UPDATED

BHP in whitson+

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Course held Virtually

24 April 2024

General Information

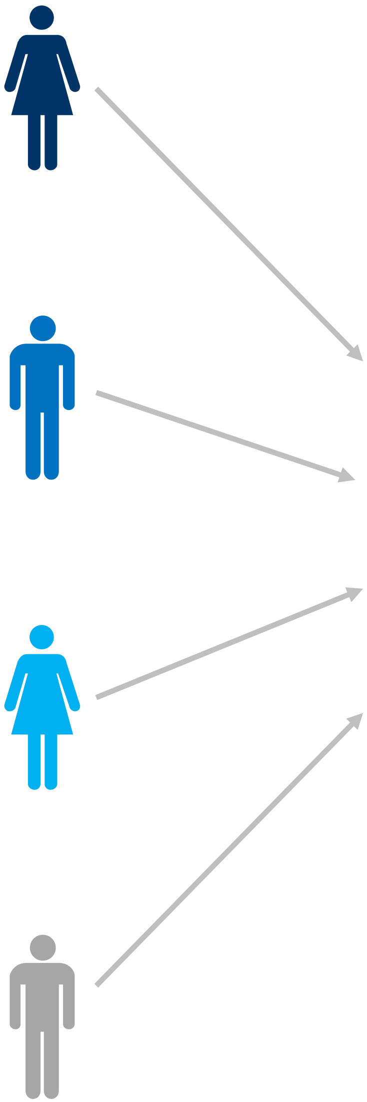
General Information

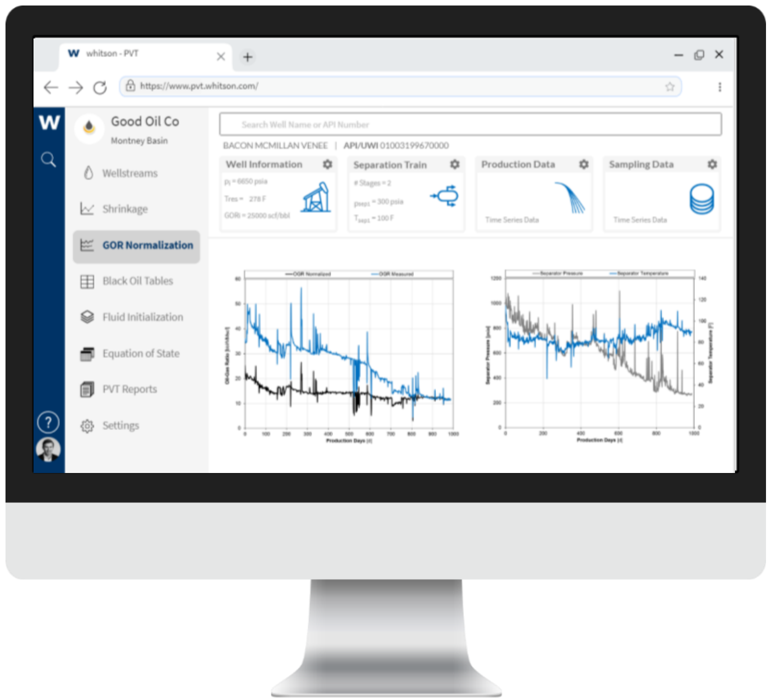
- ½ day course
- Interactive class
- Ask questions – drive the course emphasis
    - In chat or unmute to speak (mute when not talking ☺)
- Will send out all digital material after class
- Some content in this slide deck is meant for presentation purposes, while some parts are meant for reference.

whitson

Software

Access to whitson^{+}





DO NOT USE COMPANY DOMAIN!
Not same as your company domain

https://courses.whitson.com/

Username: your e-mail

Password: WhitsonBHP2024

*Send an e-mail to support@whitson.com if you need help to login.
Need to use Google Chrome, Firefox or Microsoft Edge.
Internet Explorer won't work.

Agenda

Course Agenda

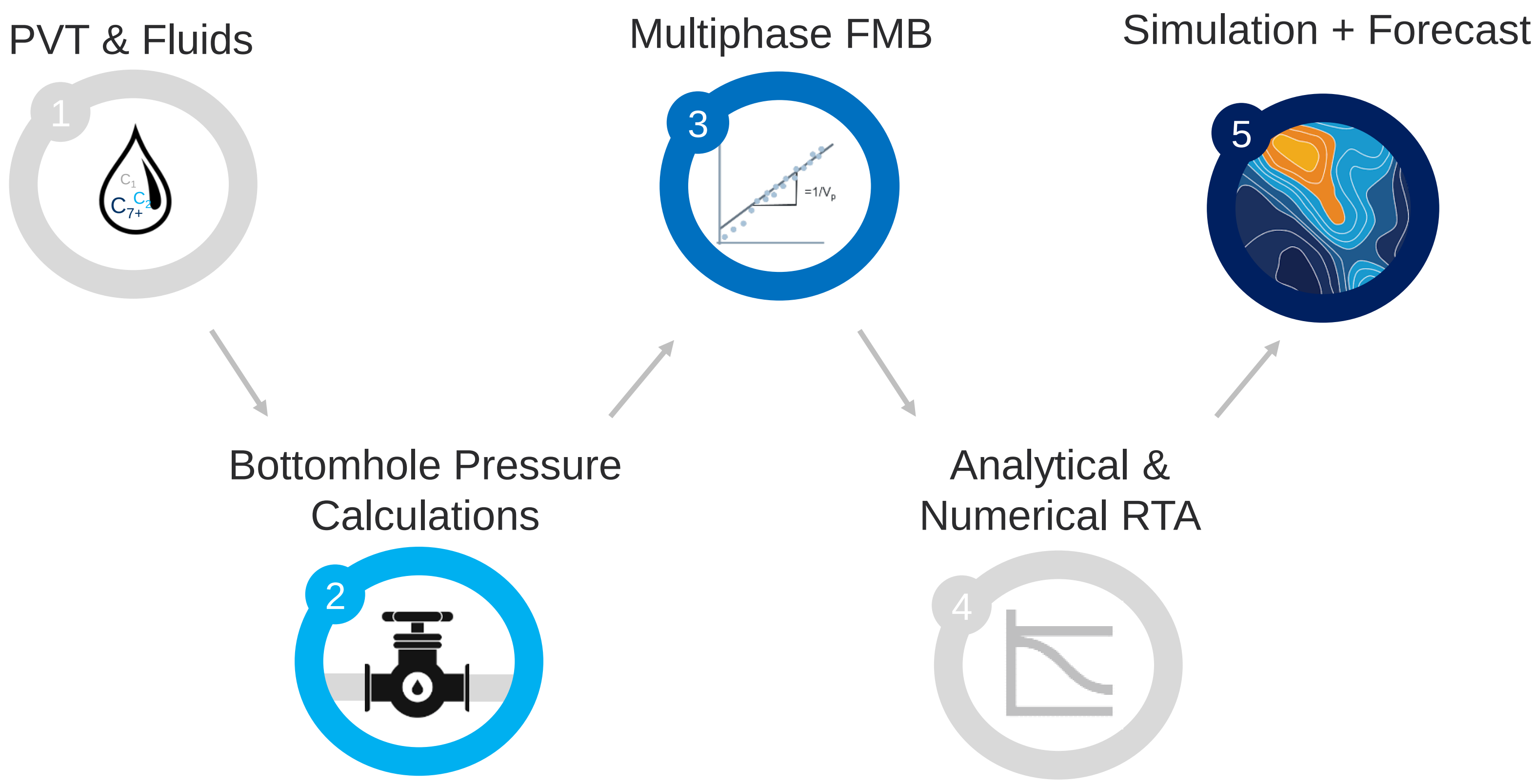
BHP Calculation Fundamentals

- Why calculate BHP
- Input to the BHP calculation
- BHP Correlations
- Flowpaths and artificial lift methods
- BHP Smoothing & Tuning
- Estimate initial reservoir pressure with IPR

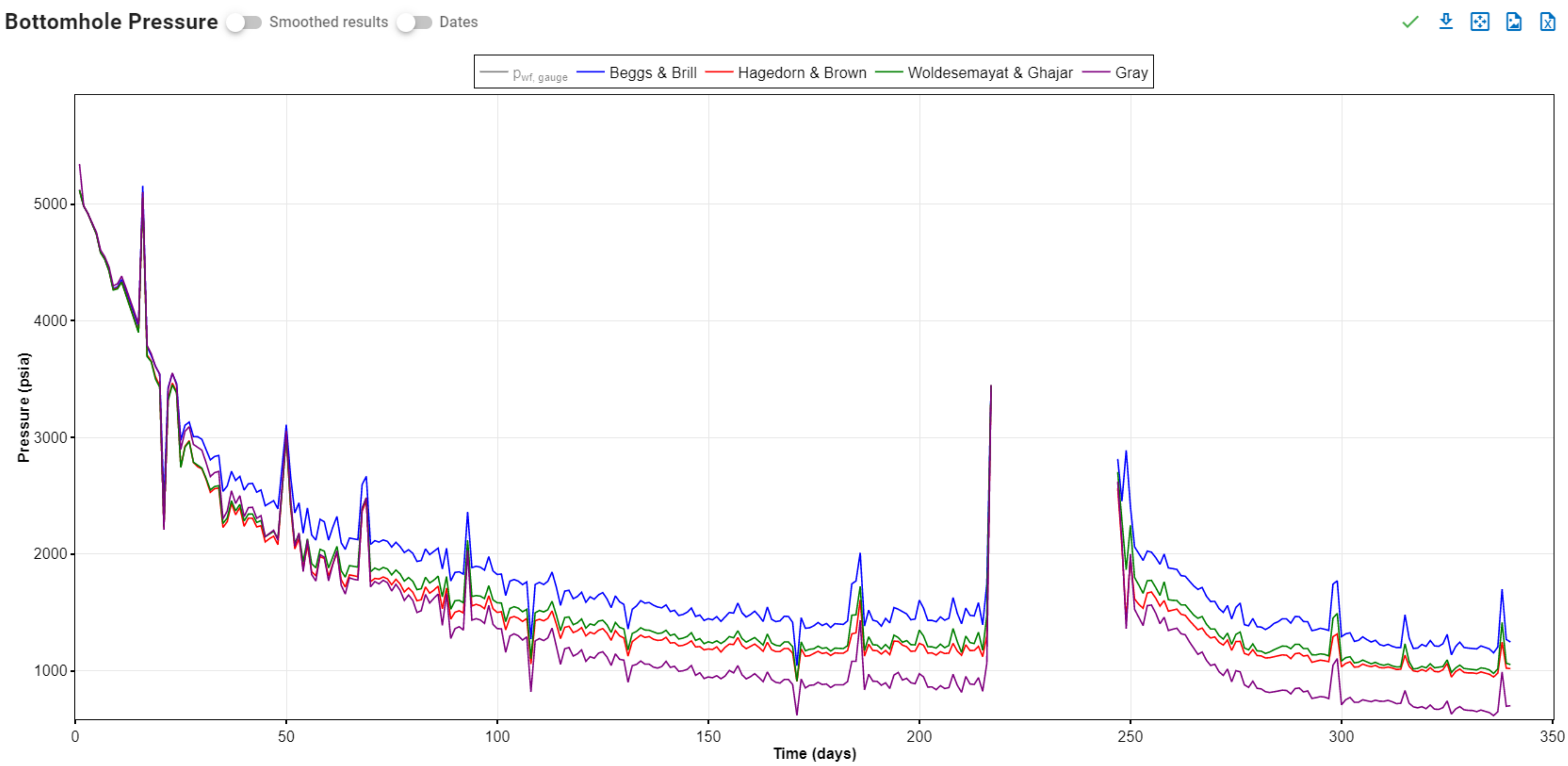
Exercises in whitson+

BHP

Unconventional Reservoir Workflow

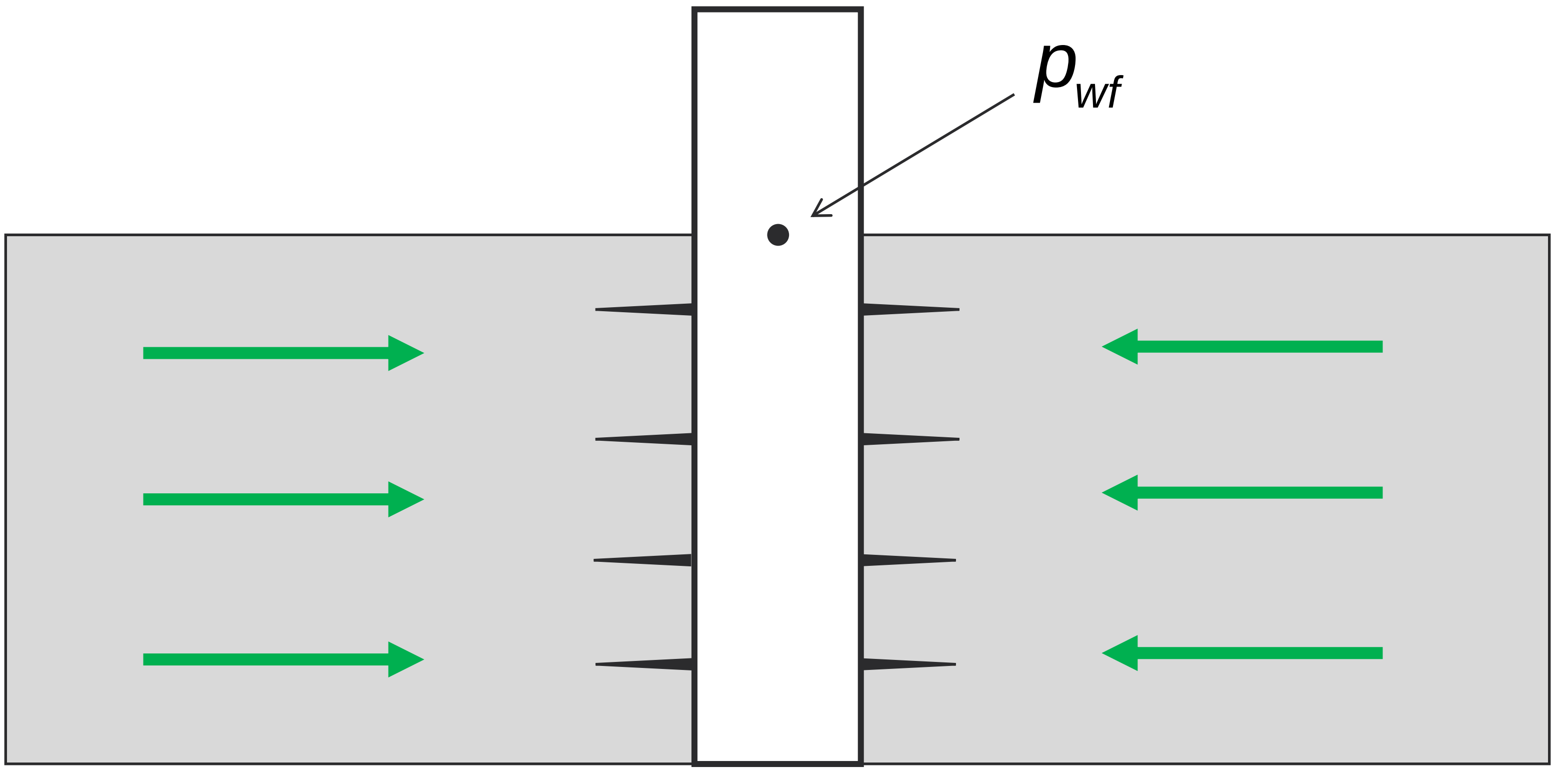


Flowing Bottomhole Pressures (p_{wf})



Bottomhole Pressure—What?

- The bottomhole pressure (BHP | p_{wf}) is defined in **whitson⁺** as the *well pressure at the top of the perforated interval (top perforation)*.



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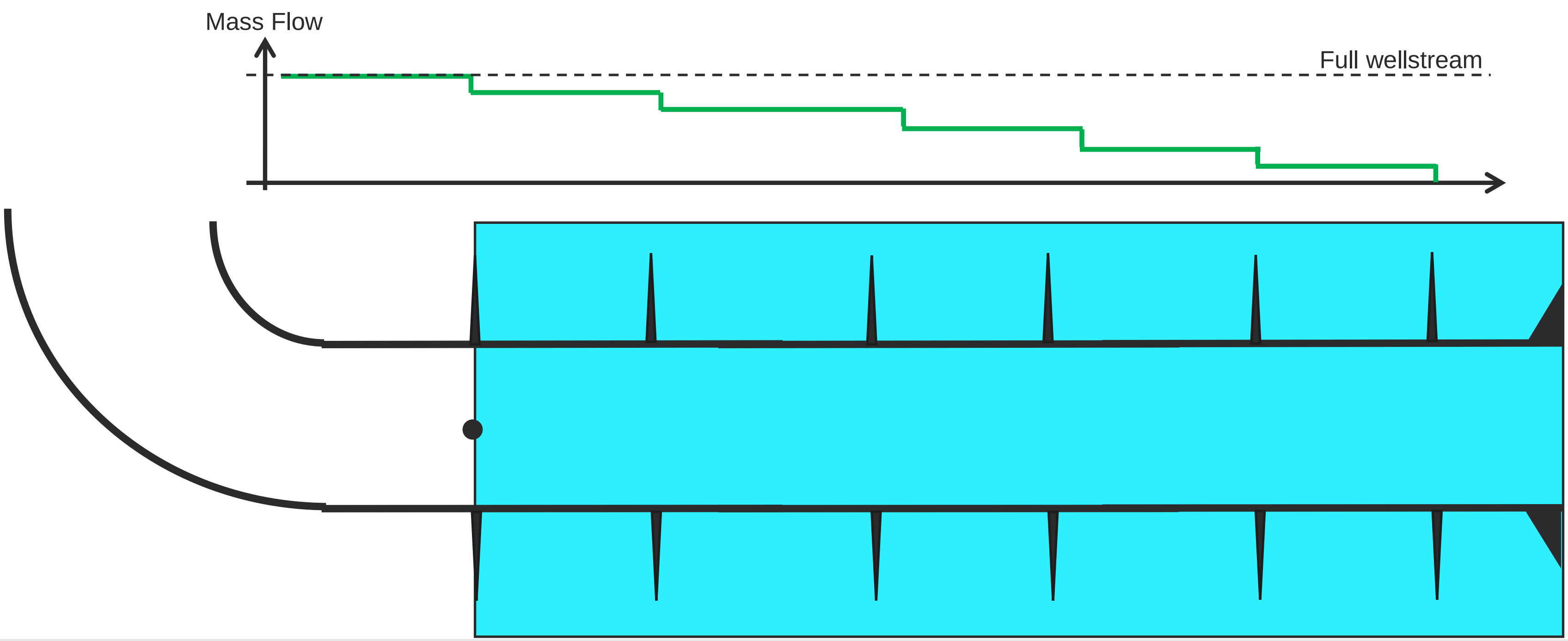
Bottomhole Pressure—What?

- The reference point for BHP is set at the *deepest point* in the well where the *full mass flow* of the well stream can be found.
- Moving the point for BHP to any other point in the perforated interval (lateral part in tight unconventionals) will require the use of an IPR to model the change in mass flow as you move from heel to toe.

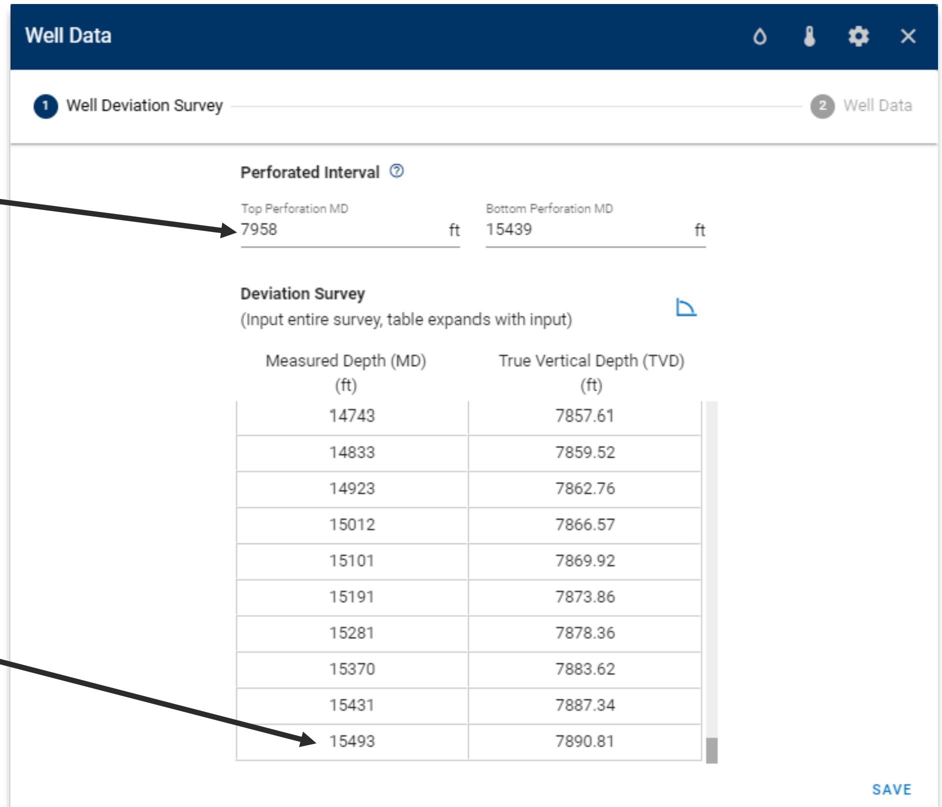


Bottomhole Pressure—What?

- The reference point can be set by the user to anywhere along the well if it is set shallower than the deepest MD in the deviation survey
  - If "Top Perforation MD" is set at well heel, then the full well stream is modeled along the lateral.

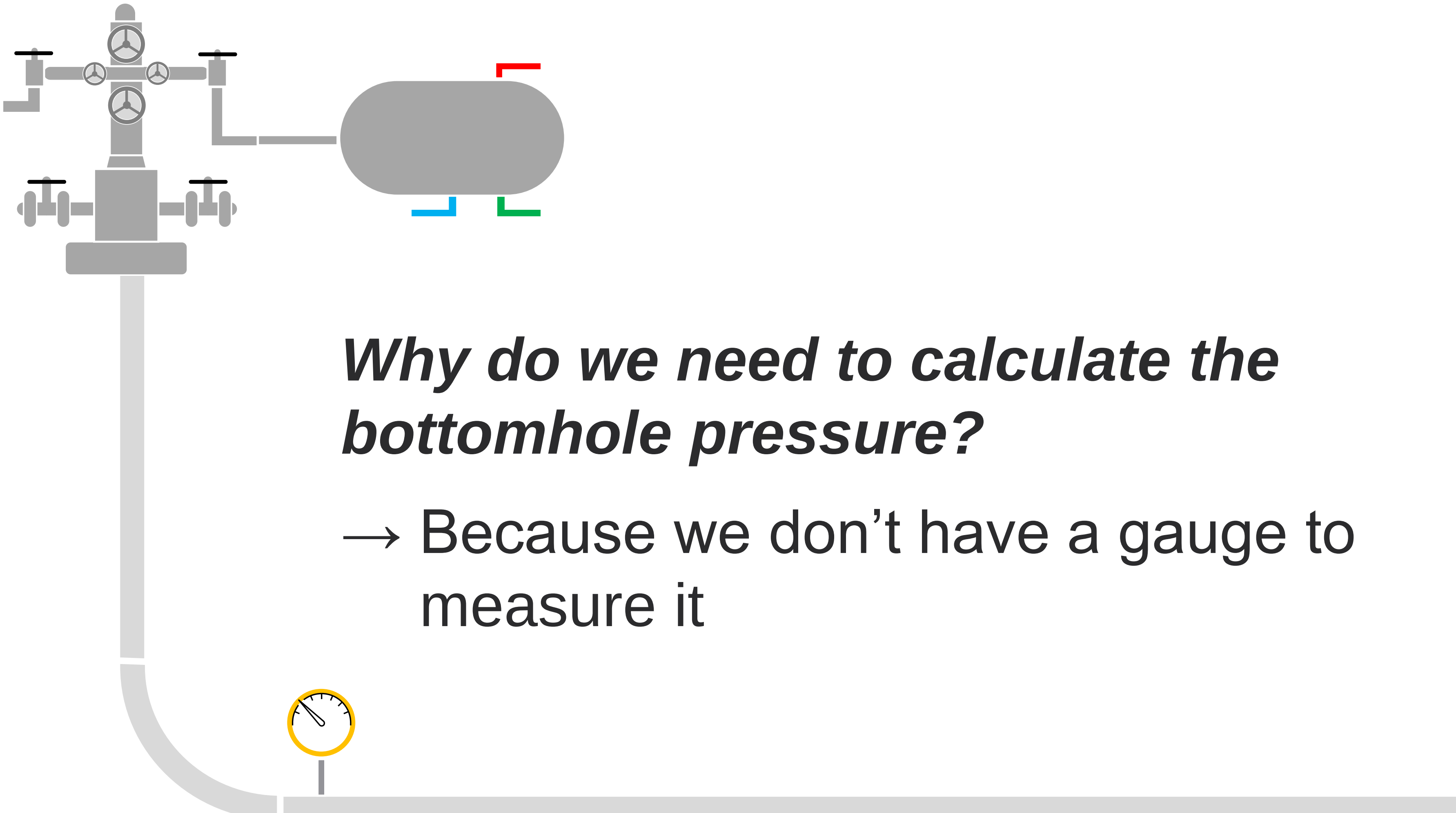
Depth at which BHP is calculated

Deepest point in the well



Why Calculate BHP?

BHP Calculations—Why?



Why do we need to calculate the bottomhole pressure?

→ Because we don’t have a gauge to measure it

BHP Calculations—Why?

- The BHP is a required input in many production data analyses.
  - DCA (p_{wf} should be constant)
  - Flowing Material Balance (FMB)
  - Analytical Rate-Transient Analysis (ARTA)
  - Numerical Rate-Transient Analysis (NRTA)
  - Numerical Model
  - Nodal Analysis
  - Production Data Diagnostics

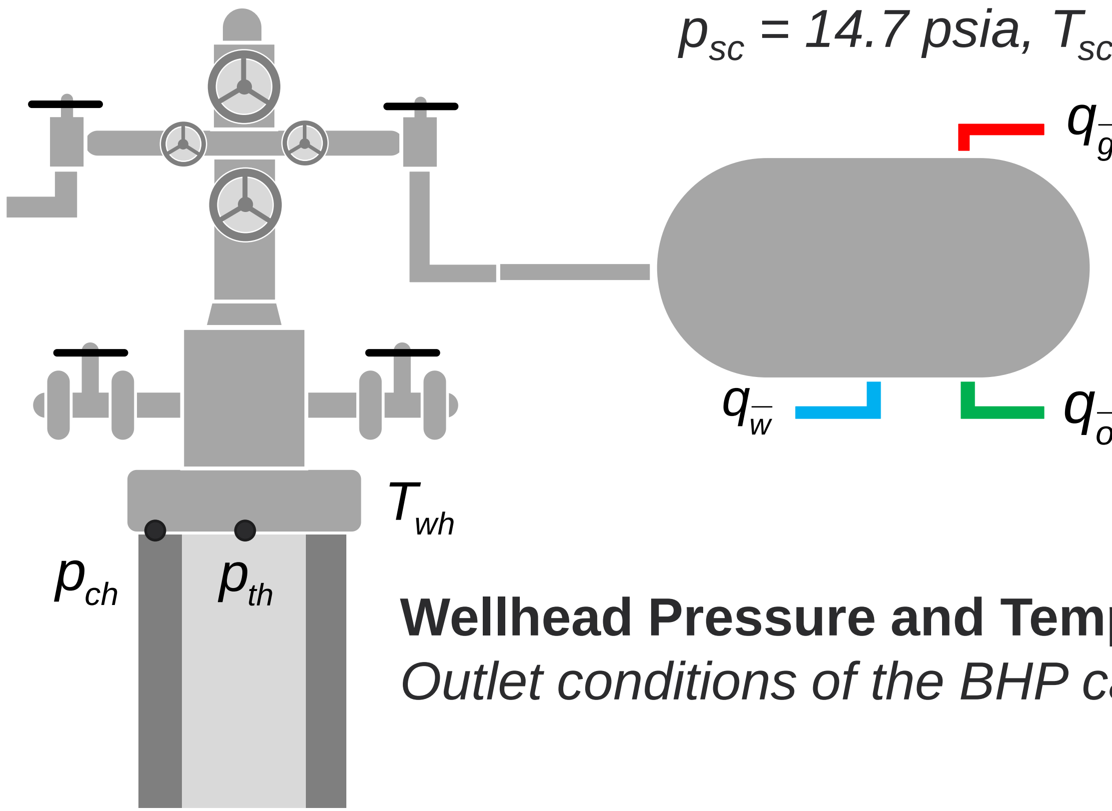
Input to BHP Calculation

Required Input—Production Data

Surface Rates

Produced volumes that are processed and measured at standard conditions

p_{sc} = 14.7 psia, T_{sc} = 60°F



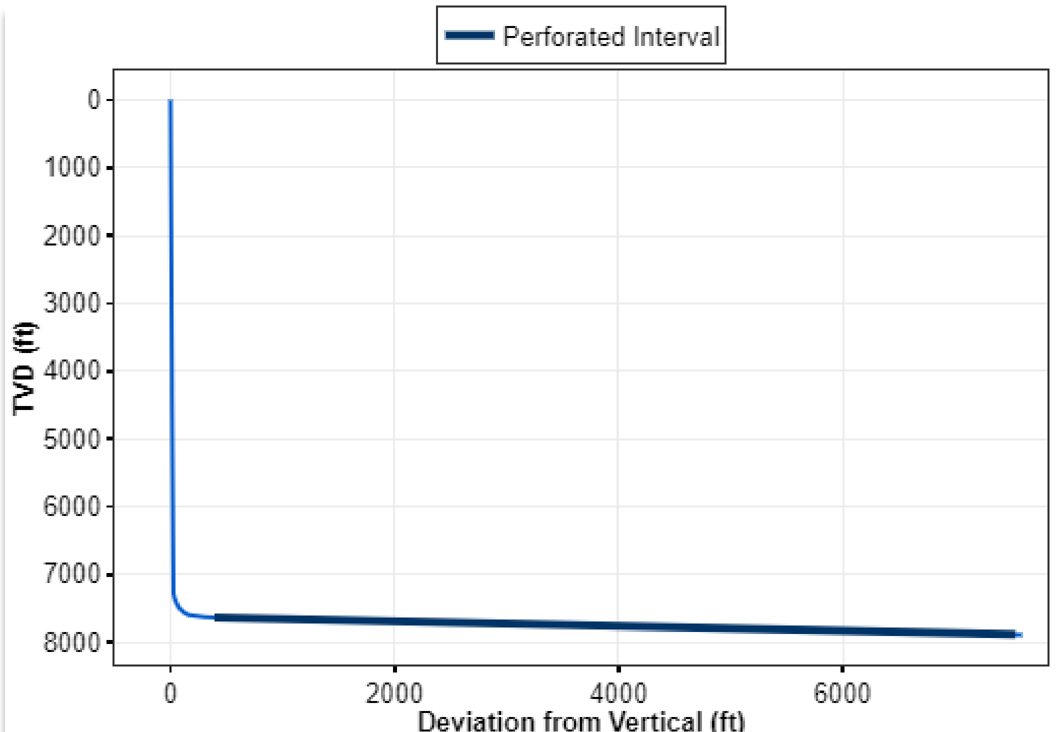
Wellhead Pressure and Temperature

Outlet conditions of the BHP calculations

Required Input—Well Data

Wellbore trajectory—Deviation Survey

- MD vs TVD
- Top and Bottom Perforation Depth (Perforated Interval)



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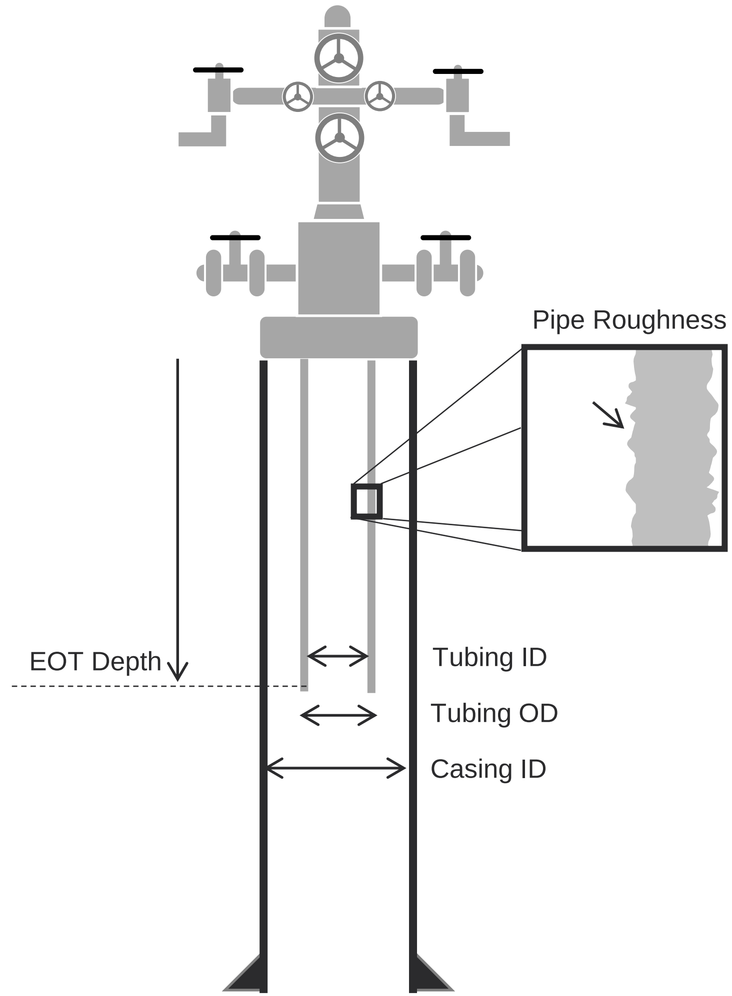
Required Input—Well Data

Well completion—Casing and Tubing Data

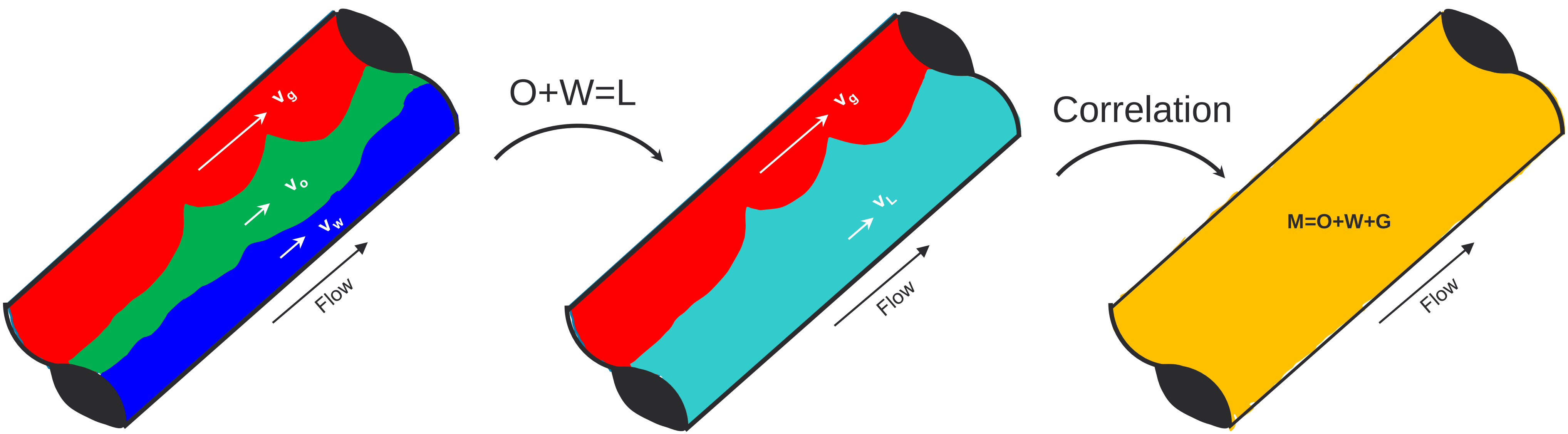
- Inner Diameter (ID)
- Outer Diameter (OD)
- Pipe roughness
- EOT depth



BHP Correlations

BHP Calculations

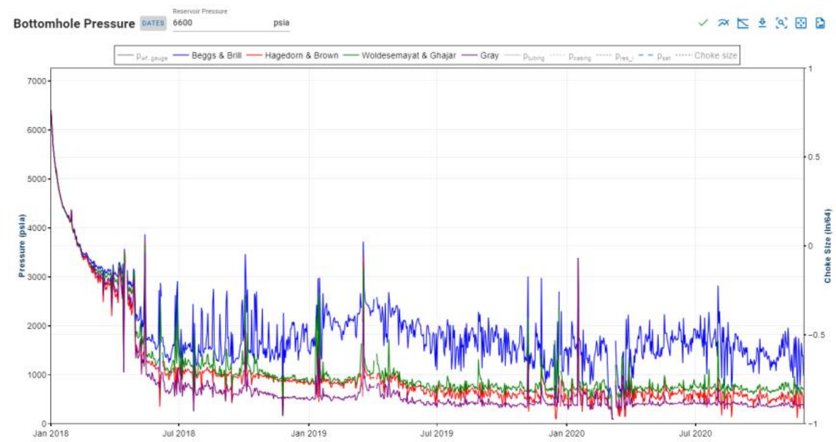
- BHP calculations rely on using single-phase flow equations to model multiphase flow.
- Oil and water are lumped together into a liquid phase.
- Liquid and gas are averaged into a single-phase mixture.
  - *Averaging is correlation dependent*



BHP Correlations

whitson+ supported correlations[1] are

- Hagedorn and Brown (1965)
- Beggs and Brill (1973)
- Gray (1978)
- Woldesemayat and Ghajar (2006)



[1] These are so-called drift-flux models, which is preferred due to their simplicity. The alternative is to solve the momentum- and energy equations for each phase separately, which is commonly referred to as mechanistic models. More in URTeC: 4045619.

