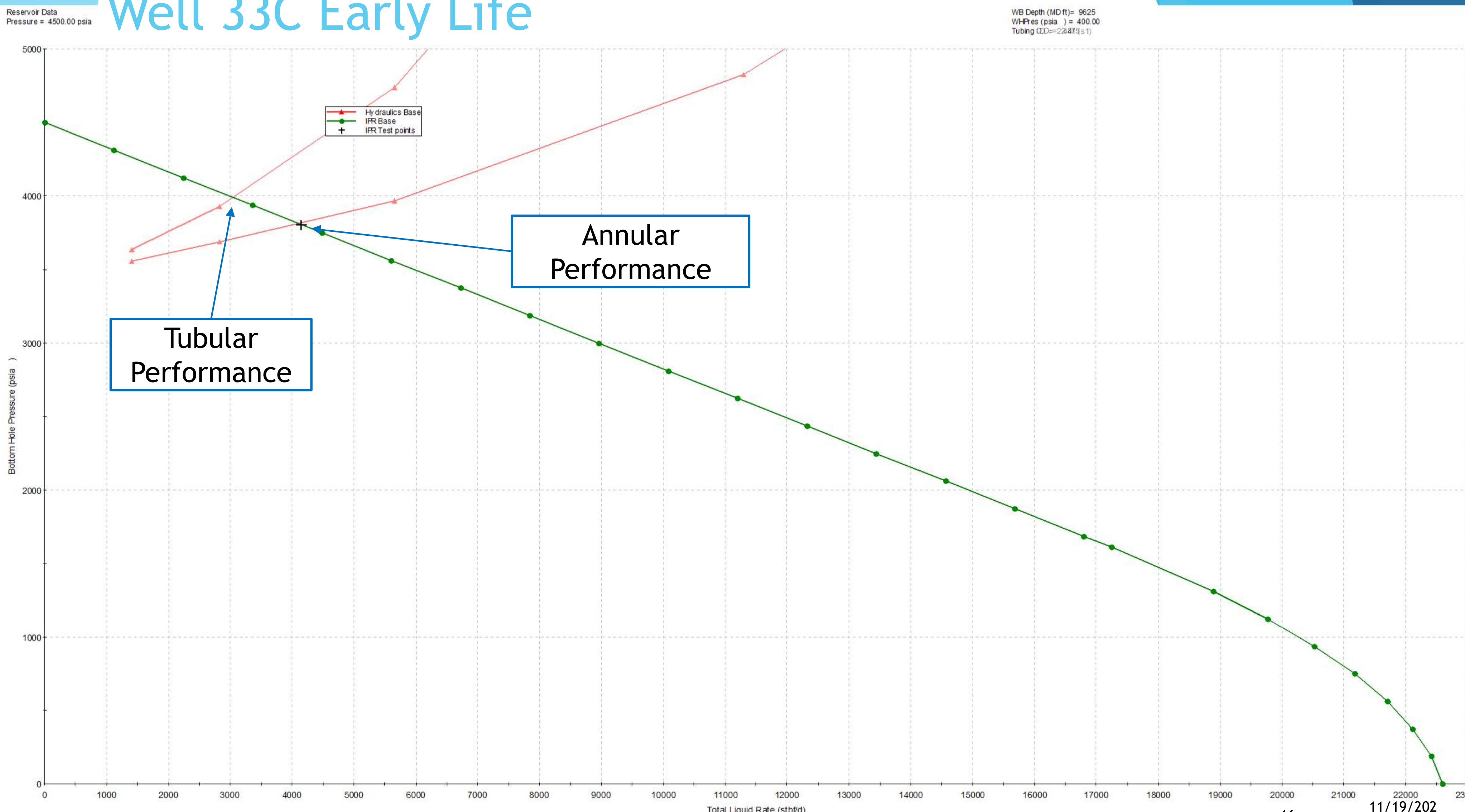
Well 23C Switching Point