BHP Calculations—Pressure Gradient

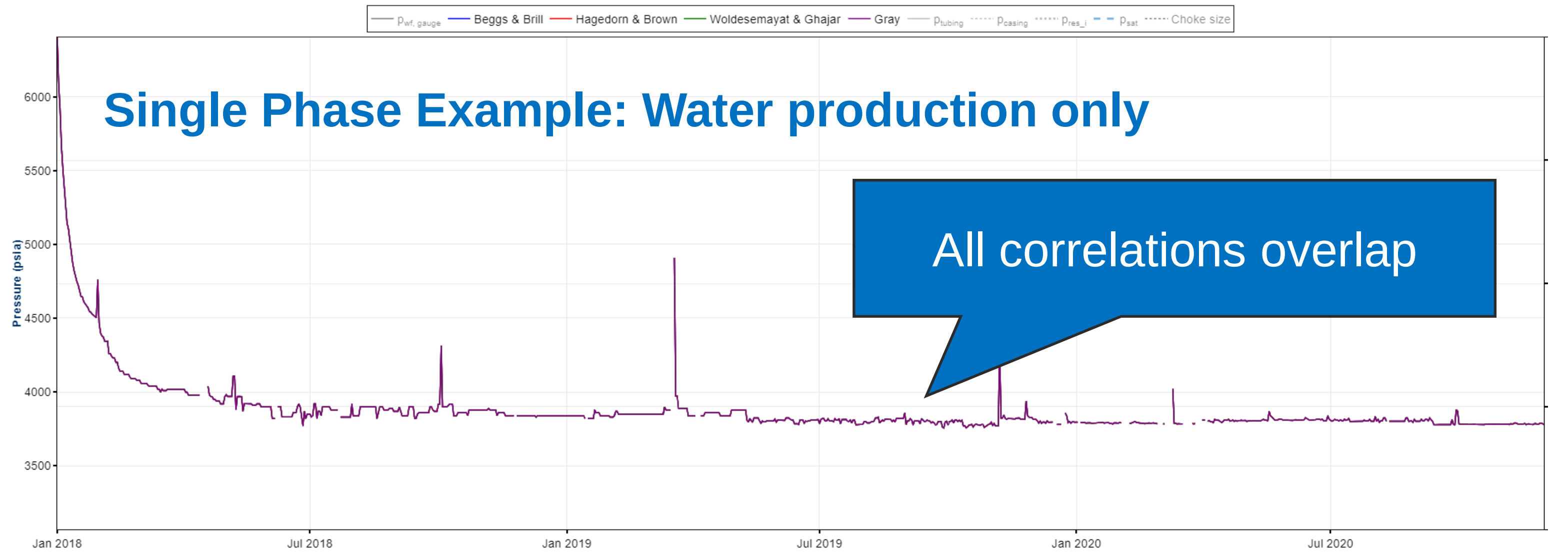
$$-\frac{dp}{ds} = \overbrace{\rho \frac{g}{g_c} \cos(\theta)}^{\text{Gravity}} + \underbrace{\frac{f_D \rho v^2}{2 d_h g_c}}_{\text{Friction}} + \overbrace{\frac{\rho v}{g_c} \frac{dv}{ds}}^{\text{Acceleration}}$$

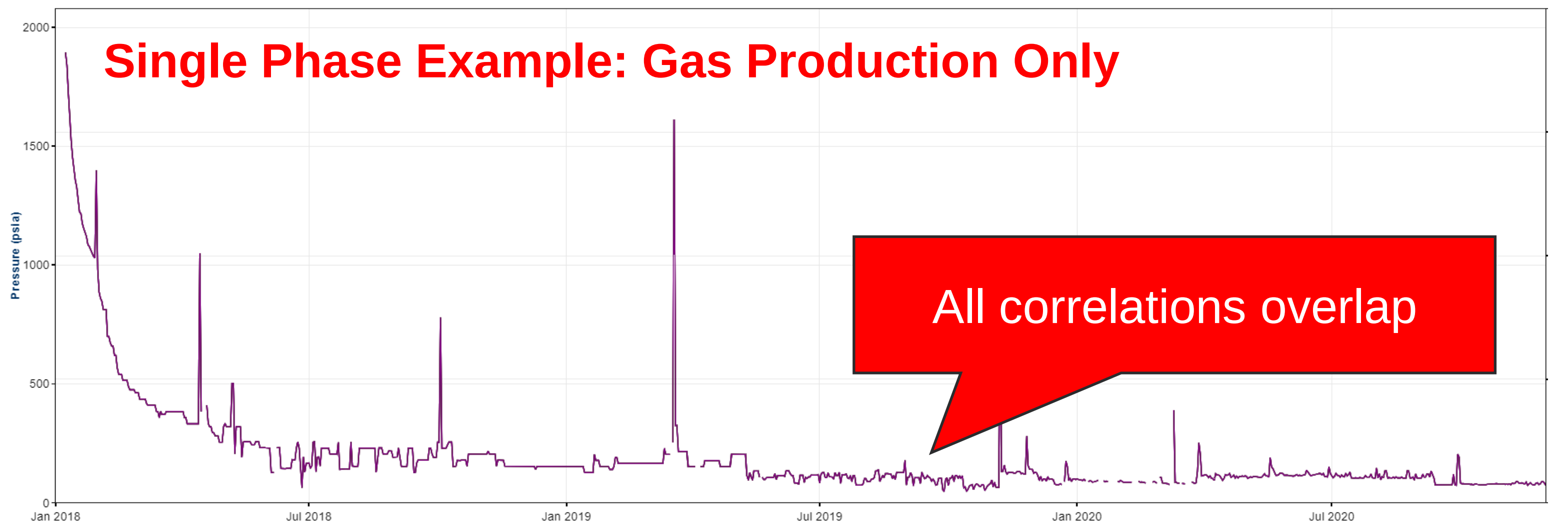
Gravity: Caused by the weight of the fluids. Acts in the direction of gravity.

Friction: Caused by the pipe wall.

Acceleration: Caused by a rapid expansion of the fluids. Only relevant for gaseous wells near the wellhead for low p_{wh}.

Differences between the Correlations





Note to instructor: BHP study URTeC Field

Correlations—The Common Equation

- The pressure-gradient equation is common to all the correlations.
- The difference between the correlations lies in how the correlations calculate the liquid hold-up
  - Affects some of the properties in the pressure gradient

Multiphase Friction Factor

Friction Density

Gravity Density

$$-\frac{dp}{ds} = \frac{\boxed{\rho_g}\dfrac{g}{g_c}\cos(\theta) + \dfrac{\boxed{f_{Ds}}\boxed{\rho_f}v_m^2}{2d_h g_c}}{1-\dfrac{\boxed{\rho_a}v_m v_{sg}}{g_c p}}$$

Acceleration Density

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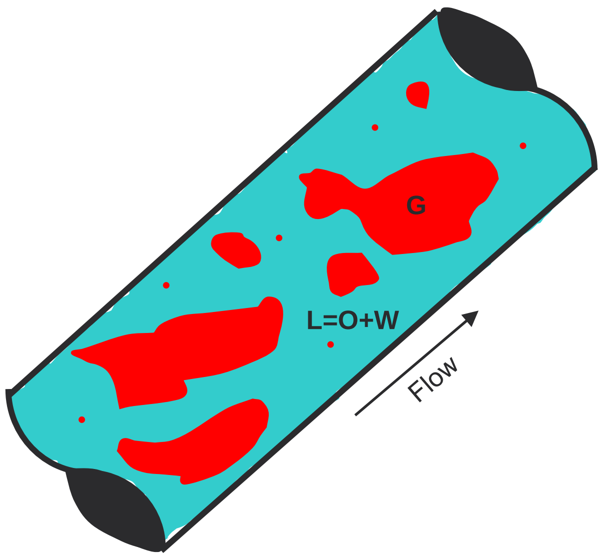
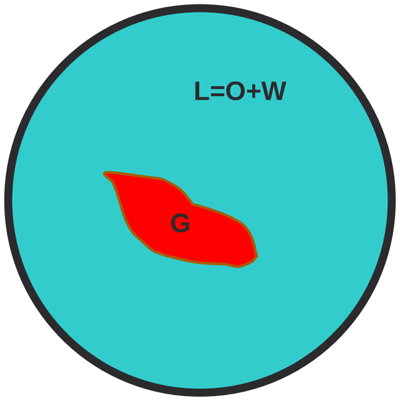
Multiphase Flow—Liquid Hold-Up

- The liquid hold-up, H_L, represents the part of the pipe cross-sectional area occupied by liquid.



$$H_L = \frac{A_L}{A_g + A_L}$$



Which BHP Correlation is the most Accurate?

Comprehensive BHP Study

Objective: Measured gauge pressure vs correlations

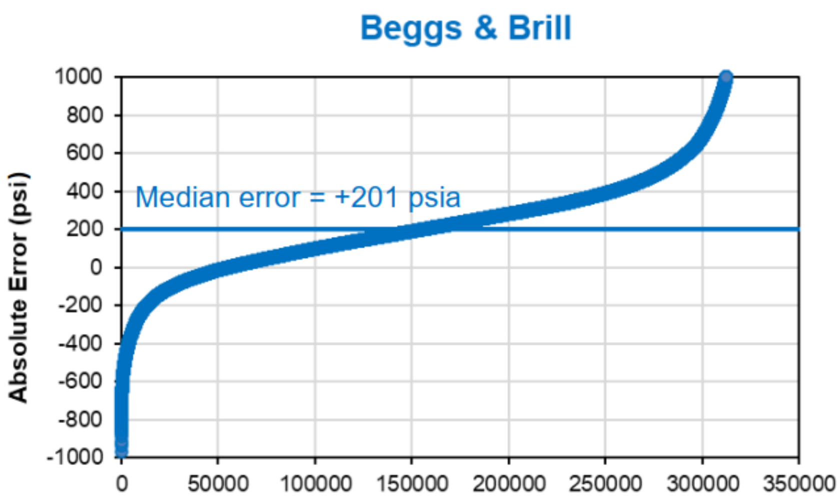
Wells: 420 wells

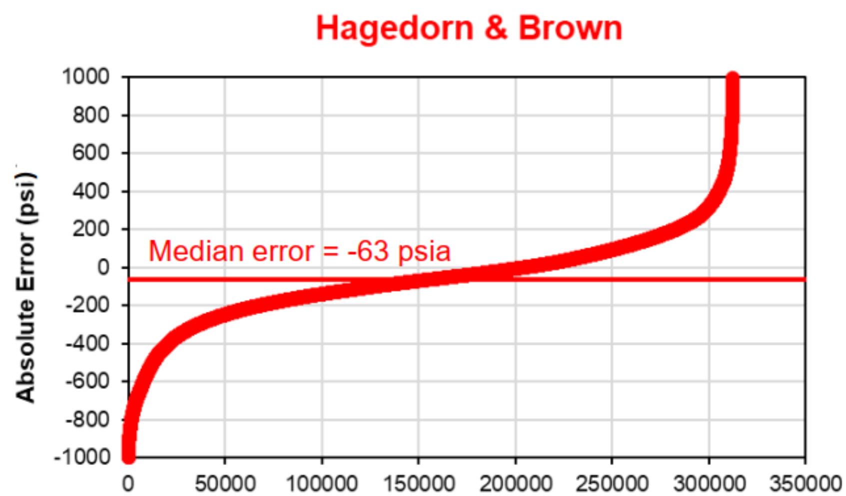
Datapoints: >300,000

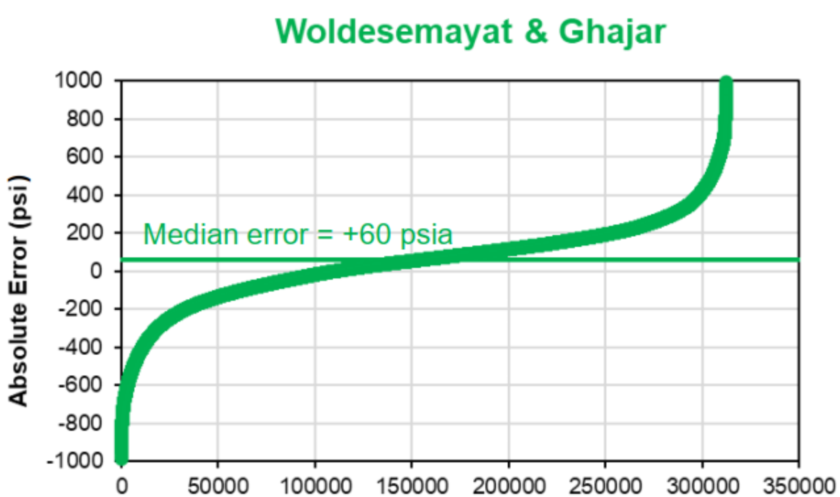
Basins: Delaware, Midland, DJ, Powder River, Anadarko and Utica

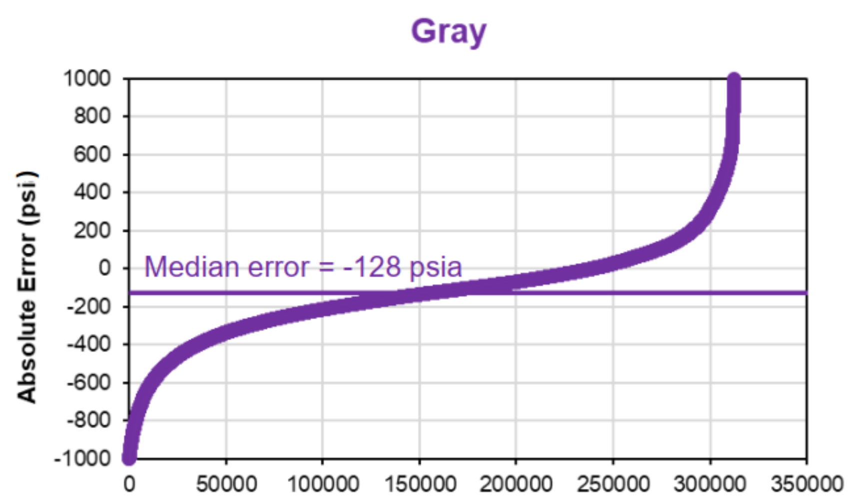
Source: URTeC 4045619

Absolute Error Distribution









Source: URTeC 4045619

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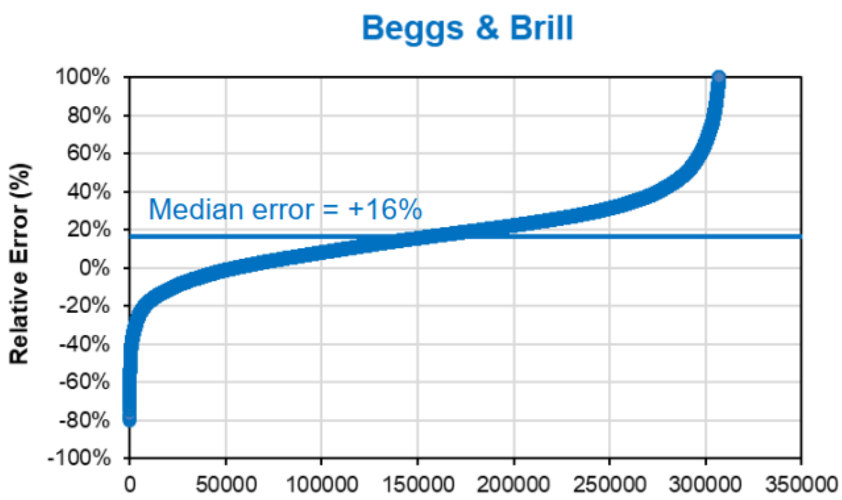
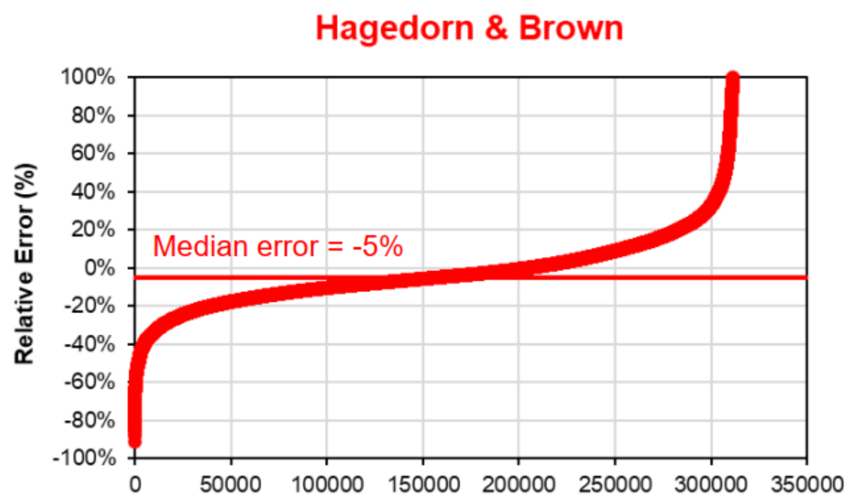
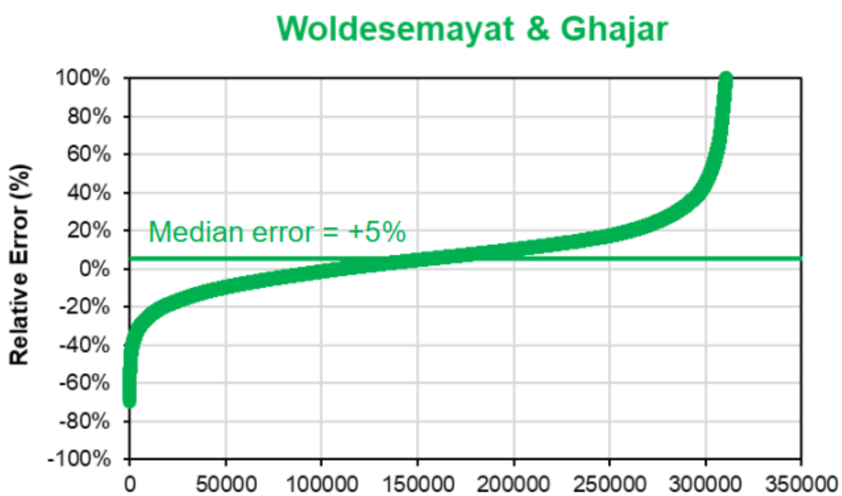
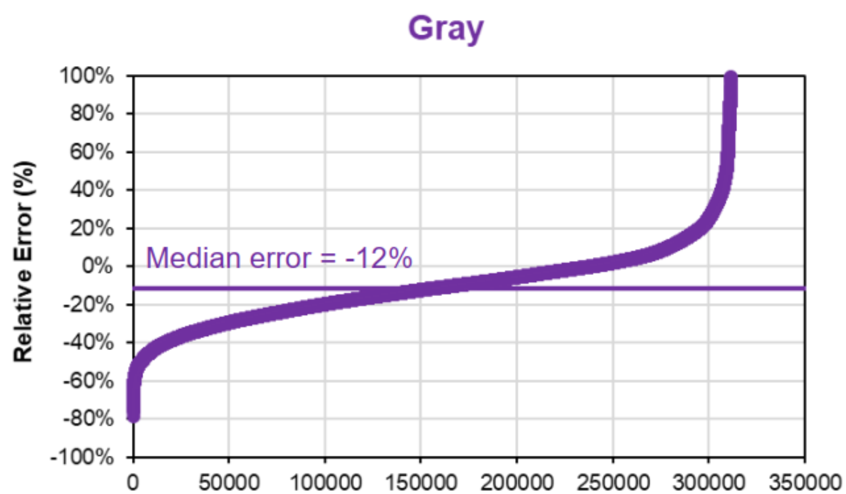
Relative Error Distribution



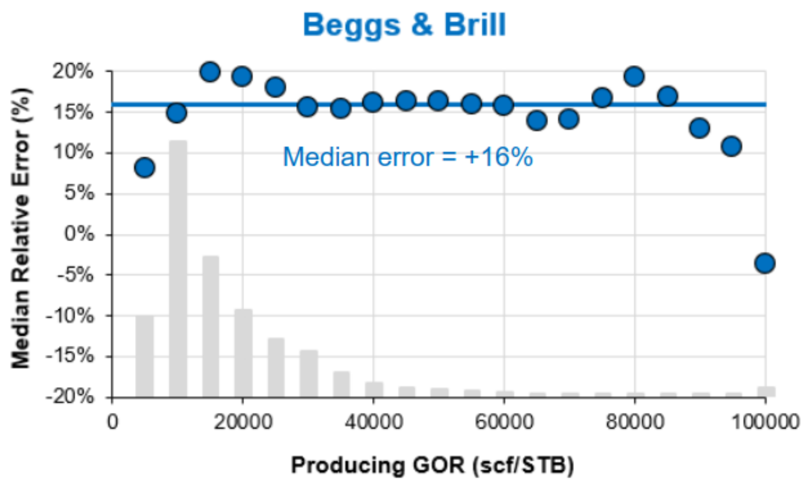


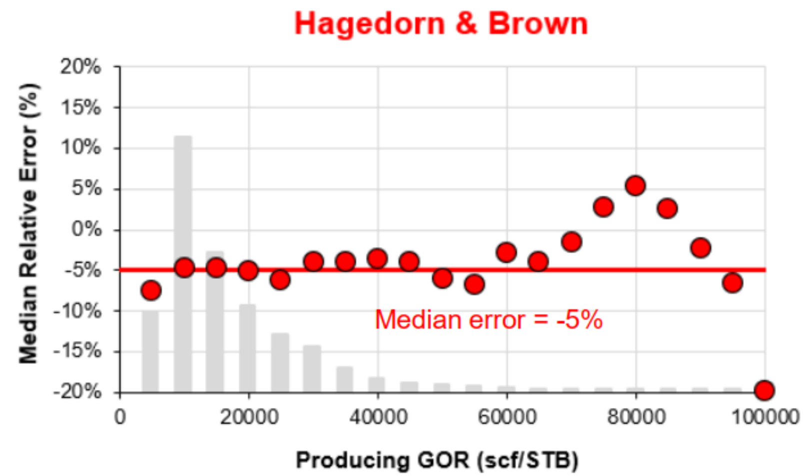


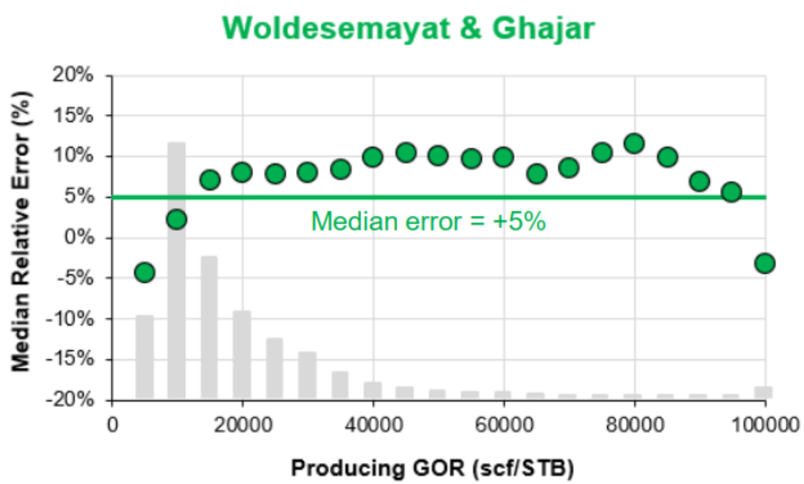


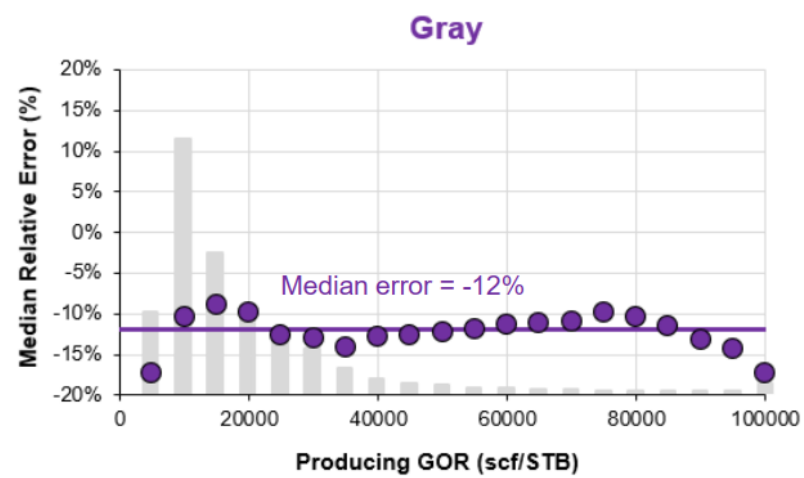
Source: URTeC 4045619

Producing GOR vs Relative Error









Source: URTeC 4045619

Summary

Recommendation 1: Compare BHP calcs to gauge data when available. Use most accurate correlation for wells in the same basin.

Recommendation 2: if no gauge data is available, use Woldesemayat & Ghajar.

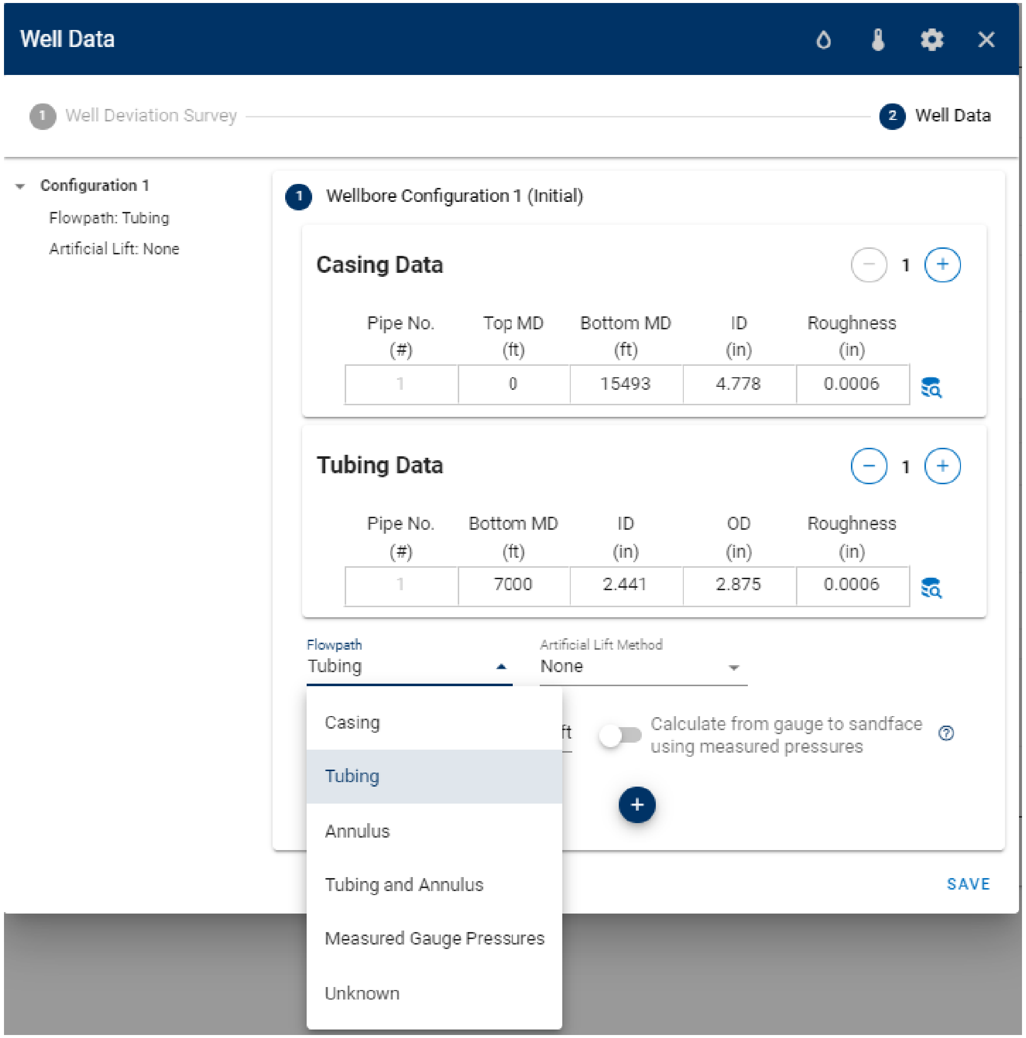
Further work: Goal is to expand on this study over the next year (include more wells).

Source: URTeC 4045619

Flow Paths

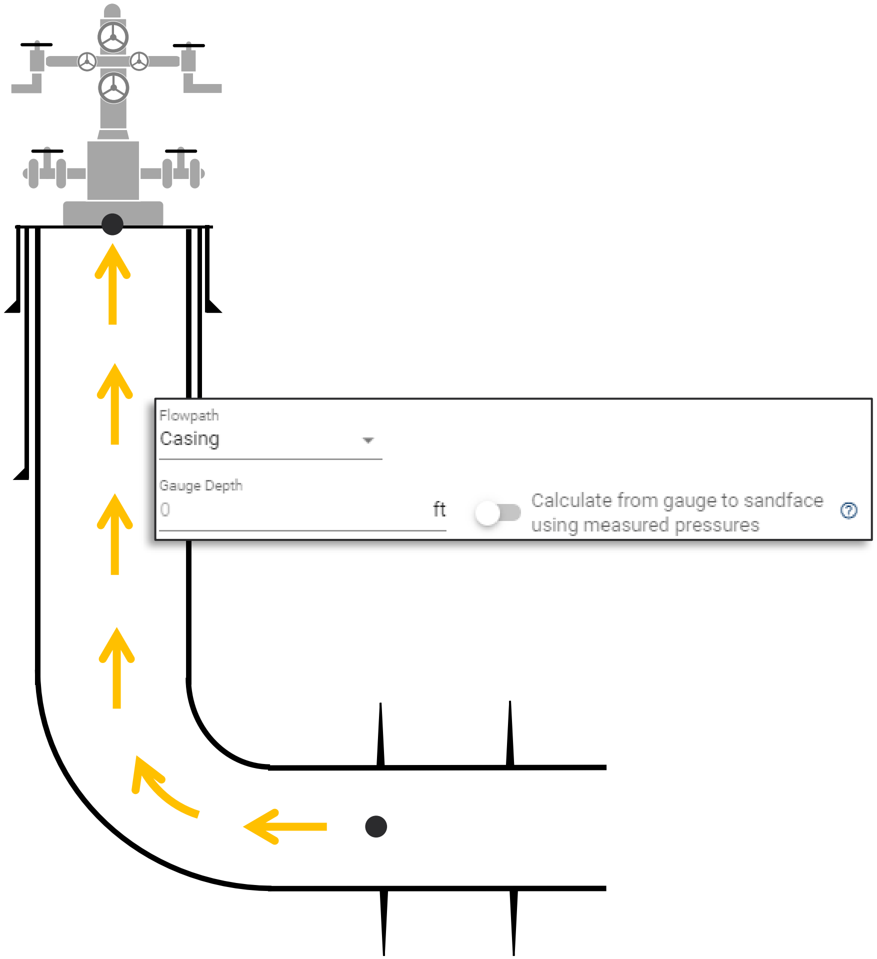
Flow Paths—Overview

- Several flow paths may be selected in **whitson+**
  - Casing
  - Tubing
  - Annulus
  - Tubing and Annulus
  - Measured BHP
  - Unknown

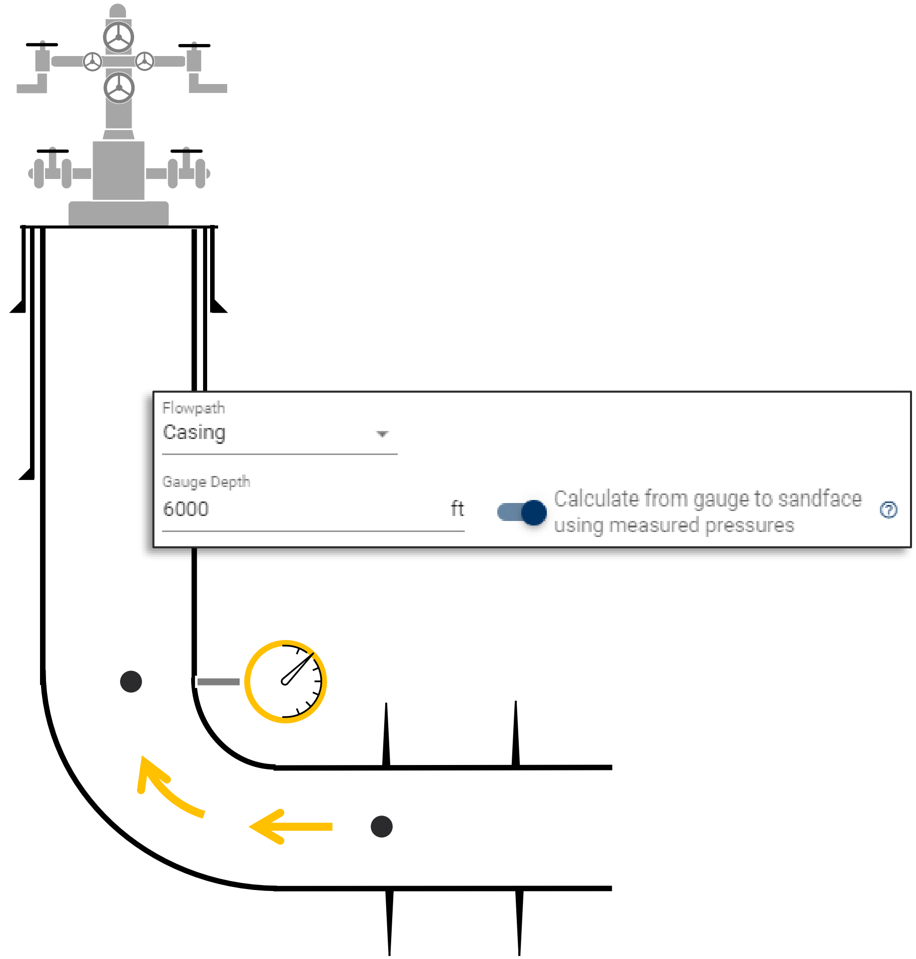


Flow Paths—Casing

From wellhead to top perf.

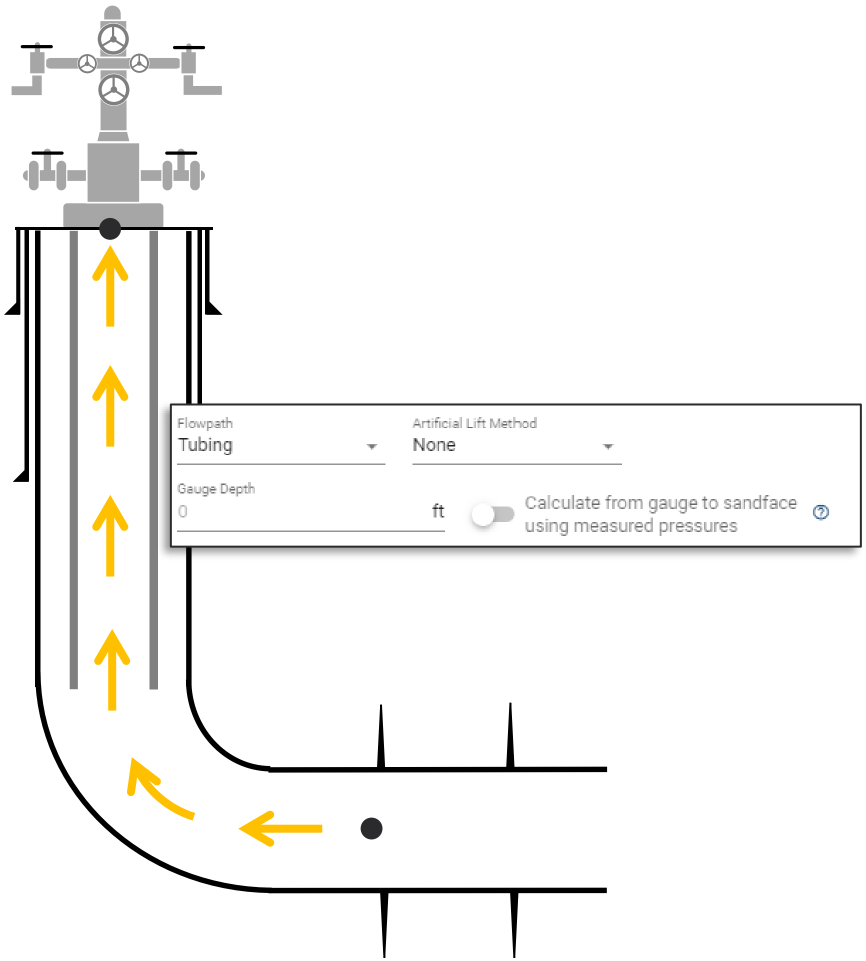


From gauge to top perf.

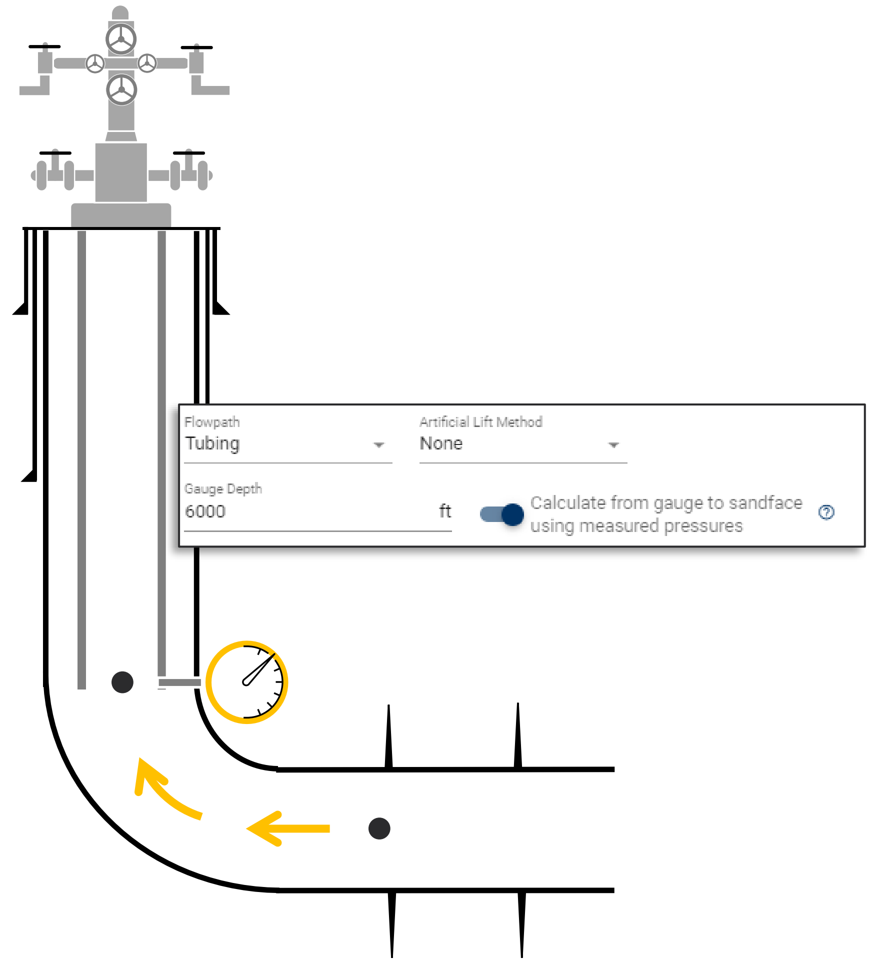


Flow Paths—Tubing

From wellhead to top perf.

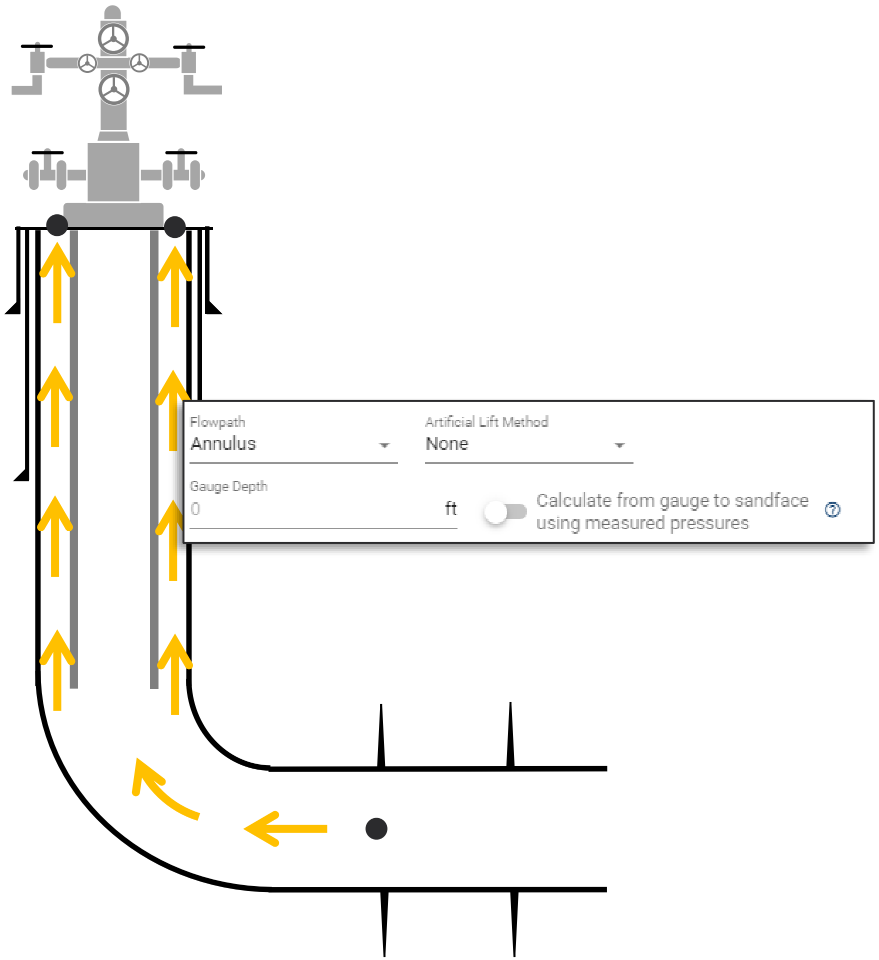


From gauge to top perf.

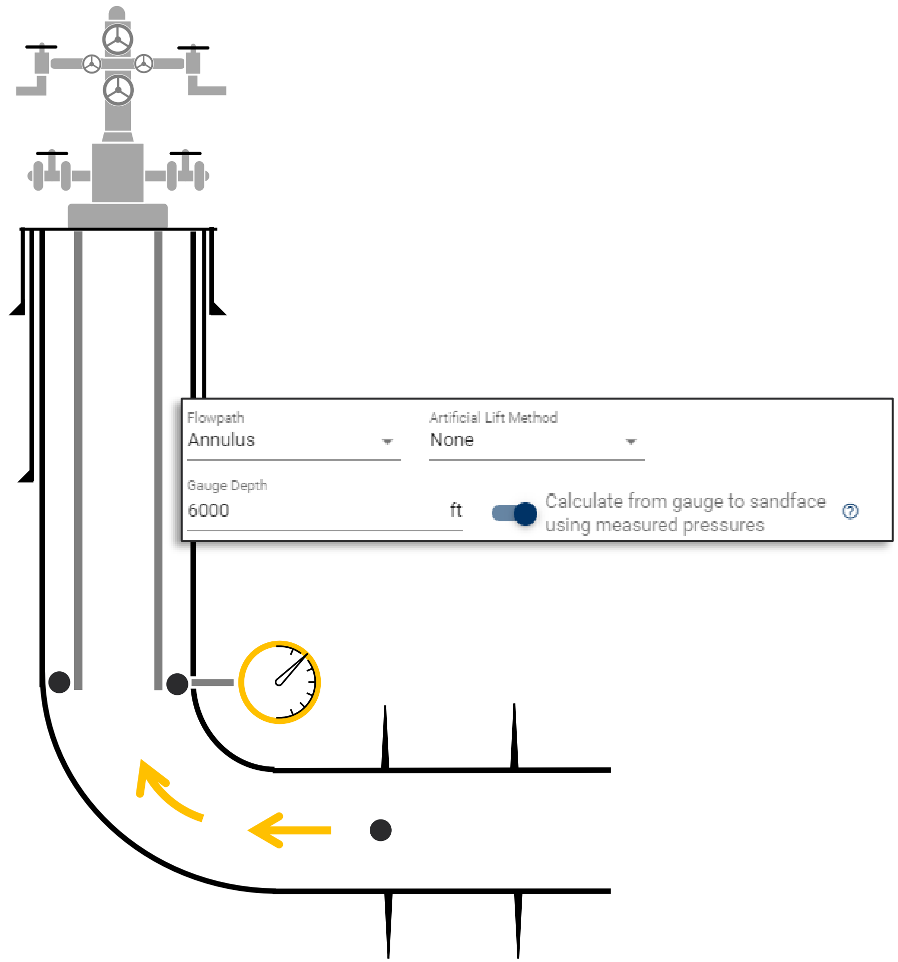


Flow Paths—Annulus

From wellhead to top perf.

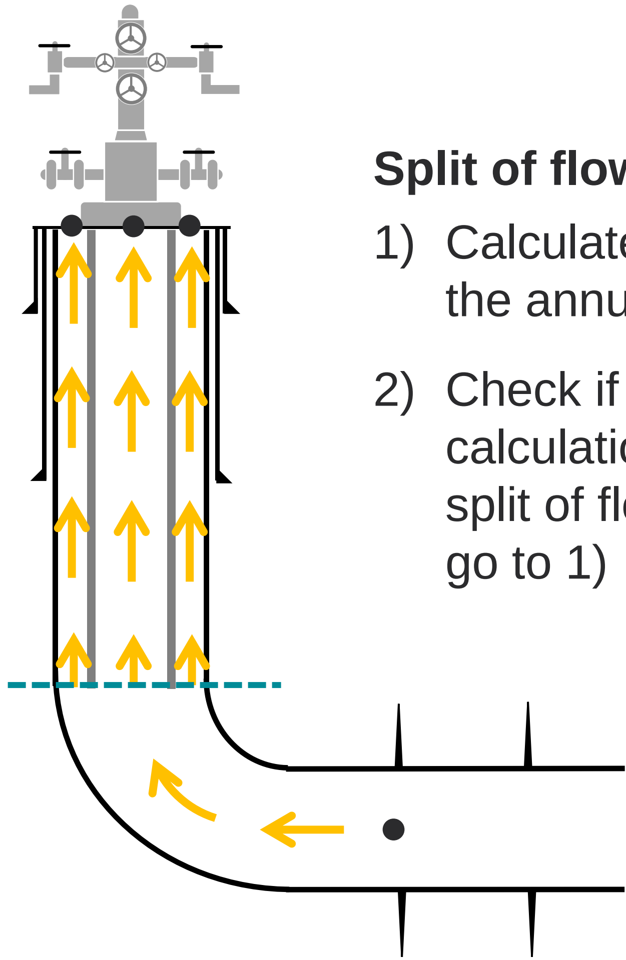


From gauge to top perf.



Flow Path—Tubing and Annulus (Parallel)

From wellhead to top perf.

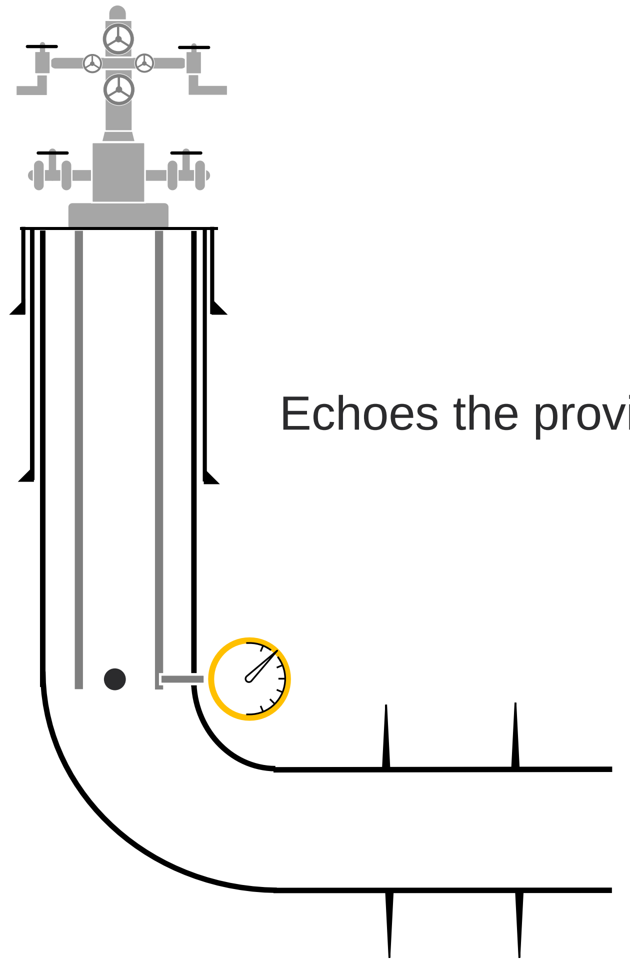


Split of flow is calculated at EOT

1) Calculate the pressure profile down the annulus and tubing

2) Check if pressure at EOT from each calculation is equal for a specified split of flow. If not, change split, and go to 1)

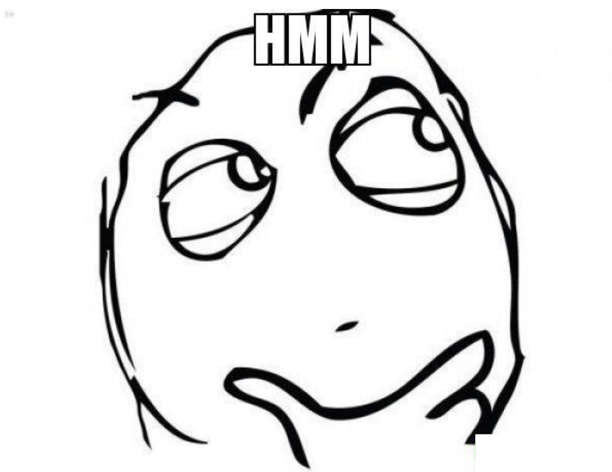
Flow Paths—Measured BHP

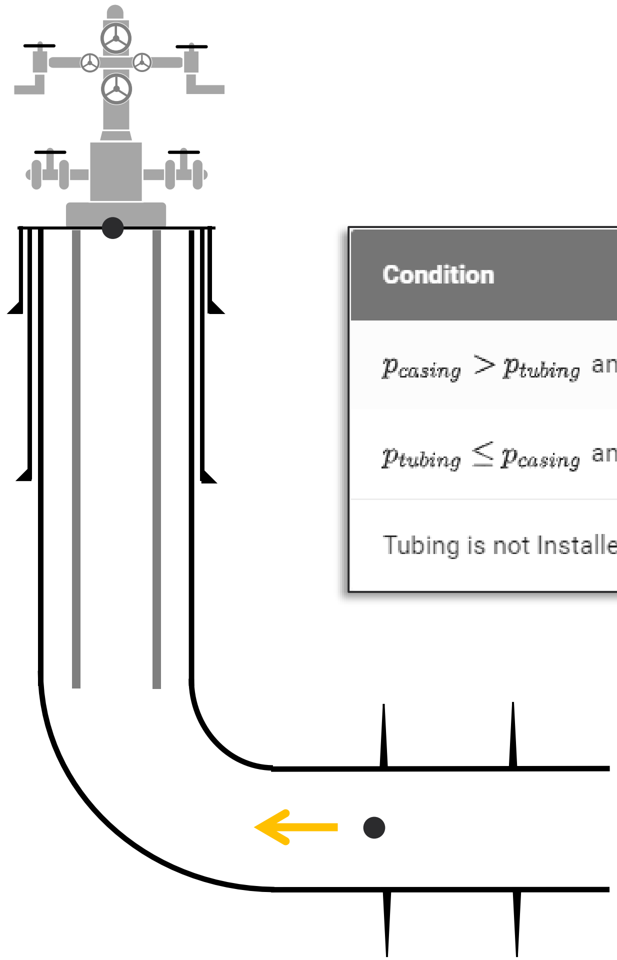


Echoes the provided $p_{wf,gauge}$

Flow Path—Unknown

From wellhead to top perf.

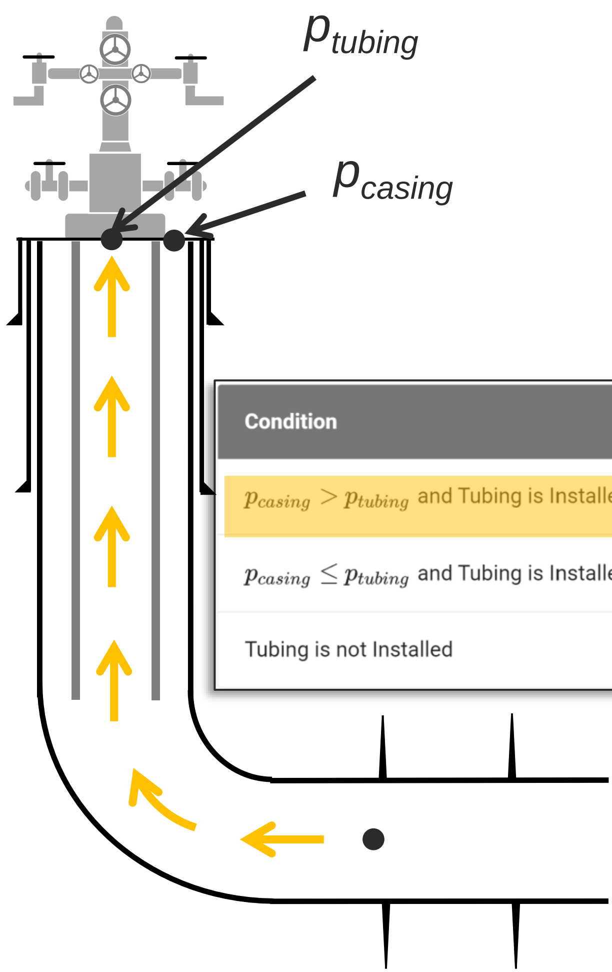




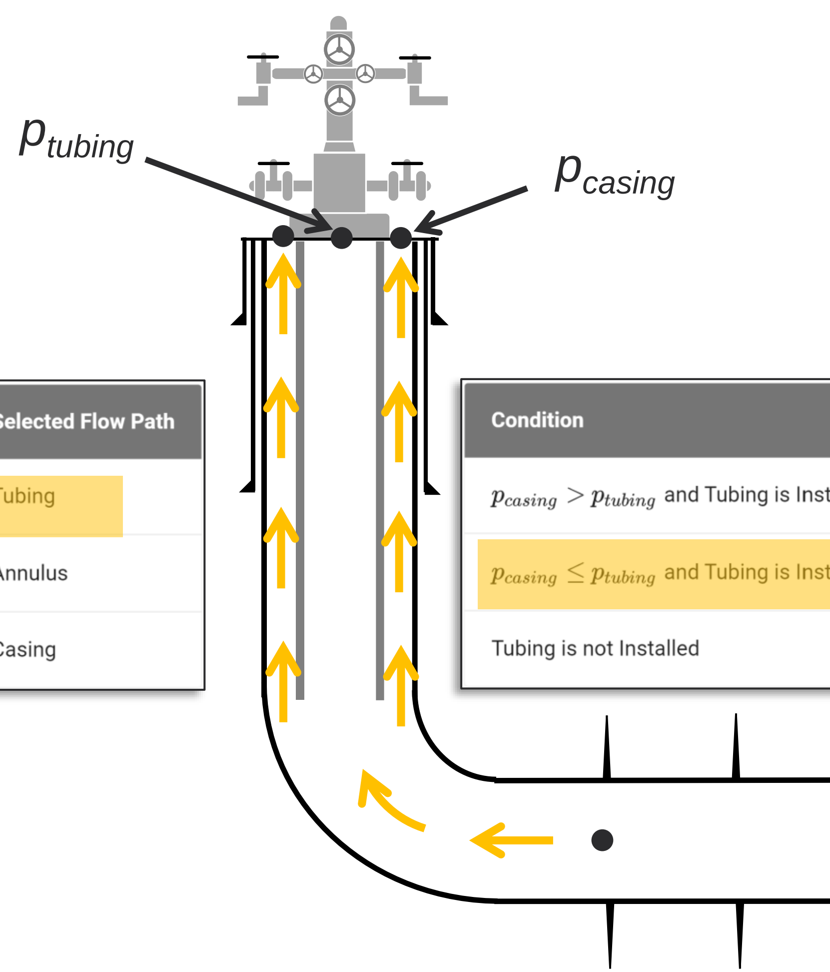
Condition	Selected Flow Path
$p_{casing} > p_{tubing}$ and Tubing is Installed	Tubing
$p_{tubing} \leq p_{casing}$ and Tubing is Installed	Annulus
Tubing is not Installed	Casing

Flow Path—Unknown

Tubing Installed



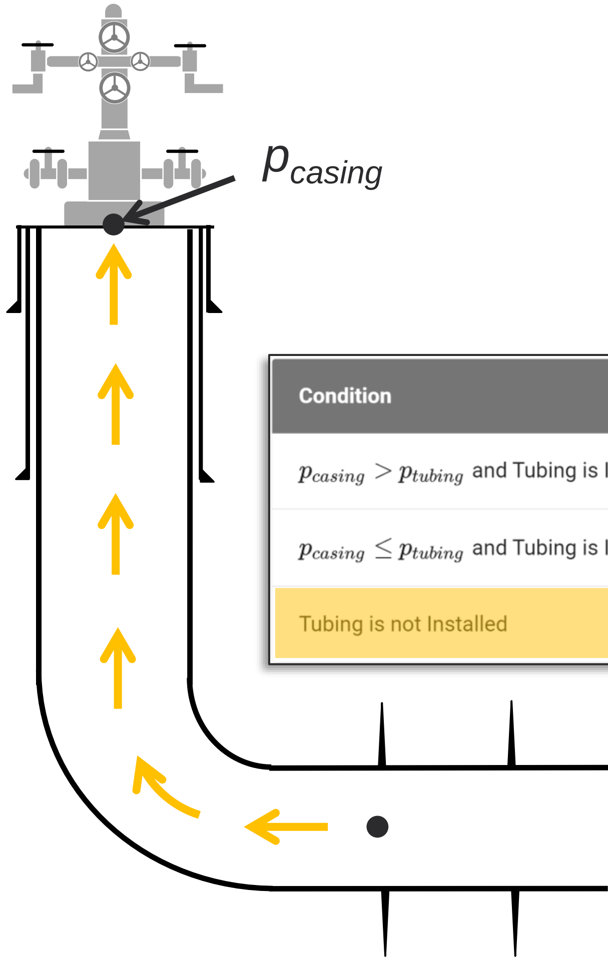
Condition	Selected Flow Path
$p_{casing} > p_{tubing}$ and Tubing is Installed	Tubing
$p_{casing} \leq p_{tubing}$ and Tubing is Installed	Annulus
Tubing is not Installed	Casing



Condition	Selected Flow Path
$p_{casing} > p_{tubing}$ and Tubing is Installed	Tubing
$p_{casing} \leq p_{tubing}$ and Tubing is Installed	Annulus
Tubing is not Installed	Casing

Flow Path—Unknown

No Tubing Installed



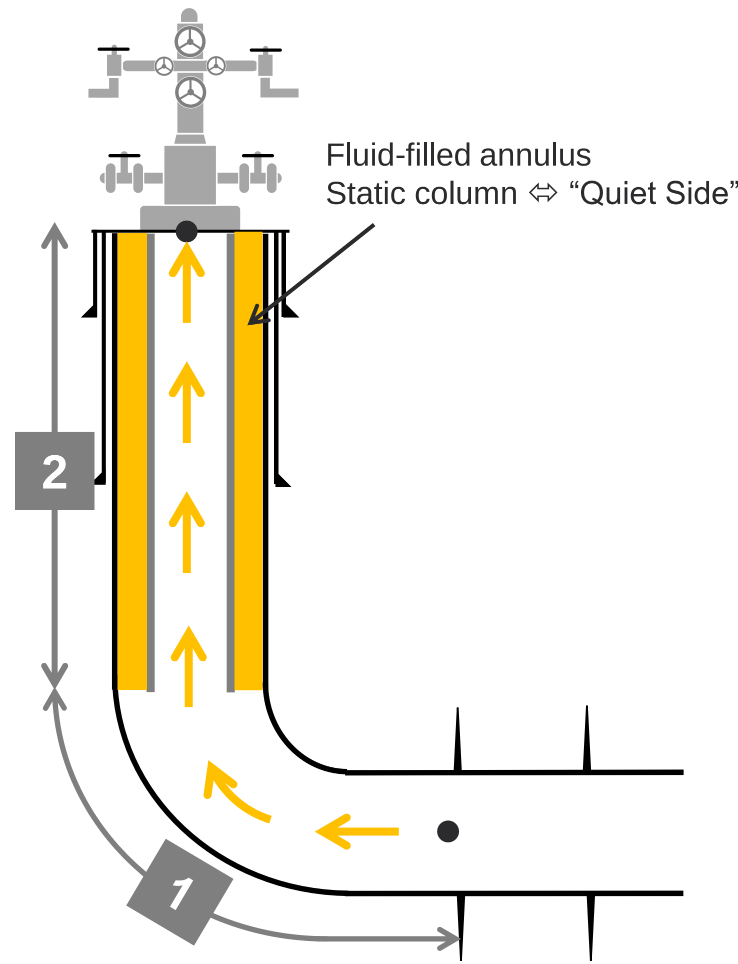
Condition	Selected Flow Path
$p_{casing} > p_{tubing}$ and Tubing is Installed	Tubing
$p_{casing} \leq p_{tubing}$ and Tubing is Installed	Annulus
Tubing is not Installed	Casing

Flowing vs Quiet Side Calculations

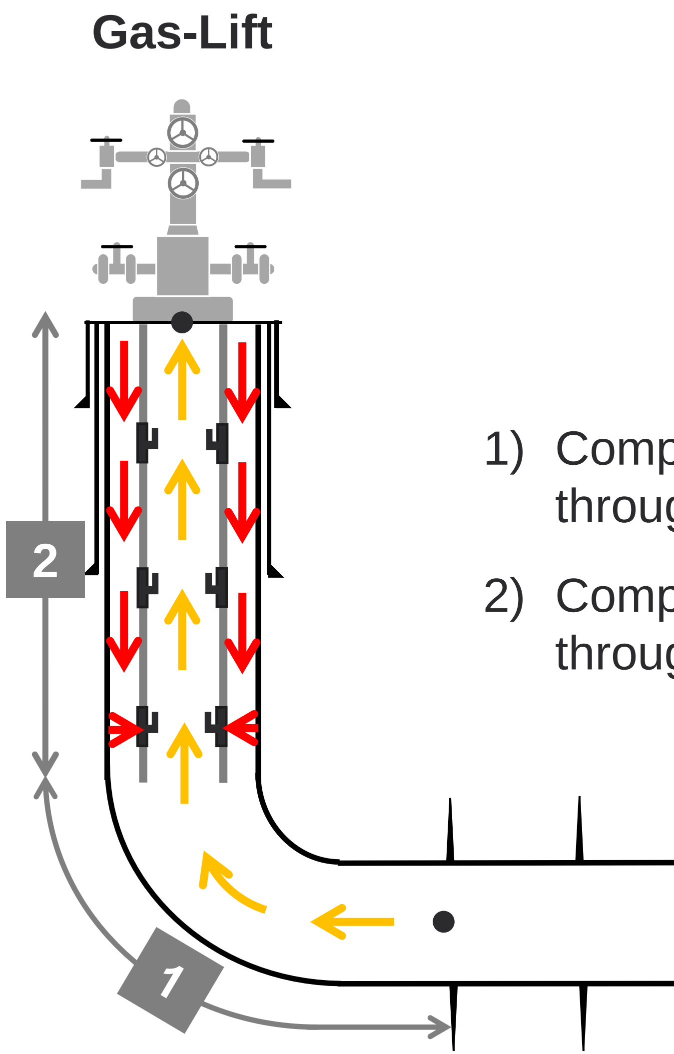
BHP Calculations Using the "Quiet Side"

Quiet Side:

- Annulus assumed filled with a single-phase fluid with communication to the flowing side at end of tubing (EOT), i.e. no isolation packer.
- Compute BHP by splitting the well into two segments
    1. Multiphase flow from top perforation (TP) to EOT
    2. Static fluid column from EOT to WH



BHP Calculations Using the "Quiet Side"



1) Compute the well pressure from TP to valve through the *multiphase* wellstream
2) Compute the well pressure from valve to WH through the *single-phase* lift-gas column

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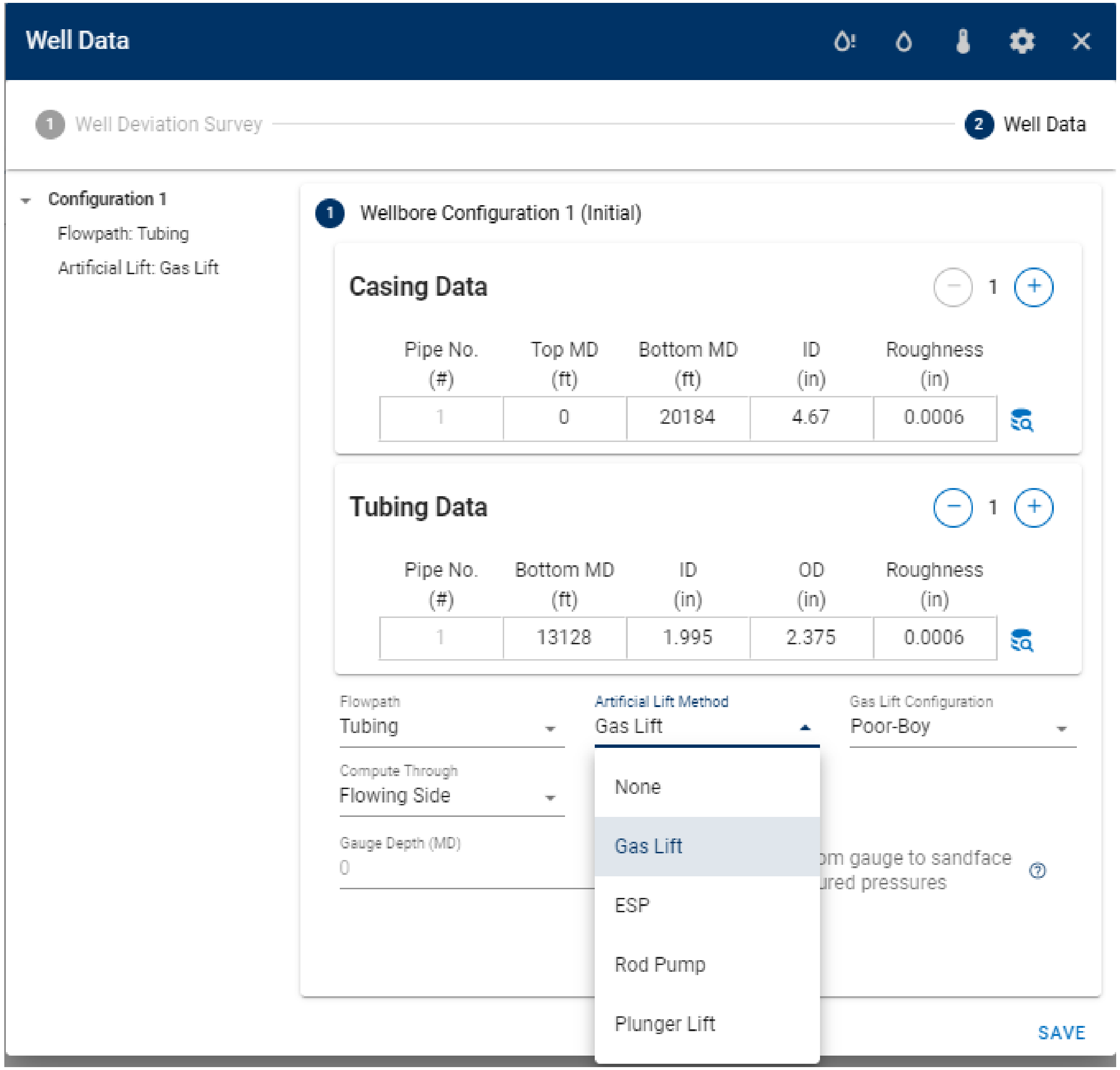
Artificial Lift Methods

Artificial Lift Methods

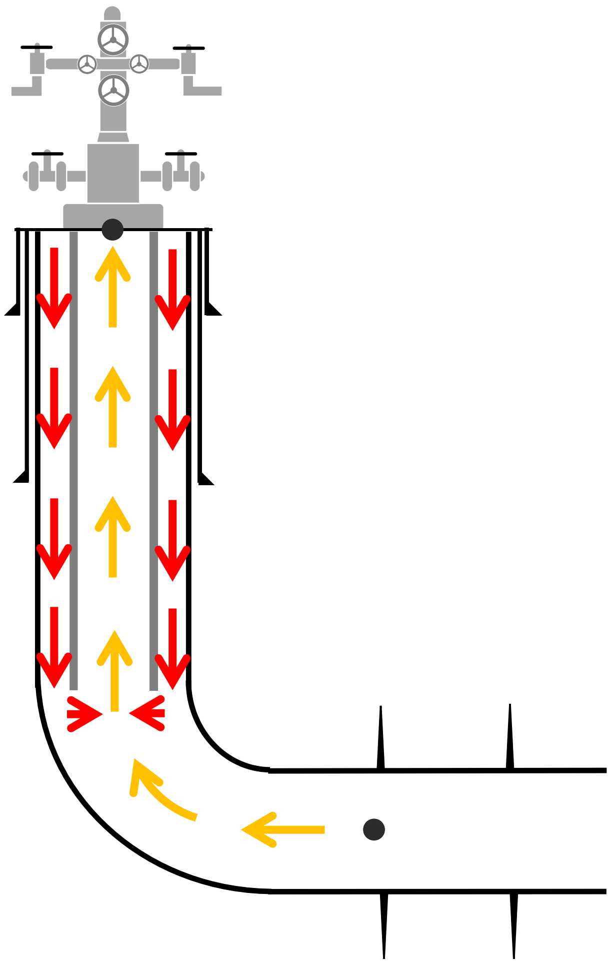


Artificial Lift—Gas Lift

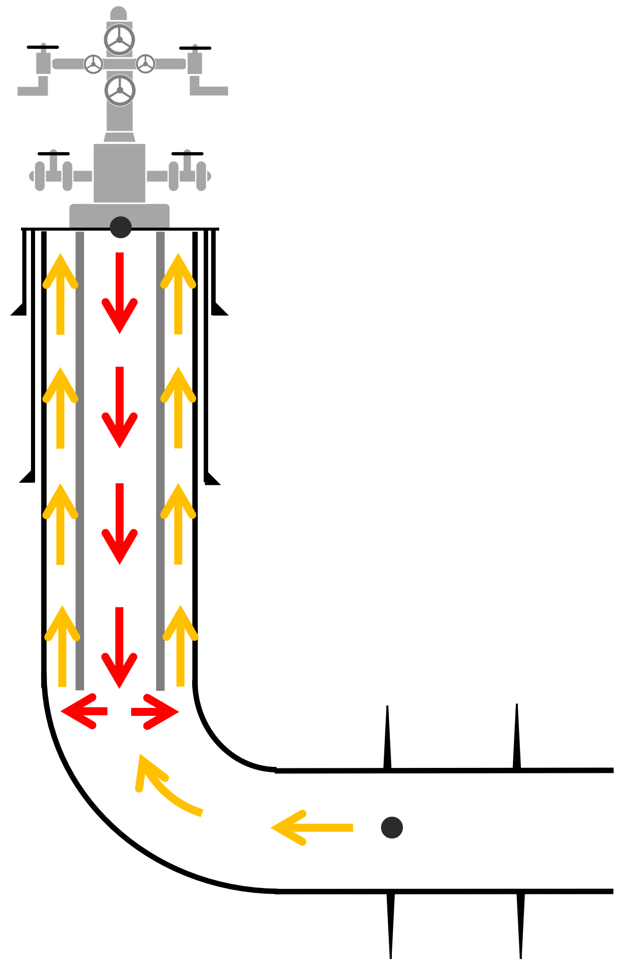
- Three types of gas-lift configurations:
  - Poor-Boy—Injection at EOT
  - Valves—Injection through the first open valve based on the surface pressure
  - Automatic—Injection at equal-pressure point in the tubing and annulus

Artificial Lift—Gas Lift | Poor-Boy

Flow Path: Tubing

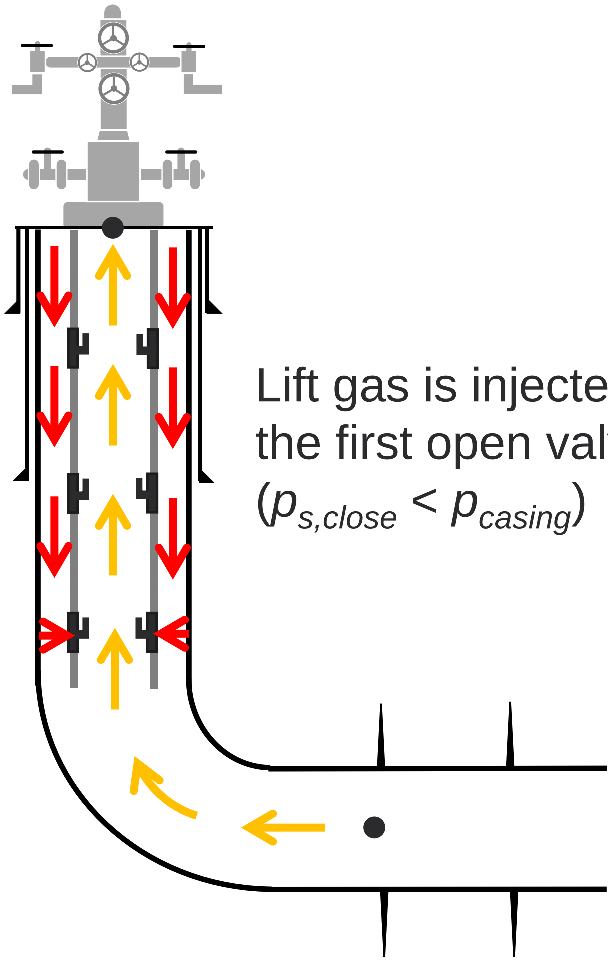


Flow Path: Annulus (*Reversed gas lift*)



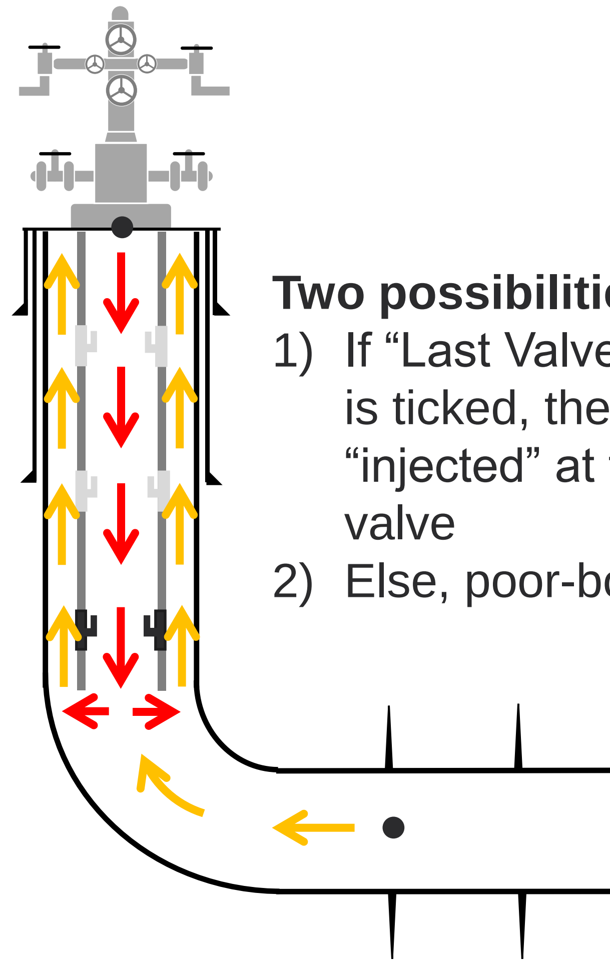
Artificial Lift—Gas Lift | Valves

Flow Path: Tubing



Lift gas is injected through the first open valve ($p_{s,close} < p_{casing}$)

Flow Path: Annulus (*Reversed gas lift*)



Two possibilities

1) If "Last Valve Always Open" is ticked, then lift gas is "injected" at through the last valve
2) Else, poor-boy (EOT)

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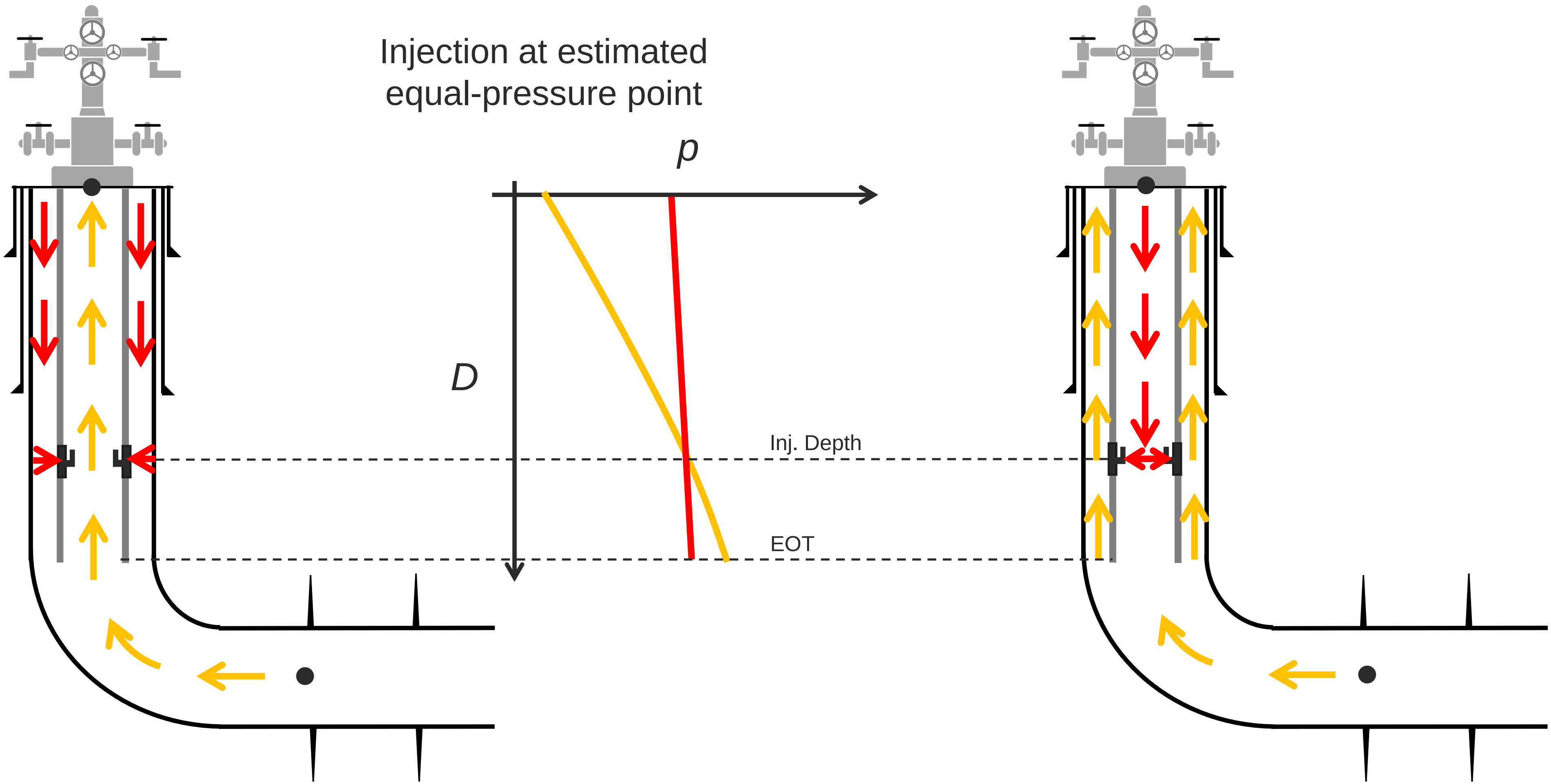
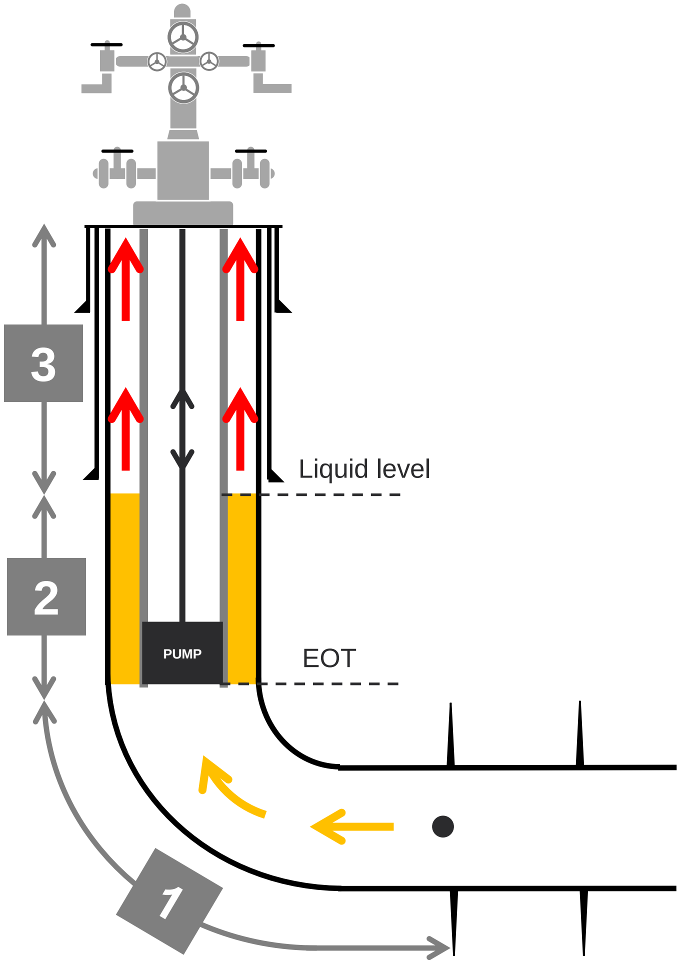
Artificial Lift—Gas Lift | Automatic

Flow Path: Tubing

Flow Path: Annulus (*Reversed gas lift*)



Artificial Lift—Rod Pump



Three Well Segments

1) Top Perforation to EOT:
Regular multiphase pipe flow

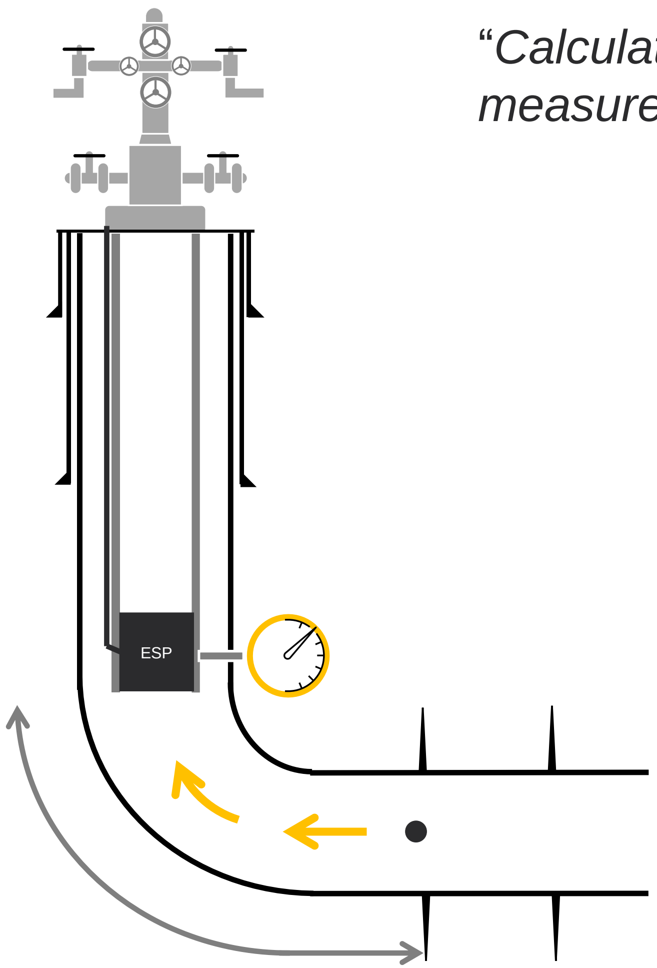
2) EOT to Liquid Level in Annulus:
Stagnant column of liquid and gas

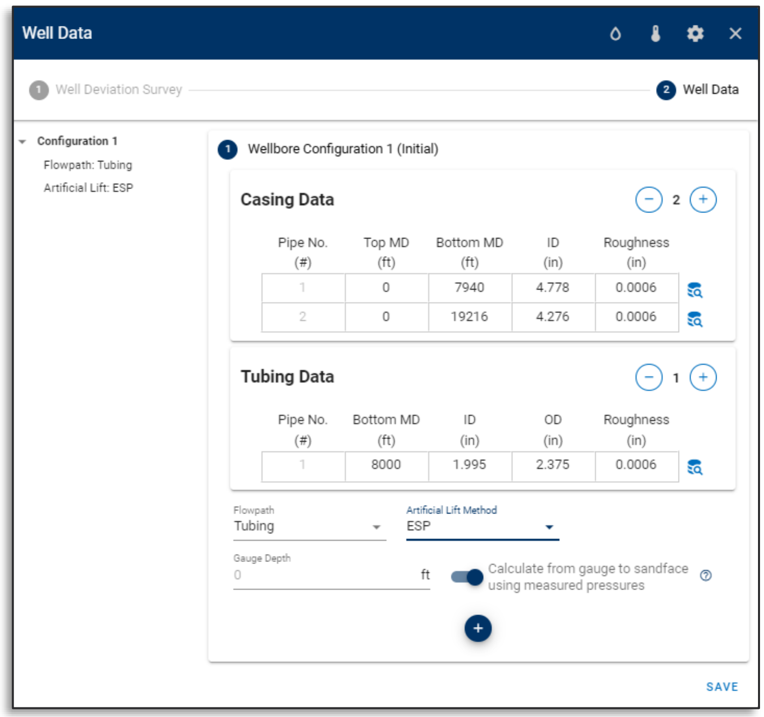
3) Liquid Level in Annulus to Wellhead
Single-phase gas flow

Artificial Lift—ESP

The measured pressures from the ESP gauge can be used with the option:

> "*Calculate from gauge to sandface using measured pressures*".