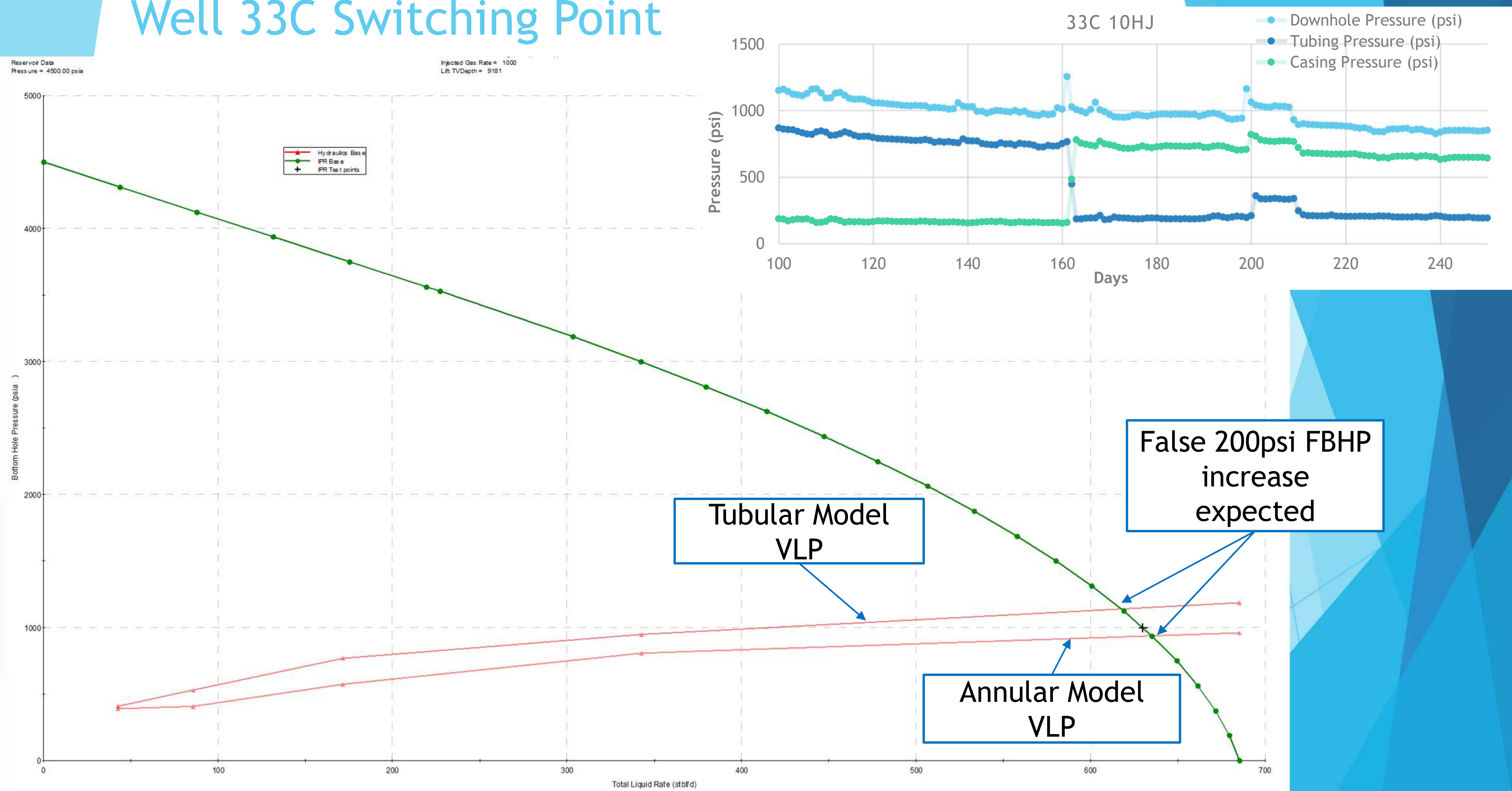
Well 23C Switching Point Velocity Gradient