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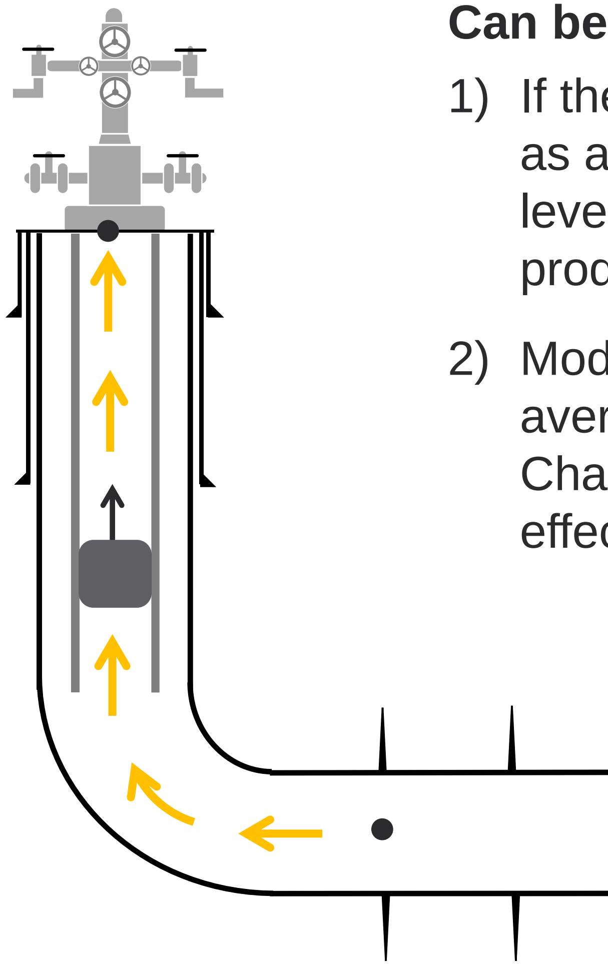
Artificial Lift—Plunger Lift



Can be modeled in two ways:

1) If the liquid level is measured, it can be modeled as a rod pump configuration provided the liquid level corresponds to times when the well is producing.

2) Model as if plunger lift is not installed by using average rates from the production period. Change the OGR of the well to capture the effect of less liquid in the tubing.

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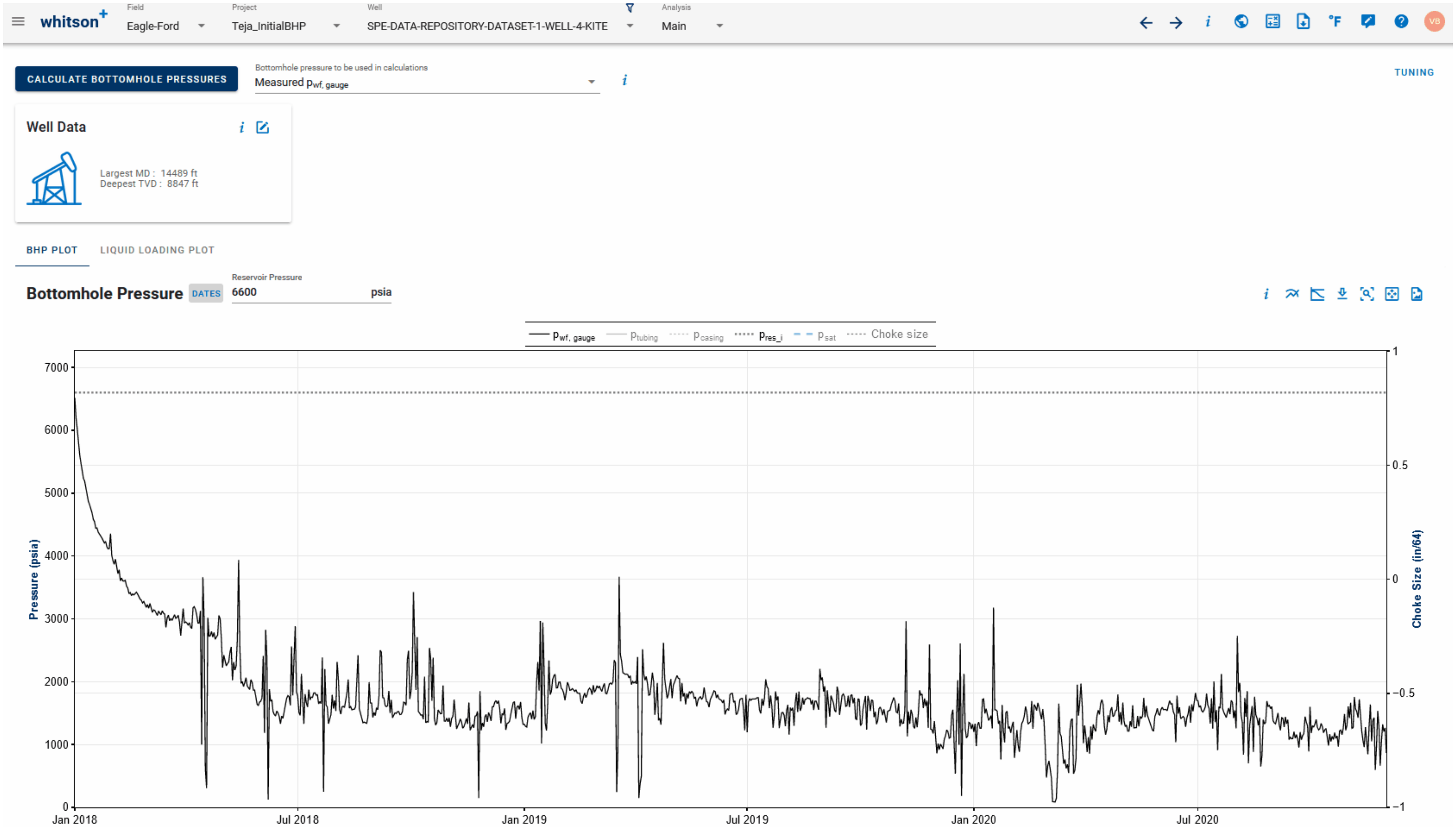
Estimate initial reservoir pressure with IPR

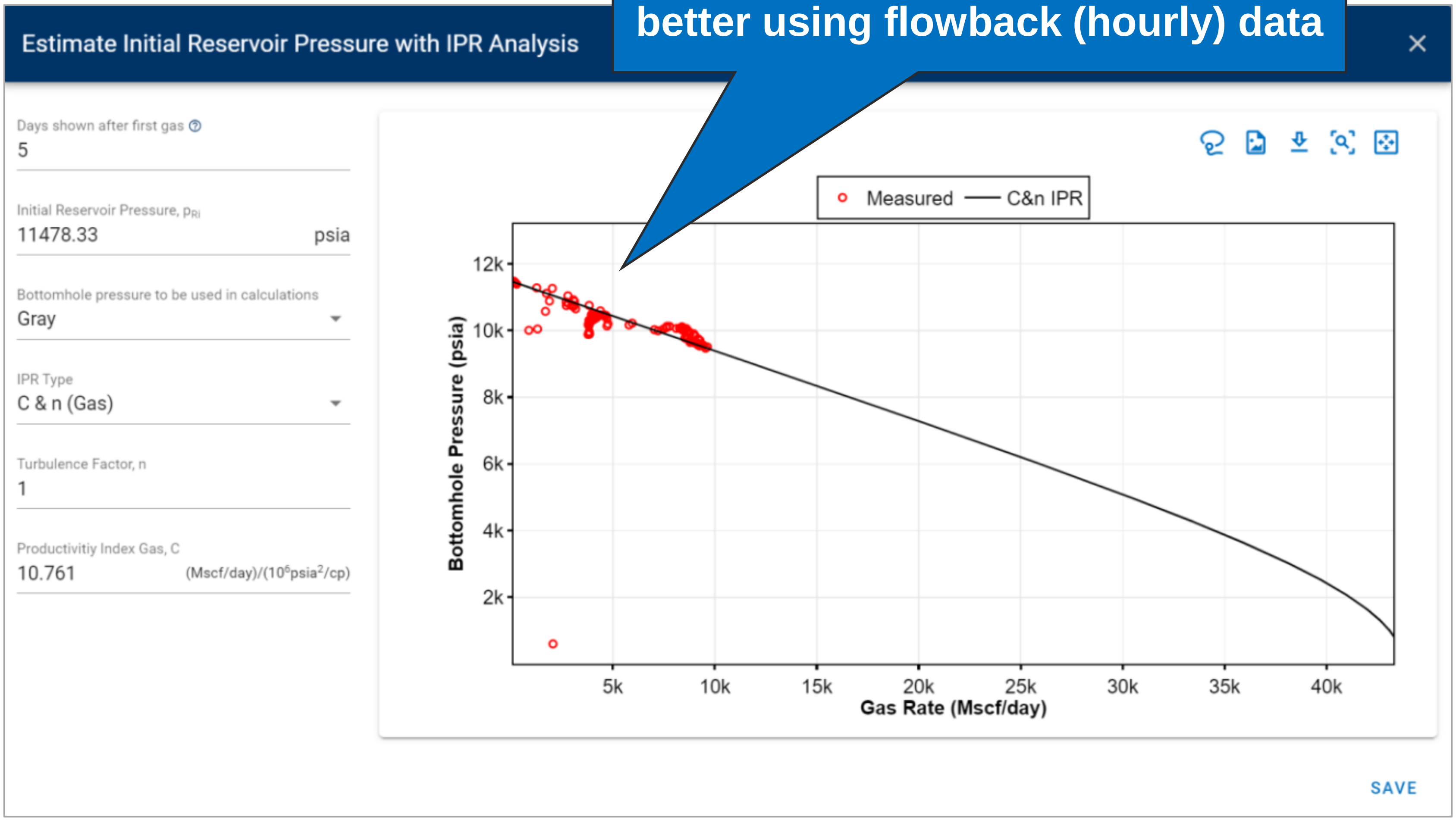
Estimate Initial Reservoir Pressure from IPR



Case study can be found here: https://youtu.be/PkR-Al0DPj4?feature=shared&t=6298

Estimate Initial Reservoir Pressure from IPR

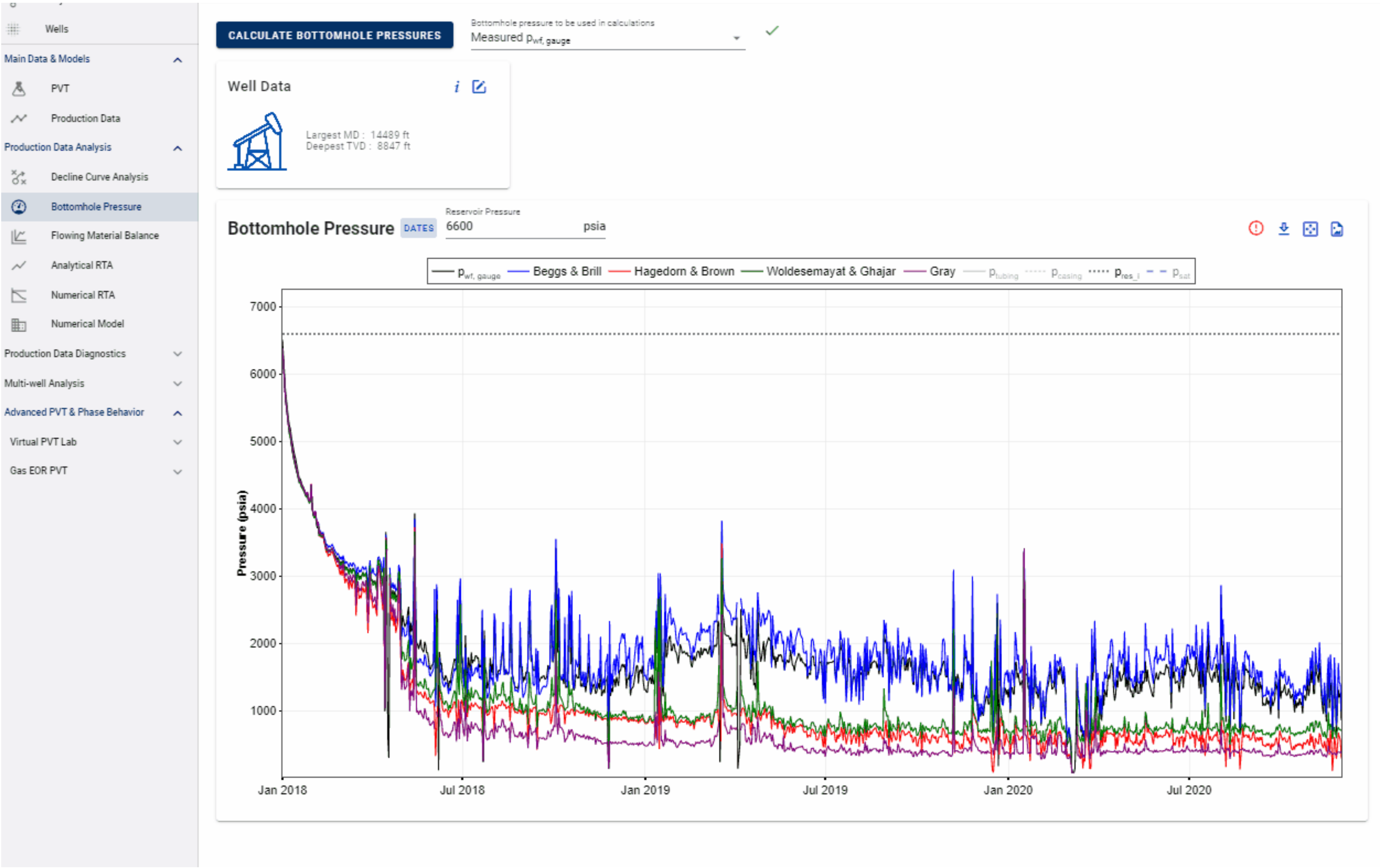
Works with daily data, but even better using flowback (hourly) data



Case study can be found here: https://youtu.be/PkR-Al0DPj4?feature=shared&t=6298

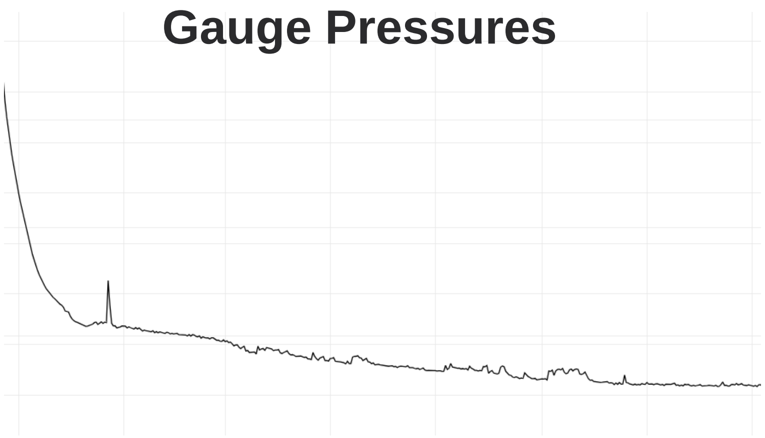
BHP Smoothing

BHP Smoothing

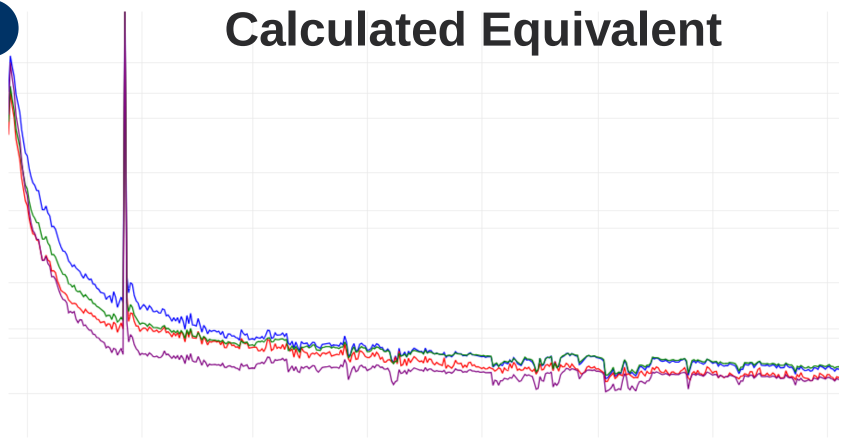


Examples: Gauge Pressures are Smooth!

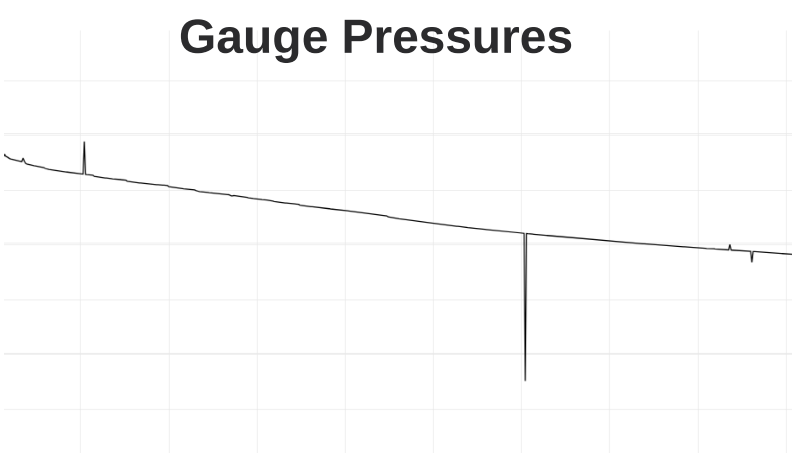
1



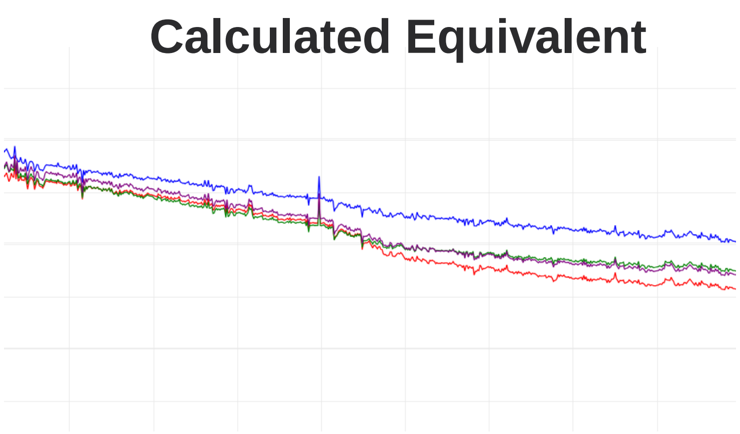
1



2

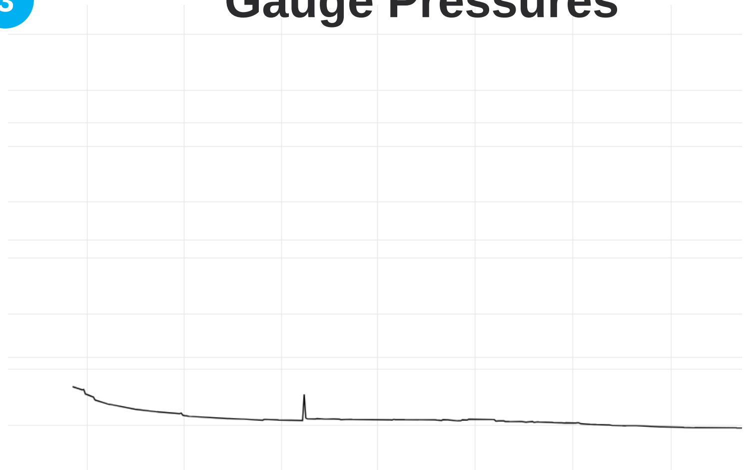


2

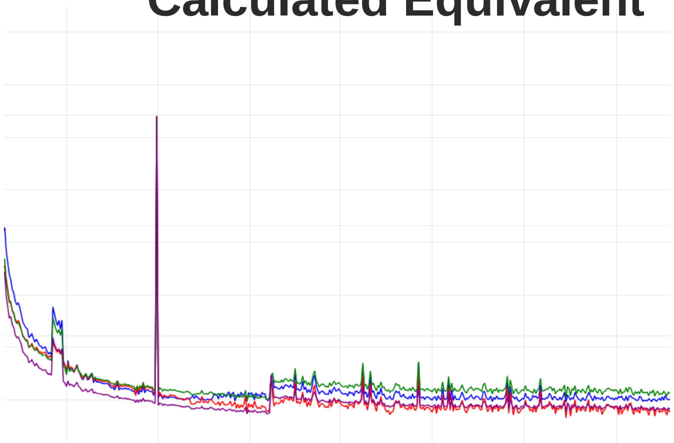


Examples: Gauge Pressures are Smooth!

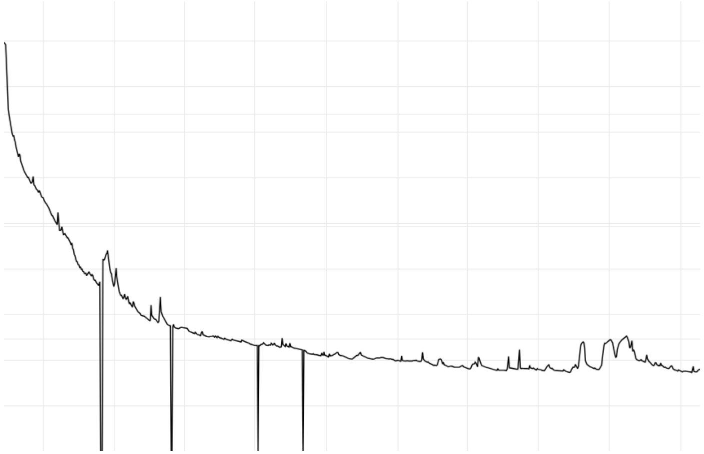
3 Gauge Pressures



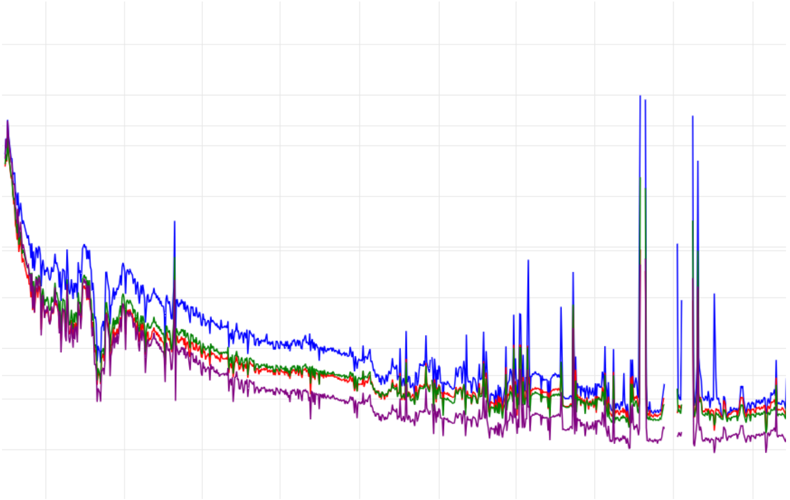
3 Calculated Equivalent



4 Gauge Pressures



4 Calculated Equivalent

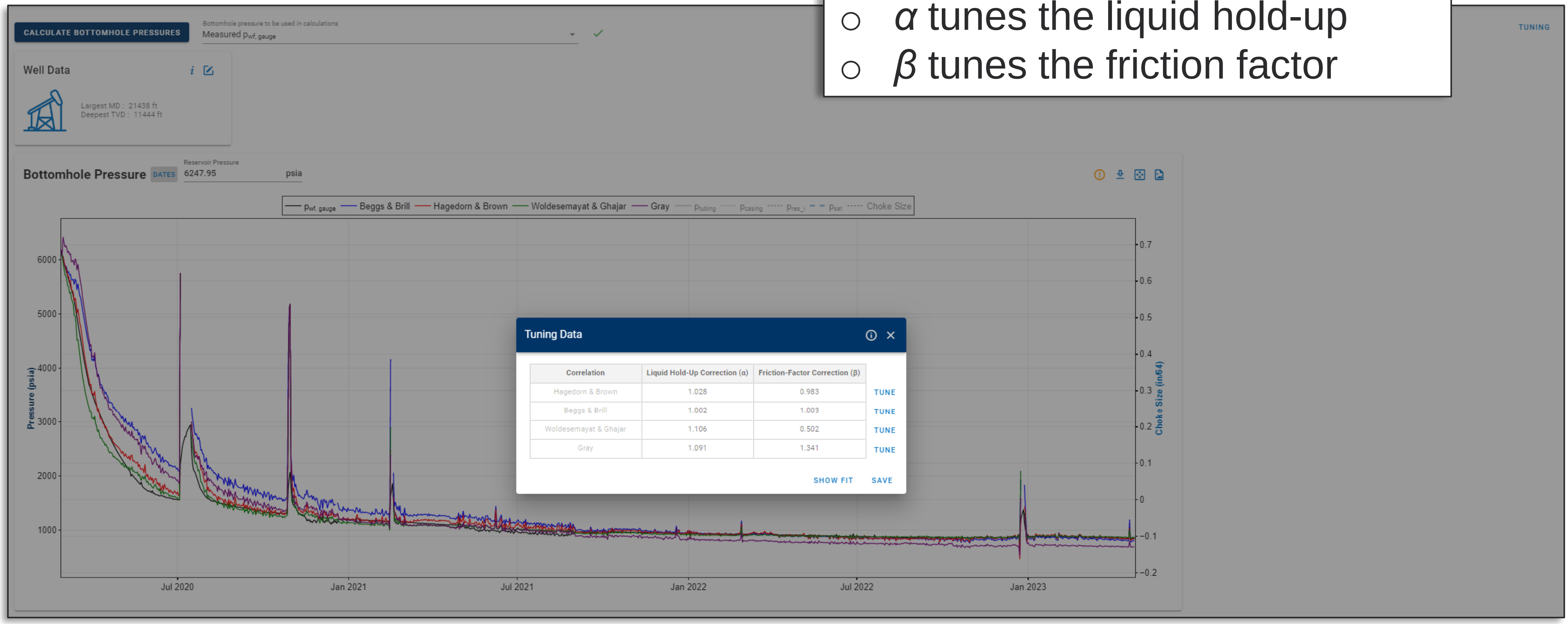


BHP Tuning

Tuning of Correlations

- The multiphase flow correlations can be tuned against measured pressures

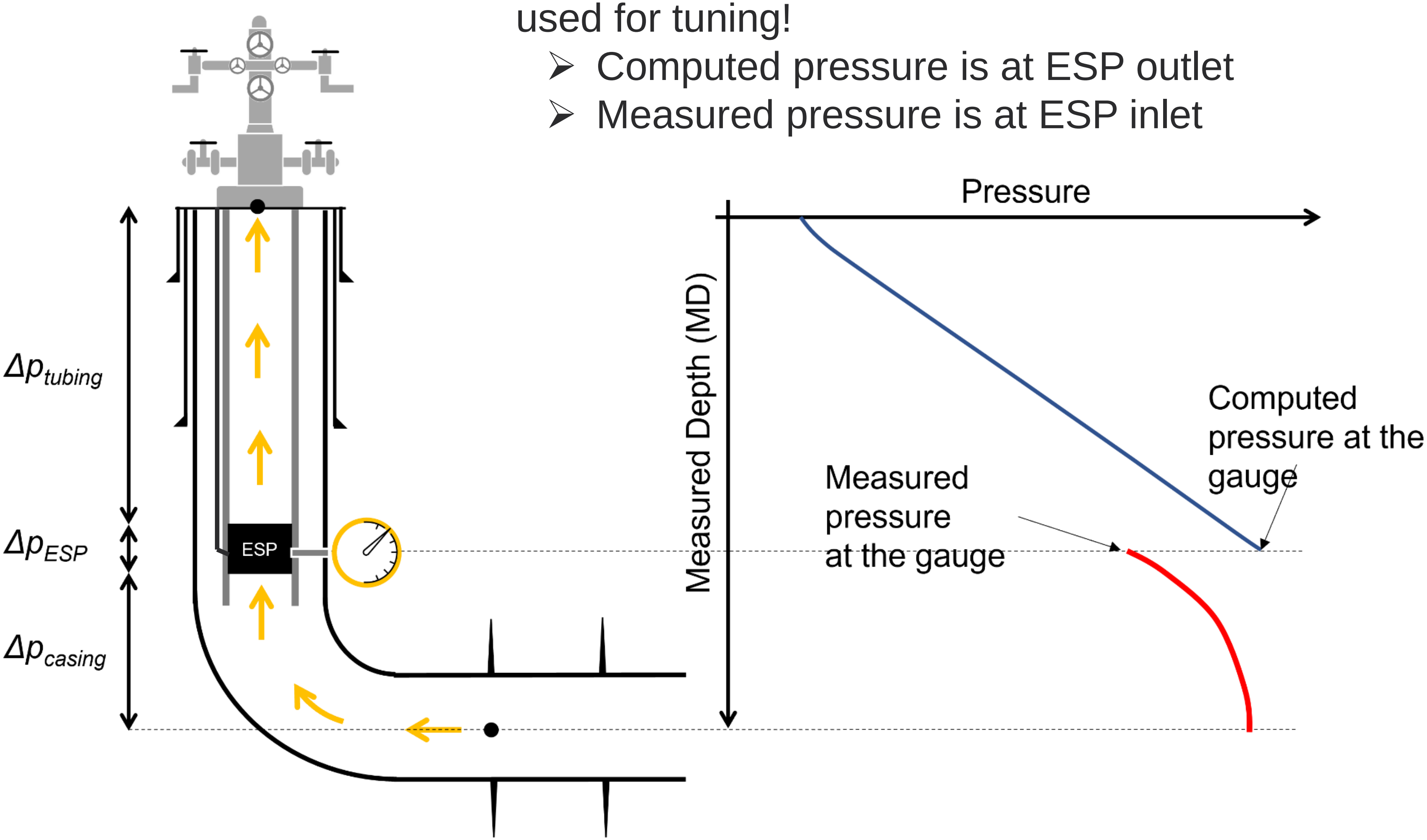
Two-parameter tuning:
- ○ α tunes the liquid hold-up
- ○ β tunes the friction factor



Tuning of Correlations—ESP

Caution

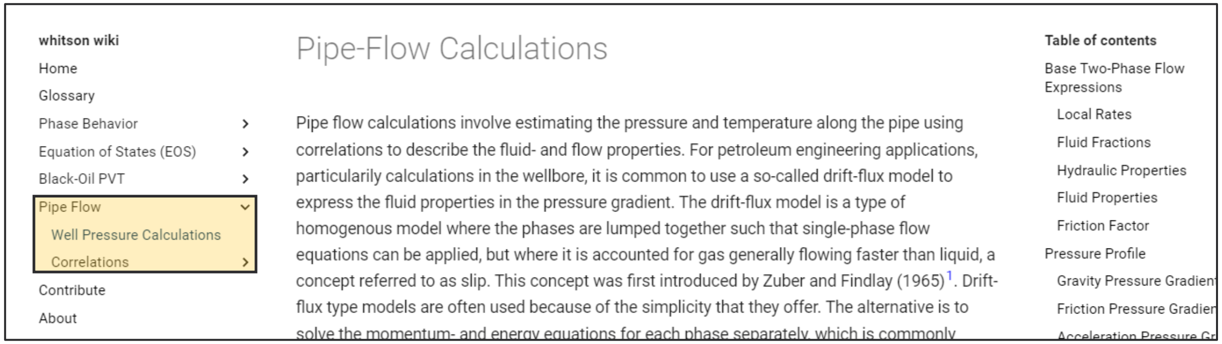
- Measured pressures from an ESP should not be used for tuning!
  - Computed pressure is at ESP outlet
  - Measured pressure is at ESP inlet



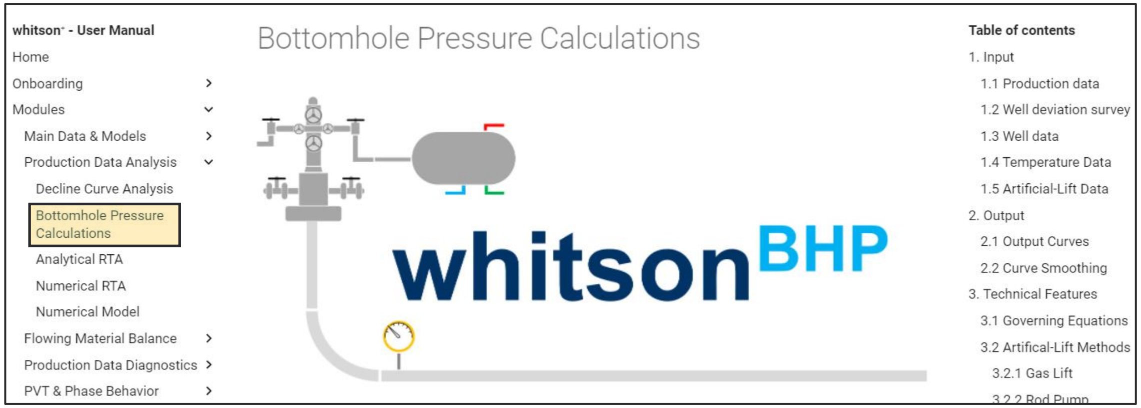
References

Wiki and Manual

- Pipe-flow theory and correlations
  - https://wiki.whitson.com/pipeflow/well_pressure_calculations/



- BHP calculations in **whitson+**
  - https://manual.whitson.com/modules/well-performance/bottomhole-pressure-calculations/



Exercises

Exercise – Agenda

1. Key Features & Functionality:

a. BHP calculation for well on gas lift
   - Poorboy
   - Valves
   - Automatic (flowing & quiet side)

b. Custom BHP / BHP smoothing

c. BHP calculation setting

d. BHP calculation for well with rod pump

e. BHP calculation for well on ESP

f. BHP calculation for dry gas well / Liquid loading

2. BHP tuning exercise

3. Advanced: BHP using Mass Upload Sheet

Access to whitson+

DO NOT USE COMPANY DOMAIN!
Not same as your company domain

https://courses.whitson.com/

Username: your e-mail

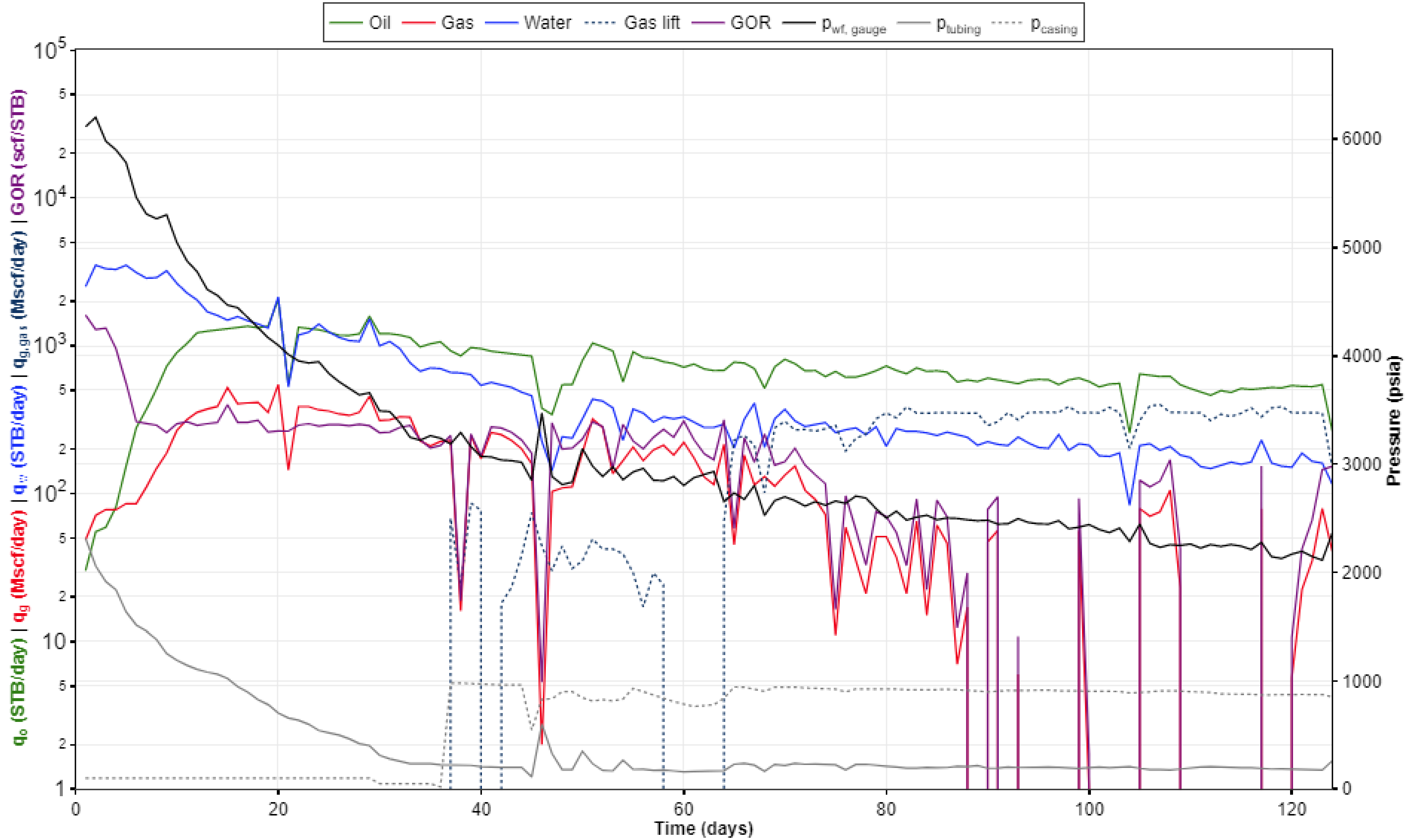
Password: WhitsonBHP2024

*Send an e-mail to support@whitson.com if you need help to login.
Need to use Google Chrome, Firefox or Microsoft Edge.
Internet Explorer won't work.