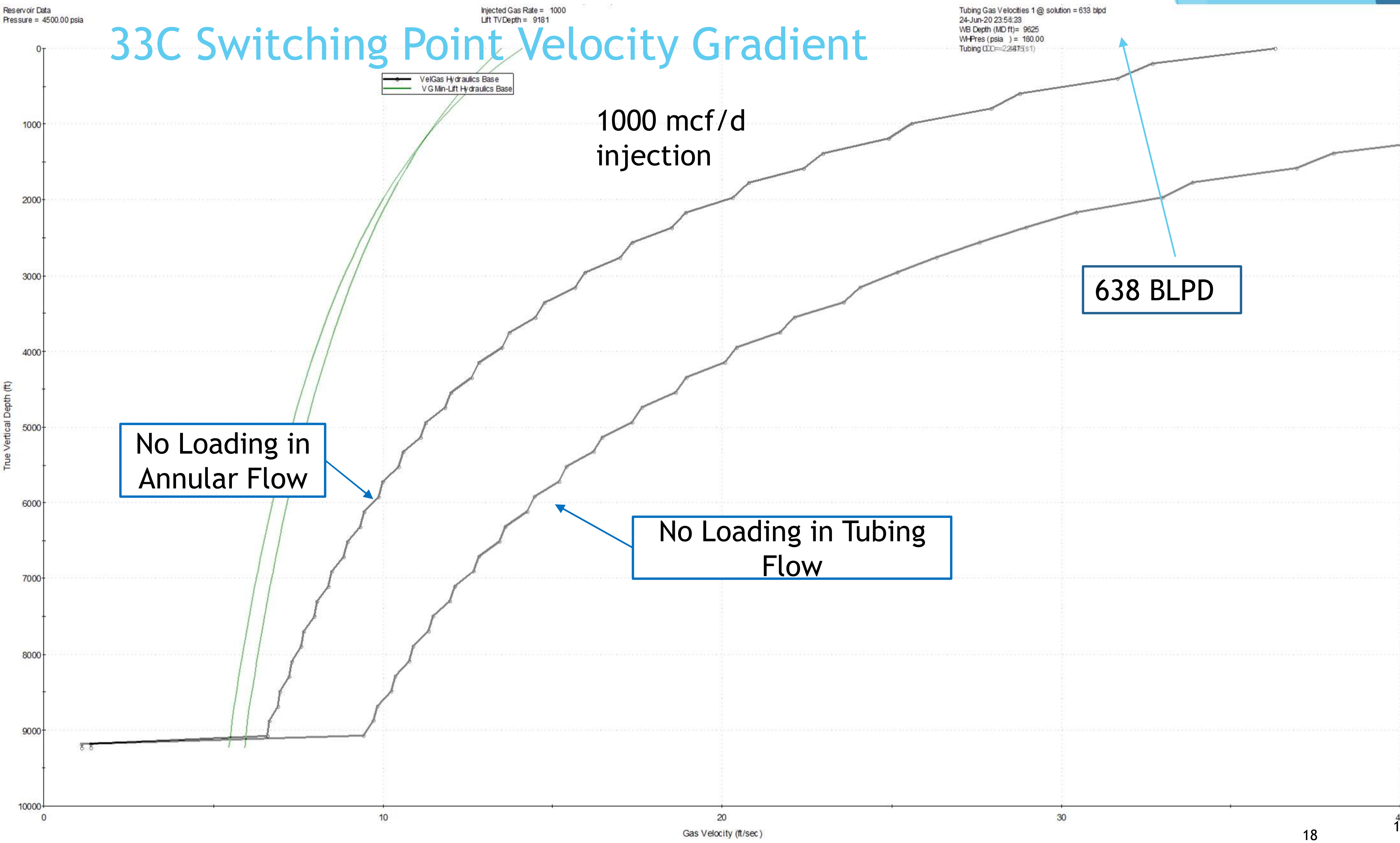
Well 33C Early Life

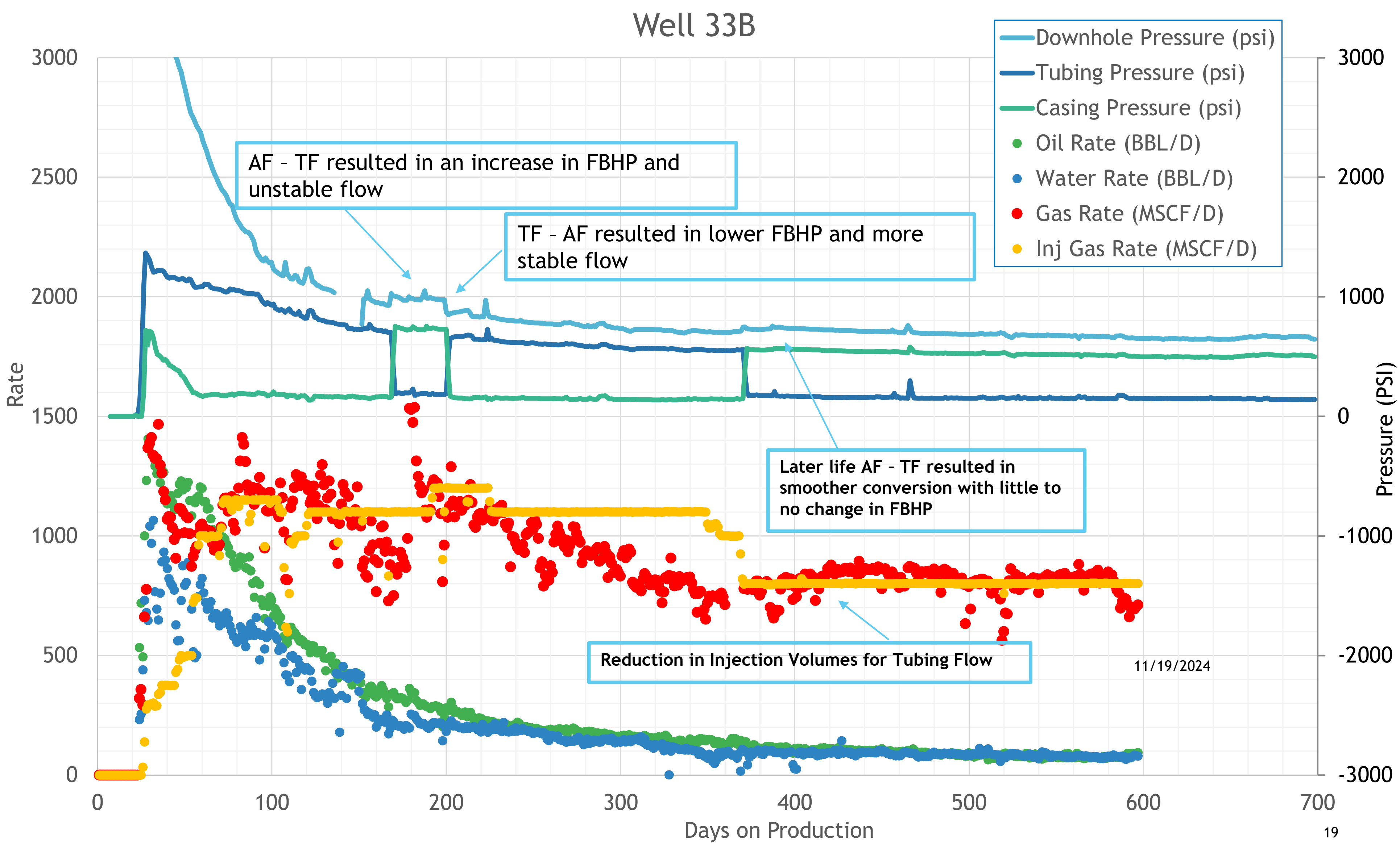


Well 33C Switching Point

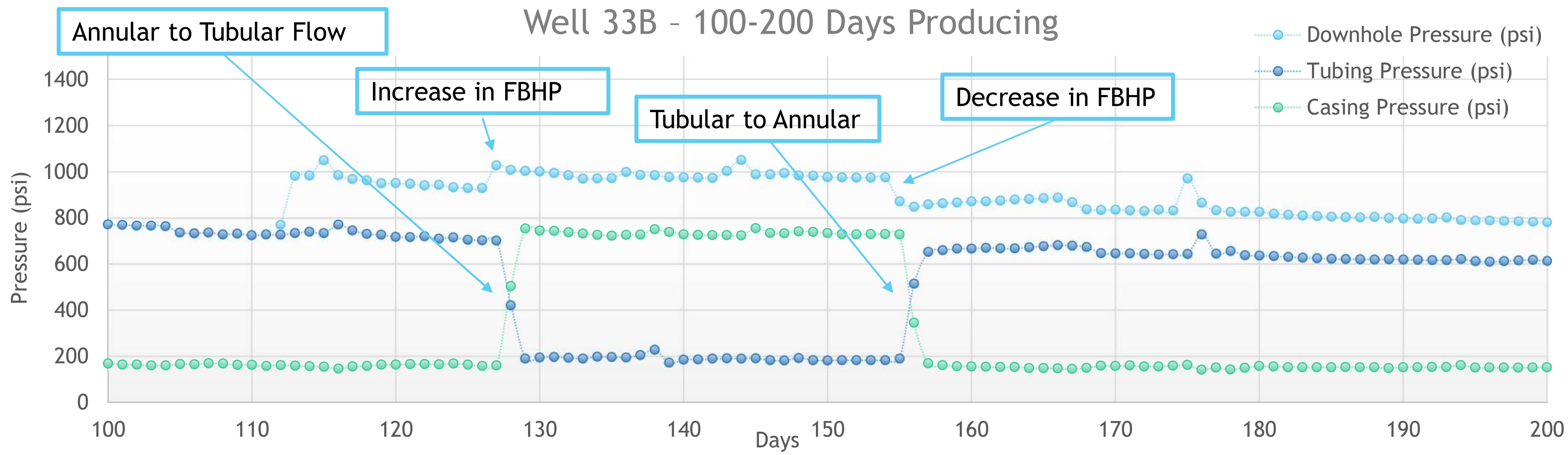


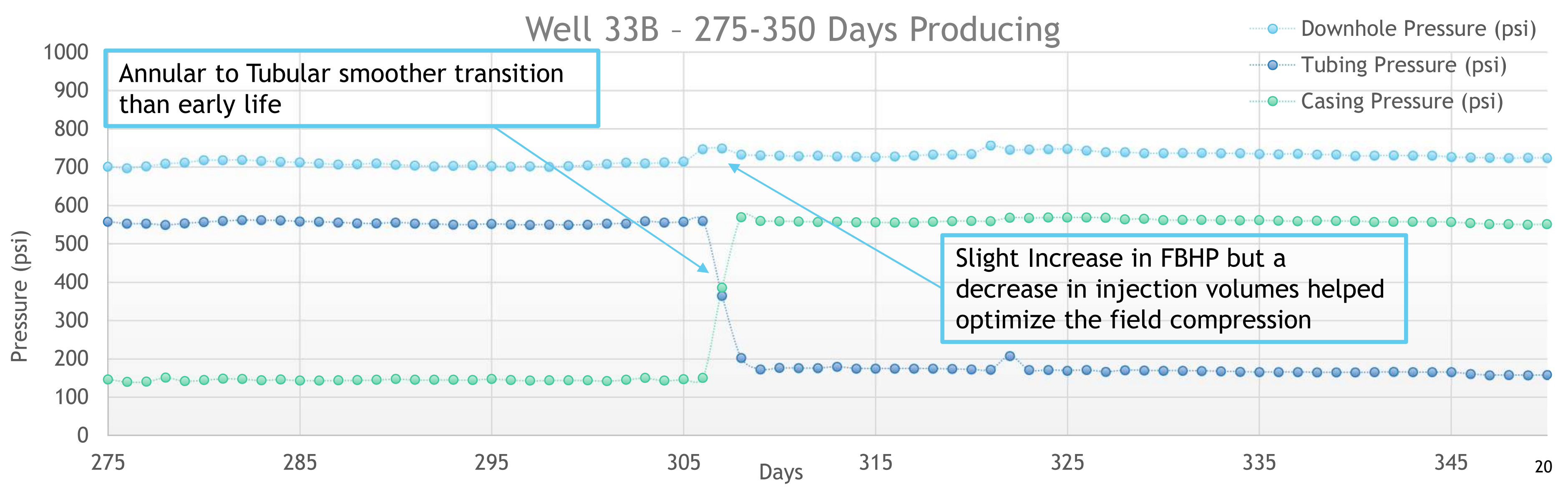
33C Switching Point Velocity Gradient





Well 33B
Downhole Pressure (psi)
Tubing Pressure (psi)
Casing Pressure (psi)
Oil Rate (BBL/D)
Water Rate (BBL/D)
Gas Rate (MSCF/D)
Inj Gas Rate (MSCF/D)
AF – TF resulted in an increase in FBHP and unstable flow
TF – AF resulted in lower FBHP and more stable flow
Later life AF - TF resulted in smoother conversion with little to no change in FBHP
Reduction in Injection Volumes for Tubing Flow
11/19/2024
Rate
Pressure (PSI)
Days on Production
0
100
200
300
400
500
600
700
0
500
1000
1500
2000
2500
3000
-3000
-2000
-1000
0
1000
2000
3000


Well 33B – 100-200 Days Producing
Annular to Tubular Flow
Increase in FBHP
Tubular to Annular
Decrease in FBHP
Downhole Pressure (psi)
Tubing Pressure (psi)
Casing Pressure (psi)
Pressure (psi)
1400
1200
1000
800
600
400
200
0
100
110
120
130
140
150
160
170
180
190
200
Days


Well 33B – 275-350 Days Producing
Annular to Tubular smoother transition than early life
Slight Increase in FBHP but a decrease in injection volumes helped optimize the field compression
Downhole Pressure (psi)
Tubing Pressure (psi)
Casing Pressure (psi)
Pressure (psi)
1000
900
800
700
600
500
400
300
200
100
0
275
285
295
305
315
325
335
345
Days

Lesson Learned

- Switching from Annular Flow to Tubing Flow too early in the wells production life caused an increase in FBHP and a reduction in production rates as Nodal Analysis predicted
- Modelling the conversion from annular flow to tubing flow heavily relied upon IPR data and velocity plots to identify and predict liquid loading and unstable flow regimes
- Adding a secondary wing valve to the B-Section of the wellhead to mitigate erosional concerns
- Flow off both sides of the casing during Annular Flow to maintain the lowest WHBP

Acknowledgements, & Thank You

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