Exercise 1.a

BHP Calculations well on gas lift (Poorboy)

Gas Lift – Poorboy Configuration



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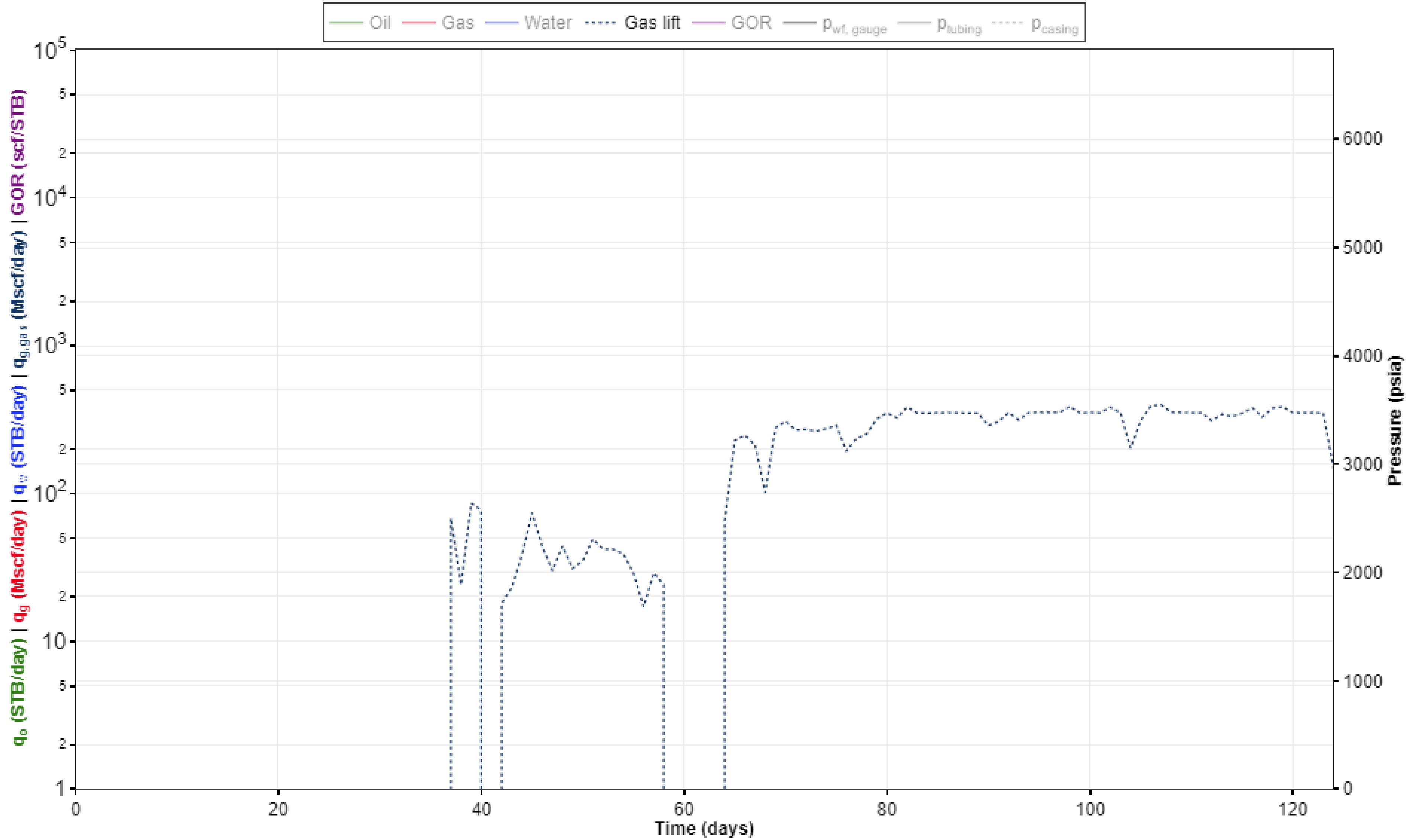
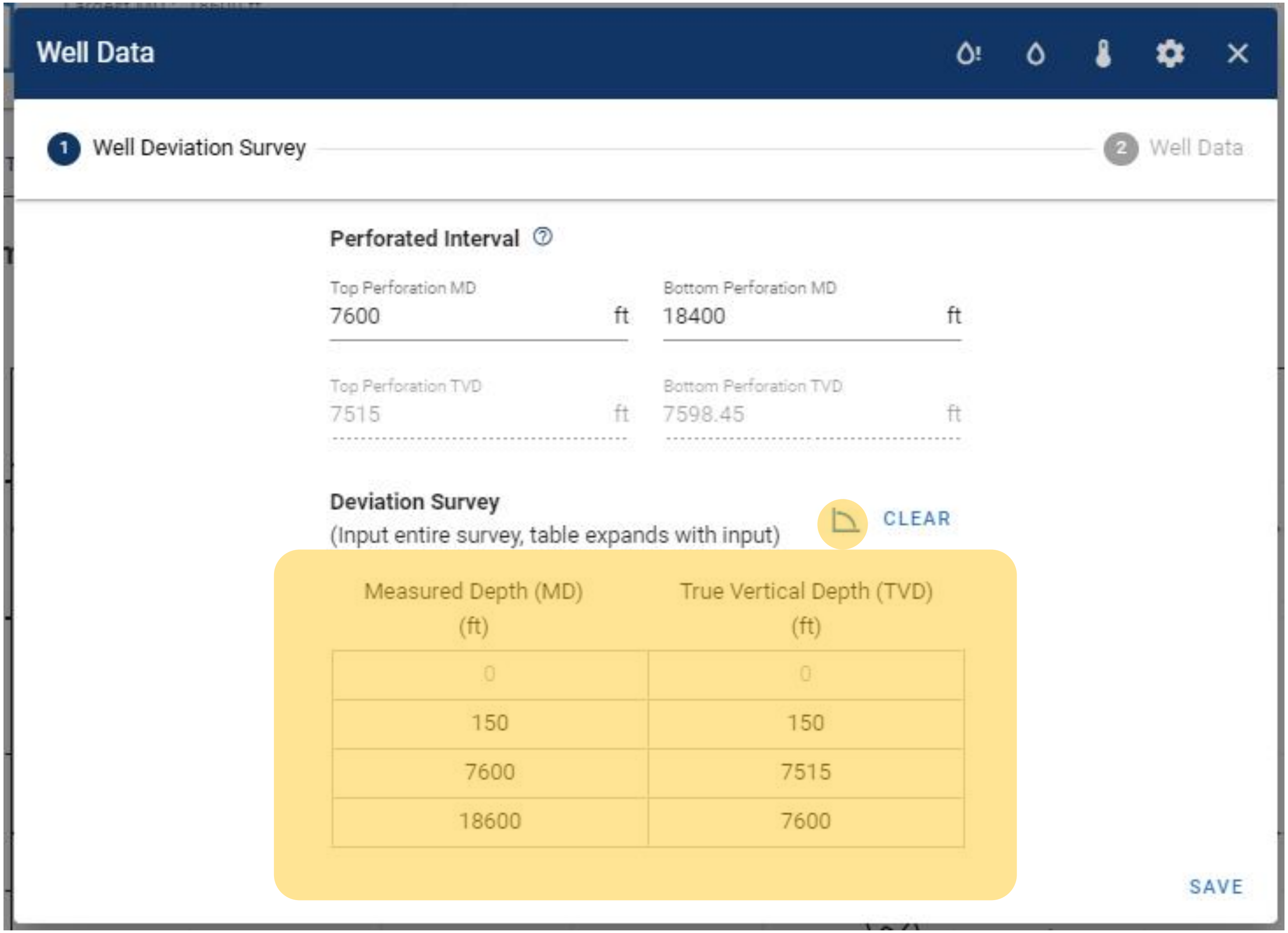
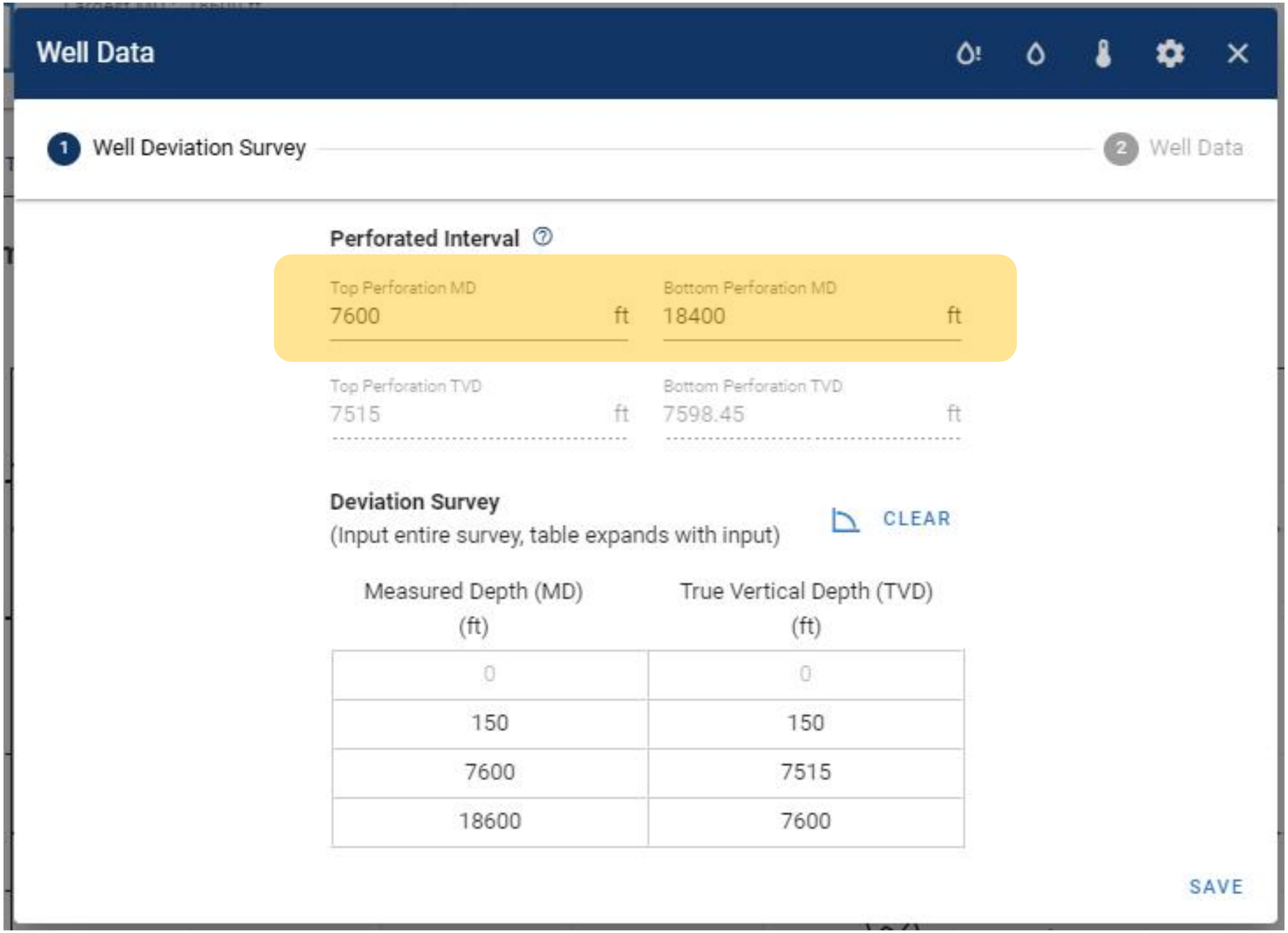
Gas Lift – Poorboy Configuration



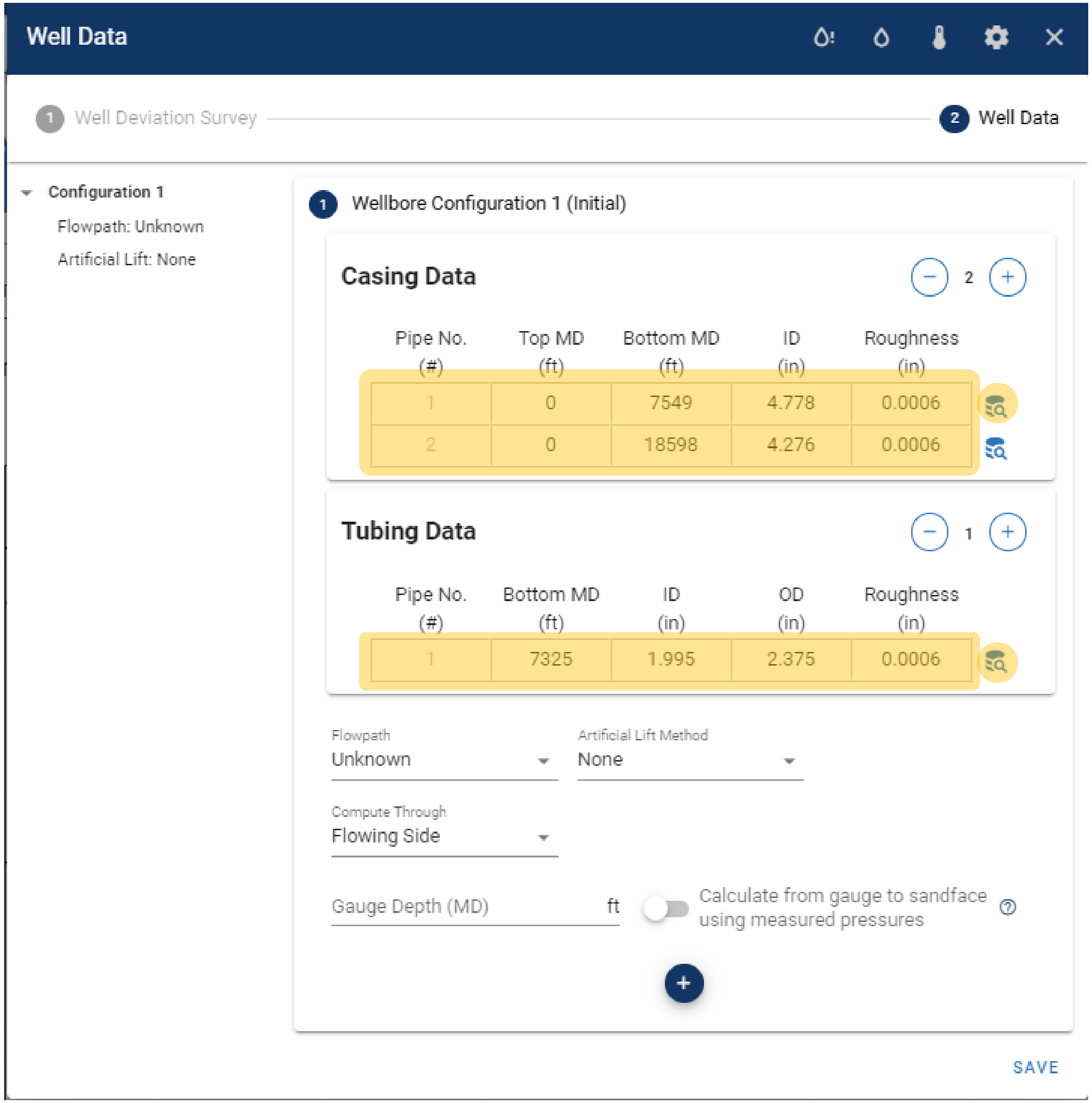
Well Deviation Survey



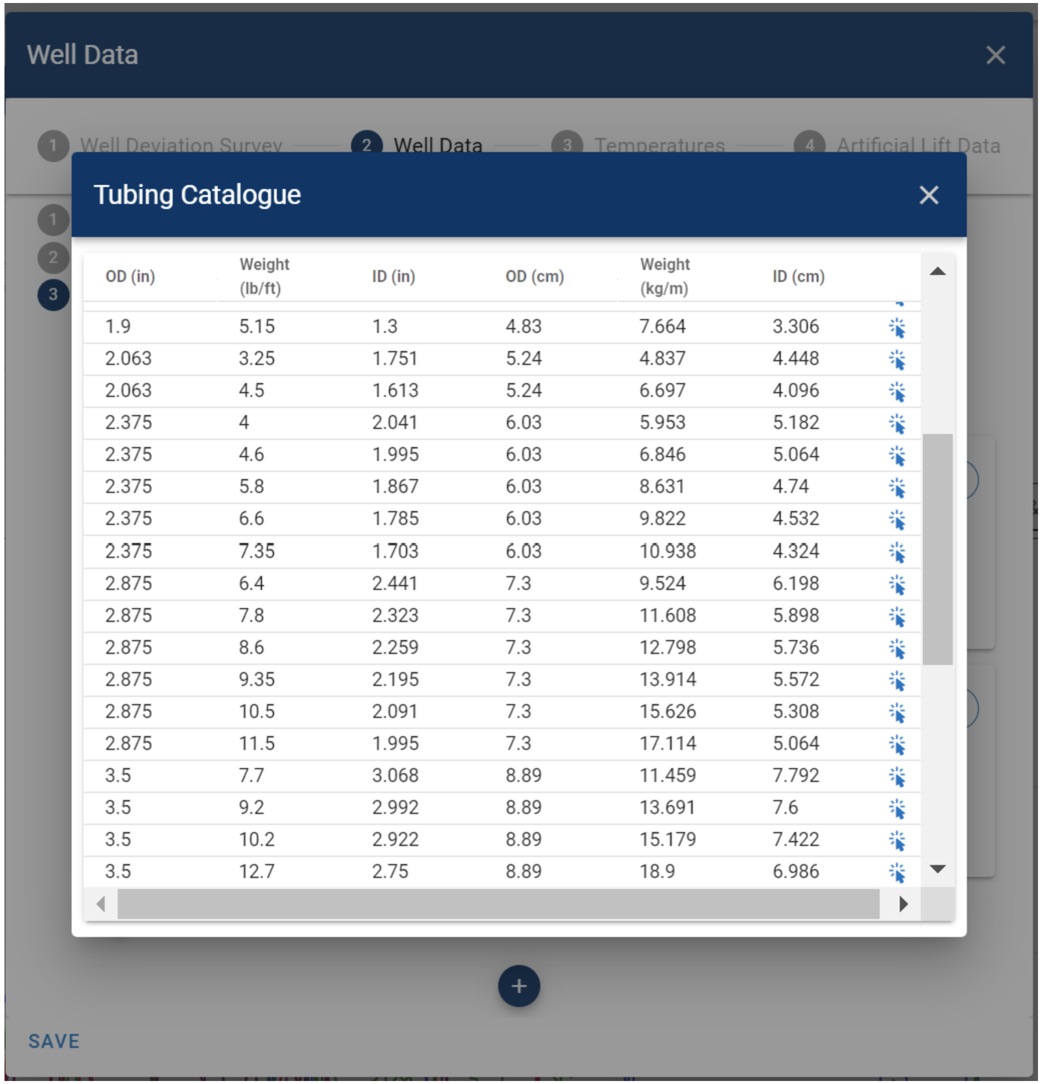
Top & Bottom Perforation Depths



Wellbore Configuration – Casing & Tubing Data



Using the Tubing / Casing Catalogue



OD (in)	Weight (lb/ft)	ID (in)	OD (cm)	Weight (kg/m)	ID (cm)
1.9	5.15	1.3	4.83	7.664	3.306
2.063	3.25	1.751	5.24	4.837	4.448
2.063	4.5	1.613	5.24	6.697	4.096
2.375	4	2.041	6.03	5.953	5.182
2.375	4.6	1.995	6.03	6.846	5.064
2.375	5.8	1.867	6.03	8.631	4.74
2.375	6.6	1.785	6.03	9.822	4.532
2.375	7.35	1.703	6.03	10.938	4.324
2.875	6.4	2.441	7.3	9.524	6.198
2.875	7.8	2.323	7.3	11.608	5.898
2.875	8.6	2.259	7.3	12.798	5.736
2.875	9.35	2.195	7.3	13.914	5.572
2.875	10.5	2.091	7.3	15.626	5.308
2.875	11.5	1.995	7.3	17.114	5.064
3.5	7.7	3.068	8.89	11.459	7.792
3.5	9.2	2.992	8.89	13.691	7.6
3.5	10.2	2.922	8.89	15.179	7.422
3.5	12.7	2.75	8.89	18.9	6.986

Wellbore Configuration

1 Well Deviation Survey — 2 Well Data

Configuration 1
- Flowpath: Tubing
- Artificial Lift: Gas Lift

1 Wellbore Configuration 1 (Initial)

Casing Data

− 2 +

Pipe No. (#)	Top MD (ft)	Bottom MD (ft)	ID (in)	Roughness (in)
1	0	7549	4.778	0.0006
2	0	18598	4.276	0.0006

Tubing Data

− 1 +

Pipe No. (#)	Bottom MD (ft)	ID (in)	OD (in)	Roughness (in)
1	7325	1.995	2.375	0.0006

Flowpath: Tubing

Artificial Lift Method: Gas Lift

Gas Lift Configuration: Poor-Boy

Compute Through: Flowing Side

Gauge Depth (MD) ft

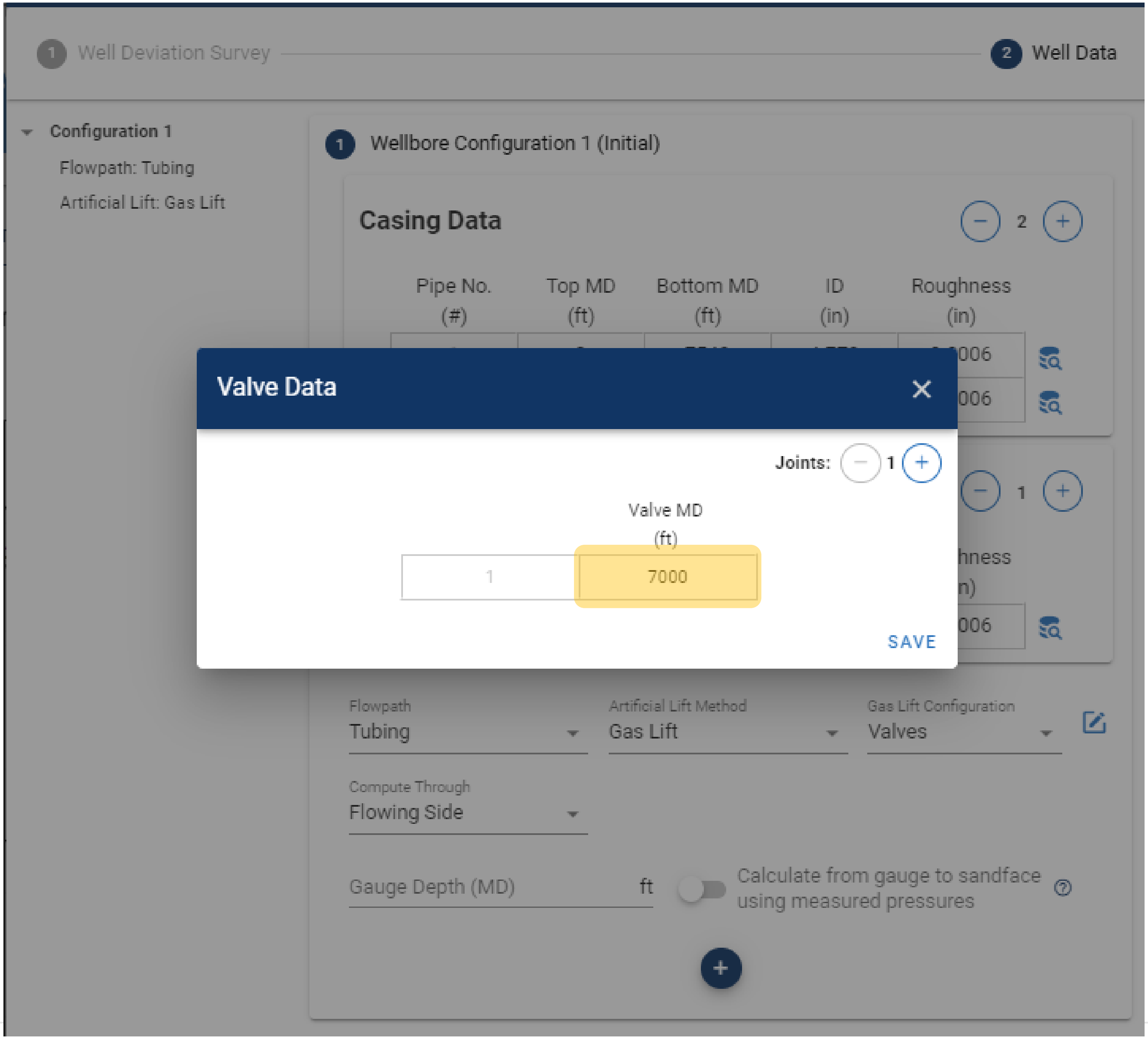
Calculate from gauge to sandface using measured pressures

+

Exercise 1.a

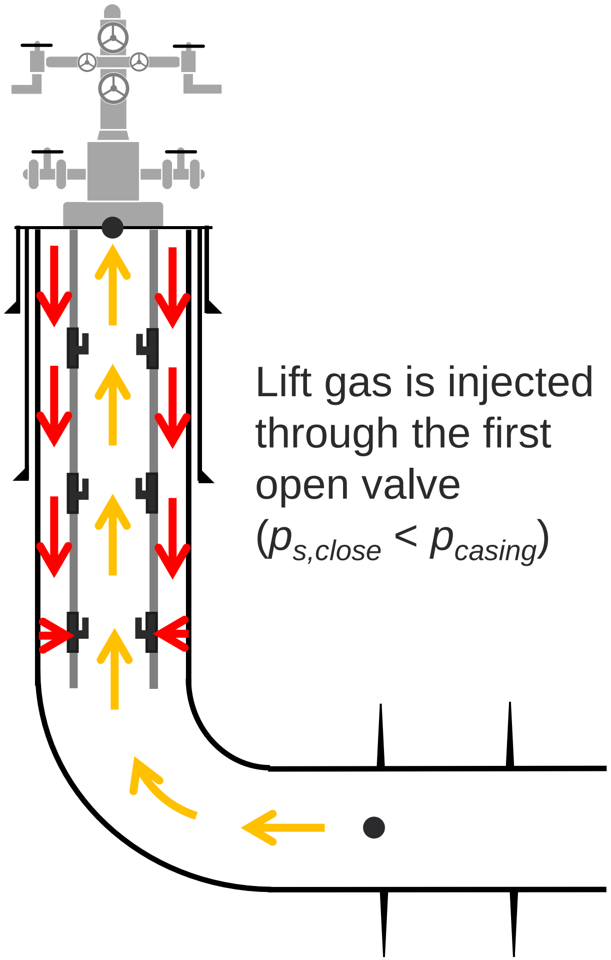
BHP Calculations well on gas lift (Valves)

Gas Lift – Single Valve Depth

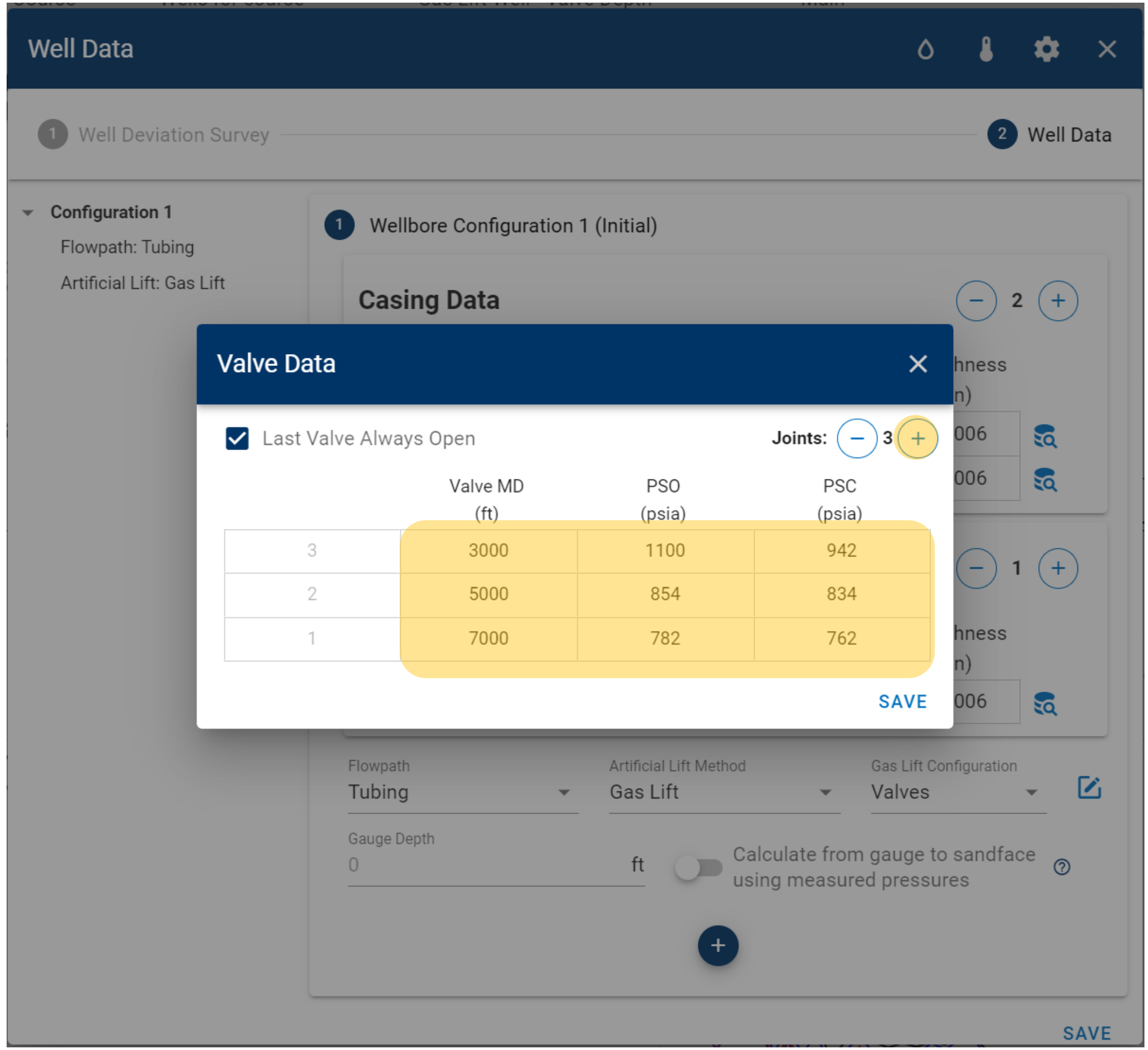


Gas Lift – Multiple Valves vs Depth

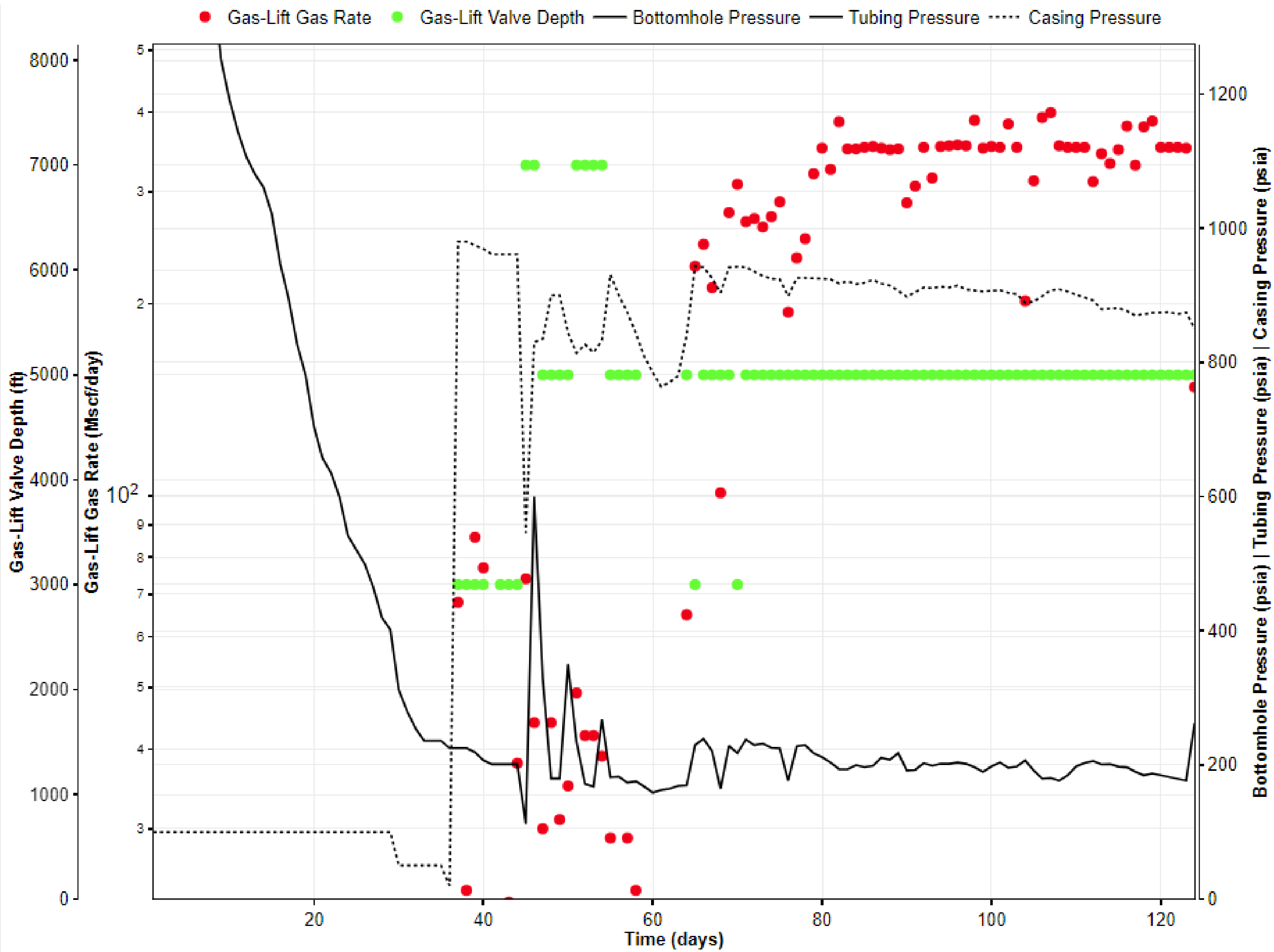
Flow Path: Tubing



Lift gas is injected through the first open valve ($p_{s,close} < p_{casing}$)



Gas Lift – Multiple Valves vs Depth



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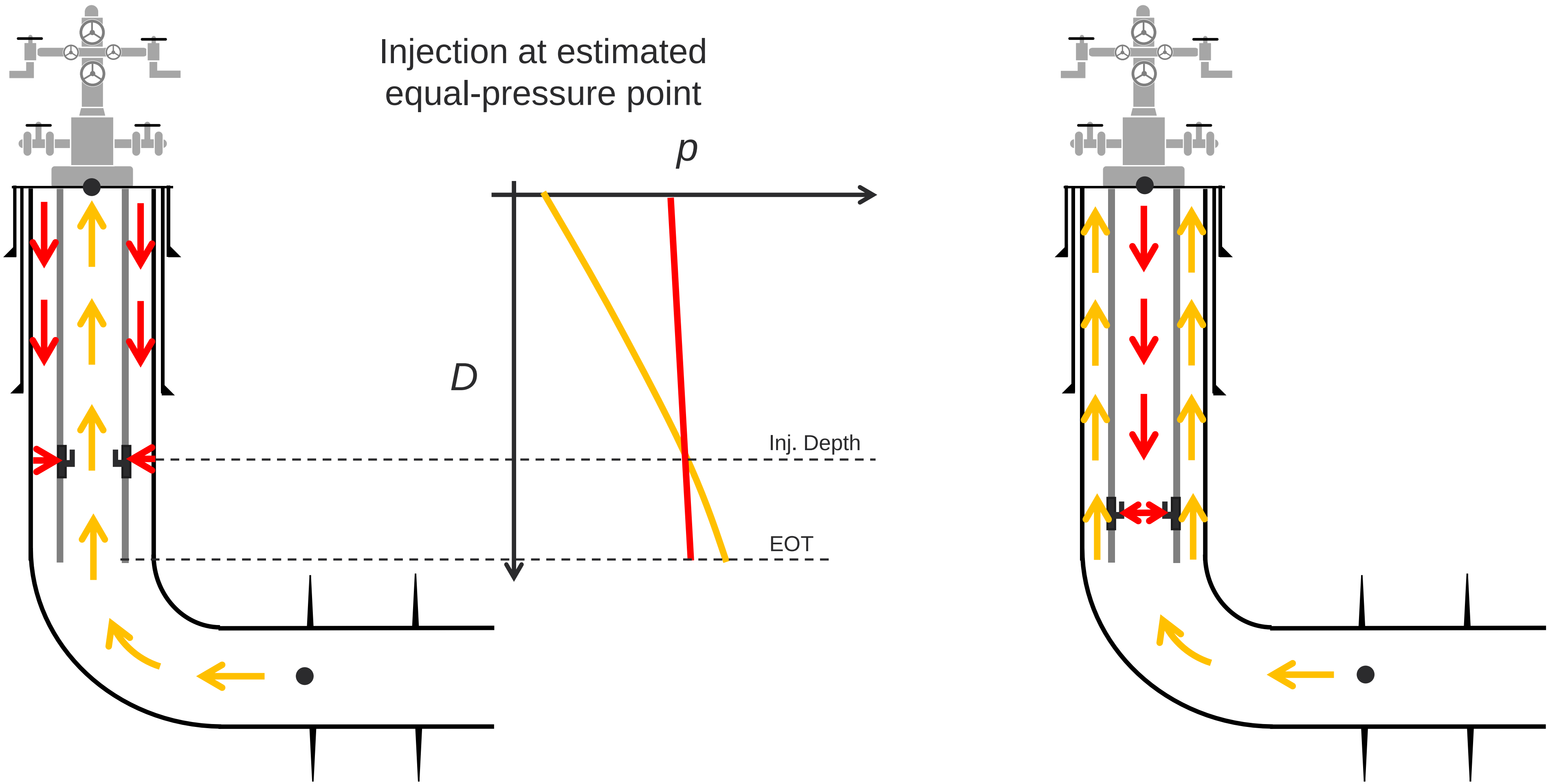
Exercise 1.a

BHP Calculations well on gas lift (Automatic)

Artificial Lift—Gas Lift | Automatic

Flow Path: Tubing

Flow Path: Annulus (*Reversed gas lift*)



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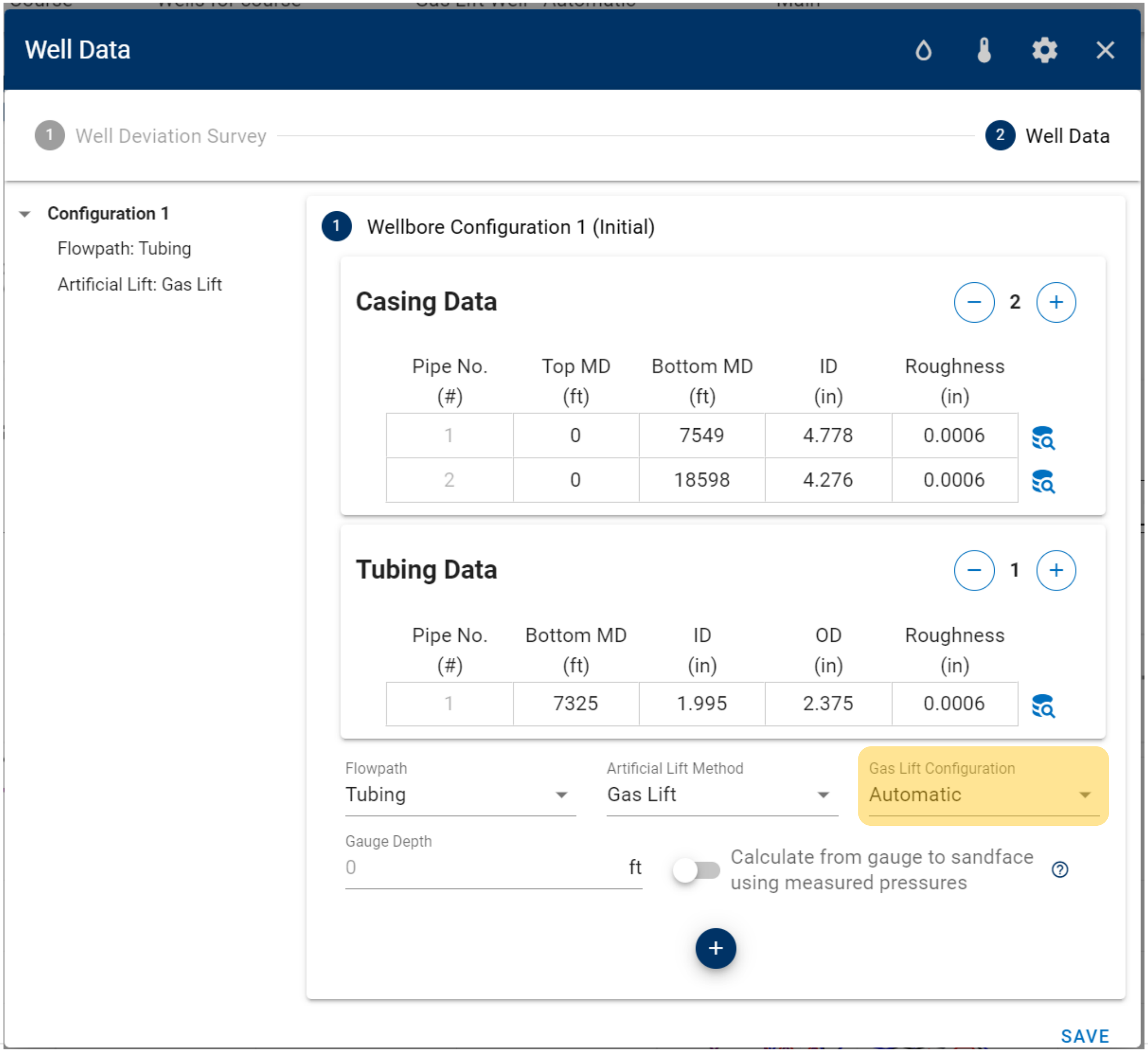
Gas Lift – Automatic



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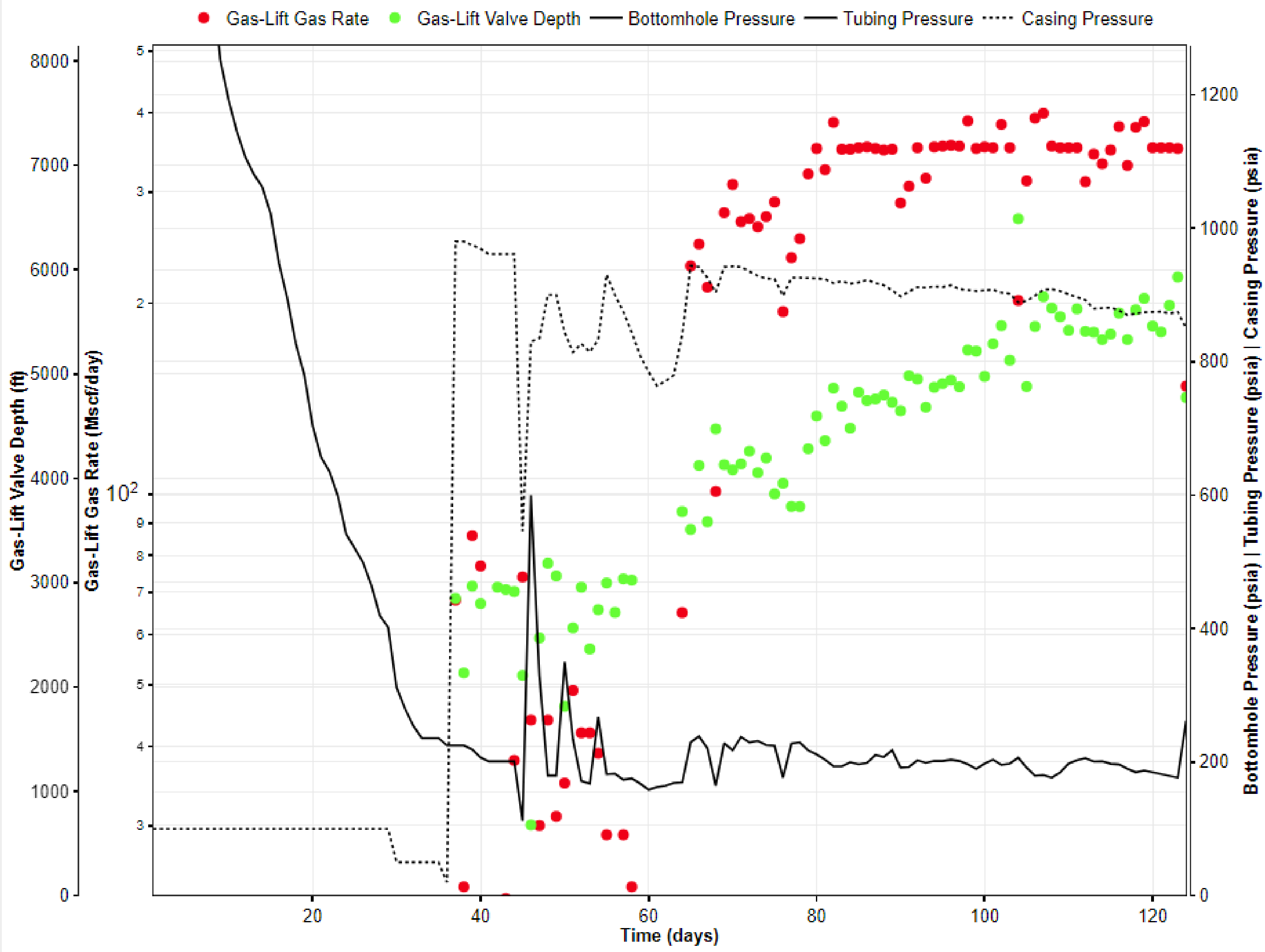
Gas Lift – Multiple Valves vs Depth



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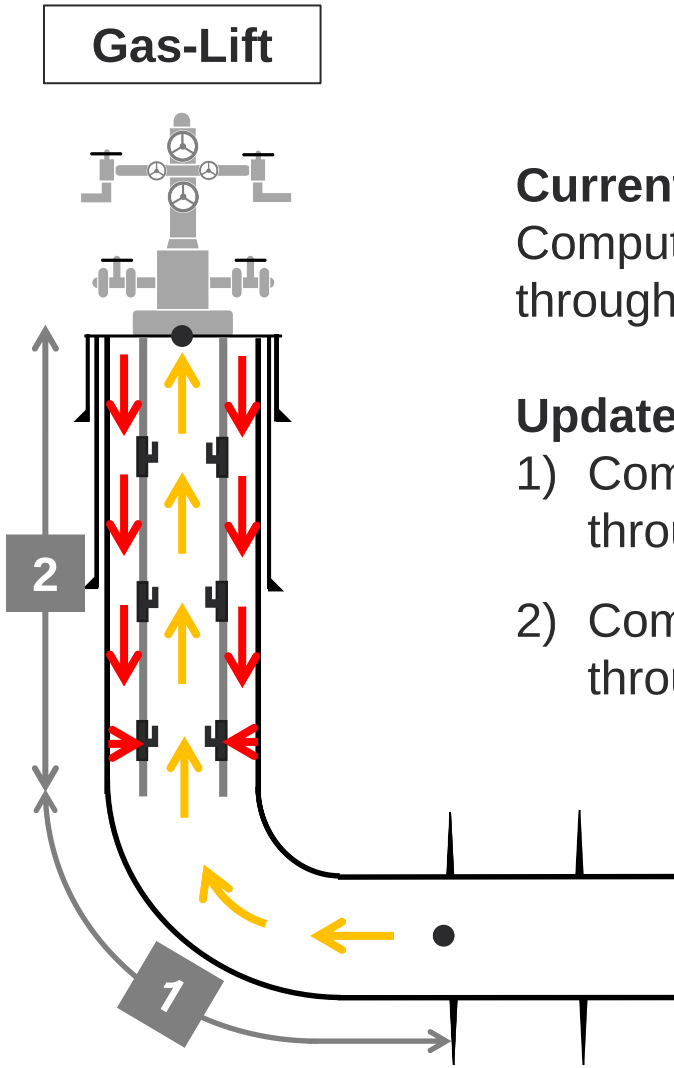
Exercise 1.a

BHP Calculations
well on gas lift
(Quiet / Silent Side)

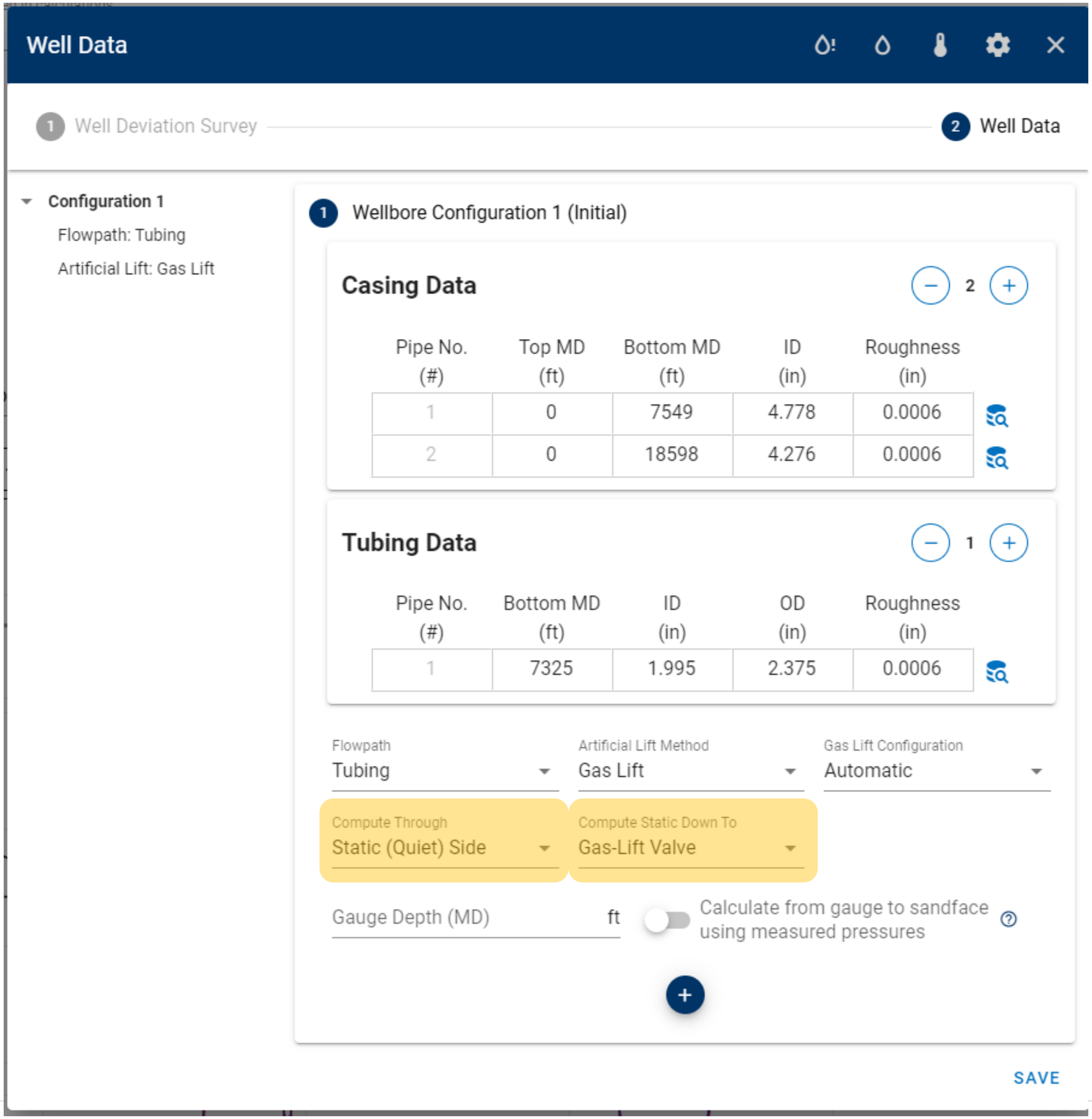
BHP Calculations Using the "Quiet Side"



Current:
Compute the well pressure from TP to WH through the multiphase wellstream

Update:
1) Compute the well pressure from TP to valve through the *multiphase* wellstream
2) Compute the well pressure from valve to WH through the *single-phase* lift-gas column

Gas Lift – Automatic

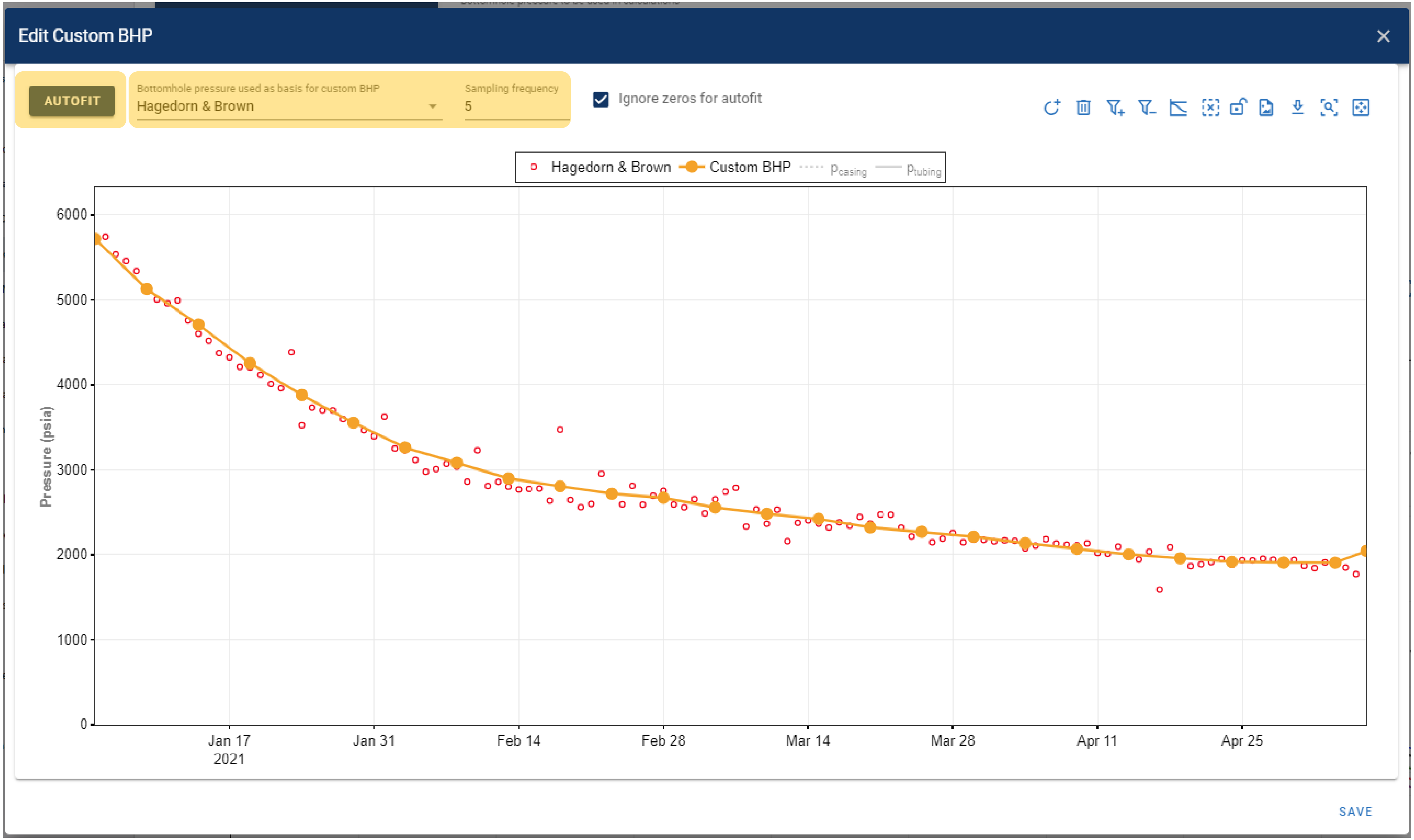


Exercise 1.b

Custom p_{wf}

p_{wf} Smoothing

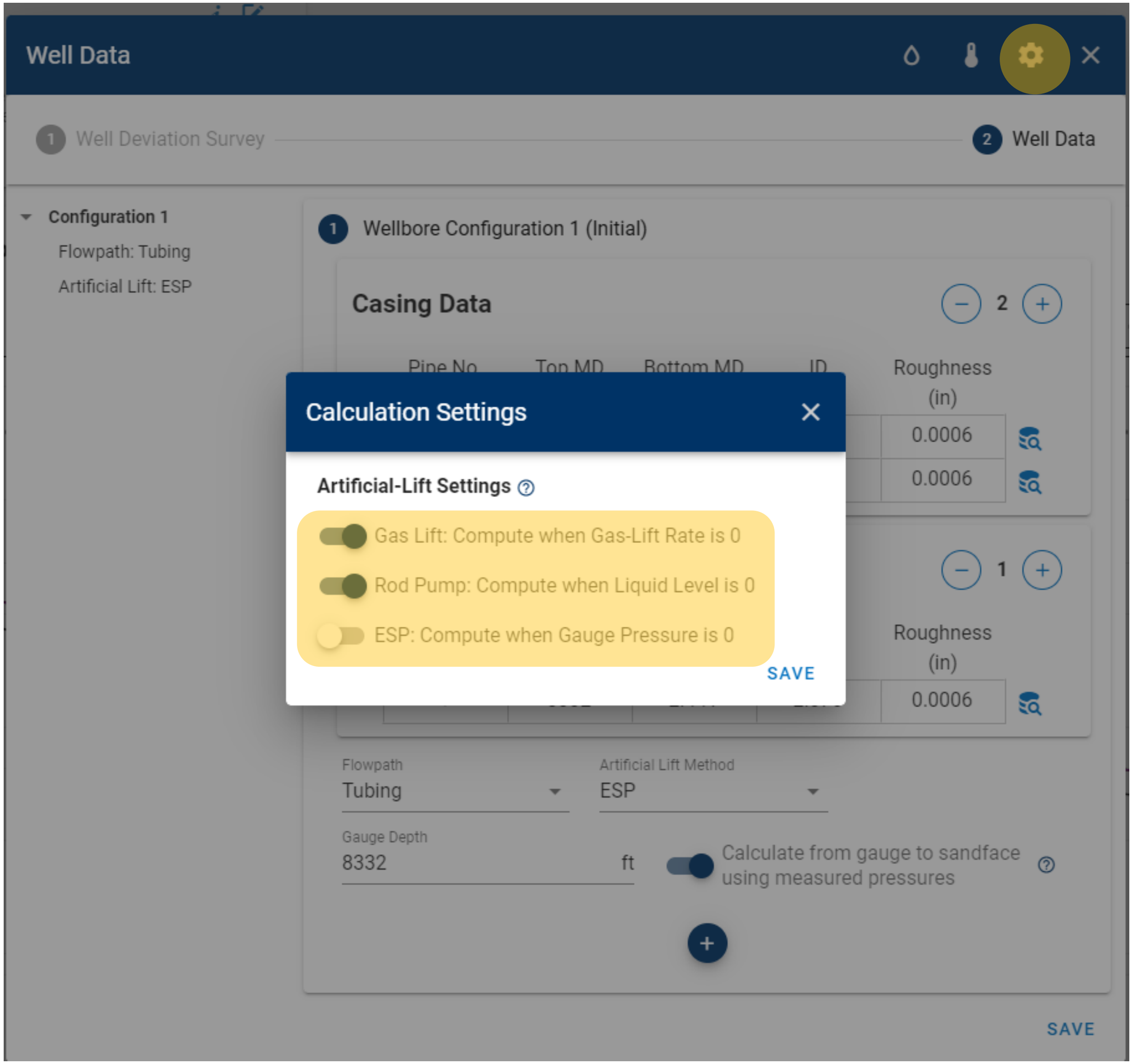
Custom p_{wf} / p_{wf} Smoothing



Exercise 1.c

BHP Calculation Settings

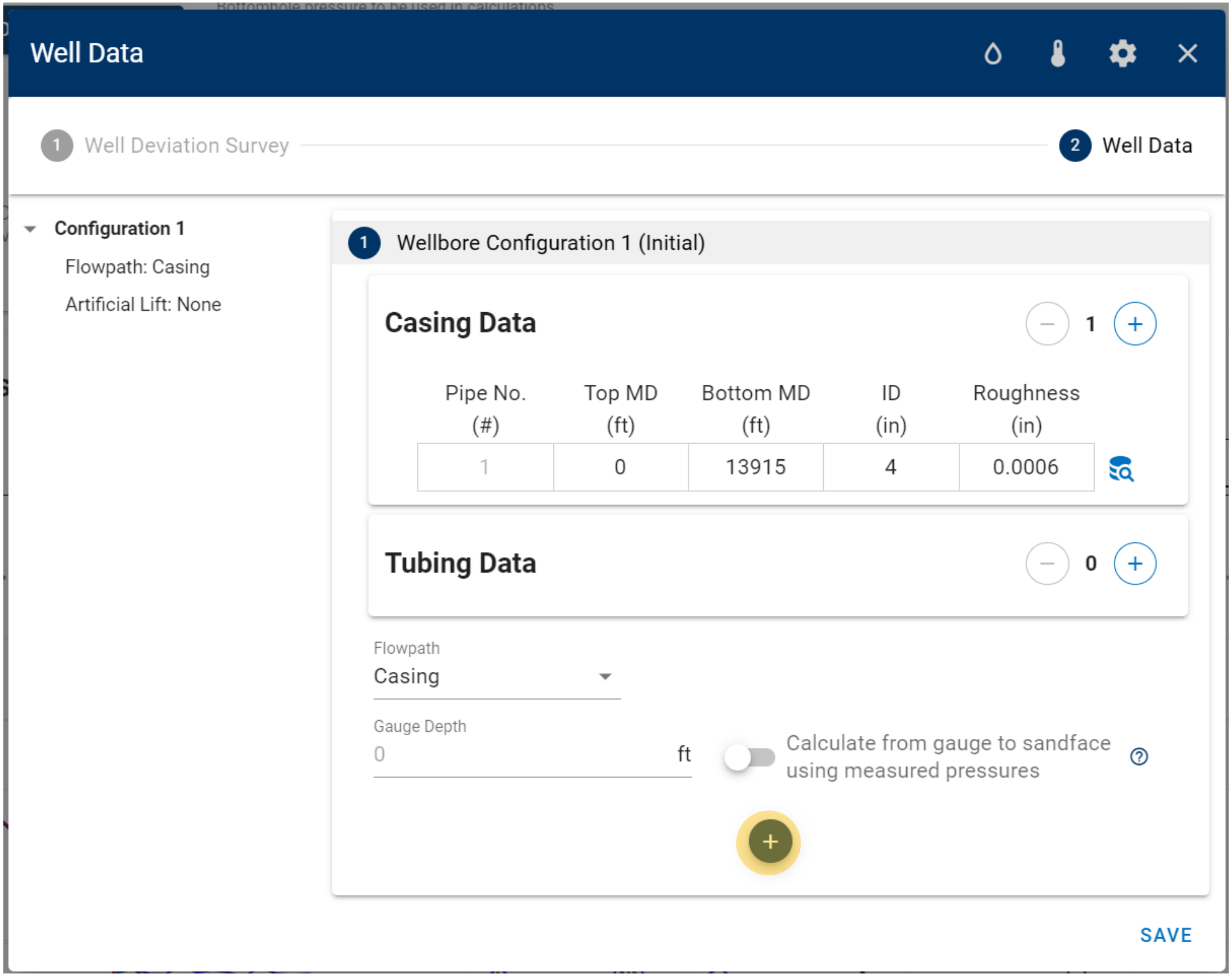
BHP Calculation Settings



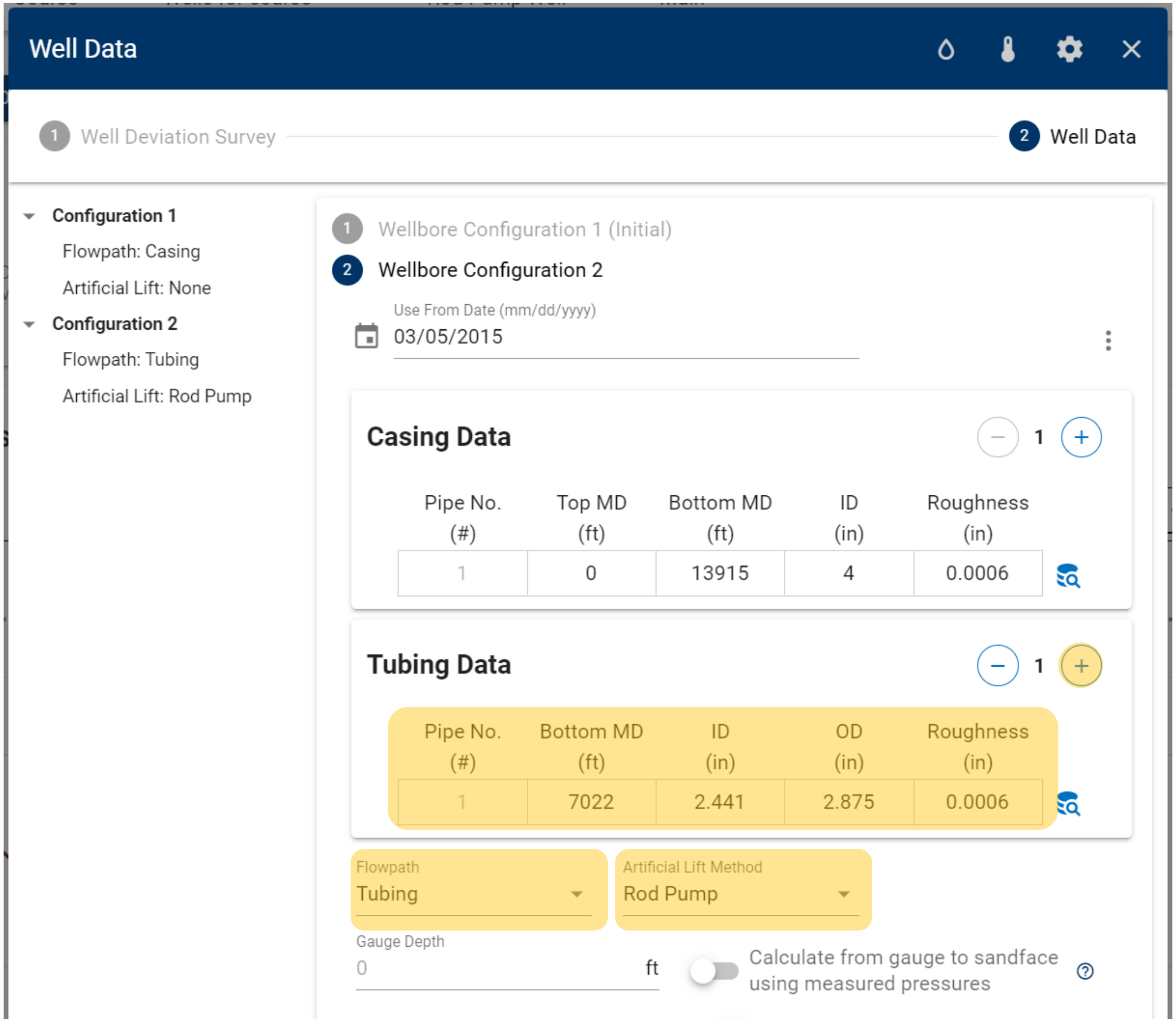
Exercise 1.d

BHP Calculations well with rod pump

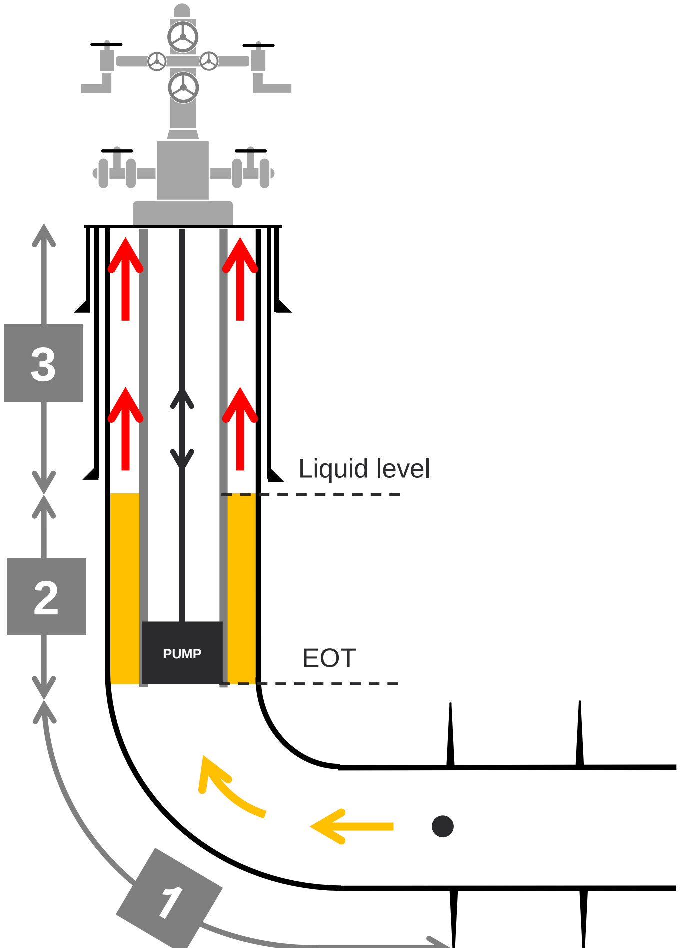
Well Data – Add New Configuration



Well Data – Select Rod Pump AL Method



Artificial Lift—Rod Pump



Three Well Segments

1) Top Perforation to EOT:
Regular multiphase pipe flow

2) EOT to Liquid Level in Annulus:
Stagnant column of liquid and gas

3) Liquid Level in Annulus to Wellhead
Single-phase gas flow

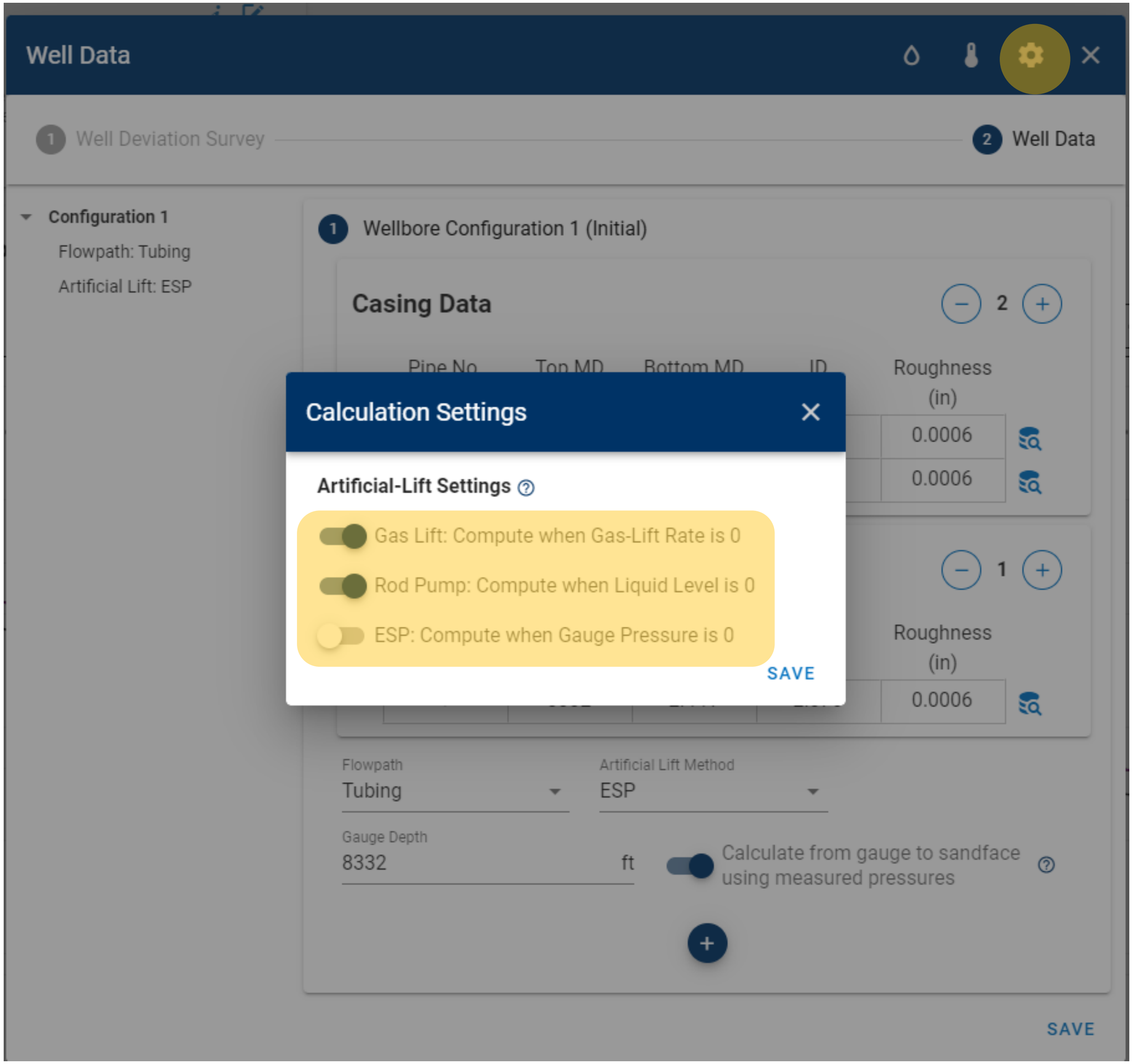
Quiz !

Bottomhole Pressure
DATES
Reservoir Pressure
5400
psia
p_wf, gauge
Beggs & Brill
Hagedorn & Brown
Woldesemayat & Ghajar
Gray
p_tubing
p_casing
p_res_i
p_sat
Choke Size
What is happening here?
(Mar 19, 2015, 2,823.085)
Gray
Pressure (psia)
Choke Size (in/64)
5000
4000
3000
2000
1000
1
0.5
0
−0.5
−1
Jan 11
2015
Jan 25
Feb 8
Feb 22
Mar 8
Mar 22
Apr 5
Apr 19

Quiz !

Bottomhole Pressure
DATES
Reservoir Pressure
5400
psia
pwf, gauge
Beggs & Brill
Hagedorn & Brown
Woldesemayat & Ghajar
Gray
ptubing
pcasing
pres_i
psat
Choke Size
Pressure (psia)
Choke Size (in/64)
5000
4000
3000
2000
1000
1
0.5
0
−0.5
−1
Jan 11
2015
Jan 25
Feb 8
Feb 22
Mar 8
Mar 22
Apr 5
Apr 19
(Mar 19, 2015, 2,823.085)
Gray
How to fix it?

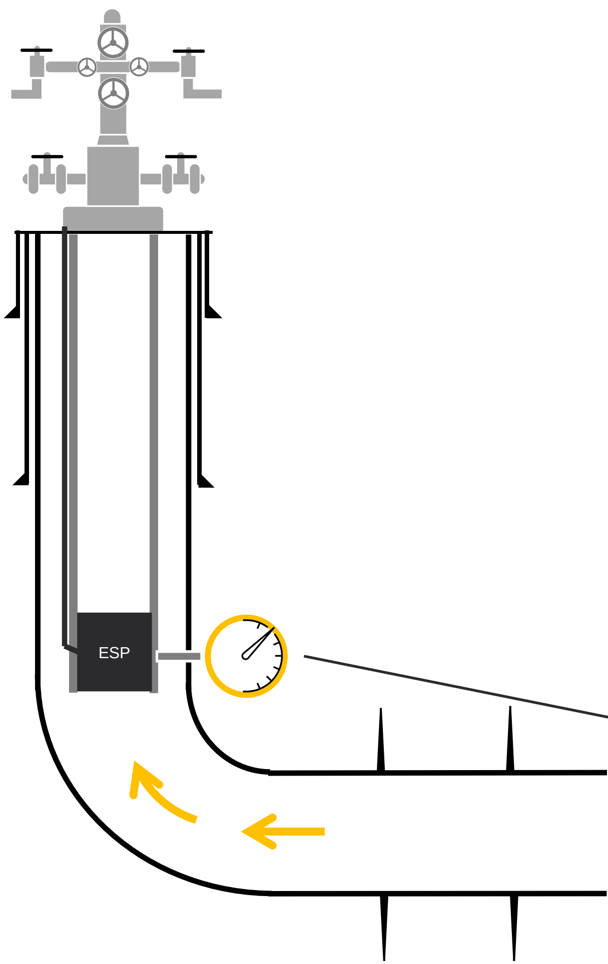
BHP Calculation Settings

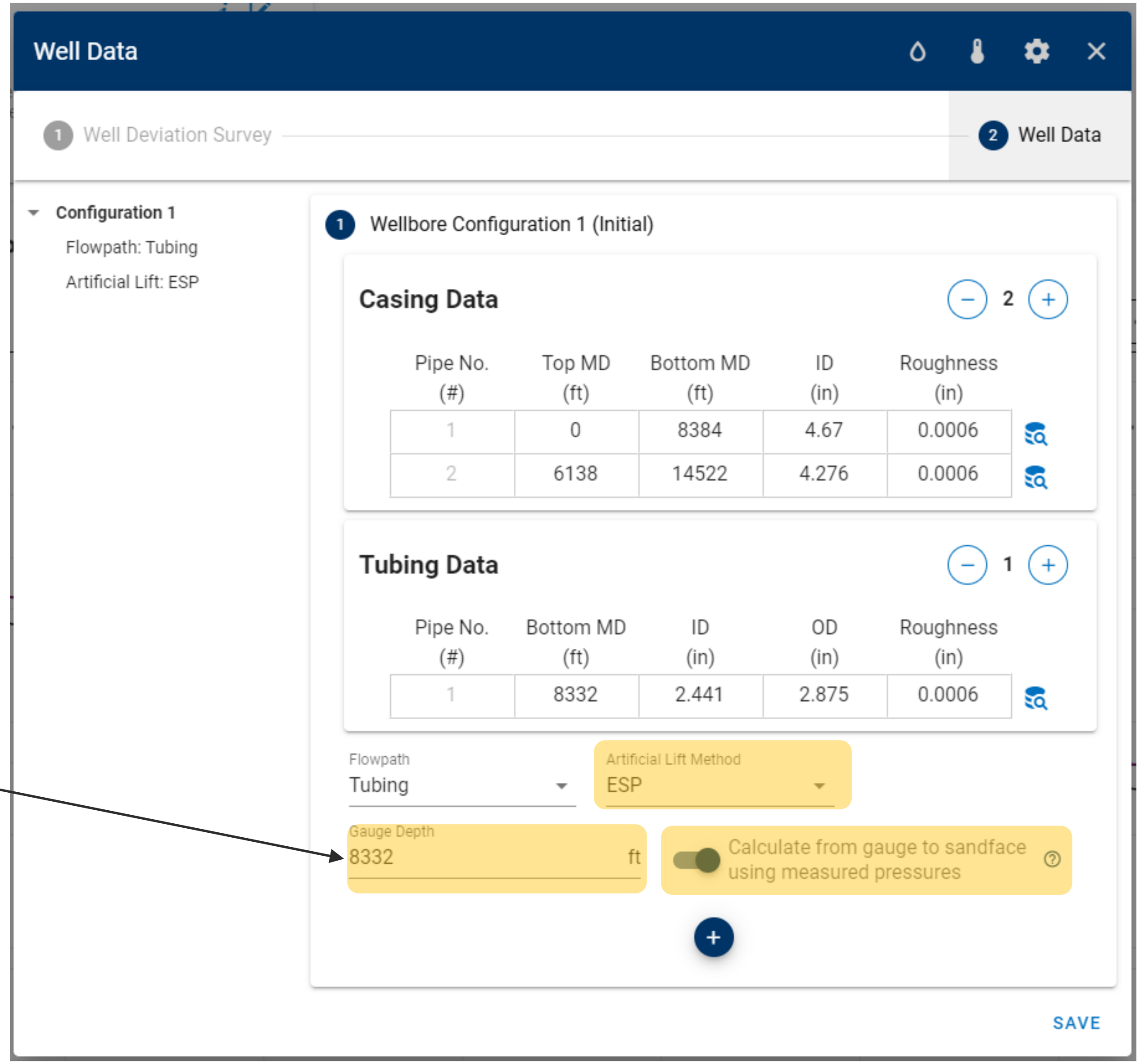


Exercise 1.e

BHP Calculations well on ESP

BHP Calculation – Well on ESP





Exercise 1.f

BHP Calculations on a Dry Gas Well (Liquid Loading)

BHP Calculation – Well on ESP

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Nodal Analysis

Graham Helfrick

2 October 2024

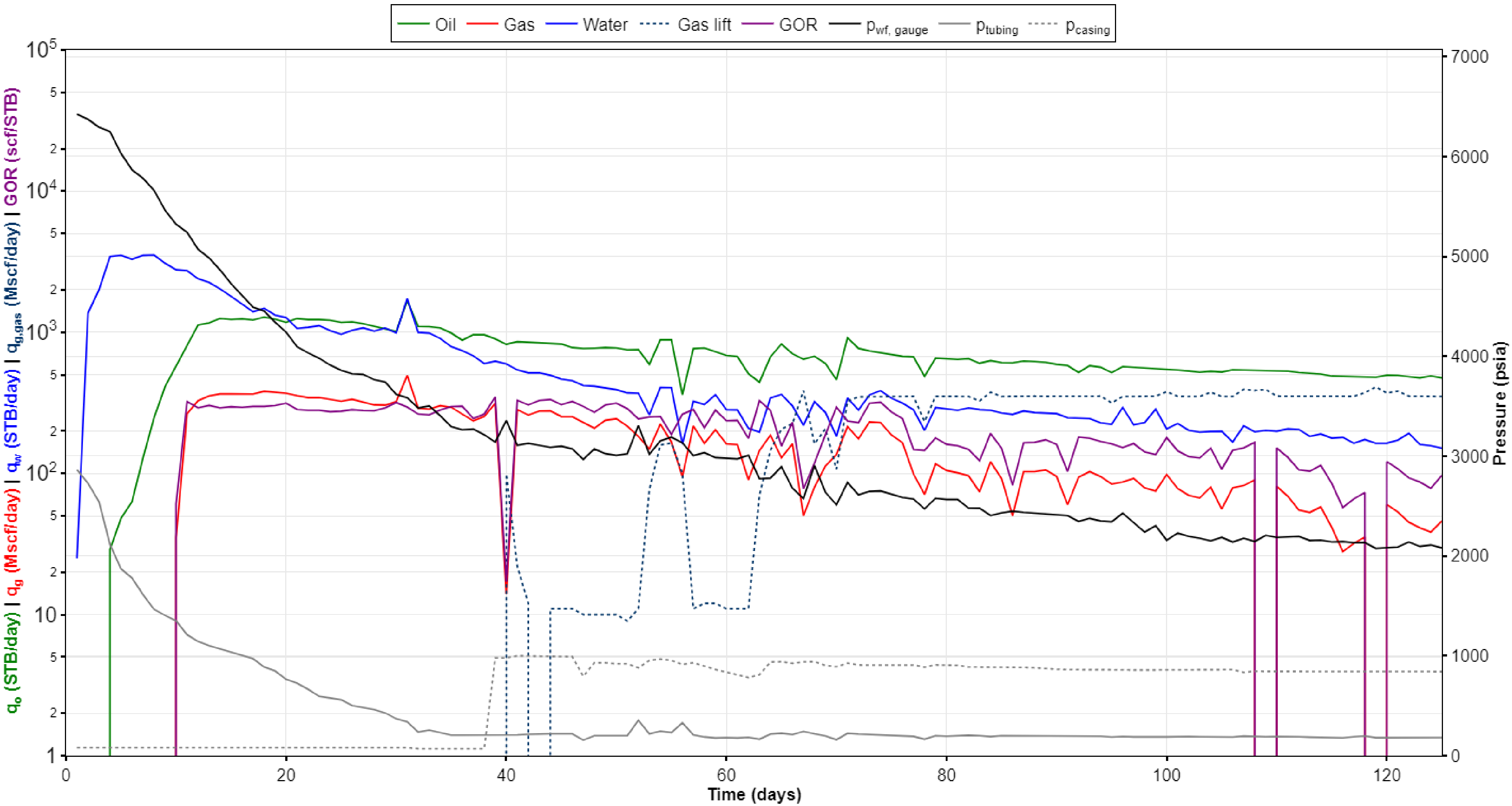
½ Day Course

(Included in your subscription!)

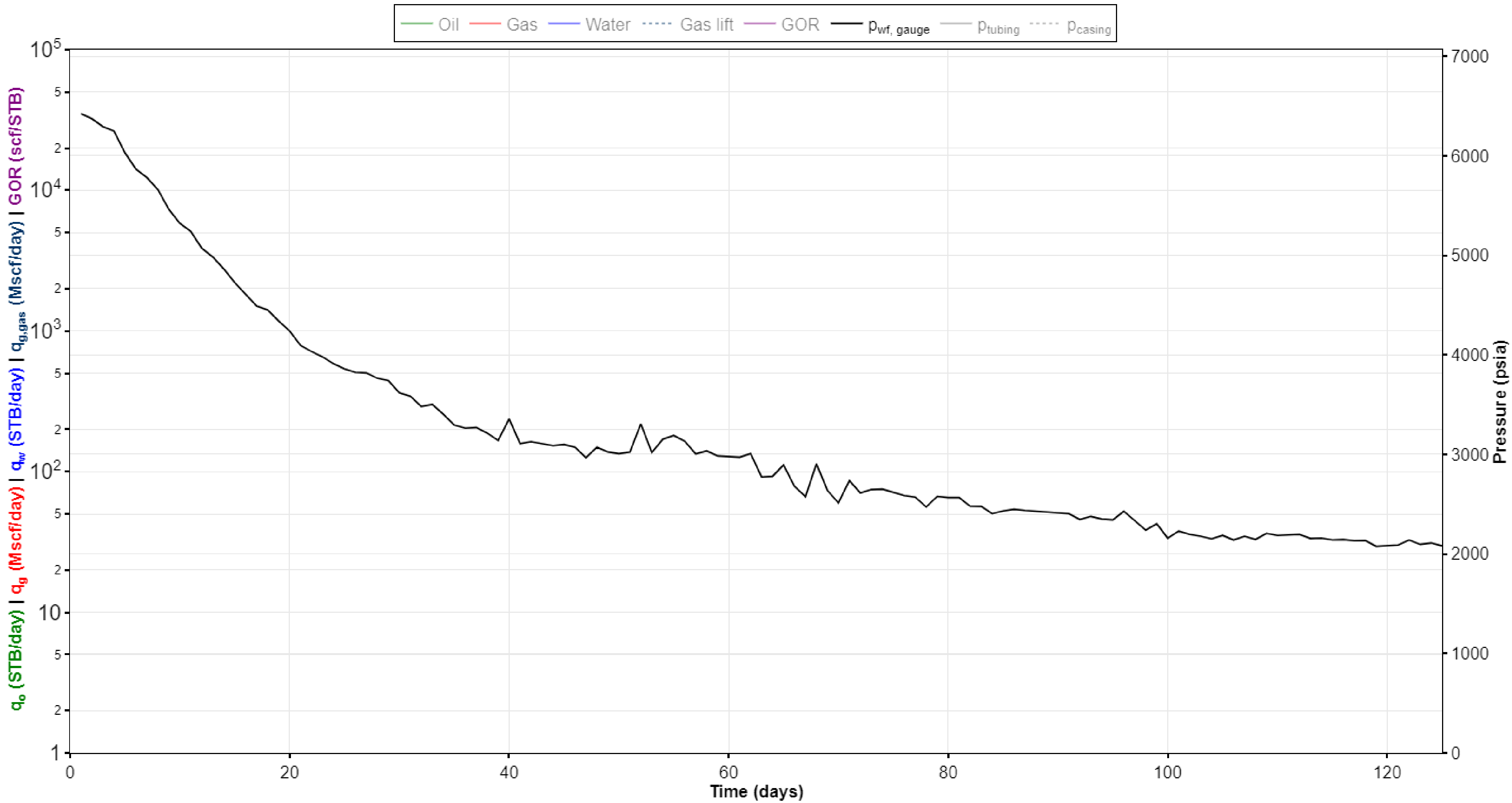
Exercise 2

BHP Correlation Tuning to Measured Gauge Data

BHP Tuning – Measured Gauge Pressures



BHP Tuning – Measured Gauge Pressures



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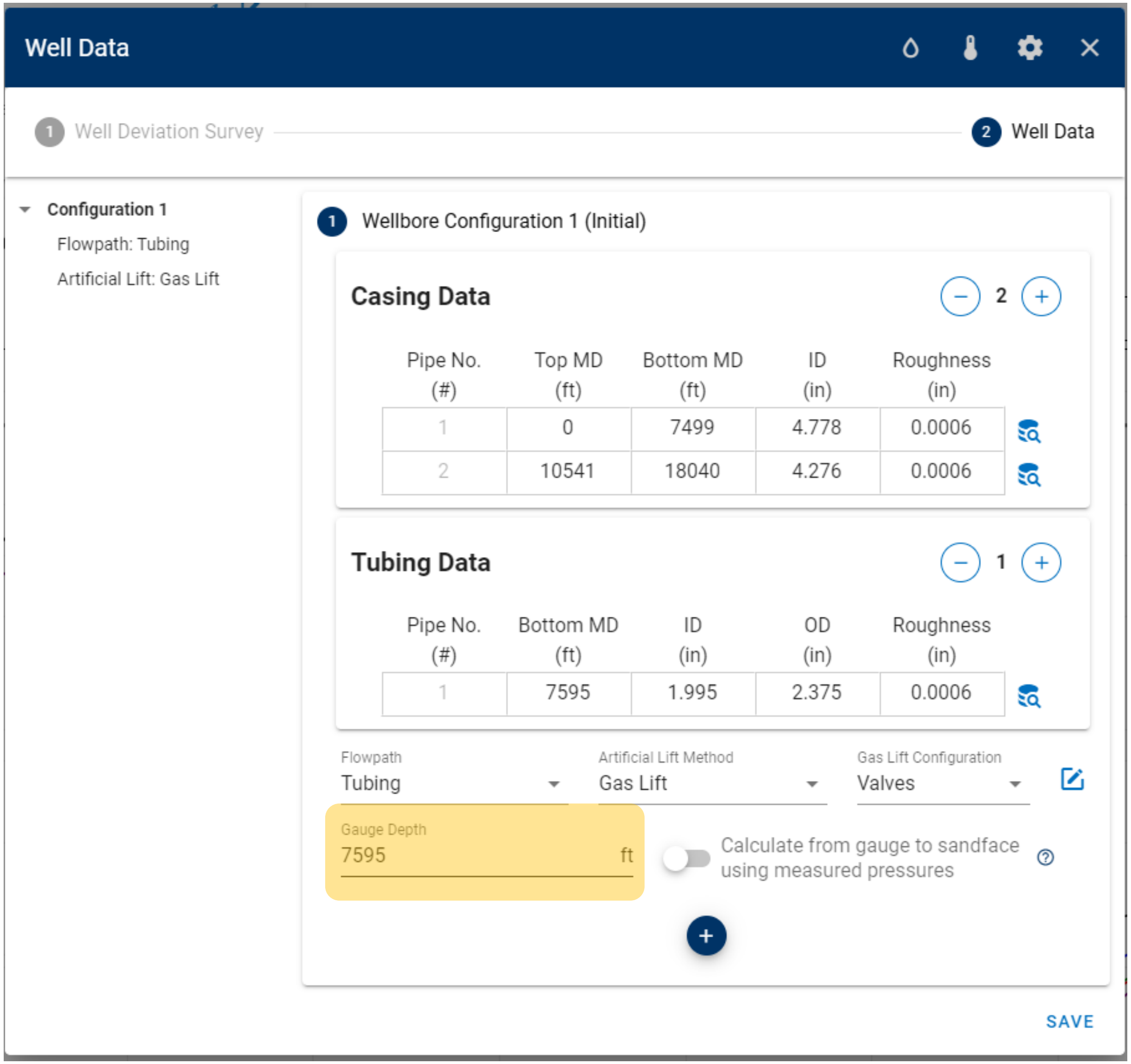
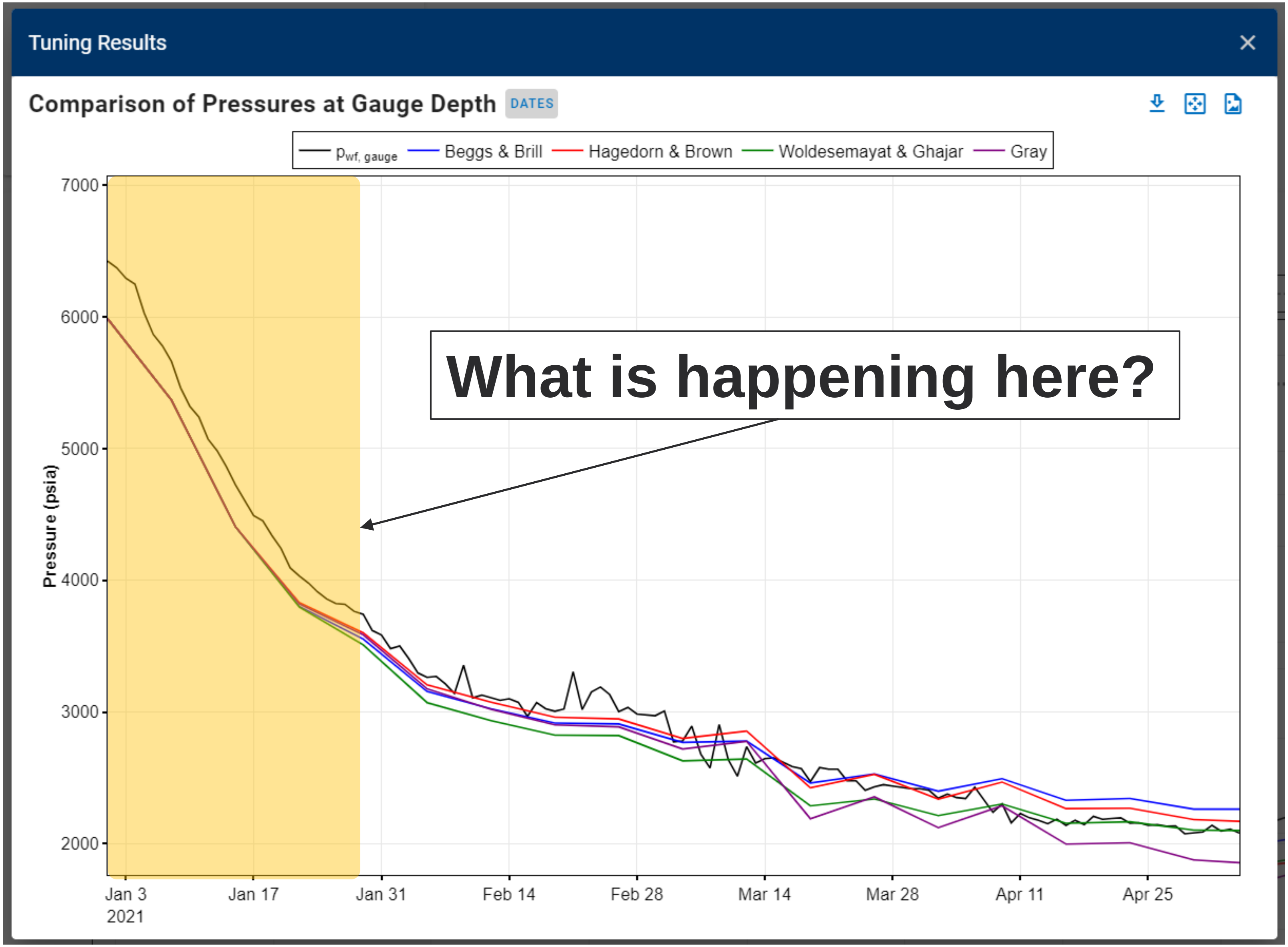
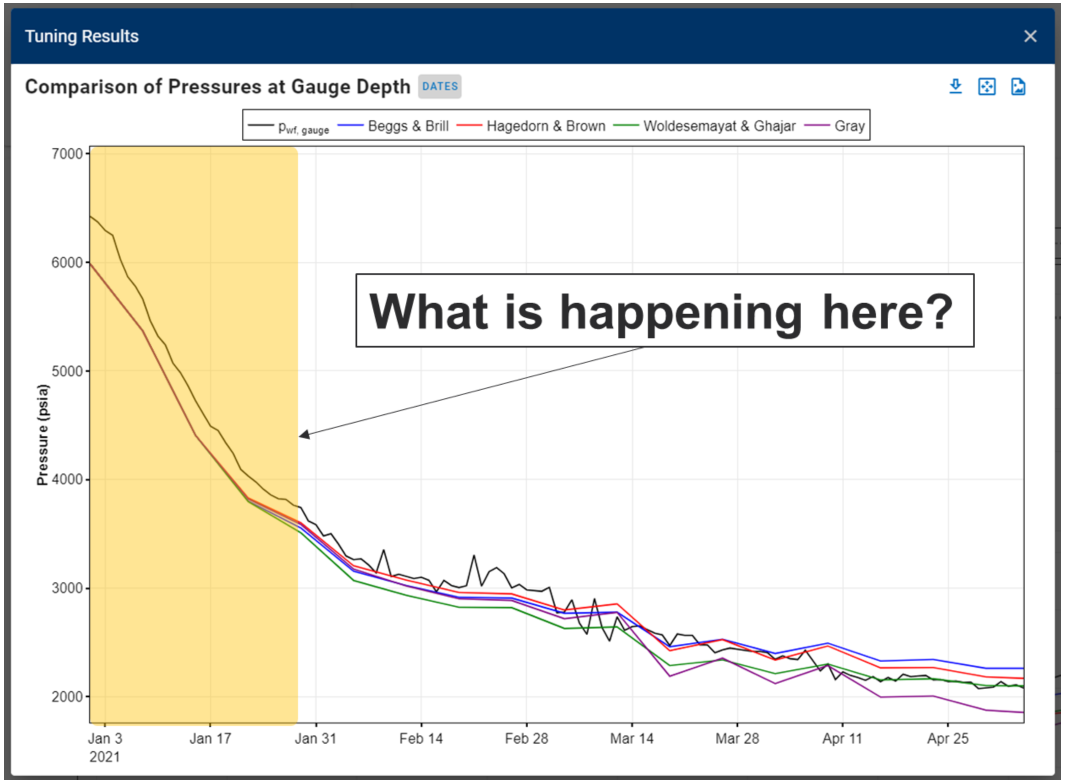
BHP Tuning – Gauge Depth



BHP Tuning – 1st Iteration



BHP Tuning – 1st Iteration



This is the region where the wellbore is still filled with **single phase fluid**.

For this **single phase** region, tuning the **multiphase correlations** doesn't make much sense.

Instead we need to adjust the fluid densities which is done through:

- PVT (for oil & gas densities)
- water salinity (for water density)

Always start with salinity if you have a single phase region.

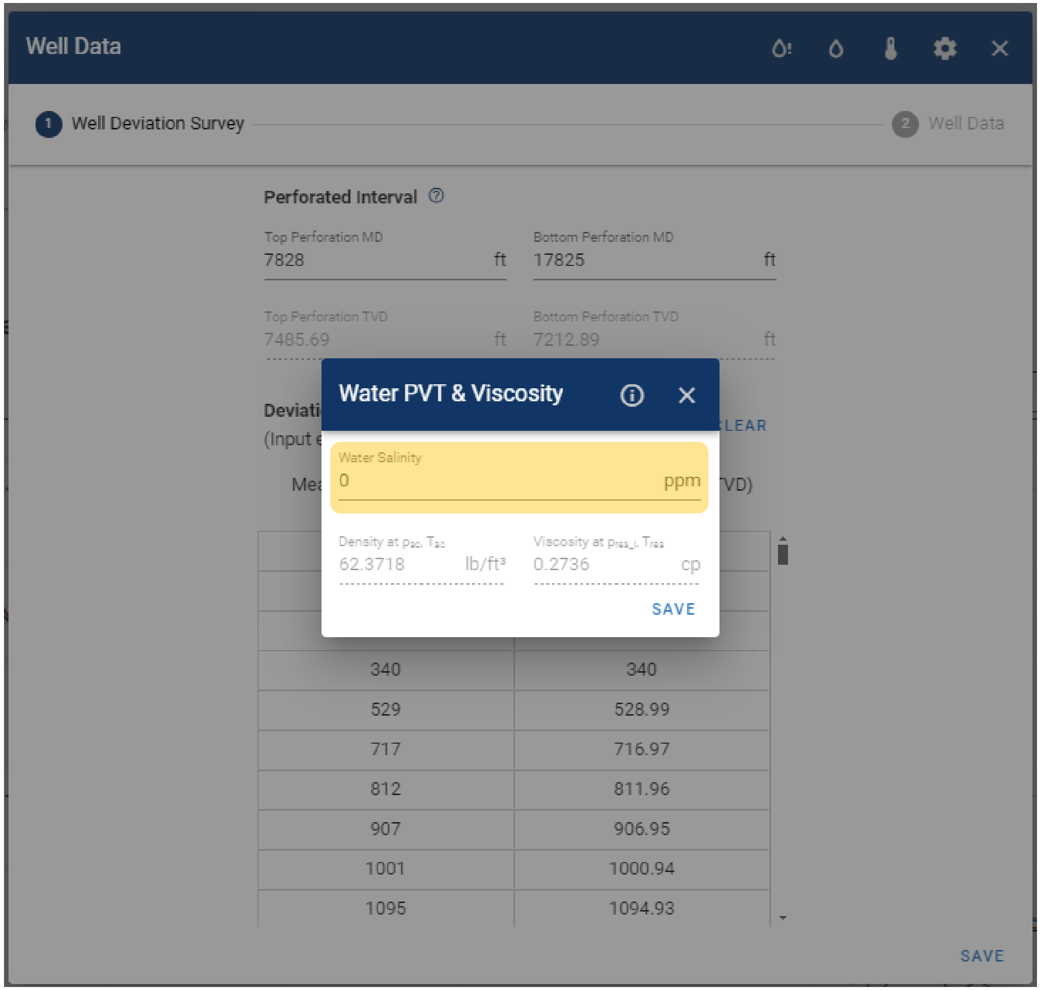
BHP Tuning – 2nd Iteration (Salinity)

Adjust salinity iteratively until the single phase region gives a better match.

For this exercise, we can focus on the **Hagedorn & Brown** correlation only.

As a reference

- **Sea water salinity:** 10k – 35k ppm
- **Brine salinity:** 35k – 250k ppm



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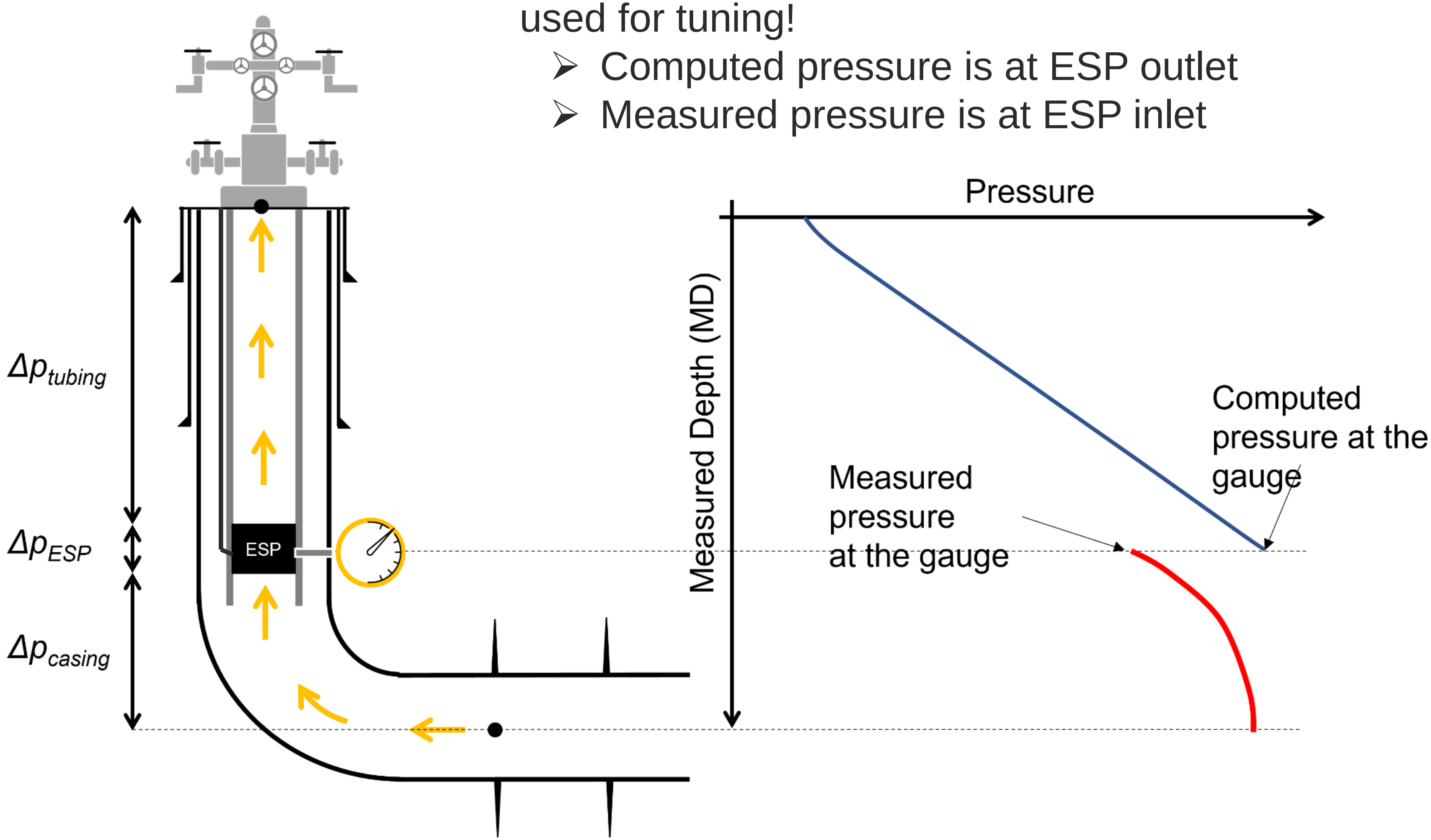
REMINDER: Tuning of Correlations with ESP

Caution

- Measured pressures from an ESP should not be used for tuning!
  - Computed pressure is at ESP outlet
  - Measured pressure is at ESP inlet



Exercise 3

BHP using Mass Upload Sheet

(Multiple Wells)

Mass Upload – Production Data

	A	B	C	D	E	K	L	M	N
1	**Well**	**Time**	**Stock Tank Rates**			**Measured Pressures, Temperatures and Gas-Lift Rates**			
2	**Name**	**Date**	q_o	q_g	q_w	p_{wf}	p_{tubing}	p_{casing}	$q_{g,gas\ lift}$
3	**-**	**-**	**STB/d**	**Mscf/d**	**STB/d**	**psia**	**psia**	**psia**	**Mscf/d**
4	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-01 00:00	504.39	145.0	718	5050	15	2065	
5	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-02 00:00	564.76	186.0	922	5010	15	1990	
6	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-03 00:00	653.51	231.0	753	4796	15	1865	
7	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-04 00:00	740.71	268.0	700	4697	15	1815	
8	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-05 00:00	678.06	261.0	530	4547	15	1715	
9	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-06 00:00	789.29	329.0	580	4886	15	2065	
10	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-07 00:00	915.05	303.0	700	4106	15	1285	
11	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-08 00:00	797.53	260.0	590	3994	15	1185	
12	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-09 00:00	777.06	252.0	530	3853	15	1065	
13	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-10 00:00	710.58	236.0	429	3754	15	995	
14	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-11 00:00	675.50	223.0	380	3658	15	915	
15	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-12 00:00	635.51	210.0	343	3589	15	855	
16	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-13 00:00	705.49	237.0	360	3445	15	725	
17	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-14 00:00	638.78	208.0	332	3388	15	665	
18	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-01-15 00:00	735.32	247.0	392	3203	15	505	

Mass Upload – Deviation Survey

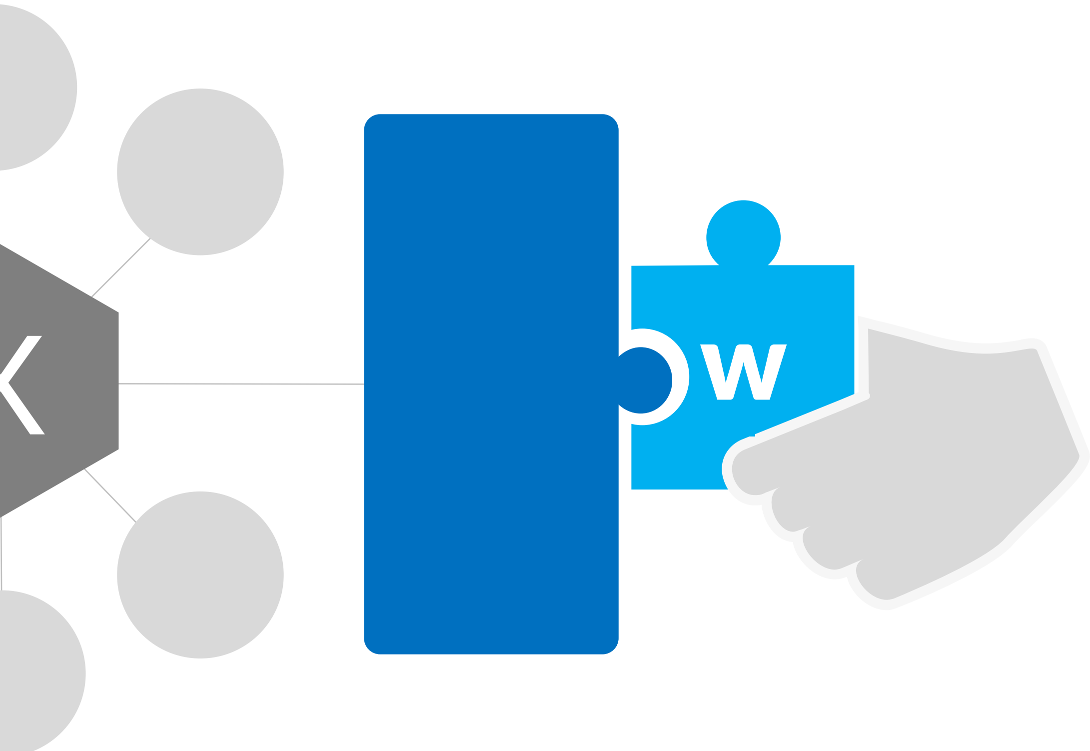
	A	B	C
1	**Well Name**	**MD**	**TVD**
2	**-**	**ft**	**ft**
3	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	0	0
4	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	95.1	95.1
5	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	153.6	153.6
6	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	214.8	214.8
7	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	273.1	273.1
8	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	333.9	333.9
9	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	393	393
10	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	454	454
11	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	513.6	513.6
12	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	576.8	576.8
13	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	640	640
14	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	703.3	703.3
15	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	766.3	766.3
16	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	829.5	829.5

Mass Upload – Wellbore Data

A1 Well Name

	A	E	F	G	H	I	J	K	L	M
1	**Well Name**	**Use from Date**	**Flowpath**	**Wellhead Temperature**	**Tubing Bottom MD**	**Tubing ID**	**Tubing OD**	**Tubing Roughness**	**Casing 1 Top MD**	**Casing 1 Bottom MD**
2	**-**	**yyyy-mm-dd or empty**	**select from list**	**F**	**ft**	**in**	**in**	**in**	**ft**	**ft**
3	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY		Casing	70					0	13915
4	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2015-03-05	Tubing	70	7022	2.441	2.875	0.0006	0	7029
5	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2018-01-05	Tubing	70	6764	2.441	2.875	0.0006	0	6941
6	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2018-07-26	Tubing	70	6825	2.441	2.875	0.0006	0	6941
7	SPE-DATA-REPOSITORY-DATASET-1-WELL-1-OSPREY	2019-05-22	Tubing	70	6764	2.441	2.875	0.0006	0	6941
8	SPE-DATA-REPOSITORY-DATASET-1-WELL-2-HAWK	2021-01-01	Tubing	60	7325	1.995	2.375	0.0006	0	7549
9	SPE-DATA-REPOSITORY-DATASET-1-WELL-3-EAGLE	2017-01-01	Tubing	60	7500	2.441	2.875	0.0006	0	15493
10	SPE-DATA-REPOSITORY-DATASET-1-WELL-4-KITE	2018-01-01	Tubing	65	8332	2.441	2.875	0.0006	0	8384
11	SPE-DATA-REPOSITORY-DATASET-1-WELL-5-SWIFT	2018-01-01	Tubing	70	7626	2.441	2.875	0.0006	0	7693
12	SPE-DATA-REPOSITORY-DATASET-1-WELL-5-SWIFT	2020-06-17	Tubing	70	7626	2.441	2.875	0.0006	0	7693
13	SPE-DATA-REPOSITORY-DATASET-1-WELL-6-SPARROW	2018-01-01	Tubing	70	7682	2.441	2.875	0.0006	0	7559
14	SPE-DATA-REPOSITORY-DATASET-1-WELL-6-SPARROW	2020-06-12	Tubing	70	7682	2.441	2.875	0.0006	0	7559
15	SPE-DATA-REPOSITORY-DATASET-1-WELL-7-LARK	2019-01-01	Tubing	70	8174	2.441	2.875	0.0006	0	7975
16	SPE-DATA-REPOSITORY-DATASET-1-WELL-7-LARK	2020-03-17	Tubing	70	8174	2.441	2.875	0.0006	0	7975
17	SPE-DATA-REPOSITORY-DATASET-1-WELL-8-CARDINAL	2019-01-01	Tubing	70	8211	2.441	2.875	0.0006	0	8031
18	SPE-DATA-REPOSITORY-DATASET-1-WELL-8-CARDINAL	2020-05-12	Tubing	70	8211	2.441	2.875	0.0006	0	8031
19	SPE-DATA-REPOSITORY-DATASET-1-WELL-9-JAY	2019-01-01	Tubing	70	8050	2.441	2.875	0.0006	0	7905
20	SPE-DATA-REPOSITORY-DATASET-1-WELL-9-JAY	2020-05-13	Tubing	70	8050	2.441	2.875	0.0006	0	7905
21	SPE-DATA-REPOSITORY-DATASET-1-WELL-10-CROW	2020-01-01	Tubing	70	8000	1.995	2.375	0.0006	0	7940
22	SPE-DATA-REPOSITORY-DATASET-1-WELL-11-FALCON	2021-02-09	Tubing	60	7595	1.995	2.375	0.0006	0	7499

API & Database



Plug-in API

Plug our API into already existing databases and solutions

DB Connection

Expose your DB tables to us and we will make the updates

Input & Output

Flexible API allows for two way communication and dataflow

Appendix

Multiphase Flow

No Slip:

- Assumes gas and liquid flow with the same velocity

$$v_g = v_L$$

- Define liquid-flux fraction

$$C_L = \frac{q_L}{q_L + q_g}$$

- Gas and liquid properties are averaged by

$$\rho_m = C_L \rho_L + (1 - C_L)\rho_g$$

$$\mu_m = C_L \mu_L + (1 - C_L)\mu_g$$

Slip:

- Assumes gas flows faster than liquid

$$v_g \geq v_L$$

- Define liquid hold-up (=*1−void fraction*)

$$H_L = \frac{A_L}{A_L + A_g}$$

$$H_L = \frac{q_L}{q_L + \frac{v_L}{v_g} q_g} \overset{v_g \geq v_L}{\geq} \frac{q_L}{q_L + q_g} = C_L$$

- Gas and liquid properties are averaged by

$$\rho_s = H_L \rho_L + (1 - H_L)\rho_g$$

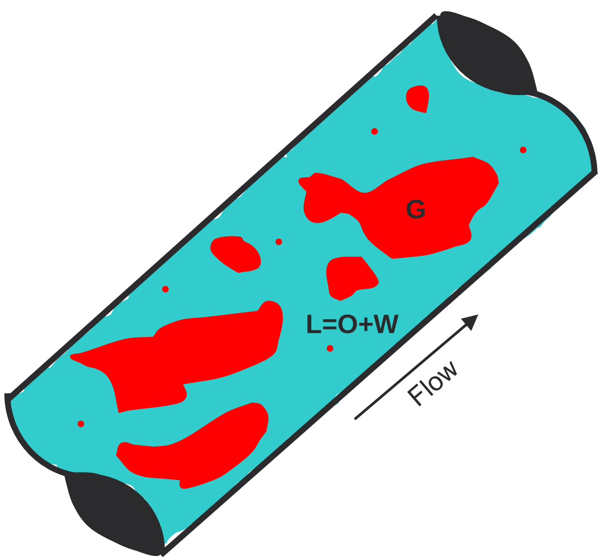
$$\mu_s = H_L \mu_L + (1 - H_L)\mu_g$$

Multiphase Flow—Liquid Hold-Up

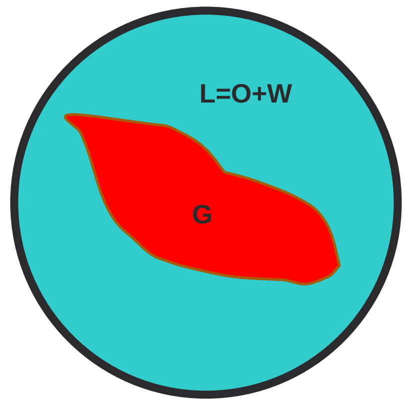
- The liquid hold-up represents the part of the pipe cross-sectional area occupied by liquid.

$$C_L = \frac{q_L}{q_L + q_g} = \frac{v_L A_L}{v_L A_L + v_g A_g} = \frac{A_L}{A_L + \frac{v_g}{v_L} A_g}$$

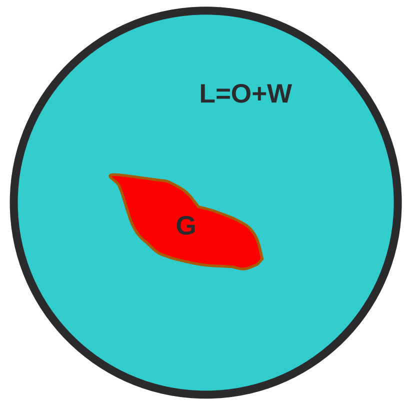
If $v_g > v_L$, then $C_L < H_L$,
→ Using C_L rather than H_L will account for too much gas in the cross-sectional area



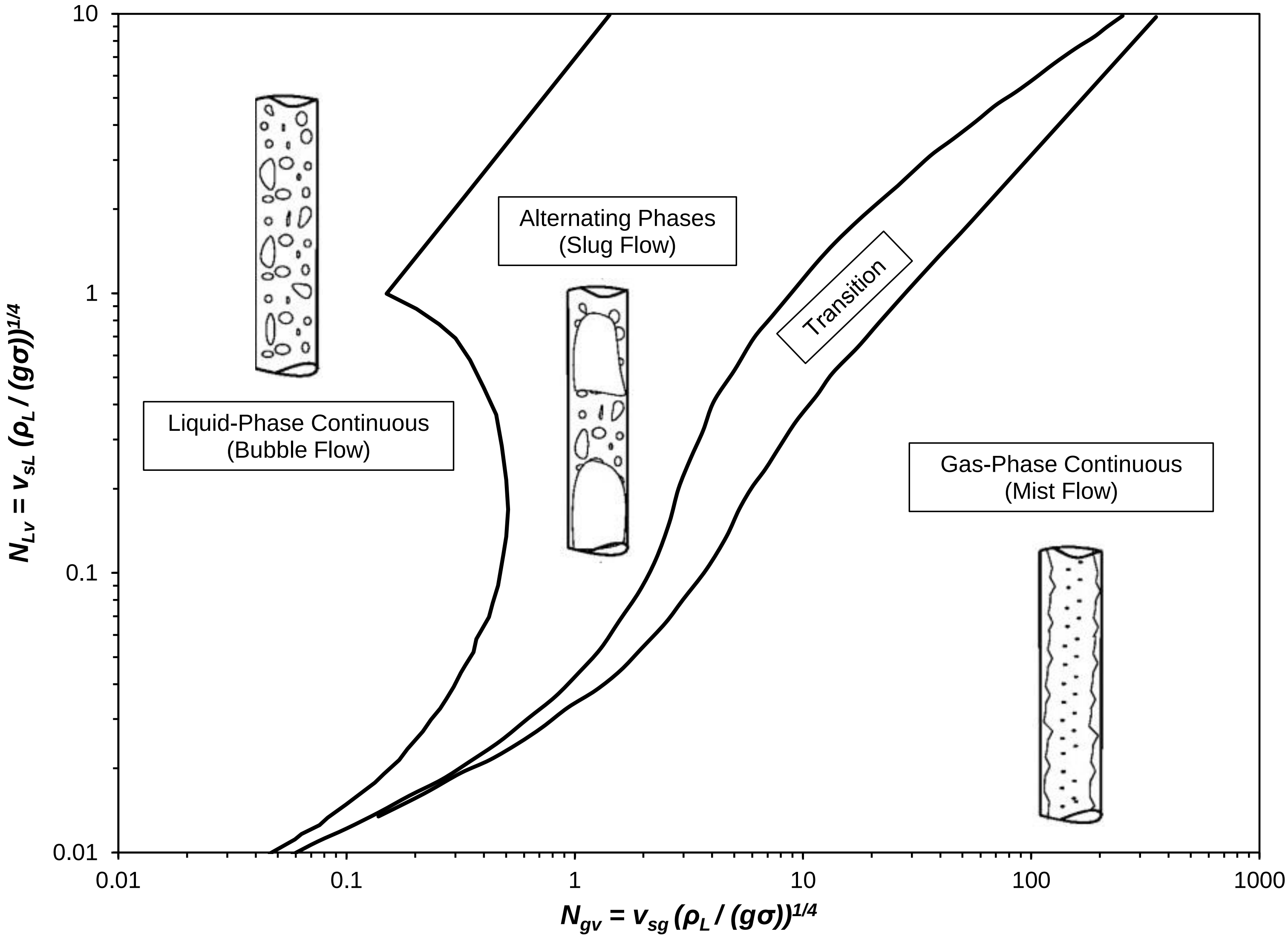
$$C_L = \frac{q_L}{q_g + q_L}$$



$$H_L = \frac{A_L}{A_g + A_L}$$



Flow Regimes—Gould et al. (1974)



Multiphase Flow—Pressure Gradient

- Velocity gradient in acceleration term is approximated as

$$\frac{dv_m}{ds} \approx -\frac{v_{sg}}{p}\frac{dp}{ds}$$

- Pressure gradient is rewritten to

$$-\frac{dp}{ds} = \frac{\rho_g \dfrac{g}{g_C}\cos(\theta) + \dfrac{f_{Ds}\rho_f v_m^2}{2d_h g_C}}{1 - \dfrac{\rho_a v_m v_{sg}}{g_C p}}$$

- The correlations provide the method of calculating the different terms in the equation

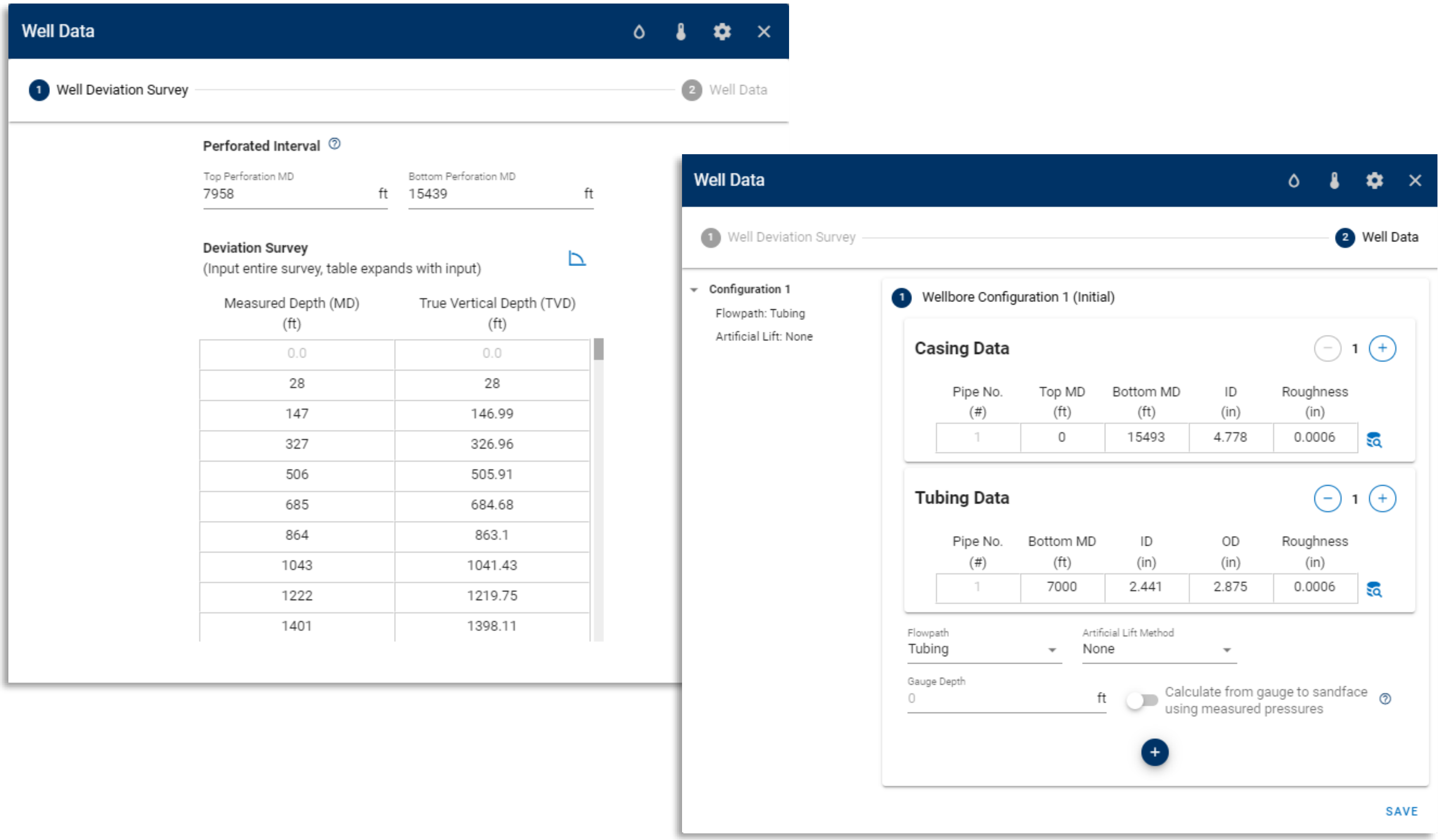
Multiphase Flow—Three Examples

- Same well configuration, three different fluids flowing

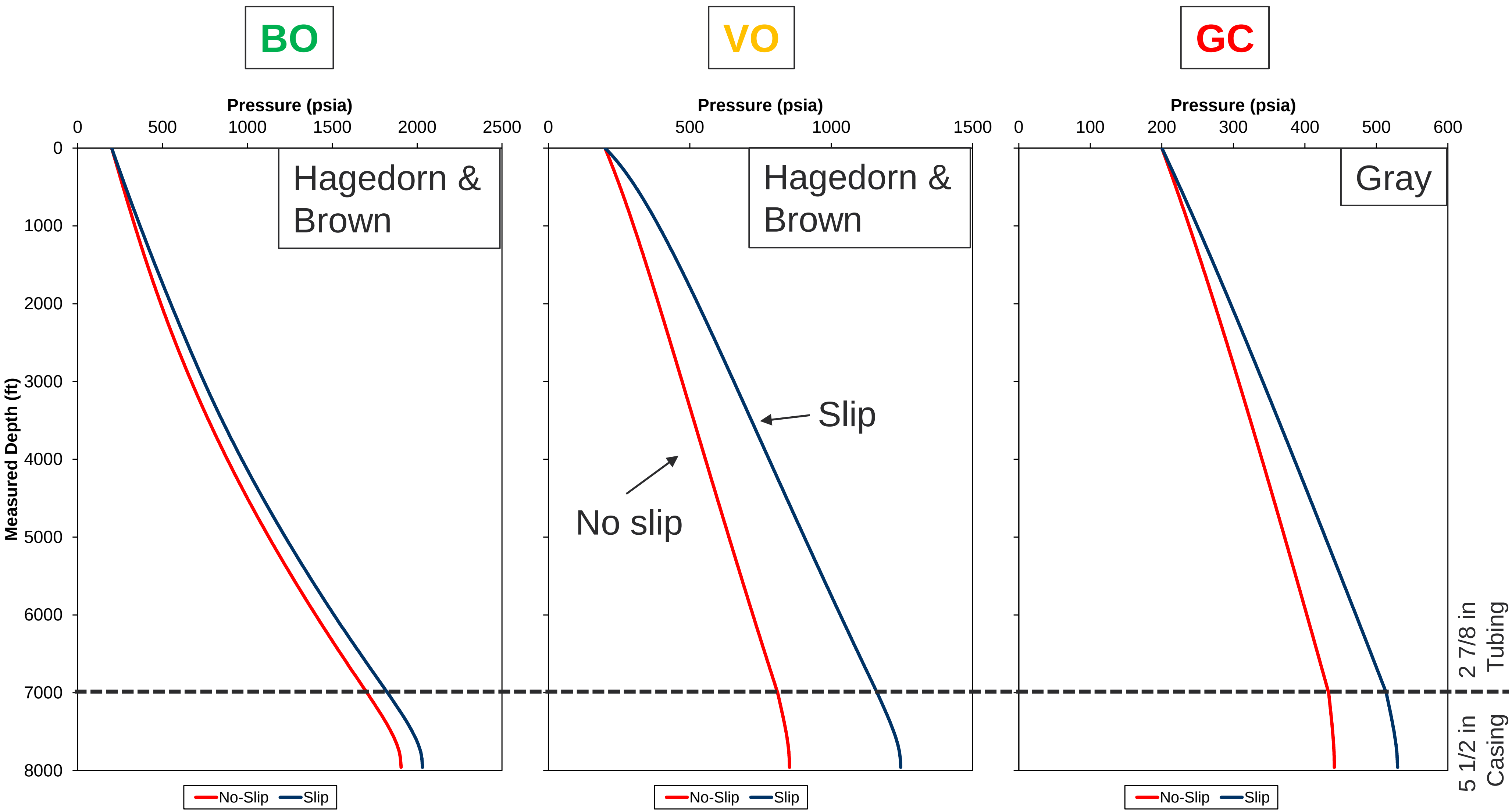
	BO	VO	GC
q_o (STB/d)	2000	1000	100
q_g (Mscf/d)	1000	2500	2500
q_w (STB/d)	100	100	5
p_{th} (psia)	200	200	200
T_{wh} (°F)	100	100	100
T_R (°F)	200	200	230
GOR (scf/STB)	500	2500	25000
WOR (STB/STB)	0.1	0.05	0.1

Multiphase Flow—Three Examples

- Same well configuration, three different fluids flowing



Multiphase Flow—Pressure Profile



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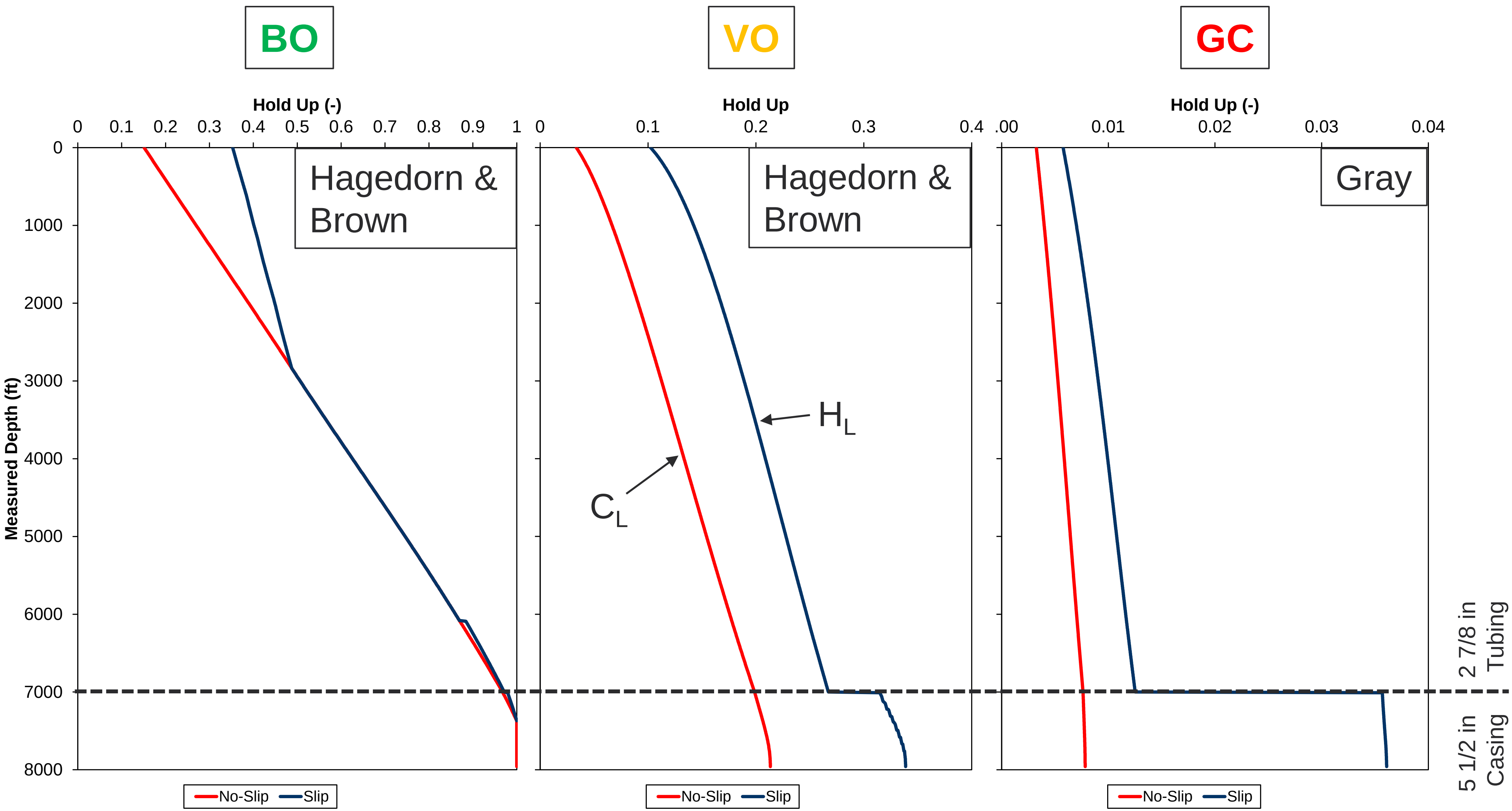
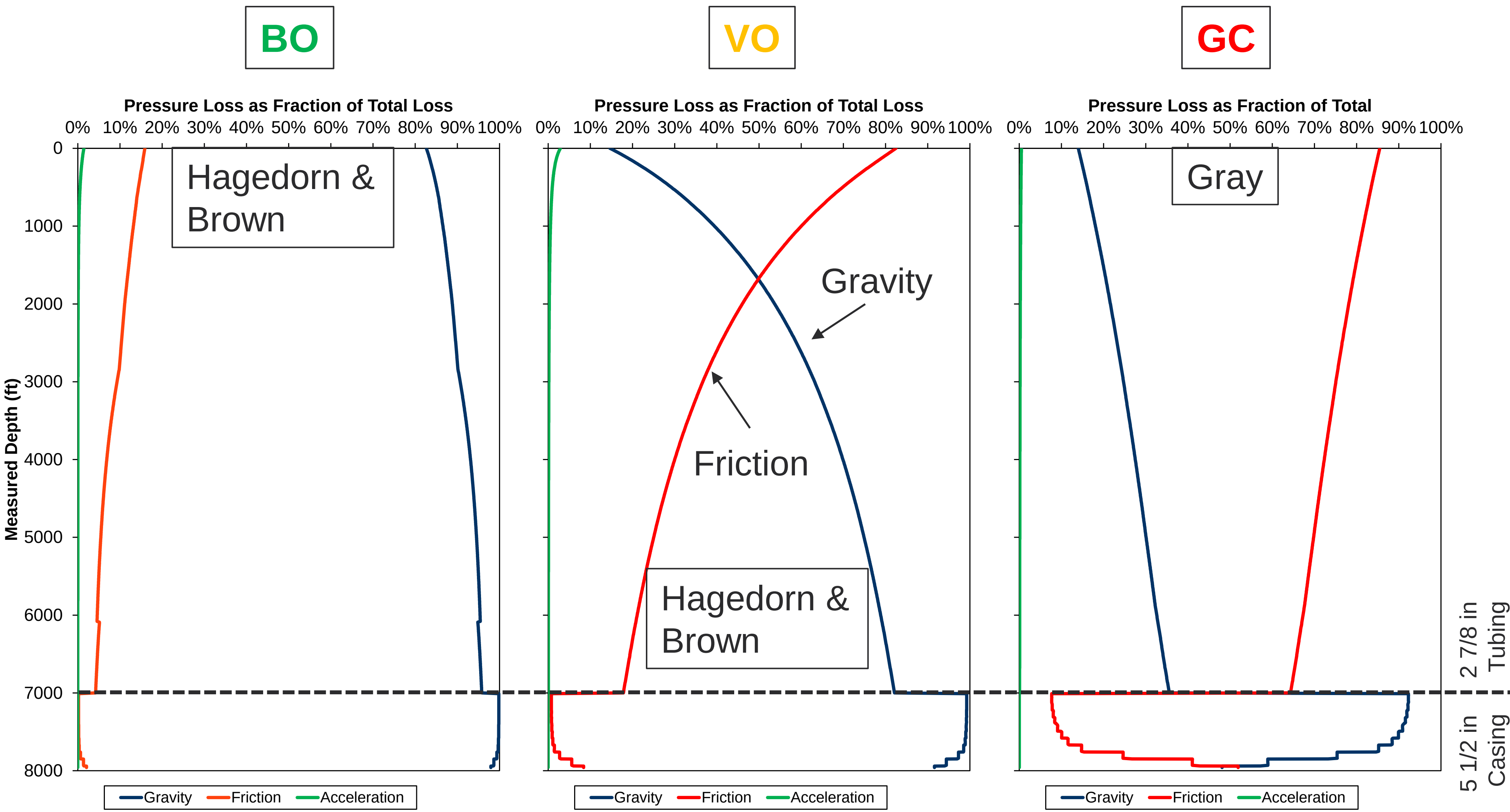
Multiphase Flow—Liquid Fractions



Multiphase Flow—Pressure Gradient



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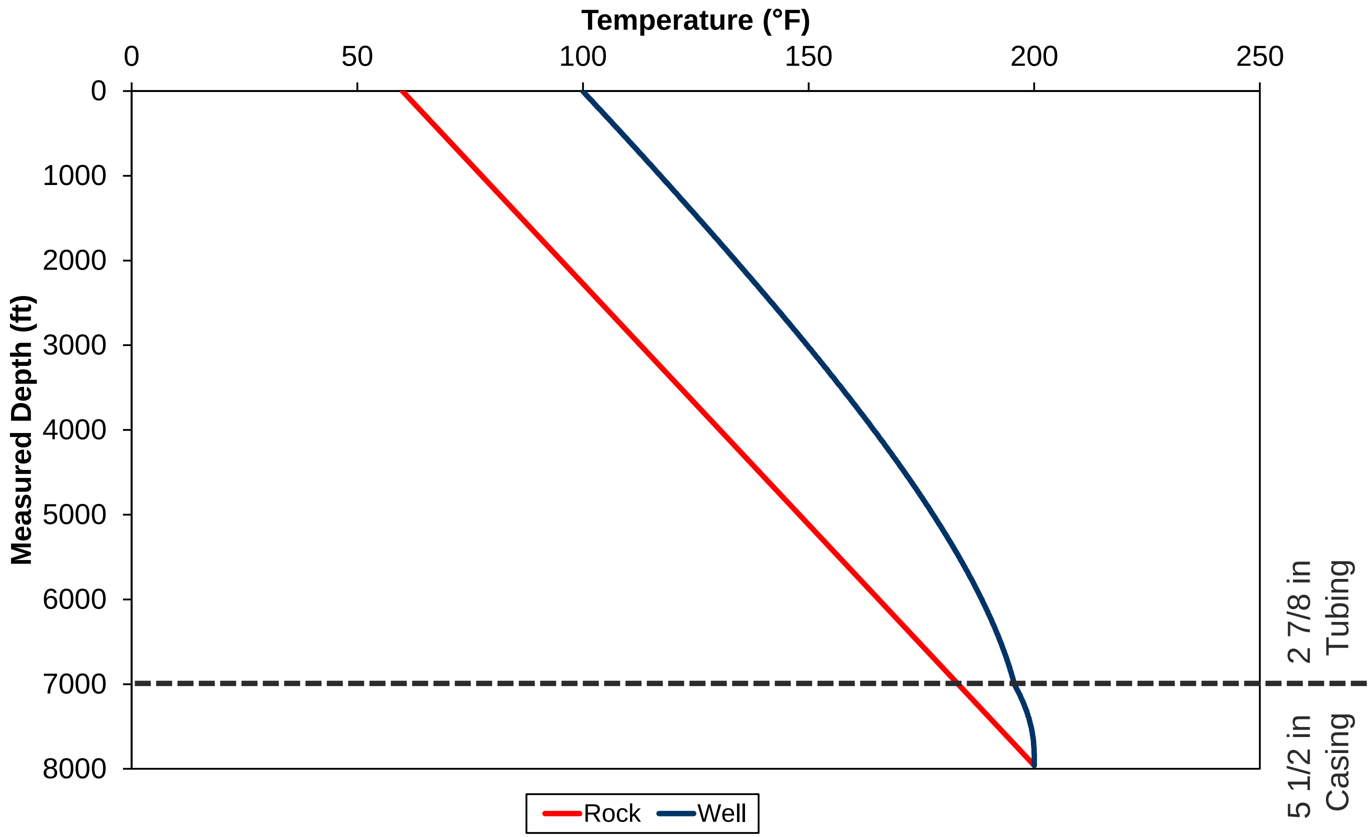
BHP Calculations—Temperature Gradient

- Simple thermodynamic relationships give a temperature gradient on the form

$$-\frac{dT}{ds}=\frac{U\pi d_h}{c_p\dot{m}}\left(T-T_{rock}\right)$$



Correlations

Correlations—Hagedorn and Brown

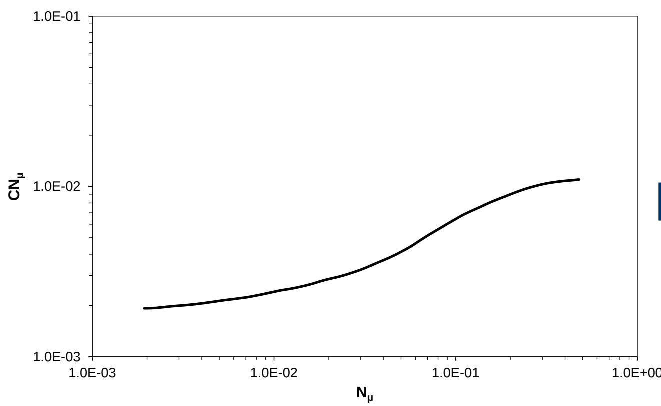
- Hagedorn and Brown (1965)
- Liquid hold-up is calculated by four dimensionless numbers and graphical lookup.

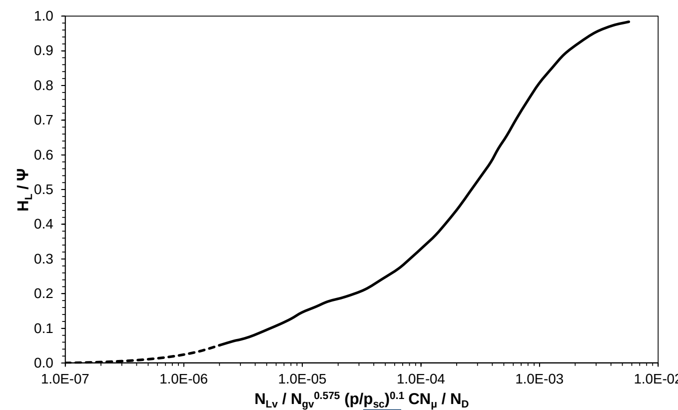
$$N_{Lv} = v_{sL}\left(\frac{\rho_L}{g\sigma}\right)^{1/4}$$

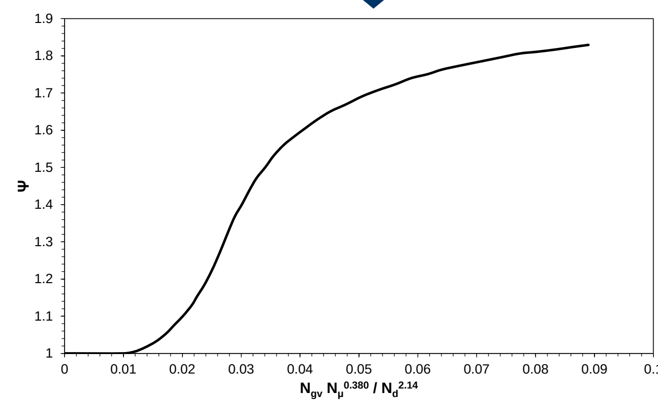
$$N_{gv} = v_{sg}\left(\frac{\rho_L}{g\sigma}\right)^{1/4}$$

$$N_d = d_h\left(\frac{\rho_L g}{\sigma}\right)^{1/2}$$

$$N_\mu = \mu_L\left(\frac{g}{\rho_L \sigma^3}\right)^{1/4}$$







Calculate pressure gradient by setting

$$\rho_g = \rho_a = \rho_s$$

$$\rho_f = \rho_m^2 / \rho_s$$

$$f_{Ds} = f_D(N_{\mathrm{Re}}) \text{ where } N_{\mathrm{Re}} = \rho_s v_m d_h \Big/ \left(\mu_L^{H_L} \mu_g^{1-H_L}\right)$$

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Correlations—Hagedorn and Brown

- It's common to apply a modification to the original Hagedorn and Brown when bubble flow occurs. The modification follows the suggested calculation by Griffith.

Bubble flow occurs when

$$1 - C_L < \max\left\{1.071 - 0.2218\frac{v_m^2}{d_h},\ 0.13\right\}$$

Calculate liquid hold-up by

$$H_L = -\frac{v_m - v_s + \sqrt{(v_m - v_s)^2 + 4v_s v_L}}{2v_s}$$

$$v_s = 0.8 \text{ ft/s}$$

Calculate the pressure gradient by setting

$$\rho_g = \rho_a = \rho_s$$

$$\rho_f = \rho_L$$

$$v_m = v_L$$

$$f_{Ds} = f_D(N_{\mathrm{Re}}) \text{ where } N_{\mathrm{Re}} = \rho_L v_L d_h / \mu_L$$

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Correlations—Beggs and Brill

- Beggs and Brill (1973)
- Relies on calculating the liquid hold-up for horizontal flow, and then correcting it by inclination.

$$\frac{H_L(\phi)}{H_L(0)} = \psi$$

- Both the horizontal liquid hold-up and the inclination correction factor are functions of flow regime.

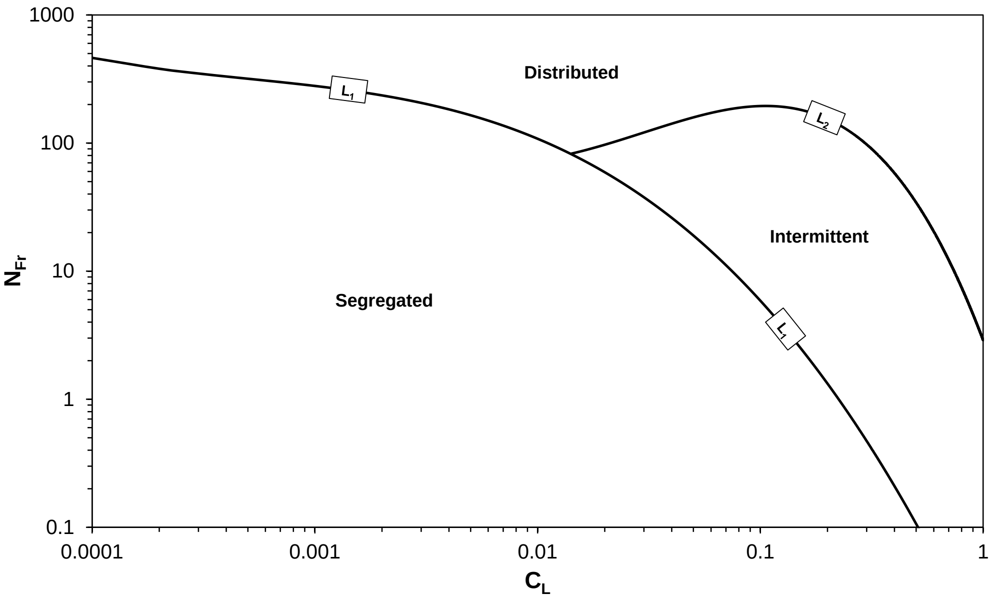
$$H_L(0) = AC_L^{\alpha} N_{Fr}^{\beta} \qquad \psi = 1 + \left[(1 - C_L)\ln\left(DC_L{}^{\delta} N_{Fr}^{\varepsilon} N_{Lv}^{\varsigma}\right)\right]\left(\sin(\phi) - \frac{1}{3}\sin(\phi)^3\right)$$

	A	α	β	D	δ	ε	ζ
Segregated	0.98	0.4846	-0.0868	0.011	-3.768	-1.614	3.539
Intermittent	0.845	0.5351	-0.0173	2.96	0.305	0.0978	-0.4479
Distributed	1.065	0.5824	-0.0609	1	0	0	0

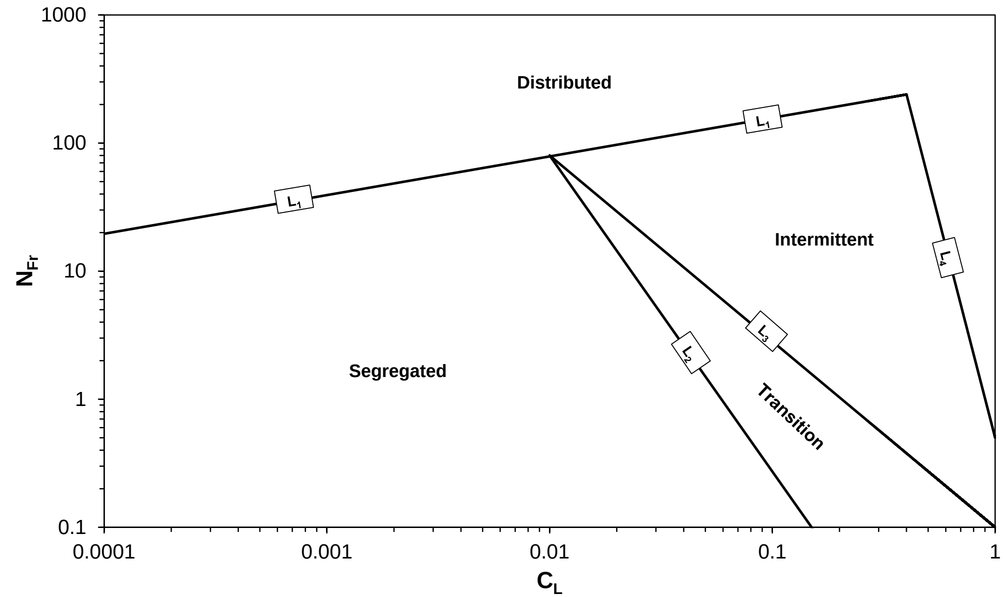
Correlations—Beggs and Brill

- Flow-regime map in the original paper is replaced by a later suggested map that includes "transition" flow.

Original Flow Map



Revised Flow Map



$$N_{Fr} = \frac{v_m^2}{g d_h}$$ Froude Number

Correlations—Beggs and Brill

- Friction factor is corrected to account for multiphase flow

$$\frac{f_{Ds}}{f_D} = e^S$$

where S is a function of $H_L(\phi)$.

Calculate the pressure gradient by setting:

$$\rho_g = \rho_a = \rho_s$$

$$\rho_f = \rho_m$$

$f_D(N_{\mathrm{Re}})$ where $N_{\mathrm{Re}} = \rho_m v_m d_h / \mu_m$

Correlations—Gray

- Gray (1971)
  - Published in *User's Manual for API 14B SCSSV Sizing Computer Program*
- Assumes mist flow in well → Only applicable in gas wells
- Corrects the friction term by using an effective roughness that reflects liquid adhering to the pipe wall.

Calculate the pressure gradient by setting:

$$\rho_g = \rho_a = \rho_s$$

$$\rho_f = \rho_m$$

$f_{Ds} = f_D(N_{\mathrm{Re}})$ where $N_{\mathrm{Re}} = \rho_m v_m d_h / \mu_m$ and k_{eff} / d_h instead of k/d_h

Correlations—Woldesemayat and Ghajar

- Woldesemayat and Ghajar (2007)
- Correlation based on an extensive review of correlations and data for inclined pipe flow.

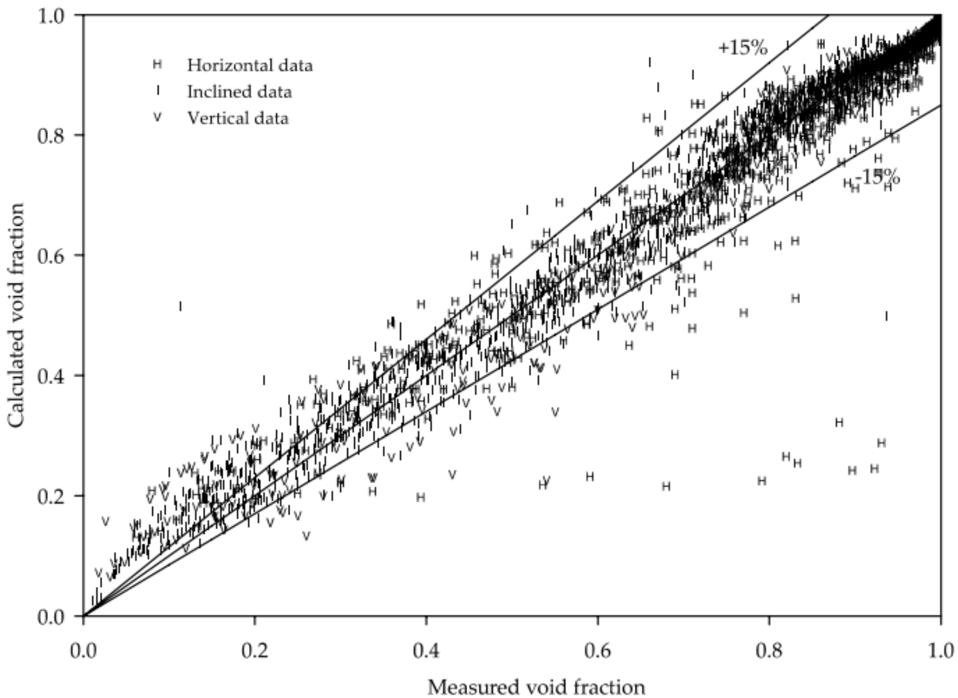


Fig. 7. Comparison of present study correlation with measured combined total experimental data.

Calculate the pressure gradient by setting:

$$\rho_g = \rho_a = \rho_f = \rho_s$$

$$f_D(N_{\mathrm{Re}}) \text{ where } N_{\mathrm{Re}} = \rho_s v_m d_h / \mu_s$$

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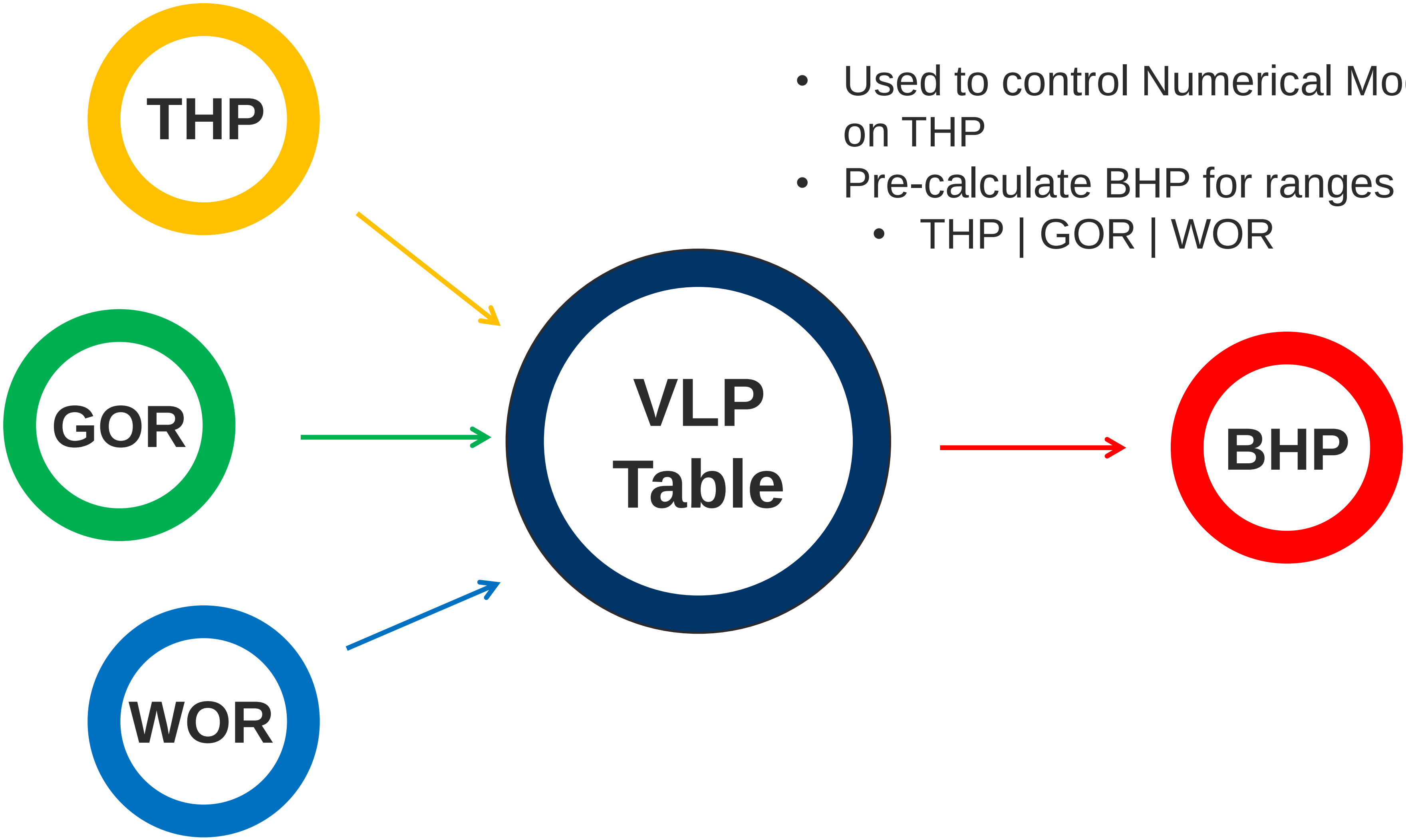
Tubing Tables / VLP in Numerical Model

Vertical Lift Performance Tables

“Tubing Tables”

- Used to control Numerical Model on THP
- Pre-calculate BHP for ranges of
  - THP | GOR | WOR



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